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September 1982

REVIEW OF SHOREHAM
WATER LEVEL MEASUREMENT SYSTEM

Prepared for
Long Island Lighting Company

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REVIEW OF SHOREHAM
WATER LEVEL MEASUREMENT SYSTEM

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Prepared for:
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Section 1

SUMMARY

A detailed, plant-specific study was carried out for the reactor water level system at Shoreham. The evaluation considered potential water level indication errors, including flashing errors, the relationship between measured water level and the state of the core, as well as an in-depth failure analysis of the Shoreham level system, including water level system reference leg breaks or leaks. Plant behavior and operator capability to respond were assessed under all such circumstances. A probabilistic risk assessment was also performed to determine the contribution of water level system failures to the previously calculated frequency of core vulnerable conditions at Shoreham.

The plant and operator performance evaluations reveal that water level indication errors due to changes in process conditions and instrument line flashing do not jeopardize plant safety because of the small reference line drops employed at Shoreham. Some combinations of a level system reference line break or significant leak plus additional single instrument failures will require operator action to assure adequate water inventory. However, the operator is expected to manually initiate a water make-up system from the information available to him and from plant procedures and operator training which prescribe appropriate action under degraded circumstances. The probabilistic risk assessment confirms the preceding findings. It verifies that most of the water level system failure contributions to risk come from a reference line break or a significant leak. All water level system failures were found to contribute about 11 percent to the revised total core vulnerable frequency. However, the predominant portion of the core vulnerable frequency attributable to the water level system would occur with the containment intact at the onset of core melt so that its contribution to offsite consequences would be much less than 11 percent of the total Shoreham consequences.

Section 2

INTRODUCTION

In January 1982, the Boiling Water Reactor Owners Group (BWROG) commissioned an extensive review of Boiling Water Reactor (BWR) water level measurement systems. The review consisted of examining the operating experience of BWR water level systems, identifying all their potential weaknesses, and proposing long-term improvements which might remedy the discovered weaknesses. The results of that investigation are reported in Reference (1). Reference (1) emphasizes the importance of carrying out plant-specific water level measurement studies. It is the purpose of this report to provide a detailed study of the Shoreham reactor water level system. It is is based upon the findings and methods contained in References (1) and (2).

The study consists of:

- A summary description of the reactor water level system utilized at the Shoreham plant. It provides a description of the level measurement system, the vessel level instrumentation arrangement, the pertinent instrument line routing information, operator displays, and the water level system application to the control and safety of the power plant.
- An evaluation of the performance of the Shoreham water level measurement system. An evaluation of the measurement errors due to variations in plant conditions, including conditions which cause a loss of fluid in the reference leg, is provided. Also, an evaluation of the relationship between water level and the state of the core is provided, including the ability of the Shoreham water level system to determine the state of the core.
- An in-depth failure analysis of the Shoreham level system, including a thorough review of drawings and logic diagrams to determine the vulnerability of the plant to postulated single failures in the level instrumentation.
- A qualitative analysis of the Shoreham specific response to plant transients and accidents for various failures of the water level system.

- A probabilistic assessment of the risks contributed by failures of the water level system as they impact the plant operators and the automatic initiation of safety systems. This water level probabilistic risk is compared to overall Shoreham plant risks to put into perspective any need to modify or improve the Shoreham water level system.

- A concluding section which summarizes the key findings.

Section 3

SHOREHAM WATER LEVEL SYSTEM

This section provides a detailed description of the Shoreham water level measurement system. The information provides the basis for the water level system failure and probabilistic analyses given in subsequent sections. Shoreham is an 846 Megawatt electrical (MW_e) BWR. It is one of the BWR-4 class of plants and utilizes a Mark II pressure suppression type containment. The nuclear Steam Supply System (NSSS) is being provided by General Electric (GE). The balance of the plant is the responsibility of Stone and Webster (S&W). The key parameters of the Shoreham plant are given in Table 3-1.

In order to analyze water level measurement systems, it is necessary to identify the physical layout and the plant system functions for each of the primary level sensors. It also is necessary to compile the pertinent facts regarding placement of the instrument nozzles and condensing chambers, the physical arrangement of the instrument piping and connections to the instruments themselves, and the plant system safety and control functions that are influenced by the instruments.

The purpose of this section is to provide the pertinent information of the level measurement system for Shoreham as follows:

- Role of the water level system.
- Description of the level sensing system which includes vessel elevations that correspond to the trip settings and other key levels, system physical separation, and plant systems assigned to each level transmitter.
- Pertinent instrument line routing information.
- Description of the displays available to the operator.

Table 3-1

Pertinent Plant Design Parameters

NSSS Supplier	General Electric
A/E	Stone & Webster
Turbine Supplier	General Electric
Reactor Type	BWR-4/220-inch Vessel I.D.
Plant Thermal Rating	2436 Megawatt Thermal (MWt)
Gross Electrical Power	849 Megawatt Electrical (MWe)
Steam Flow at Rated	10.47 Million lb/hr
Bypass Capacity	25 percent
Number of Fuel Assemblies	560
Active Fuel Length	150 inches
Average Fuel Heat Generation Rate	5.39 Kw/ft
Core Flow Rate	77.0 Million lb/hr
Jet Pump M Ratio	1.18
Jet Pump Exit Velocity	14.4 ft/sec
Rated Jet Pump Head	91.7 feet
Instrumentation Type	Rosemount Transmitters with Bailey 7000 Alarm/Trip units
Feedwater Temperature	420°F
Number of SRV's	11
SRV Manufacturer	Target Rock
Feedpump Drive Type	Turbine
Rated Separator/Dryer Pressure Drop	12 psid
Dynamic Head at Level 1 at Rated Conditions	18 inches of water

3.1 SAFETY AND CONTROL ROLE OF SHOREHAM WATER LEVEL SYSTEM

The plant systems that require signals from the output of the level instruments are the reactor protection system, the high pressure coolant injection systems, the isolation systems, the low pressure coolant injection systems (including the automatic depressurization system), the feedwater control system, the Anticipated Transient Without Scram (ATWS) features, plus equipment protection trips for the recirculation flow and main turbine control systems. The signals these systems receive are based upon the function of the system and its relationship to reactor vessel water level. Figure 3-1 shows the vessel levels and their relationship to the reactor core and other vessel internals, along with the Shoreham elevations that correspond to each of the levels.

Briefly, the significance of the various water level designations are:

Level 8 - High Water Level Trip

1. Main Turbine Trip - Protects turbine against the occurrence of gross carryover of moisture.

2. Trip of Reactor Feedwater Pumps - Prevents reactor vessel overfill and protects feedwater turbine against gross moisture carryover.

3. Trip of Reactor Core Isolation Cooling (RCIC) and High Pressure Coolant Injection (HPCI) turbines - Prevents vessel overfill.

Level 7 - High Water Level Alarm

Annunciates the level above which the moisture carryover in the steam is expected to increase at a significant rate while operating at full load.

Level 5 - Automatic Level Control Range

Water level is maintained within this range in order to minimize moisture carryover and steam carryunder over the normal reactor steam flow range during transient level disturbance conditions. The water level usually is kept at any level above Level 4 and below Level 7.

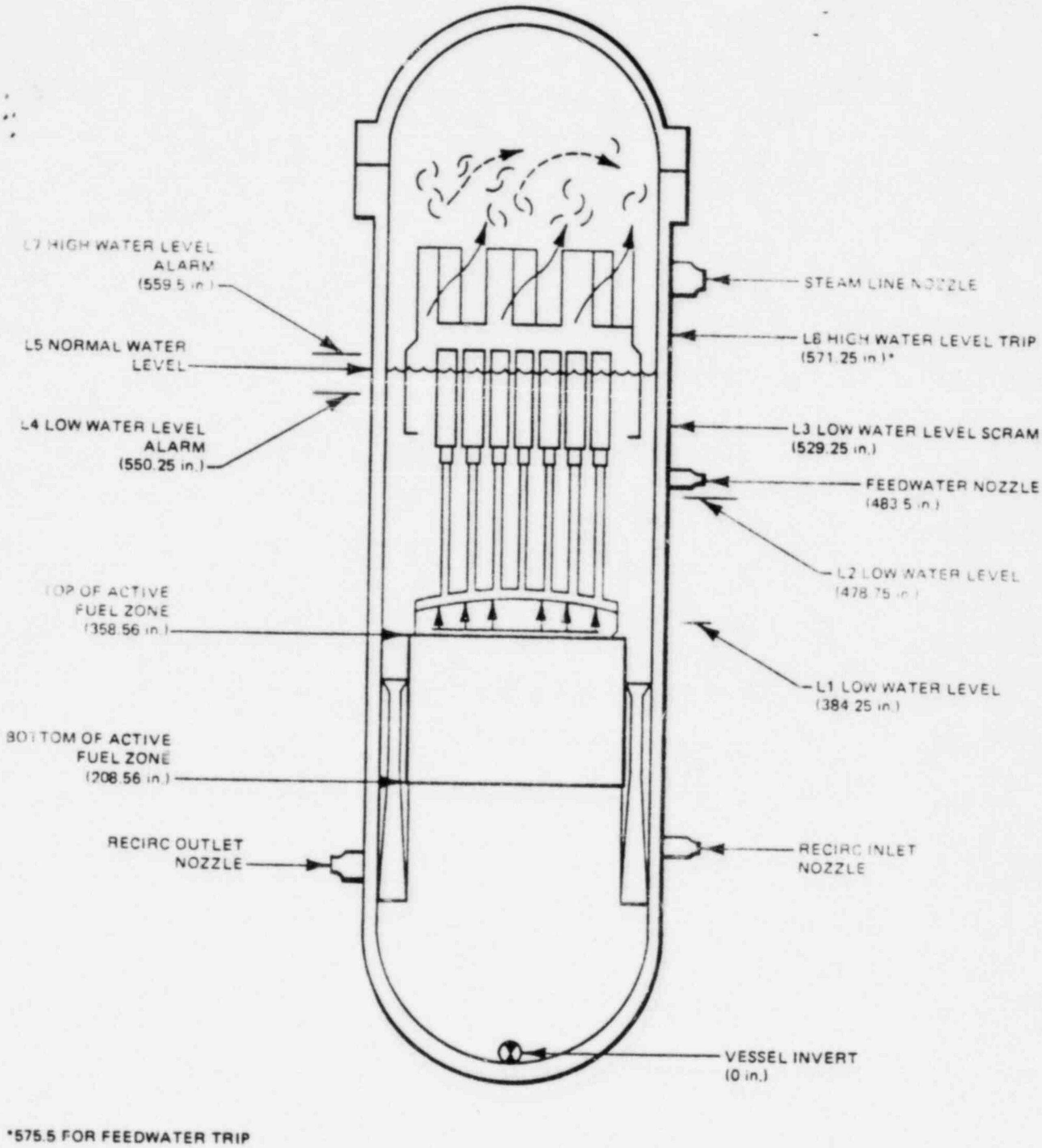


Figure 3-1: Relative Reactor Vessel Water Level

Level 4 - Low Water Level Alarm

Annunciates the level below which the steam carryunder in the water is likely to begin affecting the recirculation flow rate significantly under full load conditions, or below which the reduction of vessel inventory following a loss of one feedwater pump would cause reactor scram.

Level 3 - Scram and Recirculation Flow Runback

1. This level is above the bottom of the dryer seal skirt. The quantity of inventory below this level is sufficient to allow for evaporation losses and displacements of coolant from the reactor system following interruption of reactor feedwater flow without the vessel level dropping to Level 1. This quantity of inventory accounts for steam voids contained below Level 3 while operating at full reactor power and is based on the Reactor Core Isolation Cooling system operating as designed.

2. When the recirculation flow is run back, the error on the wide range water level instrumentation due to the annulus flow is reduced, thereby reducing premature water level trips on decreasing water level for normal large-scale transients.

Level 2 - Initiate HPCI, RCIC, and Main Steam Isolation Valve (MSIV) Closure

Considerations involved in determining this level's set points are as follows:

1. The volume between Level 2 and Level 3 corresponds to the partial core void collapse caused by a low level scram from full power.

2. The set point is low enough so that the RCIC and HPCI will not be falsely initiated after a scram due to vessel water level, providing feedwater flow is available.

3. The set point is high enough so that for complete loss of feedwater flow, the RCIC system flow will be sufficient to prevent initiation of systems at Level 1.

Level 1 -

This level is set to assure timely ECCS system initiation in order to maintain core cooling above prescribed limits in the event of the design basis LOCA.

3.2 DESCRIPTION OF LEVEL MEASUREMENT SYSTEM

The Shoreham water level measurement system uses an unheated ("cold") reference leg connected to the reactor vessel steam space via a condensing chamber and a variable leg connected to the reactor vessel at an elevation below the water level. The water level in the reactor vessel is then determined by measuring the differential pressure between the reference leg and variable leg through appropriate instrumentation. In a cold reference leg system the fluid temperature in the instrument line is not affected by process conditions but is determined by the ambient temperature. The fluid temperature in the variable leg will also be determined by the ambient temperature.

The Shoreham water level system uses five different instrument ranges as shown in Figure 3-2. The vessel levels covered by each of the instruments are related to key vessel levels and vessel internals features shown in Table 3-2. There are several instruments connected to the appropriate vessel taps in each of the five ranges as shown in Figure 3-3. The level instruments shown in Figure 3-3 are used by the various systems via the Analog Trip System (ATS). In the ATS, the outputs of the level transmitters are sent to a trip unit which compares the sensor output to a set point. When the level output from the transmitter moves across the set point, the output of the trip unit changes state and causes the desired action to occur. The use of ATS allows the trip set points to be set at a control room panel so no access to the instruments is required for set point adjustments.

The system assignment of level instruments to the various systems is shown in Table 3-3. There are various stages of logic between the sensors shown in Table 3-3 and the system functions they initiate, as described in Appendix A. The important information from Table 3-3 is the sharing of instruments between systems. Table 3-3 shows that sensors N091A, B, C, & D are used in the following systems:

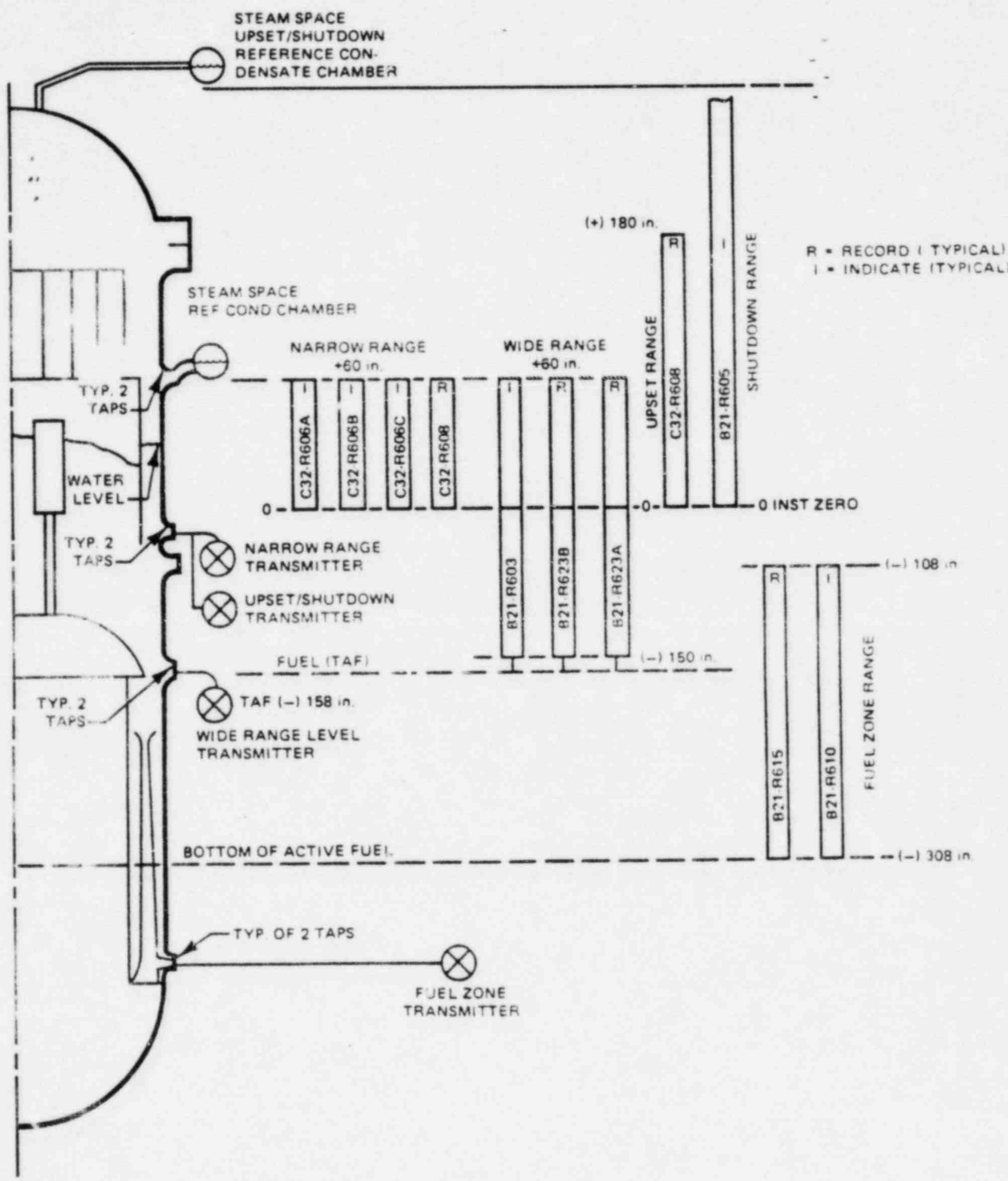


Figure 3-2: Level Instrument Ranges

Table 3-2

Shoreham
Vessel Level Trip Elevation Correlation

Reference	Description	TAF (1)	Instr. Zero (3)	Vessel Zero
		Inches Above:		
Tap "a" nozzle	Steam tap for condensing chambers	227.69	69.5	586.25
	Narrow and wide range upscale	218.19	60	576.75
Level 8	RCIC, HPCI Turbine Steam Inlet valve closure. Close main turbine stop valves. Trip feed pumps.	212.69	54.5(4)	571.25
Level 7	Feedwater control high level alarm.	200.94	42.75	559.5
Level 4	Feedwater control low level alarm.	191.69	33.5	550.25
Level 3	Scram and close RHR shutdown cooling isolation valves. ADS level permissive.	170.69	12.5	529.25
Instr. zero	For wide, narrow, shutdown/upset range Inst. Narrow range and shutdown range downscale.	158.19	0	516.75
Tap "b" nozzle	Narrow range tap (variable leg)	150.44	-7.75	509.0
	Feedwater sparger	124.94	-33.25	483.5
Level 2	Initiate RCIC and HPCI. Start Div. 3 diesel. Close primary system isolation valves (except RHR shutdown isolation valves). Trip recirc. pumps. Close MSIV's.	120.19	-38	478.75
	Fuel Zones upscale	50	-108.19	408.56
Level 1	Initiate LPCS and RHR. Start Div. 1 and Div. 2 standby diesels. Contribute to ADS,	25.69	-132.5	384.25
	Wide Range downscale	8.19	-150	366.75
TAF	Top of active fuel Fuel Zone Inst. Zero	0	-158.19	358.56
Tap "c"	Wide range tap (variable leg)	-0.56	-158.75	358
BAF	Bottom of Active Fuel Fuel zone downscale	-150	-308.19	208.56
Tap "d"	Fuel Zone variable leg	-226.56	-384.75	132

Notes:

(1) Top of active fuel, approximate.

(2) Vessel zero, cold (approximate).

(3) Level instrument zero.

(4) 58.75 for feedwater trip.

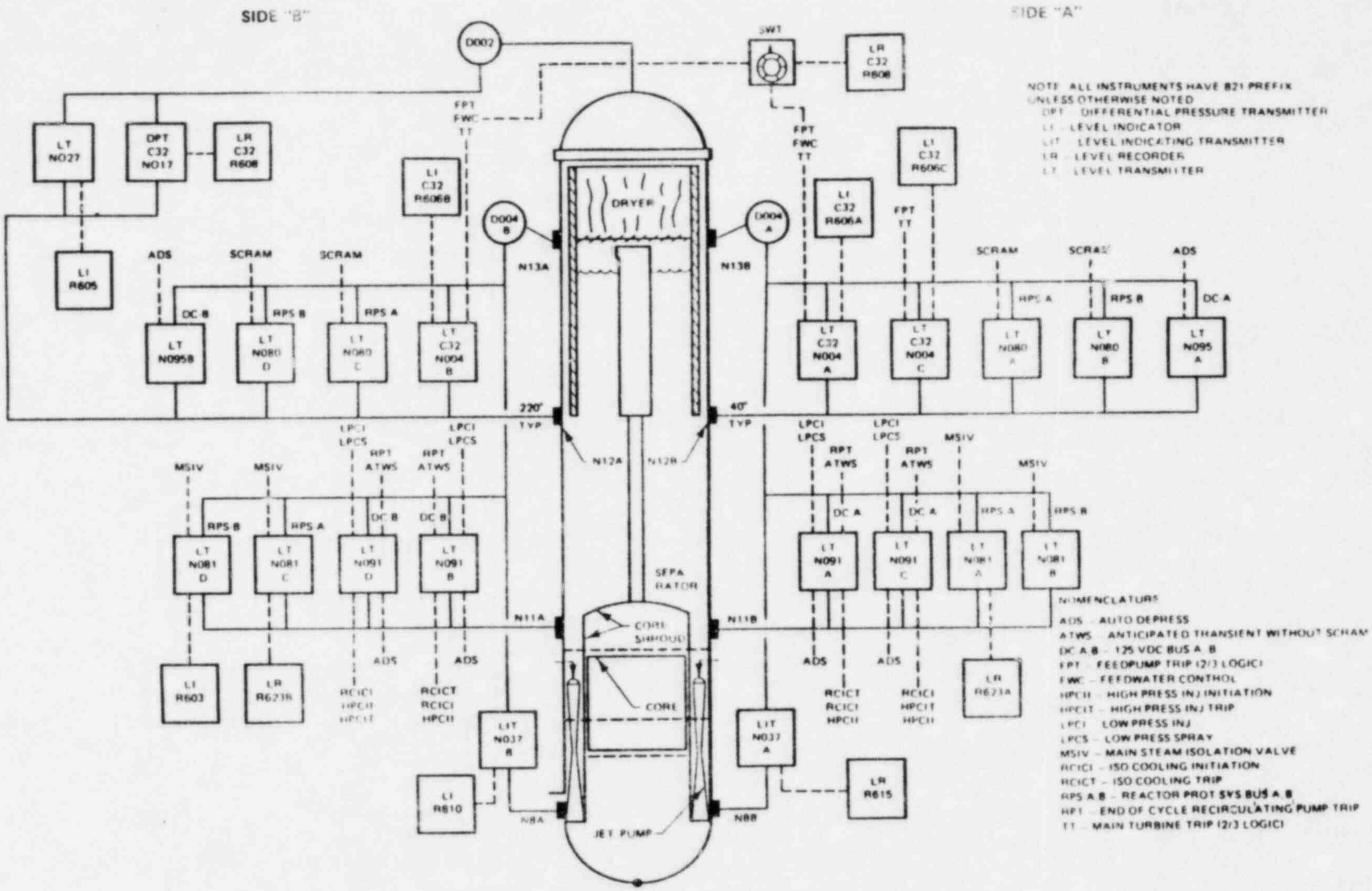


Figure 3-3: Reactor Vessel Level Instrumentation Orientation

Table 3-3

Level Instrument Assignments

Function	Side A Instrument	Side A Power	Side B Instrument	Side B Power
Scram & RHR ISO	LT B21-N080A(L3) LT B21-N080B(L3)	RPS A RPS B	LT B21-N080C(L3) LT B21-N080D(L3)	RPS A RPS B
HPCI Trip	LT B21-N091C(L8)	DC-A	LT B21-N091D(L8)	DC-B
HPCI Initiate	LIS B21-N091A(L2) LIS B21-N091C(L2)	DC-A DC-A	LT B21-N091B(L2) LT B21-N091D(L2)	DC-B DC-B
RCIC Trip	LT B21-N091A(L8)	DC-A	LT B21-N091D(L8)	DC-B
RCIC Initiate	LT B21-N091A(L2) LT B21-N091C(L2)	DC-A DC-A	LT B21-N091B(L2) LT B21-N091D(L2)	DC-B DC-B
MSIV	LT-B21-N081A(L2) LT-B21-N081B(L2)	RPS A RPS B	LT-B21-N081C(L2) LT-B21-N081D(L2)	RPS A RPS B
ATWS RPT	LT B21-N091A(L2) LT B21-N091C(L2)	DC-A DC-A	LT B21-N091B(L2) LT B21-N091D(L2)	DC-B DC-B
ATWS ARI	LT B21-N091A(L2) LT B21-N091C(L2)	DC-A DC-A	LT B21-N091B(L2) LT B21-N091D(L2)	DC-B DC-B
LPCI LPCS	LT B21-N091A(L1) LT B21-N091C(L1)	DC-A DC-A	LT B21-N091B(L1) LT B21-N091D(L1)	DC-B DC-B
ADS	LT B21-N095A(L3) LT B21-N091A(L1) LT B21-N091C(L1)	DC-A DC-A DC-A	LT B21-N095B(L3) LT B21-N091B(L1) LT B21-N091D(L1)	DC-B DC-B DC-B
Feed and Main TT	LT C32-N004A(L8) LT C32-N004C(L8)	Vital AC INST A	LT C32-N004B(L8)	INST B
Narrow Range Display*	LT C32-N004A(IND) LT C32-N004C(IND) LT C32-N004A(REC)+	Vital AC INST A Vital AC	LT C32-N004B(IND) LT C32-N004B(REC)+	INST B INST B
WR Display*	LT B21-N081A(REC)	RPS-A	LT B21-N081C(REC) LT B21-N081D(IND)	RPSB RPSB
Shutdown			LT B21-N027(IND)	INST A
Upset			LT C32-N017(REC)	INST A
Fuel Zone	LT B21-N037A(REC)	INST A	LT B21-N037B(IND)	INST B

* REC = Recorder; IND = Indicator.

\+ Recorder switched between sensors.

- LPCS - Low Pressure Core Spray
- LPCI - Low Pressure Coolant Injection
- HPCI - High Pressure Coolant Injection
- RCIC - Reactor Core Isolation Cooling
- ATWS - Anticipated Transient Without Scram
- ADS - Automatic Depressurization System

3.3 INSTRUMENT LINE ROUTING

The routing of the instrument lines from the vessel tap to the level sensors is required to determine the effect of changes in the fluid density in the lines on sensed level. For conditions where flashing does not occur, the error is proportional to the difference between the reference and variable leg drops. At a particular set of conditions the error due to reference line flashing will depend on the instrument line routing. For example, routing with a vertical drop followed by a long horizontal run will give a different error characteristic than a routing which has a long horizontal run followed by a vertical drop. A schematic of the Shoreham reference leg routing is shown in Figure 3-4. Tables 3-4 and 3-5 list the total lengths and vertical drops for each of the runs shown in Figure 3-4. The required routing information for establishing errors due to fluid density changes when flashing has not occurred are shown in Figure 3-5. The dimensions for various instrument ranges are shown in Table 3-6.

3.4 OPERATOR DISPLAYS

The various level displays available to the operator are located on the reactor control benchboard, reactor core cooling benchboard, and reactor water clean-up benchboard. The locations of these panels on the main control console are as shown in Figure 3-6. The displays on each of these panels are also listed on the figure.

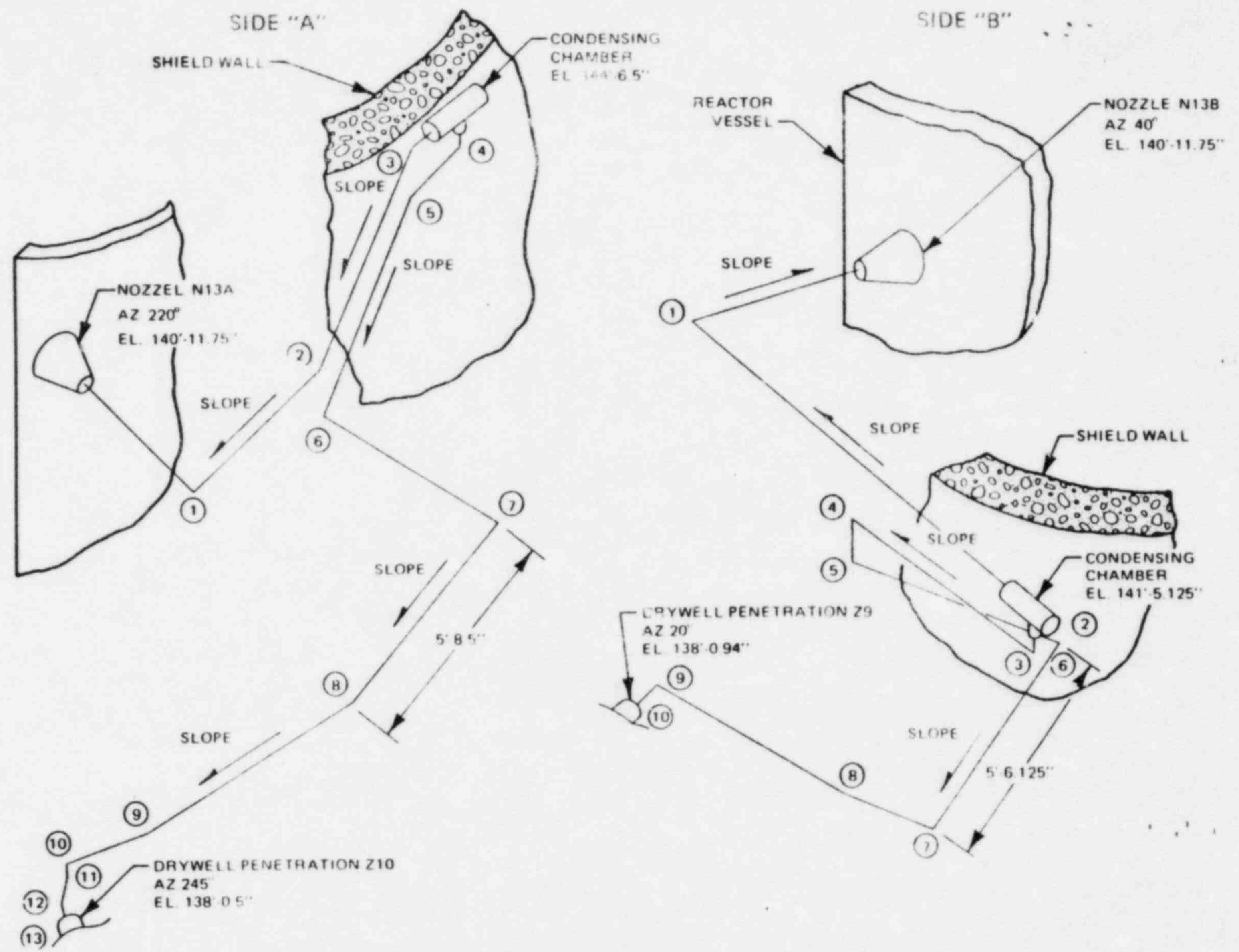


Figure 3-4: Water Level Reference Line Pictorial

Table 3-4

Reference Leg Side "A" Lengths

Point	Elevation	Vert. Drop From Prev. El	Accum. Vert. Drop	True Length From Prev. Pt.	Accum. True Length	AZ
N13A	140'-11.75"	—	—	—	—	220°
1	141'-0.25"	-0.5"	-0.5"	3'-7"	3'-7"	—
2	144'-6.0"	-3'-5.75"	-3'-6.25"	9'-7"	13'-2"	—
3 Cond. Pot (1)	144'-6.5"	-0.5"	-3'-6.75"	1'-2"	14'-4"	—
4	143'-8.5"	10"	10"	10"	10"	—
5	143'-7.5625"	.9375"	10.9375"	1'-1.25"	1'-11.25	—
6	141'-0.375"	2'-7.1875"	3'-6.125"	5'-3.375"	7'-2.625"	—
7	140'-6.625"	5.75"	3'-11.875"	5'-0.25"	12'-2.875"	—
8	140'-4.25"	2.375"	4'-2.25"	5'-8.5"	17'-11.375"	—
9	140'-1.9375"	2.3125"	4'-4.5625"	5'-6.875"	23'-6.25"	—
10	140'-0.75"	1.1875"	4'-5.75"	2'-11"	26'-5.25"	—
11	139'-3.375"	9.375"	5'-3.125"	9.625"	27'-2.875"	—
12	138'-0.6875"	1'-2.6875"	6'-5.8125"	1'-2.75"	28'-5.625"	—
13 Drywell Pent	138'-0.50"	0.1875"	6'-6"	3.625"	28'-9.25"	245°

Note (1): The condensing chamber is considered "zero" for purposes of determining the vertical drop and true length of pipe from the condensing chamber to the drywell penetration.

Table 3-5

Reference Leg Side "B" Lengths

Point	Elevation	Vert. Drop From Prev. El	Accum. Vert. Drop	True Length From Prev. Pt.	Accum. True Length	AZ
N13B	140'-11.75"	—	—	—	—	40°
1	141'-0.25"	-0.5"	-0.5"	3'-7"	3'-7"	—
2 Cond Pot (1)	141'-5.125"	-4.875"	-5.375"	10'-6.0625"	14'-1.0625"	—
3	140'-5"	1'-0.125	1'-0.125"	1'-0.125"	1'-0.125"	—
4	140'-4.25"	0.75"	1'-0.875"	5'-6"	6'-6.125"	—
5	139'-6.375"	9.875"	1'-10.75"	9.875"	7'-4"	—
6	139'-5.875"	0.625"	1'-11.375"	5'-0.5"	12'-4.5"	—
7	138'-2.5"	1'-3.25"	3'-2.625"	5'-6.125"	17'-10.625"	—
8	138'-2.1875"	0.3125"	3'-2.9375"	1'-10.875"	19'-9.5"	—
9	138'-1.5625"	0.625"	3'-3.5625"	5'-2.5"	25'-0"	—
10 Drywell Pent	138'-0.9375"	0.625"	3'-4.1875"	4.3125"	25'-4.3125"	20°

Note (1): The condensing chamber is considered "zero" for purposes of determining the vertical drop and true length of pipe from the condensing chamber to the drywell penetration.

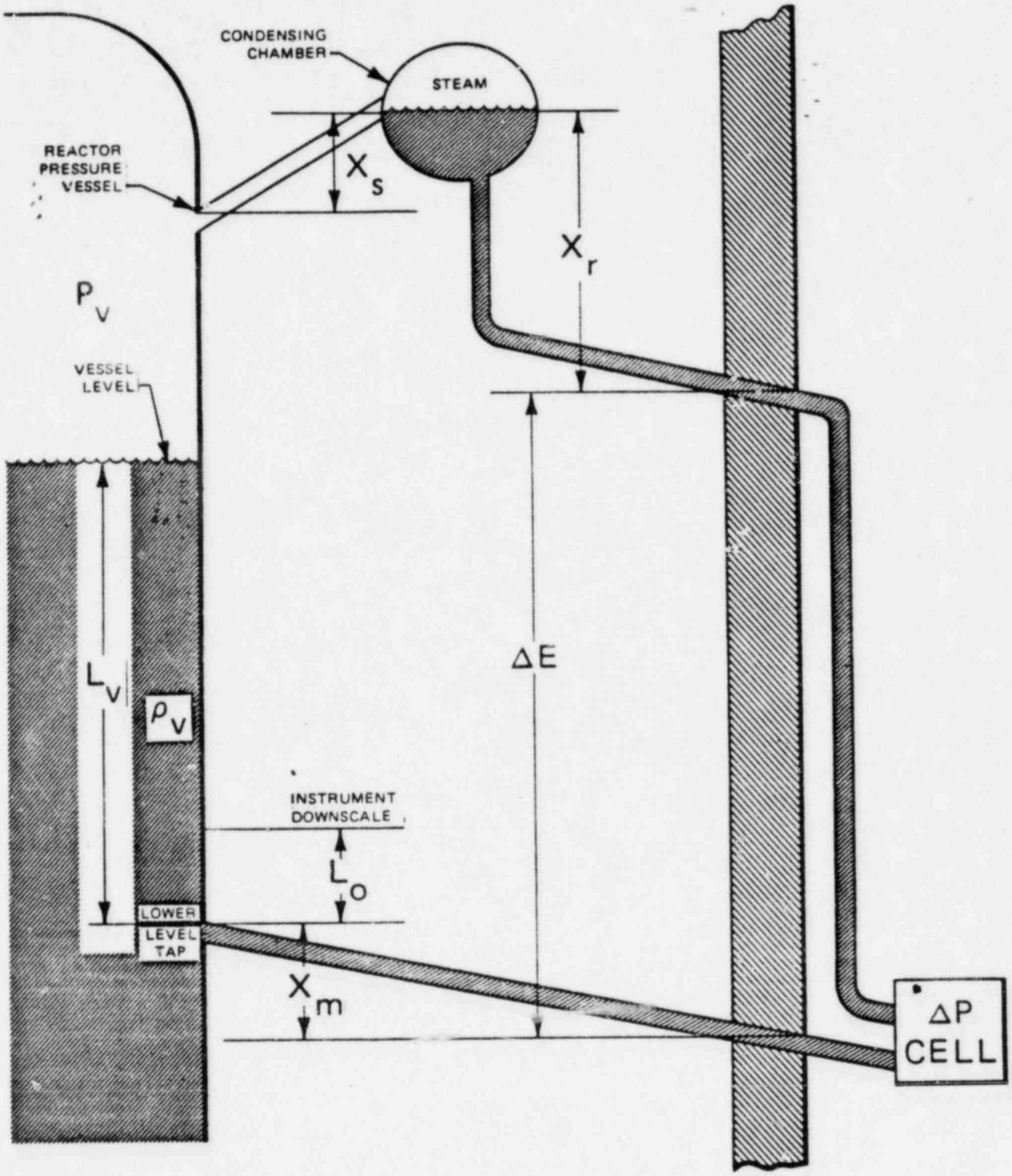
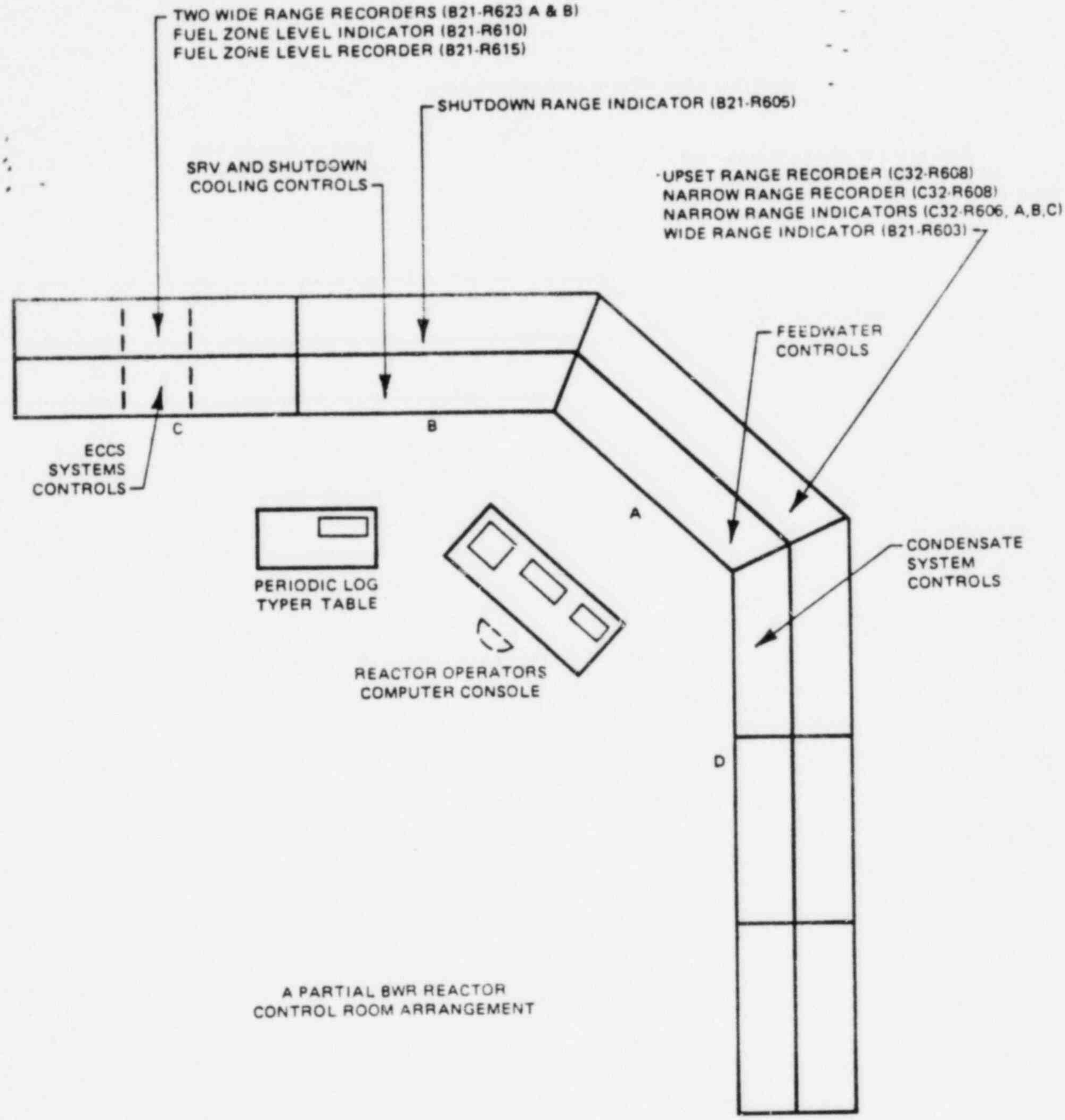


Figure 3-5: Level Instrument Elevations

Table 3-6

Instrument Line Drops

Parameter	Side A Dimensions--Inches			Side B Dimensions--Inches		
	Narrow Range	Wide Range	Fuel Zone	Narrow Range	Wide Range	Fuel Zone
X_s	42.75	42.75	42.75	5.38	5.38	5.38
X_r	78.0	78.0	78.0	40.2	40.2	40.2
ΔE	77.25	228.25	581.75	77.25	228.25	581.75
X_m	36	36	163.5	36	36	163.5
$X_r - X_m$	42	42	-85.5	4.2	4.2	-123.3
L_o	7.75	8.75	76.6	7.75	8.75	76.6



A	1H11-P603	REACTOR CONTROL BENCHBOARD (BB)
B	1H11-P602	REACTOR WATER CLEANUP AND RECIRC BB
C	1H11-P601	REACTOR CORE COOLING BB
D	1H11-MCB-01	BALANCE OF PLANT (BOP) PANELS

Figure 3-6: Reactor Water Level Indications in Control Room

In addition to the recorders and indicators shown on Figure 3-6, there are various indicators and annunciators that are activated on level signals as follows:

- High Level Trip Indicators. These consist of three amber lamps mounted on the feedwater panel. Each lamp is driven by one of the three level transmitters in the feedwater system (LT C32-N004,A,B,C) and will illuminate when the transmitter indicates that level is above level 8.

- High/Low Level Annunciator. This annunciator is driven from the level transmitter that is selected for feedwater control. The annunciator will sound when indicated level from the transmitter is above level 7 or below level 4.

- Level 2 Indicators/Annunciators. When any one of the ECCS transmitters (LT B21-N091A,B,C,D) reaches level 2, an annunciator will sound. The "System A low level" annunciator will sound if either N091A or C indicates below level 2. The "System B low level" annunciator will sound if either N091 or D indicates low level. In addition, there are four white indicator lamps that will illuminate to show which transmitters indicate below level 2.

- Level 1 Indicators/Annunciators. The level 1 annunciator/indicators are identical to the level 2.

- Level 8 Indicators. A white indicator light is associated with each HPCI high level trip transmitter (LT B21-N091C,D). The indicator will illuminate when its corresponding transmitter indicates level is above level 8.

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Section 1

SUMMARY

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- An evaluation of the performance of the Shoreham water level measurement system. An evaluation of the measurement errors due to variations in plant conditions, including conditions which cause a loss of fluid in the reference leg, is provided. Also, an evaluation of the relationship between water level and the state of the core is provided, including the ability of the Shoreham water level system to determine the state of the core.
- An in-depth failure analysis of the Shoreham level system, including a thorough review of drawings and logic diagrams to determine the vulnerability of the plant to postulated single failures in the level instrumentation.
- A qualitative analysis of the Shoreham specific response to plant transients and accidents for various failures of the water level system.

- A probabilistic assessment of the risks contributed by failures of the water level system as they impact the plant operators and the automatic initiation of safety systems. This water level probabilistic risk is compared to overall Shoreham plant risks to put into perspective any need to modify or improve the Shoreham water level system.

- A concluding section which summarizes the key findings.

Section 3

SHOREHAM WATER LEVEL SYSTEM

This section provides a detailed description of the Shoreham water level measurement system. The information provides the basis for the water level system failure and probabilistic analyses given in subsequent sections. Shoreham is an 846 Megawatt electrical (MW_e) BWR. It is one of the BWR-4 class of plants and utilizes a Mark II pressure suppression type containment. The nuclear Steam Supply System (NSSS) is being provided by General Electric (GE). The balance of the plant is the responsibility of Stone and Webster (S&W). The key parameters of the Shoreham plant are given in Table 3-1.

In order to analyze water level measurement systems, it is necessary to identify the physical layout and the plant system functions for each of the primary level sensors. It also is necessary to compile the pertinent facts regarding placement of the instrument nozzles and condensing chambers, the physical arrangement of the instrument piping and connections to the instruments themselves, and the plant system safety and control functions that are influenced by the instruments.

The purpose of this section is to provide the pertinent information of the level measurement system for Shoreham as follows:

- Role of the water level system.
- Description of the level sensing system which includes vessel elevations that correspond to the trip settings and other key levels, system physical separation, and plant systems assigned to each level transmitter.
- Pertinent instrument line routing information.
- Description of the displays available to the operator.

Table 3-1

Pertinent Plant Design Parameters

NSSS Supplier	General Electric
A/E	Stone & Webster
Turbine Supplier	General Electric
Reactor Type	BWR-4/220-inch Vessel I.D.
Plant Thermal Rating	2436 Megawatt Thermal (MWt)
Gross Electrical Power	849 Megawatt Electrical (MWe)
Steam Flow at Rated	10.47 Million lb/hr
Bypass Capacity	25 percent
Number of Fuel Assemblies	560
Active Fuel Length	150 inches
Average Fuel Heat Generation Rate	5.39 Kw/ft
Core Flow Rate	77.0 Million lb/hr
Jet Pump M Ratio	1.18
Jet Pump Exit Velocity	14.4 ft/sec
Rated Jet Pump Head	91.7 feet
Instrumentation Type	Rosemount Transmitters with Bailey 7000 Alarm/Trip units
Feedwater Temperature	420°F
Number of SRV's	11
SRV Manufacturer	Target Rock
Feedpump Drive Type	Turbine
Rated Separator/Dryer Pressure Drop	12 psid
Dynamic Head at Level 1 at Rated Conditions	18 inches of water

3.1 SAFETY AND CONTROL ROLE OF SHOREHAM WATER LEVEL SYSTEM

The plant systems that require signals from the output of the level instruments are the reactor protection system, the high pressure coolant injection systems, the isolation systems, the low pressure coolant injection systems (including the automatic depressurization system), the feedwater control system, the Anticipated Transient Without Scram (ATWS) features, plus equipment protection trips for the recirculation flow and main turbine control systems. The signals these systems receive are based upon the function of the system and its relationship to reactor vessel water level. Figure 3-1 shows the vessel levels and their relationship to the reactor core and other vessel internals, along with the Shoreham elevations that correspond to each of the levels.

Briefly, the significance of the various water level designations are:

Level 8 - High Water Level Trip

1. Main Turbine Trip - Protects turbine against the occurrence of gross carryover of moisture.

2. Trip of Reactor Feedwater Pumps - Prevents reactor vessel overfill and protects feedwater turbine against gross moisture carryover.

3. Trip of Reactor Core Isolation Cooling (RCIC) and High Pressure Coolant Injection (HPCI) turbines - Prevents vessel overfill.

Level 7 - High Water Level Alarm

Annunciates the level above which the moisture carryover in the steam is expected to increase at a significant rate while operating at full load.

Level 5 - Automatic Level Control Range

Water level is maintained within this range in order to minimize moisture carryover and steam carryunder over the normal reactor steam flow range during transient level disturbance conditions. The water level usually is kept at any level above Level 4 and below Level 7.

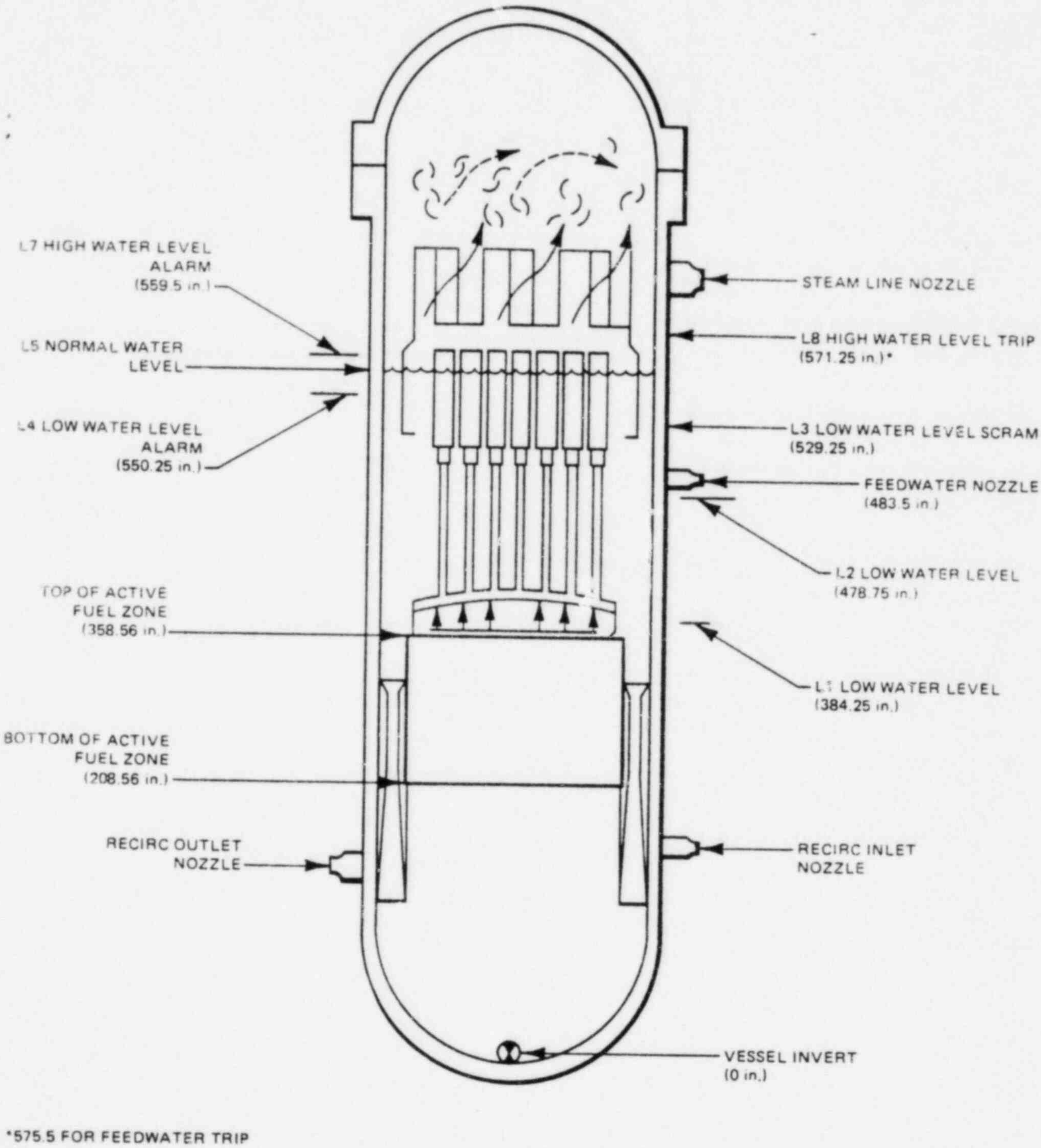


Figure 3-1: Relative Reactor Vessel Water Level

Level 4 - Low Water Level Alarm

Annunciates the level below which the steam carryunder in the water is likely to begin affecting the recirculation flow rate significantly under full load conditions, or below which the reduction of vessel inventory following a loss of one feedwater pump would cause reactor scram.

Level 3 - Scram and Recirculation Flow Runback

1. This level is above the bottom of the dryer seal skirt. The quantity of inventory below this level is sufficient to allow for evaporation losses and displacements of coolant from the reactor system following interruption of reactor feedwater flow without the vessel level dropping to Level 1. This quantity of inventory accounts for steam voids contained below Level 3 while operating at full reactor power and is based on the Reactor Core Isolation Cooling system operating as designed.

2. When the recirculation flow is run back, the error on the wide range water level instrumentation due to the annulus flow is reduced, thereby reducing premature water level trips on decreasing water level for normal large-scale transients.

Level 2 - Initiate HPCI, RCIC, and Main Steam Isolation Valve (MSIV) Closure

Considerations involved in determining this level's set points are as follows:

1. The volume between Level 2 and Level 3 corresponds to the partial core void collapse caused by a low level scram from full power.

2. The set point is low enough so that the RCIC and HPCI will not be falsely initiated after a scram due to vessel water level, providing feedwater flow is available.

3. The set point is high enough so that for complete loss of feedwater flow, the RCIC system flow will be sufficient to prevent initiation of systems at Level 1.

Level 1 -

This level is set to assure timely ECCS system initiation in order to maintain core cooling above prescribed limits in the event of the design basis LOCA.

3.2 DESCRIPTION OF LEVEL MEASUREMENT SYSTEM

The Shoreham water level measurement system uses an unheated ("cold") reference leg connected to the reactor vessel steam space via a condensing chamber and a variable leg connected to the reactor vessel at an elevation below the water level. The water level in the reactor vessel is then determined by measuring the differential pressure between the reference leg and variable leg through appropriate instrumentation. In a cold reference leg system the fluid temperature in the instrument line is not affected by process conditions but is determined by the ambient temperature. The fluid temperature in the variable leg will also be determined by the ambient temperature.

The Shoreham water level system uses five different instrument ranges as shown in Figure 3-2. The vessel levels covered by each of the instruments are related to key vessel levels and vessel internals features shown in Table 3-2. There are several instruments connected to the appropriate vessel taps in each of the five ranges as shown in Figure 3-3. The level instruments shown in Figure 3-3 are used by the various systems via the Analog Trip System (ATS). In the ATS, the outputs of the level transmitters are sent to a trip unit which compares the sensor output to a set point. When the level output from the transmitter moves across the set point, the output of the trip unit changes state and causes the desired action to occur. The use of ATS allows the trip set points to be set at a control room panel so no access to the instruments is required for set point adjustments.

The system assignment of level instruments to the various systems is shown in Table 3-3. There are various stages of logic between the sensors shown in Table 3-3 and the system functions they initiate, as described in Appendix A. The important information from Table 3-3 is the sharing of instruments between systems. Table 3-3 shows that sensors N091A, B, C, & D are used in the following systems:

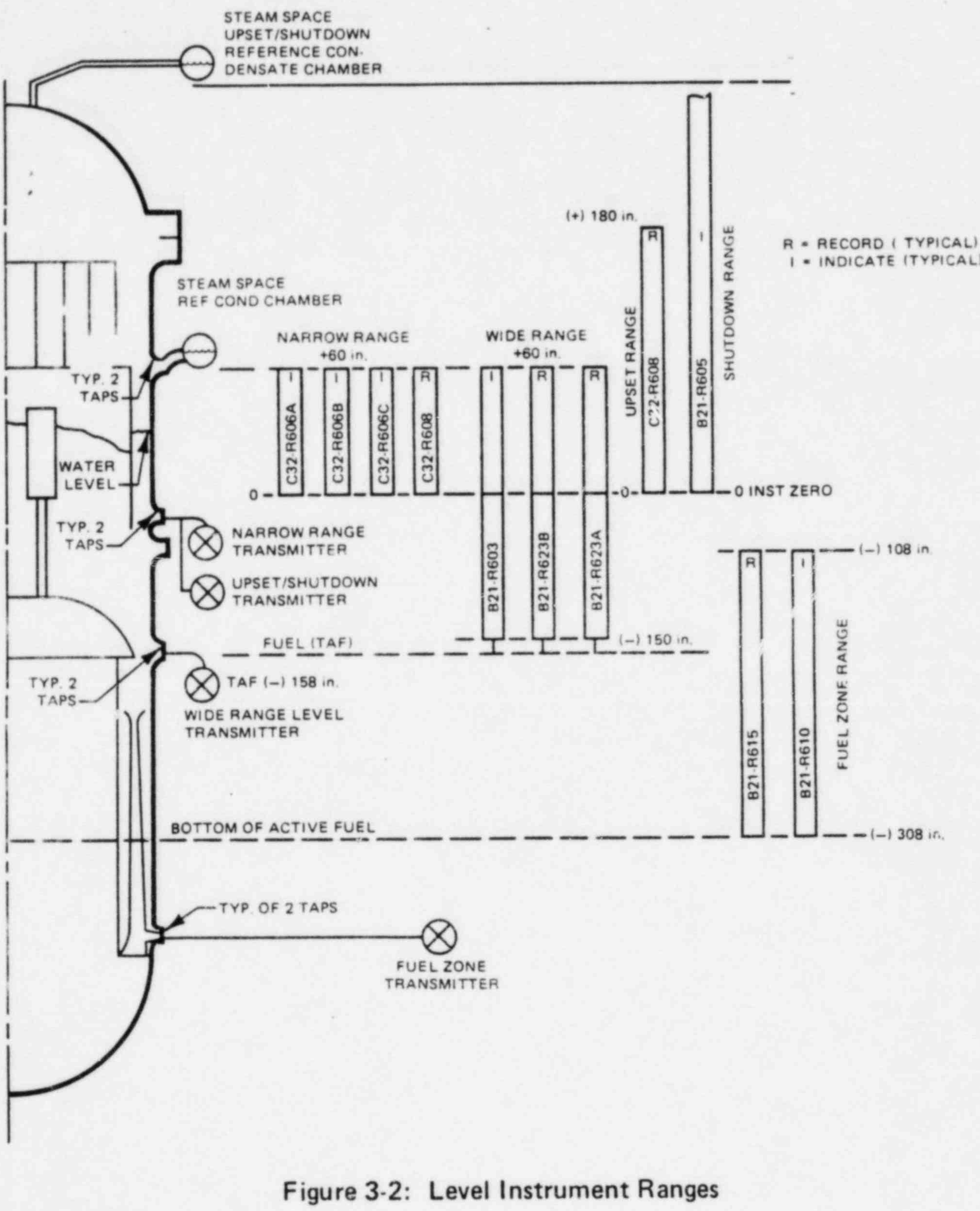


Figure 3-2: Level Instrument Ranges

Table 3-2

Shoreham
Vessel Level Trip Elevation Correlation

Reference	Description	Inches Above:		
		TAF (1)	Instr. Zero (3)	Vessel Zero
Tap "a" nozzle	Steam tap for condensing chambers	227.69	69.5	586.25
	Narrow and wide range upscale	218.19	60	576.75
Level 8	RCIC, HPCI Turbine Steam Inlet valve closure. Close main turbine stop valves. Trip feed pumps.	212.69	54.5(4)	571.25
Level 7	Feedwater control high level alarm.	200.94	42.75	559.5
Level 4	Feedwater control low level alarm.	191.69	33.5	550.25
Level 3	Scram and close RHR shutdown cooling isolation valves. ADS level permissive.	170.69	12.5	529.25
Instr. zero	For wide, narrow, shutdown/upset range Inst. Narrow range and shutdown range downscale.	158.19	0	516.75
Tap "b" nozzle	Narrow range tap (variable leg)	150.44	-7.75	509.0
	Feedwater sparger	124.94	-33.25	483.5
Level 2	Initiate RCIC and HPCI. Start Div. 3 diesel. Close primary system isolation valves (except RHR shutdown isolation valves). Trip recirc. pumps. Close MSIV's.	120.19	-38	478.75
	Fuel Zones upscale	50	-108.19	408.56
Level 1	Initiate LPCS and RHR. Start Div. 1 and Div. 2 standby diesels. Contribute to ADS,	25.69	-132.5	384.25
	Wide Range downscale	8.19	-150	366.75
TAF	Top of active fuel Fuel Zone Inst. Zero	0	-158.19	358.56
Tap "c"	Wide range tap (variable leg)	-0.56	-158.75	358
BAF	Bottom of Active Fuel Fuel zone downscale	-150	-308.19	208.56
Tap "d"	Fuel Zone variable leg	-226.56	-384.75	132

Notes:
(1) Top of active fuel, approximate.

(2) Vessel zero, cold (approximate).

(3) Level instrument zero.

(4) 58.75 for feedwater trip.

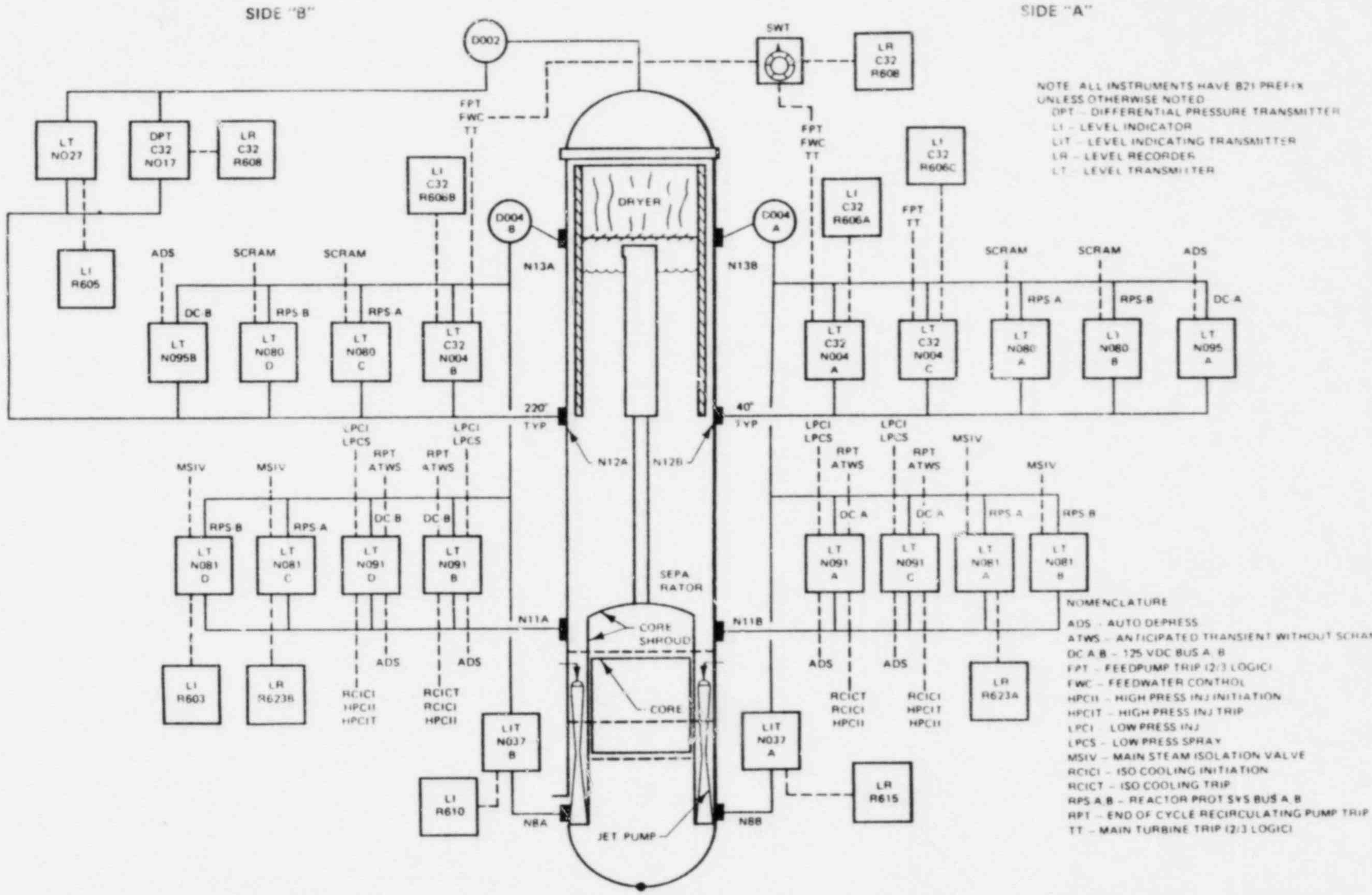


Figure 3-3: Reactor Vessel Level Instrumentation Orientation

Table 3-3

Level Instrument Assignments

Function	Side A		Side B	
	Instrument	Power	Instrument	Power
Scram & RHR ISO	LT B21-N080A(L3) LT B21-N080B(L3)	RPS A RPS B	LT B21-N080C(L3) LT B21-N080D(L3)	RPS A RPS B
HPCI Trip	LT B21-N091C(L8)	DC-A	LT B21-N091D(L8)	DC-B
HPCI Initiate	LIS B21-N091A(L2) LIS B21-N091C(L2)	DC-A DC-A	LT B21-N091B(L2) LT B21-N091D(L2)	DC-B DC-B
RCIC Trip	LT B21-N091A(L8)	DC-A	LT B21-N091D(L8)	DC-B
RCIC Initiate	LT B21-N091A(L2) LT B21-N091C(L2)	DC-A DC-A	LT B21-N091B(L2) LT B21-N091D(L2)	DC-B DC-B
MSIV	LT-B21-N081A(L2) LT-B21-N081B(L2)	RPS A RPS B	LT-B21-N081C(L2) LT-B21-N081D(L2)	RPS A RPS B
ATWS RPT	LT B21-N091A(L2) LT B21-N091C(L2)	DC-A DC-A	LT B21-N091B(L2) LT B21-N091D(L2)	DC-B DC-B
ATWS ARI	LT B21-N091A(L2) LT B21-N091C(L2)	DC-A DC-A	LT B21-N091B(L2) LT B21-N091D(L2)	DC-B DC-B
LPCI LPCS	LT B21-N091A(L1) LT B21-N091C(L1)	DC-A DC-A	LT B21-N091B(L1) LT B21-N091D(L1)	DC-B DC-B
ADS	LT B21-N095A(L3) LT B21-N091A(L1) LT B21-N091C(L1)	DC-A DC-A DC-A	LT B21-N095B(L3) LT B21-N091B(L1) LT B21-N091D(L1)	DC-B DC-B DC-B
Feed and Main TT	LT C32-N004A(L8) LT C32-N004C(L8)	Vital AC INST A	LT C32-N004B(L8)	INST B
Narrow Range Display*	LT C32-N004A(IND) LT C32-N004C(IND) LT C32-N004A(REC)+	Vital AC INST A Vital AC	LT C32-N004B(IND) LT C32-N004B(REC)+	INST B INST B
WR Display*	LT B21-N081A(REC)	RPS-A	LT B21-N081C(REC) LT B21-N081D(IND)	RPSB RPSB
Shutdown			LT B21-N027(IND)	INST A
Upset			LT C32-N017(REC)	INST A
Fuel Zone	LT B21-N037A(REC)	INST A	LT B21-N037B(IND)	INST B

* REC = Recorder; IND = Indicator.

\+ Recorder switched between sensors.

- LPCS - Low Pressure Core Spray
- LPCI - Low Pressure Coolant Injection
- HPCI - High Pressure Coolant Injection
- RCIC - Reactor Core Isolation Cooling
- ATWS - Anticipated Transient Without Scram
- ADS - Automatic Depressurization System

3.3 INSTRUMENT LINE ROUTING

The routing of the instrument lines from the vessel tap to the level sensors is required to determine the effect of changes in the fluid density in the lines on sensed level. For conditions where flashing does not occur, the error is proportional to the difference between the reference and variable leg drops. At a particular set of conditions the error due to reference line flashing will depend on the instrument line routing. For example, routing with a vertical drop followed by a long horizontal run will give a different error characteristic than a routing which has a long horizontal run followed by a vertical drop. A schematic of the Shoreham reference leg routing is shown in Figure 3-4. Tables 3-4 and 3-5 list the total lengths and vertical drops for each of the runs shown in Figure 3-4. The required routing information for establishing errors due to fluid density changes when flashing has not occurred are shown in Figure 3-5. The dimensions for various instrument ranges are shown in Table 3-6.

3.4 OPERATOR DISPLAYS

The various level displays available to the operator are located on the reactor control benchboard, reactor core cooling benchboard, and reactor water clean-up benchboard. The locations of these panels on the main control console are as shown in Figure 3-6. The displays on each of these panels are also listed on the figure.

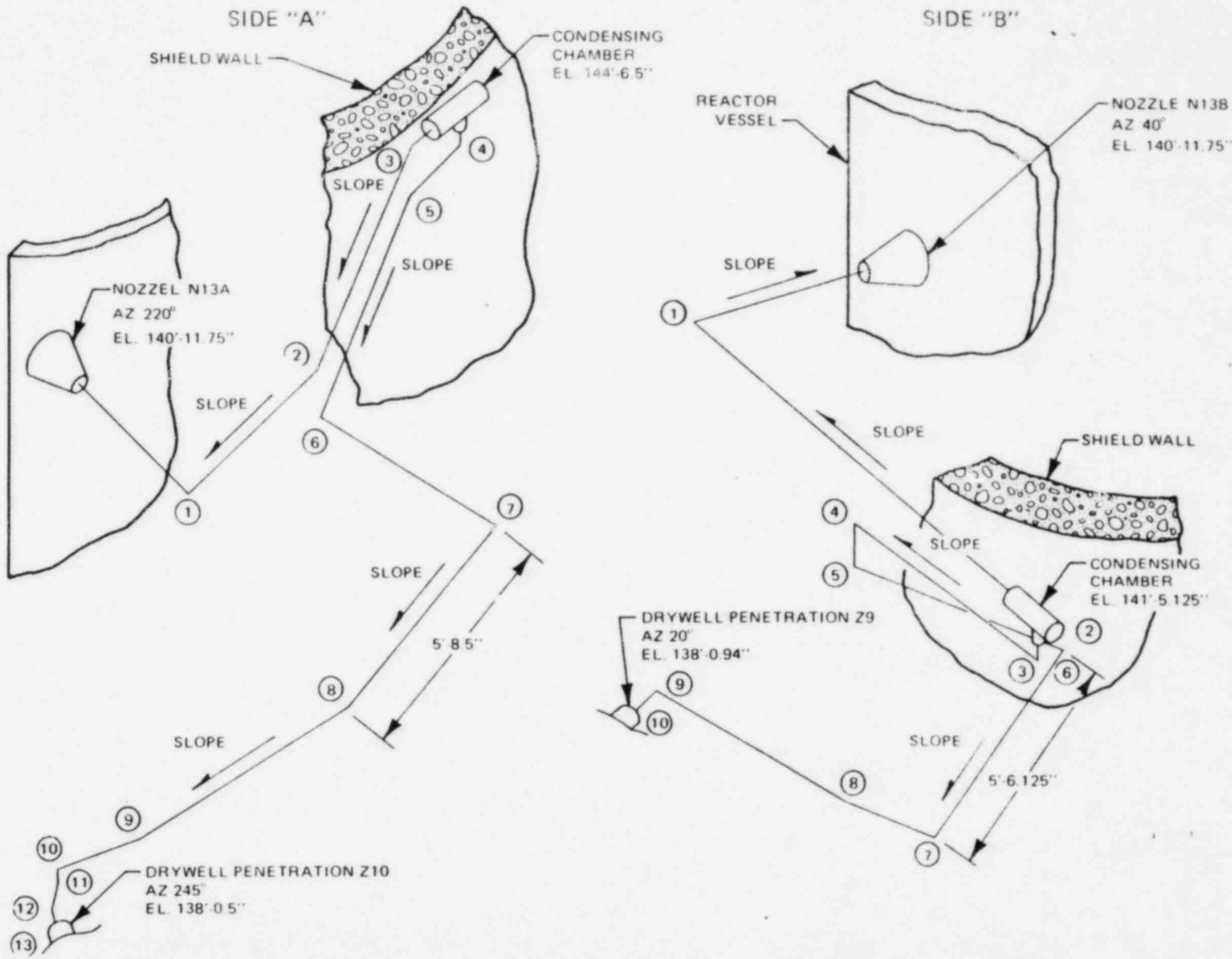


Figure 3-4: Water Level Reference Line Pictorial

Table 3-4

Reference Leg Side "A" Lengths

Point	Elevation	Vert. Drop From Prev. El	Accum. Vert. Drop	True Length From Prev. Pt.	Accum. True Length	AZ
N13A	140'-11.75"	—	—	—	—	220°
1	141'-0.25"	-0.5"	-0.5"	3'-7"	3'-7"	—
2	144'-6.0"	-3'-5.75"	-3'-6.25"	9'-7"	13'-2"	—
3 Cond. Pot (1)	144'-6.5"	-0.5"	-3'-6.75"	1'-2"	14'-4"	—
4	143'-8.5"	10"	10"	10"	10"	—
5	143'-7.5625"	.9375"	10.9375"	1'-1.25"	1'-11.25	—
6	141'-0.375"	2'-7.1875"	3'-6.125"	5'-3.375"	7'-2.625"	—
7	140'-6.625"	5.75"	3'-11.875"	5'-0.25"	12'-2.875"	—
8	140'-4.25"	2.375"	4'-2.25"	5'-8.5"	17'-11.375"	—
9	140'-1.9375"	2.3125"	4'-4.5625"	5'-6.875"	23'-6.25"	—
10	140'-0.75"	1.1875"	4'-5.75"	2'-11"	26'-5.25"	—
11	139'-3.375"	9.375"	5'-3.125"	9.625"	27'-2.875"	—
12	138'-0.6875"	1'-2.6875"	6'-5.8125"	1'-2.75"	28'-5.625"	—
13 Drywell Pent	138'-0.50"	0.1875"	6'-6"	3.625"	28'-9.25"	245°

Note (1): The condensing chamber is considered "zero" for purposes of determining the vertical drop and true length of pipe from the condensing chamber to the drywell penetration.

Table 3-5

Reference Leg Side "B" Lengths

Point	Elevation	Vert. Drop From Prev. El	Accum. Vert. Drop	True Length From Prev. Pt.	Accum. True Length	AZ
N13B	140'-11.75"	—	—	—	—	40°
1	141'-0.25"	-0.5"	-0.5"	3'-7"	3'-7"	—
2 Cond Pot (1)	141'-5.125"	-4.875"	-5.375"	10'-6.0625"	14'-1.0625"	—
3	140'-5"	1'-0.125	1'-0.125"	1'-0.125"	1'-0.125"	—
4	140'-4.25"	0.75"	1'-0.875"	5'-6"	6'-6.125"	—
5	139'-6.375"	9.875"	1'-10.75"	9.875"	7'-4"	—
6	139'-5.875"	0.625"	1'-11.375"	5'-0.5"	12'-4.5"	—
7	138'-2.5"	1'-3.25"	3'-2.625"	5'-6.125"	17'-10.625"	—
8	138'-2.1875"	0.3125"	3'-2.9375"	1'-10.875"	19'-9.5"	—
9	138'-1.5625"	0.625"	3'-3.5625"	5'-2.5"	25'-0"	—
10 Drywell Pent	138'-0.9375"	0.625"	3'-4.1875"	4.3125"	25'-4.3125"	20°

Note (1): The condensing chamber is considered "zero" for purposes of determining the vertical drop and true length of pipe from the condensing chamber to the drywell penetration.

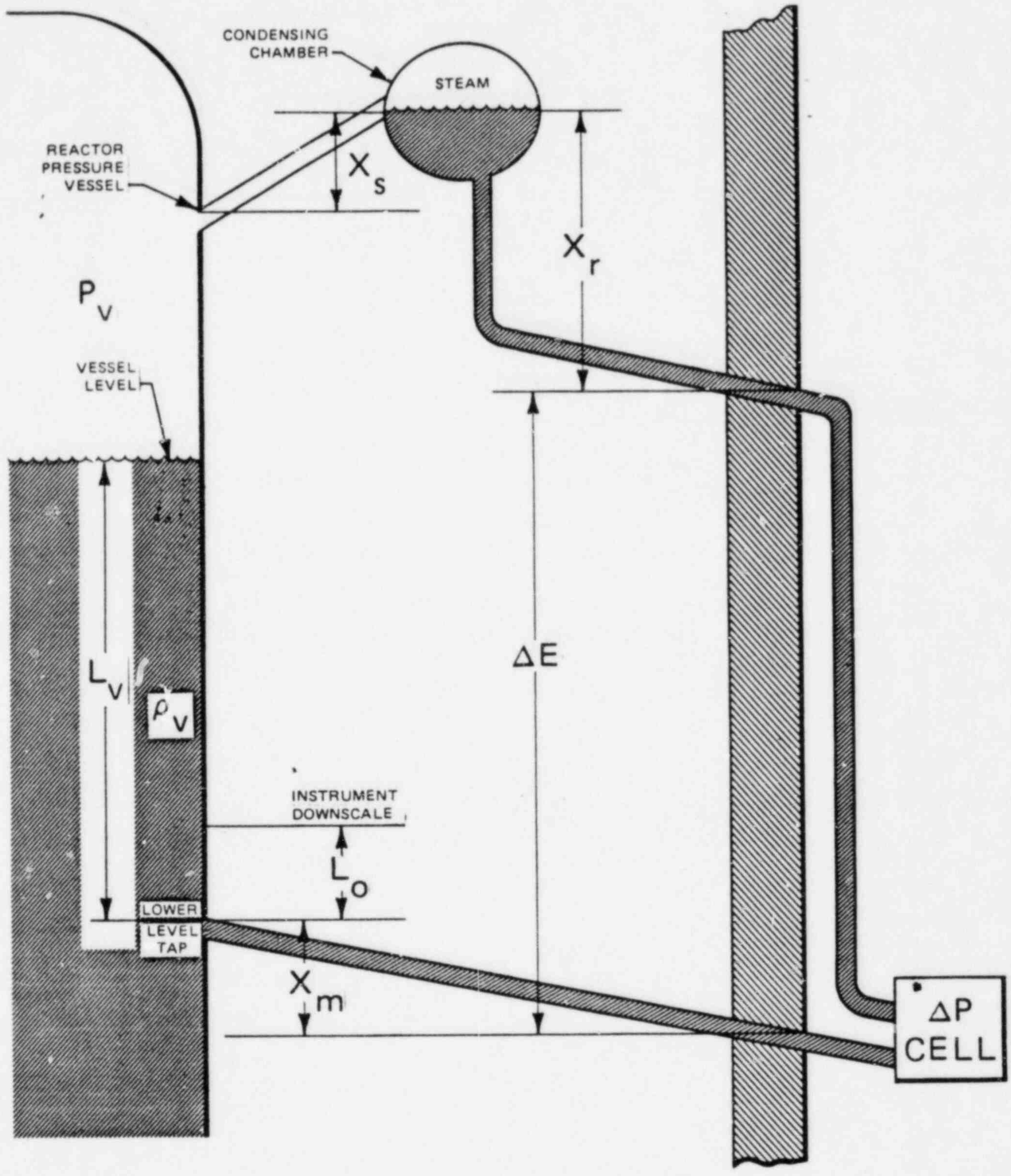
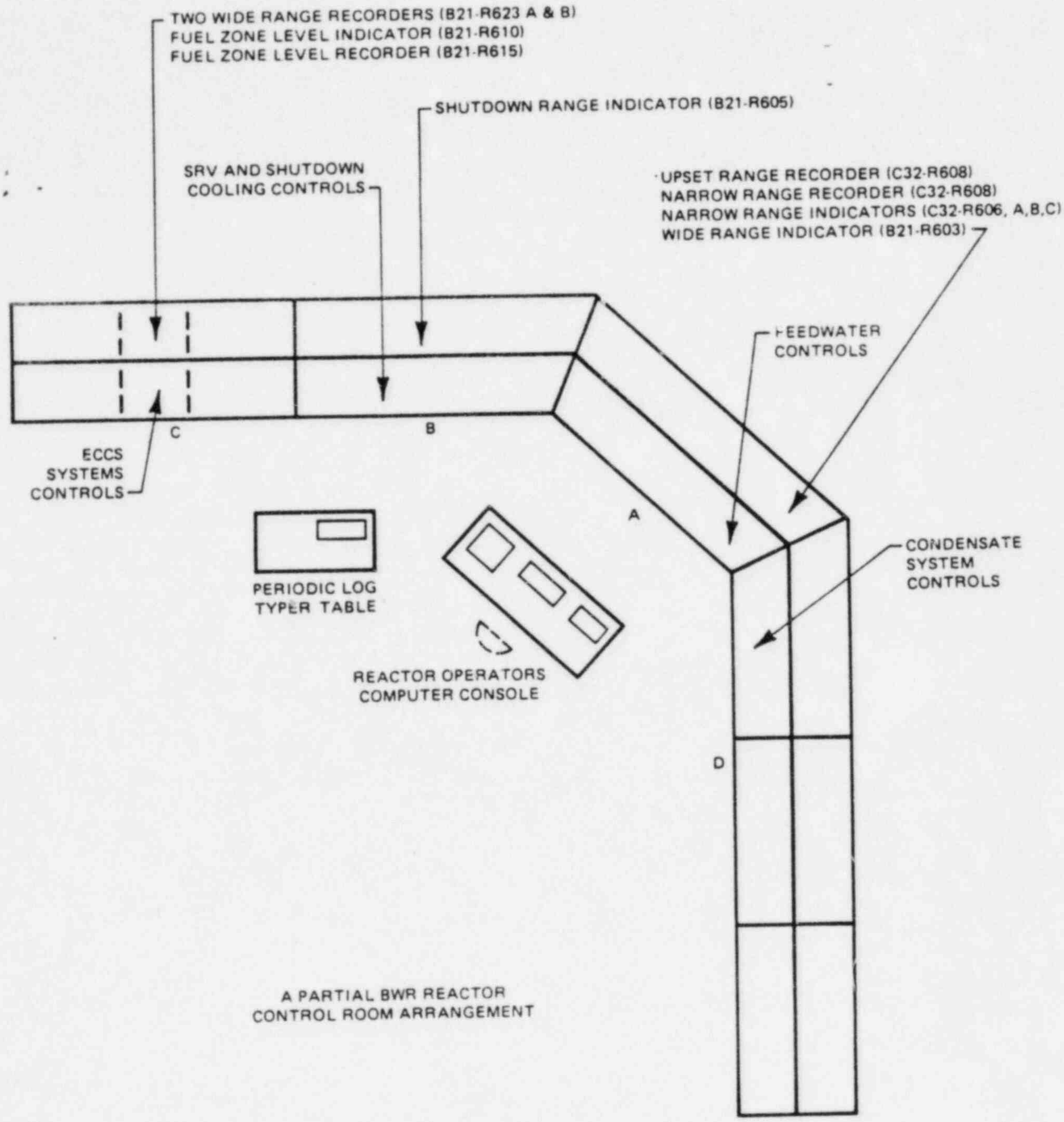


Figure 3-5: Level Instrument Elevations

Table 3-6

Instrument Line Drops

Parameter	Side A Dimensions--Inches			Side B Dimensions--Inches		
	Narrow Range	Wide Range	Fuel Zone	Narrow Range	Wide Range	Fuel Zone
X_s	42.75	42.75	42.75	5.38	5.38	5.38
X_r	78.0	78.0	78.0	40.2	40.2	40.2
ΔE	77.25	228.25	581.75	77.25	228.25	581.75
X_m	36	36	163.5	36	36	163.5
$X_r - X_m$	42	42	-85.5	4.2	4.2	-123.3
L_o	7.75	8.75	76.6	7.75	8.75	76.6



A 1H11-P603 REACTOR CONTROL BENCHBOARD (BB)
B 1H11-P602 REACTOR WATER CLEANUP AND RECIRC BB
C 1H11-P601 REACTOR CORE COOLING BB
D 1H11-MCB-01 BALANCE OF PLANT (BOP) PANELS

Figure 3-6: Reactor Water Level Indications in Control Room

In addition to the recorders and indicators shown on Figure 3-6, there are various indicators and annunciators that are activated on level signals as follows:

- High Level Trip Indicators. These consist of three amber lamps mounted on the feedwater panel. Each lamp is driven by one of the three level transmitters in the feedwater system (LT C32-N004,A,B,C) and will illuminate when the transmitter indicates that level is above level 8.

- High/Low Level Annunciator. This annunciator is driven from the level transmitter that is selected for feedwater control. The annunciator will sound when indicated level from the transmitter is above level 7 or below level 4.

- Level 2 Indicators/Annunciators. When any one of the ECCS transmitters (LT B21-N091A,B,C,D) reaches level 2, an annunciator will sound. The "System A low level" annunciator will sound if either N091A or C indicates below level 2. The "System B low level" annunciator will sound if either N091 or D indicates low level. In addition, there are four white indicator lamps that will illuminate to show which transmitters indicate below level 2.

- Level 1 Indicators/Annunciators. The level 1 annunciator/indicators are identical to the level 2.

- Level 8 Indicators. A white indicator light is associated with each HPCI high level trip transmitter (LT B21-N091C,D). The indicator will illuminate when its corresponding transmitter indicates level is above level 8.

Section 4

WATER LEVEL SYSTEM PEREFORMANCE

This section provides an analysis of the performance of the Shoreham level system. First, a description of level system's errors due to changes in process conditions are given, followed by a discussion of the relationship between water level and the state of the core. An evaluation of the Shoreham water level measurement system's ability to assure core integrity is given in a summary section.

4.1 LEVEL INDICATION ERRORS

The Shoreham level measurement system uses the pressure increase caused by the weight of water in the vessel to provide level indications. If the static pressure above the water column, the static pressure below the water column, and the density of the water are known, then the level can be determined accurately. Note that the water level system measures collapsed level (level that would result if all the steam entrained in the water was removed) because the steam entrained in the water has little effect on the density head. In the Shoreham level measurement system, the two pressures are transmitted to a remote location via water-filled instrument lines and connected to an instrument that is sensitive to the pressure difference between the lines. The transmission process modifies the pressure due to elevation changes in the instrument lines and the dynamic effect of the lines. An ideal measurement system would measure the differential pressure at the instrument end of the lines, the density in the vessel, and the density of the water in the instrument lines. With these measurements, an extremely accurate level indication could be provided. The Shoreham level measurement system measures only the differential pressure at the instrument end of the lines and is calibrated for assumed constant densities in the vessel and instrument lines. In other words, density changes in the vessel and instrument lines are not distinguishable from actual variations in water level. Also, the pressure at the vessel end of the instrument lines is total, not static, pressure so the sensed pressure contains kinetic terms. The indicated level therefore contains errors caused by:

- Differences between actual and assumed vessel density;
- Differences between actual and assumed density in the instrument lines;
- Kinetic components in the sensed pressure;
- Dynamic effects of the instrument lines.

Under most conditions these errors are small, and different calibration strategies are used for the various instrument ranges so indication of water level is reliable. This section provides estimates of indicated level errors when the process and environmental conditions vary dramatically from calibration conditions.

The errors in indicated level due to density are caused by two distinct--but related--phenomena. Changes in the density of the process fluid and of the fluid in the instrument lines as a function of process temperature and drywell temperature cause changes in the sensed level, and extreme combinations of process pressure and drywell temperature cause flashing in the instrument lines. The flashing induces transient pressures in the instrument lines which induce errors in both the reference and variable legs so indicated level may be high, low, or oscillate between the two while flashing is occurring. The indicated error is not readily quantifiable under these circumstances because it depends on the relationship between flashing in the reference and variable legs. However, bounds on the effects can be established. After the initial transient, the system reaches steady state with some loss of fluid from the reference leg. Bounds on the amount of fluid lost may be determined from thermodynamics. The fluid lost from the variable leg will be quickly replaced by fluid from the vessel so, subsequent to flashing, the variable leg will be filled with fluid at vessel conditions.

The error analysis of the level measurement system depends on the assumed conditions used for instrument calibration. For this analysis the calibration conditions used are as given on the Shoreham Nuclear Boiler System P&ID (729E616BD, Rev. 13).

FUEL ZONE	:	Instruments are calibrated for saturated water-steam conditions @ 0 psig in the vessel with no jet pump flow. The instruments are assumed to be calibrated for 135°F drywell temperature.
WIDE RANGE	:	Instruments are calibrated for 1000 psig in the reactor pressure vessel, 135°F in the drywell with no jet pump or vessel steam flow, and 20 btu/lbm subcooling below the narrow range variable leg vessel tap and saturated conditions above.
NARROW RANGE	:	Instruments are calibrated for saturated conditions at 1000 psig in the vessel, 135°F drywell temperature, and rated vessel steam flow.
UPSET RANGE	:	Instruments are calibrated for saturated water-steam conditions @ 1000 psig in the reactor pressure vessel, 135°F drywell temperature, and no reactor steam flow.
SHUTDOWN	:	Instruments are calibrated for 120°F water @ 0 psig in the reactor pressure vessel and 80°F in the drywell, and no vessel steam flow.

The temperature outside the containment is assumed to be 80°F.

The following sections develop level instruments' errors as a function of various parameters.

4.1.1 Errors Caused by Fluid Density Change

The indicated level error due to changes in plant parameters with no instrument line flashing will be provided in this section. The plant installation parameters used for this analysis are defined in Figure 3-5 and Table 3-6. As indicated in Table 3-6, the fuel zone, wide, and narrow range instruments are connected to the reference leg which is attached to the vessel tap just above the top of the steam separators.

The upset and shutdown range instruments are connected to a reference leg which is attached to a tap in the top of the vessel head. The indicated level errors (positive error means indicated level is high) for the different instrument ranges are:

a. Narrow Range, Upset Range, Shutdown Range

$$E_N = K_c L + K_{co} + K_{ca} + K_{cx} + K_{wd} \quad (4\text{-}1)$$

b. Wide Range

$$E_w = K_c L + K_{co} + K_{cs} L_s + K_{ca} + K_{cx} + K_{wd} + K_{wr} \quad (4\text{-}2)$$

c. Fuel Zone

$$E_f = K_c L + K_{co} + K_{cs} L_s + K_{ca} + f(W_{rc}) + K_{cx} + K_{wd} \quad (4\text{-}3)$$

K_c = Sensitivity change due to change in bulk water density

L_s = Height of subcooled water above lower tap--inches

K_{cs} = Sensitivity change due to changes in subcooling

K_{ca} = Zero shift due to changes in drywell temperature--inches

K_{cx} = Zero shift due to changes in reactor building temperature--inches

L = Distance from instrument downscale vessel elevation to actual level--inches

K_{co} = Error due to vessel density effect on instrument zero elevation above the lower tap--inches

K_{wd} = Kinetic term due to dryer pressure drop--inches

K_{wr} = Kinetic term in the region of the wide range lower tap--inches

$f(W_{rc})$ = Kinetic term at the jet pump discharge--inches

The parameter K_c in these equations reflects indicated level sensitivity to changes in the saturation density of the bulk water as a function of system pressure as shown in Figure 4-1 for the narrow, wide and fuel zone ranges. K_c for the upset range is the same as the narrow range, while the shutdown range value may be found by subtracting 0.03 from the fuel zone value. The term (K_cL) represents a fraction of point error because it acts on the vessel water level above the instrument zero.

The term K_{co} represents the zero shift due to changes in vessel density. The zero shift occurs because the instrument downscale elevation is some distance above the lower tap elevation. The zero shift is equal to K_c times the elevation of the instrument zero referenced to its lower tap (L_o in Table 3-6). For the Shoreham plant, the elevations are:

Narrow Range	7.75 in.
Wide Range	8.75 in.
Fuel Zone	76.56 in.

Plots of zero offset shift due to vessel density changes are shown in Figure 4-2 for the narrow range, wide range and fuel zone range. K_{co} for the upset range is equal to the value for the narrow range, while the shutdown range value is approximately equal to the narrow range value minus 3.5 inches.

The parameter K_{cs} indicates the system sensitivity to changes in average density caused by changes in the subcooling of the bulk water below the feedwater sparger. The subcooling is a function of system pressure, feedwater temperature, and the ratio of feedwater flow to recirculation flow. If level is above the feedwater sparger, then the term (L_s) is the elevation difference between the lower tap and the feedwater sparger. If the level is below the feedwater sparger, then L_s is the actual level referenced to the lower tap. The subcooling term K_{cs} is proportional to the difference between the density change due to subcooling at calibration conditions and operating conditions. The difference between saturated and subcooled density for wide range calibration conditions is 1.01 lb/cubic feet (20 btu/lb subcooling). A lower subcooling will cause

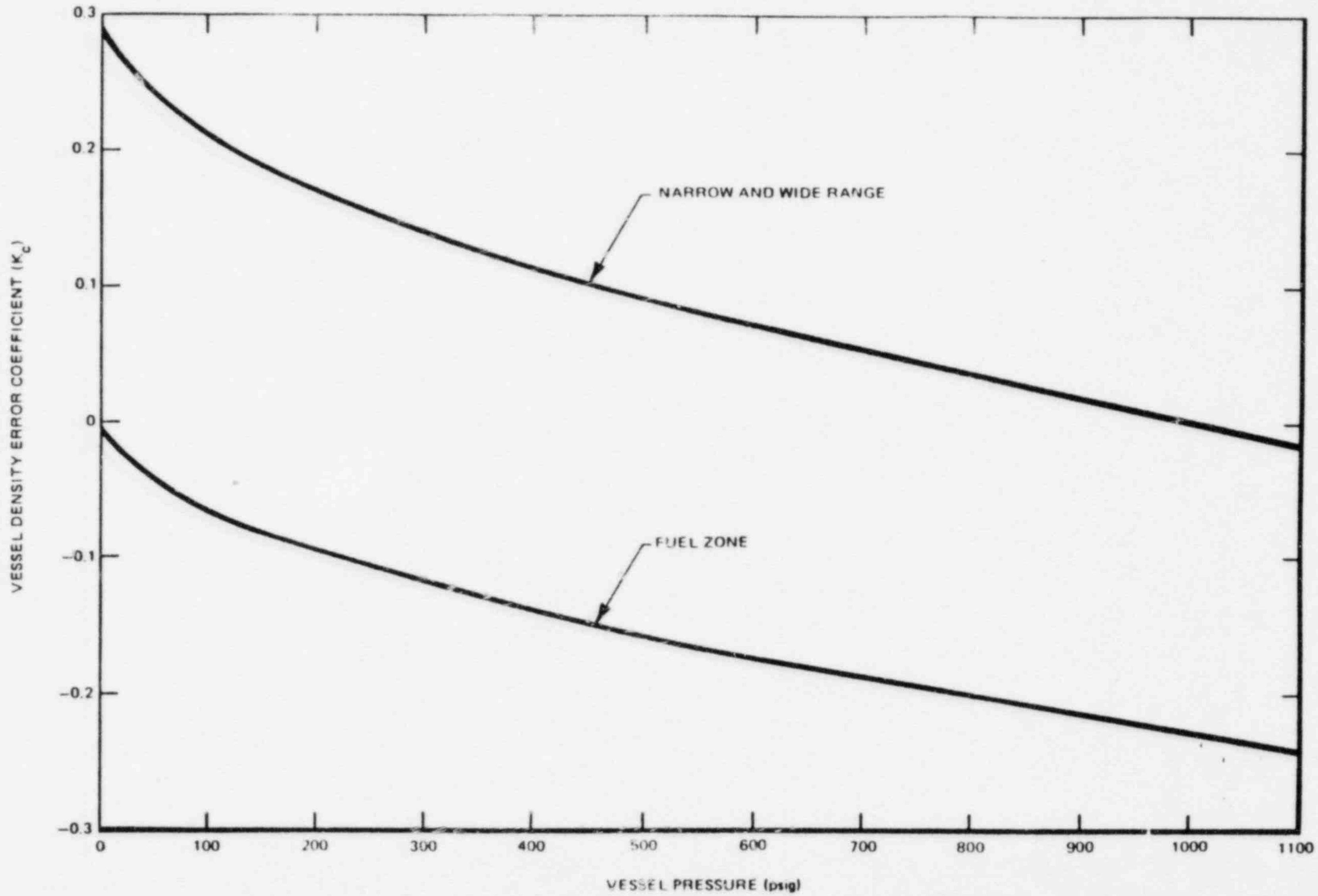


Figure 4-1: Vessel Pressure Effect on Sensed Level

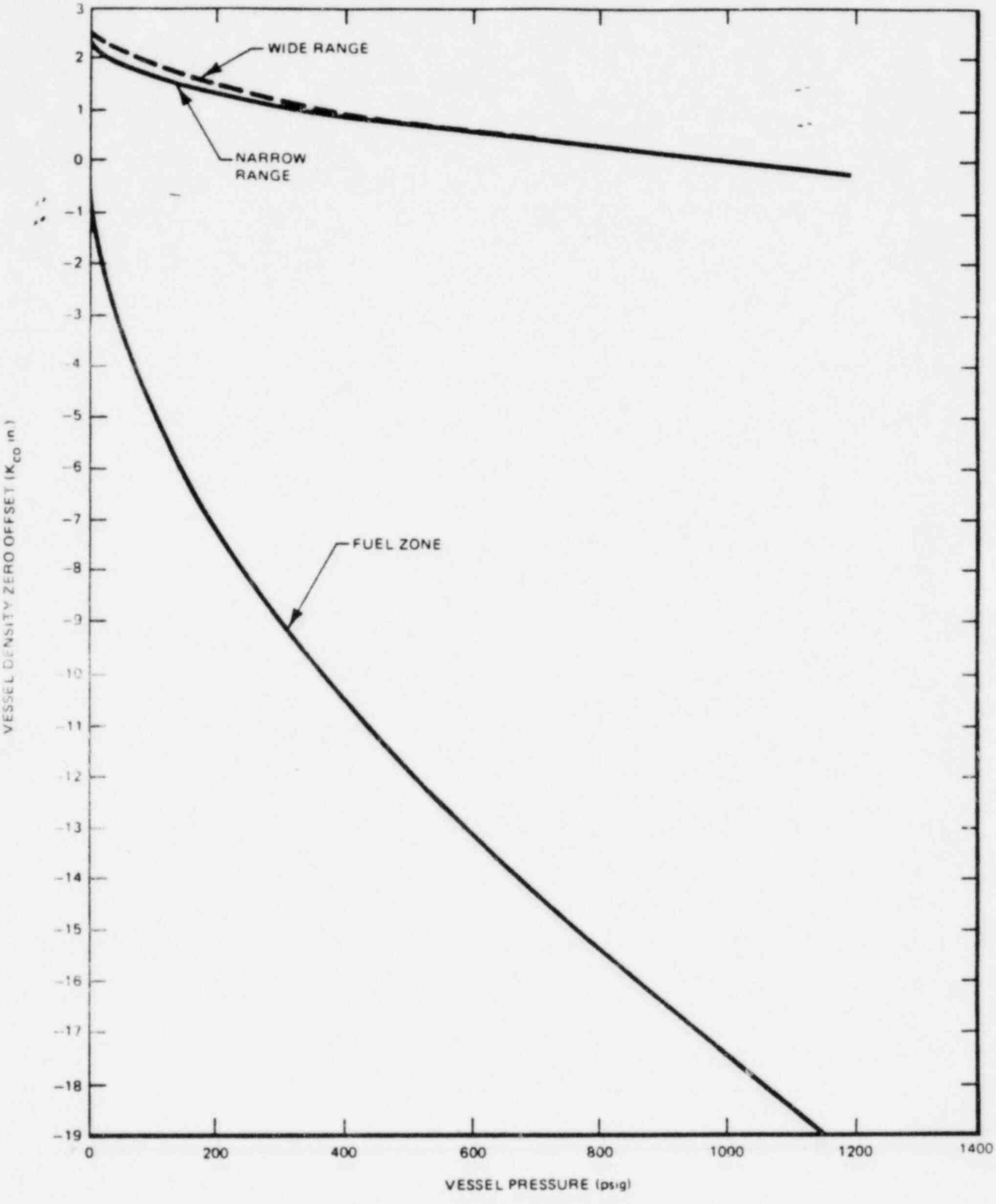


Figure 4-2: Vessel Density Effect on Zero Offset

the wide range indication to decrease and a higher subcooling will cause the indication to increase. At saturated 1000 psig vessel conditions (no subcooling), the error in wide range indication will be -2.8 inches and, if feedwater temperature decreases by 100°F (higher subcooling), the error will be +2.6 inches when the level is above the sparger. The errors will decrease linearly to zero as level drops from the sparger to the lower tap. The fuel zone instrument is calibrated for saturated conditions so its indication will increase with subcooling. The fuel zone error will be +7.8 and +15.1 inches at nominal operating conditions and for a 100°F decrease in feedwater temperature, respectively. The narrow, upset, and shutdown instruments are above the feedwater sparger where the vessel inventory is always saturated during plant operation.

The parameter K_{ca} accounts for the indicated level zero shift due to changes in the fluid density in lines that are at drywell temperature when no flashing occurs. The value of this parameter is proportional to the product of the difference between actual and assumed instrument line fluid density times the difference between the reference and variable leg drops in the drywell. Figure 4-3 shows K_{ca} as a function of drywell temperature for the narrow, wide and fuel zone ranges. The value for the upset and shutdown ranges is about twenty times the value for the Side A narrow range. The curves in Figure 4-3 show that the effect of drywell temperature on the Side B wide and narrow range instruments is negligible. The Side A narrow and wide range instruments are somewhat sensitive to drywell temperature with an error of about 4-1/2 inches when the drywell is at its maximum expected temperature (320°F), which occurs subsequent to a large Loss of Coolant Accident (LOCA). The Side A narrow and wide range sensitivity to drywell temperature is greater than Side B because the difference between the reference and variable leg drops is ten times greater for Side A. The fuel zone instruments on both sides have a negative error because the variable leg drop is longer than the reference leg drop. At 320°F drywell temperature, the Side A and B fuel zone instruments have errors of about -8-1/4 and -12-1/2 inches, respectively. The Side B error is larger because it has a shorter reference leg, while the fuel zone variable legs are the same length on both sides.

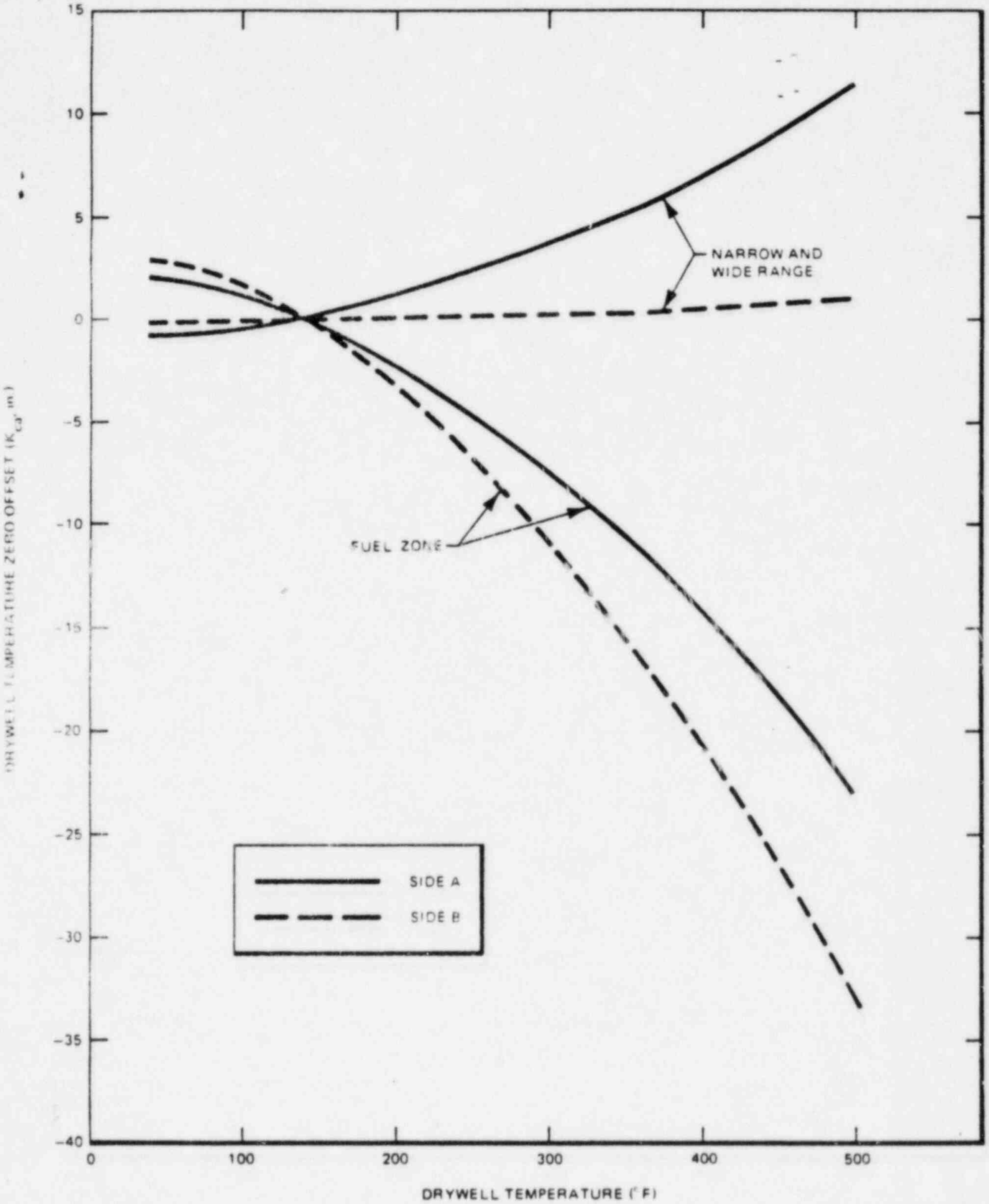


Figure 4-3: Offset Error Due to Drywell Temperature Changes

The term K_{cx} represents the change in instrument zero in response to changes in the temperature of instrument lines in the reactor building. The value of this parameter is set by the variation in instrument line fluid density with reactor building temperature and the elevation difference between the reference and variable leg drywell penetrations. Figure 4-4 shows a plot of K_{cx}. The narrow and wide range instruments are not very sensitive to this parameter, with a maximum 2.5-inch error at 120°F in the reactor building. The value for the shutdown and upset ranges is negative and about 1/2 of the narrow range value. The fuel zone instrument is more sensitive to the reactor building temperature because of the longer difference between the variable leg drop and reference leg drop in the reactor building. The fuel zone instrument error is about 8.5 inches when the building temperature is 120°F and the vessel at zero psig.

The term K_{wd} represents the change in indicated level as a function of the changes in dryer pressure drop as steam flow changes. The reference leg vessel penetration is in communication with the steam space above the dryers and will respond to the changes. The term K_{wr} represents the change in velocity head at the wide range lower tap as recirculation suction flow changes. Both terms vary as the square of flow as shown in Figure 4-5. Total recirculation flow may be used to find K_{wr} since drive flow and suction flow follow each other closely, except at low flow where the term is small.

The term, $f(W_{rc})$, for the fuel zone instrument, represents the effect that recirculation flow has on the pressure at the lower tap. The high pressure drive flow will cause the pressure to be much higher than the density head under high flow conditions. Under natural circulation conditions, the jet pump friction loss causes the pressure to be slightly less than the density head. The velocity head in the jet pump tailpipe is a small fraction of the other effects under any conditions and may be neglected. Figure 4-6 shows the fuel zone level error as a function of recirculation flow for nominal plant conditions. The actual error will

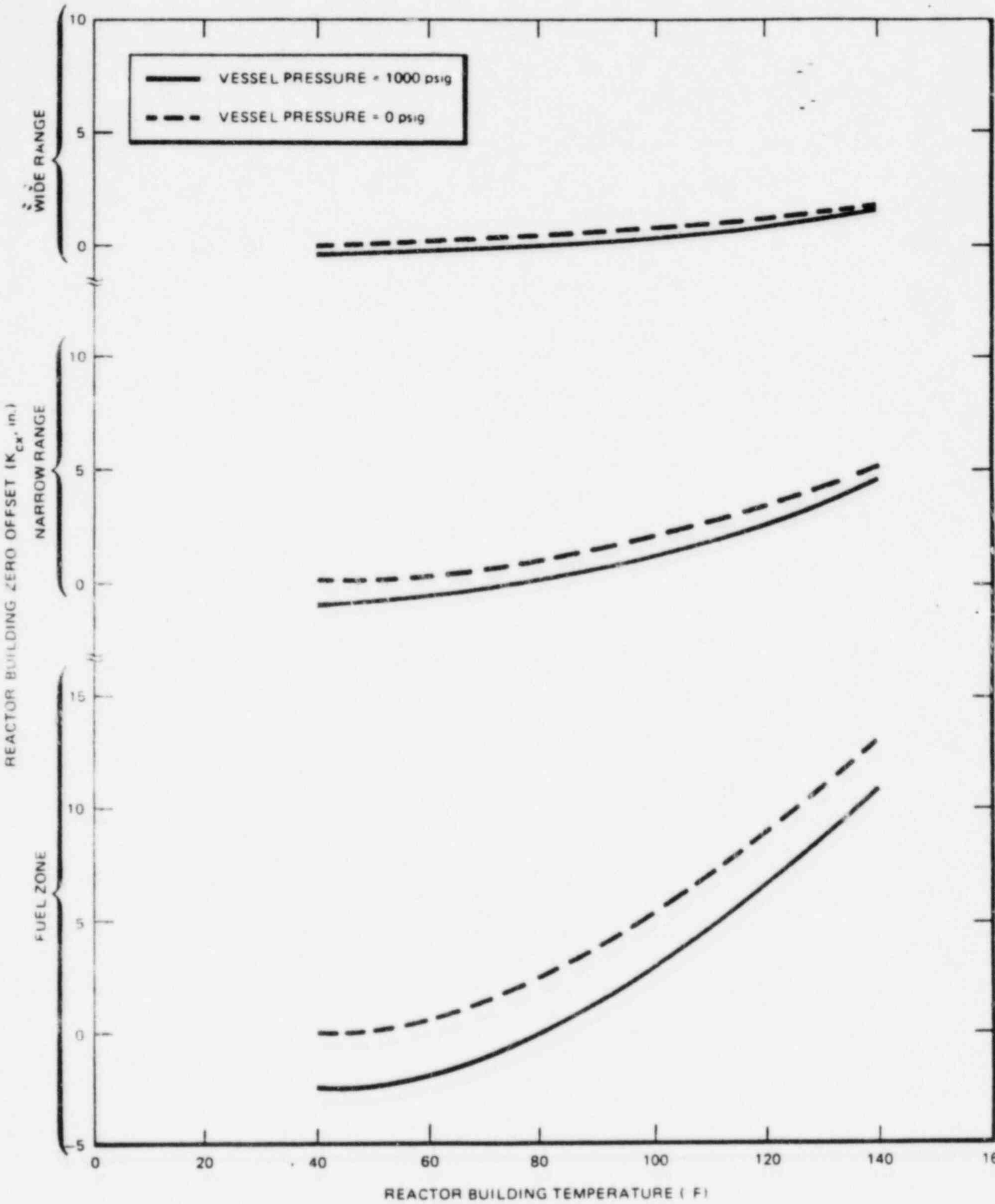


Figure 4-4: Reactor Building Temperature Effect on Zero Offset

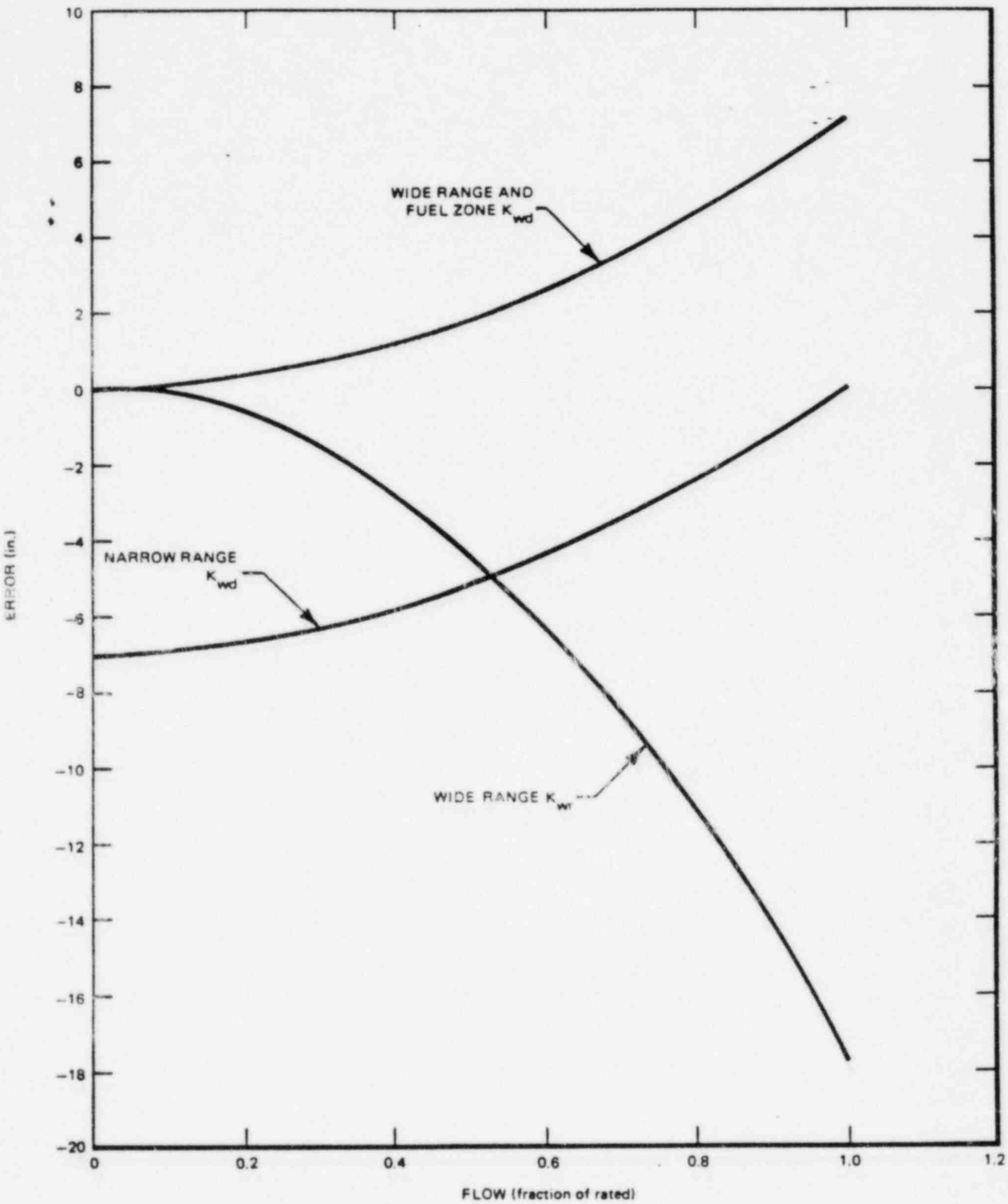


Figure 4-5: Error Due to Steam and Recirculation Flow

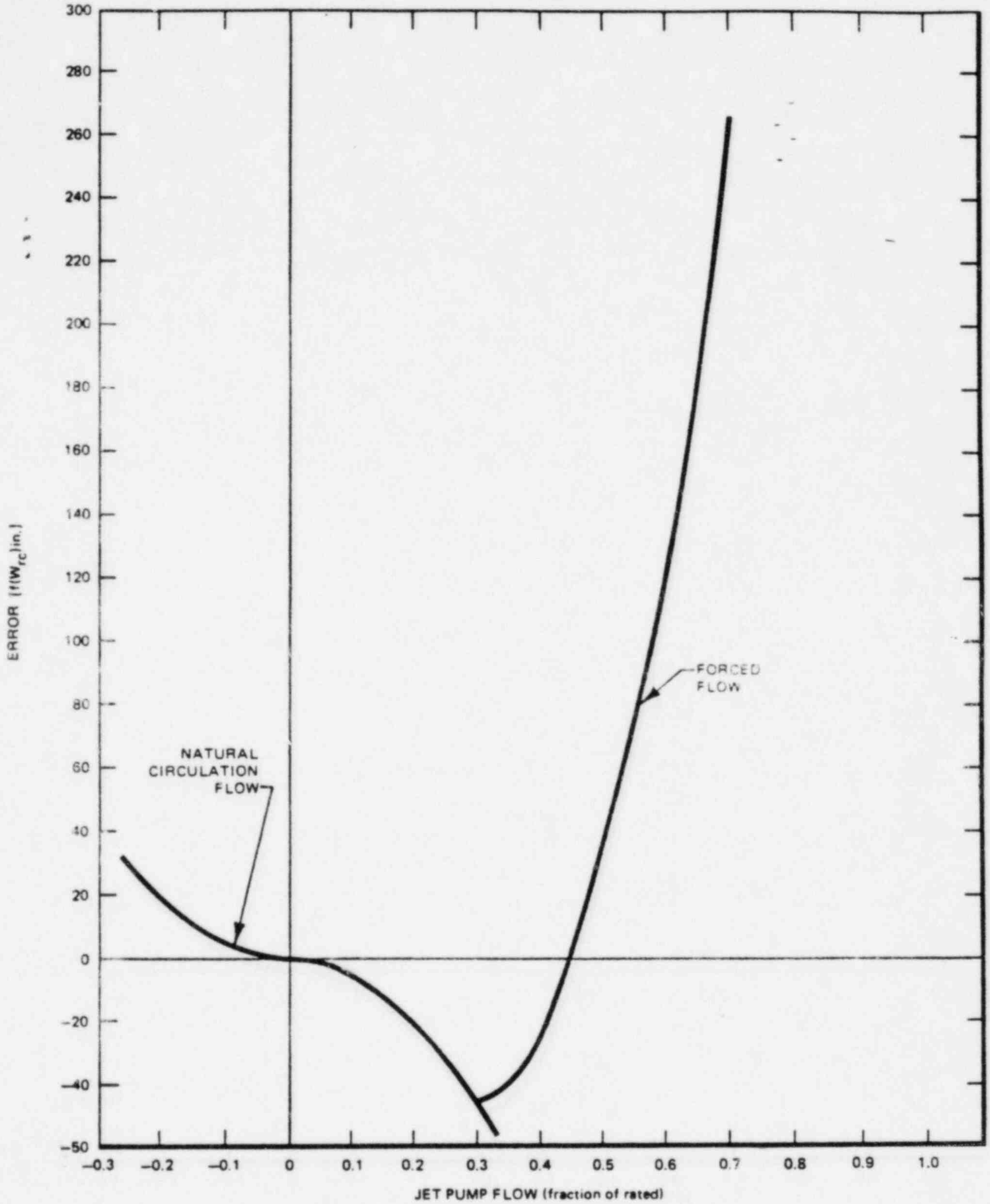


Figure 4-6: Jet Pump Flow Effect on Fuel Zone

vary with level, degree of imbalance between the loops, power level, etc. However, the fuel zone instrument will be used primarily under natural circulation conditions and the indicated level error shown on the figure will be nearly correct for any natural circulation condition.

4.1.2 Instrument Line Flashing Errors

High drywell temperature accompanied by reactor depressurization can result in instrument line flashing. Flashing is initiated when vessel pressure drops to a point where the temperature of the fluid in the instrument line is above the saturation temperature corresponding to the vessel pressure. The variable leg piping slopes monotonically downward from the reactor vessel nozzle assuring that, shortly after depressurization has stopped, this leg will be refilled with vessel water; therefore, the effects of flashing on the variable leg are transitory. Refilling of the reference leg will occur when the operator floods the vessel, as directed by procedures, and actual level is above the vessel reference leg tap. Shortly after the transient is over, the variable leg will be filled with fluid at the vessel saturation conditions and some portion of the reference legs will not contain water.

4.1.2.1 Steady-State Flashing Errors

This section provides the level indication errors that would occur after the initial transient but before the vessel is flooded and drywell temperature is reduced. When the flashing transient is over, the amount of fluid that has been removed from the reference leg can be estimated from the initial temperature of the leg and the final steady-state vessel pressure. The fluid left in the reference leg will drain down to replace the fluid lost from the horizontal runs, so the routing of the piping must be considered when determining error. The maximum error is proportional to the vertical line drop in the drywell, regardless of the total line length. The indicated level error, as a function of initial temperature of the fluid in the line and the final pressure, is shown in

Figures 4-7 and 4-8 for the wide and narrow range instruments and in Figures 4-9 and 4-10 for the fuel zone instruments. The error for the upset and shutdown range is about 20 times the Side A narrow range error. Two cases are shown on each of the figures. One case is based on assuming full carryover during the flashing. That is, the expanding steam forces the steam/water mixture out of the line, thus the amount of water remaining in the line is a function of the void fraction. The other case is based on assuming no carryover during flashing. That is, the steam bubbles out of the line without displacing fluid, thus the water remaining in the line is a function of the quality. For the full carryover case, the indicated level error changes rapidly with changes in vessel pressure and reference leg temperature, while in the no carryover case, the indicated error changes relatively slowly. Since Shoreham uses a cold reference leg system, the reference leg temperature is approximately equal to the drywell temperature (maximum expected value of about 320°F). The full carryover case represents the maximum possible error and the no carryover case the minimum. The actual error will lie somewhere between the two cases.

The side A and B error curves have different magnitudes and shapes. The lower magnitude on side B is due to the smaller reference line drop. The difference in shape is due to the difference in line routing. The portion of total vertical drop occurring for a specific amount of total fluid loss will depend on how the horizontal and vertical runs are intermixed. A plot of vertical drop versus total length of line is shown in Figure 4-11. Figure 4-11 shows that the vertical drop characteristic for sides A and B have the same general profile for the first half of the runs. In the second half of the runs, the side B line drops rapidly in the early part of the run and then drops slowly in the latter part of the run. The side A line drops very slowly for most of the run and then drops rapidly in the latter portion.

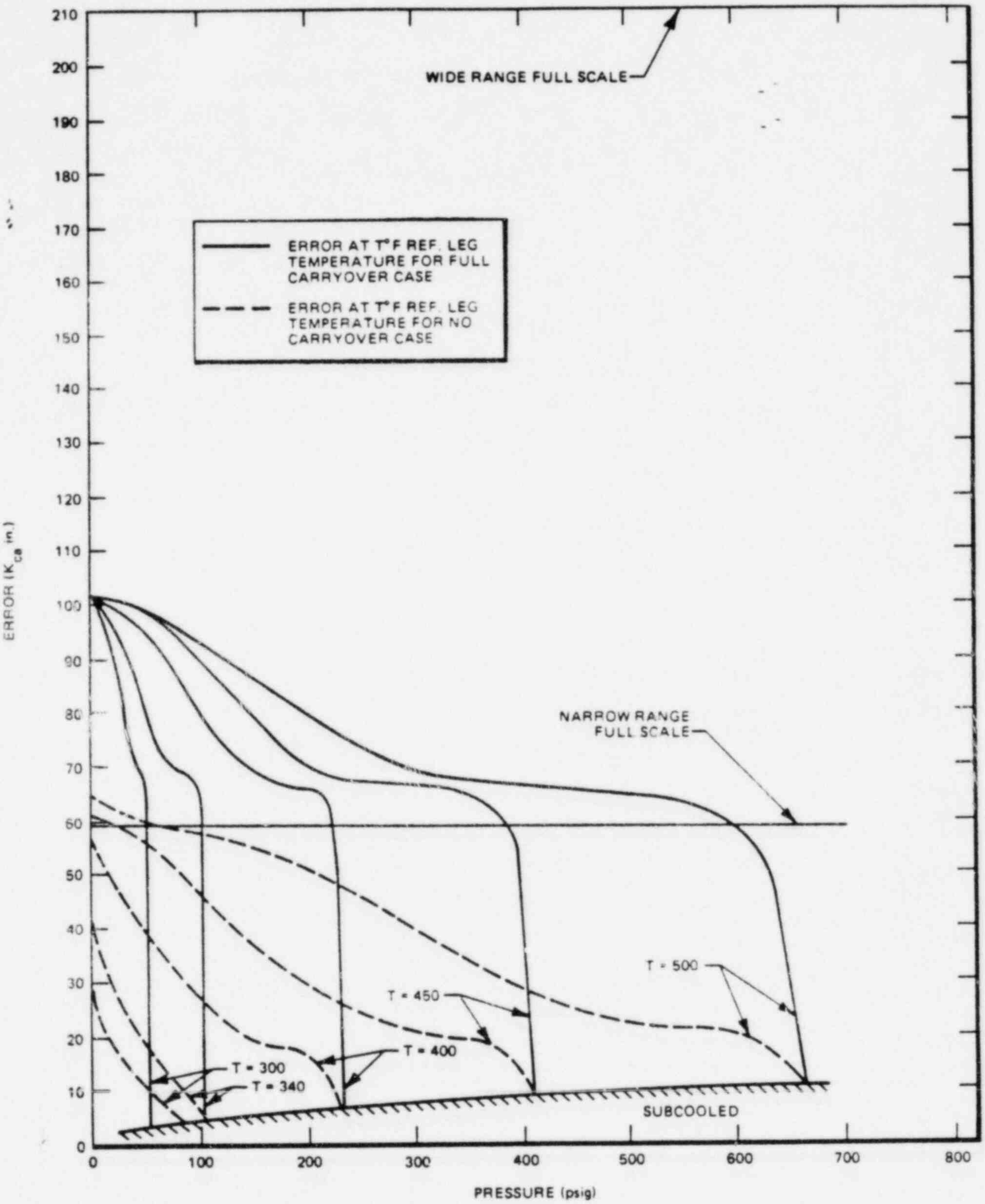


Figure 4-7: Side A Narrow and Wide Range Indication Error Subsequent to Flashing

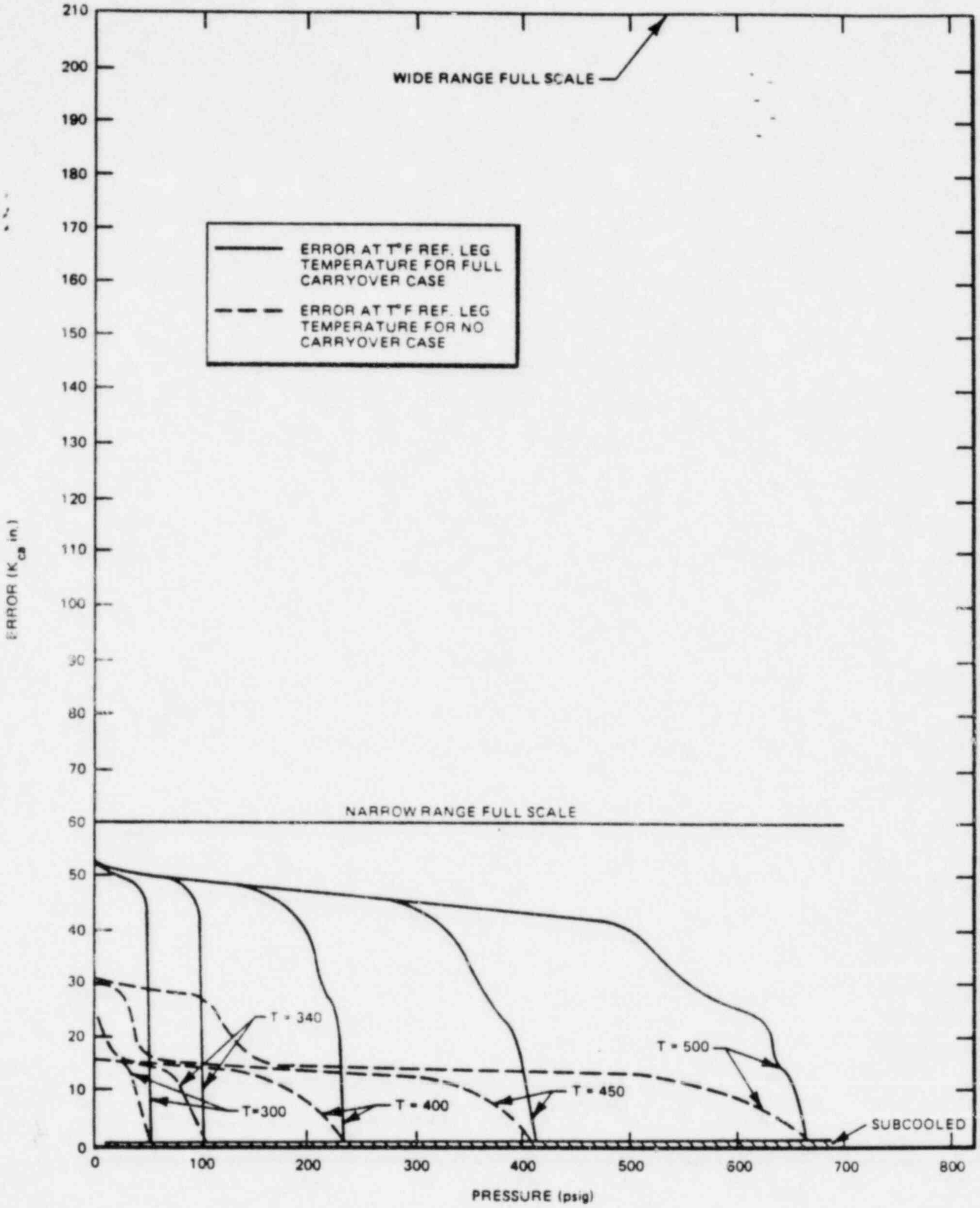


Figure 4-8: Side B Narrow and Wide Range Indication Error Subsequent to Flashing

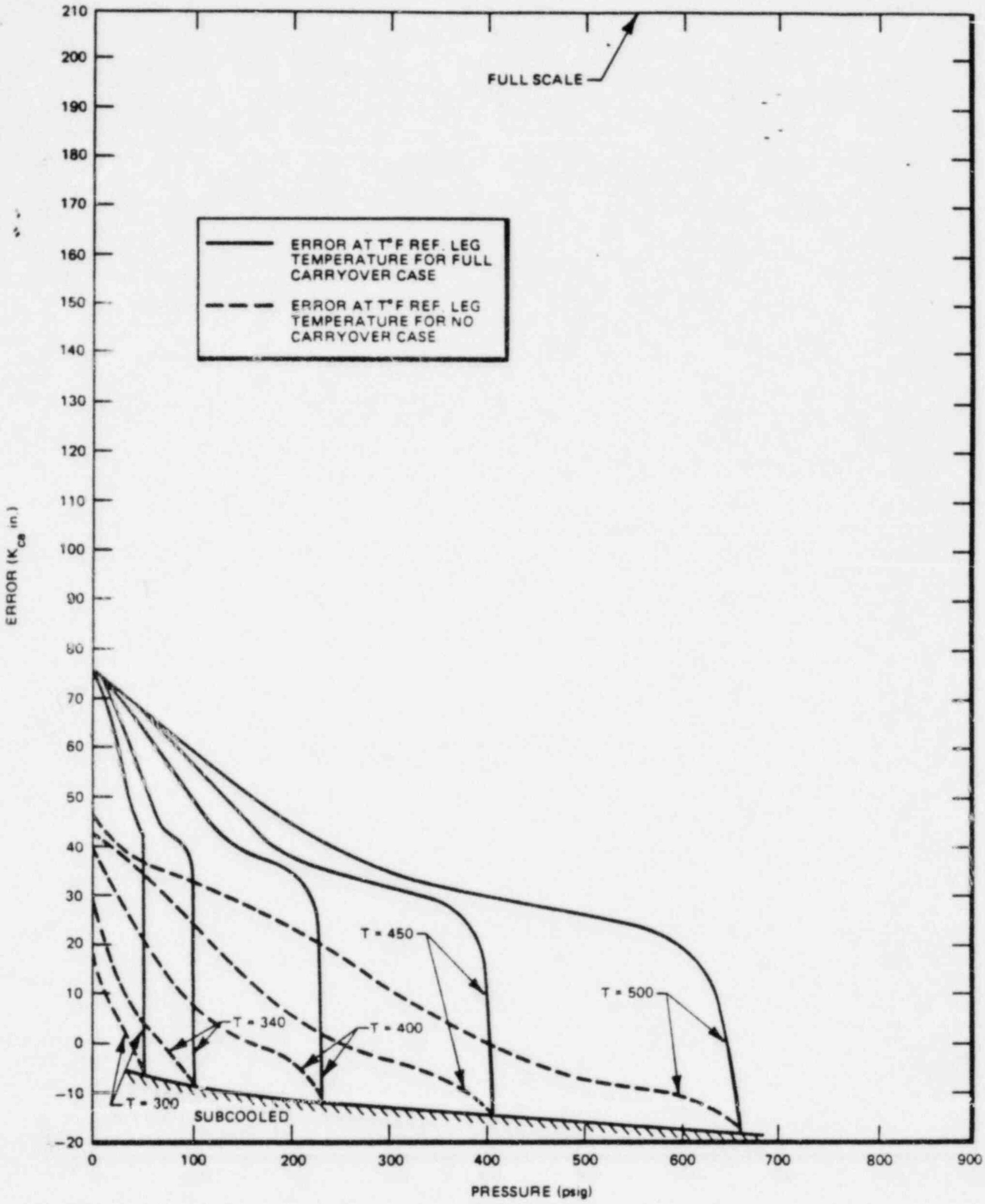


Figure 4-9: Side A Fuel Zone Indication Error Subsequent to Flashing

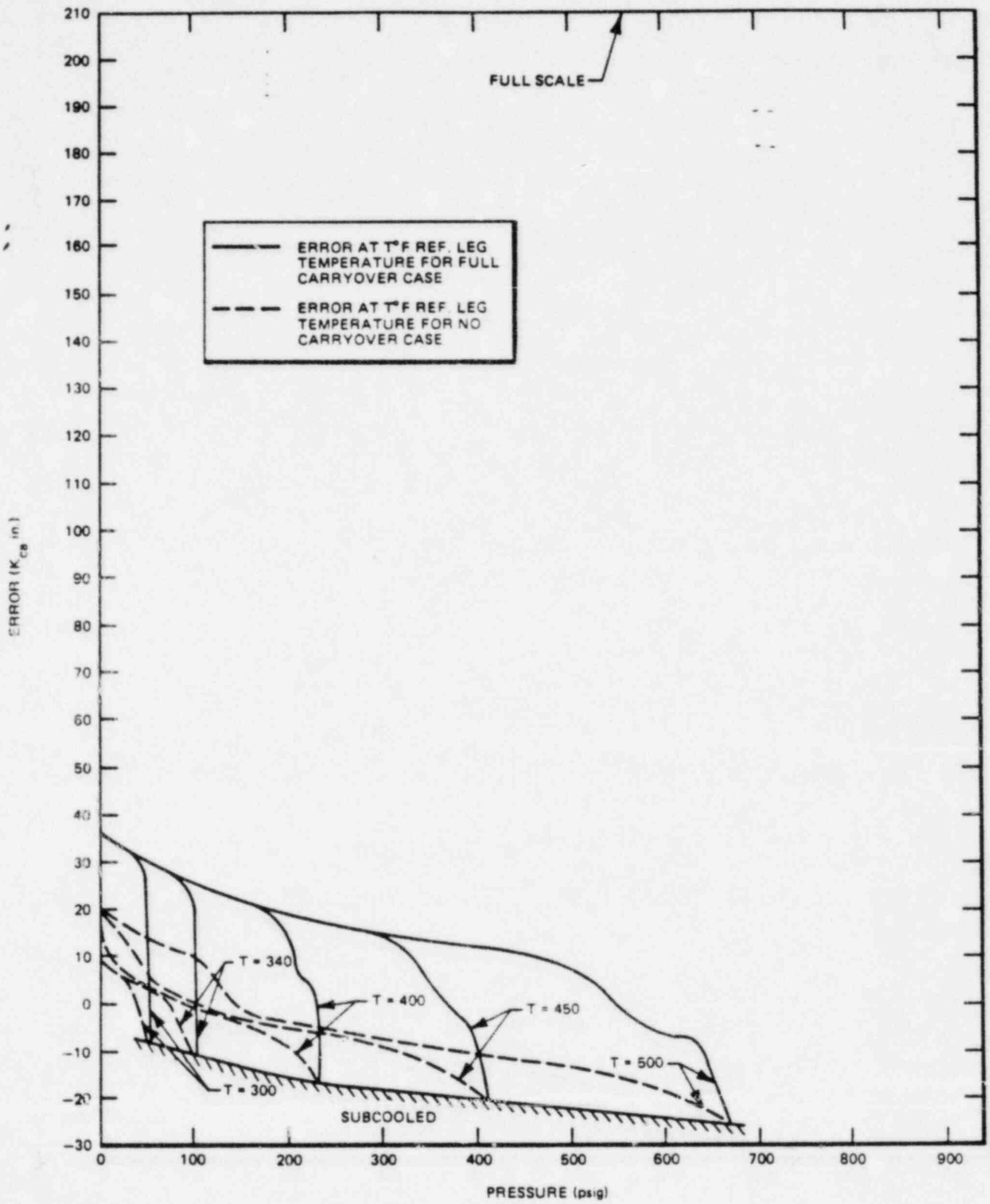


Figure 4-10: Side B Fuel Zone Indication Error Subsequent to Flashing

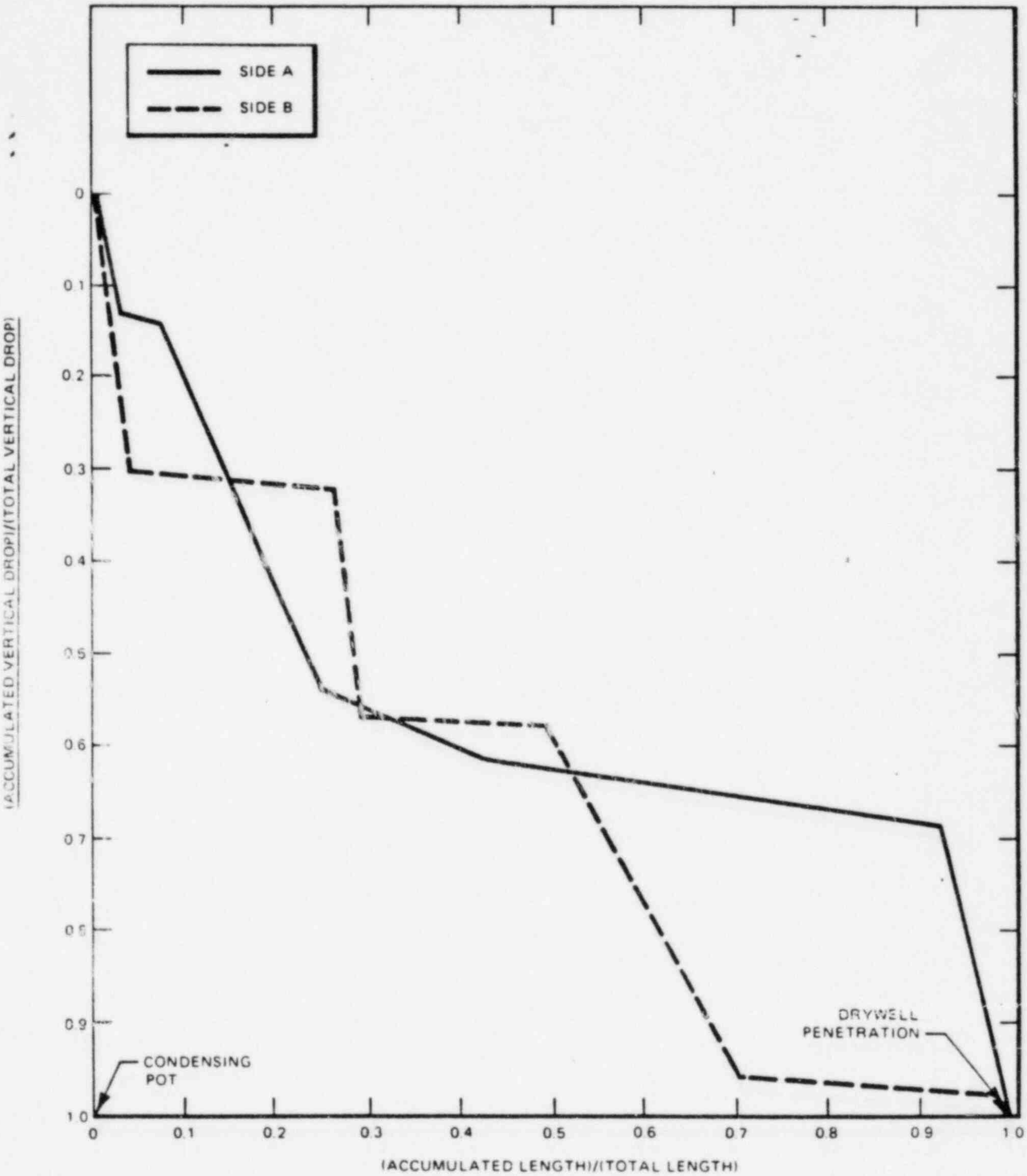


Figure 4-11: Reference Line Vertical Drop vs. Length

4.1.2.2 Transient Flashing

While flashing is occurring, the fluid in the instrument lines flows toward the vessel to accommodate the expansion of the fluid. This flow is accompanied by a pressure gradient which causes the pressure at the instrument to remain high while vessel pressure continues to decrease. Reference leg flashing results in transient low level indications, and variable leg flashing results in transient high level indications. The transient pressures can cause level to be high, low, or oscillate between the two, depending on the relationship between the variable and reference leg flashing. A summary of the effect of transient flashing follows. For a complete discussion, see Reference 1.

Flashing of the variable leg occurs when the reactor pressure drops below the saturation pressure corresponding to the drywell temperature. The flow velocity in the instrument line at a distance "Y" from the drywell penetration is given by:

$$V = Y \quad \frac{v_{fg}}{h_{fg}} \quad \frac{dh_{\ell}}{dP} \quad \frac{dP}{dt} \qquad (4\text{-}4)$$

where dP/dt is the depressurization rate. The terms h_{ℓ} and h_{fg} correspond to liquid enthalpy and heat of vaporization, respectively. P represents pressure and v_{fg} the difference between water and steam specific volumes. Equation (4-4) shows that the maximum velocity will be obtained close to the reactor vessel. The fluid properties in Equation (4-4) are the saturation properties of the fluid in the instrument line when flashing begins and can therefore be determined from drywell temperature. The maximum velocity may be found from:

$$V_{max} = F_y(T)L(dP/dt) \qquad (4\text{-}5)$$

where L is the instrument line length in the drywell, V_{max} is the maximum flow velocity near the reactor vessel, T is the drywell temperature, and $F_y(T)$ is the steam property term in Equation (4-4).

Using Equation (4-5) and the standard flow squared loss relationship gives an equation for the total head losses due to friction in the line.

$$H_f = F_v(T)\ L^3\ (dP/dt)^2 \tag{4-6}$$

$F_v(T)$ is $F_y(T)$ modified by the appropriate loss coefficient for the instrument line conditions. Figure 4-12 shows the normalized head losses $F_v(T)$ vs. the initial variable leg temperature. Figure 4-13 shows the effect of transient flashing on level indication as a function of drywell temperature for two pressure rates. One case is the pressure rate that results when the Automatic Depressurization System (ADS) is initiated, and the second case is the pressure rate which corresponds to a 100°F cooldown rate. The transient flashing error for the variable legs is about the same for all instruments. The transient error due to reference leg flashing for the narrow, wide and fuel zone range is as shown in Figure 4-13, while the value for the upset and shutdown range is about 20 times greater than as shown on Figure 4-13.

A restricting orifice in the variable or reference leg can cause a discrete loss. The velocity V_o, at the flow restriction orifice depends on the orifice location and the orifice size and is given by:

$$V_o = F_y(T)\ L_o A_r \frac{dP}{dt} \tag{4-7}$$

where L_o is the distance between the orifice and the drywell penetration and Ar is the ratio of the line to the orifice flow area.

The local head losses in the orifice are given by:

$$H_o = F_v(T)\ L_o\ (dP/dt)^2\ A_r$$

For Shoreham, the distance L_o is very small since the orifices are located very close to the drywell wall. Therefore, the velocity is very small and the pressure drop across the orifice is negligible.

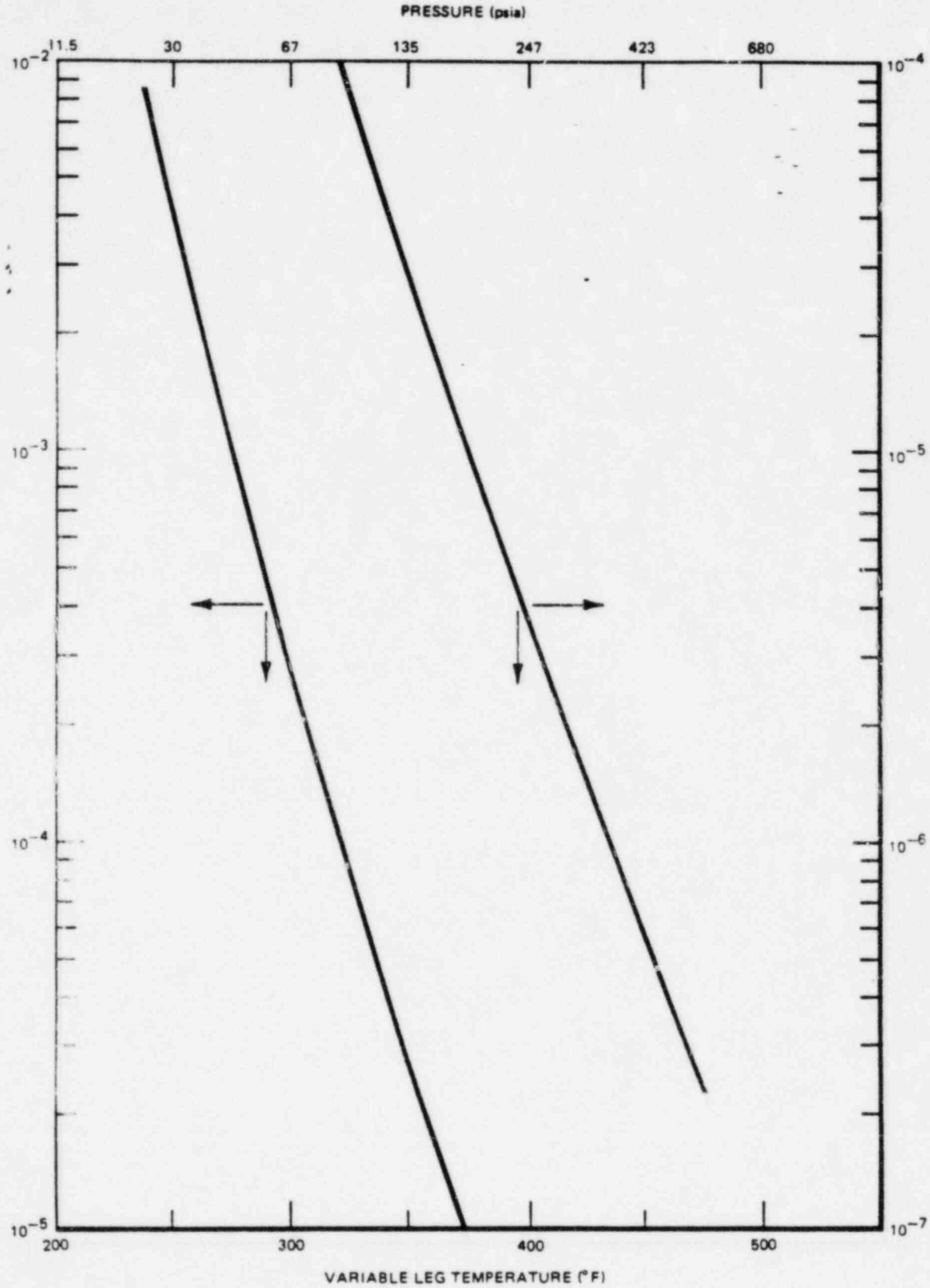


Figure 4-12: Friction Head Losses

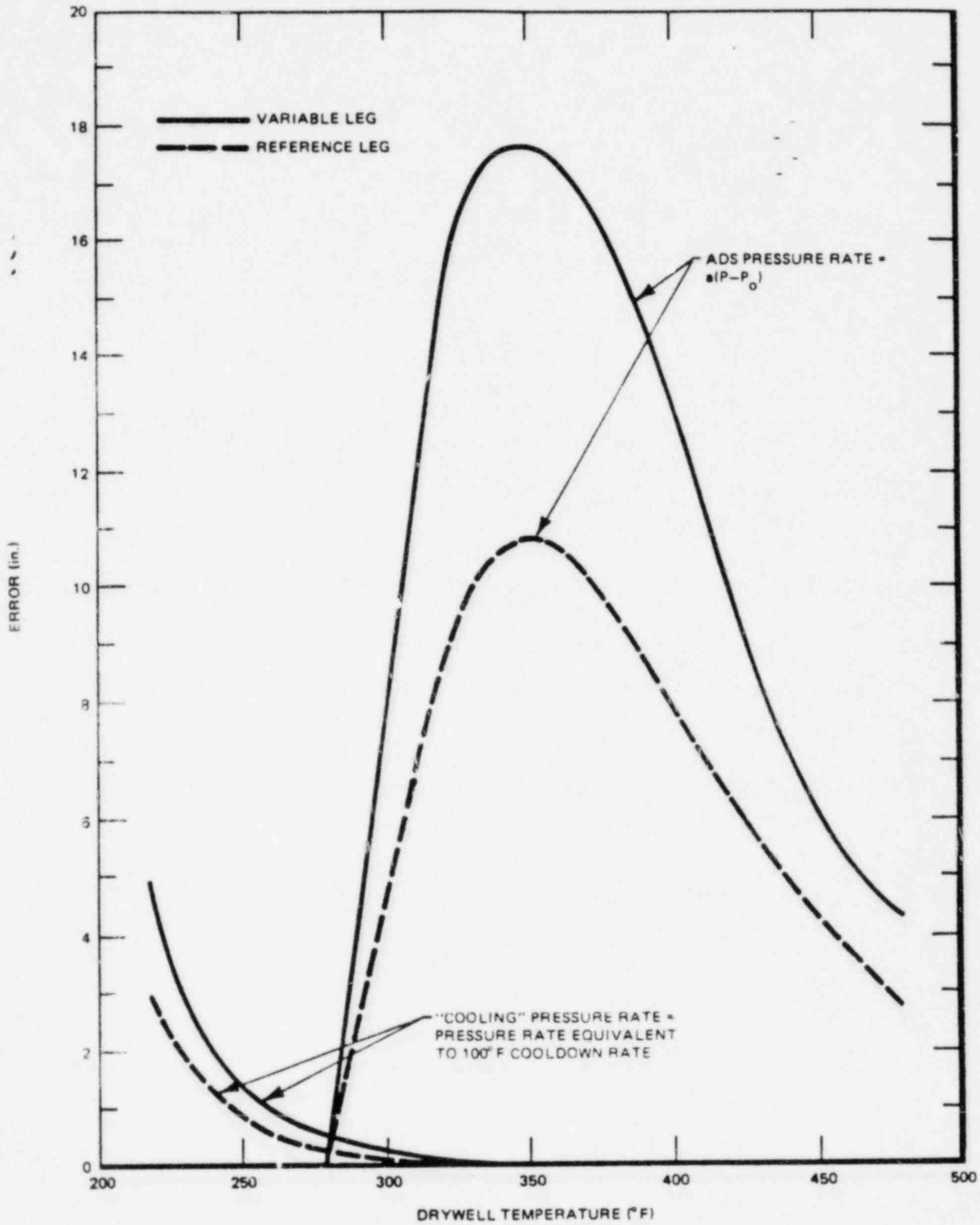


Figure 4-13: Transient Flashing Error

Figure 4-13 indicates that the maximum transient flashing error for the ADS case occurs when the drywell temperature is at about 350°F, while the maximum error for the "cooling" case occurs at 212°F drywell temperature. The total error is the reference leg value subtracted from the variable leg value. If only the variable leg were to flash during ADS, the indicated level would be high by a maximum of about 11 inches. If only the reference leg were to flash during ADS, the indicated level would be low by a maximum of about 18 inches. If both the reference and variable legs flashed at about the same time, the maximum level indication error would be low by 6 to 8 inches. For the "cooling" pressure rate case, the errors are much smaller and most likely would not be noticeable, particularly if both legs flashed at about the same time.

4.2 WATER LEVEL RELATIONSHIP TO CORE STATE

The water level system provides measurements to indicate vessel inventory as described in the preceding sections. This section provides a discussion of the relationship between water level and the state of the core under decay power, natural circulation conditions. The discussion given here is a summary of the analysis given in Reference (2). As described in (2), there are several hardware and procedural restrictions which prevent plant operation in regimes where efficient fuel heat removal can be impaired by heat flux phenomenon, so a discussion of the water level system performance under these conditions is not required.

In order to adequately assess the performance of the water level system, a definition of satisfactory core cooling is required. Reference 2 concludes that a peak clad temperature of less than 1300°F in the average fuel bundle is a satisfactory definition of adequate core cooling.

4.2.1 The Relationship Between Water Level and The Core State During Uncovery

In a BWR, there is a direct and unambiguous relationship between collapsed level and coolant inventory. Because of the boiler's physical layout, collapsed level above, in, and below the core can be directly interpreted in terms of coolant inventory. Collapsed level is defined as the level which would result if all of the steam were assumed to be above the liquid. In the analysis which follows, this relationship is used to illustrate the connection between water level and the core state. The analysis is a summary of the analysis given in Reference 2.

A typical condition which could lead to a postulated threat to core integrity is initiated with isolation of the BWR primary system. Isolation can occur for several reasons, but the particular cause is unimportant to the accident sequence. The reactor will be scrammed, the recirculation pumps tripped, and neither the Reactor Core Isolation Cooling system nor the Emergency Core Cooling System are assumed to be available. No break is postulated. Hence, the vessel will remain pressurized but without inventory make-up. Sensible and decay heat in the fuel will continue to boil off the system's inventory. The steam produced is assumed to escape at a steady rate so that the reactor vessel will remain at a constant pressure. In this situation, natural circulation will continue in the vessel until enough liquid inventory has been lost so that the downcomer water level can no longer provide sufficient elevation head to drive flow through the core and steam separators. After this time, circulation will continue inside the core shroud, with flow going up through the fuel assemblies and down the common bypass region between the channel walls. Unless make-up inventory is supplied, the liquid level will eventually drop below the top of the fuel bundles, breaking the coolant circulation loop, and the accident will progress into a boil-off and core heat-up phase.

For an event such as the one postulated, liquid inventory depletion is related directly to the net amount of fuel sensible heat and decay heat

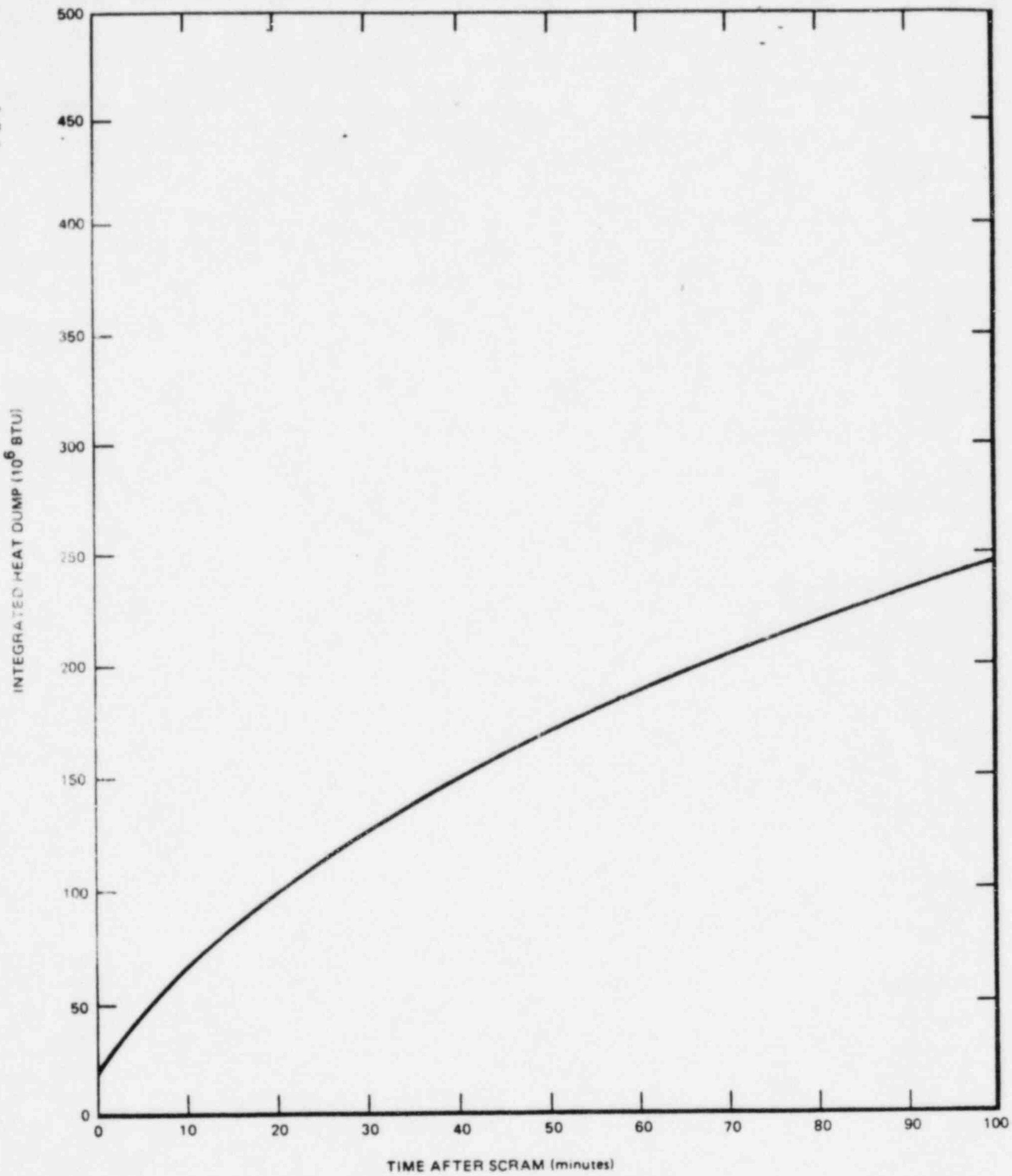


Figure 4-14: Integrated Net Heat Dump

transferred to the fluid. For the present study, the American Nuclear Society decay heat standard for infinite fuel exposure is used to provide a conservatively high decay heat. The control rod drive cooling system is assumed to be operating. The integrated net heat dump to the fluid is the time integral of the fuel decay heat plus the fuel sensible heat, minus the reactor vessel heat losses, minus the heat removed by the control rod drive cooling flow. A plot of the net heat dump to the fluid inventory for a typical BWR/4 is shown in Figure 4-14.

The net heat dump shown in Figure 4-14 may be converted to downcomer level by:

- Using the first few seconds of heat dump to heat all subcooled inventory to saturation conditions.
- Assuming the remaining heat dump goes to boiling of vessel inventory. This assumption is no longer valid when the core begins to uncover since some of the energy would contribute only to heating the fuel and superheating the steam.
- Determining the inventory split between the downcomer and core for a particular decay heat/total inventory condition.
- Converting the downcomer inventory to downcomer level.

Note that iteration between the last two steps is required. The inventory split is a function of the downcomer level and core conditions since a hydrostatic balance must exist between the downcomer and core, while the core condition is a function of downcomer level.

The level in the active core is also established by this process and the time of core uncovery may be determined. Once the core has uncovered, the downcomer and core bypass (region between the fuel channels) levels are essentially equal since little heat is added to the fluid in the bypass region. The lowest power bundle will be the first to uncover because this bundle has the lowest voids and therefore the highest density; therefore, the hydrostatic head will not support as high a level.

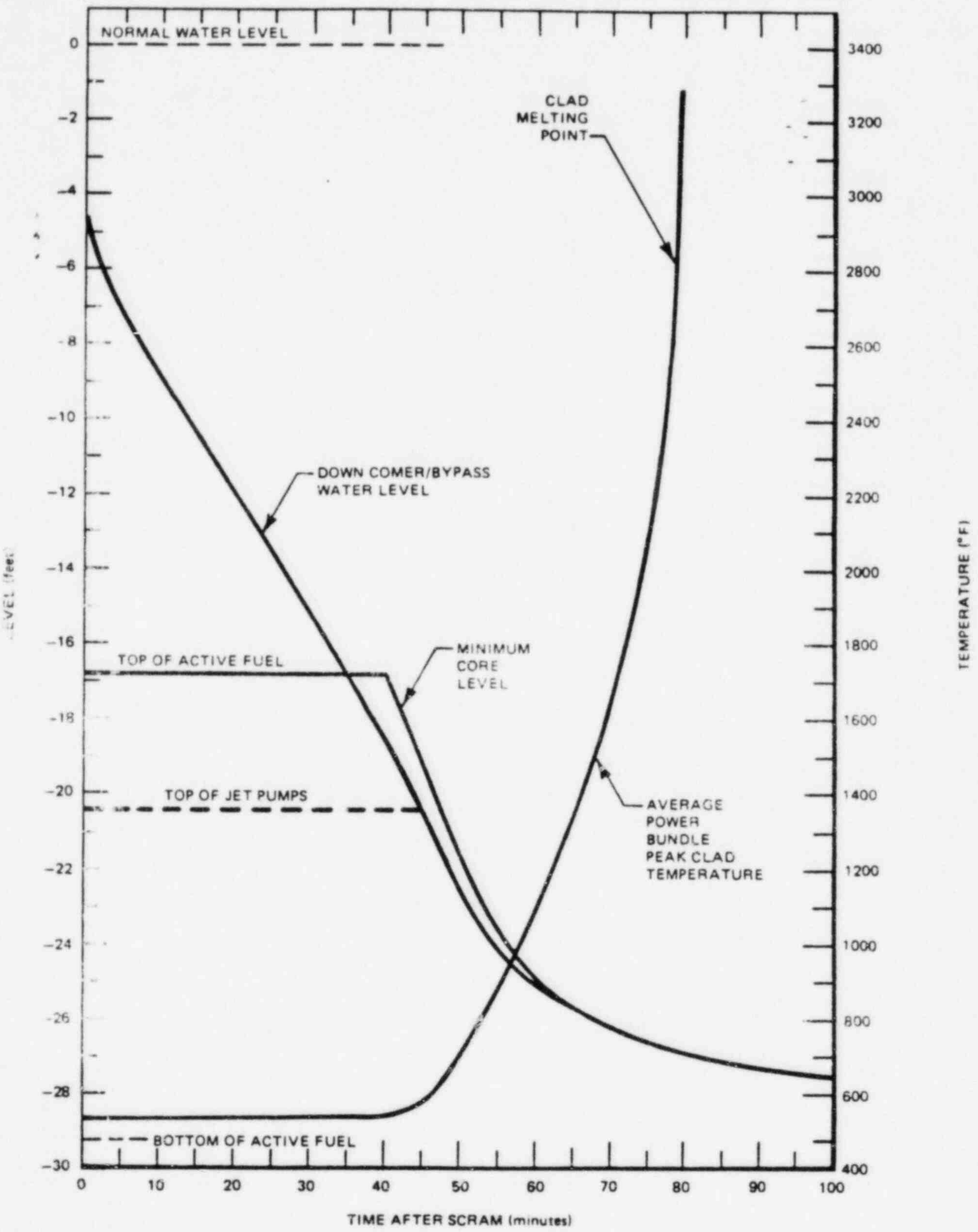


Figure 4-15: Core Boiloff Scenario

A time history of downcomer level and the minimum core water level (water level in the coldest bundle) for the postulated event is shown in Figure 4-15. The downcomer level shown in Figure 4-15 is collapsed level, while the core level is the lowest value of the two-phase steam/water mixture level in the fuel bundles. Note that the lowest power bundle would not begin to uncover until the downcomer level had dropped midway between the Top of Active Fuel and the jet pump suction. To be more specific, this analysis predicts that in the absence of inventory make-up the core would not begin to uncover until some 40 minutes after scram, by which time the downcomer level would have dropped about 18-1/2 feet below normal water level.

Prior to core uncovery, the clad temperature is slightly above the saturation temperature of the steam/water mixture. As the core begins to uncover, the fuel cladding temperature in the uncovered portion of the fuel will begin to increase, and the peak cladding temperature will occur in the low power bundles. As the inventory drops further, more of the core will begin to uncover, and the peak clad temperature will shift to the high power bundles and the rate of temperature rise will increase.

A detailed heat-up analysis was performed (2), using a model which included appropriate radiation, conduction, and convective heat transfer terms and also accounted for the energy released by the exothermic metal/water reaction that occurs when the temperature exceeds 1800°F. The model contained eight radial groups, each consisting of three types of bundles. Each bundle contained corner, peripheral, and center rods with six axial nodes apiece. A plot of the maximum clad temperature for the average power bundle is shown in Figure 4-15. The average bundle is shown since core vulnerability was defined in terms of the average bundle peak clad temperature.

Much of the data shown in Figure 4-15 is displayed in Figure 4-16 from a different perspective. Figure 4-16 shows the relationship between peak cladding temperature and water level for the postulated event. For the

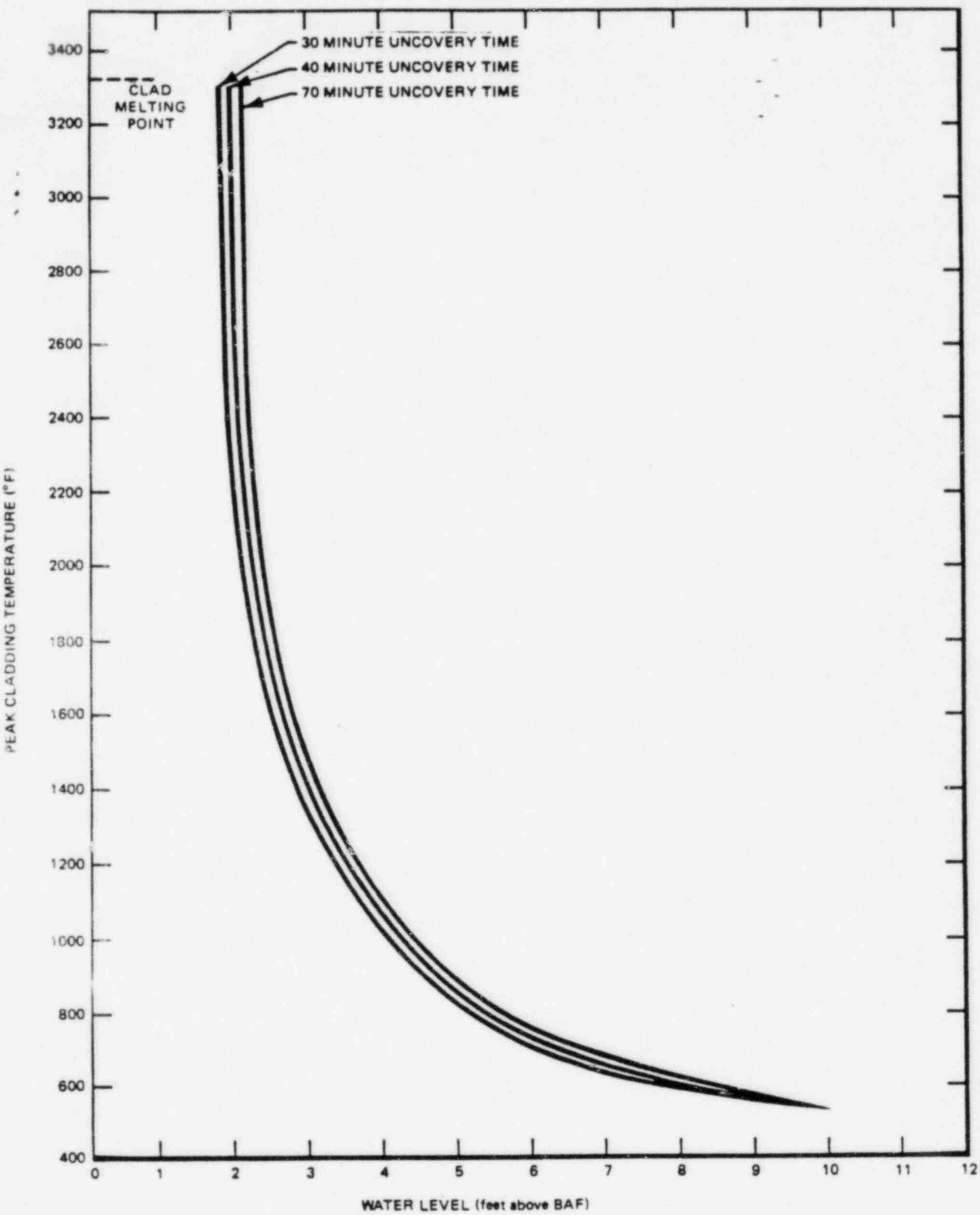


Figure 4-16: Water Level as an Indicator of Fuel Integrity

definition used here, core vulnerability would occur when level is about 8.5 feet below the top of the active fuel. The sensitivity of the water level/clad temperature relationship to changes in the time between scram and core uncovery is also shown in Figure 4-16. These curves show that the relationship does not change over a wide range of core uncovery times. The water level/clad temperature relationship is therefore applicable to other events. The variation is small because of the steam cooling effect on the uncovered portion of the rods. At earlier uncovery times, the additional steam generated in the covered portion of the bundles removes more heat than is added by the higher decay heat in the uncovered portion.

Effect of Changing Pressure

The previous analysis assumed that the vessel pressure was constant and the inventory loss occurred continuously at a rate equal to the boil-off rate. The intermittent SRV action that would occur subsequent to isolation was not modeled. Using this basis, however, was more conservative than assuming the sawtooth-shaped pressure/flow characteristic associated with intermittent SRV action. If the SRV were to open, the two-phase coolant level would jump upward, owing to the sudden pressure drop, thereby re-wetting portions of previously uncovered fuel rods. Note that indicated level would also increase since the slight depressurization caused by SRV action would also cause a level swell in the downcomer/bypass region.

Blowdown by means of selected SRVs may be activated either automatically or by operator action. The effect of blowdown, given the additional postulated failure of all low pressure systems, is as follows. To estimate the effect that the ADS would have had on the analysis, realize first that rod-to-steam convection is the most important heat transfer mechanism insofar as clad heatup is concerned. The convective cooling provided by the rising steam is directly proportional to both the steam mass flow rate and the temperature difference between the rods and the steam. Furthermore, the boil-off rate is inversely proportional to the latent heat of vaporization of water. If the analysis had been conducted at 100 psia instead of 1000 psia, the latent heat of vaporization would then be 37 percent higher so the steam mass flow would be 27 percent lower, but the saturated steam would be over 200°F cooler. All other things being equal, the convective cooling in the early stages of stagnant boil-off would be greater at the lower pressure because the increase in heat transfer due to the cooler steam temperature would have more effect than the decrease in heat transfer due to the lower steam flow rate. Hence, the present analysis encompasses events that occur at lower pressure.

4.2.2 The Relationship Between Water Level and Core State During Core Recovery

In the event that the core does uncover, recovery of the core will cool it and restore adequate core cooling. Conservative calculations in BWR FSAR analyses show this to be the case. If the period of uncovery is extended, then fuel failures and resulting local damage and flow blockages may occur. The review of tests and analysis given in Reference 2 shows that fuel damage will not progress following core recovery, even for almost total channel blockages. The key points from Reference 2 are:

- Core Blockages. A body of tests and analyses indicate that core cooling is adequate for almost total local channel blockages, while, conversely, large local blockages are not expected due to the axial distribution of fuel failures within a bundle.
- Counter Current Flow Limiting (CCFL). Water level in the downcomer or bypass reflects the state of the core since it relates to the lower plenum level with very little influence from the upper plenum level. Furthermore, recently completed 30° core sector tests show that CCFL is not expected to occur in BWR's.

In summary, water level is a good indication of the state of the core because core damage cannot occur or propagate when level is high, and water level can be used to predict the peak clad temperature.

4.3 Summary

The indication errors as a function of various plant parameters may be used to estimate indication errors due to process parameter changes for differing plant conditions. Under normal operating conditions (~1000 psig vessel, 80°F drywell, 80°F reactor building) no flashing can occur and the errors due to other factors will be as follows:

NARROW RANGE : Negligible error

WIDE RANGE : +7 inches due to dryer pressure drop, -18 inches due to jet pump flow, for a total of -11 inches

FUEL ZONE : Full upscale due to jet pump discharge head.

If power is reduced to natural circulation (30% recirculation flow, 45% power) no flashing will occur and the other indication errors will be:

NARROW RANGE : -5 inches due to change in drye pressure drop.

WIDE RANGE : +1 inch due to dryer pressure rop, -1 inch due to jet pump flow for zero total.

FUEL ZONE : -45 inches due to jet pump flow, -90 inches due to vessel density for a total of -135 inches. Will be just onscale if water level is near normal.

If the vessel is depressurized, the errors will be:

NARROW RANGE : -7 inches due to loss of dryer pressure drop, +11 inches due to vessel density if water level is near normal for total of +4 inches. Maximum flashing errors would be 103 inches for side A and 53 inches for side B.

WIDE RANGE : +56 inches due to vessel density effect if level is near normal. Will be offscale until level drops to about 15 inches above instrument zero. Maximum flashing errors would be 103 inches for side A and 53 inches for side B.

FUEL ZONE : Negligible error since this is the calibration condition. Maximum flashing errors will be 75 inches for side A and 36 inches for side B. The flashing error is less for the fuel zone instrument because the variable leg density decrease compensates to some degree for the reference leg density decrease.

The various instruments are useful under differing plant conditions. The narrow range instrument is very accurate under normal operating conditions and remains reasonably accurate for other expected plant conditions where no line flashing occurs. The wide range is reasonably accurate until vessel pressure is reduced and then indicates high due to vessel density effect. Note, however, that its absolute accuracy will improve as level drops since the vessel density causes a fraction of point error, and will be less than +8 inches when level reaches level 1. The fuel zone instrument gives good accuracy subsequent to vessel depressurization.

In summary, the Shoreham level measurement system has short vertical line drops since it does not employ the heated reference leg system, and its susceptibility to flashing and temperature errors is limited. Further discussion of the impact of errors caused by flashing is given in Section 5.

The fuel zone instrument may be used to indicate the core state when vessel level is low enough to threaten core integrity. At those conditions, the jet pump flow is essentially zero, so it does not contribute to the fuel zone indication error. At high pressure, the error due to vessel density will be about -45 inches when the coldest bundle uncovers. Thus, under these conditions, the indicated level is conservative and actual level is easily determined if desired. When pressure is reduced and no instrument line flashing occurs, the fuel zone error is quite small and reliably indicates actual downcomer/bypass level. Note that the indications always conservatively indicate core state since the indication is conservative for the event analyzed in Section 4.2, while the core heat-up analysis is conservative at low pressure, where the indication is accurate.

If flashing should occur, the fuel zone error would be +75 inches on Side A and +35 inches on Side B until the vessel is flooded and the reference line is filled. Prior to restoring the reference lines, the level indications under various conditions would be as follows. Actual level is about 3 feet below the top of the active fuel when side B indicated level is at the top of the active fuel. Figure 4-16 shows that, under these conditions, very little clad heat-up would occur and no fuel damage would be expected. If the Side A instrument indicated that level was at the top of the active fuel, the actual level would be about 5.5 feet below the top of the active fuel, and the peak clad temperature would still be more than 500°F below the point where the core is considered vulnerable.

In conclusion, the water level system at Shoreham will conservatively indicate the core state under most conditions and, if indicated level is kept above the top of the active fuel, will assure that no fuel damage will occur even during the period between postulated reference line flashing and refill of the reference line. The water level system is therefore a satisfactory device for assuring adequate core cooling and for indicating the potential of inadequate core cooling.

Since water level does not require placing a device in the core, it is also a reliable indication of the recovery from a condition where fuel damage could occur. Restoring indicated wide range water level to near level 2 assures that the core is in an adequately cooled state since the occurrence of gross fuel damage will not degrade the water level measurement system.

Section 5

PLANT EVENT ANALYSIS

The purpose of this section is to present a performance analysis of the Shoreham water level measurement system. In Subsection 5.1, several plant events and their interaction with the water level measurement systems are examined to identify selected events which may challenge the system and to determine the response of the plant to the events. Subsection 5.2 presents the results of the failure analysis of level detection and logic schemes for the Shoreham water level measurement system. Subsection 5.2 focuses on the level detection instrumentation, the logic, trip, and initiation functions, and examines the system with respect to its response to various postulated water level system failures.

The analysis given in this section is based on the analysis methods and techniques used in Reference (1).

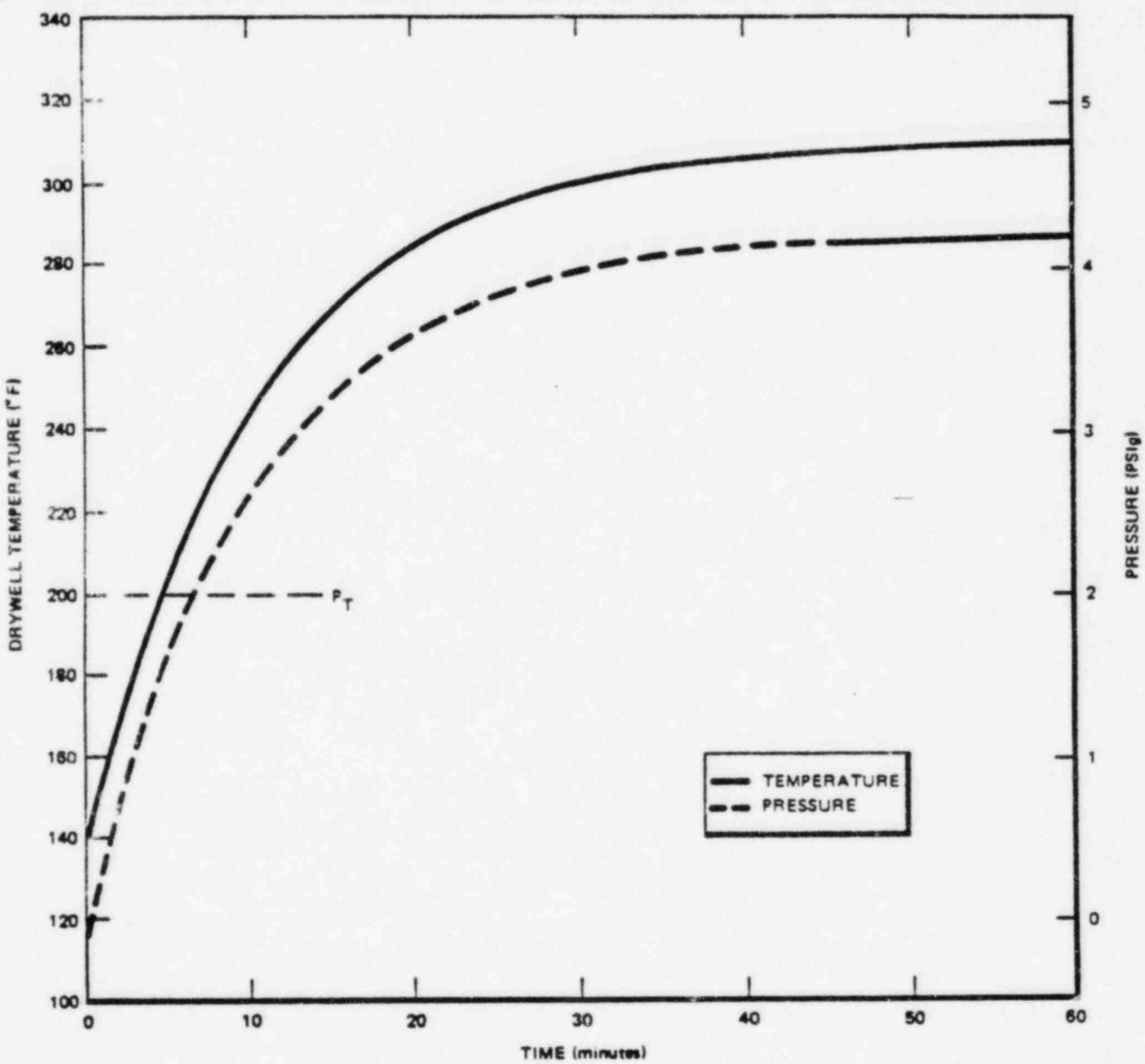
5.1 PLANT TRANSIENT AND ACCIDENT ANALYSIS

This section provides an analysis of the interaction between plant events, the plant water level measurement system, and the plant systems used to mitigate the events. The water level indication errors developed in Section 4 are used to estimate the indicated level at various points in selected plant transients. The plant transients selected are those which cause the parameters affecting sensed level to deviate considerably from the calibration conditions.

As discussed in Section 4, a review of the parameters affecting indicated level shows that concurrent high drywell temperature and low vessel pressure are required before significant degradation of level indications is expected. Ther error caused by high drywell temperature is 0.25 to 8 percent for the narrow and wide range instruments when drywell temperature is at its maximum expected value (320°F) and vessel pressure is near 1000 psig. Low pressure alone can cause an error of 30 percent of point in the narrow and wide range instruments. However, the absolute error caused by low pressure is small at the low end of the instrument ranges, so the error caused by pressure changes alone does not degrade the ability of the operator and automatic plant systems to maintain adequate inventory. When high drywell temperature and low vessel pressure occur concurrently, the total error is the sum of the two errors and it increases correspondingly. As described in Section 4, extreme combinations of vessel pressure and drywell temperature can cause flashing of the instrument lines and subsequent substantial errors in indicated level. Plant event profiles that lead to the simultaneous existence of these two conditions are therefore of the greatest interest. The following subsections examine plant events that may lead to this circumstance. The discussion of the events which follow is based on typical BWR responses. The analysis does not represent a second by second analysis of the Shoreham Plant response. Rather, it provides bounds on how the plant and level instruments are expected to respond under abnormal conditions.

5.1.1 Loss of Drywell Cooling

Interruption of adequate drywell cooling will cause a fairly rapid increase in drywell temperature and pressure with the resulting scram and plant shutdown. If the vessel is depressurized as part of the normal shutdown process, instrument line flashing may occur. A drywell thermal time constant of about ten minutes and a maximum drywell temperature of 310°F will be used in this analysis. These values are typical of BWR's and are not Shoreham-specific. However, the event progression would not be signficantly different if the Shoreham-specific values were used. The 310°F temperature requires the heat transfer from the vessel to the drywell to be approximately equal to the heat transfer from the drywell to the reactor building. Figure 5-1 shows the typical BWR drywell



Loss of Drywell Coolers Containment Temperature and Pressure Response

Figure 5-1

temperature and pressure response developed in reference (1) and used in this analysis. The pressure response is obtained from the temperature response and the ideal gas law. The event description assumes all trips occur when the indicated parameter is at the normal trip setting given in Table 3-2 and that the thermal time constant for sensing line heating is small compared to the drywell thermal time constant. The second assumption is not precise but generally gives conservative results for drywell heat-up events.

5.1.1.1 Event Progression

As the drywell heats up, the indicated narrow range level will increase. The feedwater control system will respond to this increase in indicated level by decreasing feedwater flow. Therefore, actual water level will decrease even though the indicated narrow range level will remain near the level set point. At the high drywell pressure trip point (2 psig), scram and ECCS initiation signals (HPCI initiation and injection, LPCI and core spray startup in the recirculation mode) will occur. The drywell temperature will be about 218°F as indicated by Figure 5-1. (The temperature actually may be lower since the initial drywell pressure is slightly higher than atmospheric pressure.) Vessel pressure will remain high and will have little effect on indicated level so the actual level will be about two inches below the side A narrow range indicated level if feedwater control is on Side A. The wide range instrument will indicate 16 inches low on Side A and 18 inches low on Side B. The fuel zone instrument will read full upscale until the recirculation pumps trip.

HPCI injection will not participate in the early part of the transient following scram. There are three general plant conditions that may exist a few seconds after the scram. The plant conditions that may occur depend on the relative response rates of various systems and are as follows:

A. <u>Pressure regulator controlling pressure; feedwater system tripped.</u> This condition occurs if the pressure regulator is fast and the feedwater system is slow. In this case, the pressure regulator will quickly reduce steamline flow, and vessel pressure will decrease slightly but feedflow will remain high. The excess feedwater flow, coupled with the level rise due to the pressure decrease, will cause the level to rise to above the feed pump and HPCI high level trip. In this case, pressure is maintained within the regulation band by the pressure regulator and the inventory is being lost through the turbine bypass valves.

B. Pressure regulator controlling pressure; feedwater maintaining level. This condition occurs if the difference in response rates between the regulator and feedwater system is such that the level stays below the high level feed pump trip. Note that a high level trip of the feed pump and HPCI would eventually occur if the operator does not turn off HPCI.

C. Vessel isolated. This condition occurs if the pressure regulator is slow enough to allow the steamline pressure to drop below the 850 psig MSIV closure set point before the operator switches from the run mode to the shutdown mode. Subsequent to MSIV closure, a turbine trip and the resulting recirculation pump trip occur. In this case, the Safety Relief Valves (SRV's) are maintaining vessel pressure within the limits and the feedwater pumps are off since no steam is available to power their turbines. The inventory will slowly be depleted through intermittent SRV action. The operator must manually control HPCI to maintain level. The high level HPCI trip would occur if the operator fails to provide adequate manual control.

Conditions A and C are similar in that feedwater is not available. In Condition A, the pressure will be somewhat lower, but this will not have a significant effect on the event. In either case, inventory will be slowly lost as a result of decay heat boil-off. Recirculation drive flow will be reduced to a low value in both cases due to recirculation flow runback signals originating in the feedwater system. Therefore, the two cases to consider are shutdown with and without feedwater.

5.1.1.2 Shutdown Without Feedwater.

For this case the feedwater system is assumed to be lost early in the transient. In this situation, the operator will be using the high pressure ECCS system pump controls and level indicators on the emergency core cooling benchboard to control level and the relief valve controls on the shutdown cooling benchboard to control pressure while taking the plant to cold shutdown. Subsequent to the scram and loss of feedwater, the actual water level will be on the order of 10 inches below narrow and wide range instrument zero; the vessel pressure will be high; and the drywell temperature will be about 220°F. For these conditions, the narrow range instrument indication will be downscale, and the wide range will indicate two inches high on Side A, with little error on Side B. If the recirculation pumps are operating at about 50 percent flow, then the fuel zone error is about 50 inches low, and they will remain offscale high. If the recirculation pumps trip, the fuel zone instrument will indicate 130 inches low on Side A and 135 inches low on Side B, which is large enough for the instruments to be on scale. Note that the large error in the fuel zone instrument is a result of its calibration for low vessel pressure.

Normal Cooldown Event Profile Without Feedwater. Plant emergency procedures require the operator to rapidly depressurize and flood the vessel before drywell temperature reaches 296°F. If the operator fails to implement this procedure, the cooldown and depressurization could proceed at the normal rate. The error caused by a drywell temperature of 310°F is only 4 inches on the Side A wide and narrow range instruments and 0.5 inch on the Side B instruments, so the normal cooldown would not be affected until vessel pressure dropped below 63 psig (saturation pressure corresponding to the 310°F drywell temperature) and the instrument lines begin to flash. Prior to achieving this pressure, the plant would have been placed in the shutdown cooling mode, and indicated level on the narrow range instruments would be between Level 7 and Level 4. The operator is directed to keep the narrow range instrument indication near normal water level to provide margin to the low level isolation of the Residual Heat Removal (RHR) system. Under these conditions as pressure approaches 63 psig, but before flashing occurs, the indicated level error caused by combined high drywell temperature and low vessel pressure would cause the narrow range indicated level to be 12 inches high, and the wide range instruments would be upscale because of the large error due to the vessel pressure effect. When pressure drops further, flashing will occur and level indications will rise. The flashing error under these circumstances is assumed to follow the no carryover characteristic. A drop in pressure to 50 psig would cause the narrow range indication error to suddenly increase to about 22 inches on both Side A and Side B narrow range indications and the wide range would remain upscale. An error of this magnitude would not significantly affect plant operation. Also, the sudden rise in indicated level caused by the flashing coupled with operator training and procedures that identify the potential for flashing, would warn the operator that something has occurred in the level system since no inventory change is expected under shutdown cooling conditions. Therefore, this situation will not jepordize core cooling if the operator maintains level above level 3 on the wide range instruments, as plant operating procedures require.

Event Profile with ADS Without Feedwater. If the operator fails to depressurize and flood the vessel and the high pressure systems are unavailable or do not initiate, the vessel must be depressurized to within the range of the low pressure systems before makeup water can be supplied. If no operator action is taken, the level will continue to decrease until the ADS initiation level is reached. At 310°F drywell temperature and 1000 psig vessel pressure, the indicated wide range level will be within 4 inches of actual, so that ADS will initiate as required. The vessel inventory would drop to the ADS level 20 to 25 minutes after scram. Once ADS is initiated, pressure will drop with approximately an exponential decay. Pressure is expected to reach a minimum of about 50 psia during ADS. Since the depressurization is fairly rapid, the error due to flashing will follow the full carryover case. The indication error during the flashing transient would be erratic with a maximum error of about 10 inches on the narrow and wide range instruments. Subsequent to the flashing transient, the indicated level will be about 70 inches high on the side A wide range instruments and about 50 inches high on side B. The fuel zone will read 45 inches high on side A and 28 inches high on side B. If the operator does not inject with the low pressure systems until drywell temperature is less than 212°F, as required by procedure he is assumed to increase level to at least level 3. When indicated level is at level 3 on the side A wide range, actual level is still more than six feet above the top of the active fuel (TAF), and adequate core cooling is assured. If the operator follows procedures and rapidly depressurizes the level when drywell temperature approaches the stated limit, the indication errors would be about the same as the automatic ADS case. However, level would not be expected to reach level 1 since the procedure which requires depressurization also calls for flooding the vessel, so the operator would be expected to disregard level indications and use other means to establish that the vessel is full of water.

5.1.1.3 Shutdown with Feedwater. This case is no different from shutdown without feedwater (except that the operator's primary perception will be at the feedwater control panel) because shutdown cooling will be established before flashing occurs.

5.1.2 Small Steam Break

The small steam break is similar to the loss of drywell coolers except the drywell temperature may go as high as 320°F. Subsequent to scram, the same plant conditions are possible. Plant operating procedures would require the operator to depressurize and flood the vessel because drywell temperature is high. However, as in the loss of drywell cooling event, other postulated sequences will be evaluated to illustrate the performance of the water level system. For this break size HPCI is designed to initiate automatically and fill the vessel to level 8. If the HPCI fails to initiate on high drywell pressure then level will decrease until HPCI and/or RCIC initiate on low level. As long as a high pressure system is available, level indications will be satisfactory since pressure remains high.

If the high pressure systems fail, the level will continue to decrease until the ADS is initiated. For a 320°F drywell temperature, the wide range level will indicate approximately 5 inches high, so ADS initiation will occur as required. The low pressure ECCS system will begin to inject water as pressure drops below their shutoff head. Flashing will begin when pressure reaches 103 psig, which is low enough for shutdown cooling to be established.

The steady-state indication errors subsequent to flashing for side B will be about the same as the loss of drywell coolers case. For side A, the error will be about 85 inches. The maximum error during the flashing transient will be 16 to 17 inches. If the operator does not flood the vessel but maintains level near level 3 on the side A wide range indicator, actual level will still be about five feet above the TAF and adequate core cooling is assured. Actual level would remain higher if the Side B wide range indicator was maintained near level 3.

Long-Term Effects. For the small steam break, long-term boil-off of all reference legs will occur 1.0 to 2.5 hours after the event, depending on the break size and the procedures used by the operator, because pressure is expected to drop below the instrument line flashing pressure at some point in the shutdown process. Prior to refill of the instrument lines via vessel flooding the side A error would be 100 inches, but the actual level will still be nearly 4.5 feet above the fuel when side A wide range indicated level is near level 3, with higher actual level maintained if the Side B wide range indicators were near level 3.

5.1.3 Large Steam Break

The large steam break is characterized by rapid depressurization of the vessel. This transient is so rapid that all necessary level initiations will occur before the temperature increase in the drywell can affect the level measurement instruments. The long-term effects will be the same as the small steam break except the instrument reference leg boil-off will occur some 20 to 45 minutes after the break.

5.1.4 Plant Event Summary

The previous analysis shows that the level indications are satisfactory for maintaining adequate core cooling even under extreme conditions where the reference lines flash or boil off. With indicated level near the level 3 on side A, there is still almost 4-1/2 feet of water above the TAF. If indicated level was kept near level 3 on side B, there would be nearly 8 feet of water above the core. The operator would have to allow the side A wide range level to drop a foot below level 2 before the core begins to uncover.

5.2 FAILURE ANALYSIS OF SHOREHAM WATER LEVEL MEASUREMENT SYSTEM

This section provides an in-depth analysis of the level measurement systems for the Shoreham plant. The level measurement system elementary drawings and the Piping and Instrumentation Diagrams (P&ID) were thoroughly reviewed in order to determine the basic logic for reactor systems and system actions that are affected by the level measurement system. A detailed description of the review process and logic diagrams for the affected systems are contained in Appendix A. The logic diagrams identify the specific level transmitters and the transmitter sensing line divisions. These detailed logic diagrams provide a foundation from which to determine the vulnerability of the plant to postulated failures in the level instrumentation.

In order to perform a complete evaluation of all relevant failure events, it is necessary to first determine the plant vulnerabilty to potential level sensing system failure combinations. A review of the water level measurement system logic reveals that the "worst case" set of failures is a reference leg blowdown with postulated single failures in a division not served by the failed reference leg. The reference leg blowdown is significant in that this postulated event affects all instruments that are connected to the reference leg. The reference leg blowdown will cause the level instrumentation connected to that leg to indicate full scale high level regardless of the actual water level in the reactor pressure vessel. In this study, a line break or a leak or misvalving sufficient to affect fluid level in a reference leg is conservatively considered to cause high level indications. The vulnerabilities of the Shoreham plant to a reference line failure plus a single level instrument failure are shown in Table 5-1. The systems may be initiated by other signals and conversely, single failure in other components may cause loss of system initiation. The analysis here addresses only the system vulnerabilities with respect to the water level measurement system. This table summarizes the information contained in the detailed system logic diagrams and analysis that are provided in Appendix A. To avoid confusion on the meaning and use of these tables, a detailed explanation is provided herein:

a. The first row in the table identifies the location of the postulated reference leg failure, i.e., Side A or Side B.

b. The second row identifies the physical location of a postulated additional single failure. Each column in the table then represents a particular worst combination of reference leg break and additional single failure location.

c. The remaining rows in the table identify, on a system by system basis, the plant "vulnerability" to each combination of reference leg break and additional single failure. A "V" in any location in these rows means that there is at least one level transmitter single failure that could cause the system in question to fail to automatically initiate due to a reactor water level condition.

Table 5-1

Vulnerability of Systems to Automatic Initiation Failure
Caused by Combinations of Reactor Level Reference Leg
and Single Level Instrument Failure

Reference Leg Failure(s):	A side	B side
Single Level Instrument Failure:	B side	A side
SYSTEM		
• RPS	V(1)	V
• ADS Confirming	V	V
• HPCI] (4)	V(3)	V(3)
• RCIC]	V	V
• CS/LPCI]	V(3)	V(3)
• ADS]	V	V
• ATWS (5)]	V	V
• MSIV	V	V
• FEEDWATER		
- A Control	DS (2)	DS* (2)
- B Control	DS*	DS

NOTES:

(1) V = Vulnerability of the system(s) to fail to initiate automatically on level inputs due to the indicated combination of reference leg failure(s) and single worst case failure in the instrument utilized for the indicated system(s).

(2) DS = Feedwater will decrease, then shut off under the conditions of the indicated combination of reference leg failure(s). DS* = same effect as DS but due to single worst case failure in the instrument utilized for the Feedwater Control System.

(3) If a high drywell pressure signal occurs, these systems are not vulnerable to level sensor failures. If the drywell pressure stays below set point, then the systems are vulnerable to level sensor failure.

(4) Bracket] indicates that these systems share the same set of level instruments.

(5) ATWS mitigation also initiates on high reactor pressure.

d. The feedwater control system is treated differently in these tables. A "DS" in any location in the matrix means that the feedwater control system will cause the feedwater flow to decrease and shut off. "DS" means that the decrease and shut off is caused by the reference leg break alone. "DS*" means that the decrease and shut off is caused by an additional single failure.

To complete the failure analysis, it is necessary to determine the consequences of each reference leg break/additional single failure combination for which a system vulnerability has been identified. such a consequence analysis has been performed qualitatively and the plant response scenarios are described in the following sections.

5.2.1 Water Level System Failure Analysis

A review has been conducted of the consequences of reactor vessel water level system reference leg breaks (or significant leaks) with an additional active component failure which could effect the automatic systems initiation on vessel water level. Six primary events, depending on the specific additional single failure, have been identified--failure of an RPS transmitter, failure of an ADS transmitter, failure of an MSIV transmitter, failure of a coolant injection system transmitter, failure of a feedwater control transmitter and a failure in one of the redundant power buses supplying the level instruments. The response scenarios for each of these events are described below.

It has been concluded that the consequences of the additional single failure are of concern only when a coolant injection system initiation transmitter has an undetected failure or a power bus fails subsequent to the reference line failure, because these events require operator action to assure adequate vessel inventory. Several indications are available in the control room to give the operator information relative to the event. The high natural circulation flow, coupled with the decay heat removal by the control rod drive flow allows the operator 30 to 40 minutes to take action before jepordizing the core (see Section 4); so successful operator mitigation of the event is expected.

5.2.2 Plant Response to Failure

Assumed Initial Operating Conditions. The reactor is operating at full power. Feedwater flow is under automatic control through the level instrumentation on side A. There is an undetected failure in a single level transmitter in the level instrumentation on side B. The response scenarios discussed below are unchanged if feedwater control is through the side B instrumentation and the instrumentation failure is on side A.

Event Initiation. The transient event is initiated by a break in the level instrumentation reference leg in level instrument side A (the side controlling feedwater flow).

Response Scenarios. Several possible events result from the reference leg break depending on which side B level transmitter has experienced the undetected failure. The response scenarios for each of these events are described qualitatively in the remainder of this section. The initial system response is the same for all events of interest. The reference leg break will cause a high level indication to the feedwater control system that will result in a reduction of feedwater flow. Feedwater system inertia results in a four to five second feedwater flow decrease before flow reaches its minimum. The decrease in feedwater flow produces a slight system pressure decrease and a decrease in core inlet subcooling. Both of these effects lead to an increase in core void fraction which reduces reactor power and moderates the decrease in reactor vessel water level for the first few seconds of the transient event. Sensed reactor vessel water level on the intact side B instrumentation decreases quickly and reaches level 3 approximately six seconds into the transient. The scenario up to this point is virtually identical to that of the loss of feedwater flow event analyzed in the plant Final Safety Analysis Report (FSAR). It has not yet been affected by the undetected instrument failure. From this point on, the scenarios are influenced by the single instrument failures, and separate discussions will be provided for each failure.

5.2.2.1 Failure of Reactor Protection System (RPS) Transmitter

From Tables 5-1 and A-2, and from Figure A-4, we see that there are several reference leg break/single instrument failure combinations to which the RPS is vulnerable. For example. with feedwater under control of side A and a side A reference leg blowdown, a failure in either transmitter LT-B21-N080C or LT-B21-N080D will cause a loss of scram initiation on level 3. and loss of isolation of RHR sample lines and discharge to radwaste. However, when the sensed level reaches level 2, low level signals from LT-B21-N081C and LT-B21-N081D activate the Main Steam Isolation Valve (MSIV) closure, which closes in 3 to 10 seconds. Position switches on the MSIV signal the Reactor Protection System (RPS), resulting in reactor scram. All coolant injection systems that are assumed to respond to the event are unaffected by the RPS transmitter failure and operate as required to provide long-term cooling and maintenance of coolant inventory. It should be noted that, although the postulated break will be releasing energy into the drywell, this scenario assumes that the energy is not sufficient to result in a high drywell pressure signal and subsequent scram. This event is similar to the loss of feedwater event reported in the plant FSAR. The scram is delayed and achieved indirectly, but there is clearly no danger of the core uncovering, nor is there any requirement for unusual operator action.

5.2.2.2 Failure of Automatic Depressurization System (ADS) Transmitter

From Tables 5-1 and A-2, and from Figures A-10 and A-11, we see that there are reference leg break/single instrument failure combinations to which the ADS is vulnerable. For example, if we substitute failure of the side B ADS confirming level transmitter into the prior case, ADS level initiation will be lost. However, this is a benign situation since low level initiation of the high pressure injection systems (HPCI and RCIC) is not effected so ADS is not required.

5.2.2.3 Failure of MSIV Transmitter

From Tables 5-1 and A-2, and from Figure A-7, we see that there are several reference leg break/single instrument failure combinations to which the MSIV function is vulnerable. For example, with feedwater control on side A and a side A reference leg break, a failure in either transmitter LT-B21-N081C or LT-B21-N081D causes a loss of main steam line isolation on level 2. Reactor scram will occur on a level 3 trip and will cause some lines to isolate, but most, including the main steam lines, will not isolate. All coolant injection systems that are assumed to respond to the event are unaffected by the transmitter failure and operate as required to provide long-term cooling and to maintain pressure vessel coolant inventory. There is clearly no danger of the core uncovering in this event, nor is there any need for unusual operator action.

5.2.2.4 Failure of Coolant Injection System Transmitter

From Tables 5-1 and A-2, and from Figures A-5, A-6, A-8 and A-9, we see that there are several reference leg break/single instrument failure combinations to which the coolant injection systems are vulnerable. For example, with feedwater control on side A and a side A reference leg blowdown, a failure in either transmitter B21-N091B or B21-N091D will cause a loss of low level automatic initiation the following systems: High Pressure Coolant Injection (HPCI), Reactor Core Isolation Cooling (RCIC), Low Pressure Coolant Injection (LPCI), Core Spray (CS), and The Automatic Depressurization System (ADS). Reactor scram, system isolation, and recirculation pump trip level instrumentation are unaffected by this transmitter failure. The RPS will scram the reactor at level 3. MSIV closure will occur at level 2. It should be noted that, although the postulated instrument line failure will be releasing energy into the drywell, this scenario conservatively assumes the energy is not sufficient to result in a high drywell pressure signal and subsequent HPCI and low pressure ECCS pump initiation. The rate of water level decrease will slow appreciably following closure of the MSIV, but coolant will continue to be lost from the primary system through the level instrumentation reference leg break and through intermittent action of the safety/relief valves. Failure of the operator to manually initiate a coolant injection system would eventually lead to uncovering of the core.

The level instrumentation failure will also prevent level initiation of ATWS-RPT and ATWS-ARI, but they will initiate on high reactor pressure causing the reactor recirculation pumps to trip and alternate control rod insertion (backup scram) to occur, if a turbine trip or MSIV closure occurs from high power.

The reactor operator will see an indication of high water level from the feedwater controlling instrumentation and will see that feedwater flow has been shut off. The operator will also observe a mismatch between the level instrumentation of side A and side B. This mismatch may help the operator to detect the reference line break (or an indication that there is a failure in the level instrumentation), but, potentially, not in time to terminate the event by taking manual control of feedwater flow or by switching automatic control to the other instrumentation side. The failure of the coolant injection system transmitter should be evident to the operator when he observes that reactor scram and system isolation have occurred and no coolant injection systems are operating. Indications of the break in the reference leg through increased drywell temperature, increased drywell pressure, and drywell sump pump actuation may also be available to the operator. Finally, uncovery of the core will not occur for 30 to 40 minutes, giving the operator a substantial amount of time to manually initiate one of the many inventory make-up systems.

5.2.2.5 Feedwater Control Transmitter Failure

From Tables 5-1 and A-2, we see that there are no safety trips vulnerable to a reference line break and a single failure of the feedwater control transmitter in the other mechanical division. This is the case because the feedwater control transmitters (LT-N004A, B, and C) do not initiate any safety trips.

5.2.2.6 Power Bus Failure

The Shoreham plant has four essential (Class 1E) power buses for powering the plant safety systems, as follows:

- RPS Bus A (120 VAC)
- RPS Bus B (120 VAC)
- DC Bus A (125 VDC)
- DC Bus B (125 VDC)

The failure of a power bus in addition to the instrument line failure will also cause loss of low level initiation as discussed in Appendix A. A failure in instrument line A plus a failure in DC Bus B will cause loss of automatic level initiation of HPCI, RCIC, LPCI, LPCS, ADS, and ATWS mitigation features. Similarly, a failure in instrument line B plus a failure in DC Bus A will cause the loss of automatic initiation on low level for the same systems. A loss of power will not affect the RPS or MSIV initiation because they are de-energized to operate systems, so a power failure causes one of the channels to generate a system initiate signal (i.e. isolation and scram). The power bus failure is different from the instrument failure in that it will be detected as soon as it occurs because annunciators are provided to warn the operator of the failure. Therefore, the power failure must occur subsequent to the line breaks, which has a much lower probability than the undetected sensor failure.

5.3 PLANT ANALYSIS SUMMARY

The preceding analysis of the Shoreham plant shows that flashing of the instrument lines will not jeopardize core cooling because the reference line drop is short enough so that adequate vessel inventory is assured when the operator maintains level above level 3. When indicated level is above level 3, as required by normal operating procedures, there is sufficient inventory to assure adequate core cooling. The reference leg drop is also short enough so high drywell temperature will not cause a large shift in the low level ADS initiation setpoints. Thus, the setpoint adjustment described in Reference (7) will not have a significant impact on the Shoreham ADS setpoint.

The reference line failure plus additional single failures in some cases require operator action to assure adequate inventory. However, the many level indications in the control room provide the operator with sufficient information to select and correctly implement the appropriate procedures to assure adequate inventory. Note that the plant vulnerability to reference line failure plus single active failure is due primarily to the use of sensors LT-B21-N091A, B, C, and D to initiate all emergency core cooling systems, combined with the feedwater control signal vulnerability to the instrument line failure.

This section provides a deterministic based analysis of the reference leg failures plus an additional single active failure. The next section provides a probabilistic analysis of the reference line break combined with one, two or more additional failures, including errors made by the plant opeators. A probabilistic analysis of the interation between the plant, operator, and level measurement system for other events is also given in the next section.

Section 6

REACTOR WATER LEVEL INSTRUMENTATION CONTRIBUTION TO CORE VULNERABILITY

Reactor water level measurement instrumentation affects both the operator's perception of the condition of the core and the automatic controls of normal and safety systems. As a result, failure modes of this instrumentation which can disable multiple systems become important in the evaluation of plant safety despite the low frequency of the postulated failure modes.

The failure modes of the water level instrumentation which have been postulated and observed in the operating experience data base include:

1. Leaks or breaks in the reference leg of the reactor water level instruments;

2. High drywell temperatures causing boiling or flashing of the reference leg;

3. Other water level instrument failure modes, including miscalibration.

The methods used in this section to investigate the impact of various postulated failure modes on plant safety applies the Probabilistic Risk Assessment (PRA) techniques used in the Shoreham PRA. The use of event trees and fault trees provides the framework for evaluating the consequences of reactor water level instrumentation failures. This consistent basis of comparison then allows the potential risk associated with the water level instrumentation failure modes to be placed in perspective relative to other sources of risk at the Shoreham plant.

A calculation of the contribution to core vulnerable frequency is presented for four specific situations which are affected by water level instrumentation.

* <u>Breaks or leaks in the reactor water level instrumentation lines (Section 6.2).</u> The potential for accident sequences involving failures in a reactor water level instrumentation reference leg is a source of risk which was not explicitly evaluated in the Shoreham draft PRA, but it is evaluated here.

* <u>Loss of Drywell Cooling following other initiators (Section 6.3).</u> The loss of drywell cooling during the course of previously identified accident scenarios could cause some adverse impact on the operator response. The impact of the loss of drywell cooling is calculated based on the operating procedure guidelines for Shoreham. The added contribution to calculated core vulnerable frequency is small compared with other contributors.

* <u>Loss of Drywell Cooling Initiators (Section 6.4).</u> Manual shutdown caused by the degradation or inoperability of the drywell coolers was not explicitly included in the Shoreham draft PRA. The results of the evaluations included here represent a small addition to the calculated frequency of core vulnerability from all sequences.

* <u>Inherent reactor water level instrumentation failure contribution (Section 6.5).</u> This evaluation was performed in the original Shoreham PRA. The results are summarized here both for purposes of comparison and to provide a complete summary of the impact of water level instrumentation failures.

6.1 APPLICATION OF PROBABILISTIC TECHNIQUES AND METHODOLOGY

The Shoreham plant has been analyzed using probabilistic techniques. This analysis provides a logic model of the plant which describes component and system level interaction. Specific accident sequences have already been analyzed within this framework and included in the quantitative calculation of the core vulnerable frequency associated with the operation of Shoreham. This methodology can easily be extended to the evaluation of other accident sequences which were not included in the Shoreham draft PRA.

6.1.1 Background of PRA Application

The Shoreham Probabilistic Risk Assessment (PRA) applies the WASH-1400 (3) techniques, i.e., event trees and fault trees, with appropriate modifications. In the Shoreham PRA analysis, event trees were constructed to relate mitigating systems to selected accident initiators. Fault trees were constructed as required for the events that appear in the event trees. Independent failure modes as well as common mode miscalibration of the reactor water level instruments were included, as appropriate, in the fault trees of the original analysis. However, consistent with previous analyses such as WASH-1400 (3), RSSMAP (4), and IREP (5), the failure of, or inaccurate readings from, the reactor water level sensors as a result of high drywell temperature or instrument line failure were not considered in the draft Shoreham analysis.

This study will evaluate the water level system contribution to core vulnerable frequency. New event sequences derived from modified event trees and event trees constructed specifically for this analysis were quantified using the appropriate failure probabilities from the Shoreham fault tree logic model, along with the frequencies and conditional probabilities calculated for new events included in this study. The contribution of level instrumentation failures was calculated by evaluating the dominant core vulnerable sequences in the Shoreham PRA to determine the instrument contribution to the sequence probabilities. "Dominant accident sequences" are those sequences which make the largest contribution to plant risk. Note that a core vulnerable sequence is defined as a serial list of failures that must occur before a core vulnerable condition occurs. A sequence begins with an initiator and is followed by failures in systems required to mitigate the progression of the initiating event.

The PRA logic models form the framework into which the engineering details of the reactor water level system are integrated. Specifically, the following key features of the reactor water level measurement system are incorporated:

1. Basic design;

2. Interface of water level instruments with normal and safety systems;

3. Operator perception if failures occur in the level instrumentation;

4. Operating procedures in response to various water level readings including spurious signals.

This input information has been developed for Shoreham and is summarized in Section 3 and Appendix A.

6.1.2 Core Vulnerable Sequence Endpoints

The Shoreham PRA categorized the accident sequences leading to core vulnerability into five classes. The five classes are defined according to effects on core, containment, and potential for radionuclide source.

Class I: Loss of Inventory Makeup. This class is characterized by a failure to maintain adequate core cooling and a relatively fast core melt with the containment intact at the onset of core melt.

Class II: Loss of Containment Heat Removal. This class is characterized by an inability to remove heat from containment and a relatively slow core melt with the containment failed prior to the core melt.

Class III: LOCA Plus Loss of Inventory Makeup. This class is characterized by a relatively fast core melt with incipient containment failure due to high containment pressure at the onset of core melt.

Class IV: ATWS Plus Loss of Poison Injection or Loss of Suppression Pool Cooling. This class is characterized by a relatively fast core melt with the containment failed at the onset of core melt.

Class V: Interfacing LOCA Outside Containment. This class is characterized by a loss of primary coolant to the reactor building and a relatively fast core melt with a direct bypass of the containment during core melt.

In general, the Class I and II events have relatively high frequencies and relatively low consequences, while the other classes have relatively low frequencies and higher consequences.

6.1.3 Guidelines for the Probabilistic Analysis

In order to understand the significance of the probabilistic calculations, it is necessary to establish the limitations and guidelines under which the analysis is performed. The key items are:

- The existing Shoreham PRA is used as the basic logic model for the calculation of the frequency of core vulnerable conditions associated with water level instrumentation and for the comparison of the frequencies with other contributors.

- The Shoreham PRA has not exhaustively addressed external events (e.g., seismic events, fires). Therefore, the calculations and comparisons will be based upon the frequency of core vulnerability due to internal events (e.g., transients and LOCA's) (6).

- Operator action may involve a wide spectrum of activities both during the test and maintenance operations required by plant procedures and during the course of a postulated accident scenario. In the Shoreham PRA, those planned or unplanned manipulations which are required by procedure, or which are possible remedies to a failed system, are depicted and evaluated. Operator actions which are caused by failed instrumentation are also included in the analyses; however, operator actions which defeat system performance or which aggravate the achievement or maintenance of stable hot shutdown without apparent cause are not evaluated. This approach is consistent with previous nuclear power plant PF 's such as WASH-1400 (3), RSSMAP (4), and IREP (5). (See also Appendix C).

- The uncertainty in the best estimate frequency of core vulnerability in the Shoreham PRA has been quoted as approximately a factor of 20. This indicates that the absolute value of the core vulnerable frequency may be significantly different than the best estimate value quoted. It is not surprising then that there are accident sequences which may add to the previously evaluated frequency of core vulnerable condition. However, these additions should be well within the uncertainty of the calculated frequency.

Given these restraints on the basic probabilistic analysis, the potential contribution of water level measurements indication, and control systems to the calculated frequency of core vulnerabililty can then be isolated and compared on a consistent basis with Shoreham and other plant analyses.

6.1.4 Data

The input data required to quantify the accident sequences are developed in Appendexes to this report or in the Shoreham PRA as follows:

- Component failure rates and system level unavailabilities are developed in the Shoreham PRA (6).
- Instrument line failure initiator frequencies from operating experience data are developed in Appendix B.
- Operator response error probabilities are developed in Appendix C.
- Fault trees for developing the probabilities of the functional events required for this analysis are given in Appendix D.

These data are applied using the event tree models presented here and the fault tree models which are presented in the Shoreham PRA (6). The event trees and selected fault trees were requantified for this specific evaluation.

6.1.5 Potential Impact

The results of this investigation into the impact of reactor water level instrumentation failures on core vulnerable frequency can be categorized as to the potential for adverse consequences using five unique classes or core vulnerable conditions with differing potential consequences. The class with the lowest radionuclide source term, i.e., Class I, is the class in which the additional identified sequences involved in a water level have the largest impact. Therefore, while these sequences will have an effect on the calculated frequency of core vulnerable condition, there will be little effect on the larger public consequence accident sequences of Classes IV and V.

6.1.6 Significant Shoreham-Specific Considerations

The probabilistic evaluation of the Shoreham reactor water level instrumentation and its impact on the frequency of postulated core vulnerable conditions has used the following important Shoreham-specific plant design details and procedures.

1. The normal operating mode of Shoreham will be with the feedwater level controls set to use the Side A water level instrumentation. This procedure decreases the potential for loss of feedwater and the resulting plant transient subsequent to water level reference leg disturbances.

2. Shoreham operating and maintenance procedures prohibit surveillance testing on the nuclear boiler system instrument racks when the reactor is at power. This reduces the potential for maintenance personnel inducing reference leg leaks at power, as described in Appendix B.

3. The Shoreham water level measurement system uses analog trip units rather than switches, as used in older plants from which most of the operating experience data has been collected. This aspect of the Shoreham design results in fewer maintenance actions at the instrument racks and reduces the potential for maintenance-induced leaks, as described in Appendix B.

4. Validation of the reactor water level signals will be performed once per shift. This familiarizes the operator with the relationship between the various level indications.

5. The SNPS procedures require written sign off by the technician and then an independent verification by a qualified person.

6.2 REACTOR WATER LEVEL INSTRUMENT LINE FAILURE

Previous reviews of operating experience and analytic effort have identified that the reactor water level instrumentation is subject to a low frequency failure mode which could result in false indications of reactor water level to the operator. The identified failure mode is a loss of inventory in the reactor water level instrument reference leg, as discussed in Section 5. This low frequency failure mode could act as an accident initiator which challenges the plant systems needed to insure a safe shutdown. The purpose of this subsection is to calculate the potential contribution of these failures to the frequency of a core vulnerable condition at Shoreham.

6.2.1 Initiator Frequency

The probability of a leak sufficient to drain the reactor water level reference leg has been calculated for the following two cases:

a. Instrument line break;
b. Leak or valve misoperation.

The frequencies of these initiators are combined and assumed to have equivalent impact on the operator and automatic initiation logic. They are treated in the same event tree since the level sensors connected to the line are assumed to indicate upscale regardless of the failure mode.

The initiating event frequency for the reference leg pipe break was estimated by using the WASH-1400 small pipe break failure rate per foot multiplied by the number of operating hours per year multiplied by the reference leg length, plus the failure frequency associated with weld joints and valves in the line. The combined frequency of leaks in fittings and valves and of the misoperation of valves which drain the reference leg were estimated by examining the Licensing Event Report (LER) database for such events. Appendix B summarizes the calculation of the frequency of potential leaks in the reference leg based upon the number of events and the accumulated operating experience. The result of the calculations is that the initiator frequency is conservatively estimated to be 0.020 per reactor year for each of the reference legs, a value which is dominated by the potential for failures outside containment.

6.2.2 Event Tree Structure

The postulated reactor water level instrument reference line failure is treated separately for side A and side B; that is, the effects of instrument line problems are not identical due to the asymmetric nature of the signals derived from side A versus side B. The principal differences between side A and side B (see Section 3) are:

- The feedwater high level trip logic is any 2 of 3 transmitters. There are two side A transmitters and only one on side B. Therefore, the potential impact on feedwater is substantially different depending upon which side is affected by the postulated leak.
- The HPCI and RCIC controls are powered from opposite DC buses and therefore the coupled failure of a reference water leg and a DC power supply would also be asymmetric.
- The level indications on the various panels do not contain symmetric Side A/Side B displays.

The important aspects of the quantitative evaluation include the following:

- Two quantifications are included on the event tree since side A is not symmetrical with side B. The functional event values for a postulated leak in each leg are provided in Figure 6-1. The calculated sequence frequency given is the summation of sequences occurring on both sides.
- The fault tree system logic models were recalculated, where appropriate, for the pre-existing condition of a reference line leak.

The event tree for the instrument line failure is shown in Figure 6-1, sheets 1 through 5. The event functions included in the event tree are described in detail in Appendix D; however, a capsule summary is included here to describe the nature of the functional system interaction.

Initiator (T_R Section B.1, Table B-4)

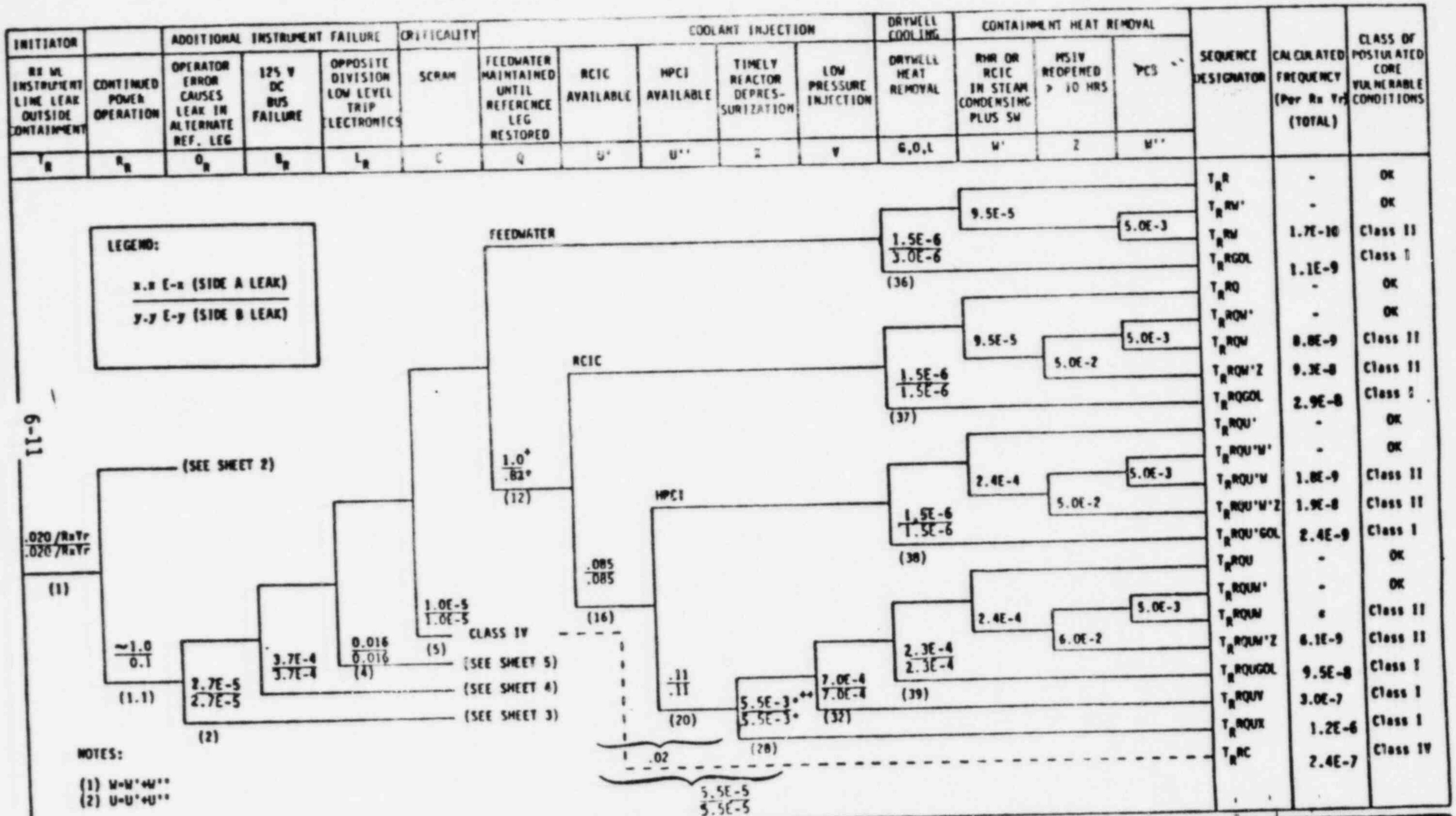
As discussed in Section 6.2.1, the initiating frequency for the water level instrument line leak is 0.020 events per year, which is judged to be equally applicable to both side A and side B.

Continued Power Operation (R_R Section D.1.1, Figure D-1)

A loss of the reference leg will not always result in a plant transient. If feedwater maintains adequate level control, then power operation will continue. The possible events following a loss of reference leg are:

- Failure is on reference leg A. A high level feedwater trip will occur since two of the three transmitters for the 2-out-of-3 high level feedwater trip logic are on side A.
- Side B Failure/Side B Control. In this case, a high level trip will not occur, but the feedwater controls will shut off feedwater due to the high level signal from the side B transmitter unless the operator successfully achieves manual control.
- Side B Failure/Side A Control. In this case, power operation will continue since no high level trip occurs and feedwater control will be unchanged.

The probability for continued power operation developed in Appendix D accounts for these events and includes consideration of the Shoreham procedures which require feedwater control to be on side A unless there are compelling reasons to do otherwise.



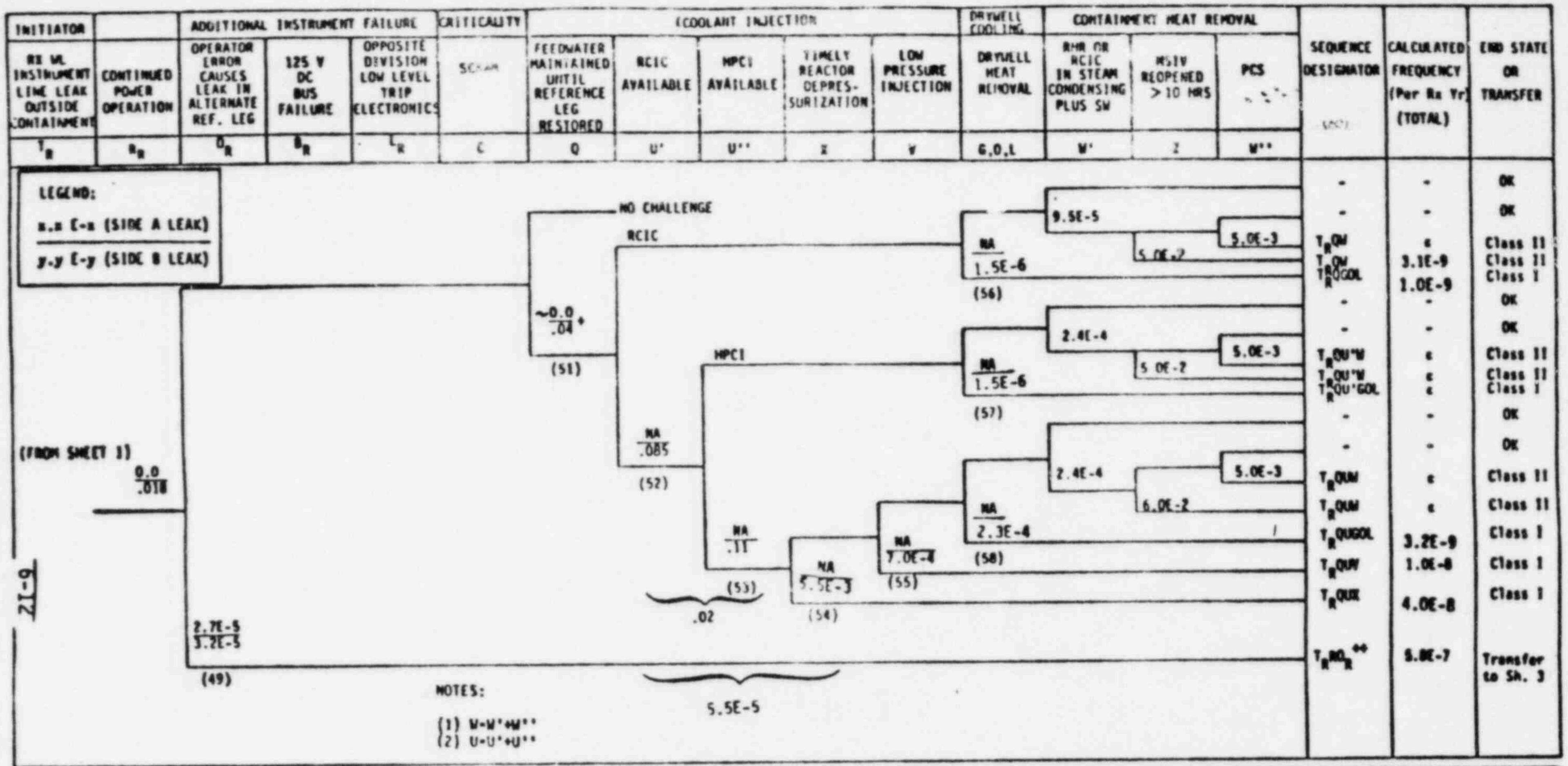
+Includes benefit for operator switching to feedwater on seperate level channel.

++10 minutes to 30 minutes

*Includes the conditional probability that the feedwater will not be available due to the initiator.

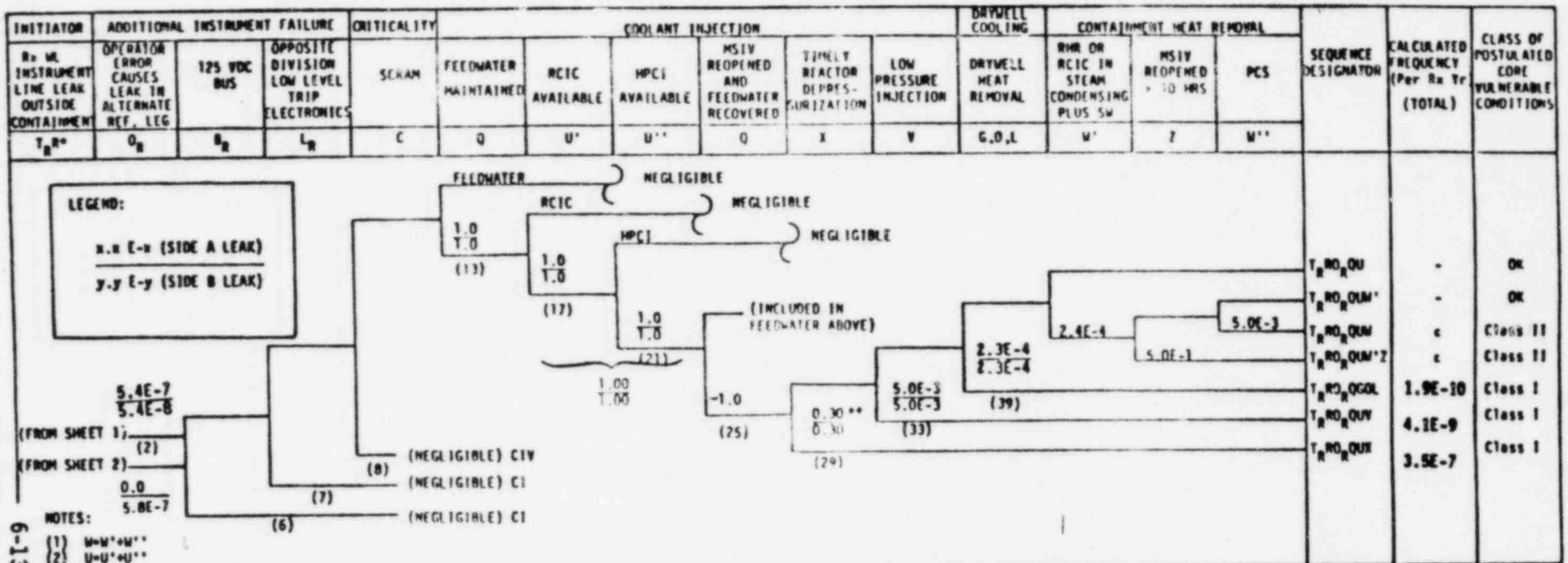
DWN	K. RYAN	
CHKD		
APPD		
APPD		
	Sh 1 of 5	REV
	DWG NO	

TITLE: Figure 6.1. Event Tree Diagram for Sequences Following Reactor Water Level Instrument Line Leak



* Based upon a spurious trip during the period of operation with a single reference leg operational.
** Reactor SCRAM is assumed for both of these sequences.

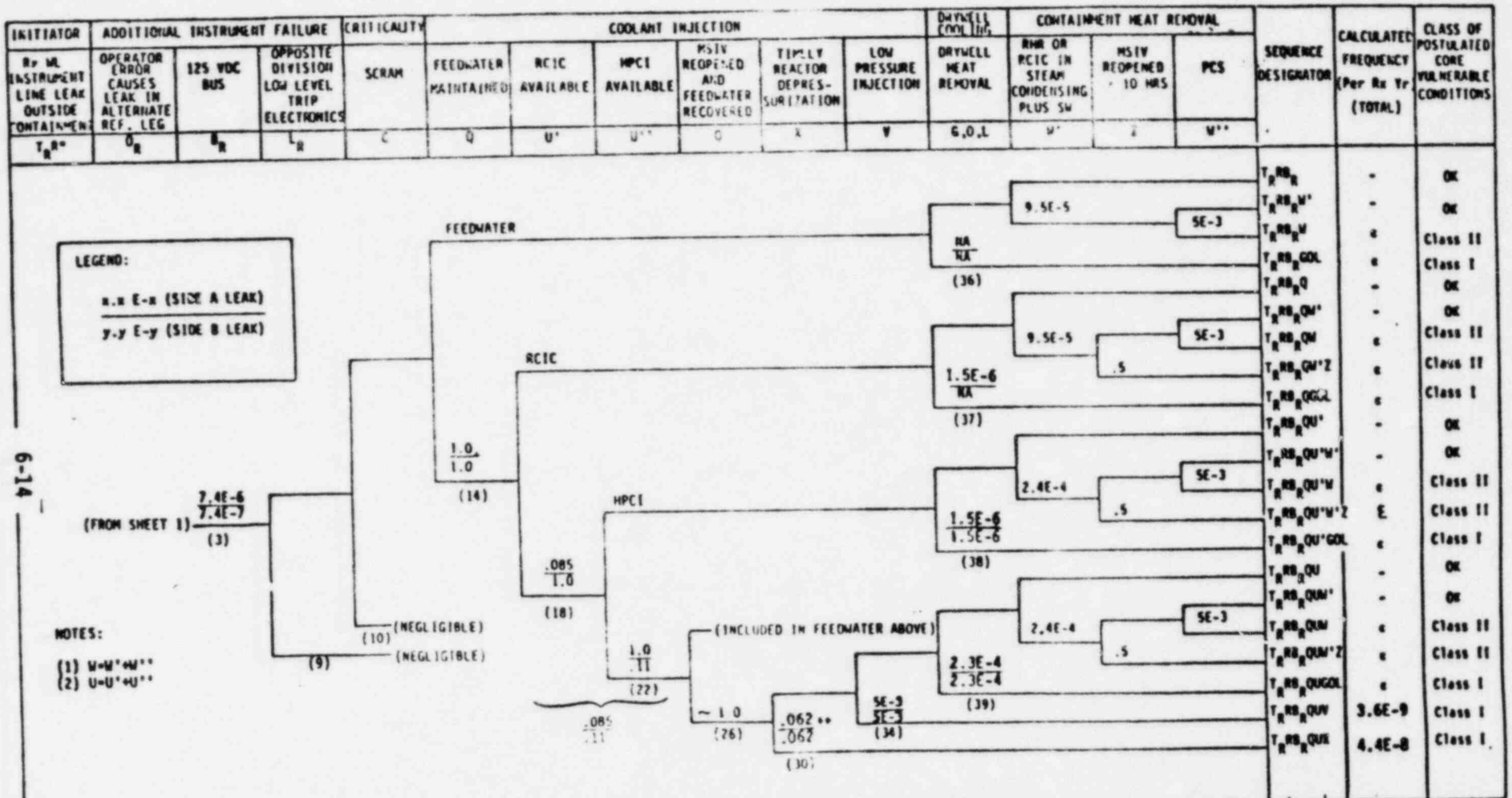
DWN	K. RYAN		TITLE:
CHKD			Figure 6.1. Event Tree Diagram for Sequences Following Reactor Water Level Instrument Line Leak
APPD			
APPD			
	Sh 2 of 5 / DWG NO	REV	



*Includes the conditional probability that the feedwater will not be available due to the initiator

** 10 minutes to 30 minutes

DWN	K. RYAN		TITLE: Figure 6.1. Event Tree Diagram for Sequences Following Reactor Water Level Instrument Line Leak
CHKD			
APPD			
APPD			
	Sh 3 of 5 DWG NO	REV	



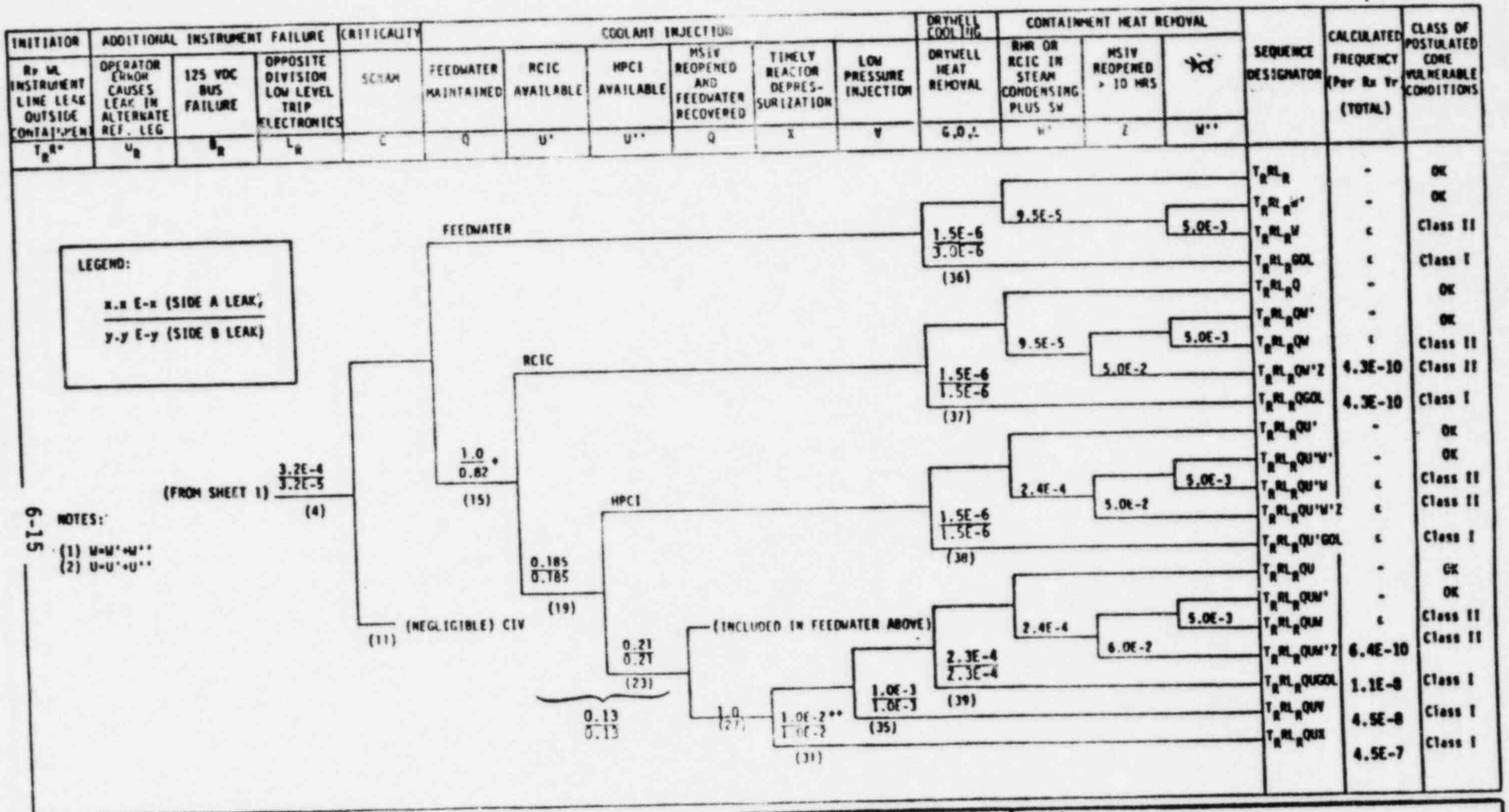
* Includes benefit for operator switching to feedwater on separate level channel.

** 10 minutes to 30 minutes

*Includes the conditional probability that the feedwater will not be available due to the initiator.

DWN	K. RYAN		TITLE:
CHKD			
APPD			
APPD			
	Sh 4 of 5	REV	
	DWG NO		

Figure 6.1: Event Tree Diagram for Sequences Following Reactor Water Level Instrument Line Leak



6-15

* Includes benefit for operator switching to feedwater on separate level channel.
** 10 minutes to 30 minutes

*Includes the conditional probability that the feedwater will not be available due to the initiator

DWN	K. RYAN		TITLE:
CHKD			
APPD			
APPD			
	Sh 5 of 5	REV	
	DWG NO		

Figure 6.1J Event Tree Diagram for Sequences Following Reactor Water Level Instrument Line Leak

Operator Error Causes Leak in Alternate Reference Leg (O_R) Section D.1.2, Figure D-2.

The potential for an operator error causing a failure in the alternate leg must be assessed. A loss of the alternate leg may occur if repairs or tests are performed on the intact leg. With a failure in both reference legs, the high pressure injection systems (feedwater, HPCI, and RCIC) will be locked out due to the high water level (L8) trip of these systems. Successful coolant injection will therefore depend on the operator depressurizing the plant and providing coolant injection with low pressure systems while all level indications are high except the shutdown and upset range instruments.

125 Volt DC Bus (B_R; Section D.1.3)

Given the pre-existing condition of a high level indication on the instrument connected to one side, an additional (although unlikely) failure is that the DC bus powering instruments on the other side may also fail during the shutdown period. This could cause the loss of instrument channels, powered from the bus, located on the side with the intact reference leg.

Opposite Reference Leg Low Level Trip Failure (L_R; Section D.1.4, Figure D-3)

The loss of inventory in one reference leg causes all level instrumentation on that side to read high. If either one of the two level instruments on the other side supplying initiation signals to a particular safety system fails, automatic initiation of that system may not occur. The inclusion of these failures in the event tree rather than the fault tree is done in order to deal as explicitly as possible with the potential failures which could defeat multiple systems.

Reactor Shutdown (C Section D.1.5)

The methods for initiating a scram are sufficiently redundant that, for most cases investigated, the conditional probability of successful scram is equivalent to that used elsewhere in the Shoreham PRA (see also Appendix D).

Feedwater Available (Q Section D.1.6, Figure D-4)

Feedwater is the normal mode of coolant injection during power operation and during most shutdowns. When power operation continues, the feedwater system vulnerability to a high level trip is increased due to the high level signal from the side B feedwater transmitter. The feedwater failure probability for these branches accounts for the increased vulnerability.

For branches where a loss of feedwater occurs because the feedwater controls shut off feedflow, feedwater may be restored immediately if the operator is able to achieve manual feedwater control. When a loss of feedwater is caused by a high level trip, no credit for feedwater recovery is given because the high level trip logic would have to be defeated. The main turbine trip logic is identical to the feedwater trip logic, so a turbine trip is assumed to occur whenever a reactor water level failure causes a feedwater trip.

High Pressure Injection - HPCI/RCIC (U', U", U; Section D.1.7, Figures D-7, D-6, D-5

As a backup to the feedwater system, HPCI and RCIC provide high pressure coolant makeup. However, similar to the feedwater system, these systems can be shut off if reactor water high level (L8) signals are present.

The value for U is the Boolean product of U' and U". However, because the HPCI and RCIC systems are closely linked and vulnerable to common-cause failures from reactor water level and other causes, the value for U is not simply the product of the independent values U' and U". The value for U was obtained by evaluating a combined HPCI/RCIC fault tree to account for common elements in the systems, and is displayed using brackets in the event tree. The events U' and U" represent the independent failure probabilities for RCIC and HPCI, respectively, and are evaluated to include the increased vulnerability to high level trips.

Timely Reactor Depressurization (X Section D.1.8, Figure D-8)

Plant procedures call for reactor depressurization if water level cannot be determined. The instrument line failure is assumed not to cause high drywell pressure directly, so automatic ADS initiation will not occur initially, but may eventually occur later in the event. The operator response to manually initiate ADS can be modeled using the analysis in Appendix C and the fault trees in Appendix D.

High Pressure Injection/Reactor Depressurization (UX Section D.1.9, Figure D-9)

ADS is linked to both HPCI and RCIC through the initiating signals from reactor water level, so that, while UX is the Boolean product of the events U', U" and X, the value for UX is not simply the product of their corresponding independent probabilities. The value for UX was obtained by evaluating a combined ADS/HPCI/RCIC fault tree to properly account for common elements, and is displayed using brackets in the event tree.

Low Pressure Injection (V Section D.1.10, Figure D-10)

This event combines the operation of three redundant low pressure injection systems: Core Spray, Low Pressure Injection pumps, and Condensate Pump injection. The redundancy in low pressure pumps is sufficiently high that the success of adequate cooling via the low pressure systems is governed by the ability to achieve low pressure in the reactor (event

"X"), and by the ability to establish stable cooling with inaccurate level indications.

Drywell Cooling (G,O,L; Section D.1.11, Figure D-11)

In the event that drywell cooling is unavailable subsequent to the initiating event, the drywell temperature may rise sufficiently high to prompt the operator to depressurize the plant in accordance with the procedures, which, in turn, may cause the reference leg to flash and accurate water level indication to be lost. The procedures then direct the operator to flood the primary system. The probability that the operator fails to perform this procedure dominates the determination of G,O,L. The loss of adequate drywell cooling event is discussed in more detail in Section 6.3, 6.4, and Appendix D.

Containment Heat Removal (W, W', Z; Section D.1.12, Figure D-12)

Residual Heat Removal (RHR) and Service Water (SW)--(W') designator). The RHR system must provide a complete flow path from and to the containment through at least one RHR heat exchanger. In addition, the SW system must provide cooling water to the corresponding RHR heat exchanger from the service water screenwell.

Heat removal via the RHR steam condensing mode is an additional design feature which allows flexibility in maintaining a safe reactor condition. The RHR steam condensing mode utilizes a large number of systems, so it provides only a small improvement in the overall calculated probability of successful containment heat removal.

MSIV Reopens in 15 Hours (Z). The use of the Power Conversion System (PCS) as a method of containment heat removal is possible if at least one main steam line path can be maintained and there is not a large diversion of reactor decay heat directly to the suppression pool. The PCS can be either maintained intact throughout the transient or regained with a high confidence. If the MSIV's close early in the transient, the conditional probability of regaining the PCS approaches a high value after two to three hours if the condenser is available.

Power Conversion System (W"). For the PCS to successfully transfer fission product decay heat to the environment, all of the following are required:

- One complete condensate-feedwater system is able to deliver water from the condenser hotwell to the reactor vessel. This requires the condensate and feedwater pump to be operable or that the condensate pump is operable and that the operator reduces reactor pressure to below 540 psia.
- The main steam line isolation valves in one of the four main steam lines must be open and the turbine bypass valves must open.
- At least one of the main condenser circulating water pumps must be delivering cooling water to the main condenser.

6.2.3 Results of the Accident Sequence Quantification

The event tree of Figure 6-1 shows that, for the postulated water level instrument line failure, the sequences which present the highest frequency of degraded core conditions are those involving:

- Failure to supply coolant inventory makeup to the reactor due to loss of feedwater, high pressure systems, and low pressure systems as a result of system trips caused by the postulated initiator in one reference leg, either alone (e.g., T_RQUV and T_RQUX) or in combination with the previously undetected failure of an instrument served by the other reference leg (e.g., T_RL_RQUV and T_RL_RQUX).
- Failure to supply coolant inventory makeup water late in the sequence due to water level reference leg flashing from failure to provide adequate drywell heat removal (e.g., T_RGOL).
- Failure to adequately remove decay heat from the containment following a high reactor water level (L8) caused turbine trip (T_RW).

Table 6-1 summarizes the results of the reactor water level instrument line failure sequence by class and compares them with the overall results of the Shoreham PRA. The results can be summarized as follows:

- The total reactor water level instrument line break contribution of 3.0×10^{-6} per reactor year is a 7 percent addition to the total core vulnerable frequency of 4.4×10^{-5} per reactor year, which is well within the uncertainty of the Shoreham core vulnerable frequency analysis.

- 90 percent of the accident sequences from this initiator are in Class I, with a resulting 10 percent increase in the total frequency of the class.

- As was the case in the sequences examined in the Shoreham PRA, the largest contribution to the frequency of core vulnerable condition resulting from sequences following this newly identified initiator is due to Class I and II sequences, i.e.,

  -- Loss of coolant makeup following transient challenges

  -- Loss of containment heat removal following transient challenges

- Based upon previous PRA work, the consequences of Class I and II events tend to be the lowest, while Class IV and V are more likely to result in higher consequences.

Figure 6-2 displays the results contained in Table 6-1. Since the frequency is shown on a log scale, the relative contribution for low frequency classes appear larger than actual. For example, Class V represents an extremely rare sequence of events which has a calculated frequency of 2×10^{-8} per reactor year, which is less than 0.1 percent of the Class I frequencies.

Figures 6-3 through 6-5 display, in a histogram format, the ranking of reactor water level instrument line breaks among the other dominant sequences in each class. The water level line break contributes a larger share to Class I than any of the initiators evaluated in the Shoreham PRA, but is a much smaller contributor to the potentially more severe

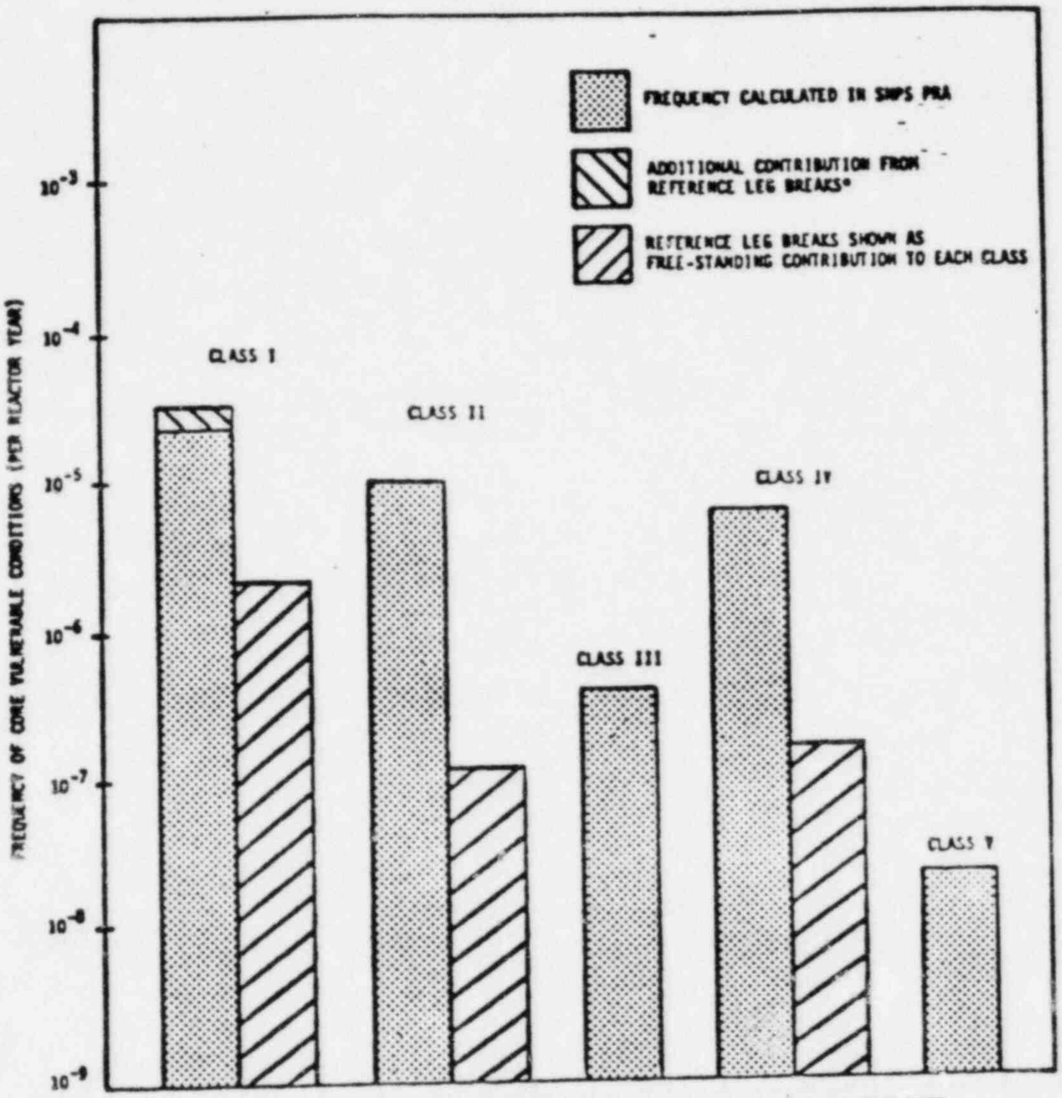
Table 6-1

Comparison of the Reactor Water Level Reference Leg Break Contribution

With the Frequencies of Core Vulnerble Condition

by Accident Class Calculated in the Shoreham PRA

Generalized Class	Class	Frequency of Core Vulnerable (Per Reactor Year) From PRA	Additional Frequency Contribution by Reactor Water Level Reference Leg Break
			Total
Loss of Coolant Makeup	I	2.7E-5	2.6E-6
Loss of Containment Heat Removal	II	1.0E-5	0.13E-6
LOCA	III	6.6E-7	---
ATWS w/o Poison Injection	IV	6.1E-6	0.22E-6
LOCA Outside Containment	V	2.0E-8	---
Total Core Vulnerable Frequency (Per Rx Yr)		4.4E-5	3.0E-6



*REFERENCE LEG BREAK CONTRIBUTIONS ARE SHOWN TWICE: ONCE ALONGSIDE SNPS PRA FREQUENCY FOR COMPARISON, AND ONCE ON TOP OF SNPS PRA FREQUENCY TO SHOW CONTRIBUTIONS TO TOTAL IN EACH CLASS. FREQUENCY IS SHOWN ON A LOGARITHMIC SCALE.

Figure 6.2. Summary of Effect of Adding Reactor Water Level Event Tree Quantification to Each Class of Core Vulnerable Condition Evaluated in Shoreham PRA.

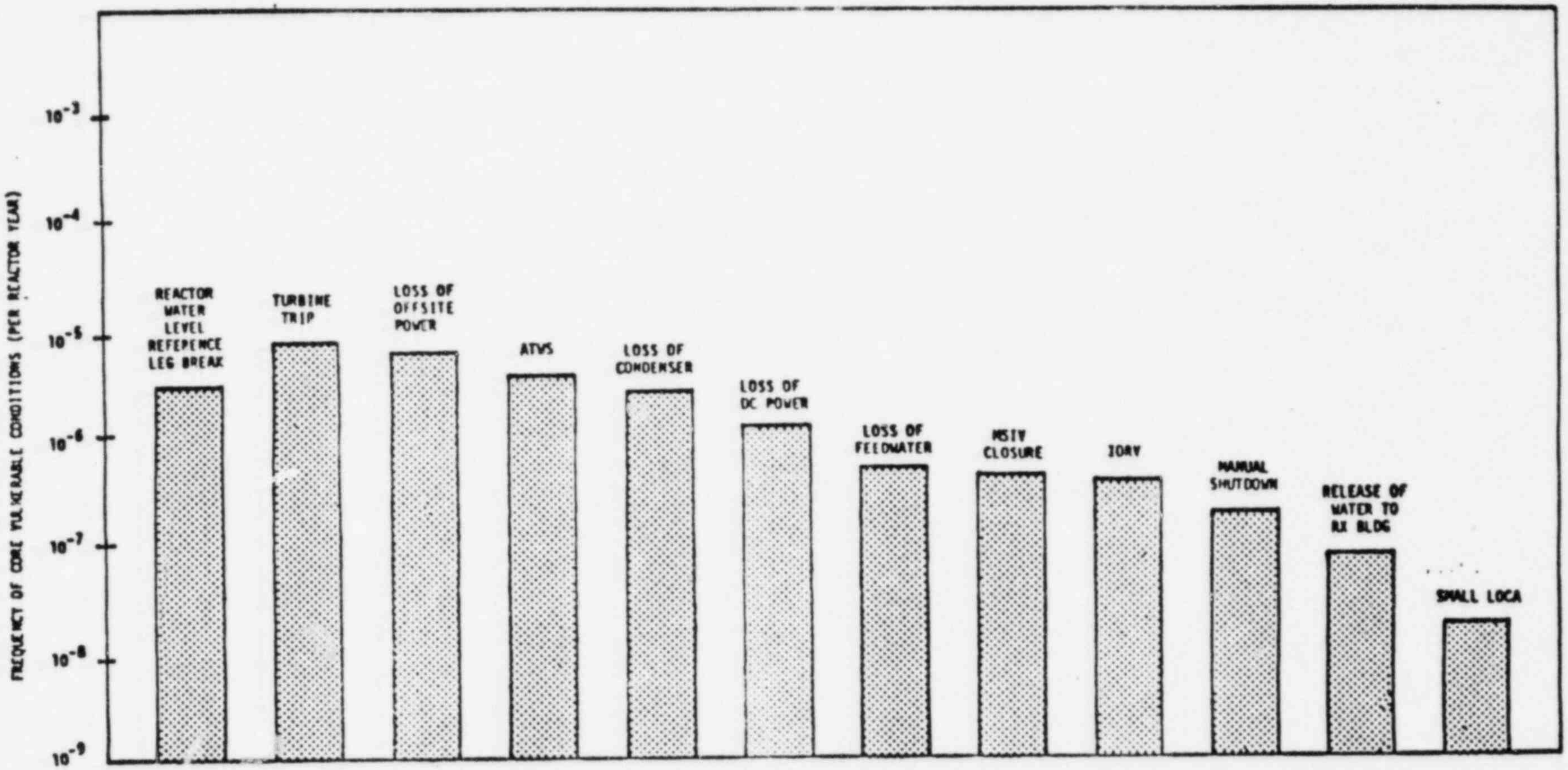


Figure 6.3. Summary of the Sequences Contributing to the Class I Frequency of Postulated Core Vulnerable Condition, Showing Relative Contribution of Reactor Water Level Reference Break.

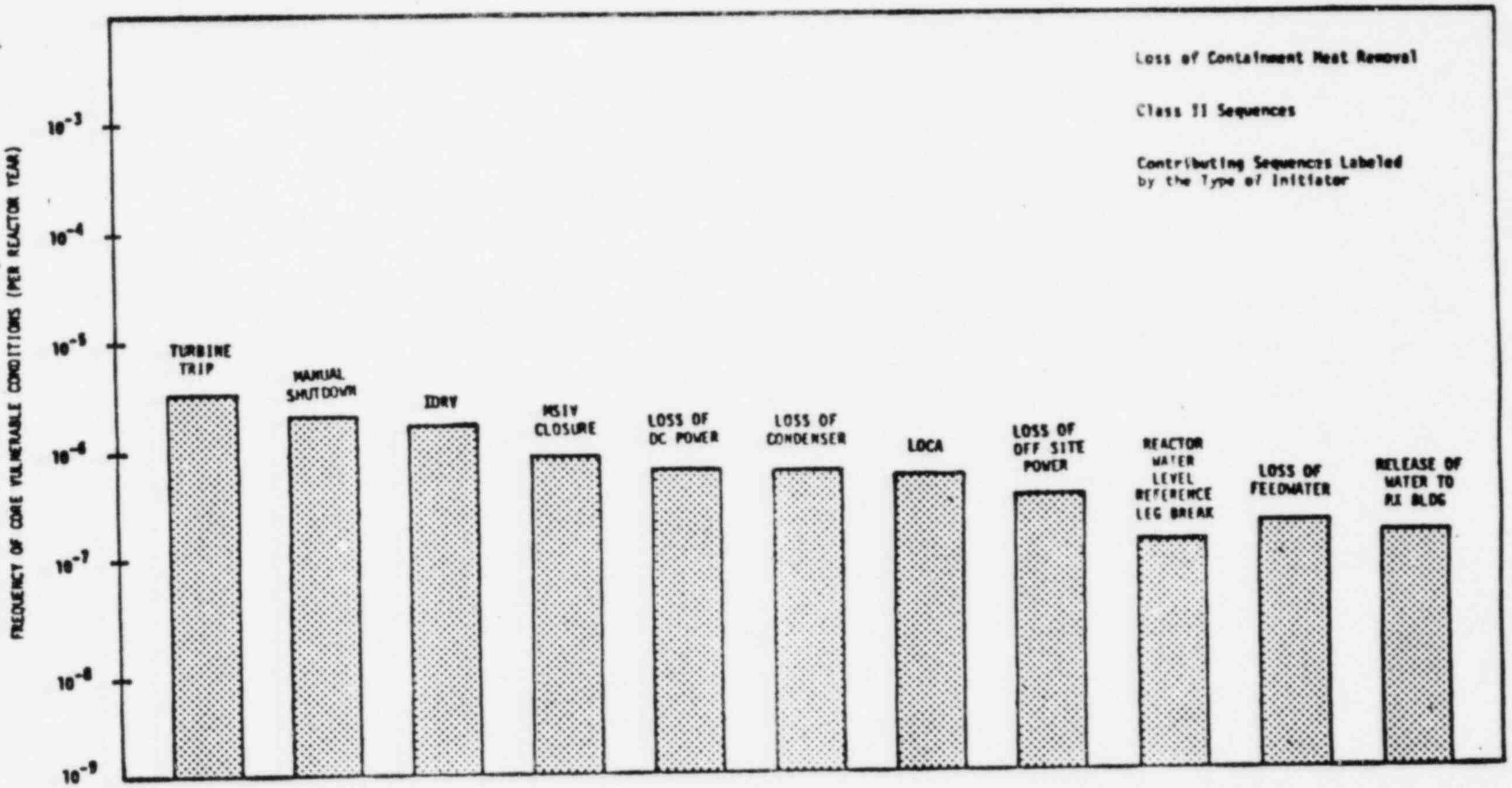


Figure 6.4. Summary of the Sequences Contributing to the Class II Frequency of Postulated Core Vulnerable Condition, Showing Relative Contribution of Reactor Water Level Reference Leg Break

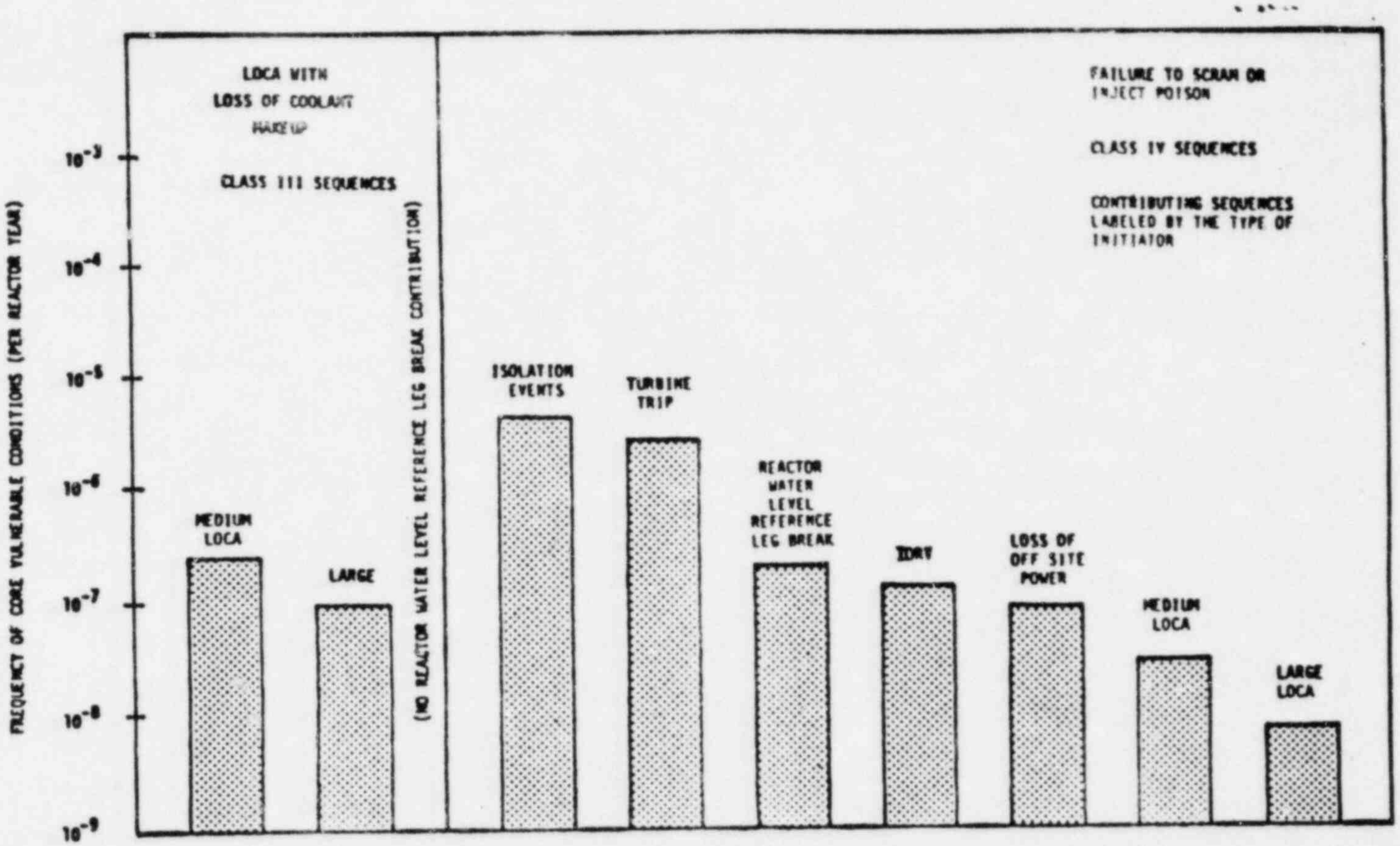


Figure 6.5. Summary of the Sequences Contributing to the Class III and IV Postulated Core Vulnerable Conditions, Showing Relative Contribution of Reactor Water Level Reference Leg Break

Classes II and IV. The water level line break sequence contribution is a factor of three smaller than the largest contributor to Class II, and a factor of ten smaller than the largest contributor to Class IV. Water level instrument line failures were found to make no contribution to the frequency of Classes III and no contribution to Class V.

6.3 HIGH DRYWELL TEMPERATURE DURING PLANT SHUTDOWN

As discussed in Section 3, inadequate drywell cooling during a plant shutdown can lead to high temperatures in the drywell and possible flashing of the water in the reference legs, with the resulting higher than actual indicated level. This subsection evaluates the contribution to core vulnerable frequency associated with the loss of drywell cooling subsequent to identified event initiators.

6.3.1 Initiating Events Considered in Evaluation of the Impact of High Drywell Temperatures

The event trees in the Shoreham PRA were modified to include the effects of the unavailability of drywell coolers during a reactor shutdown. The initiators and initiator frequency in the Shoreham PRA are:

- Manual Shutdown (M_S) — 4.3 per reactor year
  - Turbine Trip (T_T) — 4.24 per reactor year
  - Loss of Condensor Vacuum (T_C) — 0.38 per reactor year
  - MSIV Closure (T_M) — 0.24 per reactor year
  - Loss of Feedwater (T_F) — 0.16 per reactor year
  - Inadvertent Opening of Relief Valve (T_I) — 0.07 per reactor year
  - Loss of Offsite Power (T_E) — 0.065 per reactor year (modified to 0.00018 - See discussion)

- Control Rod Withdrawal — 0.03 per reactor year
- Small LOCA (S_1) — 0.008 per reactor year
- Medium LOCA (S_2) — 0.003 per reactor year
- Large LOCA (S_3) — 0.0007 per reactor year

An event tree for the large loss of coolant accident (LOCA) was not included because it was assessed to have a small contribution. For this event, pressure will decrease rapidly and all automatic system initiations will occur before the drywell heats up. Also, the initiating frequency is very small for this event, so its contribution will be correspondingly small.

6.3.2 Event Trees

Three events were included in the event trees to model drywell heat removal systems, the operator's ability to detect water level instrument line flashing, and operator actions required to establish a stable coolant injection mode. These modifications to the Shoreham event tree were included to model the response of water level instrumentation and its effects on operator event diagnosis. The changes to the structure include:

Adequate Drywell Heat Removal	(G Designator)	The adequate removal of heat from the drywell during the course of an accident sequence may be necessary to ensure accurate water level indication.
Reference Line Flashing or Boil-off Detected	(O Designator)	If adequate drywell cooling cannot be maintained, then there is a possibility during the long-term cooldown that the reactor water level instrument reference line flashing or boil-off could lead to errors in the indicated water level. The operator's ability to maintain adequate cooling will depend on his recognition of the occurrence of flashing.

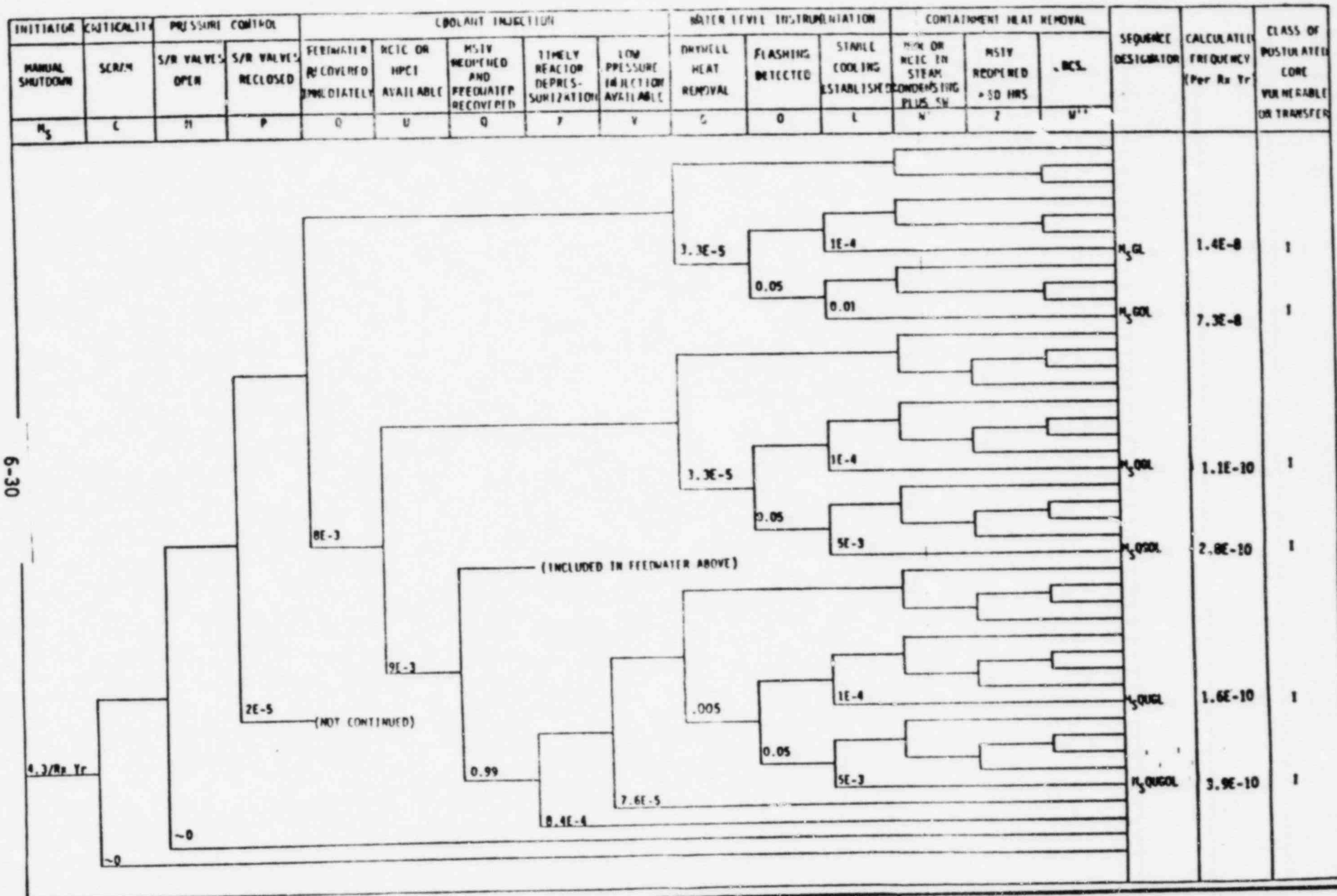
Stable Cooling Established (L Designator) For cases in which adequate drywell cooling is not available, then the conditional probability of successful long-term stable cooling must be established both with and without detection of instrument line boil-off or flashing.

A detailed description of the events G, O, and L and the probabilities associated with them are given in Appendix D.

The event trees modified to include the G, O, and L events are shown in Figures 6-6 through 6-14. Only the impact of the additional events on the core vulnerable frequency are evaluated on the event trees. The risk for other sequences will remain as calculated in the Shoreham PRA. Some points to note regarding the event trees are:

- The control rod withdrawal and turbine trip initiators are combined in the same manner as in the Shoreham PRA.
- Anticipated Transients Without Scram (ATWS) sequences were judged not to be affected by Loss of Drywell Cooling. For these events, plant operators are instructed to maintain a high reactor pressure and initiate containment heat removal systems so the conditions required for instrument line flashing are not expected to occur.
- The transient event sequences involving multiple stuck open relief valves (SORV) with subsequent loss of drywell coolers were assumed to depressurize and cool the primary system faster than the drywell would heat up. This eliminates the drywell heatup scenarios from being considered when event P has occurred.

The result of the addition of the G, O, L branches to the event trees can be readily ascertained. For example, the turbine trip transient shown in Figure 6-7 is essentially the same event tree as was used in the Shoreham PRA for the initiating event and criticality, pressure control, and coolant injection events. At this point, event G (Drywell Heat Removal) describes the challenge to containment heat removal systems. If they perform as designed, then the risk in making the transition to cold shutdown



DWN	K. RYAN	
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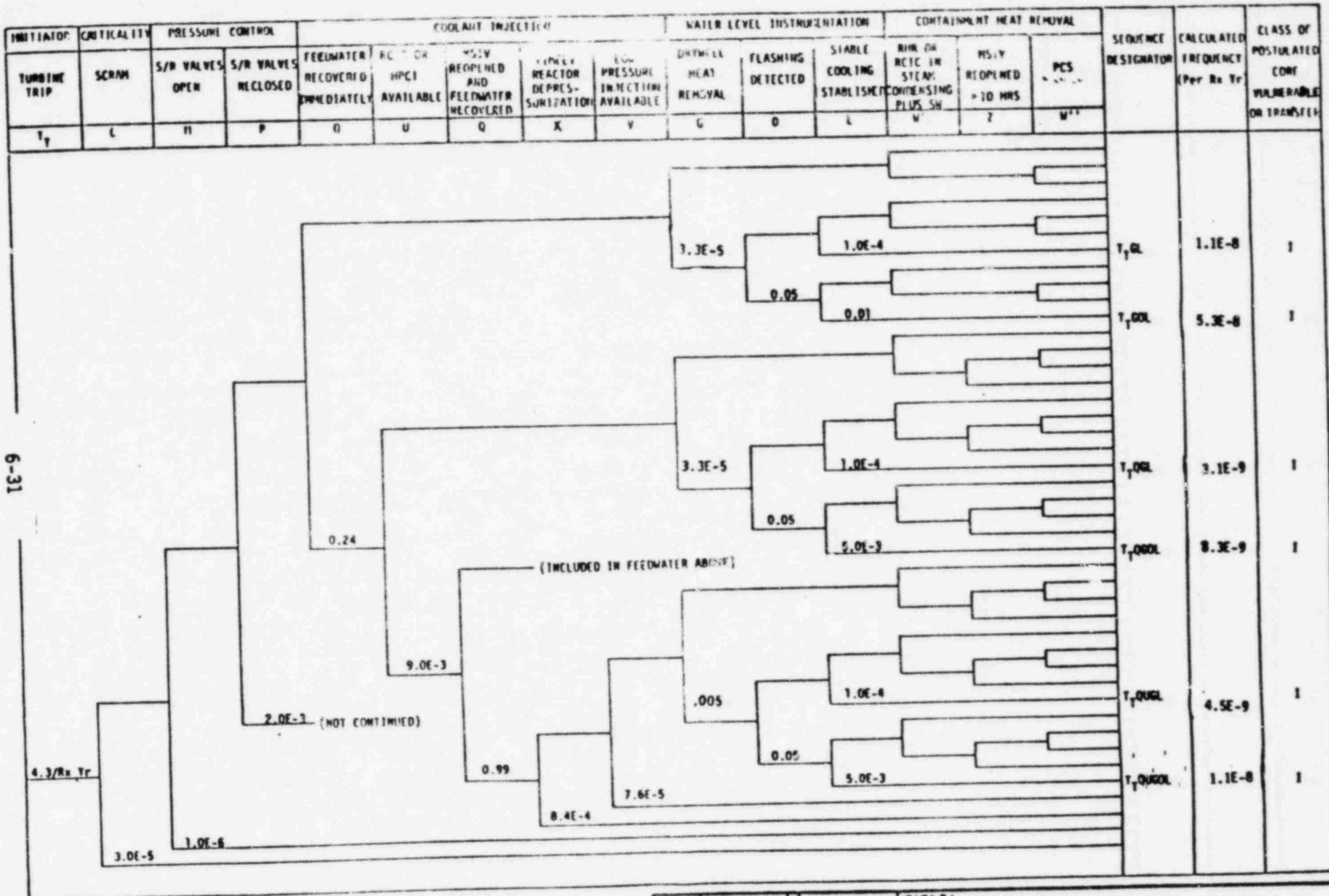
Figure 6.6. Manual Shutdown Event Tree



DWN	K. RYAN	
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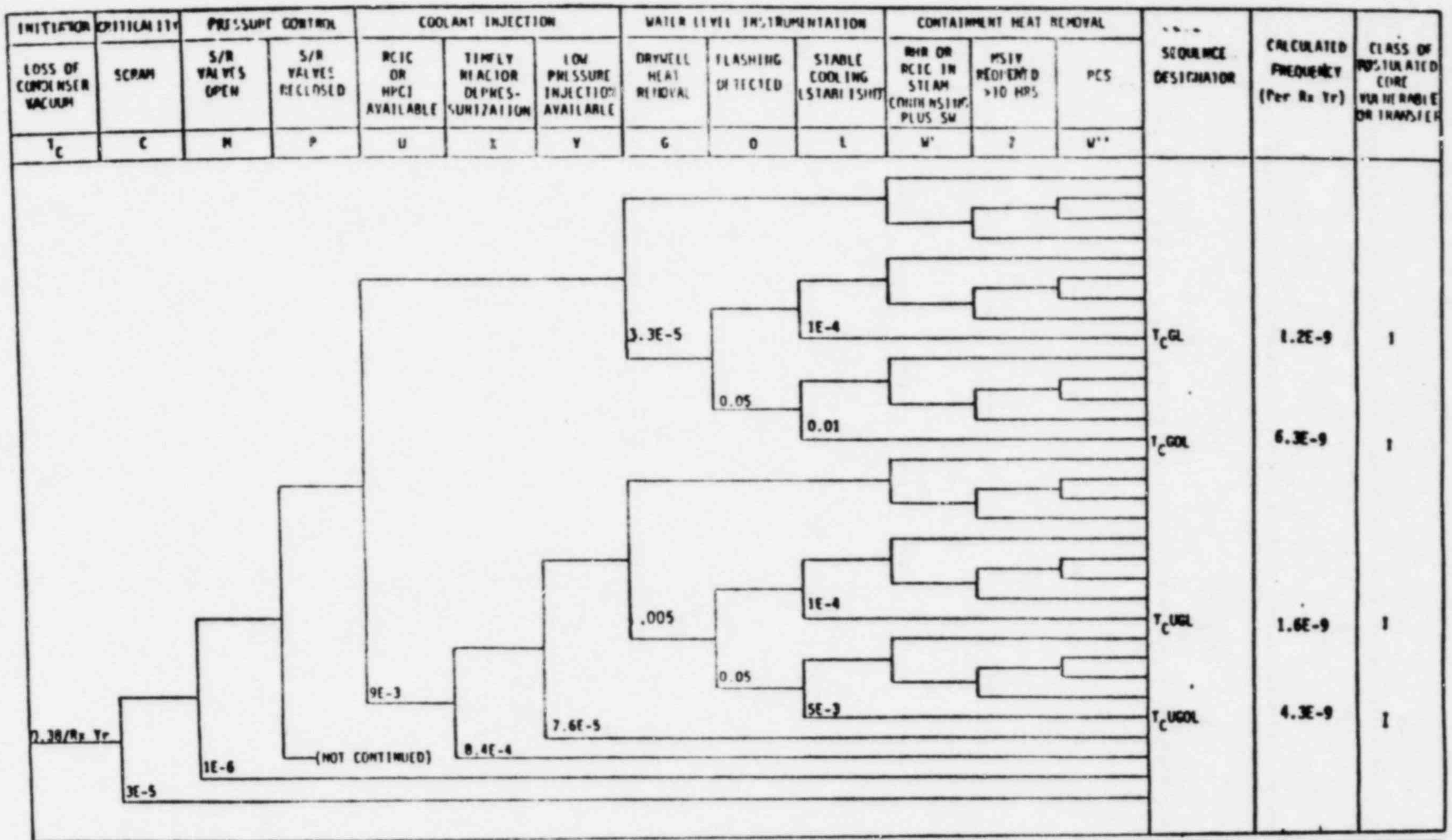
Figure 6.7. Turbine Trip Event Tree



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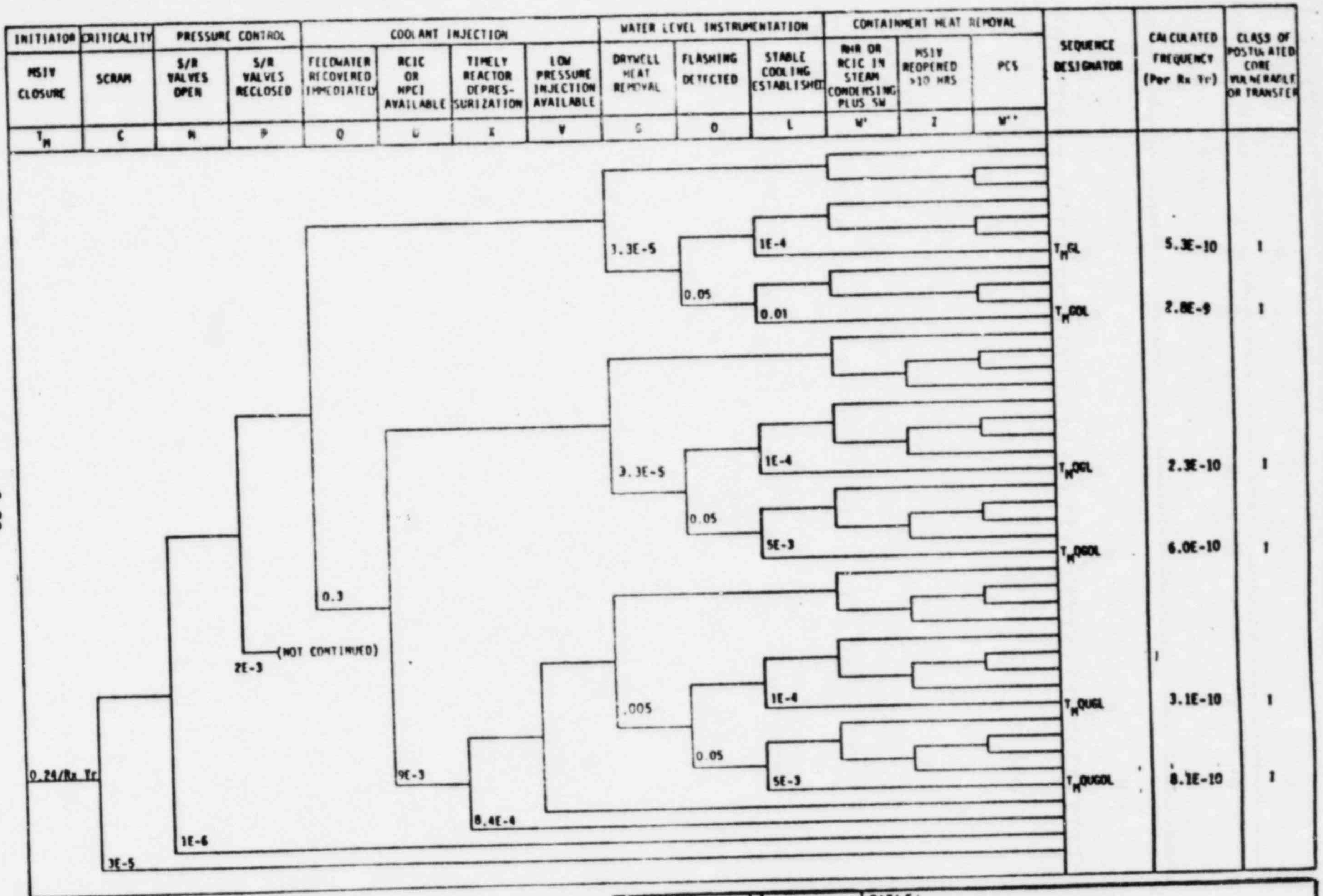
	DWG NO		

Figure 6.8. Loss of Condenser Vacuum Event Tree



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	DWG NO		

Figure 6.9. MSIV Closure Event Tree

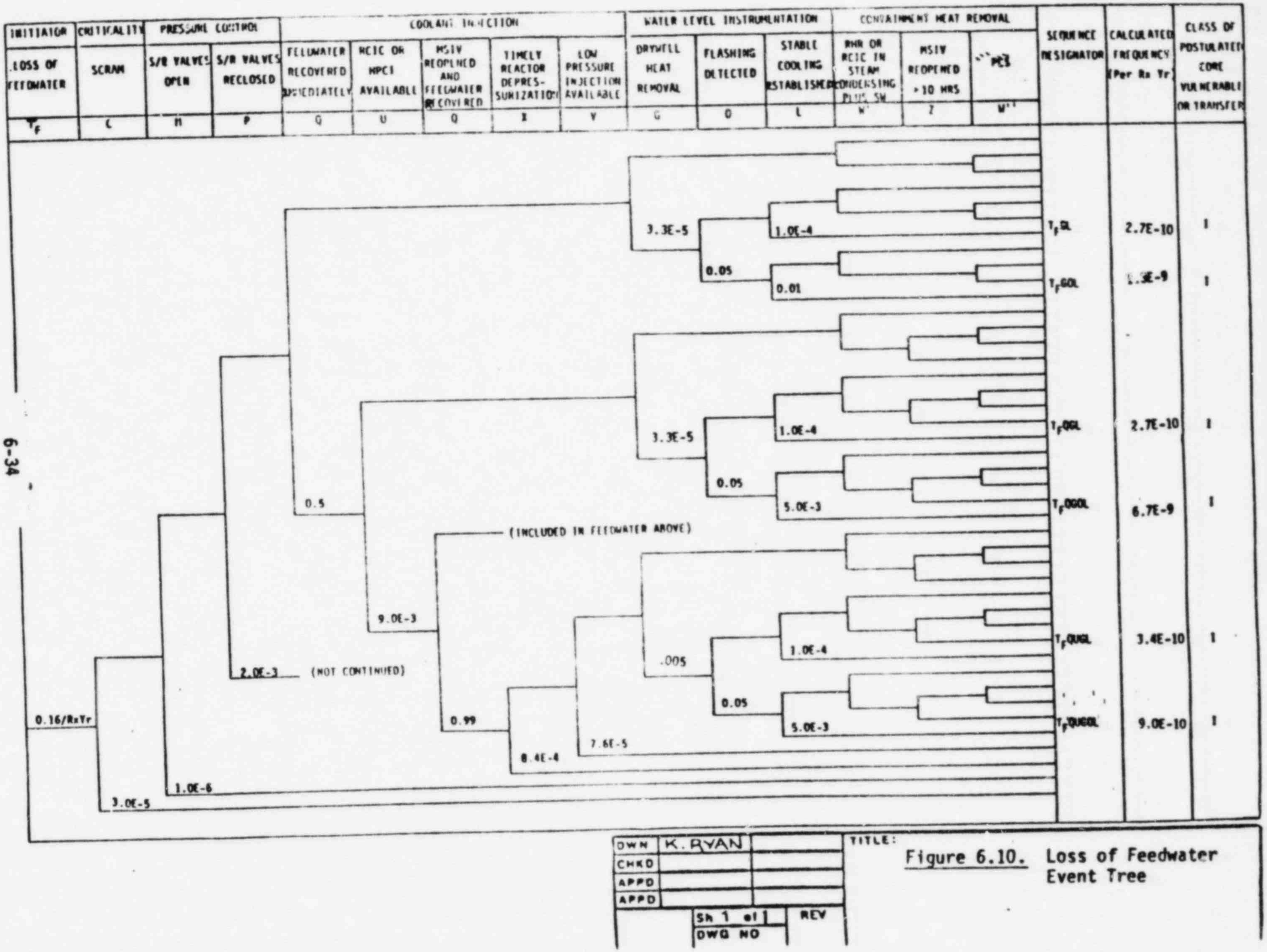

Figure 6.10. Loss of Feedwater Event Tree

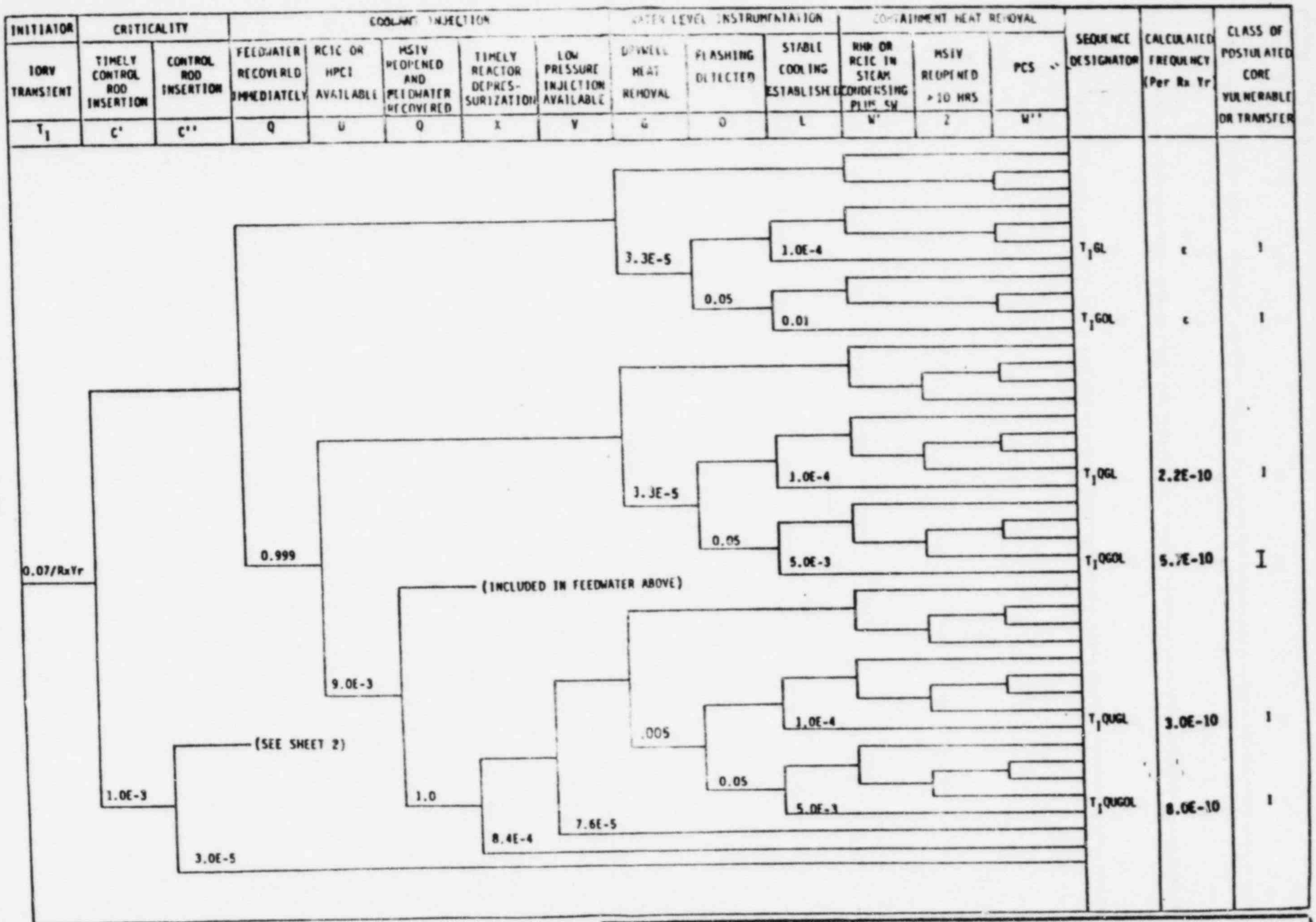

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Figure 6.11. . IORV Event Tree

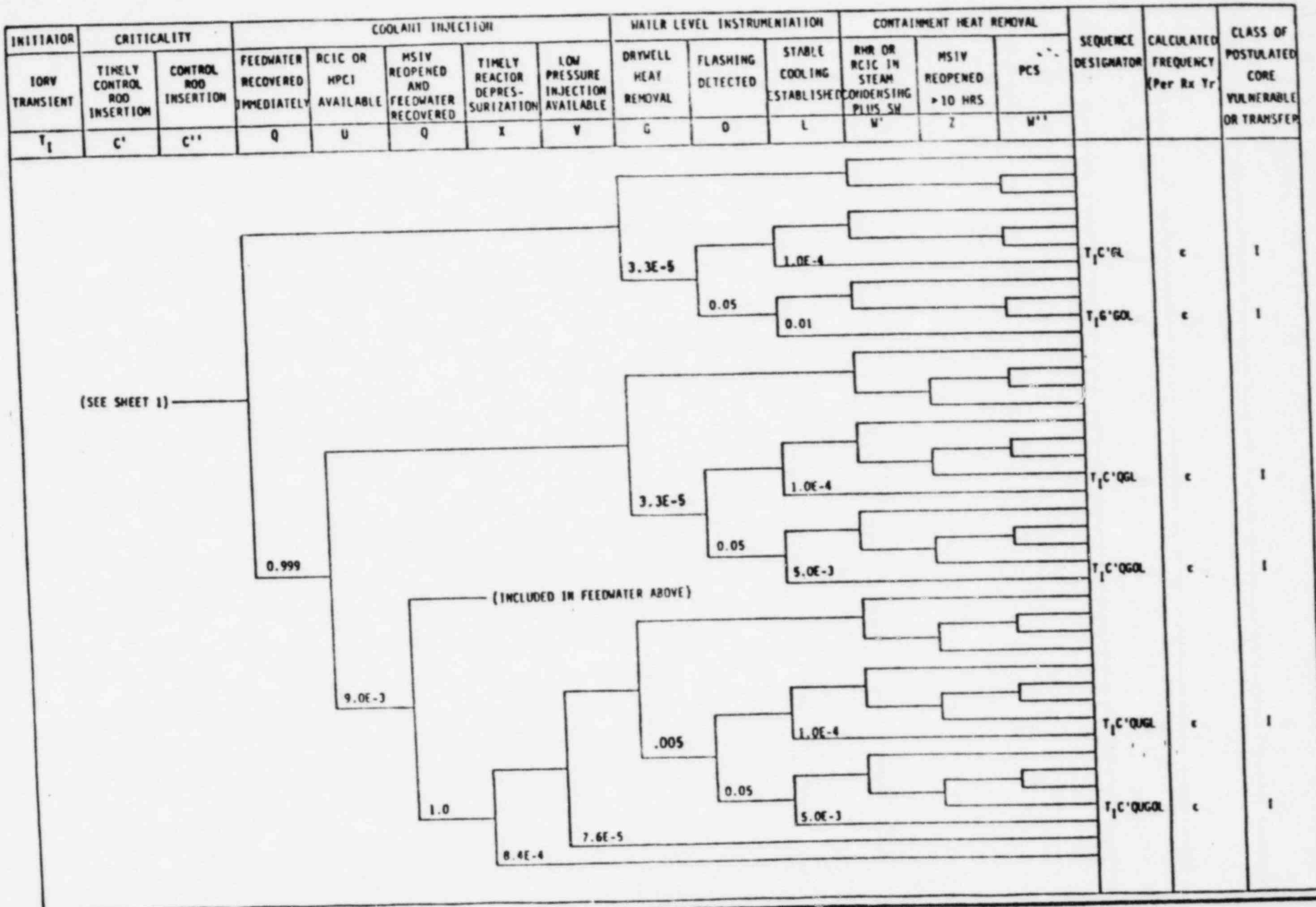

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Figure 6.11. IORV Event Tree

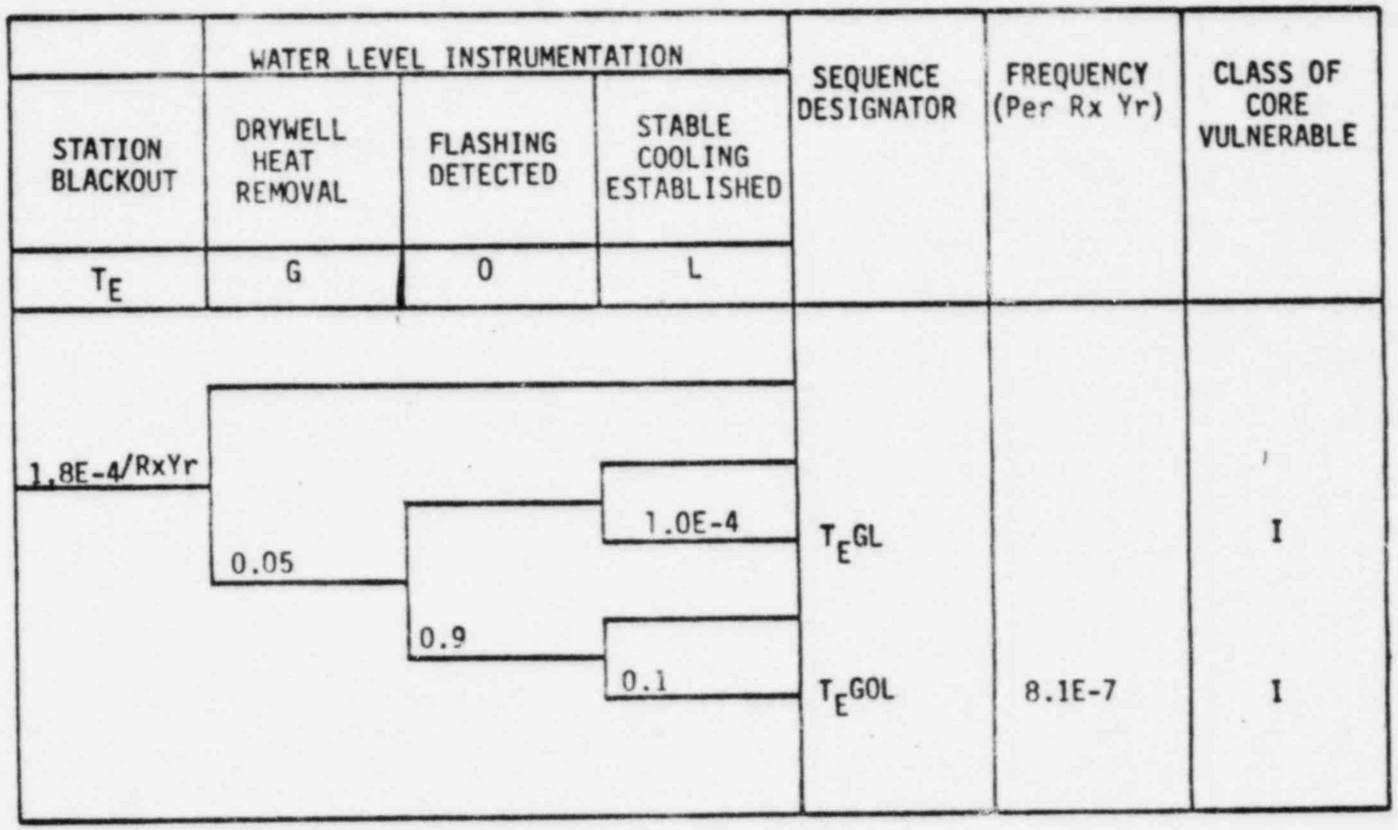
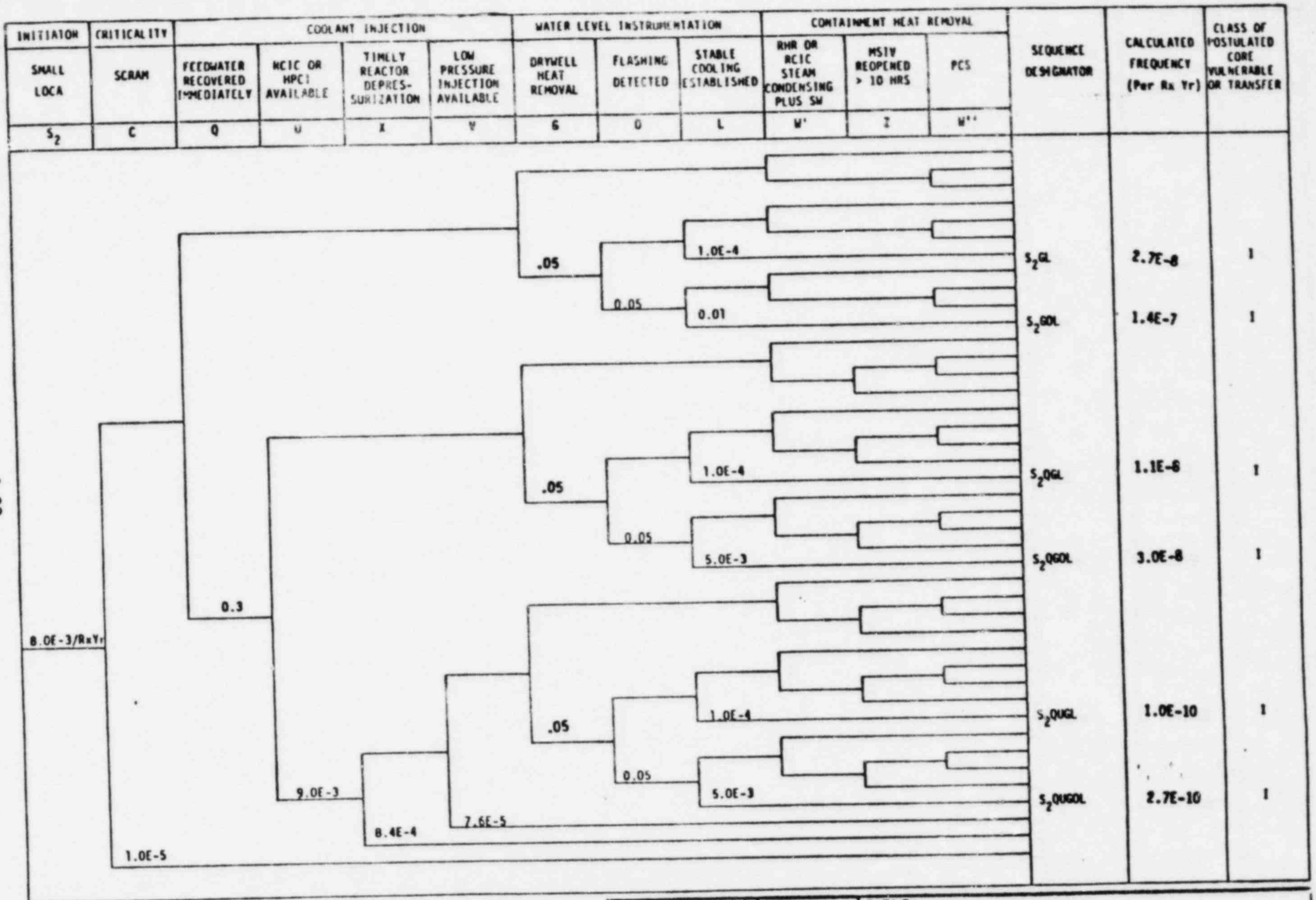


Figure 6.12. Loss of Offsite Power Event Tree



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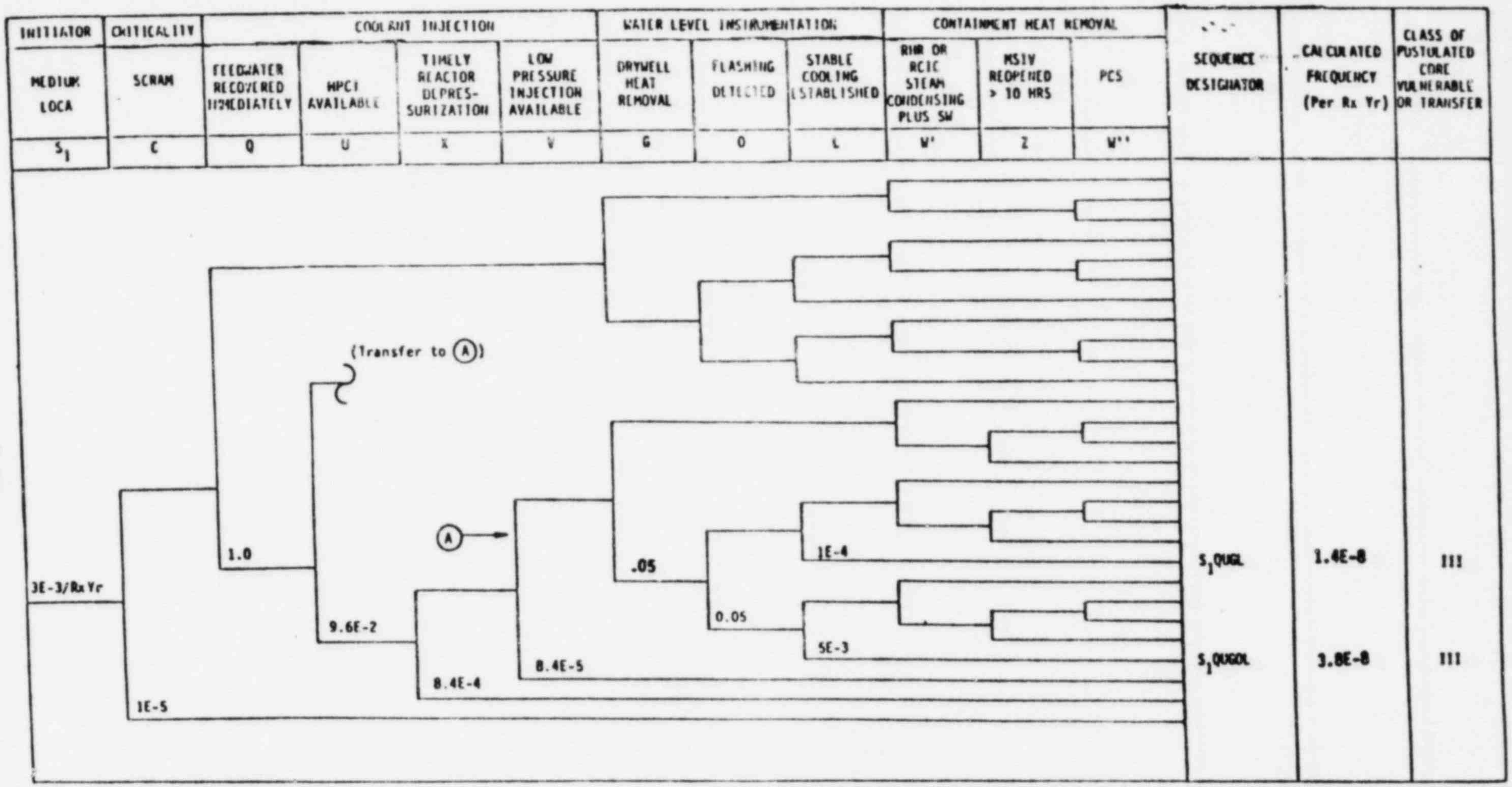
	DWG NO		

Figure 6.13. Small LOCA Event Tree



DWN	K. RYAN		TITLE:
CHKD			Figure 6.14. Medium LOCA Event Tree
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	DWG NO		

is as evaluated in the Shoreham PRA. Failure of drywell heat removal systems coupled with eventual reactor depressurization is assumed to lead to flashing or boil-off of the water in the reference legs of the water level instruments. If the flashing is detected by the operator, then there is a very high probability he will take appropriate actions to recover the water level instruments or use alternate indications to determine water level (Event O). The next event is the operator's ability to maintain the RPV water level based on the outcome of event O. If the operator succeeds in establishing a stable cooling mode, the event tree proceeds to the containment heat removal functional event. If the operator fails to establish stable core cooling, the event tree sequence ends in a core vulnerable condition. The net result of the event tree quantification is an addition to the frequency of Class I core vulnerable sequences. These additional end points are evaluated explicitly on the event trees.

The loss of offsite power event tree is evaluated differently than the other event trees because there is a dependency of the drywell cooling system availability on the availability of the electric power system. If the Division I or II diesel generator is working, then there is still a power source for the drywell coolers and the transient resembles an MSIV closure transient. If power from the Division I and II diesel generators is unavailable, then the drywell will heat up, leading to the sequence of events affecting the water level instruments. Therefore, the dominent contribution to core vulnerable frequency, my be evaluated by using an inititor frequency which is the product of the loss of offiste power initiator times the conditional failure probability of the Division I and II diesel generators. It was also determined that following recovery of electric power at any time the suppression pool temperature would already be high enough to require drywell cooling and that the drywell coolers would be unavailable due to a high drywell pressure isolation signal. Thus, all loss of emergency electric power sequences leads to the same G, O, L sequence so there is no dependency upon the performance of the high pressure injection systems. The event tree which quantifies the contribution of the loss of offsite power initiator to the G,O,L sequences appears in Figure 6-12.

The small and medium LOCA event trees in Figures 6-14 and 6-15, respectively, are similar to the loss of offsite power initiator in that they are precursors to drywell cooler isolation on high drywell pressure. The evaluation of events G, O, and L for these two event trees is discussed in Appendix D.

6.3.3 Summary

The results of the quantified event trees with G, O, and L events are summarized in Table 6-2. The only significant or noticeable additions to the calculated core vulnerable frequency, over that calculated in the Shoreham PRA, are those transient sequences involving event L, operator failure to establish a stable cooling mode. Of these, the event sequences that provided the largest addition to the new core vulnerable frequency were the TGOL sequences. The dominant contributing sequences are those which most frequently challenge the operator, i.e., those for which the main feedwater or condensate system is supplying coolant makeup to the reactor. In addition to the fact that these sequences have the highest challenge rate, an evaluation of the operator perception of reactor conditions during such sequences was also made. In these sequences, the operator is expected to use the 3 narrow range and 1 wide range level displays on the feedwater control panel as his primary level indications. Under the circumstances, the operator is judged to have a higher error rate than in sequences where his primary perception is at the emergency core cooling panel. (See also Appendix D.)

Table 6-2

Additional Contribution to Core Vulnerable Frequency

For Initiators Affected by High Drywell Temperature

Initiator	Additional Frequency (Per Rx Year)	Accident Class
Manual Shutdown	8.8×10^{-8}	I
Turbine Trip*	9.1×10^{-8}	I
Loss of Condenser Vacuum	1.3×10^{-8}	I
MSIV Closure	5.3×10^{-9}	I
Loss of Feedwater	9.8×10^{-9}	I
Inadvertent Open Relief Valve	1.9×10^{-9}	I
Loss of Offsite Power	8.1×10^{-7}	I
Small LOCA	2.1×10^{-7}	I
Medium LOCA	5.2×10^{-8}	III
Total	1.2×10^{-6} 0.052×10^{-6}	I III

* Includes contribution from Control Rod Withdrawal Initiator

6.4 MANUAL SHUTDOWN RESULTING FROM HIGH DRYWELL TEMPERATURE DUE TO DRYWELL COOLER DEGRADATION OR FAILURE

Generalized manual shutdown initiators and postulated sequences following them have been included in the Shoreham PRA, and sequences involving loss of drywell cooling subsequent to the manual shutdown initiator were addressed in Section 6.3. However, the possibility of a common-cause event leading to both high initial drywell temperature and a manual shutdown must also be considered.

For this initiator, the sequences begin as a controlled shutdown which may eventually be complicated by the loss of accurate reactor water level measurement. The initiating event is a loss of drywell cooling followed by a rise in drywell temperature well above the technical specification limit of 135°F. Appendix B provides the operating experience basis for the initiator frequency for these events. Given the conditions of very high drywell temperature, the Shoreham emergency procedures require a plant shutdown and initiation of the drywell sprays. The structure of the event tree for the manual shutdown due to the high drywell temperature initiator (Figure 6-15) reflects these actions. The event tree in Figure 6-15 is similar to the trees developed for the manual shutdown initiator discussed in Section 6.3, except the conditional failure probability associated with event O (instrument line flashing detected by operator) in the G, O, L sequence was reduced to $2x10^{-2}$/demand. The reduction was made because the operator was judged to be more cognizant of the possibility of instrument line flashing since the initiator was caused by an awareness of high drywell temperature. The additional contribution to the Class I core vulnerable frequency caused by the G,O,L sequences, given that the manual shutdown was caused by high drywell temperature, was calculated to be $1.5x10^{-7}$ events per reactor year.

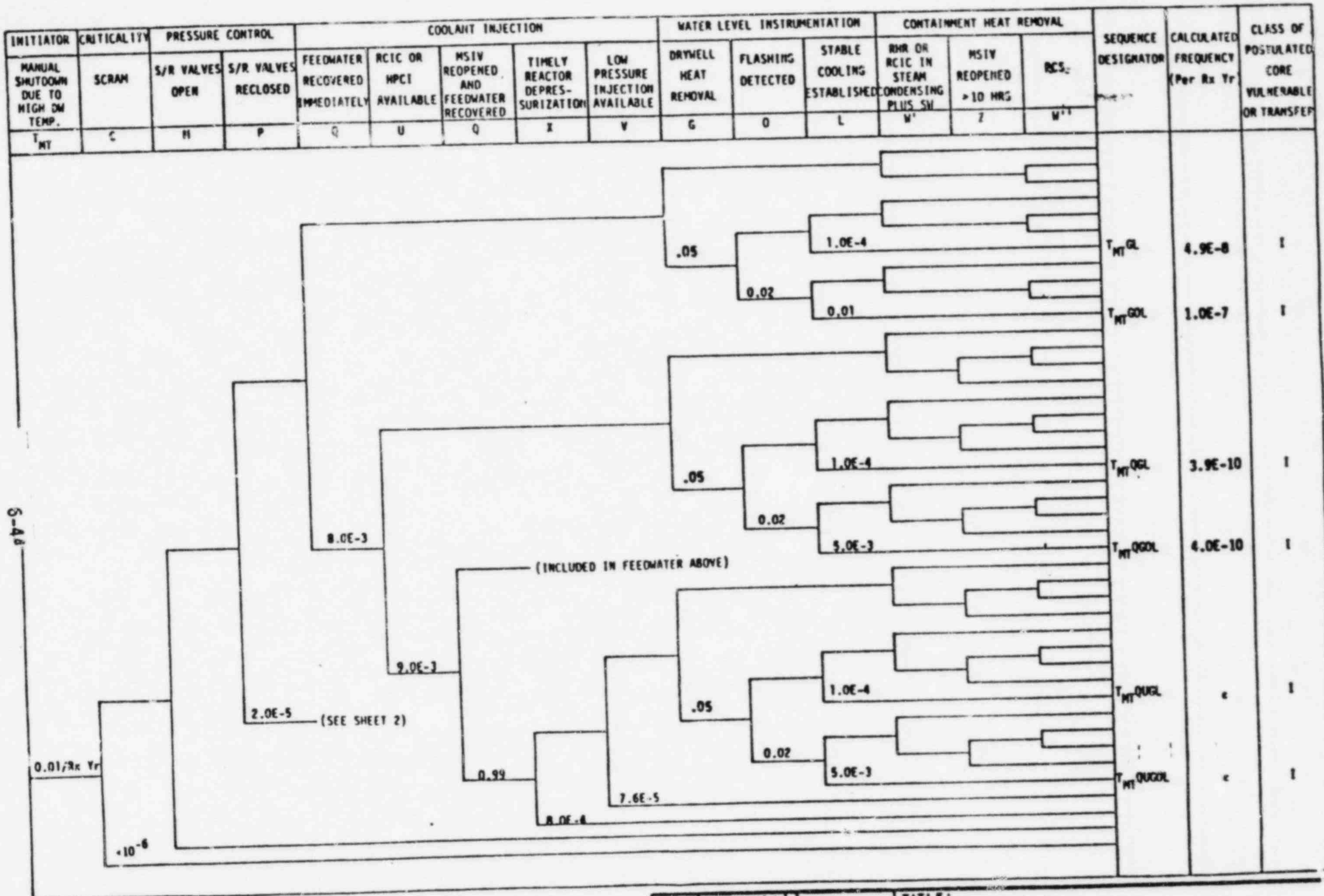

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Figure 6.15. Manual Shutdown Due to High Drywell Temperature Event Tree

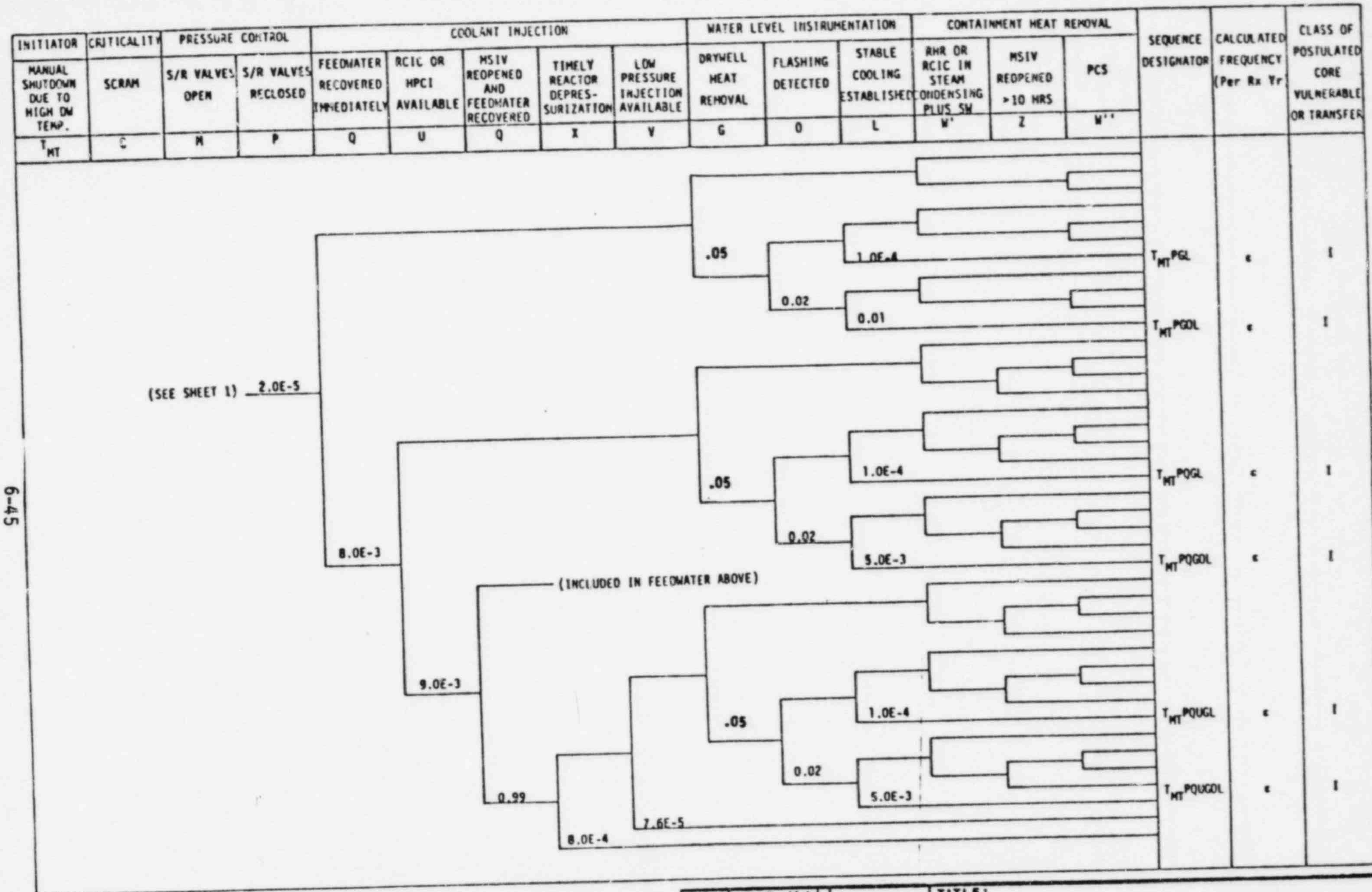

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Figure 6.15. Manual Shutdown Due to High Drywell Temperature Event Tree

6.5 INSTRUMENT FAILURE CONTRIBUTION

Level instrumentation failures contribute to core vulnerable frequency as contributors to the loss of feedwater initiator (T_F) and as a contributor to core vulnerable sequences that involve loss of inventory makeup. These contributions were quantified by re-evaluating the pertinent sequences using the values computed for these failure modes. Other reactor water level instrumentation failures contributing to systems appearing in core melt sequences involving ATWS (Class III, IV) were evaluated, and it was determined that the contribution was negligible.

6.5.1 Level Instrument Contribution to Loss of Feedwater Initiator

The level instruments can contribute to the loss of feedwater in three ways:

- Failure in the transmitter controlling feedwater;
- Random failure in two instruments causing a high level feedwater trip;
- Common mode miscalibration causing a high level feedwater trip.

The initiating frequency due to a failure of the level instrument controlling feedwater is the failure rate of the instrument times the number of operating hours in a year. From the Shoreham PRA, the instrument failure rate is 3.9×10^{-6} per hour so, for a 100 percent operating time, the contribution of this event to the loss of feedwater initiator is 0.034 per reactor year.

The feedwater trip logic uses 2 out of 3 logic so concurrent random failures in two instruments are required to cause a trip. There are three combinations of two failures which can cause the spurious trip. The failure rate for this event is therefore 3 times the square of the failure rate for the level instrument. Using the Shoreham value for instrument failure rates and a quarterly test interval (2200 hours) gives a rate for the spurious trip of:

$$R_T = 3 \times [3.9\times10^{-6} \times 2200]^2 \times 4 \frac{\text{quarters}}{\text{year}} = 8.8\times10^{-4} \frac{\text{events}}{\text{years}}$$

In addition to the random instrument failure, a potential exists for common-mode human error through the miscalibration of two or more instruments within the system. This potential was assessed in the Shoreham PRA (see Appendix C for a summary) to have a probability of 2.0×10^{-3} per combination of two or more instruments calibrated in the same maintenance action. A common mode miscalibration of two or more of the three feedwater trip instruments is therefore 2×10^{-3}. Again, assuming a quarterly calibration interval gives an initiating frequency of 4 times this value or 0.008 events per year.

The total contribution of level instrument failures is the sum of these three events, which is 0.042 events per year.

In order to obtain the fraction of T_F events that involve water level instrumentation failure, instrument failures that initiate loss of feedwater (T_F) were considered as a portion of the loss of feedwater initiator frequency. In the Shoreham PRA, loss of feedwater has a frequency of occurrence of 0.16 per reactor year. Dividing the instrumentation contribution to loss of feedwater by the loss of feedwater frequency gives the fractional contribution of level instrumentation to the loss of feedwater initiator sequences. (Note that this contribution is from the level sensors only and does not include failure in the control electronics.)

$$T_F \text{ water level fraction} = \frac{0.043}{0.16} = 0.27$$

The level instrument failure contribution to frequency of core vulnerable conditions for a loss of feedwater initiator is the total core vulnerable frequency for all T_F sequences multiplied by the fractional contribution to initiation frequency:

$T_{FWL} = 8.4 \times 10^{-7} \times 0.27 = 0.23$ events/million years.

6.5.2 Level Instrument Failure Contribution to Dominant Sequences

The existing Shoreham draft PRA calculates the frequency of core vulnerable conditions due to a large number of postulated accident sequences. Those sequences which lead to potential core vulnerable conditions include contributions from postulated failures of the reactor water level instrumentation. The failure modes in the Shoreham PRA include random independent failures of transmitters and logic, plus common mode failures of all level transmitters monitoring a given level.

The contribution of level instrument failures already included in the Shoreham PRA may be established for comparison purposes by determining the contribution of these level instruments to the core vulnerable frequency in the dominant event sequences (contribution of 10^{-9} or greater) in which level instrumentation is required for successful mitigation of the event. The dominant core vulnerable sequences from the Shoreham PRA are given in Table 6-3.

The dominant sequences which contain a water level measurement system contribution are those sequences involved with water makeup to the primary system, since they depend upon water level inputs for automatic initiation of safety systems. These sequences involve the feedwater system, high pressure injection systems, low pressure injection systems, ADS, and the RHR steam condensing mode. The water level initiation of the Reactor Protection System (RPS) does not have a significant contribution to the core vulnerable frequency because a failure in reactor water level-initiated scram will not by itself lead to a core vulnerable event. The event sequences shown in Table 6-3 involving feedwater (Q), HPCI/RCIC (U), low pressure ECCS systems (V), ADS (X), or the RHR steam condensing mode (W') are, therefore, the events in which water level instrumentation failures make a contribution to the calculated frequency of core vulnerable events. Sequences appearing in Table 6-3 which contain these sequence designations, either individually or in combinations, were evaluated for the water level contribution to the frequencies.

The instrumentation and logic for the Loss of Feedwater event (Q) are sufficiently distinct from those of the High Pressure Injection (U), Low Pressure Injection (V), and Depressurization (X) events for Q to be treated independently from UV and UX sequences. The high pressure injection, low pressure injection, and depressurization events (U, V, and X) share many of the same level sensors and use quite similar logic systems in generating automatic initiation and cutoff signals. For this reason, UX and UV sequences must be evaluated as single events, rather than as combination of independent events U and X. The RHR steam condensing mode (W') was evaluated as an independent event.

Since reactor water level trips do not influence the condensate system, no fractional contribution of water level to condensate was assessed.

The fractional contribution of water level instrumentation failures to events Q, UV, UX and W' were estimated by evaluating their respective fault trees in the Shoreham PRA.' In the cases of UV and UX, the individual fault trees for these events were combined into a single fault tree and evaluated. The fractional contributions for individual events U and V that appear individually in the dominant sequences listed in Table 6-3 were also obtained. Event X does not appear as an individual event because it has no significance unless low pressure systems are required. Table 6-4 summarizes the results of this analysis, including the T_F contribution derived earlier.

Table 6-5 displays the estimated contributions of reactor water level failure to the frequency of each core vulnerable condition class. These values were obtained by substituting the estimated water level failure contributions to the appropriate events in Table 6-3, then calculating and totaling the dominant sequence frequencies. The Shoreham PRA values for each core vulnerable class are also listed in Table 6-5. The contribution to the loss of feedwater initiator is also included in Table 6-5.

Table 6-3
Shoreham Dominant Sequences for Which Water Level Instrument Line Failures Contribute Significantly to Core Vulnerable Frequency (Sheet 1 of 4)

	CLASS I		CLASS II		CLASS III		CLASS IV		CLASS V	
	Sequence*	Frequency	Sequence*	Frequency	Sequence*	Frequency	Sequence*	Frequency	Sequence*	Frequency
1. Transients:										
(1) Turbine Trip	T_TQUV	6.8E-7	T_TW	1.5E-6						
	T_TQUX	7.5E-6	T_TQW	1.3E-6						
	T_TPQUV	1.4E-9	T_TQU'W	2.26E-7						
	T_TPQUX	1.5E-8	T_TQUW	5.4E-8						
			T_TQUV'V"W	7.3E-8						
			T_TPW	3.0E-8						
			T_TPQW	1.58E-8						
			T_TPQU'W	3.1E-9						
		8.2E-6		3.2E-6						
(2) Manual Shutdown	M_SQUV	2.2E-8	M_SW	2.0E-6						
	M_SQUX	2.5E-7	M_SQW	4.9E-8						
			M_SQU'W	7.8E-9						
			M_SQUW	1.9E-9						
			M_SQUV'V"W	1.7E-9						
		2.7E-7		2.1E-6						
(3) MSIV Closure	T_MQUV	4.9E-8	T_MW	7.9E-8						
	T_MQUX	5.4E-7	T_MQW	1.0E-7						
	T_MPQUX	3.3E-9	T_MQU'W	1.6E-8						
			T_MQUW	3.9E-9						
			T_MQUV'V"W	5.4E-9						
			T_MPQW	3.6E-9						
		5.9E-7		2.1E-7						
(4) Loss of Feedwater	T_FQUV	5.4E-8	T_FW	3.8E-8						
	T_FQUX	6.0E-7	T_FQW	1.1E-7						
	T_FPQUX	1.2E-9	T_FQU'W	1.8E-8						
			T_FQUW	4.3E-9						
			T_FQUV'V"W	6.0E-9						
			T_FPQW	1.3E-9						
		6.6E-7		1.8E-7						

Table 6-3
Shoreham Dominant Sequences for Which Water Level Instrument Line Failures Contribute Significantly to Core Vulnerable Frequency (Sheet 2 of 4)

	CLASS I		CLASS II		CLASS III		CLASS IV		CLASS V	
	Sequence*	Frequency	Sequence*	Frequency	Sequence*	Frequency	Sequence*	Frequency	Sequence*	Frequency
(5) Loss of Condenser Vacuum	T_CUV	2.6E-7	T_CW	5.4E-7						
	T_CUX	2.9E-6	$T_CU'W$	1.6E-7						
	T_CPUX	5.7E-9	T_CUW	2.0E-8						
			$T_CUV'V''W$	2.9E-8						
			T_CPW	5.9E-9						
			$T_CPU'W$	1.0E-9						
		3.2E-6		7.6E-7						
(6) Loss of Offsite Power	T_EUV/UX	7.5E-6	T_EW	3.8E-7						
	T_EPUV/UX	1.5E-8								
		7.6E-6		3.8E-7						
(7) IORV	T_IQUV	4.6E-8	T_IQW	6.4E-7						
	T_IQUX	5.2E-7	$T_IQU'W$	1.2E-7						
			T_IQUW	1.6E-8						
			$T_IQUV'V''W$	3.7E-7						
			$T_IC'QW$	6.0E-7						
			$T_IC'QU'W$	8.6E-8						
			$T_IC'QUW$	7.7E-9						
		5.7E-7		1.8E-6						
2. LOCA:										
(1) Large LOCA			AW	3.4E-7	AV	9.8E-8	AC	7E-9		
			AV'W	1.2E-9						
			AV'V"W	3.5E-7						
				6.9E-7						
(2) Medium LOCA			S_1QUW	7.2E-9	S_1QUV	2.4E-8	S_1C	3.0E-8		
			$S_1QUV'V''W$	1.8E-8	S_1QUX	2.4E-7				
				2.5E-8		2.6E-7				
(3) Small LOCA	S_2QUV	1.6E-9	S_2W	2.6E-9						
	S_2QUX	1.8E-8	S_2QW	3.2E-9						
		2.0E-8		5.8E-9						

Table 6-3
Shoreham Dominant Sequences for Which Water Level Instrument Line Failures Contribute Significantly to Core Vulnerable Frequency (Sheet 3 of 4)

	CLASS I		CLASS II		CLASS III		CLASS IV		CLASS V	
	Sequence*	Frequency	Sequence*	Frequency	Sequence*	Frequency	Sequence*	Frequency	Sequence*	Frequency
(4) Large LOCA Outside Containment			$A_{OUT}V'V''W$	7.0E-9					$A_{OUT}V$	2.0E-8
(5) Reactor Pressure Vessel					R_1	3.0E-7	R_0T R_2T R_1T	1.0E-9 7.0E-9 3.0E-9 1.1E-8		
3. ATWS: (1) Turbine Trip	$T_T^1C_MU$ $T_T^1C_MPU$ $T_T^1C_MC_2U$	1.1E-7 1.9E-8 2.1E-9 1.3E-7					$T_T^1(C_EK)C_2$ $T_T^1(C_ER)$ $T_T^1C_MU_M$ $T_T^1C_MD$ $T_T^1C_MUD$ $T_T^1C_MC_2$	4.3E-8 1.4E-9 3.3E-9 6.6E-9 1.1E-9 2.1E-6 2.2E-6		
(2) MSIV Closure	$T_M^2(C_EK)U$ $T_M^2(C_EK)PU$ $T_M^2(C_EK)C_2U$ $T_M^2C_MU$ $T_M^2C_MPU$ $T_M^2C_MC_2U$	6.2E-8 6.2E-9 1.7E-8 3.1E-6 3.1E-7 8.4E-7 4.3E-6					$T_M^2(C_EK)W$ $T_M^2(C_EK)PW$ $T_M^2(C_EK)C_2$ $T_M^2(C_ER)$ $T_M^2C_MW$ $T_M^2C_MU_H$ $T_M^2C_MD$ $T_M^2C_MUD$ $T_M^2C_MPW$ $T_M^2C_MPUD$ $T_M^2C_MC_2$ $T_M^2C_MC_2D$ $T_M^2C_MC_2UD$ $T_M^2C_MM$ $T_M^2C_MR$	1.0E-8 1.0E-9 6.0E-8 5.3E-9 5.0E-7 4.6E-9 9.1E-9 3.0E-8 5.0E-8 3.1E-9 3.0E-6 1.2E-9 8.5E-9 2.7E-9 2.7E-9 3.7E-6		

Table 6-3
Shoreham Dominant Sequences for Which Water Level Instrument Line Failures Contribute Significantly to Core Vulnerable Frequency (Sheet 4 of 4)

	CLASS I		CLASS II		CLASS III		CLASS IV		CLASS V	
	Sequence*	Frequency	Sequence*	Frequency	Sequence*	Frequency	Sequence*	Frequency	Sequence*	Frequency
(3) Loss of Offsite Power	$T_E^5(C_EK)U$	1.4E-9					$T_E^5(C_EK)C_2$	1.5E-9		
	$T_E^5C_WU$	6.8E-8					$T_E^5C_WW$	1.4E-8		
	$T_E^5C_WPU$	7.7E-9					$T_E^5C_WPW$	1.9E-9		
							$T_E^5C_WC_2$	7.4E-8		
		7.7E-8						9.1E-8		
(4) IORV	$T_I^6(C_EK)U$	1.0E-9					$T_I^6(C_EK)C_2$	1.6E-9		
	$T_I^6C_WU$	5.0E-8					$T_I^6C_WW$	5.5E-9		
	$T_I^6C_WC_2U$	1.9E-8					$T_I^6C_WC_2$	8.0E-8		
							T_I^6S	4.2E-8		
		7.0E-8						1.3E-7		
4. Cases Involving the Release of Excessive Water	T_2UQV	5.8E-8			$T_2UQV'V''W$	8.6E-8				
	T_6UQV	6.0E-9			$T_7UQV'V''W$	3.6E-8				
	T_6UQX	4.0E-9								
	T_7UQV	2.4E-8								
		9.2E-8				1.2E-7				
5. Cases Initiated by a Loss of DC Power Bus	$T_DQU'V$	9.3E-8			T_DW	1.3E-7				
	$T_DQU'X$	1.3E-6			T_DQW	5.9E-7				
					$T_DQU'W$	4.8E-8				
					$T_DQU'V'V''W$	7.9E-9				
		1.4E-6				7.8E-7				

* "Dominant Sequences" are those with frequencies not less than 1.0E-9

TABLE 6-4
ESTIMATED FRACTIONAL CONTRIBUTIONS OF WATER LEVEL INSTRUMENT FAILURE TO EVENTS APPEARING IN SHOREHAM DOMINANT SEQUENCES

System	Event	Estimated Fractional Contribution
Feedwater	Q	0.036
HPRC*	U	0.15
RCIC	U'	0.048
HPCI	U"	0.010
HRA**	UX	0.0057
LPCS	V'	0.0061
LPCI	V"	0.024
LPC***	V(=V'V")	0.19
Injection****	UV(=UV'V")	0.028
RHR/RCIC Steam Cond.	W'	0.0074
Feedwater Initiator	T_F	0.27

* HPRC = HPCI/RCIC
** HRA = HPCI/RCIC/ADS
*** LPC = LPCS/LPCI
**** Injection = HPCI/RCIC/LPCS/LPCI

Table 6-5

Contribution of Reactor Water Level Instrument Failure To Core Vulnerable Frequency

Class	Frequency of Core Vulnerable (Per Reactor Year)	Water Level Contribution (Per Reactor Year)	Fractional Water Level Contribution
I	2.7E-5	9.95E-7	0.037
II	1.0E-5	3.7E-8	0.0034
III	6.6E-7	3.9E-8	0.11
IV	6.1E-6	6.6E-10	0.00011
V	2.0E-8	3.8E-10	0.019
Total	4.4E-5	1.07E-6	0.024

6.6 SUMMARY OF THE IMPACT OF ADVERSE SYSTEMS INTERACTIONS DUE TO WATER LEVEL INSTRUMENTATION

The previous assessment evaluated the impact of potential adverse systems interactions, caused by water level instrumentation failures, on the frequency of calculated core vulnerable conditions. The specific failure modes of water level instrumentation investigated and their contribution to core vulnerable frequency are as follows:

- Reactor water level instrument reference line break or leak as it affects both operator and automatic system response. Contribution of 3.0 events per million years which represents a 7 percent addition to the Shoreham total.
- High drywell temperature occurring during safety system challenges which affect both reference legs due to boil-off or flashing. Contribution of 1.3 events per million years, a 3 percent addition to the Shoreham total.
- Loss of drywell cooling during power operation leading to a reactor shutdown due to high drywell temperature. Contribution of 0.15 events per million years, a 0.3 percent addition.
- An evaluation of the contribution from all other water level instrument failure modes including random failures and miscalibrations. Contribution of 1.07 events per million years, which is 2.4 percent of the Shoreham total.

Figure 6-16 is a graphical comparison of the calculated frequency of core vulnerable conditions due to the above contributors associated with reactor water level instrumentation. Note that the contribution due to "other" failure modes of reactor water level instrumentation, as calculated in Section 6.5, is already incorporated in the Shoreham PRA.

The most significant contribution to core vulnerable frequency is the instrument line break. In order to put this contribution in perspective relative to other potential contributors, Figure 6-17 compares the frequency of core vulnerability due to all causes with the frequency of core melt associated with water level instrumentation line break.

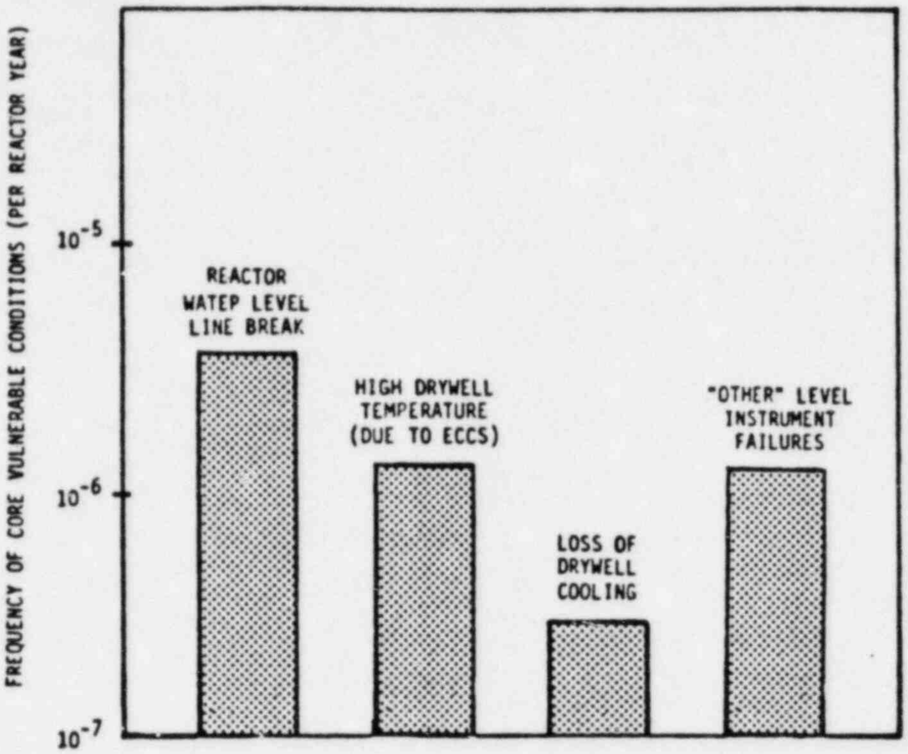


Figure 6.16. Comparison of the Frequency of Core Vulnerable Co..itions Due to Postulated Reactor Water Level Instrument Failure Modes.

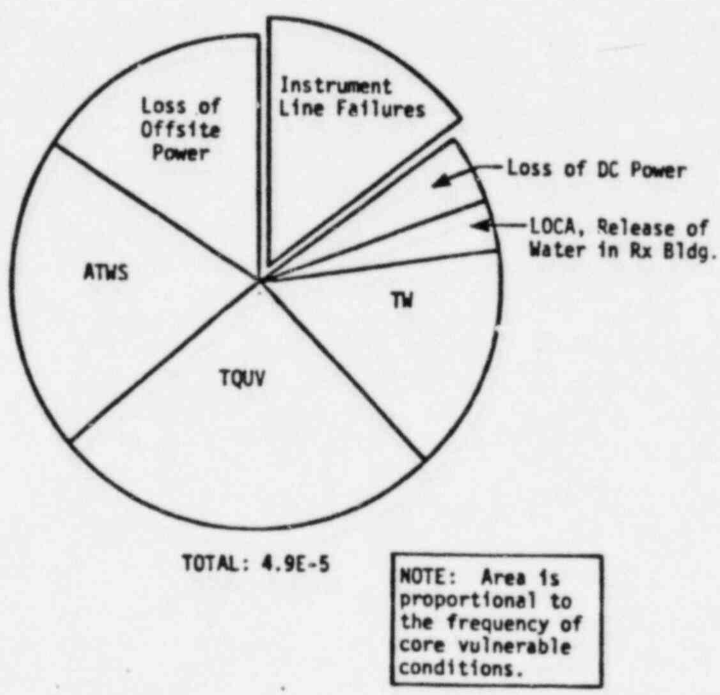
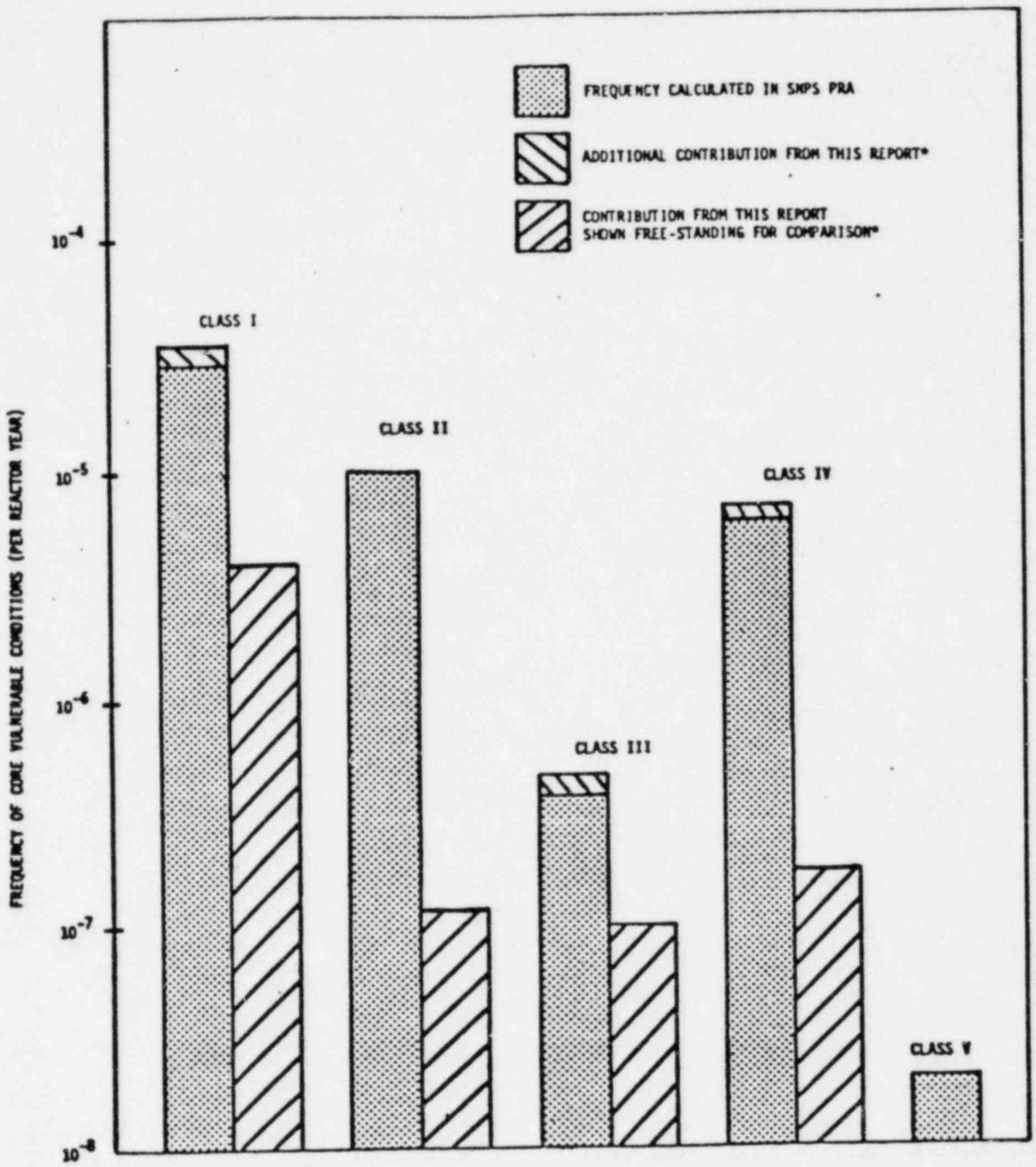


Figure 6.17. Core Vulnerable Frequency (Per Rx Yr) Due to Various Identified Contributors for Shoreham.

Figure 6-18 is a comparison, by accident class, of the incremental contribution to core vulnerable conditions from reactor water level instrumentation with the total contribution calculated in the Shoreham PRA. This comparison is crucial in understanding the potential impact of these sequences on the ex-plant consequences.

Based upon the comparison of the Shoreham PRA results with the plant-specific results of the water level contributors, it is found that sequences involving the instrument line failure initiator are a noticeable contributor to the overall frequency of core melt when compared with other internal event initiators. However, the frequency of such sequences is approximately 7 percent of the overall frequency of core vulnerable conditions, and the summation of all internal events is below the published safety goals for core melt of 1×10^{-4}/reactor year.

Ninety percent of the water level contribution to core vulnerable frequency occurs in containment Class I sequences. In the original Shoreham PRA, Class I sequences were 60 percent of the total. Since Class I sequences have a smaller consequence (i.e., offsite dose due to the event) than other containment classes, the portion of the overall risk attributable to the water level measurement system will be considerably smaller than its contribution to core vulnerable frequency.



*FREQUENCY CONTRIBUTIONS FROM THIS REPORT ARE SHOWN TWICE: ONCE ALONGSIDE THE SHOREHAM PRA FREQUENCIES FOR COMPARISON, AND ONCE ADDED TO THE SHOREHAM PRA FREQUENCIES, TO SHOW TOTALS.

Figure 6.18. Impact of Sequences Involving Reactor Water Level Instrumentation on the Frequency of Core Vulnerable Conditions Compared by Class Type.

- Generic and Shoreham-specific operating and emergency procedures coupled with operator training are designed to prevent the occurrence of degraded plant conditions and to assure that the plant operating staff will successfully manage the plant under degraded conditions should a highly improbable series of events occur.

The key results from the analysis are:

- The various level indication ranges coupled with different calibration strategies for the different ranges provide satisfactory level indications to indicate the state of the core. The water level system may be used to indicate the state of the core even when the reference lines have flashed or boiled off.

- Because of the short reference leg and variable leg drops, the significance of flashing errors is limited. Even under the worst flashing condition, the actual level will be about five feet above the top of the active fuel even if indicated level is well below the point at which plant procedures instruct the operator to maintain level.

- The nearly equal vertical drops of the reference and variable legs in the drywell assure that correct level initiation of safety systems will not be affected by high drywell temperature.

- The deterministic analysis of Section 5 shows that a reference line break or significant leak plus an additional single failure will, in some cases, require operator action to assure adequate long-term water

Section 7

CONCLUSIONS

The Shoreham water level system analysis in the previous sections is the result of a study of the interaction between the water level measurement system, the plant systems, and the plant operator. The analysis is based on the Shoreham-specific plant water level system whose key features are as follows:

- The Shoreham water level measurement system uses an unheated ("cold") reference leg connected to the reactor vessel steam space via a condensing chamber and a variable leg connected to the reactor vessel at an elevation below the water level. Control and safety systems are connected to two level measurement systems located on opposite sides of the reactor vessel.

- The Shoreham water level system has short vertical reference leg drops in the drywell. The variable leg drops for the narrow and wide range instruments are nearly equal to the reference leg drops.

- The safety system automatic initiation logic for each class of systems (i.e., scram, isolation, high pressure injection, low pressure injection) receives two signals from each side of the water level system. An initiation signal from both of the sensors on one side will cause system initiation.

- Shoreham uses an analog trip system to provide safety system initiation signals so the operator interaction with the level transmitters on the instrument racks is minimized.

inventory. Many level and other indications will be available in the control room to provide the operator with sufficient information to manually initiate inventory make-up systems.

- The probabilistic risk assessment shows the reactor water level reference line break adds 3.0×10^{-6} events per reactor year to the previously calculated core vulnerable frequency of 4.4×10^{-5} per reactor year for the Shoreham plant. Most of this added risk (2.6×10^{-6}) is associated with Class I sequences (i.e., sequences where the containment remains intact during core melt, and the consequences are much less serious due to the fission products' scrubbing by the suppression pool).

- Risk contribution from loss of drywell cooling during operation, plant shutdown due to high drywell temperatures, and all other water level instrument failure modes contribute 2.4×10^{-6} events per reactor year to the previously calculated core vulnerable frequency for the Shoreham plant.

- The total risk attributable to the water level measurement system is 5.4×10^{-6} events per reactor year, which is 11 percent of the total risk for all transient accident sequences at Shoreham.

In summary, the Shoreham water level system provides sufficient information to assure adequate water inventory in the vessel and can be used to indicate the state of the core. As described in Section 5, the biggest challenge to the system is the low probability condition of an instrument line break with a pre-existing or concurrent failure in an active component (instrument or power bus) of the water level measurement systems because operator action is required to mitigate the event. The use of an analog trip system and plant procedures which call for feedwater control on Side A and require periodic validation of water level indications reduce the impact of the event. The probabilistic risk assessment, which accounts for the Shoreham configuration and procedures, shows that this event has a small contribution to core vulnerable frequency. Since 90 percent of the core vulnerable risks associated with the water level measurement system are in Class I sequences, the fractional contribution to consequences (offsite dose) will be less than the fractional contribution to core vulnerable frequency. This is so because Class I sequences have lower consequences than other sequence classes and Class I sequences were 60 percent of the total core vulnerable frequency in the Shoreham PRA.

Section 8

LIST OF ACRONYMS

ADS	Automatic Depressurization System
ARI	Ålternate Rod Insertion
ECCS	Emergency Core Cooling System
FCD	Functional Control Diagram
FSAR	Final Safety Analysis Report
HPCI	H!gh Pressure Coolant Injection
IROV	Inadvertent Opening of Relief Valve
IREP	Interim Reliability Evaluation Program
LER	Licensee Event Report
LILCO	Long Island Lighting Company
LIS	Level Indicating Switch
LOCA	Loss of Coolant Accident
LODWC	Loss of Drywell Coolers
LPCI	Low Pressure Coolant Injection
LPCS	Low Pressure Core Spray
LT	Level Transmitter
MSIV	Main Steam Isolation Valve
MWT	Megawatts Thermal
NRC	Nucler Regulatory Commission
PCS	Power Conversion System
P&ID	Piping and Instrumentation Diagram
PRA	Probabilistic Risk Analysis
RBCCW	Reactor Building Closed Cooling Water

LIST OF ACRONYMS (CONTINUED)

RCIC	Reactor Core Isolation Cooling
RHR	Residual Heat Removal
RHRS	Residual Heat Removal System
RPS	Reactor Protection System
RPT	Recirculation Pump Trip
RSSMAP	Reactor Safety Study Methodology Applications Program
SNPS	Shoreham Nuclear Power Station
SORV	Stuck Open Relief Valve
SRV	Safety Relief Valve

REFERENCES

1. SLI-8211, Review of BWR Reactor Vessel Water Level Measurement Systems, S. Levy, Inc., July 1982.

2. Section 3 of SLI-8218, Inadequate Core Cooling Detection in Boiling Water Reactors, S. Levy, Inc., June 1982.

3. WASH-1400, Reactor Safety Study: An Assessment of Accident Risk in U.S. Commercial Nuclear Power Plants, U.S. Vol. 33, 1979.

4. Reactor Safety Study Methodology Applications Program: Oconee #3 PWR Power Plant, Prepared for U.S. Nuclear Regulatory Commission by Sandia National Laboratories, 1981.

5. Interim Reliability Evaluation Program Phase II, Procedure and Schedule Guide, Draft Revision 2, Division of Systems and Reliability Research, Office of Nuclear Regulatory Research, U.S. Nuclear Regulatory Commission, September 1980.

6. Probabilistic Risk Assessment Shoreham Nuclear Power Station Long Island Lighting Company, Preliminary Draft, Science Applications, Inc., March 1982.

7. SIL-299, "High Drywell Temperature Effect on Reactor Vessel Water Level Information," General Electric Nuclear Services Information letter (GE-SIL), July 25, 1979, and SIL-299, Supplement 1, September, 1980.

Appendix A

LEVEL LOGIC DESCRIPTION AND FAILURE ANALYSIS

In this Appendix, protective action Boolean equations for level inputs are derived by first determining the basic logic diagrams of the pertinent plant systems and then using the diagrams to write the Boolean equations. The logic information is derived from the plant drawings such as piping and instrument diagrams (P&ID's), functional control diagrams (FCD's), and elementary diagrams. The Boolean equations are next analyzed for the effects of failures of the reference legs. The failure of the reference leg could be due to: (1) a line break in the reference leg anywhere between the vessel tap and the sensor; (2) fitting leak; (3) any other occurrence, such as misvalvings, that causes blowdown of a reference leg. The effects of single instrument failures alone will not be analyzed, since this is covered by existing plant safety analyses; however, the effect of a single instrument failure in conjunction with reference leg failure will be analyzed.

A.1 CONVENTIONS

Boolean algebra is a switching algebra that involves variables that have only two states. The variables can be denoted by any convenient symbols and the two states by the symbols 0 (zero) and 1 (one). The states can imply that a relay contact is closed or open, for example, or that a voltage is applied or not applied to a relay coil. The following positive logic convention for the two states is used in this appendix: logic 1 indicates the presence of voltage; logic 0 indicates no voltage. Since each Boolean expression corresponds directly to a network of logic gates, a Boolean expression can be derived from a pictorial interconnection of logic gates and vice versa. Graphic depiction using logic gates allows illustration of the plant system logic in a convenient and consistent set of diagrams.

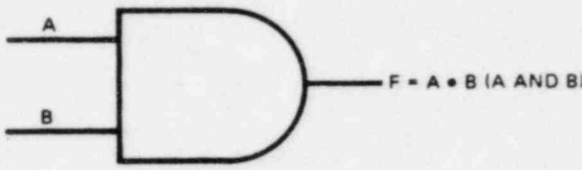
The plant system logic diagrams are used to construct a Boolean expression for the system action as a function of the reactor water level inputs. The expression is then evaluated for certain events by substituting values of 0 or 1 for each variable. The resulting expression is reduced by application of Boolean algebra definitions and theorems regarding the basic operations of AND (•) and OR (+). The definition of the AND and OR operations are given in Figures A-1 and A-2, respectively.

Certain simplifications were made in deriving the Boolean expressions from the system logic diagrams. The purpose of the logic diagrams presented is to convey the main logic flow, so logic related to resets, timers, latches, and flip-flops are not always included because they do not necessarily influence the initiation of mitigating systems. The Boolean expressions are derived by inspection of the system basic logic diagrams with respect to only the reactor level inputs and not to other variables. The worst case level instrument failures postulated are those that will cause the system protection initiation action to remain in the normal state and not respond to an event requiring initiation.

A.2 SHOREHAM PLANT LEVEL SYSTEM

The orientation for the reactor vessel level instrumentation is shown in Figure A-3. The correlation of vessel level with system actions is shown in Table A-1. The system assignment of instruments is shown in Table A-2 along with the power used for the instrument and the logic relay, connected to the Analog Trip System (ATS) trip unit output, which initiates the desired action.

SYMBOL:



TRUTH TABLE:

INPUTS		OUTPUT
A	B	F=A•B
0	0	0
0	1	0
1	0	0
1	1	1

STATEMENTS:

(1) IF BOTH INPUTS = 1, THEN OUTPUT = 1; OTHERWISE THE OUTPUT = 0

(2) IF ANY INPUT = 0, IT WILL FORCE THE OUTPUT TO 0

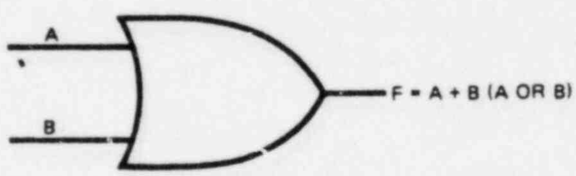
(3) THERE CAN BE MORE THAN TWO INPUTS. ALL INPUTS MUST = 1 TO OBTAIN OUTPUT = 1.

THEOREMS:

(1) $X \bullet 1 = X$
(2) $X \bullet 0 = 0$
(3) $X \bullet X = X$

Figure A-1: Definition of the AND Gate

SYMBOL:



TRUTH TABLE:

INPUTS		OUTPUT
A	B	F=A+B
0	0	0
0	1	1
1	0	1
1	1	1

STATEMENTS:

(1) IF BOTH INPUTS = 0, THEN OUTPUT = 0; OTHERWISE THE OUTPUT = 1

(2) IF ANY INPUT = 1, IT WILL FORCE THE OUTPUT TO 1

(3) THERE CAN BE MORE THAN TWO INPUTS. ALL INPUTS MUST = 0 TO OBTAIN OUTPUT = 0.

THEOREMS:

(1) $X + 0 = X$
(2) $X + 1 = 1$
(3) $X + X = X$

Figure A-2: Definition of the OR Gate

Table A-1

Shoreham
Vessel Level Trip Elevation Correlation

Reference	Description	Inches Above: TAF (1)	Instr. Zero (3)	Vessel Zero
	Narrow and wide range upscale	218.19	60	576.75
Level 8	RCIC, HPCI turbine steam inlet valve closure. Close main turbine stop valves. Trip feed pumps.	212.69	54.5 (4)	571.25
Level 7	Feedwater control high level alarm.	200.94	42.75	559.5
Level 4	Feedwater control low level alarm.	191.69	33.5	550.25
Level 3	Scram and close RHR shutdown cooling isolation valves. ADS level permissive.	170.69	12.5	529.25
Instr. zero	For wide, narrow, shutdown/upset range Inst. Narrow range and shutdown range downscale.	158.19	0	516.75
Level 2	Initiate RCIC and HPCI. Close primary system isolation valves (except RHR shutdown cooling isolation valves). Trip recirc. pumps. Close MSIV's.	120.19	-38	478.75
	Fuel Zones upscale	50	-108.19	408.56
Level 1	Initiate LPCS and RHR. Start diesel generators. Contribute to ADS.	25.69	-132.5	384.25
	Wide Range downscale	8.19	-150	366.75
TAF	Top of active fuel Fuel Zone Inst. Zero	0	-158.19	358.56
BAF	Bottom of Active Fuel Fuel zone downscale	-150	-308.19	208.56

Notes:

(1) Top of active fuel, approximate.

(2) Vessel zero, cold (approximate).

(3) Level instrument zero (exrept fuel zone).

(4) 58.75 for feedwater.

Table A-2

SYSTEM ASSIGNMENTS OF LEVEL INSTRUMENTATION

SYSTEM	ATS TRIP RELAY	LEVEL SENSOR	SENSOR LOCATION	TRIP CHANNEL	POWER BUS	FUNCTION
RPS	B21-K101A B21-K101B B21-K101C B21-K101D	B21-N080A B21-N080B B21-N080C B21-N080D	Side A Side A Side B Side B	A1 (A) B1 (B) A2 (C) B2 (D)	RPS A, 120 VAC B, 120 VAC A, 120 VAC B, 120 VAC	Level 3 SCRAM & isolation of RHR valves (sample lines & discharge to radwaste.)
HPCI	B21-K302B B21-K302D B21-K302A B21-K302C	B21-N091B B21-N091D B21-N091A B21-N091C	Side B Side B Side A Side A	B B A A	B, 125 VDC B, 125 VDC A, 125 VDC A, 125 VDC	LEVEL 2 Initiate HPCI
	B21-K303C B21-K303D	B21-N091C B21-N091D	Side A Side B	A B	B, 125 VDC B, 125 VDC	Level 8 HPCI Turbine Trip
RCIC E11-K79B E11-K80B	B21-K302A B21-K302C B21-K302B* B21-K302D*	B21-N091A B21-N091C B21-N091B B21-N091D	Side A Side A Side B Side B	A A B B	A, 125 VDC A, 125 VDC B, 125 VDC B, 125 VDC	Level 2 Initiate RCIC
	B21-K303A B21-K303B	B21-N091A B21-N091B	Side A Side B	A B	A, 125 VDC B, 125 VDC	Level 8 RCIC Turbine Trip

* Initiation signals are not taken directly from ATS signal but indirectly via the RHR system relay shown under "SYSTEM" column.

Table A-2 (Cont'd.)

SYSTEM ASSIGNMENTS OF LEVEL INSTRUMENTATION

SYSTEM	ATS TRIP RELAY	LEVEL SENSOR	SENSOR LOCATION	TRIP CHANNEL	POWER BUS	FUNCTION
MSIV	B21-K102A	B21-N081A	Side A	A1 (A)	RPS A, 120 VAC	Level 2 Isolation
	B21-K102B	B21-N081B	Side A	B1 (B)	RPS B, 120 VAC	of MSIV & Other
	B21-K102C	B21-N081C	Side B	A2 (C)	RPS A, 120 VAC	Valves except
	B21-K102D	B21-N081D	Side B	B1 (D)	RPS B, 120 VAC	RHR Valves Above.
LPCS	B21-K302A	B21-N091A	Side A	A	A, 125 VDC	Level 1
	B21-K302B	B21-N091B	Side B	B	B, 125 VDC	Initiator of
	B21-K302C	B21-N091C	Side A	A	A, 125 VDC	Core Spray
	B21-K302D	B21-N091D	Side B	B	B 125 VDC	Systems
LPCI	B21-K302A	B21-N091A	Side A	A	A, 125 VDC	Level 2 for
(Mode	B21-K302B	B21-N091B	Side B	B	B, 125 VDC	Low Level
of RHR)	B21-K302C	B21-N091C	Side A	A	A, 125 VDC	Indicating Light
	B21-K302D	B21-N091D	Side B	B	B 125 VDC	& Annunciator Only
E21A-K7A	*B21-K302A	B21-N091A	Side A	A	A, 125 VDC	Level 1 Initiation
E21A-K7B	*B21-K302B	B21-N091B	Side B	B	B, 125 VDC	
E21A-K8A	*B21-K302C	B21-N091C	Side A	A	A, 125 VDC	
E21A-K8B	*B21-K302D	B21-N091D	Side B	B	B, 125 VDC	

* These signals are not taken directly from the ATS relay, but indirectly via the core spray system relay shown under "SYSTEM" column.

Table A-2 (Cont'd.)

SYSTEM ASSIGNMENTS OF LEVEL INSTRUMENTATION

SYSTEM	TRIP RELAY	LEVEL SENSOR	SENSOR LOCATION	TRIP CHANNEL	POWER BUS	FUNCTION
ADS	B21-K301A B21-K301B B21-K301C B21-K301D	B21-N091A B21-N091B B21-N091C B21-N091D	Side A Side B Side A Side B	A B A B	A, 125 VDC B, 125 VDC A, 125 VDC B, 125 VDC	Level 1 Initiation
	B21-K304A B21-K304B	B21-N095A B21-N095B	Side A Side B	A B	A, 125 VDC B, 125 VDC	Level 3 Confirmation
ATWS Recirc. Pump Trip	B21-K305A B21-K305B B21-K305C B21-K305D	B21-N091A B21-N091B B21-N091C B21-N091D	Side A Side B Side A Side B	A B A B	A, 125 VDC B, 125 VDC A, 125 VDC B, 125 VDC	Level 2 Initiation of ATWS Recirc. Pump Trip (RPT) with 10 Sec. time delay
ATWS-ARI	B21-K302A B21-K302B B21-K302C B21-K302D	B21-N091A B21-N091B B21-N091C B21-N091D	Side A Side B Side A Side B	A B A B	A, 125 VDC B, 125 VDC A, 125 VDC B, 125 VDC	Level 2 Initiation of ATWS Alternate Rod Insertion (ARI)

Table A-2 (Cont'd.)

SYSTEM ASSIGNMENTS OF LEVEL INSTRUMENTATION

SYSTEM	TRIP RELAY	LEVEL SENSOR	SENSOR LOCATION	TRIP CHANNEL	POWER BUS	FUNCTION
FEEDWATER	C32-K624A C32-K624B C32-K624C	C32-N004A C32-N004B C32-N004C	Side A Side B Side A	A B C	Vital Bus 120 VAC Non-Essential Bus II 120 VDC Non-Essential Bus I, 120, VDC	Level 8 Trip of Main Turbine & Feed Pump Turbine
	C32-R608*	C32-N017	Side B	N/A	(Recorder Power) Instr. Bus 120 VAC	Wide Range Level Recorder Pen
	C32-R606A* C32-R606B* C32-R606C*	C32-N004A C32-N004B C32-N004C	Side A Side B Side A	N/A	Vital Bus 120 VAC Non-Ess. Bus II 120 VDC Non-Ess. Bus I 120 VDC	Narrow Range Level Indicators
	C32-R608* C32-R608*	C32-N004A C32-N004B	Side A Side B	N/A	(Recorder Power) Instr. Bus 120 VAC	Narrow Range Level Recorder Switched Between Sensor A or B

* These entries under "TRIP RELAY" column are recorder or indicator reference designations.

End of Table A-2

A.3 LOGIC SYSTEM DESCRIPTION AND FAILURE ANALYSIS

In this section, the logic for level initiation of the various plant systems are developed. A failure analysis is also given for each system for a reference leg failure plus an additional active failure.

Referring to Figure A-3, if the line to the condensing chamber fails, then the reference leg loses pressure and the associated transmitters will go upscale, and low level trips will not occur. An additional active failure then has the potential to defeat automatic systems' initiation.

A.3.1 Reactor Protection System (RPS). The RPS basic logic is shown in Figure A-4. The Boolean logic equation relating the level input to the protective function is:

$$F = (A_A \bullet C_B \bullet S_A) + (B_A \bullet D_B \bullet S_B)$$

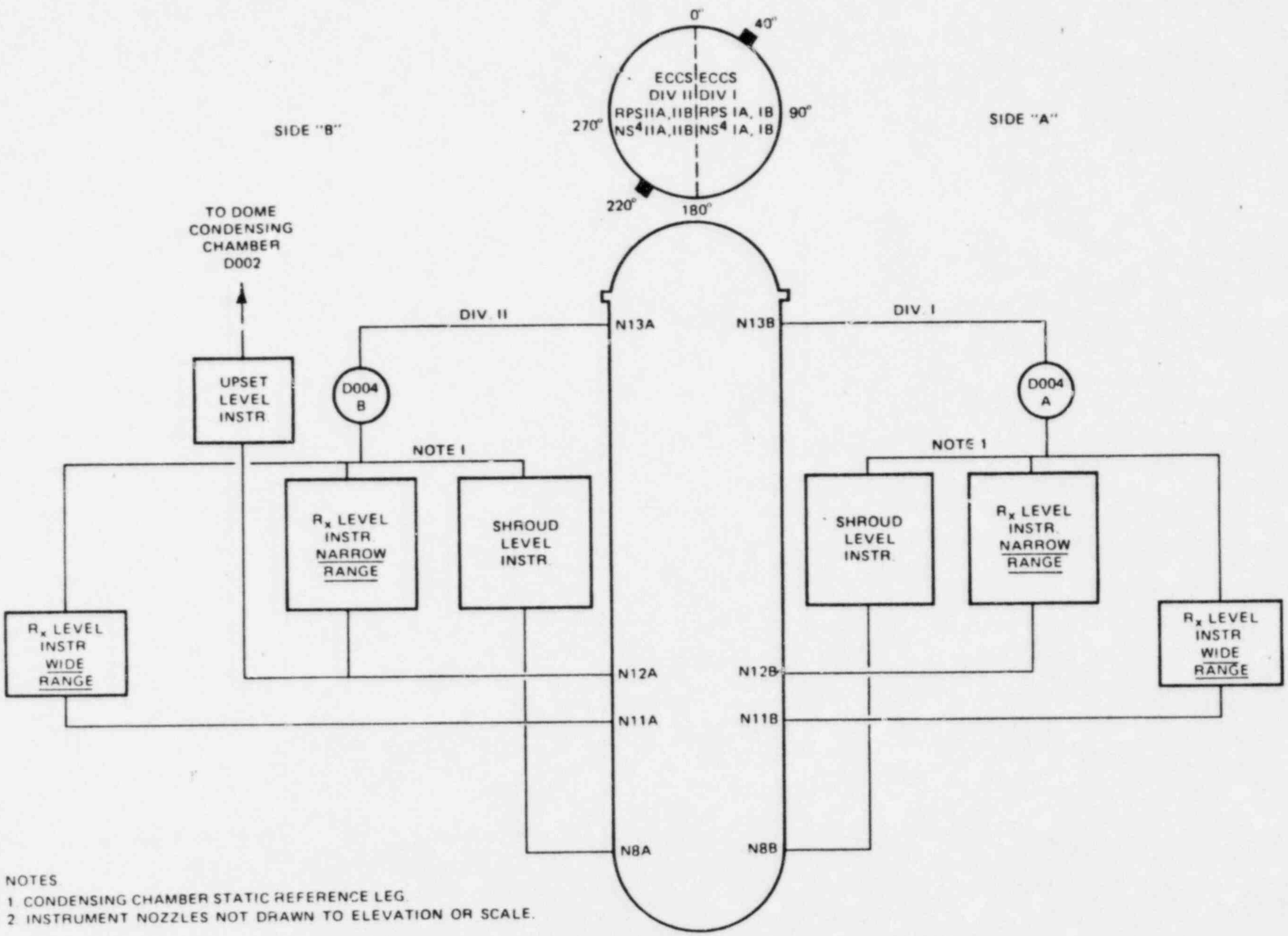
where:

A_A = LT-B21-N080A transmitter on side A
B_A = LT-B11-N080C transmitter on side A
C_B = LT-B21-N080C transmitter on side B
D_B = LT-B21-N080D transmitter on side B

S_A = RPS Bus A power
S_B = RPS Bus B power

F = 1, no scram
0, scram

A_A, B_A, C_B, D_B = 1 if level is above scram setting (Level 3)
= 0 if level is below scram setting (Level 3)



NOTES

1. CONDENSING CHAMBER STATIC REFERENCE LEG.
2. INSTRUMENT NOZZLES NOT DRAWN TO ELEVATION OR SCALE.

Figure A-3: Reactor Vessel Level Instrumentation Orientation

S_A, S_B = 1 if power is available
= 0 if power failed

For a reference line A break, the RPS equation becomes (A_A, B_A = 1)

$$F = (1 \bullet C_B \bullet S_A) + (1 \bullet D_B \bullet S_B)$$

If LT B21-N080C fails upscale and power is available, the equation becomes:

$$F = (1 \bullet 1 \bullet 1) + (1 \bullet D_B \bullet 1) = 1 + D_B = 1$$

Similarily if LT B21-N080D fails upscale:

$$F = (1 \bullet C_B) + 1 \bullet 1 = C_B + 1 = 1$$

This means that the automatic scram function is then blocked for level inputs. The same analysis would hold for failure of the side B reference leg and additional upscale failure of LT-B21-N080A or LT-B21-N080B, so a postulated break of the reference line on side B with concurrent failure of an RPS level instrument on side A would also cause scram failure. Loss of power will not prevent scram initiation since it causes one of the terms in the logic equation to become zero, which puts the channel in the scram condition.

A.3.2 High Pressure Coolant Injection (HPCI) - The logic for the HPCI low level initiation is shown on Figure A-5. The protective system Boolean equation for level input is:

$$F = [(A_A \bullet S_A + B_B \bullet S_B) \bullet (C_A \bullet S_A + D_B \bullet S_B)] \bullet S_B$$

where:

A_A = LIS-B21-N091A on side A
B_B = LT-B21-N091B on side B

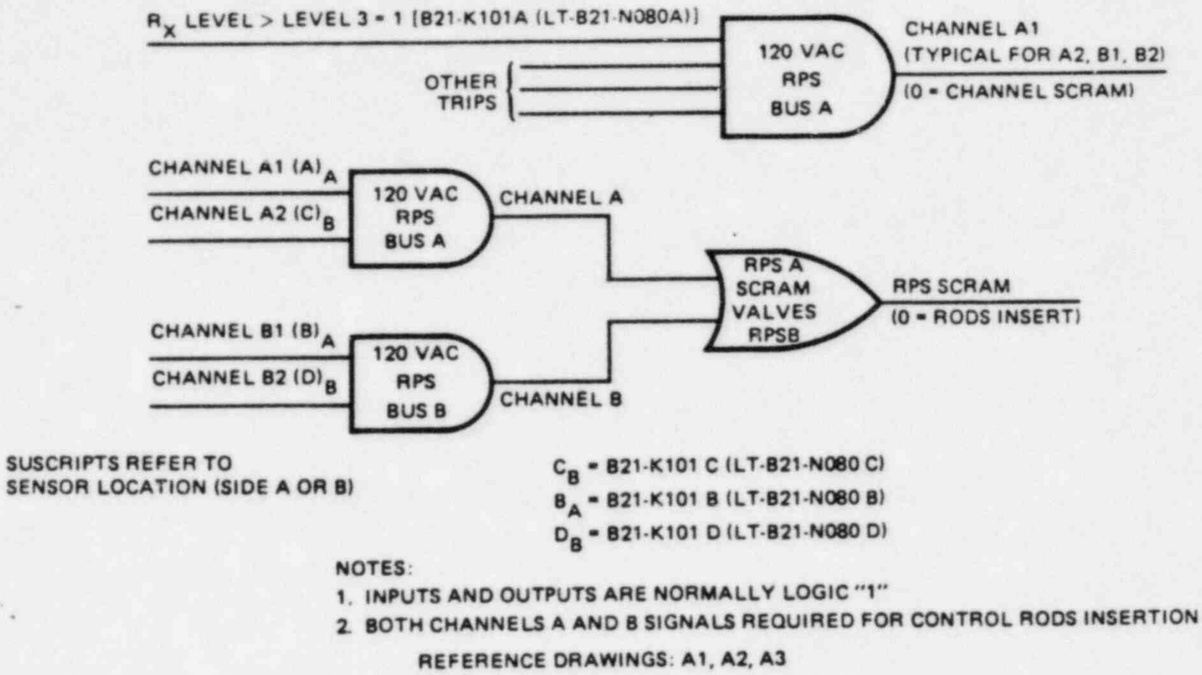


Figure A-4: Reactor Protection System (RPS) Basic Logic

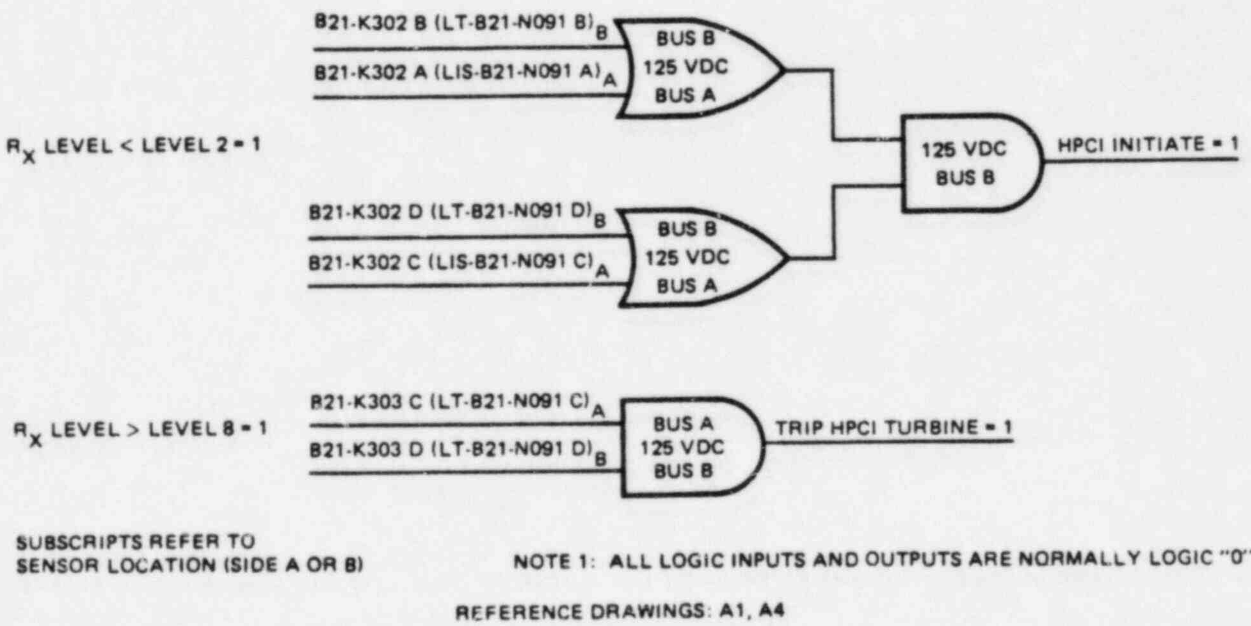


Figure A-5: High Pressure Coolant Injection (HPCI) Basic Logic

C_A = LIS-B21-N091C on side A
D_B = LT-B21-N091D on side B

S_A = 125 VDC Bus A
S_B = 125 VDC Bus B

F = 1, HPCI initiate;
= 0, normal

A_A, B_B, C_A, D_B = 0 if indicated level is above level 2.
= 1 if indicated level is below level 2.

S_A, S_B = 1 if power available.
= 0 if power fails.

If the reference leg on side A were to fail, the equation becomes:

$$F = [(0+B_B \bullet S_B) \bullet (0+D_B \bullet S_B)] \bullet S_B$$

In addition, if LT-B21-N091B fails upscale with power available, then the equation becomes:

$$F = (0+0) \bullet (0+D_B \bullet 1) \bullet 1 = 0 \bullet D_B = 0$$

This condition would prevent automatic initiation of the HPCI system due to level inputs. The same analysis holds for failure of LT-B21-N091D instead of LT-B21-N091B. If side B reference leg were to fail, then either an upscale failure in LIS-B21-N091A or LT-B21-N091C would lead to the same result.

A power failure in bus B would cause loss of HPCI since this bus provides power for the turbine controls. With a reference leg B failure and bus A power failure, the equation would be:

$$F = (A_A \bullet 0 + 0 \bullet 1) \bullet (C_A \bullet 0 + 0 \bullet 1) \bullet 1 = 0$$

so this failure condition would cause loss of HPCI initiation.

The Boolean expression for HPCI high level trip as a function of level inputs is:

$$T = (C_A \bullet S_A) \bullet (D_B \bullet S_B)$$

where:

C_A	=	LT-B21-N091C on side A
D_B	=	LT-B21-N091D on side B
T	=	1, HPCI trip;
	=	0, no trip
C_D, D_B	=	0 if level is below level 8.
	=	1 if level is above level 8.

When the reference leg on side A fails the trip equation becomes:

$$T = 1 \bullet D_B \bullet S_A \bullet S_B$$

If transmitter LT-B21-N091D then fails upscale, the HPCI would trip if power was available. If LT-B21-N091D were to fail low the HPCI trip could not occur. A loss of either power bus would cause loss of trip regardless of the state of the sensors. Similarly, a reference leg B failure and LT-B21-N091C failure would cause the HPCI trip to occur or fail, depending on the sensor failure mode.

A.3.3 Reactor Core Isolation Cooling (RCIC). The simplified logic diagrams for the RCIC low level initiate and high level trip are shown on Figure A-6. The Boolean logic equation for the initiation as function of level inputs is exactly the same as for the HPCI system; therefore, the

RCIC system would not initiate under the same failure conditions as the HPCI system, with LT-B21-N091A and C replacing LIS-B21-N031A and C. A bus A failure would cause loss of initiation regardless of the status of the level sensors. While a reference leg A failure coupled with a bus B failure would also cause loss of initiation.

The Boolean expression for RCIC trip for level is:

$$F = (A_A \bullet S_A) \bullet (B_B \bullet S_B)$$

where:

A_A	=	LT-B21-N091A on side A
B_B	=	LT-B21-N091B on side B
S_A	=	125 VDC bus A
S_B	=	125 VDC bus B
F	=	1, RCIC steam supply valve closure 0, valve remains open
A_A, B_B	=	0 if level is below level 8. 1 if level is above level 8.
S_A, S_B	=	1 if power available. 0 if power fails.

When the reference leg on side A fails, the trip equation becomes:

$$F = 1 \bullet B_B \bullet S_A \bullet S_B$$

If the transmitter LT-B21-N091B then fails high, the RCIC steam supply valve would close. If LT-B21-N091B fails low, there would be a block on RCIC steam supply valve closure. A power failure in either bus would

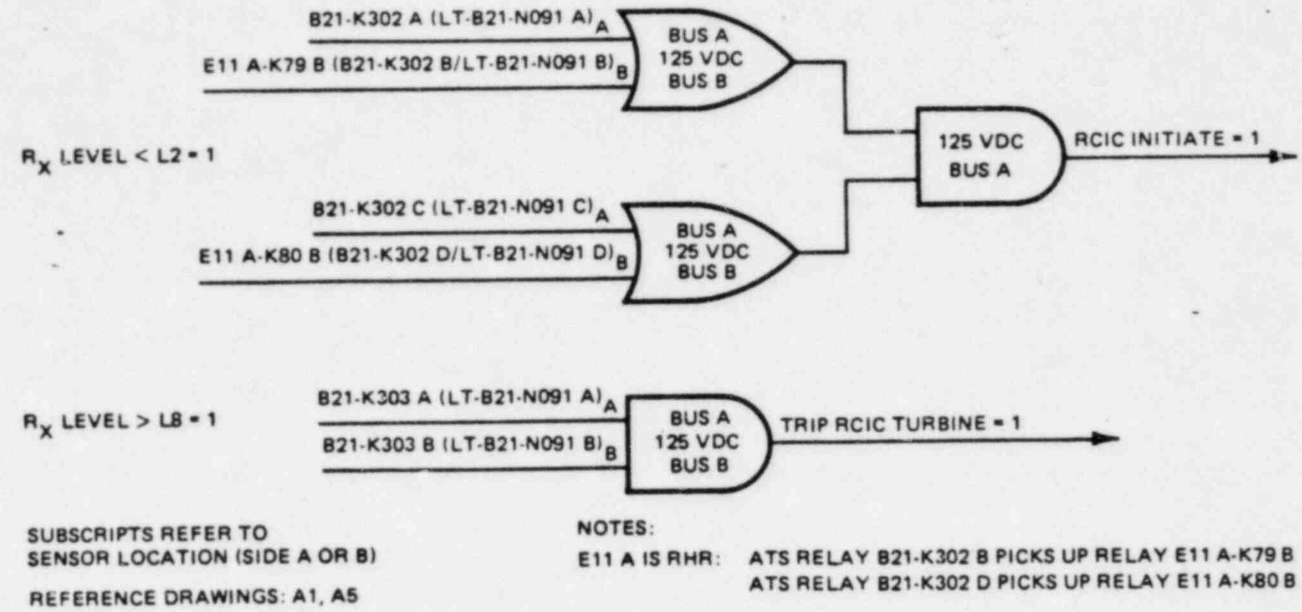


Figure A-6: Reactor Core Isolation Cooling (RCIC) Basic Logic

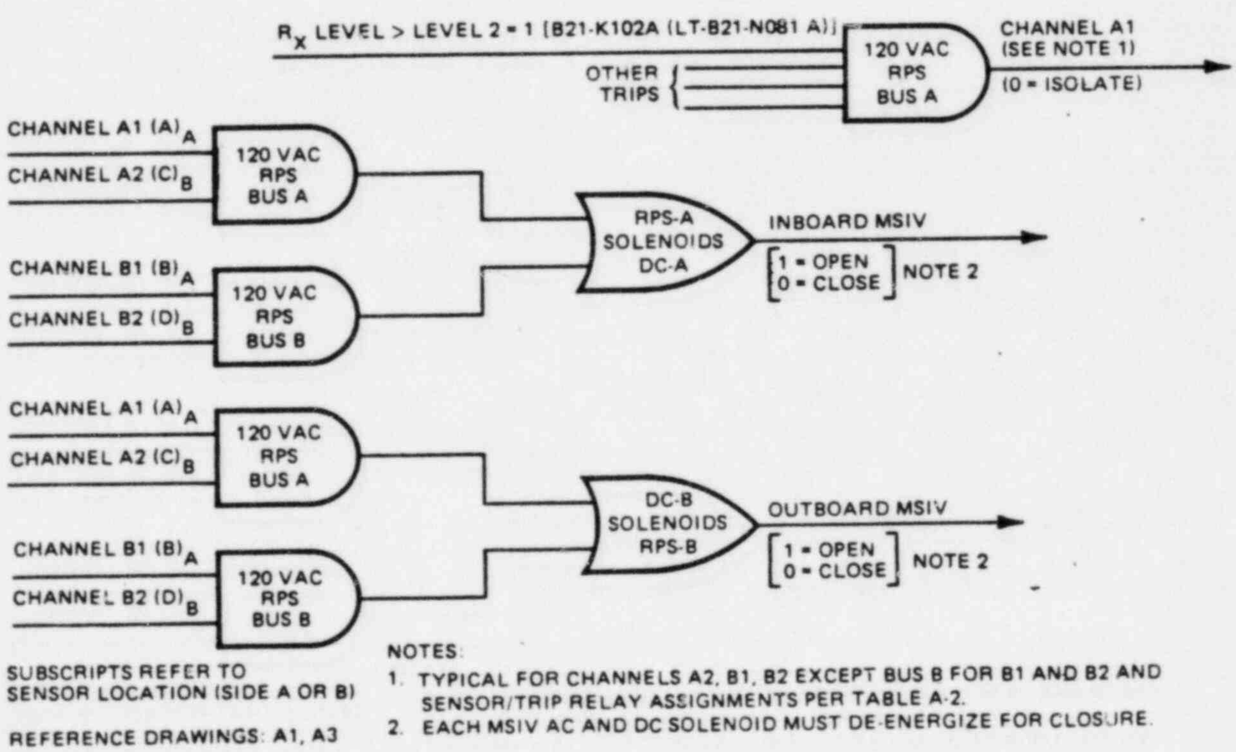


Figure A-7: Main Steam Line Isolation Valve (MSIV) Basic Logic cause loss of RCIC trip regardless of the state of the level sensors. A similar analysis holds for side B reference leg plus LT-B21-N091A failure.

There is no single transmitter failure that would cause both RCIC and HPCI to trip.

A.3.4. Main Steam Isolation Valve (MSIV) Closure. The basic logic diagram for low level initiation of MSIV closure is shown in Figure A-7. The Boolean expression for level inputs with all power available is:

$$F = (A_A \bullet C_B) + (B_A \bullet D_B)$$

where:

A_A = LT-B21-N081A on side A
B_A = LT-B21-N081B on side A
C_B = LT-B21-N081C on side B
D_B = LT-B21-N081D on side B

F = 0, MSIV closure;
= 1, normal

A_A, B_A, C_B, D_B = 1 if level is above level 2.
= 0 if level is below level 2.

This equation is of the same form as the RPS equation and the analysis is the same except a wide range transmitter is involved. A failure of the reference leg on side A with concurrent upscale failure of LT-B21-N081C or LT-B21-N081D would block MSIV closure from low level. A failure of reference leg B plus LT-B21-N081A or B would also cause failure to initiate. Also, the MSIV closure initiation, like RPS, is a de-energize to operate system, so loss of power will not cause loss of initiation.

A.3.5 Low Pressure Core Spray (LPCS) and Low Pressure Coolant Injection (LPCI). The basic logic diagram for Core Spray is shown on Figure A-8. The Low Pressure Coolant Injection basic logic diagram is shown on Figure A-9. The Boolean expression for Core Spray initiation as a function of level inputs is:

$F_1 = (A_A+A_P) \bullet (C_A+C_P) \bullet S_A$ For system I initiate

$F_2 = (B_B+B_P) \bullet (D_B+D_P) \bullet S_B$ For system II initiate

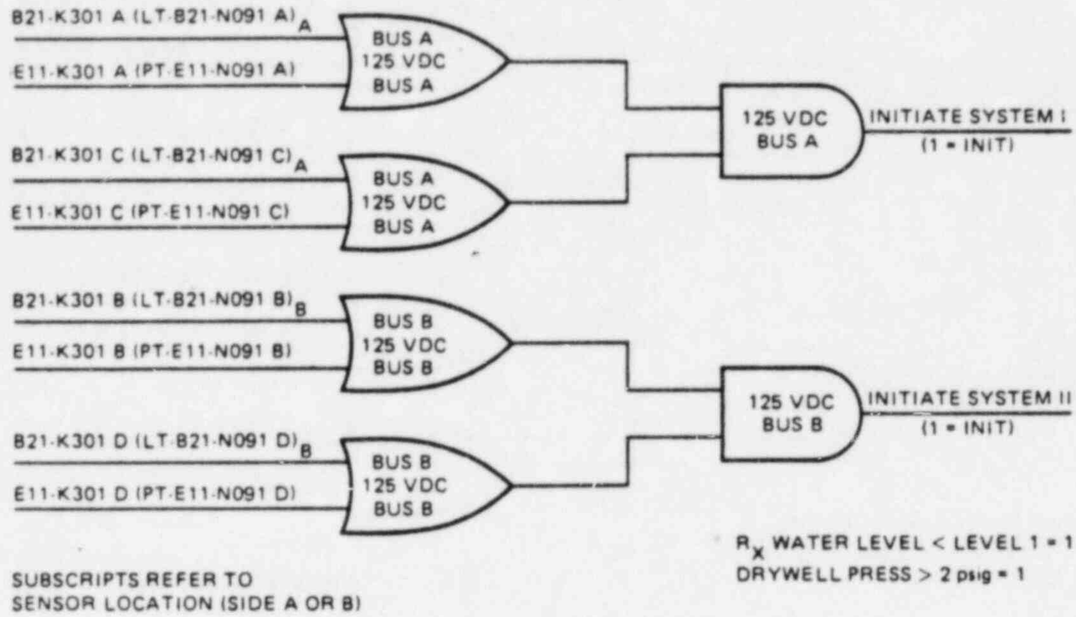
where:

A_A	=	LT-B21-N091A transmitter on side A
B_B	=	LT-B21-N091B transmitter on side B
C_A	=	LT-B21-N091C transmitter on side A
D_B	=	LT-B21-N091D transmitter on side B
A_P	=	PT-E11-N091A drywell pressure transmitter
B_P	=	PT-E11-N091B drywell pressure transmitter
C_P	=	PT-E11-N091C drywell pressure transmitter
D_P	=	PT-E11-N091D drywell pressure transmitter
S_A	=	125 VDC bus A
S_B	=	125 VDC bus B
F	=	1, LPCS initiate
	=	0, normal

A_A, B_B, C_A, D_B = 0 if level above level 2
= 1 if level below level 2

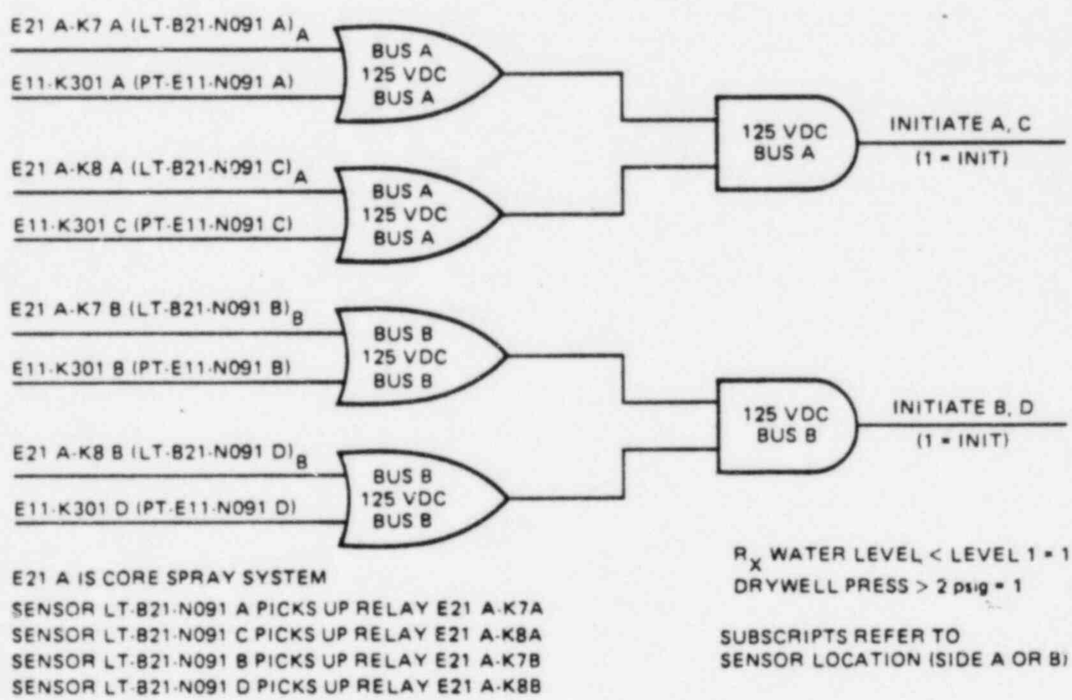
A_P, B_P, C_P, D_P = 0 if drywell pressure normal
= 1 if drywell pressure high

S_A, S_B = 1 if power available
0 if power fails.



REFERENCE DRAWINGS: A1, A6

Figure A-8: Core Spray System Basic Logic



REFERENCE DRAWINGS: A1, A7

Figure A-9: Low Pressure Coolant Injection Basic Logic

If the wide range reference leg on side A were to fail, the system I equation becomes:

$$F_1 = (0+Ap)\bullet(0+Cp)\bullet S_A$$

If drywell pressure remains normal, then:

$$F_1 = (0+0)\bullet(0+0) = 0$$

so no system I initiation on level would occur.

A high failure of LT-B21-N091B with drywell pressure normal would cause the System II equation to become:

$$F_2 = (0+0) \bullet (D_B + D_P) \bullet S_B = 0 \text{ (if no drywell pressure trip)}$$

so no system II initiation on low level would occur. Similarly, an upscale failure of LT-B21-N091D would prevent initiation. Therefore, a reference line break plus an instrument failure would prevent core spray initiation.

If power bus B fails, then the System II equation becomes:

$$F_2 = (B_B+Bp) \bullet (D_B+Dp) \bullet 0 = 0$$

and no System II automatic initiation would occur. Similarly, a reference leg B failure plus an upscale failure of LT-B21-N091A or C, or a power Bus A failure would prevent automaic LPCS initiation.

LPCI initiation has the same failure conditions because it uses the same logic and the same sensors.

A.3.6 Automatic Depressurization System (ADS). The Automatic Depressurization System basic logic for solenoid A is shown on Figure

A-10 and for solenoid B on A-11. Either of the solenoids can activate ADS so the Boolean expression for the low level and high drywell pressure initiation is

$$F = [(A_P \bullet A_{A1} \bullet A_A) \bullet (C_P \bullet C_A \bullet S_A] + [(B_P \bullet B_{B1} \bullet B_B) \bullet (D_P \bullet D_B \bullet S_B)]$$

where:

A_P = PS E11-N010A, drywell pressure switch
B_P = PS E11-N010B, drywell pressure switch
C_P = PS E11-N010C, drywell pressure switch
D_P = PS E11-N010D, drywell pressure switch
A_{A1} = LT-B21-N095A on side A (L_3)
A_A = LT-B21-N091A on side A (L_1)
C_A = LT-B21-N091C on side A (L_1)
B_{B1} = LT-B21-N095B on side B (L_3)
B_B = LT-B21-N091B on side B (L_3)
D_B = LT-B21-N091D on side B (L_1)

S_A = 125 VDC Bus A
S_B = 125 VDC Bus B

F = 1 for ADS;
= 0 normal

A_P, B_P, C_P, D_P = 0, pressure normal
= 1, pressure high

S_A, S_B = 1 if power is available
= 0 if power fails

A_A, C_A, B_B, D_B = 0 if level is above low level 1
= 1 if level is below low level 1.

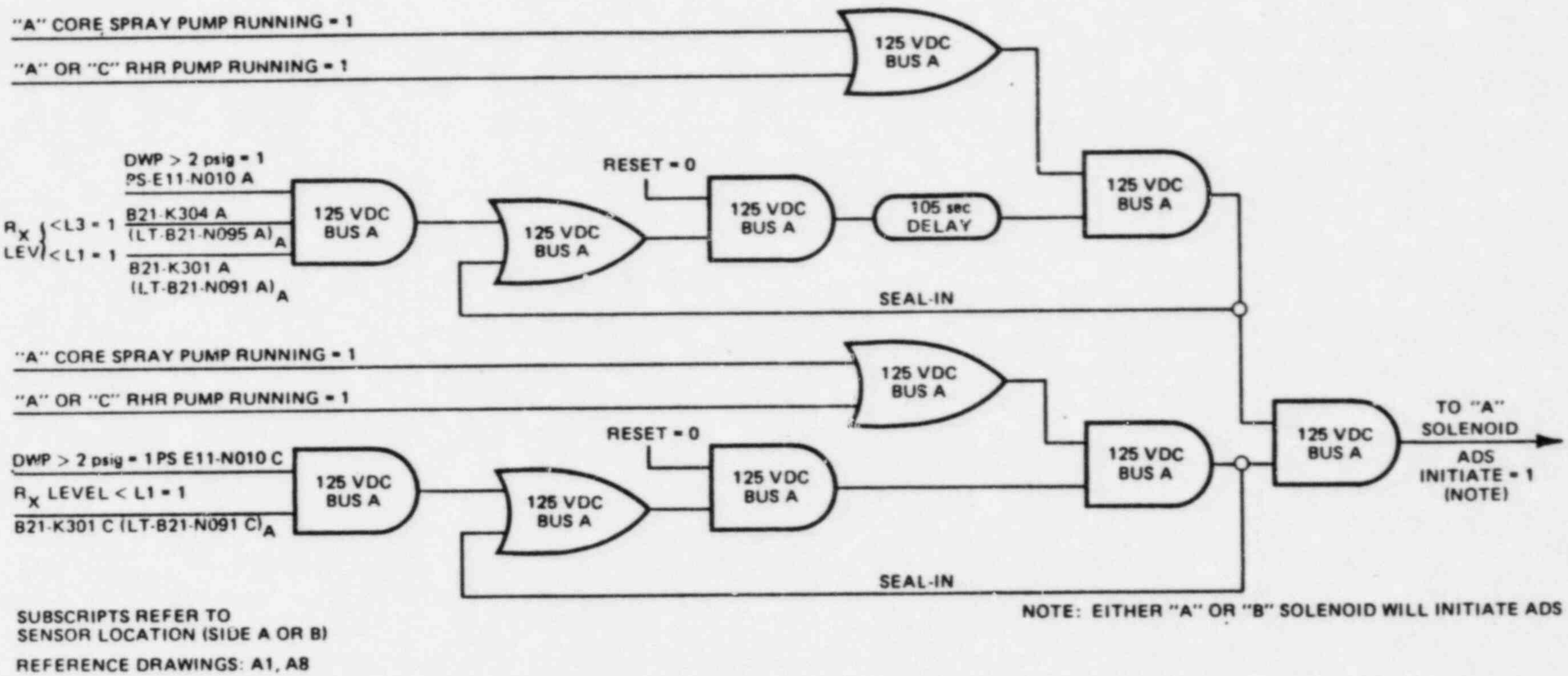


Figure A-10: Automatic Depressurization System (ADS) Basic Logic to "A" Solenoid

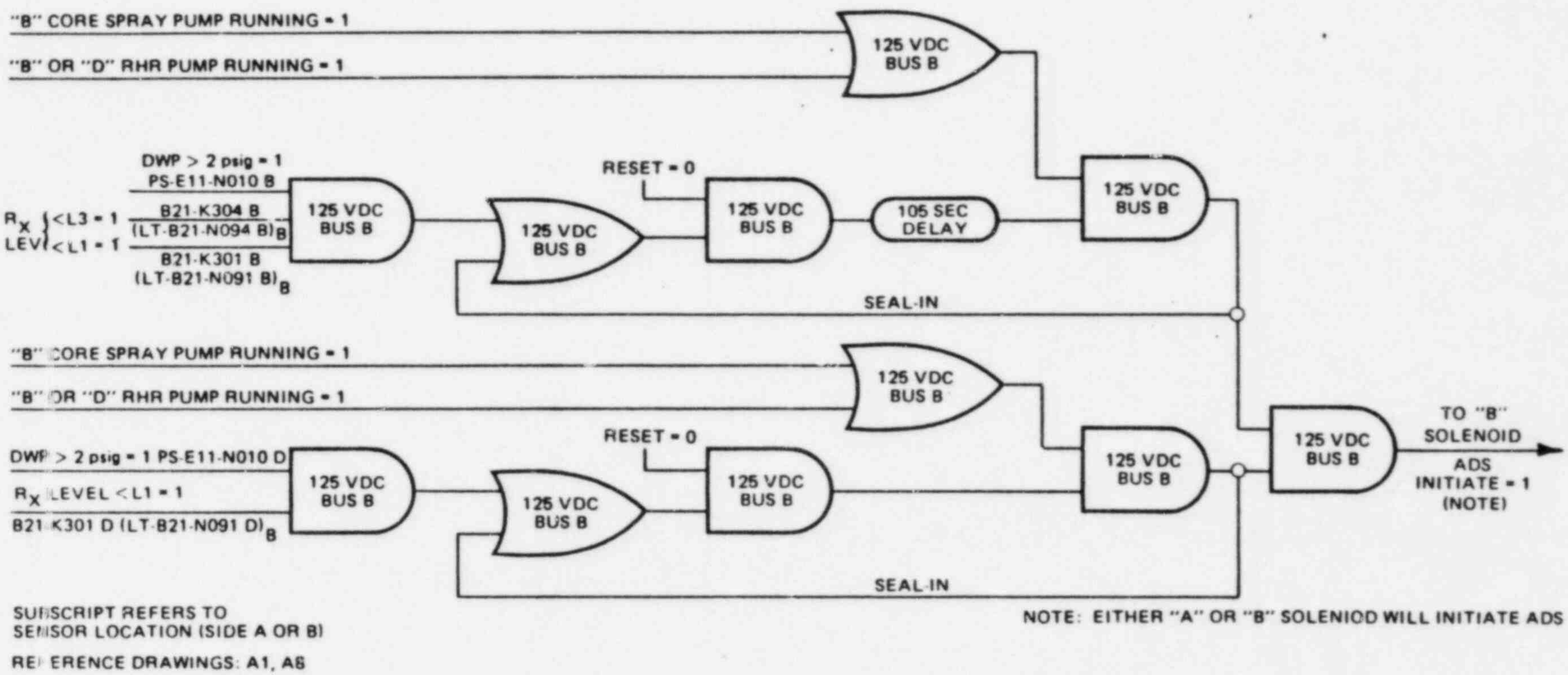


Figure A-11: Automatic Depressurization System (ADS) Basic Logic to "B" Solenoid

A_{A1}, B_{B1} = 0 if level above level 3
= 1 if level below level 3.

With a failure of the reference leg on side A, the equation becomes:

$$F = [(Ap \bullet 0 \bullet 0) \bullet (Cp \bullet 0 \bullet S_A)] + [(Bp \bullet B_{B1} \bullet 0) \bullet (Dp \bullet D_B \bullet S_B)]$$

With an additional upscale failure of sensor B_B on side B, the equation becomes:

$$F = [(Ap \bullet 0 \bullet 0) \bullet (Cp \bullet 0 \bullet S_A)] + [(Bp \bullet B_{B1} \bullet 0) \bullet (Dp \bullet D_B \bullet S_B)]$$

$$= [0] + [0] = 0$$

An upscale failure of LT-B21-N095B or LT-B21-N091D would also cause a failure of ADS initiation.

If bus B fails in addition to the reference leg A failure, then the equation becomes:

$$F = [(Ap \bullet 0 \bullet 0) \bullet (Cp \bullet 0) \bullet S_A] + [(Bp \bullet B_{B1} \bullet B_B) \bullet (Dp \bullet D_B) \bullet 0] = 0$$

and ADS initiation will not occur.

It can also be shown in a similar manner that reference leg failure on side B and an instrument failure on side A or bus A failure would also block the ADS function.

A.3.7 The Anticipated Transients Without Scram (ATWS) - Recirculation Pump Trip (RPT). This logic is shown on Figure A-12. Only the Boolean expression for level inputs need be examined since the reactor high pressure trip initiation is essentially independent.

$$F \text{ (Pump A)} = (A_A \bullet C_A) \bullet S_A + (B_B \bullet D_B) \bullet S_B$$

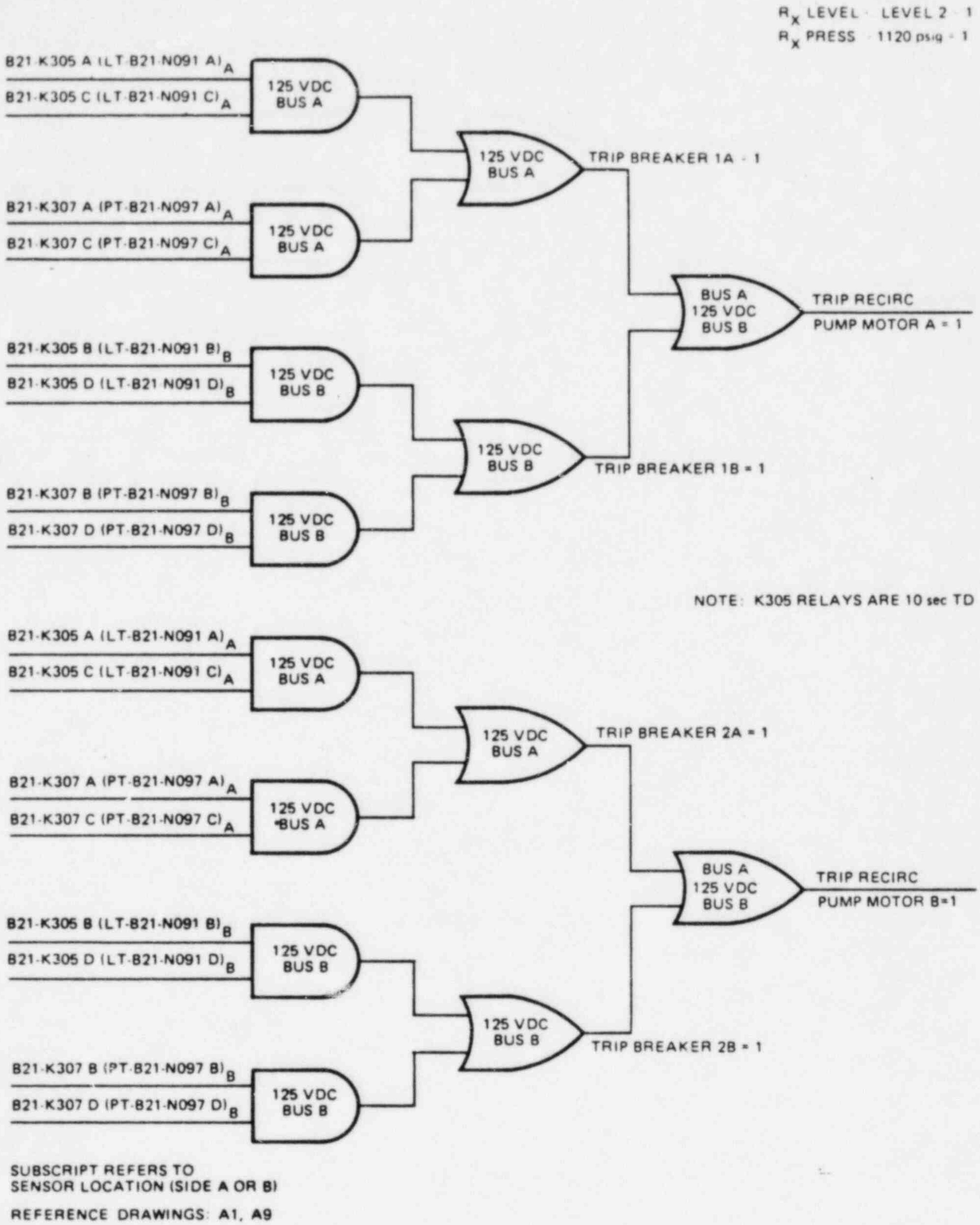


Figure A-12: ATWS – RPT Basic Logic

$F = 1$, trip pump
$= 0$, normal

The expression is the same for pump B since the same level transmitters and trip relays (but different contacts) are used.

A_A = LT-B21-N091A level transmitter on side A
B_B = LT-B21-N091B level transmitter on side B
C_A = LT-B21-N091C level transmitter on side A
D_B = LT-B21-N091D level transmitter on side B

S_A = 125 VDC Bus A
S_B = 125 VDC Bus B

$A_A, B_B, C_A, D_B = 1$, when level is below level 2
$= 0$, when level is above level 2.

$S_A, S_B = 1$, if power available
$= 0$, if power fails.

Failure of the reference leg on side A and an upscale failure of level transmitter B21-N091B on side B will result in the equation:

$$F = (0) + (0 \bullet D_B) = 0$$

hence, no level initiation of the pump trip will occur. An upscale failure in LT-B21-N091D would also cause loss of the pump trip.

If bus B power fails, the equation becomes:

$$F = 0 + (B_B \bullet D_B) = 0$$

and no pump trip will occur. Similarly, a reference leg B failure plus an upscale failure of LT-B21-N091A or C or loss of bus A will cause loss of automatic level initiation of ATWS-RPT.

The ATWS - Alternate Rod Insertion (ARI) logic is shown on figure A-13. The same analysis and conclusions as for ATWS-RPT apply, with RPS Bus A and B replacing 125 VDC bus A and B.

A.3.8 High Level Turbine Trip. The logic for the high level trips of the main and feedwater turbines is shown on Figure A-14. The logic equation for trip of the turbines is:

$$F = (A_A \bullet S_1) \bullet (C_A \bullet S_2) + (A_A \bullet S_1) \bullet (B_B \bullet S_3) + (C_A \bullet S_1) \bullet (B_B \bullet S_3)$$

A_A = LT-C32-N004A on side A

B_B = LT-C32-N004B on side B

C_A = LT-C32-N004C on side A

S_1 = Vital AC

S_2 = Instrument bus B

S_3 = Instrument bus A

F_1 = 1, trip turbines

= 0, normal

A_A, B_B, C_A = 0, if level below level 8

= 1, if level above level 8

S_1, S_2, S_3 = 1, if power available

= 0, if power failed

If reference line A fails, the equation becomes:

$$F = (1 \bullet S_1) \bullet (1 \bullet S_2) + (1 \bullet S_1) \bullet (B_B \bullet S_3) + (1 \bullet S_1) \bullet (B_B \bullet S_3) = 1$$

So a reference line failure on side A will cause the turbine to trip. If side B reference line breaks, the equation becomes:

$$F = (A_A \bullet S_1) \bullet (C_A \bullet S_2) + (A_A \bullet S_1) \bullet (1 \bullet S_3) + (C_A \bullet S_1) \bullet (1 \bullet S_3)$$

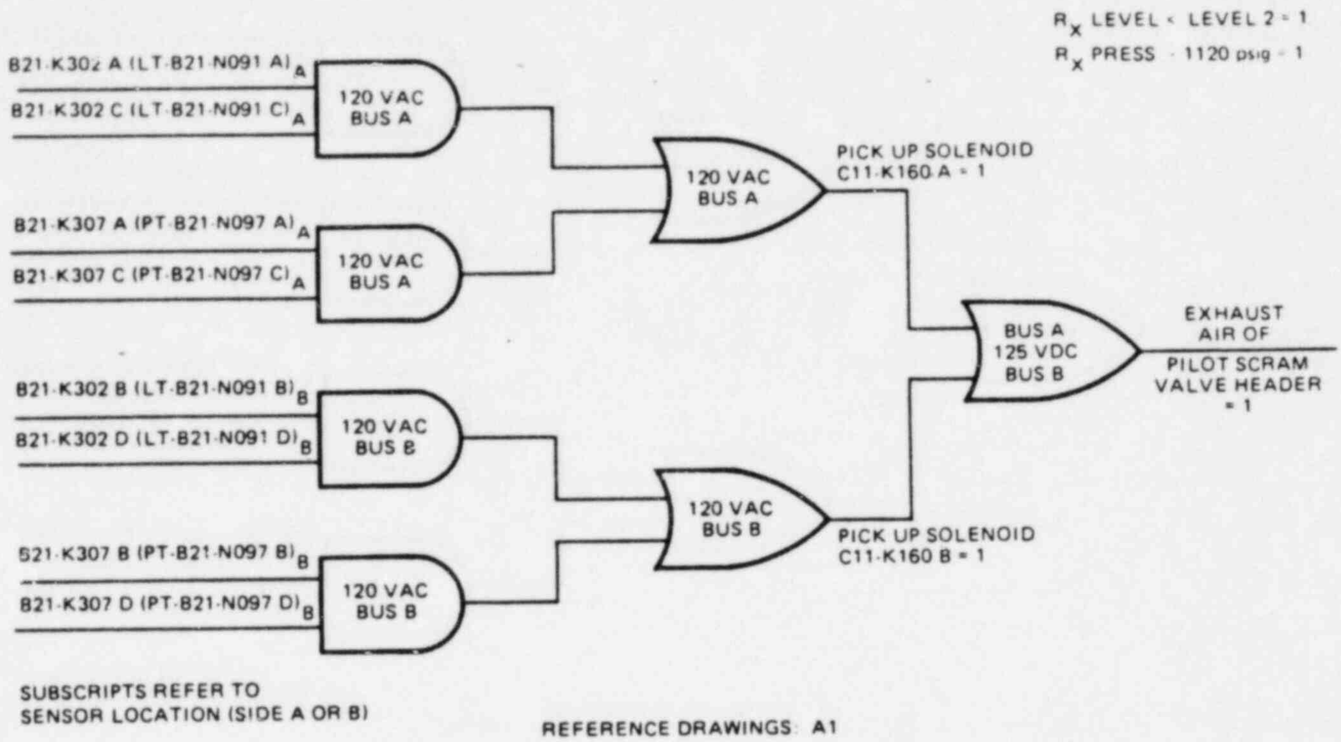


Figure A-13: ATWS – ARI Basic Logic

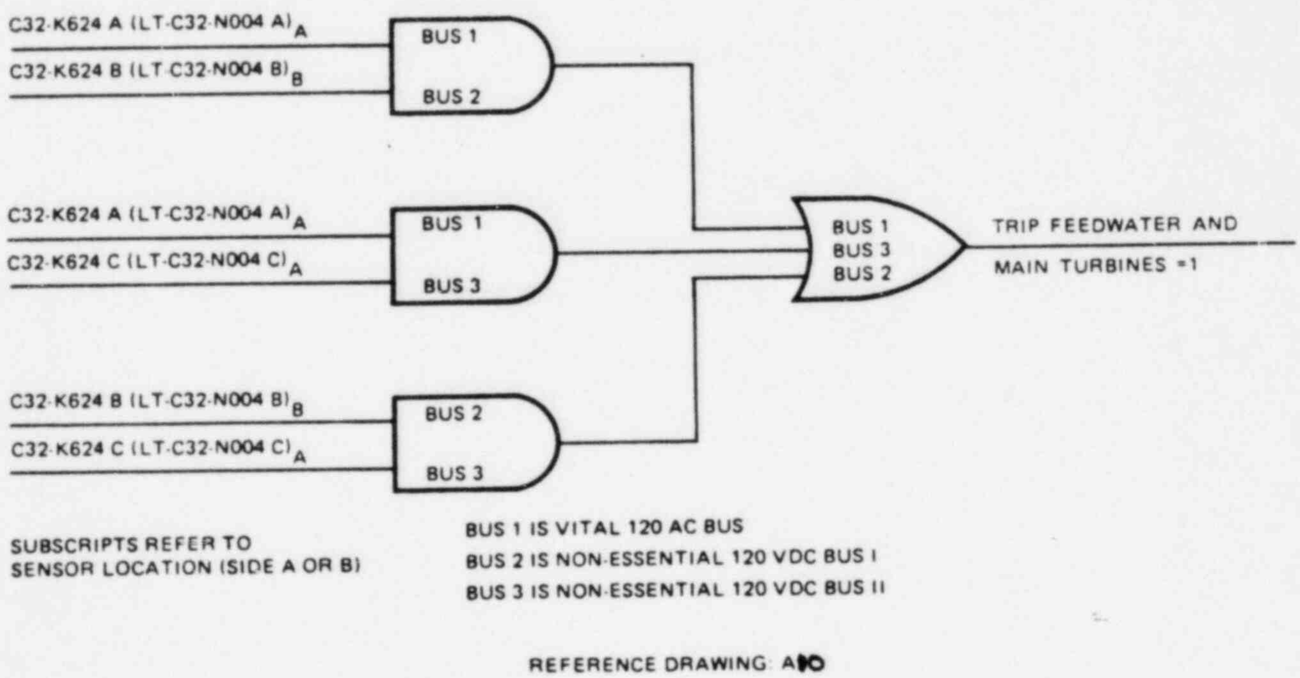


Figure A-14: Turbine Trip Basic Logic

addition upscale failure in LT-C32-N004A or C would cause the turbines to trip.

A.4 SUMMARY OF ANALYSIS

The analysis in this appendix indicates that the reference line break plus an upscale failure in a second instrument or a power loss can cause failure of the automatic initiation of systems from sensed level. A summary of the conditions is shown in Table A-3. Note that other methods--notably, high drywell pressure and operator action--are available to assure adequate make-up inventory to the vessel.

Table A-3

SUMMARY OF ANALYSIS

System	Additional Failure Which Will Defeat Auto Initiation	
	Side A Reference Leg Failure	Side B Reference Leg Failure
RPS	LT-B21-N080C or D	LT-B21-N080A or B
HPCI	LT-B21-N091B or D, 125 VDC Bus B	LT-B21-N031A or C, 125 VDC Bus B, 125 VDC Bus A, LT-B21-N091C
RCIC	LT-B21-N091B or D, 125 VDC Bus A, 125 VDC Bus B	LT-B21-N091A or C, 125 VDC Bus A
MSIV	LT-B21-N081C or D	LT-B21-N081A or B
LPCS LPCI	LT-B21-N091B or D, 125 VDC Bus B	LT-B21-N091A or C, 125 VDC Bus A
ADS	LT-B21-N091B or D, LT-B21-N095B 125 VDC Bus B	LT-B21-N091A or C, LT-B21-N095A, 125 Bus A
ATWS-RPT	LT-B21-N091B or D, 125 VDC Bus B	LT-B21-N091A or C, 125 VDC Bus A
ATWS-ARI	LT-B21-N091B or D, RPS Bus B	LT-B21-N091A or C, RPS Bus B
Turbine Trip	Spurious Trip on Line Failure	LT-C32-N004A or C

REFERENCES TO APPENDIX A

A1. "Analog Trip System Elem. Diag.," GE Dwg. #913E761, Rev. 4 (MPL #B21-2020).

A2. "Reactor Protection Sys. Elem. Diag.," GE Dwg. #791E414TF, Rev. 15.

A3. "Nuclear Steam Supply Shutoff System Elem. Diag.," GE Dwg. #791E401TF, Rev. 14 (MPL #B21-1090).

A4. "HPCI System Elem. Diag.," GE Dwg. #791E420TF, Rev. 12 (MPL #E41-1040).

A5. "RCIC System Elem. Diag.," GE Dwg. #791E421TF, Rev. 13, (MPL #E51-1040).

A6. "Core Spray System Elem. Diag.," GE Dwg. #791E419TF, Rev. 11 (MPL #E21-1040).

A7. "Residual Heat Removal Sys. Elem. Diag.," GE Dwg. #791E418TF, Rev. 16 (MPL #E11-1040).

A8. "Auto Depressurization Sys. Elem. Dwg.," GE Dwg. #791E403TF, Rev. 12 (MPL #B21-1060).

A9. "Reac. Recirc. Pump & MG Set Elem. Diag.," GE Dwg. #731E287BD, Rev. 19 (MPL #B31-1030).

A10. "Feedwater Control System Elem. Diag.," GE Dwg. #791E408TF, Rev. 8 (MPL #C32-1020).

Appendix B

BWR OPERATING EXPERIENCE RELEVANT TO INITIATOR FREQUENCY

This section deals with event initiators which directly affect the instrumentation system. In estimating the frequencies of these initiating events, past operating experience plays an important role. Thus, to establish the frequency of transient initiators which directly affect the level system in BWR's, Licensee Event Reports (LER's) from 1971-1981 were evaluated.

B.1 WATER LEVEL INSTRUMENT LEAK/BREAK INITIATOR FREQUENCY

B.1.1 Instrument Leak/Break Frequency Data Base

A failure in the reference leg will cause the level instruments connected to the leg to indicate high level. The high indicated level can initiate a transient by:

- Causing high level trips of the feedwater and main turbines;
- Causing low level trips due to feedwater shutoff when feedwater control is on the instrument that failed high.

In addition to causing plant trips, the instrument line failure increases the vulnerability of the emergency core cooling systems as discussed in Section 5.

The LER's included in the data base are those that cause or would cause plant trips if high level turbine and feedwater trips or feedwater control was from instruments connected to the failed reference leg. The LER events where plant trips did not occur but indicated level was high are included because the instrument configuration varies from plant to plant, so the fault trees in Appendix D and the event trees in Section 6 are used to reflect the plant response for the Shoreham configuration. Events that occur during plant startup and power operation are included in the data base, but events that occur while the plant is shut down are not included because they do not initiate transients.

LER events that result in low level indications are not included because these events are adequately covered by the event trees for other transient initiators since they do not jeopardize low level initiation of emergency core cooling systems.

The seven LER events which meet the above criteria and are the result of leaks are summarized in Table B-1, while the four LER events which meet the criteria and are the result of maintenance errors are shown in Table B-2. The total plant operating years for BWR's between 1971 and 1981 are 200.5 as shown in Table B-3. The initiating frequency for loss of the reference leg due to breaks or leaks is thus given by:

T_{R1} = 7/200.5 = 0.035 events per reactor year due to leak/break

The events in Table B-2 may be divided into two sub-categories:

- Trips during startup caused by maintenance or surveillance test error while shut down (2 events).
- Trips due to maintenance or surveillance test error while at power operation (2 events).

The probabilities for these two events are:

T_{R2} = 2/200.5 = 0.010 events per reactor year due to maintenance error during shutdown

T_{R3} = 2/200.5 = 0.01 events per reactor year due to maintenance error during power operation.

Table B-1

Reference Leg Failures Due to Leaks or Breaks

DATE (PLANT)	DESCRIPTION OF EVENTS	COMMENTS
September 1973 (Millstone 1)	During a plant startup, a discrepancy of 15 inches was noted between the two independent reactor level sensing columns. This mismatch was such that half of the RPS, ECCS and primary containment isolation system level switches were seeing an indicated level that was higher than the actual level in the reactor. The mismatch could result in late initiation signals for the systems in a situation were a failure occurred in the level switches that were reading properly. An investigation revealed a valve that is normally used for filling the system was leaking. The water was being drained from the reference column at a rate greater than the make-up rate by condensation in the level column condensing pot. A loss of water from the reference column in a device such as this causes the indicated level to rise. The valve was replaced and the indicated levels converted such that they were within the requirements of the Technical Specifications.	Leaking valve found by operators prior to trip. This precursor was found before challenging any normal or safety systems.
May 1976 Brunswick 2	During startup, a level indicating switch (Yarway) malfunctioned due to an internal leak. The associated instrument channel was manually tripped. The cause of the occurrence was that the threaded pipe inside the instrument housing leaked because of a crossed thread.	First year operation; startup.

Table B-1 (continued)

Reference Leg Failures Due to Leaks or Breaks

DATE (PLANT)	DESCRIPTION OF EVENTS	COMMENTS
December 1977 Cooper	While at 75% power, during a plant tour, it was noted that three reactor level instruments were reading high upscale. Further investigation revealed that the instrument line excess flow check valve was leaking around the body nut. The leak at the valve caused the condensing chamber and reference leg level to decrease, thus causing instruments associated with that sensing line to read upscale.	Leak outside containment.
May 1979 Dresden 2	During startup, the main turbine tripped on high water level. It was discovered that a packing leak existed on the isolation valve for the local pressure indication, PI-263-60B. The "B" reference leg drained to an abnormally low level through the packing leak. This resulted in an upscale reading on all the Yarways on instrument rack 2206. The "B" reference leg root valve was shut to isolate the leak which isolated the following components: PS-263-55C, 55D, LIS-263-58A, 58B, 72B, 72D, and LITS-263-59B. A control systems technician locally isolated PI-263-60B (local pressure indication) and PS-263-55D (reactor high pressure scram) via their common sensing line root valve. The "B" reference leg root valve was then opened and the reference leg filled. Since the Technical Specifications require two instrument channels per trip	Startup.

Table B-1 (continued)

Reference Leg Failures Due to Leaks or Breaks

DATE (PLANT)	DESCRIPTION OF EVENTS	COMMENTS
	system, an orderly reactor shutdown was begun immediately. The packing was tightened and subjected to a hydro of 1000 psi. No leaks were discovered. The isolation valves for PS-263-55D and PI-263-60B were opened and the common sensing line root valve was opened, returning the system to normal.	
Sept. 23, 1979 Monticello 1	During normal operation, a leak developed in a reactor pressure gauge. The leak lowered the reference leg of the scram and ECCS Yarway level switches connected to the same process tap. As a result, the Yarways indicated a false high level and would not have tripped within the settings specified in Sections 3.1.1 and 3.2.3 of Technical Specifications. Redundant level instruments were operable. One previous similar occurrence reported in AO 50-263/75-12. Pressure gauge is Helse Model C, 8-1/2 inch dial, 0-1500 psig, Ho3 Stainless Steel Bourdon Tube. Small crack discovered in Bourdon Tube; most probable cause is fatigue. Gauge isolated and removed. New gauge with wide range and improved Bourdon tube material to be installed on different process tap.	Very small leak; found by operator.

Table B-1 (continued)

Reference Leg Failures Due to Leaks or Breaks

DATE (PLANT)	DESCRIPTION OF EVENTS	COMMENTS
Feb. 7, 1981 Brunswick 2	The auxiliary operator noticed that reactor level instrument B21-LIS-N017D was pegged high. On February 12, 1981, it was discovered that the N017D instrument was reading higher than the other level instruments. Both events were caused by a low level in the reference leg.	
Dec. 12, 1981 Brunswick 1	Reactor level instrument 1-B21-LT-N017D-1 was indicating upscale. This event also occurred on Jan. 6, Jan. 7, and Jan. 8, 1982. N017D-1 supplies a reactor low level input into the RPS and Primary Containment Isolation System (PCIS). The inoperability of this instrument inops one of four low level scram inputs to RPS and would fail to isolate the outboard isolation valves for Groups 2, 6, 7, and 8 of PCIS. These events resulted from a stem packing leak on the N017D-1 reference leg excess flow check valve bypass valve.	

Table B-2

Reference Leg Failures Due to Maintenance Errors

DATE (PLANT)	DESCRIPTION OF EVENTS	COMMENTS
Aug. 14, 1977 (LER 77-30L) Browns Ferry 2	During startup from cold shutdown, reactor water column "B" reference leg was low, producing a +20 inch error in two reactor water low-level scram switches. Redundant switches were operable and in service. The reference leg was refilled and water level agreement confirmed. This was not a repetitive problem.	Trip due to error made during shutdown.
March 1978 Brunswick 2	Technicians were performing a test while at 97% power (reactor water level inside shroud) on a Yarway instrument when the main turbine and feedwater pump turbines tripped, causing a reactor scram. The scram occurred as a result of a pressure change in the common level instrument reference leg which apparently actuated the N004 instruments. The pressure change apparently occurred due to the bellows movement in the instrument being calibrated. No personnel error was detected. They were shut down for 25 hours. An investigation was to be performed to determine the most suitable instrument arrangement and test procedures necessary to prevent reference leg pressure changes. The investigation was to consist of an industrial survey and a design review.	Trip due to error made during power operation.

Table B-2 (continued)

Reference Leg Failures Due to Maintenance Errors

DATE (PLANT)	DESCRIPTION OF EVENTS	COMMENTS
March 31, 1981 (RO 50-260/ 81014) Browns Ferry 2	During normal operations while decreasing load for MG set maintenance, the reactor water level instrumentation indicated full upscale, resulting in a turbine trip. There was no hazard to the health or safety of the public. Instruments affected were: 2-LITS-3-52; 2-LIS-3-203A, &; 2-LIS-3-184. The technical specifications were fully complied with at all times. Equalizing valve, on 2-LITS-3-52 was partially open. Closed equalizing valve and verified reactor water instrument operable.	Trip due to error made while at power operation.
May 25, 1981 (LER 81-027/ 03L-U) Browns Ferry 3	During startup, following a maintenance outage, reactor water level instrumentation 3-LIS-3-203A and B indicated full upscale and were declared inoperable. There was no danger to the health and safety of the public. Redundant systems were available and operable. Reference leg was lost on the water column for undetermined reasons, causing the Barton model 288 A, bellows type indicating switch, to indicate full upscale. The water leg was backfilled and the instruments returned to operable status.	Trip due to error made during shutdown.

Table B-3

Calculation of Reactor Years for BWR's

Plant	Date of First Commercial Operation	Plant Operating Time 1971 to 1981	
		Years	Months
Brunswick 2	11/75	6	3
1	3/77	4	10
Dresden 1	8/60	11	0
2	7/70	11	0
3	10/71	10	3
Quad 1	8/72	9	5
Quad 2	8/72	9	5
Humboldt Bay	8/63	6	6*
Big Rock Point	12/65	11	0
La Crosse	11/69	11	0
Hatch 1	12/75	6	0
2	1979	3	0
Oyster Creek	12/69	11	0
Cooper	7/74	7	6
Nine Mile Point	9/69	11	0
Millstone 1	1/71	11	0
Monticello	12/70	11	0
Peach Bottom 2	7/74	7	6
3	12/74	7	2
Fitzpatrick	8/75	6	5
Browns Ferry 1	8/74	7	5
2	3/75	6	10
3	3/77	4	10
Vermont Yankee	12/72	9	2
Total Plant Operating Time		200.5 plant years	

* Shutdown 6-76

B.1.2 Shoreham Reference Leg Failure Frequencies

The total number of instruments connected to the reference legs is assumed to be equal to the number of instruments at operating plants, so the frequency of trips due to leaks or breaks is T_{R1}.

Most of the operating BWR's use switches mounted in the level instruments for generating the logic signals needed for safety system initiation. These instruments typically require monthly calibration at the instrument to maintain the setpoints within the technical specification limits. Shoreham uses the Analog Trip System (ATS) so the periodic trip setpoint adjustment is performed at a control room panel not at the instrument rack. Calibration of the instruments will be performed only during refueling outages. The effect of this design difference is that the initiator frequency due to surveillance testing would be reduced for Shoreham. An informal survey of most (15) of the operating BWR's showed that at least three of them use analog trip units driven by the reactor water level transmitters. A minimum of 13 reactor years have been accumulated on ATS without a transient initiation being reported. This data, while limited, supports the reduction in plant transient initiation when an analog trip system is used. The transient initiator frequency due to instrument maintenance or surveillance test errors for Shoreham may be found by estimating the rate of errors per maintenance or test for operating plants and multiplying by the frequency for Shoreham.

The instrument surveillance test frequency during shutdown for operating plants may be estimated by assuming that it is performed each time the plant is manually shut down. The frequency of manual shudown, given in Section 6, is 4.3 per reactor year. The error rate for maintenance errors during shutdown may then be determined from:

$$T'_{MO} = \frac{T_{R2}}{4.3} = \frac{0.010 \text{ events/year}}{4.3 \text{ maintenances/year}} = 0.00233 \frac{\text{events}}{\text{maintenance}}$$

Surveillance testing at Shoreham will be conducted only during refueling outages. Although the Shoreham Technical Specifications are based on an 18-month refueling cycle, a conservative assumption of instrument maintenance once a year will be used for calculating the initiator frequency for the reference leg failure due to shutdown testing. The value for Shoreham is therefore:

$$T_{MO} = T'_{MO} \frac{\text{events}}{\text{maintenances}} \times 1 \frac{\text{maintenances}}{\text{year}} = 0.00233 \text{ events/year}$$

In addition to transient initiations due to errors during shutdown, plant transients may be caused by errors made during instrument maintenance at power operation. At Shoreham, the only maintenance required during power operation will be to repair or replace a failed instrument. There are 51 instruments connected to the reference legs at Shoreham so, for the instrument failure rate used in the Shoreham PRA, the maintenance frequency is:

$$F_M = 3.9 \times 10^{-6} \frac{\text{failure}}{\text{hr}} \times 8760 \frac{\text{hr}}{\text{year}} \times 51 = 1.74 \text{ inst. maint./year}$$

The frequency of maintenance during power operation for operating plants is the surveillance testing performed during power operation plus the maintenance performed to repair or replace a failed instrument. For a monthly surveillance test interval, the number of surveillance tests during power operation is 12 minus the number of surveillance tests performed while shut down (4.3). If the random failure rate for operating plants is assumed to be equal to the rate for Shoreham (i.e., about the same number of instruments on all plants) the frequency of maintenance during power operation for operating plants is:

$$F'_M = 12 - 4.3 + 1.74 = 9.44 \text{ inst. maint./year}$$

The error rate for maintenance errors during power operation for operating plants may be obtained from the frequency of transient initiation due to maintenance during power operation (T_{R2}) and the maintenance frequency which is:

$$T'_{MP} = \frac{T_{R3}}{F_M} = \frac{0.010 \text{ events/year}}{9.44 \text{ maint./year}} = 0.00106 \frac{\text{events}}{\text{maint.}}$$

The initiator frequency at Shoreham for transients caused by maintenance errors during plant operations is then the error rate times the maintenance frequency, or:

$$T_{MP} = T'_{MP} \times F_M = 0.00106 \frac{\text{events}}{\text{maint.}} \times 1.74 \frac{\text{maint.}}{\text{year}} = 0.00184$$

The total initiator frequency is then the sum of T_{R1}, T_{MO} and T_{MP} or 0.039 event per year. Since the instruments are nearly equally divided between the two reference legs (26 vs. 25), the failures are assumed to be equally divided between the reference legs, so the initiator frequency per leg is 0.020 events per reactor year. A summary of the initiation frequency calculation is given in Table B-4.

B.2 HIGH DRYWELL TEMPERATURE INITIATOR FREQUENCY

Licensee Event Reports for the period 1971-1981 which described BWR high drywell temperature-initiated degradation of reactor water level instrumentation accuracy were examined in order to establish a generic value for BWR High Drywell Temperature initiator frequency.

As was the case for water level instrument breaks/leaks, the data base for High Drywell Temperature frequency covered approximately 200.5 reactor years of operation. Two events were found in this data base in which drywell temperatures in excess of 212°F caused erratic reactor water level indications; thus, High Drywell Temperature initiator was assigned a frequency of 2/200 or 10^{-2} events per reactor year. Lower drywell temperatures were not reported to have degraded reactor water level instrument response.

Table B-4

Summary of Reference Leg Failure Initiator Frequency

A	LER Events due to Leaks/Breaks	7 events
B	Reactor Operating Years for LER Timeframe	200.5 reactor years
C	Initiator Frequency for Leaks/ Breaks (A/B)	0.035 events/reactor year
D	LER Events due to Maintenance during Shutdown	2 events
E	Initiation Frequency for Maintenance Errors during Shutdown at Operating Plants (D/B)	0.010 events/reactor year
F	Maintenance Frequency during Shutdown for Operating Plants	4.3 maint./years
G	Error Rate for Shutdown Maintenance Errors (E/F)	0.00233 events/maint.
H	Shutdown Maintenance Frequency for Shoreham	1.0 maint./year
I	Initiation Frequency for Maintenance Errors during Shutdown for Shoreham (GxH)	0.00233 events/year
J	LER Events due to Maintenance during Power Operation	2 events
K	Initiator Frequency for Maintenance Errors during Power Operation (J/B)	0.010 events/year
L	Maintenance Frequency during Power Operation for Operating Plants (12-F+N)	9.44 maint./year
M	Error Rate for Power Operation Maintenance Errors (K/L)	0.00106 events/maint.
N	Maintenance Frequency for Shoreham during Power Operation	1.74 maint./year
O	Initiator Frequency for Errors during Power Operation at Shoreham (MxN)	0.00184 events/year
P	Total Initiator Frequency at Shoreham (C+I+O)	0.039 event/reactor year
Q	Initiator Frequency for Reference Leg (P/2)	0.020 event/reactor year

Appendix C

HUMAN ERROR ANALYSIS

An examination of Licensee Event Reports (LERs) and other data sources indicates that operator actions play a very important role during accident sequences. Operator interactions prior to, and during, accident sequences were included in the Shoreham PRA to the maximum extent possible. However, certain human actions were specifically excluded, such as sabotage and other forms of intentional malevolent behavior. Other errors, such as fabrication and installation errors, as well as many design errors, were not explicitly analyzed but were included in the component failure data base and thus were accounted for in the component failure rate estimates.

There are limitations inherent in the human failure analysis of any PRA. However, current state-of-the-art methods are used for evaluation of human errors in the Shoreham PRA. Section C.1 contains a brief summary of techniques used in analyzing human failure for the Shoreham study. Section C.2 then presents examples of the analyses used in this assessment. Section C.3 provides the human failure analysis for operator initiation of vessel depressurization for the sequences following the instrument line failure initiator. Section C.4 provides the human failure analysis for the operator action necessary to provide long-term stable cooling.

C.1 METHODS OF ANALYSIS

The Shoreham PRA considers two main types of human interaction errors:

- Errors committed during tests or maintenance (referred to as maintenance errors);
- Errors committed in responding to an accident situation (referred to as operator errors).

The principal difference between these two types of errors is that maintenance errors are essentially independent of individual event sequences, while the role of operator error varies with the particular sequences being evaluated.

C.1.1 Maintenance Errors

Many types of maintenance errors are considered in this analysis, although some are not included explicitly. For example, the failure of a component due to improper repair is included in the component failure rate estimate. Maintenance errors as initiating events (e.g., taking the wrong item off-line) are also not explicitly considered, although many of these errors are included in the operating experience data base from which the initiator frequencies are derived.

The investigation of maintenance errors was generally limited to components that are manipulated during test or maintenance (primarily failure to restore valves to the proper position) and components subject to common-mode effects (such as calibration errors). These components were identified and the appropriate procedures were reviewed to determine the relevant potential human error. The appropriate procedures and other factors affecting human performance were then analyzed, and human reliability event trees were formed. This procedure is explained in Appendix A.3 of the Shoreham PRA, which includes several examples. The human error probability obtained is then included in the appropriate place in the fault tree as though it were a component failure probability. It should be noted that the maintenance analyses generally accounted for first-level recovery due to the standard tagging/checking procedures. A small conservatism is introduced here since it is conceivable that an error not corrected at this early stage may be corrected at some later time.

C.1.2 Operator Errors

Operator Errors are defined here to be those human errors made during the course of accident sequences. As such, these errors are highly sequence dependent and must be analyzed for each particular accident scenario. Operator errors may be either errors of omission (e.g., failing to start a manual system) or errors of commission (e.g., overriding an operating system).

The analysis of operator errors begins with an operator action tree (Figure C.1). Generally, the time available for perception is small; however, the existence of many annunciators in the control room reduces the probability of the operator failing initially to perceive that a problem has occurred. The diagnosis branch is usually the dominant contributor to operator error due to:

(a) the limited amount of time available to the operator,

(b) potentially conflicting indicators, and

(c) multiple distinct failure events used as input to a single annunciator.

The response or action branch is also significant, but makes a smaller contribution to the frequency of operator error than the diagnosis branch when a plant-specific emergency procedure is available and familiar to the operator.

The quantification of the operator event tree is highly dependent upon the specific action, the postulated accident sequence, the plant design and operator training. Each branch of the operator event tree for a specific plant event sequence is evaluated based upon the applicable emergency procedure, supplemental information obtained from plant management and operating personnel, LER information, human reliability event trees (Shoreham PRA Appendix A.3), and engineering judgment.

Generally, only errors associated with expected (procedure-directed) operator response actions were included. That is, given that the correct procedure was selected, only errors of omission were considered, unless information to the contrary was available.

There are recognized limitations to this approach. For example, if the operator diagnoses the situation incorrectly, the wrong procedures will be used. Even if the diagnosis is correct, there is still the possibility that the wrong procedure will be chosen inadvertently. Recovery from operator error is not considered in the analysis which contributes some conservatism to the human-error evaluation. It is likely that in some instances, even if the wrong procedure is used initially, feedback from the plant will prompt the operator to re-analyze the situation and correct the error before plant operation is disrupted.

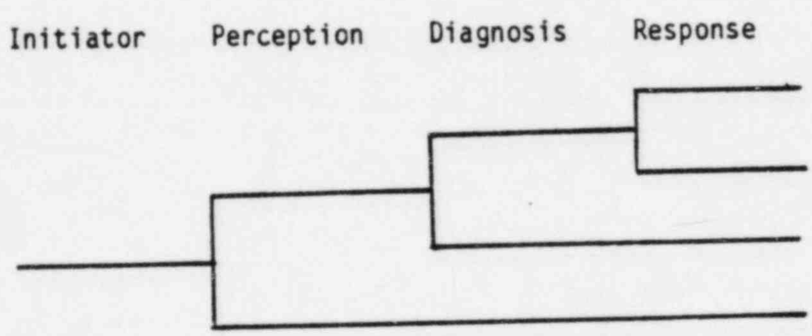


Figure C.1 Generalized Operator Action Tree (Taken from NUS developmental studies on operator response modeling)

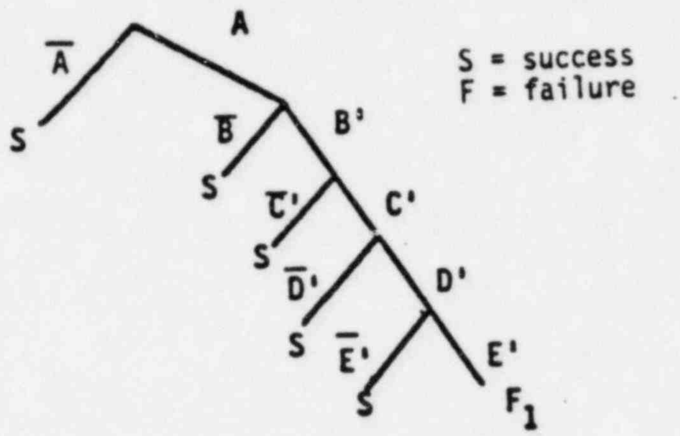
C.2 EXAMPLES

This section presents two sample analyses that have been prepared for the Snoreham PRA.

C.2.1 Miscalibration of Four Level Sensors During Regularly Scheduled Maintenance (Procedure Available)

This example is an extension of one evaluated explicitly in WASH-1400 (C-1). The probability that a technican would miscalibrate four similar sensors independently is negligible, but the probability of a common-mode miscalibration may be significant. The dominant common-mode failure used in WASH-1400 and by Swain and Guttman (C-2) is due to a faulty setup, such as using the wrong scale or connecting at an incorrect point. An estimate of this probability is 10^{-2}. This is treated as a gross miscalibration which results in the inability of the sensors to function on demand. However, recovery from the setup error can be factored into the evaluation as follows. If the test setup led to a large calibration change on the first sensor, the technician would recheck the setup 70% of the time. If the setup were not rechecked initially, and if the second calibration proved also to be in error, then the probability of the technician rechecking the setup would be 0.3. If the technician did not discover the error after the first two sensors, he would also not detect the error after the third and fourth. It is assumed that if the technician rechecked the setup then the sensors would be calibrated correctly.

As shown in the event tree in Figure C.2, the probability of miscalibrating three or more sensors is approximately 2×10^{-3}.



A: Probability that equipment is set up incorrectly = 0.01

B': Probability of not being suspicious after 1st large miscalibration = 0.3

C': Probability of not being suspicious after 2nd large miscalibration = 0.7

D': Probability of not being suspicious after 3rd large miscalibration = 1.0

E': Probability of not being suspicious after 4th large miscalibration = 1.0

The probability of failure (miscalibrating all four sensors due to incorrect setup) is:

$$P(F_1) = [A \times B' \times C' \times D' \times E'] = 2.10^{-3}$$

Figure C.2 Human Error Probability Tree for Sensor Miscalibration

C.2.2 Immediate Response (0 - 10 minutes) Under High Stress Environment

This analysis is based upon the operator action tree of Figure C.3. It is assumed that a major accident that requires an immediate response has occurred. The combination of a very rare event and a short response time is assumed to lead to high stress for the operator.

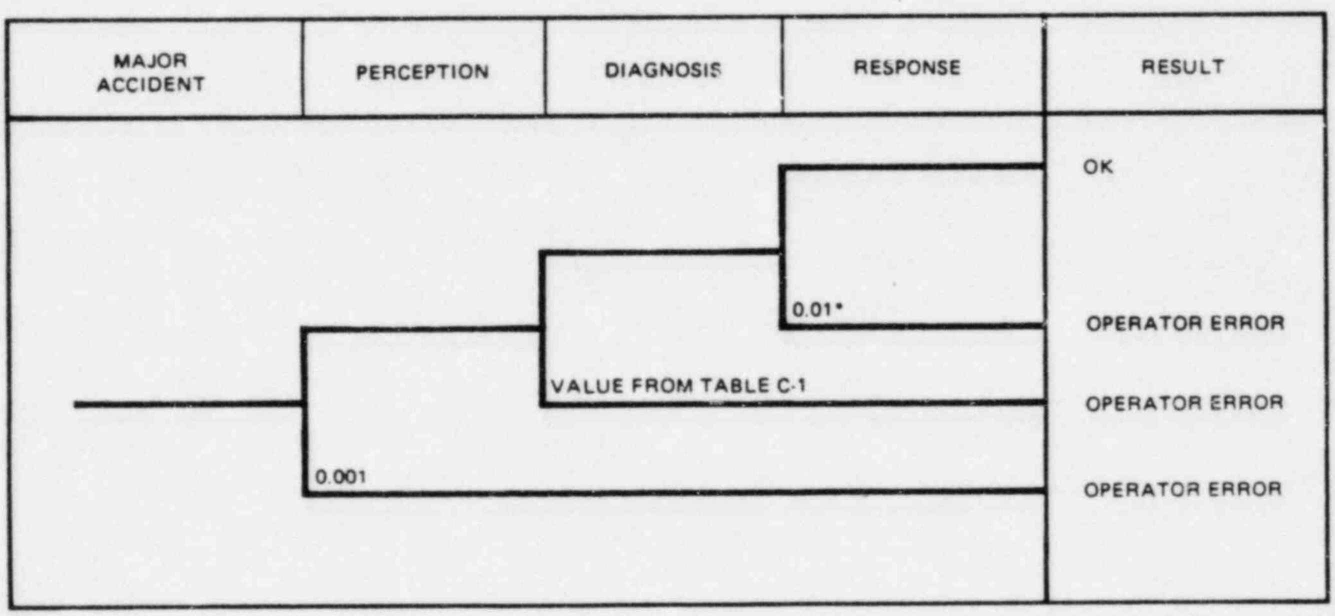
Due to the multitude of alarms and other indications that would follow a major accident, it is very likely that an operator would perceive that something has gone wrong. A value of 0.001 for perception is shown in Figure C.3. Human error immediately after the event would tend to be higher than a stable high-stress value because of a probable incredulity response (i.e., since the probability of a major accident is so small, for some moments a potential response would be to disbelieve panel indicators). Under such conditions, no action at all might be taken for at least one minute, and if any action were taken it would likely be inappropriate. WASH-1400 and Swain assessed that the error rate as a function of time after the occurrence of a high stress event is as given in Table C-1 and in Figure C.4 for a single operator. These values may be used in the diagnosis branch of the operator action tree of Figure C.3. It is apparent from the tree that for short response times, the diagnosis error dominates the operator error probability.

From Table C-1, the probability of an operator diagnosis error decreases with time after a major accident. It was estimated in WASH-1400 that by 7 days after an accident there would be a complete recovery to the normal, steady-state error rates, assuming that the nuclear plant is brought under control. At this later time, the operator response error may dominate operator errors, depending on the response required. For the purposes of this example, the response error rate several hours after the accident is taken to be the steady-state general error of omission (0.003) from Swain's handbook (C-2). At an earlier period in the course of the accident, the response error rate is multiplied by a factor of 3 due to the stresses involved, as shown in Table C-1.

Table C-1

PROBABILITY OF ERROR BY A SINGLE OPERATOR AS A FUNCTION OF TIME IN A HIGH STRESS SITUATION

ACTION REQUIRED WITHIN	PROBABILITY OF ERROR FOR A SINGLE OPERATOR
1 MINUTE	1.0
5 MINUTES	0.9
30 MINUTES	0.1
SEVERAL HOURS	0.01
7 DAYS	NORMAL ERROR PROBABILITY



*ERROR RATE SHORTLY AFTER THE EVENT. OCCURRENCE FAILURE PROBABILITY DROPS TO 0.003 SEVERAL HOURS AFTER THE EVENT.

Figure C-3: Operator Action Tree for Immediate Response Under High Stress

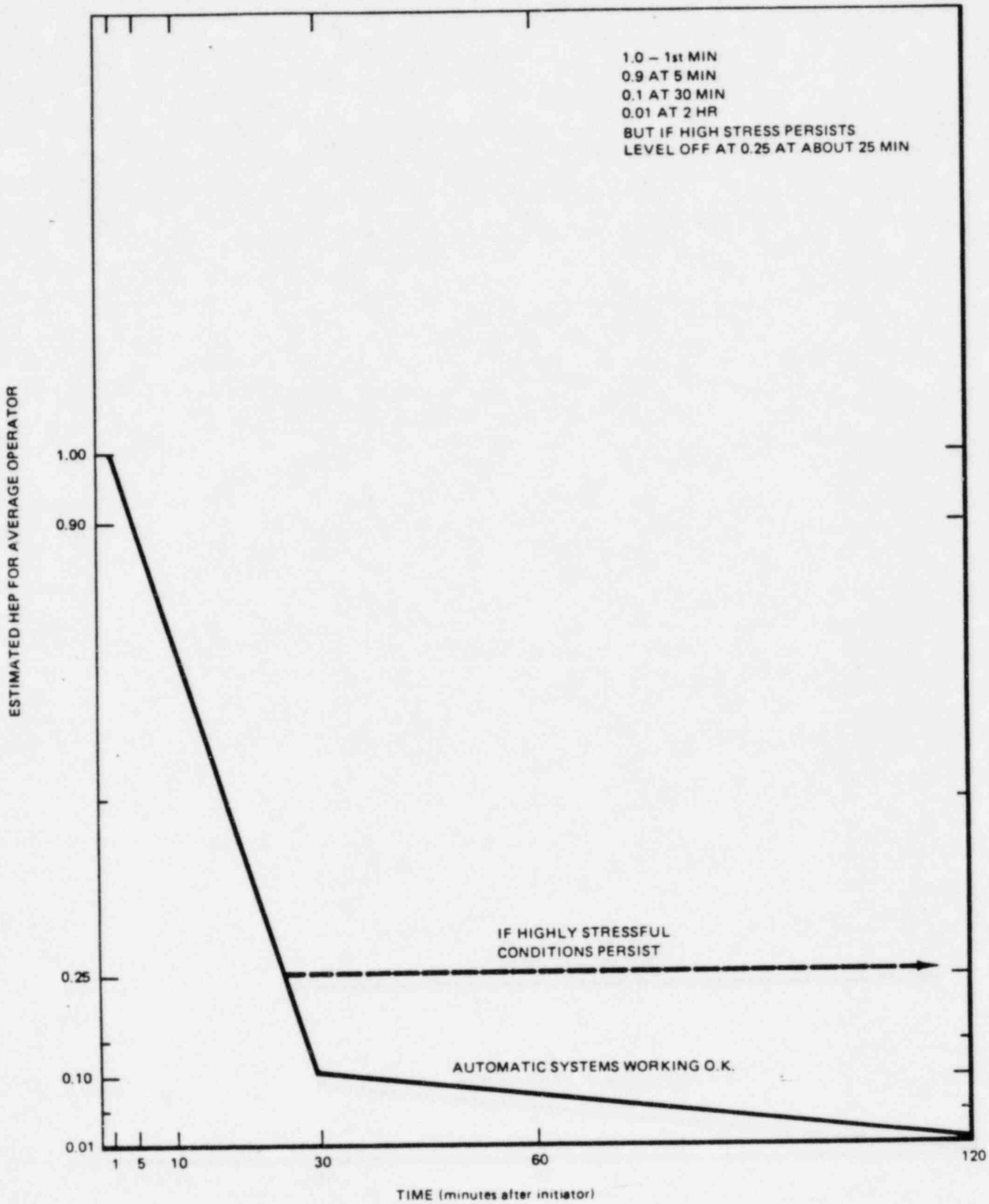


Figure C-4: Estimated Human Performance After Major Accident for a Single Reactor Operator

C.3 OPERATOR INITIATION OF ADS

One of the principal manual actions which the operator has available to him to maintain coolant inventory is the depressurization of the plant using the safety/relief valves to allow injection by the low pressure systems. This section addresses the derivation of the conditional probability of this function under the accident sequence conditions of the event trees in Section 6. Four cases are investigated to determine the conditional probability of ADS in sequences initiated by a reactor water level reference line failure coupled with the following events:

- Case 1 Unavailability of high pressure systems;
- Case 2 Failure of the opposite reference leg;
- Case 3 Loss of DC bus;
- Case 4 Level transmitter failure.

Initiation of ADS requires the operator to perceive that vessel level is low and that low pressure injection is required to provide make-up inventory. The quantification of this case, given in the following sections, was the Shoreham plant-specific level related displays and annunciators. Appropriate plant-specific procedures are also used, including procedures that familiarize the operator with the relationship between the level indications (e.g., procedures that call for level indication logging and comparison once each shift).

C.3.1 Case 1: Single Reference Leg Failure Plus Loss of High Pressure Systems

In this case, the level instruments on one side are reading high and all high pressure make-up systems are unavailable. The operator must depressurize to allow the low pressure systems to provde inventory make-up.

The events on the operator action tree shown in Figure C.5 are as follows:

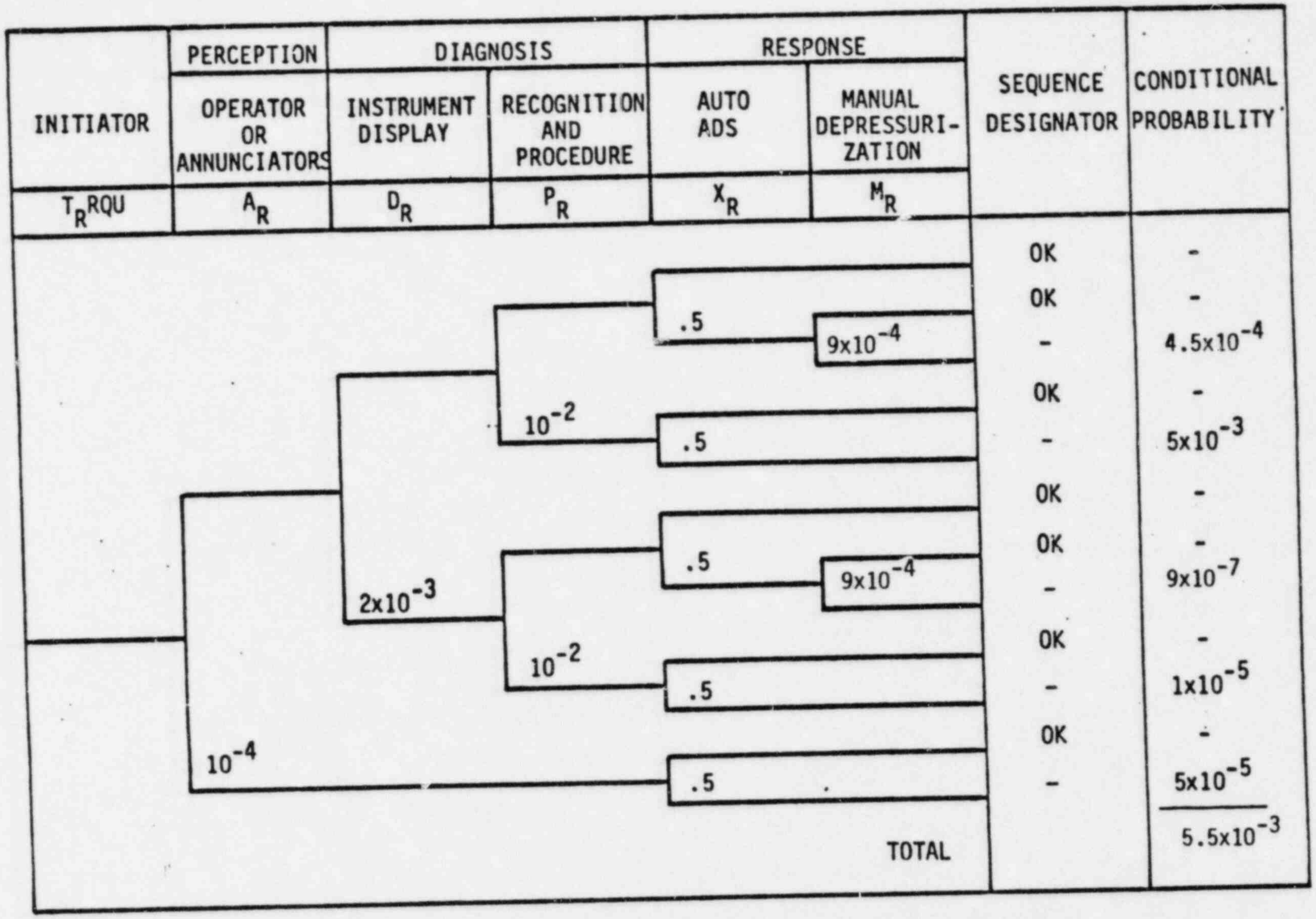


Figure C.5. Case 1: Leak in a Single Water Level Reference Leg Evaluation of Reactor Depressurization Function When Required for Instrument Line Break Initiators (See Figure 6.1, Sheets 1 and 2 of 5 - Branches 28 and 54)

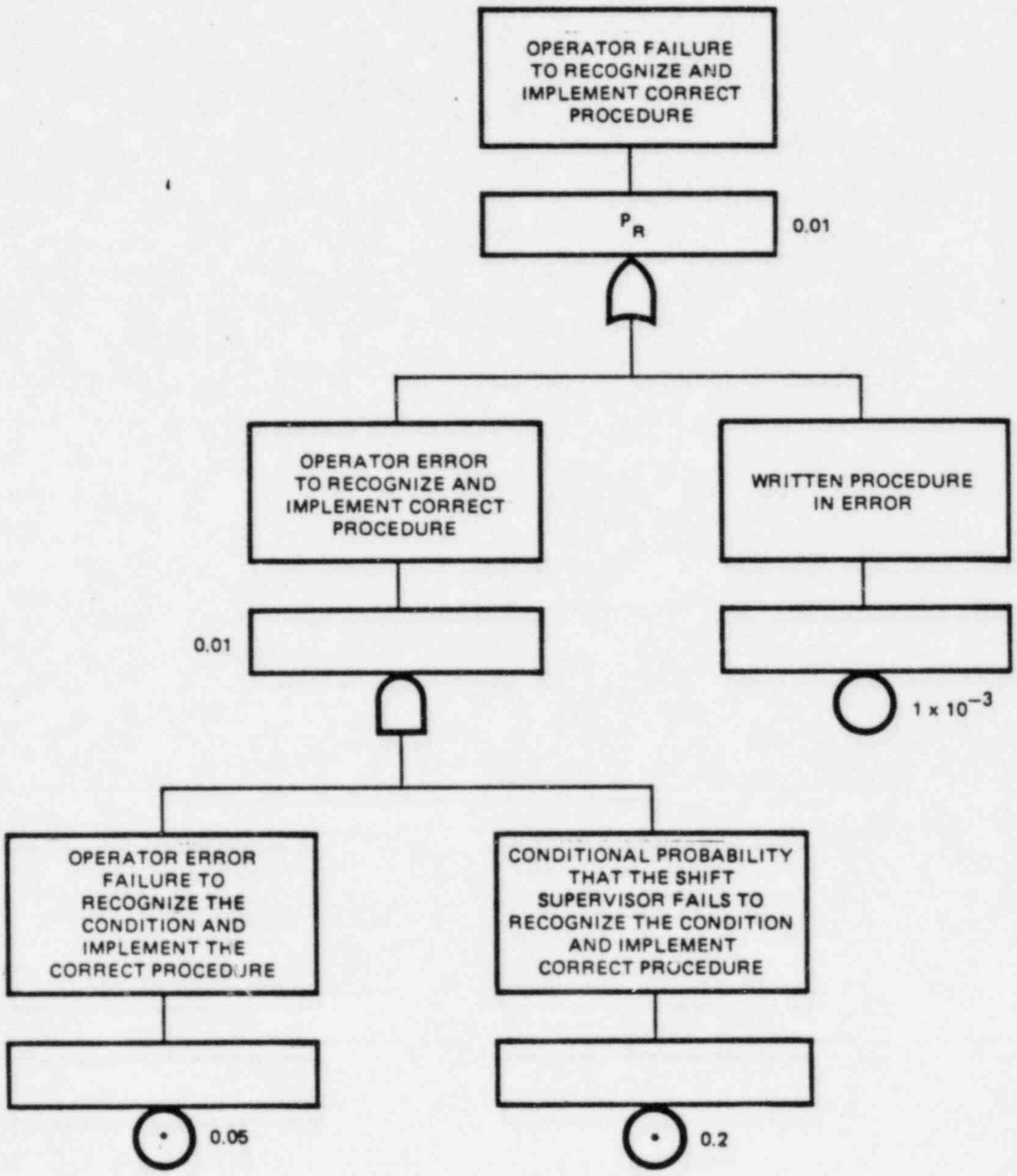
A_R - Success: Reactor Scram has occurred on turbine trip or on low reactor water level. The operator is well aware that a challenge to safe shutdown is proceeding.

D_R - Success: Two reactor water level channels are reading upscale indicating high water levels in the reactor vessel. The opposite side indicators are dropping below level 1 due to the loss of high pressure injection. The operator is expected to detect the disparity in indications.

P_R - Success: The operating procedure is assumed to dictate that the operator follow the indication of the lower level once the disparity is confirmed and a probable cause identified. The potentially dominant contributor to a failure of manual ADS is the probability that the operator fails to recognize the transient and choose the correct procedure. Swain and Guttman indicate that for a case with conflicting signals operator response can be severely hampered and the human error probability (HEP) is found to be as shown in Figure C.6.

X_R - Success: Automatic ADS is assumed to be possible in the case where reactor water level drops below level 1, the drywell coolers isolate (i.e., operator does not de-isolate them), and drywell temperature and pressure rise. However, because this action is dependent upon a chain of events, including the prevention of operator manual inhibit of ADS, it is judged that very little credit should be given to automatic ADS in the quantification of successful depressurization.

M_R - Success: The manual initiation of ADS is a straightforward action which, when the timing and presence of the shift supervisor are included, results in a high reliability for performance. The hardware unavailability of ADS is included in the determination of the probability for this event.



*REFERENCE: SWAIN AND GUTTMAN (REFERENCE C-2)

Figure C-6: Fault Tree for Operator Recognition and Procedure Implementation

C.3.2 Case 2: Leaks in Both Water Level Reference Legs

In this case, a common-mode failure in the alternate reference leg causes all level indications to be high with the resulting loss of automatic high pressure system initiation. The events in the operator tree of Figure C.7 are as follows:

A_R - With all water level instrumentation reading high, a reactor scram on turbine trip due to high indicated level will occur. The operator will be aware that a transient is in progress.

D_R - All reactor water level instrumentation will be reading high indicating to the operator that the reactor has more than enough water. Therefore, the only remaining indications to the operator are:

- No coolant injection is occurring because FW, HPCI, and RCIC are all off.
- The MSIV's are open and there is loss of inventory directly to the main condenser.

The operator has only these indications for approximately 30 minutes.

P_R - Based upon the common view available from the water level indications, the operator must depend on the secondary indications mentioned above to diagnose the problem and pick the correct recovery procedure. The conditional probability has been evaluated using Swain-Guttman methods and shaping factors (see Figure C.4). However, there are no comparable quantified estimates in Swain; therefore, engineering judgment was used.

X_R - Automatic ADS will not occur because no low water level signal will be present.

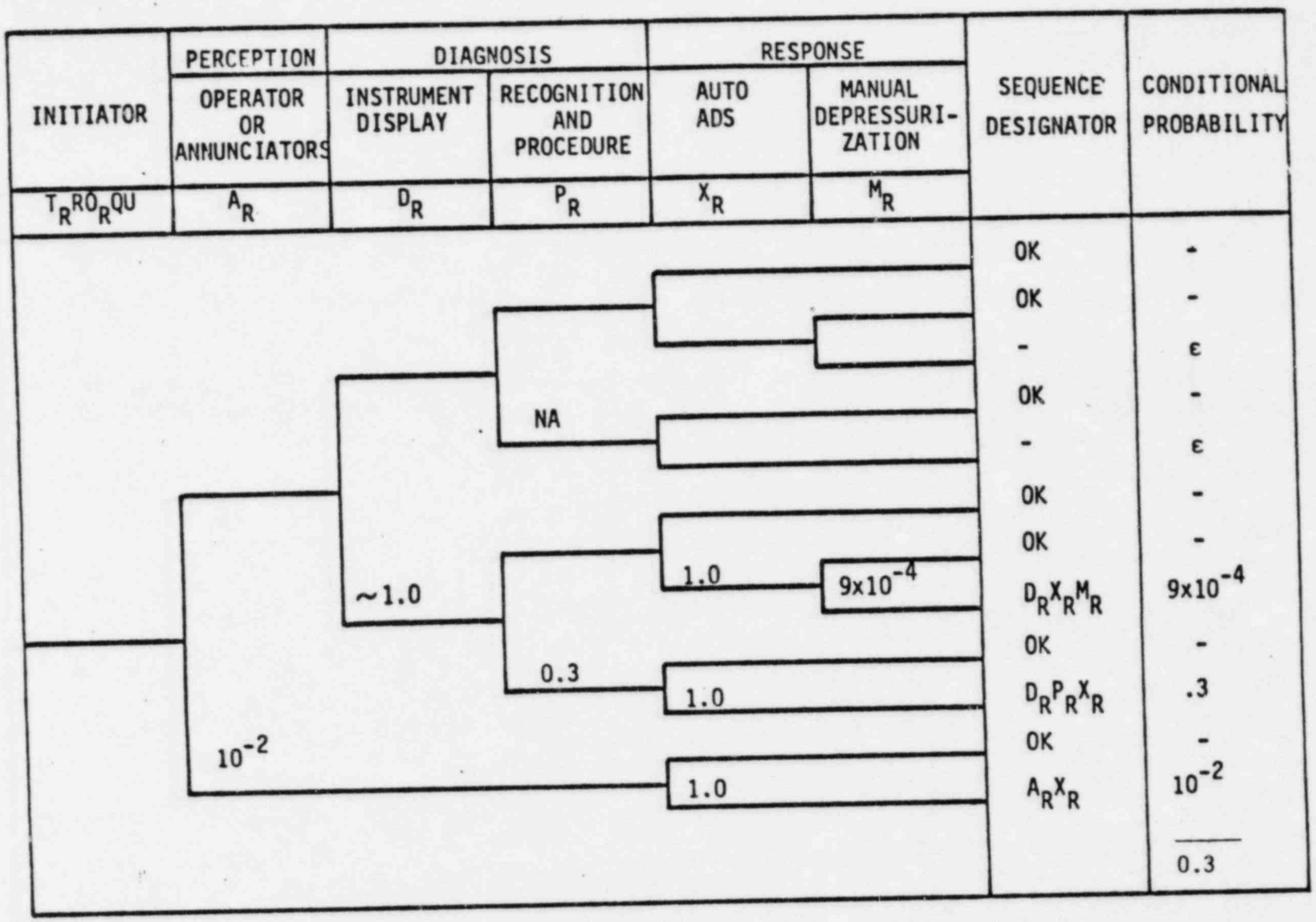


Figure C.7. Case 2: Leaks in Two Water Level Reference Legs Evaluation of Reactor Depressurization Function When Required for Instrument Line Break Initiators (See Figure 6.1, Sheet 3 of 5 - Branch 29)

M_R - Same as Case 1.

C.3.3 Case 3: Single Reference Leg Failure Coupled with a DC Bus Failure

The loss of the DC bus will cause loss of either the HPCI or RCIC system, depending on which bus failed. The events for the operator tree of Figure C.8 are as follows.

A_R - High reactor water level indication on one leg may result in reactor scram due to turbine trip, or the low level isolation from sensors on the intact leg may also result in a scram.

D_R - The display of reactor water level is available from indicators not affected by the initiators. However, operator recognition is still required to make this display effective.

P_R - The loss of the DC Bus coupled with the initiator causes the loss of the level 1 and level 2 annunciators, so the operator must use the disparity in level indications to diagnose the event. Therefore, this case is assessed to be similar to, but slightly better than Case 2.

X_R, M_R - Same as Case 2.

C.3.4 Case 4: Single Reference Leg Failure Plus Instrument Failure in the Opposite Side

In this case, the failure of a single instrument on the opposite side causes loss of automatic low level initiation of all ECCS systems. All event functions on the operator tree of Figure C.[illegible] are similar to that of Case 3 except:

A_R - One instrument is available to initiate an annunciator so this case lies between Case 1 and Case 3.

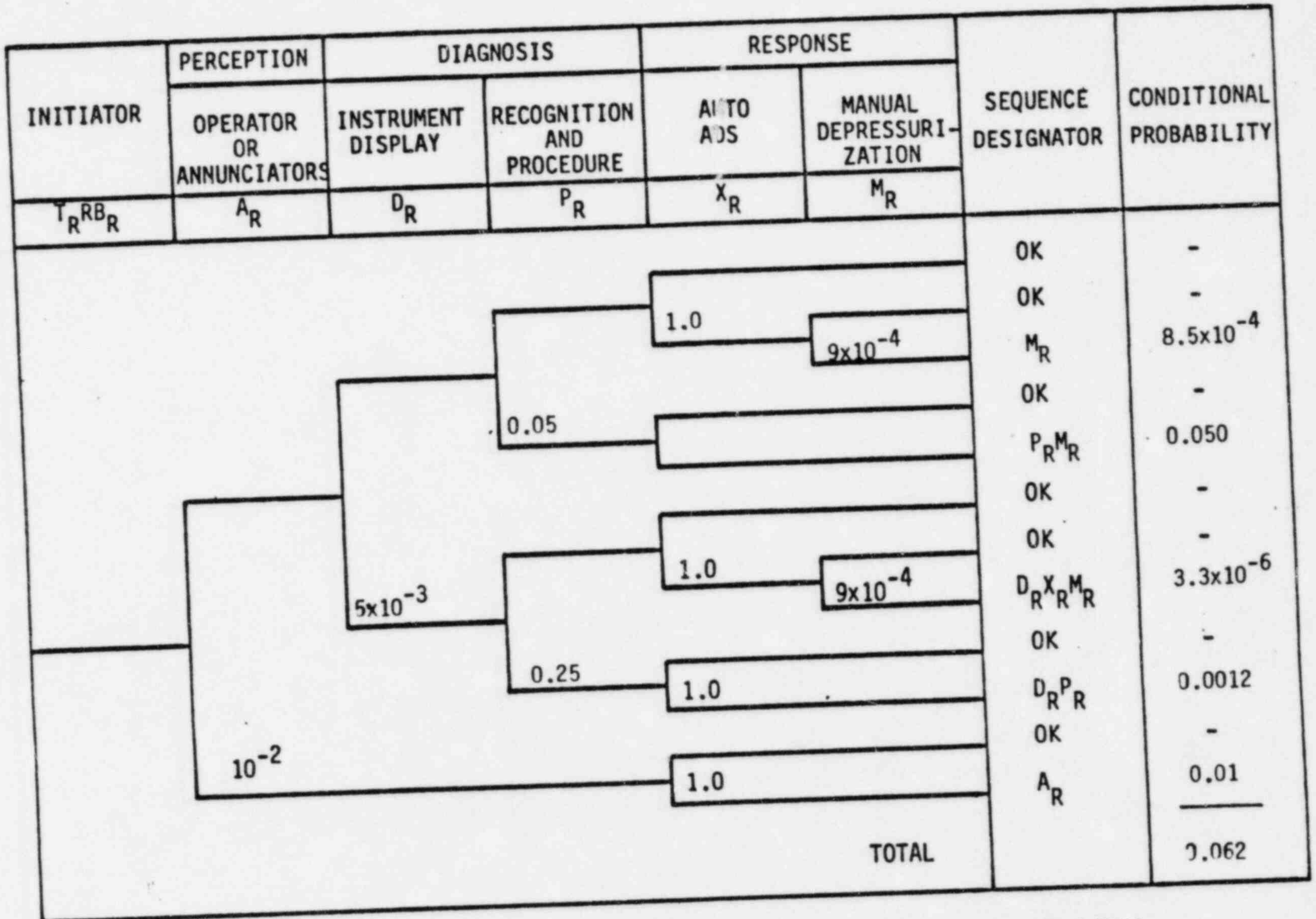


Figure C.8. Case 3: Leak in a Single Reference Leg Coupled With A DC Bus Failure
Evaluation of Reactor Depressurization Function When Required for Instrument Line Break Initiators
(See Figure 6.1, Sheet 4 of 5 - Branch 30)

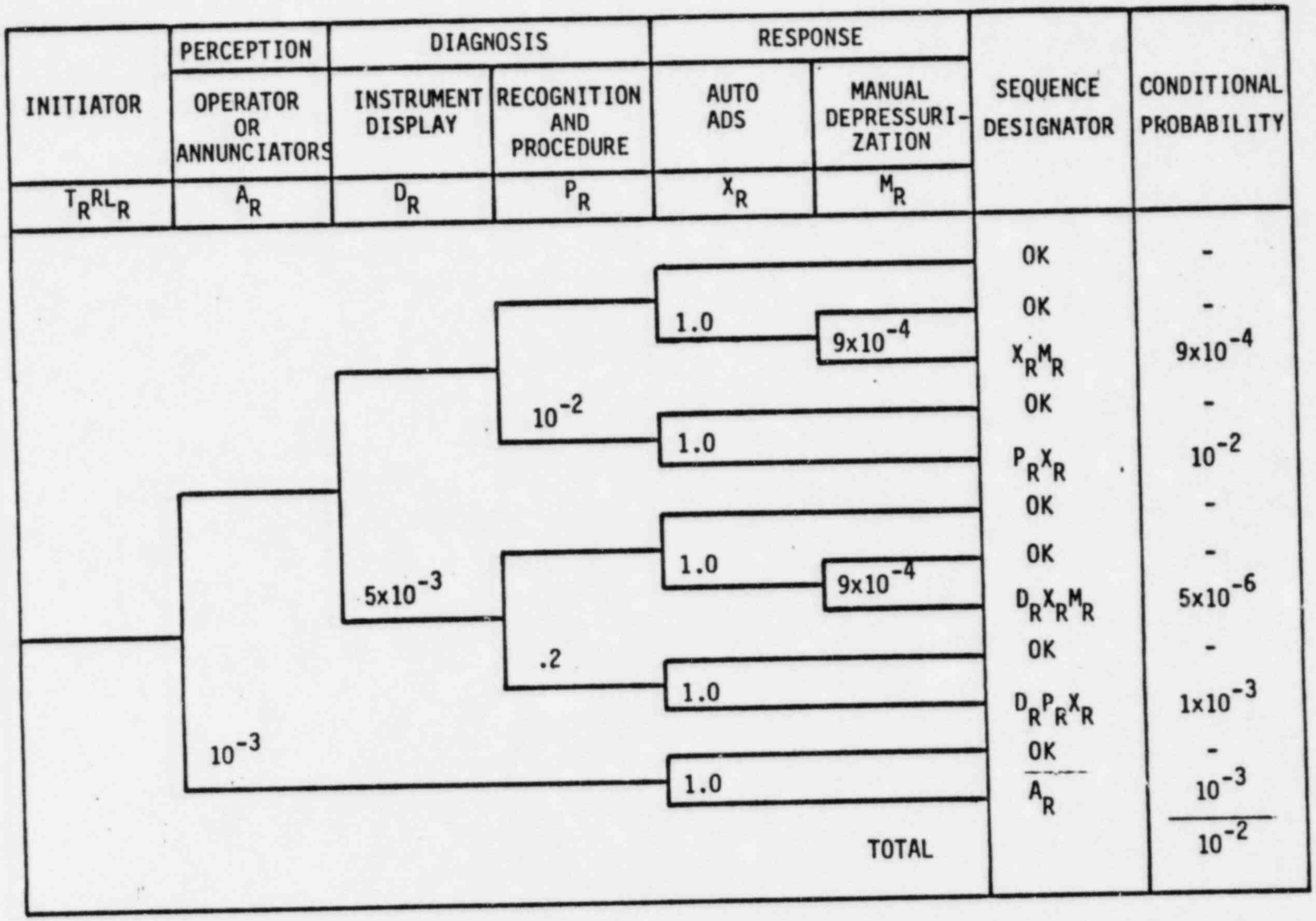


Figure C.9. Case 4: Leak in a Single Reference Leg Coupled With An Instrument Failure in the Opposite Side Evaluation of Reactor Depressurization Function When Required for Instrument Line Break Initiators (See Figure 6.1, Sheet 5 of 5 - Branch 31)

D_R - Same as Case 3.

P_R - The remaining annunciator provides a diagnostic aid that was not available in Case 3, so the probability for this case is slightly better than in Case 3.

X_R, M_R - Same as Case 3.

C.4 OPERATOR RESPONSE TO CONTINUE LONG-TERM STABLE COOLING

Normal operator response to maintain adequate core cooling during long-term reactor shutdown using low pressure systems is anticipated to be quite reliable and is characterized by the Wreathall Operator Response Curve. However, there may be cases in which the operator response may be compromised by the plant conditions and by his perception of those conditions. Table C-2 summarizes the variability in operator response as a function of plant condition and operator perception. These values are based generally upon Swain and Guttman models (C-2); however, the point values used in this analysis are developed using a Shoreham plant-specific analysis. The basis for the values used in Table C-2 are as follows:

1. For the cases with no flashing, the following conditions are assumed to be applicable:

    -- Operator response is required over the long-term.

    -- Clear procedural steps state that indicated water level on the wide range indicators is to be maintained above level 5.

    -- Water level indication is sufficiently accurate with no reference leg flashing or leaks.

    The value used is from the Wreathall Human Error Probability (HEP) Curve.

2. For cases with flashing of the instrument lines which is detected by the operator, the following addition considertion is included:

Table C-2

Human Error Probabilities for Long-Term Stable Cooling

Condition	Human Error Probability
No flashing; low pressure system operating.	10^{-5}
Flashing occurs and is detected with systems operating.	10^{-4}
Flashing not detected; operator at ECCS panel.	5×10^{-3}
Flashing not detected; operator at feedwater control panel.	0.01
Instrument line failure; flashing undetected.	0.05 to 0.1

-- Moderate stress is imposed on the operator model due to the excessively high drywell temperature.

3. For those cases where flashing is not detected, operator response is characterized by:

   -- High stress;

   -- Inappropriate procedural action already;

   -- Possibility of ignoring further procedural steps.

4. The case of an instrument line break with undetected flashing is assigned a relatively high failure probability because of:

   -- Conflicting signals among level indications;

   -- Inappropriate procedural actions in the face of excessive drywell temperature;

   -- High stress due to both of these occurrences.

REFERENCES TO APPENDIX C

C-1 WASH-1400, Reactor Safety Study: An Assessment of Accident Risk in U.S. Commercial Nuclear Power Plants, USNRC, October 1975.

C-2 Swain, A. D., and H. E. Guttman, Handbook of Human Reliability Analysis with Emphasis on Nuclear Power Plant Applications, NUREG/CR-1278, April 1080. (Draft)

Appendix D

FUNCTIONAL LEVEL FAULT TREES

This appendix provides the derivation of the conditional probabilities associated with the functional events used in the quantification of the event trees for the following cases:

1. Sequences following a Reactor Water Level Reference Leg Failure (Section D.1).

2. Sequences following Various Transient Initiators (Section D.2).

D.1 FUNCTIONAL FAULT TREES FOR SEQUENCES FOLLOWING A REACTOR WATER LEVEL REFERENCE LEG FAILURE

The reference leg failure is different from other initiators because it causes the loss of the safety system low level initiation channels due to the high level signals from all instruments connected to the line. The fault trees for events following this initiator are given in the following subsections. The required fault trees and the fault tree figure numbers for the events appearing in the event tree for this initiator are:

Label	Designator	Figure No.
Continued operation	R_R	D-1
Operator Error	O_R	D-2
125V DC Bus Failure	B_R	N/A
Opposite Division Level Trip	L_R	D-3
Scram	C	N/A
Feedwater	Q	D-4
HPCI/RCIC	U	D-5
HPCI	U"	D-6
RCIC	U'	D-7
ADS	X	D-8
Coolant Injection	UX	D-9
Low Pressure	V	D-10
Drywell Cooling	GOL	D-11
Containment Heat Removal	W	D-12

The numbers in parenthesis in the paragraph headings and on the fault trees refer to the event tree branch numbers in Section 6 where the fault tree probabilities are used. The sources for the values given on the fault trees are as discussed in Section D.3 and delineated on Table D-2.

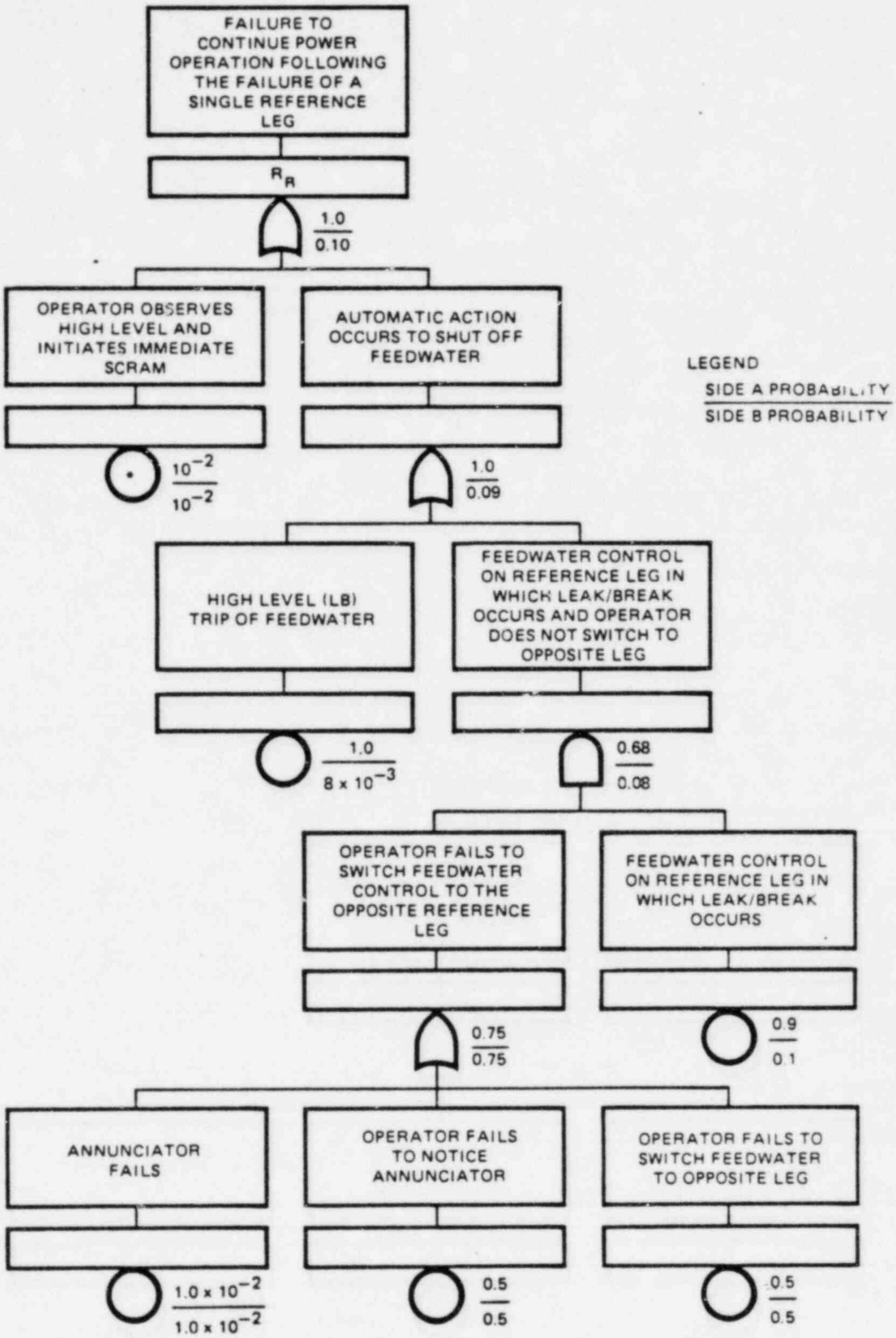
D.1.1 Continued Power Operation: R_R

The water level instrumentation and feedwater control configurations are arranged so a loss of the reference leg does not necessarily lead to a plant shutdown. The important considerations for establishing the failure to continue power operation are:

- Side A Failure With No Operator Intervention. A high level turbine trip will occur since two of the three high level trip instruments are connected to the Side A and the trip logic is 2-of-3.
- Side B Failure With No Operator Intervention. If feedwater control is on the Side B level instrument, the feedwater controls will shut off feedwater and a low level scram will occur from the Side A level sensors. If feedwater control is on Side A, then power operation will continue.
- The operator is instructed to assume manual control of feedwater if the high/low level annunciator or the high level trip annunciator sounds. The procedure calls for manual control of feedwater until the problem is diagnosed and appropriate action taken.

The fault tree shown in Figure D-1 accounts for these considerations. Since the trips are assumed to occur shortly after the failure, little credit for successful operator intervention is given. The Shoreham operating procedures are expected to call for using the Side A sensor for input to the feedwater level controls unless there is a compelling reason to use the Side B sensor. It is conservatively assumed that the Side B sensor will be unavailable 10 percent of the time.

The probability for a high level trip when the failure is on Side A is 1.0. The Side B probability for this event is low since it requires a failure in an instrument and is evaluated to be 0.008. The



*BASED ON THE ASSUMPTION THAT THE SHOREHAM PROCEDURE SPECIFIES THAT THE OPERATOR WILL INVESTIGATE THE CAUSE OF THE WATER LEVEL INSTRUMENT ANOMALY PRIOR TO INITIATION OF PLANT SHUTDOWN

Figure D-1: Fault Tree for Continued Power Operation Subsequent to Reference Line Failure

Side A/Side B failure probability for continued power operation is as shown on Figure D-1.

D.1.2 Failure in Alternate Reference Leg: O_R

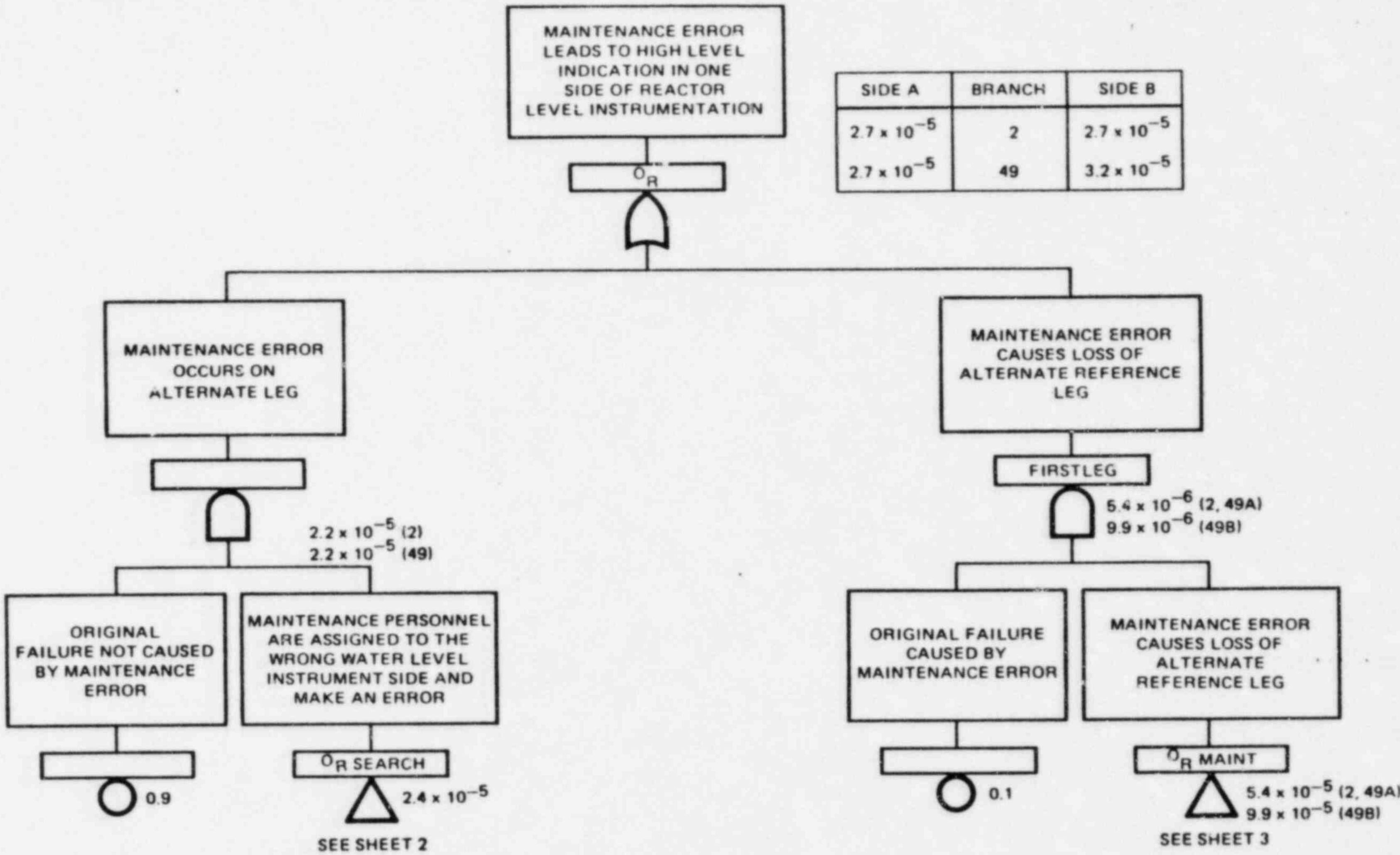
The possibility of a common cause failure is included in the event tree. Figure D-2 summarizes the functional events considered in the quantification. The loss of the other reference leg, subsequent to a failure in one reference leg, is most likely to be caused by a maintenance error. Based upon this knowledge and recognizing the importance of the water level measurement system, LILCO has taken steps to minimize the potential for adverse impact of the operation and maintenance personnel on the water level system. The LILCO procedures define the following important items:

- During power operation, if it is necessary to manipulate valves on one of the reactor level sensing lines, the control room operator will be notified at the start and completion of the work and will perform frequent validation checks during the work period.

- There are <u>no</u> scheduled surveillance tests of any type that require manipulation of any valves associated with any reactor level sensing line during power operation. Additionally, all station procedures used for instrument calibration or maintenance are written on a detailed step-by-step basis and require sign-off by the technician at each step. Also, after the completion of the work task, all procedural steps, including valve alignment, are independently verified by a second qualified person.

The quantification of the functional event in Figure D-2 considers the positive improvements gained from each of the above items.

The probability of a failure in the alternate reference leg given that a failure in one reference leg has already occurred, depends on the source of the original error and the particular sequence under consideration. When the original failure is caused by a leak, an alternate reference leg failure can occur if the following events occur simultaneously:



SIDE A	BRANCH	SIDE B
2.7×10^{-5}	2	2.7×10^{-5}
2.7×10^{-5}	49	3.2×10^{-5}

Figure D-2 (Sht 1): Fault Tree for Operator Error Causes Failure of Alternate Reference Leg

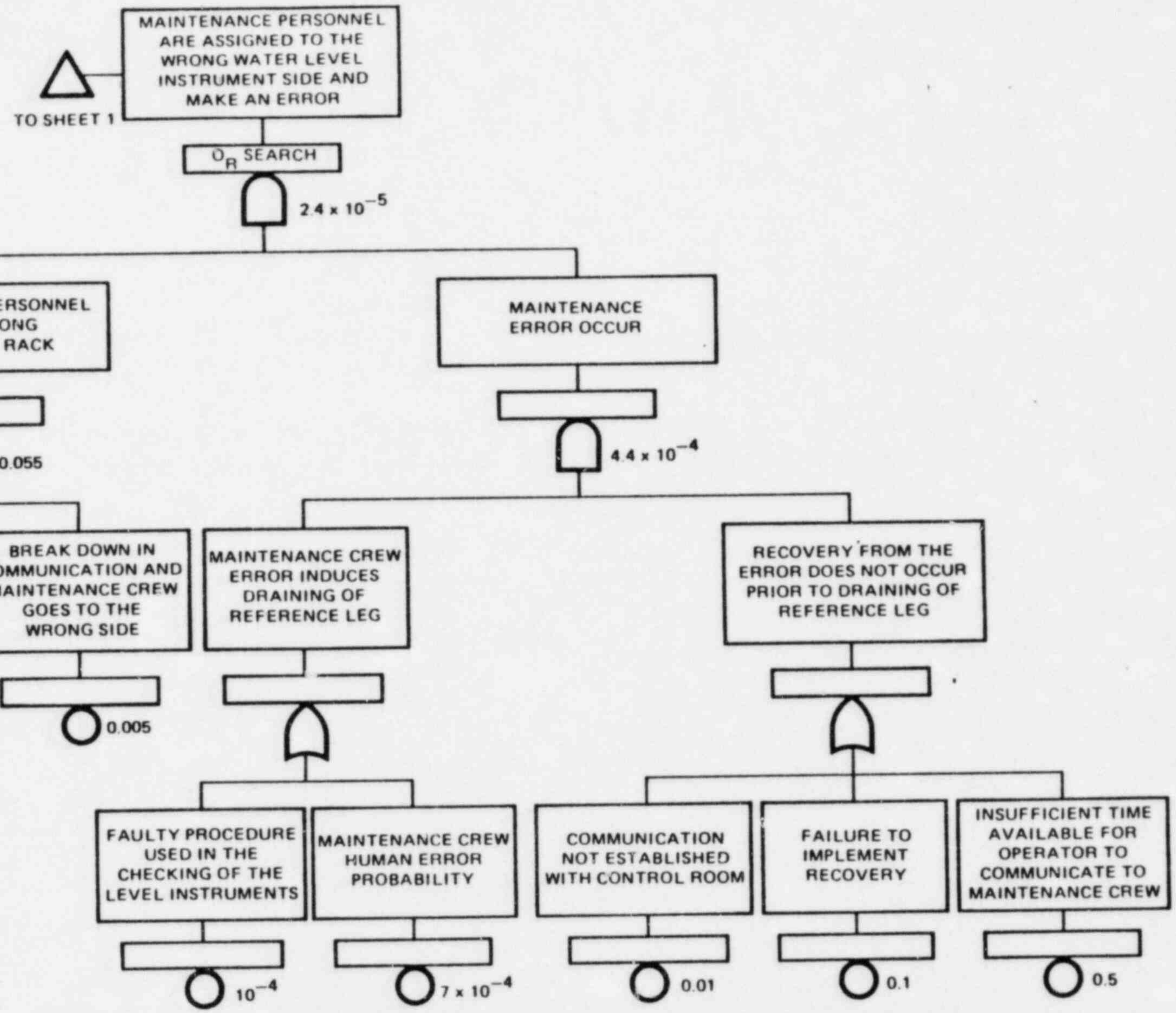


Figure D-2 (Sht 2): Fault Tree for Operator Error Causes Failure of Alternate Reference Leg

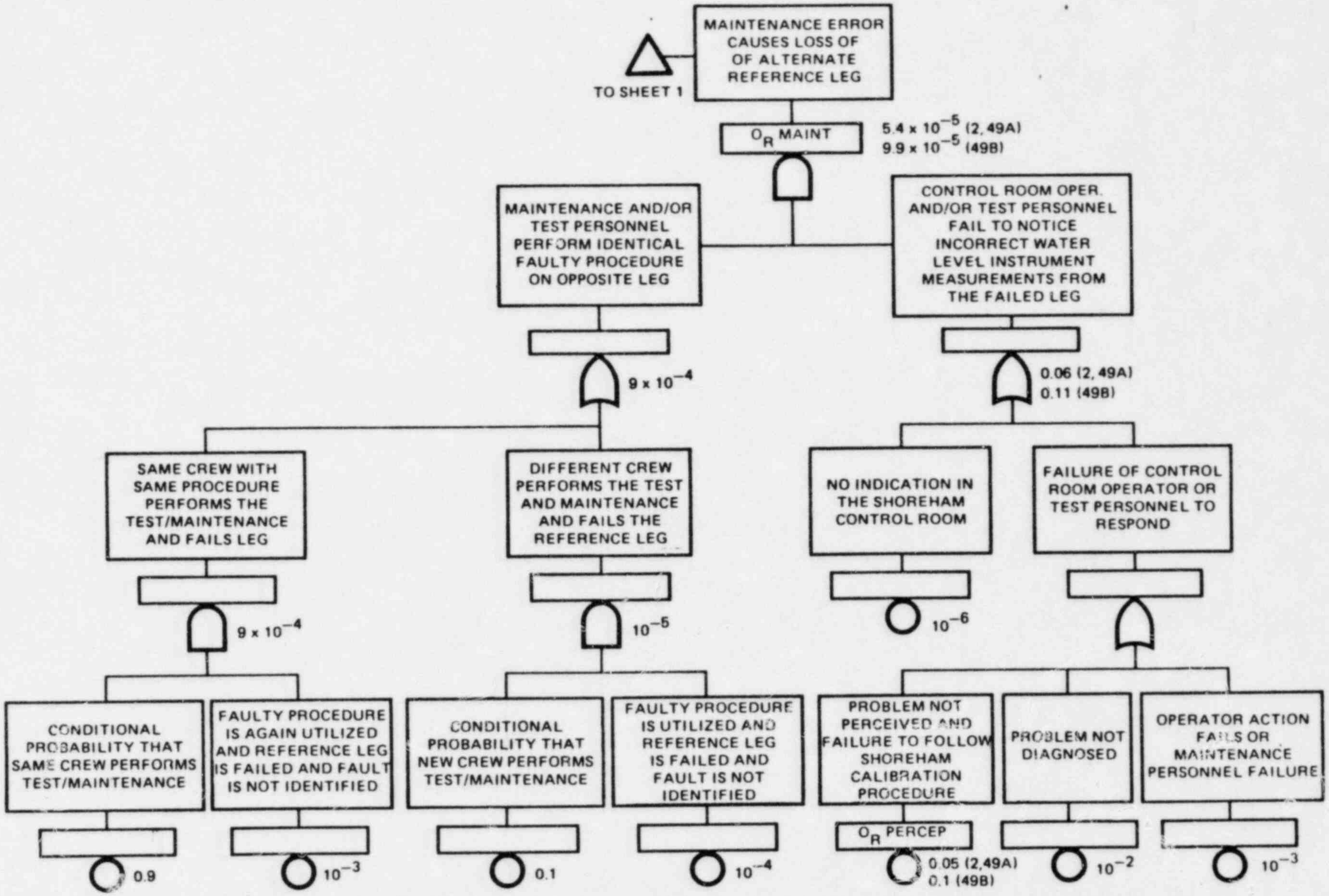


Figure D-2 (Sht 3): Fault Tree for Operator Error Causes Failure of Alternate Reference Leg

1. Maintenance crew accesses wrong instrument rack.

2. Maintenance crew performs an action which causes loss of the alternate reference leg.

The fault tree for evaluating these events is shown on Sheet 2 of Figure D-2.

When the original reference leg failure is due to a maintenance error, the probability of failure of the alternate reference leg will depend on whether the original error occurred during shutdown or during power operation as well as the sequence. The loss of both legs will occur when a maintenance error occurs on the alternate leg before the original failure is detected and diagnosed. The probability of the occurrence of the second error, given that the first error is not detected, is developed on the left-hand side of Sheet 3 of Figure D-2. The failure of the operator to detect and diagnose the first error is shown on the right-hand side of Sheet 3 of Figure D-2. The operator detection of the error will depend on the sequence. The cases to be considered when the original error occurs during power operation are:

- Original error causes loss of power operation (Branch 2). In this case, the operator is expected to detect the original error.

- Original error is on Side B with Side B feedwater control and power operation continuing. The operator is assumed to detect the original error since manual operation of the feedwater is required to maintain power operation.

- Original error is on Side B with Side A in control. Since the only immediate indication of the error is a single yellow light on the feedwater panel, the probability of the operator detecting the error in time is judged to be 0.1.

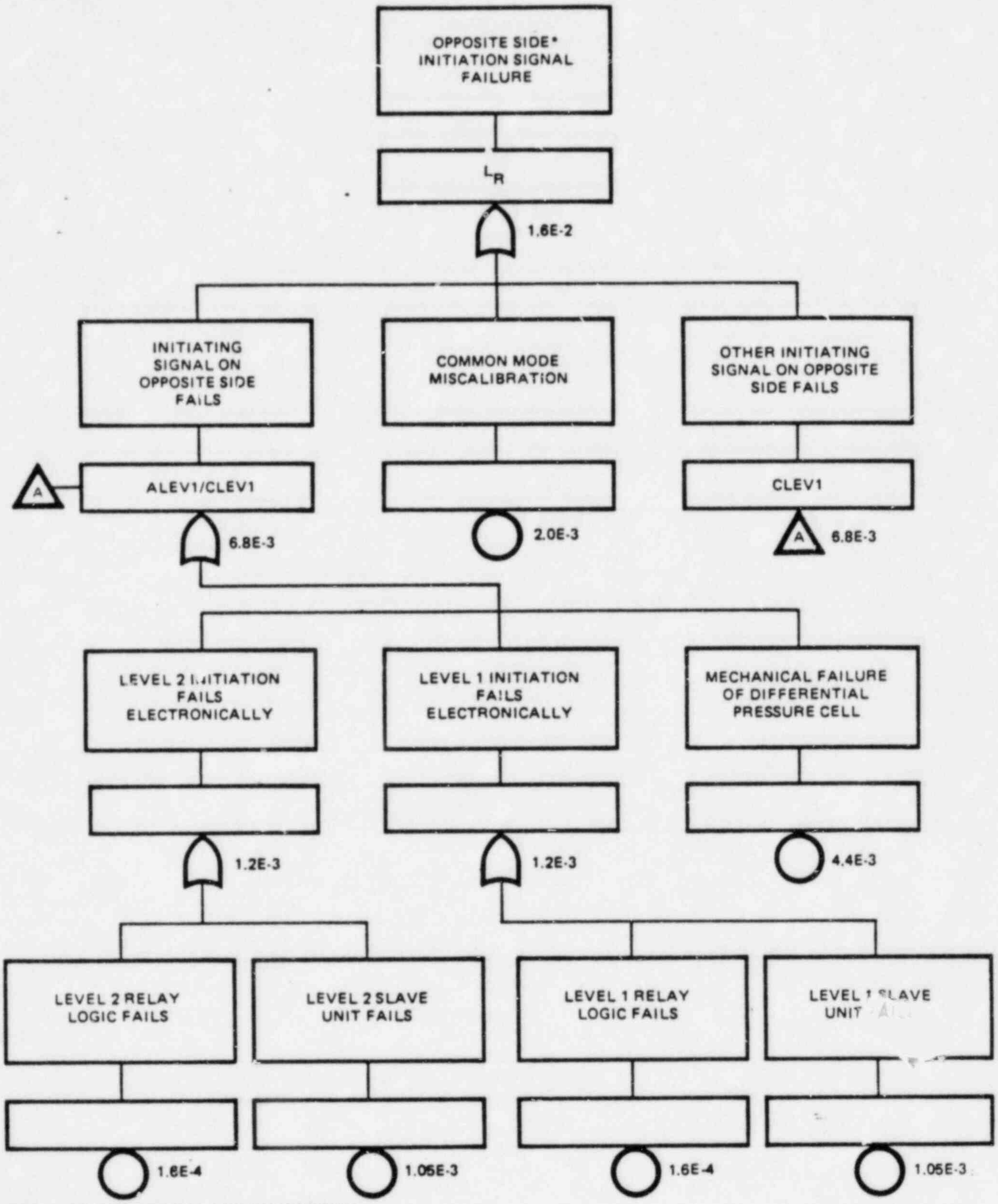
If the original error occurred during shutdown, the probability of timely detection of the original error is assigned a value of 0.1 because the long time available to detect the error is counterbalanced by the fact that less attention is given to the indications during shutdown. As indicated in Appendix B, the fraction of the initiators due to maintenance errors is 0.1, with an approximately equal split for errors occurring during power operation and during shutdown. The detection probabilities shown on Sheet 3 of Figure D-2 reflect these considerations and represent the combined failure probabilities for errors which occur during shutdown and power operation.

D.1.3 Failure of 125V DC Bus (3,6): B_R

The quantified probability of a single electrical bus failure developed in the Shoreham PRA electrical power fault tree is directly applicable to the conditional failure probability of the DC bus (B_R) for the duration of this accident ($3.7x10^{-4}$). For this reason, a fault tree for this event is not developed.

D.1.4 Opposite Side Level Instrumentation Failure (4,7,9): L_R

The postulated reference leg failure on one side causes loss of one safety system low level initiation channel, so an upscale failure in either one of the sensors and associated electronics on the other side will result in loss of automatic low level initiation. The functional fault tree for this event is shown in Figure D-3. The failure rates for the various components represented in Figure D-3 are taken from the Shoreham PRA, with a quarterly test interval used for calculating the event probabilities. The event ALEV1 in Figure D-3 represents the random failure probability for one of the instruments on the intact reference leg and CLEV1, which contains the same items as ALEV1, represents the failure of the other instruments. A common-mode miscalibration of the two instruments is also included in Figure D-3.



*FAILURE OF EITHER ONE OF INSTRUMENT
CHANNELS ON OPPOSITE SIDE CAUSES
LOSS OF INITIATION

Figure D-3: Fault Tree for Loss of Low Level Initiation from One Division

D.1.5 Reactor Scram: C

The reactor scram failure probability used is the same as used in the Shoreham PRA, with the alternate rod insertion feature included in the evaluation of scram failure rate ($1x10^{-5}$). The reference leg failure causes the loss of one low level scram channel. However, as discussed in Section 5, a scram initiation signal would be expected to originate from other sources (e.g., turbine trip, other level channel, MSIV closure) so the loss of the reference leg would not significantly affect the scram failure probability.

D.1.6 Feedwater Availability: Q

For events where feedwater is lost due to the initiator, the feedwater availability depends on the operator's ability to restore feedwater.

For the event where the initiator does not cause loss of feedwater, the feedwater availability is set by the probability of a spurious trip given that one reference leg has failed, which is assessed to have a probability of 0.04, based on a conservative evaluation of the feedwater system, MSIV, main condenser, and the high level trip circuit failure probabilities for 24 hours following the initiator.

D.1.6.1 Feedwater Maintained or Restored Immediately (12,13,14,15,&51): Q.

When the initiator is a failure of the Side A reference leg, the feedwater system is assumed to remain unavailable since the high level trip logic would have to be defeated to restore feedwater. For the Side B failure with Side B in control, the operator could restore feedwater by assuming manual control as discussed in Section D.1.1. Since the action required to restore feedwater would have to occur rapidly and the operator would have to resolve conflicts between level indications, the failure to restore feedwater is evaluated to have a probability of 0.75

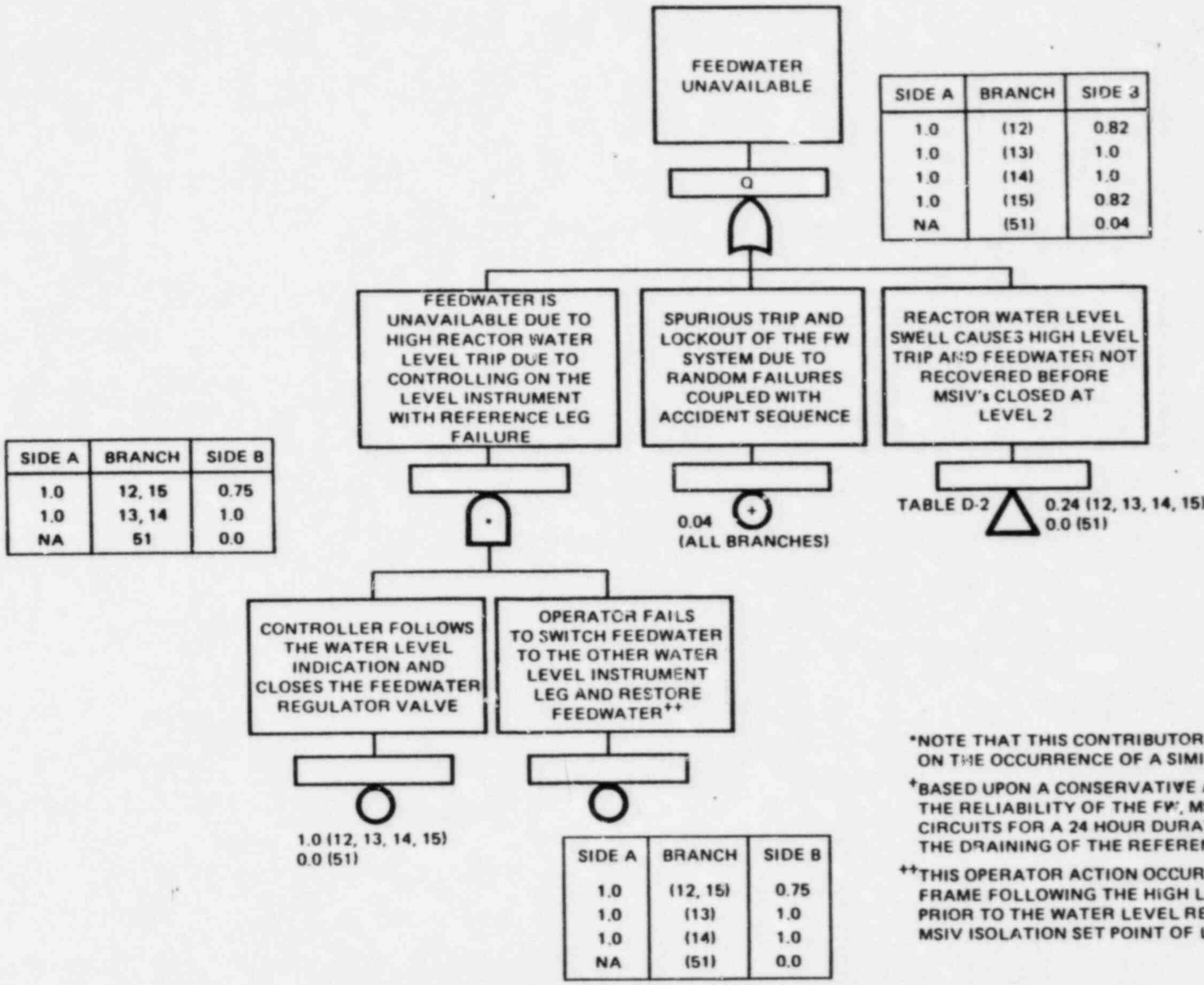
as shown on Figure D-4. In addition to the probability for the failure of manual control, there is the probability that the transient following scram could result in a high level trip or that a spurious trip could occur. The probability of a spurious trip is assessed in the same manner as with feedwater available, and the probability of the transient causing a trip is assessed to be 0.24. The total failure probability for restoring feedwater is the Boolean combination of these three terms, or 0.82 as shown on Figure D-4.

D.1.6.2 Feedwater Recovered (25,26,27): Q

Subsequent to loss of feedwater due to the initiator, the operator could recover feedwater in time to use it for core cooling. In order to restore feedwater, the operator must clear the high level trips and open the MSIV's. Since clearing high level trips requires bypassing the trip electronics, no credit for restoring feedwater is given. For O_R sequences (Branch 25), the high level feedwater trips will occur and will not clear as water level drops; consequently, no credit for feedwater recovery is given for these sequences. For other sequences, the dominant contribution to core vulnerable frequency is due to a side A failure. With a side A failure, the high level trips will not clear as level drops. Therefore, no credit for recovery is given on any sequence.

D.1.7 High Pressure ECCS Systems Available (16,17,18,19,20,21,22,23): U, U', U"

The High Pressure Coolant Injection (HPCI) and Reactor Core Isolation Cooling (RCIC) systems share the same low level initiation signals, which requires consideration of a common-mode failure of both systems. The fault tree for a common-mode failure of the HPCI/RCIC systems is shown in Figure D-5. The common mode event failure probability shown on Figure D-5 is calculated by including a common-mode term in the Boolean combination operation represented in Figure D-5. The combined HPCI/RCIC unavailability is based on a re-evaluation of the fault trees in the Shoreham PRA, which include credit for manual initiation of the systems.



SIDE A	BRANCH	SIDE 3
1.0	(12)	0.82
1.0	(13)	1.0
1.0	(14)	1.0
1.0	(15)	0.82
NA	(51)	0.04

SIDE A	BRANCH	SIDE B
1.0	12, 15	0.75
1.0	13, 14	1.0
NA	51	0.0

SIDE A	BRANCH	SIDE B
1.0	(12, 15)	0.75
1.0	(13)	1.0
1.0	(14)	1.0
NA	(51)	0.0

*NOTE THAT THIS CONTRIBUTOR IS CONDITIONAL ON THE OCCURRENCE OF A SIMILAR EVENT IN R_R.

+BASED UPON A CONSERVATIVE ASSESSMENT OF THE RELIABILITY OF THE FW, MSIV's, AND TRIP CIRCUITS FOR A 24 HOUR DURATION FOLLOWING THE DRAINING OF THE REFERENCE LEG.

++THIS OPERATOR ACTION OCCURS IN THE TIME FRAME FOLLOWING THE HIGH LEVEL TRIP AND PRIOR TO THE WATER LEVEL REACHING THE MSIV ISOLATION SET POINT OF LEVEL 2.

Figure D-4: Fault Tree for Feedwater Availability Following Reference Line Failure

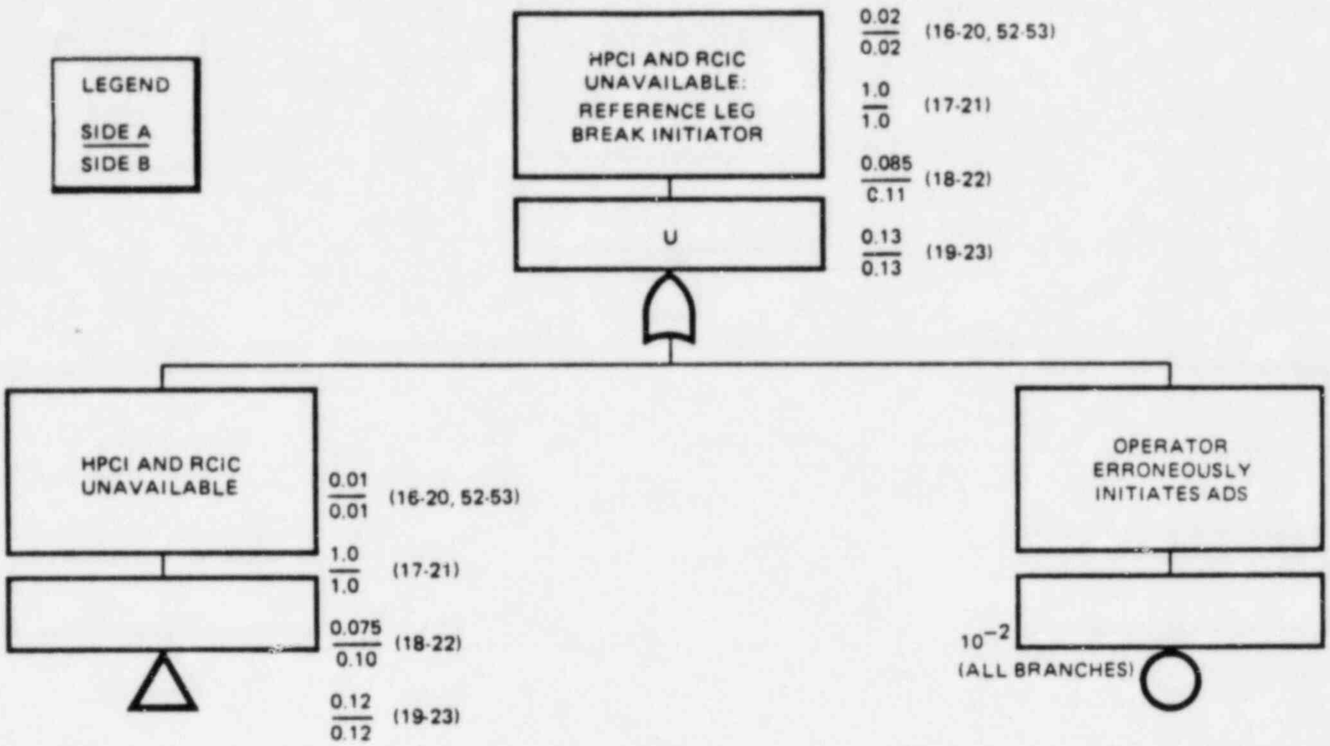


Figure D-5: Fault Tree for Common Mode and Random Failures of HPCI and RCIC for Reference Leg Failure Initiator

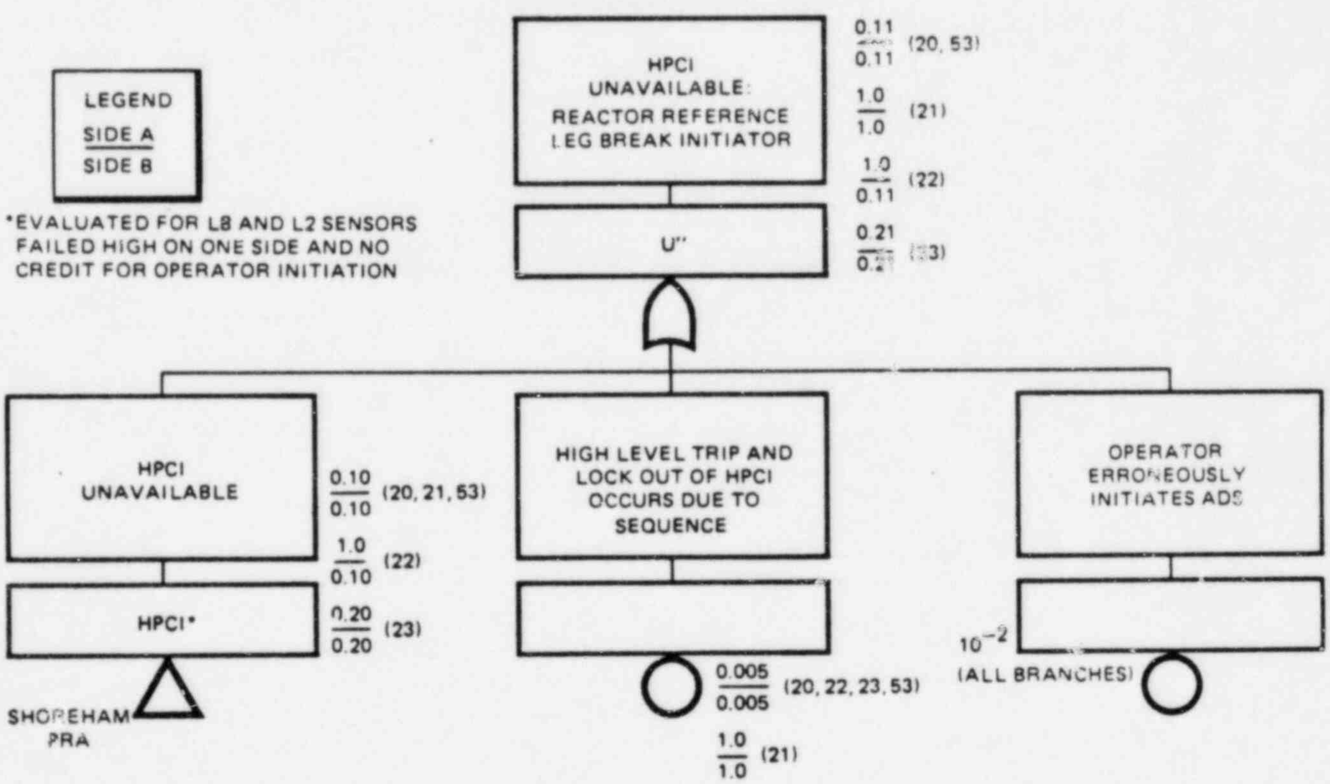


Figure D-6: HPCI Fault Tree for Reference Line Failure Initiator

In addition to the common mode failure probabilities, the HPCI and RCIC also have independent failure modes so that one of the systems may operate when the other fails. The fault trees for the HPCI and RCIC system's independent failure probabilities are shown in Figures D-6 and D-7, respectively, where the HPCI and RCIC unavailabilities are obtained from the fault trees in the Shoreham PRA.

D.1.8 Timely Reactor Depressurization (28,29,30,31): X

The ability to provide adequate coolant injection at high pressure is augmented by the ability to depressurize the primary system, allowing the low pressure injection pumps to provide coolant makeup from the suppression pool.

Reactor depressurization can be performed in a number of ways at Shoreham, including:

1. Automatic Depressurization System (ADS), which requires high drywell pressure, low level and low pressure ECCS pump running signals for successful operation. Also, the operator can inhibit automatic ADS for two minutes after the initiation signals are received.

2. Manual depressurization through the safety/relief valves. Plant procedures call for manual depressurization under various conditions, including a condition where level cannot be determined.

3. Manual operation of valves in the HPCI and RCIC steam lines to the suppression pool.

The ADS automatic initiation logic at Shoreham requires both high drywell pressure and low reactor vessel level signals to trigger the ADS 2-minute timer. Subsequent to time out of the timer, a signal confirming the operation of a low pressure ECCS pump is required before ADS occurs. Automatic initiation may be effective since high drywell pressure signals could occur when the drywell coolers isolate at level 1 with the subsequent rise in drywell temperature and pressure.

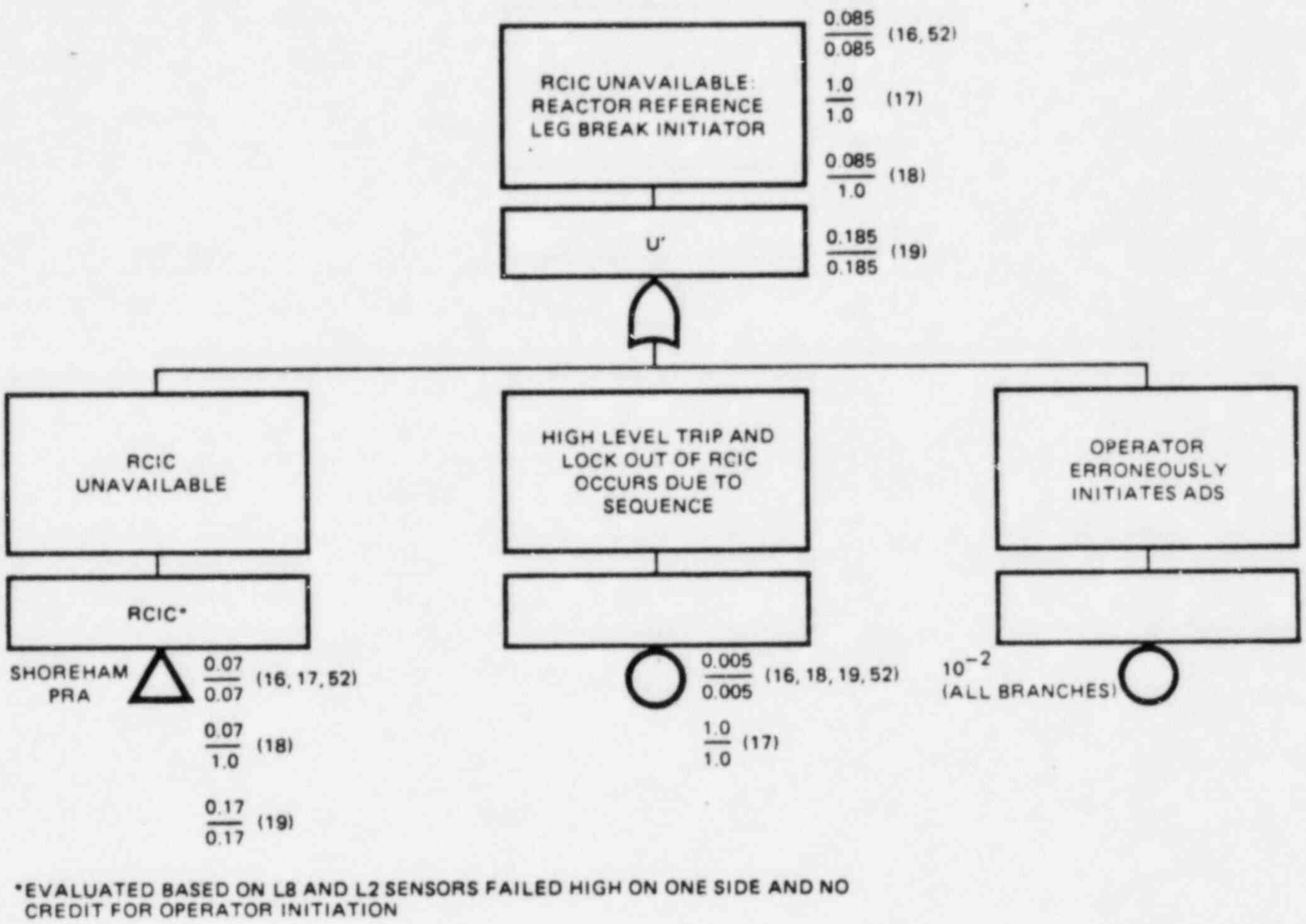


Figure D-7: RCIC Fault Tree for Reference Leg Failure Initiator

The functional fault tree for ADS in Figure D-8 reflects the above considerations. The following important considerations were used in the quantification of the conditional probability of successful depressurization.

1. Automatic ADS is given relatively little credit since it relies upon the rise in drywell pressure following the non-safety trip of drywell coolers at level 1 and the initiation signal originates in the same level sensors used for initiating the ECCS systems. In addition, this trip occurs late in the transient, so depressurization may be too late to prevent a core vulnerable condition.

2. For cases in which one reference leg is leaking (i.e., one Division reading high) and there is a leak in the other reference leg or a failure in the DC bus for the other Division, no automatic depressurization will occur.

3. The conditional failure probability for manual depressurization is derived in a structured framework which accounts for the quality of the information available to the operator for a specific sequence.

4. The alternate methods of depressurization require operator action. The failure of the operator to manually initiate ADS encompasses the failure of the operator to initiate alternate methods so a failure probability of 1.0 is used for alternate depressurization methods.

A detailed evaluation of the failure probabilites for manual depressurization under various conditions is given in Appendix C. Figure D-8 summarizes the evaluation given in Appendix C and shows the event tree branch numbers associated with the various conditions.

D.1.9 Coolant Injection: UX

The automatic initiation logic for ADS uses some of the same instrumentation as the automatic initiation logic for HPCI and RCIC. In addition, all three of these methods can be initiated by operator action, which may require the operator to respond correctly in the face of conflicting information. Therefore, a quantitative evaluation of HPCI, RCIC, and ADS failure must be performed together to properly account for intersystem

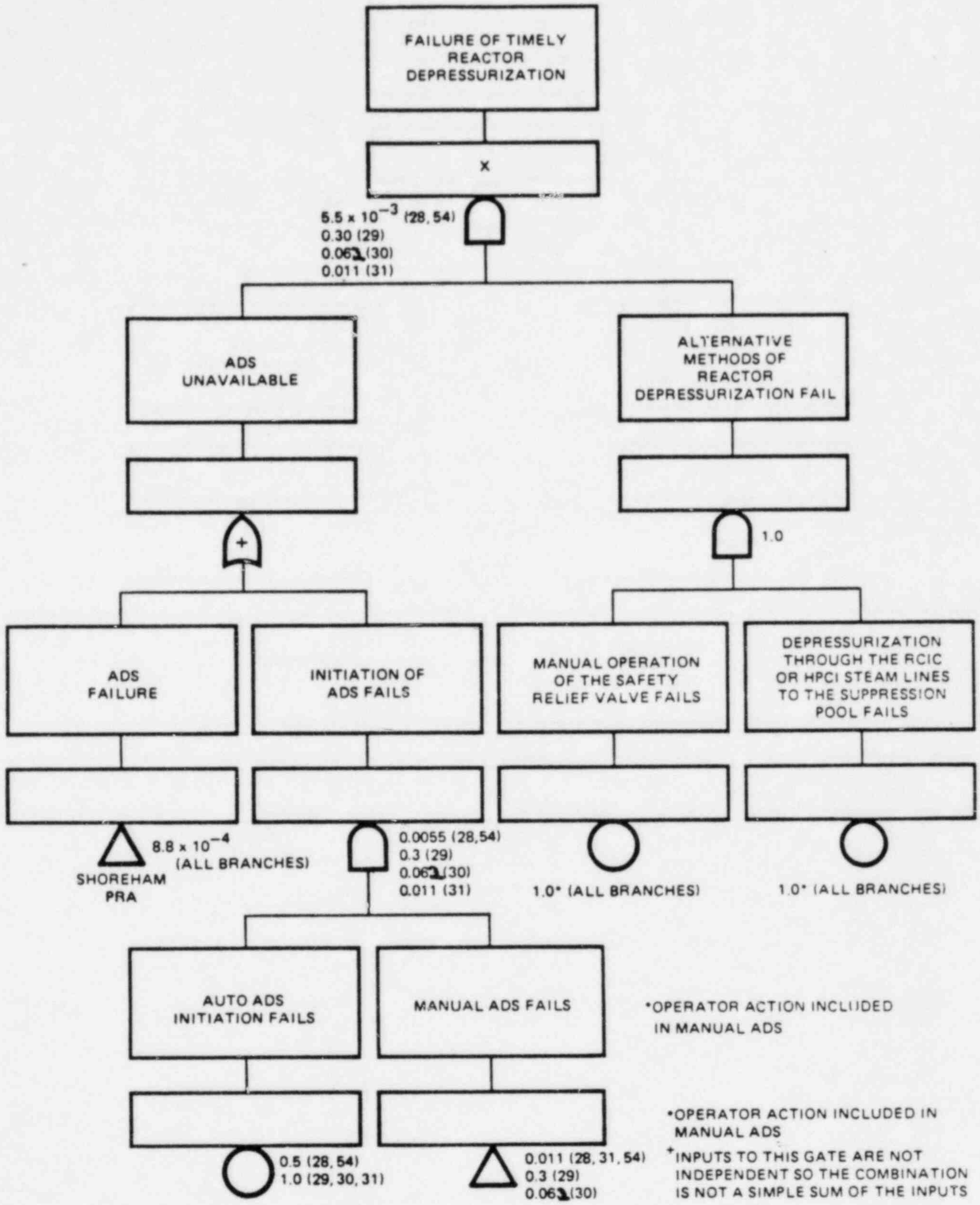


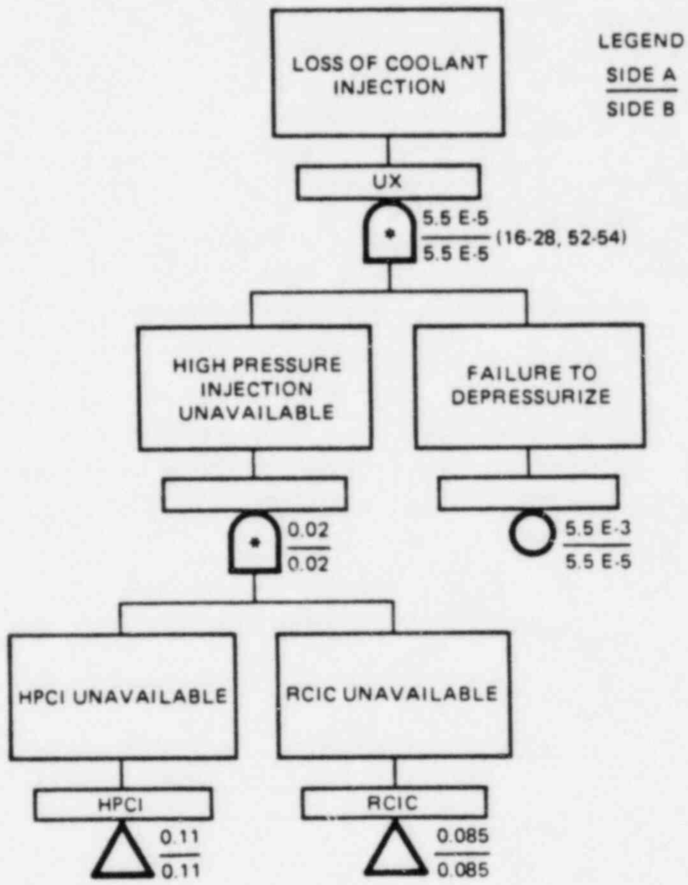
Figure D-8: Fault Tree for Timely Depressurization Following Reference line Failure dependencies and the potential for common-mode failures in the system. The functional fault tree for the combination of the RCIC, HPCI, and ADS systems is presented in Figure D-9.

D.1.10 Low Pressure Coolant Injection (32,33,34,35): V

There are three low pressure injection systems at Shoreham: Core Spray (V'), LPCI (V"), and Condensate (V'"). Once the reactor is depressurized, these pumps are sufficiently redundant to ensure with a high probability that sufficient coolant injection is available (V). However, in the sequences in which the operator may be misled by the high level indication on one set of level instruments, the operator perception of the reactor water level will dominate the response of the low pressure systems. Figure D-10 is the functional fault tree for the three low pressure injection systems. The failure probabilities for the injection systems are based on an evaluation of the unavailability of the combined low pressure systems. The fault trees, appearing in the Shoreham PRA, for the three systems were combined and evaluated to account for common-mode or dependent failures between the systems. The probabilities of the operator prematurely securing the systems are based on assessments of the information available on a particular sequence. The manual initiation failure probabilities shown on Figure D-10 are 1.0 when automatic initiation is successful, since manual initiation is not required, and 0.0 when automatic initiation fails because the operator must initiate ADS under these circumstances, so the human error is covered in the ADS fault tree.

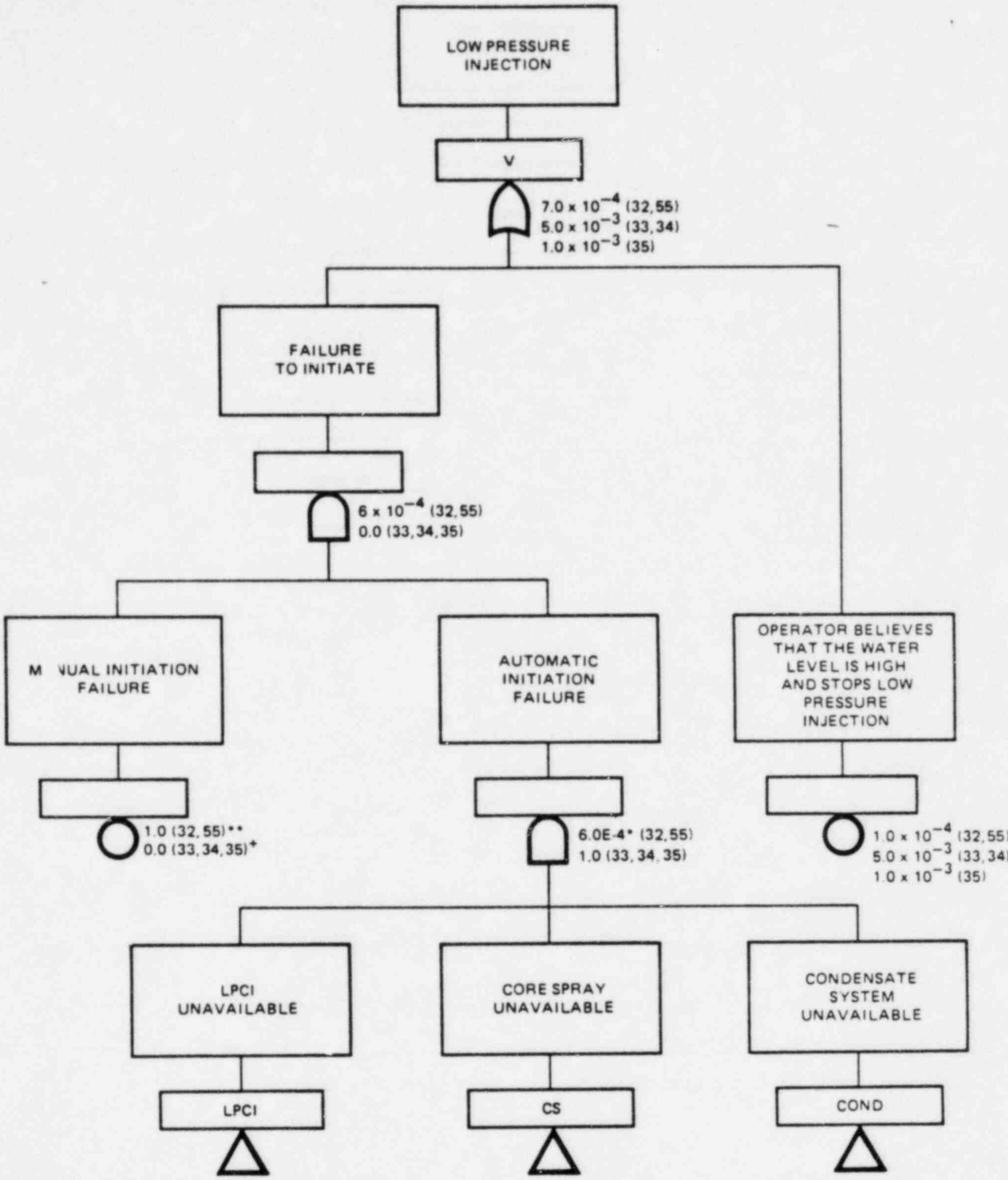
D.1.11 Drywell Cooling (36,37,38,39,40,41,42,43,44,45,46,47): GOL

Drywell cooling may be required in certain accident sequences to prevent degradation of the water level measurement systems. Specifically, inadequate drywell cooling may result in sufficiently high drywell temperatures to lead to boil-off or reference instrument line flashing when the primary system pressure is reduced, i.e., for long-term shutdown cooling or access to low pressure coolant injection.



*INPUTS TO THESE GATES ARE NOT INDEPENDENT; THE SYSTEMS SHARE SOME COMPONENTS. THEREFORE, THE GATE REPRESENTS A BOOLEAN COMBINATION WHICH IS NOT THE PRODUCT OF THE TWO INPUTS.

Figure D-9: Fault Tree for Loss of HPCI/RCIC Coupled with Failure to Depressurize



*COMBINED LOW PRESSURE SYSTEM UNAVAILABILITY WITH COMMON ELEMENTS AND SYSTEM INTERDEPENDENCIES CONSIDERED

**MANUAL INITIATION NOT REQUIRED WHEN AUTO INITIATION OCCURS

+OPERATOR ACTION INCLUDED IN ADS FAULT TREE

Figure D-10: Fault Tree for Low Pressure Injection Following Reference Line Failure

Plant shutdown with loss of adequate heat removal is modeled by three events as discussed in Section D.2. For the reference leg failure initiator, these events are combined in a single event, using the fault tree shown in Figure D-11. The failure probabilities for these events are sequence dependent as indicated in Figure D-11.

D.1.12 Containment Heat Removal (W)

The containment heat removal function can be satisfied by either of two principal modes of heat removal:

1. The RHR system (W')
2. The Power Conversion system (W")

The Containment Heat Removal function is described in the fault tree shown in Figure D-12. The object of the functional level fault trees is to identify the sequence dependencies which may arise and affect the conditional probability of the successful completion of the function.

The following assumptions are important in understanding the calculated conditional probabilities for adequate containment heat removal:

1. Operator action to open MSIV's is assumed to be difficult to justify for cases where water level indicators are in conflict. Specifically, it is judged that the MSIV's will not be reopened for cases where there is a conflict of water level measurements or where all water level measurements are above level 8 or below level 2.

2. RCIC in the steam condensing mode is considered a viable option for cases in which water level measurement is responsive; however, in case of water level measurement conflicts and high water level cases, RCIC in the steam condensing mode is assumed to be unavailable because of the potential for high level turbine trips or because of the uncertainty of effective operator response.

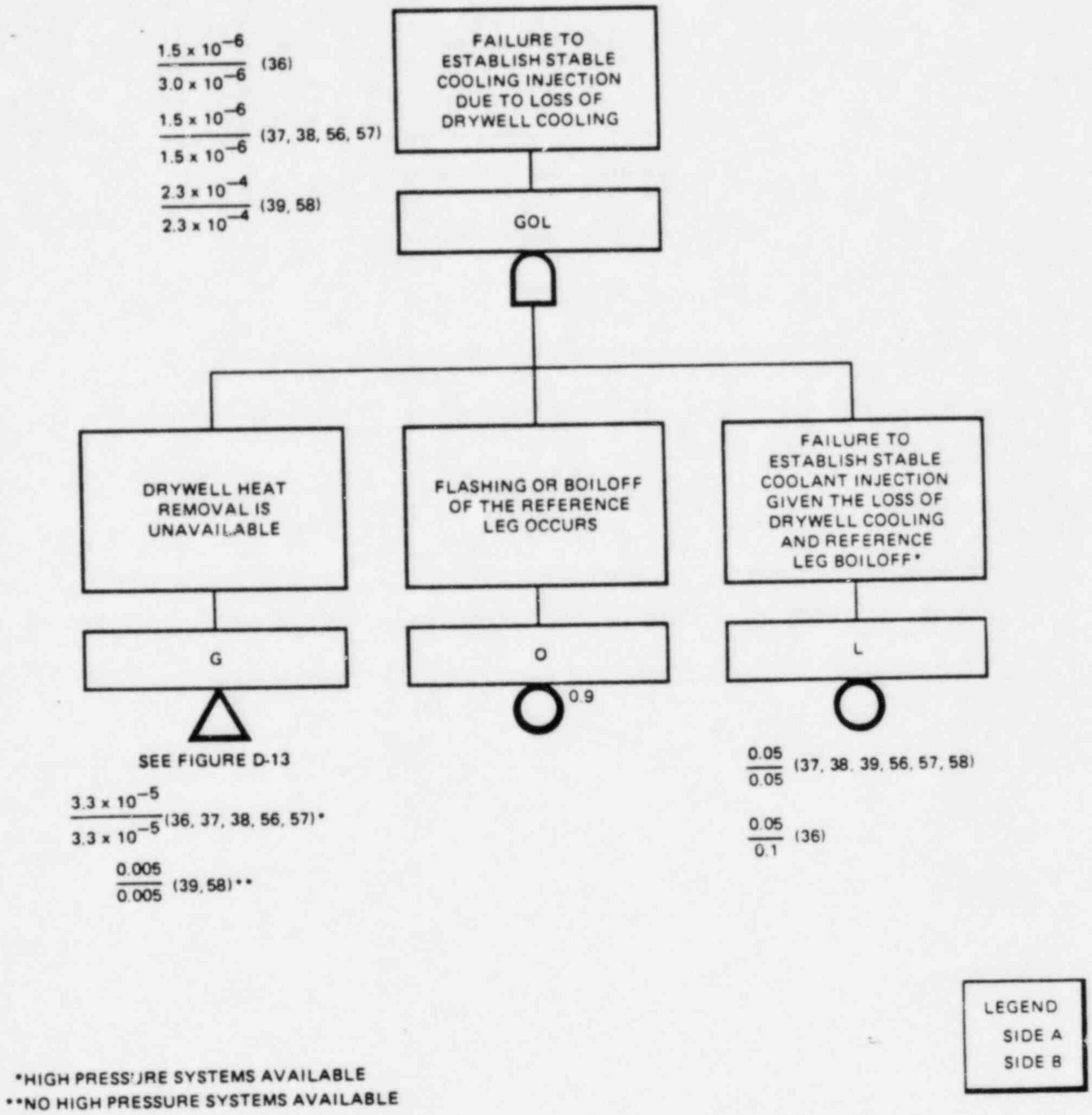
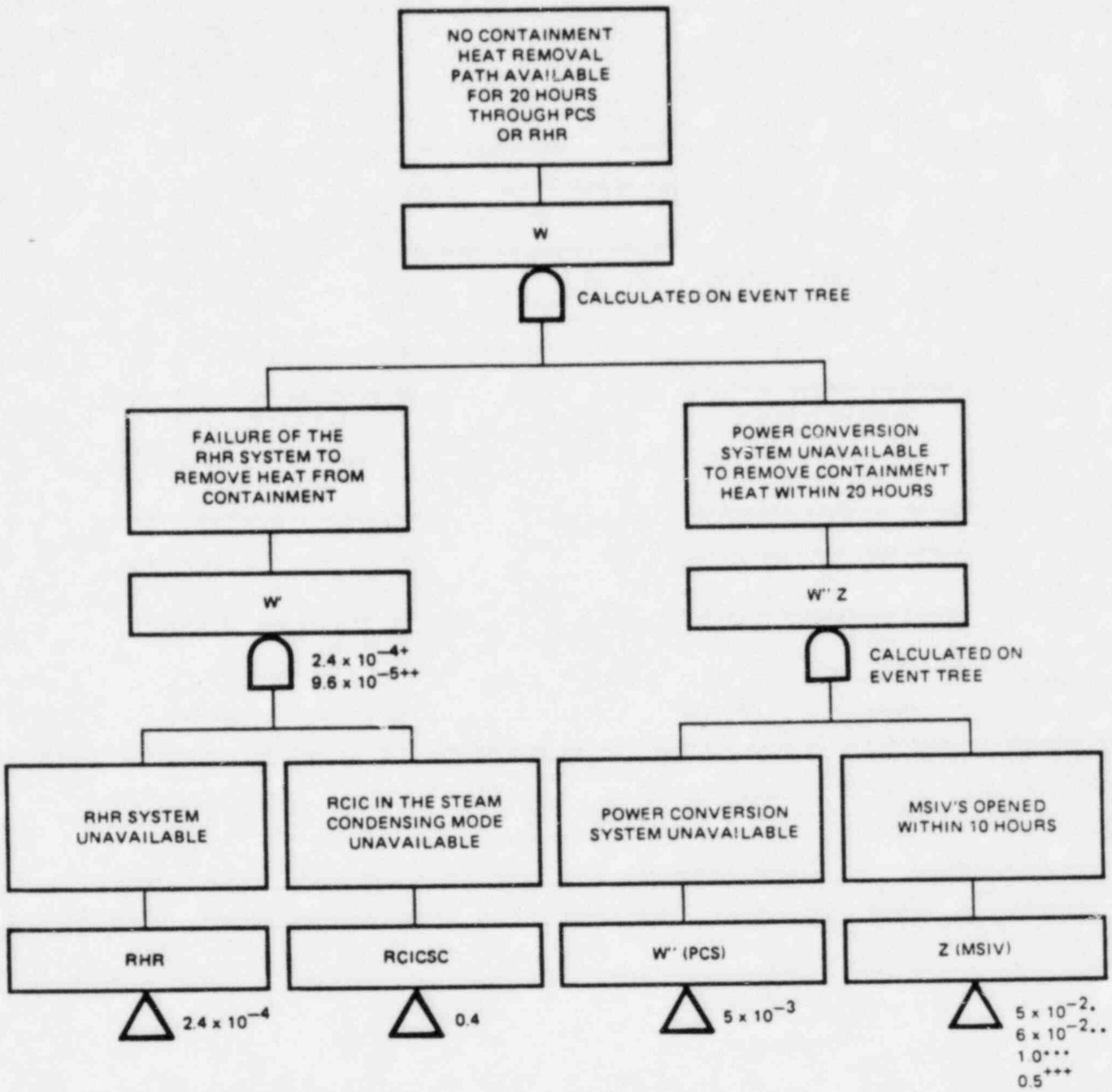


Figure D-11: Fault Tree for Inadequate Drywell Cooling Following Reference Leg Break



+W' – WHEN RCIC IS UNAVAILABLE
++W' – WHEN RCIC IS AVAILABLE
+++PROBABILITY OF Z FOR COMMON MODE REFERENCE LEG FAILURE AND LOSS OF DC BUS SEQUENCES
*PROBABILITY OF Z WHEN HIGH PRESSURE ECCS SYSTEM IS AVAILABLE
**PROBABILITY OF Z WHEN NO HIGH PRESSURE ECCS SYSTEM IS AVAILABLE
***PROBABILITY OF Z WHEN FEEDWATER IS AVAILABLE

Figure D-12: Fault Tree for Long-Term Containment Heat Removal Following Instrument Line Failure

D.1.12.1 RHR or RCIC in the Steam Condensing Model (W')

The RHR heat exchangers can be used to remove decay heat from the containment. These heat exchangers require service water pumps for removal of heat to the ultimate heat sink and either the RCIC or the RHR pumps to provide primary flow to the reactor vessel or the suppression pool. For the cases investigated here, the RCIC in the steam condensing mode is assumed to be ineffective because of the questionable reactor water level indication.

D.1.12.2 MSIV Reopened/PCS (Z) and (W")

In the event that the RHR is unavailable, the operator faces the dilemma of needing to open the MSIV's without knowing where the reactor water level is.

The containment heat removal function using the power conversion system has been assumed in this analysis to be adversely impacted by the inability to determine reactor water level, and, therefore, operator action to reopen the MSIV's is assumed to be degraded due to this uncertainty.

D.2 FUNCTIONAL FAULT TREES FOR LOSS OF ADEQUATE DRYWELL HEAT REMOVAL SEQUENCES

When low pressure and high drywell temperature occur together, the potential for instrument line flashing and the subsequent degradation of level indication exist. Safe plant operation under these conditions depends on the operator's ability to achieve stable cooling with abnormally high level indications. The operator's ability to achieve stable cooling depends on whether or not the operator is aware that flashing has occurred. Three distinct events are therefore required to model these sequences:

- Adequate Drywell Heat Removal (G designator);

- Flashing Detected (O designator);
- Stable Cooling Established (L designator).

The quantification of these events is highly sequence dependent. In general, there are four classes of transient initiators for which these sequences must be developed:

- Plant Transient Initiators;
- Loss of Offsite Power Initiator;
- LOCA Initiation;
- Instrument Line Failure Initiator.

D.2.1 Adequate Drywell Heat Removal

Loss of Drywell Cooling is modeled by the functional fault tree shown in Figure D-13. This fault tree reflects the fact that both the containment sprays and drywell coolers must be unavailable in order to cause loss of adequate heat removal and the subsequent rise in drywell temperature.

D.2.1.1 Containment Sprays Are Unavailable. This event represents the unavailability of the containment sprays when drywell temperature is high. The functional fault tree for this event, shown in Figure D-14, indicates that failure of the operator to initiate the sprays dominates the unavailability. The Shoreham emergency procedures instruct the operator to turn on the containment sprays when drywell temperature approaches the drywell design temperature. The probability that the operator fails to initiate the drywell sprays is evaluated to be 0.05, as shown on Figure D-14. This relatively high failure probability reflects three factors that would tend to inhibit the action:

1. Actuation of the containment spray system may cause water damage to equipment within the drywell.
2. The drywell temperature may remain below the design temperature.

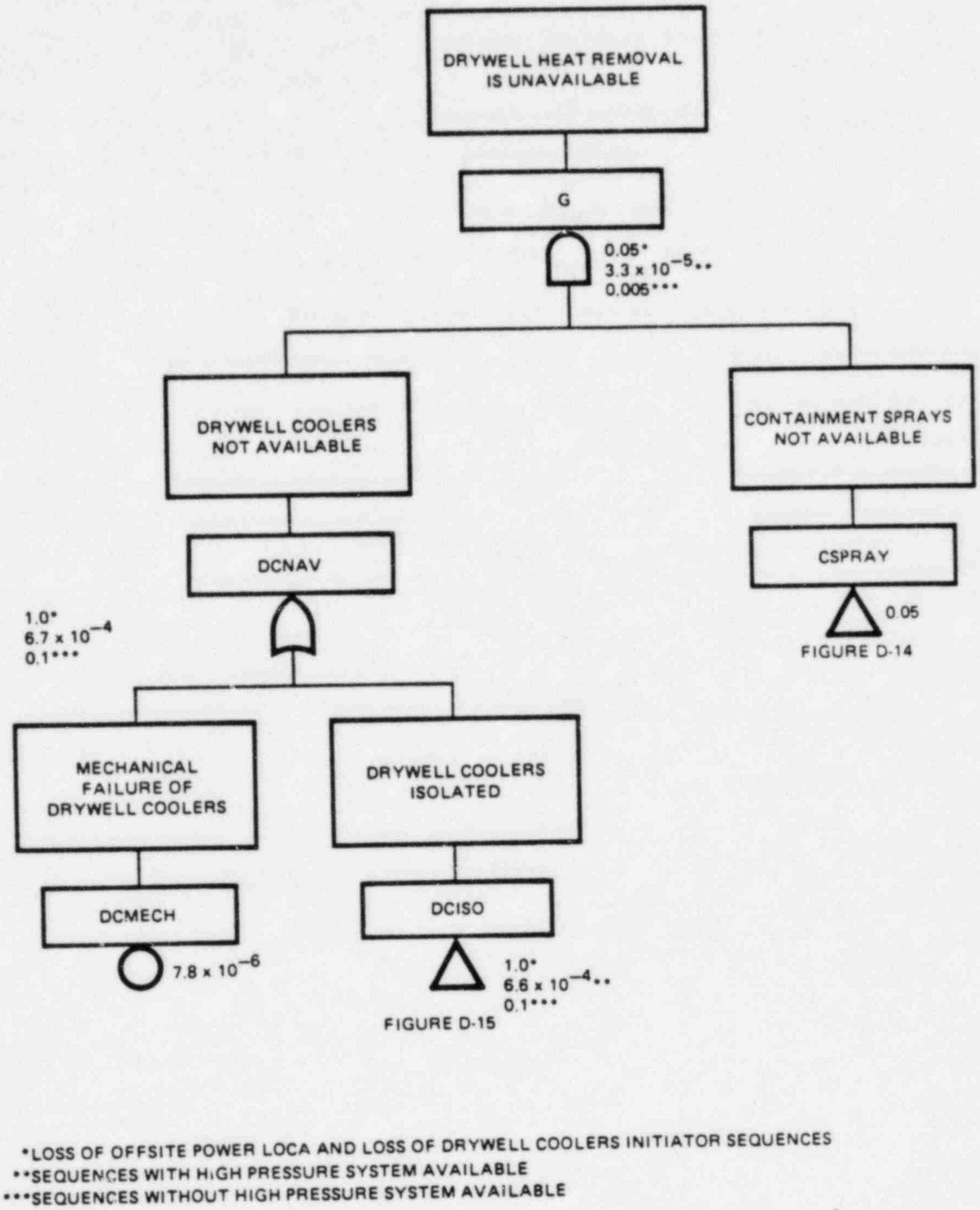


Figure D-13: Loss of Drywell Cooling Fault Tree

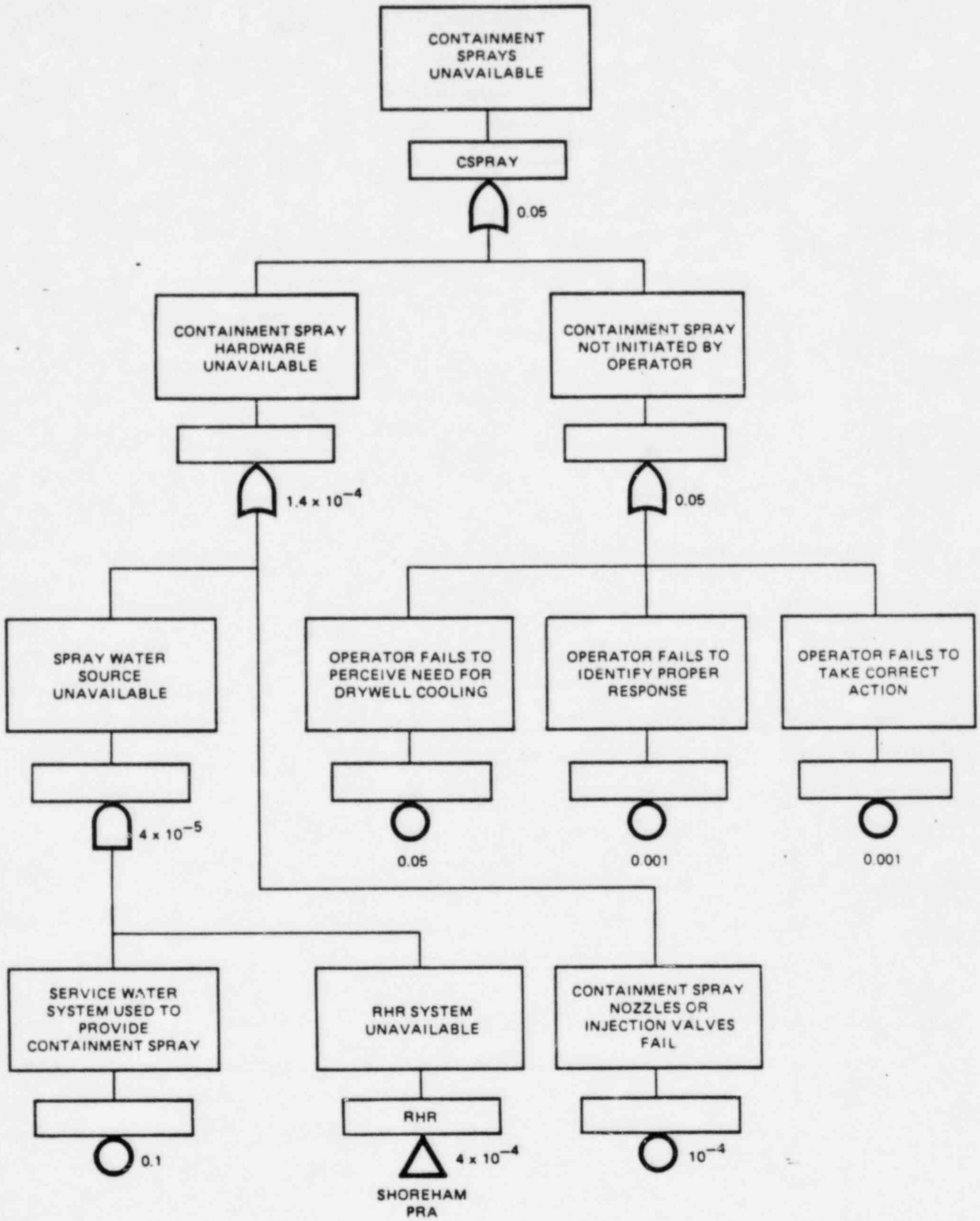


Figure D-14: Fault Tree for Containment Sprays

3. There is no immediate direct threat to the reactor from failure to spray.

The availability of the containment sprays also depends on the availability of a source of water for the sprays and the containment spray injection system. The failure rates for RHR and spray injection systems are as given in the Shoreham PRA. The use of service water as a source is given little credit because the contaminents in the water would make the operator reluctant to use it. The containment spray unavailability is assessed to be the same for all event sequences since it depends only on the operator response to drywell temperature increase.

D.2.1.2 Drywell Coolers Unavailable

The drywell coolers can be lost due to a mechanical failure prior to achieving cold shutdown (assumed to be period of 5 hours), or because the drywell coolers are isolated and not restored. The probability of mechanical failure of the drywell coolers may be calculated from:

$$P(\text{cooler failure}) = 1 - \mathrm{EXP}[-\lambda_c 5]$$

where λ_c is the failure rate of the coolers. The failure rate of the coolers may be derived from operating experience. The LER data base contains two loss of drywell cooling events that caused drywell temperatures to go above 212°F. λ_c may therefore be estimated by:

$$\lambda_c = \frac{\#\ \text{failures}}{\text{reactor years} * 8760 * 0.7} = \frac{2}{200 \times 8760 \times .7} = 1.6 \times 10^{-6}/\text{hr}$$

where 200 is the number of reactor years for BWR's (see Appendix B), 8760 is the number of hours in a year and .7 is the average availability of BWR plants. The estimated failure rate may then be used to calculate the failure probability which yields 7.8×10^{-6} as the estimated probability of mechanical failure of the drywell coolers during the transient. This failure probability is independent of the event sequence. The probability of isolating the drywell coolers depends on the event sequence. The drywell coolers will isolate on low reactor water level (L1) a low-low level signal from the Reactor Building Closed Cooling Water (RBCCW) system head tanks A or B, or a high drywell pressure signal.

Drywell Cooler Isolation for Plant Transient and Loss of Reference Leg Initiators

For the plant transient and loss of reference leg initiators, the probability of isolating the drywell coolers will depend on the availability of the high pressure systems, as indicated in the functional fault tree shown in Figure D-15.

High Pressure Systems Available. If high pressure systems are available, the probability of reaching the low level isolation is very small as indicated in Figure D-16. For this case, the probability of isolating the coolers is set by the failure probability of the Reactor Building Closed Cooling Water (RBCCW) head tank level switches as indicated in Figure D-15.

High Pressure Systems Unavailable. If high pressure systems are unavailable, the low level isolation signal is assumed to occur. The availability of the coolers will then depend on the operator resetting the low level isolation when level is restored. The probability of the operator restoring the coolers is assessed to be 0.1 as shown in Figure D-15.

Drywell Cooler Isolation Following a LOCA

For the LOCA initiator, the high drywell pressure signal is assumed to occur, so the failure probability for drywell coolers is 1.0 for this case.

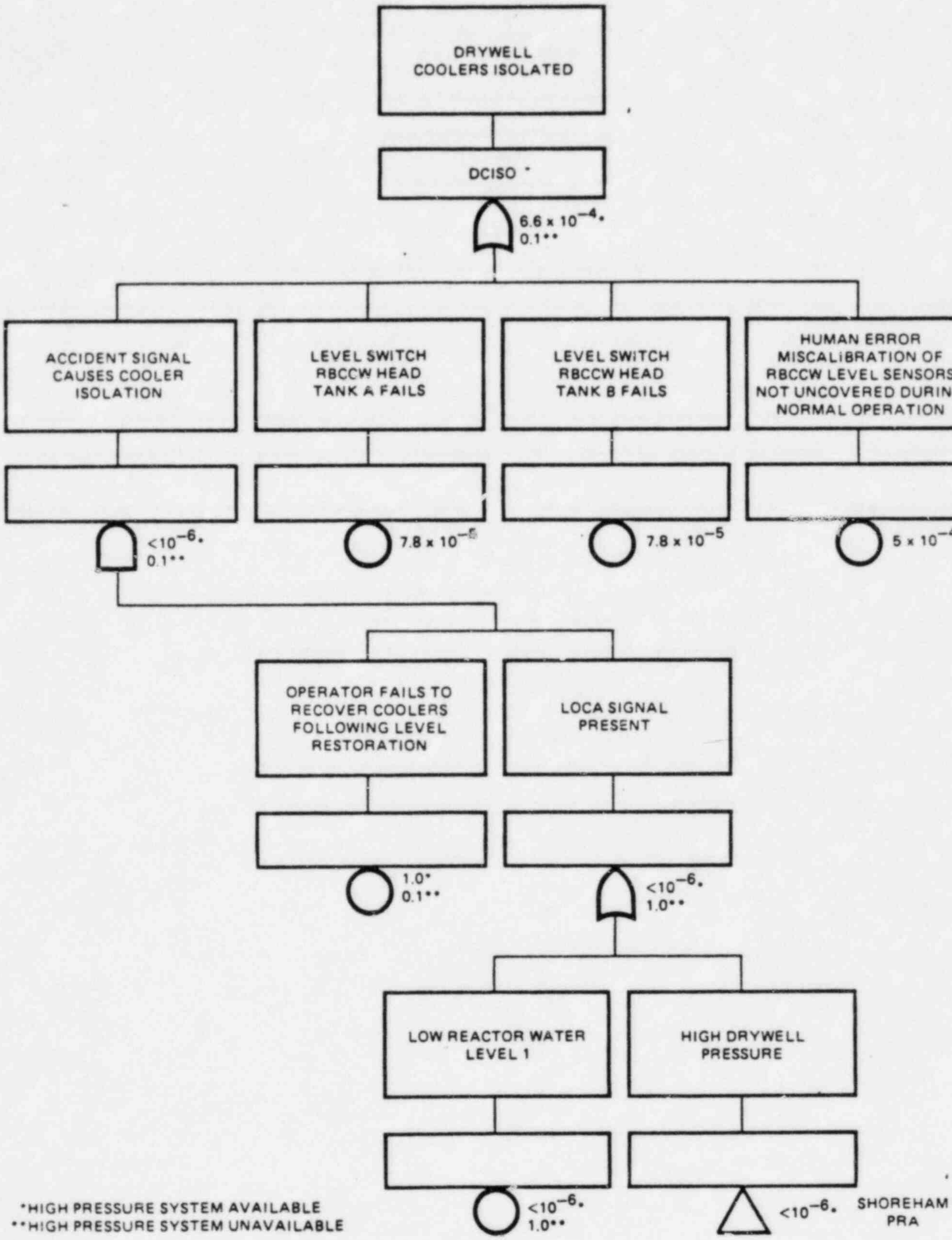


Figure D-15: Fault Trees for Isolation of Drywell Coolers

Drywell Cooler Isolation for LOSP (Station Blackout)

The probability of drywell cooler isolation for loss of offsite power is conservatively evaluated as follows. Drywell cooler operation is halted when the emergency electric power supply is lost and even brief power losses are enough to result in a LOCA signal due to high drywell pressure caused by loss of drywell cooling. Therefore, it is assumed that recovery of the emergency electric power supply will not restore operation of the drywell coolers. This is reflected in the functional level fault tree shown in Figure D-13, in which the conditional probability of the drywell coolers being permanently unavailable due to high drywell pressure is assigned a value of 1.0 for all cases involving station blackout (loss of both on-site and offsite power) at the initiation of the sequence.

D.2.2 Occurrence and Detection of Flashing (O Designator)

The Shoreham emergency operating procedures call for RPV depressurization and containment spray actuation in the event of Loss of Drywell Cooling. If the operator fails to initiate containment spray prior to depressurization and the drywell temperature is sufficiently high, the reference legs of the level instrumentation are assumed to flash and cause all instruments to read high. For most sequences the operator's ability to achieve stable shutdown (Event L, discussed later), following a loss of drywell cooling and subsequent instrument line flashing, is expected to improve if he has detected the occurrence of flashing. Therefore, Event O represents the occurrence of flashing and the operator recognition of flashing, as shown in Figure D-16. Two positive factors are associated with the event:

- The procedure that calls for depressurization alerts the operator to the potential for reference leg flashing and the resulting level indication errors.
- The operator will be watching reactor level during depressurization, and the level change associated with flashing will be abnormally fast and erratic.

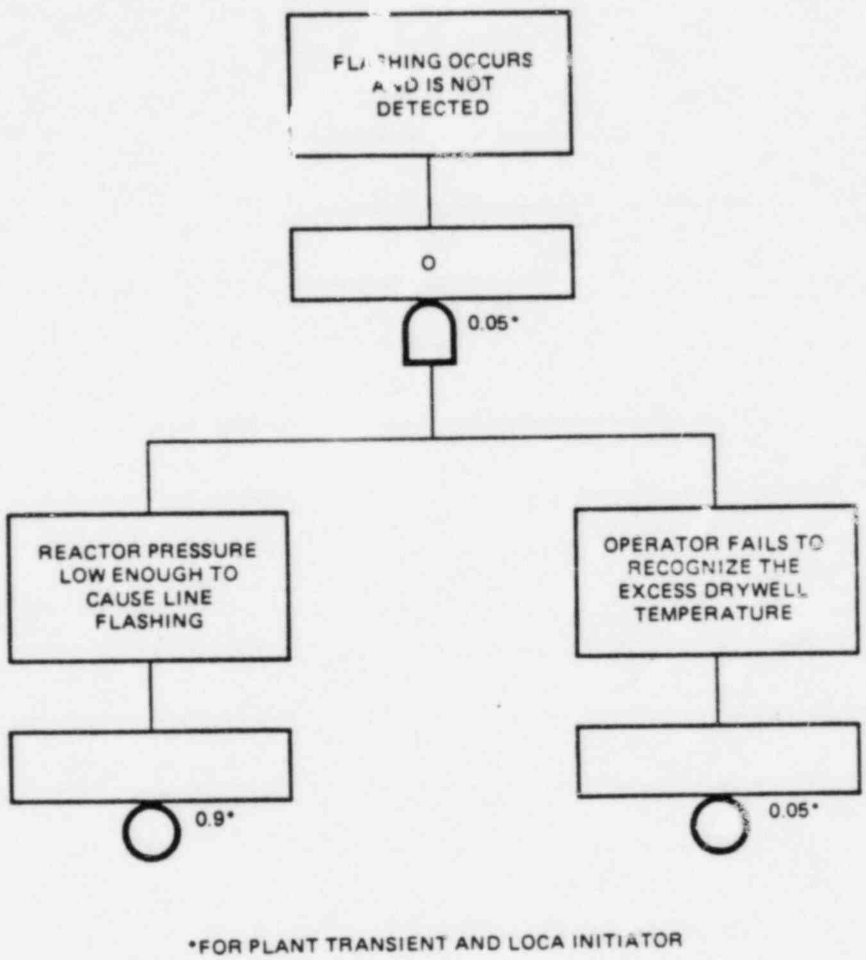


Figure D-16: Fault Tree for Operator Detection of Instrument Line Flashing

A negative factor related to the assessment of the operator error is that for this situation to occur, the operator may have disregarded a portion of the operating procedures and alarms calling for containment spray actuation. Once a portion of a procedure has been ignored, subsequent errors are found to be more likely. For the plant transient and LOCA initiators, the operator error of failing to detect flashing was assessed to have a probability of 0.05. Event O for the loss of drywell cooler plant transient initiator is modified to 0.02 to account for increased operator awareness of the potential for flashing because he has already identified the high drywell temperature condition. When loss of drywell cooling occurs subsequent to a loss of reference leg initiator, the operator's ability to achieve stable shutdown is not expected to vary significantly as a function of the recognition of flashing. Therefore, for the reference leg failure initiator, Event O represents only the occurrence of flashing. The loss of offsite power is assumed to cause a loss of both reactor protection system (RPS) buses and a loss of the instrument buses. Under these conditions, all level instruments indications will be lost since they are powered by either the RPS or instrument buses. Therefore, operator action is not expected to depend on detection of flashing, as in the reference leg failure initiator.

D.2.3 Stable Cooling Established (L Designator)

Long-term stable cooling depends on the availability of a system to provide coolant injection and the operator's ability to maintain acceptable level control. The availability of a coolant injection system and the operator's perception of the actual vessel level relative to the indicated level are both sequence dependent. Since the reference leg failure initiator causes a loss of valid level indications on one side prior to line flashing, it is considered separately from the other initiators.

D.2.3.1 Stable Shutdown Cooling for Plant Transient and LOCA Initiators. The probability of failing to establish a stable cooling mode for these sequences is dependent upon the operator's awareness of the fact that his level sensors are reading incorrectly. This leads to two cases depending upon the outcome of the previous event (O) in the event tree:

- Case 1: The operator has successfully detected reference leg flashing;
- Case 2: He initially has not detected the flashing.

For Case 1, the operator may use shutdown cooling or injection with either LPCI, Core Spray, or the Condensate Systems to provide heat removal. Based on these options plus the long period of time available to the operator to establish a cooling mode, the probability for failure to establish a stable cooling mode, given that the operator has detected instrument line flashing, is dominated by failure of the operator to adequately assess water level and is evaluated to be $1x10^{-4}$, as discussed in Appendix C.

Case 2 represents a more serious challenge to the operator. In this case, the operator is unaware that flashing has taken place in the reference legs. At this point, Case 2 can be subdivided into two events that depend upon which water level indicators the operator is likely to be using to control water level. If the operator is controlling water level by the use of the feedwater/condensate system, he is more likely to rely upon the combinatiom of 3 narrow range and 1 wide range water level indicators located on the reactor control benchboard. However, if he is controlling water level using any of the ECCS systems, he is likely to be relying upon the two wide range and two fuel zone displays located on the core cooling benchboard. Subsequent to flashing, two of the narrow range instruments will read upscale and the third will indicate above the high level alarm regardless of the actual water level, while the fuel zone and wide range instruments will indicate abnormally low water level well before actual level drops to the top of the active fuel. Therefore, the operator is more likely to fail to establish stable cooling when he is using the narrow range indicators. For Case 2, the probability of the operator failing to establish stable cooling is assessed to be 0.01 when using the narrow range indicators and 0.005 when using the wide range indicators. The evaluated operator error probability recognizes that adequate core cooling is assured if the operator controls level according to procedures even if he is unaware that reference line flashing has occurred.

D.2.3.2 Stable Cooling for Reference Leg Failure and LOSP Initiators. For these sequences, the degradation of level instruments prior to instrument line flashing also degrades the operator's ability to properly assess and manage the transient.

It is important at this stage to consider the effects of the water level displays that are available to the operator for controlling water level. The availability of water level displays depends on which reference leg drained at the start of the transient and which control panel (reactor control or core cooling) the operator is using. This results in four possible cases with varying effects on the operator's ability to establish a stable cooling mode. The four cases are related to the asymmetric nature of the reference leg arrangement. The pertinent Side A/Side B asymmetrical features are:

- The reference leg vertical drop is different for Side A and Side B;
- Location of level displays in the control room;
- Instruments which initiate automatic main and feedwater turbine trips are asymmetrically located.

The four cases to be assessed are:

Case 1 - Side A reference leg drains; operator perception at the feedwater control station. Operator has two out of three narrow range indicators reading offscale high. One narrow range and one wide range indicator reads on scale, but high. Controlling indicated wide range water level at Level 5 keeps actual water level above top of active fuel (TAF).

Case 2 - Side A reference leg drains; operator perception at the ECCS control station. Operator has two wide range indicators: one reads upscale; the other reads on scale, but high. Controlling the on-scale water level at indicated Level 5 keeps actual water level above TAF.

Case 3 - Side B reference leg drains; operator perception at the feedwater control station. All indicators read offscale high. There is no indication of changing water level.

Case 4 - Side B reference leg drains; operator perception at the ECCS control station. Operator has two wide range indicators: one reads offscale high; the other reads on scale, but high. Controlling water level at indicated Level 5 keeps actual water level above TAF.

Cases 1, 2, and 4 are similar in that adequate core cooling is assured if the lowest reading wide range instrument is kept in the normal water level range. However, the conflicting water level indications will cause confusion so the human error rate will be higher than it is for other initiators. For cases 1, 2, and 4, the failure probability of the large level errors resulting in inadequate level control is assessed to be 0.05, per Appendix C. For Case 3, the failure probability will be higher because the operator is more likely to be using the narrow range instruments. However, since Shoreham procedures call for water level indication logging and comparison each shift, the operator would be expected to check other level indications. The failure probability for this case is assessed to be 0.1. For the LOSP initiator, the situation is similar to Case 3, so a failure probability of 0.1 is used for this initiator.

D.2.4 Summary of Loss of Drywell Cooling Sequence Probabilities

The probabilities for the drywell cooling events discussed in the preceding sections are dependent on both the initiator and also the particular sequence for a given initiator. The failure probabilities to be used for a particular sequence are as follows:

- Plant transient initiators (M_S, T_T, T_C, T_M, T_F, T_I, T_{MT} designators):
  - -- G (Adequate Drywell Cooling)
    - -- with high pressure systems (FW/HPCI/RCIC) available--3.3×10^{-5}
    - -- without high pressure systems available--0.005
  - -- O (Flashing Occurrence and Detection)--0.05
    - -- for LODWC initiator (T_{MT}) 0.02
  - -- L (Stable Cooling Established)
    - -- with flashing detected--0.0001
    - -- flashing undetected using feedwater/condensate systems--0.01
    - -- flashing undetected using ECCS--0.005

- Loss of offsite power initiator:

-- G (Adequate Drywell Cooling)--0.05

-- O (Flashing Occurs)--0.9

L (Stable Cooling Established)--0.1

- LOCA Initiator

  G (Adequate Heat Removal)--0.05

  O (Flashing Occurrence & Detection)--0.05

  L (Stable Cooling)

  - -- with flashing detected--0.0001
  - -- flashing undetected using feedwater/condensate system--0.01
  - -- flashing undetected using ECCS system--0.005

- Loss of Reference Leg Initiator:

  -- G (Adequate Drywell Heat Removal)

    -- with high pressure system available--3.3×10^{-5}

    -- without high pressure system available--0.005

  -- O (Flashing Occurs)--0.9

  -- L (Stable Cooling Established)

    -- Side A failure using feedwater/condensate controls--0.05

    -- Side A failure using ECCS controls--0.05

    -- Side B failure using feedwater/condensate controls--0.1

    -- Side B failure using ECCS controls--0.05

D.3 SUMMARY OF INPUT VALUES FOR THE FUNCTIONAL FAULT TREES

The event trees and functional fault trees for the evaluation of the postulated failure modes of the reactor water level instrumentation system are quantified using a number of sources which include the following principal ones:

- The main source is the Shoreham PRA and the associated system fault tree evaluations which have been performed to calculate the system reliabilities at Shoreham for a wide variety of accident sequences.

- Operator response plays a major role in the evaluation of the functional fault trees. The quantification of human error probability is based upon operator response models constructed for Shoreham, using methods and data taken from Swain-Guttman and Wreathall et al. Appendix C summarizes the principal contributors to this evaluation and how they were implemented for the Appendix D evaluation.

Table D-2 is the tabular summary of the key events in the functional fault trees along with their respective references.

Table D-2

Summary of the Conditional Probabilities Used in the Quantification of the Event Tree Functions

Figure	Top Event	Basic Event	Probability	Refs.
D-1	R_R	Operator observes high level and initiates Scram	1E-2	2, 8
		High level trip of FW	A:1.0 B:8E-3	8, 6
		FW is being controlled on Ref. leg with break	A:0.9 B:0.1	8
		Annunciator fails	1E-2	6
		Operator fails to notice Annunciator	.5	2, 6
		Operator sees Annunciator, but fails to switch over	.5	2, 6
D-2 Sht. 3	O_R Maint	No indication in control room	1E-6	4
		Same crew performs test/maintenance	.9	6
		Same crew uses faulty procedure	1E-3	2
		Different crew performs test/maintenance	.1	4
		Different crew uses faulty procedure	1E-4	2, 4
		Problem not diagnosed	1E-2	2, 6
		Operator action failure or maintenance failure	1E-3	2, 6
		Problem not perceived	0.05(2,49A) 0.1(49B)	4, 8
D-2 Sht. 2	O_R Search	Faulty procedure	10^{-4}	2, 4
		Maintenance crew error	7×10^{-4}	2, 6
		Communication not established	0.01	8
		Failure to implement recovery	0.1	2, 8
		Insufficient time for communication	0.5	8
		Operator assigns wrong side	0.05	2, 8
		Maintenance crew goes to wrong side	0.005	2, 8
D-2 Sht. 1	O_R	Original failure not caused by maintenance	0.9	5
		Original failure caused by maintenance	0.1	5
D-3	L_R	Relay logic fails	1.6E-4	6
		Slave unit fails	1.05E-3	6
		Differential Pressure cell mechanical failure	4.4E-3	6
		Common-mode failure	2E-3	6
D-4	Q	Transient level swell	0.24	6
		Controls shut off feedwater	0.0(51);1.0(12,13,14,15)	8
		Operator failure to maintain control	0.75(12B,15B); 1.0(12A,13,14,15A); 0.0(51)	2, 8
		Spurious trip	0.04	6, 7
D-5,6,7	U	Operator depressurizes to flood vessel (Erroneous ADS)	1E-2	2, 4
		High level trip locks out RCIC (HPCI)	.005(16,18,19,20,22,23), 1.0(17,21)	7, 8
		RCIC (U')	0.07(16,17,52,18A); 0.1(18B); 0.17(19)	7
		HPCI	0.1(20,21,53,22B); 1.0(22A); 0.2(23)	7
		RCIC/HPCI	0.01(16-20); 1.0(17-21); 0.75(18A-22A) 0.1(18B-22B); 0.12(19-23)	7
D-8	X	Depressurization through steam lines fails	1.0	2, 4
		Manual operation of S/R valves fails	1.0	2, 4
		ADS unavailable	8.8E-4	7
		ADS auto fails	.5(28), 1.0(29,30,31)	8
		ADS manual fails	0.011(28), .3(29), 0.063(30), 0.011(31)	2, 3

Table D-2 (continued)

Summary of the Conditional Probabilities Used in the Quantification of the Event Tree Functions

Figure	Top Event	Basic Event	Probability	Refs.
D-9	UX	Failure to depressurize	5.5×10^{-3}	2, 8
		RCIC	0.085	7, 8
		HPCI	0.11	7, 8
		RCIC/HPCI	0.02	7, 8
D-10	V	Operator stops low press. injection	1E-4(32), 5E-3(33), 5E-3(34), 1E-3(35)	2, 3
		LPCI/CS/COND	6E-4	7
D-11	GOL	These values are obtained in subsequent figures		
D-12	W	RHR System unavailable	2.4×10^{-4}	7
		RCIC steam condensing mode	1.0; 0.4	7
		PCS available	5×10^{-3}	7
		MSIV's opened	0.5; 5×10^{-2}, 6×10^{-2}, 1.0	2, 4
D-13	G	Loss of Drywell Coolers		
		These are obtained in subsequent figures		
D-14	CSPRAY	Containment Spray Nozzles fail	1E-4	6
		RHR	4E-4	7
		Operator fails to perceive need for cooling	5E-2	2, 6
		Operator fails to identify proper response	0.001	2, 6
		Operator fails to take action	1E-3	2, 6
D-15	DCISO	Miscalibration of level sensors	5E-4	2, 6
		Level switch fails	7.8E-5	6
		Operator fails to recover coolers	.1	2
		Low Reactor Water Level signal	1E-6 / 1.0	4
		High Drywell Pressure signal	1E-6	4
D-16	O	Operator fails to recognize the excess temp.	0.05	2, 3
		Failure of drywell cooling	.9	8

REFERENCES FOR TABLE D-2

1. Reactor Safety Study, WASH-1400.

2. Swain, A. D., and H. E. Guttman, Handbook of Human Reliability Analysis with Emphasis on Nuclear Power Applications, NUREG/CR-1278, April 1980.

3. Appendix C of the Shoreham Water Level System Report.

4. Engineering Judgment.

5. Appendix B of the Shoreham Water Level Measurement System Report.

6. Shoreham Nuclear Power Station Probabilistic Risk Assessment (Draft), Science Application, Inc., March 1982.

7. Shoreham Nuclear Power Station Probabilistic Risk Assessment (Draft), Fault Tree Quantification, March 1982.

8. Evaluated Sequence Dependent Event Functions.