HOPE CREEK GENERATING STATION

INDIVIDUAL PLANT EXAMINATION

Public Service Electric and Gas Company
April 1994

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ACKNOWLEDGMENTS

Although it was the policy of Public Service Electric and Gas Company to use its employees throughout the Individual Plant Examination (IPE), technical support was supplied by various recognized experts and firms. The following are recognized for their efforts with the Hope Creek Generating Station (HCGS) IPE:

SAIC provided technical direction for the updated HCGS IPE in the following areas: Event tree development, special initiating event analyses, human reliability analysis, and cutset editing and analysis. SAIC also performed an HCGS-specific containment bypass analysis and provided technical expertise and training for the HCGS back-end analysis.

Halliburton NUS provided training and the primary leadership for the baseline quantification tasks.

Gabor, Kenton and Associates reviewed a portion of the MAAP parameter file.

ERIN provided the primary leadership and performed evaluations for the plant-specific Interfacing System LOCA analysis.

ABB Impell performed an HCGS-specific containment capacity analysis.

Reliability And Performance Associates provided technical direction for the independent review of the HCGS IPE.

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ACRONYM LIST

AB	Auxiliary Building
AC	Alternating Current
ACP	Alternating Current Power
ADS	Automatic Depressurization System
AOV	Air Operated Valve
APRM	Average Power Range Monitor
ARI	Alternate Rod Injection
ASME	American Society of Mechanical Engineers
ATWS	Anticipated Transient Without Scram
BHP	Brake Horsepower
BOP	Balance of Plant
BWR	Boiling Water Reactor
CAC	Containment Atmosphere Control
CACHS	Control Area Chilled Water System
CCI	Core Concrete Interaction
CD	Core Damage
CDF	Core Damage Frequency
CET	Containment Event Tree
CFE	Early Containment Failure
CFL	Late Containment Failure
CHS	Chilled Water System
CIG	Containment Instrument Gas
CNS	Condensate System
CPCS	Containment Prepurge Cleanup System
CRD	Control Rod Drive
CRIDS	Control Room Integrated Display System
CRW	Clear Radwaste
CSC	Containment Spray Cooling
CSS	Core Spray System
CST	Condensate Storage Tank
DC	Direct Current
DCH	Direct Containment Heating
DDFP	Diesel Driven Fire Pump
DF	Decontamination Factor
DGAV	Diesel Generator Area Ventillation
DGS	Diesel Generator System
DP	Differential Pressure
DRW	Dirty Radwaste
E1	Early, High Release
E2	Early, Medium-High Release
E3	Early, Medium Release
E4	Early, Low Release

ACRONYM LIST (Continued)

EACS	Equipment Area Cooling System
ECCS	Emergency Core Cooling Systems
EDG	Emergency Diesel Generator
EHC	Electrohydraulic Control
EIAC	Emergency Instrument Air Compressor
EOP	Emergency Operating Procedure
EPG	Emergency Procedure Guidelines
EPRI	Electric Power Research Institute
ESF	Engineered Safety Features
FCI	Fuel Coolant Interaction
FO	Fail-Open
FPR	Fission Product Retention
FPS	Fire Protection System
FRVS	Filtration, Recirculation and Ventilation System
FSAR	Final Safety Analysis Report
FWS	Feedwater System
GPM	Gallons Per Minute
GSI	Generic Safety Issue
H	Hours
HCGS	Hope Creek Generating Station
HCLPF	High Confidence of Low Probability of Failure
HCTL	Heat Capacity Temperature Limit
HCU	Hydraulic Control Unit
HEP	Human Error Probability
HEPA	High Efficiency Particulate Air
HPCI	High Pressure Coolant Injection
HPME	High Pressure Melt Ejection
HRA	Human Reliability Analysis
HVAC	Heating, Ventilation and Air Conditioning
HX	Heat Exchanger
IAS	Instrument Air System
ID	Inside Diameter
IEEE	Institute of Electrical and Electronic Engineers
IGS	Instrument Gas System
IICS	Intercooler and Injector Cooling System
ILRT	Integrated Leak Rate Testing
INPO	Institute of Nuclear Power Operations
IORV	Inadvertent Opening of a Relief Valve
IPE	Individual Plant Examination
IPEEE	Individual Plant Examination for External Events
IPRDS	In-Plant Reliability Data Base
IREP	Interim Reliability Evaluation Program
ISLOCA	Interfacing System Loss of Coolant Accident
JCO	Justification for Continuation of Operation
JWCS	Jacket Water Cooling System

ACRONYM LIST (Continued)

KV	Kilovolt
KVAC	Kilovolts Alternating Current
L1	Late, High Release
L2	Late, Medium-High Release
L3	Late, Medium Release
L4	Late, Low Release
L5	Low, Low Release
LCO	Limiting Condition of Operation
LER	Licensee Event Report
LO	Locked Open
LOCA	Loss of Coolant Accident
LOP	Loss of Offsite Power
LOS	Lubricating Oil System
LPCI	Low Pressure Coolant Injection
LT-SBO	Long Term Station Blackout
MAAP	Modular Accident Analysis Program
MCC	Motor Control Center
MCCI	Molten Core Concrete Interaction
MDFP	Motor Driven Fire Pump
MGL	Multiple Greek Letter
MOP	Motor Operated Potentiometer
MOV	Motor Operated Valve
MSIV	Main Steam Isolation Valves
MSL	Mean Sea Level
MSS	Main Steam System
MW	Megawatt
NPRDS	Nuclear Power Reliability Data System
NPSH	Net Positive Suction Head
NRC	Nuclear Regulatory Commission
NSAC	Nuclear Safety Analysis Center
NSSS	Nuclear Steam Supply System
P&ID	Piping and Instrumentation Diagram
PCIG	Primary Containment Instrument Gas
PCPL	Primary Containment Pressure Limit
PCS	Power Conversion System
PDS	Plant Damage State
PJM	Pennsylvania - Jersey - Maryland
PRA	Probabilistic Risk Assessment
PSE&G	Public Service Electric and Gas Company
PSF	Performance Shaping Factor
PSID	Pounds per Square Inch - Differential
PSIG	Pounds per Square Inch - Gauge
PWR	Pressurized Water Reactor
RACS	Reactor Auxiliaries Cooling System
RALOS	Rocker Arm Lube Oil System

ACRONYM LIST (Continued)

RB	Reactor Building
RBVS	Reactor Building Ventilation System
RCIC	Reactor Core Isolation Cooling
RCS	Reactor Coolant System
RF	Range Factor, Release Fraction
RFP	Reactor Feed Pump
RFPT	Reactor Feed Pump Turbine
RFS	Reactor Feedwater System
RFW	Reactor Feedwater
RHR	Residual Heat Removal
RMIEP	Risk Methods Integration and Evaluation Program
RPV	Reactor Pressure Vessel
RPT	Recirculation Pump Trip
RRCS	Redundant Reactivity Control System
RWCU	Reactor Water Clean Up
SACS	Safety Auxiliaries Cooling System
SBO	Station Blackout
SCFM	Standard Cubic Feet per Minute
SDC	Shutdown Cooling
SDV	Scram Discharge Valve
SGTS	Standby Gas Treatment System
SHARP	Systematic Human Action Reliability Procedure
SJAE	Steam Jet Air Ejector
SLC	Standby Liquid Control
SORV	Stuck Open Relief Valve
SOV	Solenoid Operated Valve
SPC	Suppression Pool Cooling
SPCHS	Safety Panel Chilled Water System
SPE	Steam Packing Exhauster
SRCS	Switchgear Room Cooling System
SRO	Senior Reactor Operator
SRV	Safety Relief Valve
SSW	Station Service Water
SSWS	Station Service Water System
ST-SBO	Short Term Station Blackout
STA	Shift Technical Advisor
SWBAY	Service Water Bay
T	Time
TACS	Turbine Auxiliaries Cooling System
TAF	Top of Active Fuel
TCV	Turbine Control Valve
THERP	Technique for Human Error Rate Prediction
TIP	Transverse Incore Probe
TM	Test and Maintenance
TS	Technical Specifications

ACRONYM LIST (Continued)

TSC	Technical Support Center
TW	Loss of Decay Heat Removal
UFSAR	Updated Final Safety Analysis Report
UPS	Uninterruptable Power Supply
UR	Unreliability
USI	Unresolved Safety Issue
V	Volts
VAC	Volts Alternating Current
VC	Valve Closed
VDC	Volts Direct Current
VF	Vessel Failure
VO	Valve Open

1.0 EXECUTIVE SUMMARY

This report documents the Individual Plant Examination (IPE) for Severe Accident Vulnerabilities performed on the Hope Creek Generating Station (HCGS).

1.1 Background And Objectives

The HCGS IPE report was prepared in accordance with the United States Nuclear Regulatory Commission's (NRC's) Generic Letter GL 88-20 (Reference 1-1) and the submittal guidance furnished in NUREG-1335 (Reference 1-2). The NRC referenced several NRC and industry reports (References 1-3 through 1-13) in NUREG-1335 (Reference 1-2) that provide perspective and background for specific IPE tasks. The NRC requested (Reference 1-1) that the HCGS IPE determine vulnerabilities to severe accidents and cost-effective safety improvements that could reduce or eliminate the important vulnerabilities.

This IPE is an integrated systematic examination of the HCGS for plant specific risk contributors. The HCGS IPE objectives are:

1. Develop an overall appreciation of severe accident behavior.
2. Develop a clear understanding of the more likely severe accident sequences for the HCGS.
3. Gain a qualitative and quantitative understanding of core damage and radioactive material releases.
4. Generate an accurate baseline assessment of core damage frequency for the HCGS.
5. Develop methods and models necessary for safety and economic evaluations of planned plant improvements.
6. Increase PSE&G's capability to perform and maintain Probabilistic Risk Assessments independently.
7. If necessary, reduce the overall probability of core damage and radioactive material release by appropriate modifications to procedures, software and hardware that would assist in prevention of severe accidents or in mitigation of their effects.

Generic Letter GL 88-20 identifies three approaches for performing the IPE:

1. A Level I Probabilistic Risk Assessment (PRA) plus a containment performance analysis, based upon the current design, that addresses severe accident phenomenological issues.
2. The IDCOR system analysis methods.

3. Other system examination methods acceptable to the NRC staff.

PSE&G's IPE is based upon a PRA approach (Level I and II). The small event tree and large fault tree methodology is used in the HCGS PRAs. The Level I PRA examines core damage vulnerabilities. It was updated using procedures presented in NUREG/CR-2300 (Reference 1-5) to provide for its integration with the back-end (Level 2 PRA) analysis. The Level II PRA examines fission product release from the containment. The Level II PRA examines severe accident phenomenological issues and is based on the guidelines set forth in NSAC-159 (Reference 1-14).

The PRA approach was chosen because it provides models which can be revised to incorporate design, operational, procedural and phenomenological updates. PSE&G has developed a Programmatic Standard (Reference 1-15) to update the HCGS PRA as required to support operations, design changes, and severe accident management planning. PSE&G has the trained staff and necessary computer software to effectively implement this program onsite.

1.2 Plant Familiarization

The HCGS is owned* and operated by PSE&G. The station is located on the southern part of Artificial Island on the east bank of the Delaware River in Lower Alloways Creek Township, Salem County, New Jersey.

The site is located approximately 15 miles south of the Delaware Memorial Bridge, 18 miles south of Wilmington, Delaware, 30 miles southwest of Philadelphia, Pennsylvania, and 7.5 miles southwest of Salem, New Jersey. The station is located on approximately 300 acres of a 700 acre site owned by PSE&G. Artificial Island is also the site of the Salem 1 and 2 generating stations. Figure 1-1 shows the geographic location of Artificial Island, and Figure 1-2 shows an overall view of the plant.

The HCGS employs a General Electric boiling water reactor (BWR/4) and is operated at a core thermal power of 3293 MW (100% steam flow) with a gross electrical output of approximately 1118 MWe and net electrical output of approximately 1067 MWe.

The HCGS dual barrier containment system consists of a pressure suppression primary containment system and a secondary containment system consisting of a dome-shaped reactor building.

The reactor building (or secondary containment) is a concrete-reinforced structure which houses the primary containment system, and the fuel storage area. It is capable of containing any radioactive materials released into it subsequent to a design basis loss of coolant accident (LOCA) so that offsite doses remain below 10CFR100 requirements. Figure 1-3 shows the HCGS primary and secondary containments. The HCGS reactor building is equipped with blowout panels to limit internal pressures during specific accidents. The primary containment system consists of a drywell housing the reactor and a suppression pool. There are vacuum

* Atlantic Electric owns 5% of HCGS

breakers between the suppression pool and drywell (eight - one in each vent pipe), and between the reactor building and suppression pool (two pairs) to ensure integrity of the primary containment.

The Emergency Core Cooling Systems (ECCSs) at the HCGS are similar to the ones used in the NUREG-1150 reference plant, Peach Bottom Atomic Power Station (PBAPS) (Reference 1-16). A brief explanation of some important safety systems and certain plant-specific designs, features, and procedures follows:

1. There are four Residual Heat Removal (RHR) subsystems with one pump in each loop and one heat exchanger in two of the four loops. Loop "B" of RHR can be operated in the shutdown cooling (SDC) mode via the remote shutdown panel. The four primary modes of the RHR system are: 1) to provide Low Pressure Coolant Injection (LPCI), 2) to provide Suppression Pool Cooling, 3) to provide Shutdown Cooling, and 4) to provide a Containment Spray. Procedures for using the Reactor Water Cleanup (RWCU) system for decay heat removal are in place, although no credit has been taken for them in the IPE.

2. The HCGS is equipped with two high pressure steam driven pumps: The High Pressure Coolant Injection (HPCI) and the Reactor Core Isolation Cooling (RCIC) pumps. The turbine of each of these pumps exhausts into the torus. The HPCI and RCIC pumps trip when the torus pressure (turbine exhaust pressure) exceeds 140.0 PSIG and 25 PSIG, respectively. The (HPCI) system injects 3000 gpm through the Feedwater system and 2600 gpm through the Core Spray (CS) system sparger. RCIC injects 600 gpm through the Feedwater System.

3. The Core Spray System (CSS) has two loops with two pumps in each loop. The CSS pumps take their suctions from the torus; however, they can be manually aligned to take suction from the Condensate Storage Tank (CST). The CSS Loop A spray spargers are shared with HPCI and Standby Liquid Control (SLC).

4. The Automatic Depressurization System (ADS) is an ECCS utilizing five of 14 Target Rock Safety Relief Valves (SRVs).

5. The Standby Liquid Control (SLC) system injects to the vessel automatically when initiated by the Redundant Reactivity Control system (RRCS) in response to Anticipated Transient Without Scram (ATWS) scenarios. It can also be initiated manually.

6. There are four Emergency Diesel Generators (EDGs) at the HCGS.

7. There is a connection point at RHR Loop B for Station Service Water (SSW) System injection or containment flooding. In addition, both the diesel-driven and motor-driven fire pumps can be connected to the RHR system to provide additional alternate methods of injection to the RPV. Loop B of the RHR system can divert flow to the reactor vessel head spray line.

8. The HCGS is equipped with a twelve-inch hard pipe vent which originates from the top of the torus. This vent can be opened remotely from the control room with battery power. The vent can also be operated locally, in the absence of any electric power. HCGS is also equipped with a six-inch hard pipe vent, which is used for Integrated Leak Rate Testing (ILRT). Some credit is given to this pipe for containment venting through both the drywell and the torus. The HCGS is also equipped with ducts, which can be used for venting; however, no credit is taken for them in the IPE.

9. There are three trains of feedwater/condensate, each containing one feedwater pump, one secondary pump and one primary condensate pump in series, which can inject to the vessel.

10. The Control Rod Drive (CRD) pumps are powered by the Class 1E electrical buses, through two in-series breakers (one Class 1E and one non-Class 1E). Upon receipt of a LOCA signal, the Class 1E breaker trips and the non-Class 1E breaker opens on undervoltage.

11. The blowout panels in various locations of the reactor building protect the primary containment against high external pressure.

12. The HCGS primary containment has an internal design pressure of 56.0 PSIG, a maximum calculated internal design pressure of 58.0 PSIG with an allowable maximum internal design pressure of 62.0 PSIG (110 percent of design pressure based on the ASME code). The primary containment maximum external design pressure is 3 PSID, and its design temperature is 340°F.

13. The Emergency Operating Procedures (EOPs) are based on Revision 4 of the Boiling Water Reactor Owner's Group (BWROG) Emergency Procedure Guidelines (EPGs) (Reference 1-23).

Plant walkdowns constituted an important part of the plant familiarization effort. Plant walkdowns were performed by the PRA analyst assigned to the individual system in all cases. When information from various data sources, such as drawings or specifications, could not be independently confirmed, it was supplemented by HCGS SROs, system engineers, or other cognizant engineering personnel. Plant system engineers and other engineering personnel are intimately familiar with the plant configuration and continually perform "walkdowns" as part of their daily responsibilities. Both system engineers and senior reactor operators (SROs) performed detailed reviews of all plant system and accident sequence models. The walkdown process became more formalized for the Level II portion of the IPE.

1.3 Overall Methodology

1.3.1 Introduction

The application of probabilistic risk assessment (PRA) to the evaluation of reactor systems provides a method of estimating the likelihood of undesired events such as core melt and radionuclide release and of determining their consequences. The methodology used in the HCGS study employed fault trees and event trees in a manner similar to the approach used in the Reactor Safety Study (Reference 1-18) and the NRC sponsored Interim Reliability Evaluation Program (IREP). Fault trees are a set of logic diagrams describing potential hardware failure modes, software errors, and human errors that could disable a system or group of systems. These logic diagrams are evaluated numerically by available computer programs. The analysis begins with the definition of accident sequences and the selection of accident initiators. The "defense-in-depth" concept used in U. S. nuclear plant design makes it very probable that any given accident sequence will be prevented or terminated before it can cause an undesired event, such as core damage.

The complexity of systems used in nuclear plants necessitates diagrams which show the progression of accident sequences. These diagrams are called event trees. The quantification of accident sequences depends on the probabilities at each decision point in the event tree. The probabilities at the decision points (nodes) of the event trees are determined using fault trees prepared to model the system, software, and human reliabilities. Component failure rates, human error rates, and software error rates are obtained from a database using plant specific and generic data. Event tree and fault tree analyses constitute a formalized deductive technique which provides a systematic approach to investigating possible modes of occurrence of an undesired event. The fault tree model of a plant or system has been used as a logical method of displaying and quantifying component and system inter-relationships.

The methodology used to perform the HCGS IPE consisted of a Level I PRA, for front-end analysis, and a Level II PRA for the back-end analysis. This methodology and the resultant submittal fully complies with the requirements of GL 88-20 (Reference 1-1) and NUREG-1335 (Reference 1-2). The HCGS Level I PRA is based upon the large fault tree/small event tree approach of NUREG/CR-2300 (Reference 1-5). The HCGS Level II PRA is based on the methodology described to NSAC-159 (Reference 1-14).

1.3.2 Front-End Analysis

In the HCGS Level I PRA, system level fault trees, in response to potential initiating events, are used to quantify the individual system unavailabilities. The fault tree models include:

- Hardware failures
- Software errors
- Human errors (e.g., operations and maintenance)
- Dependent failures (e.g., cascade and common mode failures)
- Unavailability due to test and corrective or preventative maintenance
- Flow diversion
- Support Systems

The event trees are used to define the principal accident sequences to be evaluated. In the event tree process, all safety functions which are required to mitigate an event are identified.

The systems capable of accomplishing those safety functions are identified as the event tree headings. Functional fault trees of each system provide the integration of systems for the quantification of event tree nodes.

Various tasks involved in the analysis are listed below, and their interrelationships are shown in Figure 1-4.

- Plant familiarization
- Initiating event identification and quantification
- Event tree development
- Fault tree development
- Dependent failure analysis
- Human reliability analysis
- Data development, based on current industry data and plant-specific data
- System quantification
- Accident sequence (core damage) quantification
- External and spatially-dependent internal event analysis (focusing on internal floods)
- Uncertainty and sensitivity (including importance calculations) analysis

1.3.3 Back-End Analysis

The HCGS Level II PRA uses logic models in the form of linked event trees integrated in a large Containment Event Tree (CET) to display the logic. The term "linked" means that there are common events among the trees. This methodology is consistent with the Electric Power Research Institute (EPRI) Generic Methodology [Generic Framework for Back-End (Level II) Analysis], NSAC-159 (Reference 1-14).

The software used for the CET analysis was the EVNTRE code (Reference 1-17).

The HCGS CET utilizes various questions which are, for the most part, common to all Plant Damage States (PDS). Split fractions are assigned to each question based on:

- Plant data
- Hand calculations
- Severe accident analysis
- Engineering judgment and experts' opinions
- The severe accident phenomenological issues documented in NUREG-1150 (Reference 1-16), NUREG/CR-4551 (Reference 1-20), and NUREG/CR-5331 (Reference 1-21).

The code used for severe accident analysis was the Modular Accident Analysis Program (MAAP) (Reference 1-22) Version 3.0B, Revision 8.1. This code is used for predicting the timing of the thermal hydraulics parameters, such as pressure and temperature rise. It is also used to determine the Decontamination Factors (DF) and Release Fractions (RF) in the containment. Selected outputs from MAAP are inserted into the HCGS CET to predict the release category.

A source term algorithm is incorporated into the CET to determine the release fractions of the key radionuclide groups for each PDS. The five radionuclide groups evaluated in the HCGS IPE are (1) Noble gases, (2) Iodine, (3) Cesium, (4) Tellurium, and (5) Strontium. This algorithm estimates source terms based upon sequence-dependent RFs and DFs input. Through a careful selection and detailed examination of the top events in the CET, insight is gained on many variables including:

- Reactor Depressurization (DP)
- Early Reactor Injection (INJ)
- Vessel Failure (VF)
- Early Containment Failure (CFE)
- Early Suppression Pool Bypass (EPOOL)
- Drywell Spray (DWSpry)
- Late Reactor Injection (L-INJ)
- Debris Coolability (DCOOL)
- Late Containment Failure (CFL)
- Late Suppression Pool Bypass (LPOOL)
- Fission Product Retention (FPR)
- Reactor Building Natural Deposition (RB)
- Containment Venting (VENT)
- Release for Five Source Terms (NG, I, Cs, Te & Sr)

1.4 Summary Of Major Findings

The Internal Events Core Damage Frequency for the HCGS is 4.58E-5/yr. This is approximately one order of magnitude higher than the reported CDFs for the NUREG-1150 studies for Peach Bottom and Grand Gulf (References 1-26 and 1-27). Major differences are attributable to differences in the data utilized in the HCGS study and the high level of detailed analysis of HCGS support systems. Loss of offsite power sequences contribute 73.8% to the CDF, while the contribution to the Peach Bottom CDF was 46.6%. The notable difference in results is derived from the conservatism in the HCGS IPE analysis with respect to the design of the SSW/SACS systems. A plan to re-evaluate this conservatism is discussed in Section 1.4.3. Transients account for a greater contribution to HCGS CDF than the Peach Bottom CDF, although this contribution is a relatively small 14.8%. Differences are attributable to the detailed modeling of HCGS support systems such as HVAC. The ATWS contribution of only 1.6% is notably smaller than the Peach Bottom contribution of 42.6%. This is attributed to HCGS's automatic Standby Liquid Control System. Special Initiators are minor contributors in both studies. Unresolved Safety Issue A-45, Decay Heat Removal Due to Internal Events, is not a concern at HCGS as evidenced by the low contribution of Loss of Decay Heat Removal sequence (1.2% to the total HCGS Internal Events CDF). The resolution of USI A-45 is presented in Section 3.4.3.

Interfacing System Loss of Coolant Accidents (ISLOCA) contribute only 1.7E-9 events/year to the HCGS CDF. This is over 4 orders of magnitude less than the internal events CDF, emphasizing its low importance. Internal flooding only contributes 5.5E-7 events/year or 1.2% of the total internal events plus internal flooding CDF.

Finally, the containment analysis indicated the capability of the HCGS containment was typical of the Mark I design, with no unique vulnerabilities.

1.4.1 Front-End Analysis

The following safety features and vulnerabilities were identified by the Hope Creek Front-End Analysis:

- Numerous room heatup calculations have demonstrated that only a few rooms are susceptible to HVAC system failures. Of the 52 rooms studied, only 12 were found to be susceptible to risk important failures. Heatup time ranged from 5 to 24 hours.

- Operator simulator observations highlighted excellent human performance reliability and PSE&G's effective operator training program.

- HCGS design substantially limits the CDF due to internal flooding to a negligible level, 5.5E-7/yr which represents the sum of all sequences.

- The contribution to the HCGS CDF due to ISLOCA sequences is nearly four orders of magnitude lower than the internal events CDF. Results of a plant-specific ISLOCA study (Reference 1-28) indicate that overpressurizations of low pressure systems outside containment are primarily dominated by hardware failures.

- The automatic initiation of the Standby Liquid Control (SLC) system by RRCS limits the ATWS contribution to only 1.6% of the internal events CDF.

- The availability of the hard pipe vent system greatly improves HCGS's ability to remove decay heat during severe accidents. This vent can be manually operated in the absence of any support systems.

- Special initiators (such as loss of the SSWS/SACS or the loss of the Instrument Air System) contribute slightly over 3% to the internal events CDF. This contribution is minimized by the high level of redundancy and separation designed into support systems at HCGS.

- The largest contribution to the internal events was over 70% from station blackout events. This results from conservative heat sink models which require two out of two SACS and SW pumps per subsystem (loop) for successful heat removal to allow for diesel generator operation. A plan to address this conservatism is suggested in Section 1.4.3.

- The only vulnerability identified at the HCGS was the inability to supply long-term cooling to critical rooms upon HVAC system failures. A risk-based procedure (Reference 1-29) has been developed to address this item and is credited in the IPE analysis.

1.4.2 Back-End Analysis

The following findings were made based on the Level II PRA:

- Due to the dominance of the long-term Station Blackout (LT-SBO) sequences, the sensitivity study showed little variation to most of the parameters considered. This was especially true of changes to engineered safety system availability. The frequency of high early and medium early releases are 9.42E-6/yr and 6.14E-6/yr, respectively.

- The results were found to be very sensitive to AC power recovery assumptions. If AC power is always recovered early, the early high release frequency decreases from 21% to 4% of the total CDF, while the late high release category decreases from 7% to 1.4%. If, on the other hand, early AC power recovery never occurs, the frequency of an early high release increases to 32% of the CDF, while the frequency of a late high release increases to 11%.

- The results were found to be relatively insensitive to the availability and use of drywell sprays. If sprays are always available, and are always used late, the frequency of the early high and medium-high release categories decrease to 18% and 7.5% (from 19% and 14%), respectively. Again, the drywell sprays are not very important because of the unavailability of AC power in many sequences. If the CDF were not dominated by SBO sequences, the sprays would be more important. However, a sensitivity analysis indicated that if the fire pumps were used for containment spray, the early high and medium high release frequencies would be significantly reduced.

- The FRVS is a system unique to the HCGS which will circulate air and filter radionuclides with high efficiency. However, the results were found to be relatively insensitive to the availability and effectiveness of the FRVS. This is due to two reasons: the high frequency of early containment ruptures (DW shell melt-through) and the lack of AC power to operate the system. The FRVS will not function if either condition occurs.

- The results were found to be sensitive to two uncertainties in ex-vessel phenomena: drywell shell melt-through and debris coolability. Both of these are related to uncertainties in the rate of heat loss from the core debris to an overlying water pool. Currently, there is significant uncertainty regarding heat transfer to the water:

    - If drywell shell melt-through is assumed not to occur, the frequency of an early release decreases significantly from 62% (some of these are early releases during venting) to 29%. Late containment failures increase as there is a greater opportunity for either late overpressure, temperature, or sump failure. In addition, the frequency of an early high and early medium-high release decreases to 8% and 4% (from 21% and 14%, respectively).

    - If the ex-vessel core debris is assumed to be coolable whenever water is present, the frequency of an early or late medium-high release goes almost to zero since sequences with uncoolable core debris and water present now have coolable debris and no releases from core-concrete interaction. These sequences are shifted primarily into the early or late low release category. The early high and late high release categories are almost unaffected by debris coolability assumptions because these high releases occur primarily in sequences without water injection.

- The core damage frequency and radionuclide release characteristics of the HCGS is expected to be improved by reducing the frequency of LT-SBO and/or increasing the probability of AC power recovery. These sequences currently dominate the CDF, the containment failure frequency, and the early high release frequency.

1.4.3 Suggestions for Plant Improvement

PSE&G will review and finalize the SACS and SSW system analysis to remove modeling conservatisms. The most notable contributors to the HCGS CDF are Loss of Offsite Power sequences ultimately leading to loss of all AC power. These sequences contribute over 70% to the CDF. In fact, the reason for this is highlighted in the Importance Results provided in Section 3.4.1.2. As presently modeled SACS and SSW system failures result in diesel generator failures. The IPE utilizes a conservative success criteria of two-out-of-two SSW and SACS subsystems being required for successful operation of the respective loop. However, yet unverified calculations indicate this underestimates the ability of these systems. To fully understand the amount of design margin in the SACS and SSW systems, PSE&G has developed a detailed model for the operation of these systems. Preliminary results indicate that, with operator intervention, each SACS loop can function with only one pump. This may potentially reduce the Station Blackout contribution by as much as 50%. Therefore, PSE&G intends to complete evaluations to define the operational margins of these support systems. PSE&G will also consider developing procedures for operating the SACS system for severe accidents (beyond design basis). Once these revisions are completed, the HCGS PRA models will be adjusted to reflect actual conditions.

1.5 References

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1-2 U.S. Nuclear Regulatory Commission, NUREG-1335, "Individual Plant Examination: Submittal Guidance," August 1989.

1-3 W. T. Pratt, "Severe Accident Insights Report" Brookhaven National Laboratory, NUREG/CR-5132, April 1988.

1-4 Brookhaven National Laboratory, "Assessment of Severe Accident Prevention and Mitigation Features" NUREG/CR-4920, Volumes 1-5, July 1988.

1-5 J. W. Hickman, "PRA Procedures Guide: A Guide to the Performance of Probabilistic Risk Assessments for Nuclear Power Plants," American Nuclear Society and Institute of Electrical and Electronic Engineers, NUREG/CR-2300, Volumes 1 and 2, January 1983.

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1-7 M. McCann et al., "Probabilistic Safety Analysis Procedures Guide," Brookhaven National Laboratory, Revision 1 to NUREG/CR-2815, Volumes 1 and 2, August 1985.

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1-9 Letter from A. Thadani, NRC, to W. Rasin, NUMARC, "Staff Evaluation of IDCOR IPEMs," dated November 22, 1988.

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1-18 "Reactor Safety Study: An Assessment of Accident Risks in U.S. Commercial Nuclear Power Plants," NRC, WASH-1400 (NUREG-75/014), October 1975.

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1-20 "Evaluation of Severe Accident Risks: Methodology for Accident Progression, Source Term, Consequence, Risk Integration, and Uncertainty Analysis," NUREG/CR-4551, Volume 1, December 1990.

1-21 "MELCOR Analysis for Accident Progression Issues," NRC, NUREG/CR 5331.

1-22 "Modular Accident Analysis Program" Version 3.0B, Revision 8.1, EFRI, 1992.

1-23 "BWROG Emergency Procedures Guidelines (EPGs)," Revision 4. NEDO-31331.

1-24 NUREG-1289 "Regulatory and Backfit Analysis: Unresolved Safety Issue A-45, Shutdown Decay Heat Removal Requirements", November 1988.

1-25 GL 89-16 "Installation of Hardened Wetwell Vent", September, 1989.

1-26 "Analysis of Core Damage Frequency: Peach Bottom, Unit 2 Internal Events." U.S.NRC, Washington DC, 1989. NUREG/CR-4550.

1-27 "Analysis of Core Damage Frequency from Internal Events: Grand Gulf, Unit 1." April 1987.

1-28 "Hope Creek Generating Station, Interfacing System LOCA Evaluation," Erin Engineering, April 1992.

1-29 HCGS Procedure No. HC.OP-AB.ZZ-0209(Q), "Loss of HVAC;" April 1994.

Figure 1-1
HCGS Site Location

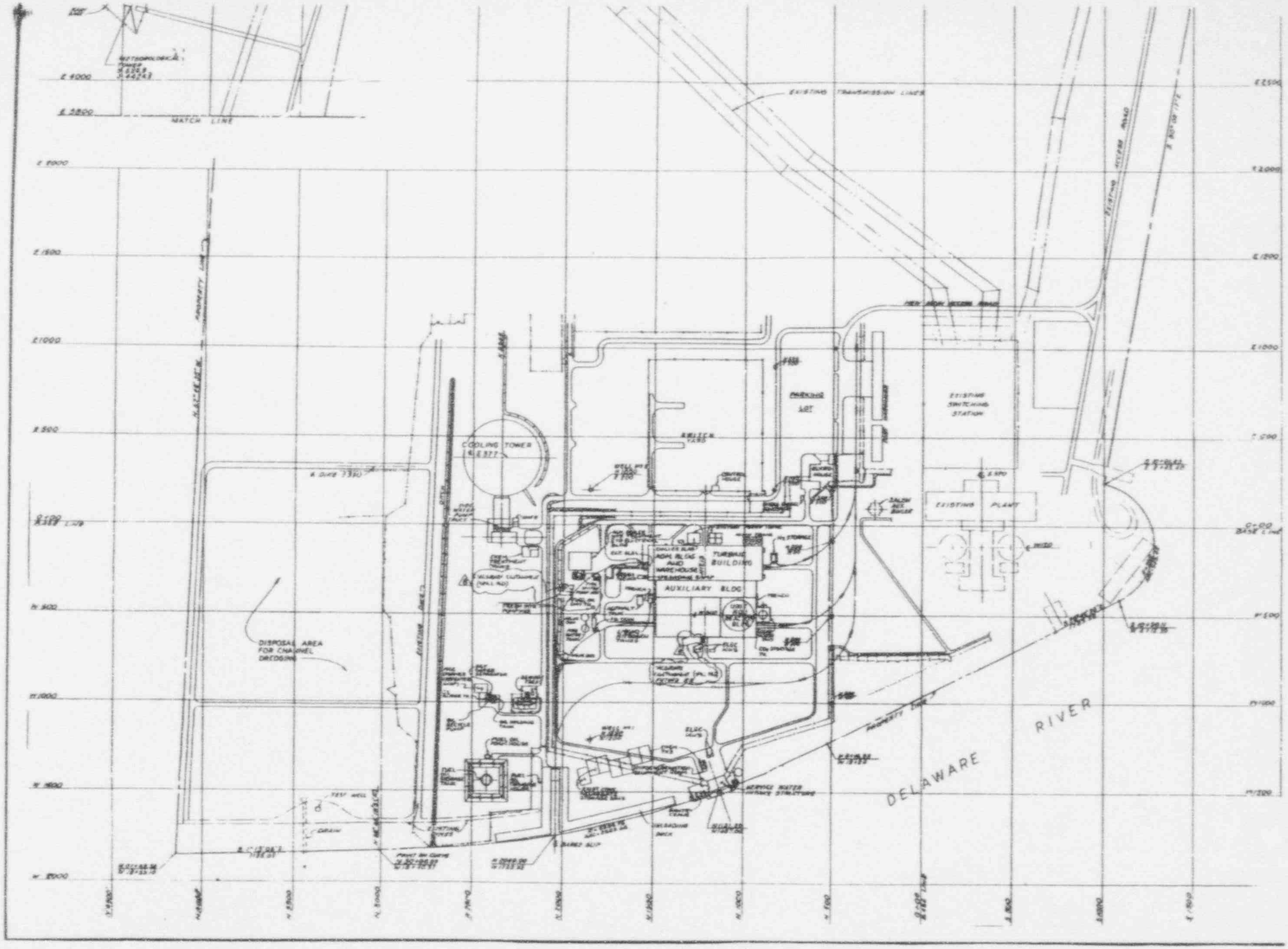

Figure 1-2
HCGS Site Building Layout

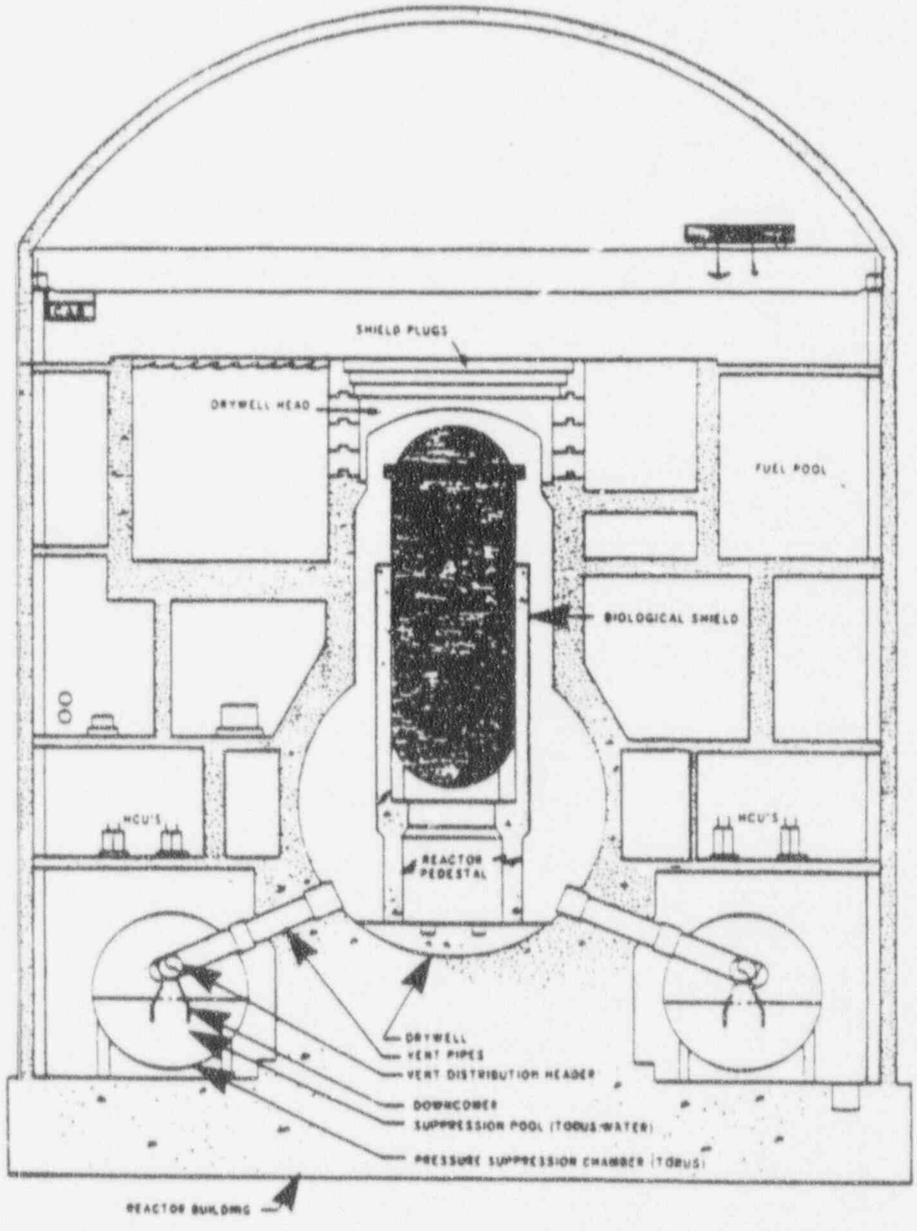

Figure 1-3
Primary And Secondary Containment Layout

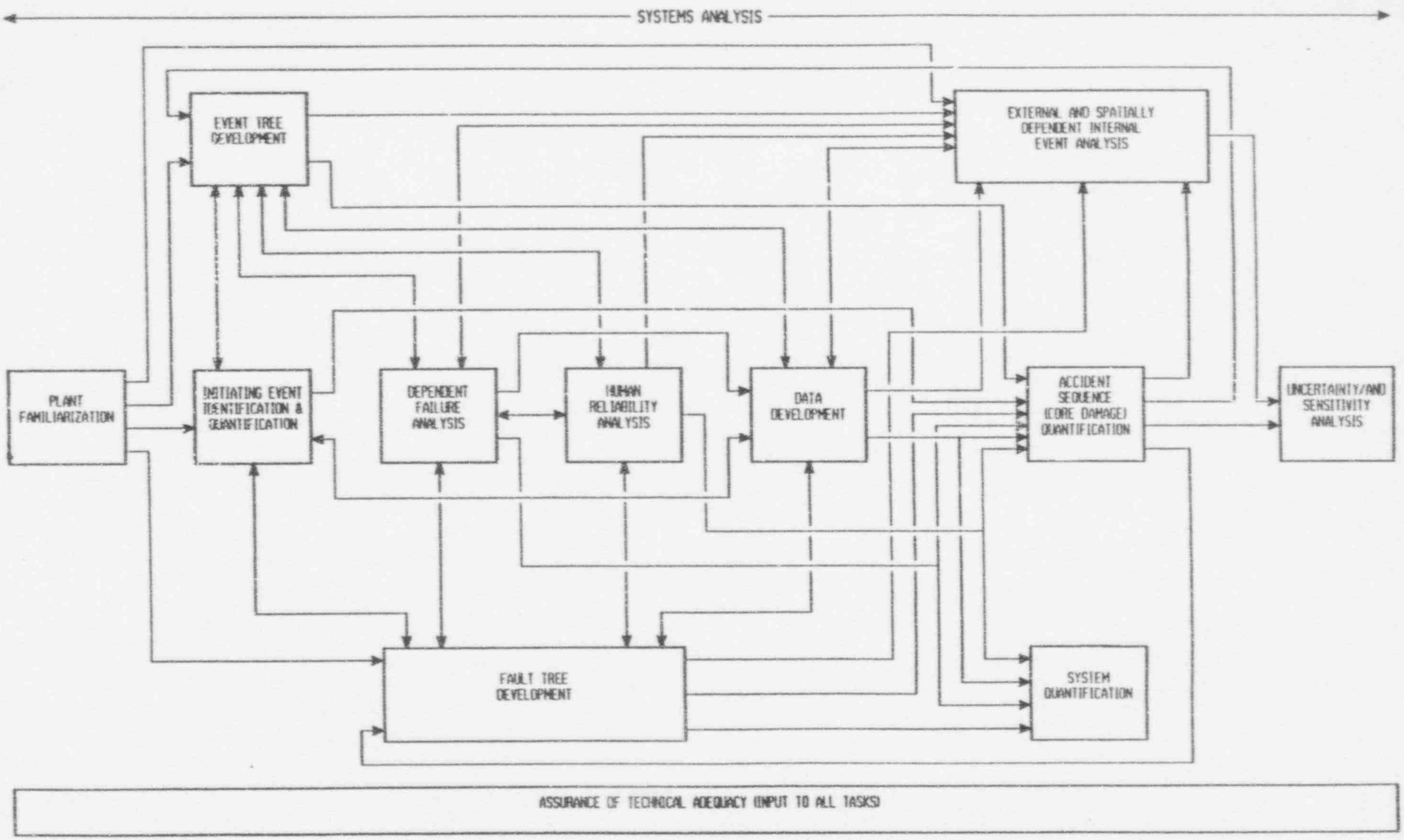

Figure 1-4
HCGS PRA Task Flowchart

2.0 EXAMINATION DESCRIPTION

2.1 INTRODUCTION

The Hope Creek Generating Station (HCGS) is operated by Public Service Electric and Gas Company (PSE&G) and is located approximately 18 miles south of Wilmington, Delaware and 30 miles southwest of Philadelphia, Pennsylvania. The HCGS employs a General Electric boiling water reactor (BWR) designed to operate at a rated core thermal power of 3,293 MWt (100% steam flow) with a gross electrical output of approximately 1,118 MWe and net electrical output of approximately 1,067 MWe. The unit uses a Mark 1 containment and a natural draft cooling tower. The HCGS began commercial operation in December 1986.

This submittal represents the first tier documentation of the Individual Plant Examination (IPE) for the HCGS. It was developed in response to GL88-20 (Reference 2-1). It provides the methodology used to perform and the results of comprehensive, plant-specific Level I and Level II Probabilistic Risk Assessments (PRAs) used to meet the front-end analysis and back-end analysis requirements of the generic letter and Unresolved Safety Issue No. USI A-45.

A PRA may be defined as a comprehensive, logical, and structured methodology that identifies and quantitatively evaluates potential significant accident sequences. The significant accident sequences of interest in this study begin with a disturbance of the plant from its initial status of steady-state power operation, followed by safety system failures and operator errors that can result in significant core damage, containment failure, or radionuclide release.

The results of the Level I PRA include an overall core damage frequency (with associated uncertainty bounds) for the HCGS, frequencies for individual core damage sequences, and combinations of component failures and human errors resulting in each core damage sequence. Both Internal Events and Internal Flooding are addressed. These results can be used to evaluate the relative safety of the plant and to help identify improvements in safety.

Furthermore, this report details a Level II PRA of the HCGS to assess the containment response to severe accidents.

The end products of the back-end analysis include: (1) a set of release categories which characterize the radionuclide releases into the environment, (2) a quantification of the mean frequency of each release category, and (3) an evaluation of the sensitivities associated with the risk dominant release categories. The release categories constitute the endpoints of the Level II PRA and provide a measure of the potential consequences of severe accidents. Another important product of the back-end analysis is the identification of individual accident sequences whose frequencies exceeded the screening frequency prescribed in NUREG-1335 (Reference 2-2). This product is especially important because it is the key to the development of insights into plant safety characteristics and will form part of the basis for accident management activities.

2.1.1 Background

Recognizing the importance of developing a plant-specific model for assessing plant risk and developing the capability to develop and manipulate risk models, PSE&G performed a Level I PRA. The initial HCGS Level I PRA was performed over an 18-month period from August 1988 through January 1990. The Internal Events Analysis was completed first so that the evaluation of Internal Flooding could benefit from the previously generated risk models. Because GL88-20 and the IPE submittal guidance in NUREG-1335 (Reference 2-2) were not issued until November 23, 1988 and August 1989 respectively, the study was performed and documented in accordance with the guidance provided in NUREG/CR-2300 (Reference 2-4) and the IREP Procedures Guide (Reference 2-5).

PSE&G responded in writing to Supplement No. 1 to GL88-20 (Reference 2-6) on November 1, 1989 (Reference 2-7). In that letter, PSE&G noted that it had initiated its PRA Program in advance of receiving IPE guidance because of its desire to produce a risk-based tool that could be used during the plant modification process and aid in the prioritization of resources. It also identified its intention to use the Level I PRA to satisfy the front-end analysis requirements of GL88-20 (Reference 2-1).

However, to provide the most current data within the IPE and for internal studies, the HCGS Level I PRA was updated. The update was initiated in August 1990 and completed by the end of the year. The scope of the update included verification that system risk models still accurately reflected current configurations, reviewing and revising scoping assumptions, adding containment isolation events, and requantifying the entire model.

After completing the update of the Level I PRA, a detailed, plant-specific assessment of risk due to Interfacing Systems Loss-of-Coolant Accidents was completed (Reference 2-8). The results of that study were integrated into the updated Level I PRA.

By the middle of 1991, work was initiated on a Level II PRA to meet the back-end analysis requirements of GL88-20 (Reference 2-1). The completion of a plant-specific, probabilistic containment capacity assessment was included within this effort (Reference 2-9).

A plant-specific analysis was undertaken in accordance with its desire to develop and maintain a state-of-the-art risk assessment. The Level II PRA was performed in accordance with the back-end analysis guidelines of NUREG-1335 (Reference 2-2) and was completed by the end of 1992.

After the completion of the original Level I PRA, risk models were used on occasion for the prioritization of resources for resolution of plant discrepancies, review of design modifications, evaluations of Technical Specifications, and in support of Justifications for Continued Operation (JCO).

An independent review of a draft version of the HCGS IPE submittal report was completed in 1993. The review identified modeling conservatisms and noted that many recent changes were made to the plant configuration which were not represented in the analysis. In Letter

No. NLR-N93-118 (Reference 2-3), PSE&G notified the NRC that the July 1993 submittal date would not be met. It stated, "... It became apparent during the review of the draft HCGS IPE by the Independent Review Team and Station personnel that the draft product did not meet our standards and that the July 1993 date was no longer attainable. It was decided that a schedule extension was necessary." A revised submittal date of April 1994 was accepted by the NRC. A recovery plan was formulated to update both Level I and II PRA models. Additionally, all system- and procedure-related modeling was reviewed by HCGS Technical Department engineers and Senior Reactor Operators to assure modeling conservatisms would be minimized. The report revisions were reviewed by the Independent Review Team and HCGS personnel throughout the recovery effort. The findings from these reviews, as well as a description of the reviews, is provided in Section 5.

The IPE submittal presents a summary of the updated Level I and II PRA analyses,along with a description of the review process, a description of insights learned through the IPE process, as well as PSE&G management plans for the future use of the HCGS PRAs, and the insights gained through the IPE process.

2.1.2 Motivation and Objectives

PSE&G's PRA program was initially motivated by the desire to have a comprehensive and structured basis to improve plant safety. This basis is needed to plan how to meet internal safety goals. Additionally, developed risk models continue to be maintained to support planned maintenance activities as well as potential severe accident management activities.

Specific objectives of the HCGS PRA program were the following:

1. Generation of an accurate baseline assessment of plant risk for the HCGS in terms of core damage frequency and release frequencies.

2. Development of methods and models that are necessary to evaluate plant improvements from safety and economic perspectives.

3. Attainment of the capability to maintain the analysis and to perform PRA evaluations independently.

In addition, it has been an immediate goal of the PRA program to fulfill the requirements of GL88-20 by performing an IPE consistent with the guidance provided in NUREG-1335 for each commercial nuclear power plant. Within that framework, PSE&G shared the following objectives of the IPE with the United States Nuclear Regulatory Commission:

1. To develop an appreciation of the behavior of potential severe accidents at the HCGS.

2. To understand the more likely severe accident sequences that could occur at the HCGS.

3. To gain a more quantitative understanding of the overall probabilities of core damage and fission product release.

4. If necessary, to reduce the overall probabilities of core damage and fission product release by modifying hardware and procedures that would help prevent or mitigate severe accidents at the HCGS.

Finally, PSE&G agrees with the statement in GL88-20 that "... The maximum benefit from the IPE would be realized if the licensee's staff were involved in all aspects of the examination to the degree that knowledge gained from the examination becomes an integral part of plant procedures and training program." Therefore, it has been an objective to involve the maximum number of PSE&G personnel in all activities associated with the IPE and to minimize the use of contractor support. Utilization of the results of the IPE in design review, procedure review, and personnel training continues to be part of the on-going PRA program maintained by PSE&G.

Compliance with the preceding objectives will be discussed in Section 2.2 and throughout this submittal.

2.1.3 Organization of HCGS IPE Submittal

As part of the NRC's submittal guidance for IPEs (Reference 2-2), a standard table of contents for the utility submittal was presented. This standard table of contents is shown as Table 2-1. The NRC's motivation for providing a standard table of contents for the utility submittal was to indicate in general terms what should be provided, especially for utilities that had not developed PRAs for their plants. The NRC has since clarified that the standard table of contents was a guide and that utilities who already possessed PRA reports for their plants, written to a different format, need not rewrite their reports to satisfy the IPE guidance. However, due to the size of the HCGS Level I PRA, it was believed that the review of the IPE would be expedited by condensing the complete Level I PRA such that information extraneous to the submittal guidance would be removed. The results of the Level II PRA are included essentially in total.

Section 1.0 follows the exact format described in the standard table of contents.

Section 2.0 has been arranged in accordance with the standard table of contents. Detailed subsections have been included to insure that all relevant information is provided and is easily identifiable.

Section 3.0 generally follows the standard table of contents with the following exceptions:

- Section 3.1.4 of the standard table of contents has been excluded because it is not applicable to the linked fault tree modeling approach. Variations in support system configurations due to initiating events are identified in the system description.

- Section 3.3.6 of the standard table of contents was omitted because support system states were not used in the quantification of the front-end analysis. Quantification of support system states does not apply to a linked fault tree (i.e. small event tree-large fault tree) methodology.

Section 4.0 provides all the data requested in the submittal guidance and follows the standard table of contents.

Section 5.0 presents the comments of the IPE Independent Review Team organized in accordance with NRC guidance, along with the responses of the PSE&G staff.

Section 6.0 describes insights from the IPE process in terms of identification of plant safety features and risk reduction suggestions.

Section 7.0 abstracts the results of the Level I and II PRAs from Sections 3.4 and 4.7.

2.1.4 Study Team and PSE&G Participation

The HCGS IPE was a cooperative effort. In accordance with the previously described objectives, PSE&G utilized contractor support to train PSE&G staff in PRA technologies with emphasis on hands-on training. This philosophy was maintained throughout the IPE process.

PSE&G provided overall coordination of the original HCGS Level I PRA from its Probabilistic Risk Assessment Group, provided engineers to support the study, performed portions of the PRA tasks, and reviewed the results. A contractor provided technical direction, PRA expertise and training, and assisted PSE&G in performing major portions of the initial analyses for the HCGS. A subcontractor provided support for human reliability analysis. As noted previously, all system and procedural models were reviewed by HCGS personnel.

Most work on the PRA was performed onsite at the HCGS. This arrangement provided easy access to the unit and to plant personnel. In addition, the onsite presence maximized the technology transfer.

A contractor provided leadership in a plant-specific containment bypass study and Level II Probabilistic Risk Assessment.

The plant-specific containment bypass analysis included Interfacing System Loss of Coolant Accidents (ISLOCA) and containment isolation failures. Although a contractor provided the primary leadership and performed all evaluations of human error, technical assistance was provided by a full-time PSE&G engineer.

The Level II PRA for the HCGS was completed with the support and the technical guidance of a contractor. PSE&G provided one full-time engineer to directly support the effort and one half-time engineer to develop and utilize a HCGS specific Modular Accident Analysis Program (MAAP) model.

The containment capacity analysis (Reference 2-9) was completed by a contractor.

2.2 CONFORMANCE WITH GENERIC LETTER 88-20 AND SUPPORTING MATERIAL

The NRC has issued GL88-20 (Reference 2-1) to all licensees holding operating licenses and construction permits for nuclear power reactor facilities. By this generic letter, the NRC has requested that each utility perform a plant-specific systematic examination of each facility's vulnerabilities to severe accidents and submit the results to the NRC. The generic letter includes several specific guidelines for performing the IPE. The sections that follow address the conformance of the HCGS IPE to each of the specific requests.

Supplement No. 1 (Reference 2-6) announced additional submittal guidance in the form of NUREG-1335 (Reference 2-2). Supplement Nos. 2 and 3 (References 2-10 and 2-11) provided insights which may be used in the IPE. Compliance with Supplement No. 1 will be addressed in Section 2.2.10. Supplements Nos. 2 and 3 are not specifically addressed, but were utilized in the completion of relevant analyses.

As requested by the NRC, PSE&G has responded to Supplement 4 of Generic Letter 88-20 (Reference 2-12) with a separate plan and schedule. This information is provided in PSE&G Letter No. NLR-N91207 (Reference 2-13). The details of the HCGS IPE of External Events are not addressed further in this report.

2.2.1 NRC Objectives/General Intent

As noted in Section 2.1.2, the purposes for performing individual plant examinations, or IPEs, are stated in the Generic Letter as follows:

1. to develop an appreciation of severe accident behavior,

2. to understand the most likely severe accident sequences that could occur,

3. to gain a more quantitative understanding of the overall probabilities of core damage and fission product releases, and

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

Within the context of the IPE, it is difficult to identify specific "proofs" that PSE&G has developed an appreciation of severe accident behavior. PSE&G has completed this plant-specific examination of the HCGS. PSE&G personnel including trainers, operators, and system engineers were involved throughout the study, as described in Section 2.1.4. A representative from the Probabilistic Risk Assessment Group has been assigned to the Emergency Response Team to provide insights into severe accident management. PSE&G has an appreciation of severe accident behavior based on plant-specific analyses relative to the HCGS. Therefore, PSE&G has met the first stated objective relative to the HCGS.

Clearly, the evaluation of core damage sequences and release scenarios with their frequencies demonstrates that PSE&G has met the second and third objectives relative to the HCGS. This information is highlighted in Sections 3.4, 4.7, 6 and 7.

With regard to the fourth stated purpose of the IPE, PSE&G has identified certain plant procedure modifications for potential risk reduction and has made progress on their implementation. Suggestions for improvement are described in Section 6 of this report. Therefore, PSE&G has met the fourth stated purpose of the IPE.

2.2.2 Examination Process

The HCGS IPE has been prepared primarily by PSE&G staff engineers knowledgeable in plant systems. PRA engineers have devoted several man-years to the IPE effort, and consultants have been used primarily for technology transfer. In addition, various portions of the HCGS IPE have been reviewed by HCGS system engineers, and various calculations and analyses which form the analytical basis for this IPE have been independently reviewed. Section 5 of this report describes the IPE independent review process. In addition, Sections 2.1.1 and 2.1.4 address the review process.

In conclusion, NRC expectations have been fully satisfied. Due to its nature, it is nearly impossible to complete a PRA without plant-specific knowledge of system configurations and operation without generating visible defects. Furthermore, the number and types of review performed give PSE&G high confidence that the HCGS IPE will provide a firm basis for Severe Accident Management as well as other plant betterment activities.

As stated in GL88-20, through participation in the IPE process, utility staff engineers are expected to:

1. examine and understand the plant emergency procedures, design, operations, maintenance, and surveillance to identify potential severe accident sequences for the plant;

2. understand the quantification of the expected sequence frequencies;

3. determine the leading contributors to core damage and unusually poor containment performance, and determine and develop an understanding for their underlying causes;

4. identify any proposed plant improvements for the prevention and mitigation of severe accidents;

5. examine each of the proposed improvements, including design changes as well as changes in maintenance, operating, and emergency procedures, surveillance, staffing, and training programs; and

6. identify which proposed improvements will be implemented and their schedule.

The first expectation has been met as a result of the plant-specific efforts completed by PSE&G personnel, such as data collection, system modeling, human error identification and quantification, and basic event and risk model quantification. Furthermore, PSE&G PRA engineers became very familiar with emergency operating procedures during the execution of both the Level I and II PRAs for the HCGS.

It has always been an objective of PSE&G to be able to modify its PRA models without the benefit of contractor support. To this end, PSE&G personnel have performed the quantification of both the Level I and Level II models. Contractors have only been used to provide instruction for sequence quantification. PSE&G fully complies with the second expectation.

Identification of leading contributors to core damage frequency and containment failure is provided in Sections 3.4 and 4.7, respectively. Important contributors are identifiable either by inspection of the cutsets or through the sensitivity and importance studies performed for both the front and back-end analyses described in this report. Therefore, PSE&G fully complies with the third expectation.

Section 6 describes the insights gained from the IPE process. It identifies safety features and a procedural modification to decrease plant risk. However, no conditions of unusually high risk of core damage nor unusually poor containment performance were identified. Therefore, PSE&G is in full compliance with the last three expectations.

2.2.3 External Events

PSE&G has included an examination of internal flooding in this IPE. The examination of externally initiated events, e.g., seismic, internal fires, high winds, external floods, and transportation accidents will be performed separately as part of the IPEEE Program. A separate schedule for completion of the IPEEE has been sent to the NRC (Reference 2-13).

As a result of performing the IPE, PSE&G has developed various information and data which will be used for the IPEEE analyses. Information obtained from plant walkdowns is expected to be directly useful in performing the IPEEE, and the plant-specific component failure rate/outage data and plant system dependency matrices may be used for IPEEE if probabilistic analyses are to be performed for any of the external events. Similarly, the accident sequence event trees, the functional fault trees and the deterministic transient analyses may also be applied to the IPEEE effort.

2.2.4 Methods of Examination

The HCGS IPE was completed utilizing the first approach described in Section 4 of GL88-20 (Reference 2-1). As described in Section 2.1.1, the original HCGS Level I PRA was performed in accordance with the instructions provided in NUREG/CR-2300 (Reference 2-4).

The HCGS Level I PRA was updated in 1990 and again in 1993 to certify that the PRA was based on the most current design.

Key tasks in the update of the HCGS Level I PRA were the following:

1. Dependency Table Development
2. Additional Plant-Specific Data Collection and Implementation
3. Review of System Models
4. Common Cause Failure Enhancement
5. Containment Isolation System Analysis
6. Human Reliability Analysis of Additional Actions
7. Investigations of Key Internal Event Contributors and Dependencies
8. Investigations of Key Internal Flooding Contributors
9. HCGS PRA Requantification
10. Revision to HCGS PRA Documentation

The back-end analysis for the HCGS IPE was completed with a Level II PRA. The NSAC-159 methodology (Reference 2-14) was used to quantify the frequency of containment failure and release. This methodology addressed all NRC guidance both in GL88-20 (Reference 2-1) and NUREG-1335 (Reference 2-2). Therefore, PSE&G has fully complied with Section 4 of the generic letter.

2.2.5 Resolution of Unreviewed/General Safety Issues

In part 5 of GL88-20 (Reference 2-1), the NRC suggests that Unresolved Safety Issue (USI) A-45, entitled "Shutdown Decay Heat Removal Requirements," be addressed as part of the IPE. PSE&G's analysis of decay heat removal capability is contained in Section 3.4.4 of this report. Section 6 also provides a discussion of vulnerabilities and safety features including any which may be related to decay heat removal. PSE&G has reviewed Appendix 5 of the generic letter. As suggested in the Appendix, special attention was given to the modeling of human errors. Therefore, PSE&G has responded to USI A-45 via this IPE submittal.

2.2.6 PRA Benefits

As described in Section 2.1.2, PSE&G initiated the first HCGS Level I PRA prior to the issuance of GL88-20 (Reference 2-1). PSE&G had already identified PRA as the centerpiece of various plant improvement activities. The studies which supported the IPE process will provide further benefit in the form of a sound technological base for plant betterment activities, which may improve the overall cost-effectiveness of plant operation. Current PRA uses consist of the following:

- Development of a risk-based method of evaluating proposed design changes and reviewing Design Change Packages.
- Development of a method for improving technical specifications from the perspectives of safety, plant availability, and ease of operation.
- Assistance to the ongoing Maintenance Rule Program by providing models and data.
- Assistance in the resolution of other USIs and Generic Safety Issues (GSIs).
- Assistance in developing JCO letters and miscellaneous licensing documentation to support plant operation.
- Review and prioritization of plant discrepancies.

PRA is a permanent part of HCGS Engineering and Operations.

2.2.7 Severe Accident Sequence Screening

Appendix 2 of the Generic Letter provides a list of screening criteria for assessing dominant sequences for IPE reporting. The review of the accident sequences for the HCGS against these criteria are contained in Section 4.

2.2.8 Use of IPE Results

Part 8 of GL88-20 states the NRC's expectation that licensees will "move expeditiously to correct any identified vulnerabilities that it determines warrant correction." Section 3.4 of this submittal provides a description of implemented changes, and Section 6.0 provides suggestions for future activities.

2.2.9 Documentation of IPE Results

The documentation of the HCGS IPE conforms to the "two-tier" approach recommended in the GL. This IPE report represents the first tier, and the numerous recorded calculation packages retained by PSE&G are the second tier of documentation.

For the original HCGS Level I PRA all of the documentation listed in Appendix 4 has been developed and maintained except walkdown reports. Because the PRA was initiated prior to the issuance of GL88-20, only data developed during the numerous and varied walkdowns was recorded within the system notebooks.

When the voluminous Level I PRA was updated, it was decided to maintain that document as the primary Tier-II documentation. Drawings reviewed during the update are maintained by the PRA Group in accordance with NRC direction. The PRA document is being updated to reflect the latest modeling provided in the IPE report.

For the Level II PRA, Tier-II documentation is maintained as a notebook of relevant hand calculations and data (Reference 2-15), the documentation of the containment capacity analysis (Reference 2-9), a notebook describing the HCGS MAAP parameter File (Reference 2-16), and the output of various MAAP analyses maintained on magnetic media.

2.2.10 Compliance with Submittal Format Requirements

A description of the format of this IPE submittal is provided in Section 2.1.3. As explained in that Section, only sections not relevant to the linked-fault tree modeling approach were excluded. In all other cases, the only additional changes were additions of material to expedite the review of this submittal.

2.3 GENERAL METHODOLOGY

2.3.1 Front-End Analysis

The front-end analysis portion of the Hope Creek Generating Station (HCGS) Level I probabilistic risk assessment (PRA) involved the following:

1. Plant Familiarization
2. Initiating Event Identification and Quantification
3. Event Tree Development
4. Fault Tree Development
5. Dependent Failure Analysis
6. Human Reliability Analysis
7. Data Development
8. Accident Sequence (Core Damage) Quantification
9. Internal Flooding Analysis
10. Uncertainty and Sensitivity (Including Importance Calculations) Analysis

The interrelationships of these tasks are shown in Figure 1-4. Each of these tasks is described subsequently.

2.3.1.1 Plant Familiarization

The initial systems analysis task performed for the HCGS PRA was plant familiarization. This task involved the initial familiarization of the study team with the HCGS design and documentation, including current HCGS operator lesson plans. As indicated in Figure 1-4, there were no PRA tasks that provided input to this task. However, outputs from this task were used in the initiating event identification and quantification, event tree development, fault tree development, and external and spatially dependent internal event analysis tasks.

The main result of the plant familiarization task was the identification of the systems to be modeled in the HCGS PRA and the dependencies among these systems. The systems included both frontline (coolant injection, decay heat removal, and others) and support (electrical, cooling water, and others). Tables 3.2-3 and 3.2-4 in Section 3.2.2 contain information on the dependencies between systems. Although various systems may depend on support systems such as room cooling or compressed air for certain modes of operation, for purposes of the HCGS PRA some of these dependencies did not need to be considered.

2.3.1.2 Initiating Event Identification And Quantification

Methodologies used in the initiating event analysis task may be grouped into those relating to identification and those relating to quantification. The methodology used for identification is referred to as a comprehensive engineering evaluation (Reference 2-4). Identification of initiating events was performed on both a generic and a plant-specific basis. The generic sources for initiators included the following:

1. EPRI NP-2230 (Reference 2-17)

2. NUREG/CR-3862 (Reference 2-18)

3. Licensee Event Report (LER) Search

4. Past Probabilistic Risk Assessments (PRAs)

5. The Reactor Safety Study (Reference 2-19)

Review of these sources resulted in a list of initiating events that are potentially applicable to the HCGS design.

The second step in the identification of initiating events was a detailed study of the HCGS design and experience. This step was used to identify HCGS-specific initiators not already identified in the generic review and to evaluate those initiators identified in the first step that are applicable to the HCGS. The two steps described above were applied to both the transient and the loss of coolant accident (LOCA) classes of initiators.

Various quantification methodologies were used, depending on the type of initiator. Plant-specific data were used wherever possible.

The relationship of the initiating event analysis task to other systems analysis tasks is shown in Figure 1-4. The basic input to this task was from the plant familiarization task. The event tree analysis task interacted with the initiator task. Finally, interaction also occurred with the fault tree development, database, and accident sequence quantification tasks to quantify the initiator frequencies.

Output from the initiating event analysis task, a list of initiating event categories and frequencies that are applicable to the HCGS, was input to the event tree analysis task.

2.3.1.3 Event Tree Development

In the PRA Procedures Guide (Reference 2-4), two general philosophies for development of event trees are described:

1. development of functional event trees, and

2. expansion of the functions into systems, or development of event sequence diagrams, which are then organized into event trees.

The first method is normally associated with the small event tree and large fault tree approach. This approach uses small event trees containing approximately 5 to 15 top events, resulting in possibly 50 to several hundred sequences. Accident sequences are then quantified by linking fault trees of failed systems (and accounting for system successes, whenever appropriate). The fault trees are normally large because they contain all support systems (e.g., electrical and cooling) required for operation of the system in question.

In contrast, the other general event tree development philosophy described above is normally associated with large event trees and small fault trees. Such an approach involves many more event tree top events, resulting in thousands to hundreds of thousands of accident sequences. Fault trees for this approach are normally small because support systems and dependencies with other systems are modeled separately.

The small event tree and large fault tree approach was chosen for the HCGS Level I PRA mainly for the following reasons:

1. The small event trees are relatively easy to understand and result in a small number of accident sequences.

2. Changes to event trees or fault trees to reflect system or procedure changes are easier to identify and implement.

Initiating events were identified for the HCGS. These events were then grouped into distinct categories for input to the event tree development task.

Event trees were developed by first identifying the functions that must be fulfilled to reach a stable shutdown state. In general, the functions required are similar for all initiating event categories developed into event trees. Functions of concern include reactivity control (shutdown), maintenance of primary system integrity, maintenance of primary system coolant inventory, core decay heat removal, and containment pressure and temperature control. Certain functions are broken down into early and late phases.

Several initiating event categories were developed with different philosophies. These categories are the following:

1. Loss of Instrument Air System

2. Loss of Reactor Auxiliaries Cooling System

3. Loss of Station Service Water/Station Auxiliaries Cooling System

4. Loss of Heating, Ventilation and Air Conditioning

5. Interfacing System Loss of Coolant Accident (LOCA)

6. Internal Flooding

7. Anticipated Transient Without Scram (ATWS)

Success criteria for each of the event trees for the HCGS were developed and are provided later in this report. These criteria indicate both the systems that can fulfill each function and the success criteria; e.g., one of two pumps. Success criteria were based on plant-specific thermal hydraulic models. Some success criteria are best estimates and were based on the following sources:

1. PRAs of Peach Bottom (Reference 2-20), Brunswick (Reference 2-21), Limerick (Reference 2-22), Shoreham (Reference 2-23), and Grand Gulf (Reference 2-24).

2. General Electric Boiling Water Reactor Owners Group (BWROG) "Emergency Procedure Guidelines" (Reference 2-25).

3. "Radionuclide Release Calculations for Selected Severe Accident Scenarios" (Reference 2-26).

4. HCGS Updated "Final Safety Analysis Report" (Reference 2-27).

Success criteria are discussed in detail in Section 3.1.1.4.

Actual construction of the HCGS event trees was accomplished mainly by reviewing the HCGS Emergency Operating Procedures (Reference 2-28). Event tree top events were generally placed in a temporal order. No attempt was made to minimize the number of accident sequences by reordering the top events. Reordering would make the event trees less clear. Additional sources used in the event tree construction task included the Peach Bottom, Brunswick, Limerick, Shoreham and Grand Gulf PRAs.

In general, the event trees were constructed to model accident sequences to the point at which either significant core damage occurred or a stable hot shutdown (operational condition 3) was achieved. The time required to reach a stable hot shutdown state can vary from several hours to perhaps longer than a day, depending on the initiating event and the combination of system successes and failures for each sequence. In general, a time frame of 24 hours following an initiating event was chosen for representation in the event trees.

To characterize core damage sequences for Level II analyses (core damage progression, containment response, and radionuclide behavior analyses, and containment event tree development), the containment performance model was developed in the form of linked event trees. The dependencies between the event trees that represent the different phenomena considered are fully treated. This is consistent with the EPRI Generic Methodology (Reference 2-14). However, the fault tree models for the CET top events have been replaced with event tree models. The CETs consider all of the relevant events and phenomena included in the EPRI Generic Methodology. These events and phenomena were identified based on an in-depth review of the analysis of Peach Bottom 2 (Reference 2-20). Thirteen subtrees, one supporting the quantification of each CET top event have been developed. Some of the subtrees have sub-subtrees for specific phenomena. These are discussed in Section 4. The linked subtrees (and sub-subtrees) are solved simultaneously using the EVNTRE (Reference 2-29) software.

Certain accident sequences leading to core damage can be recovered. Recovery in this sense implies regaining the use of a system or component that was initially unavailable or bypassing a failed system or component such that core damage is averted. Some recovery actions may be modeled in the system fault trees; others might be shown explicitly in the event trees, while the remainder can be added to core damage sequence cutsets in the quantification task. In general, component-level recoveries that are described clearly in the Emergency Operating Procedures and can be performed from the control room were modeled in the system fault trees. Most system-level recovery events were modeled in the event trees. Component-level recoveries performed outside the control room and certain system-level recoveries were applied in the quantification task.

The relationship of the initiating event analysis task to other systems analysis tasks is shown in Figure 1-4. The basic input to this task was from the plant familiarization task. The event tree analysis task interacted with the initiator task.

2.3.1.4 Fault Tree Development

The purpose of the HCGS PRA fault tree development task was to identify and model failures of the safety systems (and, in some cases, nonsafety systems) contained in the event trees. These models support the quantification of the event tree sequences. The interrelationship of the fault tree development task with other tasks is shown in Figure 1-4.

Fault tree analysis is a disciplined and deductive methodology for the identification of system failure causes. An undesired top event is defined, and then the credible faults leading to the top event are deduced. The fault tree is used to develop and depict the logical interrelationships of basic events (faults) that can lead to the top event. Use of the fault tree methodology is recommended by both the Interim Reliability Evaluation Program Procedures Guide (Reference 2-5) and the PRA Procedures Guide (Reference 2-4) for the modeling of system failures. Detailed information on fault tree methodology is presented in the Fault Tree Handbook (Reference 2-30).

The inputs required for the fault tree development task came from the event tree development and plant familiarization tasks. The event tree headings indicate the systems, human actions, components, and states that are important in the mitigation of various initiators. From the event tree development task, the event tree top events were identified. Of all the event tree top events (and initiating events), some were evaluated by developing fault trees or combinations of fault trees. Other event tree top events not evaluated by using fault trees are discussed in Section 3.1.1.

Some top events in Section 3 were based on failures of systems such as AC and DC power, SSWS, and Heating, Ventilating, and Air Conditioning (HVAC). These systems are required to support operation of the frontline systems identified by the event tree top events. The dependencies between frontline and support systems are identified in Section 3.2.2.

The output from the fault tree development task, fault tree models for top events identified in the event trees, was the major input to the accident sequence quantification task. In addition, the fault tree models supported the data development task, the human reliability task, and the dependent failure analysis task. (Strictly speaking, the fault tree development task relationship to these three tasks is interactive). Finally, the outputs from the fault tree development task were used as inputs to the external and spatially dependent internal event analysis.

Fault trees for the HCGS were developed following detailed guidelines outlined in the document HCGS PRA System Fault Tree Development Handbook (Reference 2-31). Guidelines from this document are summarized below.

The fault trees developed for the HCGS were developed down to the component level. Examples of components include various types of valves (e.g., manual, motor-operated, and pneumatic) and pumps (motor-driven and turbine-driven), electric relays, switches, circuit breakers, motors, fuses, and instrumentation. The level of definition is consistent with the level of definition of the database developed.

In general, passive failures such as piping leakage and cable open or short circuits were not modeled because such event probabilities are considered to be much lower than other events modeled. Plugging of locked-open valves and internal leakage of locked-closed valves were modeled wherever appropriate. Finally, flow diversion paths up to and including the first closed valve were modeled wherever appropriate.

Sources of information used in developing the HCGS system fault trees included training materials, the updated Final Safety Analysis Report (Reference 2-27), plant P&IDs, electrical diagrams, plant walk-throughs, and discussions with system engineers and senior reactor operators. For the purposes of the HCGS PRA fault tree development, the design was frozen as of August, 1993.

Human errors modeled in the fault trees included miscalibration, failure to return components to their normal state after testing or maintenance, and operator errors during an accident.

Test outages were modeled in the system fault trees. Normally test outage for a system or subsystem was modeled as a separate event (included in a combined test and maintenance outage event). Test outage events were not included for cases in which the system is automatically realigned upon demand. Test outages as modeled in the fault trees can result in multiple system test outages which may be a violation of the technical specifications. In the quantification of the fault trees, minimal cutsets containing such violations were eliminated from the results.

Maintenance outages (at a system or train level) while the plant is in operating condition 1 or 2 were modeled. In general, maintenance outage was modeled as a separate event (combined with test outage). By modeling maintenance outages in this manner, multiple maintenance outages that could be identified as violations of the technical specifications were easily removed from the quantification results.

Dependent failures were modeled in the system fault trees. A thorough discussion of dependent failure modeling is presented in Section 3.3.4 of this report.

The basic event labeling scheme used in the HCGS PRA is similar to that used in the NUREG/CR-4550 effort (Reference 2-24). A basic event label identifies the level to which each event was modeled; e.g., train, pipe segment, individual component, or human error. The failure mode of the basic event is also identified in the event name. A variety of failure modes were defined to permit flexibility in system modeling. The nature of an event's failure mode can be either specific or general, as is appropriate for each system and each basic event.

The event labeling system is illustrated below:

XXX - YYY - ZZ - AAAAA

where:

XXX = a three-letter code denoting the system to which the basic event either belongs or is related (Table 2-2).

YYY = a three-letter code denoting the level of modeling corresponding to the event (Table 2-3).

ZZ = a two-letter code denoting the failure mode associated with the event (Table 2-4).

AAAAA = an alphanumeric event descriptor.

The last five spaces were used to specifically identify individual components according to their numbering on the system schematics; e.g., 01, 1234, OA, 1B. Other types of basic events (e.g., pipe segment failures or train failures) were also identified according to their designations in the system models. When such specific identification was not applicable, a descriptive abbreviation of the event's nature was used.

A list of general guidelines and assumptions used in the HCGS PRA fault tree development is shown in Table 2-5.

2.3.1.5 Dependent Failure Analysis

Dependent failure events have historically been significant contributors in probabilistic risk assessments. Two redundant failure events are said to be dependent if the combined failure probability of both events is greater than the product of the two individual failure probabilities. The existence of such dependent failures can greatly increase the frequencies of accident sequences leading to core damage. Neglecting dependent failure events can result in underestimation of the frequency of core damage.

Dependent failure analysis is not an isolated task in a PRA. Figure 1-4 indicates that interaction occurs with many of the other PRA tasks. Interaction occurs with the event tree and fault tree development tasks and with the human reliability task. Also, interaction occurs with the spatially-dependent failure task, which is actually a subset of all dependent failures. Finally, the outputs of the dependent failure analysis task are inputs for the data development task and the accident sequence quantification tasks.

The remainder of the section deals with the classification of various types of dependent failures, the identification of those types that have been modeled in the HCGS PRA, the development of beta and gamma factors for parametric modeling of dependent failures, guidelines for the spatially-dependent (physical interaction) failure task, and a review of historically-identified dependent failures.

The PRA Procedures Guide (Reference 2-4) lists the types of dependent failures that should be included in a comprehensive systems analysis. The nine types are:

1. Common-cause initiating event dependencies resulting from external and internal initiating events that increase the failure probability of multiple systems. Examples of such events are fires, floods, earthquakes, and loss of offsite power.

2. Intersystem dependencies resulting from events or failure causes that create interdependencies among the various safety and support systems. Such intersystem dependencies include:

a. Functional dependencies, which are dependencies among systems that result from plant design philosophy or system capabilities and limitations. An example is a frontline system dependency on a support system for successful operation.

b. Shared-equipment dependencies, which are dependencies resulting from the sharing of components, subsystems, or support systems.

c. Physical interaction dependencies, which are failure mechanisms similar to those for type 1 that can cause multiple system failures but that are not initiating events. Such failure mechanisms are often related to environmental stresses, and normally occur as a result of common locations.

d. Human interaction dependencies, which are system dependencies due to human actions, including errors of omission, commission, and recognition. This category also includes operator, maintenance, and calibration errors, as well as design and construction errors.

3. Intercomponent dependencies resulting from events or failure causes that create interdependencies among components within a system. Types of intercomponent dependencies include:

   a. Functional Dependencies

   b. Shared-Equipment Dependencies

   c. Physical Interaction Dependencies

   d. Human Interaction Dependencies

The last four types of dependencies, 3a through 3d, are similar to 2a through 2d except that the dependencies usually occur within a single system.

In addition to these nine types of dependent failures, a tenth has been added for this study. This tenth category is denoted as 3e and represents other component dependencies not covered by 3a through 3d.

The dependencies modeled in the HCGS PRA are discussed in the following paragraphs. The format follows the order previously described. Recommended methods for analyzing the various types of dependencies are taken from Reference 2-4, and are indicated in Table 2-5. Methods used in the HCGS PRA are indicated in the discussion for each type of dependent failure.

Type 1 events, common-cause initiating event dependencies, can be divided into external event and internal event classes. The HCGS PRA includes a comprehensive screening analysis of internal flooding events. With respect to internal events, initiating event and system dependencies have been explicitly modeled in the event trees. For example, dependencies resulting from the loss of offsite power initiators have been modeled explicitly both in the appropriate event tree and in the system fault tree models used for the loss of offsite power event tree. Support system failures that are initiating events and affect safety systems have been identified and have been included in the event sequence calculations.

Intersystem functional dependencies have been modeled in several ways. Functional dependencies between frontline systems in the event trees have been modeled in the event tree structure.

The other type of intersystem function dependency, frontline or support system dependence on other support systems, is modeled in the individual frontline system fault trees. All significant support systems have been included in the fault trees.

Intersystem shared-equipment dependencies have also been modeled in the HCGS PRA. The use of a consistent component and subsystem naming scheme and the merging of frontline safety system fault tree models to obtain accident sequence cutsets ensures that shared-equipment dependencies have been identified and quantified correctly. Components within a system that have a different system identifier (letters one through three) in their event codes are generally shared by other systems.

Physical interaction dependencies include those resulting from internal flooding events and those resulting from internal events. Physical interaction dependencies, including those resulting from fire, external flood, and seismic events, will be addressed as part of the IPE of External Events.

Finally, a number of intersystem human interaction dependencies have been modeled in the HCGS PRA. Operator failures to initiate systems have been included in the system models or event trees and have been quantified.

Intercomponent dependencies have been modeled within the system fault trees. Functional and shared-component dependencies identified by the fault tree analysts were modeled explicitly within the system fault trees. Human interaction dependencies were examined as part of the human reliability analysis task. Also some of these types of events are covered by the beta and gamma factors used in the parametric modeling of similar component dependent failures.

These approaches helped to identify the HCGS-specific design susceptibilities to dependent failures. As a complement to this explicit identification and modeling of dependent failures, a parametric method was used to account for potential dependent failure mechanisms not already modeled in the fault trees. A discussion of the parametric method is presented in Section 3.3.4.1

2.3.1.6 <u>Human Reliability Analysis</u>

The human reliability analysis (HRA) task of a PRA involves the identification, modeling, and quantification of human actions affecting core damage sequences. The relationship of the

HRA task to other PRA tasks is shown in Figure 1-4. Interaction occurs with four tasks: event tree development, fault tree development, dependent failure analysis, and external and spatially dependent internal event analysis. The outputs of the HRA task, probabilities for all human actions contained in the plant models and a model for accident sequence recovery, are inputs to the accident sequence (core damage) quantification task.

The HCGS HRA was divided into two subtasks: analysis of human errors before an accident, and analysis of human (operator) errors during an accident. Furthermore, the operator errors during an accident were subdivided into three types: normal operator actions to manually start or align components (modeled in the system fault trees), operator actions modeled as top events in the event trees, and recovery events applied to the event sequence cut sets. Each type of human error is discussed in the following sections.

In general, the HCGS HRA tasks used the following references:

1. "Handbook of Human Reliability Analysis With Emphasis on Nuclear Power Plant Operations" (Reference 2-32)

2. "Systematic Human Action Reliability Procedure (SHARP)" (Reference 2-33)

3. "Post Event Human Decision Errors: Operator Action Tree/Time Reliability Correlation" (Reference 2-34)

4. "Risk Methods Integration and Evaluation Program (RMIEP) Methods Development: A Data-Based Method for Including Recovery Actions in PRA, Vol. 1: Development of the Data Based Methodology" (Reference 2-35)

5. "Accident Sequence Evaluation Program Human Reliability Analysis Procedure" (Reference 2-36)

6. "A Human Reliability Analysis Approach Using Measurements for Individual Plant Examination" (Reference 2-37)

Quantification of all human error events modeled in the HCGS PRA was performed on a screening basis, and then any dominant events that arose from the accident sequence quantification were re-evaluated on a more detailed basis. The screening methodologies for various types of human errors are described in Section 3.3.3. Human error events that were re-evaluated because of their initial dominance are also described in that Section.

2.3.1.7 Data Development

The HCGS PRA data development task involved four tasks:

1. Development of a generic database.

2. Collection of plant-specific data.

3. Quantification of the system fault tree basic events.

4. Quantification of special event tree top events that were not developed into fault trees.

Each of these four tasks is discussed in Sections 3.3.1 and 3.3.2.

The relationship of the data development task to other PRA tasks is shown in Figure 1-4. Inputs came from the initiating event identification task and the dependent failure analysis. Interaction occurred with the event and fault tree development tasks. Data development outputs were inputs to the accident sequence quantification task.

2.3.1.8 Accident Sequence (Core Damage) Quantification

Development of HCGS accident sequence models and data to support these models has been discussed previously. Evaluation of these models is discussed in the section on accident sequence quantification. Specifically, every accident sequence leading to core damage, as indicated in the event trees, was evaluated either by calculation or by comparison with other sequences. In addition, any initiating event leading directly to core damage was evaluated. The accident sequence quantification task involved several steps, as follows:

1. Accident sequence cutset generation.

2. Cutset modification, as necessary.

3. Recovery analysis.

4. Analysis of results.

Each of these steps is discussed subsequently.

The relationship of the quantification task to other PRA tasks is shown in Figure 1-4. Essentially all of the tasks provide input to the quantification. Results were input to the external and spatially dependent internal event analysis and uncertainty and sensitivity analysis.

2.3.1.8.1 Accident Sequence Cutset Generation

The RELMCS code (Reference 2-38) was used to evaluate the core damage sequences modeled in the event trees. Frontline systems were merged with their respective support systems to obtain equations representing the basic event combinations leading to failure of the frontline systems. These equations then were combined (AND gate logic) to evaluate unique combinations of system failures found in the event trees. Actual core damage cutsets were then obtained by adding the appropriate initiating events and other event tree top events (failures), accounting for system successes, removing illegal combinations of testing and maintenance (TM) outage events, removing other operationally impossible cutsets, and applying recovery factors where appropriate.

Several of the event tree top events represent combinations or variations of the system fault trees.

In general, the quantification was performed such that cutsets with a frequency less than 1.0E-10 per year were truncated. This cutoff value is sufficiently low to result in accurate estimates of overall core damage frequency and important plant damage state frequencies. With a truncation value of 1.0E-10 per year, accident sequences with frequencies greater than 1.0E-8 per year were not significantly affected by the cutoff. However, sequences with listed frequencies of less than 1.0E-8 per year may be underpredicted because of truncation of the event tree top events.

System successes in accident sequences were accounted for by using special procedures available with the quantification code. Specifically, cutsets were generated for the failure of the systems that were successful. These cutsets then were deleted from the accident sequence cutsets in question.

2.3.1.8.2 Cutset Modification

Combinations of Test and Maintenance (TM) events in the accident sequence cutsets that violate the Technical Specifications were removed. For example, HPCI and RCIC systems Technical Specifications indicate that only one system can be unavailable at a time because of TM. (If more than one system is unavailable, the unit must be in hot shutdown within 13 hours.) Because these fault trees have TM events modeled for each of the systems, cutsets appear that include combinations of two systems unavailable because of TM. These cutsets were removed. These were removed with a special fault tree during the quantification process.

The accident sequence cutsets remaining after accounting for system successes required further manipulation. Some cutsets physically did not make sense and were eliminated. For example, one train of the SACS might be unavailable because of maintenance while the other train fails to start. Because the SACS is a normally operating system (at least one of two trains must be operating), a train would not be taken out for maintenance before the other train was started and was operating successfully. These operationally impossible cutsets arise because the fault trees were created using only AND and OR gates, with no attempt to model all types of conditional events. It was much more efficient to keep the fault tree structures fairly universal and to review the resulting system or sequence cutsets for these operationally impossible cases. These operationally impossible cutsets were found only in normally operating systems.

2.3.1.8.3 Recovery Analysis

The final modifications to the core damage sequence cutsets involved the application of recovery events, where appropriate. These events were added based on an examination of the actual failures in each cutset, with appropriate timing considerations (which varied from sequence to sequence). In addition to the recovery events applied to individual cutsets, recovery actions also appear in the event trees, applied to entire sequences, and in the fault trees.

2.3.1.9 Internal Flooding Analysis

This analysis considered potential internal flooding events occurring in the reactor building, in the turbine building, or in the service water intake building. For the case when the internal flood occurs in the reactor building or in the intake building, the turbine building (including the secondary side of the balance of plant) is not directly affected. Therefore, the turbine trip event tree logic was used to quantify the impact of the internal flooding initiating event on the core damage frequency. For the internal flood in the turbine building, the secondary side of the balance of plant may be affected, and the MSIV closure event tree logic was used. The rooms in which internal flooding can be considered an initiating event, were identified in the section of the initiating events. In this context, a room is defined as one or more rooms, which are isolated from other rooms by means of watertight isolation (like watertight doors). For each room exposed to internal flooding, a separate event tree was used, in which the specific room flooding is defined as the initiating event, followed by the failure of the equipment which is present in this room and failure of additional specific equipment when the flood is propagated to other rooms. Therefore, despite the fact that the event tree logic looks the same (like that of the turbine trip), each internal flood event tree was different, because the initiating event was different and the equipment impacted by the common cause flood was different.

2.3.1.10 Uncertainty And Sensitivity Analysis

The results of quantification of front-end accident sequences are considered to be mean frequencies obtained by using mean values for the initiating events, fault tree basic events, dependent failures, human errors, and others. However, the mean frequency results present an incomplete picture. The remaining part of the picture is the uncertainty associated with each mean frequency. The relationship of the uncertainty and sensitivity analysis to other PRA tasks is shown in Figure 1-4.

The PRA Procedures Guide (Reference 2-4) indicates that three major types of uncertainties are involved in PRA results: data, completeness, and analysis-related. The data-related uncertainties result from plant-to-plant, component-to-component, and year-to-year "random" variations in initiating event frequencies and fault tree component failure rates. Also, dependent failure events, human errors, and event tree top events not developed into fault trees are considered to have a random nature and associated uncertainties. These types of uncertainties can be estimated. The resulting uncertainty distributions can then be propagated through the sequence cutset expressions to obtain resulting uncertainty distributions for the core damage frequencies. This type of analysis has been performed.

Uncertainties related to completeness concerns are much more difficult to estimate. Completeness cannot be proven in PRAs; however, several things can be done to ensure completeness to the maximum extent possible. These include the use of recommended methodologies for each PRA task, the use of experienced PRA practitioners in the study, and participation from and review by plant personnel. All three have been followed in the HCGS PRA. Therefore, completeness concerns have been minimized in the study. (Most incompleteness in PRA studies results in additional, usually unknown, contributions to the overall core damage. However, it is believed that by following the suggestions outlined, the incompleteness contributions to uncertainty can be reduced below data-related and modeling-related uncertainties.)

Finally, analysis uncertainties involve such areas as success criteria, event tree structure, fault tree structure, and others. In general, such uncertainties are evaluated most appropriately by performing sensitivity studies. Results from such studies are discussed in Section 3.4.1.

2.3.2 Back-End Analysis

The back-end analysis portion of the HCGS IPE involved the following:

1. Containment Bypass Review And Interfacing Systems Loss Of Coolant Accident Analysis
2. Screening for Level II and Front-End to Back-End Interfaces
3. Accident Sequence Binning
4. Emergency Operating Procedure Review and Human Reliability Assessment
5. Containment Event Tree (CET) Development and End State Definition
6. Plant Feature, Containment and Containment System Review
7. Containment Capacity Analysis
8. Accident Progression and Radionuclide Release Analysis
9. Equipment Operability and Survivability Assessment
10. CET Quantification and Sensitivity/Uncertainty Analyses
11. Radionuclide Release Category Definition
12. Compilation of Results and Identification of Safety Features and Vulnerabilities
13. Development of Risk Reduction Strategies
14. Independent Review

15. Documentation

Each of these tasks, as well as their relationship to other tasks, is described subsequently.

2.3.2.1 Containment Bypass Review and Interfacing Systems Loss of Coolant Accident (ISLOCA) Analysis

This task included a complete evaluation of potential containment bypass paths and an interfacing system LOCA scenario analysis.

First, a survey of all potential paths, using walkdowns and drawings, for material to bypass the containment and escape outside of containment was completed. These paths included contact of high pressure water from the reactor vessel with low pressure piping, seals, gaskets and relief valves. The survey also covered (a) all systems with penetrations through containment and into the reactor vessel, (b) all systems which penetrate containment and are connected to systems which connect with the reactor vessel, and (c) all systems connected to the reactor vessel which also are connected to a system which penetrates containment.

Next, a screening criteria was developed for discarding paths with little potential for bypassing containment. High pressure piping or sufficiently redundant combinations of closed valves and check valves were used as the criteria (Reference 2-8). Subsequently, initiating event frequencies were developed for all paths which survive the screening process.

Plant and operator responses to the initiating event were then modeled using event trees, human action review and analysis, fault trees, and appropriate thermal hydraulic analysis. The fault tree and event tree models were quantified and a description of the conditions in the reactor and auxiliary buildings during core melt was made.

2.3.2.2 Screening for Level II and Front-End to Back-End Interface

The purposes of this task were to ensure a clean interface in the tracing of sequences between the Level I and Level II models and to provide critical information that was needed to ensure that NUREG-1335 (Reference 2-2) reporting criteria had been met. This task includes the following:

- Identification of the Level I systematic sequences that are to be included for the Level II analysis and reported to the NRC in accordance with Section 2.1.6 of NUREG-1335 (Reference 2-2).

- Identification of the PDSs that characterize the Level I sequences in a manner that smoothly interfaces with Level II.

- Delineation of the important front-end and back-end dependencies of the CET top events with front-end top events in accordance with Appendix 1 of GL88-20 (Reference 2-1).

These task activities involved the review of the results of the Level I quantification to identify and characterize those systematic sequences whose mean frequencies exceed the criteria noted in Section 2.1.6 of NUREG-1335. They included a description of the PDSs used to assign end states to those Level I sequences that result in core damage. A list was developed for each sequence that identified the initiating event, the top events (or cutsets) that failed, the sequence frequency, the specific NUREG-1335 criteria that are satisfied, and the PDS to which the sequence is assigned. This table appears in Section 4. It also documented the required front-end to back-end cross-checking information identified in Appendix 1 of GL88-20. Most of the aspects addressed in Appendix 1 of the generic letter have been captured in well-defined PDS definitions.

Since the HCGS sequences were most conveniently expressed in systematic terms, the new criteria would apply. Any systematic sequence which meets one or more of the following criteria was included in the Level II analysis:

- "Any systemic sequence that contributes 1E-7 or more per reactor year to core damage."
- "All systemic sequences within the upper 95 percent of the total core damage frequency."
- "All systemic sequences within the upper 95 percent of the total containment failure frequency."
- "Systemic sequences that contribute to a containment bypass frequency in excess of 1E-8 per reactor year."
- "Any systemic sequence that the utility determines from previous applicable PRAs or by utility engineering judgment to be an important contributor to core damage frequency or poor containment performance."
- "The total number of unique sequences to be reported ... should not exceed the 100 most significant sequences."

The mean accident sequence frequencies were used for screening.

2.3.2.3 Accident Sequence Binning

GL88-20 (Reference 2-1) stipulates that only sequences which pass the screening criteria require radionuclide release calculations. This task determined the sequences for which such calculations have been reported to the NRC. It was achieved via two subtasks.

- Grouping the risk-significant Level I sequences based on system or component failures that had the potential to impact the CET results.
- Combining these initial sequence groups, based on implied timing and combinations of failures that actually altered the CET results.

Differences within the groups that had negligible impact on the CET results were essentially deleted. Once the screening criteria had been applied, a total of five Level II initiators were defined.

2.3.2.4 Emergency Operating Procedure (EOP) Review and Human Reliability Assessment

This task included the following:

- Review of the HCGS's Emergency Operating Procedures to identify human actions for applicability to post core melt containment and system response.

- Incorporation of applicable human actions into the CET.

- Incorporation into the CET of other obvious recovery actions, such as recovery of offsite power and manual initiation of equipment, that are not derived from scenario-specific considerations.

This task involved reviewing the Emergency Operating Procedures (EOP) for their applicability in the CET. Those mitigation actions that are in existing procedures were incorporated into the initial CET. Any other obvious mitigation or recovery actions that are of a general (nonscenario-specific) nature (e.g., manually initiating equipment that failed to automatically actuate, or delayed recovery of onsite power) were also documented and included in the initial CET. At this stage of the Level II analysis, recovery actions that are covered by existing procedure were included in the initial CET. The human error rates of these procedurized actions were quantified subsequently. After the CET was quantified and the results were combined with the Level 1 PDS frequencies, the results were carefully reviewed to determine the risk significant accident scenarios. At this stage, further recovery actions by the plant operators or the emergency response organization were evaluated on a scenario-specific basis. These actions were not covered by existing procedures because they are beyond the design basis, but were evaluated qualitatively and, whenever appropriate, quantitatively.

Assessment of the allowed time for operator actions was divided into two phases. The first phase included activities associated with procedural recovery actions; the second phase included activities associated with non-procedural recovery actions that would be under consideration for risk reduction. The assessment generally involved thermal-hydraulic analyses to determine the progression of containment pressure and temperature and a comparison of these with the containment capacity information to assess time for operator actions. The thermal-hydraulic results were obtained from the PSE&G MAAP analyses, scoping hand calculations, or other related studies.

Finally, human error probabilities were calculated. Supporting activities included:

- Interview of PSE&G operations staff personnel to help evaluate the performance-shaping factors.

- Quantification of human error rates using the same method as employed in the HCGS Level I PRA.

This task began by quantifying the human error probabilities for actions covered by existing procedures. Once the baseline risk was evaluated, the second phase of this task quantified the expected frequency and the associated uncertainties of those risk-significant mitigation actions not covered by procedures that are judged to be significant and practical. This often required further discussions and interviews with the cognizant PSE&G personnel. The actions were incorporated into the CET, and the resulting analysis is documented in the HCGS IPE submittal. Again, supporting MAAP analyses were sometimes required.

2.3.2.5 Containment Event Tree (CET) Development and End State Definition

This task consisted of the following:

- Development of a comprehensive CET that included all currently meaningful containment challenges, as recognized by the NRC-sponsored NUREG/CR-4550 (Reference 2-20) analyses for other BWRs (Peach Bottom and Grand Gulf). The CET included provisions to evaluate relevant operator mitigative actions as well as equipment survivability under beyond design basis conditions.

- Development of a release category assignment logic structure that indicated the release category assignment logic for each CET sequence.

This task essentially was the development of the HCGS-specific CETs with a description of how the CET sequences are assigned to a specific release category.

The containment performance logic model for the HCGS is developed in the form of linked event trees. In this context the term "linked" means that there are common events among the event trees that have been developed to reflect each aspect of containment response. The events and phenomena included in the EPRI methodology were identified based on an in-depth review of the analysis of Peach Bottom Unit 2 (Reference 2-20). These events and phenomena are pertinent to BWRs with Mark I containments. Any HCGS-specific design features that would affect accident progression or containment performance were documented and incorporated as appropriate. The CET generally was constructed chronologically, beginning at the onset of core damage and ending in either an intact containment or a containment failure with release category assignment. The containment capacity analysis was used to differentiate containment failure characterizations (i.e., a controlled leak versus a large uncontrolled break) By its very nature, the CET generally addressed phenomenological issues but also included relevant operator mitigations actions.

2.3.2.6 Plant Feature, Containment and Containment System Review

This task satisfied the plant data requirements in NUREG-1335 (Reference 2-2) and provides the information collection needed to begin various Level II PRA tasks. It was achieved via two subtasks:

- Development of simplified containment geometry drawings, by review of plant drawings and plant walkdowns, to demonstrate understanding of the containment design features which influence severe accident progression and containment capacity. Examples of features to investigate were:

  - Post-melt debris flow paths for high pressure core melt scenarios

  - Post-melt debris collection locations for low pressure core melt scenarios

  - Water flow paths for coolability of collected debris.

- Identification, description, and summary in tabular form of plant features and containment systems which may impact CET top events, their failure probability, accident progression phenomena, and potential for radionuclide release.

2.3.2.7 Containment Capacity Analysis

In support of the back-end analysis conducted for the HCGS containment structure to estimate the probability of radioactive release from the containment during a hypothetical severe accident, a detailed evaluation of the capacity of the HCGS containment structure for elevated temperature and pressure loadings was completed. Consistent with the nature of the probabilistic safety assessment, the evaluation methodology is based on estimating the capacity of the containment structure in terms of probabilistic parameters for a number of possible modes of failure.

Several potential failure modes were investigated for the containment in which failure was defined as incipient leakage or a breach of the pressure boundary. The potential failure modes examined included membrane failures of the drywell shell, failure of the drywell head flange seal, failure of the vent line from the drywell to the suppression chambers, failure of the suppression chamber shell, and failure at penetrations. These failure modes were evaluated for temperature conditions well in excess of the accident temperature. Median (50th percentile) failure pressures and their associated variabilities were estimated. Using these values, the probability of failure were estimated as a function of pressure for the controlling failure modes. Leak areas were also estimated for those failure modes that do not result in catastrophic failure.

For the investigation it was assumed that the failure pressures associated with all modes of failure could be treated as quasi-static (i.e., pressure rise times of at least several seconds are assumed). Effects such as dynamic amplification of the pressure pulse on the containment shell or internal pressure wave loading on cables and equipment were not considered. In addition, all temperatures in the materials were assumed to correspond to steady-state conditions.

2.3.2.8 Accident Progression and Radionuclide Release Analysis

This task investigated the pre- and post-melt accident progression to gain sufficient information to provide plant specific qualifications of the HCGS CET. Timing of events gained from this task is an important input to the human action quantification. This task also provided estimates of plant specific radionuclide releases for categorization as release categories and as a measure for evaluation of potential plant improvements and risk reduction strategies. The investigations used MAAP coupled with separate effects analyses, prior analyses available in the literature, and some verification analyses using other codes.

It proved advantageous to use MAAP to provide timing for crucial recovery actions and insight into crucial phenomenological questions in the Level I study. For example, it was necessary to know the allowed time for successful recovery actions during a station blackout.

This task was divided into five subtasks:

- Development of a plant-specific MAAP parameter file for HCGS

- Completion of cases to support the following:

    - accident progression knowledge in the vessel, in the containment, and in the reactor building

    - operator action studies relating to core cooling

    - operator action studies relating to containment, reactor building, and auxiliary building integrity

    - sensitivity studies to resolve outstanding NRC/IDCOR issues concerning MAAP.

- Performance of separate effects calculations to develop specific knowledge in areas needed to quantify the CET and to defend the use of MAAP.

- Completion of base and sensitivity cases with MAAP to determine the radionuclide releases for the CET end states and defend the use of decontamination factors. This subtask also includes the cases required for containment bypass events from Task 1.

- Completion of MAAP cases to support the quantification of the probability of recovery actions.

2.3.2.9 Equipment Operability and Survivability Assessment

This task addressed the concern of NUREG-1335 (Reference 2-2) to pay "particular attention to equipment vulnerability and survivability" when taking credit for such equipment in the

CET quantification. The equipment was assessed at the same temperature, pressure, humidity, radiation, and other environmental conditions as predicted in the accident progression analysis.

Because formal environmental qualification requirements are not applicable to the IPE, when credit is taken for equipment in severe accidents, an assessment must be made of the ability of the equipment to perform the function for the period of time it is required. Some evidence of the ability of the equipment in withstanding potentially harsh post-melt environments was developed. In addition, if a person is required to operate, initiate, or turn-off equipment, then evidence that the person can function in the environment is offered.

Environmentally induced failures were either directly (or indirectly) modeled in the CET. A supporting discussion of the equipment operability is provided in Section 4.0. Discussion of human actions, including stress factors is provided within the discussion of the quantification of CET top events.

This task consisted of the following:

- Definition of equipment whose survivability is required and definition of the environmental conditions under which it is to be assessed. Environments were based on MAAP analyses outputs.
- Judgmental assessment and support of the probability of equipment survivability during each sequence.
- Model the equipment failures or human errors within the CET.

2.3.2.10 CET Quantification and Sensitivity/Uncertainty Analyses

This task involved CET quantification and any sensitivity and uncertainty studies. The CET was quantified for each PDS grouping. In general, the CET top event split fractions (i.e., the conditional probability of failure at each node in the event tree) varied for the particular PDS grouping evaluated as well as the sequence-specific status of prior top events; i.e., whether previous events have succeeded or failed. Due to the complexity of the split fraction evaluation and assignment task, only relevant, publicly available information was used (e.g., NUREG-4550, Volumes 4 and 6 - References 2-20 and 2-24), along with the results of HCGS-specific MAAP analysis done by PSE&G and the results of the HCGS containment capacity analysis.

This task consisted of the following:

- Mean value quantification of the comprehensive CET for each key PDS grouping.
- Development of release category frequencies associated with the specialized models for significant containment bypass sequences.

- Requantification of CET for sensitivity investigations.

- Sensitivity analysis of release category frequency for significant release categories.

- Reasonableness checks of quantification.

- Performance of MAAP runs for base case and sensitivity analysis.

2.3.2.11 Radionuclide Release Category Definition

A total of nine radionuclide release categories were generated. The radionuclide release categories were distinguished by the timing of the release and by the magnitude of the release to the environment.

Two categories of radionuclide release times are considered in the CET: early release and late release. An early release is assumed to occur within two to four hours of when a General Emergency would have been declared. A late release is assumed to occur after four hours after a General Emergency would have been declared.

The magnitude of radionuclide release is categorized in terms of five levels of release: high, medium-high, medium, low, and low-low. These levels are designated by numbers 1 through 5, where 1 refers to a high level of release, and 5 refers to a low-low level of release. Levels are assigned based on the magnitude of the iodine and tellurium releases calculated for each accident sequence.

A source term algorithm was generated for the HCGS IPE, which is comprised of correlations that relate release fractions and decontamination factors in a self-consistent fashion to calculate environmental release fractions.

2.3.2.12 Compilation of Results and Identification of Safety Features and Vulnerabilities

This task included the compilation of results in accordance with the NUREG-1335 (Reference 2-2) requirements. It answers the question, "What is the baseline risk?" A description of the dominant Level II sequences and the dominant joint Level I/ Level II sequences was developed. A comparison of results with other published studies to determine the relative strengths and vulnerabilities of the HCGS was also made. Sequences that were prominent (either by being much lower or higher in frequency or consequence) relative to similar studies were reviewed in detail. Dominant sequences which exhibited a significantly higher frequency or consequence than similar sequences in other plants were candidates for further investigation. Such investigation took two forms. The first was a re-examination of the assumptions, approximations, and calculations to find errors, omissions, and conservatisms to be removed.

The second was performed when a sequence continued to be an outlier after the analysis had been re-examined. An investigation into risk reduction strategies and plant improvements was then performed.

2.3.2.13 Development of Risk Reduction Strategies

This task includes the following:

- Development of specific risk reduction strategies.
- Revisions of the risk models to reflect each strategy.
- Requantification of the risk models to estimate the change in risk associated with the strategies.

In essence, this task was a set of sensitivity analyses that investigate the potential effect of suggested plant hardware and/or procedure modifications.

The previous tasks involved the development of a mature risk model, quantification of the model [with necessary iterations to incorporate "analytical fixes" (as opposed to hardware or procedural changes)], presentation of results, and discussions of the insights gained (both the HCGS-specific beneficial safety features and any vulnerabilities that might have been uncovered). This task involved a collaborative effort between the PSE&G Engineering and Plant Betterment Department and HCGS staff to transcend from the analytical stage into the design improvement and/or accident management stage. Consultants provided technical insights from their experiences in performing PRAs on similar plants. This involved a careful evaluation of the Level I and Level II models and results to identify potential design or procedure changes to reduce either the likelihood of core damage or, if core damage occurs, the onsite and/or offsite consequences. PSE&G personnel reviewed the identified insights and developed risk reduction responses which were then independently reviewed. Only one plant modification was implemented, as described in Section 3.4.2.

2.3.2.14 Independent Review

This task provided for the independent review of the HCGS IPE. The review of the IPE was in two parts. The first was an ongoing senior level review of the team's technical work. This was performed by the team leader and his consultants. The second was a more formal independent review performed near the end of the study. The review team was composed of PSE&G personnel and a consultant who did not participate in the technical study. The reviews focused on the accuracy of the plant representation, the methodology, the data, the dominant accident sequences and their contributors, the identified strengths and vulnerabilities, the risk reduction strategies to be recommended, and the clarity of reporting. The background of the reviewers along with a description of their activities is provided in Section 5.

2.3.2.15 Documentation

This task included the writing and production of this report which conforms to the requirements of GL88-20 and NUREG-1335 (References 2-1 and 2-2). It also included the preparation of complete, detailed records of all IPE tasks for internal use and as technical backup (Tier II) information to the NRC submittal. Four subtasks were involved:

- Preparation of internal PSE&G documentation of IPE tasks.
- Publishing of a preliminary report for PSE&G internal review.
- Preparation and publishing of the final report for NRC submittal..
- Maintenance of supporting (Tier II) documentation.

2.3.3 Identification And Assessment of Specific Safety Features or Vulnerabilities and Development of Potential Plant Improvements

This aspect of the IPE was addressed for two instances:

1. Identification of vulnerabilities (and safety features) directly through the front-end and back-end analyses, and

2. Prioritization of discrepancies as part of PSE&G's discrepancy reporting process.

In the first instance, the methodology described in Section 2.3.2.13 was invoked. For the second, a formal process would be initiated as described in PSE&G Procedure No. NC.DE-AP.ZZ-0018(Q) (Reference 2-39). This process would include an assessment of the discrepancy on the core damage frequency. Based on this assessment, the impact of vulnerabilities for immediate response would be identified.

2.4 INFORMATION ASSEMBLY

Several major sources of plant-specific information were used in the HCGS IPE. These included the following:

1. Hope Creek Generating Station, Updated Final Safety Analysis Report (Reference 2-27)

2. System Descriptions and Configuration Baseline Documentation (CBDs)

3. Operator Lesson Plans

4. Plant and System Drawings

5. Emergency Operating Procedures

6. Reactor Operators, Training Personnel, and System Engineers

7. Plant and System Walk-Throughs

Because the HCGS is continually being modified, a cutoff date for design changes had to be chosen. The HCGS configuration was frozen as of August 1993.

For the back-end analysis portion, the design was also frozen as of August 1993.

Many additional sources of information were used throughout the PRA effort. These sources included the following:

1. PRA Studies of Other Plants

2. PRA Procedures Guides

3. Data Compilations and Analyses

4. Reports Concerning Specific PRA Tasks

5. PRA Computer Codes

These sources either are generic or apply to other plants. Their use in the HCGS IPE is indicated in the individual task methodology (Section 2) or performance (Sections 3 and 4) write-ups.

2.4.1 Data Gathering Approach

As previously described, the HCGS Level I PRA was performed in accordance with the provisions of the PRA Procedures Guide (Reference 2-4). Initially, data was segregated into System and Data Notebooks. Although they were comprehensive in nature, they were eventually replaced by the Hope Creek Generating Station Probabilistic Risk Assessment (Reference 2-3) and Systems Configuration Baseline Documents (CBDs) as the primary Tier II documentation for the HCGS IPE.

The HCGS PRA is currently being revised to reflect the updated information in the IPE analysis. This report will contain all the same material plus detailed Tier II documentation, such as the specific evaluation of HEP and Room Heatup calculations. Although these have not been assembled by April 1994, it is planned to have them available by July 1994. All of the Tier II documentation which will appear in the PRA document has been supplied to internal reviewers and is available for inspection.

The HCGS PRA documents specific references used in both the Level I and II analyses.

Data used in the development of the plant-specific MAAP input parameter file was assembled into a controlled engineering evaluation. The containment capacity analysis (Reference 2-9) and its supporting calculations are documented in the same manner. MAAP computer results will be maintained in accordance with the Programmatic Standard (Reference 2-41) described in Section 2.4.6. Finally, all other supporting calculations used in the back-end analysis are compiled into a separately maintained report (Reference 2-15).

2.4.2 Review of Other Probabilistic Risk Assessments

Various PRAs were reviewed throughout the IPE process. The specific uses of data from these documents are described in Section 2, although the references are provided in Sections 3 and 4. For identification of vulnerabilities, the NUREG-4550 reports for Peach Bottom and Grand Gulf were the primary references (References 2-20 and 2-24). Although publicly available IPE results from other BWRs were also reviewed as described in Section 3.4.1.5.

2.4.3 Plant-Specific Documentation

In addition to the HCGS UFSAR (Reference 2-27), the following data sources were consulted:

1. System Piping and instrumentation drawings
2. Elementary wiring diagrams
3. Electrical one-line diagrams
4. System logic diagrams
5. Detailed system descriptions or Configuration Baseline Documentation (CBDs)
6. Normal and emergency operating procedures
7. Technical specifications
8. Test and maintenance procedures
9. Operator lesson plans

Specific references including revision version and dates appear in Sections 3 and 4.

2.4.4 Engineering, Operations, and Training Department Support of the HCGS IPE

Performance of the PRA tasks was aided by close cooperation from appropriate HCGS personnel, including senior reactor operators (SROs), system engineers, and trainers. This close cooperation ensured that the initial HCGS Level I PRA models accurately represented the plant. Of special note is the fact that the fault tree modeling for each system was reviewed by the HCGS system engineers and SROs.

During the update of the Level I PRA and throughout the back-end analysis, operators, trainers, and HCGS system engineers were consulted.

2.4.5 Plant Walkthrough

During the original HCGS Level I PRA, plant walkdowns were performed by the PRA analyst assigned to the individual system when information from various data sources, such as drawings, could not be supplemented or confirmed by onsite plant system engineers or other cognizant engineering personnel. Such personnel were intimately familiar with the plant configuration because they often performed "walkdowns" as part of their daily responsibilities.

Walkdowns in support of the Level I PRA update were performed by a PSE&G PRA analysts and consultants for each system analyzed. The scope of the walkdown included the following:

1. Areas identified by the Internal Flooding Analysis

2. Areas impacted by HVAC failures

3. ECCS equipment areas

4. The HCGS Control Room

2.4.6 Maintenance of Tier II Documentation

Because PSE&G intends to use PRA for various plant improvement projects, it has developed a programmatic standard to define the guidelines for an on-going PRA Program, including maintenance of relevant data. The PRA Programmatic Standard (Reference 2-41) addresses the following:

- PRA Program Scope

- PRA Document Maintenance

- Human Reliability Analysis

- Analysis of External Events

- PRA Software Utilization and Maintenance.

The Programmatic Standard was issued in April 1993. It covers maintenance of the Level I and II PRAs, databases, system and event sequence analyses, and all documentation including software documentation.

2.5 REFERENCES

2-1 U. S. Nuclear Regulatory Commission, Generic Letter 88-20," Individual Plant Examination for Severe Accident Vulnerabilities - 10CFR§50.54(f)," November 23, 1988.

2-2 U. S. Nuclear Regulatory Commission, NUREG-1335, "Individual Plant Examination: Submittal Guidance," August 1989.

2-3 PSE&G Letter No. NLR-N93-118, "Hope Creek Generating Station, Individual Plant Examination," July 1993.

2-4 J. W. Hickman, "PRA Procedures Guide: A Guide to the Performance of Probabilistic Risk Assessments for Nuclear Power Plants," American Nuclear Society and Institute of Electrical and Electronics Engineers, NUREG/CR-2300, Volumes 1 and 2, January 1983.

2-5 "Interim Reliability Evaluation Program Procedures Guide." U.S. Nuclear Regulatory Commission, January 1983: NUREG/CR-2728.

2-6 U. S. Nuclear Regulatory Commission, Generic Letter 88-20, Supplement 1, "Initiation of the Individual Plant Examination for Severe Accident Vulnerabilities - 10CFR§50.54(f)," August 29, 1989.

2-7 PSE&G Letter No. NLR-N89218, "Individual Plant Examination For Severe Accident Vulnerabilities, November 1, 1989.

2-8 PSE&G Engineering Evaluation HI-GSA-MEE-0808, "Hope Creek Generating Station Interfacing System Loss of Coolant Accident (ISLOCA) Analysis."

2-9 PSE&G Engineering Evaluation H-1-GS-MEE-0809, "Hope Creek Generating Station Containment Fragility Analysis."

2-10 U. S. Nuclear Regulatory Commission Generic Letter 88-20, Supplement 2: "Accident Management Strategies For Consideration In The Individual Plant Examination Process," April 4, 1989, Correction May 16, 1990.

2-11 U. S. Nuclear Regulatory Commission Generic Letter 88-20, Supplement 3. "Completion Of Containment Performance Improvement Program And Forwarding Of Insights For Use In The Individual Plant Examination For Severe Accident Vulnerabilities," July 6, 1990.

2-12 U. S. Nuclear Regulatory Commission Generic Letter 88-20, Supplement 4: "Individual Plant Examination of External Events (IPEEE) For Severe Accident Vulnerabilities - 10CFR§50.54(f)," June 28, 1991.

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2-14 Z. T. Mendoza et. al., "Generic Framework For IPE Back-End Analysis," NSAC-159, Electric Power Research Institute, June 1991.

2-15 "Plant Feature Notebooks." PRA-PN001 through PRA-PF006.

2-16 MAAP Parameter File For HCGS." HCGS Engineering Evaluation Number H-1-GS-MEE-0420.

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2-18 "Development of Transient Initiating Event Frequencies for Use in Probabilistic Risk Assessment," NUREG/CR-3862, U. S. Nuclear Regulatory Commission, Washington DC, June 1984.

2-19 "Reactor Safety Study: An Assessment of Accident Risks in U.S. Commercial Nuclear Power Plants," WASH 1400 (NUREG-75/014), October 1975.

2-20 "Analysis of Core Damage Frequencies from Internal Events: Peach Bottom Unit 2," U. S. Nuclear Regulatory Commission, NUREG/CR-4550/Volume 4, Washington DC, October 1986.

2-21 "Brunswick Steam Electric Plant Probabilistic Risk Assessment," Carolina Power & Light Company, Raleigh, North Carolina, April 1988.

2-22 "Probabilistic Risk Assessment, Limerick Generating Station," Philadelphia Electric Company, Pittsburgh, Pennsylvania, June 1982.

2-23 "Probabilistic Risk Assessment, Shoreham Nuclear Power Station," Long Island Lighting Company, Hicksville, New York, June 1983.

2-24 "Analysis of Core Damage Frequencies from Internal Events: Grand Gulf 1," U. S. Nuclear Regulatory Commission, NUREG/CR-4550/Volume 6, Washington DC, April 1987.

2-25 General Electric Company Boiling Water Reactor Owners Group (BWROG), "Emergency Procedure Guidelines," Revision 4: NEDO-31331.

2-26 "Radionuclide Release Calculations for Selected Severe Accident Scenarios," Volume 5. U.S. Nuclear Regulatory Commission, July 1986: NUREG/CR-4624.

2-27 Updated "HCGS Final Safety Analysis Report." Public Service Electric And Gas Company, Hancocks Bridge, NJ, April 11, 1991.

2-28 "HCGS Emergency Operating Procedures," based on BWROG EPG Revision 4. Public Service Electric And Gas Company, Hancocks Bridge, NJ, February 14, 1991.

2-29 "A Reference Manual for the Event Progression Analysis Code ." Sandia National Laboratories, September 1989: NUREG/CR-5174.

2-30 "Fault Tree Handbook," U. S. Nuclear Regulatory Commission, January 1986: NUREG-0492.

2-31 "HCGS PRA System Fault Tree Development Handbook." Idaho Falls, ID: EI International, Inc., September 1988.

2-32 "Handbook of Human Reliability Analysis With Emphasis on Nuclear Power Plant Operations." U.S. Nuclear Regulatory Commission, August 1983: NUREG/CR-1278.

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2-39 "Engineering Descrepancy Control." PSE&G Procedure N. NC.DE-AP.ZZ-0018(Q).

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TABLE 2-2 SYSTEM IDENTIFIERS

System Identifier (XXX)	System Name
ACP	AC Power System
ADS	Automatic Depressurization System
CAR	Control Area Air Conditioning System
CAS	Control Air System
CHS	Chilled Water System
CIS	Containment Isolation System
CNS	Primary Condensate and Feedwater System
CRH	Control Rod Drive (Hydraulics)
CSS	Core Spray System
CWS	Circulating Water System
DCP	DC Power System
DGS	Diesel Generator System
EAS	Control Room Emergency Filtration (CREF)
ESF	Engineered Safety Features
HCS	Hydrogen Control System
HPI	High-Pressure Coolant Injection System
IAS	Instrument Air System
IGS	Primary Containment Instrument Gas System
LPI	Low-Pressure Coolant Injection System
PCS	Power Conversion System
RAC	Reactor Auxiliaries Cooling System
RCI	Reactor Core Isolation Cooling System
RCS	Reactor Coolant System
RHS	Residual Heat Removal System
RPS	Reactor Protection System
RWC	Reactor Water Cleanup
SAC	Safety Auxiliaries Cooling System
SLC	Standby Liquid Control System
SRV	Safety/Relief Valves - Pressure Relief
SSWS	Station Service Water System
TBS	Turbine Bypass System
UVI	Alternate Injection Systems
VAS	Auxiliary Building Ventilation System
VCA	Control Area Air Conditioning System
VCS	Containment Ventilation System
VDG	Diesel Generator Area Ventilation System
VSW	Switchgear Area Ventilation System

TABLE 2-3

EVENT AND COMPONENT TYPE IDENTIFIERS

Identifier (YYY)	Component/Event
ACT	Actuation Train
ACU	Air Cleaning Unit/Air Handling Unit
ACX	Air Cooling Heat Exchanger
AHU	Air Heating Unit
AOV	Air-Operated Valve
BAC	Electrical Bus - ac
BAT	Battery
BDC	Electrical Bus - dc
BDD	Back-Draft Damper
BRK	Circuit Breaker
CAL	Calculational Unit
CBL	Electrical Cable
CHG	Charger (Motor Generator)
CHL	Chiller Unit
CKV	Check Valve
CND	Signal Conditioner
CRH	Control Rods (Hydraulically-Driven)
DCT	Ducting
DGN	Diesel Generator
DPT	Differential Pressure Sensor/Transmitter Unit
DRP	Supply Drain Pot, Exhaust Drain Pot
ECT	Exciter Regulator
EDP	Engine-Driven Pump
EPV	Explosive Valve
FAN	Motor-Driven Fan
FLT	Filter
FPS	Flow Process Switch
FST	Flow Sensor/Transmitter Unit
FUS	Fuse
HDV	Hydraulic Valve
HRU	Hydrogen Recombiner Unit
HTR	Heater Element
HTX	Heat Exchanger
ICC	Instrumentation and Control Circuit
INV	Inverter
ISL	Instrument Sensing Line
ISO	Electric Isolation Device
LOG	Logic Unit
LPS	Level Process Switch
LPW	Local Power Supply

Table 2-3
Event And Component Type Identifiers (Continued)

Identifier (YYY)	Component/Event
LST	Level Sensor/Transmitter Unit
LSW	Limit Switch
MDC	Motor-Driven Compressor
MDP	Motor-Driven Pump
MGN	Motor-Generator Unit
MOD	Motor-Operated Damper
MOV	Motor-Operated Valve
NOZ	Nozzle
NST	Neutron Flux Sensor/Transmitter Unit
ORF	Orifice
PHT	Pipe Heat Tracing
PIP	Piping
PND	Pneumatic/Hydraulic Damper
PPS	Pressure Process switch
PRV	Power-Operated Relief Valve
PST	Pressure Sensor/Transmitter Unit
REC	Rectifier
RLY	Relay and Contactor Unit
RST	Radiation Sensor/Transmitter Unit
SCV	Stop-Check Valve
SDT	Steam-Driven Turbine
SOV	Solenoid-Operated Valve
SPE	Special Event
SPV	Spring Diaphragm (Pressure Regulating) Valve
SRV	Safety/Relief Valve
STR	Strainer
TAC	AC Electrical Train
TCV	Testable Check Valve
TDC	DC Electrical Train
TDP	Turbine-Driven Pump
TFM	Transformer
TNK	Tank
TPS	Temperature Process Switch
TST	Temperature Sensor/Transmitter Unit
TSW	Transfer Switch
TXX	Bistable Trip Unit
XDM	Manual Damper
XHE	Operator Action
XVM	Manual Valve
ZST	Physical Position Sensor/Transmitter Unit
ZSW	Manual Control Switch

TABLE 2-4

FAILURE MODE IDENTIFIERS

Code (ZZ)	Failure Mode
Valves, Dampers, Relays, Circuit Breakers and Switches (Demand Failures):	
FT	Fails to Transfer
OO	Normally Open, Remains Open (Fails to Close)
OC	Normally Open, Fails Closed (Fails to Remain Open)
CC	Normally Closed, Remains Closed (Fails to Open)
CO	Normally Closed, Fails Open (Fails to Remain Closed)
Valves, Filters, Orifices, Heat Exchangers, Piping, and Nozzles (Time Failures):	
PG	Plugged
IL	Internal Leakage
Pumps, Motors, Diesels, Turbines, Fans and Compressors:	
FS	Fail to Start (Demand Failure)
FR	Fail to Continue Operating (Time Failure)
Sensors, Signal Conditioners, and Bistable (Time Failures):	
HI	Fail High
LO	Fail Low
NO	No Output
Segments, Trains, and Miscellaneous Agglomerations:	
LF	Loss of Flow, No Flow (Time Failure)
AF	Actuation Fails (Demand Failure)
LP	Loss of Power, No Power (Time Failure)
VF	Failure (for miscellaneous fault agglomerations) (Demand Failure)
SA	Spurious Actuation (use CO or OC for valves and dampers) (Demand Failure)
Batteries, Buses, and Transformers (Time Failures):	
LP	Loss of Power, No Pow
ST	Short
OP	Open

Table 2-4

Failure Mode Identifiers (Continued)

Code (ZZ)	Failure Mode
Tanks, Pipes, Seals, Tubes, Valves, Pumps, Ducts, Dampers, and Fans (Time Failures):	
LK	Leak (only used in exceptional cases)
RP	Rupture (only used in exceptional cases)
Human Errors (Demand Failures):	
FO	Failure to Operate
MC	Miscalibrate
RE	Fail to Restore from Test or Maintenance
Normal Operations (unavailable because of a planned activity (Demand Failure):	
TM	Test or Maintenance

TABLE 2-5

FAULT TREE DEVELOPMENT GENERAL GUIDELINES

<u>Assumption</u>

1. In general, spurious actuation or trip events were not modeled. (The system operational history was reviewed to verify that such events had not occurred in the past.)

2. In general, piping and valve ruptures were not modeled. (The system operational history was reviewed to verify this.)

3. Plugging of valves or piping was not modeled unless one of the following was true:
   - The valve or pipe is not flow tested.
   - The interval between flow tests is several years or more.
   - The valve or pipe is in a "dirty" system (seawater, borated water, etc).

4. Tabular OR gates were not used.

5. Only AND and OR gates were used. Only basic, developed, and undeveloped events were used.

6. For valves, the following were considered to be part of the basic event for valve failure:
   - mechanical valve body,
   - driver (operator),
   - local I&C circuitry (mounted on or near the valve body), and
   - limit or torque switches.

7. For pumps, the following were considered to be part of the basic event(s) for pump failure:
   - mechanical pump body,
   - driver,
   - local I&C circuitry (mounted on or near the pump body),
   - torque switches, and
   - local self-cooling systems.

8. Operator failure to restore (mispositioning) events were not modeled if any of the following were true:
   - Auto-realignment of the component occurs when the system is demanded.
   - Testing following maintenance would indicate a failure to restore.
   - The component is not aligned away from its normal position during maintenance.
   - Mispositioning is annunciated in the control room or is checked each shift or daily.

Table 2-5

Fault Tree Development General Guidelines (Continued)

Assumption

9. Test outage contributions were not modeled if any of the following were true:
   - No testing is allowed while the plant is in modes 1 or 2.
   - Auto-realignment occurs if the system is demanded.
   - The system or channel or component is in a fail-safe condition during the test. For example, the component is not aligned away from its normal position during the test. Another example is an RPS channel being put in the trip position during a test.

10. The following types of human errors were modeled:
    - restoration errors following tests or maintenance,
    - calibration errors,
    - manual initiation (from the control room) of systems, and
    - other normal manual actions outlined in system operating procedures and performed from the control room.

11. Dependent failures were, in general, modeled explicitly in the fault trees.

12. Diversion paths with pipe diameters less than one-third that of the primary path were ignored for once-through systems. For closed systems all significant diversion paths were considered.

13. For each component which receives an automatic actuation signal, the actuation failure was divided into a developed event (top event in an actuation fault tree) and an undeveloped event (all other actuation and control circuitry associated with the components). The undeveloped event was designated by ICC-AF in the event identifier.

14. For large motor-driven pumps, the circuit breaker between the motive power bus and the pump was modeled as a separate basic event. For small pumps and valves, the motive power circuit breaker was lumped into the component instrumentation and control undeveloped event. (In the latter code, the circuit breaker is normally closed, and power to the component is controlled by contacts.)

3.0 FRONT-END ANALYSIS

This chapter describes the methods and results of evaluating the frequency of accident sequences which result in severe core damage at HCGS. The accident sequences which have the potential to cause core damage represent the input for the containment performance analysis given in Chapter 4.

3.1 Accident Sequence Delineation

Practically speaking, there are an infinite number of potential arrangements or combinations of failed/successful equipment and human actions in a nuclear power plant. Most of these success/failure combinations will not result in core damage. However, a small fraction of the success/failure combinations may result in severe core damage. The objective of this section is to delineate the core damage sequences in a measurable way. The approach selected in this report, and fully described in Chapter 2, is based on delineating the accident sequences according to their initiating events. After defining an accident sequence initiating event, this approach combines (links) the fault trees for the event-tree top events (failed and/or successful functional system headings) to form a new set of events, which are the core damage accident sequences.

3.1.1 Initiating Events Identification and Quantification

This section describes the methodology that was used to identify and quantify the initiating events for HCGS. An initiating event is defined as an anomalous event that requires or causes a plant shutdown and challenges the plant safety systems. For such events, subsequent failures in safety systems could result in core damage and radionuclide release from the fuel. Only the internal initiating events which arise from failures within the plant are considered. External events such as earthquakes, external flooding, fire, and turbine missiles are excluded.

At the time of the initiating event, the reactor is assumed to be in a steady state at full power operation. Initiating events occurring during shutdown or refueling were not considered, nor were those events concerned with sources of radioactivity other than the core.

3.1.1.1 Initiating Events Identification

The methodology used for initiating event identification is described in NUREG/CR2300 (Reference 3.1.1-1). The identification process was performed in two steps, first on a generic basis and second on a plant-specific basis. The generic sources for identifying and quantifying initiating events included a survey of U.S. boiling water reactor (BWR) experience. This survey included EPRI NP-2230, NUREG/CR-3863, LER search covering 1984 through 1989, and previously performed PRA studies (Brunswick, Shoreham, Limerick, Peach Bottom, Grand Gulf). As a result of the first step, 55 initiating events were identified as potentially applicable to HCGS.

Many initiating events have an identical or very similar impact on the plant. Therefore, similar events were grouped into two classes: transients and LOCAs. A transient event is defined as any event which does not cause a direct breach in the primary cooling system boundaries of the reactor. The transient category may be further divided into general and special initiators. The special initiators generally involve failures in support systems that result in a plant trip and adversely affect one or more safety systems. A LOCA initiating event is defined as any event which involves a breach (small, intermediate, or large) of the primary cooling system boundaries of the reactor. The LOCA category may be further subdivided into LOCAs within containment and interfacing system LOCAs (ISLOCAs).

An internal flooding study was conducted to identify flooding events which would necessitate a plant shutdown with the potential for core damage. Internal flooding differs from LOCA or ISLOCA in that the flooding water source does not originate (directly or indirectly) in the primary reactor coolant system.

The second step in identifying initiating events included the performance of a detailed study of HCGS design and plant operating experience. This task was further divided into two subtasks: evaluation of the initiators identified in the first step to determine their applicability to HCGS, and identification of HCGS-specific initiators not previously identified during the generic industry review. A key aspect of the analysis was to determine whether peculiar features of the plant could pose potential challenges to plant systems if these systems failed to operate as designed.

The data base collected for Hope Creek covers the entire available operational experience, starting from 1986, when Hope Creek was connected to the grid, and ending on July 31, 1993. The study validated for HCGS the general trend in the industry of reduction of the frequency of inadvertent trips (initiating events).

In addition, all support systems for HCGS were examined to determine if loss of each support system would cause a plant trip and concurrently degrade one or more of the systems required to mitigate the event (e.g., HPCI, RCIC). Such a search was used to identify plant-specific "special initiators" or "special transients." However, if any of the events discussed below cause only an administrative shutdown, particularly after multiple days, due to a limiting condition for operation (LCO) in an orderly manner (i.e., manual shutdown), then such an event is not treated as a special initiator in this study. The search for special initiators, based on Hope Creek's design, included review of the following <u>potential</u> special initiators:

<u>Service Water Systems:</u>

- Station Service Water
- Safety Auxiliaries Cooling System
- Turbine Auxiliaries Cooling System
- Reactor Auxiliary Cooling System

Power Systems:

Class 1E AC Bus Systems
Class 1E DC Bus Systems

Compressed Gas System:

Instrument Air/Service Air System
Instrument Gas System

HVAC Systems:

Diesel Room HVAC
Switchgear Room Cooling
SACS Room Cooling
Control Room Cooling
Control Equipment Room Cooling
Class 1E Panel Room Supply
Emergency Area Coolers
Service Water Intake Structure Ventilation
Traveling Screen Motor Room Ventilation
Steam Tunnel Cooling supplied by Turbine Building Chilled Water
Reactor Building Ventilation
Turbine Building Ventilation/Chilled Water
Control Area Chilled Water (for numerous HVACs)
Safety Related Panel Room Chilled Water

The following summarize the results of this review.

Service Water

Procedure HC.OP-AB.ZZ-0122(Q) addresses operational response to Service Water malfunctions. The procedure basically calls for reducing reactor power and heat loads in an attempt to keep the plant on-line while the malfunction is corrected. The one exception notes that if RACS must be isolated to repair a leak, the unit must be shut down. However, if the entire system were to be lost and expected to be non-recoverable for some time, operators would need to initiate a forced shutdown of the plant because of the concern for RACS, SACS and TACS heatups. Particularly, operators would monitor heat loads and eventually begin a shutdown. Since the Delaware river is the ultimate heat sink for the entire plant, the loss of this system would clearly affect multiple mitigating systems at the same time. Thus, loss of Service Water is treated as a special initiator.

SACS

Procedure HC.OP-AB.ZZ-0124(Q) addresses malfunctions in this system. The procedure states that if both SACS loops are lost and cannot be restored, scram the reactor. Operators would monitor heat loads and initiate a forced shutdown as required to avoid equipment damage. Hence, loss of this system calls for an eventual trip (loss of TACS would also be induced, probably leading to a trip) and the SACS loss would also affect many mitigating systems. Loss of SACS is, therefore, a special initiator. However, note that the CRD and RACS would still be initially available (to differentiate this event from the loss of Service Water) since these systems are not cooled by SACS.

TACS

Procedure HC.OP-AB.ZZ-0148(Q) addresses TACS malfunctions. The procedure clearly calls for a trip on a complete and sustained loss of TACS. Hence, such a loss meets the trip portion of the definition to be a special initiator. However, TACS failure affects only the secondary side of the plant and cooling to the station air compressors. There are still many mitigating systems not affected. The instrument air still has a backup using the emergency instrument air compressor. Hence, loss of TACS does not significantly affect mitigating capability to shut down from a loss of TACS, so this is not considered a special initiator. Loss of TACS can instead be treated as a loss of the secondary side of the plant (including loss of condensate since the secondary condensate pumps require cooling from TACS) which is already covered as a transient initiator.

RACS

Procedure HC.OP-AB.ZZ-123(Q) addresses RACS malfunctions. The procedure indicates the need to scram and shutdown within 10 minutes to avoid reactor recirculation pump seal damage. Based on the expected quick isolation of the Gaseous Radwaste System, condenser back pressure could increase, but this should be easily controlled using the mechanical vacuum pumps. Hence, this event is similar to a turbine trip. RACS cools CRD which is credited in the PRA as a possible RPV injection source. Because both a reactor scram will occur and CRD operability is affected, loss of RACS is treated as a special initiator.

Class 1E AC Bus Systems NOTE: Non-Class 1E AC systems do not support mitigating systems such as HPCI, LPCI, etc., and so were included in the Turbine Trip initiator.

Because of the typical independence of Class 1E divisions in nuclear plants and the typically low frequencies of losing an AC bus, the search for special initiators has usually involved examining the loss of one division of AC (at most) at any one time. Much of the AC system bus loading has been reviewed to see if loss of any one division of AC power (e.g., loss of 4160 VAC Div. A) would cause a scram, since obviously such a loss would affect at least one train of many mitigating systems. A systematic search of the loads on each bus has identified only one possibility in which one division loss of AC would induce a possible scram at Hope Creek. Other plants have found that this could occur due to isolation or failure of air or other systems that could cause leakdown of the air to the scram pilot valves, thereby causing rod drift into the core or, for example, degraded drywell cooling so that a high drywell pressure could occur. No such causes of a trip have been found at Hope Creek due to a single division failure. The one exception is unit substation 480V-10B420. Loss of this particular AC supply, by itself, can cause a diversion of RACS flow around the heat exchangers, thereby leading to a loss of RACS cooling. Loss of RACS has been identified as a special initiator as mentioned above. Loss of this particular substation does not significantly impact other systems in the plant and, hence, it is virtually a loss of RACS. Additionally, the frequency of loss of this substation is relatively low compared with the loss of RACS frequency. Because the effects of loss of this substation can be treated as part of loss of RACS, loss of this power supply will not be a significant contributor to core damage as compared to other turbine trip initiators or loss of RACS. Hence, such a loss is not treated as a special initiator in the HCGS IPE. Nevertheless, because of uncertainties in the ability to review every possible circuit in the plant to assure a scram would not occur, this is examined in a sensitivity analysis in Section 3.4.1.4.

Class 1E DC Bus Systems

Similar discussion as for the AC system is applicable here. A sensitivity analysis is performed in Section 3.4.1.4.

Instrument Air/Service Air

Procedure HC.OP-AB.ZZ-0131(Q) addresses loss of these systems. As the procedure indicates, total loss of this interconnected system would lead to such events as control rods drifting in, loss of condensate/feedwater, slow closure of outboard MSIVs, etc., resulting in a reactor scram. Because such a loss would concurrently affect one pneumatic supply used for containment venting (there is also a set of backup nitrogen bottles) and fail one of the two RPV injection headers for CRD (the charging water header would still be available), loss of Instrument/Service Air is treated as a special initiator.

Instrument Gas

Procedure HC.OP-AB.ZZ-0133(Q) addresses this loss. The concern associated with this malfunction is the closure of inboard MSIVs and the ability to operate SRVs long-term. In this case, however, there is a very easy and proceduralized recovery action which is to manually valve in the instrument air (this is a backup to instrument gas) which would prevent any trip situation from ultimately occurring because of MSIVs drifting closed. Operators are required to monitor drywell oxygen concentration for this lineup. Also, loss of instrument gas does not really fail any mitigating system since the SRVs can still be used for a considerable time period by cycling different valves, using accumulator-supplied nitrogen. Based on the high likelihood of recovering from this event and the limited effect on SRV operability, loss of Instrument Gas is not considered a special initiator.

Diesel Room HVAC

These systems cool the diesel generators when required; however, the diesels are required only under loss of normal power conditions. Hence, if a diesel room cooling system were to fail as an initiator during normal operations, no plant trip would occur. At most, an LCO-forced shutdown in a controlled manner would occur but with offsite power still available. Hence, there would be no loss of AC power and so no mitigating systems would be affected. Therefore, this is not a special initiator.

Switchgear Room Cooling

This is made up of four separate and independent HVAC sub-systems much like the AC/DC divisions. Any one failure would at most affect only one division of power and, based on the findings, is not a concern. It will take multiple failures of switchgear room cooling particularly due to common-cause mechanisms, to be of concern. Furthermore, based on room heatup calculations and review of the system, loss of switchgear room cooling is expected to be dominated by loss of all fans or the combination of loss of control area chilled water and loss of fresh air intake. As such, loss of Switchgear Room Cooling is treated as a special initiator, but as part of a more global initiator called loss of HVAC.

SACS Room Cooling

Room heatup calculations show a high probability that SACS pumps can operate without SACS room cooling for at least a day or longer. Loss of this room cooling is, therefore, not a special initiator and is already bounded by the loss of SACS itself.

Control Room Cooling

Procedure HC.OP-AR.ZZ-0019(Q) addresses Control Area HVAC malfunctions and notes that easy recoverable actions are proceduralized involving opening doors, opening panels, and providing temporary forced ventilation if all control ventilation is lost. A calculation also indicates that several hours (at least 3 hours) would be available before a significant concern might arise, even if no actions were taken. If both control room ventilation subsystems become inoperable as defined in Technical Specification 3.7.2, then commencement of a reactor shutdown is required as defined by Technical Specification 3.0.3. Technical Specifications (3/4.7.2) requires commencing shutdown of the plant within one hour after the event if cooling were not restored. If the main control room became uninhabitable due to high temperature, procedure HC.OP-AB.ZZ-0130(Q), Control Room Evacuation, would be carried out involving shutdown from the remote shutdown area. The easy detection and recovery of this event, the time to perform recovery or repair actions, and the last resort recovery action all suggest this need not be treated as a special initiator since the shutdown would be done in a controlled fashion without significant effects on mitigating system operability.

Control Equipment Room Cooling

The effects of Loss of Control Equipment Room Cooling are bounded by the more serious loss of switchgear room cooling and so are not treated as a different special initiator.

Class 1E Panel Room Supply

This system serves several areas such as, inverter, battery, battery charger. In particular, some normal plant operating controls and such systems as SACS, HPCI, and RCIC could be affected by high temperature in the relay room below the control rooms in about one-half day. Hence, based on the potential for subsequent loss of room cooling-induced failures of the equipment served by this system, loss of this system is considered to be a special initiator. Loss of this system or its supporting Safety-Related Panel Chilled Water System in conjunction with loss of fresh air intake for the panel room HVAC would have similar effects on the plant. Hence, the potential loss of either system is treated as the same initiator as part of the more global loss of HVAC event.

Equipment Area Coolers

With the exception of SACS, these coolers serve systems not normally operating and so loss of any one these systems during normal operation would not induce a short-term trip, but at most a controlled shutdown. SACS room heatup calculations show no failures within 24 hours. Therefore, these equipment area coolers are not treated as special initiators.

Service Water Intake Structure Ventilation

Service Water pump room heatup calculations show that the small amount of air infiltration available without ventilation and with all SSW pumps running, leads to equipment qualification limits being exceeded in approximately 8 hours. Compared with the loss of SSW itself, which affects plant systems within one hour, loss of ventilation is a much slower acting event easily detected and can be mitigated by providing air flow to the room. Hence, this event is bounded by the loss of SSW initiator, and so loss of this ventilation system will not be treated as a special initiator.

Traveling Screen Motor Room Ventilation

Assessment of heat loads, room size and configuration show that this event is not likely to cause loss of SSW function and is bounded by the loss of SSW itself, which will have a more immediate impact on the plant. Hence, loss of this ventilation system is not a special initiator.

Steam Tunnel Cooling/Turbine Building Chilled Water

Loss of steam tunnel cooling can potentially cause an MSIV closure on high temperature (160°F) but this is the only effect. This is included in the general MSIV closure initiator, and so loss of Steam Tunnel Cooling is not a special initiator. The MSIV closure initiating event frequency includes the contribution of the potential failure of the steam tunnel cooling. However, this is a negligible contribution (approximately one percent, or less) to the total frequency of the MSIV closure.

Reactor Building Ventilation

If the normally operating RBVS were to be totally lost, temperatures in the reactor building would rise somewhat but not likely affect equipment in the reactor building (such equipment as RACS pumps, CRD pumps, MCCs of many systems). Room heatup calculations show that some confined areas served by this system do not rise in temperature significantly. Additionally, such an event would be detected and alarmed, and an operational recovery action is called for involving start of the FRVS which could independently provide the necessary cooling. In fact, tests are performed monthly at the plant in which the reactor building is cooled for 20 hours at a time using FRVS. Hence, no trip of the plant or adverse conditions would be expected unless both systems were to fail. Therefore, loss of RBVS is not considered a special initiator.

Turbine Building Ventilation/Chilled Water

Loss of this system (or the turbine building chilled water as a support) would affect only balance of plant equipment (without backup), leaving other mitigating systems unaffected. These effects are adequately covered by other non-special initiators such as turbine trip, etc. Also, the large size of the turbine building and the ability to open the building to the environment will likely prevent high temperatures in this area. Hence, the loss of this system is not treated as a special initiator.

Control Area Chilled Water

This system was mentioned earlier under the Switchgear Room discussion. The Control Area Chilled Water serves numerous rooms' HVAC equipment. Loss of refrigeration by this system concurrent with loss of fresh air intake which provides some cooling, could cause simultaneous multiple room heatups, thereby potentially causing a plant trip due to equipment failure or Technical Specification requirements (e.g., Control Room HVAC) as a result of rising temperatures, as well as room heatup-induced failures of mitigating system equipment such as multiple switchgear for AC power possibly within a day time period. Such a wide-spread potential effect (similar to the wide-spread effects caused by a loss of service water) provides justification to examine loss of Control Area Chilled Water as part of the global loss of HVAC event.

Safety-Related Panel Room Chilled Water

See discussion under Panel Room Supply.

SUMMARY OF SPECIAL INITIATORS

The resulting special initiators are, therefore, loss of Service Water, loss of SACS (loss of SSW or SACS are grouped together into a "loss of heat sink" type event), loss of RACS, loss of Instrument/Service Air, loss of Switchgear/Class 1E Panel Room Supplies (including loss of Safety-Related Panel Room Chilled Water and loss of Controlled Area Chilled Water). Loss of the HVAC/Chilled Water systems are combined into a single "loss of HVAC" event.

It should be noted that some of the special initiators considered here are not necessarily always initiating events if the loss is not sustained for a sufficiently long period. For example, a short-term loss of the SACS subsystem may not require immediate manual shutdown. If SACS is recovered soon enough, support systems will not overheat, and a trip will not occur (or be necessary). Nevertheless, the present study conservatively assumes that each loss is sufficiently long to result in a special initiating event.

Loss of Coolant Accidents

The LOCA search for the HCGS was divided into two categories: LOCAs inside and outside containment. For LOCAs within containment, LOCA events can be divided according to the size of the break. NEDO-24708A (Reference 3.1.1-2) indicates that liquid pipe breaks up to approximately 0.005 ft^2 (1-inch diameter) can be handled by RCIC. A large LOCA is defined as a steam or liquid pipe break large enough to cause rapid vessel depressurization. Based on NEDO-24708A, steam and liquid pipe break sizes larger than 0.3 ft^2 (8-inch diameter) were considered to be large LOCAs. Intermediate LOCAs are liquid pipe breaks of the range 0.005 to 0.3 ft^2 and steam pipe breaks of the range 0.1 to 0.3 ft^2. Another category of LOCA is the excessive LOCA. The excessive LOCA is defined as a LOCA event beyond the capability of the ECCS. For HCGS, the only case of excessive LOCA is a large reactor vessel rupture.

ISLOCAs are another type of LOCA, and are located outside the containment. An ISLOCA is one in which the barriers between the high pressure reactor coolant system and an adjoining low pressure system fail, permitting the high pressure reactor cooling water to enter the low pressure system. The primary importance of the ISLOCA sequences is that they have the potential to create a direct release pathway from the reactor cooling system to the environment (through the reactor building).

A survey of HCGS high-to-low pressure piping interfaces was performed (Reference 3.1.1-3) for the purpose of determining interfaces that could reasonably contribute to the risk of ISLOCAs or that could bypass the containment. "Low pressure" piping systems are susceptible to rupture if they are opened to reactor coolant at high pressure. Seventy interfaces were identified from the survey. Nine interfaces were deemed to warrant further analysis and consisted of seven RHR lines (including injection, suction, and return lines), and two CSS injection lines. These interfaces were evaluated quantitatively.

Other LOCAs outside containment (e.g., main steam line), with failure to isolate were deemed too improbable as compared to the nine ISLOCAs, and so were not analyzed further.

Internal Flooding

Records of previous flooding events were reviewed to ascertain the types of flood scenarios which have occurred previously in United States nuclear plants. The actual Hope Creek plant operating experience was reviewed over the same time frame as the study database. No internal flood event caused a unit trip or disabled safety-related equipment during normal power operation. All of the areas of the plant were reviewed and evaluated for internal flooding (Reference 3.1.1-7). This study also identified all equipment by building, elevation, room numbers, design and expected maximum flood levels.

Modeling of flooding events identified sources of flooding which include leaking pipes, heat exchangers, tanks, gaskets, valve stems, pumps which are running during normal plant operation, and isolation valves used during TM activity.

The following assumptions were made concerning modeling of flood initiators:

- Pipe lengths (from which the frequency of rupture was calculated) and pipe diameters were determined from the piping isometric diagrams.
- Tank ruptures were assumed to result in the complete spilling of tank contents.
- The analysis of isolation valve leakage was limited to TM activity of pumps, and excluded that of valves, heat exchangers, gaskets and other pipe fittings.
- Any flooding event whose source is the reactor system that could be classified as a small, medium, or large LOCA is not evaluated in this section. This includes smaller instrumentation lines as well as sections of the RWCU system which are not isolated from the reactor system. Any such event is modeled directly in the event trees described in Section 3.1.2, which are based on actual historical operational experience.

3.1.1.2 Initiating Events Categorization

To optimize the event tree development efforts, the initiating events identified for Hope Creek were grouped into categories. Grouping was accomplished by examining each of the following initiating events for its effects on the plant:

1. Trip signals expected following the initiator,
2. Plant systems required to respond to the initiator, and
3. Effect of the initiator on the availability of plant systems required to respond.

Final initiating event categories for HCGS are shown in Table 3.1.1-1. The un' e characteristics of each category are also listed in the table.

The events considered for the flood initiators fall into three categories:

A. Equipment submergence,

B. Water spray, and

C. Inadvertent actuation of fire sprinkler systems.

The initiating events which occurred at Hope Creek are listed in Table 3.1.1-2. This table also shows the initiating event category to which they belong.

3.1.1.3 <u>Initiating Events Quantification</u>

Initiating events were quantified individually. Then the results were summed to obtain event category frequencies. Quantification of the individual initiators involved five listed distinct cases:

1. General transients,

2. Special transients,

3. LOCAs,

4. Interfacing system LOCAs, and

5. Internal flooding.

Each of them is discussed individually.

For the general transients, a generic frequency distribution was determined, based on NUREG/CR-3862 (Reference 3.1.1-4). However, Hope Creek trip events (general transient events) covering operation through July 31, 1993 were summarized and used, because it reflected better plant-specific experience. The HCGS loss of power (LOP) frequency was calculated from data taken from NSAC-182 (Reference 3.1.1-5).

It should be noted that the special transient initiating events are generally rare events. It is not practical to estimate their occurrence frequencies only from experience data. Therefore, the special transients were quantified on a case-by-case basis by quantifying the fault trees for these systems (SSW, SACS, etc.) characteristic of a year's exposure time to obtain a yearly frequency estimate.

LOCAs inside containment were assigned frequencies based on a survey of past PRAs and EPRI analyses. Table 3.1.1-3 summarizes the LOCA frequencies for HCGS and presents, as a means of comparison, LOCA initiator frequencies used in previously performed BWR PRAs. A dedicated analysis was performed for HCGS to evaluate the occurrence frequencies of ISLOCA initiating events outside containment. Seventy potential interfacing LOCA paths were identified, and sixty-one were screened out. The remaining nine ISLOCA paths include those associated with the high pressure RCS water entering the RHR or CSS systems via either the suction line or at least one of the RHR or CSS injection lines. These are the so-called V sequences as defined in WASH-1400. The ISLOCA initiating events flow paths are defined as the following:

1. Core spray pump BP206/DP206 discharge line,

2. Core spray pump AP206/CP206 discharge line,

3. RHR pump AP202 discharge line (LPCI),

4. RHR pump BP202 discharge line (LPCI),

5. RHR pump CP202 discharge line (LPCI),

6. RHR pump DP202 discharge line (LPCI),

7. RHR pump AP202/BP202 suction from reactor recirculation Loop B suction header (SDC),

8. RHR pump BP202 return line to recirculation Loop B (SDC), and

9. RHR pump AP202 return line to recirculation Loop A (SDC).

Internal flooding initiating event frequencies were calculated individually for each room exposed to the hazard of internal flooding. Initiated floods may be isolated by the operators before plant equipment is damaged. For this analysis, a 30 minute period following the initiation of the flooding event was allowed for the operators to attempt to isolate the flood. Table 3.1.1-4 summarizes all these Hope Creek room numbers (first column), their respective total flood initiating event frequencies (second column), a 30 minute isolation failure (third column) and the unisolated flood frequency.

The integrated results from the initiating event frequency analysis are summarized in Table 3.1.1-5.

3.1.1.4 Success Criteria

After the occurrence of an initiating event, the successful shutdown of the reactor depends on the success and failure combinations of a large number of equipment components and human actions. For each initiating event, success criteria represent the minimum combination of systems, trains, loops, components or human actions that will accomplish the necessary functions to prevent core damage. These functions appear typically as event headings in the event trees. Seven functional event headings were used for the HCGS IPE. They are:

1. Reactivity control, to stop the chain reaction in the core, and reduce the power to decay heat levels.

2. Reactor primary coolant system integrity.

3. High pressure primary coolant inventory control.

4. Early containment pressure and temperature control.

5. Reactor vessel depressurization.

6. Low pressure primary coolant inventory control.

7. Long term heat removal via either PCS or containment pressure and temperature control.

The outcome of the successful or failed status of these top functions determine if the core is damaged or not. The criterion used to determine core integrity or core damage is water level sufficiently low that average core temperatures predict significant clad oxidation, and clad damage and the onset of fuel melt. This is typically expected to occur when the sustained vessel level is approximately 1/3 core height using the MAAP code modeling. Large uncertainties can exist regarding the phenomenology associated with core degradation and the acceptance criteria may not be universally applied under every possible scenario. However, the criteria were conservatively chosen, so that the impact of the success criteria on the core damage frequency is limited. To reduce the uncertainties, specific success criteria were defined for each initiating event. Success criteria for each individual initiating event and their justifications are given in the next sections. The justifications are based on system flow capabilities, success criteria used in other PRAs where applicable similarities exist, and a number of MAAP calculations. The success criteria tables (Tables 3.1.1-6 to 3.1.1-19) show where uncertain criteria were validated by MAAP calculations.

3.1.1.4.1 Turbine Trip Success Criteria

Success criteria for a turbine trip, which is a transient with PCS available, are shown in Table 3.1.1-6.

For reactivity control to be successful, sufficient rods must be inserted within approximately 1/2 minute. At least several rods would have to fail to insert in order to fail to shut down the unit. If this function fails, then an ATWS state exists, for which a separate set of success criteria apply (see Section 3.1.1.4.14).

Reactor coolant system integrity involves two separate concerns: automatic opening of SRVs when pressure increases, and automatic reclosing of the SRVs after the pressure is reduced. Failure to open SRVs on demand is very unlikely, due to the high redundancy and separation between the SRVs and the small number of open valves required. For scenarios with PCS available, two open valves, out of 14, are sufficient to avoid reactor overpressurization (per MAAP calculation).

High pressure inventory control is normally accomplished by one out of three feedwater trains. If the initiating event included the loss of one or two of the feedwater trains, then the redundancy of feedwater is decreased. However, the probability of loosing the rest of the feedwater due to high level trip and/or operator errors is significantly larger than due to the reduction in the redundancy of the feedwater trains. Moreover, if a lower number of feedwater trains is available the risk of excessive increase in reactor level diminishes. If feedwater is unavailable, successful injection by the turbine driven RCIC or HPCI pumps is acceptable. HPCI and RCIC initiation is automatic, with manual backup. MAAP calculations show that after approximately 2 hours, 2 CRD pumps with enhanced flow is sufficient, at high or low pressure, to maintain coolant inventory. CRD needs manual alignment and initiation.

Early containment pressure and temperature control are not required for this transient, because no fluid is expected to accumulate in the containment, and most of the decay heat is being transferred to the condenser; therefore, there is no challenge to the containment.

Reactor depressurization, if required, is successful if the turbine bypass valves are open to the main condenser. Based on MAAP calculations, rapid depressurization is successful if two out of 14 SRVs are opened manually allowing for low pressure injection.

Low pressure inventory control is successful if one out of three condensate trains, or one out of four LPCI/RHR loops, or one out of two core spray loops (with two pumps per loop) is successful. LPCI and core spray initiate automatically, with manual backup. CRD can maintain level after other successful injection (see CRD discussion above).

In addition, 2 of 2 condensate transfer pumps cross-tied to LPCI or core spray with a diesel or motor-driven fire pump cross tied to LPCI, can together provide sufficient flow for long term make-up. Note that because it will take time to align these alternate makeup water sources for injection, or because of their relatively low flow rating, these systems are credited only long term cooling. While service water cross-tied through LPCI could be used, credit is conservatively not given in the analysis.

Long term heat removal is achieved through normal heat removal to the condenser or one out of two RHR pumps in the SPC or CSC mode, or containment venting. To get to cold shutdown the SDC mode of RHR could be used, but is not credited here to make the modeling simpler and since achievement of successful hot shutdown status is sufficient for the present IPE/PRA purposes.

3.1.1.4.2 Loss of Condenser (Vacuum) Success Criteria

Success criteria for a loss of condenser vacuum, which is a transient with PCS initially unavailable, are shown in Table 3.1.1-7. The success criteria for this transient are similar to those of a turbine trip with the following exceptions or clarifications:

Reactor coolant system integrity requires more SRVs to open to relieve pressure when the MSIVs are closed. MAAP estimates are that at least 5 SRVs, out of 14, must open.
Initial high pressure inventory control can be accomplished by the turbine driven RCIC or HPCI pumps only, because steam flow is shut off from the turbine driven feedwater pumps, due to the MSIV closure and feedwater cannot be used. CRD is still available to maintain level with 2 pump enhanced flow after approximately 2 hours. Secondary condensate pumps are available at 700 psig reactor pressure for RPV water level control.

Early containment pressure and temperature control is challenged as a result of SRV discharge to the pool, but not enough to cause failure before RHR is initiated. Hence this function is considered unnecessary.

If high pressure inventory control is not successful, reactor vessel depressurization can be achieved either with HPCI in full flow test mode (which is the normal, slow depressurization) or with two out of 14 SRVs opened manually (which is an emergency, faster depressurization). Turbine bypass valves cannot be used in this case, because the MSIVs are closed.

Long term heat removal is achieved through one out of two (A or B) RHR pumps in the SPC or CSC mode, or containment venting. PCS is not available for this initiator.

3.1.1.4.3 MSIV Closure Success Criteria

Success criteria for MSIV closure, which is a transient with PCS initially unavailable, are shown in Table 3.1.1-8. The success criteria for this transient are identical to the loss of condenser vacuum. The probability of recovering the power conversion system, which includes reopening a main steam path to the condenser and use of the condensate system, is conservatively assumed to be the same for MSIV closure as for loss of condenser vacuum initiating events.

3.1.1.4.4 Loss of Feedwater Success Criteria

Success criteria for loss of feedwater are shown in Table 3.1.1-9. The success criteria for this transient are similar to the turbine trip with the following exceptions or clarifications:

High pressure inventory control is accomplished by the turbine driven RCIC or HPCI pumps. CRD can maintain level after about 2 hours.

If feedwater is quickly recovered and no MSIV closure occurs, the normal power conversion system will remain available for heat removal. If MSIV closure occurs, the reactor heat is transferred to the suppression pool, and RHR in SPC or CSC mode will be needed for containment heat removal.

3.1.1.4.5 Stuck Open Safety/Relief Valve Success Criteria

Success criteria for a stuck open safety/relief valve (SORV), which at Hope Creek is a transient with PCS available, are shown in Table 3.1.1-10. The success criteria for this transient are similar to those of a turbine trip with the following exceptions or clarifications:

The reactor coolant integrity is not maintained. However, contrary to LOCAs, no immediate harsh environment is created in the containment although some temperature rise in the suppression pool is expected.

Since at Hope Creek the MSIVs are expected to remain open, high pressure inventory control can be accomplished by feedwater, HPCI or RCIC. However, since these are all steam driven systems, they will eventually isolate (HPCI at 100 psi, RCIC at 64.5 psi) due to loss of primary steam pressure from the SORV. Note that condensate will be available once pressure has decreased below 600-700 psig.

Reactor vessel depressurization can be achieved easier because of the already stuck open valve. If more rapid depressurization is required, such as if all high pressure cooling water were to fail, additional SRVs can be opened.

While energy transfer to the pool is greater, earlier in this event, no immediate challenge to containment is expected before RHR can be initiated, especially since the MSIVs remain open.

3.1.1.4.6 Loss of Offsite Power Success Criteria

Upon occurrence of a loss of offsite power, immediate attempts are made to restore offsite power and to supply emergency onsite power via four diesel generators. The following must be considered for this event:

1. MSIVs close, because of loss of power to MSIV solenoids. Additionally, condenser vacuum is lost, because of loss of power to the circulating water pumps and other equipment.

2. HPCI and RCIC rely on DC power for starting and control. This DC power is supplied by the station batteries. Battery life is assumed to be 4 hours (minimum), if charging by AC sources is lost. Therefore, HPCI and RCIC are assumed to fail during a SBO of more than 4 hours.

3. The probabilities to recover offsite power and/or diesel generators are based on data in NSAC-182.

Considering these assumptions, the success criteria for a loss of offsite power, which is a transient with PCS initially unavailable, are shown in Table 3.1.1-11. The success criteria for this transient are similar to those of MSIV closure with the following exceptions or clarifications:

Rapid reactor depressurization, if needed (e.g., if level decreases below TAF), is successful if at least two out of 14 SRVs is opened. During SBO, long term operation of HPCI and RCIC are affected by battery depletion, containment back pressure on turbine exhausts (particularly RCIC), and high pool temperature if the pool is used for suction. Without RHR, containment pressure could compromise the required differential pressure across the SRV pilot, thereby causing SRV closure. Additionally, battery depletion can also cause failure to maintain an SRV open since DC power is required. Note that the pressure safety function of the SRV is not affected even if DC power is lost.

Only condensate and condensate transfer are directly affected by the loss of offsite power. If SBO occurs, all other low pressure inventory control is unavailable, except for the fire water system. However, by itself, sufficient flow from fire water is uncertain, because of the loss of pump head through small pipes and connections. Therefore, during SBO, no credit is taken for the fire water in the IPE.

Once offsite or onsite power is recovered, long term heat removal is achieved through normal heat removal through the condensate system, or one out of two RHR loops in SPC or CSC mode, or through containment venting. However, the availability of the RHR loops depend on the boundary conditions dictated by the timing of the recoveries.

During SBO, only containment venting is available for containment heat removal.

The maximum successful period of coolant injection during a SBO is assumed to be 6 hours, which is the designed depletion time of the batteries.

3.1.1.4.7 Large LOCA Success Criteria

Various size loss of coolant accidents were defined in section 3.1.1.1 (Initiating events identification). Success criteria for a large LOCA are shown in Table 3.1.1-12.

For reactivity control to be successful, sufficient rods must be inserted within approximately 1/2 minute. At least several rods would have to fail to insert into the core in order to fail to shut down the unit. If this function fails, then an ATWS state exists, for which a separate set of success criteria apply (see section 3.1.1.4.14).

Reactor coolant system integrity is lost for LOCA initiating events. A harsh environment will be created at the break location, due to the loss of primary coolant inventory.

High pressure inventory control is not applicable, because of a rapid depressurization of the reactor coolant system. Feedwater is also not available because of MSIV closure (at -129").

Early containment pressure and temperature control are required for this transient, because the inventory loss is expected to accumulate in the containment. This is achieved by the pressure suppression system using the torus/drywell vacuum breakers.

Reactor depressurization is successful during a large LOCA.

Low pressure inventory control is successful if one out of four LPCI loops or one out of two core spray loops is successful. Condensate is conservatively not credited as a continuous low pressure injection source since makeup to the hotwell is not sufficient to maintain NPSH for the condensate pumps. Condensate is credited as an intermittent source of water following other successful injection, once the required flow rate is small and hotwell level is likely to be maintained.

Long term heat removal is achieved through one out of two RHR loops in SPC or CSC modes or containment venting.

3.1.1.4.8 Intermediate LOCA Success Criteria

Success criteria for an intermediate LOCA are shown in Table 3.1.1-13. The success criteria for this accident are similar to those of a large LOCA with the following exceptions or clarifications:

Feedwater is again assumed to be unavailable because of MSIV closure at -129". HPCI can be used initially, because the system has sufficient flow capacity to successfully supply enough inventory to the reactor system. However, HPCI will soon fail (within less than fifteen minutes) due to loss of steam pressure.

No credit is given to RCIC, because it has insufficient coolant flow makeup capacity to compensate for the intermediate size loss of coolant initiating event.

Reactor depressurization is achieved during an intermediate LOCA by the LOCA itself. If rapid depressurization is needed (e.g., if HPCI failed) then manual opening of one or two out of 14 SRVs may be needed; particularly if the break is a water leak instead of a steam leak. Hence two SRVs are conservatively assumed to be required.

3.1.1.4.9 Small LOCA Success Criteria

Success criteria for a small LOCA are shown in Table 3.1.1-14. The success criteria for this accident are similar to those of a turbine trip transient with the following exceptions or clarifications:

Reactor coolant system integrity is not maintained for a small LOCA initiating event. A harsh environment will be created at the break location, and a small loss of primary coolant inventory occurs.

High pressure inventory control, through feedwater, HPCI, or RCIC is assumed to be successful only for a limited time, until the pressure vessel depressurizes below the design limit of the turbine driven pumps.

Note that pressure suppression is assumed to be required like the other LOCAs and CRD is not credited for injection due to uncertainties in the required flow rate depending on the size and location of the break.

The power conversion system may remain available during a small LOCA, and hence it is credited for long term heat removal because it will likely remove sufficient heat to avoid a significant challenge to containment.

If the small LOCA is a recirculation pump seal LOCA, the success criteria are similar to those of the turbine trip initiating event.

3.1.1.4.10 Loss of Instrument/Service Air Success Criteria

Loss of instrument/service air is a special initiator because (a) it affects multiple systems (e.g., control rods, outboard MSIVs, condensate/feedwater) that will cause a scram and MSIV closure, and (b) it affects one path for CRD injection as well as use of feedwater/condensate, containment venting, and backup to long term SRV operation.

The success criteria for this event are shown in Table 3.1.1-15 and are identical to that for the MSIV closure event except (a) condensate is not credited for injection, and (b) containment venting must be performed using the backup nitrogen bottle or manually. Also note that one pathway for CRD long-term injection is failed because of loss of air to the cooling water header flow control station, but the charging water header is still potentially available. Additionally, MSIV reopening and restoration of the balance-of-plant is not feasible without restoration of air.

3.1.1.4.11 Loss of RACS Success Criteria

Total loss of RACS is a special initiator in that loss of RACS (a) requires a scram within 10 minutes to avoid recirculation pump seal damage, and (b) it prevents use of CRD injection since the CRD pumps require lube oil cooling via RACS.

Success criteria for a loss of RACS is identical to that for turbine trip, except CRD injection for long term inventory control can not be used. The success criteria are shown in Table 3.1.1-16.

3.1.1.4.12 Loss of Station Service Water (SSW) or SACS Success Criteria

Loss of either service water or SACS as special initiators can be treated virtually identically although there may be sequence timing differences as well as one subtle difference. The sequence timing differences exist because of the potentially different times for heat-up of the plant loads depending on whether SSW or SACS is lost initially. The one subtle difference is that CRD and SSW for injection may be able to be operated for a while when SACS is lost (i.e., SSW is available and RACS is available for CRD pump cooling). However, effects of the loss of SACS on room cooling makes the long-term viability of CRD and SSW operation indeterminate.

Therefore to simplify the analysis, both SSW loss and SACS loss are treated the same way and without credit for long term SSW and CRD use. Table 3.1.1-17, therefore, provides the success criteria for both loss of SSW and loss of SACS. These criteria are identical to that for MSIV closure except (a) CRD, SSW, and condensate operation are not credited, (b) containment venting will require use of the nitrogen bottles or manual operation since loss of air and power occur due to loss of compressor cooling followed by battery depletion, (c) RHR cooling is not viable due to loss of the heat exchangers as a heat sink, and (d) loss of cooling can ultimately affect long-term operation of nearly all the mitigating systems in the plant.

3.1.1.4.13 Loss of HVAC Success Criteria

In this study, the general term of "Loss of HVAC" is defined as the loss of Class 1E panel room HVAC or the loss of all switchgear room HVAC. As described by the initiating event section, loss of these systems can have eventual adverse effects on several systems because of loss of room cooling to various inverter, battery and charger, relays and other electrical equipment rooms. A reactor trip could potentially be induced because of equipment heat-up and spurious operation or failure, or because the operators quickly shutdown the plant as room temperatures rise. Such an event would likely start as a turbine trip event but if not recovered, could lead to mitigating system failures, due to electrical rooms heat-up causing potential failure of electrical equipment.

Table 3.1.1-18, therefore, shows the success criteria as being the same as a turbine trip but with the overall caveat that systems can fail in the long term due to electrical equipment failures.

3.1.1.4.14 ATWS Success Criteria

Two cases are identified for anticipated transients without scram: 1) Feedwater available with MSIVs open (turbine trip type transients) and 2) MSIV closure transients (MSIV closure or loss of condenser vacuum, when feedwater is unavailable). In the former case when feedwater is available, level control is achieved, with no need of HPCI, and the initial power spike will be small. The automatic/manual actuation of SLC will successfully shutdown the plant.

The second case of MSIV closure ATWS is more of a concern, and the success criteria of Table 3.1.1-19 are focused on this initiating event. The MSIV closure ATWS is of a greater concern at Hope Creek because of the following reasons:

1. The first result of the MSIV closure ATWS is a power spike and a pressure increase which may require a number of SRVs to open, depending on the magnitude and duration of the power increase.

2. The feedwater is not available leaving only HPCI and RCIC for control level.

3. It is assumed that the operators are exposed to substantial stress during the first few minutes of an ATWS sequence. They must control level with high pressure means, and they must inhibit ADS, to avoid rapid system depressurization. The normal flow of HPCI must be modified as soon as possible (HC.OP-EO.ZZ-0322), to avoid HPCI injection inside the shroud, via the core spray flow path.

Success criteria for MSIV closure anticipated transients without scram are shown in Table 3.1.1-19 and are described in the following paragraphs.

For reactivity control to be successful after the initial failure of sufficient rod insertion within approximately 1/2 minute, both recirculation pump trips must be successful along with either fast restoration of rod insertion or poison injection by two out of two SLC pumps. At Hope Creek, SLC pumps are initiated automatically by the RRCS or manually.

Reactor coolant system integrity involves two separate concerns: opening of SRVs when pressure increases, and reclosing the SRVs after the pressure surge is over. For MSIV closure ATWS events, both concerns have a significantly higher impact than for other initiating events. Recirculation pump trip also has a depressurization effect on the primary system because it lowers the reactor power.

The demands on SRVs to open and to close will follow the power and pressure fluctuations. Due to the highly redundant SRVs (14), it is still expected, similar to other transients, that opening of SRVs on demand has a high probability of success during the first few minutes of an ATWS. However, contrary to other transient scenarios, the failure probability of SRVs to reclose is higher, due to the high number of demands.

High pressure inventory control is achieved by the RCIC pump or the HPCI pump through the flow path outside the shroud. Both pumps are turbine driven.

Early containment pressure and temperature control are required because of the high temperature expected in the suppression pool (because of numerous open SRVs). The control is achieved by using one out of two RHR loops operating in the SPC or CSC mode. This means pressure suppression operates and SRV tail pipes remain intact and wetwell/drywell vacuum breakers reclose.

Automatic reactor depressurization by the ADS system needs to be inhibited in the early stages of the event, which requires a successful human action. Normal cooldown by the operators is required in the late stages of the event, after the boron weight has been injected.

Low pressure inventory control, with special emphasis on level control, is successful if one out four LPCI, one out of two core spray loops (with two pumps per loop), or one out three condensate trains, or two out of two condensate transfer pumps and the Diesel fire pump can be used. Because of high pool temperature, core spray suction will need to be switched to the CST for continuous operation.

Long term heat removal is achieved through the power conversion system (if recovered), or RHR, or through containment venting.

3.1.1.5 References

3.1.1-1 "PRA Procedures Guide; A Guide To The Performance Of Probabilistic Risk Assessments For Nuclear Power Plants." American Nuclear Society and Institute of Electrical and Electronics Engineers, sponsored by the U.S. Nuclear Regulatory Commission and EPRI, April 1983: NUREG/CR-2300.

3.1.1-2 "Additional Information Required For NRC Staff Generic Report On Boiling Water Reactors." General Electric Co., San Jose, CA: Nuclear Fuel Division, 1980: NEDO-24708A.

3.1.1-3 "Hope Creek Generating Station ISLOCA Evaluation Report." ERIN Engineering, Doc No. C101-91-02-288, April 14, 1992.

3.1.1-4 Development Of Transient Initiating Event Frequencies For Use In Probabilistic Risk Assessments." David P. Mackowiak, Washington, D.C.: Springfield, VA: U.S. Nuclear Regulatory Commission, 1985: NUREG/CR-3862.

3.1.1-5 "Losses Of Offsite Power At U.S. Nuclear Power Plants Through 1991." EPRI, 1992: NSAC-182.

3.1.1-6 "Severe Accident Risks: An Assessment for Five U.S. Nuclear Power Plants." U.S. NRC NUREG-1150, June 1989.

3.1.1-7 "Hazards Evaluation Program." Bechtel: Design Criteria 10855-D7.3, 1987.

3.1.2 Event Tree Development

This section delineates the system and operator response that may follow the initiating events in functional event trees. Event trees are pictorial representations of significant plant responses to the initiating event categories, which were described in the last section. Each path in the event tree results in either an undamaged or a damaged core. Minor and local core damage that does not represent a safety risk is assumed in the analysis to represent an undamaged core. Event trees are developed by starting with an initiating event category and branching to the right as various safety functions are questioned for success or failure. Branches of the event trees leading to core damage are called core damage sequences and they are quantified to obtain core damage frequency estimates. A full description of the methodology of event tree analysis is given in Chapter 2 of this report.

In Section 3.1.1, fifty-five initiating events were identified for HCGS. These events were then grouped into fifteen distinct categories for input to the event tree development task (including internal flooding and interfacing system LOCAs). The Hope Creek initiating event frequencies grouped in representative categories are listed in Table 3.1.2-1.

Event trees were developed by first identifying the functions that must be fulfilled to reach a stable shutdown state. In general, the functions required are similar for all initiating event categories. Functions of concern include reactivity control (shutdown), maintenance of reactor coolant system integrity, maintenance of reactor coolant system inventory, core decay heat removal, and containment pressure and temperature control.

The event tree analysis defines the possible paths of an accident through the success and failure states of principal plant functions. The functions are defined in terms of systems and the systems in terms of components, including human actions. One of the essential elements of an event tree analysis is the determination of the success criteria, which represent the minimum complement of operable equipment and human actions required to accomplish each safety function.

The HCGS event tree analysis used the success criteria described in Section 3.1.1.4. These criteria indicate both the systems that can fulfill each function and the success criteria (e.g., one of two pumps). These success criteria are best estimates and were based on the following sources:

1. PRAs of other plants,

2. General Electric Owners Group "Emergency Procedure Guidelines" (Reference 3.1.2-1),

3. "Radionuclide Release Calculations for Selected Severe Accident Scenarios" (Reference 3.1.2-2),

4. HCGS Updated FSAR (Reference 3.1.2-3),

5. HCGS-specific thermal-hydraulic analyses performed for this study.

Construction of the HCGS event trees included a review of the HCGS Emergency Operating Procedures (Reference 3.1.2-4). In general, the event trees were constructed to model accident sequences to the point at which either significant core damage occurred or at least a stable hot shutdown was achieved. A time frame of 24 hours following an initiating event was chosen for representation in the event trees with a few exceptions such as loss of long-term heat removal. Long-term heat removal from the containment may take multiple days before either a core damage or safe state is achieved.

Certain accident sequences potentially leading to core damage can be recovered. Recovery implies regaining the use of some system or component that was initially unavailable or bypassing a failed system or component to avert core damage. For example, the loss of offsite power or the loss of HVAC (which also leads to SBO) are initiating event categories that have the potential to lead directly to core damage, if not recovered. Therefore, the event tree for these categories deal mainly with recovery of the failed systems. If the systems are not recovered within a certain time period, core damage is assumed to occur. If recovery is successful, then the sequence is considered to be successfully mitigated. Component or system level recoveries that are described clearly in the Emergency Operating Procedures were treated either in the system fault trees or as functional top headings in the event tree or as additional events added into the sequence cutsets.

A list of event tree top events is presented in Table 3.1.2-2. The sequences are tracked to either successful hot or cold shutdown, or to the point where a challenge exists to the core. Note that all sequences' outcomes belong to one of the following groups:

1. Undamaged core (safe shutdown); containment may or may not be damaged;

2. Core is damaged; occurrence frequency is calculated;

3. Sequence transfer (a sequence which strongly resembles another sequence analyzed at the transfer address).

3.1.2.1 Event Tree Model Descriptions

The following subsections contain detailed discussions of each event tree. Within each subsection, the following are discussed:

1. Initiating event category,

2. Accident sequence characterization,

3. Event tree construction.

The first event tree (turbine trip) is discussed in full detail. The rest of the subsections include only details specific to the individual event trees, that were not discussed in the turbine trip subsection.

3.1.2.1.1 Event Tree Model of the Turbine Trip Transient

1) Initiating Event Description

The turbine trip initiating event causes the closure of the turbine stop valves and, therefore, a turbine trip. This event will cause a reactor scram and a reduction in the steam flow from the reactor vessel. The feedwater control system will adjust to the reduced demand for feedwater makeup.

2) Accident Sequence Characterization

A turbine trip results in a reactor trip. This transient involves a minimal challenge to the reactor shutdown systems. Feedwater/condensate flow will be sufficient to achieve hot shutdown. Alternately, RCIC, HPCI, reactor depressurization and low pressure injection systems, together with containment heat removal, can also achieve a safe shutdown condition. Success criteria for the turbine trip transient are given in Table 3.1.1-6.

3) Event Tree Construction

The event tree for the turbine trip transient is shown in Figure 3.1.2-1. Forty-two sequences are shown, of which 20 do not lead to core damage; 4 transfer to another event tree. Each of the functional event headings listed across the top of the event tree are discussed below.

Turbine Trip Initiator (Event Tt)

There are a large number of potential causes of turbine trips. The grouping of all initiating events which were included in the category "turbine trip" is presented in Table 3.1.1-1.

Reactivity Control (Event C)

This event refers to a reactor scram required during a transient. A scram can be either automatic or manual, and it should occur within approximately 30 seconds of the transient. A scram will successfully shut down the plant unless several rods fail to insert into the core. If a sufficient number of control rods fails to insert into the core (indicated by the "down" branch under the C event), the sequence becomes an Anticipated Transient Without Scram (ATWS) and transfers to an event tree developed to explicitly evaluate plant and operator response to a failure of rods to insert. The ATWS event tree is described in Section 3.1.3.7. Success (indicated by the horizontal line to the next event) implies a sufficient number of control rods inserted to shut down the fission process.

HVAC (Event Hvc)

Top event Hvc represents continued availability of the HVAC function, which is achieved via switchgear and Class 1E panel room HVAC systems. If there is no loss of HVAC after the turbine trip initiating event, the systems, subsystems and components serviced by HVAC are not degraded by the common-cause failure of HVAC. PCS is not directly impacted by failure of HVAC. If loss of HVAC occurs after the turbine trip, various systems, subsystems and components may fail due to the common-cause failure of HVAC. This scenario is then described later by the HVAC special event tree (see Section 3.1.3).

Offsite Power (Event E)

Top Event E represents continued availability of offsite power after a turbine trip has occurred. If there is no loss of offsite power after the turbine trip initiating event, PCS is not lost due to direct impact of this event. If a loss of power (LOP) occurs after the turbine trip, the MSIVs close, and a demand is placed on the diesel generators. This scenario is then described by the LOP event tree in Section 3.1.2.1.6.

Safety/Relief Valves Open (Event M)

The turbine generator is assumed to trip during all transient initiators. Closure of the turbine stop valves as a result of the turbine trip causes a pressure transient throughout the reactor coolant system.

The safety relief valves (SRVs) provide ASME boiler code protection against overpressure of the RPV. If the main steam line SRVs and the turbine bypass valves fail to open during this pressure transient, the RCS pressure limits may be exceeded, and a system rupture (i.e., large LOCA) is conservatively assumed to occur. Therefore, failure of event M is transferred to the large LOCA event tree.

All Safety/Relief Valves Reclose (Events P and P2)

Success of event P implies the closing of all open SRVs after they have successfully prevented RPV overpressurization. The failure of these valves to reclose impacts plant performance in the following ways:

1. The heat load caused by the stuck open SRVs represents a challenge to the RHR system to remove the additional heat from the suppression pool.

2. There is a potential for the power conversion system (PCS) to be ineffective as a means of removing decay heat because steam flow that would normally go to the condenser via the turbine bypass valves is now going to the suppression pool via the SRVs.

3. Reactor coolant system will be depressurized, resulting in gradual degradation of the turbine-driven high pressure injection systems. The decrease in the RPV pressure will cease if the SRV closes.

4. A greater demand on required reactor coolant flow rate may occur to keep the core covered.

Treatment of event P considers the fact that the likelihood of a stuck open SRV (SORV) to occur and to persist is low, but not negligible. The likelihood of a SRV to reclose is affected by the type of SRVs installed and by the setpoints of the valves. HCGS uses the improved two-stage Target Rock SRVs and the higher, preferable, SRV setpoints. The value used in this analysis for the conditional probability of a SRV failing to reclose is 2E-3 per demand. For the turbine trip transient, three demands (cycles) are assumed.

Success of the P event implies that all valves successfully reclosed. Failure indicates that at least one SORV exists. Should P fail, the P2 event indicates whether more than one SORV exists. The probability of multiple SORVs to occur and remain open is very low, but possible (it has occurred in BWR operation experience). Success of the P2 event implies that only <u>one</u> SORV has occurred and has logic similar to the S2 event tree in the non-seal LOCA part.

Failure implies that two SORVs exist. This size LOCA can be approximated by the S1 event, so failure of P2 has a similar logic as the S1 event tree, with successful reactor depressurization, but without the harsh environment created by LOCA.

Feedwater Available (Event Q)

This top event heading addresses the availability of the feedwater system as a high pressure injection source. Following a turbine trip, the feedwater-condensate system together with the steam flow through the turbine bypass valves represent the normal PCS method of maintaining reactor coolant inventory and decay heat removal. Availability of feedwater flow to the core requires the following:

a) At least one train of the condensate-feedwater system is operable and able to deliver water from the condenser hotwell to the reactor vessel. This requires that one primary and one secondary condensate pump, along with one feedwater pump in the train, be available.

b) Steam must be available from the reactor to the feedwater pump turbines through the main steam isolation valves.

c) To maintain condenser vacuum, at least one of the main condenser circulating water pumps must be available to deliver cooling water to the main condenser; also at least one of the steam jet air ejectors or one of the mechanical vacuum pumps must be available.

Note that if Q is successful, it is assumed that the entire PCS remains available and so decay heat is being transferred to the main condenser and, ultimately, the environment.

The initial reactor water level rise following the turbine trip has a subsequent attempt by feedwater control to restore level to normal. This will cause a subsequent level increase, which may lead to a feedwater system trip on high level (Level 8), but only if the operator fails to control the feedwater and does not respond in time. If the feedwater system trips, the operator must recover feedwater to prevent automatic ECCS actuation when RPV water level reaches Level 2. Due to the fact that feedwater is a normally operating system with which the operators are extremely familiar, the feedwater system represents an important and relatively reliable capability for maintaining reactor coolant inventory. If feedwater is not recovered, the vessel water level will decrease to Level 2, where HPCI and RCIC systems will receive initiation signals.

Failure of this event implies that feedwater has been lost as a high pressure injection source so that other injection is required. On a failure of feedwater, RHR cooling is required only if HPCI or RCIC is used for high pressure injection. If primary and secondary condensate pumps are available, pressure will be decreased to allow condensate pumps to feed vessel (at approximately 600-700 psig). Provided at least one primary condensate pump is operating, and automatic hotwell level control back and forth to CST remains in operation. Changes in condenser hotwell level have a negligible effect on condenser vacuum, provided the steam jet air ejectors on mechanical vacuum pumps remain in operation.

<u>High Pressure Coolant (Event U)</u>

If feedwater is not available, the high pressure injection systems RCIC and/or HPCI can operate over a wide range of RCS pressures and are capable of providing makeup to the RPV until pressure decreases to the point that inlet turbine pressure is approximately 100 psig for HPCI and 65 psig for RCIC. The RCIC and HPCI systems are reactor steam turbine driven, and despite the difference in their injection rates, successful initiation and operation of either of the systems is sufficient to maintain reactor water level following a turbine trip. It should be noted that if both HPCI and RCIC fail immediately after the feedwater failure (after scram), the lower flow rate of CRD as a high pressure makeup source cannot avoid core damage without additional injection sources. Based on MAAP calculations, high pressure CRD is credited in this analysis only if previous high pressure injections systems were successful for approximately two hours. However, with successful depressurization, the condensate or LPCI or CSS systems will successfully sustain reactor water level control. Note that in a SORV scenario (P fails), eventual depressurization is expected so that if U is successful, low pressure injection (V event) is assumed to be required following HPCI/RCIC shutoff on low pressure.

<u>Reactor Depressurization (Event X)</u>

In the event that the high pressure syster[illegible] navailable to maintain adequate coolant inventory, the RPV can be depressurize[illegible] core spray, LPCI, or condensate can be employed to establish low pressure coolant injection.

The principal method of depressurization is to relieve steam via the main turbine bypass valves to the main condenser. Other methods of depressurization are the use of HPCI in full flow test or the operator taking manual control of the SRVs.

Success of this event is described as the timely depressurization of the reactor vessel after failure of high pressure injection. If the SRVs are used, at least two valves must be opened for success.

Alternate methods of depressurization are through the RCIC lines, Steam Jet Air Ejector (SJAE), feedpump turbines, RWCU, or the main steam line drains. While these alternate depressurization features are viable methods, they involve more operator actions. The equipment failure probability associated with the bypass valves and the SRVs is already so low, credit for these alternate methods of depressurization is not required in the IPE.

<u>Low Pressure Coolant Makeup (Event V)</u>

Successful depressurization provides the opportunity to inject into the RPV with low pressure systems. Among these systems are core spray, LPCI, and the condensate. Other relatively low flow systems which cannot restore and maintain water level early in the event are not explicitly discussed here.

The core spray system (CSS), with an operating range of 0 to 380 psig, and the low pressure coolant injection system (LPCI), with an operating range of 0 to 340 psig, initiate after receipt of a low water level signal (-129"). However, water is not injected to the RPV unless pressure is below the pumps shutoff head. The condensate system can inject water into the reactor through the feedwater pumps, starting at approximately 700 psig of reactor pressure. This system is normally operating and has a high likelihood of being available, provided that coolant inventory can be maintained in the condenser hotwell. Success of this event implies that at least one of these systems is supplying injection to the RPV per the requirements of the success criteria presented in Table 3.1.1-6.

Containment Heat Removal (Event W)

This event represents the removal of decay heat either directly from the reactor vessel or from the containment. This removal of heat occurs through the PCS-condensate system or through the shutdown cooling (SDC) mode or the suppression pool cooling (SPC) mode of the Residual Heat Removal (RHR). As described in Section 3.1.1.4.1, the SDC mode is not modeled in the IPE to simplify certain modeling interactions.

The RHR system can be employed successfully to remove the containment heat load if a flow path from the containment torus through at least one RHR heat exchanger can be established. Alignment of RHR requires manual action. In addition, the SACS system must provide cooling water to the corresponding RHR heat exchanger. The use of the PCS as a method of containment heat removal is possible if at least one main steam line path and a returning condensate path can be maintained to exhaust steam to the condenser, and there is not a large diversion of reactor decay heat directly to the suppression pool. As described under the Q event, the PCS is assumed to be available if Q is available, and unavailable if Q fails.

Containment Venting (Event W1)

This event evaluates the situation where the containment integrity is threatened because of failure of the normal containment heat removal features, but the core has sufficient coolant makeup. The EOPs of Hope Creek instruct the operator to vent the suppression chamber when its pressure reaches 65 psig, regardless of the condition of the core.

Success of this event is defined as the controlled venting of the containment to remove heat and pressure (per EOP) from the containment.

Failure of containment venting after failure of other methods of heat removal leads to containment failure due to overpressurization. Containment failure causes an uncontrolled release of the pressure and heat and may impact core cooling capability because of flushing of the pool and adverse environmental conditions in the reactor building. If venting fails, forced closure of the SRVs is postulated due to inadequate differential air supply between the accumulators and the containment atmosphere. This causes repressurization of the RPV and thus inability to use low pressure injection systems.

It should be noted that the hard pipe venting system is successful even if power is lost because it is possible to manually operate the system.

Long-term Coolant Makeup (Event Uv)

This event evaluates the availability of continued coolant injection following failure of early successful core cooling. Failure of early successful core cooling systems can be caused by such events as those discussed above under the W1 discussion or because an uncontrolled depressurization of the reactor coolant system (e.g., SORV) forces HPCI and RCIC (turbine-driven systems) to be isolated. This event is particularly important following W or W1 failure when containment challenges are severe and operability of core injection systems can be affected.

Which systems are applicable to the Uv event depends on the particular sequence being examined and, hence, which systems are still available and capable for long-term makeup. Table 3.1.2-2 summarizes all the possible Uv combinations used in all the event trees. The event trees themselves depict which Uv combination applies to the sequences where Uv is evaluated. In each case, success of the Uv event indicates successful long-term cooling of the core (even though containment might be failed). Otherwise, failure of Uv results in core damage.

3.1.2.1.2 Event Tree Model of the Loss of Condenser Vacuum Transient

1) Initiating Event Description

The normal condenser pressure range is between 1 and 4 inches of HgA. When the condenser vacuum decreases to 7.5 inches HgA, the main turbine trips, which initiates a reactor scram. Further loss of condenser vacuum causes automatic isolation of the MSIVs at 21.5" HgA. When the condenser vacuum decreases to 22.9 inches HgA, the bypass valves close.

2) Accident Sequence Characterization.

A loss of condenser vacuum causes a main turbine trip, a reactor feed pump trip, a closure of all the MSIVs and bypass valves, and results in a reactor trip. From this point on, the accident sequence characterization is similar to that of the closure of all the MSIVs. With the reactor isolated from the main condenser, the decay heat is removed from the reactor by discharging the steam via the SRVs to the suppression pool. It is expected that these relief valves will open early in the sequence to limit the pressure rise, then these valves sequentially reclose as the stored energy in the vessel is dissipated into the suppression pool. Six SRV opening demands are modeled in the of this transient.

The combination of discharge to the torus and loss of feedwater flow will cause the vessel water level to decrease. At the Level 2 setpoint, both RCIC and HPCI are automatically initiated. The initiation of the RCIC and HPCI systems may occur within one minute of the feedwater trip to restore water level. It should be noted that if both HPCI and RCIC fail immediately after MSIV closure, the lower flow rate of CRD as a high pressure makeup source cannot avoid core damage without additional injection sources. However, with successful depressurization, the LPCI and CSS systems will successfully sustain reactor water level control. Containment heat removal is normally achieved by the RHR system for this initiating event. Should RHR fail for these sequences, the MSIVs and turbine bypass valves must reopen and perhaps repairs performed on the initiating fault before PCS can be used to remove decay heat. Additionally, the operator is required by procedure to vent the containment as a last means to control containment energy addition, if needed.

The loss of condenser vacuum initiator deserves a separate investigation from the turbine trip (through a separate event tree), because:

1. It may result in isolation of the condenser,
2. The frequency of the initiating event is relatively high,
3. The mechanisms which result in loss of vacuum may not be readily repairable.

3) Event Tree Construction

The event tree for the loss of condenser vacuum transient is identical in appearance to the event tree of the MSIV closure transient. Therefore, for the sake of simplicity, the event tree of loss of condenser vacuum was combined to the MSIV closure event tree, which is described in the next section.

3.1.2.1.3 Event Tree Model of the MSIV Closure Transient

This section presents the event tree model for accident sequences which may occur as a result of MSIV closure, caused by failures related directly to the MSIV equipment or its control. While other accident sequence initiators may also lead to a closure of the MSIVs (as a planned precaution), these cases are treated within their respective event trees, such as loss of HVAC, large LOCA, loss of offsite power, etc. However, as mentioned previously, the MSIV closure event tree represents also the loss of condenser vacuum event tree (due to their identical appearance and similar characterization).

1) Initiating Event Description

A closure of the MSIVs causes an immediate scram to counteract the effects of a positive reactivity insertion from void collapse under high vessel pressure.

2) Accident Sequence Characterization

MSIV closure results in a reactor scram and turbine trip. Steam flow to the feedwater turbines is terminated, leading to feedwater coastdown. High reactor pressure causes the actuation of safety relief valves to control RPV pressure, further depleting RPV water inventory. With the reactor isolated from the main condenser, the decay heat is removed from the reactor by venting the steam via the SRVs to the suppression pool. It is expected that approximately six SRVs will be demanded to open early in the sequence to limit the pressure rise, then these valves sequentially reclose as the stored energy in the vessel is dissipated into the suppression pool.

The combination of steam venting and loss of feedwater flow will cause the vessel water level to decrease. At the Level 2 setpoint, both RCIC and HPCI are automatically initiated. The initiation of the RCIC and HPCI systems may occur within one minute of the feedwater trip to restore water level. It should be noted that if both HPCI and RCIC fail immediately after MSIV closure, the lower flow rate of CRD as a high-pressure makeup source cannot avoid core damage without additional injection sources. Based on MAAP calculations, high pressure CRD is credited in this analysis only if previous high pressure injection systems were successful for approximately two hours. However, with successful depressurization, the LPCI and CSS systems will successfully sustain reactor water level control. Containment heat removal is normally achieved using the SPC or CSC mode of the RHR system for this initiating event. Should RHR fail for these sequences, the MSIVs and turbine bypass valves must be reopened and perhaps repairs performed on the initiating fault before PCS can be used to remove decay heat. Additionally, the operator is required by procedure to vent the containment to control containment energy addition, if needed.

3) Event Tree Construction

The event tree for the MSIV closure transient is shown in Figure 3.1.2-2. Forty sequences are shown, of which eighteen do not lead to core damage. Three transfer to other event trees. The functional event headings listed across the top of the event tree are similar to those of the turbine trip event tree. However, the individual functional events will link a different set of system fault trees according to the specific success criteria for the MSIV closure transient, which are given in Table 3.1.1-8.

3.1.2.1.4 Event Tree Model of the Loss of Feedwater Transient

1) Initiating Event Description

The normal reactor vessel water level is approximately 16 feet above the top of the active fuel (TAF). A loss of feedwater leads to a sharp reduction in the coolant makeup rate. Consequently, core subcooling decreases and causes a reduction in the core power level and pressure. When RPV water level drops to Level 3, the reactor protection system actuates to scram the reactor.

2) Accident Sequence Characterization

Loss of feedwater results in a reactor scram and a turbine trip. The electrohydraulic control (EHC) logic opens the bypass valves to allow steam flow to the condenser. At Level 2, the EOC-RPT will trip the reactor recirculation pumps if not bypassed before ATWS-RPT, and the HPCI and RCIC systems start.

The initiation of the RCIC and HPCI systems may occur within less than one minute of the feedwater trip to restore water level. It should be noted that if both HPCI and RCIC fail immediately after the loss of feedwater, the reduced flow rate of CRD as a high pressure makeup source cannot prevent core damage without additional injection sources. Based on MAAP calculations, high pressure CRD is credited in this analysis only if previous high pressure injection systems were successful for approximately two hours. However, with reactor depressurization, the low pressure injection systems can also sustain reactor water level control. Containment heat removal is normally achieved for this transient through the PCS (since the turbine bypass valves are open) or through the CSC mode or the SPC mode of the RHR. Should RHR fail for these sequences, the operator is required by procedure to vent the containment to control containment energy addition.

3) Event Tree Construction

The event tree for the loss of feedwater transient is shown in Figure 3.1.2-3. Fifty-three sequences are shown, of which 26 do not lead to core damage. Four transfer to other event trees. The functional event headings listed across the top of the event tree are similar to those of the turbine trip event tree. However, the individual functional events will combine a different set of system fault trees, according to the specific success criteria for the loss of feedwater transient, which are given in Table 3.1.1-9.

3.1.2.1.5 Event Tree Model of Inadvertent Open Relief Valve (IORV) Transient

1) Initiating Event Description

The opening of an SRV allows steam to be discharged into the suppression pool. The sudden increase in the rate of steam flow leaving the reactor vessel causes a depressurization transient. The pressure regulator senses the reactor vessel pressure decrease and regulates the turbine control valves to stabilize reactor vessel pressure at a slightly lower value. Reactor power settles at nearly initial power level. Initially, makeup systems response to an IORV event will be similar to the demand caused by a medium LOCA event. However, reactor scram is initiated by the operators if the open SRV cannot be closed within two minutes.

2) Accident Sequence Characterization

Inadvertent open relief valve (with failure to reclose in 2 minute) results in a manual reactor scram and turbine trip. Once the reactor is shut down, the IORV event is treated similar to the turbine trip transient. However, since the reactor has been at full power and has been discharging steam into the suppression pool, the pool temperature will be elevated. This may decrease the time allowed for initiation of RHR and result in high containment pressure, loss of makeup to the reactor, and eventual core damage. However, reduced feedwater flow will be sufficient to achieve a safe shutdown condition. Alternately, RCIC, HPCI, reactor depressurization and low pressure injection systems, together with containment heat removal, will also achieve a safe shutdown condition.

3) Event Tree Construction

The event tree for the inadvertent open relief valve transient is shown in Figure 3.1.2-4. Twenty-four sequences are shown, of which nine do not lead to core damage. Two transfer to other event trees. The functional event headings listed across the top of the event tree are similar to those of the turbine trip event tree. However, the individual functional events will link a different set of system fault trees, according to the specific success criteria for the loss of feedwater transient, which are given in Table 3.1.1-10.

3.1.2.1.6 Event Tree Model of Loss of Offsite Power Transient

1) Initiating Event Description

The loss of offsite power (LOP) initiating event is a loss of normal AC power. As a result of the loss of power, the reactor protection system de-energizes resulting in a reactor scram.

2) Accident Sequence Characterization

Loss of offsite power results in a reactor scram and turbine trip and MSIV closure. AC power is required for long-term operation of systems required to maintain the reactor in a shutdown condition. If offsite power is unavailable, these systems require power from the 4160 VAC emergency diesels. Therefore, the diesel generators are expected to start automatically per design on loss of offsite power and provide power to their respective emergency buses within 10 seconds following the start signal. Operator actions are required only if a diesel generator fails to start or load. In parallel with the potential efforts made to start and align the emergency diesel generators, efforts are made to recover offsite power.

Without offsite power, feedwater is unavailable since the condensate pumps as well as the circulating water pumps responsible for maintaining condenser vacuum are all powered by these non-Class 1E buses. RCIC and HPCI have steam driven pumps and rely on DC power for startup and control. If none of the AC sources (offsite or diesels) can be recovered, a station blackout (SBO) situation arises. In an SBO all the power in the station, both DC and AC, is originated from the energy stored in the batteries, which is calculated to be sufficient for at least four hours. After depletion of the batteries, HPCI and RCIC are assumed to fail. Unrecovered failure of HPCI and RCIC during a station blackout is assumed to cause core damage.

Successful EDG operation or offsite power recovery would provide the operator many options for reestablishing coolant injection, including CSS and LPCI if the reactor is successfully depressurized. Only one RHR and core spray pump can be loaded on a vital bus powered by a diesel generator.

In the absence of offsite power, containment heat removal can be achieved through RHR or containment venting. The PCS is unavailable during a LOP. If offsite power is recovered or onsite emergency power is available, the transient scenario is similar to the MSIV closure.

3) Event Tree Construction

Two approaches are available for the loss of offsite power event tree analysis. One is to develop an event tree similar to other MSIV closure transients and apply the power and system recoveries at the cutset level. The second approach, the time-phased approach, is used to separate different operator and system responses that are dependent on the successful recovery of onsite and offsite power and other systems. The first approach is implemented.

The event tree for the loss of offsite power initiated transient is shown in Figure 3.1.2-5. Forty-one sequences are shown, of which fifteen do not lead to core damage. Four are transfers to other event trees. Most of the functional event headings listed across the top of the event tree are similar to those of the turbine trip event tree, with the exception of the EDG top event, which represents the start of the emergency diesel generators upon loss of offsite power. However, the individual functional top events will link a different set of system fault trees according to the specific success criteria for the loss of offsite power transient, which are given in Table 3.1.1-11. The following sections describe explicitly the top events EDG and the other LOP-specific event headings.

HVAC (Event Hvc)

Top event Hvc represents continued availability of the HVAC function, which is achieved via switchgear and panel room cooling after the loss of offsite power has occurred. If there is no loss of HVAC after the initiating event, the systems, subsystems, and components serviced by HVAC are not degraded by the common cause failure of HVAC. The offsite and onsite power itself depends on the HVAC, and this dependency is kept explicitly in the fault trees and the event tree. If loss of HVAC occurs after LOP, various systems, subsystems, and components may fail due to the common cause failure of HVAC. This scenario is then described later in the discussion of the HVAC special event tree (see Section 3.1.3).

Availability of Diesel Generators (Event EDG)

This event includes the failure of all four diesel generators and leads to the initial station blackout scenario.

It should be noted that there are various combinations with one or two diesel generators available, but they will fail due to additional failures of support systems (for example SACS).

In these cases, a station blackout scenario develops. These scenarios are identified automatically by the quantification program and are printed in the cutsets.

In the initial station blackout sequences, recovery of offsite power and diesel generators is questioned by the PRA analyst for each individual cutset.

High Pressure Coolant (Event U)

The requirements for successful high pressure coolant injection are similar to a MSIV closure initiated event, in that HPCI and RCIC can supply adequate inventory makeup to the reactor. HPCI and RCIC are designed to be able to start and run initially without any AC dependency, and they use DC power for control and auxiliary systems for room cooling. The following considerations affect the availability of auxiliary systems required for coolant injection following a LOP:

- Battery availability (DC power)
- Room cooling requirements (HPCI/RCIC Isolation on high temperature)
- High suppression pool temperatures due to lack of containment heat removal may have an adverse effect on the RCIC pump seals leading to the release of steam into the RCIC area. This in turn may also cause isolation or electrical malfunction if RCIC suction is from the suppression pool. In the longer term, high suppression pool temperature may also have an adverse impact on the HPCI and RCIC pump bearing failure. Additionally, EOP instructions may lead the operator to depressurize upon reaching the heat capacity temperature limit (HCTL) causing the loss of HPCI and RCIC.

Reactor Depressurization (Event X)

Reactor depressurization is strongly sequence dependent because the reliabilities associated with automatic and manual depressurization may vary substantially among the sequences analyzed. The following items are of particular importance in evaluating the conditional probability of failure to depressurize:

- Automatic ADS would be inhibited in the case of station blackout.
- The emergency operating procedures direct the operator to depressurize when the HCTL is reached.
- RCIC operation may terminate sooner if depressurization occurs due to the high exhaust back-pressure trip (25 psig). Since RCIC isolates on low pressure, it is not credited for long-term makeup supply to the core.
- Under station blackout conditions, the SRV pneumatic supply is maintained by safety-related accumulators.

- Without suppression pool cooling, the containment pressure may rise sufficiently (80 to 85 psi) to compromise the required differential pressure across the SRV pilot valves. However, at a containment pressure of 65 psi, the EOPs direct the operators to begin suppression chamber venting. Containment venting can be performed from the Control Room if battery power is available.

Low Pressure Coolant Makeup (Event V)

Low pressure ECCS pumps require 4160 VAC power, which is available from the emergency buses supplied by either offsite power or the diesel generators. There is a direct dependency between the low pressure ECCS system's success, diesel availability, and the ability to depressurize the primary system.

Containment Heat Removal (Event W)

Containment heat removal is a long-term function that must take into account the following considerations specific to the LOP initiating event:

- The PCS is unavailable in the absence of offsite power due to the loss of electric driven pumps and condenser vacuum.

- The RHR and SACS pumps and valves depend upon the emergency AC power sources.

- For the short-term station blackout (i.e., for less than four hours), the containment heat removal is not required when examined on a realistic basis (see also 10 CFR 50.63, the station blackout rule).

Containment Venting (Event W1)

Venting can be performed during station blackout. The initiation of venting can be remotely controlled provided batteries are available, or manual (performed locally).

Long-term Coolant Makeup (Event Uv)

This event is similar to the Uv top event, described in the turbine trip event tree. However, LOP and SBO specific nodal equation assignments are used as defined in Table 3.1.2-2.

3.1.2.1.7 Event Tree Model of Small LOCA

1) Initiating Event Description

The small break LOCA is characterized by slow or no reactor vessel depressurization and a gradual inventory loss from the vessel. However, immediately after the postulated small break in the primary system inside containment, drywell pressure will increase. The increase in drywell pressure will actuate the reactor protection system, and the reactor will scram.

2) Accident Sequence Characterization

A small break LOCA results in a reactor scram and turbine trip. High drywell pressure (1.68 psig) causes a loss of the feedwater pumps due to LOCA Level 1 load shed of MCCs for lube oil pumps. This load shed can be overridden from the control room and feedwater pumps placed back in service. The increase in drywell pressure will also start the diesel generators and initiate ECCS. However, these small break LOCA events are within the capacity of RCIC (600 gpm) and, in most cases, the excess capacity of the feedwater system will compensate for the loss in reactor vessel inventory. On a small LOCA with high drywell pressure and no level decrease to -38", RCIC must be started manually. However, the HPCI system will begin injecting water into the vessel within 30 seconds of the high drywell initiating signal. The operator will take manual control of the makeup systems later to maintain pressure level and proceed to cold shutdown. If the operator does not take manual control of HPCI within a few seconds after initiation, the reactor level could rapidly rise to Level 8 and cause a trip of both HPCI and feedwater. If the water level outside the shroud reaches the low water level trip setpoint, the recirculation pumps trip and the RCIC system starts to provide additional makeup to the vessel. RCIC and HPCI will both automatically reinitiate if Level 2 is subsequently reached.

It should be noted that most of the small LOCAs observed in the BWR industry were seal LOCAs, which could be isolated. Therefore, specific top events in the small LOCA event tree were developed to address this issue.

3) Event Tree Construction

The event tree for the small LOCA initiating event is shown in Figure 3.1.2-6. Thirty-six sequences are shown, of which 14 do not lead to core damage. Four are transfers to other event trees. The functional event headings listed across the top of the event tree are similar to those of the turbine trip event tree (with the exception of the top events S3, Iso, and D). However, the individual functional events will link a different set of system fault trees, according to the specific success criteria for the small LOCA transient, which are given in Table 3.1.1-14. Description of small LOCA specific event headings follow.

Small LOCA initiator (Event S2)

Small LOCA is defined as a break in the primary system for which the RCIC makeup capability is sufficient to maintain adequate coolant inventory. This can be approximated by pipe breaks of less than 0.005 ft^2 for a liquid line and less than 0.1 ft^2 for a steam line (refer to Section 3.1).

Seal LOCA (Event S3)

Event S3 represents the probability that the small LOCA is, in fact, a seal LOCA.

Isolation of a Seal LOCA (Event Iso)

Event Iso represents the probability that the seal LOCA is isolated a short time after its occurrence.

Pressure Suppression (Event D)

Event D represents the initial containment pressure control during a LOCA. During a LOCA, the high energy primary fluid is released directly to the drywell. The drywell and torus are interconnected by downcomer vents which direct the steam and air from the drywell to the torus after a postulated LOCA. The steam is condensed in the torus, which limits the pressure rise in the drywell. Event D represents the probability that this pathway and the passive pool system fail, including the chance that the vacuum breakers will be non-functional due to the severe environment and stresses to which they may be exposed during a LOCA. A failure of this passive system could result in rapid pressurization of containment above the design limits. Vacuum breakers are provided to allow a return flow path for noncondensibles from the torus to the drywell. The vacuum breakers have been constructed to pass sufficient flow through the system to maintain a 1 psig/sec depressurization rate in the torus atmosphere following a containment design basis accident with drywell spray actuation. Each vacuum breaker system consists of a check valve to prevent a potential backflow bypass path between the drywell and the torus air space. This torus bypass mechanism would severely reduce the torus's effectiveness in LOCA mitigation. The pressure suppression event represents the requirement for the downcomers to pass steam from the drywell to the torus. Failure of this equipment could result in a breached containment.

Containment Heat Removal (Event W)

Similar to the discussion for the turbine trip transient, temperature and pressure control of containment can be fulfilled by a number of systems. The considerations not discussed with regard to the transient event tree models include:

- Temperature Control. After a small break LOCA with a slow rise in drywell pressure and successful pressure suppression, operators would override the drywell cooling isolations and place drywell cooling fans back in service. This action is directed by the Emergency Operating Procedures. This will not be successful in the long term due to loss of cooling to chilled water and RACS, but will help in the short term.

- Pressure Control. Pressure suppression through the downcomers and into the suppression pool may not be important for small LOCAs. This is because the slow containment pressurization allows sufficient time for operator action to depressurize the RPV directly to the suppression pool or use containment sprays to condense the accumulated steam in the drywell. Both actions can prevent containment overpressurization caused by pressure suppression functional failure. In addition to the consideration of pressure suppression, long-term containment heat removal can be successfully employed to mitigate containment pressurization.

- Sequences with MSIVs Open. If the MSIVs are open and the main condenser is available (PCS available), the challenges to the containment pressure integrity will be less severe. This is because a large percentage of the steam flow will be diverted from being vented to the suppression pool, and there is a much lower likelihood of a containment challenge. However, if the small LOCA results in a drywell pressure increase above 1.68 psig, the MSIVs will eventually close on loss of air. The high drywell pressure signal isolates the containment instrument gas to the inboard MSIVs and also causes an isolation of TACS. This will cause a loss of the station air compressors and an eventual loss of instrument air to the outboard MSIVs. The emergency instrument air compressor will fail due to the isolation of the service water to the RACS heat exchanger.

- Sequences with MSIVs Closed. If the flow of steam is not relieved to the main condenser (PCS unavailable), then it is discharged to the suppression pool causing the water temperature to rise. If suppression pool cooling is not effective, the containment temperature and pressure will also begin to increase. The status of the MSIVs after a small LOCA is questioned on the system fault tree level.

3.1.2.1.8 Event Tree Model of Intermediate (Medium) LOCA

1) Initiating Event Description

The intermediate (medium) LOCA is characterized by slow vessel depressurization (but faster than during a small LOCA) and a gradual inventory loss from the vessel. However, immediately after the postulated break in the RCS inside containment, drywell pressure will increase. The increase in drywell pressure and subsequent lowering of RPV inventory will actuate the reactor protection system, and the reactor will scram.

2) Accident Sequence Characterization

A medium LOCA results in a reactor scram and turbine trip. Drywell pressure exceeding 1.68 psig will also start the diesel generators and initiate ECCS. However, these intermediate size LOCA events are considered initially within the capacity of HPCI (5600 gpm) although it will isolate on low steam pressure. The HPCI system will begin injecting water into the vessel within 30 seconds of the high drywell pressure initiating signal. Heat removal from the reactor is accomplished via flow out of the break. This is a passive function and will be assured as long as water inventory is maintained in the vessel. A combination of high and low pressure coolant systems will assure long-term water inventory makeup and core protection.

Drywell pressure control is achieved by steam quenching in the suppression pool or by drywell sprays. As steam generation continues in the reactor, there is a continuing need to provide containment heat removal and prevent containment overpressurization.

3) Event Tree Construction

The event tree for the intermediate LOCA initiating event is shown in Figure 3.1.2-7. Thirty-one sequences are shown, of which 12 do not lead to core damage. Two are transfers to other event trees. Description of medium LOCA specific event headings follow (i.e., those that are unique to this use). Otherwise, the events are the same as described earlier.

Intermediate (Medium) LOCA initiator (Event S1)

A medium LOCA is defined as a break in the primary system for which the HPCI makeup capability is initially sufficient to maintain adequate coolant inventory. This can be approximated by pipe breaks between 0.005 and 0.1 ft^2 for a liquid line, and between 0.1 and 0.3 ft^2 for a steam line (refer to Section 3.1).

Pressure Suppression (Event D)

Event D represents the initial containment pressure control during a LOCA. During a LOCA the high energy primary fluid is released directly to the drywell. The drywell and torus are interconnected by downcomer vents which direct the steam and non-condensibles from the drywell to the torus after a postulated LOCA. The steam is condensed in the torus, which limits the pressure rise in the drywell. Event D represents the probability that this pathway and the passive pool system fail, including the chance that the vacuum breakers will be nonfunctional due to the severe environment and stresses to which they may be exposed during a LOCA. A failure of this passive system could result in rapid pressurization of containment above the design limits. Vacuum breakers are provided to allow a return flow path for noncondensibles from the torus to the drywell. The vacuum breakers have been constructed to pass sufficient flow through the system to maintain a 1 psig/sec depressurization rate in the torus atmosphere following a containment design basis accident with torus spray actuation. The pressure suppression event represents the requirement for the downcomers to pass steam from the drywell to the torus. Failure of this equipment could result in a breached containment.

HPCI System (Event U1)

The size of the intermediate LOCA is such that HPCI, with its high flow rate, can initially reflood the primary system. However, after less than about 15 minutes of operation it is expected that HPCI will no longer be functional because of the severe depressurization that will occur as a result of this size break. Hence, low pressure injection must then be used to continually supply water to the RPV. Success of HPCI provides early injection and additional depressurization of the primary system.

Reactor Depressurization (Event X)

This event is similar to that described earlier, except only one SRV is required to sufficiently lower pressure in the RPV to allow for rapidly restoring and maintaining water level by the low pressure injection systems. This additional depressurization is required only if HPCI fails to initially reflood the system and depressurize the primary system as a result of adding cold water to the primary system, and exhausting steam from the turbine exhaust to the suppression pool. Otherwise, successful PCS operation precludes the need for SRVs in order to use low pressure injection.

Low Pressure Coolant Makeup (Event V1)

High capacity systems are required to provide adequate makeup. This event represents the success or failure of LPCI and CSS per the success criteria provided in Table 3.1.1-13. Condensate is conservatively not credited for this initiator since makeup to the hotwell is considered insufficient to maintain condensate as a continuous injection source.

Containment Heat Removal (Event W)

This event is like that previously described for transients with the containment spray cooling (CSC) mode of RHR included, along with the SPC mode, in this event. This is because the CSC mode can have an early direct and continuous effect on decreasing containment temperature and pressure by quickly condensing the steam exiting the break location. Success of this event implies that either mode of RHR is operable using an RHR heat exchanger and SACS cooling for heat removal.

Long-Term Coolant Makeup (Event Uv)

For the intermediate LOCA, possible credit for the Uv event is given to only high capacity systems, which survived the severe environmental conditions in the suppression pool or the reactor building which can occur when containment heat removal is failed. These systems are the LPCI, core spray, and condensate. Due to the large amount of small piping and hoses involved, the use of fire water for vessel injection is not credited during intermediate or large LOCA.

3.1.2.1.9 Event Tree Model of Large LOCA

1) Initiating Event Description

The Hope Creek evaluation considers the following two types of large LOCA initiators:

- A break of the recirculation line (a water line break).
- A break in piping above the core (a steam line break).

If the large steam line break LOCA occurs outside the containment, the MSIVs will close and isolate the steam flow path to the environment, external to the containment. Failure of the MSIVs to close on a steam line break LOCA is considered as a containment bypass failure.

The large LOCA is characterized by rapid vessel depressurization and rapid inventory loss from the vessel. Immediately after the postulated break in the primary system inside containment, drywell pressure will increase. This increase in drywell pressure and the decreasing water level in the RPV will actuate the reactor protection system, and the reactor will be scrammed.

2) Accident Sequence Characterization

A large LOCA results in a reactor scram and turbine trip. The increase in drywell pressure and low RPV water level will start the diesel generators and initiate ECCS. The large break LOCA events are not within the capacity of HPCI and/or RCIC, and feedwater will not be available due to expected MSIV closure. Reactor depressurization is accomplished via flow out of the break. If the break is not isolated, only low pressure coolant systems will assure long-term water inventory makeup and core protection.

Some subtle differences exist between the two types of large LOCA initiators mentioned in the previous subsection.

A steam line break results in a less immediate coolant inventory loss than a large break in the recirculation line, but causes rapid depressurization of the RPV allowing low-pressure ECCS to make up water inventory almost immediately following the break. A steam line break will not spill makeup water from the RPV before the core is flooded, while a recirculation line break can spill water before the core is completely covered.

The recirculation line break causes a rapid loss of vessel inventory. The uncovered portion of the core is cooled by the natural circulation of steam generated in the water-covered region of the core. The core remains adequately cooled by the low pressure systems.

Containment heat removal is achieved by RHR or by containment vent system. The PCS is assumed to be unavailable during large LOCA.

The two types of large LOCAs are treated in the same event tree model in the probabilistic analysis. While there could be some minor timing and other thermal response differences in core cooling for steam line versus water line LOCAs, these differences are not judged to significantly alter the calculated values of the accident sequences.

3) Event Tree Construction

The event tree for the large LOCA initiating event is shown in Figure 3.1.2-8. Seventeen sequences are shown, of which six do not lead to core damage. Two are transfers to other event trees. The functional event headings listed across the top of the event tree are virtually identical to those of the medium LOCA event tree. Note, however, that the rapid depressurization caused by this initiator precludes HPCI success, nor is manual depressurization needed to ensure successful low pressure coolant injection. Description of large LOCA specific event headings follow.

Large LOCA Initiator (Event A)

A large LOCA is defined as a break in the primary system for which the HPCI makeup capability is insufficient to maintain adequate coolant inventory. This can be approximated by pipe breaks larger than 0.3 ft^2 for both liquid and steam lines (refer to Section 3.1).

All other events are similar to those described for the intermediate LOCA.

3.1.2.2 References

3.1.2-1 BWR Owner's Group Emergency Procedure Guidelines, Revision 4: NEDO-31331.

3.1.2-2 Radionuclide Release Calculations For Selected Severe Accident Scenarios. Washington, D.C.: U.S. Nuclear Regulatory Commission, July 1986. NUREG/CR-4624, Volume 5.

3.1.2-3 "Hope Creek Generating Station Final Safety Analysis Report." Public Service Electric And Gas Company, Hancocks Bridge, NJ, Revision 3, April 11, 1991.

3.1.2-4 "Hope Creek Generating Station Emergency Operating Procedures." Public Service Electric And Gas Company, Hancocks Bridge, NJ.

3.1.3 Special Event Trees

Several initiating event categories, or classes of accidents, were developed into event trees which address the unique aspects of these events. These categories are the following:

1. Special initiators including:

    a) Complete loss of Instrument Air System,

    b) Complete loss of RACS,

    c) Complete loss of SSW/SACS,

    d) Complete loss of Class 1E Panel Room HVAC or Switchgear Room HVAC (globally referred to as loss of HVAC).

2. Interfacing system loss of coolant accident (ISLOCA).

3. Internal flooding.

4. ATWS.

The following subsections provide the special features included in the development of these event trees.

3.1.3.1 Event Tree Model of Loss of Instrument/Service Air System

Compressed gas systems provide the function of providing the motive force for pneumatic valves and/or valves which "fail safe" during an accident. A variety of valves require compressed air as a support system.

The instrument air system (IAS) at Hope Creek includes two service air compressors (run and standby) and an emergency instrument air compressor, which is automatically actuated upon low instrument air pressure. Note that if a station air compressor is removed from service, a diesel air compressor is normally installed temporarily. As described in Section 3.1.1.1, a total and sudden loss of all air is considered important as a special initiator because the loss of air would cause control rod drift, outboard MSIV closure, and affect feedwater/condensate, CRD, and limit containment venting activation choices.

While very similar to an MSIV closure event, the loss of air event was treated as a unique initiating event because of these additional effects. Furthermore, reopening of the MSIVs to establish long term heat removal is hampered by the need to recover air. Consequently, the loss of IAS requires the operator to deal with several degraded systems.

1) Initiating Event Description

Upon a complete loss of the instrument air system, control rod drift and slow closure of the outboard MSIVs will occur, which will first initiate a reactor trip followed by a turbine trip. Multiple control rod drifts also require the operators to scram the reactor manually.

2) Accident Sequence Characterization

The framework for the loss of IAS event tree is derived from the model developed for treatment of the MSIV closure scenarios.

3) Event Tree Construction

The event tree for the loss of IAS transient is shown in Figure 3.1.3-1. This tree is virtually identical to the MSIV closure tree. The discussion of the MSIV closure event tree describes the functional events and their relationships, without explicit consideration for the unavailability of the IAS. The unavailability of IAS is considered in the component-specific dependencies on air in the fault trees. The next significant effect on the event tree is that condensate is not credited (due to its dependency on air for flow injection/control to the RPV) for either Event V or as part of the Uv event. Recovery of condensate post-initiator is treated in Section 3.3.3.

3.1.3.2 Event Tree Model of Loss of RACS

RACS provides either primary (reactor building and radwaste auxiliaries) or backup (turbine building chilled water) cooling to various equipment in the plant. Of particular importance is its primary cooling function for the reactor recirculation pumps and the CRD pumps, as discussed in Section 3.1.1.1. Because of these two dependencies on RACS, loss of RACS is treated as a special initiator.

1) Initiating Event Description

Upon a total loss of RACS, a forced shutdown within 10 minutes would occur to prevent reactor recirculation pump damage. Additionally, as noted in the procedure for loss of RACS, isolation of gaseous radwaste is expected with possible loss of condenser vacuum. Should this occur, MSIV closure would result. However, as discussed in Section 3.1.1.1, operation of the mechanical vacuum pumps is expected and this would prevent loss of vacuum. The IPE, therefore, treats this initiator similar to a turbine trip event, but also considers inoperability of the CRD pumps.

2) Accident Sequence Characterization

The framework for the loss of RACS event tree is derived from the model developed for treatment of the turbine trip scenarios.

3) Event Tree Construction

The event tree for the loss of RACS is shown in Figure 3.1.3-2. This tree is virtually identical to the turbine trip tree. The discussion of the turbine trip event tree described the functional events and their relationships, but without explicit consideration for the unavailability of RACS. The most significant impact is that CRD injection as a long-term injection source is not credited as part of the Event Uv because of its dependency on RACS for pump cooling.

3.1.3.3 Event Tree Model of Loss of SSW/SACS

As described in Section 3.1.1.1, SSW and SACS provide ultimate cooling to essentially all heat loads within the plant. SACS (including TACS) generally cools PCS equipment, chillers, ECCS pump rooms, RHR pumps and heat exchangers, diesel generators, instrument gas compressors, etc. SSW, in turn, cools SACS as well as RACS. Hence, complete loss of SACS or SSW represents a loss of heat sink which will force a manual shutdown or an eventual scram while, at the same time, affecting nearly all equipment in the plant. Hence, loss of these systems are special initiators.

1) Initiating Event Description

A complete loss of SSW or SACS would result in close monitoring of the plant heat load temperatures by the operational staff. If recovery is not almost immediately achieved, the plant would be administratively scrammed. Failure to do so would still lead to an eventual scram because the corresponding loss of TACS would cause heatup of balance of plant loads.

2) Accident Sequence Characterization

Upon a loss of either SSW or SACS and the resulting shutdown of the plant, loss of heat removal to various pumps, heat exchangers, and chiller equipment as well as loss of TACS and other mitigating equipment failures could occur within a fairly short time frame after the initiator event. These subsequent effects will cause heatup of equipment associated with the power conversion system (main steam/feedwater/condensate) possibly causing the inability to maintain the condenser as a heat sink. Depending on the ability to maintain condenser vacuum and hotwell level, subsequent MSIV closure could also occur. The inability to cool the RHR heat exchangers and RHR pumps further worsens the event by causing a loss of heat removal by either the PCS or RHR. Other pump systems not directly dependent on SSW or SACS (e.g., HPCI, RCIC, Core Spray) will operate until containment conditions or low level in the condensate storage tank causes failure of these systems, if not mitigated. Hence, loss of either SSW or SACS ultimately takes on the characteristics of a loss of heat removal type accident.

3) Event Tree Construction

The event tree for the loss of SSW/SACS event is shown in Figure 3.1.3-3. The event tree logic and functional events are nearly identical to those described for the MSIV closure transient event tree. While MSIV closure may not occur immediately following the event, the loss of SSW/SACS has been conservatively modeled as such to address uncertainties regarding (a) how long the operators might continue to operate the plant while equipment heatup occurs in hope of restoring SSW/SACS, and (b) the uncertainties regarding when the condenser may be lost. Hence, the event tree looks quite similar to the MSIV closure event tree with the primary difference being that the "W" event (heat removal via RHR) is assumed failed. The Uv events in the tree also account for the loss of SSW/SACS effects on long-term operability of equipment.

3.1.3.4 Event Tree Model of Loss of IE Panel Room HVAC or Switchgear Room HVAC (globally referred to as loss of HVAC)

As described in Section 3.1.1.1, these systems serve numerous room cooling needs throughout the plant, primarily involving electrical equipment room HVAC. Similar to the SSW/SACS discussion, loss of either of these systems is likely to cause the need for a forced manual shutdown of the plant or a scram due to failed equipment as a result of loss of HVAC. Additionally, loss of HVAC could affect a variety of mitigating systems. Hence, these are special initiators.

1) Initiating Event Descriptions

Similar to loss of SSW/SACS discussion in that room heatups would be monitored and if the loss of HVAC equipment is not restored, shutdown would eventually have to occur or it would be induced.

2) Accident Sequence Characterization

The losses of these systems have been previously described in Section 3.1.1.1. For the loss of Switchgear Room HVAC, room heatup calculations suggest that the AC switchgear room temperatures could be expected to rise sufficiently above equipment qualification limits in about 20 hours causing possible failures of this equipment. The cascading effects of a loss of switchgear equipment would cause the plant to respond in a way similar to a station blackout event (albeit with a time delay for the room heatups to occur) and, hence, this event ultimately looks like a loss of power and heat sink event.

Similarly, if loss of the Class 1E Panel Room HVAC occurs, electrical equipment failures could occur in about 12 hours particularly in the relay room below the control room as well as other areas which affect SACS and other system operation. These electrical equipment failures could cause loss of equipment control and/or power. Possible SACS loss causes the effects mentioned for the loss of SSW/SACS initiator. Hence, this event looks like a delayed loss of power and/or other system operability which also leads to loss of heat removal.

To simplify the modeling of these very complex interrelationships, the IPE treats these events as a "Loss of HVAC" event which is treated as a loss of power/heat sink event and, hence, looks similar to a station blackout. The timing delays, however, allow for the recovery of the lost HVAC systems before loss of power/heat sink occurs.

3) Event Tree Construction

Since losses of these systems (treated as a loss of HVAC) ultimately can lead to a loss of power/heat sink, the event tree model (Figure 3.1.3-4) appears the same as the Station Blackout portion of the Te (Loss of Power) event tree. This is a simple model for what is actually a complex sequence of events involving time delay for room heatups to occur. These timing delays and credit for recovery actions, such as restoring HVAC, and opening room doors, will be appropriately treated in the quantification of these sequences.

3.1.3.5 Event Tree Analysis of Interfacing System Loss of Coolant Accident

Interfacing system loss of coolant (ISLOCA) is defined as a class of accidents in which a break occurs in a system connected to the reactor coolant system, causing a loss of inventory. Subsequent breaks of the low pressure system may cause a harsh environment and additional common cause failures.

ISLOCAs which occur outside containment are of special concern because of offsite radiological concerns and because RCS inventory is not retrievable (it is lost for long-term core cooling).

After screening out improbable core damage contributors, the low-pressure system interfaces which are potentially susceptible to an interfacing LOCA during power operation are the following:

- Core Spray Discharge Lines for pumps AP206/BP206/CP206/DP206,
- RHR Injection Lines for pumps AP202/BP202/CP202/DP202,
- RHR shutdown cooling suction line,
- RHR shutdown cooling return to reactor recirculation loops A/B,
- RHR vessel head spray line.

Figures 3.1.3-5 and 3.1.3-6 provide the Hope Creek valve configuration at the high to low pressure interface for each of the identified potential ISLOCA pathways. The evaluation of Hope Creek core damage frequency from an ISLOCA event is based on the valve configuration for a single line in each of the potential ISLOCA pathways.

The ISLOCA event tree/sequence diagrams are initiated by the low pressure system overpressurization and describe the possible accident and core melt progression scenarios that could cause release of radionuclides bypassing containment. Event trees were constructed in Reference 3.1.3-1 for the interfacing pathways. These event trees are presented in Figures 3.1.3-7 to 3.1.3-10.

1) Initiating Event Description

As a result of an ISLOCA event, the pressure indicators for the low pressure system and the alarms would alert the control room operators. Upon receiving an alarm indicating leakage through the high/low pressure interface, operators are guided by Technical Specifications to commence a shutdown and to be in HOT SHUTDOWN in 12 hours. Conditions in the reactor building would require actions to be taken in accordance with the OP-EO.ZZ-0103, Reactor Building Control. If only one area is affected, a reactor scram is required only if a room is being flooded and the break cannot be isolated. A small ISLOCA may not cause operators to scram the reactor.

If the ISLOCA is not identified by the operator, the reactor will eventually trip on low level. However, depending on the size of the ISLOCA, a low level scram may not occur because normal feedwater flow will increase to provide proper makeup.

2) Accident Sequence Characterization

With the exception of the break location and potential containment bypass, ISLOCA is characterized in a similar way to a large or medium LOCA.

3) Event Tree Construction

Separate event trees were developed for ISLOCA leaks (approximately 100 gpm) and for ISLOCA breaks (greater than 150 gpm). ISLOCA event trees are similar, and full documentation is in Reference 3.1.3-1.

Core Spray Discharge Line ISLOCA Initiator (Event FOP)

As stated in Reference 3.1.3-1, the ISLOCA initiating events are very rare events and no statistical data from the industry can be used. Therefore, an initiating event fault tree was constructed, which modeled both hardware failures such as valve leakage/rupture and human failures such as valve mispositioning due to maintenance and surveillance activities.

No Rupture of Low Pressure Piping (Event R)

As a result of the initiating break at the high to low pressure interface, the low pressure piping and valves are exposed to a higher pressure than design, and a secondary rupture may occur. The degree to which the low pressure system integrity is affected following overpressurization depends on the design capacity of the relief valves on the low pressure system, and the characteristics of the system piping and other components such as flanges, seals, bolts, etc. This top event addresses the concern of this secondary rupture of the low pressure system.

No Leak of Low Pressure Piping (Event L)

More probable than a secondary break, first a secondary leak will develop in the low pressure system. This top event addresses the concern of this secondary leakage.

Early Isolation of Low Pressure Piping (Event IS1)

After the ISLOCA event is identified, the operators will try to isolate the break. The Hope Creek EOPs direct the operators to control secondary containment conditions within a prescribed envelope as defined in OP-EO.ZZ-0103, Reactor Building Control. There are numerous indications that are potentially available to the operator such as:

- Reactor Building high temperature,
- Reactor Building high pressure differential,
- Reactor Building high local radiation,
- Reactor Building high water level,
- Reactor Building high HVAC exhaust radiation,
- Refueling floor high HVAC exhaust radiation,
- Interfacing System high pressure.

The isolation of the ISLOCA event is done by the operators through the inboard and outboard MOVs. This top event addresses this recovery action, which includes both human and equipment constituents.

High Pressure Coolant Makeup (Event U)

If the ISLOCA failure is a rupture and is not isolated, the reduction in reactor pressure and/or environmental conditions would disable the HPCI, RCIC, and feedwater pumps which are all turbine driven.

Reactor Depressurization (Event X)

The EOPs call for the operators to depressurize the RPV under severe environmental conditions in the reactor building or during low RPV water level. Either or both of these will be present during the postulated ISLOCA event. This event is treated in a way similar to the depressurization top event of the LOCA event trees.

Low Pressure Coolant Makeup (Event V)

If the break is large during an ISLOCA in the low pressure portion of CSS, the reactor will rapidly depressurize. At low reactor pressure LPCI can be injected to the RPV.

The opposite core spray loop of two CSS pumps can also be used to provide makeup.

During an ISLOCA in the low pressure portion of LPCI, all four CSS pumps can be used to provide makeup flow to the vessel. In addition, the unaffected LPCI loops can be used to provide injection.

During an ISLOCA in the RHR shutdown cooling line, both CSS loops, as well as the RHR pumps not being used for shutdown cooling (CP202 and DP202), can be used to provide makeup.

During the ISLOCA in the RHR shutdown cooling return to reactor recirculation loops A and B, all four CSS pumps as well as the RHR pumps not affected by ISLOCA and not used for SDC (CP202 and DP202) can be used to provide makeup.

During an ISLOCA in the RHR vessel head spray line, all four CSS pumps as well as the RHR pumps not used for vessel head spray (AP202, CP202 and DP202) can be used to provide makeup.

Other Makeup Sources (Event O)

If coolant makeup cannot be provided using available ECCS, non-ECCS systems such as the cross connection from the SSWS or control rod drive injection can be used to prevent core damage. The ability of non-ECCS systems to inject successfully into the reactor is dependent on the local environment and the mitigating measures taken by operator in response to the accident.

Late Isolation of Low Pressure Piping (Event IS2)

This top event node is the assessment of whether the pathways can be isolated after blowdown. This isolation can result in avoidance of containment bypass even though damage may still result.

3.1.3.6 Event Tree Analysis of Internal Flooding

The discussion of the analysis of internal flooding is provided in Section 3.3.9. As described in Section 3.3.9, the turbine trip and the MSIV closure event trees were used to model internal flooding in various flood areas. Therefore, it was unnecessary to include the individual flooding event trees in the Report.

3.1.3.7 Event Tree Analysis of Anticipated Transients Without Scram

1) Initiating Event Description

ATWS Event Tree Evaluation

One of the functional requirements for successful accident mitigation is the ability to insert sufficient negative reactivity into the core to bring the reactor sub-critical. This section focuses on those low frequency event sequences in which an initiator, principally an anticipated transient, occurs with a subsequent failure to insert the control rods. Other initiators, such as LOCAs or other transient initiated accident sequences, coupled with the failure of the reactivity control function are of low frequency (negligible) compared to the dominant ATWS sequences discussed herein.

The response of plant systems and the operating staff to a postulated failure to insert control rods following an anticipated transient potentially involves the operation of normally operating and standby safety systems. This response is generally similar among BWRs. The basic functions that satisfy the requirements for a safe and successful shutdown are:

- RCS pressure control,
- coolant injection and RCS inventory control,
- reactivity control, and
- containment heat removal.

The ATWS event can be divided into two distinct parts for discussion and analysis. These are:

- Prevention: This includes those system features designed to assure that the control rods will be inserted when required.

- Mitigation: This includes the systems or features designed to provide a diverse method of reactor shutdown if the control rods cannot be inserted.

Particular features which are considered in the assessment of the plant's capability to fulfill these functions and prevent or mitigate an ATWS event, are presented below:

- Safety-grade level sensors in the scram discharge volume plus a scram discharge volume design consistent with the BWR Owner's Group recommendation after their examination of the Browns Ferry partial scram incident;

- ARI circuitry and solenoid valves;

- RPT;

- ADS Inhibit Switch;

- Standby Liquid Control (SLC) system which satisfies the NRC SLC capacity requirements per 10CFR50.62;

- Operating procedures to deal explicitly with incidents involving failure of control rods to insert (i.e., reactivity control failure) based upon the BWR Owner's Group Emergency Procedure Guidelines (Rev. 4);

- A Hardened Plant Vent which aids in primary containment pressure control. This vent is described in Section 3.2.1.8.

These design and operational features are incorporated into the ATWS event model and the system level fault trees describing each function. The following assumptions were also incorporated in the ATWS modeling:

a) The ATWS event is assumed to occur at reactor full power.

b) The occurrence of a recirculation pump trip is assumed to reduce core power to approximately 40% of full power. Failure of the recirculating pumps to trip is assumed to result in overpressurization of the reactor vessel leading to vessel rupture and core damage.

c) Reduction of vessel level (initial level control) to the TAF while at high pressure is assumed to additionally reduce the core power to approximately 20% of full power. There is a high uncertainty regarding the core power at TAF. A range of 15% to 25% is used in various published PRAs.

d) No credit is given for the high pressure CRD flow during the initial level control since the flow rate is insufficient to maintain the reactor level above TAF. Depressurization and use of low pressure systems would be required by the procedure.

e) Operation of all core cooling systems using the pool for suction in loss of RHR type sequences is assumed to fail in the long term because of high pool temperature (200°F). High pool temperature causes loss of CSS/LPCI, and HPCI/RCIC turbine lube oil failure after suction switchover to the pool, or HPCI/RCIC loss of steam pressure when depressurizing for HCTL.

f) Long-term failure of RHR also makes successful long-term core cooling vulnerable to eventual failure because of closure of SRVs upon high containment pressure (affects low pressure injection).

g) LOCA initiated events with a subsequent ATWS do not require explicit event tree analysis due to low frequency of occurrence. However, ATWS-induced LOCAs are considered in this analysis.

2) Accident Sequence Characterization

After an ATWS event occurs, subsequent to an initiating event, efforts are made (following the EOPs) to reduce core power and to cool the core and the containment. The condenser may or may not be available as a heat sink (power conversion available) depending on the transient. For these transients, the severity of the accident is driven by the initiating event itself. However, if MSIVs are closed, feedwater and power conversion are unavailable, and the severity of the accident is driven by the ATWS event.

For an MSIV closure type ATWS, a large number of operator actions are needed in a short period of time (within the first five minutes). Manual scram is attempted, alternate rod insertion (ARI) is tried, recirculating pumps are tripped, automatic depressurization is inhibited and HPCI flow inside the shroud is isolated. At Hope Creek, SLC may be actuated automatically, but manual actuation of SLC may occur even before the automatic actuation setpoint is triggered. The operator also controls the level in the reactor.

The ATWS part of the accident is terminated when an adequate amount of boron is continuously present in the reactor, either in the form of control rods, borated solution, or borated precipitate. At this time the accident is driven again by the initiating event.

Success criteria for ATWS are given in Table 3.1.1-19.

3) Event Tree Construction

To describe more effectively the specific details related to the ATWS events, two event trees were constructed, one representing the group of transients which result in MSIV closure (event tree called Ta), and one representing the group of transients where MSIVs remain open (called Tat).

The ATWS event tree Ta is shown in Figure 3.1.3-11. Seventy-eight sequences are shown, of which 20 do not lead to core damage. Three sequences represent uncertain damage states of the core and are called "vulnerable."

The ATWS event tree Tat is shown in Figure 3.1.3-12. Ninety-six sequences are shown, of which 33 do not lead to core damage. Four sequences represent uncertain damage states of the core and are called "vulnerable." Eight sequences represent transfers to the Tam event tree. The ATWS specific functional event headings listed across the top of the event tree are discussed below.

Event Tree Model Description

The following principal mitigating events are discussed as they apply to accident sequences initiated by a postulated ATWS:

RPS Electrical and Mechanical Failure (Events C_E and C_M): The mechanical redundancy of the control rod drive mechanisms makes the common-mode failure of multiple adjacent control rods unlikely; however, an estimate of the probability has been based on the NRC staff accepted value from NUREG-0460. The electrical diversity in sensors, logic, and scram solenoids help to reduce the potential for common-mode failures leading to failure of multiple control rods to insert due to an electrical common-mode failure. An estimate for this failure mode is also based upon NUREG-0460. The split between mechanical and electrical failures is based upon available BWR precursors.

The mechanical function is shown first only for ease of construction of the event tree. Additional branches are required to describe the logical possibilities; however, there is no difference in the quantification or qualitative understanding.

Recirculation Pump Trip (Event RPT): The recirculation pumps provide a method of changing core reactivity without changing the control rod position. Positive reactivity can be inserted by increasing the recirculation pump flow. The recirculation pumps automatically trip on either high reactor pressure or low reactor water level. The RPT is effective in rapidly inserting sufficient negative reactivity into the core to limit the power and pressure rise following an ATWS to within acceptable limits. At Hope Creek, the reactor power will drop to approximately 40% to 50% following an RPT from a 100% power turbine trip ATWS.

Failure to trip (manually or automatically) the Recirculation Pumps (RPT) following a turbine trip from 100% power is assumed to lead to high RCS pressures greater than 1500 psi. Without RPT, the core power remains approximately 100%; approximately 25% power is removed by the turbine bypass valves, and 25% power is removed by the SRVs. The remaining power, approximately 20% to 50% power will represent the power source of the pressure increase in the RCS. Level control at TAF is assumed to be unsuccessful under these circumstances. It is then assumed that a breach in the primary system would occur, (i.e., a large LOCA); low pressure injection would automatically initiate, causing recriticality and containment pressure would rise and would not be mitigated, leading directly to a challenge to the containment.

Alternate Rod Insertion (ARI) (Event K): ARI is a functionally diverse system to the electrical portion of the RPS. It incorporates a number of changes including additional sensors, logic, and solenoid valves to provide added assurance that the postulated electrical failures will not prevent control rod insertion.

Adequate Pressure Control (Event M): The large number of safety relief valves at Hope Creek provide a high level of confidence that there will be sufficient relief valve capacity to avoid excessive pressures inside the reactor system following an ATWS. Given the ATWS initiator, failure of 'M' is assumed here to imply that a LOCA would result. The LOCA is assumed to result in replenishing coolant inventory from the low pressure systems. This cold unborated water is assumed to cause recriticality, possibly leading to containment failure. Successful pressure control is a function of the number of challenges and the number of SRVs required to open per challenge.

High Pressure Coolant Makeup (Event U): Following a MSIV closure, the turbine driven feedwater system is unavailable for coolant injection. Therefore, HPCI or RCIC are necessary for successful coolant injection, i.e., a high pressure coolant injection source is necessary to avoid the high-volume low-pressure system from injecting and diluting the boron in the vessel. Therefore, the calculated reliability of the coolant injection function is based upon the HPCI and RCIC fault tree models.

3.1.3.8 References

3.1.3-1 "Hope Creek Generating Station ISLOCA Evaluation Report." ERIN Engineering, Doc. No. C101-91-02-288. April 14, 1992.

3.1.3-2 "Hope Creek Generating Station Probabilistic Risk Assessment," Section 3.10.3.1. Public Service Electric And Gas Company, Hancocks Bridge, NJ.

3.1.3-3 "Hope Creek Generating Station Probabilistic Risk Assessment," Appendix N. Public Service Electric And Gas Company, Hancocks Bridge, NJ.

3.1.3-4 "Hazards Evaluation Program." Bechtel: Design Criteria 10855-D7.3.

The ATWS event tree Tat is shown in Figure 3.1.3-12. Ninety-six sequences are shown, of which 33 do not lead to core damage. Four sequences represent uncertain damage states of the core and are called "vulnerable." Eight sequences represent transfers to the Tam event tree. The ATWS specific functional event headings listed across the top of the event tree are discussed below

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Failure to trip (manually or automatically) the Recirculation Pumps (RPT) following a turbine trip from 100% power is assumed to lead to high RCS pressures greater than 1500 psi. Without RPT, the core power remains approximately 100%; approximately 25% power is removed by the turbine bypass valves, and 25% power is removed by the SRVs. The remaining power, approximately 20% to 50% power will represent the power source of the pressure increase in the RCS. Level control at TAF is assumed to be unsuccessful under these circumstances. It is then assumed that a breach in the primary system would occur, (i.e., a large LOCA); low pressure injection would automatically initiate, causing recriticality and containment pressure would rise and would not be mitigated, leading directly to a challenge to the containment.

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High Pressure Coolant Makeup (Event U): Following a MSIV closure, the turbine driven feedwater system is unavailable for coolant injection. Therefore, HPCI or RCIC are necessary for successful coolant injection, i.e., a high pressure coolant injection source is necessary to avoid the high-volume low-pressure system from injecting and diluting the boron in the vessel. Therefore, the calculated reliability of the coolant injection function is based upon the HPCI and RCIC fault tree models.

3.1.3.8 References

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3.1.3-2 "Hope Creek Generating Station Probabilistic Risk Assessment," Section 3.10.3.1. Public Service Electric And Gas Company, Hancocks Bridge, NJ.

3.1.3-3 "Hope Creek Generating Station Probabilistic Risk Assessment," Appendix N. Public Service Electric And Gas Company, Hancocks Bridge, NJ.

3.1.3-4 "Hazards Evaluation Program." Bechtel: Design Criteria 10855-D7.3.

Table 3.1.1-1

HCGS INITIATING EVENT CATEGORIES

Initiating Event Category	Initiating Events Included	EPRI NP-2230 Transient Designator	Comments
General Transients			
1. Turbine trip (T_t)	1. Electric load rejection	BWR1	Events cause closure of turbine control and/or stop valves. Turbine bypass is assumed to be available and MSIVs are assumed to be open.
	3. Turbine trip	BWR3	
	6. Inadvertent closure of one MSIV	BWR6	
	7. Partial main steam isolation valve closure	BWR7	
	14. Recirculation control failure - increasing flow	BWR14	
	15. Recirculation control failure - decreasing flow	BWR15	
	16. Trip of one recirculation pump	BWR16	
	17. Trip of all recirculation pumps	BWR17	
	18. Abnormal startup of idle recirculation pump	BWR18	
	19. Recirculation pump seizure	BWR19	
	20. Feedwater - Increasing flow at power	BWR20	
	21. Loss of feedwater heater	BWR21	

Table 3.1.1-1 (Continued)

HCGS INITIATING EVENT CATEGORIES

Initiating Event Category	Initiating Events Included	EPRI NP-2230 Transient Designator	Comments
	23. Trip of one feedwater or condensate pump	BWR23	
	24. Feedwater low flow at power	BWR24	
	25. Low feedwater flow during startup or shutdown	BWR25	
	26. High feedwater flow during startup or shutdown	BWR26	
	27. Rod withdrawal at power	BWR27	
	28. High flow due to rod withdrawal	BWR28	
	29. Inadvertent insertion of rod or rods	BWR29	
	30. Detected fault in reactor protection system	BWR30	
	32. Loss of auxiliary power (loss of auxiliary transformer)	BWR32	
	33. Inadvertent startup of HPCI/LPCI	BWR33	
	34. Scram due to plant occurrences	BWR34	
	35. Spurious trip via instrumentation, reactor protection system fault	BWR35	
	36. Manual scram - no out of tolerance condition	BWR36	

Table 3.1.1-1 (Continued)

HCGS INITIATING EVENT CATEGORIES

Initiating Event Category	Initiating Events Included	EPRI NP-2230 Transient Designator	Comments
	37. Cause unknown	BWR37	
2. Loss of condenser (T_c)	2. Electric load rejection with turbine bypass valve failure	BWR2	This transient precludes the use of the condenser as a heat sink.
	4. Turbine trip with turbine bypass valve failure	BWR4	
	8. Loss of normal condenser vacuum	BWR8	
	10. Pressure regulator fails closed	BWR10	
	13. Turbine bypass valves cause increased pressure (closed)	None	
3. Total main steam isolation valve closure (T_m)	5. Main steam isolation valve closure	BWR5	PCS is isolated due to MSIV closure.
	9. Pressure regulator fails open	BWR9	
	12. Turbine bypass fails open	BWR12	
4. Total loss of feedwater (T_t)	22. Loss of all feedwater flow	BWR22	Loss of all feedwater occurs. No recovery of feedwater is assumed to be possible. Reactor trip occurs as a result of low level in the reactor vessel. No immediate automatic reactor trip occurs.
5. Stuck open safety/relief valve (T_i)	11. Inadvertent opening of a safety/relief valve (stuck)	BWR11	Manual trip will occur in 2 minutes; if not, then automatic trip will occur at low reactor pressure (less than 756 psi).

Table 3.1.1-1 (Continued)

HCGS INITIATING EVENT CATEGORIES

Initiating Event Category	Initiating Events Included	EPRI NP-2230 Transient Designator	Comments
Loss-of-Offsite-Power			
6. Loss-of-Offsite-Power	31. Loss-of-offsite-power	BWR31	Total loss of all offsite electric power sources. Reactor trip occurs from deenergizing the RPS and MSIV closure occurs.
Special Initiators			
7. Loss of dc bus	38. Loss of dc vital bus	None	Not applicable at Hope Creek Generating Station (HCGS).
8. Loss of ac vital bus	40. Loss of ac vital bus	None	Impact on Loss of RACS special initiator.
9. Loss of service water	41. Loss of a service water system	None	Special initiator for HCGS.
10. Loss of safety auxiliaries cooling system.	44. Loss of safety auxiliary cooling system	None	Special initiator for HCGS.
11. Loss of reactor auxiliaries cooling system	41. Loss of a service water system	None	Special initiator for HCGS.
12. Loss of instrument/service air	43. Loss of air	None	Special initiator for HCGS.
13. Loss of Panel Room Supply	42. Loss of HVAC	None	Special initiator for HCGS.
14. Loss of Controlled Area Room Cooling	42. Loss of HVAC	None	Special initiator for HCGS
15. Loss of Switchgear Room Cooling	42. Loss of HVAC	None	Special initiator for HCGS
16. Partial loss of reactor vessel water level measurement system	45. Partial loss of reactor vessel water level measurement system	None	Several channels still available. Can be treated as part of Turbine Trip initiator.

Table 3.1.1-1 (Continued)

HCGS INITIATING EVENT CATEGORIES

Initiating Event Category	Initiating Events Included	EPRI NP-2230 Transient Designator	Comments
17. Partial loss of compressed gas system	46. Partial loss of compressed gas system	None	
LOCA			
18. Small LOCA inside containment (S_2) (< 0.005 ft^2 for liquid, < 0.1 ft^2 for steam)	39. Leakage in primary system other than SRV (above Technical Specification limit)	None	
	47. Small LOCA inside containment (S^2) (< 0.005 ft^2 for liquid, < 0.1 ft^2 for steam)	None	Reactor trip occurs as a result of high drywell pressure or low level in the reactor vessel. RCIC is capable of providing adequate coolant makeup.
19. Intermediate LOCA inside containment (S_1) (0.005 to 0.3 ft^2) for liquid, 0.1 to 0.3 ft^2 for steam)	48. Intermediate LOCA inside containment (0.005 to 0.3 ft^2 for steam)	None	This is similar to Category 18 but RCIC is not adequate for coolant makeup.
20. Large LOCA inside containment (A) (> 0.3 ft^2)	49. Large LOCA inside containment (> 0.3 ft^2)	None	Reactor trip occurs as a result of high drywell pressure or low level in the reactor vessel. The primary coolant system depressurizes rapidly and remains depressurized.
21. Reactor vessel rupture (X)	50. Reactor vessel rupture	None	Reactor trip results from high drywell pressure or low level in the reactor vessel. The break size is large enough such that coolant level cannot be maintained in the reactor vessel. Such an event is assumed to lead directly to core damage.

HCGS INITIATING EVENT CATEGORIES

Initiating Event Category	Initiating Events Included	EPRI NP-2230 Transient Designator	Comments
LOCA (Outside Containment)			
22. Steam line LOCA outside containment (A_{sl})	51. Steam line LOCA outside containment with failure of MSIVs to close	None	
23. Feedwater/condensate LOCA outside Containment	52. Feedwater or condensate LOCA with failure of check valves to close	None	
24. RHR suction line LOCA outside containment.	53. Interfacing system LOCA for RHR suction	None	
25. RHR discharge or return line interfacing LOCA	54. Interfacing system LOCA for RHR discharge		
26. Core Spray discharge line interfacing LOCA	55. Interfacing system LOCA for Core Spray		

Table 3.1.1-2

HOPE CREEK INITIATING EVENTS DATA BASE

LER #	Initiating Event Description	IE Group (from Table 3.1.1-1)	IE Category (from Table 3.1.1-1)
86 - 65	Partial Loss of FW	23	T_t
86 - 60	Partial Loss of FW	23	T_t
86 - 85	Turbine Trip	3	T_t
86 - 92	Spurious Low/High Level of Load Reject	1	T_t
87 - 13	Leakage	39	T_t
87 - 17	Turbine Trip	3	T_t
87 - 34	Loss of FW (Control)	22	T_f
87 - 37	Loss of Condenser Vacuum	8	T_c
87 - 39	Turbine Trip	3	T_t
87 - 47	Inadvertent Open Relief Valve	11	T_t
87 - 51	Spurious Grounding	35	T_t
88 - 12	MSIV Closure After Manual Scram	5	T_m
88 - 13	Partial Loss of FW	23	T_t
88 - 15	Manual Scram No Out of Tolerance	36	T_t
88 - 22	Turbine Trip	3	T_t
88 - 27	Loss of Feedwater Flow	22	T_f
88 - 29	Load Reject and Turbine Trip	1	T_t
89 - 17	CRD HCU Electrical	34	T_t
89 - 25	Turbine Trip	3	T_t
90 - 1	Turbine Trip	3	T_t
90 - 3	Loss of FW (Marsh Fire)	22 (External)	Tf
90 - 24	Single MSIV Closure	6	T_t
90 - 28	Turbine Trip	3	T_t
91 - 5	Partial Loss of FW	23	T_t
91 - 8	Partial Loss of FW	23	T_t
92 - 6	Suppression Pool - Vacuum Breakers Failed	35	T_t
92 - 13	Manual Scram - Recirc. Fans Failed	35	T_t
93 - 4	Turbine Trip	3	T_t

Table 3.1.1-3

SURVEY OF PRA LOCA FREQUENCIES (MEAN) PER YEAR

LOCA Type	Brunswick	Peach Bottom	Grand Gulf	Shoreham	Limerick	WASH-1400	HCGS
Small	3.0E-2	2.7E-3	3.0E-3	8.0E-3	1.0E-2	2.7E-3	2.8E-2*
Intermediate	3.0E-3	8.0E-4	8.0E-4	3.0E-3	2.0E-3	8.0E-4	3.0E-3
Large	3.0E-4	2.7E-4	2.0E-4	7.0E-4	4.0E-4	2.7E-4	7.0E-4

* includes contribution from recirc pump seal LOCAs of 2.0E-2/year

TABLE 3.1.1-4
FLOOD FREQUENCIES BY ROOM

ROOM	TOTAL FLOOD INITIATOR FREQUENCY	30 MINUTE ISOLATION FAILURE[1]	UNISOLATED FLOOD FREQUENCY
110	2.0E-3	1.2E-3	2.4E-6
4104	3.1E-2	1.2E-3	3.7E-5
4105	3.1E-2	1.2E-3	3.7E-5
4107	3.7E-2	1.2E-3	4.4E-5
4108	2.0E-5	1.2E-3	2.4E-8
4109	3.6E-2	1.2E-3	4.3E-5
4110	2.6E-2	1.2E-3	3.1E-5
4111	9.8E-2	1.2E-3	1.2E-4
4113	3.6E-2	1.2E-3	4.3E-5
4114	3.7E-2	1.2E-3	4.4E-5
4116	3.1E-2	1.2E-3	3.7E-5
4118	3.1E-2	1.2E-3	3.7E-5
4201	7.2E-2	1.2E-3	8.6E-5
4202	5.6E-2	1.2E-3	6.7E-5
4203	6.7E-6	1.2E-3	8.0E-9
4215	2.3E-5	1.2E-3	2.8E-8
4301	7.2E-2	1.2E-3	8.6E-5
4303	7.2E-2	1.2E-3	8.6E-5
4309	5.6E-2	1.2E-3	6.7E-5
4310	7.2E-2	1.2E-3	8.6E-5

NOTE:

1: The flood isolation failure rate within the 30 minute time frame was determined with the use of the method for group 1 items for 30 minutes.

Table 3.1.1-5

HCGS INITIATING EVENT FREQUENCIES

Initiating Event	Description	Frequencies
T_t	Turbine Trip	4.0
T_c	Loss of Condenser Vacuum	1.8E-1
T_f	Loss of Feedwater	5.5E-1
T_m	MSIV Closure	1.8E-1
T_i	Inadvertent Open SRV	3.8E-2
$T_{sw/sacs}$	Loss of Service Water / SACS	2.1E-4
T_{rac}	Loss of RACS	1.0E-2
T_{hv}	Loss of HVAC	2.4E-3
T_{ias}	Loss of Instrument Air / Service Air	1.0E-2
T_e	Loss of Offsite Power	3.4E-2
S_2	Small LOCA	2.8E-2
S_1	Intermediate LOCA	3.0E-3
A	Large LOCA	7.0E-4
ISLOCA	ISLOCA	1.0E-3 (Leakage) 1.0E-5 (Rupture)
T_{fl}	Internal Flooding Failure to isolate within 30 minutes	7.0E-1 1.0E-3

Table 3.1.1-6

Turbine Trip (T_t) Success Criteria

Reactivity Control	Reactor Cooling System Integrity	High Pressure Inventory Control	Early Cont. Pres./Temp. Control	Reactor Vessel Depressurization	Low Pressure Inventory Control	Long Term Heat Removal
Sufficient rods inserted (RPS or manual trip within 1/2 minute)	Open at least 2*/14 (at most 5/14) SRVs when pressure increases and all SRVs reclose. when pressure is normal	1/3 feedwater pump injectin or RCIC pump injecting cr HPCI pump injecting or 2*/2 CRD pumps injecting. (applicable after 2 hours*)	Not Required	Turbine bypass valves open to the main condenser or 2*/14 SRVs open	1 out of 3 condensate trains or 1 out of 4 LPCI loops inject or Core Spray injection 1/2 loops with 2 pumps/loop** or 2*/2 CRD pumps injecting. (applicable after 2 hours*) or 2/2 Condensate transfer pumps and Diesel fire pump***	Normal Heat Removal MSIV open & Power Conversion through Condensate or A or B RHR pump in SPC or CSC mode or Containment venting

* Assumption validated by MAAP calculation.
** In the long term, suction must be from CST, if suppression pool is approaching HCTL.
*** Long term only, following other successful injection.

Table 3.1.1-7

Loss of Condenser Vacuum (T_c) Success Criteria

Reactivity Control	Reactor Coolant System Integrity	High Pressure Inventory Control	Early Cont. Pres./Temp. Control	Reactor Vessel Depressurization	Low Pressure Inventory Control	Long Term Heat Removal
Sufficient rods inserted (RPS or manual trip within 1/2 minute)	Open at least 5*/14 (at most 8/14) SRVs when pressure increases and all SRVs reclose when pressure is normal	RCIC pump injecting or HPCI pump injecting or Feedwater (if at least 1 steam path is reopened and feedwater is recovered) or 2*/2 CRD pumps injecting. (applicable after 2 hours*)	Not Required	HPCI in full flow test mode or 2*/14 SRVs open	1 out of 4 LPCI loops inject or Core Spray injection 1/2 loops with 2 pumps/loop** or 1 out of 3 condensate trains or 2*/2 CRD pumps injecting. (applicable after 2 hours*) or 2/2 Condensate transfer pumps and Diesel fire pump***	A or B RHR pump in SPC or CSC mode or Containment venting or PCS through condensate (after reopening the MSIVs)

* Assumption validated by MAAP calculation.
** In the long term, suction must be from CST, if suppression pool is approaching HCTL.
*** Long term only, following other successful injection.

Table 3.1.1-8

MSIV Closure (T_m) Success Criteria

Reactivity Control	Reactor Coolant System Integrity	High Pressure Inventory Control	Early Cont. Pres./Temp. Control	Reactor Vessel Depressurization	Low Pressure Inventory Control	Long Term Heat Removal
Sufficient rods inserted (RPS or manual trip within 1/2 minute)	Open at least 5/14 (at most 8/14) SRVs when pressure increases and all SRVs reclose when pressure is normal	RCIC pump injecting or HPCI pump injecting or Feedwater (if at least 1 steam path is reopened and feedwater is recovered) or 2*/2 CRD pumps injecting. (applicable after 2 hours*)	Not Required	HPCI in full flow test mode or 2*/14 SRVs open	1 out of 4 LPCI loops inject or Core Spray injection 1/2 loops with 2 pumps/loop** or 1 out of 3 condensate trains or 2*/2 CRD pumps injecting. (applicable after 2 hours*) or 2/2 Condensate transfer pumps and Diesel fire pump***.	A or B RHR pump in SPC or CSC mode or Containment venting or (PCS through condensate, after reopening the MSIVs)

* Assumption validated by MAAP calculation.

** In the long term, suction must be from CST, if suppression pool is approaching HCTL.

*** Long term only, following other successful injection.

Table 3.1.1-9

Loss of Feedwater (T_F) Success Criteria

Reactivity Control	Reactor Cooling System Integrity	High Pressure Inventory Control	Early Cont. Pres./Temp. Control	Reactor Vessel Depressurization	Low Pressure Inventory Control	Long Term Heat Removal
Sufficient rods inserted (RPS or manual trip within 1/2 minute)	Open at least 2/14 (at most 5/14) SRVs when pressure increases and all SRVs reclose, when pressure is normal	RCIC pump injecting or HPCI pump injecting or Feedwater (if feedwater is recovered, and MSIVs remain open) or 2*/2 CRD pumps injecting. (applicable after 2 hours*)	Not Required	Turbine bypass valves open to the main condenser and MSIVs remain opened. or 2*/14 SRVs open	1/3 condensate trains and MSIVs remain open. or 1 out of 4 LPCI loops inject or Core Spray injection 1/2 loops with 2 pumps/loop** or 2*/2 CRD pumps injecting. (applicable after 2 hours*) or 2/2 Condensate transfer pumps and Diesel fire pump***	Normal Heat Removal if MSIVs remain open (Power Conversion through Condensate) or A or B RHR pump in SPC or CSC mode or Containment venting

* Assumption validated by MAAP calculation.
** In the long term, suction must be from CST, if suppression pool is approaching HCTL.
*** Long term only, following other successful injection.

Table 3.1.1-10

Stuck Open Safety/Relief Valve (T_i) Success Criteria

Reactivity Control	Reactor Coolant System Integrity	High Pressure Inventory Control	Early Cont. Pres./Temp. Control	Reactor Vessel Depressurization	Low Pressure Inventory Control	Long Term Heat Removal
Sufficient rods inserted (RPS or manual trip within 1/2 minute)	Not Applicable (stuck open SRV results in loss of integrity, but without the harsh environment of other LOCAs)	1/3 feedwater pumps injecting** or HPCI pump injecting** or RCIC* pump injecting**	Not Required*	Turbine bypass valves open to the main condenser or 1/14 SRVs open	1 out of 3 condensate trains inject or 1 out of 4 LPCI loops inject or Core Spray Injection 1/2 loops with 2 pumps/loop** or 2/2 Condensate transfer pumps and Diesel fire pump***	PCS through condensate, if MSIVs remain open. or A or B RHR pump in SPC or CSC mode or Containment venting

* Assumption validated by MAAP calculation.
** In the long term, suction must be from CST, if suppression pool is approaching HCTL.
*** Long term only, following other successful injection.

Table 3.1.1-11

Loss of Offsite Power (T_e) Success Criteria*

Reactivity Control	Reactor Coolant System Integrity	High Pressure Inventory Control**	Early Cont. Pres./Temp. Control	Reactor Vessel Depressurization**	Low Pressure Inventory Control**	Long Term Heat Removal**
Sufficient rods inserted (RPS or manual trip within 1/2 minute)	Open at least 2/14 (at most 8/14) SRVs when pressure increases	RCIC pump injecting	Not Required	2/14 SRVs open	1/4 LPCI loops inject	A or B RHR pump in SPC or CSC mode
	and	or			or	or
	all SRVs reclose when pressure is normal	HPCI pump injecting			Core Spray injection 1/2 loops with 2 pumps/loop	Containment venting (During SBO: via nitrogen bottles or manual operation)
		or			or	or
		2/2 CRD pumps injecting. (applicable after 2 hours)			1/3 condensate trains***	PCS through condensate (*** and reopening the MSIVs)
					or	
					2/2 CRD pumps injecting. (applicable after 2 hours)	
					or	
					2/2 Condensate transfer pumps*** and Diesel fire pump (long term only)	

* Upon occurrence of a loss of offsite power, immediate attempts are made to restore offsite power and to supply emergency onsite power via four diesel generators.

** The ability to operate AC driven systems in a subsequent station blackout (SBO) is precluded until power is recovered. Long term operability of HPCI, RCIC and SRVs are also challenged in SBO type scenarios.

*** Systems operable after recovery of offsite power.

Table 3.1.1-12

Large LOCA (A) Success Criteria

Reactivity Control	Reactor Cooling System Integrity	High Pressure Inventory Control	Early Cont. Pres./Temp. Control	Reactor Vessel Depressurization	Low Pressure Inventory Control	Long Term Heat Removal
Sufficient rods inserted (RPS or manual trip within 1/2 minute)	Not Applicable (LOCA results in loss of integrity)	Not Applicable* (Insufficient steam pressure or flow capacity)	Pressure suppression system operates passively*. (Including at least 1* wetwell/drywell vacuum breaker opens when demanded, and none are stuck open, before LOCA occurs)	Depressurized during large LOCA	1 out of 4 LPCI loops injecting or Core spray injection: 1 out of 2 loops with 2 pumps per loop** or Condensate 1/3 injection paths***	A or B RHR pump in SPC or CSC* mode. or Containment venting

* Assumption validated by MAAP calculation.
** In the long term, suction must be from CST, if suppression pool is approaching HCTL.
*** Long term only, following other successful injection.

Table 3.1.1-13

Intermediate LOCA (S1) Success Criteria

Reactivity Control	Reactor Cooling System Integrity	High Pressure Inventory Control	Early Cont. Pres./Temp. Control	Reactor Vessel Depressurization	Low Pressure Inventory Control	Long Term Heat Removal
Sufficient rods inserted (RPS or manual trip within 1/2 minute)	Not Applicable (LOCA results in loss of integrity)	HPCI pump injecting*. (Successful for a limited time until vessel depressurizes).	Pressure suppression system operates passively*. (Including at least 1* wetwell/drywell vacuum breaker opens when demanded, and none are stuck open, before LOCA occurs)	Depressurized by HPCI or 2/14 SRV open. (To ensure sufficiently rapid depressurization).	1 out of 4 LPCI loops injecting or 1 out of 2 CSS loops with 2 pumps per loop** or Condensate 1/3 injection paths***	A or B RHR pump in SPC or CSC* mode. or Containment venting

* Assumption validated by MAAP calculation.

** In the long term, suction must be from CST, if suppression pool is approaching HCTL.

*** Long term only, following other successful injection.

Table 3.1.1-14

Small LOCA (S2) Success Criteria

Reactivity Control	Reactor Cooling System Integrity	High Pressure Inventory Control	Early Cont. Pres./Temp. Control	Reactor Vessel Depressurization	Low Pressure Inventory Control	Long Term Heat Removal
Sufficient rods inserted (RPS or manual trip within 1/2 minute)	Not applicable (LOCA results in loss of integrity)	1/3 feedwater pump injecting or HPCI pump injecting or RCIC pump injecting* (High pressure systems are successful for a limited time until vessel depressurizes).	Pressure suppression system operates passively*. (Including no more than 1* wetwell/drywell vacuum breaker fails to reclose if demanded during cooldown).	Turbine bypass valves open to the main condenser or 2/14 SRVs open	Condensate 1/3 injection paths. or 1 out of 4 LPCI loops inject or Core Spray injection 1/2 loops with 2 pumps/loop** or 2/2 Condensate transfer pumps and Diesel fire pump***	A or B RHR pump in SPC or CSC* mode or Containment venting

* Assumption validated by MAAP calculation.

** In the long term, suction must be from CST, if suppression pool is approaching HCTL.

*** Long term only, following other successful injection.

Table 3.1.1-15

Loss of Instrument/Service Air (T_{ias}) Success Criteria

Reactivity Control	Reactor Coolant System Integrity	High Pressure Inventory Control	Early Cont. Pres./Temp. Control	Reactor Vessel Depressurization	Low Pressure Inventory Control	Long Term Heat Removal
Sufficient rods inserted (RPS or manual trip within 1/2 minute)	Open at least 5/14 (at most 8/14) SRVs when pressure increases and all SRVs reclose when pressure is normal	RCIC pump injecting or HPCI pump injecting or 2*/2 CRD pumps injecting. (applicable after 2 hours*)	Not Required	2*/14 SRVs open	1 out of 4 LPCI loops inject or Core Spray injection 1/2 loops with 2 pumps/loop** or 2*/2 CRD pumps injecting. (applicable after 2 hours*) or 2/2 Condensate transfer pumps and Diesel fire pump***	A or B RHR pump in SPC or CSC mode or Containment venting via nitrogen bottles or manual operation

* Assumption validated by MAAP calculation.

** In the long term, suction must be from CST, if suppression pool is approaching HCTL.

*** Long term only, following other successful injection.

Table 3.1.1-16

Loss of RACS (T_{rac}) Success Criteria

Reactivity Control	Reactor Coolant System Integrity	High Pressure Inventory Control	Early Cont. Pres./Temp. Control	Reactor Vessel Depressurization	Low Pressure Inventory Control	Long Term Heat Removal
Sufficient rods inserted (RPS or manual trip within 1/2 minute)	Open at least 5/14 (at most 8/14) SRVs when pressure increases	1/3 feedwater pump injecting	Not Required	2*/14 SRVs open	1 out of 3 condensate trains	A or B RHR pump in SPC or CSC mode
	and	or			or	or
	all SRVs reclose when pressure is normal	RCIC pump injecting			1 out of 4 LPCI loops inject	Containment venting
		or			or	or
		HPCI pump injecting			Core Spray injection 1/2 loops with 2 pumps/loop**	PCS through condensate (after reopening the MSIVs)
					or	
					2/2 Condensate transfer pumps and Diesel fire pump***	

* Assumption validated by MAAP calculation.

** In the long term, suction must be from CST, if suppression pool is approaching HCTL.

*** Long term only, following other successful injection.

Table 3.1.1-17

Loss of Service Water or SACS (T_{SW} or T_{SAC}) Success Criteria

Reactivity Control	Reactor Coolant System Integrity	High Pressure Inventory Control	Early Cont. Pres./Temp. Control	Reactor Vessel Depressurization	Low Pressure Inventory Control	Long Term Heat Removal
Sufficient rods inserted (RPS or manual trip within 1/2 minute)	Open at least 5/14 (at most 8/14) SRVs when pressure increases	RCIC pump injecting**	Not Required	2*/14 SRVs open	1 out of 4 LPCI loops inject**	Containment venting (via nitrogen bottles or manual operation)
	and	or			or	
	all SRVs reclose when pressure is normal	HPCI pump injecting**			Core Spray injection 1/2 loops with 2 pumps/loop**	
					or	
					2/2 Condensate transfer pumps and Diesel fire pump***	

*	Assumption validated by MAAP calculation

**	Short term only until loss of service water/SACS causes delayed failure.

***	Long term only, following other successful injection.

Table 3.1.1-18

Loss of HVAC (T_{hvc}) Success Criteria*

(1E Panel Room HVAC/Chilled Water or Loss of Control Area Chilled Water)

Reactivity Control	Reactor Coolant System Integrity	High Pressure Inventory Control	Early Cont. Pres./Temp. Control	Reactor Vessel Depressurization	Low Pressure Inventory Control	Long Term Heat Removal
Sufficient rods inserted (RPS or manual trip within 1/2 minute)	Open at least 5/14 (at most 8/14) SRVs when pressure increases and all SRVs reclose when pressure is normal	1/3 feedwater pump injecting or RCIC pump injecting or HPCI pump injecting or 2/2 CRD pumps injecting (applicable after 2 hours)	Not Required	Turbine bypass valves open to the main condenser or 2/14 SRVs open	1/4 LPCI loops inject or Core Spray injection 1/2 loops with 2 pumps/loop or 1 out of 3 condensate trains or 2/2 CRD pumps (applicable after 2 hours) or 2/2 Condensate transfer pumps and Diesel fire pump**.	Normal PCS through condensate (if at least one steam path is open) or A or B RHR pump in SPC or CSC mode or Containment venting via nitrogen bottles or manual operation.

* All systems are eventually subject to failure if room cooling loss is not recovered and electrical equipment failures occur. Specific system effects are addressed by the detailed dependency modeling in the fault trees.

** Long term only, following other successful injection.

Table 3.1.1-19

ATWS (Ta) Success Criteria

Reactivity Control	**Reactor Cooling System Integrity**	**High Pressure Inventory Control**	**Early Cont. Pres./Temp. Control**	**Reactor Vessel Depressurization**	**Low Pressure Inventory Control**	**Long Term Heat Removal**
Successful trip of the recirculation pump (RPT). and either fast restoration of rod insertion (ARI) or Poison injection by 2/2 SLC pumps initiated automatically or manually	Open sufficient number of SRVs (between 8 and 14) to prevent vessel overpressurization and All SRVs reclose. and Recirculation pump trip (RPT).	1/3 feedwater pump injecting (Note 1). or RCIC pump injecting or HPCI pump injecting through FW flow path (once level is low).	PCS (Note 1). or A or B RHR pump in SPC or CSC mode. (This means pressure suppression operates and SRV tail pipes remain intact and wetwell/drywell vacuum breakers reclose)	Early INHIBIT ADS and Slow, manual depressurization after poison injection is completed	1 out of 4 LPCI loops inject or Core Spray injection 1/2 loops with 2 pumps/loop (Note 2). or 1 out of 3 condensate trains or 2/2 Condensate transfer pumps and Diesel fire pump (Note 3).	PCS (Note 1). or A or B RHR pump in SPC or CSC mode or Containment venting

Notes

1. PCS is considered unavailable for the following transient initiators:
   Tc, Tm, Tf, Te, A, S1, Tias, Trac, Tsac.
2. In the long term, suction must be from CST, if suppression pool is approaching HCTL.
3. Long term only, following other successful injection.

Table 3.1.2-1

HOPE CREEK ANTICIPATED INITIATING EVENT FREQUENCIES GROUPED IN REPRESENTATIVE CATEGORIES

Transients	Frequency per reactor year
1. Turbine Trip (Tt*) (1, 3, 6, 7, 14, 15, 16, 17, 18, 19, 20, 21, 23, 24, 25, 26, 27, 28, 29, 30, 32, 33, 34, 35, 36, 37, 39) **	4.0
2. Loss of Condenser Availability (Tc*) (2, 4, 8, 10, 13) **	1.8E-1
3. MSIV Closure (Tm*) (5, 9, 12) **	1.8E-1
4. Loss of Feedwater (Tf*) (22) **	5.5E-1
5. Stuck Open Safety/Relief Valve (Ti*) (11) **	3.8E-2
6. Manual Shutdown	Included in Tt
7. Loss of Offsite Power (Te*) (31) **	3.4E-2

LOCAs	Frequency per reactor year
1. Small LOCA inside Containment (S2) (includes recirc pump seal contribution of 2.0E-2) (39, 47)**	2.8E-2
2. Intermediate LOCA inside Containment (S1) (48) **	3.0E-3
3. Large LOCA inside Containment (A) (49) **	7.0E-4
4. Reactor Vessel Rupture (Ro) (50) **	Negligible***
5. Steam Line LOCA outside Containment (Unisolated) (51) **	Negligible
6. Interfacing System LOCAs (53, 54, 55) **	1.0E-3 (Leakage) 1.0E-5 (Rupture)

* Acronym used in the event trees for this initiating event.

** Numbers indicate initiator category in reference to Table 3.1.1-1.

*** The frequency of RV rupture beyond the capability of ECCS systems is considered negligible.

Table 3.1.2-1 (cont'd.)

HOPE CREEK ANTICIPATED INITIATING EVENT FREQUENCIES GROUPED IN REPRESENTATIVE CATEGORIES

Special Initiators	Frequency per reactor year
1. Loss of one 4 Kv Bus (TAC) (40) **	N/A***
2. Loss of one DC Bus (TDC) (38) **	N/A***
3. Loss of Service Water (Tsw) (41) **	2.0E-2
4. Loss of Safety Auxiliary Cooling (Tsac) (44) **	1.6E-3
5. Loss of Reactor Auxiliary Cooling (Trac) (41) **	1.0E-2
6. Loss of Panel Room Supply or Chilled Water(Tprs) or Loss of Controlled Area Chilled Water (Tcac) (42) **	9.0E-2
7. Loss of Instrument Air (Tia) (43) **	1.0E-2
8. Partial Loss of Reactor Water Level Measurement System (Tlvl) (45) **	N/A****
9. Partial Loss of Compressed Gas (Tigs) (46) **	N/A***
10. Internal Flooding (Tfl)	7.9E-1
Failure to isolate within 30 minutes	1.0E-3

* Acronym used in the event trees for this initiating event.

** Numbers indicate initiator category in reference to Table 3.1.1-1.

*** These events either do not cause a reactor trip, or they do not result in the loss of a safety system. Therefore, these events are not considered special initiators.

**** Loss of any one set of level instruments should not induce a trip.
Loss of multiple channels could cause a trip and affect auto-initiation of ECCS.
Multiple channel loss is unlikely and manual ECCS is still possible.
Additionally, EOPs call for RPV flooding if level is uncertain.
All these factors were considered in the determination not to treat this event as a unique initiator.

Table 3.1.2-2

EVENT TREE TOP EVENTS AND EQUATION ASSIGNMENTS

Top Event	Top Event Description	Applicable Initiator	Functional Equation Designator	Fault Tree	Gate to Solve
A	Large LOCA	Large LOCA	A	IE-TOP	LARGE-LOCA
C	Reactor protection system (RPS)	All but ATWS	C	C-TOP	C-TOP
Ce	RPS Electrical	ATWS	CE	ATWS-TOP	RPS-ELECT
Cm	RPS mechanical	ATWS	CM	ATWS-TOP	RPS-MECH
C2	Boron injection by SLC	ATWS	C2	SLC	SLC1
D	Vapor suppression	Large LOCA and Medium LOCA	D	D-TOP	VAPOR-SUPP-FAILS
D	Vapor suppression	Small LOCA	D-S2	D-TOP	D-S2
E	Loss of offsite power	Transients	E	E-TOP	ACP-FAILS-OFFSIT
E	Loss of offsite power	LOCA	E-LOC	E-TOP	ACP-FAILS-OFFSIT
Edg	Power supply by emergency diesel generators	Loss of offsite power	EDG	EDG-TOP	ACP-FAILS-EDG
Edg	Power supply by emergency diesel generators	Large LOCA and Medium LOCA	EDG-LOC	EDG-TOP	ACP-FAILS-EDG
H	Water level control by the operator	ATWS	H-HIGH	ATWS-TOP	H-HIGH
H	Water level control by the operator	ATWS	H-LOW	ATWS-TOP	H-LOW
Hvc	Availability of HVAC	Transients	HVC	HVAC	ROOM-COOL
Hvc	Availability of HVAC	LOCA	HVC-LOC	HVAC	ROOM-COOL
Hvc	Availability of HVAC	Loss offsite power	HVC-LOP	HVAC	ROOM-COOL
Hvc	Availability of HVAC	Loss of SACS/SW	HVC-LOP	HVAC	ROOM-COOL
In1	Inhibit HPCI via CS by the operator	ATWS	IN1	ATWS-TOP	INHIBIT-HPCI-CS
In2	Inhibit ADS by the operator	ATWS	IN2	ATWS-TOP	INHIBIT-ADS
Iso	Isolation of seal LOCA	Small LOCA	ISO	SEALLOCA	SEAL-ISOL
K	ARI	ATWS	K	ATWS-TOP	ARI
M	SRVs open on demand (2 out of 14)	Transients	M-2	M-TOP	SRV-FAIL-OPEN
M	SRVs open on demand (8 out of 14)	ATWS	M-ATWS	ATWS-TOP	SRVS-FTO
Msv	Operator bypasses MSIV closure with no SORV	ATWS	MSV-1	ATWS-TOP	MSIV-CLOSURE-1
Msv	MSIV closure with one SORV	ATWS	MSV-2	ATWS-TOP	MSIV-CLOSURE-2
Msv	MSIV closure with two SORVs	ATWS	MSV-3	ATWS-TOP	MSIV-CLOSURE-3
P	One SRV closes	S2, Tt, Tf	P	P-TOP	SRV-1-CLOSE-DMD3
P	One SRV closes	Tm, Te, Thv, Tia, Tra, Tsa	P-TM	P-TOP	SRV-1-CLOSE-DMD6
P	One SRV closes	ATWS	P-ATWS	ATWS-TOP	SRV-1-CLOSE-ATWS
P2	Two SRVs close	Tt, Tf	P2	P-TOP	SRV-2-CLOSE-DMD3

Table 3.1.2-2

EVENT TREE TOP EVENTS AND EQUATION ASSIGNMENTS
(Continued)

Top Event	Top Event Description	Applicable Initiator	Functional Equation Designator	Fault Tree	Gate to Solve
P2	Two SRVs close	Tm, Te, Tia, Thv, Tra, Tsa	P2-TM	P-TOP	SRV-2-CLOSE-DMD6
P2	Two SRVs close	Inadvertent SORV	P2-1	P-TOP	SRV-2-CLOSE-DMD3
P2	Two SRVs close	ATWS	P2-ATWS	ATWS-TOP	SRV-2-CLOSE-ATWS
Q	High pressure injection / feedwater	Tt, Ti	Q	Q-PCS	Q-PCS
Q	High pressure injection / feedwater	ATWS	Q-ATWS	Q-PCS	Q-PCS
Q	Recovery of feedwater	Loss of feedwater	QR	Q-PCS	Q-PCS
Q	High pressure injection / feedwater	Small LOCA	Q	Q-PCS	Q-PCS
Q	High pressure injection / feedwater	Loss of RACS	Q-RA	QTT	QTT
Rpt	Recirculation pump trip	ATWS	RPT	ATWS-TOP	RECIRC-PMP-TRIP
S1	Medium break LOCA	Medium LOCA	S1	IE-TOP	MED-LOCA
S2	Small break LOCA	Small LOCA	S2	IE-TOP	SMALL-LOCA
S3	Seal LOCA	Small LOCA	S3	SEALLOCA	SEAL-LOCA
Scr	Manual scram	ATWS	SCR	ATWS-TOP	MAN-SCRAM
Tat	Turbine trip ATWS	ATWS	TAT	ATWS-IE	TAT
Ta1	Turbine trip ATWS	ATWS	TA1	ATWS-IE	TA1
Ta	MSIV closure ATWS	ATWS	TA	ATWS-IE	TAM
Ta2	MSIV closure ATWS	ATWS	TA2	ATWS-IE	TAM
Te	Loss of offsite power	Loss offsite power	TE	IE-TOP	LOSP
Tf	Loss of feedwater	Loss of feedwater	TF	IE-TOP	LOSS-FW
Thv	Loss of HVAC	Loss of HVAC	THV	IE-TOP	LOSS-HVAC
Ti	Inadvertent open SRV	Inad. open SRV	TI	IE-TOP	INAD-OPEN-SRV
Tia	Loss of instrument air	Loss of inst. air	TIA	IE-TOP	LOSS-IA
Tm	MSIV closure or loss of condenser vacuum	Tm / Tc	TM	IE-TOP	MSIV-CLOSE
Tra	Loss of RACS	Loss of RACS	TRA	IE-TOP	LOSS-RACS
Tsa	Loss of SACS or SW	Loss SACS / SW	TSA	IE-TOP	LOSS-SACS-SW
Tt	Turbine trip	Turbine trip	TT	IE-TOP	TURB-TRIP
U	High pressure injection by HPCI or RCIC	Tt, Tm, Ti	U	U-TOP	HPI-RCI-FAIL
U	High pressure injection by HPCI or RCIC	ATWS	U-ATWS	U-TOP	HPI-RCI-FAIL
U	High pressure injection by HPCI or RCIC	Loss of HVAC	U-HV	U-TOP	HPI-RCI-FAIL
U	High pressure injection by HPCI or RCIC	Loss of instr. air	U-IA	U-TOP	HPI-RCI-FAIL
U	High pressure injection by HPCI or RCIC	Small LOCA	U-LOC	U-TOP	HPI-RCI-FAIL
U	High pressure injection by HPCI or RCIC	Loss offsite power	U-LOP	U-TOP	HPI-RCI-FAIL

Table 3.1.2-2

EVENT TREE TOP EVENTS AND EQUATION ASSIGNMENTS
(Continued)

Top Event	Top Event Description	Applicable Initiator	Functional Equation Designator	Fault Tree	Gate to Solve
U	High pressure injection by HPCI or RCIC	Loss of RACS	U-RA	U-TOP	HPI-RCI-FAIL
U	High pressure injection by HPCI or RCIC	Loss of SACS/SW	U-SA	U-TOP	HPI-RCI-FAIL
U1	High pressure injection by HPCI	Loss of feedwater	U1	HPCI	HPCI1
U1	High pressure injection by HPCI	Medium LOCA	U1-LOC	HPCI	HPCI1
U1	High pressure injection by HPCI	S1 and Te	U1-LCLP	HPCI	HPCI1
U2	High pressure injection by RCIC	Loss of feedwater	U2	RCIC	RCIC1
Uv	Long term make-up water	Loss offsite power	UV-1	UV-TRAN	UV-01
Uv	Long term make-up water	Loss offsite power	UV-2	UV-TRAN	UV-02
Uv	Long term make-up water	Tt, Tm, Tf,Te,Tia	UV-3	UV-TRAN	UV-03
Uv	Long term make-up water	Loss offsite power	UV-4	UV-TRAN	UV-04
Uv	Long term make-up water	Loss offsite power	UV-5	UV-TRAN	UV-05
Uv	Long term make-up water	Tt, Tm, Tf,Te,Tia	UV-6	UV-TRAN	UV-06
Uv	Long term make-up water	Loss SACS / SW	UV-6S	UV-TSASW	UV-06
Uv	Long term make-up water	Tt, Tm, Tf, Ti	UV-7	UV-TRAN	UV-07
Uv	Long term make-up water	Loss of instr. air	UV-7-IA	UV-TRAN	UV-07
Uv	Long term make-up water	Loss SACS / SW	UV-7S	UV-TSASW	UV-07
Uv	Long term make-up water	Loss RACS	UV-8	UV-SPEC	UV-8
Uv	Long term make-up water	Tt, Tm, Tf, Ti	UV-9	UV-TRAN	UV-9
Uv	Long term make-up water	Loss of instr. air	UV-9-IA	UV-TRAN	UV-9
Uv	Long term make-up water	Loss SACS / SW	UV-9S	UV-TSASW	UV-9
Uv	Long term make-up water	Tt, Tm, Tf, Ti	UV-10	UV-TRAN	UV-10
Uv	Long term make-up water	Loss SACS / SW	UV-10S	UV-TSASW	UV-10
Uv	Long term make-up water	Tt, Tm, Tf, Ti	UV-11	UV-TRAN	UV-11
Uv	Long term make-up water	Loss SACS / SW	UV-11S	UV-TSASW	UV-11
Uv	Long term make-up water	Loss offsite power	UV-12	UV-TRAN	UV-12
Uv	Long term make-up water	Tt, Tm, Tf	UV-13	UV-TRAN	UV-13
Uv	Long term make-up water	Loss SACS / SW	UV-13S	UV-TSASW	UV-13
Uv	Long term make-up water	Loss RACS	UV-15	UV-SPEC	UV-15
Uv	Long term make-up water	Tt, Tm	UV-16	UV-LOCA	UV-16
Uv	Long term make-up water	Large/Med LOCA	UV-16-LC	UV-LOCA	UV-16
Uv	Long term make-up water	Loss SACS / SW	UV-16S	UV-TSASW	UV-16
Uv	Long term make-up water	Loss of instr. air	UV-17	UV-SPEC	UV-17
Uv	Long term make-up water	Small LOCA	UV-18	UV-LOCA	UV-18
Uv	Long term make-up water	Small LOCA	UV-19	UV-LOCA	UV-19
Uv	Long term make-up water	Loss of instr. air	UV-19-IA	UV-LOCA	UV-19
Uv	Long term make-up water	Loss RACS	UV-20	UV-SPEC	UV-20
Uv	Long term make-up water	Loss of instr. air	UV-21	UV-SPEC	UV-21
Uv	Long term make-up water	Small LOCA	UV-22	UV-LOCA	UV-22
Uv	Long term make-up water	Loss RACS	UV-22-RA	UV-LOCA	UV-22
Uv	Long term make-up water	Small LOCA	UV-23	UV-LOCA	UV-23

Table 3.1.2-2

EVENT TREE TOP EVENTS AND EQUATION ASSIGNMENTS
(Continued)

Top Event	Top Event Description	Applicable Initiator	Functional Equation Designator	Fault Tree	Gate to Solve
Uv	Long term make-up water	Loss RACS	UV-23-RA	UV-LOCA	UV-23
Uv	Long term make-up water	Tt, Tm	UV-24	UV-LOCA	UV-24
Uv	Long term make-up water	Large/Med LOCA	UV-24-LC	UV-LOCA	UV-24
Uv	Long term make-up water	Loss SACS / SW	UV-24S	UV-TSASW	UV-24
Uv	Long term make-up water	Large/Med LOCA	UV-25	UV-LOCA	UV-25
Uv	Long term make-up water	Loss of instr. air	UV-25-IA	UV-LOCA	UV-25
Uv	Long term make-up water	Loss RACS	UV-25-RA	UV-LOCA	UV-25
Uv	Long term make-up water	A, S1, Tia, Tra	UV-26	UV-LOCA	UV-26
Uv	Long term make-up water	ATWS	UV-27	UV-ATWS	UV-27
Uv	Long term make-up water	ATWS	UV-28	UV-ATWS	UV-28
Uv	Long term make-up water	ATWS	UV-29	UV-ATWS	UV-29
Uv	Long term make-up water	ATWS	UV-30	UV-ATWS	UV-30
Uv	Long term make-up water	ATWS	UV-29L	UV-ATWS	UV-29
Uv	Long term make-up water	ATWS	UV-30L	UV-ATWS	UV-30
V	Low pressure injection	Tt, Tm, Tf, Ti	V	V-TOP	CNS-LPI-CS-FAILS
V	Low pressure injection	Small LOCA	V-LOC	V-TOP	CNS-LPI-CS-FAILS
V	Low pressure injection	Loss of RACS	V-RA	V-TOP	CNS-LPI-CS-FAILS
V	Low pressure injection	Loss of SACS/SW	V-S	V-TOP	CNS-LPI-CS-FAILS
V	Low pressure injection	Tt, Tm, Ti	V1	V1-TOP	LPI-CS-FAILS-V1
V	Low pressure injection	Loss offsite power	V1-LOP	V1-TOP	LPI-CS-FAILS-V1
V	Low pressure injection	Large/Med LOCA	V1-LOC	V1-TOP	LPI-CS-FAILS-V1
V	Low pressure injection	Large/Med LOCA	V1-LCLP	V1-TOP	LPI-CS-FAILS-V1
W	Containment heat removal	Tt, Tm, Tf, Ti, Tia, Tra	W	W-TOP	CSC-SPC-FAILS-W
W	Containment heat removal	LOCA	W-LOC	W-TOP	CSC-SPC-FAILS-W
W	Containment heat removal	Loss offsite power	W-LOP	W-TOP	CSC-SPC-FAILS-W
W	Containment heat removal	Large/Med LOCA	W-LCLP	W-TOP	CSC-SPC-FAILS-W
W1	Containment vent	Tt, Tm, Tf, Ti	W1	CONTVENT	CONTVENT
W1	Containment vent	Loss of instr. air	W1-IA	CONTVENT	CONTVENT
W1	Containment vent	LOCA	W1-LOC	CONTVENT	CONTVENT
W1	Containment vent	Loss offsite power	W1-LOP	CONTVENT	CONTVENT
W1	Containment vent	Large/Med LOCA	W1-LCLP	CONTVENT	CONTVENT
W1	Containment vent	Loss of RACS	W1-RA	CONTVENT	CONTVENT
W1	Containment vent	Loss of SACS/SW	W1-S	CONTVENT	CONTVENT
X	Depressurization of the RPV	Tt, Tm, Tf, Ti	X	RXDP	RXDP
X	Depressurization of the RPV	ATWS	X-ATWS	RXDP	RXDP
X	Depressurization of the RPV	Loss of instr. air	X-IA	RXDP	RXDP
X	Depressurization of the RPV	Small/Med LOCA	X-LOC	RXDP	RXDP
X	Depressurization of the RPV	Loss offsite power	X-ATWS	RXDP	RXDP
X	Depressurization of the RPV	Medium LOCA	X-LCLP	RXDP	RXDP
X	Depressurization of the RPV	Loss of RACS	X-RA	RXDP	RXDP

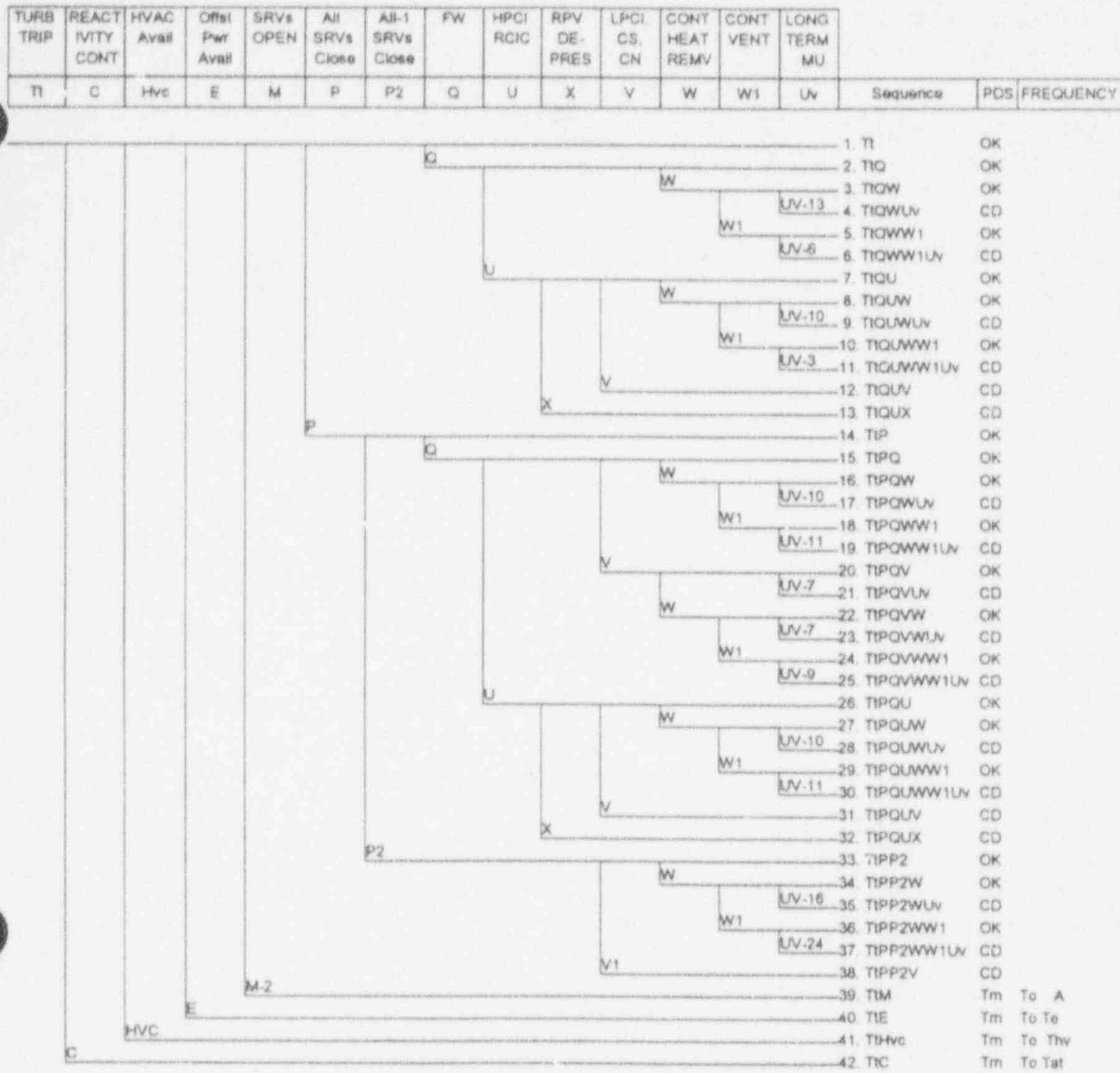


Figure 3.1.2-1: Event tree of the turbine trip initiator.

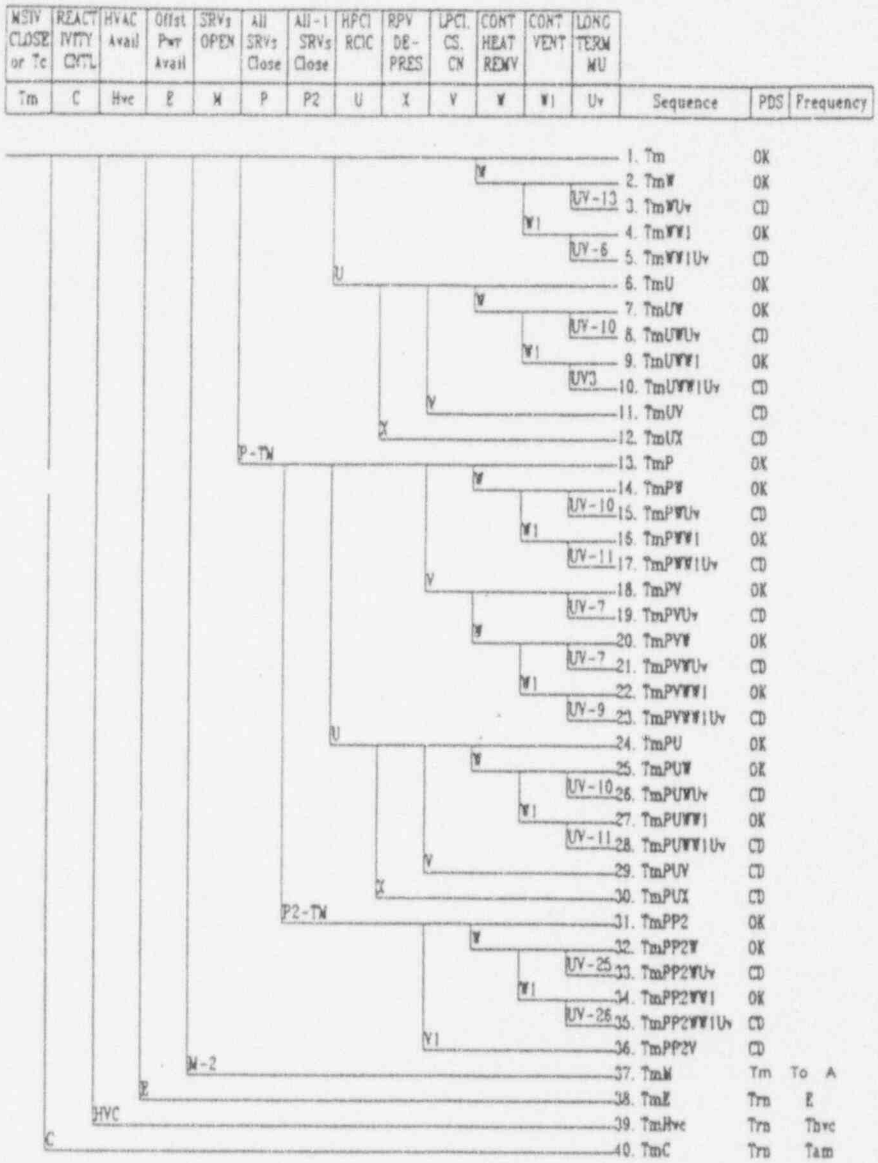


Figure 3.1.2-2: Event tree of the MSIV closure initiator.

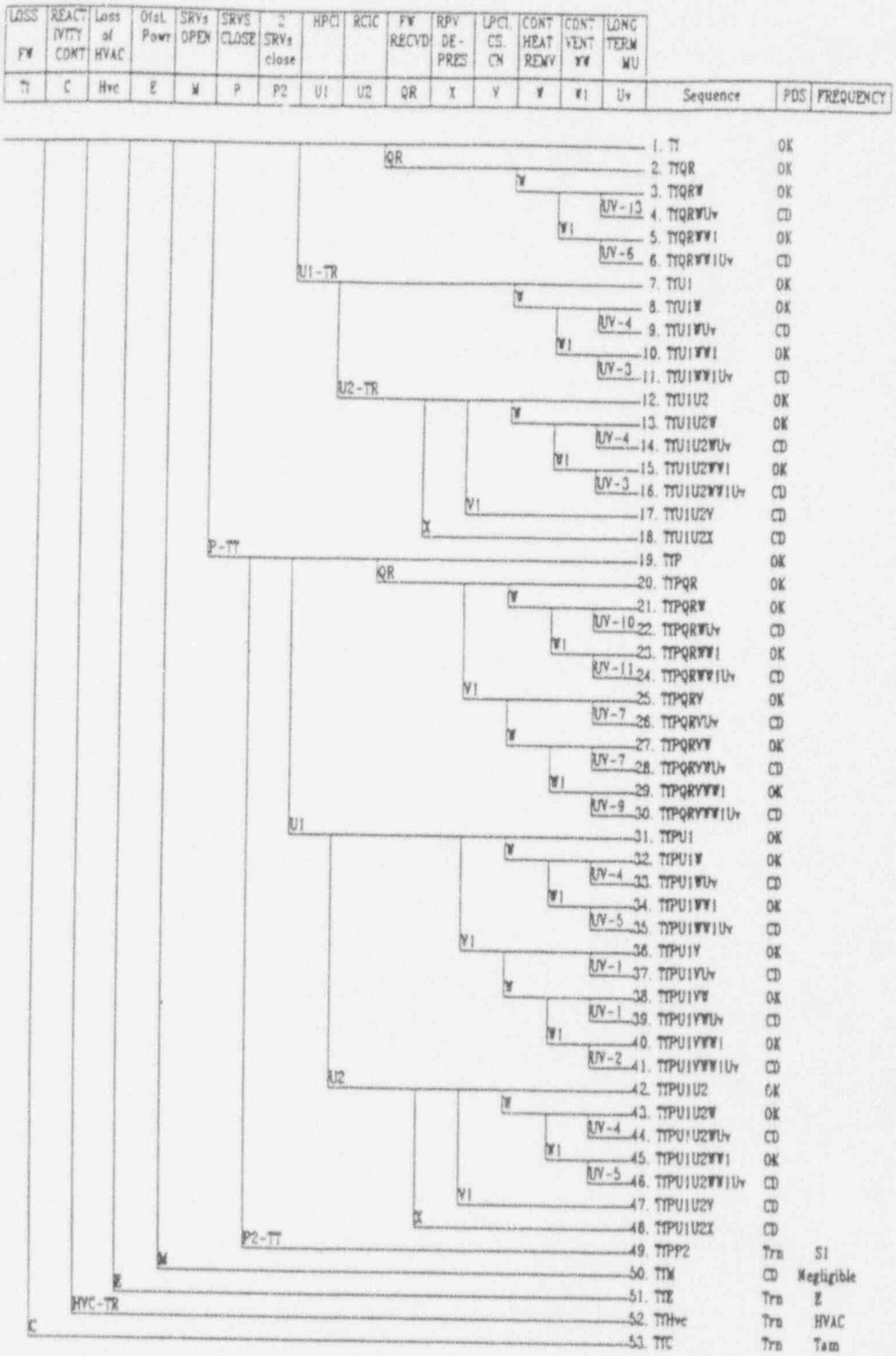


Figure 3.1.2-3: Event tree of the loss of feedwater initiator.

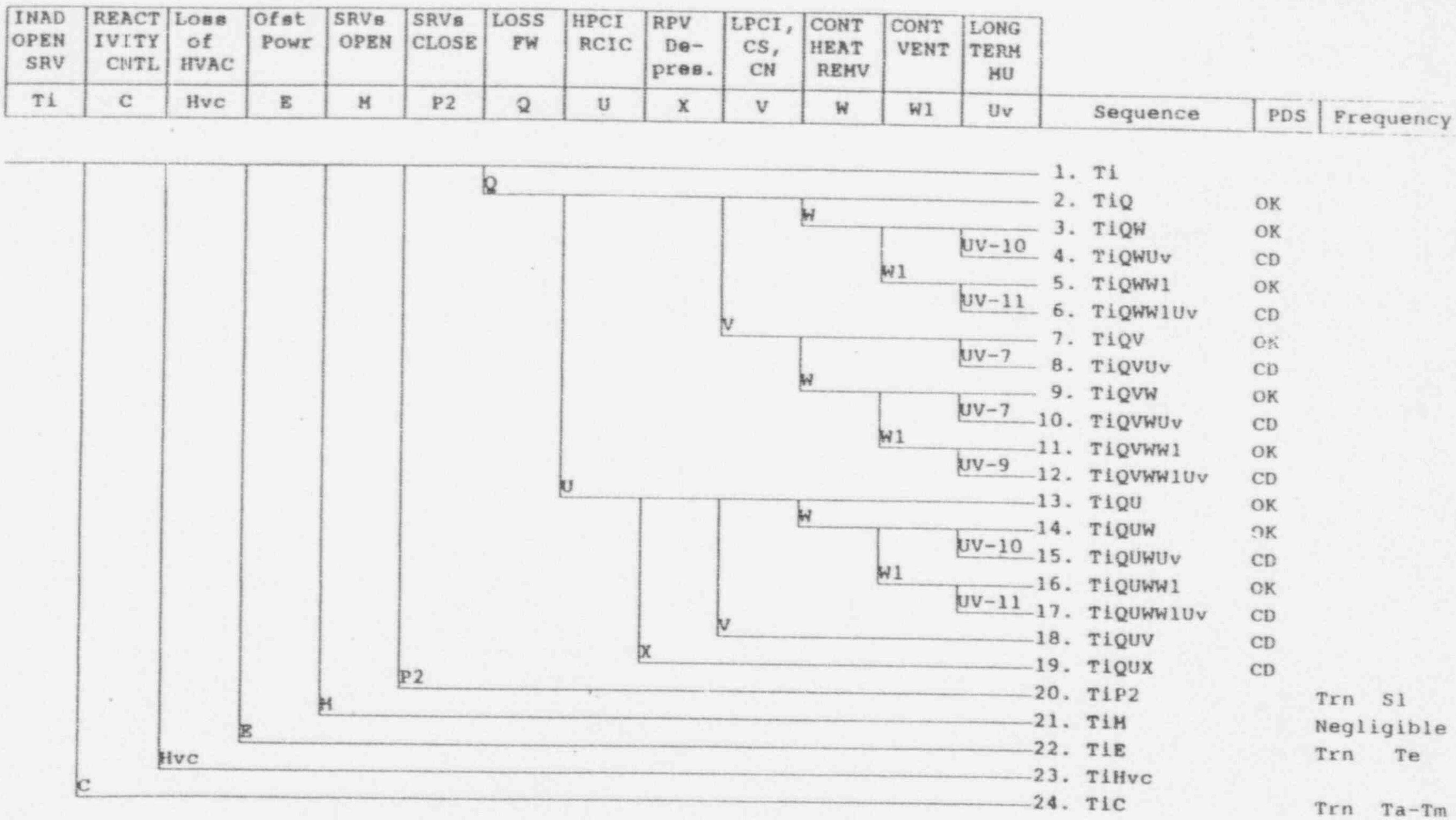


Figure 3.1.2-4: Event tree of the inadverten open relief valve initiator.

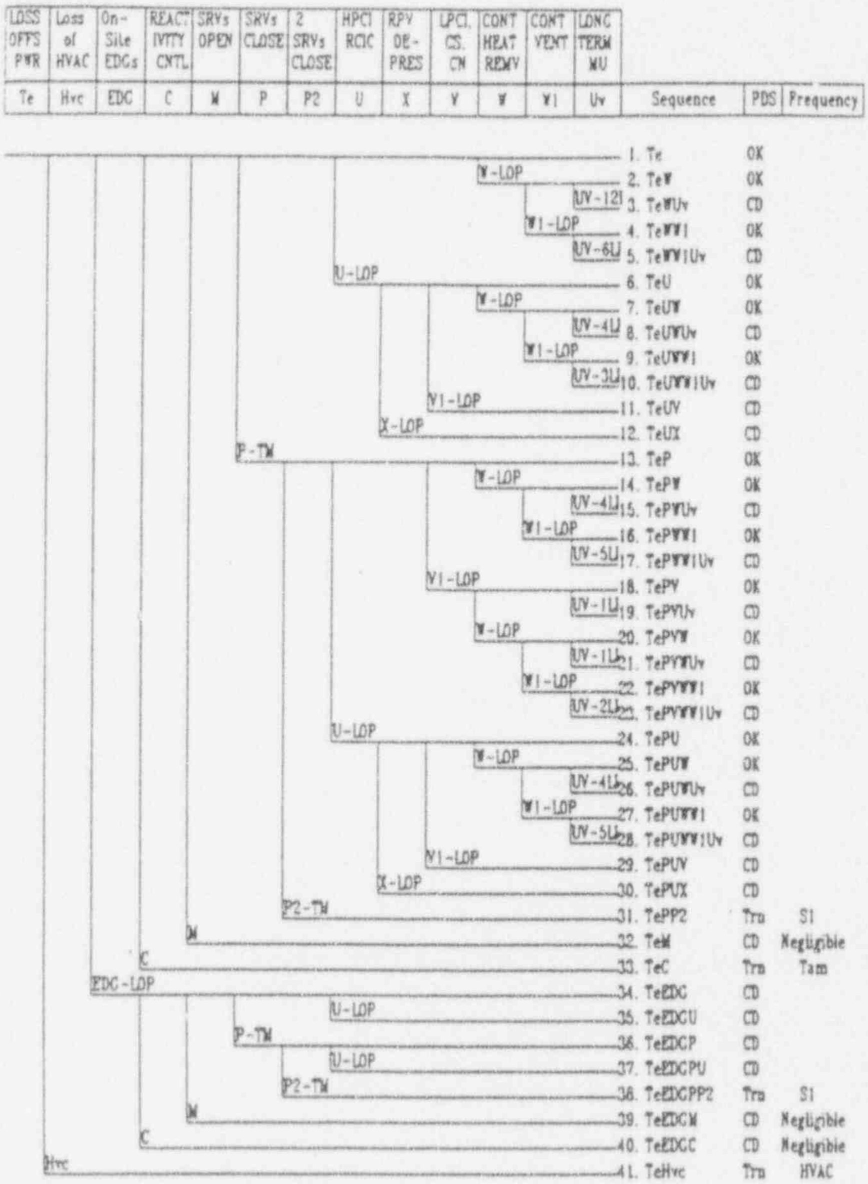


Figure 3.1.2-5: Event tree of the loss of offsite power initiator.

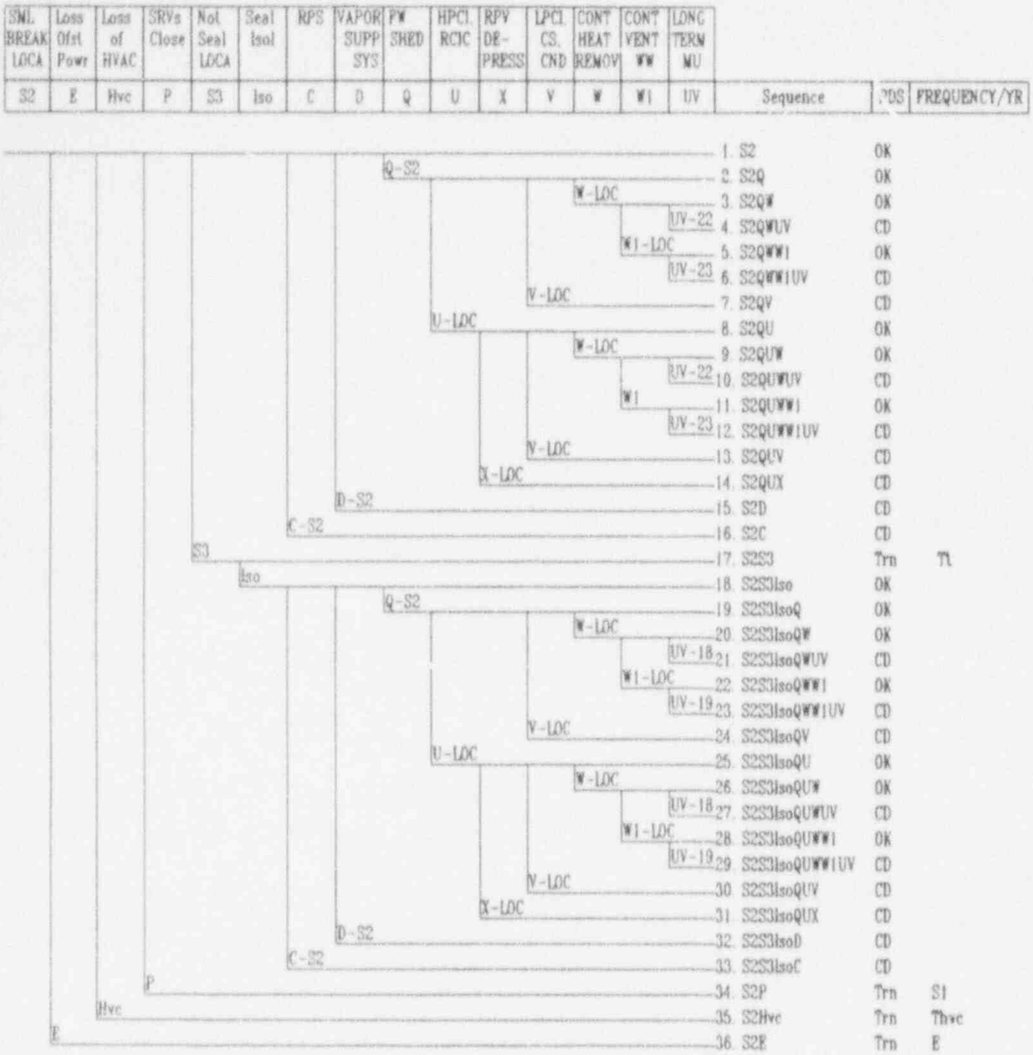


Figure 3.1.2-6: Event tree of the small LOCA initiator.

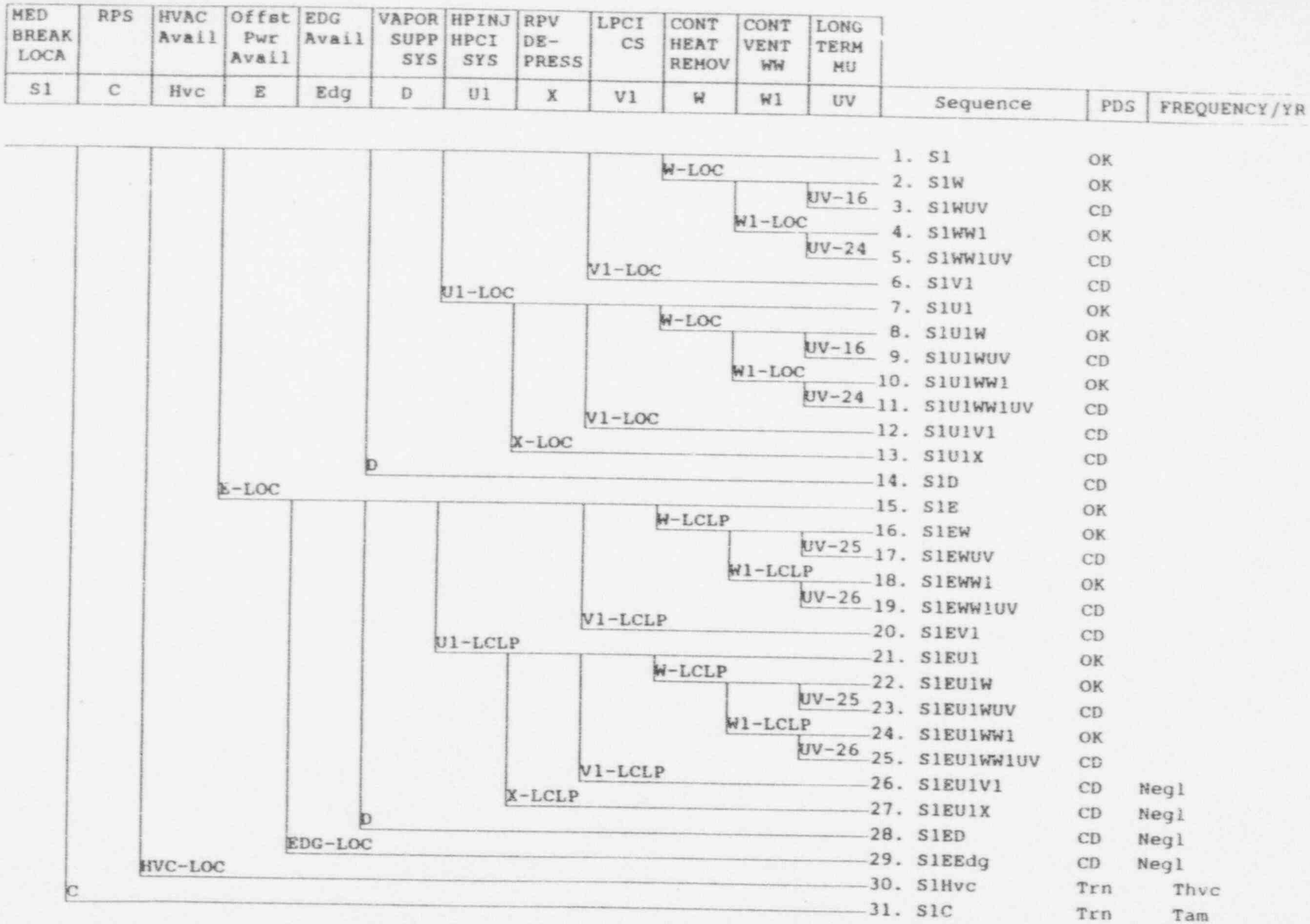


Figure 3.1.2-7: Event tree of the intermediate LOCA initiator.

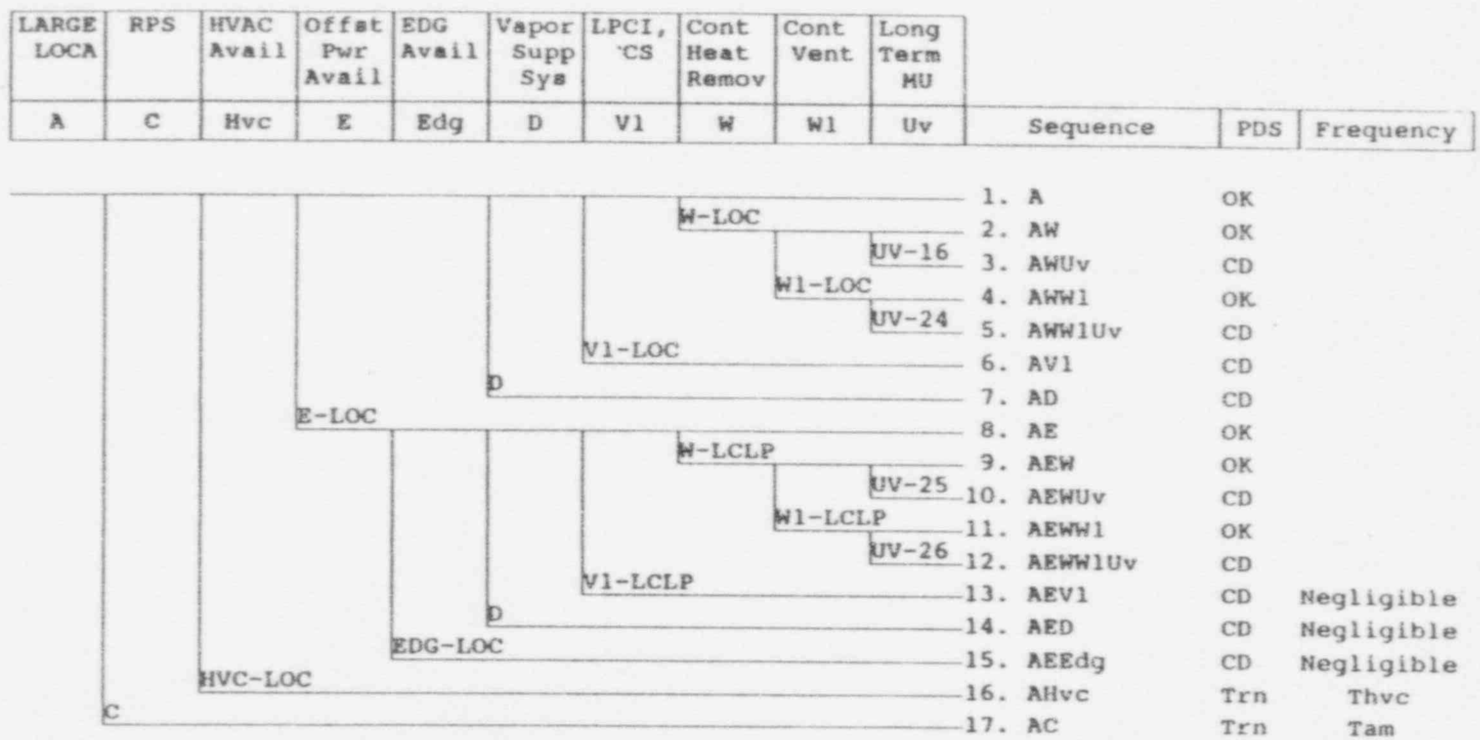


Figure 3.1.2-8: Event tree of the large LOCA initiator.

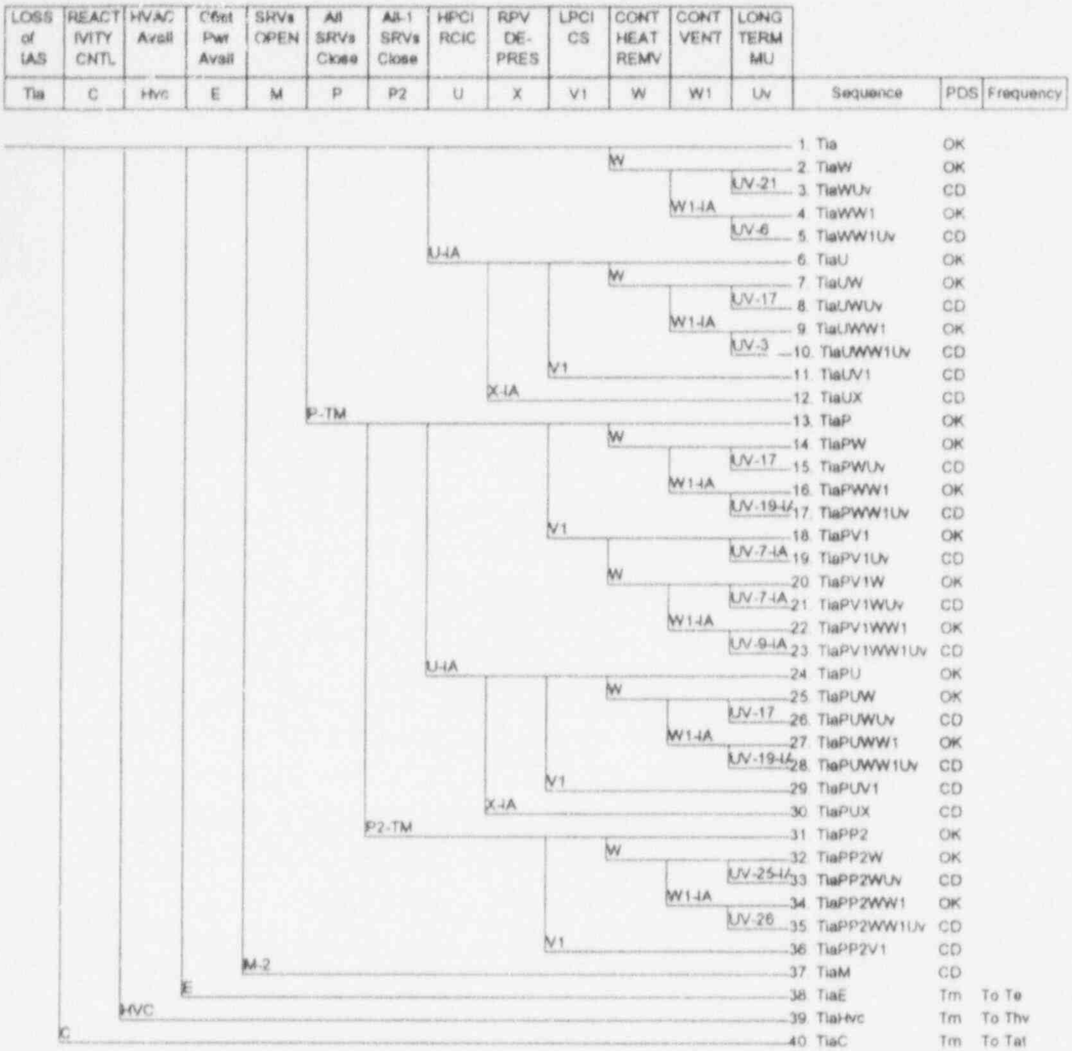


Figure 3.1.3-1: Event tree of the loss of IAS initiator.

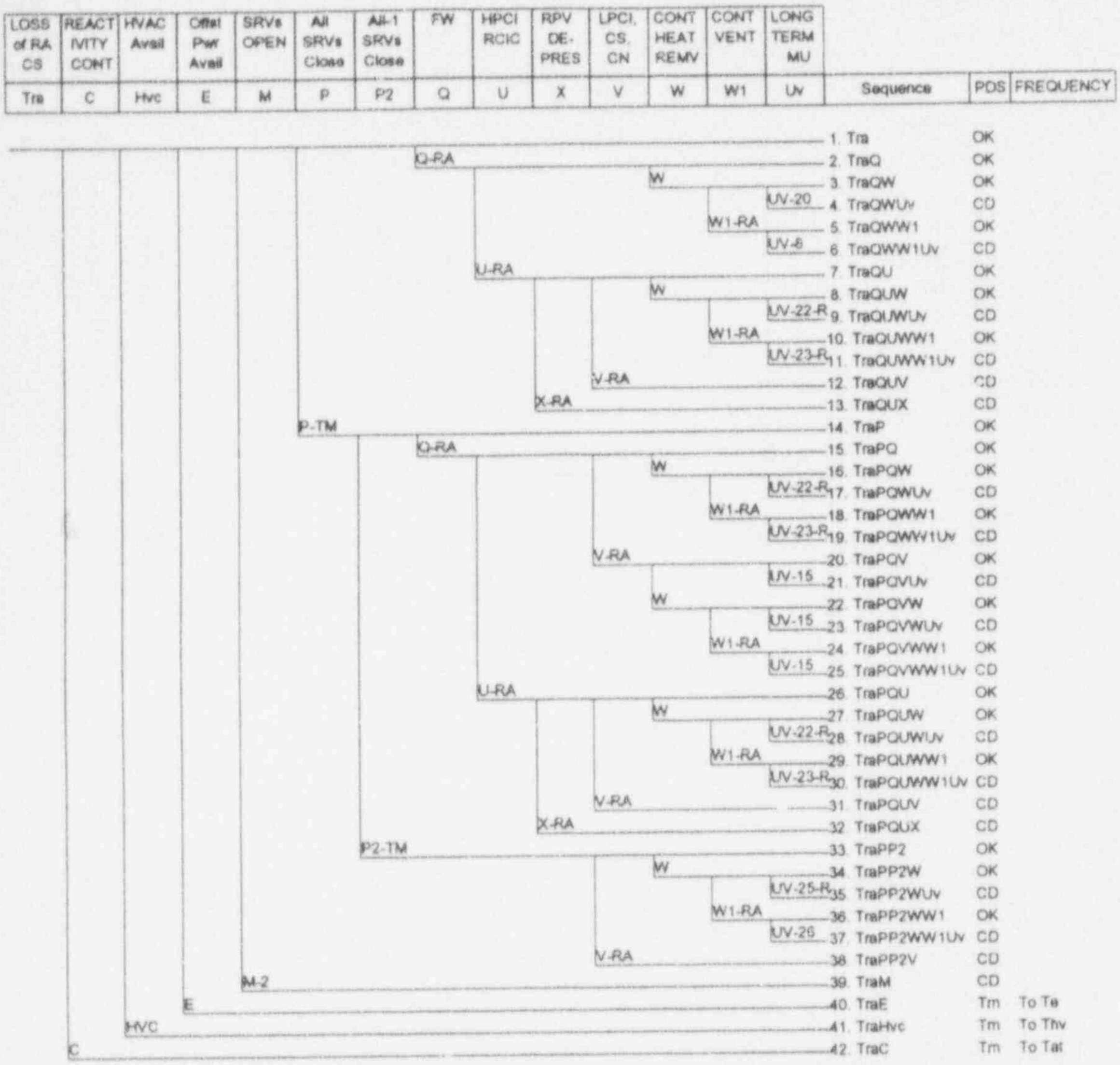


Figure 3.1.3-2: Event tree of the loss of RACS initiator.

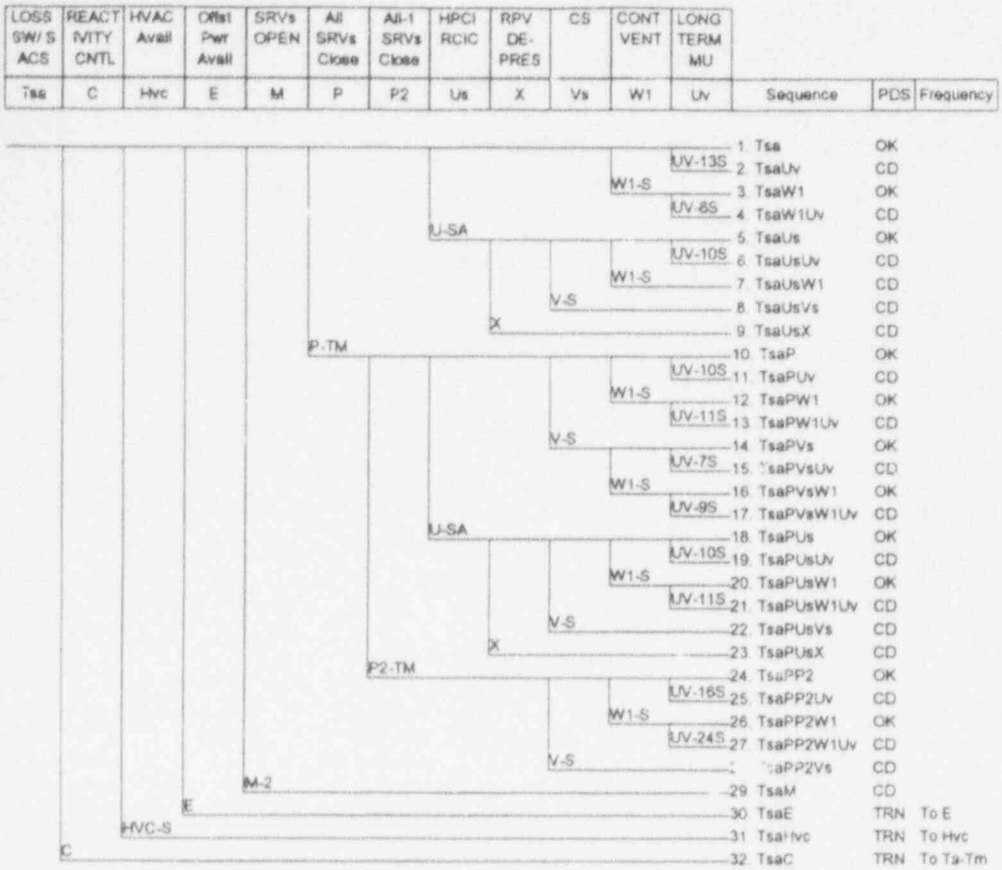


Figure 3.1.3-3: Event tree of the loss of SSW/SACS initiator.

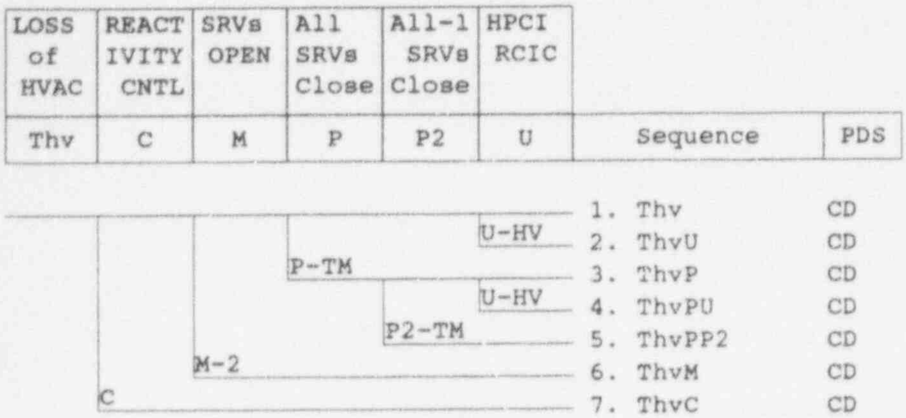


Figure 3.1.3-4: Event tree of the loss of HVAC initiator.

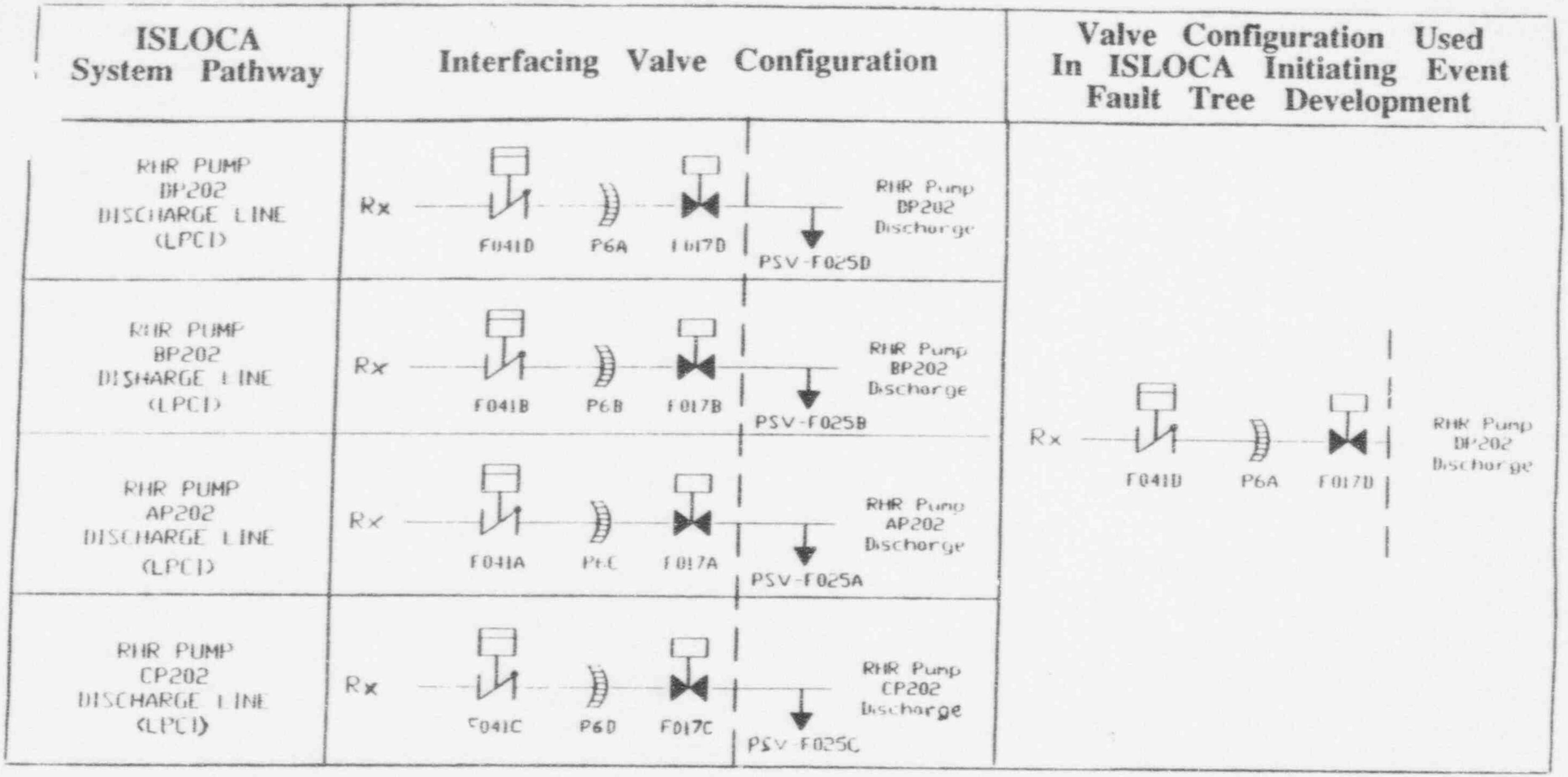


Figure 3.1.3-5

Piping And Valve Arrangement Associated With The RHR ISLOCA Flowpaths

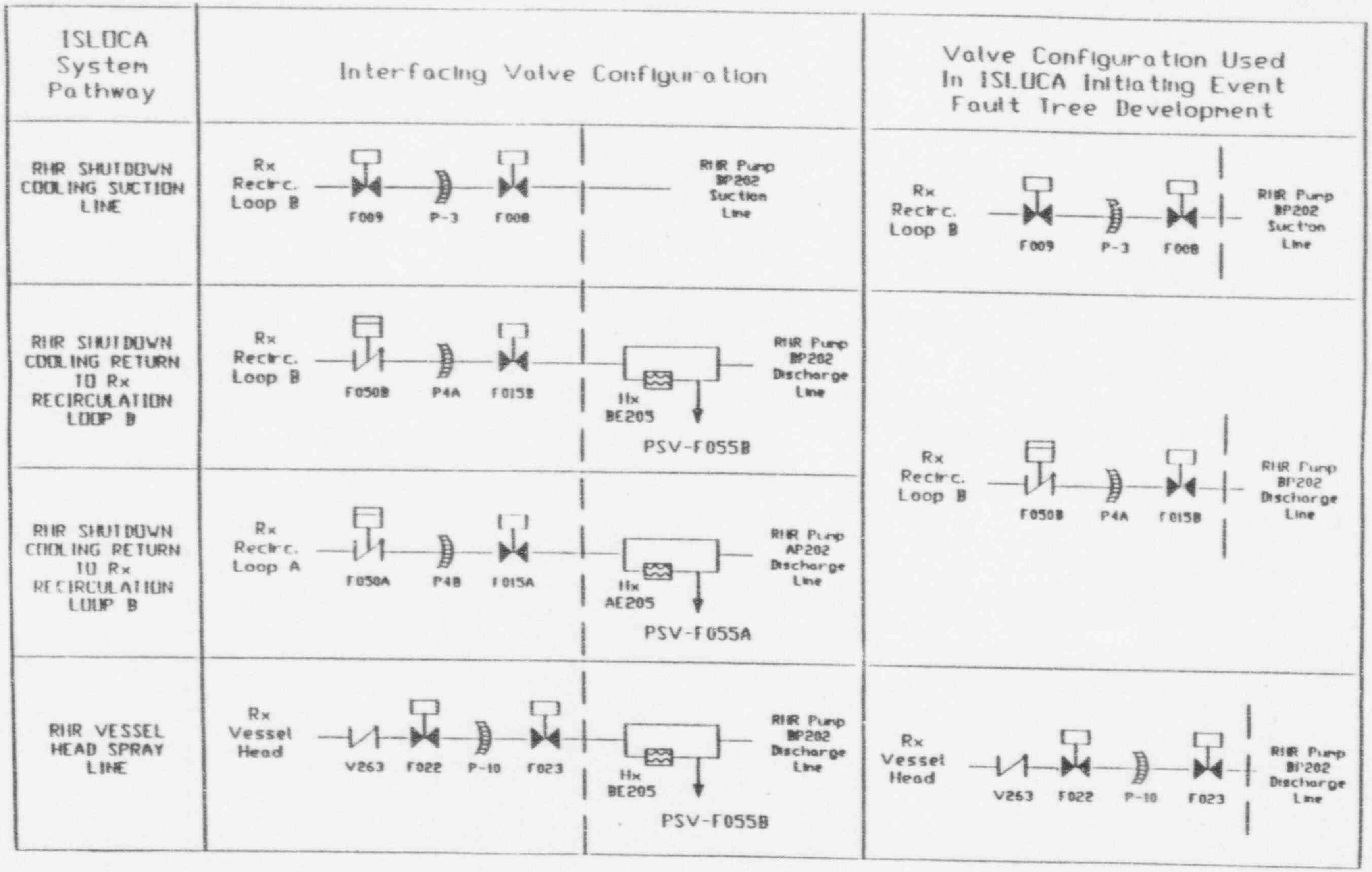


Figure 3.1.3-5 (Continued)

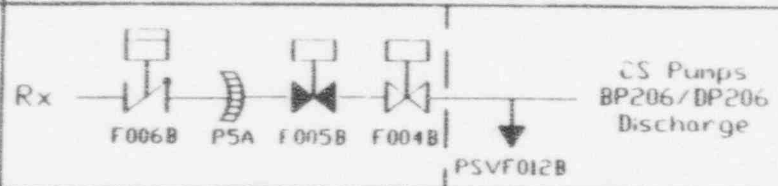
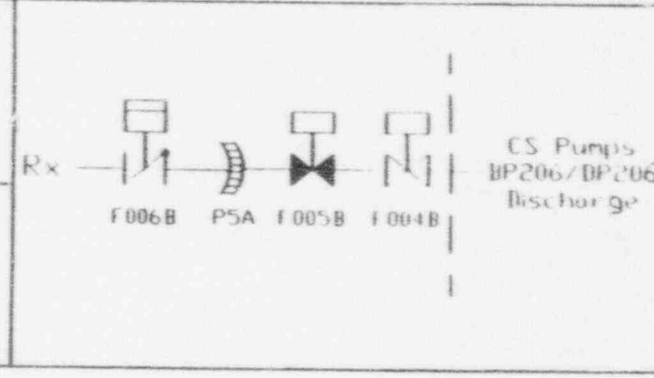
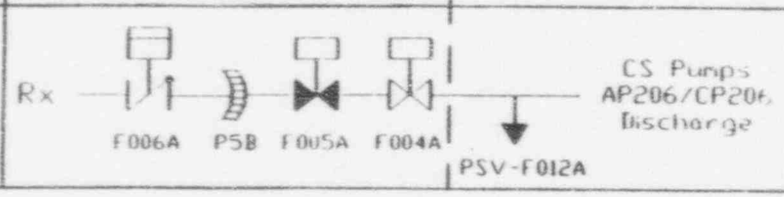
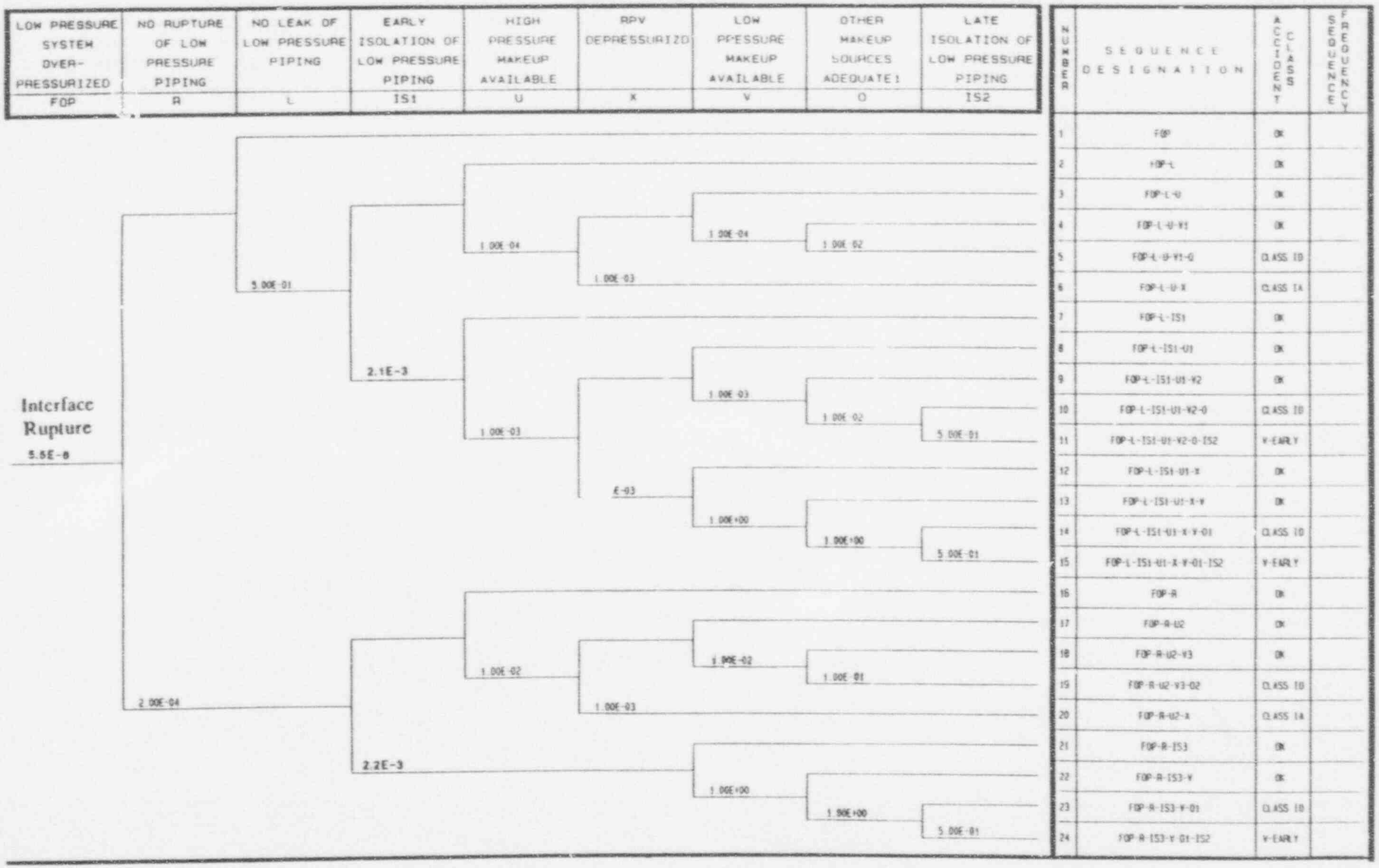
ISLOCA System Pathway	Interfacing Valve Configuration	Valve Configuration Used In ISLOCA Initiating Event Fault Tree Development
CS PUMPS BP206/DP206 DISHARGE LINE		
CS PUMPS AP206/CP206 DISHCHARGE LINE		

Figure 3.1.3-6

Piping And Valve Arrangement Associated With The CS Discharge Lines

CS PUMPS AP206/BP206/CP206/DP206 DISCHARGE LINES

HOPE CREEK



3.1-102

Figure 3.1.3-7

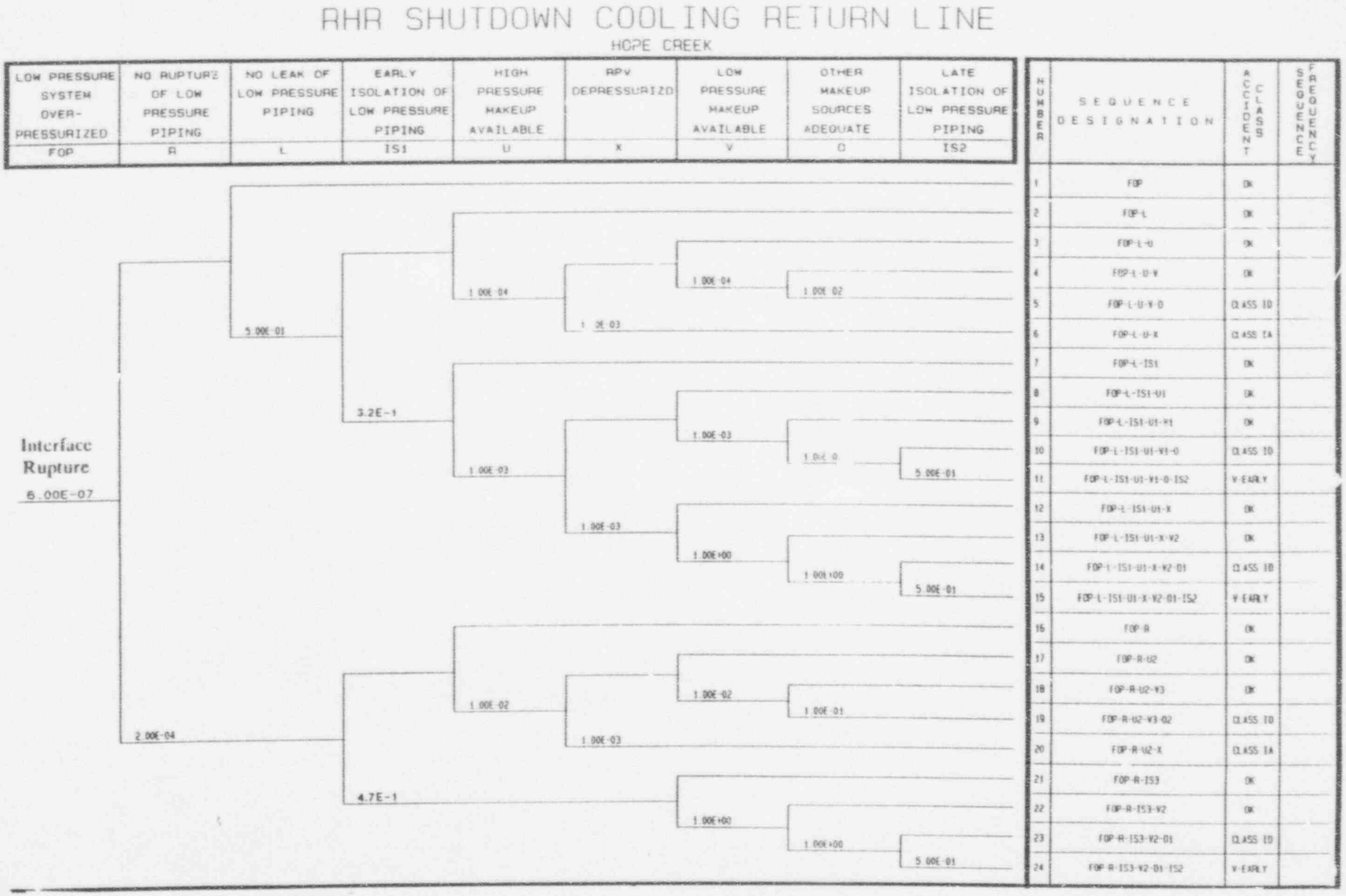
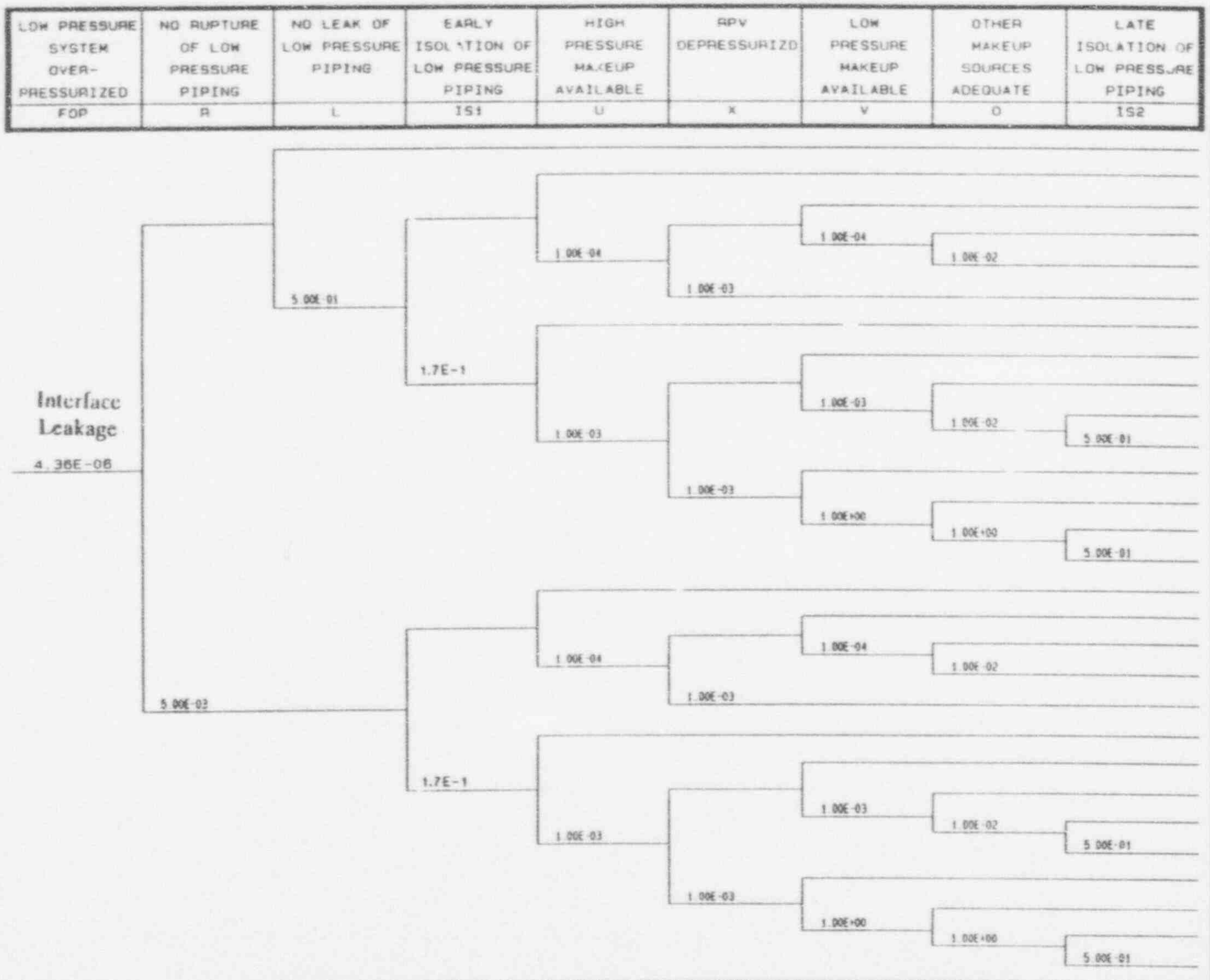

RHR SHUTDOWN COOLING RETURN LINE
HOPE CREEK
LOW PRESSURE SYSTEM OVER-PRESSURIZED
FOP
NO RUPTURE OF LOW PRESSURE PIPING
R
NO LEAK OF LOW PRESSURE PIPING
L
EARLY ISOLATION OF LOW PRESSURE PIPING
IS1
HIGH PRESSURE MAKEUP AVAILABLE
U
RPV DEPRESSURIZD
X
LOW PRESSURE MAKEUP AVAILABLE
V
OTHER MAKEUP SOURCES ADEQUATE
O
LATE ISOLATION OF LOW PRESSURE PIPING
IS2
NUMBER
SEQUENCE DESIGNATION
ACCIDENT CLASS
SEQUENCE FREQUENCY
Interface Rupture
6.00E-07
5.00E-01
1.00E-04
1.00E-04
1.00E-02
3.2E-1
1.00E-03
1.00E-03
5.00E-01
1.00E-03
1.00E+00
1.00E+00
5.00E-01
2.00E-04
1.00E-02
1.00E-02
1.00E-01
1.00E-03
4.7E-1
1.00E+00
1.00E+00
5.00E-01
1 FOP OK
2 FOP-L OK
3 FOP-L-U OK
4 FOP-L-U-V OK
5 FOP-L-U-V-O CLASS ID
6 FOP-L-U-X CLASS IA
7 FOP-L-IS1 OK
8 FOP-L-IS1-U1 OK
9 FOP-L-IS1-U1-V1 OK
10 FOP-L-IS1-U1-V1-O CLASS ID
11 FOP-L-IS1-U1-V1-O-IS2 V-EARLY
12 FOP-L-IS1-U1-X OK
13 FOP-L-IS1-U1-X-V2 OK
14 FOP-L-IS1-U1-X-V2-O1 CLASS ID
15 FOP-L-IS1-U1-X-V2-O1-IS2 V-EARLY
16 FOP-R OK
17 FOP-R-U2 OK
18 FOP-R-U2-V3 OK
19 FOP-R-U2-V3-O2 CLASS ID
20 FOP-R-U2-X CLASS IA
21 FOP-R-IS3 OK
22 FOP-R-IS3-V2 OK
23 FOP-R-IS3-V2-O1 CLASS ID
24 FOP-R-IS3-V2-O1-IS2 V-EARLY

Figure 3.1.3-8

RHR SHUTDOWN COOLING SUCTION LINE

HOPE CREEK

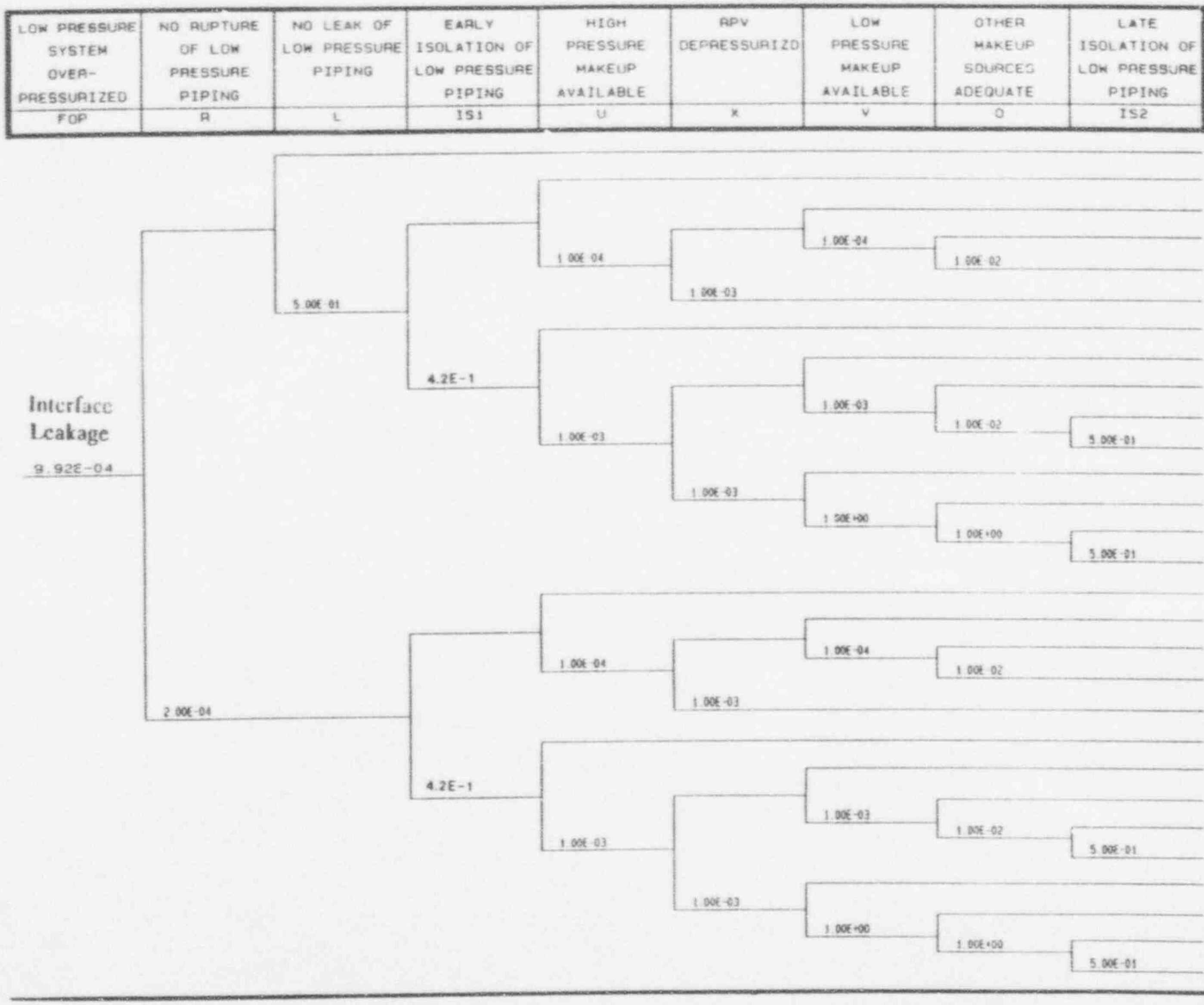


NUMBER	SEQUENCE DESIGNATION	ACCIDENT CLASS	SEQUENCE FREQUENCY
1	FOP	OK	
2	FOP-L	OK	
3	FOP-L-U	OK	
4	FOP-L-U-V	OK	
5	FOP-L-U-V-O	CLASS ID	
6	FOP-L-U-X	CLASS IA	
7	FOP-L-IS1	OK	
8	FOP-L-IS1-U1	OK	
9	FOP-L-IS1-U1-V1	OK	
10	FOP-L-IS1-U1-V1-O	CLASS ID	
11	FOP-L-IS1-U1-V1-O-IS2	V-EARLY	
12	FOP-L-IS1-U1-X	OK	
13	FOP-L-IS1-U1-X-V2	OK	
14	FOP-L-IS1-U1-X-V2-O1	CLASS ID	
15	FOP-L-IS1-U1-X-V2-O1-IS2	V-EARLY	
16	FOP-R	OK	
17	FOP-R-U	OK	
18	FOP-R-U-V	OK	
19	FOP-R-U-V-O	CLASS ID	
20	FOP-R-U-X	CLASS IA	
21	FOP-R-IS1	OK	
22	FOP-R-IS1-U1	OK	
23	FOP-R-IS1-U1-V1	OK	
24	FOP-R-IS1-U1-V1-O	CLASS ID	
25	FOP-R-IS1-U1-V1-O-IS2	V-EARLY	
26	FOP-R-IS1-U1-X	OK	
27	FOP-R-IS1-U1-X-V2	OK	
28	FOP-R-IS1-U1-X-V2-O1	CLASS ID	
29	FOP-R-IS1-U1-X-V2-O1-IS2	V-EARLY	

Figure 3.1.3-9

RHR PUMPS AP202/BP202/CP202/DP202 DISCH LINES (LPCI)

HOPE CREEK



NUMBER	SEQUENCE DESIGNATION	ACCIDENT CLASS	SEQUENCE FREQUENCY
1	FOP	OK	
2	FOP-L	C'	
3	FOP-L-U	OK	
4	FOP-L-U-V	OK	
5	FOP-L-U-V-O	CLASS ID	
6	FOP-L-U-X	CLASS IA	
7	FOP-L-IS1	OK	
8	FOP-L-IS1-U1	OK	
9	FOP-L-IS1-U1-V1	OK	
10	FOP-L-IS1-U1-V1-O	CLASS ID	
11	FOP-L-IS1-U1-V1-O-IS2	V-EARLY	
12	FOP-L-IS1-U1-X	OK	
13	FOP-L-IS1-U1-X-V2	OK	
14	FOP-L-IS1-U1-X-V2-O1	CLASS ID	
15	FOP-L-IS1-U1-X-V2-O1-IS2	V-EARLY	
16	FOP-R	OK	
17	FOP-R-U	OK	
18	FOP-R-U-V	OK	
19	FOP-R-U-V-O	CLASS ID	
20	FOP-R-U-X	CLASS IA	
21	FOP-R-IS1	OK	
22	FOP-R-IS1-U1	OK	
23	FOP-R-IS1-U1-V1	OK	
24	FOP-R-IS1-U1-V1-O	CLASS ID	
25	FOP-R-IS1-U1-V1-O-IS2	V-EARLY	
26	FOP-R-IS1-U1-X	OK	
27	FOP-R-IS1-U1-X-V2	OK	
28	FOP-R-IS1-U1-X-V2-O1	CLASS ID	
29	FOP-R-IS1-U1-X-V2-O1-IS2	V-EARLY	

Figure 3.1.3-10

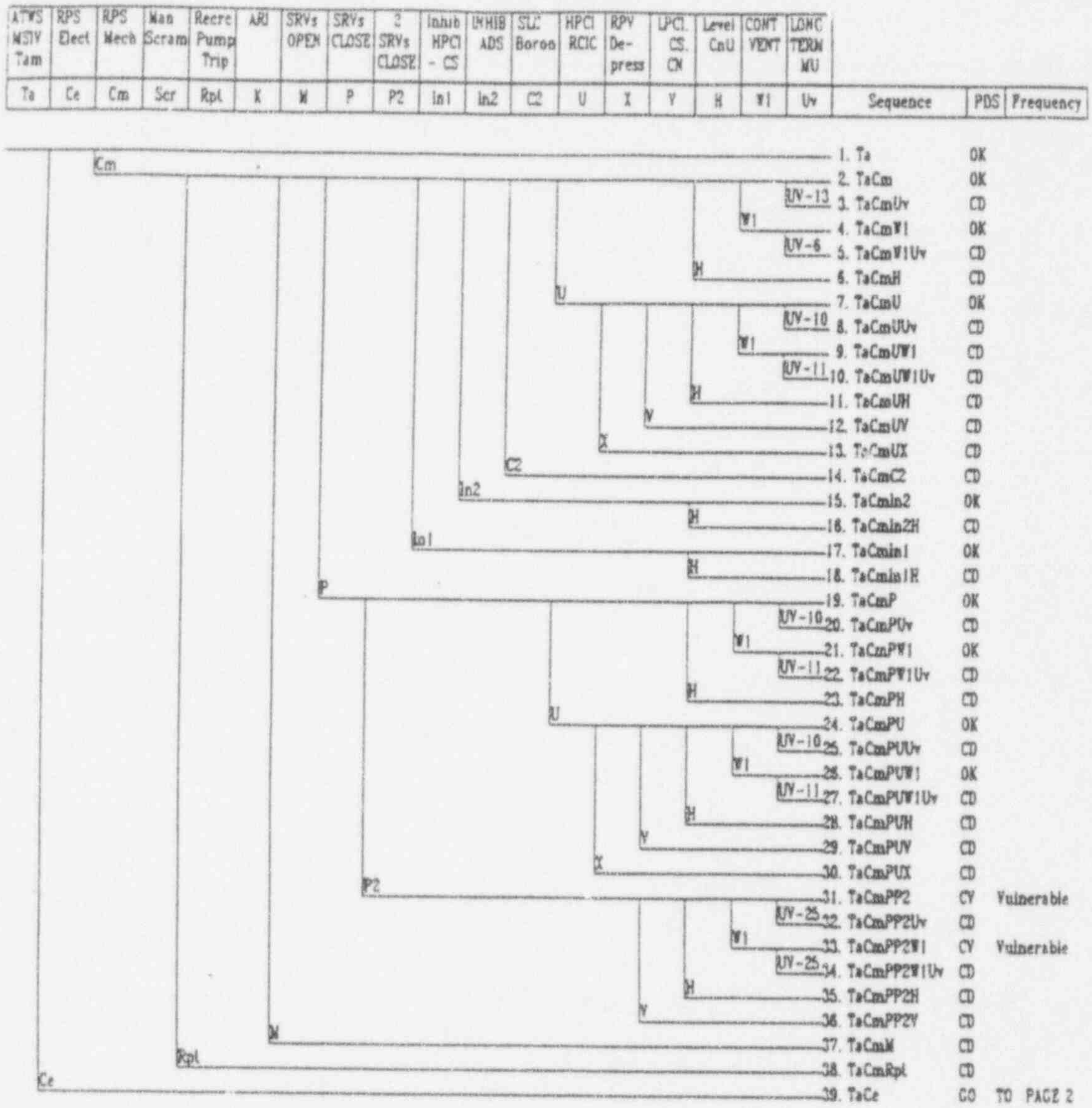


Figure 3.1.3-11: Event tree of the MSIV closure ATWS initiator.

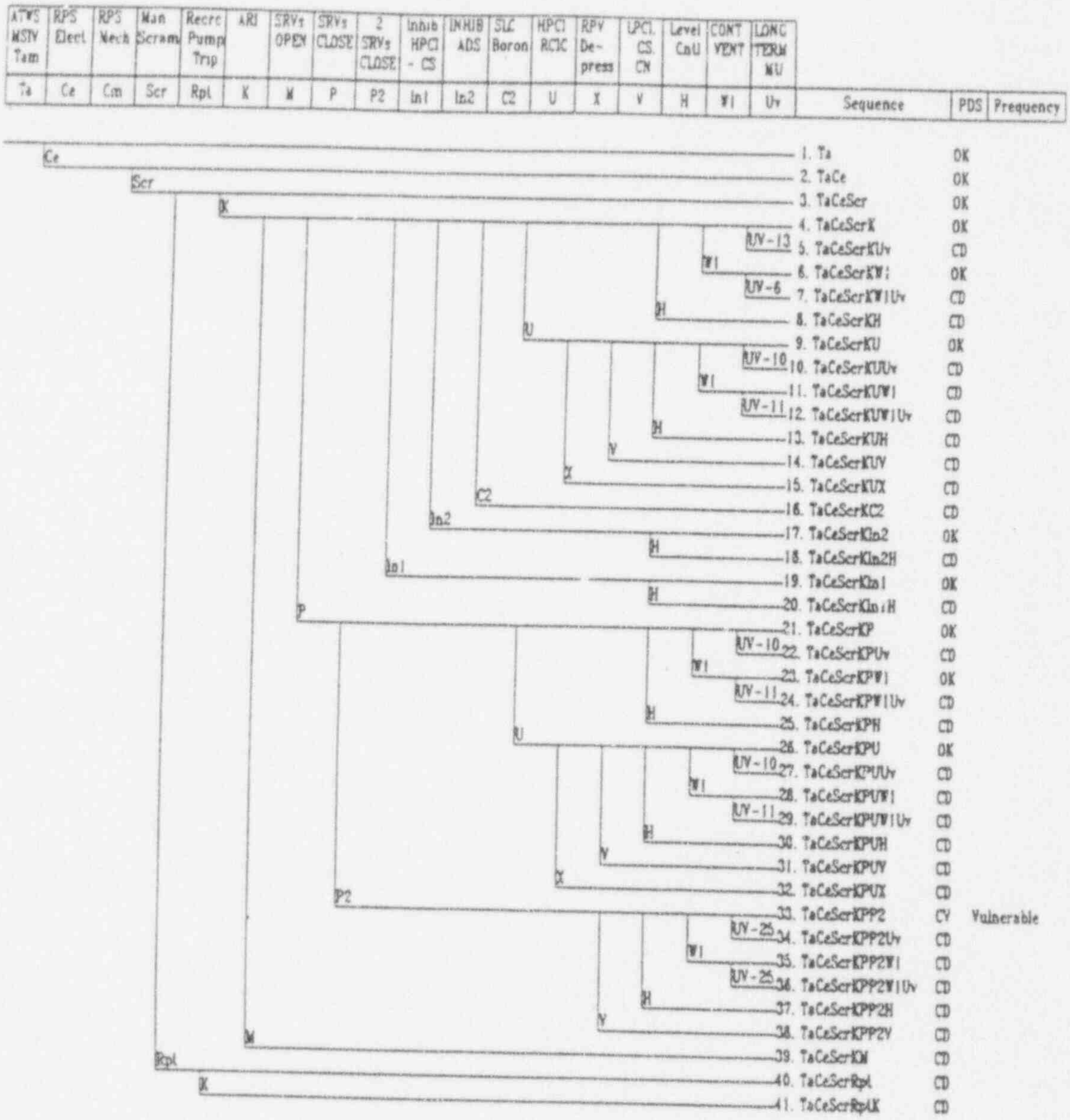


Figure 3.1.3-11: (continued)

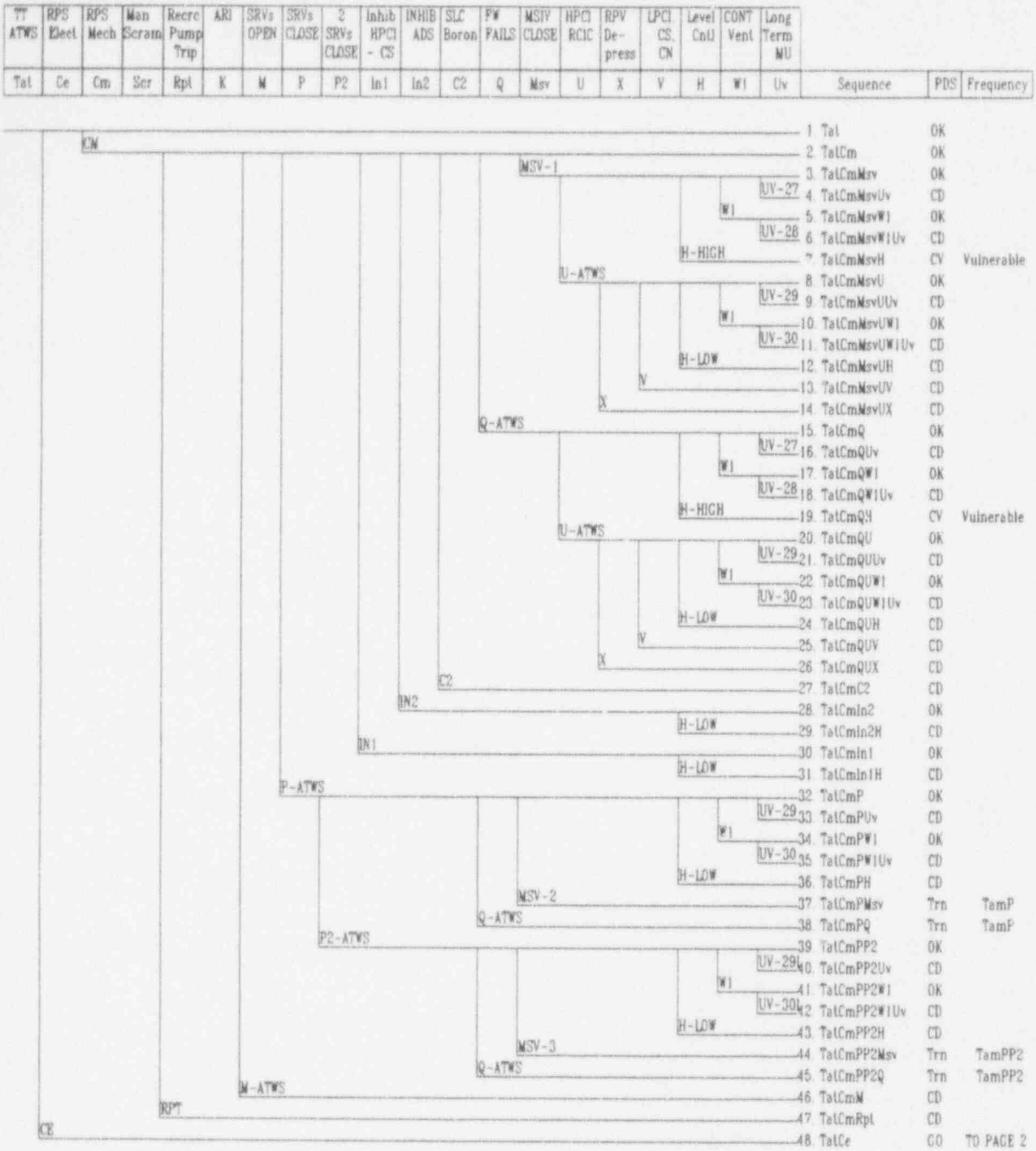


Figure 3.1.3-12: Event tree of the turbine trip ATWS initiator.

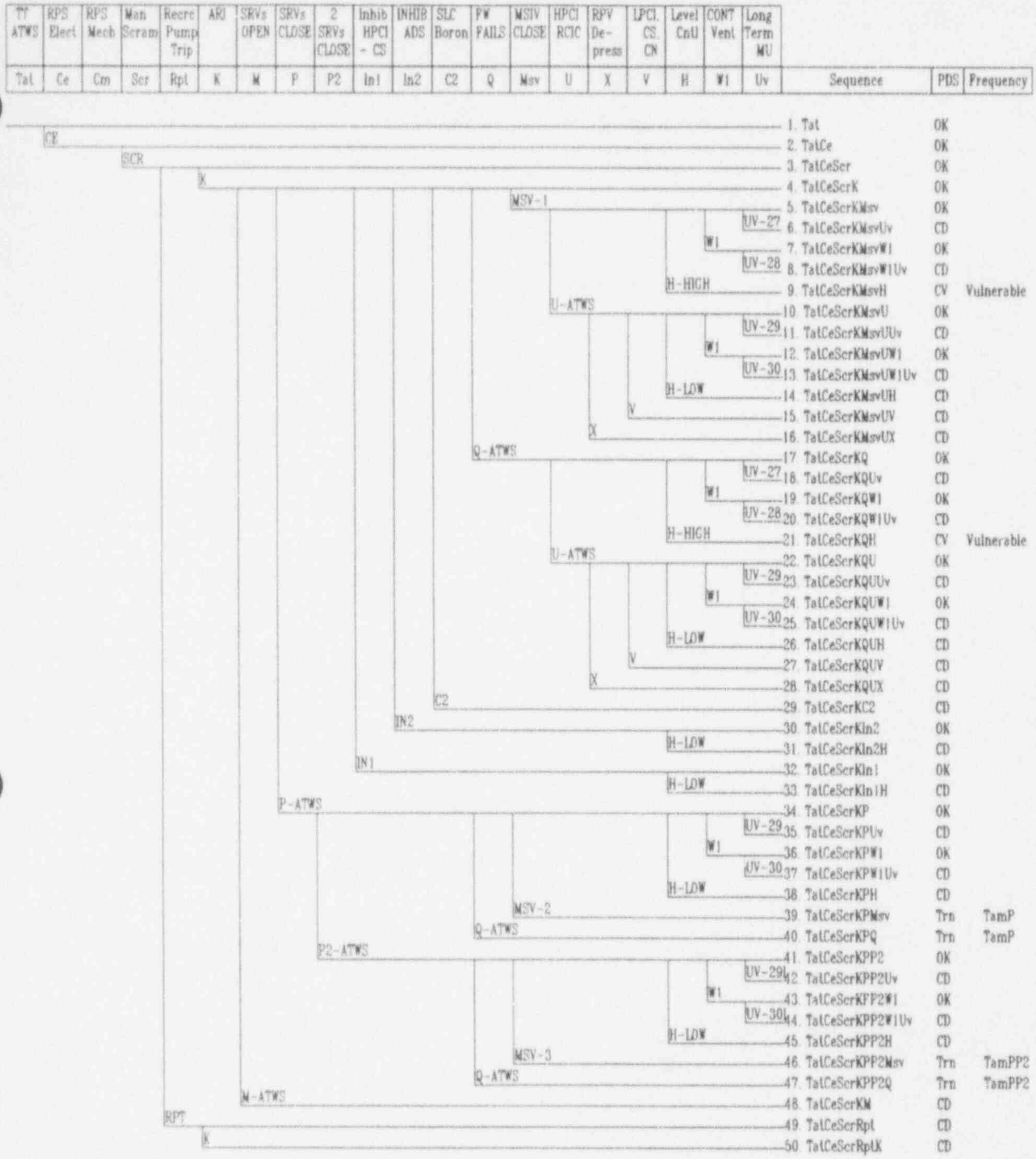


Figure 3.1.3-12: (continued)

3.2 System Analysis

The purposes of this section are to present a description of systems analyzed in the HCGS IPE, as well as a description of how the systems were analyzed. The HCGS IPE was performed using the large linked fault tree, small event tree approach. By using the linked fault trees, all system dependencies are modeled directly in the system fault trees.

Section 3.2.1 presents a description of each system analyzed in the HCGS IPE along with its simplified diagram. For each system, an extensive fault tree was created which includes component failures, instrumentation failures, human failures, test and maintenance unavailabilities, and system dependencies. These fault trees are maintained as Tier II information, and have not been included in this report. Information about the data that were used in the system analyses, along with descriptions of the actual quantification process are provided in Section 3.3.

Section 3.2.2 presents the dependency matrix for all support systems and front-line systems used in the HCGS IPE. As was mentioned previously, each system dependency is modeled directly in the system's fault tree, thereby insuring that no dependencies are lost in the system analysis.

3.2.1 System Descriptions

This section presents the descriptions and simplified diagrams of all front-line and support systems considered in the HCGS IPE. Each of the following subsections is devoted to a system, and for each system, the system function, description, and operation are discussed. Also presented for each system is a brief description of the system fault tree.

The front-end of the HCGS IPE was performed using the large linked fault tree, small event tree approach. By using the linked fault trees, all system dependencies are modeled directly in the system fault trees.

For each system described in Section 3.2.1, a fault tree was developed. Fault tree analysis is a disciplined and deductive methodology for the identification of system failure causes. An undesired top event is defined and then the credible faults leading to the top event are deduced. The fault tree is used to develop and depict the logical interrelationships of basic events (faults) which can lead to the top event. Use of the fault tree methodology is recommended by both the Interim Reliability Evaluation Program (IREP) Procedures Guide (Ref. 3.2.1-1) and the PRA Procedures Guide (Ref. 3.2.1-2) for the modeling of system failures. Detailed information on fault tree methodology is presented in the Fault Tree Handbook (Reference 3.2.1-3).

Fault trees for HCGS were developed following detailed guidelines outlined in the HCGS PRA Project System Fault Tree Development Handbook (Ref. 3.2.1-4). Guidelines from this document are summarized below.

The fault trees developed for the system analyses for HCGS were developed down to the component level. Examples of components include various types of valves (e.g. manual, motor-operated, and pneumatic) and pumps, electric relays, switches, circuit breakers, motors, fuses, and instrumentation.

In general, passive failures such as piping leakage and cable open or short circuits were not modeled because such event probabilities are considered to be significantly lower than other events modeled. Plugging of locked-open valves and internal leakage of locked-closed valves were modeled where appropriate. Finally, flow diversion paths up to and including the first closed valve were modeled where appropriate.

Sources of information used in developing the HCGS system fault trees included training materials, the updated Final Safety Analysis Report, plant P&IDs, electrical diagrams, plant walk-throughs, and discussions with system engineers and operators.

Human errors modeled in the fault trees included miscalibration, failure to return components to their normal state after testing or maintenance, and operator errors during an accident.

Test and maintenance outages were modeled in the system fault trees. Normally, test and maintenance outages for a system or subsystem were modeled as one separate event (included in a combined test and maintenance outage event, and given the designator "TM"). Test and maintenance events were not included for cases in which the system automatically realigns upon demand. Test and maintenance outages as modeled in the fault trees can result in multiple system test and maintenance outages which may be a violation of the Technical Specifications. In the quantification of the event trees, minimal cutsets containing such violations were eliminated from the results.

Dependent failures were modeled in the system fault trees. A thorough discussion of dependent failure modeling is presented in Section 3.3 of this report.

References:

3.2.1-1. Interim Reliability Evaluation Program Procedures Guide. Washington, DC.: US. Nuclear Regulatory Commission, January 1983.

3.2.1-2. PRA Procedures Guide. Washington, DC.: US. Nuclear Regulatory Commission, January 1983. NUREG/CR-2300.

3.2.1-3. Fault Tree Handbook. Washington, DC.: US. Nuclear Regulatory Commission, January 1986. NUREG-0492.

3.2.1-4. Hope Creek Generating Station Probabilistic Risk Assessment Fault Tree Development Handbook. Idaho Falls, ID: EI International, Inc., September 1988.

3.2.1.1 <u>High-Pressure Coolant Injection System (HPCI)</u>

3.2.1.1.1 System Function

The High Pressure Coolant Injection System (HPCI) maintains reactor vessel inventory after small and intermediate breaks in the Reactor Coolant System (RCS). The term small breaks implies that these breaks are not large enough to depressurize the reactor to enable adequate core cooling with the low-pressure portions of the Emergency Core Cooling Systems (ECCS). The HPCI system is also used to maintain adequate inventory or pressure control following a reactor isolation and failure of the Reactor Core Isolation Cooling (RCIC) system.

3.2.1.1.2 System Description

General design

HPCI is one of four systems which comprise the Emergency Core Cooling System (ECCS). HPCI consists of a steam-driven turbine, a constant-flow pump assembly (including a booster pump), and associated system piping, valves, controls and instrumentation. A simplified diagram of HPCI is presented in Figure 3.2-1.

Flow Path

HPCI is a safety-related emergency core cooling system. The system pump initially takes suction from the condensate storage tank (CST) but can be aligned to take suction from the suppression pool. The booster pump takes suction from the water source and discharges to the HPCI main pump which in turn discharges to the reactor vessel via the "A" Core Spray Line spargers and the "A" Reactor Feedwater Line.

The HPCI turbine is driven by steam supplied from the reactor vessel. The steam is extracted from main steam line C upstream of the main steam isolation valves (MSIVs). The inboard and outboard HPCI steam line containment isolation valves are normally open. This results in an elevated piping temperature at close proximity to the turbine which permits rapid startup of the HPCI system. The turbine steam exhaust is discharged below the surface of the suppression pool.

Location

The HPCI turbine-driven pump assembly and associated valves, piping, and instrumentation are located in the HPCI pump room, Reactor Building (RB) Elevation 54'. The CST is located outside the Auxiliary Building (AB) and the suppression pool is located inside containment at Elevation 54'. The valves modeled which are located inside containment are the steam supply inboard isolation valve 1FDHV-F002, the check valve 1BEHV-F006A in Core Spray line A, and check valve 1AEV007, and motor-operated valve 1AEHV-F011A in feedwater line A. All other valves modeled in the HPCI system are located outside containment.

Component Descriptions

HPCI Turbine Driven Pump

The HPCI main pump (OP204) is a 100% capacity pump installed on a common base plate with the HPCI turbine and booster pump. The booster pump (OP217) is driven by the same turbine as the main pump and it provides suction to the HPCI main pump. The HPCI turbine (OS211) provides the driving force for the booster and HPCI main pumps. The HPCI turbine-driven pump has a 5600 gpm injection capacity.

Condensate Storage Tank

The condensate storage tank (CST) provides the initial HPCI pump suction supply during system operation. The tank contains up to 500,000 gallons of demineralized water of which 135,000 gallons is dedicated for use by the HPCI and RCIC systems. The portion of the suction piping exposed to outside air temperatures is protected from cold weather by 1-1/2 inches of insulation and a single heat trace on each line.

Suppression Pool

The suppression pool provides secondary makeup water to the reactor vessel when either the CST becomes depleted or the suppression pool water level is high. The torus-shaped suppression chamber is located around and below the RPV and contains a water volume of approximately 118,000 ft^3.

3.2.1.1.3 System Interfaces

Shared Components

HPCI shares valve 1BEHV-F006A with the Core Spray System (CSS) and valves 1AEHV-F074A, 1AEV007, and 1AEHV-F011A with the feedwater system. The suppression pool is shared by HPCI, LPCI, RCIC, and CSS. The CST is shared by RCIC, HPCI, CSS, and the Control Rod Drive Hydraulic systems.

Electrical

HPCI is supplied 250 VDC electrical power exclusively through MCC 10D251. The 125 VDC Class 1E distribution system supplies DC electrical power to the HPCI control circuits. HPCI success is independent of AC power; however, AC power is used for control of components that are not essential for HPCI operation.

Air

All of the pneumatically operated valves which are associated with the HPCI system are associated only with the operation of the condensate pump, drain lines, or steam trap bypass. Their operation is not required for the HPCI system to operate.

Actuation

The HPCI system is automatically actuated by high drywell pressure (+1.68 psig) or low reactor vessel water level (-38") signals.

Control

HPCI control is not shared by any other system. The HPCI controls are located in the control room and are equipped with manual actuation switches. They are powered from 125 VDC Class 1E Distribution Panel 1AD417.

Component Cooling

Turbine lube oil cooling water is taken from a portion of the booster pump discharge flow. No other component cooling is required. HPCI will isolate due to high room temperature at 160°F.

Room Cooling

The HPCI pump room is cooled by two redundant units which use the SACS system as a heat sink. The HPCI pipe chase is cooled by RBVS. HPCI pump room cooling is evaluated in Section 3.2.1.21.

3.2.1.1.4 Instrumentation and Control

The control logic in the HPCI system is designed to function upon automatic initiation. In addition to the automatic operational features of the HPCI system, provisions are included for remote manual startup, operation and shutdown in case automatic initiation fails. Functional testing of the logic is possible during normal plant operation.

System Actuation

A reactor low water level (-38 inches on wide range) or a high drywell pressure (+1.68 psig) signal causes the following valves to open:

- 1FDHV-F001 (turbine steam supply valve)
- 1FDFV-4880 (turbine stop valve),
- 1BJHV-F007 (HPCI pump discharge valve),
- 1BJHV-F006 (HPCI pump discharge valve to Core Spray),
- 1BJHV-F010 (HPCI suction from the CST) if closed, and
- 1BJHV-8278 (HPCI pump discharge valve to Feedwater).

Control

The HPCI pump may be started either manually or automatically. Once the pump is running, the turbine control valve's position is controlled by signals from the controller. The amount of steam available to the turbine is determined by the turbine control valve position which adjusts the turbine speed.

HPCI pump suction is initially from the CST and can be manually controlled. Automatic control is actuated by HPCI initiation signals which opens valve 1BJHV-F004, the HPCI suction valve from CST. This valve is closed by a "HPCI suction valve from suppression pool fully open" signal. The suppression pool suction valve 1BJHV-F042 has both manual and automatic control. Automatic control of actuation and isolation of this valve is described in the interlocks section below. The automatic signal can be overridden by a manual control switch. This allows the pump suction to be aligned back to the CST from the suppression pool.

Interlocks

HPCI interlocks related to system actuation and operation are as follows:

1. 1FDHV-F001 (HPCI turbine steam supply) automatically or manually opens on HPCI initiation only if 1FDHV-F071 (turbine exhaust isolation) is fully open.

2. 1BJHV-F004 (pump suction from CST) automatically closes if 1BJHV-F042 (pump suction from suppression pool) is fully open. 1BJHV-F004 will automatically open on HPCI initiation if 1BJHV-F042 is not fully open.

3. 1BJHV-F042 (pump suction from suppression pool) automatically opens on CST low level or suppression pool high level if the BJHV-F042 handswitch is not in the AUTO OPEN OVRD position and if there is no HPCI isolation signal. 1BJHV-F042 may be manually opened if there is no HPCI isolation signal. 1BJHV-F042 auto closes on HPCI isolation signal.

4. 1BJHV-F006 (pump discharge to Core Spray) automatically closes if 1FDHV-F001 (HPCI turbine steam supply) is fully closed or 1FDFV-4880 (turbine stop valve) is fully closed. 1BJHV-F006 will automatically open on HPCI initiation if 1FDFV-4880 is not fully closed and 1FDHV-F001 is not fully closed.

5. 1BJHV-8278 (HPCI discharge to Feedwater) automatically closes if 1FDHV-F001 (turbine steam supply) or 1FDFV-4880 (HPCI turbine stop valve) is fully closed. 1BJHV-8278 will automatically open on HPCI initiation if 1FDFV-4880 and 1FDHV-F001 are not fully closed.

Instrumentation and Annunciators

Instrumentation that provides monitoring functions for safe operation of HPCI include such alarms/indicators as HPCI out of service, HPCI steam flow high, and HPCI turbine trip. Over

30 alarm/indication annunciators exist for the HPCI system, and they are located in the control room and are indicated on Panel 10C650 and alarmed on Panel 10C800.

System Isolation

There are seven signals which will automatically isolate the HPCI system. Examples include low steam supply pressure, steam line high differential pressure, HPCI pipe chase high temperature, and HPCI pump room high temperature. All high temperature isolation signals for the HPCI system can be bypassed by placing the Steam Leak Detection System keylock switches into the BYPASS position.

3.2.1.1.5 Operator Actions

The HPCI System automatically starts upon receipt of a reactor pressure vessel low water level signal or a primary containment high pressure signal. Therefore, the only operator actions modeled are:

1. <u>Operator fails to control water level</u> - RPV water level needs to be controlled to prevent a HPCI turbine trip on an RPV high-water-level signal. Although HPCI will restart if one high-water level signal clears, the operators are instructed to maintain RPV water level below +54" in the EOPs. Failure to control RPV water level below +54", combined with a failure of the Level 8 trip circuitry, will be considered a failure of the system.

2. <u>OP fails to align HPCI for ATWS (FW only)</u> - injecting HPCI through the core spray sparger may cause an adverse reactivity effect during an ATWS event. Operators are instructed in HC.OP-EO.ZZ-0322(Q) to prevent HPCI flow to Core Spray line A during an ATWS if HPCI injection flow is not needed to maintain RPV water level above TAF. Failure to do so will be considered a failure of the system during an ATWS.

3.2.1.1.6 Technical Specification Limitations

Technical Specifications (TS) 3/4.5.1 and 3/4.3.2 apply to HPCI. TS 4.5.1 and 4.3.2 are surveillance requirements and are not summarized here. TS 3.5.1 and 3.3.2 are LCO requirements, and are summarized below.

Limiting Condition for Operation (LCO)

The HPCI system is operable if the following are met:

1. one operable HPCI pump, and

2. an operable flow path capable of taking suction from the suppression chamber and transferring the water to the reactor vessel.

Should the HPCI system become inoperable during operational conditions 1, 2, or 3 with the CSS, LPCI, ADS, and RCIC systems operable, the HPCI system must be restored to operable status within 14 days or be in at least hot shutdown within the next 12 hours and reduce reactor steam dome pressure to less than or equal to 200 psig within the following 24 hours.

Several other LCOs exist for conditions involving inoperable HPCI actuation instrumentation channels. These LCOs ensure that redundant HPCI actuation instrumentation channels are available.

3.2.1.1.7 Testing

The system is designed such that a full flow functional test can be performed any time the system is in Standby Readiness Mode (within the limitations of the Technical Specifications). Testing does not affect the ability of the HPCI system to inject water into the reactor vessel following a transient. Major test requirements are outlined in the Technical Specification Surveillance Requirements.

3.2.1.1.8 System Operation

Normal operation

During normal plant operation, the system is in a ready standby condition.

Abnormal operation

During abnormal plant conditions when the HPCI system is required to function, startup and operation are automatically initiated and controlled. Upon receipt of initiation signals, the HPCI controls automatically start the system and bring it to design flowrate within 35 seconds.

During and following a leak or break in the HPCI steam lines or loss of room or steam tunnel cooling, a HPCI isolation signal may occur. The following events occur upon receipt of an isolation signal:

1. the steam supply (1FDHV-F002 and F003), min flow (1BJHV-F012), injection to core spray (1BJHV-F006), and injection to feedwater (1BJHV-8278) close.

2. the turbine trip solenoid energizes,

3. the pump suction from suppression pool valve (1BJHV-F042) closes,

4. a status light "isolation logic A and C tripped" illuminates, and

5. the alarm "HPCI out of service" annunciates.

3.2.1.1.9 System Fault Tree

3.2.1.1.9.1 Description

Components modeled in the HPCI system fault tree are shown in the simplified diagram in Figure 3.2-1. The top event for the HPCI fault trees is insufficient HPCI flow to the reactor vessel.

3.2.1.1.9.2 Success and Failure Criteria

The HPCI operation is successful if the system can inject water through the Core Spray line A or Feedwater line A for 24 hours (non-ATWS). During an ATWS sequence, HPCI is successful if the system can inject through the feedwater line for 24 hours, and no injection through the core spray line occurs. Failure of HPCI may be caused by:

1. failure of the HPCI turbine driven pump,

2. no flow path to Core Spray or Feedwater systems,

3. failure of HPCI suction,

4. failure of the steam path to and from the HPCI turbine driven pump,

5. injection through the core spray line, during an ATWS sequence.

3.2.1.1.9.3 Assumptions

In addition to the assumptions stated in the "Hope Creek Fault Tree Handbook," the following assumptions apply for this system.

Model-Related

1. RHR heat exchangers A and B potential flow diversion paths off the HPCI steam line are not included in the fault tree since these lines are not operable and are sealed closed.

2. The recirculation line diversion flow path was determined not to be large enough to deplete the HPCI flow path of minimum coolant required for core cooling. The size of the minimum-flow line is 4 inches and the discharge line is 14 inches, which is less than one-third of the discharge line size.

3. The potential flow diversion path test line to the CST from the HPCI pump discharge is not modeled because of the low probability of this scenario taking place. In order for this diversion to occur, the normally-closed valve 1BJHV-F008 would have to be left in an open position and an actuation signal opening valve 1BJHV-8278 or interlocks between 1BJHV-8278 and 1BJHV-F006 would need to fail. In addition, 1BJHV-F011 would need to fail open.

4. Either the Core Spray line or the Feedwater line provide sufficient flow (2600 gpm minimum) for accident mitigation except ATWS. During an ATWS operators are instructed to inject HPCI through one feedwater line only. Failure to do so will be considered a failure of the system.

5. The CST is located outside of the Auxiliary Building. The piping for the CST is heat traced to prevent freezing in the lines. Since the heat tracing is alarmed in the control room the freezing of the CST line was not modeled.

6. HPCI flow diversion back through the core spray or feedwater lines is prevented in the Core Spray line by normally closed motor-operated valve 1BEHV-F005A and check valve 1BEV014 and in the feedwater line by check valve 1AEHV-F032A. Spurious opening of the MOV and failure of the check valve are required for flow diversion through the Core Spray line and are not modeled due to the low probability of this event occurring.

7. Failure of the jockey pump does increase the likelihood of water hammer in the discharge line but does not directly fail the HPCI system. Therefore, the failure of the jockey pump was not modeled.

8. The turbine-driven pump data includes the booster and main pump, the turbine governor valve, the lube oil cooling system, and associated equipment.

9. The successful operation of HPCI requires an automatic switch to the suppression pool for suction. The suppression pool supply is sufficient for all operational modes of HPCI; therefore, the CST supply, which is not sufficient for all modes, is not required for successful operation.

10. Operator failure to control RPV level, preventing a HPCI turbine trip on an RPV high water level signal, combined with a failure of the Level 8 trip circuitry, will be considered a failure of the system.

11. Failure of 1BJHV-F004 (pump suction from CST) to remain open is not modeled, since the system would fail only if the turbine failed to trip automatically or if the operator failed to respond to the system alarms after the turbine tripped.

Quantification-Related

1. A mission time of 24 hours was used to quantify the HPCI fault tree.

3.2.1.1.10 References

1. "Hope Creek Generating Station updated Final Safety Analysis Report," Section 6.3.1.2.1 Public Service Electric and Gas Company, Hancocks Bridge NJ, April 11, 1991.

2. "Hope Creek Generating Station Licensed Operator Systems," Lesson Plan Number 302HC-000.00-026-14. Public Service Electric and Gas Company, Hancocks Bridge NJ, May 1989.

3. "Hope Creek Generating Station Technical Specifications 3/4.5." Public Service Electric and Gas Company, Hancocks Bridge NJ, July 1986.

4. Public Service Electric and Gas Company Operating Procedures OP-IS.BJ-001
OP-IS.BJ-101
OP-IS.BJ-102
OP-SO.BJ-001
OP-EO.ZZ-312
OP-EO.ZZ-316
OP-EO.ZZ-322

5. Public Service Electric and Gas Drawings
M-41-1
M-42-1
M-55-1
M-56-1
J-55-0
J-56-0
J-0650
E41-1040
E-6074-0
E-6074-1
E-6431-0
E-6439-0
E-6440-0

3.2.1.2 Reactor Core Isolation Cooling System (RCIC)

3.2.1.2.1 System Function

The Reactor Core Isolation Cooling (RCIC) System provides adequate reactor core cooling following reactor isolation if the feedwater system is unavailable to provide the required makeup water. RCIC can also be used to cooldown and depressurize the reactor after shutdown.

3.2.1.2.2 System Description

General Design

The RCIC system is a safety-related system consisting of a steam-driven turbine, turbine-driven pump, and associated piping, valves, controls and instrumentation. RCIC is capable of ensuring adequate core cooling with no Emergency Core Cooling Systems (ECCS) actuation following a reactor isolation and a loss of feedwater flow. The flow rate is approximately equal to the boil-off rate 15 minutes after a reactor shutdown. A simplified diagram of the RCIC system is presented in Figure 3.2-2.

Flow Path

RCIC delivers makeup water to the reactor vessel through Feedwater Line B. The RCIC pump's initial water source is the Condensate Storage Tank (CST). The RCIC pump discharges to the reactor vessel via the Loop B Feedwater supply header. The suppression pool is used as a makeup water source following the depletion of the CST. The RCIC pump and turbine are located below the water level of the CST and suppression pool. The RCIC steam turbine is supplied with steam from main steam line A upstream of the main steam isolation valve (MSIV). Steam exhausted from the RCIC turbine is directed to the suppression pool. A minimum-flow recirculation line leading to the suppression pool is provided to prevent overheating the pump when it is operating near the shutoff head.

Location

The RCIC turbine-driven pump assembly and associated valves, piping and instrumentation are located in the RCIC pump room, at Reactor Building Elevation 54'. The CST is located outside the Auxiliary Building, and the suppression pool is located inside containment at Elevation 54'. The valves modeled which are inside containment are the steam supply inboard isolation valve (FCHV-F007), check valve AEV003 and motor-operated valve AEHV-F011B in Feedwater line B. All other modeled valves in the RCIC system are located outside containment.

Component Descriptions

RCIC Turbine-Driven Pump

The RCIC main pump (OP203) is a 100% capacity steam-turbine driven pump designed to deliver flow to the reactor vessel within a reactor pressure range of 64.6 psig to 1120 psig. The RCIC turbine (OS212) provides the motive force to drive the RCIC pump. Steam supply to the turbine is from main steam line A. The RCIC turbine-driven pump has a 600 gpm injection capacity.

Condensate Storage Tank

The Condensate Storage Tank (CST) provides the initial RCIC pump suction supply during system operation. The tank contains up to 500,000 gallons of demineralized water of which 135,000 gallons is designed for use by the RCIC and HPCI systems. The portion of the suction piping exposed to outside air temperatures is protected from the cold weather by 1-1/2 inches of insulation and a single heat trace on each line.

Suppression Pool

The suppression pool provides secondary makeup water to the reactor vessel when the CST becomes depleted or high torus level occurs. The torus-shaped suppression chamber is located around and below the reactor vessel and contains a water volume of approximately 118,000-ft^3.

3.2.1.2.3 System Interfaces

Shared Components

RCIC shares check valves AEHV-F074B, AEF032B and AEV003, and motor-operated valve AEHV-F011B with the feedwater system. The CST is shared by RCIC, HPCI, CSS, and the Control Rod Drive Hydraulic systems and the suppression pool is shared by RCIC, HPCI, LPCI, and CSS.

Electrical

RCIC is supplied 250 VDC power exclusively through MCC 10D261. The 1BD417 125 VDC Class 1E distribution panel supplies DC electrical power to the RCIC control circuits. RCIC system success is independent of AC power; however, AC power is used for control of components that are non-essential to RCIC success.

Air

There are five pneumatic valves in RCIC which are supplied by the instrument air system. However, these valves are all associated with the operation of the condensate pump, drain lines, and steam trap bypass. Their operation is not required for the operation of the RCIC system.

Actuation

RCIC is automatically actuated by a low reactor vessel water level (-38 inches) signal.

Control

RCIC control is not shared by any other system. Controls are located in the control room on the Control Room Panel 10C650 and are equipped with manual actuation switches. RCIC may also be controlled at the remote shutdown panel.

Component Cooling

The lube oil cooling system maintains RCIC turbine lube oil at the proper operating temperature to ensure proper operating turbine bearing temperature. The barometric condenser receives cooling water from the discharge of the RCIC pump. No other component cooling is required.

Room Cooling

The RCIC pump room is cooled by two redundant cooler units which use the SACS system as a heat sink. The RCIC pipe chase is cooled by RBVS. RCIC pump room cooling is evaluated in Section 3.2.1.21.

3.2.1.2.4 Instrumentation and Control

Control logic in the RCIC system is designed to function upon automatic initiation. In addition to the automatic operational features of the RCIC system, provisions are included for remote manual startup, operation, and shutdown in case automatic initiation fails. Functional testing is available during normal plant operation.

System Actuation

A reactor water low level signal (-38 inches, wide range) automatically initiates the RCIC system, which includes the following operations:

1. the turbine steam supply valve (FCHV-F045) opens,

2. the RCIC pump suction from the CST valve (BDHV-F010) opens, if closed,

3. the RCIC pump discharge valves (BDHV-F012 and BDHV-F013) receive an open signal admitting water to the reactor when pump discharge pressure is greater then the reactor pressure (thus opening the associated check valves).

Control

The RCIC pump may be started either manually or automatically. Once the pump is running, the turbine control valve's position is controlled by signals from the controller. The amount of steam available to the turbine is determined by the position of the turbine control valve, which adjusts the turbine speed.

A minimum-flow line protects the RCIC pump from overheating when it is operating at low-flow conditions. Automatic control of the minimum-flow valves (BDSV-F019 and BDSV-4405) is accomplished by flow indicator switches. The valves are closed by interlocks with FCFV-4282 (fully closed), FCHV-F045 (fully closed), or by a pump discharge flow high signal.

RCIC pump suction is initially taken from the CST and can be manually controlled. Automatic control is actuated by RCIC initiation signals which open valve BDHV-F010, the RCIC suction valve from the CST. This valve is closed by a "RCIC suction valve from suppression pool fully open" signal. The suppression pool suction valve BDHV-F031 has both manual and automatic control. Automatic control of actuation and isolation of this valve is described in the interlocks section below. The automatic signal can be overridden by a manual control switch. This allows the pump suction to be aligned back to the CST from the suppression pool.

Interlocks

RCIC interlocks during and after system initiation include:

1. FCHV-F007 (steam supply line inboard isolation valve) automatically closes upon a RCIC isolation signal. FCHV-F007 cannot be reopened if the isolation signal is still present.

2. FCHV-F008 (steam supply line outboard isolation valve) automatically closes upon a RCIC isolation signal. FCHV-F008 cannot be reopened if the isolation signal is still present.

3. BDHV-F010 (pump suction from the CST) opens upon a RCIC automatic or manual initiation signal if BDHV-F031 (pump suction from the suppression pool valve) is not fully open. BDHV-F010 closes automatically when BDHV-F031 is fully open.

4. BDHV-F031 (RCIC pump suction from the suppresion pool) automatically opens on CST low level if the BDHV-F031 handswitch is not in the AUTO OPEN OVRD position.

5. BDHV-F012 (RCIC pump discharge valve) opens upon a receipt of an automatic or manual initiation signal.

6. BDHV-F013 (RCIC Feedwater isolation valve) opens upon a receipt of an automatic or manual initiation signal provided that FCHV-F045 (turbine steam supply valve) and FCHV-4282 (RCIC turbine trip and throttle valve) are not fully closed. HV-F013 automatically closes if FCHV-4282 or FCHV-F045 is fully closed.

7. FCHV-F045 (turbine stop valve) automatically opens upon receipt of an automatic or manual initiation signal provided that FCHV-F059 (turbine exhaust to suppression pool) is fully open.

8. FCHV-4282 (turbine trip and throttle valve) has both automatic and manual actuation and isolation and trip reset control.

Instrumentation

Instrumentation that provides monitoring functions for safe operation of RCIC include such alarms/indicators as RCIC out of service, RCIC steam flow high, and RCIC turbine trip. A total of 30 alarm/indication annunciators exist for the RCIC system. These annunciators are located in the control room and are indicated on Panel 10C650 and alarmed on Panel 10C800.

System Isolation

There are seven isolation signals which will automatically isolate the RCIC system. These are reactor low pressure, high exhaust diaphragm pressure, RCIC pipe chase high temperature, high steam line flow, RCIC pump room ventilation duct high differential temperature, torus compartment high temperature, and RCIC pump room high temperature. All temperature isolation signals for the RCIC system can be bypassed at Panel 621 or 640 by placing switch S5B and S5D, respectively, in the BYPASS position.

3.2.1.2.5 Operator Actions

The RCIC system, when required, is automatically initiated by a reactor vessel low water level (-38") signal. Therefore, the only operator action modeled is:

Operator fails to control water level - RPV water level needs to be controlled to prevent a RCIC turbine trip on an RPV high water level signal. RCIC will restart if the high water level signal clears, but may suffer a failure to restart.

3.2.1.2.6 Technical SpecificationLimitations

Technical Specifications (TS) 3/4.7.4 and 3/4.3.5 apply to RCIC. TS 4.7.4 and 4.3.5 are surveillance requirements and are not summarized here. TS 3.7.4 and 3.3.5 are LCO requirements and are summarized below.

Limiting Condition for Operation (LCO)

The RCIC system is operable if an operable flow path exists that is capable of taking suction from the suppression chamber and transferring the coolant to the reactor vessel.

Should the RCIC system become inoperable in modes 1, 2, or 3 with the steam dome pressure greater than 150 psig, operation may continue provided the HPCI system is operable. However, the RCIC system must be returned to operable status within 14 days or be in at least hot shutdown within the next 12 hours and the reactor steam dome pressure must be less than or equal to 150 psig within the following 24 hours.

Several other LCOs exist for conditions involving inoperable RCIC actuation instrumentation channels. These LCOs ensure that redundant RCIC actuation instrumentation channels are available.

Instrumentation

To ensure prompt RCIC system actuation and isolation, RCIC actuation instrumentation must be operable as specified in Technical Specification Tables 3.3.5-1, and 3.3.5-2.

3.2.1.2.7 Testing

The system is designed such that a full-flow functional test can be performed any time the system is in the Standby Readiness Mode (within the limitations of the Technical Specifications). Testing does not affect the ability of the RCIC system to inject water into the reactor vessel following a RCIC actuation due to a transient. Major test requirements are outlined in the Technical Specifications Surveillance Requirements.

3.2.1.2.8 System Operation

Normal operation

During normal plant operation, the system is in a ready-standby condition.

Abnormal operation

During abnormal operating conditions when the RCIC system is required to function, startup and operation are automatically initiated and controlled. The RCIC pump develops sufficient head to pump water into the reactor vessel at full operating pressure. Thus, the RCIC system can restore reactor vessel water level even if the water loss is not accompanied by depressurization.

3.2.1.2.9 System Fault Tree

3.2.1.2.9.1 Description

Components modeled in the RCIC system fault tree are shown in the simplified diagram in Figure 3.2-2. The top event for the RCIC fault tree is "RCIC fails to provide sufficient flow to the RPV."

3.2.1.2.9.2 Success and Failure Criteria

RCIC operation is successful if the system can inject water through the Feedwater line B for 24 hours. Failure of RCIC may be caused by:

1. failure of the RCIC pump,

2. no flow path to the Feedwater system,

3. failure of the steam path to or from the RCIC turbine-driven pump,

4. failure of RCIC pump suction.

3.2.1.2.9.3 Assumptions

In addition to the assumptions stated in the "Hope Creek Fault Tree Handbook," the following assumptions apply for this system.

Model-Related

1. Included in the turbine-driven pump data is the main pump, the turbine governor valve, the lube oil cooling system and associated equipment.

2. The CST is located outside of the Auxiliary Building. The piping for the CST is heat traced to prevent freezing in the lines. Since the heat tracing is alarmed in the control room the freezing of the CST line was not modeled.

3. Failure of the jockey pump does increase the likelihood of water hammer in the discharge line but does not directly fail the RCIC system. Therefore, the failure of the jockey pump was not modeled.

4. The potential minimum flow line diversion path to the suppression pool was modeled. The pipe size of the minimum flow line is 2 inches compared to the RCIC line which is 6 inches. It is assumed that the minimum flow line valves will open during RCIC system startup.

5. The successful operation of RCIC requires a switch to the suppression pool for suction. The suppression pool supply is sufficient for all operational modes of RCIC. Therefore, the CST supply, which is not sufficient for all modes, is not required for successful operation.

6. The potential full-flow test line diversion path to the CST was not modeled because of the low probability of this scenario taking place. In order for this diversion to occur, two normally closed MOVs (BDHV-F022 and HPCI valve BJHV-F011) would have to fail open.

7. The potential failure of the Torus-Drywell vacuum breakers to reclose, bypassing the suppression pool, and tripping the RCIC turbine on high exhaust pressure will not be modeled due to low probability.

8. Operator failure to control RPV level, preventing a RCIC turbine trip on an RPV high water level signal combined with failure of the Level 8 trip circuitry, will cause a failure of the system.

9. Failure of BDHV-F010 (pump suction from the CST) to remain open is not modeled, since the system would fail only if the turbine failed to trip automatically or if the operator failed to respond to the system alarms after the turbine tripped.

Quantification-Related

A mission time of 24 hours was used to quantify the RCIC fault tree.

3.2.1.2.10 References

1. Hope Creek Generating Station UFSAR Section 5.4.6.1.1.1.

2. "Hope Creek Generating Station Licensed Operator Systems," Lesson Plan Number 302HC-000.00-030-13. Public Service Electric and Gas Company, Hancocks Bridge, NJ, October 25, 1991.

3. "Hope Creek Generating Station Technical Specifications 3/4.7.4." Public Service Electric and Gas Company, Hancocks Bridge, NJ, July 1986.

4. Public Service Electric and Gas Company Operating Procedures
   HC.OP-EO.ZZ-313
   HC.OP-EO.ZZ-317
   HC.OP-IS.BD-001
   HC.OP-IS.BD-101
   HC.OP-IS.BD-102
   HC.OP-ST.BD-001
   HC.OP-ST.BD-003

5. Public Service Electric and Gas Drawings
   M-49-1
   M-50-1
   M-52-1
   M-55-1
   J-49-0 Series
   J-50-0 Series
   E51-C002
   E51-F031
   E51-F084
   E51-1030-61
   E51-1040
   E-6082-1
   E-6084-0
   E-6085-0
   E-6086-0
   E-6433-0

3.2.1.3 Core Spray System (CSS)

3.2.1.3.1 System Function

The Core Spray System (CSS) is one of the four Emergency Core Cooling Systems. It operates to limit fuel clad temperature to less than 2200°F in the event of a LOCA. The CSS automatically initiates on low reactor vessel water level or high drywell pressure signals and sprays water onto the fuel assemblies when reactor pressure is less than 380 psig. The CSS also functions in conjunction with the Automatic Depressurization System (ADS) to limit fuel clad temperature during a LOCA when the reactor vessel is not rapidly depressurized, and the High-Pressure Coolant Injection System (HPCI) cannot adequately cool the reactor core (this function is discussed more in the ADS section of this report).

3.2.1.3.2 System Description

General Design

The CSS is comprised of two independent loops (loops A and B) with two independent trains supplying each loop. The CSS draws water from the suppression pool. Each CSS loop consists of two suction strainers located in the suppression pool, two 50% capacity spray pumps, spray spargers located in the reactor vessel, system piping, and valves. A simplified diagram of the CSS is presented in Figure 3.2-3.

Flow Path

During system operation, water is drawn from the suppression pool through the core spray pump suction strainers and is pumped into two separate spray headers. CSS trains A and C supply water to CSS loop A, and trains B and D supply water to loop B. A minimum-flow line is installed in each CSS loop to prevent pump damage in the event that coolant flow is less than 650 gpm. One test return line, which returns water to the suppression pool during flow testing, is installed in each CSS loop.

In the event of a LOCA and CSS initiation, water is pumped by the CSS into the RPV from the suppression pool. Coolant moves through the reactor core and passes out the break in the reactor coolant system to the suppression pool. Thus, a closed flow cycle is established, allowing the CSS to operate continuously following an accident.

Location

The CSS pumps, valves, and piping are located in four separate rooms on the east side of the Reactor Building on Elevation 54'. The CSS pump suction strainers are located in the suppression pool, and the CSS spray spargers are installed in the upper shroud area of the reactor pressure vessel.

Component Descriptions

CSS Pumps

Four 50% capacity pumps are installed to provide CSS flow. The pumps are six-stage, vertical, centrifugal type and each has a rated flow of 3175 gpm. Pump shutoff head is 380 psi. The pump seals are mechanical, and seal leakage drains to the liquid radwaste system.

CSS Pump Suction Strainers

A strainer is provided on each CSS pump suction header to prevent debris from being drawn into the CSS. The strainers are disc and spacer type, and each has a 3950 gpm flowrate capacity with a 1.0 ft. pressure drop when operating with the strainer 50% plugged.

Core Spray Spargers

The CSS spargers distribute spray within the reactor vessel. Four sparger headers are provided; two are supplied from each flow loop. A total of 256 spray nozzles are directed downward and toward the core vertical centerline.

CSS Valves

The CSS pump minimum-flow valves, 1BEHV-F031A(B), are used to establish a flow path between the CSS pump discharge and the suppression pool during low flow conditions to prevent CSS pump damage due to overheating. The valves are normally open and will automatically open, if closed, when their respective CSS pump or pumps are running and CSS loop flow is less than 650 gpm.

The CSS loop downstream injection valves 1BEHV-F005A(B) are normally closed and provide isolation of CSS loop injection lines to the reactor vessel. The valves are manually operated from the control room and will automatically open on a CSS initiation signal.

The CSS loop testable check valves, 1BEHV-F006A(B), provide protection against overpressurizing the CSS due to backflow from the reactor vessel. The valves also prevent flow from the reactor vessel through a leak in the CSS piping.

ECCS Jockey Pumps

The ECCS jockey pump(s) keeps the CSS discharge piping full of water. This minimizes water injection time and prevents water hammer from inflicting damage when the associated CSS pumps are started.

3.2.1.3.3 System Interfaces

Condensate Storage and Transfer System

The condensate storage system provides various connections for CSS filling and venting, and also for system testing when the reactor is shutdown. The condensate storage tank (CST) also provides as an alternate makeup water source to the CSS pump suctions. This option may be examined further as a recovery action upon plugging of the strainers.

Shared Components

Water is maintained in the CSS pump headers by means of two ECCS jockey pumps, which are part of the RHR system. The CSS shares the RHR and CSS vital inverter and relay board Divisions I, II, III, and IV with the RHR. The inverter and relay board divisions are employed for CSS initiation. The CSS loop A injection line is also used by HPCI and SLC. The CSS shares no other components with plant systems.

Electrical

The electrical buses supplying the CSS pumps A, B, C, and D are the 4160 VAC vital buses 10A401, 10A402, 10A403, and 10A404, respectively. The CSS motor-operated valves are supplied with 480 VAC power from motor control centers. The 125 VDC buses, 1AD417, 1BD417, 1CD417, and 1DD417 supply power to the RHR and CSS vital inverter and relay board Divisions I, II, III, and IV. 1AD417, 1BD417, 1CD417, and 1DD417 also supply control power for the closing and opening of the feeder breakers for CSS pumps A, B, C, and D.

Actuation

The CSS automatically initiates on reactor low water level (-129 inches) or drywell high pressure (+1.68 psig) signals. The initiation signal starts the CSS pumps, provides a supply line isolation valve open permissive, and closes the CSS test isolation valves, 1BEHV-F015A(B), if open. Reactor pressure must be reduced to approximately 380 psig before core spray flow will enter the reactor vessel. In the event of a large break, reactor depressurization would be rapid and would lead directly to CSS initiation. In the event of a small break, depressurization is slower, and the HPCI and the SRVs are used to add water and/or reduce reactor pressure to core spray injection pressure.

Control

In the event of CSS actuation, the CSS loops are automatically aligned for operation. Manual control is available in the event that the automatic functions fail.

Component Cooling

No equipment in the CSS receives component cooling.

Room Cooling

Each of the four CSS pump rooms is cooled by two Equipment Area Cooling System (EACS) units. The heat sink for the room coolers is provided by the Safety Auxiliaries Cooling System (SACS). The EACS is described in Section 3.2.1.21, and SACS is described in Section 3.2.1.15.

3.2.1.3.4 Instrumentation and Control

System Actuation

The CSS initiation logic is a one-out-of-two taken twice. Any of the following signals generate a system actuation:

1. Two reactor low level signals (less than -129"), or

2. Two drywell high pressure signals (greater than +1.68 psig), or

3. A low level and a high pressure signal (from opposite channels of the same division), or

4. CSS logic-manual-initiation, push button armed and depressed.

Upon receipt of signals 1, 2, 3, or 4 with offsite power available, a 10-second time delay pickup is energized. If the signal or signals persist for 10 seconds, the four CSS pumps receive start signals. If actuation occurs during a LOP, CSS pumps start 6 seconds after the applicable diesel generator breaker closes. Also, the CSS injection valves 1BEHV-F005A(B) open when reactor pressure is below 461 psig to allow water to enter the core. CSS upstream injection valves, 1BEHV-F004A(B), are normally open, but will also receive a signal to open if they are closed.

Control

The CSS pumps, full flow test valves, and injection valves are controlled automatically for CSS operation. The components may be manually controlled from the control room if automatic actuation fails.

CSS minimum-flow valves 1BEHV-F031A(B) are operated manually from the control room and will open automatically, if they are closed, to prevent pump damage when their associated CSS pumps are running and the respective CSS loop flow is less than 650 gpm. The operation of the minimum-flow loop prevents CSS pump damage due to overheating.

The CSS injection valves, 1BEHV-F004A(B), and 1BEHV-F005A(B), receive automatic signals to open when all of the following are present:

1. CSS logic initiation signal (manual or automatic),

2. Low reactor pressure (less than 461 psig), and

3. Power available to the respective CSS pump.

System Interlocks

CSS upstream injection valve, 1BEHV-F004A(B), is interlocked with the CSS injection valve, 1BEHV-F005A(B), such that 1BEHV-F005A(B) cannot be manually opened unless 1BEHV-F004A(B) is fully closed. The reverse is not true. Therefore, with 1BEHV-F004A(B) closed, it should not be manually opened until 1BEHV-F005A(B) is closed. This interlock does not affect system operation as modeled for the analysis and was therefore excluded from further consideration.

Instrumentation and Annunciators

Instrumentation that provides monitoring functions for safe operation of the CSS system include such alarms and instrumentation as CSS pump motor alarm, pump motor overcurrent alarm, and CSS loop A and B pump flow. There are a total of nine alarms and two instrumentation monitors for the CSS in the control room.

CSS full flow test valves, 1BEHV-F015A(B), isolate the flow paths between the CSS loops and the torus used during system testing. The test valves can be operated from the control room and will automatically close, if they are open, on CSS initiation.

3.2.1.3.5 Operator Actions

Operation of the CSS normally requires no operator actions. If a malfunction of the automatic operation occurs, the operator can manually provide the initiation signal.

If automatic actuation of CSS pump minimum-flow valves, 1BEHV-F031A(B), fails, the valves may be opened manually from the control room when their associated CSS pump or pumps are running and their respective CSS loop flows are less than 650 gpm.

3.2.1.3.6 Technical Specifications

Technical Specifications (TS) 3.5.1, 3.5.2 (Limiting Condition for Operation) and 4.5.1, 4.5.2 (Surveillance Requirements) apply to the CSS. TS 3/4.3.3 applies to the actuation of CSS; this logic is discussed in Section 3.2.1.14. TS 3/4.4.3.2 and 3/4.6.3 apply to the isolation of CSS; this logic is not within the scope of the Level I PRA. TS 3.5.1 is summarized below.

Limiting Condition for Operation for the CSS

The CSS shall be operable consisting of two subsystems with each subsystem comprised of:

1. Two operable CSS pumps, and

2. An operable flow path capable of taking suction from the suppression chamber and transferring the water through the spray sparger to the reactor vessel.

With one core spray subsystem inoperable, provided that at least two Low-Pressure Coolant Injection subsystems are operable, the inoperable CSS subsystem must be restored to operable status within seven days or the unit is to be in at least hot shutdown within the next 12 hours and in cold shutdown within the following 24 hours. With both CSS subsystems inoperable, the unit is to be in at least hot shutdown within 12 hours and in cold shutdown within the next 24 hours.

With a CSS header pressure differential channel inoperable (necessary for the CSS line-break detection system), the inoperable channel must be restored to operable status within seven days or the header differential pressure determined locally at least once per 12 hours; otherwise the associated CSS subsystem is to be declared inoperable.

3.2.1.3.7 Testing

Tests involving the CSS are performed in conformance with the Technical Specifications and include a full flow test. A full flow test line installed in each loop provides full flow test capability where water is drawn from the torus and then returned through test valves 1BEHV-F015A(B).

3.2.1.3.8 System Operation

Normal Operation

During normal plant operation, the CSS is in a standby mode. ECCS Jockey pumps in the RHR system operate continuously to maintain water level in the CSS pump discharge lines to prevent water hammer in the event of CSS actuation.

Abnormal Operation

During and after a LOCA, the CSS operates to provide water to the core. The system provides reactor core protection for reactor coolant pressure boundary breaks when the following components are unable to maintain the reactor water level:

1. Main feedwater pumps,

2. Control rod drive water pumps,

3. Reactor Core Isolation Cooling pump, and

4. HPCI pump.

The CSS automatically initiates on reactor low water level and/or drywell high pressure signals. The initiation signals start the pumps, provide a supply line isolation valve open permissive, and close the test isolation valves (if open). The reactor pressure must be reduced to approximately 380 psig before core spray flow will enter the reactor vessel. In the event of a large break, reactor depressurization below 380 psig would be rapid, and no intervention is necessary to depressurize. In the event of a small break, depressurization is slower, and the HPCI and SRVs are used to add water and/or reduce reactor pressure to core spray injection pressure. The supply line isolation valves will not open until reactor pressure is below 461 psig. Until this setpoint is reached, the CSS pumps discharge through the minimum-flow lines to the suppression pool. The minimum-flow line isolation valves automatically close when sufficient flow is detected through the common CSS supply lines.

3.2.1.3.9 System Fault Tree

3.2.1.3.9.1 Description

The CSS fault tree identifies the credible ways in which the CSS could fail to supply a sufficient quantity of water to the core. A simplified diagram indicating those components modeled in the CSS fault tree is shown in Figure 3.2-3.

3.2.1.3.9.2 Success and Failure Criteria

CSS operation is successful if one of two CSS loops operates in the event the core is uncovered by the loss of reactor coolant. The operation of a CSS loop is successful if the two respective CSS trains in that loop operate successfully. For example, successful operation of CSS loop A requires the successful operation of trains A and C. A CSS train will fail to provide flow (which thereby fails the associated CSS loop) if one or more of the following failures occur:

1. Pump failure,

2. Power unavailability to the train's pump or valves,

3. Suction or discharge valves in wrong configuration,

4. Loss of pump room cooling,

5. Loss of system actuation and a subsequent failure to manually initiate the CSS, or

6. Instrumentation and control failures.

3.2.1.3.9.3 Assumptions

Model-Related

1. The failure to close of valves 1BEHV-F031A(B) in the minimum flow line was not modeled. The minimum flow line is a 3-inch diameter pipe, while the core spray line

is a 12-inch diameter pipe. If valves 1BEHV-F031A(B) were to fail open, the potential diversion flow path would be through a line whose diameter is less than one-third the diameter of the system pipe, and this diversion path is considered insufficient to fail the system.

2. Valve restoration failures were not modeled for the following valves in accordance with the requirements for this project (Table 2.5 of the IPE submittal, Item 8). Position annunciated in control room: 1BEHV-F001A, 1BEHV-F001B, 1BEHV-F001C, 1BEHV-F001D, 1BEHV-F004A, 1BEHV-F004B, 1BEHV-F005A, 1BEHV-F005B, 1BEHV-F015A, 1BEHV-F015B, 1BEHV-F031A, 1BEHV-F031B, 1BE-V001, and 1BEV005. Testing following maintenance would indicate misalignment: 1BEV009, 1BEV010, 1BEV011, 1BEV012, 1BEV102, and 1BEV103. Position remains unchanged: 1BEV027, 1BEV029, 1BEV031, and 1BEV033.

3. The probability of accidental draining of the CST through piping connected to the CSS pump suction headers was considered to be insignificant, so the modeling of the possible consequences and resulting operator actions was judged to be unnecessary. The connection from the CSS to the CST is normally isolated with locked-closed manual valves. A double fault would be necessary, i.e., a valve restoration error (in switching from the hook-up to the CST to the normal CSS standby configuration) and the failure of the control room operators to notice the system's incorrect configuration would be necessary for the restoration error to go unnoticed.

4. Water is maintained in the CSS pump discharge headers by means of the ECCS jockey pumps. Since "keep filled" alarm instrumentation is available for the discharge headers, and the water level is verified at least once per 31 days by venting at the high point vents, the probability of system failure due to water hammer was judged to be insignificant, and it was not included in the fault tree model.

5. Piping connecting the CSS pump discharge headers with the RHR flushing and the condensate transfer system was not considered to be a potential flow diversion path because two check valves are located on the line to prevent flow, and the piping is of insufficient diameter (less than one-third the diameter of the main CSS piping).

6. Failure to restore the isolation valves located between the CSS pump suction piping and the lines connected to the radioactive waste system (1BEV045, 1BEV047, 1BEV056, 1BEV061) would have the potential to introduce air into the CSS pump suction piping. However, this event was not modeled since the radioactive waste system piping is of relatively small diameter (2 inches in diameter compared to the 16-inch diameter of the suction piping), and the net positive suction head available in the pump suction piping would preclude the introduction of air.

7. Plugging failures were not modeled for the CSS spray nozzles. The CSS pump suction strainers were assumed to hinder debris sufficiently to prevent plugging as set forth by the Updated Hope Creek Generating Station Final Safety Analysis Report.

8. HPCI pump discharge piping to CSS loop A was not considered to be a potential flow diversion from the CSS because a normally closed isolation valve, 1BJHV-F006, is installed in the piping. Since the position of 1BJHV-F006 is indicated in the control room, a valve restoration error as well as a failure to notice the incorrect position of 1BJHV-F006 would be necessary for the piping to be a potential flow diversion.

Quantification-Related

1. A single failure-to-open event was modeled in the system fault trees for the CSS minimum-flow control valves, 1BEHV-F031A(B). Although 1BEHV-F031A(B) may be required to open and close several times during CSS operation, it is assumed that the initial successful operation of 1BEHV-F031A(B) will result in successful operation during the remainder of the CSS operation.

2. Plugging of more than one of the CSS pump suction strainers was judged to most likely involve all four strainers (rather than various combinations of two or three strainers) since they are each installed in an identical manner in the suppression pool. A single dependent failure was therefore modeled for the plugging of all four strainers.

3. A single fault, CSS-XHE-FO-INIT, was included in the CSS fault tree to account for the failure of an operator to manually initiate the CSS in the event that automatic initiation fails.

3.2.1.3.10 References

1. Hope Creek Generating Station UFSAR Section 6.3.2.2.3.

2. "Hope Creek Generating Station Licensed Operator Training," Lesson Plan Number 302HC-000.00H-027-12. Public Service Electric and Gas Company, Hancocks Bridge, NJ, December 16, 1992.

3. "Hope Creek Generating Station Technical Specifications 3/4." Public Service Electric and Gas Company, Hancocks Bridge, NJ, June 1990.

4. Public Service Electric and Gas Drawings

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   E-6023-0
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5. Public Service Electric and Gas Company Operating Procedures
OP-IS.BE-0001
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OP-IS.BE-0102
OP-IS.BE-0103
OP-SO.BE-0001
OP-ST.BE-0001
OP-ST.BE-0002
OP-ST.BE-0003

3.2.1.4 Residual Heat Removal (RHR) System

3.2.1.4.1 System Function

The Residual Heat Removal (RHR) System is designed to establish a closed cooling water path within the containment to restore reactor vessel coolant inventory. The primary functions of the RHR system for this study are:

1. low-pressure coolant injection (LPCI),

2. shutdown cooling (SDC),

3. suppression pool cooling (SPC), and

4. drywell spray/containment spray (CSC).

The secondary functions of the RHR system are:

1. torus spray,

2. alternate RPV injection from SSWS/Firewater (see Section 3.2.1.24),

3. fuel pool cooling augmentation,

4. containment flooding, and

5. torus/RPV letdown to radwaste.

When operating in the LPCI mode, RHR is designed to restore and maintain reactor vessel water level following a loss-of-coolant accident (LOCA). The LPCI mode provides water from the torus directly to the reactor vessel. Following depressurization of the reactor vessel, the LPCI mode also provides inventory makeup following a small break LOCA. At low reactor system pressure, the RHR is placed in the SDC mode of operation to remove decay and sensible heat from the fuel and nuclear boiler system. The SPC mode of operation is designed to ensure that the suppression pool temperature immediately after a blowdown does not exceed 170°F.

3.2.1.4.2 System Description

General Design

The RHR system consists of four motor-driven pumps, two heat exchangers, four suppression pool strainers, containment and suppression pool spargers, system valves, and piping.

Flow Path

The flow paths vary for the various modes of RHR operation: the LPCI, SDC, SPC, and CSC modes. Each mode requires a particular system configuration as shown in Figure 3.2-4(a-e).

In this study the following terminology was used: A train is a pump train. A loop is a pump train and a heat exchanger. A side or subsystem is either trains A and C or trains B and D.

On a LPCI initiation signal, all four RHR pumps start, and the system automatically aligns to deliver suppression pool water from the torus to the reactor vessel. Operation of each of the four RHR trains differs somewhat for LPCI operation. RHR trains C and D are dedicated to the LPCI configuration and cannot be aligned to support any other operational mode. Torus water is drawn through the suction valve 1BCHV-F004C(D) to RHR pump C(D), and the water is then delivered to the reactor vessel via the injection valve 1BCHV-F017C(D) and testable check valve 1BCHV-F041C(D). LPCI flow is piped into the core shroud where it is dumped directly on the core. RHR trains A and B will also automatically align to support LPCI operation. The flow path of trains A and B is similar to trains C and D except that the pump discharge is directed through the RHR heat exchanger bypass valve 1BCHV-F048A(B) and then into the vessel via injection valve 1BCHV-F017A(B) and testable check valve 1BCHV-F041A(B).

During the SDC mode of operation, RHR loops A and B pump water from the reactor recirculation loop B suction header and return it to the discharge of either recirculation loop through the RHR heat exchangers.

During the SPC mode of operation, when energy is transferred from the suppression pool to the Safety Auxiliary Cooling System (SACS), RHR pumps A and B move suppression pool water through the RHR heat exchangers, past full flow test valves 1BCHV-F024A and 1BCHV-F024B, and then return it to the torus.

During CSC, RHR pumps A and B move water from the torus through the RHR heat exchangers, past valves 1BCHV-F016A(B) and 1BCHV-F021A(B), and out to the free air space of the drywell. For the torus spray flowpath, RHR pumps A and B pump water from the torus through the RHR heat exchangers, through valves 1BCHV-F027A(B) to the torus air space via the spray header.

Location

Each RHR pump is located in an individual pump room on Elevation 54' of the west side of the Reactor Building. The RHR heat exchangers are located in RHR pump rooms A and B.

Component Descriptions

RHR Pumps A, B, C, and D

Four motor-driven pumps are installed to provide RHR flow. The RHR pumps are four-stage, centrifugal, deepwell pumps and can each provide a flow rate of 10,000 gpm at a discharge head of about 175 psig. Pump shutoff head is about 340 psig.

RHR Heat Exchangers A and B

The two RHR heat exchangers are designed to remove heat from the reactor, suppression pool, and drywell space. Heat is transferred from RHR to SACS which moves through the tube side of the heat exchangers.

RHR Suction Strainers

A strainer is provided on each RHR pump suction header to hinder debris from being drawn into RHR. Each of the four 24-inch RHR pump suction nozzles penetrates the torus wall at a point on the circumference 30° up from the bottom of the pool. The suction nozzles extend 6 inches beyond the torus interior surface, and the strainers are mounted on top of the nozzle penetration end. Each strainer is designed to have no more than 1-foot head loss at a flow of 10,750 gpm with 50% of the total strainer area plugged. The strainer mesh is sized to screen out all particles greater than 0.125 inches in diameter. Particles equal to or smaller than 0.125 inches in diameter do not impair RHR pump, heat exchanger, drywell spray, and suppression pool spray performance.

RHR Valves

Injection valves installed in RHR include those for the LPCI, SDC, SPC, and CSC modes of operation, each being motor-operated and closed during standby.

The RHR pumps have a number of associated valves installed for system operation. All of these valves are motor-operated valves or check valves.

Flow to and around the RHR heat exchangers is normally controlled by the heat exchanger inlet valves (1BCHV-F047A, B) and the heat exchanger bypass valves (1BCHV-F048A, B). For LPCI operation, the heat exchangers are bypassed, while for the other modes of the RHR system, flow is routed through the heat exchangers. During the LPCI mode, it is acceptable to have some flow going through the heat exchangers. During the SDC, SPC, and CSC modes it is acceptable to have some of the flow bypass the heat exchangers.

The valves for LPCI are automatically actuated. The valves for SDC, SPC, and CSC are manually controlled from the control room.

ECCS Jockey Pumps

The ECCS jockey pump(s) keep the RHR pump discharge piping full of water to minimize water injection time and prevent water hammer and resulting damage when the RHR pumps are started.

Actuation and Control

The LPCI mode of operation automatically actuates on low reactor level (-129 inches) or high drywell pressure (1.68 psig). RHR is aligned for the SDC, SPC, and CSC modes of operation by manual actions from the control room.

3.2.1.4.3 System Interfaces

Shared Components

The RHR pump headers are kept filled by means of two ECCS jockey pumps, which also supply water to the Core Spray System (CSS) pump headers. The RHR system also shares the vital inverter and relay board Divisions I, II, III, and IV with the CSS. The inverter and relay board divisions are employed for LPCI initiation following a LOCA. The suppression pool is shared by HPCI, RCIC, LPCI and CSS.

Electrical

The RHR system is provided with both AC and DC power sources. The 4160 VAC vital buses, 10A401, 10A402, 10A403, and 10A404, supply power to RHR pumps A, B, C, and D, respectively. The LPCI motor-operated valves receive power for control and operation from 480 VAC motor control centers. The 125 VDC busses, 1AD417, 1BD417, 1CD417, and 1DD417, supply power to the RHR actuation and control logic circuitry. Feeder breakers for RHR pumps A, B, C, and D require 125 VDC control power from buses 1AD417, 1BD417, 1CD417, and 1DD417, respectively.

Actuation

The CSS and LPCI actuation divisions, I, II, III, and IV, provide for automatic system actuation of LPCI. See also CSS actuation.

Control

Equipment which must operate during LPCI operation is automatically controlled. If automatic control malfunctions, operation of the RHR pumps and valves can be accomplished manually from the control room.

All facets of SDC, SPC, and CSC modes of operation require manual control of equipment except the following:

1. SDC return isolation valves, 1BCHV-F015A(B), will close automatically if reactor vessel pressure is more than 82 psig or reactor vessel water level is low (Level 3), and

2. SDC suction isolation valves, 1BCHV-F008 and 1BCHV-F009, will automatically close if the reactor vessel water level is low (Level 3) or the reactor vessel pressure is high (82 psig or greater).

Pneumatic

The valves which permit SACS coolant to flow to the RHR pumps are air-operated and open when the respective RHR pump is started. These valves also fail open (desired position) on loss of instrument air. No other pneumatic equipment is installed in RHR.

Room Cooling

The RHR pumps A, B, C, and D are each located in separate, individually cooled pump rooms. In addition, the Reactor Building Ventilation System provides cooling to the RHR pump rooms. Each RHR pump room is cooled by two cooling units. The cooling units use the SACS system as a heat sink. The RHR pump room cooling is evaluated in Section 3.2.1.21.

Component Cooling

SACS provides cooling to the RHR pump seals and the RHR heat exchangers. The SACS flow to the RHR pumps is normally isolated and automatically begins to flow when the respective RHR pump is started. The SACS to RHR heat exchanger outlet valves (EGHV-2512A,B) are normally closed. These isolation valves are operated from the control room.

3.2.1.4.4 Instrumentation and Control

System Actuation

Low reactor level (-129 inches) or high drywell pressure (1.68 psig) signals automatically initiate the LPCI mode of operation and align RHR system valves to the LPCI flowpath. Inlet and outlet valves for the RHR heat exchangers receive no automatic signals since the system is designed to provide rated flow to the reactor vessel whether they are open or not. To ensure continuity of core cooling, signals to isolate the primary containment do not operate any RHR system valves that interfere with the LPCI mode of operation.

RHR is aligned for the SDC, SPC, and CSC modes of operation by manual actions from the control room.

Control

The RHR pumps and valves have automatic and/or manual controls for system operation.

The LPCI injection valves 1BCHV-F017A(B, C, D) will automatically open in response to the LPCI initiation signal if the following conditions exist:

1. LPCI initiation signal is present in the respective RHR loop logic, and

2. power is available on the respective RHR pump bus, and

3. reactor pressure is less then 450 psig.

Reactor pressure must be less than 450 psig to open the LPCI injection valves either automatically or manually. The auto open signal can be disengaged by depressing the "AUTO OPEN OVERRIDE" pushbutton. The operator can then close the associated injection valve if desired.

For SDC operation, reactor pressure must be less than 82 psig to enable the opening of SDC suction valves, 1BCHV-F008(9). Additionally, both valves will automatically close if either low reactor level (Level 3) or high reactor vessel pressure (greater than 82 psig) occurs.

In addition to electrical faults, the RHR pumps will trip if a suction path is not available. The RHR pumps also have minimum-flow valves, 1BCHV-F007A, B, C, and D to provide a flow path for minimum pump flow requirements to prevent pump overheating and subsequent damage. Manual operation of each minimum-flow valve can be initiated from the control room. The minimum-flow valves are normally open when the RHR system is in standby, and the valves will automatically close once RHR pump flow exceeds approximately 1270 gpm. If system flow decreases below 1250 gpm for ten seconds or more (with the pump breaker closed), the associated minimum-flow valve will automatically open. If the minimum-flow valve is closed when the RHR pump is stopped, the valve will remain closed and must be repositioned by the operator to restore the open standby status.

Interlocks

System interlocks on the RHR valves are installed to prevent malfunction due to improper system configurations. For all modes of operation, any of the four RHR pumps will not start if a suction path is not available (through either valves 1BCHV-F006A[B], 1BCHV-F008, and 1BCHV-F009 for SDC, or 1BCHV-F004A[B, C, D] for other modes of operation).

For SDC operation, the following valves are interlocked with 1BCHV-F006A(B) such that they must be 100% closed to allow 1BCHV-F006A(B) to open:

1. 1BCHV-F004A(B) RHR pump suction from the torus,

2. 1BCHV-F024A(B) test return line to the torus, and

3. 1BCHV-F027A(B) torus spray isolation.

In addition, SDC suction valves, 1BCHV-F008, 1BCHV-F009, and 1BCHV-F006A(B), must be 100% open to allow the respective A or B pump to start during SDC, and reactor pressure must be less than 82 psig to enable opening of 1BCHV-F008, and 1BCHV-F009. 1BCHV-F008 and 1BCHV-F009 will automatically close in response to:

1. low reactor water level 3, or

2. high reactor vessel pressure.

The CSC mode of operation employs interlocks on the CSC injection valves, 1BCHV-F021A(B) and 1BCHV-F016A(B), such that each of the following conditions must be present to open both valves and spray the drywell:

1. LPCI signal present,

2. high drywell pressure, and

3. respective LPCI injection valve, 1BCHV-F017A(B) must be 100% closed.

Instrumentation and Annunciators

Instrumentation that provides monitoring functions for safe operation of RHR include such alarms/annunciators as RHR pump flow, RHR LPCI line break alarm, valve positions, and jockey pump trouble alarm. These alarms/annunciators are located in the control room to allow operator monitoring.

System Isolation

The RHR pump suction piping is automatically isolated during the SDC mode of operation in the event of low reactor water level 3 or high reactor vessel pressure.

3.2.1.4.5 Operator Actions

If automatic LPCI actuation fails, manual initiation of the LPCI initiation logic can be accomplished from the control room. Operation of the LPCI mode during manual initiation is identical to that following automatic initiation.

Initiation for the SDC, SPC, and CSC modes of operation are performed from the control room. Failures to initiate the SDC, SPC, and CSC modes of operation are modeled in the RHR fault trees as single events for each mode of operation.

3.2.1.4.6 Technical Specifications

Technical Specifications 3.3.3, 3.5.1, 3.5.2, 3.6.2.2, 3.6.2.3, 3.9.11.1, and 3.9.11.2 (Limiting Condition for Operation) and 4.3.3, 4.5.1, 4.5.2, 4.6.2.2, 4.6.2.3, 4.9.11.1, and 4.9.11.2 (Surveillance Requirements) apply to the RHR. TS 3.5.1, 3.9.11 and 3.6.2.3 are summarized below.

Limiting Condition for Operation for LPCI (T.S. 3.5.1)

LPCI shall be operable consisting of:

1. one operable RHR pump, and

2. an operable flow path capable of taking suction from the suppression chamber and transferring the water to the reactor vessel.

With one LPCI subsystem inoperable, provided that at least one Core Spray subsystem is operable, the inoperable LPCI subsystem is to be restored to operable status within 30 days or the unit is to be placed in HOT SHUTDOWN within the following 12 hours and in COLD SHUTDOWN within tht following 24 hours.

With two LPCI subsystems inoperable, provided at least one Core Spray subsystem is operable, at least one LPCI subsystem is to be restored to operable status within 7 days or the unit is to be in at least hot shutdown within the next 12 hours and in cold shutdown within the following 24 hours.

With three LPCI subsystems inoperable, provided that both Core Spray subsystems are operable, at least two LPCI subsystems are to be restored to operable status within 72 hours or the unit is to be in hot shutdown within the next 12 hours and in cold shutdown within the following 24 hours.

With all four LPCI subsystems inoperable, the unit is to be in at least hot shutdown within 12 hours and in cold shutdown within the next 24 hours.

With a LPCI header differential pressure instrumentation channel inoperable, the inoperable channel is to be restored to operable status within 7 days or the LPCI header differential pressure is to be determined locally at least once per 12 hours.

Limiting Condition for Operation for SDC (TS 3.9.11)

During the refueling operational condition, at least one shutdown cooling mode loop of RHR must be operable and in operation with one operable RHR pump and one operable RHR heat exchanger. TS 3.9.11.1 applies in refueling when the reactor well is flooded and 3.9.11.2 applies in refueling when the well is not flooded.

1. With no RHR shutdown cooling mode loop operable demonstrate within one hour and at least once per 24 hours thereafter, that at least one alternate method capable of

decay heat removal is operable. Otherwise, suspend all operations involving an increase in the reactor decay heat load and establish secondary containment integrity within four hours.

2. With no RHR shutdown cooling mode loop in operation, within one hour establish reactor coolant circulation by an alternate method and monitor reactor coolant temperature at least once per hour.

Limiting Condition for Operation for SPC (TS 3.6.2.3)

The suppression pool cooling mode of the RHR system must be operable with two independent loops, each loop consisting of one operable RHR pump and an operable flowpath capable of recirculating water from the suppression chamber through an RHR heat exchanger.

1. With one suppression pool cooling loop inoperable, restore the inoperable loop to operable status within 72 hours, or be in at least hot shutdown within the next 12 hours and in cold shutdown within the following 24 hours.

2. With both suppression pool cooling loops inoperable, be in at least hot shutdown within 12 hours and in cold shutdown within the next 24 hours.

3.2.1.4.7 Testing and Maintenance (TM)

Any of the components of RHR may be individually isolated for TM while the plant is in operation. The unavailability of one RHR train due to TM will not affect the availability of the other RHR trains.

3.2.1.4.8 System Operation

Normal Operation

RHR is in standby during normal plant operation.

Abnormal Operation

For LPCI operation, all RHR pumps receive a start signal in response to a LOCA signal of:

1. high drywell pressure (1.68 psig), or

2. low reactor water level (-129 inches).

In addition, the following valves receive close signals:

1. test return valves 1BCHV-F010A(B) and 1BCHV-F024A(B), and

2. torus spray valves 1BCHV-F027A(B).

Valves which receive open signals are:

1. RHR heat exchanger bypass valves 1BCHV-F048A(B), and

2. LPCI injection valves 1BCHV-F017A(B, C, D) (when reactor pressure decreases to less than 450 psig).

When the initiation signal is completed, the white "A(B, C, D) INIT AND SEALED-IN" indication illuminates.

The SDC, SPC, and CSC modes are initiated manually from the control room.

3.2.1.4.9 System Fault Trees

3.2.1.4.9.1 Description

Simplified diagrams indicating those components modeled in the LPCI, SDC, SPC, and CSC fault trees and the configuration of the system in each mode are shown in Figures 3.2-4(a-e).

3.2.1.4.9.2 Success and Failure Criteria

LPCI operation is successful if one of four RHR trains (A, B, C, or D) successfully operate. SDC, SPC, and CSC operation is successful if one of two RHR loops (A or B) operate. A RHR train will fail if any one or more of the following occur:

1. RHR pump failure,

2. injection valve fails to open,

3. one of two check valves fails to open, or

4. pump suction strainer plugged.

A RHR loop will also fail if the path through the heat exchanger is unavailable for the SDC, SPC, and CSC modes.

3.2.1.4.9.3 Assumptions

In addition to the assumptions stated in the "Hope Creek Fault Tree Handbook," the following assumptions apply for this system.

Model-Related

1. Failure of a RHR pump minimum-flow line to successfully operate is assumed to fail the corresponding RHR pump. The minimum-flow path valves, 1BCHV-F007A, B, C, and D, are normally open. Therefore, failure of these valves to close would constitute a failure.

2. The RHR pumps were assumed to be flow tested following maintenance. Therefore, no restoration errors were modeled for the pump inlet and outlet valves.

3. The RHR trains A and B successfully perform system function during the LPCI mode if water flows through the RHR heat exchanger inlet valves 1BCHV-F047A(B) or the heat exchanger bypass valves 1BCHV-F048A(B) or both. The RHR loops perform successfully in the SDC, SPC, or CSC modes if 1BCHV-F047A(B) are open. Since both 1BCHV-F047A(B) and 1BCHV-F048A(B) are normally open valves and the valve position is annunciated in the control room, the probability of failure of RHR train/loop A(B) due to both valves being closed was considered negligible and not modeled in the LPCI fault trees.

4. The cross-connect piping and the manual valves, V043 and V133, located between the SDC suction piping and the RHR pumps in the C and D trains, was not considered to be a flow diversion pathway. If a restoration error existed and valves V043 and/or V133 were left open, the suction piping could not be pressurized before SDC operation. Therefore, the error would be noticed and sufficient time would be available to diagnose and correct the error. In addition, if RHR trains C and D were required to operate and a restoration error existed, the cross-connect would still be isolated by normally closed valves in the SDC cooling suction piping (1BCHV-F006A(B), 1BCHV-F008, 1BCHV-F009).

5. Piping connecting the condensate storage transfer system (CST) with the RHR pump discharge piping was not modeled as a potential flow diversion because check valves are located in the lines, and the CST piping diameter is less than one-third the diameter of the associated RHR piping.

6. The contribution of RHR failure due to water hammer was considered negligible because two independent trains maintain water in the discharge header piping by means of two jockey pumps, and the malfunction of either jockey pump is alarmed in the control room. The jockey pumps are not included in this model.

7. The cross-connection between the RHR loop B and the SSWS through valve 1BCHV-F075 was not considered to be a potential flow diversion from RHR since two check valves are located in the line, and the piping is of insufficient diameter (less than one-third the diameter of the main RHR piping).

8. The piping leading from the RHR pump discharge piping to the spent fuel pit was not considered to be a potential flow diversion because normally closed valves are installed in the piping. If the isolation valves were accidentally left in the open position, discharge from the RHR jockey pumps would subsequently lead to the overflow of the spent fuel pool. Thus, an alarm would eventually sound, alerting the control room operators to correct the problem.

9. Failure to restore RHR pump suction from the auxiliary cooling of the spent fuel pool was judged to not affect successful operation of RHR during SDC. One reason is that the spent fuel pool auxiliary cooling mode is employed infrequently. However, if a restoration error did occur, the error would be noticed before SDC startup since water from the CST is normally used to pressurize the SDC suction piping to within 10 psig of the reactor vessel pressure. Pressurization of the piping would not be possible if the system was in the spent fuel cooling configuration.

10. The failure modes for the inlet valves providing SACS coolant to the RHR pumps include failure to open and failure of instrumentation and control. Failure modes not modeled include loss of valve motive power and actuation signals because both of these are automatically received during pump startup. In other words, if the RHR pumps successfully start, it is assumed that the associated inlet valves providing SACS coolant will receive a signal to open. Additionally, if air supplying the motive power for the valves is lost, the valves fail open.

11. Prior to LPCI, SDC, and SPC operation, RHR is assumed to be in the normal standby configuration. Before CSC operation, RHR is assumed to be in the configuration necessary for LPCI operation.

12. A restoration error occurring in 1BCHV-F006A(B) such that the valve or valves were left in the open position was judged to not be a potential failure of LPCI operation in the A and B trains. The closure of 1BCHV-F006A(B) is necessary for operation of trains A or B during LPCI due to interlocks. However, the position of 1BCHV-F006A(B) is indicated in the control room, and therefore, failure of the system due to the mispositioning of 1BCHV-F006A(B) is unlikely.

13. The HPCI piping connected to the RHR heat exchanger outlet lines (PS-1 and PS-3) is permanently out of service and, therefore, not modeled in the fault trees (a blank plate is installed in the piping, and the associated isolation valves are chained closed and are tagged "OUT OF SERVICE"). The RCIC piping connected to the heat exchanger inlet lines (PS-2 and PS-4) is similarly placed out of service and is not modeled in the fault trees.

14. Plugging failures were not modeled for the drywell space spray nozzles because the RHR pump suction strainers were assumed to hinder debris sufficiently as set forth by the HCGS UFSAR.

15. Failure of the low pressure permissives for SDC suction valves, 1BCHV-F008 and 1BCHV-F009, resulting in a failure to open upon demand of either valve, was assumed to not fail SDC operation. It is assumed that sufficient time would be available during SDC to diagnose the problem, and the permissives would be bypassed locally, if necessary, to allow SDC operation to be initiated.

16. Operation of Torus Spray is not required for CSC; however, valve 1BCHV-FO27A(B) being in an open state will not fail CSC.

17. Catastrophic actuator failure resulting from personnel error during VOTES testing has been added to the fault trees as a human error affecting the individual valves due to plant experience.

Quantification-Related

1. Operator failure to manually initiate the various operating modes of RHR have been modeled in the RHR fault trees as a single event for each of the operating modes. Although procedures to initiate LPCI, SDC, SPC, and CSC involve more than one step, a failure event was inserted in the fault trees for each RHR operating mode modeled representing the collection of operator errors which could mitigate system operation. The event for the operator failing to initiate LPCI has been placed in the ESF fault tree for actuation of LPCI.

2. For LPCI operation, dependent failures of valves and pumps were modeled for the pumps and valves of LPCI side A (trains A and C combined), LPCI side B (trains B and D combined), as well as a combination of both sides. For the remaining RHR operating modes, only RHR loops A and B operate. Therefore, dependent failures were modeled strictly for the pumps and valves of loops A and B in the SDC, SPC, and CSC fault trees.

3. A single dependent failure was modeled for the plugging of all four RHR pump strainers rather than various combinations of two or three strainers because the dependency of failure for the four strainers was judged to be high. In other words, plugging of a number of the strainers was judged to most likely involve all four strainers since they are each installed in an identical manner in the suppression pool.

3.2.1.4.10 References

1. Hope Creek Generating Station UFSAR Sections 6.3 and 5.4.7.

2. "Hope Creek Licensed Operator Training," Lesson Plan Number 302HC-000.00H-000028-11. Public S.:vice Electric and Gas Company, Hancocks Bridge, NJ, May 18, 1989.

3. "Hope Creek Generating Station Technical Specifications 3/4.5." Public Service Electric and Gas Company, Hancocks Bridge, NJ, July 1986.

4. Public Service Electric and Gas Drawings:

M-11-1
M-51-1
M-53-1
E-0309-0
E-0310-0
E-2108-0
E-2231-0
E-2234-0
E-2404-0
E-6234-0
E-6404-0
E-6435-0
E-6441-0
E-6443-0
J-4051-0
J-51-0
10855-B21-1060
791E419AC

5. Public Service Electric and Gas Company Operating Procedures:

HC.OP-FT.BC-0001
HC.OP-FT.BC-0002
HC.OP-FT.BC-0101
HC.OP-FT.BC-0102
HC.OP-FT.BC-0103
HC.OP-FT.BC-0104
HC.OP-FT.BC-0105
HC.OP-FT.BC-0106
HC.OP-FT.BC-0107
HC.OP-FT.BC-0109
HC.OP-FT.BC-0110
HC.OP-IS.BC-0001
HC.OP-IS.BC-0002
HC.OP-IS.BC-0003
HC.OP-IS.BC-0004
HC.OP-IS.BC-0101
HC.OP-IS.BC-0102
HC.OP-IS.BC-0103
HC.OP-IS.BC-0104
HC.OP-IS.BC-0105
HC.OP-SO.BC-0001
HC.OP-ST.BC-0001

5. Public Service Electric and Gas Company Operating Procedures (Continued):
HC.OP-ST.BC-0004
HC.OP-ST.BC-0005
HC.OP-ST.BC-0006
HC.OP-ST.BC-0007

3.2.1.5 Automatic Depressurization System (ADS)

The Automatic Depressurization System (ADS) is part of the Nuclear Pressure Relief System that protects the reactor coolant pressure boundary from damage due to over pressure. Of the 14 safety/relief valves (SRVs) in the Nuclear Relief System, five are designated to also serve the automatic depressurization function. A simplified diagram of the ADS is presented in Figure 3.2-5.

3.2.1.5.1 System Function

The Automatic Depressurization System (ADS) is one of the four emergency core cooling systems (ECCSs). If the High-Pressure Coolant Injection (HPCI) System or the non-ECCS Reactor Core Isolation Cooling (RCIC) System are unable to maintain the reactor water level during small break or loss of feed flow conditions, ADS reduces the reactor vessel pressure so that Low-Pressure Coolant Injection (LPCI) and/or Core Spray System (CSS) flow can enter the reactor vessel to cool the core and limit the fuel cladding temperature. ADS is designed to initiate automatically; however, because of the EOP structures, the operators inhibit its initiation and initiate it manually upon further reactor level reduction.

3.2.1.5.2 System Description

General Design

The ADS consists of five designated SRVs from the fourteen Nuclear Pressure Relief System SRVs, ten solenoid actuation valves, ten vacuum breakers, and discharge piping. One ADS SRV is located on each main steam line upstream of the inboard main steam isolation valve (MSIV), except for line C, which has two ADS SRVs.

Flow Path

When opened, the five ADS SRVs discharge energy from their respective steam lines directly to the suppression pool through "T" quencher spargers. The discharge lines are arranged to provide even heat distribution in the suppression pool. Vacuum breakers are installed in the discharge lines to prevent siphoning suppression pool water into the lines.

Location

The ADS SRVs are located upstream of the inboard MSIVs on the main steam lines. Valve PSV-F013A is located on main steam line A, PSV-F013B on line B, PSV-F013C and -F013E on line C, and PSV-F013D on line D.

Component Descriptions

ADS Safety/Relief Valves

Each SRV is a two-stage Target Rock valve that consists of a pilot stage assembly directly coupled to provide a dual-function SRV. Each SRV has a design flow of 818,000 to 950,000 lb/h, depending on the set pressure. The ADS SRVs open on pilot actuation (based on increasing system pressure) or solenoid/pneumatic actuation.

Accumulators

Each SRV has a five-gallon capacity accumulator which ensures that the valve can be opened and held open following a failure of the PCIG supply. The accumulator capacity is sufficient to open the SRV and hold it open against a drywell pressure of 62 psig. Designed capacity also ensures that there is sufficient nitrogen available to allow two relief valve actuations against a drywell pressure of 43.4 psig (70% of design).

ADS Solenoid Valves

Each ADS SRV has two solenoid valves associated with it that supply PCIG to the SRV actuators. The solenoid valves open when energized. Energizing either one of the two solenoid valves will cause its respective SRV to open. The non-ADS SRVs have only one solenoid.

ADS Discharge Line "T" Quenchers

There is one "T" quencher for each SRV, which distributes steam flow from the SRV discharge pipe into the suppression pool water to limit jet forces acting on the discharge pipe.

ADS Discharge Line Vacuum Breakers

Each SRV discharge line has two spring-closed, lift-check valves that act as vacuum breakers. The vacuum breakers prevent drawing water up into the tail pipe, which may cause water hammer or pressure oscillations.

Actuation and Control

The five ADS SRVs will automatically open and relieve reactor vessel pressure upon receipt of all of the following signals unless the operator inhibits them (the EOPs require the operator to inhibit ADS and initiate it manually, upon further level reduction):

1. high drywell pressure greater than 1.68 psig, or a five-minute high drywell pressure bypass timer timed out;

2. reactor level less than -129 inches (Level 1);

3. confirmatory low reactor water level less than +12.5 inches;

4. one RHR pump discharge pressure greater than 125 psig or two core spray pumps discharge pressure greater than 145 psig;

5. 105-second time delay.

The ADS SRVs will also open at 1130 psig to provide vessel over pressure protection.

3.2.1.5.3 System Interfaces

Shared Components

The five ADS SRVs are shared with the Nuclear Pressure Relief System, which has nine other non-ADS SRVs. The ADS shares no other components with other plant systems.

Electrical

All "A" ADS solenoid valves are powered from Class 1E 125 VDC Distribution Panel 1BD417, while the "B" ADS solenoid valves are powered from Class 1E 125 VDC Distribution Panel 1DD417. These two Distribution Panels power all the SRV solenoids.

Actuation

The reactor vessel instrumentation provides the high drywell pressure and low reactor water level signals that actuate the ADS valves. The Residual Heat Removal System or Core Spray System provides ADS initiation logic permissives. However, based on the EOPs, the operator inhibits actuation of ADS and depressurizes the reactor vessel manually using either the ADS or non-ADS SRVs.

Control

The Class 1E 125 VDC Distribution Panel 1BD417 provides power to ADS logic train B, and Distribution Panel 1DD417 provides power to ADS logic train D. The logic for the non-ADS SRVs are also powered through these two Distribution Panels.

Pneumatic

The Primary Containment Instrument Gas (PCIG) System supplies nitrogen to the ADS pilot actuators and accumulators, and the Instrument Air System (IAS) provides a backup to PCIG.

Component Cooling

The SRV valves (both ADS and non-ADS) are all located within the primary containment and do not require component cooling. Technical specifications place a 135°F limit on the maximum containment temperature; however, since the containment design temperature is 340°F, it is judged that these valves would perform their function at least until the design temperature is reached.

Room Cooling

The logic and relay system for the SRVs (both ADS and non-ADS) are located in the lower relay room, which is cooled by the chilled water system.

3.2.1.5.4 Instrumentation and Control

System Actuation

ADS actuation is automatic, unless the operator is successful in inhibiting it. Once inhibited, ADS will not actuate automatically, even if all the proper conditions exist. Each of the ADS SRVs has two solenoid valves associated with it. Energizing one of the two solenoid valves ("A" or "B") will cause its respective SRV to open. Opening each solenoid requires that both subchannels (B and F or D and H) of the associated logic train B or D be energized.

The ADS "A" ("B") solenoids are automatically energized on receipt of all of the following:

1. high drywell pressure ($\geq$1.68 psig) or the high drywell pressure bypass timers timed out;
2. low reactor vessel water level (Level 1, $\leq$ -129 inches);
3. confirmatory low reactor vessel water level (Level 3, $\leq$ +12.5 inches);
4. CSS pumps B and D (A and C) discharge pressure ($\geq$145 psig) or RHR pump B or D (A or C) discharge pressure ($\geq$125 psig); and
5. 105-second time delay timed out.

The drywell pressure bypass timers allow automatic actuation of the ADS after a five-minute delay (given all other actuation signals are present) for initiators that do not affect drywell pressure (e.g., a steam line break outside containment). The time delays within the ADS actuation circuitry provide the operator with enough time to actuate systems to recover reactor water level without having to blow down the reactor vessel to the suppression pool.

However, before automatic initiation of ADS, the operator is expected to inhibit ADS and depressurize the reactor vessel manually; using any number of the 14 SRVs that may be required upon further reactor level reduction to Top of Active Fuel (TAF).

Control

Each ADS solenoid valve has an AUTO/OPEN push button on Control Room Panel 10C650C. When in AUTO, the associated solenoid valve is de-energized and will respond to ADS actuation logic. When in OPEN, the solenoid valve is energized and the associated SRV will open. The "A" and "E" ADS SRVs also have AUTO/OPEN keylock switches on lower relay room panel 10C631. The ADS valves cannot be operated through the remote shutdown panel; however, three of the non-ADS SRVs (F, H, and M) can be operated from there in case any manual depressurization is needed.

Interlocks

ADS will automatically initiate only if the correct combination of core spray or RHR pumps are operating as sensed by pump discharge pressure and if operator has failed to inhibit it.

Instrumentation and Annunciators

ADS inhibition and reactor depressurization take place in a very short time period; hence, the operator is highly dependent on accurate instrumentation.

The following ADS instrumentation is located in the control room:

1. an acoustic monitor for each SRV, and

2. a discharge temperature recorder point for each SRV.

This instrumentation indicates if an ADS SRV is not closed.

Alarm status lights for the following conditions are located on Control Room Panel 10C650C:

1. logic power fail,

2. trip unit in cal or gross fail,

3. trip unit out of file or power fail,

4. out of service,

5. in test status, and

6. remote shutdown panel (RSP) takeover.

Each of these status indications has one light per ADS logic channel, except for RSP takeover.

The following conditions are annunciated on Panel 10C800 in the control room:

1. ADS safety/relief valve not closed,

2. ADS manual initiation switch armed,

3. ADS channel B (D) initiation pending,

4. ADS channel B (D) initiated,

5. ADS isolator card trouble,

6. ADS channel B (D) out of service, and

7. ADS drywell pressure bypass timer initiated.

System Isolation

There are two ADS inhibit keylock switches (S34B and S34D). When in NORMAL, the ADS solenoid valves will energize once the automatic initiation logic is satisfied. When in INHIBIT, the ADS solenoid valve automatic initiation will be prevented. Both ADS inhibit switches must be in the INHIBIT position to disable ADS automatic initiation. Manual operation of the SRV; manual initiation of ADS or operation on high reactor pressure (1130 psig) is still possible. Placing both switches in INHIBIT will not close the ADS valves if they are already open. Based on EOPs, the operator must use these switches to inhibit ADS.

Each ADS logic train has a reset switch. Depressing both logic switches will reset both logic trains and close the ADS valves even if an automatic or manual initiation signal is present. If the drywell pressure was greater than 1.68 psig, the ADS SRVs will reopen after 105 seconds provided the necessary low-level and CS/RHR pump signals are present. If the drywell pressure was less than 1.68 psig, the SRVs will reopen after five minutes provided that the necessary low-level and CS/RHR pump signals are present.

3.2.1.5.5 Operator Actions

The operator has to inhibit ADS from the control room through switches S34B and D at Panel 10C650C.

The operator may manually initiate the ADS by means of four pushbuttons (PBs) 1ABHS(B21)-S6B, (D, F, and H). To do so, both PBs in one channel (B and F or D and H) must be armed and depressed. This will energize the associated ADS solenoid valves. Manual initiation does not require the CS or RHR pumps to be operating and does not include any time delays in the circuitry.

The operator may also manually operate the individual ADS SRVs by means of AUTO/OPEN pushbuttons [1ABHS(B21)-F013A1(2) for the "A" ADS valve or 1ABHS(B21)-F013E1(2) for the "E" ADS valve]. Opening two of the ADS SRVs is also possible through the lower relay room switches B21C-S12A and B21C-S12E (in panel 10C631).

In case depressurization through both control room and the lower relay room fails, the operator can manually open three of the non-ADS SRVs (F, H, and M) through the remote shutdown panel.

3.2.1.5.6 Technical Specification Limitations

Technical Specifications (TS) 3.3.3 and 3.5.1 (Limiting Condition for Operation) and 4.3.3 and 4.5.1 (Surveillance Requirements) apply to the ADS and its actuation instrumentation during operating modes 1, 2, and 3, as described below. Technical Specification 3/4.4.2 apply to all SRVs.

Limiting Condition for Operation

The ADS actuation instrumentation channels for reactor vessel water level (Level 1) or drywell pressure (high) should be operable. Based on Action 30 of the TS 3.3.3:

With the number of operable channels less than required by the minimum operable channels per trip function requirement, do the following:

a. With one channel inoperable, place the inoperable channel in the tripped condition within one hour or declare the associated system inoperable.

b. With more than one channel inoperable, declare the associated system inoperable.

Based on Action 31 of TS 3.3.3, if one or more of the ADS actuation instrumentation channels for the following functions are inoperable, the ADS shall be declared inoperable:

1. ADS timer,

2. core spray pump discharge pressure permissive,

3. RHR LPCI mode pump discharge pressure permissive,

4. reactor vessel water level (Level 3) permissive,

5. ADS drywell pressure bypass timer, or

6. ADS inhibit switch.

Based on Action 33 of TS 3.3.3., if one or more of the ADS actuation instrumentation channels for manual initiation are inoperable, the inoperable channel shall be restored to operable within 8 hours or the ADS is declared inoperable.

Based on TS 3.3.3.a, with an ADS actuation instrumentation channel trip function setpoint less conservative than the value shown in the Allowable Values Column of Table 3.3.3-2, declare the channel inoperable until the channel is restored to OPERABLE status with the trip setpoint adjusted consistent with trip setpoint value.

The ADS portion of ECCS consists of five ADS valves that must be operable when the reactor steam dome pressure is greater than 100 psig, based on LCO 3.5.1.d. Based on Action 3.5.1.d, if one of the ADS valves is inoperable, but the HPCI, core spray, and LPCI systems are operable, the inoperable ADS valve must be restored to operable within 14 days or the plant be placed in hot shutdown within the next 12 hours and the reactor steam dome pressure reduced to below 100 psig within the next 24 hours. Based on Action 3.5.1.d if two or more ADS valves are inoperable, the plant must be in hot shutdown within 12 hours and the reactor steam dome pressure reduced to below 100 psig within the next 24 hours.

Technical Specification 3.4.2.1 for the SRVs require the safety valve function of 13 of 14 SRVs to be operable. Based on Action 3.4.2.1.a, with the safety valve function of two or more SRVs inoperable the plant has to be in at least hot shutdown within the next 12 hours and in cold shutdown within the next 24 hours.

Surveillance Requirements

Per Surveillance Requirement (SR) 4.3.3.1, a channel check for the following ADS trip functions instrumentation channels shall be performed each 12 hours:

1. reactor vessel water level (Level 1),

2. drywell pressure (high),

3. core spray pump discharge pressure,

4. RHR LPCI mode pump discharge pressure, and

5. reactor vessel water level (Level 3).

A channel functional test for the following ADS trip functions instrumentation channels shall be performed every 31 days:

1. reactor vessel water level (Level 1),

2. drywell pressure (high),

3. ADS timer,

4. core spray pump discharge pressure,

5. RHR LPCI mode pump discharge pressure,

6. reactor vessel water level (Level 3), and

7. ADS drywell pressure bypass timer.

Additionally, a channel functional test for the ADS inhibit switch and ADS manual initiation instrumentation channels shall be performed every 18 months (refueling).

A channel calibration for the ADS timer and ADS drywell pressure bypass timer must be performed every 92 days:

Additionally, a channel calibration for the following trip functions instrumentation channels must be performed every 18 months:

1. reactor vessel water level (Level 1),

2. drywell pressure (high),

3. core spray pump discharge pressure,

4. RHR LPCI mode pump discharge pressure, and

5. reactor vessel water level (Level 3).

Per SR 4.3.3.2 logic system functional tests and simulated automatic operation of all channels are performed every 18 months.

Per SR 4.5.1.d.1 at least once per 31 days a channel functional test of the Primary Containment Instrument Gas (PCIG) low pressure alarm is performed. Furthermore, per SR 4.5.1.d.2.a, every 18 months a system functional test which includes simulated automatic actuation of the system throughout its emergency operating sequence, but excluding actual valve actuation, is performed. Also, per SR 4.5.1.d.2.c every 18 months channel calibration of the PCIG low pressure alarm is performed to verify an alarm setpoint of 85 ± 2 psig on decreasing pressure.

At least once per 18 months each ADS valve is manually opened when the reactor steam dome pressure is greater than or equal to 100 psig to observe that:

1. the main turbine control valve or bypass valve position responds accordingly, or

2. there is a corresponding change in the measured steam flow.

Finally, SR 4.4.2.1 requires that every 18 months at least 1 of 2 of the SRVs be removed, set pressure tested and reinstalled or replaced with spares that have been previously set pressure tested, in such a way that within 40 months all SRVs go through this task.

3.2.1.5.7 Testing and Maintenance

All active components of ADS, except the accumulator check valves, the SRVs, and associated solenoid valves, are designed to allow testing during normal operation. Major tests of the ADS are outlined in the Technical Specifications Surveillance Requirements.

In accordance with the Technical Specifications, one of the five ADS valves may be out of service for up to 14 days without reducing system reliability, provided HPCI, CS and LPCI are operable. As the ADS valves are located inside the drywell, maintenance performed during modes 1 and 2 generally involves the actuation and logic circuitry.

3.2.1.5.8 System Operation

Normal Operation

During normal plant operation, the ADS is in passive standby.

Abnormal Operation

During loss-of-coolant accident (LOCA) or loss of feed flow conditions, the ADS provides backup to the HPCI and RCIC systems. If these systems fail to maintain reactor water level, the ADS depressurizes the reactor vessel to allow LPCI or CSS flow to enter the core.

Depressurization would be accomplished by automatic opening of the ADS SRVs, which discharge to the suppression pool if the operator does not inhibit ADS. However, the operator inhibits ADS in the hope of recovery of high pressure injection so he can prevent a thermal shock to the containment. However, if the level reduces to the top of active fuel, then the operator depressurizes the reactor using any of the 14 SRVs that may be needed, including the ADS valves. HCGS-specific analysis indicates that two SRVs are required to depressurize the reactor on time to prevent core damage.

Depressurization is required only for transients and small breaks in which the high pressure systems are not operable. For large breaks the system will depressurize rapidly through the break.

3.2.1.5.9 System Fault Tree

3.2.1.5.9.1 Description

Figure 3.2-5 is a simplified diagram showing the nine SRVs and the five ADS SRVs. Because of usage of House Events in the fault trees, one ADS fault tree was developed to circumscribe the Transient, LOCA and LOP initiators. The top event in this tree is RXDP; "RX depressurization fails when needed."

3.2.1.5.9.2 Success and Failure Criteria

Since operators are expected to inhibit ADS and depressurize the reactor upon further reduction of the level, the success criteria is defined as either:

1. Depressurization at TAF using 2 of 14 SRVs; or ADS at Level 1 using 2 of 5 ADS/SRVs. However, operators are given credit for preventing ADS 99% of the time. In other words, the major contribution to the top event for reactor depressurization is through failure to depressurize at TAF.

Although unsuccessful inhibition of ADS is considered a failure from the EOP point of view, initiation of ADS is considered to be a success in the PRA. This is because core damage will be prevented if the ADS is initiated and the low pressure systems are operable. The time it takes for the reactor level to reduce from Level 1 to TAF is generally very short (5 to 10 minutes), and the PRA is not so sensitive that it can distinguish the difference.

2. Failure of 125 VDC Distribution Panels which power the SRVs prevents depressurization. Manual depressurization through either the control room, the lower relay room or the remote shutdown panel is considered to be successful.

3. Since each SRV has a charged accumulator, availability of either the accumulators, the PCIGS, or the IAS is considered to provide adequate pneumatic supply.

3.2.1.5.9.3 Assumptions

Model-Related

1. The generic data for instrument failure suggests a failure probability of 1.2E-5, based on 24 hour operability. However, due to the fact that the level instruments may not operate effectively near TAF, their failure rate is increased by a factor of 100 and hence, a failure probability of 1.2E-3 is used instead.

2. No SRV failure due to test and maintenance (TM) is modeled since the Technical Specifications disallow two or more ADS valves to be inoperable for more than 12 hours.

3. Failure associated with all the 14 SRV accumulators due to leakage or insufficiently being charged is considered to be negligible; a failure probability of 1.E-8 is used.

4. Except for the event described above (operator failure to ensure that accumulators charged), insufficient gas pressures to open the SRVs were not considered. It was assumed that if an accumulator is fully charged, the pressure is adequate for opening the SRV during all sequences where depressurization is questioned (i.e., for all drywell pressures). If this is not true for a sequence, the event tree development does not include SRV depressurization as a mitigator.

5. The fault tree is focused on manual operation action to open at least two of the SRVs from either the control room, the lower relay room or the remote shutdown panel. The effect of logic or switch failure is negligible compared to the probability of the operator action "Operator fails to depressurize."

6. Dependent failure of 13 of 14 SRVs is considered to be negligible.

7. It is assumed that the availability of a combination of either the PCIGS, the IAS, or the accumulators and either of the two 125 VDC Distribution Panels is adequate to energize the solenoid of at least two SRVs and open the associated SRV.

8. The ADS SRV discharge line vacuum breakers were not modeled. If the vacuum breakers for a line fail and water is siphoned into it, operation of only the associated SRV will be impaired. If the resulting jet forces at the discharge of the SRV were sufficient to cause the tailpipe to break off, the SRV would simply discharge directly to the drywell. Additionally, the probability of an SRV tailpipe failure ANDed with an operator failure to keep the affected SRV from opening is considered negligible. The failure of the tailpipe would cause a reduction in SRV discharge pressure, which would affect the SRVs lift setpoint. This effect would be limited to that SRV.

Quantification-Related

1. A mission time of 24 hours was used to quantify the RXDP fault tree.

3.2.1.5.10 References

1. Hope Creek Generating Station UFSAR Sections 5.1.4, 5.2.2, 6.3, 7.3, 8.1.

2. Operator Training Manual, Lesson Plan 29

3. Technical Specifications, Sections 3/4.3.3, 3/4.4.2, 3/4.5.1

4. Operating Procedures — HC.OP-EO.ZZ-0101, HC.OP-EO.ZZ-0202, HC.OP-AB.ZZ-0120, HC.OP-AB.ZZ-0121

5. Drawings — M-41-1, M-42-1, M-59-1, E-6067-0, B21-1060

6. NPRDS

3.2.1.6 Control Rod Drive (CRD) Hydraulic System

3.2.1.6.1 System Function

The Control Rod Drive (CRD) Hydraulic System is used during normal plant operation to operate the control rod drive mechanisms for power operation control and rapid reactor shutdown (scram). During accident conditions, the CRD system may be used for emergency makeup to the RPV. This is the CRD operating mode which is relevant for the HCGS PRA.

3.2.1.6.2 System Description

General design

The CRD consists of two drive water pumps, two suction and two discharge drive water filters, two flow control valves, one pressure control valve, associated discharge valves and piping, and a dedicated hydraulic control unit (HCU) for each control rod drive. A simplified diagram of the CRD Hydraulic System is presented in Figure 3.2-6.

Flow Path

The two drive water pumps take suction from the condensate reject line or alternatively, the condensate storage tank (CST) through two parallel pump suction filters. The drive water pumps then discharge through a common header to two parallel drive water filters which are followed by two parallel flow control valves and a single pressure control valve. The charging water header branches off upstream of the flow control valves, and the drive water header branches off between the flow control valves and the pressure control valve. The cooling water and exhaust water headers are downstream of the pressure control valve. Flow from the charging water header passes through the individual HCU scram inlet valves to the 185 control rod drive mechanisms and the RPV.

Location

The CRD pumps and suction filters are located at Elevation 77' of the Reactor Building (RB). The drive water filters, flow control valves, pressure control valve, and HCUs are at RB Elevation 102'.

Component Descriptions

Suction Isolation Valve

Motor-operated isolation valve HV-4005 directs water from the condensate reject line to the RB and the CRD pumps. This valve is normally open and has no interlocks or automatic features.

Pump Suction Filters

The pump suction filters (AF201 and BF201) remove particulate contamination which could damage the drive water pumps. One filter is normally in service and the other isolated by manual valves. Both may be bypassed with a strainer in the bypass line.

Drive Water Pumps

The drive water pumps (AP207 and BP207) are 250HP, 10-stage centrifugal pumps driven by 480 VAC motors, with design flow rates of 98 gpm. Each pump has an inlet and a discharge isolation valve, relief valve, and a common minimum flow line back to the CST. One pump is normally operating.

Drive Water Filters

Drive water filters AF-204 and BF-204 remove particulate matter at the outlet of the drive water pumps. One drive water filter is normally in service and the other isolated by manual valves.

Flow Control Valves

The flow control valves (FV-F002A and B) are air-operated globe valves which are used to throttle the CRD system flow. One valve is normally in service and is automatically positioned from the control room, and the other valve is isolated by manual valves.

Pressure Control Valve

Pressure control valve HV-F003 is a motor-operated valve which is positioned to maintain drive water pressure at 250 psi greater than reactor pressure.

3.2.1.6.3 System Interfaces

Shared Components

The CRD system does not share components with any other plant systems.

Electrical

Drive water pumps AP207 and BP207 are powered from Class 1E 480 VAC unit substations 10B430 and 10B440 respectively. The power from the substations is supplied through two in-series breakers (one Class 1E and one Non-Class 1E). The Class 1E breakers will trip on a LOCA signal, which will in turn cause the Non-Class 1E breakers to trip on bus undervoltage. The breakers can be reclosed as described in the operator action subsection.

Isolation valve HV-4005 is powered from Class 1E 480 VAC MCC 10B232 and pressure control valve HV-F003 from Non-Class 1E 480 VAC MCC 10B263.

Actuation

The CRD system does not receive any automatic actuation signals for emergency operation.

Control

The CRD flow control station controls the flow control valves only during normal (automatic) operation.

Pneumatic

The Instrument Air System (IAS) supplies air to the air-operated flow control valves in the CRD system. The CRD air system includes two parallel filters.

Component Cooling

The drive water pumps are cooled by Reactor Auxiliaries Cooling System (RACS) water.

Room Cooling

The CRD system does not require room cooling.

3.2.1.6.4 Instrumentation and Control

System Actuation

Actuation of the CRD system for emergency makeup to the RPV must be performed by the operator as described under the operator actions subsection.

Control

Control of the CRD system flow for emergency makeup to the RPV must be performed by the operator as described under the operator actions subsection.

Interlocks

CRD interlocks related to system operation are:

1. The drive water pumps will trip on low suction pressure.

2. The drive water pumps Class 1E breakers (and subsequently the Non-Class 1E breakers) will trip on a LOCA signal and must be reclosed to use the pumps for emergency makeup.

3. The HCU scram inlet and outlet valves will close when the scram signal is reset.

Instrumentation and Annunciators

The Control Room Integrated Display System (CRIDS) displays CRD system status, including such parameters as pump running/stopped, Class 1E breaker status, MOV suction valve position, flow, and flow control valves positions.

Local panels at Reactor Building elevations 77 and 102 provide indications for 10 parameters, including pump suction pressure, pump discharge pressure and exhaust water header pressure.

The "CRD System Trouble" alarm on the control room overhead annunciator panel will be activated when any of six conditions occur. These conditions are pump motor malfunction, low pump suction pressure, low charging water header pressure, high drive water filter differential pressure, high pump suction filter differential pressure, and suction isolation valve malfunction.

System Isolation

There are no automatic isolation signals for the CRD system. However, if the scram signal is reset, the HCU scram inlet valves will close, no longer allowing CRD system flow from the charging water header.

3.2.1.6.5 Operator Actions

The CRD Hydraulic System must be manually aligned for emergency makeup to the RPV. The following steps must be performed (locally unless otherwise specified):

1. Place the standby suction filter in service,

2. place the standby drive water filter in service,

3. start the idle drive water pump (main control room),

4. fully open the pressure control valve (main control room) and one pressure control valve bypass,

5. fully open one flow control valve, and

6. throttle the other FCV to maintain pump discharge header pressure greater than 1063 psig minimum to prevent pump runout.

Resetting one scram signal will close the scram inlet valve, preventing flow into the charging water header from reaching the RPV.

When a LOP occurs, the non-Class 1E circuit breakers will trip on undervoltage; the Class 1E breakers remain closed. Therefore, no breakers need to be reset for CRD pump operation.

When a LOCA signal (-129 inches Rx LVL or 1.68 psig drywell pressure) occurs, the CRD pumps' Class 1E circuit breakers will trip. The LOCA signal must be overridden and the circuit breakers closed before CRD pump operation (main control room).

Following a LOP or LOCA, operators must manually start the first CRD pump.

3.2.1.6.6 Technical Specifications Limitations

Technical Specifications (TS) 3.1.3 and 4.1.3 apply to the control rod drive (CRD) system. However, no limiting conditions for operation or surveillance requirements are outlined specifically for the CRD hydraulic system in these specifications. The CRD hydraulic system is specifically required to satisfy TS 3.1.3.5.a.2.a. In addition, procedure HC.OP-AB.ZZ-0105(Q) is as restrictive and requires that if reactor pressure is $\geq$900 psig and charging water header pressure cannot be restored after 20 minutes, manually scram the reactor.

3.2.1.6.7 Testing

Tests of the control rod drive (CRD) and CRD hydraulic systems include:

1. weekly CRD exercise,
2. weekly CRD accumulator check,
3. monthly scram discharge volume (SDV) valve test,
4. monthly SDV trip bypass test,
5. control rod system valves in-service test, and
6. CRD/CRD hydraulic system valves cold shutdown test.

One CRD pump is normally used as the preferred pump for an entire fuel cycle. The operating pump is monitored/tested for performance on a monthly basis. The standby pump is started and performance tested quarterly.

3.2.1.6.8 System Operation

Normal Operation

During normal plant operation, one drive water pump is operating, taking suction through one pump suction filter from the condensate reject line.

The other drive water pump is in standby and the suction filter is isolated. A portion (20 gpm) of the pump discharge flow is routed back to the CST to prevent the pump from overheating at low flows. The remaining discharge passes through the in-service drive water filter (the other is isolated). Some flow (6 to 10 gpm) is diverted for reactor recirculation pump seal cooling.

The discharge flow then passes through a flow element which provides control of the in-service flow control valve (the standby valve is isolated). The flow control valve is positioned to maintain 70 gpm through the flow element. The charging water header taps off between the flow element and flow control valves. Constant water pressure is supplied to the CRD accumulators through this header.

Downstream of the flow control valves is the drive/cooling water pressure control valve, which is throttled to maintain drive water header pressure 250 psig above reactor pressure. A portion of the flow bypasses the pressure control valve through two of four stabilizing valves.

Downstream of the pressure control valve are the pressure equalizing valves which maintain 75 psig backpressure in the exhaust water header. Upstream of the pressure equalizing valves, the cooling water header supplies cooling water to the 185 hydraulic control units (HCUs) where it flows to the CRD mechanism. Each CRD mechanism receives about 0.2-0.4 gpm; this represents the majority of the CRD system flow.

During a reactor scram, the pressure of a CRD accumulator is decreased when the scram inlet and outlet valves open to allow water from the accumulator to insert the control rod. The CRD system attempts to keep the accumulators charged, and charging water header flow increases up to approximately 175 gpm due to the loss of head. The flow control valve automatically closes so all but 5 gpm of the flow is diverted to the charging water header.

Abnormal Operation

During emergency operation, the CRD system may be used to maintain the RPV water level. The CRD system is aligned for emergency makeup to the RPV as outlined in the Operator Actions section previously.

During emergency makeup, both the in-service and standby suction filters, drive water pumps, drive water filters, flow control valves, and pressure control valve and bypass are placed in operation. The scram signal must not be reset so the scram inlet and outlet valves on the HCUs remain open to allow flow from the charging water header through the HCU to the CRDs and the reactor. Flow also passes through the HCU from the cooling water header for a total CRD hydraulic flow of approximately 180 gpm.

3.2.1.6.9 System Fault Tree

3.2.1.6.9.1 Description

Figure 3.2-6 is a simplified diagram showing the CRD hydraulic system components modeled in the CRD hydraulic fault trees.

3.2.1.6.9.2 Success Criteria

The success criteria for the CRD hydraulic fault tree top event is flow from both CRD drive pumps through all four filter trains, injecting via either the charging or cooling water header.

3.2.1.6.9.3 Assumptions

Model-Related

1. Suction flow from the condensate reject line (at the secondary condensate pump suction) was assumed to be unavailable for all sequences.

2. The suction filter bypass line was not modeled, although filter plugging is accelerated during two-pump operation. This was considered as a recovery action.

3. The "A" suction filter, pump, drive water filter, and flow control valve were assumed to be in operation, thus no test and maintenance or valve restoration events were included for these components.

Quantification-Related

A mission time of 24 hours was used to quantify the CRD hydraulic fault trees.

3.2.1.6.10 References

1. Hope Creek Generating Station UFSAR Sections 4.6, 8.3.

2. "Hope Creek Generating Station Licensed Operator Systems," Lesson Plan Number 302HC-000.00-006-10. Public Service Electric and Gas Company, Hancocks Bridge, NJ, January 6, 1993.

3. "Hope Creek Generating Station Technical Specifications 3/4.1.3." Public Service Electric and Gas Company, Hancocks Bridge, NJ, July 1986.

4. Public Service Electric and Gas Company Operating Procedures:
   HC.OP-AB.ZZ-0105(Q)
   HC.OP-EO.ZZ-101(Q)
   HC.OP-SO.BF-001(Q)

5. Public Service Electric and Gas Drawings:
   10855-C11-1030
   10855-C11-1060
   10855-E-6420-0

5. Public Service Electric and Gas Drawings (Continued):

10855-E-6421-0
10855-E-6422-0
10855-E-6060-0
J-46-0
J-47-0
M-46-1
M-47-1

3.2.1.7 <u>Condensate and Feedwater Systems</u>

3.2.1.7.1 System Function

The functions of the Condensate and Feedwater Systems are to condense the main turbine exhaust steam, collect the condensed steam as condensate in the main condenser hotwells, preheat and transfer the condensate to the suction of the main feedwater pumps, boost the pressure by use of the feedwater pump, and return the heated feedwater to the reactor pressure vessel to be reconverted into steam and thereby complete the closed steam/feed cycle. The condensate and/or feedwater pumps may be used as a means of maintaining reactor water level following a transient.

3.2.1.7.2 System Description

General Design

The Condensate System (CNS) condenses and deaerates main and reactor feed pump turbine exhaust steam, accepts and deaerates feedwater heater drains, and serves as the turbine bypass steam heat sink. The condenser allows radioactive decay of the condensate before re-entry into the heat cycle. The CNS transports condensate through the low pressure feedwater heaters to the Reactor Feedwater (RFW) pump suction in sufficient quantities to maintain proper net positive suction head. The RFW system maintains reactor water level by pumping heated condensate through the last stage of feedwater heating to the reactor vessel.

The CNS is a piping system comprised of the following major components:

1. condenser,

2. three primary condensate pumps,

3. seven condensate demineralizers,

4. three secondary condensate pumps,

5. five low-pressure feedwater heater stages, and

6. piping and valves.

The RFW system consists of the following major components:

1. Three turbine-driven reactor feed pumps

2. High-pressure feedwater heater stage

3. Piping and valves

The CNS components and piping are non-safety related. The RFW system is non-safety related up to the outermost primary containment isolation valve, and it is safety-related from that valve to the reactor vessel.

Simplified diagrams of the Condensate and Feedwater Systems are presented in Figures 3.2-7a and 3.2-7b.

Flow Path

The condensed steam from the condenser is collected in three condensate hotwells which are interconnected to the suction piping of the three primary condensate pumps (AP102, BP102, and CP102). The discharge of the primary condensate pumps provides cooling for the steam jet air ejector (SJAE) and the steam packing exhauster (SPE) condensers before entering the condensate demineralizing system where it is filtered and purified. The secondary condensate pumps (AP137, BP137, and CP137) boost system pressure to maintain adequate RFP suction pressure. The discharge of the secondary condensate pumps is then directed through five stages of feedwater heating before being delivered to the feedwater pump suction header, at which point it is termed feedwater. The feedwater pumps (AP101, BP101, and CP101) discharge to a common header, and then the feedwater is heated in three parallel high-pressure feedwater heaters (6A, 6B, and 6C). The output from the heaters discharges into a common header which splits into two feedwater headers that penetrate the containment. The feedwater enters the reactor through six feedwater nozzles. The system flowrate is dependent on a demand signal from the reactor water level control system which controls the speed of the individual reactor feed pump turbines. Low pressure steam from main turbine moisture separator "B" or high pressure steam from main steam piping can supply steam to the reactor feedpump turbines (RFPTs) which is exhausted to the condenser hotwells.

There are bypass and/or minimum recirculation paths around each stage of the flow path. The primary condensate pumps are protected by a common minimum-flow recirculation line which is connected from the SJAE/SPE discharge header and directs flow back to the main condenser header. The secondary condensate pumps have individual minimum-flow recirculation lines which tap off the pump discharge and direct flow back to the main condenser. Bypass lines with remotely controlled valves are provided to bypass the secondary condensate pump, the feedwater heater stages 1 and 2, the feedwater heater stages 3, 4, and 5, the feedwater pump, and the stage 6 high-pressure heater to provide flexibility in providing feedwater to meet demand and the ability to isolate components for testing and maintenance.

Location

The condenser is located in the Turbine Building at Elevation 54'. The primary condensate pumps and the secondary condensate pumps are also located in the Turbine Building at Elevation 54'. All of the feedwater heaters are located in the Turbine Building; the first two stages are at Elevation 113', stages 3, 4, and 5 are located at Elevation 102', and stage 6 is located at Elevation 137'. The controls for the condensate and feedwater systems are grouped on main control room panel 10C651, sections A and B, and on panels 1AC102, 1BC102, and 1CC102 at Elevation 81' in the turbine building. The controls on panels 1AC102, 1BC102, and 1CC102 are for feedwater heater level controls and feedwater heater startup discharge bypass valves.

Component Descriptions

Main Condenser

The main condenser is divided into three sections. Each section is a single pressure, rectangular shell which receives steam via a rectangular extended neck on top of a tapered transition section. Each shell consists of two major subsections: the condensing and the hotwell sections. Each hotwell section is located below its associated condensing section. The hotwells are connected by piping and have a combined capacity of 430,560 gallons at normal operating level.

Primary Condensate Pumps

Three primary condensate pumps (AP102, BP102, and CP102), arranged in parallel, deliver hotwell condensate to the suction of the secondary condensate pumps. The pumps are motor-driven, vertical, two-stage, centrifugal pumps, each with 12,300 gpm capacity.

Secondary Condensate Pumps

Three secondary condensate pumps (AP137, BP137, and CP137) supply the required NPSH to the reactor feed pumps (RFPs) via the low-pressure feedwater heaters. The pumps are motor-driven, horizontal, single-stage, double-suction, centrifugal pumps arranged in parallel, each with a 11,400 gpm capacity. Each pump has a shaft-driven oil pump which supplies oil to pump and motor bearings and is cooled by TACS via an oil cooler. An auxiliary oil pump is provided to supply lube oil during startups and low oil pressure conditions.

Low-Pressure Feedwater Heaters

The low-pressure feedwater heaters consist of three parallel strings of shell and tube heat exchangers. Heating steam from the Extraction Steam System is directed to the shell side of the heaters. Condensate/feedwater flowing through the tube is heated before entering the reactor vessel. Each of the three heater strings is further broken down into two sections: Section 1 consists of feedwater heaters 1, 2, and drain cooler; and Section 2 consists of feedwater heaters 3, 4, and 5. A common header connects the outlets of all Section 1 heaters with the inlets of all Section 2 heaters. Each section is provided with individual motor-operated valves on the inlet and outlet piping for isolation as required. The effluent from the three strings discharges to the suction header for the reactor feed pumps. Bypass piping with motor-operated valves is provided to either bypass each of the sections of the low-pressure heaters or to bypass the feedwater pumps to supply low-pressure condensate flow to the reactor vessel.

Reactor Feed Pumps

Three 50% capacity Reactor Feed Pumps (RFPs) (AP101, BP101, and CP101) pump heated feedwater to the reactor vessel via the 6A(B, C) feedwater heaters. Full power operation is achievable with two RFPs. Each horizontal, single-stage, centrifugal, double-suction, skid-mounted pump is coupled to a steam turbine. Each RFP requires six gpm of pressurized ~~(15 to 20)~~ oil for bearing lubrication. The oil is provided from the RFP turbine oil system. Water is provided to each RFP shaft seal from the secondary condensate pump discharge header. The seal water flow is regulated by a temperature control valve.

The RFP flowrate is controlled by regulating the amount of steam admitted to the reactor feed pump turbine (RFPT). The low- and high-pressure steam inlet control valves are positioned by an electrohydraulic governor. Each RFPT has two AC-driven and one DC-driven vertically mounted, positive displacement oil pumps which provide pressurized oil to the governor and to the turbine and pump bearings. Each RFPT has dual oil coolers cooled by water supplied from the TACS. Each turbine has a motor-operated turning gear assembly which automatically disengages when the turbine rpm increases above 6 rpm.

High Pressure Feedwater Heaters

Three high pressure feedwater heaters (6A, 6B, and 6C) provide the final stage of heating for the pressurized feedwater before injection into the reactor vessel. Each is a 50% capacity shell and tube, horizontal, double-pass type heat exchanger. Each heater has motor operated valves (MOV) on the inlet and outlet piping for isolation. Each heater also has a small (3-inch) bypass line and associated MOV around the outlet valve. Extraction steam from the fourth stage of the high-pressure turbine is admitted to the shell side of the heaters where it is condensed as it supplies the heat for the feedwater.

3.2.1.7.3 System Interfaces

Shared Components

The RWCU system utilizes both the "A" and "B" feedwater penetration piping to return water to the reactor pressure vessel (RPV). The connection is in the steam tunnel before the point where the feedwater lines enter the containment.

The RCIC system utilizes the "B" feedwater line to inject water into the RPV. The connection is in the steam tunnel before the point where the "B" feedwater line enters the containment.

The HPCI system utilizes the "A" feedwater line to inject water into the RPV.

Electrical

The primary condensate pumps are supplied by the group buses (Non-Class 1E) as follows: AP102 from 7200 VAC bus 10A110, BP102 from 7200 VAC 10A120, and CP102 from 4160 VAC bus 10A102.

The secondary condensate pumps are also supplied by the group buses as follows: AP137 from 7200 VAC bus 10A110, BP137 from 7200 VAC 10A120, and CP137 from 4160 VAC bus 10A104.

The lube oil system for each RFPT includes two AC powered pumps (main and auxiliary) and one DC powered emergency oil pump. The main lube oil pumps (A1P124, B1P124, and C1P124) are powered by Non-Class 1E 480 VAC buses 10B313, 10B323, and 10B272 respectively. The auxiliary lube oil pumps (A2P124, B2P124, and C2P124) are powered by 10B272, 10B313, and 10B323 respectively. The emergency oil pumps (AP125, BP125, and CP125) are all powered from 250 VDC bus 10D170.

Non-Class 1E power (480 VAC and 120 VAC) supplies the CNS and RFW valves, support equipment, and instrumentation and controls.

Actuation

The CNS and RFW systems do not receive any automatic actuation signals. The systems must be placed in service by the operator.

Control

A signal from the Redundant Reactivity Control System (RRCS) will cause the RFPs to run back to the governor minimum speed to achieve a negative reactivity effect. Control is then returned to governor manual control after 30 seconds.

When the RFP is placed in automatic governor control mode, the turbine speed is controlled from the Reactor Level Control System.

Pneumatic

The feedwater heater level control valves, the start-up vent valves, secondary condensate pump min flow valves, RFP min flow valves, and startup level control valves that bypass the #6 feedwater heaters are air-operated globe valves actuated by instrument air from the Instrument Air System (IAS). The startup level control valves are required after a scram to prevent overfeeding.

Component Cooling

The primary condensate pumps do not require water cooling. The secondary condensate pumps have individual bearing oil coolers which are cooled by water from the TACS. The reactor feed pumps each have two lube oil coolers which are also cooled by water from the TACS.

Room Cooling

The stage three, four, and five feedwater heater rooms each have room cooling. There are area coolers associated with each of the primary and secondary condensate pumps and with the condenser mezzanine areas. The high pressure feedwater heater rooms and the RFPT areas are cooled by turbine building ventilation.

3.2.1.7.4 Instrumentation and Control

System Actuation

The CNS and RFW system must be placed in service by the operator as described in the operator actions subsection.

Control

The primary condensate pumps (AP102, BP102, and CP102) have start/stop pushbutton controls on panel 10C651 in the control room. Pump discharge MOVs, HV1680A, B, and C are MOVs which have auto-lockout modes which can be selected at panel 10C651 in the control room. In auto, the valve can either be opened manually via the pushbutton or in response to an open command from its corresponding pump. The associated pump must be stopped before the valve can be manually closed and switched to lockout. Concurrent with pump start, timers are activated and the discharge valve must reach full open within the preset time or a trip signal will be sent to the pump. Each of the primary pumps also has a pump suction isolation valve (HV-1639A, B, and C) with manual control and indication on panel 10C651 in the control room.

There is a common minimum recirculation MOV, HV-1710, for the primary CNS pumps that will open automatically when the flow drops below a predetermined flow rate with the proper number of pumps in service. The valve can also be controlled manually from control room panel 10C651.

Each of the SJAE and SPE condensers have inlet and outlet isolation MOVs which are manually operated from the control panel 10C651. There is an SJAE/SPE bypass valve, PDV-1719, which is a pneumatically controlled valve modulated by a differential pressure transmitter, which monitors the differential pressure across the inlet and outlet headers to maintain a differential pressure of 6 PSID.

The secondary condensate pumps (AP137, BP137, and CP137) have start and stop pushbuttons on panel 10C651 in the control room. Each pump has suction and discharge MOVs which can be operated from panel 10C651 in the control room. There is a secondary condensate pump bypass valve, HV-1654, which can also be manually controlled from the control room panel 10C651.

The feedwater heaters can be isolated to remove stages one and two, stages three, four, and five, and stage six by isolation MOVs controlled from the control room.

There are four modes of RFPT control. Positioner Control Mode is for full range control with no automatic adjustment or feedback. Governor Manual Control Mode maintains the RFPTs at a manually set speed. Governor Auto (Master) Control Mode responds to the reactor water level control system. Startup Control Mode throttles the startup level control valve to maintain a set level, and the feedpumps must also be in manual for operation in this mode.

The RFPs can be started from control room panel 10C651B. The indications and manual controls for the turbine and turbine lube oil systems are provided on local control panels 1AC-1CC132, and 133. The main lube oil pumps can be started from control room panel 10C651A. Once the RFP and turbine are hot and are operating at a turbine speed of 2500 rpm, the governor speed set can be switched to governor control mode where the speed can be controlled by either a manual or automatic signal from the reactor level control system.

A new digital feedwater level control system will be installed at a later date.

Each of the RFPs can be isolated by MOVs controlled from control room panel 10C651B. The RFPs, mounted in parallel, can be bypassed using MOV HV-1786, which can be manually operated from control room panel 10C651B.

Interlocks

Each of the primary condensate pumps has a start inhibit on a low-low level signal from the main condenser hotwell supplying the suction to the pump. If the hotwell low-low level is reached while a pump is operating, the pump will be tripped. Two out of three logic for low hotwell level will trip all primary condensate pumps.

Each of the primary and secondary condensate pumps and RFPs is inhibited from starting or will trip if one of the following conditions exist. For the primary CNS pump:

1. trip on low-low condenser level;

2. trip if associated suction valve is not 100% open;

3. will not start if discharge valve is not closed, and will trip if discharge valve fails to open after pump receives start signal (valve automatically opens);

4. trip if recirculation valve HV-1710 is not at least 30% open with one primary and zero secondary, or two primary and one secondary CNS pumps running;

5. recirculation valve will automatically open if one primary and no secondary, or two primary and one secondary CNS pump are running. If three primary and no secondary pumps are running, the alarm will sound;

6. the first pump will not start if SJAE/SPE bypass valve (remote-manual operation) is not 100% open.

For the secondary CNS pump:

1. will not start if associated discharge valve is not closed, if associated suction valve is not 100% open, or if two of three primary CNS pumps are not running;

2. trip if associated suction valve is not 100% open;

3. associated secondary pumps (A, B, or C) trip if five of six CNS pumps were running and two primary pumps stop;

4. trip on low lube oil pressure,

5. trip on low flow after 30-second time delay after pump start;

6. trip on low suction pressure;

For the RFPs:

1. trip on low condenser vacuum (two of three);

2. associated RFPs (A, B, or C) trip if five of six CNS pumps were running and two secondary pumps stop;

3. suction valve cannot be opened unless associated discharge stop check valve is closed, associated minimum-flow valve is open, and recirculation valve is closed;

4. trip on low-low lube oil pressure;

5. low pressure steam stop valve closes on associated RFPT trip (also high pressure stop valve);

6. minimum flow valve will not open unless an associated RFPT lube oil pump is running;

7. recirculation valve closes on associated RFPT trip;

8. all RFPs trip on high-high discharge pressure (two of three);

9. associated RFPs trip on low-low suction pressure (two of three);

10. all RFPs trip on high reactor water level at level eight;

11. all RFPs trip on high-high condenser pressure (two of three);

12. associated RFP trips on high exhaust pressure (two of three);

13. associated RFP trips on high exhaust temperature (two of three);

14. associated RFP trips if drain valve (HV-1765A, B, and C) or suction valve (HV-1781A, B, and C) are not 100% open;

15. associated RFPT trips on overspeed, loss of speed sensing signals, thrust bearing wear, or low flow and speed greater than 5400RPM for five seconds;

16. associated RFPT control valves close on low control oil pressure.

Other interlocks include:

1. main turbine bypass valve closes on low condenser vacuum (two of three);

2. main turbine trips on low condenser vacuum (one of three taken twice);

3. MSIV closure on low condenser vacuum (one of two taken twice);

4. FW heater strings 1 and 2 isolation valves close on heater shell high-high level (trip must be cleared and reset to reopen the valves);

5. Five out of six CNS/RFW pump logic:

   if five of six CNS pump had been running and:

   - one secondary CNS pump is left running, non-associated RFPs will trip,

   - one primary CNS pump is left running , non-associated RFPs will trip,

6. startup reactor level control valves fail closed on loss of air or power;

7. with two or more RFPs on line and feed flow greater than 85%, the trip of one of three secondary condensate pumps will cause a RFP runback to 80% and an intermediate recirculation pump runback;

8. with two or more RFPs on line and feed flow greater than 75%, the trip of one of three primary condensate pumps will cause a RFP runback to 70% and a full recirculation pump runback;

9. when a RFPT is in governor control, and an RRCS signal is received from the APRMs not being downscale, and reactor pressure is greater than 1071 psig after a 25-second time delay, the RFPTs will run back to governor minimum. Control is returned to governor manual after 30 seconds.

Instrumentation and Annunciators

Control room instrumentation that provides monitoring functions for safe operation of the CNS/RFW systems includes eight control room indicators for CNS, 11 annunciator lights and alarms for CNS, seven indicators for RFW, about 30 annuciator lights and alarms for RFW, and the CRIDS computer. Examples of CNS alarms include "Main condenser vacuum low," "Condensate pump vibration high," and "Condensate recirculation capacity exceeded." Examples of RFP alarms include "RFPT exhaust valve seal level low/high," "RFP turbine trip," and "RFPT turbine vibration high."

3.2.1.7.5 Operator Actions

After a transient in which CNS/RFW flow is lost, the operator will attempt to restore flow from this system to provide coolant makeup to the reactor. To restore flow (assuming component failure within the CNS/RFW system was not the cause of the lost flow) the operator must clear any trip conditions and reset the tripped components. The system components are then restarted as described in the following paragraphs.

The primary condensate pumps start against a closed discharge valve which begins to open automatically after the pump is started. The initial flowpath for the pumps is established before pump start by manually opening the SJAE/SPE bypass and the minimum recirculation valves. Two pumps may be started and operated in this system configuration.

The secondary condensate pumps start against closed discharge and minimum recirculation valves. The minimum recirculation flow is controlled by a flow element installed in the pump suction line and set at a predetermined setpoint. After system flow satisfies the minimum flow requirements, the recirculation valve is closed.

In starting the feedwater pump, the pump discharge valve is closed, and the turbine is manually accelerated to a predetermined speed. When the minimum recirculation pump flow setpoint is reached, the recirculation valve closes automatically. After warm-up has been completed, the turbines can be manually accelerated to an automatically controllable speed (approximately 2500RPM), and the control can be transferred to governor control which responds to demands from the Reactor Level Control System.

3.2.1.7.6 Technical Specifications Limitations

The CNS has no limitations defined by the Technical Specification. The RFW system is limited by Technical Specifications (TS) 3.3.9 and 4.3.9. The limiting condition for operation (TS 3.3.9) is summarized below.

Limiting Conditions for Operation

A minimum of three feedwater/main turbine trip system actuation instrumentation channels shall be operable. The trip setpoint for high reactor vessel water level, level 8, must be set at a trip point of 54 inches or less with the maximum allowable values less than or equal to 55.5 inches.

With only two channels operable, the inoperable channel must be restored within 7 days or the reactor placed into the startup mode within the next 6 hours. With only one channel available, at least one of the inoperable channels must be restored within 72 hours, or the reactor must be placed in the startup mode within the next 6 hours.

3.2.1.7.7 Testing

Tests are performed in conformance with the Technical Specifications.

3.2.1.7.8 System Operation

Normal Operation

During normal operation, the three primary condensate pumps take suction from the condenser hotwells through a common suction line and deliver condensate through the SJAE/SPE condensers and condensate demineralizers to the suction of the secondary condensate pumps. Minimum flow through the primary pumps during pump startup or shutdown is assured by the recirculation valve, HV-1710, which directs flow from the discharge header of the primary CNS pumps to the condenser hotwell. Condensate flow is balanced through the parallel array of SPE and SJAE condensers and regulated by the SPE/SJAE bypass valve, PDV-1719.

The three secondary pumps deliver effluent from the demineralizers through the low pressure heaters to the suction of the reactor feed pumps. Minimum flow through each of the secondary condensate pumps during pump startup or shutdown is assured by the recirculation lines on each pump discharge.

The condensate is progressively heated by extraction steam as it flows through three parallel trains of five low-pressure heaters. In each feedwater train, either heater stages 1 and 2 and the drain cooler, or heater stages 3, 4, and 5 may be isolated from the system. Upon removal of one of these heater trains, each of the remaining two parallel trains can operate continuously at flow up to 150% of their normal rating.

Steam to drive the RFPTs originates from two sources. With three RFPs operating and with the main turbine loads at approximately 40% or higher, low pressure steam from the cross-around piping downstream of the moisture separators drives the RFP turbines. With two RFPs operating at near rated conditions, the LP steam is sufficient to drive the RFP turbines without high pressure steam.

When reactor power is above 40%, the feedwater is heated through three parallel high pressure heaters before delivery to the reactor vessel. The RFP turbines are in the governor control mode, and they are controlled automatically from the Reactor Level Control System which regulates the turbine speed. When the power level is less than 40%, the number six feedwater heaters are not in service, and the feedwater flow to the reactor is controlled by two reactor level control valves (split-range) that are installed in parallel to regulate flow. These valves are modulated by the Reactor Level Control System, and the RFPs are controlled by manual speed settings to the turbines which are in the positioner control mode until transfer to automatic turbine speed control is possible.

Abnormal Operation

Following reactor trip, the CNS and RFW systems may be used to maintain the reactor vessel water level. When the reactor vessel pressure is below 720PSIG, the condensate pumps can be used to pump condensate through the bypass piping (around the feedwater heaters and the feedwater pump) to the reactor vessel.

According to the EOPs, when the reactor pressure is above 720PSIG, the feedwater pumps will be controlled manually. The feedwater can be pumped through or around the high-pressure feedwater heaters to the reactor vessel. The normal pressure for water delivery to the reactor vessel is about 550 psig for the secondary condensate pumps.

The CNS and the RFW system will not operate without offsite power.

3.2.1.7.9 System Fault Tree

3.2.1.7.9.1 Description

Simplified diagrams indicating those components modeled in the fault tree are shown in Figures 3.2-7a and 3.2-7b. The fault tree top events represent no CNS/RFW flow to the RPV.

3.2.1.7.9.2 Success and Failure Criteria

The CNS/RFW operation is considered successful in the fault tree if the system can supply enough flow to adequately maintain the reactor vessel water level. Failure to supply sufficient flow for level control occurs if:

1. all RFPs fail to provide sufficient flow to maintain reactor vessel level when reactor pressure is greater than 720PSIG;

2. all primary and secondary CNS pumps fail to provide sufficient flow to maintain RPV level when reactor pressure is less than 720PSIG;

3. all the flowpaths are interrupted to prevent flow from reaching the reactor vessel;

4. offsite power is unavailable;

5. loss of hotwell and CST inventory;

6. instrument air is unavailable;

7. loss of the SACS or station service water prevents use of the feedwater pumps or secondary condensate pumps for reactor vessel injection;

8. loss of the condenser vacuum, or closure of the MSIVs prevents use of the feedwater pumps for reactor vessel injection. Since the loss of the PCIGS causes the closure of the MSIVs, it is modeled in the RFW fault tree.

3.2.1.7.9.3 Assumptions

Model-Related

1. The system is assumed to have been running properly before the transient.

2. All the piping for testing, venting, and/or flushing the CNS and RFW systems have double manually operated isolation valves. Restoration errors of these valves were excluded on probabilistic ground; at least two valves must be mispositioned to cause a failure.

3. If pump discharge check valves fail to close, flow diversion could exist by backflow through the idle pumps. However, reverse rotation of a secondary condensate pump is sensed by a $\geq$ 35 psig pressure in the oil pump suction line, which is indicated in the control room.

Quantification-Related

There are no quantification related assumptions.

3.2.1.7.10 References

1. Hope Creek Generating Station UFSAR Sections 5.4.9.3.2, 7.6.1.7, 7.7.1.3, and 10.4.7.

2. "Hope Creek Generating Station Licensed Operator Systems," Lesson Plan Number 302HC-000.00-052-13 and 302HC-000.00-058-07. Public Service Electric and Gas Company, Hancocks Bridge, NJ, January 18, 1993 and August 26, 1991.

3. "Hope Creek Generating Station Technical Specifications 3/4.3.9." Public Service Electric and Gas Company, Hancocks Bridge, NJ, July 1986.

4. Public Service Electric and Gas Company Operating Procedures
   HC.OP-SO.AD-001
   HC.OP-SO.AE-001
   HC.OP-EO.ZZ-004

5. Public Service Electric and Gas Drawings
   M-02-1
   M-03-1
   M-04-1
   M-05-1
   M-06-1
   M-08-1
   M-16-1
   M-19-1
   M-29-1
   M-31-1
   M-41-1
   J-03-0
   J-04-0
   J-05-0
   J-06-0
   J-16-0
   J-19-0
   J-31-0
   J-41-0
   J-0651-1
   J-0650-1
   791E405AC

3.2.1.8 Containment Atmosphere Control (CAC) System

The Containment Atmosphere Control System (CACS) is composed of the Hydrogen-Oxygen Analyzer System (HOAS), the Containment Hydrogen Recombiner System (CHRS), the Vacuum Relief Valve System (VRVS), the Containment Inerting and Purging System (CIPS) and the 12" Hard Pipe Containment Venting System (HPCVS), which can be considered a sub-system of the CIPS. The design features of the CACS include the capability for controlled venting of the primary containment. This is achieved mainly through various CIPS and HPCVS valves, which are the portion of CAC system of interest for the HCGS PRA.

3.2.1.8.1 System Function

The Containment Atmosphere Control (CAC) System, in particular the CIPS, will permit a controlled venting of the primary containment atmosphere at very low containment pressures. The Filtration, Recirculation, and Ventilation System (FRVS) removes radioactive contaminants from the vented gas prior to release to the environment.

The CIPS can also be used for venting the containment at moderate to high containment pressures. However, in this mode the release from the containment will not be treated by the FRVS if either of the hard pipe vent pathways, the 12" HPCVS or the 6" Integrated Leak Rate Testing (ILRT) lines, are used.

Other functions of the CACS and CIPS are not applicable to this analysis of containment venting capability.

3.2.1.8.2 System Description

General Design

Venting using the CIPS requires some operator actions locally, as well as from the control room, depending on the vent path used. There are 15 valves within the CIPS/HPCVS portion of the CACS that may be used in various combinations for containment wetwell and drywell venting, as shown in Figure 3.2-8. Twelve of these valves are instrument air operated valves that can be controlled from the control room. The other three (GSV058, GSV067 and GPV0129) are manual valves that must be aligned locally; however, GSV067 is a normally open valve and does not need to be aligned. Furthermore, there are a total of three flanges, one spectacle and two blind ones, that need to be rotated or removed, and a piece of pipe needs to be aligned, before the 6" hard pipe line can be used for venting. The 12" HPCVS also has a spectacle flange that is normally open.

All the air operated valves in the CIPS are powered from 120VAC Class 1E uninterruptible power supplies. Furthermore, the valves in the 12" HPCVS path can be operated from a manual control station on the 102-foot elevation of the reactor building. This enables operators to open and close the valves using hydraulic hand pumps without any dependency on air or power. As of April 1994 (the fifth HCGS refueling outage), the remainder of the valves (for the six-inch vent paths) can also be operated from a remote manual control station. This allows manual operations without exposure to harsh environments.

Flow Path

Depending on suppression pool and containment water levels, there are nine basic flow paths for venting the containment. Illustrated in Figure 3.2-8, these containment vent paths in the order of preference are:

1. 12" HPCVS;
2. 6" ILRT Hard Pipe Suppression Chamber Supply;
3. 6" ILRT Hard Pipe Drywell Supply;
4. Suppression Chamber 2" Duct Pipe Exhaust;
5. Drywell 2" Duct Pipe Exhaust;
6. Suppression Chamber 24" Duct Pipe Exhaust;
7. Suppression Chamber 24" Duct Pipe Supply;
8. Drywell 26" Duct Pipe Supply;
9. Drywell 26" Duct Pipe Exhaust

All the duct pipe vent paths are treated by FRVS and monitored prior to release to the environment. Furthermore, the EOPs provide procedures for using them. However, the soft pipes are not modeled in the HCGS PRA, due to the fact that they will fail under pressure. Upon failure, any released fission products could impact operators or systems that are needed to prevent core damage.

Location

All valves used for containment venting are located on lines from the containment drywell or suppression chamber. The release elevation point of the 6" hard pipe is about 8' above the ground, while the release point of the 12" HPCVS is at 250' Elevation; about 150' above the ground level. The local station for manual operation of the 12" HPCVS valves, the rupture disk, radiation monitoring device and a spectacle flange are all located at the 102' Elevation, in the Reactor building. Also, two of the flanges (one blind and one spectacle) and valve GS-V058 for the 6" Hard Pipes are located at this elevation. Valve GP-V129 is located outside the reactor building.

Component Descriptions

12 Inch HPCVS Isolation Valve

The 12" HPCVS has a Rupture Disk and a 12" normally closed/fail closed air-operated valve (1GSHV-11541), which is backed by two redundant loops of nitrogen gas bottles and its solenoid is powered from a 120VAC Class 1E uninterruptible power supply. This valve has a manual control station inside the reactor building, at 102' elevation, which allows for operators to open the valve locally independent of air or power.

12 Inch Rupture Disk

The 12" rupture disk is placed in line downstream of the 1GSHV-11541, to prevent any leakage from the 12" HPCVS line, prior to 35 PSIG. However, operators can either manually remove this disk or rupture it by connecting service air or compressed air bottles to a 1" line between the rupture disk and 1GSHV-11541, should there be a need to vent the containment prior to 35 PSIG.

Containment to Containment Purge Cleanup System Valves

The inboard and outboard valves from the drywell (1GSHV-4952 and 1GSHV-4950) and suppression chamber (1GSHV-4964 and 1GSHV-4962) to the CPCS are normally closed, air-operated valves that fail closed on loss of air or solenoid power. Similar to 1GSHV-11541, the HV-4964 is also backed by nitrogen gas bottles. Like the rest of the CIPS air operated valves, the electric supply to these valves is from a 120 VAC Class 1E uninterruptible power supply. Valves 1GSHV-4964 and 1GSHV-4962 have a manual control station at the 102' elevation in the Reactor building, which allows the operator to open them independent of either air or power.

CPCS Return to Containment Valves

The return valves from the CPCS to the drywell (1GSHV-4956 and 1GSHV-4979) and suppression chamber (1GSHV-4958 and 1GSHV-4980) are normally closed, air-operated valves that fail closed on loss of air or solenoid power. As of April 1994, these valves have a manual control station outside the torus room, on the 102' elevation of the reactor building, which allows operators to open them without any dependency on either air or power.

Nitrogen Makeup/Exhaust Valves

The drywell (1GSHV-4951) and suppression chamber (1GSHV-4963) nitrogen exhaust valves are normally closed, air-operated valves that fail closed on loss of air or solenoid power. These valves are in parallel with 1GSHV-4950 and 1GSHV-4962, respectively.

Nitrogen Supply Header Valves

The nitrogen supply header isolation valve (1GSHV-4978) is a normally closed, air-operated valve that fails closed on loss of air or solenoid power. As of April 1994, this valve has a manual control station outside the torus room, on the 102' elevation of the Reactor Building, which allows the operators to open it without any dependency on either air or power. The nitrogen supply header compressed air supply valve (GS-V058) is a normally closed manual valve.

ILRT Sensing Line Isolation Valve

The primary containment Integrated leak rate testing (ILRT) sensing line isolation valve (GP-V129) is a normally closed manual valve with a spectacle flange upstream and a blind flange downstream.

Drywell Purge/Vent Exhaust Damper

The drywell purge/vent exhaust damper (1GTHD-9372A) is a normally closed, air-operated damper. This damper directs vented air from the drywell to the RBVS exhaust system.

Actuation and Control

The CACS has no automatic actuations for containment venting associated with it. The valves in the desired vent paths must be opened and closed manually (remote or local) in order to reduce and control containment pressure. However, the VRVS portion of CACS has two vacuum breakers which automatically open to ensure the 3 PSIG external design pressure of the primary containment will not be exceeded.

3.2.1.8.3 System Interfaces

Shared Components

The valves used for containment venting are shared among the CIPS portion of the CACS, the FRVS and CPCS portions of the reactor building heating, ventilating and air conditioning (RB HVAC) system, the primary containment integrated leak rate testing system, and the primary containment isolation system.

Electrical

Air-operated valves 1GSHV-4952, 1GSHV-4956, 1GSHV-4958, and 1GSHV-4964 receive solenoid power from 120 VAC Distribution Panel 1AJ481 via Fuse Panel 1YF401. Air-operated valves 1GSHV-4950, 1GSHV-4951, 1GSHV-4962, 1GSHV-4963, 1GSHV-4978, 1GSHV-4980 and 1GSHV-11541 receive solenoid power from 120 Vac Distribution Panel 1DJ481 via Fuse Panel 1YF404. 1AJ481 and 1DJ481 are powered from 120 VAC Class 1E uninterruptible power supplies.

Actuation

The VRVS portion of CACS responds to two pressure switches 1GSPDS-5029 and 1GSPDS-5031. These switches will actuate at a low pressure of 4.99" WC and automatically open the vacuum relief valves 1GSHV-5029 and 1GSHV-5031. However, these valves are not modeled in the containment venting.

Control

The CACS does not receive any automatic control signals for reducing and maintaining containment pressure via containment venting. However, the VRVS portion of CACS does respond automatically to pressure switches 1GSPDS-5029 and 1GSPDS-5031 to assure that the primary containment pressure is always greater than the secondary containment pressure.

Pneumatic

The Instrument Air System (IAS) supplies air to the air-operated CACS valves. However, valves 1GSHV-4964 and 1GSHV-11541 are backed by Nitrogen gas bottles, as well.

Manual/Local Station

As of April 1994, valves 1GSHV-4964, 1GSHV-4962, 1GSHV-11541, 1GSHV-4956, 1GSHV-4958, 1GSHV-4978, 1GSHV-4979, 1GSHV-4980 are all equipped with a manual control station in the reactor building (outside the torus room), which allows operators to locally operate these valves, independent of pneumatic or power supply.

Component Cooling

The CACS does not require component cooling for containment venting.

Room Cooling

The CACS does not require room cooling for containment venting.

3.2.1.8.4 Instrumentation and Control

System Actuation

Alignment of the CACS for containment venting must be performed by the operator, as described in the "Operator Actions" subsection.

Control

Control of containment pressure by means of venting through the CACS is done manually.

Interlocks

Most CACS valves are also part of the primary containment isolation system. In order to open these valves for venting, any primary containment isolation signal must be overridden. Isolation override push buttons are located on control panel 10C650 near the valve open and close push buttons.

Instrumentation and Annunciators

Control room status lights are provided for the CACS valves, which can be overridden and reopened with an isolation signal present. Specific valves are assigned to "isolation override" switches. If a switch is depressed with an isolation signal present, an "overridden" status light will be lit.

Control room indications are provided for drywell pressure (-5 to +5 psig) and suppression chamber pressure (-5 to +5 psig).

Control room alarms are provided for high (1.5 psig) low (0.1 psig) drywell pressure and for high-high (1.68 psig) drywell pressure.

The 12" HPCVS has a radiation monitoring device at the 102' Elevation which provides indication and alarms in the control room.

System Isolation

The CACS valves 1GSHV-4950, 1GSHV-4951, 1GSHV-4952, 1GSHV-4956, 1GSHV-4958, 1GSHV-4962, 1GSHV-4963, 1GSHV-4964, 1GSHV-4978, 1GSHV-4979, and 1GSHV-4980 automatically isolate the primary containment upon receipt of one of the following signals:

1. High drywell pressure (1.68 psig);

2. Low reactor water level (-38 inches); or

3. RB high-high radiation (1.0E-3 uCi/cc).

To vent the containment the isolation signals must be manually overridden.

3.2.1.8.5 Operator Actions

The operator is required to manually align the CACS for containment venting. The vent paths chosen are based on the containment and torus water levels, and they are prioritized for controlled venting and maximum scrubbing of the vented gas. For torus level less than 180", the preferred venting is via the 12" HPVCS, as follows:

1. In the lower relay room, located outside reactor building in the Auxiliary Building - control area at Elevation 102', at panel 1YF404, clear red tag and install fuse (6 amp fuse). This allows air to enter the solenoid on the actuator for valve 1GSHV-11541.

2. Depress the isolation override and open 1GSHV-4964; suppression chamber to CPCS damper (This can be accomplished from the control room.).

3. Once 1GSHV-4964 is full open, then open 1GSHV-11541; torus vent isolation valve.

4. Repeat the above steps as necessary to reduce and maintain drywell pressure below PCPL (65 PSIG).

For a suppression pool level less than 180 inches, provided that the 12" HPVCS has been unsuccessful, the following steps are performed (from panel 10C650 unless otherwise noted). When using the 6" hard pipe ILRT line:

1. Rotate the spectacle flange, and remove the flanges downstream of valve GS-V058 (RB elevation 102') and downstream of GP-V129 (outside the building).

2. Open GP-V129 then GS-V058 (RB elevation 102');

3. Depress the isolation override PBs for 1GSHV-4958 and 1GSHV-4978;

4. Open 1GSHV-4958 then 1GSHV-4978;

5. Close valves and repeat the above steps as necessary to maintain drywell pressure below 65 PSIG.

In case vent paths 1 and 2 have failed or if suppression pool level is greater than 180", the following steps are performed:

1. Rotate the spectacle flange, and remove the flanges downstream of valve GS-V058 (RB elevation 102') and downstream of GP-V129;

2. Open GP-V129 then GS-V058;

3. Depress the isolation override PBs for 1GSHV-4978 and 1GSHV-4956;

4. Open 1GSHV-4978 then 1GSHV-4956;

5. Close valves and repeat steps 1 through 4 as necessary.

For a containment level greater than 50 feet but less than 93 feet, the following steps are performed via the vent paths 5 and 9.

1. Depress the isolation override PBs for the suppression chamber and drywell exhaust inboard and outboard isolation valves;

2. Open HD-9372A;

3. Open 1GSHV-4951 then 1GSHV-4952;

4. Close valves and repeat steps 1 through 3 as necessary to maintain drywell pressure below 65 psig, or if pressure is not reduced, continue;

5. Open 1GSHV-4950; and

6. Close valves and repeat steps 1 through 5 as necessary.

As was mentioned before, no credit is given to the soft pipes for venting. It should be mentioned that because of the structure of the EOPs it is highly unlikely that torus level could exceed 180" or that containment level could exceed 50', prior to a need for depressurization using the hard pipe vents. The only time the containment level could exceed 50' is when the level in the reactor can not be maintained.

3.2.1.8.6 Technical Specifications Limitations

Technical Specifications 3.6.1.6, 3.6.1.8 (Limiting Condition for Operation), 4.6.1.6, and 4.6.1.8 (Surveillance Requirements) apply to the containment pressure and CAC system during operating modes 1 and 2, as described below.

Limiting Condition for Operation

The drywell and suppression chamber internal pressure must be maintained between -0.5 and +1.5 psig. If these limits are exceeded, the pressure must be restored to within the limit within 1 hour or the reactor placed in hot shutdown within the next 12 hours and cold shutdown within the following 24 hours.

The drywell and suppression chamber purge system may be in operation for up to 120 hours each 365 days with the isolation valves in one supply line and one exhaust line open for prepurge cleanup, inerting, de-inerting, or pressure control. If the 2-inch bypass lines are used for pressure control, these valves are not subject to the 120 hours per 365 days limit.

Surveillance Requirements

The drywell and suppression chamber pressure must be determined to be within limits at least once per 12 hours. Before being opened, the drywell and suppression chamber purge supply and exhaust butterfly isolation valves must be verified not to have been open for more than 120 hours in the previous 365 days. This does not apply to the 2-inch bypass line valves for containment pressure control.

At least once per 18 months, the 26-inch drywell purge supply and exhaust isolation valves, the 24-inch suppression chamber purge supply and exhaust isolation valves, and the 6-inch nitrogen supply valve must be demonstrated operable by verifying that the leakage rate is within limits.

3.2.1.8.7 Test and Maintenance

The CAC system is tested according to the surveillance requirements outlined in the Technical Specifications. This includes in-service testing of the CAC system valves.

No major maintenance is performed on the CACS valves during power operation.

3.2.1.8.8 System Operation

Normal Operation

During normal plant operation, the CACS is used to control the containment pressure and to maintain the oxygen concentration within specified limits by supplying nitrogen gas and/or releasing gases from the primary containment in a controlled manner.

The CACS is used prior to power operation to introduce nitrogen gas into the primary containment at a high flow rate to displace the air originally in the containment. This is to reduce the oxygen concentration in the containment atmosphere.

The CAC system is also used with the RBVS to provide a filtered, outdoor air purge flow to the containment to provide a safe atmosphere for entry following cold shutdown of the reactor.

Abnormal Operation

Following a LOCA, the CACS is used to monitor and alarm high hydrogen or oxygen concentrations in the containment and to recombine hydrogen and oxygen with sufficient capacity to prevent the accumulation of combustible concentrations.

The CACS is also designed to permit a controlled venting of the containment atmosphere to control the pressure following a LOCA. The FRVS is used to remove radioactive contaminants from the vented gas; however, FRVS does not treat the gases released to environment through the hard pipe vents. The containment venting is performed by remote manual control, as specified in procedure OP-EO.ZZ-318 and outlined in the operator actions subsection of this description. Finally, the CACS will automatically isolate all lines that penetrate the primary containment during accident conditions. The isolation valves may be remote-manually reopened by first depressing isolation override push buttons.

3.2.1.8.9 System Fault Tree

3.2.1.8.9.1 Description

Figure 3.2-8 is a simplified diagram showing the CACS valves modeled in the containment venting fault trees. The top event for the Vent fault tree is "CONTVENT: Containment Venting Fails, When Needed."

3.2.1.8.9.2 Success and Failure Criteria

The success criteria for the containment venting fault tree is the successful venting of the containment through one or more of the three hard pipe flow paths to the environment. Therefore, venting through the soft pipes are considered to be a failure, since steam or fission products released in the containment could affect personnel (operations, mainly) or the required systems.

Factors affecting containment venting are:

1. No clear indications of the containment conditions; i,e instruments malfunction.

2. Operators and the Technical Support Center (TSC) undecided whether they should take a wait-and-see attitude. This becomes a concern if the 6" vent is being used.

3. Failure of components, such as valves, rupture disks, air or power systems.

4. Failure of operator to manually and locally align the vent paths; this becomes of concern during usage of 6" vent lines.

3.2.1.8.9.3 Assumptions

Model-Related

1. It was assumed that flow through one of the three hard piped flow paths was sufficient to reduce containment pressure.

2. The fault tree attempts to model the specific order in which the flow paths are prioritized by modeling concerns (such as radiation exposure) about the alternate flow paths as basic events in the fault tree.

3. Test and maintenance were not modeled for the valves. This is because no major maintenance can be performed on the containment isolation valves during power operation, and testing will not affect the function of the valves. Besides, the Technical Specifications do not require any testing of these valves during power operation.

4. It was assumed that a containment isolation signal had occurred, and, thus, the valves used for containment venting were all initially closed.

5. The FRVS was not included in the containment venting fault trees, since the vent paths considered are not treated by it.

6. Based on detailed analysis (Reference 6), it was assumed that it takes at least 18 hours for containment pressure to reach 65 psig. Hence, many proceduralized activities were considered not to be important contributors to the systems's function failure.

Quantification-Related

1. A mission time of 24 hours was used to quantify the containment venting fault trees.

2. The same basic events values were used for all initiating events, based on the most conservative assumptions. For example, venting in a LOCA scenario may be necessary within 18 hours; however, for normal transients venting will not be required untill 28 hours. Therefore, conservatively it was assumed that venting will be needed within 18 hours, regardless of the initiating event.

3.2.1.8.10 References

1. Hope Creek Generating Station UFSAR Sections 1.14.1.71, 6.2.4, 6.2.5, 7.3.1, 9.4.2.

2. "HCGS Licensed Operator Systems," Lesson Plan Number 302HC-000.00-032-11 and 302H-000.00H-042-08. PSE&G Company, April 27, 1993 and March 16, 1993.

3. "HCGS Technical Specifications, Sections 3/4.1.6, 3/4.1.8

4. Operating Procedures — HC.OP-EO.ZZ-318(Q)
HC.OP-SO.GS-0001(Q)

5. PSE&G Drawings — 10855-M-57-1
10855-M-60-1
10855-M-76-1
10855-E-0298-0
10855-E-0300-0
10855-J-57-0

6. PSE&G, HCGS Engineering Evaluation No. H-1-GS-MEE-0473 "Containment Hard Vent Study for the MARK I Containment of the HCGS", Rev. 0, 9/15/93.

3.2.1.9 Standby Liquid Control System

3.2.1.9.1 System Function

The Standby Liquid Control System (SLC) is an independent backup system for the control rod drive system. The SLC system is capable of bringing the reactor from full power to a cold shutdown condition, and of maintaining subcriticality until cold shutdown is achieved. In the event of an ATWS, injection of the sodium pentaborate solution can be initiated manually by the operator or automatically by the Redundant Reactivity Control System (RRCS).

3.2.1.9.2 System Description

General Design

The SLC system is a safety-related, open-loop system which provides for the preparation, storage, and injection of sodium pentaborate solution into the reactor as necessary to provide reactor shutdown without control rod movement. This system is a redundant, independent, backup system for the control rod drive system. The SLC system consists of the following major components:

1. Storage tank and neutron absorber solution,

2. Two positive displacement pumps,

3. Two explosive injection valves, and

4. Associated valves and piping.

A simplified diagram of the SLC system is presented in Figure 3.2-9.

Flow Path

The sodium pentaborate solution is prepared and stored in storage tank 0T204 which is equipped with a heater system designed to maintain the solution above its crystallization temperature. There are separate heat traced lines from the storage tank to the suction side of each of the positive displacement pumps, AP208 and BP208. When the SLC system is automatically actuated, both SLC pumps start, and their associated explosive valves (BHXV-F004A and BHXV-F004B) fire. The two downstream motor-driven block check valves (HV-F006A and HV-F006B) motor-operators are normally in the open position allowing a flowpath from the storage tank to the "A" core spray sparger in the reactor vessel to be established. The RWCU system is isolated from the RCS piping by closing two motor-driven isolation valves (BGHV-F001 and BGHV-F004) when the SLC pumps are started. This prevents the loss of the borate solution.

Component Description

SLC Storage Tank

The SLC storage tank is a stainless steel cylindrical vessel with a usable capacity of 5150 gallons. The tank is provided with an overflow line, a removable hatch, an access ladder, and electrical heaters. Piping connections are provided to the demineralized water and compressed air systems. Compressed air can be introduced through the sparger to aid mixing as needed.

Demineralized water is added as required to compensate for solution evaporation losses. Two electric heaters, in the lower portion of the tank, maintain the tank contents above the sodium pentaborate saturation temperature.

SLC Pumps

The two 50% capacity positive displacement SLC pumps (AP208 and BP208) inject the entire sodium pentaborate solution into the reactor vessel to effect a chemical shutdown of the reactor. Each pump has a design flow of 43 gpm and is driven by a 40 hp 460 VAC motor. Each pump has a relief valve set at the pump design pressure of 1400 psig, which discharges back to the pump suction line. The electrical power to each of the pump motors is provided from a separate vital bus.

SLC Explosive-Actuated Injection Valves

The two SLC explosive actuated injection valves, BHXV-F004A and BHXV-F004B, provide a reliable and positive barrier preventing sodium pentaborate from entering the reactor vessel or interconnecting piping. The valves are arranged in parallel, with each capable of passing full system flow when actuated. Each valve is closed by a plug in the inlet chamber. The plug is circumscribed with a deep groove so that the end can be sheared off by a plunger actuated by an explosive charge. Dual firing primers are installed in each explosive cartridge for redundancy. The explosive cartridges are each fired by a 2 ampere current which is initiated from the corresponding SLC pump control circuitry. Circuit continuity is monitored by a trickle current.

SLC Isolation Valves

Containment isolation for the SLC discharge line is provided by an inboard check valve, BHV-029, and by two parallel isolation check valves. The two motor-operated stop check globe valves, BHHV-F006A and BHHV-F006B, are located outside containment and are operated from the control room. Operation of the motor operator only inserts or withdraws the valve stem; the actual valve position depends on the presence and direction of flow through the system.

3.2.1.9.3 System Interfaces

Shared Components

The SLC system utilizes a portion of the core spray system piping and the core spray sparger through which the SLC borate solution is injected. There are no valves in the shared portion of piping which could be misaligned to affect the operation of the SLC system. Upon a SLC pump start, the RWCU suction isolation valves receive a signal to close.

Electrical

The buses powering the SLC pumps AP208 and BP208 are the 480 VAC vital MCCs 10B212 and 10B222, respectively. The electrical impulses to fire the explosive valves originate in the pump control panel. Therefore, explosive valve F004A is powered from 10B212, and explosive valve F004B is powered from 10B222. Motor-operated stop check valves BHHV-F006A and BHHV-F006B are powered from MCCs 10B212 and 10B242, respectively.

Actuation

Both SLC pumps will start in response to an initiation signal from either RRCS division. Each SLC pump may also be started manually from control room panel 10C651.

Control

SLC control circuitry, via the Nuclear Steam Supply Shutoff System (NSSSS), initiates a closure of the RWCU suction isolation valves upon a SLC pump start. The RRCS provides a redundant isolation signal to these valves. There are four differential pressure type level instruments which provide interlocks in the pump logic to prevent the pumps from starting, or to trip already running pumps, when there is a low level in the storage tank.

Component Cooling

The SLC system does not require component cooling.

Room Cooling

Since the SLC pumps are relatively small pumps, and since there are no other heat sources which would cause an overheating of the room were ventilation to be lost, no room cooling dependencies were modeled for the SLC system.

3.2.1.9.4 Instrumentation and Control

System Actuation

Operation of the SLC pumps can be initiated from a panel in the control room or via manual/auto initiation of the RRCS. The SLC pumps can also be started locally for pump in-service testing. When a SLC pump is started for situations other than in-service testing, its explosive-actuated injection (squib) valve fires and the associated RWCU isolation valve closes. Both pumps are automatically actuated by a signal from either of the two channels of the RRCS.

Control

During operation of the SLC system, essentially no control is necessary. All necessary valves are fully opened and the pumps operate at maximum capacity. The pumps are stopped by a low SLC tank level signal from redundant SLC tank level transmitters.

Interlocks

The SLC storage tank has four liquid level transmitters. The output from two of the transmitters is connected to each of the SLC pump control logics. Each of the SLC pumps will automatically stop (or will be prevented from starting) upon a logic condition of two out of two low level signals from the redundant SLC tank liquid level instruments.

Concurrent with a SLC pump start, the following operations will occur:

1. AP208 start will fire explosive valve BHXV-F004A and close RWCU isolation valve BGHV-F001, and

2. BP208 start will fire explosive valve BHXV-F004B and close RWCU isolation valve BGHV-F004.

Instrumentation and Annunciators

Control room monitoring of the SLC system provides for the safe operation of the equipment. Examples of control room alarms for the SLC system include "SLC tank low level pump trip," "SLC squib valve loss of continuity," and "SLC injection valve stem not fully open."

System Isolation

There are no signals which automatically isolate the SLC system. The SLC pumps are automatically stopped on low tank level as described in the interlocks subsection. The motor-operated stop check valves are then closed manually by the operator after the boron has been injected.

3.2.1.9.5 Operator Actions

Normal operator actions are performed in accordance with SLC System Operating Procedure, OP-SO.BH-0001. Under operating conditions in which the reactor is producing power and containment integrity is being challenged, SLC is manually or automatically initiated in accordance with Emergency Operating Procedure HC.OP-EO-ZZ-0101.

Manual initiation of SLC is performed in the control room via either the SLC bezel or the RRCS bezel. When using the SLC bezel, the operator starts the SLC pumps one at a time. When manually initiated via the RRCS bezel, both pumps are started simultaneously, assuming certain conditions are met after a 3.9 minute time delay. When a pump is started, its squib valve fires, and the associated RWCU isolation valve closes.

If the RRCS system sends an automatic start signal to both of the SLC injection pumps, and the pumps do not start, a "RRCS INITIATION FAILURE" flashes at the SLC control panel. The operator must then manually start both pumps.

When the SLC injection pumps stop due to the receipt of a low level signal from the storage tank level instrumentation, the operator closes the motor-driven block check valves, F006A and F006B, to isolate the SLC system from containment.

3.2.1.9.6 Technical Specification Limitations

Technical Specifications (TS) applying to the breakers on the SLC power lines are covered in TS 3.8.4.1, Primary Containment Penetration Overcurrent Protective Devices.

Technical Specifications 3.1.5 and 3.6.3 (Limiting Condition for Operation) and 4.1.5 and 4.6.3 (Surveillance Requirements) apply to the SLC system. The applicable portions of TS 3.1.5 and 3.6.3 are summarized below:

1. TS 3.1.5 requires the two redundant trains of SLC be operable during modes 1 and 2. If the minimum requirements or TS 3.1.5 are not met, the following actions apply:

   - With one SLC system train inoperable, the train must be restored to operable status within 7 days or be in at least hot shutdown within the next 12 hours.

   - With both SLC system trains inoperable, at least one train must be restored to operable status within 8 hours or be in at least hot shutdown within the next 12 hours.

2. TS 3.6.3 requires the primary containment isolation valves specified in TS Table 3.6.3-1 be operable with isolation times less than or equal to the times shown in Table 3.6.3-1. (The valves of interest for the SLC system are BHHV-F006A, BHHV-F006B, BGHV-F001, BGHV-F004 and BHV-029). If the minimum requirement of TS 3.6.3 are not met, the following actions apply:

   - With one or more of the primary containment isolation valves inoperable, at least one isolation valve must be operable in each affected penetration that is open; within 4 hours either:

     a. restore the inoperable valve(s) to operable status, or

b. isolate each affected penetration by use of at least one deactivated automatic valve secured in the isolated position, or

c. isolate each affected penetration by use of at least one closed manual valve or blind flange.

Otherwise be in at least hot shutdown within the next 12 hours and in cold shutdown within the following 24 hours.

3.2.1.9.7 Testing

Tests of the SLC system are summarized in Technical Specifications Sections 4.1.5 and 4.6.3.

3.2.1.9.8 System Operation

Normal Operation

The SLC system is in standby during normal plant operation.

Abnormal Operation

The SLC system maintains a soluble boron concentration adequate to bring the reactor to cold shutdown upon injection into the reactor vessel. The RRCS system monitors reactor pressure, vessel level and the six average power monitors (APRMs). Upon detection of a high reactor pressure, the RRCS system logic initiates several actions to mitigate the ATWS event including:

1. Alternate rod insertion,

2. Recirculation pump trip,

3. Feedwater runback, and

4. Initiation of the SLC system.

The action in the logic to initiate the SLC system is based on a time delay. If the associated APRM is still not downscale after 230 seconds, the RRCS logic sends a signal to both SLC pumps to start automatically to inject the boron into the reactor vessel.

3.2.1.9.9 System Fault Tree

3.2.1.9.9.1 Description

A simplified diagram which shows those components modeled in the SLC fault tree is shown in Figure 3.2-9. The top event for the SLC fault tree is failure to inject sufficient boron into the reactor pressure vessel (RPV).

3.2.1.9.9.2 Success and Failure Criteria.

SLC operation is successful if the system injects sufficient boron into the RPV to shut down the reactor and to maintain it subcritical during cold shutdown. This is conservatively assumed to require a flow path consisting of both SLC pumps, at least one explosive-actuated valve, and both stop check valves. At least one of the RWCU isolation valves must close for all scenarios.

3.2.1.9.9.3 Assumptions

Model-Related

1. Storage tank heaters and heat tracing of the pump suction piping are backed up by the room heating which maintains the temperature of the room above 70°F. This is required to prevent precipitation of the sodium pentaborate solution and plugging of the SLC piping. A pipe plugging event has been included in the fault trees. This event encompasses plugging failures due to a loss of the heaters or heat tracing; therefore, the heaters and heat tracing were not modeled explicitly.

2. The operator would normally start both SLC pumps so the same operator error for failure to start applies to both pumps.

3. An unavailability of either pump due to testing or maintenance has been modeled.

4. A failure to restore either pump following maintenance has been modeled.

5. Pump dependent failures were not modeled since a failure of one pump is assumed to fail the system. Dependent failures were not modeled for the pump discharge check valves or motor-operated stop check valves for similar reasons.

6. Dependent failures were modeled for the squib valves since successful actuation of only one of these valves is necessary for system success. (Both valves must fail to fail the system.) Dependent failures were modeled for the RWCU isolation valves for similar reasons.

7. Since the SLC pumps are relatively small pumps, and since there are no other heat sources which would cause an overheating of the room were ventilation to be lost, no room cooling dependencies were modeled for the SLC system.

Quantification-Related

The boron concentration and precipitation events were quantified by human errors either to verify/maintain sufficient boron concentration, or to verify/maintain minimum required temperature of the SLC storage tank and/or the piping heat tracing.

3.2.1.9.10 References

1. Hope Creek Generating Station UFSAR Section 7.4.1.2.

2. "Hope Creek Licensed Operator Training," Lesson Plan Number 302H-000.00H-000023-10. Public Service Electric and Gas Company, Hancocks Bridge, NJ, January 1993.

3. "Hope Creek Generating Station Technical Specifications 3/4.1.5, 3/4.6.3 and 3.8.4" Public Service Electric and Gas Company, Hancocks Bridge, NJ, July 1990.

4. Public Service Electric and Gas Company Operating Procedures
   - OP-SO.BH-001
   - OP-ST.BH-001
   - OP-ST.BH-002
   - OP-ST.BH-003
   - OP-ST.BH-004
   - OP-IS.BH-001
   - OP-IS-BH-002
   - OP-IS.BH-101
   - OP-IS.BH-102

5. Public Service Electric and Gas Drawings
   - 10855-M-48-1
   - 10855-M-41-1
   - 10855-J-48-0
   - 10855-E-0021-1
   - 10855-E-0023-1
   - 10855-J-0650-1
   - 10855-J-0651-1
   - 10855-J-1651-1
   - 10855-J-3000-1

3.2.1.10 Diesel Generator System (DGS)

3.2.1.10.1 System Function

The emergency diesel generators provide AC electric power to Class 1E loads (and selected Non-Class 1E loads) in the event of a loss of offsite power (LOP). In the event of an LOP concurrent with a design basis loss of coolant accident (LOCA), the diesels are designed to provide sufficient AC electric power to shut down the plant and maintain the plant in a safe condition.

3.2.1.10.2 System Description

General Design

The DGS consists of four divisional 4.16 kV, 4430 kilowatt, 12 cylinder Colt-Pielstick diesel engines, four Beloit Power Systems alternators each coupled to a diesel engine, 4.16 kV diesel generator circuit breakers, diesel auxiliary support systems, and Woodward governors.

Flow Path

On a LOCA, LOP, or manual start signal, the diesel generator is started by redundant air-start solenoid valves. Fuel oil, to keep the diesel running, is supplied from a fuel oil day tank via an engine-driven fuel oil pump. A backup motor-driven fuel oil pump is also available to supply fuel to the diesel if the engine-driven pump fails. To maintain an adequate fuel inventory in the fuel oil day tank, fuel is transferred from the fuel oil storage tanks via 1 of 2 motor-driven fuel oil transfer pumps. The diesel generators are cooled by the Safety Auxiliaries Cooling System (SACS). The diesel engine is coupled directly to a synchronous generator which is capable of continuous operation at 4430 kW at a 0.8 power factor. The generator exciter voltage regulator is a solid state device. Initial excitation is supplied by divisional 125 VDC buses and 4.16 kV power is supplied to the Class 1E 4.16 kV buses by closing the diesel generator output breaker which can be a manual or automatic function.

Location

The Class 1E 4.16 kV emergency diesel generators are located at the 102-foot elevation level of the Auxiliary Building in rooms 5307, 5305, 5306, and 5304 for Class 1E channels A, B, C and D, respectively. The diesel generator output breakers are located in the Auxiliary Building at the Elevation 130' level in rooms 5417, 5413, 5415, and 5411 for Class 1E channels A, B, C, and D, respectively.

Component Descriptions

Generator

The generator converts mechanical energy supplied by the diesel engine into electrical energy to supply power to the Class 1E switchgear loads. There are four generators, one for each of the four divisional diesels. The generator consists of an air-cooled alternator and a static exciter/voltage regulator for generator output control. The alternator is a synchronous generator which is coupled directly to the diesel engine and is capable of continuous operation at 4430 kW at a 0.8 power factor. Loading the generator above 4430 kW is acceptable for short durations. The generator exciter/voltage regulator is a solid state device which is mounted in the generator potential transformer and exciter control panel in each associated diesel generator room. Initial excitation is supplied by the appropriate divisional 125 VDC bus. After initial field flashing is removed, generator excitation is supplied by the generator output.

Diesel Engine

The diesel engine is a 4 cycle, 12 cylinder (in a 45° "V" configuration) engine rated at 5148 BHP (4430 kW net) at 514 rpm for continuous operation. Ten percent overload is permitted for 2 hours out of 24 consecutive hours of operation without special inspection. The engine is started by admission of compressed air to the cylinders of both banks with proper timing to cause rotation. Each bank has a separate but functionally equivalent identical 100% capacity starting air system for redundancy with each system capable of starting the engine. Engine driven auxiliary components ensure self-sufficiency of the diesel generator during startup and operation.

Diesel Engine Auxiliary Systems

The diesel generator is also reliant upon several diesel engine auxiliary systems. The diesel generator Jacket Water Cooling System removes excess heat from the engine cylinders and cools the turbocharger turbine casings. Furthermore, hot jacket water is mixed with intercooler water to maintain the optimum water temperature for cooling the injector nozzles. The Intercooler and Injector Cooling System removes excess heat of compression (after the turbochargers) from the engine combustion air and cools the injector nozzles while the emergency diesel generator is operating. The system also cools the emergency diesel generator bearings. The lube oil system is designed to provide the diesel with clean, cool lubricating oil during all modes of operation and is sized to contain the maximum amount of lube oil expected to be used in 200 hours of operation. The Rocker Arm Lube Oil System provides lubrication to the engine rocker arm bushings and to the engine push rods and tappets. This system is separated from the main lube oil system to prevent contamination of the main lube oil in the event of water or fuel oil leakage in the cylinder head area, and to alarm in case of such leakage. The Starting and Control Air System provides the diesel generator with a reliable source of air for starting the diesel engine, for control air, and for diesel engine shutdown.

Diesel Engine Support Systems

Diesel Fuel Oil System

The Diesel Fuel Oil System is a safety-related system which supplies fuel oil to the emergency diesel generators. Each system consists of a standby motor-driven fuel oil pump, an engine-driven fuel oil pump, fuel oil pump suction strainers, fuel oil pump discharge filters, a diesel generator fuel oil day tank and fuel injection pumps. Both the motor-driven (standby) and engine-driven fuel oil pumps take suction on the fuel oil day tank via an inlet suction strainer. With the diesel operating normally, the engine driven fuel pump will supply the diesel fuel headers via a pump discharge filter. Excess fuel is returned to the day tank. Day tank level is maintained by operation of the fuel oil transfer pumps, which supply fuel oil from the fuel oil storage tanks.

Fuel Oil Storage and Transfer System

This system consists of two fuel oil storage tanks per diesel, two fuel oil transfer pumps per diesel, and miscellaneous instrumentation. On a low level signal from the diesel generator day tank, one of the two fuel oil transfer pumps will start and transfer fuel oil from the fuel oil storage tanks to the diesel generator day tank. Once the tank is filled, the pump that has just operated stops and returns to a standby condition. The next time a transfer is needed the other pump will start. This alternation will continue as long as necessary to supply the diesel with fuel.

3.2.1.10.3 System Interfaces

Shared Components

The diesel generator shares no components with other safety systems.

Electrical

The fuel oil and fuel oil transfer pumps require power from Class 1E 480 VAC MCCs. Diesel control circuitry, lockout circuitry, and all start valves need Class 1E 125 VDC power. The governor and diesel engine auxiliary system solenoid-operated valves require Class 1E 120 VAC power.

Actuation

The diesel generators are automatically started on a LOCA signal, but they will not load the 4.16 kV Class 1E buses as long as offsite power is available. On an undervoltage signal from a bus, the corresponding diesel generator will start and load that bus.

Low fuel oil day tank level will actuate the fuel oil transfer pumps (in auto) to fill the day tank.

Control

The diesel generator and its associated electrically operated support systems can be either manually or automatically started.

Room Cooling

The diesel generators require room cooling. Cooling to the diesel generator room is supplied by the Diesel Generator Room Recirculation System. This system uses SACS as a heat sink. Some diesel generator switchgear is cooled by the Switchgear Room Cooling System, which uses the chilled water system as a heat sink.

Component Cooling

The SACS provides cooling to the diesel generator jacket water heat exchanger, intercooler heat exchanger, and lube oil heat exchanger.

3.2.1.10.4 Instrumentation and Control

System Actuation

Under normal plant operations, the diesels are in standby unless they are being tested. On receipt of a LOCA signal, each diesel will automatically start and run, but will not load its associated bus as long as offsite power remains available for that particular bus. If an undervoltage occurs on any of the Class 1E 4.16 kV buses, the diesel generator(s) for the affected bus(es) will automatically start and begin loading the affected bus(es) within 10 seconds. If a diesel generator(s) does not start, it may be manually started and loaded from the control room. The manual and automatic start sequences are essentially the same and proceed as follows:

1. Solenoid air start valves are energized to admit starting air to the engine (both banks of cylinders).

2. Engine rotation begins.

3. Fuel racks are positioned for maximum boost.

4. When the engine reaches 95 rpm, starting air is shut off.

5. Two time delay relays (cranking timers) energized at the time the diesel initially started will energize the engine start failure relay which shuts off starting air if the diesel does not reach a speed greater then 125 rpm within 7 seconds. (Note: If the diesel engine is really running but has a slow acceleration rate, it will not stop if the start failure relay is energized. When the engine speed exceeds 125 rpm, the start failure relay can be reset by depressing the emergency shutdown reset pushbuttons.)

6. If there were no problems and the diesel had achieved greater than 125 rpm within 7 seconds, then the following actions would occur:

   a. Redundant signal to shut off starting air;

   b. Diesel room recirculation fans start;

   c. SACS cooling to the diesel heat exchangers is initiated;

   d. Fuel oil standby and rocker arm lube oil prelube (standby) are armed to auto-start if required;

   e. Generator field flash circuit is activated;

   f. Jacket water keepwarm pump and heater are deenergized;

g. Lube oil keepwarm heater is deenergized;

h. Engine run time meter is activated;

i. Diesel generator space heaters are deenergized;

j. Normal stop switches are deactivated (emergency stop on the remote or local control panels is still functional) (LOP/LOCA start only);

k. Test Lockout Relay (86T) is deactivated (LOP/LOCA start only);

l. The governor shifts to isochronous mode (if in droop). Governor speed controls are deactivated and the governor motor operated potentiometer (MOP) is centered at 60 Hz (LOP/LOCA start only);

m. The voltage regulator sifts to automatic. Voltage regulator RAISE/LOWER switches are deactivated and the voltage regulator output is centered at 4160 volts (LOP/LOCA start only).

7. When engine speed reaches 365 rpm (375 rpm as sensed by the redundant jacket water pressure switch) signals are again sent to activate generator field flash and shut off starting air.

8. Seven seconds after reaching 365 rpm, the low lube oil pressure shutdown is enabled and various alarm circuits are enabled.

9. When voltage reaches >3950 volts and the frequency reaches >57 Hz, the diesel generator "Ready For Load" indication is illuminated and the diesel generator output breaker closes onto the 4.16 kV bus if there is an undervoltage on that bus.

Component Control

The diesel generators can be started from the control room by pushing the momentary START pushbutton. When the button is depressed, it is backlit to indicate operation. The diesel generators can be stopped from the control room by depressing the momentary STOP pushbutton or simultaneously depressing both emergency STOP buttons. The STOP pushbutton is disabled on an emergency start signal but the emergency pushbuttons are still functional.

Diesel Engine Governor

The operating modes for the governor can be selected from the control room. Upon a diesel emergency start signal, the governor is automatically shifted to the ISOCHRONOUS MODE. The ISOCHRONOUS MODE is automatically deselected when the SYNCH position or DROOP is selected. The INCREASE/DECREASE pushbutton controls the governor/engine speed when in the DROOP mode.

Voltage Regulator Controls

The AUTO momentary pushbutton places the voltage regulator in automatic control. The MANUAL momentary pushbutton places the voltage regulator in manual control. Each button is backlit when depressed and de-selects the opposite mode. The voltage regulator is placed in the AUTO mode if an emergency start signal is present. The INCREASE/DECREASE momentary pushbutton is used to raise or lower generator voltage.

Breaker Controls

The CLOSE pushbutton closes the diesel generator breaker provided that the synchroscope is ON or both normal and alternate 4.16 kV feeder breakers are OPEN. This button is backlit when breaker is closed.

The TRIP pushbutton trips the diesel generator output breaker and is backlit when the breaker is open.

Instrumentation

A partial list of the control room annunciators associated with the DGS is provided below:

1. DIESEL GENERATOR BREAKER MALFUNCTION,
2. DIESEL GENERATOR PANEL A/B/C/D/ C422,
3. DIESEL ENGINE PANEL A/B/C/D/ C423.

3.2.1.10.5 Operator Actions

The operator is required to stop the diesels during a LOCA if offsite power is still available. During a LOP, all initial actions are automatic; however, the operator will have to reconnect any necessary loads that were not automatically loaded.

3.2.1.10.6 Technical Specifications

Technical Specifications (TS) 3.3.3, and 3.8.1 (Limiting Conditions for Operation) and 4.3.3, and 4.8.1 (Surveillance Requirements) apply to the DGS. The applicable portions of TS 3.3.3 and 3.8.1 are summarized below.

As a minimum the following must be operable:

1. The emergency core cooling system (ECCS) actuation instrumentation channels shall be operable. (The logic associated with the Core Spray System Low Reactor Vessel Water Level, High Drywell Pressure, and Manual Initiation trip functions also actuate the associated emergency diesel generators.)

With an ECCS actuation instrumentation channel trip less conservative than the setpoint value, declare the channel inoperable until the channel is restored to operable status with its trip setpoint adjusted consistent with the setpoint value. With 1 or more ECCS actuation instrumentation channel inoperable, take appropriate action as follows:

a. With one channel (Reactor Vessel Water Level-Low Low Low, Level 1; Drywell Pressure-High) inoperable, place the inoperable channel in the tripped condition within 1 hour or declare the associated system inoperable. With more than one channel inoperable, declare the system inoperable.

b. With the number of operable Core Spray Manual Initiation channels fewer than required, restore the inoperable channel to OPERABLE status within 8 hours or declare the Core Spray System inoperable.

2. Four separate and independent diesel generators each with a separate fuel oil day tank containing a minimum of 200 gallons of fuel, a separate fuel storage system consisting of two storage tanks containing a minimum of 48,800 gallons of fuel, and a separate fuel transfer pump for each storage tank must be operable. Two physically independent circuits between the offsite transmission network and the onsite Class 1E distribution system must also be operable.

If the minimum requirements of TS 3.8.1 are not met, the following actions apply:

a. With one offsite circuit of the required AC electrical power sources inoperable, demonstrate the OPERABILITY of the remaining AC sources by performing the appropriate surveillance requirement within 1 hour and at least once per 8 hours thereafter. If any diesel generator has not been successfully tested within the past 24 hours, demonstrate this OPERABILITY by performing the appropriate surveillance requirement for each such diesel generator separately within 24 hours. Restore the inoperable offsite circuit to operable status within 72 hours or be in at least hot shutdown within the next 12 hours and in cold shutdown within the following 24 hours.

b. With one diesel generator of the required AC electrical power source inoperable, demonstrate the operability of the required AC offsite sources by performing the appropriate surveillance requirement within 1 hour and at least once per 8 hours thereafter. If the diesel generator became inoperable due to any cause other than preplanned preventive maintenance or testing, demonstrate the operability of the remaining diesel generators by performing the appropriate surveillance requirements separately for each diesel generator within 24 hours; restore the inoperable diesel generator to operable status within 72 hours or be in at least hot shutdown within the next 12 hours and in cold shutdown within the following 24 hours.

c. With one offsite circuit of the required AC sources and one diesel generator of the required AC electrical power sources inoperable, demonstrate the operability of the remaining AC sources by performing the appropriate surveillance requirement within 1 hour and at least once per 8 hours thereafter. If the diesel generator became inoperable due to any causes other than preplanned preventive maintenance or testing, demonstrate the operability of the remaining operable diesel generators separately for each diesel generator by performing the appropriate surveillance requirement within 24 hours. Restore at least two offsite circuits and all four of the above required diesel generators to operable status within 72 hours from time of the initial loss or be in at least hot shutdown within the next 12 hours and in cold shutdown within the following 24 hours. A successful test of diesel generator operability using the appropriate surveillance requirement performed under this action statement for the operable diesel generators satisfies the diesel generator test requirements of the action statement (b) above.

d. With both of the required offsite circuits inoperable, demonstrate the operability of all of the required diesel generators by performing the appropriate surveillance requirement separately for each diesel generator within 8 hours, unless the diesel generators are already operating; restore at least one of the above required offsite circuits to operable status within 24 hours or be in at least hot shutdown within the next 12 hours. With only one offsite circuit restored to operable status, restore at least two offsite circuits to operable status within 72 hours from time of initial loss, or be in at least hot shutdown within the next 12 hours, and in cold shutdown within the following 24 hours. A successful test(s) of diesel generator operability per the appropriate surveillance requirement performed under this action statement for the operable diesel generators satisfies the diesel generator test requirements of action statement (a).

e. With two diesel generators of the above-required AC electrical power sources inoperable, demonstrate the operability of the above-required AC offsite sources by performing the appropriate surveillance requirement within 1 hour and at least once per 8 hours thereafter, and demonstrate the operability of the remaining diesel generators by performing the appropriate surveillance requirement separately for each diesel generator within 8 hours. Restore at least one of the inoperable diesel generators to operable status within 2 hours or be in at least hot shutdown within the next 12 hours and in cold shutdown within the following 24 hours. Restore both of the inoperable diesel generators to operable status within 72 hours from time of initial loss or be in at least hot shutdown within the next 12 hours and in cold shutdown within the following 24 hours. A successful test(s) of diesel generator operability per the appropriate surveillance requirement performed under this action statement for the operable diesel generators satisfies the diesel generator test requirements of action statements (a) and (b).

f. With two diesel generators of the required AC electrical power sources inoperable, in addition to action statement (e) above, verify within 2 hours that all required systems, subsystems, trains, components and devices that depend on the remaining diesel generators as a source of emergency power are also operable; otherwise, be in at least hot shutdown within the next 12 hours and in cold shutdown within the following 24 hours.

g. With one offsite circuit and two diesel generators of the above required AC electrical power sources inoperable, demonstrate the operability of the remaining AC sources by performing the appropriate surveillance requirement within 1 hour and at least once per 8 hours thereafter and demonstrate the operability of the remaining diesel generators by performing the appropriate surveillance requirement separately for each diesel generator within 8 hours. Restore at least one of the required inoperable AC sources to operable status within 2 hours or be in at least hot shutdown within the next 12 hours and in cold shutdown within the following 24 hours. Restore the inoperable offsite circuit and both of the inoperable diesel generators to operable status within 72 hours from time of initial loss or be in at least hot shutdown within 12 hours and in cold shutdown within the following 24 hours.

3.2.1.10.7 Testing

Tests of the diesel generator system are summarized in the Technical Specifications Section 4.8.1.1.2.

3.2.1.10.8 System Operation

Normal Operation

The DGS does not operate during normal conditions.

Abnormal Operation

In the event of a LOP or LOCA, the diesel generators will start automatically. In the case of a LOCA without a LOP, the diesels will come up to speed and run without loading the 4.16 kV Class 1E buses. In the case of a LOP, the diesels will come up to speed and voltage and load the 4.16 kV Class 1E buses, given that the interlock with the normal and alternate offsite power supply breakers to the 4.16 kV Class 1E buses is satisfied. This interlock requires that both normal and alternate supply breakers be open before the diesel generator output breaker closes onto a Class 1E 4.16 kV bus.

3.2.1.10.9 System Fault Tree

3.2.1.10.9.1 Description

Simplified diagrams indicating modeled components are shown in Figures 3.2-10a and 3.2-10b. The simplified diagrams for the fuel oil system for diesels B, C, and D are similar to the diagram for diesel A, but they are not included in this report.

3.2.1.10.9.2 Success and failure criteria

DGS operation is successful if the diesel starts and loads in response to an undervoltage signal. Success criteria as to the number of diesels needed to successfully endure an accident are documented in the event tree section of this report.

3.2.1.10.9.3 Assumptions

Model-Related

1. Failure of the three-way thermostatic control valve in the jacket water cooling system will not have an adverse effect on the diesel fuel oil injector nozzles.

2. The diesel generator auxiliary systems (Jacket Water Cooling, Intercooler and Injector Cooling, Lube Oil, Starting and Control Air) are considered part of the diesel and are not modeled separately. Diesel failure data includes the failures of these systems.

3. SACS cooling to EDG A and C (Intercooler and Injector, Jacket Water, Lube Oil Heat Exchangers) is initially aligned to Loop A, while the SACS cooling for EDG B and D is initially aligned to Loop B. To switch to the opposite SACS cooling loop, manual realignment of several valves is required.

4. Switchgear room cooling system is required for long-term operation of the DGS switchgear. It is not needed for diesel generator starting and loading. Switchgear room cooling also serves the diesel generator control room.

5. Diesel area Class 1E panel room supply is necessary for continued functioning of the 120 VAC inverters and the longevity of the batteries, but not for diesel generator starting and loading.

6. DGS room recirculation system is needed for long-term DGS operation but not for diesel generator starting and loading.

7. Developed event ACP-120V-1AJ481 contains the probabilities that Contact 1 will open and alternate Contact 2 in Panel 1AJ481 will fail to close as well as power dependence and any circuit failure dependence. This applies also for events 1BJ481, 1CJ481, and 1DJ481.

8. Event DGS-ICC-AF-AP402 (electric-driven fuel oil pump/AP402 ICC circuit actuation faults) includes failure to close of supply breaker 52-411045. This also applies for events DGS-ICC-AF-BP402, DGS-ICC-AF-CP402, DGS-ICC-AF-DP402 and their associated supply breakers.

9. Event DGS-ICC-AF-AP401 (fuel oil transfer pump 1AP401 ICC circuit actuation faults) also includes failure to close of supply breaker 52-411013. This also applies for events DGS-ICC-AF-BP401, DGS-ICC-AF-CP401, DGS-ICC-AF-DP401 and their associated supply breakers.

Quantification-Related

1. Based on a fuel oil day tank nominal volume of 550 gallons and a diesel usage rate of 5.24 gpm, the fuel oil day tank will run dry within 2 hours if no additional fuel is transferred into it. Therefore, failure of the fuel oil transfer pumps will cause a long-term failure of the diesel generator.

2. No credit is being taken for the LOCA start of the diesel generators since no automatic loading occurs with this signal. and the operators will shut off the diesels if power is still available. Credit for starting and loading the diesels on a bus undervoltage is being credited.

3.2.1.10.10 References

1. Hope Creek Generating Station UFSAR Sections 8 and 9.

2. "Hope Creek Generating Station Configuration Baseline Documentation," Doc. No. DE-CB.DG-0024. Public Service Electric and Gas Company, May 21, 1992.

3. "Hope Creek Generating Station Technical Specifications 3.3.3, 3.8.1." Public Service Electric and Gas Company, Hancocks Bridge, NJ, July 1990.

4. Public Service Electric and Gas Drawings:

   E-0001
   E-0006
   E-0007
   E-0008
   E-0085
   E-0106
   E-0107
   E-3065
   E-3081
   M-30-1
   M-88-1
   J-00A

5. Public Service Electric and Gas Company Operating Procedures:

   AP-AB.ZZ-135
   AP-AB.ZZ-137

5. Public Service Electric and Gas Company Operating Procedures (Continued):

OP-DL.ZZ-006
OP-SO.KJ-001
OP-SO.JE-001
OP-SO.PB-001
OP-ST.KJ-001
OP-ST.KJ-002
OP-ST.KJ-003
OP-ST.KJ-004
OP-ST.KJ-005
OP-ST.KJ-006
OP-ST.KJ-007
OP-ST.KJ-008

3.2.1.11 Diesel Generator Area Ventilation Systems (DGAV)

3.2.1.11.1 System Function

The Diesel Generator Area Ventilation Systems provide a suitable operating environment for the diesel generator rooms, the safety- and non-safety-related battery rooms, fuel oil storage rooms, electrical chases corridors in the diesel area, and Class 1E panel rooms during all modes of plant operation. These HVAC systems consist of both safety- and non-safety-related systems. For the purposes of this evaluation, only the following systems were modeled:

1. Switchgear Room Cooling System (SRCS),

2. Diesel Generator Room Recirculation

3. Class 1E Panel Room Supply System.

These systems are independently documented in the following sections.

Switchgear Room Cooling System

The function of the Switchgear Room Cooling System is to provide conditioned air to the switchgear room, battery charger room, battery room and control room of each respective diesel generator.

Class 1E Panel Room Supply System

The function of the Class 1E Panel Room Supply System is to provide conditioned air to two safety-related and two non-safety-related battery rooms, nine invertor rooms, two HVAC rooms, the elevator machine room, and the Control Equipment Room.

Diesel Generator Room Recirculation System

The function of the Diesel Generator Room Recirculation System is to recirculate and cool the air in the diesel generator rooms during diesel generator operation.

3.2.1.11.2 System Description

General Design

Switchgear Room Cooling System

Each of the four Switchgear Room Cooling System trains (one train for each of the respective emergency diesel generators) includes a supply train for the respective switchgear rooms, battery charger room, battery room, and EDG control room. Each train additionally includes an exhaust train for the respective battery room.

The SRCS is a safety-related system with all trains normally operating in all plant conditions. During a LOP, the trains are sequenced onto their respective vital buses.

A mixture of outside air and recirculated air is drawn into the respective unit coolers for filtration through a low efficiency filter and cooling. Cooling is provided by two 100% capacity coils that are supplied by the Auxiliary Building Control Area Chilled Water System. The air is then supplied to the respective switchgear room, battery charger room, battery room, and EDG control room. The air from the switchgear room, battery charger room and control room is recirculated back to the SRCS unit cooler. Air to the battery room is exhausted to the outside via a single exhaust fan for each battery room. Duct heaters are included in the supply duct for each respective battery room. Each of the two cooling coils in the unit coolers is supplied by the separate trains of the chilled water system. Therefore, 100% cooling is available if either chilled water system train is available.

Loss of airflow on any of the SRCS fans is annunciated in the main control room. High/low temperature alarms are annunciated for the SRCS coolers and battery room exhaust ducts.

The switchgear room cooling system units, A through DVH401, each contains a low efficiency filter, cooling coils, and a centrifugal supply fan. The unit is designed to move 11,000 cfm and to remove 410,000 Btu per hour.

The battery room exhaust fans are centrifugal units designed to move 1500 cfm of air.

Class 1E Panel Room Supply System

The Class 1E Panel Room Supply System (PRSS) consists of two 100% capacity HVAC trains to supply conditioned air to two safety-related and non-safety-related battery rooms, nine invertor rooms, two HVAC rooms, the elevator machine room, and the Control Equipment Room. In the IPE evaluation, the exhaust trains for the two safety-related battery rooms were evaluated in conjunction with the panel room supply.

The PRSS is a safety-related, normally operating system in all modes of plant operation. It is usually operated with a single train in operation and the second train in auto-standby. In the event of a LOP, the components are sequenced onto the vital buses.

A mixture of outside air and recirculated air is drawn into the operating HVAC unit. Each unit consists of high and low efficiency filters, an electric heating coil, chilled water coil, and a centrifugal supply fan with integral automatic inlet vanes. The cooling coil is supplied by the auxiliary building control area chilled water system. Loop A of the chilled water system supplies train 'A' of PRSS and Loop B of the chilled water system supplies PRSS train 'B'. The conditioned air is then supplied to the rooms mentioned previously. Room air is recirculated back to the HVAC units with the exception of the air supplied to the battery room. The air through the two safety-related battery rooms is exhausted to the outside via redundant 100% capacity exhaust fans. Duct heaters are included in the supply duct for each respective battery room.

Loss of airflow through the operating PRSS train alarms in the control room and starts the standby unit. The control room alarms are via common trouble alarms from local panels. Similarly, loss of airflow through the operating battery room exhaust train alarms in the control room and starts the standby exhaust fan.

The panel room supply units A and BVH408 each contain high and low efficiency filters, a heater element, a cooling coil, and a centrifugal fan. The unit is designed to move 41,000 cfm and remove 1,800,000 Btu per hour.

The battery room exhaust fans are 1500 cfm centrifugal units. Each battery room duct heater is a 700 cfm, 14 kW unit.

Diesel Generator Room Recirculation System

Each of the four diesel generator rooms utilizes an independent recirculation subsystem to provide ambient cooling during periods of high heat load. Each subsystem includes two 100% capacity trains to provide redundancy.

The Diesel Generator Room Recirculation System is a safety-related system. Each subsystem is normally in standby with one fan in auto lead and the other in auto. The fans will start when the respective diesel generator starts or when a high room temperature is detected. During a LOP, each subsystem is powered by the respective emergency diesel generator.

During system operation, a fan recirculates air through the respective diesel generator rooms. After passing through the rooms, the air is drawn through coolers to maintain the desired air temperature. Coolant for the coolers is provided by SACS. Manual crosstie valves are installed such that any cooler may receive flow from either the A or B loop of SACS. Coolant flow is regulated by a temperature control valve to maintain the desired diesel generator room temperature.

Loss of airflow on the "auto-lead" operating fan initiates an alarm and auto-starts the auto-standby fan. The auto-standby fan also auto-starts on high room temperature when the diesel generator is operating.

The diesel generator room recirculation fans, A through HV412, are 108,000 cfm vaneaxial units. The heat exchangers A through HVE412 are designed to flow 500 gpm of coolant and remove 2,000,000 Btu per hour.

3.2.1.11.3 System Interfaces

Switchgear Room Cooling System

SRCS components are powered from Class 1E 480 VAC sources and are sequenced on to the vital buses during a LOP.

Cooling is provided by the Auxiliary Building Control Area Chilled Water Systems. Each SRCS unit cooler contains two cooling coils, one supplied by 'A' train chilled water and the other supplied by 'B' train chilled water. Therefore, 100% cooling is available regardless of which chilled water train is in operation.

Instrumentation and control power for the SRCS is supplied by the Class 1E 120 VAC system.

Class 1E Panel Room Supply System

The PRSS components and safety-related battery room exhaust components are powered by Class 1E 480 VAC sources and are sequenced on to the vital buses during a LOP.

Cooling is provided by the Auxiliary Building Control Area Chilled Water System. Train A of PRSS is supplied by Loop A of the chilled water system while Train B of PRSS is supplied by Loop B of the chilled water system.

Diesel Generator Room Recirculation System

Diesel Generator Room Recirculation components are powered from Class 1E 480 VAC sources and are sequenced on to the vital buses during a LOP. Instrumentation for DGRR components are powered by the Class 1E 120 VAC system.

Cooling water supply is from the safety-related SACS. Cooling for EDG rooms A and C is normally supplied from SACS Loop A while cooling for EDG rooms B and D is supplied by SACS Loop B. However, the coolers may be supplied by either SACS loop through manipulation of manual valves. SACS flow is controlled to the individual coolers via air-operated valves based upon room temperature. These valves fail open upon loss of power or loss of air supply.

3.2.1.11.4 Instrumentation and Control

Switchgear Room Cooling System

All Switchgear Room Cooling System components are started and stopped from local panels. Low flow conditions are annunciated in the main control room. High differential pressure across the SRCS unit cooler filters is annunciated on a local panel and is relayed to the main control room.

Class 1E Panel Room Supply System

All PRSS and safety-related battery room exhaust components are operated from local panels. Loss of airflow in the operating PRSS train initiates a local alarm that is relayed to the main control room and automatically starts the standby train. Loss of airflow through the operating battery exhaust train is annunciated on a local panel (and the main control room) and automatically starts the standby train.

High differential pressure across the high and low efficiency PRSS unit filters is annunciated on a local panel and in the main control room.

Electric heater coil operation for PRSS is controlled by temperature sensors downstream of the respective PRSS unit. Operation of the battery room duct heating coils is controlled by temperature sensors in the respective battery rooms.

Chilled water flow to the PRSS unit cooling coils is controlled by an air-operated temperature control valve in the chilled water outlet piping for the respective PRSS units. Valve position is controlled via temperature controllers and sensors downstream of the respective PRSS unit.

Flow and temperature alarms are annunciated on local panels, and they are annunciated in the main control room as common trouble alarms.

PRSS fans AVH408 and BVH408 are interlocked to operate in auto-mode with chilled water pumps 1AP414 and 1BP414 respectively.

Diesel Generator Room Recirculation System

The Diesel Generator Room Recirculation System trains are normally interlocked to start with their respective diesel generator on a high room temperature or when the auto lead fan trips. The trains may also be started manually from the respective local panel.

The "auto-lead" fan auto-starts when the respective diesel operates or when the room temperature is high. The auto-standby fan runs if a low flow is detected on the "auto-lead" fan or when the diesel operates or the room temperature is high. A time delay keeps the operating fan running for 45 minutes after the respective diesel generator is shut down.

The room temperature is displayed in the main control room, and alarms are provided for high and low room temperature. If low airflow on the operating fan is detected, the condition is annunciated, the operating fan stops, and the standby fan is started.

3.2.1.11.5 Operator Actions

Switchgear Room Cooling System

All SRCS components are manually started and stopped from local panels. The SRCS systems are non-redundant trains; therefore, there is no switchover performed upon loss of a train. Corrective actions/maintenance must be performed to correct the problem and restore HVAC to the affected areas. With the exceptions of manually starting and stopping the system, periodically monitoring component operations, and responding to system alarms, there are no required operator actions.

Class 1E Panel Room Supply System

All PRSS and safety-related battery room exhaust components are manually started and stopped from local panels. Loss of airflow in the operating PRSS train alarms on Panel 1EC486 and in the main control room, and it auto-starts the standby train. Loss of airflow in the operating safety-related battery room exhaust train alarms on Panel 1EC486 and in the main control room, and it auto-starts the standby trains. A common trouble alarm is annunciated in the main control room from any Panel 1EC486 alarm. PRSS supply high and low temperatures and filter differential pressure high are also annunciated on Panel 1EC486.

Diesel Generator Room Recirculation System

The various trains of the Diesel Generator Room Recirculation System are placed in auto service from the applicable local panel. For each diesel room, one train is switched into the "auto-lead" position while the second is placed in the auto position.

3.2.1.11.6 Technical Specification Limitations

Switchgear Room Cooling System

There are no Technical Specification requirements or limitations related to the Switchgear Room Cooling System.

Class 1E Panel Room Supply System

There are no Technical Specification requirements or limitations related to the Class 1E Panel Room Supply System.

Diesel Generator Room Recirculation System

There are no Technical Specification requirements or limitations related to the Diesel Generator Room Recirculation.

3.2.1.11.7 Testing

Switchgear Room Cooling System

The Switchgear Room Cooling System is a normally operating system. There are no routine system tests performed on this system.

Class 1E Panel Room Supply System

The Class 1E Panel Room Supply System is a normally operating system. There are no routine system tests performed on this system.

Diesel Generator Room Recirculation System

The Diesel Generator Room Recirculation System function is verified during routine surveillances at the respective diesel generators. SACS inlet valves to the room coolers are tested quarterly per the IST program. No other scheduled tests are conducted that specifically test this system.

3.2.1.11.8 System Operation

Switchgear Room Cooling System

The Switchgear Room Cooling System normally operates with all four systems in operation. This includes operation of the supply fans/trains and battery room exhaust trains. Battery room duct heater operation will automatically occur based on the respective room temperature. . Cooling to the SRCS is supplied by the Auxiliary Building Control Area Chilled Water System. SRCS will operate in this mode under all plant conditions. During a LOP, the SRCS components are sequenced on to the vital buses.

Class 1E Panel Room Supply System

The PRSS normally operates with one 100% capacity train in operation and the second train in standby. The PRSS fans AVH408 and BVH408 are interlocked to operate in auto-mode with chilled water pumps AP414 and BP414, respectively. The standby PRSS train will auto-start on a low flow signal from the operating train. The PRSS operates in all modes of unit operation. During a LOP, the fans are sequenced to emergency Class 1E power.

The battery room exhaust fans normally operate with one fan in operation and the second in standby. The standby exhaust fan will auto-start on a low flow signal from the operating train. The battery room exhaust operates under all modes of unit operation. During a LOP, the fans are sequenced to emergency Class 1E power.

Diesel Generator Room Recirculation System

The Diesel Generator Room Recirculation System is normally in standby with two recirculation trains prepared to serve each of the four emergency generator rooms. One of the trains for each diesel room is in an "auto-lead" mode while the second train is in an auto-standby mode. Upon a diesel start, or upon high room temperature, the "auto-lead" train will automatically start. If low flow is detected on the operating train, or if the diesel is running and a high room temperature is detected, the auto-standby train will automatically start. The running recirculation train will continue to operate 45 minutes following shutdown of the diesel generator.

The Diesel Generator Room Recirculation System trains may be manually started from the respective local panel.

3.2.1.11.9 System Fault Tree

3.2.1.11.9.1 Description

Switchgear Room Cooling System

The Switchgear Room Cooling System includes four independent trains to serve four separate groups of rooms. An independent fault tree was constructed for each train. This allows switchgear room cooling to be treated as four independent systems for use as support for the equipment in the separate groups of rooms.

Additionally, the Switchgear Room Cooling System provides the supply to the associated train battery room. The exhaust trains for the battery rooms were treated as separate systems with their own fault trees. This allows the function of the Switchgear Room Cooling System (as a supply source) to continue as a support system regardless of any battery room exhaust problems.

Class 1E Panel Room Supply System

The Class 1E Panel Room Supply System includes two redundant 100% capacity trains to serve one group of supplied rooms. A single tree adequately addresses this supply system. Additionally, the Class 1E Panel Room Supply System provides the supply air to the battery rooms. A common battery room exhaust train utilizes redundant fans. Each battery room supply inlet has its own non-redundant duct heater. Therefore, the supply and exhaust for each battery room is treated as a separate system and fault tree. This allows the function of the panel room supply to continue as a support system regardless of battery room exhaust problems. Additionally, treating the two battery rooms separately allows the continued function of one room HVAC train even if there is a loss of the duct heater for the second room.

Diesel Generator Room Recirculation System

The Diesel Generator Room Recirculation System contains four independent subsystems, each supplying a separate diesel generator room. This allows diesel generator room recirculation to be treated as four separate systems for use as support for the equipment in the respective four diesel generator rooms. Each of the four subsystems includes a redundant train. Therefore, an independent fault tree was constructed for each train to accurately depict the independence of the recirculation subsystems.

3.2.1.11.9.2 Success and Failure Criteria

A simplified diagram for the Diesel Generator Room Recirculation system is shown in Figure 3.2-11a. Figure 3.2-11b shows the simplified diagram for the Switchgear Room Cooling Train A. The diagrams for Switchgear Room Cooling Trains B, C, and D are shown in Figures 3.2-11c, 3.2-11d, and 3.2-11e, respectively. A simplified diagram of the Panel Room Supply System is shown in Figure 3.2-11f.

Switchgear Room Cooling System

Each train of Switchgear Room Cooling provides conditioned air to a separate group of equipment rooms. There is no redundancy; therefore, each train must function successfully as a separate support system. To successfully fulfill its support function, each train must provide air recirculation and cooling as required.

The battery room exhaust trains also support separate battery rooms without redundancy. Each train must function as a separate system. To successfully support the battery rooms, supply must be available from the respective switchgear room cooling train, the duct heater must be functional to help maintain proper battery temperature, and the exhaust train must function to remove the supplied air.

Class 1E Panel Room Supply System

The Class 1E Panel Room Supply System includes two independent 100% trains, thus providing 100% redundancy. To successfully fulfill its support function, one train must function to provide air recirculation and cooling as required.

The battery rooms are supplied by the Class 1E Panel Room Supply System. This provides redundancy in the supply. A common room exhaust utilizes redundant fans to remove the supplied air. Each battery room supply inlet includes a duct heater to help ensure that battery temperature is maintained. As a support system for the battery rooms, each battery room must be separately considered because of the heaters. Therefore, for each battery room, system success requires an operating panel room supply train, an operating exhaust train, and the functional heater in the inlet to the respective room.

Diesel Generator Room Recirculation System

Each subsystem of Diesel Generator Room Recirculation System recirculates and cools the air in the respective diesel generator room block. Each subsystem includes two redundant trains of 100% capacity. To successfully fulfill its support function, one train of each subsystem must start when its respective diesel generator starts, and it must continue to circulate and cool the diesel room air while the diesel is in operation.

3.2.1.11.9.3 Assumptions

Switchgear Room Cooling System

1. Fire protection and tornado dampers were not modeled because they are normally open, and they are designed not to close unless a fire or a tornado (respectively) were to occur. The unintentional closing of these dampers is an extremely unlikely event.

2. Manual dampers were not modeled since it was assumed that they were properly positioned during system balancing, and there are no requirements to change damper position.

3. Heating for the switchgear room supply trains was not modeled since a loss of heating would not immediately affect equipment in the supplied rooms. A low temperature alarm is annunciated for low air return temperature, and high room temperature is also annunciated.

4. Heaters for battery rooms were modeled due to the requirement to maintain the battery electrolyte temperatures in the proper range to ensure battery capability.

5. Mispositioning of chilled water system valves was modeled due to the potentially long time delay for the valves to be inadvertently closed and a high temperature to be annunciated for the return air temperature.

Class 1E Panel Room Supply System

1. Fire protection and tornado dampers were not modeled because they are normally open, and they are designed not to close unless a fire or a tornado (respectively) were to occur. The unintentional closing of these dampers is an extremely unlikely event.

2. Manual dampers were not modeled since it was assumed that they were properly positioned during system balancing, and there are no requirements to change damper positions.

3. Heating for the panel room supply trains was not modeled since a loss of heating would not immediately affect equipment in the supplied rooms and a low temperature alarm is annunciated.

4. Heaters for battery rooms 5609 and 5614 were modeled due to the requirement to maintain the battery electrolyte temperatures in the proper range to ensure capability. Heaters for battery rooms 5626 and 5627 were not modeled since the batteries serve non-safety-related loads.

5. High and low efficiency filters are combined into a single filter for the models.

6. ICC faults include actuation signals.

7. Miscalibration of instrument trains was disregarded since no scheduled PM IOs are in evidence.

8. Exhaust for this system was not modeled since a loss of exhaust would not immediately affect the equipment if the supply to the rooms were operating.

Diesel Generator Room Recirculation System

Diesel generator normal room supply and exhaust systems were not modeled for the following reasons:

1. The UFSAR states diesels will start with low room temperatures.

2. The diesel generator room recirculation fan starts on high room temperature.

3. The diesel generator room recirculation fan starts on diesel start.

4. Fire protection dampers were not modeled since they were addressed by the fire protection evaluation.

5. Manual dampers were not modeled since they are normally open, and they are designed not to close unless a fire were to occur. The unintentional closing of these dampers is an extremely unlikely event.

6. Misoperation and mispositioning of SACS manual valves were not modeled since the system operating procedure states that two pumps are running in one loop and a single pump operating in the second loop. The TRIS line up lists the subject valves as either throttled open or locked open in Operational Condition 1.

3.2.1.11.10 References

1. Hope Creek Generating Station UFSAR Sections 7.3.1.1.11.6.2 and 9.4.6.

2. Operations Procedures:

   OP-SO.GM-001
   OP-AR.GM-001
   OP-AR.GM-002

3. Public Service Electric and Gas Company Drawings:

H-88-0 (UFSAR Figure 7.3-24)
M-85-1 Rev 14 (UFSAR Figure 9.4-15)
M-88-1 Rev 11 (UFSAR Figure 9.4-16)
M-90-1 Rev 14 (UFSAR Figure 9.2-15)
M-12-1 Rev 15 (UFSAR Figure 9.2-5)

3.2.1.12 AC Power (ACP) System

3.2.1.12.1 System Function

The Alternating Current Power (ACP) System distributes AC electric power for plant operation for both normal and abnormal conditions. The system provides redundant sources of power for critical safety systems.

3.2.1.12.2 System Description

General design

The ACP system consists of transformers, circuit breakers, 7200 VAC Non-Class 1E buses, 4160 VAC Class 1E and Non-Class 1E buses, 480 VAC Class 1E and Non-Class 1E unit substations (USS), 480 VAC Class 1E and Non-Class 1E motor control centers (MCC), 120 VAC Class 1E and Non-Class 1E uninterruptable power supplies (UPS), 120 VAC Class 1E and non-Calss 1E distribution panels, diesel generators, a 13.8 kV ring bus, and a 500 kV switchyard. Simplified diagrams of the ACP system are presented in Figure 3.2-12. Non-Class 1E AC power is not modeled in detail in the Hope Creek PRA except for the 7200 VAC buses, and is not discussed in detail in the Hope Creek PRA or IPE. The diesel generators are discussed in Section 3.2.1.10.

Flow Path

The 4160 VAC Class 1E buses, which feed safeguard equipment, are energized by either of two station service transformers served by the 13.8 kV ring bus. Power to each of the sections of the 13.8 kV ring bus is supplied by its associated station power transformer (T1, T2, T3, or T4), with transformers T1 and T4 normally supplying the sections of the 13.8 kV ring bus which supply the Class 1E 4160 VAC buses. The station power transformers are supplied by sections of the 500 kV switchyard. The 500 kV switchyard normally receives offsite power from the Keeney and New Freedom lines, and the Salem 500 kV switchyard to Hope Creek 500 kV switchyard tie lines.

Location

Class 1E electrical switchgear, unit substations and motor control centers are located in various rooms throughout the plant. Rooms 5417, 5413, 5415, and 5411 are located on the 130' elevation of the diesel generator area of the auxiliary building and contain the following Class 1E equipment:

Room 5417: 4160 VAC BUS 10A401
480 VAC USS 10B410
480 VAC USS 10B450
480 VAC MCC 10B411
480 VAC MCC 10B451

Room 5413: 4160 VAC BUS 10A402
480 VAC USS 10B420
480 VAC USS 10B460
480 VAC MCC 10B421
480 VAC MCC 10B461

Room 5415: 4160 VAC BUS 10A403
480 VAC USS 10B430
480 VAC USS 10B470
480 VAC MCC 10B431
480 VAC MCC 10B471

Room 5411: 4160 VAC BUS 10A404
480 VAC USS 10B440
480 VAC USS 10B480
480 VAC MCC 10B441
480 VAC MCC 10B481

Rooms 4309, 4303, 4310 and 4201 also contain Class 1E equipment. Rooms 4309, 4303, and 4310 are located in the Reactor Building on the 102' elevation while Room 4201 is located on the 77' elevation of the Reactor Building. These rooms contain 480 VAC motor control centers 10B212, 10B222, 10B232, and 10B242, respectively. The service water structure also houses Class 1E motor control centers at the 102' elevation. Service water bay 1 contains 480 VAC Class 1E motor control centers 10B563 and 10B583 in the MCC room, while service water bay 3 contains 480 VAC Class 1E motor control centers 10B553 and 10B573 in the MCC room. The 120 VAC Class 1E uninterruptable power supplies are contained in various rooms and elevations in the Auxiliary Building. Room 5501 is on the 137' elevation, 5448 is on the 124' elevation, and rooms 5616, 5615, 5613, and 5607 are on the 163' elevation. Location of the Class 1E 120 VAC UPSs are as follows:

Room 5501: 120 VAC UPS INVERTER CABINET 1AD481
120 VAC UPS INVERTER CABINET 1CD481
120 VAC UPS DISTR PNL 1AJ481
120 VAC UPS DISTR PNL 1CJ481

Room 5548: 120 VAC UPS INVERTER CABINET 1BD481
120 VAC UPS INVERTER CABINET 1DD481
120 VAC UPS DISTR PNL 1BJ481
120 VAC UPS DISTR PNL 1DJ481

Room 5616:	120 VAC UPS INVERTER CABINET 1AD482 120 VAC UPS DISTR PNL 1AJ482
Room 5615:	120 VAC UPS INVERTER CABINET 1BD482 120 VAC UPS DISTR PNL 1BJ482
Room 5613:	120 VAC UPS INVERTER CABINET 1CD482 120 VAC UPS DISTR PNL 1CJ482
Room 5607:	120 VAC UPS INVERTER CABINET 1DD482 120 VAC UPS DISTR PNL 1DJ482

Non-Class 1E 7200 VAC buses 10A110 and 10A120 are the only non-class 1E buses that have fault tree models in the Hope Creek PRA. They are located on elevation 120' of the turbine building in Room 1406, which is the electrical equipment mezzanine area.

The diesel generators are located on the 102' elevation of the Auxiliary Building in rooms 5307, 5305, 5306, and 5304. Class 1E diesels 1AG400, 1BG400, 1CG400 and 1DG400 are located in these rooms, respectively.

Component Descriptions

500 kV Switchyard

The switchyard supplies offsite power to the 13.8 kV ring bus through the four stepdown station power transformers T1, T2, T3 and T4. Offsite power comes from either the Keeney and New Freedom lines or the Salem 500 kV switchyard to Hope Creek 500 kV switchyard tie line. Station power transformers T1 and T4 feed the portions of the 13.8 kV ring bus used for Class 1E power.

13.8 kV Ring Bus

The 13.8 kV ring bus supplies power to both Class 1E and Non-Class 1E buses by means of stepdown station service transformers. Station service transformers 1AX501 and 1BX501 supply the Class 1E 4.16 kV buses.

4160 VAC Class 1E Buses 10A401, 10A402, 10A403, 10A404

Class 1E buses 10A401, 10A402, 10A403, and 10A404 are part of the four Class 1E electrical divisions in the plant, Div I, Div II, Div III, and Div IV, respectively. These divisions are also given alphabetic channel descriptions A, B, C, and D, respectively. (Throughout this document the divisions are also referred to as channels A, B, C, and D) These four buses are fed from the 13.8 kV ring bus by means of station service transformers 1AX501 and 1BX501. Either transformer can feed all four buses. During normal operation, two of the buses, 10A401 and 10A403 (A and C), are fed from station service transformer 1AX501 while the other two buses, 10A402 and 10A404 (B and D), are fed from station service transformer 1BX501. Upon undervoltage to the infeed breaker of a particular 4.16 kV bus or the occurrence of a "dead" bus, an automatic transfer occurs which opens the infeed breaker from the affected station service transformer and closes the 4.16 kV infeed breaker from the unaffected station service transformer. Each 4.16 kV Class 1E bus supplies power to two Class 1E 480 VAC unit substations through two stepdown transformers. The Class 1E 4.16 kV buses also supply power to large safety related motor loads. There are no interconnections between the Class 1E buses.

480 VAC Class 1E Unit Substations (USSs)

There are two Class 1E 480 VAC unit substations powered from each of the four 4.16 kV Class 1E buses. Each of the eight 480 VAC Class 1E unit substations is fed through stepdown transformers. The 480 VAC unit substations carry the same divisional and channel designation (I, II, III, or IV and A, B, C, or D) as their Class 1E 4.16 kV parent bus. The Class 1E 480 unit substations supply power to 480 VAC motor control centers and small motors from 100 hp to 250hp. Non-Class 1E 480 VAC motor control centers supplied by a 480 VAC Class 1E unit substation are supplied via auxiliary breaker centers.

480 VAC Class 1E Motor Control Centers (MCCs)

Each of the eight Class 1E 480 VAC unit substations supplies two Class 1E 480 VAC motor control centers. Each Class 1E 480 VAC motor control center carries the same divisional and channel designation as its parent Class 1E 480 VAC unit substation. Class 1E 480 VAC motor control centers supply power to small motors less than 50hp, battery chargers, UPS inverters, and Class 1E 208/120 VAC distribution panels.

Auxiliary Breaker Centers

Four auxiliary breaker centers are located in the auxiliary building diesel generator area at the 130' elevation and contain the Non-Class 1E breakers which supply the non-safety related loads powered from the Class 1E 480 VAC unit substations. For each of these Non-Class 1E loads there are two breakers arranged in series. The Class 1E breakers are located in the Class 1E 480 VAC unit substations and open automatically upon a LOCA Level 1 signal and 4.16 kV bus undervoltage signal from loss of power to that bus. The Non-Class 1E breakers are closed for routine equipment operation.

120 VAC Class 1E Uninterruptable Power Supply (UPS) System

There are eight Class 1E uninterruptable power supplies (UPSs), two per division or channel. Each UPS is comprised of a static rectifier, a static inverter, a static switch assembly, and a regulated power supply. The static rectifier provides regulated DC power to the inverter. The normal AC supply from a Class 1E 480 VAC motor control center is rectified and auctioneered with the alternate DC supply. The output of the static rectifier assembly is a regulated 120 to 140 VDC at 200 amps. The static inverter converts the DC input from the static rectifier to 120 VAC for application to system loads via the static switch assembly. The output of the static inverter is a single phase, 60 Hz, 120 Volts AC. The static switch monitors the output of the static inverter, and it shifts to the backup AC power supply (Class 1E 480 VAC MCC powered from an MCC different than the one powering the UPS static rectifier), if a loss of inverter output is indicated. The load is shifted to the backup supply within 0.25 Hz and without a power loss. The static switch is NORMAL seeking and will automatically return to the inverter source once its output has been restored.

The following Non-Class 1E power sources are each modeled in the Hope Creek PRA as a single undeveloped event:

4160	VAC	Bus	10A102
4160	VAC	Bus	10A104
4160	VAC	Bus	10A501
4160	VAC	Bus	10A502
480	VAC	MCC	10B122
480	VAC	MCC	10B131
480	VAC	MCC	10B132
480	VAC	MCC	10B143
480	VAC	USS	10B250
480	VAC	MCC	10B502
480	VAC	MCC	10B503
120	VAC	Distribution Panel	10Y406
120	VAC	Distribution Panel	1YF407
120	VAC	Distribution Panel	1DJ484

3.2.1.12.3 System Interfaces

Shared Components

The AC power system shares no components with other safety systems.

Electrical

Diesel generator DC equipment, flashing circuitry and switchgear, and 4160 VAC, 480 VAC USS and 480 VAC MCC Class 1E switch gear receive 125 VDC control and actuation power from the Class 1E 125 VDC power system. Additionally, the 125 VDC Class 1E system provides the alternate power source for the 120V Class 1E UPS system.

Actuation

The diesel generators are automatically started on a LOCA signal but will not load the buses. When a degraded voltage condition is present, an undervoltage signal from a bus will start the corresponding diesel generator(s) and load the affected bus(es) (see Section 3.2.1.10 for a description of the diesel generator system). The Salem tie line breaker is closed by Salem operators upon request from Hope Creek.

Control

The infeed breakers of the Class 1E 4160 VAC buses, 480 VAC USSs, and the 480 VAC MCCs function both manually and automatically.

Room Cooling

Room cooling is provided for the rooms where all ACP system equipment is located.

3.2.1.12.4 Instrumentation and Control

System Actuation

When an undervoltage condition is present to one of the Class 1E 4.16 kV infeed breakers, or there is a dead Class 1E 4.16 kV bus, an automatic transfer occurs over to the unaffected station service transformer. If there is degraded voltage on both of the incoming feeder breakers to a Class 1E 4.16 kV bus ($\leq$92 percent) for 20 seconds or more, the associated diesel generator is emergency started. At less than or equal to 92-percent voltage, the associated feeder breaker is also tripped (if closed) and/or auto closure is blocked. Additionally, if both feeders to a 4.16 kV bus are less than or equal to 92-percent voltage and bus voltage is <70 percent voltage, the associated diesel generator is emergency started. This condition is a LOP. If the undervoltage conditions persists for approximately 0.25 seconds, the LOP load shedding sequence from the buses is initiated, and the sequencer initiates process start inhibit signals (PSIS) to prevent automatic starting of selected loads until the LOP timer cycles. The timer is initiated by concurrent signals from the LOP circuitry and diesel generator output breaker closed signals. The timer will time out at various intervals as necessary to restore power to process loads.

During a LOCA, the signal is generated from the core spray logic, which monitors reactor vessel level and drywell pressure. If the LOCA signal(s) is (are) received, the diesel is started and the LOCA emergency load sequencer is activated. The sequencer initiates load shedding of selected (Non-Class 1E) loads, initiates PSIS signals to prevent automatic starting of selected equipment until the LOCA timer cycles, and sequences power to the selected loads at predetermined intervals.

Component Control

The 500 kV breakers are closed from the control room by turning the keylock switch ON, which energizes the synchroscope. The CLOSE momentary push button will close its associated breaker provided permissives are satisfied. The TRIP momentary push button trips the breaker when depressed and is backlit indicating the breaker is open.

The 13.8 kV circuit breakers are controlled by a CLOSE momentary push button, which closes the breaker and is backlit when the breaker is closed. The TRIP momentary push button opens the breaker and is backlit when the breaker is tripped.

The 4.16 kV bus feeder breaker control has an INOP light/push button, which flashes when the breaker is inoperative, and depressing the INOP push button acknowledges the inoperative condition and the light will remain backlit. The keylocked synch switch has two positions, SYNCH and OFF. The KEY is removable in the OFF position. To close the feeder breaker with the SYNCH not selected the EDG output breaker must be open. Placing the keylock switch to the synch position allows paralleling. The white light below the switch is illuminated when selecting SYNCH. The auto close block momentary push button is backlit when depressed and prevents automatic closure of the feeder breaker. The TRIP push button opens the associated breaker. The CLOSE push button shuts the associated breaker conditionally.

The 480V Class 1E unit substation controls have a trip push button which trips open the associated unit substation feeder breaker and is backlit when depressed. The CLOSE push button shuts the associated breaker conditionally and is backlit when depressed.

Instrumentation

Instrumentation that provides monitoring functions for safe operation of the ACP includes such annunciators as "120 VAC UPS Trouble," "13.8 kV Bus Lockout Relay Trip," and "Main Transformer Trouble." These and many other annunciators are displayed directly in the control room.

3.2.1.12.5 Operator Actions

The Hope Creek 500 kV switchyard can be energized after a loss of offsite power, if possible, by a Salem operator via a request from a Hope Creek operator.

3.2.1.12.6 Technical Specifications

Technical Specifications 3.3.3, 3.8.1, 3.8.3, and 3.8.4.5 (Limiting Conditions for Operation) and 4.3.3, 4.8.1 and 4.8.3 (Surveillance Requirements) apply to the ACP system. The limiting conditions for operation are summarized below.

As a minimum, the following must be operable:

1. The Emergency Core Cooling System (ECCS) actuation instrument channels.

2. Two physically independent circuits between the offsite transmission network and the onsite Class 1E distribution system.

3. Four separate and independent diesel generators, each with a separate fuel oil day tank containing a minimum of 200 gallons of fuel, a separate fuel storage system consisting

of two storage tanks for each diesel generator containing a minimum of 48,800 gallons of fuel total, and a separate fuel transfer pump for each storage tank.

4. All Class 1E isolation breaker (tripped by a LOCA signal) overcurrent protective devices. Technical specifications involving ECCS actuation instrumentation channels are summarized in the diesel generator section (Section. 3.2.1.10).

5. Channel A, B, C, and D power systems with each channel having one Class 1E 4.16 kV switchgear bus, two Class 1E 480 VAC unit substations, four Class 1E 480 VAC motor control centers, three Class 1E 208/120 VAC distribution panels, and three 120 VAC distribution panels. These are listed below:

AC Power Distribution;

a. Channel A consisting of:

1) 4160 volt AC switch gear bus	10A401
2) 480 volt AC load centers	10B410 10B450
3) 480 volt AC MCCs	10B212 10B411 10B451 10B553
4) 208/120 volt AC distribution panels	10Y401 (source: 10B411) 10Y411 (source: 10B451) 10Y501 (source: 10B553)
5) 120 volt AC distribution panels	1AJ481 1YF401 (source: 1AJ481) 1AJ482

b. Channel B consisting of:

1) 4160 volt AC switch gear bus	10A402
2) 480 volt AC load centers	10B420 10B460
3) 480 volt AC MCCs	10B222 10B421 10B461 10B563

4) 208/120 volt AC distribution panels | 10Y402 (source: 10B421)
10Y412 (source: 10B461)
10Y502 (source: 10B563)

4) 208/120 volt AC distribution panels	10Y402 (source: 10B421) 10Y412 (source: 10B461) 10Y502 (source: 10B563)
5) 120 volt AC distribution panels	1BJ481 1YF402 (source:1BJ481) 1BJ482

c. Channel C consisting of:

1) 4160 volt AC switch gear bus	10A403
2) 480 volt AC load centers	10B430 10B470
3) 480 volt AC MCCs	10B232 10B431 10B471 10B573
4) 208/120 volt AC distribution panels	10Y403 (source:10B431) 10Y413 (source: 10B471) 10Y503 (source: 10B573)
5) 120 volt AC distribution panels	1CJ481 1YF403 (source: 1CJ481) 1CJ482

d. Channel D consisting of:

1) 4160 volt AC switch gear bus	10A404
2) 480 volt AC load centers	10B440 10B480
3) 480 volt AC MCCs	10B242 10B441 10B481 10B583
4) 208/120 volt AC distribution panels	10Y404 (source:10B441) 10Y414 (source: 10B481) 10Y504 (source: 10B583)

5) 120 volt AC distribution panels — 1DJ481
1YF404 (source: 1DJ481)
1DJ482

3.2.1.12.7 Test

Tests are summarized in the Technical Specifications. Maintenance procedures which disable a 4.16 kV or 480V bus are not allowed during power operation. However, maintenance on the Class 1E inverters and associated equipment can be performed at power by switching the 120 VAC UPS to its backup power source. The backup supply comes through a Class 1E 480 VAC MCC, through a stepdown transformer to the 120 VAC UPS bus directly. The 480 VAC MCC comes from the same channel but the opposite unit substation for that 4.16 kV bus channel.

3.2.1.12.8 System Operation

Normal Operation

The 4.16 kV buses 10A401 (Channel A) and 10A403 (Channel C) are normally powered from Section 7 of the 13.8 kV ring bus via station service transformer 1AX501. This source (1AX501) is also the alternate power supply for 10A402 (Channel B) and 10A404 (Channel D).

The 4.16 kV buses 10A402 and 10A404 are normally powered from Section 2 of the 13.8 kV ring bus via station service transformer 1BX501. This source (1BX501) is also the alternate power supply for 10A401 and 10A403.

Each 4.16 kV vital bus supplies two 480 VAC unit substations (USSs) via stepdown transformers. The 480 VAC unit substations distribute power to the Class 1E loads and Class 1E MCCs. Power is also supplied to selected Non-Class 1E loads through Class 1E isolation breakers located in the USS and Non-Class 1E (in series) breakers located in the auxiliary breaker centers.

Class 1E power from 480 VAC MCCs feed 120 VAC for distribution panels and instrumentation uninterruptable power supplies (UPSs).

Abnormal Operation

In the event that the normal source of power to a 4.16 kV Class 1E bus becomes unavailable, that bus automatically transfers to its alternate source of power. In the event that all offsite power is lost, the emergency diesel generators (one for each 4.16 kV Class 1E bus) are automatically started, and the normal infeed breakers to each 4.16 kV Class 1E bus are opened (tripped). When each diesel generator is up to speed and voltage (in less than or equal to ten seconds), the associated diesel generator supply breaker is closed to energize that particular 4.16 kV Class 1E bus. An interlock between the normal offsite 4.16 kV Class 1E power supply breakers and the diesel generator supply breaker prevents auto closure of the associated diesel generator supply breaker unless both 4.16 kV Class 1E offsite power supply breakers are open.

This interlock prevents prevents a diesel generator from being paralled to offsite power out of phase or with unmatched voltage. Surveillance tests are performed in which a diesel generator is manually paralleled to the offsite AC power grid.

3.2.1.12.9 System Fault Tree

3.2.1.12.9.1 Description

Simplified diagrams indicating those components modeled in the ACP fault trees are shown in Figure 3.2-12.

3.2.1.12.9.2 Success and Failure Criteria

ACP operation is successful if each of the loads required by other systems remains energized. The ACP mission time (including the diesel generator mission time) is 24 hours. System failure can occur as a result of any of the following: a bus fails, a transformer fails, a feeder breaker fails, switchgear cooling fails, or a diesel generator fails coincident with loss of offsite power. Room cooling is only modeled in an ACP system fault tree if it is required within the 24-hour mission time.

3.2.1.12.9.3 Assumptions

Model-Related

1. The Salem to Hope Creek tie breaker is normally closed.

2. The 4.16 kV Class 1E Divisions I (A) and III (C) are normally powered from station service transformer 1AX501, and 4.16 kV Class 1E Divisions II (B) and IV (D) are normally powered from station service transformer 1BX501. This corresponds to station power transformer T4 for 4.16 kV channels A and C.

3. The event in the fault tree that contains the failure to get power from Salem Station does not include failure of the Hope Creek switchyard 125 VDC battery system or the 120 VAC instrument and control system.

4. Failure of the Hope Creek switchyard 125 VDC and 120 VAC instrument and control power is contained in the event for failure of the 500 kV switchyard.

5. Undeveloped events ACP-ICC-AF-AJ481, BJ481, CJ481 and DJ481 contain the failure to transfer to backup contacts in panels 1A, 1B, 1C, and 1DJ481, if the normal contacts transfer open spuriously.

6. Event ACP-XHE-MC-40101 also contains the probability that the UV sensor on the 4.16 kV breaker 52-40101, which senses voltage greater than or equal to 94 percent of normal voltage, is miscalibrated.

7. Events ACP-REC-NO-AD481(2), BD481(2), CD481(2), and DD481(2) rectifier failure (AC power supply to inverter from the 480 VAC MCC), includes the failure all circuit fuses (for 120 VAC UPS).

8. Events ACP-AUT-FT-AD481(2), BD481(2), CD481(2) and DD481(2), auctioneering device (between rectified 480 VAC to 130 VDC and the 125 VDC batteries) failing to transfer when required, includes the failure of the disconnect switch and the 125 VDC supply breaker CB20. Additionally, this probability is a combination of the necessity for transfer (i.e., failure of the primary power circuit 480 VAC to 130 VDC) and the basic failure of the auctioneering circuit.

9. Events ACP-INV-NO-AD481(2), BD481(2), CD481(2) and DD481(2), loss of 125 VDC to 120 VAC inverter output due to miscellaneous faults, include inverter circuit breaker and disconnect malfunctions (120 VAC Class 1E UPS).

10. The static switch ICC faults, events ACP-ICC-AF-SWA81(2), SWB81(2), SWC81(2), and SWD81(2), include contact closure malfunctions as well as fuse failures and disconnect switch failures (Class 1E 120 VAC UPS).

11. The static switch logic faults, events ACP-LOG-FC-SWA81(2), SWB81(2), SWC81(2), and SWD81(2), include failure of the logic circuits to recognize loss of primary and alternate power supplies to the Class 1E 120 VAC inverter.

12. Events ACP-TFM-VF-AD481(2), BD481(2), CD481(2), and DD481(2), failure of the transformer and voltage regulating circuitry for the backup supply to the 120 VAC Class 1E UPS, include failure of the voltage regulator and disconnect switch.

13. Vital bus infeed breakers, 52-40101, 52-40108, 52-40201, 52-40208, 52-40301, 52-40308, 52-40401, and 52-40408 when open will remain open and when closed will remain closed with a loss of 125 VDC control power.

14. Infeed breakers 52-40103, 52-40203, 52-40303, and 52-40403 (for the Class 1E USSs) when open will remain open and when closed will remain closed with a loss of 125 VDC control power.

15. Faults resulting in power unavailability from the 500 kV switchyard were treated as a single event.

16. Only one infeed breaker on a Class 1E 4.16 kV bus (either from the diesel or from offsite power) may be closed at a time due to electrical interlocks.

17. Manual actuation of the Class 1E 4.16 kV infeed breakers and diesel generators was excluded from the fault trees.

Quantification-Related

The probability of a loss of offsite power within a 24-hour mission time (the fault tree event labeled ACP-OFFSITE-NORM) was derived by converting the yearly frequency for loss of offsite power of 0.05/yr to an hourly rate, using 8766*0.8 hrs/yr (the fraction of time the plant is at power). A probability of 3.04E-4 was obtained by multiplying the hourly rate by the 24 hour mission time, and was rounded to 3.0E-4. The frequency of faults in the 500 kV switchyard (identified by label ACP-SPE-VF-500 kV) were assumed to be 1.0E-3 for a 24-hour period. The unavailability of offsite power from the SGS switchyard (event ACP-OFFSITE-SALEM) is 1.3E-3 for a 24-hour mission time. It is assumed to be the sum of 3.0E-4 for a loss of offsite power at Salem and a ground fault that has a probability of 1.0E-3 for a 24-hour mission time.

The probabilities of undeveloped events ACP-BAC-VF-13K12 and ACP-BAC-VF-13K67, which are faults on Section 1-2 and 6-7 of the 13.8 kV ring bus, are based on the event that caused a fault on the 13.8 kV ring bus on May 13, 1993, and the amount of time since initial criticality at Hope Creek. The answer was rounded off to 2.0E-4/24 hours.

Room cooling is not modeled for 480 VAC MCC 00B474 because it is not called by any other fault trees modeled in the Hope Creek PRA. Room cooling is not modeled for 480 VAC MCCs 10B313 and 10B323 because they are called by fault trees for power to battery chargers that also receive power from other MCCs, and they are located in a large room. Room cooling is not modeled for MCCs 10B222, 10B232, 10B242, 10B252, 10B262, 10B272, and 10B282 because they are cooled via the reactor building ventilation system, and temperatures in the rooms they are in are not expected to increase to the point where equipment will fail within a 24-hour mission time based on the increase in temperature in the HPCI and RCIC pipe chases. Room cooling is not modeled for MCC 10B212 even though it is in one of the rooms with SACS pumps and heat exchangers because the only load required after it fails, which would take about 13 hours, is a core spray pump room cooler, which would lead to failure of the core spray pump in about another 12 hours, which is longer than the 24-hour mission time.

3.2.1.12.10 References

1. Hope Creek Generating Station UFSAR Section 8.

2. "Hope Creek Licensed Operator Training," Lesson Plan Number 302H-000.00H-000065-10. Public Service Electric and Gas Company, Hancocks Bridge, NJ, November 30, 1992.

3. "Hope Creek Licensed Operator Training," Lesson Plan Number 302HC-000.00-0666-06. Public Service Electric and Gas Company, Hancocks Bridge, NJ, June 21, 1993.

4. "Hope Creek Licensed Operator Training," Lesson Plan Number 302H-000.00H-000068-15. Public Service Electric and Gas Company, Hancocks Bridge, NJ, March 23, 1993.

5. "Hope Creek Generating Station Technical Specifications Sections 3.3.3, 3.8.1, 3.8.3 and 3.8.4.5." Public Service Electric and Gas Company, Hancocks Bridge, NJ, July 1986.

6. Public Service Electric and Gas Company Drawings

E-0001
E-0002
E-0003
E-0004
E-0005
E-0007
E-0008
E-0012
E-0013
E-0018
E-0019
E-0020
E-0021
E-0022
E-0023
E-0046
E-0106
E-0109
E-0118
E-1412
E-1417
E-3060
E-3062
E-3080
J-00A

7. Public Service Electric and Gas Company Procedures:

IC-PM.NA-001(Z)
IC-PM.NA-002(Z)
IC-PM.NB-001(Z)
IC-PM.NG-001(Z)
IC-PM.NG-002(Z)
IC-PM.NG-003(Z)
IC-PM.NQ-001(Z)
IC-PM.PN-001(Q)
IC-PM.PN-001(Q)
MD-CM.NA-001(Z)
MD-CM.PB-001(Q)
MD-CM.PH-001(Q)
MD-CM.PN-001(Q)
MD-CM.PN-002(Z)

7. Public Service Electric and Gas Company Procedures (Continued):

MD-PM.NA-002(Z)
MD-PM.PB-001(Q)
MD-PM.PB-002(Q)
MD-PM.PB-002(Z)
MD-PM.PN-001(Q)
MD-PM.PN-002(Z)
MD-PM.PN-003(Q)
MD-ST.PB-002(Q)
MD-ST.PB-003(Q)
MD-ST.PB-004(Q)
MD-ST.PB-007(Q)
OP-AB.ZZ-134(Q)
OP-AB.ZZ-135(Q)
OP-AR.MA-001(Z)
OP-AR.MH-001(Z)
OP-FT.MH-001(Z)
OP-SO.MA-001(Q)

3.2.1.13 DC Power (DCP) System

3.2.1.13.1 System Function

The purposes of the Class 1E DC power system are to supply 250 VDC power to required pumps and valves for the high pressure coolant injection (HPCI) and reactor core isolation cooling (RCIC) systems, to supply, as the Class 1E 125 VDC system, control power for 4.16 kV Class 1E buses, 480 VAC Class 1E unit substations, and 250 VDC Class 1E breakers and to supply backup power to vital and safety related equipment inverters. The 125 VDC Class 1E system also provides backup power to inverters for Non-Class 1E systems such as the plant security systems, public address systems and the NSSS computer systems. Non-Class 1E DC power is not modeled in the Hope Creek PRA except for 125 VDC buses 10D470 and 10D480, and 125 VDC distribution panels 1AD318, 1BD318, 1CD318, and 1DD318. These are similar to the 125 VDC Class 1E buses and distribution panels and are not discussed in detail in the Hope Creek PRA or IPE.

3.2.1.13.2 System Description

General Design

The Class 1E DCP system consists of battery banks, battery chargers, circuit breakers, fuses and DC control buses. There are two channelized Class 1E 250 VDC batteries (Channel A and Channel B) and four channelized Class 1E 125 VDC batteries (Channel A, Channel B, Channel C, and Channel D). The channels are also referred to as divisions. Although there are four 125 VDC channels, there are six banks of batteries for these divisions. Channel C and Channel D both have two distinct banks of batteries located at different elevations in the plant. Four of the 125 VDC battery banks have two separate 100 percent battery chargers per bank, while the other two banks have one 100 percent battery charger per bank. The two 250 VDC battery banks have one 100 percent battery charger per bank. The DC buses are supplied power by the battery chargers or the batteries in the event of the loss of the charger supply. A simplified diagram of the 125 VDC Class 1E Channel A DCP system is presented in Figure 3.2-13a. A simplified diagram of the 250 VDC Class 1E Channel A DCP system is presented in Figure 3.2-13b.

The Non-Class 1E DCP system includes one 250 VDC switchboard, five 125 VDC buses, five 125 VDC distribution panels, and two 24 VDC distribution panels.

Flow Path

The Class 1E 250 VDC and the 125 VDC battery chargers are supplied power by the Class 1E 480 VAC motor control centers (MCCs). The 125 VDC Class 1E buses 10D410, 10D420, 10D430 and 10D440 are supplied simultaneously by two 100 percent capacity battery chargers per bus. The battery chargers are supplied by two MCCs, one from each unit substation off of the respective 4.16 kV divisional bus. The 125 VDC Class 1E buses 10D436 and 10D446 are supplied by one battery charger per bus. Buses 10D410, 10D420, 10D430 and 10D440 each supply a 125 VDC Class 1E distribution panel, as well as 120 VAC Class 1E inverters and other 1E and Non-Class 1E DC loads. Buses 10D436 and 10D446 supply only Class 1E 120 VAC inverters. Similarly, the two 250 VDC buses 10D450 and 10D460 supply HPCI and RCIC loads exclusively. Bus 10D450 (Channel A) supplies HPCI and 10D460 (Channel B) supplies RCIC. Each of the 250 VDC Class 1E buses also supply a 250 VDC motor control center, 10D251 and 10D261. From these motor control centers various HPCI and RCIC components are powered.

Location

The Class 1E batteries are located as follows:

Channel	Volt	Battery	Bus	Bldg	Room	Elevation
A	125V	1AD411	10D410	Aux	5545	146'
B	125V	1BD411	10D420	Aux	5541	146'
C	125V	1DD411	10D430	Aux	5543	146'
D	125V	1DD411	10D440	Aux	5539	146'
C	125V	1CD447	10D436	Aux	5619	163'
D	125V	1DD447	10D446	Aux	5609	163'
A	250V	10D421	10D450	Aux	5104	54'
B	250V	10D431	10D460	Aux	5128	54'

Each battery is in a separate room. Switchgear for the Class 1E batteries are located as follows:

Channel	Volt	Bus	Bldg	Room	Elevation
A	125V	10D410	Aux	5417	130'
B	125V	10D420	Aux	5413	130'
C	125V	10D430	Aux	5415	130'
D	125V	10D440	Aux	5411	130'
C	125V	10D436	Aux	5613	163'
D	125V	10D446	Aux	5607	163'
A	250V	10D450	Aux	5129	54'
B	250V	10D460	Aux	5130	54'

Each battery charger is located in a separate room, but on the same elevation, near the respective battery that it is supplying.

The Non-Class 1E DC buses and corresponding batteries, and the distribution panels that are modeled as fault trees in the Hope Creek PRA are located as follows:

Channel	Volt	Bus	Bldg	Room	Elevation
A	125V	10D470	Aux	5102	54'
B	125V	10D480	Aux	5102	54'

Channel	Volt	Battery	Bldg	Room	Elevation
A	125V	1A1D471	Aux	5126	54'
A	125V	1A2D471	Aux	5126	54'
B	125V	1B1D471	Aux	5126	54'
B	125V	1B2D471	Aux	5126	54'

Channel	Volt	Distribution Panels	Bldg	Room	Elevation
A	125V	1AD318	Radwaste	3449	124'
B	125V	1BD318	Radwaste	3449	124'
A	125V	1CD318	Radwaste	3432	124'
B	125V	1DD318	Radwaste	3432	124'

Component Descriptions

250 VDC Batteries

These batteries have 120 cells. The HPCI batteries are rated at 825 amp-hours at an eight hour rate and the RCIC batteries are rated at 330 amp-hours at an eight hour rate. The batteries are mounted in corrosion resistant steel racks in separately ventilated and isolated areas. The HPCI battery feeds its bus through a 1200 amp high capacity fuse and the RCIC battery feeds its bus through an 800 amp high capacity fuse. Both batteries are lead calcium batteries with acidic electrolyte. Battery capacity is based on supplying system loads for four hours without the availability of the battery chargers.

125 VDC Batteries for Buses 10D410, 10D420, 10D430 and 10D440

The batteries have 60 cells and are rated at 1800 amp-hours at an eight hour rate. The batteries are mounted on corrosion resistant steel racks in separately ventilated and isolated areas. Each battery feeds its respective bus through a 2000 amp high capacity fuse. The batteries are lead calcium batteries with an acidic electrolyte. The capacity is based on meeting system loads for four hours without the availability of the battery chargers.

125 VDC Batteries for Buses 10D436 and 10D446

The batteries have 60 cells and are rated at 577 amp-hours at an eight hour rate. The batteries are mounted on corrosion resistant steel racks in separately ventilated and isolated areas. Each battery feeds its respective bus through an 800 amp high capacity fuse. The batteries are lead calcium batteries with an acidic electrolyte. The capacity is based on meeting system loads for four hours without the availability of the battery chargers.

125 VDC Battery Chargers

Buses 10D410, 10D420, 10D430 and 10D440 are each supplied by two 100 percent capacity battery chargers. Buses 10D436 and 10D446 have one charger supplying each bus.

250 VDC Battery Chargers

There is one 100 percent capacity battery charger supplying each of these buses.

125 VDC Control Buses

There are six 125 VDC buses supplying four electrical channels. Four buses (10D410, 10D420, 10D430, and 10D440) supply a distribution panel, and they act as alternate supply to the Class 1E 120 VAC UPS inverters, in addition to supplying necessary vital and selected non vital loads. Two buses (10D436 and 10D446) act as alternate supply to Class 1E 120 VAC UPS inverters. There is no cross connection between channels for the 125 VDC Class 1E system. These buses supply control power through the distribution panels for valves, breakers, diesel generator field flashing and control, etc.

250 VDC Control Buses

Each of the two 250 VDC buses supply a 250 VDC motor control center. These buses represent two channels (A and B). Bus 10D450 is dedicated to supplying DC power for HPCI and bus 10D460 is dedicated to supplying DC power for RCIC. These buses have no other functions. The loads are supplied through 250 VDC MCCs 10D251 (Channel A - HPCI) and 10D261 (Channel B - RCIC). The loads are valves, pumps, etc.

3.2.1.13.3 System Interfaces

Shared Components

The DCP system shares no components with other safety systems.

Electrical

An alternate power source to the AC powered 120 VAC UPS/vital instrument buses is provided by the 125 VDC system. The Class 1E 480 VAC power from the MCCs is the preferred source of power; however, the DC power provides an alternate power source.

The DCP battery chargers are supplied by the Class 1E 480 VAC MCCs.

The 250 VDC Class 1E system is a highly reliable source of power for the ECCS functions of HPCI and RCIC. The 250 VDC battery chargers are supplied by Class 1E 480 VAC MCCs. Control power for 250 VDC MCC breakers is provided by the 125 VDC system.

Actuation

The batteries provide an automatic backup source of power for the DC buses.

Room Cooling

Room cooling is provided for the rooms where all DCP system equipment is located.

3.2.1.13.4 Instrumentation and Control

System Actuation

If there were a failure of a battery charger to supply power to a DC bus, the battery connected to the affected bus automatically supplies power.

Instrumentation

Instrumentation indicating the status of the DCP system is listed below:

1. Control Room Indication

   A 125 VDC
   1. Battery Voltage.
   2. Battery Current.
   3. Bus Voltage.
   4. Bus Current.

5. Switchgear/Distribution Panel Ground Detection Current.
6. Charger Current.
7. Charger Voltage.

B. 250 VDC
1. Charger Voltage.
2. Charger Current.
3. Bus Voltage.
4. Bus Current.
5. Switchgear/MCC Ground Detection Current.
6. Battery Current.
7. Battery Voltage.
8. Switchboard Trouble.

2. Control Room Overhead Annunciator Alarms

A. 125 VDC
1. System Trouble.

B. 250 VDC
1. System Trouble.

3. Control Room Computer Point Alarms

A. 125 VDC
1. Class 1E Switchgear Undervoltage
2. Class 1E Battery Charger Trouble.
3. Class 1E Battery Monitor Problem.
4. Non-Class 1E Switchgear Panel Trouble.
5. Non-Class 1E Battery Charger Trouble.
6. Non-Class 1E Battery Monitor Trouble.

B. 250 VDC
1. Class 1E Switchgear High Ground or Low Voltage.
2. Class 1E Battery Charger Trouble.
3. Class 1E Battery Monitor Trouble.

Control

Fuse transfer switches (six for 125 VDC and two for 250 VDC) connect the respective battery to its associated switchgear. There is a two position switch. The ON LINE position connects the battery to the switchgear. The switch can be locked in this position. The OFF LINE position of the switch connects the respective battery to the battery test tees.

3.2.1.13.5 Operator Actions

Operators monitor both control room and local instrumentation of the DCP system.

3.2.1.13.6 Technical Specifications

Technical Specifications 3.8.2 and 3.8.3 (Limiting Conditions for Operation) and 4.8.2 and 4.8.3 (Surveillance Requirements) apply to the DCP system. The limiting conditions for operation are summarized below:

Limiting Conditions for Operation

1. As a minimum, in Modes 1, 2, and 3, the following DC electrical power sources shall be operable:

   a. Channel A consisting of:

1)	125 volt battery	1AD411
2)	125 V full capacity charger	1AD413 or 1AD414
3)	250 volt battery	10D421
4)	250 V full capacity charger	10D423

   b. Channel B consisting of:

1)	125 volt battery	1BD411
2)	125 V full capacity charger	1BD413 or 1BD414
3)	250 volt battery	10D431
4)	250 V full capacity charger	10D433

   c. Channel C consisting of:

1)	125 volt battery	1CD411
2)	125 V full capacity charger	1CD413 or 1CD414
3)	125 volt battery	1CD447
4)	125 V full capacity charger	1CD444

   d. Channel D consisting of:

1)	125 volt battery	1DD411
2)	125 V full capacity charger	1DD413 or 1DD414
3)	125 volt battery	1DD447
4)	125 V full capacity charger	1DD444

With less than the items required operable in 1 (above) perform the following actions:

a. With any 125V battery and/or all associated chargers of the above required DC electrical power sources inoperable, restore the inoperable channel to operable status within two hours or be in at least hot shutdown within the next 12 hours and in cold shutdown within the following 24 hours.

b. With any 250V battery and/or charger of the above DC electrical power sources inoperable, declare the associated HPCI or RCIC system inoperable and take the appropriate action required by the applicable specification.

2. As a minimum, in Modes 1, 2, and 3, the following power distribution system channels shall be energized:

a. Channel A consisting of:

1) 125 volt DC switchgear	10D410
2) 125 volt DC fuse box	1AD412
3) 125 volt DC distribution panel	1AD417
4) 250 volt DC switch gear	10D450
5) 250 volt DC fuse box	10D422
6) 250 volt DC MCC	10D251

b. Channel B consisting of:

1) 125 volt DC switch gear	10D420
2) 125 volt DC fuse box	1BD412
3) 125 volt DC distribution panel	1BD417
4) 250 volt DC switch gear	10D460
5) 250 volt DC fuse box	10D432
6) 250 volt DC MCC	10D261

c. Channel C consisting of:

1) 125 volt DC switch gear	10D430 10D436
2) 125 volt DC fuse box	1CD412 1CD448
3) 125 volt DC distribution panel	1CD417

d. Channel D consisting of:

1) 125 volt DC switch gear	10D440 10D446

2)	125 volt DC fuse box	1DD412 1DD448
3)	125 volt DC distribution panel	1DD417

With less than the above systems energized, perform the following:

a. If any one of the above required 125 VDC distribution system channels is not energized, re-energize the division within two hours or be in at least hot shutdown within the next 12 hours and in cold shutdown within the following 24 hours.

b. With any one of the above required 250 VDC distribution systems not energized, declare the associated HPCI or RCIC system inoperable and apply the appropriate action required by the applicable specifications.

3.2.1.13.7 Testing

Tests are summarized in the Technical Specifications Section 4.8.2.1.

3.2.1.13.8 System Operation

Normal Operation

The battery chargers normally energize the DC buses and maintain a float charge on the batteries.

Abnormal Operation

If AC power is lost to a battery's charger or chargers, such as from a station blackout, the battery will supply power to its respective bus until it is depleted, or until power is restored to a battery charger.

3.2.1.13.9 System Fault Tree

3.2.1.13.9.1 Description

The DCP fault trees identify the credible component and support system faults. A simplified diagram indicating those components modeled in the 125 and 250 VDC Class 1E Channel A DCP fault trees is shown in Figures 3.2-13a and b. Similar diagrams were used to model the fault trees for the other DCP channels. The fault trees are not included in the IPE report.

3.2.1.13.9.2 Success and Failure Criteria

DCP operation is successful as long as each of the DC power loads remain energized. Failure to energize loads occurs as the result of a feeder breaker failure, bus failure, or power unavailable from the battery bank and associated charger(s).

3.2.1.13.9.3 Assumptions

Model-Related

1. Loss of ventilation to the battery enclosures will not cause a failure of the batteries within the 24 hour mission time.

2. Breaker fault probabilities for the battery chargers are to be included in the ICC faults for the battery chargers.

3. Events of the type DCP-CHG-NO-XXXXX "125 VDC battery charger XXXXX shorts and miscellaneous faults" assume loss of the charger due to electrical shorts in the charger and other faults that open circuits on the associated charger, thereby producing no output.

4. Room cooling is not modeled for Non-Class 1E 125 VDC distribution panels 1AD318, 1BD318, 1CD318, and 1DD318 because they are in the radwaste building and are assumed to be in rooms that have low cooling requirements.

Quantification-Related

Room cooling is not included in the Class 1E and Non-Class 1E DCP system fault trees because the ACP system supplies for power for battery chargers for the DCP system would fail before the DCP system from a loss of room cooling.

3.2.1.13.10 References

1. Hope Creek Generating Station UFSAR Section 8.3.2.

2. "Hope Creek Licensed Operator Training," Lesson Plan Number 302H-000.004-000069-11. Public Service Electric and Gas Company, Hancocks Bridge, NJ, January 18, 1993.

3. "Hope Creek Generating Station Configuration Baseline Documentation," Doc. No. DE-CB.PJ-0061, DE-CB.NJ-0061, DE-CB.PK-0062, DE-CB.NK-0062, DE-CB.PL-0063, DE-CB.NL-0063. Public Service Electric and Gas Company, June 1991.

4. "Hope Creek Generating Station Technical Specifications 3.8.2, 3.8.3, 4.8.2, and 4.8.3." Public Service Electric and Gas Company, Hancocks Bridge, NJ, July 1986.

5. Public Service Electric and Gas Company Drawings
   E-0009
   E-0010
   E-0011
   E-0019-1

5. Public Service Electric and Gas Company Drawings

E-0010-1
E-3090

6. Public Service Electric and Gas Company Operating Procedures

MD-CM.PJ-001(Q)
MD-CM.PJ-002(Q)
MD-CM.PK-001(Q)
MD-GP.ZZ-014(Q)
MD-GP.ZZ-015(Q)
MD-PM.ZZ-014(Q)
MD-ST.PJ-002(Q)
MD-ST.PJ-002(Q)
MD-ST.PJ-003(Q)
MD-ST.PK-001(Q)
MD-ST.PK-002(Q)
MD-ST.PK-005(Q)
OP-AB.ZZ-147(Q)
OP-AB.ZZ-149(Q)
OP-AB.ZZ-150(Q)
OP-SO.PJ-001(Q)
OP-ST.ZZ-001(Q)
SA-AP.ZZ-032(Q)

3.2.1.14 Engineered Safety Features (ESF)

3.2.1.14.1 System Function

The Engineered Safety Features (ESF) at HCGS include some systems, such as the Redundant Reactivity Control System (RRCS), and initiation features of other systems, such as initiation of the Core Spray System (CSS). These features are the link between the Nuclear Boiler Instrumentation and the pumps and valves that are required to operate at certain setpoints. The primary functions of ESF for this study are initiation of the following systems:

1. High Pressure Coolant Injection (HPCI),

2. Reactor Core Isolation Cooling (RCIC),

3. Residual Heat Removal, Low Pressure Coolant Injection mode (RHR/LPCI),

4. Core Spray (CSS), and

5. Standby Liquid Control (SLC) through RRCS.

There are other features of ESF that are not developed here because they are not required for this study. Some of these are:

1. Diesel generator actuation on a LOCA signal,

2. MSIV closure,

3. Containment isolation, and

4. ADS actuation.

3.2.1.14.2 System Description

General Design

The ESF receives signals from level, pressure and/or differential pressure transmitters and sends an initiation or actuation signal to pumps and/or valves as required. There are 4 ESF channels, A, B, C, and D, and there are 2 RRCS channels, A and B. The channels receive signals at the following setpoints:

Reactor low level - level 1 (-129"),

Reactor low level - level 2 (-38"),

High drywell pressure (1.68 psig),

Reactor vessel low level (+12.5"),

Reactor high pressure (1071 psig), and

Manual

3.2.1.14.3 System Interfaces

Electrical

Engineered Safeguards 125 VDC buses A and B supply power to the instruments utilized by the Emergency Core Cooling Systems (ECCS - HPCI, RHR, and CSS). Power from these buses is also supplied to the instruments that provide indication at the Remote Shutdown Panel (RSP).

Power to the RRCS cabinets (for SLC) is supplied by the 1E 125 VDC power system. Channel A logics are powered from 1AD417 and channel B logics are powered from 1BD417.

3.2.1.14.4 Instrumentation and Control

For HPCI initiation, there are 4 reactor low level transmitters (level 2: -38"), 1BBLT-N091A and 1BBLT-N091E (channel A) and 1BBLT-N091C and 1BBLT-N091G (channel C), and 4 high drywell pressure transmitters (1.68 psig), 1BBPT-N094A and 1BBPT-N094E (channel A) and

1BBPT-N094C and 1BBPT-N094G (channel C). The initiation logic is 1 out of 2 taken twice for the level transmitters or 1 out of 2 taken twice for the pressure transmitters. When HPCI receives the initiation signal from ESF, the following things happen: the auxiliary oil and vacuum pumps start; valves 1FDHV-F001, 1FDFV-4880, 1FDFV-4879, 1BJHV-F004, 1BJHV-F007, 1BJHV-F006, 1BJHV-8278, 1BJHV-F059, and 1BJHV-F012 open; and valves 1BJHV-F008, 1APHV-F011, 1FDHV-F028, 1FDHV-F029, 1FDHV-F026, 1FDLV-F025, and 1FDHV-4922 close.

For RCIC initiation, there are 4 reactor low level transmitters (level 2: -38"), 1BBLT-N091B and 1BBLT-N091F (channel B) and 1BBLT-N097D and 1BBLT-N097H (channel D). The initiation logic is 1 out of 2 taken twice. When the RCIC initiation signal is generated, valves 1FDHV-F045, 1BDHV-F010 (if closed and 1BDHV-F031 is not full open), 1BDHV-F012 (if closed), 1BDHV-F013 and 1BDHV-F046 open. Valves 1BDHV-F022 (if open), 1BDHV-F025, 1BDHV-F026, 1BDLV-F004, and 1BDLV-F005 close. The barometric condenser vacuum pump starts.

For RHR and CSS initiation, there are 4 channels. There are 2 reactor low level transmitters (level 1: -129") and 2 high drywell pressure transmitters (1.68 psig) per channel. The initiation logic is 1 out of 2 of both the level and pressure transmitters or 2 out of 2 of either the level or pressure transmitters. Although the CSS and RHR logic processors receive inputs from the same transmitters, each system has its own processor. Channel A sends input signals to the logic processors for RHR and CSS pumps A. The transmitters for channel A are 1BBLT-N091A, 1BBLT-N091E, 1BBPT-N094A, and 1BBPT-N094E. Channel B sends input signals to the logic processors for RHR and CSS pumps B. The transmitters for channel B are 1BBLT-N091B, 1BBLT-N091F, 1BBPT-N094B, and 1BBPT-N094F. Channel C sends input signals to the logic processors for RHR and CSS pumps C. The transmitters for channel C are 1BBLT-N091C, 1BBLT-N091G, 1BBPT-N094C, and 1BBPT-N094G. Channel D sends input signals to the logic processors for RHR and CSS pumps D. The transmitters for channel D are 1BBLT-N091D, 1BBLT-N091H, 1BBPT-N094D, and 1BBPT-N094H. When the LPCI initiation signal is generated, the pumps start and 1EGHV-2520(A-D) open. The LPCI valves require a low reactor pressure permissive (<450 psig) to open. The Containment Spray (CSC) mode of RHR requires a LPCI signal and high drywell pressure (1.68 psig). When the CSS initiation signal is generated, the pumps start and 1BEHV-F015A(B) close. Valves 1BEHV-F004A(B) and 1BEHV-F005A(B) also receive a signal, but they also require a low reactor pressure permissive (<461 psig).

For SLC initiation (RRCS), there are 2 channels with 2 reactor low level transmitters (level 2: -38") and 2 reactor high pressure transmitters (1071 psig) per channel. The transmitters for channel A are 1BBLT-N402A, 1BBLT-N402E, 1BBPT-N403A, and 1BBPT-N403E. The transmitters for channel B are 1BBLT-N402B, 1BBLT-N402F, 1BBPT-N403B, and 1BBPT-N403F. The logic here is 2 out of 2 taken once for the level indications or 2 out of 2 taken once for the pressure indications for each channel. When SLC receives an initiation signal, both pumps start (on a signal from either channel), both squib valves fire (on a signal from either channel), and the RWCU suction valves isolate (1BGHV-F001 on a signal from channel A and 1BGHV-F004 on a signal from channel B). SLC will not initiate unless APRMs are >4% power 3.9 minutes after the low level or high pressure signal is received.

3.2.1.14.5 Operator Actions

No operator actions are required to initiate this system in any mode. In certain cases, to regain manual control, an operator action may be required to reset the actuation if it is a sealed in signal, which prevents operators from interfering with safety system actuation.

3.2.1.14.6 Technical Specifications

Limiting Condition for Operation for ECCS Actuation Instrumentation (TS 3.3.3)

The ECCS (HPCI, RHR, and CSS) actuation instrumentation channels shall be operable with their trip setpoints set as shown in the Tech Specs Table 3.3.3-2 and with the response time as shown in Table 3.3.3-3.

With an ECCS actuation instrumentation channel trip setpoint less conservative than the value shown in Tech Spec Table 3.3.3-2, declare the channel inoperable until the channel is restored to operable status with its trip setpoint adjusted consistent with the Trip Setpoint value.

With one channel of the HPCI actuation instrumentation channels inoperable, place the inoperable channel in the tripped condition within 1 hour or declare HPCI inoperable. With more than one channel inoperable declare HPCI inoperable.

With one RHR and/or CSS high drywell pressure or level 1 low reactor level channel inoperable, place the inoperable channel in the tripped condition within 1 hour or declare the associated system(s) inoperable. With more than one channel inoperable declare the associated system(s) inoperable.

Limiting Condition for Operation for RCIC Actuation Instrumentation (TS 3.3.5)

The RCIC actuation instrumentation channels for level 2 reactor vessel level shall be operable with their trip setpoints set consistent with the values shown in Tech Spec Table 3.3.5-2.

With a RCIC system actuation instrumentation channel trip setpoint less conservative than the value shown in Table 3.3.5-2 of the Tech Specs, declare the channel inoperable until the channel is restored to operable status with its trip setpoint adjusted consistent with the Trip Setpoint value.

With one RCIC channel inoperable, place the inoperable channel in the tripped condition within 1 hour or declare RCIC inoperable. With more than one channel inoperable, declare RCIC inoperable.

3.2.1.14.7 Testing

ESF testing (as required by the Technical Specifications) includes the following:

1. Each ESF channel shall be demonstrated operable by the performance of a channel check at least once per 12 hours, a channel functional test at least once per 31 days, and a channel calibration at least once per 18 months.

2. The total interlock function (logic check) shall be demonstrated operable at least once per 18 months during the channel calibration. Furthermore, the logic for the interlocks shall be demonstrated operable during automatic actuation logic tests.

3. The Engineered Safety Features response time for each ESFAS function shall be demonstrated to be within the limit at least once per 18 months.

3.2.1.14.8 System Operation

Normal Operation

Under normal operation, the system monitors plant conditions for a sign of an abnormal plant condition.

Abnormal Operation

Under LOP conditions, with bus voltage 70 percent, the LOP sequencer is initiated, and process start inhibit signals (PSIS) are generated to prevent standby loads from starting (if power is available to these loads) in response to process parameters (low flow, etc.). The diesel will not start or load unless voltage is less than 92% on both infeeds.

Once the diesel generator output breaker closes on the bus (an "a" contact from the breaker), the LOP timer is initiated. The timer output is used to sequence on selected loads at predetermined time intervals. If a LOCA signal is received, the LOP sequencer does not control the starting of loads. The LOCA sequencer will be activated, and it will control the starting of loads after the diesel generator breaker closes on the bus. The LOCA sequencer always has priority.

Sequencer Response Under LOCA Condition

The LOCA sequencer is activated from the Core Spray circuitry on drywell pressure $\geq$1.68 psig, reactor vessel level $\leq$-129 inches or Core Spray manual initiation pushbuttons.

Process start inhibiting signals (PSIS) are generated to prevent standby loads from starting in response to process parameters. The LOCA timer is initiated to sequence the selected loads at predetermined intervals.

If a LOP signal is concurrent with the LOCA, the LOCA sequencer will not initiate any load start signals until the diesel generator has restored power to the bus (diesel generator out-breaker closed). These signals (high drywell pressure or reactor low level) are also used to initiate LOCA load shedding of Non-Class 1E loads. The signals which initiate load shedding are not processed by the LOCA timer. These signals pass through the individual sequencer cabinets but are not processed by any logic circuitry prior to load shed initiation.

Under conditions in which both a LOP and a LOCA signal are present, the LOCA sequencer will always be the controlling device once power is restored to the bus. Each core spray manual initiation pushbutton activates the LOCA sequencer in its respective division.

3.2.1.14.9 System Fault Tree

3.2.1.14.9.1 Description

Different trees were developed to adequately describe ESF actuation. ESF actuation logic fault trees were developed for CSS, LPCI (RHR), HPCI, RCIC, SLC, RRCS, and the sequencer (ELS). Many other pumps, motor operated valves etc., in systems other than ECCS, receive a LOCA or LOP signal from the respective sequencer. Simplified logic diagrams are shown in Figure 3.2-14a and b.

3.2.1.14.9.2 Success and Failure Criteria

A channel is considered to be successful when it provides the appropriate actuation signal as designed to the respective component. The success criteria may differ depending upon the requirement of the system under different accident conditions. The success criteria are then defined in the system description of that system.

3.2.1.14.9.3 Assumptions

1.. Faults of timers are not individually modeled since they are included in the ICC failures.

2. Faults in comparators are included in various faults of transmitter events.

3. Dependent failures of miscalibration are modeled on a channel basis or on a transmitter type basis (i.e., all level transmitters).

3.2.1.14.10 References

1. Hope Creek Generating Station UFSAR Section 7.3.2.

2. "Hope Creek Generating Station Licensed Operator Systems," Lesson Plan Numbers 302H-000.00H-000024-11, 302H-000.00H-000025-08, 302H-000.00H-000026-14, 302H-000.00H-000027-12, 302H-000.00H-000028-11, and 302H-000.00H-000030-13. Public Service Electric and Gas Company, Hancocks Bridge, NJ, May 18, 1989.

3. "Hope Creek Generating Station Technical Specifications 3.3.1/4.3.1, 3.3.3/4.3.3, 3.3.5/4.3.5," Public Service Electric and Gas Company, Hancocks Bridge, NJ, July 1986.

4. Public Service Electric and Gas Operating Procedures: OP-SO.BC-0001, OP-SO.BE-0001, OP-SO.BJ-0001, OP-SO.SA.0001.

5. Public Service Electric and Gas Drawings

E-6067-0
J-48-0
M-42-1
PN1-C22-1030-0052
PN1-C22-4010-0001
PN1-C22-4010-0003
PN1-C41-1030-0043
PN1-E11-1030-0020
PN1-E21-1030-0001
PN1-E41-1030-0064
PN1-E51-1030-0061
PN1-E51-1040-0005

3.2.1.15 Safety Auxiliaries Cooling System (SACS)

3.2.1.15.1 System Function

The Safety Auxiliaries Cooling System (SACS) is a closed loop cooling system designed to supply cooling water to various safety-related equipment during all plant operating modes. The system is a part of the overall system called the Safety and Turbine Auxiliaries Cooling System (STACS), which also supplies cooling water to various auxiliary equipment during normal operation and various shutdown conditions.

3.2.1.15.2 System Description

General Design

The STACS consists of two redundant loops. A simplified diagram of STACS is presented in Figure 3.2-15. Each STACS loop contains two pumps, two heat exchangers, one expansion tank, one demineralizer, and one chemical addition tank, in addition to pipes and valves. The pumps circulate the demineralized cooling water through components and equipment. The circulating water is cooled by the station service water system in the SACS heat exchangers. Each SACS loop is completely independent of the other, eliminating the possibility of a single failure causing the loss of the entire system. The pumps and the associated motor-operated valves for each loop receive power from separate and independent Class 1E AC buses. Similarly, control power for each essential loop comes from separate and independent Class 1E

DC buses. The SACS is designed with seismic Category I and Quality Group C ESF components that should withstand postulated accident conditions without impaired function. The SACS provides cooling water to the following safety auxiliary coolers:

1. Residual heat removal pump seal and pump motor bearing cooler,
2. RHR heat exchangers,
3. Diesel generator intercooler heat exchangers, jacket water heat exchangers, and lube oil coolers,
4. Diesel generator room coolers,
5. Fuel pool heat exchangers,
6. Residual heat removal pump room coolers,
7. High pressure coolant injection pump room coolers,
8. Reactor core isolation cooling pump room coolers,
9. Core spray pump room coolers,
10. Filtration, Recirculation, and Ventilation System (FRVS) recirc trains,
11. Control room chillers (AK400 and BK400),
12. Safety-related panel room chillers (AK403 and BK403),
13. Primary Containment Instrument Gas compressor coolers,
14. The post accident sampling system coolers are normally valved out, but can be manually valved to either loop.

The TACS portion provides cooling water to the following turbine auxiliary coolers:

1. Service air compressors,
2. Secondary condensate pump motor bearing coolers,
3. Main turbine lube oil coolers,
4. Main turbine EHC hydraulic fluid coolers,
5. Generator stator coolers,

6. Generator hydrogen coolers,

7. Reactor recirculation pump M-G set coolers,

8. Reactor feed pump lube oil coolers,

9. Isophase bus duct coolers,

10. Alterrex air cooler,

11. Mezzanine pipe chase unit coolers,

12. Condenser compartment unit coolers,

13. Turbine building chiller condensers and pump out unit coolers,

14. Turbine building sample station coolers.

Flow Path

The STACS is a closed loop system consisting of two redundant SACS loops and a single TACS loop. The flow path through one SACS loop and the TACS loop is explained below.

The STACS water is cooled as it passes through the parallel SACS heat exchangers. The heat exchangers are equipped with a bypass line which is used to maintain the SACS water temperature. Flow through the bypass line is controlled by a temperature control valve which modulates in response to signals from a downstream temperature transmitter. The discharge from the heat exchangers combines with the bypass flow and proceeds to the two parallel pumps. In the common pump suction header between the heat exchangers and the pumps, a tap-off is provided for the expansion tank. After the pumps, STACS cooling water flows through a total flow transmitter in the common discharge header and is divided into various flow paths.

Two filter demineralizer tanks and one skid rack are installed in the TACS portion of the STACS system. They are supplied by the STACS water off of a line which proceeds to the service air coolers. A small amount of water flows through the demineralizers; however, over time a sufficient amount of water will have passed through these tanks to achieve the desired condition for the TACS water. The filter demineralizers are used as an alternative form of corrosion treatment because of the negative effects of the chemical addition tanks.

Two filter demineralizer tanks are installed in the SACS portion of the STACS system. Each SACS loop is equipped with its own Demineralizer Loop. Demineralizer Loop A taps off the SACS Pump AP-210 discharge and Loop B taps off of SACS Pump DP-210 discharge. SACS water passing through either demineralizer loop is then returned to SACS at the suction of its respective pump (i.e., just downstream of the SACS Heat Exchanger outlet). The Demineralizer Tanks remove impurities, reduce the conductivity, and minimize corrosion of the SACS water.

A STACS cooling water flow tap-off is provided from the common pump discharge header for flow to the RHR heat exchanger and from there to the return header. Downstream of the RHR heat exchanger, a tap-off to the Radiation Monitoring System (RMS) is provided to monitor for radioactive water leakage into the cooling water. The return flow from the RMS is to the common line to the inlet of the SACS pumps.

The STACS system normally operates with both pumps operating in one loop (supplying TACS loads) and one pump in the opposite loop (supplying SACS loads). The cooling water supplying the SACS loads (Refer to P&IDs M-11-1(Q) and M-12-1(Q) returns to its loop's return header and proceeds to the SACS heat exchangers. The flow to the heat exchangers is controlled by temperature control valves (HV-2457A and B and TV-2517A and B) which allow a variable flow to bypass the heat exchangers.

The TACS loads are supplied with STACS cooling water through hydraulically operated butterfly valves (HV-2522A-D). Flow to TACS from either STACS loop then passes through a cross-connect which joins both STACS headers. STACS cooling water flows through the SACS/TACS common supply isolation valves (HV-2522E, F) to the supply side accumulator. Cooling water is then supplied to the TACS loads (Refer to P&ID M-14-1) and returned to the TACS header through the return side accumulator. The cooling water is then returned to the common line to the inlet of the heat exchangers.

Component Descriptions

SACS Pumps

Four 50% capacity SACS pumps circulate demineralized water through the SACS and the TACS to cool various plant components and equipment. The pumps are designated AP210, BP210, CP210, and DP210. The pumps are motor-driven, horizontal, split casing, centrifugal type. The SACS pumps are equipped with mechanical seals to prevent leakage along the pump shaft. The pumps have automatic starting capabilities to provide greater system reliability.

Each pump has a capacity of 11,600 gpm at a discharge pressure of 125 psig. Each pump has a 600 hp motor powered by 4.16 kV redundant Class 1E bus.

Heat Exchangers

Four heat exchangers, designated A1E201, A2E201, B1E201, and B2E201, are located on Reactor Building EL 102-ft. The heat exchangers provide heat transfer between the STACS and the Station Service Water System. Each heat exchanger is the horizontal, shell and tube type. Two heat exchangers are stacked in parallel in each STACS loop.

The shell side of the heat exchanger (the STACS side) is kept at a higher pressure than the tube side (the SSWS side). In the event of a heat exchanger rupture or leak, this pressure differential allows leakage from the STACS into the SSWS, thereby providing a barrier which prevents brackish river water from entering the STACS.

The STACS loop coolant supply temperature is continuously monitored and controlled to the designed temperature range by the STACS heat exchanger bypass valves (HV-2457A and B and TV-2517A and B). In the event of excessive temperature rise or a LOCA or LOP, the heat exchanger bypass valves automatically close to provide maximum cooling.

System Valves

The affected STACS loop can be isolated from TACS by closing the supply isolation valves (HV-2522A-F) in conjunction with the return isolation valves (HV-2496A-D). The supply isolation valves (HV-2522A-D) and the common supply isolation valves (HV-2522E, F) are hydraulic valves. The return isolation valves are motor-operated butterfly valves (HV-2496A-D). The STACS heat exchanger inlet valves (HV-2491A, B and HV-2494A, B) are motor-operated butterfly valves (one per heat exchanger) which isolate individual heat exchangers. Two air operated temperature control valves (HV-2457A and B and TV-2517A and B) in each heat exchanger bypass line maintain outlet temperature of the heat exchangers in the designed range. On the SSWS side, there is one motor-operated valve on the discharge side of each heat exchanger. These valves (1EAHV-2371A, B and 1EAHV-2355A, B) will be open if their associated SSWS pumps are operating, and closed if their associated pumps are not running.

3.2.1.15.3 System Interfaces

The support systems modeled for the SACS are the electrical power system and the station service water system. For successful operation of SACS during a transient, control air is not required since all the control air-operated valves will fail safe on the loss of control air.

Electrical

The SACS requires AC and DC power for its control, actuation, and operation. The following Class 1E AC and DC power is required:

1. 4.16 kVAC buses 10A401, 10A402, 10A403, 10A404,

2. 480 VAC MCCs 10B212, 10B222, 10B232, 10B242,

3. 120 VAC Instr. Dist. Panels 1AJ481, 1BJ481, 1CJ481, 1DJ481,

4. 125 VDC buses 10D410, 10D420, 10D430, 10D440.

Room Cooling

Room cooling in the area of the SACS pumps is provided by the Equipment Area Cooling System (Section 3.2.1.21). The heat sink for the room coolers is the chilled water system.

3.2.1.15.4 Instrumentation and Control

System Actuation

During normal plant operation, both pumps in the loop providing TACS cooling, and one pump from the opposite loop are in operation. The SACS pumps can be operated from the control room or locally, provided that control is transferred. SACS loop B can also be operated from the remote shutdown panel.

All SACS pumps auto-start on the following signals:

1. LOCA Level 1 (-129" or 1.68 psig) at T=45 seconds,

2. LOP at T=45 seconds,

3. Low flow to TACS from the operating SACS loop (13,260 gpm) will start the opposite loop pumps if in AUTO,

4. Chilled water loop low flow with the circulation water pump in AUTO and the respective SACS pump in AUTO,

   a. AP414 Chilled Water Pump autostart or running (AP210 only) (TSC chiller),

   b. BP414 Chilled Water Pump autostart or running (BP210 only) (TSC Chiller),

   c. AP400 Chilled Water Pump autostart or running (CP210 only) (Control Room Chiller),

   d. BP400 Chilled Water Pump autostart and running (DP210 only) (Control Room Chiller).

5. A and B SACS pumps autostart on the following signals if in AUTO:

   a. LOCA Level 2 (-38 inches Rx level or 1.68 lb. drywell pressure),

   b. Reactor Building Ventilation Exhaust Radiation Hi-Hi ($1x10^{-3}$uC/cc),

   c. Refuel Floor Radiation Ventilation Exhaust Hi-Hi ($2x10^{-3}$uC/cc).

All SACS pumps trip on the following signals:

1. LOP,

2. Low pump differential (PDSL-2485A-D) pressure 30 seconds after a pump start. B and D SACS pumps will not trip on this signal if their control has been transferred to the RSP,

3. The SACS pumps will auto-trip on undervoltage and overcurrent.

The heat exchanger inlet valve HV-2491A, B or HV-2494A, B will open when its associated pump starts. The TACS supply and return valves (HV-2496A-D and HV-2522A-D) will close when their respective pumps stop, and can be overridden using their respective pump "STOP INPUT OVERRIDE" switches. These valves auto trip on a LOCA or LOP signal. The normally open air-operated valves HV-2457A(B) in series with one modulating air-operated valve TV-2517A(B) in the heat exchanger bypass line fail closed on a LOP or loss of air. Valve HV-2457A(B) auto-closes on high heat exchanger outlet temperature of 95°F, while valve TV-2517A(B) modulates to maintain the heat exchanger outlet temperature at 72°F or auto-closes on high heat exchanger outlet temperature of 95°F.

3.2.1.15.5 Operator Actions

Under normal conditions, one SACS loop with both pumps running (supplying SACS and TACS loads), and one SACS pump from the opposite SACS loop (supplying SACS loads) are in operation. The fourth SACS pump is in auto-standby. The pump in auto-standby will auto-start on a LOCA or a LOP signal. However, for the non-LOCA/LOP initiators, it is conservatively assumed that a manual action is needed to start the fourth pump.

3.2.1.15.6 Technical Specification Limitations

Technical Specifications 3.7.1.1 (Limiting Conditions for Operation) and 4.7.1.1 (Surveillance Requirements) apply to the STACS. The limiting conditions for operation are summarized below.

Limiting Conditions for Operations

In Operational Conditions 1, 2, or 3, both SACS pumps in each loop and an operable flow path consisting of a closed loop through the SACS heat exchangers and SACS pumps and to the associated safety-related equipment shall be operable. If any SACS pump or heat exchanger is inoperable, restore the inoperable pump or heat exchanger to operable status within 72 hours or be in at least hot shutdown within the next 12 hours and in cold shutdown within the following 24 hours.

In Operational Conditions 1, 2, or 3, if any SACS subsystem (loop) is inoperable, realign the affected diesel generators to the operable SACS subsystem within two hours, and restore the inoperable subsystem to operable status with at least one pump and heat exchanger within 72 hours or be in at least hot shutdown within next 12 hours and in cold shutdown within the following 24 hours.

In Operational Conditions 1, 2, or 3, the unit shall be placed in at least hot shutdown within 12 hours and in cold shutdown within the following 24 hours if one SACS pump or heat exchanger in each loop or both SACS loops are inoperable.

3.2.1.15.7 Test

During normal operation, the following tests are performed:

	TEST	PROCEDURE NO.
1.	SACS Subsystem A Valves In Service Test	HC.OP-IS.EG-0101(Q)
2.	SACS Subsystem B Valves in Service Test	HC.OP-IS.EG-0102(Q)
3.	SACS Pump In Service Test	HC.OP-IS.EG-0001(Q) through HC.OP-IS.EG-0004(Q)
4.	SACS Flowpath Verification	HC.OP-ST.EG-0001 (Monthly)

3.2.1.15.8 System Operation

Normal Operation

The STACS is normally maintained in automatic operation with both SACS pumps operating in one loop supplying the normal TACS loads, and one SACS pump from the other loop supplying the normal SACS loads. The fourth SACS pump is maintained in standby.

The SACS loop coolant supply temperature is continuously monitored and controlled to the designed temperature range by modulating the SACS heat exchanger bypass valves. In the event of excessive temperature rise, the heat exchanger bypass valves automatically close to provide maximum cooling. The bypass is reopened by manual initiation from the local control panel.

Similarly, the STACS is monitored continuously to detect in-leakage of radioactively contaminated water from the reactor associated components. Any in-leakage will be accommodated by the SACS expansion tanks.

Abnormal Operation

The SACS pump differential pressure is monitored by a differential pressure transmitter. The SACS loop flow is monitored by a flow transmitter. If an operating SACS pump differential pressure is low, the pump will trip automatically. If this trip occurs in the loop supplying TACS, it will cause a low TACS supply flow to be sensed. This will start the standby pump in the opposite loop, close the TACS isolations in the associated loop, and open the TACS isolations in the opposite loop.

LOCA signals of reactor vessel low water level (L1) and/or drywell high pressure from the Core Spray System or a LOP will initiate operation of all four SACS pumps at T=45 seconds. Any pump start will open the inlet valve of the associated SACS heat exchangers. The SACS will operate as two isolated, redundant loops to provide cooling water.

The same signals of LOCA and/or LOP will also initiate closure of the following STACS valves:

1. TACS supply and return isolation valves,

2. Fuel pool cooling heat exchanger cross connecting valves,

3. PCIGS compressor cooler cross connecting valves.

The SSWS has inter-ties to the SACS to provide emergency makeup water during conditions where makeup water is needed and the normal supply from the demineralized water system is unavailable. To prevent inadvertent admission of station service water to the STACS, each emergency makeup loop is isolated from the SSWS by two normally closed, keylocked, motor-operated butterfly valves.

3.2.1.15.9 System Fault Tree

3.2.1.15.9.1 Description

The SACS fault tree identifies all of the major component faults contributing to the system inability to cool safety equipment. A simplified diagram indicating those components modeled in SACS fault trees is shown in Figure 3.2-15. One SACS fault tree for each loop was developed; the fault trees are not included in the IPE report.

3.2.1.15.9.2 Success and Failure Criteria

The success criteria of the SACS depend on the initiating event:

1. In case of a LOP or non-LOCA transients, a minimum of one SACS loop with both pumps operating is required to successfully bring the HCGS to the cold shutdown mode.

2. In case of a LOCA, one SACS pump and heat exchanger in each loop is required to satisfy the minimum cooling requirement for the first 10 minutes. For the remainder of the transient, one fully operating loop is required to satisfy the minimum cooling requirements.

The success criteria for only one SACS loop operable is, therefore, modeled as a fully operational loop (with both SACS pumps operating, both SACS heat exchangers allowing the required heat transfer to the SSWS, and all of the system valves properly positioned to form a complete flowpath in that loop) for LOP, LOCA, and normal shutdown conditions. This approach (for only one loop operation) is conservative because it does not take any credit for operation with less than a fully operating loop (e.g., one pump operation if the other pump in the loop fails).

The success criteria for two loop operation of the SACS system is modeled such that the failure of one pump does not mean failure of all of the equipment which are cooled by that pump's loop. If one SACS pump were not sufficient to cool all of the equipment in that loop, SACS cooling to certain equipment can be cross-tied such that the SACS loop with two operating pumps would provide the cooling flow. Procedure HC.OP-SO.EG-0001(Q) describes the steps needed to cross-tie the SACS cooling to the Diesel Generator coolers and room coolers, the FRVS cooling coil, the RHR unit coolers, the HPCI and RCIC unit coolers, the RHR pump and motor coolers, the Core Spray unit coolers, the PASS liquid coolers, the PCIG compressor coolers, and the Fuel Pool Heat Exchangers. These proceduralized actions are credited in the IPE. However, it is assumed that a SACS loop with only one pump operating cannot be used to cool that loop's RHR heat exchanger.

3.2.1.15.9.3 Assumptions

1. It is assumed that STACS loop A is normally operating with both pumps to cool the TACS loads. SACS pump B is assumed to be normally operating to cool the SACS loads. SACS pump D is assumed to be in standby.

2. It is conservatively assumed that an operator action is always required to start SACS pump D for the transient (not LOCA or LOP) initiators. In many situations, an automatic start signal would be generated (e.g. a pump failure in the opposite STACS loop would cause a low flow signal), but in others, manual actuation would be required. For the LOCA and LOP initiators, an automatic start signal is always generated.

3. Dependent events of heat exchanger blockage or leakage are not modeled.

4. The outlet valves of heat exchangers A1E201 and B1E201 are assumed to be open at the onset of a transient.

3.2.1.15.10 References

1. Hope Creek Generating Station UFSAR Sections 7.3.1.1.11.2 and 9.2.2.

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"

1

IMAGE EVALUATION TEST TARGET (MT-3)

150mm

6"

2. "Hope Creek Generating Station Licensed Operator Systems," Lesson Plan Number 302HC-000.00-080-04. Public Service Electric and Gas Company, Hancocks Bridge, NJ.

3. "Hope Creek Generating Station Technical Specifications 3.7.1.1/4.7.1.1." Public Service Electric and Gas Company, Hancocks Bridge, NJ.

4. Public Service Electric and Gas Company Operating Procedures
   HC.OP-SO.EG-0001
   HC.OP-AB.ZZ-0124
   HC.OP-AB.ZZ-0148

5. Public Service Electric and Gas Drawings
   M-10-1
   M-11-1
   M-12-1
   M-14-1
   E-0217-0
   E-0218-0
   E-0221-0

6. "Configuration Baseline Documentation for Safety and Turbine Auxiliary Cooling." PSE&G Document No. DE-CB.EG-0054(Q).

3.2.1.16 Reactor Auxiliary Cooling System (RACS)

3.2.1.16.1 System Function

The Reactor Auxiliary Cooling System (RACS) provides cooling to non-essential reactor components, and it transfers the gained heat in a closed loop fashion to the Station Service Water System (SSWS). The RACS does not have a safety-related function.

3.2.1.16.2 System Description

General design

The RACS is a closed loop cooling water system consisting of three parallel 50% capacity pumps, a heat exchanger bypass flow control valve, two parallel 50% capacity heat exchangers, and an expansion tank. A simplified diagram of the RACS is shown in Figure 3.2-16. The RACS is normally operating with both heat exchangers and two pumps in service. The RACS provides cooling to reactor building loads, drywell loads, auxiliary building loads and turbine building loads as follows:

A. RACS heat loads in the Reactor Building,
   - reactor water cleanup (RWCU) pumps,
   - reactor water cleanup non-regenerative heat exchangers,
   - reactor building sample station coolers,

- alternate cooling to selected chilled water loads: drywell air coolers, recirculation pump motor air cooler, drywell equipment drain sump, and the steam tunnel air coolers,
- reactor recirculation pumps,
- control rod drive (CRD) pump coolers,
- reactor building equipment drain sump.

B. RACS heat loads in the Auxiliary Building
- charcoal compartment refrigeration,
- standby charcoal compartment refrigeration,
- glycol refrigeration machine,

B. RACS heat loads in the Auxiliary Building (Continued)
- feed gas cooler condensers,
- concentrated waste tanks,
- waste evaporator condensers,
- solid radwaste loads,
- crystallizer bottom tank vent gas cooler, crystallizer lube oil cooler, distillate sub-cooler and crystallizer vapor condenser.

C. RACS heat loads in the Turbine Building
- breathing air compressor (abandoned in-place),
- emergency instrument air compressor and aftercooler.

The system is monitored continuously to detect any radioactivity in-leakage from the equipment being cooled. The station service water in the tube side of the RACS heat exchanger is maintained at a higher pressure than the RACS closed loop system in the heat exchanger shell side. In the event of tube failure, the SSW would leak into the closed loop system to preclude the possibility of radioactive release to the environment in the unlikely condition that the RACS cooling loop becomes contaminated with radioactive material.

Flow Path

The RACS circulating water is cooled by the SSWS as it passes through the parallel RACS heat exchangers. The heat exchangers are equipped with a bypass line which is used to maintain the RACS supply temperature. Flow through the bypass line is controlled by a temperature control valve which modulates in response to signals from a downstream temperature transmitter. The discharge from the heat exchangers combines with the bypass flow and proceeds to the three parallel pumps. In the common pump suction header between the heat exchangers and the pumps, a tap-off is provided for the expansion tank. After the pumps, the RACS cooling water flows through a flow meter in the common discharge header and is divided into various flowpaths. Two RACS demineralizers minimize the corrosion in the RACS.

Component Descriptions

Pumps

Three 50% capacity RACS pumps (AP209, BP209, and CP209) circulate demineralized water through the RACS to cool various plant components and equipment. The RACS pumps are located at the 77-ft. elevation level of the Reactor Building. The pumps are the motor-driven, horizontal, centrifugal type. Each pump has a capacity of 3400 gpm at a discharge pressure of 59 psig. Each pump has a 150-hp motor.

Heat Exchangers

Two heat exchangers, designated as AE217 and BE217, are located in the Reactor Building. The heat exchangers are 50% capacity, horizontal, shell and tube type. The RACS water flows through the tube side and is cooled by the station service water which flows through the shell side. If a tube failure were to occur, leakage would be from the station service water system to the RACS.

System Valves

RACS outlet temperature from the heat exchangers is automatically maintained at a normal setpoint of 67°F by controlling the amount of RACS flow that bypasses the heat exchangers. This is done by pneumatically operated temperature control valve 1EDTV-2617. The pneumatic operating supply is modulated by an electric signal from temperature transmitter 1EDTT-2617 which senses heat exchangers outlet temperature.

The motor-operated valves, 1EDHV-2537A and B are located at the inlet of the heat exchangers, AE217 and BE217, respectively. These valves must be fully opened to manually start the RACS pumps.

The air-operated flow control valve 1EDFV-2601 is located in the recirculation line. The pumps discharge into a common header where total flow is measured (1EDFE-2601) before splitting off to supply system loads. Flow through 1EDFE-2601 to the system loads is automatically maintained constant by partially recirculating flow through the valve 1EDFV-2601 to the inlet of the heat exchangers.

Expansion Tank

The expansion tank provides the necessary Net Positive Suction Head (NPSH) to the pumps, and it allows for expansion, contraction, and makeup. Makeup to the expansion tank is from the demineralized water system.

3.2.1.16.3 Support Systems

The RACS interfaces with the electrical power system, the instrument air system, the station service water system, the demineralized water system, the liquid radwaste system, and process radiation monitoring.

Electrical

The power supplies for the RACS pumps are:

- 480V AC Non-Class 1E auxiliary building load center 10B415 supplies the A pump, 10B426 supplies the B pump, and reactor building load center 10B250 supplies the C pump;

- the auxiliary building load centers are powered from 1E 480V panels 10B410 and 10B420 respectively;

- 10B410 and 10B420 are powered through transformers from 4.16 kV 1E buses 10A401 and 10A402 respectively.

Station Service Water System

The SSWS cools the RACS circulating water via the RACS heat exchangers.

The other support systems are not modeled in the RACS fault tree. They are not required to function to allow the RACS to cool either the Emergency Instrument Air Compressor (EIAC) or the CRD pumps, which are the only RACS loads modeled.

3.2.1.16.4 Instrumentation and Control

System Actuation

1. The SSW valves to and from the heat exchangers (1EAHV-2203, 2204, 2207, 2346) will automatically close on a room high level indication (1 inch).

2. System response to the Loss of Offsite Power (LOP) sequencer:

   A. RACS to and from the auxiliary building isolates. Recoverable once bus voltage is restored;
   B. thirteen seconds after the LOP, both loops of chilled water to the drywell loads isolate. Also, at this point the drywell cooling fans are sequenced on;
   C. fifty-five seconds after the LOP, the SSW pumps are sequenced on;
   D. both heat exchanger inlet valves (1EDHV-2537A and B) open at T = 85 second;
   E. pumps AP- and BP-209 get a start signal at T = 85 seconds (whether or not they are in remote or local). The pumps initially tripped due to Class 1E bus undervoltage which causes a loss of voltage to the pumps;

F. at T = 85 seconds the RACS supply to the drywell chilled water loads is opened.

3. Either heat exchanger inlet valve must be open to allow for a RACS pump start.

4. RACS pumps auto trip on:

A. Low-Low Head Tank Level,
B. Low-Low Flow,
C. LOCA Level 1 signal (A and B pumps only),
D. Electrical Faults.

5. RACS F/D will auto shutdown by closing the automatic shutoff valve (SV-2624) on the following signals:

A. high conductivity on the outlet of the second vessel,
B. emergency Instrument Air Compressor starting.

6. The PCIS valves which supply RACS to the recirculation pump (1EDHV-2553, 2554, 2555, 2556) close on the following Group 16 signals:

A. -129 inches - reactor level,
B. 1.68 psig - drywell pressure.

7. The RACS supply to and return from the Auxiliary Building is controlled via a set of valves (1EDHV-2598, 2599). These valves will auto close on the following:

A. LOCA Level 1 (-129" or 1.68 psig),
B. LOP.

8. The RACS will provide backup cooling to the drywell loads normally carried by chilled water upon a **LOP without a LOCA**. Loads are:

A. drywell air coolers,
B. reactor recirculation pump motor air coolers,
C. drywell equipment drain sumps,
D. steam tunnel air coolers.

9. RACS response to a LOCA Level 1:

A. RACS supply and return (1EDHV-2598 and 2599) to the auxiliary building loads closes,
B. RACS pumps AP- and BP-209 trip due to Class 1E breaker trip,
C. RACS supply to and from the recirc pump close,
D. Service Water to and from the RACS heat exchangers isolates.

Power can be restored to the RACS pumps after a LOCA by overriding the Class 1E breakers supplying the RACS pumps. However, SSW is not recoverable to the RACS heat exchangers in this scenario unless the operator restores the SSWS cooling.

Alarms and Annunciators

RACS malfunctions are alarmed in the control room to ensure the safe operation of the RACS system.

3.2.1.16.5 Operator Actions

RACS pumps AP and BP-209 are assumed to be operating before the onset of a shutdown. Should either pump fail, an operator action is modeled to isolate the waste evaporator condenser. However, during LOCA and LOP transients, this action is not needed as long as the Reactor Building/Auxiliary Building isolating valves close on their automatic signal. If pump CP-209 can be started, cooling to the waste evaporator condenser would be re-established, but since the waste evaporator condenser is not modeled in the IPE, this restoration action is not modeled.

On a LOCA signal, RACS pumps AP and BP-209 are shed from their Class 1E buses, and SSWS cooling to RACS is isolated. Should the RACS be required to operate after isolating, operator action is required to close the Class 1E breakers and restart the AP and BP-209 RACS pumps. RACS pump CP-209 does not isolate from its (Non-Class 1E) power source. However, since operator action is also required to restore SSWS cooling to RACS (Procedure HC.OP-EO.ZZ-319(Q), Restoring Instrument Air in an Emergency), one operator action is modeled to envelope the actions of restoring the RACS pumps <u>and</u> the SSWS cooling.

3.2.1.16.6 Technical Specification Limitations

Table 3.8.4.5-1 of the HCGS Technical Specifications (TS) presents a list of Class 1E isolation breaker overcurrent protective devices (breakers tripped by a LOCA signal). Included in this table are the breakers for RACS pumps 1AP209 and 1BP209.

Table 3.6.3-1 of the TS presents a list of primary containment isolation valves and reactor instrumentation line excess flow check valves and their respective maximum allowable isolation times. This table includes the RACS supply (1EDHV-2554 inside and 1EDHV-2553 outside) and return (1EDHV-2556 inside and 1EDHV-2555 outside) isolation valves.

No other TS relates directly to the RACS.

3.2.1.16.7 Testing

There is no testing of the RACS during normal power operations.

3.2.1.16.8 System Operation

Normal Operation

The RACS does not have a safety-related function. The RACS operates during normal conditions, following a LOP, and during scheduled unit shutdown conditions. Coolant water in a closed loop system transfers heat through the RACS heat exchangers to the SSWS.

Abnormal Operation

During normal operation and normal shutdown operating conditions, the failure of a pump or a motor will annunciate in the Main Control Room. Simultaneously, it would cause a low flow in the supply header which also annunciates in the Main Control Room. The RACS pump 1CP-209 serves as a standby to RACS pumps 1AP-209 and 1BP-209. In the event that one of the operating pumps fails, the standby RACS pump 1CP-209 can be manually started to preclude the need to isolate the waste evaporator condenser for extended periods of time. In this event, the waste evaporator condenser outlet valve 0EDHV-2572A or 0EDHV-2572B should be manually isolated until the C RACS pump (1CP-209) can be placed in service. The isolation of the waste evaporator condenser is a plant limiting condition, and the plant will be required to shut down when the liquid radwaste storage facilities are filled to capacity.

LOP

Upon a LOP without the occurrence of a LOCA, the A and B RACS pumps restart automatically via the LOP sequencer at 85 seconds. The C RACS pump is not connected to a Class 1E bus and is unavailable on a LOP. The RACS Reactor Building isolation valves close automatically cutting off the RACS flow to the auxiliary building. However, once the RACS pumps have restarted, the Reactor Building isolation valves can be opened manually from the main control room (if desired) to provide RACS water supply to the offgas and radwaste equipment.

The RACS has connections to supply cooling water to the drywell coolers as a backup to the chilled water system. This backup is automatic following a LOP without a LOCA. The loads that RACS supplies are:

1. drywell air coolers,

2. reactor recirculation pump motor air coolers,

3. drywell equipment drain sumps,

4. steam tunnel air coolers.

LOCA

The RACS has no safety-related function (other than for containment isolation) and is not required to operate following a LOCA. Upon a LOCA signal, the RACS heat exchangers are automatically isolated from the balance of the SSWS. The RACS A and B pumps trip due to Class 1E breaker trip. Each supply and return header to and from the drywell has two containment isolation valves that close automatically upon a LOCA signal. In addition, the RACS Reactor Building supply and return isolation valves will automatically isolate upon a LOCA or LOP signal.

Total Loss of RACS

If a total loss of RACS has occurred and cannot be immediately restored, the reactor is scrammed.

3.2.1.16.9 System Fault Tree

3.2.1.16.9.1 Description

The RACS fault tree identifies all of the major component faults contributing to the system inability to cool non-essential reactor components. A simplified diagram indicating those components modeled in RACS fault is shown in Figure 3.2-16.

3.2.1.16.9.2 Success and Failure Criteria

The RACS is not a safety-related system, and it is not needed for the safe shutdown of the plant. However, the control rod drive pumps can be used to inject cold water in the core, and the RACS provides the cooling to the control rod drive pumps. The RACS also provides cooling to the EIAC, which is also modeled in the HCGS IPE. A single RACS pump and heat exchanger are sufficient to provide adequate cooling to the non-essential reactor equipment during a LOCA, LOP, or normal shutdown given that the load to the waste evaporator condenser is isolated. If the waste evaporator condenser is not isolated, two pumps and heat exchangers are required.

3.2.1.16.9.3 Assumptions

1. Pumps AP and BP-209 are assumed to be operating normally before the onset of a transient. Restoration errors for the valves in these flowpaths are, therefore, not modeled.

2. Leakage from the RACS closed loop system to other components which are at lower pressure is not modeled since most of these systems will be isolated.

3.2.1.16.10 References

1. Hope Creek Generating Station UFSAR Section 9.2.8.

2. "Hope Creek Generating Station Licensed Operator Systems," Lesson Plan Number 302HC-000.00-081-11. Public Service Electric and Gas Company, Hancocks Bridge, NJ, January 27, 1993.

3. Public Service Electric and Gas Company Operating Procedures
OP-SO.ED-001
OP-IS.ED-101
OP-AB.ZZ-123
OP-EQ.ZZ-319

4. Public Service Electric and Gas Drawings
M-13-0 M-10-1
M-13-1
E-0211-1

5. Hope Creek Configuration Baseline Documentation - Reactor Auxiliaries Cooling System. PSE&G Doc. No. DE-CB.ED-0082(Q).

3.2.1.17 Station Service Water System (SSWS)

3.2.1.17.1 System Function

The Station Service Water System (SSWS) provides river water to cool the Safety Auxiliary Cooling System (SACS) heat exchangers and the Reactor Auxiliary Cooling System (RACS) heat exchangers during normal operating conditions and loss of offsite power (LOP) conditions. During a loss-of-coolant accident (LOCA), the SSWS provides river water to cool the SACS heat exchangers only.

3.2.1.17.2 System Description

General Design

The SSWS consists of two redundant loops. Each loop cools a separate SACS loop. Either one of these loops can be used for cooling the RACS heat exchangers. RACS is normally supplied by both SSWS loops. Each SSWS loop contains the following major components:

1. Traveling water screens,
2. Service water pumps,
3. Service water strainers,
4. Spray water pumps, and
5. Associated valves, piping, and instrumentation.

Both SSWS loops provide a backup source of water for fuel pool makeup, SACS expansion tank (A for SSWS Loop A, B for SSWS Loop B) makeup, and alternate Reactor Pressure Vessel (RPV) Injection, in an emergency. SSWS Loop B has a fire hose connections which allow the alignment of Fire Water for Alternate RPV injection. A discussion of the use of Fire Water and of the SSWS as Alternate Injection sources is provided in Section 3.2.1.24.

The SSWS components are designed in accordance with the seismic category and NRC quality groups outlined in Section 3.2 of the HCGS UFSAR.

SSWS pumps and associated equipment are located in a seismic Category I intake structure. Piping is routed through the yard to the Reactor Building where the RACS and SACS heat exchangers are located. A simplified diagram of the SSWS is presented in Figure 3.2-17.

Flow Path

The SSW pumps take suction at individual sumps. The water in each sump flows from the Delaware River through a trash rack and traveling screen to prevent large debris from passing further into the system. Partial flow lateral sluices are provided between sumps so that a pump can also draw water from adjacent bays in the event its associated screen is partially blocked.

The discharge of the SSW pumps passes through self-cleaning, automatic strainers. The strainer backwash cleaning water is routed to the strainer backwash trough and returned to the river.

Discharge from each strainer passes through a motor-operated discharge valve (1EAHV-2198A, B, C, and D). The discharges from SSW pumps A and C form SSW loop A, and the discharges from SSW pumps B and D form SSW loop B, as shown on the SSWS P&IDs.

Each loop supplies bearing lubrication water to its associated pumps (loop A supplies the A and C pumps, and loop B supplies the B and D pumps). A prelube head tank provides bearing lubrication on initial pump start and during periods of low lube water pressure. Water is also supplied from the common headers to the spray wash booster pumps which clean the traveling screens.

The loop A header supplies SACS A heat exchangers and also provides a flow path to the RACS heat exchangers. The loop B header supplies SACS B heat exchangers and also provides a flow path to the RACS heat exchangers.

Water from both SSWS loops A and B, and water from the RACS heat exchangers is sent to the cooling tower basin for Circulating Water System makeup. This water can also be sent back to the intake structure for de-icing or it can bypass the cooling tower and be sent directly to the river via the cooling tower river blowdown line.

Component Descriptions

Service Water Pumps

The SSW pumps (AP, BP, CP, and DP-502) supply the necessary head to ensure flow through the RACS and SACS heat exchangers. In addition, the SSWS pumps supply water to the cooling tower basin for makeup.

Each pump provides a rated flow of 16,500 gpm at a head of 150 feet. Each pump is powered by an 800 hp motor from a Class 1E power supply.

Service Water Strainers

The strainers (AF, BF, CF, and DF-509) remove small particles from the pump discharge to prevent clogging of the heat exchangers.

Spray Water Booster Pumps

The spray water pumps (AP, BP, CP, and DP-507) take suction from the SSWS common loop header. The spray wash can be cross-tied within a loop (A with C, or B with D). The spray water pumps provide the proper pressure for cleaning the Traveling Water Screens.

Traveling Water Screens

Each SSW pump pit has its own traveling screen (AS, BS, CS, and DS-501) to prevent debris from entering the service pump. The traveling screens consist of fish baskets mounted on screens carried by roller chains driven by an electric motor.

Lubrication Head Tanks

There are two tanks located at the 130 ft. elevation of the SSW structure. Each lubrication head tank supplies bearing lubrication water to the associated SSW pumps on initial startup and during periods of low lube water pressure. During normal operation the lubrication water is supplied from the discharge side of the SSWS pumps. Either tank can be cross-tied through a normally closed cross-tie valve (1EAV-567) to feed either SSWS loop.

The valves SV-2247A through D will auto-open on a low lube water pressure signal. An alarm signal is generated on high gland box temperature.

System Valves

Service water pump discharge valves, 1EAHV-2198A through D, are 28-inch, motor-operated, butterfly valves. They allow the isolation of the respective SSW pumps when not in service. When in AUTO, these valves open when the associated SSW pump starts and close when the associated pump stops.

Spray water booster pump discharge valves, 1EAHV-2225A through D, will auto-open when the respective associated SSW pump discharge valve, 1EAHV-2198 is 100% open.

The SSW to SACS cooling outlet valves to the cooling tower, 1EAHV-2357A and B, are 36-inch motor-operated butterfly valves; 1EAHV-2356A and B, which dump to the yard, are 20-inch motor-operated butterfly valves.

The 30-inch, motor-operated butterfly valves, 1EAHV-2203 and 1EAHV-2204, and the 24-inch motor-operated butterfly valves 1EAHV-2207 and 1EAHV-2346 provide isolation of the RACS heat exchangers on a LOCA signal or upon receipt of a "RACS Room Flooded" signal.

The SSWS to SACS heat exchanger outlet valves (1EAHV-2371A and B and 1EAHV-2355A and B) open (when in AUTO) upon the start of their associated SACS pump and close upon the stop of their associated SSW pump.

The SACS heat exchanger discharge piping vacuum breaker valves (1EASV-2367A, B, C, and D) open (when in AUTO) on a LOP and will remain open for 60 seconds after the restoration of power.

The Station Service Water Strainer Backwash Valves (1EAHV-2197A, B, C, and D) open (when in AUTO) for 5 minutes when their associated SSW pump is running for greater than or equal to 10 seconds, and they will remain open unless strainer high differential pressure exists or the backwash timer comes on to keep the valve open. The backwash valve will then cycle on strainer differential pressure or by the backwash timer.

The Yard Dump Valves (1EAHV-2356A and B) will open (when in AUTO) when the SACS heat exchanger SSW outlet pressure exceeds a preset value (16.7 psig, 2/3 logic).

3.2.1.1[illegible] System Interfaces

The only support systems modeled for the success of the SSWS are the electric power and room cooler/HVAC systems.

Electrical

The SSWS requires the following Class 1E electrical AC power buses and DC power for its control, actuation, and operation:

1. 4.16 kVAC buses 10A401, 10A402, 10A403, 10A404,

2. 480 VAC buses 10B553, 10B563, 10B573, 10B583,

3. 480 VAC buses 10B212, 10B222, 10B232,

4. 125 VDC buses 10D410, 10D420, 10D430, 10D440.

Component Cooling

Upon the initiation of the station service water system and during periods of low lube water pressure, the lubrication head tanks provide the lubrication water to their associated station service water pumps.

Cooling in the bay area is provided by the service water intake structure ventilation system. The traveling screen motor room ventilation system provides the cooling to the traveling screen motor room.

3.2.1.17.4 Instrumentation and Control

System Actuation

During normal plant operation, two station SSW pumps, one in each loop, are required. The second pump in each loop is in auto-standby and will start if the operating pump in that loop fails.

The SSW pumps will auto-start (if control is in auto and no process start inhibit signal is present) on the following signals:

1. low flow from pump in associated loop starts the remaining pump in that loop,
2. reactor water level (-38 inches),
3. drywell pressure ($\geq$1.68 psig),
4. reactor building radiation high-high ($1x10^{-3}$uCi/cc),
5. refuel floor radiation high-high ($2x10^{-3}$uCi/cc),
6. containment manual isolation.

The SSWS pumps auto-start on a sequence timer initiated by a LOCA or a LOP whether in auto or manual.

The SSWS pumps B and D will not auto-start if control is transferred to the remote shutdown panel (RSP).

The SSWS pumps will auto-trip on undervoltage and overcurrent.

In auto-mode, the SSW pump discharge valve (HV-2198A-D) will open when the associated pump starts.

The spray water booster pump discharge valve (HV-2225A-D) in auto-mode will auto-open when the associated SSW pump discharge valve, (HV-2198) is 100% open, respectively.

In auto-mode, the traveling screens will auto-start on low speed when the respective SSW discharge valve (1EAHV-2198A-D) is 100% open and spray water flow is established by a flow switch (1EPFS-2225A-D) and will auto-stop when the valve is less than 100% open.

3.2.1.17.5 Operator Actions

It is assumed in the fault trees for the SSWS that one SSW pump in each loop is normally operating (even though during much of the year, three SSWS pumps are normally operating; see Section 3.2.1.17.8). It is conservatively assumed that an operator action is always required to start the two non-operating SSW pumps for the transient (not LOCA or LOP) initiators. In many situations, an automatic start signal would be generated (e.g. a low flow condition in a SSWS loop with one pump operating would cause a pump start signal for the other pump in that loop), but in others, manual actuation would be required. For the LOCA and LOP initiators, an automatic start signal is always generated, and no operator action is needed.

As shown in Figure 3.2-17, the SSW Loop A and B to RACS Heat Exchanger Header Supply Valves (1EAHV-2203 and 2204 respectively) are normally open. Because of this, there exists a potential flow diversion path from one SSW loop to the SACS heat exchangers of the opposite SACS loop.

For example, after a LOP, all four diesel generators start and load their respective buses. All SSW, SACS, and RACS pumps A and B start, and all four SSWS to SACS heat exchanger outlet valves (1EAHV-2355A and B and 1EAHV-2371A and B) open.

If the B and D (A and C) diesels were then to trip, the B and D (A and C) SACS and SSWS pumps and the B (A) RACS pump would trip, and the SSWS to SACS loop B (A) heat exchanger outlet valves and the B RACS heat exchanger valves would remain open. The A and C (B and D) SSW pumps would then be sending flow to all four SACS heat exchangers and both RACS heat exchangers (as well as flow to the spray wash booster pumps and to the SSW pump lube water header). The SSW pumps are not designed to handle this capacity. The pumps may trip on overcurrent in which case they can be restarted. However, until the flow diversion to the SSWS to SACS Loop B (A) heat exchangers is isolated, the SACS loop A (B) heat exchangers would not have the designed SSWS flow. An operator action is modeled in the SSWS fault trees to credit the operator's ability to cut off this flow diversion.

This potential flow diversion is not modeled for LOCA Initiating Events since a LOCA signal will automatically isolate the SSWS to RACS Heat Exchanger Header Supply Valves (1EAHV-2203 and 2204). The probability of the failure of these valves to automatically isolate along with the other failures required for this flow diversion is judged to be insignificant.

3.2.1.17.6 Technical Specification Limitations

Technical Specifications (TS) 3.7.1.2 (Limiting Conditions for Operation) and 4.7.1.2 (Surveillance Requirements) apply to the SSWS. The limiting conditions for operation are summarized below.

Limiting Conditions for Operations

While at power, both SSW pumps in each loop and a flow path capable of taking suction from the Delaware River and transferring the water to the SACS heat exchangers must be operable. If any pump is inoperable, then the inoperable pump must be restored to operable status within seven days or be in the hot shutdown operational condition within the next 12 hours and in cold shutdown within the following 24 hours.

If one SSW pump in each loop is inoperable or one SSW loop is inoperable, restore the inoperable pumps or loop to operable status with at least one operable pump within 72 hours or be in at least shutdown within next 12 hours and in cold shutdown within the following 24 hours.

TS 3.8.4.2 applies to the thermal overload protection bypass circuits (including the SSWS MOVs). If the circuit is declared inoperable and cannot be restored to the operable status within 8 hours, the affected MOV is declared inoperable, and the above TS is entered.

TS 3/4.7.1.3 apply to the ultimate heat sink (the Delaware River). This TS is summarized below for power operation.

Limiting Condition For Operation

The ultimate heat sink shall be OPERABLE with:

a. a minimum river water level at or above elevation -13 feet, 0 inches Mean Sea Level, USGS datum (76 feet, 0 inches PSE&G datum), and

b. an average river water temperature of less than or equal to 90.5°F.

When either of these requirements is not met, in Operational Condition 1, 2 or 3, the unit must be in at least Hot Shutdown within 12 hours and in Cold Shutdown within the next 24 hours.

Surveillance Requirements

The ultimate heat sink shall be determined OPERABLE:

a. by verifying the river water level to be greater than or equal to the minimum limit at least once per 24 hours.

b. by verifying river water temperature to be within its limit:

   1. at least once per 24 hours when the river water temperature is less than or equal to 85°F

   2. at least once per 6 hours when the river water temperature is greater than 85°F.

3.2.1.17.7 Test

The following procedures describe the testing requirements of the SSWS.

No.	Test	Procedure
1.	SW Pump-In Service Test	HC.OP-IS.EA-001/004
2.	SW Subsystem-In Service Test	HC.OP-IS.EA-101 and 102
3.	Spray Water Pump-In Service Test	HC.OP-IS.EP-001/004
4.	Service Water Screen Wash Subsystem - In Service Test	HC.OP-IS.EP-101 and 102
5.	Service Water System Valves - Cold Shutdown - In Service Test	HC.OP-IS.EA-103
6.	SW System Functional Test	HC.OP-ST.EA-002

3.2.1.17.8 System Operation

Normal Operation

During normal operation, shutdown, startup, and refueling, the SSWS is operating with two SSWS pumps (one in each loop) providing flow. The second pump in each loop is in standby and autostarts on any of the signals listed in Section 3.2.1.17.4 for the SSWS pumps. In the warmer months of the year, when the river water and the ambient air temperatures may be high, three pumps are required. The SSWS Loop with two pumps operating is used to cool the heat exchangers of the SACS loop which has two SACS pumps operating (and is cooling the TACS loads).

For the HCGS IPE, it is assumed that only two SSWS pumps, AP and BP502 (and their associated equipment), are operating at the onset of an event.

Abnormal Operation

Loss of Coolant Accident (LOCA)

During a LOCA, all four SSW pumps, with corresponding strainers, provide flow through the redundant loops to provide cooling water to the SACS heat exchangers. The three valves connected to the common header supplying, and the valves discharging from, the RACS heat exchangers automatically close in the event of LOCA. The non-operating pumps are started via the LOCA sequencer at T = 55 seconds. One SSW pump in each system loop is required to satisfy minimum cooling requirements of the SACS heat exchangers in the initial phase, when RHR heat exchangers are not in service. During the long-term containment-cooling mode, one loop with two SSW pumps operating provides sufficient cooling to satisfy the minimum requirements of the SACS heat exchangers in the corresponding SACS loop (i.e., both SSWS loop A pumps provide cooling to the two loop A SACS heat exchangers).

Loss of Power (LOP)

In the event of a LOP without a LOCA, all four SSW pumps will start and cool all SACS and RACS heat exchangers. Only one SSWS loop with two pumps is required (References 2 and 6). The SSWS pumps are restarted by the LOP sequencer at T = 55 seconds; however, only one SSWS loop with both pumps is required to safely shut down the plant.

Transients

For the non-LOCA/LOP transients, three SSW pumps are used initially to supply cooling water to the SACS and RACS heat exchangers. For long term shutdown, only two SSW pumps are required to cool the SACS and RACS heat exchangers (Reference 2).

3.2.1.17.9 System Fault Tree

3.2.1.17.9.1 Description

The SSWS fault tree identifies all of the major component faults contributing to the system inability to cool SACS and RACS cooling water. A simplified diagram indicating those components modeled in SSWS fault trees is shown in Figure 3.2-17.

3.2.1.17.9.2 Success/Failure Criteria

The success criteria of the SSWS depend on the initiating event:

1. In the cases of LOP and non-LOCA transients, a minimum of one SSW loop with two fully operational pumps is required to successfully bring the plant to the cold shutdown operational condition and to provide-long term cooling.

2. In case of a LOCA, a minimum of one pump per loop is required to cool the heat exchangers in the associated SACS loop in the initial phase when the RHR heat exchangers are not in service. During the long-term containment cooling mode, one loop with two SSW pumps operating provides sufficient cooling to satisfy the minimum requirements of the SACS heat exchangers. In this phase, only one SACS loop is needed (References 2 and 6). Since the mission time of the SSWS fault tree is 24 hours, the success criteria for a SSW loop is assumed to be two fully operational pumps in that loop.

3. There is no flow diversion from one SSW loop to the SACS heat exchangers of the opposite SSW loop.

3.2.1.17.9.3 Assumptions

1. Service water pumps A and B are assumed to be in operation providing cooling water to the SACS and RACS heat exchangers before the beginning of a transient.

2. Since the strainers operate on timers or on the D/P across the strainers, both control systems have to fail, and the strainer has to be plugged for an inadequate flow through the strainer. Therefore, the individual component faults in SSW strainers are not modeled. The dependent failure modes of strainers are assumed to be the same as for the motor-driven pumps.

3. It is assumed that the failure to operate the strainer will result in the plugging of the strainer.

4. A train is assumed to be unavailable due to TM if any of the components in the train is unavailable due to TM.

5. The diversion of flow from an operating SSW pump to a pump which is not operating is not modeled. This flow diversion would require the failure of the non-operating pump's discharge valve (1EAHV-2198A, B, C, or D) (which receives a signal to close if its associated SSW pump stops) in series with the failure of a check valve (1EAV-359, 361, 363, or 365). The SSW strainer backwash line is a potential diversion path between these two valves. However, besides requiring the failure of the motor-operated backwash valve (1EAHV-2197A, B, C, or D), this strainer backwash line is a 6-inch diameter pipe. This diameter is much less than one-third of the 28-inch diameter pipe to which it connects, and this path can be neglected.

6. To simplify the modeling of the inadvertent flow diversion from one SSW loop to the SACS heat exchangers of the opposite SSW loop, it is assumed that the only significant failure mode is the loss of the A <u>and</u> C (B <u>and</u> D) 4.16kV buses. The loss of these two buses would, by common cause, cause the failures of the SSWS pumps A and C (B and D) and cause the SSWS to SACS heat exchanger outlet valves (1EAHV-2355A (B) and 2371A (B) to fail as is (therefore, this diversion will not occur if the valves never opened; note that, at present, the loop B SSWS to SACS heat exchanger outlet valves, 1EAHV-2355B and 2371B, leak significantly even when they are closed, but this leakage is assumed not to be large enough to model a flow diversion of SSW loop A when the loop B heat exchanger outlet valves are closed). However, the independent failures of two SSW pumps in one loop and of the two heat exchanger outlet valves in the same SSW loop to fail open is judged to be probabilistically insignificant.

   This potential flow diversion is not modeled for LOCA initiatiors since a LOCA signal isolates 1EAHV-2203 and 2204. By including these additional failures, this flow diversion is judged to be insignificant during a LOCA.

7. Unavailability of trains A and B is included in the unavailability of trains C and D due to TM, respectively.

8. Since the failure of the movement of the trash bar rake will not necessarily result in the plugging of the bay, it is not modeled.

9. The SSWS discharge from each loop to the towers or the yard dump is not modeled since the pressure rupture disk is provided in parallel to the valves HV-2356A-B and HV-2357A-B (also in parallel). This will result in the third order failure mode with a maximum failure rate of the valve: 1.0E-3 (i.e., HV-2356 valve fails to open).

10. Since all of the traveling screen systems are located in one room, and dependent failure of all four of the traveling screen systems is likely to be higher than the dependent failure of two of the traveling screen systems in a loop, the dependent failure of the traveling screen systems per loop is not modeled.

11. It is conservatively assumed that an operator action is always required to start SSWS pumps CP and DP-502 for the transient (not LOCA or LOP) initiators. In many situations, an automati start signal would be generated (e.g. a low flow condition in a SSWS loop with one pump operating would cause a pump start signal for the other pump in that loop), but in others, manual actuation would be required. For the LOCA and LOP initiators, an automatic start signal is always generated.

12. The loss of room cooling to the SSWS pumps is assumed to fail the pumps in that room. The loss of HVAC to the Service Water Intake Structure is assumed to fail the system.

3.2.1.17.10 References

1. Hope Creek Generating Station UFSAR Sections 7.3.1.1.11.1, and 9.2.1.

2. "Hope Creek Generating Station Licensed Operator Systems," Lesson Plan Number 302HC-000.00-079-10. Public Service Electric and Gas Company, Hancocks Bridge, NJ, January 20, 1993.

3. "Hope Creek Generating Station Technical Specifications," Sections 3.7.1.2/4.7.1.2 and 3.8.4.2. Public Service Electric and Gas Company, Hancocks Bridge, NJ.

4. Public Service Electric and Gas Company Operating Procedures
   HC.OP-SO.EA-001
   HC.OP-SO.EP-001
   HC.OP-AB.ZZ-122

5. Public Service Electric and Gas Drawings
   M-09-1
   M-10-1
   E-0208-0
   E-0211-0
   E-0212-0

6. Hope Creek Configuration Baseline Documentation - Station Service Water Systems. PSE&G Document No. DE-CB.EA/EP-0052(Q) and DE-CB.EQ-0052(Z).

3.2.1.18 <u>Chilled Water System (CHS)</u>

3.2.1.18.1 System Function

The Chilled Water System (CHS) consists of two separate parts, a Control Area Chilled Water System (CACHS), and a Safety-Related Panel Room Chilled Water System (SPCHS).

The CACHS provides continuous cooling to the control area equipment while the SPCHS provides the continuous cooling to the equipment in the safety-related panel room. Both systems are required to be in operation during all modes of plant operation.

Since both systems are similar in their operation and requirement, the following discussion of the CACHS also applies to the SPCHS, unless otherwise noted.

3.2.1.18.2 System Description

General Design

The CACHS consists of two 100% redundant closed loop cooling systems. Each loop provides continuous cooling to the components or the systems as listed below:

1. control room air conditioning cooling units,

2. switchgear rooms,

3. SACS room air handling and cooling units,

4. control equipment room air conditioning units.

The SPCHS supplies continuous cooling to the following:

1. Class 1E panel room cooling units,

2. technical support center cooling unit,

3. remote shutdown panel room cooling units.

Each loop consists of a circulating pump, a skid-mounted chiller package, a head (surge) tank, a chemical addition tank (not modeled) and associated piping, valves, and instrumentation. A simplified diagram of the SPCHS is provided in Figure 3.2-18a, and a simplified diagram of the CACHS is provided in Figures 3.2-18b. Each pump circulates the chilled water through the components. The circulating water in loops A and B is cooled by the SACS loops A and B, respectively.

Normally, only one loop is in service. Both loops are completely independent of each other, eliminating the possibility of a single failure causing the loss of the entire system. The pumps and the associated motor-operated valves for each loop receive power from separate and independent Class 1E AC and DC buses. The CACHS and the SPCHS are designed with seismic Category I and quality Group C ESF components that withstand postulated accident conditions without impaired function.

Flow Path

The SPCHS and CACHS flow paths are arranged in parallel with the heat rejection portion of the systems. Each cooling coil is supplied with 45°F cooling water. Cooling water flows through cooling coils absorbing heat from the area served by the cooling unit. It then flows through a common suction header back to the circulating pump.

The circulating pump raises the pressure of the water and supplies it to the evaporator inlet on the chiller. Heat is transferred to the chiller refrigerant as it passes through the evaporator. Cooling water exits the evaporator and is supplied to the system cooling units to repeat the cycle.

Component Descriptions

Circulating Pump

Two 100% capacity, single stage, horizontal centrifugal, direct-drive pumps rated at 1330 gpm each circulate the water through the CACHS loops A and B. These pumps are designated as AP400 and BP400 and are located on the 155-ft elevation level in the control building in rooms 5602 and 5630 with their respective chillers.

The circulating pumps in the SPCHS are designated as AP414 and BP414 and are located in room 5704 at the 178-ft elevation level in the diesel building with their respective chillers. The pumps are 100% capacity single-stage, horizontal centrifugal pumps rated at 430 gpm.

Normally, only one pump for each system is running while the other is in the standby mode. The standby pump starts automatically upon sensing the low flow signal in the operating loop.

Chiller

The CACHS has two 100% capacity chillers, AK400 and BK400, which are cooled by SACS loops A and B, respectively. Each chiller has a 563 ton capacity and is powered by 4.16 kV Class 1E AC power. The SPCHS also has two 100% capacity chillers, AK403 and BK403, which are cooled by SACS loops A and B, respectively. Each SPCHS chiller has a 180-ton capacity and is powered by 4.16 kV Class 1E AC power.

The chillers consist of an evaporator, a compressor, a chiller, a lubricating oil system, a condenser, a flash economizer, a pump down unit, and a hot gas bypass valve. The circulating water flows through the tubes and the refrigerant flows on the shell side. Each chiller is located in the same room as its respective circulation pump.

Air Operated Valves

There is an air-operated valve on the SACS outlet line of each chiller condenser. This valve is normally open and fails open on loss of air or power.

3.2.1.18.3 System Interfaces

The CACHS and the SPCHS interface with the electrical power, the control air, the room coolers, and the SACS systems. For successful operation of the CACHS and the SPCHS, the control air system is not required since the air-operated valves fail open on loss of control air.

Electrical

The SPCHS loops A and B and the CACHS loops A and B require the following Class 1E electrical AC power buses and DC power for its control, actuation, and operation, respectively:

1. 4.16 kVAC buses 10A401, 10A402, 10A403, 10A404;
2. 480 VAC buses 10B411 and 10B451, 10B421 and 10B461, 10B431, 10B441;
3. 125 VDC buses 10B410, 10B420, 10B430, 10B440.

Component Cooling

The refrigerant in each chiller is condensed by SACS.

Room Cooling

The CACHS and SPCHS rooms are cooled by the control equipment room cooling system.

3.2.1.18.4 Instrumentation and Control

System Actuation

During normal plant operation, one loop in each system is required to be in operation. The second loop is in standby mode and, if the pump controls are in auto, it starts on a low-low flow condition in the operating loop. The CACHS and the SPCHS can be operated and controlled from the control room or locally. The B pumps and chillers can be operated from the remote shutdown panel (RSP).

The LOP sequencer will send an auto start signal to both loops of chilled water which will start each loop's chiller and circulating pump. On a LOP or LOCA, the operating chilled water systems are tripped and sequenced onto Diesel Generator power after a 60-second time delay for the chiller and a 65-second time delay for the circulating pump, if the chiller controls are not in remote. All loads on both loops of chilled water auto start either in response to the chilled water circulating pump starting or in response to a sequencer signal. When control of the system has been transferred to the RSP, all automatic start signals for the 'B' train are defeated.

An auto-start of the standby loop in the CACHS will auto-start the respective SACS pump, the SACS pump room cooling fans, and the control equipment room air supply unit. Similarly, an auto-start of standby loop in the SPCHS will auto-start the respective SACS pump and the safety panel room air supply unit.

Control

During operation of the CACHS and SPCHS, essentially no control is necessary. Operators can manually start the circulating pumps and chillers from the control room, if necessary.

Interlocks

The chillers in the CACHS and the SPCHS will auto-trip due to various conditions including high refrigerant, oil or motor temperatures, low chiller water or cooler refrigerant temperatures, low evaporator flow, high refrigerant pressure, low refrigerant or oil pressure, or a compressor motor overload.

The circulating pumps in the CACHS will also auto-trip on a chiller motor malfunction, a low flow condition in either the control room or the control equipment room fan, a SACS room cooling fan malfunction, low flow conditions through the evaporator, or pump power failure.

The circulating pumps in the SPCHS will also auto-trip on a chiller malfunction, low air flow, or low circulating water flow.

Instrumentation and Annunciators

Various CACHS and SPCHS conditions alarm in the control room including a low chilled water tank level, chiller panel trouble, chilled water trouble alarms, and chilled water pump high vibration alarms.

3.2.1.18.5 Operator Actions

The chilled water systems are required to provide continuous cooling under all operating modes. In the case of a LOP or a LOCA, both loops in both chilled water systems start automatically. No operator actions are required; however, the operator can manually start the system if automatic actuations fail.

3.2.1.18.6 Technical Specification Limitations

Technical Specification 3.3.7.4 requires controls for both the 'B' loop of CACHS and the 'B' loop of SPCHS to be operable from the RSP. A failure of the CACHS will cause the operator to implement Technical Specification 3.7.2 for the Control Room Emergency Filtration (CREF) system. The operators may declare the control room ventilation inoperable if it is unable to maintain temperatures below 85°F.

3.2.1.18.7 Testing

No tests for the CACHS or SPCHS were identified.

3.2.1.18.8 System Operation

Normal Operation

One loop in each chilled water system is normally running, while the other loop is maintained in the standby mode. If the "B" loop is in standby mode, and its control is transferred to the remote shutdown panel, all automatic start features are removed.

The various temperatures and pressures in the chilled water system are constantly being monitored. Alarms in the control room will annunciate if the predetermined setpoints are met. Similarly, chilled water flow is continuously being monitored. In the event of low flow in an operating loop, the loop will be tripped automatically, and the pump in the standby loop will be started automatically if its control switch is in auto.

Abnormal Operation

In the event of a LOP, the LOP sequencer will send an auto-start signal to both loops of chilled water, which will start the chiller and circulation pump in each loop. The CACHS chillers will start in 60 seconds, and the circulation pumps in 65 seconds. All loads on both loops of chilled water auto-start either in response to the circulation pump starting or in response to a sequencer signal. In the event of a LOCA, a LOCA Level 1 signal (vessel level -129 inches and/or 1.68 psig drywell pressure) will cause both loops of chilled water to auto-start with the CACHS chillers starting at 65 seconds, and the circulation pumps starting at 60 seconds. In this case, all loads on both loops auto-start. If control of any chiller is transferred to REMOTE, all auto starts are defeated; however, all chillers can be manually operated from the remote (local) panels. The SPCHS chillers and pumps are sequenced on at 75 seconds.

The 'B' chillers can also be operated from the remote shutdown panel. If the RSP switch is in the EMERGENCY position, all automatic start signals for the 'B' train are defeated, including those from the sequencers.

3.2.1.18.9 System Fault Tree

3.2.1.18.9.1 Description

The Chilled Water System fault trees identify all of the major component faults contributing to the system's inability to provide continuous cooling to the components. Simplified diagrams indicating those components modeled in the fault trees are shown in Figures 3.2-18a and 3.2-18b. The acronyms, "CHC" and "CHS", are used for the CACHS and the SPCHS, respectively, in the fault trees.

3.2.1.18.9.2 Success and Failure Criteria

During any operational condition of plant operation, at least one loop in the CACHS and one loop in the SPCHS is required to be operable. For each loop, failure occurs if either the circulating pump or the chiller fails in that loop.

3.2.1.18.9.3 Assumptions

1. Since SACS Loop A is assumed to be in operation, Loop A Circulating Pump AP400 in the CACHS system and Loop A Circulating Pump AP414 in the SPCHS system are assumed to be in operation.

2. Unavailability of any component in a loop will render that loop unavailable. Therefore, instead of modeling the individual TM events in a loop, only one TM event per loop is modeled.

3. Except for the power supplies to the chiller, no faults of individual sub-components of chillers are modeled. Any sub-compartment level fault is subsumed into the fail-to-start and run failure rates for the Chiller or into the TM unavailability of the system.

3.2.1.18.10 References

1. Hope Creek Generating Station UFSAR Section 9.2.7.2.

2. "Hope Creek Generating Station Licensed Operator Systems," Lesson Plan Number 302H-000.00H-000082-09. Public Service Electric and Gas Company, Hancocks Bridge, NJ, January 12, 1993.

3. "Hope Creek Generating Station Licensed Operator Systems," Lesson Plan Number 302H-000.00H-000083-09. Public Service Electric and Gas Company, Hancocks Bridge, NJ, March 6, 1993.

4. Public Service Electric and Gas Company Operating Procedure
   HC.OP-SO.GJ-001

5. Public Service Electric and Gas Drawings
   M-90-1
   E-0435-0
   E-0436-0

3.2.1.19 Control Room and Control Area HVAC System

3.2.1.19.1 System Function

The Control Room and Control Area HVAC Systems function to provide a suitable operating environment for personnel and for equipment in the various rooms in the control area of the Auxiliary Building. These HVAC systems include both safety related and non-safety related systems. The Control Room and Control Area HVAC Systems include the Control Room Supply System (CRS), the Control Area Exhaust System (CAE), the Control Room Emergency Filtration System (CREF), Control Equipment Room Supply System (CERS), Control Area Battery Exhaust System (CABE), Control Area Smoke Exhaust System (CASE), Wing Arca Supply (WAS) and Wing Area Exhaust (WAE). Of these systems, only the following were evaluated in the IPE:

- Control Room Supply System,
- Control Room Emergency Filter System,
- Control Equipment Room Supply System, and

These systems are independently documented in this section.

Control Room Supply System

The CRS provides heating, ventilation, cooling, and environmental control for the control room and a number of adjacent areas. The CRS operates during all modes of unit operation. Under accident conditions, the CRS operates in conjunction with the CREF.

Control Room Emergency Filtration System

Under accident conditions, the CREF operates in conjunction with the CRS to ensure that the control room will remain habitable during and following all design basis accidents. The CREF processes recirculated control room air and makeup air to limit the radiological exposure to operating personnel.

Control Equipment Room Supply System

The CERS provides heating, cooling, ventilation, and environmental control for a number of areas containing control equipment and instrumentation. These areas include the diesel area equipment room, the control equipment mezzanine, the lower control equipment room, and the cable spreading and electrical equipment rooms.

3.2.1.19.2 System Description

General Design

Control Room Supply

The CRS is a safety-related normally operating system. It is designed to seismic Category 1 requirements and is powered by Class 1E sources. The CRS system maintains design conditions in the main control room and in associated adjacent rooms. It is comprised of two 100% capacity air handling units. Each unit is equipped with an outside air intake, outside air radiation monitors, an outside air smoke detector, motorized isolation dampers, 55% ASHRAE dust spot efficient pre-filters, 80 to 85% ASHRAE dust spot high efficiency filters, humidifier, chilled water coil, electric heating coil, and supply fan. A fixed amount of outside air is provided to satisfy ventilation, exhaust, and pressurization requirements. Each unit is connected to a common intake duct system that distributes supply air throughout the rooms. Air is returned from the rooms by a control room return air (CRRA) fan to the CRS unit. The CRS unit is actuated manually from the main control room. The excess ventilation air is exhausted to the outside environment by the CAE system.

Supply air temperature of the CRS unit is controlled by a temperature controller modulating the electric heating coil or chilled water valve. The humidifier in the CRS unit is controlled by a moisture controller. The moisture controller can also modulate the chilled water valve for dehumidification by means of a low signal selector. The supply units are designed and controlled to deliver a constant volume of supply air.

Filter differential pressures and airflow for each CRS unit alarm in the main control room. The temperature controller for the heating and cooling coils, the moisture controller for humidity control, and the airflow controllers for modulating the fan's inlet vanes all indicate on a remote panel.

The chilled water for the cooling coils in each unit is supplied by the Control Area Chilled Water Supply System. The Chilled Water System is interlocked with the supply air fan so that the water chiller cannot operate without the fan being energized. Failure of an operating supply fan trips its associated Chilled Water System Train and is annunciated in the main control room The standby chilled water and air systems then start automatically. The CRS supply fans are direct drive centrifugal units capable of flowing air at 18,500 cfm. The CRRA fans are direct-drive vaneaxial units capable of flowing air at 18,500 cfm. Each CRS unit's electric heating coil has a heat capacity of 307,170 Btu/hr. The CRS unit cooling coils are designed for a cooling capacity of 821,600 Btu/hr. Each CRS unit contains low efficiency (55%) prefilters and high efficiency (80 to 85%) filters. During a LOP, CRS components are sequenced on to the vital buses.

Control Room Emergency Filtration System

CREF is a safety-related standby system that is activated on a LOCA signal or when high radiation level is detected at the CRS outside air intake. Upon actuation CREF automatically functions in the Outside Air (OA) mode. In addition, the operator has the option to manually change system operation to the Recirculation mode. The CREF is designed to seismic Category 1 requirements and is powered by Class 1E sources.

The CREF does not operate during normal plant operation. However, in the unlikely event that a LOCA occurs or when a high radiation level is detected at the outside air intake, the main control room outside air is automatically diverted through the CREF when the mode switch is in the outside air position. When the CREF system is in operation, the volume of air flowing through it is continuously indicated on a remote panel. The supply fans are designed and controlled to deliver a constant airflow quantity. The loss of airflow in the CREF system automatically trips and isolates the operating train and alarms in the main control room. Manual operation may be required to start the standby train. A high radiation level provides a start signal to each CREF train, which will automatically start a CREF train if it is in service or if the appropriate dampers are manually isolated. Loss of airflow and/or high pressure differential across the filter train are alarmed in the main control room. Each CREF train operates in series with one CRS unit.

The CREF filter units are located downstream of the CREF supply fan. Each CREF filter unit consists of a prefilter, electric heating coil, upsteam high efficiency particulate air (HEPA) filters, charcoal adsorber and downstream HEPA filters. The heating coil has a capacity of 44,370 BTU/hr. The prefilter is a 55% efficient unit while the HEPA filters are rated at 99.97% efficiency. Each CREF unit is capable of handling 4000 cfm of air, either entirely recirculated from the control room or a combination of 3000 cfm recirculated air mixed with 1000 cfm of outside air. The CREF supply fans are direct-drive centrifugal units capable of flowing air at 4000 cfm. During a LOP, CREF components are sequenced on to the vital buses.

Control Equipment Room Supply System

The CERS is a normally operating safety-related system. It is designed to seismic Category 1 requirements and is powered by Class 1E sources. The CERS system maintains design conditions in the control area HVAC equipment room, diesel area HVAC equipment room, electrical access inverter area, control equipment room and mezzanine, cable spreading room, battery rooms and electrical equipment room. It consists of two 100% capacity air handling units. Each CERS unit includes a fan, chilled water coils, an electric heating coil, 55% ASHRAE dust spot efficient prefilters, and 80 to 85% ASHRAE dust spot high efficiency filters. The CERS unit is actuated by manual switches in the main control room. A portion of the air supplied to the electrical equipment room by the CERS system is transferred to the battery rooms, which are also directly supplied by the CERS system. The mixed supply air and transfer air is then exhausted from the battery rooms by an exhaust fan of the CABE system. All other supply air is returned to the CERS unit, where it is mixed with a fixed amount of outside air and then heated or cooled, as required, to maintain the design space temperatures. The CERS system operates during normal, shutdown, and abnormal plant operation, and it is automatically connected to the emergency power supply in the event of a LOP to ensure operation of the system.

Supply air temperature for the CERS unit is controlled by a temperature controller modulating the electric heating coil or chilled water valve. Filter differential pressures and airflow for each CERS unit alarm in the main control room. The temperature controller for the heating and cooling coils and the airflow controllers for modulating the fan's inlet vanes all indicate on a local control panel.

The chilled water cooling coils in each CERS unit are supplied by the same Chilled Water Supply System that serves the CRS system. The Chilled Water system is interlocked with the supply air fan so that the water chiller cannot operate without the fan being energized. Failure of the operating supply fan is annunciated in the main control room, and it trips its chilled water system. The standby chilled water and the standby supply air systems then start automatically. Isolation of control circuits is provided between redundant trains to ensure that the single failure criterion is met.

The CERS unit heating coils have a capacity of 341,300 Btu/hr. The cooling coils have a design capacity of 3,492,540 Btu/hr. The CERS supply fans are direct drive centrifugal units capable of flowing air at 65,000 cfm.

3.2.1.19.3 System Interfaces

Control Room Supply System

The CRS fans, heaters, and damper drives are provided with Class 1E 480 V AC power. Control cabinets are provided with 120 V AC power via transformers connected to 480 V AC MCCs that are supplied from the vital buses. The CRS components are sequenced on to the vital buses by the Class 1E LOP/LOCA sequencers. These components are provided with power from channels "C" or "D". The CRS units are provided with cooling water from the Control Area Chilled Water System. Air actuated equipment is provided with control/instrument air.

The Radiation Monitoring System (RMS) provides input to the CRS to isolate from the outside air makeup in the event of detected high radiation at the makeup inlet.

Control Room Emergency Filtration System

The CREF fans, heaters, and damper drives are provided with Class 1E 480 V AC power. Control cabinets are provided with 120 V AC control power via transformers on 480 V AC MCCs. These components are provided power from channels "C" or "D". The CREF initiates on a LOCA signal or on high radiation signal from the radiation monitoring system.

Control Equipment Room Supply System

The CERS fans, heaters, and damper drives are provided with Class 1E 480 V AC power. Control cabinet power is supplied by static inverters from the safety-related 120 V AC system.

These components are provided power from channels "C" or "D". The CERS unit are provided with cooling water from the Control Area Chilled Water System.

3.2.1.19.4 Instrumentation and Control

Control Room Supply System

One train of the CRS is normally operating with the second train in standby. The operating return air fan maintains positive pressure to the operating CRS fan suction. To ensure a positive pressure is maintained in the control room, flow rates are adjusted such that the CRS fan is providing more air than is being exhausted by the CRRA fans. The CRRA fans are controlled from the main control room. The CRRA fans trip on a low flow signal after a 30-second time delay. The CRS fans are controlled from the main control room. CRS fan flow is automatically controlled by the flow controller located in local panels, A and BC485. The controller modulates the CRS fan vanes as necessary to maintain the flow at the setpoint. Flow is measured at the outlet of the air handling unit. Low flow is alarmed in the main control room and automatically trips the CRS fan after a 15-second time delay.

A trip of the running CRS fan will cause the trip of its associated CRRA fan, CREF unit fan, Controlled Area Chilled Water (CACW) pump and chiller, CERS, and SACS Room Cooler fans. The standby CRS train, chilled water train (i.e., chiller, pump), SACS Room Cooler fans, CERS fan, and the associated SACS pump will all auto-start.

Control room temperature is monitored, and it provides an input to the CRS unit temperature controller. The temperature controller regulates heating elements or the chilled water flow to maintain the controller temperature setpoint. The control room temperature is maintained at a nominal 76°F for personnel comfort and equipment protection.

Control room humidity is monitored and controlled from approximately 40 to 50% for personnel comfort and equipment protection. Humidity is automatically controlled by the humidity controller by energizing the humidifier heaters. The humidifier water level is controlled by a float regulated level control valve. The humidifier heaters are de-energized on a low level condition or when the associated CRS fan is not operating.

CRS unit filter differential pressure is monitored and a high DP condition is alarmed in the main control room. A differential pressure detector monitors the pressure at the inlet of the CRS fan relative to the control area pressure on the 155-ft. elevation. This provides an input to the pressure controllers located in the local panels. The pressure controller modulates the dampers at the inlet of the CRS unit. A low CRS unit inlet pressure alarm is annunciated in the main control room. This control adjustment is used to maintain the control room at a positive pressure relative to adjacent areas. The RMS monitors the CRS makeup at the inlet. Upon detection of a high rad condition, the CRS makeup isolation dampers close (along with the control air exhaust dampers). The CRS then operates in conjunction with the CREF to maintain control room availability.

Control Room Emergency Filtration System

The CREF is normally in a standby condition. It operates in conjunction with the applicable operating CRS Train. The CREF is initiated on high radiation at the control room air intake (2E-5 micro curies per cc) and/or LOCA signal (Reactor Vessel Level 1 or drywell pressure at 1.68 psig). The CREF system may also be manually initiated in the main control room by selecting the CRS/CREF isolate mode.

Flow through the CREF train is monitored at the outlet of the CREF unit. The flow sensor provides input to the flow controller at the applicable local panel. The flow controller modulates the CREF fan inlet vanes to maintain an approximate 4000 cfm flow rate. Low flow is also annunciated in the main control room.

Differential pressure across the CREF unit upstream HEPA filter is monitored and indicated in the control room. A high DP condition is annunciated in the control room. Airstream moisture content is monitored upstream of the charcoal filter and provides an input signal to the CREF humidity controllers located in the applicable local panels. The controllers regulate the train inlet heater to maintain humidity less than the 70% maximum design humidity for the charcoal adsorber beds.

The airstream temperature upstream of the charcoal beds is monitored to ensure that the charcoal temperature remains sufficiently low to preclude ignition. The firewater deluge system must be manually started in the event of a charcoal fire. The applicable CREF train is automatically shut down if the deluge is activated. Loss of airflow in an operating CREF train automatically trips and isolates the operating train and is alarmed in the control room. Manual operation is required to start the standby train.

Control Equipment Room Supply System

One train of the CERS is normally operating with the second train in standby. The CERS train flow is measured at the outlet at the CERS unit and is input to the flow controllers in the applicable local panel. The flow controller modulates the CERS fan inlet vanes to maintain the desired flowrate. Low flow is annunciated in the main control room. Failure of the operating supply fan automatically trips the CERS train, associated CACW pumps, CACW chiller, CRRA fan, CRS fan, and SACS room cooler fans. The standby CERS train and related chilled water train then are automatically started.

The airstream temperature is measured at the outlet of the CERS unit and is input to the temperature controller at the appropriate local panel. The temperature controller regulates the heating elements and chilled water flow to maintain the defined temperature. CERS filter DP is monitored and a high DP alarm is annunciated in the main control room.

3.2.1.19.5 Operator Actions

Control Room Supply System

The CRS is controlled from the main control room. The CRS trains may be started automatically or manually when the trains are switched into the AUTO position. In the event of the failure of an operating train, the standby train will auto-start without requiring operator involvement.

Operator responses to the various alarms associated with CRS are addressed in procedure HC.OP-AR.ZZ-019(Q). The operator may choose to operate the CRS in a normal or isolate mode. When the isolate mode is selected, the CRS makeup train is isolated and CREF is started.

Control Room Emergency Filtration System

The CREF is controlled from the main control room. CREF is a standby system that will auto-start upon receipt at a LOCA or CRS inlet high radiation signal. In the event that an operating CREF train trips, the standby train will not automatically start and must be manually started from the main control room.

Operator response to the various alarms associated with the CREF are addressed in procedure HC.OP-AR.ZZ-019(Q). The CREF may be operated, at the operators discretion, in the outside air or recirculation mode. The outside air mode allows the CREF to mix an amount of outside air with the recirculated air for processing and supply to CRS. The recirculation mode isolates the makeup path from the outside thereby allowing CREF to process only recirculated air for return to CRS.

Control Equipment Room Supply System

The CERS is controlled from the main control room. The CERS trains may be started automatically or manually when the trains are switched into the AUTO position. In the event of the failure of an operating train, the standby train will auto-start without requiring operator involvement. Operator response to the various alarms associated with CERS are addressed in procedure HC.OP-AR.ZZ-019(Q).

3.2.1.19.6 Technical Specification Limitations

Control Room Supply System

The CRS is addressed by Technical Specification LCO 3.7.2 by virtue of its vital relationship to CREF. The CRS involvement in LCO 3.7.2 is discussed below in the CREF section. The CRS is also addressed by Technical Specification surveillance 4.7.2 by the requirement to verify the control room temperature is less than or equal to 85°F.

Control Room Emergency Filtration System

Technical Specification LCO 3.7.2 requires the operability of two independent control room emergency filtration subsystems. Each subsystem consists of one CRS supply unit, one CREF filter train, and one control room return air fan. The LCO is applicable in all operational conditions and when irradiated fuel is being handled in the secondary containment.

In operational conditions 1, 2, or 3 and when one CREF subsystem is inoperable, the inoperable subsystem must be restored to operability in 7 days, or the unit must be placed in hot shutdown within 12 hours and cold shutdown in the following 24 hours. When both trains of CREF are inoperable, Technical Specification LCO 3.0.3 applies. If the Limiting Condition is not met within one hour, action shall be initiated to place the unit in an operational condition in which the Specification does not apply or achieve hot shutdown in 12 hours and cold shutdown in the following 24 hours.

In operational conditions 4, 5, or when irradiated fuel is being moved in secondary containment and one CREF subsystem is inoperable, the inoperable subsystem must be restored to operable status in seven days or the operable subsystem must be started and maintained in the pressurization/recirculation mode of operation. With both CREF subsystems inoperable, core alterations must be suspended, and all handling of irradiated fuel in the secondary containment and operations with a potential for draining the vessel must be suspended.

Control Equipment Room Supply

There are no Technical Specification requirements or limitations related to CERS.

3.2.1.19.7 Test

Control Room Supply System

No major system tests/surveillances are performed on the CRS other than those required by Tech Spec.

Control Room Emergency Filter System

No major system tests/surveillances are performed on CREF other than those required by Tech Spec.

Control Equipment Room Supply System

No major system tests/surveillances are performed on CERS with Technical Specification LCOs.

3.2.1.19.8 System Operation

Control Room Supply System

During normal operations, one train of CRS operates, and the second train is in standby. The CRRA fan draws 3000 cfm of outside air and 15,500 cfm of recirculated air. The total 18,500 cfm is discharged to the CRS unit which serves to filter, heat, cool and control the humidity of the supplied air. The CRS unit also houses the CRS fan, which supplies the processed air to the area mentioned previously. Excess ventilation air is exhausted from the supplied rooms to the outside atmosphere by the control area exhaust system. Tripping/loss of a CRS fan will cause a trip of the associated CRRA fan, CREF unit fan, CACW pump, CACW chiller, CERS, and SACS Room Cooler fans. The standby CRS train, chilled water train (i.e., chiller, pump), SACS Room Cooler fans, CERS fan and the associated SACS pump will all auto-start. Under certain conditions, the CRS operates in an isolation mode in conjunction with CREF. Operation of the CRS in this mode is discussed below.

Control Room Emergency Filtration System

During normal station operation, the CREF is in a standby mode. Upon receipt of Reactor Vessel LOCA Level 1 signal, high drywell pressure signal or CRS air intake high radiation signal, the CRS enters the isolation mode, and the CREF is auto-started. The isolation mode may also be manually selected from the main control room.

The CRS isolates by the closing of the normal outside air intake isolation dampers. Additionally, the control area exhaust fans are tripped and the exhaust isolation dampers closed. The applicable CREF train then starts to run in conjunction with the operating CRS train. The CREF may be operated in the outside air mode or in the recirculation mode at the discretion of the operator.

In the outside air mode, the CREF processes 4000 cfm of air. Three thousand is drawn from the suction of the CRRA fan and 1000 cfm is drawn from outside air via the CREF makeup train. The air is processed through the CREF unit low efficiency filters, the HEPA filters, and charcoal adsorbers. The processed air is then provided to the inlet of the CRS units along with the 14,500 cfm of recirculated air, thus maintaining a total flow of 18,500 cfm. Since the control area exhaust trains have been isolated, the only air loss is due to outleakage, and the control room will therefore be pressurized to prevent possible infiltration of contaminated air.

The recirculation mode is manually selected by the operator. Operation in the recirculation mode is required if smoke and/or toxic gases are detected in the air supply. When operating in the recirculation mode, the CREF makeup train from the outside air is isolated. The CREF unit then processes 4000 cfm of air drawn from the suction of the CRRA fan. The processed air is provided to the inlet of the CRS units for processing, along with the 14,500 cfm of recirculated air, thus maintaining a total flow of 18,500 cfm. In the recirculation mode, there is no makeup, and room pressurization cannot be maintained. Control room pressure will then equalize. Room air infiltration then minimized by the room design features which reduce infiltration.

Control Equipment Room Supply System

During normal operation, one train of CERS is in operation, and the second train is in standby. Failure of the operating supply fan automatically trips the CERS train, associated CACW pump, CACW chiller, CRRA fan, CRS fan, and SACS Room Cooler fan. This failure initiates an auto start of the standby CERS train, associated CACW pump, CACW chiller, CRRA fan, and SACS Room Cooler fans. CERS operates in this manner under all plant conditions, and it is loaded to the vital buses for operation during a LOP.

During operation, the CERS mixes recirculated air with outside makeup air for supply to the serviced areas. The system is designed to draw 5000 cfm of outside air to combine with 54,500 cfm of recirculated air. Approximately 3500 cfm of the supplied air is exhausted by Non-Class 1E ventilation systems. This mode of operation serves to maintain a slight positive pressure in the serviced areas.

3.2.1.19.9 System Fault Tree

3.2.1.19.9.1 Description

Simplified diagrams of the CERS, CREF/CRS and CRS are shown in Figures 3.2-19a, 3.2-19b, and 3.2-19c, respectively.

Control Room Supply System

The CRS system includes a normally operating train and a redundant standby train. A single tree adequately addresses the normal operation of this system. Under LOCA conditions, CRS operates in conjunction with CREF, and therefore, a separate tree was constructed for CREF that includes the CRS contribution.

Control Room Emergency Filtration System

The CREF system is normally in standby with the train associated with the running CRS train capable of auto initiation and the second train available for manual initiation. A single tree adequately addresses the expected operation of this unit. Under LOCA conditions, the CREF operates in conjunction with the CRS. Therefore, the CREF Fault Tree includes this particular operating condition of CRS.

Control Equipment Room Ventilation System

The CERS system includes a normally operating train and a redundant standby train. A single tree adequately addresses the normal operation of the system. The tree reflects a running train with the standby train auto-starting upon failure of the operating train.

3.2.1.19.9.2 System Fault Tree Success/Failure Criteria

Control Room Supply System

The CRS system includes two independent 100% capacity trains, thus providing 100% redundancy. To successfully fill its support function, one train must operate to provide air circulation and processing. This requires the operability of the CRS train dampers, and all associated fans (i.e., CERS fan, etc.) in the ventilation loop to establish the proper flow path.

Control Room Emergency Filter System

The CREF system includes two 100% capacity trains, thus providing 100% redundancy. One train will normally be capable of auto-initiation to operate in conjunction with the running CRS train, while the other train must be manually started if it is needed. To successfully fulfill its function, one CREF train must operate with its related CRS train in the isolate mode of CRS. Success will require either Scenario A or B below.

A. Initiation signal (LOCA or CRS inlet high rad signal is received)
   - CRS train continues to operate,
   - Chilled water train continues to operate,
   - CRS train isolates from outside
   - CREF train auto-starts and aligns to the CRS train.
   - CERS train continues to operate.

B. Operator manually initiates the standby CREF train,
   - Standby CRS and chilled water trains auto-start,
   - CRS train remains isolated from outside air,
   - CREF train aligns to the CRS train.

Control Equipment Room Supply System

The CERS system includes two 100% capacity trains, thus providing 100% redundancy. One train is normally operating while the second train is in standby and will autostart upon the loss of the first train. To succeed in fill its support function, one train of CERS must operate to provide air circulation and processing.

3.2.1.19.9.3 Assumptions

Control Room Supply System

1. High and low efficiency filters in a single CRS unit were modeled as a single filter.

2. Fire protection dampers were not modeled since they were included in the fire protection evaluation.

3. Manual balancing dampers were not modeled since it was assumed they were correctly positioned during system balancing and there are no requirements to reposition them.

4. Humidifiers were not modeled since they are primarily for personnel comfort; failure would not seriously affect equipment or personnel over a reasonable period of time.

Control Room Emergency Filtration System

1. Upstream low efficiency and HEPA filters for a single unit were modeled as a single filter since the plugging of either one will restrict airflow. The downstream HEPA filter was separately modeled since it may be exposed to additional contamination from the charcoal filters.

2. Manual balancing dampers were not modeled since it was assumed that they were properly positioned during system balancing, and there is no requirement to reposition the dampers.

3. The CREF charcoal adsorber fire deluge system was ignored for this model. Operation of the deluge system requires opening of the automatic valves along with the opening of normally closed manual isolation valves. Therefore, unavailability due to inadvertent deluge is considered insignificant.

4. CREF initiation on high CRS inlet radiation is assumed to be part of the component ICC faults.

5. Little unavailability documentation could be located for charcoal adsorbers. IEEE lists a failure rate at 1.6E-6, but did not document which failure modes were included. Therefore, the failure rate of 1.0E-5/hour was assumed for plugging of normal filters.

Control Equipment Room Supply

1. High and low efficiency filters contained in a single unit were modeled as a single filter.

2. Fire protection dampers were not modeled since they were included in the fire protection evaluation.

3. Manual balancing dampers were not modeled since it is assumed that they were correctly positioned during system balancing, and there are no requirements to reposition them.

3.2.1.19.10 References

1. Hope Creek Generating Station UFSAR Sections 7.3.1.1.7 and Section 9.4.1.

2. "Hope Creek Generating Station Licensed Operator Systems," Lesson Plan Number 302HC-000.00-096A-01. Public Service Electric and Gas Company, Hancocks Bridge, NJ, May 25, 1988.

3. "Hope Creek Generating Station Technical Specifications 3.7.2." Public Service Electric and Gas Company, Hancocks Bridge, NJ, July 1986.

4. Public Service Electric and Gas Company Operating Procedures

   OP-ST.GK-002 Rev. 2
   OP-ST.GK-001 Rev. 3
   OP-AR.GK-001 Rev. 0
   OP-AR.GM-001 Rev. 0
   OP-SO.GK-001(Q)
   OP-SO.GJ-001(Q)
   OP-AR.ZZ-019(Q)

5. Public Service Electric and Gas Drawings

   M-78-1 Rev. 14 (UFSAR Fig. 9.4-1)
   M-89-1 Rev. 19 (UFSAR Fig. 9.4-2)
   M-85-1 Rev. 09 (UFSAR Fig. 9.4-15)
   E-0018-1 Rev. 2
   E-0019-1 Rev. 1
   E-0020-1 Rev. 3
   E-0023-1 Rev. 10
   H-89-0 (UFSAR Figure 7.3-16)
   H-90-0 (UFSAR Figure 7.3-23)
   H-90-1 (UFSAR Figure 9.2-15)

3.2.1.20 Service Water Intake Structure Ventilation Systems

3.2.1.20.1 System Function

The Service Water Intake Structure Ventilation Systems include two independent systems, the Intake Structure Ventilation System and the Traveling Screen Motor Room Ventilation System.

Intake Structure Ventilation System

The function of the Intake Structure Ventilation System is to maintain the appropriate design ambient temperatures in the SSW pump bays.

Traveling Screen Motor Room Ventilation System

The function of the Traveling Screen Motor Room Ventilation System is to maintain the appropriate design ambient temperature in the traveling screen motor room.

3.2.1.20.2 System Descriptions

Intake Structure Ventilation System

The Intake Structure Ventilation System is an Engineered Safety Feature System (ESF), is powered by Class 1E sources, and is designed to seismic Category 1.

This system is composed of two subsystems, each subsystem supplying one of two station service water pump bays. Each subsystem includes two 100% capacity redundant trains to supply cooling makeup air and recirculation. Each train includes a supply and exhaust vaneaxial fan, each capable of moving 60,000 cfm.

For each subsystem, both trains are normally in an auto-standby mode, with both trains actuated on high room temperature. The temperature switches are adjusted for 93°F on one train and 97°F for the second train.

For the operation of a train, outside air is mixed with recirculated air via variable setting dampers to maintain pump bay temperature at less than 86°F (less than 90°F for the redundant train). The fans will auto-stop at a room temperature of less than 81.7°F (less than 85.7°F for the redundant train).

High and low room temperatures and low flow conditions are annunciated on local panels and transmitted to the main control room as a common trouble alarm. If a running supply or exhaust fan indicates low airflow, both supply and exhaust fans are auto-stopped. The redundant supply and exhaust fans will auto-start when room temperature exceeds the temperature switch setpoint.

Electric unit heaters are also located at various locations in the bay to provide winter shutdown freeze protection. However, the unit heaters are not required if at least one pump is in operation.

Traveling Screen Motor Room Ventilation System

The Traveling Screen Motor Room Ventilation System is an Engineered Safety Feature System (ESF), is powered by Class 1E sources, and is designed to seismic Category 1.

This system is composed of two 100% capacity trains, each supplying the single traveling screen motor room. Each train is composed of proportioning dampers and single vaneaxial, 6000 cfm fans.

One train will normally be in operation, with the proportioning dampers modulating to mix outside air with recirculated air to maintain room temperature. Low flow on the operating train will auto-start the redundant train.

Room high and low temperatures and low flow conditions are annunciated on a local panel and transmitted to the main control room as a common trouble alarm.

Electric unit heaters are also located in the traveling screen motor room to provide winter shutdown freeze protection. However, the unit heaters are not required if the traveling screens are in operation.

3.2.1.20.3 System Interfaces

Intake Structure Ventilation System

The supply and exhaust fans and damper drives for the Intake Structure Ventilation System are powered by Class 1E 480 VAC sources.

120 VAC control instrumentation power is taken from the same Class 1E 480 VAC buses via transformers.

Traveling Screen Motor Room Ventilation System

The Traveling Screen Motor Room Ventilation System fans and damper drives are powered by Class 1E 480 VAC sources. 120 VAC control/instrumentation power is taken from the same Class 1E 480 VAC buses via transformers.

3.2.1.20.4 Instrumentation and Control

Intake Structure Ventilation System

Each subsystem and train of the Intake Structure Ventilation System is controlled from local panels. The train may be actuated manually or automatically. When in automatic, the fan in the lead train of each subsystem will auto-start when room temperature reaches 8[illegible]°F and will auto-stop when room temperature falls below 74.5°F. The temperature switches for the redundant train are set to auto-start the fans at 99°F and to auto-stop the fans at 91.5°F.

The dampers reposition automatically on fan starts and stops. While the fans are operating, the dampers automatically modulate to mix outside air and recirculated air to maintain room temperature at 84°F. Above 84°F, 100% outside air is used.

Room high-low temperature switches annunciate on local panels and thereby activate a common trouble alarm in the main control room. A low flow alarm on the operating train similarly causes a local panel trouble alarm and a common trouble alarm in the main control room.

Low flow indication on the operating train causes the supply fans and the associated exhaust fan to stop. The standby train will auto-start when its high temperature setpoint is reached.

Traveling Screen Motor Room Ventilation System

Both trains of the Traveling Screen Motor Room Ventilation System are controlled from local panels. One train is normally operating with the second train in standby.

During operation of the train, the dampers automatically reposition to mix outside air with recirculated air in order to maintain room temperature at the desired level.

High and low room temperatures are annunciated on a local panel, and they are transmitted to the main control room as a common trouble alarm. Low room temperature is alarmed at 60°F and high temperature is alarmed at 104°F.

Low flow on a running fan is annunciated on a local panel and is transmitted to the main control room as a common trouble alarm. The low flow condition also stops the operating fan and auto-starts the standby fan.

3.2.1.20.5 Operator Actions

Intake Structure Ventilation System

When placing the Intake Structure Ventilation System in service, all supply and exhaust fans are placed in the auto position. The operator verifies that the thermostatic controls for the dampers are properly set. These actions are addressed in Procedure HC.OP-SO.GQ-001, Service Water Intake Structure Ventilation System Operation.

Operator response to the main control room common trouble alarm for intake structure HVAC is addressed in Procedure HC.OP-AR.ZZ-001. HC.OP-AR.ZZ-001 directs the operator to Panel 1EC581 and to respond to the situation in accordance with Procedure HC.OP-AR.GQ-001.

Traveling Screen Motor Room Ventilation System

When placing the Traveling Screen Motor Room Ventilation System in service, one fan/train is placed in the run mode while the second fan/train is placed in an auto-standby mode. These actions are addressed in Procedure HC.OP-SO.GQ-001, Service Water Intake Structure Ventilation System Operation.

Operator response to the main control room common trouble alarm for intake structure HVAC is addressed in Procedure HC.OP-AR.ZZ-001. HC.OP-AR.ZZ-001 directs the operator to Panel 1EC581 and to respond to the situation in accordance with Procedure HC.OP-AR.GQ-001.

3.2.1.20.6 Technical Specification Limitations

Intake Structure Ventilation System

There are no Technical Specification requirements or limitations directly affecting the Intake Structure Ventilation System. However, operability of the Intake Structure Ventilation System may affect the operability of the SSWS.

Traveling Screen Motor Room Ventilation System

There are no Technical Specification requirements or limitations directly affecting the Traveling Screen Motor Room Ventilation System. However, operability of the Traveling Screen Motor Room Ventilation System may affect the operability of the SSWS.

3.2.1.20.7 Testing

Intake Structure Ventilation System

The Intake Structure Ventilation System is a normally operating system. There are no routine system tests performed on this system. However, periodic preventive maintenance is performed at a 1 to 3 year frequency. The operation of the system is tested following this maintenance.

Traveling Screen Motor Room Ventilation System

The Traveling Screen Motor Room Ventilation System is a normally operating system. There are no routine system tests performed on this system. However, periodic preventive maintenance is performed at a 1 to 3 year frequency. The operation of the system is tested following this maintenance.

3.2.1.20.8 System Operation

Intake Structure Ventilation System

Normal operation at the Intake Structure Ventilation System is for both trains of both subsystems to be in standby operation.

One train of each subsystem is set to have the associated fans auto-start at 82°F and auto-stop at 74.5°F. The dampers for this train automatically reposition to maintain an 84°F room temperature.

The second train of each subsystem is set to have the associated fans auto-start at 99°F and auto-stop at 91.5°F. The dampers for this train automatically reposition to provide 100% outside air above 84°F room temperature.

A low flow condition on the operating train will trip the associated fans after a 20-second time delay.

Traveling Screen Motor Room Ventilation System

Normal operation of the Traveling Screen Motor Room Ventilation System is for one train to be in operation with the second train to be in standby.

During train operation, the associated dampers automatically reposition to mix outside air and recirculated air, maintaining room temperature between 62°F and 104°F.

Low flow on the operating train will auto-start the standby train and trip the operating train.

3.2.1.20.9 System Fault Tree

3.2.1.20.9.1 Description

Intake Structure Ventilation System

The Intake Structure Ventilation System includes two subsystems. Each subsystem is comprised of two redundant trains and serves a single pump bay. To support the equipment in each of the pump bays, each subsystem must be operable. For a subsystem to be operable, one train of the two trains must be operable. A simplified diagram of the system is shown in Figure 3.2-20a.

A separate fault tree was prepared for each pump bay to accurately reflect the missions of the two independent subsystems of the Intake Structure Ventilation System. Each tree reflects the operability requirement for the intake and exhaust fans to move the air, the makeup inlet air damper to open to supply cooler air, and the exhaust damper to be open to provide the flow path out of the room.

Traveling Screen Motor Room Ventilation System

The Traveling Screen Motor Room Ventilation System includes two 100% capacity trains. To complete its function as a support system, one of two trains must be operable. For a train to be operable, the fan and associated dampers must be functional and operate to control the room temperature within the desired range.

The exhaust backdraft damper is shared between the two trains.

3.2.1.20.9.2 Success and Failure Criteria

Intake Structure Ventilation System

A simplified drawing of the Intake Structure Ventilation System is shown in Figure 3.2-20a. The two subsystems of the Intake Structure Ventilation System each support different SSW pump bays. In order to adequately reflect this configuration, separate trees were prepared for the subsystems. For success as a support system, both subsystems must be operable with at least one train operable in each subsystem. Each operable train requires the intake and exhaust fans to start and run, the power operated dampers to reposition to establish a flow path and provide makeup air, and the backdraft dampers to open.

Traveling Screen Motor Room Ventilation System

A simplified drawing of the Traveling Screen Motor Room Ventilation System is shown in Figure 3.2-20b. To complete its function as a support system, one of two trains of the Traveling Screen Motor Room Ventilation System must be operable during all modes of unit operation. An operable train requires a fan to run, the power operated dampers to reposition to establish a flow path and to provide makeup air, and the common backdraft damper to open.

3.2.1.20.9.3 Assumptions

Intake Structure Ventilation System

1. Tornado dampers were not modeled since they are associated with external events only.

2. Room heaters were not modeled since the UFSAR states that they are not necessary if a pump is in operation.

3. Manual dampers were not modeled since it is assumed that they were properly positioned during system balancing and that there is no periodic repositioning of the dampers.

4. Recirculation was not modeled. Recirculation is only to help keep the room temperatures from falling too low. This mode is redundant as the following considerations would keep the room temperature at an acceptable level:

   a. The fans auto-cycle off when room temperature falls below 74.5°F for the lead train and 91.5°F for the standby train.

   b. Room/area heaters are set to operate when the room temperature drops below 60°F.

   c. The room temperature is monitored and alarmed when the low temperature setpoint is reached.

5. Dampers TD9773A1 through D1 include two hydraulic operators for damper operation. Since both operators are required and the tree failure data is for failure of hydraulic dampers, no special modeling or data manipulation was considered necessary.

Traveling Screen Motor Room Ventilation System

1. Tornado dampers were not modeled since they are associated with external events only.

2. Room heaters were not modeled since the UFSAR states they are not necessary if a traveling screen is in operation.

3.2.1.20.10. Reference

1. Hope Creek Generating Station UFSAR Section 9.4.7.

2. Public Service Electric and Gas Company Operating Procedures:

   HC.OP-SO.EA-001
   HC.OP-SO.EP-001
   HC.OP-IS.EA-001 THROUGH 004
   HC.OP-IS.EA-101 AND 102

2. Public Service Electric and Gas Company Operating Procedures (Continued):

HC.OP-IS.EP-001 THROUGH 104
HC.OP-ST.EA-002
HC.OP-AB.ZZ-122
HC.OP-SO-GQ-001B
HC.OP-AR.ZZ-001
HC.OP-AR.GQ-001

3. Public Service Electric and Gas Drawings

M81-0
M95-0 Rev. 13
R0022-1

3.2.1.21 Equipment Area Cooling System (EACS)

3.2.1.21.1 System Function

The Equipment Area Cooling System (EACS) is an engineered safeguard ventilation system that provides standby supplementary cooling to pump rooms, where normal ventilation requirements would be excessive, in order to relieve the equipment heat gain. The EACS is an independent subsystem of the Reactor Building Ventilation System (RBVS).

3.2.1.21.2 System Description

Each pump room is provided with two full-capacity unit coolers. The coolers consist of a vaneaxial fan and a SACS water cooling coil, except for the SACS pump rooms which are provided with chilled water cooling coils. Each unit is also provided with an independent room temperature sensing instrumentation train. One unit cooler runs while the other one is in standby. The EACS units are safety-related components designed to Seismic Category 1 and are powered by Class 1E sources.

General Design

Both EACS units in an ECCS pump compartment will normally be in standby operation with one unit in an auto-lead mode. The unit in the auto-lead mode will auto-start on a room nominal temperature of 110°F. The second unit will auto-start at a nominal 115°F room temperature. A low airflow condition on a running EACS unit will cause an auto-start of the second unit. A simplified diagram of the SACS room 4309 (4307) EACS is shown in Figure 3.2-21a. Figure 3.2-21b is the simplified diagram for the HPCI room 4111 EACS. The RCIC room 4110 EACS is shown in Figure 3.2-21c. Figure 3.2-21d is the simplified diagram for the RHR room 4113 (4114) EACS, and Figure 3.2-21e is the simplified diagram for RHR Room 4107 (4109) EACS. Figure 3.2-21f is the simplified diagram for the CS room 4118 (4116) EACS. CS room 4104 (4105) EACS is shown in Figure 3.2-21g.

The EACS units are located in the HCGS pump rooms as shown in Table 3.2-1.

Component Description

RHR Pump Room Unit Coolers

Each RHR pump room is provided with two full-capacity unit coolers, each consisting of a SACS water cooling coil and a direct-connected motor-driven fan. Each RHR pump room cooler has a cooling capacity of 448,500 BTU/hr and an air flow rating of 30,000 CFM.

CS Pump Room Unit Coolers

Each CS pump room is provided with two full-capacity unit coolers, each consisting of a SACS water cooling coil and a direct-connected motor-driven fan. Each CS pump room cooler has a cooling capacity of 269,150 BTU/hr and an air flow rating of 18,000 CFM.

HPCI Pump Room Unit Coolers

The HPCI pump room is provided with two full-capacity unit coolers, each consisting of a SACS water cooling coil and a direct-connected motor-driven fan. Each HPCI pump room cooler has a cooling capacity of 269,150 BTU/hr and an air flow rating of 18,000 CFM.

RCIC Pump Room Unit Coolers

The RCIC pump room is provided with two full-capacity unit coolers, each consisting of a SACS water cooling coil and a direct-connected motor-driven fan. Each RCIC pump room cooler has a cooling capacity of 119,600 BTU/hr and an air flow rating of 8,000 CFM.

SACS Pump Room Unit Coolers

Each SACS pump room is provided with two full-capacity unit coolers, each consisting of a chilled water cooling coil and a direct-connected motor-driven fan. Each SACS pump room cooler has a cooling capacity of 485,000 BTU/hr and an air flow rating of 12,000 CFM.

3.2.1.21.3 System Interfaces

Electrical

The power supply for all EACS units originates from 480 VAC vital buses. Table 3.2-2 indicates the vital bus associated with each EACS unit. Each EACS cooler has its own temperature sensing and controlling circuitry. Power to the EACS unit control cabinets is supplied via the 125 VDC system as is shown in Table 3.2-2. Control power for the isolation valves controlling SACS flow to individual coolers is part of the temperature sensing/initiation control circuitry. The valves are designed to fail open on a loss of control power.

Component Cooling

The cooling supply for the SACS pump room EACS units is from the Auxiliary Building Control Area Chilled Water Systems. Water circulates through the coolers whenever the associated chilled water loop is in service, i.e., there is no flow control valve associated with the water supply.

The cooling supply for the remaining EACS units is from SACS. SACS flow to individual coolers is permitted by an open/closed isolation valve during operation of the associated EACS unit.

Control

Each EACS cooler unit has its own temperature sensing and controlling circuitry. Valve control is part of the temperature sensing/initiation control circuit.

Pneumatic

The EACS cooling units' SACS flow isolation valves use control air for motivation, and are designed to fail to the open position of a loss of control air.

3.2.1.21.4 Instrumentation and Control

System Actuation

The individual EACS units include their own temperature sensing/actuation circuits, including individual temperature switches. When both room units are in the auto-mode, the lead cooler starts automatically when the room temperature exceeds a nominal 110°F, and the standby/lagging cooler will automatically start at a nominal 115°F. If a low airflow condition occurs in the running lead cooler, the standby cooler automatically starts and an alarm is annunciated in the main control room.

Control

During operation of the EACS room coolers, essentially no manual control is necessary. The individual EACS units start automatically and continue to run as long as necessary to control room temperatures. If automatic actuation of the units fails, or if a unit trips, manual controls for the EACS units are located on local control panels AC281, BC281, CC281, and DC 281 in the reactor building.

With the exception of the SACS pump room EACS units, the unit initiation circuitry also causes the cooling flow control valve to open permitting SACS water to flow through the respective cooler. These flow control valves fail open upon loss of control power or control air. The SACS pump room EACS units do not incorporate coolant flow control valves.

Interlocks

SACS pump room unit coolers AVH214 and BVH214 are interlocked to operate in auto only if chilled water pump AP400 is in service. SACS pump room unit coolers, CVH214 and DVH214, are interlocked to operate in Auto only if chilled water pump BP400 is in service.

Instrumentation and Annunciators

Any alarm, such as a control switch out of position or a fan stopped due to low flow, will actuate a control room overhead alarm and a computer alarm. Should an EACS pump's room temperature exceed 150°F, an alarm will be actuated in the main control room.

3.2.1.21.5 Operator Actions

When placing the EACS units in service, both units associated with an ECCS pump room are made available for operation. One unit is switched into the Auto-lead position and the other is placed in the Auto position.

Operator response to control room alarms associated with the EACS units is addressed in the alarm response procedures.

3.2.1.21.6 Technical Specification Limitations

There are no Technical Specification limitations or surveillances associated with the EACS; however, the operability of the systems cooled by the EACS coolers could be affected by the operability of the coolers.

3.2.1.21.7 Testing

On an 18 month basis, each EACS units is functionally tested for proper auto initiation of the room coolers and associated SACS valves. This is performed by utilizing a heat gun (or equivalent) to blow hot air over the temperature switches and to verify that the fan starts and the coolant flow valves open.

Preventive maintenance of the EACS units is limited to lubrication of the motor bearings, general visual inspection of the unit and calibration of the temperature sensors. Bearing lubrication and unit visual inspections are performed on an 18-month basis. Calibration of the temperature sensors is performed on a six-month basis and requires the outage of the associated EACS unit.

3.2.1.21.8 System Operation

Each ECCS pump room contains two EACS unit coolers. All EACS unit coolers are normally in a standby auto condition. When placing the system in service, the operator places one EACS unit in an auto-lead mode for each ECCS pump room. The second EACS unit in each

ECCS pump room is put into auto-mode. In this configuration, the lead unit auto starts at a nominal room temperature of 110°F. The second unit will auto-start at a nominal temperature of 115°F.

Operation based on room temperature is normal for all plant modes. The EACS units are sequenced on to the vital buses during a LOP.

3.2.1.21.9 System Fault Tree

3.2.1.21.9.1 Description

A separate fault tree was constructed for the pair of EACS units in each ECCS pump room. This was done to reflect the various independent support functions for the EACS system.

To function, each EACS unit must have 480 VAC power, 125 VDC power, and a supply of cooling water (chilled water for SACS pump room units, SACS coolant for all other EACS units).

3.2.1.21.9.2 Success and Failure Criteria

The EACS system was broken down into 12 subsystems for the purpose of fault tree generation. Each subsystem consists of the two EACS units in a given ECCS pump room. In order to fulfill its function as a support system, at least one EACS unit in a given ECCS pump room must be operational. To be operational, the EACS unit fan must start and run, coolant flow must be available from chilled water or SACS (as appropriate), and the actuation instrumentation must provide the start signal.

3.2.1.21.9.3 Assumptions

1. Air flow sensing instrumentation was not considered/modeled since the redundant EACS unit will start on high room temperature regardless of flow status on the lead unit.

2. Loss of control power or control air to the coolant flow control solenoid valves was not modeled since the flow control valves fail open on loss of control power or control air. Loss of control power for the start signal for the pumps was modeled.

3. Manual SACS and chilled water flow isolation valves were not modeled since both are second verification required systems. Therefore, proper valve positioning is verified when any valve positioning/repositioning is performed.

4. Recirculation was not modeled for either an idle train or an operating train failing and the backup train starting. Either case would require a backdraft damper failing to close, a hydraulic operator flow control damper (fan inlet) failing to close (fails closed on loss of power), and either a second backdraft damper failing to close or a hydraulically operated valve failing to close (fails closed on loss of power).

3.2.1.21.10 References

1. Hope Creek Generating Station UFSAR Section 9.4.2.

2. "Hope Creek Generating Station Licensed Operator Systems," Lesson Plan Number 302H-000.00H-042-08. Public Service Electric and Gas Company, Hancocks Bridge, NJ, March 16, 1993.

3. Public Service Electric and Gas Company Operating Procedures
   OP-SO.GR-001, Reactor Building Ventilation System Operation.
   OP-FT.ZZ-001, EACS Rm Clr Funct. Test 18 months.
   OP.AR.ZZ-018

4. Public Service Electric and Gas Drawings
   M-76-1 Rev. 16
   M-83-1 Rev. 19
   M-84-1, Sh. 1, Rev. 22
   M-84-1, Sh. 2, Rev. 0
   M-11-1, Sh. 1, Rev. 25
   M-11-1, Sh. 2, Rev. 19
   M-11-1, Sh. 3, Rev. 18
   M-11-1, Sh. 4, Rev. 0

   E-0020-1, Sh. 1, Rev. 11
   E-0020-1, Sh. 2, Rev. 9
   E-0021-1, Sh. 1, Rev. 13
   E-0021-1, Sh. 2, Rev. 12
   E-0021-1, Sh. 3, Rev. 11
   E-0021-1, Sh. 4, Rev. 14
   E-0021-1, Sh. 5, Rev. 11
   E-0021-1, Sh. 6, Rev. 13

3.2.1.22 <u>Primary Containment Instrument Gas System (PCIGS)</u>

3.2.1.22.1 System Function

The PCIGS provides a continuous supply of compressed gas to pneumatic valves, including the safety/relief valves (SRVs), in the drywell. If a LOCA were to occur, the PCIGS would supply compressed gas to the MSIV sealing system as well. PCIG is not required for a safe plant shutdown. PCIG is required for long-term pneumatic operation of the SRVs. Loss of PCIGS will not affect the high steam pressure actuation of the SRVs.

3.2.1.22.2 System Description

General Design

The PCIGS consists of two skid-mounted compressors that take suction from the drywell atmosphere (inerted) and supply gas to two normally connected supply headers. The compressors operate in a lead-lag mode, such that the lead compressor operates as needed to maintain system pressure.

Flow Path

After passing through filters and dryers, the gas is carried to its loads via "A" and "B" headers. Suction for the compressors is from the containment atmosphere except following a LOCA when suction is switched to the reactor building atmosphere. A cross-over from the IAS system is available, if needed.

Component Descriptions

The PCIGS compressors are belt-driven, positive displacement compressors with a capacity of 35 scfm at 105 psig. The compressors are driven by 15 HP motors, powered from 480V, Class 1E motor control centers. Lubrication is self-contained, and cooling is supplied by the Safety Auxiliaries Cooling System (SACS). Therefore, the Class 1E power and SACS cooling are the only required support systems. Under normal conditions, the compressors operate in the lead/lag mode. One compressor operates as needed to charge the receivers, and the second compressor starts only in the event of low receiver pressure. The compressors are switched from lead to lag periodically to equalize hours of operation.

3.2.1.22.3 System Interfaces

The PCIGS requires power from the Class 1E AC system and cooling from SACS. No other systems are directly connected to the PCIGS, although this system is backed up by the IAS. Primary Containment Isolation System (PCIS) may cause isolation of PCIG System valves.

3.2.1.22.4 Instrumentation and Control

During normal operation, one compressor is in the lead mode. This compressor starts when the receiver pressure drops to 90 psig (receivers are connected), and shuts off when the receiver pressure reaches 105 psig. The second compressor will start if receiver pressure drops to 85 psig. In the manual mode of operation, the compressors may be started, but they do not respond to receiver pressure control. The compressors trip when receiver pressure reaches 120 psig.

The PCIGS compressors will trip on:

- Low oil pressure,
- High oil temperature,
- High air temperature,
- High water temperature,
- High gas inlet temperature (to the compressor),
- Low SACS water flow,
- High pressure,
- Loss of Power, and
- LOCA Level 1 signal.

3.2.1.22.5 Operator Actions

The PCIGS system is normally operating. The only operator actions modeled are:

Op fails to reset PCIGS after LOCA or LOP - The PCIGS system trips following a LOCA or LOP. The operator must reset the system in order for successful operation.

Op fails to align for IAS backup - IAS may be used as a backup to PCIGS, but requires the operator to open valve HV-5125.

3.2.1.22.6 Technical Specification Limitations

There are no Technical Specifications that are directly related to the PCIGS. However, several systems which relate to the PCIGS are covered by Technical Specifications. These systems include:

- MISV Sealing System,
- Isolation Actuation Instrumentation,
- Primary Containment Isolation Valves,
- Primary Containment Penetration Conductor Overcurrent, and
- Protective Devices.

3.2.1.22.7 Testing

While at power, the following In-Service tests are performed:

- Primary Containment Instrument Gas Subsystem A(B) Valves In-Service Test
  HC.OP-IS.KL-0101(Q)
  HC.OP-IS.KL-0102(Q)

- Inboard (Outboard) MSIV Sealing System Valves - In-Service Test
  HC.OP-IS.KP-0101(Q)
  HC.OP-IS.KP-0103(Q)

3.2.1.22.8 System Operation

Normal Operation

During normal operation, the compressors operate in the lead/lag mode. One compressor operates as needed to charge the receivers, and the second compressor comes on only in the event of low receiver pressure. The compressors are switched from lead to lag periodically to equalize hours of operation.

Abnormal Operation

A LOCA (Level 1) signal will trip the compressors. Before restarting the compressors, it is necessary for the operator to open reactor building air suction valves HV-5160A and HV-5160B to provide suction for the compressors. The compressors may then be started by overriding or clearing the LOCA signal. The isolation valves (5126A and 5152A for Header A, 5126B and 5152A for Header B) must also be reopened following a LOCA signal. A LOCA signal also closes the cross-tie valves 5156A and B; these valves cannot be reopened. A LOCA signal thus separates the two trains of PCIGS and prevents IAS from being used as a backup.

After a LOP, it is necessary for the operator to reset the Safety Lockout after power has been restored. This automatically starts the compressor if it is in the automatic mode. After reset and restoration, the compressors operate normally according to their original mode.

3.2.1.22.9 System Fault Tree

3.2.1.22.9.1 Description

The fault tree for PCIGS is a simplified logic model consisting of the major components and their support systems. The PCIGS is required for the long-term pneumatic operation of the Safety/Relief Valves. The safety function of steam pressure actuated lift is not affected by the loss of the PCIGS. The simplified system diagram for PCIGS is shown in Figure 3.2-22.

3.2.1.22.9.2 Success/Failure Criteria

The success of the PCIGS requires that gas be supplied to the PCIGS header. There are two fault trees, one for each PCIGS Header. For each header, failure occurs if both compressor trains fail and the connection to the instrument air system fails.

3.2.1.22.9.3 Assumptions

1. The PCIGS compressors data includes the aftercooler and moisture separator and associated equipment.

2. PCIGS compressor AK-202 was assumed to be the lead compressor and is thus not subject to a test and maintenance failure. Compressor AK-202 was modeled with a fail-to-start failure, because the lead compressor starts only when needed.

3. The instrument gas receivers were not modeled.

4. Plugging of the dryers is modeled. No data was found for the failure rate of this failure mechanism, so the failure rate of filter plugging (1E-5/hr) was used, divided by a factor of 10 (= 1E-6/hr). This reduction was used because the plugging of a dryer is expected to be significantly less likely than the plugging of a filter.

3.2.1.22.10 References

1. Hope Creek Generating Station UFSAR Section 9.3.6, "Primary Containment Instrument Gas System."

2. "Hope Creek Generating Station Licensed Operator Systems," Lesson Plan Number 302HC-000.00-076-09. Public Service Electric and Gas Company, Hancocks Bridge, NJ, February 1992.

3. Public Service Electric and Gas Company Operating Procedures
OP-AB.ZZ-133(Q)
OP-AB.ZZ-135(Q)
OP-EO.ZZ-311(Q) Rev. 2

4. Public Service Electric and Gas Drawings
M-59-1
E-305-0
E-306-0
E-307-0
E-308-0

3.2.1.23 Instrument Air System (IAS)

3.2.1.23.1 System Function

The IAS provides clean, dry, oil-free air to pneumatically operated valves and control processes outside of the drywell containment.

3.2.1.23.2 System Description

General Design

The IAS consists of three compressors which supply air to two connected headers. Two of the compressors (the Service Air Compressors) operate in a lead lag mode, while the third compressor, the Emergency Instrument Air Compressor (EIAC), is in the standby mode. The service air compressors operate in a lead lag mode such that the lead compressor operates continuously until switched to the lag mode or tripped due to a system trip. The service air compressors are rotated from lead to lag periodically to equalize wear.

Flow Path

After passing through filters and dryers, the air supply is carried through the plant via the headers "A" and "B". Header "A" contains a cross-over to the Primary Containment Instrument Gas System (PCIGS) that may be used in an emergency, if the PCIGS is inoperable. The major components in the IAS are the three compressors along with associated valves, receivers, and filtering and drying equipment.

Component Descriptions

The main service air compressors (00K107 and 10K107) are a direct-drive, centrifugal type with a capacity of 3000 scfm at 110 psig. The compressors are driven by 800 HP motors which are powered from 7.2 kV, Non-Class 1E sources. The compressors are cooled by the Turbine Auxiliaries Cooling System (TACS), and along with the Non-Class 1E power sources are the only support systems required for operation.

The Emergency Instrument Air Compressor (EIAC) is a reciprocating, direct-drive compressor with a capacity of 700 scfm at 110 psig. The EIAC is driven by a 125 HP motor, which is powered by a Class 1E substation. This power source is interrupted by a LOCA signal, but can be restarted manually. The EIAC is normally not in operation, but it is maintained in standby mode. When in operation, the EIAC requires cooling from the Reactor Auxiliaries Cooling System (RACS), and unless cooling water pressure is sensed, the compressor will not start.

3.2.1.23.3 System Interfaces

The main support systems for IAS are 7.2 kV and 480 V AC Non-Class 1E power and the TACS for cooling. The EIAC support systems are 480 V Class 1E AC power, and the RACS for cooling. The IAS provides air to all pneumatically operated valves and processes within the plant. The IAS has the ability to back up the PCIGS.

3.2.1.23.4 Instrumentation and Control

The service air compressors are controlled by a simple on/off pushbutton control. The lead service air compressor runs continuously, and the lag compressor does not start unless the air pressure falls below 92 psig. If the EIAC is in AUTO and a pressure of 85 psig is sensed, the EIAC will start, provided that RACS coolant pressure is also sensed. The service air compressors are controlled by means of a "blow-off" valve which cycles open when air pressure reaches 110 psig. This allows the compressor output to remain constant at 3000 scfm, with the unused excess being discharged to the outside atmosphere.

The service air compressors, once running, will run continually until manually turned off. The EIAC loads and unloads according to system pressure. The EIAC will load when 85 psig is sensed, and it will unload when 100 psig is sensed.

Several conditions will auto-trip the service air compressors, such as:

- Compressor vibration,
- High oil temperature,
- Low oil pressure,
- Auto-start failure,
- Cooling water high temperature,
- High air outlet temperature.

The EIAC will auto-trip on the following signals:

- RACS high temperature,
- RACS low pressure,
- High aftercooler temperature,
- Intake filter high Dp,
- High discharge air pressure,
- High discharge air temperature,
- Compressor vibration,
- High oil temperature,
- Level 1 LOCA signal,
- Low oil pressure.

3.2.1.23.5 Operator Actions

The IAS system is normally operating. The only operator action modeled is:

Op fails to reset EIAC Bkr - Quantification of the Human Error Probability for this action was based on the actions described in HC.OP-EO.ZZ-0319, "Restoring Instrument Air in an Emergency."

3.2.1.23.6 Technical Specifications Limitations

There are no Technical Specifications applicable to the IAS.

3.2.1.23.7 Testing

Since the IAS is a continuously operating system, no major tests are required during normal operation.

3.2.1.23.8 System Operation

Normal Operation

During normal operation, a single compressor (the lead compressor) operates at full capacity to supply needed air with the excess being exhausted outside. The lead and lag compressors are rotated periodically to equalize wear.

Abnormal Operation

During a LOCA condition, the service air compressors are unavailable due to loss of TACS cooling. The EIAC becomes unavailable as its power breaker opens for a LOCA. The breaker cannot be restored until the LOCA signal is cleared and reset. Once the LOCA signal is cleared, the EIAC power breakers must be reset manually.

After a LOP event, the service air compressors are unavailable since they are supplied by Non-Class 1E power. The EIAC is recovered by restoring its Class 1E power source; it will then operate normally.

3.2.1.23.9 System Fault Tree

3.2.1.23.9.1 Description

The fault tree model for the IAS is a simplified logic model containing only the compressors, their support systems, and a few valves. This approach is justified since the IAS is not a key support system for other safety systems. A simplified diagram for the IAS is presented in Figure 3.2-23.

3.2.1.23.9.2 Success and Failure Criteria

IAS success is for one of the three compressors to provide flow to IAS Header "A."

3.2.1.23.9.3 Assumptions

1. The service air compressors and EIAC data include the blowoff valve, the aftercooler and moisture separator, and associated equipment.

2. Service air compressor 00K107 was assumed to be the lead compressor and is thus not subject to fail-to-start and test and maintenance events.

3. TACS is a continually running extension of the SACS system that isolates on LOCA or LOP. Therefore, the only TACS failures modeled were the failure of SACS and isolation due to LOCA or LOP.

4. Plugging of the dryers is modeled. No data was found for the failure rate of this failure mechanism, so the failure rate of filter plugging (1E-5/hr) was used, divided by a factor of 10 (= 1E-6/hr). This reduction was used because the plugging of a dryer is expected to be significantly less likely than the plugging of a filter.

3.2.1.23.10 References

1. Hope Creek Generating Station UFSAR Section 9.3.1.

2. "Hope Creek Generating Station Licensed Operator Systems," Lesson Plan Number 302HC-000.00-075-02 and 302HC-000.00-074-08. Public Service Electric and Gas Company, Hancocks Bridge, NJ, February 1993.

3. Public Service Electric and Gas Company Operating Procedures
HC.OP-AB.ZZ-131
HC.OP-AB.ZZ-132
HC.OP-AB.ZZ-134
HC.OP-AB.ZZ-135
HC.OP-EO.ZZ-319

4. Public Service Electric and Gas Drawings
10855-M-15-0-0
10855-E-0425-0
10855-E-0426-0
10855-E-0427-0
10855-E-0428-0
10855-E-0305-0

3.2.1.24 Proceduralized Alternate Vessel Injection Systems

3.2.1.24.1 System Function

In the unlikely event that the ECCS systems described in Sections 3.2.1.1 through 3.2.1.4, the Feedwater/Condensate systems described in Section 3.2.1.7 and the Control Rod Drive Hydraulics described in Section 3.2.1.6 are unable to maintain a safe water level in the Reactor Pressure Vessel (RPV), the HCGS Emergency Operating Procedures (EOPs) specifically describe the use of three other systems which can be used for alternate vessel injection: the Condensate Storage and Transfer System (CSTS), the Station Service Water System (SSWS), and water from the Fire Protection System. In the HCGS IPE, credit is taken for the ability of these systems to provide long-term makeup to the RPV. These systems are considered successful if they can provide approximately 200 gpm to the RPV when the unit has been shut down for a number of hours and the RPV pressure is approximately 80 psig or lower. For a discussion of the use of Alternate Injection in the event trees, refer to Section 3.1.1.

None of these systems would be used to provide makeup to the vessel unless extremely degraded plant conditions were to exist. The following caution exists in the EOPs: These procedures constitute "... actions that are only to be taken in response to severely degraded plant conditions. These actions warrant evaluation of current and future plant conditions, prioritization of available plant systems and components, and consideration of the expected consequences to the plant." (Reference 2)

3.2.1.24.2 System Description

General Design

CSTS

The main purposes of the CSTS are to:

- supply pressurized condensate for various plant services,
- supply condensate to the HPCI, RCIC, Core Spray and CRD pumps for normal and testing operational modes,
- provide a minimum 135,000 gallon reserve volume for HPCI and RCIC system operation,
- provide makeup to and store excess condensate from the main condenser hotwell as necessary to maintain desired hotwell level,
- provide storage volume for condensate quality radwaste system effluent, and
- transfer water to the reactor well, drier/separator pool, and cask pool, and return the water to the condensate storage tank (CST) as necessary to support refueling operations.

The supply of water to the HPCI, RCIC, Core Spray and CRD pumps is addressed in their respective sections. However, the other aspects of the CSTS that are listed above are <u>not</u> modeled in the HCGS IPE. The CSTS can be used to provide alternate injection to the RPV, and the remainder of this section will only consider this use of the CSTS.

Fire Water

The main purposes of the Fire Protection System are to detect fires quickly and to annunciate in the Main Control Room the fire location for fire brigade notification and personnel safety and to suppress and extinguish those fires that occur in the shortest possible time to minimize damage and to maintain safe shutdown ability. However, these aspects of the Fire Protection System are <u>not</u> modeled in the HCGS IPE. Fire Water can be used to provide alternate injection to the RPV, and the remainder of this section will only consider this use of the Fire Protection System.

SSWS

The general design of the SSWS is presented in Section 3.2.1.17. The aspects of the SSWS relating to Alternate Injection which were not discussed in Section 3.2.1.17 are discussed in this section.

Flow Path

CSTS

The HCGS EOP "Alternate Injection Using Condensate Transfer" [HC.OP-EO.ZZ-0309(Q)] proceduralizes the actions required to establish a flow path from the CSTS to the RPV. The Condensate Transfer pumps (OAP-155 and OBP-155), the Condensate Transfer Jockey pumps (OAP-156 and OBP-156), and the Refueling Water Pumps (BN-OAP-157 and BN-OBP-157) take suction from the Condensate Storage Tank (CST). The discharge from the A pumps and the B pumps joins together as shown in Figure 3.2-24b. This water flows through the Condensate Transfer Pressure Control Valves (AP-PV-2044A: note that since this valve fails closed on a loss of air, a prerequisite for HC.OP-EO.ZZ-0309[Q] is that the restoration of Instrument Air in an emergency procedure {HC.OP-EO.ZZ-0319[Q]} has been completed or is being performed concurrently), and can be directed to the vessel via either Core Spray loop and any of the LPCI loops.

Core Spray Loop A(B) of Flow Path

Verify that the Condensate Storage and Transfer supply to Reactor Building Header Isolation Valve (AP-HV-2072) is open and the Core Spray pumps BE-AP206 and BE-CP206 (BE-BP206 and BE-DP206) are not running. If a Core Spray Loop A (B) initiation signal is sealed in, verify open the Loop A (B) Core Spray Isolation MOV (BE-HV-F004A[B]) and the Core Spray Loop A(B) Reactor Isolation MOV [BE-HV-F005A(B)]. If a Core Spray Loop A(B) initiation signal is not sealed in, close the Loop A(B) Core Spray Isolation MOV (BE-HV-F004A[B]), open BE-HV-F005A(B) and open BE-HV-F004A(B). To complete the flow path to the RPV, the Condensate Storage and Transfer to Core Spray A/C(B/D) discharge fill and flush isolation valve, OAP-V041 (AP-V062) is opened locally.

LPCI Loop A(B, C, D) Flow Path

Verify that the Condensate Storage and Transfer Supply to Reactor Building Header Isolation Valve (AP-HV-2072) is open and that LPCI pump A (B, C, D) is not running. Verify closed the RHR Loop A (B, C, D) LPCI Injection MOV (BC-HV-F017 A[B, C, D]). Open the Condensate Storage and Transfer to RHR A (B, C, D) Discharge Header Fill and Flush Isolation Valve AP-V044 (V056, V047, V059) locally. To complete the flow path to the RPV, the RHR Loop A (B, C, D) LPCI Injection MOV (BC-HV-F017A[B, C, D]) is opened.

SSWS

The HCGS EOP "Alternate Injection Using Service Water" (HC.OP-EO.ZZ-0308(Q)) proceduralizes the actions required to establish a flow path from either SSWS loop to the RPV. With regard to SSWS injection to the RPV, injection from SSWS Loop B is the "Preferred Method," and injection from SSWS Loop A is the "Alternate Method." When RPV injection from SSWS Loop B is used, the Loop B RACS Heat Exchanger Header Supply Valve

(1EA-HV2204) and the SACS loop B heat exchanger outlet valves (1EAHV-2371B and 2355B) are closed to maximize the SSW flow to the RPV. When SSWS Loop A is used for RPV injection, all SSW flow to all of the SACS and RACS heat exchangers is isolated to maximize the SSW flow to the RPV.

Loop B flow path

Water flowing from station service water pumps BP and DP502 combines to provide flow through a 36 inch diameter pipe to deliver the SSW to the SACS loop B and the RACS heat exchangers. A six inch diameter pipe taps off from the 36 inch diameter pipe, and it is through this six inch pipe that a flow path can be established to direct station service water to the RPV. By opening the Emergency Makeup Inboard and Outboard Loop B isolation valves (1EAHV-2238 and 1EAHV-F073) and the SSWS to RHR Loop B supply MOV (1BCHV-F075), the SSWS Loop B is connected to the RHR loop B. Then, by opening the RHR Loop B LPCI injection MOV (1BCHV-F017B), the LPCI loop B injection path is established, and the service water from SSWS loop B can enter the RPV. The SSWS flow to the RPV can then be maximized by closing the SACS Loop B Heat Exchanger Outlet Valves (EA-HV-2371B and 2355B).

Loop A flow path

After isolating the loop B SACS/SSWS heat exchangers, the SSWS Loop A flow path to the RPV is established by opening the loops A and B RACS Heat Exchanger Header Supply Valves (1EAHV-2203 and 2204: they isolate on a LOCA signal but the procedure directs the manual opening of the breakers to these MOVs and the manual opening of the valves themselves) and the Emergency Makeup Inb[illegible] and Outboard Loop B isolation valves as described in the Loop B flow path paragraph previously. The RACS heat exchanger header inlet valve (1EAHV-2207) is then verified to be closed to isolate the SSW flow to the RACS heat exchangers, and the SSWS to RHR Loop B supply MOV and the RHR Loop B LPCI injection MOV are opened to complete the flow path to the RPV. The SSWS to SACS loop A heat exchanger outlet valves are then verified to be closed to maximize the SSW flow to the RPV.

Fire Water

The HCGS EOP "Alternate Injection Using Fire Water" (HC.OP-EO.ZZ-0310(Q)) proceduralizes the actions required to establish a flow path of Fire Water to the RPV. The Fire Water supplies available for injection which are listed in this EOP are the HCGS Fire Protection system, a cross-tie with the Salem Generating Station (SGS) Fire Protection System, or a Fire Truck.

After connecting a fire hose to the flange adapter of the Fire Water source (a 1.5 inch hose and adapter are used for a connection to the fire hose station, and a 2.5 inch hose and adapter are used for a connection to the yard fire hydrant or fire truck), the fire hose fill connection blank flange on 1BC-V426 is removed, and the hose to flange adapter is installed. The fire hose is then connected to the appropriate source of Fire Water. Depending on whether the Fire Hose Station, the Yard Fire Hydrant or the Fire Truck is used as a water source, either the Fire Hose Station Isolation Valve, the Fire Hydrant Line valve and Plug valve, or the Fire Truck valves is (are) opened. The SSWS Loop B Emergency Make-up header drain valve (1BCSV-F074) is closed by de-energizing 1EAHV-F073 to prevent the diversion of Fire Water through 1BCSV-F074 to the SSW Dewatering Tank. After opening the SSWS supply to RHR Fire Hose Fill Connection Supply Valve (1BC-V426) and the SSWS to RHR Loop B Supply MOV (BC-HV-F075), the flow path of fire water to the RPV can be completed by opening the RHR Loop B LPCI Injection MOV (BC-HV-F017B).

Component Descriptions

Condensate Storage Tank

The CST has a design capacity of 500,000 gallons. The suction line for the jockey, transfer and refueling water pumps terminates at a height equal to approximately 250,000 gallons.

Condensate Transfer Jockey Pumps

Two jockey pumps are installed to maintain the supply header pressurized while meeting small system demands. One pump is normally running while the other is in standby for larger demands. these pumps have a rated flow of 50 gpm at 160 psig.

Condensate Transfer Pumps

The two Condensate Transfer Pumps have a rated flow of 600 gpm at 160 psig. One pump is selected as the lead pump, but both pumps are normally in standby. The lead pump auto starts to back up the jockey pumps, and the other transfer pump will auto start if more capacity is needed. The auto start conditions for all of the pumps is described in the "System Actuation" paragraphs below.

Refueling Water Pumps

These two pumps have a rated flow of 1500 gpm at 160 psig. These pumps are normally aligned to provide backup capacity for the CSTS loads. Under the conditions listed in the "System Actuation" paragraphs, the "A" Refueling Water Pump will auto start. The "B" Refueling Water Pump requires a manual start.

Fire Water Storage Tanks

Two 350,000 gallon tanks (OAT508 and OBT508) serve as the source of water (and the necessary NPSH) for the Fire Water Pumps. The tanks also serve as the source of water, via gravity feed lines, for the fresh water system. However, these lines are positioned high on each tank so that 328,000 gallons remain for dedicated fire protection service.

Motor Driven Fire Pump (MDFP)

The MDFP (00P520) is a single-stage, horizontal, centrifugal type pump. It has a rated flow of 2500 gpm at a rated pressure of 125 psig. The MDFP has a Non-Class 1E 480 VAC power supply, and it can provide 100% of the fire protection water necessary during a fire condition. Features of the MDFP include an automatic air release valve on the pump suction to vent air from the system and a relief valve on the pump discharge to provide overpressure protection.

Diesel (Engine) Driven Fire Pump (DDFP)

The DDFP (00P521) is a single-stage, horizontal, centrifugal type pump. It has a rated flow of 2500 gpm at a rated pressure of 125 psig. The DDFP provides backup fire protection water supply should the MDFP be inoperative due to loss of electrical power or insufficient capacity for demand. Features of the DDFP include an automatic air release valve on the pump suction to vent air from the system and a relief valve on the pump discharge to provide overpressure protection. Both the suction and discharge pressure are indicated locally.

The diesel engine is battery started by one of two lead-acid batteries. One charger is provided to keep the batteries charged. Once started, the engine is cooled by the pump discharge. The engine is also provided with a feed pump and a fuel injection pump to transfer the fuel oil from the outside tank to the 6 cylinders. At least 250 gallons is maintained in the tank to support 8 hours of continuous operation. The DDFP will automatically shutdown on low oil pressure (with a time delay), high water temperature, overcranking or overspeeding.

Fire Protection Jockey Pump

The Fire Protection Jockey Pump (00P564) is a single stage, horizontal, centrifugal type pump. Its rated flow is 55 gpm at a rated pressure of 125 psig. The jockey pump maintains the fire protection header pressurized. When the controls for the jockey pump are in the AUTO position, the pump cycles on at 115 psig and off at 125 psig fire protection header pressure.

Fire Protection Header/Main

The fire protection water supply is distributed to the various suppression systems via a 12 inch underground iron pipe yard loop encircling the power block. Divisional valves are provided about every 75 feet. Major 8 inch and 10 inch lines tie into the main, each from two different places, with sectional post indicating valves at each tap. Should a portion of the main be lost, the major lines can be supplied from the second tap.

Hose Stations and Hydrants

Over 50 hydrants and over 200 hose stations/hose racks are located throughout the buildings and the yard.

System Valves

Depending on the Alternate RPV Injection source (CSTS to Core Spray Loops A or B, CSTS to LPCI Loops A, B, C, D, SSWS Loop B, SSWS Loop A, or Fire Water) used, different valves are required to change position to complete the flow path. The valves which are required to change position to allow alternate RPV injection for each flow path were presented in the Flow Path paragraphs previously in this section. Note that the Flow Path paragraphs do not mention normally closed check valves which need to open, but all of the valves which must change position are shown in Figures 3.2-24a and b, and are modeled in the fault tree.

3.2.1.24.3 System Interrelations

Support Systems

CSTS

The only support systems modeled for the CSTS are electrical power for pumps and MOVs, and Instrument Air for the Condensate Transfer Pressure Control Valve (AP-PV2044A).

Fire Water

The only support system modeled for the Fire Water is electrical power for the MDFP and for MOVs.

No other support systems are modeled for the successful injection of CSTS water or of Fire Water to the RPV.

The support systems of the SSWS are presented in Section 3.2.1.17.3.

3.2.1.24.4 Instrumentation and Control

System Actuation

The Standby Condensate Transfer Jockey Pump will auto start (after a 5-second time delay) under the following conditions:

A. Condensate Transfer header pressure less than 110 psig <u>and</u>

B. Condensate Transfer header flow greater than 50 gpm.

The Standby Condensate Transfer Jockey Pump will auto stop on one of the following conditions:

A. Condensate Transfer header pressure is greater than 100 psig <u>or</u>

B. Condensate Transfer header flow is less than 50 gpm.

The Lead Condensate Transfer Pump will auto start (after a 60-second time delay) on an auto start signal to the standby Condensate Transfer Jockey Pump.

The Standby Condensate Transfer Pump will auto start (after a 5-second time delay) when the Condensate Transfer header pressure is less than 110 psig with the lead Condensate Transfer pump running.

The Lead Condensate Transfer Pump will auto stop when header flow is less than 100 gpm.

The Standby Condensate Transfer Pumps will auto stop when header flow is less than 700 gpm.

The A Refueling Water Pump will auto start on one of the following conditions:

A. An auto start signal to the Standby Condensate Transfer Pump (with a 60-second time delay) or

B. Either Condensate Transfer Pump is running for 30 seconds with a low differential pressure of 90 psi.

The A Refueling Water Pump will auto stop on one of the following conditions:

A. Condensate Transfer header flow is less than 700 gpm, or

B. A Rx well low level.

The B Refueling Water Pump has no auto start feature.

The B Refueling Water Pump will auto stop on a Rx well low level of 32", El. 176' 8".

1APHV-2041 opens/closes to maintain CST Level between 123' 10" (338,375 gallons) and 135' 9" (499,712 gallons) if in auto.

The system actuation features of the SSWS are presented in Section 3.2.1.17.4.

The following paragraphs deal only with the Fire Protection System as it is used as an Alternate RPV Injection source.

When the controls for the jockey pump are in the AUTO position, the pump cycles on at 115 psig and off at 125 psig fire protection header pressure.

The MDFP starts automatically when the fire header pressure decreases to 110 psig or less. In order to stop the MDFP, the local STOP pushbutton must be depressed; however, this is disabled for 7 minutes after an automatic start. STOP also serves to reset the auto start logic. The MDFP can also be started manually (locally or from control room back panel 10C671).

When in AUTO, the DDFP will start on a fire header pressure of 100 psig or lower, or on a loss of AC logic power to the engine control cabinet. The DDFP can be also be started manually (locally or from control room back panel 10C671).

3.2.1.24.5 Operator Actions

As described in the HCGS EOPs "Alternate Injection Using Condensate Transfer" [HC.OP-EO.ZZ-0309(Q)], "Alternate Injection Using Service Water" [HC.OP-EO.ZZ-0308(Q)] and "Alternate Injection Using Fire Water" [HC.OP-EO.ZZ-0310(Q)], the set of operator actions needed to align an alternate injection flowpath depends on whether the CSTS to Core Spray Loop A or B, CSTS to LPCI Loop A, B, C, D, SSWS Loop B, SSWS Loop A, or Fire Water will be used as the Alternate Injection source. These sets of actions are also described in the "Flow Path" paragraphs in Section 3.2.1.24.2. To simplify the fault tree modelling, only one operator action is modeled to envelop the entire set of actions necessary to align the systems for RPV injection.

3.2.1.24.6 Technical Specifications

The Technical Specifications (TS) related to the SSWS are described in Section 3.2.1.17.6.

There is no TS relating to the use of either the CSTS or of Fire Water for Alternate Injection to the RPV.

3.2.1.24.7 Testing

Testing of the SSWS is addressed in Section 3.2.1.17.7.

During normal operation, there is no testing of the components of the Fire Protection system or of the CSTS that can provide alternate RPV injection.

3.2.1.24.8 System Operation

The normal and abnormal operation of the SSWS is discussed in Section 3.2.1.17.8.

The remainder of this section relates to the normal and abnormal operation of the components of the CSTS and the Fire Protection System that can be used for Alternate RPV injection.

Normal Operation

CSTS

During normal operations, one Condensate Transfer Jockey Pump will be operating to maintain the supply header pressure. If the jockey pump is unable to maintain the system pressure, the standby jockey pump will start. Additional backup flow (as needed) is provided by the lead Condensate Transfer Pump, the second Condensate Transfer Pump, the A Refueling Water Pump, and the B Refueling Pump (the B Refueling water pump is the only pump that requires manual initiation).

Fire Water

During normal operations, the Fire Protection System will be operating with the Fire Water Jockey Pump in AUTO to maintain Fire Water System header pressure between 115 psig and 125 psig. The MDFP will auto start if the Fire Water Header pressure drops below 110 psig, and the DDFP will auto start if the Fire Water header pressure drops below 100 psig.

Abnormal Operation

CSTS

If the Instrument Air System has been isolated (as happens when a LOCA signal is generated), the HCGS EOP "Restoring Instrument Air In An Emergency" [HC.OP-EO.ZZ-0319(Q)] must be completed to allow the opening of the Condensate Transfer Pressure Control Valve (AP-PV2044A), which fails closed on a Loss of Instrument Air. If a Loss of Offsite Power (LOP) were to occur, the CSTS would be unavailable for Alternate Injection to the vessel.

Fire Water

If a LOP were to occur, the Fire Water Jockey Pump and the MDFP would be unavailable (since they have a Non-Class 1E AC power source). However, on a loss of AC logic power to the engine control cabinet, the DDFP will automatically start and maintain the Fire Water system pressure.

3.2.1.24.9 System Fault Tree

3.2.1.24.9.1 Description

The Alternate Injection fault tree is a model of the faults which could cause a failure of the CSTS, the SSWS, and the Fire Water to provide make-up to the RPV. In the Flow Path paragraphs of Section 3.2.1.24.2, the operator actions required to align the flow paths to the RPV are listed. To simplify the fault tree, however, one operator action is modeled to envelop the entire set of actions which make up the failure to align the alternate injection systems for RPV make-up.

3.2.1.24.9.2 Success and Failure Criteria

The CSTS and the SSWS are considered viable Alternate Injection systems for the long term make-up of water to the RPV. This fault tree is considered successful if either SSWS loop, either Condensate Transfer pump, or either Refueling Water pump is successful in providing flow to the vessel (see Assumption 7 in Section 3.2.1.24.9.3).

3.2.1.24.9.3 Assumptions

1. Because flow from the Fire Water Storage tanks to the fire pumps is through a series of locked open valves (no components are required to change position to allow flow to the fire pumps), the unavailability of water to the fire pumps is not modeled.

2. The Fire Protection Jockey Pump is not modeled since it is not needed for vessel injection. The use of the jockey pump to provide flow is not considered since the jockey pump only has a rated flowrate of 55 gpm at 125 psig.

3. Even though the set of operator actions required to align each alternate injection flow path is unique, only one operator action is modeled to envelop the entire set of actions necessary to align the systems for RPV injection.

4. It is assumed that a LOCA level 1 signal has been generated and has isolated the Station Service Water Loops A and B RACS Heat Exchanger Header Supply Valves (1EAHV-2203 and 2204) and the Station Service Water to RACS Heat Exchangers Inlet and Outlet Valves (1EAHV-2207 and 2346). Therefore, 1EAHV-2203 and 2204 must be manually reopened (and their breakers manually opened) to allow injection from SSWS loop A. The LOCA signal is also assumed to have opened all of the SSWS to SACS heat exchanger outlet valves, and if the closing of these valves is required (for SSWS injection to the RPV), these valves must be manually closed and their breakers manually opened. To restore the EIAC, HC.OP-EO.ZZ-0319(Q) must be performed.

5. The automatic actuation circuitry for the system components is not modeled. As described in the Interlocks paragraphs previously, the pumps that are in auto will receive actuation signals under various conditions; but even if they do not start automatically, the pumps can be started manually. This manual action would be subsumed into the Operator Action "Operator Fails to Align Alternate Injection Flow Paths to the RPV."

6. The Condensate Transfer Jockey pumps are not modeled since they do not have the capability to provide at least 200 gpm to the RPV at an RPV pressure of 80 psig or less.

7. No detailed calculation of flowrate to the RPV from the Alternate Injection Systems was available. To determine the success criteria for this fault tree, the following assumptions had to be made:

   From Reference 8, the pipe connecting the SSWS to the LPCI injection path was sized to allow 300 gpm of flow. Either SSWS loop is expected to be able to supply at least 200 gpm to the RPV when the vessel pressure is under 80 psig.

   For the injection of Fire Water, however, a fire hose is connected to the SSWS at a 2 inch diameter fill connection. It is assumed that this 2 inch connection (along with the long stretch of hose and the piping connections through with the water must travel) would restrict the Fire Water flow to under 200 gpm when RPV pressure is at 80 psig, and that Fire Water would not be capable of sufficient alternate injection.

The smallest diameter pipe through which the CSTS transfers water to the LPCI loops is through a 4 inch diameter pipe. This is assumed to be sufficient for 200 gpm flow. The smallest diameter pipe through which the CSTS transfers water to the Core Spray loops is through a 2 inch diameter pipe. This is assumed not to be sufficient for 200 gpm flow. To provide the 200 gpm through the LPCI loops when the RPV pressure is 80 psig or less, it is assumed that either Condensate Transfer Pump or either Refueling Water Pump (and its associated flowpath) is needed.

8. Loss of 480 VAC power to the SSWS, SACS, and RACS valves modeled in the fault tree is not considered. If power were lost to any of these valves, the operator would manually operate the valves, and this action would be subsumed into operator action to align the system

3.2.1.24.10 References

1. Hope Creek Generating Station Licensed Operator Training Lesson Plans 302H-000.00H-000094-05, 302H-000.00H-000079-10, 302H-000.00H-000028-11, and 302H-000.00H-000039-05.

2. Public Service Electric and Gas Company Operating Procedures
   HC.OP-EO.ZZ-0308(Q)
   HC.OP-EO.ZZ-0309(Q)
   HC.OP-EO.ZZ-0310(Q)
   HC.OP-SO.KC-0001(F)
   HC.OP-SO.AP-0001(Q)

3. Public Service Electric and Gas Drawings
   M-08-0
   M-10-1
   M-22-0
   M-51-1
   M-52-1

4. HCGS Technical Specifications Section 3/4.8.4.3.

5. Design, Installation and Test Specifications (DITS) For Fire Protection System For The Hope Creek Generating Station. PSE&G Document No. 10855-D3.22.

6. Configuration Baseline Documentation For Reactor Auxiliaries Cooling System. Public Service Electric And Gas Company Document Number DE-CB.ED-0082(Q).

7. Configuration Baseline Documentation For the Station Service Water Systems. PSE&G Document Number DE-CB.EA/EP-0052(Q) and DE-CB.EQ-0052(Z).

8. HCGS UFSAR Figure 6.3-12, note 9.

3.2.2 System Dependencies (Dependency Matrix)

Intersystem functional dependencies have been modeled in two ways. Functional dependencies between frontline systems in the event trees have been modeled in the event tree structure. An example of such a dependency is that the low pressure coolant injection (LPCI) system can be used for core cooling only after the primary system has been depressurized. If depressurization does not occur, the LPCI (low pressure operation) is not available. Section 3.1.2 discusses these event tree frontline dependencies.

The other type of intersystem function dependency - frontline or support system dependence on other support systems - is modeled in the individual system fault trees. This methodology (the large fault tree, small event tree PRA methodology) insures that no system dependencies are lost in the system analysis.

The dependency matrices for the HCGS are presented in Tables 3.2-3 and 3.2-4. Table 3.2-3 shows the system dependencies for the HCGS frontline systems, and Table 3.2-4 shows the system dependencies for the HCGS support systems. In both tables, an "A" designates a full dependency on that system (i.e., if the "A" system fails, the frontline or support system in question fails). A "B" in either table designates a partial dependency on that system (i.e. if the "B" system fails, the frontline or support system in question does not necessarily fail, but a combination of "B" failures could result in the system failure).

TABLE 3.2-1

ROOM COOLER LOCATION

EACS UNIT	ECCS SERVICE	ROOM
AVH208	RCIC	4110
BVH208	RCIC	4110
AVH209	HPCI	4111
BVH209	HPCI	4111
AVH210	RHR	4113
BVH210	RHR	4109
CVH210	RHR	4114
DVH210	RHR	4107
EVH210	RHR	4113
FVH210	RHR	4109
GVH210	RHR	4114
HVH210	RHR	4107
AVH211	CORE SPRAY	4118
BVH211	CORE SPRAY	4104
CVH211	CORE SPRAY	4116
DVH211	CORE SPRAY	4105
EVH211	CORE SPRAY	4118
FVH211	CORE SPRAY	4104
GVH211	CORE SPRAY	4116
HVH211	CORE SPRAY	4105
AVH214	SACS	4309
BVH214	SACS	4307
CVH214	SACS	4309
DVH214	SACS	4307

TABLE 3.2-2

480VAC EACS COOLER POWER SUPPLY
AND
125 VDC CONTROL CABINET POWER SUPPLY

EACS Cooler Unit	ECCS Service	480V AC	125 VDC
AVH209	HPCI (4111)	10B212	1AD417
BVH209	HPCI (4111)	10B451	1AD417
AVH208	RCIC (4110)	10B222	1BD417
BVH208	RCIC (4110)	10B461	1BD417
AVH210	EHR (4113)	10B212	1AD417
BVH210	RHR (4109)	10B222	1BD417
CVH210	RHR (4114)	10B232	1CD417
DVH210	RHR (4107)	10B242	1DD417
EVH210	RHR (4113)	10B451	1AD417
FVH210	RHR (4109)	10B461	1BD417
GVH210	RHR (4114)	10B471	1CD417
HVH210	RHR (4107)	10B481	1DD417
AVH211	CS (4118)	10B212	1AD417
BVH211	CS (4104)	10B222	1BD417
CVH211	CS (4116)	10B232	1CD417
DVH211	CS (4105)	10B242	1DD417
EVH211	CS (4118)	10B451	1AD417
FVH211	CS (4104)	10B461	1BD417
GVH211	CS (4116)	10B471	1CD417
HVH211	CS (4105)	10B481	1DD417
AVH214	SACS (4309)	10B232	1CD417
BVH214	SACS (4307)	10B232	1CD417
CVH214	SACS (4309)	10B242	1DD417
DVH214	SACS (4307)	10B242	1DD417

Table 3.2-3
FRONTLINE SYSTEM DEPENDENCIES ON SUPPORT SYSTEMS

Page 1

Front line System / Support System	Feedwater* TD Pumps	High Pressure Coolant Injection		Reactor Core Isolation Cooling		Control Rod Hydraulic Pumps		Condensate System
		TD Pump	Pump Room Cooler	TD Pump	Pump Room Cooler	AP207	BP207	
AC Power[a]								
Offsite Grid								
7.2KV Bus A								B[c]
7.2KV Bus B								B[c]
4.16KV Bus A								B[c]
4.16KV Bus B								
4.16KV Bus C								
4.16KV Bus D								
480V Bus A			A					B[c]
480V Bus B					A			
480V Bus C						A[b]		
480V Bus D							A[b]	
120V Bus A								A[c]
120V Bus B								
120V Bus C								
120V Bus D								
On Site Power								
Diesel (DGS)								
A								
B								
C								
D								
DC Power[a]								
250V Bus A		A						
250V Bus B				A				
125V Bus A		A	A					
125V Bus B				A	A			
125V Bus C								
125V Bus D								
Actuation ESF								
ESF-HPCI		A						
ESF-RCIC				A				
ESF-RHR-A								
ESF-RHR-B								
ESF-RHR-C								
ESF-RHR-D								
ESF-ELSA			A					
ESF-ELSB					A			
Instrument Air (IAS)	A					B	B	A
Instrument Gas (IGS)	A							
Reactor Auxiliaries Cooling (RAC)						A	A	

A Complete Dependence
B Partial Dependence

* Feedwater system is a frontline system which depends on another frontline system (condensate) in addition to the dependency on the support systems.

Table 3.2-3 (Continued)
FRONTLINE SYSTEM DEPENDENCIES ON SUPPORT SYSTEMS

Front line System / Support System	Feedwater TD Pumps	High Pressure Coolant Injection		Reactor Core Isolation Cooling		Control Rod Hydraulic Pumps		Condensate System
		TD Pump	Pump Room Cooler	TD Pump	Pump (Room) Cooler	AP207	BP207	
Safety Auxiliaries Cooling (SAC)								
Loop A			B		B			
Loop B			B		B			
Turbine Auxiliaries Cooling (TAC)								
Torus (Suppression Pool)			B		B			
Service Water (SWS)								
A								
B								
Ventilation/ Cooling (VAS)								
A								
B								
VAS-HPCI		B						
VAS-RCIC				B				
VAS-RHR-A								
VAS-RHR-B								
VAS-RHR-C								
VAS-RHR-D								
VAS-CS-A								
VAS-CS-B								
VAS-CS-C								
VAS-CS-D								

Table 3.2-3 (Continued)
FRONTLINE SYSTEM DEPENDENCIES ON SUPPORT SYSTEMS

Frontline System / Support System	Automatic Depressurization System	Core Spray						Residual Heat Removal Low Pressure Injection								Residual Heat Removal Suppression Pool Cooling	
		Loop		Pump Room Cooler				Train				Pump Room Cooler				Loop	
		A	B	A	B	C	D	A	B	C	D	A	B	C	D	A	B
AC Power[a]																	
Offsite Grid																	
7.2KV Bus A																	
7.2KV Bus B																	
4.16KV Bus A		A						A								A	
4.16KV Bus B			A						A								A
4.16KV Bus C		A								A							
4.16KV Bus D			A								A						
480V Bus A		A		A				A				A				A	
480V Bus B			A		A				A				A				A
480V Bus C						A				A				A			
480V Bus D							A				A				A		
120V Bus A																	
120V Bus B																	
120V Bus C																	
120V Bus D																	
On Site Power																	
Diesel (DGS)																	
A																	
B																	
C																	
D																	
DC Power[a]																	
250V Bus A																	
250V Bus B																	
125V Bus A		A		A				A				A					
125V Bus B	B		A		A				A				A				
125V Bus C						A				A				A			
125V Bus D	B						A				A				A		
Actuation ESF																	
ESF-ADS	A																
ESF-HPCI																	
ESF-RCIC																	
ESF-RHR-A								A									
ESF-RHR-B									A								
ESF-RHR-C										A							
ESF-RHR-D											A						
ESF-CS-A		A															
ESF-CS-B			A														
ESF-CS-C		A															
ESF-CS-D			A														

Table 3.2-3 (Continued)
FRONTLINE SYSTEM DEPENDENCIES ON SUPPORT SYSTEMS

Frontline System / Support System	Automatic Depressurization System	Core Spray						Residual Heat Removal Low Pressure Injection								Residual Heat Removal Suppression Pool Cooling	
		Loop		Pump Room Cooler				Train				Pump Room Cooler				Loop	
		A	B	A	B	C	D	A	B	C	D	A	B	C	D	A	B
Instrument Air(IAS)																	
Instrument Gas (IGS)	B																
Reactor Auxiliaries Cooling (RAC)																	
ESF-ELSA				A								A					
ESF-ELSB					A								A				
ESF-ELSC						A								A			
ESF-ELSD							A								A		
Safety Auxiliaries Cooling (SAC)																	
Loop A				B	B	B	B	B	B	B	B	B	B	B	B	B	B
Loop B				B	B	B	B	B	B	B	B	B	B	B	B	B	B
TurbineAuxiliaries Cooling (TAC)																	
Torus (Suppression Pool)		A	A					A	A	A	A						
Service Water (SWS)																	
Pump A																	
Pump B																	
Ventialtion/Cooling (VAS)																	
A																	
B																	
VAS-HPCI																	
VAS-RCIC																	
VAS-RHR-A								A								A	
VAS-RHR-B									A								A
VAS-RHR-C										A							
VAS-RHR-D											A						
VAS-CS-A		A															
VAS-CS-B			A														
VAS-CS-C		A															
VAS-CS-D			A														

Table 3.2-3 (Continued)
FRONTLINE SYSTEM DEPENDENCIES ON SUPPORT SYSTEMS

Support System \ Frontline System	Residual Heat Removal Containment Spray Cooling		Standby Liquid Control		Containment Venting	
	Loop		Pumps		Paths	
	A	B	A	B	6" Pipe	12" Pipe
AC Power[a]						
Offsite Grid						
7.2KV Bus A						
7.2KV Bus B						
4.16KV Bus A	A					
4.16KV Bus B		A				
4.16KV Bus C						
4.16KV Bus D						
480V Bus A	A		A			
480V Bus B		A		A		
480V Bus C						
480V Bus D						
120V Bus A					B	B
120V Bus B						
120V Bus C						
120V Bus D					B	B
On Site Power						
Diesel (DGS)						
A						
B						
C						
D						
DC Power[a]						
250V Bus A						
250V Bus B						
125V Bus A						
125V Bus B						
125V Bus C						
125V Bus D						
Actuation ESF						
ESF-SLC-DIV 1			B	B		
ESF-SLC-DIV 2			B	B		
ESF-RCIC						
ESF-RHR-A	A					
ESF-RHR-B		A				
ESF-RHR-C						
ESF-RHR-D						
ESF-CS-A						
ESF-CS-B						
ESF-CS-C						
ESF-CS-D						
Instrument Air (IAS)					B	B
Instrument Gas (IGS)						
Reactor Auxiliaries Cooling (RAC)						

Table 3.2-3 (Continued)
FRONTLINE SYSTEM DEPENDENCIES ON SUPPORT SYSTEMS

Support System \ Frontline System	Residual Heat Removal Containment Spray Cooling		Standby Liquid Control		Containment Venting	
	Loop		Pumps		Paths	
	A	B	A	B	6" Pipe	12" Pipe
Safety Auxiliaries Cooling (SAC)						
Loop A	A	B				
Loop B	B	A				
Turbine Auxiliaries Cooling (TAC)						
Torus (Suppression Pool)						
Service Water (SWS)						
A						
B						
Ventilation/Cooling (VAS)						
A						
B						
VAS-HPCI						
VAS-RCIC						
VAS-RHR-A	A					
VAS-RHR-B		A				
VAS-RHR-C						
VAS-RHR-D						
VAS-CS-A						
VAS-CS-B						
VAS-CS-C						
VAS-CS-D						

a Class 1E power divisions are as follows:

4160 Vac	I	10A401 switchgear
	II	10A402 switchgear
	III	10A403 switchgear
	IV	10A404 switchgear
480 Vac	I	10B410/450 unit substations, 10V212/252/411/451/553 MCC,
	II	10B420/460 unit substations, 10B222/262/421/461/563 MCC,
	III	10B430/470 unit substations, 10B232/272/431/471/573 MCC,
	IV	10B440/480 unit substations, 10B242/282/441/481/583 MCC,
120 Vac	I	1AJ481/482 instrument distribution panels
	II	1BJ481/482 instrument distribution panels
	III	1CJ481/482 instrument distribution panels
	IV	1DJ481/482 instrument distribution panels
250 Vdc	I	10D450 switchgear, 10D251 MCC
	II	10D460 switchgear, 10D261 MCC
125 Vdc	I	10D410 switchgear, 1AD417 distribution panel
	II	10D420 switchgear, 1BD417 distribution panel
	III	10D430/436 switchgear, 1CD417 distribution panel
	IV	10D440/446 switchgear, 1DD417 distribution panel

b Non-Class 1E loads on Class 1E buses, these loads are shed on a LOCA signal.

c The Condensate System consists of components powered by the following non-Class 1E buses:

7200 Vac	10A110, 10A120 switchgear
4160 Vac	10A102, 10A104 switchgear
480 Vac	10B122, 10B132, 10B143
120 Vac	1DJ484, 1YF405 instrument distribution panels

Table 3.2-4
Support System to Support System Dependency Table

Support System (rows) / Support System (columns)	AC POWER														DIESELS			
Support System	7.2KV BUS A	7.2KV BUS B	4.16KV BUS A	4.16KV BUS B	4.16KV BUS C	4.16KV BUS D	480V Chnl A	480V Chnl B	480V Chnl C	480V Chnl D	120V Chnl A	120V Chnl B	120V Chnl C	120V Chnl D	A	B	C	D
AC Power																		
Off-Site Grid	A	A	B	B	B	B	B	B	B	B	B	B	B	B				
7.2KV Bus A																		
7.2KV Bus B																		
4.16KV Bus A							A											
4.16KV Bus B								A										
4.16KV Bus C									A									
4.16KV Bus D										A								
480V Chnl A											B				B			
480V Chnl B												B				B		
480V Chnl C													B				B	
480V Chnl D														B				B
120V Chnl A															A			
120V Chnl B																A		
120V Chnl C																	A	
120V Chnl D																		A
On-Site Power																		
Diesel																		
A			B															
B				B														
C					B													
D						B												

A Complete Dependency
B Partial Dependency

Table 3.2-4
Support System to Support System Dependency Table (Continued)

Support System	DC POWER						ACTUATION									
	250V Bus A	250V Bus B	125V Chnl A	125V Chnl B	125V Chnl C	125V Chnl D	ESF-HPCI	ESF-RCIC	ESF-RHR-A	ESF-RHR-B	ESF-RHR-C	ESF-RHR-D	ESF-CS-A	ESF-CS-B	ESF-CS-C	ESF-CS-D
AC Power																
Off-Site Grid																
7.2KV Bus A																
7.2KV Bus B																
4.16KV Bus A																
4.16KV Bus B																
4.16KV Bus C																
4.16KV Bus D																
480V Chnl A	B		B													
480V Chnl B		B		B												
480V Chnl C					B											
480V Chnl D						B										
120V Chnl A																
120V Chnl B																
120V Chnl C																
120V Chnl D																
On-Site Power																
Diesel																
A																
B																
C																
D																

Table 3.2-4
Support System to Support System Dependency Table (Continued)

Support System / Support System	Instrument Air System	Instrument Gas System		Reactor Auxiliaries Cooling System	Safety Auxiliaries Cooling System Loop		Service Water System		VENTILATION/COOLING									
									HPCI	RCIC	RHR				CS			
		A	B		A	B	A	B			A	B	C	D	A	B	C	D
AC Power																		
Off-Site Grid																		
7.2KV Bus A	B																	
7.2KV Bus B	B																	
4.16KV Bus A					A		B											
4.16KV Bus B						A		B										
4.16KV Bus C					A		B											
4.16KV Bus D						A		B										
480V Chnl A	B			B			B		A		A				A			
480V Chnl B				B				B		A		A				A		
480V Chnl C		B		A	A		B						A				A	
480V Chnl D			B			A		B						A				A
120V Chnl A					A													
120V Chnl B						A												
120V Chnl C					A													
120V Chnl D						A												
On-Site Power																		
Diesel																		
A																		
B																		
C																		
D																		

Table 3.2-4
Support System to Support System Dependency Table (Continued)

Support System / Support System	AC POWER														DIESELS			
	7.2KV BUS A	7.2KV BUS B	4.16KV BUS A	4.16KV BUS B	4.16KV BUS C	4.16KV BUS D	480V Chnl A	480V Chnl B	480V Chnl C	480V Chnl D	120V Chnl A	120V Chnl B	120V Chnl C	120V Chnl D	A	B	C	D
DC Power																		
250V Bus A																		
250V Bus B																		
125V Chnl A	A		B				B				B				A			
125V Chnl B		A		B				B				B				A		
125V Chnl C					B				B				B				A	
125V Chnl D						B				B				B				A
Actuation																		
ESF-HPCI																		
ESF-RCIC																		
ESF-RHR-A																		
ESF-RHR-B																		
ESF-RHR-C																		
ESF-RHR-D																		
ESF-CS-A															B			
ESF-CS-B																B		
ESF-CS-C																	B	
ESF-CS-D																		B
ESF-ELSA																		
ESF-ELSB																		
ESF-ELSC																		
ESF-ELSD																		

Table 3.2-4
Support System to Support System Dependency Table (Continued)

Support System / Support System	DC Power						Actuation									
	250V Bus A	250V Bus B	125V Chnl A	125V Chnl B	125V Chnl C	125V Chnl D	ESF-HPCI	ESF-RCIC	ESF-RHR-A	ESF-RHR-B	ESF-RHR-C	ESF-RHR-D	ESF-CS-A	ESF-CS-B	ESF-CS-C	ESF-CS-D
DC Power																
250V Bus A																
250V Bus B																
125V Chnl A							B		A				A			
125V Chnl B								A		A				A		
125V Chnl C							B				A				A	
125V Chnl D												A				A
Actuation																
ESF-HPCI																
ESF-RCIC																
ESF-RHR-A																
ESF-RHR-B																
ESF-RHR-C																
ESF-RHR-D																
ESF-CS-A																
ESF-CS-B																
ESF-CS-C																
ESF-CS-D																
ESF-ELSA																
ESF-ELSB																
ESF-ELSC																
ESF-ELSD																

Table 3.2-4
Support System to Support System Dependency Table (Continued)

Support System / Support System	Instrument Air System	Instrument Gas System	Reactor Auxiliaries Cooling System	Safety Auxiliaries Cooling System Loop A	Safety Auxiliaries Cooling System Loop B	Service Water System A	Service Water System B	VENTILATION/COOLING HPCI	RCIC	RHR A	RHR B	RHR C	RHR D	CS A	CS B	CS C	CS D
DC Power																	
250V Bus A																	
250V Bus B																	
125V Chnl A				A		B											
125V Chnl B					A		B										
125V Chnl C	B					B											
125V Chnl D	B						B										
Actuation																	
ESF-FW																	
ESF-HPCI																	
ESF-RCIC																	
ESF-RHR-A																	
ESF-RHR-B																	
ESF-RHR-C																	
ESF-RHR-D																	
ESF-CS-A																	
ESF-CS-B																	
ESF-CS-C																	
ESF-CS-D																	
ESF-ELSA			B	A		A											
ESF-ELSB			B		A		A										
ESF-ELSC				A													
ESF-ELSD					A												

Table 3.2-4
Support System to Support System Dependency Table (Continued)

Support System / Support System	AC POWER														DIESELS			
	7.2KV BUS A	7.2KV BUS B	4.16KV BUS A	4.16KV BUS B	4.16KV BUS C	4.16KV BUS D	480V Chnl A	480V Chnl B	480V Chnl C	480V Chnl D	120V Chnl A	120V Chnl B	120V Chnl C	120V Chnl D	A	B	C	D
Instrument Air System																		
Instrument Gas System																		
Reactor Auxiliaries Cooling System																		
Safety Auxiliaries Cooling System																		
Loop A															B	B	B	B
Loop B															B	B	B	B
Torus (Suppression Pool)																		
Service Water System																		
A																		
B																		
Ventilation/Cooling																		
VSW-A			A				A				A				A			
VSW-B				A				A				A				A		
VSW-C					A				A				A				A	
VSW-D						A				A				A				A
VAS-HPCI																		
VAS-RCIC																		
VAS-RHR-A																		
VAS-RHR-B																		
VAS-RHR-C																		
VAS-RHR-D																		

Table 3.2-4
Support System to Support System Dependency Table (Continued)

Support System (rows) / Support System (columns)	DC Power						Actuation									
	250V Bus A	250V Bus B	125V Chnl A	125V Chnl B	125V Chnl C	125V Chnl D	ESF-HPCI	ESF-RCIC	ESF-RHR-A	ESF-RHR-B	ESF-RHR-C	ESF-RHR-D	ESF-CS-A	ESF-CS-B	ESF-CS-C	ESF-CS-D
Instrument Air System																
Instrument Gas System																
Reactor Auxiliaries Cooling System																
Safety Auxiliaries Cooling System																
Loop A																
Loop B																
Torus (Suppression Pool)																
Service Water System																
A																
B																
C																
D																
Ventilation/Cooling																
VSW-A																
VSW-B																
VSW-C																
VSW-D																
VAS-HPCI																
VAS-RCIC																
VAS-RHR-A																
VAS-RHR-B																
VAS-RHR-C																
VAS-RHR-D																

Table 3.2-4
Support System to Support System Dependency Table (Continued)

Support System / Support System	Instrument Air System	Instrument Gas System		Reactor Auxiliaries Cooling Syetem	Safety Auxiliaries Cooling System (SACS)		Service Water System		VENTILATION/COOLING									
									HPCI	RCIC	RHR				CS			
		A	B		A	B	A	B			A	B	C	D	A	B	C	D
Instrument Air				A														
Instrument Gas																		
Reactor Auxiliaries Cooling System	B																	
Safety Auxiliaries Cooling System																		
Loop A	B	B							B	B	B		B		B	B	B	B
Loop B	B		B						B	B		B		B	B	B	B	B
Service Water System																		
A				B	A													
B				B		A												
Ventilation/Cooling																		
VSW-A																		
VSW-B																		
VSW-C																		
VSW-D																		
VAS-HPCI																		
VAS-RCIC																		
VAS-RHR-A																		
VAS-RHR-B																		
VAS-RHR-C																		
VAS-RHR-D																		

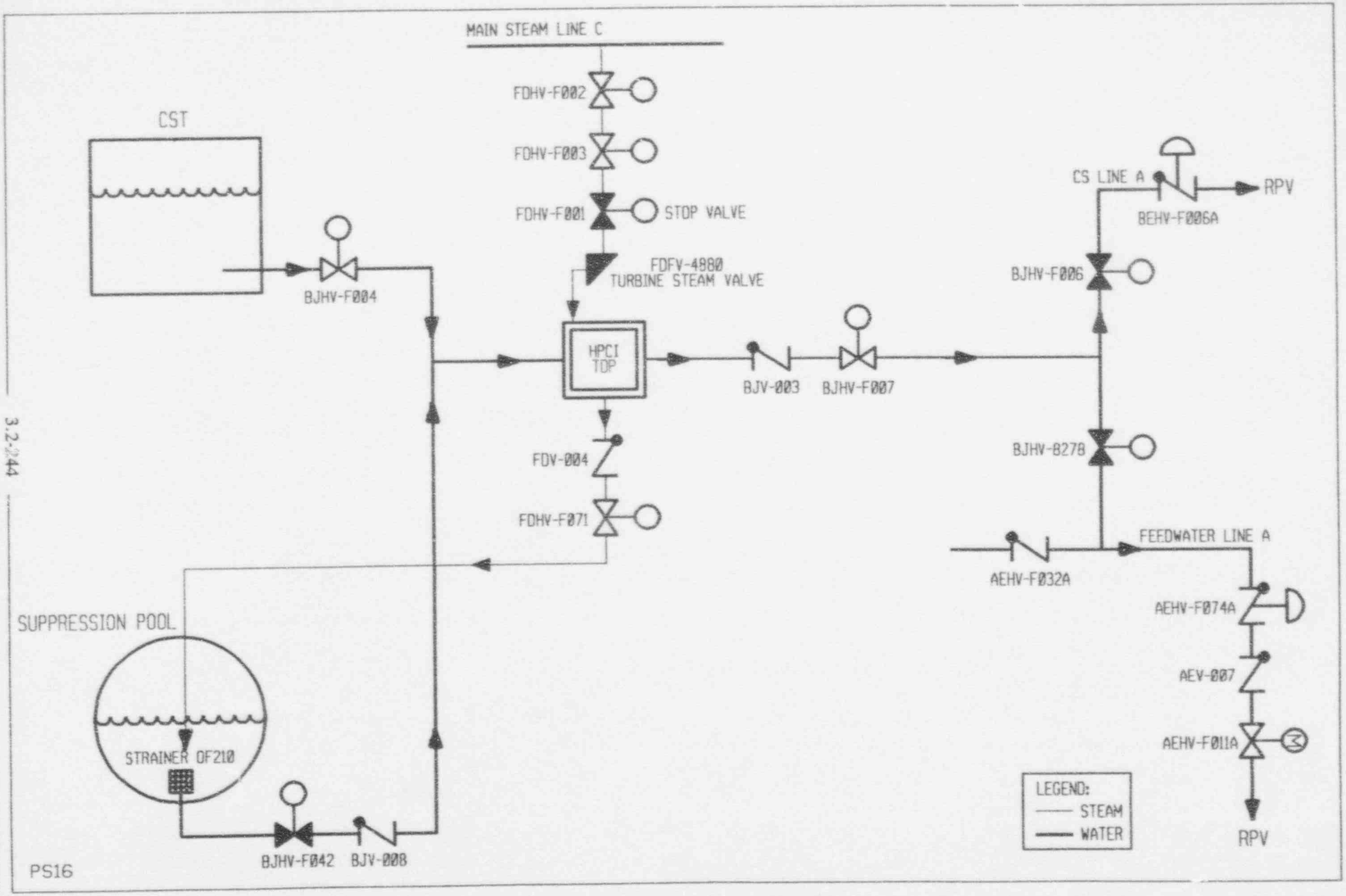


Figure 3.2-1
HPCI Simplified Diagram

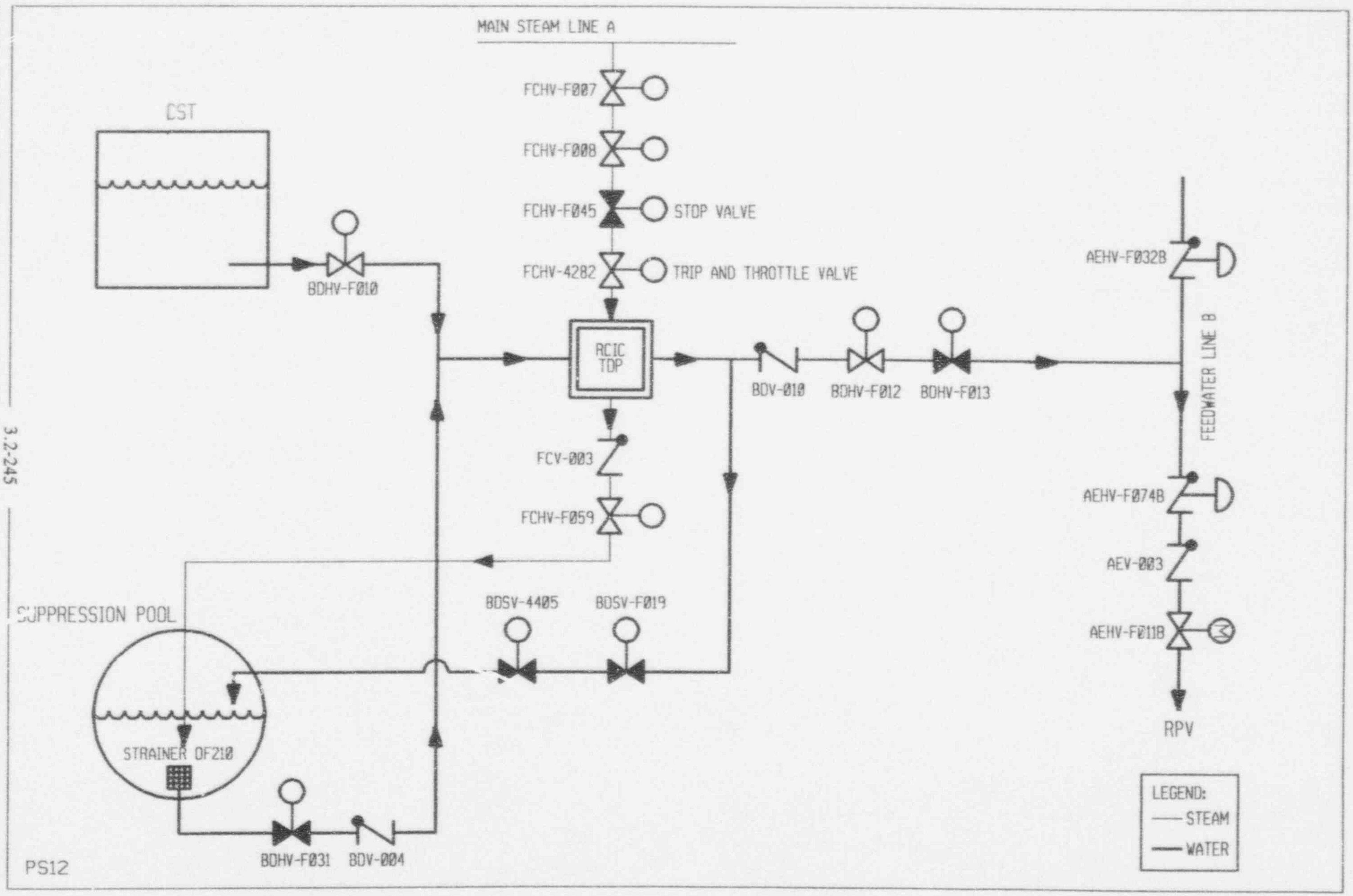


Figure 3.2-2
RCIC Simplified Diagram

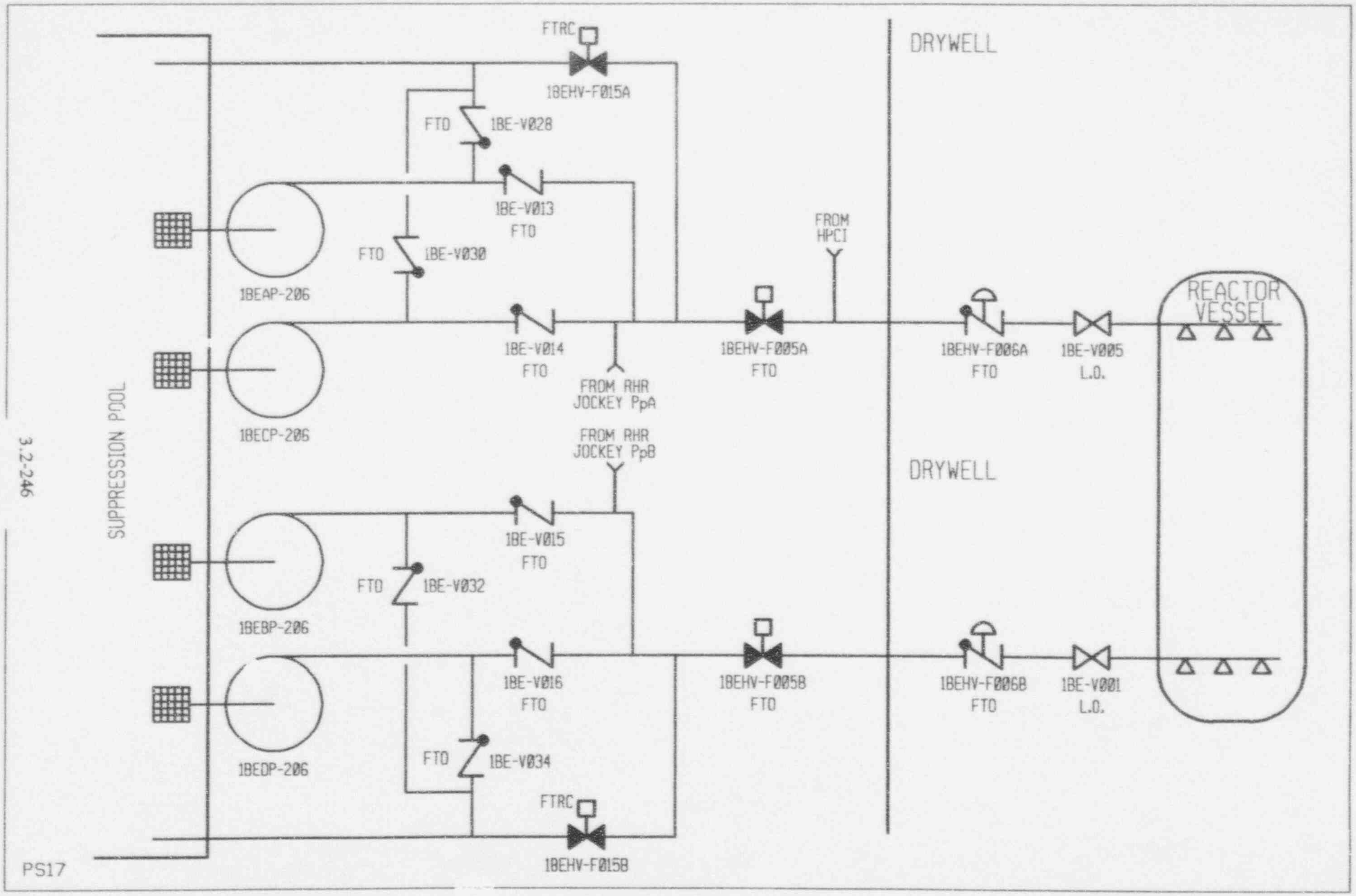


Figure 3.2-3
Core Spray System Simplified Diagram (Normal Position-Standby)

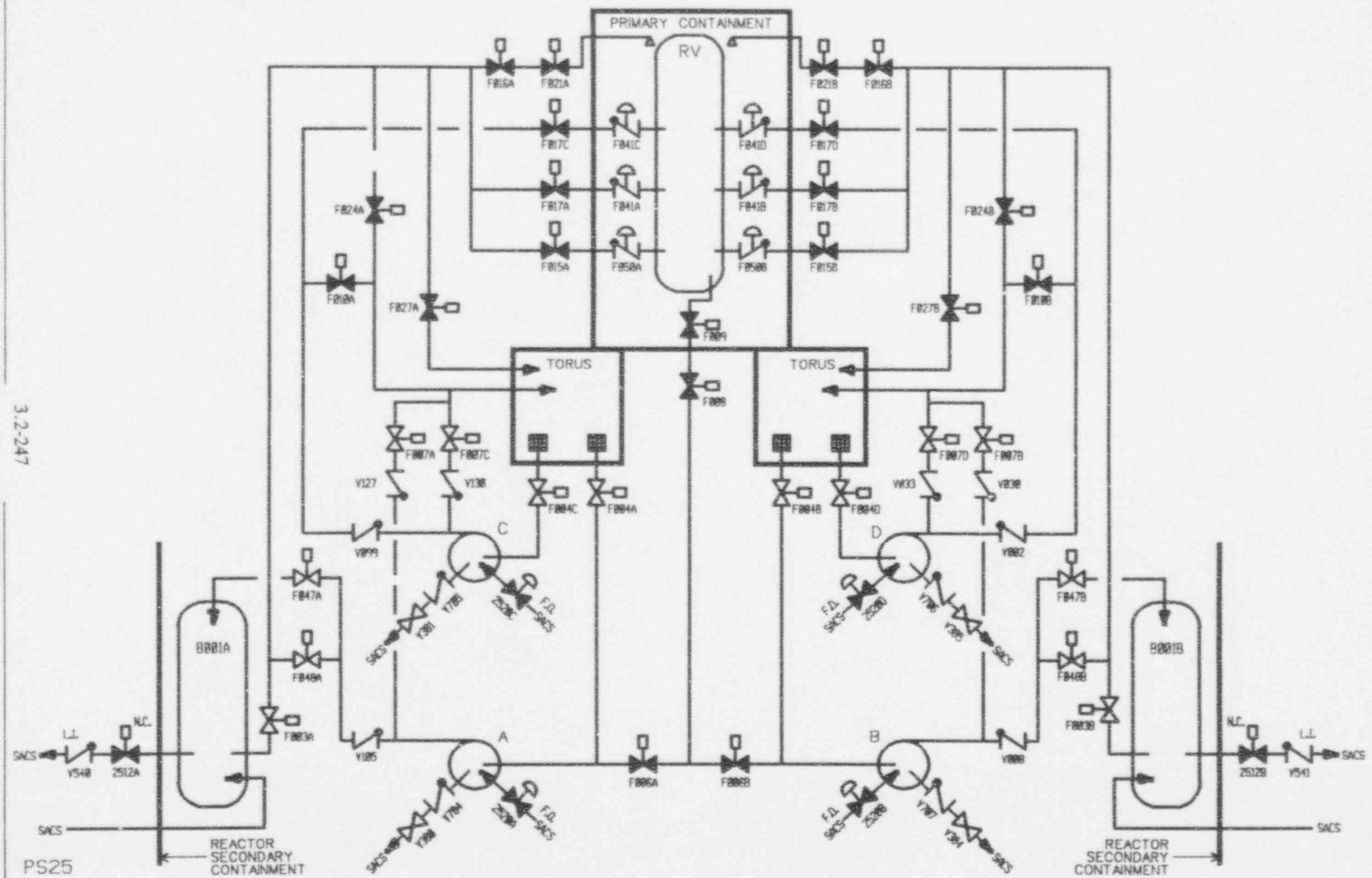


Figure 3.2-4a
RHR- Normal Configuration (Standby)

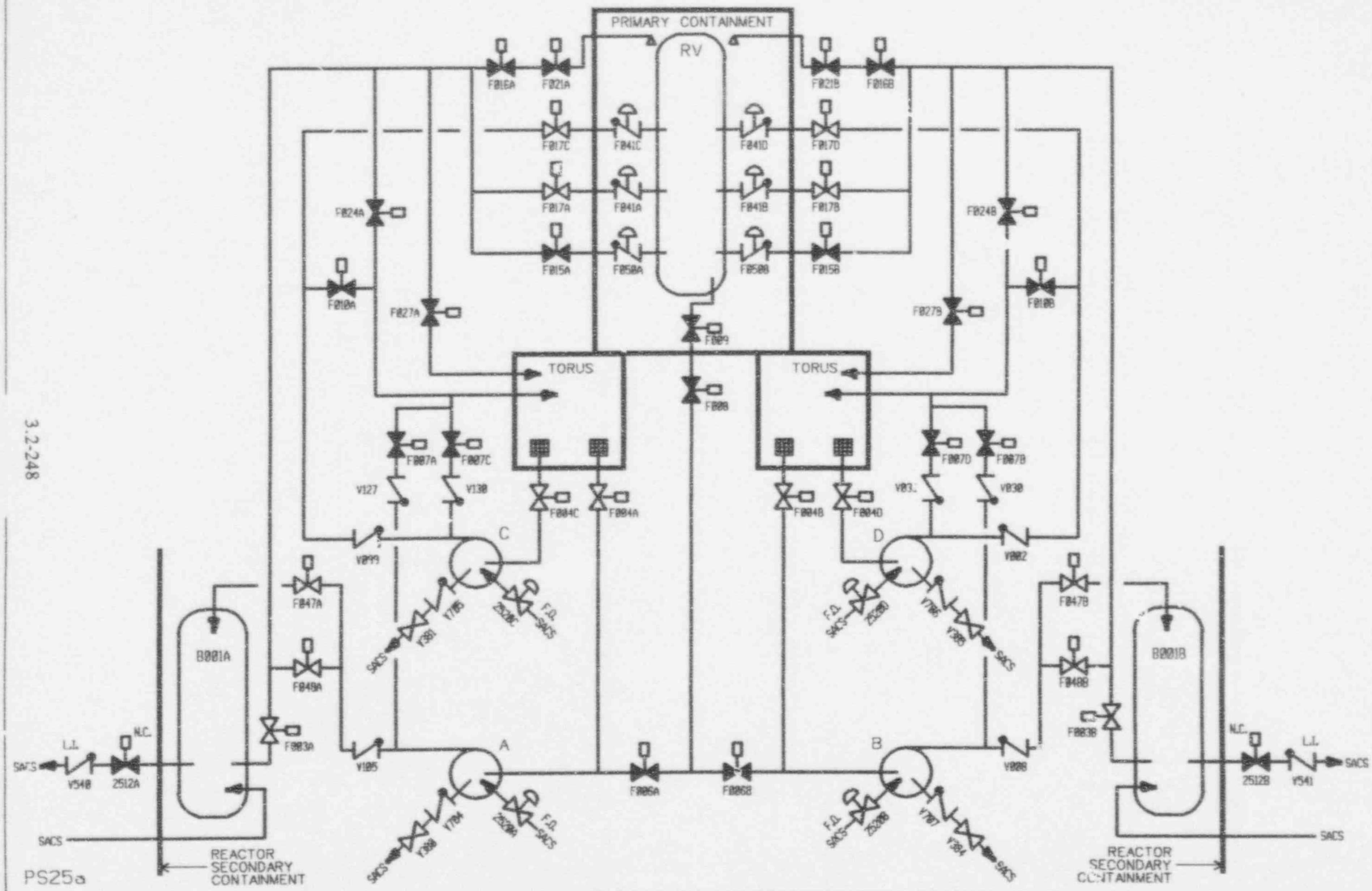


Figure 3.2-4b
RHR- LPCI Configuration

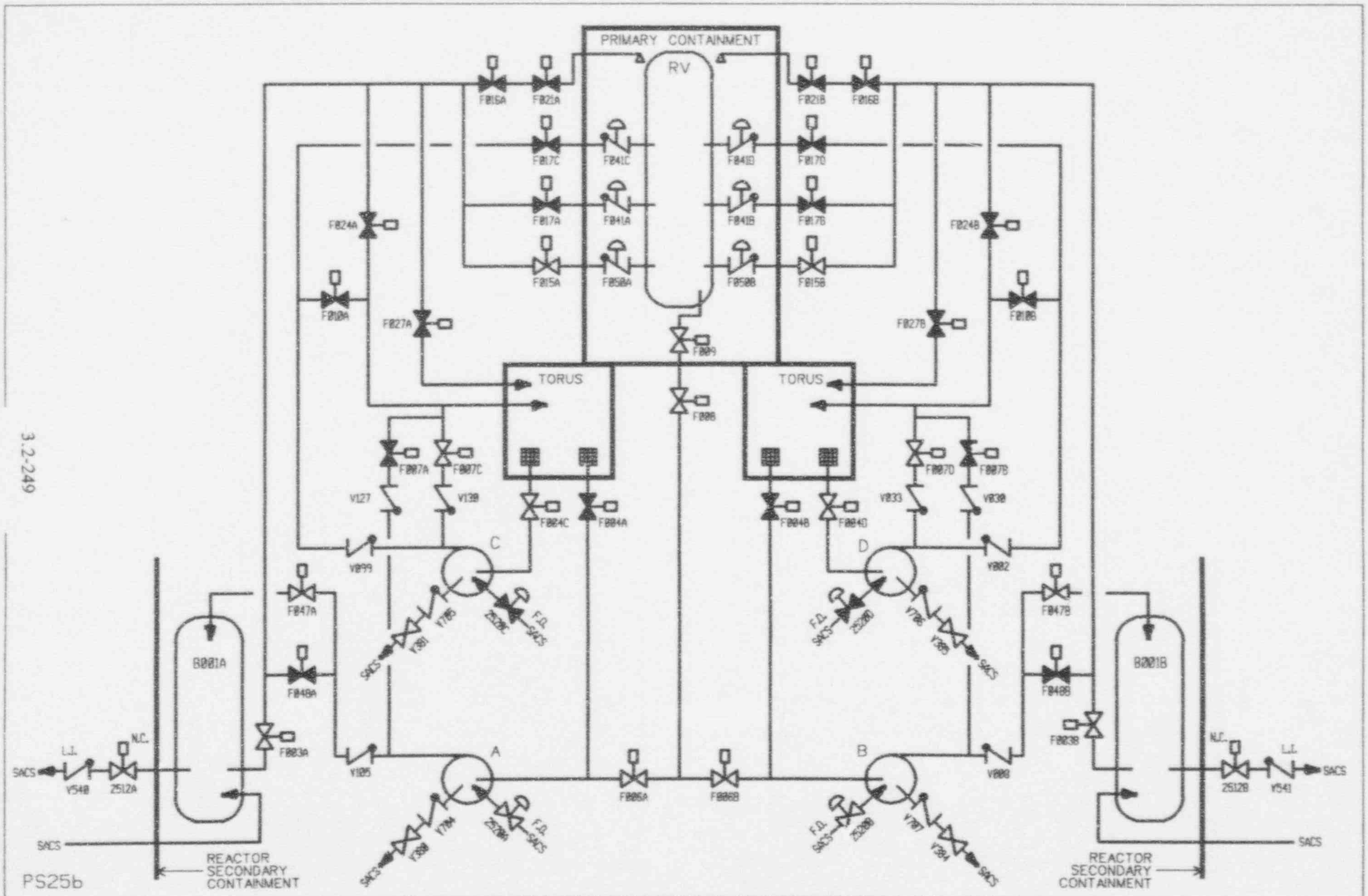


Figure 3.2-4c
RHR- SDC Configuration

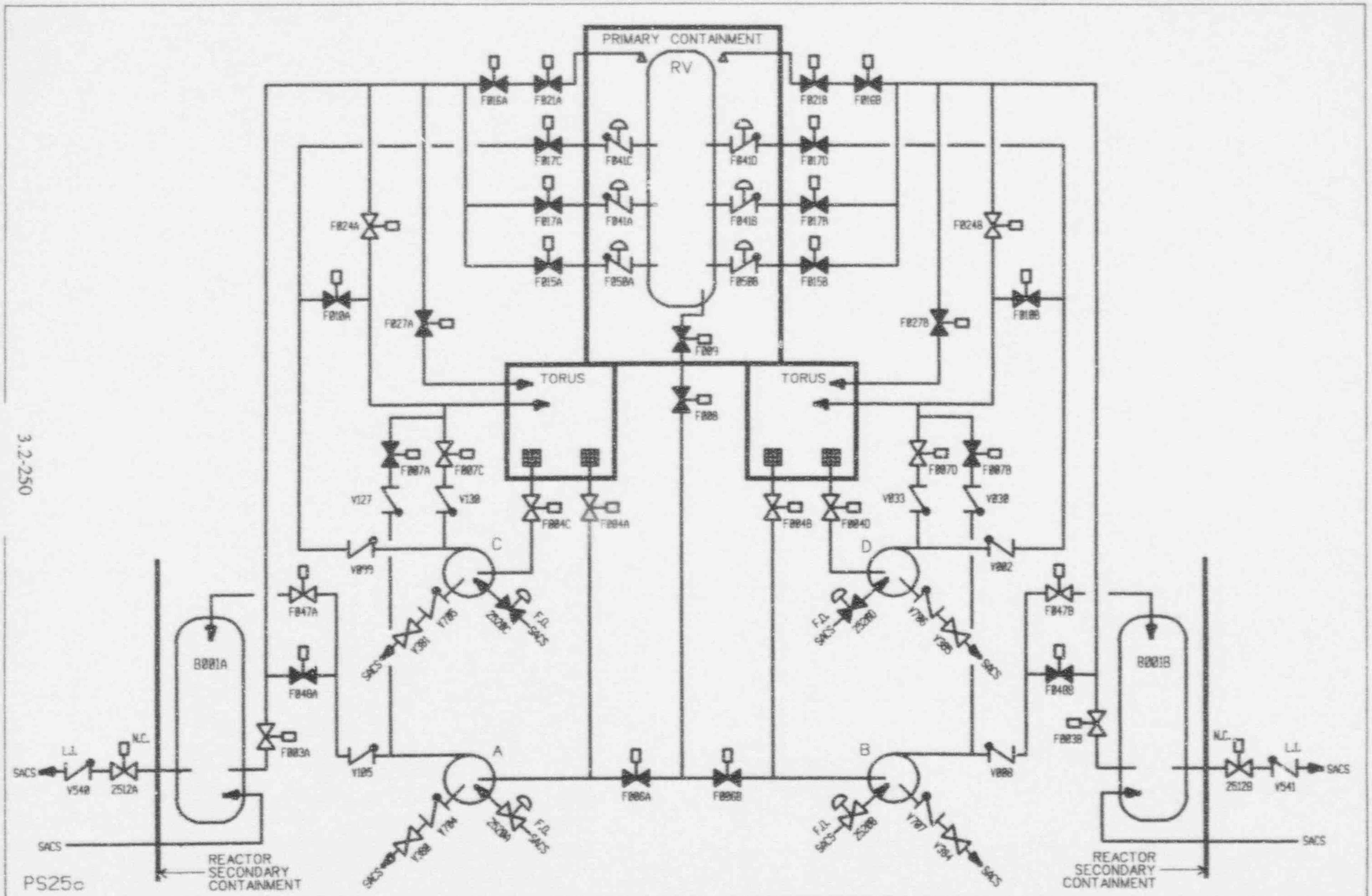


Figure 3.2-4d
RHR- SPC Configuration

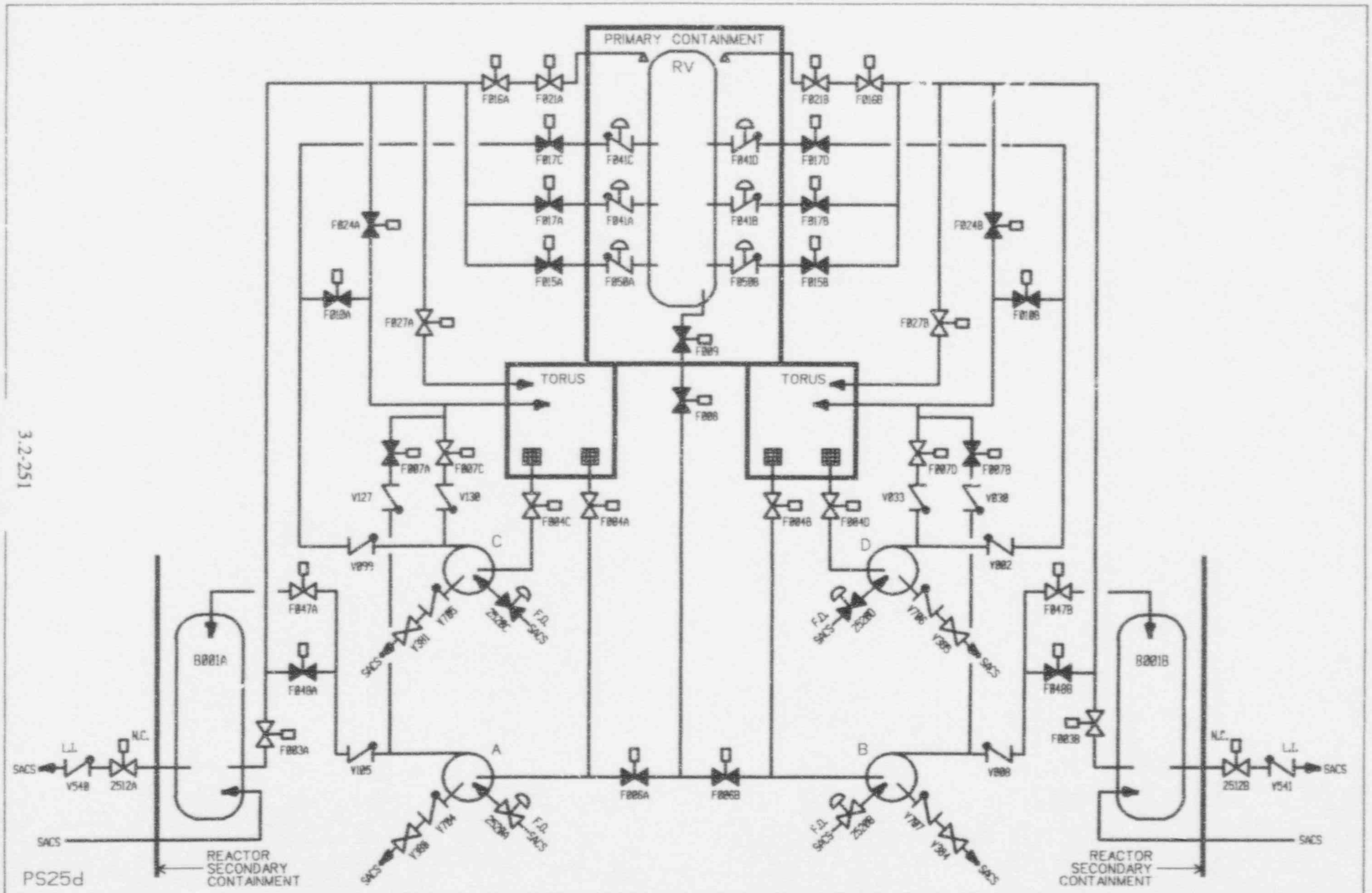
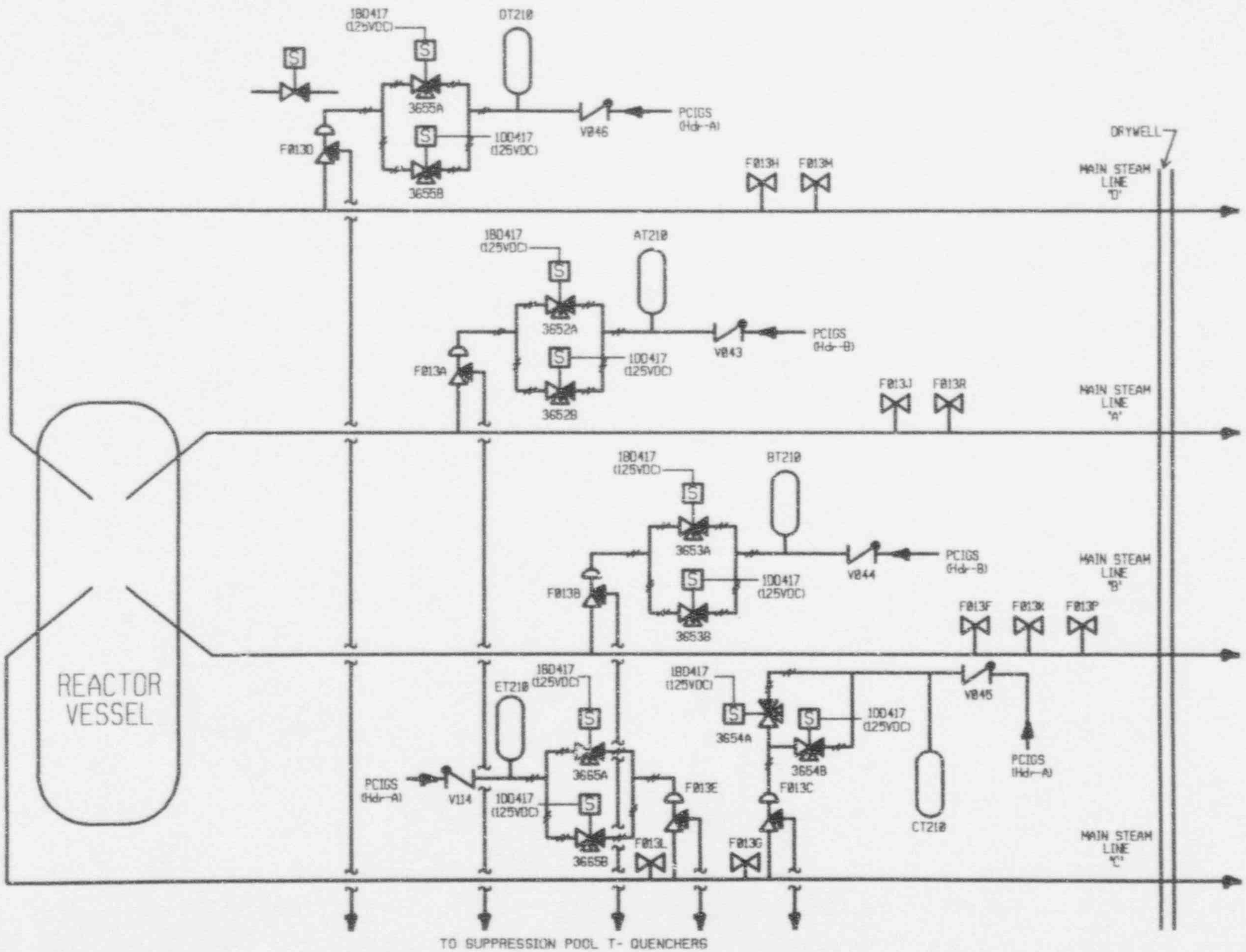


Figure 3.2-4e
RHR- CSC Configuration



PS22

Figure 3.2-5
ADS Simplified Schematic

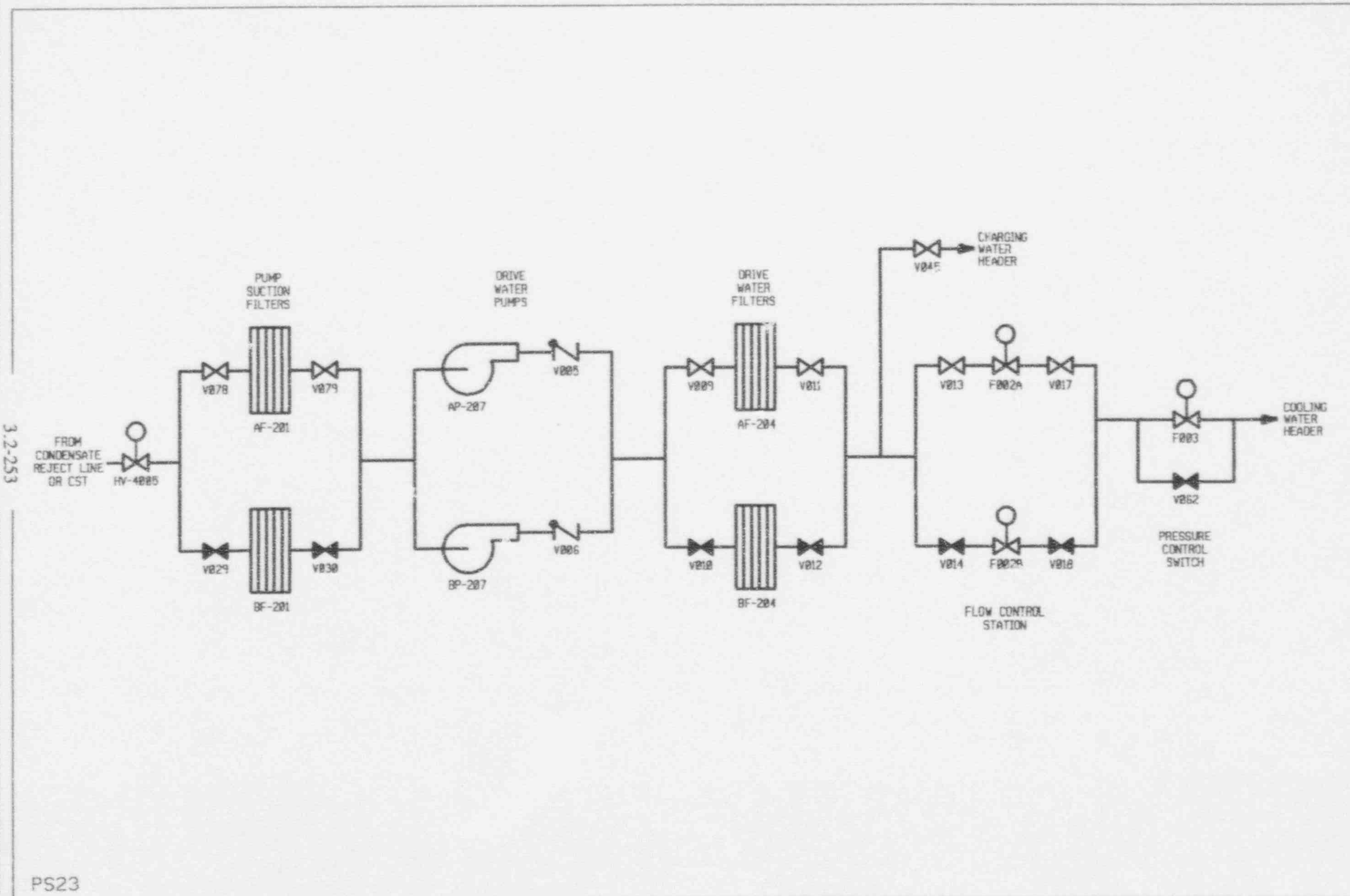


Figure 3.2-6
Control Rod Drive Hydraulic System Simplified Diagram

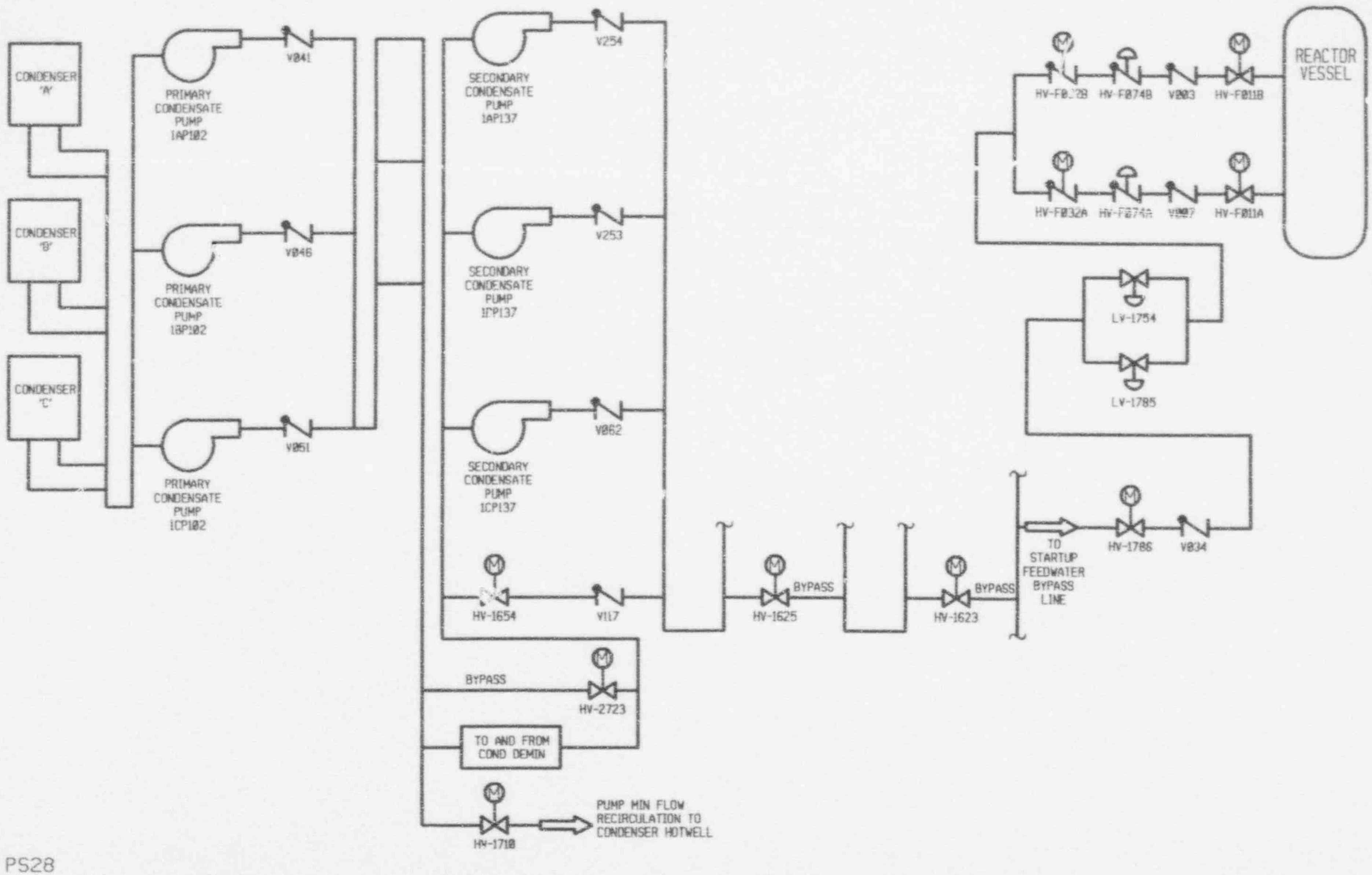


Figure 3.2-7a
Condensate System Simplified Diagram

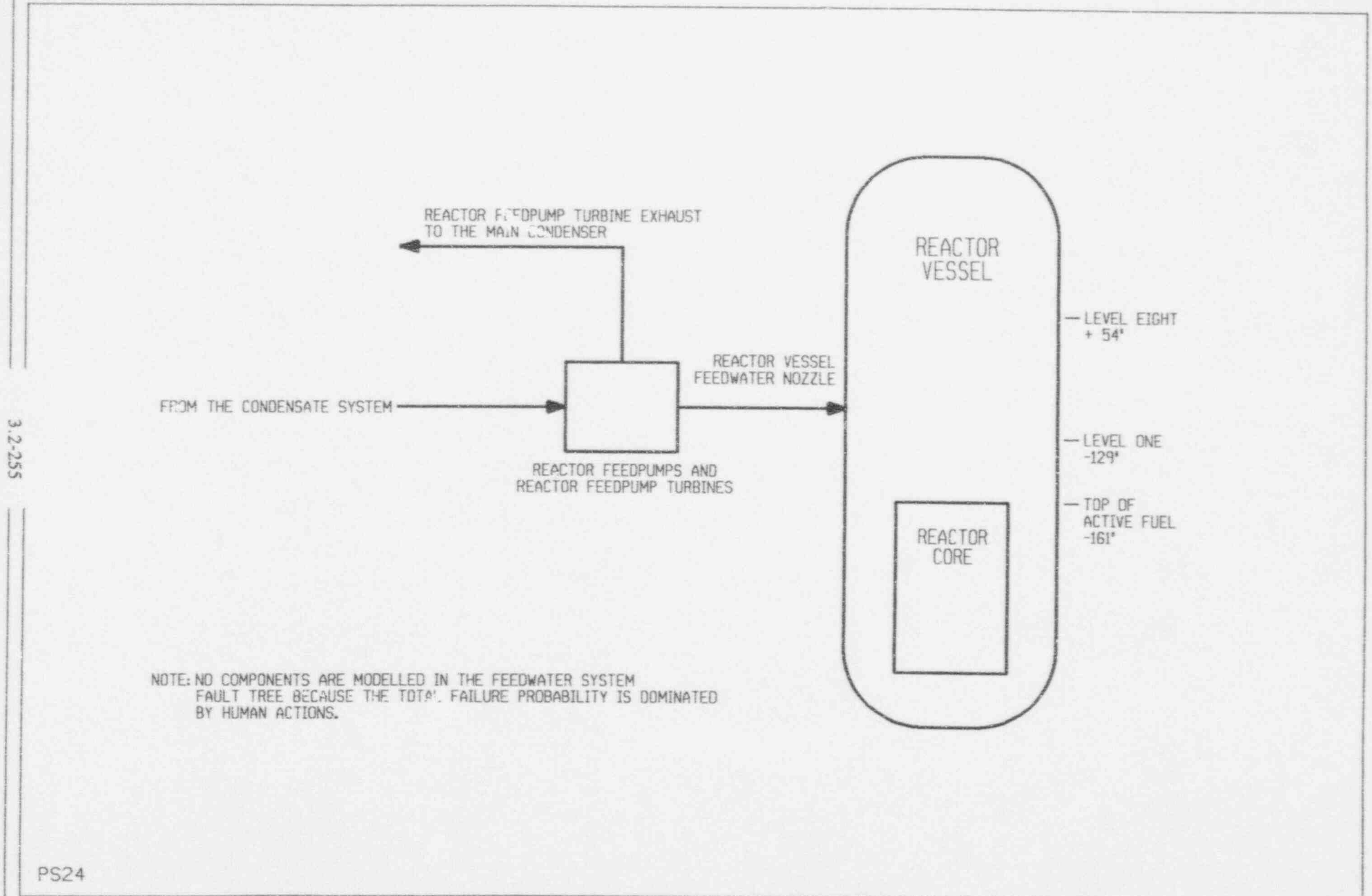


Figure 3.2-7b
Feedwater System Simplified Diagram

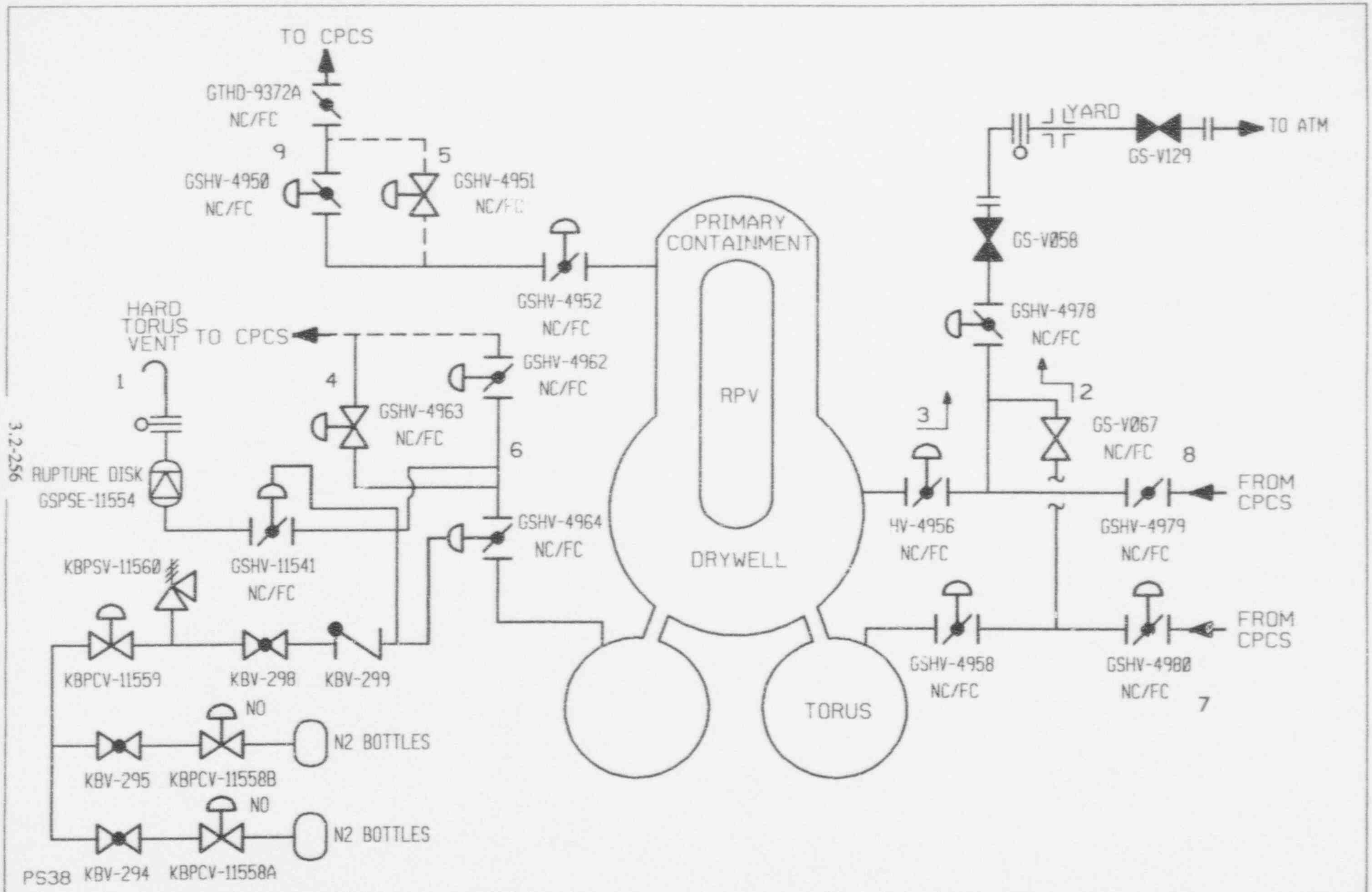
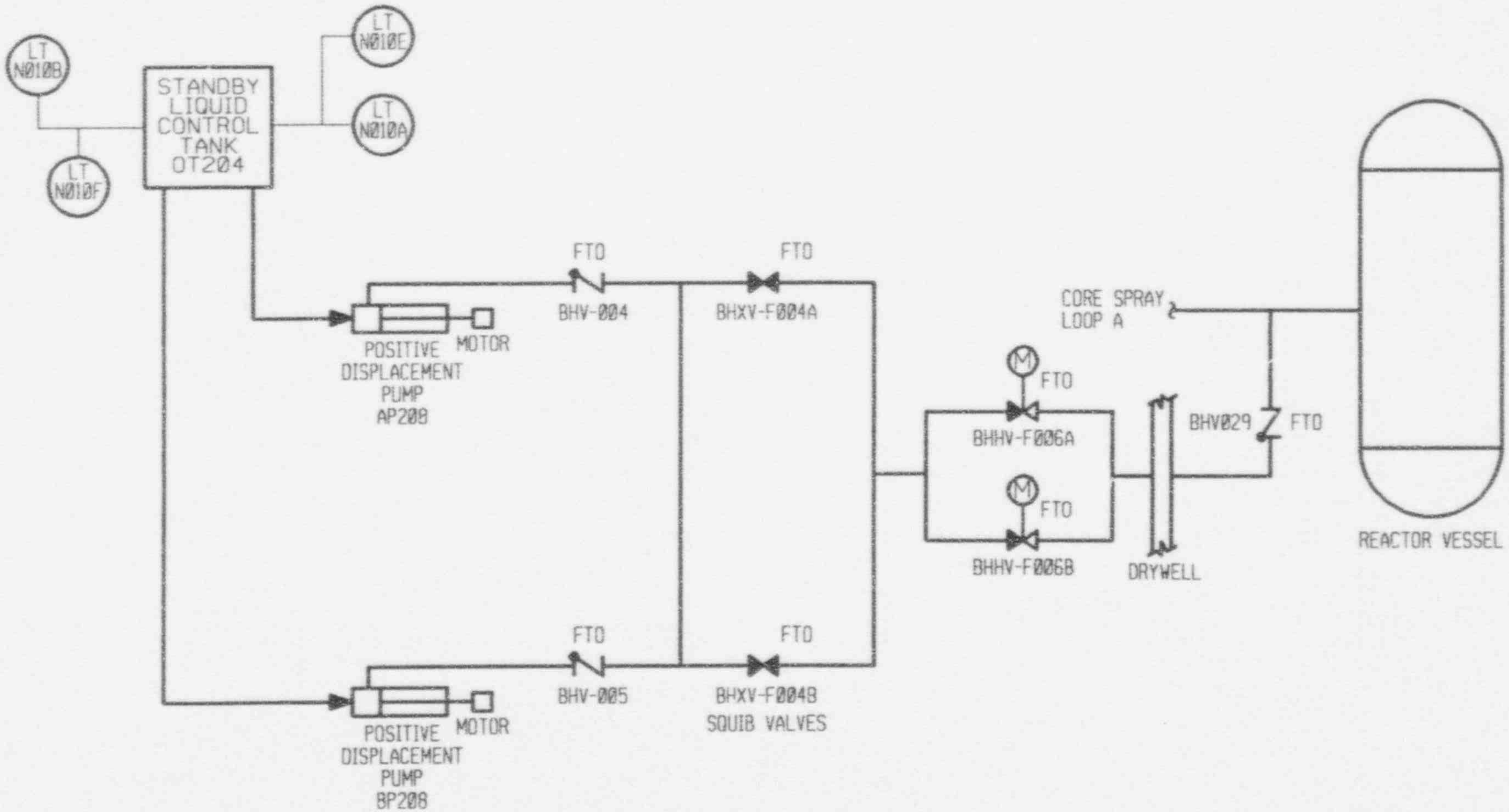


Figure 3.2-8
Containment Vent Simplified Diagram



PS11

Figure 3.2-9
Standby Liquid Control
System Simplified Diagram

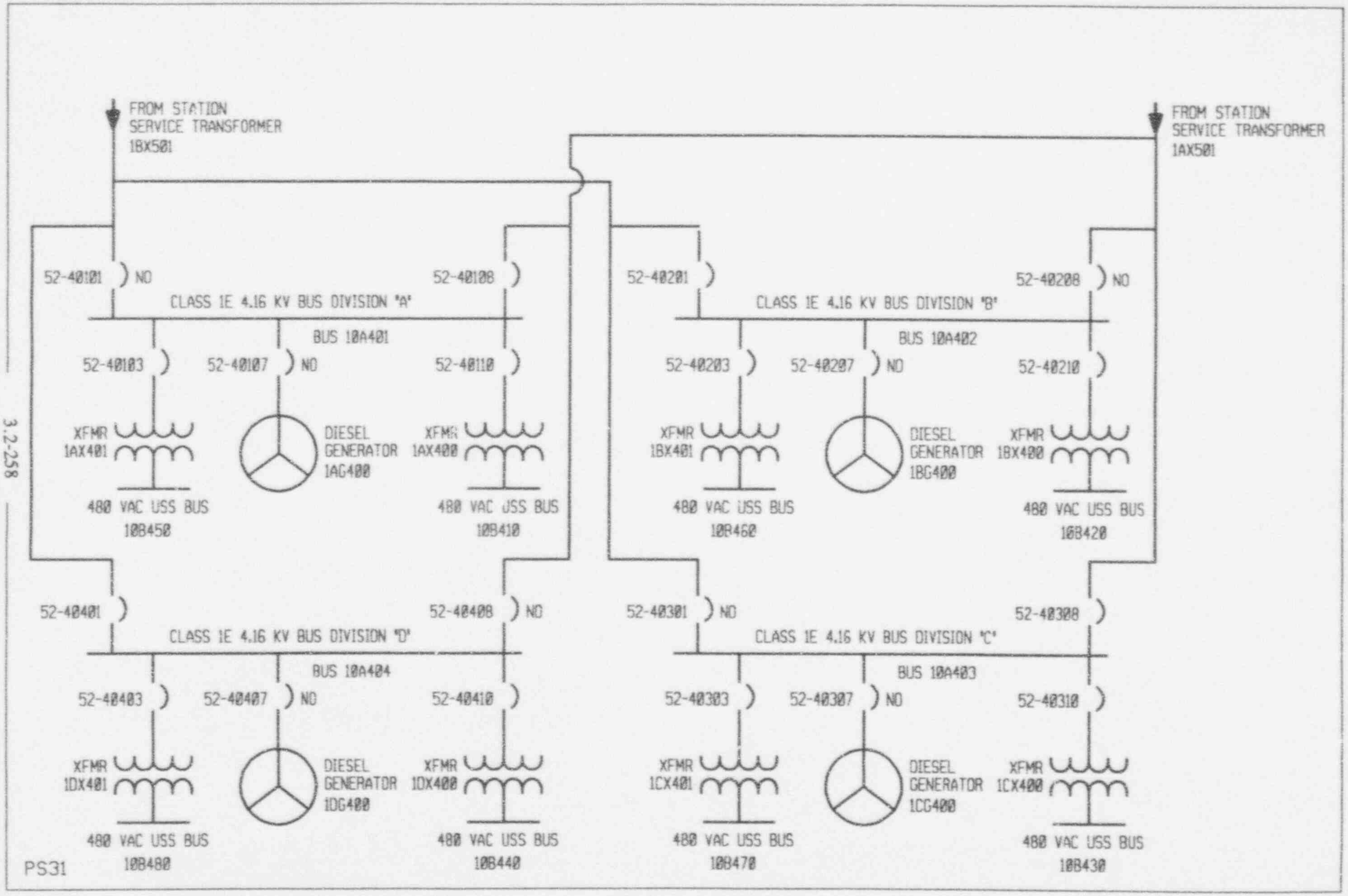


Figure 3.2-10a
Diesel Generator System Simplified Diagram

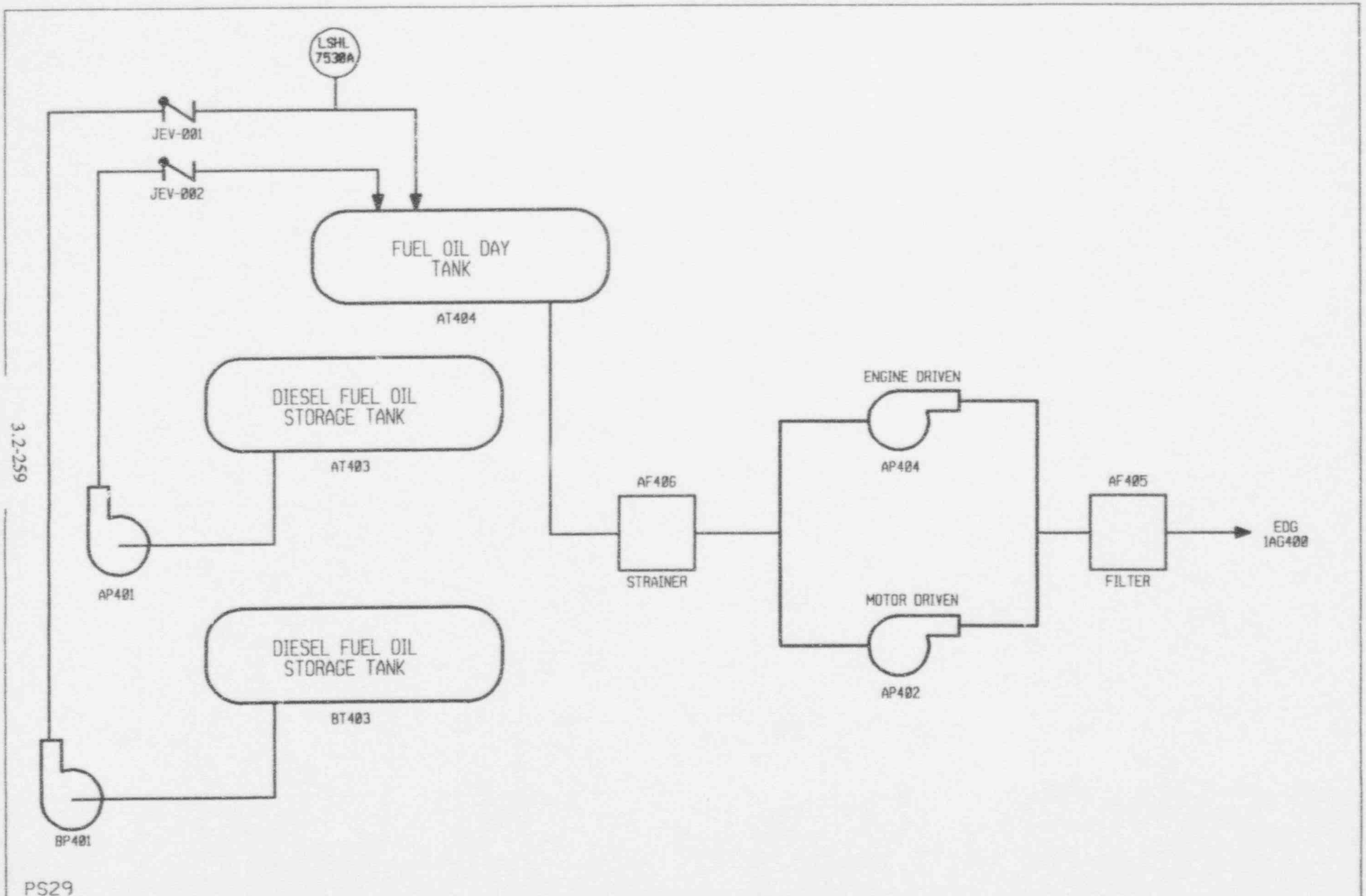


Figure 3.2-10b
Fuel oil Transfer System for DG A Simplified Diagram
(Typical for DG's B,C,D)

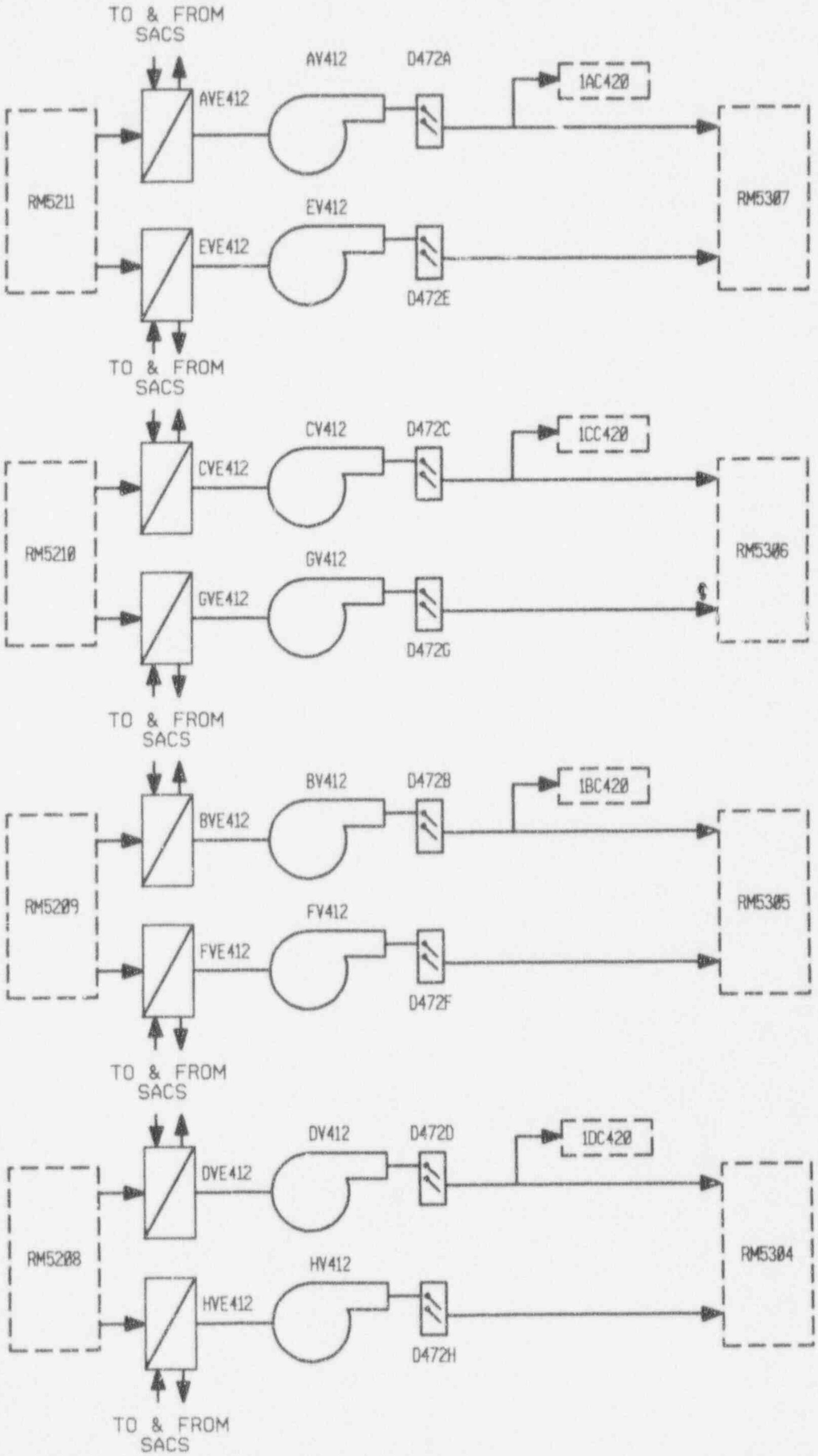
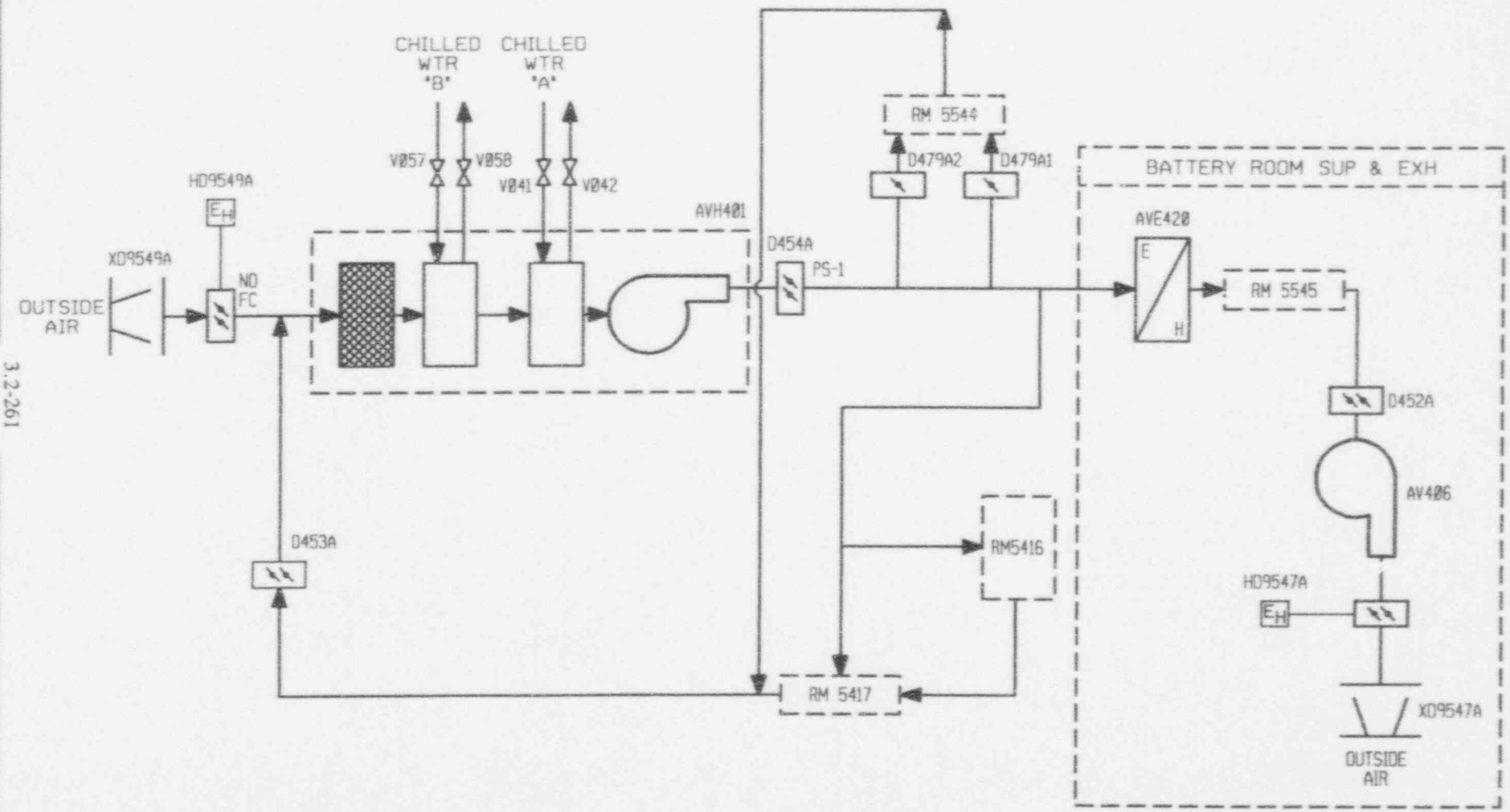


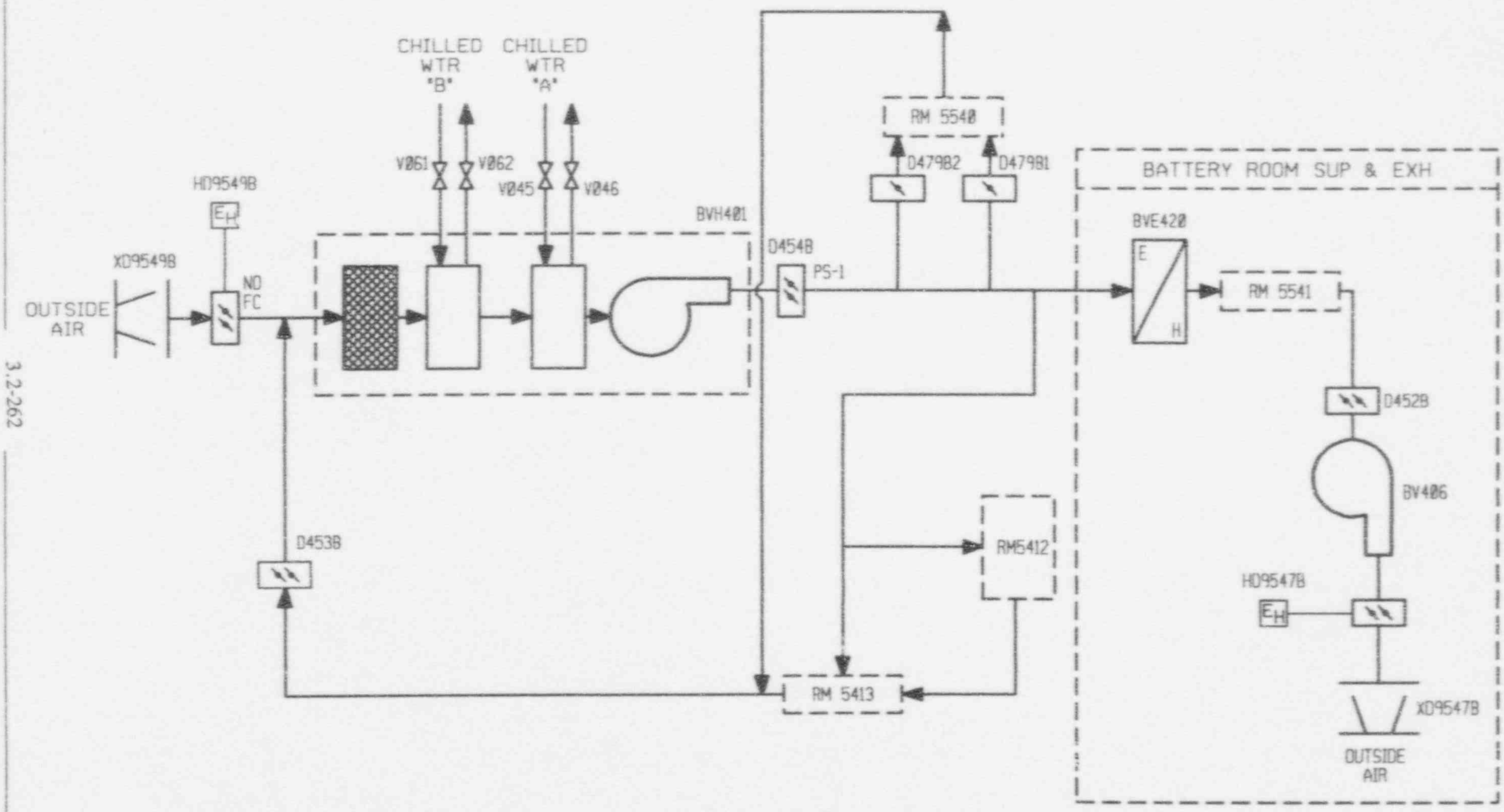
Figure 3.2-11a
D/G Room Recirculation Simplified Diagram

PS8



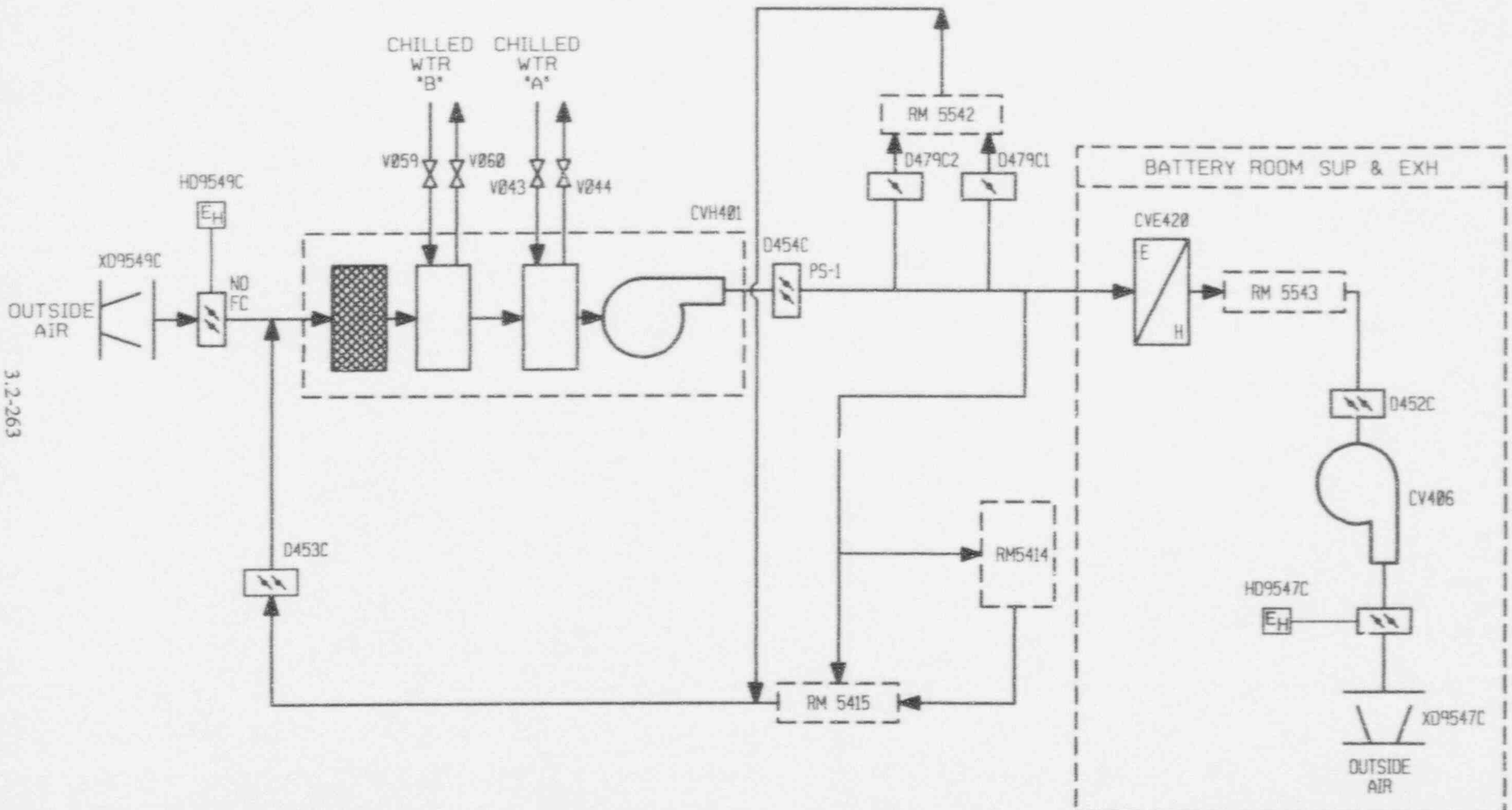
PS15

Figure 3.2-11b
Switchgear Room Cooling Train A Simplified Diagram



PS15a

Figure 3.2-11c
Switchgear Room Cooling Train B Simplified Diagram



3.2-263

PS15b

Figure 3.2-11d
Switchgear Room Cooling Train C Simplified Diagram

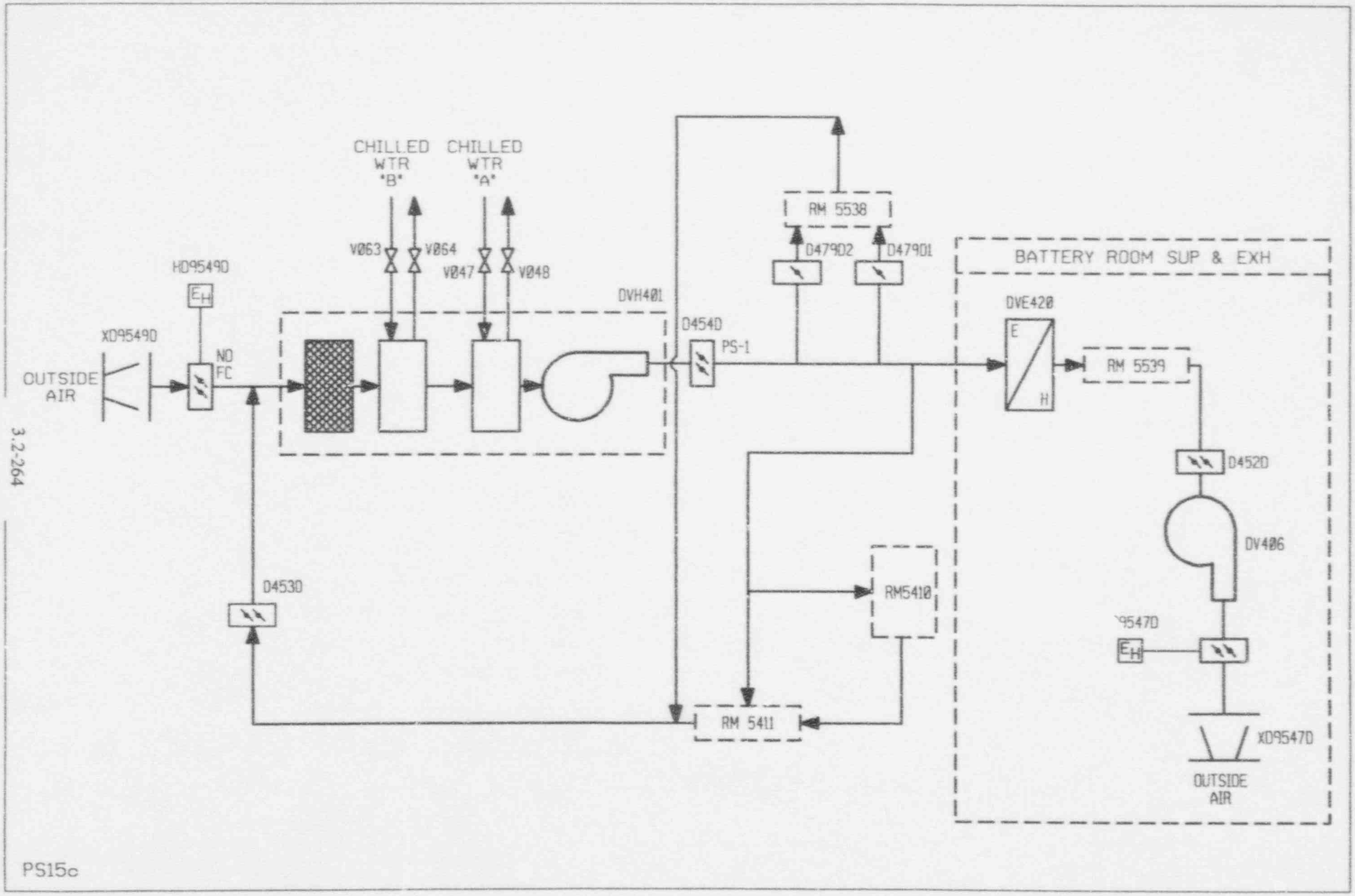


Figure 3.2-11e
Switchgear Room Cooling Train D Simplified Diagram

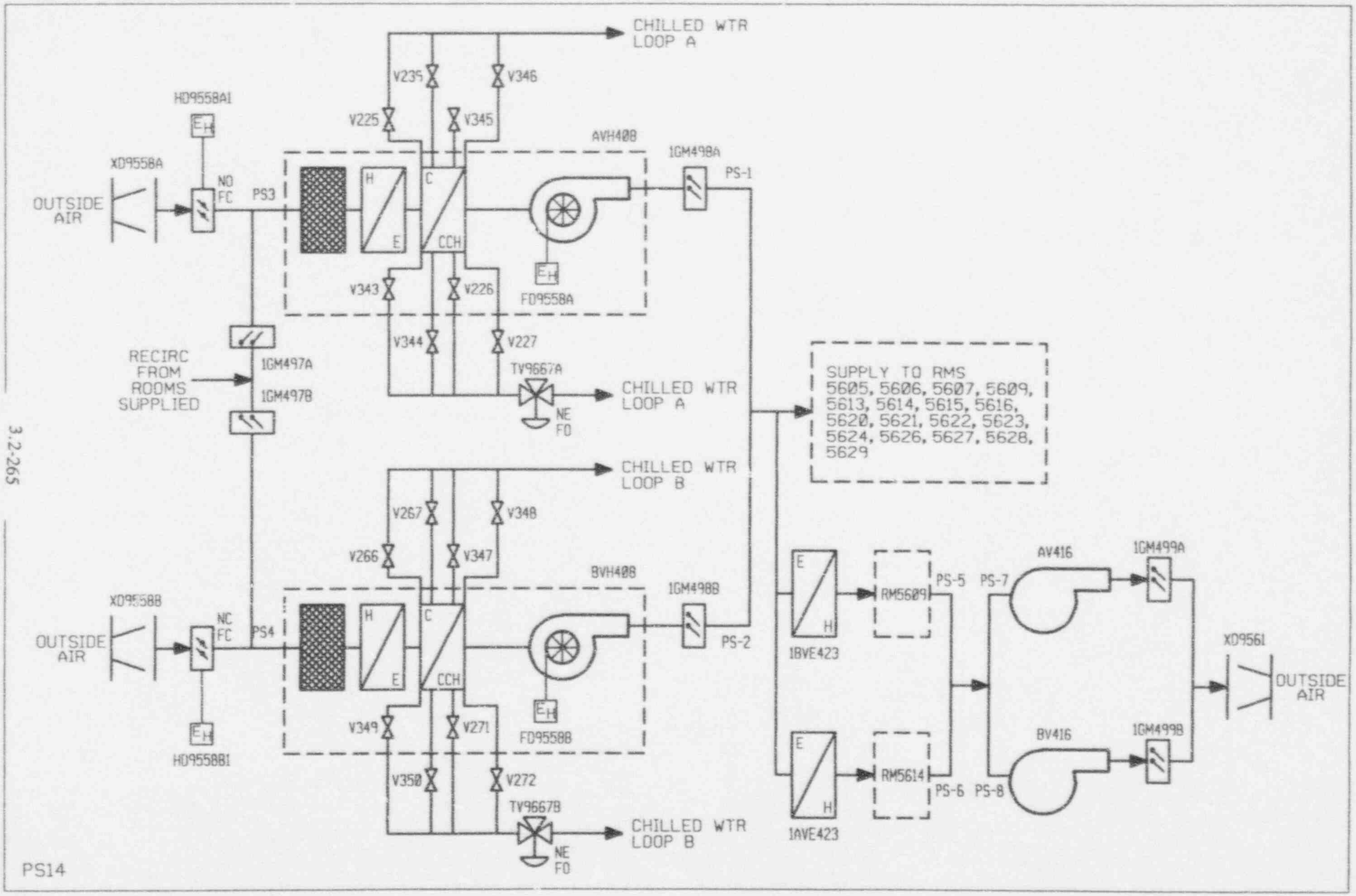


Figure 3.2-11f
Class 1E Panel Room Supply System Simplified Diagram

3.2-265

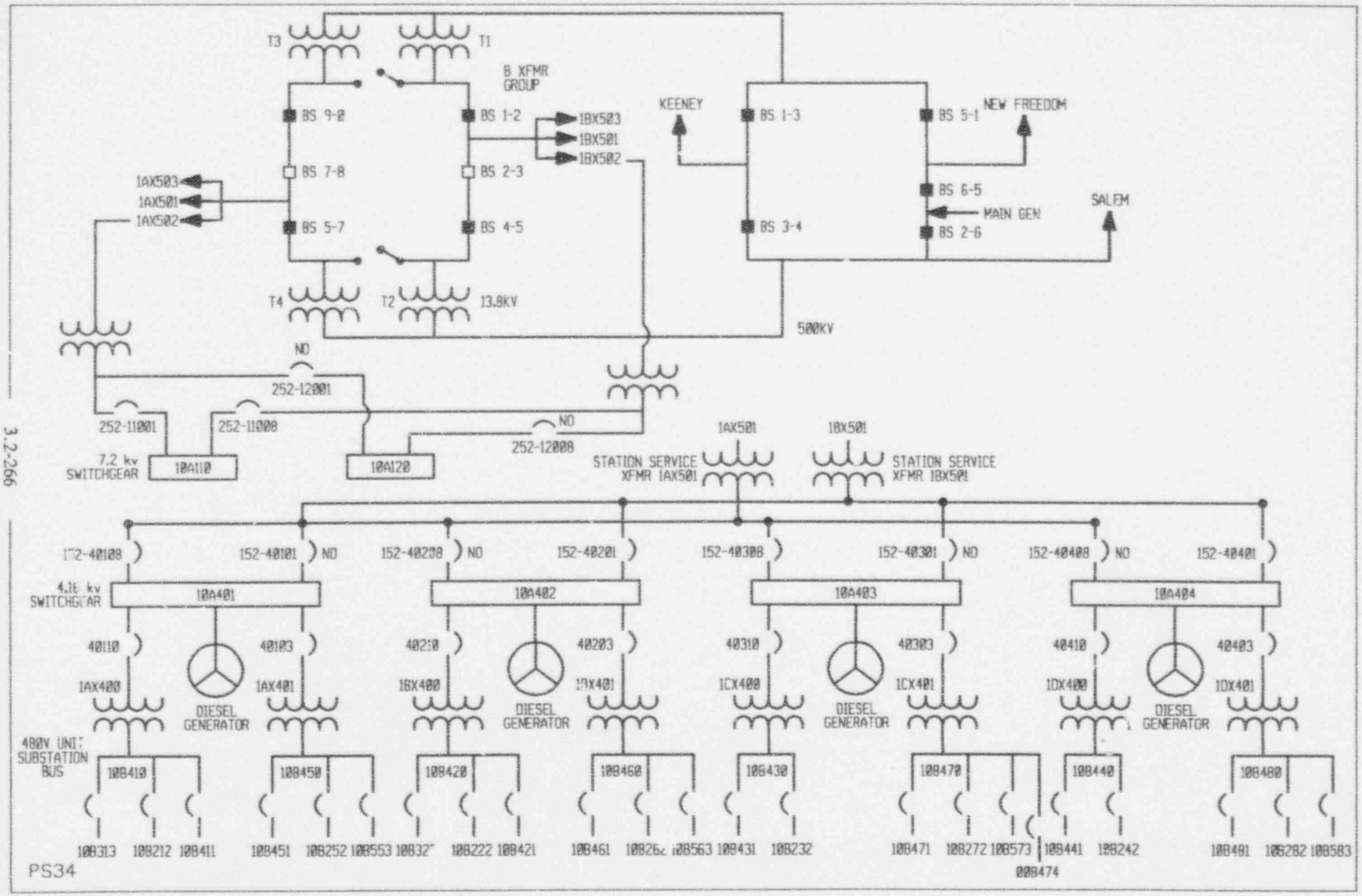


Figure 3.2-12
AC Power Simplified Diagram

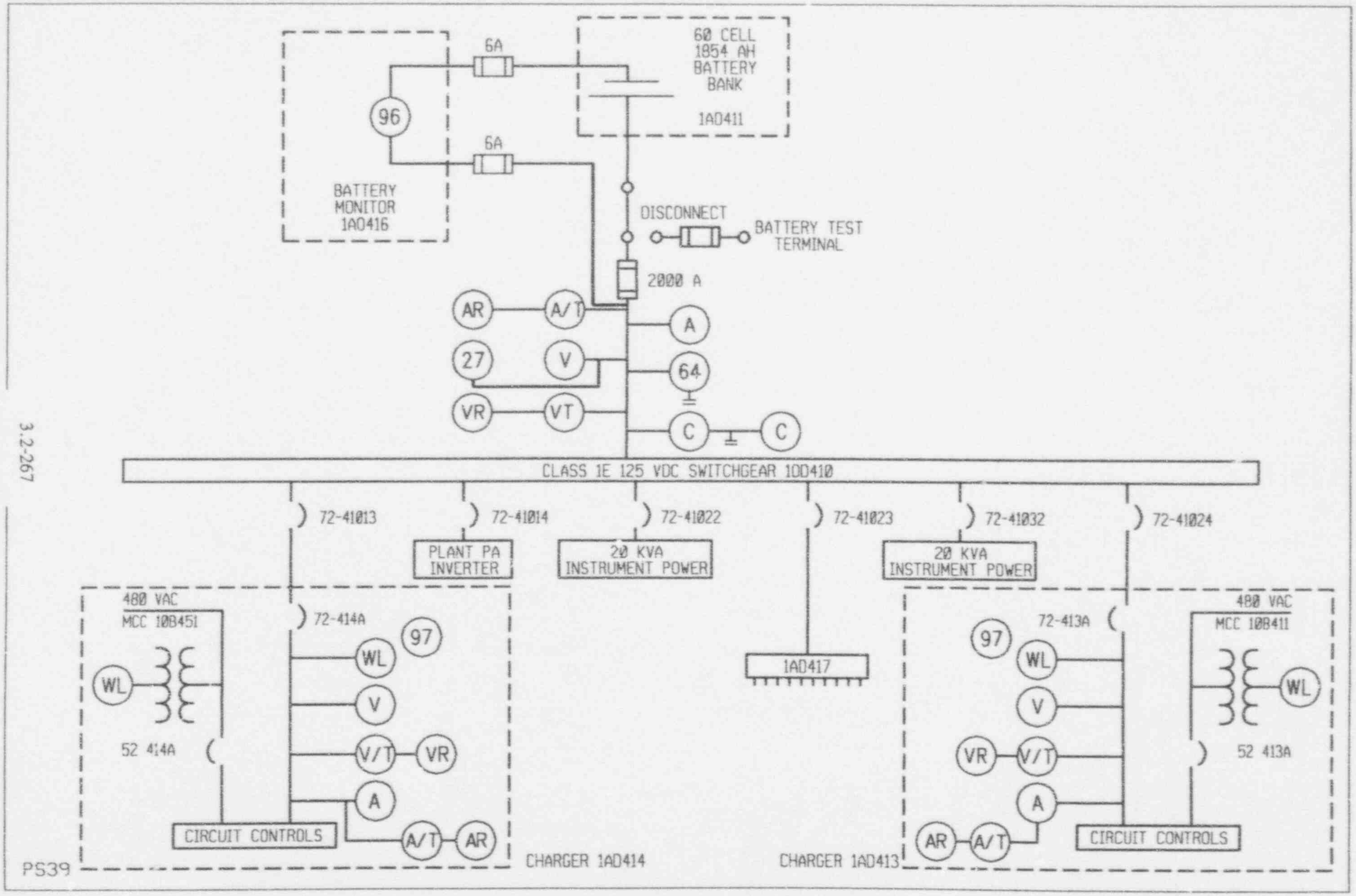


Figure 3.2-13a
DC Power System Simplified Diagram
125 VDC Class 1E Channel A

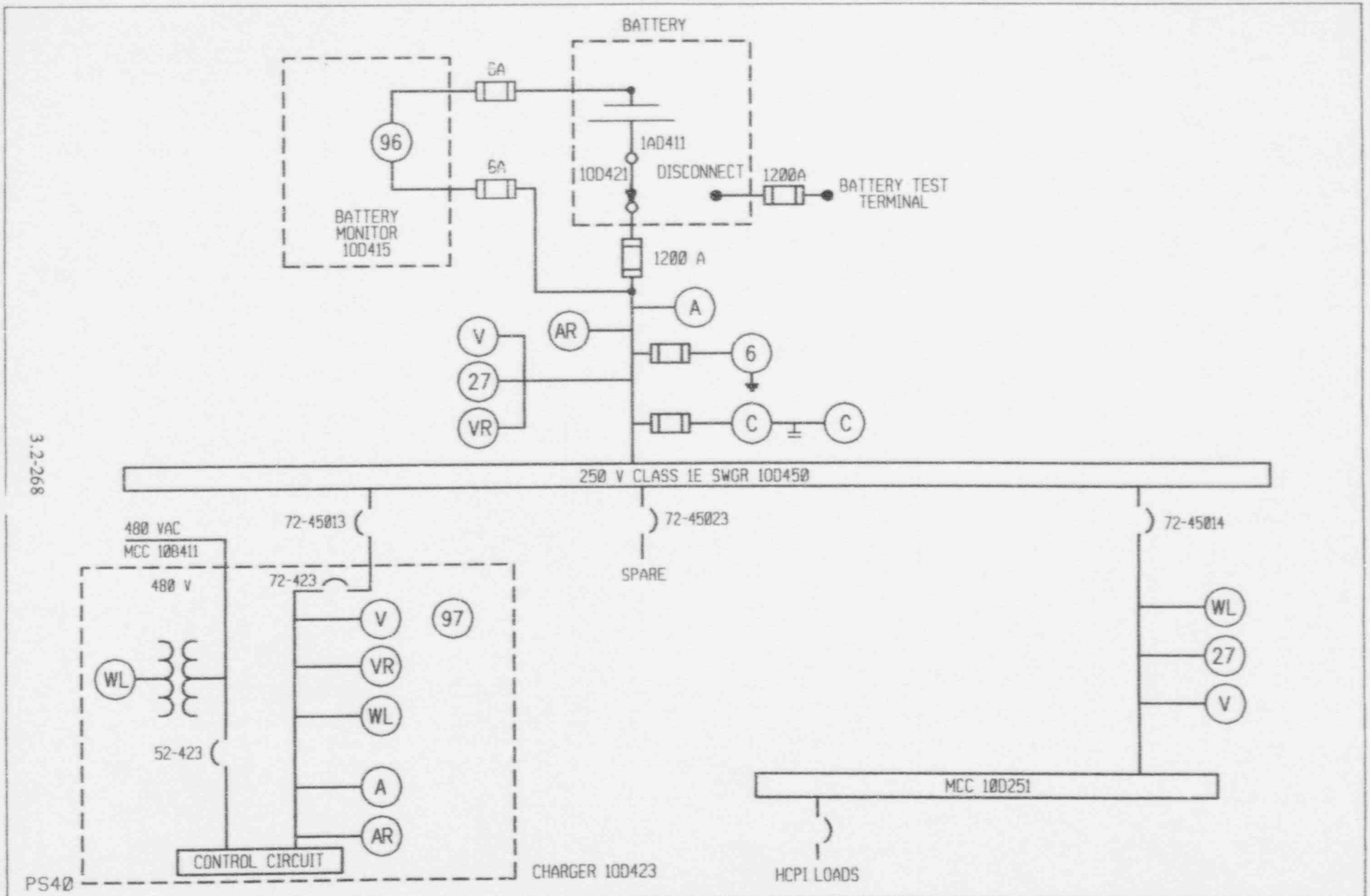
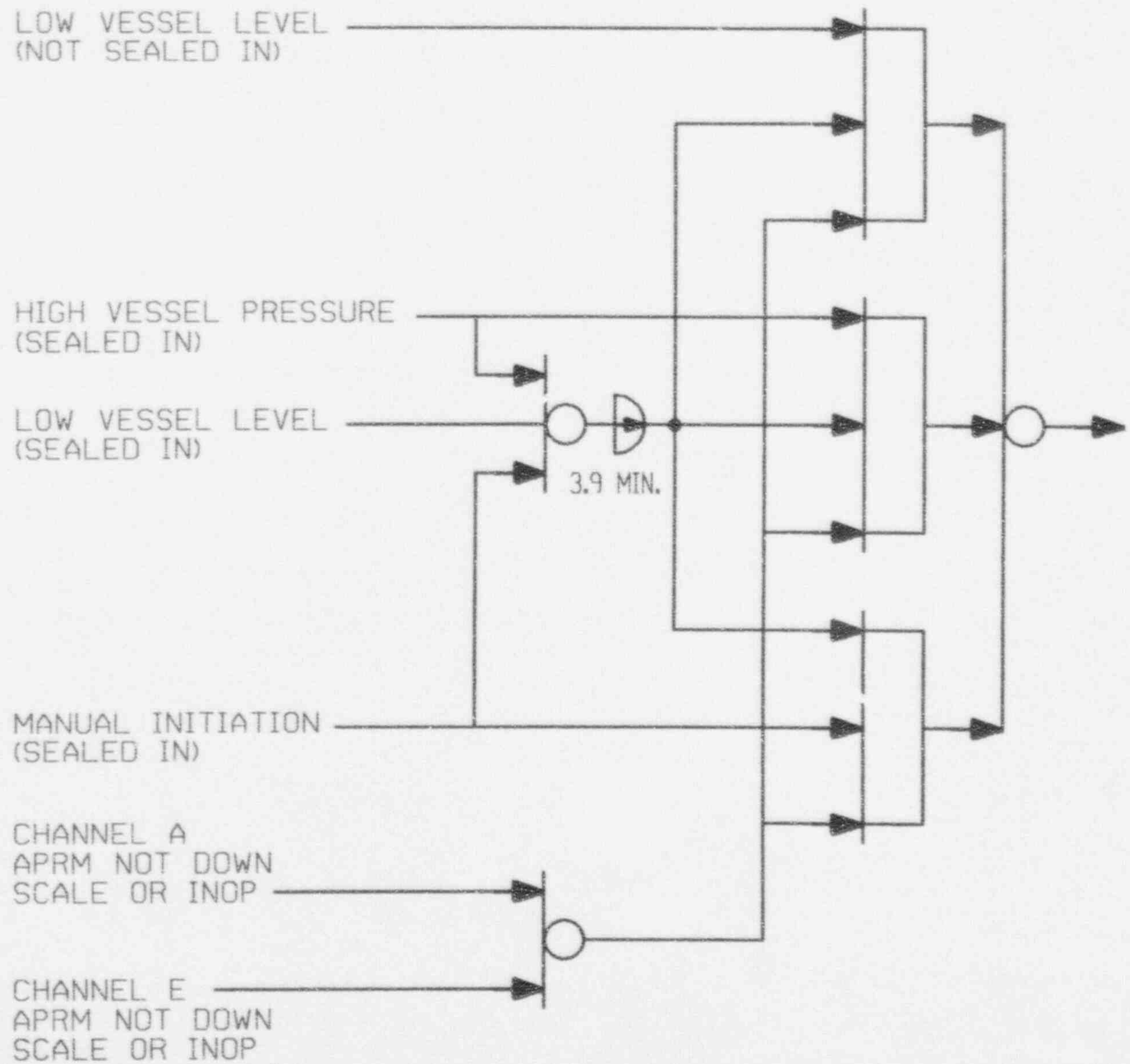


Figure 3.2-13b
DC Power System Simplified Diagram
250 VDC Class 1E Channel A



PS32

Figure 3.2-14a
ESF Logic Diagram: Standby Liquid Control Initiation

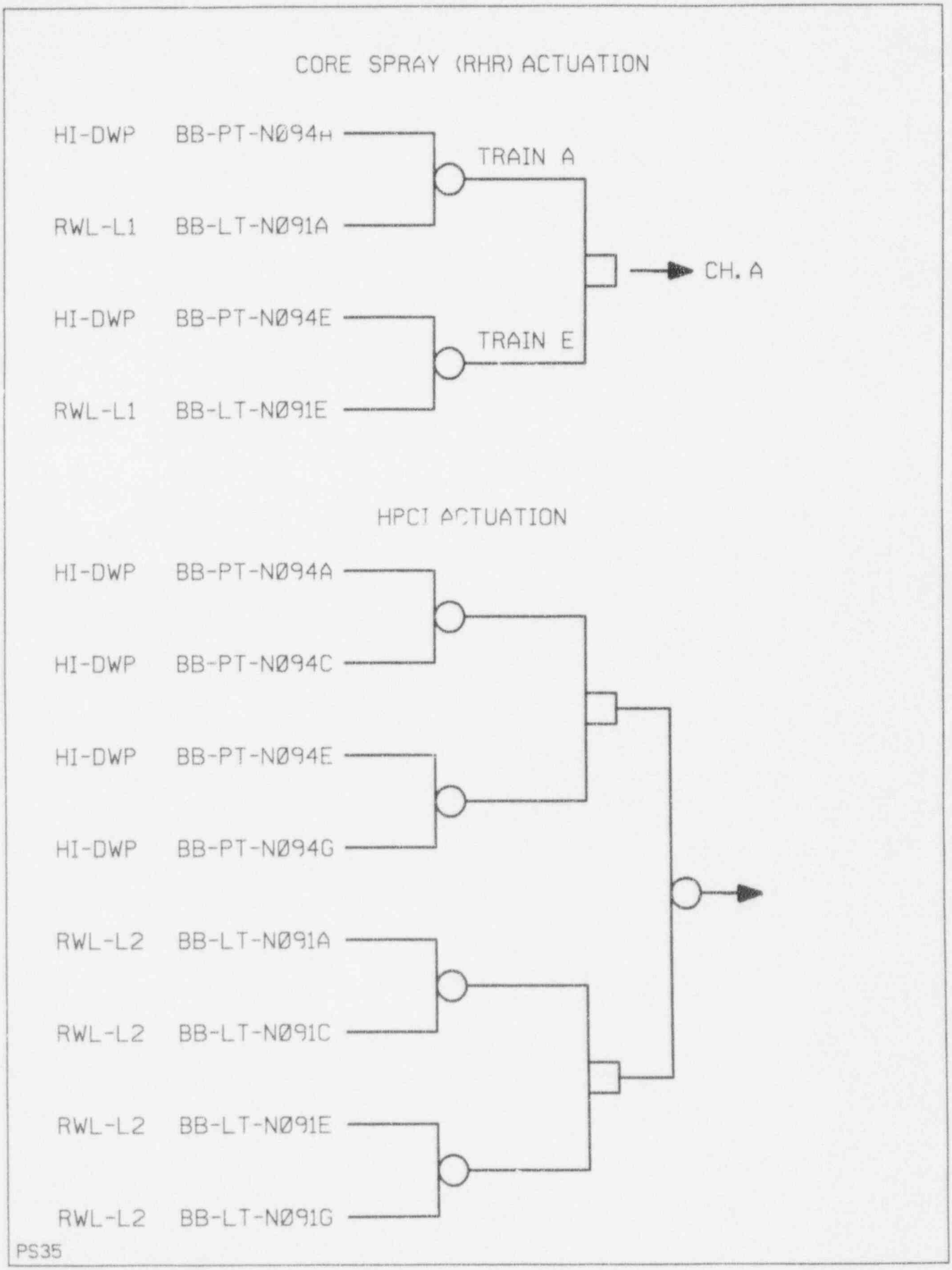


Figure 3.2-14b
ESF Logic Diagram HPCI and Core Spray Initiation

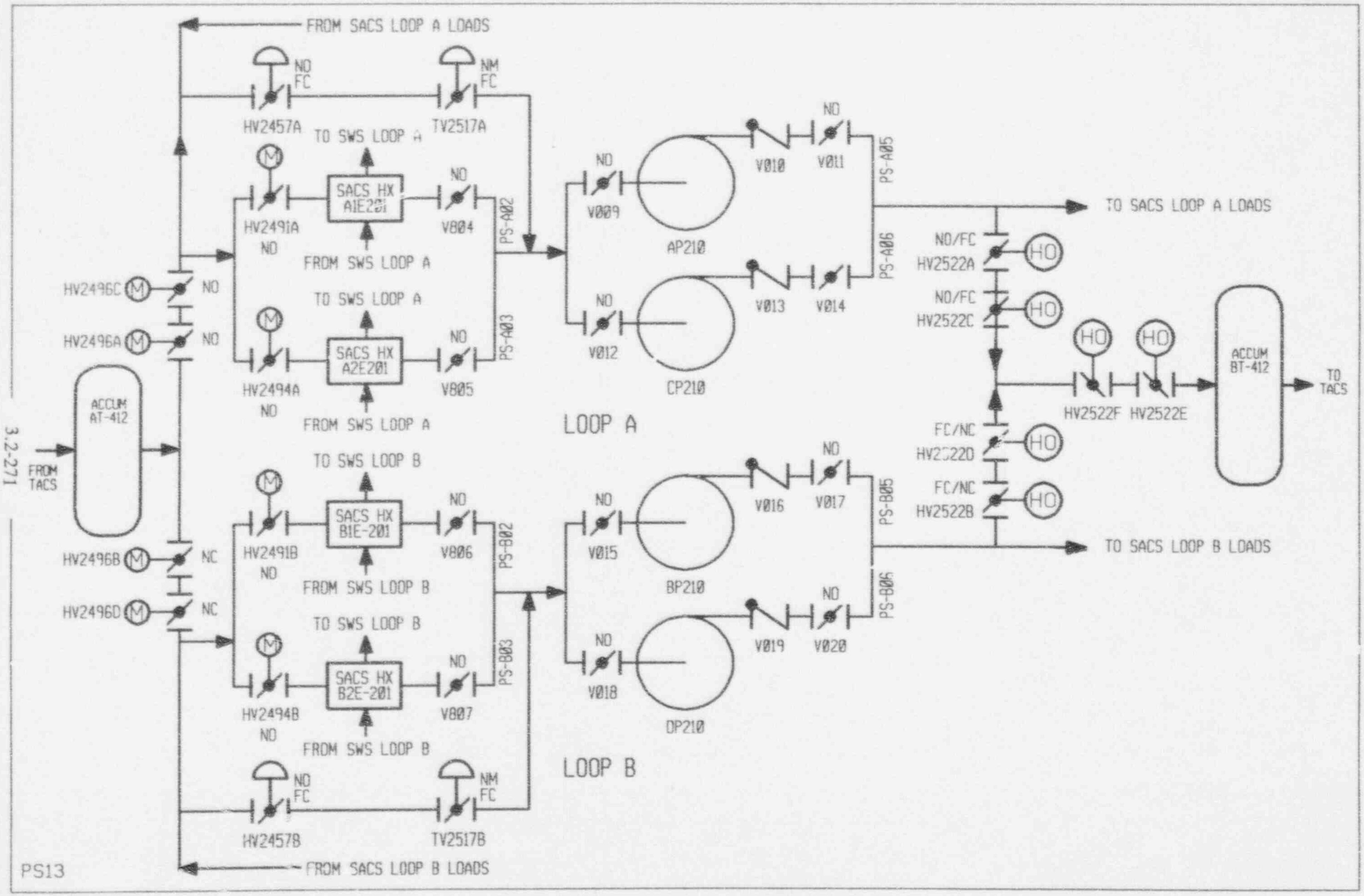


Figure 3.2-15
SACS Simplified Diagram

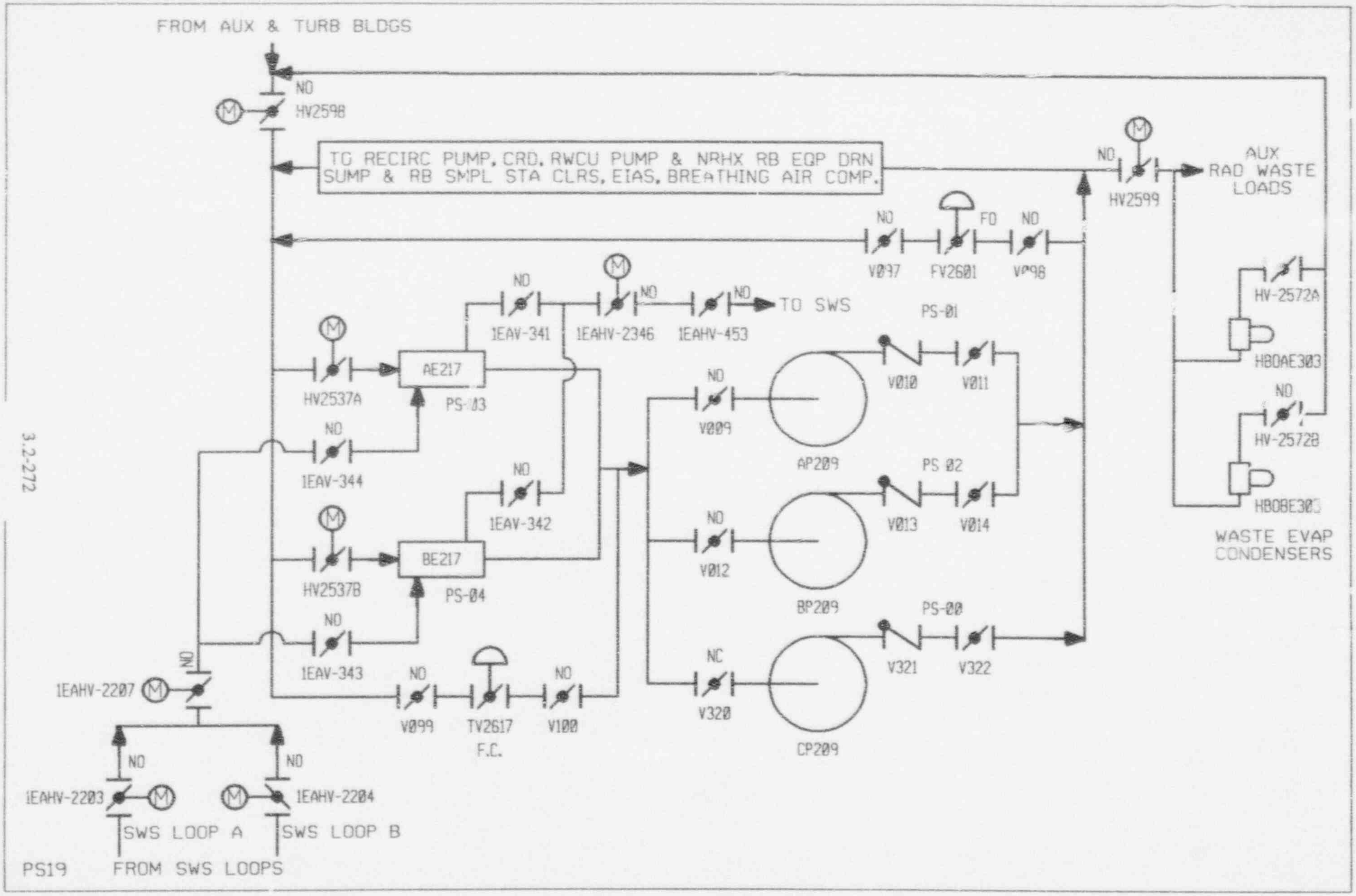


Figure 3.2-16
RACS System Simplified Diagram

3.2-272

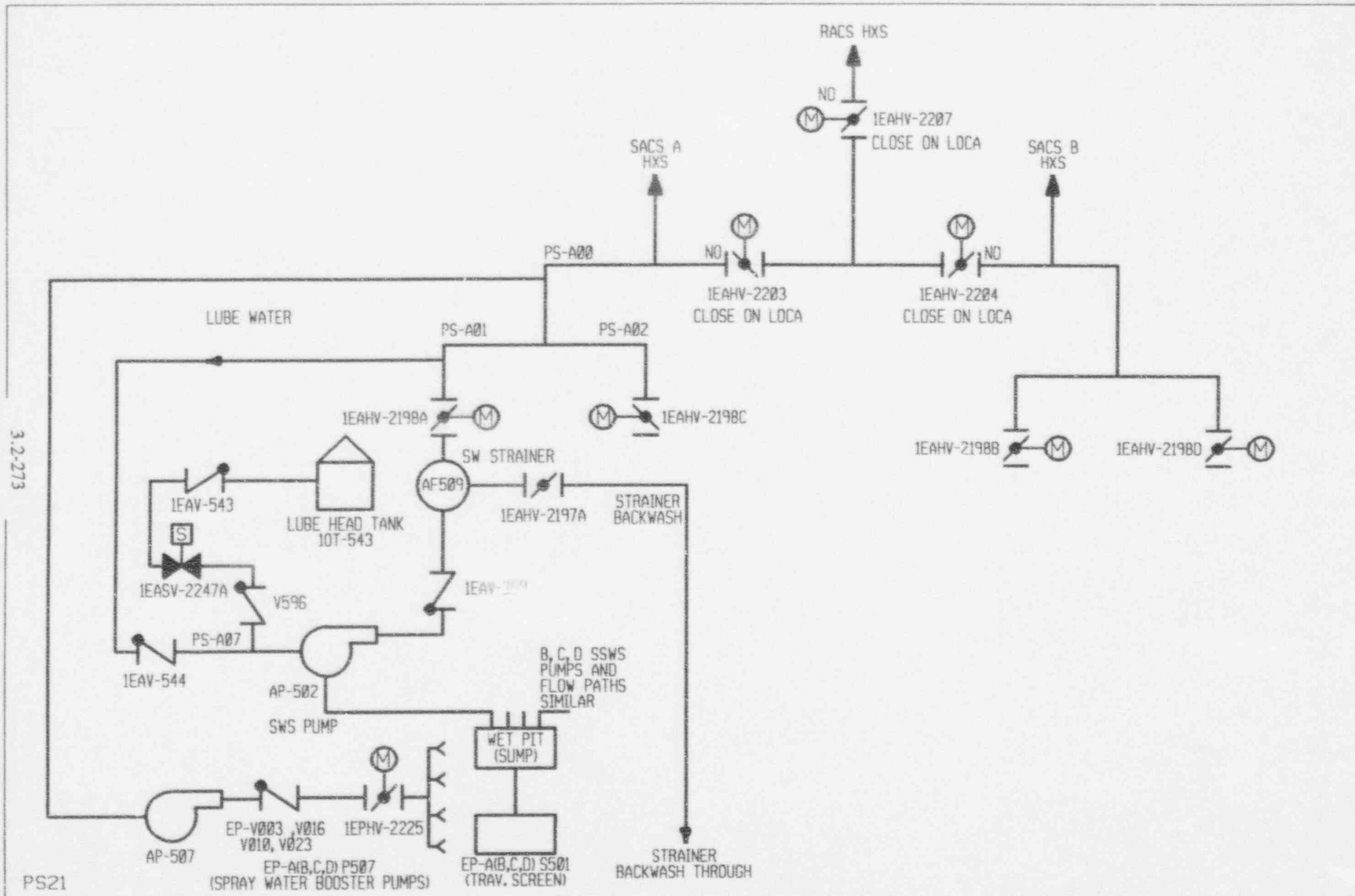
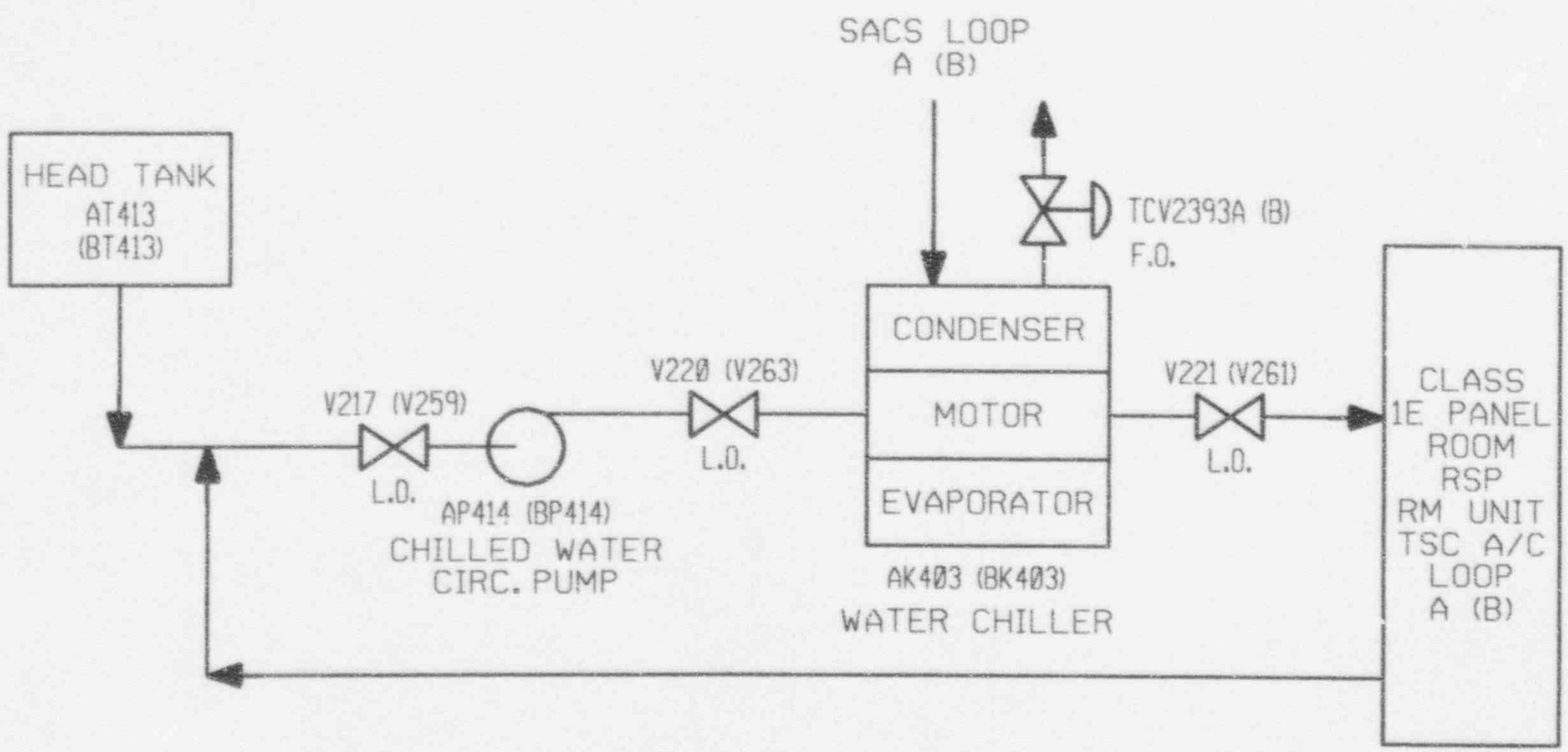
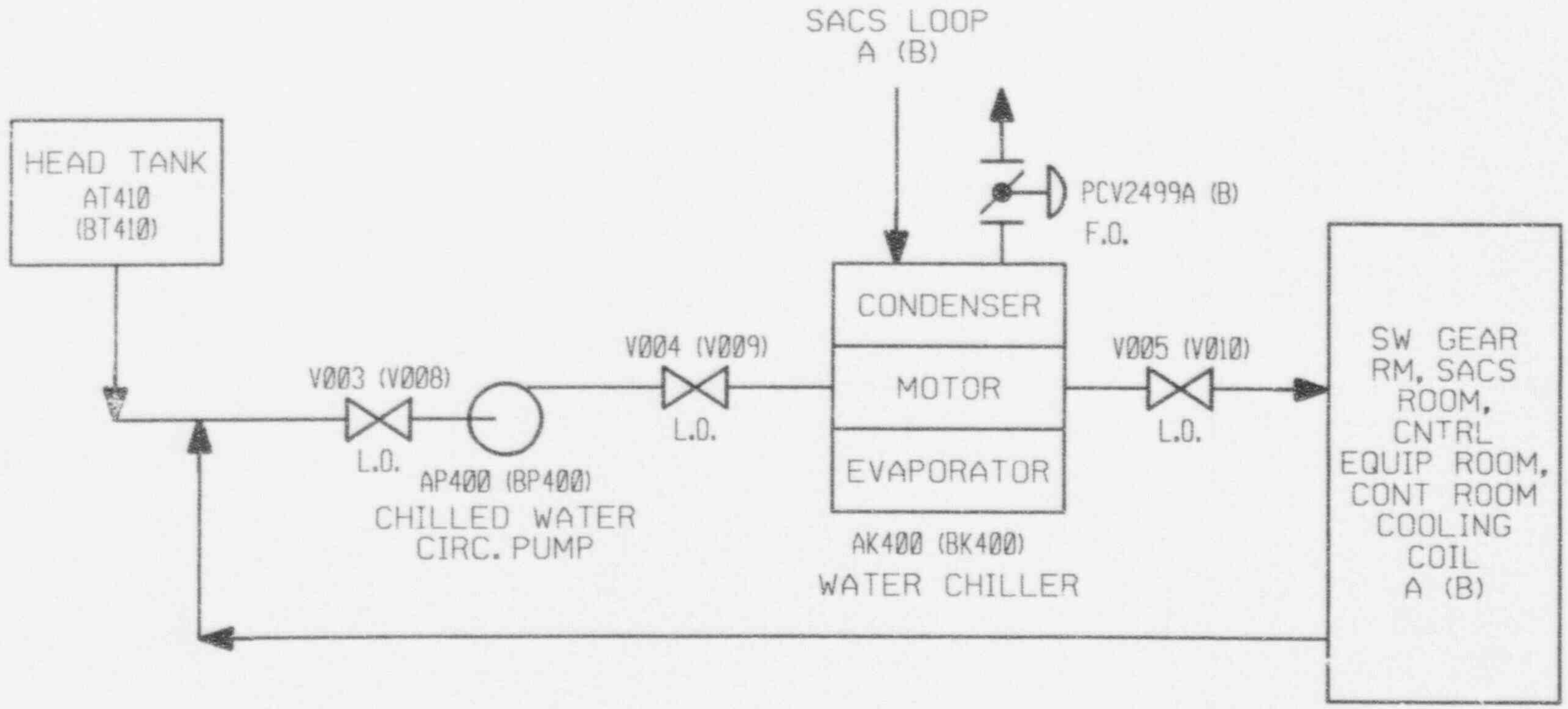


Figure 3.2-17
Service Water System Pump and Flow Path A
Simplified Diagram (B, C & D Similar)



PS36

Figure 3.2-18a
Chilled Water System Simplified Diagram:
Safety Related Panel Room Chillers Loop A (B)



PS37

Figure 3.2-18b
Chilled Water System Simplified Diagram:
Control Area Chillers Loop A (B)

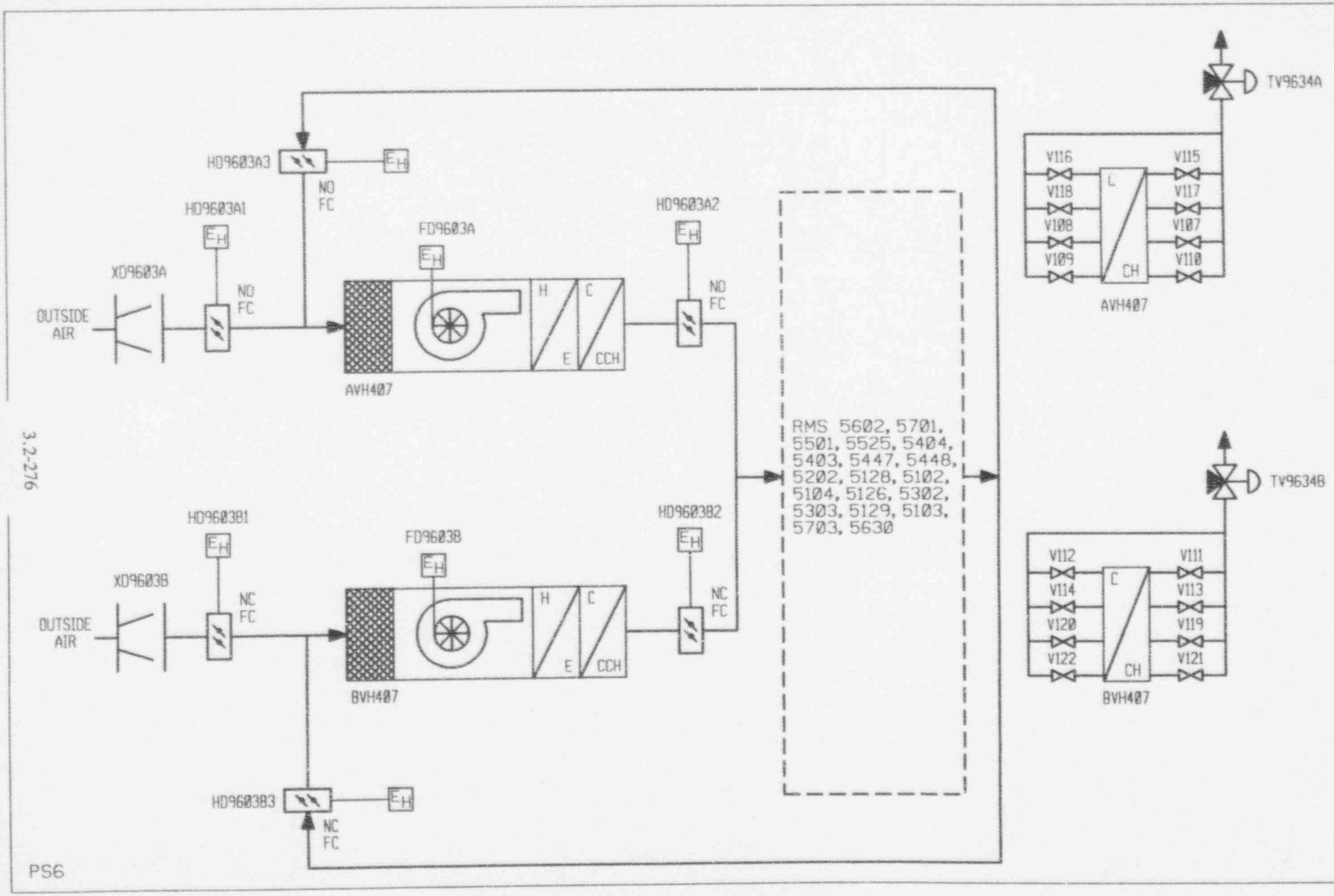


Figure 3.2-19a
Control Equipment Room Supply Simplified Diagram

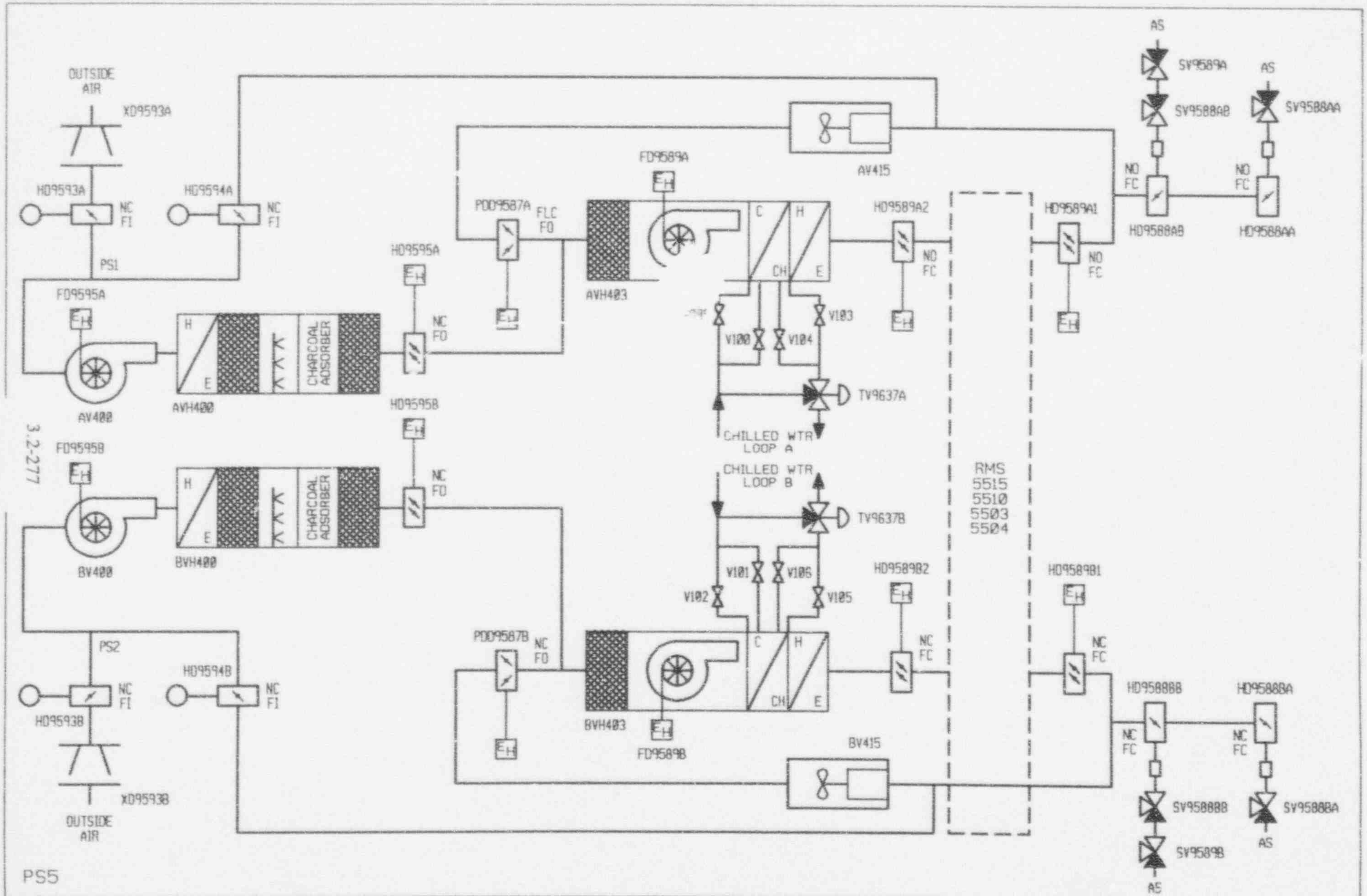
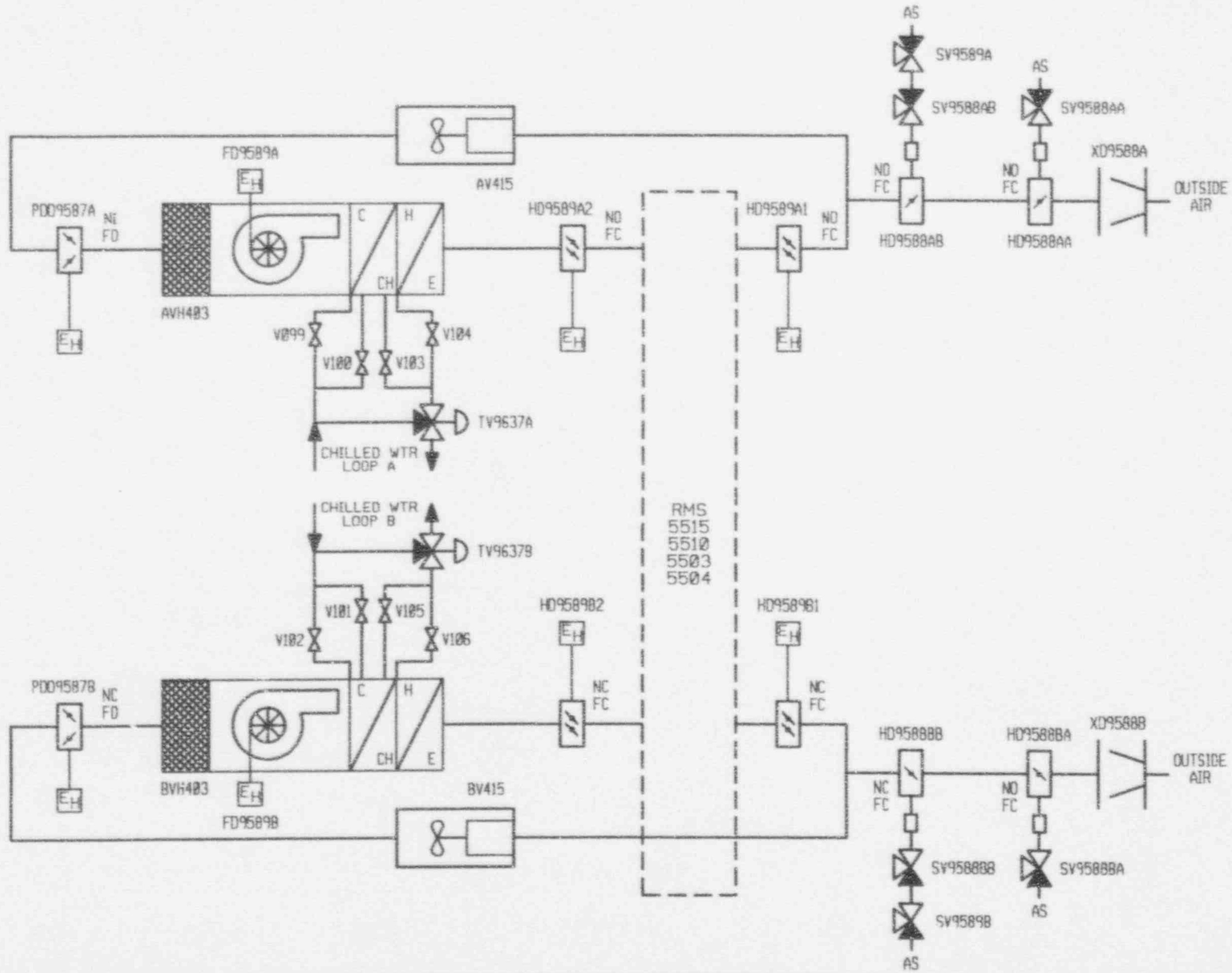
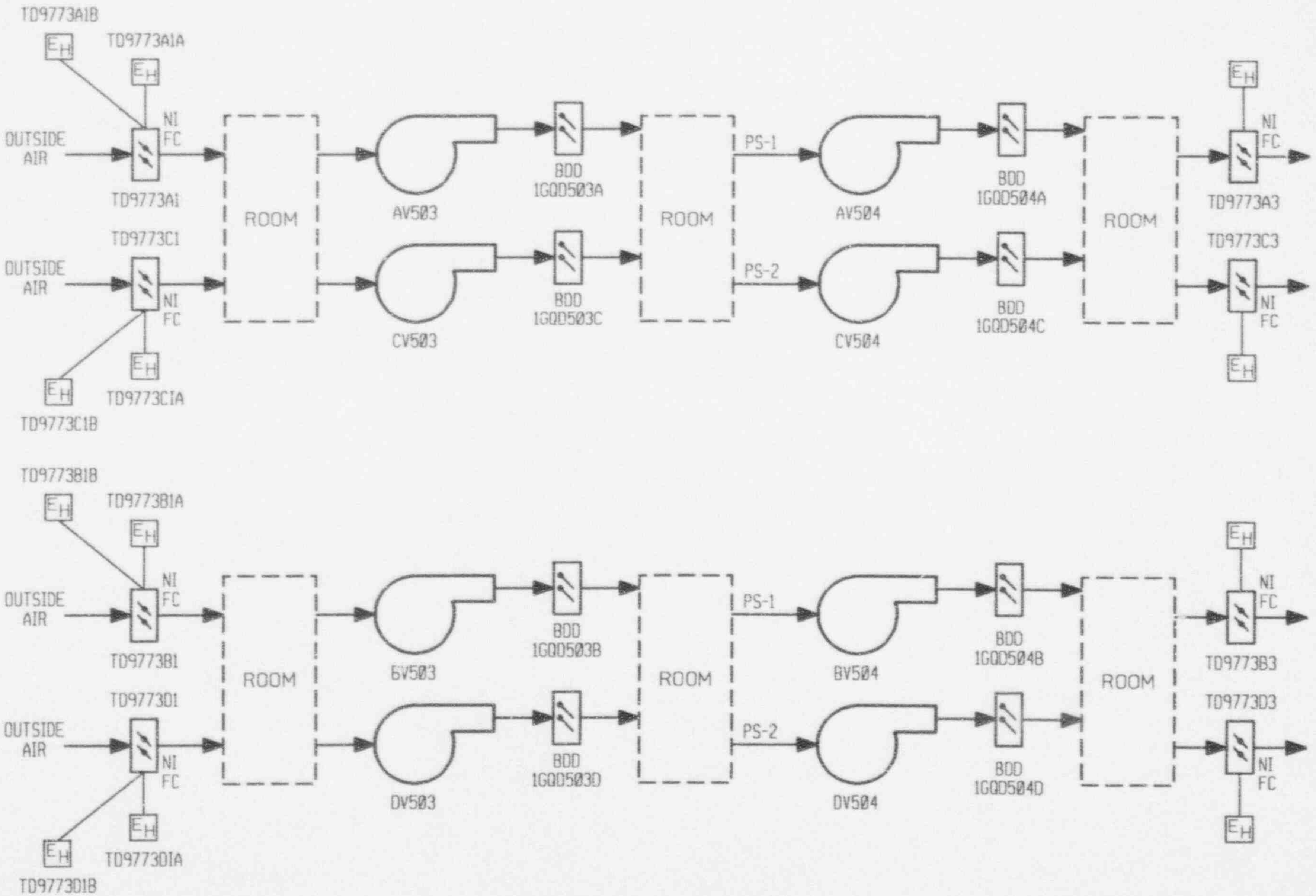


Figure 3.2-19b
CREF/CRS Simplified Diagram



PS7

Figure 3.2-19c
Control Room Supply Simplified Diagram



PS9

Figure 3.2-20a
Service Water Intake Structure
HVAC Simplified Diagram

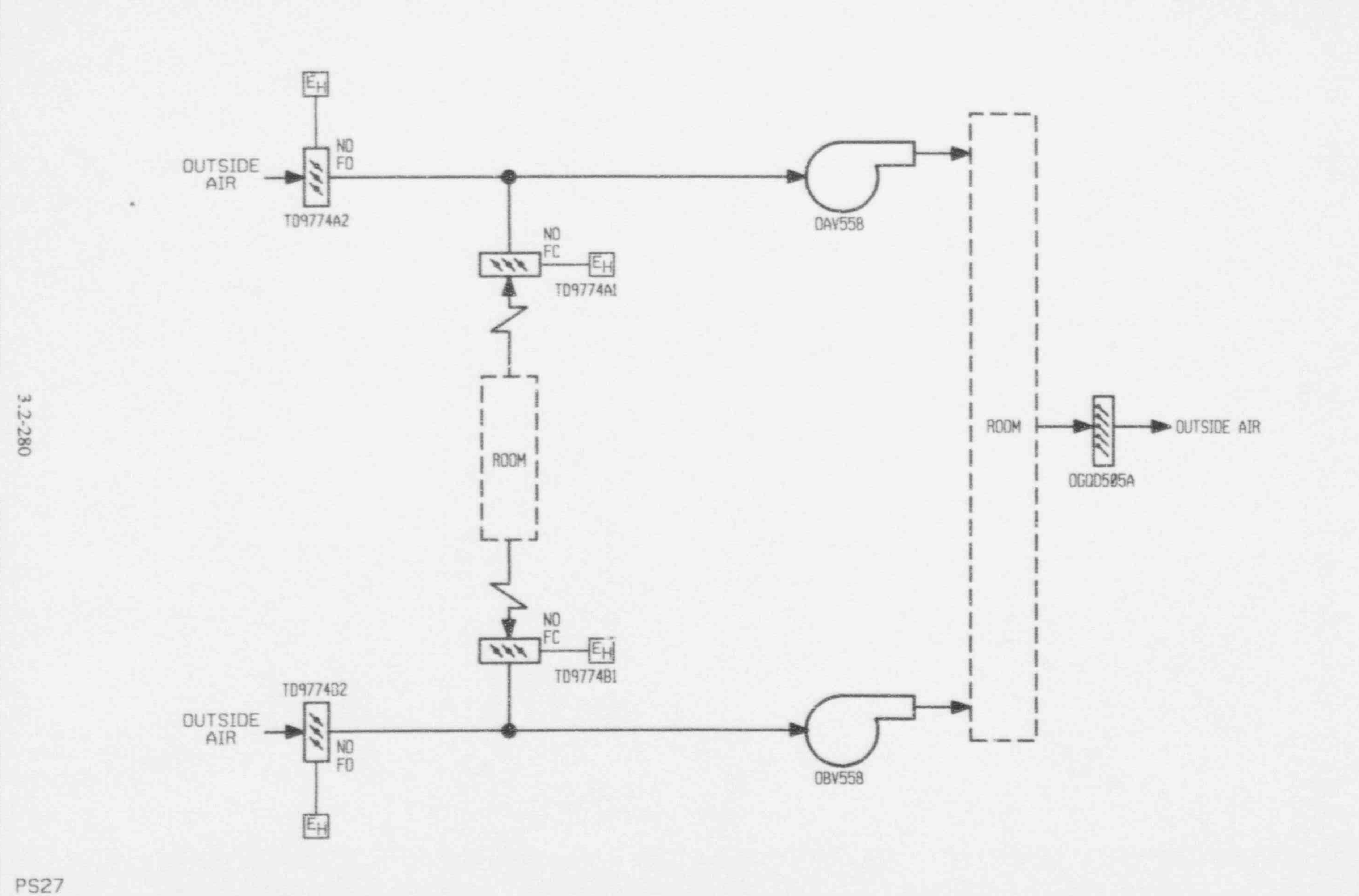
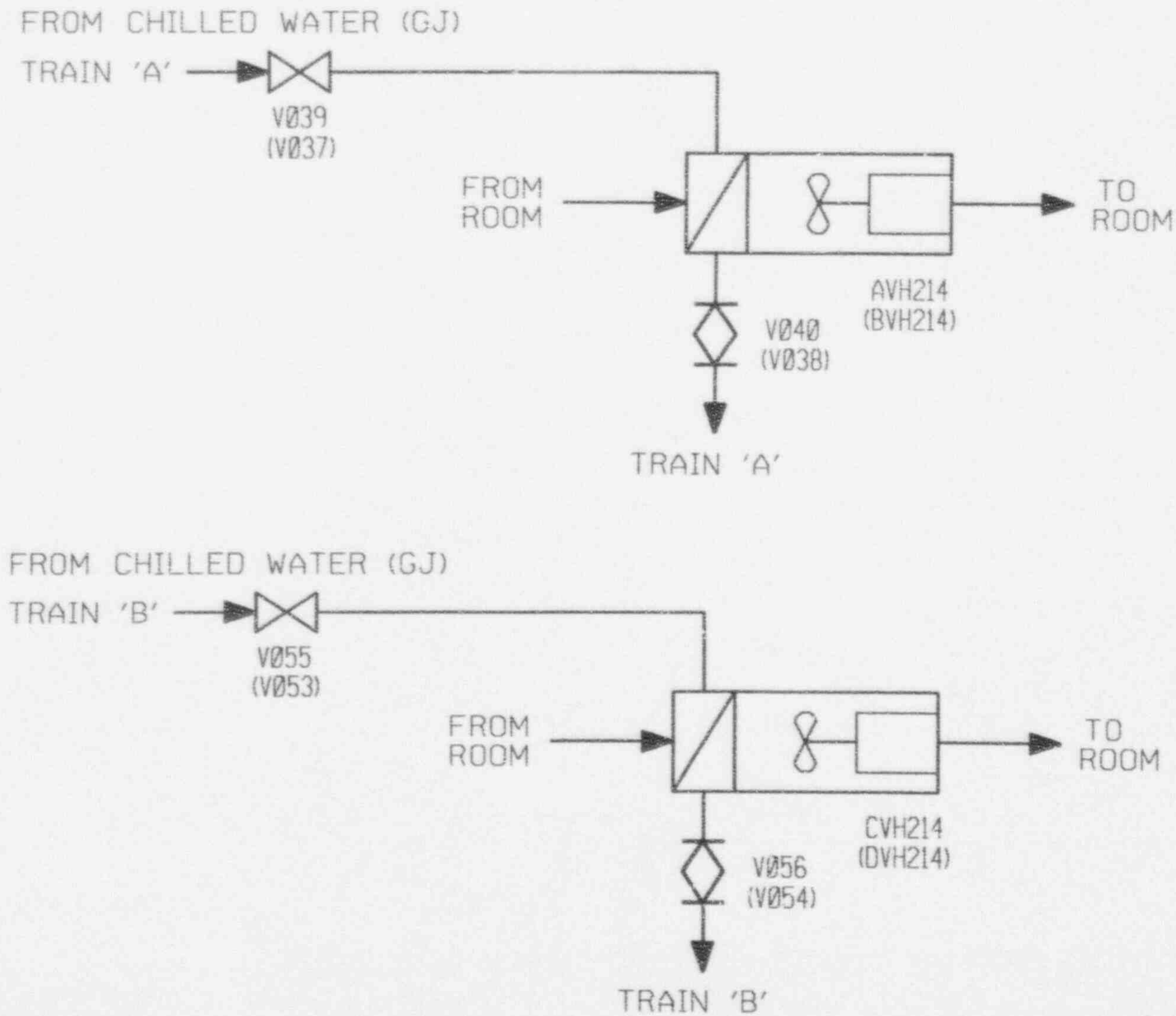


Figure 3.2-20b
Traveling Screen Motor Room
HVAC Simplified Diagram



SHOWN WITH BOTH FANS RUNNING

PS4

Figure 3.2-21a
SACS Room 4309 (4307) EACS Simplified Diagram

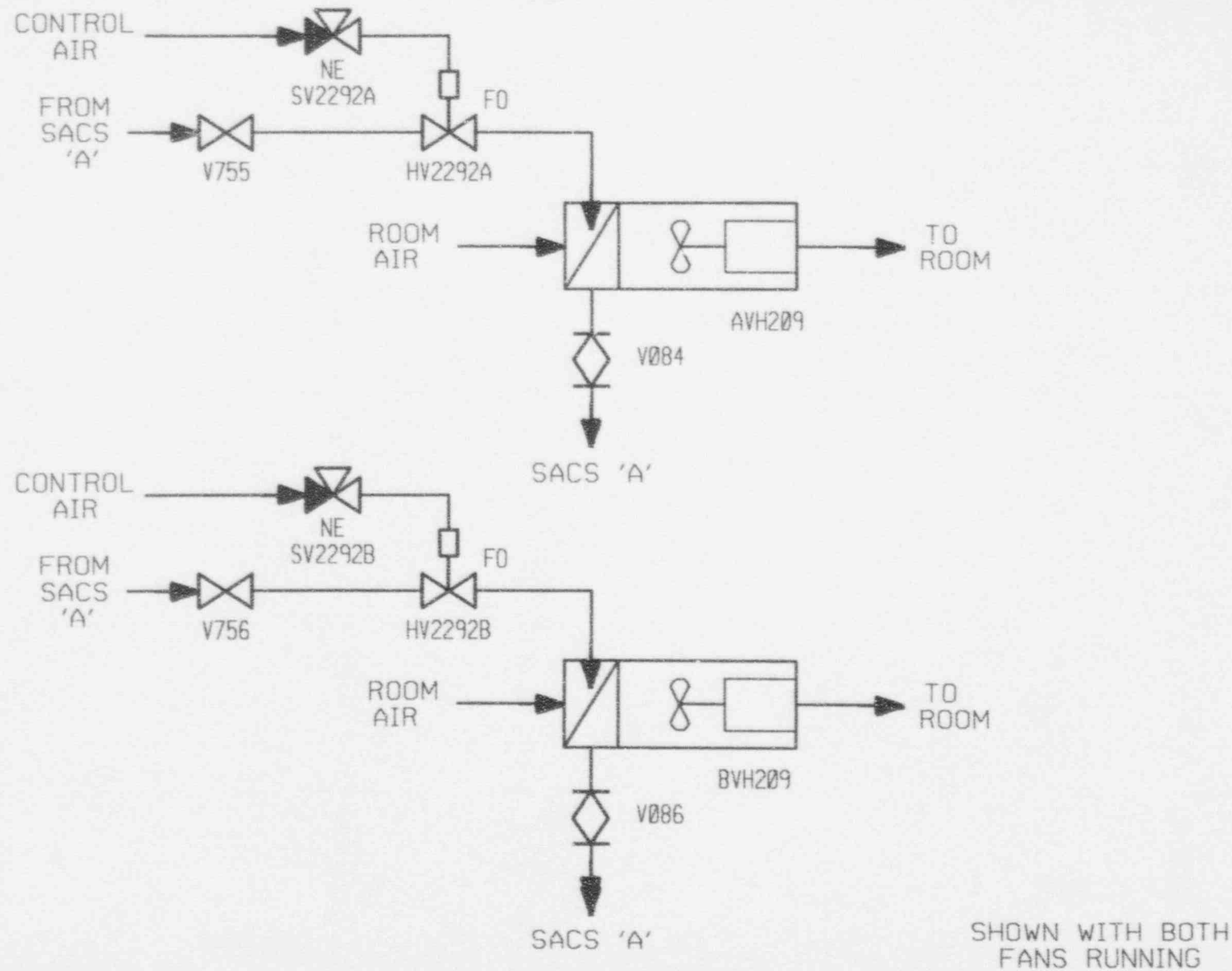


Figure 3.2-21b
HPCI Room 4111 EACS Simplified Diagram

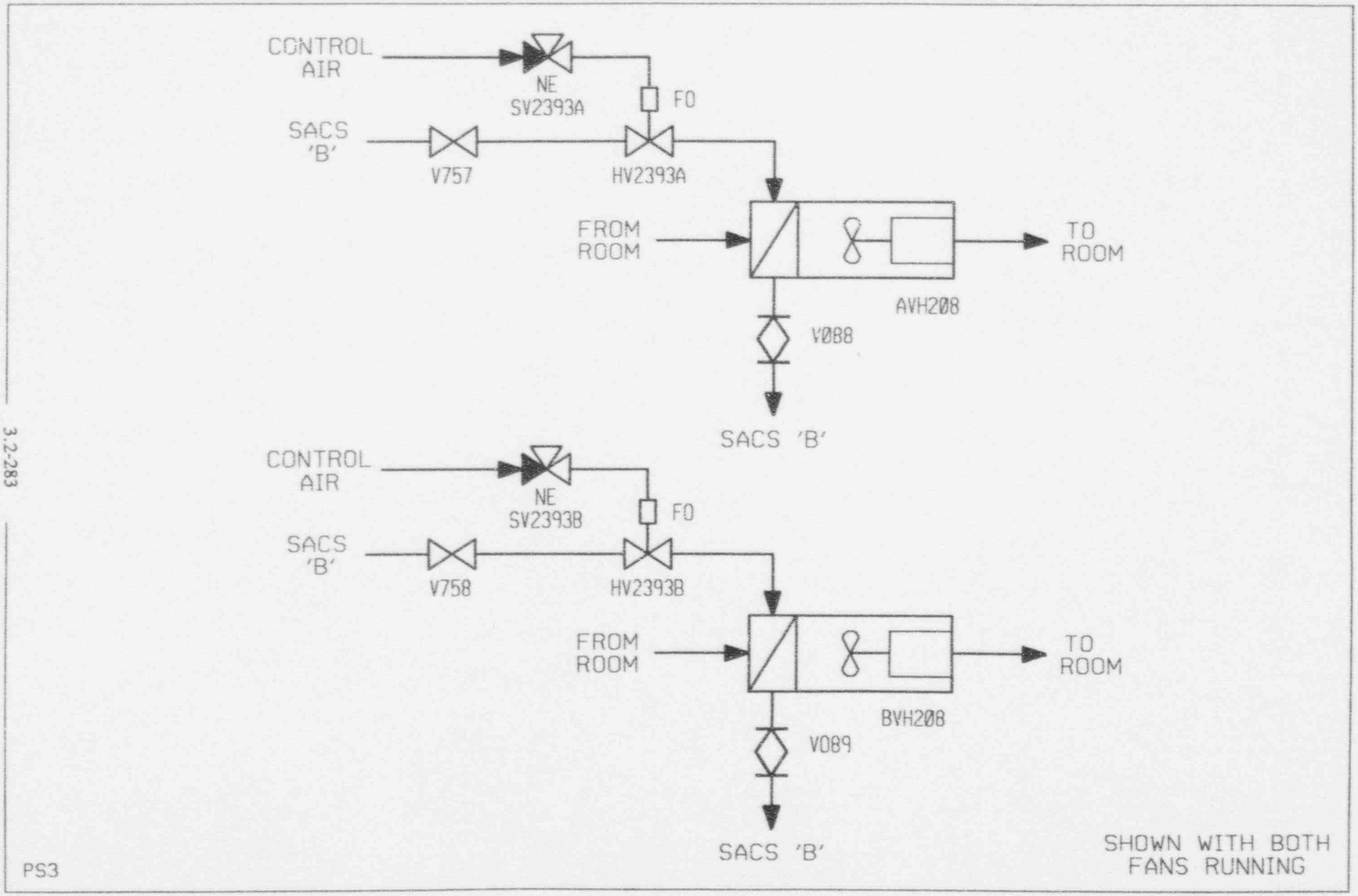


Figure 3.2-21c
RC!C Room 4110 EACS Simplified Diagram

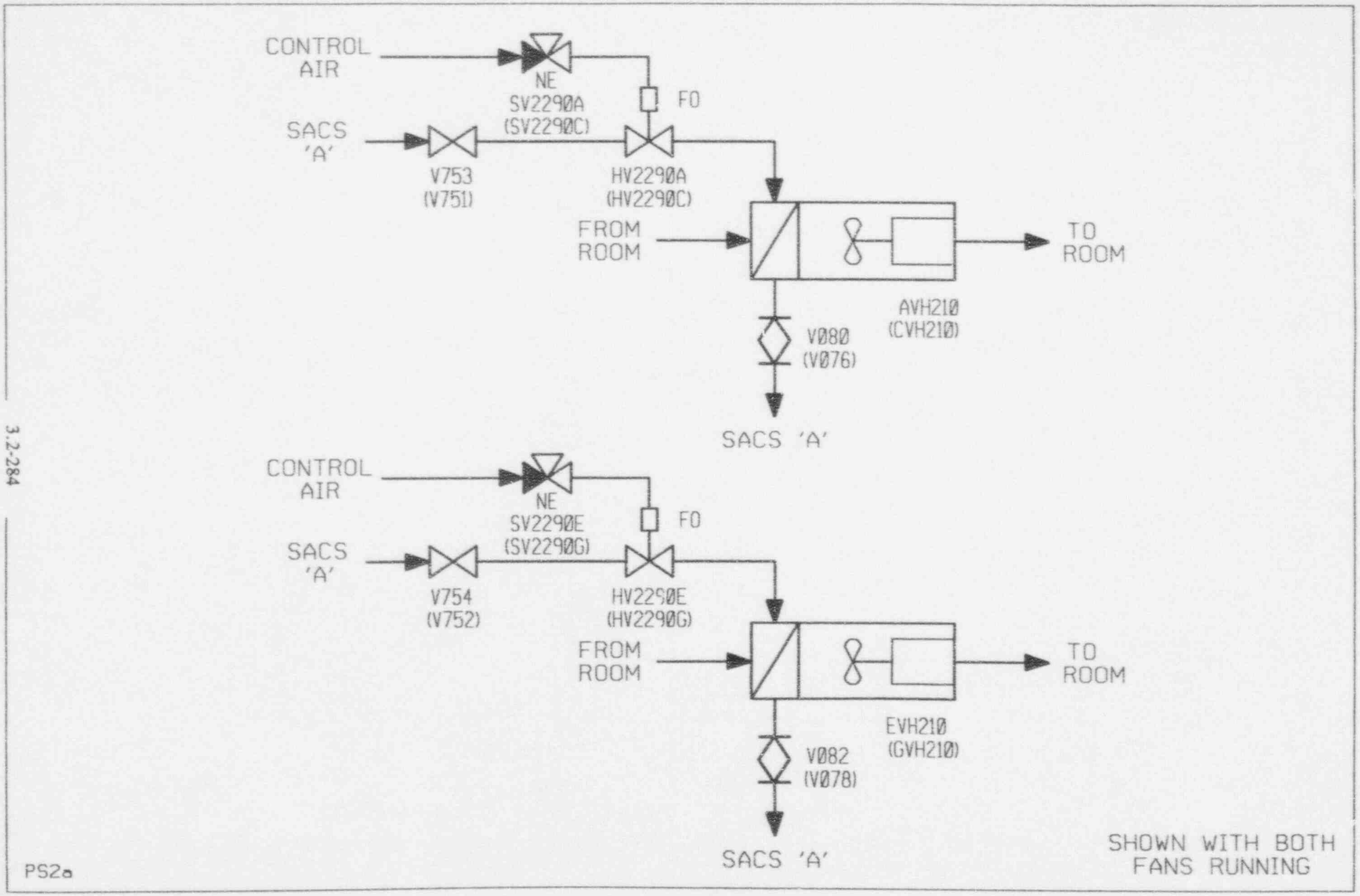
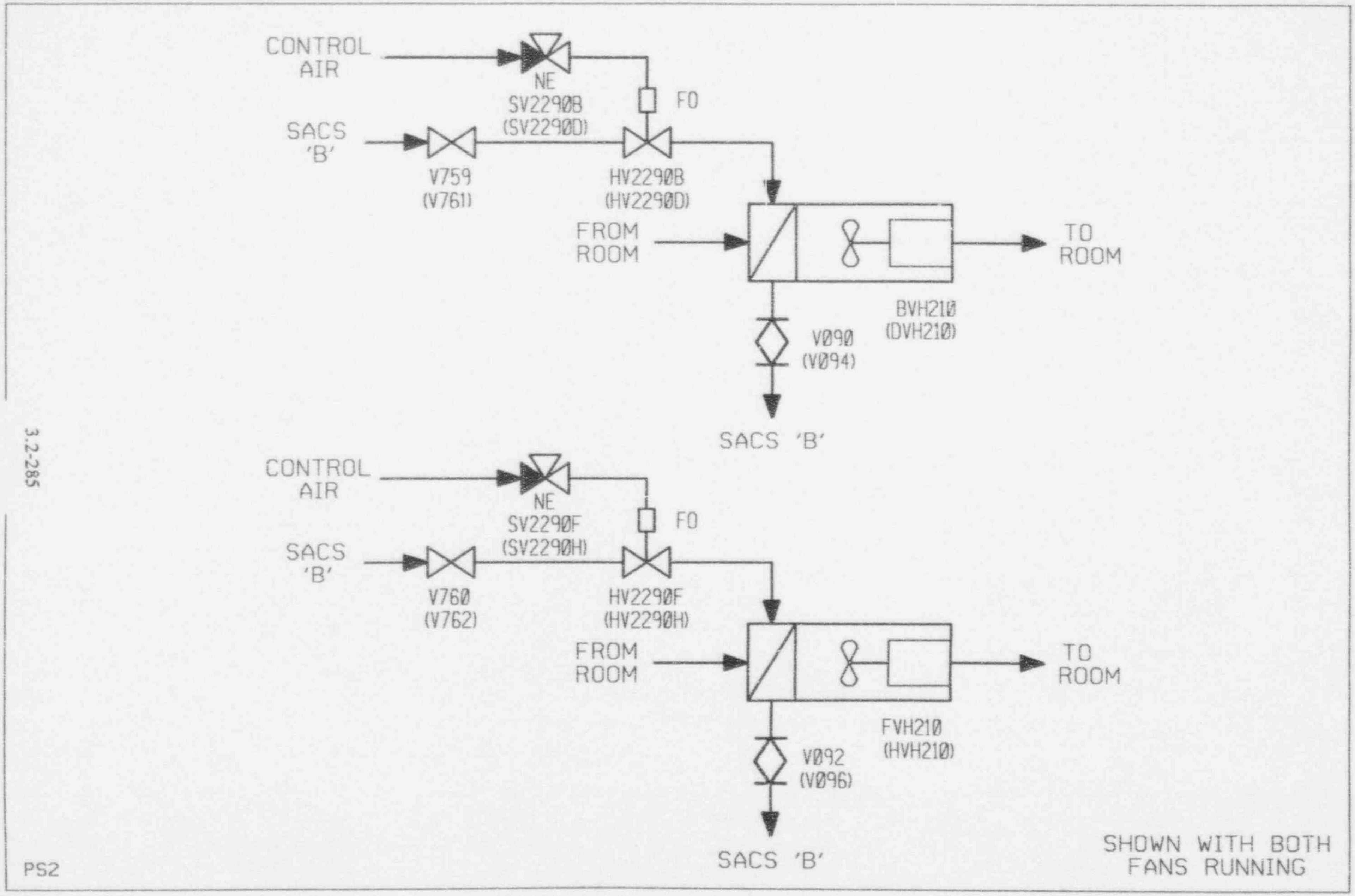


Figure 3.2-21d
RHR Room 4113 (4114) EACS Simplified Diagram



3.2-285

Figure 3.2-21e
RHR Room 4107 (4109) EACS Simplified Diagram

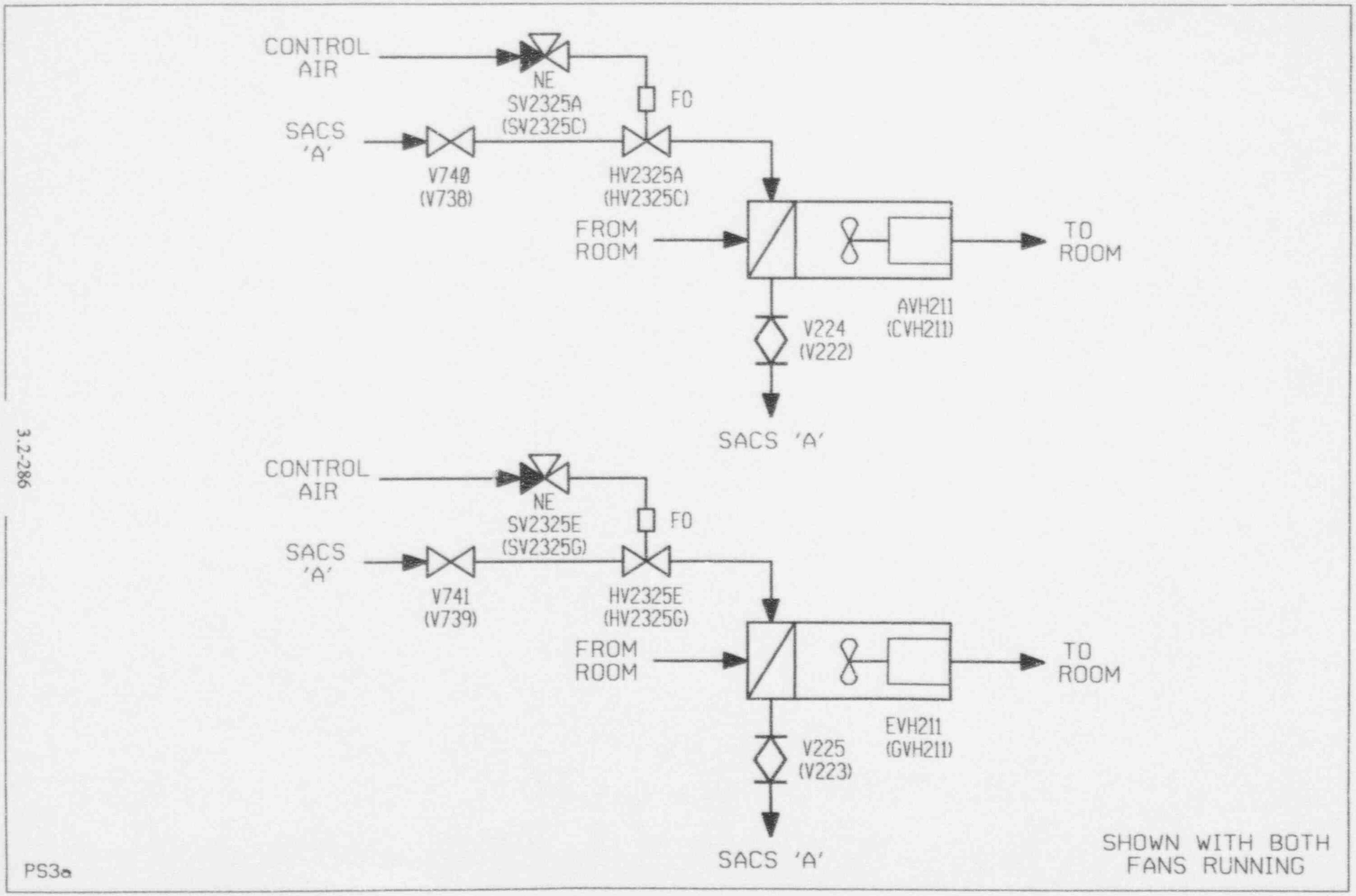
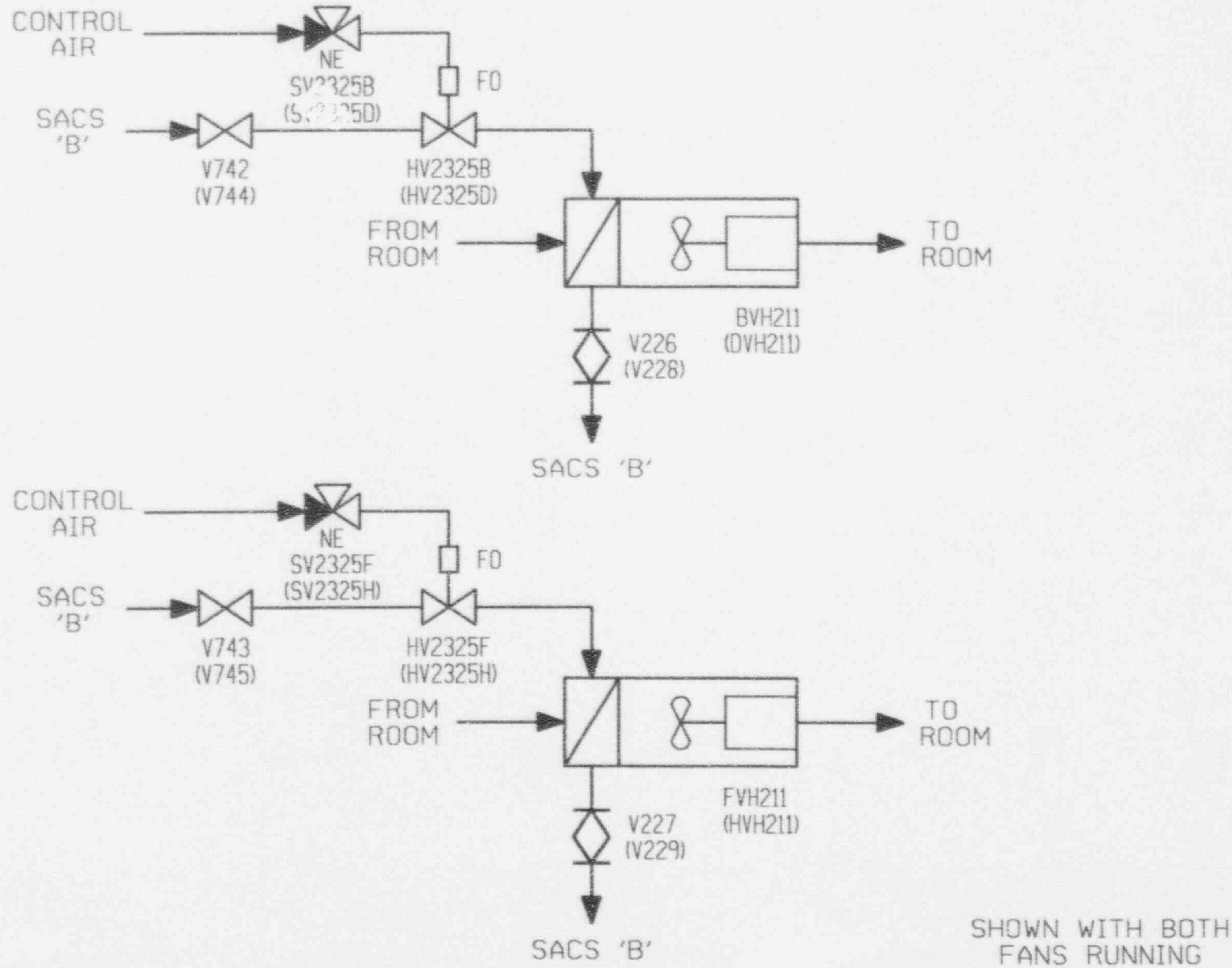
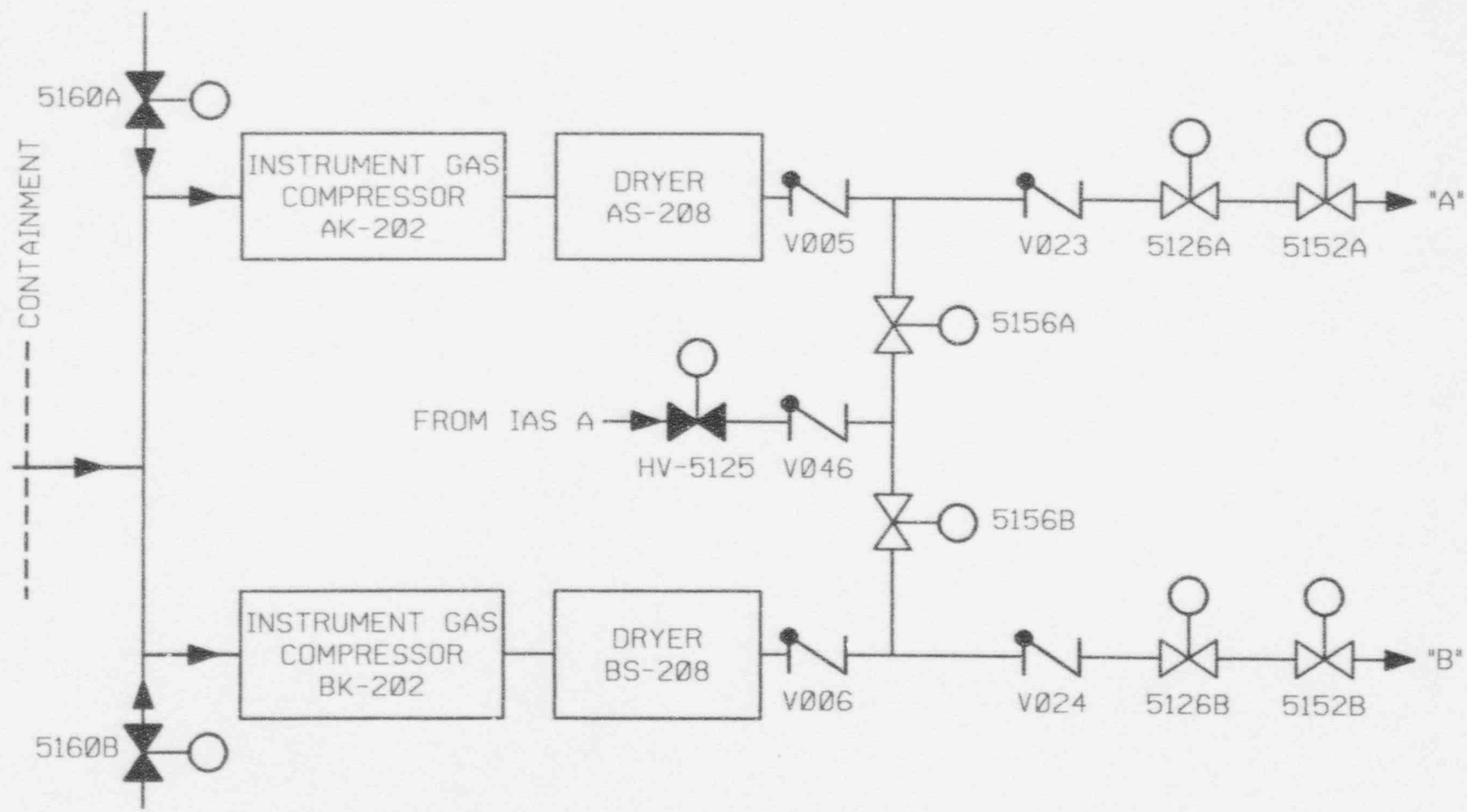


Figure 3.2-21f
Core Spray Room 4118 (4116) EACS Simplified Diagram



PS3b

Figure 3.2-21g
Core Spray Room 4104 (4105) EACS Simplified Diagram



PS1

Figure 3.2-22
Primary Containment Instrument Gas System-Simplified Diagram

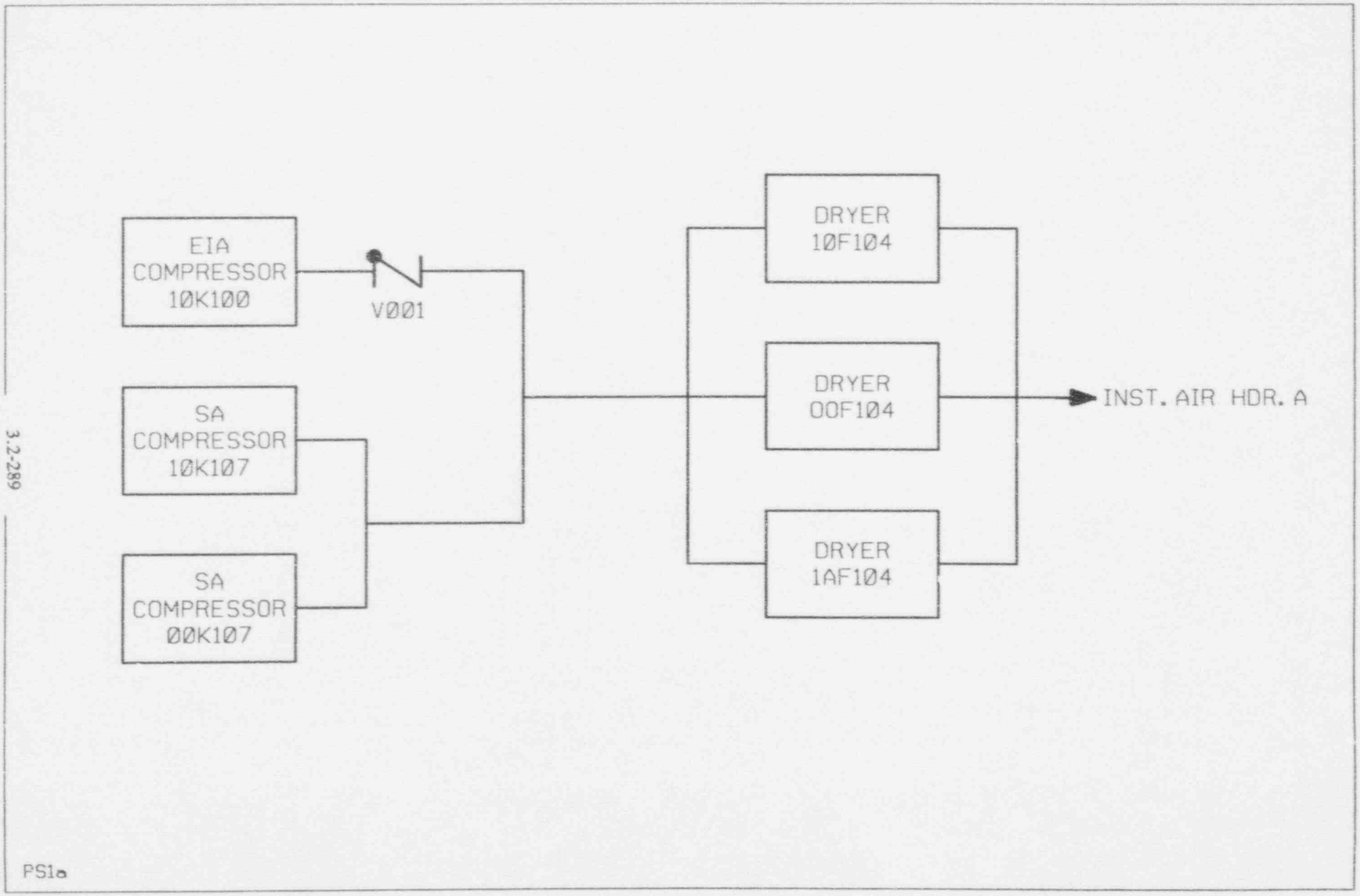


Figure 3.2-23
Instrument Air System-Simplified Diagram

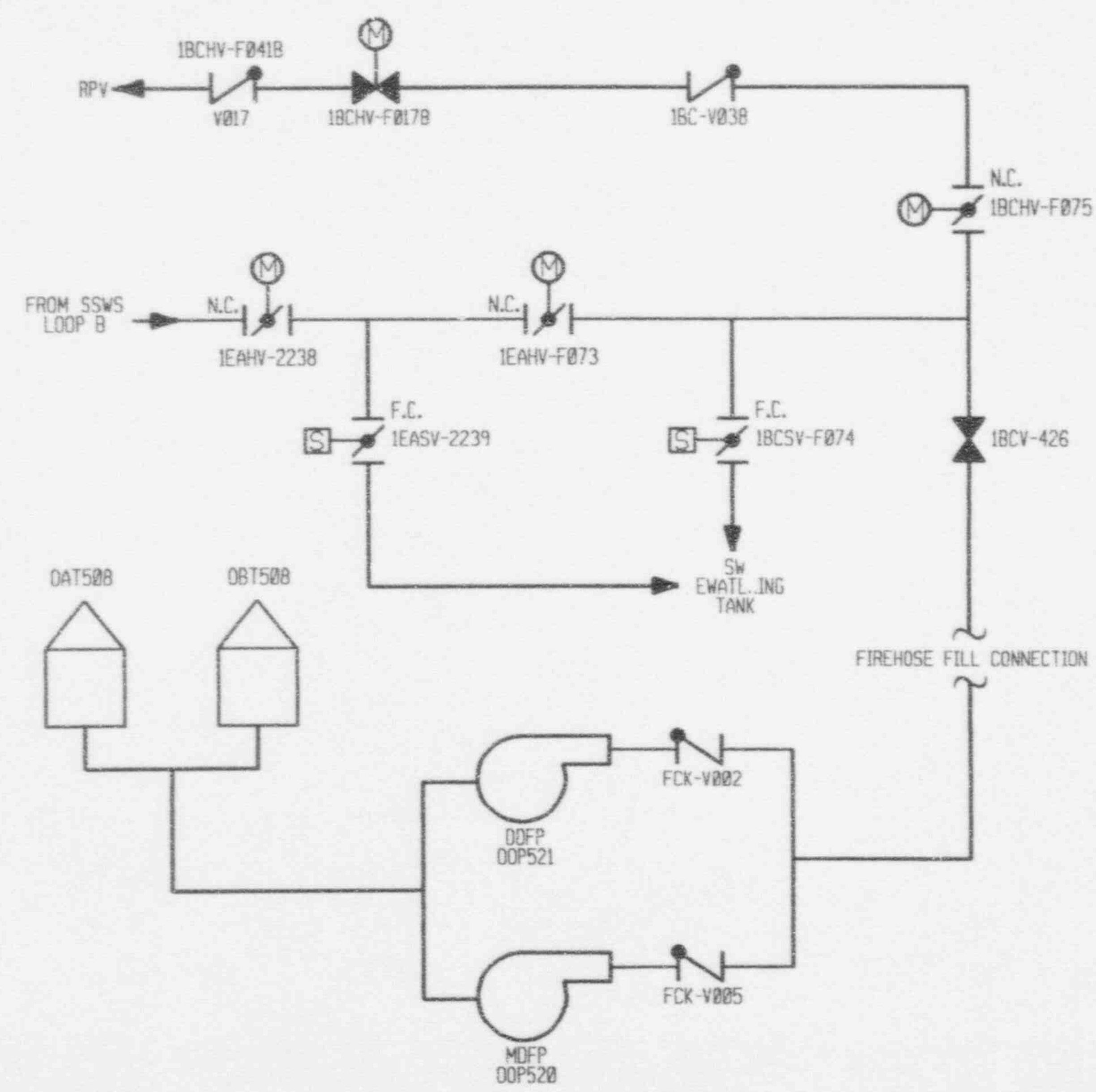


Figure 3.2-24a
Alternate Injection - Simplified Diagram

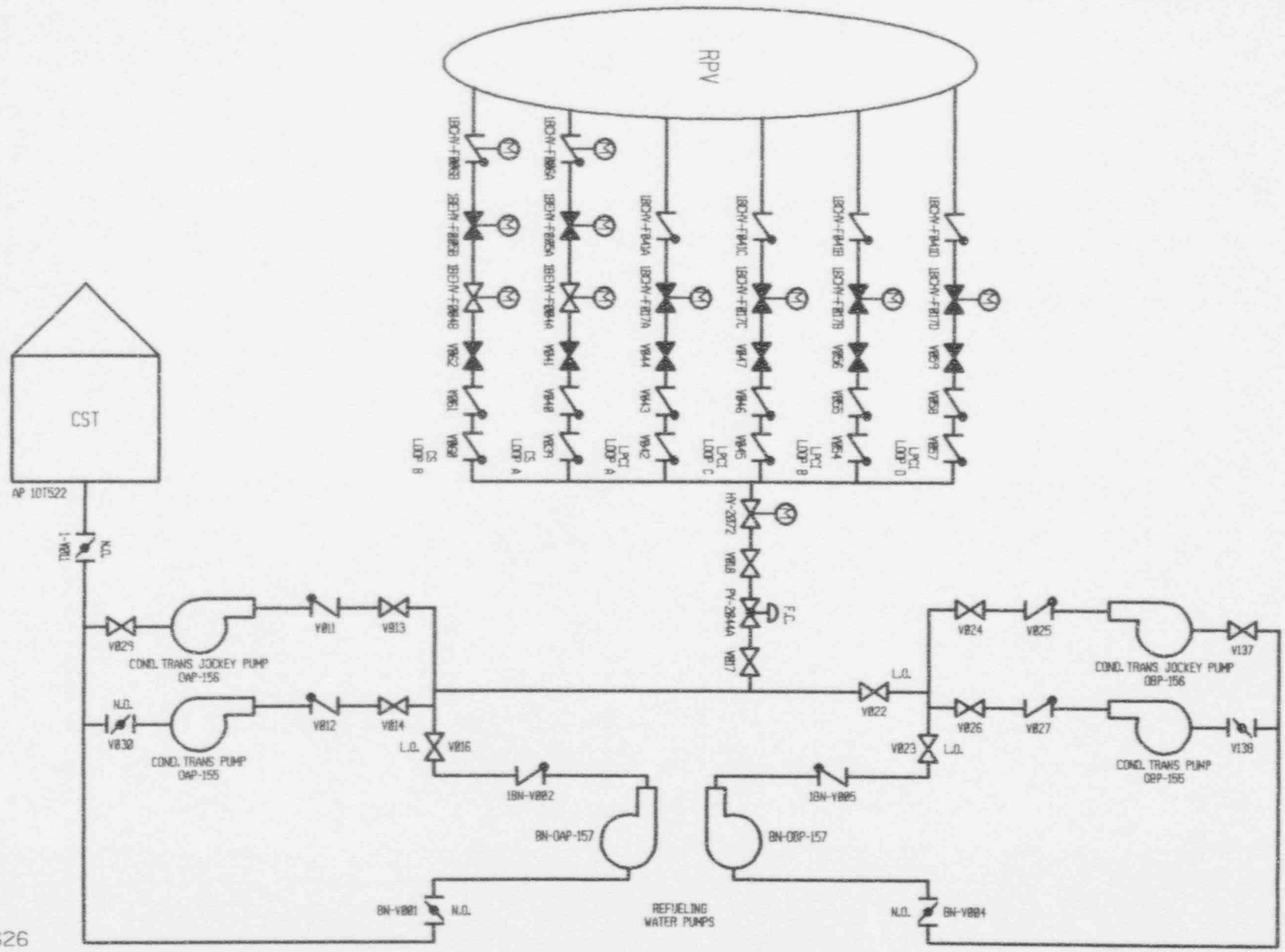


Figure 3.2-24b
Alternate Injection - Simplified Diagram

3.3 Quantification Process

3.3.1 Generic Data

The generic database used in the HCGS PRA is presented in Tables 3.3.1-1 through 3.3.1-3. The detailed development of this database is summarized in this section. A comprehensive survey of U.S. data sources (and a few foreign sources) was performed to develop the database. The resulting component failure rates (per hours or per demand) are characterized by mean and median values and a range factor. (The range factor[1] is the 95th percentile divided by the median.) The mean values were used in all calculations.

3.3.1.1 Generic Component Failure Rates

The sources of generic failure rate data (or estimates) are listed in Table 3.3.1-4.

Fault trees from various probabilistic risk assessments (PRAs) were reviewed to obtain a list of components and failure modes. The list was then expanded to include a wider range of components and failure modes in order to develop a comprehensive generic database. The resulting list was then divided into three categories:

- Mechanical Components, Water/Steam Working Fluid
- Mechanical Components, Air/Gas Working Fluid
- Electrical Components

The components and failure modes within each category were arranged in matrices included in the HCGS Level I PRA (Reference 3.3.1-1). Entries in the matrices include mean failure rates and range factors (when available). Conversions from median failure rates (indicated in some sources) to mean failure rates were accomplished assuming a lognormal distribution and a 95% confidence bound for the failure rates.[2] For primary data sources in which actual data were analyzed, the mean value was assumed to be one of the following:

- $\text{Mean} = \dfrac{\text{Number of failures}}{\text{Number of hours}}$ (for hourly failure rate)

- $\text{Mean} = \dfrac{\text{Number of failures}}{\text{Number of demands}}$ (for demand failure rate)

In instances in which a data source contained no information on a component failure mode, a dash (-) was entered into the appropriate matrix location. In cases in which the source failure

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1 $\text{RF} = \text{range factor} = \dfrac{\text{upper 95th percentile}}{\text{median}}$

2 $\text{Median} = \left\{ [\text{Mean}] \left[\exp\left(-0.5 \right) \left(\dfrac{\ln \text{RF}}{1.645} \right)^2 \right] \right\}$

rate included several different failure modes, the failure rate was listed for the uppermost included failure mode. Quotation marks (") indicate that the failure rate includes several different failure modes.

Several data sources contain information on incipient, degraded, and catastrophic failures of components (IPRDS-Valves, IPRDS-Pumps, and IEEE). IPRDS-Valves defines these types of failures as:

- **Catastrophic**. The component fails totally and fails to perform any function.

- **Degraded**. The component performance is less than its specification requirements.

- **Incipient**. The component operates within its design specifications but exhibits characteristics that indicate that degraded or catastrophic failure will eventually occur.

All failure rate information used in the front-end analysis are for catastrophic failures.

From the data matrices recommended generic component failure rates were developed. This methodology combined failure rates from basic data sources. The corresponding range factor was chosen based on the range of values listed for the specific component failure mode, and the similarity to other range factors indicated in the PRA sources. A geometric averaging technique was used to combine the failure rates from the basic sources.[3] However, only data that were applicable to the component failure mode in question were used. Cases in which a failure rate includes several failure modes were generally not included in the geometric averaging. Also, entries that represent 50% Chi-Square estimates based on zero failures were not used unless the failure rate estimates were similar to or lower than entries based on actual failures. (If the number of demands or number of hours is much less than for other data sources, the Chi-Square estimate can be overly conservative.)

For the geometric averaging technique, it was judged that median failure rates should be used. Therefore, the mean failure rate was converted to a median value assuming a lognormal distribution. For sources in which no range factors were indicated, a range factor was assumed. The range factor that was assumed was taken for the corresponding type of components. However, if the range factor from the tables was larger than 10, a range factor of 10 was assumed. This was done so that the individual source values would not be reduced by a large amount. The geometric average was assumed to represent a median value. Based on the assumed range factor and the median value, the resultant mean failure rate was determined, again assuming a lognormal distribution.

For the cases in which the failure rate is presented on a per-demand basis, hourly failure rates were converted to per-demand failure rates by assuming one demand per month. Equating the average demand failure rate to the average unavailability of a component over a 1-month test period ($0.5T_T$, where $T_T = 720$ h), the hourly standby failure rate must be multiplied by 360 hours to convert to an average demand failure rate (References 3.3.1-2 and 3.3.1-3).

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[3] $X_{ave} = (X_1 X_2 \ldots X_n)^{1/n}$

For the mechanical components processing a water/steam fluid, the following special guidelines were used:

1. Basic data sources were considered to be EPRI NP-2230, IPRDS, NPRDS, LER surveys, and the sources listed under the category entitled "Various." These sources are based directly on actual failure data.

2. If no basic source failure rates were listed for a component failure mode, then a geometric average of the other (secondary) sources was used.

3. If the resultant mean failure rate was much lower than those listed in the secondary sources, then the range factor and mean were increased, reflecting the disagreement among sources. (Increasing the range factor while treating the median as constant effectively increases the recommended mean failure rate).

The data sources for mechanical components processing an air/gas working fluid were considered to be NPRDS, IEEE, LMEC, and NPRD-2.

Finally, guidelines for the electrical components included the following:

1. Basic data sources were considered to be IEEE, LER-I&Cs, NPRD2, NPRDS, and Lyon (French).

2. If the resultant mean failure rate was much lower than those listed in the secondary sources, then the range factor and mean were increased, reflecting the disagreement among sources.

Using the above described method and guidelines, the generic component catastrophic failure rate estimates were calculated.

3.3.1.2 <u>Generic Component Maintenance and Repair Information</u>

This section deals with generic maintenance and repair assumptions. The results are generic unscheduled maintenance frequencies. (Unscheduled maintenance and repair are considered to be synonymous.)

Component repair durations were obtained from WASH-1400 and the In-Plant Reliability Data Base (IPRDS) reports (References 3.3.1-5 and 3.3.1-6). IPRDS, the Oconee PRA (Reference 3.3.1-7), the Seabrook PRA (Reference 3.3.1-8), the Shoreham PRA (Reference 3.3.1-9), and IEEE Std. 500-1984 (Reference 3.3.1-10) were used to estimate frequencies of unscheduled maintenance. It should be noted that the more recent data contained in these reports indicate significantly lower unscheduled maintenance frequencies than those listed in WASH-1400.

Generic unscheduled maintenance frequencies are divided into four categories:

- Pumps, Motors, Blowers, and Fans
- Valves and Dampers
- Other Electrical Components
- Piping

For the pump category, four sources were used to estimate an unscheduled maintenance frequency. IPRDS-Pumps indicates an average frequency of 1.7E-4/h with a range factor of approximately 25. The Oconee PRA lists three generic values: 2.8E-5/h, 8.4E-5/h, and 1.3E-4/h. Each of these frequencies has a range factor of approximately 2. Three generic values for pumps are also listed in the Seabrook PRA: 8.4E-5/h (RF = 2), 1.3E-4/h (RF = 2), and 2.2E-4/h (RF = 2.5). Finally, the Shoreham PRA indicates unscheduled maintenance frequencies, which are factors of 4 to 20 lower than WASH-1400 results. Assuming a factor of 10, the Shoreham value for pumps is then 3.0E-5/h (RF = 3). A geometric average of the four sources results in a mean frequency of approximately 8.0E-5/h. A range factor of 5 was assumed.

The same four sources were used to obtain an estimate for valve unscheduled maintenance. The IPRDS-Valves indicates a range of 3.4E-6/h to 1.82E-4/h. An average of common valve types is approximately 5.0E-5/h with a range factor of 7. Oconee and Seabrook both list 2.8E-5/h (RF = 1.4). The value for Shoreham is 3.0E-5/h (RF = 3.5), assuming a factor of 10 reduction from the WASH-1400 frequency. An average of these estimates is 3.0E-5/h. A range factor of 5 was assumed.

For electrical components, IEEE Std-500 indicates both catastrophic failure rates and failure rates for incipient and degraded behavior. A geometric average of the ratio of all modes of failure to catastrophic failure for the many types of components listed is approximately 2. Typical catastrophic failure frequencies for electrical components range from 10^{-7}/h to 10^{-5}/h. An average failure frequency is approximately 1.5E-6/h. Multiplying by 2 results in a mean unscheduled maintenance frequency of 3.0E-6/h. A range factor of 10 was assumed.

Finally, for piping, it is expected that only catastrophic failures will result in unscheduled maintenance during power operation. Therefore, a geometric average of the piping leakage frequencies is 2.6E-10/h-ft. This value was rounded up to 3.0E-10/h-ft. A range factor of 10 was assumed.

Summarizing, unscheduled maintenance (repair) frequencies are the following:

Components	M	RF
Pumps, Motors, Blowers, Fans	8.0E-5/h	5
Valves, Dampers	3.0E-5/h	5
Piping	3.0E-10/h-ft	10
Electrical Components	3.0E-6/h	10

The range factors were estimated from the sources used to determine the unscheduled maintenance frequencies. Component repair durations for two separate cases were utilized: one in which technical specification limitations require plant shutdown if the component is not repaired within a certain time limit (often 24 or 72 hours), and one in which actual repair durations apply (no technical specification limitations). For the technical specification limited case, instrumentation, trip breakers, and valves have mean repair durations of 6 hours, while pumps and diesels require approximately 20 hours. Recommended repair durations when no technical specifications apply are 40 hours for pumps, 25 hours for valves, 20 hours for diesels, and 6 hours for instrumentation and trip breakers.

3.3.1.3 Unavailability and Unreliability Expressions

Unavailability, $\overline{A}$, of a component is defined as the probability that a component fails to respond as required on demand. The failure may be the result of a previously undetected failure, a failure on demand, an outage from repair, an outage from testing, or an outage from scheduled maintenance. Unreliability, $\overline{R}$, of a component represents the probability that a component fails during a certain time duration termed the mission time (T_M), given that it was working correctly at the start of the mission.

For the purposes of calculating unavailability, components are classified as:

- Standby or operating
- Active or Passive
- Tested, Announced Failure, or No Test and No Annunciation

Combinations of the above 3 types of classifications result in 12 different categories. However, only several of the combinations are generally important for PRAs. The important combinations are described below.

Standby Component

For a standby component, failure on demand (not resulting from repair or test outage) is represented by the following:

- Q_d - active component.
- $0.5\ \lambda_s\ T_T$ - active or passive component tested regularly.
- $0.5\ \lambda_s\ T_C$ - active or passive component whose failure is not announced and which is not tested.
- $0.5\ \lambda_s\ T_A$ - active or passive component whose failure is annunciated.

The repair outage contribution to average unavailability is $\lambda_M\ t_R$.

For a standby component whose failure is unannounced and which is not tested, there is no repair outage contribution. Finally, the test outage contribution to average unavailability is t_T/T_T for all tested components.

In the above expressions, the values are defined as follows:

- Q_d = average demand failure rate.
- λ_s = standby failure rate (h^{-1}).
- T_T = test interval (h).
- T_C = replacement time of component or lifetime of plant, whichever is shorter (h).
- T_A = maximum time delay between component failure and annunciation (h).
- λ_M = Corrective maintenance (repair) frequency (h^{-1})
- t_R = Average component outage time resulting from repair (h)
- t_T = Test duration (h)

Operating Component

Whether an operating component is active or passive, it is assumed that failures are announced. Therefore, the unavailability (not resulting from repair) is 0.5 $\lambda_O t_A$, where λ_O is the failure rate when operating. The repair outage is λ_M t_R.

Unreliability Expression

Unreliability is calculated by

$$1 - e^{(-\lambda_O T_M)}$$

This expression does not allow for repair of a component during its mission time, T_M.

3.3.1.4 References

3.3.1-1 "Hope Creek Station Probabilistic Risk Assessment" Public Service Electric and Gas Company (to be published).

3.3.1-2. "Reactor Safety Study: An Assessment of Accident Risks in U.S. Commercial Nuclear Power Plants, Appendix III." Washington, D.C.: U.S. Nuclear Regulatory Commission, October 1975. NUREG 75/014 (WASH-1400).

3.3.1-3. "Interim Reliability Evaluation Program (IREP) Procedures Guide." Washington, D.C.: U.S. Nuclear Regulatory Commission, January 1983. NUREG/CR-2728.

3.3.1-4. Thomas, H. M. "Pipe and Vessel Failure Probability." Reliability Engineering, Volume 2, 1981, pp. 83-124.

3.3.1-5. "The In-Plant Reliability Data Base for Nuclear Plant Components: Interim Data Report - The Pump Component." Washington, D.C.: U.S. Nuclear Regulatory Commission, December 1982. NUREG/CR-2886.

3.3.1-6. "The In-Plant Reliability Data Base for Nuclear Plant Components: Interim Data Report - The Valve Component." Washington, D.C.: U.S. Nuclear Regulatory Commission, December 1983. NUREG/CR-3154.

3.3.1-7. "Oconee PRA: Probabilistic Risk Assessment of Oconee Unit 3." Palo Alto, California: The Nuclear Safety Analysis Center, Electric Power Research Institute, June 1984. NSAC-60.

3.3.1-8. "Seabrook Station Probabilistic Safety Assessment." Manchester, New Hampshire: Public Service Company of New Hampshire, December 1983.

3.3.1-9. "Probabilistic Risk Assessment, Shoreham Nuclear Power Station." Hicksville, New York: Long Island Lighting Company, June 1983.

3.3.1-10. "IEEE Guide to the Collection and Presentation of Electrical, Electronic, Sensing Component, and Mechanical Equipment Reliability Data for Nuclear Power Generating Stations." New York, New York: The Institute of Electrical and Electronics Engineers, Inc., 1983. IEEE Std. 500-1984.

3.3.1-11. "Analysis of Core Damage Frequency From Internal Events: Peach Bottom Unit 2." Washington, D.C.: U.S. Nuclear Regulatory Commission, October 1986. NUREG/CR-4550, Vol. 4.

3.3.2 Plant-Specific Data and Analysis

The HCGS was intially critical on June 28, 1986 and began commercial operation on December 20, 1986, and plant-specific failure rate information was used for what were considered to be potentially the most important events contributing to core damage. Plant-specific data from 1987 through July 1993 were collected for the following events modeled in the fault trees:

1. Testing and maintenance outages for most systems modeled

2. Pump failures to start for most systems modeled

3. Diesel generator failures to start

In addition, all events were examined that were reported to the Nuclear Plant Reliability Data System (NPRDS) (Reference 3.3.2-1) for systems modeled in the PRA. This review was performed to identify any problem components. Detailed plant-specific data information is presented in Reference 3.3.2-6 Section D, HCGS Specific Data Collection.

3.3.2.1 Test And Maintenance Outage Data

The first stage of the testing and maintenance (TM) outage information was obtained by examining the limiting conditions for operation (LCO) reports for each system. The LCOs were examined for events which truly disabled a system, train, or component while the unit was in Op Con 1 or 2 (power operation or startup). Each outage was evaluated as to its effect on a system; i.e., was the entire system disabled or was only a train or loop disabled?

Testing and maintenance unavailabilities for the systems and trains (if applicable) were calculated by dividing the total testing and maintenance outage time by the total unit hours in Op Con 1 or 2. The results are presented in Tables 3.3.2-1 and 3.3.2-2. The primary data sources were the HCGS System Engineering logs and the Reliability and Assessment group data system.

3.3.2.2 HCGS - Specific Component Failure Data

The first stage of the HCGS-specific component failure data collection task scope was influenced by the following factors:

1. HCGS component failures submitted to the Nuclear Plant Reliability Data System (NPRDS).

2. Availability of information concerning the number of demands and operating hours for components.

3. Significance of components modeled in the system fault trees.

The most complete data for the HCGS are of components which are reportable to NPRDS (Reference 3.3.2-2), and components whose changes of state are reported in the control room logs. This information was available for most pumps modeled in the system fault trees, the safety relief valves (SRVs), the control room emergency filters, and emergency diesel generators. Therefore, these components were covered in the data collection task. In addition, events reported to NPRDS were examined, by system, to identify any outlier components (components whose failure rates may be significantly higher than the industry average). Any such events were also included in the data collection task.

For components which must change state upon demand (start, stop, open or close), both the number of failures and the number of demands (or hours during which the demand could occur) are needed. The numbers of failures were obtained from NPRDS. Only those events which represent actual component failures as modeled in the system fault trees were counted. The numbers of demands were obtained by a review of the daily control room logs.

Data for one specific component type was obtained from another source. The emergency diesel generator failures to start were obtained from the quarterly diesel performance reports which were sent to INPO.

Given component failure data, there exist several methods for evaluating failure rates. For component failures to start, open, or close, six representative methods are listed below:

1. Plant-specific failure upon demand estimate, obtained by dividing the number of failures by the number of demands.

2. Bayesian update of the generic estimate, based on the demand model (Reference 3.3.2-3).

3. Plant-specific failure per hour estimate, assuming all failures are purely time-related (Reference 3.3.2-4).

4. Bayesian update of the generic estimate, based on the time-related model (Reference 3.3.2-3).

5. A 50 percent Chi-square calculation, based on the number of failures and number of demands.

6. Institute of Nuclear Power Operations (INPO) modified time-related methodology (Reference 3.3.2-5). (The INPO methodology counts as inoperable hours one-half of the time between a component failure and its last successful demand.)

The Bayesian methodology utilized was a single-stage update of generic failure rates in Tables 3.3.1-1 through 3.3.1-3. In two cases a 50 percent Chi-square calculation was used. This methodology is explained in detail in Reference 3.3.2-6.

The purely demand-related model (methodology 1) results in unavailabilities twice as large as those from the purely time-related model (methodology 3). (In general, failure data are often not detailed enough to determine which failures are time-related and which are demand-related.) Also, the Bayesian update models (methodologies 2 and 4) result in estimates lying somewhere between the plant-specific (methodologies 1 and 3) and generic estimates (Tables 3.3.1-1 through 3.3.1-3). The 50 percent Chi-square calculation (methodology 5) is used for cases with little failure data. Finally, the INPO methodology can result in estimates ranging from higher than the demand estimates (methodology 1) to lower than the time-related estimates (methodology 3). However, if demands occur uniformly over time, then the INPO methodology is equivalent to the purely time-related model (methodology 3).

Based on historical usage and conservatism, the demand-related methods were chosen over the time-related methods. Both (methodologies 1 and 2) were calculated. However, the Bayesian update (methodology 2) and Chi-square calculation (methodology 5) were chosen for use in the HCGS PRA. The resulting component failure data and unavailabilities are shown in Table 3.3.2-1, 3.3.2-2, and 3.3.2-3.

3.3.2.3 References

3.3.2-1. "Nuclear Plant Reliability Data System." Atlanta, Georgia: Institute of Nuclear Power Operations (Ongoing program of data collection).

3.3.2-2. "Nuclear Plant Reliability Data System (NPRDS) Reportable System and Component Scope Manual for Westinghouse Pressurized Water Reactors." Atlanta, Georgia: The Institute of Nuclear Power Operations, 1983.

3.3.2-3. "Oconee PRA." Palo Alto, California: Electric Power Research Institute, Nuclear Safety Analysis Center, June 1984. NSAC-60.

3.3.2-4. "Probabilistic Safety Analysis Procedures Guide." Washington, D.C.: U.S. Nuclear Regulatory Commission, August 1985. NUREG/CR-2815.

3.3.2-5. "Safety System Unavailability Monitoring." Atlanta, Georgia: Institute of Nuclear Power Operations, August 1986. INPO 86-021.

3.3.2-6. "Hope Creek Generating Station Probabilistic Risk Assessment" Public Service Electric And Gas Company (to be published).

3.3.3 Human Reliability Analysis

3.3.3.1 Introduction

The human reliability analysis (HRA) task of the Hope Creek Generating Station (HCGS) Individual Plant Examination (IPE) involves the identification, modeling, and quantification of human actions affecting core damage sequences. The HRA task interacts with four other IPE tasks: event tree development, fault tree development, dependent failure analysis, and external and spatially dependent internal event analyses. The HRA task also includes interactions with plant operations and training personnel. The outputs of the HRA task are probabilities for all human actions contained in the plant models, models for accident sequence recovery, and documentation for the detailed assessments. The results are input to the accident sequence (core damage) quantification task.

The HCGS HRA was divided into two subtasks: analysis of human errors before an accident (pre-initiator), and analysis of human errors during an accident (post-initiator). Pre-initiator (Type A) HRA addresses operator actions to manually start or align components following test and maintenance. These actions are modeled in the system fault trees. Post-initiator (Type C) HRA addresses operator actions to initiate standby systems given a demand as modeled in fault trees, top events representing operator system selection choices in the event trees, and recovery events applied to the event sequence cutsets. Operator actions which result in a plant trip or other initiating event (Type B) were accounted for in the initiator event frequency instead of developing a detailed HRA. The Type A and C human action models are discussed in the following sections.

The HCGS HRA tasks used the following primary references for methods and data:

1. Handbook of Human Reliability Analysis With Emphasis on Nuclear Power Plant Operations (Reference 3.3.3-1).

2. Systematic Human Action Reliability Procedure (SHARP) (Reference 3.3.3-2).

3. Post Event Human Decision Errors· Operator Action Tree/Time Reliability Correlation (Reference 3.3.3-3).

4. Risk Methods Integration and Evaluation Program (RMIEP) Methods Development: A Data-Based Method for Including Recovery Actions in PRA, Vol.: Development for the Data-Based Methodology and Vol. 2: Application of the Data-Based Method (Reference 3.3.3-4).

5. Analysis of Core Damage Frequency From Internal Events: Surry, Unit 1 (Reference 3.3.3-5).

6. Analysis of Core Damage Frequency From Internal Events: Sequoyah, Unit 1 (Reference 3.3 3-6).

7. Accident Sequence Evaluation Program Human Reliability Analysis Procedure (Reference 3.3.3-7).

8. A Human Reliability Analysis Approach Using Measurements For IPE (Reference 3.3.3-8)

All human error event quantifications included an initial screening assessment. Dominant human interactions revealed during the accident sequence quantification were reevaluated using a more detailed assessment. The screening methodologies for various types of human errors are described in Sections 3.3.3.2 and 3.3.3.3. Human error events reevaluated because of their initial dominance are described in Section 3.3.3.4. Plant specific information and data developed to support the HRA are described in Section 3.3.3.5. This includes walkdowns, simulator observations and discussions with HCGS operations staff.

3.3.3.2 HRA Methodology for Pre-Initiator Tasks

Pre-accident human errors modeled in the HCGS IPE are those related to the tasks of testing and maintenance. Errors in performing these tasks include miscalibration of sensors and failure to restore components following a test or maintenance. Errors during maintenance that result in degraded component performance or component failure are implicitly contained in the generic and plant-specific component failure rates. Errors of commission, such as inadvertently mispositioning or disabling a component outside of the planned testing and maintenance, are excluded from the explicit analysis. Such errors are difficult to qualitatively describe and have not been explicitly modeled in many PRAs. However, in the HCGS IPE, errors of commission are considered to a degree in the quantitative models by using the recommended NUREG/CR-4772 values for basic events whose values are sufficiently conservative to include errors of commission. Furthermore, the assignment of data for initiating events and dependent failures includes Type B errors that trigger an initiating event caused by errors of commission. This type of error has occurred at commercial nuclear power plants.

The methods used to assess pre-initiator operator actions are consistent with the NUREG/CR-4772 and the NUREG/CR-4550 studies. The pre-initiator operator actions modeled focused on restoration and miscalibration errors. Valves in each standby system were evaluated to determine whether a restoration error could result in partial or total failure of the system to perform its required function.

Miscalibration and restoration errors were quantified using the Handbook of Human Reliability With Emphasis on Nuclear Power Plant Operations and the Technique for Human Error Rate Prediction (THERP). Plant-specific calibration and restoration (following maintenance) procedures were examined to ensure technical accuracy of plant-specific models. Table 3.3.3-1 presents the conditions and procedures associated with calibration at the HCGS. Tables 3.3.3-2 and 3.3.3-3 show the THERP model of miscalibration used for the HCGS calculations. Table 3.3.3-4 presents the conditions and procedures associated with maintenance and restoration at the HCGS. Table 3.3.3-5 shows the THERP model for restoration errors following test or maintenance used for the HCGS calculations. The results (rounded off to multiples of 1, 3, and 5) indicate a miscalibration error rate of 3.0E-3 per calibration and a restoration error rate or 5.0E-3 per test or maintenance. Dependent miscalibration of two instruments was assigned a probability of 5.0E-4, while dependent miscalibration of three instruments was assigned 3.0E-4. Dependent restoration errors are contributors to the beta and gamma factors discussed in Section 3.3.4.

Human Error Probabilities (HEPs) developed with THERP models were used in the following equation to determine the component unavailability, UA, due to miscalibration or restoration:

$$UA = (HEP)(FDT)/(INT)$$

where

HEP = miscalibration (or restoration) error probability,
FDT = fault duration time before detection, and
INT = interval between calibrations (test or maintenance).

As indicated in the fault tree development guidelines, restoration error events were not modeled for components that automatically realign upon demand, which must be tested upon completion of the maintenance, or which are not affected by maintenance. In addition, misalignments that would be noticed on a shift basis, daily, or would be annunciated, were not modeled.

Miscalibration errors modeled in the fault trees include the letters MC in the seventh and eighth position in the event names. Restoration errors were denoted by RE. A list of all miscalibration and restoration errors is presented in Table 3.3.3-6.

3.3.3.3 Post-Initiator Human Actions

The post-initiator HRA assessments deal with activities performed by crews during and after the occurrence of an abnormal event. Such activities are usually related to maintaining or controlling a critical safety function. Once a symptom or limit that triggers an Emergency Operating Procedure (EOP) response is detected, the control room crews respond by following the logic of parallel paths within the symptom-based 100 Series and 200 Series EOP flow charts. For example, if a symptom, such as a leak is identified, the crew can isolate the leak using available valves that specifically address the condition without diagnosing the cause. A distinction has been made between the detection-planning phase and the action phase for post-initiator tasks to allow for separate examination during the HRA. Tasks of detection and planning involve problem solving and decision making supported by the EOPs, while action tasks tend to involve physical performance according to a specified procedure (e.g., 300 Series EOPs). Both parts of the post-initiator actions use time under time limited conditions.

The HRA for post-initiator tasks also takes into account the impact of Performance Shaping Factors (PSFs) on the HEPs. These include the effects of task complexity, practice, the use of well-developed EOPs, the type of action (dynamic or step-by-step) and the amount of stress (moderate or extremely high stress). Consideration of such factors in the HRA greatly increases the plant specific validity of the estimated HEPs.

The HEP estimates must also consider the range of the HEP or uncertainty. There are numerous reasons to consider uncertainty in the assessment, including the effects of different crews, and even differences in individual behavior from day to day. Therefore, each estimated HEP is assumed to represent the median value of a lognormal distribution.

Although the lognormal distribution is recommended, as discussed in Chapter 7 of NUREG/CR-1278 (Reference 3.3.3-1), and Chapter 2 of NUREG/CR-4722, (Reference 3.3.3-7), other distributions could be applied. For PRA work, it is convenient to assume a lognormal distribution to represent the uncertainty. The shape of the lognormal distribution can be determined by two parameters such as the median and the Uncertainty Bound (UCB) to reflect uncertainty range in the HEP. The UCB is the square root of the ratio of the 95th percentile to the 5th percentile of the lognormal distribution. These distributions are easily integrated with lognormal distributions for component failure probabilities.

The UCB of the lognormal distribution is assigned according to the guidelines in NUREG/CR-4772 to capture the range of variability of people and conditions being modeled, as well as the uncertainty of the analyst in assigning HEPs to a task. Therefore, the use of HCGS HRA procedure tends to err on the conservative side and indicates the degree of uncertainty in each HEP estimate. Published collections of data on human performance help verify the ranges of uncertainty in the human reliability estimates.

A process of four phases was used to integrate the post-initiator operator actions into accident sequences. The process is in accordance with NUREG/CR-4772. The NUREG/CR-4772 procedure formally uses a screening approach and a nominal analysis. A simplified and more conservative screening approach was substituted for the NUREG/CR-4772 screening approach. This approach is discussed further.

Phase 1 Identify the operator action to be modeled. Key operator actions that could have an impact on the consequences of an event sequence were identified using three modeling methods. The methods for identification are described in the following sections on constructing fault trees (3.3.3.3.1), and for cutset recoveries (3.3.3.3.2). In general, procedures for system operating (SO), emergency operating (EO), abnormal operating (AB), and alarm response (AR) procedures were used to identify and group human actions. Each method provides a unique focus on key recovery tasks given the conditions of the accident sequence or cutset.

Phase 2 Screening of the key operator actions. For quantification of post-initiator operator actions a simple, conservative screening analysis was used. The purpose of the screening analysis was to reduce the effort expended on actions that do not have significant impact on plant risk and avoid the loss of cutsets with multiple human actions that could be dependent. To effectively use the plant model which consists of event trees and fault trees, and to evaluate recovery actions, initial screening was quantified with all post-initiator actions identified in the initial models set to 1.0. By first assigning 1.0 to each HEP, it was possible to see all combinations of operator actions to ensure that all dependencies of operator actions were known. However, in examining the results (cutsets) from this screening analysis, there were an unmanageable number of cutsets which would all drop below the reporting screening criteria described in Section 3.4.1 once the recovery actions were applied.

Therefore, the next step was to assign a new screening value of 0.1 for all post-accident HEPs. This resulted in many cutsets with 1 to 3 human actions combined with several equipment failures. The value of each of those actions was then assigned a probability of 1.0 to allow the recovery methodology described below to be used. The resulting cutsets were examined, and if the recovery actions were separate in time, then the screening process outlined in the NUREG/CR-4772 reference was used. For example, if the first recovery action in a cutset was based on a detailed quantification, then the second action was included in the quantification by multiplying the greater of either the detailed HEP assessment for the second action or .03 as recommended for screening in the NUREG/CR-4772 reference. If a third action was identified, a HEP of 0.1 was assigned (or detailed assessment HEP, if greater). This process accounts for human action dependencies during the sequence quantification.

Operator actions that only appeared in cutsets lower than 1.0E-7/yr or less were left in the fault tree models at the screening value of 1.0, without further evaluation. Operator actions that appeared in cutsets greater than 1.0E-7/yr were evaluated further using refined estimates. Sequences with no operator action modeled with a probability greater than 1.0E-7 were examined to identify potential recovery actions.

The detailed assessment started with recommended HEP values from NUREG/CR-4772 for those operator actions that were not screened out and required further analysis. Operator action summary sheets were developed to fully describe the operator action and the surrounding circumstances. This approach allowed plant specific simulator observations to be incorporated into the quantification process.

Phase 3 Quantification of the remaining HRA events. The events not screened out were quantified using NUREG/CR-4772 data for slips (P3) and mistakes (P1). For non-responses (P2), the simulator based model in Reference 3.3.3-8 was substituted for the fixed time curves in NUREG/CR-4772. This model supports incorporation of generic and plant specific information into the assessments. The time available for the operator to respond was determined primarily by a combination of severe accident codes (MAAP), and simulator observations without operator actions under specified conditions. This accounted for combinations of working and inoperative control systems. The transient information was used to estimate the time to core uncovery, conditions for actions to protect the suppression pool, and construction of timing information for cutset analysis. Finally, the three estimates for detection errors (P1), non-response (P2) and post-initiator action errors (P3) were "merged into a human basic event" HEP with the UCB assigned as recommended in NUREG/CR-4772.

In cases where multiple operator actions appeared in the same cutset, the actions were evaluated as a whole to determine the possible courses of actions that the control room crew would take. This evaluation included discussions with operators, comparison with emergency operating instructions, and knowledge gained from observing simulator scenarios. The resulting recovery action (HEP) is assumed to represent the error probability for the most likely actions to be taken. The multiple tasks in each cutset are quantified and merged to form the probability of failing to successfully complete the human recovery event considering the dependency assessment methods in NUREG/CR-4772.

Phase 4 Requantify plant model and evaluate additional operator actions. The results of the event tree quantification were recalculated using a combination of screening and detailed HEPs. Again the core damage cutsets were ranked by probability. The highest cutsets were again reviewed to identify additional operator actions. These actions were reevaluated and quantified. This process of identification, evaluation and requantification of plant models was a continuous and iterative process. Each refined calculation was documented to describe the scenario and circumstances surrounding the operator action.

3.3.3.3.1 Post-Initiator Tasks Modeled in Fault Trees

Operator actions modeled in the system fault trees include manual operation or alignment of components that must be manually initiated and controlled or backup automatic operation. Such actions must be clearly addressed in the operating procedures to be included in the system fault tree models. The screening quantification of these types of errors included assessments with HEPs of 1.0, and 0.1 (as described previously).

A list of operator errors modeled in the system fault trees is presented in Table 3.3.3-7.

3.3.3.3.2 Recovery Actions Applied to Sequence Cut Sets

Recovery actions were applied in transients, ATWS events, and to the longer-term events such as loss of decay heat removal. Recovery was not applied to intermediate and large loss of coolant accidents. If several recovery actions were applicable to a cutset, then the action with the lowest unavailability was applied. In some cases, more than one recovery action was applied to a cutset, depending on the time allowed, if the actions could be considered independent.

The refined recovery actions were quantified by the process described in Section 3.3.3.4 to replace combined human actions that were screening values ranging from 1.0 to the values in Table 3.3.3-8. Resulting HEPs were compared with other assessments of similar actions described in other PRA studies. These recovery actions vary in complexity, ranging from manual operation of equipment to opening doors to promote circulation, if heating, ventilating, and air conditioning (HVAC) systems fail. These recovery actions are typically cutset dependent. Therefore, they were applied at the cutset level after the initial sequence cutsets had been grouped into similar accident sequences.

3.3.3.4 Refined Human Error Analysis

Operator actions that proved to be dominant during accident sequence quantification often required further analysis by means of a refined, or nominal, HRA. The refined analysis for one action resulted in criteria for a new procedure. The assessment helped prioritize alternate recovery strategies.

The refined HRA was performed in accordance with the NUREG/CR-4772 analysis procedure and the time dependent model and data developed in Reference 3.3.3-8. These methods also benefit from the data reported in NUREG/CR-4873 (Reference 3.3.3-4). The refined assessment reduced conservatism introduced through HRA screening, and identified specific actions that are important for maintaining the risk at the expected level. HRA quantification steps for the detailed analysis are:

Step 1 Define recovery actions that decrease a sequence below 1E-7/yr whose screening value is less than 0.1 for a cutset. This includes the combination of all recovery actions modeled in the fault trees and non-recovery actions that result from the examination of the information contained in the cutset. Use the qualitative insights from simulator observations to define the nature of the recovery actions.

Step 2 For the recovery actions that are not included in the fault trees, apply the appropriate recovery action identifier to the cutset.

Step 3 Starting with the Basic HEPs for errors of omission and commission in NUREG/CR-4772 (treated as slips - errors in actions P1 and mistakes - errors in diagnosis P3 in Reference 3.3.3-8), apply the PSFs for procedures, practice, feedback, interface designs, stress and task complexity.

P1 = PSFs1*HEPo (NUREG/CR-4772)

P3 = PSFs3*HEPc (NUREG/CR-4772)

Step 4 Estimate the time dependent part of the non-recovery probability by first determining the times for action and the system time allowed. These times can be determined from thermal-hydraulic calculations, simulator observations, experienced events, or expert judgment as recommended in NUREG/CR-4772. Specifically,

TM (the maximum time in which both phases of the recovery action must be completed) is estimated using thermal-hydraulic computer codes which provide time dependent information on core or containment parameters (i.e., pressure, temperature, water level, etc.), and/or information based on equipment failure characteristics (loss of room cooling, seal cooling, etc.).

TA (the time required to physically accomplish the action phase) can be conservatively estimated as the sum of the maximum time required to reach the area where the action is to be accomplished and the time required to accomplish the action - these should be based on actual measurements where possible.

Estimate the time available to diagnose the recovery action, Td, by the following expression:

Td = TM - TA

Step 5 Estimate the median response time, the type of cue that triggers the action or the level of cognitive processing required. Observations of simulator training, studies of procedures and walkdowns of the plant support these plant-specific assessments. Options are to use the standard conservative curve provided in NUREG/CR-4772, or grouped data from simulator observations provided in NUREG/CR-4834 Vol. 2. The desired approach in this study is to use plant-specific simulator observations, and to gain risk reduction insights through the process.

Step 6 Obtain an estimate of the median failure probability for the time dependent non-recovery portion, P2, using the correlation from EPRI 6560L Reference 3.3.3-8, or NUREG/CR-4834 data described in Step 5.

$$P2 = 1-\Phi[\ln(Td/Th)/\sigma] \qquad \text{(EPRI-6560L)}$$

Where $\Phi(.)$ is the standard normal cumulative distribution, Td is the decision time and Th is a median time estimate for crew responses, and σ is the standard deviation of normalized time derived from data in EPRI-6560L to represent the type of cue or cognitive processing required for the task.

Step 7 Estimate the median HEP for the action phase of the recovery task by assessing P1 and P3, and by applying the PSFs for each. Alternate methods using RMIEP, or the models in the Handbook (NUREG/CR-1278), can be used. These involve the development of action specific logic trees to represent each error.

Step 8 Estimate the total median failure probability for the recovery action, P(NR), using the following expression:

$$P(NR\text{-}median) = P1 + P2 + P3 - (P1{*}\,P2 + P1{*}\,P3 + P3{*}\,P2)$$

Step 9 If the detailed assessment is for the first recovery action, and a second or third action is to be applied to a single cutset, apply the dependence assessment methods in NUREG/CR-4772. To consider dependencies, the HEP for multiple actions is a product of the detailed quantification for the first action, and the greater of either the detailed assessment for the second action or .03 as recommended for screening in the NUREG/CR-4772 reference. If a third action was identified, a HEP of 0.1 was assigned (or detailed assessment HEP, if greater). This process accounts for human action dependencies during the sequence quantification. Detailed assessments of dependency can be used to justify lower dependencies on a case by case basis.

$$P(NR\text{-}Dep\text{-}median) = P(NR\text{-}median){*}P(NR2){*}P(NR3)$$

For cutsets containing hardware recoveries (e.g. recovery of offsite power, the Emergency Diesel Generators or the feedwater system), the hardware recovery was applied using its calculated value. If a second hardware recovery was applied, it was also given its detailed value. There were no cutsets which contained two hardware recoveries and any additional recoveries. For cutsets containing one hardware recovery only, up to two additional operator recoveries were allowed. The first was assigned its quantified value, and the second was assigned a value of 0.03 or the HEP value, whichever was larger.

Following these rules, no cutsets were allowed more than three post-accident recovery actions.

Step 10 Specify the uncertainty on the median HEP by assigning the Uncertainty Bound (UCB) according to the methods described in NUREG/CR-4772. The UCB is the square root of the ratio of the 95th percentile to the 5th percentile of the lognormal distribution. This assignment produces a lognormal distribution for the HEP distribution, determined by the median and the UCB. A calculated mean value from the lognormal distribution is typically used in quantifying the mean value of a cutset to reflect uncertainty range in the HEP.

Step 11 The new cutset probability, allowing for recovery, is then:

$$P(\text{cutset})_{new} = P(\text{cutset})\ \text{original} * P(\text{NR-Dep-mean})$$

The operator actions for which the detailed HRA were performed are listed in Table 3.3.3-8.

3.3.3.5 Plant Walkdowns, Operator Interviews, and Simulator Observations

The HRA used plant walkdowns, operator interviews, and simulator observations by IPE team members and consultants to enhance the plant specific understanding of key operator actions. For example, walkdowns of the actions in the 300 Series procedures, that involve lifting jumpers, realigning valves and inserting piping elements, were used to estimate times for TA. The times were formally documented in a Job Performance Measures (JPM) program administered by the Training Department. The JPM program includes data for the travel time and confirmation of the feasibility for each procedure performed outside the control room. The timing data includes the time to obtain the procedures, tools, and transient time to the local site. Additional time was added to TA for troubleshooting and carrying out the response actions such as installing the spool piece for the fire water injection based on the recommendation of operating crews interviewed during the simulator exercises. Information obtained from the walkdowns and review of the procedures included the feasibility of actions based on logistics, time availability, and ease of completion. These were used in estimating PSFs for P1 and P3.

Qualitative insights from simulator observations of four scenarios managed by two crews were developed in conjunction with the Hope Creek Simulator training staff to support the IPE HRA quantifications. Combinations of many malfunctions were selected to increase the number of key manual actions that could be observed in each scenario. Two scenarios involved anticipated transients without scram (ATWS). The effect of increased core power in these scenarios was to shorten the time between cues to initiate actions in the procedures. The scenarios were (1) Transient with turbine trip and loss of feedwater - ATWS, (2) LOP - With Loss Of High Pressure Injection, (3) MSIV closure - ATWS, and (4) a transient with loss of all injection due to loss of service water.

Primarily used for the post-initiator action analyses, simulator observations were used to either support or modify the assumptions needed to refine the HEP estimate based on NUREG/CR-4772. The simulator observations were performed after a number of important operator actions were identified during the initial phase of event tree quantification. Actions expected to result in refined quantifications were combined into four accident sequences to be run on the

Hope Creek simulator. The simulator operators and observers prepared for data collections through a practice session to tune the draft malfunctions for actual use prior to the observation sessions. Two complete and separate crews of varying experience and qualifications were asked to manage the four simulated accidents. Each session was simulated as closely as possible to the normal plant conditions including shift turnovers, and field responses to control room requests. Three observers provided information to validate the sequence timing and validate the observations. After each of the scenarios, the crews were interviewed to assess the events and circumstances surrounding the scenario.

The resulting insights, observations and discussions were documented and then incorporated into the analysis in support of Th, Td, and σ during the cutset review process. Ideally, the parameters Td, Th, and σ should be obtained for each action to be analyzed in detail. In practice, estimates for these parameters are made by considering a variety of information sources including simulator observations. The process for estimating Td is described in step 4 of the refined human error analysis. The median response time, Th, was estimated from the action time lines developed from observer notes which were compared with independent measurements from other BWRs in EPRI-6560L and NUREG/CR-4834. In many cases, the plant specific observed times were consistent enough to estimate values for Th. For the non-measured cases, human reliability estimates in observed cases were conservatively extrapolated using model data and engineering judgment.

A good estimate for the statistic σ requires more than two measures, therefore assignments were conservatively made in the range of 0.4 to 1.0 drawing upon the statistical evaluations of more than 1000 action points in EPRI-6560L. The upper bound represents both cues with little pre-warning and decisions made using knowledge-based thinking. The lower bound represents cues with pre-warning and rule or skill-based decision-making. The lower bound and intermediate estimates of 0.7 were used only when the observations demonstrated clearly that all crews would perform the same response and previous measures demonstrated the same responses at other BWR plants. Key insights from the observations are described below.

3.3.3.5.1 Generic Insights from Simulator Observations

The Hope Creek symptom based EOPs for managing events are based on the safety priority for scram, reactor water level, reactor pressure, and dry well pressure. The highest priority following a transient is reactivity control to satisfy the scram condition. Key insights included:

- Following all transients, the operators immediately verified that all control rods have fully inserted, and reactor power is decreasing. All personnel observed within the control room immediately observed and loudly announced the automatic scram failure-ATWS based on diverse instruments This is a good practice and serves to ensure that all personnel within the control room were immediately aware of the situation. Although the immediate actions are proceduralized, all personnel completed the reactor trip response actions completely, accurately, and expediently from memory, and later confirmed the actions by procedure.

- ATWS - The crews are instructed to manually control reactivity by three actions, if reactor power under a scram condition is outside the EOP limit of 4%. These are: (1) manual trip actions to insert rods (HC.OP-EO.ZZ-0101), (2) initiate standby liquid control (SLC) to introduce boron (HC.OP-EO.ZZ-0101), and (3) lower water level to reduce moderation (HC.OP-EO.ZZ-0207). SLC is manually triggered according to HC.OP-EO.ZZ-0101 when the suppression pool temperature reaches 110°F. The Redundant Reactivity Control System (RRCS) provides for automatically controlling four features that affect reactivity. The RRCS is automatically initiated if the reactor pressure reaches 1071 psig. In this high pressure case, the alternate rod insertion (ARI) is initiated, a feedwater runback is initiated after a 25 second delay, if any APRM is not downscale, the recirculation pumps are tripped and the timer for SLC is initiated. The RRCS is also initiated if the measured reactor vessel level is less than -38" (Level 2). In this case, the ARI is initiated, the recirculation pumps are tripped after a 9 second delay, and the timer for SLC is initiated. Initiating ARI opens 8 valves to bleed air from the control rod drive pilot air header causing all scram air header valves to open, and starts the SLC initiation timer. SLC initiation will occur in 3.9 minutes, if the APRM is not downscale (less than 4% power). The RRCS backs up mechanical control rod failures while controlling reactivity by other means. In the observed simulator cases, the ATWS portion was quickly handled by manual actions, even though multiple layers of automatic systems were modeled as failed. In one case, lack of flow control on the LPCI paths was identified by the crew as a potential control problem that could introduce oscillations (feedwater or condensate was preferred because of the ability to control flow).

- Loss of High Pressure Injection - The parallel EOP procedures were easily used by the crew to reach the key items for control of the situation. For example, procedures for core cooling, (HC.OP-EO.ZZ-206 or HC.OP-EO.ZZ-207, were reached within two minutes in scenario 2 by both crews. In these cases seven alternate level control methods in EOP 101 step RC/L-3 were reviewed and prioritized for use. The possible level restoration methods, given the conditions of the scenario, were pursued in parallel so that the equipment that was recovered first could be used to mitigate the event. Use of the EOPs demonstrated "parallel decision making" that can increase the probability of recovery.

- Leak Identification - Support for identification and isolation of a leak were enhanced by the diverse instrumentation, training, and procedures available in the control room. Once a cue for a leak was detected, both crews were able to identify and isolate LOCAs before any injections or isolations occurred. The annunciator signals provide both the alarm and procedure directed actions for isolation. Other diverse instrumentation on CRTs provides information for early detection. Confronted with conflicting information, the one crew was able to detect a small leak and isolate the leak before either an annunciation was triggered or a radiation alarm limit was reached by using the computer warning system. This shows that the diverse indicators improve the crews' responses. The other crew was performing a turbine admission valve stroke test and had a different screen on the CRT. They were alerted by the annunciator signal and then quickly isolated the leak.

- Depressurization - Crews were well trained on depressurizing to use low pressure systems. Once the conditions for depressurization were reached the crews rapidly inhibited ADS and, as a result of the scenario conditions, took manual control, opening 5 SRVs as directed by HC.OP-EO.ZZ-0202. If the reactor pressure is being decreased for other reasons, a varying number of SRVs will be opened depending on the cooldown rate desired.

- Use of procedures - The use of the parallel path emergency operating procedures (EOPs 100 and 200 Series) was straightforward for the trained operators. Colored markers were used to keep track of the pathway through the procedures, and acted as a check in recapping the event in progress. This allowed flexibility in addressing each operating limit that was challenged. The crews tended to anticipate needs and to act more quickly than required by the trip points in the procedures.

- Detailed recovery procedures (300 series) were initiated within 15 minutes of the initiating event. The crew was able to cross-tie service water systems without using P&IDs. The detailed 300 series procedures already include the control room and local steps.

3.3.3.5.2 Turbine Trip Transient and Loss of Feedwater with Fail to Scram

From the time of trip, different strategies were used by the crews. The first crew turned off the injection systems to control reactivity and to reduce power. This caused a Level 1 trip and the MSIVs closed before jumpers were lifted. The second crew ramped down the HPCI flow until the level dropped to about -120", where power reached 25%. In this case the MSIVs remained open, because the level stayed above the Level 1 trip at -129". In both cases the loss of injection systems rapidly cued the crews to initiate steam cooling without high pressure injection (45 seconds and 150 seconds following the loss of injection). Insights included:

- The simulator predicted power surges in both cases. Although the simulator model may not represent the plant response, it appears that in this rare case, the sensitivity of reactor power to water level makes manual control difficult. In both cases the procedures were carefully followed.

3.3.3.5.3 Loss of Offsite Power (LOP) - with Loss of High Pressure Injection

Observations were made for loss of offsite power conditions in scenarios 1 and 4. The LOP was immediately observable in the control room and loudly communicated. Besides the loss of normal light levels in the control room, the reactor operator immediately verified the loss of offsite power based on indication and under-voltage annunciators. If the DGs are available, then low pressure systems will be available for injection. The feedwater and condensate systems require restoration of non-1E AC electrical sources and reopening of the MSIVs.

If all AC power is unavailable, then only the RCIC and HPCI turbine-driven pumps are available for injection to the core. These turbine-driven pumps should start automatically when the core level reaches -38" (Level 2) following a LOP, and continue to run using DC control power. There should be no competing actions within the control room for trying to restore offsite power and emergency diesel generators. These actions are generally performed by personnel outside the control room. Key insights are:

* Core Cooling - Time for recovery actions was created by cooling with the existing core water inventory. Ex-control room recovery teams were sent out to reestablish injection by attempting to restart RCIC and recover DG to power the low pressure systems, and offsite power for feedwater and condensate systems. Following damage reports saying that these options were unavailable, new options were considered. Both crews initiated steam cooling by opening SRVs in 10 and 12 minutes respectively following the station blackout, and lined up the diesel driven fire pump, because its operation is independent of electrical power.

* Injection to maintain inventory - In this event the operators were able to initially control HPCI flow to avoid a Level 8 trip. After HPCI failed and repair attempts were not effective, emergency depressurization was required.

  The 310 procedures for use of the firewater system were started in both cases within 13 and 3 minutes. Local operation must be coordinated with the control room where level indication should still be available. Realignments from the control panels seemed well practiced and procedures allow for selection of the most appropriate system.

* Containment cooling - RHR cooling of the suppression pool was started early in the scenario before the station blackout. This action was triggered by a relief valve opening.

3.3.3.5.4 MSIV Closure - ATWS

In both simulations the key actions of reactivity control, suppression pool temperature control, water level control during different phases of the event, and containment control were performed as required. On the basis of the symptoms, the operators quickly and efficiently identified the key actions to manage the event situation. A difference in the runs was the availability of the B train of the SLC. This difference had little impact on the overall actions (Manual reactor trip attempt at 22 seconds and 16 seconds; stop injections 54 seconds and 68 seconds; and manual SLC initiation 124 seconds and 42 seconds before the suppression pool temperature reached 110°F, respectively). Insights for operator action quantification are:

* Level control - Control of the level with low pressure systems following an ATWS requires operators to be very alert in selecting and manually controlling the flow of multiple systems under low pressure conditions to avoid power surges. Reactivity control by lowering level was also under way rapidly (54 seconds and 68 seconds for the MSIV closure, and 180 seconds and 240 seconds for the turbine trip). For the observed cases, the immediate steps were performed by the separate crews in a different order. This is allowed by the parallel path procedures (HC.OP-EO.ZZ-0101 path RC/Q for manual rod insertion and SLC injection with parallel transfer to HC.OP-EO.ZZ-0207 step LP-1 for terminating injection for level control). These actions were well known to the crews through training and practice in the simulator.

  In both ATWS cases, RPV level control after emergency depressurization and subsequent low pressure injection was very difficult, leading to power surge(s) and rapid opening and closing of multiple SRVs as level was increased. The impact of one versus two SLC pumps was undetectable during the simulations, because level control by the crews dominated the power control. This means that the insertion of the control rods is a high priority recovery action even though boron has been injected.

- Suppression Pool Temperature - Both crews kept the suppression pool temperature below the HCTL and took manual actions to initiate SLC injection. The manual injection of SLC was very rapid (124 seconds and 42 seconds for the MSIV closure and 234 seconds and 120 seconds for the turbine trip).

  Suppression pool cooling was initiated early in the events as the temperature increased. The cue for this action is any active or anticipated heat addition to the torus, an open SRV, or injection of HPCI, RCIC, or a LOCA indicated by increasing drywell pressure. Both crews started RHR cooling of the suppression pool and noted that only one train was available within 1 minute following the initiating event.

- Pressure control - Crew actions to control SRVs using the ADS inhibit switch to prevent five valves from opening at once and then controlling the depressurization according to the dynamics of the scenario was extremely fast and accurate. In both cases the ADS was manually inhibited to gain control over the depressurization. Then, due to the conditions of the scenario, 5 SRVs were manually opened according to HC.OP-EO.ZZ-0202 to depressurize for low pressure injection within 10 and 15 seconds.

- Fire Water injection - The simulator malfunction recoveries varied. In the first case, the low pressure systems were recovered soon after procedure HC.OP-EO.ZZ-0310 (fire water injection) was discussed, whereas the second case included time for fire water hookup and injection, before other low pressure systems were restored.

3.3.3.5.5 Loss of Station Service Water

In this scenario the temperatures for all equipment were elevated because of the high outside temperatures. This high temperature condition was expected to mask a small but growing leak in the RACS heat exchanger. Once the leak was detected the isolation was completed within two minutes by both crews. The SACS system was degraded because only the B and D service water pumps were initially available to cool standby equipment (e.g., HPCI, RCIC, and LPCI). The B pump failed in the scenario and the crews checked the Technical Specifications for continued operation, planning to go to 80% power. The scenario continued with a loss of offsite power which triggered a reactor scram, start of the EDGs, and MSIV closure. The D-SSW pump failed to restart. Lack of cooling to EDGs, HPCI and RCIC under continued operation is expected to result in high temperatures. In the case of EDGs, this leads to bearing failure if left running. In both cases the crews secured all four EDGs, and kept the RCIC and HPCI turbines running without service water because of the SACS interloop heat capacity. The STA increased vigilance on the temperature monitoring, and the in-plant control room operators opened doors to the RCIC and HPCI rooms to promote enhanced cooling. The main focus of actions was to restore some of the service water pumps.

- Tradeoffs between overheating equipment and extending time to core damage were examined. In the case of loss of service water, the crew protected the EDGs by securing them until the service water system could be restored.

- The only case where doors are opened to enhance room cooling is a station blackout in the procedures (HC.OP-EO.ZZ-135); this is not done if the service water system is lost.

3.3.3.6 Post-Initiator HRA Results

On the basis of the screening methodology described earlier, all basic events were initially given a screening probability of 1.0. All those cutsets that were greater than 1.0E-7/yr and could be addressed with available and appropriate operator actions were evaluated further using nominal HRA quantification methods (ASEP or THERP). Per NUREG-1335 (Reference 3.3.3-15), all post-initiator human actions whose probability is 0.1 or less that results in a cutset dropping below 1.0E-7/year should be reported. This is assessed in Section 3.4.1.3.

3.3.3.7 References

3.3.3-1 Handbook of Human Reliability Analysis With Emphasis on Nuclear Power Operation. Washington, DC: U.S. Nuclear Regulatory Commission, August 1983. NUREG/CR-1278.

3.3.3-2 Systematic Human Action Reliability Procedure (SHARP). Palo Alto, California: Electric Power Research Institute, June 1984. EPRI NP-3583.

3.3.3-3 Post Event Human Decision Errors: Operator Action Tree/time Reliability Correlation. Washington, DC: U.S. Nuclear Regulatory Commission, November 1982. NUREG/CR-3010.

3.3.3-4 Risk Methods Integration and Evaluation Program (RMIEP) Methods Development: A Data-Based Methodology for Including Recovery Actions in PRA, Vol. 1: Development of the Data-Based Methodology and Vol. 2: Application of the Data-Base Technology. Washington, DC: U.S. Nuclear Regulatory Commission, NUREG/CR-4873 Vol. 1 and 2.

3.3.3-5 Analysis of Core Damage Frequency From Internal Events: Unit 1. Washington, DC: U.S., November 1986. Nuclear Regulatory Commission, NUREG/CR-4550, Vol. 3.

3.3.3-6 Analysis of Core Damage Frequency From Internal Events: Sequoyah, Unit 1. Washington, DC: U.S., Nuclear Regulatory Commission, February 1987, NUREG/CR-4550, Vol. 5.

3.3.3-7 Accident Sequence Evaluation Program Human Reliability Analysis Procedure. Washington, DC: U.S., Nuclear Regulatory Commission, February 1987. NUREG/CR-4772.

3.3.3-8 A Human Reliability Analysis Approach Using Measurements For Individual Plant Examination. Palo Alto, California: Electric Power Research Institute, July 1989. EPRI NP-6560L.

3.3.3-8a Seabrook Station Probabilistic Safety Assessment. Manchester, New Hampshire: Public Service Company of New Hampshire, December 1983.

3.3.3-9 Evaluation of Station Blackout Accidents at Nuclear Power Plants. Washington, DC: U.S., Nuclear Regulatory Commission, May 1985. NUREG/CR-1032.

3.3.3-10 Guidelines and Technical Bases for NUMARC Initiatives for Addressing Station Blackout at Light Water Reactors. Washington , DC: Nuclear Management and Resources Council, November 20, 1987. NUMARC-8700.

3.3.3-11 Probabilistic Analysis and Operational Data in Response to NUREG-0737. Pittsburgh, Pennsylvania: Westinghouse Electric Corporation, February 1981. WCAP-9804.

3.3.3-12 Data Summaries of Licensee Event Reports of Pumps at U.S. Commercial Nuclear Power Plants. Washington, DC: U.S. Nuclear Regulatory Commission, January 1980. NUREG/CR-1205.

3.3.3-13 Classification and Analysis of Reactor Operating Experience Involving Dependent Events. Palo Alto, California: Electric Power Research Institute, June 1985. EPRI-3967.

3.3.3-14 Nuclear Power Experience; Boulder, Colorado: S.M. Stroller Corporation.

3.3.3-15 "Individual Plant Examination: Submittal Guidance: Final Report." U.S. Nuclear Regulatory Commission, Washington, DC, 1989. NUREG-1335.

3.3.4 Common Cause Failure Data

3.3.4.1 Parametric Dependent Failure Study

Parametric modeling of intercomponent dependent failures in the HCGS IPE involved application of the multiple Greek letter (MGL) methodology using the following steps:

1. Definition of the scope for the parametric study,

2. Determination of β, γ, and δ factors for dependent failures of similar components,

3. Review of system fault trees for similar types of components (pumps, valves, and diesel generators) in redundant trains or loops, and

4. Modification of fault trees to account for important dependent failures.

3.3.4.1.1 Scope For Parametric Study

Step 1 was performed by reviewing past PRAs such as Seabrook (Reference 3.3.4-2), the NUREG-1150 PRAs (Reference 3.3.4-3), and other reports on dependent failures (References 3.3.4-4 through 3.3.4-9). From this review, it was decided that the scope of the study should cover redundant, similar components within a system. Dependent failures of similar components in separate systems were not analyzed. The types of components considered were:

1. Valves (motor-operated, air-operated, and safety/relief),

2. Pumps (motor-driven and turbine-driven),

3. Diesel generators, and

4. Other components for which little historical data about common cause failure was available, such as fans, DC buses, and service water motors and strainers.

3.3.4.1.2 Determination of Dependent Failures Factors

Step 2 involved the determination of β, γ, and δ factors used to quantify dependent failure events of similar components. A variety of quantification models for dependent failures is available. Such models include the β factor (Reference 3.3.4-10), extended β factor approach termed the Multiple Greek Letter (MGL) method (Reference 3.3.4-9), binomial failure rate (Reference 3.3.4-11), common load (Reference 3.3.4-12), inverse stress strength interference (Reference 3.3.4-13), and others. Based on historical usage and availability of parameter estimates, the MGL method was chosen.

The MGL method is described in detail in References 3.3.4-9 and 3.3.4-15. The discussions that follow summarize the pertinent formulas and concepts for three different component redundancy configurations:

- Two-redundant-component systems
- Three-redundant-component systems
- Four-redundant-component systems

These are systems in which two, three, and four components function in parallel, respectively.

The following paragraphs discuss the symbology and the equations used to estimate the β, γ, and δ factors, as well as the equations used to calculate the various system failure probabilities.

3.3.4.1.3 Symbology

In the symbology that is defined below, the subscript "n" is used to represent the total number of redundant components in the system where,

$$2 \leq n \leq 4$$

In this context, the term "component" refers to identical equipment performing identical specific functions.

The pertinent probabilities are represented symbolically as follows:

Q	Total failure probability of one component.
$Q_{m/n}$	Total failure probability of a system, in which success of at least m out of n of the redundant components is required for system success.
β	For a specific component, the conditional probability that, given that a component has failed, at least one additional component fails - for a total of at least two failed components.
γ	For a specific component, the conditional probability that, given that a component and one other component have failed, at least one additional component fails - for a total of at least three failed components.
δ	For a specific component, the conditional probability that, given that a component and two other components have failed, at least one additional component fails - for a total of at least four failed components.
n_k	The number of events in the historical data base in which exactly k components in the system failed.

Pooled estimates of the three common cause parameters (β, γ, and δ) were obtained from industry data using the following formulas:

$$\beta = \frac{(2n_2 + 3n_3 + 4n_4)}{(n_1 + 2n_2 + 3n_3 + 4n_4)} \tag{3.3.4-1}$$

$$\gamma = \frac{(3n_3 + 4n_4)}{(2n_2 + 3n_3 + 4n_4)} \tag{3.3.4-2}$$

$$\delta = \frac{4n_4}{(3n_3 + 4n_4)} \tag{3.3.4-3}$$

Estimates of the values of these three factors are listed in Tables 3.3.4-1, 3.3.4-2, and 3.3.4-3, respectively. In each table, several data sources were used, as indicated across the top of the table. For each equipment category, the estimates from those data sources were combined to yield the estimate recommended for use in the HCGS analysis. The methods used for this combining process are discussed in the subsections below.

Most of the formulas presented below for the probability of system failure are based on the small event approximation. This approximation allows third or higher order terms in unreliability or unavailability to be dropped because such probability terms are very small. For example, if the Q for a component is 1E-3 per demand, then a term including Q^3 as a factor would be a multiplier of 1E-9, and is considered small enough to be neglected.

3.3.4.1.4 Two-Redundant-Component System

Based on a second order approximation in Q, the probability of system failure is given by

$$Q_{1/2} = (\beta)Q+(1-\beta)^2 Q^2 \qquad (3.3.4\text{-}4)$$

In calculating estimates of β, Equation (3.3.4-1) was used. The values to be used for β for this type of system are listed in Table 3.3.4-1.

3.3.4.1.5 Three-Redundant-Component System

Based on a second order approximation in Q, the probability of system failure with a one-out-of-three success criterion is as follows:

$$Q_{1/3} = \left(\frac{3}{2} Q^2\right)(\beta)(1-\beta)(1-\gamma) + 4(\beta)(\gamma)Q \qquad (3.3.4\text{-}5)$$

For a two-out-of-three system, the second order formula is:

$$Q_{2/3} = 3(1-\beta)^2 Q^2 + \frac{3}{2}(\beta)Q - \frac{1}{2}(\beta)(\gamma)Q \qquad (3.3.4\text{-}6)$$

In calculating estimates of β and γ, Equations (3.3.4-1) and (3.3.3-2) were used. Tables 3.3.4-1 and 3.3.4-2 list the values estimated for β and γ, respectively. In the latter table, γ values calculated from actual data are identified as category A in the third column. If a particular data set has double failures but no triple failures, then an extrapolation of the data was required. The formula used for that extrapolation is as follows:

$$n_3 = 0.52 n_2 \qquad (3.3.4\text{-}7)$$

This computational formula comes from using the value $\gamma = 0.43$ (which is the average value of γ as evaluated for data category A for all equipment items grouped together) in the following equation:

$$n_3 = \left(\frac{2}{3}\right) \frac{(\gamma)\, n_2}{(1-\gamma)}$$

This equation comes from the following simplified formula for a three component system:

$$\gamma = \frac{3n_3}{(2n_2 + 3n_3)}$$

γ values which were calculated using this extrapolation are identified as category B in the third column of Table 3.3.4-2.

For equipment items for which a mix of category A and B values exists, a weighted average of the γ values was recommended for use in the Hope Creek analyses. This average value was computed as follows:

$$\gamma_{HC} = \frac{\Sigma(\gamma_A) + 0.5\,\Sigma(\gamma_B)}{(N_A + 0.5\,N_B)} \qquad (3.3.4\text{-}8)$$

where Σ represents the sum over all γ values in the associated category, and N_A and N_B are the numbers of γ values in the A and B categories, respectively. Thus, the values in the A category were given full weight, while those in the B category were given only half weight.

3.3.4.1.6 Four-Redundant-Component Systems

Based on a second order approximation in Q, the probability of system failure with a one-out-of-four success criterion is as follows:

$$Q_{1/4} = (\beta)(\gamma)(\delta)\,Q + \left[\frac{1}{3}(\beta)^2(1-\gamma)^2 + \frac{4}{3}(1-\beta)(\beta)(\gamma)(1-\delta)\right]Q^2 \qquad (3.3.4\text{-}9)$$

For a two-out-of-four system, the second order formula is:

$$Q_{2/4} = 4Q^2\left[(1-\beta)\,\beta\,(1-\gamma)\right] + \frac{1}{3}Q^2\left[(\beta)^2(1-\gamma)^2\right] + \frac{4}{3}Q\left[(\beta)(\gamma)(1-\delta)\right] + (\beta)(\gamma)(\delta)\,Q \qquad (3.3.4\text{-}10)$$

For a three-cut-of-four system, the second order formula is:

$$Q_{3/4} = 6(1-\beta)^2 Q^2 + 2(\beta)\,Q - \frac{2}{3}(\beta)(\gamma)\,Q - \frac{1}{3}(\beta)(\gamma)(\delta)\,Q \qquad (3.3.4\text{-}11)$$

In calculating estimates of β, γ, and δ, Equations (3.3.4-1), (3.3.4-2), and (3.3.4-3) were used. Tables 3.3.4-1, 3.3.4-2, and 3.3.4-3 list the values estimated for β, γ, and δ, respectively. In the last table, δ values calculated from actual data are identified as category A in the third column. If a particular data set has triple failures but no quadruple failures, then a first order extrapolation of the data was made using Equation (3.3.4-12) below and classified in category B in the third column. If a particular data set had double failures but no triple or quadruple failures, then an extrapolation was made to the triple failure category using Equation (3.3.4-7). A second extrapolation was then made to the category of quadruple failures, and the data set was classified in category C in the third column. The formula used for the extrapolation from triple to quadruple failures is as follows:

$$n_4 = 0.85 n_3 \qquad (3.3.4\text{-}12)$$

This computational formula comes from using the value $\delta = 0.53$ (which is the average value of δ as evaluated for data category A for all equipment items grouped together) in the following equation:

$$n_4 = \frac{\left(\frac{3}{4}\right)(\delta)\, n_3}{(1-\delta)}$$

This equation comes from Equation (3.3.4-3).

For equipment items for which a mix of category A, B, and C values exists, a weighted average of the δ values was recommended for use in the Hope Creek analyses. This average value was computed as follows:

$$\delta_{HC} = \frac{\left[\Sigma(\delta_A) + 0.5\,\Sigma(\delta_B) + 0.25\,\Sigma(\delta_C)\right]}{\left(N_A + 0.5\,N_B + 0.25\,N_C\right)} \qquad (3.3.4\text{-}13)$$

where Σ represents the sum over all δ values in the associated category, and N_A, N_B, and N_C are the numbers of δ values in the A, B, and C categories, respectively. Therefore, the values in the A category were given full weight, while those in the B and C categories were given only half and quarter weights, respectively.

3.3.4.1.7 Application of Common Cause Failures to the Fault Tree Models

Step 3 of the parametric modeling of dependent failures involved a review of all system fault trees for similar components listed above which are redundant or are in redundant trains or loops. For example, if a system had two redundant pumps and both were motor-driven, then the failure of both pumps was identified as a potential dependent failure event. However, if one pump was motor-driven and the other turbine-driven, then no dependent failure event was identified. Similarly, if MOVs existed in redundant loops of a system, a potential dependent failure event existed. However, if one loop had an MOV and the other had an AOV, then no dependent failure event was modeled. The review of system fault trees resulted in dependent failure events being identified for many systems.

Step 4 involved the modification of system fault trees to incorporate the dependent failures. This modification involved adding the dependent failures as basic events in the fault trees. Quantification of dependent failure events was performed using the appropriate β, γ, and δ factors. The resulting probabilities of important dependent failure events are shown in Table 3.3.4-4.

3.3.4.2 Spatially-Dependent Failure Analysis

The spatially-dependent failure analysis is described in the Internal Flooding Analysis in Section 3.3.9.

It should be noted that floods internal to the plant are more accurately classified as spatially-dependent failures in this report. In the PRA Procedures Guide (Reference 3.3.4-1) and other sources, these events are generally grouped under the external events classification, even though the source of the harsh environment is within the plant.

3.3.4.3 References

3.3.4-1 "PRA Procedures Guide" Washington, DC: U.S. Nuclear Regulatory Commission, January 1983. NUREG/CR-2300.

3.3.4-2 "Seabrook Station Probabilistic Safety Assessment" Manchester, NH: Public Service Company of New Hampshire, December 1983.

3.3.4-3 "Reactor Risk Reference Document" Washington, DC: U.S. Nuclear Regulatory Commission, February 1987. NUREG-1150.

3.3.4-4 "Common Cause Fault Rates for Pumps" Washington, DC: U.S. Nuclear Regulatory Commission, February 1983. NUREG/CR-2098.

3.3.4-5 "Common Cause Fault Rates for Valves" Washington, DC: U.S. Nuclear Regulatory Commission, February 1983. NUREG/CR-2770.

3.3.4-6 "Common Cause Fault Rates for Diesel Generators: Estimates Based on Licensee Event Reports at U.S. Commercial Nuclear Power Plants, 1976-1978" Washington, DC: U.S. Nuclear Regulatory Commission, June 1982. NUREG/CR-2099.

3.3.4-7 "Common Cause Fault Rates for Instrumentation and Control Assemblies" Washington, DC: U.S. Nuclear Regulatory Commission, May 1983. NUREG/CR-3289.

3.3.4-8 "Survey and Evaluation of System Interaction Events and Sources" Washington, DC: U.S. Nuclear Regulatory Commission, January 1985. NUREG/CR-3922, Vol. 1.

3.3.4-9 "Classification and Analysis of Reactor Operating Experience Involving Dependent Events" Palo Alto CA: Electric Power Research Institute, June 1985. EPRI NP-3967.

3.3.4-10 K. N. Fleming. "A Reliability Model for Common Mode Failures in Redundant Safety Systems." "Proceedings of the Sixth Annual Pittsburgh Conference on Modeling and Simulation" Pittsburgh PA, April 1975.

3.3.4-11 W. E. Vesely. "Estimating Common Cause Failure Probabilities in Reliability and Risk Analyses: Marshall-Olkin Specializations." Nuclear Systems Reliability Engineering and Risk Assessment, Philadelphia PA: Society for Industrial and Applied Mathematics, 1977.

3.3.4-12 "Common Load Model: A Tool for Common Cause Failure Analysis" Finland: Technical Research Center of Finland, Electrical Engineering Laboratory, December 1977. Report 31.

3.3.4-13 "A Method for Estimating Common Cause Failure Probability and Model Parameters by the Inverse Stress-Strength Interference Technique" Cambridge MA: Massachusetts Institute of Technology, July 1984. MIT-EL-84-010.

3.3.4-14 "Hope Creek Generating Station Probabilistic Risk Assessment". Public Service Electric And Gas Company, To Be Published.

3.3.4-15 "Procedures for Treating Common Cause Failures in Safety and Reliability Studies" Washington DC: U.S. Nuclear Regulatory Commission, January 1988. NUREG/CR-4780, Vols. 1 and 2.

3.3.5 Event Quantification

3.3.5.1 Fault Tree Basic Event Quantification

Given the generic component failure rate estimates from Section 3.3.1 and the plant-specific data from Section 3.3.2, the fault tree basic events were quantified. In general, six different types of component failure events exist:

1. Failure upon demand, with the component failure rate given as a failure probability per demand.

2. Failure upon demand, with the component failure rate given per hour.

3. Failure to run during a mission time.

4. Test and maintenance events.

5. Human error events.

6. Special events.

For type 1, the component unavailability is the failure probability per demand multiplied by one (demand). For type 2, the component unavailability is 0.5 λ T_T, where λ is the failure rate per hour, and T_T is the effective time between tests (or the maximum effective time between component failure and failure annunciation). Failures to run (type 3) were quantified as λ T_M, where λ is the operating failure rate per hour and T_M is the mission time. In general, a mission time of 24 hours was used in the HCGS IPE. Testing and maintenance unavailabilities were obtained directly from Section 3.3 2. Human error events were quantified as discussed in Section 3.3.3. Finally, other events included all those events identified as undeveloped in the fault trees. Actual quantification of all the basic events was performed on a microcomputer, utilizing the Data Module of the PRA Workstation (Reference 3.3.5-1).

3.3.5.2 References

3.3.5-1 "PRA Workstation," Data Module. Kent, Washington: Halliburton NUS, December 1992.

3.3.6 Computer Programs and Their Applications.

This section addresses the software used to quantify the front-end analysis portion of the HCGS IPE. Software used to quantify and develop the back-end model is described in Section 4.

3.3.6.1 Front End Quantification Tools

The PRA workstation software was used to facilitate the front-end analysis. It was developed as seven modules written in the "C" programming language and linked together using the WINDOW™ environment and the BTRIEVE™ data management system. These seven modules are:

1. Event Tree Module (ETM)

2. Fault Tree Module (FTM)

3. Data Module (DATA)

4. Cutset Analysis Module (CSAM)

5. Results Module (RESULTS)

6. Importance/Uncertainty Module (I/U)

7. Cost/Benefit Module (COST)

This computer program structure provides a user-friendly interface between the user and the computer. In the WINDOW™ environment, these modules can be run separately, or data from several different modules can be displayed on the screen and manipulated simultaneously. This capability provides the user with flexibility and power in performing PRAs (Reference 3.3.6-1).

ETM is used to build, edit, and document the event trees that provide the basic logic structure for the plant models. FTM is used for constructing, editing, defining links between fault tree models, and documenting the fault tree models that display the basic logic of the various systems included in the event tree logic. DATA is used to develop, edit, manipulate, and document the failure database required to support the elements within the event trees and the fault trees. CSAM is used to solve the models developed in FTM and ETM and to view, print, and quantify any equation which is stored in the workstation. The solution of fault trees is performed individually or in a batch mode with linked or unlinked trees as appropriate. With the use of "House Events," only one fault tree needed to be developed per system. A House Event is an event which is modeled directly in the fault trees but has no numerical value. Instead, each House Event is set to "TRUE" or "FALSE" for a given accident sequence. Therefore, with House Events certain logic (e.g., LOP) can be turned on for that initiator only, and only one fault tree is needed to represent the system. House Events are defined globally for all fault trees for each accident sequence. The event tree sequence solution can be performed individually, by event tree sequence, or by any combination of event tree sequences defined in a batch file. RESULTS is used for reviewing, updating, modifying, and interpreting PRA results. It is also used to perform sensitivity studies and to apply recovery actions to the cutsets. I/U is used to calculate importance measures for events in the accident sequences or plant damage states. It is also used to study risk reduction/increase and to evaluate partial derivatives. In addition, I/U determines the median, mean, and confidence bounds of uncertainty distributions. COST is used for studying proposed design, operational, or procedural changes from a cost/benefit perspective, providing a quantitative basis for preferring one alternative over another or for rejecting proposed changes because of their unreasonably high cost for a small benefit.

Because this software was extensively used in the HCGS IPE, validation and verification testing was performed and documented (Reference 3.3.6-2).

Finally, the PRA Workstation software links to the LHS (Reference 3.3.6-3) and TEMAC (Reference 3.3.6-4) codes for the performance of importance and uncertainty analyses. The LHS code is used to develop a version of Monte Carlo sampling of the database. TEMAC performs uncertainty and importance calculations.

3.3.6.2 References

3.3.6-1 "PRA Workstation Users Manual." Halliburton NUS, Kent WA, December 1992.

3.3.6-2 "PRA Workstation Software V&V Test Report;" Halliburton NUS, Kent WA, January 1993.

3.3.6-3 "A FORTRAN 77 Program and User's Guide for the Generation of Latin Hypercube Samples for Use with Computer Models," Iman, Ronald L. and Shortencarier, Michael J.; NUREG/CR-3624, Sandia National Laboratories, March 1984.

3.3.6-4 A User's Guide for the Top Event Matrix Analysis Code," Iman, R. L. and Shortencarier, M. J., NUREG/CR-4598, Sandia National Laboratories, August 1986.

3.3.7 Accident Sequence (Core Damage) Quantification

Development of the HCGS accident sequence models and data to support these models has been discussed in previous sections. Evaluation of these models is discussed in this section. Specifically, each accident sequence determined to lead to core damage, as indicated on the event trees discussed in Section 3.1.2, was evaluated. The accident sequence quantification task involves two distinct steps, as follows:

1. Accident sequence cutset generation.

2. Recovery analysis.

Each of these steps is discussed subsequently.

3.3.7.1 Accident Sequence Cutset Generation

The event tree development task described previously in Section 3.1 resulted in the development of 14 event trees. In addition, one initiating event - reactor vessel rupture - was assumed to lead directly to core damage. Interfacing systems LOCAs (ISLOCAs) are discussed in Section 3.1.3.5. In general, the core damage sequences defined by the event trees involve an initiating event category (Section 3.1.1) and various combinations of system failures and successes defined by the event tree top event headings.

Functional equations are assigned to each of the branch points on the event tree. These 142 functional equations are defined by the specific success criteria for the event tree path involved. Many of these functional equations represent the failure of safety systems as evaluated from the fault tree models in Section 3.2.1. Other functional equations represent combinations of system failures, operator errors, or phenomenological events. The multiple system failures are evaluated by developing top logic fault tree models to reflect the applicable specific success criteria and then linking the fault trees and solving the fault tree model in the same manner as the single system models. Human errors and phenomenological events were evaluated by developing equations which represent the events. In order to insert these equations into the computer database, small fault trees including gates with single basic events were developed and solved. The method of development of the data values associated with these equations is provided in Sections 3.3.1 through 3.3.4. Table 3.3.7-1 identifies the following information for the functional equations:

1. The functional equation developed for each top event heading on the event trees,

2. The applicable event trees for the function,

3. The success criteria associated with the functional equations,

4. The applicable fault tree used to generate the equations,

5. The fault tree gate solved to generate the equations,

6. The house event settings used in the solution of the fault tree.

The functional equations are generally solved with a truncation limit of 1.0E-7. However where an extremely large number of cutsets are generated at that level and truncation could be done at 5.0E-6 while maintaining approximately 3 orders of magnitude in the cutset spread and ensuring that the dominant dependent failures were not truncated, the 5.0E-6 truncation limit is used. Table 3.3.7-2 presents information about each functional equation quantified, including the equation name, respective fault tree, gate solved, truncation value, and number of cutsets generated for the functional equation.

Following quantification of each of the functional equations, the appropriate combinations of functional equations for each accident sequence are combined and the system successes are accounted for. Cutsets which represent combinations of test and maintenance (TM) events which violate Technical Specifications are removed automatically from each resulting sequence equation. For example, the RHR system has four pumps. The Technical Specifications limit the number of RHR pumps which can be inoperable at a time. Since the RHR model has a TM event associated with each pump, combinations of RHR TM unavailability occur which represent Technical Specification violations. Due to the limited time that the plant may actually be in this state, these combinations are removed. Table 3.3.7-3 provides a summary of the combinations removed.

In general, the truncation value used for the cutsets is 1.0E-10. For some of the cutsets, a truncation limit of 1.0E-9 is used and the resultant accident sequence cutsets are reviewed to ensure adequate coverage is maintained. The accident sequence cutset equations resulting from this process represent the starting point for the recovery analysis discussed in Section 3.3.7.2. A more detailed description of the accident sequence analysis process is presented in the HCGS PRA (Reference 3.3.7-1).

3.3.7.2 Accident Sequence Recovery Analysis

Sequence recoveries are the actions that an operator can take to mitigate an accident sequence. Section 3.3.3 described the quantification of the probability of the failure to successfully perform recovery actions. Once the probability of these "non-recovery" actions was determined, these actions were applied to the cutsets with the following guidelines:

1. Cutsets with non-recoveries that are 100% operator action: The first non-recovery event applied to a cutset was applied using the value quantified in Section 3.3.3. If a second non-recovery event was applied, the value used was either 0.03 or the quantified value, whichever was higher. If a third non-recovery event was applied, the value used was either 0.1 or the quantified value, whichever was higher. No more than three recovery actions were applied to any cutset.

2. Cutsets with recoveries that are a mix of hardware non-recoveries (e.g., failure to recover a diesel generator) and operator actions: Up to two hardware recoveries were applied to the cutset. If an operator recovery action was applied, the value used was the quantified value. If a second operator recovery action was applied, the value used was 0.03 or the quantified value, whichever was higher. No more than three recovery actions were applied to any cutset.

Table 3.3.7-4 presents a list of all of the recovery actions used in the sequence recovery analysis.

3.3.7.3 References

3.3.7-1. "Hope Creek Generating Station Probabilistic Risk Assessment" To be published.

3.3.8 Quantification of Event Tree Transfer Sequences

This section addresses how event tree transfers were handled for the HCGS IPE. In some cases, quantification of the transfer was performed by ratioing the frequency of that sequence to the initiating event frequency of the event tree to which the transfer is made and applying this ratio to the frequencies of each of the sequences which had already been quantified for that initiator. However, in other cases, the transfer frequency includes failed equipment which is credited in the event tree to which the transfer is made. In these cases, if the sequence frequency is significant, a modified event tree was developed to allow the proper quantification of the transfer. The cutoff used to determine if additional analysis was needed was 1E-7. Any sequence with a transfer frequency below this was not quantified further.

The analysis of the Event tree transfers (by Event tree) is presented below.

Large LOCA:

There are no transfers from this Event tree.

Intermediate LOCA:

There are no transfers from this Event tree.

Small LOCA:

There are four transfers from this Event tree. The first is sequence S2-16, which is a recirculation pump seal LOCA which is successfully isolated. This sequence transfers to the turbine trip event tree. Since the isolated seal LOCA has no impact on any of the systems modeled in the turbine trip event tree, the sequence frequency of 3.00E-2 is taken into the turbine trip initiating event. Since the turbine trip initiating event frequency is 4 per year, this transfer frequency is a factor of 133 lower, and is negligible in comparison.

The second transfer is sequence S2-33, which is a small LOCA with a SORV. This sequence transfers to the intermediate LOCA (S1) event tree with a frequency of 5.7E-4. This frequency was ratioed with the S1 initiating event (IE) frequency of 3E-3 to determine the individual sequence frequencies after the transfer. The total quantified frequency of this transfer is 3.61E-7. The only individual sequences after the transfer which have a frequency greater than 1E-7 are S2-33 to S1-3 (1.43E-7) and S2-33 to S1-13 (1.37E-7).

The third transfer is to the loss of HVAC event tree (S2-34). The HVAC recovery event was applied to this sequence before the transfer, giving a frequency of 1.85E-9. Therefore, this sequence was not analyzed further.

The fourth transfer (S2-35) is to the LOP event tree (Te). Sequences 1 to 12 in the Te event tree were not applicable since the small LOCA behaves like a SORV. Therefore, only sequences 13 to 30 and 36 and 37 apply. The transfer frequency from sequence S2-35 is 3.80E-5. This was ratioed to the product of Te*P (3.4E-2 * 1.5E-2 = 5.1E-4), and the result was that the total frequency of the transfers was 6.52E-8. The largest sequence frequency after transfer was S2-35 to Te-36 which has a frequency of 6.43E-8.

Turbine Trip, MSIV Closure and Loss of Feedwater Transients:

These three initiators all contain three transfers. The first transfer is to the LOP event tree (Tt-40, Tm-38 and Tf-51). The sum of these three frequencies before transfer is 4.91E-3 per year. This was ratioed to the IE frequency for a LOP (3.4E-2), and the result was that the total frequency of the transfers was 4.27E-6. The only individual transferred sequences with a frequency greater than 1E-7 were Tt-40 to Te-34 (3.36E-6), Tt-40 to Te-36 (1.02E-7), Tm-38 to Te-34 (3.03E-7), and Tf-51 to Te-34 (4.63E-7).

The second transfer is to the loss of HVAC event tree (Tt-41, Tm-39, Tf-52). Before any transfer was made, the HVAC recovery event was added to Tm-39 and Tf-52, and in both cases, the sequence frequency dropped below 1E-7, and no further quantification was performed. For the Tt-41 transfer, the transfer frequency was 8.67E-4, and this frequency was ratioed to the loss of HVAC IE frequency of 2.42E-3. The total frequency of the transfers was 2.68E-7, and the only developed transfer sequence with a frequency greater than 1E-7 was Tt-41 to Thv-1, which had a frequency of 2.60E-7.

The third transfer is to the ATWS trees, and these event trees were explicitly quantified as described in Section 3.1.1.

The loss of feedwater event tree contains a fourth transfer (Tf-49), to the S1 LOCA event tree. The transfer frequency of Tf-49 is 2.72E-4. This frequency was ratioed to the IE frequency of S1 (3E-3), and the result was a total quantified transfer frequency of 1.72E-7. None of the individually quantified transfer sequences from Tf-49 have a frequency greater than 1E-7.

Inadvertent Open Relief Valve (IORV)

This event tree contains four transfers. The first (Ti-20) transfers to the S1 event tree with a transfer frequency of 5.7E-4. This was ratioed to the IE frequency of S1 (3E-3), yielding a factor of 0.19. The only individual transfer sequences with a frequency greater than 1E-7 were Ti-20 to S1-3 (1.43E-7) and Ti-20 to S1-13 (1.37E-7).

The second transfer (Ti-21) is to the LOP event tree. The transfer frequency is 3.80E-5, and this was ratioed to the TeP frequency of 1.02E-3 to give a factor of 0.037 to be applied to sequences Te-13 to 31. The total CDF of these quantified sequences is less than 1E-10.

The third transfer (Ti-22) is to the loss of HVAC event tree. The HVAC recovery event was applied to this sequence, giving a frequency of 3.36E-8, and no further quantification was needed.

The fourth transfer (Ti-23) is to the MSIV closure ATWS event trees. The recovery event "Manual initiation of ARI" was applied to the electrical failure of the control rods sequence (TiCe), giving it a frequency of 5.32E-10, and no further quantification was necessary. The sequence involving a mechanical failure of the control rods (TiCm) had a transfer frequency of 3.80E-7. This frequency was ratioed to the TaCmP frequency of 4.095E-7 (0.91 * 1E-5 * 4.5E-2) for a factor of 0.93 to be applied to sequences Ta-19 through 36. The result was a total quantified CDF of 1.27E-9 for this transfer.

Loss of Offsite Power:

This event tree contains three transfers. The first (Te-31) represents a 2-SORV scenario and transfers to the S1 event tree. Te-31 has a transfer frequency of 5.10E-5, and this was ratioed to the S1 IE frequency of 3E-3 This ratio was then applied to S1 sequences 15 to 29 for a total quantified transfer frequency of 9.09E-10.

The second transfer (Te-33) is to the MSIV closure ATWS event tree. The transfer frequency of Te-33 is 1.02E-6, but because of the LOP IE, the MSIV closure ATWS event tree and all of the respective faults trees had to be quantified with the LOP House Event set to true. The result was a total frequency of 1.12E-7, but the largest individual sequence was only 7.62E-8.

The third transfer (Te-41) transfers to the loss of HVAC event tree. The HVAC recovery event was applied to this sequence before transfer, giving a sequence frequency of 3.21E-10, and no further quantification of this sequence was needed.

Loss of HVAC:

There are no transfers from this event tree.

Loss of Station Service Water/SACS:

This event tree contains three transfers. The first (Tsa-30) has a transfer frequency of 2.13E-7, and it transfers to the LOP event tree. However, because of the loss of SSWS or SACS, only the SBO sequences (Te-34 to 38) apply. These sequences were quantified (and all of the respective fault trees) with the loss of SSWS/SACS House Event (see Section 3.3.6.1 for a discussion of Front-End quantification techniques including the use of House Events) set to TRUE to quantify the sequences, and the result was a total frequency of only 1.15E-8.

The second transfer is to the Loss of HVAC event tree (Tsa-31). The HVAC recovery event was applied to this sequence before transfer, and the resulting sequence frequency was a frequency less than 1E-10, and no further quantification of this sequence was needed.

The third transfer (Tsa-32) is to the MSIV closure ATWS event tree. The frequency of this sequence before transfer is 6.39E-9, and no further quantification of this sequence was needed.

Loss of IAS:

This event tree contains three transfers. The first (Tia-38) is to the LOP event tree, and it has a transfer frequency of 1.00E-6. Since the LOP event tree credits the use of the CRD and the Loss of IAS event tree does not, the LOP event tree and all of the respective fault trees were quantified with the Loss of IAS House Event set to TRUE with the transfer frequency of 1.00E-6. The result was a total frequency of 2.55E-9.

The second transfer is to the Loss of HVAC event tree (Tia-39). The HVAC recovery event was applied to this sequence before transfer, and the resulting frequency was 8.85E-10. No further quantification of this sequence was needed.

The third transfer (Tia-40) is to the MSIV closure ATWS event tree. The transfer frequency of this sequence is 3.00E-8, and no further quantification of this sequence was needed.

Loss of RACS:

There are three transfers on this event tree. The first is sequence Tra-40, which transfers to the LOP event tree with a transfer frequency of 1.00E-5. Since the LOP event tree credits the use of the CRD and the IAS, while the Loss of RACS event tree does not, the LOP event tree and all respective fault trees were quantified with the Loss of RACS House Event set to TRUE. The result was a total quantified frequency of 2.57E-8.

The second transfer (Tra-41) is a transfer to the Loss of HVAC event tree. The HVAC recovery event was applied to this sequence before transfer, yielding a frequency of 6.31E-8, and no further quantification of this sequence was needed.

The third transfer (Tra-42) is a transfer to the MSIV closure ATWS event tree. The transfer frequency is 3.00E-7. The MSIV closure ATWS event tree was quantified with the Loss of RACS House Event set to TRUE, and the result was a total core damage frequency of 1.23E-9.

Turbine Trip ATWS:

There are four transfers from the Ta1 (Tt ATWS with electrical failure of the control rods) and four transfers from the Tat (Tt ATWS with mechanical failure of the control rods) which transfer to the MSIV closure ATWS event tree.

The first transfer is Ta1-38. The manual initiation of ARI recovery event was applied to this sequence before transfer, and the resulting frequency was 6.32E-10, so no further quantification of these sequences was needed.

The second transfer is Ta1-39. The manual initiation of ARI recovery event was applied to this sequence before transfer, and the resulting frequency was 9.51E-9, so no further quantification of these sequences was needed.

The third transfer is Ta1-45. The manual initiation of ARI recovery event was applied to this sequence before transfer, and the resulting frequency was less than 1E-10, so no further quantification of these sequences was needed.

The fourth transfer is Ta1-46. The manual initiation of ARI recovery event was applied to this sequence before transfer, and the resulting frequency was 9.42E-10, so no further quantification of these sequences was needed.

The fifth transfer is Tat-36. The transfer frequency is 9.02E-7, and the applicable sequences in the Ta event tree are Ta-19 to 30. There are no core damage sequences greater than 1E-10 out of Ta-19 to 30, so no further quantification was performed.

The sixth transfer is Tat-37. The transfer frequency is 1.19E-5, and the applicable sequences in the Ta event tree are Ta-19 to 30. The TaCmP frequency is 4.10E-7 (0.91 * 1E-5 * .045). Even though Tat-37 is a factor of 30 higher than TaCmP, since there are no core damage sequences greater than 1E-10 out of Ta-19 to 30, it would not be possible to have any core damage sequences greater than 3E-9 from this transfer, so no further quantification was needed.

The seventh transfer is Tat-43. The transfer frequency is 8.93E-8, and no further quantification was needed.

The eighth transfer is Tat-44, and its transfer frequency is 1.35E-6. The applicable sequences in the Ta event tree are Ta-31 to 36. The frequency of TaCmPP2 is 4.05E-8 (0.91 * 1E-5 * 0.045 * 0.099). When 1.35E-6 was ratioed to 4.05E-8 (a factor of 30), there were no core damage sequences greater than 1E-7.

3.3.9 Quantification of the Internal Flooding Event Tree

3.3.9.1 Description of the Quantification Process and Methods

This analysis considered potential internal flooding events occurring in the reactor building, turbine building, or the service water intake building. For the cases when the internal flood occurs in the reactor building or in the intake building, the turbine building (including the secondary side of the balance of plant) is not directly affected. Therefore, the turbine trip event tree logic was used to quantify the impact of the internal flooding initiating event on the core damage frequency. For an internal flood in the turbine building, the secondary side of the balance of plant may be affected, and the MSIV closure event tree logic was used. The rooms in which internal flooding can be considered an initiating event are identified in Section 3.3.9.2. In this context, a room is defined as one or more rooms, which are isolated from other rooms by means of watertight isolation (like watertight doors). For each room exposed to internal flooding, a separate event tree is used, in which the specific room flooding is defined as the initiating event, followed by the failure of the equipment which is present in this room and the failure of additional equipment, when the flood is not isolated and propagates to other rooms. Therefore, even though the event tree logic looks the same as a turbine trip, each internal flood event tree was different, because the initiating event was different and the equipment impacted by the common cause flood was different.

The quantification process included the following steps:

1. Preparation of a fault tree which included the initiating events, namely the specific rooms and their respective internal flood occurrence rates per year. Each event tree analysis selected one specific gate in this fault tree, according to the initiating event analyzed. For example, when the internal flood started in the service water intake room (Room 110), the gate IE-SWS-A-110 was selected as the initiating event.

2. Definition of a set of flood specific house events and their incorporation in the relevant system fault trees. In quantifying the event trees, the house events were turned on and off (their values were assigned as 1 or 0), according to the common cause failure impact of the internal flood. For example, if the flood was initiated in Room 4118 and the flood source was isolated, and no penetration to other rooms occurred (successful drain system), then only the Core Spray Pump A house event had a value of 1, while all the other flood house events had a value of 0. However, if the drain system failed, it was assumed that all the check valves in the drain sump failed to close and

backflow penetrated to all the rooms connected to the drain sump. In this case, all the equipment located in these rooms had house events defined as 1, which meant their failure. In the example of the unisolated, undrained flood in Room 4118, the flood common cause failures caused the failure of the following ECCS equipment: Core Spray Pump C, RHR pump A, RHR heat exchanger A, RHR pump C, HPCI pump, in addition to the failure of the Core Spray Pump A. A separate study was done for the case when the separation between two sumps is broken through the common torus room, by additional check valve failures . It should be noted that all the non-flood house-events (such as transients, LOCA, loss of power, ATWS, etc.) used in the turbine trip event tree (or MSIV closure) kept their original assigned values used in the turbine trip (or MSIV closure) quantification.

3. Quantifying the internal flood event trees. After the implementation of the previous two steps, this step is very similar to the turbine trip quantification. This step included the calculation of the listing of cutsets and the application of operator recovery actions. For each room, the quantification started with the most conservative set of assumptions regarding the impact of the internal flood on equipment. That meant lack of draining, and/or failure of the check valves in drain sumps, and/or propagation of the flood to the rooms interconnected by the drain system, etc. If the most conservative set of assumptions did not result in a significant core damage sequence (see next paragraph for a definition of significance), then no further analysis was done. In the case of the reactor building, rooms which provide similar flood impact on the systems were combined together by using one event tree quantification, but with an effective flood initiating event. The occurrence frequency of the combined, effective initiating event was applied to the most severe internal flooding scenario of the turbine trip event tree.

4. Screening out insignificant sequences. For the purpose of this study, a risk significant core damage sequence was defined as any core damage sequence with a frequency greater than 1.0E-7/yr (added up by cutsets with probabilities greater than 1.0E-10/yr). The probability cutoff of 1.0E-7/yr represents less than 1 percent of the internal events core damage result.

3.3.9.2 Individual Room Evaluations

3.3.9.2.1 Rooms Modeled as Turbine Trips

The Turbine Trip event tree is shown in Figure 3.1.2-1. The following rooms are modeled as Turbine Trip flooding events. A detailed explanation of the quantification of internal flooding is given for the first room considered (Room 4105). The method used to quantify the risk contribution from the other rooms is similar, unless otherwise stated.

Reactor Building Room 4105

Room 4105 is located on Elevation 54' of the Reactor Building. This room contains the core spray pump 1DP206 and its associated piping, core spray room unit coolers 1DVH211 and

1HVH211, as well as SACS Loop B piping. A typical accident scenario initiated by internal flooding in Room 4105 includes all or some of the following elements and assumptions:

A. A system failure which causes a flood in the room. The system failure may be caused by a component or pipe rupture in the core spray or the SACS systems. Internal flooding caused by the failure of room coolers is less probable and is less severe (because of reduced flood flow rate and a reduced source capacity) .

B. Room 4105, like other rooms exposed to internal flooding, has two redundant level detectors which send alarm signals to the over-head display in the control room, if water accumulation occurs in the room.

C. As a result of the Over Head (OH) alarm signal and other available information about various system temperatures, flow rate, pressures, etc., the operator is expected to isolate the affected system and to stop the internal flood. However, it is assumed that the core spray train has lost the capability of performing its design ECCS function. In addition to that, if the operator identifies the flood source as the SACS system, he will isolate the SACS flow to the failure location. In any case, it is assumed that core spray is lost. If the flood source is the SACS failure in Room 4105, and there is no isolation, the entire SACS loop is assumed to be failed, with the potential to flood other rooms. Due to the watertight compartmentalization at Hope Creek, the dominant failure mode to propagate the flood to other rooms is through the drainage system.

D. The flood water in Room 4105 is drained into sump 1BT265. The drain sump has two level detectors, and when liquid is detected in the sump, the drain pumps are initiated automatically (one by one) to remove the sump contents to the radwaste system. There are four sumps in the reactor building. Sump 1BT265, which serves Room 4105, also serves additional rooms located at various levels in the reactor building. These rooms are isolated from a potential backflow from the sump by check valves (one check valve is installed on each drain line of each room). Low probability (between 1.0E-4 and 1.0E-5) of common cause failure was assigned to the "single flap" check valves to fail open and allow backflow to all the rooms connected to the sump. However, based on experience at Hope Creek, high probability (between 0.9 and 1.0E-2) of common cause failure was assigned to the "two flaps" check valves to fail open. Common cause failure of the check valves results in failure of all the ECCS systems connected to the affected sump. However, the ECCS systems connected to the other sumps will be available. The cross connection of the sumps via the torus area is analyzed separately.

The core damage due to internal flooding in Room 4105 was calculated for the following specific cases:

1. Isolated flood with random failure of the draining system. In this case, only core spray was assumed failed as a result of the internal flood. The calculated core damage frequency in this case is 1.1E-9/yr. Table 3.3.9-1 shows this core damage sequence as Case 1 of Core Spray Room 4105.

2. Unisolated flood with common cause failure of the draining system. In this case, all the ECCS systems connected to the failed sump are assumed failed as a result of the internal flooding. The calculated core damage frequency in this case is 2.0E-9/yr, as shown in Table 3.3.9-1 Case 2 of Core Spray Room 4105.

Reactor Building Room 4104

Room 4104 is located on Elevation 54' of the Reactor Building. This room contains the Core Spray Pump 1BP206 and its associated piping, core spray room unit coolers 1BVH211 and 1FVH211, as well as SACS Loop B piping. This room has similar internal flooding accident scenarios and core damage frequencies to those in Room 4105.

Reactor Building Room 4116

Room 4116 is located on Elevation 54' of the Reactor Building. This room contains Core Spray Pump 1CP206 and Core Spray Pump Room Unit Coolers 1CVH211 and 1GVH211. Additionally, SACS Loop A lines are located within the room. This room has similar internal flooding accident scenarios and core damage frequencies to those in Room 4105.

Reactor Building Room 4118

Room 4118 is located on Elevation 54' of the Reactor Building. This room contains Core Spray Pump 1AP206 and Core Spray Pump Room Unit Coolers 1AVH211 and 1EVH211. Additionally, SACS Loop B lines are located within the room. This room has similar internal flooding accident scenarios and core damage frequencies to those in Room 4105.

Reactor Building Room 4109

Room 4109 is located on Elevation 54' of the Reactor Building. This room contains RHR Pump 1BP202, RHR Heat Exchanger 1BE205, RHR room unit coolers 1BVH210 and 1FVH210. Additionally, SACS Loop A lines are located within the room.

The core damage due to internal flooding in Room 4109 was calculated for the following specific cases:

1. Isolated flood with random failure of the drain system. In this case, only the RHR pump 1BP202 and Heat Exchanger 1BE205 were assumed to be failed as a result of the internal flood. The calculated core damage frequency in this case is 6.38E-8/yr. This CDF is obtained from the addition of all the RHR Room 4109 (Case 1) sequences shown in Table 3.3.9-1.

2. Unisolated RHR flood with common cause failure of the draining system. In this case, all the ECCS systems connected to the failed sump are assumed failed as a result of the internal flooding. The calculated core damage frequency in this case is 2.0E-9/yr.

3. Unisolated SACS flood with common cause failure of the drain system. In this case, all the ECCS systems connected to the failed sump are assumed failed as a result of the internal flooding, and the entire SACS division is also assumed failed. The calculated core damage frequency in this case is 2.0E-8/yr.

Reactor Building Room 4107

Room 4107 is located on Elevation 54' of the Reactor Building. Room 4107 contains RHR Pump 1DP202, RHR room unit coolers 1DVH210 and 1HVH210, the ECCS jockey Pump 1DP228, and the ADS/RHR D Instrument Rack 10-C069 as well as SACS Loop B piping. This room was considered conservatively as having similar internal flooding accident scenarios and core damage frequencies to those in Room 4109.

Reactor Building Room 4113

Room 4113 is located on Elevation 54' of the Reactor Building. This room contains RHR Pump 1AP202, RHR Heat Exchanger 1AE205, RHR Room Unit Coolers 1AVH210 and 1EVH210. Additionally, SACS Loop A lines are located within the room. This room has similar internal flooding accident scenarios and core damage frequencies to those in Room 4109.

Reactor Building Room 4114

Room 4114 is located on Elevation 54' of the Reactor Building. This room contains RHR Pump 1CP202, RHR Room Unit Coolers 1CVH210 and 1GVH210, and ECCS Jockey Pump 1CP228. Additionally, SACS Loop A lines are located within the room. This room was considered conservatively as having similar internal flooding accident scenarios and core damage frequencies to those in Room 4109.

Other Rooms in the Reactor Building

Due to the high degree of separation and compartmentalization of the reactor building, the rest of the rooms were combined together in their internal flooding initiating event frequency (0.2/yr.) and only the more severe accident scenarios with lack of flood isolation and failure of the drain system to prevent back flow through the check valves was considered. The calculated core damage frequency due to internal flooding in this case is 4.0E-8/yr.

Sump Cross Connection Through the Torus Area (Room 4102)

Some of the drain pipes from the torus area (Room 4102) are connected to sump 1AT265 while others are connected to sump1BT265. Therefore, in theory, it is possible that a flood to one sump can penetrate the other sump, with a potential impact on all the trains of the ECCS systems (if the flood is not isolated and the drain pumps fail).

This accident sequence frequency is characterized by the following failures:

1) the frequency of the internal flood initiating event

2) the failure to isolate the flood

3) the failure of the sump drain pumps

4) the common cause failure of all the drain pipe check valves to prevent backflow (failure to close upon demand). This includes the loss of separation between the drain sumps.

It should be noted that if all of the events 1-4 occur, all the ECCS systems are assumed lost, and core damage is assumed to occur. However, if any of the events 2-4 does not occur, the contribution to core damage was already accounted for in a previously described sequence.

Two separate cases were analyzed:

Case 1: All the check valves are two-flap type drain check valves.

In this case, a common cause failure of 1.0E-2 was assigned for the backflow from the drain sumps. In the flood studies described in the previous reactor building rooms, the common cause failure of the check valves was assigned a very conservative screening value of 0.9, because Hope Creek has experienced this type of failure in the past. However, these mishaps at Hope Creek occurred during leakage in the drain system, when a very low differential pressure was not able to close the check valves. During a real internal flood, a high differential pressure will develop, with a significantly lower probability of common cause failure of the check valves to close. Therefore, a value of 1.0E-2 was judged to be more realistic, but still higher by a factor of between 100 to 1000, than the common cause failure of check valves as published in the industry.

The failure probability to isolate the internal flood was assigned to be 1.0E-3, based on a longer time available to the operators to avoid the failure of the ECCS systems, because the flood water raises slowly in a larger number of rooms.

The failure probability of the sump drain pumps was calculated 2.0E-3, made up by actuation failure and by random and common cause failures of the drain pumps (hardware). The actuation failure includes the failure of the automatic actuation (1.0E-2) and the failure of the operator recovery actuation (1.0E-1). The pump hardware failure contribution is 1.0E-3 (mainly common cause failure to start).

In this case, the total contribution to the core damage frequency is 4.0E-8/yr.

Case 2: All the check valves are new, one flap type drain check valves.

In this case, a common cause failure of 1.0E-5 was assigned for the backflow from the drain sumps. In this case, the contribution to the core damage frequency becomes less than 1.0E-10/yr.

Intake Structure Room 110

Room 110 is located on Elevation 70' of the Service Water Intake Structure and includes 1E electrical cables (channels A, B, C and D), 1E instruments (channels A, B, C and D), 1EA-LSH 2372A, 1EA-LSH 2372B, and Spray Water Booster Pumps 1A(B)-P507 and 1C(D)-P507, all related to Division I of the service water system. Division I is completely and physically isolated from Division II (Room 111) by a structural wall. Only one case was calculated for this room, because it is completely separated from the other buildings. The calculated core damage frequency due to internal flooding in this case is 2.3E-9/yr, as shown in Table 3.3.9-1.

Intake Structure Room 111

Room 111 is located on Elevation 70' of the Service Water Intake Structure and includes equipment related to Division II of the service water system. The core damage frequency due to internal flooding in this case is assumed to be 2.3E-9/yr, similar to that of Service Water Intake Room 110.

3.3.9.2.2 Rooms Modeled As MSIV Closure

The MSIV Closure event tree is shown in Figure 3.1.2-2. The only internal flood event modeled by this event tree is the flood in the turbine building. The calculated core damage frequency in this case is 1.88E-7/yr.

3.3.9.3 Results Summary of Internal Flooding.

The total core damage frequency due to internal flooding is 5.1E-7/yr. A list of the representative sequences and their frequencies are given in Table 3.3.9-1. Each sequence includes its name, its flood description including the representative event tree (ET) sequence number, and the frequency contribution of the sequence to the total core damage frequency.

Table 3.3.1-1

GENERIC FAILURE RATES
MECHANICAL EQUIPMENT, WATER/STEAM WORKING FLUID

Component/Failure Mode[a]	Component/ Failure Code[b]	Median[c]	Mean[c]	Range Factor[c]
Valves				
Manual				
FTO	XVM-CC	4.0E-5/d	1.0E-4/d	10
FTC	XVM-OO	4.0E-5/d	1.0E-4/d	10
Plug	XVM-PG	1.2E-8/h	3.0E-8/h	10
Internal leakage	XVM-IL	4.0E-9/h	1.0E-8/h	10
External leakage	XVM-LK	4.0E-10/h	1.0E-9/h	10
Motor-operated				
FTO	MOV-CC	6.0E-4/d	1.0E-3/d	5
FTC	MOV-OO	6.0E-4/d	1.0E-3/d	5
FTRC	MOV-CO	4.0E-7/h	1.0E-6/h	10
FTRO	MOV-OC	4.0E-7/h	1.0E-6/h	10
Plug	MOV-PG	2.0E-8/h	5.0E-8/h	10
Internal leakage	MOV-IL	4.0E-8/h	1.0E-7/h	10
External leakage	MOV-LK	4.0E-9/h	1.0E-8/h	10
Pneumatic				
FTO	AOV-CC	6.0E-4/d	1.0E-3/d	5
FTC	AOV-OO	6.0E-4/d	1.0E-3/d	5
FTRC	AOV-CO	4.0E-7/h	1.0E-6/h	10
FTRO	AOV-OC	4.0E-7/h	1.0E-6/h	10
Plug	AOV-PG	1.2E-8/h	3.0E-8/h	10
Internal leakage	AOV-IL	4.0E-8/h	1.0E-7/h	10
External leakage	AOV-LK	4.0E-9/h	1.0E-8/h	10
Solenoid				
FTO	SOV-CC	4.0E-4/d	1.0E-3/d	10
FTC	SOV-OO	4.0E-4/d	1.0E-3/d	10
FTRC	SOV-CO	1.2E-6/h	3.0E-6/h	10
FTRO	SOV-OC	1.2E-6/h	3.0E-6/h	10
Plug	SOV-PG	2.0E-7/h	5.0E-7/h	10
Internal leakage	SOV-IL	4.0E-8/h	1.0E-7/h	10
External leakage	SOV-LK	4.0E-9/h	1.0E-8/h	10
Check				
FTO	CKV-CC	4.0E-5/d	1.0E-4/d	10
Plug	CKV-PG	4.0E-8/h	1.0E-7/h	10
FTC	CKV-OO	4.0E-5/d	1.0E-4/d	10
Internal leakage	CKV-IL	4.0E-8/h	1.0E-7/h	10
External leakage	CKV-LK	2.0E-9/h	5.0E-9/h	10
Safety/relief				
FTO	SRV-CC	1.2E-3/d	3.0E-3/d	10
Premature opening	SRV-CO	1.2E-6/h	3.0E-6/h	10
Fail to reclose	SRV-OO	4.0E-3/d	1.0E-2/d	10
Internal leakage	SRV-IL	4.0E-8/h	1.0E-7/h	10
External leakage	SRV-LK	4.0E-9/h	1.0E-8/h	10

Table 3.3.1-1 (Continued)

Component/Failure Mode[a]	Component/ Failure Code[b]	Median[c]	Mean[c]	Range Factor[c]
Explosive				
FTO	EPV-CC			
Premature opening	EPV-CO			
Internal leakage	EPV-IL			
External leakage	EPV-LK			
Orifice				
Plug	ORF-PG	4.0E-7/h	1.0E-6/h	10
External leakage	ORF-LK	2.0E-7/h	5.0E-7/h	10
Pumps				
Motor-driven				
FTS	MDP-FS	4.0E-4/d	1.0E-3/d	10
FTR	MDP-FR	4.0E-6/h	1.0E-5/h	10
External leakage	MDP-LK	4.0E-7/h	1.0E-6/h	10
Turbine-driven				
FTS	TDP-FS	2.0E-2/d	5.0E-2/d	10
FTR	TDP-FR	2.0E-5/h	5.0E-5/h	10
External leakage	TDP-LK	4.0E-7/h	1.0E-6/h	10
Diesel-driven				
FTS	EDP-FS	4.0E-3/d	1.0E-2/d	10
FTR	EDP-FR	6.0E-7/h	5.0E-6/h	30
External leakage	EDP-LK	4.0E-8/h	1.0E-7/h	10
Heat Exchangers				
General				
External leakage	HTX-LK	2.0E-8/h	5.0E-8/h	10
Tubes				
Leakage	HTX-IL	4.0E-7/h-unit	1.0E-6/h-unit	10
Plug	HTX-PG	4.0E-7/h-unit	1.0E-6/h-unit	10
Chiller				
Fail to operate	CHL-FR	1.2E-5/h	3.0E-5/h	10
Vessels				
Tank				
External leakage	TNK-LK	4.0E-8/h	1.0E-7/h	
Rupture	TNK-RP			
Pipes[d]				
<3 inch				
Leakage		1.2E-10/h-ft	1.0E-9/h-ft	30
Plug		1.2E-10/h-ft	1.0E-9/h-ft	30
>3 inch				
Leakage		1.2E-11/h-ft	1.0E-10/h-ft	30

Table 3.3.1-1 (Continued)

Component/Failure Mode[a]	Component/ Failure Code[b]	Median[c]	Mean[c]	Range Factor[c]
Strainer				
Plug	STR-PG	2.0E-6/h	5.0E-6/h	10
Internal leakage	STR-IL	6.0E-8/h	5.0E-7/h	30
Diesel Generator				
FTS	DGN-FS	6.0E-3/d	1.0E-2/d	5
FTR	DGN-FR	1.2E-3/h	3.0E-3/h	10

[a]Abbreviated failure modes are the following:

FTO - Fail to open
FTC - Fail to close
FTS - Fail to start
FTR - Fail to run
FTRO - Fail to remain open
FTRC - Fail to remain closed

b The component/failure codes were used in the Data Module of the microcomputer PRA Workstation to relate fault tree basic event identifiers (Section 3.4) to the corresponding generic failure rates.

c A lognormal distribution was assumed. The range factor is the ratio of the 95th percentile value to the median.

d External Leakage frequency divided by 20 to obtain a catastrophic large leakage failure frequency.

Table 3.3.1-2

GENERIC FAILURE RATES
MECHANICAL EQUIPMENT, AIR/GAS WORKING FLUID

Component/Failure Mode[a]	Component/Failure Code[b]	Median[c]	Mean[c]	Range Factor[c]
Fans and Blowers				
FTS	FAN-FS	2.0E-5/d	5.0E-5/d	10
FTR	FAN-FR	2.0E-6/h	5.0E-6/h	10
External leakage	FAN-LK	1.2E-7/h	3.0E-7/h	10
Compressors				
FTS	MDC-FS	2.0E-4/d	5.0E-4/d	10
FTR	MDC-FR	2.0E-5/h	5.0E-5/h	10
External leakage	MDC-LK	1.2E-7/h	3.0E-7/h	10
Dampers				
Air-operated				
FTO	PND-CC	1.2E-3/d	3.0E-3/d	10
FTC	PND-OO	1.2E-3/d	3.0E-3/d	10
FTRC	PND-CO	1.2E-7/h	3.0E-7/h	10
FTRO	PND-OC	1.2E-7/h	3.0E-7/h	10
Motor-operated				
FTO	MOD-CC	1.2E-3/d	3.0E-3/d	10
FTC	MOD-OO	1.2E-3/d	3.0E-3/d	10

Table 3.3.1-2 (Continued)

Component/Failure Mode[a]	Component/Failure Code[b]	Median[c]	Mean[c]	Range Factor[c]
FTRC	MOC-CO	1.2E-7/h	3.0E-7/h	10
FTRO	MOO-OC	1.2E-7/h	3.0E-7/h	10
Vessels				
Pressurized				
External leakage	TNK-LK	4.0E-8/h	1.0E-7/h	10
Accumulator				
External leakage	TNK-LK	4.0E-8/h	1.0E-7/h	10
Filters				
Plug	FLT-PG	1.2E-6/h	1.0E-5/h	30
Valves	Use water/steam working fluid results (Table 3.3.1-1)			
Piping	Use water/steam working fluid results (Table 3.3.1-1)			

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[a] Abbreviated failure modes are the following:

FTS - Fail to start
FTR - Fail to run
FTRO - Fail to remain open
FTRC - Fail to remain closed

[b] The component/failure codes were used in the Data Module of the microcomputer PRA Workstation to relate fault tree basic event identifiers (Section 3.4) to the corresponding generic failure rates.

[c] A lognormal distribution was assumed. The range factor is the ratio of the 95th percentile value to the median.

Table 3.3.1-3

GENERIC FAILURE RATES - ELECTRICAL EQUIPMENT

Component/Failure Mode[a]	Component/Failure Code[b]	Median[c]	Mean[c]	Range Factor[c]
Batteries and Chargers				
Chargers				
Rectifier				
Failure	REC-FR	2.0E-6/h	5.0E-6/h	10
Motor-generator				
Failure	CHG-FR	2.0E-5/h	5.0E-5/h	10
Batteries				
Primary				
Failure	BAT-NO	1.2E-6/h	3.0E-6/h	10
Secondary				
Failure	BAT-NO	1.2E-6/h	3.0E-6/h	10
Circuit Breakers				
Indoors				
FTO	BKR-CC	6.0E-5/d	5.0E-4/d	30
FTC	BKR-OO	1.2E-4/d	1.0E-3/d	30
Spurious operation	BKR-SA	1.2E-7/h	1.0E-6/h	30
Relays				
FTO	RLY-CC	2.0E-6/d	5.0E-6/d	10
FTC	RLY-OO	2.0E-6/d	5.0E-6/d	10
Spurious operation	RLY-SA	1.2E-7/h	1.0E-6/h	30
Switches				
Limit				
FTO	LSW-CC	4.0E-5/d	1.0E-4/d	10
FTT	LSW-FT	4.0E-5/d	1.0E-4/d	10

Table 3.3.1-3 (Continued)

Component/Failure Mode[a]	Component/Failure Code[b]	Median[c]	Mean[c]	Range Factor[c]
FTC	LSW-OO	4.0E-5/d	1.0E-4/d	10
Spurious operation	LSW-SA	2.0E-6/h	5.0E-6/h	10
Pushbutton				
FTO	ZSW-CC	1.2E-5/d	3.0E-5/d	10
FTT	ZSW-FT	1.2E-5/d	3.0E-5/d	10
FTC	ZSW-OO	4.0E-6/d	1.0E-5/d	10
Spurious operation	ZSW-SA	4.0E-7/h	1.0E-6/h	10
Bus				
Failure AC	BAC-LP	4.0E-7/h	1.0E-6/h	10
Failure DC	BDC-LP	4.0E-7/h	1.0E-6/h	10
Fuses				
FTO	FUS-CC	6.0E-6/d	1.0E-5/d	5
Premature opening	FUS-SA	4.0E-7/h	1.0E-6/h	10
Inverter				
FTS	INV-FS	2.0E-3/d	5.0E-3/d	10
FTR	INV-FR	3.0E-6/h	5.0E-5/h	50
Heaters				
Air				
Failure	AHU-FC	1.2E-6/h	3.0E-6/h	10
Power Failure	AHU-LP	1.2E-6/h	3.0E-6/h	10

Table 3.3.1-3 (Continued)

Component/Failure Mode[a]	Component/Failure Code[b]	Median[c]	Mean[c]	Range Factor[c]
Pipe				
Failure	PHT-FC	2.0E-6/h	3.0E-6/h	5
Power Failure	PHT-LP	2.0E-6/h	3.0E-6/h	5
Transformers				
Station service				
Failure	TFM-LP	2.0E-7/h	5.0E-7/h	10
Main power				
Failure	TFM-LP	4.0E-7/h	1.0E-6/h	10
Instrument				
Failure	TFM-LP	2.0E-7/h	5.0E-7/h	10
Instruments, Controls, and Sensors				
Temperature Element/Transmitter				
Failure	TST-NO	2.0E-6/h	5.0E-6/h	10
Process switch (comparator)				
FTO/C	TPS-FT	4.0E-8/d	1.0E-7/d	10
Spurious operation	TPS-SA	1.2E-7/h	3.0E-7/h	10
Pressure				
Element/Transmitter				
Failure	DPT-NO	1.2E-6/h	3.0E-6/h	10
	PST-NO	1.2E-6/h	3.0E-6/h	10

Table 3.3.1-3 (Continued)

Component/Failure Mode[a]	Component/Failure Code[b]	Median[c]	Mean[c]	Range Factor[c]
Process switch (comparator)				
FTO/C	PPS-FT	1.2E-7/d	3.0E-7/d	10
Spurious operation	PPS-SA	4.0E-8/h	1.0E-7/h	10
Flow				
Element/Transmitter				
Failure	FST-NO	1.2E-6/h	3.0E-6/h	10
Process switch (comparator)				
FTO/C	FPS-FT	4.0E-9/h	1.0E-8/d	10
Spurious operation	FPS-SA	4.0E-7/h	1.0E-6/h	10
Level				
Element/Transmitter				
Failure	LST-NO	2.0E-6/h	5.0E-6/h	10
Process switch (comparator)				
FTO/C	LPS-FT	4.0E-8/d	1.0E-7/d	10
Spurious operation	LPS-SA	4.0E-7/h	1.0E-6/h	10
Radiation				
Failure	RST-NO	2..0E-6/h	5.0E-6/h	10
Modifier (ac-dc, analog-digital, computation, etc.)				
Failure, calculational unit	CAL-NO	1.2E-6/h	3.0E-6/h	10
Failure, signal conditioner	CND-NO	1.2E-6/h	3.0E-6/h	10

Table 3.3.1-3 (Continued)

Component/Failure Mode[a]	Component/Failure Code[b]	Median[c]	Mean[c]	Range Factor[c]
Cables				
Copper (1000 ft)				
Open circuit	CBL-OP	4.0E-7/h	1.0E-6/h	10
Short circuit	CBL-ST	4.0E-6/h	1.0E-5/h	10
Solid State Logic Module				
Failure	LOG-NO	1.2E-8/h	1.0E-7/h	30

---

[a]Abbreviated failure modes are the following:

FTO - Fail to open
FTC - Fail to close
FTO/C - Fail to open or close
FTS - Fail to start
FTR - Fail to run
FTT - Fail to transfer

[b] The component failure codes were used in the Data Module of the microcomputer PRA workstation to relate fault tree basic event identifiers (Section 3.4) to the corresponding generic failure rates.

[c] A lognormal distribution was assumed. The range factor is the ratio of the 95th percentile value to the median.

Table 3.3.1-4

COMPONENT FAILURE RATE SOURCES

Abbreviation	Reference Title
Bush	Reliability of piping in Light Water Reactors
EGG CRBRP PRA	Clinch River Breeder Reactor Plant Probabilistic Risk Assessment - Phase 1
Elec de France	Pump Reliability Data Derived from Electricite de France Operating Experience
EPRI NP-2230	ATWS: A Reappraisal
EPRI NP-2433	Diesel Generator Reliability at Nuclear Power Plants: Data and Preliminary Analysis
IEEE	IEEE Guide to the Collection and Presentation of Electrical, Electronic, Sensing Component, and Mechanical Equipment Reliability Data for Nuclear-Power Generating Stations (IEEE Std. 500-1984)
IEEE	IEEE Recommended Practice for the Design of Reliable Industrial and Commercial Power Systems (IEEE Std. 493-1990)
IPRDS Description	The In-Plant Reliability Data Base for Nuclear Power Plant Components: Data Collection and Methodology Report
IPRDS - Pumps	The In-Plant Reliability Data Base for Nuclear Plant Components: Interim Data Report - The Pump Component
IPRDS - Valves	The In-Plant Reliability Data Base for Nuclear Plant Components: Interim Reports - The Valve Component
IREP	Interim Reliability Evaluation Program (IREP) Procedures Guide
LER-CRDMs	Data Summaries of Licensee Event Reports of Control Rods and Drive Mechanisms at U.S. Commercial Nuclear Power Plants.
LER - Diesel Generators	Data Summaries of Licensee Event Reports of Diesel Generators at U.S. Commercial Nuclear Power Plants
LER - I&Cs	Data Summaries of Licensee Event Reports of Selected Instrumentation and Control Components at U.S. Commercial Nuclear Power Plants
LER - Pumps	Data Summaries of Licensee Event Reports of Pumps at U.S. Commercial Nuclear Power Plants
LER - Valves	Data Summaries of Licensee Event Reports of Valves at U.S. Commercial Nuclear Power Plants
LMEC	Failure Data Handbook
NEDM-14082	Update of the Preliminary Reliability Prediction for CRBRP Shutdown Heat Removal System
NPE	Nuclear Power Experience
NPRD-91	Nonelectric Parts Reliability Data 1991
NPRDS	Nuclear Plant Reliability Data System (NPRDS) 1982 Annual Reports
NUREG-1000	Generic Implications of ATWS Events at the Salem Nuclear Power Plant
Piping Survey	Sodium Piping Survey to July 1977
WASH-1400	Reactor Safety Study: An Assessment of Accident Risks in U.S. Commercial Nuclear Power Plants
YNPS PSS	Yankee Nuclear Power Station Probabilistic Safety Study

TABLE 3.3.2-1

HCGS OPERATIONAL HOURS
(1987 through 31 July 1993)

Year	Hours in Mode 1 or 2
1987	7,570.1
1988	7,089.5
1989	6,813.9
1990	8,020.0
1991	7,379.8
1992	7,094.3
1993 (Through July 31, 1993)	5,750.0
TOTAL:	49,717.6

HCGS UNAVAILABILITY DATA

A. Based upon Reliability and Assessment Records (30 months ending June 30, 1993)

PRA Code	Station Code	Hours Unavailable	Hours Required	Unavailability $\overline{A}$
ACP	PB	123.4	87,552	1.41E-03
CAC	GS	770.1	21,888	3.52E-02
DCP	PJ	17.3	21,888	7.90E-04
IGS	KL	46.7	21,888	2.13E-03
SAC	EG	956.3	87,552	1.09E-02
SLC	BH	66.5	37,336	1.78E-03

TABLE 3.3.2-1 (Continued)
HCGS UNAVAILABILITY DATA

B. Based upon System Engineering Data (54 months ending June 30, 1993)

PRA Code	Station Code	Hours Unavailable	Hours Required	Unavailability $\overline{A}$
DGS	KJ	920.45	151,536.0	6.07E-03
HPI	BJ-FD	608.96	33,579.4	1.81E-02
RCI	BD-FC	727.85	33,579.4	2.17E-02
RHS	BC	335.16	77,607.0	4.32E-03

C. Based upon Hope Creek PRA (Reference 3.3.2-6)

PRA Code	Station Code	Hours Unavailable	Hours Required	Unavailability $\overline{A}$
ADS	SN	100.3	22,502	4.45E-03
CSS	BE	292.5	45,004	6.50E-03
SWS	EA	1,610.8	45,004	3.58E-02

HCGS RELIABILITY DATA

A. Starts

PRA Code	Station Code	Start Attempts	Start Failures	Start Reliability
DGS	KJ	514	3	0.9942
HPI	BJ-FD	23	0	1.0000
RCI	BD-FC	23	0	1.0000

B. Run Data

PRA Code	Station Code	Load Run Hours	Load Run Failures	Load Run Reliability
DGS	KJ	2,054.8	0	1.0000

TABLE 3.3.2-2
IMPORTANT HCGS TEST AND MAINTENANCE OUTAGES

System or Train	Event Identifier	System/Train TM Outage (Hours)	System/Train Required (Hours)	TM Unavailability	Notes
RCI	RCI-TDP-TM-OP203	727.85	33,579.40	2.17E-02	
HPI	HPI-TDP-TM-OP204	608.96	33,579.40	1.81E-02	
RHS	RHS-MDP-TM-PX	335.16	77,607.00	4.32E-03	Average of four motor-driven pumps
CSS	CSS-MDP-TM-PX	292.50	45,004.00	6.50E-03	Average of four motor-driven pumps
ADS	ADS-ICG-TM-TRNX	100.30	22,502.00	4.46E-03	Average of two trains, B and D
SLC	SLC-MDP-TM-XP208	66.50	37,336.00	1.78E-03	Average of two motor-driven pumps
SAC	SAC-MDP-TM-PSXDX	956.30	87,552.00	1.09E-02	Average of four motor-driven pumps
SWS	SWS-MDP-TM-XP502	1610.80	45,004.00	3.58E-02	Average of four motor-driven pumps
DGS	DGS-DGN-TM-XG400	920.45	151,536.00	6.07E-03	Average of four diesel generators
CHS	CHC-CHL-TM LOOP			1.00E-02	Estimate
	CHS-CHL-TM LOOP			1.00E-02	Estimate
CNS	CNS-TDP-TM-XP101			1.00E-03	Estimate
	CNS-MDP-TM-X-102			1.00E-03	Estimate
	CNS-MDP-TM-XP137			1.00E-03	Estimate
IAS	IAS-CMP-TM-K100			1.50E-02	Estimate
	IAS-CMP-OK107			1.00E-02	Estimate
	IAS-CM--TM-1K107			1.50E-02	Estimate
RAC	RAC-HX-TM-XE217			1.00E-03	Estimate
	RAC-MDP-TM-XP209			1.00E-03	Estimate
VAS	VAS-ACX-TM-CSSBX			1.00E-02	Estimate
VCA	VCA-FAN-TM-CRSTX			1.00E-02	Estimate
	VCA-FAN-TM-CREFX			1.00E-02	Estimate
	VCA-FAN-TM-CETRX			1.00E-02	Estimate
VDG	VDG-FAN-TM-DGTRX			1.00E-02	Estimate
VSW	VSW-FAN-TM-TRX			2.00E-02	Estimate
	VSW-FAN-TM-BTYNX			2.00E-02	Estimate

The range factor for all plant-specific TM unavailabilities is 5, and the range factor for estimated TM unavailabilities is 10.

TABLE 3.3.2-3
HCGS COMPONENT FAILURE DATA

System	Event Identifier	Failures Per Demand	Plant-Specific Failure Rate (Demand)	Generic Failure Rate (Demand)	Updated Rate (Demand)	Updated Range Factor	HCGS PRA Value
CSS	CSS-MDP-FS-PX	0/21	0.0	1.00E-03	8.86E-04	10.0	8.86E-04
DGS	DGS-DGN-FS-XG400	3/514	5.84E-03	1.00E-02	6.28E-03	2.25	6.28E-03
	DGS-DGN-FR-XG400	0/2054.8*	0.0	7.20E-02**	6.61E-03**	5.0	6.61E-03**
HPI	HPI-TDP-FS-OP204	0/23	0.0	5.00E-02	4.21E-03	12.2	4.21E-03
RCI	RCi-TDP-FS-OP203	0/23	0.0	5.00E-02	4.21E-03	12.2	4.21E-03
RHS	RHS-MDP-FS-PX	0/142	0.0	1.00E-03	5.34E-04	10.0	5.34E-04
SAC	SAC-MDP-FS-XP210	0/111	0.0	1.00E-03	5.95E-04	10.0	5.95E-04
SWS	SWS-MDP-FS-XP502	1/196	5.10E-03	1.00E-03	3.24E-03	3.6	3.24E-03

* 2054.8 is hours, not demands.

** Failure rate per 24 hours.

Table 3.3.3-1

CONDITIONS AND PROCEDURES ASSOCIATED WITH CALIBRATION AT HCGS

---

1. Calibration is normally performed every 3, 6, 12 or 18 months as applicable.

2. Each calibration is covered by a separate procedure sheet.

3. Calibration teams normally involve two or more people:

    a. One person performs the calibration

    b. The other person or persons observe the work and check off each step as it is completed.

4. Procedure sheets have a before calibration reading entry and an after calibration entry which are to be compared when calibration is completed (prior to shift foreman signoff).

5. The I&C maintenance foreman checks the consistency of before and after readings after the calibration. This is accomplished within three working days.

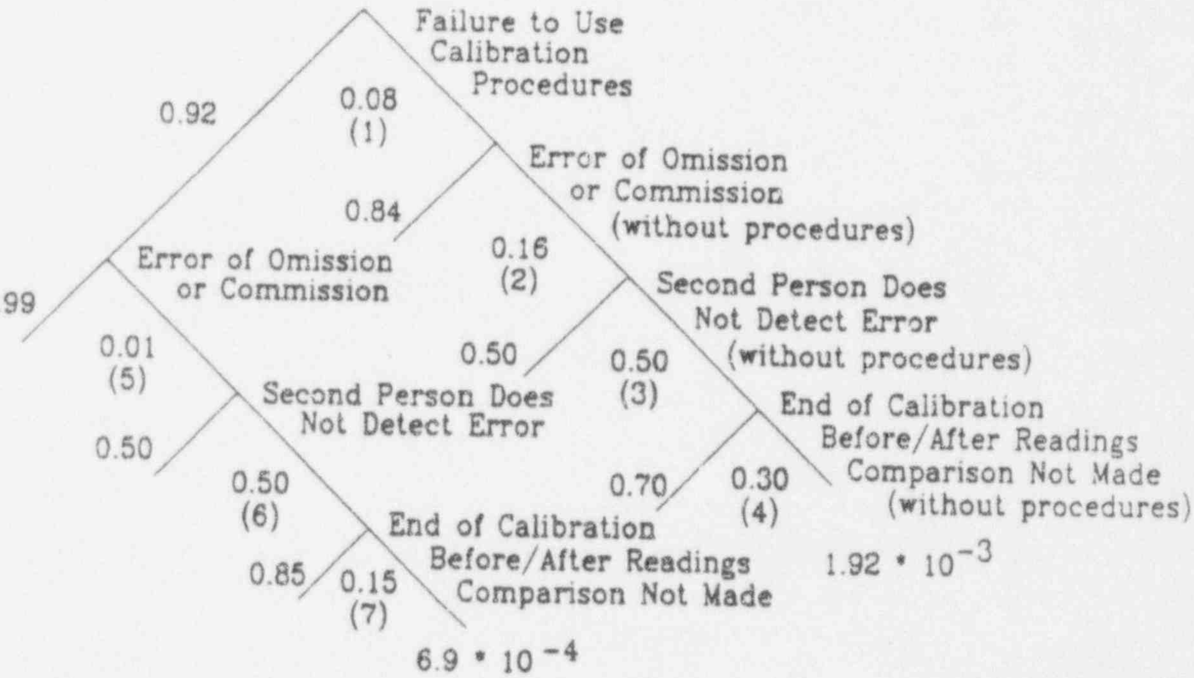
6. Some of the instrument panel checks are completed by reactor operators observing the indicated value from the calibrated instrument, and comparing those readings with other instrument readings.

7. Calibration procedures involve a second person or group to check the procedure.

8. I&C technicians can close and open most instrument sensing line valves with approved test procedures and shift foreman permission. Other sensing line valves must be closed (and opened) by an operator.

Table 3.3.3-2

THERP MODEL OF MISCALIBRATION AT HCGS



Sum of failure path probabilities = $2.61 \cdot 10^{-3}$

Table 3.3.3-2 (continued)

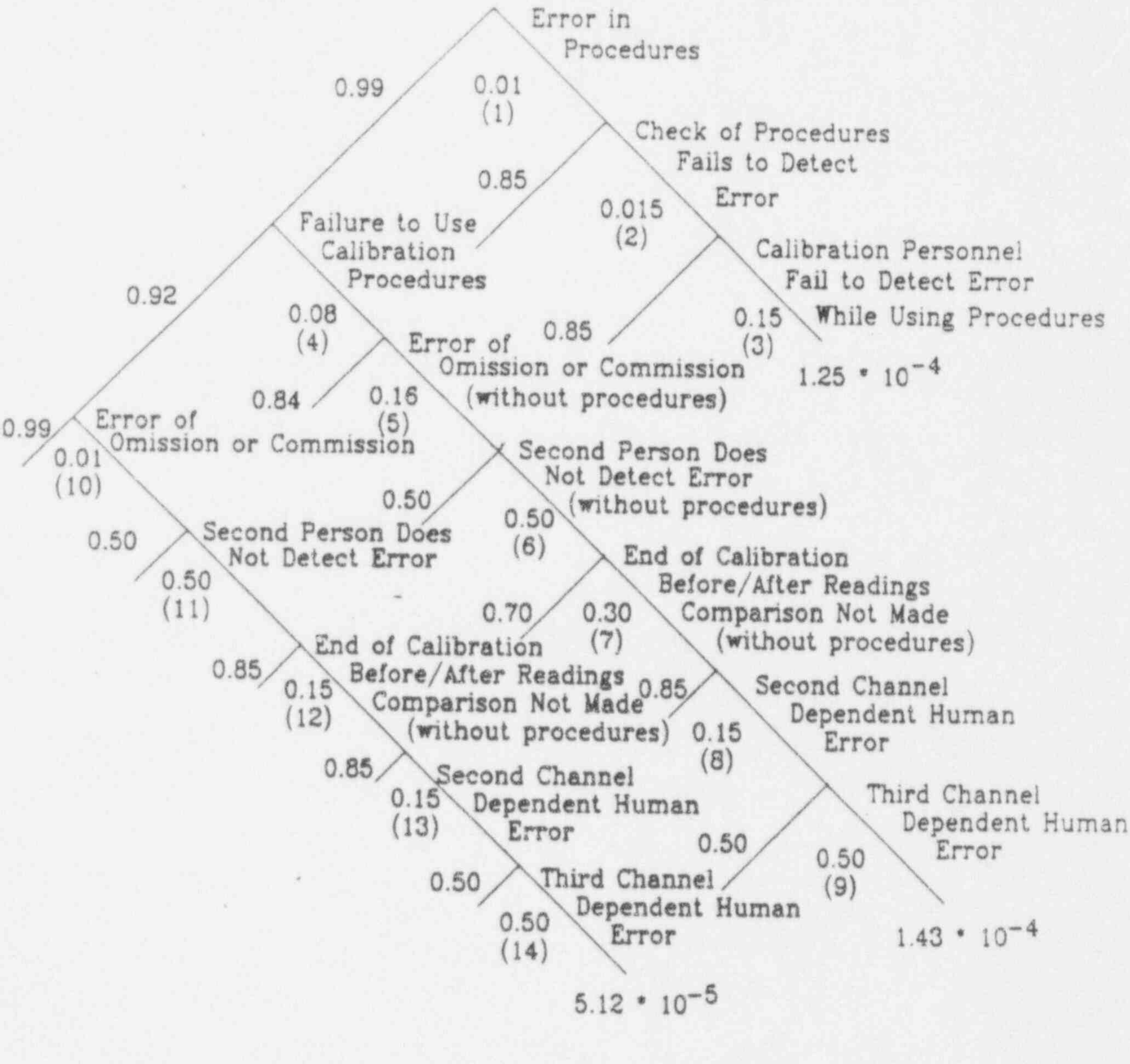
Note	Handbook Source (3.3.3-1)	Median	RF	Mean
1.	Table 20-6, item 6	0.05	5	0.08
2.	Table 20-7, item 5 (value doubled to account for both types of errors)	0.05	5	0.08
3.	Table 20-22, item 8	0.50	2	0.50
4.	Table 20-22, item 2	0.2	5	0.3
5.	Table 20-7, item 2	0.003	5	0.005
6.	Same as note 3			
7.	Table 20-22, item 1	0.01	5	0.15

Assumptions

1. No credit was taken for maintenance section manager recovery or operator recovery.
2. The before and after readings check for consistency was treated as an independent and separate task in the procedures.

Table 3.3.3-3

THERP MODEL FOR DEPENDENT MISCALIBRATION
OF THREE CHANNELS AT HCGS



Sum of failure path probabilities = 3.19 * 10^{-4}

Table 3.3.3-3

Note	Handbook Source 3.3.3-1	Human Error Rate Median	RF	Mean
1.	Table 20-5, items 1 and 3	0.003	5	0.005
2.	Table 20-22, item 1	0.1	5	0.15
3.	Table 2-22, item 1	0.1	5	0.15
4.	Table 20-6, item 6	0.05	5	0.08
5.	Table 20-7, item 5 (value doubled to account for both types of errors)	0.05	5	0.08
6.	Table 20-22, item 8 (no distinction for with or without procedures)	0.05	5 (reduced to 2)	0.5
7.	Table 20-22, item 2	0.2	5	0.3
8.	Table 10-2, moderate dependence	--	--	0.15
9.	Table 10-2, high dependence	--	--	0.5
10.	Table 20-7, item (or page 20-13) (value doubled to account for both types of errors)	0.003	5	0.08
11.	Same as note 6			
12.	Same as note 7			
13.	Same as note 8			
14.	Same as note 9			

Table 3.3.3-4

CONDITIONS AND PROCEDURES ASSOCIATED WITH MAINTENANCE AND RESTORATION AT HCGS

1. Scheduled maintenance may be performed while the unit is at power. [a]

2. Unscheduled maintenance can be performed during power operation, within the Technical Specification guidelines.

3. Most maintenance acts have an applicable set of procedures.

4. Operations personnel perform all isolation before maintenance and realignment after maintenance.

5. After maintenance is complete, the shift supervisor approves removal of the blocking tags.

6. Maintenance teams normally involve two or more people:
   a. One or more persons perform the maintenance.
   b. One person observes the work and checks off each step as it is completed, if there is an applicable procedure.

7. Each component maintained is tested for proper operation following maintenance, if required.

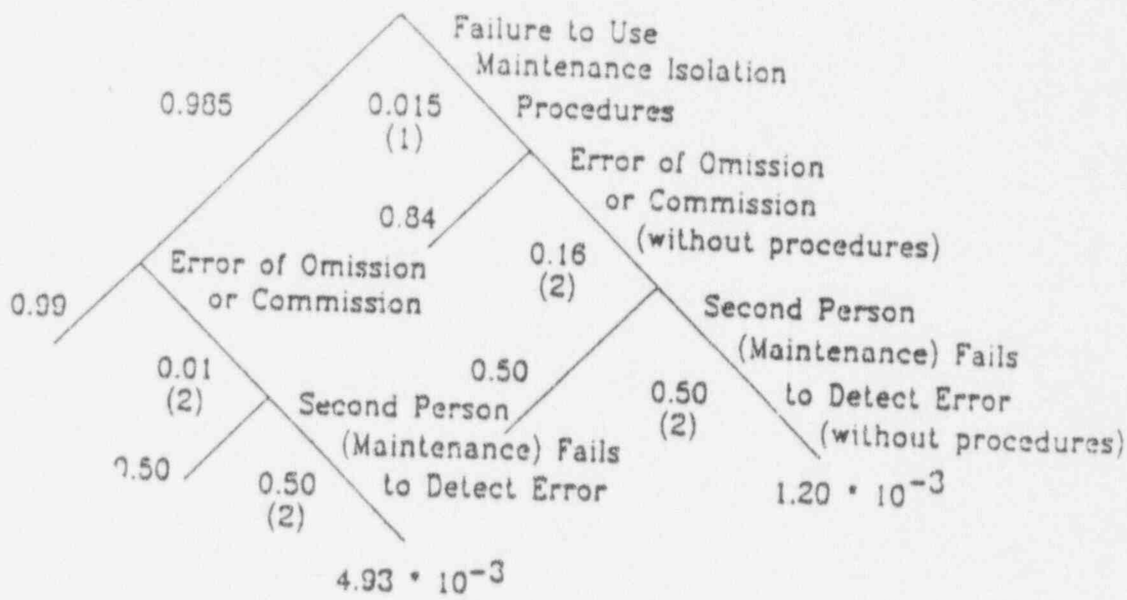
8. The maintenance supervisor verifies that blocking tags are physicaly in place for personnel safety prior to allowing any personnel to start work on a component.

9. When components in safety-related systems are tagged out, and again when the tags are released, a second operator independently verifies the tag/release. This is in addition to the maintenance personnel verification.

a Scheduled maintenance involves routine preventive maintenance performed on a regular schedule. Unscheduled maintenance is corrective maintenance (repair) performed when a component fails.

Table 3.3.3-5

THERP MODEL FOR RESTORATION ERROR FOLLOWING TEST OR MAINTENANCE AT HCGS



Sum of failure path probabilities = 6.13 E-3

Note	Handbook Source (Ref. 3.3.3-1)
1.	Table 20-6, Item 5
2.	Human Error rates are similar to those used for calibration

Human Error Probability		
Median	RF	Mean
0.01	5	0.015

Table 3.3.3-6

CALIBRATION AND RESTORATION ERRORS MODELED IN FAULT TREES

Event	Description	Detect[a] Code	TM Int[b] Code	HEP[c] Code	Screen[d] Value
ACP-XHE-MC-11008	miscal. breaker fdr bus volt sensor 52-11008	DT6	TI10	C1	1.6E-4
ACP-XHE-MC-12001	same - sensor 52-12001	DT6	TI10	C1	1.6E-4
ACP-XHE-MC-40101	same - sensor 52-40101	DT10	TI10	C1	3.0E-3
ACP-XHE-MC-40208	same - sensor 52-40208	DT10	TI10	C1	3.0E-3
ACP-XHE-MC-40301	same - sensor 52-40301	DT10	TI10	C1	3.0E-3
ACP-XHE-MC-40408	same - sensor 52-40408	DT10	TI10	C1	3.0E-3
ACP-XHE-MC-A0373	miscal. of UV sensor for UV relaying 1A0373	DT6	TI10	C1	1.6E-4
ACP-XHE-MC-A0374	same - 1A0374	DT6	TI10	C1	1.6E-4
ACP-XHE-MC-A0375	same - 1A0375	DT6	TI10	C1	1.6E-4
ACP-XHE-MC-A0376	same - 1A0376	DT6	TI10	C1	1.6E-4
CHC-XHE-MC-FTA3	miscal. FT-9468A, no loop A signal	DT10	TI10	C1	3.0E-3
CHC-XHE-RE-MV057	chilled wtr. train B inlet valve mispositioned	DT6	TI9	R1	4.1E-4
CHC-XHE-RE-MV059 to 64	same - valves MV059 to MV064	DT6	TI9	R1	4.1E-4
CHC-XHE-RE-MV098	same - valve MV098	DT6	TI9	R1	4.1E-4
CHS-XHE-MC-FTA1	miscal. FT-9666A1, no loop A signal	DT10	TI10	C1	3.0E-3
CHS-XHE-RE-CWSVB	chilled wtr. train B valves mispositioned	DT6	TI9	R1	4.1E-4
DGS-XHE-MC-7508A	miscal. DG A fuel oil pressure switch	DT6	TI10	C1	1.6E-4
DGS-XHE-MC-7508B	same - DG B	DT6	TI10	C1	1.6E-4
DGS-XHE-MC-7508C	same - DG C	DT6	TI10	C1	1.6E-4
DGS-XHE-MC-7508D	same - DG D	DT6	TI10	C1	1.6E-4
DGS-XHE-MC-7530A	miscal. DG A day tank level switch	DT6	TI10	C1	1.6E-4
DGS-XHE-MC-7530B	same - DG B	DT6	TI10	C1	1.6E-4
DGS-XHE-MC-7530C	same - DG C	DT6	TI10	C1	1.6E-4
DGS-XHE-MC-7530D	same - DG D	DT6	TI10	C1	1.6E-4
ESF-XHE-MC-402A	miscal. of level XMTER SA-LT-402A	DT6	TI10	C1	1.6E-4
ESF-XHE-MC-402B, E, F	same - XMTERs SA-LT-402B, E, F	DT6	TI10	C1	1.6E-4
ESF-XHE-MC-403A, B, E, F	same - XMTERs SL-PT-403A, B, E, F	DT6	TI10	C1	1.6E-4
ESF-XHE-MC-DF01	miscal. of all pressure XMTERs	DT6	TI10	C3	1.6E-5
ESF-XHE-MC-DF01A	dep. miscal. CSS ch. A pressure xmtrs	DT6	TI10	C4	2.7E-5
ESF-XHE-MC-DF01B	dep. miscal. ADS ch. B pressure xmtrs	DT6	TI10	C4	2.7E-5
ESF-XHE-MC-DF01C	dep. miscal. CSS ch. C pressure xmtrs	DT6	TI10	C4	2.7E-5
ESF-XHE-MC-DF01D	dep. miscal. ADS ch. D pressure xmtrs	DT6	TI10	C4	2.7E-5
ESF-XHE-MC-DF02	miscal. of all level XMTERs	DT6	TI10	C3	1.6E-5

Table 3.3.3-6 (Continued)
CALIBRATION AND RESTORATION ERRORS MODELED IN FAULT TREES

Event	Description	Detect[a] Code	TM Int[b] Code	HEP[c] Code	Screen[d] Value
ESF-XHE-MC-N035A, E	miscal. of level XMTERs N035A, E	DT6	TI10	C1	1.6E-4
ESF-XHE-MC-N058A TO D	miscal. of pressure XMTERs E11-N058A, B, C, D	DT6	TI10	C1	1.6E-4
ESF-XHE-MC-N061A, E	miscal. of level XMTER LI-N061A, E	DT6	TI10	C1	1.6E-4
ESF-XHE-MC-N062A, E	miscal. of level XMTER LI-N062A, E	DT6	TI10	C1	1.6E-4
ESF-XHE-MC-N090A, B, E, F, J, K, N, P	miscal. of pressure XMTER B21-N090A, B, E, F, J, K, N, P	DT6	TI10	C1	1.6E-4
ESF-XHE-MC-M097D, H	miscal. of BB-LI-N097D, H	DT6	TI10	C1	1.6E-4
ESF-XHE-MC-DF02A	dep. miscal. CSS ch. A level xmtrs	DT6	TI10	C4	2.7E-5
ESF-XHE-MC-DF02B	dep. miscal. ADS ch. B level xmtrs	DT6	TI10	C4	2.7E-5
ESF-XHE-MC-DF02C	dep. miscal. CSS ch. C level xmtrs	DT6	TI10	C4	2.7E-5
ESF-XHE-MC-DF02D	dep. miscal. ADS ch. D level xmtrs	DT6	TI10	C4	2.7E-5
ESF-XHE-MC-NO91A	miscal. L1 level xmtr LT-N091A	DT6	TI10	C1	1.6E-4
ESF-XHE-MC-NO91B	miscal. L1 level xmtr LT-N091B	DT6	TI10	C1	1.6E-4
ESF-XHE-MC-NO91C	miscal. L1 level xmtr LT-N091C	DT6	TI10	C1	1.6E-4
ESF-XHE-MC-NO91D	miscal. L1 level xmtr LT-N091D	DT6	TI10	C1	1.6E-4
ESF-XHE-MC-NO91E	miscal. L1 level xmtr LT-N091E	DT6	TI10	C1	1.6E-4
ESF-XHE-MC-NO91F	miscal. L1 level xmtr LT N091F	DT6	TI10	C1	1.6E-4
ESF-XHE-MC-NO91G	miscal. L1 level xmtr LT-N091G	DT6	TI10	C1	1.6E-4
ESF-XNE-MC-NO91H	miscal. L1 level xmtr LT-N091H	DT6	TI10	C1	1.6E-4
ESF-XHE-MC-NO94A	miscal. pressure xmtr PT-N094A	DT6	TI10	C1	1.6E-4
ESF-XHE-MC-NO94B	miscal. pressure xmtr PT-N094B	DT6	TI10	C1	1.6E-4
ESF-XHE-MC-NO94C	miscal. pressure xmtr PT-N094C	DT6	TI10	C1	1.6E-4
ESF-XHE-MC-NO94D	miscal. pressure xmtr PT-N094D	DT6	TI10	C1	1.6E-4
ESF-XHE-MC-NO94E	miscal. pressure xmtr PT-N094E	DT6	TI10	C1	1.6E-4
ESF-XHE-MC-NO94F	miscal. pressure xmtr PT-N094F	DT6	TI10	C1	1.6E-4
ESF-XHE-MC-NO94G	miscal. pressure xmtr PT-N094G	DT6	TI10	C1	1.6E-4
ESF-XHE-MC-NO94H	miscal. pressure xmtr PT-N094H	DT6	TI10	C1	1.6E-4
RAC-XHE-MC-2601	miscal. flow control element FE-2601	DT10	TI10	C1	3.0E-3
RAC-XHE-MC-T2617	miscal. of sensor TE-2617	DT10	TI10	C1	3.0E-3
SAC-XHE-MC-DF01	dep. miscal. HV-2457s temp. controller	DT10	TI10	C4	5.0E-4
SAC-XHE-MC-DF02	dep. miscal. HV-2517s temp. controllers	DT10	TI10	C4	5.0E-4
SAC-XHE-RE-V380	fail to restore RHS pump A cooler SAC valve	DT6	TI10	R1	2.7E-4
SAC-XHE-RE-V384	same - pump B	DT6	TI10	R1	2.7E-4
SAC-XHE-RE-V381	same - pump C	DT6	TI10	R1	2.7E-4
SAC-XHE-RE-V385	same - pump D	DT6	TI10	R1	2.7E-4
SLC-XHE-RE-AP208	Op fails to align AP208 post-maint.	DT6	TI6	R3	5.0E-4

CALIBRATION AND RESTORATION ERRORS MODELED IN FAULT TREES

Event	Description	Detect[a] Code	TM Int[b] Code	HEP[c] Code	Screen[d] Value
SLC-XHE-RE-BP208	Op fails to align BP208 post-maint.	DT6	TI6	R3	5.0E-4
SWS-XHE-RE-PSA04	fail to restore the SWS-TWSCP-507 path	DT7	TI10	R2	1.6E-4
SWS-XHE-RE-PSB04	same - DP-507	DT7	TI10	R2	1.6E-4
(SIMILAR EVENTS FOR ALL OTHER ROOM COOLERS QUANTIFIED IN THE SAME MANNER)					
VCA-XHE-MC-CETRA	miscal. CER train A instrumentation	DT10	TI10	C1	3.0E-3
VCA-XHE-MC-CETRB	same - train B	DT10	TI10	C1	3.0E-3
VCA-XHE-MC-CRSFA	miscal. CREF/CRS train A instrumentation	DT10	TI10	C1	3.0E-3
VCA-XHE-MC-CREFB	same - train B	DT10	TI10	C1	3.0E-3
VCA-XHE-MC-CRSTA	miscal. CRS train A instrumentation	DT10	TI10	C1	3.0E-3
VCA-XHE-MC-CRSTB	same - train B	DT10	TI10	C1	3.0E-3
CHC-XHE-RE-CHWVA	fail to restore CER train A CHC valves	DT10	TI10	R2	1.0E-3
CHC-XHE-RE-CHWVB	same - train B	DT10	TI10	R2	1.0E-3
CHC-XHE-RE-CRSCH	fail to restore CRS train A CHC valves	DT10	TI10	R2	1.0E-3
CHC-XHE-RE-CRSCW	same - train B	DT10	TI10	R2	1.0E-3
SAC-XHE-RE-SACSV	fail to restore DG room A coolers SAC valves	DT6	TI10	R2	5.5E-5
(SIMILAR EVENTS FOR ALL OTHER DG ROOMS HVAC QUANTIFIED IN A SIMILAR MANNER)					
CHS-XHE-RE-CWSV[h]	fail to restore PRS train A CHS valves	DT10	TI10	R2	1.0E-3
CHS-XHE-RE-CWSVB[h]	same - train B	DT10	TI10	R2	1.0E-3
VSW-XHE-MC-SWTRA	miscal. VSW train A instrumentation	DT10	TI10	C1	3.0E-3
VSW-XHE-RE-BTYTA	fail to restore battery room train A dampers	DT10	TI10	R2	1.0E-3
VSW-XHE-RE-MDMPR	fail to restore VSW train A manual dampers	DT10	TI10	R2	1.0E-3
(SIMILAR EVENTS FOR VSW TRAIN B QUANTIFIED IN THE SAME MANNER)					
CHS-XHE-RE-MV016	fail to restore VSW train A CHS valve	DT10	TI10	R1	5.0E-3
CHS-XHE-RE-MV041	same	DT10	TI10	R1	5.0E-3
CHS-XHE-RE-MV057	same - train B	DT10	TI10	R1	5.0E-3
CHS-XHE-RE-MV098	same - train B	DT10	TI10	R1	5.0E-3

CALIBRATION AND RESTORATION ERRORS MODELED IN FAULT TREES

Footnotes to Table 3.3.3-6

[a] Fault detection time (FDT) codes entered into the Data Module for event quantification are defined as follows:

DT1 = 1 h	DT6 = 720 h
DT2 = 8 h	DT7 = 2160 h
DT3 = 12 h	DT8 = 4380 h
DT4 = 24 h	DT9 = 8760 h
DT5 = 168 h	DT10 = 13140 h

[b] Test or maintenance interval (INT) time codes entered into the Data Module for event quantification are defined as follows:

TI1 = 1 h	TI6 = 720 h
TI2 = 8 h	TI7 = 2160 h
TI3 = 12 h	TI8 = 4380 h
TI4 = 24 h	TI9 = 8760 h
TI5 = 168 h	TI10 = 13140 h

[c] Human Error Probability (HEP) codes entered into the Data Module for event quantification are defined as follows:

C1 = 3E-3 (calibrate 1 component)	R1 = 5E-3 (restore 1 component)
C4 = 5E-4 (calibrate 2 component)	R2 = 1E-3 (restore 2 component)
C3 = 3E-4 (calibrate 3 component)	R3 = 5E-4 (restore 3 component)

[d] The screening values were calculated from the following equation:

$$\frac{\text{Rn (or Cn)} * \text{DTn}}{\text{TIn}}$$

Rather than entering these screening values directly into the Data Module as user-specified values, the time codes were entered along with the applicable HEP codes as MC- or RE-specified events.

Table 3.3.3-7

OPERATOR ERRORS MODELED IN FAULT TREES

EVENT	DESCRIPTION
ADS-XHE-ATWS-INH	fail to inhibit ADS during an ATWS
ADS-XHE-FO-DEPRE	fail to manually depressurize
ATW-XHE-ARI-FAIL	fail to initiate ARI
ATW-XHE-HP-CS-IN	fail to prevent HPCI inj. through CS line during ATWS
CAC-XHE-FO-12WW	fail to initiate containment venting
CHC-XHE-FO-LOOPB	fail to start CHC Loop B
CHS-XHE-FO-LOOPB	fail to start CHS Loop B
CNS-XHE-FO-CNSP	fail to initiate primary condensate pumps
CNS-XHE-FO-CNSS	fail to initiate secondary condensate pumps
CRH-XHE-FO-MKUP	fail to align CRD hydraulics for max flow
CRH-XHE-FO-SCRAM	fail to ensure scram no reset
CSS-XHE-FO-INIT	fail to initiate CSS
CST-XHE-FO-ALIGN	fail to align CSS suction to CST for long-term makeup
HPI-XHE-FO-ISOL	fail to bypass HPCI/RCIC high temperature isol.
HPI-XHE-FO-INIT	fail to manually initiate HPCI
HPI-XHE-FO-LCNTL	fail to control RPV water level-high
HPI-XHE-FO-XFER	fail to manually switch HPCI/RCIC suction to SP
HPS-XHE-FO-WTLVL	fail to control water level with HPCI during an ATWS
HVAC-XHE-FO-RECY	fail to recover HVAC per procedure
IAS-XHE-FO-EIAC	fail to reclose emer. IAS compr. bkr. after LOCA or LOP
IGS-XHE-FO-IAS	fail to open IAS cross-tie to IGS
IGS-XHE-FO-RESET	fail to reset IGS after LOCA or LOP
LPI-XHE-FO-LCNTL	fail to control RPV water level-low
QAT-XHE-FO-LVL	fail to prevent MSIV closure on low level
QAT-XHE-FO-LVL8T	fail to prevent FW trip on high level during ATWS
QAT-XHE-FO-MSBY	fail to bypass MSIV closure during ATWS
QAT-XHE-FO-RESF	fail to restart FW during ATWS
QFW-XHE-FO-RECOV	fail to recov. FW after loss of FW IE
QS1-XHE-FO-LVL1	fail to recover FW (LOCA)
RAC-XHE-FO-LOCA	fail to realign SSWS cooling to RACS after LOCA signal
RAC-XHE-FS-CP209	fail to start RACS pump CP209
RCI-XHE-FO-INIT	fail to manually initiate RCIC
RCI-XHE-FO-XFER	fail to transfer RCIC suction
RCIC-XHE-FO-ISOL	fail to bypass isolation
RHS-XHE-FO-CSC	fail to initiate RHR flow through CSC
RHS-XHE-FO-LPI	fail to man. initiate RHR LPCI flow
RHS-XHE-FO-SPC	fail to initiate RHR SPC flow
SAC-XHE-FS-A through DP210	fail to start pump A through DP210
SDG-XHE-FEEDBKR	fail to load and start DG
SWS-XHE-FS-A through DP502	fail to start pump A through DP502
UV1-XHE-FO-ALIGN	fail to align alternate injection flowpaths to RPV
VCA-XHE-FO-CREFB	fail to manually initiate CREF train B
XHE-FO-SEAL-ISOL	fail to isolate seal LOCA

TABLE 3.3.3-8
DESCRIPTION OF HUMAN RECOVERY ACTIONS APPLIED

	Recovery	Description	Value
1.	NR-AIR-24	Failure to recover the IAS within 24 hours	5.7E-3
2.	NR-ATWS-ADS-INH	Failure to inhibit ADS during an ATWS	7.5E-2
3.	NR-ATWS-ARI	Failure to manually initiate ARI	1.4E-2
4.	NR-ATWS-DEP	Failure to manually depressurized the RPV during an ATWS	5.6E-2
5.	NR-ATWS-HPCI-30M	Failure to initiate HPCI during an ATWS	5.0E-2
6.	NR-ATWS-HPCI-CS	Failure to isolate HPCI injection through the Core Spray piping during an ATWS	2.4E-1
7.	NR-ATWS-LCNTL-LO	Failure to control RPV water level with LPCI during an ATWS	4.7E-1
8.	NR-COND-5	Failure to restart condensate pumps after other injection systems fail	3.7E-2
9.	NR-DG-6	Failure to recover D/Gs within 6 hours (independent failures of D/Gs)	7.0E-1
10.	NR-DG-DF-6	Failure to recover D/Gs within 6 hours (common cause failures of D/Gs)	6.0E-1
11.	NR-HPCI-LCNT-HIE	Failure to control RPV water level using HPCI during an ATWS to prevent core damage	4.6E-2
12.	NR-HVC-PNRM-12	Failure to provide alternate ventilation to the Panel Room within 12 hours after a loss of HVAC	3.0E-4
13.	NR-HVC-SWGR-24	Failure to provide alternate ventilation to the Switchgear Room within 24 hrs after loss of HVAC	1.6E-4
14.	NR-IGS-24	Failure to restart the EIAC after RACS cooling has been restored followed a LOCA isolation	3.8E-3
15.	NR-LOSP-24	Failure to restore offsite power within 24 hours	2.2E-3
16.	NR-LOSP-12	Failure to restore offsite power within 12 hours	1.5E-2
17.	NR-LOSP-6	Failure to restore offsite power within 6 hours	5.0E-2
18.	NR-LOSP-5	Failure to restore offsite power within 5 hours	7.0E-2
19.	NR-LOSP-1	Failure to restore offsite power within 1 hour	4.0E-1
20.	NR-LOSP-40M	Failure to restore offsite power within 40 minutes	5.5E-1
21.	NR-LOSP-30M	Failure to restore offsite power within 30 minutes	6.0E-1

Table 3.3.3-8 (continued)

22.	NR-PCS-24	Failure to restore the PCS within 24 hours following a turbine trip or MSIV closure initiating event	7.0E-4
23.	NR-PCS-1	Failure to restore the PCS within 1 hour	6.0E-1
24.	NR-PCS-40M	Failure to restore the PCS within 40 minutes	9.0E-1
25.	NR-Q-FWLVH-4M	Failure to prevent a level 8 trip of feedwater during a transient	1.4E-2
26.	NR-Q-FWLVL-24M	Failure to prevent a level 8 trip of feedwater during a small LOCA	4.9E-3
27.	NR-RACS-24	Failure to restore the RACS after a LOCA isolation	3.8E-3
28.	NR-RHR-INIT	Failure to initiate RHR for decay heat removal within 24 hours	5.0E-5
29.	NR-SLEAK-ISO-15M	Failure to isolate recirculation pump seal LOCA	8.2E-2
30.	NR-SPL-LVLL-4	Failure to align core spray to the CST for long-term injection (without decay heat removal)	1.1E-1
31.	NR-U1X-DEP-30M	Failure to manually depressurize the RPV within 30 minutes	7.5E-3
32.	NR-U1X-DEP-40M	Failure to manually depressurize the RPV within 40 minutes	5.2E-3
33.	NR-U1X-DEP-60M	Failure to manually depressurize the RPV within 1 hour	4.6E-3
34.	NR-UV-ECCS-1	Failure to manually initiate ECCS within 1 hour	3.9E-2
35.	NR-UV-WTLVL-20M	Failure to control RPV water level with high pressure injection systems (not during ATWS)	4.3E-2
36.	NR-VENT-5	Failure to initiate containment venting	2.0E-3
37.	NR-WW1-SWP-1	Failure to manually start SSWS or SACS pumps within 1 hour	1.2E-2
38.	NR-WW1-SWP-12	Failure to manually start SSWS or SACS pumps within 12 hours	1.9E-4
39.	NR-WW1-SWP-20	Failure to manually start SSWS or SACS pumps within 20 hours	7.4E-5
40.	NR-WW1-SWP-40M	Failure to manually start SSWS or SACS pumps within 40 minutes	1.6E-2

Table 3.3.4-1

DEPENDENT FAILURE BETA FACTOR ESTIMATES

BETA Factor by Source

Component Type	Failure Mode	EPRI NP-3967	NUREG/CR-2098	NUREG/CR-2099	NUREG/CR-2770	Seabrook PSA	HCGS Recommended BETA Factor	Comments
Motor-Operated Valve	Fail to Open/Close	0.08			0.08	0.04	0.07	Arithmetic Mean
Air-Operated Valve	Fail to Open/Close				0.17		0.17	Arithmetic Mean
Check Valve	Fail to Open				0.22		0.22	
Safety-Relief Valve	Fail to Open	0.22			0.65		0.44	Arithmetic Mean
Safety-Relief Valve	Fail to Close	0.22					0.22	Same as FO value
Diesel Generator	Fail to Start	0.06		0.04		0.01	0.04	Arithmetic Mean
Diesel Generator	Fail to Run	0.06		0.04		0.03	0.04	Arithmetic Mean
Pumps - Condensate	Fail to Run	0.04	0.30			0.08	0.14	Arithmetic Mean
	Fail to Start					0.11	0.11	
Pumps -	Fail to Start	0.14	0.25			0.04	0.14	Arithmetic Mean
CCW (SACS, SSWS, RACS, CHC, CHS)		0.18				0.07		
Pumps -	Fail to Run	0.14	0.09			0.02	0.09	Arithmetic Mean
CCW (SACS, SSWS, RACS, CHC, CHS)		0.18				0.03		
Pumps - RHR, CSS, SLC, UV1	Fail to Start		0.23				0.23	
Pumps - RHR, CSS, SLC, UV1	Fail to Run	0.09					0.09	
Pumps - Turbine Driven (HPCI/RCIC)	Fail to Start		0.03				0.03	Point Estimate
	Fail to Run		0.02				0.02	Point Estimate
Generic Component						0.125	0.125	

Table 3.3.4-2

DEPENDENT FAILURE GAMMA FACTOR ESTIMATES

GAMMA Factor by Source

Component Type	Failure Mode	*	EPRI NP-3967	NUREG/CR-2098	NUREG/CR-2099	NUREG/CR-2770	Seabrook PSA	HCGS Recommended GAMMA Factor	Comments
Motor-Operated Valve	Fail to Open/Close	A	0.24			0.27		0.26	Arithmetic Mean
Air-Operated Valve	Fail to Open/Close	A						0.43	
		B				0.43			
Safety-Relief Valve	Fail to Open	A	0.79			0.84		0.82	Arithmetic Mean
Safety-Relief Valve	Fail to Close	A	0.79					0.79	Same as FO Value
Diesel-Generator	Fail to Start	A	0.30					0.34	Weighted Average
		B			0.43				
Diesel-Generator	Fail to Run	A	0.30					0.34	Same as FS Value
		B			0.43				
Pumps - Condensate	Fail to Run	A	0.67	0.71				0.69	Arithmetic Mean
	Fail to Start							0.41	Used Value for CCW Pumps
Pumps - CCW (SACS, SSWS, RACS, CHC, CHS)	Fail to Start	A	0.27					0.41	Weighted Average
		A	0.53						
		B		0.43					
Pumps - CCW(SACS, SSWS, RACS, CHC, CHS)	Fail to Run	A	0.27					0.41	Same as FS Value
		A	0.53						
		B		0.43					
Pumps - RHR, CSS, SLC, UV1	Fail to Start	A		0.13				0.13	
Pumps - RHR, CSS, SLC, UV1	Fail to Run	A		0.60				0.60	
Generic Component								0.41	Used same gamma as CCW pumps

* "A" signifies that the parameter values are based entirely on actual data.
"B" signifies that the parameter values are based on extrapolations, as indicated in the text.

Table 3.3.4-3
DEPENDENT FAILURE DELTA FACTOR ESTIMATES
DELTA Factor by Source

Component Type	Failure Mode	*	EPRI NP-3967	NUREG/CR-2098	NUREG/CR-2099	NUREG/CR-2770	Seabrook PSA	HCGS Recommended DELTA Factor	Comments
Motor Operated Valve	Fail to Open/Close	A	0.67					0.62	Arithmetic Mean
		B				0.53			
Air-Operated Valve	Fail to Open/Close	A						0.53	
		B							
		C				0.53			
Safety-Relief Valve	Fail to Open	A	0.71			0.78		0.75	Arithmetic Mean
Safety-Relief Valve	Fail to Close	A	0.71					0.71	Same as FO Value
Diesel-Generator	Fail to Start	A	0.31					0.35	Weighted Average
		B							
		C			0.53				
Diesel-Generator	Fail to Run	A	0.31					0.35	Same as FS Value
		B							
		C			0.53				
Pumps - CCW (SACS, SSWS, RACS, CHC, CHS)	Fail to Start	A						0.53	Weighted Average
		B	0.53						
		C		0.53					
Pumps - CCW (SACS, SSWS, RACS, CHC, CHS)	Fail to Run	A						0.53	Same as FS Value
		B	0.53						
		C		0.53					
Pumps - RHR, CSS, SLC, UV1	Fail to Start	A						0.53	
		B		0.53					
Pumps - RHR, CSS, SLC, UV1	Fail to Run	A						0.53	
		B		0.53					
Generic Component								0.53	Used same delta as CCW pumps

* "A" signifies that the parameter values are based entirely on actual data.
"B" signifies that the parameter values are based on first order extrapolations, as indicated in the text.
"C" signifies that the parameter values are based on second order extrapolations, as indicated in the text.

Table 3.3.4-4

IMPORTANT DEPENDENT EVENTS MODELED PARAMETRICALLY

System	DEPENDENT Event Identifier	DEPENDENT Event Quantification	DEPENDENT Event Description
HPCI	HPI-MOV-CC-DF01	1.00E-3	Valves HV-8278 and F006 fail to open
RCIC	RCI-SOV-CC-DF01	1.70E-4	Valves SV-4405 and F016 fail to close
CRH	CRH-MDP-FS-DF01	1.40E-4	Pumps A and BP207 fail to start
	CRH-MDP-FR-DF01	2.20E-5	Pumps A and BP207 fail to run
CNS	CNS-MDP-FS-DF03	1.16E-5	Pumps A through CP102 fail to start
	CNS-MDP-FS-DF02	1.68E-5	Pumps A through CP137 fail to start
	CNS-MDP-FR-DF03	1.45E-7	Pumps A through CP102 fail to run
	CNS-MDP-FR-DF02	2.10E-7	Pumps A through CP137 fail to run
	CNS-TDP-FS-DF01	8.40E-4	Pumps A through CP101 fail to start
	CNS-TDP-FR-DF01	1.05E-6	Pumps A through CP101 fail to run
	CNS-MOV-CC-DF01	1.82E-5	Valves HV-1680A through C fail to open

Table 3.3.4-4 (Continued)

System	DEPENDENT Event Identifier	DEPENDENT Event Quantification	DEPENDENT Event Description
	CNS-MOV-CC-DF02	1.82E-5	Valves HV-1651A through C fail to open
CSS	CSS-MDP-FS-DF01	2.04E-5	Pumps A through DP207 fail to start
	CSS-MDP-FR-DF01	5.04E-6	Pumps A through DP207 fail to run
	CSS-MOV-CC-DF01	3.00E-5	Valves HV-F005A and B fail to open
	CSS-MOV-CC-DF02	3.00E-5	Valves HV-F031A and B fail to open
RHS	RHS-MDP-FS-DF01	1.72E-5	Pumps A through DP202 fail to start
(LPI,	RHS-MDP-FS-DF02	1.00E-3	Pumps A and BP202 fail to start
CSC,			
SDC)	RHS-MDP-FR-DF01	4.50E-6	Pumps A through DP202 fail to run
	RHS-MDP-FR-DF02	2.20E-5	Pumps A and BP202 fail to run

Table 3.3.4-4 (Continued)

System	DEPENDENT Event Identifier	DEPENDENT Event Quantification	DEPENDENT Event Description
RHS	RHS-MDP-FR-DF03	2.20E-5	Pumps A and CP202 fail to run
(cont'd)	RHS-MDP-FR-DF04	2.20E-5	Pumps B and DP202 fail to run
	RHS-MOV-CC-DF01	6.30E-6	Valves HV-F017A through D fail to open
	RHS-MOV-CC-DF02	3.00E-5	Valves HV-F017A and B fail to open
	RHS-MOV-CC-DF03	6.30E-6	Valves HV-F007A through D fail to open
	RHS-MOV-CC-DF04	1.00E-3	Valves HV-F007A and B fail to open
	RHS-MOV-CC-DF05	1.00E-3	Valves HV-F021A and B fail to open
	RHS-MOV-CC-DF07	1.00E-3	Valves HV-F047A and B fail to open
SLC	SLC-EPV-CC-DF2	1.70E-4	Valves HV-F004A and B fail to open
	SLC-MDP-FS-DF02	1.40E-4	Pumps A and BP208 fail to start
	SLC-MDP-FR-DF02	2.20E-5	Pumps A and-BP208 fail to run
	RWC-MOV-OO-DF04	7.00E-5	Valves HV-F001 and F004 fail to close

Table 3.3.4-4 (Continued)

System	DEPENDENT Event Identifier	DEPENDENT Event Quantification	DEPENDENT Event Description
CAC	CAC-AOV-CC-DF01	1.50E-5	Large butterfly vent valves fail to open (HV-4950, 4952, 4956, 4958, 4962, 4964, 4978, 4980)
	CAC-AOV-CC-DF02	5.00E-5	Small vent valves fail to open (HV-4951, 4963)
DGS	DGS-DGN-FS-DF01	3.33E-5	Diesel generators A through DG400 fail to start
	DGS-DGN-FS-DF02	2.06E-5	Diesel generators A, B and CG400 fail to start
	DGS-DGN-FS-DF03	2.06E-5	Diesel generators A, B and DG400 fail to start
	DGS-DGN-FS-DF04	2.06E-5	Diesel generators A, C and DG400 fail to start
	DGS-DGN-FS-DF05	2.06E-5	Diesel generators B, C and DG400 fail to start
	DGS-DGN-FS-DF06	6.16E-5	Diesel generators A and BG400 fail to start
	DGS-DGN-FS-DF07	6.16E-5	Diesel generators A and DG400 fail to start
	DGS-DGN-FS-DF08	6.16E-5	Diesel generators A and DG400 fail to start
	DGS-DGN-FS-DF09	6.16E-5	Diesel generator B and CG400 fail to start

Table 3.3.4-4 (Continued)

System	DEPENDENT Event Identifier	DEPENDENT Event Quantification	DEPENDENT Event Description
	DGS-DGN-FS-DF10	6.16E-5	Diesel generator B and DG400 fail to start
	DGS-DGN-FS-DF11	6.16E-5	Diesel generator C and DG400 fail to start
	DGS-DGN-FR-DF01	3.43E-4	Diesel generators A through DG400 fail to run
	DGS-DGN-FR-DF02	2.12E-4	Diesel generators A, B, CG400 fail to run
	DGS-DGN-FR-DF03	2.12E-4	Diesel generators A, B, DG400 fail to run
	DGS-DGN-FR-DF04	2.12E-4	Diesel generators A, C, D, G400 fail to run
	DGS-DGN-FR-DF05	2.12E-4	Diesel generators B, C, D, G400 fail to run
	DGS-DGN-FR-DF06	6.34E-4	Diesel generators A, B, G400 fail to run
	DGS-DGN-FR-DF07	6.34E-4	Diesel generators A, C, G400 fail to run
	DGS-DGN-FR-DF08	6.34E-4	Diesel generators A, D, G400 fail to run
	DGS-DGN-FR-DF09	6.34E-4	Diesel generators B, C, G400 fail to run
	DGS-DGN-FR-DF10	6.34E-4	Diesel generators B, D, G400 fail to run
	DGS-DGN-FR-DF11	6.34E-4	Diesel generators C, D, G400 fail to run

Table 3.3.4-4 (Continued)

System	DEPENDENT Event Identifier	DEPENDENT Event Quantification	DEPENDENT Event Description
RAC	RAC-MDP-FS-DF01	2.30E-4	Pumps A and BP209 fail to start
	RAC-MDP-FR-DF01	2.16E-5	Pumps A and BP209 fail to run
	RAC-MOV-CC-DF01	7.00E-5	Valves HV-2537A and B fail to open
	RAC-MOV-OO-DF02	7.00E-5	RACS Isln valves to the aux. bldg. fail to close
SAC	SAC-MDP-FS-DF01	2.30E-4	Pumps A and CP210 fail to start
	SAC-MDP-FS-DF02	2.30E-4	Pumps B and DP210 fail to start
	SAC-MDP-FS-DF03	7.59E-5	Pumps A through DP210 fail to start
	SAC-MDP-FR-DF01	2.16E-5	Pumps A and CP210 fail to run
	SAC-MDP-FR-DF02	2.16E-5	Pumps B and DP210 fail to run
	SAC-MDP-FR-DF03	7.13E-6	Pumps A through DP210 fail to run
	SAC-MOV-CC-DF20	3.00E-5	Valves Hv-2512A and B fail to open

Table 3.3.4-4 (Continued)

System	DEPENDENT Event Identifier	DEPENDENT Event Quantification	DEPENDENT Event Description
SWS	SWS-MDP-FS-DF01	4.00E-5	Pumps A and CP502 fail to start
	SWS-MDP-FS-DF02	4.00E-5	Pumps B and DP502 fail to start
	SWS-MDP-FS-DF03	3.17E-5	Pumps A through DP502 fail to start
	SWS-MDP-FS-DF04	2.16E-5	Pumps A through DP507 fail to start
	SWS-MDP-FR-DF01	4.08E-5	Pumps A and CP502 fail to run
	SWS-MDP-FR-DF02	4.08E-5	Pumps B and DP502 fail to run
	SWS-MDP-FR-DF03	3.42E-5	Pumps A through DP502 fail to run
	SWS-MDP-FR-DF04	1.50E-5	Pumps A through DP507 fail to run
	SWS-MOV-CC-DF03A	3.00E-5	SWS Strainer valves HV-2197 A and C fail to open
CHS	CHC-CHL-FS-DF01	1.00E-3	Chillers A and BK400 fail to start
	CHC-CHL-FR-DF01	7.20E-5	Chillers A and BK400 fail to run
	CHC-MDP-FS-DF01	2.16E-5	Pumps A and BP400 fail to start
	CHC-MDP-FR-DF01	2.16E-5	Pumps A and BP400 fail to run
	CHS-CHL-FS-DF01	1.00E-3	Chillers A and BK403 fail to start

Table 3.3.4-4 (Continued)

System	DEPENDENT Event Identifier	DEPENDENT Event Quantification	DEPENDENT Event Description
	CHS-CHL-FR-DF01	7.20E-5	Chillers A and BK403 fail to run
	CHS-CHL-FS-DF01	1.00E-3	Pumps A and BP414 fail to start
	CHS-MDP-FR-DF01	2.16E-5	Pumps A and BP414 fail to run
	CHS-MDP-FS-DF01	2.30E-4	Pumps A and BP414 fail to start
IAS	IAS-CMP-FR-DF02	9.60E-5	Compressors 00K107 and 10K107 fail to run
IGS	IGS-CMP-FS-DF01	2.85E-4	Compressors A and BK202 fail to start
	IGS-CMP-FR-DF02	4.70E-4	Compressors A and BK202 fail to run
	IGS-MOV-CC-DF03	7.00E-5	Headers A and B valves fail to open (HV-5126A, B; 5152A, B; 5160A, B)
VCA	VCA-FAN-FR-DF01	1.20E-5	Fans A and BV415 fail to run
	VCA-FAN-FS-DF02	5.00E-6	Fans A and BV415 fail to start

Table 3.3.4-4 (Continued)

System	DEPENDENT Event Identifier	DEPENDENT Event Quantification	DEPENDENT Event Description
VDG	VDG-FAN-FS-DF04	5.00E-6	Fans D and HV412 fail to start
	VDG-FAN-FR-DF05	1.20E-5	Fans A and EV412 fail to run
VPR	VPR-FAN-FR-DF01	1.20E-5	Fans A and BV408 fail to run
	VPR-FAN-FR-DF02	1.20E-5	Fans A and BV416 fail to run
	VPR-FAN-FS-DF03	5.00E-6	Fans A and BV408 fail to start
	VPR-FAN-RS-DF04	5.00E-6	Fans A and BV416 fail to start

TABLE 3.3.7-1
HOPE CREEK FUNCTIONAL EQUATION SUMMARY TABLE

Top Event	Description	ET	Fcn Eqn	Success Criteria	FT(s)	Gate to Solve	XHOS (Linked FT)
A	Large LOCA	A	NA	IE-TOP	LARGE-LOCA	NA	
C	RPS	all but ATWS	C	RPS (electrical & mechanical)	C-TOP	C-TOP	NA
Ce	RPS electrical	Ta, Tat, Ta1, Ta2	CE	RPS electrical portion functions	ATWS-TOP	RPS-ELECT	NA
Cm	RPS mechanical	Ta, Tat, Ta1, Ta2	CM	RPS mechanical portion functions	ATWS-TOP	RPS-MECH	NA
C2	SLC boron	Ta, Tat, Ta1, Ta2	C2	2/2 SLC pumps provide boration	SLC	SLC1	XHOS-BRK = 0 XHOS-HIDWP = 1 XHOS-LOCA = 0 XHOS-LOP = 0 XHOS-THV = 0 XHOS-TRAN = 1 XHOS-TSASW = 0
D	vapor suppression system	A, S1	D	general system success (1 UE) [1 WW/DW vacuum breaker opens, and none stuck open prior to LOCA]	D-TOP	VAPOR-SUPP-FAILS	NA
		S2	D-S2	general system success (1UE) [no more than 1WW/DW vacuum breaker fails to reclose if demanded]	D-TOP	D-S2	NA
E	off-site power available	Tt, Tm, Tf, Ti, Tia, Tra	E	off-site power to 1/4 4160V 1E ac buses	E-TOP	ACP-FAILS-OFFSIT	XHOS-HIDWP=1 XHOS-LOCA=0 XHOS-LOP=0 XHOS-THV=0 XHOS-TRAN=1 XHOS-TSASW=0
		A, S1, S2	E-LOC	off-site power to 1/4 4160V 1E ac buses, following LOCA	E-TOP	ACP-FAILS-OFFSIT	XHOS-HIDWP=0 XHOS-LOCA=1 XHOS-LOP=0 XHOS-THV=0 XHOS-TRAN=0 XHOS-TSASW=0
Edg	emergency diesel generator available	Te	EDG	power to 4160V 1E bus from 1/4 DGs	EDG-TOP	ACP-FAILS-EDG	XHOS-HIDWP=1 XHOS-LOCA=0 XHOS-LOP=1 XHOS-THV=0 XHOS-TRAN=0 XHOS-TSASW=0
Edg		A, S1	EDG-LOC	power to 4160V 1E bus from 1/4 DGs, following LOCA	EDG-TOP	ACP-FAILS-EDG	XHOS-HIDWP=0 XHOS-LOCA=1 XHOS-LOP=1 XHOS-THV=0 XHOS-TRAN=0 XHOS-TSASW=0
H	Operator succesfully controls water level in ATWS	Ta, Tat, Ta1, Ta2	H-HIGH	control of water level using high pressure injection systems	ATWS-TOP	H-HIGH	NA
		Ta, Tat, Ta1, Ta2	H-LOW	control of water level using low pressure injection systems	ATWS-TOP	H-LOW	NA
Hvc	HVAC available	Tt, Tm, Tf, Ti, Tia, Tra	HVC	panel room cooling and 1 Switchgear room cooling loop	HVAC	ROOM-COOL	XHOS-HIDWP=1 XHOS-LOCA=0 XHOS-LOP=0 XHOS-THV=0 XHOS-TRAN=1 XHOS-TSASW=0

TABLE 3.3.7-1
HOPE CREEK FUNCTIONAL EQUATION SUMMARY TABLE (Cont'd.)

Top Event	Description	ET	Fcn Eqn	Success Criteria	FT(s)	Gate to Solve	XHOS (Linked FT)
		A, S1, S2	HVC-LOC	panel room cooling and 1 Switchgear room cooling loop, following LOCA	HVAC	ROOM-COOL	XHOS-HIDWP=0 XHOS-LOCA=1 XHOS-LOP=0 XHOS-THV=0 XHOS-TRAN=0 XHOS-TSASW=0
		Te	HVC-LOP	panel room cooling and 1 Switchgear room cooling loop, given LOSP	HVAC	ROOM-COOL	XHOS-HIDWP=1 XHOS-LOCA=0 XHOS-LOP=1 XHOS-THV=0 XHOS-TRAN=0 XHOS-TSASW=0
	HVAC available	Tsa	HVC-S	panel room cooling and 1 Switchgear room cooling loop, given Loss of SACS/SW	HVAC	ROOM-COOL	XHOS-HIDWP=1 XHOS-LOCA=0 XHOS-LOP=0 XHOS-THV=0 XHOS-TRAN=1 XHOS-TSASW=1
In1	Operator inhibits HPCI/CS operation	Ta, Tat, Ta1, Ta2	IN1	successful inhibit of HPCI/CS system following ATWS	ATWS-TOP	INHIBIT-HPCI-CS	NA
In2	Operator inhibits ADS operation	Ta, Tat, Ta1, Ta2	IN2	successful inhibit of ADS following ATWS	ATWS-TOP	INHIBIT-ADS	NA
Iso	seal isolation	S2	ISO	isolation of seal loca	SEALLOCA	SEAL-ISOL	NA
K	ARI	Ta, Tat, Ta1, Ta2	K	Successful operation of ARI	ATWS-TOP	ARI	NA
M	SRVs open	Tt, Tm, Tf, Te, Thv, Tia, Tra, Tsa	M-2	2/14 SRVs open	M-TOP	SRV-FAIL-OPEN	NA
		Ta, Tat, Ta1, Ta2	M-ATWS	8/14 SRVs open	ATWS-TOP	SRVS-FTO	NA
Msv	MSIV closed	Tat, Ta1	MSV-1	MSIVs remain open with no SORVs	ATWS-TOP	MSIV-CLOSURE-1	NA
		Tat, Ta1	MSV-2	MSIVs remain open with one SORV	ATWS-TOP	MSIV-CLOSURE-2	NA
		Tat, Ta1	MSV-3	MSIVs remain open with two or more SORVs	ATWS-TOP	MSIV-CLOSURE-3	NA
P	SRVs close	S2, Tt, Tf	P	all SRVs close (given 3 demands)	P-TOP	SRV-1-CLOSE-DMD3	NA
		Tm, Te, Thv, Tia, Tra, Tsa	P-TM	all SRVs close (given 6 demands)	P-TOP	SRV-1-CLOSE-DMD6	NA
		Ta, Tat, Ta1, Ta2	P-ATWS	all SRVs close following ATWS	ATWS-TOP	SRV-1-CLOSE-ATWS	NA
P2	all but one SRVs close	Tt, Tf	P2	all but one SRVs close (given 3 demands)	P-TOP	SRV-2-CLOSE-DMD3	NA
		Tm, Te, Tia, Thv, Tra, Tsa	P2-TM	all but one SRVs close (given 6 demands)	P-TOP	SRV-2-CLOSE-DMD6	NA
		Ti	P2-1	all SRVs close (given 3 demands)	P-TOP	SRV-1-CLOSE-DMD3	NA
		Ta, Tat, Ta1, Ta2	P2-ATWS	all but one SRVs close following ATWS	ATWS-TOP	SRV-2-CLOSE-ATWS	NA

TABLE 3.3.7-1
HOPE CREEK FUNCTIONAL EQUATION SUMMARY TABLE (Cont'd.)

Top Event	Description	ET	Fcn Eqn	Success Criteria	FT(s)	Gate to Solve	XHOS (Linked FT)
Q	FW	Tt, Ti	Q	injection from 1/3 FW pumps and heat removal from PCS	Q-PCS	Q-PCS	XHOS-ATWS=0 XHOS-FW=0 XHOS-HIDWP=1 XHOS-LOCA=0 XHOS-LOP=0 XHOS-NOATWS=1 XHOS-THV=0 XHOS-TIAS=0 XHOS-TRAC=0 XHOS-TRAN=1 XHOS-TSASW=0
Q	FW	Tat, Ta1	Q-ATWS	injection from 1/3 FW pumps and heat removal from PCS following ATWS	Q-PCS	Q-PCS	XHOS-ATWS=1 XHOS-FW=0 XHOS-HIDWP=1 XHOS-LOCA=0 XHOS-LOP=0 XHOS-NOATWS=0 XHOS-THV=0 XHOS-TIAS=0 XHOS-TRAC=0 XHOS-TRAN=1 XHOS-TSASW=0
	FW	Tf	QR	recovery of feedwater	Q-PCS	Q-PCS	XHOS-ATWS=0 XHOS-FW=1 XHOS-HIDWP=1 XHOS-LOCA=0 XHOS-LOP=0 XHOS-NOATWS=1 XHOS-THV=0 XHOS-TIAS=0 XHOS-TRAC=0 XHOS-TRAN=1 XHOS-TSASW=0
		S2	Q-LOC	injection from 1/3 FW pumps and heat removal from PCS following LOCA	Q-PCS	Q-PCS	XHOS-ATWS=0 XHOS-FW=0 XHOS-HIDWP=0 XHOS-LOCA=1 XHOS-LOP=0 XHOS-NOATWS=1 XHOS-THV=0 XHOS-TIAS=0 XHOS-TRAC=0 XHOS-TRAN=0 XHOS-TSASW=0
Q		Tra	Q-RA	Injection from 1/3 FW pumps following loss of RACS	QTT	QTT	XHOS-ATWS=0 XHOS-FW=0 XHOS-HIDWP=1 XHOS-LOCA=0 XHOS-LOP=0 XHOS-NOATWS=1 XHOS-THV=0 XHOS-TIAS=0 XHOS-TRAC=1 XHOS-TRAN=1 XHOS-TSASW=0
Rpt	Recirc. pump trip	Ta, Tat, Ta1, Ta2	RPT	recirc pump trip occurs	ATWS-TOP	RECIRC-PMP-TRIP	NA
S1	medium break LOCA	S1	S1	NA	IE-TOP	MED-LOCA	NA

TABLE 3.3.7-1
HOPE CREEK FUNCTIONAL EQUATION SUMMARY TABLE (Cont'd.)

Top Event	Description	ET	Fcn Eqn	Success Criteria	FT(s)	Gate to Solve	XHOS (Linked FT)
S2	small break LOCA	S2	S2	NA	IE-TOP	SMALL-LOCA	NA
S3	no seal LOCA	S2	S3	no seal LOCA occurs	SEALLOCA	SEAL-LOCA	NA
Scr	Manual scram	Ta, Tat, Ta1, Ta2	SCR	Operator manually scrams reactor	ATWS-TOP	MAN-SCRAM	NA
Tat	turbine trip ATWS	Tat	TAT	NA	ATWS-IE	TAT	NA
Ta1	turbine trip ATWS	Ta1	TA1	NA	ATWS-IE	TA1	NA
Ta	MSIV closure ATWS	Ta	TA	NA	ATWS-IE	TAM	NA
Ta2	MSIV closure ATWS	Ta2	TA2	NA	ATWS-IE	TAM	NA
Te	loss of offsite power	Te	TE	NA	IE-TOP	LOSP	NA
Tf	loss of FW	Tf	TF	NA	IE-TOP	LOSS-FW	NA
Thv	loss of HVAC	Thv	THV	NA	IE-TOP	LOSS-HVAC	NA
Ti	inadvertently open SRV	Ti	TI	NA	IE-TOP	INAD-OPEN-SRV	NA
Tia	loss of instrument air	Tia	TIA	NA	IE-TOP	LOSS-IA	NA
Tm	MSIVs close or loss of condenser vacuum	Tm	TM	NA	IE-TOP	MSIV-CLOSE	NA
Tra	loss of RACS	Tra	TRA	NA	IE-TOP	LOSS-RACS	NA
Tsa	loss of SACS or loss of SW	Tsa	TSA	NA	IE-TOP	LOSS-SACS-SW	NA
Tt	turbine trip	Tt	TT	NA	IE-TOP	TURB-TRIP	NA
U	HPCI, RCIC	Tt, Tm, Ti	U	injection from HPCI or RCIC pump	U-TOP	HPI-RCI-FAIL	XHOS-ATWS=0 XHOS-HIDWP=1 XHOS-LOCA=0 XHOS-LOP=0 XHOS-NOATWS=1 XHOS-THV=0 XHOS-TIAS=0 XHOS-TRAC=0 XHOS-TRAN=1 XHOS-TSASW=0
		Ta, Tat, Ta1, Ta2	U-ATWS	injection from HPCI or RCIC pump following ATWS	U-TOP	HPI-RCI-FAIL	XHOS-ATWS=1 XHOS-HIDWP=1 XHOS-LOCA=0 XHOS-LOP=0 XHOS-NOATWS=0 XHOS-THV=0 XHOS-TIAS=0 XHOS-TRAC=0 XHOS-TRAN=1 XHOS-TSASW=0
		Thv	U-HV	injection from HPCI or RCIC pump following loss of HVAC	U-TOP	HPI-RCI-FAIL	XHOS-ATWS=0 XHOS-HIDWP=1 XHOS-LOCA=0 XHOS-LOP=0 XHOS-NOATWS=1 XHOS-THV=1 XHOS-TIAS=0 XHOS-TRAC=0 XHOS-TRAN=1 XHOS-TSASW=0
		Tia	U-IA	injection from HPCI or RCIC pump following loss of IA	U-TOP	HPI-RCI-FAIL	XHOS-ATWS=0 XHOS-HIDWP=1 XHOS-LOCA=0 XHOS-LOP=0 XHOS-NOATWS=1 XHOS-THV=0 XHOS-TIAS=1 XHOS-TRAC=0 XHOS-TRAN=1 XHOS-TSASW=0

Top Event	Description	ET	Fcn Eqn	Success Criteria	FT(s)	Gate to Solve	XHOS (Linked FT)
U		S2	U-LOC	injection from HPCI or RCIC pump following LOCA	U-TOP	HPI-RCI-FAIL	XHOS-ATWS=0 XHOS-HIDWP=0 XHOS-LOCA=1 XHOS-LOP=0 XHOS-NOATWS=1 XHOS-THV=0 XHOS-TIAS=0 XHOS-TRAC=0 XHOS-TRAN=0 XHOS-TSASW=0
		Te	U-LOP	injection from HPCI or RCIC pump, given LOSP	U-TOP	HPI-RCI-FAIL	XHOS-ATWS=0 XHOS-HIDWP=1 XHOS-LOCA=0 XHOS-LOP=1 XHOS-NOATWS=1 XHOS-THV=0 XHOS-TIAS=0 XHOS-TRAC=0 XHOS-TRAN=0 XHOS-TSASW=0
		Tra	U-RA	injection from HPCI or RCIC pump following loss of RACS	U-TOP	HPI-RCI-FAIL	XHOS-ATWS=0 XHOS-HIDWP=1 XHOS-LOCA=0 XHOS-LOP=0 XHOS-NOATWS=1 XHOS-THV=0 XHOS-TIAS=0 XHOS-TRAC=1 XHOS-TRAN=1 XHOS-TSASW=0
		Tsa	U-SA	injection from HPCI or RCIC pump following loss of SACS or SW	U-TOP	HPI-RCI-FAIL	XHOS-ATWS=0 XHOS-HIDWP=1 XHOS-LOCA=0 XHOS-LOP=0 XHOS-NOATWS=1 XHOS-THV=0 XHOS-TIAS=0 XHOS-TRAC=0 XHOS-TRAN=1 XHOS-TSASW=1
U1	HP injection, HPCI system	Tf	U1	injection from HPCI pump	HPCI	HPCI1	XHOS-ATWS=0 XHOS-HIDWP=1 XHOS-LOCA=0 XHOS-LOP=0 XHOS-NOATWS=1 XHOS-THV=0 XHOS-TRAN=1 XHOS-TSASW=0
		S1	U1-LOC	injection from HPCI pump, following LOCA	HPCI	HPCI1	XHOS-ATWS=0 XHOS-HIDWP=0 XHOS-LOCA=1 XHOS-LOP=0 XHOS-NOATWS=1 XHOS-THV=0 XHOS-TRAN=0 XHOS-TSASW=0

TABLE 3.3.7-1
HOPE CREEK FUNCTIONAL EQUATION SUMMARY TABLE (Cont'd.)

Top Event	Description	ET	Fcn Eqn	Success Criteria	FT(s)	Gate to Solve	XHOS (Linked FT)
		S1	U1-LCLP	injection from HPCI pump following LOCA, given LOSP	HPCI	HPCI1	XHOS-ATWS=0 XHOS-HIDWP=0 XHOS-LOCA=1 XHOS-LOP=1 XHOS-NOATWS=1 XHOS-THV=0 XHOS-TRAN=0 XHOS-TSASW=0
U2	HP injection, RCIC system	Tf	U2	injection from RCIC pump	RCIC	RCIC-1	XHOS-HIDWP=1 XHOS-LOCA=0 XHOS-LOP=0 XHOS-THV=0 XHOS-TRAN=1 XHOS-TSASW=0
Uv	Long-term make-up	Te	UV-1	injection from CRD or firewater following LOSP	UV-TRAN	UV-01	XHOS-ATWS=0 XHOS-HIDWP=1 XHOS-LOCA=0 XHOS-LOP=1 XHOS-NOATWS=1 XHOS-THV=0 XHOS-TIAS=0 XHOS-TRAC=0 XHOS-TRAN=0 XHOS-TSASW=0
		Te	UV-2	survival of CRD after containment failure, or injection from firewater	UV-TRAN	UV-2	(XHOS settings NA, equation consists of UEs only)
Uv		Tt, Tm, Tf, Te, Tia	UV-3	survival of CRD after containment failure	UV-TRAN	UV-3	(XHOS settings NA, equation consists of UEs only)
		Te	UV-4	injection from 1/4 LPCI, 1/2 CSS (2 pumps/loop), 2/2 CRD, or firewater following LOSP	UV-TRAN	UV-4	same as UV-1
		Te	UV-5	survival of LPCI, CSS, or CRD after containment failure, or injection from firewater	UV-TRAN	UV-5	(XHOS settings NA, equation consists of UEs only)
		Tt, Tm, Tf, Te, Tia	UV-6	survival of HPCI or CRD after containment failure	UV-TRAN	UV-6	(XHOS settings NA, equation consists of UEs only)
		Tsa	UV-6S	survival of HPCI after containment failure	UV-TSASW	UV-6	(XHOS settings NA, equation consists of UEs only)
		Tt, Tm, Tf, Ti	UV-7	injection from 2/2 CNT, 2/2 CRD, or firewater	UV-TRAN	UV-7	same as UV-13
		Tia	UV-7-IA	injection from 2/2 CNT, 2/2 CRD, or firewater given loss of IA	UV-TRAN	UV-7	same as UV-21
		Tsa	UV-7S	injection from 2/2 CNT or firewater	UV-TSASW	UV-7	XHOS-HIDWP=1 XHOS-LOCA=0 XHOS-LOP=0 XHOS-THV=0 XHOS-TRAN=1 XHOS-TSASW=1

TABLE 3.3.7-1
HOPE CREEK FUNCTIONAL EQUATION SUMMARY TABLE (Cont'd.)

Top Event	Description	ET	Fcn Eqn	Success Criteria	FT(s)	Gate to Solve	XHOS (Linked FT)
		Tra	UV-8	injection from 2/2 CNT, 2/2 CRD, or 1/3 primary CNS given loss of RACS	UV-SPEC	UV-8	same as UV-20
		Tt, Tm, Tf, Ti	UV-9	injection from 2/2 CNT or firewater, or survival of CRD after containment failure	UV-TRAN	UV-9	same as UV-13
		Tia	UV-9-IA	injection from 2/2 CNT or firewater, or survival of CRD after containment failure, given loss of IA	UV-TRAN	UV-9	same as UV-21
		Tsa	UV-9S	injection from 2/2 CNT or firewater after containment failure	UV-TSASW	UV-9	same as UV-7S
		Tt, Tm, Tf, Ti	UV-10	injection from 1/4 LPCI, 1/2 CSS (2 pumps/loop), 1/3 primary CNS, 2/2 CRD, 2/2 CNT, or firewater	UV-TRAN	UV-10	same as UV-13
		Tsa	UV-10S	injection from 1/2 CSS (2 pumps/loop), 2/2 CNT, or firewater	UV-TSASW	UV-10	same as UV-7S
Uv		Tt, Tm, Tf, Ti	UV-11	injection from 1/3 primary CNS, 2/2 CNT or firewater, or survival of LPCI, CSS, or CRD after containment failure	UV-TRAN	UV-11	same as UV-13
		Tsa	UV-11S	injection from 2/2 CNT or firewater, or survival of CSS after containment failure	UV-TSASW	UV-11	same as UV-7S
		Te	UV-12	injection from HPCI (long-term, with room cooling), 1/4 LPCI, 1/2 CSS (2 pumps/ loop), 2/2 CRD, or firewater following LOSP	UV-TRAN	UV-12	same as UV-1
		Tt, Tm, Tf	UV-13	injection from HPCI (long-term, with room cooling), 1/3 primary CNS, 1/4 LPCI, 1/2 CSS (2 pumps/ loop), 2/2 CRD, 2/2 CNT, or firewater	UV-TRAN	UV-13	XHOS-ATWS=0 XHOS-HIDWP=1 XHOS-LOCA=0 XHOS-LOP=0 XHOS-NOATWS=1 XHOS-THV=0 XHOS-TIAS=0 XHOS-TRAC=0 XHOS-TRAN=1 XHOS-TSASW=0
		Tsa	UV-13S	injection from HPCI (long-term, with room cooling), 1/2 CSS (2 pumps/ loop), 2/2 CNT, or firewater	UV-TSASW	UV-13	same as UV-7S
		Tra	UV-15	injection from 2/2 CNT or firewater given loss of RACS	UV-SPEC	UV-15	same as UV-20

TABLE 3.3.7-1
HOPE CREEK FUNCTIONAL EQUATION SUMMARY TABLE (Cont'd.)

Top Event	Description	ET	Fcn Eqn	Success Criteria	FT(s)	Gate to Solve	XHOS (Linked FT)
		Tt, Tm	UV-16	injection from 1/4 LPCI, 1/2 CSS (2 pumps/ loop), or 1/3 primary CNS paths	UV-LOCA	UV-16	XHOS-HIDWP=1 XHOS-LOCA=0 XHOS-LOP=0 XHOS-THV=0 XHOS-TIAS=0 XHOS-TRAC=0 XHOS-TRAN=1 XHOS-TSASW=0
		A, S1	UV-16-LC	injection from 1/4 LPCI, 1/2 CSS (2 pumps/loop), or 1/3 primary CNS paths following LOCA	UV-LOCA	UV-16	XHOS-HIDWP=0 XHOS-LOCA=1 XHOS-LOP=0 XHOS-THV=0 XHOS-TIAS=0 XHOS-TRAC=0 XHOS-TRAN=0 XHOS-TSASW=0
Uv		Tsa	UV-16S	injection from 1/2 CSS (2 pumps/ loop)	UV-TSASW	UV-16	XHOS-HIDWP=0 XHOS-LOCA=1 XHOS-LOP=0 XHOS-THV=0 XHOS-TRAN=0 XHOS-TSASW=1
		Tia	UV-17	injection from 1/4 LPCI, 1/2 CSS (2 pumps/loop), 2/2 CRD, 2/2 CNT, or firewater given loss of IA	UV-SPEC	UV-17	same as UV-21
		S2	UV-18	injection from 1/4 LPCI, 1/2 CSS (2 pumps/loop), 2/2 CRD, 1/3 CNS, 2/2 CNT, or firewater following S2 LOCA with seal LOCA	UV-LOCA	UV-18	same as UV-16-LC
		S2	UV-19	injection from 2/2 CNT or firewater, or survival of LPCI, CSS, or CRD after containment failure, following S2 LOCA with seal LOCA	UV-LOCA	UV-19	same as UV-16-LC
		Tia	UV-19-IA	injection from 2/2 CNT or firewater, or survival of LPCI, CSS, or CRD after containment failure, given loss of IA	UV-LOCA	UV-19	same as UV-21
		Tra	UV-20	injection from HPCI (long-term, with room cooling), 1/4 LPCI, 1/2 CSS (2 pumps/ loop), 1/3 primary CNS, 2/2 CNT, or firewater given loss of RACS	UV-SPEC	UV-20	XHOS-HIDWP=1 XHOS-LOCA=0 XHOS-LOP=0 XHOS-THV=0 XHOS-TIAS=0 XHOS-TRAC=1 XHOS-TRAN=1 XHOS-TSASW=0
		Tia	UV-21	injection from HPCI (long-term, with room cooling), 1/4 LPCI, 1/2 CSS (2 pumps/ loop), 2/2 CRD, 2/2 CNT, or firewater given loss of IA	UV-SPEC	UV-21	XHOS-HIDWP=1 XHOS-LOCA=0 XHOS-LOP=0 XHOS-THV=0 XHOS-TIAS=1 XHOS-TRAC=0 XHOS-TRAN=1 XHOS-TSASW=0
		S2	UV-22	injection from 1/3 CNS, 1/4 LPCI, 1/2 CSS (2 pumps/loop), 2/2 CNT, or firewater following S2 LOCA	UV-LOCA	UV-22	same as UV-16-LC

TABLE 3.3.7-1
HOPE CREEK FUNCTIONAL EQUATION SUMMARY TABLE (Cont'd.)

Top Event	Description	ET	Fcn Eqn	Success Criteria	FT(s)	Gate to Solve	XHOS (Linked FT)
		Tra	UV-22-RA	injection from 1/3 CNS, 1/4 LPCI, 1/2 CSS (2 pumps/loop), 2/2 CNT, or firewater given loss of RACS	UV-LOCA	UV-22	same as UV-20
Uv		S2	UV-23	injection from 1/3 CNS, 2/2 CNT, or firewater, or survival of LPCI or CSS after containment failure, following S2 LOCA	UV-LOCA	UV-23	same as UV-16-LC
		Tra	UV-23-RA	injection from 1/3 CNS, 2/2 CNT, or firewater, or survival of LPCI or CSS after containment failure given loss of RACS	UV-LOCA	UV-23	same as UV-20
		Tt, Tm	UV-24	injection from 1/3 primary CNS paths, or survival of RHR (LPCI) or CSS after containment failure	UV-LOCA	UV-24	same as UV-16
		A, S1	UV-24-LC	injection from 1/3 primary CNS paths, or survival of RHR (LPCI) or CSS after containment failure following LOCA	UV-LOCA	UV-24	same as UV-16-LC
		Tsa	UV-24S	survival of CSS after containment failure	UV-TSASW	UV-24	same as UV-16S
		A, S1	UV-25	injection from 1/4 LPCI or 1/2 CSS (2 pumps/loop) paths following LOCA, given LOSP	UV-LOCA	UV-25	XHOS-HIDWP=0 XHOS-LOCA=1 XHOS-LOP=1 XHOS-THV=0 XHOS-TIAS=0 XHOS-TRAC=0 XHOS-TRAN=0 XHOS-TSASW=0
		Tia	UV-25-IA	injection from 1/4 LPCI or 1/2 CSS (2 pumps/loop) paths given loss of IA	UV-LOCA	UV-25	same as UV-21
		Tra	UV-25-RA	injection from 1/4 LPCI or 1/2 CSS (2 pumps/loop) paths given loss of RACS	UV-LOCA	UV-25	same as UV-20
		A, S1, Tia, Tra	UV-26	survival of RHR (LPCI) or CSS after containment failure	UV-LOCA	UV-26	(XHOS settings NA, equation consists of UEs only)
		Ta, Ta1, Ta2, Tat	UV-27	injection from HPCI (long-term, with room cooling), 1/3 primary CNS, 1/4 LPCI, 1/2 CSS (2 pumps/ loop), or 2/2 CNT	UV-ATWS	UV-27	XHOS-ATWS=1 XHOS-HIDWP=1 XHOS-LOCA=0 XHOS-LOP=0 XHOS-NOATWS=0 XHOS-THV=0 XHOS-TIAS=0 XHOS-TRAC=0 XHOS-TRAN=1 XHOS-TSASW=0

TABLE 3.3.7-1
HOPE CREEK FUNCTIONAL EQUATION SUMMARY TABLE (Cont'd.)

Top Event	Description	ET	Fcn Eqn	Success Criteria	FT(s)	Gate to Solve	XHOS (Linked FT)
Uv		Ta, Ta1, Ta2, Tat	UV-28	survival of HPCI, RHR (LPCI), or CSS after containment failure or injection from 1/3 primary CNS or 2/2 CNT	UV-ATWS	UV-28	XHOS-ATWS=1 XHOS-HIDWP=1 XHOS-LOCA=0 XHOS-LOP=0 XHOS-NOATWS=0 XHOS-THV=0 XHOS-TIAS=0 XHOS-TRAC=0 XHOS-TRAN=1 XHOS-TSASW=0
		Ta, Ta1, Ta2, Tat	UV-29	injection from 1/3 primary CNS, 1/4 LPCI, 1/2 CSS (2 pumps/ loop), or 2/2 CNT	UV-ATWS	UV-29	XHOS-ATWS=1 XHOS-HIDWP=1 XHOS-LOCA=0 XHOS-LOP=0 XHOS-NOATWS=0 XHOS-THV=0 XHOS-TIAS=0 XHOS-TRAC=0 XHOS-TRAN=1 XHOS-TSASW=0
		Ta, Ta1, Ta2, Tat	UV-30	survival of RHR (LPCI) or CSS after containment failure or injection from 1/3 primary CNS or 2/2 CNT	UV-ATWS	UV-30	XHOS-ATWS=1 XHOS-HIDWP=1 XHOS-LOCA=0 XHOS-LOP=0 XHOS-NOATWS=0 XHOS-THV=0 XHOS-TIAS=0 XHOS-TRAC=0 XHOS-TRAN=1 XHOS-TSASW=0
		Ta, Ta1, Ta2, Tat	UV-29L	injection from 1/3 primary CNS, 1/4 LPCI, 1/2 CSS (2 pumps/ loop), or 2/2 CNT with 2 or more SORVs	UV-ATWS	UV-29	XHOS-ATWS=1 XHOS-HIDWP=1 XHOS-LOCA=1 XHOS-LOP=0 XHOS-NOATWS=0 XHOS-THV=0 XHOS-TIAS=0 XHOS-TRAC=0 XHOS-TRAN=0 XHOS-TSASW=0
Uv		Ta, Ta1, Ta2, Tat	UV-30L	survival of RHR (LPCI) or CSS after containment failure or injection from 1/3 primary CNS or 2/2 CNT with 2 or more SORVs	UV-ATWS	UV-30	XHOS-ATWS=1 XHOS-HIDWP=1 XHOS-LOCA=1 XHOS-LOP=0 XHOS-NOATWS=0 XHOS-THV=0 XHOS-TIAS=0 XHOS-TRAC=0 XHOS-TRAN=0 XHOS-TSASW=0
V	LPCI, CS, CNS	Tt, Tm, Tf, Ti	V	injection from 1/3 condensate paths, 1/4 LPCI loops, or 1/2 CS loops (2 pumps/loop)	V-TOP	CNS-LPI-CS-FAILS	XHOS-HIDWP=1 XHOS-LOCA=0 XHOS-LOP=0 XHOS-THV=0 XHOS-TIAS=0 XHOS-TRAC=0 XHOS-TRAN=1 XHOS-TSASW=0
		S2	V-LOC	injection from 1/3 condensate paths, 1/4 LPCI loops, or 1/2 CS loops (2 pumps/loop) following LOCA	V-TOP	CNS-LPI-CS-FAILS	XHOS-HIDWP=0 XHOS-LOCA=1 XHOS-LOP=0 XHOS-THV=0 XHOS-TIAS=0 XHOS-TRAC=0 XHOS-TRAN=0 XHOS-TSASW=0

TABLE 3.3.7-1
HOPE CREEK FUNCTIONAL EQUATION SUMMARY TABLE (Cont'd.)

Top Event	Description	ET	Fcn Eqn	Success Criteria	FT(s)	Gate to Solve	XHOS (Linked FT)
		Tra	V-RA	injection from 1/3 condensate paths, 1/4 LPCI loops, or 1/2 CS loops (2 pumps/loop) following loss of RACS	V-TOP	CNS-LPI-CS-FAILS	XHOS-HIDWP=1 XHOS-LOCA=0 XHOS-LOP=0 XHOS-THV=0 XHOS-TIAS=0 XHOS-TRAC=1 XHOS-TRAN=1 XHOS-TSASW=0
		Tsa	V-S	injection from 1/2 CS loops (2 pumps/loop) following loss of SACS/SW	V-TOP	CNS-LPI-CS-FAILS	XHOS-HIDWP=1 XHOS-LOCA=0 XHOS-LOP=0 XHOS-THV=0 XHOS-TIAS=0 XHOS-TRAC=0 XHOS-TRAN=1 XHOS-TSASW=1
V (Tt,Tm) V1 (Tia)		Tt, Tm, Tia	V1	injection from 1/4 LPCI loops or 1/2 CS loops (2 pumps/loop)	V1-TOP	LPI-CS-FAILS-V1	XHOS-HIDWP=1 XHOS-LOCA=0 XHOS-LOP=0 XHOS-THV=0 XHOS-TRAN=1 XHOS-TSASW=0
V		Te	V1-LOP	injection from 1/4 LPCI loops or 1/2 CS loops (2 pumps/loop) given LOSP	V1-TOP	LPI-CS-FAILS-V1	XHOS-HIDWP=1 XHOS-LOCA=0 XHOS-LOP=1 XHOS-THV=0 XHOS-TRAN=0 XHOS-TSASW=0
		A, S1	V1-LOC	injection from 1/4 LPCI loops or 1/2 CS loops (2 pumps/ loop) following LOCA	V1-TOP	LPI-CS-FAILS-V1	XHOS-HIDWP=0 XHOS-LOCA=1 XHOS-LOP=0 XHOS-THV=0 XHOS-TRAN=0 XHOS-TSASW=0
		A, S1	V1-LCLP	injection from 1/4 LPCI loops or 1/2 CS loops (2 pumps/ loop) followiing LOCA, given LOSP	V1-TOP	LPI-CS-FAILS-V1	XHOS-HIDWP=0 XHOS-LOCA=1 XHOS-LOP=1 XHOS-THV=0 XHOS-TRAN=0 XHOS-TSASW=0
W	containment heat removal	Tt, Tm, Tf, Ti, Tia, Tra	W	1/2 RHR loops in SPC or CSC mode, after FW/PCS failure or 2 SRVs stuck open	W-TOP	CSC-SPC-FAILS-W	XHOS-HIDWP=1 XHOS-LOCA=0 XHOS-LOP=0 XHOS-THV=0 XHOS-TRAN=1 XHOS-TSASW=0
		A, S1, S2	W-LOC	1/2 RHR loops in SPC or CSC mode following LOCA	W-TOP	CSC-SPC-FAILS-W	XHOS-HIDWP=0 XHOS-LOCA=1 XHOS-LOP=0 XHOS-THV=0 XHOS-TRAN=0 XHOS-TSASW=0
		Te	W-LOP	1/2 RHR loops in SPC or CSC mode given LOSP	W-TOP	CSC-SPC-FAILS-W	XHOS-HIDWP=1 XHOS-LOCA=0 XHOS-LOP=1 XHOS-THV=0 XHOS-TRAN=0 XHOS-TSASW=0
W		A, S1	W-LCLP	1/2 RHR loops in SPC or CSC mode following LOCA, given LOSP	W-TOP	CSC-SPC-FAILS-W	XHOS-HIDWP=0 XHOS-LOCA=1 XHOS-LOP=1 XHOS-THV=0 XHOS-TRAN=0 XHOS-TSASW=0

TABLE 3.3.7-1
HOPE CREEK FUNCTIONAL EQUATION SUMMARY TABLE (Cont'd.)

Top Event	Description	ET	Fcn Eqn	Success Criteria	FT(s)	Gate to Solve	XHOS (Linked FT)
W1	containment vent	Tt, Tm, Tf, Ti	W1	vent from drywell or torus	CONTVENT	CONTVENT	XHOS-HIDWP=1 XHOS-LOCA=0 XHOS-LOP=0 XHOS-THV=0 XHOS-TIAS=0 XHOS-TRAC=0 XHOS-TRAN=1 XHOS-TSASW=0
		Tia	W1-IA	vent from drywell or torus given loss of IA	CONTVENT	CONTVENT	XHOS-HIDWP=1 XHOS-LOCA=0 XHOS-LOP=0 XHOS-THV=0 XHOS-TIAS=1 XHOS-TRAC=0 XHOS-TRAN=1 XHOS-TSASW=0
		A, S1, S2	W1-LOC	vent from drywell or torus following LOCA	CONTVENT	CONTVENT	XHOS-HIDWP=0 XHOS-LOCA=1 XHOS-LOP=0 XHOS-THV=0 XHOS-TIAS=0 XHOS-TRAC=0 XHOS-TRAN=0 XHOS-TSASW=0
		Te	W1-LOP	vent from drywell to torus given LOSP	CONTVENT	CONTVENT	XHOS-HIDWP=1 XHOS-LOCA=0 XHOS-LOP=1 XHOS-THV=0 XHOS-TIAS=0 XHOS-TRAC=0 XHOS-TRAN=0 XHOS-TSASW=0
W1		A, S1	W1-LCLP	vent from drywell or torus following LOCA, given LOSP	CONTVENT	CONTVENT	XHOS-HIDWP=0 XHOS-LOCA=1 XHOS-LOP=1 XHOS-THV=0 XHOS-TIAS=0 XHOS-TRAC=0 XHOS-TRAN=0 XHOS-TSASW=0
		Tra	W1-RA	vent from drywell of torus given loss of RACS	CONTVENT	CONTVENT	XHOS-HIDWP=1 XHOS-LOCA=0 XHOS-LOP=0 XHOS-THV=0 XHOS-TIAS=0 XHOS-TRAC=1 XHOS-TRAN=1 XHOS-TSASW=0
		Tsa	W1-S	vent from drywell or torus given loss of SACS or SW	CONTVENT	CONTVENT	XHOS-HIDWP=1 XHOS-LOCA=0 XHOS-LOP=0 XHOS-THV=0 XHOS-TIAS=0 XHOS-TRAC=0 XHOS-TRAN=1 XHOS-TSASW=1
X	RPV depressurized	Tt, Tm, Tf, Ti	X	2/14 SRVs open, after FW/PCS failure	RXDP	RXDP	XHOS-HIDWP=1 XHOS-LOCA=0 XHOS-LOP=0 XHOS-THV=0 XHOS-TIAS=0 XHOS-TRAC=0 XHOS-TRAN=1 XHOS-TSASW=0

TABLE 3.3.7-1
HOPE CREEK FUNCTIONAL EQUATION SUMMARY TABLE (Cont'd.)

Top Event	Description	ET	Fcn Eqn	Success Criteria	FT(s)	Gate to Solve	XHOS (Linked FT)
		Ta, Ta1, Ta2, Tat	X-ATWS	2/14 SRVs open, after ATWS and HPCI/RCIC failure	RXDP	RXDP	XHOS-HIDWP=1 XHOS-LOCA=0 XHOS-LOP=0 XHOS-THV=0 XHOS-TIAS=0 XHOS-TRAC=0 XHOS-TRAN=1 XHOS-TSASW=0
X		Tia	X-IA	2/14 SRVs open given loss of IA	RXDP	RXDP	XHOS-HIDWP=1 XHOS-LOCA=0 XHOS-LOP=0 XHOS-THV=0 XHOS-TIAS=1 XHOS-TRAC=0 XHOS-TRAN=1 XHOS-TSASW=0
		S1, S2	X-LOC	2/14 SRVs open given LOCA	RXDP	RXDP	XHOS-HIDWP=0 XHOS-LOCA=1 XHOS-LOP=0 XHOS-THV=0 XHOS-TIAS=0 XHOS-TRAC=0 XHOS-TRAN=0 XHOS-TSASW=0
		Te	X-LOP	2/14 SRVs open given LOSP	RXDP	RXDP	XHOS-HIDWP=1 XHOS-LOCA=0 XHOS-LOP=1 XHOS-THV=0 XHOS-TIAS=0 XHOS-TRAC=0 XHOS-TRAN=0 XHOS-TSASW=0
		S1	X-LCLP	2/14 SRVs open given LOCA and LOSP	RXDP	RXDP	XHOS-HIDWP=0 XHOS-LOCA=1 XHOS-LOP=1 XHOS-THV=0 XHOS-TIAS=0 XHOS-TRAC=0 XHOS-TRAN=0 XHOS-TSASW=0
		Tra	X-RA	2/14 SRVs open given loss of RACS	RXDP	RXDP	XHOS-HIDWP=1 XHOS-LOCA=0 XHOS-LOP=0 XHOS-THV=0 XHOS-TIAS=0 XHOS-TRAC=1 XHOS-TRAN=1 XHOS-TSASW=0

TABLE 3.3.7-2
HCGS FUNCTIONAL EQUATION ASSIGNMENTS

Equation Name	Fault Tree	Gate Solved	Truncation	No. of Cutsets
A	IE-TOP	LARGE-LOCA	1.0E-07	1
C	C-TOP	C-TOP	1.0E-07	2
C2	SLC	SLC1	1.0E-07	285
CE	ATWS-TOP	RPS-ELECT	1.0E-07	1
CM	ATWS-TOP	RPS-MECH	1.0E-07	1
D	D-TOP	VAPOR-SUPP-FAILS	1.0E-07	1
D-S2	D-TOP	D-S2	1.0E-07	1
E	E-TOP	ACP-FAILS-OFFSIT	1.0E-07	2
E-LOC	E-TOP	ACP-FAILS-OFFSIT	1.0E-07	2
EDG	EDG-TOP	ACP-FAILS-EDG	5.0E-06	735
EDG-LOC	EDG-TOP	ACP-FAILS-EDG	5.0E-06	714
H-HIGH	ATWS-TOP	H-HIGH	1.0E-07	1
H-LOW	ATWS-TOP	H-LOW	1.0E-07	1
HVC	HVAC	ROOM-COOL	1.0E-07	84
HVC-LOC	HVAC	ROOM-COOL	1.0E-07	53
HVC-LOP	HVAC	ROOM-COOL	1.0E-06	463
HVC-S	HVAC	ROOM-COOL	1.0E-06	13
IN1	ATWS-TOP	INHIBIT-HPCI-CS	1.0E-07	1
IN2	ATWS-TOP	INHIBIT-ADS	1.0E-07	1
ISO	SEALLOCA	SEAL-ISOL	1.0E-07	1
K	ATWS-TOP	ARI	1.0E-07	1
M-2	M-TOP	SRV-FAIL-OPEN	1.0E-09	1
M-ATWS	ATWS-TOP	SRVS-FTO	1.0E-09	1
MSV-1	ATWS-TOP	MSIV-CLOSURE-1	1.0E-07	1
MSV-2	ATWS-TOP	MSIV-CLOSURE-2	1.0E-07	1
MSV-3	ATWS-TOP	MSIV-CLOSURE-3	1.0E-07	1
P	P-TOP	SRV-1-CLOSE-DMD3	1.0E-07	1
P-ATWS	ATWS-TOP	SRV-1-CLOSE-ATWS	1.0E-07	1
P-TM	P-TOP	SRV-1-CLOSE-DMD6	1.0E-07	1
P2	P-TOP	SRV-2-CLOSE-DMD3	1.0E-07	1
P2-1	P-TOP	SRV-1-CLOSE-DMD3	1.0E-07	1
P2-ATWS	ATWS-TOP	SRV-2-CLOSE-ATWS	1.0E-07	1
P2-TM	P-TOP	SRV-2-CLOSE-DMD6	1.0E-07	1
Q	Q-PCS	Q-PCS	5.0E-06	264
Q-ATWS	Q-PCS	Q-PCS	1.0E-06	913
Q-LOC	Q-PCS	Q-PCS	1.0E-06	429
Q-RA	QTT	QTT	1.0E-07	256
QR	Q-PCS	Q-PCS	5.0E-06	265
RPT	ATWS-TOP	RECIRC-PMP-TRIP	1.0E-07	1
S1	IE-TOP	MED-LOCA	1.0E-07	1
S2	IE-TOP	SMALL-LOCA	1.0E-07	1
S3	SEALLOCA	SEAL-LOCA	1.0E-07	1
SCR	ATWS-TOP	MAN-SCRAM	1.0E-07	1
TA	ATWS-IE	TAM	1.0E-07	4
TA1	ATWS-IE	TAT	1.0E-10	3
TA2	ATWS-IE	TAM	1.0E-07	4
TAT	ATWS-IE	TAT	1.0E-10	3

TABLE 3.3.7-2
HCGS FUNCTIONAL EQUATION ASSIGNMENTS

Equation Name	Fault Tree	Gate Solved	Truncation	No. of Cutsets
TE	IE-TOP	LOSP	1.0E-07	1
TF	IE-TOP	LOSS-FW	1.0E-07	1
THV	IE-TOP	LOSS-HVAC	1.0E-07	1
TI	IE-TOP	INAD-OPEN-SRV	1.0E-07	1
TIA	IE-TOP	LOSS-IA	1.0E-07	1
TM	IE-TOP	MSIV-CLOSE	1.0E-07	1
TRA	IE-TOP	LOSS-RACS	1.0E-07	1
TSA	IE-TOP	LOSS-SACS-SW	1.0E-07	1
TT	IE-TOP	TURB-TRIP	1.0E-07	1
U	U-TOP	HPI-RCI-FAIL	1.0E-07	165
U-ATWS	U-TOP	HPI-RCI-FAIL	1.0E-07	230
U-HV	U-TOP	HPI-RCI-FAIL	1.0E-07	165
U-IA	U-TOP	HPI-RCI-FAIL	1.0E-07	165
U-LOC	U-TOP	HPI-RCI-FAIL	1.0E-07	164
U-LOP	U-TOP	HPI-RCI-FAIL	1.0E-07	179
U-RA	U-TOP	HPI-RCI-FAIL	1.0E-07	165
U-SA	U-TOP	HPI-RCI-FAIL	1.0E-07	165
U1	HPCI	HPCI1	1.0E-07	48
U1-LCLP	HPCI	HPCI1	1.0E-07	222
U1-LOC	HPCI	HPCI1	1.0E-07	47
U2	RCIC	RCIC-1	1.0E-07	49
UV-1	UV-TRAN	UV-01	1.0E-06	856
UV-2	UV-TRAN	UV-2	1.0E-07	1
UV-3	UV-TRAN	UV-3	1.0E-07	2
UV-4	UV-TRAN	UV-4	5.0E-06	714
UV-5	UV-TRAN	UV-5	1.0E-07	1
UV-6	UV-TRAN	UV-6	1.0E-07	1
UV-6S	UV-TSASW	UV-6	1.0E-07	1
UV-7	UV-TRAN	UV-7	1.0E-07	20
UV-7-IA	UV-TRAN	UV-7	1.0E-07	2
UV-7S	UV-TSASW	UV-7	1.0E-07	2
UV-8	UV-SPEC	UV-8	1.0E-07	14
UV-9	UV-TRAN	UV-9	1.0E-07	2
UV-9-IA	UV-TRAN	UV-9	1.0E-07	2
UV-9S	UV-TSASW	UV-9	1.0E-07	2
UV-10	UV-TRAN	UV-10	1.0E-08	4
UV-10S	UV-TSASW	UV-10	1.0E-07	2
UV-11	UV-TRAN	UV-11	1.0E-08	3
UV-11S	UV-TSASW	UV-11	1.0E-07	2
UV-12	UV-TRAN	UV-12	1.0E-06	175
UV-13	UV-TRAN	UV-13	1.0E-09	1
UV-13S	UV-TSASW	UV-13	1.0E-07	1
UV-15	UV-SPEC	UV-15	1.0E-08	3
UV-16	UV-LOCA	UV-16	1.0E-06	269
UV-16-LC	UV-LOCA	UV-16	1.0E-06	85
UV-16S	UV-TSASW	UV-16	1.0E-07	451
UV-17	UV-SPEC	UV-17	1.0E-08	8

TABLE 3.3.7-2
HCGS FUNCTIONAL EQUATION ASSIGNMENTS

Equation Name	Fault Tree	Gate Solved	Truncation	No. of Cutsets
UV-18	UV-LOCA	UV-18	1.0E-09	10
UV-19	UV-LOCA	UV-19	1.0E-09	2
UV-19-IA	UV-LOCA	UV-19	1.0E-07	1
UV-20	UV-SPEC	UV-20	1.0E-09	2
UV-21	UV-SPEC	UV-21	1.0E-09	2
UV-22	UV-LOCA	UV-22	1.0E-09	11
UV-22-RA	UV-LOCA	UV-22	1.0E-08	8
UV-23	UV-LOCA	UV-23	1.0E-09	33
UV-23-RA	UV-LOCA	UV-23	1.0E-07	5
UV-24	UV-LOCA	UV-24	1.0E-07	339
UV-24-LC	UV-LOCA	UV-24	1.0E-07	168
UV-24S	UV-TSASW	UV-24	1.0E-07	1
UV-25	UV-LOCA	UV-25	5.0E-06	715
UV-25-IA	UV-LOCA	UV-25	1.0E-06	284
UV-25-RA	UV-LOCA	UV-25	1.0E-06	284
UV-26	UV-LOCA	UV-26	1.0E-07	1
UV-27	UV-ATWS	UV-27	1.0E-09	5
UV-28	UV-ATWS	UV-28	1.0E-08	2
UV-29	UV-ATWS	UV-29	1.0E-08	4
UV-29L	UV-ATWS	UV-29	1.0E-08	1
UV-30	UV-ATWS	UV-30	1.0E-07	2
UV-30L	UV-ATWS	UV-30	1.0E-07	2
V	V-TOP	CNS-LPI-CS-FAILS	1.0E-07	444
V-LOC	V-TOP	CNS-LPI-CS-FAILS	1.0E-06	22
V-RA	V-TOP	CNS-LPI-CS-FAILS	1.0E-06	43
V-S	V-TOP	CNS-LPI-CS-FAILS	1.0E-06	161
V1	V1-TOP	LPI-CS-FAILS-V1	1.0E-07	458
V1-LCLP	V1-TOP	LPI-CS-FAILS-V1	5.0E-06	715
V1-LOC	V1-TOP	LPI-CS-FAILS-V1	1.0E-07	193
V1-LOP	V1-TOP	LPI-CS-FAILS-V1	5.0E-06	751
W	W-TOP	CSC-SPC-FAILS-W	5.0E-06	335
W-LCLP	W-TOP	CSC-SPC-FAILS-W	5.0E-06	856
W-LOC	W-TOP	CSC-SPC-FAILS-W	1.0E-06	828
W-LOP	W-TOP	CSC-SPC-FAILS-W	5.0E-06	910
W-W1	W-TOP	CHR-ATWS-FAILS	5.0E-06	458
W1	CONTVENT	CONTVENT	5.0E-06	100
W1-IA	CONTVENT	CONTVENT	1.0E-06	105
W1-LCLP	CONTVENT	CONTVENT	5.0E-06	214
W1-LOC	CONTVENT	CONTVENT	1.0E-06	181
W1-LOP	CONTVENT	CONTVENT	5.0E-06	217
W1-RA	CONTVENT	CONTVENT	1.0E-06	254
W1-S	CONTVENT	CONTVENT	1.0E-06	105
X	RXDP	RXDP	1.0E-07	6
X-ATWS	RXDP	RXDP	1.0E-07	6
X-IA	RXDP	RXDP	1.0E-07	6
X-LCLP	RXDP	RXDP	1.0E-07	6
X-LOC	RXDP	RXDP	1.0E-07	6

TABLE 3.3.7-2
HCGS FUNCTIONAL EQUATION ASSIGNMENTS

Equation Name	Fault Tree	Gate Solved	Truncation	No. of Cutsets
X-LOP	RXDP	RXDP	1.0E-07	6
X-RA	RXDP	RXDP	1.0E-08	8

TABLE 3.3.7-3

DISALLOWED MAINTENANCE COMBINATIONS OF SYSTEMS MODELED IN THE HCGS IPE *

1. Two Standby Liquid Control Pumps
2. Two Core Spray Loops
3. Four LPCI Loops
4. Three LPCI and one Core Spray Loop
5. Two LPCI and two Core Spray Loops
6. RHR Loops A and B
7. The HPCI and RCIC systems
8. HPCI and any LPCI loop
9. HPCI and either Core Spray loop
10. Two SACS subsystems
11. Two SSWS loops
12. Two diesel generators
13. Two DC channels
14. Two AC distribution channels

*Note that HCGS Technical Specifications define "OPERABLE/OPERABILITY" of a system as the capability of that system to perform its function and the capability of all necessary supporting systems to perform their function.

TABLE 3.3.7-4
DESCRIPTION OF HUMAN RECOVERY ACTIONS APPLIED

	Recovery	Description	Value
1.	NR-AIR-24	Failure to recover the IAS within 24 hours	5.7E-3
2.	NR-ATWS-ADS-INH	Failure to inhibit ADS during an ATWS	7.5E-2
3.	NR-ATWS-ARI	Failure to manually initiate ARI	1.4E-2
4.	NR-ATWS-DEP	Failure to manually depressurized the RPV during an ATWS	5.6E-2
5.	NR-ATWS-HPCI-30M	Failure to initiate HPCI during an ATWS	5.0E-2
6.	NR-ATWS-HPCI-CS	Failure to isolate HPCI injection through the Core Spray piping during an ATWS	2.4E-1
7.	NR-ATWS-LCNTL-LO	Failure to control RPV water level with LPCI during an ATWS	4.7E-1
8.	NR-COND-5	Failure to restart condensate pumps after other injection systems fail	3.7E-2
9.	NR-DG-6	Failure to recover D/Gs within 6 hours (independent failures of D/Gs)	7.0E-1
10.	NR-DG-DF-6	Failure to recover D/Gs within 6 hours (common cause failures of D/Gs)	6.0E-1
11.	NR-HPCI-LCNT-HIE	Failure to control RPV water level using HPCI during an ATWS to prevent core damage	4.6E-2
12.	NR-HVC-PNRM-12	Failure to provide alternate ventilation to the Panel Room within 12 hours after a loss of HVAC	3.0E-4
13.	NR-HVC-SWGR-24	Failure to provide alternate ventilation to the Switchgear Room within 24 hrs after loss of HVAC	1.6E-4
14.	NR-IGS-24	Failure to restart the EIAC after RACS cooling has been restored followed a LOCA isolation	3.8E-3
15.	NR-LOSP-24	Failure to restore offsite power within 24 hours	2.2E-3
16.	NR-LOSP-12	Failure to restore offsite power within 12 hours	1.5E-2
17.	NR-LOSP-6	Failure to restore offsite power within 6 hours	5.0E-2
18.	NR-LOSP-5	Failure to restore offsite power within 5 hours	7.0E-2
19.	NR-LOSP-1	Failure to restore offsite power within 1 hour	4.0E-1
20.	NR-LOSP-40M	Failure to restore offsite power within 40 minutes	5.5E-1
21.	NR-LOSP-30M	Failure to restore offsite power within 30 minutes	6.0E-1

Table 3.3.7-4 (continued)

22.	NR-PCS-24	Failure to restore the PCS within 24 hours following a turbine trip or MSIV closure initiating event	7.0E-4
23.	NR-PCS-1	Failure to restore the PCS within 1 hour	6.0E-1
24.	NR-PCS-40M	Failure to restore the PCS within 40 minutes	9.0E-1
25.	NR-Q-FWLVH-4M	Failure to prevent a level 8 trip of feedwater during a transient	1.4E-2
26.	NR-Q-FWLVL-24M	Failure to prevent a level 8 trip of feedwater during a small LOCA	4.9E-3
27.	NR-RACS-24	Failure to restore the RACS after a LOCA isolation	3.8E-3
28.	NR-RHR-INIT	Failure to initiate RHR for decay heat removal within 24 hours	5.0E-5
29.	NR-SLEAK-ISO-15M	Failure to isolate recirculation pump seal LOCA	8.2E-2
30.	NR-SPL-LVLL-4	Failure to align core spray to the CST for long-term injection (without decay heat removal)	1.1E-1
31.	NR-U1X-DEP-30M	Failure to manually depressurize the RPV within 30 minutes	7.5E-3
32.	NR-U1X-DEP-40M	Failure to manually depressurize the RPV within 40 minutes	5.2E-3
33.	NR-U1X-DEP-60M	Failure to manually depressurize the RPV within 1 hour	4.6E-3
34.	NR-UV-ECCS-1	Failure to manually initiate ECCS within 1 hour	3.9E-2
35.	NR-UV-WTLVL-20M	Failure to control RPV water level with high pressure injection systems (not during ATWS)	4.3E-2
36.	NR-VENT-5	Failure to initiate containment venting	2.0E-3
37.	NR-WW1-SWP-1	Failure to manually start SSWS or SACS pumps within 1 hour	1.2E-2
38.	NR-WW1-SWP-12	Failure to manually start SSWS or SACS pumps within 12 hours	1.9E-4
39.	NR-WW1-SWP-20	Failure to manually start SSWS or SACS pumps within 20 hours	7.4E-5
40.	NR-WW1-SWP-40M	Failure to manually start SSWS or SACS pumps within 40 minutes	1.6E-2

TABLE 3.3.9-1

REPRESENTATIVE INTERNAL FLOOD SEQUENCES AND THEIR FREQUENCIES

DOMINANT SEQUENCES for HC-FLD-R		
SEQUENCE	FLOOD DESCRIPTION	FREQUENCY
110-35	Service Water Intake Room 110, Turbine Trip Sequence 35	2.3E-009
FLD-CS0-35	Core Spray Room 4105 - Case 1, Turbine Trip Sequence 35	1.1E-009
FLD-CS3-12	Core Spray Room 4105 - Case 2, Turbine Trip Sequence 12	2.0E-009
FLD-RH0-13	RHR Room 4109 - Case 1, Turbine Trip Sequence 13	1.9E-008
FLD-RH0-17	RHR Room 4109 - Case 1, Turbine Trip Sequence 17	3.8E-008
FLD-RH0-32	RHR Room 4109 - Case 1, Turbine Trip Sequence 32	1.5E-009
FLD-RH0-35	RHR Room 4109 - Case 1, Turbine Trip Sequence 35	4.9E-009
FLD-RH0-38	RHR Room 4109 - Case 1, Turbine Trip Sequence 38	3.6E-010
O-10-12	Other Rooms in Reactor Building, Turbine Trip Sequence 12	1.7E-008
O-10-13	Other Rooms in Reactor Building, Turbine Trip Sequence 13	8.0E-009
O-10-38	Other Rooms in Reactor Building, Turbine Trip Sequence 38	1.5E-008
T-FLD-03	Turbine Building, MSIV Closure Sequence 3	2.8E-008
T-FLD-05	Turbine Building, MSIV Closure Sequence 5	7.5E-008
T-FLD-11	Turbine Building, MSIV Closure Sequence 11	1.5E-008
T-FLD-12	Turbine Building, MSIV Closure Sequence 12	1.9E-008
T-FLD-15	Turbine Building, MSIV Closure Sequence 15	3.9E-008
T-FLD-19	Turbine Building, MSIV Closure Sequence 19	2.2E-009
T-FLD-30	Turbine Building, MSIV Closure Sequence 30	6.6E-010
T-FLD-33	Turbine Building, MSIV Closure Sequence 33	5.9E-009
T-FLD-36	Turbine Building, MSIV Closure Sequence 36	4.8E-010
	Sump Cross Connection Through the Torus Area	4.0E-008

3.4 FRONT-END RESULTS AND SCREENING PROCESS

The total core damage frequency (CDF) for the HCGS is 4.58E-5/yr. There are 4412 minimal cutsets which have frequencies greater than 1.0E-10/yr. These 4412 cutsets comprise 81 core damage sequences.

Table 3.4-1 presents the 81 accident sequences ranked by frequency, and Table 3.4-2 presents the same list of sequences alphabetically. Table 3.4-3 presents the CDF broken down by sequence type, and Figure 3.4-1 presents a breakdown of the CDF by initiating event category.

The following sections provide the details of the results and screening process of the front end analysis of the HCGS IPE.

3.4.1 Application of Generic Letter Screening Criteria

The quantification of the HCGS IPE resulted in 81 core damage sequences with cutsets greater than 1.0E-10/yr. This includes only those sequences initiated by internal events, excluding internal flooding. The results of the internal flooding analysis are presented in Section 3.3.9. Also excluded from this assessment are those core damage sequences initiated by external events such as seismic events, tornadoes, external floods, and fire. The external events analysis is being performed as part of the IPEEE.

The overall result (4.58E-5/yr) of the quantitative assessment of core damage frequency for the HCGS was based on best-estimate, mean calculations of the frequencies of postulated accidents which could occur at the HCGS.

Section 2.1.6 of NUREG-1335 (Reference 3.4-1) provides the criteria for reporting potentially important systematic core damage sequences. These core damage systematic sequence criteria are as follows:

- "Any systemic sequence whose frequency is greater than 1E-7 per year."
- "All systemic sequences within the top 95% of the total core damage frequency."
- "All systemic sequences within the top 95% of the total containment failure frequency."
- "Any containment bypass systemic sequence whose frequency is greater than 1E-8 per year."
- "Any other systemic sequences judged to be important contributors to either core damage or poor containment performance."
- "The total number of systemic sequences should not exceed 100."

Appendix 2 of NRC Generic Letter No. 88-20 (Reference 3.4-2) provides similar guidance with regard to functional sequences. These are similar to those described above, but the cutoff frequencies for the first and fourth items above are increased by a factor of 10. Because the HCGS Level I analysis uses the linked fault tree approach rather than the large event tree approach, the Level I core damage accident scenarios are more correctly considered as functional sequences rather than systematic sequences. However, because some of the sequences may be described as "mixed," (part functional, part systematic) according to the guidance provided in NUREG-1335, the systematic criteria was conservatively used for reporting purposes.

After screening, there remains 17 core damage sequences. These 17 sequences comprise 97.3% of the total CDF, and are presented in Table 3.4-1 (the top 17 sequences in the table). Note that there are no containment bypass sequences with a frequency greater than 1E-8.

3.4.1.1 Dominant Accident Sequences

Five accident sequences have a CDF greater than 1.0E-6/yr. These five sequences contribute approximately 84.2% of the total CDF at the HCGS. Six additional sequences contribute at least 1% each to the total CDF. Together, these 11 dominant accident sequences represent 94.0% of the total CDF at the HCGS. A description of these dominant accident seq iences follows.

1) TeEDG

The CDF of this accident sequence is 3.27E-5/yr, comprising 71.4% of the total CDF. TeEDG is a Loss of Offsite Power (LOP) with the failure of all of the diesel generators (D/Gs), resulting in a Station Blackout (SBO). For the first four hours of this sequence, water injection to the vessel is accomplished with the turbine-driven HPCI and or RCIC pumps. Four hours after the LOP initiating event, the DC batteries are depleted, causing the HPCI and RCIC injection to the vessel to be terminated. In another two hours, neither onsite nor offsite power have been recovered, and enough water has boiled out of the RPV to cause fuel damage.

The failure of all four D/Gs is dominated by a combination of two failures in the D/G system, the Station Service Water System (SSWS), and/or the Safety Auxiliaries Cooling System (SACS) which cause the failure of the cooling water to all four D/Gs, resulting in a loss of all four D/Gs. For example, a LOP and the failure of the C and D SSWS pumps results in a SBO. The failure of SSWS pump C results in inadequate cooling of SACS Loop A, which results in inadequate cooling of D/Gs A and C, causing the loss of D/Gs A and C. Similarly, the failure of SSWS pump D results in the loss of D/Gs B and D. Therefore, the LOP with only two failures has caused an SBO.

2) TfU1U2X

The CDF of this sequence is 2.76E-6/yr, comprising 6.0% of the total CDF. TfU1U2X is a total loss of feedwater followed by a failure of both HPCI and RCIC to inject and a failure to depressurize the RPV. Fuel damage occurs in about one hour, since there is no injection of water to the RPV from the time of the initiating event.

The dominant failures in this sequence are split between a total loss of DC power and the hardware failure of HPCI and RCIC combined with a failure to depressurize the RPV.

3) TmUX

The CDF of this sequence is 1.05E-6/yr, comprising 2.3% of the total CDF. TmUX is a sequence initiated by the closure of all of the MSIVs, followed by a failure of both HPCI and RCIC to inject and a failure to depressurize the RPV. Fuel damage occurs in about one hour, since there is no injection of water to the RPV from the time of the initiating event.

The dominant failures in this sequence are split between a total loss of DC power and the hardware failure of HPCI and RCIC combined with a failure to depressurize the RPV.

4) S1WUv

This sequence has a frequency of 1.04E-6/yr, contributing 2.3% of the total CDF. S1WUV is a medium LOCA with a loss of decay heat removal. Containment venting is successful, but long term make-up is unsuccessful.

The dominant failures in this sequence are combinations of two SSWS and SACS failures (similar to TeEDG above) and the failure to use the core spray system in the long term.

5) TtQUX

The CDF of this sequence is 1.03E-6/yr, comprising 2.3% of the total CDF. TtQUX is a turbine trip initiating event followed by a failure of feedwater, a failure of both HPCI and RCIC to inject and a failure to depressurize the RPV. Fuel damage occurs in about one hour, since there is no injection of water to the RPV from the time of the initiating event.

The dominant failures in this sequence are feedwater failures combined with either a total loss of DC power or the hardware failure of HPCI and RCIC combined with a failure to depressurize the RPV.

6) S1U1X

This sequence has a frequency of 9.96E-7/yr, contributing 2.2% of the total CDF. S1U1X is a medium LOCA with the failure of HPCI and the failure to depressurize the RPV. The dominant failures in this sequence are HPCI hardware failures combined with a failure to depressurize.

7) Thv

This sequence has a frequency of 9.87E-7/yr and contributes 2.2% to the total CDF. Thv is a loss of HVAC to either the Panel Room or to the Switchgear Room and a failure to recover the HVAC before those rooms overheat and equipment fails.

8) TeEDGP

This sequence has a frequency of 9.67E-7/yr and contributes 2.1% of the total CDF. TeEDGP is a SBO identical to TeEDG above, except that in addition to the SBO, there is a stuck-open Safety Relief Valve (SRV).

9) TfQRWW1Uv

This sequence has a frequency of 5.30E-7/yr, and contributes 1.2% of the total CDF. TfQRWW1Uv is a total loss of feedwater with a failure to recover feedwater, a failure of containment heat removal, a failure of containment venting and a failure of long term make-up.

The cutsets which dominate this sequence involve service water failures (as described in TeEDG above) combined with a failure to initiate containment venting. Since HPCI and RCIC are successful in this sequence, the time to core damage in this sequence is at least 24 hours.

10) TiQUX

This sequence has a frequency of 5.29E-7/yr, and contributes 1.2% of the total CDF. TiQUX is initiated by an Inadvertent Opening of a SRV (IORV) which is followed by a failure of feedwater, of HPCI and RCIC, and a failure to depressurize the RPV. Other than the IORV initiating event, this sequence is similar to TfU1U2X above.

11) TatC2

This sequence has a frequency of 5.07E-7/yr, and contributes 1.1% of the total CDF. TatC2 is a turbine trip initiating event with a mechanical failure of the control rods to insert (such that ARI or any other alternate method of control rod insertion will not be successful) and a failure of Standby Liquid Control (SLC) to inject sufficient boron into the core to prevent fuel damage.

3.4.1.2 Basic Event Importance

An importance analysis was performed on the 745 highest frequency cutsets, including 393 basic events, which represent 90% of the HCGS IPE results. The importance ranking measures used are the partial derivative, risk reduction and risk increase, which are the built-in ranking capabilities of the PRA workstation software used by PSE&G. Complete listing of importance ranking of all the 393 basic events was prepared, but only a selection of the most important 30 individual basic events (hardware or human failures) are presented in Tables 3.4-4 and 3.4-5.

Risk reduction reflects the improvement (decrease) in the expected CDF achieved by reducing the failure probability of a basic event. Risk increase reflects the degradation (increase) in the expected CDF from arbitrarily failing a basic event (probability of one to fail).

The most important basic event failures as ranked by the risk increase importance measure are the common cause failure of safety/relief valves (SRVs), failure of DC buses, mechanical failure of the reactor protection (scram) system, miscalibration of level transmitters, failure of HPCI/RCIC, failure of vapor suppression during LOCA, operator failure to recover HVAC, failure of SACS or SSW systems, and failure of diesel generators.

The most important basic event failures as ranked by the risk reduction importance measure are the operator recovery of offsite power, operator recovery of diesel generators, test or maintenance of SSW and SACS loops, failure to depressurize, failure of the diesel generators, HPCI unavailability due to TM, failure to recover HVAC, etc. Importance ranking of various MOVs is also identified by this importance measure.

The following events were found important based on both risk increase and risk decrease importance measures: the diesel generator failures, HPCI/RCIC failures, SSW and SACS failures, failure of diesel generators, and failure to provide alternate ventilation to the Class 1E Panel Room within 12 hours after a loss of HVAC.

It should be noted that the 30 highest ranked basic events, as measured by the partial derivative (Birnbaum) or risk increase have similar importance measures (values).

3.4.1.3 Sequences Screened Out by Recovery Actions

Section 2.1.6 of NUREG-1335 (Reference 3.4-1) requires the reporting of any core damage sequence whose frequency was reduced by more than an order of magnitude to below the screening cutoff due to the application of human recovery action(s). Since the sequence frequency used as a cutoff was 1E-7/yr (as described in Section 3.4.1), it is appropriate to report here any sequence whose frequency is greater than 1E-6/yr (before recoveries) and was not reported in Section 3.4.1.1.

Table 3.4-6 presents each of the core damage sequences whose frequency was greater than or equal to 1E-6/yr before recovery actions were applied, but were screened out in Section 3.4.1.1 after the application of recoveries. This table presents the core damage sequence, its frequency before and after the recoveries were applied, and the actual recovery actions applied. A brief description of the sequences in Table 3.4-6 is provided below.

The first two sequences (TtQWW1Uv and TmWW1Uv) are transients with the loss of decay heat removal (DHR), with core damage occurring after 24 hours. The recovery actions applied in each sequence were NR-PCS-24, NR-RHR-INIT, NR-WW1-SWP-20, and NR-VENT-5. Note that a maximum of three recoveries were applied to any one cutset, and when multiple recoveries were applied to one cutset, the rules detailed in Section 3.3.3

were followed. Section 3.3.3 also details the quantification of the probability of the human recovery actions applied. All of the human recovery actions quantified in Section 3.3.3 are summarized in Table 3.4-7.

The third sequence (TeWW1Uv) is a LOP with a loss of DHR. The time to core damage would be at least 24 hours. The recovery actions applied in this sequence are NR-LOSP-24, NR-RHR-INIT, and NR-VENT-5.

The fourth sequence (TmPP2WUv) is a transient initiated by an MSIV closure with two stuck open relief valves (SORVs) and a loss of DHR. The time to core damage for this sequence is at least 24 hours. The recovery actions applied to this sequence are NR-PCS-24, NR-RHR-INIT, and NR-WW1-SWP-20.

The fifth sequence (S1WW1Uv) is a medium LOCA with a loss of DHR. The time to core damage for this sequence is at least 24 hours. The recovery actions applied are NR-RHR-INIT and NR-VENT-5.

The sixth sequence (TtPP2WW1Uv) is a turbine trip with two SORVs and a loss of DHR. The time to core damage for this sequence is at least 24 hours. The recovery actions applied are NR-RHR-INIT, NR-WW1-SWP-20 and NR-VENT-5.

The seventh sequence (AWW1Uv) is a large LOCA with a loss of DHR. The time to core damage for this sequence is at least 24 hours. The recovery actions applied are NR-RHR-INIT and NR-VENT-5.

The eighth sequence (TmPP2WW1Uv) is similar to the fourth sequence except that there is an additional failure to vent the containment. Therefore, the recovery actions applied are NR-PCS-24, NR-WW1-SWP-20, NR-RHR-INIT and NR-VENT-5.

The ninth sequence (TiaWW1Uv) is a loss of the Instrument Air System (IAS) and a loss of DHR. The time to core damage for this sequence is at least 24 hours. The recovery actions applied are NR-RHR-INIT, NR-WW1-SWP-20 and NR-VENT-5.

The tenth sequence (S2S3IsoQUX) is a recirculation pump seal LOCA with a loss of Feedwater (FW), a loss of HPCI and RCIC and a failure to depressurize the Reactor Pressure Vessel (RPV). The time to core damage in this sequence is 40 minutes. The recovery actions applied are NR-SLEAK-ISO-15M and NR-U1X-DEP-40M.

The eleventh sequence (ThvP) is a loss of HVAC with a SORV. The time to recover from the loss of HVAC is either 12 or 24 hours (depending on the cutset), but the 12 hour time period was conservatively assumed for the entire sequence. The recovery action applied is NR-HVC-PNRM-12.

The twelfth sequence (TtPQUX) is a turbine trip with a SORV, loss of FW, loss of HPCI and RCIC and a failure to depressurize the RPV. The time to core damage for this sequence is 40 minutes. The recovery actions applied are NR-PCS-40M, NR-U1X-DEP-40M and NR-Q-FWLVH-4M.

The thirteenth sequence (TraPP2WUv) is a loss of RACS with two SORVs and a loss of DHR. The time to core damage for this sequence is at least 24 hours. The recovery actions applied are NR-WW1-SWP-20 and NR-SPL-LVLL-4.

The fourteenth sequence (TfU1U2V) is a loss of feedwater with a failure of all injection to the RPV. The time to core damage for this sequence is 1 hour. The recovery actions applied are NR-UV-WTLVL-20M and NR-UV-ECCS-1.

The fifteenth sequence (TeUX) is a LOP with a failure of HPCI and RCIC and a failure to depressurize the RPV. The time to core damage for this sequence is 1 hour. The recovery actions applied are NR-LOSP-60M and NR-U1X-DEP-60M.

The sixteenth sequence (S2QUX) is a small LOCA with a failure of FW, HPCI and RCIC, and a failure to depressurize the RPV. The time to core damage for this sequence is 40 minutes. The recovery actions applied are NR-U1X-DEP-40M and NR-Q-FWLVL-24M.

The seventeenth sequence (TraQUX) is a loss of RACS with a failure of FW, HPCI and RCIC, and a failure to depressurize the RPV. The time to core damage for this sequence is one hour. The recovery actions applied are NR-U1X-DEP-60M, NR-Q-FWLVH-4M and NR-WW1-SWP-1.

The eighteenth sequence (TmUV) is an MSIV closure with a failure of all injection to the RPV. The time to core damage for this sequence is one hour. The recovery actions applied are NR-PCS-1, NR-UV-ECCS-1 and NR-UV-WTLVL-20M.

The nineteenth sequence (TfPU1U2X) is a loss of FW with a SORV, failure of HPCI and RCIC, and a failure to depressurize the RPV. The time to core damage for this sequence is 40 minutes. The recovery action applied is NR-U1X-DEP-40M.

The twentieth sequence (S1U1WW1Uv) is a medium LOCA with a failure of HPCI and a loss of DHR. The time to core damage for this sequence is at least 24 hours. The recovery actions applied are NR-RHR-INIT and NR-VENT-5.

The twenty-first sequence (TePWW1Uv) is a LOP with a SORV and a loss of DHR. The time to core damage for this sequence is at least 24 hours. The recovery actions applied are NR-LOSP-24, NR-RHR-INIT and NR-VENT-5.

The twenty-second sequence (TmPUX) is an MSIV closure with a SORV, failure of HPCI, and a failure to depressurize the RPV. The time to core damage for this sequence is 40 minutes. The recovery action applied is NR-U1X-DEP-40M.

The twenty-third sequence (TatQU1X) is an MSIV-closure ATWS (mechanical failure of the control rods) with a failure of feedwater, HPCI and a failure to depressurize the RPV. Core damage for this sequence would occur in a few minutes. The recovery actions applied are NR-ATWS-HPCI and NR-ATWS-DEP.

The twenty-fourth sequence (TraPP2WW1Uv) is a loss of RACS with two SORVs and a loss of DHR. The time to core damage for this sequence is at least 24 hours. The recovery actions applied are NR-WW1-SWP-20, NR-RHR-INIT and NR-VENT-5.

The twenty-fifth sequence (TiaPP2WUv) is a loss of IAS with two SORVs and a loss of DHR. The time to core damage for this sequence is at least 24 hours. The recovery actions applied are NR-WW1-SWP-20 and NR-SPL-LVLL-4.

The twenty-sixth sequence (ThvPP2) is a loss of HVAC with two SORVs. The time to recover from the loss of HVAC is either 12 or 24 hours (depending on the cutset), but the 12-hour time period was conservatively assumed for the entire sequence. The recovery action applied is NR-HVC-PNRM-12.

The twenty-seventh sequence (ThvU) is a loss of HVAC with a failure of HPCI and RCIC. The time to recover from the loss of HVAC is either 12 or 24 hours (depending on the cutset), but the 12 hour time period was conservatively assumed for the entire sequence. The recovery action applied is NR-HVC-PNRM-12.

The twenty-eighth sequence (TiQUV) is an inadvertent opening of a SRV with a failure of FW and all other injection to the RPV. The time to core damage for this sequence is 40 minutes. The recovery actions applied are NR-UV-WTLVL-20M and NR-UV-ECCS-40M.

The twenty-ninth sequence (TeEDGU) is a LOP with a failure of onsite AC power (a station blackout) and a failure of HPCI and RCIC. The time to core damage for this sequence is one hour. The recovery actions applied are NR-LOSP-1, NR-UV-ECCS-1 and NR-UV-WTLVL-20M.

The thirtieth sequence (TtQWUv) is a turbine trip with a failure of feedwater and a loss of DHR. The time to core damage for this sequence is at least 24 hours. The recovery action applied is NR-PCS-24.

3.4.1.4 Uncertainty and Sensitivity of the Core Damage Frequency

3.4.1.4.1 Uncertainty of the Core Damage Frequency

The occurrence probabilities of the basic events of the Hope Creek PRA are best estimate point values. However, uncertainty boundaries are assigned for each type of basic event, in the form of a lognormal distribution. These uncertainty boundaries are based on those used generically in the industry. A probability density function of the total core damage frequency of the most dominant 180 cutsets was estimated by a calculation using the computer code TEMAC (Reference 3.4-3). The calculated distribution of the total core damage frequency is shown in Figure 3.4-2.

Due to memory and computation time limitations, the TEMAC code is not able to calculate the uncertainty distribution of the complete set of 4412 cutsets that comprise the CDF of theHope Creek IPE. Therefore the number of cutsets used in the uncertainty analysis was reduced until TEMAC was capable of performing the calculations. This occurred when the number of core damage cut sets was reduced to the top 180. For a given set of cutsets, TEMAC calculates the number of sample trials that it is capable of performing. For the 180 cutsets, TEMAC used 221 sample trials. The deviation between the mean and nominal values of the CDF results from the limitations of the TEMAC estimation technique. For a smaller number of cutsets, this deviation could be reduced, but then a larger percentage of the core damage frequency would have been ignored.

3.4.1.4.2 Sensitivity Analyses

Three sensitivity cases were quantitatively analyzed by manipulating the baseline HCGS IPE results in the RESULTS MODULE of the PRA WORKSTATION software (Reference 3.4-4). The first sensitivity case is an assessment of the impact of a less conservative assumption about the mission time of the Emergency Diesel Generators (EDGs) (i.e. decreasing the mission time from 24 hours to six hours). The second and third sensitivity cases are estimates of the core damage frequency (CDF) that would have been calculated had the Loss of an AC bus and the Loss of a DC bus (respectively) been included as special initiating events. It is appropriate to note that the importance analysis of Section 3.4.1.2 is a form of sensitivity analysis at the basic event level.

Further sensitivity studies were not performed because of the high degree of HCGS in the development of the PRA models. For example, the sensitivity of post-accident operator errors may be studied by adjusting the HEP values upward or downward. This was not performed because HEPs were based on actual simulator training, and would not likely change. Similarly, because most plant models were developed with support from the HCGS Technical or Operations Departments, few uncertainties or variabilities are believed to exist. Finally, test and maintenance unavailabilities are based on plant-specific data, as opposed to generic values; therefore, it was unnecessary to perform a sensitivity study of variations in that data.

3.4.1.4.2.1 Decrease EDG Mission Time From 24 Hours To Six Hours

The mission time of the diesel generators was modeled as 24 hours in the diesel generator fault trees (described in Section 3.2.1.10). This is a conservative assumption, since it is unlikely that offsite power would not be recovered within 24 hours. The offsite power recovery curve used (which was derived from NUREG-1032, Reference 3.4-5) predicts a 95% probability of offsite power recovery within six hours. Therefore, this sensitivity case is an analysis of the impact of a change in the EDG mission time from 24 hours to six hours.

Table 3.4-8 shows the results of this sensitivity analysis. The only core damage sequences (with a frequency greater than or equal to 1E-10) which are affected are the five Station Blackout (SBO) sequences shown. There is a reduction in the total CDF from 4.58E-5 to 3.94E-5, or a reduction of 14.0%. Although this is not a negligible reduction in the total CDF, the contribution of SBO sequences to the total CDF would still be 69.5%. When this SBO contribution is compared to the 73.7% calculated in the baseline results, it is clear that the assumption of a 24 hour mission time for the EDGs does not have any impact on the overall conclusions of the HCGS IPE.

3.4.1.4.2.2 Loss Of A Class 1E AC Vital Bus Special Initiating Event

The loss of a Class 1E AC vital bus was not considered as a special initiating event in the HCGS IPE, since it was not found to cause a reactor trip. However, as was mentioned in Section 3.1, this sensitivity analysis will approximate what the core damage frequency would have been, had the loss of a Class 1E AC vital bus been considered as an initiating event.

If the loss of a Class 1E AC vital bus were to cause a reactor trip, the accident sequence is assumed to be identical to a turbine trip initiating event (see Section 3.1.2 for a discussion of a turbine trip initiating event), except that one Class 1E AC vital bus would be unavailable. Therefore, to perform this sensitivity analysis, the following steps were executed:

1. Establish a frequency for the loss of a Class 1E AC vital bus initiating event.

2. In the baseline results of the IPE, assign a probability of 1.0 to an event which represents the unavailability of one 4.16KV AC vital bus. Note that this is done on the cutset level in a way which is applied across all of the cutsets which contain that Class 1E AC vital bus failure.

3. Examine the new CDF of each of the turbine trip core damage sequences. Since these were calculated with the turbine trip initiating event frequency (4/year), this frequency is divided out of the cutsets, and they are then multiplied by the frequency of the loss of a Class 1E AC vital bus initiating event. The resulting cutsets show the frequency of core damage resulting from a Class 1E AC vital bus failure which in some way caused a reactor trip.

For the first step, as an estimate of the initiating event frequency of the loss of a Class 1E AC vital bus, the frequency from NUREG-4550 (Reference 3.4-6) was used. This frequency was 5.0E-3/yr, and it is given the designation "Tac."

For the second step, the unavailability of the Class 1E 4.16KV bus 10A401 was set to 1.0. Division A of power was chosen for this sensitivity.

For the third step, the resulting core damage sequences were multiplied by 5.0E-3/yr and divided by 4.0/yr to give the core damage frequency due to the loss of a Class 1E AC vital bus initiating event. An example of this third step is provided below for a cutset transferred from sequence "TtQUX" to "TacQUX":

Original cutset: Turbine trip (4/yr) * 10A401 unavailable (1.41E-3)
* HPCI/RCIC dependent failure (1.35E-4) * Fail to depress RPV (4.6E-3)
* Fail to recover PCS w/i 1 hour (0.6)
= 2.10E-9/yr

Revised cutset: Loss of AC bus (5.0E-3/yr) * 10A401 unavailable (1.0)
* HPCI/RCIC dependent fail (1.35E-4) * Fail to depress RPV (4.6E-3)
* Fail to recover PCS w/i 1 hour (0.6)
= 1.86E-9/yr

The result of this sensitivity analysis is a total CDF from the loss of an AC bus initiating event of 1.04E-8/yr. The three Tac core damage sequences with a frequency greater than 1E-10/yr are shown in Table 3.4-9.

3.4.1.4.2.3 Loss Of A DC Bus Special Initiating Event

The loss of a DC bus was not considered as a special initiating event in the HCGS IPE, since it was not found to cause a reactor trip. However, as was mentioned in Section 3.1, this sensitivity analysis will approximate what the core damage frequency would have been, had the loss of a DC bus been considered as a special initiating event.

This sensitivity analysis is identical to the previous sensitivity analysis (the loss of a Class 1E AC vital bus), except that instead of assigning a 1.0 unavailability to a 4.16KV AC bus, the 1.0 unavailability was assigned to the 125VDC bus 10D410. Similar to Tac, the frequency of the loss of a DC bus was taken from NUREG-4550. It is designated "Tdc" and its frequency is 5.0E-3/yr.

The result of this sensitivity analysis is a total CDF from the loss of a DC bus of 1.99E-8/yr. The three Tdc core damage sequences with a frequency greater than 1E-10 are shown in Table 3.4-10.

3.4.1.5 Comparison With Other Studies

Table 3.4-11 presents a comparison of the HCGS Level I results with those from the NUREG-1150 Reference Plant similar to HCGS (Peach Bottom), and the IPE Submittals of other BWRs with Mark I Containments. The Internal Events Core Damage Frequency (CDF) for the HCGS (4.58E-5/yr) is approximately one order of magnitude higher than the NUREG-1150 results for Peach Bottom (Reference 3.4-6). A review of the NUREG-1150 study has shown that many support system dependencies were not reviewed with the depth of detail used in the HCGS IPE. The HCGS CDF compares reasonably with the results from the other BWR IPEs.

Table 3.4-11 also details the percentage distributions for the separate studies. Loss of Power sequences account for a higher percentage of the CDF at Hope Creek (73.8%) than at Peach Bottom, but the HCGS results are comparable to most of the other BWR IPEs. As discussed in Section 3.4.2, conservative design assumptions with respect to the SACS and SSW systems

at HCGS contribute significantly to the LOP results. Transients account for a greater contribution to the HCGS IPE than the Peach Bottom NUREG-1150 study, although the contribution is relatively small (14.8%), and lower than most of the other BWR IPEs. This is likely due to the amount of detail in the HCGS IPE, and the relatively large contribution of ATWS to the Peach Bottom results. LOCAs are generally minor contributors in all of the studies. ATWS is a notably small contributor (1.6%) at the HCGS. This is generally due to automatic operation of the SLC system. Special initiators also contribute very little to the Internal Events CDF in all cases. Finally, the Internal Flooding results at HCGS were comparable to the published BWR IPE results.

3.4.2 Vulnerability Screening

Neither GL88-20 nor NUREG-1335 strictly define "vulnerability." Words which appear in relation to vulnerability include "weakness" and "outlier." The first implies an absolute relationship, while the second implies a relative relationship. Therefore, for a sequence or event to be considered indicative of a vulnerability, it had to pass the screening criteria defined in Section 3.4.1 and contribute inordinately to the HCGS Core Damage Frequency with respect to either (1) other HCGS core damage sequences or contributing events, or (2) in comparison to similar sequences or events for other nuclear power plants as determined from published risk assessment results.

As described in Section 3.4.1, after screening, 17 sequences remained comprising 97.3% of the Total Internal Events and Internal Flooding CDF. Five core damage sequences have frequencies greater than 1.0E-6/year. These five sequences contribute approximately 84.2% to the total CDF. Six additional sequences each contribute at least 1% to the total CDF. The remaining six each contribute less than 1% to the total CDF. As described in Section 3.4.1.1, a single sequence, TeEDG, contributes 71.4% to the CDF.

During the recovery analysis portion of the HCGS IPE quantification, transients were identified which, when they involved certain HVAC failures, based on room heatup calculations, led to core damage. The greatest contributor of these was a loss of Switchgear or Class 1E Panel Room HVAC with a frequency of 3.29E-3/year prior to recovery. Clearly this sequence inordinately contributed to the CDF. It was immediately labeled a "vulnerability" and reported to the HCGS. A recovery procedure (Reference 3.4-9) was developed by the HCGS to supply alternate ventilation to prioritized rooms as determined from the IPE's Room Heatup Calculations. (The quantification of recovery actions is described in Section 3.3.3.) The new procedure eliminated the "vulnerability."

With elimination of the loss of HVAC sequences described above, the principal contributors to the internal events CDF are sequences involving station blackout (SBO). The five SBO sequences contribute 73.7% of the total CDF of 4.58E-5/yr. However, it was determined that SBO does not represent a vulnerability at the HCGS, for the following reasons:

1. A comparison of Hope Creek with other BWRs with Mark I Containments shows SBO to be a significant contributor to CDF in all cases, and the highest single contributor in most cases (See Section 3.4.1.5).

Original cutset: Turbine trip (4/yr) * 10A401 unavailable (1.41E-3)
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The result of this sensitivity analysis is a total CDF from the loss of a DC bus of 1.99E-8/yr. The three Tdc core damage sequences with a frequency greater than 1E-10 are shown in Table 3.4-10.

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With elimination of the loss of HVAC sequences described above, the principal contributors to the internal events CDF are sequences involving station blackout (SBO). The five SBO sequences contribute 73.7% of the total CDF of 4.58E-5/yr. However, it was determined that SBO does not represent a vulnerability at the HCGS, for the following reasons:

1. A comparison of Hope Creek with other BWRs with Mark I Containments shows SBO to be a significant contributor to CDF in all cases, and the highest single contributor in most cases (See Section 3.4.1.5).

2. The total CDF for Hope Creek, including the SBO sequences, is reasonable when compared to other BWRs.

3. The principal reason for the large contribution of SBO sequences to overall CDF is the conservative design assumptions used for SACS and the SSW systems in the analysis of Loss of Offsite Power sequences. A more detailed thermo-hydraulic evaluation of theses systems is underway, which may result in as much as a 50% reduction in the SBO contribution to total CDF.

Based on the above discussion, the loss of HVAC was determined to be the only vulnerability at the HCGS, and it was addressed in a new HVAC recovery procedure.

3.4.3 Unresolved and Generic Issues

By the way of participation in the Individual Plant Examination, as evidenced by this submittal report, PSE&G has resolved GSI 105, "Intersystem LOCA Outside Containment," as well as USI A-45, "Decay Heat Removal" for the HCGS. Specific details of the ISLOCA analysis appear in Section 3.1.3.5 and Reference 3.1.3-1. It is notable that due to the low frequency of core damage resulting from ISLOCAs, 1.7E-9/yr., these sequences fell below the screening criteria for inclusion in the back-end analysis. USI A-45 is subsequently discussed in Section 3.4.4.

3.4.4 Decay Heat Removal Evaluation

This section defines the concerns of the Unresolved Safety Issue (USI) A-45 (Reference 3.4-8) in regard to decay heat removal and describes how the HCGS IPE addressed the issue.

Unresolved Safety Issue A-45 concerns the performance of the decay heat removal function, to ensure heat transfer from the reactor coolant system to an ultimate heat sink after reactor shutdown. The decay heat removal function is similar to other safety related functions in the plant because it includes a number of alternative, redundant systems, that are controlled by the reactor protection system, under the supervision of operators. The redundant systems which are primarily responsible for the decay heat removal depend on various support systems, such as AC and DC electrical power, ventilation and cooling, air systems, etc.

A total loss of the decay heat removal function would cause a steady increase of the temperature and pressure. This concern is valid, but for the HCGS it is not an unresolved issue for the following reasons:

- The contribution of TW (loss of decay heat removal) sequences to the total core damage frequency (CDF) at the HCGS is only 5.45E-7 per year, or 1.2% of the total CDF.

- At the HCGS, the residual heat removal system (RHR) is a very robust system, with high redundancy (two loops, two heat exchangers, and complete electrical separation between various trains). To provide additional redundancy, the HCGS is implementing a design change to allow a cross-tie capability between RHR loops A and C, and between loops B and D. This enables the alignment of the C RHR pump to the A RHR heat exchanger, and of the D RHR pump to the B RHR heat exchanger. In addition to this, the HCGS has a hard-pipe containment venting system which has the capability to remove decay heat in the unlikely situation that the RHR system fails.

- The coincidental failure of the 125 VDC batteries with a loss of offsite power and failure to start all the diesel generators has a very low frequency of occurrence. This sequence was below the screening cutoff discussed in Section 3.4.1.

- The USI A-45 NRC BWR case studies identified a potential weakness in that each diesel generator had only one cooling pump, and failure of that pump would cause failure of the diesel generator. The HCGS diesels are cooled by SACS, which is a highly redundant system (2 loops, two pumps in each loop). If one SACS pump fails, the cooling of the diesel generators is not affected, because HCGS procedures would direct the cross-tie of SACS cooling to the diesels such that all four diesels could be cooled by the operating SACS pumps.

- The USI A-45 NRC BWR case studies identified a potential weakness in that following a loss of offsite power, diesel generator failures are dominant contributors to core damage frequency, in the range of 1.0E-4/yr. At the HCGS, the total core damage frequency is lower (approximately 4.58E-5/yr).

- The USI A-45 NRC BWR case studies identified a potential weakness in that failure of MOVs in the reactor building closed cooling system could isolate cooling water to the ECCS room coolers, or divert cooling water to non-critical loads. At the HCGS, the Safety Auxiliaries Cooling System (SACS), with its two redundant loops and two pumps in each loop, provides cooling to the RHR pump seal cooler and motor bearing cooler and to all ECCS room coolers. All of the SACS valves used to provide cooling to the ECCS are pneumatically controlled, with the exception of the motor-operated SACS Heat Exchanger Inlet Valves. These MOVs are part of PSE&G GL89-10 program and will be statically and dynamically tested to ensure their capability to perform their intended function under design basis conditions.

In view of all these arguments, loss of decay heat removal at the HCGS is considered a resolved issue.

3.4.5 References

3.4-1 "Individual Plant Examination: Submittal Guidance: Final Report." U.S. Nuclear Regulatory Commission, Washington, DC, 1989: NUREG-1335.

3.4-2 "Individual Plant Examination for Severe Accident Vulnerabilities - 10CFR 50.54(f)," Generic Letter No. 88-20. U.S. Nuclear Regulatory Commission, Washington, DC, November 23, 1988.

3.4-3 "A User's Guide To The Top Event Matrix Analysis Code (TEMAC)." U.S. Nuclear Regulatory Commission, Washington, DC, August 1986: NUREG/CR-4598.

3.4-4 "PRA Workstation Users Manual." NUS, Kent, WA, December 1992.

3.4-5 "Stress and Duress Detection for NRC Licensed Facilities: A Constitutional and Regulatory Analysis." U.S. NRC, Washington, DC, 1979. NUREG/CR-1032.

3.4-6 "Analysis of Core Damage Frequency: Peach Bottom, Unit 2 Internal Events." U.S. NRC, Washington, DC, 1989. NUREG/CR-4550.

3.4-7 NUREG/CR-4550, Vol. 6, "Analysis of Core Damage Frequency From Internal Events: Grand Gulf, Unit 1." April 1987.

3.4-8 "Shutdown Decay Heat Removal Requirements." U.S. Nuclear Regulatory Commission, Office Of The Secretary, Washington, DC, 1988: USI A-45 BWR Case Study.

3.4-9 HCGS Procedure No. HC.OP-AB.ZZ-0209(Q), "Loss of HVAC;" April 1994.

TABLE 3.4-1

CORE DAMAGE SEQUENCES SORTED BY FREQUENCY

	Sequence	Frequency
1	TeEDG	3.2679E-005
2	TfU1U2X	2.7566E-006
3	TmUX	1.0470E-006
4	S1WUv	1.0359E-006
5	TtQUX	1.0343E-006
6	S1U1X	9.9570E-007
7	Thv	9.8736E-007
8	TeEDGP	9.6715E-007
9	TfQRWW1Uv	5.2964E-007
10	TiQUX	5.2884E-007
11	TatC2	5.0747E-007
12	TtQUV	3.9697E-007
13	S1D	3.0000E-007
14	TsaW1Uv	2.9846E-007
15	AWUv	2.0736E-007
16	TtPP2WUv	1.7924E-007
17	TaCmC2	1.1898E-007
18	S2C	7.9912E-008
19	TfPU1U2X	7.8040E-008
20	AD	7.0000E-008
21	TeEDGU	5.8460E-008
22	TeEDGPP2	5.8396E-008
23	S1EEdg	5.2409E-008
24	S2S3IsoQUX	5.0521E-008
25	TmPUX	5.0183E-008
26	TeUX	4.9568E-008
27	S1V1	4.9315E-008
28	TtPP2V	4.6004E-008
29	TfU1U2V	4.5486E-008
30	TraQUX	4.2972E-008
31	S2S3IsoQV	4.2650E-008
32	TtCeScrRpt	4.0000E-008
33	TtCmRpt	4.0000E-008
34	TsaPP2Uv	3.5464E-008
35	S1C	3.0000E-008
36	S2S3IsoC	2.4616E-008
37	ThvP	2.1780E-008
38	AC	2.1000E-008
39	TraQUV	1.9694E-008
40	TmUV	1.7863E-008
41	TfPU1U2V	1.5867E-008
42	TtPQUX	1.4829E-008
43	AV1	1.4793E-008
44	TtCmQU1X	1.4499E-008
45	TtQWW1Uv	1.3989E-008
46	S1U1WUv	1.2977E-008
47	TtM	1.2000E-008
48	S1U1V1	1.1806E-008
49	TmPP2V	1.0562E-008
50	Ta2CeScrRpt	9.8200E-009
51	TaCmRpt	9.8200E-009
52	TeEDGPU	9.2219E-009
53	S2D	7.9800E-009
54	S2QUX	7.5906E-009
55	AEEdg	7.3930E-009
56	TiaUV1	4.8502E-009
57	TraPP2WUv	4.1177E-009
58	TiQUV	3.5993E-009
59	TiaUX	3.1425E-009
60	S2S3IsoD	2.4616E-009
61	TtPP2WW1Uv	2.2821E-009
62	TraPQUX	1.8091E-009
63	TtCmMsvU1X	1.7033E-009
64	TfM	1.6500E-009
65	TePUX	1.6412E-009
66	S1WW1Uv	1.6200E-009
67	TsaPP2W1Uv	1.3419E-009
68	Ta1ScrKMsvU1X	1.2139E-009
69	ThvPP2	1.0890E-009
70	TmM	1.0800E-009
71	TiaWW1Uv	1.0337E-009
72	AWW1Uv	8.8192E-010
73	TsaUsVs	8.0111E-010
74	TtQWUv	7.2670E-010
75	TtPQWUv	6.0102E-010
76	TaCmU1X	5.5233E-010
77	S1EU1X	4.0808E-010
78	S1ED	3.0000E-010
79	TsaUsX	2.7669E-010
80	TmPP2WUv	2.6049E-010
81	TraPP2V	2.4658E-010
TOTAL CDF =		4.58E-5

TABLE 3.4-2

CORE DAMAGE SEQUENCES SORTED ALPHABETICALLY

	Sequence	Frequency
1	AC	2.1000E-008
2	AD	7.0000E-008
3	AEEdg	7.3930E-009
4	AV1	1.4793E-008
5	AWUv	2.0736E-007
6	AWW1Uv	8.8192E-010
7	S1C	3.0000E-008
8	S1D	3.0000E-007
9	S1ED	3.0000E-010
10	S1EEdg	5.2409E-008
11	S1EU1X	4.0808E-010
12	S1U1V1	1.1806E-008
13	S1U1WUv	1.2977E-008
14	S1U1X	9.9570E-007
15	S1V1	4.9315E-008
16	S1WUv	1.0359E-006
17	S1WW1Uv	1.6200E-009
18	S2C	7.9912E-008
19	S2D	7.9800E-009
20	S2QUX	7.5906E-009
21	S2S3IsoC	2.4616E-008
22	S2S3IsoD	2.4616E-009
23	S2S3IsoQUX	5.0521E-008
24	S2S3IsoQV	4.2650E-008
25	Ta1ScrKMsvU1X	1.2139E-009
26	Ta1ScrRpt	4.0000E-008
27	Ta2CeScrRpt	9.8200E-009
28	TaCmC2	1.1898E-007
29	TaCmRpt	9.8200E-009
30	TaCmU1X	5.5233E-010
31	TatC2	5.0747E-007
32	TatMsvU1X	1.7033E-009
33	TatQU1X	1.4499E-008
34	TatRpt	4.0000E-008
35	TeEDG	3.2679E-005
36	TeEDGP	9.6715E-007
37	TeEDGPP2	5.8396E-008
38	TeEDGPU	9.2219E-009
39	TeEDGU	5.8460E-008
40	TePUX	1.6412E-009
41	TeUX	4.9568E-008
42	TfM	1.6500E-009
43	TfPU1U2V	1.5867E-008
44	TfPU1U2X	7.8040E-008
45	TfQRWW1Uv	5.2964E-007
46	TfU1U2V	4.5486E-008
47	TfU1U2X	2.7566E-006
48	Thv	9.8736E-007
49	ThvP	2.1780E-008
50	ThvPP2	1.0890E-009
51	TiaUV1	4.8502E-009
52	TiaUX	3.1425E-009
53	TiaWW1Uv	1.0337E-009
54	TiQUV	3.5993E-009
55	TiQUX	5.2884E-007
56	TmM	1.0800E-009
57	TmPP2V	1.0562E-008
58	TmPP2WUv	2.6049E-010
59	TmPUX	5.0183E-008
60	TmUV	1.7863E-008
61	TmUX	1.0470E-006
62	TraPP2V	2.4658E-010
63	TraPP2WUv	4.1177E-009
64	TraPQUX	1.8091E-009
65	TraQUV	1.9694E-008
66	TraQUX	4.2972E-008
67	TsaPP2Uv	3.5464E-008
68	TsaPP2W1Uv	1.3419E-009
69	TsaUsVs	8.0111E-010
70	TsaUsX	2.7669E-010
71	TsaW1Uv	2.9846E-007
72	TtM	1.2000E-008
73	TtPP2V	4.6004E-008
74	TtPP2WUv	1.7924E-007
75	TtPP2WW1Uv	2.2821E-009
76	TtPQUX	1.4829E-008
77	TtPQWUv	6.0102E-010
78	TtQUV	3.9697E-007
79	TtQUX	1.0343E-006
80	TtQWUv	7.2670E-010
81	TtQWW1UvAAA	1.3989E-008
TOTAL CDF =		4.58E-5

TABLE 3.4-3
CORE DAMAGE FREQUENCY DISTRIBUTION

SEQUENCE	FREQUENCY	% OF TOTAL
Station Blackout (SBO)	3.38E-05	73.7%
Transient with loss of FW, HPCI/RCIC, & failure to depressurize (TQUX)	5.41E-06	11.7%
LOCAs	3.07E-06	6.7%
Special Initiators	1.42E-06	3.1%
ATWS	7.45E-07	1.6%
Loss of decay heat removal (TW)	5.45E-07	1.2%
Transient with loss of all high pressure & low pressure injection (TQUV)	4.64E-07	1.0%
Stuck-open Safety Relief Valve (TP)	3.98E-07	0.9%
Loss of Offsite Power (D/Gs operate)	5.12E-08	0.1%
Total CDF from internal events:	4.58E-5 / year	100.0%

Table 3.4-4

The Most Important 30 Basic Event Failures Sorted by the Risk Increase Measure

	Basic Event	Description
1.	SRV-13-FTO-CCF	Common cause failure to open 13 SRVs.
2.	DCP-BDC-VF-DF03	Common cause failure of 125VDC buses 10D410, 20, & 40.
3.	DCP-BDC-VF-DF01	Common cause failure of 125VDC buses 10D410, 20, 30 &40.
4.	CM	RPS mechanical failure prevents scram.
5.	ESF-XHE-MC-DF02	Miscalibration of all level transmitters.
6.	DCP-BDC-VF-DF10	Common cause failure of 125VDC BUSES 10D420 AND D440.
7.	ESF-XHE-MC-DF01	Miscalibration of all pressure transmitters.
8.	HAR-TDP-FS-DPF01	Common cause failure to start of HPCI and RCIC turbine driven pumps.
9.	HAR-TDP-FR-DPF01	Common cause failure to run of HPCI and RCIC turbine driven pumps.
10.	VAP-SUP-SY-FAILS	Vapor suppression (breakers) fail during large or intermediate LOCA.
11.	NR-HVC-PNRM-12	Failure to provide alternate ventilation to the Panel Room within 12 hours after a loss of HVAC.
12.	DCP-BDC-VF-DF06	Common cause failure of 125VDC buses 10D410 and 10D420.
13.	CE	RPS electrical failure prevents scram.
14.	SWS-MOV-CC-DF01	Dependent failures of 2198 C and D VALVES
15.	SWS-MDP-FS-DF04	Dependent failures to start SWS-TWSs.
16.	SWS-MDP-FR-DF04	Dependent failures to run SWS-TWSs.
17.	SWS-TWS-FR-DF01	Dependent failures to run ALL 4 TWSs.
18.	SWS-MDP-FR-DF03	Dependent failures to run ALL SWS pumps.
19.	SAC-MDP-FR-DF07	ALL 4 SACS pumps fail to run.
20.	SWS-MOV-CC-DF03	Dependent failures of strainer MOVs HV-2197.
21.	SWS-MOV-CC-DF02	Dependent failures of all 4 MOV-2225 VALVES
22.	SAC-MDP-FS-DF07	ALL 4 SACS pumps fail to start.
23.	DGS-DGN-FS-DF02	Dependent failure to start SDGs A, B, & C.
24.	DGS-DGN-FS-DF03	Dependent failure to start SDGs A, B, & D.
25.	DGS-DGN-FS-DF04	Dependent failure to start SDGs A, C, & D.
26.	DGS-DGN-FS-DF05	Dependent failure to start SDGs B, C, & D.
27.	SAC-MDP-FR-DF02	Dependent failure to run pumps AP & DP-210.
28.	SAC-MDP-FR-DF01	Dependent failure to run pumps AP & BP-210.
29.	SAC-MDP-FR-DF03	Dependent failure to run pumps BP & CP-210.
30.	SWS-STR-FS-DF01	Dependent failure to start ALL SWS STR motors.

Table 3.4-5

The Most Important Basic Event Failures Sorted by the Risk Reduction Measure.

Basic Event		Description
1.	NR-LOSP-6	Failure to restore offsite power in 6 hours
2.	NR-DG-6	Failure to recover EDGs within 6 hours of independent failures of EDGs.
3.	SWS-MDP-TM-TRAND	Due to TM SWS train-D is unavailable.
4.	SWS-MDP-TM-TRANC	Due to TM SWS train-C is unavailable.
5.	SAC-MDP-TM-PSB06	Due to TM SACS loop B path PS-B06 is unavailable.
6.	NR-DG-DF-6	Failure to recover EDGs within 6 hours of common cause failures of EDGs.
7.	ADS-XHE-FO-DEPRE	Operator fails to depressurize.
8.	ADS-XHE-OK-INHIB	ADS fails at level I due to INHIBIT by operator.
9.	NR-U1X-DEP-60M	Failure to manually depressurize the RPV within 60 minutes.
10.	NR-PCS-1	Failure to restore the PCS within 1 hour.
11.	DGS-DGN-FR-CG400	Division C diesel 1CG400 fails to run.
12.	DGS-DGN-FR-AG400	Division A diesel 1AG400 fails to run.
13.	DGS-DGN-FS-CG400	Division C diesel 1CG400 fails to start.
14.	DGS-DGN-FS-AG400	Division A diesel 1AG400 fails to start.
15.	HPI-TDP-TM-OP204	HPCI turbine driven pump is inavailable due to TM.
16.	SWS-XHE-FO-ISOL	Operator fails to isolate SWS flow diversion.
17.	DGS-DGN-FR-DG400	Division D diesel 1DG400 fails to run.
18.	DGS-DGN-FR-BG400	Division B diesel 1BG400 fails to run.
19.	SWS-MDP-FS-CP502	Failure to start SWS pump CP-502.
20.	CST-XHE-FO-ALIGN	Operator fails to align condensate storage tank.
21.	DGS-DGN-FS-BG400	Division B diesel 1BG400 fails to start.
22.	DGS-DGN-FS-DG400	Division D diesel 1DG400 fails to start.
23.	NR-HVC-PNRM-12	Failure to provide alternate ventilation to the Panel Room within 12 hours after a loss of HVAC.
24.	SWS-MDP-FS-AP502	SWS pump AP-502 fails to start.
25.	RCI-TDP-TM-OP203	RCIC turbine driven pump is inavailable due to TM.
26.	NR-SPL-LLVL-4-03	Failure to align core spray to the CST for long-term injection (without decay heat removal).
27.	HAR-TDP-FS-DPF01	Common cause failure of HPCI and RCIC turbine driven pumps to start.
28.	NR-U1X-DEP-30M	Failure to manually depressurize the RPV within 30 minutes.
29.	HPI-TDP-FS-OP204	HPCI turbine driven pump fails to start.
30.	SWS-MDP-FS-DP502	SWS pump DP-502 fails to start.

Table 3.4-6
Sequences Screened Out Due To Recovery Actions

		FREQUENCY:		
		before recovery	after recovery	Recovery Actions Applied
1	TtQWW1Uv	2.08E+00	1.40E-08	NR-PCS-24, NR-RHR-INIT, NR-WW1-SWP-20, NR-VENT-5
2	TmWW1Uv	1.43E-01	<1E-10	NR-PCS-24, NR-RHR-INIT, NR-WW1-SWP-20, NR-VENT-5
3	TeWW1Uv	6.39E-03	<1E-10	NR-LOSP-24, NR-RHR-INIT, NR-VENT-5
4	TmPP2WUv	1.87E-03	2.60E-10	NR-PCS-24, NR-RHR-INIT, NR-WW1-SWP-20
5	S1WW1Uv	1.10E-03	1.62E-09	NR-RHR-INIT, NR-VENT-5
6	TtPP2WW1Uv	1.09E-03	2.28E-09	NR-RHR-INIT, NR-WW1-SWP-20, NR-VENT-5
7	AWW1Uv	3.16E-04	8.82E-10	NR-RHR-INIT, NR-VENT-5
8	TmPP2WW1Uv	3.01E-04	<1E-10	NR-PCS-24, NR-WW1-SWP-20, NR-RHR-INIT, NR-VENT-5
9	TiaWW1Uv	2.05E-04	1.03E-09	NR-RHR-INIT, NR-WW1-SWP-20, NR-VENT-5
10	S2S3IsoQUX	9.58E-05	5.05E-08	NR-SLEAK-ISO-15M, NR-U1X-DEP-40M
11	ThvP	7.26E-05	2.18E-08	NR-HVC-PNRM-12
12	TtPQUX	7.06E-05	1.48E-08	NR-PCS-40M, NR-U1X-DEP-40M, NR-Q-FWLVH-4M
13	TraPP2WUv	3.65E-05	4.12E-09	NR-WW1-SWP-20, NR-SPL-LVLL-4
14	TfU1U2V	2.71E-05	4.55E-08	NR-UV-WTLVL-20M, NR-UV-ECCS-1
15	TeUX	2.17E-05	4.96E-08	NR-LOSP-60M, NR-U1X-DEP-60M
16	S2QUX	2.08E-05	4.94E-08	NR-U1X-DEP-40M, NR-Q-FWLVL-24M
17	TraQUX	1.89E-05	4.30E-08	NR-U1X-DEP-60M, NR-Q-FWLVH-4M, NR-WW1-SWP-1
18	TmUV	1.78E-05	1.79E-08	NR-PCS-1, NR-UV-ECCS-1, NR-UV-WTLVL-20M
19	TfPU1U2X	1.04E-05	7.80E-08	NR-U1X-DEP-40M
20	S1U1WW1Uv	9.79E-06	<1E-10	NR-RHR-INIT, NR-VENT-5
21	TePWW1Uv	8.26E-06	<1E-10	NR-LOSP-24, NR-RHR-INIT, NR-VENT-5
22	TmPUX	6.72E-06	5.02E-08	NR-U1X-DEP-40M
23	TatQU1X	5.19E-06	1.45E-08	NR-ATWS-HPCI, NR-ATWS-DEP
24	TraPP2WW1Uv	4.40E-06	<1E-10	NR-WW1-SWP-20, NR-RHR-INIT, NR-VENT-5
25	TiaPP2WUv	3.65E-06	<1E-10	NR-WW1-SWP-20, NR-SPL-LVLL-4
26	ThvPP2	3.63E-06	1.09E-09	NR-HVC-PNRM-12
27	ThvU	1.61E-06	<1E-10	NR-HVC-PNRM-12
28	TiQUV	1.25E-06	3.60E-09	NR-UV-WTLVL-20M, NR-UV-ECCS-40M
29	TeEDGU	1.22E-06	5.85E-08	NR-LOSP-1, NR-UV-ECCS-1, NR-UV-WTLVL-20M
30	TtQWUv	1.04E-06	7.27E-10	NR-PCS-24

TABLE 3.4-7
DESCRIPTION OF HUMAN RECOVERY ACTIONS APPLIED

	Recovery	Description	Value
1.	NR-AIR-24	Failure to recover the IAS within 24 hours	5.7E-3
2.	NR-ATWS-ADS-INH	Failure to inhibit ADS during an ATWS	7.5E-2
3.	NR-ATWS-ARI	Failure to manually initiate ARI	1.4E-2
4.	NR-ATWS-DEP	Failure to manually depressurized the RPV during an ATWS	5.6E-2
5.	NR-ATWS-HPCI-30M	Failure to initiate HPCI during an ATWS	5.0E-2
6.	NR-ATWS-HPCI-CS	Failure to isolate HPCI injection through the Core Spray piping during an ATWS	2.4E-1
7.	NR-ATWS-LCNTL-LO	Failure to control RPV water level with LPCI during an ATWS	4.7E-1
8.	NR-COND-5	Failure to restart condensate pumps after other injection systems fail	3.7E-2
9.	NR-DG-6	Failure to recover D/Gs within 6 hours (independent failures of D/Gs)	7.0E-1
10.	NR-DG-DF-6	Failure to recover D/Gs within 6 hours (common cause failures of D/Gs)	6.0E-1
11.	NR-HPCI-LCNT-HIE	Failure to control RPV water level using HPCI during an ATWS to prevent core damage	4.6E-2
12.	NR-HVC-PNRM-12	Failure to provide alternate ventilation to the Panel Room within 12 hours after a loss of HVAC	3.0E-4
13.	NR-HVC-SWGR-24	Failure to provide alternate ventilation to the Switchgear Room within 24 hrs after loss of HVAC	1.6E-4
14.	NR-IGS-24	Failure to restart the EIAC after RACS cooling has been restored followed a LOCA isolation	3.8E-3
15.	NR-LOSP-24	Failure to restore offsite power within 24 hours	2.2E-3
16.	NR-LOSP-12	Failure to restore offsite power within 12 hours	1.5E-2
17.	NR-LOSP-6	Failure to restore offsite power within 6 hours	5.0E-2
18.	NR-LOSP-5	Failure to restore offsite power within 5 hours	7.0E-2
19.	NR-LOSP-1	Failure to restore offsite power within 1 hour	4.0E-1
20.	NR-LOSP-40M	Failure to restore offsite power within 40 minutes	5.5E-1
21.	NR-LOSP-30M	Failure to restore offsite power within 30 minutes	6.0E-1

Table 3.4-7 (continued)

22.	NR-PCS-24	Failure to restore the PCS within 24 hours following a turbine trip or MSIV closure initiating event	7.0E-4
23.	NR-PCS-1	Failure to restore the PCS within 1 hour	6.0E-1
24.	NR-PCS-40M	Failure to restore the PCS within 40 minutes	9.0E-1
25.	NR-Q-FWLVH-4M	Failure to prevent a level 8 trip of feedwater during a transient	1.4E-2
26.	NR-Q-FWLVL-24M	Failure to prevent a level 8 trip of feedwater during a small LOCA	4.9E-3
27.	NR-RACS-24	Failure to restore the RACS after a LOCA isolation	3.8E-3
28.	NR-RHR-INIT	Failure to initiate RHR for decay heat removal within 24 hours	5.0E-5
29.	NR-SLEAK-ISO-15M	Failure to isolate recirculation pump seal LOCA	8.2E-2
30.	NR-SPL-LVLL-4	Failure to align core spray to the CST for long-term injection (without decay heat removal)	1.1E-1
31.	NR-U1X-DEP-30M	Failure to manually depressurize the RPV within 30 minutes	7.5E-3
32.	NR-U1X-DEP-40M	Failure to manually depressurize the RPV within 40 minutes	5.2E-3
33.	NR-U1X-DEP-60M	Failure to manually depressurize the RPV within 1 hour	4.6E-3
34.	NR-UV-ECCS-1	Failure to manually initiate ECCS within 1 hour	3.9E-2
35.	NR-UV-WTLVL-20M	Failure to control RPV water level with high pressure injection systems (not during ATWS)	4.3E-2
36.	NR-VENT-5	Failure to initiate containment venting	2.0E-3
37.	NR-WW1-SWP-1	Failure to manually start SSWS or SACS pumps within 1 hour	1.2E-2
38.	NR-WW1-SWP-12	Failure to manually start SSWS or SACS pumps within 12 hours	1.9E-4
39.	NR-WW1-SWP-20	Failure to manually start SSWS or SACS pumps within 20 hours	7.4E-5
40.	NR-WW1-SWP-40M	Failure to manually start SSWS or SACS pumps within 40 minutes	1.6E-2

TABLE 3.4-8

RESULTS OF DECREASING EDG MISSION TIME
FROM 24 HOURS TO 6 HOURS

SEQUENCE	CDF WITH 24-HOUR MISSION TIME	CDF WITH 6-HOUR MISSION TIME
1. TeEdg	3.27E-5	2.64E-5
2. TeEdgU	5.85E-8	5.07E-8
3. TeEdgP	9.67E-7	7.79E-7
4. TeEdgPU	9.22E-9	9.22E-9
5. TeEdgPP2	5.84E-8	4.34E-8
TOTAL:	3.38E-5	2.74E-5
Total CDF From All Sequences:	4.58E-5	3.94E-5
SBO % of Total CDF:	73.7%	69.5%

TABLE 3.4-9

RESULTS OF SENSITIVITY ANALYSIS OF CDF IF THE LOSS OF AN AC BUS WERE CONSIDERED AS A SPECIAL INITIATING EVENT

	SEQUENCE	FREQUENCY
1.	TacQUV	4.96E-10
2.	TacQUX	9.71E-9
3.	TacPP2WUv	2.24E-10
	TOTAL:	**1.04E-8/yr**

TABLE 3.4-10

RESULTS OF SENSITIVITY ANALYSIS OF CDF IF THE LOSS OF A DC BUS WERE CONSIDERED AS A SPECIAL INITIATING EVENT

	SEQUENCE	FREQUENCY
1.	TdcQUV	4.96E-10
2.	TdcQUX	1.92E-8
3.	TdcPP2WUv	2.24E-10
	TOTAL:	**1.99E-8/yr**

TABLE 3.4-11
CORE DAMAGE FREQUENCY COMPARISON

	HOPE CREEK IPE		PEACH BOTTOM NUREG-1150		PEACH BOTTOM IPE		MILLSTONE 1 IPE		DRESDEN IPE	
INITIATOR	CDF	%	CDF	%	CDF	%	CDF	%	CDF	%
LOSS OF OFFSITE POWER	3.39E-05	73.8	2.10E-06	46.6	1.85E-06	34.3	8.07E-06	73.4	4.98E-06	26.8
o Diesel Generator Unavailable	3.38E-05									
o Diesel Generator Available	5.12E-08									
TRANSIENTS	6.79E-06	14.8	2.30E-07	5.1	1.50E-06	27.8	1.09E-06	9.9	4.47E-07	2.4
o Turbine Trip	1.70E-06									
o MSIV Closure/Loss of Cond. Vac.	1.13E-06									
o Loss of Feedwater	3.42E-06									
o Inadvertant Open Relief Valve	5.33E-07									
LOCAs	3.07E-06	6.7	2.60E-07	5.8	5.95E-07	11.0	5.91E-07	5.4	1.42E-06	7.6
o Vessel Rupture	Negl.									
o Large LOCA	3.21E-07									
o Intermediate LOCA	2.49E-06									
o Small LOCA	2.58E-07									
o ISLOCA	1.70E-09									
ATWS	7.45E-07	1.6	1.92E-06	42.6	1.44E-06	26.7	1.06E-06	9.6	5.34E-07	2.9
o Turbine Trip	6.05E-07									
o All Others	1.39E-07									
SPECIAL INITIATORS	1.42E-06	3.1	-	0.0	7.00E-09	0.1	2.17E-06	19.7	1.12E-05	60.3
o Loss of SACS	3.36E-07									
o Loss of RACS	6.89E-08									
o Loss of IAS	9.02E-09									
o Loss of HVAC	1.01E-06									
Total Internal Events	4.59E-05	100.0	4.51E-06	100.0	5.39E-06	100.0	1.10E-05	100.0	1.86E-05	100.0
Internal Flooding	5.50E-07				1.47E-07		-			
Total Internal Events + Flooding	4.65E-05				5.54E-06		1.10E-05			

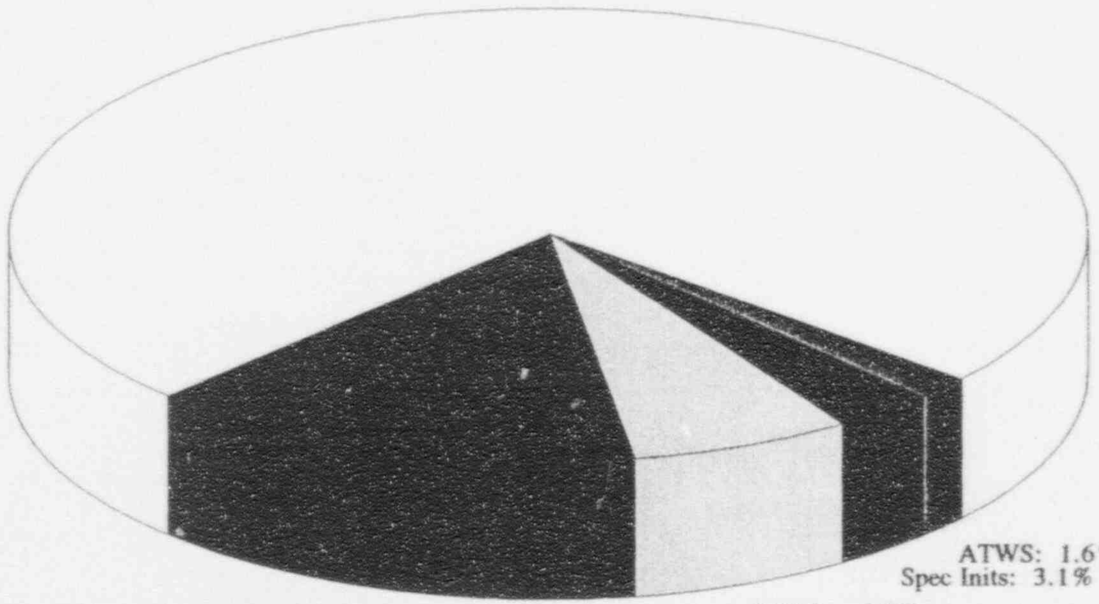
TABLE 3.4-11
CORE DAMAGE FREQUENCY COMPARISON (Continued)

	BROWNS FERRY		BRUNSWICK		DUANE ARNOLD		VERMONT YANKEE		MONTICELLO	
	IPE		IPE		IPE		IPE		IPE	
INITIATOR	CDF	%	CDF	%	CDF	%	CDF	%	CDF	%
LOSS OF OFFSITE POWER	3.30E-05	76.2	1.80E-05	65.4	2.57E-06	33.0	8.60E-07	20.0	1.20E-05	62.5
o Diesel Generator Unavailable										
o Diesel Generator Available										
TRANSIENTS	7.60E-06	17.6	8.61E-06	31.3	3.20E-06	41.0	2.30E-06	54.0	3.50E-06	18.2
o Turbine Trip										
o MSIV Closure/Loss of Cond. Vac.										
o Loss of Feedwater										
o Inadvertant Open Relief Valve										
LOCAs	7.50E-07	1.7	1.98E-07	0.7	1.56E-07	2.0	2.60E-07	6.0	1.20E-06	6.3
o Vessel Rupture										
o Large LOCA										
o Intermediate LOCA										
o Small LOCA										
o ISLOCA										
ATWS	1.30E-06	3.0	7.00E-07	2.5	1.87E-06	24.0	8.20E-07	20.0	2.50E-06	13.0
o Turbine Trip										
o All Others										
SPECIAL INITIATORS	6.60E-07	1.5	-	0.0	-	0.0	-	0.0	3.10E-08	0.2
o Loss of SACS										
o Loss of RACS										
o Loss of IAS										
o Loss of HVAC										
Total Internal Events	4.33E-05	100.0	2.75E-05	100.0	7.80E-06	100.0	4.30E-06	100.0	1.92E-05	100.0
Internal Flooding	4.70E-06								6.80E-06	
Total Internal Events + Flooding	4.80E-05								2.60E-05	

TABLE 3.4-11
CORE DAMAGE FREQUENCY COMPARISON (Continued)

	COOPER	
	IPE	
INITIATOR	CDF	%
LOSS OF OFFSITE POWER	2.77E-05	34.8
o Diesel Generator Unavailable		
o Diesel Generator Available		
TRANSIENTS	3.87E-05	48.5
o Turbine Trip		
o MSIV Closure/Loss of Cond. Vac.		
o Loss of Feedwater		
o Inadvertant Open Relief Valve		
LOCAs	7.17E-07	0.9
o Vessel Rupture		
o Large LOCA		
o Intermediate LOCA		
o Small LOCA		
o ISLOCA		
ATWS	3.91E-06	4.9
o Turbine Trip		
o All Others		
SPECIAL INITIATORS	8.69E-06	10.9
o Loss of SACS		
o Loss of RACS		
o Loss of IAS		
o Loss of HVAC		
Total Internal Events	7.97E-05	100.0
Internal Flooding		
Total Internal Events + Flooding		

Figure 3.4-1
CDF BREAKDOWN BY INITIATING EVENT



DESCRIPTIVE STATISTICS FOR THE FREQUENCY OF TOP EVENT

NUMBER OF TRIALS IS 221

MEAN	1.43E-05
STD DEV	1.31E-05
LOWER 5%	2.84E-06
LOWER 25%	5.65E-06
MEDIAN	9.43E-06
UPPER 25%	1.87E-05
UPPER 5%	4.40E-05

*****LOG SCALE*****

```
5% = 2.84E-06                                          95% = 4.40E-05

   I-------------------[---------------*-----------M---------]-----------------------I
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Figure 3.4-2: Uncertainty Distribution Of The Core Damage Frequency
90% uncertainty interval for the core damage frequency (innermost brackets denote interquartile range, asterisk denotes median and M denotes mean).

4.0 BACK-END ANALYSIS

The back-end (or Level II) portion of the IPE assesses the progression of accident sequences beyond the point of core damage with evaluation of the likely modes of containment failure being the principal objective. The evaluation includes both determination of the probability of each of the potential modes of containment failure and the characterization of the radionuclide releases that may accompany each mode. The results are reported in terms of the frequency (i.e., expected number of occurrences per year) of each of the specific release categories. A release category is characterized by the fraction of the initial core inventory of fission products that is released from the containment and by the timing of that release.

The approach applied for this analysis is based on that developed for EPRI (Reference 4.1-1). Under this methodology, accident progression, the containment loads resulting from that progression, and the response of the containment to those loads are predicted probabilistically. Logic models similar to those used for the front-end (i.e., Level I) analysis are used to support the evaluation of results. Quantification of the logic models is based on mechanistic analysis of the plant features and the phenomena involved. The MAAP code (Reference 4.1-2) was used as the principal tool for developing an integrated perspective on plant response to postulated severe accidents.

4.1 <u>PLANT DESCRIPTION</u>

This section describes key features of the HCGS that are relevant to the back-end analysis. Prior to discussing each of the significant features of the HCGS design, a brief overview of the HCGS design is provided as follows:

The HCGS is a General Electric Company BWR/4-251 (251-inch diameter vessel) with a Mark I containment. The HCGS is very similar to Peach Bottom Unit 2, which was used as the reference plant for this analysis. The principal difference is the use of a secondary containment building rather than a Reactor Building to house support systems. Figure 4.1-1 provides an elevation plan view of the plant. The Mark I primary containment, shown in Figure 4.1-2, is composed of two connecting structures. The first structure, the drywell, is an inverted lightbulb shaped steel pressure vessel containing the reactor vessel, the reactor coolant recirculation system, and other primary system piping. The second structure, the wetwell or torus, is a toroidal-shaped steel pressure vessel placed below and encircling the drywell. The drywell is connected to the torus via eight vent pipes that connect to a header inside the torus. Downcomers extend down from this header into the water. This design provides the pressure suppression function for the containment. Pressurization of the drywell forces effluent gases through the vent pipes, header, and downcomers into the pool. Steam in that flow is largely condensed.

Following is a brief description of the most significant components, systems, structures, and safety features at HCGS. These descriptions were verified and complemented by plant walkdowns. In each sub-section, a brief discussion is presented concerning the vulnerability of the systems or compartments during the accidents. The insights gained during the plant walkdowns were used as the basis for assessing equipment survivability, severe accident mitigation potential, and accident progression (see Section 4.6). This information is compared to the Peach Bottom data in Table 4.1-1 and summarized in Table 4.1-2.

4.1.1 Drywell

The drywell portion of the HCGS containment vessel (shown in Figure 4.1-2) is made of SA-516, Grade 70 steel. Reference 4.1-3 provides details of the structural design that are summarized below. The drywell head is hemi-ellipsoidal with a major diameter of 33 feet 2 inches and a head thickness of 1.5 inches. The drywell head is connected to a cylindrical shell which has a radius of 16 feet 7 inches and a thickness of 1.5 inches. A cone-shaped structure connects the upper cylindrical shell to a lower cylindrical shell. The cone thickness is 1.5 inches. The lower cylindrical shell is divided into two portions. The radius and thickness values for the top portion of the cylindrical shell are 20 feet, 3 inches and 1.5 inches, respectively. The lower portion of the cylindrical shell has a 20-foot 3-inch radius and a 0.9375 inch thickness. A transition knuckle connects the cylindrical shell to the spherical bottom of the drywell. The knuckle has a thickness of 2.875 inches. The spherical bottom shell has a radius of 34 feet and a thickness of 1.5 inches. The drywell has an overall height of 114 feet 9 inches and a free volume of approximately 178,000 cubic feet (including the reactor vessel pedestal and the suppression pool vent system) (Reference 4.1-4).

The HCGS drywell has the following design parameters:

a. 56.0 psig internal design pressure, 58.0 psig maximum calculated accident design pressure (internal), and 62.0 psig maximum internal design pressure allowed by ASME code (110% of design pressure).

b. 3.0 psig maximum external design pressure.

c. 340°F maximum temperature.

The drywell is closed at the top by a removable, double gasketed, bolted head (shown in Figure 4.1-3) to facilitate reactor refueling. It is also surrounded by reinforced concrete for shielding purposes and to provide additional resistance to deformation and buckling in areas where the concrete backs up the stee' shell. Above the foundation transition zone, the drywell is separated from the reinforced concrete by an air gap of approximately 1 3/4 inches to 2 1/2 inches (Reference 4.1-3) to accommodate thermal expansion of the drywell shell. Four drain sumps are located in the drywell floor. The sump layout is shown in Figure 4.1-4. Two of these sumps are located in the RPV pedestal floor. These sumps play a significant role in the possible progression of severe accidents. They are discussed in more detail in Section 4.1.5. The other two sumps are smaller pump sumps that are located outside of the pedestal. These sumps are located immediately adjacent to the pedestal wall. They are approximately 2 feet square and 3 feet deep. Each contains a sump pump. They are connected to one of the pedestal sumps by an imbedded pipe. A 4-inch high concrete curb surrounds the lip of each sump to prevent any water that may lea.. onto the floor frm accumulating in the sump. The bottom corner of the sump is approximately 7.4 inches from the drywell shell. Collection of molten core debris in these sumps could occur subsequent to RPV melt-through. This could occur either as a result of debris flow through the embeded drain pipes or from debris spreading over the drywell floor flowing over the curb. Erosion of the concrete floor of the sump could lead to failure of the drywell shell due to contact with the molten debris. This is a postulated mode of containment failure in this analysis.

Access to the drywell is provided by one 8-foot 10 1/2-inch diameter personnel access lock. One 2-foot diameter personnel access hatch is also provided on the drywell head, as indicated in Figure 4.1-3 (Reference 4.1-3). A 2-foot ID construction access hatch is located at 77 feet 10 inches. Both 2-foot access hatches are bolted in place. Two equipment access hatches having 12-foot diameters are also provided. One of these hatches is connected to the personnel access lock. The other hatch is bolted in place. The CRD removal hatch is located at an elevation of 103 feet 6 inches and has an ID of 3 feet 0 inch (shown in Figure 4.1-5).

4.1.2 Torus

The torus is a toroidal-shaped, steel pressure vessel below and encircling the drywell. Design details provided below are summarized from Reference 4.1-3. The torus centerline diameter is approximately 112 feet 8 inches. Figures 4.1-6 and 4.1-7 provide plan and cross-section views for torus and vent pipe assembly, respectively. The torus cross-sectional diameter is 30 feet 8 inches, and its thickness is nominally 1.0 inch. The torus contains a minimum of 118,800 cubic feet of water and has a net air space above the water pool of 133,500 cubic feet. The torus is not directly enclosed by concrete but is located below ground level in a large room called the torus room.

Vent pipes connect the drywell and the torus with the torus acting as a pressure suppression pool. A total of eight circular vent pipes, each having a diameter of 6 feet 2 inches are anchored at the drywell, radiate outward at 45 degree intervals, and penetrate the torus shell at alternating segments midway between ring girders (Reference 4.1-5). The drywell vents are connected to a 4-foot 3-inch diameter ring header, which is essentially a circular pipe suspended in the airspace of the suppression chamber above the suppression pool. The ring header has the same temperature and pressure design requirements as the vent pipes. Projecting downward from the header are 80 downcomer pipes, each 24 inches in diameter. The vent header system is supported by 16 pairs of 10-inch pipe columns with each pair pinned to the bottom of a ring girder. The downcomers terminate a minimum of four feet below the surface of the pool. In addition to its function as a path for energy and mass transfer from the drywell to the suppression chamber under accident conditions, the vent pipes also allow the passage of the Safety/Relief Valve (SRV) tailpipes (also known as relief lines) to the suppression pool.

The torus has several functions:

- It serves as a heat sink for postulated transients and accidents. Energy is transferred to the water by either the safety/relief tailpipes or the drywell vent system downcomers, both of which discharge beneath the water surface. The torus also serves as a heat sink for HPCI and RCIC turbine. It also contains the HPCI & RCIC vacuum breakers.

- It serves as the primary source of water for the CS and RHR Systems and as a backup source of water for the HPCI and RCIC Systems.

- In the event of a LOCA the steam and water escaping from the reactor vessel or recirculation system will be released into the drywell gas space. Steam and water may also leak into the drywell gas space from steam lines. If the increase in drywell pressure resulting from any of these leaks is greater than approximately 1.7 psi, a mixture of nitrogen, steam, and water would be forced through the vent system lines into the pressure suppression pool. The steam condenses rapidly in the suppression pool, mitigating the containment pressure increase. For LOCAs, nitrogen transferred during reactor blowdown to the suppression pool pressurizes the torus and is subsequently vented to the drywell through eight vacuum breakers when the pressure in the drywell drops 0.2 psid below that in the suppression pool. Water in the suppression pool can be cooled by the Suppression Pool Cooling mode of the RHR System.

- It provides a scrubbing mechanism for any fission products that may be released during the containment venting, via the torus.

4.1.3 Primary Containment Vacuum Relief System

The vacuum relief system is composed of two separate systems: the torus-to-drywell vacuum breakers and the secondary containment-to-torus vacuum breakers. The torus-to-drywell vacuum breakers, shown in Figure 4.1-8, relieve pressure from the torus to the drywell if there is a pressure differential greater than 0.2 psid. There are eight torus to drywell vacuum breakers. Each one is a 24-inch swing-check type valve with an attached air operator for testing. The eight valves are installed in lines connecting the torus airspace to the vent pipes. No support systems are required for vacuum breaker operations.

The secondary containment-to-torus vacuum breakers allow air reentry from the secondary containment to the torus air space if the external (secondary containment) pressure is 0.25 psid above torus pressure. Operation of the vacuum breakers is designed to maintain differential pressure between the secondary containment and the primary containment less than 3 psid.

4.1.4 Primary Containment Summary

The principal function of the primary containment (i.e., the drywell and torus) is to prevent release of radiation and fission products to the environment. Technical Specifications require that primary containment integrity be maintained at all times when the reactor is in operational conditions 1, 2, and 3. The following containment parameters are monitored to ensure proper performance of the primary containment, its supporting systems, and other plant systems:

- Containment pressure
- Suppression pool water level
- Hydrogen and oxygen concentrations
- Radioactivity radiation levels

- Temperature
- Humidity
- Identified and unidentified leakage from the RPV and connected systems

The oxygen concentration within the containment is maintained about 0.5% by volume during normal operation; however, the Technical Specification Limit for it is 4%. Limiting the containment oxygen concentration to 4% or less precludes the possibility of hydrogen combustion. A nitrogen purge system is used to force air from the containment as part of startup operations. Air is replaced during the reactor shutdown process to allow entry into the containment. If the oxygen concentration exceeds the 4% limit during operational condition 1 and the concentration cannot be restored to within its limit in 24 hours, Technical Specifications require placing the plant into operational condition 2 within 8 hours. This requirement does not apply during the 24 hour period after reaching 15% power during a startup or the 24 hour period prior to reducing power below 15% during a shutdown. Historically, reactor operation with an oxygen concentration sufficient to support hydrogen combustion is very rare with an estimated probability less than 0.005. Hydrogen combustion within the primary containment has thus been assumed to have sufficiently low probability that it need not be addressed in the containment analysis.

Failure of the primary containment as a result of the internal pressures and temperatures that are expected during postulated severe accidents has been analyzed in detail. These results are presented in Section 4.4.

4.1.5 Reactor Vessel Pedestal

The primary function of the reactor pedestal is to support the RPV in its lateral and vertical positions. It also acts as a radiation and missile barrier. The pedestal houses the control rod drives and contains drain sumps for collecting expected leakage in the primary containment. A cross-section of the pedestal is shown in Figure 4.1-9. Although not shown in the figure, the control rod drive mechanisms and the supporting structures occupy the upper half of the pedestal volume.

The reactor pedestal is essentially a right circular cylinder with an inside diameter of 20.25 feet. A reinforced concrete wall supports both the RPV and the biological shield wall that surrounds it. The pedestal wall is 4 feet 10 inches thick at the bottom, 5 feet 9 inches thick at the top, and contiguous with the concrete forming the drywell floor. The inside of the pedestal wall has a stainless-steel liner. There is no liner outside the pedestal wall at the floor level.

There is a 3-foot by 7-foot personnel access door flush with the drywell floor. The doorway is shown in the plan view of Figure 4.1-4.

The two pedestal floor drain sumps, the Clean Radwaste (CRW) and the Dirty Radwaste (DRW) sumps, are used to collect water from known (i.e., recirculation pump seals) and unidentified sources, respectively. Each sump is connected to two pumps located in each of the two sumps outside of the pedestal wall by a pipe approximately 4 feet under the concrete.

The two inside sumps have a cross-sectional area of 36 square feet each and are 2 feet 11 inches deep. The total volume of the two sumps is 210 cubic feet. Each sump is covered by a stainless steel grating which is 3/16-inch thick. Any water in the sumps is pumped to the radwaste facilities.

4.1.6 Secondary Containment

The secondary containment, commonly referred to as the Reactor Building, consists of two sections integrally constructed to form a single containment structure. The inner section is cylindrical in shape and houses the reactor and its pressure suppression primary containment system, as well as other reactor plant equipment. The outer section is rectangular and surrounds the cylindrical portion (Figure 4.1-1). Each section consists of reinforced concrete approximately 3 feet thick and is designed as a seismic category I structure. Both sections rest on the containment foundation which is a concrete slab approximately 14 feet thick.

The cylindrical section of the Reactor Building is separated into 8 floors or levels with the lowest level at the 54-foot elevation, followed by elevations 77-foot, 102-foot, 132-foot, 145-foot, 162-foot, 178-foot 6-inch and 201-foot. These floors are connected with each other through elevators, stairways, hatches, and the ventilation system ductwork. Two enclosed stairways and an elevator connect the grade level, Elevation 102 feet, and the refueling floor, Elevation 201 feet, within the interior section. A 20-foot by 25-foot open hatch extends from the 102-foot Elevation up to the refueling floor on the west side of the building. This hatchway is interrupted by a normally closed motorized hatch cover at Elevation 132 feet. The motorized hatch can be opened during plant operation to allow for delivery of materials, such as fuel. However, an interlock between this motorized hatch and the receiving bay door, at Elevation 102 feet, will ensure integrity of the containment. Figures 4.1-10 through 4.1-14 show the boundary outline plan for Elevations 102-foot, 132-foot, 145-foot, 162–178-foot, and 201-foot, respectively.

Normal entrance from the cylindrical section to the rectangular section is through either a 3-feet by 7-feet door on the northeast section of the 102-foot floor or through a 3-feet by 7-feet pressure tight door on the southwest section of the 102-foot floor. Four stairways and an elevator extend down from grade level, the 102-foot Elevation, to 54-foot Elevation, in the rectangular section. The entrance to rooms with high radiation levels are locked closed and require a special permit for entry. However, the doors to rooms without high radiation levels are not monitored. Most rooms and stairways within the rectangular section have leak-tight doors with a pressure capacity of 3.0 psig or greater. These doors all swing open away from their related rooms, unless noted otherwise. Figures 4.1-15 and 4.1-16 show the boundary outline plan for the below-grade Elevations 77 feet and 54 feet, respectively.

The entrance doors from the stairways to each level above the 102-foot Elevation in the cylindrical section is through regular 3-feet by 7-feet doors which have a 1-inch opening on the bottom and have a pressure rating of 0.1 psig or less.

The secondary containment volume is conservatively calculated to be 2.86 million cubic feet, for the purpose of the IPE.

What follows is a brief description of important rooms and elevations in the Reactor Building.

4.1.6.1 Below Grade Elevations (54-Foot and 77-Foot)

The grade level at HCGS is at the 102-foot Elevation. The 54-foot and 77-foot Elevations are, therefore, below the grade level.

Inner Section: The 54-foot and 77-foot elevations of the inner section combine to house the torus and form the torus compartment. The torus is not directly enclosed by concrete, but is located below ground level in a large room called the torus room. The access to the torus is provided through four manways with double gasketed, bolted covers located in the torus room.

Torus Room: The HPCI, RCIC and 'A' and 'B' RHR rooms communicate with the torus room through their blowout panels. The torus room in turn communicates with the environment through the blowout panels in the steam vent, located directly above it. The torus room has two pressure tight doors, with a pressure rating of 3.0 psig or greater, that swing open away from the torus room towards the 77-foot Elevation in the inner section of the Reactor Building. The torus room houses or provides a pathway for all components that originate from or terminate in the torus. For example, the eight vent pipes that connect drywell to torus are housed in the torus room. The air in the torus room does not easily communicate with rooms and elevations outside of it. However, there is an indirect communications through air leakage and FRVS recirculation.

The floor of the torus room is at the 54-foot Elevation. The volume of the torus room is calculated to be approximately 550,000 cubic feet.

Outer Section: Major components located on the 54-foot Elevation include the RHR pumps and Heat Exchangers, Core Spray pumps, the HPCI and RCIC turbine skids, as well as two 250 VDC Class 1E MCCs. Major components located on the 77-foot Elevation include the RACS pumps and Heat Exchangers, and the CRD pumps and related equipment. The RHR Heat Exchanger rooms also extend up through the 77-foot Elevation. Four MCCs are located on the 77-foot Elevation.

Pressure-tight doors with a rating of 3.0 psig are provided for access to all rooms, except the MCC rooms. The air in the 54-foot and 77-foot Elevations communicates with each other through four stairways, providing a pathway for fission products movement.

4.1.6.2 Grade Level (102-Foot Elevation)

Inner Section: The inner section contains the CRD HCU, the TIP room, and equipment and personnel access points to the primary containment. This elevation provides access to the Steam Tunnel through a controlled leak-tight door, with a rating of at least 3.0 psig. This door swings open away from the steam tunnel. This elevation provides access to the rectangular section of the Reactor Building through a 3-foot by 7-foot doorway and through a pressure tight door. The air in this elevation communicates with the 132-foot Elevation through two stairways, an elevator. Also, a 20-foot by 25-foot hatch, if open, provides a pathway for fission product movement to the 132-foot Elevation.

Outer Section: Equipment located in the outer section includes the SACS pumps and Heat Exchangers, and the Reactor Recirculation pump RPT breakers. This elevation also contains a MCC.

4.1.6.3 132-Foot Elevation

Inner Section: The inner section at this level houses 2 FRVS recirculation fans and filter units, PCIG compressors and related equipment, and RWCU pumps. This elevation provides access to both the steam tunnel and steam vent. Access to the steam tunnel is through a monitored and chained leak-tight double door, which has a pressure rating of 15 psig and swings open away from the steam tunnel. Access to the steam vent, however, is through a non-monitored leak-tight door with a pressure rating of 3.0 psig, which swings open towards the steam vent (Figure 4.1-11).

The air in this elevation easily communicates with the 102-foot Elevation below it, and the 145-foot Elevation above it, through two stairways and one elevator. Also, the air in this elevation easily communicates with the 145-foot Elevation through a 20-foot by 25-foot open hatch and the 102-foot Elevation, provided that the motorized hatch in this elevation is open. This motorized hatch is interlocked with the truck bay door on the 102-foot Elevation, and it could be open during operation. Position of this motorized hatch is not believed to have any significant effect on the analysis.

Steam Vent: The Steam Vent is located above the torus room. Its function is to provide a flow path for pressure relief from the torus room. The Steam Vent contains louvered blowout panels that open towards the environment (Figure 4.1-11). These blowout panels are located on the west side of the Reactor Building. The entrance door to the Steam Vent is located at the 132-foot elevation. This door is a non-controlled pressure-tight door. The floor of the Steam Vent is formed by six hinged hatches that separate the torus room from the Steam Vent; and the torus room can be seen through them. These hinged hatches lift at 1.5 psid. The air in the steam vent does not easily communicate with rooms and elevations, other than the torus room, outside of it. However, there could be an indirect communication through air leakage.

Steam Tunnel: The steam tunnel provides a pathway for the steam lines through the secondary containment to the turbine building. The portion of the steam tunnel in the Reactor Building is equipped with 13 blowout panels of various sizes that open to the emergency vent stacks in the steam tunnel (Figure 4.1-11). The emergency vent stack is equipped with different sizes of blowout panels which open towards north and south at different elevations. The air in the steam tunnel does not easily communicate with rooms and elevations outside of it. However, there is an indirect communications through air leakage and FRVS recirculation.

Outer Section: The 132-foot Elevation comprises the roof of the rectangular section of the Reactor Building.

4.1.6.4 145-Foot Elevation

The 145-foot Elevation contains two FRVS vent fans and filter units, and RWCU Heat Exchangers and demineralizer equipment and two MCCs. The normal personnel access to the Reactor Building is at this elevation, through a controlled pressure tight air-lock. The pressure rating of each of the two personnel access doors is at least 5.0 psig. The 145-foot Elevation easily communicates with the 132-foot Elevation below it, and the 162-foot Elevation above it, through a 20-foot by 25-foot open hatch and through two stairways and an elevator; hence, it provides a pathway for fission product movement.

4.1.6.5 162-Foot Elevation

The 162-foot Elevation contains the CPCS equipment, SLC pumps and associated equipment, FPCC and Heat Exchangers, and 2 FRVS recirculation fans and filter units. The air in the 162-foot Elevation easily communicates with the 145-foot Elevation below it, and the 201-foot Elevation above it, through a 20-foot by 25-foot open hatch and through two stairways and an elevator. This elevation also communicates with the 178-foot 6-inch Elevation through one stairway and an elevator.

4.1.6.6 178-Foot 6-Inch Elevation

The 178-foot 6-inch Elevation only exists on the east side of the Reactor Building and houses 2 FRVS recirculation fans and filter units. The air in this elevation communicates with the 162-foot Elevation, below it, and the 201-foot Elevation, above it, through one stairway and an elevator. This elevation is the base of the dryer/separator pool.

4.1.6.7 201-Foot Elevation (Refueling Floor)

The containment dome over the refueling floor, located at Elevation 201 feet, creates an enclosed volume of approximately 1.1 million cubic feet. There are no blowout panels above the refueling floor. However, a 33-inch opening on the containment dome provides an exhaust path for the FRVS. The reactor well is in the refueling floor, located directly above the drywell head and in between the spent fuel pool and the dryer/separator storage pool (Figure 4.1-14). It has a volume of about 28 thousand cubic feet. This cavity contains two round concrete shield plugs during plant operation, to provide a shield against radiation. The shield plugs are removed and the cavity is flooded during refueling operations. The cavity has a volume of approximately 14,825 cubic feet and is covered by a hatch. The containment failure analysis, described in Section 4.4, indicates that the drywell head seal is the most likely location for large containment leakage to occur during postulated severe accidents. Leakage from this location would be directly upward through the gaps in the shield plugs and into the volume above the refueling floor. Thus, this is a likely location for fission product release into the secondary containment.

The air in this elevation communicates with all elevations down to 102-foot Elevation, within the interior section of the secondary containment, through either of the two stairways, the elevator or through a 20-foot by 25-foot open hatch on the west side of the building. Furthermore, this air volume is expected to communicate with the rectangular section of the Reactor Building, through a regular 3-foot by 7-foot door at 102-foot Elevation. Therefore, a good pathway exists for fission product transport throughout the entire Reactor Building. However, as was mentioned above, air communication with rooms that have any blowout panels takes place through either leakage or FRVS recirculation.

The volume between the refueling floor and the top of the containment dome is calculated to be 1.08 million cubic feet.

4.1.7 Reactor Building Pressure Relief

Secondary containment overpressure protection is provided by blowout panels located at various points in the Reactor Building. There are two types of blowout panels, both of which reduce pressure by relieving pressure buildup to additional volume.

The first type of blowout panel provides protection for the "A" and "B" RHR rooms, the HPCI room, and the RCIC room. These systems have piping that either contains or has the potential to contain high energy fluid. Each blowout assembly consists of two hinged doors which open against spring pressure. They are set to open when differential pressure across the doors reach 0.25 psid, and spring pressure will close them once this differential pressure is reduced. Following actuation, the magnets must be adjusted to restore the set pressure to 0.25 psid. These blowout panels open towards the torus room to prevent exceeding the maximum room pressure of 3 psig. The torus room in turn exhausts to the environment through the steam vent.

The second type of blowout panel is designed to relieve when the differential pressure reaches 1.5 psid. Unlike the blowout panels used for the ECCS rooms, these are designed for a one-time-use and must be replaced following actuation. These panels are located at various places throughout the plant. In the Reactor Building, they are located in the steam vent at the 132-foot and 162-foot Elevations and relieve to the outside atmosphere. They are also located in the steam tunnel and serve as a ventilation barrier as well as a blowout panel. The steam tunnel panels relieve to the Emergency Vent Stack, which has its own blowout panels and is not considered as a part of the secondary containment. The blowout panels in the Emergency Vent Stack open towards north (two double units and a single unit) and south on 153-foot elevation (two quadruple units) and towards south at 137-foot Elevation (two louvered quadruple units).

4.1.8 Instrumentation

The reactor vessel level, power, pressure, temperature, and steam line flow instrumentation provide indication of these key parameters. Following core damage, operability of these instruments becomes questionable.

The primary containment instruments provide level, temperature and pressure indication. Following vessel failure, operability of these instruments becomes questionable, due to adverse environment.

The secondary containment instruments consist of Reactor Building Differential Pressure (DP), the FRVS vent system filter flow and filter DP, and the Reactor Building pressure and temperatures at various points throughout the building. Also, the position of major Reactor Building mechanical access penetrations and certain hatches and blowout panels are monitored. These indications are all sent to the control room. Following the primary containment failure, operability of these instruments could be challenged, not necessarily due to the instruments themselves, but rather due to the MCCs that power them.

4.1.9 Main Steam System

The MSS delivers the generated steam to the main turbine, the three feed pump turbines, the HPCI turbine, the RCIC System turbine, and auxiliary steam loads. The relevant components of this system are described in this section.

4.1.9.1 Main Steam Isolation Valves

HCGS has four main steam lines. Isolation of steam flow to the turbine is provided by two MSIVs and one main steam stop valve per line. One MSIV is located inside the drywell (inboard), with the other located in the steam tunnel (outboard). Both valves close automatically on a variety of signals, including low RPV level. Valve actuator or solenoid failure also leads to closure. In the Level II analysis, no credit is given to opening of the MSIVs once closure has occurred. Some leakage could be expected through the MSIVs. However, this level of leakage is negligible in comparison to that resulting from containment failure. Thus, it has not been considered in this analysis.

Main steam line "A" supplies steam to the RCIC System. Steam line "C" is the source of steam for the HPCI System. Both of these connections are upstream of the inboard MSIV. As long as the RPV is intact, the steam supply to these systems should not be interrupted.

4.1.10 Safety/Relief Valves

Fourteen eight-inch Target Rock SRVs are located upstream of the MSIVs. The SRV lines have a design flow of 818,000 to 950,000 lb/hr. Each SRV relief line (tailpipe) is equipped with two six-inch vacuum breakers. The vacuum breakers will open whenever the drywell pressure is 0.5 psi greater than the relief valve discharge pressure, drawing drywell atmosphere into the line to equalize pressure. The purpose of the vacuum breakers is to prevent condensation of steam in the SRV tailpipe from drawing torus water up into the tailpipe. This event would pose a threat of excessive jet forces at the discharge of the SRV which could cause the tailpipe to break off inside the torus and above the water line. Pressure oscillations on the exhaust side of the SRVs are also mitigated. Pressure fluctuations could result in improper valve operation.

The safety feature of the SRVs provides for automatic actuation, without any dependency on support systems, once the RPV pressure exceeds their spring setpoint. If actuated in their safety mode, the SRVs will close automatically once the reactor pressure has dropped 55 to 100 psig below their opening setpoints. The relief mode of the SRVs requires 125 VDC power and nitrogen pressure in their associated accumulators.

The five Automatic Depressurization System (ADS) SRVs have a safety setpoint of 1130 psig. All remaining SRVs have a safety setpoint of either 1108 or 1120 psig (Figure 4.1-17). Two of the SRVs have a low-low operating setpoint of 1017 and 1047 psig. Once armed by the reactor pressure at 1047 psig, the low-low set SRVs will open and their setpoints will be automatically lowered so that one re-opens at 1017 psig and closes at 905 psig, while the other opens at 1047 psig and closes at 935 psig.

The SRV operation is not expected to be impacted by containment conditions prior to vessel failure. However, the Target Rock SRVs will spring actuate closed (even if an open signal is present) under the following conditions:

- Containment pressure greater than the containment instrument gas pressure; 85 psig.
- To open a closed SRV, differential pressure between the Reactor and torus pressure must be about 50 psig. This differential pressure is also required to maintain an SRV in open position.
- Loss of DC, including the SRV solenoids.

It could be postulated that the passage of very hot gases from the damaged core (2000-5000°F) through the steam lines and SRVs could lead to their failures in either open or closed position. Leakage through the SRVs, even in the closed position, and creep rupture failure of the steam line are potential failure modes. Either failure mode is expected to lessen the severity of accidents where the RPV remains pressurized at the time of vessel breach. However, these failure modes were not considered in the current analysis due to the sparsity of analysis supporting their occurrence.

4.1.10.1 Automatic Depressurization System

The ADS is an ECCS System. Its function is to automatically or manually reduce the RPV pressure such that the low pressure systems, mainly the CSS and the low pressure coolant injection (LPCI) mode of RHR, can inject. Five of the 14 SRVs are devoted to the ADS. They are equipped with dual, redundant, 125 VDC Class 1E powered solenoids, in contrast with a single solenoid 125 VDC Non-Class 1E for the rest of the SRVs.

Automatic initiation of ADS requires:

- Availability of DC and Containment Instrument Gas or Nitrogen Bottles, similar to rest of the SRVs,

- Discharge pressure of CS pumps in one loop >145 psig or discharge pressure of one RHR pump >125 psig,
- Reactor vessel level <-129", confirmed with Reactor vessel level <12.5",
- Drywell pressure >1.68 psig,
- Elapse of a 105-second timer,
- Operator action: EOPs require that the operator initially inhibit ADS and actuate it manually, later, upon further RPV level reduction.

4.1.11 Containment Instrument Gas and Instrument Air

The Primary Containment Instrument Gas (PCIG) System provides pneumatic motive force to position the inboard MSIVs and for manual operation of the SRVs and ADS SRV operation during an automatic ADS initiation. Each SRV has a five-gallon capacity accumulator which can open the relief valve and hold it open against a drywell pressure of 62 psig and allows for two actuations against a drywell pressure of 43.4 psig (73.7% of design). The accumulators on each SRV are normally charged to 90-105 psig by the PCIG System. Upon failure of the PCIG System, the accumulator will supply nitrogen to the ADS valve actuators. The PCIG System normally takes its suction from the primary containment; however, upon a LOCA, the PCIG System trains will be aligned to take suction from the Reactor Building, and the primary containment isolation valves can be overridden to supply gas to the SRVs.

Instrument air, which is powered by the Non-Class 1E sources, provides air supply to the outboard MSIVs and most air operated valves in the Reactor Building. Although not required for the support of the PCIG System, instrument air system provides 100% backup capabilities to the PCIG System should it totally fail. The PCIG System, provides backup to instrument air for the Reactor Building-to-torus vacuum breakers. Upon loss of instrument air due to LOP, the Emergency Instrument Air Compressor (EIAC), which is fed through the DGs, will automatically respond to any Auto or Manual start/stop command. However, when a LOCA condition is sensed, the EIAC will not respond automatically. Instead, the operator has to re-close a breaker locally, align RACS to the EIAC System locally, and reset the logic from the control room.

4.1.12 Reactor Feedwater System

The RFS provides pre-heated feedwater to the reactor. Turbine-driven reactor feed pumps are used at HCGS. Since the MSIVs are assumed to be closed for the Level II analysis, no credit is given to the feedwater system.

4.1.13 Condensate System

The main condensate system provides feedwater flow to the RFPs. This subsystem consists of:

- Three primary condensate pumps that take suction from a common header joining the three condenser hotwells and provide flow to the secondary condensate pumps suction, mainly through the condensate demineralizers. Two of these pumps are fed through the 7.2 KVAC Non-1E buses and one is fed through the 4.16 KVAC Non-1E buses These pumps can deliver approximately 12,300 gpm at a discharge pressure of 152 psig, and have a shutoff head of 202 psig.

- Three secondary condensate pumps discharge the pre-heated water to the RFPs. Two of the pumps are fed through 7.2 KVAC Non-1E buses while the other one is fed through the 4.16 KVAC Non-1E buses. These pumps are capable of supplying 11,400 gpm at 415 psid and have a shutoff head of 535 psig.

  The condensate pumps are modeled as part of the alternate injection system in the HCGS CET.

  The primary condensate pumps don't require cooling; however, the secondary pumps are dependent on the TACS, which is dependent on SACS for component cooling. TACS isolates on a containment isolation signal, and its restoration requires some local actions, by operators.

4.1.14 Control Rod Drive System

The CRD hydraulic system is used during normal plant operation to operate the CRD mechanisms for power operation control and for rapid reactor shutdown (SCRAM). Since the water to the CRD mechanisms enters the reactor vessel, the CRD System can, under accident conditions, be used to provide additional makeup to the vessel. The main components of this system are:

- Two Non-Class 1E, centrifugal CRD pumps, which are fed through the 480 VAC 1E buses, and are capable of injecting 90 gpm at any reactor pressure. One pump is normally operating while the other is in standby. Since they are powered from Class 1E 480 VAC buses, the CRD pumps would be available with some operator actions even without offsite power available. The normal source of the water for this system is the condensate system via the condensate reject bypass valve. The alternative water source is the less purified water of the CST. The cooling to CRD pumps is provided by RACS. RACS isolates on a containment isolation signal and its restoration could require some operator actions, locally (Figure 4.1-18).

4.1.15 Residual Heat Removal (RHR) System

The RHR System can be aligned to perform multiple functions (Figure 4.1-19 provides a simplified schematic drawing).

- In the LPCI mode, it is designed to restore and maintain reactor vessel water level following LOCA.

- In either the suppression pool cooling, torus spray or drywell spray modes, the RHR System functions to restore and/or maintain the pressure suppression capability of the primary containment.

- In the shutdown cooling mode, the RHR System removes decay and sensible heat from the fuel and nuclear boiler system.

- In the fuel pool cooling assist mode, the RHR system removes decay heat from the spent fuel assemblies in the spent fuel pool.

The RHR System is also designed to provide a flow path for an alternate source of water (station service water or the fire protection system) to either the reactor vessel or the containment.

The major components of the RHR System are:

- Four loops, each supplied by a 4160 VAC Class 1E pump. Each RHR pump is capable of injecting 10,000 gpm to the reactor vessel, through the reactor core shroud region, at a discharge head of 175 psig. The shutoff head is about 340 psig. Loops C and D function solely during the LPCI mode.

- Two heat exchangers, one in Loop A and one in Loop B. Loops A and B can be used in the SPC, containment spray, and Fuel Pool Cooling mode. RHR can be used in the SDC mode if the reactor pressure is below 82 psig and either the "A" or the "B" loop of the RHR is available.

- The containment spray mode of the RHR System consists of two spray rings in the drywell and one spray ring in the torus. Either RHR loop A or B can be used to spray the torus and drywell. The capacity of each RHR pump for drywell spray and torus spray is 9500 gpm and 500 gpm, respectively (Reference 4.1-4, Table 6.2-2).

The B loop of the RHR can be used in several modes. It can be used for:

- Diverting water to the reactor vessel head spray;

- Containment flooding by the SSW System;

- Shutdown cooling from the remote shutdown panel; and

- Diverting water from the torus to liquid radwaste.

- Cooling the post accident hydrogen recombiners. (RHR loop 'A' does this, too.)

4.1.16 Station Service Water System

The SSW System is a Class 1E system that is used to supply the SACS and RACS heat exchangers during both normal and emergency conditions. The SSW System consists of two redundant loops, with two pumps in each loop. This system can also be cross-tied to the RHR System through a six-inch line in the RHR loop B to provide makeup to the vessel or to flood the containment.

Each SSW loop is supplied by two pumps, which are fed through the 4.16 KVAC Class 1E buses, with a rated flow of 16,500 gpm at 45 psig. The SSW pumps can inject to the RPV as long as the vessel pressure is below 75 psig. There is also a connecting point for a fire hose from the Fire Protection System (Figure 4.1-20).

The SSW is modeled as an alternate injection system in the HCGS CET. The SSW pumps are located outside the Reactor Building.

4.1.17 Fire Protection System

The FPS is a Non-Class 1E system used for detection and suppression of fire. Figure 4.1-21 provides a schematic drawing. This system can be used as an alternate injection system utilizing the B RHR loop. (i.e., due to loss of all electrical power) (Reference 4.1-6).

The major components of this system are:

- A Motor Driven Fire Pump (MDFP) and a standby Diesel Driven Fire Pump (DDFP), each rated at 2500 gpm, at a discharge pressure of approximately 90 to 125 psig. The MDFP is driven by a 480 VAC power supply. The diesel engine is battery started by one of two lead-acid batteries that are kept charged by a 120 VAC power supply. Two 150 gallons of diesel oil are maintained in the DDFP fuel tank to support eight hours of continuous operation. The DDFP will start automatically on the low fire pressure header (< 100 psig), or on a loss of AC logic power to the engine control cabinet.

- Two 350,000-gallon fire water storage tanks with 328,000 gallons in each tank dedicated to the fire protection system. Immersed heaters in these tanks prevent them from freezing.

- Two deep well pumps can provide fresh makeup to these tanks at the rate of 683 gpm with two pumps and 456 gpm with one pump. Level switches allow for automatic makeup initiation at 375 inches and makeup termination at 468 inches. These pumps require offsite power.

- The fire pumps can be started as required from the control room or locally to maintain the FPS pressure.

- An outside fire hydrant or fire hose station are attached to a flange on the B RHR loop in the Diesel Building.

- A cross-connect is provided to allow connection of the Salem FPS to the Hope Creek FPS.

It is expected that the alignment of the FPS to the SSW System and RHR Systems can take place within 30 minutes. Although a procedure is available for using the FPS for containment spray, no credit is given to it in the base case study of the HCGS Level II. This is due to insufficient data regarding injection capability of the FPS pumps in the containment spray mode and the fact that during the station blackout (SBO) scenarios some valves have to be manipulated, locally. However, sensitivity analysis were performed considering availability of the FPS for containment spray.

The FPS System and its supporting equipment are all located outside the secondary containment; hence it will not be affected by accident progression.

4.1.18 The Core Spray System

The CSS primary function is to provide makeup to the vessel by spraying water onto the reactor core.

The major components in this system are:

- Two loops, each containing two 50% capacity pumps, fed through the 4160 VAC Class 1E buses, with a rated flow of 3175 gpm and shutoff head of 380 psig (Figure 4.1-22).

- The torus serves as the primary water source for the CSS; however, suction can be aligned to the CST, if needed.

The CSS System is modeled along with the RHR System in the HCGS CET as part of the low pressure ECCS.

4.1.19 Venting System

The HCGS is equipped with a 12-inch hard pipe vent which originates from the top of the torus and terminates 150 feet above the ground level, outside the secondary containment. The vent pipe contains a 35 psig rupture disk. This vent can be opened remotely from the control room as well as locally, at the 102-foot Elevation in the secondary containment. Local actuation can be accomplished in the absence of any electric or pneumatic power. The electric power source for the two isolation valves in the vent path is through distribution panels that are powered by the 120 VAC Uninterruptible Power Supplies (UPS); the UPS is backed up by the 125 VDC batteries. The effective diameter of this pipe is six inches; hence, it is capable of removing 1% decay heat as required by Generic Letter 89-16.

The plant is also equipped with a six-inch hard pipe vent, which is used for drywell supply and ILRT piping. The six-inch vent originates from both the drywell and the top of the torus and terminate about eight feet above the ground level outside the secondary containment. The failure probability of this vent is conservatively assumed to be high. The effective diameter of this pipe is 3.3 inches, and it is not adequate for removing 1% decay heat. However, it does provide the relief capability that could maintain low containment pressure under most postulated severe accidents. The six-inch vent that originates from the drywell is the only method of hard pipe venting, once the torus is filled.

The HCGS is also equipped with a containment purge system with ductwork connections to the primary containment that can be used for venting. All the duct pipe vent paths are treated by FRVS and monitored prior to release to the environment. However, no credit is given to them in the IPE, since they will most likely rupture. There is no local opening capability for the valves in the duct work paths (Figure 4.1-23).

Procedures require opening of the vent at the primary containment pressure limit (PCPL) of 65 psig and require that operators maintain the containment pressure below 60 psig.

4.1.20 Filtration, Recirculation, and Vent System

The FRVS recirculation system is an engineered safeguard recirculation and filtration system located inside the Reactor Building. This system consists of six 25% capacity recirculation fans and filter trains and is connected in parallel with the RBVS to the supply and exhaust ducts within the Reactor Building. Four of the six centrifugal fans, with inlet valves and isolation dampers, recirculate the Reactor Building air through moisture separators, electric heating coils, HEPA filters, charcoal filters, and SACS water cooling coils. The four operating FRVS recirculation unit cooling coils limit the expansion and temperature of the Reactor Building air during a LOCA. Each of the six trains of air handling units provide 30,000 SCFM.

The FRVS vent system is also an engineered safeguard ventilation system and filtration system that maintains the Reactor Building at a negative pressure. This system is located inside the Reactor Building and consists of two full-capacity centrifugal fans and filter trains. Each fan is provided with inlet vanes and isolation dampers. One vent unit runs while the other is in standby. The vent unit takes suction from the FRVS recirculation system discharge duct and discharges the air through an electric heating coil, charcoal filter, and HEPA filter to the atmosphere through a vent at the top of the Reactor Building dome.

FRVS automatically initiates to filter fission products from the secondary containment should a release occur. The RBVS is shown schematically in Figure 4.1-24. The FRVS Vent System draws suction from the 145-foot Elevation within the secondary containment.

All six recirculation fans start on:

- Reactor vessel level <-38",
- Drywell Pressure > 1.68 psig,
- Reactor Building exhaust or refueling floor exhaust high-high radiation,
- Auto start signal from their respective LOCA sequencer at 19 seconds.

4.1.21 Condensate Storage Tank

The CST is a half-million gallon tank outside the containment with a minimum reserved capacity of 135,000 gallons. It is the preferred source of water for the HPCI, RCIC, and an alternate source for the CRD and CS pumps. The reserved capacity will assure at least four hours of injection to the vessel in order to maintain normal reactor level, in absence of any other injection. Four 50,000-gallon tanks of demineralized water provide backup to the CST.

4.1.22 References

4.1-1 Z. T. Mendoza, et al., "Generic Framework for IPE Back-End (Level II) Analysis," NSAC-159, Electric Power Research Institute, June 1991.

4.1-2 "Modular Accident Analysis Program (MAAP)," Version 8.01, Fauske and Associates, Inc.

4.1-3 PSE&G Drawing No. C-0926-0, Rev. 13, "Containment Vessel Requirements - Plan Sections & Details - Sheet 1," March 11, 1981.

4.1-4 The Updated Hope Creek Generating Station, "Final Safety Analysis Report (FSAR)/DDG-88-0023," April 11, 1988.

4.1-5 PSE&G Drawing No. C-0929-0, Rev. 19, "Containment Vessel Requirements - Drywell Penetration Schedule," December 6, 1985.

4.1-6 PSE&G Document: OP-EO.ZZ-310, "Alternate Injection Using Fire Water."

Table 4.1-1
Comparison of Basic RPV and Containment Features of HCGS and Peach Bottom, Unit 2

Parameter Description		
PLANT NAME	HCGS	PEACH BOTTOM
TYPE OF REACTOR	BWR/4	BWR/4
TYPE OF CONTAINMENT	Mark I	Mark I
DATE OF COMMERCIAL OPERATION	4/11/86	7/5/74
Reactor Core		
Thermal Power (MW_t)	3,293	3,293
Number of Fuel Assemblies	764	764
Number of Control Rods	185	185
Core Weight	—	—
Uranium Dioxide (lbm)*	365,236	351,440
Zircaloy (lbm)*	165,000	144,382
Reactor Vessel		
Inside Diameter (in)	251	251
Inside Height (ft)	72.54	72.92
Operating Pressure (psig)	1,020	1,020
Primary system oper. temp. (°F)	555	555
Lowest Safety Valve SP (psig)	1,130	1,230
Number of Safety/Relief Valves	14	11
Lowest Rel. Valve SP (psig)	1,017 **	1,105
Relief Valves Cap. (klb/hr)/vlv	818–950	819
* Cycle-dependent due to fuel design evolution ** Low-low set		
Reactor Coolant Recirculation		
Number of Loops	2	2
Number of Pumps	2	2
Inlet Pressure (psig)	1250	1250
Outlet Pressure (psig)	1500	1500
Number of Jet Pumps	20	20
Flow Rate/Pump (gpm)	45,200	45,200
RHR System		
Number of Loops	4	2
Number of Pumps	4	4
Flow Rate/Pump (gpm @ psig)	10,000 @ 170	10,000 @ 200
Number of Heat Exchangers (Hx)	2	4
Max. Cap. of Hx (Btu/hr) (per 2 Hx set)	130,000,000 (for containment cooling, MTD = 88.7°F)	70,000,000
Injection Point to the Reactor Vessel	Central Core Shroud Region	Reactor Recirculation Loop

Table 4.1-1
Comparison of Basic RPV and Containment Features of HCGS and Peach Bottom, Unit 2 (Continued)

Parameter Description		
PLANT NAME TYPE OF REACTOR TYPE OF CONTAINMENT DATE OF COMMERCIAL OPERATION	HCGS BWR/4 Mark I 4/11/86	PEACH BOTTOM BWR/4 Mark I 7/5/74
Core Spray System		
Number of Loops	2	2
Number of Pumps	4	4
Flow Rate (gpm/pump)	3,175 @ 380 psig	3,125 @ 122 psid
Construction		
Drywell	Inverted light-bulb shape; steel vessel	Inverted light-bulb shape; steel vessel
Pressure Suppression Chamber	Torus; steel vessel	Torus; steel vessel
Drywell Internal Design Pressure (psig)	+56	+56
Drywell Free Volume (ft^3)	178,000	175,800
Drywell Design Temperature (°F)	340	281
Pressure Suppression Chamber Design Pressure (psig)	+56	+56
Pressure Suppression Chamber Water Volume (ft^3)	118,800	123,000
Pressure Suppression Chamber Free Volume (ft^3)	142,600	132,000
Reactor Building/Secondary Containment Design	Domed cylindrical structure; concrete	Rectangular building; concrete and sheet metal

Table 4.1-2
Primary Containment Design Parameters and Characteristics of Hope Creek Generating Station

1.	Design Data	
	Type	Pressure Suppression
	Drywell	Light-bulb shape; steel vessel
	Wetwell	Torus; steel vessel
	Drywell: internal design pressure (psig) external design pressure (psid)	 56 3
	Wetwell: internal design pressure (psig) external design pressure (psid)	 56 3
	Drywell Free Volume (ft^3) (including vent system)	178,000
	Wetwell Free Volume (ft^3)	142,600
	Pressure Suppression Pool Water Volume (ft^3)	118,800
	Submergence of Vent Pipe Below Pool Surface (ft)	4
	Design Temperature of Drywell (°F)	340
	Design Temperature of Wetwell (°F)	340
	Torus minor radius (ft)	15.3
	Sump volume in drywell region(ft^3)	139
	Sump Volume in Pedestal Region (ft^3) Total Containment Sump Capacity (ft^3)	210 349
2.	Air Gap Nominal gap between drywell shell and concrete shield building (in)	 2.0
3.	Embedment Elevation Outside drywell Inside drywell	 86' 11" 86' 11"
4.	a. Drywell Head Ellipsoidal dome Radius (in) Thickness (in) R/T Ratio	 199 1.5 132.7
	b. Drywell Shell Cylindrical Shell below Flange and above Cone Radius (ft) Thickness (in) R/T Ratio	 20.25 1.5 162
	Transition Cone Thickness (in)	1.5
	Cylindrical Shell below Cone Radius (ft) Thickness (in) R/T Ratio	 20.25 0.9375 259

Table 4.1-2 (Continued)
Primary Containment Design Parameters and Characteristics of Hope Creek Generating Station

	Knuckle Radius (in) Thickness (in) R/T Ratio	 100.1 2.875 34.8
	Sphere Radius (ft) Thickness (in) R/T Ratio	 34 1.5 272
5.	Torus Shell Number of miter sections Distance from torus centerline to drywell centerline (ft) Elevation of torus centerline (ft) Thickness (in)	 16 56' 4" 72' 4" 1.0
6.	Torus Support Columns Number of columns	 16 pairs
7.	Venting (Hard Pipe)	
	Size of Vent Line (in)	12
	Vent Origination	Torus
	Vent Exhausts to	Environment
	Support Systems	UPS—Class 1E; and Dedicated Nitrogen Station or Inst. Air. Manual hydraulic Jack provides an alternative opening method.
8.	Integrated Leak Rate Test	
	Size of Hard Pipe Vent Line (in)	6
	Vent Origination	Torus and/or Drywell
	Vent Exhaust	Environment
	Power Source	UPS—Class 1E; and Instrument Air
9.	Secondary Containment Filtration, Recirculation, and Venting System	
	Number of Recirculation Units	6 (25% capacity)
	Number of Vent Units	2 (100% capacity)
	Flow Rate of Recirculation Unit	30,000 cfm
	Flow Rate of Vent Units	9,000 cfm
10.	Station Service Water System	
	No. of Pumps	4
	No. of Loops	2
	Flow Rate at Pressure	16,500 gpm @ 45 psig
	Power Source	4.16 KVAC, Class 1E
11.	Core Spray	
	No. of Loops	2
	No. of Pumps	4
	Flow Rate/Pump (gpm @ psig)	3,175 @ 380 psig
12.	High-Pressure Coolant Injection	
	Power Source	Steam and DC
	Flow Rate (rated pressure)	3,000 gpm to Core 2,600 gpm Outside Shroud
	Suction Temperature Limit	190°F
	Exhaust Pressure Limit	140 psig
	RPV Operating Pressure Range	100–1250 psig

Table 4.1-2 (Continued)
Primary Containment Design Parameters and Characteristics of Hope Creek Generating Station

13.	Reactor Core Isolation Cooling	
	Power Source	Steam and DC
	Flow Rate	625 gpm
	Suction Temperature Limit	190°F
	Exhaust Pressure Limit	25 psig
	RPV Operating Pressure Range	65–1120 psig
14.	Condensate Storage Tank	
	Max. Capacity	500,000 gallons
	Reserved Capacity	135,000 gallons
15.	Fire Protection System	
	No. of Pumps	2
	Type of Pumps	480 VAC and Diesel-Driven (Standby)
	No. of Water Tanks	2
	Capacity of Fire Water Tanks	350,000 gallons
	Flow Rate	2,500 gpm @ 90 psig

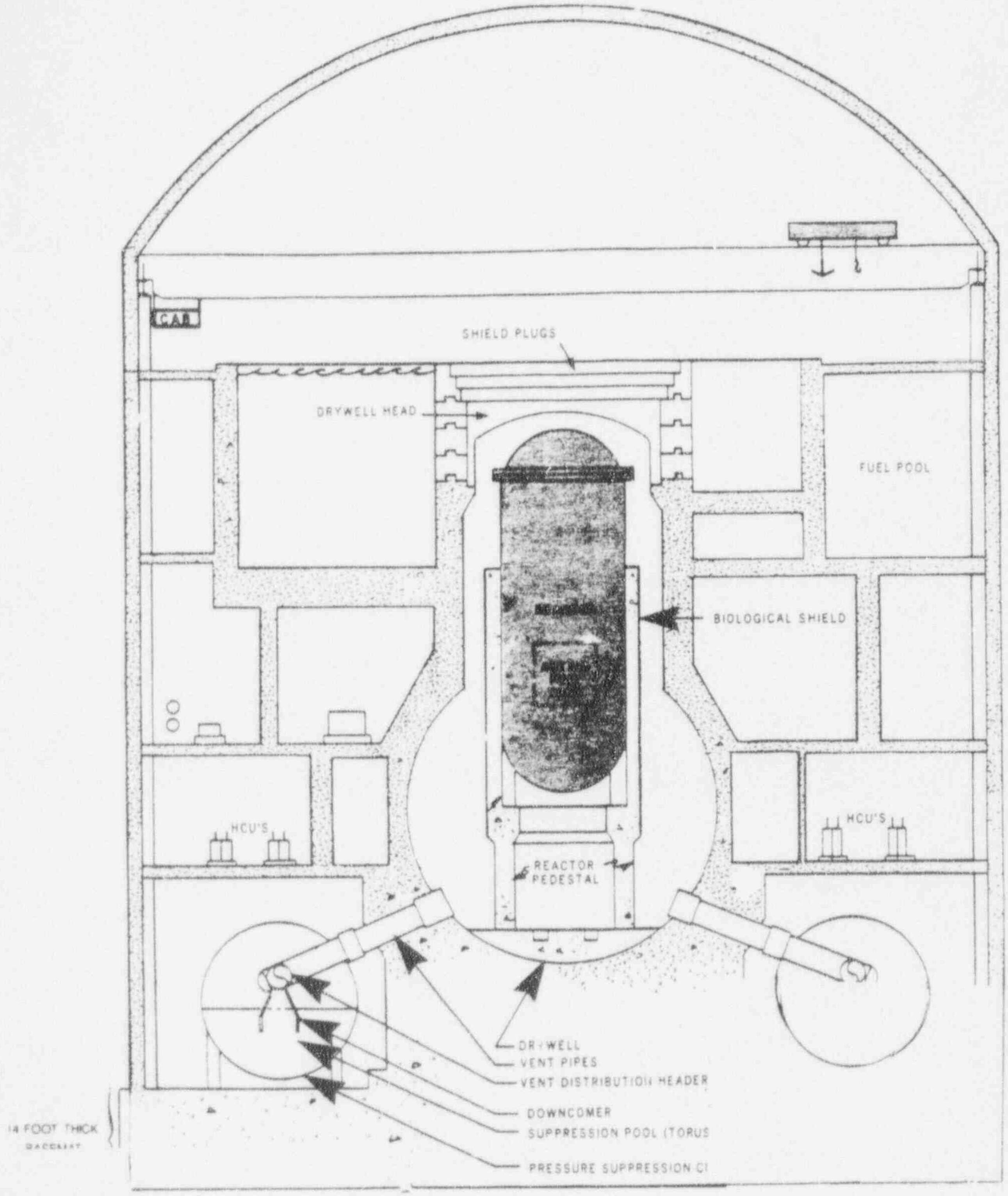

Figure 4.1-1. Containment Elevation Plan

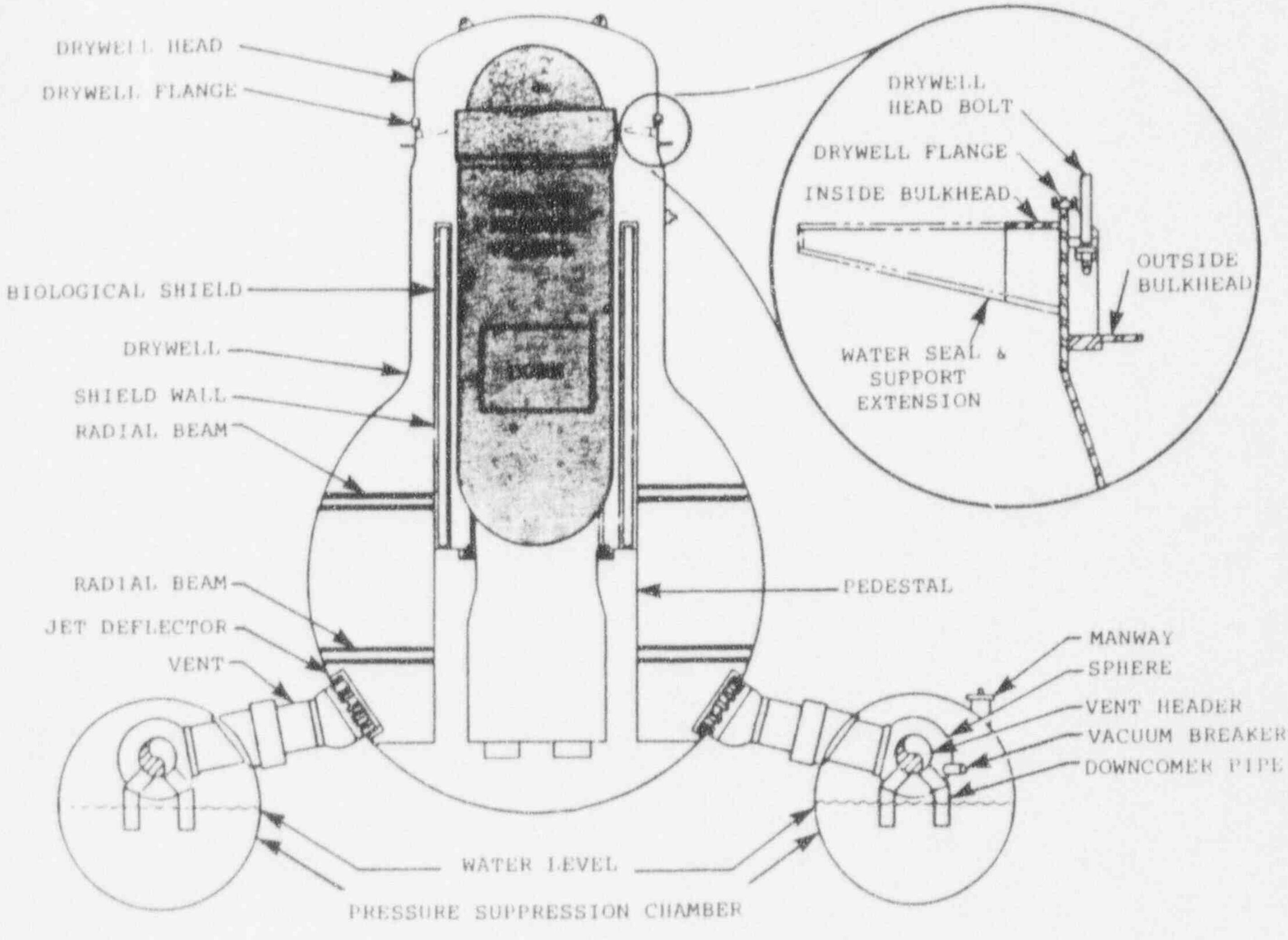

Figure 4.1-2. Mark I Primary Containment

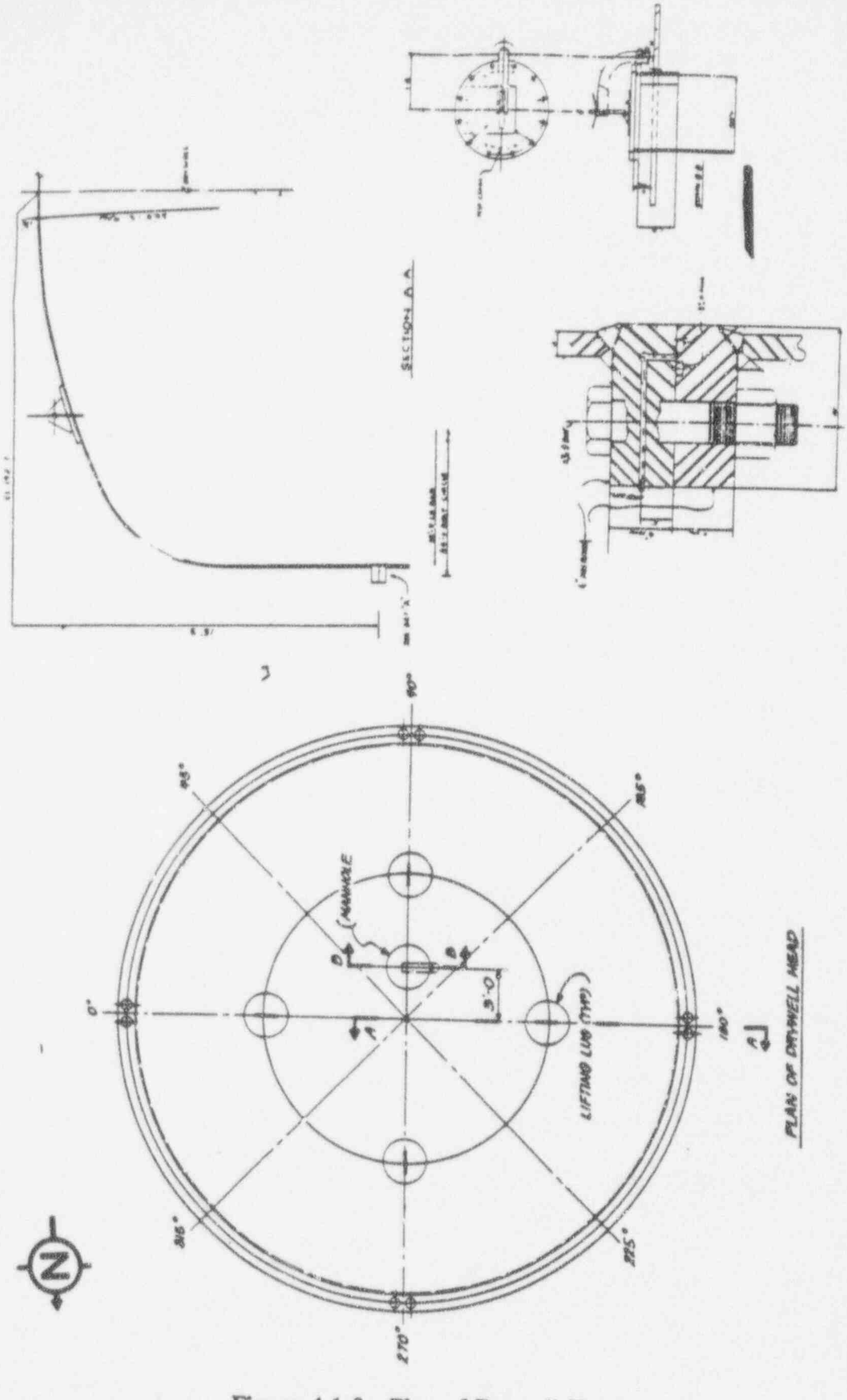

Figure 4.1-3. Plan of Drywell Head

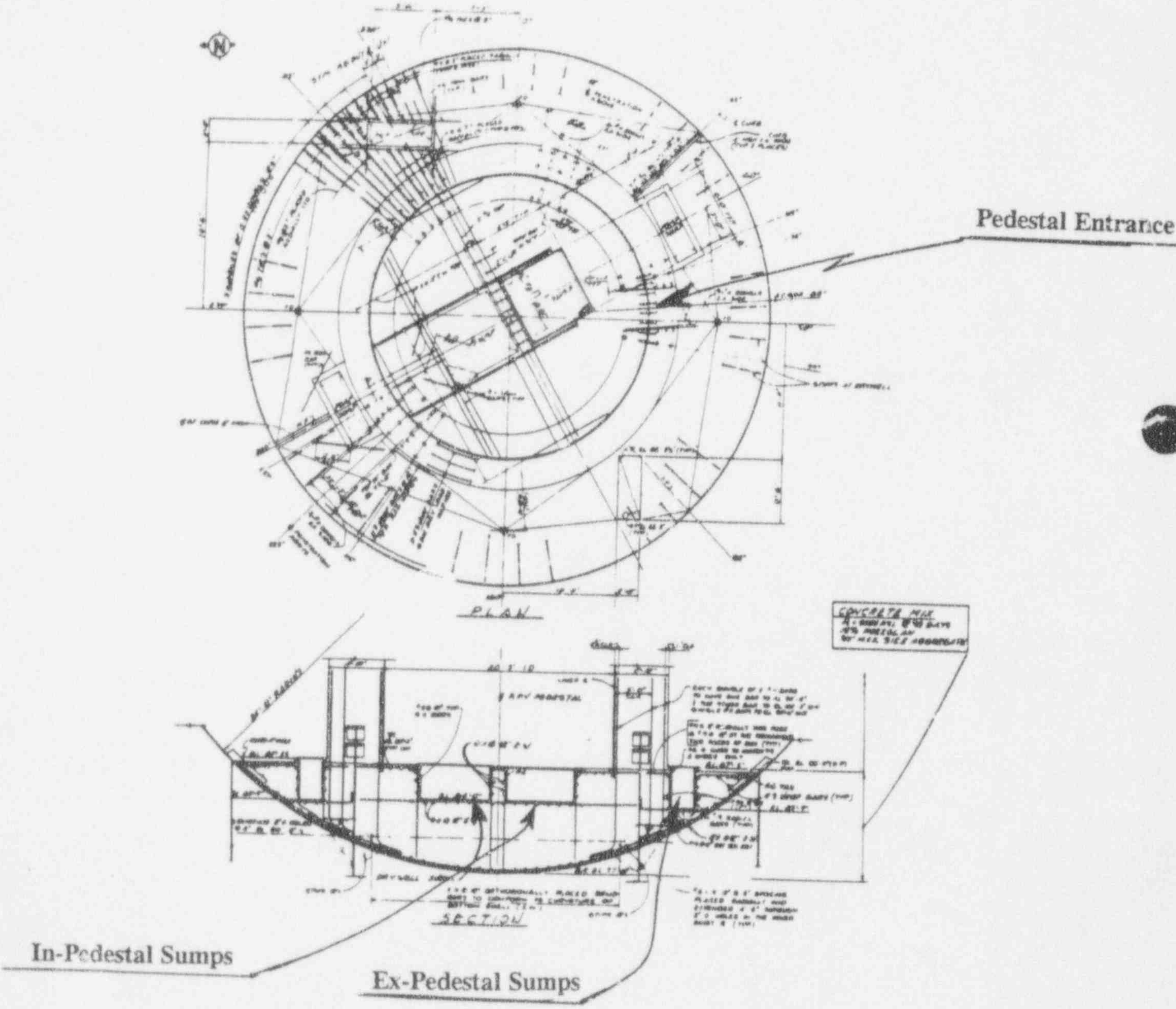

Figure 4.1-4. RPV Pedestal Floor Reinforcing

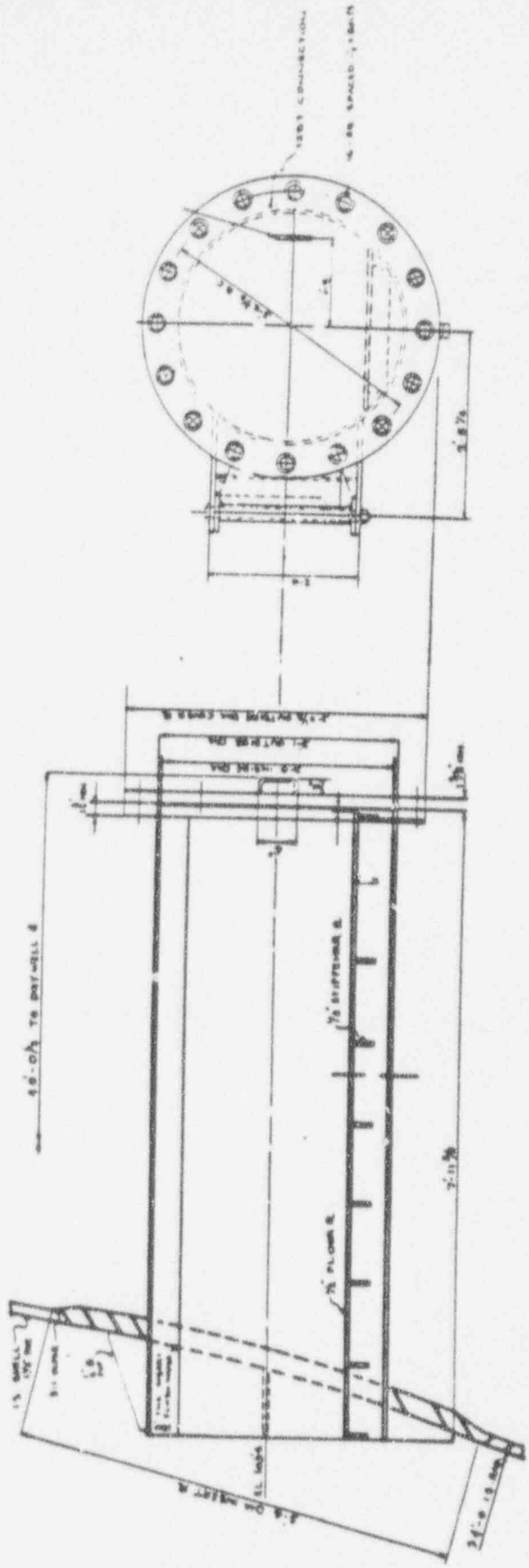

Figure 4.1-5. CRD Removal Hatch C-3

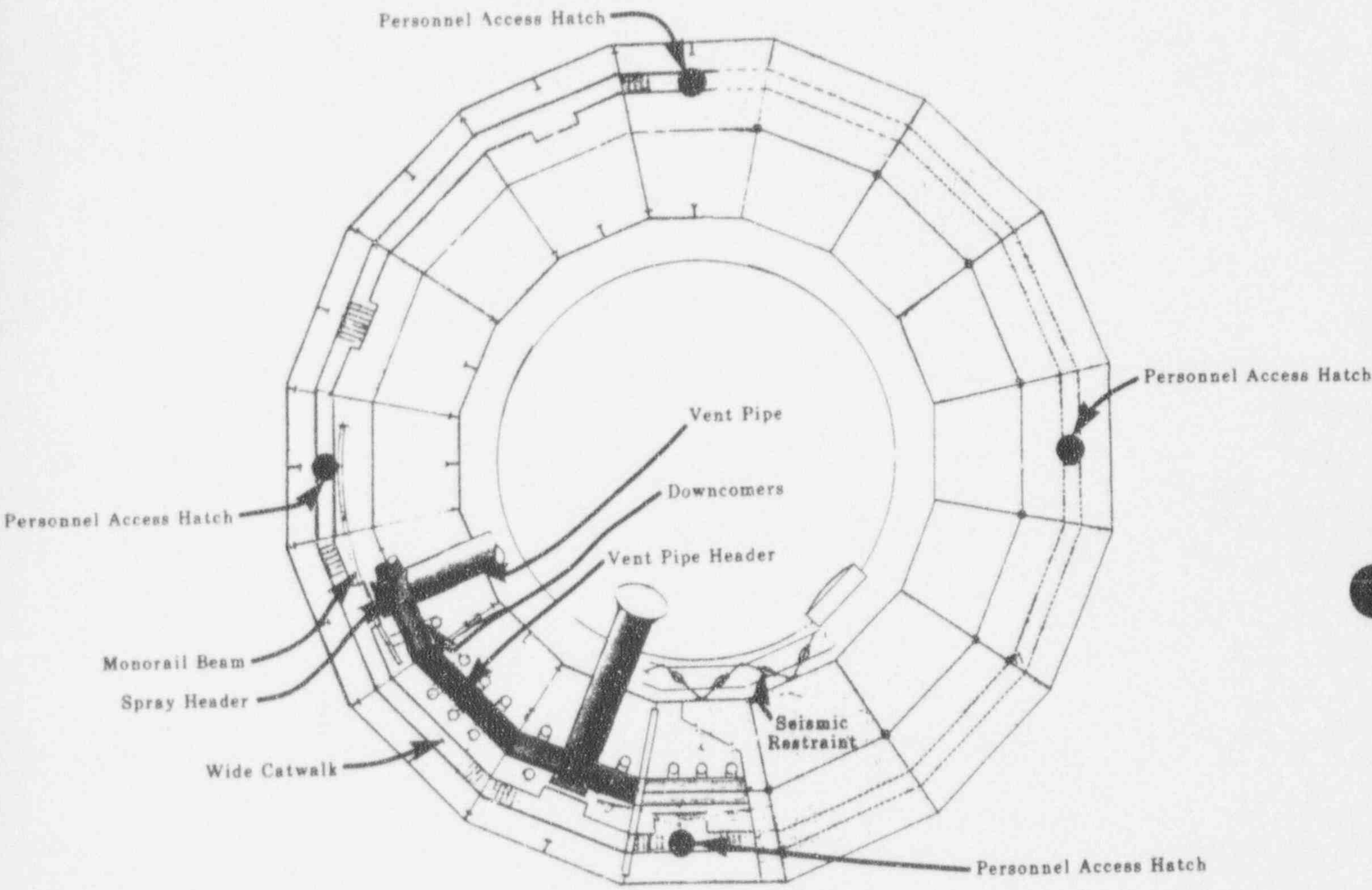

Figure 4.1-6. Plan--Suppression Chamber

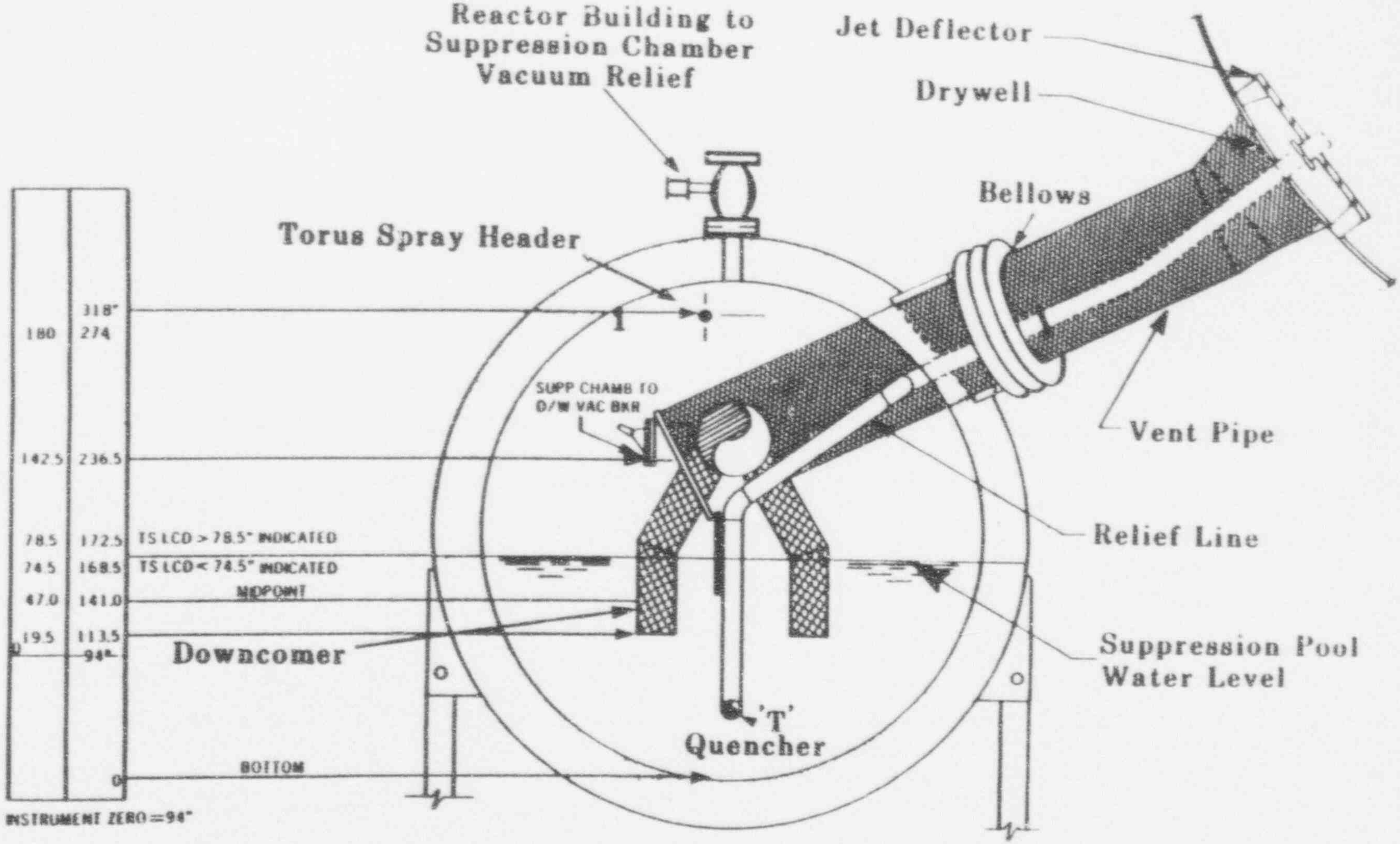

Figure 4.1-7. Vent Pipe Assembly

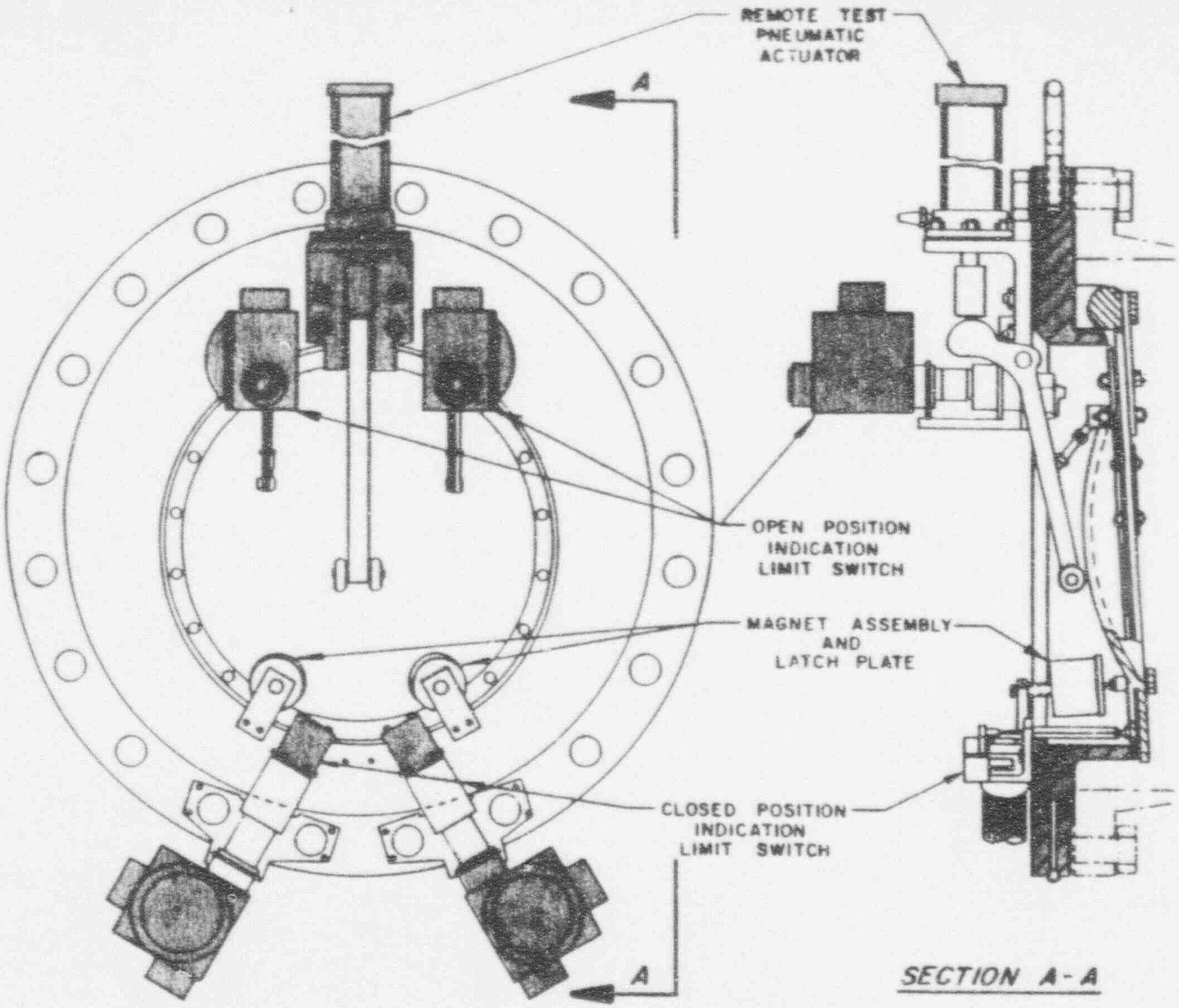

Figure 4.1-8. Torus to Drywell Vacuum Relief Valve

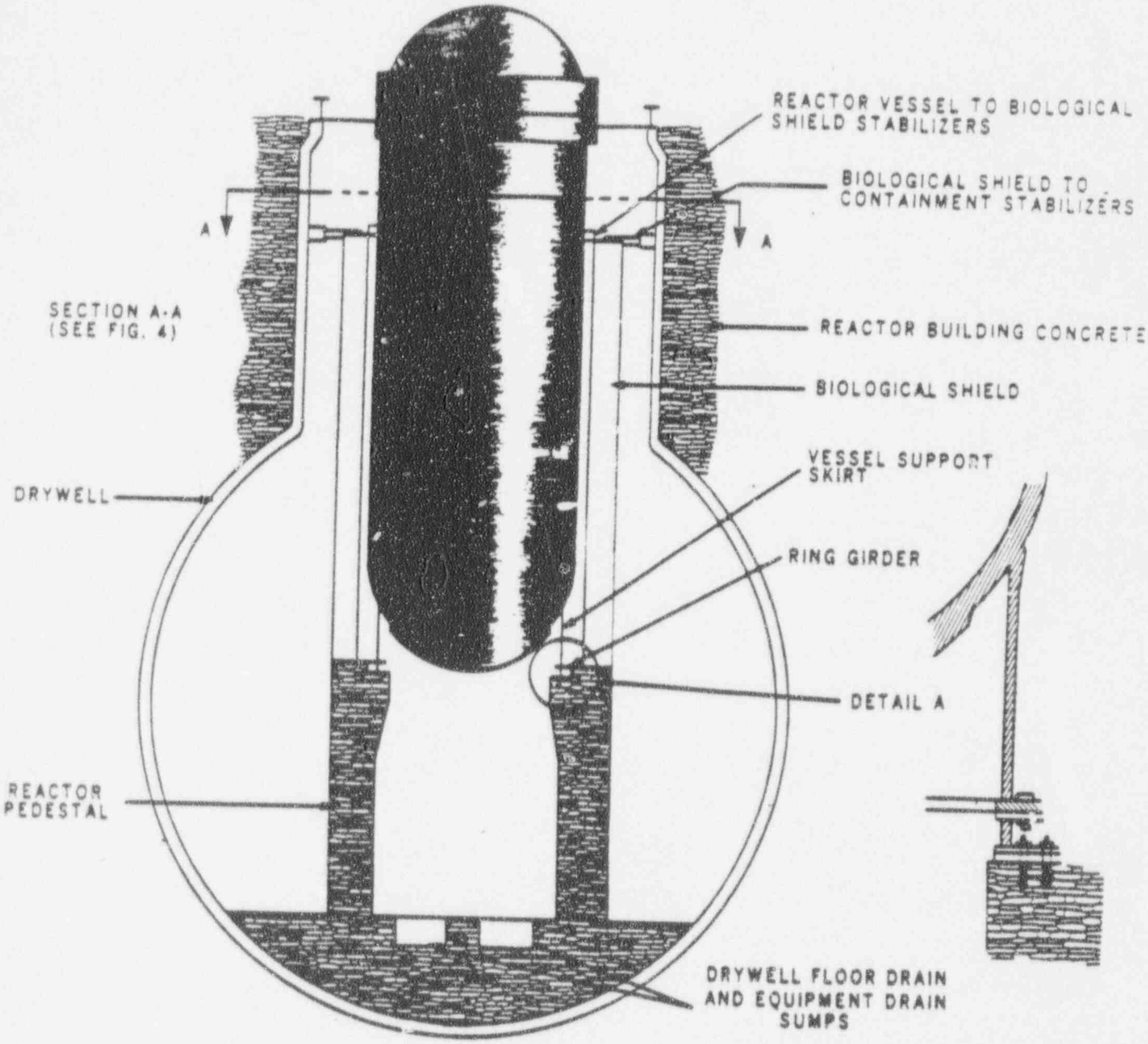

Figure 4.1-9. Reactor Vessel Vertical and Lateral Supports

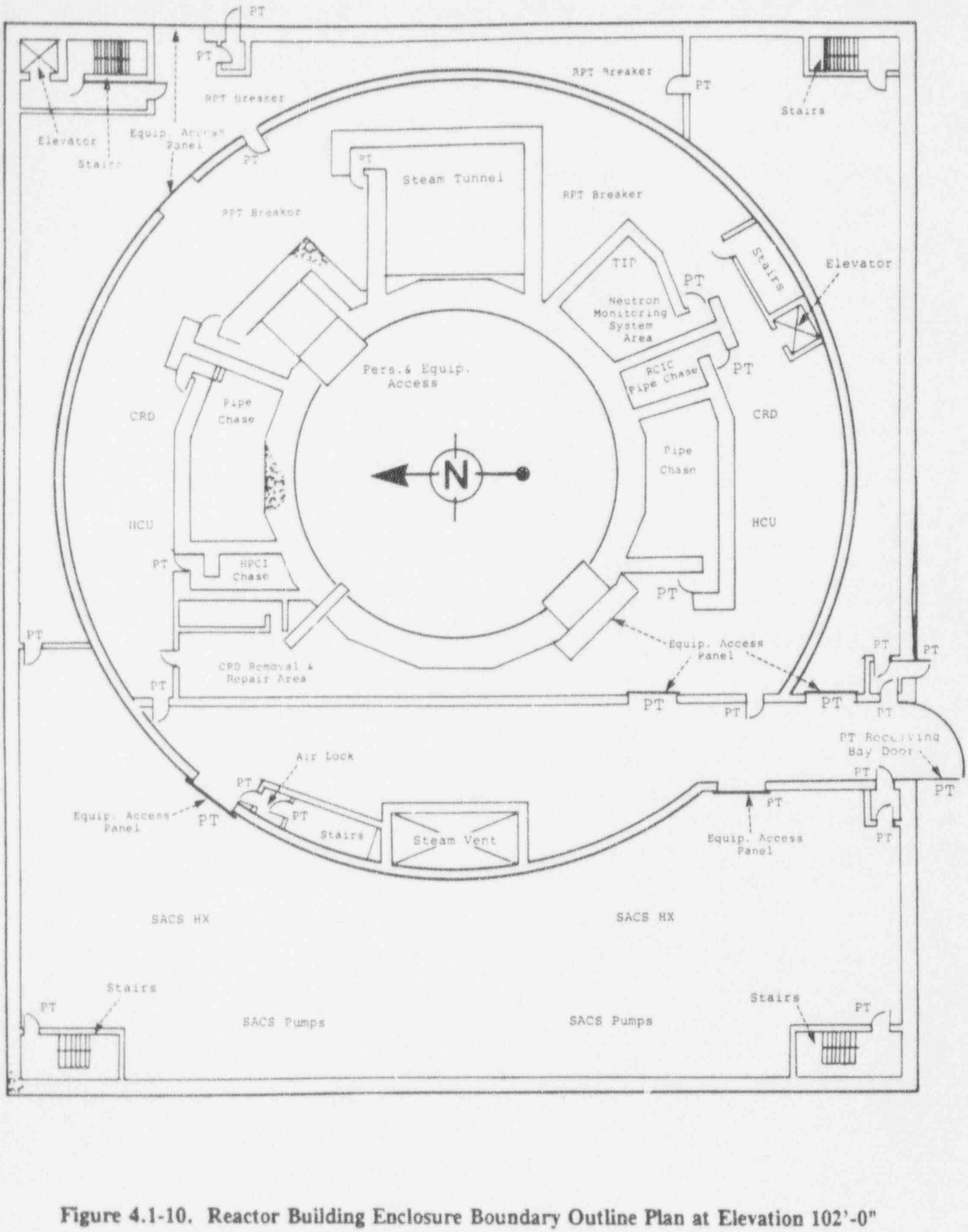

Figure 4.1-10. Reactor Building Enclosure Boundary Outline Plan at Elevation 102'-0"

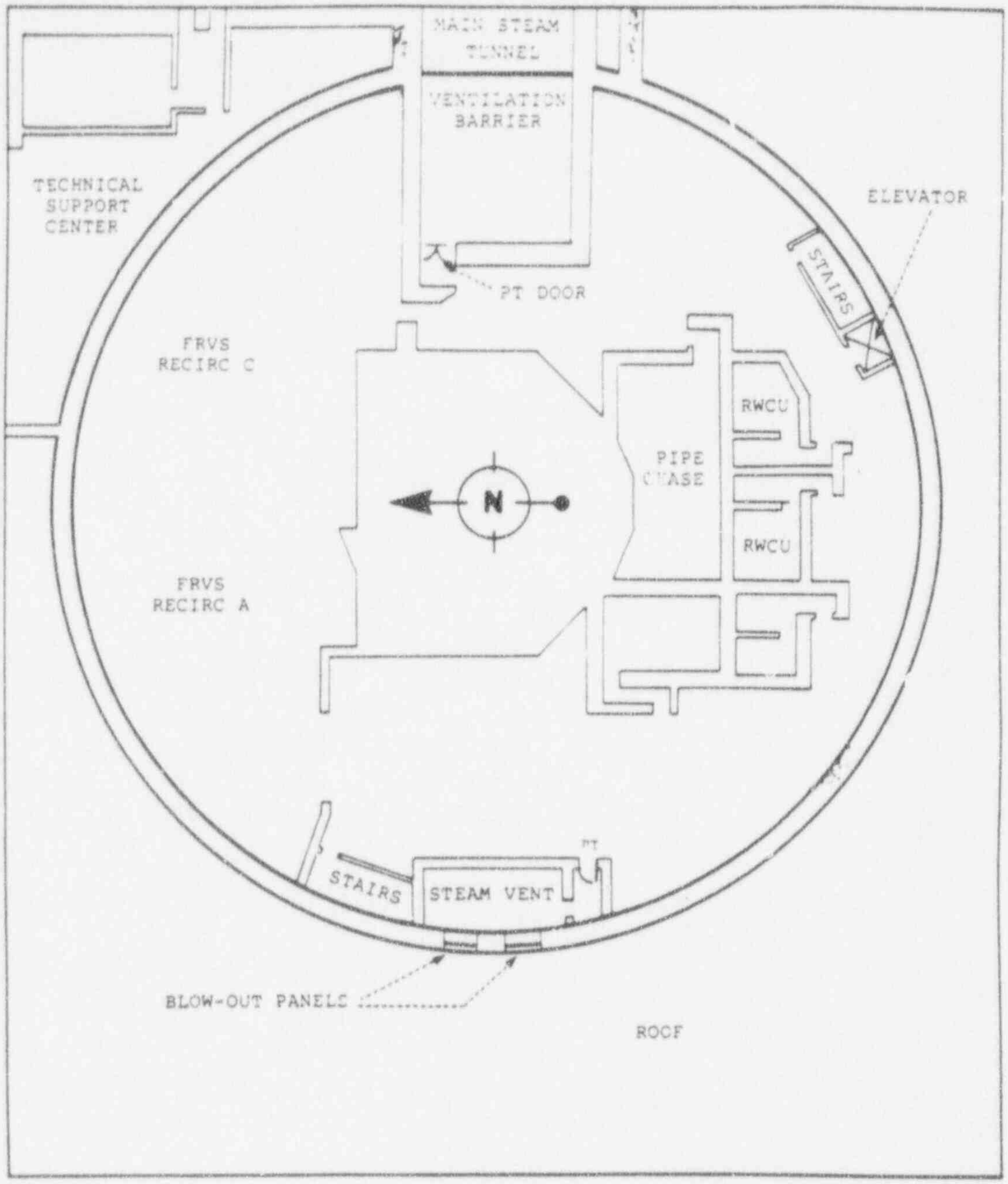

Figure 4.1-11. Reactor Building Enclosure Boundary Outline Plan at Elevation 132'-0"

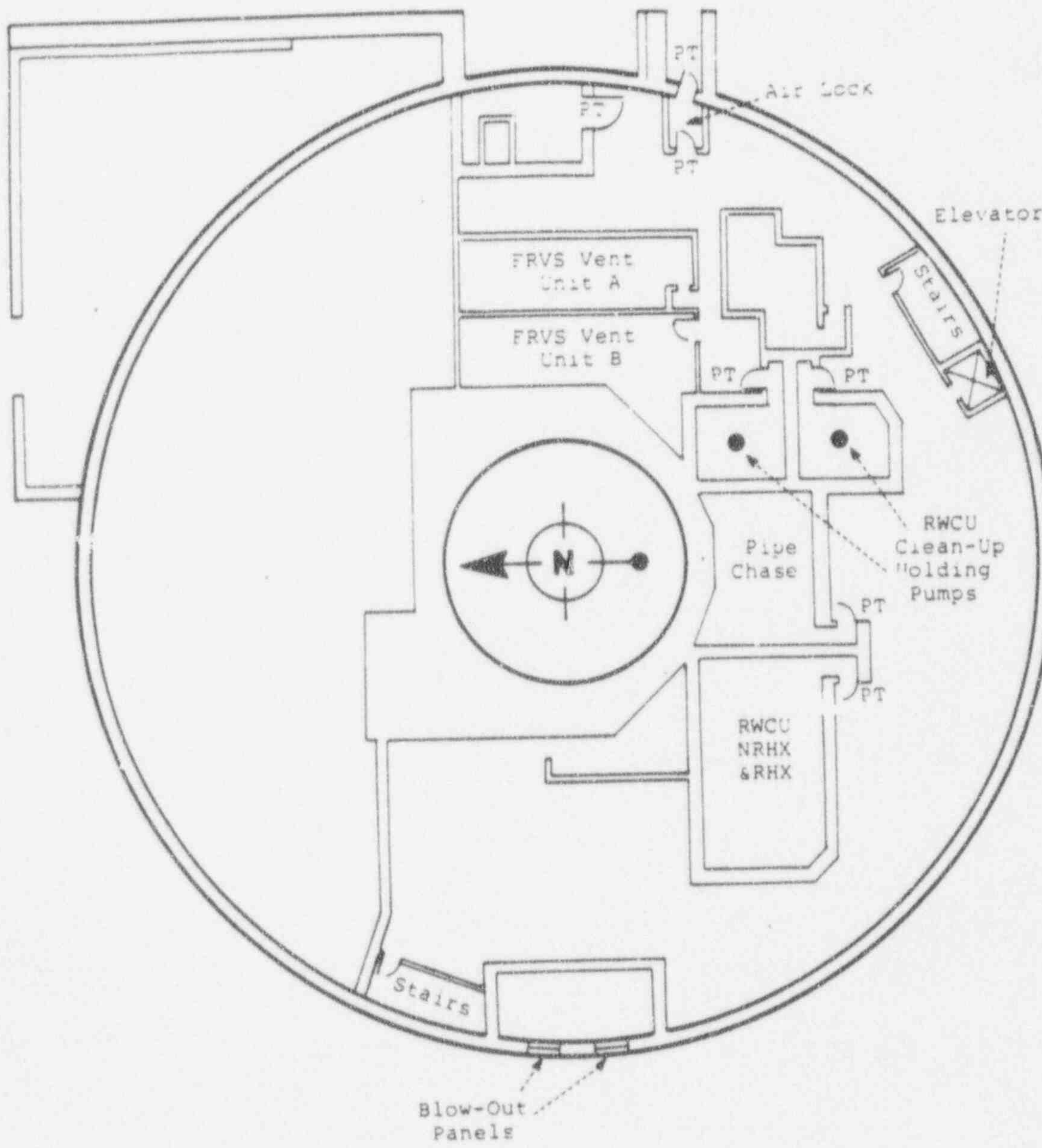

Figure 4.1-12. Reactor Building Enclosure Outline Plan at Elevation 145'-0"

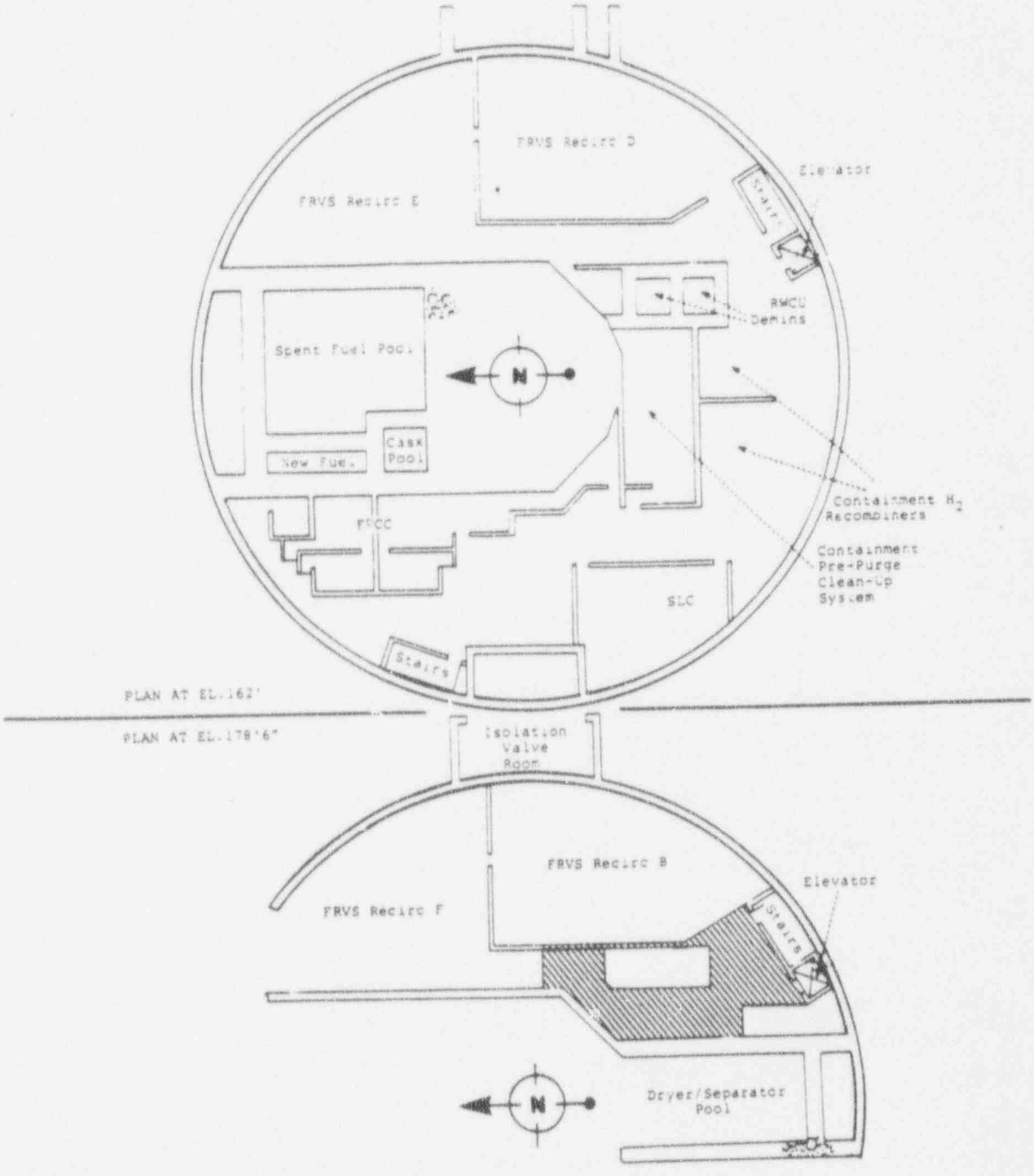

Figure 4.1-13. Equipment Location Reactor Building Plan—Elevation 162'-0" and 178'-0"

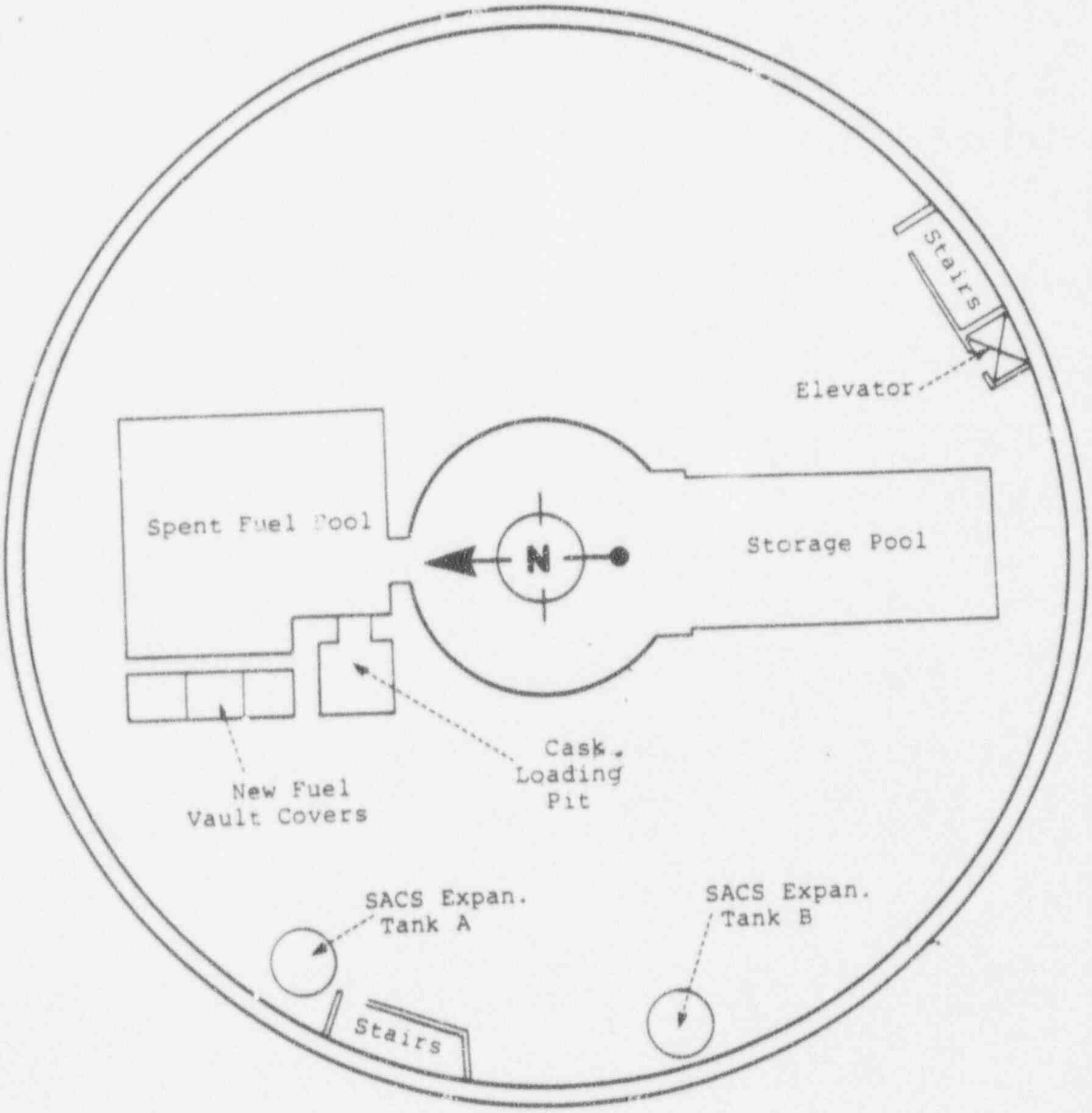

Figure 4.1-14. Reactor Building Enclosure Boundary Outline Plan at Elevation 201'-0"

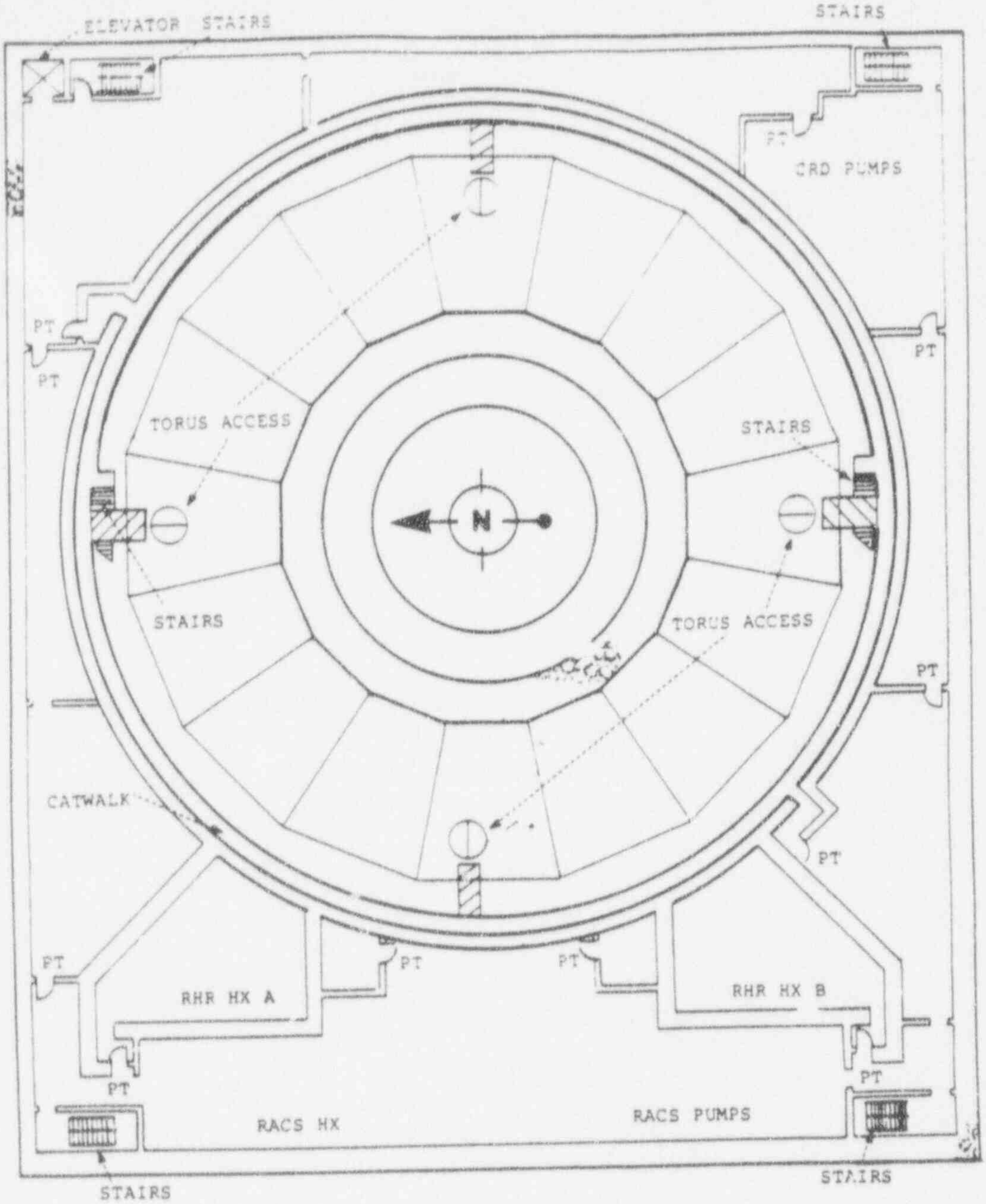

Figure 4.1-15. Reactor Building Shielding and Radiation Zoning Drawing Plan Elevation 77'-0"

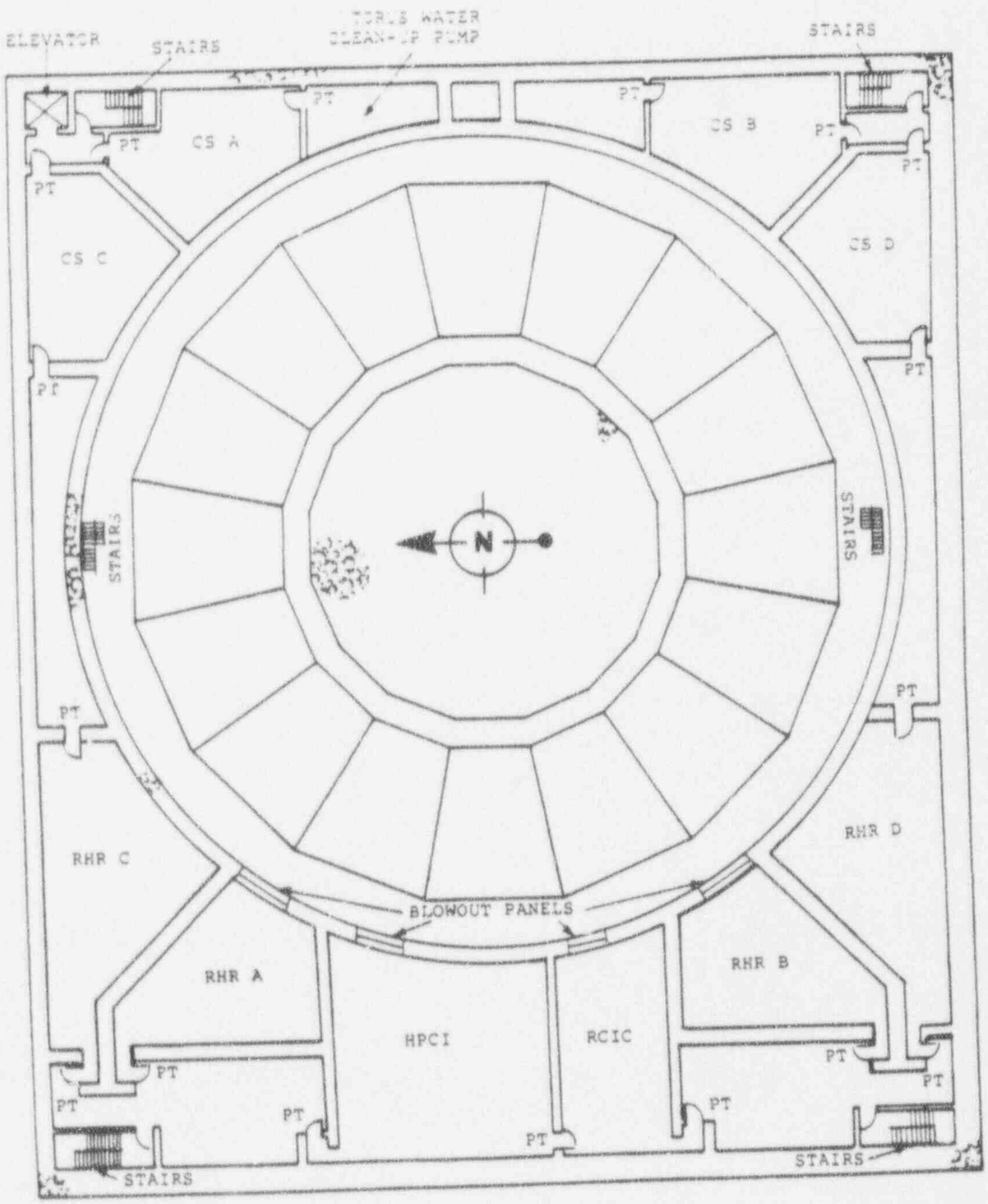

Figure 4.1-16. Reactor Building Shielding and Radiation Zoning Drawing Plan Elevation 54'-0"

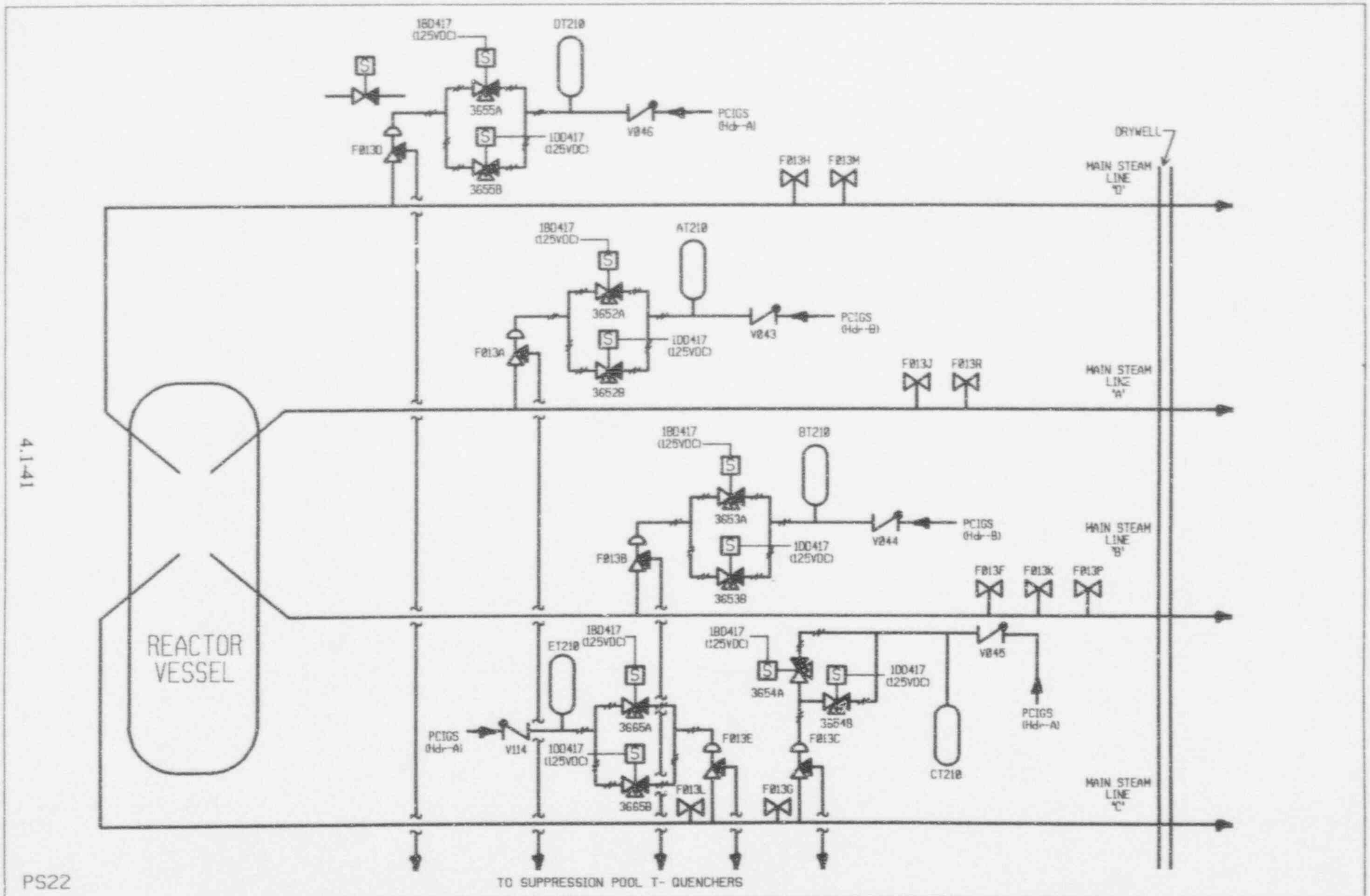

Figure 4.1-17. SRV and ADS Steamline Orientation

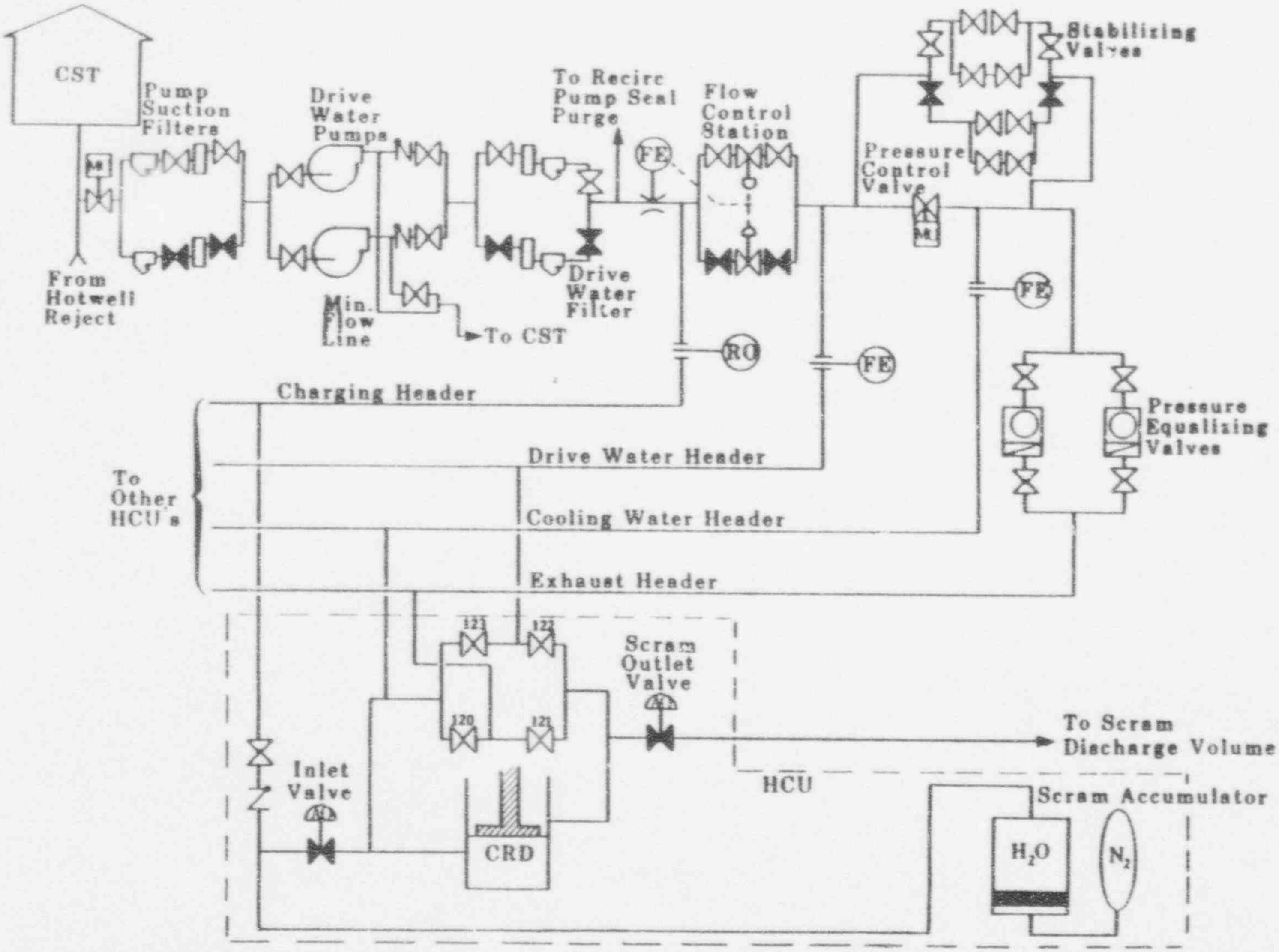

Figure 4.1-18. CRD Hydraulic System

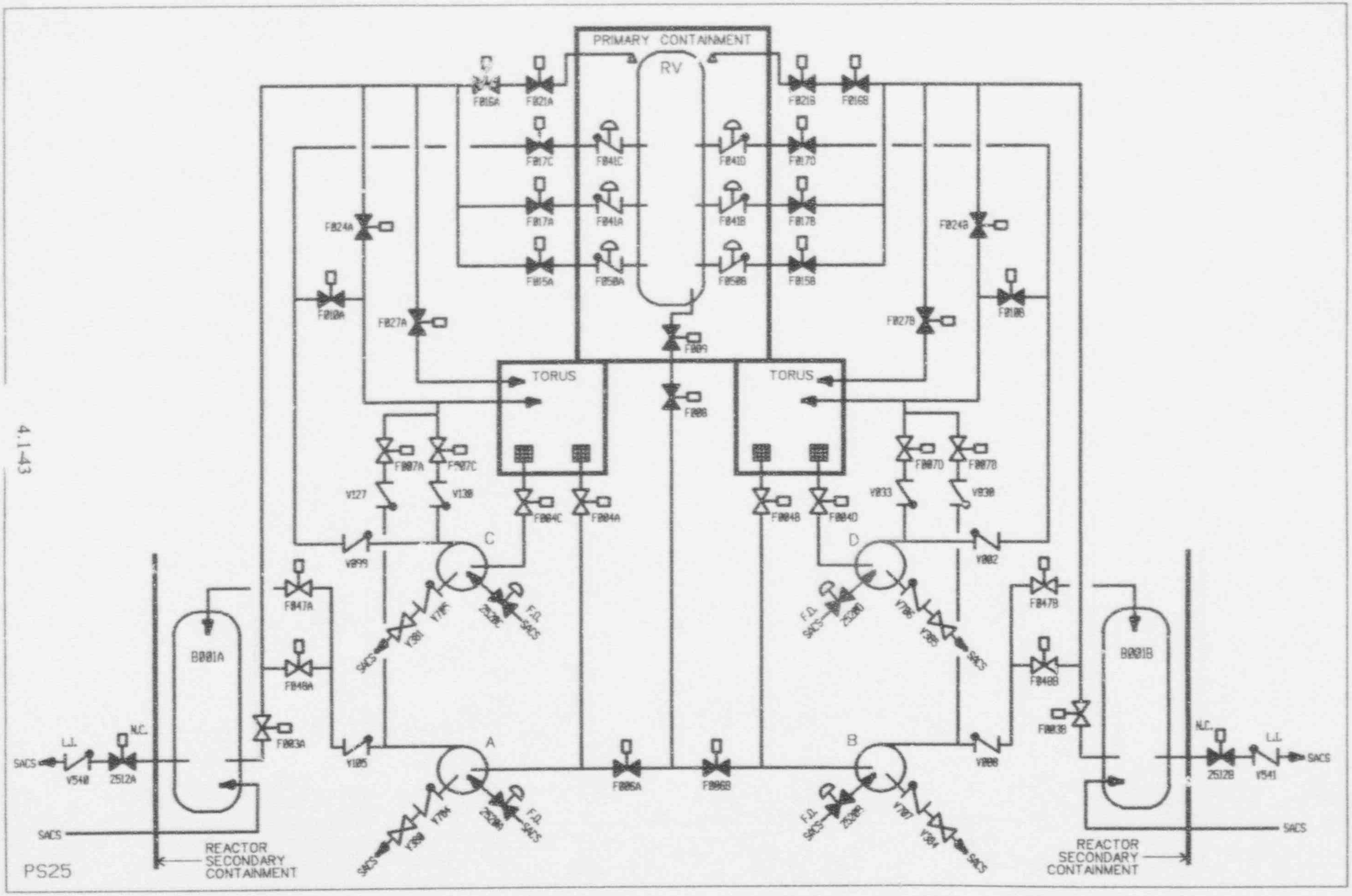

Figure 4.1-19. RHR Simplified Diagram

STATION SERVICE WATER SYSTEM

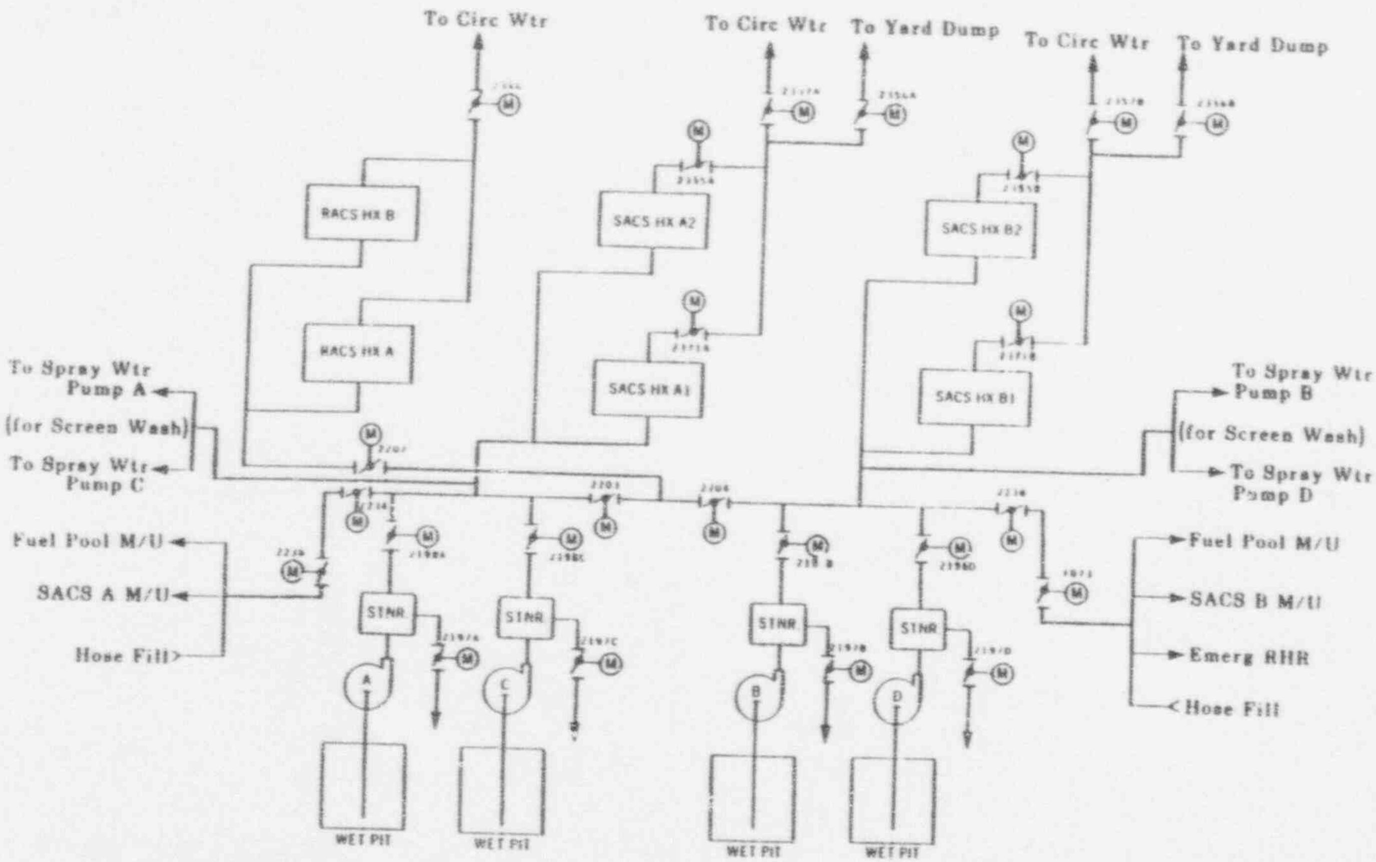

Figure 4.1-20. Station Service Water System

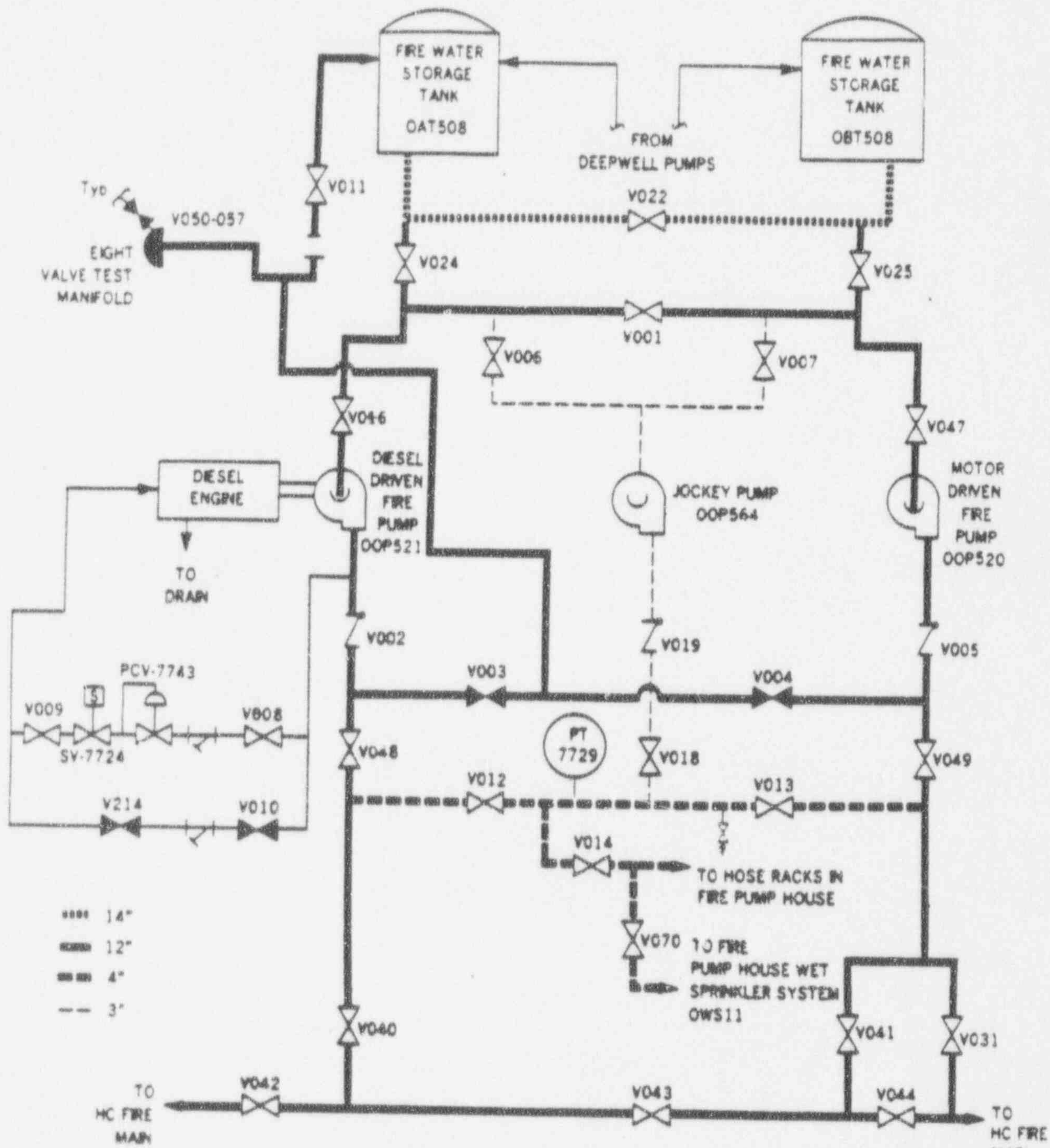

Figure 4.1-21. Fire Protection Water Supply

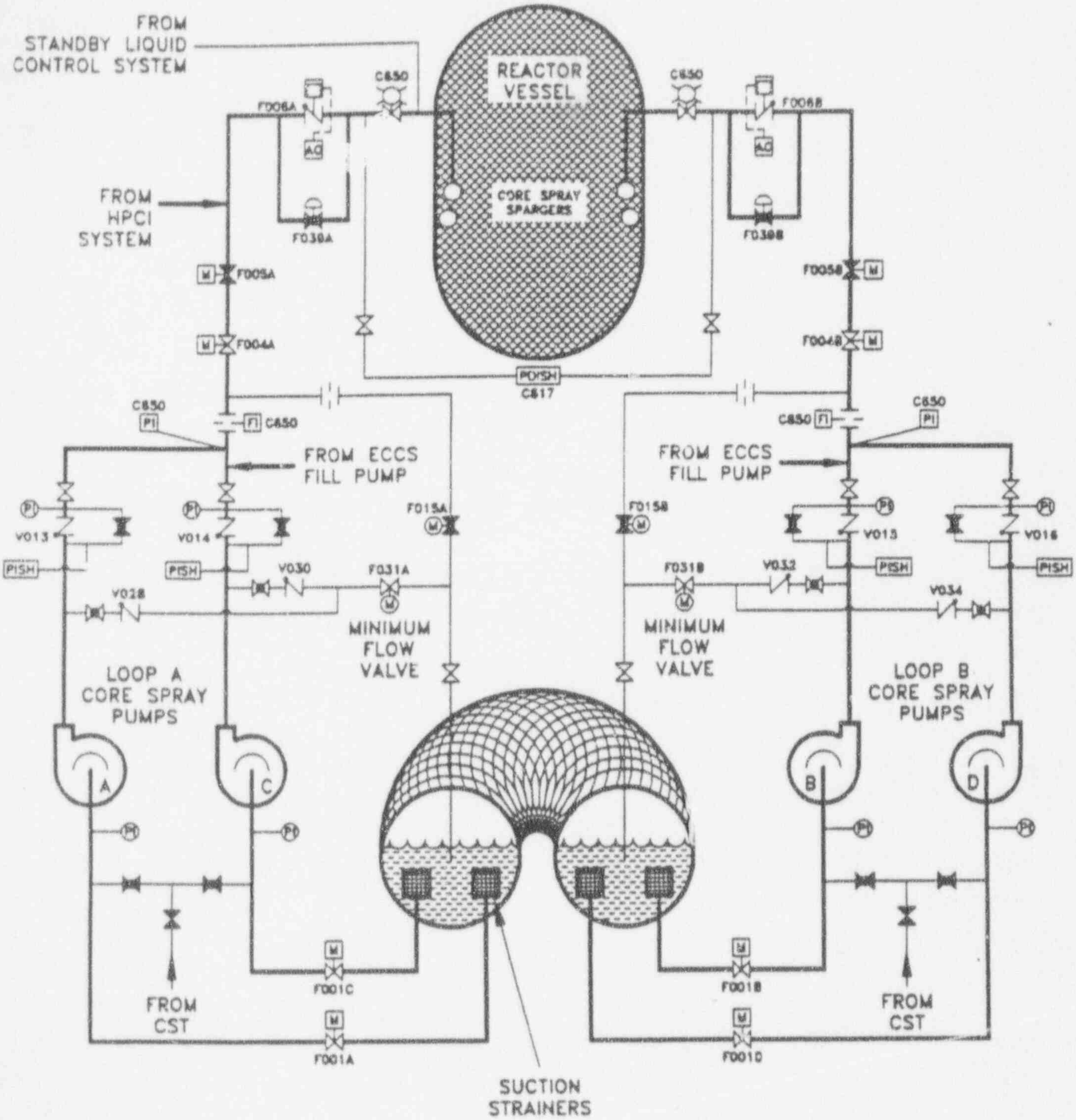

Figure 4.1-22. Core Spray System

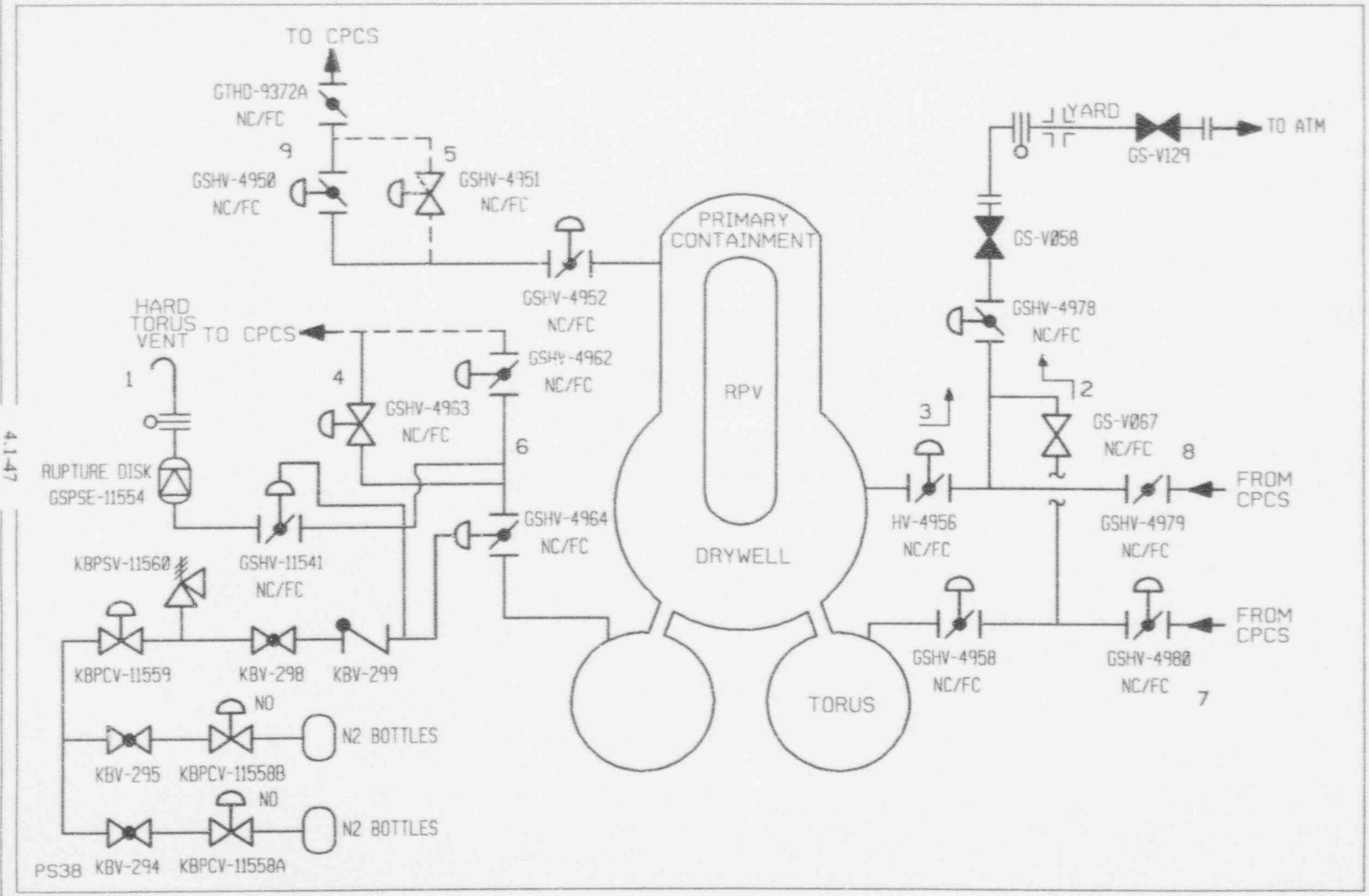

Figure 4.1-23. Containment Venting System

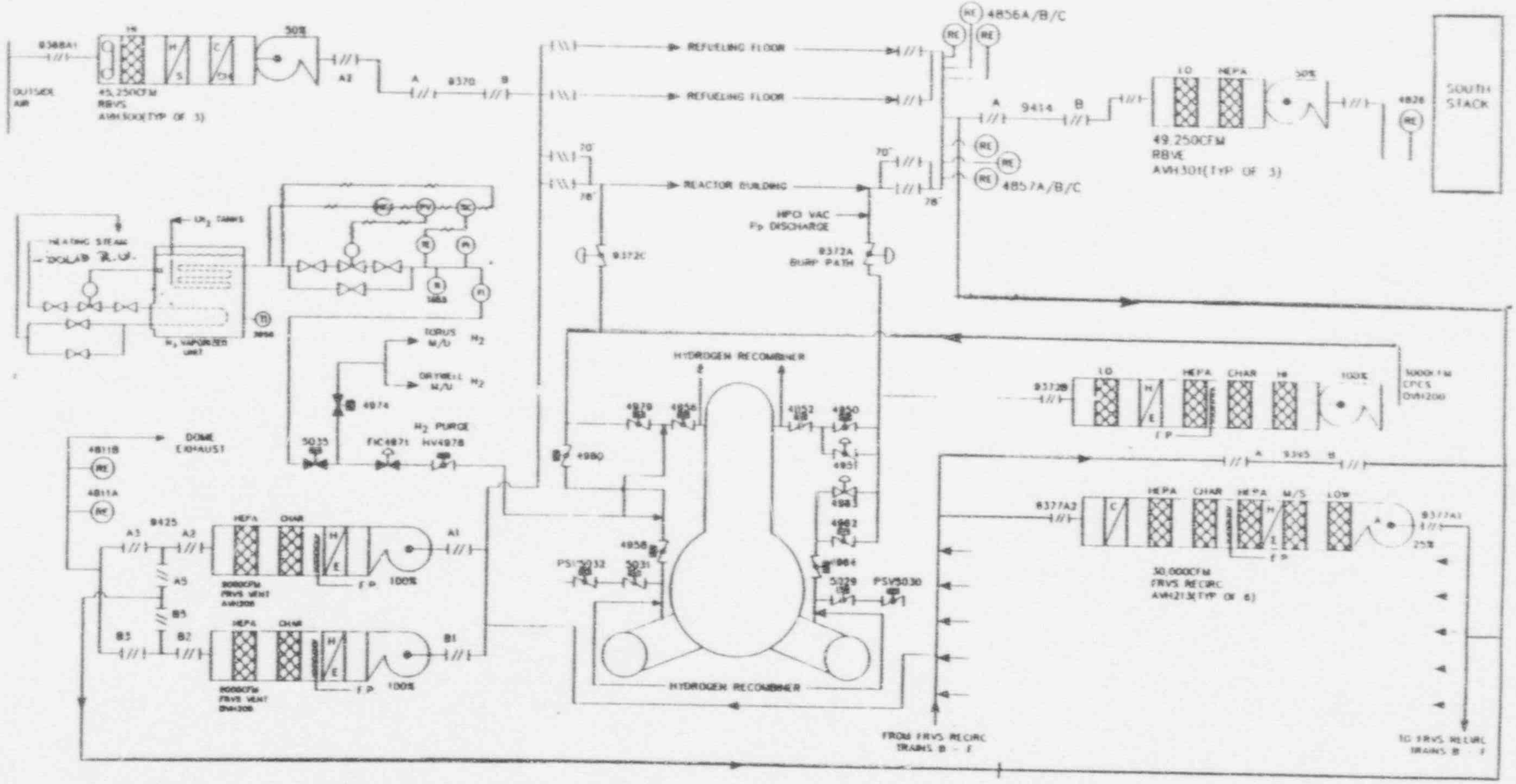

Figure 4.1-24. Reactor Building Ventilation

4.2 PLANT MODELS AND METHODS FOR PHYSICAL PROCESSES

4.2.1 Introduction

To support the Level II portion of the HCGS IPE, information was required concerning the response of the HCGS containment to severe accident conditions and for radionuclide release and transport within the containment and to the environment. Most of the basic event probabilities needed for the HCGS CET were evaluated based on the accident progression results calculated by the MAAP code (Reference 4.2-1). The version of the MAAP used in this analysis was MAAP 3.0B Revision 8.1. The EVNTRE code (Reference 4.2-2) was used for the evaluation of the CET. Calculation of the radionuclide source terms for each CET end state was performed by an algorithm coupled to the EVNTRE code. Values of source term parameters (e.g., release fractions and decontamination factors) used in this algorithm were set during each EVNTRE sequence evaluation. This approach is similar to the use of the PBSOR Code in the NUREG-1150 analysis (Reference 4.2-3). It is also consistent with the EPRI Generic Methodology for Back-End Analysis (Reference 4.2-4). The source terms were evaluated for each sequence and were modeled in the CET. A more detailed discussion of the source term analysis is provided in Section 4.7.1.

Most of the basic event probabilities used in the CET were evaluated based on either the plant-specific accident analyses or on plant-specific human reliability analyses. In addition to the MAAP calculations, published results from NRC codes such as RELAP5/MOD3, MELCOR, and BWRSAR/CONTAIN were considered in the CET quantification. For some basic events that are not adequately addressed in the BWR MAAP model, separate analyses were performed or values were taken from the NUREG-1150 (Reference 4.2-3) analyses documented in NUREG/CR-4551 (References 4.2-5 and 4.2-6).

This section provides a short summary of the phenomenological models in MAAP and describes how the MAAP results were used in the CET development and quantification. For phenomena that included information supplemental to MAAP, a brief summary is provided of how these phenomena were treated in the HCGS CET.

4.2.2 Overview of the MAAP 3.0B Code

Several codes are available for thermal hydraulic and severe accident analysis of BWRs. PSE&G opted to use the MAAP 3.0B computer code (Reference 4.2-1). This decision was based on the modularity of MAAP, its ease of use, and its wide-spread industry support. PSE&G has used MAAP to support several important studies, including the "HCGS Station Blackout Study" (Reference 4.2-7). PSE&G has been active in the MAAP User's Group and has implemented all the code changes released by the code developers. Version 3.0B, Revision 8.1 of MAAP was used to support the HCGS IPE. The MAAP parameter file was developed and reviewed internally by PSE&G personnel. All of the MAAP runs used for the CET quantification were performed internally by the PRA group at PSE&G and were independently reviewed. Also, results from EPRI-sponsored codes such as RETRAN and GOTHIC were used to verify the MAAP thermal hydraulic behavior in several instances.

MAAP uses difference equations to solve a set of lumped parameter, nonlinear, coupled, first order ordinary differential equations. Conservation equations for mass and energy are set up for each physical region of the plant. The momentum balances of the regions are assumed to be quasi-steady state. This assumption reduces the momentum equations to algebraic expressions and eliminates the need for differential equation treatment for the conservation of momentum. The physical models in MAAP are contained in the region subroutines which call the required phenomenological subroutines and thermodynamic relations. An integration subroutine uses the rates of change to update the dynamic variables of mass and internal energy.

The HCGS MAAP model consists of a fixed parameter file and run-dependent input files. The parameter file consists of data related to six physical regions of the plant, including: (1) the primary system, (2) the pedestal, (3) the drywell, (4) the wetwell/torus, (5) the secondary containment, and (6) the environment. In the HCGS analyses, the secondary containment was further subdivided into nine separate control volumes interconnected by flow paths (Figure 4.2-1). Accurate modeling of the Reactor Building was necessary to obtain realistic predictions of Reactor Building response following containment failure and radionuclide release from the Reactor Building to the environment.

Development of the HCGS MAAP parameter file required the gathering of information for approximately 1500 variables, considering both plant-specific information and model parameters. Most of the plant-specific information was determined based on a review of plant drawings and other plant descriptions. In assembling the plant-specific information relative to the initial conditions of the accident, the most conservative initial conditions allowed by the Technical Specifications were used. Therefore, all MAAP runs were initiated from full power with the lowest allowable reactor water level and highest allowable containment pressure and temperature. Values assigned to sensitive model parameters were based on the recommendations by EPRI (Reference 4.2-8). The HCGS MAAP parameter file is documented in Reference 4.2-9.

The MAAP input files provide user control of a variety of variables related to engineered safeguards, containment performance, etc. By varying the parameters in the input file, the user can simulate a broad spectrum of accident initiators and a wide range of plant responses (e.g., containment failure modes). The input files were formulated such that the requirements of the EOPs were not violated as long as the equipment required is operable for the plant damage state modeled.

The following sections provide a description of the models employed in MAAP and their significance to the HCGS CET. For phenomena not adequately addressed in MAAP, a brief summary is provided of how the required CET parameters were determined. The phenomena addressed in the following discussion include:

- In-vessel melt progression,
- Melt expulsion from the reactor vessel,

- Fuel-coolant interactions,
- Ex-vessel debris coolability,
- Molten core-concrete interactions and drywell shell failure,
- Flammable gas combustion,
- Primary containment failure,
- Radionuclide revolatilization from the primary system,
- Fission product transport within the containment, and
- Aerosol scrubbing by water pools.

4.2.3 In-Vessel Melt Progression

MAAP models core degradation with coincident hydrogen generation and radionuclide release. An important aspect of the MAAP melt progression model is its treatment of blockage formation within the core. This modeling has a large impact on both hydrogen generation and fission product release. Here the user has three options for controlling the formation of core blockages. These are referred to as the "no blockage" option, the "nodal or local blockage" option, and the "channel blockage" option. These options are described below:

i. "No Blockage" Option: Blockages do not form as core material relocates. Consequently, fuel and cladding relocation has little impact on gas flows and fission product release. No restrictions are placed on the steam-Zr reaction rates and hydrogen production rates are maximized. This option provides a conservative upper limit to in-vessel hydrogen generation. It also leads to unrealistically high predictions of fuel temperature. Fission product release is, therefore, also maximized.

ii. "Nodal Blockage" Option: Molten core material can relocate and form blockages within core nodes. The movement of zircalloy away from the melting region terminates oxidation in that node. Gas flows and fission product release are affected slightly by the relocating fuel and cladding. This option provides intermediate levels of in-vessel hydrogen production.

iii. "Channel Blockage" Option: Movement of core material quickly seals off the entire channel. This results in pressurization of the channel, expulsion of the remaining water, and termination of gas flow in that channel. This is consistent with assuming that the fuel channel remains intact both above and below the melted region. Oxidation of Zr ceases due to lack of steam. This option provides a lower bound on the magnitude of in-vessel hydrogen production.

Most of the HCGS MAAP calculations were run with the "nodal blockage" option selected. This is consistent with the EPRI recommendations. A few calculations were performed with the "no blockage" and "channel blockage" options selected in order to provide bounding estimates of hydrogen production during core degradation.

Two options are also available to the user for calculating radionuclide release from the fuel. The user may choose to calculate release based on the NUREG-0772 methodology (Reference 4.2-10) (i.e., using release rates that are an exponential function of temperature) or using the IDCOR/EPRI steam oxidation model (Reference 4.2-11) for release of volatile radionuclides. If the IDCOR/EPRI steam oxidation model is selected, a correlation by Kelly (Reference 4.2-12) is used to calculate strontium release. The IDCOR/EPRI steam oxidation model was used in the HCGS calculations.

The user can also control release of tellurium by setting a flag in the parameter file. When this flag is set, as was done in the HCGS MAAP calculations, the tellurium is assumed to be alloyed with the unoxidized zirconium in the core to form a zirconium telluride. This compound is quite stable and is, therefore, not released during core degradation. Consequently, no in-vessel release of tellurium is calculated by MAAP. If zirconium telluride formation is neglected, MAAP calculates nearly complete release of the tellurium during core degradation. While some tellurium will almost certainly react with zirconium, complete reaction does not seem credible. Because it was felt that neither of these limiting cases are realistic, values for tellurium release were taken from the NUREG-1150 expert elicitation documented in NUREG/CR-4551.

4.2.4 Melt Expulsion from the Reactor Vessel

MAAP models both high and low pressure expulsion of core material from the vessel. For low pressure expulsion, the code assumes that the core debris exits the reactor vessel and falls into the pedestal region. For high pressure expulsion, the debris is assumed to be entrained by the exiting gas stream and dispersed if the gas flow velocity exceeds a critical value.

Experiments (Reference 4.2-13) have shown that high pressure expulsion of molten material can lead to rapid pressurization of the containment atmosphere. This pressurization occurs due to the rapid heat transfer from, and oxidation of, the finely fragmented molten material. These phenomena are commonly referred to as DCH. The BWR version of MAAP 3.0B does not treat DCH phenomena during high pressure melt expulsion from the vessel. For that reason, DCH was treated in the HCGS CET by a separate analysis utilizing the results from NUREG/CR-4551 (Reference 4.2-5). Based on this analysis, DCH was determined to increase the magnitude of the hydrogen production at vessel breach. The probabilities of early containment failure were also determined to be higher for sequences with high pressure melt expulsion from the vessel that would be calculated using the MAAP results alone.

4.2.5 Fuel-Coolant Interactions

MAAP does not model explosive interactions between the core debris and the coolant within the reactor vessel or the pedestal region. The code does, however, treat rapid vapor formation following addition of molten core debris into a pool of water. Under these conditions, the steam generation rate is assumed to be governed by hydrodynamic flow limitations. The resulting high steam production rates lead to a pressure spike in the containment that is quickly relieved as the steam condenses. This so-called "steam spike" is considered in the pressure rise estimates used in the HCGS CET.

Explosive fuel-coolant interactions were considered in the CET by including probabilities for reactor vessel failure, drywell failure and containment failure due to these interactions. The probabilities assumed for these events were taken from NUREG-1150 and NUREG/CR- 4551 (Reference 4.2-3 and 4.2-6).

4.2.6 Ex-Vessel Debris Coolability

As discussed in the next section, much of the ex-vessel radionuclide release results from molten core-concrete interactions in the reactor pedestal and on the drywell floor. This is especially true of radionuclides such as tellurium and strontium that are not released to a significant extent during in-vessel processes. If the core debris is cooled by water in the pedestal, core-concrete interactions will be prevented and release of these radionuclides will be minimal.

With the default modeling parameter values, MAAP assumes that heat transfer from the core debris to the coolant is at the flat plate critical heat flux. At this high heat transfer rate (~1 MW/m^2) the core debris is nearly always coolable whenever water is present. This result has not yet been validated by comparison to experiments and has, in fact, been contradicted by some experiments (References 4.2-14 and 4-2-15). Because of this, other views of ex-vessel debris coolability were considered in the quantification of the HCGS CET. The result of this assessment was that the core debris may or may not be coolable depending on the availability of water and the extent of debris dispersal.

4.2.7 Molten Core-Concrete Interactions and Drywell Shell Failure

Once the core debris exits the reactor vessel and falls to the pedestal floor, it can begin to interact with the concrete in the pedestal. When heated by the core debris, the concrete releases steam and carbon dioxide which can then react chemically with the core debris to produce the flammable gases, hydrogen and carbon monoxide. These gases contribute to the potential for the gradual overpressurization of the containment and to the flammable gas combustion in the secondary containment. Since the temperature of the core debris is significantly above the melting temperature of the concrete, ablation of the concrete in the pedestal also occurs.

MAAP calculates gas release from the concrete, concrete ablation, and flammable gas production. The MAAP results were used in the evaluation of the probabilities for flammable gas combustion in the secondary containment and late containment failure due to overpressurization.

Substantial radionuclide release also occurs during core-concrete interactions. Release of refractory radionuclides, such as tellurium and strontium, are particularly significant since these radionuclides are not released to a significant degree during in-vessel core degradation. The MAAP results were used in the evaluation of radionuclide release during core-concrete interactions.

Depending on the extent to which the core material spreads across the drywell floor, it may reach the steel drywell liner. Debris contact with the drywell liner may lead to failure of the liner either by melt-through or structural failure (i.e., creep-rupture at high temperatures). EPRI currently recommends that, due to uncertainties in liner failure phenomena, the NRC staff view be used. Hence, PSE&G has addressed this issue based on analyses of the Peach Bottom Atomic Power Station published in NUREG/CR-4551 and, more recently, in NUREG/CR-5423 (Reference 4.2-16).

4.2.8 Flammable Gas Combustion

Because the HCGS primary containment is normally inerted, flammable gases generated during core degradation and core-concrete interactions can only burn within the secondary containment or if the containment atmosphere becomes de-inerted. Combustion of these gases can result in rapid pressurization and failure of the Reactor Building.

MAAP models local or global deflagrations within the Reactor Building control volumes and can calculate continuous burning of a high temperature gas jet as it enters an air environment (e.g., in the secondary containment following containment failure). The code calculates combustion if the required flammability limits are exceeded. The flammability limits are based on the relative concentrations of flammable gases, oxygen, and "inert" gases (e.g., nitrogen and steam). If these limits are exceeded, MAAP calculates combustion completeness based on the size of the compartment and the calculated flame velocity. The combustion completeness determines the magnitude of the energy addition to the compartment and the depletion of the flammable gas concentration.

The MAAP results were used in the CET for determining the probability of secondary containment failure. (In this context, "failure" implies low retention of fission products. Structural failure of the secondary containment was not a principal concern.) Because of the enhanced gas flow from the secondary containment during a burn, the effect of hydrogen combustion on radionuclide transport from the secondary containment to the environment was also considered in the CET.

4.2.9 Primary and Secondary Containment Failure

Failures of the primary containment and secondary containment were treated in the MAAP analysis through specification of temperature-dependent failure pressures and failure sizes. All significant containment failure modes were modeled in the calculations. A more detailed discussion of containment failure is provided in Section 4.4.

4.2.10 Radionuclide Revolatilization From the Primary System

Revolatilization of radionuclides initially trapped within the primary system can be a significant contributor to late release from the containment. MAAP evaluates revolatilization by calculating the temperature of primary system structures and the rate of mass transport from the structures to the adjacent gas stream. The code neglects chemical interactions between the trapped radionuclides and structural materials. Neglecting these interactions may be highly conservative, since radionuclides such as cesium are known to form stable compounds with structural steel (Reference 4.2-17). Since an adequate basis for using less conservative values could not be established, the conservative revolatilization fractions calculated by MAAP were used in the HCGS source term analysis.

4.2.11 Fission Product Transport Within the Containment

MAAP assumes that radionuclides are transported between compartments along with transported gases. Radionuclide vapors form aerosols by vapor condensation. These aerosols agglomerate in the compartment atmosphere to form larger aerosol particles. Within a compartment, aerosol deposition is calculated by gravitational settling, diffusiophoresis (i.e., deposition driven by steam condensation), thermophoresis, and impaction. Aerosol removal by sprays is determined using a droplet-aerosol collision efficiency determined from experiments. As discussed earlier, MAAP also calculates revolatilization of deposited radionuclides as structures are heated.

Deposition of radionuclides on primary system surfaces is considered in the HCGS source term algorithm using a vessel decontamination factor. Similarly, radionuclide deposition in the primary and secondary containment were modeled using the corresponding decontamination factors for these volumes. These decontamination factors were calculated from the MAAP results.

4.2.12 Aerosol Scrubbing by Water Pools

MAAP calculates aerosol removal in the HCGS suppression pool using correlations based on results calculated using the SUPRA code (Reference 4.2-18). The SUPRA results are implemented in the form of tables for the functional dependence of the removal rate on: (1) the aerosol particle size, (2) the steam mass fraction in the rising bubbles, (3) the submergence of the T-Quenchers and wetwell vents, (4) the subcooling of the water pool, and (5) the ambient pressure. The MAAP results for T-Quencher DFs are used to define the decontamination factor for early suppression pool scrubbing while the calculated vent DFs are used for late suppression pool scrubbing.

4.2.13 Miscellaneous Assumptions and MAAP Sensitivity Studies

Each room in the secondary containment of the HCGS is supplied by a fire extinguishing mechanism consisting of either fire sprays or CO_2 fire suppression. However, not every room is equipped with the sprinkler system. Because of this, it was decided that the beneficial effects of the Reactor Building fire sprays in scrubbing fission products would not be considered in the MAAP analyses or in the CET. Similarly, the CO_2 fire suppression system was not modeled.

Prior to installation of the 12" containment hard pipe vent, the HCGS EOPs directed operators to cycle the containment vents between the PCPL, about 65 psig, and 60 psig. However, this cycling frequency was relaxed to allow the operators to open the containment vent at the PCPL, and to maintain the containment pressure below 60 psig. Therefore, the EOP provides the flexibility to assess the probability of continued vent path operability in making the decision to isolate the vent. The basis for this relaxation was a sensitivity analysis, performed using MAAP, to compare the number of containment vent cycles between the PCPL and 60 psig, versus cycling between 62 psig and 25 psig. The 25 and 62 psig setpoints were used as an example to determine the sizing of the accumulators for the hard pipe vent isolation valves. The reduction in cycling of the vent valve with the 25/62 psig setpoints, as shown in Figure 4.2-2, indicates that the burden on both the equipment and the operators would be much less with the relaxed cycling frequency. However, this operation of the vent will not always result in the minimum offsite release. All base case MAAP runs, which assume vent cycling, for the back-end IPE analyses assume cycling setpoints of 25 and 60 psig.

Multiple MAAP cases were studied for each Level II initiating event to circumscribe all possible accident progressions. As is described in section 4.3, the initiating events fell into five categories: LT-SBO, TW, LOCA, ATWS and other transients.

With the exception of the TW (loss of decay heat removal) sequences, the base cases for all the Level II initiating events assumed that loss of injection to the reactor occurred at the start of the calculation; this assures reactor vessel failure. For the TW sequences, loss of injection was assumed to occur when the reactor repressurized due to pressurization of the containment. Events that would lead to containment failure were investigated in detail. For the SBO, sensitivity cases were performed to determine the effect of the "core blockage" option on hydrogen production. The effects of late injection to the vessel, drywell sprays, and containment venting on accident progression were studied for all Level II initiating events. The effects of liner melt-through on Reactor Building failure and fission product release were investigated for an SBO case, with no injection to the reactor vessel or the drywell.

4.2.14 Summary

In the preceding discussion, a brief summary of the models in the MAAP code and how they were used in quantification of the HCGS CET was provided. For cases in which the MAAP models were felt to be inadequate, supplemental analyses were briefly described. Additional discussion of the MAAP analysis, human reliability analysis, containment failure evaluation, and source term assessment are provided in Sections 4.6 and 4.7.

4.2.15 References

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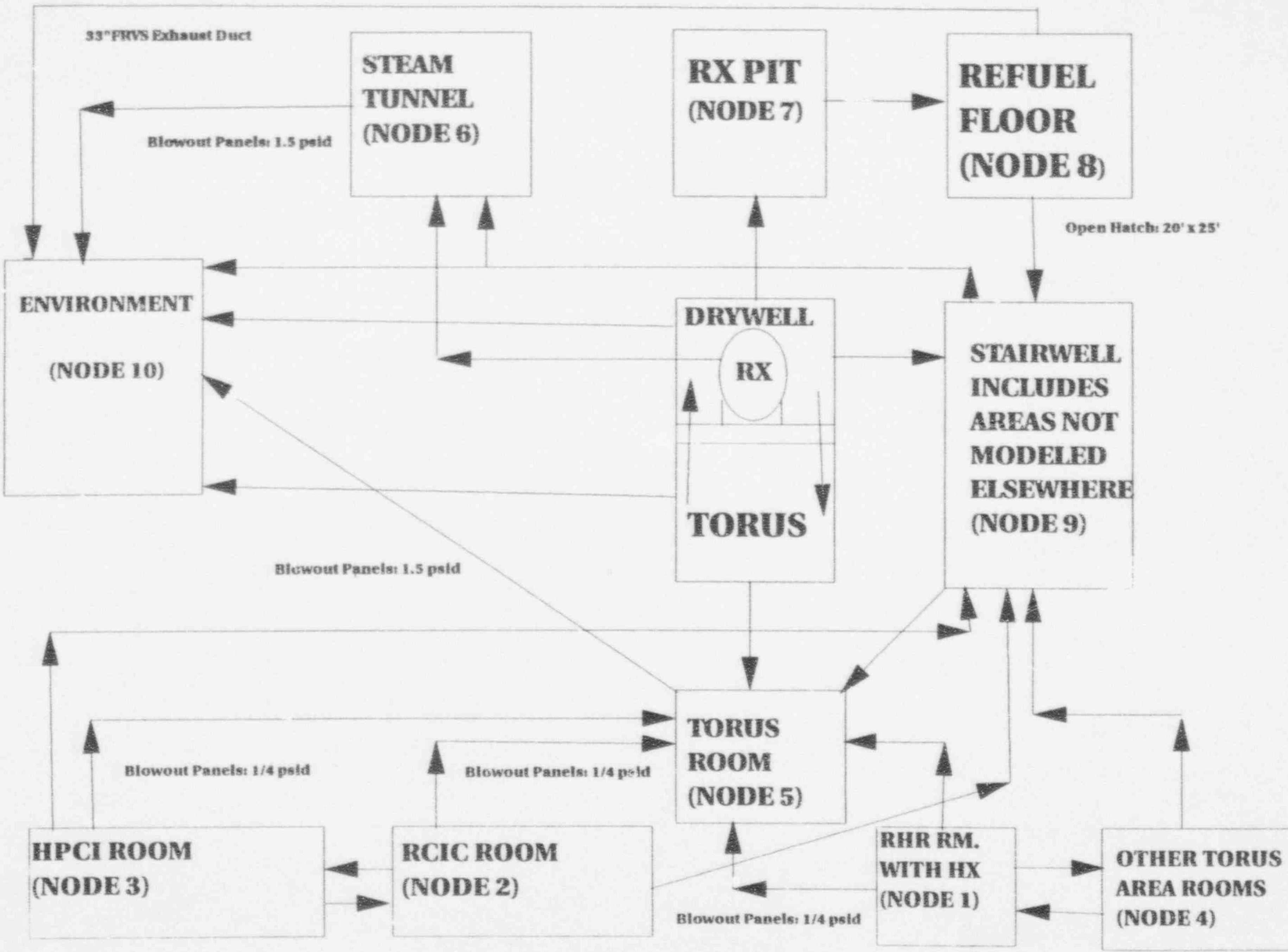

Figure 4.2-1. HCGS RX BUILDING ACCIDENT PATHWAYS

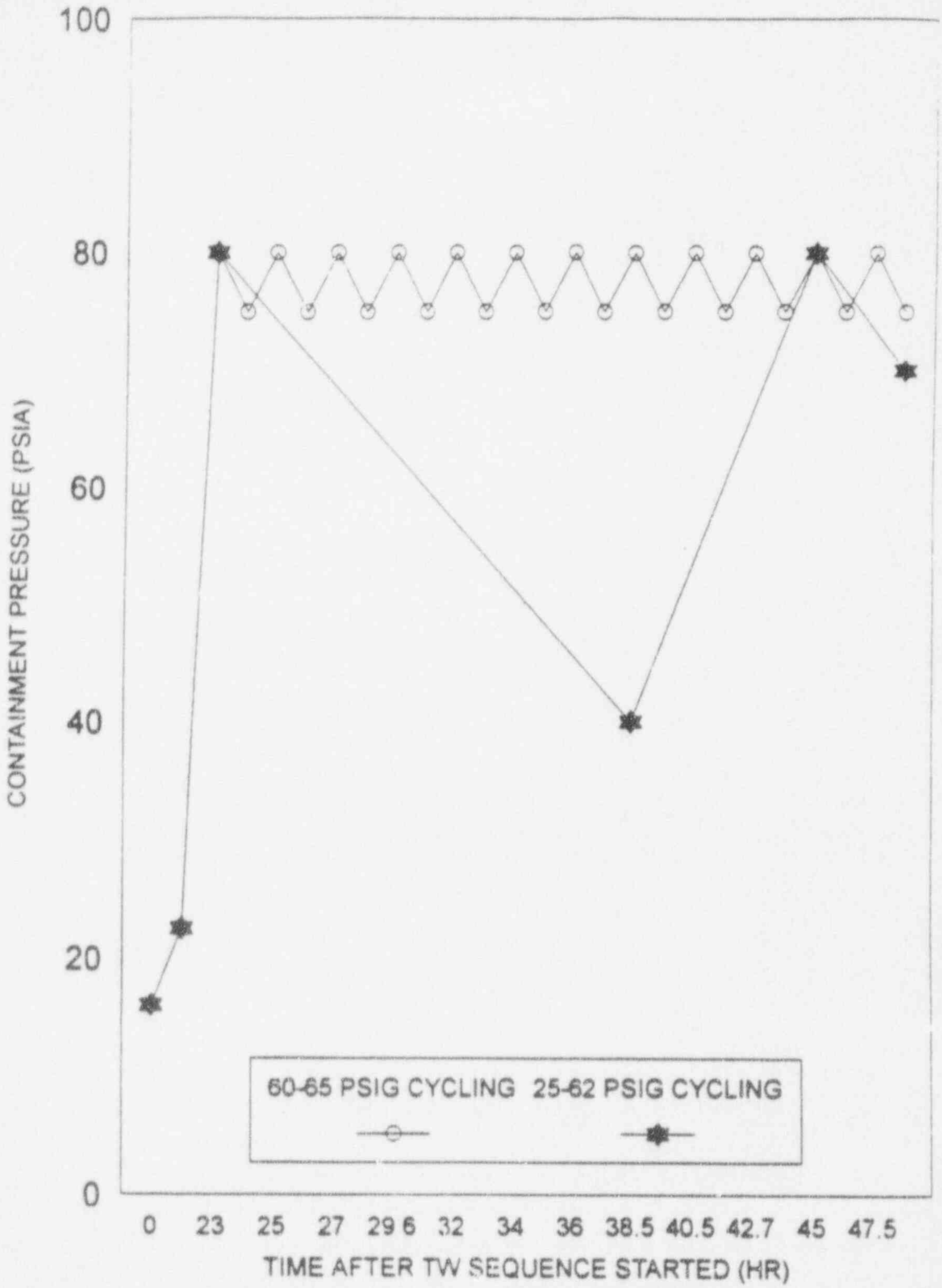

Figure 4.2-2. Example of HCGS TW Sequence

4.3 LEVEL I - LEVEL II INTERFACE

To proceed with the Level II portion of the HCGS IPE, it is necessary to determine plant damage states (PDSs) that are relevant to the Level II. The Level II PDSs are groups (or bins) that combine sequences that present similar initial and boundary conditions to the Containment Event Tree (CET) analysis. To establish plant damage states for the Level II analysis, Level I sequences were grouped based on system, function or component failures that had the potential to impact the CET results.

4.3.1 Summary of Front End Analysis

The front end analysis involved construction of functional event trees to delineate the potential accident sequences for each initiating event, including special initiators. Fault tree models for both the front line (e.g., low-pressure core spray, reactor protection) and support (e.g., electric power, service water) systems were developed. A fault tree linking approach was used to evaluate the frequency of sequences leading to core damage. Approximately 81 sequences were found to be greater than 10×10^{-10}/yr. The frequencies of these sequences ranged from 3.27×10^{-5}/yr down to 1.4×10^{-10}/yr.

As is typical for BWRs, the core damage results were dominated by transient-initiated sequences involving failures of a support system (i.e., AC power or service water). Sequences initiated by primary system breaks and failure to scram (ATWS) also contributed; however, their contribution to the core damage frequency (CDF) was relatively small.

To prepare for the Level II binning, the Level I cutsets were grouped into characteristic sequences based on the initiating events and system functional availabilities. Seventeen characteristic Level I sequences were developed based on the screening criteria provided in Section 2.1.6 of NUREG-1335. Specifically, they account for greater than 95% of the CDF, and include all sequences with greater than a 1.0×10^{-7} frequency. The 17 dominant sequences are listed in Table 4.3-1.

4.3.2 Plant Damage State Binning

The Level II binning criteria were developed based on the criteria applied in the NUREG-1150 analysis of Peach Bottom Unit 2 (References 4.3-1 and 4.3-2). These criteria are reflected in the logic models that constitute the EPRI Generic Methodology (Reference 4.3-3) and in the logic models that support the HCGS CET (described in Section 4.5).

The binning criteria include all system and component failures that could affect accident progression and containment response. The criteria used in the Level II binning are shown in Table 4.3-2. Based on these criteria, vectors containing the sequence characteristics were developed. For example, sequence Te34 - a station blackout sequence (SBO) with a frequency of 3.27×10^{-5} had cutsets that fell into the following three categories (or vectors):

- LOSP-B-DC-RX1-I2-C2-R2-CS2-V2-FR2-DT (53.7%)

- LOSP-B-DC-RX1-I2-C3-R1-CS1-V2-FR1-DT (44.5%)

- LOSP-RX2-I2-C4-R2-CS2-V2-FR2-DT (1.8%)

Therefore, these vectors indicate that of all the cutsets within the Te34 sequence, 53.7% fell into the first category, 44.5% fell into the second category and 1.8% fell into the last category. The same methodology was applied to all 17 of the sequences. The results of this categorization are shown in Table 4.3-3. With the percentage splits shown in the table, there are 35 unique vectors representing 35 unique combinations of binning criteria. These combinations represent 35 unique PDSs. All 35 PDSs are represented explicitly in the Level II analysis; however, for reporting purposes, results are provided only by initiator.

The initiators considered in the HCGS Level II are: LT-SBO, transients with loss of RHR (TW), other transients, medium to large LOCAs, and ATWS (Table 4.3-4). The criteria used for selection of the initiators were as follows:

- All vector(s) within Total Loss of HVAC sequence and the two SBO sequences were binned into the LT-SBO initiator; total loss of HVAC will lead to loss of power. Furthermore, all vectors which had total loss of DC power were also grouped in this initiator.

- All vectors within the three medium break LOCA sequences and the Large LOCA sequence were binned into the LOCA initiator.

- Of all the transient vectors, the ones that had failure of the RHR were binned into the TW initiator and the rest were grouped into the Transients initiator.

- All vectors within the two ATWS sequences were binned into the ATWS initiator. Hence, the ATWS vectors with SBO were also grouped in this initiator.

Note that there were no short term station blackout or small break LOCAs that met the screening criterion of 1.E-7 that was applied to the Level I sequences.

The TW sequence is separated from other transients because failure of RHR typically leads to more severe containment threats, and consequently greater radionuclide release to the environment than for transients without RHR failure. It is useful, therefore, to focus attention on the TW sequences, and their sensitivity to assumptions in the CET

4.3.3 References

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TABLE 4.3-1 DOMINANT SEQUENCES CONSIDERED FOR HCGS LEVEL II BINNING

SEQUENCE		FREQUENCY	SEQUENCE DESCRIPTION
1.	Te34 (TeEDG)	3.2679E-005	LOP with loss of EDGs (batteries ok for 4 hrs).
2.	Tf18 (TfU1U2X)	2.7566E-006	Loss of: FW, HPCI, RCIC & Depressurization.
3.	Tm12 (TmUX)	1.0470E-006	Loss of HPCI & RCIC with failure to Depressurize.
4.	S103 (S1WUV)	1.0359E-006	Medium break LOCA and loss of both decay heat removal and long term cooling.
5.	Tt13 (TtQUX)	1.0343E-006	Turbine trip with loss of FW, HPCI & RCIC & failure to depressurize.
6.	S113 (S1U1X)	9.9570E-007	Medium break LOCA, loss of HPCI & RX not depressurized on time.
7.	Thv01 (Thv)	9.8736E-007	Loss of HVAC.
8.	Te36 (TeEDGP)	9.6715E-007	LOP and Loss of EDGs, along with an SORV.
9.	Tf06 (TfQRWW1Uv)	5.2964E-007	Loss of : FW, FW recovery, cont. heat removal, vent & long term makeup.
10.	Ti19 (TiQUX)	5.2884E-007	IORV, loss of FW, loss of HPCI & RCIC & failure to depressurize.
11.	Tat26 (TatC2)	5.0747E-007	Turbine trip ATWS, with failure of SLC.
12.	Tt12 (TtQUV)	3.9697E-007	Turbine trip with loss of: FW, HPCI/RCIC and LPCI/CS/Condensate
13.	S114 (S1D)	3.0000E-007	Medium break LOCA & failure of vapor supp system.
14.	Tss04 (TssW1Uv)	2.9846E-007	Loss of SW/SACS, failure of containment vent and long term makeup.
15.	A03 (AWUv)	2.0736E-007	Large LOCA, loss of both cont. heat removal & long term makeup.
16.	Tt35 (TtPP2WUv)	1.7924E-007	Turbine trip with 2 SORVs and failure of both cont. heat removal & long term makeup capability.
17.	Ta14 (TaCmC2)	1.1898E-007	MSIV closure ATWS, RPS mech. failure and loss of SLC.

TABLE 4.3-2 PDS BINNING CRITERIA FOR LEVEL I/LEVEL II INTERFACE

CRITERIA	VECTOR IDENTIFIER	POSSIBLE ANSWERS
Initiating Event:	L	LOCA.
	T	Transient.
RX Subcriticality Status:	C	RX is Critical.
Offsite AC power status:	LOSP	LOP.
Onsite AC power status:	B	SBO.
DC power status:	DC	Loss of all DC.
SRV status:	P	1 or more SORV.
Pressure suppression system status:	R	SRV tailpipe rupture.
RX vessel pressure status:	RX1	RPV at hi press, at the onset of core damage & depressurization is not possible.
	RX2	RPV at hi pressure at the onset of core damage, but can be depressurizaed.
	RX3	RPV is at low pressure.
Injection Status:	I1	Injection is not recoverable after the core damage.
	I2	Some injection with either high or low press systems is recoverable after onset of core damage.
CRD Status:	C1	CRD is not injecting into vessel and is not recoverable
	C2	CRD is not injecting, but is recoverable.
	C3	CRD has failed.
	C4	CRD is injecting.
RHR Status:	R1	RHR not available, nor recoverable.
	R2	RHR is available or recoverable.
Cont. spray status:	CS1	Spray not available nor recoverable.
	CS2	Sprays available or recoverable.
Cont. venting status:	V1	Containment vented.
	V2	Containment venting possible.
	V3	Containment venting not possible.
Cont. leakage status:	L	Small containment isolation failure or leakage prior to core damage.
	R	Large containment isolation failure or leakage prior to core damage.
Leakage location:	L1	Drywell.
	L2	Drywell head.
	L3	Wetwell.
FRVS Status:	FR1	FRVS not available, nor recoverable.
	FR2	FRVS is available or recoverable.
Timing:	IT	Core damage occurs within one hour.
	ST	Core damage occurs within one to 4 hrs.
	DT	Core damage occurs within 4 to 24 hours.
	LT	Core damage occurs after 24 hours.

TABLE 4.3-3 CHARACTERIZATION OF LEVEL I SEQUENCES FOR LEVEL II PDS BINNING

Sequences From Level I	Freq-uency	Time to CD	Initia-ting Event	RX Sub-criti-cal Status	Off-site AC Status	On-site AC Status	DC PWR Status	SRV Status	Torus Status	RPV Status	INJ Status	CRD Status	RHR Status	Cont Spray Status	Cont. vent status	Cont leak Status	FRVS Status	Tim-ing
1-Te34 (TeEDG)	3.2679E-005	6 hrs	T	----	LOSP	B 98.23% (Note 1)	DC 100%	----	----	RX1 98.23% RX2 1.77% (Note 2)	I2[3,4,5], 55.4% I2[1] 100%.	C2 53.7%, C3 44.6% C4 1.7%	R2 51.65%, R1 41.5%	CS2 55.5%, CS1 44.5%	V2	----	FR2 55.5%, FR1 44.5%	DT
2-Tf18 (TfU1U2X)	2.7566E-006	1 hr	T	----	----	B 24.3%	DC 24.3%	----	----	RX1 24.3%, RX2 75.7%	I1 24.3%, I2[1] 75.7%	C3 24.3%, C4 75.7%	R1 24.3%, R2 75.7%	CS1 24.3%, CS2 75.7%	V2	----	FR1 24.3%, FR2 75.7%	IT
3-Tm12 (TmUX)	1.0470E-006	1 hr	T	----	----	B 23.6%	DC 23.6%	----	----	RX1 23.6%, RX2 76.4%	I1 23.6%, I2[1] 76.4%	C3 23.6%, C4 76.4%	R1 23.6%, R2 76.4%	CS1 23.6%, CS2 76.4%	V2	----	FR1 23.6%, FR2 76.4%	IT
4-S105 (S1WUV)	1.0359E-006	18 hrs	L	----	----	B 99.4%	----	----	----	RX3	I1 99.4%, I2[4] .6%	C3	R1	CS1	V2	----	FR2	DT
5-Tt13 (TtQUX)	1.0343E-006	1 hr	T	----	----	B 49.44%	DC 18.34%	----	----	RX2 73.7%, RX1 18.34%	I2[1] 73.7%, I1 18.34%	C3 53.7%, C4 46.3%	R1 53.7%, R2 46.3%	CS1 49.4%, CS2 42.6%	V2	----	FR1 19.9%, FR2 80.1%	IT
6-S113 (S1U1X)	9.9570E-007	40 min	L	----	----	B .56%	DC .56%	----	----	RX2 99.5%, RX1 .5% (100% RX3 by vessel failure)	I1 .56%, I2[1&3] 99.44%	C4 99.44%, C1 .56%	R2 99.44%, R1 .56%	CS1 99.44%, CS2 .56%	V2	----	FR2	IT
7-Thv01 (Thv)	9.8736E-007	12 hrs	T	----	----	B	DC	----	----	RX1	I1	C3	R1	CS1	V2	----	FR1	DT
8-Te36 (TeEDGP)	9.6715E-007	6 hrs	T	----	LOSP	B	DC	P	----	RX3	I2[6]	C2 57.6%, C3 42.4%	R2 57.6% R1 42.4%,	CS2 57.6% CS1 42.4%,	V2	----	FR2 57.6%, FR1 42.4%	DT
9-Tf06 (TfQRWW1Uv)	5.2964E-007	24 hrs	T	----	----	B 16.7%	----	----	----	RX1	I2[1]	C3	R1	CS1	V3	L	FR2	DT 23.1%, LT 76.9%

1- I2 IS DUE TO CORE SPRAY SYSTEM.
2- I2 IS DUE TO CS, CONDENSATE PUMPS AND HPI, IN THE SHORT RUN.
3- I2 IS DUE TO CRD.
4- I2 IS DUE TO SW PUMPS.
5- I2 IS DUE TO EITHER CS, RHR OR COMBINATION OF BOTH.
6- I2 IS DUE TO EITHER HIGH PRESSURE OR LOW PRESSURE INJECTION.

Notes: 1) 1.77% of the time the DC buses have failed.
2) RX is depressurizable, if DC is recovered.

TABLE 4.3-3 CHARACTERIZATION OF LEVEL I SEQUENCES FOR LEVEL II PDS BINNING (Continued)

Sequences From Level I	Freq-uency	Time to CD	Initiating Evnt	RX Sub-critical Status	Off-site AC status	On-site AC Status	DC PWR Status	SRV Status	Torus Status	RPV Status	INJ Status	CRD Status	RHR Status	Cont Spray Status	Cont. vent status	Cont leak Status	FRVS Status	Timing
10-Ti19 (TiQUX)	5.2884E-007	40 min	T !ORV	------	------	------	DC 17.2%	P	------	RX2 82.8%, RX1 17.2%	I2[1] 82.8%, I1 17.2%	C3 49.61%, C4 50.39%	R2 82.8% R1 17.2%,	CS2 82.8% CS1 17.2%,	V2	------	FR2 82.8% FR1 17.2%,	IT
11-Tat26 (TatC2)	5.0747E-007	Within 1/2 hr to 4 hrs	T	C	LOSP 2.95%	B 2.95%	------	------	------	RX2 97.05%, RX1 2.95%	Assume no injection is possible.	C4 97.05%, C3 2.95%	R2 97.05%, R1 2.95%	CS2 97.05%, CS1 2.95%	V2 97.05%, V3 2.95%	L 2.95%	FR2 97.05%, FR1 2.95%	IT 14.25%, ST 85.75%
12-Ti12 (TiQUV)	3.9697E-007	1 HR to 4 HRs	T	------	------	------	------	------	------	RX1	I2[4]	C4 66.67%, C3 33.33%	R2 FOR SPC & CSC	CS2	V2	------	FR2	IT
13-S114 (S1D)	3.0000E-007	< 1 HR	L	------	------	------	------	------	R	RX2	I2[2]	C4	R1	CS1	V3	L	FR2	IT-LT
14-Taa04 (TaaW1Uv)	2.9846E-007	> 24 hrs	T	------	------	B	------	------	------	RX1	I2[3]	C3	R1	CS1	V3	L	FR2	DT
15-A03 (AWU:)	2.0736E-007	18 hrs	L	------	------	B	------	------	------	RX3	I1	C3	R1	CS1	V2	------	FR2	DT
16-Ti35 (TiPP2WUv)	1.7924E-007	18 hrs	T	------	------	B	------	P	------	RX3 75.04%, RX1 24.96%	I1	C3	R1	CS1	V1 75.04%, V3 24.96%	------	FR2	DT 75.04%, LT 24.96%
17-Ts14 (TsCmC2)	1.1898E-007	Within 1/2 hr to 4 hrs	T	C	LOSP 2.7%-	------	------	------	------	RX1 26.47%, RX3 67.4%, RX2 6.13%	Assume no injection is possible.	C4	R2	CS2	V2 96.42% V3 3.58%	L 2.31%, R 1.273%	FR2	ST 96.42%, IT 3.58%

1- I2 IS DUE TO CORE SPRAY SYSTEM..
2- I2 IS DUE TO CS, CONDENSATE PUMPS AND HPI, IN THE SHORT RUN.
3- I2 IS DUE TO CRD.
4- I2 IS DUE TO SW PUMPS.
5- I2 IS DUE TO EITHER CS, RHR OR COMBINATION OF BOTH.
6- I2 IS DUE TO EITHER HIGH PRESSURE OR LOW PRESSURE INJECTION.

Table 4.3-4 Initiators Considered in the HCGS Level II

Initiator	Frequency
LT-SBO	3.46E-5
Other Transients	4.39E-6
LOCA	2.54E-6
TW	2.38E-6
ATWS	6.24E-7

4.4 CONTAINMENT FAILURE CHARACTERIZATION

This section describes the assessment of containment performance in response to postulated severe accident loads. The full range of potential loads, including static pressurization, elevated temperatures, and dynamic loads resulting from energetic phenomena (e.g., fuel-coolant interaction) have been considered. The objective of this assessment was the characterization of the potential containment failure modes. Determination of the timing of failure relative to the predicted progression of accidents was the principal focus. Failure location, and the corresponding pathway for fission product release to the secondary containment or environment was also a primary consideration. It is recognized that the rate at which fission products released during an accident escape from the containment can have a significant effect on the magnitude of the overall releases. Thus, an assessment of the size of induced failures was also undertaken.

4.4.1 Primary Containment Structural Analysis

A detailed evaluation of the fragility of the HCGS containment has been undertaken (Reference 4.4-1). A complete structural analysis of the primary containment was performed. This analysis was limited to the consideration of quasi-static pressurization. Potential failure locations were identified and analyzed in detail. These locations included:

(1) Drywell shell;
(2) Drywell head flange;
(3) Vent lines from the drywell to the suppression pool;
(4) Torus shell (wetwell);
(5) Drywell equipment hatch;
(6) Drywell personnel airlock;
(7) Control rod drive (CRD) removal hatch; and
(8) Piping penetrations.

Selected failure locations were analyzed to determine the mean failure pressure. Failure pressure was defined as the internal static pressure that leads to incipient leakage at that location. It was assumed that the failure probability was lognormally distributed as a function of pressure according to the following expression:

$$P_f = Prob\ (P \le p) = \Phi \left[\frac{\ln\left(p / \hat{P}\right)}{\beta_c} \right]$$

where,

P_f = probability that failure occurs at a pressure $P \le p$
P = random pressure capacity

β_c = logarithmic standard deviation of P

$\hat{P}$ = median pressure capacity

$\Phi(\cdot)$ = cumulative distribution function for a standard random variable

A lognormal distribution was assumed because it is mathematically tractable and has been shown to adequately describe the measured variability in the strengths of materials. In addition, when a variable is expressed as the product and quotient of several randomly distributed variables, as is the containment failure pressure, its distribution tends to be lognormal regardless of the distribution assumed for the random variables. The logarithmic standard deviation for the failure pressure at each location was calculated considering both uncertainty in the modeling of failure pressure and the uncertainty in material properties. This latter contribution to the uncertainty leads to an increase in β_c with increasing temperature. The effect of greater uncertainty in the strength of structural materials has little impact on the results. Failure modes that result from the failure of elastomer seals undergo a severe reduction in mean failure pressure in the temperature range from 400 to 600°F. Figure 4.4-1 summarizes the results of Reference 4.4-1 in terms of the mean failure pressure. The results shown in the figure suggest that containment failure modes are similar in the range from 200 to 400°F. Above 600°F, there is also little change in the anticipated failure modes. There are, however, significant differences between these two regimes.

Based on MAAP calculations, the containment temperature prior to vessel breach is in the lower range. Following vessel breach it rises rapidly to values in the higher range. Therefore, the discussion of the results of the containment fragility analysis will focus on the evaluations at 200°F and 600°F as being representative for the before-vessel-breach and after-vessel-breach regimes, respectively.

Figure 4.4-2 presents the fragility curves for the dominant failure modes at 200°F. The arrow in the figure indicates the median failure pressure (i.e., equal confidence that failure will occur above this pressure as below this pressure). That pressure is approximately 120 psig. The total failure probability is also plotted in the figure. The almost complete overlap of the line indicating total failure probability and that indicating the probability of failure at the drywell head flange indicates that the latter failure mode dominates the results. Other failure modes contribute only above the ninetieth percentile of the failure distribution for the drywell head flange. Based on the figure, this means that the flange would have to survive to between 145 and 150 psig before there would be any significant likelihood of a different failure mode. Based on these results, the maximum probability of wetwell failure was determined to be 0.02 given that some failure has occurred. A value of 0.1 was used in the CET analysis. This higher value reflects potential uncertainties arising from the analysis approach of Reference 4.4-1.

The conclusion from these results is that failure of the drywell head flange predominates containment failure modes prior to vessel failure.

Figure 4.4-3 presents the failure probability distributions for 600°F. Again, the arrow in the figure indicates the median failure pressure. A value of 21 psig is indicated. As for the case with the containment at 200°F, containment failure at elevated temperature is dominated by a single failure mode. This mode is failure of the CRD removal hatch. These results indicate that failure is certain at 40 psig or lower. There is no contribution from torus failure.

The conclusion from these results is that failure of the CRD removal hatch predominates late failures. It is also clear that this leakage will be induced as the drywell temperature rises following vessel failure even without any increase in drywell pressure.

Based on this study, two failure modes are thus relevant for the HCGS containment undergoing quasi-static pressurization. The first is the drywell head flange. This mode of failure may occur if pressures in the containment during the early phase of an accident exceed 73 to 78 psig (i.e., the pressure at which there is high confidence of a low probability of failure (HCLPF) in the 200 to 400°F range). The median failure pressure is in the range from 107 to 120 psig. It is postulated that if failure occurs at this elevated pressure, the "O"-Ring seals in the head flange will be rapidly eroded. Erosion of the seals will enlarge the leakage area to the point that rapid depressurization of the containment would be expected. It is thus assumed that this failure mode will have characteristics similar to a rupture of the containment.

The dominant late failure mode is leakage from the CRD removal hatch. Leak areas due to this failure mode are so small that the containment pressure increase would likely continue. If the pressure is not relieved by this mode, the drywell head flange failure mode would also be induced. As discussed above, this failure would rapidly reduce containment pressure. However, once the pressure is reduced, the containment leaks would maintain the internal pressure at approximately the failure level (15 to 40 psig). In essence, steam and non-condensible gases would leak from the containment as they were generated by the severe accident. This failure mode is classified as a leak in the CET.

4.4.2 Bypass and Isolation Failure Potential

A thorough investigation of potential bypass and isolation failures was conducted. As part of the Level 1 analysis, PSE&G undertook a complete, separate, and independent assessment of the potential for primary system failure through an interfacing system. The results of this study lead to the conclusion that the frequency of such events is negligible for the HCGS. As part of the back-end analysis, a thorough review of all containment penetrations was conducted. Penetrations were identified based on the HCGS Final Safety Analysis Report (FSAR). Lines connecting to the primary system received special attention since the potential for bypass existed. It was concluded that the probability of either containment bypass or containment isolation failure for HCGS was sufficiently small that sequences involving either one had frequencies below the NUREG-1335 screening criteria. This conclusion is consistent with that in the NUREG-1150 assessment of Peach Bottom.

4.4.3 Containment Response to Severe Accident Loads

Temperatures and pressures beyond the containment design basis may accompany postulated severe accidents. The MAAP code was the principal tool used to predict pressure and temperature histories within the containment. These predictions were used in conjunction with the capacity assessments to predict the timing and location of containment failure. Available information from NRC contractor studies of the Peach Bottom and Browns Ferry plants was also considered as part of the assessment of uncertainty in the results obtained based on the MAAP predictions. Loads due to high pressure melt ejection (which are not modeled in the BWR version of MAAP) were also assessed on the basis of NRC contractor studies. The basis for quantifying the probability of containment failure is discussed more completely in Section 4.6. Included in this section is the treatment of the probability of containment failure due to direct contact between the core debris and the drywell shell.

An assessment of the potential for containment leakage through the seals on electrical penetrations was made. The principal conclusion from that assessment was that the electrical penetrations had significantly higher leak resistance at elevated temperatures than either the CRD removal hatch or the drywell head access hatch. Therefore, electrical penetration failure was not included as a distinct failure mode.

Response to the dynamic loading that has been postulated as a possible consequence of fuel-coolant interaction (FCI) within the reactor vessel and on the drywell floor was not explicitly examined. Assessment of the structural capacity of the containment to this phenomena, which involves substantial uncertainty, was considered to be outside the scope of the IPE. Containment failure probabilities for FCI used in the analysis of Peach Bottom for NUREG-1150 were adopted for this study. Since the core and primary containment designs for HCGS and Peach Bottom are essentially similar, this approach was judged to be adequate.

Containment failure due to upward motion of the vessel during blowdown was not considered, since it was judged that vessel thrust forces would be inadequate to cause the vessel to impact the drywell shell. Structural failure of the pedestal leading to tearout of containment penetrations was also not considered in the HCGS CET. This containment failure mode was neglected since lateral spreading of the core debris in the drywell will limit the debris depth in the pedestal, and the extent of lateral concrete erosion. Therefore, it is unlikely that there would be sufficient erosion of the pedestal wall to cause it to collapse.

4.4.4 Containment Response to Other Thermal Loads

The steel drywell shell can fail thermally due to direct contact with the core debris. Though this mode of containment failure is often referred to as drywell shell melt-through, melting of the shell is not a necessary requirement for failure. The shell may also fail structurally when its temperature increases above 1000 to 1200 K.

Two modes of drywell shell failure are considered to be plausible for HCGS. One mode involves containment failure near the surface of the ex-pedestal floor. Failure of the drywell at this location is possible if molten core material flows out of the personnel access doorway in the pedestal, flows across the drywell floor, and directly contacts the drywell shell. Eventually, heat transfer from the core material to the shell may be sufficient to either melt the shell or to increase its temperature to the point where creep rupture can occur. Drywell failure may also occur in the portion of the shell buried in the concrete embedment. This is most likely to occur below the ex-pedestal sump just outside the pedestal access doorway. This sump is likely to fill with molten core material, and ablation of the concrete lining the sump is likely to occur. Since, the bottom of this sump is only 7.4 inches from the drywell shell, direct contact between the core debris and the shell is likely after a relatively short period of concrete ablation. Once contact occurs, thermal failure of the drywell shell is possible from either melting or creep rupture.

4.4.5 Secondary Containment Response to Severe Accident Loads

The Reactor Building at HCGS, as in other Mark I containments, is not designed to withstand high pressure loads. MAAP analyses performed by PSE&G staff have shown that the Reactor Building is likely to fail a few hours after primary containment failure, usually as a result of the pressure increase caused by flammable gas combustion in one or more of the Reactor Building compartments. Failure occurs when one or more of the louvered blowout panels in the Reactor Building (e.g., in the steam vent, or in the steam tunnel) open under differential pressures exceeding 1.5 psid. The blowout panels open to the environment. The FRVS at HCGS will delay or could even prevent the time to Reactor Building failure, if it is fully operational during the accidents.

4.4.6 References

4.4-1. PSE&G Engineering Evaluation No. H-1-GS-MEE-0809, "Hope Creek Generating Station Containment Fragility Analysis," Revision 0.

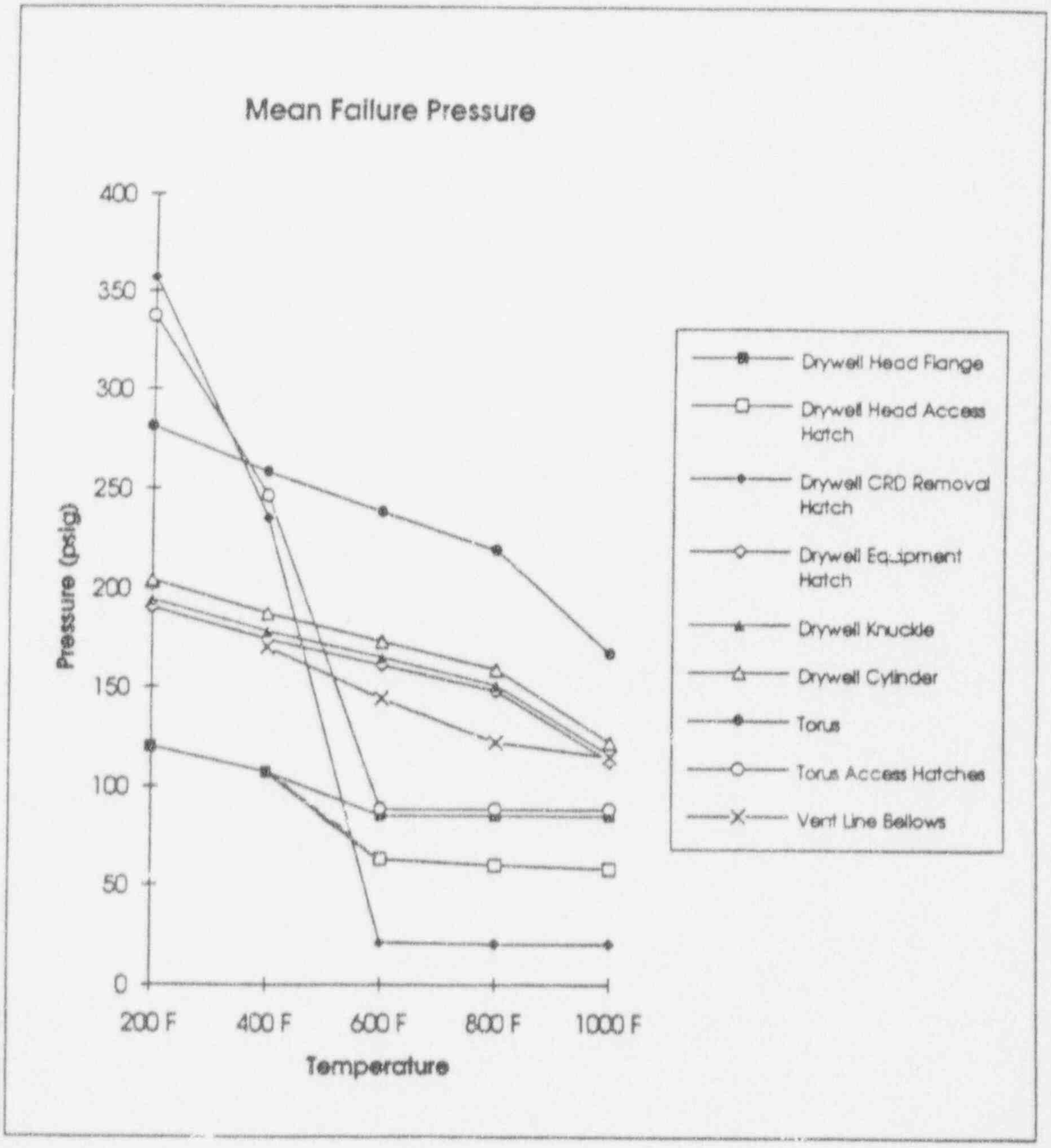

Figure 4.4-1. Mean Pressure Failure

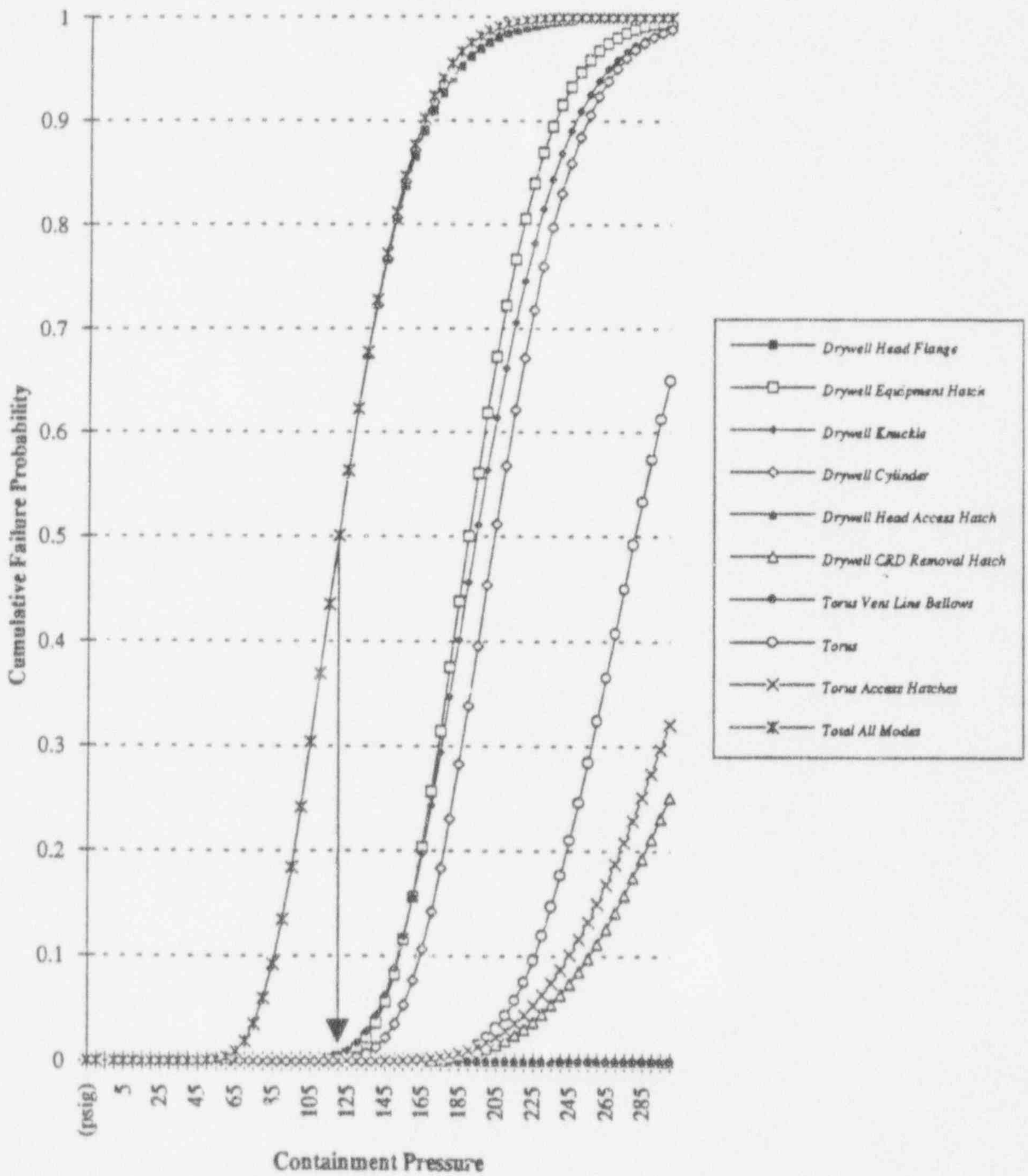

Figure 4.4-2. Containment Failure for 200°F

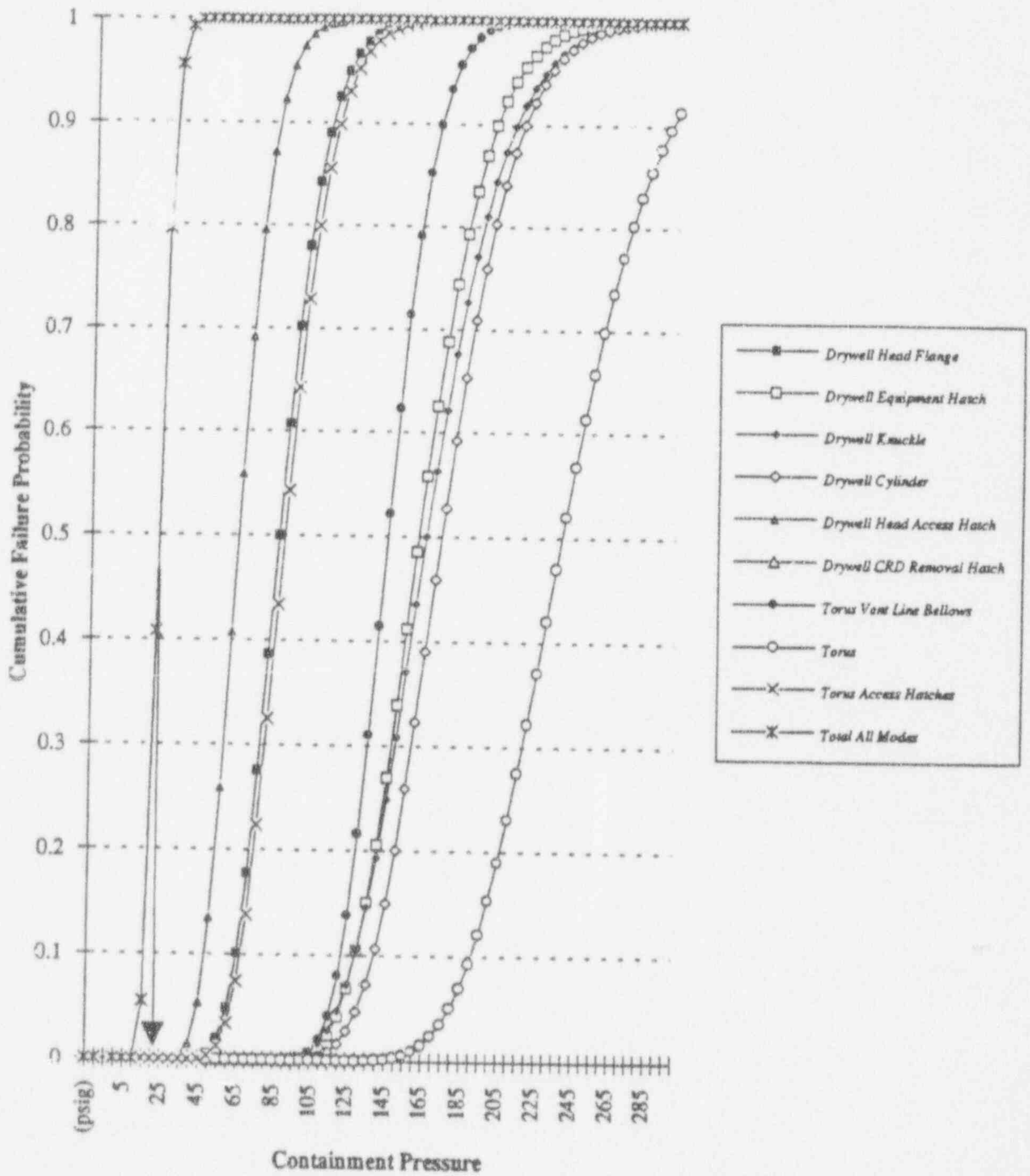

Figure 4.4-3. Containment Failure for 600°F

4.5 HOPE CREEK CONTAINMENT EVENT TREE

The containment performance logic model for the Hope Creek Generating Station (HCGS) has been developed in the form of linked event trees. In this context, the term "linked" means that there are common events among the event trees that have been developed to reflect each aspect of containment response. The dependencies between the event trees that represent the different phenomena considered are fully treated. This is consistent with the EPRI Generic Methodology. However, unlike the EPRI methodology, the fault tree models for the CET top events have been replaced with event tree models. The CETs consider all the relevant events and phenomena included in the EPRI Generic Methodology. The events and phenomena included in the EPRI methodology were identified based on an in-depth review of the analysis of Peach Bottom Unit 2 PRA performed in support of the first draft on NUREG-1150. This includes the phenomena listed in Table 2.2 of NUREG-1335 pertinent to BWRs with Mark I containments. An event tree format has been used to display the logic. There are two motivations for this approach: (1) event trees have historically been applied to back-end analysis and are more amenable to review and (2) the event trees are more flexible and powerful tools for modeling Level II accident sequences in that success paths and dependent probability assignments are more readily handled. The discussion that follows provides a brief summary of the basis for the CETs employed.

4.5.1 Methodology

The HCGS CET differs slightly from that appearing in the EPRI Generic Methodology. Thirteen subtrees, one supporting the quantification of each CET top event node have been developed. Some of the subtrees have sub-subtrees for specific phenomena. These provide the basis for the evaluation of specific top events in the subtrees. The linked subtrees (and sub-subtrees) are solved simultaneously using the EVNTRE software. Graphical display of the results has been provided by reformatting the output of EVNTRE and loading the results into event tree editing software. The event tree figures provided in this document were produced in this manner.

Branch points in the CET are each evaluated based on the subtree model results. The probability assigned to a branch is simply the sum of the probabilities of the subtree end states that correspond to the indicated outcome. A few top events in the subtrees are evaluated in the same manner using sub-subtrees. Branch points in the sub-subtrees, and those in the subtrees not evaluated with sub-subtrees, are evaluated directly by the analyst. These are referred to as basic events in order to emphasize the similarity between this approach and the fault tree linking approach used for the Level I. Evaluation of the basic events is discussed in Section 4.6.

The same CET is applied for each plant damage state (PDS) identified in the Level 2 binning process. The evaluation of the split fractions varies based on the subtree and sub-subtree logic structure. Basic events that reflect the characteristics of all Level 2 PDSs are incorporated directly into the subtrees and sub-subtrees. When these are evaluated as either zero, unity, or a split fraction that has been determined based on the Level I results, the subtree structure is altered. (Assignment of zero or unity to a basic event eliminates the branch point and indicates success or failure, respectively, for the corresponding top event.) This alteration of the subtree structure changes the end state probabilities. The corresponding CET top event probabilities are thus adjusted based on the PDS characteristics. This approach is similar to that used in NUREG-1150 since there is in fact only one CET and the quantification is varied based on the PDS definition. Table 4.5-1 indicates the basic events that reflect the Level 2 PDS characteristics.

4.5.2 Containment Event Tree Structure

Figures 4.5-1A(B, C, D & E) depict the HCGS CETs for each of the level II initiators. A description is provided below. A summary of the top events considered in the supporting subtrees is then provided.

Containment Event Tree Description

The HCGS CET was developed based on consideration of events that have the potential to affect the source term. Both timing as well as magnitude of a release contribute to the source term.

Five initiating events (or more appropriately, accident classes) were identified from the Level 2 binning process. These included: long-term station blackout (LT-SBO), medium to large loss of coolant accidents (LOCA), transients (Trans), Transients with total loss of decay heat removal (TW) and anticipated transients without scram (ATWS). There were no short term station blackouts or small break LOCAs that met the 1.E-7 screening criterion applied during the Level 2 screening processs. Each initiating event is identified by a branch label corresponding to the definitions in Table 4.5-1.

Event 1: Vessel Depressurized (DP)

The question asked in this top event identifies depressurization of the RPV prior to vessel breach. Success in this branch implies that RPV pressure is reduced either through the capability of the operator to depressurize the reactor or through a phenomenological condition that induces RPV depressurization. Conversely, transient accident sequences in which the RPV is at low pressure (through opening the SRVs) may be repressurized if the ADS valves cannot be maintained open. This event node is considered to indicate a potential recovery or mitigating condition during core melt but prior to vessel breach.

For accident sequences with the RPV at high pressure (and low pressure coolant injection initially unable to deliver makeup to the vessel due to the high pressure in the vessel), depressurization of the RPV can mean either of the following:

- The condition that precludes low pressure coolant injection is removed, and coolant makeup is likely to occur; or
- High RPV pressure that could exacerbate containment challenges at vessel breach (such as high pressure melt ejection) is removed.

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"

1

IMAGE EVALUATION TEST TARGET (MT-3)

150mm

6″

This event node directly impacts the likelihood of the subsequent CET event nodes related to in-vessel recovery and early containment challenge. The downward branch in the CET (/DP) represents high pressure sequences while the upward branch (DP) represents low pressure sequences.

Event 2: Injection Recovered In-Vessel (INJ)

The question asked in this top event is related to recovery of coolant injection after core degradation and prior to vessel breach. This event addresses the vessel injection recovery measures that have the potential for arresting core melting and subsequent thermal failure of the reactor vessel. It considers high-pressure injection systems, the possibility of low pressure injection systems working once the RPV is depressurized, and the recovery of injection systems given AC power recovery in station blackout scenarios.

For sequences where the containment is initially intact and the RPV is at pressure, core damage might be induced by lack of coolant makeup due to failure of the high pressure injection systems. However, the low pressure injection systems may be available, but coolant injection is prevented by conditions that preclude pump operation (i.e., RPV pressure exceeding the shut-off head). Once the high pressure condition is removed (as modeled in the previous event node, DP), coolant injection would most likely be recovered. This event considers the possibility of human intervention along with successful recovery of alternative systems that may have failed prior to core damage, but could potentially succeed given additional time for operator action. Success at this branch facilitates core recovery in-vessel, implies fission product scrubbing, and may prevent ultimate containment failure. For sequences involving low RPV pressure (i.e., large LOCAs with failure to provide adequate coolant makeup), success at this event node is not likely, as implied by the accident sequence definition.

This event node directly affects the subsequent event node relative to arresting core melting and precluding thermal failure of the vessel bottom head. The downward branch in the CET (/INJ) represents failure to recover injection in-vessel while the upward branch (INJ) represents successful injection recovery.

Event 3: Vessel Failure (VF)

The question raised in this event addresses recovery of a degraded core within the vessel, which prevents vessel lower head thermal attack. Core melt recovery within the vessel is considered only to the extent that coolant makeup has been successful in the previous event node (INJ). This requires that core cooling be recovered prior to core blocking (MAAP model) or relocation of molten debris to the lower plenum and thermal attack of vessel head. Therefore, the primary consideration for successful in-vessel recovery is the time available from incipient core degradation to the point of non-recovery.

The outcome of this event node directly affects the total fission product release fraction and significantly influences the subsequent accident progression. The downward branch in the CET represents no vessel failure while the upward branch represents vessel failure.

Event 4: Early Containment Failure (CFE)

The question asked at this event node addresses containment failure at or prior to vessel failure. Intentional venting of the containment is included in this event. While venting constitutes a failure of the containment function, it is not a failure of the structure as could be implied. The CET does include a venting event which distinguishes between containment venting and containment failure. This in turn is used to evaluate various fission product decontamination mechanisms and a fractional release of fission products from the primary to the secondary containment.

Early containment structural failure can be induced by the phenomena accompanying vessel failure. These phenomena are addressed specifically in the subtree. Containment leakage (failure size sufficient to prevent further long-term pressure increase and lead to reduction to atmospheric pressure over a period longer than ten to twelve hours) and containment rupture (failure size sufficient to reduce containment pressure to atmospheric within half an hour) are distinctly treated by the fission product retention (FPR) event. This distinction significantly impacts the environmental source term.

Event 5: Early Release to Pool (EPOOL)

The EPOOL event only considers complete suppression pool bypass. (i.e. releases to the drywell with wetwell-to-drywell vacuum breakers stuck open.) Under these conditions, fission product releases from the vessel during core damage are not subject to suppression pool scrubbing. Events that change the fission product transport pathways (as indicated in the EPOOL subtree) occur either prior to core damage or at vessel failure. The outcome of the Late Release to Pool (LPOOL) event is used to determine fission product scrubbing for releases occurring subsequent to vessel failure. This approach is slightly conservative (i.e., tends to overestimate releases) but is far more defensible than assuming the early release transport pathway pertains at vessel breach. The downward branch in the CET represents pool bypass (/EPOOL) while the upward branch (EPOOL) represents pool scrubbing of early fission product releases.

Event 6: Drywell Sprays Operate (DWSpry)

The question asked at this event addresses the function of the drywell sprays after vessel failure. Drywell sprays provide significant aerosol fission product removal, containment heat removal, containment pressure suppression (given loss of pool pressure suppression function), and a source of water to potentially cool ex-vessel debris. This event considers the effect of severe accident phenomena (such as draining of the suppression pool and supporting equipment failure in harsh environments) and late AC power recovery on drywell spray function. Successful actuation of drywell sprays will reduce the containment loads and mitigate the fission product release. The downward branch (LnDWSPry) in the CET represents no late drywell spray actuation while the upward branch (L-DWSpry) represents successful spray function.

Event 7: Injection Provided to Debris Following Vessel Failure (L-INJ)

This event asks if coolant injection is provided to the debris following vessel failure. Late coolant injection influences the potential for revolatilization of fission products deposited in-vessel, the coolability of ex-vessel debris, and fission product removal by creating an overlying pool of water. This event considers the availability of injection systems, AC power, the actuation probability given AC power recovery after vessel failure, and RPV pressure. Late injection actuation is likely provided either of the following: (1) the availability of injection systems and late AC power recovery in station blackout scenarios, or (2) the availability of low pressure injection systems and RPV failure at high pressure. For example, for sequences where the low pressure injection systems were previously unable to inject due to high RPV pressure, these systems would likely start to deliver coolant when the vessel is breached. Coolant injection could potentially quench the debris. This event significantly affects the subsequent accident progression. Successful late injection will eliminate or reduce the revolatilization fission product release fraction and will likely cool an ex-vessel debris bed, precluding late releases from core-concrete interactions. The downward branch (nWATER) in the CET represents no water being supplied to the debris late while the upward branch (WATER) represents water being supplied to the debris late.

(Note that the availability of the diesel-driven fire system is not modeled in the base case CET.)

Event 8: Coolable Debris Forms Ex-Vessel (DCOOL)

This event is included in the CET to signify the termination of the core melt progression subsequent to vessel breach. The success branch at the CET node means that a coolable debris bed is formed, terminating concrete attack, and thus precluding ex-vessel fission product releases from core-concrete interactions. Following the success branch also implies that containment overpressure challenges from non-condensable gas generation is precluded, thus containment integrity may be maintained in the long term if heat removal or sufficient makeup is available.

Failure at this branch implies that concrete attack occurs in the sumps on the drywell floor. Sparging of the concrete decomposition products through the melt releases the less volatile fission products to the containment atmosphere. This condition is considered to be more likely if a deep core debris bed is formed in the pedestal and, absent coolant addition, the debris is not able to effectively dissipate the decay heat to the surroundings. Should an impervious crust form, coolant addition would not likely terminate concrete attack, although the released fission product aerosols would be scrubbed by the overlying water pool.

Event 9: Late Containment Failure (CFL)

This event is included in the event tree to address the potential loss of containment integrity in the long term, after vessel breach and core-concrete interactions. Event CFL includes such events as overpressure failure of the primary containment, containment penetration failure due to high temperatures, and basemat penetration (a less probable condition). The success path here depends strongly on the recovery of systems that establish successful heat transfer from the core debris to the ultimate heat sink. One of the most important considerations is related to the potential for overpressure failure due to the relatively smaller containment volume of the Mark I containment.

Successful late containment function will retain fission product releases (early or late), substantially reducing the total environmental release. Given a late containment failure, the location and size of that failure also significantly influences fission product retention. The downward branch in the CET (CFL) represents loss of late containment function while the upward branch (/CFL) represents successful late containment function.

Event 10: Late Release to Pool (LPOOL)

This event is similar to event EPOOL. It addresses the importance of suppression pool scrubbing in mitigating the magnitude of fission products released from the debris. The success branch at this event node implies that the fission product transport path subsequent to late containment failure is through the suppression pool and the wetwell airspace. The suppression pool is not bypassed (i.e., given late containment failure, the location is in the wetwell airspace and the pool water is not drained); fission products released during core-concrete interaction (ex-vessel releases) and revolatilization from vessel surfaces are scrubbed by the pool. The dependency of LPOOL on failure in EPOOL is noted in the CET. The downward branch in the CET (/LPOOL) represents bypass of the pool and no scrubbing of ex-vessel fission product releases. The upward branch (LPOOL) represents successful scrubbing of releases.

Event 11: Fission Product Retention (FPR)

To quantify this event, the generic framework considers the effects of drywell spray, water on the drywell floor, and containment integrity on fission product retention within the containment. Consideration of whether containment failure occurs through a leak or a rupture and the location of that failure is also included. Leak-size failures enhance fission product retention by increasing the extent of deposition within containment. This increase results from the greater residence time for fission products when the rate of egress is slowed by a small failure. The added retention afforded by a leak-size failure is comparable to that afforded by water scrubbing of core-concrete interaction releases or deposition of airborne materials due to drywell spray operation in the Mark I configuration.

Event 12: Secondary Containment Retention (RB)

This event is included in the CET to characterize the impact of mitigation afforded by the secondary containment following containment failure. The magnitude of fission products released from the primary containment can be significantly reduced in the secondary containment through removal mechanisms within the Reactor Building provided the residence time is significant. This event considers the type of containment failure (i.e., vent, size, and location), whether or not a Reactor Building burn occurs, and the availability of active fission product removal by the FRVS.

Following primary containment loss of integrity, the Reactor Building provides another barrier for mitigating release of radioactive materials to the environment since the secondary completely surrounds the primary containment. While its ability to withstand the pressure loads resulting from containment failure is small, the secondary containment does present substantial deposition sites for aerosol removal and could significantly mitigate fission products released from the primary containment.

Event 13: Vent

The VENT event is a summary event that gives the model the capability to differentiate between containment failure and intentional venting. This avoids including containment venting as a form of containment failure. The model can identify those sequences in which venting occurs but the containment does not fail. Sequences where venting is successful at preventing either early or late containment failure have a significantly lower environmental fission product release than sequences where the containment structurally fails. Venting through the installed hard pipe system assures that all releases are scrubbed by the suppression pool and results in a relatively long containment retention time (i.e., similar to a leak containment failure). These provide for substantial fission product decontamination. In addition, this event facilitates modeling a fractional release from the primary containment to the Reactor Building. This would be appropriate if it could be assumed that the vent would ultimately be closed and remain closed.

4.5.3 <u>Subtree Structure</u>

Having described the events that comprise the main CET, the remainder of this section describes the structure for the logic trees that support the quantification of the CET top events.

CET Event 1: Vessel Depressurized (DP)

An example of the HCGS DP Subtree is shown in Figure 4.5-2. The first six events in the subtree reflect plant damage state (PDS) characteristics and are designated as PDS basic events in the logic model. Events seven through nine each represent at least one unique basic event.

Event 1: I-Event - Initiating Event

Event 2: SORV - Represents a PDS-dependent basic event indicating a stuck open relief valve. If an SRV is stuck open, it is assumed that the RPV will be depressurized.

Event 3: OP-SRV - Operable Safety/Relief Valve. For the plant to be at low pressure, the relief valves must first be operational. If not, then the plant will remain at pressure. This event is dependent on the PDS being quantified.

Event 4: DC - DC power available. DC power is required to operate the SRVs and depressurize the RPV, and it is also used for venting. It is dependent only on

AC power being restored. If no DC power is available, then the relief valves are considered to be non-operational and the reactor will stay at pressure. (No ST-SBO

Event 5: OPR-DP - Automatic or operator depressurization prior to core damage. This top event determines if the operator had depressurized the plant prior to core damage occurring. As such, it is dependent on the PDS being quantified.

Event 6: ECP - PDS-dependent basic event with success indicating that the containment pressure prior to core damage was below the level at which the SRVs are operable in relief mode.

Event 7: PCD-Vnt - This PDS-dependent basic event represents venting of the containment prior to core damage. Prior to core damage venting could lower the containment pressure, facilitating RPV depressurization by opening the SRVs.

Event 8: AC - This event represents either the AC power recovery frequency or the availability of AC power for non-blackout PDSs.

Event 9: OPDP - RPV depressurization by operator after core damage. This event considers the inability of the operator to depressurize due to high containment pressure preventing normal SRV operation. If the containment is vented under these conditions, SRV function will return and the RPV can be depressurized. This event also considers operator failure to depressurize prior to CD.

Event 10: DP (Outcome) - System may either remain at High Pressure (HP) or it may be depressurized [Low Pressure (LP)].

CET Event 2: Injection Recovered In-Vessel (INJ)

An example of the HCGS INJ Subtree is shown in Figure 4.5-3.

Event 1: I-Event - Initiating Event.

Event 2: AC - Same as Event 8 in the DP subtree.

Event 3: CRD-ADQ - Adequacy of CRD flow to arrest in-vessel core-melt progression is addressed by this event. This basic event reflects the analysts' level of confidence that CRD alone could arrest core damage.

Event 4: a CRD - PDS-dependent basic event representing the availability of the CRD system.

Event 5: E_CRD - This event determines whether the operator maintains or recovers CRD flow.

Event 6: HP - Result of DP subtree that indicates whether the vessel is depressurized prior to breach.

Event 7: a ECCS - PDS-dependent basic event representing the availability of low-pressure emergency core cooling.

Event 8: a ALTinj - PDS basic event representing the availability of alternative low-pressure injection systems (e.g., condensate or service water).

Event 9: E_ECCS - This event determines if ECCS flow is recovered once all conditions necessary to permit it are met.

Event 10: E_ALTI - This event determines if alternate injection sources are aligned and initiated, injecting coolant to the RPV.

Event 11: INJ (Outcome) - Injection restored during the core damage process.

CET Event 3: Vessel Failure (VF)

An example of the HCGS VF Subtree is shown in Figure 4.5-4.

Event 1: INJ - Result of the INJ subtree indicating the restoration of injection during core damage process. If injection is not recovered, it is assumed that the vessel will fail.

Event 2: <26%_CM - This event represents the frequency with which injection would be recovered prior to the fraction of the fuel that has melted attaining the 26 percent level. It is assumed that recovery (i.e., termination of core melt progression) is virtually assured before this point.

Event 3: SLUMP - This event represents the subjective probability that the core will collapse en masse once more than 26 percent of the fuel has melted.

Event 4: VF - Represents the subjective probability that injection will not arrest core melt progression. Also determines the outcome for this subtree.

CET Event 4: Early Containment Failure (CFE)

An example of the HCGS CFE Subtree is shown in Figure 4.5-5. Containment failure due to overpressurization resulting from vessel blowdown is treated by looking at the sum of the pressure rise in containment resulting from vessel blowdown and the pressure in containment when the vessel fails. Both the pressure rise and the base pressure have been subdivided into low, medium, and high ranges. The numerical values for pressure corresponding to these ranges were established during CET quantification.

Event 1: PCD-Vnt - Same as Event 7 in the DP subtree.

Event 2: BLOW - Hi-Pressure rise in containment due to vessel blowdown at failure in the high range. This pressure rise is determined based on the vessel blowdown (Blowdown) Sub-subtree.

Event 3: CP-Hi - Base pressure in the containment immediately prior to vessel breach in the high range. This base pressure is determined based on the containment pressure rise (CPRISE) Sub-subtree.

Event 4: BLOW-Md - Pressure rise in containment due to vessel blowdown at failure in the medium range given that it was not in the high range. BLOW Sub-subtree outcome.

Event 5: CP-Mod - Base pressure in the containment immediately prior to vessel breach in the moderate range given that it was not in the high range. CPRISE Sub-subtree outcome.

Event 6: CF-FCI - Indicates the occurrence of an FCI that produces containment failure. The FCI sub-subtree is used to determine the outcome of this event.

Event 7: CF-MLT - Indicates the occurrence of drywell shell melt-through due to either debris impingement or spreading. The MELT Sub-subtree is used to determine the outcome of this event.

Event 8: CFE (Outcome) - Indicates the occurrence of early containment failure.

CET Event 5: Early Release to Pool (EPOOL)

An example of the HCGS EPOOL subtree is shown in Figure 4.5-6. This subtree considers sequences where there is an early release of fission products to the drywell, and those fission products either escape the containment prior to being scrubbed by the suppression pool or bypass the pool altogether.

Event 1: LOCA - PDS-dependent basic event. A LOCA initiator results in early fission product releases to the drywell.

Event 2: SORV - PDS-dependent basic event. Same as Event 2 in the DP subtree.

Event 3: SO_TVB - Represents the frequency for a SRV tailpipe vacuum breaker failing to reclose. A SO-TVB results in early fission product releases to the drywell.

Event 4: E-Vnt - This event determines if the containment is vented early (either prior to or during core damage).

Event 5: DWVENT - Given that the containment was vented early, this event determines if operator error results in venting from the drywell rather than the wetwell airspace. Drywell venting produces a release pathway for fission products that bypass the suppression pool.

Event 6: C-DWVB - This event determines if one or more wetwell-to-drywell vacuum breakers fails to reclose.

Event 7: EPOOL (Outcome) - This summary event determines if early fission product releases are scrubbed by the suppression pool or bypass the pool.

CET Event 6: Late Drywell Sprays Operate (L_SPRY)

An example of the HCGS L-SPRY subtree is shown in Figure 4.5-7. Late drywell spray function is assessed based on the availability of the system and AC power.

Event 1: a_SPRY - This PDS-dependent basic event determines the availability of the drywell spray system.

Event 2: SBO - This PDS-dependent event identifies if the sequence being evaluated is a station blackout.

Event 3: EAC - This event determines if AC power was available or recovered during the in-vessel phase of the accident.

Event 4: E_SPRY - This event determines if the drywell sprays were functioning during the in-vessel phase of the accident.

Event 5: L-AC - This event determines if AC power is available following vessel failure. This event includes the probability of recovering AC power following vessel failure.

Event 6: L-SPRY - This event determines if the drywell sprays are functioning following vessel failure. This event includes the probability of supporting hardware failures due to severe environments in the Reactor Building.

CET Event 7: Water Supplied to the Debris Late (L-INJ or LT-WTR)

An example of the HCGS L-INJ subtree is shown in Figure 4.5-8. Water being supplied to the debris following vessel failure is assessed by identifying all sources of late injection and late sprays. This event considers the probability of supporting system hardware failure due to severe environments in the Reactor Building and loss of coolant inventory resulting from wetwell containment failure and subsequent draining of the suppression pool.

Event 1: SBO - Same as Event 2 in the L_SPRY subtree.

Event 2: L_AC - Same as Event 5 in the L_SPRY subtree.

Event 3: LaECCS - This event determines if ECCS systems are available to supply water to the debris late. This event includes the probability of supporting system hardware failure due to severe environments in the Reactor Building from an early containment failure, and early draining of the suppression pool precluding late ECCS operation.

Event 4: L_ECCS - This event determines if ECCS systems are supplying water to the debris following vessel failure.

Event 5: LaAINJ - This event determines if alternate injection systems are available to supply water to the debris late. This event includes the probability that severe environments in the Reactor Building from an early containment failure may preclude alternate injection systems from operating.

Event 6: L_ALT_FL - This event determines if alternate injection systems are supplying water to the debris late.

Event 7: CRD-AVL - This event determines if the CRD system is available to supply water to the debris late. This event includes the probability that severe environments in the Reactor Building from an early containment failure may preclude the CRD system from operating.

Event 8: L_CRD - This event determines if CRD flow supplies water to the debris late.

Event 9: SPRY - Outcome of the L_SPRY subtree.

Event 10: WATER - This summary event determines if ECCS flow, alternate injection flow, or drywell sprays are supplying water to the debris late: outcome of the water sub-subtree.

Event 11: CFL - Outcome of the CFL subtree.

Event 12: LT-WTR - This event determines if water is being supplied to the debris late. This event includes the probability that severe environments in the Reactor Building from late containment failures or late draining of the suppression pool may preclude injection systems from operating.

CET Event 8: Coolable Debris Forms Ex-Vessel (LT-DC)

An example of the HCGS DCOOL Subtree is shown in Figure 4.5-9. Coolability is assessed separately in the subtree for nine different possible conditions. The subtree involves significant decomposition in determining coolability. The probability of coolability is different if the debris falls into water at vessel failure instead of water being added to the top after vessel failure.

Event 1: VF - Outcome of the VF Subtree.

Event 2: INJ - Outcome of the INJ Subtree.

Event 3: SPRAY - Represents the probability of operating the drywell sprays prior to vessel breach. Same as Event 4 in the L_SPRY subtree.

Event 4: WATER - Represents the late addition of water to the debris based on the WATER Sub-subtree.

Event 5: DSPRS - Represents the dispersion of core debris by an energetic event associated with vessel breach. Dispersal is based on the DISPERSE Sub-subtree.

Event 6: SLUMP - Event 3 in the VF subtree.

Event 7: DCOOL - Represents the coolability of core debris.

Event 8: LT-WTR - Outcome of the L-INJ subtree.

Event 9: LT-DC (Outcome) - Represents the long-term coolability of core debris.

CET Event 9: Late Containment Failure (CFL)

An example of the HCGS CFL Subtree is shown in Figure 4.5-10. The principal failure mechanisms considered are failure due to noncondensable gas generation and thermal failure of seals. Hydrogen burn is assumed not to contribute to late containment failure. This assumption is believed to be valid for a Mark I containment, independent of nitrogen inerting.

Event 1: CFE - Outcome of the CFE Subtree.

Event 2: WATER - Represents the late addition of water to the debris based on the WATER Sub-subtree.

Event 3: DCOOL - Outcome of the DCOOL Subtree.

Event 4: TEMP-F - Represents the probability of thermal failure of the drywell hatch or electrical penetration seals.

Event 5: SUMP-F - Represents CCI ablation of the drywell sumps followed by failure of the drywell shell below the drywell floor.

Event 6: CRD-ONLY - This event determines if the only supply of water to the debris late is from the CRD system.

Event 7: CFL (Outcome) - Indicates the occurrence of late containment failure.

CET Event 10: Late Release to Pool (LPOOL)

An example of the HCGS LPOOL Subtree is shown in Figure 4.5-11.

Event 1: VF - Outcome of the VF subtree.

Event 2: CFE - Outcome of the CFE Subtree.

Event 3: CFL - Outcome of the CFL Subtree.

Event 4: TEMP-F - Same event as Event 4 in the CFL Subtree.

Event 5: WW_Fail - This event determines if containment failure occurred in the wetwell.

Event 6: C-DWVB - This event determines if one or more wetwell-drywell vacuum breakers fail to reclose.

Event 7: POOL - Represents the probability of loss of suppression pool level (early or late) below the downcomer due to containment failure in the torus.

Event 8: LPOOL (Outcome) - Indicates the occurrence of late pool bypass.

CET Event 11: Fission Product Retention (FPR)

An example of the HCGS FPR Subtree is shown in Figure 4.5-12.

Event 1: VF - Outcome of the VF Subtree

Event 2: INJ - Outcome of the INJ Subtree.

Event 3: WATER - Outcome of the Water Sub-subtree.

Event 4: SEV-F - This event determines if severe environments in the Reactor Building due to either early or late containment failures result in failure of systems supporting coolant injection to the primary containment.

Event 5: CFE - Outcome of the CFE Subtree.

Event 6: CFL - Outcome of the CFL Subtree.

Event 7: TEMP-F - Same event as Event 4 in the CFL Subtree.

Event 8: SUMP-F - Same event as Event 5 in the CFL Subtree.

Event 9: LEAK - This event determines if a containment failure area is a leak or a rupture.

Event 10: FPR (Outcome) - Represents the outcome of fission product retention.

CET Event 12: Secondary Containment Retention (NAT-DEP or RB)

An example of the HCGS NAT-DEP Subtree is shown in Figure 4.5-13. Ascertaining the likely residence time for fission products in the secondary containment based on the established accident progression is the principal focus.

Event 1: CF - Summary outcome of the CFE and CFL Subtrees.

Event 2: RB-By - Represents whether the containment failure was due to venting using a pathway that bypasses the Reactor Building.

Event 3: BURN - Represents two different probabilities relative to determination of whether hydrogen combustion occurs in the Reactor Building. These are:

(a) With sufficient hydrogen and containment leak.

(b) With sufficient hydrogen and containment rupture.

Event 4: FRVS - This event represents the operation of the filtration, recirculation and ventilation system.

Event 5: SUMP-F - Same event as Event 5 in CFL Subtree.

Event 6: LEAK - Same as Event 9 in the FPR subtree.

Event 7: Nat_Dep - Represents the determination of whether the Reactor Building would provide significant fission product retention by natural deposition mechanisms.

CET Event 13: VENT

An example of the HCGS VENT subtree is shown in Figure 4.5-14. It is used to determine the occurrence of containment venting given that containment structural failure does not occur.

Event 1: CF - Same as Event 1 in the NAT-DEP subtree.

Event 2: aVnt - PDS-dependent basic event.

Event 3: PCD-Vnt - PDS-dependent basic event (prior to core damage venting).

Event 4: E-AC - Same event as Event 8 in the DP Subtree.

Event 5: ECP - PDS-dependent basic event.

Event 6: E-Vnt - This event determines if venting started during the phase of the accident and at or prior to vessel failure.

Event 7: L-AC - Same as Event 5 in the L_SPRY subtree.

Event 8: DCOOL - Outcome of the DCOOL Subtree.

Event 9: L-Vnt - This event determines if containment is vented late given that no leak has occurred, AC power is available, and the pressure continues to rise.

Event 10: VENT (Outcome) - This event represents the outcome of containment venting.

4.5.4 Sub-Subtrees

The sub-subtrees are the representation of the logic used to quantify some of the top events in the subtrees. There are five sub-subtrees. These trees are made up of basic events, phenomenological events, human actions, pre-existing conditions, and previous subtrees. The individual sub-subtrees are described below.

CPRISE

This sub-subtree determines the containment pressure rise resulting from the hydrogen production during core damage. It is dependent on the initial containment pressure, whether or not the containment is vented, and injection sources. An example of the HCGS CPRISE tree is graphically represented in Figure 4.5-15. The seven top events associated with this tree are described below:

ECP - This event determines if the containment was at an elevated pressure prior to the generation of hydrogen during core damage. It is a plant damage state specific event. The downward branch denotes no elevated pressure. The upper branch denotes elevated pressure.

INJ - This event determines if there is injection to the core. If so, then the probability of hydrogen production must be adjusted. The downward branch denotes no vessel injection. The upper branch denotes injection.

CRD - If the injection is from the CRD system, then a different probability of hydrogen production is quantified. The downward branch denotes no CRD flow established. The upper branch denotes CRD flow.

HP - The pressure of the vessel has an impact on the amount of hydrogen produced. Therefore, this question is asked to determine vessel pressure. The downward branch denotes large amounts of hydrogen produced. The upper branch denotes moderate or low amounts produced.

H2HI - This question, determines high hydrogen production. It has the same dependencies as the previous question. The downward branch denotes high amounts of hydrogen produced. The upper branch denotes low amounts produced.

H2MED - This question, determines moderate hydrogen production. It has the same dependencies as the HP question. The downward branch denotes low amounts of hydrogen produced. The upper branch denotes moderate amounts produced.

CPRISE - This question uses the previous questions to determine which probability to assign this event. The probabilities of having either a high, moderate, or low pressure rise are dependent on the path that is taken through this tree.

BLOWDOWN

An example of the HCGS BLOWDOWN sub-subtree is shown in Figure 4.5-16. It is used to determine the pressure rise in containment resulting from the blowdown of a pressurized vessel into the containment when breach occurs. The tree determines whether the pressure rise is high, medium, or low. The events for the tree are as follows:

HP - This event determines if the vessel is at high pressure or not. It is assumed that a failure of a depressurized vessel will not lead to a significant containment pressure rise due to the blowdown process. The downward branch denotes vessel at low pressure. The upper branch denotes vessel at high pressure.

V-RUPT - This event represents the probability that the reactor vessel ruptures. The downward branch denotes rupture. The upper branch denotes no rupture.

VF - This event indicates whether or not a vessel breach occurs. If the vessel does not fail, there will be no pressure rise in the containment due to blowdown. The downward branch denotes vessel failure. The upper branch denotes vessel intact.

SLUMP - This event represents the probability that the postulated phenomena of core slumping occurs. It is assumed that slump is required for direct containment heating to occur. The downward branch denotes SLUMP occurs. The upper branch denotes no SLUMP.

HPME - This event represents the probability that a high pressure melt ejection occurs. This is a phenomena that would result in direct containment heating that would, in turn, lead to a high pressure rise. The downward branch denotes high pressure melt ejection. The upper branch denotes no high pressure melt ejection.

WET - This event represents the condition of water being on the drywell floor. If present, then there is a likelihood that the core material will cause it to flash to steam, causing a rapid pressure rise. The downward branch denotes the drywell floor is dry. The upper branch denotes it is wet.

HI-RISE - This event represents the probability that the pressure rise will be high given the preceding sequence of events. The HI-RISE denotes a high containment pressure rise. The /HI-RISE denotes no high pressure rise.

MD-RISE - This event represents the probability that the pressure rise will be moderate given the preceding sequence of events. The MD-RISE denotes a moderate containment pressure rise. The /MD-RISE denotes a low pressure rise.

BLOW (Outcome) - This event summarized the two previous top events.

MELTTHROUGH

An example of the HCGS liner meltthrough sub-subtree is shown in Figure 4.5-17. It is used to determine the failure of the containment due to either direct impingement of debris on the drywell wall or contact between debris and the wall due to spreading across the floor. The description of the events for this tree are as follows:

VF - This event represents whether or not the vessel failed. If the vessel remains intact, there will be no ablation of the drywell shell by molten core debris. The downward branch denotes vessel failure. The upper branch denotes vessel intact.

SLUMP - This event represents the probability that the postulated phenomena of core slumping occurs. It is assumed that slump would increase the likelihood of drywell shell failure since more debris, at a higher temperature, would exit the vessel at vessel breach. The downward branch denotes a SLUMP occurs. The upper branch denotes no SLUMP.

HPME - This event represents that a high pressure melt ejection occurs. The probability that melt is ejected in sufficient quantity to cause shell melt-through by impingement is viewed as dependent on whether or not slump occurs. The downward branch denotes a high pressure melt ejection occurs. The upper branch denotes no high pressure melt occurs.

DSPRS - This event represents that the core material is dispersed when it leaves the vessel. Dispersal has a direct impact on the coolable geometry of the debris and, therefore, impacts the melt-through probability for the drywell liner. The downward branch denotes fuel dispersal. The upper branch denotes no fuel dispersal.

WET - This event represents whether or not the drywell floor is wet. If wet then there is a probability that the debris will be cooled sufficiently to prevent ablation of the liner. The downward branch denotes no water on the drywell floor. The upper branch denotes the floor is wet.

MELT - This event represents the probability of a liner meltthrough given the preceding sequence of events. The downward branch denotes the drywell liner melts through. The upper branch denotes it does not.

FCI

An example of the HCGS FCI sub-subtree is shown in Figure 4.5-18. It is used to determine the occurrence of fuel-coolant interaction and the outcome of this event relative to a containment failure.

SLUMP - This event represents the probability that the postulated phenomena of core slumping occurs. It is assumed that slump would increase the likelihood of an FCI and, given that FCI occurs, would lead to a more energetic interaction. Therefore, it is assumed that a slump is required for an in-vessel FCI to occur The downward branch denotes a SLUMP has occurred. The upper branch denotes no SLUMP.

IV-FCI - This event represents the probability that an FCI occurs in the vessel. This is dependent on a slump occurring. The downward branch denotes an in-vessel fuel coolant interaction occurs. The upper branch denotes it has not occurred.

V-RUPT - This event represents the probability that, given an FCI occurs in the vessel, it is sufficiently energetic to result in vessel rupture. The downward branch denotes the reactor vessel has ruptured. The upper branch denotes it has not ruptured.

VF - This event represents the occurrence of a vessel failure. If there is no failure, then an ex-vessel FCI is precluded. The downward branch denotes the reactor vessel has failed. The upper branch denotes it has not failed.

HPME - This event determined whether or not a high pressure melt ejection occurs. If a HPME occurs, it is assumed that an ex-vessel FCI is not possible. The downward branch denotes a high pressure melt ejection has occurred. The upper branch denotes it has not occurred.

WET - This event determines if the drywell floor is wet. If the drywell floor is dry, then there is no water available to interact with the debris. This precludes an ex-vessel FCI. The downward branch denotes the drywell floor is dry. The upper branch denotes it is wet.

EX-FCI - This event represents the probability that, given the drywell floor is wet, a fuel coolant interaction occurs. The downward branch denotes an ex-vessel fuel coolant interaction occurs. The upper branch denotes it does not occur.

FCI-CF - This event represents the probability that an FCI results in containment failure. Again, it is noted that, if the drywell floor is dry at the time of vessel breach, it is assumed that the containment cannot fail from the effects of FCI. The downward branch denotes the containment fails from an FCI if it occurs. The upper branch denotes that a fuel coolant interaction does not fail the containment.

DSPRS

An example of the HCGS DSPRS, or disperse, sub-subtree is shown in Figure 4.5-19. It is used to determine the dispersion of core debris by an energetic event associated with vessel breach. The events used in this tree are described below:

VF - This event represents whether or not a vessel failure has occurred. If the vessel remains intact, then a dispersion of the fuel is precluded. The downward branch denotes the reactor vessel has failed. The upper branch denotes no vessel failure.

V-RUPT - This event represents the probability that, given an FCI occurs in the vessel, it is sufficiently energetic to result in vessel rupture. The downward branch denotes the reactor vessel has ruptured. The upper branch denotes no rupture.

HP - This event represents a sequence dependent event indicating whether or not the vessel is depressurized prior to core damage. Vessel depressurization prevents HPME. The downward branch denotes that the vessel is not at high pressure. The upper branch denotes it is at high pressure.

HPME - This event represents high pressure melt ejection. This contributes directly to the probability of fuel dispersal. The downward branch denotes high pressure melt ejection occurs. The upper branch denotes it does not.

EX-FCI - This event represents the probability that, given that the drywell floor is wet, fuel coolant interaction occurs. the downward branch denotes an ex-vessel fuel coolant interaction occurs. The upper branch denotes it does not occur.

DSPRS (Outcome) - This event summarizes the preceding events.

TABLE 4.5-1

PDS BASIC EVENTS

Event	Outcomes	Definition
I-Event	S-LOCA*	Small LOCA. Vessel depressurization required to prevent core damage if high pressure make-up is unavailable.
	M-LOCA*	Medium LOCA. Vessel depressurization sufficiently rapid for low pressure make-up systems to prevent core damage if they are operable.
	L-LOCA*	Large LOCA. Vessel depressurization sufficiently rapid for low pressure make-up systems to prevent core damage if they are operable.
	ST-SB*	Short term station blackout. Total loss of AC power and turbine-driven make-up systems (i.e., HPCI and RCIC).
	LT-SB*	Long term station blackout. Total loss of AC power. Turbine-driven make-up supplied until battery depletion results in failure.
	Trans*	Any transient leading to reactor scram without leakage from the RPV and AC power available to at least one emergency bus.
	ATWS*	Anticipated transient without scram. AC power available to at least one emergency bus. Both SLC pumps are assumed to be needed to prevent core damage.
	TW*	Transients with total loss of decay heat removal capability. Unavailability of the RHR system is the main contributor to such events.
SORV	SORV nSORV	One or more SRVs stuck open SRVs reclose and reseat
OP-SRV	op-SRV nop-SRV	At least one SRV operates in relief mode No SRV operable in relief mode due to hardware failure
DC	DC nDC	DC power available on at least one bus No DC power

* The HCGS CET is constructed such that eight different types of initiating events can be modeled in it. However, only TW, ATWS, Trans, LT-SBO and L-LOCA were necessary for the finalized CET. The Medium and Large LOCA initiators were combined into one Large LOCA initiator, since they have similar effects on reactor vessel and containment (i.e., both are assumed to lead to early - prior to core damage - vessel depressurization).

TABLE 4.5-1

PDS BASIC EVENTS (CONTINUED)

Event	Outcomes	Definition
DP	SRV-DP	RPV depressurized using SRVs prior to core damage
	nSRV-DP	SRVs not used to depressurize RPV prior to core damage
ECP	ECP-Lo	Containment pressure at onset of core damage does not force SRV reclosure
	ECP-Hi	Containment pressure at core damage prevents SRV operation in relief mode
Vent	PCD-Vnt	Containment vented prior to core damage
	PCDnVnt	Containment not vented prior to core damage
CRDADQ	CRD-ADQ	CRD flow is adequate to terminate core damage
	CRDnADQ	CRD flow is not adequate to terminate core damage
CRD	aCRD	CRD hydraulic system make-up available if AC power available
	fCRD	CRD failed
ECCS	aECCS	LPCI and/or LPCS available if AC power available
	fECCS	LPCI and LPCS failed
ALT	aALTINJ	Condensate and/or service water available for water make-up if AC power available
	fALTINJ	Both condensate and service water failed
SPRAY	aSPR	Drywell sprays available if AC power available
	fSPR	Drywell spray failed
Vntng	aVntng	Containment venting is available
	fVntng	Containment venting has failed
DWVB	SODWVB	At least one wetwell-to-drywell vacuum breaker is stuck open.
	nSODWVB	Wetwell-to-drywell vacuum breakers close and reseat
FRVS	aFRVS	FRVS is available
	fFRVS	FRVS has failed

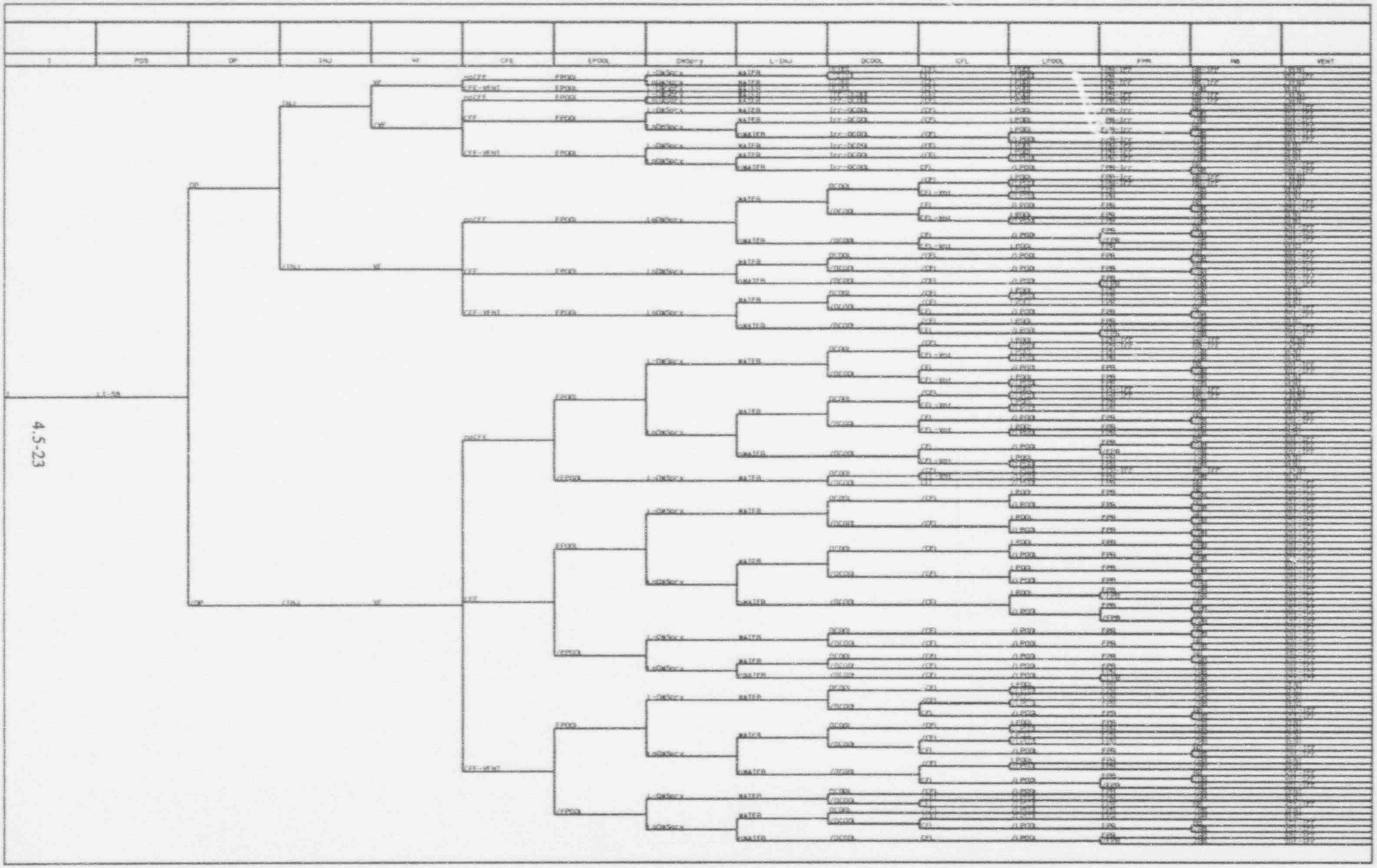

Figure 4.5-1A. HCGS Containment Event Tree (Lt-SBO Initiator)

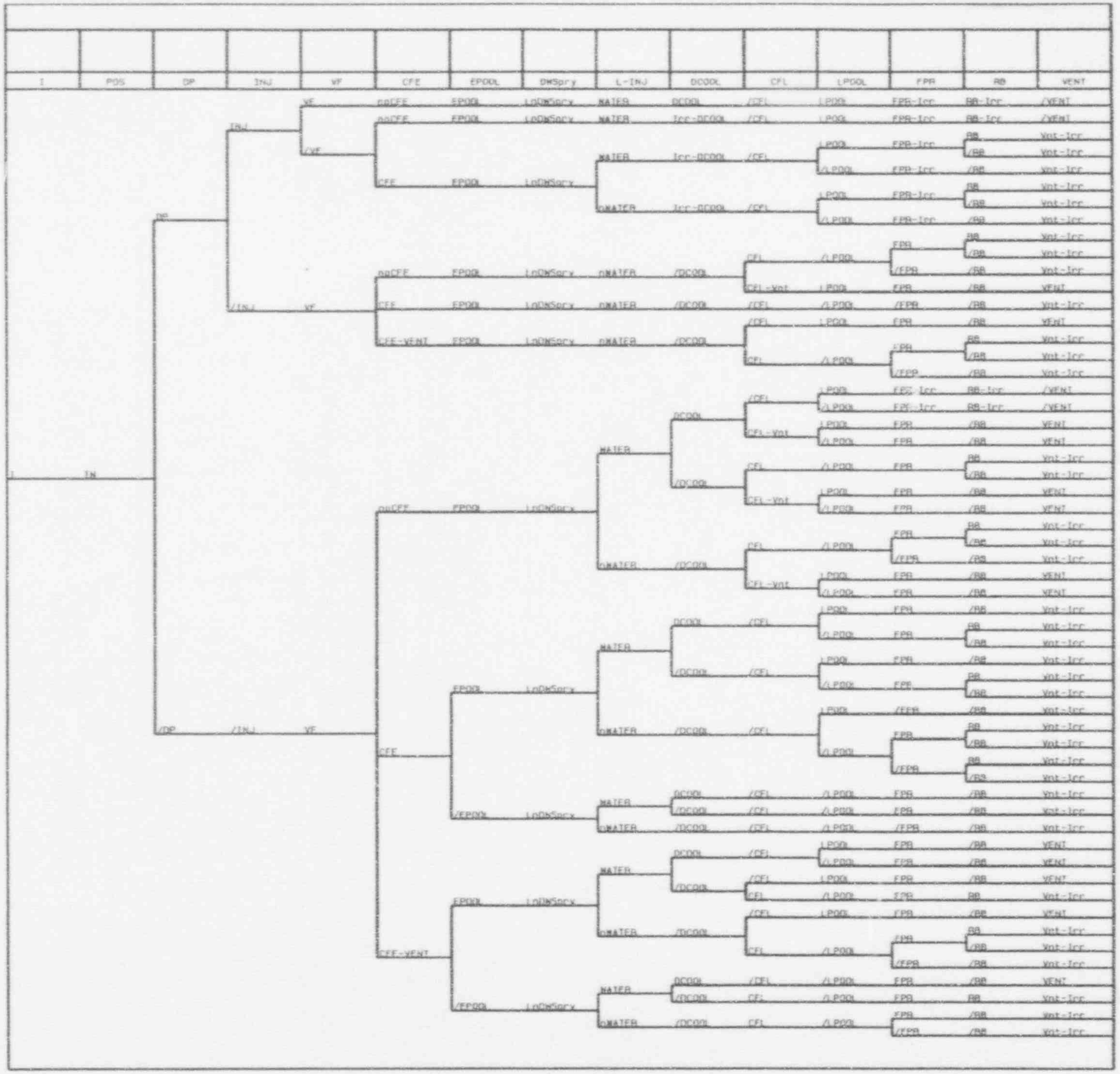

Figure 4.5-1B. HCGS Containment Event Tree (TW Initiator)

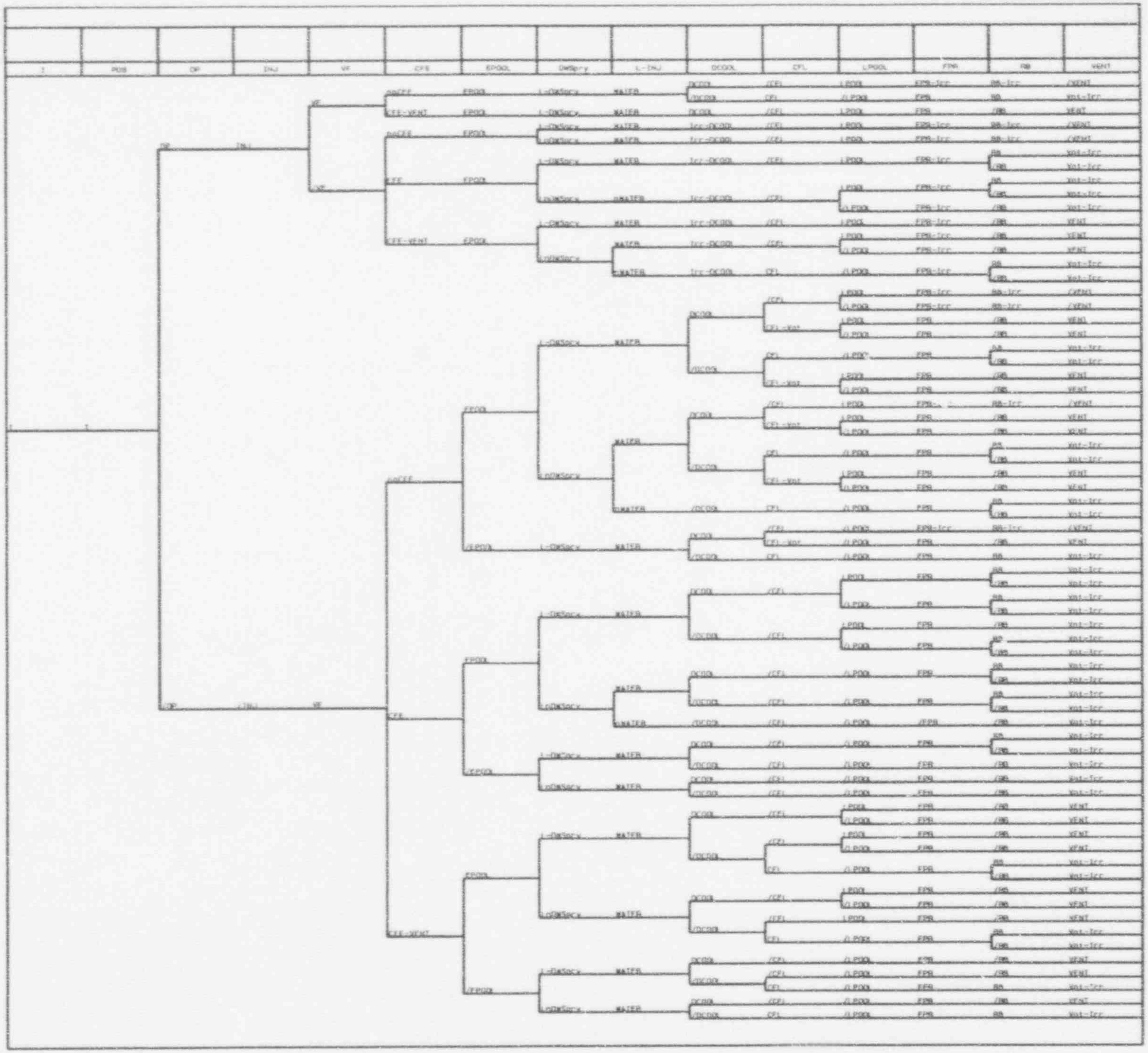

Figure 4.5-1C. HCGS Containment Event Tree (Tr[illegible]ent Initiator)

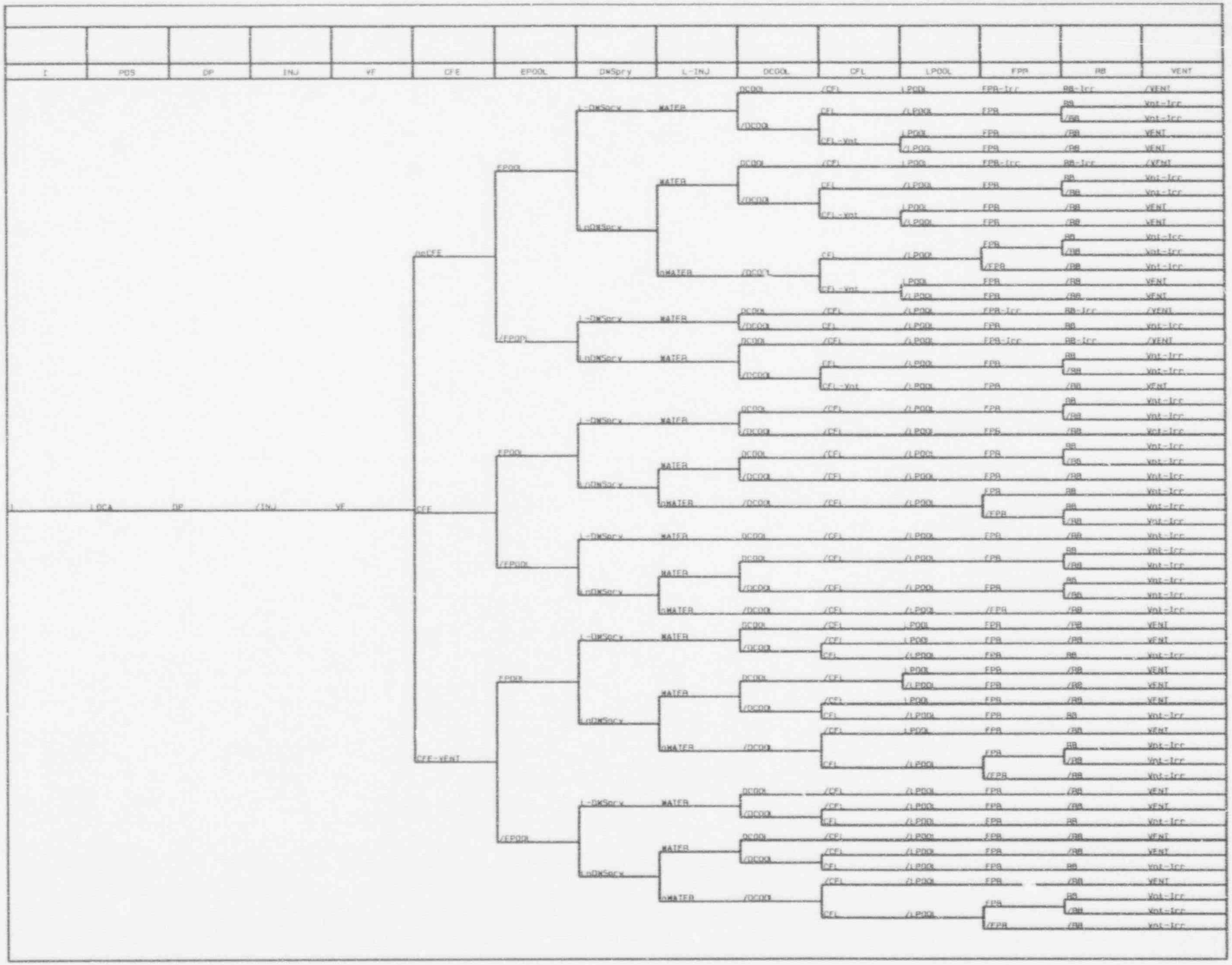

Figure 4.5-1D. HCGS Containment Event Tree (LOCA Initiator)

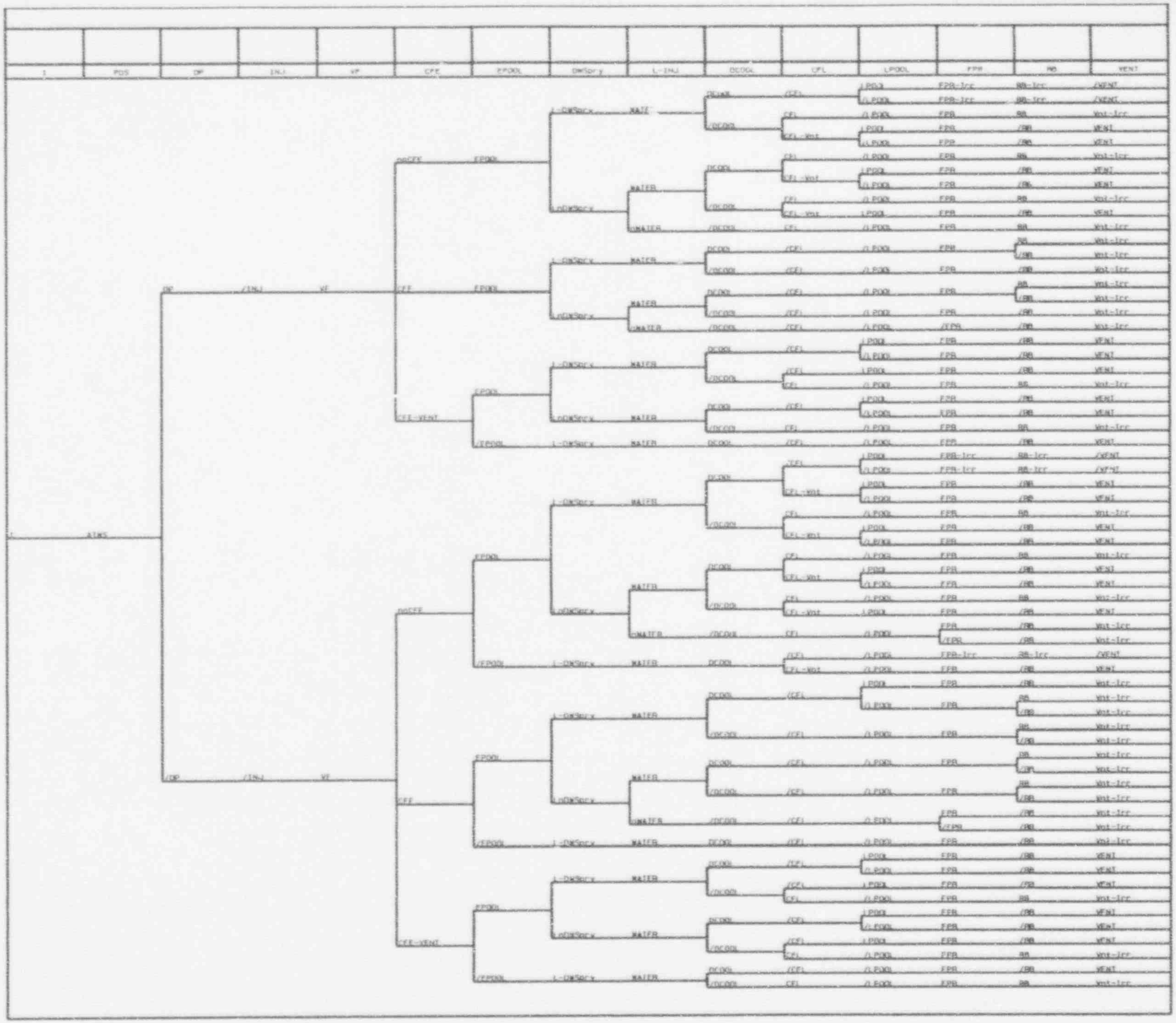

Figure 4.5-1E. HCGS Containment Event Tree (ATWS Initiator)

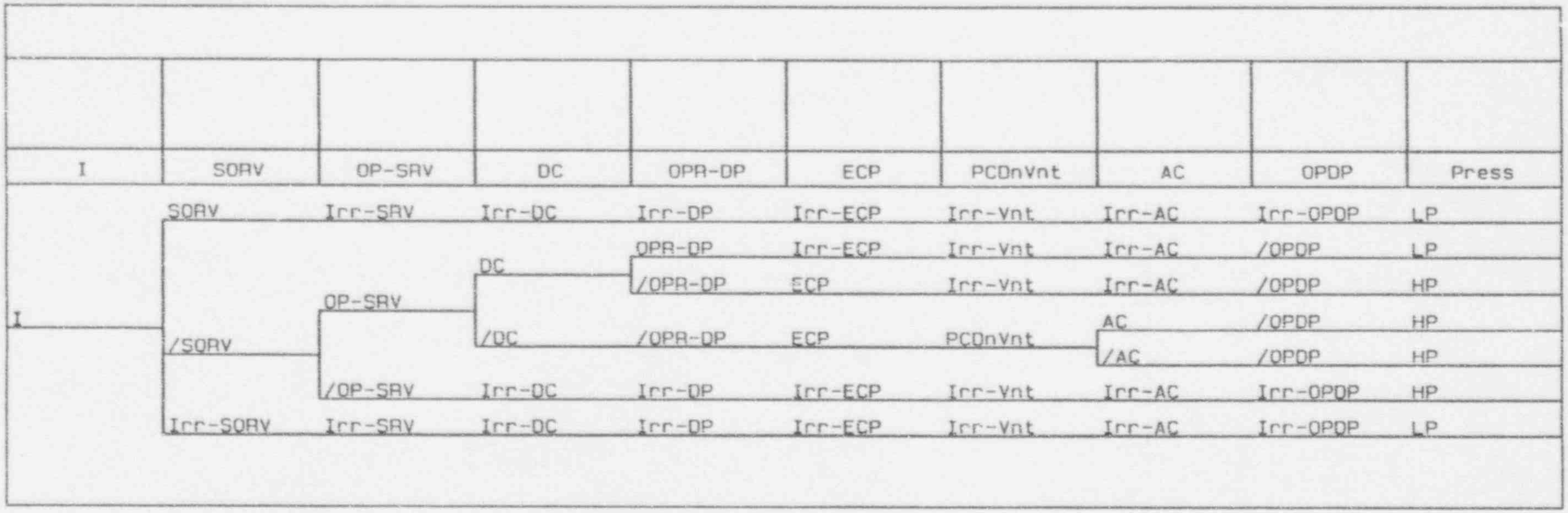

Figure 4.5-2. Vessel Depressurized Subtree

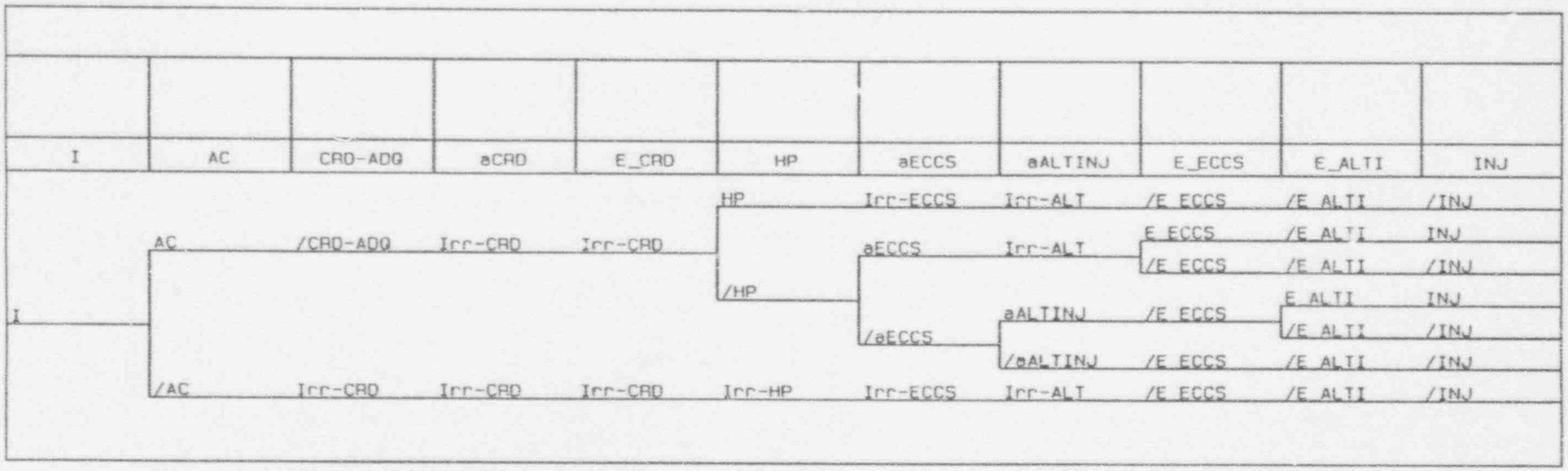

Figure 4.5-3. Injection Recovered In-Vessel Subtree

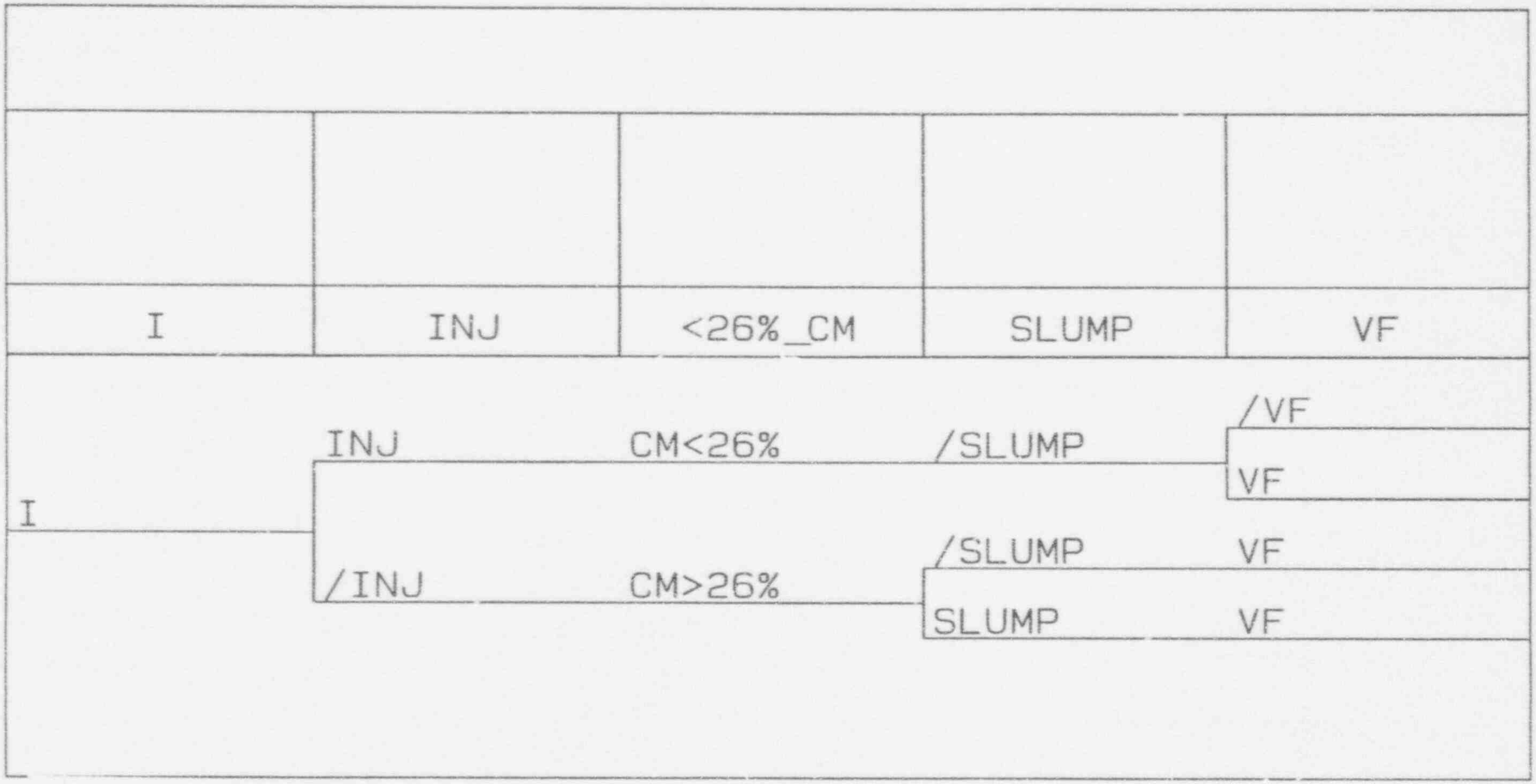

Figure 4.5-4. Vessel Failure Subtree

Figure 4.5-5. Early Containment Failure Subtree

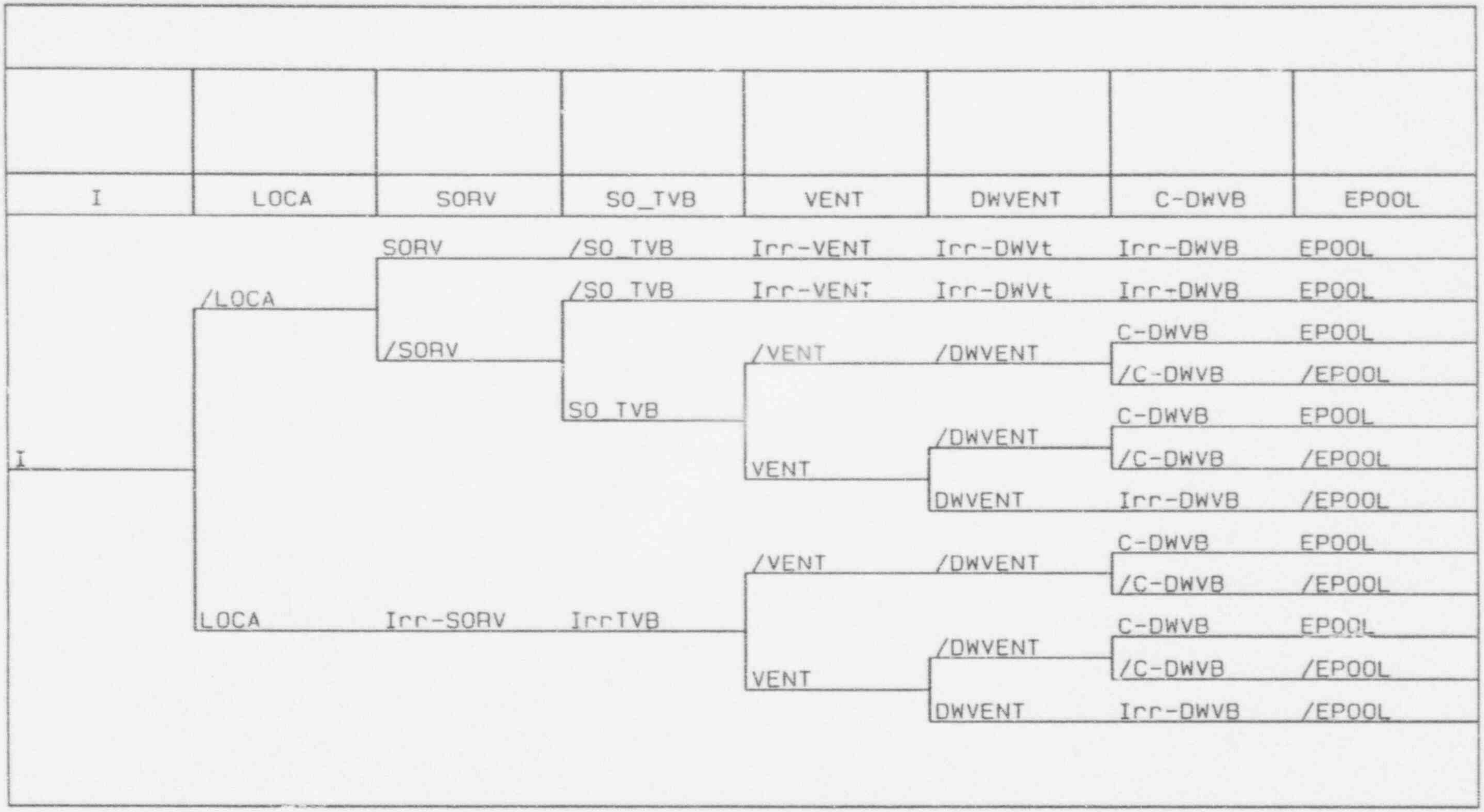

Figure 4.5-6. Early Release to Pool Subtree

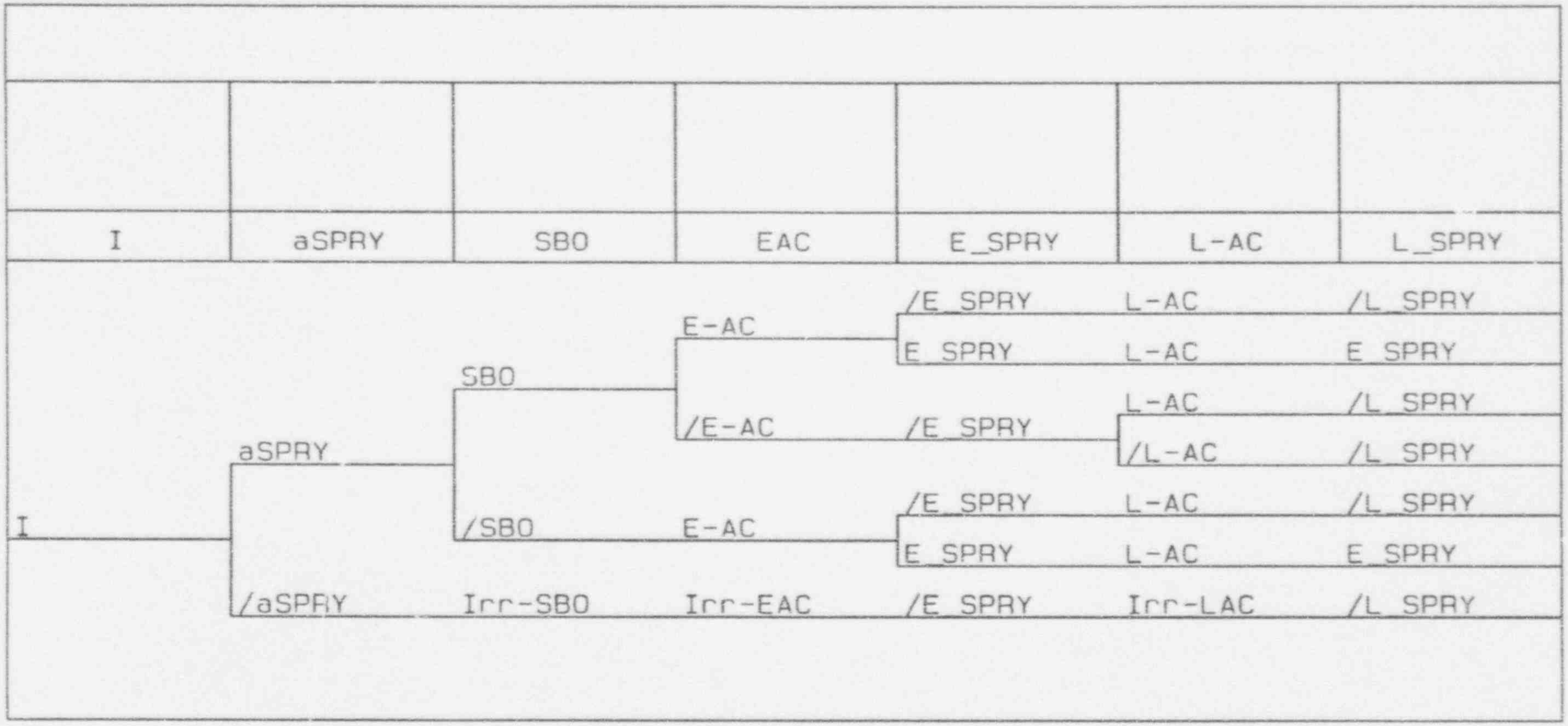

Figure 4.5-7. Late Drywell Spray Subtree

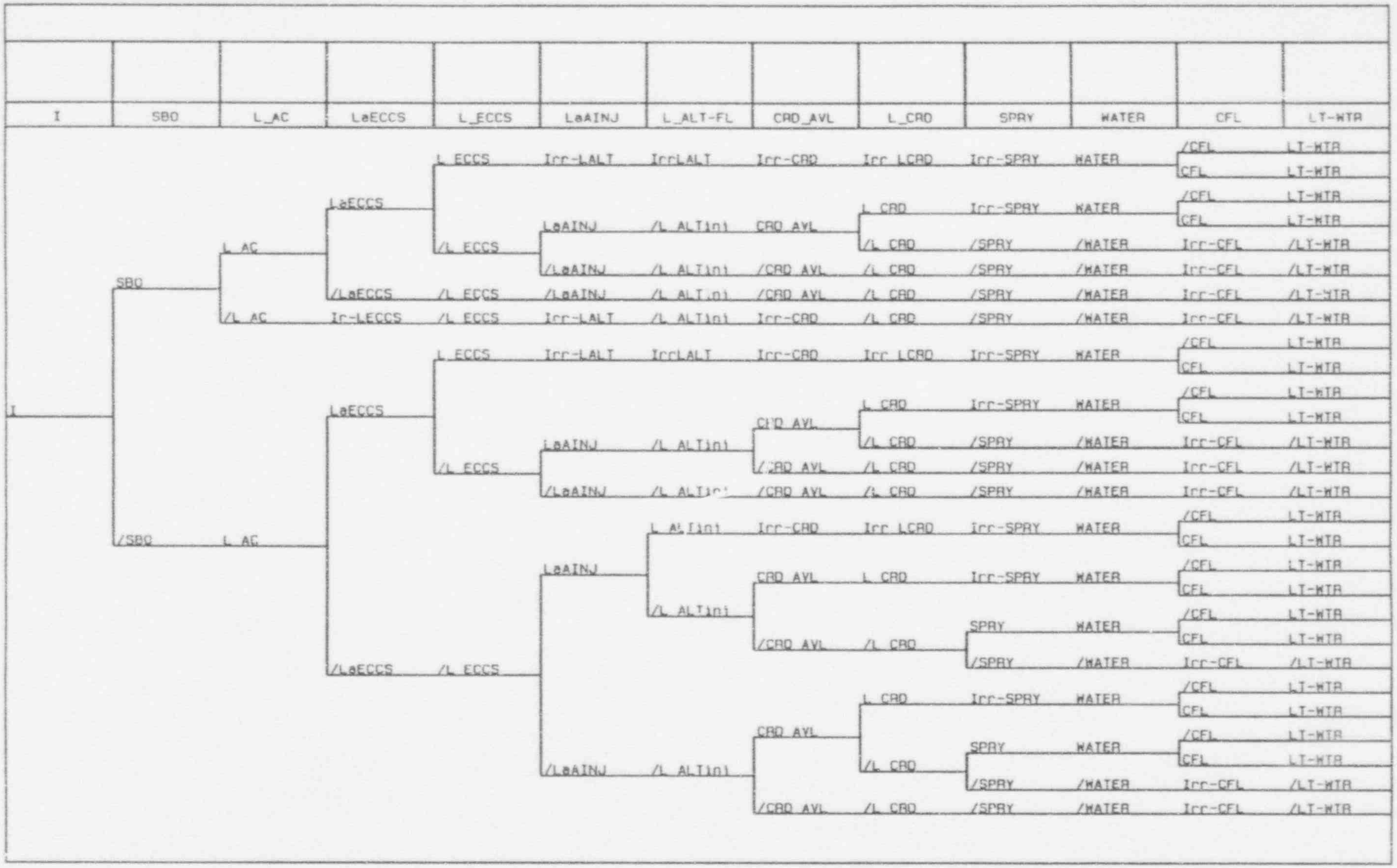

Figure 4.5-8. Water Supplied to Debris Late Subtree

Figure 4.5-9. Coolable Debris Forms Ex-Vessel Subtree

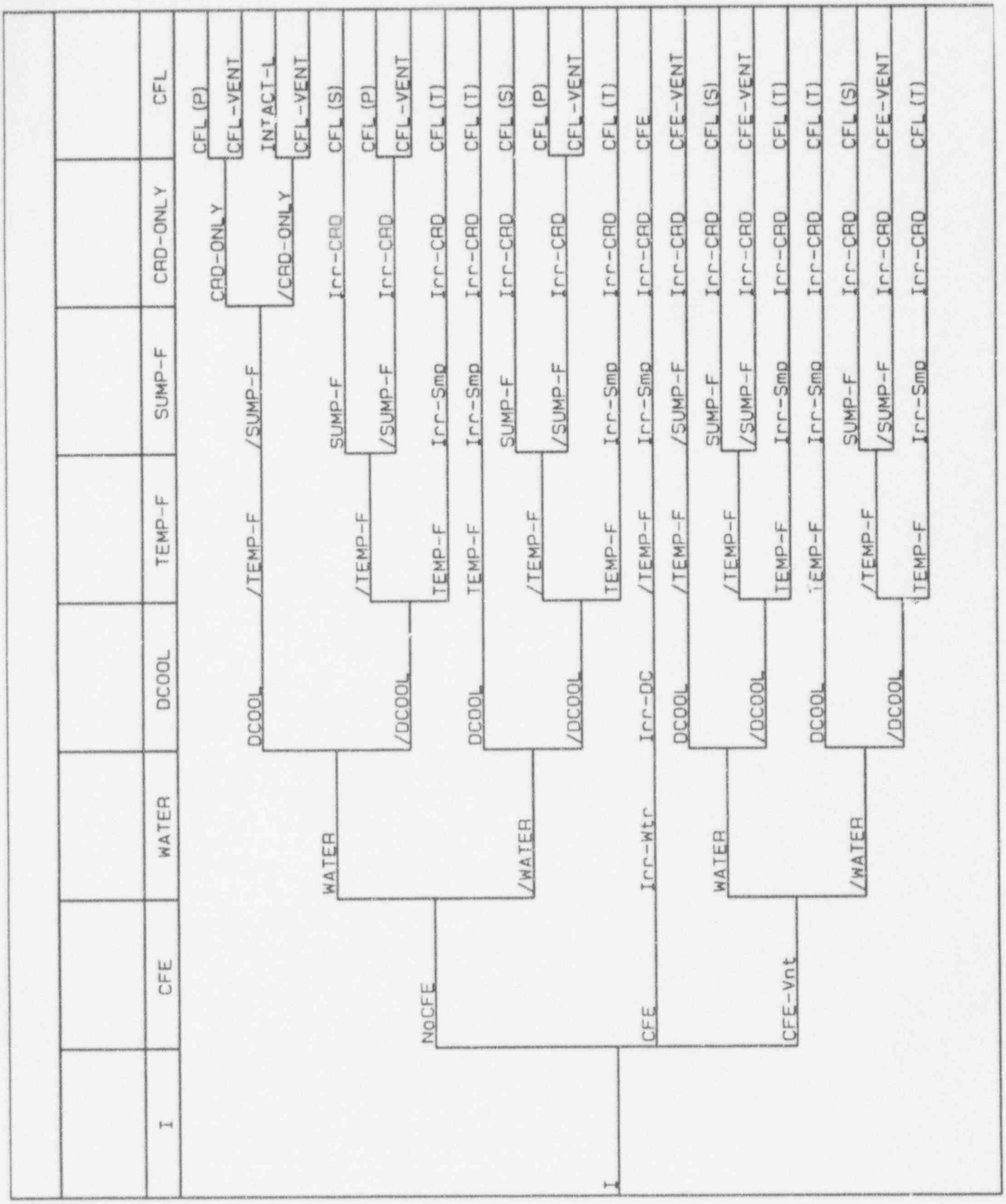

Figure 4.5-10. Late Containment Failure Subtree

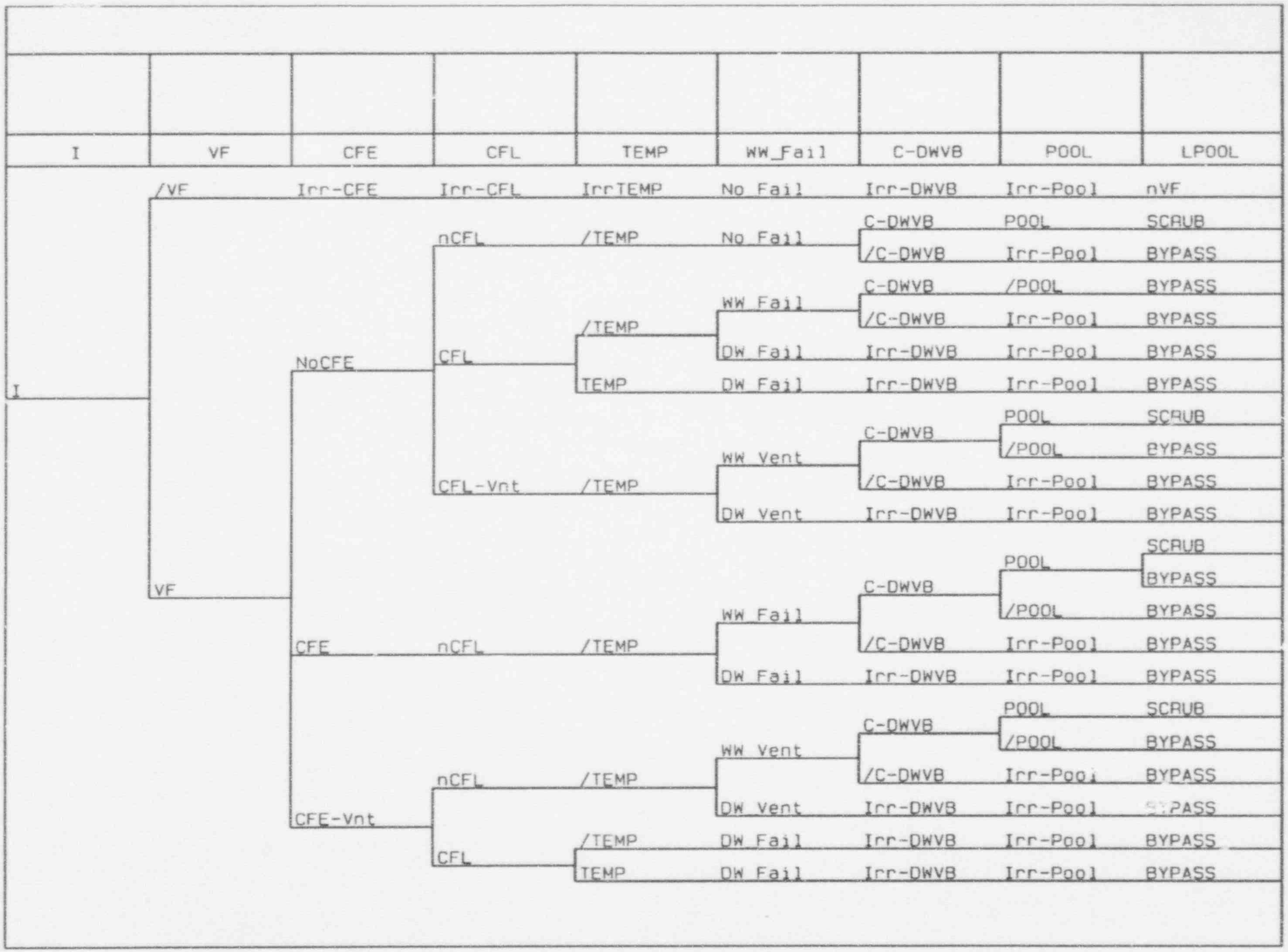

Figure 4.5-11. Late Release to Pool Subtree

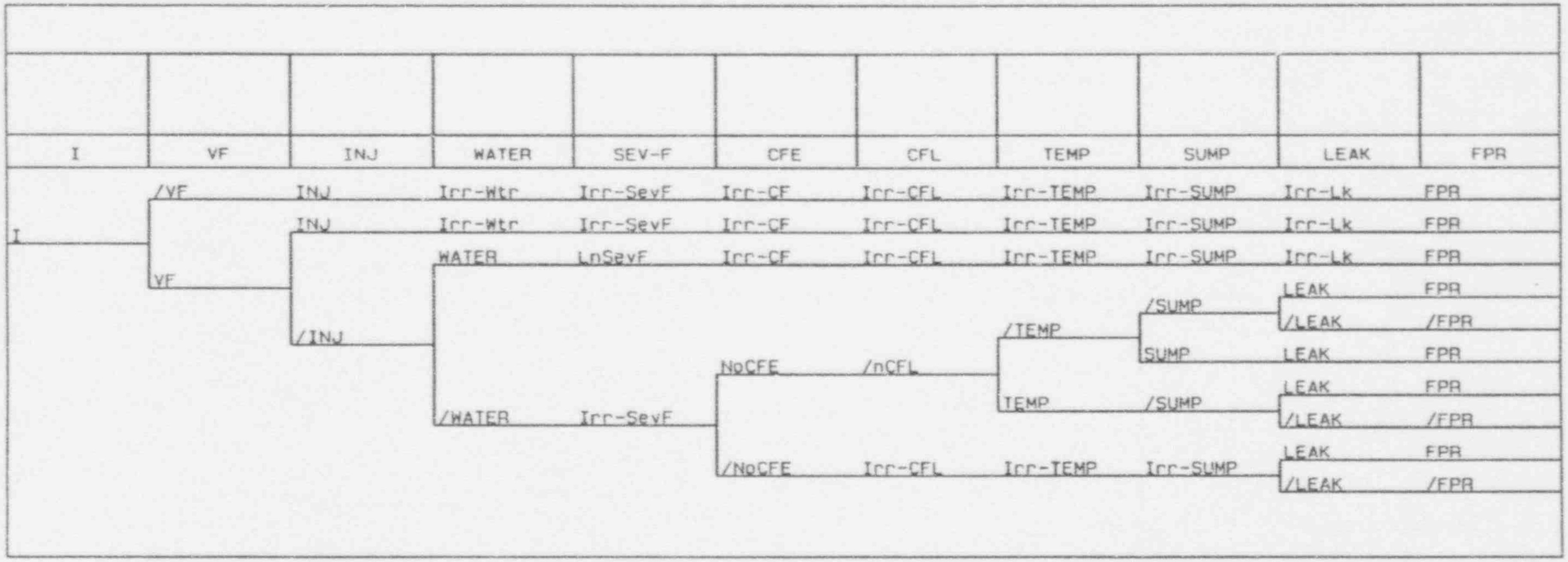

Figure 4.5-12. Fission Product Retention Subtree

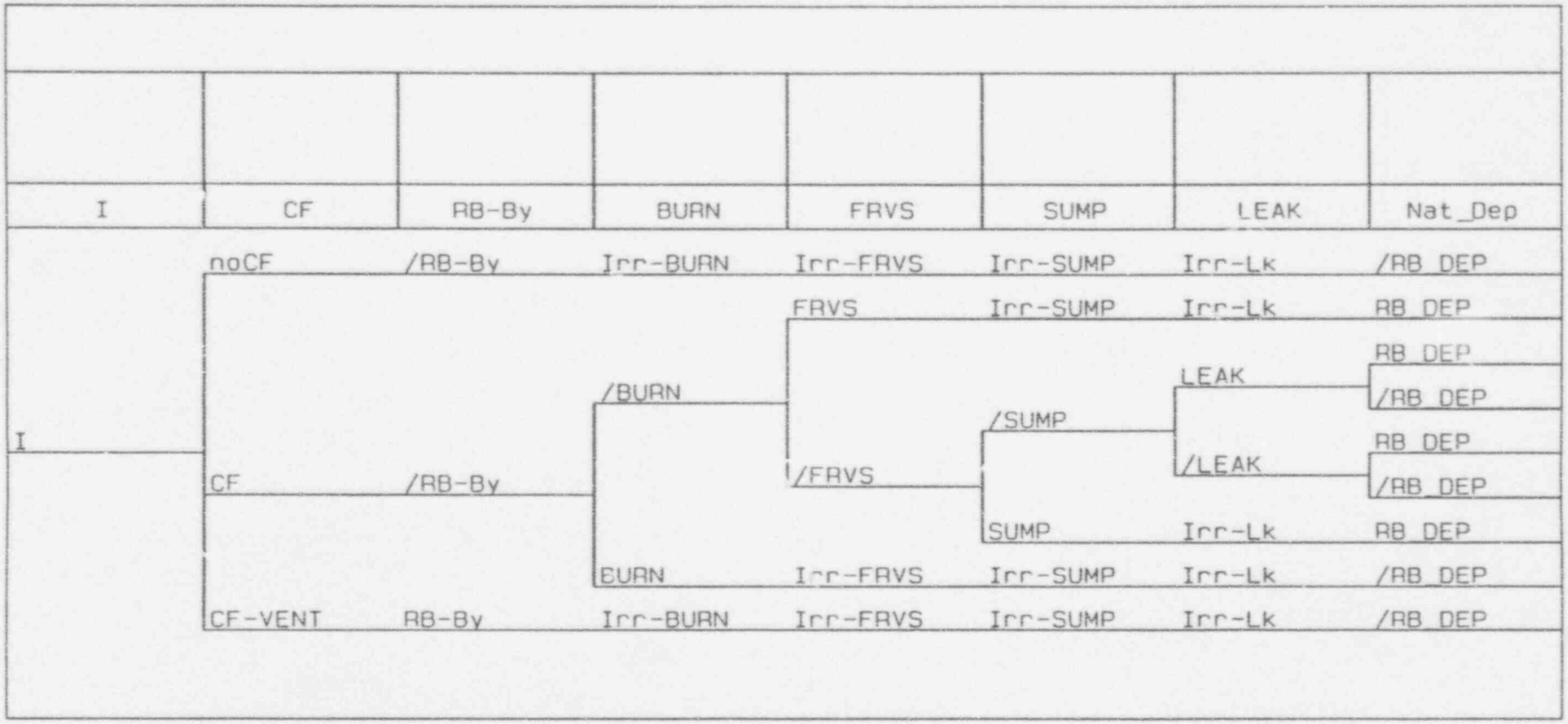

Figure 4.5-13. Secondary Containment Retention Subtree

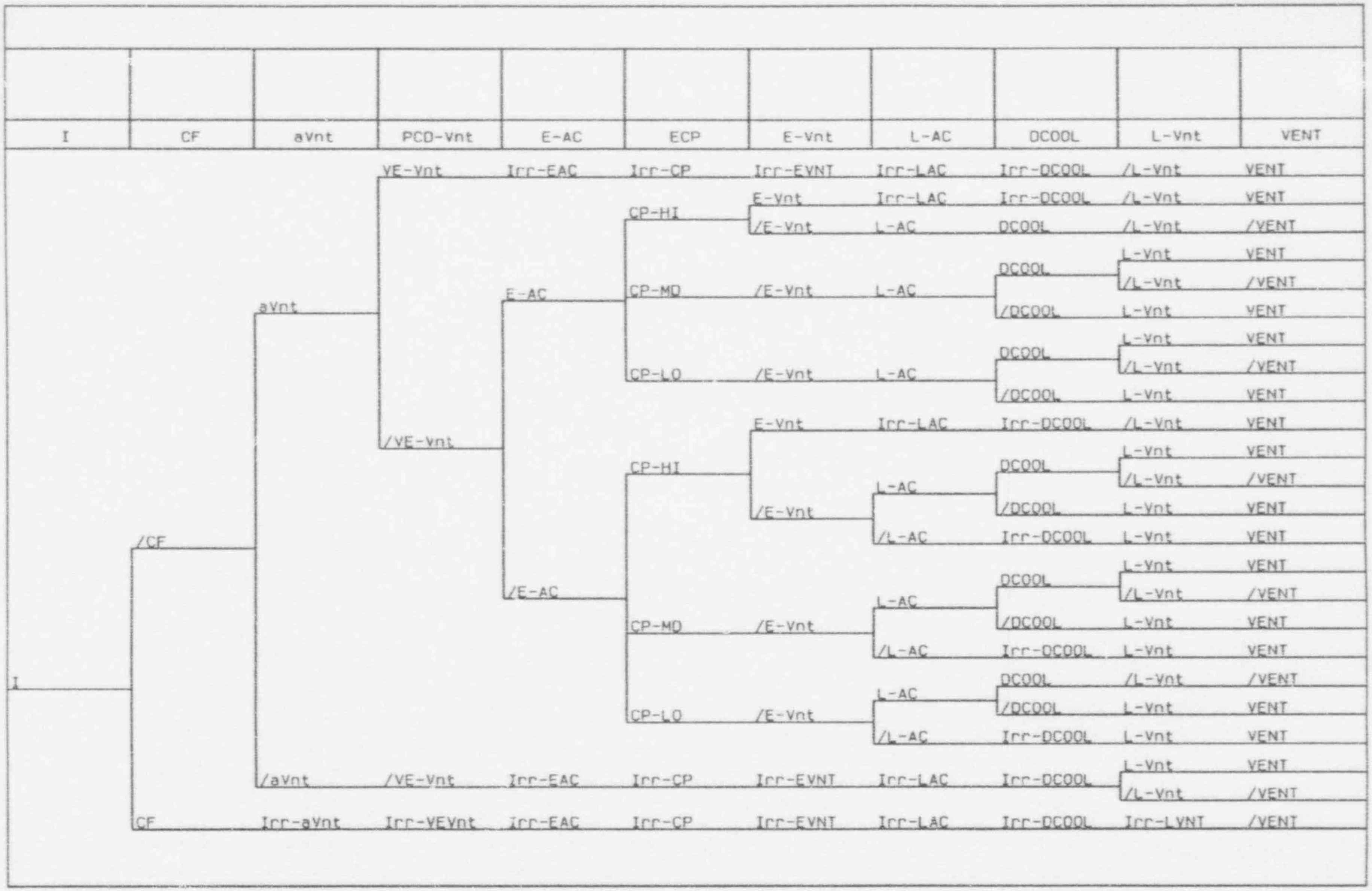

Figure 4.5-14. Vent Subtree

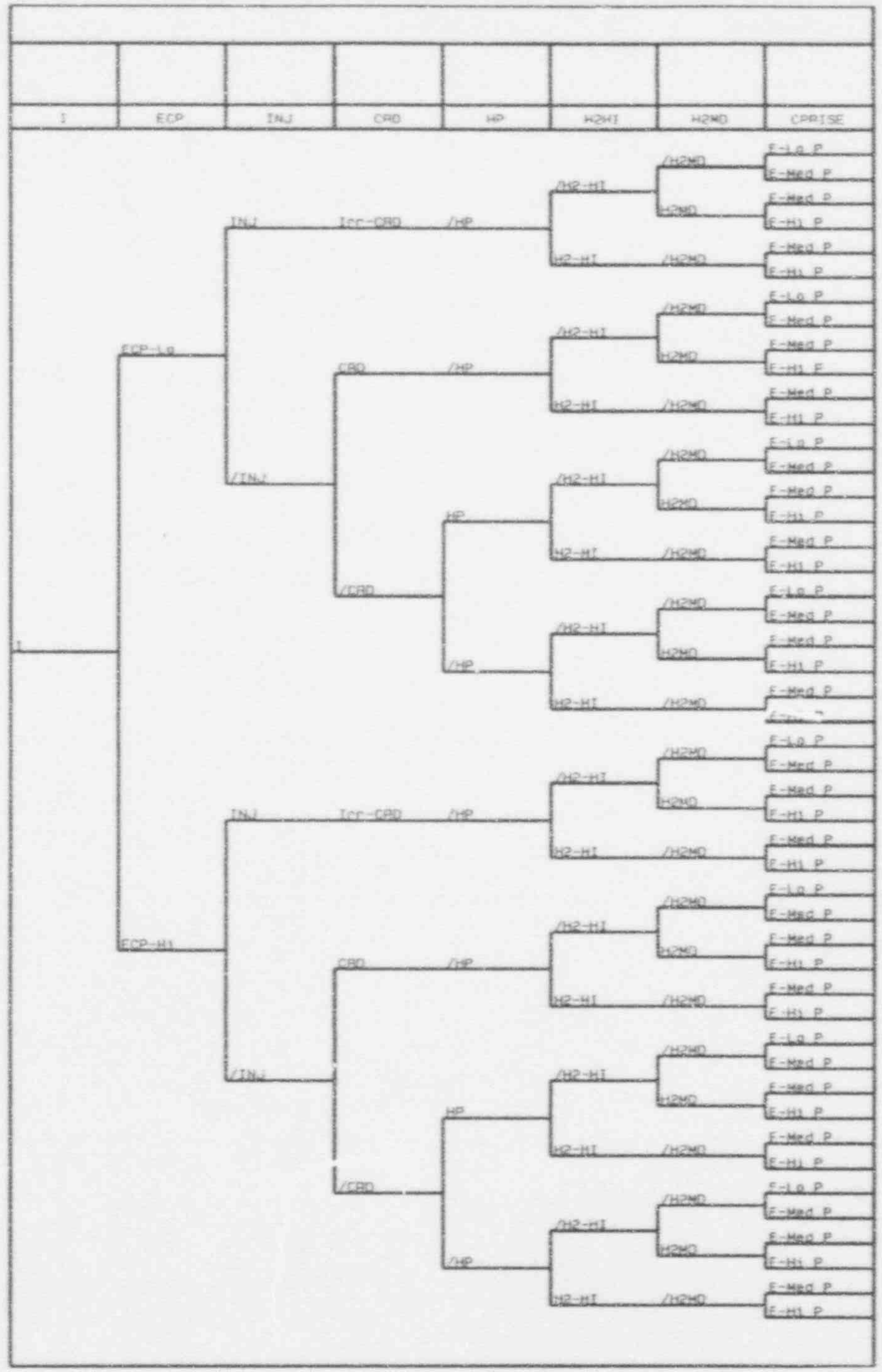

Figure 4.5-15. Containment Pressure Rise Prior to Vessel Breach (CPRISE) Sub-Subtree

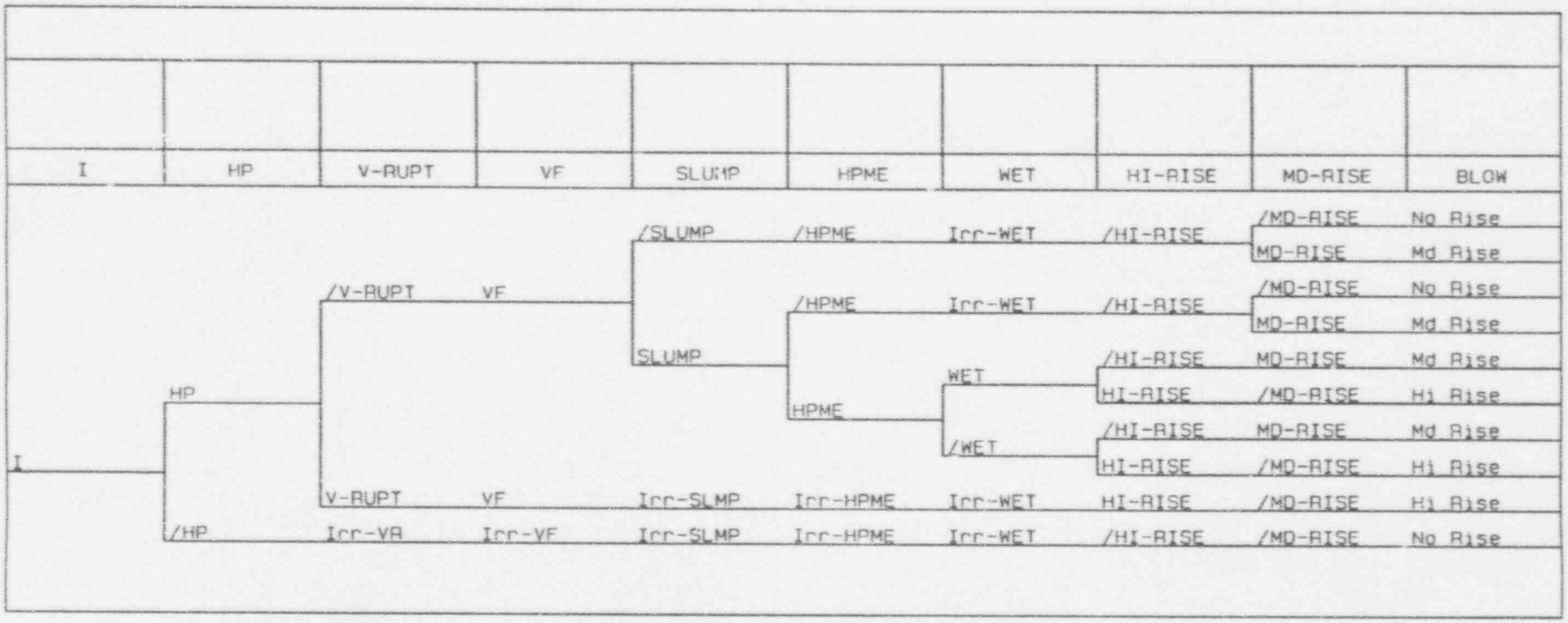

Figure 4.5-16. Containment Pressure Spike at Vessel Breach (BLOWDOWN) Sub-Subtree

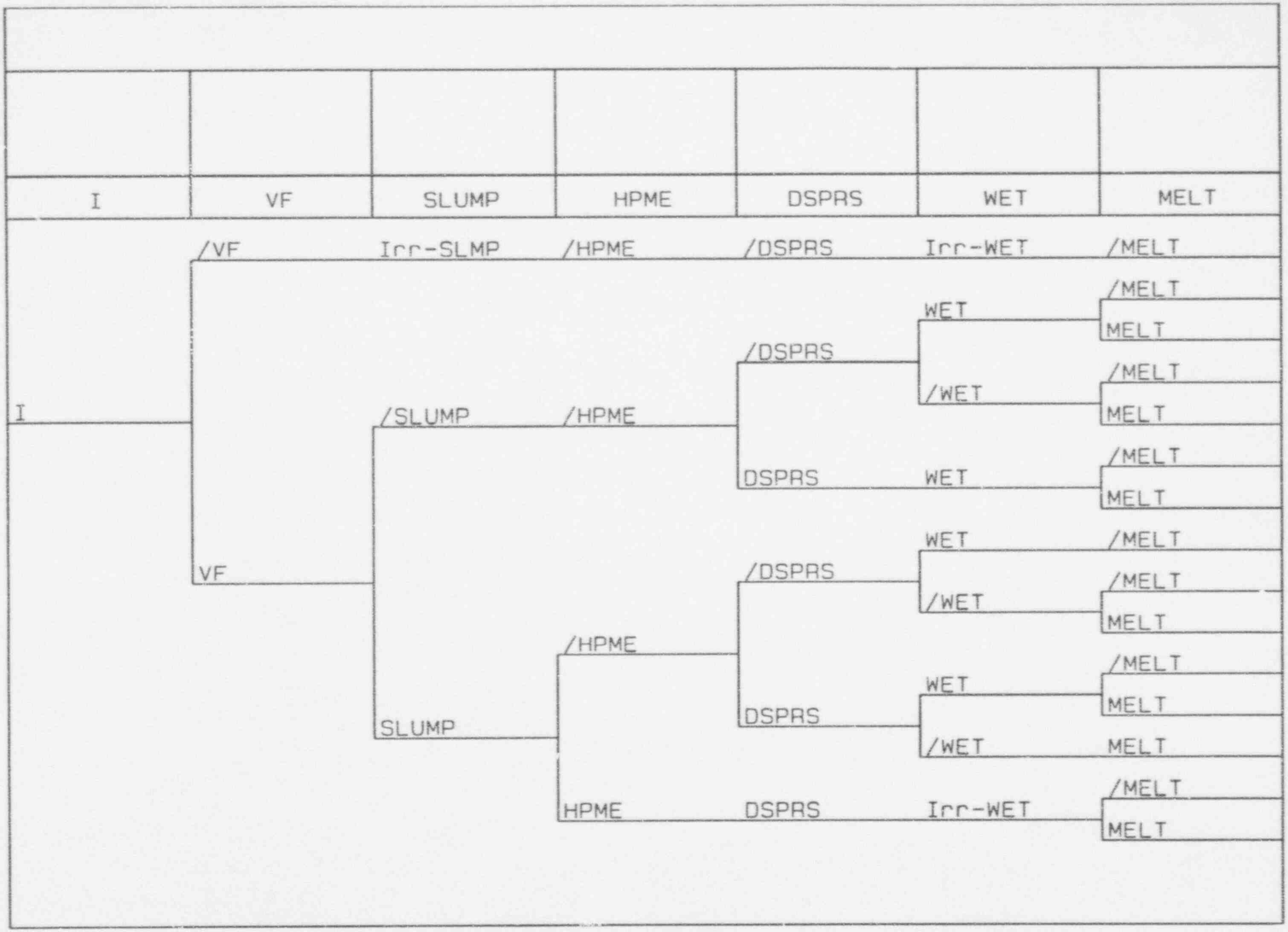

Figure 4.5-17. Drywell Melt-Through (MELT) Sub-Subtree

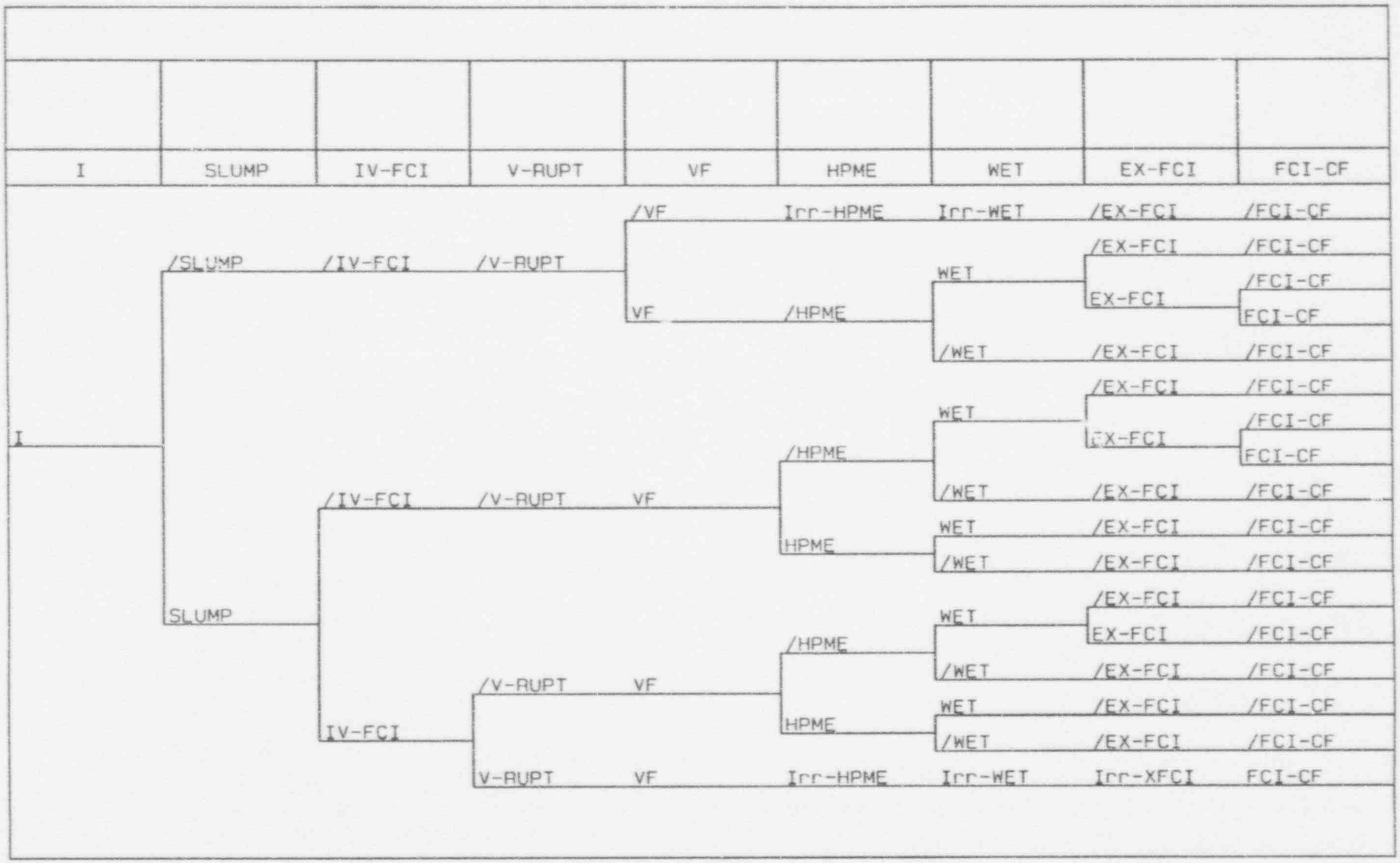

Figure 4.5-18. Fuel-Coolant Interaction Containment Failure Mode (FCI) Sub-Subtree

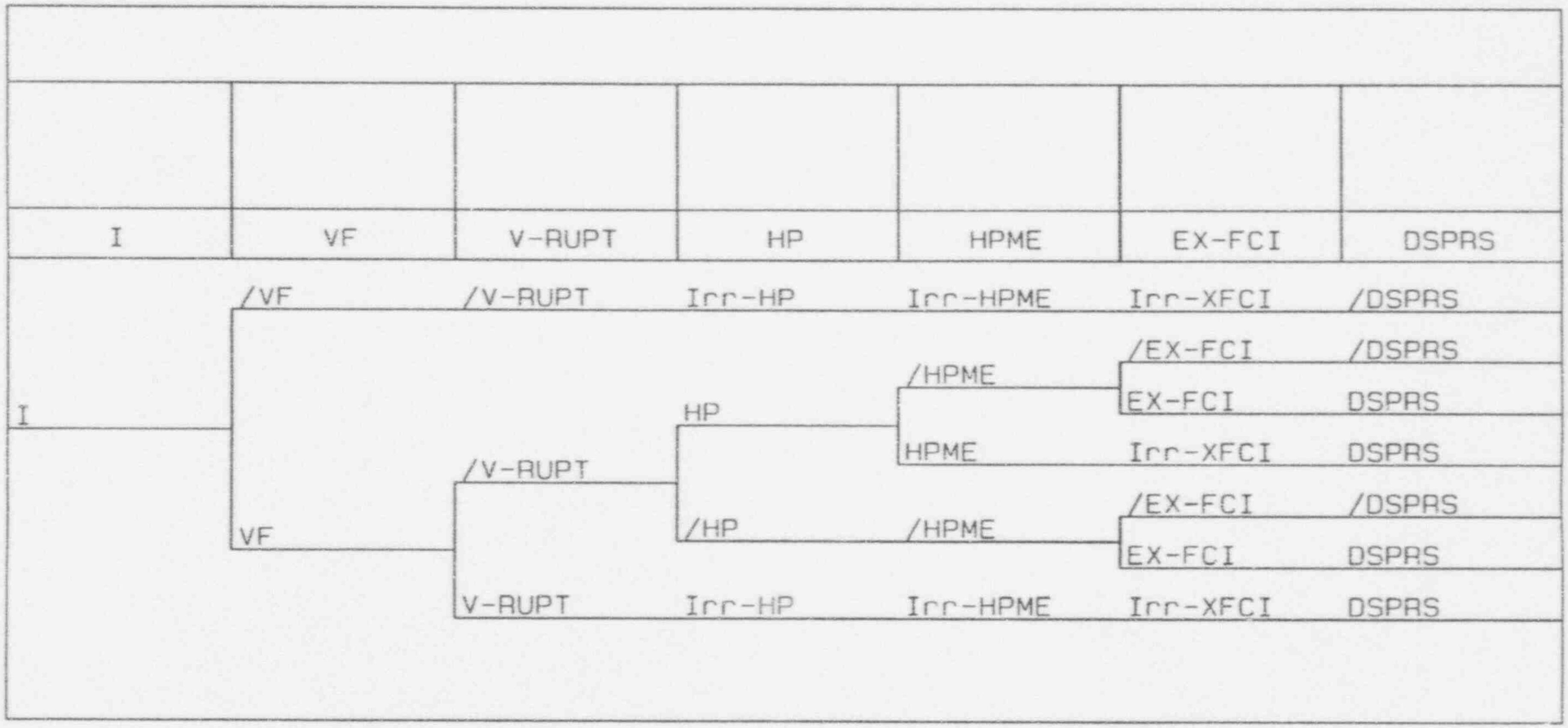

Figure 4.5-19. Debris Dispersal (DSPRS) Sub-Subtree

4.6 ACCIDENT PROGRESSION AND CET QUANTIFICATION

This section summarizes the results of the MAAP 3.0B (Reference 4.6-1) analyses performed to support the HCGS IPE, and provides a description of the methods used in the quantification of the basic event probabilities used in the HCGS CET. Quantification of basic events associated with containment performance and equipment survivability are highlighted.

4.6.1 Accident Progression Analyses

A substantial amount of information for the CET quantification was derived from the results of the HCGS MAAP calculations. The MAAP calculations were used to determine event timing (e.g., times of vessel failure and containment failure), magnitude of in-vessel and ex-vessel hydrogen generation, containment pressure loads, mechanism and location of containment failure, radionuclide release fractions, and radionuclide decontamination factors. When possible, the MAAP results were supplemented with published results obtained using other accident analyses codes.

The following discussion briefly summarizes the key results of the MAAP analyses. Only those results relevant to the quantification of the CET are discussed here. MAAP results used in the quantification of the source term algorithm parameters are discussed in Section 4.7. A more detailed discussion of the MAAP results and their use in the quantification of the CET is provided in Reference 4.6-2.

4.6.1.1 Event Timing

The MAAP calculations were used to provide information on the timing of core uncovery, vessel failure, containment failure, and Reactor Building failure. These times were needed for the analysis of human error basic events and also for basic events associated with AC power recovery.

4.6.1.2 Flammable Gas Production and Combustion

Since the HCGS primary containment is inerted, flammable gas (i.e., hydrogen and carbon monoxide) combustion in the primary containment is not considered in the HCGS CET. However, flammable gas combustion can occur in the Reactor Building, and may lead to Reactor Building failure. In addition to failing the Reactor Building, combustion increases gas flow and radionuclide transport from the Reactor Building to the environment.

To assess the potential for combustion in the Reactor Building, it is necessary to determine the magnitude of hydrogen production during core degradation, and the magnitude of hydrogen and carbon monoxide production during core-concrete interactions. Base case MAAP calculations were run with the "nodal blockage" option set. Depending on the accident sequence being calculated, between approximately 5 and 20 percent of the available zircaloy was calculated to oxidize during core degradation. Additional calculations were performed using the "no blockage" option to determine an upper bound to the in-vessel hydrogen production. These calculations showed as much as 45 percent in-vessel oxidation of the zircaloy. Both sets of results were used in the quantification of the HCGS CET; however, the nodal blockage results were considered to be more realistic, and were therefore weighted more heavily.

MAAP always predicts ex-vessel debris coolability whenever sufficient water is available to cover the core debris. Because this result has not been accepted by the NRC, the MAAP calculations were performed without late coolant injection. As a result, a core-concrete interaction always occurred, resulting in substantial generation of hydrogen and carbon monoxide. Subsequently, when containment failure was calculated, flammable gas combustion was nearly always predicted to occur in the secondary containment within the first hours following containment failure, unless the FRVS was operable. Multiple burns were calculated in some of the accident simulations. The MAAP results indicated that in absence of the FRVS, flammable gas combustion in the secondary containment is highly likely whether the containment failure is a leak or a rupture. The FRVS exhaust the hydrogen to the atmosphere, hence reducing its concentration and thereby minimizing the possibility of combustion within the secondary containment.

4.6.1.3 Containment Pressure and Temperature

The MAAP results formed much of the basis for the quantification of early and late containment failure due to high pressures or temperatures. The MAAP calculations provide predictions of the containment pressure rise during core damage, at vessel breach, and after vessel breach. The pressures calculated by MAAP were used along with the pressure rise results calculated in other BWR Mark I accident analyses to produce a range of possible containment pressures before and after vessel breach.

Because the failure pressures of the various hatches and other penetrations in the containment are very sensitive to the temperature of the containment, MAAP predictions of the containment temperature were also used in the CET quantification. The MAAP results were again supplemented with published results from other BWR Mark I severe accident analyses.

4.6.1.4 Containment Failure Mechanism and Location

The HCGS MAAP model included a simulation of all of important containment failure modes identified in Reference 4.6-3. Failure criteria for each failure mode were specified as a function of temperature and pressure. The failure location and failure size were also modeled in the MAAP input file. The failure size was specified as a function of pressure and temperature in accordance with the analysis presented in Reference 4.6-3, and described in Section 4.4.

When the failure criteria were exceeded during a time step, MAAP indicated that the containment had failed by sending an appropriate event message to the output files. This message identified the time of the failure, and the failure mode. If the containment failure size was insufficient to prevent further pressurization, subsequent containment failures at other locations were sometimes calculated to occur.

Most late containment failures were calculated to occur at the CRD hatch or the drywell head. These failures generally occurred when the containment temperature increased above 600°F, and the pressure capacity of the CRD hatch or drywell head fell to 21 psi. Based in part on the MAAP predictions of containment pressure and temperature after vessel failure, it was concluded that late containment failure is most likely to be caused by failure (i.e., loss of resiliency) of the seal material in the various hatches or the drywell head, and that the failure is likely to be a leak rather than a rupture.

Two MAAP calculations were performed to examine early failure due to drywell liner melt-through. In these calculations, the failure size was either 0.9 or 7.32 ft^2. These calculations were performed primarily to investigate secondary containment response and fission product transport following early drywell liner failure.

Other than the two liner melt-through simulations, no MAAP calculations showed early containment failure. This is not surprising since at the relatively low containment temperatures calculated by MAAP during the early phase of the accident, overpressure failure of the containment is likely only at very high containment pressures.

4.6.2 CET Quantification

4.6.2.1 Quantification Methods

The probabilities assigned to the basic events used in the CET were quantified using several different approaches depending on whether the basic events were specific to the Hope Creek Generating Station, whether they were generic to Mark I BWRs, or whether they involved human or system reliability. The following discussion outlines the methodology used for the quantification of each of these CET basic event classes. Table 4.6-1 provides a list of each basic event in the CET, along with a brief description of its meaning, the method used in the quantification, and the value assigned in the CET.

Many of the plant-specific CET basic events were evaluated based on the results of computer code calculations. These are shown as Class 2 basic events in Table 4.6-1. The primary source for these results was the set of calculations performed by PSE&G staff using the MAAP 3.0B code (Reference 4.6-1). For some basic events, published results calculated using other computer codes such as MELCOR (Reference 4.6-4) and CONTAIN (Reference 4.6-5) were used to supplement the MAAP results. For example, basic events associated with the magnitude of in-vessel hydrogen production or containment pressure rise were quantified by tabulating the calculated results and defining ranges (i.e., high, moderate, and low) for specific values. Basic event probabilities were then assigned to these ranges based on the relative number of code predictions falling in the range of interest. In some cases, the code calculations were further supplemented by results taken from NUREG/CR-4551 (Reference 4.6-6).

Other plant specific variables were not available from computer code calculations, but could be determined by comparison to analyses performed for similar plants. These basic events are shown as Class 3 in Table 4.6-1. An important example of this class of basic event is the probability of drywell shell melt-through. An analysis of drywell shell failure for a plant similar to HCGS has been published by Theofanous as NUREG/CR-5423 [4.6-7]. In assessing the probabilities of drywell shell failure under a variety of accident conditions, the results in NUREG/CR-5423 were used where possible. For cases not considered in the referenced analysis, values were taken from NUREG/CR-4551. These values were determined by expert elicitation, rather than on a detailed analysis.

Generic CET basic events correspond to probabilities for which specific features of the HCGS plant are not important or in which the uncertainties in the relevant phenomena are far greater than the potential impact of specific plant features. These basic events are shown as Class 1 in Table 4.6-1. For these basic events, CET values were taken from generic analyses or from other PRAs. Prime examples of basic events in this class are the probabilities of an in-vessel steam explosion, or of vessel failure given an in-vessel steam explosion. In both of these examples, probabilities were taken from the NUREG-1150 analysis of the Peach Bottom plant, which is documented in NUREG/CR-4551 (Reference 4.6-6).

Human reliability analyses (HRA) (i.e., Class 4 in Table 4.6-1) were performed for CET basic events associated with operator actions. The HRA used in the CET quantification considered the human error associated with the failure to diagnose a problem, and the human error associated with performing the corrective action. The human error probabilities (HEPs) associated with diagnosis and action are functions of the time available for the operator to act, the level of stress the operator is under, whether step-by-step procedures are available to guide the operator, and whether technical oversight is provided (e.g., by a senior reactor operator (SRO), or by the technical support center (TSC)).

For the basic events quantified in the CET, the time available for the operator to act is so long (typically on the order of one hour or more) that the diagnosis HEP becomes very small. Consequently, the majority of the HEP is associated with the failure of the operator to perform the correct actions. Here, the potential for technical oversight and correction of initially incorrect actions can be important. In the CET quantification, we have assumed that all actions performed in the control room by the operator will be guided by the SRO or TSC. Since only actions governed by existing emergency operating procedures (EOPs) are considered in the CET, all operator actions were assumed to have associated procedures for the operator to follow. The HEP analysis assumed that the operators would be under high stress during the back-end (Level II) portion of the accident.

System reliability analyses were performed for CET basic events concerned with functionality (i.e., availability) of equipment that could potentially mitigate the accident. These basic events are shown as Class 5 in Table 4.6-1. If a similar analysis was performed as part of the front-end (Level I) assessment, those results were used, but were modified to account for conditions present during the back-end (Level II) portion of the accident.

A detailed analysis of AC power recovery was beyond the scope of the Level II portion of the IPE. For this reason, the AC power non-recovery tables derived in NUREG/CR-4550 [4.6-8] were used in the CET quantification.

The following two sections provide more detail on the quantification of basic events related to containment failure, and basic events related to equipment survivability in the harsh environments that would exist in the secondary containment following containment failure.

4.6.2.2 Containment Loads and Containment Failure

This section discusses quantification of the containment loads and containment failure mechanisms considered in the HCGS CET. The containment failure mechanisms discussed below include: static overpressurization of the containment, containment failures induced by in-vessel and ex-vessel steam explosions, drywell shell failure due to direct contact with core debris, and thermal failure due to high drywell temperatures.

Static Overpressurization and Thermal Failure

Phenomena that affect overpressurization of the containment include: pressure rise during core degradation, pressure rise at vessel breach, high pressure melt ejection, and rapid steam generation when core debris pours into water on the drywell floor (i.e., steam spike). All of these phenomena were considered in the quantification of the probability of overpressure failure of the containment.

First, the MAAP calculations were reviewed in order to tabulate the pressure rise during core damage, and the pressure rise at vessel breach for all of the HCGS plant damage states. Other BWR Mark I analyses for similar accident sequences were also tabulated. The values for pressure rise prior to vessel breach were then grouped with respect to suppression pool temperature (subcooled or saturated), and magnitude of in-vessel hydrogen production. The values for pressure rise at vessel breach were similarly grouped; however, here the considerations were vessel pressure (high or low) at the time of vessel breach, occurrence of a high pressure melt ejection (HPME), presence of water on the drywell floor, and suppression pool temperature. (Note: since MAAP does not calculate the effects of HPME, the HPME pressure rise used in NUREG/CR-4551 (Reference 4.6-6) was used. This pressure rise was added to the base pressure determined from the MAAP analyses to determine the total pressure rise at vessel breach given that HPME occurs.)

With the available information tabulated and grouped as described, probabilities associated with three levels of pressure rise (e.g., high, moderate, and low) were then assigned based on the technical support for each level. For example, if most of the accident analyses show containment pressures during core damage that are in the moderate range, a much higher probability would be assigned to the moderate pressure level. The CET split fractions are assigned to each of the three levels of pressure rise during core damage, and three levels of pressure rise at vessel breach.

The various combinations of high, moderate, and low pressure rise prior to and immediately following vessel failure were then combined to determine the resulting total pressure levels in the containment following vessel failure. These pressures were then compared to the HCGS containment failure curves shown in Section 4.4 to determine the resulting probability of early containment failure. Combinations with similar containment failure probabilities were considered together in the CET, with a characteristic average failure probability defined for each such grouping.

Late failure of the containment was treated somewhat differently from early failure due to the sensitivity of the containment failure pressure to the temperature in the drywell. The MAAP calculations indicate that containment failure at one of the drywell hatches or at the drywell head is virtually assured at elevated drywell temperatures (i.e., at drywell temperatures greater than 500°F). These failures occur because the material comprising the seals in the hatches and the drywell head flange assembly loses its resiliency at high temperatures. When this occurs, the seals begin to degrade and leak. (This failure mode is referred to as "thermal failure" in the HCGS CET.) The failure size and, consequently, the leakage rate depend on the existing containment pressure. The MAAP calculations indicate that leakage through the seals is sufficient to prevent structural failure of the torus or drywell at very high pressures.

If the temperature in the drywell remains well below 500°F, such as in cases with a saturated steam environment in the drywell, thermal failure of the drywell is unlikely, but overpressure failure is still possible. In the CET, late overpressure failure is assumed to be virtually assured unless sufficient water is supplied to the ex-vessel core debris to maintain the overlying water pool in a subcooled state. Without subcooling, the pressure buildup due to steam and non-condensable gases from the concrete is assumed to be sufficient to eventually fail the containment.

Containment Failures Induced by Steam Explosions

The substantial uncertainty associated with steam explosion phenomena makes a detailed assessment of steam-explosion-induced containment failures unwarranted. Consequently, probabilities in the CET related to steam explosion phenomena were determined, supported by the results used in NUREG/CR-4551 and the analysis provided in Reference 4.6-10.

The median probability of an in-vessel steam explosion was determined to be 0.05 based on consideration of the results provided in References 4.6-10 and 4.6-6. These references indicated values for this probability that ranged from 0.002 to 0.2.

Given that an in-vessel steam explosion occurs, it was necessary to determine the probability that the explosion was sufficient to rupture the reactor vessel. Assessment of this probability was simplified by assuming that rupture of the reactor vessel results in containment failure. Values for the probability of in-vessel steam explosion induced containment failure (commonly referred to as the alpha mode failure probability) have been determined in several studies. The value given in Reference 4.6-10 was used in the HCGS quantification. Since the vessel rupture probability is conditional upon the occurrence of an in-vessel steam explosion, this probability was determined by dividing the alpha mode failure probability given in the reference (0.0001) by the probability of an in-vessel steam explosion. The resulting vessel rupture probability is 0.002.

The probability of an ex-vessel steam explosion was determined for two cases that differ only by whether the core collapses en masse (i.e., a large mass of molten material is present). Without a large mass of molten material present, an ex-vessel steam explosion was judged to be unlikely. This judgement is supported by the analysis provided in Reference 4.6-10. Based on this qualitative assessment, a probability of 0.1 was assigned. With a large mass of molten material present, the probability of an ex-vessel steam explosion is much higher. NUREG/CR-4551 (Reference 4.6-6) assumed a value of 0.85 for this probability, while analyses provided to support the MAAP model indicate that large ex-vessel steam explosions are very unlikely (Reference 4.6-1). Based on these two widely divergent views, the ex-vessel steam explosion probability was viewed to be indeterminate, and a value of 0.5 was assigned.

Given that an ex-vessel steam explosion occurs, a probability exists that the explosion will be sufficient to fail the containment. Pressure relief off the free surface of the shallow water pool in the drywell should reduce the transmitted pressure such that containment structures are unlikely to be threatened. Based on engineering judgement supported by the qualitative analysis provided in Reference 4.6-10, the probability of containment failure was determined to be 0.1 given that a large mass of molten material is involved in the steam explosion, and 0.01 given that a large mass of molten material is not involved in the steam explosion.

Drywell Shell Failure Caused by Direct Debris Contact

Two modes of drywell shell failure were considered in the HCGS CET. One mode involves early containment failure caused by contact of core debris with the ex-pedestal portion of the drywell shell. A second mode involves late drywell failure caused by contact of core debris with the portion of the drywell in the concrete embedment.

The first mode of drywell shell failure is often referred to as drywell shell melt-through, although melting of the shell is not a necessary requirement for failure. This mode of containment failure was considered in the NUREG-1150 study of the Peach Bottom plant, and has been widely studied in recent years. The most complete analysis of this failure mechanism is presented in NUREG/CR-5423 (Reference 4.6-7). This document formed the basis for much of the quantification of containment failure by drywell shell melt-through.

Seven different cases were considered in the HCGS CET. These cases represent different combinations of (a) mass of molten material available at vessel breach, (b) extent of debris dispersal at vessel breach, and (c) whether the drywell floor is flooded or not. Cases that were addressed in the NUREG/CR-5423 analysis were assigned the same containment failure probabilities as in that study. Cases not addressed in NUREG/CR-5423 were quantified using probabilities taken from NUREG/CR-4551 (Reference 4.6-11). These values were determined by experts elicitation. The resulting containment failure probabilities are shown in Table 4.6-1.

Drywell shell failure in the concrete embedment can occur late in the accident if the concrete is eroded to a sufficient depth. If core debris collects in the sump just outside the personnel access doorway in the pedestal and a core-concrete interaction ensues, penetration of the drywell shell directly below the sump would appear likely since the drywell shell is approximately 7 inches from the bottom of the sump. Because it is expected that the core debris would flow through the doorway and into the sump, a high probability (0.9) was assigned to this failure mode.

4.6.2.3 Survivability of Engineered Safeguards

Given the harsh environment that might exist in the secondary containment following containment failure, the survivability (i.e., continued function) of engineered safeguards must be considered. The HCGS CET considers survivability of alternate injection systems, ECCS systems, and the CRD system following containment failure.

For the quantification of these basic events, the NUREG-1150 values determined for the Peach Bottom plant (Reference 4.6-6) were used as a baseline. Upon reviewing differences between the designs of the secondary containment in the HCGS and Peach Bottom plants, it was concluded that, due to its more extensive compartmentalization, the HCGS design has distinct advantages over the Peach Bottom design. Because the HCGS design is more compartmentalized, harsh environments in one area of the secondary containment are less likely to be communicated to other areas. In addition, some elements of the alternate injection system (e.g., the condensate pumps) are in the turbine building rather than the reactor building. Thus, there is a greater likelihood that some systems will survive a containment failure. Since the Peach Bottom plant survivability values are used as the baseline for the HCGS, the treatment of equipment survivability in the HCGS CET is believed to be conservative.

Sensitivity analysis are performed on availability of the ECCS, alternate injection systems and the FRVS to circumscribe all uncertainties regarding survivability of these systems.

4.6.3 References

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TABLE 4.6-1
CET BASIC EVENT QUANTIFICATION

Basic Event Name	Class	Description	Value
AC-PWR-EARLY-1	4,5	AC POWER IS NOT RESTORED EARLY GIVEN EVENT IS A ST-SBO: Probability that AC Power is not restored early given that a short term station blackout has occurred.	0.305
AC-PWR-EARLY-2	4,5	AC POWER IS NOT RESTORED EARLY (LT-SBO) Probability that AC Power is not restored early given that a long term station blackout has occurred.	0.605
AC-PWR-LATE-1	4,5	LATE AC POWER NOT RESTORED GIVEN EVENT IS A ST-SBO: Probability that AC Power is not available late given that a short term station blackout has occurred and AC Power is not restored early.	0.17
AC-PWR-LATE-2	4,5	LATE AC POWER NOT RESTORED GIVEN EVENT IS A LT-SBO: Probability that AC Power is not available late given that a long term station blackout has occurred and AC Power is not restored early.	0.50
ALT-FL-1	4	OPERATOR FAILS TO PROVIDE ALTERNATE COOLING TO DEBRIS: Probability that the operator fails to provide flow from alternate systems after vessel failure, given that there was no station blackout, low-pressure ECCS is not available and alternate injection systems are available. Vessel was not depressurized prior to vessel breach, thus is the first opportunity to use alternate injection.	0.052
ALT-FL-2	4	OPERATOR FAILS TO PROVIDE ALTERNATE COOLING TO DEBRIS: Similar to ALT-FL-1, except that the vessel was previously depressurized. Operators have previously failed to use alternate injection source as required.	1.0
ALT-FL-3	4	OPERATOR FAILS TO PROVIDE ALTERNATE COOLING TO DEBRIS: Probability that the operator fails to provide flow from alternate systems, given a station blackout, but with AC Power restored late. ECCS is not available.	0.052
ALT-FLOW-1	4	ALTERNATE FLOW NOT INITIATED: Human error probability for failure to align alternate injection systems (condensate or service water) during core damage given that at least one system is available, and because of a prior error of omission was not previously restored.	1.0
ALT-FLOW-2	4	ALTERNATE FLOW NOT INITIATED: Human error probability for failure to align alternate injection systems (condensate or service water) during core damage given that at least one system is available, AC power is restored early, and ECCS is not available.	0.052
BRN-LK-1	2	H_2 BURNS IN THE REACTOR BUILDING AFTER CONTAINMENT LEAK: Probability of a Reactor Building H_2 burn, given leakage into the Reactor Building, coolable debris is formed ex-vessel (i.e., no ex-vessel H_2 and in-vessel H_2 production is high.	0.95
BRN-LK-2	2	H_2 BURNS IN THE REACTOR BUILDING AFTER CONTAINMENT LEAK: Probability of a Reactor Building H_2 burn, given leakage into the Reactor Building and ex-vessel debris is not coolable (i.e., H_2 source is substantial).	0.999

TABLE 4.6-1
CET BASIC EVENT QUANTIFICATION (CONTINUED)

Basic Event Name	Class	Description	Value
BRN-RPT1	2	H_2 BURNS IN REACTOR BUILDING AFTER CONTAINMENT RUPTURE: Probability of a Reactor Building H_2 burn, given that there is no reactor building bypass, coolable debris is formed ex-vessel, in-vessel H_2 production is high, and containment rupture occurs.	0.999
BRN-RPT2	2	H_2 BURNS IN REACTOR BUILDING AFTER CONTAINMENT RUPTURE: Probability of a Reactor Building H_2 burn, given that there is no reactor building bypass, ex-vessel debris is not coolable, and containment rupture occurs.	1.0
CD -> DP - 1	4	OPERATOR FAILS TO DEPRESSURIZE AFTER CORE DAMAGE: Probability that the operator fails to depressurize the RPV after core damage, given that the SRVs are operable in relief mode and DC Power is available (i.e., prior error of omission).	1.0
CD -> DP - 2	5	FAILURE TO DEPRESSURIZE AFTER CORE DAMAGE: Operator depressurizes early but containment pressure recloses SRVs prior to core damage. Containment is successfully vented (Containment venting is irrelevant for CD -> DP - 1). This event reflects the failure of the SRVs to reopen in sufficient time to prevent core damage.	2.E-5
CD -> DP - 3	4	OPERATOR FAILURE TO DEPRESSURIZE AFTER CORE DAMAGE: Probability that the operator fails to depressurize after core damage given that the SRVs are operable in relief mode but DC Power was previously unavailable and AC Power is then restored.	0.052
CFE-HI-HI/MD	2	CONTAINMENT FAILS EARLY DUE TO OVERPRESSURIZATION: Probability that the containment fails early due to high pressure rise during vessel breach.	0.95
CFE-MD-HI	2	CONTAINMENT FAILS EARLY DUE TO OVERPRESSURIZATION: Probability that the containment fails early due to high pressure during core damage and moderate pressure rise during vessel breach.	0.75
CFE-MD-MD	2	CONTAINMENT FAILS EARLY DUE TO OVERPRESSURIZATION: Probability that the containment fails early due to moderate pressure during core damage and moderate pressure rise during vessel breach.	0.3
CM>26%	2,4	GREATER THAN 26% CORE MELT: Probability that >26% of the core melts prior to low-pressure injection recovery.	0.5
COOL-1	3	DEBRIS NOT COOLED: Probability that debris is not cooled given that vessel breach occurs, water is present on the drywell floor at vessel breach due to either spray operation or recovery of injection prior to vessel breach, debris is not dispersed at vessel failure, and the core does not collapse en-masse.	0.1

TABLE 4.6-1
CET BASIC EVENT QUANTIFICATION (CONTINUED)

Basic Event Name	Class	Description	Value
COOL-2	3	DEBRIS NOT COOLED: Same as COOL-1, except core collapses en-masse (SLUMPS).	0.5
COOL-3	3	DEBRIS NOT COOLED: Same as COOL-1, except that debris is dispersed at vessel failure.	0.05
COOL-4	3	DEBRIS NOT COOLED: Probability that debris is not cooled given that vessel breach occurs, there is no water on drywell floor at vessel breach, but water addition to the containment is restored following vessel failure. Debris is not dispersed at vessel failure and the core does not collapse en-masse.	0.5
COOL-5	3	DEBRIS NOT COOLED: Same as COOL-4, except core collapses en-masse (SLUMPS).	0.9
COOL-6	3	DEBRIS NOT COOLED: Same as COOL-4, except debris is dispersed at vessel failure.	0.1
COOL-7	3	DEBRIS NOT COOLED: Probability that debris is not cooled given that the debris is dispersed at vessel breach, but that no water is being added to the drywell.	0.99
CP-LO/MD	2	CONTAINMENT PRESSURE RISE IS LOW NOT MODERATE PRIOR TO VESSEL BREACH: Probability that the containment pressure rise prior to vessel breach is low rather than moderate given moderate hydrogen production in-vessel, and suppression pool temperature is subcooled.	0.9
CP-MD/HI-1	2	CONTAINMENT PRESSURE RISE IS MODERATE NOT HIGH PRIOR TO VESSEL BREACH: Probability that the containment pressure rise prior to vessel breach is moderate rather than high given high hydrogen production in-vessel.	0.1
CP-MD/HI-2	2	CONTAINMENT PRESSURE RISE IS MODERATE NOT HIGH PRIOR TO VESSEL BREACH: Probability that the containment pressure rise prior to vessel breach is moderate rather than high given moderate hydrogen production in-vessel, and suppression pool subcooled.	0.9
CP-MD/HI-3	2	CONTAINMENT PRESSURE RISE IS MODERATE NOT HIGH PRIOR TO VESSEL BREACH: Probability that the containment pressure rise prior to vessel breach is low rather than moderate given moderate hydrogen production in-vessel, and suppression pool temperature > 200 F.	0.9
CRD-FLOW	4	HUMAN ERROR FAILURE TO RESTORE CRD: Probability that the operator fails to provide CRD flow to the vessel, given that AC Power is restored, and control rod drive pumps are operable.	0.052

TABLE 4.6-1
CET BASIC EVENT QUANTIFICATION (CONTINUED)

Basic Event Name	Class	Description	Value
CRD-L-1	4	OPERATOR FAILS TO PROVIDE CRD FLOW TO DEBRIS: Probability that the operator fails to provide CRD flow to the debris given that there is not a station blackout and CRD pumps are operable. This implies that operators had previously failed to restore CRD flow as required.	1.0
CRD-L-2	4	OPERATOR FAILS TO PROVIDE CRD FLOW TO DEBRIS: Probability that the operator fails to provide CRD flow to the debris given a station blackout but with AC Power restored late. CRD pumps are operable.	0.052
DEPOSIT1	2	FISSION PRODUCT RETENTION IS LOW IN REACTOR BUILDING: Probability that natural deposition does not occur given that containment failure results in leakage that does not bypass reactor building, no hydrogen combustion occurs in the building and standby gas treatment fails.	0.1
DEPOSIT2	2	FISSION PRODUCT RETENTION IS LOW IN REACTOR BUILDING: Same as DEPOSIT1, except containment rupture occurs.	0.95
DWF-E	2	CONTAINMENT FAILS EARLY IN DRYWELL: Probability that the failure is in the drywell given that the containment fails early.	0.9
DWF-L	2	CONTAINMENT FAILS LATE IN DRYWELL: Probability that containment fails late in drywell given that the containment does not fail early and thermal failure is prevented late.	0.95
ECCS-FLOW	5	ECCS FLOW NOT RECOVERED PRIOR TO VESSEL FAILURE: Probability that ECCS flow does not occur given that AC Power is restored prior to vessel breach, the vessel is depressurized, and low-pressure ECCS is available.	1.E-4
ECCS-L-1	5	LATE ECCS FLOW NOT PROVIDED TO DEBRIS: Probability that ECCS flow is not provided to the debris late given that there is no station blackout and low-pressure ECCS is available. Vessel pressure was high prior to vessel breach and so ECCS was not previously operable.	1.E-4
ECCS-L-2	5	LATE ECCS FLOW NOT PROVIDED TO DEBRIS: Probability that ECCS flow is not provided to the debris late given a station blackout, but with the AC Power restored late. Low-pressure ECCS was not available previously.	1.E-4
FCI-CF-1	1	FCI INDUCED CONTAINMENT FAILURE: Probability of an FCI-induced containment failure given that an ex-vessel FCI occurs that does not involve a large mass of molten material (i.e., SLUMP does not occur).	0.01

TABLE 4.6-1
CET BASIC EVENT QUANTIFICATION (CONTINUED)

Basic Event Name	Class	Description	Value
FCI-CF-2	1	FCI INDUCED CONTAINMENT FAILURE: Same as FCI-CF-1, except a large mass of molten material is involved.	0.1
FCI-EX-1	1	EX-VESSEL FUEL COOLANT INTERACTION: Probability that ex-vessel fuel-coolant interaction occurs given that either the core does not collapse en-masse or core collapse induces an in-vessel FCI, in-vessel fuel coolant interaction is prevented, vessel breach occurs, and there is water on the drywell floor.	0.1
FCI-EX-2	1	EX-VESSEL FUEL COOLANT INTERACTION: Probability that ex-vessel fuel coolant interaction occurs given that the core collapses en-masse (SLUMP), in-vessel fuel coolant interaction is prevented, vessel breach occurs, and there is water on the drywell floor.	0.5
FCI-IN	1	IN-VESSEL FUEL COOLANT INTERACTION: Probability of an in-vessel FCI given that the core collapses en-masse (SLUMPS).	0.05
FCI-VSLRPT	1	VESSEL RUPTURE WITH FCI AND SLUMP: Probability that the vessel ruptures given that the core does collapse en-masse (SLUMP) and in vessel FCI occurs.	0.002
H2MD-CRD	1,2	MODERATE HYDROGEN PRODUCTION GIVEN CRD FLOW: Probability that hydrogen production is moderate (1000 lbm $< H_2 <$ 2000 lbm) given that CRD flow occurs during core damage. No other injection is restored, and H_2 production is not high.	0.63
H2MD-CRD-HP	2	MODERATE HYDROGEN PRODUCTION GIVEN HIGH PRESSURE AND CRD RECOVERY: Probability that hydrogen production is moderate (1000 lbm $< H_2 <$ 2000 lbm) given that the vessel remains at high pressure, CRD flow is restored, and H_2 production is not high.	0.85
H2MD-HP	2	MODERATE HYDROGEN PRODUCTION GIVEN HIGH PRESSURE: Probability that hydrogen production is moderate (1000 lbm $< H_2 <$ 2000 lbm) given that the vessel remains at high pressure, there is no CRD flow, and H_2 production is not high.	0.85
H2MD-INJ	2	MODERATE HYDROGEN PRODUCTION GIVEN INJECTION RECOVERY: Probability that hydrogen production is moderate (1000 lbm $< H_2 <$ 2000 lbm) given that injection is restored during core damage and H_2 production is not high.	0.85
H2MD-LP	2	MODERATE HYDROGEN PRODUCTION GIVEN LOW PRESSURE: Probability that hydrogen production is moderate (1000 lbm $< H_2 <$ 2000 lbm) given that the vessel is depressurized during core damage. There is not CRD flow, injection is not restored prior to vessel breach, and H_2 production is not high.	0.63

TABLE 4.6-1
CET BASIC EVENT QUANTIFICATION (CONTINUED)

Basic Event Name	Class	Description	Value
H2HI-CRD	2	HIGH HYDROGEN PRODUCTION GIVEN CRD FLOW: Probability that hydrogen production is high (> 2000 lbm) given that CRD flow occurs during core damage and no other injection is restored.	0.05
H2HI-CRD-HP	2	HIGH HYDROGEN PRODUCTION GIVEN CRD FLOW: Probability that hydrogen production is high (> 1000 lbm) given that CRD flow occurs during core damage and no other injection is restored.	0.1
H2HI-HP	2	HIGH HYDROGEN PRODUCTION GIVEN HIGH PRESSURE AND CRD FLOW: Probability that hydrogen production is high (> 2000 lbm) given that the vessel remains at high-pressure during core damage and CRD flow is restored.	0.1
H2HI-INJ	2	HIGH HYDROGEN PRODUCTION GIVEN INJECTION RECOVERY: Probability that hydrogen production is high (> 2000 lbm) given that injection is restored during core damage.	0.05
H2HI-LP	2	HIGH HYDROGEN PRODUCTION GIVEN LOW PRESSURE: Probability that hydrogen production is high (> 2000 lbm) given that the vessel is depressurized during core damage. There is no CRD flow, and injection is not restored prior to vessel breach.	0.05
HPME	1	HIGH PRESSURE MELT EJECTION: Probability of high-pressure melt ejection given that the vessel is at high-pressure when vessel breach occurs and the core collapses en-masse (SLUMP).	0.8
LK-1	2	CONTAINMENT FAILURE EARLY RESULTS IN LEAK: Containment leak is the consequence of early containment failure.	0.1
LK-2	2	CONTAINMENT FAILURE LATE RESULTS IN LEAK: Probability of containment leak due to late over-pressure failure.	0.9
LK-3	2	CONTAINMENT FAILURE LATE RESULTS IN LEAK: Probability of containment leak due to late thermal failure.	0.9
MELT-1	3	DRYWELL SHELL MELTS AT EMBEDMENT: Probability that the drywell shell melts at the embedment given that the core does not collapse en-masse (no SLUMP), vessel breach occurs, debris does not disperse, and water covers the drywell floor.	0.0001
MELT-2	3	DRYWELL SHELL MELTS AT EMBEDMENT: Same as MELT-1 except water does not cover the drywell floor.	0.63

TABLE 4.6-1
CET BASIC EVENT QUANTIFICATION (CONTINUED)

Basic Event Name	Class	Description	Value
MELT-3	3	DRYWELL SHELL MELTS AT EMBEDMENT: Probability that the drywell shell melts at the embedment given that the core does not collapse en-masse (no SLUMP), vessel breach occurs, and the debris disperses after vessel failure.	0.51
MELT-4	3	DRYWELL SHELL MELTS AT EMBEDMENT: Probability that the drywell shell melts at the embedment given that the core collapses en-masse (SLUMP), vessel breach occurs, high-pressure melt ejection is prevented, debris dispersal is prevented, and water covers the drywell floor.	6.E-5
MELT-5	3	DRYWELL SHELL MELTS AT EMBEDMENT: Same as MELT-4 except water does not cover the drywell floor.	0.999
MELT-6	3	DRYWELL SHELL MELTS AT EMBEDMENT: Probability that the drywell shell melts at the embedment given that the core collapses en-masse (SLUMP), vessel breach occurs, high-pressure melt ejection is prevented, but debris dispersal occurs.	0.6
MELT-7	3	DRYWELL SHELL MELTS AT EMBEDMENT: Probability that the drywell shell melts at the embedment given that the core collapses en-masse (SLUMP), vessel breach occurs, and high-pressure melt ejection occurs.	0.79
NOAI-CF	1	NO ALTERNATE INJECTION SYSTEMS AVAILABLE DUE TO A CONTAINMENT FAILURE: Loss of alternate injection capabilities due to harsh environments created by containment failure.	0.59
NOAI-CWF	1	NO ALTERNATE INJECTION SYSTEMS AVAILABLE DUE TO A CATASTROPHIC WETWELL FAILURE: Loss of alternate injection capabilities due to harsh environments created by containment failure.	0.73
NONI-CF	1	NO ECCS OR CRD SYSTEMS AVAILABLE DUE TO A CONTAINMENT FAILURE: Loss of injection sources from inside the reactor building due to harsh environments created by containment failure.	0.52
NONI-CWF	1	NO ECCS OR CRD SYSTEMS AVAILABLE DUE TO A CONTAINMENT FAILURE: Loss of injection sources from inside the reactor building due to harsh environments created when the wetwell fails, with a subsequent draining of the suppression pool.	0.68
POOL-1	3	SUPPRESSION POOL DRAINED GIVEN OVERPRESSURE FAILURE OF THE TORUS: Probability that the suppression pool is drained given that containment fails and that failure is in the torus..	0.03
POOL-2	3	SUPPRESSION POOL DRAINED: Probability that the suppression pool is drained given that the containment is vented from the torus.	0.01

TABLE 4.6-1
CET BASIC EVENT QUANTIFICATION (CONTINUED)

Basic Event Name	Class	Description	Value
RISE-HI-1	2	HIGH PRESSURE RISE IN CONTAINMENT AT VESSEL BREACH: Probability that the containment pressure rise is high given that high-pressure melt ejection occurs.	0.01
RISE-MD-1	2	MODERATE PRESSURE RISE IN CONTAINMENT AT VESSEL BREACH: Probability that the containment pressure rise is moderate given that high-pressure melt ejection occurs.	0.99
RISE-MD-2	2	MODERATE PRESSURE RISE IN CONTAINMENT AT VESSEL BREACH: Probability that the containment pressure rise is moderate given that the reactor vessel is at high pressure, high-pressure melt ejection does not occur, and the suppression pool temperature is > 200 F.	0.9
RISE-MD-3	2	MODERATE PRESSURE RISE IN CONTAINMENT AT VESSEL BREACH: Same as RISE-MD-2 except that the suppression pool is subcooled.	0.5
SLUMP	1	CORE HAS COLLAPSED EN-MASSE: Probability that the core collapses en-masse.	0.1
SO-DWVB-BRK	5	STUCK OPEN DRYWELL VACUUM BREAKERS: Probability that the drywell vacuum breakers are stuck open given challenge curing core damage. This basic event applies to LOCAs.	0.001
SO-DWVB-TRN	5	STUCK OPEN DRYWELL VACUUM BREAKERS: Probability that the drywell vacuum breakers are stuck open given challenge curing core damage. The basic event applies to transients.	0.001
SO-TPVB	5	TAIL PIPE VACUUM BREAKERS FAIL OPEN: Probability that a tail pipe vacuum breaker is stuck open given that a LOCA does not occur and there are no SORVs.	0.255
SPRY-E	4	OPERATOR FAILURE TO ACTUATE SPRAYS EARLY TO DEPRESSURIZE CONTAINMENT: Probability that operator fails to initiate drywell sprays early (as required) to depressurize the containment.	0.052
SPRY-L-1	4	OPERATOR FAILURE TO ACTUATE SPRAYS TO COOL DEBRIS: Probability that operator fails to initiate drywell sprays to cool core debris given that the vessel has breached and drywell sprays are available.	1.0
SPRY-L-2	4	OPERATOR FAILURE TO ACTUATE SPRAYS TO COOL DEBRIS: Probability that operator fails to initiate drywell sprays to cool core debris after vessel failure given a station blackout with AC Power restored early and sprays available.	1.0
SPRY-L-3	4	OPERATOR FAILURE TO ACTUATE SPRAYS TO COOL DEBRIS: Probability that operator fails to initiate drywell sprays to cool core debris given vessel failure, station blackout, and late restoration of AC Power. Spray system is available.	1.0

TABLE 4.6-1
CET BASIC EVENT QUANTIFICATION (CONTINUED)

Basic Event Name	Class	Description	Value
SUMP	2	CONTAINMENT FAILURE INDUCED AT SUMP: Probability that containment failure induced at sump bottom given no other failure mode has occurred and the core debris is not coolable.	0.9
TEMP-1	2,3	THERMAL FAILURE OF CONTAINMENT OCCURS: Probability of thermal failure of containment given that water is supplied to the drywell floor and the debris is not cooled.	0.01
TEMP-2	2,3	THERMAL FAILURE OF CONTAINMENT OCCURS: Probability of thermal failure of containment given that water is not supplied to the drywell floor and the debris is not cooled.	0.95
TEMP-3	2,3	THERMAL FAILURE OF CONTAINMENT OCCURS: Probability of thermal failure of containment given water is not supplied to the drywell floor and the debris is cooled.	1.0
VB-CM<26%	1,2	VESSEL FAILURE OCCURS WITH <26% CORE MELT AND INJECTION: Probability that vessel breach occurs given that low-pressure injection is recovered and less than 26% of the core has melted.	0.001
VB-CM>26%	1,2	VESSEL FAILURE OCCURS WITH >26% CORE MELT AND INJECTION: Probability that vessel breach occurs given that low-pressure injection is recovered, greater than 26% of the core melts and the core does not collapse en-masse (no SLUMP).	0.3
VENT-E/AC	4	OPERATOR FAILS TO VENT CONTAINMENT EARLY: Probability that the operator fails to vent containment prior to vessel failure given that containment pressure is sufficient to require venting, and AC Power and vent valves are available.	0.052
VENT-E/DW	4	OPERATOR VENTS CONTAINMENT EARLY THROUGH DRYWELL: Probability that the operator vents containment early through the drywell and not through the wetwell, given that the containment has been vented.	0.05
VENT-E/MAN	4	OPERATOR FAILS TO VENT CONTAINMENT EARLY: Probability that the operator fails to manually vent the containment early given that containment pressure is elevated, AC Power is not available, and vent valves are available.	0.31
VENT-L/AC	4	OPERATOR FAILS TO VENT CONTAINMENT LATE: Probability that the operator fails to vent the containment late given that containment pressure is sufficient to require venting and AC Power is available.	0.052

TABLE 4.6-1
CET BASIC EVENT QUANTIFICATION (CONTINUED)

Basic Event Name	Class	Description	Value
VENT-L/DW-INJ	4	OPERATOR VENTS CONTAINMENT LATE THROUGH DRYWELL: Probability that the operator vents containment late through the drywell and not through the wetwell, given that the containment has been vented, and injection systems are operating.	0.95
VENT-L/DW-DRY	4	OPERATOR VENTS CONTAINMENT LATE THROUGH DRYWELL: Probability that the operator vents containment late through the drywell and not through the wetwell, given that the containment has been vented, and injection systems are not operating.	0.05
VENT-L/MAN-L	4	OPERATOR FAILS TO VENT CONTAINMENT LATE: Probability that the operator fails to manually vent the containment late given that containment pressure is elevated, AC Power is not available, and vent valves are available. This basic event applies to long terms SBO sequences.	0.31
VENT-L/MAN-S	4	OPERATOR FAILS TO VENT CONTAINMENT LATE: Probability that the operator fails to manually vent the containment late given that containment pressure is elevated, AC Power is not available, and vent valves are available. This basic event applies to short term SBO sequences.	0.31

4.7 RADIONUCLIDE RELEASE CHARACTERIZATION

The consequences of a reactor accident are determined to a large extent by the magnitude of the radionuclide release to the environment. Thus, to complete the HCGS IPE, predictions of the radionuclide source term are required. This section describes the development of a model for source term evaluation, quantification of the source term model parameters, integration of the source term model into the HCGS Containment Event Tree (CET), and, finally, the results obtained from this analysis.

4.7.1 Method for Assessing Radionuclide Release

A wide variety of radioactive fission products build up in an operating reactor core. Different fission product species would be expected to behave in very different ways during the course of an accident. For example, noble gases (primarily krypton and xenon) evolve from the fuel during the fuel degradation process while ruthenium stays within the fuel matrix until very high temperatures are achieved during molten core-concrete interactions. Furthermore, some species are readily decontaminated by pool scrubbing (e.g., cesium iodide and cesium hydroxide), while others are unaffected by decontamination mechanisms (e.g., noble gases). Because so many fission product isotopes exist and because many types of isotopes behave differently throughout the course of an accident, they are typically categorized into groups.

Release is considered for each group of fission product elements. The element groups are defined based on similar chemical behavior. Nine groups have typically been considered. These are shown in Table 4.7-1. In this analysis only the first five groups are included. This simplification is made based on the results of NUREG/CR-4467 (Reference 4.7-1). The EPRI Generic Methodology outlined in NSAC-159 (Reference 4.7-2) also suggests this simplification for use in the IPEs.

The five radionuclide groups being evaluated in the HCGS IPE are (1) noble gases, (2) iodine, (3) cesium, (4) tellurium, and (5) strontium. The IPE source term algorithm is designed to calculate the fractional release of each of these radionuclide groups for each of the main accident sequences. The results of the source term evaluation is a list of release fractions, representing the environmental release for each group.

The method applied for estimating source terms is based on NSAC-159 (Reference 4.7-2). This method was derived from the methodology used for NUREG-1150 (Reference 4.7-3) and documented in NUREG/CR-4551 (Reference 4.7-4). It consists of a parametric model for the magnitude of fission product release. The model is embodied in seven algebraic expressions. Parameters in these expressions indicate the magnitude of release from the fuel and the extent of retention by various plant features.

4.7.1.1 The Source Term Algorithm

Source terms for the HCGS IPE were calculated using a source term algorithm built into the containment performance model. This was accomplished using an EVNTRE user function.

As used here, the term "source term" refers to the fractional release to the environment of the five key radionuclide groups defined above. The algorithm estimates source terms based upon sequence-dependent radionuclide release fractions (RFs) and decontamination factors (DFs) input and documented within the containment event tree input deck. The source term algorithm applies RFs and DFs within correlations that calculate the net fractional radionuclide release for the five radionuclide species for each sequence through the CET.

The source term algorithm for the HCGS IPE is comprised of correlations that relate release fractions and decontamination factors in a self-consistent fashion to calculate environmental release fractions. The release fractions and decontamination factors considered in the HCGS source term algorithm are described below.

A release fraction is defined as the mass fraction of the available fission product group that is released from the core debris and thus becomes available for release. Release fractions are defined for three processes:

(1) In-vessel release from the fuel—$RF_{IV}(i)$;

(2) Ex-vessel release from core debris during interactions with structural concrete—$RF_{CCI}(i)$; and

(3) Revolatilization release of radionuclides that are initially released in-vessel but are trapped on primary system surfaces—$RF_{REV}(i)$.

These RFs are determined for each of the five radionuclide groups.

A decontamination factor is defined as the ratio of the initial mass available for release from a given volume to the mass that remains available after the decontamination mechanism has taken effect. In simpler terms, a DF is defined as the mass entering a volume divided by the mass leaving the volume. The decontamination considered in the HCGS CET are listed below:

(1) Early suppression pool scrubbing—$DF_{EPOOL}(i)$
(2) Late suppression pool scrubbing—$DF_{LPOOL}(i)$
(3) Primary system deposition—$DF_{VSL}(i)$
(4) Early containment deposition—$DF_{ECONT}(i)$
(5) Early scrubbing by containment sprays—$DF_{ESPR}(i)$
(6) Early secondary containment deposition—$DF_{ERB}(i)$
(7) Late containment deposition—$DF_{LCONT}(i)$
(8) Late scrubbing by containment sprays—$DF_{LSPR}(i)$
(9) Late secondary containment deposition—$DF_{LRB}(i)$

The source term algorithm applies the following decontamination factors to in-vessel releases: (1) primary system natural deposition, (2) early pool scrubbing due to passage of fission products through the "T"-quenchers, (3) early containment deposition, (4) early containment spray wash-out, and (5) early secondary containment deposition. The following decontamination factors are applied to both ex-vessel (i.e., CCI) releases and revolatilization releases: (1) late pool scrubbing due to passage of fission products through the drywell vents, (2) late containment deposition, (3) late containment spray wash-out, (4) late secondary containment deposition.

The following rules and assumptions are applied throughout the source term algorithm to provide consistency between the source term estimation and the current understanding of radionuclide behavior:

(1) If the pool scrubbing DF is large (i.e., $DF_{POOL}(i) > 10$), the effect of containment sprays is neglected. This is done to prevent double counting for the effect of water pool and spray decontamination, which each act to remove aerosols in a similar size.

(2) All noble gas decontamination factors are unity.

The source term algorithm is embodied in a set of equations that calculate release to the environment from in-vessel, ex-vessel, and revolatilization processes, and also the total environmental release. These equations are discussed below.

Total Environmental Release

The total atmospheric release of a particular isotope group can be expressed as the sum of the releases due to in-vessel, core-concrete interactions, and revolatilization releases for that group and corrected for hold-up in the secondary containment. This relationship can be shown as:

$$R_{TOT}(i) = \left(R_E(i) \times \frac{F_{Vent}}{DF_{ESC}(i)} \right) + \left(\left[R_{MCCI}(i) + R_{REV}(i) \right] \times \frac{F_{Vent}}{DF_{LSC}(i)} \right)$$

where,

$R_{TOT}(i)$	=	Total release from containment to atmosphere
$R_E(i)$	=	(Early) In-vessel release
$R_{MCCI}(i)$	=	Molten Core-concrete interaction release
$R_{REV}(i)$	=	In-vessel revolatilization release
F_{VENT}	=	Fractional release of fission products from the containment to the secondary containment. Values less than unity represent hold-up of fission products within the containment. This may be considered possible if the containment vent can be reclosed following complete recovery from the accident.
$DF_{ESC}(i)$	=	Secondary containment decontamination factor for early (in-vessel) releases
$DF_{LSC}(i)$	=	Secondary containment decontamination factor for late (ex-vessel and revolatilization) releases

In-Vessel Release

The early release is calculated by dividing the in-vessel release fraction by the in-vessel decontamination factor in the following relationship:

$$R_E(i) = RF_{IV}(i) \times \frac{1}{DF_{IV}(i)}$$

where,

$$DF_{IV}(i) = DF_{EPOOL}(i) \times DF_{VSL}(i) \times DF_{ECONT}(i) \times DF_{ESPR}(i)$$

and

$RF_{IV}(i)$	=	In-vessel release fraction
$DF_{IV}(i)$	=	In-vessel decontamination factor
$DF_{EPOOL}(i)$	=	Early pool scrubbing decontamination factor
$DF_{VSL}(i)$	=	Primary system decontamination factor
$DF_{ECONT}(i)$	=	Containment decontamination factor for early (in-vessel) releases
$DF_{ESPR}(i)$	=	Containment sprays decontamination factor for early (in-vessel) releases

MCCI Release

Similarly, the release from molten core-concrete interactions (MCCI) is found by multiplying the fraction of the isotope group remaining after in-vessel releases times the MCCI release fraction and dividing by the MCCI decontamination factor:

$$R_{MCCI}(i) = (1 - RF_{IV}(i)) \times \frac{RF_{MCCI}(i)}{DF_{MCCI}(i)}$$

where,

$$DF_{MCCI}(i) = DF_{LPOOL}(i) \times DF_{LSPR}(i) \times DF_{LCONT}(i)$$

and

$RF_{MCCI}(i)$	=	Core-concrete interaction release fraction
$DF_{MCCI}(i)$	=	Core-concrete interaction decontamination factor
$DF_{LPOOL}(i)$	=	Late pool scrubbing decontamination factor
$DF_{LCONT}(i)$	=	Containment decontamination factor for late (ex-vessel and revolatilization) releases
$DF_{LSPR}(i)$	=	Containment sprays decontamination factor for late (ex-vessel and revolatilization) releases

Revolatilization Release

Release due to revolatilization is calculated by multiplying the fraction of radionuclides trapped within the vessel times the revolatilization release fraction and divided by the revolatilization decontamination factor:

$$R_{REV}(i) = \left[RF_{IV}(i) \times \left(1 - \frac{1}{DF_{VSL}(i)} \right) \right] \times RF_{REV}(i) \times \frac{1}{DF_{REV}(i)}$$

where,

$$DF_{REV}(i) = DF_{LSPR}(i) \times DF_{LCONT}(i) \times DF_{LPOOL}(i)$$

and

$RF_{REV}(i)$ = Revolatilization release fraction
$DF_{REV}(i)$ = Revolatilization decontamination factor

The next section discusses quantification of the source term parameters used in the HCGS CET.

4.7.1.2 Quantification of the HCGS Source Term Parameters

The values for the RFs and DFs used in the source term algorithm were determined from the results of the HCGS MAAP 3.0B calculations. In some instances, the MAAP results were supplemented by results taken from the NUREG-1150 expert elicitations documented in NUREG-4551 (Reference 4.7-5).

Release fraction values were determined by dividing the mass released from the core debris by the total mass available. The in-vessel release fraction is the fraction of the initial inventory of each radionuclide group that is released during core degradation. The release fraction from core-concrete interactions is defined as the fraction of the radionuclide inventory available for ex-vessel release (i.e., not including the inventory released during core degradation) that is released during core-concrete interactions. The revolatilization release fraction is the fraction of radionuclides trapped initially in the primary system that are subsequently released when the primary system surfaces heat up. The standard MAAP output file provides all of the information needed to calculate these release fractions.

It should be noted that due to the limitations of MAAP in modeling in-vessel release of tellurium (see the discussion in Section 4.2), we did not rely on MAAP for predictions of the in-vessel release fractions for tellurium. Instead, results from the NUREG-1150 expert elicitations were used. The structure of the source term algorithm assured conservation of tellurium mass even with the adjustment of release timing.

Decontamination factors were determined based on the calculated mass of fission products entering and leaving a cell. Since MAAP provides detailed temporal information on the location and form of radionuclides in the containment and secondary containment, most of the DFs were relatively easy to calculate. The exceptions to this were the early and late spray DFs, and the early secondary containment DF. The spray DFs were difficult to determine because radionuclides scrubbed by the sprays eventually flow into the wetwell as the drywell floods to the level of the vent pipe opening. Consequently, it is impossible to separate the effect of the sprays from the effect of suppression pool scrubbing. Early secondary containment DFs could not be determined since there were no MAAP calculations with significant early release from the primary containment. The spray DFs and early secondary containment DFs were taken from the NUREG-1150 expert elicitation documented in NUREG-4551 (Reference 4.7-5).

Table 4.7-2 presents the source term parameter values used in the HCGS CET. A brief summary of the rationale for the choice of each parameter value is also provided in the table. Note that some of the RFs and DFs are defined for specific radionuclides (e.g., NG = noble gases, I = iodine, Cs = cesium, Te = tellurium, and Sr = strontium), while others are defined for aerosols (Ae) in general. The radionuclide-specific values are those for which the chemical behavior of the individual radionuclides is important. The aerosol-specific values are those for which chemical phenomena are less important than the characteristics of the aerosol particles.

4.7.2 Radionuclide Release for the Base Case Calculations

The calculations described in this section utilize the basic event probabilities shown in Table 4.6-1. These calculations are referred to as the Base Case, to distinguish them from the results of the sensitivity studies discussed in Section 4.7.3.

4.7.2.1 Definition of Release Categories

The discussion in this section focuses on radionuclide release to the environment. Accident progression events that influence radionuclide release (e.g., containment failure, suppression pool bypass, core-concrete interactions, etc.) are examined in detail. Here, an attempt is made to evaluate the relative importance of specific events in determining the magnitude of the release to the environment. Events that influence the timing of the release are also important to consider. Early containment failure or early venting (i.e., early release), and late containment failure or late venting (i.e., late release).

To simplify the discussion of radionuclide release a list of nine "release categories" based on the timing of the release and the magnitude of the release to the environment was developed. As discussed below, these release categories can be qualitatively related to the relative risk and consequences of a particular accident sequence or plant damage state.

The timing of the radionuclide release is assumed to determine the extent to which the surrounding population can be evacuated before the release occurs. Two categories of radionuclide release times are considered in the CET: early release and late release. An early release is assumed to occur within two hours after vessel failure. This time interval is assumed to be too short for evacuation to be very effective. A late release is assumed to occur after a general emergency would have been declared and is therefore assumed to provide an opportunity for effective evacuation. Clearly, the highest risk to the surrounding population is associated with early releases.

It should be noted that an early release does not necessarily imply an early containment failure since early venting also leads to a release to the environment. Early venting sequences generally lead to small early releases of cesium and iodine since venting is nearly always from the wetwell, and the releases are therefore scrubbed by the suppression pool. The sensitivity of release to venting is considered in two of the sensitivity studies discussed in Section 4.7.3. Early release could also occur prior to vessel failure; however, both the magnitude and possibility of such release are negligible when compared to release after vessel failure.

The magnitude of radionuclide release is categorized in terms of five levels of release: high, medium-high, medium, low, and low-low. These levels are designated by numbers 1 through 5, where 1 refers to a high level of release and 5 refers to a low-low level of release. Levels are assigned based on the magnitude of the iodine and tellurium releases calculated for each accident sequence. First, levels are individually assigned to the iodine and tellurium releases according to the limits shown below:

Release Level	Iodine	Tellurium
High	> 6 %	> 6 %
Medium	0.1 to 6 %	0.1 to 6 %
Low	10^{-3} to 0.1 %	10^{-7} to 0.1 %
Low-Low	< 10^{-3} %	< 10^{-7} %

The limits shown in this table were selected to ensure an adequate differentiation of releases.

Next, the release category levels are assigned by considering combinations of these iodine and tellurium release levels. The "high" release category contains all sequences that have both high iodine and high tellurium. The "medium-high" release category contains all sequences that have either high iodine release and medium tellurium release, or high tellurium release and medium iodine release. The "low" release category contains all sequences that have both low iodine and low tellurium release. The "low-low" release category has sequences that have both low-low iodine and low-low tellurium release. These are only sequences that have no containment failure. The "medium" release category contains all sequences not included in the other release categories.

An EVNTRE binner was written to bin the calculated accident sequence source terms into these nine release categories. Figure 4.7-1 shows the HCGS tree that bins into release categories. The tree first determines whether the release was early or late. The CF top event shown in the figure considers both containment failure and venting, when determining the timing of release. Next, the levels of iodine and tellurium release are considered. Release categories E1 through E4 are assigned to the Early-High through Early-Low combinations, while L1 through L4 are assigned to the Late-High through Late-Low combinations. The Low-Low category is given the designation L5 although it does not actually involve containment failure or venting. The L5 release is due only to normal leakage from the containment. Figure 4.7-2 is identical to Figure 4.7-1; however, it sorts the release categories based on the containment failure modes.

4.7.2.2 Summary of Base Case Results for Each Level II Initiating Event

The following discussion summarizes the accident sequence and radionuclide release results for the six initiating events considered in the HCGS Level II IPE. Tables are provided for each initiating event showing the dominant accident sequences (i.e., in terms of sequence frequency). The characteristics of these dominant sequences are then summarized in terms of the CET top events, which are defined in Section 4.5. Tables are also provided showing the dominant "high" and "medium-high" source term sequences for each initiating event. The characteristics of these sequences that lead to higher radionuclide release are then discussed.

4.7.2.2.1 Results for the Level II LT-SBO Sequences (Initiating Event - 1)

The LT-SBO initiating event contains all sequences which can be represented by a loss of off-site power with the high pressure coolant injection, the reactor core isolation cooling, and automatic depressurization systems available for four hours (i.e., battery depletion is assumed to occur after four hours). This initiating event also contains unrecovered loss of HVAC, since such an event eventually results in loss of the switchgear rooms and causes a station blackout. Tables 4.7-3 and 4.7-4 show the most likely accident sequences and the highest source term sequences for this type of initiator. In these and subsequent initiating event tables, at least the top 10 sequences by frequency are included in the first table, while the highest frequency medium-high and high source term sequences are presented in the second of the two tables.

As shown in Table 4.7-3, all of the dominant sequences have vessel failure at high pressure since the ADS system is unavailable after four hours. Nearly all of the sequences have no early coolant injection, and as a result, nearly all sequences lead to vessel failure. The containment fails early in 5 of the 14 sequences shown in the table. These sequences comprise approximately half of the total frequency. In addition, early venting occurs in one sequence. Three of the sequences do not have either late or early containment failure, or early or late containment venting. All of the dominant sequences have early suppression pool scrubbing (i.e., EPOOL = Yes) and half of the sequences have early drywell sprays. Most of the dominant sequences have late coolant injection and most have coolable ex-vessel debris (i.e., DCOOL = Yes). Six of the dominant sequences have late suppression pool scrubbing and most have good fission product retention in the containment (i.e., FPR = Yes). Only three of the sequences have good fission product retention in the Reactor Building (i.e., RB = yes). The results shown in Table 4.7-3 comprise over 90% of the significant accident progression bins for the Level II LT-SBO categorized initiating events.

Table 4.7-4 shows the dominant high and medium-high source term sequences for the LT-SBO initiator. Greater than 97% of the high and medium-high sequence frequency is included in this table, and 93% of this frequency is represented in the first four sequences.

As shown in the table, high and medium-high source term sequences comprise a substantial portion of the total LT-SBO frequency (approximately 52%). About 24 percent of the total sequence frequency is in the early high release category, with most of this total included in the first sequence. The features of this sequence that lead to a high source term include: no early injection, vessel failure, early containment failure, no late drywell sprays, no late injection, uncoolable debris, no late suppression pool scrubbing, poor fission product retention in the containment, and poor retention in the Reactor Building. The second of the dominant source term sequences leads to an early medium-high release. This sequence, which accounts for nearly all of the early medium-high frequency, differs from the first sequence in that late injection is available, and there is good radionuclide retention in the containment. The next two dominant source term sequences involve late containment failure. The first of these leads to a late high release and the next leads to a late medium-high release. The sequence with the late high release has the following characteristics that lead to the high source term: no early injection, vessel failure, no drywell sprays, no late injection, uncoolable debris, no late suppression pool scrubbing, and poor retention in the Reactor Building. The sequence with the late medium-high release has similar characteristics except that it has late coolant injection.

4.7.2.2.2 Results for the Level II Transient Sequences (Initiating Event-2)

For reporting purposes, we divided transient initiators into two classes: one containing sequences with loss of residual heat removal (RHR), and one containing all other transients. Transients with RHR available are included in this section, while transients without RHR are discussed in the following section.

The transients included here involve a wide spectrum of sequences including sequences with and without stuck open relief valves (SORVs), sequences with and without automatic vessel depressurizaton, and sequences with and without low pressure injection available. All relevant combinations of these events, and resulting system availabilities are modeled in the HCGS CET. Tables 4.7-5 and 4.7-6 show the most likely accident sequences and the highest source term sequences for this Level II initiating event.

The sequences shown in Table 4.7-5 comprise 95% of the significant accident progression bins for the Level II transients with the RHR available. As shown in the table, vessel failure occurs with high primary system pressure and low containment pressure in 75% of these transient sequences, while in 16.67% of the dominant sequences, vessel failure is prevented.

As shown in Table 4.7-5, 90% of the dominant sequences that lead to vessel failure have vessel depressurization, and none of the sequences that lead to vessel failure have early coolant injection. The containment fails early in 5 of the 10 sequences that lead to vessel failure. These sequences comprise approximately 26% of the total frequency. Also, among sequences that resulted in vessel failure, one resulted in early containment venting. This sequence comprised approximately nine percent of the total frequency. Only one of the sequences that led to vessel failure did not lead to any containment venting or containment failure (neither Early nor Late). However, this sequence comprises 31.4% of the total frequency. One sequence leads to late containment failure and two lead to late containment venting. All of the dominant sequences have early suppression pool scrubbing. Seventy five percent of the sequences have early or late drywell spray. All of the dominant sequences have late coolant injection, and 70% of the sequences that lead to vessel failure have coolable ex-vessel debris. Due to the high probability for hydrogen burns in the Reactor Building, most sequences have poor fission product retention in the Reactor Building.

Table 4.7-6 shows the dominant high and medium-high source term sequences for the transients with available decay heat removal. As shown in the table, the high and medium-high source term sequences comprise only abount 1.7% of the total initiator frequency, with nearly all of this total included in the first sequence. The frequency of high or medium-high release is low because most sequences have late coolant injection, and as a result, most sequences have coolable core debris (i.e., no releases from core-concrete interactions). The source term for the first sequence is in the early medium-high release category. The features of this sequence that lead to a high source term include: no early injection, vessel failure, early containment failure, no late drywell sprays, uncoolable debris, no late suppression pool scrubbing, and poor retention in the Reactor Building.

4.7.2.2.3 Results for the Level II TW Sequences (Initiating Event -3)

Discussed in this section are all transient sequences in which decay heat removal has been lost (TW sequences). These include sequences with and without SORVs, sequences with and without low pressure injection, and sequences with and without automatic vessel depressurization. Tables 4.7-7 and 4.7-8 show the most likely accident sequences and the highest source term sequences for this initiating event.

As shown in Table 4.7-7, three of the dominant sequences have vessel depressurization. Only one of the sequences has early coolant injection, and that sequence has no vessel failure. Three of the sequences result in early containment failure, two result in early containment venting and four sequences result in late containment failure. All of the dominant sequences have early suppression pool scrubbing. None of the sequences have early or late drywell sprays. Fifty percent of the dominant sequences have late coolant injection, and, 25% of have coolable ex-vessel debris. About 92% of the dominant sequences have no late suppression pool scrubbing, and 37% have poor fission product retention in the containment. Due to the high probability for hydrogen burns in the Reactor Building, most sequences have poor fission product retention in the Reactor Building. The results shown in Table 4.7-7 comprise 94% of the significant accident progression bins for the Level II TW categorized initiating events.

Table 4.7-8 shows the dominant high and medium-high source term sequences for the transient initiators with loss of decay heat removal. As shown in the table, a substantial portion of the TW sequences lead to high or medium-high release (approximately 65%). Greater than 98% of these sequences are represented in the table, with 82% included in the first three sequences.

The first sequence comprises 44% of the high and medium-high release frequency. This sequence leads to an early high release, and is characterized by the following features common to nearly all of the early high release sequences: no early injection, vessel failure, early containment failure, no late drywell sprays, no late injection, uncoolable debris, no late suppression pool scrubbing, poor fission product retention in the containment, and poor retention in the Reactor Building. The second sequence in the table leads to an early medium-high release. This sequence differs from the first in that there is late injection, and good fission product retention in the containment. The third sequence shown in the table leads to a late high release. In addition to timing of containment failure, this sequence differs from the first sequence in that it has good radionuclide retention in the containment. Good retention in the containment results from the predominant late containment failure mode - thermally induced leakage through the CRD hatch or drywell head assembly. Late injection of coolant into the reactor vessel greatly reduces the revolatilization release of the iodine and cesium trapped on surfaces in the primary system. Since early releases of these radionuclides are scrubbed by the suppression pool and late revolatilization is reduced, the total release of iodine and cesium is calculated to be less than one percent.

4.7.2.2.4 Results for the Level II LOCA Sequences (Initiating Event-4)

The LOCA initiating events include both medium and large LOCA sequences. There were no small break LOCA sequences that met the Level II screening criterion of 1.E-7. All large and medium LOCAs are assumed to be sufficent to depressurize the reactor vessel. Tables 4.7-9 and 4.7-10 show the most likely accident sequences and the highest source term sequences for this initiating event.

As shown in Table 4.7-9, all the dominant sequences have vessel depressurization due to medium and large LOCAs. Furthermore, all the dominant sequences have no early injection and as result all lead to vessel failure. However, in two of the 10 sequences shown in Table 4.7-9, the containment does not fail and there is no need for venting. These two sequences comprise 34.2% of the dominant sequences. The containment fails early in only two sequences, which comprise approximately seven percent of the dominant sequences. Early containment venting takes place in two of the 10 dominant sequences. Also, one of the early containment venting sequences lead to late containment failure. Ninety percent of the dominant sequences have early suppression pool scrubbing, 40% have debris coolability and 32% have late suppression pool scrubbing. Eight percent of the dominant sequences have poor containment retention capability and 14% of them have poor Reactor Building retention capability. The results shown in Table 4.7-9 comprise 93% of the significant accident progression bins for the Level II LOCA categorized initiating events.

Table 4.7-10 shows the dominant high and medium-high source term sequences for the LOCA initiator. As shown in the table, high and medium-high source term sequences comprise only a small percentage of the total LOCA frequency (approximately 11%). Greater than 92% of the high and medium-high frequency is captured in the table, with more than 70% of this total in the first two sequences.

The first two sequences lead to high release. Both sequences have all of the characteristics of the high release sequences mentioned previously, including: no early injection, vessel failure, early containment failure, no late drywell sprays, no late injection, uncoolable debris, no late suppression pool scrubbing, poor fission product retention in the containment, and poor retention in the Reactor Building.

4.7.2.2.5 Results for the Level II ATWS Sequences (Initiating Event - 5)

The ATWS initiating event comprises all the sequences in which the reactor is critical. It also includes sequences in which the reactor is critical and the plant experiences a coincident station blackout. However, the frequency of the ATWS-SBO sequence is only 8.91E-9, which by itself would be below the 1.E-7 Level II screening criterion. The ATWS-SBO sequence has been maintained in the Level II for completeness, and because it was simple to combine it with the other ATWS sequences. Tables 4.7-11 and 4.7-12 show the most likely accident sequences and the highest source term sequences for this initiating event.

As shown in Table 4.7-11, only 12.3% of the sequences have a depressurized reactor vessel and none has early injection. As a result, all sequences lead to vessel failure. Two of the sequences do not lead to containment failure or venting. Twenty six percent of the sequences lead to early containment failure and about seven percent lead to late containment failure. Three sequences lead to early containment venting, of which one leads to late containment failure, as well. Also, two sequences lead to late containment venting. All sequences have early suppression pool scrubbing, and, with the exception of the ATWS-SBO sequence, all have late injection. Thirteen of the 16 sequences have late drywell sprays and 10 have ex-vessel debris coolability. With the exception of the ATWS-SBO sequence, all sequences have good containment fission product retention, while about half of the sequences have good Reactor Building retention. The results shown in Table 4.7-11 comprise approximately 92% of the significant accident progression bins for the Level II ATWS initiating events.

Table 4.7-12 shows the dominant high and medium-high source term sequences for the ATWS initiator. As shown in the table, the contribution from the ATWS initiator to the high and medium-high release frequency is extremely small, with most of the ATWS contribution coming from the ATWS sequences with coincident SBO (total frequency of 1.2E-8). The low ATWS contribution is due to the high availability of containment sprays. In most ATWS sequences, except those with SBO, containment sprays are available and are used early. Spray usage reduces early failures by reducing the shell meltthrough frequency. Sprays also increase the probability of debris coolability, and provide for good radionuclide removal.

4.7.2.3 Aggregation of All Base Case Results

Tables 4.7-13 through 4.7-21 provide a summary of the key base case results for all five accident initiators. Tables 4.7-13 through 4.7-18 show the frequency of occurrence for several top events important to the assessment of the source term, while Tables 4.7-19 through 4.7-21 summarize the radionuclide release results in terms of release category.

Table 4.7-13 shows the frequency of top events associated with containment failure (CFE and CFL), containment venting (CFE-Vnt and CFL-Vnt), suppression pool scrubbing (EPOOL and LPOOL), and debris coolability (LT-DC). The table shows that early containment failure is calculated to occur in approximately one-half of the accident sequences leading to core damage, while early containment venting occurs in only about 6 percent of these sequences. Also, late containment failure occurs in approximately 18 percent of the sequences, while late containment venting occurs in 10 percent. Subtracting these contributions from unity leaves a probability of no containment failure or venting of approximately 12 percent. The table also shows that early pool scrubbing occurs in nearly all of the sequences, while late pool scrubbing occurs in approximately one-fourth of all sequences. Ex-vessel core debris is coolable in approximately half of the sequences, and core-concrete interactions are therefore prevented. The table shows that these results are particularly influenced by the results for the LT-SBO sequence (which comprises greater than three-fourths of the total core damage frequency). The LT-SBO sequence includes 88% of the early containment failures, and 74% of the late containment failures. Much of the remaining early and late containment failure frequency comes from the TW sequence (7% of the early failures, and 6% of the late failures). The LOCA sequences contribute significantly to the frequency of late containment failure (18% of the total). Table 4.7-14 is similar to Table 4.7-13, with this difference that it shows the resultant conditional probability of containment failure for each initiating event category.

Tables 4.7-15 and 4.7-16 show the dominant early and late containment failure modes, respectively. Table 4.7-15 shows that 47 percent of the total early containment failure probability of 56 percent is due to drywell shell meltthrough, while approximately 9 percent is due to overpressurization. As expected, early containment failures from steam explosions contribute little to the early containment failure probability. Table 4.7-16 shows that late containment failure is primarily from thermally induced seal leakage (10 percent out of 18 percent), with sump failure second in importance (7.5 percent) and pressure failure last in importance (< 1 percent). The high probability of late thermal failure results from the low probability for late coolant injection. Without late coolant injection, the temperature in the containment will increase to the temperature at which the seal material in the various hatches or drywell head assembly begin to degrade and leak. Tables 4.7-17 and 4.7-18 are similar to Tables 4.7-15 and 4.7-16, respectively, with this difference that they illustrate the resultant conditional probability of early and late containment failure modes.

Tables 4.7-19, 4.7-20 and 4.7-21 summarize the radionuclide release results from the base case CET evaluation. The discussion below focuses on the radionuclide release results of greatest significance with respect to public risk. These include the early high (E1), early medium-high (E2), late high (L1), and late medium-high (L2) release categories.

Table 4.7-19 shows the aggregate source term results for the five accident initiators evaluated in the HCGS IPE. The results are presented in terms of the overall frequency of occurrence for each release category. Table 4.7-20 shows the aggregate source term results presented in terms of frequencies conditional upon the given initiator. In other words, the results shown in the table are the fraction of initiator frequency in each release category (i.e., summing over all release categories for a given initiator yields a value of 1.0). The discussion that follows refers to results in both tables.

The tables show that the highest frequencies for the early high (E1) release category, on a percentage basis, are associated with the LT-SBO and TW initiators. The early high release category makes up approximately 24 to 37 percent of the total sequence frequency for these initiators. The initiator with the next highest frequencies of early high release is the LOCA initiator, in which the E1 release category is approximately 4 percent of the total sequence frequency. If the early high and early medium-high release categories (E1 and E2) are taken together, the LT-SBO and TW sequences are again found to have the highest frequency, on a percentage basis. The LT-SBO sequences have 40% of the sequence frequency in these release categories, while the TW sequences have 54%. The next highest contributor is the LOCA initiator, which has only 6% of its frequency in the E1 and E2 release categories. The same general trends hold for the late high (L1) or late medium-high (L2) release categories.

The last row in Table 4.7-19 presents the aggregate source term results for all of the accident initiators. The release category values shown in the table are obtained by dividing the total frequency of each release category by the total Level II frequency. These results are also presented graphically in Figure 4.7-3. Table 4.7-21 ranks the release categories with respect to their frequencies and conditional probabilities.

As the table and figure show, the early high (E1) release category comprises 21 percent of the total frequency, while the early medium-high (E2) release category is approximately 14 percent of the total. The contributions from the late high (L1) and late medium-high (L2) release categories are 7% and 2.5%, respectively. The total percentage of high and medium-high release categories is approximately 44.5%.

At the other end of the spectrum are the low and low-low release categories. The table and figure show that 23 percent of the radionuclide release results fall into the late low (L4) and late low-low (L5) release categories. These two release categories would be expected to produce little or no risk to the public because they involve both low and late release. The early low (E4) release category contributes 12%, so that the total percentage in the low and low-low release categories is approximately 35%. The remaining 20% of the total sequence frequency falls in the early or late medium release category.

The contributions of each initiator to the total frequency of the early high and early medium-high release categories are shown in Figure 4.7-4. Figure 4.7-4 shows that the LT-SBO and TW initiators are by far the largest contributors to the frequency of an early high release, with the LT-SBO sequences comprising about 89% of the total E1 frequency and the TW sequences comprising 9.4% of the remainder. A similar trend holds when both the early high and early medium-high release categories are considered: the LT-SBO sequences include 90% of the total, while TW sequences include 8.2% of the remainder.

4.7.3 Summary of Results from the HCGS Sensitivity Study

This section describes the results from the HCGS sensitivity studies. These sensitivity studies examined parameters in the HCGS CET that were felt to be uncertain and were thought to have a potentially significant impact on the calculated radionuclide release. The next section discusses the rationale for the selection of the sensitivity study parameters. The subsequent sections discuss the results from the sensitivity study and summarize the insights gained from these results.

4.7.3.1 Selection of Sensitivity Study Parameters

This section provides the rationale for the selection of the basic events included in the sensitivity analysis for the level II portion of the HCGS IPE. These basic events were chosen based in part on the experience gained in previous analyses of BWRs with Mark I containments. Consideration was also given to the guidance provided by the NRC in the IPE Submittal Guidance (NUREG-1335).

The primary objective of the IPE Back-End Analysis is the examination of containment response to postulated severe accidents. In this context, containment integrity is the key measurement of performance. Sensitivity of containment performance measures to important parameters (i.e., basic event probabilities) in the CET was therefore the main focus of the sensitivity assessment. Consideration was given to parameters that might affect either early or late containment failure.

The probability of an early containment failure is often used as a key measure for containment performance. Early failure is assumed to mean failure within two hours after vessel failure. Conversely, late failure is assumed to refer to any failure that would occur after there has been sufficient time to begin the evacuation. Providing adequate time for evacuation is one of the primary issues in the assessment of containment performance.

Ability to retain radionuclides within the plant structures is another important consideration. Clearly, if containment integrity is maintained, radionuclide release will be minimal. Natural deposition mechanisms will also limit radionuclide release if there is sufficient time between release from the fuel and release to the environment. Thus, the containment failure time also affects the magnitude of the release. The mode of containment failure (i.e., slow leak versus rapid depressurization through a sizable breach) affects fission product retention by determining the length of time that radionuclides remain suspended in the containment atmosphere. The longer the time period before release (i.e., the lower the leakage rate), the greater the opportunity for natural deposition on structures in the containment. Consideration of the timing, and mode of containment failure were the principal factors in choosing parameters to be examined in the sensitivity study.

Engineered safeguards can also play an important role in radionuclide retention. In a Mark I containment, the suppression pool, the injection systems, and the drywell sprays play a key role in radionuclide retention. A hard pipe vent was added at HCGS and was considered in the CET. The hard pipe venting system provides a robust means for venting the containment from the wetwell. Venting through the wetwell (rather than the drywell) causes all radionuclides released through the vent path to be scrubbed by the suppression pool. Thus, wetwell venting greatly reduces the probability for suppression pool bypass, while also reducing the containment pressure and the likelihood for overpressure failure of the containment. The basic events that characterize the performance of these engineered safeguards are important candidates for the sensitivity investigation.

The FRVS system at HCGS can also function to increase radionuclide retention. First, radionuclides can be trapped on the FRVS filter media. The trapping efficiency of the FRVS filters is greater than 99%, so that less than one percent of the radionuclides would escape to the environment. Operation of the FRVS also has been shown to prevent Reactor Building failure by preventing pressure buildup in the Reactor Building and eliminating the potential for large hydrogen deflagrations. Consequently, measures of FRVS effectiveness and availability are good candidates for the sensitivity study.

With the above considerations in mind, we selected the list of basic events shown in Table 4.7-22 for assessment in the HCGS Level 2 sensitivity studies. The table lists the issue being investigated, the value or values changed in the sensitivity study, and the basis for these choices. A more detailed discussion of this rationale is provided in the sections that follow. Note that limiting values were assigned to the individual basic event probabilities in order to assess their maximum effect. Consequently, the results of the sensitivity study should not be regarded as an assessment of uncertainty.

The results of the sensitivity study are summarized in Table 4.7-23 and in Figure 4.7-5. A brief discussion of each sensitivity is provided in Sections 4.7.3.2 through 4.7.3.17.

4.7.3.2 Sensitivity Study 1 - Sprays Always Available

Even in accident scenarios in which the equipment required for containment spray operation has failed, containment sprays can be made available if the operators align the service water system to allow injection through the drywell spray system. Alignment of the service water system could be especially important for scenarios involving loss of decay heat removal, since the sprays have been determined to be unavailable under these conditions. Use of the sprays is also important in sequences without coolant injection, since the sprays provide a means to introduce water into the containment to cool the ex-vessel core debris.

To examine the effect of this potential operator action, the availability of drywell sprays was set equal to unity for all plant damage states. Table 4.7-23 shows the results of this change on the calculated release category frequencies.

As shown in the table, the availability of sprays has a relatively minor impact on the calculated radionuclide release and containment failure probability. This is largely due to the dominance of the LT-SBO sequences. Since spray operation requires AC power, only LT-SBO sequences in which AC power is recovered will be affected by spray availability. Also, the CET assumes that sprays are not used late even if AC power is recovered since conditions in the drywell would preclude spray operation (according to the EOPs).

Early sprays provide a source of coolant to the ex-vessel core debris, which reduces the probability of drywell shell meltthrough. This appears as a general reduction in the frequency of early release from about 62 to 57% of the total sequence frequency. The sprays also reduce the magnitude of the calculated release, with some of the frequency of the E1, E2, and E3 release categories shifted into the early low category, E4. The total frequency of early high (E1) and early medium-high (E2) release is reduced from approximately 34% to about 26%.

The sprays also have an impact on late containment failure and late release. The sprays are assumed to provide a continuous source of subcooled coolant to the ex-vessel core debris. This source of coolant keeps the core debris coolable in a larger percentage of the sequences, and therefore prevents late overpressurization of the containment by noncondensable gases from core-concrete interactions. The subcooled coolant also prevents steam pressurization by condensing steam before it can be released to the containment atmosphere. As a result of these effects, the frequency of the L5 release category (no containment failure) increases from approximately 12% to 18% of the total. The sprays also reduce the late high, medium-high, and medium release categories from a combined 14% to roughly 9%.

4.7.3.3 Sensitivity Study 2 - Operators Always Use Sprays Late If Available

The HCGS CET currently assumes that the conditions in the containment after vessel failure will be outside the temperature-pressure range for which spray operation would be allowed by the Emergency Operating Procedures (EOPs). This assumption is based on MAAP calculations performed by the PSE&G staff.

The EOP limits for spray operation are derived based on the assumption that the pressurization in the containment is primarily due to saturated steam (e.g., following a large-break LOCA). Under these conditions, sudden condensation of steam following spray initiation could cause the pressure in the containment to fall below the pressure outside the containment. If this negative pressure difference is large enough, the containment could collapse. The EOPs attempt to prevent this situation by proscribing spray operation for conditions of high steam partial pressure. Since the partial pressure of steam is not measured directly, the EOP limits correspond to a range of containment temperatures and pressures.

Following vessel failure, much of the containment pressurization is likely to be due to noncondensable gases from core-concrete interactions rather than steam. Under these conditions, spray initiation is unlikely to cause a negative pressure that would threaten containment integrity. Realizing this, the operators may initiate sprays even though the conditions in the containment are outside the EOP limits. This is especially likely if the Technical Support Center (TSC) is available to provide guidance to the operators.

To examine the effect of late spray operation, the probability of late spray initiation by the operators was set equal to unity. This probability applies only for sequences in which the sprays are available, and were not used earlier. The results from this sensitivity study are shown in Table 4.7-23.

As shown in the table, late spray operation has little effect on the overall results since the dominant accident sequence, LT-SBO, has sprays available only half of the time, and then, of course, sprays would only be used if AC power were recovered. Consequently, there was no significant change in the frequency of an early high release, while the frequency of the medium-high release category decreased from 14% to 9%. There was little or no effect on the overall frequency of an early release. The effect on the late release categories was also insignificant.

4.7.3.4 Sensitivity Study 3 - Sprays Always Available and Always Used Late

This sensitivity combines the effects of the preceding two sensitivity studies. The effect of this combination was to reduce the frequency of early high release from 21 to 18% of the total frequency, and to reduce the frequency of an early medium-high release from 14% to almost zero. The change to the early high release category is relatively small since most of these sequences have no AC power recovery either early or late. The availability and use of sprays is irrelevant in sequences without AC power recovery.

The dramatic change in the early medium-high release category results from late spray operation in those sequences with AC power recovery. With late releases in these sequences reduced by more than an order of magnitude due to the sprays, the release category frequency shifts from the early medium-high and medium release categories to the early medium and early low release categories, respectively. This shift is evident in Figure 4.7-5.

4.7.3.5 Sensitivity Study 4 - No Drywell Shell Meltthrough

Early containment failure in the HCGS CET can result from:

(1) In-vessel or ex-vessel steam explosion that rupture the containment,

(2) Meltthrough of the drywell shell when molten core debris spreads across the drywell floor and contacts the steel shell at the edge of the concrete, and

(3) Quasi-static pressure rise resulting from pressurization before vessel failure, and additional pressure rise at vessel failure.

Drywell meltthrough was found to be the dominant early containment failure mode in the Base Case results (see Table 4.7-15). However, because there is still substantial uncertainty associated with drywell shell meltthrough phenomena, the drywell shell meltthrough probability was considered in a sensitivity study. For this study, the drywell shell meltthrough probability was set equal to zero. This was done to illustrate the contribution of drywell shell meltthrough, and to show how the radionuclide release characteristics of the HCGS plant might change if drywell shell meltthrough could be prevented. The results of this sensitivity study are shown in Table 4.7-23.

Without drywell shell meltthrough, there are much fewer early containment failures and, therefore, far fewer early releases. The total frequency of early release decreases from about 62% to 29% of the total sequence frequency. This has the general effect of decreasing the frequency of all of the early release categories. Most importantly, the frequency of an early high release decreases from 21% to approximately 8% of the sequences, while the frequency of an early medium-high release decreases from approximately 14% to less than 4%.

Without early failures by drywell shell meltthrough, the late containment failure frequency increases. The overall frequency of late releases increases from 20% to 53%. Late failures provide greater opportunity for evacuation of the surrounding population, and would therefore result in greatly reduced consequences.

4.7.3.6 Sensitivity Study 5 - No Early AC Power Recovery

Since many engineered safeguards require AC power, power recovery provides the only possibility for mitigating the effects of a station blackout accident. Both extremes of the AC power non-recovery probability were considered in the HCGS sensitivity study. The sensitivity study discussed in this section addresses the effect of no early AC power recovery (i.e., early non-recovery probability equal to unity), while the sensitivity study discussed in the next section considers the effect of certain AC power recovery both early and late. The results for this sensitivity study are shown in Table 4.7-23.

Without early AC power recovery, the probability of early containment failure is higher in the long-term station blackout sequences (early containment failure increases from 69% to 75%), while the early high release frequency increases from 24 to 38% of the LT-SBO frequency. Since the LT-SBO sequences comprise 78% of the total core damage frequency, the overall frequency of an early high release increases from 21% to 32% of the total frequency.

4.7.3.7 Sensitivity Study 6 - AC Power Always Recovered Early and Late

This sensitivity study represents the other extreme from the sensitivity study discussed in the preceding section. Here it is assumed that AC power is always recovered early and late. Again, this change affects only the long-term station blackout sequence. The results for this sensitivity study are presented in Table 4.7-23.

With AC power recovered, the operators can use all available engineered safety systems to mitigate the accident. As stated previously, use of coolant injection and containment sprays greatly reduces the frequency and magnitude of early release. The frequency of an early high release decreases from 24% to 2.5% for the LT-SBO sequences. The total frequency of early release also decreases to 59% from 69% for the LT-SBO sequences, with nearly all (83%) of the early releases in the early low release category.

With the LT-SBO sequences comprising 78% of the total core damage frequency, the overall effect on the release category frequencies is substantial. The early high release category frequency decreases from 21% to 4% of the total frequency, while the early medium-high release category frequency decreases from 14% to 13%.

4.7.3.8 Sensitivity Study 7 - Ex-Vessel Core Debris Not Coolable

Ex-vessel core-concrete interactions (CCI) contribute to both late containment failure and the magnitude of radionuclide release to the environment should the containment fail. In the HCGS CET, CCI is assumed to lead to eventual containment failure since the Mark I containment has insufficient volume to retain the non-condensable gases that are released from the concrete without overpressurization. Coolability of core debris is thus a key determinant in the evaluation of long-term containment integrity. Core-concrete interactions also lead to release of radionuclides such as tellurium and strontium that are not released to a significant extent during in-vessel core degradation. Thus, for an accident sequence to lead to radionuclide release in the high release category (E1 or L1), core-concrete interactions must occur.

There is significant uncertainty associated with the phenomena of ex-vessel debris coolability. This is particularly true for Mark I BWRs since there is substantial drywell floor over which the core debris may spread. Spreading of the core debris over the available floor area could enhance the potential for coolability.

To examine the effect of ex-vessel core debris coolability on the calculated results, the debris coolability probability was varied from zero to one under all accident conditions. This section discusses the result from setting the probability of coolability to zero. The results of this sensitivity study are shown in Table 4.7-23.

Ex-vessel core-concrete interactions are assumed in the HCGS source term algorithm to lead to significant release of tellurium and strontium. Since most early releases of these radionuclides are scrubbed by the suppression pool, and late revolatilization is assumed to be negligible, CCI is the only mechanism for significant release of tellurium and strontium.

As shown in Table 4.7-23, increasing the likelihood of CCI more than doubles the frequency of an early medium-high release, while reducing the frequency of the early medium and early low release categories. This result indicates that some sequences with low releases of tellurium and strontium (i.e., coolable core debris) now have high or medium releases (i.e., uncoolable debris). The table also shows that the early high release category is almost unchanged. The reason for this is explained below.

Sequences with high iodine release almost always have no late coolant injection. This is true since early iodine releases are usually scrubbed by the suppression pool and are therefore small; consequently, high iodine release is usually associated with late revolatilization. High revolatilization releases of iodine are only significant if there is no coolant injection since coolant injection cools the primary system surfaces and prevents revolatilization. Without coolant injection, the HCGS CET assumes that the ex-vessel core debris is nearly always uncoolable. Similarly, base case sequences with coolable core debris probably have late coolant injection and small iodine release from revolatilization.

Table 4.7-23 also shows that the frequencies of early and late release do not change significantly since ex-vessel debris coolability only affects late containment behavior. Note, however, that since the core debris is always uncoolable, the containment fails or is vented in all but 2% of the sequences.

4.7.3.9 Sensitivity Study 8 - Ex-Vessel Core Debris Always Coolable

To consider the converse to the preceding study, the effect of assuming that ex-vessel core debris is always coolable if water is present and/or the debris is dispersed such as by high pressure melt ejection (HPME) or energetic fuel coolant interactions (FCIs) was examined. Given that the probability of HPME or a large FCI is small, the important dependency is the presence of a water source.

Since most sequences leading to early or late high release have no source of water to cool the core debris, these release categories are not affected by debris coolability assumptions. Note, however, that assuming coolability and therefore no CCI release when water is present leads to the almost complete elimination of the early and late medium-high release categories. The early medium-high release category sequences now fall into the early medium or low release categories, while the late medium-high release category sequences now fall into the late medium, low, or low-low release categories. The latter release category, which corresponds to no containment failure, increased from 12 to 16% of the total frequency.

4.7.3.10 Sensitivity Study 9 - Injection Systems Never Fail Due to Harsh Environments

Coolant injection systems are important to the long-term coolability of the core debris, and long-term heat removal from the containment. If the containment fails, injection systems that are available and operating may subsequently fail due to the harsh environment in the Reactor Building (e.g., due to hydrogen combustion). The HCGS CET checks for failure of the injection systems following containment failure, and assumes that a core-concrete interaction eventually occurs if coolant injection is lost.

The harsh environment failure probabilities for HCGS were taken from the NUREG-1150 study of the Peach Bottom Atomic Power Station. These probabilities were felt to be conservative for HCGS since the Reactor Building is more compartmentalized at HCGS than at Peach Bottom, so harsh environments in one area are less easily communicated to other areas of the Reactor Building. In addition, some of the vital alternate injection equipment (such as the condensate pumps) is located in the turbine building rather than the Reactor Building. Thus, there should be a much higher probability that at least one injection system will survive.

To examine the effect of injection system failures due to harsh environments, the HCGS CET calculations were repeated assuming that the low pressure ECCS and alternate injection systems never fail due to harsh environments. The results from this sensitivity study are shown in Table 4.7-23.

As shown in the table, the calculated results are not very sensitive to the probability of injection failure due to harsh environments. This is true because most sequences with injection have no containment failure. Consequently, few sequences are affected by the probability of injection failure following containment failure.

4.7.3.11 Sensitivity Study 10 - Alternate Injection Systems Never Fail Due to Harsh Environments

This sensitivity considered a subset of the sensitivities examined in the preceding study. Here, only the alternate injection systems were considered to survive in all cases following containment failure. The probabilities for failure of the low pressure ECCS systems were reset to their base case values. Given that the calculated results were not affected by assuming that neither injection system fails, the results were not sensitive to the survivability of the alternate injection systems.

4.7.3.12 Sensitivity Study 11 - Venting Always from the Drywell

PSE&G has installed a hardened vent at HCGS to provide a durable and controlled venting path from the wetwell. This system vents from the wetwell to the environment, and releases are therefore scrubbed by the suppression pool. This sensitivity study was performed to examine the benefit of wetwell venting through the hardened vent. To do this, the probability of drywell venting was set to one for all sequences with venting. The results from this sensitivity study are presented in Table 4.7-23.

Venting is effective only if there are no containment failures. Most early and late containment failures require hot core debris. This is true, for example, of containment failures by drywell shell meltthrough (the dominant early failure mechanism) and containment failures by thermally induced seal leakage (the dominant late failure mechanism). Since these sequences generally have uncoolable debris, they usually result in high and medium-high releases. As a result, wetwell venting is important only for sequences with venting (10% of the total frequency), and then only for sequences leading to the medium and low release categories. Table 4.7-23 and Figure 4.7-5 show a slight shift from the low to the medium release categories when venting is from the drywell rather than the wetwell.

4.7.3.13 Sensitivity Study 12 - FRVS Efficiently Retains Radionuclides

The HCGS CET assumes that the FRVS has an effective aerosol removal efficiency of 90% (i.e., a DF of 10). The actual efficiency of the FRVS filters is probably greater than 99%, which would lead to a DF of greater than 100. At this level, less than 1% of the radionuclides that reached the filters would pass through and potentially escape to the environment. We adopted a conservative approach in the CET because of uncertainty in the survivability of the FRVS when subjected to the gas temperatures and aerosol loadings typical of a severe accident.

Recent MAAP analyses performed by the PSE&G staff have shown, however, that the aerosol loadings and gas temperatures may not be as severe as was thought. For this reason, a sensitivity study was performed that considered a Reactor Building DF of 100 whenever the FRVS was operating. The results from this study are shown in Table 4.7-23 and Figure 4.7-5.

The FRVS requires AC power to operate and it therefore can operate only in those LT-SBO sequences with early or late AC power recovery. In addition, the FRVS is assumed to fail whenever a containment rupture occurs. Since the dominant early containment failure mode, drywell shell meltthrough, is treated as a rupture, FRVS is assumed to fail in a large fraction of the sequences with AC power recoverv. Early and late overpressure failures are also assumed to lead to ruptures 90% of the time. All other failure modes are predominantly leaks, and will therefore have a functioning FRVS if AC power is available and the FRVS has not failed.

As shown in Table 4.7-23, the effect of increasing the FRVS DF is very small. This can be explained by considering that the FRVS functions only when the following are true: FRVS is available, AC power is available, and the containment failure is a leak. The probability of all three conditions being true is low. This is especially true because the dominant accident initiator at HCGS is a long-term station blackout.

4.7.3.14 Sensitivity Study 13 - FRVS Always Available

This sensitivity study examines the effect of assuming that the FRVS is always available. As noted above, this is one of the three conditions necessary assumed in the CET in order for the FRVS to function.

As shown in Table 4.7-23, the effect of FRVS availability on the early high and medium-high release categories is small since most sequences leading to these release categories involve either containment ruptures or unavailable AC power or both. There is a slight reduction in the frequency of late high or medium-high releases since most late containment failures involve seal leakage rather than containment ruptures.

4.7.3.15 Sensitivity Study 14 - FRVS Always Fails

This sensitivity study examines the converse of the preceding study: FRVS is always assumed to fail. As in the preceding study, FRVS availability has little affect on the early high or medium-high release categories since these release categories generally occur when the containment ruptures or AC power is unavailable. There is a slight effect on late release categories since late release usually result from containment leaks. With the FRVS failed in all late containment failure sequences, the frequency of the late high and late medium-high release categories increased slightly.

4.7.3.16 Sensitivity Study 15 - Use of Fire System to Ensure Late Spray Availability

Sensitivity studies 1 through 3 considered alternate assumptions regarding drywell spray availability and late spray usage. Each of these sensitvities required that AC power be available in order to use the sprays. Because LT-SBO sequences are the dominant contributors to the HCGS core damage frequency, and late AC power is unavailable in a significant fraction of these sequences, the radionuclide release results were found to be relatively insensitive to the spray availability and usage assumptions considered in these sensitivity studies. The FPS is independent of AC power; however, using it for drywell spray requires some valve alignments. Remote valve alignment is dependent on AC and DC power. This sensitivity study assumes that the drywell spray valves are open and its purpose is just to show the effect of adding water to drywell through a non-AC dependent injection source.

In this sensitivity study, we consider an alternate means for ensuring spray availability that does not rely on AC power; namely, alignment of the FPS to inject through the drywell sprays. Since alignment of the FPS requires several manual operator actions, we consider it only for late spray usage (i.e, when the vessel has failed). Another reason for assuming late spray usage is that no specific calculation is performed to determine the flow rate of the Fire pumps, when injecting through the drywell sprays. Besides, as long as the vessel is not failed, the operators will align the Fire system to the reactor vessel. For this study, sprays are always assumed to be available and to operate late. Implicit in this assumption is that the operators would be directed by the TSC to use the sprays even though the EOPs would preclude their use. The results from this study are shown in Table 4.7-23.

Not surprisingly, the release category results were very sensitive to late spray usage. Since all sequences have drywell sprays on late in the accident ("late" as used here refers to after vessel failure, but before containment failure), all releases are scrubbed by the sprays. Since the spray DF is assumed to be 10, this results in at least an order of magnitude reduction in all calculated source terms. Late releases are generally reduced more since, in many sequences, the ex-vessel core debris will be coolable and there will be no release from core-concrete interactions.

The net effect of the sprays is to completely eliminate the high and early medium-high release categories since all previously high iodine or tellurium releases are now medium or low releases. Note the early containment failure frequency is the same as in the base case since the sprays were assumed to be used too late to prevent early containment failure. This is a conservative assumption since the drywell sprays would improve the probability that the drywell shell would survive (recall that drywell shell meltthrough is the dominant early containment failure mode). Note also that there is a higher frequency of no containment failures since the higher probability for ex-vessel debris coolability leads to a reduced probability for late containment failures due to temperature, pressure, or melt-through of the drywell shell below the sumps.

4.7.3.17 Sensitivity Study 16 -Early Opening of the Torus Hard Pipe Vent

The HCGS is equipped with a 12" hard pipe vent that can be opened locally, independent of any power. No sensitivity analysis was done to determine the advantage of opening this vent prior to vessel failure, when the containment pressure is low. However, based on engineering judgement it is believed that opening of the vent prior to vessel failure will reduce the magnitude of the high early releases. This is true, since a good portion of the released fission products will go to the torus via the SRVs. Furthermore, after the vessel is failed the fission products will go to torus through the eight torus to drywell vent pipes. Any fission product released to the torus will be scrubbed to some degree, prior to being released to the environment. Hence, the magnitude and timing of the source terms, specially the high early releases, is expected to be reduced substantially..

4.7.4 Summary of Results from the HCGS Level II IPE

The following is a brief summary of the results from the Level II portion of the HCGS IPE.

Summary of Base Case Results

- The HCGS core damage frequency is dominated by long-term station blackout (LT-SBO) sequences. LT-SBO sequences constitute 77.7% of the total CDF. The LT-SBO sequences lead to a high frequency of early containment failures, and generally higher releases. This is because AC power is not available in many sequences to operate the engineered safety features such as low pressure ECCS, alternate coolant injection, and drywell sprays.

- Of the other sequences, transients without decay heat removal (TW) are also important because they often lead to early containment failure and high release. However, TW sequences make up only about 5% of the total CDF.

- The early containment failure frequency for the base case is driven by the unavailability of coolant injection in many sequences. Early containment failure is predicted to occur in 55.7% of the sequence frequency. Approximately 84% of these cases have containment failure by drywell shell meltthrough. The high probability of shell meltthrough is again due to the lack of coolant injection. Injected coolant would provide a means of heat removal for the shell, which increases the probability that the shell will survive. Similarly, coolant on the drywell floor improves the probability that the ex-vessel core debris will be coolable and core-concrete interactions will not occur.

- Drywell shell meltthrough is treated in the CET as a large containment failure (i.e., a rupture). Under these conditions, radionuclide retention in the primary containment and the RB is assumed to be small. Since the drywell is failed, radionuclides also bypass the suppression pool. Finally, the FRVS is assumed to fail following a containment rupture. All of these conditions favor high radionuclide release.

- Due to the high frequency of drywell shell meltthrough and the radionuclide retention characteristics of this failure mode, radionuclide releases are relatively high in a significant fraction of the accident sequences. The frequency of an early high release is 21% of the total CDF, and the frequency of an early medium high release is an additional 14%.

- Late containment failure occurs in an additional 18% of the sequences. The containment does not fail in approximately 20% of the cases, with venting taking place in approximately half of these cases. Venting is almost always from the wetwell, and through the hardened venting system installed at HCGS.

Summary of Sensitivity Study Results

- Due to the dominance of the LT-SBO sequences, the sensitivity study showed very little sensitivity to most of the parameters considered. This was especially true of those sensitivities to engineered safety system availability since AC power is unavailable in many of the SBO sequences.

- The results were found to be very sensitive to AC power recovery assumptions. If AC power is always recovered early, the early high release frequency decreases from 21% to 4% of the total CDF, while the late high release category decreases from 7% to 1.4%. If, on the other hand, early AC power recovery never occurs, the frequency of an early high release increases to 32% of the CDF, while the frequency of a late high release increases to 11%.

- The results were found to be relatively insensitive to the availability and use of drywell sprays. If sprays are always available (due to alignment with the service water system), and are always used late (because the TSC directs the operators to use the sprays although the EOPs would preclude their use), the frequency of the early high and medium-high release categories decrease to 18% and 7.5% (from 19% and 14%), respectively. The limited sensitivity to drywell spray operation is again because of the unavailability of AC power in many sequences.

- The results were found to be very sensitive to the availability and use of drywell sprays if spray usage is not dependent on AC power. If the firewater system is aligned to inject into the drywell spray system (without AC power), and the sprays are always used late, there are no high and medium-high releases. This occurs because all early and late releases are reduced by at least an order of magnitude.

- The results were found to be relatively insensitive to the availability and effectiveness of the FRVS. This is due to two conditions: the high frequency of early containment ruptures (primarily due to drywell shell meltthrough) and the lack of AC power to operate the system. The FRVS will not function if either condition occurs.

- The results were found to be very sensitive to two uncertainties in ex-vessel phenomena: drywell shell meltthrough, and ex-vessel debris coolability. Both of these phenomena are strong functions of the extent to which the core debris is cooled by overlying water. There is significant uncertainty regarding heat transfer to the water.

- If drywell shell meltthrough is assumed not to occur, the frequency of an early release (some of which are due to venting) decreases significantly from 62% to 29%. Late containment failures undergo a consequent increase as there is a greater opportunity for either late overpressure, temperature, or sump failure. In addition, the frequency of an early high and early medium-high release decreases to 8% and 4% (from 21% and 14%).

- If the ex-vessel core debris is assumed to be coolable whenever water is present, the frequency of an early or late medium-high release goes almost to zero as sequences with uncoolable core debris and water present, now have coolable debris and no releases from core-concrete interaction. These sequences are shifted primarily into the early or late low release category. The early high and late high release categories are almost unaffected by debris coolability assumptions because these high releases occur primarily in sequences without water injection.

- No sensitivity analysis was performed on use of torus hard pipe vent prior to vessel failure. However, this practice is expected to improve the magnitude and timing of releases, specially the high early ones.

4.7.5 References

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4.7-6 D. A. Powers, "Source Term Attenuation by Water in the Mark I Boiling Water Reactor Drywell," SAND92-2688, Sandia National Laboratories, Albuquerque, New Mexico, November 1992 (draft for comment).

TABLE 4.7-1

ISOTOPES IN EACH RADIONUCLIDE RELEASE GROUP

Release Group	Isotopes Included
1. Inert Gases	Kr-85, Kr-85M, Kr-87, Kr-88, Xe-133, Xe-135
2. Iodine	I-131, I-132, I-33, I-134, I-135
3. Cesium	Rb-86, Cs-134, Cs-136, Cs-137
4. Tellurium	Sb-127, Sb-129, Te-127, Te-127M, Te-129, Te-129M, Te-131M, Te-132
5. Strontium	Sr-89, Sr-90, Sr-91, Sr-92
6. Ruthenium	Co-58, Co-60, Mo-99, Tc-99M, Ru-193, Ru-105, Ru-106, Rh-105
7. Lanthanum	Y-90, Y-91, Y-92, Y-93, Zr-95, Zr-97, Nb-95, La-140, La-141, La-142, Pr-143, Nd-147, Am-241, Cm-242, Cm-244
8. Cerium	Ce-141, Ce-143, Ce-144, Np-239, Pu-238, Pu-239, Pu-240, Pu-241
9. Barium	Ba-139, Ba-140

Table 4.7-2

Quantification of the Source Term Parameters

Source Term Parameter	Value Assigned	Parameter Description	Rationale for Parameter Value
RFIV(NG)_VF	1	In-vessel release fractions with vessel failure	MAAP 3.0B calculations were used to provide release fractions for cases with vessel failure. Except for Te, all release fractions calculated by MAAP are greater than those used in NUREG/CR-4551. The Te release fraction in NUREG/CR-4551 was 0.15, whereas MAAP calculates essentially no release in-vessel. The MAAP value for Te release is below the median values of any of the experts elicited, and below predictions of NRC codes. The NUREG/CR-4551 value for Te release is judged to be more reasonable.
RFIV(I)_VF	0.99		
RFIV(Cs)_VF	0.99		
RFIV(Te)_VF	0.15		
RFIV(Sr)_VF	0.001		
RFIV(NG)_nVF	0.99	In-vessel release fractions without vessel failure	MAAP 3.0B analyses were used to provide release fractions for cases without vessel failure. MAAP predicts high releases of NG, Cs, and I unless injection is added within the first half-hour following core damage. MAAP predicts no Te release, which is not consistent with values used in NUREG/CR-4551. Te release for no vessel failure was scaled down from the value chosen for release with vessel failure.
RFIV(I)_nVF	0.9		
RFIV(Cs)_nVF	0.9		
RFIV(Te)_nVF	0.01		
RFIV(Sr)_nVF	0.0		
DFVSL(Cs)_VF	2.0	Primary system DF with vessel failure	MAAP 3.0B calculations provide the basis for these parameter values. MAAP predicts values from 1.3 to 5.0, with most values clustered
DFVSL(Ae)_VF	3.0		

Table 4.7-2

Quantification of the Source Term Parameters (continued)

Source Term Parameter	Value Assigned	Parameter Description	Rationale for Parameter Value
DFVSL(Cs)_nVF	10.0	Primary system DF for cases with no vessel failure	No MAAP calculations were run with core damage and no vessel failure. Given that vessel failure is prevented only by coolant addition, the primary system surfaces should be cooler than for the cases with vessel failure. In addition, without vessel failure, the holdup time for fission products will be higher. Retention should therefore be higher. NUREG/CR-4551 had primary system DFs of greater than 10 (approximately 12 for I, and 30 for other fission products) for cases in which the holdup time was assumed to be long. The NUREG/CR-4551 values are used.
DFVSL(Ae)_nVF	30.0		
DFEPOOL(Ae)	1000.0	DF for early suppression pool scrubbing	MAAP predicts T-quencher DFs of approximately 120 to 3000. The MAAP model is based on the SUPRA code, which predicts values significantly higher than current NRC codes. Recent analyses [4.7-6] have shown that the NRC codes probably underestimate pool scrubbing. Thus, the MAAP values are used.
DFESPR(Ae)	10.0	DF for early sprays	It is difficult to extract spray DFs from MAAP output, so MAAP-based values were not used. NUREG/CR-4551 elicited experts and obtained values of 11 for early spray DF and 17 for late spray DF. Spray DFs could be much higher or lower than these values depending on the length of time the sprays are operating. To be conservative, values of 10 for late and early sprays are used.
DFLSPR(Ae)	10.0	DF for late sprays	

Table 4.7-2

Quantification of the Source Term Parameters (continued)

Source Term Parameter	Value Assigned	Parameter Description	Rationale for Parameter Value
RFREV(NG)_nWTR	1.00	Release fractions for revolatilization from the primary system given no late coolant injection	Values were obtained from MAAP calculations. NUREG/CR-4551 values for I and Cs are much smaller—0.115 for I, and 0.051 for Cs. MAAP predicts high primary system surface temperatures in the accidents analyzed by PSE&G. This leads to high release by revolatilization. Though the MAAP values may be very conservative, they were used.
RFREV(I)_nWTR	0.7		
RFREV(Cs)_nWTR	0.7		
RFREV(Te)_nWTR	0.0		
RFREV(Sr)_nWTR	0.0		
RFREV(NG)_WTR	1.0	Release fractions for revolatilization from the primary system given late coolant injection	No MAAP calculations were run with late coolant injection. Values were taken from NUREG/CR-4551.
RFREV(I)_WTR	0.03		
RFREV(Cs)_WTR	0.001		
RFREV(Te)_WTR	0.00		
RFREV(Sr)_WTR	0.00		
RFMCCI(NG)	1.00	Release fractions for release during core-concrete interactions.	These release fractions were obtained from MAAP 3.0B calculations. Release fractions selected are in the upper range of MAAP results. NUREG/CR-4551 values were 1.0 for NG, I, and Cs; 0.32 to 0.36 for Te; and 0.052 for Sr. The MAAP values are comparable to the NUREG/CR-4551 values except for Sr release. Lower values for Sr release are justified based on the results from recent experiments at ANL and SNL that appear to indicate much lower Sr than previously thought.
RFMCCI(I)	0.95		
RFMCCI(Cs)	0.95		
RFMCCI(Te)	0.40		
RFMCCI(Sr)	0.01		
DFLPOOL(Ae)	100.0	Decontamination factor for late release through drywell vents.	MAAP values for vent DFs range from 25 to 900. The MAAP model is based on the SUPRA code which tends to predict higher DFs than current NRC codes. Recent analyses [4.7-6] have shown that the NRC codes probably underestimate water pool scrubbing. Consequently, the MAAP values are used. An approximate median value of 100 was selected.

Table 4.7-2

Quantification of the Source Term Parameters (continued)

Source Term Parameter	Value Assigned	Parameter Description	Rationale for Parameter Value
DFECONT(Ae)_FPR	3.5	Containment DFs for early release—high retention	Early containment DFs are not available from MAAP calculations since no runs were made with early releases to the primary containment. NUREG/CR-4551 values ranged from 1.3 to 3.5 for early containment DFs. These values will be used.
DFECONT(Ae)_nFPR	1.3	Containment DFs for early release—low retention	
DFLCONT(Ae)_FPR	3.0	Containment DFs for late release—high retention	Late containment DFs are available from the MAAP results. The MAAP values range from 1.2 to greater than 10. These values are somewhat lower than NUREG/CR-4551 values, which range from 15 to 24 for late containment failure. The large NUREG/CR-4551 values are due to the assumed long time to containment failure (i.e., long period for aerosol deposition). Containment failure times were shorter in the MAAP calculations, so smaller DFs are justified.
DFLCONT(Ae)_nFPR	1.4	Containment DFs for late release—low retention	
DFERB(Ae)_nDEP	1.5	Reactor building DFs for early release—low deposition	No MAAP calculations were performed with early release to the reactor building. Values used for the early reactor building DF were assumed to be the same as for the late reactor building DF (discussed below).
DFERB(Ae)_DEP	10.0	Reactor building DFs for early release—high deposition	
DFLRB(Ae)_nDEP	1.5	Reactor building DFs for late release—low deposition	Results from MAAP calculations were used to determine these DFs. Calculated values ranged from just above 1.0 to around 20. In the group with high DF values, 10 was representative of the lower portion of the range. NUREG/CR-4551 values ranged from 1.35 to 4.02. All values were obtained assuming reactor building failure. These values are comparable to the low deposition MAAP cases. A value of 1.5 will be used for the low deposition cases, while a value of 10 will be used for the high deposition cases. High DFs are assigned for cases with leakage failure of the containment and no hydrogen burns in the reactor building. These scenarios provide the greatest opportunity for radionuclide deposition.
DFLRB_DEP	10.0	Reactor building DFs for late release—high deposition	

Table 4.7-3. Summary of Significant Accident Progression Bins for LT-SBO Initiating Events

Initiating Event - LT-SBO													
Moderate to High Source Term Sequences													
Seq. Freq.	**DP**	**INJ**	**VF**	**CFE**	**EPOOL**	**L-DWSpry**	**L-INJ**	**DCOOL**	**CFL**	**LPOOL**	**FPR**	**RB**	**VENT**
7.72E-06	NO	NO	YES	YES	YES	NO	NO	NO	NO	NO	NO	NO	IRR
5.75E-06	NO	NO	YES	YES	YES	NO	YES	YES	NO	NO	YES	NO	IRR
5.33E-06	NO	NO	YES	YES	YES	NO	YES	NO	NO	NO	YES	NO	IRR
2.46E-06	NO	NO	YES	NO	YES	NO	NO	NO	YES	NO	YES	NO	IRR
2.37E-06	NO	NO	YES	NO	YES	YES	YES	YES	VENT	YES	YES	NO	YES
1.85E-06	NO	NO	YES	YES	YES	YES	YES	YES	NO	NO	YES	NO	IRR
1.20E-06	NO	NO	YES	NO	YES	NO	YES	YES	NO	YES	IRR	IRR	NO
1.10E-06	NO	NO	YES	NO	YES	NO	YES	NO	YES	NO	YES	NO	IRR
8.04E-07	NO	NO	YES	NO	YES	NO	YES	YES	VENT	YES	YES	NO	YES
7.41E-07	NO	NO	YES	NO	YES	YES	YES	YES	NO	YES	IRR	IRR	NO
6.45E-07	NO	NO	YES	NO	YES	NO	YES	NO	YES	NO	YES	YES	IRR
6.13E-07	NO	NO	YES	VENT	YES	YES	YES	YES	NO	YES	YES	NO	YES
3.51E-07	NO	NO	YES	VENT	YES	NO	NO	NO	YES	NO	YES	NO	IRR
3.32E-07	NO	NO	YES	YES	YES	NO	YES	YES	NO	NO	YES	YES	IRR
3.31E-07	NO	NO	YES	NO	YES	YES	YES	NO	NO	YES	YES	YES	IRR
Sum of LT-SBO Sequence Frequencies shown: 3.16E-5													
Total LT-SBO Frequency: 3.46E-5													
Note: IRR = Irrelevant													

TABLE 4.7-4

SUMMARY OF DOMINANT RELEASE CATEGORIES FOR LT-SBO INITIATING EVENTS

Initiating Event—Long Term Station Blackout													
Moderate to High Source Term Sequences													
Seq. Freq.	DP	INJ	VF	CFE	EPOOL	DWSpry	L-INJ	DCOOL	CFL	LPOOL	FPR	RB	RC
7.72E-6	No	No	Yes	Yes	Yes	No	No	No	No	No	No	No	E1
5.33E-6	No	No	Yes	Yes	Yes	No	Yes	No	No	No	Yes	No	E2
2.46E-6	No	No	Yes	No	Yes	No	No	No	Yes	No	Yes	No	L1
1.10E-6	No	No	Yes	No	Yes	No	Yes	No	Yes	No	Yes	No	L2
3.51E-7	No	No	Yes	Vent	Yes	No	No	No	Yes	No	Yes	No	E1
2.59E-7	No	No	Yes	No	Yes	No	No	No	Yes	No	No	No	L1
1.96E-7	Yes	No	Yes	Yes	Yes	No	No	No	No	No	No	No	E1
1.86E-7	No	No	Yes	Vent	Yes	No	Yes	No	Yes	No	Yes	No	E2
1.09E-7	Yes	No	Yes	Yes	Yes	No	Yes	Yes	No	No	Yes	No	E2

Table 4.7-5. Summary of Significant Accident Progression Bins for Transient Initiating Events

Initiating Event - Transients (Other than TW)													
Moderate to High Source Term Sequences													
Seq. Freq.	DP	INJ	VF	CFE	EPOOL	L-DWSpry	L-INJ	DCOOL	CFL	LPOOL	FPR	RB	VENT
1.31E-06	NO	NO	YES	NO	YES	YES	YES	YES	NO	YES	IRR	IRR	NO
6.44E-07	NO	NO	YES	NO	YES	YES	YES	YES	VENT	YES	YES	NO	YES
3.63E-07	YES	YES	NO	NO	YES	NO	YES	IRR	NO	YES	IRR	IRR	NO
5.06E-08	YES	YES	NO	VENT	YES	YES	YES	IRR	NO	YES	IRR	NO	YES
1.42E-07	NO	NO	YES	NO	YES	YES	YES	YES	VENT	NO	YES	NO	YES
2.03E-07	YES	NO	YES	NO	YES	YES	YES	NO	YES	NO	YES	YES	IRR
7.53E-08	NO	NO	YES	YES	YES	YES	YES	YES	NO	NO	YES	YES	IRR
7.50E-07	NO	NO	YES	YES	YES	YES	YES	YES	NO	NO	YES	NO	IRR
6.18E-08	NO	NO	YES	YES	YES	YES	YES	NO	NO	NO	YES	NO	IRR
1.09E-07	NO	NO	YES	YES	YES	NO	YES	YES	NO	NO	YES	NO	IRR
7.08E-08	NO	NO	YES	YES	YES	NO	YES	NO	NO	NO	YES	NO	IRR
3.93E-07	NO	NO	YES	VENT	YES	YES	YES	YES	NO	YES	YES	NO	YES
Sum of Transient Sequence Frequencies shown: 4.17E-6													
Total Transient Frequency: 3.46E-5													
Note: IRR = Irrelevant													

TABLE 4.7-6

SUMMARY OF DOMINANT RELEASE CATEGORIES FOR LT-SBO TRANSIENTS (OTHER THAN TW)

Initiating Event—Transient (Other Than TW)												
Moderate to High Source Term Sequences												
Seq. Freq.	DP	INJ	VF	CFE	EPOOL	DWSpry	L-INJ	DCOOL	CFL	LPOOL	FPR	RB	RC
7.08E-8	No	No	Yes	Yes	Yes	No	Yes	No	No	No	Yes	No	E2
8.16E-10	No	No	Yes	No	Yes	No	Yes	No	Yes	No	Yes	No	L2
4.64E-10	No	No	Yes	Yes	Yes	No	No	No	No	No	No	No	E1
3.22E-10	No	No	Yes	No	Yes	No	Yes	No	Vent	No	Yes	No	L2
1.51E-10	No	No	Yes	Yes	No	No	Yes	Yes	No	No	Yes	No	E2
1.47E-10	No	No	Yes	Vent	Yes	No	Yes	No	Yes	No	Yes	No	E2
8.99E-11	No	No	Yes	Yes	No	No	Yes	No	No	No	Yes	No	E1
7.71E-11	No	No	Yes	Vent	No	No	Yes	No	No	No	Yes	No	E2
6.83E-11	No	No	Yes	No	Yes	No	No	No	Yes	No	Yes	No	L1

Table 4.7-7. Summary of Significant Accident Progression Bins for TW Initiating Events

Initiating Event - TW													
Moderate to High Source Term Sequences													
Seq. Freq.	**DP**	**INJ**	**VF**	**CFE**	**EPOOL**	**L-DWSpry**	**L-INJ**	**DCOOL**	**CFL**	**LPOOL**	**FPR**	**RB**	**VENT**
6.73E-07	NO	NO	YES	YES	YES	NO	NO	NO	NO	NO	NO	NO	IRR
4.09E-07	NO	NO	YES	YES	YES	NO	YES	YES	NO	NO	YES	NO	IRR
3.84E-07	NO	NO	YES	YES	YES	NO	YES	NO	NO	NO	YES	NO	IRR
2.10E-07	NO	NO	YES	NO	YES	NO	NO	NO	YES	NO	YES	NO	IRR
1.52E-07	YES	NO	YES	YES	YES	NO	NO	NO	NO	NO	NO	NO	IRR
1.33E-07	NO	NO	YES	NO	YES	NO	YES	NO	YES	NO	YES	YES	IRR
9.77E-08	NO	NO	YES	NO	YES	NO	YES	YES	NO	YES	IRR	IRR	NO
5.48E-08	NO	NO	YES	NO	YES	NO	YES	YES	VENT	YES	YES	NO	YES
4.13E-08	NO	NO	YES	VENT	YES	NO	NO	NO	YES	NO	YES	NO	IRR
4.08E-08	YES	YES	NO	NO	YES	NO	YES	IRR	NO	YES	IRR	IRR	NO
4.04E-08	YES	NO	YES	VENT	YES	NO	NO	NO	YES	NO	YES	YES	IRR
Sum of TW Sequence Frequencies shown: 1.56E-6													
Total TW Frequency: 2.37E-6													
Note: IRR = Irrelevant													

Table 4.7-8. Summary of Dominant Release Categories for TW Initiating Events

Initiating Event—Transient With Loss of RHR (TW)													
Moderate to High Source Term Sequences													
Seq. Freq.	DP	INJ	VF	CFE	EPOOL	DWSpry	L-INJ	DCOOL	CFL	LPOOL	FPR	RB	RC
6.73E-7	No	No	Yes	Yes	Yes	No	No	No	No	No	No	No	E1
3.84E-7	No	No	Yes	Yes	Yes	No	Yes	No	No	No	Yes	No	E2
2.10E-7	No	No	Yes	No	Yes	No	No	No	Yes	No	Yes	No	L1
1.52E-7	Yes	No	Yes	Yes	Yes	No	No	No	No	No	No	No	E1
4.13E-8	No	No	Yes	Vent	Yes	No	No	No	Yes	No	Yes	No	E1
2.31E-8	Yes	No	Yes	Yes	Yes	No	No	No	No	No	No	No	E1
2.20E-8	No	No	Yes	No	Yes	No	No	No	Yes	No	No	No	L1

Table 4.7-9. Summary of Significant Accident Progression Bins for ATWS Initiating Events

Initiating Event - LOCA

Moderate to High Source Term Sequences

Seq. Freq.	DP	INJ	VF	CFE	EPOOL	L-DWSpry	L-INJ	DCOOL	CFL	LPOOL	FPR	RB	VENT
9.26E-07	YES	NO	YES	NO	YES	NO	NO	NO	YES	NO	YES	YES	IRR
6.83E-07	YES	NO	YES	NO	YES	YES	YES	YES	NO	YES	IRR	IRR	NO
1.25E-07	YES	NO	YES	NO	NO	NO	YES	YES	NO	NO	IRR	IRR	NO
1.11E-07	YES	NO	YES	NO	NO	NO	YES	NO	YES	NO	YES	YES	IRR
1.00E-07	YES	NO	YES	VENT	YES	NO	NO	NO	YES	NO	YES	YES	IRR
9.80E-08	YES	NO	YES	NO	YES	NO	NO	NO	YES	NO	NO	NO	IRR
9.70E-08	YES	NO	YES	YES	YES	NO	NO	NO	NO	NO	NO	NO	IRR
8.33E-08	YES	NO	YES	NO	YES	YES	YES	NO	YES	NO	YES	RB	IRR
7.34E-08	YES	NO	YES	VENT	YES	YES	YES	YES	NO	YES	YES	NO	YES
6.56E-08	YES	NO	YES	YES	YES	YES	YES	YES	NO	NO	YES	NO	IRR

Sum of LOCA Sequence Frequencies shown: 2.36E-6

Total LOCA Frequency: 2.54E-6

Note: IRR = Irrelevant

Table 4.7-10. Summary of Dominant Release Categories for LOCA Initiating Events

Initiating Event—Large or Medium LOCA													
Moderate to High Source Term Sequences													
Seq. Freq.	**DP**	**INJ**	**VF**	**CFE**	**EPOOL**	**DWSpry**	**L-INJ**	**DCOOL**	**CFL**	**LPOOL**	**FPR**	**RB**	**RC**
9.80E-8	Yes	No	Yes	No	Yes	No	No	No	Yes	No	No	No	L1
9.70E-8	Yes	No	Yes	Yes	Yes	No	No	No	No	No	No	No	E1
1.96E-8	Yes	No	Yes	Yes	No	No	Yes	Yes	No	No	Yes	No	E2
1.43E-8	Yes	No	Yes	Vent	No	No	Yes	Yes	No	No	Yes	No	E2
1.14E-8	Yes	No	Yes	No	No	No	Yes	No	Vent	No	Yes	No	L1
1.06E-8	Yes	No	Yes	Vent	Yes	No	No	No	Yes	No	No	No	E1

Table 4.7-11. Summary of Significant Accident Progression Bins for ATWS Initiating Events

Initiating Event - ATWS													
Moderate to High Source Term Sequences													
Seq. Freq.	DP	INJ	VF	CFE	EPOOL	L-DWSpry	L-INJ	DCOOL	CFL	LPOOL	FPR	RB	VENT
1.75E-07	NO	NO	YES	NO	YES	YES	YES	YES	NO	YES	IRR	IRR	NO
9.96E-08	NO	NO	YES	YES	YES	YES	YES	YES	NO	NO	YES	NO	IRR
9.90E-08	NO	NO	YES	NO	YES	YES	YES	YES	VENT	YES	YES	NO	YES
5.51E-08	YES	NO	YES	NO	YES	YES	YES	YES	NO	YES	IRR	IRR	NO
5.27E-08	NO	NO	YES	VENT	YES	YES	YES	YES	NO	YES	YES	NO	YES
2.81E-08	NO	NO	YES	NO	YES	YES	YES	NO	YES	NO	YES	YES	IRR
1.42E-08	NO	NO	YES	YES	YES	NO	YES	YES	NO	NO	YES	NO	IRR
9.78E-09	NO	NO	YES	YES	YES	YES	YES	YES	NO	NO	YES	YES	IRR
9.12E-09	NO	NO	YES	YES	YES	NO	YES	NO	NO	NO	YES	NO	IRR
8.91E-09*	NO	NO	YES	YES	YES	NO	NO	NO	NO	NO	NO	NO	IRR
7.96E-09	NO	NO	YES	YES	YES	YES	YES	NO	NO	NO	YES	NO	IRR
6.49E-09	YES	NO	YES	NO	YES	YES	YES	NO	YES	NO	YES	YES	IRR
6.21E-09	NO	NO	YES	NO	YES	YES	YES	YES	VENT	NO	YES	NO	YES
5.89E-09	YES	NO	YES	VENT	YES	YES	YES	YES	NO	YES	YES	NO	YES
5.38E-09	NO	NO	YES	VENT	YES	YES	YES	NO	YES	NO	YES	YES	IRR
5.08E-09	YES	NO	YES	YES	YES	YES	YES	YES	NO	NO	YES	NO	IRR
Sum of ATWS Sequence Frequencies shown: 5.90E-7													
Total ATWS Frequency: 6.42-7E													
Note: IRR = Irrelevant													

Table 4.7-12. Summary of Dominant Release Categories for ATWS Initiating Events

Initiating Event—ATWS With and Without SBO													
Moderate to High Source Term Sequences													
Seq. Freq.	**DP**	**INJ**	**VF**	**CFE**	**EPOOL**	**DWSpry**	**L-INJ**	**DCOOL**	**CFL**	**LPOOL**	**FPR**	**RB**	**RC**
9.12E-9	No	No	Yes	Yes	Yes	No	Yes	No	No	No	Yes	No	E2
8.91E-9*	No	No	Yes	Yes	Yes	No	No	No	No	No	No	No	E1
2.92E-9*	No	No	Yes	No	Yes	No	No	No	Yes	No	Yes	No	L1
2.19E-10*	No	No	Yes	No	Yes	No	No	No	Yes	No	No	No	L1

* Sequences with station blackout

Table 4.7-13. Frequencies for Key Containment Failure Top Events

Frequency of Occurrence for Initiator								
Initiator	**CFE**	**CFE-Vnt**	**CFL**	**CFL-Vnt**	**EPOOL**	**LPOOL**	**LT-DC**	**Total Frequency**
LT-SBO	2.19E-5	1.83E-6	5.68E-6	3.60E-6	3.45E-5	6.34E-6	1.50E-5	3.46e-5
TW	1.65E-6	1.10E-7	4.94E-7	7.19E-8	2.36E-6	1.74E-7	6.38E-7	2.38e-6
Other Transients	1.09E-6	5.27E-7	2.79E-7	8.20E-7	4.37E-6	2.40E-6	3.93E-6	4.39e-6
LOCA	1.98E-7	2.39E-7	2.66E-8	2.66E-8	2.22E-6	7.96E-7	1.02E-6	2.54e-6
ATWS	1.60E-7	6.99E-8	1.13E-7	1.13E-7	6.12E-7	3.96E-7	5.33E-7	6.24e-7
Total (Fraction of Total CDF)	2.48E-5 (0.557)	2.78E-6 (0.062)	7.89E-6 (0.177)	4.63E-6 (0.104)	4.41E-5 (0.991)	1.01E-5 (0.227)	2.11E-5 (0.475)	4.46e-5

Table 4.7-14. Resultant Conditional Probabilities for Key Containment Failure Top Events

Frequency of Occurrence for Initiator								
Initiator	CFE	CFE-Vnt	CFL	CFL-Vnt	EPOOL	LPOOL	LT-DC	Total Initiator Frequency
LT-SBO	6.33E-1	5.29E-2	1.642E-1	1.04E-1	9.97E-1	1.832E-1	4.34E-1	3.46e-5
TW	6.93E-1	4.62E-2	2.076E-1	3.02E-2	9.92E-1	7.31E-02	2.68E-01	2.38e-6
Other Transients	2.48E-1	1.20E-1	6.36E-2	1.87E-1	9.95E-1	5.47E-1	8.95E-1	4.39e-6
LOCA	7.8E-2	9.41E-2	1.05E-2	1.05E-2	8.74E-1	3.13E-1	4.02E-1	2.54e-6
ATWS	2.56E-1	1.12E-1	1.81E-1	1.81E-1	9.81E-1	6.35E-1	8.54E-1	6.24e-7

Table 4.7-15. Frequencies of Early Containment Failure Modes

Frequency of CFE Mode			
Initiator	**CFE-DW Melt**	**CFE-FCI**	**CFE-Press**
LT-SBO	1.85E-5	1.14E-8	3.27E-6
TW	1.52E-6	0.00	1.37E-7
Other Transients	5.55E-7	5.74E-9	5.25E-7
LOCA	1.81E-7	1.3[illegible]-8	3.57E-9
ATWS	8.89E-8	8.02E-10	6.99E-8
Total (Fraction of Total CDF)	2.09E-5 (0.469)	3.13E-8 (0.0[illegible]7)	4.01E-6 (0.09)

Table 4.7-16. Frequencies of Late Containment Failure Modes

Frequency of CFL Mode			
Initiator	**CFL-Press**	**CFL-Temp**	**CFL-Sump**
LT-SBO	1.54E-8	3.09E-6	2.57E-6
TW	1.71E-9	3.39E-7	1.53E-7
Other Transients	1.12E-9	2.78E-9	2.76E-7
LOCA	1.30E-9	1.10E-6	2.86E-7
ATWS	2.58E-10	3.33E-9	4.42E-8
Total (Fraction of Total CDF)	1.98E-8 (0.0004)	4.53E-6 (0.102)	3.33E-6 (0.075)

Table 4.7-17. Conditional Probabilities of Early Containment Failure Modes

Frequency of CFE Mode			
Initiator	**CFE-DW Melt**	**CFE-FCI**	**CFE-Press**
LT-SBO	5.35E-1	3.29E-4	9.45E-2
TW	6.39E-1	0.00	5.75E-2
Other Transients	2.33E-1	2.41E-3	2.21E-1
LOCA	7.13E-2	5.28E-3	1.41E-3
ATWS	1.42E-1	1.29E-3	1.12E-1

Table 4.7-18. Conditional Probabilities of Late Containment Failure Modes

Frequency of CFL Mode			
Initiator	CFL-Press	CFL-Temp	CFL-Sump
LT-SBO	4.45E-4	8.93E-2	7.43E-2
TW	7.18E-4	1.42E-1	6.43E-2
Other Transients	2.55E-4	1.17E-3	1.16E-1
LOCA	5.12E-4	4.33E-1	1.13E-1
ATWS	4.13E-4	5.34E-3	7.10E-2

Table 4.7-19 Base Case Release Category Frequencies for Each Accident Initiator

Initiator	Frequency	Release Category Frequencies for Each Accident Initiator								
		E1	E2	E3	E4	L1	L2	L3	L4	L5
LT-SBO	3.46e-05	8.41e-06	5.64e-06	6.16e-06	3.53e-06	2.81e-06	1.13e-06	7.25e-07	3.87e-06	2.32e-06
TW	2.37e-06	8.85e-07	3.84e-07	4.61e-07	3.21e-08	2.57e-07	8.82e-10	1.39e-07	6.78e-08	1.39e-07
Trans.	4.38e-06	5.54e-10	7.12e-08	1.90e-07	1.35e-06	6.83e-11	1.14e-09	3.52e-08	1.02e-06	1.71e-06
LOCA	2.54e-06	1.13e-07	3.44e-08	1.34e-07	1.55e-07	1.14e-07	8.86e-11	1.06e-06	9.77e-08	8.30e-07
ATWS	6.14e-07	9.04e-9	1.05e-08	2.55e-08	1.85e-07	3.14e-09	0.00	3.63e-09	1.47e-07	2.30e-07
Total	4.45e-05	9.42e-06	6.14e-06	6.97e-06	5.25e-06	3.18e-06	1.13e-06	1.96e-06	5.20e-06	5.23e-06
Fraction of CDF		2.12e-01	1.38e-01	1.57e-01	1.18e-01	7.16e-02	2.54e-02	4.41e-02	1.17e-01	1.18e-01

Table 4.7-20 Base Case Release Category Frequencies (Fraction in Each Release Category)

		Fraction of Total Initiator Frequency in Each Release Category								
PDS Name	PDS Freq.	E1	E2	E3	E4	L1	L2	L3	L4	L5
LT-SBO	3.46e-05	2.43e-01	1.63e-01	1.78e-01	1.02e-01	8.12e-02	3.27e-02	2.10e-02	1.12e-01	6.71e-02
TW	2.37e-06	3.74e-01	1.62e-01	1.95e-01	1.36e-02	1.09e-01	3.73e-04	5.88e-02	2.87e-02	5.88e-02
Trans.	4.38e-06	1.27e-04	1.63e-02	4.34e-02	3.08e-01	1.56e-05	2.60e-04	8.04e-03	2.33e-01	3.91e-01
LOCA	2.54e-06	4.45e-02	1.36e-02	5.28e-02	6.11e-02	4.49e-02	3.49e-05	4.18e-01	3.85e-02	3.27e-01
ATWS	5.14e-07	1.47e-02	1.71e-02	4.15e-02	3.01e-01	5.11e-03	0.00	5.91e-03	2.39e-01	3.75e-01
Total	4.45e-05									

Table 4.7-21

Release Categories Ranked With Respect to

Frequency and Conditional Probability

Type of Release	Release Category Ranking With Respect to Frequency	Release Category Ranking with Respect to Coditional Probability
E1	9.42E-06	21.17%
E3	6.97E-06	15.70%
E2	6.14E-06	13.80%
E4	5.25E-06	11.8%
L5	5.23E-06	11.75%
L4	5.20E-06	11.69%
L1	3.18E-06	7.15%
L3	1.96E-06	4.40%
L2	1.13E-06	2.54%

TABLE 4.7-22
SENSITIVITY EVALUATIONS

Page 1 of 2

Case	ISSUE	EVALUATION	BASIS
1	Use of the Service Water System for Drywell Sprays	Set the probability of drywell spray availability to unity.	Show the effect of aligning the service water system to allow injection into the drywell spray system.
2	Operator Initiates Sprays Late	Set operator failure probability to zero.	Technical Support Center (TSC) may direct operators to initiate sprays late even though they may be precluded by the EOPs.
3	Late drywell spray usage.	Set availability of late sprays to unity and operator failure to use sprays to zero.	Show effect of ensuring spray operation late due to use of the service water system and TSC direction.
4	Drywell Shell Meltthrough	Set probability of occurrence to zero in all cases.	Illustrate contribution to early containment failure.
5	AC Power Non-Recovery	Set to unity early	Show effect of recovery assumptions on overall results.
6	AC Power Non-Recovery	Set to zero early and late	Show effect of recovery assumptions on overall results.
7	Core Debris Coolability	Set probability of failure to cool to unity.	Precluding coolability is consistent with previous NRC position for the HCGS geometry.
8	Core Debris Coolability	Set probability of failure to cool to zero.	Assuming coolability is consistent with industry position for HCGS geometry.
9	Injection System Survivability Following Containment Failure	Set failure probability for low pressure ECCS and alternate injection to zero.	Base case probabilities are NRC values (NUREG-1150) survivability probably higher.

TABLE 4.7-22
SENSITIVITY EVALUATIONS
Page 2 of 2

Case	ISSUE	EVALUATION	BASIS
10	Alternate Injection System Survivability Following Containment Failure	Set failure probability alternate injection to zero.	Base case probabilities are NRC values (NUREG-1150) survivability probably higher.
11	Containment Venting	Set drywell venting probability to unity.	Show significance of wetwell venting.
12	FRVS Effectiveness	Set reactor building DF to 100 when FRVS is operating.	MAAP calculations show that the FRVS is likely to survive. The FRVS DF is at least 100.
13	FRVS Availability	Set FRVS availability to unity.	Examine the importance of FRVS in reducing radionuclide release and preventing reactor building failure.
14	FRVS Availability	Set FRVS availability to zero.	Examine the importance of FRVS in reducing radionuclide release and preventing reactor building failure.
15	Use of Fire Sprays to Ensure Late Spray Availability	Set late spray usage to unity.	Examine the importance of using fire sprays to provide a source of water to drywell sprays that is independent of AC power.
16	Open Torus Hard Pipe Vent Prior to Vessel Failure.	Discuss it using Engineering Judgement.	Discuss the effect of complete or partial torus water scrubbing on source term releases.

Table 4.7-23. Summary of Sensitivity Study Results

Case	Fraction of Total Frequency in Each Release Category								
	E1	E2	E3	E4	L1	L2	L3	L4	L5
Base	2.12e-01	1.38e-01	1.57e-01	1.18e-01	7.16e-02	2.54e-02	4.41e-02	1.17e-01	1.18e-01
1	1.86e-01	8.40e-02	1.10e-01	1.87e-01	6.00e-02	2.20e-04	3.42e-02	1.78e-01	1.60e-01
2	2.12e-01	9.13e-02	1.52e-01	1.70e-01	7.16e-02	2.53e-02	2.77e-02	1.33e-01	1.18e-01
3	1.80e-01	7.46e-04	1.04e-01	2.83e-01	5.94e-02	0.00	2.96e-03	2.08e-01	1.61e-01
4	8.24e-02	4.11e-02	5.58e-02	1.12e-01	1.99e-01	7.21e-02	8.27e-02	1.78e-01	1.76e-01
5	3.23e-01	1.40e-01	1.55e-01	5.32e-02	1.09e-01	1.90e-02	5.24e-02	5.34e-02	9.44e-02
6	4.21e-02	1.34e-01	1.59e-01	2.18e-01	1.38e-02	3.53e-02	3.13e-02	2.14e-01	1.53e-01
7	2.13e-01	2.92e-01	8.27e-02	3.74e-02	7.19e-02	5.25e-02	6.88e-02	1.65e-01	1.70e-02
8	2.10e-01	1.78e-03	2.76e-01	1.37e-01	6.92e-02	0.00	2.54e-02	1.22e-01	1.59e-01
9	2.12e-01	1.38e-01	1.57e-01	1.18e-01	7.16e-02	2.55e-02	4.40e-02	1.17e-01	1.17e-01
10	2.12e-01	1.38e-01	1.57e-01	1.18e-01	7.16e-02	2.55e-02	4.40e-02	1.17e-01	1.17e-01
11	2.17e-01	1.40e-01	1.70e-01	9.80e-02	7.20e-02	2.97e-02	6.51e-02	9.14e-02	1.17e-01
12	2.12e-01	1.38e-01	1.54e-01	1.21e-01	7.16e-02	2.55e-02	2.51e-02	1.36e-01	1.17e-01
13	2.10e-01	1.33e-01	1.63e-01	1.18e-01	6.28e-02	3.22e-04	7.78e-02	1.17e-01	1.17e-01
14	2.15e-01	1.41e-01	1.53e-01	1.15e-01	9.49e-02	4.44e-02	1.64e-02	1.02e-01	1.17e-01
15	0.00	0.00	2.44e-01	3.80e-01	0.00	0.00	6.00e-02	1.61e-01	1.54e-01

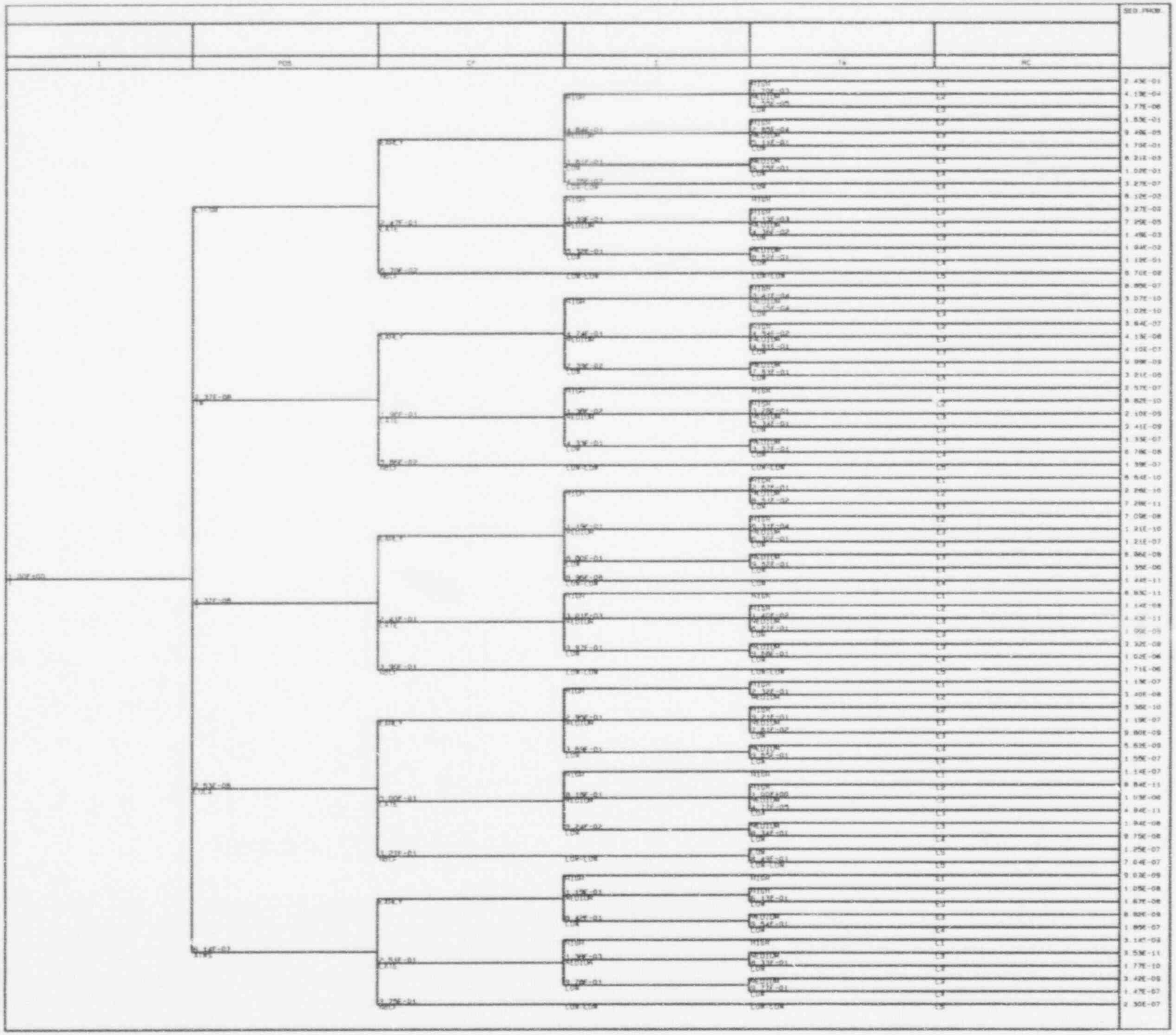


Figure 4.7-1 HCGS Event Tree Used for Binning into Release Categories

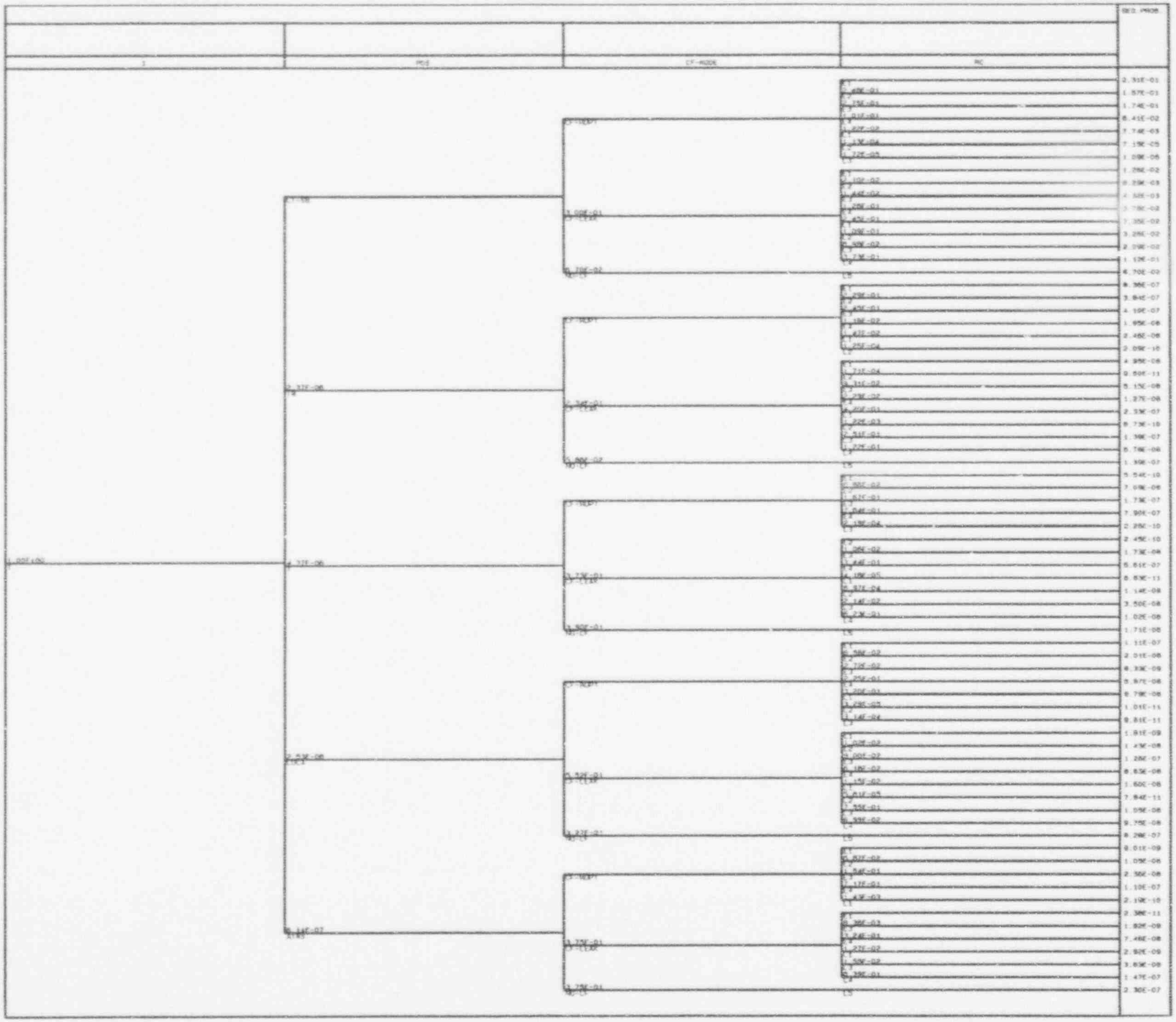


Figure 4.7-2. HCGS Release Categories Sorted Based On Containment Failure Mode

Figure 4.7-3. Fraction in Each Release Category

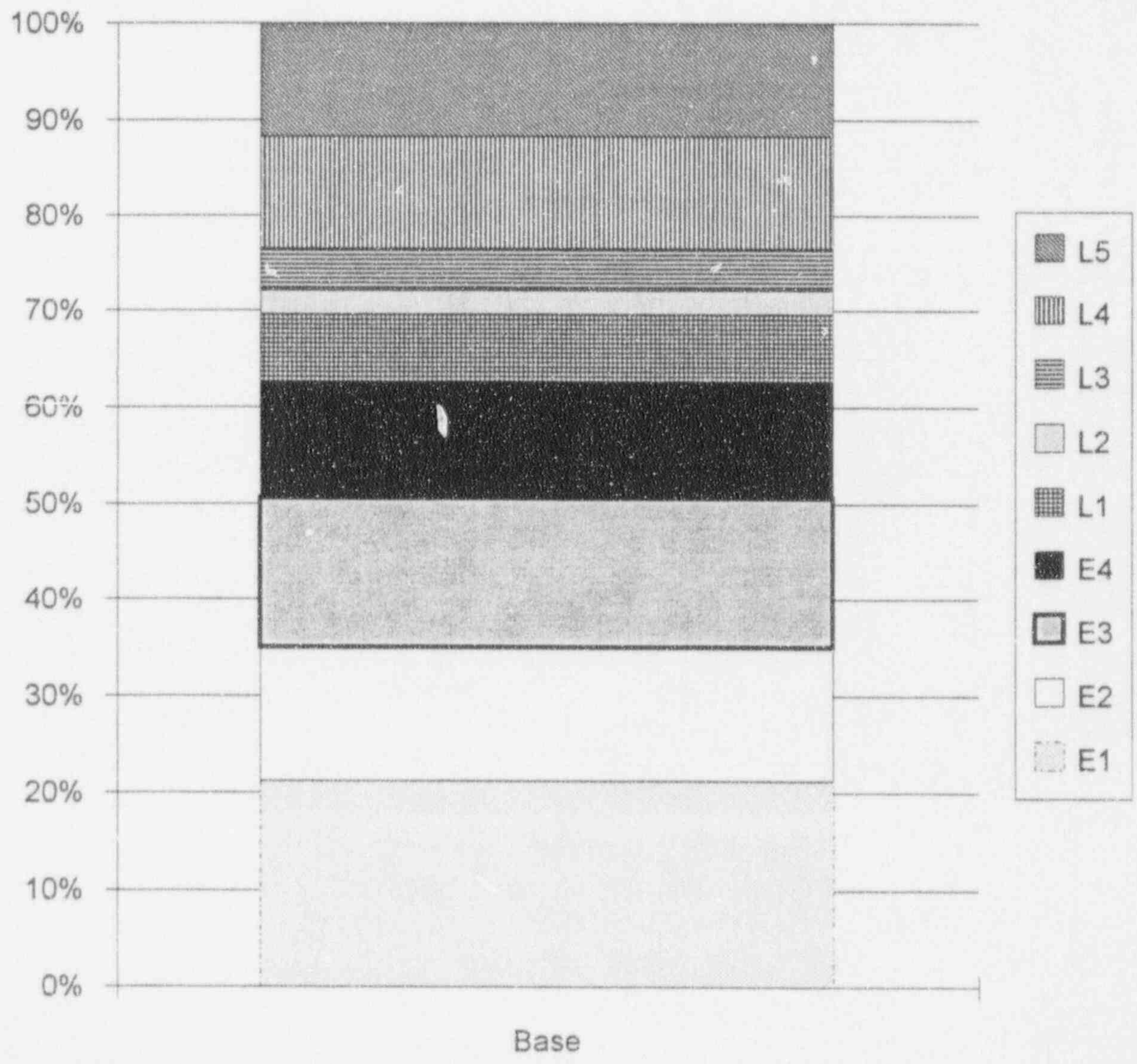


Figure 4.7-4. Percentage Contribution by Initiator - Base Case

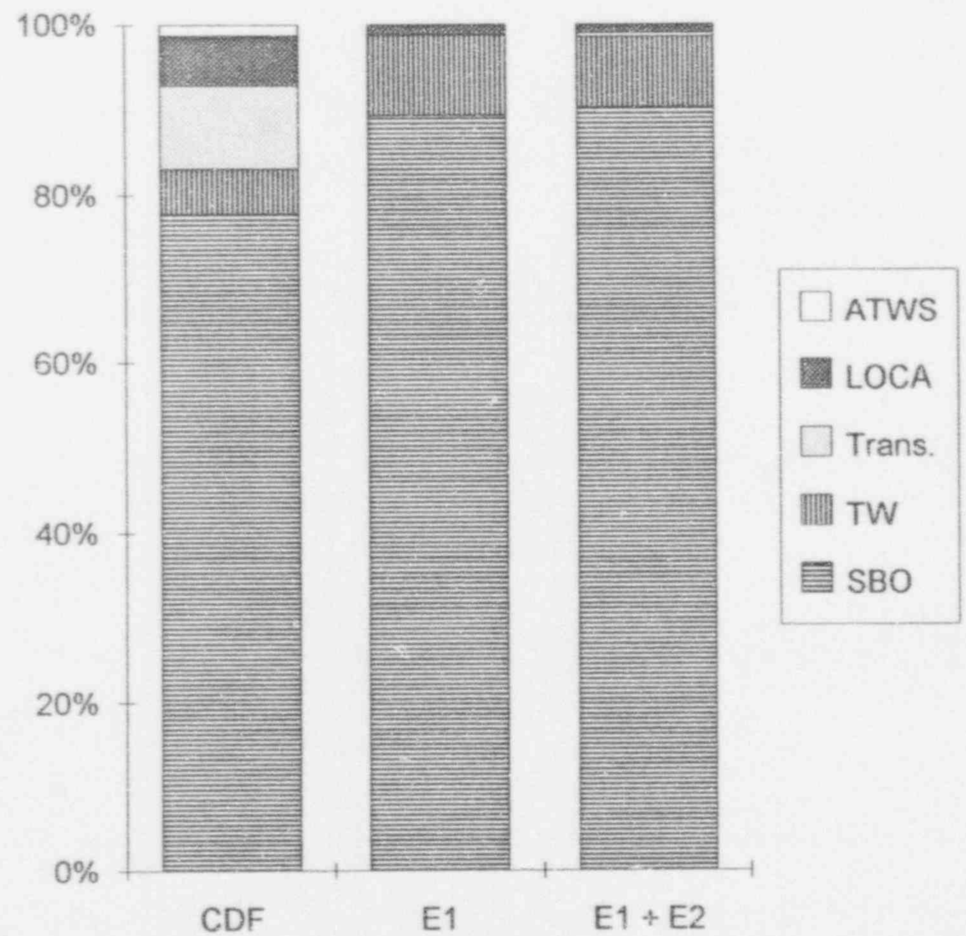
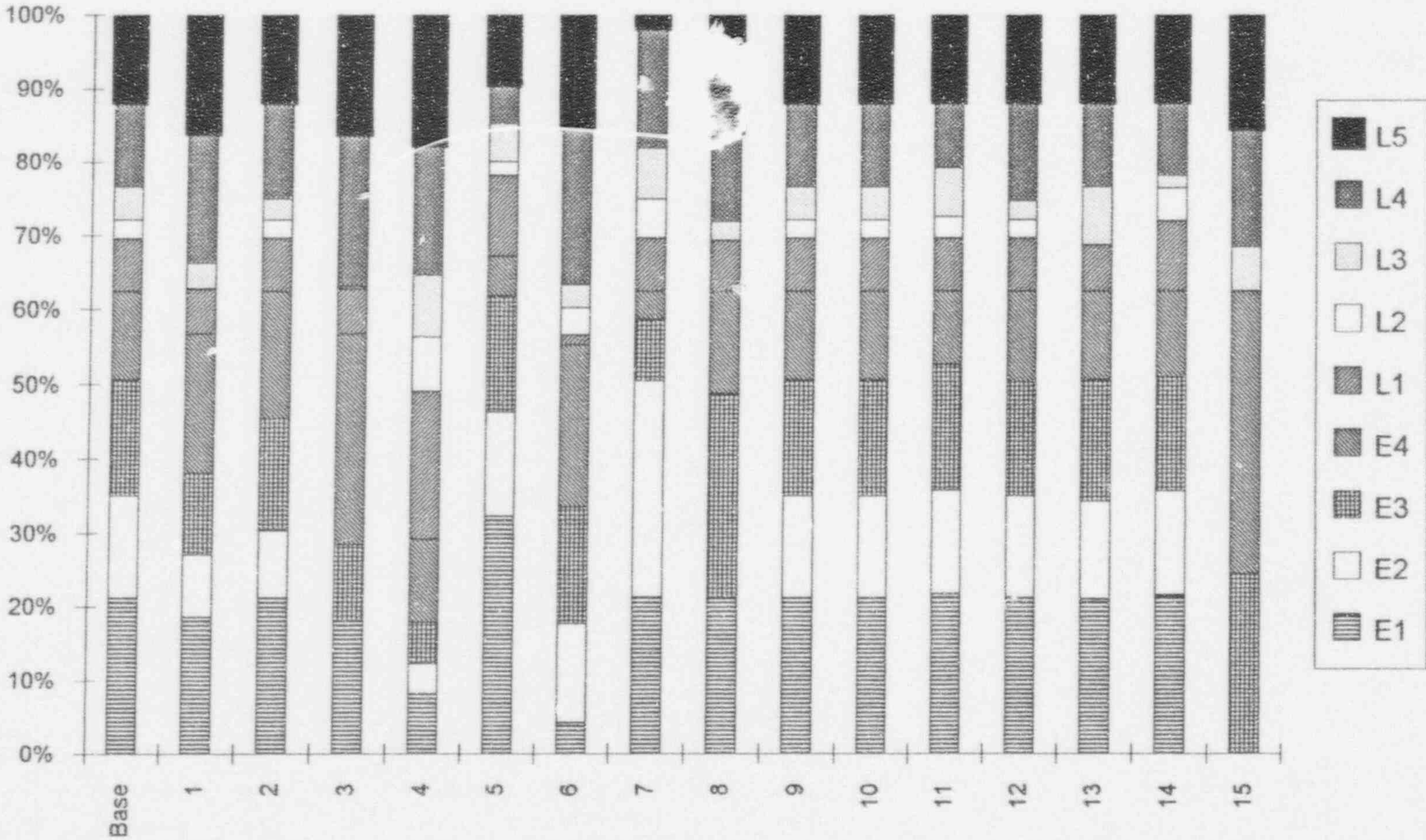


Figure 4.7-5. Releasc Category Results for the HCGS Sensitivity Study



5.0 INDEPENDENT REVIEW

EXECUTIVE SUMMARY

The independent review team completed its review of the front end (Level 1) internal events and the back end (Level 2) containment analysis portions of the Hope Creek Generating Station (HCGS) Individual Plant Examination (IPE) submittal and its associated documentation which includes:

- certain sections of Probabilistic Risk Assessment
- system notebooks
- Emergency Operating Procedures
- Human Reliability Analysis

In particular, the team reviewed the following:

- IPE process
- initiating events
- event trees
- system modeling (fault trees)
- human factors
- walkdowns
- data
- internal flooding
- intersystem LOCA
- computer codes
- residual heat removal evaluation (USI-A45)
- uncertainty, sensitivity, and importance measures
- results and conclusions

This independent review team report also covers:

- Level 2 (back end) containment response

This independent review team report does not cover:

- IPE external events (IPEEE) such as seismic events and fire

These will be included in separate review reports later. The first IPE submittal to the NRC will address only internal events. A separate and updated IPEEE study will be completed, reviewed, and submitted at a later date.

The latest revision of the IPE is dated March 1994, and is based on the unit configurations as of July 1993. The review team believes that the document is up to date. A complete and up-to-date PRA is not yet available for review or as a supporting document, although certain additional information (such as fault trees, cutsets, and HRA documentation) is available. The review team is composed of members with extensive experience in PRA, emergency and normal operating procedures, systems engineering, safety analysis and review, reliability and performance, and licensing. In particular, one review team member has senior reactor operator (SRO) certification, and he was further supported by other SROs.

The team reviewed the IPE modeling, which includes initiating events, event trees, system dependency matrices, success criteria, model assumptions, system fault trees, and other special topics as indicated above.

It should be noted that the IPE independent review does not certify the bottom-line core damage frequency by performing an independent or parallel calculation. Neither does it certify the accuracy of special analyses such as containment ultimate pressure capability, room heatup calculations, or adequacy or behavior of certain hydraulic systems. Rather, by combining the PRA expertise of an outside consultant and the utility knowledge and experience of PSE&G personnel knowledgeable in system configurations, operating practices, and design and technical specification requirements, the IPE was reviewed for correctness, completeness, compliance, consistency, and reasonableness.

Based on the review, the team found that, overall, the IPE submittal document and the associated documentation meets the intent of Generic Letter 88-20 and its related supplements. This conclusion is based on the following:

1. The IPE is complete in scope with regard to Generic Letter 88-20 requirements.

2. The IPE process used at Hope Creek is sound and conforms to normal industry practices. It is capable of identifying plant-specific vulnerabilities to severe accidents.

3. The system model and data conform acceptably well to the actual analyzed plant configuration and experience.

4. The conclusions drawn from the study are consistent with the analysis.

5. The submittal document format conforms to the NUREG-1335 requirements.

6. PSE&G personnel participated extensively in the IPE study as part of the NRC requirements.

The independent review team noted that the calculated core damage frequency appears to be reasonable and the dominant contributors are those expected, based on the findings of similar PRAs. Therefore, it is concluded that Hope Creek is not an outlier with respect to similar plants and that no immediate safety concern exists. However, certain specific suggestions from the review team are included in the main body of the report. The sensitivity and uncertainty studies are particularly noted.

A summary of the review team's suggestions is given in Table 5-1. A list of the components that most contribute to the core damage frequency (CDF) may be found in Table 3.4-5 of the IPE. The total CDF is 4.58E-5 per year for internal events. Additionally, internal flooding contributes 0.05E-5 per year to the CDF. The frequency of a large, early release is 9.7E-6 per year.

5.1 Background

The NRC issued Generic Letter 88-20 on November 23, 1988, (Reference 5.5.1) which promulgated the IPE requirements. On August 29, 1989, the NRC issued the final version of NUREG-1335 (Reference 5.5.2) to establish format and content guidelines for submitting the IPE results. The Generic Letter requests that each utility conduct "... an independent in-house review to ensure the accuracy of the documentation packages and to validate both the IPE process and its results." In NUREG-1335, it is stated (Reference 5.5.2, page C-28) that "it might be prudent to have an outside contractor review the submittal ..." It also states (Reference 5.5.2, Section 2.4) that the IPE submittal "should contain, as a minimum, a description of the internal review performed, the results of the review team's evaluation, and a list of the review team members."

This Section is to fulfill the independent review requirement.

5.2 Review of Hope Creek's Level 1 Internal Events Analysis

This section documents the independent review team's examination of the Level 1 (front end) portion of the Hope Creek IPE. The Level 2 (containment analysis) portion is in Section 5.3.

5.2.1 Documents and Review Process

The independent review team examined the latest version of the IPE, dated March 1994. The system models were developed based on the unit configurations as of July 1993. Plant data collection originally covered the years 1986 through 1989, but was updated through July 1993.

The review team believes that the model configuration and data are reasonably up to date. The review team provided preliminary and informal comments to an earlier (1992-1993) version of the draft IPE. These comments were resolved and incorporated into the March 1994, version as a result of a Recovery Plan to improve the old version.

The independent review team examined the following key documents:

Hope Creek Level 1 IPE internal event submittal document to the NRC
portions of the Hope Creek PRA (incomplete and not issued)
PRA system notebooks
Emergency operating procedures
Human Reliability Assessment

The review team used a general approach and a plant-specific approach to review the documents. In the general approach, the emphasis was placed on completeness of scope, correctness in methodology, reasonableness in depth and assumptions, compliance to NRC submittal guidelines, and comparison to industry practices and findings, using the knowledge and experience of the PRA consultant and the utility personnel. In the plant-specific approach, systems critical to the CDF were checked for modeling accuracy of the IPE analytical process. Such checking included a fairly detailed review of the system fault tree modeling.

The review team had periodic meetings and question and answer sessions among team members and with the PRA group members.

The review team also collected information by the following means:

* Informal individual discussions with the PRA group members
* Written requests (and responses) for information
* Presentations by the PRA group members on specific areas of interest (e.g., SACS adequacy, Level 2 analysis)
* Meetings with upper management for information and feedback.

The review team found that there was excellent HCGS staff participation in the IPE study. Over 200 questions were asked by the review team. The team is convinced that the PRA Group has a good understanding of the plant model and the IPE process.

5.2.2 Initiating Events

The IPE analysis is basically a small event tree and large fault tree model. There are 25 initiating event categories, including 6 transients, 10 special initiators, 7 LOCAs, and 2 interfacing system LOCAs (IPE Table 3.1.1-1). The review team compared the list of 25 event categories to similar lists generated in other IPEs/PRAs and agreed that the methodology used in grouping those events is a commonly accepted method, and the list of event categories is complete.

5.2.3 Initiating Event Frequency Quantification (IPE Section 3.1.1.3)

The methodology used to arrive at the initiating event frequency is reasonable and generally acceptable. The use of single-stage Bayesian update to industry-wide generic frequencies is appropriate. It may be of interest to note the treatment of special initiating events as "rare events" and "the special transients were quantified on a case-by-case basis by quantifying the fault trees for these systems (SW, SACS, etc.) characteristic of a year's exposure time to obtain a yearly frequency estimate." The review team found that the initiating event frequencies are in the expected range and order (IPE Table 3.1.1-4).

5.2.4 Event Trees And Sequences

There are 17 event trees (IPE Section 3.1 figures) including 5 transients (LOOP/SBO included), 3 LOCAs, 2 ATWS, 3 ISLOCA, and 4 special initiators.

A discussion is given for each of the event trees. The discussion includes initiating event category description, accident sequence characterization, success criteria, event tree construction, accident sequence discussion, and potential recovery actions. The review team found that the selection of the event trees is complete and the discussions are appropriate and reasonably detailed and inclusive.

There are 4412 minimal cutsets with frequencies greater than 1E-10/yr. These cutsets comprise 81 core damage sequences (IPE Table 3.4-1). The review team believes that the 4412 cutsets are sufficient to give a good representation of the risk profile of HCGS.

5.2.5 Fault Trees

To support the 17 event trees, fault trees were developed based on 24 systems (IPE Sections 3.2-1 through 3.2-24). The review team found the 24 systems which include 10 front line systems and 14 support systems to be sufficient for a good plant model.

"Guidelines" are given (IPE Table 2.5) for the fault tree modeling of various components. The review team found that these guidelines are reasonable.

For each of the 24 systems, the system function, system description, system operation, system interfaces, and system fault tree are described. These are further supported by separate system notebooks. Dependency matrices between front line system and support systems (and among support systems themselves) are also given (IPE Tables 3.2-3 and 3.2-4). A simplified diagram is given for each system (IPE Figures 3.2-1 through 3.2-24), showing the components modeled in the system fault trees. The review team found that the information provided is clear and useful. The team also found that the fault tree modeling is reasonable and contains the appropriate details.

5.2.6 System Notebooks

A member of the review team visited the offices of the PRA group and examined representative system notebooks. It was found that the group did not produce a separate system document to integrate information. Rather, there were binders, labeled by systems, that contained information such as copies from the system training manual, FSAR, fault trees, etc. In other words, various references were collected. However, it was evident that many of the references were out of date, and since there was not a single, dated system notebook to document the different revisions of the reference materials, it was virtually impossible to determine if the PRA model was indeed based on the latest available information in 1993 as claimed. However, certain comments on the systems from the HCGS operation staff were included in the collection and they appeared to be very recent. The review team suggests that in a future revision of the PRA, a dated system document for each of the systems be produced referencing the latest available information. It is noted that Section 3.2 of the IPE contains system-related information, but some of the information required for fault tree modeling is missing. For example, it is not clear how one can get from the system notebook information concerning which MCC powers a certain pump and which load distributing center supplies power to the MCC.

5.2.7 Walkdowns

It is required (Reference 5.5.2) to perform plant walkdowns. Walkdowns are a viable process that the PRA analysts use to look for spatial interactions and to confirm that the PRA represents the as-built, as operated plant, with no obvious errors of omission. The review team found that the compliance to the walkdown requirements is marginal. The PRA group had a significant change of personnel within the last four years and documentation on previous walkdowns was minimal. There is no documentation that the current group has walked down the most critical components as indicated by the IPE study. The PRA Group stated that plant walkdowns were performed by the PRA analyst assigned to the individual system in all cases. When information from various data sources, such as drawings and specifications, was not available nor adequate, it was supplemented or confirmed by plant SROs, system engineers or other cognizant engineering personnel. It is suggested that a focused post analysis confirmatory walkdown be performed and documented. Seismic and fire related walkdowns can be done separately with the IPEEE effort, but those walkdowns will be performed with special and focused interests in mind.

5.2.8 Human Reliability Analysis (IPE Section 3.3.3)

The HRA for Hope Creek is straight forward and conventional. It is documented in a separate report. It models two types of errors:

(a) pre-accident human error (THERP model, Technique for Human Error Rate Prediction, NUREG/CR-1278):

- miscalibration (3E-3/calibration)
- failure to restore (5E-3/test)

(b) human errors during an accident (SHARP model, Systematic Human Action Reliability Procedure, EPRI-NP-3583. Also, NUREG/CR-3010):

* quantified on skill-based, rule-based, or knowledge-based errors
* failure to start/align components
* failure in recovery actions
* time dependent

and the modeling takes two steps:

(a) initial screening analysis
(b) detailed reevaluation of dominant sequences

Dependent failure probabilities for a particular calibrating procedure may be as low as 2.7E-5 (IPE Table 3.3.3-6). The review team noted that the PRA group considered it appropriate to use such low and calculated "screening" values. Otherwise, screening values used, particularly when multiple human actions are involved, are quite appropriate and would not unduly truncate out sequences of interest.

Operator errors modeled in the system fault trees are provided (IPE Tables 3.3.3-6 and 3.3.3-7). Key operator recovery actions are also provided (IPE Table 3.4-7). They are useful for operator training purposes.

The sequences screened out due to recovery actions are given (IPE Table 3.4-6). The review team found that the presentation was adequate.

The review team found that the HRA methodology is reasonable and acceptable, although in some areas a more conservative approach may be applied and may, therefore, be easier to defend. For example, by using somewhat higher screening values, one may be sure that no important cutsets are lost prematurely by truncation during the screening analysis, and the analyst may gain additional confidence in reevaluating in detail certain sequences that "survive" the truncation.

The review team also believes that key operator actions that were modeled are covered by officially issued plant procedures. Generally, credit should not be taken for non-proceduralized actions. If procedures are provided to the operators to perform these actions as part of the emergency operating procedures, credit can then be confidently taken and the drop in the corresponding CDF will be assured. In one instance, the IPE identified the need for a Loss of HVAC abnormal procedure. The IPE team assisted station operators in the development of the procedure and took credit for it in the IPE analysis, with the understanding that the procedure would be implemented prior to submittal of the IPE.

The review team noted a very interesting section on "simulator observations" in the IPE (Section 3.3.3.5). To seek and to have that kind of insight and emphasis is to accomplish one of the major goals of the IPE.

5.2.9 <u>Internal Flooding</u> (IPE/PRA Section 3.3.9)

While internal flooding is usually considered an external event, it is included here because it is required by GL88-20 and NUREG-1335. The study considered the following:

equipment submergence
water spray
steam flooding
pipe whip
inadvertent actuation of fire sprinkler systems

The review team noted the following:

(a) There is no mention of passageways and tunnels between buildings and how they are treated.

(b) It is not clear what analytical model is used to calculate "pipe rupture" probability. It is not clear if the model is sensitive to only pipe length, or does it also consider weld joints, as in the "Thomas Correlation."

(c) It is not clear if the analysis considers damage to electrical cabinets critical to plant shutdown, and it is not clear if all the related circuits that are associated with these cabinets were fully considered.

(d) For external event analysis, which includes fire, it is necessary to consider the effect of flooding due to fire protection system malfunction. However, for this internal event analysis, internal flooding is included and the flooding due to fire protection system malfunction is also included. In other words, the scope exceeds the minimum requirements. However, it is not clear if the effects of inadvertent actuation of fire sprinklers on electrical equipment is considered.

(e) It was assumed that "all floods can be isolated within 30 minutes of the detection of a flooding event." While this appears reasonable, it is not clear what happens if the flood is not detected.

With the exception of the comments above, other assumptions were generally reasonable and the detail of the analysis was at a level expected.

It is noted that the internal flooding analysis used a sequence truncation cutoff of 1E-7. The review team finds that to be acceptable.

5.2.10 Intersystem LOCA

Little information on ISLOCA is available in the IPE. As in other BWRs, the ISLOCA contribution is from the RHR discharge or return line and from the core spray discharge line (IPE Table 3.1.1-1 and Figures 3.1.3.3-1 and 3.1.3.3-2). The contribution to the CDF is only 1.7E-9 events/year and is below the "cutoff." It is not even considered in the Level 2 analysis. The review team found this to be acceptable.

5.2.11 Data (IPE Section 3.3)

The component failure/unavailability data used in the IPE consists of generic and certain plant-specific data. The review team had the following comments:

(a) Certain plant-specific data on the following were collected for various periods up to July, 1993:

core spray motor driven pumps
Emergency diesel generators
HPCI turbine-driven pump
RCIC turbine-driven pump
RHR motor-driven pumps
SACS motor-driven pumps
SSWS motor-driven pumps

and unavailability data were collected on the following systems:

AC power	EDG	SSWS
DC power	HPCI	ADS
PCIG	RCIC	SLC
SACS	RHR	

The review team found this to be a very good list. However, it would be desirable to have some data on a few critical MOVs, such as those in the HPCI and RCIC suction lines and in the inlet steam lines to the HPCI and RCIC turbine.

(b) NPRDS data was used. The data is dependent on the technicians who input them. Very often, it is not clear what is a failure and the input may not be accurate. In other words, the NPRDS failure definition does not match that of the PRA. In addition, the review team notes that NPRDS records failures, but not demands. Therefore, it is not useful for standby safety systems.

(c) The INPO methodology on modified time-related inoperable hours was used. That methodology is questionable. The PRA recognizes that fact (see IPE Section 3.3.2.2), but the methodology was used anyway.

Except for the concerns noted above, it appears that the handling of input data was appropriate. The use of one-stage Bayesian update of generic failure rates is acceptable. A rather extensive listing of basic event failure/unavailability data was provided. That should help make the IPE/PRA more useful as an application tool. It is suggested that after the critical components are identified (see paragraph 5.2.15 below), the data be looked at again more closely and refined as appropriate.

5.2.12 <u>Quantification of Core Damage Frequency CDF</u> (IPE Section 3.4)

The CDF quantification process used in the PRA study was logical and routine. It involved four major steps:

accident sequence cut set generation
cut set modification
recovery analysis
analysis of results

Fault tree linking was used to solve for sequence-level cut sets. The quantification was performed with a "PRA Workstation" which contained an event tree module, fault tree module, data module, cutset analysis module, results module, and importance/uncertainty module, etc. The workstation was used with a cut set truncation limit of 1E-10/yr. The cutset modification step involved the removal of illegal combinations of testing and maintenance outage events and operationally impossible cutsets in order to eliminate mutually exclusive cutsets and those that contain technical specification violations. Appropriate recovery events were added to each remaining cut set. The review team considered that truncation limit as conservative and acceptable. It was found that there are 4412 minimal cutsets that have frequencies greater than 1E-10/yr. These cutsets comprise 81 core damage sequences.

The review team noted that these surviving events are usually very important for BWRs similar to Hope Creek and also noted and agreed that support system failures could be the main cause of CDF. While the review team did not attempt to duplicate the quantification process, it concluded that the process is acceptable, judging from the reasonableness of the results, and consistent with the input.

Regarding the removal of "operationally impossible" cutsets, such as those containing failures to start in both trains of a constant running system (e.g. SACS), it must be noted that for a LOP initiating event, when a component (e.g. pump) loses normal offsite power and be loaded onto emergency power, failures to start of both trains are not "operationally impossible." Therefore, those cutsets should not be removed. The review team looked into this and understood that the PRA Group handled it properly.

5.2.13 Results

Of the 81 core damage sequences from the 4412 cutsets that survived the operator recovery actions and the 1E-10/year truncation limit, (IPE Table 3.4-1), the following table is obtained:

# of Sequences	Frequency Range	% CDF	CDF
1	1E-5 to 1E-6	71.4%	3.268E-5
4	1E-6 to 1E-7	12.8%	0.587E-5
12	1E-7 to 1E-8	13.1%	0.602E-5
64	1E-8 to 1E-10	2.7%	0.123E-5
Total = 81	above 1E-10	100.0%	4.58E-5

The overall CDF is 4.58E-5 per year, excluding internal flooding.

By initiating events, the top contributors are:

Initiating Events	% CDF
Station blackout, (SBO)	73.7
Transient with loss of FW, high pressure injection, and failure to depressurize, (TQUX)	11.7
LOCAs	6.7
Others (special initiators, ATWS, TW, TQUV, TP, etc.)	7.9
Total	100.0%

The review team found these risk profiles to be reasonable.

Part lists of critical components and operator non-recovery actions that contribute most to the CDF may be found in Tables 3.4-4 and 3.4-5 of the IPE. These lists are very important to plant operation and maintenance. They are also useful in conjunction with the Maintenance Rule, with the understanding that these lists come from an integrated plant model and not just by systems. The lists contribute to the understanding of the plant. The review team agreed with how the lists are obtained, but believed the list presented in the IPE should have been more extensive in order to provide additional insights.

The review team found human recovery actions (Tables 3.4-6 and 3.4-7) to be adequately covered.

Judging from a comparison with other BWRs (IPE Table 3.4-11) and from the HCGS plant-specific results, the review team agreed that HCGS is not an "outlier" and that it has no obvious "vulnerability."

It was clear that the dependency and success criteria of the 4 diesels to the 4 SAC pumps are the most important assumptions impacting the HCGS risk profile. After a recommendation by the review team, a special study was done to evaluate the true capability of the SACS. However, that study was not available to the review team. The review team considered it acceptable for the IPE study to use the "conservative" assumption, but understands that a realistic assumption will be used in a future revision of the PRA.

5.2.14 Uncertainty and Sensitivity (IPE Section 3.4.1.4)

I. Uncertainty Analysis

The overall uncertainty in the IPE results is a combination of uncertainty in data, uncertainty in the consideration and completeness of all events and failures, and uncertainty in the method of analysis. The TEMAC computer code developed by Sandia National Laboratory was used in the uncertainty analysis. An internal events uncertainty analysis was performed on the "most dominant 180 cutsets" (See Section 3.4.1.4.1 and Figure 3.4-[illegible]).

The review team noted that:

(a) There is no discussion of confidence level. In other words, there is no assurance on how repeatable the computer run(s) are. There is also no mention of how many "sampled trials" were used in the TEMAC Monte Carlo analysis.

(b) A probability density function curve would be very helpful in the understanding of what was analyzed. For example, it is not clear if the curve is "log-normal."

(c) Because of the limited numbers of cutsets utilized in the uncertainty analysis, there is a significant difference between the mean and nominal values of the CDF distribution. The uncertainty analysis presentation is limited.

II. Sensitivity Analysis

Three sensitivity cases were presented. These cases (decrease EDG mission time, loss of a AC bus, loss of a DC bus) were appropriate. The review team believed that additional cases, such as reduction of unavailability due to test/maintenance outage by a factor of 5, would offer insight to the risk characteristics of the plant.

It was reported in many places that with operator intervention, each SACS loop can function with only one pump, which may potentially reduce the SBO contribution by as much as 50%. That assumption should be more fully reported in the form of a sensitivity study.

The dependency of a new HVAC recovery procedure to mitigate certain HVAC failures based on room heatup calculations was reported. Without crediting this procedure, it was reported that it might more than double the HCGS CDF prior to recovery. Again, that assumption should be more fully reported in the form of a sensitivity study.

Even with these comments, the review team believed that the PRA Group had learned to put emphasis on important items and less on insensitive items.

It is noted that certain human factors have designated values of 0.1 and a "range factor" of 10 (see PRA Table 3.11-1). That means the 95th value is 1.0. In other words, 5% of the probabilistic "log-normal" distribution is for probability larger than 1.0. Presumably, the impact of that is minimal. (It should be pointed out that this does not impact the mean value calculation of the CDF.)

5.2.15 <u>Importance</u> (IPE Section 3.4.1.2)

Three types of importance measures were calculated for the basic events in the core damage sequence cut sets. They are:

partial derivative
risk reduction (modified Fussell-Vesely)
risk increase

The analysis was performed on the 745 highest frequency cutsets, which represent 90% of the HCGS IPE results. From these "importance" studies, one obtains the list of components that contribute most to the CDF (IPE Tables 3.4-4 and 3.4-5, each with 30 items). As stated in Section 5.2.13 above, the review team felt that the lists should have been more extensive.

5.2.16 <u>RHR Evaluation, USI-A45</u> (IPE Section 3.4.4)

The review team found that the presentation was appropriate. The statement was made in the IPE that "if one SACS pump fails, the cooling of the diesel generators is not affected, because HCGS procedures would direct the cross-tie of SACS cooling to the diesels such that all four diesels could be cooled by the operating SACS pumps." It is noted that the IPE insights led to the consideration of the cross-tie.

5.2.17 <u>Computer Codes</u>

The IPE study used a "PRA Workstation" for fault tree modeling and other analyses. Other computer codes were used in thermal hydraulic calculations such as success criteria and time dependent room heatup calculations. The independent review team did <u>not</u> perform a verification and validation task on the computer codes, particularly the one used in the SACS hydraulic analysis. It is suggested that a complete listing and a brief description for each of the computer codes used be added, at least for reference purposes. Perhaps that can be done in the PRA rather than in the IPE.

5.3 <u>Review of Level 2 Containment Analyses</u> (IPE Section 4)

The Level 2 analysis was performed by PSE&G using a rather common methodology (NSAC-159, dated June 1991). It appeared to be a routine linked event trees analysis of a Mark I containment, with expected results. The review team had the following comments, focusing on the unusual features, assumptions, methodologies, and results, when compared with other Mark I BWRs.

5.3.1 It is noted that a cross-connect is provided to allow connection of the Salem Nuclear Plant Fire system to the Hope Creek Fire Protection system. However, the review team believed that this addition of yet another level of mitigation would not significantly affect the Level 2 analysis.

5.3.2 Four drain sumps are located in the drywell floor, including two in the RPV pedestal floor. It is reported (IPE Section 4.1.1) that "these sumps plays a significant role in the possible progression of severe accidents." In addition, it is understood that these two sumps are larger (totaling 210 cu. ft.) than normal and therefore may delay the accident progression. However, the review team believed that this would not significantly affect the Level 2 analysis.

5.3.3 The review team has no comment on the containment structural analysis, including both the potential failure locations and the fragility curves for the dominant failure modes.

5.3.4 The containment event tree (CET) has 13 subtrees. The linked subtrees were solved using the EVNTRE software. Five accident classes (initiators) were identified from the Level 2 binning process. The Level 1 cutsets were grouped into characteristic sequences based on the initiating events and system functional availabilities. Seventeen such sequences were developed covering 95% of the total CDF and all sequences with greater than a 1E-7 frequency. There are 100 "basic events" in the CET (IPE Table 4.6-1) The review team found these to be appropriate and inclusive.

5.3.5 MAAP 3.0B was used in the accident progression analysis. The review team did not certify the validity of the software, but recognized that the code is used extensively in the industry. The timing, locations, and nature of containment failures under various accident conditions were not surprising, in accordance with the current state of knowledge of the accident progression phenomena.

5.3.6 Five radionuclide groups were used to obtain release fractions instead of nine groups. The review group found that to be acceptable.

5.3.7 The decontamination factors considered included suppression pool scrubbing, containment sprays, and containment deposition. The review team found that to be appropriate.

5.3.8 The nine "release categories" were based on the timing of the release and the magnitude of the release. An early release was assumed to occur within two hours after vessel failure. This was found to be reasonable.

5.3.9 The five release levels were "selected to ensure that a significant portion of the total frequency would fall into each release category." Specifically, levels are assigned to the iodine and tellurium releases as shown below:

Release Level	Iodine	Tellurium
High	>6%	>6%
Medium	0.1 to 6%	0.1 to 6%
Low	0.001 to 0.1%	10^{-7} to 0.1%
Low-Low	<0.001%	$<10^{-7}$%

The review team noted that these "selections" were arbitrary and implicitly defined "large release," a term that the industry has yet to reach agreement on. However, the "selections" were judged to be reasonable by the review team.

5.3.10 It was found (IPE Table 4.7-16) that the frequency of an early high release is 21.2% of the total CDF, and the frequency of an early medium-high release is an additional 13.8%. Using only the 21.2% and the CDF of 4.58E-5/yr, an early "large release" frequency of 9.7E-6/yr is calculated. This is 10 times higher than the 1E-6/yr "guideline for regulatory implementation" (See Reference 5.5.3) However, the review team believed that the results are acceptable since the "selection" of release levels is arbitrary (see paragraph above) and the definition of "large release" has not been agreed to by the industry.

5.3.11 The sensitivity study on the Level 2 analysis has 16 cases. The review team found that to be appropriate and was impressed by the discussions and insights offered by the Level 2 analysts.

5.3.12 The Level 2 analysis did not include an uncertainty analysis. The review team recognized the dominating nature of the SBO sequence at HCGS and believed that the biggest uncertainty in the Level 2 analysis is in the assumed accident progression phenomenology. Considering the state of knowledge in the industry, an uncertainty analysis in not meaningful. Therefore, the review team found it acceptable to not have an uncertainty analysis.

Overall, the independent review team found the analytical process, methodology, scope, and results as standard, complete, reasonable, and expected.

5.4 Conclusions

Based on the review, the team concluded the following:

5.4.1 Overall, the IPE submittal document and the associated documentation meet the intent of Generic Letter 88-20 and NUREG-1150.

5.4.2 The IPE is complete in scope with regard to Generic Letter 88-20 requirements.

5.4.3 The IPE process used at Hope Creek is sound and conforms to normal industry practices. It is capable of identifying plant-specific vulnerabilities to severe accidents.

5.4.4 The system model and data appear to conform well to the actual analyzed plant configuration and experience.

5.4.5 The conclusions drawn from the study are consistent with the analysis.

5.4.6 The submittal document format conforms to the NUREG-1335 requirements.

5.4.7 The PSE&G personnel participated extensively in the IPE/PRA study and that should be sufficient to meet NRC requirements.

5.4.8 The calculated core damage frequency appears to be reasonable and the dominant contributors are those expected, based on the findings of similar PRAs.

5.4.9 Therefore, it is concluded that Hope Creek is not an outlier with respect to similar plants and that no immediate safety concern exists.

5.4.10 However, certain specific suggestions from the review team are included in the main body of the report. A summary of the review team's suggestions is given in Table 5-1.

5.5 References

5.5.1 NRC Generic Letter 88-20

5.5.2 NRC, IPE Submittal Guidance, NUREG-1335, final report, August 1989.

5.5.3 Federal Register, Vol. 51, No. 162, August 21, 1986, Pages 30028 - 30033, on Safety Goals, particularly page 30031.

5.6 Description of Independent Review Team Members

5.6.1 Dr. Allen Ho

The independent review team is under the project management of Dr. Ho. He is a Nuclear Technical Consultant at the Nuclear Department of PSE&G. Prior to joining PSE&G in 1988, Dr. Ho was with Westinghouse and he is the author of the Westinghouse reactor core thermal-hydraulic design & analysis code (WESTER). He specializes in NSSS system analysis for both PWRs and BWRs.

5.6.2 Dr. Wang Lau

The independent review team is under the technical lead of Dr. Lau, a consultant from Reliability And Performance Associates (RAPA). Dr. Lau spent 19 years at TVA and was a Branch Chief of the System Engineering Branch and a Head Engineer of the safety analysis, severe accident, and PRA groups. He is the author of a nuclear reactor engineering textbook and was an invited speaker (by the NRC) at the First IPE Workshop at Fort Worth. He was also a member of the Industry Degraded Core (IDCOR) Program's Technical Advisory Group. Dr. Lau is a principal partner of RAPA. In addition to being an independent reviewer of the IPEs for Salem, Hope Creek, and Surry, he has been involved with the PRAs of Browns Ferry, Sequoyah, Watts Bar, Bellefonte, and River Bend. He is currently a reviewer/analyst of the NRC's accident sequence precursor program.

5.6.3 Ms. Lisa Castagna

Ms. Castagna is a member of the independent review team representing the Licensing and Regulations Department. After completing her Bachelors Degree in Mechanical Engineering at the University of Delaware in 1990, she began work for PSE&G in the Technical Department for Hope Creek. She successfully completed the Hope Creek System Engineering Training Program and is a qualified System Engineer. Ms. Castagna remained a member of the Hope Creek Technical department for approximately three years before accepting an engineering position in the Licensing and Regulations Group in June of 1993. As a Licensing Engineer, Ms. Castagna attended Nuclear Licensing for Operating Reactors Training. Presently Ms. Castagna is enrolled in the MBA program at the University of Delaware.

5.6.4 Mr. Scott G. Gillespie

Mr. Gillespie is a Principal Engineer in the Nuclear Safety Review Department's Offsite Safety Review Group. His staff is responsible for the independent review of facility changes made under 10CFR50.59, the oversight of Technical Specification required audits, and for conducting independent investigations and assessments of issues involving nuclear safety. Mr. Gillespie has been with PSE&G in the Nuclear Safety Review Department since 1986. Prior to that, he worked at Pacific Gas and Electric Company (1972-1978), where he participated in the Diablo Canyon Seismic Risk Study; and Portland General Electric Company (1978-1986), where he was responsible for following PRA-related issues applicable to the Trojan Nuclear Plant. He also has extensive experience in licensing, radiological engineering and emergency preparedness. He has a Bachelors Degree in Engineering Physics (1970) and Masters Degree in Nuclear Engineering (1972) and Mechanical Engineering (1978) from the University of California at Berkeley. He holds Professional Engineer Licenses in the states of California and Oregon.

5.6.5 Mr. Richard Murray

Mr. Murray is a Principal Engineer of Reliability assigned to the Maintenance Rule Implementation Project team in the Nuclear Department of PSE&G. Prior to joining PSE&G in 1985, Mr. Murray served the General Electric Nuclear Energy Business Operation in reliability, risk and thermal hydraulics analyses and project engineering capacities for nearly 20 years. During that period he directed the first PRA attempted on a light water reactor configuration during the 1970-1971 time frame. The paper, "Loss of Coolant Accident, A Probabilistic View," delivered at the ASME 1972 Winter Meeting was the result of a portion of this work. In addition to Boiling Water Reactors, Mr. Murray has examined Liquid Metal Fast Breeder Reactor safety configurations. At PSE&G, Mr. Murray served on a number of PRA-related BWR Owners Group Subcommittees. Mr. Murray is an alumnus of the Catholic University of America with a Bachelor of Mechanical Engineering (BME) Degree.

5.6.6 Mr. Philip A. Opsal

Mr. Opsal graduated from the Georgia Institute of Technology in 1979 with a Bachelors of Chemical Engineering. As a Navy Headquarters engineer from June 1979 through December 1984, Mr. Opsal was assigned responsibility for 1) numerous research and development programs involving improved primary nuclear plant components and 2) operating Nuclear Powered ship/land based prototype plant maintenance. In December 1984 Mr. Opsal joined PSE&G as a construction engineer responsible for the proper construction of Hope Creek's Nuclear Steam Supply Systems (NSSS). Mr. Opsal has been in various positions such as Milestone Manager, lead Senior NSSS system engineer, and Hope Creek Mechanical Engineering Supervisor. In February 1989 Mr. Opsal successfully completed Senior Reactor Operator (SRO) Class and received a SRO certification. He was then selected to serve as the Senior Operations Technical Supervisor, where his responsibilities included development and enhancement of Hope Creek's Operating Procedures and oversight of the effort to upgrade Hope Creek's Emergency Operating Procedures. Mr. Opsal is currently the NSSS Technical Engineer for Hope Creek and holds Professional Engineer Licenses in the states of Virginia and New Jersey.

TABLE 5-1

SUMMARY OF REVIEW TEAM SUGGESTIONS

		Reference Paragraph #
1	Dated system notebooks should be produced to support future revisions of PRA.	5.2.6
2	Perform focused post analysis confirmatory walkdown for spatial interactions.	5.2.7
3	Make sure that the HVAC "recovery procedure" is issued.	5.2.8
4	Internal flooding needs better documentation in the PRA.	5.2.9
5	Have a longer "critical" component list via an expanded importance study.	5.2.13 5.2.15
6	The Level 1 uncertainty analysis should be improved. The Level 1 sensitivity study should be expanded.	5.2.14
7	Provide a complete listing and a brief description for each of the computer codes used.	5.2.17

6.0 SAFETY FEATURES AND RISK REDUCTION SUGGESTIONS

6.1 Summary Of Major Findings

The Internal Events Core Damage Frequency for the HCGS is 4.58E-5/yr. This is approximately one order of magnitude higher than the reported CDFs for the NUREG-1150 studies for Peach Bottom and Grand Gulf. Major differences are attributable to the plant-specific data utilized in the HCGS study and the detailed analysis of HCGS support systems. Loss of offsite power sequences contribute 73.8% to the CDF, while the contribution to the Peach Bottom CDF was 46.6%. The notable difference in results derives from the conservatism in the HCGS IPE analysis with respect to the design of the SSW/SACS systems. A plan to re-evaluate this conservatism is discussed in Section 6.4. Transients account for a greater contribution to HCGS CDF than the Peach Bottom CDF, although this contribution is a relatively small 14.8%. Differences are attributable to the detailed modeling of HCGS support systems such as HVAC. The ATWS contribution of only 1.6% is notably smaller than the Peach Bottom contribution of 42.6%. This is attributed to HCGS's automatic Standby Liquid Control System. Special Initiators are minor contributors in both studies. Unresolved Safety Issue A-45, Decay Heat Removal Due to Internal Events, is not a concern at HCGS as evidenced by the low contribution of Loss of Decay Heat Removal sequences of 1.2% to the total HCGS Internal Events CDF. The resolution of USI A-45 is presented in Section 3.4.3.

Interfacing System Loss of Coolant Accidents (ISLOCA) contribute only 1.7E-9 events/year to the HCGS CDF. This is over 4 orders of magnitude less than the internal events CDF, emphasizing its low importance. Internal flooding only contributes 5.5E-7 events/year or 1.2% of the total internal events plus internal flooding CDF.

Finally, the containment analysis indicated the capability of the HCGS containment was typical of the Mark I design, with no unique vulnerabilities.

6.2 Front-End Analysis

The following safety features and vulnerabilities were identified by the Hope Creek Front-End Analysis:

- Numerous room heatup calculations have demonstrated that only a few electrical equipment rooms are susceptible to HVAC system failures. Of the 52 rooms studied, only 12 were found to be susceptible to risk important failures. Heatup time ranged from 5 to 24 hours.

- Operator simulator observations highlighted excellent human performance reliability and PSE&G's effective operator training program.

- HCGS design substantially limits the CDF due to internal flooding to a negligible level, 5.5E-7/yr.

- The contribution to the HCGS CDF due to ISLOCA sequences is nearly four orders of magnitude lower than the internal events CDF. Results of a plant-specific ISLOCA study indicate that overpressurizations of low pressure systems outside containment are primarily dominated by hardware failures.

- The automatic operation of the Standby Liquid Control (SLC) system limits the ATWS contribution to only 1.6% of the internal events CDF.

- The availability of the hard pipe vent system improves HCGS's ability to remove decay heat during severe accidents. This vent can be manually operated in the absence of any support systems.

- Special initiators (such as a loss of SSWS/SACS or the loss of Instrument Air System) contribute slightly over 3% to the internal events CDF. This contribution is minimized by the high level of redundancy and separation designed into support systems at HCGS.

- The largest contribution to the internal events was over 70% from station blackout events. This results from conservative heat sink models which require two out of two SACS and SSW pumps per subsystem for successful heat removal to allow for diesel generator operation. A plan to address this conservatism is suggested in Section 6.4.

- The only vulnerability identified at the HCGS was the inability to supply long-term cooling to critical rooms upon HVAC system failures. A risk-based procedure has been developed to address this item and is credited in the IPE analysis.

6.3 Back-End Analysis

The following findings were made based on the Level II PRA:

- Due to the dominance of the long-term Station Blackout (LT-SBO) sequences, the sensitivity study showed little variation to most of the parameters considered. This was especially true of changes to engineered safety system availability. The frequency of high early and medium early releases are 9.42E-6/yr and 6.14E-6/yr, respectively.

- The results were found to be very sensitive to AC power recovery assumptions. If AC power is always recovered early, the early high release frequency decreases from 21% to 4% of the total CDF, while the late high release category decreases from 7% to 1.4%. If, on the other hand, early AC power recovery never occurs, the frequency of an early high release increases to 32% of the CDF, while the frequency of a late high release increases to 11%.

- The results were found to be relatively insensitive to the availability and use of drywell sprays. If sprays are always available and are used late, the frequency of the early high and medium-high release categories decrease to 18% and 7.5% (from 19% and 14%), respectively. Again, the drywell sprays are not very important because of the unavailability of AC power in many sequences. If the CDF were not dominated by SBO sequences, the sprays would be more important. However, a sensitivity analysis indicated that if the fire pumps were used for containment spray, the early high and medium high release frequencies would be significantly reduced.

- The FRVS is a system unique to the HCGS which will circulate air and filter radionuclides with high efficiency. However, the results were found to be relatively insensitive to the availability and effectiveness of the FRVS. This is due to two reasons: the high frequency of early containment ruptures (DW shell melt-through) and the lack of AC power to operate the system. The FRVS will not function if either condition occurs.

- The results were found to be sensitive to two uncertainties in ex-vessel phenomena: drywell shell melt-through and debris coolability. Both of these are related to uncertainties in the rate of heat loss from the core debris to an overlying water pool. There is significant uncertainty regarding heat transfer to the water:

  - If drywell shell melt-through is assumed not to occur, the frequency of an early release decreases significantly from 62% (some of these are early releases during venting) to 29%. Late containment failures increase as there is a greater opportunity for either late overpressure, temperature, or sump failure. In addition, the frequency of an early high and early medium-high release decreases to 8% and 4% (from 21% and 14%, respectively).

  - If the ex-vessel core debris is assumed to be coolable whenever water is present, the frequency of an early or late medium-high release goes almost to zero since sequences with uncoolable core debris and water present now have coolable debris and no releases from core-concrete interaction. These sequences are shifted primarily into the early or late low release category. The early high and late high release categories are almost unaffected by debris coolability assumptions because these high releases occur primarily in sequences without water injection.

- The core damage frequency and radionuclide release characteristics of the HCGS is expected to be improved by reducing the frequency of LT-SBO and/or increasing the probability of AC power recovery. These sequences currently dominate the CDF, the containment failure frequency, and the early high release frequency.

6.4 SUGGESTIONS FOR PLANT IMPROVEMENT

PSE&G will review and finalize the SACS and SSW system analysis to remove modeling conservatisms. The most notable contributors to the HCGS CDF are Loss of Offsite Power sequences ultimately leading to loss of all AC power. These sequences contribute over 70% to the CDF. In fact, the reason for this is highlighted in the Importance Results provided in Section 3.4.1.2. As presently modeled SACS and SSW system failures result in diesel generator failures. The IPE utilizes a conservative success criteria of two-out-of-two SSW and SACS subsystems being required for successful operation of the respective loop. However, yet unverified calculations indicate this underestimates the ability of these systems. To fully understand the amount of design margin in the SACS and SSW systems, PSE&G has developed a detailed model for the operation of these systems. Preliminary results indicate that, with operator intervention, each SACS loop can function with only one pump. This may potentially reduce the Station Blackout contribution by as much as 50%. Therefore, PSE&G intends to complete evaluations to define the operational margins of these support systems. PSE&G will also consider developing procedures for operating the SACS system for severe accidents (beyond design basis). Once these revisions are completed, the HCGS PRA models will be adjusted to reflect actual conditions.

7.0 SUMMARY OF RESULTS AND FINDINGS

This section provides the combined results from both the Level I and II PRA analyses in one place. It is extracted from Sections 3.4 and 4.7 and is provided for convenience of review and for quick reference.

7.1 Front-End Results And Screening Process

The total core damage frequency (CDF) for the HCGS is 4.58E-5/yr. There are 4412 minimal cutsets which have frequencies greater than 1.0E-10/yr. These 4412 cutsets comprise 81 core damage sequences.

Table 7.1-1 presents the 81 accident sequences ranked by frequency, and Table 7.1-2 presents the same list of list of sequences alphabetically. Table 7.1-3 presents the CDF broken down by sequence type, and Figure 7.1-1 presents a breakdown of the CDF by initiating event category.

The following sections provide the details of the results and screening process of the front end analysis of the HCGS IPE.

7.1.1 Application of Generic Letter Screening Criteria

The quantification of the HCGS IPE resulted in 81 core damage sequences with cut sets greater than 1.0E-10/yr. This includes only those sequences initiated by internal events, excluding internal flooding. The results of the internal flooding analysis are presented in Section 3.3.9. Also excluded from this assessment are those core damage sequences initiated by external events such as seismic events, tornadoes, external floods, and fire. The external events analysis is being performed as part of the IPEEE.

The overall result (4.58E-5/yr) of the quantitative assessment of core damage frequency for the HCGS was based on best-estimate, mean calculations of the frequencies of postulated accidents which could occur at the HCGS.

Section 2.1.6 of NUREG-1335 provides the criteria for reporting potentially important systematic core damage sequences. These core damage systematic sequence criteria are as follows:

> "Any systemic sequence whose frequency is greater than 1E-7 per year."
>
> "All systemic sequences within the top 95% of the total core damage frequency."
>
> "All systemic sequences within the top 95% of the total containment failure frequency."
>
> "Any containment bypass systemic sequence whose frequency is greater than 1E-8 per year."

"Any other systemic sequences judged to be important contributors to either core damage or poor containment performance."

"The total number of systemic sequences should not exceed 100."

Appendix 2 of NRC Generic Letter No. 88-20 provides similar guidance with regard to functional sequences. These are similar to those described above, but the cutoff frequencies for the first and fourth items above are increased by a factor of 10. Because the HCGS Level I analysis uses the linked fault tree approach rather than the large event tree approach, the Level I core damage accident scenarios are more correctly considered as functional sequences rather than systemic [sic] sequences. However, because some of the sequences may be described as "mixed," (part functional, part systemic [sic]) according to the guidance provided in NUREG-1335, the systemic [sic] criteria was conservatively used for reporting purposes.

After screening, there remains 17 core damage sequences. These 17 sequences comprise 97.3% of the total CDF, and are presented in Table 7.1-1 (the top 17 sequences in the table). Note that there are not containment bypass sequences with a frequency greater than 1E-8.

7.1.1.1 Dominant Accident Sequences

Five accident sequences have a CDF greater than 1.0E-6/yr. These five sequences contribute approximately 84.2% of the total CDF at the HCGS. Six additional sequences contribute at least 1% each to the total CDF. Together, these 11 dominant accident sequences represent 94.0% of the total CDF at the HCGS. A description of these dominant accident sequences follows.

1) TeEDG

The CDF of this accident sequence is 3.27E-5/yr, comprising 71.4% of the total CDF. TeEDG is a Loss of Offsite Power (LOP) with the failure of all of the diesel generators (D/Gs), resulting in a Station Blackout (SBO). For the first four hours of this sequence, water injection to the vessel is accomplished with the turbine-driven HPCI and or RCIC pumps. Four hours after the LOP initiating event, the DC batteries are depleted, causing the HPCI and RCIC injection to the vessel to be terminated. In another two hours, neither onsite nor offsite power have been recovered, and enough water has boiled out of the RPV to cause fuel damage.

The failure of all four D/Gs is dominated by a combination of two failures in the D/G system, the Station Service Water System (SSWS), and/or the Safety Auxiliaries Cooling System (SACS) which cause the failure of the cooling water to all four D/Gs, resulting in a loss of all four D/Gs. For example, a LOP and the failure of the C and D SSWS pumps results in a SBO. The failure of SSWS pump C results in inadequate cooling of SACS Loop A, which results in inadequate cooling of D/Gs A and C, causing the loss of D/Gs A and C. Similarly, the failure of SSWS pump D results in the loss of D/Gs B and D. Therefore, the LOP with only two failures has caused an SBO.

2) TfU1U2X

The CDF of this sequence is 2.76E-6/yr, comprising 6.0% of the total CDF. TfU1U2X is a total loss of feedwater followed by a failure of both HPCI and RCIC to inject and a failure to depressurize the RPV. Fuel damage occurs in about one hour, since there is no injection of water to the RPV from the time of the initiating event.

The dominant failures in this sequence are split between a total loss of DC power and the hardware failure of HPCI and RCIC combined with a failure to depressurize the RPV.

3) TmUX

The CDF of this sequence is 1.05E-6/yr, comprising 2.3% of the total CDF. TmUX is a sequence initiated by the closure of all of the MSIVs, followed by a failure of both HPCI and RCIC to inject and a failure to depressurize the RPV. Fuel damage occurs in about one hour, since there is no injection of water to the RPV from the time of the initiating event.

The dominant failures in this sequence are split between a total loss of DC power and the hardware failure of HPCI and RCIC combined with a failure to depressurize the RPV.

4) S1WUv

This sequence has a frequency of 1.04E-6/yr, contributing 2.3% of the total CDF. S1WUV is a medium LOCA with a loss of decay heat removal. Containment venting is successful, but long term make-up is unsuccessful.

The dominant failures in this sequence are combinations of two SSWS and SACS failures (similar to TeEDG above) and the failure to use the core spray system in the long term.

5) TtQUX

The CDF of this sequence is 1.03E-6/yr, comprising 2.3% of the total CDF. TtQUX is a turbine trip initiating event followed by a failure of feedwater, a failure of both HPCI and RCIC to inject and a failure to depressurize the RPV. Fuel damage occurs in about one hour, since there is no injection of water to the RPV from the time of the initiating event.

The dominant failures in this sequence are feedwater failures combined with either a total loss of DC power or the hardware failure of HPCI and RCIC combined with a failure to depressurize the RPV.

6) S1U1X

This sequence has a frequency of 9.96E-7/yr, contributing 2.2% of the total CDF. S1U1X is a medium LOCA with the failure of HPCI and the failure to depressurize the RPV.

The dominant failures in this sequence are HPCI hardware failures combined with a failure to depressurize.

7) Thv

This sequence has a frequency of 9.87E-7/yr and contributes 2.2% to the total CDF. Thv is a loss of HVAC to either the Panel Room or to the Switchgear Room and a failure to recover the HVAC before those rooms overheat and equipment fails.

8) TeEDGP

This sequence has a frequency of 9.67E-7/yr and contributes 2.1% of the total CDF. TeEDGP is a SBO identical to TeEDG above, except that in addition to the SBO, there is a stuck-open Safety Relief Valve (SRV).

9) TfQRWW1Uv

This sequence has a frequency of 5.30E-7/yr, and contributes 1.2% of the total CDF. TfQRWW1Uv is a total loss of feedwater with a failure to recover feedwater, a failure of containment heat removal, a failure of containment venting and a failure of long term make-up.

The cutsets which dominate this sequence involve service water failures (as described in TeEDG above) combined with a failure to initiate containment venting. Since HPCI and RCIC are successful in this sequence, the time to core damage in this sequence is at least 24 hours.

10) TiQUX

This sequence has a frequency of 5.29E-7/yr, and contributes 1.2% of the total CDF. TiQUX is initiated by an Inadvertent Opening of a SRV (IORV) which is followed by a failure of feedwater, of HPCI and RCIC, and a failure to depressurize the RPV. Other than the IORV initiating event, this sequence is similar to TfU1U2X above.

11) TatC2

This sequence has a frequency of 5.07E-7/yr, and contributes 1.1% of the total CDF. TatC2 is a turbine trip initiating event with a mechanical failure of the control rods to insert (such that ARI or any other alternate method of control rod insertion will not be successful) and a failure of Standby Liquid Control (SLC) to inject sufficient boron into the core to prevent core damage.

7.1.1.2 Basic Event Importance

An importance analysis was performed on the 745 highest frequency cutsets, including 393 basic events, which represent 90% of the HCGS IPE results. The importance ranking measures used are the partial derivative, risk reduction and risk increase, which are the built-in ranking capabilities of the PRA workstation used by PSE&G. Complete listing of importance ranking of all the 393 basic events was prepared and the most important 30 individual basic events (hardware or human failures) are presented in Tables 3.4-4 and 3.4-5.

Risk reduction reflects the improvement (decrease) in the expected CDF achieved by making a perfect basic event (zero probability to fail). Risk increase reflects the degradation (increase) in the expected CDF from arbitrarily failing a basic event (probability of one to fail).

The basic event failures shown in Table 3.4-4 were sorted by the risk increase measure. The miscalibration events, safety/relief valves (SRVs), DC buses, reactor protection (scram) and HPCI/RCIC are the most important basic events, based on the risk increase importance measure.

The basic event failures shown in Table 3.4-5 were sorted by the risk reduction ranking measure. The operator recovery of offsite power, operator recovery of diesel generators, test/maintenance of SSW and SACS loops, failure to depressurize and failure of the diesel generators are the most important basic events, based on the risk reduction importance measure.

By a review of Tables 3.4-4 and 3.4-5, the following events were observed to be important based on both risk increase and risk decrease importance measures: the diesel generator failures, HPCI/RCIC failures, station service water system failures, and failure to provide alternate ventilation to the Class 1E Panel Room within 12 hours after a loss of HVAC.

It should be noted that the 30 highest ranked basic events, have similar importance measures either by the risk increase or by the partial derivative (Birnbaum) ranking methods.

7.1.1.3 Sequences Screened Out by Recovery Actions

Section 2.1.6 of NUREG-1335 (Reference 7.1-1) requires the reporting of any core damage sequence whose frequency was reduced by more than an order of magnitude to below the screening cutoff due to the application of human recovery action(s). Since the sequence frequency used as a cutoff was 1E-7/yr (as described in Section 3.4.1), it is appropriate to report here any sequence whose frequency is greater than 1E-6 (before recoveries) and was not reported in Section 3.4.1.1.

Table 7.1-6 presents each of the core damage sequences whose frequency was greater than or equal to 1E-6/yr before recovery actions were applied, but were screened out in Section 3.4.1.1 after the application of recoveries. This table presents the core damage sequence, its frequency before and after the recoveries were applied, and the actual recovery actions applied. A brief description of the sequences in Table 7.1-6 is provided below.

The first two sequences (TtQWW1Uv and TmWW1Uv) are transients with the loss of decay heat removal (DHR), and the time to core damage occurring after 24 hours. The recovery actions applied in each sequence were NR-PCS-24, NR-RHR-INIT, NR-WW1-SWP-20, and NR-VENT-5. Note that a maximum of three recoveries were applied to any one cutset, and when multiple recoveries were applied to one cutset, the rules detailed in Section 3.3.3 were followed. Section 3.3.3 also details the quantification of the probability of the human recovery actions applied. All of the human recovery actions quantified in Section 3.3.3 are summarized in Table 7.1-7.

The third sequence (TeWW1Uv) is a LOP with a loss of DHR. The time to core damage would be at least 24 hours. The recovery actions applied in this sequence are NR-LOSP-24, NR-RHR-INIT, and NR-VENT-5.

The fourth sequence (TmPP2WUv) is a transient initiated by an MSIV closure with two stuck open relief valves (SORVs) and a loss of DHR. The time to core damage for this sequence is at least 24 hours. The recovery actions applied to this sequence are NR-PCS-24, NR-RHR-INIT, and NR-WW1-SWP-20.

The fifth sequence (S1WW1Uv) is a medium LOCA with a loss of DHR. The time to core damage for this sequence is at least 24 hours. The recovery acuons applied are NR-RHR-INIT and NR-VENT-5.

The sixth sequence (TtPP2WW1Uv) is a turbine trip with two SORVs and a loss of DHR. The time to core damage for this sequence is at least 24 hours. The recovery actions applied are NR-RHR-INIT, NR-WW1-SWP-20 and NR-VENT-5.

The seventh sequence (AWW1Uv) is a large LOCA with a loss of DHR. The time to core damage for this sequence is at least 24 hours. The recovery actions applied are NR-RHR-INIT and NR-VENT-5.

The eighth sequence (TmPP2WW1Uv) is similar to the fourth sequence except that there is an additional failure to vent the containment. Therefore, the recovery actions applied are NR-PCS-24, NR-WW1-SWP-20, NR-RHR-INIT and NR-VENT-5.

The ninth sequence (TiaWW1Uv) is a loss of the Instrument Air System (IAS) and a loss of DHR. The time to core damage for this sequence is at least 24 hours. The recovery actions applied are NR-RHR-INIT, NR-WW1-SWP-20 and NR-VENT-5.

The tenth sequence (S2S3IsoQUX) is a recirculation pump seal LOCA with a loss of Feedwater (FW), a loss of HPCI and RCIC and a failure to depressurize the Reactor Pressure Vessel (RPV). The time to core damage in this sequence is 40 minutes. The recovery actions applied are NR-SLEAK-ISO-15M and NR-U1X-DEP-40M.

The eleventh sequence (ThvP) is a loss of HVAC with a SORV. The time to recover from the loss of HVAC is either 12 or 24 hours (depending on the cutset), but the 12 hour time period was conservatively assumed for the entire sequence. The recovery action applied is NR-HVC-PNRM-12.

The twelfth sequence (TtPQUX) is a turbine trip with a SORV, loss of FW, loss of HPCI and RCIC and a failure to depressurize the RPV. The time to core damage for this sequence is 40 minutes. The recovery actions applied are NR-PCS-40M, NR-U1X-DEP-40M and NR-Q-FWLVH-4M.

The thirteenth sequence (TraPP2WUv) is a loss of RACS with two SORVs and a loss of DHR. The time to core damage for this sequence is at least 24 hours. The recovery actions applied are NR-WW1-SWP-20 and NR-SPL-LVLL-4.

The fourteenth sequence (TfU1U2V) is a loss of feedwater with a failure of all injection to the RPV. The time to core damage for this sequence is 1 hour. The recovery actions applied are NR-UV-WTLVL-20M and NR-UV-ECCS-1.

The fifteenth sequence (TeUX) is a LOP with a failure of HPCI and RCIC and a failure to depressurize the RPV. The time to core damage for this sequence is 1 hour. The recovery actions applied are NR-LOSP-60M and NR-U1X-DEP-60M.

The sixteenth sequence (S2QUX) is a small LOCA with a failure of FW, HPCI and RCIC, and a failure to depressurize the RPV. The time to core damage for this sequence is 40 minutes. The recovery actions applied are NR-U1X-DEP-40M and NR-Q-FWLVL-24M.

The seventeenth sequence (TraQUX) is a loss of RACS with a failure of FW, HPCI and RCIC, and a failure to depressurize the RPV. The time to core damage for this sequence is one hour. The recovery actions applied are NR-U1X-DEP-60M, NR-Q-FWLVH-4M and NR-WW1-SWP-1.

The eighteenth sequence (TmUV) is an MSIV closure with a failure of all injection to the RPV. The time to core damage for this sequence is one hour. The recovery actions applied are NR-PCS-1, NR-UV-ECCS-1 and NR-UV-WTLVL-20M.

The nineteenth sequence (TfPU1U2X) is a loss of FW with a SORV, failure of HPCI and RCIC, and a failure to depressurize the RPV. The time to core damage for this sequence is 40 minutes. The recovery action applied is NR-U1X-DEP-40M.

The twentieth sequence (S1U1WW1Uv) is a medium LOCA with a failure of HPCI and a loss of DHR. The time to core damage for this sequence is at least 24 hours. The recovery actions applied are NR-RHR-INIT and NR-VENT-5.

The twenty-first sequence (TePWW1Uv) is a LOP with a SORV and a loss of DHR. The time to core damage for this sequence is at least 24 hours. The recovery actions applied are NR-LOSP-24, NR-RHR-INIT and NR-VENT-5.

The twenty-second sequence (TmPUX) is an MSIV closure with a SORV, failure of HPCI, and a failure to depressurize the RPV. The time to core damage for this sequence is 40 minutes. The recovery action applied is NR-U1X-DEP-40M.

The twenty-third sequence (TatQU1X) is an MSIV-closure ATWS (mechanical failure of the control rods) with a failure of feedwater, HPCI and a failure to depressurize the RPV. Core damage for this sequence would occur in a few minutes. The recovery actions applied are NR-ATWS-HPCI and NR-ATWS-DEP.

The twenty-fourth sequence (TraPP2WW1Uv) is a loss of RACS with two SORVs and a loss of DHR. The time to core damage for this sequence is at least 24 hours. The recovery actions applied are NR-WW1-SWP-20, NR-RHR-INIT and NR-VENT-5.

The twenty-fifth sequence (TiaPP2WUv) is a loss of IAS with two SORVs and a loss of DHR. The time to core damage for this sequence is at least 24 hours. The recovery actions applied are NR-WW1-SWP-20 and NR-SPL-LVLL-4.

The twenty-sixth sequence (ThvPP2) is a loss of HVAC with two SORVs. The time to recover from the loss of HVAC is either 12 or 24 hours (depending on the cutset), but the 12-hour time period was conservatively assumed for the entire sequence. The recovery action applied is NR-HVC-PNRM-12.

The twenty-seventh sequence (ThvU) is a loss of HVAC with a failure of HPCI and RCIC. The time to recover from the loss of HVAC is either 12 or 24 hours (depending on the cutset), but the 12 hour time period was conservatively assumed for the entire sequence. The recovery action applied is NR-HVC-PNRM-12.

The twenty-eighth sequence (TiQUV) is an inadvertent opening of a SRV with a failure of FW and all other injection to the RPV. The time to core damage for this sequence is 40 minutes. The recovery actions applied are NR-UV-WTLVL-20M and NR-UV-ECCS-40M.

The twenty-ninth sequence (TeEDGU) is a LOP with a failure of onsite AC power (a station blackout) and a failure of HPCI and RCIC. The time to core damage for this sequence is one hour. The recovery actions applied are NR-LOSP-1, NR-UV-ECCS-1 and NR-UV-WTLVL-20M.

The thirtieth sequence (TtQWUv) is a turbine trip with a failure of feedwater and a loss of DHR. The time to core damage for this sequence is at least 24 hours. The recovery action applied is NR-PCS-24.

7.1.1.4 Uncertainty and Sensitivity of the Core Damage Frequency

7.1.1.4.1 Uncertainty of the Core Damage Frequency

The occurrence probabilities of the basic events of the Hope Creek PRA are best estimate point values. However, uncertainty boundaries are assigned for each type of basic event, in the form of a lognormal distribution. These uncertainty boundaries are based on those used generically in the industry. Utilizing these uncertainty boundaries, a probability density function of the total core damage frequency of the most dominant 180 cutsets was estimated by a calculation using the computer code TEMAC (Reference 3.4-3). The calculated distribution of the total core damage frequency is shown in Figure 3.4-2.

Due to memory and computation time limitations, the TEMAC code is not able to calculate the uncertainty distribution of the complete set of 4412 cutsets that comprise the CDF of the Hope Creek IPE. Therefore, the number of cutsets used in the uncertainty analysis was reduced until TEMAC was capable of performing the calculations. This occurred when the number of core damage cutsets was reduced to the top 180. For a given set of cutsets, TEMAC calculates the number of sample trials that it is capable of performing. For the 180 cutsets, TEMAC used 221 sample trials. The deviation between the mean and nominal values of the CDF results from the limitations of the TEMAC estimation technique. For a smaller number of cutsets, this deviation could be reduced, but then a larger percentage of the core damage frequency would have been ignored.

7.1.1.4.2 Sensitivity Analyses

Three sensitivity cases were quantitatively analyzed by manipulating the baseline HCGS IPE results in the RESULTS MODULE of the PRA WORKSTATION software. The first sensitivity case is an assessment of the impact of a less conservative assumption about the mission time of the Emergency Diesel Generators (EDGs) (i.e. decreasing the mission time from 24 hours to six hours). The second and third sensitivity cases are estimates of the core damage frequency (CDF) that would have been calculated had the Loss of an AC bus and the Loss of a DC bus (respectively) been included as special initiating events. It is appropriate to note that the importance analysis of Section 7.1.1.2 is a form of sensitivity study at the basic event level.

Further sensitivity studies were not performed because of the high degree of HCGS support and the development of the PRA models. For example, the sensitivity of post-accident operator errors may be studied by adjusting the HEP values upward or downward. This was not performed because HEPs were based on actual simulator training, and would not likely change. Similarly, because most plant models were developed with support from the HCGS Technical and Operations Departments, few uncertainties or variabilities are believed to exist. Finally test and maintenance unavailabilities are based on plant-specific data, as opposed to generic values; therefore, it was unnecessary to perform a sensitivity study of variations in that data.

7.1.1.4.2.1 Decrease EDG Mission Time From 24 Hours To Six Hours

The mission time of the diesel generators was modeled as 24 hours in the diesel generator fault trees (described in Section 3.2.1.10). This is a conservative assumption, since it is unlikely that offsite power would not be recovered within 24 hours. The offsite power recovery curve used (which was derived from NUREG-1032, Reference 7.1-5) predicts a 95% probability of offsite power recovery within six hours. Therefore, this sensitivity case is an analysis of the impact of a change in the EDG mission time from 24 hours to six hours.

Table 7.1-8 shows the results of this sensitivity analysis. The only core damage sequences (with a frequency greater than or equal to 1E-10) which are affected are the five Station Blackout (SBO) sequences shown. There is a reduction in the total CDF from 4.58E-5 to 3.94E-5, or a reduction of 14.0%. Although this is not a negligible reduction in the total CDF, the contribution of SBO sequences to the total CDF would still be 69.5%. When this SBO contribution is compared to the 73.7% calculated in the baseline results, it is clear that the assumption of a 24 hour mission time for the EDGs does not have any impact on the overall conclusions of the HCGS IPE.

7.1.1.4.2.2 Loss Of A 1E AC Vital Bus Special Initiating Event

The loss of a 1E AC vital bus was not considered as a special initiating event in the HCGS IPE, since it was not found to cause a reactor trip. However, as was mentioned in Section 3.1, this sensitivity analysis will approximate what the core damage frequency would have been, had the loss of a 1E AC vital bus been considered as an initiating event.

If the loss of a 1E AC vital bus were to cause a reactor trip, the accident sequence is assumed to be identical to a turbine trip initiating event (see Section 3.1.2 for a discussion of a turbine trip initiating event), except that one 1E AC vital bus would be unavailable. Therefore, to perform this sensitivity analysis, the following steps were executed:

1. Establish a frequency for the loss of a 1E AC vital bus initiating event.

2. In the baseline results of the IPE, assign a probability of 1.0 to an event which represents the unavailability of one 4.16kV AC vital bus. Note that this is done on the cutset level in a way which is applied across all of the cutsets which contain that 1E AC vital bus failure.

3. Examine the new CDF of each of the turbine trip core damage sequences. Since these were calculated with the turbine trip initiating event frequency (4/year), this frequency is divided out of the cutsets, and they are then multiplied by the frequency of the loss of a Class 1E AC vital bus initiating event. The resulting cutsets show the frequency of core damage resulting from a Class 1E AC vital bus failure which in some way caused a reactor trip.

For the first step, as an estimate of the initiating event frequency of the loss of a Class 1E AC vital bus, the frequency from NUREG-4550 was used. This frequency was 5.0E-3/yr, and it is given the designation "Tac."

For the second step, the unavailability of the Class 1E 4.16kV bus 10A401 was set to 1.0. Division A of power was chosen for this sensitivity.

For the third step, the resulting core damage sequences were multiplied by 5.0E-3/yr and divided by 4.0/yr to give the core damage frequency due to the loss of a Class 1E AC vital bus initiating event. An example of this third step is provided below for a cutset transferred from sequence "TtQUX" to "TacQUX":

Original cutset: Turbine trip (4/yr) * 10A401 unavailable (1.41E-3)
* HPCI/RCIC depen fail (1.35E-4) * Fail to depress RPV (4.6E-3)
* Fail to recover PCS w/i 1 hour (0.6)
= 2.10E-9/yr

Revised cutset: Loss of AC bus (5.0E-3/yr) * 10A401 unavailable (1.0)
* HPCI/RCIC depen fail (1.35E-4) * Fail to depress RPV (4.6E-3)
* Fail to recover PCS w/i 1 hour (0.6)
= 1.86E-9/yr

The result of this sensitivity analysis is a total CDF from the loss of an AC bus initiating event of 1.04E-8/yr. The three Tac core damage sequences with a frequency greater than 1E-10/yr are shown in Table 7.1-9.

7.1.1.4.2.3 Loss Of A DC Bus Special Initiating Event

The loss of a DC bus was not considered as a special initiating event in the HCGS IPE, since it was not found to cause a reactor trip. However, as was mentioned in Section 3.1, this sensitivity analysis will approximate what the core damage frequency would have been, had the loss of a DC bus been considered as a special initiating event.

This sensitivity analysis is identical to the previous sensitivity analysis (the loss of a Class 1E AC vital bus), except that instead of assigning a 1.0 unavailability to a 4.16kV AC bus, the 1.0 unavailability was assigned to the 125VDC bus 10D410. Similar to Tac, the frequency of the loss of a DC bus was taken from NUREG-4550. It is designated "Tdc" and its frequency is 5.0E-3/yr.

The result of this sensitivity analysis is a total CDF from the loss of a DC bus of 1.99E-8/yr. The three Tdc core damage sequences with a frequency greater than Class 1E-10 are shown in Table 7.1-10.

7.1.1.5 Comparison With Other Studies

Table 3.4-11 presents a comparison of the HCGS Level I results with those from the NUREG-1150 Reference Plant similar to HCGS (Peach Bottom), and the IPE Submittals of other BWRs with Mark I Containments. The Internal Events Core Damage Frequency (CDF) for the HCGS (4.58E-5/yr) is approximately one order of magnitude higher than the NUREG-1150 results for Peach Bottom (Reference 3.4-6). A review of the NUREG-1150 study has shown that many support system dependencies were not reviewed with the depth of detail used in the HCGS IPE. The HCGS CDF compares reasonably with the results from the other BWR IPEs.

Table 3.4-11 also details the percentage distributions for the separate studies. Loss of Power sequences account for a higher percentage of the CDF at Hope Creek (73.8%) than at Peach Bottom, but the HCGS results are comparable to most of the other BWR IPEs. As discussed in Section 3.4.2, conservative design assumptions with respect to the SACS and SSW systems

at HCGS contribute significantly to the LOP results. Transients account for a greater contribution to the HCGS IPE than the Peach Bottom NUREG-1150 study, although the contribution is relatively small (14.8%), and lower than most of the other BWR IPEs. This is likely due to the amount of detail in the HCGS IPE, and the relatively large contribution of ATWS to the Peach Bottom results. LOCAs are generally minor contributors in all of the studies. ATWS is a notably small contributor (1.6%) at the HCGS. This is generally due to automatic operation of the SLC system. Special initiators also contribute very little to the Internal Events CDF in all cases. Finally, the Internal Flooding results at HCGS were comparable to the published BWR IPE results.

7.1.2 Vulnerability Screening

Neither GL88-20 nor NUREG-1335 strictly define "vulnerability." Words which appear in relation to vulnerability include "weakness" and "outlier." The first implies an absolute relationship, while the second implies a relative relationship. Therefore, for a sequence or event to be considered indicative of a vulnerability, it had to pass the screening criteria defined in Section 7.1.1 and contribute inordinately to the HCGS Core Damage Frequency with respect to either (1) other HCGS core damage sequences or contributing events, or (2) in comparison to similar sequences or events for other nuclear power plants as determined from published risk assessment results.

As described in Section 7.1.1, after screening, 17 sequences remained comprising 97.3% of the Total Internal Events and Internal Flooding CDF. Five core damage sequences have frequencies greater than 1.0E-6/year. These five sequences contribute approximately 84.2% to the total CDF. Six additional sequences each contribute at least 1% to the total CDF. The remaining six each contribute less than 1% to the total CDF. As described in Section 7.1.1.1, a single sequence, TeEDG, contributes 71.4% to the CDF.

During the recovery analysis portion of the HCGS IPE quantification, transients were identified which, when they involved certain HVAC failures based on room heatup calculations, led to core damage. The greatest contributor of these was a loss of Switchgear or Class 1E Panel Room HVAC with a frequency of 3.29E-3/yr prior to recovery. Clearly this sequence inordinately contributed to the CDF. It was immediately labeled a "vulnerability" and reported to the HCGS. A recovery procedure (Reference 7.1-9) was developed by the HCGS to supply alternate ventilation to prioritized rooms as determined from the IPE's Room Heatup Calculations. (The quantification of recovery actions is described in Section 3.3.3.) The new procedure eliminated the "vulnerability."

With elimination of the loss of HVAC sequences described above, the principal contributors to the internal events CDF are sequences involving station blackout (SBO). The five SBO sequences contribute 73.7% of the total CDF of 4.58E-5/yr. However, it was determined that SBO does not represent a vulnerability at the HCGS, for the following reasons:

1. A comparison of Hope Creek with other BWRs with Mark I Containments shows SBO to be a significant contributor to CDF in all cases, and the highest single contributor in most cases (See Section 3.4.1.5).

2. The total CDF for Hope Creek, including the SBO sequences, is reasonable when compared to other BWRs.

3. The principal reason for the large contribution of SBO sequences to overall CDF is the conservative design assumptions used for SACS and the SSW systems in the analysis of Loss of Offsite Power sequences. A more detailed thermo-hydraulic evaluation of these systems is underway, which may result in as much as a 50% reduction in the SBO contribution to total CDF.

Based on the above discussion, the loss of HVAC was determined to be the only vulnerability at the HCGS, and it was addressed in a new HVAC recovery procedure.

7.1.3 Unresolved and Generic Issues

By the way of participation in the Individual Plant Examination, as evidenced by this submittal report, PSE&G has resolved GSI 105, "Intersystem LOCA Outside Containment," as well as USI A-45, "Decay Heat Removal" for the HCGS. Specific details of the ISLOCA analysis appear in Section 3.1.3.5 and Reference 3.1.3-1. It is notable that due to the low frequency of core damage resulting from ISLOCAs, 1.7E-9/yr., these sequences fell below the screening criteria for inclusion in the back-end analysis. USI A-45 is subsequently discussed in Section 7.1.4.

7.1.4 Decay Heat Removal Evaluation

This section defines the concerns of the Unresolved Safety Issue (USI) A-45 (Reference 7.1-8) in regard to decay heat removal and describes how the HCGS IPE addressed the issue.

Unresolved Safety Issue A-45 concerns the performance of the decay heat removal function, to ensure heat transfer from the reactor coolant system to an ultimate heat sink after reactor shutdown. The decay heat removal function is similar to other safety related functions in the plant because it includes a number of alternative, redundant systems, that are controlled by the reactor protection system, under the supervision of operators. The redundant systems which are primarily responsible for the decay heat removal depend on various support systems, such as AC and DC electrical power, ventilation and cooling, air systems, etc.

A total loss of the decay heat removal function would cause a steady increase of the containment temperature and pressure. This concern is valid, but for the HCGS it is a resolved issue for the following reasons:

- The contribution of TW (loss of decay heat removal) sequences to the total core damage frequency (CDF) at the HCGS is only 5.45E-7 per year, or 1.2% of the total CDF.

- At the HCGS, the residual heat removal system (RHR) is a very robust system, with high redundancy (two loops, two heat exchangers, and complete electrical separation between various trains). In addition to this, the HCGS has a hard-pipe containment venting system which has the capability to remove decay heat in the unlikely situation that the RHR system fails.

- The coincidental failure of the 125 VDC batteries with a loss of offsite power and failure to start all the diesel generators has a very low frequency of occurrence. This sequence was below the screening cutoff discussed in Section 7.1.1.

- The USI A-45 NRC BWR case studies identified a potential weakness in that each diesel generator had only one cooling pump, and failure of that pump would cause failure of the diesel generator. The HCGS diesels are cooled by SACS, which is a highly redundant system (2 loops, two pumps in each loop). If one SACS pump fails, the cooling of the diesel generators is not affected, because HCGS procedures would direct the cross-tie of SACS cooling to the diesels such that all four diesels could be cooled by the operating SACS pumps.

- The USI A-45 NRC BWR case studies identified a potential weakness in that following a loss of offsite power, diesel generator failures are dominant contributors to core damage frequency, in the range of 1.0E-4/yr. At the HCGS, the total core damage frequency is lower (approximately 4.58E-5/yr).

- The USI A-45 NRC BWR case studies identified a potential weakness in that failure of MOVs in the reactor building closed cooling system could isolate cooling water to the ECCS room coolers, or divert cooling water to non-critical loads. At the HCGS, the Safety Auxiliaries Cooling System (SACS), with its two redundant loops and two pumps in each loop, provides cooling to the RHR pump seal cooler and motor bearing cooler and to all ECCS room coolers. All of the SACS valves used to provide cooling to the ECCS are pneumatically controlled, with the exception of the motor-operated SACS Heat Exchanger Inlet Valves. These MOVs are part of PSE&G GL89-10 program and will be statically and dynamically tested to ensure their capability to perform their intended function under design basis conditions.

In view of all these arguments, loss of decay heat removal at the HCGS is considered a resolved issue.

7.2 Back-End Analysis Results

The back-end analysis provided the following results:

- The frequency of high early and medium early releases are 9.42E-6/yr and 6.14E-6/yr, respectively.

- The CDF is dominated by long-term station blackout (LT-SBO) sequences - 77% of the total CDF. This leads to a high frequency of early containment failures, and higher releases because AC power is not available in many sequences to operate the engineered safety features at HCGS.

- Of the other sequences, transients without decay heat removal (TW) are also important because they often lead to early containment failure and high release. However, the TW sequences make up only about 5% of the total CDF.

- The early containment failure frequency for the base case is driven by the unavailability of coolant injection in many sequences. Early containment failure is predicted to occur 55.7% of the time. Eighty-four percent (84%) of these cases have containment failure by drywell shell melt-through. The high probability of shell melt-through is due again to the lack of coolant injection to cool the shell and the ex-vessel core debris. Drywell shell melt-through is treated in the CET as a large containment failure (i.e., a rupture). Under these conditions, radionuclide retention in the primary containment and the RB is assumed to be small. Since the drywell is failed, radionuclides also bypass the suppression pool. Note also that the FRVS is assumed to fail following a containment rupture.

- Due to the high frequency of drywell shell melt-through and the radionuclide retention characteristics of this failure mode, radionuclide releases are relatively high in a significant number of cases. The frequency of an early high release is 21% of the total CDF, and the frequency of an early medium-high release is an additional 14%.

- Late containment failure occurs in 17.7% of the sequences. The containment does not fail in approximately 20% of the cases, with venting taking place in approximately half of these cases. Venting is almost always from the wetwell.

7.3 References

7.1-1 "Individual Plant Examination: Submittal Guidance: Final Report." U.S. Nuclear Regulatory Commission, Washington, DC, 1989: NUREG-1335.

7.1-2 "Individual Plant Examination for Severe Accident Vulnerabilities - 10CFR 50.54(f)," Generic Letter No. 88-20. U.S. Nuclear Regulatory Commission, Washington, DC, November 23, 1988.

7.1-3 "A User's Guide To The Top Event Matrix Analysis Code (TEMAC)." U.S. Nuclear Regulatory Commission, Washington, DC, August 1986: NUREG/CR-4598.

7.1-4 "PRA Workstation Users Manual." NUS, Kent, WA, December 1992.

7.1-5 "Stress and Duress Detection for NRC-Licensed Facilities: A Constitutional and Regulatory Analysis." U.S. NRC, Washington, DC, 1979. NUREG/CR-1032.

7.1-6 "Analysis of Core Damage Frequency: Peach Bottom, Unit 2 Internal Events." U.S. NRC, Washington, DC, 1989. NUREG/CR-4550.

7.1-7 NUREG/CR-4550, Vol. 6, "Analysis of Core Damage Frequency From Internal Events: Grand Gulf, Unit 1." April 1987.

7.1-8 "Shutdown Decay Heat Removal Requirements." U.S. Nuclear Regulatory Commission, Office Of The Secretary, Washington, DC, 1988: USI A-45 BWR Case Study.

7.1-9 HCGS Procedure No. HC.OP-AB.ZZ-0209(Q), "Loss of HVAC;" April 1994.

TABLE 7.1-1

CORE DAMAGE SEQUENCES SORTED BY FREQUENCY

	Sequence	Frequency
1	TeEDG	3.2679E-005
2	TfU1U2X	2.7566E-006
3	TmUX	1.0470E-006
4	S1WUv	1.0359E-006
5	TtQUX	1.0343E-006
6	S1U1X	9.9570E-007
7	Thv	9.8736E-007
8	TeEDGP	9.6715E-007
9	TfQRWW1Uv	5.2964E-007
10	TiQUX	5.2884E-007
11	TatC2	5.0747E-007
12	TtQUV	3.9697E-007
13	S1D	3.0000E-007
14	TsaW1Uv	2.9846E-007
15	AWUv	2.0736E-007
16	TtPP2WUv	1.7924E-007
17	TaCmC2	1.1898E-007
18	S2C	7.9912E-008
19	TfPU1U2X	7.8040E-008
20	AD	7.0000E-008
21	TeEDGU	5.8460E-008
22	TeEDGPP2	5.8396E-008
23	S1EEdg	5.2409E-008
24	S2S3IsoQUX	5.0521E-008
25	TmPUX	5.0183E-008
26	TeUX	4.9568E-008
27	S1V1	4.9315E-008
28	TtPP2V	4.6004E-008
29	TfU1U2V	4.5486E-008
30	TraQUX	4.2972E-008
31	S2S3IsoQV	4.2650E-008
32	TtCeScrRpt	4.0000E-008
33	TtCmRpt	4.0000E-008
34	TsaPP2Uv	3.5464E-008
35	S1C	3.0000E-008
36	S2S3IsoC	2.4616E-008
37	ThvP	2.1780E-008
38	AC	2.1000E-008
39	TraQUV	1.9694E-008
40	TmUV	1.7863E-008
41	TfPU1U2V	1.5867E-008
42	TtPQUX	1.4829E-008
43	AV1	1.4793E-008
44	TtCmQU1X	1.4499E-008
45	TtQWW1Uv	1.3989E-008
46	S1U1WUv	1.2977E-008
47	TtM	1.2000E-008
48	S1U1V1	1.1806E-008
49	TmPP2V	1.0562E-008
50	Ta2CeScrRpt	9.8200E-009
51	TaCmRpt	9.8200E-009
52	TeEDGPU	9.2219E-009
53	S2D	7.9800E-009
54	S2QUX	7.5906E-009
55	AEEdg	7.3930E-009
56	TiaUV1	4.8502E-009
57	TraPP2WUv	4.1177E-009
58	TiQUV	3.5993E-009
59	TiaUX	3.1425E-009
60	S2S3IsoD	2.4616E-009
61	TtPP2WW1Uv	2.2821E-009
62	TraPQUX	1.8091E-009
63	TtCmMsvU1X	1.7033E-009
64	TfM	1.6500E-009
65	TePUX	1.6412E-009
66	S1WW1Uv	1.6200E-009
67	TsaPP2W1Uv	1.3419E-009
68	Ta1ScrKMsvU1X	1.2139E-009
69	ThvPP2	1.0890E-009
70	TmM	1.0800E-009
71	TiaWW1Uv	1.0337E-009
72	AWW1Uv	8.8192E-010
73	TsaUsVs	8.0111E-010
74	TtQWUv	7.2670E-010
75	TtPQWUv	6.0102E-010
76	TaCmU1X	5.5233E-010
77	S1EU1X	4.0808E-010
78	S1ED	3.0000E-010
79	TsaUsX	2.7669E-010
80	TmPP2WUv	2.6049E-010
81	TraPP2V	2.4658E-010
TOTAL CDF =		4.58E-5

TABLE 7.1-2

CORE DAMAGE SEQUENCES SORTED ALPHABETICALLY

	Sequence	Frequency
1	AC	2.1000E-008
2	AD	7.0000E-008
3	AEEdg	7.3930E-009
4	AV1	1.4793E-008
5	AWUv	2.0736E-007
6	AWW1Uv	8.8192E-010
7	S1C	3.0000E-008
8	S1D	3.0000E-007
9	S1ED	3.0000E-010
10	S1EEdg	5.2409E-008
11	S1EU1X	4.0808E-010
12	S1U1V1	1.1806E-008
13	S1U1WUv	1.2977E-008
14	S1U1X	9.9570E-007
15	S1V1	4.9315E-008
16	S1WUv	1.0359E-006
17	S1WW1Uv	1.6200E-009
18	S2C	7.9912E-008
19	S2D	7.9800E-009
20	S2QUX	7.5906E-009
21	S2S3IsoC	2.4616E-008
22	S2S3IsoD	2.4616E-009
23	S2S3IsoQUX	5.0521E-008
24	S2S3IsoQV	4.2650E-008
25	Ta1ScrKMsvU1X	1.2139E-009
26	Ta1ScrRpt	4.0000E-008
27	Ta2CeScrRpt	9.8200E-009
28	TaCmC2	1.1898E-007
29	TaCmRpt	9.8200E-009
30	TaCmU1X	5.5233E-010
31	TatC2	5.0747E-007
32	TatMsvU1X	1.7033E-009
33	TatQU1X	1.4499E-008
34	TatRpt	4.0000E-008
35	TeEDG	3.2679E-005
36	TeEDGP	9.6715E-007
37	TeEDGPP2	5.8396E-008
38	TeEDGPU	9.2219E-009
39	TeEDGU	5.8460E-008
40	TePUX	1.6412E-009
41	TeUX	4.9568E-008

	Sequence	Frequency
42	TfM	1.6500E-009
43	TfPU1U2V	1.5867E-008
44	TfPU1U2X	7.8040E-008
45	TfQRWW1Uv	5.2964E-007
46	TfU1U2V	4.5486E-008
47	TfU1U2X	2.7566E-006
48	Thv	9.8736E-007
49	ThvP	2.1780E-008
50	ThvPP2	1.0890E-009
51	TiaUV1	4.8502E-009
52	TiaUX	3.1425E-009
53	TiaWW1Uv	1.0337E-009
54	TiQUV	3.5993E-009
55	TiQUX	5.2884E-007
56	TmM	1.0800E-009
57	TmPP2V	1.0562E-008
58	TmPP2WUv	2.6049E-010
59	TmPUX	5.0183E-008
60	TmUV	1.7863E-008
61	TmUX	1.0470E-006
62	TraPP2V	2.4658E-010
63	TraPP2WUv	4.1177E-009
64	TraPQUX	1.8091E-009
65	TraQUV	1.9694E-008
66	TraQUX	4.2972E-008
67	TsaPP2Uv	3.5464E-008
68	TsaPP2W1Uv	1.3419E-009
69	TsaUsVs	8.0111E-010
70	TsaUsX	2.7669E-010
71	TsaW1Uv	2.9846E-007
72	TtM	1.2000E-008
73	TtPP2V	4.6004E-008
74	TtPP2WUv	1.7924E-007
75	TtPP2WW1Uv	2.2821E-009
76	TtPQUX	1.4829E-008
77	TtPQWUv	6.0102E-010
78	TtQUV	3.9697E-007
79	TtQUX	1.0343E-006
80	TtQWUv	7.2670E-010
81	TtQWW1UvAAA	1.3989E-008
TOTAL CDF =		4.58E-5

TABLE 7.1-3
CORE DAMAGE FREQUENCY DISTRIBUTION

SEQUENCE	FREQUENCY	% OF TOTAL
Station Blackout (SBO)	3.38E-05	73.7%
Transient with loss of FW, HPCI/RCIC, & failure to depressurize (TQUX)	5.41E-06	11.7%
LOCAs	3.07E-06	6.7%
Special Initiators	1.42E-06	3.1%
ATWS	7.45E-07	1.6%
Loss of decay heat removal (TW)	5.45E-07	1.2%
Transient with loss of all high pressure & low pressure injection (TQUV)	4.64E-07	1.0%
Stuck-open Safety Relief Valve (TP)	3.98E-07	0.9%
Loss of Offsite Power (D/Gs operate)	5.12E-08	0.1%
Total CDF from internal events:	4.58E-5 / year	100.0%

Table 7.1-4

The Most Important 30 Basic Event Failures Sorted by the Risk Increase Measure

Basic Event		Description
1.	SRV-13-FTO-CCF	Common cause failure to open 13 SRVs.
2.	DCP-BDC-VF-DF03	Common cause failure of 125VDC buses 10D410, 20, & 40.
3.	DCP-BDC-VF-DF01	Common cause failure of 125VDC buses 10D410, 20, 30 &40.
4.	CM	RPS mechanical failure prevents scram.
5.	ESF-XHE-MC-DF02	Miscalibration of all level transmitters.
6.	DCP-BDC-VF-DF10	Common cause failure of 125VDC BUSES 10D420 AND D440.
7.	ESF-XHE-MC-DF01	Miscalibration of all pressure transmitters.
8.	HAR-TDP-FS-DPF01	Common cause failure to start of HPCI and RCIC turbine driven pumps.
9.	HAR-TDP-FR-DPF01	Common cause failure to run of HPCI and RCIC turbine driven pumps.
10.	VAP-SUP-SY-FAILS	Vapor suppression (breakers) fail during large or intermediate LOCA.
11.	NR-HVC-PNRM-12	Failure to provide alternate ventilation to the Panel Room within 12 hours after a loss of HVAC.
12.	DCP-BDC-VF-DF06	Common cause failure of 125VDC buses 10D410 and 10D420.
13.	CE	RPS electrical failure prevents scram.
14.	SWS-MOV-CC-DF01	Dependent failures of 2198 C and D VALVES
15.	SWS-MDP-FS-DF04	Dependent failures to start SWS-TWSs.
16.	SWS-MDP-FR-DF04	Dependent failures to run SWS-TWSs.
17.	SWS-TWS-FR-DF01	Dependent failures to run ALL 4 TWSs.
18.	SWS-MDP-FR-DF03	Dependent failures to run ALL SWS pumps.
19.	SAC-MDP-FR-DF07	ALL 4 SACS pumps fail to run.
20.	SWS-MOV-CC-DF03	Dependent failures of strainer MOVs HV-2197.
21.	SWS-MOV-CC-DF02	Dependent failures of all 4 MOV-2225 VALVES
22.	SAC-MDP-FS-DF07	ALL 4 SACS pumps fail to start.
23.	DGS-DGN-FS-DF02	Dependent failure to start SDG'S A, B, & C.
24.	DGS-DGN-FS-DF03	Dependent failure to start SDG'S A, B, & D.
25.	DGS-DGN-FS-DF04	Dependent failure to start SDG'S A, C, & D.
26.	DGS-DGN-FS-DF05	Dependent failure to start SDG'S B, C, & D.
27.	SAC-MDP-FR-DF02	Dependent failure to run pumps AP & DP-210.
28.	SAC-MDP-FR-DF01	Dependent failure to run pumps AP & BP-210.
29.	SAC-MDP-FR-DF03	Dependent failure to run pumps BP & CP-210.
30.	SWS-STR-FS-DF01	Dependent failure to start ALL SWS STR motors.

Table 7.1-5

The Most Important Basic Event Failures Sorted by the Risk Reduction Measure.

	Basic Event	Description
1.	NR-LOSP-6	Failure to restore offsite power in 6 hours
2.	NR-DG-6	Failure to recover EDGs within 6 hours of independent failures of EDGs.
3.	SWS-MDP-TM-TRAND	Due to TM SWS train-D is unavailable.
4.	SWS-MDP-TM-TRANC	Due to TM SWS train-C is unavailable.
5.	SAC-MDP-TM-PSB06	Due to TM SACS loop B path PS-B06 is unavailable.
6.	NR-DG-DF-6	Failure to recover EDGs within 6 hours of common cause failures of EDGs.
7.	ADS-XHE-FO-DEPRE	Operator fails to depressurize.
8.	ADS-XHE-OK-INHIB	ADS fails at level I due to INHIBIT by operator.
9.	NR-U1X-DEP-60M	Failure to manually depressurize the RPV within 60 minutes.
10.	NR-PCS-1	Failure to restore the PCS within 1 hour.
11.	DGS-DGN-FR-CG400	Division C diesel 1CG400 fails to run.
12.	DGS-DGN-FR-AG400	Division A diesel 1AG400 fails to run.
13.	DGS-DGN-FS-CG400	Division C diesel 1CG400 fails to start.
14.	DGS-DGN-FS-AG400	Division A diesel 1AG400 fails to start.
15.	HPI-TDP-TM-OP204	HPCI turbine driven pump is inavailable due to TM.
16.	SWS-XHE-FO-ISOL	Operator fails to isolate SWS flow diversion.
17.	DGS-DGN-FR-DG400	Division D diesel 1DG400 fails to run.
18.	DGS-DGN-FR-BG400	Division B diesel 1BG400 fails to run.
19.	SWS-MDP-FS-CP502	Failure to start SWS pump CP-502.
20.	CST-XHE-FO-ALIGN	Operator fails to align condensate storage tank.
21.	DGS-DGN-FS-BG400	Division B diesel 1BG400 fails to start.
22.	DGS-DGN-FS-DG400	Division D diesel 1DG400 fails to start.
23.	NR-HVC-PNRM-12	Failure to provide alternate ventilation to the Panel Room within 12 hours after a loss of HVAC.
24.	SWS-MDP-FS-AP502	SWS pump AP-502 fails to start.
25.	RCI-TDP-TM-OP203	RCIC turbine driven pump is inavailable due to TM.
26.	NR-SPL-LLVL-4-03	Failure to align core spray to the CST for long-term injection (without decay heat removal).
27.	HAR-TDP-FS-DPF01	Common cause failure of HPCI and RCIC turbine driven pumps to start.
28.	NR-U1X-DEP-30M	Failure to manually depressurize the RPV within 30 minutes.
29.	HPI-TDP-FS-OP204	HPCI turbine driven pump fails to start.
30.	SWS-MDP-FS-DP502	SWS pump DP-502 fails to start.

Table 7.1-6
Sequences Screened Out Due To Recovery Actions

		FREQUENCY:		
		before recovery	after recovery	Recovery Actions Applied
1	TtQWW1Uv	2.08E+00	1.40E-08	NR-PCS-24, NR-RHR-INIT, NR-WW1-SWP-20, NR-VENT-5
2	TmWW1Uv	1.43E-01	<1E-10	NR-PCS-24, NR-RHR-INIT, NR-WW1-SWP-20, NR-VENT-5
3	TeWW1Uv	6.39E-03	<1E-10	NR-LOSP-24, NR-RHR-INIT, NR-VENT-5
4	TmPP2WUv	1.87E-03	2.60E-10	NR-PCS-24, NR-RHR-INIT, NR-WW1-SWP-20
5	S1WW1Uv	1.10E-03	1.62E-09	NR-RHR-INIT, NR-VENT-5
6	TtPP2WW1Uv	1.09E-03	2.28E-09	NR-RHR-INIT, NR-WW1-SWP-20, NR-VENT-5
7	AWW1Uv	3.16E-04	8.82E-10	NR-RHR-INIT, NR-VENT-5
8	TmPP2WW1Uv	3.01E-04	<1E-10	NR-PCS-24, NR-WW1-SWP-20, NR-RHR-INIT, NR-VENT-5
9	TiaWW1Uv	2.05E-04	1.03E-09	NR-RHR-INIT, NR-WW1-SWP-20, NR-VENT-5
10	S2S3IsoQUX	9.58E-05	5.05E-08	NR-SLEAK-ISO-15M, NR-U1X-DEP-40M
11	ThvP	7.26E-05	2.18E-08	NR-HVC-PNRM-12
12	TtPQUX	7.06E-05	1.48E-08	NR-PCS-40M, NR-U1X-DEP-40M, NR-Q-FWLVH-4M
13	TraPP2WUv	3.65E-05	4.12E-09	NR-WW1-SWP-20, NR-SPL-LVLL-4
14	TfU1U2V	2.71E-05	4.55E-08	NR-UV-WTLVL-20M, NR-UV-ECCS-1
15	TeUX	2.17E-05	4.96E-08	NR-LOSP-60M, NR-U1X-DEP-60M
16	S2QUX	2.08E-05	4.94E-08	NR-U1X-DEP-40M, NR-Q-FWLVL-24M
17	TraQUX	1.89E-05	4.30E-08	NR-U1X-DEP-60M, NR-Q-FWLVH-4M, NR-WW1-SWP-1
18	TmUV	1.78E-05	1.79E-08	NR-PCS-1, NR-UV-ECCS-1, NR-UV-WTLVL-20M
19	TfPU1U2X	1.04E-05	7.80E-08	NR-U1X-DEP-40M
20	S1U1WW1Uv	9.79E-06	<1E-10	NR-RHR-INIT, NR-VENT-5
21	TePWW1Uv	8.26E-06	<1E-10	NR-LOSP-24, NR-RHR-INIT, NR-VENT-5
22	TmPUX	6.72E-06	5.02E-08	NR-U1X-DEP-40M
23	TatQU1X	5.19E-06	1.45E-08	NR-ATWS-HPCI, NR-ATWS-DEP
24	TraPP2WW1Uv	4.40E-06	<1E-10	NR-WW1-SWP-20, NR-RHR-INIT, NR-VENT-5
25	TiaPP2WUv	3.65E-06	<1E-10	NR-WW1-SWP-20, NR-SPL-LVLL-4
26	ThvPP2	3.63E-06	1.09E-09	NR-HVC-PNRM-12
27	ThvU	1.61E-06	<1E-10	NR-HVC-PNRM-12
28	TiQUV	1.25E-06	3.60E-09	NR-UV-WTLVL-20M, NR-UV-ECCS-40M
29	TeEDGU	1.22E-06	5.85E-08	NR-LOSP-1, NR-UV-ECCS-1, NR-UV-WTLVL-20M
30	TtQWUv	1.04E-06	7.27E-10	NR-PCS-24

TABLE 7.1-7

DESCRIPTION OF HUMAN RECOVERY ACTIONS APPLIED

	Recovery	Description	Value
1	NR-AIR-24	Failure to recover the IAS within 24 hours	5.7E-3
2	NR-ATWS-ADS-INH	Failure to inhibit ADS during an ATWS	7.5E-2
3	NR-ATWS-ARI	Failure to manually initiate ARI	1.4E-2
4	NR-ATWS-DEP	Failure to manually depressurized the RPV during an ATWS	5.6E-2
5	NR-ATWS-HPCI-30M	Failure to initiate HPCI during an ATWS	5.0E-2
6	NR-ATWS-HPCI-CS	Failure to isolate HPCI injection through the Core Spray piping during an ATWS	2.4E-1
7	NR-ATWS-LCNTL-LO	Failure to control RPV water level with LPCI during an ATWS	4.7E-1
8	NR-COND-5	Failure to restart condensate pumps after other injection systems fail	3.7E-2
9	NR-DG-6	Failure to recover D/Gs within 6 hours (independent failures of D/Gs)	7.0E-1
10	NR-DG-DF-6	Failure to recover D/Gs within 6 hours (common cause failures of D/Gs)	6.0E-1
11	NR-HPCI-LCNT-HIE	Failure to control RPV water level using HPCI during an ATWS to prevent core damage	4.6E-2
12	NR-HVC-PNRM-12	Failure to provide alternate ventilation to the Panel Room within 12 hours after a loss of HVAC	3.0E-4
13	NR-HVC-SWGR-24	Failure to provide alternate ventilation to the Switchgear Room within 24 hrs after loss of HVAC	1.6E-4
14	NR-IGS-24	Failure to restart the EIAC after RACS cooling has been restored followed a LOCA isolation	3.8E-3
15	NR-LOSP-24	Failure to restore offsite power within 24 hours	2.2E-3
16	NR-LOSP-12	Failure to restore offsite power within 12 hours	1.5E-2
17	NR-LOSP-6	Failure to restore offsite power within 6 hours	5.0E-2
18	NR-LOSP-5	Failure to restore offsite power within 5 hours	7.0E-2
19	NR-LOSP-1	Failure to restore offsite power within 1 hour	4.0E-1
20	NR-LOSP-40M	Failure to restore offsite power within 40 minutes	5.5E-1
21	NR-LOSP-30M	Failure to restore offsite power within 30 minutes	6.0E-1
22	NR-PCS-24	Failure to restore the PCS within 24 hours following a turbine trip or MSIV closure initiating event	7.0E-4
23	NR-PCS-1	Failure to restore the PCS within 1 hour	6.0E-1
24	NR-PCS-40M	Failure to restore the PCS within 40 minutes	9.0E-1
25	NR-Q-FWLVH-4M	Failure to prevent a level 8 trip of feedwater during a transient	1.4E-2

Table 7.1-7 (Continued)

	Recovery	Description	Value
26	NR-Q-FWLVL-24M	Failure to prevent a level 8 trip of feedwater during a small LOCA	4.9E-3
27	NR-RACS-24	Failure to restore the RACS after a LOCA isolation	3.8E-3
28	NR-RHR-INIT	Failure to initiate RHR for decay heat removal within 24 hours	5.0E-5
29	NR-SLEAK-ISO-15M	Failure to isolate recirculation pump seal LOCA	8.2E-2
30	NR-SPL-LVLL-4	Failure to align core spray to the CST for long-term injection (without decay heat removal)	1.1E-1
31	NR-U1X-DEP-30M	Failure to manually depressurize the RPV within 30 minutes	7.5E-3
32	NR-U1X-DEP-40M	Failure to manually depressurize the RPV within 40 minutes	5.2E-3
33	NR-U1X-DEP-60M	Failure to manually depressurize the RPV within 1 hour	4.6E-3
34	NR-UV-ECCS-1	Failure to manually initiate ECCS within 1 hour	3.9E-2
35	NR-UV-WTLVL-20M	Failure to control RPV water level with high pressure injection systems (not during ATWS)	4.3E-2
36	NR-VENT-5	Failure to initiate containment venting	2.0E-3
37	NR-WW1-SWP-1	Failure to manually start SSWS or SACS pumps within 1 hour	1.2E-2
38	NR-WW1-SWP-12	Failure to manually start SSWS or SACS pumps within 12 hours	1.9E-4
39	NR-WW1-SWP-20	Failure to manually start SSWS or SACS pumps within 20 hours	7.4E-5
40	NR-WW1-SWP-40M	Failure to manually start SSWS or SACS pumps within 40 minutes	1.6E-2

TABLE 7.1-8

RESULTS OF DECREASING EDG MISSION TIME FROM 24 HOURS TO 6 HOURS

SEQUENCE	CDF WITH 24-HOUR MISSION TIME	CDF WITH 6-HOUR MISSION TIME
1. TeEdg	3.27E-5	2.64E-5
2. TeEdgU	5.85E-8	5.07E-8
3. TeEdgP	9.67E-7	7.79E-7
4. TeEdgPU	9.22E-9	9.22E-9
5. TeEdgPP2	5.84E-8	4.34E-8
TOTAL:	3.38E-5	2.74E-5
Total CDF From All Sequences:	4.58E-5	3.94E-5
SBO % of Total CDF:	73.7%	69.5%

TABLE 7.1-9

RESULTS OF SENSITIVITY ANALYSIS OF CDF IF THE LOSS OF AN AC BUS WERE CONSIDERED AS A SPECIAL INITIATING EVENT

	SEQUENCE	FREQUENCY
1.	TacQUV	4.96E-10
2.	TacQUX	9.71E-9
3.	TacPP2WUv	2.24E-10
	TOTAL:	**1.04E-8/yr**

TABLE 7.1-10

RESULTS OF SENSITIVITY ANALYSIS OF CDF IF THE LOSS OF A DC BUS WERE CONSIDERED AS A SPECIAL INITIATING EVENT

	SEQUENCE	FREQUENCY
1.	TdcQUV	4.96E-10
2.	TdcQUX	1.92E-8
3.	TdcPP2WUv	2.24E-10
	TOTAL:	**1.99E-8/yr**

TABLE 7.1-11
CORE DAMAGE FREQUENCY COMPARISON

	HOPE CREEK IPE		PEACH BOTTOM NUREG-1150		PEACH BOTTOM IPE		MILLSTONE 1 IPE		DRESDEN IPE	
INITIATOR	CDF	%	CDF	%	CDF	%	CDF	%	CDF	%
LOSS OF OFFSITE POWER	3.39E-05	73.8	2.10E-06	46.6	1.85E-06	34.3	8.07E-06	73.4	4.98E-06	26.8
o Diesel Generator Unavailable	3.38E-05									
o Diesel Generator Available	5.12E-08									
TRANSIENTS	6.79E-06	14.8	2.30E-07	5.1	1.50E-06	27.8	1.09E-06	9.9	4.47E-07	2.4
o Turbine Trip	1.70E-06									
o MSIV Closure/Loss of Cond. Vac.	1.13E-06									
o Loss of Feedwater	3.42E-06									
o Inadvertant Open Relief Valve	5.33E-07									
LOCAs	3.07E-06	6.7	2.60E-07	5.8	5.95E-07	11.0	5.91E-07	5.4	1.42E-06	7.6
o Vessel Rupture	Negl.									
o Large LOCA	3.21E-07									
o Intermediate LOCA	2.49E-06									
o Small LOCA	2.58E-07									
o ISLOCA	1.70E-09									
ATWS	7.45E-07	1.6	1.92E-06	42.6	1.44E-06	26.7	1.06E-06	9.6	5.34E-07	2.9
o Turbine Trip	6.05E-07									
o All Others	1.39E-07									
SPECIAL INITIATORS	1.42E-06	3.1	-	0.0	7.00E-09	0.1	2.17E-06	19.7	1.12E-05	60.3
o Loss of SACS	3.36E-07									
o Loss of RACS	6.89E-08									
o Loss of IAS	9.02E-09									
o Loss of HVAC	1.01E-06									
Total Internal Events	4.59E-05	100.0	4.51E-06	100.0	5.39E-06	100.0	1.10E-05	100.0	1.86E-05	100.0
Internal Flooding	5.50E-07				1.47E-07		-			
Total Internal Events + Flooding	4.65E-05				5.54E-06		1.10E-05			

TABLE 7.1-11
CORE DAMAGE FREQUENCY COMPARISON (Continued)

	BROWNS FERRY		BRUNSWICK		DUANE ARNOLD		VERMONT YANKEE		MONTICELLO	
	IPE		IPE		IPE		IPE		IPE	
INITIATOR	CDF	%	CDF	%	CDF	%	CDF	%	CDF	%
LOSS OF OFFSITE POWER	3.30E-05	76.2	1.80E-05	65.4	2.57E-06	33.0	8.60E-07	20.0	1.20E-05	62.5
o Diesel Generator Unavailable										
o Diesel Generator Available										
TRANSIENTS	7.60E-06	17.6	8.61E-06	31.3	3.20E-06	41.0	2.30E-06	54.0	3.50E-06	18.2
o Turbine Trip										
o MSIV Closure/Loss of Cond. Vac.										
o Loss of Feedwater										
o Inadvertant Open Relief Valve										
LOCAs	7.50E-07	1.7	1.98E-07	0.7	1.56E-07	2.0	2.60E-07	6.0	1.20E-06	6.3
o Vessel Rupture										
o Large LOCA										
o Intermediate LOCA										
o Small LOCA										
o ISLOCA										
ATWS	1.30E-06	3.0	7.00E-07	2.5	1.87E-06	24.0	8.20E-07	20.0	2.50E-06	13.0
o Turbine Trip										
o All Others										
SPECIAL INITIATORS	6.60E-07	1.5	-	0.0	-	0.0	-	0.0	3.10E-08	0.2
o Loss of SACS										
o Loss of RACS										
o Loss of IAS										
o Loss of HVAC										
Total Internal Events	4.33E-05	100.0	2.75E-05	100.0	7.80E-06	100.0	4.30E-06	100.0	1.92E-05	100.0
Internal Flooding	4.70E-06								6.80E-06	
Total Internal Events + Flooding	4.80E-05								2.60E-05	

TABLE 7.1-11
CORE DAMAGE FREQUENCY COMPARISON (Continued)

	COOPER	
	IPE	
INITIATOR	CDF	%
LOSS OF OFFSITE POWER	2.77E-05	34.8
o Diesel Generator Unavailable		
o Diesel Generator Available		
TRANSIENTS	3.87E-05	48.5
o Turbine Trip		
o MSIV Closure/Loss of Cond. Vac.		
o Loss of Feedwater		
o Inadvertant Open Relief Valve		
LOCAs	7.17E-07	0.9
o Vessel Rupture		
o Large LOCA		
o Intermediate LOCA		
o Small LOCA		
o ISLOCA		
ATWS	3.91E-06	4.9
o Turbine Trip		
o All Others		
SPECIAL INITIATORS	8.69E-06	10.9
o Loss of SACS		
o Loss of RACS		
o Loss of IAS		
o Loss of HVAC		
Total Internal Events	7.97E-05	100.0
Internal Flooding		
Total Internal Events + Flooding		

Figure 7.1-1
CDF BREAKDOWN BY INITIATING EVENT