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Evaluation of Potential Severe Accidents During Low Power and Shutdown Operations at Surry, Unit 1

Analysis of Core Damage Frequency from Internal Events During Mid-Loop Operations

Appendices A – D

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ABSTRACT

Traditionally, probabilistic risk assessments (PRA) of severe accidents in nuclear power plants have considered initiating events potentially occurring only during full power operation. Some previous screening analyses that were performed for other modes of operation suggested that risks during those modes were small relative to full power operation. However, more recent studies and operational experience have implied that accidents during low power and shutdown could be significant contributors to risk.

During 1989, the Nuclear Regulatory Commission (NRC) initiated an extensive program to carefully examine the potential risks during low power and shutdown operations. The program includes two parallel projects being performed by Brookhaven National Laboratory (BNL) and Sandia National Laboratories (SNL). Two plants, Surry (pressurized water reactor) and Grand Gulf (boiling water reactor), were selected as the plants to be studied.

The objectives of the program are to assess the risks of severe accidents initiated during plant operational states other than full power operation and to compare the estimated core damage frequencies, important accident sequences and other qualitative and quantitative results with those accidents initiated during full power operation as assessed in NUREG-1150. The scope of the program includes that of a level-3 PRA.

The objective of this volume of the report is to document the approach utilized in the level-1 internal events PRA for the Surry plant, and discuss the results obtained. A phased approach was used in the level-1 program. In phase 1, which was completed in Fall 1991, a coarse screening analysis examining accidents initiated by internal events (including internal fire and flood) was performed for all plant operational states (POSs). The objective of the phase 1 study was to identify potential vulnerable plant configurations, to characterize (on a high, medium, or low basis) the potential core damage accident scenarios, and to provide a foundation for a detailed phase 2 analysis.

In phase 2, mid-loop operation was selected as the plant configuration to be analyzed based on the results of the phase 1 study. The objective of the phase 2 study is to perform a detailed analysis of the potential accident scenarios that may occur during mid-loop operation, and compare the results with those of NUREG-1150. The scope of the level-1 study includes plant damage state analysis, and uncertainty analysis. Volume 1 summarizes the results of the study. Internal events analysis is documented in Volume 2. It also contains an appendix that documents the part of the phase 1 study that has to do with POSs other than mid-loop operation. Internal fire and internal flood analyses are documented in Volumes 3 and 4. A separate study on seismic analysis, documented in Volume 5, was performed for the NRC by Future Resources Associates, Inc. Volume 6 documents the accident progression, source terms, and consequences analysis.

In the phase 2 study, system models applicable for shutdown conditions were developed and supporting thermal hydraulic analysis were performed to determine both the timing of the accidents and success criteria for systems. Initiating events that may occur during mid-loop operations were identified and accident sequence event trees were developed and quantified. In the preliminary quantification of the mid-loop accident sequences, it was found that the decay heat at which the accident initiating event occurs is an important parameter that determines both the success criteria for the mitigating functions and the time available for operator actions. In order to better account for the decay heat, a "time window" approach was

developed. In this approach, time windows after shutdown were defined based on the success criteria established for the various methods that can be used to mitigate the accident. Within each time window, the decay heat and accident sequence timing are more accurately defined and new event trees developed and quantified accordingly. Statistical analysis of the past outage data was performed to determine the time at which a mid-loop condition is reached, and the duration of the mid-loop operation. Past outage data were used to determine the probability that an accident initiating event occurs in each of the time windows. This probability is used in the quantification of the accident sequences.

The mean core damage frequency of the Surry plant due to internal events that may take place during mid-loop operations is 5E-06 per year, and the 5th and 95th percentiles are 5E-07 and 2E-05 per year, respectively. This can be compared with the mean core damage frequency from internal events of 4E-05 per year estimated in the NUREG-1150 study for full power operations.

Contents

FOREWORD

(NUREG/CR-6143 and 6144)
Low Power and Shutdown Probabilistic Risk Assessment Program

Traditionally, probabilistic risk assessments (PRA) of severe accidents in nuclear power plants have considered initiating events potentially occurring only during full power operation. Some previous screening analysis that were performed for otl r modes of operation suggested that risks during those modes were small relative to full power operation. However, more recent studies and operational experience have implied that accidents during low power and shutdown could be significant contributors to risk.

During 1989, the Nuclear Regulatory Commission (NRC) initiated an extensive program to carefully examine the potential risks during low power and shutdown operations. The program includes two parallel projects performed by Brookhaven National Laboratory(BNL) and Sandia National Laboratories(SNL), with the seismic analysis performed by Future Resources Associates. Two plants, Surry (pressurized water reactor) and Grand Gulf (boiling water reactor), were selected as the plants to be studied.

The objectives of the program are to assess the risks of severe accidents due to internal events, internal fires, internal floods, and seismic events initiated during plant operational states other than full power operation and to compare the estimated core damage frequencies, important accident sequences and other qualitative and quantitative results with those accidents initiated during full power operation as assessed in NUREG-1150. The scope of the program includes that of a level-3 PRA.

The results of the program are documented in two reports, NUREG/CR-6143 and 6144. The reports are organized as follows:

For Grand Gulf:

NUREG/CR-6143 - Evaluation of Potential Severe Accidents during Low Power and Shutdown Operations at Grand Gulf

Volume 1:	Summary of Results
Volume 2:	Analysis of Core Damage Frequency from Internal Events for Operational State 5 During a Refueling Outage Part 1: Main Report Part 1A: Sections 1 - 9 Part 1B: Section 10 Part 1C: Sections 11 - 14 Part 2: Internal Events Appendices A to H Part 3: Internal Events Appendices I and J Part 4: Internal Events Appendices K to M
Volume 3:	Analysis of Core Damage Frequency from Internal Fire Events for Plant Operational State 5 During a Refueling Outage
Volume 4:	Analysis of Core Damage Frequency from Internal Flooding Events for Plant Operational State 5 During a Refueling Outage
Vol:me 5:	Analysis of Core Damage Frequency from Seismic Events for Plant Operational State 5 During a Refueling Outage

Foreword (continued)

	Volume 6:	Evaluation of Severe Accident Risks for Plant Operational State 5 During a Refueling Outage Part 1: Main Report Part 2: Supporting MELCOR Calculations

For Surry:

NUREG/CR-6144- Evaluation of Potential Severe Accidents during Low Power and Shutdown Operations at Surry Unit-1

Volume 1:	Summary of Results
Volume 2:	Analysis of Core Damage Frequency from Internal Events during Mid-loop Operations Part 1: Main Report Part 1A: Chapters 1 - 6 Part 1B: Chapters 7 - 12 Part 2: Internal Events Appendices A to D Part 3: Internal Events Appendix E Part 3A: Sections E.1 - E.8 Part 3B: Sections E.9 - E.16 Part 4: Internal Events Appendices F to H Part 5: Internal Events Appendix I
Volume 3:	Analysis of Core Damage Frequency from Internal Fires during Mid-loop Operations Part 1: Main Report Part 2: Appendices
Volume 4:	Analysis of Core Damage Frequency from Internal Floods during Mid-loop Operations
Volume 5:	Analysis of Core Damage Frequency from Seismic Events during Mid-loop Operations
Volume 6:	Evaluation of Severe Accident Risks during Mid-loop Operations Part 1: Main Report Part 2: Appendices

APPENDIX A

DATA BASE OF PLANT EXPERIENCE IDENTIFIED FOR INITIATING EVENT QUANTIFICATION

Appendix A

Data Base of Plant Experience Identified for Initiating Event Quantification

Appendix A.1 One Line Summary of All Events in the Data Base

PHASE 2 - LOSS OF RESIDUAL HEAT REMOVAL WHILE AT SHUTDOWN FOR PWRS

	PHASE 2 CAT	SSS CAT	PLANT NAME	DOCKET NO	EVENT DATE	LER	INITIAL PLANT CONDITION	RECOVERY TIME	NSAC52 CAT.	SEA-BROOK CAT.	AEOD	CR5015 CAT	GI99 CAT	LER SEARCH	NUREG 1410	APPLI-CABIL.
1			Byron 1	5000454	07/24/85	85-070-1	Mode 1			A-10						NA2
2			Davis Besse 1	5000346	06/05/78	78-063	Mode 5		A.7				E27			NA2
3			Maine Yankee	5000309	09/29/82	82-032	Mode 6			A-10						NA2
4			McGuire 1	5000369	02/07/81	81-010	Mode 6		A.5				E11			NA1,2
5			Palisades	5000255	06/22/84	84-007	Mode 5			A-1						NA2
6			Rancho Seco	5000312	05/26/83	83-023	Mode 6			A-10						NA2
7			Rancho Seco	5000312	07/25/89	009	Mode 5	1 hr 26 min						98		NA2
8			Salem 1	5000272	05/20/89	019	zero power	58 min						33	3.51	NA2
9			Three Mile Island	5000320	09/08/77		Mode 4 and 5		A.9				E40			NA1
10			Zion 1	5000295	09/10/82	82-028	Mode 1	Not actual failure		A-4						NA2
11			Zion 1	5000295	11/16/82	82-042	Mode 1	Not actual failure		A-4						NA2
12			Zion 1	5000295	06/09/83	83-018	Hot or cold shut.	Not actual failure		A-4						NA2
13	3b	3b	Braidwood 2	5000457	03/18/90	002	zero power	10 min						231		
14	3b	3b	Callaway 1	5000483	07/17/84	84-016	Mode 5			A-3		D.2				
15	3b	3b	Ginna	5000244	03/07/84	84-003	Mode 5			A-3		B.1				NA3
16	3b	3b	Maine Yankee	5000309	03/24/82	82-013	Mode 5			A-3						
17	3b	3b	McGuire 2	5000370	09/05/89	010	Mode 5	2 hr 51 min						179		
18	3b	3b	Rancho Seco	5000312	04/19/81	81-024	Mode 5		A.3				Da6			
19	3b	3b	Sequoyah 1	5000327	02/01/87	013	Mode 5							124		
20	3b	3b	St. Lucie 1	5000335	11/03/78	78-041	Mode 5	3.7 hr	A.3				Db1			
21	4KV	6b	Arkansas Nuclear 1	5000313	12/05/89	040, 1 of 2 events	CSD							103		
22	4KV	6b	Arkansas Nuclear 1	5000313	12/06/89	040, 2 of 2 events	CSD	9 min						103		
23	4KV	6b	Arkansas Nuclear 2	5000368	11/14/89	022	Shutdown	1 min						171		
24	4KV	4	Beaver Valley 1	5000334	07/03/79	79-018	Mode 5 or 6	21 min	A.6				E20			
25	4KV	5a	Beaver Valley 1	5000334	06/29/83	83-020	Mode 6	92 sec		A-6	AEOD-A		E10			NA1
26	4KV	5b	Catawba 1	5000413	01/07/89	001	Mode 5							193		
27	4KV	6a	Crystal River 3	5000302	08/28/89	031	Mode 5	19 min						77		
28	4KV	6b	Davis Besse 1	5000346	05/28/78	78-060	Mode 6	1.5 min	A.6		AEOD-C		E15			

PHASE 2 - LOSS OF RESIDUAL HEAT REMOVAL WHILE AT SHUTDOWN FOR PWRS

	PHASE 2 CAT	SSS CAT	PLANT NAME	DOCKET NO	EVENT DATE	LER	INITIAL PLANT CONDITION	RECOVERY TIME	NSAC52 CAT.	SEA-BROOK CAT.	AEOD	CR5015 CAT	GI99 CAT	LER SEARCH	NUREG 1410	APPLI-CABIL.
29	4KV	6b	Davis Besse 1	5000346	06/15/78	78-067	Cold shut.	2 min (total of 3 events)	A.6		AEOD-C		E16			
30	4KV	6b	Ft. Calhoun	5000285	12/14/85	85-011	Refueling shut.	15 min				E.5				
31	4KV	6b	McGuire 1	5000369	11/29/88	038	zero power							174		
32	4KV	6b	Millstone 2	5000336	12/09/81	81-043	Mode 5	30-60 min	A.6				E25			
33	4KV	6b	North Anna 1	5000338	03/23/89	006	Mode 5	10 sec						150		
34	4KV	6b	North Anna 1	5000338	04/16/89	010	Mode 5							151		
35	4KV	6b	North Anna 2	5000338	04/16/89	010, inferred from LER	Mode 5							151		
36	4KV	1	Rancho Seco	5000312	12/08/86	86-030	Mode 5			A-1		A.4				
37	4KV	2b	Salem 1	5000272	04/24/79	79-059	Mode 6	2 min (second event on 05/08/79)	A.6				E18			
38	4KV	2b	Salem 1	5000272	05/08/79	79-059	Mode 6	4 min (1st event on 04/24/79)	A.6				E18			
39	4KV	10	Salem 1	5000272	03/16/82	82-015		45 min			AEOD-A		E2			
40	4KV	1	Salem 2	5000311	12/20/83	83-066	Mode 5	22 min		A-1	AEOD-A		A7			
41	4KV	6b	Surry 1	5000280	05/24/86	86-017	Mode 6			A-6		E.3				
42	4KV	6b	Three Mile Island	5000289	01/09/87	001	Refueling shutdown							64		
43	4KV	6b	Wolf Creek		10/16/87			17 min							1.34	
44	4KV/P6	4	Calvert Cliffs 1	5000317	11/12/80	80-058	Mode 5 or 6	10 min	A.4				E6			
45	4KV/P6	1	Diablo Canyon 1	5000275	01/25/85	85-006	Mode 5	2 min		A-1		A.6				
46	4KV/P6	6b	Farley 1	5000348	01/16/81	81-001	Shutdown	1 min	A.6				E23			
47	4KV/P6	6b	North Anna 2	5000339	04/08/83	83-031	Mode 5			A-6						
48	4KV/P6	6b	Salem 1	5000272	01/04/83	83-001	Modes 4 and 5			A-6			A12			
49	4KV/P6	6b	Salem 2	5000311	04/13/83	83-014, 1 of 2 events	Mode 5	< 1 min		A-6						
50	4KV/P6	6b	Salem 2	5000311	04/18/83	83-014, 2 of 2 events	Mode 5	< 1 min		A-6						

PHASE 2 - LOSS OF RESIDUAL HEAT REMOVAL WHILE AT SHUTDOWN FOR PWRS

PHASE 2 CAT	SSS CAT	PLANT NAME	DOCKET NO	EVENT DATE	LER	INITIAL PLANT CONDITION	RECOVERY TIME	NSAC52 CAT.	SEA-BROOK CAT.	AEOD	CR5015 CAT	G199 CAT	LER SEARCH	NUREG 1410	APPLI-CABIL.
51 4KV/P6	6b	Surry 1	5000280	02/04/89	005, Unit 2 event also	Mode 5	3 min						44		
52 4KV/P6	6b	Surry 1	5000280	04/06/89	010, Unit 2 event also	Mode 5	1 min						47		
53 4KV/P6	6b	Surry 2	5000280	02/04/89	005 (descr in Surry 1)	Mode 5							44		
54 4KV/P6	6b	Surry 2	5000280	04/06/89	010 (descr in Surry 1)	Mode 5	1 min						47		
55 4KV/P6	6b	Zion 2	5000304	01/17/86	86-005-1	Mode 5			A-6		E.9				
56 AIR		Beaver Valley 1	5000334	08/29/85	85-015	Mode 1	10 min						12		
57 AIR		Callaway	5000483	11/05/84	84-059	Mode 1	20 min						35		
58 AIR		Calvert Cliffs 1	5000317	01/27/87	87-003	Mode 1	20 min						2		
59 AIR		Catawba 1	5000413	01/14/85	85-004	Mode 2	15 min						51		
60 AIR		Cook 1	5000315	11/25/85	NPE	Mode 1	20 min			2969					
61 AIR		Davis Besse 1	5000346	12/07/87	87-015	Mode 1	31 min						62		
62 AIR		McGuire 1	5000369	11/02/85	85-034	Mode 1	20 min						179		
63 AIR		Millstone 3	5000423	04/12/87	87-020	Mode 1	20 min						1		
64 AIR	10	North Anna 2	5000339	04/03/89	89-007	Mode 6	22 min						153		NA
65 AIR		Oconee 3	5000287	08/14/84	84-005	Mode 1	20 min						1		
66 AIR		Prairie Island 1	5000282	05/08/85	85-009	Mode 1	20 min						246		
67 AIR		Shearon Harris 1	5000400	08/04/87	87-041	Mode 1	20 min						245		
68 AIR		Surry 1	5000280	01/07/86	86-001	Mode 1	10 min						287		
69 AIR		Yankee Rowe	5000029	10/04/86	86-012	Mode 1	10 min						305		
70 CCW	10	Braidwood 1	5000456	01/21/87	011	zero power	14 min						226		
71 CCW	10	Byron 1	5000454	04/08/87	012	zero power	17 min						222		
72 CCW	10	Maine Yankee	5000309	06/02/81	81-007	Mode 6	30 min	A.10				E47			
73 CCW	10	Salem 2	5000311	06/23/83	83-032					AEOD-A		E5			NA
74 CCW	10	Turkey Point 3	5000250	10/07/83	83-018					AEOD-A		E1			
75 DIL	TRANS	Surry 2	281	10/25/89	015	CSD									
76 ESFAS	6b	Arkansas Nuclear 2	5000368	04/23/88	007	Mode 5	5 min						168		NA3
77 ESFAS	4	Calvert Cliffs 1	5000317	05/07/79	79-015	Shutdown	15 min	A.4				E5			NA3
78 ESFAS	4	Calvert Cliffs 1	5000317	11/03/80	80-062 - 2 of 3 events	Mode 6		A.4				E7			NA3

PHASE 2 - LOSS OF RESIDUAL HEAT REMOVAL WHILE AT SHUTDOWN FOR PWRS

PHASE 2 CAT	SSS CAT	PLANT NAME	DOCKET NO	EVENT DATE	LER	INITIAL PLANT CONDITION	RECOVERY TIME	NSAC52 CAT.	SEA-BROOK CAT.	AEOD	CR5015 CAT	G199 CAT	LER SEARCH	NUREG 1410	APPLI-CABIL.
79 ESFAS	4	Calvert Cliffs 1	5000317	11/03/80	80-062 - 1 of 3 events	Mode 6		A.4				E7			NA3
80 ESFAS	4	Calvert Cliffs 1	5000317	11/04/80	80-062 - 3 of 3 events	Mode 6		A.4				E7			NA3
81 ESFAS	4	Calvert Cliffs 2	5000318	09/24/78	78-033	Mode 5 or 6	23 min	A.4				E4			NA3
82 ESFAS	4	Calvert Cliffs 2	5000318	01/07/83	83-005		9 min			AEOD-A		E8			NA3
83 ESFAS	6b	Cook 1	5000315	09/07/85	85-046	Mode 5	2 min		A-1		E.10				
84 ESFAS	1	Davis Besse	5000346	05/14/77	77-006					AEOD-C					
85 ESFAS	1	Davis Besse	5000346	05/19/77	77-007					AEOD-C					
86 ESFAS	1	Davis Besse	5000346	05/27/77	77-002					AEOD-C					
87 ESFAS	1	Davis Besse	5000346	05/28/77	77-003					AEOD-C					
88 ESFAS	1	Davis Besse	5000346	06/12/77	77-005					AEOD-C					
89 ESFAS	1	Davis Besse 1	5000346	04/19/80	80-029	Mode 6	2 hr 30 min	A.1, A.4		AEOD-C		A11, E1			
90 ESFAS	4	Davis Besse 1	5000346	06/14/80	80-049	Mode 6	2 min	A.4		AEOD-C		E2			
91 ESFAS	1	Davis Besse 1	5000346	07/24/80	80-058, 1 of 2 events	Mode 5	50 min	A.1		AEOD-C		A14			
92 ESFAS	1	Davis Besse 1	5000346	07/24/80	80-058, 2 of 2 events	Mode 5	2 min	A.1		AEOD-C		A15			
93 ESFAS	1	Davis Besse 1	5000346	08/01/80	80-058, 8/3/80 in descrip	Mode 5	3 min	A.1				A16			
94 ESFAS	1	Davis Besse 1	5000346	08/13/80	80-060	Mode 5	5 min	A.1		AEOD-C		A17			
95 ESFAS	1	Diablo Canyon 1	5000275	09/08/86	86-012	Mode 5	2 min		A-1		A.7				
96 ESFAS	1	Farley 1	5000348	09/18/78	78-069	Mode 5	7 min	A.1				A6			
97 ESFAS	1	North Anna 1	5000338	11/06/79	79-145	Mode 6	5 min	A.1				A9			
98 ESFAS	1	Salem 1	5000272	09/02/76	76-004	Mode 6	19 min	A.1				A1			
99 ESFAS	6b	Salem 2	5000311	06/23/83	83-031, 2 of 2 events	Mode 5			A-6	AEOD-A		E4			
100 ESFAS	6b	Salem 2	5000311	06/23/83	83-031, 1 of 2 events	Mode 5			A-6	AEOD-A		E4			
101 ESFAS	1	Sequoyah 1	5000327	09/16/82	82-116	Mode 5	6 min		A-1	AEOD-A		A13			
102 ESFAS	1	Summer	5000395	10/02/84	84-044	Mode 5	immediately		A-1		A.18				
103 ESFAS	LTOP	Surry 1	280	11/13/84	023	Refueling SD									NA

PHASE 2 - LOSS OF RESIDUAL HEAT REMOVAL WHILE AT SHUTDOWN FOR PWRS

	PHASE 2 CAT	SSS CAT	PLANT NAME	DOCKET NO	EVENT DATE	LER	INITIAL PLANT CONDITION	RECOVERY TIME	NSAC52 CAT.	SEA-BROOK CAT.	AEOD	CR5015 CAT	G199 CAT	LER SEARCH	NUREG 1410	APPLI-CABIL.
104	ESFAS	4	Surry 2	281	08/18/89	004	0%, Unit 2 CSD							384*		
105	ESFAS	1	Trojan	5000344	03/20/78	78-010	Mode 5		A.1				A4			
106	ESFAS/SI	LTOP	Surry 1	280	04/26/80	024	CSD Maintenance									
107	ESFAS/SI	TRANS	Surry 1	280	03/01/84	005; loss of 2 vital bus'	CSD									
108	ESFAS/SI	LTOP	Surry 1	280	11/16/84	024	Refueling SD									
109	ESFAS/SI	LTOP	Surry 1	280	05/11/86	014	Shutdown									
110	ESFAS/SI	LTOP	Surry 1	280	06/05/89	022	CSD									
111	ESFAS/SI	LTOP	Surry 2	281	06/12/85	007	Refueling SD									
112	ESFAS/SI	LTOP	Surry 2	281	11/16/86	016	CSD									
113	ESFAS/SI	4	Surry 2	281	09/08/89	005	0%; Unit 2 CSD							385*		
114	HCVCS	HCVCS	Turkey Point 3	250	01/15/88	002	being cooled down									
115	HRHR	HRHR	Catawba 1	413	06/11/90	013	CSD (Mode 5)									
116	HRHR	HRHR	Sequoyah 1	327	02/11/81	021			A.3				Db2			
117	HRHR	HRHR	Sequoyah 2	328	08/06/81	094			A.3,A.4				E3			NA1
118	JCVCS	JCVCS	Robinson 2	261	01/29/81	005										
119	JCVCS	JCVCS	Waterford 3	382	12/16/85	057	plnt heatup									
120	JCVCS	JCVCS	Yankee Rowe	029	06/27/86	010	Mode 5, Maint Out					D.1				
121	JRHR	JRHR	Braidwood 1	456	03/25/88	008	0% power level									
122	JRHR	JRHR	Braidwood 1	456	12/01/89	016	0% power level									
123	JRHR	JRHR	McGuire 2	370	08/05/84	017	0% power level									
124	JRHR	JRHR	Summer 1	395	05/06/85	014	CSD (Mode 5)					A.20				
125	KRCS	KRCS	North Anna 1	338	06/17/87	014	0% power, refuel.									
126	KRCS	KRCS	Trojan	344	07/03/81	013										

PHASE 2 - LOSS OF RESIDUAL HEAT REMOVAL WHILE AT SHUTDOWN FOR PWRS

PHASE 2 CAT	SSS CAT	PLANT NAME	DOCKET NO	EVENT DATE	LER	INITIAL PLANT CONDITION	RECOVERY TIME	NSAC52 CAT.	SEA-BROOK CAT.	AEOD	CR5015 CAT	G199 CAT	LER SEARCH	NUREG 1410	APPLI-CABIL.
127 LOOP		Connecticut Yankee	5000213	08/24/84	84-014	0% power	20 min				E.1				LOOP
128 LOOP		Ft. Calhoun 1	5000285	03/21/87	008	Refueling cond.	40 min						53		LOOP
129 LOOP		Indian Point 3	5000286	11/16/84	84-015	Mode 5					E.6				LOOP
130 LOOP		McGuire 1	5000369	09/16/87	021	zero power	29 min						173		LOOP
131 LOOP	6b	Oconee 3	5000287	09/11/88	005	Mode 5	15 min						62	1.35	
132 LOOP	6b	Salem 1	5000272	06/02/84	84-013, 1 of 2 events	Mode 6	30 sec		A-6		E.2				
133 LOOP	6b	Salem 2	5000272	06/02/84	84-013, 2 of 2 events	Mode 5	30 sec		A-6		E.2				
134 LOOP		San Onofre 1	5000206	04/22/80	80-015	Mode 5	4 min	A.6				E21			LOOP
135 LOOP	2b	Vogtle 1	5000424	03/20/90	006	Refueling outage	36 min						207		
136 RHR1	1	Beaver Valley 1	5000334	05/21/80	80-031	Mode 5		A.1				A12			
137 RHR1	1	Braidwood 2	5000457	02/23/89	001	zero power	43 min						230		
138 RHR1	1	Calvert Cliffs 1	5000317	10/12/83	83-061	Mode 6	30 min		A-1	AEOD-A		A9			
139 RHR1	1	Calvert Cliffs 1		10/23/83			40 min							3.23	
140 RHR1	1	Calvert Cliffs 1	5000317	03/22/86	86-002	Mode 5	1 min				A.13				
141 RHR1	1	Calvert Cliffs 2	5000318	10/22/79	79-038	Mode 5	3 min	A.1				A8			
142 RHR1	1	Catawba 1	5000413	08/15/86	86-044-1	Mode 5	15 min		A-1		A.21				
143 RHR1	1	Crystal River 3	5000302	03/06/80	80-015	Mode 5	8 min	A.1				A10			
144 RHR1	1	Crystal River 3	5000302	10/23/88	022	Mode 5							74		
145 RHR1	1	Davis Besse	5000346	07/22/77	77-009 (two events)					AEOD-C					
146 RHR1	1	Davis Besse	5000346	08/08/80	80-058		3 min			AEOD-C					
147 RHR1	1	Davis Besse 1	5000346	05/28/80	80-043	Mode 6	2 min	A.1		AEOD-C		A13			
148 RHR1	1	Diablo Canyon 1	5000275	09/29/81	84-004	Modes 4/5/6	5 min		A-1						
149 RHR1	1	Diablo Canyon 1	5000275	10/27/83	84-004	Modes 4/5/6	1 hr		A-1						
150 RHR1	1	Diablo Canyon 1	5000275	01/20/85	85-005	Mode 5	9 min		A-1		A.5				
151 RHR1	1	Farley 1	5000348	09/18/78	78-069	Mode 5	3 min	A.1				A6			
152 RHR1	1	Farley 1	5000348	11/28/80	80-077	Mode 5	4 min	A.1				A18			
153 RHR1	1	Farley 1	5000348	12/25/80	80-080	Mode 6	5 min	A.1				A19			
154 RHR1	1	Farley 1	5000348	05/06/85	85-008	Mode 5	47 min		A-1		A.16				

PHASE 2 - LOSS OF RESIDUAL HEAT REMOVAL WHILE AT SHUTDOWN FOR PWRS

	PHASE 2 CAT	SSS CAT	PLANT NAME	DOCKET NO	EVENT DATE	LER	INITIAL PLANT CONDITION	RECOVERY TIME	NSAC52 CAT.	SEA-BROOK CAT.	AEOD	CR5015 CAT	G199 CAT	LER SEARCH	NUREG 1410	APPLI-CABIL.
155	RHR1	1	Ft. Calhoun 1	5000285	01/08/89	001	Refueling cond.	5 min						59		
156	RHR1	1	Indian Point 3	5000286	09/30/76	76-3-36(A)	Mode 5	8 min	A.1				A3			
157	RHR1	1	McGuire 1	5000369	04/27/81	81-072	Mode 5	15 min	A.1				A21			NA1
158	RHR1	1	McGuire 1	5000369	08/04/81	81-129	Mode 5	15 min	A.1				A22			NA1
159	RHR1	1	McGuire 1	5000369	11/18/81	81-185	Mode 5	22 min	A.1				A23			NA1
160	RHR1	1	McGuire 2	5000370	01/15/84	84-002	Mode 5	49 min		A-1	AEOD-B	A.17				
161	RHR1	1	North Anna 2	5000339	04/23/80	80-001	Mode 6		A.1				A11+			NA1
162	RHR1	1	North Anna 2	5000339	04/14/83	83-023	Mode 6	< 1 min		A-1	AEOD-A		A17			
163	RHR1	1	Rancho Seco	5000312	08/08/85	85-016	Mode 5					A.10				
164	RHR1	1	Rancho Seco	5000312	08/14/85	85-016	Mode 5					A.10				
165	RHR1	1	Rancho Seco	5000312	07/15/87	038	Mode 5	40 min						93		
166	RHR1	1	Rancho Seco	5000312	02/28/89	002	Mode 5	10 min						97		
167	RHR1	1	Salem 1	5000272	09/20/76	76-005	Mode 5	30 min	A.1				A2			
168	RHR1	1	Salem 2	5000311	05/14/83	83-024, 2 of 2 events					AEOD-A		A5			
169	RHR1	1	Salem 2	5000311	02/09/84	84-002	Mode 5	17 min		A-1	AEOD-B	A.9				
170	RHR1	1	Seabrook 1	5000443	10/11/89	012	zero power	50 min						217		NA1
171	RHR1	1	Sequoyah 1	5000327	05/14/85	85-020	Mode 5	16 min		A-1		A.15				
172	RHR1	1	Shearon Harris 1	5000400	10/15/87	060	Mode 5	5 min, 15 min						185		
173	RHR1	1	Shearon Harris 1	5000400	12/10/89	022	Mode 5	3 min						186		
174	RHR1	1	St. Lucie 1	5000335	03/29/83	83-021		10 min		A-1	AEOD-A		A14			
175	RHR1	1	Summer	5000395	09/16/82	82-002				A-1						
176	RHR1	1	Summer	5000395	10/15/82	82-004	Mode 5	1 min		A-1						
177	RHR1	1	Turkey Point 3	5000250	10/08/83	83-019	Mode 6	6 min		A-1	AEOD-A		A2			
178	RHR1	1	Turkey Point 3	5000250	10/25/85	85-036	Mode 5	27 min		A-1		A.1				
179	RHR1	1	Turkey Point 3	5000250	11/21/88	029	Cold shutdown	4 min						16		
180	RHR1	1	Turkey Point 4	5000251	11/28/81	81-015, 1 of 2 events	Mode 5	2 min	A.1				A24			
181	RHR1	1	Turkey Point 4	5000251	11/29/81	81-015, 2 of 2 events	Mode 5	1 min	A.1				A25			
182	RHR1	1	Turkey Point 4	5000251	11/30/84	84-027	Mode 6	4 min		A-1		A.2				

PHASE 2 - LOSS OF RESIDUAL HEAT REMOVAL WHILE AT SHUTDOWN FOR PWRS

PHASE 2 CAT	SSS CAT	PLANT NAME	DOCKET NO	EVENT DATE	LER	INITIAL PLANT CONDITION	RECOVERY TIME	NSAC52 CAT.	SEA-BROOK CAT.	AEOD	CR5015 CAT	GI99 CAT	LER SEARCH	NUREG 1410	APPLI-CABIL.
183 RHR2A	2a	Arkansas Nuclear 2	5000368	08/29/84	84-023	Mode 5				AEOD-B	B.5				
184 RHR2A	2a	Catawba 1	5000413	04/22/85	85-028	Mode 5	12 min		A-2		B.8				
185 RHR2A	2a	Cook 2		06/16/88			22 min							3.46	
186 RHR2A	2a	Davis Besse 1	5000346	04/18/80	80-030	Mode 5	29 min	A.3		AEOD-C		Da3			
187 RHR2A	2a	Ginna	5000244	04/12/83	83-015	Mode 6	12 min		A-2	AEOD-A		C1			
188 RHR2A	2a	McGuire 1	5000369	03/02/82	82-024	Mode 5	50 min		A-2	AEOD-A		B7			
189 RHR2A	2a	McGuire 1	5000369	04/05/83	83-017	Mode 6			A-2	AEOD-A		B8			
190 RHR2A	2a	McGuire 2	5000370	12/31/83	83-092	Mode 5	43 min		A-2	AEOD-A		B9			
191 RHR2A	2a	McGuire 2	5000370	01/09/84	84-001	Mode 5	62 min		A-2	AEOD-B	B.6				
192 RHR2A	2a	North Anna 2	5000339	05/20/82	82-026		8 min		A-2	AEOD-A		B5			
193 RHR2A	2a	North Anna 2	5000339	05/20/82	82-026		26 min		A-2	AEOD-A		B4			
194 RHR2A	2a	North Anna 2	5000339	05/20/82	82-026		1 hr		A-2	AEOD-A		B3			
195 RHR2A	2a	North Anna 2	5000339	05/03/83	83-038	Mode 6			A-2	AEOD-A		C5			
196 RHR2A	2a	North Anna 2	5000339	10/16/84	84-008-1	Mode 5	2 hr		A-2	AEOD-B	B.3				
197 RHR2A	2a	San Onofre 2	5000361	03/26/86	86-007	Mode 5	49 min				B.4				
198 RHR2A	2a	Sequoyah 2	5000328	08/06/83	83-101	Mode 6	77 min		A-2	AEOD-A		C3			Mode 10
199 RHR2A	2a	Trojan	5000344	03/25/78	78-011, 1 of 2 events	Mode 5	10 min	A.2				B1			
200 RHR2A	2a	Trojan	5000344	03/25/78	78-011, 2 of 2 events	Mode 5	10 min	A.2				B2			
201 RHR2A	2a	Trojan	5000344	06/26/81	81-012	Mode 5	75 min	A.2				B4			
202 RHR2A	2a	Waterford	5000382	03/14/86	86-004	Mode 5	1 hr 19 min				E.11				
203 RHR2A	2a	Waterford	5000382	07/14/86	86-015	Mode 5	3 hr 41 min				B.7				
204 RHR2A	2a	Waterford 3		05/12/88										3.45	
205 RHR2A	2a	Zion 1	5000295	09/14/84	84-031	Mode 5	45 min		A-2	AEOD-B	B.2				
206 RHR2B	2b	Beaver Valley 1	5000334	09/04/78	78-049		1 hr	A.2				C3			
207 RHR2B	2b	Beaver Valley 1	5000334	01/17/80	80-002	Mode 5		A.2				C5			
208 RHR2B	2b	Beaver Valley 1	5000334	04/08/80	80-022	Mode 5	35 min	A.2				C6			
209 RHR2B	2b	Beaver Valley 1	5000334	04/11/80	80-023	Mode 5	70 min	A.2				C7			
210 RHR2B	2b	Beaver Valley 1	5000334	03/05/81	81-019	Mode 5	54 min	A.2				C8			
211 RHR2B	2b	Byron 1	5000454	09/19/88	007	Mode 6	14 min						224		
212 RHR2B	2b	Cook 2	5000316	05/21/84	84-014	Mode 5	25 min		A-2	AEOD-B	C.2				
213 RHR2B	2b	Diablo Canyon 2	5000323	04/10/87	005	Mode 5	1 hr 28 min						116		

PHASE 2 - LOSS OF RESIDUAL HEAT REMOVAL WHILE AT SHUTDOWN FOR PWRS

PHASE 2 CAT	SSS CAT	PLANT NAME	DOCKET NO	EVENT DATE	LER	INITIAL PLANT CONDITION	RECOVERY TIME	NSAC52 CAT.	SEA-BROOK CAT.	AEOD	CR5015 CAT	GI99 CAT	LER SEARCH	NUREG 1410	APPLI-CABIL.
214 RHR2B	2b	Millstone 2	5000336	03/14/79	79-008	Mode 5		A.2				C4			
215 RHR2B	2b	North Anna 1	5000338	10/19/82	82-067	Mode 6	36 min		A-2	AEOD-A		B1			
216 RHR2B	2b	North Anna 1	5000338	10/20/82	82-067	Mode 6	33 min		A-2	AEOD-A		B2			
217 RHR2B	2b	North Anna 2	5000339	07/17/82	82-049	Mode 5			A-2						
218 RHR2B	2b	North Anna 2	5000339	07/30/82	82-049		46 min			AEOD-A		B6			
219 RHR2B	2b	Palisades	5000255	10/15/87	035	Cold shutdown	29 min						22	3.44	
220 RHR2B	2b	Ringhals 4		08/23/84			26 min							3.30	NA1
221 RHR2B	2b	Salem 1	5000272	06/30/79	79-059	Mode 6	34 min	A.2				B3			
222 RHR2B	2b	Sequoyah 1	5000327	10/09/85	85-040	Mode 5			A-2		C.3				
223 RHR2B	2b	Sequoyah 1	5000327	01/28/87	012	Mode 5	30 min						123	3.40	
224 RHR2B	2b	Sequoyah 1	5000327	05/23/88	021	Mode 5							134		
225 RHR2B	2b	Surry 1	5000280	05/17/83	83-024	Mode 5			A-2	AEOD-A		C2			
226 RHR2B	2b	Trojan	5000344	05/21/77	77-016	Mode 5	55 min	A.2				C1			
227 RHR2B	2b	Trojan	5000344	04/17/78	78-011	Mode 6		A.2				C2			
228 RHR2B	2b	Trojan	5000344	05/04/84	84-010-1	Mode 5	40 min		A-2	AEOD-B					
229 RHR2B	2b	Zion 2	5000304	12/14/85	85-028	Mode 5	75 min				C.1				
230 RHR2B	2b	Zion 2	5000304	01/13/86	85-028	Mode 5	75 min		A-2						
231 RHR3	3a2	Arkansas 2	5000368	11/14/79	79-087	Mode 5	3 hr	A.7				E28			
232 RHR3	9	Calvert Cliffs 2	5000318	10/17/78	78-035	Mode 5	2 hr	A.10				E45			
233 RHR3	3a2	Calvert Cliffs 2	5000318	03/24/87	003	Mode 6	15 hr 20 min						113		
234 RHR3	3a2	Calvert Cliffs 2	5000318	05/07/87	004	Mode 5	16 hr 55 min						114		
235 RHR3		Crystal River 3	5000302	02/12/86		Mode 5									
236 RHR3	5b	Davis Besse 1	5000346	07/10/80	80-057	Mode 6		A.5				E9			NA3
237 RHR3	3a2	Diablo Canyon	5000275	06/25/88	017	Mode 5							34		NA2
238 RHR3	6a	Farley 2	5000364	09/28/83	83-042	Mode 6			A-6	AEOD-A		E11			
239 RHR3	5b	McGuire 1	5000369	04/28/81	81-073	Mode 5	20 min	A.8				E37			NA1
240 RHR3	9	McGuire 1	5000369	06/02/81	IE Circ. 81-10 07/02/81	Mode 5		A.9				E42			NA1
241 RHR3	11	McGuire 2	5000370	03/07/83	83-002	Mode 6	3 hr		A-10						Mode 8
242 RHR3	5b	Palisades	5000255	01/08/78	78-003	Mode 5	45 min	A.5				E8			
243 RHR3	3a2	Palo Verde	5000528	03/19/88	022	Mode 6							247		LEAK
244 RHR3	5b	Salem 2	5000311	04/13/81	81-005	Mode 5	5 hr 22 min	A.7				E33			

PHASE 2 - LOSS OF RESIDUAL HEAT REMOVAL WHILE AT SHUTDOWN FOR PWRS

PHASE 2 CAT	SSS CAT	PLANT NAME	DOCKET NO	EVENT DATE	LER	INITIAL PLANT CONDITION	RECOVERY TIME	NSAC52 CAT.	SEA-BROOK CAT.	AEOD	CR5015 CAT	GI99 CAT	LER SEARCH	NUREG 1410	APPLI-CABIL.
245 RHR3	3a2	Zion 1	5000295	01/04/90	001	Mode 3	7 hr 47 min						70		
246 RHR4	6a	Arkansas 2	5000368	08/16/78	78-001	Mode 5	2.8 hr	A.6				E17			NA1
247 RHR4		Arkansas 2	5000368	01/01/79	79-086	Mode 5									
248 RHR4	3a1	Arkansas 2	5000368	10/13/79	79-086	Mode 6		A.10				E46			
249 RHR4	3a1	Arkansas 2	5000368	01/09/83	83-003	Mode 5			A-10						
250 RHR4	3a1	Calvert Cliffs 1	5000317	01/24/78	78-004, 78-011	Mode 4 and 5		A.10				E44			
251 RHR4	6a	Crystal River 3	5000302	04/25/78	78-020	Cold shut.		A.6				E14			
252 RHR4	6a	Crystal River 3	5000302	02/02/86	86-003	Mode 5	24 min		A-6		E.8				
253 RHR4	3c	Farley 2	5000364	11/27/87	008	Refueling outage							167		
254 RHR4	5a	McGuire 1	5000369	02/05/81	81-009	Mode 6	3 hr	A.5				E10			NA1
255 RHR4	9	McGuire 1	5000369	11/23/88	049	Mode 6	39 min						175		
256 RHR4	6a	North Anna 1	5000338	06/14/82	82-043	Mode 5			A-6						
257 RHR4	6a	North Anna 2		08/02/82										3.17	
258 RHR4	6a	North Anna 2	5000339	08/16/82	82-050	Mode 5			A-6						
259 RHR4	3a1	North Anna 2	5000339	05/22/83	83-042	Mode 4	30 min		A-10						NA
260 RHR4	6a	Rancho Seco	5000312	05/05/82	82-012	Mode 5			A-6						
261 RHR4	3a1	Salem 1	5000272	12/13/82	82-089	Mode 6			A-6						
262 RHR4	3a1	San Onofre	5000361	08/31/87	014	Mode 5	18 hr						16.		
263 RHR4	3a1	Trojan	5000344	04/25/78	78-017	Mode 5	1 min	A.3				Da1			
264 RHR4	6a	Turkey Point 3	5000250	10/23/85	85-034	Mode 5			A-7						
265 RHR5	5b	Arkansas Nuclear 1	5000313	10/26/88	014	Mode 6	23 min						100	3.50	
266 RHR5	5b	Arkansas Nuclear 1	5000313	12/19/88	024	zero power	12 min						101		
267 RHR5	5a	Beaver Valley 1	5000334	05/12/82	82-018	Mode 5	2 min		A-6	AEOD-A		E9			
268 RHR5	3c	Calvert Cliffs 1	5000317	02/08/80	80-011	Mode 5	1 hr 33 min	A.3				Da2			Closed
269 RHR5	6b	Calvert Cliffs 1	5000317	05/17/82	82-026		2 min			AEOD-A		E6			
270 RHR5	5b	Calvert Cliffs 2	5000318	01/23/81	81-003	Mode 6	5 min	A.7				E32			
271 RHR5		Connecticut Yankee	5000317	03/05/88		Mode 5	1 hr 2 min								
272 RHR5	6b	Connecticut Yankee	5000317	03/10/88	007	Mode 5	1 hr 22 min						6		
273 RHR5	6b	Cook 2	5000316	12/09/82	82-109	Mode 6			A-6						
274 RHR5	6b	Crystal River 3	5000302	07/16/80	IE Info Notice 81-10	Mode 5	21 min	A.3, A.7				Da5, E31			
275 RHR5	9	Crystal River 3	5000302	04/21/81	IE Circ. 81-10,	Mode 5	Similar event	A.9				E41			

PHASE 2 - LOSS OF RESIDUAL HEAT REMOVAL WHILE AT SHUTDOWN FOR PWRS

	PHASE 2 CAT	SSS CAT	PLANT NAME	DOCKET NO	EVENT DATE	LER	INITIAL PLANT CONDITION	RECOVERY TIME	NSAC52 CAT.	SEA-BROOK CAT.	AEOD	CR5015 CAT	GI99 CAT	LER SEARCH	NUREG 1410	APPLI-CABIL.
						07/02/81		10/01/81								
276	RHR5		Crystal River 3	5000302	10/01/81		Mode 5									
277	RHR5	6b	Davis Besse 1	5000346	05/31/80	80-044	Mode 6	8 min	A.7		AEOD-C		E29			
278	RHR5	6b	Davis Besse 1	5000346	04/18/81	81-024	Mode 5	1 min (2 min in AEOD-C)	A.6		AEOD-C		E24			
279	RHR5	6b	Farley 1	5000348	03/07/83	83-009	Mode 6			A-6						
280	RHR5	3c	Farley 1	5000348	11/07/86	86-020	Mode 5			A-3						Mode 12
281	RHR5		Farley 1	5000348	11/15/86		Mode 5									
282	RHR5	6b	Ft. Calhoun	5000285	10/19/77	77-023	Mode 6		A.7				E26			
283	RHR5	5a	Ginna	5000244	05/01/83	83-017	Mode 5			A-6	AEOD-A		A1			
284	RHR5	3a2	Indian Point 3	5000286	05/12/83	83-002	Mode 5			A-10						
285	RHR5	5b	Maine Yankee	5000309	06/10/81	81-008	Mode 6	5 min	A.5				E12			
286	RHR5	11	Millstone 3	5000423	06/08/87	030	Mode 5	33 min						199		
287	RHR5	3a2	North Anna 1	5000338	06/01/80	80-053	Mode 5	34 min	A.3, A.7				Da4, E30			
288	RHR5	6b	North Anna 1	5000338	02/18/83	83-009	Mode 5	5 min		A-10	AEOD-A		C4			
289	RHR5	9	Oconee 1	5000269	06/29/81	Duke ltr to NRC 07/31/81	Mode 5		A.9				E43			
290	RHR5	3a2	Oconee 3	5000287	04/06/87	005	Mode 5							61		
291	RHR5	5b	Palisades	5000255	07/18/81	81-030	Mode 5	1 hr 30 min	A.5				E13			
292	RHR5	4	Rancho Seco	5000312	10/03/86	86-016	Mode 5	13 min				A.11				
293	RHR5	3a2	Robinson	5000261	06/11/87	014	zero power							27		
294	RHR5	3c	Salem 2	5000311	06/12/81	81-041	Mode 4	1 hr 5 min	A.3				Da7			
295	RHR5	6b	Salem 2	5000311	05/24/83	83-025	Mode 5			A-6	AEOD-A		E3			
296	RHR5	9	San Onofre 2	5000361	03/14/82	82-002	Mode 6	90 min		A-10						
297	RHR5	6b	Summer	5000395	11/06/84	IE Daily Report		7 min			AEOD-B					
298	RHR5	10	Surry 1	5000280	03/18/89	009	zero power	11 hr 28 min						46		
299	RHR5	10	Surry 2	5000281	02/19/86	86-004	Mode 5	10 min				E.4				
300	RHR5	7	Vogtle 1	5000424	03/18/87	055	Mode 3							205		NA2
301	RHR6	8	Beaver Valley 1	5000334	05/03/81	81-048	Mode 4		A.8				E38			
302	RHR6	8	Crystal River 3	5000302	08/15/77	77-101	Mode 4		A.8				E34			
303	RHR6	8	Crystal River 3	5000302	03/04/79	79-022	Mode 4		A.8				E35			
304	RHR6	8	Crystal River 3	5000302	04/25/79	79-046	Mode 4		A.8				E36			

PHASE 2 - LOSS OF RESIDUAL HEAT REMOVAL WHILE AT SHUTDOWN FOR PWRS

	PHASE 2 CAT	SSS CAT	PLANT NAME	DOCKET NO	EVENT DATE	LER	INITIAL PLANT CONDITION	RECOVERY TIME	NSAC52 CAT.	SEA-BROOK CAT.	AEOD	CR5015 CAT	GI99 CAT	LER SEARCH	NUREG 1410	APPLI-CABIL.
305	RHR6	8	Davis Besse 1	5000346	01/07/81	81-004	Mode 4	15 min	A.6		AEOD-C		E22			
306	RHR6	8	Ginna	5000244	03/03/84	84-002	Mode 4			A-8						
307	RHR6	8	Ginna	5000244	05/14/84	84-005	Mode 4			A-8						
308	RHR6	8	Oconee 2	5000270	09/18/81	81-017	Mode 1		A.8				E39			
309	RHR6	8	Oconee 3	5000287	10/15/85	85-003	Mode 4			A-8		E.7				
310	RHR6	8	Robinson	5000261	07/15/82	82-009	Mode 6			A-8						
311	RHR6	8	Robinson	5000261	07/27/82	82-009	Mode 6			A-8						
312	RHR6	8	San Onofre 2	5000361	04/26/83	83-038	Mode 4			A-8						
313	RHR6	8	Turkey Point 4	5000251	05/23/89	004	Mode 4							20		
314	SWGR	12	Surry 2	5000281	03/12/87	001	Mode 5							48		
315	TRANS	TRANS	Surry 1	280	07/09/81	026	Routine startup									
316	TRANS	TRANS	Surry 1	280	01/05/82	010	Routine SD									
317	TRANS	TRANS	Surry 1	280	01/06/82	001	HSD									
318	TRANS	TRANS	Surry 1	280	04/15/82	048	Routine startup									
319	TRANS	TRANS	Surry 1	280	10/17/82	112	Routine startup									
320	TRANS	TRANS	Surry 1	280	04/07/84	008	Routine SD									
321	TRANS	TRANS	Surry 1	280	06/19/84	016	Routine startup									
322	TRANS	TRANS	Surry 1	280	01/27/85	004	Routine startup									
323	TRANS	TRANS	Surry 1	280	01/28/85	006	Startup									
324	TRANS	TRANS	Surry 1	280	02/07/86	010	Routine startup									
325	TRANS	TRANS	Surry 1	280	02/08/86	009	Routine startup									
326	TRANS	TRANS	Surry 1	280	09/16/86	022, event on 9/20/86	CSD									
327	TRANS	TRANS	Surry 1	280	07/18/89	030	100%, Unit 2 CSD							265*		
328	TRANS	TRANS	Surry 1	280	07/23/89	031	100%, Unit 2							266*		

PHASE 2 - LOSS OF RESIDUAL HEAT REMOVAL WHILE AT SHUTDOWN FOR PWRS

	PHASE 2 CAT	SSS CAT	PLANT NAME	DOCKET NO	EVENT DATE	LER	INITIAL PLANT CONDITION	RECOVERY TIME	NSAC52 CAT.	SEA-BROOK CAT.	AEOD	CR5015 CAT	GI99 CAT	LER SEARCH	NUREG 1410	APPLI-CABIL.
							CSD									
329	TRANS	TRANS	Surry 2	281	12/19/82	075	Hot SD									
330	TRANS	TRANS	Surry 2	281	09/21/83	038	Hot SD									
331	TRANS	TRANS	Surry 2	281	04/15/84	009	2% power									
332	TRANS	TRANS	Surry 2	281	04/20/84	012	Hot SD									
333	TRANS	TRANS	Surry 2	281	03/16/87	002	Hot SD									
334	TRANS	TRANS	Surry 2	281	09/10/88	022	Refueling outage									
335	TRANS	TRANS	Surry 2	281	09/16/89	007	Subcritical									
336	TRANS	TRANS	Surry 2	281	09/18/89	009	14% power									
337	VITAL	1	Calvert Cliffs 2	5000318	02/04/81	81-004	Mode 6	17 min	A.1				A20			
338	VITAL	1	Calvert Cliffs 2	5000318	11/22/82	82-053	Mode 6	4 min		A-1	AEOD-A		A10			
339	VITAL	6b	Calvert Cliffs 2	5000318	11/24/82	82-054					AEOD-A		E7			
340	VITAL	1	Calvert Cliffs 2	5000318	12/28/82	82-055					AEOD-A		A11			
341	VITAL	1	Calvert Cliffs 2	5000318	01/04/83	83-001		15 min			AEOD-A		A12			
342	VITAL	1	Catawba 1	5000413	11/26/88	026	Mode 5	2 sec						191		
343	VITAL	2b	Comanche Peak 1		07/18/89										3.52	NA1
344	VITAL	1	Crystal River 3	5000302	08/19/78	78-042	Mode 6	15 min	A.1				A5			
345	VITAL	1	Davis Besse 1	5000346	06/28/79	79-067	Mode 5	18 min	A.1		AEOD-C		A7			
346	VITAL	1	Diablo Canyon 2	5000323	01/17/86	86-002	Mode 5	13 min		A-1		A.14				
347	VITAL	1	Diablo Canyon 2	5000323	06/29/87	011	Mode 4	5 min						118		
348	VITAL	1	McGuire 1	5000369	06/24/82	82-053		6 min			AEOD-A		A19			
349	VITAL	1	McGuire 1	5000369	07/13/82	82-053				A-1						
350	VITAL	1	Millstone 2	5000336	01/06/82	82-002		7 min			AEOD-A		A15			
351	VITAL	1	North Anna 1	5000338	01/22/83	83-003	Mode 6	4 min		A-1	AEOD-A		A16			
352	VITAL	1	North Anna 1	5000338	04/22/87	007	Mode 5							146		
353	VITAL	1	North Anna 2	5000339	04/29/83	83-036	Mode 6	< 1 min		A-1	AEOD-A		A18			
354	VITAL	1	Palo Verde 2	5000529	01/30/86	86-005	Mode 5					E.12				
355	VITAL	6b	Rancho Seco	5000312	06/24/82	82-015	Modes 4 and 5			A-6	AEOD-A		A8			
356	VITAL	1	Rancho Seco	5000312	11/15/86	86-024	Mode 5			A-1		A.12				
357	VITAL	1	Salem 2	5000311	05/14/83	83-024,1 of 2-5/15/83 LER	Modes 4 and 5	immediately		A-1	AEOD-A		A4			

PHASE 2 - LOSS OF RESIDUAL HEAT REMOVAL WHILE AT SHUTDOWN FOR PWRS

	PHASE 2 CAT	SSS CAT	PLANT NAME	DOCKET NO	EVENT DATE	LER	INITIAL PLANT CONDITION	RECOVERY TIME	NSAC52 CAT.	SEA-BROOK CAT.	AEOD	CR5015 CAT	G199 CAT	LER SEARCH	NUREG 1410	APPLI-CABIL.
358	VITAL	1	Salem 2	5000311	11/28/83	83-062	Mode 5			A-1	AEOD-A		A6			
359	VITAL	6b	South Texas 1	5000498	02/12/89	008	Mode 5							243		
360	VITAL	1	Summer	5000395	11/12/83	83-136	Mode 5	5 min		A-1	AEOD-A		A20			
361	VITAL	1	Summer	5000395	10/18/84	84-045	Mode 5	25 min		A-1	AEOD-B	A.19				
362	VITAL	1	Turkey Point 4	5000251	03/15/86	86-006	Mode 6	5 min		A-1		A.3				
363	VITAL	1	Zion 1	5000295	03/17/82	82-011	Mode 6	3 min		A-1	AEOD-A		A3			
364	VITAL	1	Zion 2	5000304	01/03/86	86-001	Mode 5			A-1		A.8				

Number of Records 364

file: query and report Fullphs2

Appendix A.2 Descriptions of Events Used in the Quantification

Appendix A.2.1 Loss of RHR Events (RHR2A, 2B, 3, 4, 5, 6)

PHASE 2 CATEGORY	PLANT NAME	EVENT DATE	INITIAL PLANT CONDITION	RECOVERY TIME
RHR2A	Arkansas Nuclear 2	08/29/84	Mode 5	

(from AEOD): During RCS draindown, faulty level instrumentation led to air binding of the DHR pump. A tygon manometer configuration was being used - however, the operators did not account for reactor vessel pressurization due to the presence of nitrogen purge gas. RCS temp. went from 140 deg Fah to 205 deg Fah (approx. 35 min. loss).

(from CR5015): Power level - 0%. On 8/29/84 the plant was in mode 5 and the RCS level was being monitored by a temporary level indicator connected to the bottom of the RCS hot leg and vented to atmosphere. A nitrogen purge of the RCS was in progress to "sweep" hydrogen from the system prior to maintenance. The RCS was being vented via the upper vessel head vent and due to nitrogen flow exceeding vent flow capacity the RCS became slightly pressurized. This resulted in a manometer effect and inaccurate indication of RCS level. The level indication inaccuracy led to draining of the water in the RCS hot leg below the minimum level for adequate shutdown cooling pump suction. SDS loop flow indication began oscillating between 2000 and 4000 gpm indicating cavitation of the SDC pump. Consequently the "B" SDC pump was nitrogen purge were secured. Decay heat r moval alignment was shifted to the "A" SDC loop and normal flow of approx. 3000 gpm was established. During the period SDC flow was off, RCS bulk average temperature increased from approx. 140 to 205 deg Fah resulting in a change from mode 5 to mode 4. To prevent recurrence the temporary level system reference leg has been changed from venting to atmosphere to venting to the pressurizer steam space. Changes have been made to normal and abnormal operating procedures to improve system and operator response to similar events.

RHR2A	Catawba 1	04/22/85	Mode 5	12 min

(from Seabrook): Both trains of Residual Heat Removal (ND) were inoperable. This was the result of ND Train A being declared inoperable on April 20, 1985, at 1600 hrs for the performance of various ND Train A related work requests and ND Pump B being secured on April 22, 1985, at 2039:21 hrs due to loss of pump suction. Also, Tech. Spec. 3.4.1.4.2 was violated on April 22, 1985 at 0522 hrs when reactor coolant (NC) system draining began with ND train A inoperable.

(from CR5015): Power level - 0%. On April 22, 1985, from 2039:21 to 2051:17 hrs, both trains of residual heat removal (RHR) were inoperable. This was a result of RHR train A being declared inoperable on April 20, 1985, at 1600 hrs, for the performance of various train A related work requests, and RHR pump B being secured on April 22, 1985, at 2039:21 hrs due to loss of pump suction. Also, tech spec 3.4.1.4.2 was violated on April 22, 1985, at 0522 hrs when reactor coolant (RC) system draining began with RHR train A inoperable. Catawba Unit 1 was in mode 5 (cold shutdown) when these incidents occurred. False RC system level indication apparently contributed to the loss of RHR pump B suction. However, the cause of the false level indication is not known at this time. With RHR Train A inoperable, the limiting conditions for operation of Tech Spec 3.4.1.4.2 were not met. However, prior to beginning RC system draining, a decision had been made to allow draining to begin with

RHR2A	Cook 2	06/16/88		22 min

After all fuel from the reactor vessel had been removed with the reactor cavity flooded, the upper internals were replaced. The mid-loop water level indicator was valved out. The water level was reduced by pumping water to the refueling water storage tank at 2000 gpm with a residual heat removal pump. When the observed water level decreased to the top of the upper internals, the pump began to cavitate. The pump was stopped and vented. The pump was then started at a reduced flow rate. After approximately 22 minutes of operation with the observed water level just below the top of the upper internals, the pump again started to cavitate. The mid-loop water level indicator was valved in and indicated that the reactor vessel level was at mid-loop. Because the pump flow rate exceeded the leakage rate around the upper internals, a void had been created under the upper internals. The industry was informed of this event in INPO Significant Event Report (SER) 36-88.

PHASE 2 CATEGORY	PLANT NAME	EVENT DATE	INITIAL PLANT CONDITION	RECOVERY TIME
RHR2A	Davis Besse 1	04/18/80	Mode 5	29 min

(from NSAC52, p. A-11): RCS water level decreased from 70" to 37" above the hot leg piping centerline, causing erratic flow rate due to inadequate pump suction conditions. The RHRS pump was secured five minutes later at a level of 35". The inventory loss was via a partially open discharge valve from RHRS cooler #2 to the makeup and purification system. Some inventory may have also been lost via cross connects to RHRS loop 1, which was being drained.

(from AEOD): 29-minute loss of DHR. Leakage of RCS water through a partially closed valve resulted in inadequate DHR pump NPSH and erratic pump flow operation. The pump was secured until the leak was stopped and RCS level restored. During the event, RCS temperature rose from 93 deg Fah to 103 deg Fah.

RHR2A	Ginna	04/12/83	Mode 6	12 min

(from Seabrook): Prior to the dilute chemical addition, a small amount of water was being used in the channel head in conjunction with air pressure at 30 psig to properly seat the dams to minimize leakage past the dams into RCS. During this process, water drained completely through the leaky dam in the cold leg nozzle, thus allowing air to pass through, resulting in an air bubble formation passing through the RCS and entraining the RHR pump suction thus causing loss of the RHR located on the hot leg of the same loop. The RHR pump in operation at the time was manually tripped by the Control Room operator to prevent damage to the pump. Prior to this event, the RCS Boron Concentration had been borated to greater than 2400 ppm (2000 ppm required for refueling shutdown mode).

(from AEOD): Air binding of RHR pump (12 minute loss).

RHR2A	McGuire 1	03/02/82	Mode 5	50 min

(from Seabrook): A Residual Heat Removal (ND) pump low discharge alarm resulted in ND Pump 1A being stopped due to signs of cavitation. With the redundant Pump 1B out of service for maintenance, no means existed for core residual.

(from AEOD): Low RCS level due to vessel draining and inaccurate level indication. Operating RHR pump started to cavitate, the other pump was undergoing maintenance. (Event lasted 50 minutes - a licensee analysis indicated that 4 hrs were available prior to the onset of boiling.)

RHR2A	McGuire 1	04/05/83	Mode 6	

(from Seabrook): The Residual Heat Removal (ND) Pumps began to cavitate and eventually both the pumps were stopped.

(from AEOD): Low RCS level due to vessel draining and valved out level sensor. Both RHR pumps cavitated. (Duration of event unknown)

RHR2A	McGuire 2	12/31/83	Mode 5	43 min

(from Seabrook): Residual Heat Removal (ND) Pump B was observed to have zero discharge flow and was subsequently tripped and ND Train B declared inoperable.

(from AEOD): Low RCS level due to draining and inadequate level indication. Running RHR pump had no flow (43 min. loss).

RHR2A	McGuire 2	01/09/84	Mode 5	62 min

(from Seabrook): During draining operators of the Reactor Coolant (NC) System Residual Heat Removal (ND) Pump B was observed to have zero discharge flow. Pump B motor amperage was low and the ND system pressure and Pump B discharge pressure were equal. Based on these factors, ND Pump B was tripped and ND train B was declared inoperable at 1650. The FWST to ND Pump Isolation valve was twice cycled to

PHASE 2 CATEGORY	PLANT NAME	EVENT DATE	INITIAL PLANT CONDITION	RECOVERY TIME

provide core cooling and raise NC System level with water from the Fueling Water Storage Tank while venting the ND Suction line and pump B. The core temperature rate of rise decreased after the first water addition, and the second addition resulted in slightly decreased core temperatures. ND Pump B was restarted at 1720 and flow was restored. On January 9, 1984, operators were again decreasing level in the Reactor coolant loops when a computer alarm for low ND Pump A discharge pressure was received. Fluctuations in ND Pump A discharge pressure was received. Fluctuations in ND Pump A motor amperage were noted and simultaneous fluctuations in discharge pressure and flow also occurred. After the low ND Flow annunciator alarmed, ND Pump A was tripped at 1246 and ND Train A was therefore inoperable. Operators manually opened the ND system to FWST isolation valve, raising the Reactor Coolant Loop level with water from the FWST. The suction line and pump were vented and the pump was restarted at 1348.

(from AEOD): During draining operations, a procedural deficiency led to inadequate NPSH/air entrainment of the DHR pumps (1 hr. 2 min. loss).

(from CR5015): Power level - 0%. On Dec. 31, 1983 at 1640, during draining operations of the reactor coolant (NC) system, residual heat removal (ND) pump B was observed to have zero discharge flow. Pump B motor amperage was low, and the ND system pressure and pump B discharge pressure were equal. Based on these factors, ND pump B was tripped and ND train B was declared inoperable at 1650. The FWST to ND pump isolation valve was twice cycled to provide core cooling and raise NC system level with water from the refueling water storage tank, while venting the ND suction line and pump B. The core temperature rate of rise decreased after the first water addition, and the second addition resulted in decreased core temperatures. ND pump B was restarted at 1720, and flow was restored. On Jan. 9, 1984 operators were decreasing level in the reactor coolant loops when a computer alarm for low ND pump A discharge pressure was received. Fluctuations in ND pump A motor amperage were noted and simultaneous fluctuations in discharge pressure and flow also occurred. After the "low ND flow" annunciator alarmed, ND pump A was tripped at 1246, and ND train A was inoperable. Operators manually opened the ND system to FWST isolation valve, raising the reactor coolant loop level with water from the FWST. The suction line and pump were vented, and the pump was restarted at 1348. These incidents are due to inadequate guidelines recording the water level to be maintained in the reactor coolant loops during ND operation.

RHR2A North Anna 2 05/20/82 1 hr

(from Seabrook): Not found in A-2

(from AEOD): Lost suction to RHR pumps due to draining of RCS and erroneous level indication (three events: 8 min, 26 min, 1 hr losses).

RHR2A North Anna 2 05/20/82 8 min

(from Seabrook): Not found in A-2.

(from AEOD): Lost suction to RHR pumps due to draining of RCS and erroneous level indication (3 events: 8 min, 26 min, 1 hr losses).

RHR2A North Anna 2 05/20/82 26 min

(from Seabrook): Not found in A-2.

(from AEOD): Lost suction to RHR pumps due to draining of RCS and erroneous level indication (3 events: 8 min, 26 min, 1 hr losses).

PHASE 2 CATEGORY	PLANT NAME	EVENT DATE	INITIAL PLANT CONDITION	RECOVERY TIME
RHR2A	North Anna 2	05/03/83	Mode 6	

(from Seabrook Sheet 3 of 9): On May 3, 1983, suction to the B Residual Heat Removal (RHR) pump was lost while transferring water from the Reactor Coolant system (RCS) to the refueling water storage tank (RWST) via the Refueling Purification (RP) System. The A Pump was secured and the B RHR Pump started but suction was not available.

(from AEOD): Inadequate monitoring of RCS level. Loss of RHR pump suction. (Duration of event unknown)

RHR2A	North Anna 2	10/16/84	Mode 5	2 hr

(from Seabrook Sheet 7 of 9): A complete loss of Residual Heat Removal (RHR) capability occurred when both RHR pumps were unable to operate due to the introduction of air into the RHR system. The incident occurred during the drain down of the Reactor Coolant System (RCS) when the level of the RCS was being monitored via a standpipe off the centerline of one of the RCS loops.

(from AEOD): Clogging of a standpipe used for RCS level monitoring resulted in a 64" error. Upon introduction of air, the operating pump cavitated. The redundant pump was started and it also cavitated. Both pumps became airbound (2 hr loss).

(from CR5015): Power level - 0%. On 10-16-84, with North Anna Unit 2 in Mode 5 a complete loss of RHR capability occurred when both RHR pumps were unable to operate due to the introduction of air into the RHR system. The incident occurred during the drain down of the RCS, when the level of the RCS was being monitored via a standpipe off the centerline of one of the RCS loops. The isolation valve to which the standpipe was attached became clogged sometime during the drain down and falsely indicated 64" above centerline when in fact the level was below the RHR suction line (below centerline). Subsequently, letdown from the RCS was isolated and makeup initiated. RHR capability was regained 2 hrs after initiation of the event. RCS level indication was moved to an alternate tap off loop centerline and indicated satisfactorily.

RHR2A	San Onofre 2	03/26/86	Mode 5	49 min

(from CR5015): Power level - 0%. March 26, 1986 at 2208 with Unit 2 in cold shutdown, the shutdown cooling system (SDCS) experienced a total loss of flow for a period of 49 minutes. This occurred while reactor coolant system (RCS) level was being reduced to repair a leaking cold leg steam generator nozzle dam which had been installed to allow work in steam generator channel heads. Using the established level indication, which was later found to be in error, the RCS was drained to a level where vortexing occurred at the RCS/SDCS suction connection causing the SDCS/LPSI pumps to eventually become airbound. The pumps were stopped and the system vented, reestablishing SDCS flow at 2257. Concurrent with the restoration of SDCS flow, both gas channels of the fuel handling isolation system actuated on high noble gas a result of the RCS degasing. The high pressure safety injection system was used to make-up to the RCS until SDCS flow returned to a stable state. The cause of the event was erroneous level indication resulting in the operators not recognizing the RCS low level condition prior to complete loss of SDCS flow. Immediate corrective action was taken to prevent SDCS/LPSI pump damage, restore SDCS flow to a stable state and recalibrate the level indicators. Changes in plant design, procedural revisions, formal control of level indicator installation, and operator training will be undertaken.

RHR2A	Sequoyah 2	08/06/83	Mode 6	77 min

(from Seabrook Sheet 4 of 9): At 0838 (C) during pump down of the refueling cavity to perform maintenance on the Loop 4 Reactor Coolant System Cold Leg Nozzle Inspection Plate, the B Train Residual Heat Removal Pump began to cavitate.

(from AEOD): False RCS level indication by makeshift tygon tube and rubber hose level instrument. RCS

PHASE 2 CATEGORY	PLANT NAME	EVENT DATE	INITIAL PLANT CONDITION	RECOVERY TIME

temperature rose from 103 deg Fah to 195 deg Fah in 77 min. Plant had been shut down 18 days earlier.

RHR2A Trojan 06/26/81 Mode 5 75 min

(from NSAC52, p. A-10): While reducing RCS level, in preparation for maintenance, the RHRS pump began cavitating and was secured. Inventory reduction was terminated and RCS charging was established. Investigation found a shut pressurizer vent valve which isolated the reactor vessel level indicating system internal reference leg. The pressurizer vent and reactor vessel head vent were opened, and standpipe level stabilized approx. 5 feet lower than the previously indicated level. (Close to the RHRS suction tap off an RCS hot leg.) Attempts to restart the RHRS pump failed due to air entrained in the RHRS suction line. The RHRS suction valves were closed and the RWST suction valve was opened in order to provide a positive suction to the RHRS pumps. Flow was restored 75 minutes after event initiation.

RHR2A Waterford 03/14/86 Mode 5 1 hr 19 min

(from CR5015): Power level - 0%. On 3-14-86 Waterford Steam Electric Station Unit 3 was in Mode 5 (cold shutdown) (as a result of a scheduled surveillance/maintenance outage which began on 3-7-86) with both loops of the reactor coolant system (AB) drained. At 1035 hrs on 3-14-86 operations personnel, in preparation for maintenance on SI-406A, loop 2 shutdown cooling return relief valve, started low pressure safety injection (LPSI) pump B (BP). The primary nuclear plant operator observed the flow in the B shutdown cooling (BP) train to be zero (0 gpm) and LPSI pump B motor current to be 33 amps. The control room supervisor ordered the pump secured, and proceeded to the B safeguards pump room to investigate local conditions. The investigation revealed that SI-124B, low pressure safety injection pump B discharge valve, was closed with a danger tag affixed to the valve. The valve was mistakenly closed during a tag-out which was conducted on the 3/13-14/86 midnight shift. The valve was opened and at 1154 hrs on 3-14-86 the B LPSI pump was placed into service. The valve was inadvertently closed because plant operators did not use the clearance request sheet when they conducted the tag-out. To prevent this from recurring, a revision will be made to procedure UNT-5-003, "Clearance Requests, Approval and Release," and the operations superintendent will stress the function of clearance sheets with operations personnel.

RHR2A Waterford 07/14/86 Mode 5 3 hr 41 min

(from CR5015): Power level - 0%. On July 14, 1986 Waterford Steam Electric Station Unit 3 was in Mode 5 (cold shutdown) when operations personnel were draining the reactor coolant system (RCS) (AB) to facilitate the replacement of the seal package for reactor coolant pump 2A. The RCS was being maintained by draining into the refueling water storage pool (RWSP) (via the low pressure safety injection pump B mini-recirculation valves, SI-120B, -121B) and holdup tanks (via the chemical volume control system (CB) purification ion SI-423). At 0113 hrs operations personnel secured draining the RCS by closing SI-423. However, operations personnel neglected to close SI-120B and -121B resulting in RCS inventory being pumped into the RWSP. In addition, because of insufficient nitrogen pressure, local reactor vessel level indication was suspect. At 0317 hrs LPSI pump B began cavitating. Operations immediately secured the pump, terminating shutdown cooling (SDC) (BP). At 0658 hrs SDC was restored by a process of refilling the RCS and cycling the LPSI pumps to restore flow. (Since the RCS temperature increased to the point of localized boiling, the LPSI pumps were subjected to steam binding). This event was due to simultaneously using more than one method of draining the RCS, and inaccurate level indication. These problems will be corrected by plant modification and procedural changes.

RHR2A Waterford 3 05/12/88

(from NUREG-1410): The reactor vessel water level was being lowered to mid-loop to remove the steam generator nozzle dams and to test a new digital reactor vessel water level indicator. Tygon tubing was being used to monitor the reactor vessel water level. At an indicated level of 18 ft on the tygon tubing and 14 ft on the digital instrument, the operating low pressure safety injection pump started cavitating and was secured. The water level was raised and the other low pressure safety injection

PHASE 2 CATEGORY	PLANT NAME	EVENT DATE	INITIAL PLANT CONDITION	RECOVERY TIME

pump was started. However, a loop seal in the tygon tubing was not detected. The reactor vessel water level was again lowered until the operating low pressure safety injection pump started cavitating. The reactor vessel water level was then raised, restoring decay heat removal. The industry was informed of this event in INPO Significant Operating Experience Report (SOER) 88-3.

RHR2A	Zion 1	09/14/84	Mode 5	45 min

(from Seabrook Sheet 6 of 9): While in cold shutdown, draining the RCS in preparation for steam generator primary-secondary leak testing, the RCS level dropped below the suction line for the RHR pump.

(from AEOD): While draining the RCS in preparation for primary-secondary leak testing, the RCS level dropped below the DHR suction line. The liquid level was being read from a manometer type arrangement. Incorrect level measurement resulted from the fact that the manometer reference leg was pressurized by nitrogen purge gas. RCS temperature increased from 110 deg Fah to 147 deg Fah (45 min. loss).

(from CR5015): Power level - 0%. While in cold shutdown, draining the RCS in preparation for SG primary-secondary leak testing the RCS level dropped below the suction line for the RHR pump as a result of an improper valve lineup which gave false indication of the RCS level. The RHR pump was stopped when it was noticed that the motor amperage was fluctuating. The valve lineup was checked and the lineup error corrected. RCS level was increased to normal and the RHR pump was restarted. RCS temperature increased from 110 F to 147 F during the 45 minutes the pump was off. No abnormal conditions developed as a result of this event. Station procedures will be revised to prohibit simultaneous draining and purging operations, a procedure for loss of RHR will be prepared. Retraining will be conducted in proper valve lineup procedures.

PHASE 2 CATEGORY	PLANT NAME	EVENT DATE	INITIAL PLANT CONDITION	RECOVERY TIME
RHR2B	Beaver Valley 1	01/17/80	Mode 5	

(from NSAC52, p. A-9): The reactor vessel vend eductor was in service in preparation for refueling. A low flow alarm for RHRS was received and low flow and low motor current were indicated. A second RHRS pump was started and was also air bound. Both pumps were vented and flow restored.

RHR2B	Beaver Valley 1	04/08/80	Mode 5	35 min

(from NSAC52, p. A-9): While attempting to increase RHRS flow to the Tech Spec value required for dilution (3000 gpm), the running RHRS pump lost flow. The second RHRS pump was also found to be air bound. RCS level was increased, pumps vented and flow restored in 35 minutes.

RHR2B	Beaver Valley 1	04/11/80	Mode 5	70 min

(from NSAC52, p. A-10): While attempting to increase RHRS heat exchanger flow, the running RHRS pump lost suction. (Heat exchanger flow was increased by decreasing bypass flow, not increasing pump flow.) The airbound RHRS pump was secured. The other pump was started, became airbound and was also secured. Both pumps were vented, and RCS level was increased. Full RHRS flow was restored in 70 minutes.

RHR2B	Beaver Valley 1	03/05/81	Mode 5	54 min

(from NSAC52, p. A-10): Reactor vessel water level was inadvertently lowered. The RHRS low flow alarm was actuated, accompanied by low current on the operating pump. System flow dropped to 500 gpm. Swapping the operating pump for the idle pump resulted in an indicated flow of zero gpm. Returning to the original pump restored flow to 500 gpm. 600 gallons of coolant were added to the RCS, RHRS pumps were vented, and flow restored in 54 minutes. RCS temperature increased 66 F to 168 F. Investigation revealed that remote level indication in the control room was 6" higher than actual level as indicated by a local standpipe.

RHR2B	Byron 1	09/19/88	Mode 6	14 min

(from LER Search): On Sept. 19, 1988, the reactor was fully depressurized in the refueling operational mode at a temperature of approx. 95F. Reactor cavity water level was approx. 4". A reactor vessel stud hole protective insert had worked free and was floating on the water surface. At 1052 the 1B residual heat removal (RHR) pump was operated to lower reactor cavity water level to the vessel flange to permit insert replacement. Visual sighting of cavity water level was believed to be an accurate and timely indication for the evolution based on past experience. While completing the draining evolution, the 1A RHR pump showed signs of cavitation and was stopped by a licensed reactor operator. Within 2 minutes of stopping the pump, the reactor vessel was gravity filled from the refueling water storage tank. Within 14 minutes, shutdown core cooling was restored using the 1B RHR pump. This report is submitted voluntarily. The 1A RHR pump cavitation was caused by the entrainment of air to the pump's suction. It is believed that air was admitted by a vortex when reactor vessel water level lowered below the top of the reactor coolant hot legs. The cause of the excessive lowering of vessel water level was a failure to comprehend the fluid restriction created when the upper internals assembly is fully seated on the hold down spring.

RHR2B	Cook 2	05/21/84	Mode 5	25 min

(from Seabrook): With the Reactor Coolant System at half-loop, the control Room operators started a second residual heat removal (RHR) pump in preparation for removing the operating RHR pump from service. With both pumps running, flow became excessive for the half loop condition causing cavitation and air binding of both pumps. Both pumps were out of service for approximately 25 minutes while they were being vented which is within the one hr.

(from AEOD-8): Procedural error with a partially drained RCS. Simultaneous operation of two DHR pumps caused vortexing at the loop suction. Both pumps became airbound (25 min. loss).

PHASE 2 CATEGORY	PLANT NAME	EVENT DATE	INITIAL PLANT CONDITION	RECOVERY TIME

(from CR5015): Power level - 0%. With the unit in cold shutdown (Mode 5) and the reactor coolant system at half-loop, the control room operators started a second residual heat removal (RHR) pump in preparation for removing the operating RHR pump from service. With both pumps running, flow became excessive for the half-loop condition causing cavitation and air binding of both pumps. Both pumps were out of service for approx. 25 mins while they were being vented which is within the 1 hr action statement time limit of Tech spec 3.4.1.3. To prevent recurrence the procedure which controls the operation of the RHR pumps has been changed to include specific instructions to stop the operating pump prior to starting the second pump while at half-loop.

RHR2B	Diablo Canyon 2	04/10/87	Mode 5	1 hr 28 min

(from LER Search): On April 10, 1987, at 2123 PDT, with the Unit in Mode 5 (cold shutdown) during a refueling outage, RHR flow was interrupted when both RHR trains became inoperable due to airbound RHR pumps. The 10 CFR 50.72 report was made at 2230 PDT. The RCS had been drained to midloop level for SG nozzle dam installation. The loss of RCS inventory to the reactor coolant drain tank due to a leaking valve caused a decrease in RCS water level, vortexing in the pumps' suction line, and air entrainment in the RHR pumps. At 2251 PDT, after verification that the SG manways were still installed and after venting of the RHR pumps, the RCS was flooded from the refueling water storage tank and an RHR pump started. RHR flow was interrupted for approx. 1 hr and 28 minutes. This resulted in some localized boiling and, contrary to TS 3.0.4, an inadvertent entry to Mode 4 (hot shutdown) but no damage to the core or significant radiological release occurred. The unit was stable at 0230 PDT, April 12, 1987, and was returned to normal Mode 5 midloop operation. The numerous actions taken to prevent recurrence of this event, including procedure revisions, training, and design changes, are described in the text of this LER.

RHR2B	Millstone 2	03/14/79	Mode 5	

(from NSAC52, p. A-9): RCS level was drained to the hot leg center line for SG eddy current testing. RHRS flow was lost due to RHRS pump air binding. Attempts at pump venting and transfer to the alternate pump were unsuccessful. When RCS temperature increased to 190 F, the RHRS pump suction from the RWST was opened to prime the suction. This action restored flow, but resulted in RCS floodup and spillover of approx. 15,000 gallons of water through the open S/G manway to containment. Temperature reached 208 F during the transient. Containment integrity was verified prior to entering Mode 4.

RHR2B	North Anna 1	10/19/82	Mode 6	36 min

(from Seabrook): On October 19, 1982, suction to the A and B Residual Heat Removal System (RHR) pumps was lost for about 36 minutes. On Oct. 20, 1982, A and B (RHR) pump suction was lost for 33 minutes.

(from AEOD): RCS drained to below centerline of hot leg nozzles. RHR suction was lost because of low RCS level and incorrect level indication. (10/19/82, 36 min loss)

RHR2B	North Anna 1	10/20/82	Mode 6	33 min

(from Seabrook): Not found in A-2

(from AEOD): RCS drained to below centerline of hot leg nozzles. RHR suction was lost because of low RCS level and incorrect level indication. (10/20/82, 33 min. loss)

PHASE 2 CATEGORY	PLANT NAME	EVENT DATE	INITIAL PLANT CONDITION	RECOVERY TIME
RHR2B	North Anna 2	07/17/82	Mode 5	

(from Seabrook): Not found in A-2

RHR2B	North Anna 2	07/30/82		46 min

(from AEOD): Lost suction to "A" RHR pump due to draining. Diagnosed as a pump problem. The "B" was then started and it also became airbound (46 min. loss).

RHR2B	Palisades	10/15/87	Cold shutdown	29 min

(from LER Search): On Oct. 15, 1987, at 1837, low pressure safety injection (LPSI) pump, P-67A (BP;P) was manually secured from operation due to erratic discharge pressure and flow. The reactor was in cold shutdown condition with the primary coolant system (PCS) (AB) drained to the 617'8" level (centerline of the hot and cold legs is at 618'2") at the time of the event. The PGS was drained to the centerline in order to support steam generator (AB;SG) nozzle dam modifications. At the time of the event, LPSI pump P-67A was taking suction from the PCS at the hot leg, discharging through shutdown cooling heat exchangers E-60A and E-60B (BP;HX) and returning flow to the PCS at the cold legs. The erratic discharge pressure and flow were the result of an improperly placed jumper which caused a LPSI discharge valve to cycle open/closed. The failure to properly place the jumper was the result of a data transposition error during the planning phase for "as-left" valve testing. Shutdown cooling flow was isolated for 29 minutes, with PCS temperature increasing from 92 to 129 degrees F. Shutdown cooling flow was restored after the errantly placed jumper was removed. All similar valve testing was immediately stopped and all jumpers installed to support testing removed.

(from NUREG-1410) The reactor was in cold shutdown with the reactor coolant system drained to mid-loop for steam generator nozzle dam modification. An errantly placed jumper in the control circuit for the operating low pressure safety injection pump caused the valve to cycle open and close. The valve cycling caused the reactor coolant system level to rise and fall, which resulted in 1000 gallons of water being pumped out through the open steam generator manways. The pump was then tripped by the operators. During the 29 minutes decay heat removal was lost, the reactor coolant temp. increased from 92 deg Fah. to 129 deg Fah.

RHR2B	Salem 1	06/30/79	Mode 6	34 min

(from NSAC52, p. A-9): Reactor vessel level was lowered to approximately one inch above the low operating level for the RHRS pump. The operating pump started to lose suction and was secured. Reactor vessel level was increased six inches, and the RHRS pump restarted. Flow was lost for 34 minutes.

RHR2B	Sequoyah 1	10/09/85	Mode 5	

(from Seabrook Sheet 8 of 9) At 1807 CST during cold Shutdown, swap over from B Train to A Train Residual Heat Removal (RHR) resulted in both trains becoming inoperable due to air injection into the suction of the pumps. This requires both pumps to be vented and required RCS level to be raised from 695 ft. 1 in. to 695 ft. 5 in. to prevent a possible recurrence of the vortex problem. Suction for RHR comes from the Loop 4 hot leg which has centerline of 695 ft. 5 in.

(from CR5015): Power level - 0%. On 10-9-85 at 1807 CST during cold shutdown, swap over from 'B' train to 'A' train RHR resulted in both trains becoming inoperable due to air injection into the suction of the pumps. This required both pumps to be vented and required RCS level to be raised from 695'1" to 695'5" to prevent a possible recurrence of the vortex problem. Suction for RHR comes from the loop 4 hot leg which has a center line of 695'5". The cause for the loss of flow can be attributed to the additional suction caused by placing the standby RHR pump inservice coupled with the low RCS level of 695'1". System operating instruction (SOI)-74, "RHR System," is being revised to change the lower RCS operating limit from 695'0" to 695'6" and will require the operating pump to be removed from

PHASE 2 CATEGORY	PLANT NAME	EVENT DATE	INITIAL PLANT CONDITION	RECOVERY TIME

service prior to starting the standby pump. The unit was in cold shutdown with only a 0.2 degrees F rise in RCS temperature resulting from the event. Tech Spec 3.4.1.4 action (B) says that ". . . With no RHR loops in operation, suspend all operations involving a reduction in boron concentration of the RCS." At the time of this event, the chemical volume control system (CVCS) (Makeup System) was tagged out of service; therefore, no violations of Tech Specs occurred.

RHR2B Sequoyah 1 01/28/87 Mode 5 30 min

(from LER Search): Units 1 and 2 were in Mode 5 at 0% power. Previous to this event, the Unit 1 RCS water level was drained down to elevation 695'6" for SG maintenance work. Due to a faulty level indication of 696'6" in the RCS water level indication system, the operator was lowering the water level back to about 695'6". The RHR pump 1A-A began to lose suction as indicated by the motor current and pump flow rate meters oscillating and the miniflow valve opening. The operator immediately stopped the pump; entered the action statement of Tech Spec LCO 3.4.1.4; and began to align RHR pump 1B-B for letdown to chemical volume control system (CVCS), vent pump 1A-A, and raise water level using the charging pump. Shutdown decay heat removal was lost at 0620 EST and reinstated at 0750 EST. RCS temp. increased by 20 F, and the detectable boron concentration was not reduced. About 500 gallons were spilled from the SG manways since the water level was being increased by the charging pump. No personnel were injured, and there was no equipment damage. The cause of the faulty level indication was collection of debris in the inlet to the sight glass which was being monitored. Operations initiated weekly flushings of the sight glass and installed a redundant tygon tube which will be compared to the sight glass level on a daily basis.

(from NUREG-1410): The reactor coolant system had been reduced to mid-loop for steam generator work. Because of a faulty level indicator, the reactor coolant system water level was reduced until the operating residual heat removal pump started losing suction. Approx. 500 gallons of water were spilled from the steam generator manways when level was increased using the charging pump. The false level indication was caused by the presence of debris in the inlet to the sight glass which was being monitored. During the 90 minutes that decay heat removal was lost, the reactor coolant temp. increased from 95 deg Fah to 115 deg Fah.

RHR2B Sequoyah 1 05/23/88 Mode 5

(from LER Search): On May 23, 1988, at 1215 EDT, while Unit 1 was in cold shutdown with the reactor coolant system (RCS) partially drained to support maintenance, a loss of the operating train of the residual heat removal (RHR) system occurred. The "B" train of RHR was in operation when it was decided to place the "A" train RHR heat exchanger in service to enhance plant temperature control. To place the "A" train in service, an assistant unit operator (AUO) was dispatched to open two valves. The AUO, however, misunderstood the instruction and wrote down an incorrect valve number. The incorrect valve was a manual valve (1-HCV-74-34) used to align the discharge of the RHR pumps to the refueling water storage tank (RWST). Upon opening valve 1-HCV-74-34, the AUO heard unusual flow noise and subsequently telephoned the control room (CR) operator for further instructions. The assistant shift operation supervisor (ASOS) in the CR received an RHR mini flow alarm, and noticed RHR pump amperage oscillating, unstable flow indication, and the indicated RCS water level was off-scale low. The ASOS subsequently stopped the "B" train RHR pump and entered the applicable action statements of Tech Specs for a loss of RHR. The RCS was then refilled above the top of the RCS loops by gravity feed from the RWST via the RHR system.

RHR2B Surry 1 05/17/83 Mode 5

(from Seabrook Sheet 3 of 9): The B RHR pump was removed from service on two occasions due to cavitation. This resulted in less than two operable RHR loops and no loops in operation.

(from AEOD): Inaccurate standpipe level indication - low RCS level, RHR pump cavitated. (Duration of

PHASE 2 CATEGORY	PLANT NAME	EVENT DATE	INITIAL PLANT CONDITION	RECOVERY TIME

event unknown)

RHR2B	Trojan	05/04/84	Mode 5	40 min

(from Seabrook Sheet 4 of 9): During an RCS drain down to support refueling operations at 1650 on May 4, 1984, Residual Heat Removal (RHR) Cooling could not be reinitiated for a total of 40 minutes due to air entrainment in the suction of the A RHR pump. Both RHR pumps had been stopped for ten minutes for annual ESF actuation response time testing. An additional 30 minutes were required to restore sufficient RCS water inventory to restart an RHR pump. The B RHR pump was then started and the RCS temperature rise was terminated. The highest indicated RCS hot leg temperature reached about 201 deg Fahrenheit.

(from AEOD): During RCS draindown faulty level measurement led to air binding of the RHR pump. The RCS was vented to atmosphere. A tygon manometer configuration was being used to measure RCS level, however, "crud blockage" of the manometer tap led to erroneous level measurement. RCS temperature went from 105 deg Fah to 201 deg Fah (40 min. loss).

RHR2B	Zion 2	12/14/85	Mode 5	75 min

(from CR5015): Power level - 0%. On 12-14 at 3:25, 2B RHR pump became airbound as a result of vortexing. Unit 2 was in cold shutdown with the reactor head installed but not tensioned and the RCS vented to atmosphere. 2B RHR pump had been in operation providing decay heat removal with RHR letdown in progress and 2B charging pump providing make-up flow to the RCS. Decay heat removal was lost for 75 minutes with a RCS change in temperature of 15 degrees F. The unit had been shutdown for approx. 100 days therefore the safety significance was minimal. The cause of the event was identified to be inadequate procedures coupled with the lack of knowledge of the level at which the RHR pumps begin to cavitate. As a contributing factor, there were problems found with the level indication. To prevent recurrence, procedures will be reviewed and changed reflecting the lessons learned. Training will be conducted on RCS level measurement and loss of RHR suction. The RCS level system will be modified in order to provide reliable remote level indication during all refueling configurations.

RHR2B	Zion 2	01/13/86	Mode 5	75 min

(Sheet 9 of 9) The 2B Residual Heat Removal (RHR) pump became airbound as a result of vortexing. Unit 2 was in cold shutdown (Mode 5) with the reactor head installed but not tensioned and the reactor coolant system (RCS) vented to atmosphere. 2B RHR pump had been in operation providing decay heat removal with RHR letdown in progress and 2B charging pump providing makeup flow to the RCS. Decay heat removal was lost for 75 mintues with an RCS change in temp. of 15 deg Fahrenheit. The unit had been shutdown for approx. 100 days; therefore the safety significance was minimal.

PHASE 2 CATEGORY	PLANT NAME	EVENT DATE	INITIAL PLANT CONDITION	RECOVERY TIME
RHR3	Arkansas 2	11/14/79	Mode 5	3 hr

(from NSAC52, p. A-23): Small leak discovered in socket weld on LPSI flow orifice valve. LPSI system (RHRS) was out of commission for three hrs for weld repair.

RHR3	Calvert Cliffs 2	03/24/87	Mode 6	15 hr 20 min

(from LER Search): At 1330 on March 24, 1987, with Unit 2 in mode 6 at 0% power, two in hole leaks were discovered in the 1/2" diameter inlet piping to a relief valve (2-RV-439) in the shutdown cooling (SDC)/low pressure safety injection (LPSI) system header. Borated water was spraying from the area where the pipe was welded to the header nozzle at the rate of approx. 1 gpm. At 2330 on March 24, 1987, shutdown cooling flow was reduced below the Tech Spec requirement of 3000 gpm and Unit 2 entered an action statement. At 0430 on March 25, 1987, an alternate cooling path from the reactor vessel hot leg nozzle, through LPSI pump #22 through the SDC heat exchanger to the spent fuel pool and the fuel transfer canal and to the refueling pool was established. At 0920 work was begun on replacing the leaking pipe spool and relief valve with a temporary mechanical device (i.e., nipple and cap) per plant procedures. After this replacement was completed, SDC was reestablished in the nromal mode at 1450 on March 25, 1987. The time spent in the action statement (i.e., event duration) was 15 hours and 20 minutes. On March 31, 1987, a facility change request (FCR) #87-29 was approved to investigate the piping and support configuration at 2RV 439 and to implement design changes if required.

RHR3	Calvert Cliffs 2	05/07/87	Mode 5	16 hr 55 min

(from LER Search): At 0700 on May 7, 1987, with Unit 2 in Mode 5 at 0% power, a leak was discovered in the 0.5" diameter inlet piping to a relief valve (2-RV-439) in the shutdown cooling (SDC)/low pressure safety injection (LPSI) system header. At 1400 containment integrity was established per plant procedures and an alternate cooling path to the core was established using high pressure safety injection (HPSI) pump #22 and containment spray pump #21. At 1410 with no SDC loops operable, unit 2 entered an action statement. The cracked pipe spool was replaced and SDC loop #21 was returned to service at 2355 on May 7, 1987. The event duration was 16 hours and 55 minutes. Because of a similar failure of the inlet pipe to this relief valve on March 24, 1987 and the subsequent installation of a new inlet piping support; analysis to determine the cause of failure was conducted. Metallurgical examination determined the mode of failure to be fatigue due to cyclic torsional/bending loading. An analysis and redesign of the inlet piping was performed and the new piping configuration installed on May 23, 1987. Piping associated with other relief valves in the LPSI and HPSI systems will be reviewed for similar configuration and support problems.

RHR3	Crystal River 3	02/12/86	Mode 5	

See description of Crystal River 3, 02/02/86 event.

RHR3	Farley 2	09/28/83	Mode 6	

(from Seabrook): The 2B RHR pump tripped while the B RHR loop was in service and the A RHR loop was secured.

(from AEOD): Operating RHR pump failed while redundant pump was secured. (Duration of event unknown)

RHR3	McGuire 2	03/07/83	Mode 6	3 hr

While moving a temporary incore detector, the rope used to hold the detector cable fell into the reactor vessel and was drawn into C Hot Leg. Residual Heat Removal (RHR) Pump 2A was secured from service for 3 hrs (with Pump 2B also secured) to allow rope retrieval efforts.

PHASE 2 CATEGORY	PLANT NAME	EVENT DATE	INITIAL PLANT CONDITION	RECOVERY TIME
RHR3	Salem 2	04/13/81	Mode 5	5 hr 22 min

(from NSAC52, p. A-25): All RCPs and RHRS pumps were de-energized to facilitate the replacement of a relief valve in the RHRS. Tech specs allow these pumps to be de-energized for one hour. The maintenance and restoration of RHRS flow required 5 hours and 22 minutes.

PHASE 2 CATEGORY	PLANT NAME	EVENT DATE	INITIAL PLANT CONDITION	RECOVERY TIME
RHR4	Arkansas 2	01/01/79	Mode 5	

See description of Arkansas 2, 01/09/83 event. (Date of this event is dummy date--date not specified in description.)

RHR4	Arkansas 2	10/13/79	Mode 6	

(from NSAC52, p. A-30): An RHRS heat exchanger tube leak was indicated by an increase in the heat exchanger radiation monitor reading. The heat exchanger was then isolated on both the service water and reactor coolant sides.

RHR4	Arkansas 2	01/09/83	Mode 5	

An alarm was received on the Service Water (SW) monitor (WRITS-1453) for the shutdown cooling (SDC) heat exchanger (2E-35A) which indicated the possibility of a tube leak. Radiochemistry sampling verified the tube leak. 2D-35A was secured and the redundant heat exchanger (2E-35B) was placed in service. Since this leak from the SDC system to the SW system was a degradation of a system designed to contain radioactive matter. A previous occurrence regarding SDC tube leaks was reported in LER-79-086. It should be noted that this heat exchanger tube bundle had been replaced during the last Unit 2 refueling outage.

RHR4	Crystal River 3	02/02/86	Mode 5	24 min

(from Seabrook): The Reactor Coolant system was vented to the Reactor Bldg atmosphere and drained below the level of the reactor coolant pumps. At 2148 hrs, decay heat pump tripped due to a motor overload caused by a pump shaft failure. Start up of the redundant pump was delayed because an isolation valve on the suction side of the pump could not be opened from the Control Room. The valve was manually opened and system operation was restored at 2212 hrs. On 2/12/86, the B train of the Decay Heat Removal System was being refilled and movement of the pump and piping was noticed. Examination of pipe restraints in the system revealed that several pipe hangers were loose or damaged. All damaged equipment has been repaired. Both decay heat pumps have been rebuilt.

(from CR5015): Power level - 0%. On Feb. 2, 1986, Crystal River Unit 3 was in Mode 5 while performing repairs on a reactor coolant pump. The reactor coolant system was vented to the reactor bldg atmosphere and drained below the level of the reactor coolant pumps. At 2148 hrs, decay heat pump 1B tripped due to a motor overload caused by a pump shaft failure. Start-up of the redundant pump was delayed because an isolation valve on the suction side of the pump could not be opened from the control room. The valve was manually opened and system operation was restored at 2212 hrs. On Feb. 14, 1986, the "B" train of the decay heat removal system was being refilled and movement of the pump and piping was noticed. Examination of pipe restraints in the system revealed that several pipe hangers were loose or damaged. All damaged equipment has been repaired. Both decay heat pumps have been rebuilt. Decay heat removal system operating procedures have been revised to address minimum required reactor coolant level and provide improved fill and vent instructions. New breaker and torque switch settings have been established for the isolation valve. Preventative maintenance procedures will require periodic lubrication of the valve drive shaft.

RHR4	Farley 2	11/27/87	Refueling outage	

(from LER Search): This special report is being submitted in accordance with Technical Specification 3.4.10.3. At 0445 on 11-27-87, during a refueling outage, a residual heat removal (RHR) loop suction pressure relief valve opened when one of two series RHR containment sump suction valves in the same train (MOV 8812A) was stroked. Reactor coolant system (RCS) pressure and pressurizer level decreased. The level and pressure in the pressurizer relief tank (PRT) (to which the RHR relief valve relieves) increased and the PRT rupture disk ruptured. Based on these indications, it was believed that the relief valve may have stuck in the open position. To isolate the relief valve, the operators stopped the RHR pump in the affected train and closed the loop suction isolation valves. This event was apparently caused by a localized pressure pulse created when MOV 8812A was opened. The section of pipe

PHASE 2 CATEGORY	PLANT NAME	EVENT DATE	INITIAL PLANT CONDITION	RECOVERY TIME

between the two containment sump suction isolation valves had been drained to perform a local leak rate test and had not been refilled. Apparently, the filling of this space, which occurred when MOV 8812A was opened, caused a localized pressure pulse which resulted in the lifting of the relief valve. To prevent recurrence, the applicable procedures will be changed to ensure that lines drained for local leak rate testing are subsequently refilled.

RHR4 McGuire 1 11/23/88 Mode 6 39 min

(from LER Search): On 11/28/88, at 1643, performance personnel were performing the containment spray (NS) system valve stroke timing procedure for valve 1NS-1B, NS suction from containment sump. About 25 sec after the execution of the valve stroke timing test, RHR (ND) pump 1B lost its suction pressure and operations (OPS) manually stopped the pump to prevent damage to the pump. Unit 1 was in mode 6, refueling, with train 1B of the ND system in operation. OPS implemented loss of ND procedure, and directed the reactor head maintenance crew to exit the reactor cavity area. At 1722, OPS after ensuring that ND train 1A was properly filled and vented, cross connected train 1A to the train 1B heat exchanger to pressurize the train 1A piping, started ND pump 1A, and put train 1A of the ND system in service to provide decay heat removal for the reactor coolant (NC) system. Between 1643 to 1722, the NC system temp. increased from 90 F to 116 F. At 1930, after filling and venting ND train 1B piping and ND pump 1B, OPS started ND pump 1B. At 1950, train 1B of the ND system was put back in service and at 2108, OPS secured ND train 1A. This event is assigned a cause design deficiency because inadequate system venting in the horizontal piping between valves 1NS-1B and 1NI-184B, SI containment sump B train isolation, allowed air to be trapped in the piping and forced the air to the suction of ND pump 1B causing the pump to become air bound.

RHR4 North Anna 1 06/14/82 Mode 5

On 6/14/82, only one of the coolant loops listed in T.S. 3.4.1.3 was operable due to the failure of the Residual Heat Removal Subsystem B Pump (1-RH-P-1B).

RHR4 North Anna 2 08/02/82

With the reactor coolant system drained to mid-loop, one residual heat removal pump was operating. When flow from the operating residual heat removal pump decreased, approx. 200 gallons of water was added to the reactor coolant system to restore flow to normal. Since suction to the operating residual heat removal pump was maintained, decay heat removal capability was not lost. The water level dropped below mid-loop because of a seal leak on one residual heat removal pump combined with inaccurate reactor coolant system water level indication.

RHR4 North Anna 2 08/16/82 Mode 5

The 1A Residual Heat Removal (RHR) pump was removed from service thereby leaving operable only one loop for decay heat removal since the 1B RHR pump remained available to ensure decay heat removal.

RHR4 Rancho Seco 05/05/82 Mode 5

(Sheet 1 of 11) The A Decay Heat Pump inboard bearing was found to be leaking oil. Since the unit was in cold shutdown, the only consequence was the changing over to the B Decay Heat pump.

RHR4 Salem 1 12/13/82 Mode 6

(Sheet 2 of 11) At 0750 hrs, 12/13/82, due to excessive leakage from the mechanical seal, No. 12 Residual Heat Removal (RHR) pump was declared inoperable and Action Statement 3.9.8.2 was entered. No. 11 RHR pump was started to provide RHR flow.

PHASE 2 CATEGORY	PLANT NAME	EVENT DATE	INITIAL PLANT CONDITION	RECOVERY TIME
RHR4	San Onofre	08/31/87	Mode 5	18 hr

(from LER Search): On 8/31/87, at approx. 1900, with Unit 2 in Mode 5 and the reactor coolant system (RCS) at approx. 350 psia and 127 degrees F, failure of alloy steel packing gland follower studs during manual operation of motor operated shutdown cooling system (SDCS) suction isolation valve 2HV-9378 resulted in leakage estimated at 100 gpm through the packing gland. Operation of the SDCS continued via a redundant flow path. RCS inventory was maintained by isolating letdown flow and using charging pumps as depressurization and venting of the RCS proceeded. Containment closure was promptly restored and there was no effluent release from containment above regulatory limits. At 1100 on Sept. 1, a temporary repair was completed which reduced the leak rate to approx. 1/4 gpm, effectively terminating the event. The cause of stud failure has been attributed to (1) packing leakage resulting in wastage due to boric acid corrosion, (2) decrease in lubricating characteristics and hardening of packing, and (3) the initial thrust required to open the valve. Corrective actions include reduction of the maximum thrust necessary to open the valve by installation of a modified packing gland assembly less susceptible to leakage and hardening of packing, and replacement of packing gland studs with corrosion resistent material. The health and safety of plant personnel and the public were not affected by event.

RHR4	Turkey Point 3	10/23/85	Mode 5	

(Sheet 1 of 2) At 0915 on 10/23/85, the 3A Residual Heat Removal (RHR) pump was declared out of service (OOS) when it did not meet the seal leakoff acceptance criteria during an operability test. At this time, the B emergency diesel generator (EDG) was OOS for maintenance. This placed the unit in a condition where upon loss of off-site power, no RHR loop would be available for core cooling for approx. 18 hrs. Plant management decided since the 3A RHR pump could still operate and pump water to leave it lined up to the RHR system until the B EDG was returned to service. This would allow for core cooling in the event that off-site power was lost. TS 3.4.1.E requires two coolant loops be operable and one coolant loop in operation whenever the Reactor Coolant System (RCS) temp. is less than 350 deg Fahrenheit. The 3A RHR pump being OOS exceeded the requirements of this TS. During this event, Unit 3 was in cold shutdown with the 3B RHR pump providing core cooling. The A EDG was operable and the 3A RHR pump was lined up to the RHR system to allow for core cooling in the event of a loss of off-site power until the B EDG was placed back in service. No heat up of the Reactor Coolant System was observed while the B EDG was OOS.

PHASE 2 CATEGORY	PLANT NAME	EVENT DATE	INITIAL PLANT CONDITION	RECOVERY TIME
RHR5	Arkansas Nuclear 1	10/26/88	Mode 6	23 min

(from LER Search): On 10/26/88, with the reactor in a refueling mode, I&C technicians working on a trend recorder in a control room cabinet removed an unlabeled fuse thought to be in line with the power supply to the recorder. This resulted in a loss of power to the controllers for both decay heat removal (DHR) cooler outlet valves CV-1428 and CV-1429. Upon loss of power to their controllers the valves went to the closed position, which was inconsistent with their design failure mode of open. Closure of both these valves resulted in the inoperability of both trains of DHR, due to unavailability of a flow path through the DHR coolers. The event was terminated approx. 20 minutes later when control room operators questioned the I&C technicians about their work, and the technicians reinserted the fuse. During the event, the reactor coolant temperatures increased approx. 18F to a final temperature of approx. 87F. No change in reactor bldg radiological conditions, source range counts or reactor coolant level was noted. Investigations after the event revealed that the cooler outlet valves' electric pneumatic positioner output lines had been reversed causing both valves to fail closed on loss of controller power. The reversed output lines were properly reconnected and both valves were verified to open on loss of power.

(from NUREG-1410) Refueling had been completed and the reactor head re-installed. The reactor coolant system water level was at mid-loop because the reactor coolant pump seal areas and the steam generator manways were open. A technician error caused a loss of power to both decay heat flow control valve controllers, causing the valves to close. Decay heat removal was lost for 23 minutes and reactor coolant temp. increased from 69 deg F to 87 deg F. By design, in order to prevent the unnecessary loss of core cooling capability, the decay heat removal flow control valves fail open upon loss of either control power or control air. Investigation revealed that the valves failed close because the air tubing from the valves' electric-pneumatic positioner had been reversed during installation. The industry was informed of this event in INPO Significant Event Report (SER) 26-89.

RHR5	Arkansas Nuclear 1	12/19/88	zero power	12 min

(from LER Search): On 12/19/88 the decay heat removal (DHR) system inboard suction valve (CV-1050) closed resulting in a loss of DHR system flow. Following indication that the DHR suction valve was closing, the plant operator followed the appropriate procedures to secure the operating DHR pump. Actions were then taken which returned the DHR system to operation in approx. 12 minutes. At the time of the event, a contract electrician was performing equipment inspections in the room which contains a panel housing the control relays for CV-1050. This individual inadvertently jarred the panel housing the control relays for CV-1050 at approx. the time of this event. The cause of this event has been determined to be inadvertent opening of the normally closed permissive contacts of a control relay for CV-1050. As determined during the investigation of this event, the permissive contacts of this relay are sensitive to mechanical shock. As a result of this event, a caution label has been placed at this control panel to caution against mechanical agitation of the panel. A plant modification will be implemented to replace this relay with a model less sensitive to mechanical shock. Additionally, other relays of this type will be reviewed for possible safety or operational problems due to susceptibility of these relays to mechanical shock.

RHR5	Beaver Valley 1	05/12/82	Mode 5	2 min

(From Seabrook): An attempt to start RHR pump (RH-P-1B) failed due to a circuit breaker racking mechanism problem. Immediately prior to this attempt, the power to the bus supplying the operating RHR pump (RH-P-1A) had been removed in accordance with procedure TOP 82-27. This resulted in an interruption of RHR flow lasting 2 minutes.

(from AEOD): Failure to start RHR pump due to circuit breaker problem. RHR pump that had been operating was erroneously secured prior to attempt to startup idle pump (2 min. loss).

PHASE 2 CATEGORY	PLANT NAME	EVENT DATE	INITIAL PLANT CONDITION	RECOVERY TIME
RHR5	Calvert Cliffs 1	02/08/80	Mode 5	1 hr 33 min

(from NSAC52, p. A-11): A pressure spike during pump venting caused an RHRS relief valve to lift and fail to reseat. (Required relief setpoint as 315 + or - 8 psig, but actual relief setpoint was 285 psig, so pressure spike of approx. 35 psig caused event.) Pressurizer level decreased from 140" to 90" (approx. 1,200 gallons of coolant) in about 2 minutes, when the RHRS was stopped and isolated from the RCS, halting the loss of coolant. The relief was gagged and RHRS flow restored 1-1/2 hrs later. An RCP was jogged during the loss of RHRS to circulate coolant.

RHR5	Calvert Cliffs 1	05/17/82		2 min

(from AEOD): Spurious opening of breaker from the operating DHR pump (2 min. loss).

RHR5	Calvert Cliffs 2	01/23/81	Mode 6	5 min

(from NSAC52, p. A-24): Valve position indication was lost for an RHRS suction valve. Questioning the actual valve position, the operator stopped flow temporarily to prevent possible pump damage. Valve position indication and flow were restored.

RHR5	Connecticut Yankee	03/05/88	Mode 5	1 hr 2 min

See description of Connecticut Yankee, 03/10/88 event.

RHR5	Connecticut Yankee	03/10/88	Mode 5	1 hr 22 min

(from LER Search): On 3/10/88 at 1659 while performing a plant heatup from Mode 5 (RCS pressure = 309 psig, RCS temp = 108 F) in preparation for a reactor coolant system (RCS) hydrostatic pressure test, a control operator completing an operating procedure checklist discovered that the residual heat removal (RHR) system had been shutdown for greater than one hour (1 hr, 22 minutes) resulting in a violation of the plant Tech Spec. Following the discovery of this event, a review of the operations log revealed that a similar violation occurred on 3/5/88, during a plant heatup when the operating RHR pump was shutdown for 1 hr, 2 minutes while still in Mode 5. At the time of the discovery, the plant had already entered Mode 4 where operation of the RHR system is not required. Therefore, no immediate corrective action to place the RHR system back in service was necessary. These events are the result of a failure to observe a specific precaution in the plant operating procedure for plant heatup. All licensed operators have been made aware of the violation and changes have been made to the appropriate operating procedures to prevent recurrence. This event is being reported under 10 CFR 50.73(A)(2)(I)(B) since it involved a condition prohibited by the plant's Tech Spec.

RHR5	Cook 2	12/09/82	Mode 6	

The west RHR was in service supplying core cooling at 3000 gpm. A reactor coolant high level alarm was received and investigation of equipment showed that the west RHR pump breaker had tripped.

RHR5	Crystal River 3	07/16/80	Mode 5	21 min

(from NSAC52, p. A-12): Gross packing leak on makeup pump discharge cross connect valve necessitated securing only operable makeup pump, which in turn necessitated securing RCPs due to loss of seal injection. Since the RHRS was not operating, decay heat removal was lost for 21 minutes during interim valve repair. The RHRS was then restored to operation to conduct final repairs. During those repairs, an improper valve lineup on the RHRS heat exchangers caused a rapid cooldown of the RCS and loss of pressurizer level. When recovery was attempted by depressurizing the RCS, and providing RHRS suction from the BWST, injection flow could not be established due to reverse seating of RWST check valves from RCS pressure. Inventory loss due to shrinkage caused pressurizer level to remain offscale for approx. 45 minutes.

PHASE 2 CATEGORY	PLANT NAME	EVENT DATE	INITIAL PLANT CONDITION	RECOVERY TIME

(from NSAC52, p. A-24) Same as above.

RHR5	Crystal River 3	04/21/81	Mode 5	Similar event 10/01/81

(from NSAC52, p. A-28): Final stages of plant cooldown, RHRS initiated and RCPs secured at 270 F and 250 psig; plant then cooled and depressurized over next 15 hrs to 106 F, 50 psig. During depressurization, the injection of auxiliary spray and compensating coolant letdown created a slow pressurizer outsurge of greater than 360 F water into the 'A' hotleg. Further depressurization flashed the hot water in the 'A' hot leg. Pressurizer level increased from about 82" to 180" (equating to a void of approx. 300 ft3). The A loop hot leg RTD read approx. 300 F, which was above the 50 psig saturation temperature.

RHR5	Crystal River 3	10/01/81	Mode 5	

See description of Crystal River 3, 04/21/81 event

RHR5	Davis Besse 1	05/31/80	Mode 6	8 min

(from NSAC52, p. A-23): Indicated decay heat flow dropped low off-scale. The RHRS pump was stopped to prevent possible damage. The other RHRS pump was not available due to maintenance. The pump was restarted after cause of low indication was determined.

(from AEOD): 8-minute loss of DHR flow. The operating DHR pump was secured by a control room operator. (An I&C mechanic took a DHR flow meter out of service to perform surveillance testing. Control room personnel were unaware of this. Upon seeing that the DHR system flow had dropped offscale, a control room operator stopped the pump.)

RHR5	Davis Besse 1	04/18/81	Mode 5	1 min (2 min in AEOD-C)

(from NSAC52, p. A-21): As a result of a small fire in a 345 kV bus, a rapid bus isolation was performed. A 13.8 kV bus was not transferred in sufficient time to prevent a loss of essential 4160 V power to the operating RHRS pump. The emergency diesel started and flow was restored in approx. one minute.

(from AEOD): 2-minute loss of DHR flow. In response to "two burning potential devices" on a bus, the bus was isolated. An error was made in the sequence of transferring power and isolating the bus. Power was lost to the operating DHR pump.

RHR5	Farley 1	03/07/83	Mode 6	

The A Train RHR system was declared inoperable when the 1A RHR pump was inadvertently secured.

RHR5	Farley 1	11/07/86	Mode 5	

A Residual Heat Removal (RHR) loop suction pressure relief valve opened to reduce Reactor Coolant System (RCS) pressure. On 11/7/86, the RCS (in the solid condition) pressure was being increased to 400 psig prior to starting A Reactor Coolant Pump (RCP). The operator increased pressure too rapidly and was unable to stop the increase prior to the 1B RHR loop suction pressure relief valve opening. The opening of the relief valve controlled and reduced the RCS pressure. On 11/15/86, the RCS was being maintained in the solid condition at approximately 400 psig with the 1B and 1C RCPS running. Depending on plant conditions, RCS pressure while solid can either increase or decrease when starting RCP. The operating crew had anticipated a pressure decrease; however, pressure increased when the 1A RCP was started. The operator tried to limit the pressure increase but the 1A RHR loop suction

PHASE 2 CATEGORY	PLANT NAME	EVENT DATE	INITIAL PLANT CONDITION	RECOVERY TIME

pressure relief valve opened. The opening of the relief valve controlled and reduced RCS pressure.

RHR5	Farley 1	11/15/86	Mode 5	

See description of Farley 1, 11/07/86 event.

RHR5	Ginna	05/01/83	Mode 5	

(from Seabrook): The RWST level had decreased to 20% level which required by procedure to stop one RHR pump. The A RHR pump was stopped and flow dropped to zero. Control Room operator noticed MOV-704B (B RHR pump suction valve) closed. The A RHR pump was restarted and flow reestablished and the B RHR pump stopped. Thus for a period of less than two hours while filling the reactor cavity the B RHR pump was run with its suction valve closed. The auxiliary operator checked B RHR pump and found it warm but no seal leakage. The pump was tested for flow and vibration with conditions found normal.

(from AEOD): Filling reactor refueling cavity - low RWST. Secured "A" RHR pump - Suction valve on operating "B" pump was closed. (Duration of event unknown)

RHR5	Indian Point 3	05/12/83	Mode 5	

A small leak was identified on the RHR miniflow at the weld joint between valve 1870 and Line 337.

RHR5	Maine Yankee	06/10/81	Mode 6	5 min

(from NSAC52, p. A-19): RHRS flow was interrupted when an outboard stop valve closed. Valve reopened and flow re-established in five minutes.

RHR5	Millstone 3	06/08/87	Mode 5	33 min

(from LER Search): On June 8, 1987 at 1345 hrs and 0% power, an inadvertent mode change from mode 5 (cold shutdown) to Mode 4 (hot shutdown) occurred. The incident occurred during an investigation by plant personnel to determine why the train B residual heat removal system suction isolation (from the reactor coolant system) valve did not stroke during the previous plant cool-down. The root cause of the inadvertent mode change was operator error. The reactor operator failed to monitor reactor coolant system temperature for a period of 33 minutes and did not identify the possibility of a mode change due to the isolation of the heat sink for the reactor coolant system. The entry into Mode 4 occurred before the appropriate plant technical specifications for the mode change were satisfied. After the incident was identified, the immediate operator action was to return the plant to Mode 5 (cold shutdown) below the maximum temperature requirements. As corrective action, operators have been briefed of the incident and have been reminded of the importance of monitoring plant responses during evolutions. The operator directly involved in the incident has been relieved of license duties until demonstrated deficiencies in performance can be resolved by plant management.

RHR5	North Anna 1	06/01/80	Mode 5	34 min

(from NSAC52, p. A-12 and p. A-24): To check the size of the packing gland on an RHRS valve, the packing gland nut was loosened. The mechanic was not aware that RCS pressure was being increased. The packing came loose, dislodging the packing nut, and leaking primary water into containment. To reduce RHRS pressure, the operating RHRS pump was secured for 34 minutes and the RCS pressure reduced while the packing nut was temporarily installed. One RHRS pump was then operated for 54 minutes. The pump was then secured again to repack the valve. Neither RCPs or RHRS pumps were operated for 1 hour and 43 minutes while repacking the valve.

PHASE 2 CATEGORY	PLANT NAME	EVENT DATE	INITIAL PLANT CONDITION	RECOVERY TIME
RHR5	North Anna 1	02/18/83	Mode 5	5 min

(from Seabrook): On 2/18/83, indications of cavitation were observed on B Residual Heat Removal (RHR) pump and later on A RHR pump. The B pump was started and returned to service in approximately 5 minutes. An RHR pump operability was subsequently verified.

(from AEOD): Both RHR pumps were cavitating. Cause not determined (5 min. loss).

RHR5	Oconee 1	06/29/81	Mode 5	

(from NSAC52, p. A-29): Final stages of plant cooldown: RHRS initiated and last RCP secured at 225 F, 310 psig. Pressurizer level was then reduced from 250 to 100 inches to fulfill an omitted requirement (procedure required lowering pressurizer level to 100" before securing RCPs). This RCS letdown moved 4,000-5,000 gallons of stagnant 423 F water from the pressurizer to the "A" hotleg. The RCS pressure was then lowered. After about 25 hrs of pressurizer cooldown, pressure was lowered below saturation pressure for the hottest water in the "A" loop (120 psig, 350 F). A steam bubble of approx. 300 cu. ft. was formed in the top of the "A" loop "J" leg. A rapid pressurizer insurge occurred as the 300 cu. ft void was formed.

RHR5	Oconee 3	04/06/87	Mode 5	

(from LER Search): On April 6, 1987 at approx. 1500 hrs the reactor coolant (RC) system on Unit 3 was cooled to the extent that technical specification limits in Table 3.1-2 were exceeded. Unit 3 was at cold shutdown and in preparation for startup following a refueling outage. The inadvertent cooldown was due to reactor coolant leaking through the outlet valve (3LP-12) of 3A low pressure injection cooler while the shell side of the cooler was being flushed with low pressure service water. The leakage through 3LP-12 and subsequent cooldown occurred when 3LP-11 was opened in the process of performing an equipment restoration procedure. The root cause of the event was that the procedure for performing maintenance on 3LP-12 did not provide adequate guidance to direct personnel on how to adjust the closing limit switch on valve operators which are controlled by a limit switch on the closing stroke. Immediate corrective actions were taken to isolate the low pressure injection cooler and secure the RC flow by closing valve 3LP-9 upstream of the cooler. The leaking valve 3LP-12 was then manually closed. Linear elastic fracture mechanics analysis of the most limiting reactor vessel beltline metal indicated that this event had no effect on the integrity of the pressure vessel.

RHR5	Palisades	07/18/81	Mode 5	1 hr 30 min

(from NSAC52, p. A-19): A shutdown cooling heat exchanger outlet valve failed closed, causing loss of RHRS flow. Closure of this air-operated valve isolated flow from both RHRS heat exchangers to the RCS. Primary coolant temperature increased from approx. 123 F to 197 F.

RHR5	Rancho Seco	10/03/86	Mode 5	13 min

(from CR5015): Power level - 0%. While in cold shutdown on Oct. 3, 1986, during instrument & control investigation of abnormal indication on panel H2SFB for decay heat system (DHS) "B" room sump stack lights, SFAS "B" bistables tripped causing HV-20002 to close, which tripped DHS "B" pump. The plant was without the use of the normal DHS for approx. 13 minutes. Due to the extended period that the plant has been shut down, there was a small, but detectable increase of reactor coolant temperature. Steps were taken immediately to restore a DHS train to service in accordance with the intent of Tech Spec 3.1.1.5. This event is reportable according to 10 CFR Part 50.73(a)(2)(IV & V). The cause of the incidents was I&C technicians troubleshooting abnormal indication on panel H2SFB for DHS "B" pump room (east) sump stack lights (18" level indication) on panel H2SFB. The immediate cause of the spurious actuation was an electric arc from the sump level stack light when "rolling-over" the respective bulb. The arc initiated the trip of inverter "B". As a long term corrective action, the DC vital power supplies will be modified to be equipped with static transfer switches.

PHASE 2 CATEGORY	PLANT NAME	EVENT DATE	INITIAL PLANT CONDITION	RECOVERY TIME
RHR5	Robinson	06/11/87	zero power	

(from LER Search): On June 11, 1987, during zero power physics testing following a refueling outage, a valve packing failure resulted in primary system leakage of approx. 23 gallons per minute. An unusual event was declared. Initial indications were that the leak was from the #1 seal of "C" reactor coolant pump. Based on an erratic standpipe level and high temperature in the seal leakoff line, the pump was stopped. Later, similar indications were noted for the "B" reactor coolant pump and it too was stopped. Subsequent investigation of the leakage determined the source of the leak to be residual heat removal valve RHR-750 inside containment, based on high temperature in its leakoff lines. Common piping is shared by this line and the pump seal leakoff lines. The packing was replaced, the unusual event terminated, and plant startup reinitiated. The need for additional long-term corrective action is being evaluated.

RHR5	Salem 2	06/12/81	Mode 4	1 hr 5 min

(from NSAC52, p. A-13): During plant cooldown, the RHRS suction relief valve lifted. RHRS pumps were secured and the RHRS suction valves from the RCS were closed to halt the loss of inventory. The RCS depressurization transient was terminated 1 hour 5 minutes after the relief valve actuation. The RHRS was returned to service and RCS pressure increased to 335 psig.

RHR5	Salem 2	05/24/83	Mode 5	

(from Seabrook Sheet 5 of 11): No. 21 Residual Heat Removal (RHR) pump and No. 21 Fuel Handling Bldg exhaust fan were observed to trip. Deenergization of No. 21 RHR pump resulted in no RHR loop being in operation and Action Statement 3.4.1.4B was entered. The pump was immediately restarted and flow restored. No reduction in Reactor Coolant System Boron concentration occurred with the RHR loop inoperable.

(from AEOD): RHR pump trip caused by logic/circuitry problem on the "safeguards equipment control" (SEC) system. (Duration of event unknown)

RHR5	San Onofre 2	03/14/82	Mode 6	90 min

(Sheet 1 of 5) Shutdown cooling was lost due to nitrogen intrusion as a result of backflushing a filter in the purification system. Shutdown cooling flow was lost for 90 minutes. Public safety was not endangered because no irradiated fuel was in the core.

RHR5	Summer	11/06/84		7 min

(from AEOD): A procedural error in testing relays on the bus supplying the DHR pump caused the bus to strip. The associated diesel was out for maintenance (7 min. loss).

RHR5	Surry 1	03/18/89	zero power	11 hr 28 min

(from LER Search): On 3/18/89, at 0912 hrs, it was discovered that the manual RHR and component cooling (CC) valves to the "A" RHR heat exchanger (HX) were open, but the manual RHR outlet valve of the "B" HX was closed. In addition, the CC isolation trip valve TC-CC-109A was closed thus prohibiting CC flow through the "A" RHR HX. Consequently, with no CC flow through the "A" HX and no RHR flow through the "B" HX, there was no RCS cooling loop in operation. This condition had existed since 2144 hrs, March 17, 1989 and is contrary to Tech Spec 3.1.A.1.D.2. The CC con ainment isolation trip valve for the "A" RHR HX was reopened, restoring CC flow to the HX, terminating the loss of RHR cooling and the RCS heat up. Following this discovery, a root cause analysis was performed by the personnel involved. The cause of the event was operator error. The operators were under the incorrect assumption that the "B" RHR HX outlet manual isolation valve was in the open position. In addition, the CC trip valves were manipulated without use of a procedure. Other contributing factors were also identified. Personnel associated with the event were disciplined. The number of off-shift licensed

PHASE 2 CATEGORY	PLANT NAME	EVENT DATE	INITIAL PLANT CONDITION	RECOVERY TIME

operators permitted to assume licensed positions on the same shift has been limited. In addition, off-shift operators must be relieved by an on-shift operator.

RHR5	Surry 2	02/19/86	Mode 5	10 min

(from CR5015): Power level - 0%. On 2-19-86 with Unit 2 at cold shutdown, operators were performing a test of the component cooling (CC) check valves in the residual heat removal (RHR) system. During this test, an operator made an incorrect valve lineup which resulted in the isolation of CC flow to the 'A' RHR heat exchanger and RHR flow to the 'B' RHR heat exchanger for approx. 10 minutes. During this period, RCS temperature and pressure were closely monitored and no abnormal increases were noted. The root cause of this event was human error in that the operator failed to follow the steps in the written procedure which would have ensured the proper valve lineup. A contributing factor was poor communication between the control room operator and the operator performing the valve lineup. The operators involved in this event prepared a report describing the circumstances which led to this error and it will be placed in the operator's required reading manual. This event will also be evaluated by the human performance evaluation coordinator.

PHASE 2 CATEGORY	PLANT NAME	EVENT DATE	INITIAL PLANT CONDITION	RECOVERY TIME
RHR6	Beaver Valley 1	05/03/81	Mode 4	

(from NSAC52, p. A-26): In the process of putting the RHRS in operation, one of the RHRS suction valves would not open, precluding use of the RHRS. The valve was subsequently opened manually.

RHR6	Crystal River 3	03/04/79	Mode 4	

(from NSAC52, p. A-26): During RCS cooldown, both series RHRS suction valves could not be opened from the control room. Both valves are inside containment and were opened by hand to permit RHRS flow.

RHR6	Crystal River 3	04/25/79	Mode 4	

(from NSAC52, p. A-26): An RHRS suction valve failed to open remotely during plant cooldown, due to various problems with the valve's motor operator. The valve was repaired, tested, and restored to service in 13-1/2 hrs.

RHR6	Davis Besse 1	01/07/81	Mode 4	15 min

(from NSAC52, p. A-21): A control room operator attempted to start a decay heat pump as a normal step in establishing RHRS flow during plant cooldown. The pump did not start, and the pump breaker was racked out for inspection. No problems were found; the breaker was racked in, and the pump started successfully.

(from AEOD): DHR pump failed to start due to a breaker problem. Electricians were able to restart the pump after a 15 minute delay.

RHR6	Ginna	03/03/84	Mode 4	

While cooling down the Reactor Cooling System (RCS) to cold shutdown condition for the annual refueling and maintenance outage periodic test PT-2.4.1, cold/refueling motor operated valve surveillance (RHR system - 700 valves) was in progress. MOV-700 (RCS Loop A Residual Heat Removal suction stop valve) failed to stroke to the open position when actuated from the Control Room.

RHR6	Ginna	05/14/84	Mode 4	

On 5/14/84, while cooling down the Reactor Coolant System (RCS) to the cold shutdown condition for sludge lancing and crevice cleaning, MOV-700 (RCS Loop A Residual Heat Removal Suction Valve) failed to stroke to the open position when actuated from the Control Room. Following manual unseating of the valve, maintenance personnel performed an inspection of the valve exterior. This inspection revealed that the packing gland flange had shifted out of the vertical position to a point where the flange was in contact with the valve stem. This could have caused a mechanical binding in the stem and torque-out of the valve operator. The valve was then stroked manually to verify no mechanical binding. The valve was then stroked twice electrically. The valve functioned satisfactorily with proper motor current readings and acceptable opening and closing times indicating no mechanical binding. A visual inspection of the valve stem and stem threads verified adequate cleanliness and lubrication. Torque switch settings were verified within the manufacturers design settings. On 5/22/84 when the RCS was heating up to hot shutdown, the valve was again stroked to verify proper operation. Again, the valve functioned properly with proper motor current readings and acceptable opening and closing times. Operation of this valve will continue to be monitored during the next cooldown of the RCS.

RHR6	Oconee 2	09/18/81	Mode 1	

(from NSAC52, p. A-27): Primary to secondary leakage was detected indicating a OTSG tube leak. The unit was shut down, cooled down and depressurization initiated to reduce the leak rate. When plant conditions permitted, RHRS operation was attempted. A RHRS suction valve failed to open on demand. A reactor bldg entry was made to open the valve manually. After three unsuccessful attempts to open the

PHASE 2 CATEGORY	PLANT NAME	EVENT DATE	INITIAL PLANT CONDITION	RECOVERY TIME

valve manually, the entire valve operator was removed and the valve opened with manual hoists. RHRS operation was then established, RCPs secured, and the RCS depressurized to stop the OTSG tube leak.

RHR6 Oconee 3 10/15/85 Mode 4

(from Seabrook Sheet 3 of 4) An unsuccessful attempt to open an electric motor operated (EMO) valve (3LP-2) was made from the Unit 3 Control Room. Unit 3 was in hot shutdown after coming off-line for maintenance. The valve is required to open in order to indicate the decay heat removal cooling mode.

(from CR5015): Power level - 0%. On 10-15-85 at 0955 hrs, an unsuccessful attempt to open an electric motor operated valve was made from the Unit 3 control room. Unit 3 was in hot shutdown after coming off-line for maintenance. The valve is required to open in order to initiate the decay heat removal cooling mode. The cause of the incident was the torque switch settings on the valve. Rotork nuclear actuator settings were not set high enough to operate the valve under system pressure. The EMO valve torque switch settings were not specified in the design modification package used to replace the valve actuator with a new Rotork nuclear actuator. The corrective action was to open the valve from the valve actuator contacts at the motor control center, bypassing the valve actuator's torque switch limit control circuit. The analysis supporting the licensing basis for Oconee does not require the immediate opening of this valve. The failure to immediately open this valve only results in a delay in the initiation of decay heat removal cooling mode.

RHR6 Robinson 07/15/82 Mode 6

(Sheet 1 of 4) On both occasions, motor operated valve, RHR-759A, a residual heat removal exchanger discharge valve, failed to open.

RHR6 Robinson 07/27/82 Mode 6

(Sheet 1 of 4) On both occasions, motor operated valve, RHR-759A, a residual heat removal exchanger discharge valve, failed to open.

RHR6 San Onofre 2 04/26/83 Mode 4

(Sheet 1 of 4) Preparations in progress for Mode 3 entry, Shutdown Cooling System (SDCS) heat exchanger isolation valves 2HV8150, 2HV8152 and 2HV8153 could not be remotely operated from the Control Room upon initiation of shutdown cooling to avoid personnel radiation exposure from local operation.

RHR6 Turkey Point 4 05/23/89 Mode 4

(from LER Search): On 5/23/89, at 1820 EST, with Unit 4 in Mode 4 and the reactor coolant temperture below 350 degrees, residual heat removal (RHR) motor operated valve MOV-4-751, RHR normal suction isolation valve, failed to open with the control switch. This valve was to be opened from the alternate shutdown panel to place RHR in service for its normal heat removal function as part of an operability check of the panel. When this valve failed to open, the reactor continued to be cooled by removing heat through the steam generators. The valve was manually moved from its seat. The valve subsequently stroked smoothly with the control switch. The root cause of this event is hydraulic locking of the valve. To prevent recurrence of this problem, the valve has been modified with an equalizing line which will assure that the pressure in the bonnet of the valve is at an equal or lower pressure than the high pressure side of the valve. Additionally, MOV-4-750, the RHR valve immediately upstream of valve MOV-4-751, has been modified. The corresponding Unit 3 valves will also be modified to assure that these valves do not experience a hydraulic locking event. The Unit 3 valves, MOV-3-750 and MOV-3-751, will be modified prior to the Unit's return to power.

Appendix A.2.2 Loss of 4 kV Bus (4 kV, 4 kV/P6)

PHASE 2 CATEGORY	PLANT NAME	EVENT DATE	INITIAL PLANT CONDITION	RECOVERY TIME
4KV	Arkansas Nuclear 1	12/05/89	CSD	

(from LER Search): On 12/5/89 at 0645 and 12/6/89 at 2205, while the plant was shutdown in a maintenance outage, automatic actuations of an emergency diesel generator (EDG) occurred as a result of loss of power to a 480 volt (V) engineered safeguards (ES) bus. Prior to both events, the B5 and B6 480V ES busses were crossconnected to facilitate maintenance activities. The Dec. 5 event occurred as a result of a personnel error which occurred while operators were attempting to "splitout" the B5 and B6 busses and return the ES power distribution system lineup to normal. The error resulted in a loss of power to Bus B6 which caused the offsite feeder breaker for 4.16 kilovolt bus A4 to open and initiated a start of the 'B' EDG which tied on to the A4 bus. The Dec. 6 event was also the result of a personnel error which caused a loss of power to 480V ES Bus B5. This condition caused the offsite feeder breaker for A3 to trip and the 'A' EDG to start. The momentary loss of power to A3 caused the operating decay heat removal (DHR) pump to trip. DHR flow was lost for approx. 9 minutes and resulted in a reactor coolant system temp. increase of 17 degrees. Management briefings were conducted for the operating crews prior to restart from the outage covering the lessons learned from these events.

4KV	Arkansas Nuclear 1	12/06/89	CSD	9 min

See description of Arkansas Nuclear 1, 12/05/89 event.

4KV	Arkansas Nuclear 2	11/14/89	Shutdown	1 min

(from LER Search): On 11/14/89, maintenance personnel initiated a post maintenance test, using instructions in a maintenance job order, to simulate an undervoltage on a 480 Vac engineered safety features (ESF) motor control center (2B5) by placing a jumper across the 2B5 undervoltage relay contacts. Immediately following this step, the normal offsite power feeder breaker to the associated 4160 Vac ESF bus (2A3) unexpectedly opened resulting in the loss of power to 2A3. The electrical bus deenergized as designed. The test steps provided in the job order did not identify that 2A3 would deenergize as part of the test. When 2A3 was deenergized, a low pressure safety injection (LPSI) pump, which was supplying flow for decay heat removal and a service water pump deenergized. A standby LPSI pump powered from the redundant 4160 Vac ESF electrical bus was started in approximately one minute and flow reestablished. Since the plant had been shutdown for several days prior to this event, the reactor decay heat levels were low and the momentary interruption of flow did not result in any significant reactor coolant system temperature or pressure increases. The test was reevaluated and satisfactorily completed. The root cause of this event was determined to be inadequate post maintenance test controls.

4KV	Beaver Valley 1	07/03/79	Mode 5 or 6	21 min

(from NSAC52, p. A-20): While switching a vital bus to the alternate source, containment isolation phase B (high-high containment pressure) actuation occurred. This tripped both emergency 4 kV stub bus breakers resulting in loss of the operating RHRS pump.

4KV	Catawba 1	01/07/89	Mode 5	

(from LER Search): On 1/7/89 at approx. 0302 hrs, 6900V tie breaker ITC-7 tripped after reactor coolant (NC) pump 1C had been started and power to 4160 essential bus 1ETA was lost. The loss of power caused an isolation of the bus with no back-up power available due to diesel generator 1A being out of service. The blackout resulted in a loss of power to residual heat removal pump 1A, fuel pool cooling pump 1A, and component cooling pump 1A2. Subsequently, due to a charging flow control valve failing open, NC system pressure increased and caused a pressurizer PORV to lift 7 times. The 6900V switchgear 1TC is separated into two sides which are connected by normally open tie breaker 1TC-7. The tie breaker was closed because 1T2A was out of service. The tie breaker tripped open on overcurrent because a ground overcurrent relay was installed in the time delay overcurrent relay location. The ground overcurrent relay was not designed for the inrush current caused by starting the NC pump. The

PHASE 2 CATEGORY	PLANT NAME	EVENT DATE	INITIAL PLANT CONDITION	RECOVERY TIME

unit was in Mode 5, cold shutdown, when the incident occurred and had operated in all modes of operation. This incident is attributed to an inappropriate action. It appears the relays were swapped during the initial installation during 1978. Time delay and ground overcurrent relays were placed into the correct locations. An inspection was performed to verify the correct relays were installed in all other similar applications.

4KV Crystal River 3 08/28/89 Mode 5 19 min

(from LER Search): Crystal River Unit 3 was in Mode 5 (cold shutdown) to perform repairs to a nuclear services raw water pump with the "B" decay heat train (DH) removed from service. The "A" DH train was operating and the reactor coolant system was filled and intact with an operable steam generator. At 0237 on Aug. 28, 1989, the "A" 480 volt engineered safeguards (ES) stepdown transformer faulted causing DH closed cycle cooling pump "A" (DCP-1A) to de-energize. Loss of DCP-1A removed the cooling for DH train "A", rendering this train inoperable. At 0256, DH train "B" and its support systems were started. The "A" and "B" 480 volt ES buses were then cross-tied to provide AC power to the "A" bus. The loss of DH cooling caused an increase in RCS temperature and an inadvertent entry into Mode 4 (hot shutdown). The transformer has been replaced. The transformer faulted due to insulation degradation caused by aging. During the event, operators attempted to operate the "B" train DH suction isolation valve (DHV-40) from the control room. This valve failed because the nut securing the linkage between the motor operator and the valve stem had backed off from normal operation. DHV-40 has been repaired and the nut on the linkage has been staked to prevent it from backing off. The redundant valve, DHV-39, will be staked.

4KV Ft. Calhoun 12/14/85 Refueling shut. 15 min

(from CR5015): Power level - 0%. On 12-14-85 at 1010 hrs while in a refueling shutdown, a DC bus and 2 AC instrument buses were lost as well as all essential 480V buses. The loss of power initiated safeguard signals: pressurizer pressure low signal, safety injection actuation signal, containment isolation actuation signal, and ventilation isolation actuation signal. Also lost due to the power failure were shutdown cooling, compressed air, turbine plant cooling water and some control room indications. The power failure occurred due to the personnel error and an altered electrical distribution system lineup due to testing, maintenance, and modification work. The technician inadvertently tripped the relay controlling the breaker that was providing the 161 kv power to the 4160v 1A4 safeguards bus and which in turn power all 480V buses including the battery chargers. With the loss of the battery chargers, DC bus #2 became inoperable because battery #2 was disconnected for maintenance. Also, AC instrument buses B and D were inoperable as they are powered from DC bus #2. This resulted in a partial loss of control room indications. Corrective action included restoring power to the 480V buses within 15 minutes. A meeting was held with the individuals involved before allowing them to return to their testing.

4KV McGuire 1 11/29/88 zero power

(from LER Search): On 11/29/88, operations was restoring the 1A busline to service and noticed that standby breaker 1TD-6, which supplies switchgear group 1TD of the 6900V bus, required excessive pressure to rack in the connect position. To ensure there were no problems with the breaker, OPS decided to test the breaker by cycling it. An OPS supervisor instructed an operator to rack the breaker to the test position, cycle it, and then restore it to the connect position. With the breaker in test and the control board switch in manual, the operator closed the standby breaker at 2112 from the control room. The normal breaker opened as designed and power was lost to switchgear group 1TD resulting in a train B blackout. Residual heat removal (ND) pump 1B auto tripped because it is not a blackout load. The diesel generator auto started and loaded as required. Normal power was restored and ND pump 1B was restarted to restore core cooling. The reactor coolant temp increased by 4F during

PHASE 2 CATEGORY	PLANT NAME	EVENT DATE	INITIAL PLANT CONDITION	RECOVERY TIME

the time that ND pump 1B was shut down. This event is assigned a cause of management deficiency because the OPS supervisor did not provide adequate written and/or verbal instructions to the operator for correctly testing standby breaker 1TD-6, and a contributory cause of defective procedure because procedure OP/1/A/6350/08, operation of station breakers, did not contain precautions prior to testing breakers.

4KV	Millstone 2	12/09/81	Mode 5	30-60 min

(from NSAC52, p. A-22): With the RCS depressurized and drained to the hot leg midpoint, the running RHRS pump tripped due to 345 kV switchyard breaker testing. Core heatup from 90 F to over 208 F occurred over a period of about 30-60 minutes. When the RHRS pump was restarted, previously colder, stagnant RHRS temperatures increased from 90 F to 208 F in about 2 minutes. The second RHRS pump was started, and the hot coolant in the core area and the colder coolant in the RCS and RHRS continued to equalize, resulting in an RHRS temperature drop to 130 F in about 7 minutes.

4KV	North Anna 1	03/23/89	Mode 5	10 sec

(from LER Search): At 1053 hrs on 3/23/89, with Unit 1 in Mode 5 (cold shutdown), the "1H" emergency bus was inadvertently de-energized for approx. 10 seconds during the performance of 1-PT-82.3A, 1H diesel generator test (simulated loss of offsite power in conjunction with an ESF actuation signal). This is considered an inadvertent engineered safeguards feature (ESF) actuation and is reportable pursuant to 10 CFR 50.73(A)(2)(IV). A four hour report was made in accordance with 10 CFR 50.72(A)(2)(II). Immediate corrective actions included automatic start of the "1B" component cooling water pump, the manual start of the "1B" residual heat removal pump, and verification that de-energized equipment was either returned to service or was reset. Further corrective actions include investigating and correcting the circuit design of the trip block relay. In addition, appropriate emergency diesel generator periodic tests will be revised to prevent testing when in an abnormal electrical configuration. This event posed no significant safety implications because the "1H" emergency diesel generator (EDG) started as designed and reloaded the "1H" emergency bus in less than 10 seconds. In addition, the "1J" EDG was operable and was capable of providing power to required systems when the "1H" emergency bus was inadvertently de-energized.

4KV	North Anna 1	04/16/89	Mode 5	

(from LER Search): On April 16, 1989 at 1115 hrs, with both units in Mode 5 (cold shutdown) the normal power supply to 1H and 2J 4160V emergency bus was lost when a lifted wire was inadvertently grounded during removal for switchyard modifications required for design change package (DCP) 88-05. The 1H and 2J emergency diesel generators automatically started on the loss of power and re-energized their associated emergency bus. This event is an engineered safety feature (ESF) actuation and reportable pursuant to 10 CFR 50.73(A)(2)(IV). A four hour report was made pursuant to 10 CFR 50.72(B)(2)(II). In conjunction with the loss of power the Unit 1 residual heat removal (RHR) pump, 1-RH-P-1A, tripped on undervoltage and is reportable pursuant to 10 CFR 50.73(A)(2)(V)(B). Abnormal procedure 10 was initiated and 1H and 2J emergency diesel generators (EDG) were verified in operation and supplying their respective bus. Abnormal procedure (AP) 11.2 was also initiated and residual heat removal capability subsequently restored on Unit 1 by starting "B" RHR pump. No significant safety consequences occurred due to this event, since the redundant emergency bus remained available to supply power to required plant equipment. Also, the 1H and 2J EDGs auto started and re-energized the emergency busses as designed.

4KV	North Anna 2	04/16/89	Mode 5	

See description of North Anna 1, 04/16/89 event.

PHASE 2 CATEGORY	PLANT NAME	EVENT DATE	INITIAL PLANT CONDITION	RECOVERY TIME
4KV	Rancho Seco	12/08/86	Mode 5	

(from Seabrook Sheet 20 of 20) The plant was in cold shutdown removing decay heat via the Decay Heat Removal System (DHS) Train B on Dec. 8, 1986. Startup transformer #1 was scheduled for routine preventive maintenance. A loss of the 4A bus power attendant diesel generator start and decay heat system (DHS) isolation occurred during the transfer of the source transformer at 2:18 PM on Dec. 8, 1986.

(from CR5015): (Make E.10 Table A.4) Power level - 0%. The plant was in cold shutdown, removing decay heat via the decay heat removal system (DHS) train "B" on Dec. 8, 1986. Startup transformer No. 1 was scheduled for routine preventive maintenance. A loss of the 4A bus power, attendant diesel generator start, and decay heat system (DHS) isolation occurred during the transfer of the source transformer at 2:18 PM on Dec. 8, 1986. An automatic feature of the nuclear service bus is a five-second limit on having two sources feeding the bus. The control room operator closed startup transformer No. 2 supply breaker 4A10 onto the 4A bus. When the operator opened the supply breaker (4A01) from startup transformer No. 1, breaker 4A10 from startup transformer No. 2 had just completed the automatic five-second run-out and had tripped open. These events left the 4A bus without either the normal or alternate supply. An attendant result was that when power was restored, DHS suction valve HV-20001 closed as would be expected in this situation causing the DHS isolation. The power supplies to both HV-20001 and HV-20002 are currently racked out. The purpose for the DHS system valve interlocks is to prevent over-pressuring the DHS piping with RCS pressure. Since the RCS is "open to atmosphere" there is no need for the interlocks to protect the DHS piping from over-pressure.

4KV	Salem 1	04/24/79	Mode 6	2 min (second event on 05/08/79)

(from NSAC52, p. A-20): Twice during performance of tests on vital bus breakers, the vital bus supplying the operating RHRS pump was inadvertently de-energized causing a loss of RHRS flow. Flow was restored in 2 minutes and 4 minutes respectively.

4KV	Salem 1	05/08/79	Mode 6	4 min (1st event on 04/24/79)

(from NSAC52, p. A-20): Twice during performance of tests on vital bus breakers, the vital bus supplying the operating RHRS pump was inadvertently de-energized causing a loss of RHRS flow. Flow was restored in 2 minutes and 4 minutes respectively.

4KV	Salem 1	03/16/82		45 min

(from AEOD): Vital bus tripped. Component cooling water and service water were lost. Redundant trains were out for maintenance (45 min. loss).

4KV	Salem 2	12/20/83	Mode 5	22 min

(from Seabrook Sheet 8 of 20): During a maintenance shutdown, 2RH1 closed, resulting in a loss of RHR flow. The event took place during the transfer of 2B4KV vital bus from one station power transformer to the other. The backup power supply for 2B instrument inverter was deenergized for maintenance. The transfer resulted in a momentary loss of the instrument bus; 2RH1 closed in interlock.

(from AEOD): Loss of vital bus - due to personnel error resulted in closure of suction/isolation valve (22 min. loss).

4KV	Surry 1	05/24/86	Mode 6	

(from Seabrook Sheet 10 of 11) On 5/24/86, Unit 1 was at refueling shutdown with Reactor cavity flooded and forced circulation in service; Unit 2 was at 100% power. Due to maintenance and design

PHASE 2 CATEGORY	PLANT NAME	EVENT DATE	INITIAL PLANT CONDITION	RECOVERY TIME

change work in progress on Unit 1, numerous electrical busses were cross tied. Among these were 1h and 1J4160V emergency busses and vital busses 1-II and 1-IV. #1 emergency diesel generator was out of service. At approximately 1520 hrs, reserve station service feeder breaker 15Da opened. This resulted in an undervoltage transient sensed at 1J emergency bus. #3 emergency diesel generator autostarted and assumed load. By design, the 1J stub bus breaker opened during the transient which resulted in the loss of the operating 1B residual heat removal and 1B component cooling pumps. The stub bus breaker was reset and the components were returned to service. Numerous spurious trip signals, alarms and A Hi Consequence Limiting Safeguards signal were generated during the transient.

(from CR5015): Power level - 0%. On May 24, 1986 Unit 1 was at refueling shutdown with reactor cavity flooded and forced circulation in service; Unit 2 was at 100% power. Due to maintenance and design change work in progress on Unit 1, numerous electrical buses were cross tied. Among these were 1H and 1J 4160V emergency buses and vital buses 1-II and 1-IV. #1 emergency diesel generator was out of service. At approx. 1520 hrs, reserve station service feeder breaker 15D1 opened. This reuslted in an undervoltage transient sensed at 1J emergency bus. #3 emergency diesel generator auto started and assumed load. By design, the 1J stub bus breaker opened during the transient which resulted in the loss of the operating 1B residual heat removal and 1B component cooling pumps. The stub bus breaker was reset and the components were returned to service. Numerous spurious trip signals, alarms and hi consequence limiting safeguards signal were generated during the transient.

4KV Three Mile Island 1 01/09/87 Refueling shutdown

(from LER Search): TMI-1 was in refueling shutdown mode with "B" decay heat removal system in operation. Appendix R modification work required that a wire be lifted in the circuit for the 1E 4160V current transformer. Unbeknownst to the electrician, he lifted and opened one phase on the 1E bus current transformer. With this phase open, the imbalance caused an apparent neutral current and operation of the neutral overcurrent relay. This protective feature tripped and locked out the feeder breakers to the 1E bus. The resulting undervoltage condition on the 1E bus caused the auto start of the B emergency diesel generator. The root cause of the event was inadequate instruction to the electrician performing the work at an energized bus. The automatic start of the emergency diesel generator is reportable under 10 CFR 50.73(A)(2)(IV). There was no safety significance to the auto start of the emergency diesel generator. Although the operating decay heat removal system was momentarily shutdown due to the de-energized 1E 4160V bus, there was no safety significance since the backup system was available. Corrective action taken was to reconnect the wire, reset the lockout, and re-energize the bus. Work was stopped and not restarted until the work instructions were assessed and an appropriate sequence developed.

4KV Wolf Creek 10/16/87 17 min

(from NUREG-1410): The unit was in a refueling outage and the refueling cavity was flooded with 60 fuel assemblies in the reactor. One emergency diesel generator had been removed from service and one safety bus had been removed from service for cleaning. An electrician came in contact with a lead energized from the other safety bus. The energized bus deenergized. The emergency diesel generator started and loaded. The emergency diesel generator output breaker was tripped to remove the electrician who came in contact with the energized lead. After the electrician was removed, the emergency diesel generator output breaker would not close. The anti-pump circuit of the output breaker prevented reclosure of the breaker once it had been opened after the diesel generator started on undervoltage. Decay heat removal capability was lost for 17 minutes. The industry was informed of this event in INPO Significant Event Notification (SEN) 22.

PHASE 2 CATEGORY	PLANT NAME	EVENT DATE	INITIAL PLANT CONDITION	RECOVERY TIME
4KV/P6	Calvert Cliffs 1	11/12/80	Mode 5 or 6	10 min

(from NSAC52, p. A-17): A 4 kV bus normal feed breaker spuriously opened. The diesel generator started automatically, re-energizing the bus. During the voltage transient, a vital bus voltage went low, and ESFAS A logic actuated, which caused a loss of shutdown cooling flow.

4KV/P6	Diablo Canyon 1	01/25/85	Mode 5	2 min

(from Seabrook): A loss of vital 4KV bus voltage resulted in the autostarts of diesel generator (DG) 1-2, Containment Fan Cooler System 1-5, and Auxiliary Saltwater pump 1-2. In addition, for approximately 2 minutes, the Decay Heat Removal Capability was lost when the closure of the loop 4 RHR suction valve (MOV-8702) resulted in both Residual Heat Removal (RHR) trains being isolated from the Reactor Coolant System. The RHR suction valve was subsequently opened and RHR flow established. Within two minutes all other affected equipment and systems were returned to their normal standby conditions.

(from CR5015): Power level - 0%. At 1750 PST, 1-25-85, with Unit 1 in Mode 5 (cold shutdown), a loss of vital 4KV bus voltage resulted in the autostarts of DG 1-2, containment fan cooler system 1-5, and aux saltwater pump 1-2, and the transfer of the control room ventilation system to mode 4. In addition, for approx. 2 minutes, the decay heat removal capability was lost when the closure of the loop 4 RHR suction valve (MOV-8702) resulted in both RHR trains being isolated from the RCS. The RHR suction valve was subsequently opened and RHR flow established within 2 minutes. All other affected equipment and systems were returned to their normal standby conditions. Investigation has shown that the cause of this event was misadjustment of the aux switches on the bus G feeder breakers (HG 13 and 14). The aux switches were adjusted to a new tolerance and the breakers were tested with satisfactory results. To prevent recurrence, procedure E-51.2, "4.16KV circuit breaker PM (preventative maintenance)," is being revised to identify the specific aux switch adjustment required for the bus feeder breakers. Similar events 275/85-004 and 85-005.

4KV/P6	Farley 1	01/16/81	Shutdown	1 min

(from NSAC52, p. A-21): A loss of power to a startup transformer de-energized 4160 V power to the running RHRS pump. The emergency diesel generator auto started and re-energized the bus, and the RHRS pump was restarted. Flow was lost for 1 minute.

4KV/P6	North Anna 2	04/08/83	Mode 5	

(Sheet 4 of 11) On 4/8/83 power was lost to the A Residual Heat Removal (RHR) subsystem when the 2H 4160 volt emergency bus was de-energized. This action resulted in leaving only one coolant loop (B RHR subsystem) operable. A single RHR loop provides sufficient heat removal capability in Modes 4 or 5.

4KV/P6	Salem 1	01/04/83	Modes 4 and 5	

(from Seabrook Sheet 3 of 11) The Control Room operator observed that No. 1B vital bus had tripped. Since it is supplied from the bus, No. 12 residual heat removal (RHR) pump was deenergized; loss of the pump rendered the associated RHR loop inoperable and Action Statement 3.4.1.4A was entered. The operator immediately started No. 11 RHR pump to restore core cooling flow. The second pump remained operable.

4KV/P6	Salem 2	04/13/83	Mode 5	< 1 min

See description of Salem 2, 04/18/83 event.

4KV/P6	Salem 2	04/18/83	Mode 5	< 1 min

(Sheet 4 of 11) On two separate occasions, on 4/13 and 4/18, operating loads on the No. 2A 4KV and 460V vital buses were observed to trip. In both cases, due to the de-energization of No. 21 Residual Heat Removal (RHR) pump No. 21 RHR loop was no longer in operation. In each instance, the RHR loop was

PHASE 2 CATEGORY	PLANT NAME	EVENT DATE	INITIAL PLANT CONDITION	RECOVERY TIME

immediately returned to operation.

4KV/P6	Surry 1	02/04/89	Mode 5	3 min

(from LER Search): On Feb. 4, 1989, at 2345 hrs, with Units 1 and 2 in cold shutdown, the #1 and #3 emergency diesel generators auto-started and loaded onto the 1H and 2J emergency busses respectively. This event is reported pursuant to 10 CFR 50.73(a)(2)(IV). The diesels started due to the de-energization of the 1H and 2J emergency busses due to the failure of a 4160 volt supply circuit breaker. The running residual heat removal (RHR) pump de-energized during the event. The redundant RHR pump was started approx. 3 minutes later to supply RHR flow. The failed circuit breaker was cleaned and tested satisfactory. Safety-related 4160 volt supply circuit breaker operator mechanisms will be refurbished. The preventive maintenance program for 4160 volt circuit breakers is being evaluated.

4KV/P6	Surry 1	04/06/89	Mode 5	1 min

(from LER Search): On April 6, 1989 at 0431 hrs, with Units 1 and 2 in cold shutdown, an electrical fault in the plant switchyard resulted in the failure of a lightning arrestor on the 500 kv side of the #2 auto-tie transformer. This reuslted in a differential lockout of the transformer which created under voltage conditions on the electrical buses, including the 1H and 2J 4160v emergency buses, that were being supplied by the transformer. A number of components were de-energized, including the operating "A" residual heat removal (RHR) pump for Unit 1 and certain Unit 1 radiation monitors. The redundant "B" RHR pump was started within one minute. The #3 emergency diesel generator auto started and loaded on to the de-energized 2J emergency bus. Operators performed the appropriate procedures to restore power to the affected electrical buses and components. This event is being reported due to violations of technical specifications and an unplanned engineered safety features actuation. The cause of the lightning arrestor failure cannot be determined. Some minor component failures were noted during the event. The cause of these failures are being investigated and corrective actions will be taken as appropriate.

4KV/P6	Surry 2	02/04/89	Mode 5	

See description of Surry 1, 02/04/89 event.

4KV/P6	Surry 2	04/06/89	Mode 5	1 min

See description of Surry 1, 04/06/89 event.

Appendix A.2.3 Loss of Vital Bus (VITAL)

PHASE 2 CATEGORY	PLANT NAME	EVENT DATE	INITIAL PLANT CONDITION	RECOVERY TIME
VITAL	Calvert Cliffs 2	02/04/81	Mode 6	17 min

(from NSAC52, p. A-5): RHRS flow was lost due to inadvertent de-energization of one 120 V ac vital bus. De-energizing the vital bus caused a high pressure input to an RHRS suction valve control circuit, causing the valve to shut. The pump was stopped, vital bus re-energized, and flow restored in 17 minutes.

VITAL	Calvert Cliffs 2	11/22/82	Mode 6	4 min

(from Seabrook): While deenergizing instrument power supply panel 2V02, shutdown cooling flow was lost. A shutdown cooling return valve, 2-SI-652, shut when this panel was deenergized due to an incorrectly installed temporary jumper meant to prevent 2-SI-652 closure. Shutdown cooling flow was restored four minutes later.

(from AEOD): Technician incorrectly de-energized a power supply panel; caused closure of a DHR return valve (4 min. loss).

VITAL	Calvert Cliffs 2	11/24/82		

(from AEOD): DHR lost due to a failed power supply. (Duration of event unknown).

VITAL	Calvert Cliffs 2	12/28/82		

Vital inverter failed, caused an isolation of the DHR return line. (Duration of event unknown.)

VITAL	Calvert Cliffs 2	01/04/83		15 min

Inverter tripped during surveillance testing - caused isolation of the DHR return line. (15 min loss)

VITAL	Catawba 1	11/26/88	Mode 5	2 sec

(from LER Search): On 11/26/88, at 1805:07 hrs, static inverter 1EID and 120 VAC power panelboard 1ERPD experienced an undervoltage condition for approx. 2 seconds. As a result, multiple alarms associated with engineered safeguards features were displayed in the control room. The nuclear service water (RN) pit B emergency lo level alarm occurred and cleared when it was acknowledged. All idle RN pumps started as expected and the suction valves and discharge valves for the system automatically swapped to the standby nuclear service water pond. There was a false reactor coolant (NC) system wide range pressure signal which caused residual heat removal (ND) system suction isolation valves 1ND1B and 1ND36B to close as expected. In addition, containment purge (VP) system train B, which was in service, automatically shutdown. The Unit 1 control room area ventilation system train B filter inlet valve closed due to a false chlorine detection alarm. Unit 1 was in Mode 5, cold shutdown, at the time of this incident. Unit 2 was in Mode 1, power operation, at 48% reactor power at the time of this incident. A work request was closed out. Following the undervoltage condition, operations personnel noted a ground on 125 VDC distribution center 1EDD. This condition is being investigated. The root cause for this incident could not be determined.

VITAL	Davis Besse 1	06/28/79	Mode 5	18 min

(from NSAC52, p. A-2): An accidental short circuit in one channel of reactor protection was caused by a slipped alligator clip during surveillance testing. This blew an inverter fuse, causing the loss of an essential bus. Loss of power to the SFAS channel on that bus actuated the pressure bistable trip input on one RHRS suction valve, causing a loss of RHRS flow. The RHRS pump was secured to protect the pump. The bus was reenergized from an alternate source, the suction valve reopened, and flow restored.

(from AEOD): 18-minute loss of DHR. During surveillance testing, a slipped alligator clip caused a short circuit and failure of power supply to an SFAS channel. As a result, DHR suction valve closed.

PHASE 2 CATEGORY	PLANT NAME	EVENT DATE	INITIAL PLANT CONDITION	RECOVERY TIME
VITAL	Diablo Canyon 2	01/17/86	Mode 5	13 min

(from Seabrook): At 0455 PST on 1/17/86, while attempting to transfer instrument AC Panel PY 2-1A from normal to backup power supply, an unlicensed operator went to the wrong panel and inadvertently transferred instrument AC Panel PY 2-1 to its backup power source. This momentary loss of power caused relay actuation which resulted in the closure of Residual Heat Removal (RHR) valve 8702.

(from CR5015): Power level - 0%. At 0455 PST on 1-17-86, while attempting to transfer instrument AC panel by 2-1A from normal to backup power supply, an unlicensed operator went to the wrong panel and inadvertently transferred instrument AC panel PY 2-1 to its backup power source. This momentary loss of power caused relay actuation which resulted in the closure of residual heat removal (RHR) valve 8702. In response to the ensuing loss of flow alarm, RHR pump 2-1 was secured by a licensed operator. RHR valve 8702 was reopened from the control room. RHR pump 2-1 was restarted, observed for seal damage, and declared operable at 0508 PST, 1-17-86. No operations were in progress that involved a reduction in reactor coolant system boron concentration. Thus, the requirements of Tech Spec 3.4.1.4.1 action B were met. To prevent recurrence, the operator involved has been counseled, operating procedures on transferring instrument AC panel power supplies will be revised, and panel identification labels in the instrument AC panels will be upgraded.

VITAL	Diablo Canyon 2	06/29/87	Mode 4	5 min

(from LER Search): At 1829 PDT on June 29, 1987, with the Unit in Mode 4 (hot shutdown), a faulted coil on relay 2TC441HX initiated a voltage transient on instrument power panel PY-24, which resulted in closure of residual heat removal (RHR) valve 8701. The momentary voltage transient resulted in an actuation of the RHR autoclosure interlock (ACI) function since the ACI and the faulted relay share a common instrument power supply. The ACI activation caused RHR valve 8701 to close. The licensed operators noted that RHR pump 2-1 discharge temperature was decreasing rapidly and then observed RHR valve 8701 was shut. In response to the valve closure, RHR pump 2-1 was secured and valve 8701 was reopened. RHR pump 2-1 was restarted at 1834 PDT, and no abnormal pump seal leakage was observed. The four hour non-emergency report required by 10 CFR 50.72(B)(2)(III)(B) was made at 1945 PDT. The failure of the relay was a result of the coil shorting. Melted nylon around the iron core interface surfaces and some slight corrosion of the surfaces was noted. Pgande is preparing a letter for submittal to the NRC requesting and justifying removal of the RHR ACI function. The RHR ACI function will be removed after NRC staff review and approval of the proposed change.

VITAL	McGuire 1	06/24/82		6 min

(from AEOD): Inverter failure caused closure of suction/isolation valve (6 min. loss).

VITAL	McGuire 1	07/13/82		

Static inverter EVIA malfunctioned causing a residual heat removal system (ND) isolation valve to close. Operators restored ND flow, but not before loss of flow effected a transition from Mode 5 to Mode 4.

VITAL	Millstone 2	01/06/82		7 min

(from AEOD): Technician error during a preventive maintenance test resulted in loss of a vital instrument panel, and autoclosure of the suction/isolation valves (7 min. loss).

VITAL	North Anna 1	01/22/83	Mode 6	4 min

(from Seabrook): RHR flow was lost for approximately 4 minutes.

(from AEOD): Failed inverter, caused RHR suction/isolation valve to close. (4 min loss)

PHASE 2 CATEGORY	PLANT NAME	EVENT DATE	INITIAL PLANT CONDITION	RECOVERY TIME
VITAL	North Anna 1	04/22/87	Mode 5	

(from LER Search): At 1530 hrs on April 22, 1987, with Unit 1 in Mode 5, the residual heat removal (RHR) suction line was isolated when MOV-1701 closed due to a loss of power to the 120 VAC vital bus (VB) 1-III. MOV-1701 being closed resulted in a temporary loss of the RHR system. Therefore, this event is reportable pursuant to 10 CFR 50.73(A)(2)(VII)(B). At 1515 hrs on April 22, 1987, during the performance of a periodic test, the 1-III inverter failed, resulting in a loss of power to VG 1-III. Vital bus 1-III supplies power to an auxiliary relay for pressure channel P-1403 which provides the logic to close MOV-1701 on high RCS pressure. When this auxiliary relay was de-energized an auto closure signal was sent to MOV-1701, thereby closing MOV-1701. Power was quickly restored to VB 1-III, MOV-1701 was reopened and RHR flow was restored. The cause of the inverter failure was determined to be a blown fuse. To prevent recurrence of this type of event, North Anna is actively pursuing a technical specification change to eliminate this RHR interlock.

VITAL	North Anna 2	04/29/83	Mode 6	< 1 min

(from Seabrook Sheet 5 of 20): One of two source range channels (N-31) and the Containment Particulate and Gaseous Radiation monitors (RM-259 & 26) were deenergized. The vital bus was promptly reenergized and the deenergized equipment promptly restored.

(from AEOD): Loss of vital bus. RHR suction/isolation valve closed. Caused by maintenance personnel conducting a test as loads were being transferred (<1 min. loss).

VITAL	Palo Verde 2	01/30/86	Mode 5	

(from CR5015): Power level - 0%. At 1924 MST on 1-30-86, Palo Verde 2 was in Mode 5 when an unauthorized modification on a vital power inverter caused a failure of the train 'A', class 1E, I&C power system, which resulted in a control room essential filtration actuation signal and a temporary loss of train 'A' shutdown cooling. The cause of the failure was attributed to inadequate control of a modification consisting of a resistor jumpered around a capacitor in the circuit. The modification caused an excessively high current on an inverter circuit board, and resulted in 3 blown inverter fuses. The inverter loss caused a loss of power to a radiation monitoring unit, which in turn caused the CREFAS and the temporary termination of train 'A' SDC. As corrective action, all inverters were inspected for additional unauthorized modifications, the blown fuses were replaced, and inverter specs were checked. Additionally, work control procedures will be revised to emphasize the importance of removing all temporary modifications prior to putting an electrical system back in service.

VITAL	Rancho Seco	06/24/82	Modes 4 and 5	

(from Seabrook Sheet 1 of 11): During a preventive maintenance procedure on the B inverter, there was a momentary loss of power to the B bus. This in turn caused a short duration loss of DHRS. The core temperature remained unaffected by this loss of flow and the A system was available on standby.

(from AEOD): Simultaneous test and maintenance caused failure of bus, closure of the suction/isolation valve, and loss of DHR flow. (Duration of event unknown)

VITAL	Rancho Seco	11/15/86	Mode 5	

(from Seabrook Sheet 19 of 20) The plant was in cold shutdown, removing decay heat via the Decay Heat Removal System (DHS), Train A, on Nov. 15, 1986. At 1:00 PM, in preparation for a fuse replacement activity in the S1A Bus inverter, S1A bus power was momentarily interrupted, DHS overpressure distables tripped, HV-20001 closed which tripped DHS A Pump as designed. Steps were taken immediately to restore a DHS train to service in accordance with T.S. 3.1.1.5.

PHASE 2 CATEGORY	PLANT NAME	EVENT DATE	INITIAL PLANT CONDITION	RECOVERY TIME

(from CR5015): Power level - 0%. The plant was in cold shutdown, removing decay heat via the decay heat removal system (DHS) train "A" on 11-15-86. At 1:00 PM, in preparation for a fuse replacement activity in the S1A bus inverter, S1A bus power was momentarily interrupted, DHS over-pressure bistables tripped, HV-20001 closed which tripped DHS "A" pump as designed. Steps were taken immediately to restore a DHS train to service in accordance with Tech Spec 3.1.1.5. The basic cause of the inverter failure is that the original design did not allow for testability of the device through the use of a substitute power source. That design deficiency, identified as early as 1979 (NCR's-1258, Revision 2), was recognized by the current action plan for performance improvement. There is a preventive maintenance procedure, EM 171A, "station inverter routine - static products inverters," that is scheduled to be performed once per year on the inverters, a 120VAC vital bus system improvement was approved, but has not been implemented yet.

VITAL Salem 2 05/14/83 Modes 4 and 5 immediately

(from Seabrook Sheet 5 of 20): On two separate occasions on May 14 and 15, 1983, a Residual Heat Removal system suction valve was observed to have closed, thus eliminating flow in the operating RHR loop. In each instance, the operating pump was stopped and Action Statement 3.4.1.4B was entered. No reduction in reactor coolant system boron concentration occurred with an RHR loop out of service. A loop was immediately restored to service.

(from AEOD): RHR suction valve closed during operation. (Duration of events unknown) The 05/14/83 event was triggered by a vital instrument bus which was de-energized for maintenance.

VITAL Salem 2 11/28/83 Mode 5

(from Seabrook Sheet 8 of 20): During a maintenance shutdown, 2A vital instrument bus was transferred to its alternate power supply to perform routine meter calibrations on 2A inverter. A voltage transient caused 2RH2 to shut resulting in a loss of RHR flow. The valve was immediately reopened and RHR flow was re-established.

(from AEOD): Vital bus transfer caused voltage spike which resulted in closure of suction/isolation valve. (Duration of event unknown)

VITAL South Texas 1 02/12/89 Mode 5

(from LER Search): On 2/12/89, Unit 1 was in mode 5. At 0529 hrs a plant operator noticed evidence that inverter IV-1203, which supplies uninterruptable power to distribution panel DP-1203, was overheating. The operator immediately transferred the distribution panel to its alternate source and secured the inverter. Since this was a dead bus transfer, it resulted in a momentary loss of power and subsequent actuation of the control room and fuel handling bldg HVAC systems to the emergency mode, tripping of residual heat removal pump 1B, and shifting of centrifugal charging pump 1B suction to the refueling water storage tank from the volume control tank. These systems were restored to normal operation after power was restored. The cause of this event was a short to ground on the secondary side of the inverter ferroresonant transformer. Corrective actions include replacement and failure analysis of the failed transformer.

VITAL Summer 11/12/83 Mode 5 5 min

(from Seabrook Sheet 7 of 20) An Engineered Safety Feature (ESF) 120 VAC vital instrumentation panel, APN-5901, was transferred to alternate power to accommodate modifications to its normal power source. With Train B Residual Heat Removal System in service, its suction valve, XVG-8701A closed. The valve was reopened within approximately 5 minutes. No adverse consequences resulted due to plant conditions and the short duration of the event.

PHASE 2 CATEGORY	PLANT NAME	EVENT DATE	INITIAL PLANT CONDITION	RECOVERY TIME

(from AEOD): (Date is 11/12/84) Bus transfer during plant modification caused an interruption of power to an ESF instrumentation bus. An erroneous overpressurization signal resulted causing suction/isolation valve closure, and interruption of DHR flow (5 min. loss).

VITAL	Summer	10/18/84	Mode 5	25 min

(from Seabrook Sheet 11 of 20): On Oct. 18, 1984, outage with Train A of the Residual Heat Removal (RHR) System in service, RHR Train B out of service for routine maintenance, and the reactor coolant system (RCS) vented at a temperature of approximately 110 deg Fahrenheit. At 1605 hrs, a power loss to 120 VAC distribution panel APN-5901 deenergized Solid State Protection System (SSPS) Channel I and caused the instrument panel for RCS wide range pressure (PT-403) to initiate valve XVG-8701A.

(from AEOD): 1 DHR loop was out for surveillance testing. An inverter failure caused closure of the operating loop's suction isolation valve (25 min. loss).

(from CR5015): Power level - 0%. On 10-18-84, the plant was in Mode 5 for the first refueling outage with train 'A' of the RHR system in service, RHR train 'B' out-of-service for routine maintenance, and the RCS vented at a temperature of approx. 110 F. At 1604 hrs a power loss to 120V AC distribution panel APN-5901 de-energized solid state protection system (SSPS) channel I and caused the instrument channel for RCS wide range pressure (PT-403) to initiate an auto-closure of the operable RHR train's suction isolation valve XVG-8701A. Following determination that the power loss had been caused by personnel error during the performance of a plant modification, operations personnel restored power to APN-5901. XVG-8701A was opened and train 'A' of the RHR system returned to operable status at 1630 hrs (total time of RHR isolation was approx. 25 minutes). RCS temperature increased from 110 F to 130 F during the event. The loss of RHR met the conditions of an alert, and the proper notifications were made in accordance with the emergency plan.

VITAL	Turkey Point 4	03/15/86	Mode 6	5 min

(from Seabrook Sheet 18 of 20) Work was progressing to deenergize and replace a vital bus feeder breaker, 4P08. When breaker 4P08-3 was opened, the RHR pump suction valve went closed. Upon receipt of the letdown, isolation alarm, the RHR pump was stopped,the breaker re-energized, the valve re-opened, the pump restarted, and flow restored in approximately 5 minutes.

(from CR5015): Power level - 0%. On 3-15-86, while Unit 4 was in a scheduled refueling outage Mode 6, work was progressing to de-energize and replace a vital bus feeder breaker 4P08. When breaker 4P08-3 was opened, the RHR pump suction valve went closed. Upon receipt of the letdown isolation alarm, the RHR pump was stopped, the breaker re-energized, the valve reopened, the pump restarted and flow restored in approx. 5 minutes. Tech Spec action statement 3.10.7.2 was entered during the approx. 5 minutes of flow loss. There was no noticeable increase in the 93 F system temperature. When breaker 4P08-20 was opened, a process radiation monitor rack was lost, causing the containment ventilation system to isolate and the control room ventilation system to isolate and switch over to the recirculation mode, as designed. The purge valves were secured per Tech Spec action statement 3.10.2.A, by removing power fuses. No significant increase in activity was recorded on the plant vent effluent monitoring system during this event; other means of monitoring containment activity were available. No release path to outside containment was available. When de-energized, feeder breaker FP08 replacement was completed, power was restored and the systems were then returned to their normal line-up.

VITAL	Zion 1	03/17/82	Mode 6	3 min

(from Seabrook Sheet 1 of 20): RHR suction valve 1MOV-RH8702 started to close due to an inadvertent opening of inverter 111 output breaker. The running pump was tripped. The inverter output breaker was

PHASE 2 CATEGORY	PLANT NAME	EVENT DATE	INITIAL PLANT CONDITION	RECOVERY TIME

reclosed, RHR suction valve 1MOV-RH8702 was reopened, and the RHR system was restored to operation within 3 minutes.

(from AEOD): Inadvertent (contractor personnel) opening of inverter output breaker caused closure of the RHR pump suction valve (3 min. loss).

VITAL	Zion 2	01/03/86	Mode 5	

(from Seabrook Sheet 17 of 20) A momentary fluctuation of output of inverter power supply Bus 213 (cause unknown) caused the charging flow control valve, 2VC-FCV121, to fail to the 20% demand position and also caused 2MOV-RH8701, the RHR pump suction isolation valve to fail closed. This increased charging flow from 39 to 190 gpm and isolated letdown flow resulting in lifting of the pressurizer power operated relief valves (PORVs). While investigating the cause, Bus 213 was again deenergized and the PORVs again lifted.

(from CR5015): Power level - 0%. At 1547 on 1-3-86 Unit 2 was shut down for a refueling outage and the RCS was filled solid with no bubble in the pressurizer. A momentary fluctuation of output of inverter power supply bus 213 (cause unknown) caused the charging flow control valve, 2VC-FCV121, to fail to the 20% demand position, and also caused 2MOV-RH8701 the RHR pump suction isolation valve to fail closed. This increased charging flow from 39 to 190 gpm, and isolated letdown flow resulting in lifting of the pressurizer power operated relief valves (PORV's). While investigating the cause, Bus 213 was again deenergized and the PORV's again lifted. The cause of the bus output fluctuation is currently unknown. This event is reportable since Tech Spec 6.6.3.H requires a 30 day written report on actuation of the overpressure protection system.

Appendix A.2.4 Loss of Component Cooling Water (CCW)

PHASE 2 CATEGORY	PLANT NAME	EVENT DATE	INITIAL PLANT CONDITION	RECOVERY TIME
CCW	Braidwood 1	01/21/87	zero power	14 min

(from LER Search): The 1B residual heat removal (RHR) heat exchanger (HX) was out of service with the tube side drained. Preparations were made for draining the component cooling water (CC) shellside of the HX to allow replacement of a flange gasket. AT 1745 draining of the shell side of the HX was started. At 1802 the 1A CC pump tripped due to low level in the CC surge tank. The low level alarm on the main control board did not annunciate although the sequence of events recorder did indicate a low level. The draining was stopped, the surge tank refilled, and the isolation valves were checked. At 1816 the 1A CC pump was restarted and the system was restored to normal. The cause was the CC inlet isolation valve leaking and contributing was the failure of the CC surge tank high/low level alarm to annunciate on the main control board. Additionally, the CC motor operated outlet valve on the 1B RHR HX was found 6 turns off its seat. The leaking valve has been repaired, the limits for a motor operated valve were adjusted, the main control board alarm was troubleshot and the symptoms could not be duplicated. Work is in progress to check the calibration and scaling on the CC surge tank instrument loop.

CCW	Byron 1	04/08/87	zero power	17 min

(from LER Search): On 4/8/87, at approx. 1725, a contracted maintenance crew began work on the limitorque motor operator of the "1A" residual heat removal (RH) heat exchanger component cooling water outlet isolation valve, 1CC9412A. This valve was a point of isolation for work on the RH heat exchanger, which required it to be drained of component cooling water (CC). Shift operating personnel granted permission, with the understanding that if it became necessary for the crew to stroke the valve, they would obtain authorization. Maintenance crew stroked the valve in order to release torque on the motor gear set. It is unclear whether they actually received authorization or not. This allowed CC to back flow through 1CC9412A to the heat exchanger and out the drain. This caused the (CC) surge tank to reach the low level CC pump trip. The "1A" CC pump tripped at 1726 on 4/8/87. The surge tank is common to both trains, consequently, both trains of component cooling were inoperable. Leak was discovered and isolated. System was then re-filled, and the "1A" CC pump re-started. Total time both trains were inoperable was 17 minutes. Cause of the event was a communication breakdown between the maintenance crew and shift operating personnel. Contracted maintenance personnel now work under the same procedures as station personnel. Similar event: 455/86-001.

CCW	Maine Yankee	06/02/81	Mode 6	30 min

(from NSAC52, p. A-30): During refueling shutdown, service water cooling to the RHRS cooler was interrupted for approx. 30 minutes as a result of a breaker trip.

CCW	Turkey Point 3	10/07/83		

(from AEOD): Flow restriction on component cooling water discharge valve on RHR heat exchanger. (Duration of event unknown)

Appendix A.2.5 Inadvertent Safety Feature Actuation (ESFAS, ESFAS/SI)

PHASE 2 CATEGORY	PLANT NAME	EVENT DATE	INITIAL PLANT CONDITION	RECOVERY TIME
ESFAS	Cook 1	09/07/85	Mode 5	2 min

(from Seabrook): Power was lost to the Control Room instrument bus distribution circuits for channel 3 and channel 4. This resulted in various ESF reactor trip signals and loss of the residual heat removal pumps. Channel 3 and 4 circuits were being powered by an alternate source while the normal power source was out of service.

(from CR5015): Power level - 0%. On 9/7/85 at 0720 hrs with Unit 1 in Mode 5 power was lost to the control room instrument bus distribution circuits for channel 3 and 4. This resulted in various ESF reactor trip signals and loss of the RHR pumps. Channel 3 and 4 circuits were being powered by an alternate source while the normal power source was out of service. The circuit breaker for channel 3 tripped as a result of an inadequately terminated lead. A licensed operator investigating the power loss thought the channel 4 circuit breaker had tripped also. The operator then attempted to reset the breakers by opening then closing the breaker. This resulted in the channel 4 breaker being momentarily de-energized. This caused various ESF reactor trip signals and the loss of RHR pumps (due to the refueling water storage tank level indication reading low from power loss). This placed the unit in a LCO per Tech Spec 3.4.1.3. The RHR system was made operable within 2 mins after loss. To prevent recurrence the operator has been counseled not to take immediate actions where the situation does not require it.

ESFAS	Davis Besse 1	04/19/80	Mode 6	2 hr 30 min

(from NSAC52, p. A-3, p. A-15): A loss of two vital instrument buses resulted in a safety features actuation (SFA) while in mode 6. Control power was also lost to the RHRS suction valves interlock, causing them to shut. The SFA caused the suction of decay heat pump #2 to be transferred to the BWST and then emergency sump. Water from the BWST was gravity fed to the emergency sump during valve stroking time (approx. 1-1/2 minutes). The RHRS pump injected about 3,500 gallons of BWST water into the RCS, resulting in a small amount flowing out of tygon tubing used for vessel level indication. Approx. 1,500 gallons of RWST water drained to the emergency sump. The RHRS pump then lost suction and became airbound. Extensive pump venting was conducted and RHRS flow was restored 2-1/2 hrs later. RCS temperature increased from 90 F to 170 F.

(from AEOD): 2-1/2 hr loss of DHR. Vibration from construction work actuated a ground fault relay. Due to an abnormal electrical lineup associated with outage activities, loss of power resulted in SFAS actuation. Control power to the DHR suction valves was lost, causing the suction valves to close. The SFAS actuation transferred the DHR pump suction to the BWST and then to the empty sump. The pump became airbound. RCS temperature increased from 90 deg Fah to 170 deg Fah while the vessel head was detensioned (140 deg Fah is the maximum temp. allowed while the vessel head is detensioned).

ESFAS	Davis Besse 1	06/14/80	Mode 6	2 min

(from NSAC52, p. A-15): Maintenance induced voltage transient in containment pressure section of the Safety Features Actuation System (SFAS) caused an SFAS actuation. This caused RHRS pump suction to switch from the RCS to the borated water storage tank, injecting 16,000 gallons of BWST water into the refueling canal. Seven minutes later, a low BWST level actuation of SFAS shifted RHRS pump suction to the empty emergency sump. The RHRS pump lost suction and was stopped causing a loss of decay heat flow.

(from AEOD): DHR pump flow loss for about 2 minutes. Inadvertent SFAS actuation caused DHR pump realignment to the BWST and BWST isolation. An I&C mechanic was restoring containment pressure inputs to SFAS following an Integrated Leak Rate Test. Because of a procedural inadequacy, SFAS was actuated and the DHR pump was realigned to deliver BWST water to the RCS and the refueling canal. When BWST level dropped to the low level limit, SFAS level 5 actuation took place closing the BWST isolation valve causing a loss of suction to the DHR pump.

PHASE 2 CATEGORY	PLANT NAME	EVENT DATE	INITIAL PLANT CONDITION	RECOVERY TIME
ESFAS	Davis Besse 1	07/24/80	Mode 5	2 min

(from NSAC52, p. A-4): While attempting to clear lights on the SFAS following maintenance, technicians adjusted a potentiometer, unaware the RHRS suction valve trip feature had been restored. This caused an RHRS suction valve closure. The RHRS pump was immediately stopped, and flow was restored within 2 minutes.

(from AEOD): DHR flow was lost for about 2 minutes due to an inadvertent closure of one of the DHR isolation valves. Subsequent to making a plant modification, an I&C mechanic performed restoration work out of sequence. As a result, one of the isolation valves closed.

ESFAS	Davis Besse 1	07/24/80	Mode 5	50 min

(from NSAC52, p. A-4): A loss of RHRS flow was caused by inadvertent automatic closure of an RHRS suction valve. The running RHRS pump was stopped to prevent damage. A manual bypass line around the shut RHRS suction valve was opened, system venting was performed, and the pump restarted. RHRS flow was lost for 50 minutes.

(from AEOD): DHR flow was lost for 50 minutes because of an automatic closure of an isolation valve. An electrician blew a fuse while conducting wire pulling operations associated with a plant design change. As a result of the blown fuse, an automatic closure of one of the DHR isolation valves took place, and the pump became air-bound. The DHR flow path was restored by opening the manual bypass valves. During the event, the hottest in-core thermocouple temp. rose from 104 deg Fah to 111 deg Fah.

ESFAS	Davis Besse 1	08/01/80	Mode 5	3 min

(from NSAC52, p. A-5): (Date is 8/3/80) During maintenance, a SFAS bistable was removed resulting in closure of a RHRS suction valve. The operating RHRS pump was stopped to prevent damage. The bistable was replaced and RHRS flow restored in approx. 3 minutes.

ESFAS	Davis Besse 1	08/13/80	Mode 5	5 min

(from NSAC52, P. A-5): Maintenance performed on a SFAS cabinet resulted in RHRS suction valve closure. The operating pump was stopped. The RHRS suction valve was reopened, the pump vented, and RHRS flow reestablished in approx. 5 minutes.

(from AEOD): DHR flow was lost for about 5 minutes due to an inadvertent closure of one of the DHR isolation valves. Valve closure occurred during SFAS channel modification work. The I&C mechanic failed to fully defeat the automatic isolation valve trip prior to performing SFAS channel modification work.

ESFAS	Diablo Canyon 1	09/08/86	Mode 5	2 min

(from Seabrook): An Instrumentation and Controls (I&C) technician inadvertently grounded a power supply while installing a modification in a Solid State Protection System (SSPS) cabinet. The momentary grounding of the power supply caused relay actuation which resulted in the closure of Residual Heat Removal (RHR) valve 8702 and an RHR low flow alarm. In response to the RHR low flow alarm, the operating RHR pump was secured by a licensed operator. RHR valve 8702 was reopened from the Control Room. The RHR pump was restarted at 2316 PDT and no seal damage was observed.

(from CR5015): Power level - 0%. AT 2314 PCT on Sept. 8, 1986, with the unit in Mode 5 (cold shutdown), an instrumentation and controls (I&C) technician inadvertently grounded a power supply while

PHASE 2 CATEGORY	PLANT NAME	EVENT DATE	INITIAL PLANT CONDITION	RECOVERY TIME

installing a modification in a solid state protection systems (SSPS) cabinet. The momentary grounding of the power supply caused relay actuation which resulted in the closure of residual heat removal (RHR) valve 8702 and an RHR low flow alarm. In response to the RHR low flow alarm, the operating RHR pump was secured by a licensed operator. RHR valve 8702 was reopened from the control room. The RHR pump was restarted at 2316 PDT, and no seal damage was observed. A significant event report was not filed within the 4-hour time requirement of 10 CFR 50.72. The significant event report was made at 1744 PDT, Sept. 9, 1986. The event was reviewed at an I&C tailboard meeting emphasizing attention to energized and potentially energized circuits when working on electrical components. The circumstances and lessons learned from the event will be evaluated for possible inclusion in the generic new employee training program for I&C personnel. Additional training on 10 CFR 50.72 reporting requirements will be provided for all applicable personnel.

ESFAS North Anna 1 11/06/79 Mode 6 5 min

(from NSAC52, p. A-3): A jumper was installed in the solid state protection system for the purpose of conducting time response testing without disabling the automatic closure of RHRS suction valves. A false high pressure signal caused an RHRS suction valve to shut. Flow was re-established in approx. 5 minutes.

ESFAS Salem 2 06/23/83 Mode 5

See description of other Salem 2, 06/23/83 event.

ESFAS Salem 2 06/23/83 Mode 5

(from Seabrook Sheet 6 of 11): During routine shutdown operation, the Control Room operator observed two different instances in which a spurious Safeguards Equipment Control (SEC) System actuation caused various loads on the No. 2A vital bus to be de-energized. In the second case, the bus infeed breaker opened with no automatic transfer, rendering the bus inoperable. In both instances, due to the loss of the operating Residual Heat Removal (RHR) pump, flow in the operating RHR loop was lost.

(from AEOD): Loss of RHR pump due to spurious actuation of the SEC (safeguards equipment control) system. (Duration of event unknown)

ESFAS Sequoyah 1 09/16/82 Mode 5 6 min

(from Seabrook Sheet 3 of 20): Both trains of the Residual Heat Removal System were declared inoperable due to the inadvertent closing of RHR suction valve 1-FCV-74-2.

(from AEOD): Power was removed to allow modification work on solid state protection system; RHR suction valve closed. (Duration of event unknown)

ESFAS Summer 10/02/84 Mode 5 immediately

(from Seabrook Sheet 11 of 20) With Train B of the Residual Heat Removal (RHR) system in service, an instrument and control (I&C) technician removed two (2) fuses in Solid State Protection System (SSPS) Cabinet XPN-7020 for personnel safety during implementation of a modification. The fuses were immediately replaced when the technician heard a relay activate. The deenergized circuit caused the Train A RHR suction isolation valves XVG-8702A and B (one valve in each RHR train) to close. Operations personnel immediately restored Train B RHR to service after the valve closure.

(from CR5015): Power level - 0%. On Oct. 2, 1984, the plant was in Mode 5 with train "B" of the residual control (I&C) technician removed two (2) fuses in solid state protection of a modification. The fuses were immediately replaced when the technician heard a relay activate. The de-energized circuit caused the train "A" RHR suction isolation valves XVG-8702 A & B (one valve in each RHR train)

PHASE 2 CATEGORY	PLANT NAME	EVENT DATE	INITIAL PLANT CONDITION	RECOVERY TIME

to close. Operations personnel immediately restored train "B" RHR to service after the valve closure. The cause was determined to be drawing errors. At 1700 hrs during performance of the same modification on SSPS cabinet XPN-7010, a similar RHR isolation occurred via the train "B" RHR suction isolation valves XVG-8701 A & B (one valve in each RHR train). The I&C technician was lifting leads affected by the modification to prevent a repeat of the previously mentioned isolation when a defective fuse holder interrupted power to the train "B" circuitry. Operations personnel immediately restored train "B" RHR to service after the valve closure. To prevent a potential recurrence, the licensee initiated a drawing revision and replaced the defective fuse holder on Oct. 9 and Oct. 10, 1984, respectively.

ESFAS	Surry 2	08/18/89	0%, Unit 2 CSD	

Power level - 0%. On 8/18/89 with Unit 2 at cold shutdown (CSD) at 1010 hrs, 3 motor operated valves (MOVs) in the safety injection (SI) system actuated. The valves are designed to reposition when a recirculation mode transfer (RMT) signal is generated upon a low level condition in the RWST. However, no low level existed at the time. This spurious RMT actuation constitutes an unplanned engineered safety features (ESF) component actuation and was reported to the NRC per 10CFR50.72(B)(2)(II). An electrician inadvertently energized a relay that actuated the valves while placing a jumper on an adjacent terminal in support of an engineering work request. A human performance evaluation system (HPES) investigation was conducted and a report prepared. Recommendations made in the report will be evaluated and appropriate actions taken.

PHASE 2 CATEGORY	PLANT NAME	EVENT DATE	INITIAL PLANT CONDITION	RECOVERY TIME

ESFAS/SI Surry 1 04/26/80 CSD Maintenance

Power level - 0%. On 6/12/85 at 1735 hrs with the unit in refueling shutdown, a spurious safety injection occurred during PT 18.2A (SI functional test). The procedure contains 1 step that executes 2 actions, reset and then block SI. This led to the spurious SI. The SI function test for units 1 and 2 will be modified to provide separate steps and signoffs to reset and block SI.

ESFAS/SI Surry 1 03/01/84 CSD

Power level - 0%. On March 1, safety injection signals were initiated as a result of completing 3 of 4 high containment pressure signals and completing 2 of 3 high steam flow signals. At the time of the event, operators were performing MOP 26.9 (removal of vital bus sola transformer I-I) when vital bus I and III were mistakenly cross connected out of phase. This reusited in a voltage transient on vital bus I and III, which caused spurious containment high pressure and high steam flow signals. The voltage transient in vital bus I and III is believed to have resulted in tripping 2 of 4 containment high pressure relays. Since channel II was in trip prior to the voltage transient, the 3 of 4 matrix for containment high pressure was completed and safety injection was initiated. Also, the power transient resulted in resetting the high steam flow low tavg or low steam pressure safety injection circuitry. since high steam flow signals were also generated with voltage transient and both low header pressure low tavg were present, safety injection was actuated. The operator was re-instructed in the correct manner of removing the vital bus sola transformer. Labels have been made for both unit's manual transfer switches. Fan 588 iris damper shall be run in the automatic mode.

ESFAS/SI Surry 1 11/16/84 Refueling SD

Power level - 0%. With the unit in a refueling shutdown condition, a spurious safety injection occurred when returning CLS-hi (equivalent to containment depressurization actuation system) to service. The controlling procedure was inadequate in that the procedure did not require the resetting of CLS-hi. The impact on the unit was minimal and the unit was returned to a normal condition. Outstanding work procedures, that required the de-energizing of CLS-hi, were held in abeyance until the procedures could be modified.

ESFAS/SI Surry 1 05/11/86 Shutdown

Power level - 0%. On May 11, 1986 at 0841 with Unit 1 shutdown and on the residual heat removal system and Unit 2 at 100% power, Unit 1 experienced a temporary degradation of 'B' dc bus voltage. The decrease in 'B' dc bus voltage caused 'B' train reactor annunicator panels F-K to become inoperable. Safety injection actuation caused the pressurizer level to increase and exceed the tech spec limit of 33%. The event and its cause were diagnosed and safety injection terminated by 0843. Pressurizer level peaked at 42% and decreased to less than 33% by 0847. RCS pressure remained constant during the event. The 'B' dc bus was restored to full voltage at 0900 and the annunciators returned to service at 0905. The cause of the event was an inadequate procedure in a design change to replace the 'B' batteries. Design changes for replacing the other station batteries will use a revised procedure to preclude recurrence.

ESFAS/SI Surry 1 06/05/89 CSD

Power level - 0%. On June 5, 1989 at 1141 hrs, with Unit 1 at cold shutdown, an unplanned initiation of an engineered safety feature (ESF) occurred during preparations to commence a special test. The initiating signal was a low steam generator (S/G) level trip that resulted in closure of the S/G blowdown trip valves, opening of the auxiliary feedwater (AFW) valves, closure of the motor driven AFW pump breaker and opening of the steam driven AFW pump steam supply valves. The ESF actuation occurred while simulated S/G level signals were being transferred from one channel to another. The test directors were aware of the potential consequences of this action, but did not inform the shift supervisor. The test directors were counseled as to the necessity of keeping the shift supervisor cognizant of testing activities.

PHASE 2 CATEGORY	PLANT NAME	EVENT DATE	INITIAL PLANT CONDITION	RECOVERY TIME
ESFAS/SI	Surry 2	06/12/85	Refueling SD	

Power level - 0%. On 6/12/85 at 1735 hrs with the unit in refueling shutdown, a spurious safety injection occurred during PT 18.2A (SI functional test). The procedure contains one step that executes 2 actions, reset and then block SI. This led to the spurious SI. The SI function test for units 1 and 2 will be modified to provide separate steps and signoffs to reset and block SI.

ESFAS/SI	Surry 2	11/16/86	CSD	

Power level - 0%. On Nov. 16, 1986 with Unit 2 at cold shutdown, during the performance of periodic test 16.3 (type 'A' test), a hi consequence limiting safeguards (CLS) signal was generated resulting in the unplanned closure of the containment radiation monitoring trip valves TV-RM-200A, 200B, and 200C. This event was due to an inadequate procedure which did not instruct test personnel to close the trip valves affected by the hi CLS signal. The procedure will be modified to correct this inadequacy. This report is submitted pursuant to 10CFR50.73(A)(2)(IV).

ESFAS/SI	Surry 2	09/08/89	0%; Unit 2 CSD	

Power level - 0%. On Sept. 8, 1989 at 2142 hrs, with Unit 2 in cold shutdown, during performance of a periodic test on the turbine building flood control circuitry, two of the four condenser waterbox circulation water (CW) inlet isolation valves closed unexpectedly. The condenser inlet valves are designed to close upon the initiation of a hi hi consequence limiting safeguards (CLS) signal in coincidence with a loss of offsite power; however, no actual hi hi cls signal was present. The event is being reported as an unplanned engineered safety features (ESF) component actuation. A four hour non-emergency report was made to the NRC per 10CFR50.72. The event was caused by a relay in the flood control circuit that did not drop out as required during testing which resulted in actuation of the valves. It was determined that the original relay had been replaced with a new relay which required 1 less hold-in current causing this event to occur. An investigation will be conducted to determine how the new relays were installed.

Appendix A.2.6 Loss of Instrument Air

PHASE 2 CATEGORY	PLANT NAME	EVENT DATE	INITIAL PLANT CONDITION	RECOVERY TIME
AIR	Beaver Valley 1	08/29/85	Mode 1	10 min

On 8/29/85 at 1248 hrs, a low station air pressure alarm was received. Operations personnel responded by starting the standby station air compressor. The reduced air pressure initially caused one main steam isolation valve to drift closed. The resultant increased steam flow caused steam line pressures to drop in the other two steam lines. The pressure drops were sufficient to actuate the rate-compensated low steamline pressure safety injection signal. The safety injection signal caused a resultant reactor trip. The control room operators followed the applicable emergency procedures and stabilized the plant in hot standby. An unusual event was declared at 1300 hrs and terminated at 1315 hrs. The low station air pressure was the result of a failed solder fitting on the instrument air system. The solder fitting failed due to a faulty heater control on an instrument air dryer and improper equipment restoration. During subsequent plant recovery actions, water was found spraying from both low head safety injection pump wedge control rod seals. Both pumps were declared inoperable which required an entry into cold shutdown. Postulated failure on the control rod seals was from a minor flow induced pressure transient. Following equipment repair, a plant startup to full power operations was commenced on 9/1/85.

AIR	Callaway	11/05/84	Mode 1	20 min

On 11/5/84 at 1156 CST and 11/6/84 at 0450, with the plant in mode 1 at 45% power and 16% power, respectively, air lines supplying the SG feedwater regulating valves failed which caused ESF actuations along with reactor trips. The first event was due to a failure of the air line connection to the feedwater control valve, FCV-530, for SG 'C'. Upon the loss of air supply, FCV-530 failed closed resulting in a lo-lo level in SG 'C' which caused a reactor trip, turbine trip, feedwater isolation signal (FWIS), aux feedwater actuation signal (AFAS) and SG blowdown isolation signal (SGBIS). The second event was due to a failure of the air line to the 'A' feedwater pump recirculation valve FV-2B causing it to fail open and closed then open. The resultant feedwater flow oscillations produced a high level in SG 'C' causing a turbine trip, FWIS, AFAS and SGBIS. Due to the FWIS and AFAS, SG levels began to decrease and at 0454 a lo-lo level on SG 'D' caused a reactor trip. The air line failures were due to improper material applications and resulting fatigue cracking caused by the vibrations imposed on the air lines during feedwater system operation. Temporary repairs using copper or stainless steel tubing were made and design changes to install hangers are being made in accordance with administrative procedures.

AIR	Calvert Cliffs 1	01/27/87	Mode 1	20 min

Power level - 100%. At 1809 on Jan. 27, 1987 the unit was manually tripped due to decreasing steam generator levels, which resulted from a loss of instrument air. At 1816 the reactor coolant pumps were stopped, because cooling water was isolated upon the loss of air pressure. Reactor coolant system temperature was maintained by the use of auxiliary feedwater and manual control of the atmospheric dump valves. At 1825 instrument air pressure was restored, and two reactor coolant pumps were started. At 1840 the remaining two reactor coolant pumps were started and the unit was maintained in Mode 3 (hot standby). To prevent recurrence of this type of event an engineering analysis is being performed to identify modifications that can increase the reliability of the instrument air system, and the general supervisor-operations is reviewing this event with all operators.

AIR	Catawba 1	01/14/85	Mode 2	15 min

On 1-14-85, at 1440 hrs, the Unit 1 reactor was manually tripped. The reactor coolant pumps had been previously shutdown due to the loss of motor cooling water, and the ability to control unit reactivity was therefore less than desirable. The loss of motor cooling is attributed to a malfunction of service water valve 1RN-A83, which opens to supply an alternate source of cooling water to the reactor coolant pumps when the normal source is not available. On 1-14-85, a vendor was onsite to drill additional wells associated with the cathodic protection system. While drilling, an instrument air system line

PHASE 2 CATEGORY	PLANT NAME	EVENT DATE	INITIAL PLANT CONDITION	RECOVERY TIME

was drilled through. The VI line which was ruptured supplies control air to the cont. chilled water control panel (1YV-CP-1). The loss of control air to 1YV-CP-1 caused the YV chillers and pumps to shutdown. This sytem supplies the normal source of cooling water to the reactor coolant pump motors. The 4 service water swap-over valves, which supply an alternate water source, are supplied by a different VI header than 1YV-CP-1. The swap-over valves therefore did not attempt to realign as they did not experience a loss of control air. Realizing that a swap-over to service water had not occurred, the NCO realigned the YV control switch from auto to service water but did not receive indication that a swap-over had taken place. Verification revealed that 1RN-A83 was still closed.

AIR	Cook 1	11/25/85	Mode 1	20 min

On 25 Nov, the reactor tripped while surveillance from the nuclear power range instrument N-41 time constant rate trip circuit was in progress. The surveillance required the bistables for N-41 to be tripped. That resulted in a standing quadrant power tilt (QPT) alarm. Tech Specs required that the QPT be calculated with less than 4 power range instruments in service. During the process of taking electrical current readings from the other power range channels, to perform the tilt calculations, a spike occurred on N-44. The spike was found to have been caused by removal of the meter probe used for taking the current readings. The spike in power range instrument N-44 resulted in the 2-out-of-4 logic required for a rate trip.

Following the reactor trip with the turbine driven aux FW pump (TDAFP) operating at its normal speed, the turbine would not respond to control signals to reduce speed. The TDAFP was tripped and SG level was controlled using motor driven aux FW pumps. Local control of the TDAFP could have been taken if it had been required. During the investigation, it was discovered that the control air tubing to the TDAFP governor had broken off. The cause of the tubing failure was attributed to its location. It was believed that personnel had used the tubing as a hand hold while checking TDAFP governor oil level.

To prevent recurrence of the reactor trip, operating procedures were changed to prohibit the use of a meter probe in an operable power range drawer for current readings when the bistables were tripped in another power range drawer for surveillance testing. To prevent recurrence of the control air tubing failure, a design change was completed that rerouted the tubing to prevent its being used as a hand hold.

AIR	Davis Besse 1	12/07/87	Mode 1	31 min

On 12/7/87 the unit experienced a reactor trip at 0656 hrs from 81% reactor thermal power. The initiating event was a loss of instrument air pressure which caused several secondary system valves to go to their failed position. Reactor power increased to the integrated control system (ICS) high demand limiter, feedwater flow increased causing reactor coolant system Tave to decrease. Due to a large moderator temperature coefficient, reactor power increased to the reactor protection system high flux trip setpoint. The post-trip plant response was normal except that steam generator 1.1 pressure was slightly lower and steam generator 1.2 level was higher than the expected post trip ranges. Operator actions were required to close the moisture separator reheater (MSR) second stage reheat steam source valves and to stabilize steam generator 1.1 water levels. The loss of instrument air pressure was caused by direct venting of the instrument air header to atmosphere when a solenoid valve failed on instrument air dryers 1-1 and 1-2. This solenoid valve was repaired. The MSR second stage reheat steam source valves did not close due to a pressure switch failure. This switch was replaced. The ICS did not respond fast enough to steam generator 1-1 decreasing water level. A modification to the ICS is scheduled.

PHASE 2 CATEGORY	PLANT NAME	EVENT DATE	INITIAL PLANT CONDITION	RECOVERY TIME
AIR	McGuire 1	11/02/85	Mode 1	20 min

On 11-2-85 at 0640 a section of braided, flexible pipe on the discharge of instrument air compressor B ruptured at a welded seam. As a result, all VI loads not protected by check valves experienced decreased VI pressure. The low VI pressure caused the feedwater control valves on each unit to begin to close, causing SG levels to decrease. At 0641, Unit 1 experienced a reactor/turbine trip on SG 1A low-low level. Pressurizer pressure dropped below the safety injection setpoint (1845 psig) initiating SI. The pressure dropped was partially due to a higher than normal steam loads with some valves failing open on loss of VI. Unit 2 tripped on SG 2A low-low level, but pressure did not decrease to the SI setpoint. Both units were at 100% power at the time of the incident. VI compressor B was isolated and VI pressure returned to normal. The ruptured pipe was replaced. Several modifications are being reviewed for possible implementation.

AIR	Millstone 3	04/12/87	Mode 1	20 min

On April 12, 1987 at 0618 hrs, while operating at 66% power in Mode 1, a reactor trip occurred due to low low steam generator level in the D steam generator. The control room operators were in the process of increasing power during the initial startup following a scheduled maintenance outage. Approx. 15 minutes prior to the trip, the operators had increased reactor power from 56% to 66% within a 16 minute interval. When at 66% power the speed controller to the A turbine-driven feedwater pump (3FWS-P2A) began to oscillate. The responsible operator assumed manual control of the pump in an attempt to stop the oscillations. He was unable to do so before the level in the D steam generator fell to the low low level and the plant tripped. The operators verified the opening of all reactor trip breakers and full insertion of all control rods. The root cause of the reactor trip is equipment failure. The primary cause was an air leak in an air supply line to the D feedwater regulating valve, which resulted in low low steam generator level. The leak had been fixed. A contributing cause was oscillations in the A turbine-driven feedwater pump controller. A vendor representative was consulted and found no problems with the pump controller. It responded correctly during a plant startup on April 13, 1987. No other work is planned.

AIR	Oconee 3	08/14/84	Mode 1	20 min

On Aug. 14, 1984 at 1126 hrs, Unit 2 tripped from 100% full power (FP) when the instrument air line to the POWDEX outlet valves was accidentally sheared. The loss of air to the outlet valves caused the valves to fail shut which resulted in a loss of condensate flow to the condensate booster (CB) pumps. The CB pumps tripped and caused the main feedwater (MFDW) pumps to trip on low suction pressure. The loss of the MFDW pumps initiated a reactor anticipatory trip. Approx. 16 minutes after the trip, the "3A" MFDW pump was restarted to reestablish MFDW flow. The emergency feedwater (EFDW) control valves, 3FDW-315, 316, closed on an indication of 750 psig discharge pressure from the "3A" MFDW pump as designed. The once through steam generator's (OTSG's) were isolated from all feedwater flow for approx. 9 minutes as a result of the automatic closing of the EFDW control valves and lack of MFDW flow due to insufficient discharge pressure from 3A MFDW pump. The immediate corrective action was to stabilize the unit in a hot shutdown condition using emergency feedwater (EDFW). The immediate corrective action to restore feedwater flow to the OTSG was to manually open the EFDW control valves and to increase 3A MFDW pump speed. The sheared air line was repaired. The unit was restarted and reached 100% FP at 0100 on Aug. 17, 1984.

AIR	Prairie Island 1	05/08/85	Mode 1	20 min

On May 8, 1985 at about 1323, a 2-inch copper instrument air line seperted at a soldered elbow joint (PSF). As a result, the Unit 1 side of the instrument air system (LD) depressurized enough to cause the feedwater regulating valve (FCV) to No. 12 steam generator to close. At 1326, Unit 1 tripped on low steam generator level plus feedwater flow/steam flow mismatch. Cable tray (TY) wrapping for

PHASE 2 CATEGORY	PLANT NAME	EVENT DATE	INITIAL PLANT CONDITION	RECOVERY TIME

Appendix R compliance was in progress in the vicinity of the break, and the air line was moved somewhat to accomplish the wrap. This apparently placed enough stress on the elbow to cause it to separate. The Unit was maintained in hot shutdown while repairs were made. A walkdown inspection of the instrument air system was performed in areas of the plant where cable tray wrapping had taken place or was in progress. No additional problem areas were identified. The Unit was returned to service at 1847 on May 9.

AIR	Shearon Harris 1	08/04/87	Mode 1	20 min

The plant was operating at 100% reactor power in Mode 1, power operational on Aug. 1987. Instrument air dryer 1A was out of service for repairs. Instrument air dryer was bypassed at approx. 1715 hrs to replace the desiccant. Work was completed the dryer 1B and at approx. 2150 hrs the clearance on the dryer was removed. The restoration alignment on the clearance for placing dryer 1B back into service was incorrect. When the valves were repositioned in accordance with the clearance restoration lineup the instrument air compressors were isolated from the air system. The air isolation caused air pressure to decay and caused air operated valve to go to "fail safe" positions. In particular, the main feedwater regulating valves to drift shut and the heater drain level control valves to divert drain flow to the condenser. Heater drain pumps 1A and 1B tripped and a manual turbine runback was initiated. This was followed by a trip of main feedwater pump 1A which initiated an automatic turbine runback. The loss of instrument air resulted in a decrease in steam generator water levels. The turbine runback resulted in shrink in steam generator levels and resulted in a reactor trip at 2154 hrs due to steam generator feedwater steam/flow mismatch with low steam generator water levels.

AIR	Surry 1	01/07/86	Mode 1	10 min

On 1-7-86, an 'aux. ventilation system safety mode initiated' alarm was received in the control room at 2059 hrs and the aux. ventilation emergency fans, 1-VS-F-58A and 58B, auto started. Within seconds, trip valves TV-1204 and TV-CC-107 closed. While the operators attempted to open the trip valves, they noted instrument air header pressure decreasing and feed flows decreasing. Immediately, the operators attempted to open the feed reg. valves (FRV). However, due to the decrease of instrument air (IA) pressure, operators could not prevent the FRV's from fully closing and at 2104 hrs a reactor trip occurred as a result of a low steam generator (S.G.) level coincident with feed flow less than steam flow signal. The decrease of IA pressure was due to ice formation in the Unit 1 IA dryer that resulted in blocking air flow. A hot gas bypass valve in the dryer was not properly adjusted. The Unit 1 IA dryer was the source of the problem and was bypassed. IA pressure was returned to normal and the affected system and components were realigned. The bypass valve was properly adjusted by a service representative. Turbine building logs will be revised to incorporate IA dryer condenser temperature readings.

AIR	Yankee Rowe	10/04/86	Mode 1	10 min

While operating at 100% power in Mode 1 at 0917 on Oct. 4, 1986, the No. 3 (main) control air compressor air pressure switch CA-PS-453 failed. As a result of this failure and the subsequent inability of the back-up air compressors to rapidly restore the air pressure, the air header pressure decreased sufficiently to lock (by design) the feedwater control valves (FCV-FW-1000, 1100, 1200, and 1300) into the as-is position at 0918. Subsequently, the operators initiated steps by procedure to reset/restore the feedwater control valves to normal. As soon as the first feedwater control valve was reset (unlock) it began to rapidly open. This preferential feeding of No. 1 steam generator caused the levels in the other three steam generators to rapidly decrease, resulting in a reactor scram on low steam generator level at 0938. The root cause of this event is the failure of the air pressure switch (CA-PS-453) coupled with recovery procedure guidance inadequacies for resetting of the feedwater control valves upon lock-up. Corrective action included repair of the failed equipment and clarification of procedure instructions. All automatic safety systems functioned as required. The

PHASE 2 CATEGORY	PLANT NAME	EVENT DATE	INITIAL PLANT CONDITION	RECOVERY TIME

faulty air pressure switch for No. 3 control air compressor was replaced.

Appendix A.2.7 LOCAs (HCVCS, HRHR, JCVCS, JRHR, KRCS)

PHASE 2 CATEGORY	PLANT NAME	EVENT DATE	INITIAL PLANT CONDITION	RECOVERY TIME
HCVCS	Turkey Point 3	01/15/88	being cooled down	

Power level - 0%. On 1/15/88, Unit 3 was being cooled down and depressurized. Pzr spray valve PCV-3-455B was identified as having erratic operation on 1/11/88, and a plant work order to correct the problem was issued. With the reactor coolant system (RCS) temp. at 400 degrees F and pressure at approx. 950 psig, it was decided to slow the cooldown rate from 90 deg. F per hr to about 20 deg per hr, due to the shortly upcoming shift turnover. At 0650, as the cooldown rate was being decreased, the pzr level started to increase. At this point, the reactor control operator (RCO) secured charging pump 3A. An adjustment was made to valve PCV-3-455B at 0650 in order to decrease RCS pressure. By 0730, shortly after turnover, RCS pressure decreased to 625 psig and the accumulators started to inject. Upon noticing the RCS pressure drop, an RCO immediately closed PCV-3-455B and terminated the RCS pressure decrease. Approx. 65 gallons of water were injected into the RCS. The primary cause of the event was a defective controller for valve PCV-3-455B. Contributing causes were the RCO's failure to note the decreasing RCS pressure in time to take prompt corrective action, and a miscommunication between the oncoming and the offgoing RCO's. The controller for valve PCV-3-455B was replaced.

HRHR Sequoyah 1 02/11/81

The residual heat removal (RHR) containment spray was inadvertently initiated when an assistant unit operator (AUO) opened valve 1-FCV-72-40, which isolates the RHR system from the containment spray header. The spray continued for approx. 35 minutes releasing approx. 40,000 gallons of primary water and 65,000 gallons of refueling water storage tank water to the containment bldg. The UO received alarms indicating a rapid decrease in pressurizer level and pressure. The UO notified the shift engineer (SE) of the condition and then tripped reactor coolant pumps 1 and 2 (pumps 3 and 4 were not running). The situation was diagnosed as a possible loss of coolant accident (LOCA) and emergency operating instruction (EIO) 0 and 1 were consulted. The AUO, who opened the isolation valve, entered the control room with another UO discussing the valve. At this time the control room employee checked the indicator light and verified it was indeed open. The valve was shut and IP-4 was terminated.

(from NSAC2, p. A-13) An RHRS containment spray isolation valve was inadvertently opened creating a loss of coolant accident (LOCA) from the RCS via the RHRS to the containment spray header. The pressurizer emptied and RHRS pump suction was essentially lost in about 2 minutes. The LOCA lasted for 39 minutes, during which (minute 10) the RWST was valved into the RHRS in an attempt to makeup for lost inventory. But the RHRS suction valve from the RCS was left open, permitting the LOCA to continue. Also, residual RCS pressure overcame the pressure head of the RWST, limiting the supply of makeup water. High pressure safety injection was manually initiated after 35 minutes. A total of approx. 40,000 gallons of reactor coolant and 60,000 gallons of RWST water was sprayed into the containment.

JCVCS Robinson 2 01/29/81

A spurious safeguards actuation and reactor trip were received resulting from a high steam flow spike caused by turbine governor valve/E-H oil problems. Letdown flow was restored. RCS pressure began decreasing with containment pressure and dew point increasing. Upon containment entry following letdown isolation, a letdown line drain valve (CVCS-200E) was found partially opened and leaking through with its pipe end-cap missing. Cause is the valve vibrating open and the pipe cap, which was serving as a pressure boundary, failing to hold at sometime following the first SI. Approx. 4500-6000 gallons of water leaked to the containment sump during the event. Letdown was secured. The valve was secured in the closed position and a new cap was installed.

JCVCS Waterford 3 12/16/85 plnt heatup

Power level - 0%. On Dec. 12, 1985, Waterford Steam Electric Station Unit 3 was conducting a plant heatup following an outage. At 2340 hrs the plant was at 444 degrees and 1490 psia when a reactor coolant system (RCS) leak was indicated inside containment. The chemical and volume control system (CVCS) was isolated at 0007 hrs and the leakage stopped. At 0040 hrs an inspection of the containment

PHASE 2 CATEGORY	PLANT NAME	EVENT DATE	INITIAL PLANT CONDITION	RECOVERY TIME

determined the leakage to be from relief valve RC 526 on the temporary reactor coolant pump seal injection system. The system was isolated and the CVCS was restarted at 0046 hrs. A subsequent calculation verified RCS leakage was less than one gallon per minute. Since there was no operable boration flow path or charging path while RC 526 was opened, the plant was in a condition prohibited by technical specifications for approx. 29 minutes. The apparent root cause of the event was the failure of utility licensed operators to document the status of this sytem during shift turnover. The shift turnover procedure has been revised to provide for a 24 hr format turnover sheet for all licensed positions. This will facilitate review of turnover information from several previous shifts. Since, due to plant conditions, the boration capability of the charging system would not have been required during an accident, this event did not affect public health and safety.

JCVCS Yankee Rowe 06/27/86 Mode 5, Maint Out

Power level - 0%. On June 27, 1986, at 0137 hrs during a maintenance outage with the plant in Mode 5, main coolant was inadvertently drained to the low pressure surge tank (LPST). This could have resulted in a loss of shutdown cooling. This event occurred while transferring to the alternate method of shutdown cooling per procedure OP-2162, Attachment C. Performance of this procedure was necessary because of the failure of the shutdown cooling pump's shaft seal. During the evolution, approx. 2000 gallons of water was drained from the pzr and main coolant pressure dropped from 100 psig to 10 psig. The pzr did not empty. The control room operator (CRO) immediately secured the LPST cooling pump and the primary auxiliary operator (PAO) isolated the flow path. The CRO started all three charging pumps and restored pzr level and pressure. The root cause of this occurrence has been attributed to personnel error. While conducting the alternate shutdown cooling valve lineup, CH-V-654 was not fully shut, which resulted in a main coolant system to LPST flow path. The PAO thought that the valve had completed its full travel when he operated the manual valve. This occurrence was reviewed with the appropriate plant personnel and the need for strict procedural compliance was emphasized. This is the first occurrence of this nature. There were no adverse effects to the public health or safety as the result of this occurrence.

JRHR Braidwood 1 03/25/88 0% power level

Power level - 0%. On March 25, 1988 and March 27, 1988, operators noted a decreasing volume control tank level which caused increased make-up. Reactor coolant water inventory balance surveillances confirmed that unidentified leakage was in excess of 1 gpm. The source of the March 25, 1988 occurrence was thought to be an improperly locked closed valve which was inadvertently bumped off its closed seat. The residual heat removal (RHR) pump suction relief valves may have contributed to the generating station emergency plan unusual event for both occurrences. Leakage past the seats by measuring the downstream temperature indicated the source of leakage. Subsequent investigation of one of the relief valves indicated that the disc insert pin was broken as a result of improper nozzle ring setting. The 1A RHR suction relief valve has been repaired and reinstalled. The 1B relief valve will be tested and repaired as necessary prior to restart of the unit. There have been no previous occurrences of Crosby relief valve failures.

JRHR Braidwood 1 12/01/89 0% power level

Power level - 0%. At 0142 on 12/1/89 while drawing a bubble in the pzr, reactor coolant system (RCS) pressure slowly increased from 375 psig to 404 psig. At this time the 1B residual heat removal (RHR) pump suction relief valve, which had a setpoint of 450 psig, actuated and remained open. Charging flow was increased but pzr level indicated 0% by 0151. Reactor operators concluded that an RHR pump suction relief valve had lifted because hold up tank levels were increasing rapidly. The operating train of RHR, 1A, was isolated at 0155. At 0200 RCS pressure reached 272 psig and stabilized. RCS level was at the lower portion of the pzr surge line and flow into the RCS was equal to the flow exiting the RCS. At 0215 the licensed supervisors decided to return the second charging pump to service per 10CFR50.54(X). At 0235 the second charging pump was started. At 0245 pzr level was above 0%. At 0319

PHASE 2 CATEGORY	PLANT NAME	EVENT DATE	INITIAL PLANT CONDITION	RECOVERY TIME

field reports identified that the 1B RHR pump suction relief had actuated. At 0350 the "B" RHR train was isolated which terminated the event. Approx. 64,000 gallons had relieved through the valve. The cause of the early lift was dirt between the valve spindle and guide sleeve which affected valve lift setpoint adjustment. The cause for the valve remaining open was an incorrect nozzle ring setting due to a personnel error.

JRHR	McGuire 2	08/05/84	0% power level	

Power level - 0%. On 8/6/84, McGuire 2 operators discovered a broken weld on the residual heat removal (RHR) system letdown line to the chemical and volume control system (CVCS). The RHR system was in service at the time, and water was spraying from the broken pipe and from the stem of the valve (2NV-121) in the CVCS. An estimated 3000 to 7000 gallons of contaminated water was contained in the heat exchanger room, the RHR and containment spray sump, and the B floor drain sump and tank. Upon discovery the leaking line was isolated, a subsequent inspection revealed a number of supports/restraints (S/RS) damaged, and the broken socket weld completely separated. On 45/85, 7 socket welds with crack indications were discovered on the 2-inch crossover piping between valves 2ND-17 and 2ND-32. No weld failured occurred as in 8/84. Six of the welds with indications were in piping replaced after the failure, but before vibration testing following the 8/84 failure. Causes of the August event are attributed to component malfunction/failure, due to loose packing in 2NV-121, and to an unusual service condition, because a gas void in the line resulted in water hammer. The cause of the April event is classified as an unusual service event, because socket welds were not designed to witnstand the severe loading of the vibration testing that occurred in 8/84. Damaged piping and S/RS have been replaced. The subject valves have been modified.

JRHR	Summer 1	05/06/85	CSD (Mode 5)	

Power level - 0%. On May 5, 1985 at approx. 22 hrs, a reactor coolant system (RCS) pressure transient resulted in a challenge of a residual heat removal (RHR) suction relief valve. The plant was in cold shutdown (Mode 5) with RHR system (Train "A") in operation. Diesel generator (D/G) surveillance testing was in progress and had resulted in a non-valid test failure during an attempt to parallel the D/G to the ESF bus (XSW-1DB). The failure to parallel the D/G was a result of failure of the speed control switch on the main control board. During troubleshooting activities on the D/G, a personnel error resulted in a loss of ESF bus (XSW-1DB). Major equipment affected included the loss of the "B" component cooling water (CCW) pump, "B" service water (SW) pump, and "B" HVAC chiller and chill water pump. The loss of CCW flow to the reactor coolant pump (RCP) required the shutdown of the operating RCP. The breaker was reclosed to ESF bus (XSW-1DB) and the bus was reloaded. Upon restart of the RCP with solid plant operation, pressure spikes occurred which resulted in the challenge to the train "A" RHR suction relief valve. Following the relief valve actuation, an operator noted that pressurizer relief tank (PRT) level continued to increase apparently due to a failure of the relief valve to reseat. Approx. 1600 gallons of RCS inventory were released to the PRT.

KRCS	North Anna 1	06/17/87	0% power, refuel.	

Power level - 0%. On June 6, 1987, during the 59th day of a refueling outage with Unit 1 in Mode 5 and Unit 2 in Mode 1, a problem developed with the Unit 1 'A' reactor coolant pump (RCP) motor which required motor replacement. The RCP motor was uncoupled at 0420 hrs on June 18, 1987, resulting in a small but expected leak up the pump shaft of several gallons per minute. It was believed that the makeup flow rate to the reactor coolant system (RCS) compensated for this and other inventory loss because pressurizer level was held at approx. 20%. However, at 0130 hrs on June 21, 1987, it was discovered that pressurizer pressure was subatmospheric, and as a result, pressurizer level was not a reliable indication of RCS inventory. RCS inventory had decreased by approx. 17,005 gallons. There was no impact on safety because the residual heat removal system remained in service throughout this event. Corrective actions have been identified to address procedural, training and RCS inventory indication inadequacies during Mode 5 operation. Although there was no impact on safety, and it is not reportable under 10CFR50.73, this report is being submitted as a voluntary LER due to the potential for

PHASE 2 CATEGORY	PLANT NAME	EVENT DATE	INITIAL PLANT CONDITION	RECOVERY TIME

inadvertent RCS inventory loss.

KRCS	Trojan	07/03/81		

Reactor coolant system leakage of approx. 14 gallons per minute was experienced during the performance of a reactor coolant system integrity test. This is in excess of the technical specifications limit of 10 gmp for identified leakage. The source was leaking drain valves on the reactor coolant loops. The type of valve used to isolate the loop drains must be torqued to ensure they seat properly. Plant procedures did not specify this requirement. As a result, the valves were checked shut during preoperational valve lineups but were not torqued.

Appendix A.2.8 Transients

PHASE 2 CATEGORY	PLANT NAME	EVENT DATE	INITIAL PLANT CONDITION	RECOVERY TIME
TRANS	Surry 1	07/09/81	Routine startup	

The maximum allowable containment partial pressure of T.S. was exceeded. The unit was shut down and brought to cold shutdown in accordance with T.S. requirements. The containment pressure increase was caused by a feedwater leak through a failed flange gasket for "A" auxiliary feedwater line flow limiting venturi. The high temperature viton gasket used was not compatible with the slip on flanges used. The gaskets for all three AFW venturies were replaced with flexatalic gaskets.

TRANS	Surry 1	01/05/82	Routine SD	

While removing the unit from service, a spurious SI signal was generated. Trip valve, TV-CC-109B, failed to close as designed. The component cooling (CC) system is a closed system and its itnegrity was maintained during the event; therefore, an isolation barrier existed between the containment and the environment. A search for an electrical cause for the valve malfunction revealed no problems. No specific mechanical cause has been found. Efforts have been initiated to further investigate the event but no definitive answers are available at this time.

TRANS	Surry 1	01/06/82	HSD	

A spurious safety injection caused a phase 1 containment isolation. Trip valve CC-109B failed to close as required by tech spec. The cause of the event was determined to be a piece of teflon tape (type used to seal threaded air fittings) which prevented operation of the three way SOV that controls TV-CC-109B. Corrective actions consisted of checking valve operator circuit, establishing administrative control of the valve, removing foreign material, testing as per PT 18.6B and returning to service.

TRANS	Surry 1	04/15/82	Routine startup	

The reactor coolant system was diluted to a boron concentration wherein the critical rod position achieved, if the control rod assemblies were withdrawn in normal sequence, would have been lower than the insertion limit for zero power. This is contrary to tech spec 3.12.A.4 and reportable per tech spec 6.6.2.B.(3). Failure to maintain makeup boron concentration equal to RCS concentration resulted in an overdilution. Because of errors in the ECP calculations, the dilution was not detected until the subsequent approach to criticality. The controlling bank was inserted and the RCS borated to the required concentration.

TRANS	Surry 1	10/17/82	Routine startup	

One of two required boric acid flow paths to the core became unavailable and bit recirc was terminated due to the temporary loss of boric acid transfer pump 1-CH-P-2A. This is contrary to tech spec 3.2.C.4 and 3.3.A.3, and is reportable per tech spec 6.6.2.B(2). The motor trip appears to have been a random incident. The pump breaker was reset and flow verified to the VCT and blender.

TRANS	Surry 1	04/07/84	Routine SD	

Power level - 0%. On April 7, 1984, with Unit 1 at 5 x 10(-11) amperes on the intermediate range and inserting control rods shutdown, a reactor trip was initiated when source range NI-31 (EIIS No. R1) reinstated with indication above the high flux trip setpoint. Immediately following the trip, all control and protection systems functioned as expected with the exception of source range NI-31, which failed high. Approx. 4.5 hrs following the reactor trip, with NI-31 failed high, source range NI-32 was declared inoperable due to noise. With the unit at a hot shutdown condition, source range indication was unavailable for about 4 hrs. Appropriate abnormal procedures were implemented to insure positive reactivity was not added to the core. The preamp to NI-31 was replaced and source range indication was established. Prior to the start-up, the source range detector for NI-32 was replaced and the channel returned to service.

PHASE 2 CATEGORY	PLANT NAME	EVENT DATE	INITIAL PLANT CONDITION	RECOVERY TIME
TRANS	Surry 1	06/19/84	Routine startup	

Power level - 010%. On June 19, 1984, with the unit just less than 10% power, a reactor trip resulted when 2 of 4 nuclear power channels, NI 44 and NI 41 exceeded 10% power with the turbine unlatched. A primary plant cooldown of approx. .8 F/min and a primary dilution of 58 ppm contributed to the power increase. Following the trip, all control and protection systems functioned as expected. Main steam was isolated and the turbine stop valves were closed to limit primary plant cooldown. Precautions will be added to station procedures (OP 1.4 and PT 15.1C) to prevent testing the steam driven auxiliary feedwater pump near the P-10 setpoint without the main turbine being latched.

TRANS	Surry 1	01/27/85	Routine startup	

Power level - 010%. On 1/27/85, Unit 1 was critical with reactor power stable at 5% following a reactor trip on 1/26/85 (see LER 85-003-00). The steam dump valves were isolated earlier because of known but not specifically identified or quantified leakage. As the dumps were unisolated, the resulting leakge led to a primary system temperature decrease which caused reactor power to increase. As power neared 10%, it was decided to latch the turbine to prevent a trip. Approx. 2 minutes after the turbine was latched, the 4 turbine stop valves closed resulting in a reactor trip at 0748 hrs. One factor contributing to the trip was not sufficiently considering the effect of the steam leakage on plant parameters. Another contributor to the event was that only one electro hydraulic (EH) pump was available and running when the turbine was latched and it did not satisfy the EH demands during the latching operation. The steam dump leakage was identified and isolated. The human performance evaluation system coordinator is investigating this event and will provide feedback to the operating staff to improve human performance in similar circumstances.

TRANS	Surry 1	01/28/85	Startup	

Power level - 015%. On 1/28/85, during a Unit 1 startup, a reactor trip occurred due to a differential pressure anti-motoring turbine trip. Plant parameters did not indicate that a generator motoring condition existed. The trip occurred because the exhaust pressure sensing line root valve in the anti-motoring instrumentation was isolated. It is believed that this valve, while shut, developed a small leak during a previous period of power operation, allowing the sensing line to become pressurized. The line remained sufficiently pressurized during the shutdown period to cause the anti-motoring delta p setpoint to be exceeded as the turbine was being loaded. Station drawings and valve line up checklists for the main steam system will be changed to reflect the correct position and function of the valves. (from chulowp.ler)

TRANS	Surry 1	02/07/86	Routine startup	

Power level - 015%. On 2/7/86, a Unit 1 startup was in progress. Feedwater control was in manual and the transition from bypass to main feed regulating valve (FRV) (EIIS FCV) was taking place when the "C" steam generator feed flow suddenly had a step increase above demand. When demand was decreased, the flow went to zero. When the "C" FRVwas opened the second time, the flow again increased significantly. The operator closed the FRV; however, he was unable to prevent a high level condition in the steam generator and at 2338 hrs, a feed pump trip and turbine trip occurring initiated a reactor trip. The cause of this event was the failure to adjust the feedback cam on the "C" FRV following maintenance, which prevented fine control of the valve. Due to a procedural inadequacy, the instrument department was not notified to check the control adjustments of the valve following maintenance just prior to startup.

TRANS	Surry 1	02/08/86	Routine startup	

Power level - 002%. On 2/8/86, at 2% power, during a Unit 1 startup, the operating main feedwater pump tripped due to a high level in 'C' SG. This caused the AFW pumps to auto start. The high SG level occurred when the 'C' main feedwater bypass valve failed to close on demand. This valve was found to have a dust accumulation in the air pilot relay which blocked air to the valve operator. The blockage

PHASE 2 CATEGORY	PLANT NAME	EVENT DATE	INITIAL PLANT CONDITION	RECOVERY TIME

was removed and the valve closed. SG levels were returned to normal. Engineering will evaluate methods for controlling contamination in the instrument air system.

TRANS Surry 1 09/16/86 CSD

Power level - 100%. On Sept. 16, 1986, with Unit No. 1 and Unit No. 2 at 100% power, a reactor protection system relay failed during the performance of Unit 1 monthly surveillance testing. The relay failure resulted in a partial train 'B' engineered safety feature (ESF) actuation. On Sept. 20, 1986 with Unit 1 at hold shutdown and Unit 2 at 100% power the same reactor protection relay failed. Again, a partial train 'B' ESF actuation was initiated. The cause of both relay failures was determined to be a failure of the coil. The coil has been replaced, the relay re-installed and satisfactorily tested.

TRANS Surry 1 07/18/89 100%, Unit 2 - CSD

Power level - 100%. On July 18, 1989 with Unit 1 at 100% power and Unit 2 in cold shutdown, following the manipulation of a service water (SW) valve to the Unit 2 bearing cooling heat exchangers, the Unit 1 charging pump SW pumps became air bound and the pumps were declared inoperable. This is contrary to Technical Specification 3.3.A.7. The cause of this event has been attributed to air entering the SW lines that supply the charging pump SW pumps. The affected pumps were vented and returned to service. Additional high point vents are being installed. A procedure for periodic venting has been developed and restoration procedures enhanced. In addition, a design change being implemented to increase the size and number of the SW supply lines to the pumps has appropriate vents to facilitate removal of entrapped air. Engineering is also continuing their investigation of the event to determine if other actions are required.

TRANS Surry 1 07/23/89 100%, Unit 2 CSD

Power level - 100%. On July 23, 1989 at 1747 hrs, with Unit 1 at 100% power an Unit 2 at cold shutdown, following manipulation of a service water (SW) valve to the Unit 2 bearing cooling water heat exchangers, discharge pressures for the control room/relay room (CR/RR) air conditioning chillers' SW pumps and the Unit 1 and Unit 2 charging pump SW pumps decreased due to air binding in the pumps. The pumps were declared inoperable. Also, the two operating CR/RR chillers tripped on high condenser discharge pressure. This is contrary to Technical Specification 3.3.A.7 and 3.23.C. The cause of the event has been attributed to air entering the SW lines that supply the pumps. The affected pumps were vented and returned to service and the CR/RR chillers were returned to service. Additional high point vents are being installed. A procedure for periodic venting has been developed and the abnormal procedure for restoration has been enhanced. In addition, a design change being implemented to increase the size and number of SW supply lines to the pumps has provisions for appropriate vents to facilitate removal of entrapped air. Engineering is continuing their investigation of the event to determine if other actions are required.

TRANS Surry 2 12/19/82 Hot SD

While conducting the RCs integrity test (PT 11), a weld leak on the 'A' steam generator channel head drain piping at 2-RC-159 was identified. Immediate action was taken to return the unit to CSD. This event is reporable pursuant to Tech Spec 6.6.2.A.(3). The leakage was within the capability of the normal make up system. The cause of this event is believed to be poor fusion between successive passes in a small area of the weld. The unit was returned to CSD and the defective weld was repaired. Liquid penetrant examination of the final weld revealed no defects.

TRANS Surry 2 09/21/83 Hot SD

With Unit 2 at hot shutdown while conducting the RCS integrity test (PT 11) a weld leak on the "A" steam generator channel head drain piping at 2-RC-159 was identified. Actions were taken to return the Unit to cold shutdown. This event is contrary to tech spec 3.1.C.4 and is reportable per tech spec 6.6.2.B.(4). Leakage was within the capability of the normal make-up system. The exact cause has not

PHASE 2 CATEGORY	PLANT NAME	EVENT DATE	INITIAL PLANT CONDITION	RECOVERY TIME

been determined. An identical event occurred on 12/19/82 and the weld leak was attributed to inadequate fusion between successive weld passes. Only the portion of the weld determined to be defective was repaired. It is suspected that undetected defects remained and propagated to the surface. The weld was completely ground out and rewelded and tested satisfactorily.

TRANS Surry 2 04/15/84 2% power

Power level - 002%. At 1604 on 4/15/84 following a maintenance outage, Unit 2 was at 2% reactor power when a reactor trip occurred as a result of an intermediate range (NI-35) high flux trip. Plant parameters did not indicate a valid high flux trip. An electrician was checking for continuity across the switch for TV-SS-201A when an arc occurred resulting ina spike on vital bus 1 2which caused the spike on NI-35. The multimeter was selected to resistance instead of voltage. (from chulowp.ler)

TRANS Surry 2 04/20/84 Hot SD

Power level - 0%. On April 20, 1984 at 0216 hrs, with the unit at hot shutdown, a reactor trip occurred due to a high flux on source range NI-32. The reason for the trip was personnel error by a instrument technician while he was troubleshooting NI-32 which had a failed preamp. The instrument technician was disciplined. A replacement preamp is on order and will be installed when it arrives.

TRANS Surry 2 03/16/87 Hot SD

Power level - 0%. On March 16 1987 at 1704 hrs, Unit 2 was at intermediate shutdown with shutdown banks 'A' and 'B' withdrawn. During the performance of a periodic test of a steam flow transmitter (EIIS-FT) on Unit 2, a reactor trip by turbine trip occurred, resulting in the insertion of the shutdown banks (EIIS-ROD). This test trips permissive P-7 bistables (EIIS-33) (turbine first stage pressure) ad simulates a signal of 10% power. Since the turbine was unlatched at the time, permissive P-7 (EIIS-JC) was activated, resulting in a reactor trip by turbine trip. The periodic test procedure requires the instrument technician to ensure that the turbine is latched if plant conditions are such that the reactor trip breakers (RTB'S) are closed and reactor power is less than 10%. The technician believed that the RTB's were open when in fact, they had been closed earlier in the day. The technician continued with the proceudre, and tripped the P-7 bistables, resuting in the activation of P-7 and the ensuing reactor trip by turbine trip. The technicians have been re-instructed to obtain the status of plant conditions from the shift supervisor.

TRANS Surry 2 09/10/88 Refueling outage

Power level - 004%. On Sept. 10, 1988 at 0158 hrs, with the unit 2 reactor at 4% power, during a shutdown for a refueling outage, a reactor trip by turbine trip occurred. The event occurred while oeprators were attepting to maintain the turbine at synchronous speed, with the generator output breakers open. When the valve position limiter was raised, per the procedure, a unexpectedly rapid opening of the turbine governor valves and a rapid increase in turbine first stage pressure occurred, resulting in a turbine trip/reactor trip. Operators followed appropriate plant procedures and quickly stabilized the plant following the trip. The cause of the event has been attributed to a combination of an inadequate procedure, a faulty valve position limit indication, and an unexpectedly fast valve position limiter setting response. The controlling procedure used during the event will be revised to ensure that the turbine control system is placed in the configuration intended. Testing will be performed on the electro hydraulic control (EHC) system, which will determine if any additional actions will be required.

TRANS Surry 2 09/16/89 Subcritical

Power level - 0%. On Sept. 26, 1989 at 1228 hrs with Unit 2 subcritical, during a reactor startup, a manual reactor trip was initiated when it was determined that improper bank overlap existed between the 'A' and 'B' control rod banks. The reactor trip was initiated to insert all control rods and to reset the control rod step counters to zero. A four hour non-emergency report was made to the Nuclear

PHASE 2 CATEGORY	PLANT NAME	EVENT DATE	INITIAL PLANT CONDITION	RECOVERY TIME

Regulatory Commission per 10CFR50.72. Troubleshooting did not reveal the cause of the improper bank overlap. During the subsequent reactor startup, no problems were encountered with control rod bank overlap.

TRANS	Surry 2	09/18/89	14% power	

Power level - 14%. On Sept. 18, 1989, at 1042 hrs, with Unit 2 reactor at 14% power and the turbine at 1800 rpm under no load conditions, a reactor trip signal was generated. A generator backup differential lockout relay 86 Bu tripped the turbine, and since reactor power was greater than 10%, the turbine trip initiated a reactor trip. Operators performed the appropriate plant procedures and quickly stabilized the plant following the trip. The 86 bu generator backup lockout relay trip was caused by the spurious actuation of the generator backup impedance relay (KD-41). The exact cause of the spurious actuation of the relay could not be determined, however faults were discovered in the relay. The faulted KD-41 relay was replaced and appropriate testing was performed. The generator startup procedure has been revised to ensure that reactor power is less than 10% prior to closing the exciter field breaker. A four hour non-emergency report was made to the Nuclear Regulatory Commission in accordance with 10CFR50.72.

APPENDIX B

Review of U.S. Nuclear Regulatory Commission (NRC)

Information Notices, Generic Letters, Bulletins and Circulars

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B.1 - Summary of Findings

Potential Degradation of Systems that Can Be Used for Accident Mitigation

1. Due to the activities in an outage, transient material and debris may be inside the containment. They may clog up the suctions from the containment sump in a LOCA. The operability of the low head injection system, inside containment recirculation system, and outside containment recirculation system will be affected. (IN 88-22) Use the June 16, 1988 event as failure data for recirculation pumps. (IN 89-77)

2. During startup, when the power is above 10%, the intermediate power level(25%) trip will be blocked. If the reactor power is lowered below 10%, and two of the four bistable switches fails to reset, then the reactor will not trip until 109%. This applies to both power range and intermediate range channels. Tech. Spec. allows one channel to be taken out of service. (IN 86-105)

3. Common mode failure of four normally closed motor operated valves, that control the service water flow to the recirculation spray heat exchangers, to open.(IN 83-46)

Potential Initiating Events

1. Inadvertent lifting of fuel assembly while lifting the upper internal, February 26, 1986 and Indian Point Oct. 90 (NSAC-129, IN88-92,IN 86-58) Damage to fuel assembly during refueling (IEC 80-13).

2. Inadvertent withdrawal of control rod. The events at Vermont Yankee on November 7, 1973 and Millstone 1 on November 12, 1976 can be used as a data.(IN 88-21)

3. Pressurizer surge line movement and deformation due to thermal stratification (IEB 88-11)

B.2 Review of NRC Information Notices:

90-19: Potential Loss of Effective Volume for Containment Recirculation Spray at PWR Facilities
Entrapment of containment spray water in the refueling canal may lead to insufficient water returned to the sump, and inadequate net positive suction head to the containment spray pumps and low head safety injection pumps. This may happen if the refueling canal drain valve is closed.

Resolution: The RWSTs of both units are cross connected, and the amount of water that can be heldup in the refueling canal is only a small fraction of the water in a RWST.

89-77: Debris in Containment Emergency Sumps and Incorrect Screen Configurations
June 16,1988, Surry. July 8, 1989, Trojan. Diablo Canyon.

88-28: Potential for Loss of Post-LOCA Recirculation Capability due to Insulation Debris Blockage
March 14, 1988, Susquehanna. (It appears that any recirculation will be not likely during an outage. Due to the activities going on, it is not likely to keep the floor inside the containment clean.)

Resolution: The concern regarding the ability to use recirculation while the reactor is shutdown due to the potential problem of transient material, debris due to the activities during shutdown need to be modelled. Surry's low pressure injection/recirculation system does not have heat exchanger for heat removal. Therefore, long term heat removal may depend on containment spray/recirculation.

90-06: Potential for Loss of Shutdown Cooling While at Low Reactor Coolant Level
July 18, 1989, Comanche Peak. Loss of the invertor supplying power to the controller for the RHR heat exchanger flow control valve (FCV) caused the FCV to open to the fully open position. The sudden increased flow caused vortexing at the RHR suction.

Resolution: Use it as a loss of RHR event. It occurred prior to initial criticality. Therefore, it is not used to estimate the frequency of loss of RHR.

90-05: Inter-system Discharge of Reactor Coolant
December 1, 1989, Braidwood, 68000 gallon. Stuck open RHRS relief valve, and inability of operators to identify the leak(lack of EOP) caused the incident to last more than 3 hours before the condition of the plant is stabilized.

Resolution: Use it as a loss of RHR event with RCS solid while drawing a bubble in POS 12.

89-73: Potential overpressurization of Low Pressure Systems
September 5, 1989, McGuire Unit 2. Containment spray system(design pressure 220psig) was overpressurized by 450 psig RCS pressure during functional test of suction valve from the sump. 2200 gallons of coolant was lost. In adequate test procedure.

Resolution: Surry's RHR system does not take suction from the sump. Neither does the containment spray system. The two recirculation systems do, however, they do not take suction from RWST. The low head injection system injects into all cold and hot legs, takes suction from the RWST and the containment sump, and does not take suction from the RCS. Therefore, this scenario does not apply to Surry. The injection lines are shared between the high head injection system and low head injection system. Normally the LHSI is isolated from charging

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by one check valve and two closed MOVs. Upon spurious SI in shutdown condition, if the check valve fails open, the LHSI may be overpressurized. LHSI flow path will be open with the normally operating charging pump injecting to it and the RCS. Similar scenario may occur at power. We need to review test procedures for high head injection system, low head injection system and RHRS to identify possible scenarios that may lead to an interfacing systems LOCA. This should be considered as a special initiator.

89-41: Operator Response to Pressurization of Low-Pressure Interfacing System
March 9, 1989, Votgle. Leakage through inboard isolation valve of the RHR system cause the RHR system pressure to stay high after taken out of service. Operators opened the suction valves from the RWST to relieve the pressure.

Resolution: This can be used as a data in interfacing LOCA analysis. Surry's RHR system does not take suction from RWST.

89-71: Diversion of the Residual Heat Removal Pump Seal Cooling Water Flow during Recirculation Operation Following a Loss-of-Coolant Accident
Haddam Neck PRA. During normal operation, CCW system provides cooling to the RHR heat exchangers and pump seal coolers. During a LOCA condition, CCW is isolated and service water is used to provide cooling to the RHR components. A single failure of one of the service water motor-operated valves to open following a LOCA would result in only one branch of service water being available to provide cooling to both RHR heat exchangers and the seal water coolers.

Resolution: A review of ccw and sw operations at Surry showed that the CCW to the RHR heat exchanger will be isolated on a safety injection signal. However, RHR is not used for safety injection. The low head injection pumps at Surry are self-cooled. Loss of CCW and SW are considered in support system failures.

89-67: Loss of Residual Heat Removal Caused by Accumulator Nitrogen Injection
May 20, 1989, Salem 1, cold shutdown. Full flow test of accumulator check valve caused 1800 cubic feet of nitrogen to enter the RCS. Both RHR pumps were nitrogen bound. Operators had difficulty in locating the drain and vent valves.

Resolution: Use it as a loss of RHR data

88-23: Potential for Gas Binding of High-Pressure Safety Injection Pumps During a Loss-of-Coolant Accident
February 26, 1988, Farley 1. Hydrogen from VCT may accumulate in the high point in the charging pump suction (pipe segment between the charging pump suction and the LHSI discharge).

Resolution: Need to get isometrics for LHSI, HHSI, RHR and RCS.

May 13, 1988, South Texas. **October 12, 1988, Surry.** Hydrogen from the volume control tank or air dissolved in RWST water may be released to ECCS piping between RWST and HPSI.

Resolution: Need to get isometrics for LHSI, HHSI, RHR and RCS.

October 30, 1989, Trojan nuclear plant. Both high head injection pump may be inoperable if a safety injection signal occurs while the manual "bypass" valve around the motor operated VCT outlet isolation valves is opened per test procedure.

Resolution: At Surry, the seal water go to the charging pump suction directly without going to the VCT. It is connected to the VCT only through a relief valve RV1362B that allows relief into the VCT.

87-57: Loss of Emergency Boration Capability due to Nitrogen Gas Intrusion
May 28, 1987, Turkey Point Unit 4. Nitrogen entered the boric acid system through a failed boric acid transfer pump mechanical seal. The seal is provided with an accumulator tank partially filled with demineralized water. The accumulator is given a 40-psi nitrogen overpressure to preclude leakage of the boric acid across the seal faces. As demineralized water entered the boric acid system through the failed seal, additional nitrogen was automatically supplied to the accumulator to maintain the pressure. The falling water level then allowed the nitrogen cover gas to enter the boric acid system through the failed seal.
Resolution: A failure mode of boric acid transfer pump

82-19: Loss of High Head Safety Injection Emergency Boration and Reactor Coolant Makeup Capability
February 12, 1982, McGuire unit 1. Hydrogen from the positive displacement pump suction dampener entered the common suction of the charging system, causing both centrifugal charging pumps and the PDP to be inoperable.
Resolution: A CCF of charging pumps. Surry does not have a positive displacement charging pump.

83-49 and 82-32: Sampling and Prevention of Intrusion of Organic Chemicals into Reactor Coolant System
February 13, 1983, Hatch. April 24, 1982 Hatch Unit 1. May 5, 1983, LaSalle. (Can similar events occur at a PWR leading to degraded core heat removal or reactivity accident?)
Resolution: A systematic way of identifying such scenarios is needed, otherwise, these events can be used as data for the scenarios. The Lasalle event is considered also possible for a PWR, with the condensate storage tank replaced by primary grade water storage tank. However, the event does not seem to have any significant safety impact. It may require cleanup of the RCS, but is not an initiating event.

89-54: Potential Overpressurization of the Component Cooling Water System
May 15, 1989, Surry. A design deficiency in the CCW system relief valve was reported. The capacity of the relief valve is not sufficient to relieve a tube rupture of the thermal barrier heat exchanger. Additional relieve valves installed.
Resolution: In design change package 89-008, the CCW inlet check valve to the thermal barrier was replaced by two check valves in series. The thermal barrier outlet is isolated by a trip valve upon high flow.

89-32: Surveillance Testing of Low-Temperature Over-Pressurization Systems
Beaver Valley, Turkey Point, Shearon Harris. Stroke time requirement in inservice testing (15 sec) for PORV was not consistent with the safety analysis (2 sec).
Resolution: LTOP has been identified before and will be considered.

88-92: Potential for Spent Fuel Pool Draindown
October 2, 1988, Surry Unit 1. Potential drain down of spent fuel pool to 13 inch above top of fuel assembly.

Resolution: Design change package ??? installed new cavity seal in the Oct. 90 refueling outage. NSAC-129 **identify events involving drop of one fuel assembly, inadvertent lifting of a fuel assembly, and misposition of 4 fuel assemblies into 4 control cells with the control rods withdrawn.**

84-93: Potential for Loss of Water from the Refueling Cavity
August 21, 1984, Haddam Neck.
Resolution: Beyond the scope except for flooding
Resolution: Consider it for internal flooding analysis

88-87: Pump Wear and Foreign Objects in Plant Piping Systems
May 16, 1988 Surry Unit 2, auxiliary feedwater system. June 6, 1988, Surry Units 1 and 2, recirculation spray pumps.
Resolution: Get information on improvement in design or operation. Include these failure modes.

88-36: Possible Sudden Loss of RCS Inventory During Low Coolant Level Operation
Diablo Canyon. Westinghouse cold opening scenario

87-23: Loss of Decay Heat Removal During Low Reactor Coolant level Operation
Diablo Canyon.

86-101: Loss of Decay Heat Removal due to Loss of Fluid Levels in Reactor Coolant System
Resolution: Already identified.

88-21: Inadvertent Criticality Events at Oskarshamn and at U. S. Nuclear Power Plants
July 30, 1987, Oskarshamn. November 7, 1973, Vermont Yankee. November 12, 1976. Inadvertent withdrawal of a control rod that is adjacent to a fully withdrawn control rod leads to criticality, and the scram system shutdown the reactor.
Resolution: This is a reactivity accident that should be modelled.

88-17: Summary of Responses to NRC Bulletin 87-01, "Thinning of Pipe Walls in Nuclear Power Plants"
December 9, 1986, Surry Unit 2. 1987, Trojan. December 10, 1987, LaSalle Unit 1. Pipe thinning in feedwater line.

86-106: Feedwater Line Break
December 9. 1986, Surry Unit 2.
Resolution: Find information on improvement in surveillance of feedwater lines and determine if the scenario need to be modelled.

87-59: Potential RHR Pump Loss
Potential for dead heading one of two RHR pumps in systems that have a common miniflow recirculation line serving both pumps, during a small LOCA. Capacity of miniflow recirculation line for single pump operation.
Resolution: NRC or Westinghouse should have resolved this. Get resolution from NRC.

87-46: Unidentified Loss of Reactor Coolant
June 21, 1987, North Anna Unit 1, cold shutdown. 17,000 gallons of coolant was lost and voids formed in the vessel head and SG tubes. Misleading pressurizer level indication.

Resolution: This is a LOCA event that can be used as data. Misleading level indication need to be modelled.

84-55: Seal Table Leaks at PWRs
January 20 ,1984, Zion Unit 1. April 19, 1984, Sequoyah.
Resolution: Minor leaks during power operation. We will look into failure of temporary seals used during refueling.

87-40: Backseating Valves Routinely to Prevent Packing leakage
June 12, 1987, Surry Unit 1. A low flow reactor trip occurred due to the failure of the stem of a hot leg loop stop valve. Similar event occurred March 7, 1974.
Resolution: Surry does not use electrical backseating of the loop stop valves any more. Use it as data for power operation.

86-105: Potential for Loss of Reactor Trip Capability at Intermediate Power Levels
(If a reactivity insertion occurs above 10% power, no scram will occur until 109% power)(If a reactivity insertion occurs below 10% a single failure of a bistable switch to reset may lead to failure of scram system.)
Resolution: We need to model it.

86-79: Degradation or Loss of Changing Systems at PWR Nuclear power Plants Using Swing-Pump Designs
June 26, 1985, Surry Unit 1. Pump A was down for maintenance, and when pump B was racked out, an interlock caused the running pump C (swing pump) to trip.
Resolution: This will be modeled. No additional action needed.

86-63: Loss of Safety injection Capability
December 28, 1984, Indian Point 2. Two leaky valves in the discharge of the boron injection tank enabled highly concentrated boric acid to flow to the low pressure discharge line (SI pump suction) and to precipitate in the pumps, which were not heat traced. Degassing of the nitrogen cover gas dissolved in the boric acid solution is believed to be one of the likely sources of gas found in the pumps.
Resolution: Surry does not have boron injection tank.

86-58: Dropped Fuel Assembly
February 26, 1986, Haddam Neck. A spent fuel assembly was inadvertently lifted from the core when the upper core support structure was removed from the reactor vessel. The assembly impacted the core barrel and was knocked off.
Resolution: Use it as well as the recent Indian Point incident as data for failure of one fuel assembly.

85-12: Recent Fuel Handling Events
Resolution: We need to model it along with events in NSAC-129.

86-01: Failure of Main Feedwater Check Valves Causes Loss of Feedwater System Integrity And Water-hammer Damage
November 21, 1985, San Onofre Unit 1.
Resolution: We need to model it.

80-01: Fuel Handling Events

December 11, 1979, inadvertent raising of spent fuel assembly, December 17, 1979, a new fuel assembly was dropped in the fuel pool. Pilgrim.

Resolution: Combine with NSAC-129.

84-70: Reliance on Water Level Instrumentation with a Common Reference Leg
All the wide range level instruments have a common reference leg that developed a leak. The leak made the operators to maintain an apparent level while the actual level decreased, thereby causing the pressurizer to drain and a bubble to enter the top of the head.

Resolution: We need to find out about the design of level instrumentation at Surry. Is this a LOCA?

84-42: Equipment Availability for Conditions During Outages Not Covered by Technical Specifications
January 8, 1984, Palisades. Loss of offsite power with one diesel generator 2 down for maintenance and the service water pump that is powered from diesel generator 1 was also down for maintenance. DG 1 was tripped 50 minutes later upon overheating.

Resolution: Already identified.

83-46: Common-Mode Valve Failures Degrade Surry's Recirculation Spray Subsystem
February 9, 1983, Surry. Four normally closed MOVs that permit service water flow to the recirculation spray heat exchangers failed to open. Possible causes are corrosion, marine growth, infrequent testing, and low torque switch setting.

Resolution: A common mode failure. Check if 1150 models it.

83-41: Actuation of Fire Suppression System Causing Inoperability of Safety-Related Equipment
May 28, 1981, Surry unit 2. and other events. Discharge from the foam distributor system installed in the main (reserve) diesel fuel oil tank caused 4000 gallons of water be introduced and widely distributed in the diesel fuel system before a routine periodic test disclosed the presence of water.

Resolution: Get information on fixes implemented to determine if it need to be modelled.

82-45: PWR Low Temperature Overpressurization Protection
August 1976, Turkey Point Unit 4. Possible causes of inoperable PORVs:

1. Operation with both PORVs isolated (block valves closed) because of known PORV leakage.
2. Operator error during maintenance.
3. Isolation and venting of instrument air to the PORV actuators during integrated leak rate testing.
4. Low nitrogen(backup accumulator) pressure to PORV actuators.

Resolution: LTOP will be analyzed.

82-17: Overpressurization of Reactor Coolant System
November 28, 29, 1981, Turkey Point 4. A pressure spike caused by starting a reactor coolant pump caused automatic isolation of the RHR suction valves. OMS failed to operate because a pressure transmitter isolation valve was found closed, the summator in the supposedly operable electrical circuitry failed, and the redundant OMS circuit was out of service.

Resolution: Already identified.

82-28: Hydrogen Explosion While Grinding in the Vicinity of Drained And Open Reactor Coolant System

April 20, 1982, Arkansas nuclear One Unit 1. A craftsman was grinding the HPI pipe line in preparation for welding. A hydrogen explosion occurred and blew the craftsman away by about 3 feet.

Resolution: Consider it in fire analysis.

81-10: Inadvertent Containment Spray due to Personnel Error

February 11, 1981, Sequoyah.

Resolution: Already identified.

81-09: Degradation of Residual Heat Removal

March 5, 1981, Beaver Valley, midloop operation.

Resolution: Already identified.

81-04: Cracking in Main Steam Lines

February 23, 1981, Surry Unit 1. A lengthy crack indication in the I.D. counterbore area of a weldment on the in-line "T" fitting which connects the vertical run of 30-inch piping to the safety relief valve header and 30-inch main steam line of steam generator A.

Resolution: Use it in LOCA frequency assessment.

80-44: Actuation of ECCS in the Recirculation Mode While in Hot Shutdown

December 5, 1980, Davis Besse. Inadvertent actuation caused a flow path to the RCS via the borated water storage tank and the DHR piping. No BWST water was pumped into the RCS. Rather, during the valve transition time of about 1.5 minutes, approximately 15,000 gallons of borated water was drained from the BWST to the containment emergency sump.

Resolution: RHR system at Surry is independent of safety injection system and does not take suction from RWST or containment sump.

80-20: Loss of Decay Heat Removal Capability at Davis-Besse unit While in a Refueling Mode

April 19, 1980, Davis-Besse. Loss of power to non-essential 480 v bus caused recirculation mode actuation, and loss of RHR suction. (extensive maintenance activities)

Resolution: Already identified in RHR data base.

80-34: Boron Dilution of Reactor Coolant During Steam Generator Decontamination

May 29, 1980, Trojan. July 5, 1980, San Onofre 1, high pressure demineralized flushing water leaked by a dislodged nozzle seal and the resulting reactivity addition exceeded the tech. specs.

Resolution: Already included in reactivity accident.

79-04: Degradation of Engineered Safety Features

Arkansas Nuclear One, units 1 and 2. MSIV closure at unit 1 lead to loss of ac power at unit 2 which was in hot standby.

Resolution: A cause for loss of offsite power.

B.3 Review of Generic Letters, IE Bulletins & IE Circulars

Conclusions
GL -- generic letter
IEB -- IE Bulletin
IEC -- IE Circular

1) Loss of RHR. Some special concerns are: a) in midloop operation, if boiling begins in the RCS and the cold leg is open (e.g. maintenance on the pumps), the increased pressure will force water out of the opening, thus further decreasing time available for recovery (GL 87-12, 88-17; Diablo Canyon April 10, 1987); air ingestion will cause erroneous level indication (it should be noted that in the Diablo Canyon event, RHR pumps were able to handle a few percent air ingestion). c) maintenance activities may cause loss of redundancy during shutdown (IEB 80-12, Davis Besse, April 19, 1980). d) service water problems may cause loss of RHR (IEC 81-11, GL 89-13; Brunswick, a BWR, Dec 8, 1980 -- SW train A in maintenance, B not aligned because a expected to be repaired before boiling reached, A train repair took too long).

2) Steam void generation during depressurization. Hot metal out of the main flow path. Pressurizer level increases suddenly. Steam can interfere with heat removal. (IEC 81-10, 80-15; Crystal River 3, April 21, 1981, during cold shutdown; McGuire 1, June 1981, during heatup; also St. Lucie 1, June 11, 1980 during full power -- loss of CCW flow to RCPs causes reactor trip -- cooldown for a few hours until rise in press. level. Problems lead to eventual use of LPSI)

3) Condensate booster pumps can be used for secondary, but need to depressurize first (GL 88-20)

4) Steam binding of AFW pumps. Due to leakage past isolation valves of hot water from the MFW. IEB 85-01, GL 88-03; Crystal River 3 1982 & 1983; Robinson 2, 1981 through 1983; D. C. Cook, 1981; McGuire 2, 1984; Catawba 1, Nov. 1984)

5) Water hammer can disable important safety systems. (GL 86-07; San Onofre 1, Nov. 21, 1985, 60% power, loss of all ac power for 4 min followed by a severe water hammer which caused a steam leak, damage to plant equipment and loss of feedwater for 3 min; caused by check valve failure)

6) Overfill of steam generators, overcooling, overheating -- obvious concerns (GL 81-28, 81-16, 83-37)

7) Low temperature overpressurization. (GL 88-11; the critical limits and the operating window had been changed recently -- to make it more difficult).

8) Boron dilution events during hot standby (only 15 mins available btw. an alarm and loss of shutdown margin)

9) Control rod withdrawal with only one RCP operating in hot standby may violate DNBR (for W plants -- FSAR says 2 RCPs operating in hot standby, but TS allows only one -- OK for most accidents except uncontrolled rod withdrawal; GL 86-13)

10) Sump screen blockage. Obvious concern, maybe more so in shutdown. Plants most vulnerable are the ones with small debris screen area (< 100 sq. ft), high ECCS recirc. pump requirements (> 8000 gpm) and small NPSH margins(< 1-2 ft of water) (GL 85-22)

11) Control of **heavy loads**. Surry did a load drop analysis to satisfy requirements (GL 85-11).

12) **Loss of shutdown margin** during refueling operations. Baltimore Gas & Electric presented this analysis for its Calvert Cliffs units, in March of 1987. It shows that at some intermediate positions during refueling, and assuming clustering of higher enrichment fresh fuel for the extended cycle, criticality can occur. (GL 89-03).

13) **Pressurizer surge line movement and deformation due to thermal stratification**. This occurs during heatup, cooldown and also steady state, due to stratification of hot water flowing from the pressurizer and the layer of "cold" water from the hot leg in the pressurizer surge line (IEB 88-11; Trojan observed unexpected movement of PSL at each refueling since 1982, with the "latest" one actually touching the restraints and causing plastic deformation; Beaver Valley 2 also noticed the PSL movement and the snubber movement during power ascension).

14) Possible loss of pumps (e.g. RHR pumps) in miniflow conditions. The stronger pump will cause deadheading of the weaker pump (2 pumps in parallel with a common miniflow line). The capacity of line may not be enough to support even one pump miniflow (IEB 88-04)

15) Damage to fuel assemblies during refueling. Observed extensive damage to grid straps in W fuel assemblies, caused by hitting diagonally neighboring assembly during insertion (IEC 80-13, Salem 1, LER 79-44).

Generic Letters of Interest to Surry Shutdown Study

81-07: Control of Heavy Loads, also GL 85-11. The response should include use of electrical interlocks or mechanical stops, single failure proof cranes and load drop analysis. The last one was done at Surry, and the areas analyzed were the spent fuel pool area and the containment building. Boron dilution events during hot standby. 15 min available between the first alarm and loss of all shutdown margin.

81-16: Overfilling of steam generators

81-22: CVCS leak at H.B. Robinson plant -- inadvertent operation of charging pumps. 6000 gal in letdown train of CVCS. Inconsistency between tech specs and safety analysis (in 3 loop W plants). FSAR assumes 2 RCPs in operation in Mode 3 (hot standby). Tech specs say one is OK. With only one pump, an uncontrolled withdrawal of the control bank from the subcritical condition may cause violation of DNBR criteria.

86-07: Water hammer and loss of power at San Onofre. This occurred at 60% power. All 5 check valves were disabled.

85-22: Post LOCA sump screen blockage. The plants that are most vulnerable are the ones with: - small debris screen area (<100 ft**2) - high ECCS recirculation pumping requirements (>8,000 gpm) - small NPSH margins (<1-2 ft of water).

85-16: High boron concentration. At Indian Point 2, all 3 SI pumps were frozen with crystallized H_3BO_3. Boron injection tank(BIT) has a high concentration of boric acid (in case of a steam line break). Surry 1 & 2 have requested to remove the BIT or reduce the concentration to 2,000 ppm. The request was granted.

85-13: Davis Besse loss of main and auxiliary feedwater

85-09: Generic W modifications for reactor trip system. Require at power testing of undervoltage and shunt trip attachments.

85-07: Inadvertent boron dilution events. 110% pressure in the RHR. Instrumentation is not required.

85-02: SGTR prevention. TV camera for loose parts and foreign objects -- after any secondary side modifications and eddy current testing.

89-21: USIs and GSIs:
water hammer
SG tube integrity
A-31 RHR shutdown requirements
A-49 pressurized thermal shock
A-47 control systems: overfill protection, overcooling, overheating transients. Surry has 2 out of 3 logic, with one channel used both for control and protection. MFW isolated by closing the MFW isolation valves and tripping the MFW pumps.
System interactions -- flood, seismic, electrical reliability and operator actions

89-13: Service water system problems

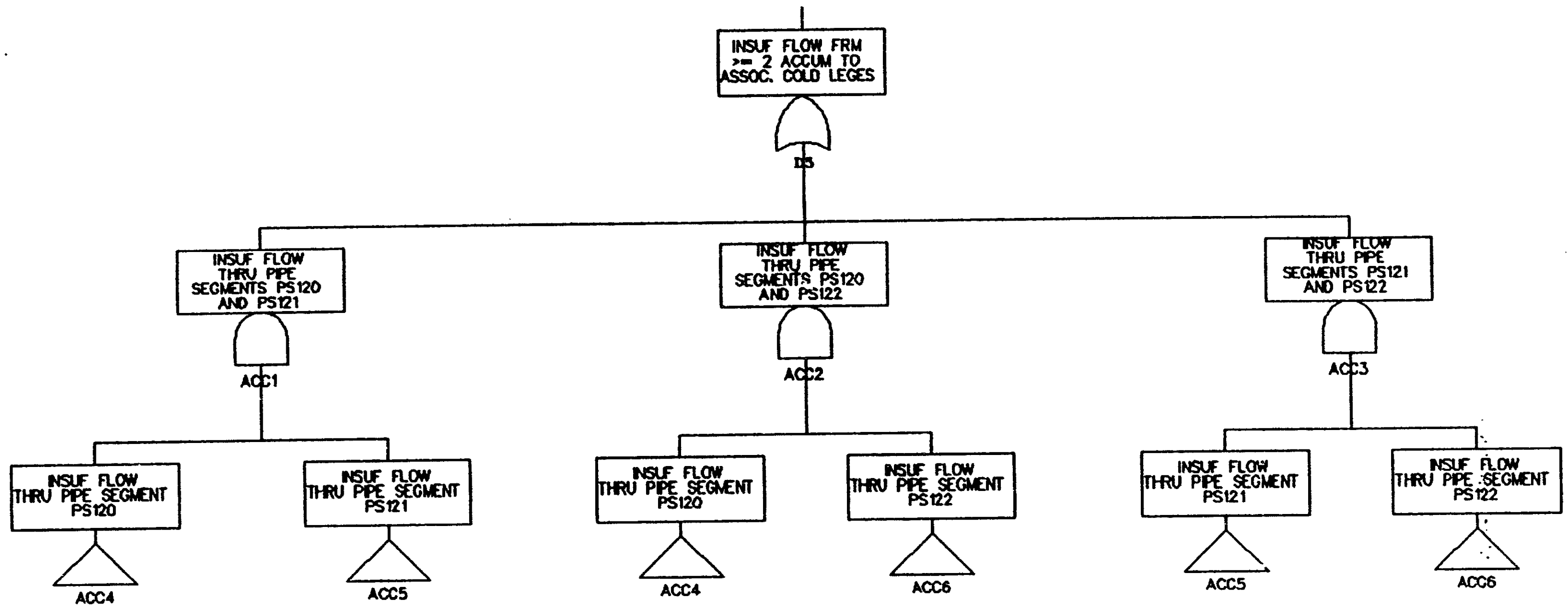
88-17: **Loss of decay heat removal. NUREG-1269 (report on Diablo Canyon event) identified many generic weaknesses.**

APPENDIX C SYSTEM FAULT TREES

APPENDIX C SYSTEM FAULT TREES

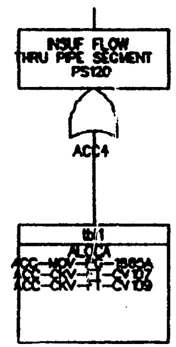
Appendix C.1 Accumulator System

ACCUMULATORS (ACC)
(D5)



PAGE 1, 2 & 3

ACCUMULATORS (ACC4)
(ACC)



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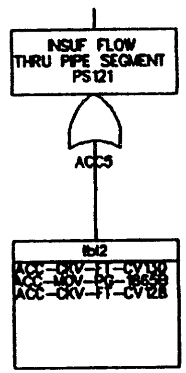
ACCUMULATORS (ACC)
(ACC5)



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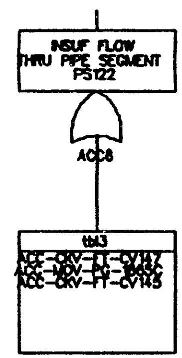
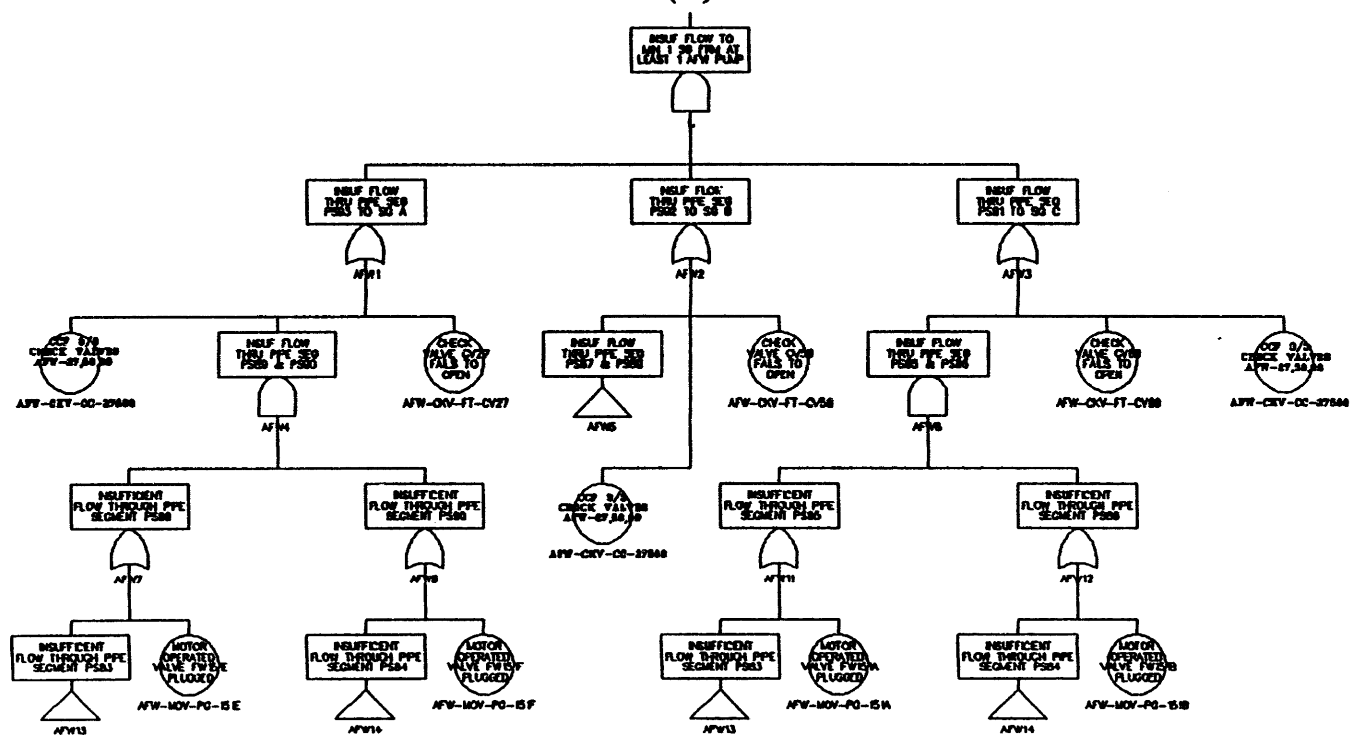
ACCUMULATORS (ACC)
(ACC6)



PAGE 1, 2 & 3

Appendix C.2 Auxiliary Feedwater System

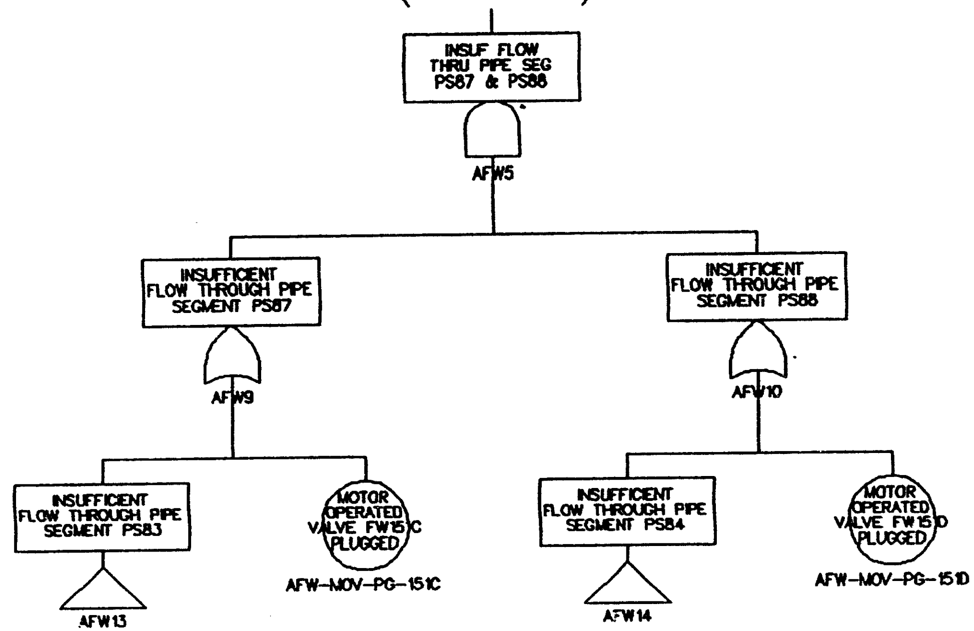
AUXILIARY FEEDWATER TO 1 OF 3 SG (AFW-1)
(L)



PAGE 1 & 9

C-9

AUXILIARY FEEDWATER TO 1 OF 3 SG (AFW-1)
(AFW5)



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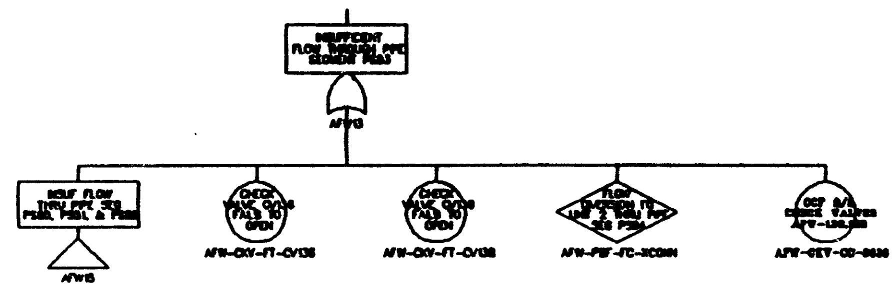
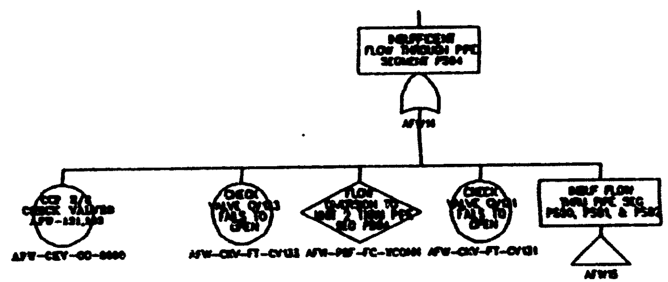
(AFW13)

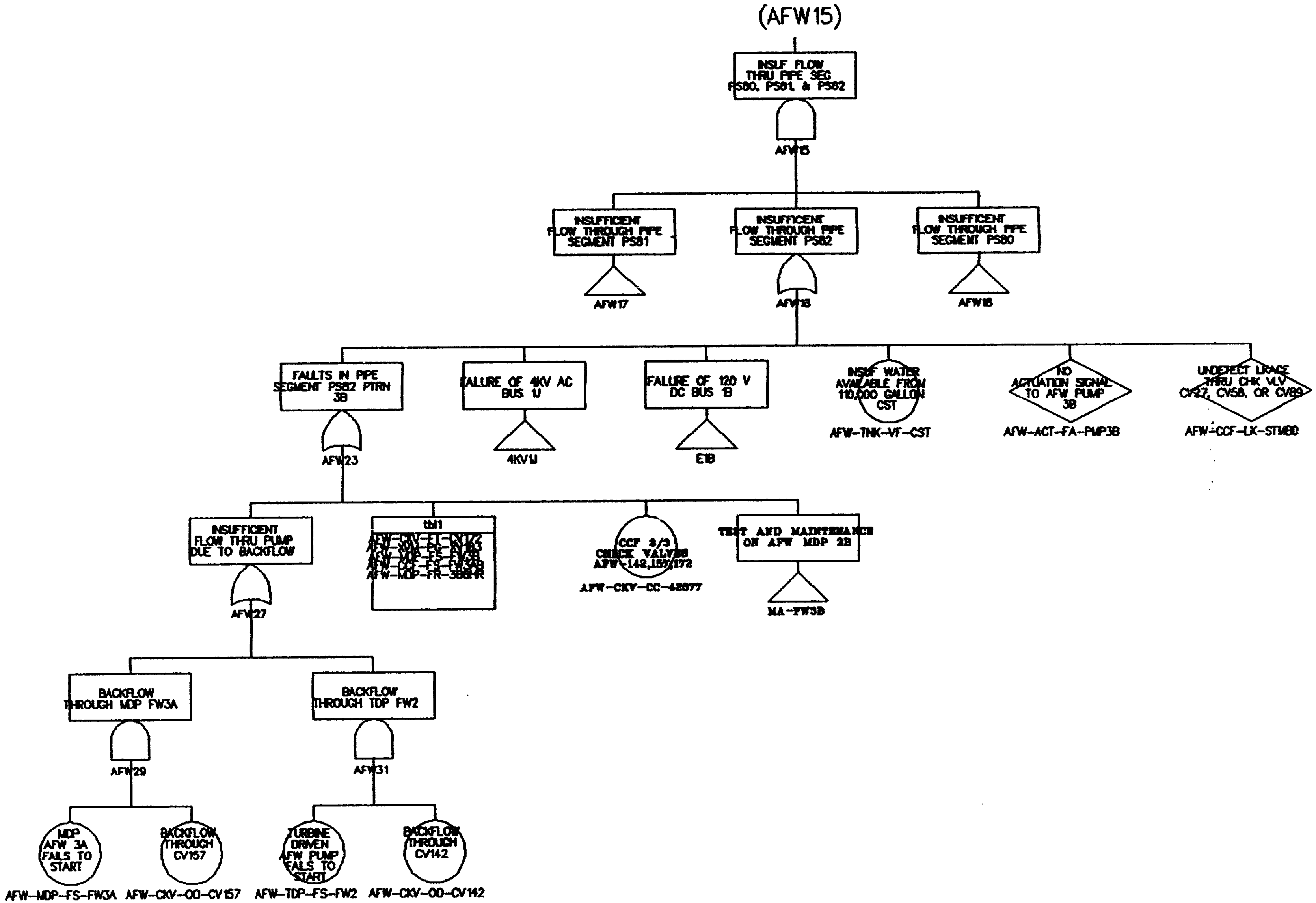


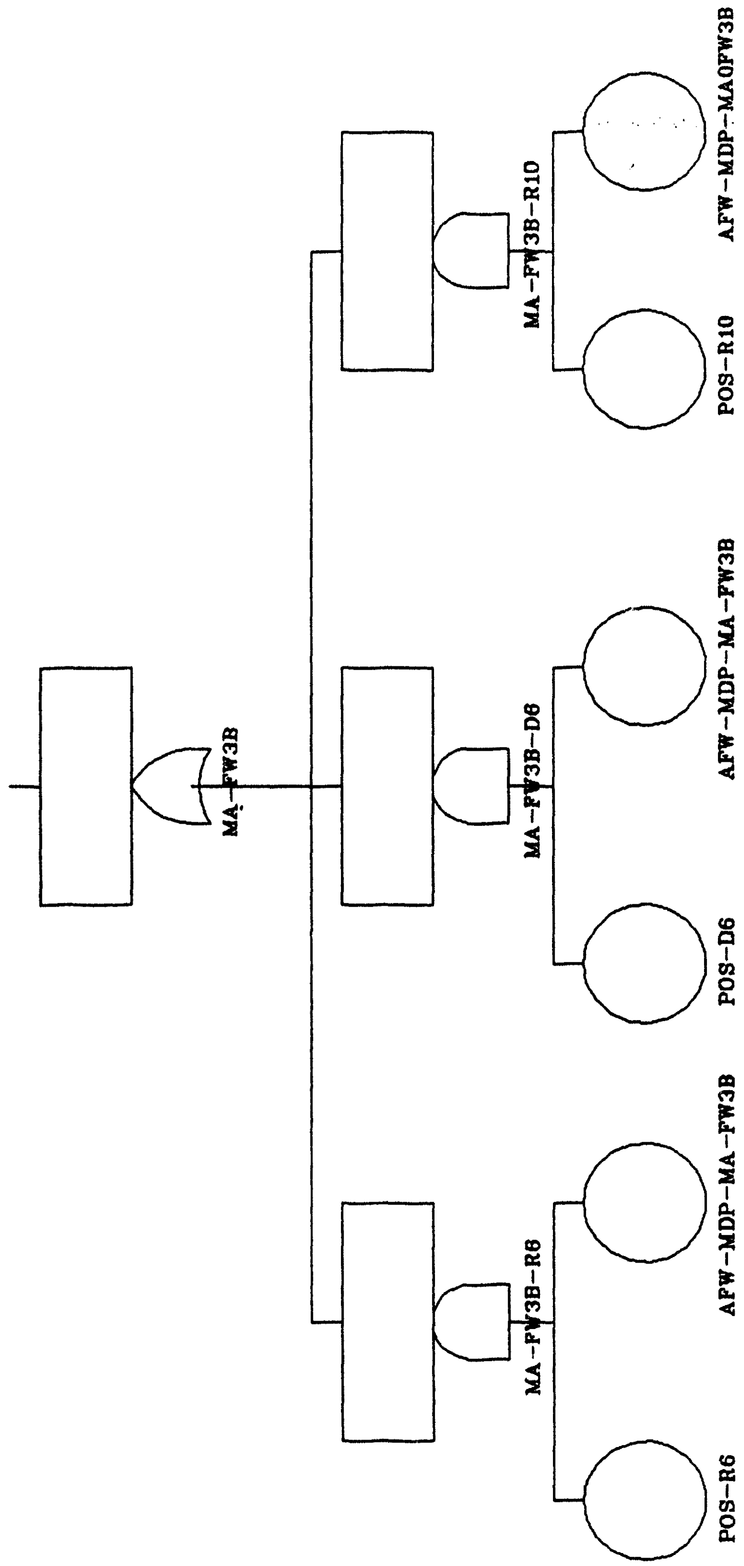
C-12

AUXILIARY FEEDWATER TO 1·OF 3 SG (AFW-1)
(AFW14)



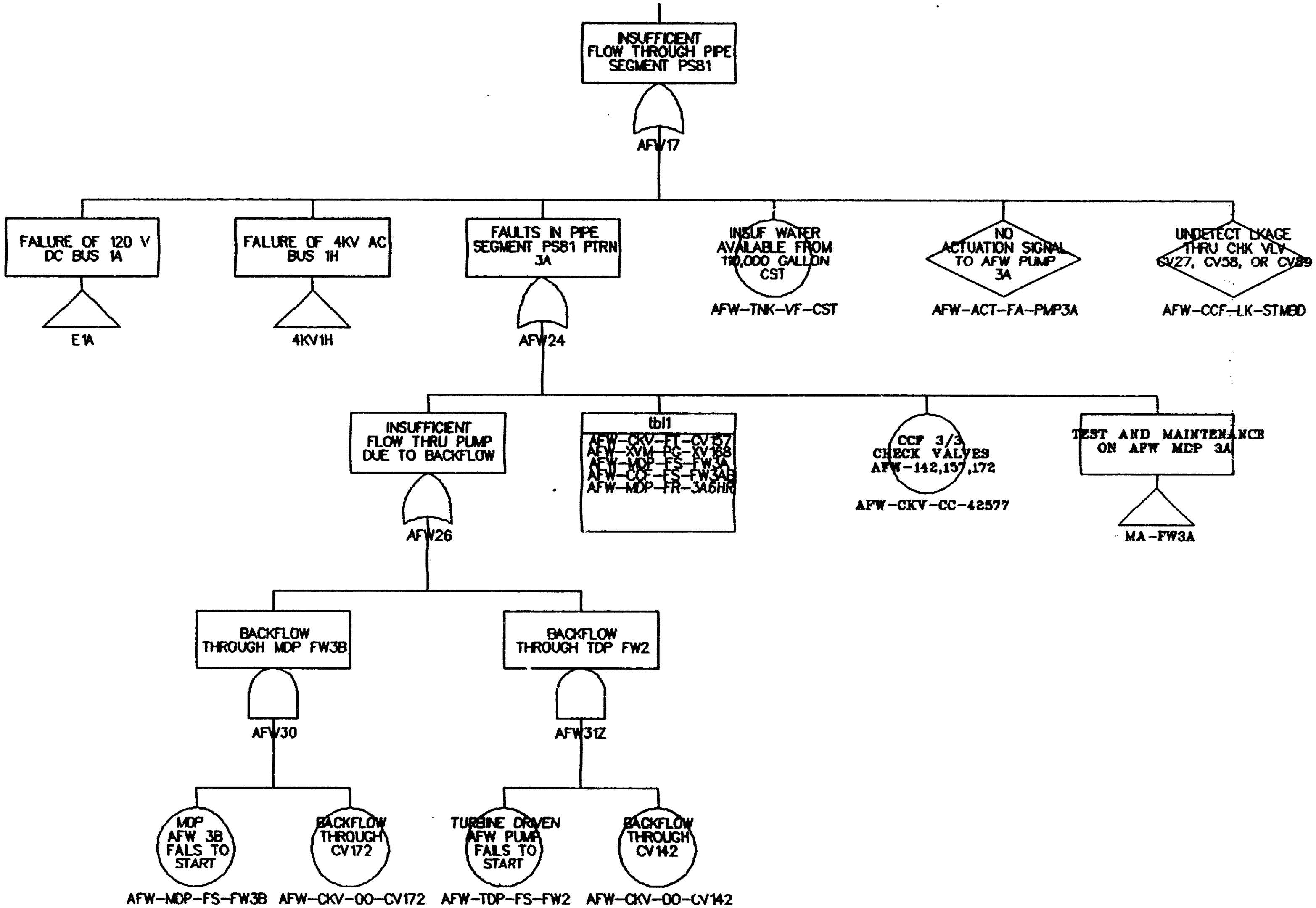
AUXILIARY FEEDWATER TO 1 OF 3 SG (AFW-1)




MA-FW3B
MA-FW3B-R10
MA-FW3B-D6
MA-FW3B-R6
POS-R10
AFW-MDP-MAOFW3B
POS-D6
AFW-MDP-MA-FW3B
POS-R6
AFW-MDP-MA-FW3B

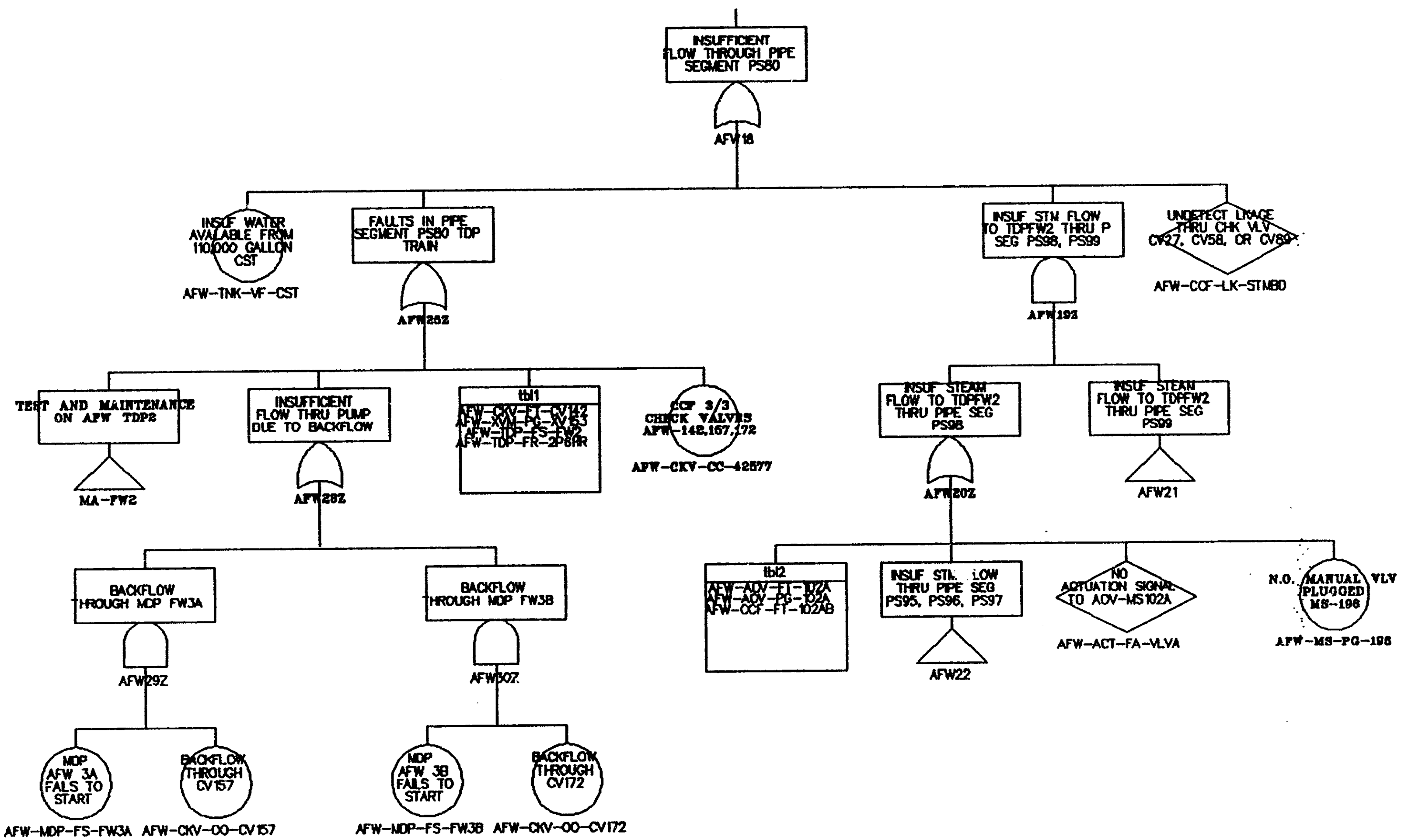
AUXILIARY FEEDWATER TO 1 OF 3 SG (AFW-1)

(AFW17)

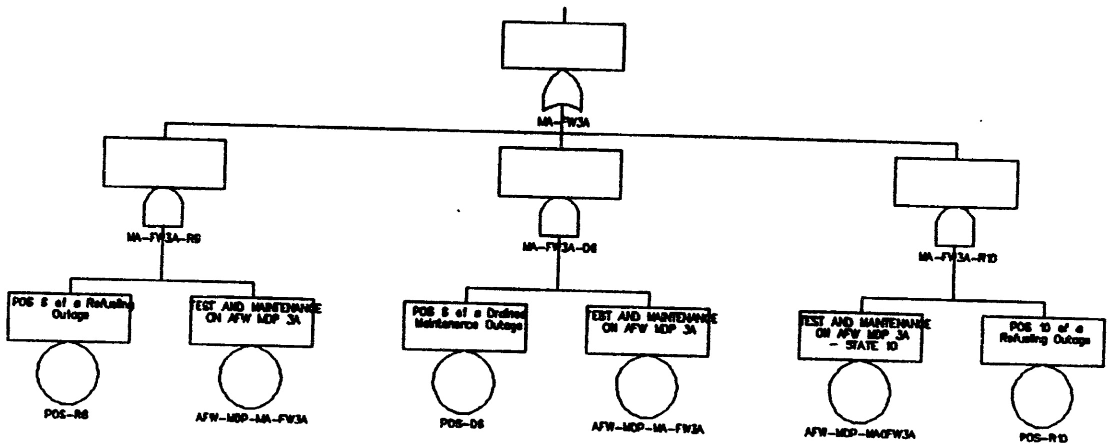


AUXILIARY FEEDWATER TO 1 OF 3 SG (AFW-1)

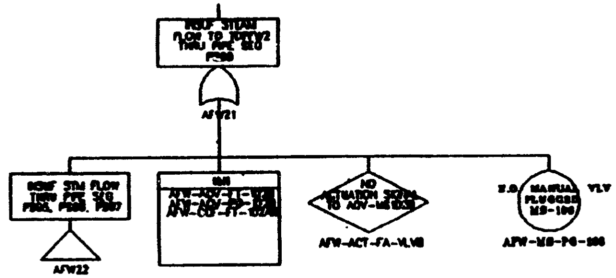
(AFW18)



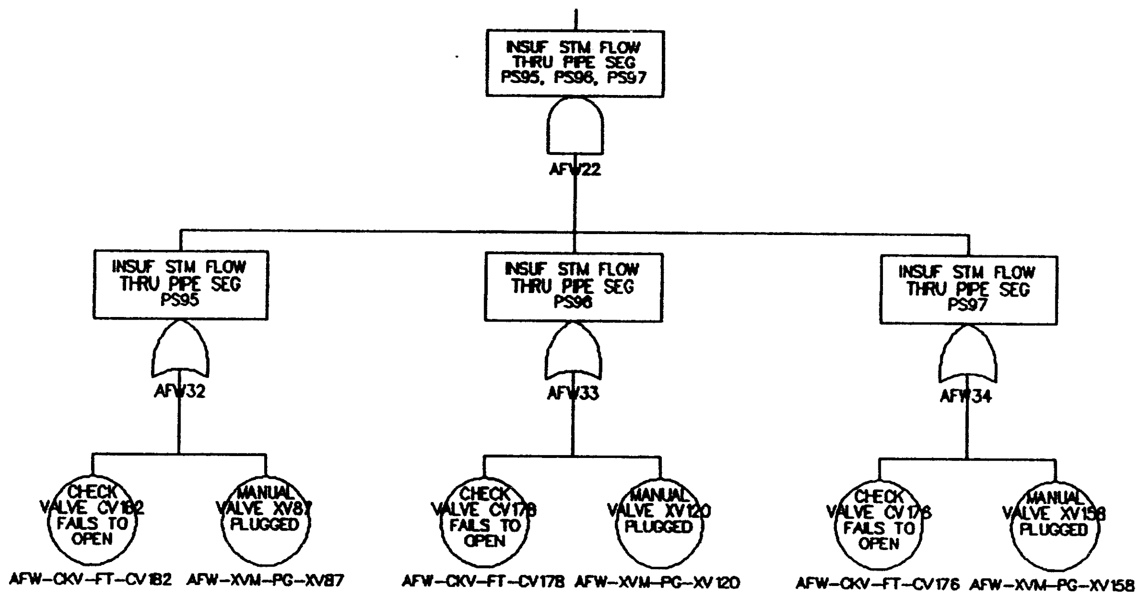
TEST AND MAINTENANCE ON AFW MDP 3A



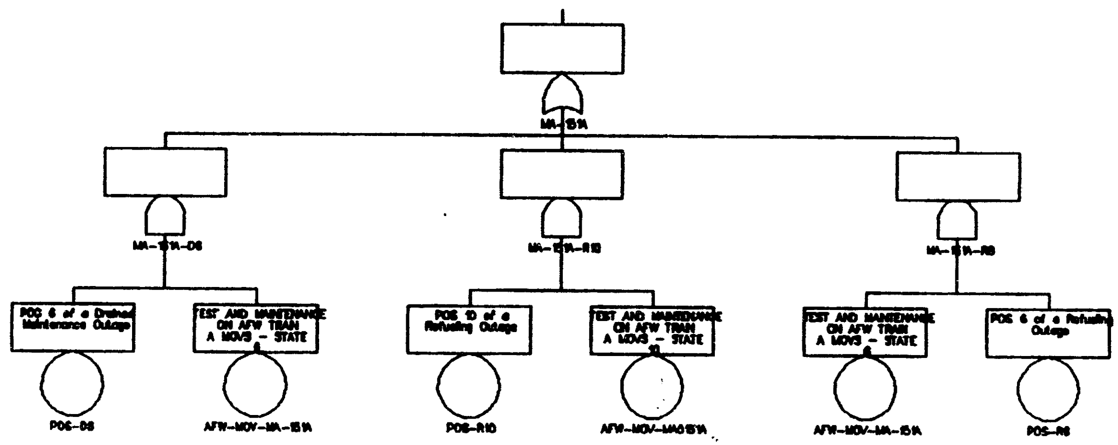
AUXILIARY FEEDWATER TO 1 OF 3 SG (AFW-1)
(AFW21)



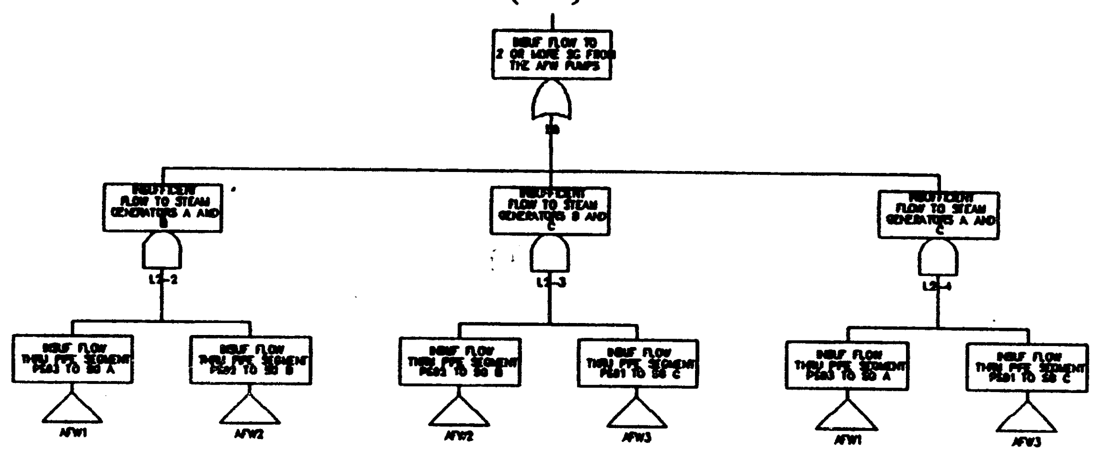
AUXILIARY FEEDWATER TO 1 OF 3 SG (AFW-1) (AFW22)



TEST AND MAINTENANCE ON AFW TRAIN A MOVS



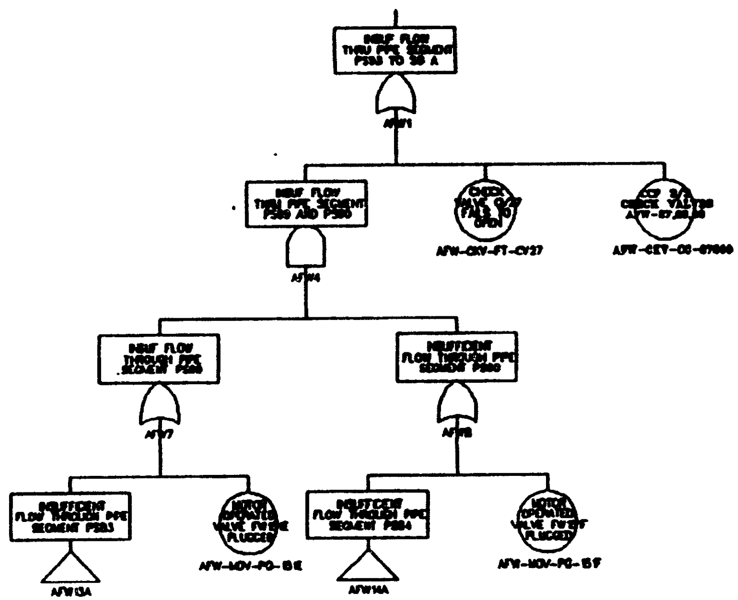
AUXILIARY FEEDWATER TO 2 OF 3 SG (AFW-2)
(L2)



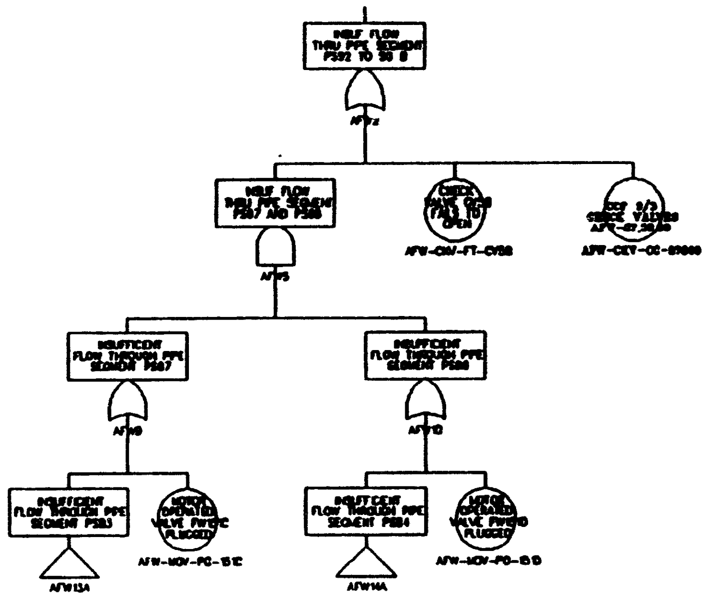
PAGE 1

AUXILIARY FEEDWATER TO 2 OF 3 SG (AFW1)

(AFW1)

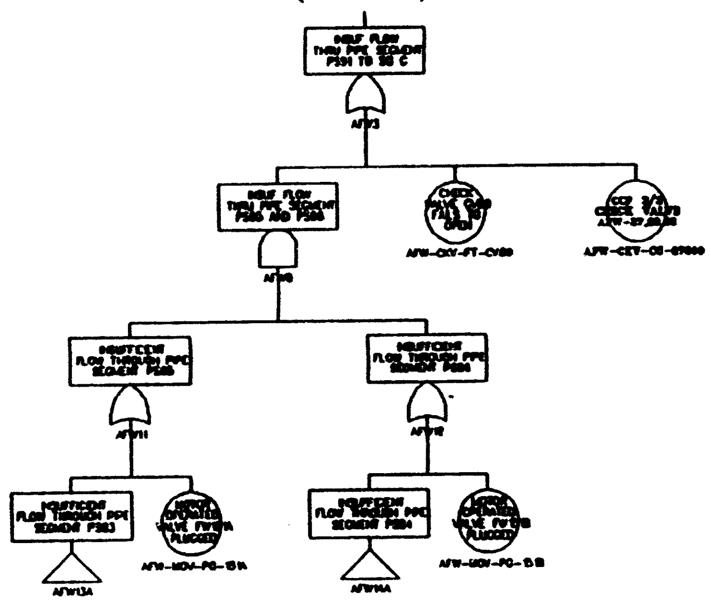


AUXILIARY FEEDWATER TO 2 OF 3 SG (AFW-2)
(AFW2)

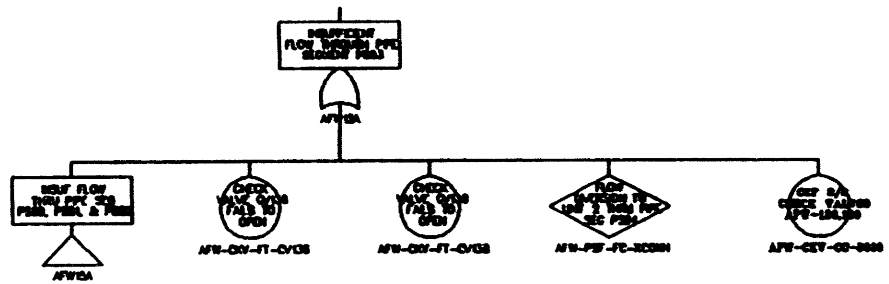


C-24

AUXILIARY FEEDWATER TO 2 OF 3 SG (AFW-2)
(AFW3)



AUXILIARY FEEDWATER TO 2 OF 3 SG (AFW-2)
(AFW13A)



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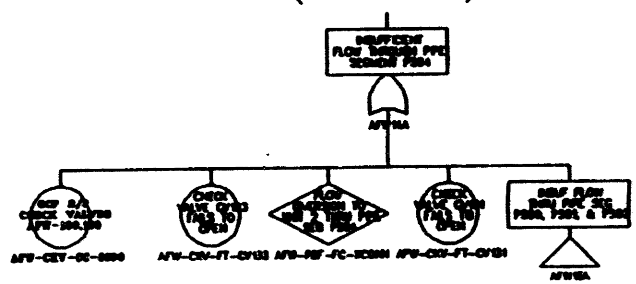
(AFW14A)



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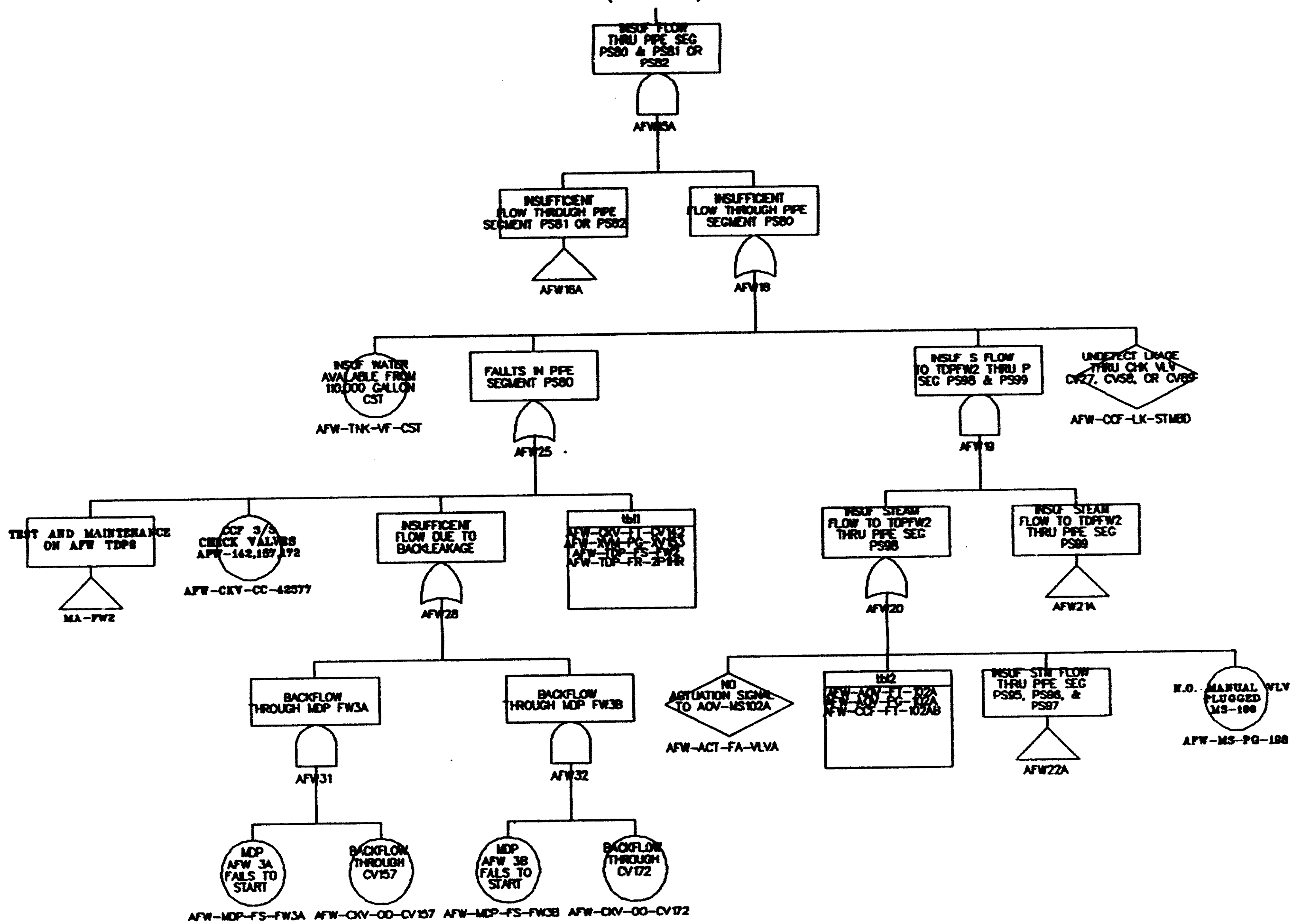
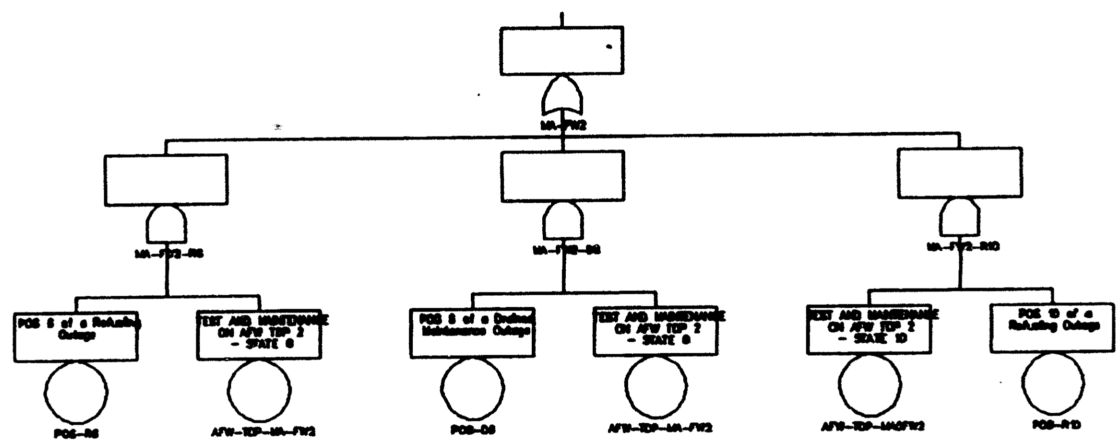
(AFW15A)

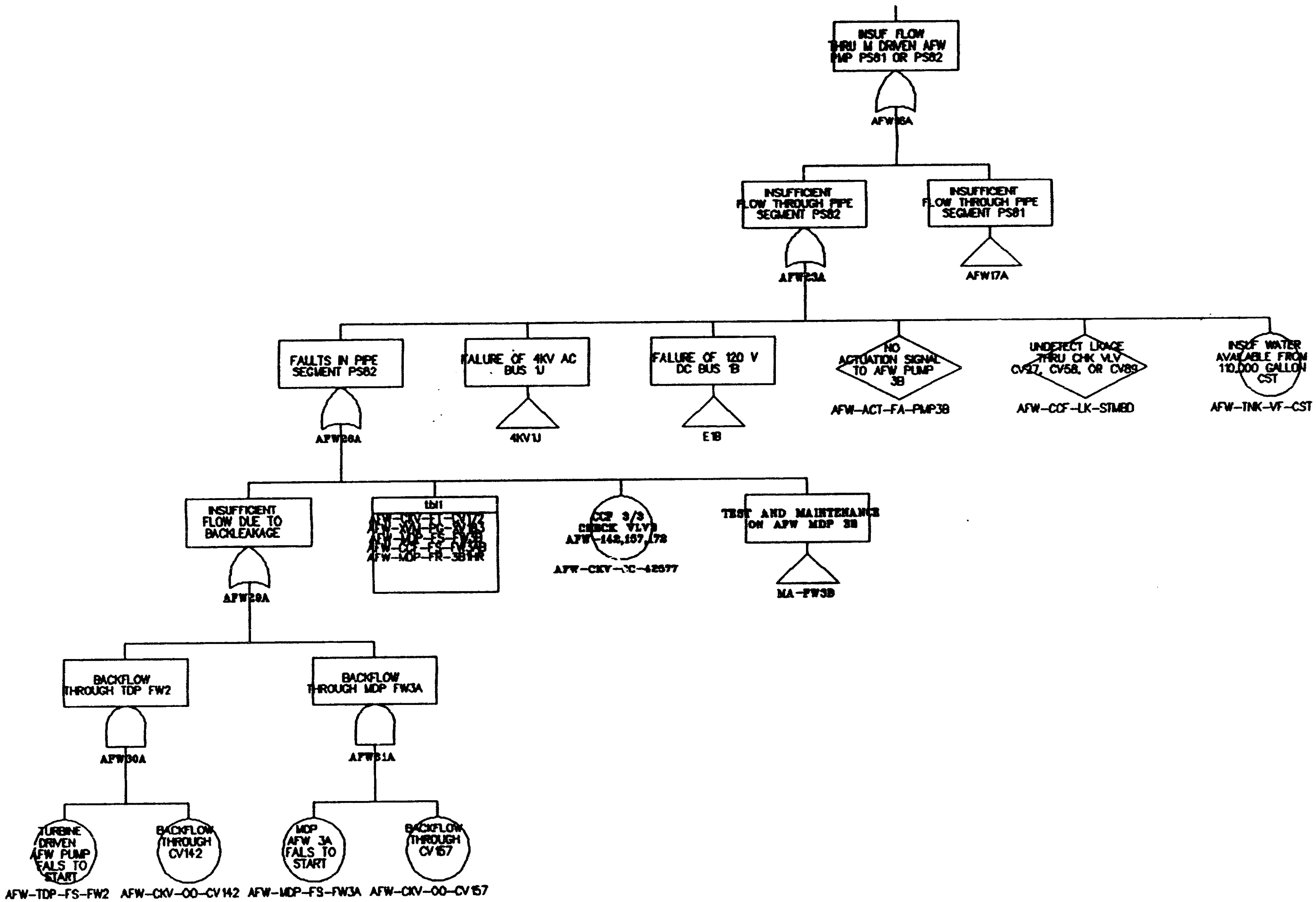


TEST AND MAINTENANCE ON AFW TDP2



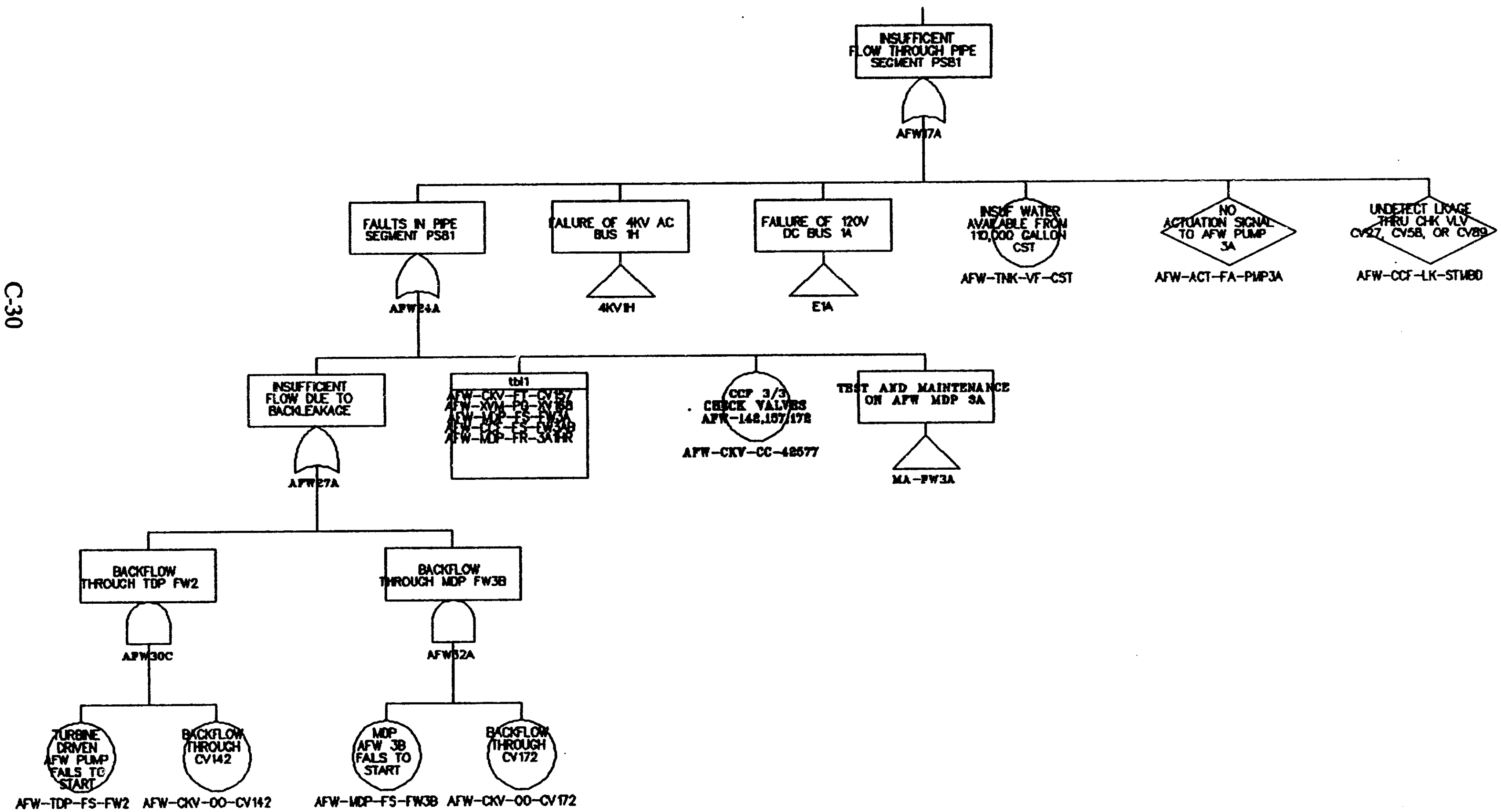
AUXILIARY FEEDWATER TO 2 OF 3 SG (AFW-2)

(AFW16A)



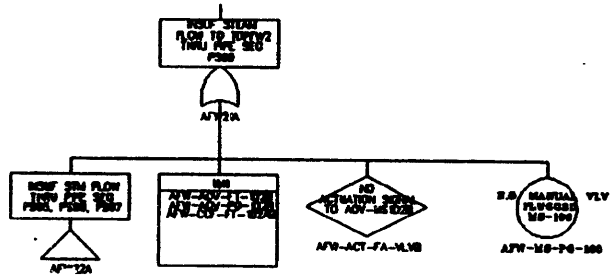
AUXILIARY FEEDWATER TO 2 OF 3 SG (AFW-2)

(AFW17A)

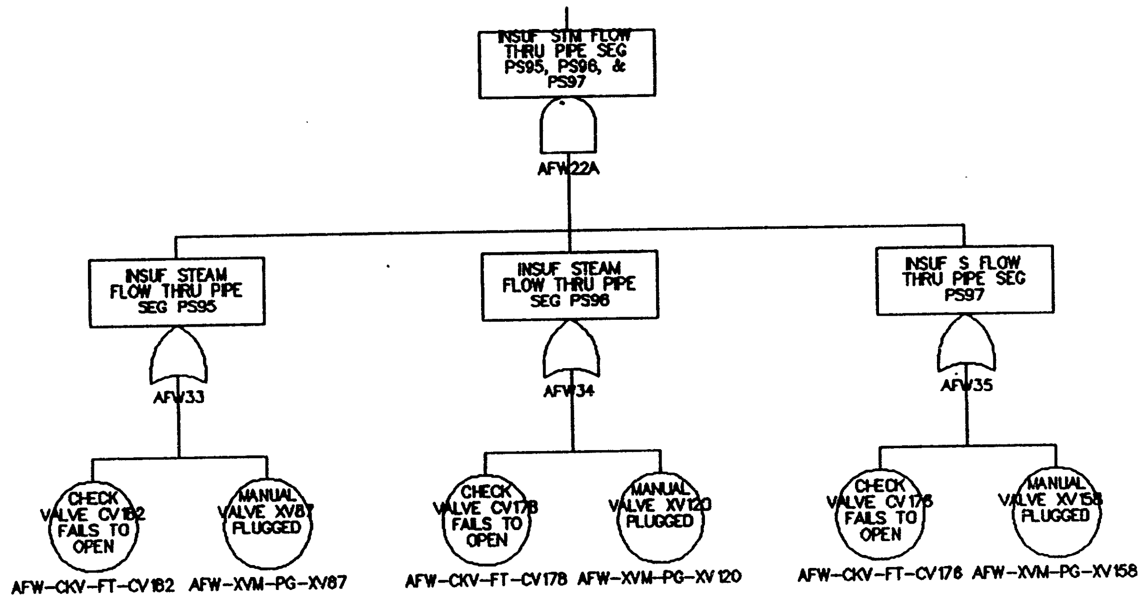


C-31

AUXILIARY FEEDWATER TO 2 OF 3 SG (AFW−2)
(AFW21A)



AUXILIARY FEEDWATER TO 2 OF 3 SG (AFW-2) (AFW22A)



AUXILIARY FEEDWATER TO 1 OF 2 SG (AFW-3)
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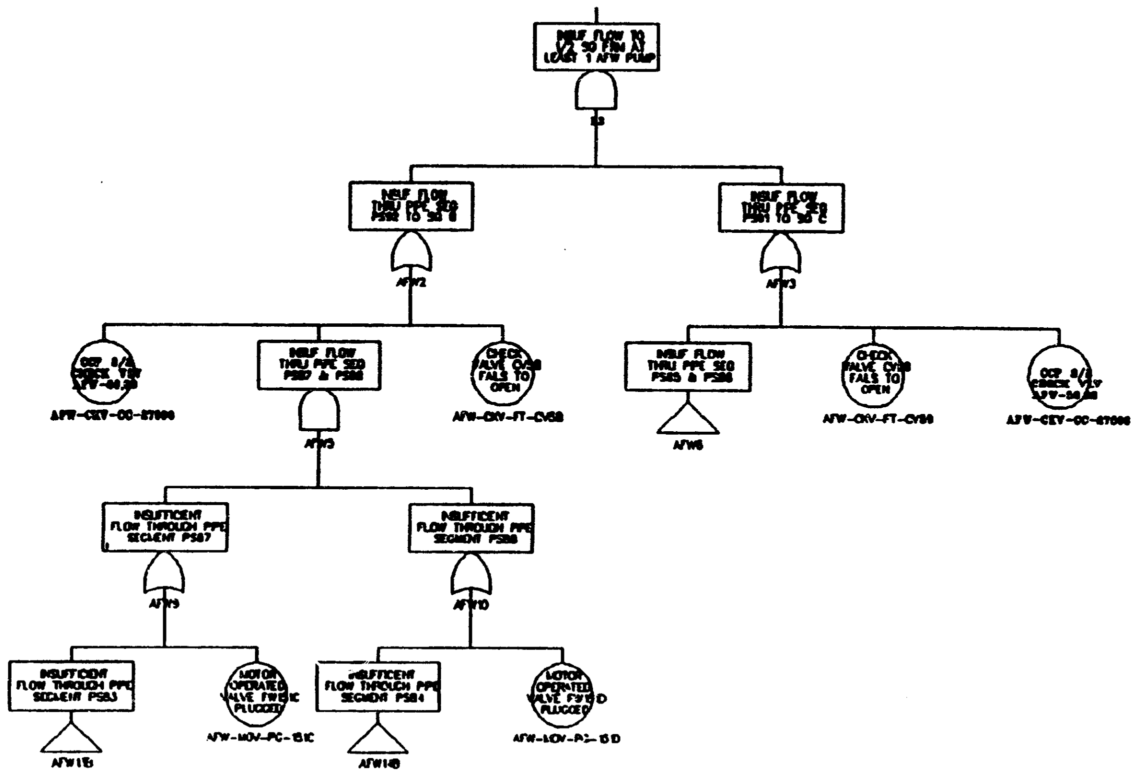
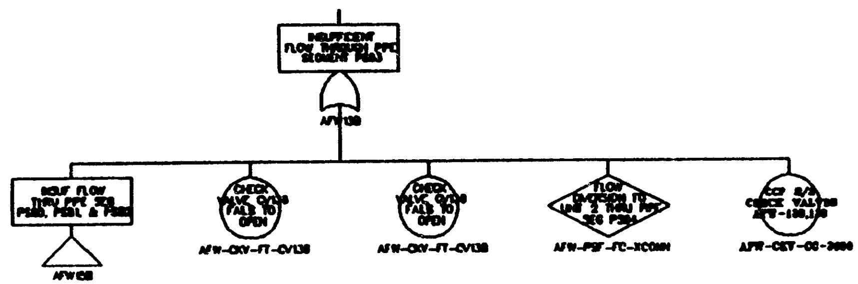


C-34

AUXILIARY FEEDWATER TO 1 OF 2 SG (AFW-3)
(AFW13B)



AUXILIARY FEEDWATER TO 1 OF 2 SG (AFW-3)
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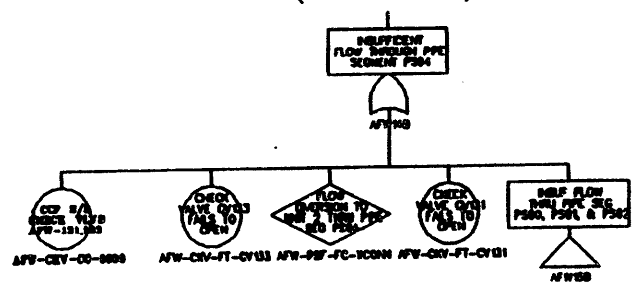
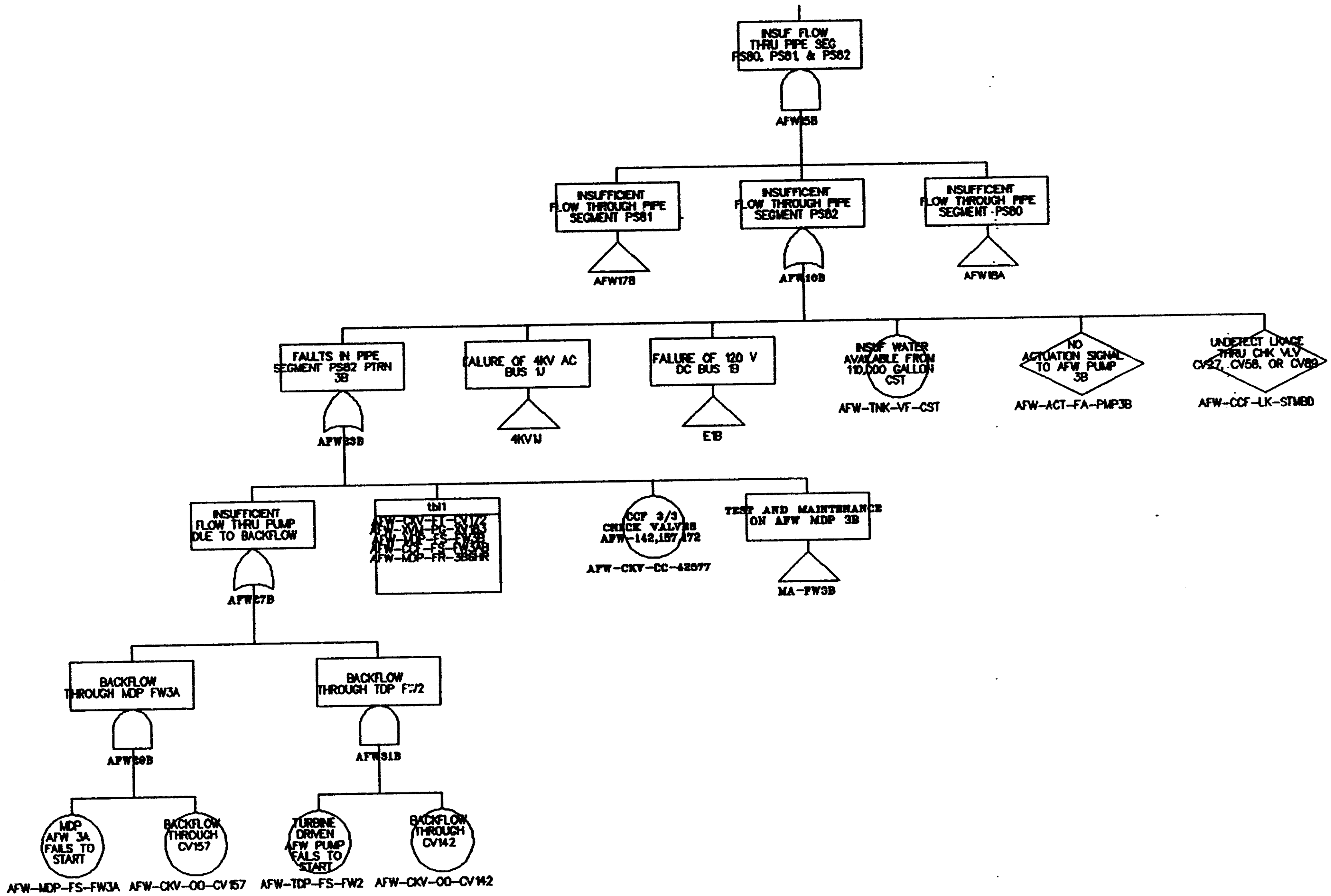


C-35

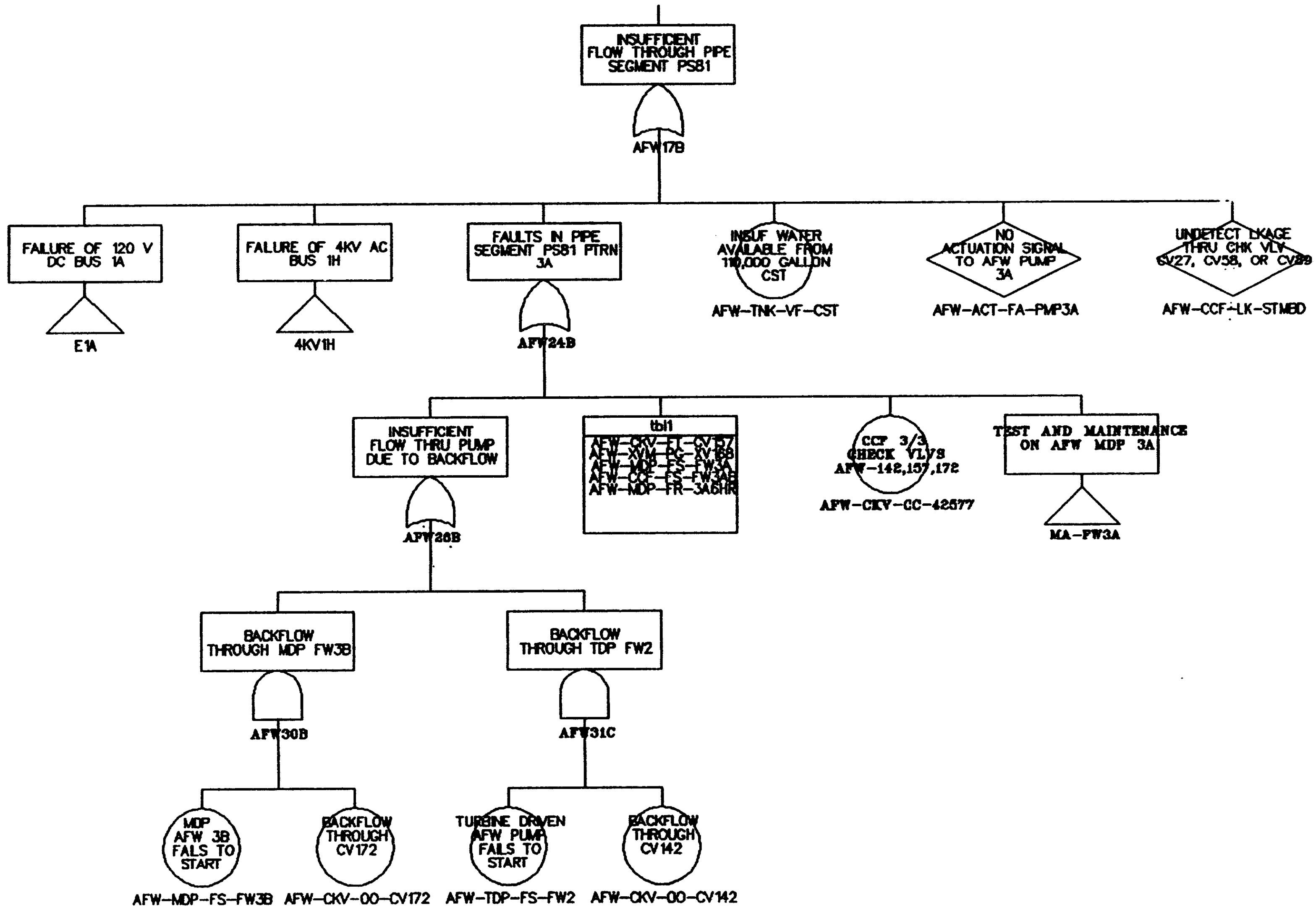
AUXILIARY FEEDWATER TO 1 OF 2 SG (AFW-3)

(AFW15B)



AUXILIARY FEEDWATER TO 1 OF 2 SG (AFW-3)

(AFW17B)



AUXILIARY FEEDWATER TO 1 OF 2 SG (AFW-3)

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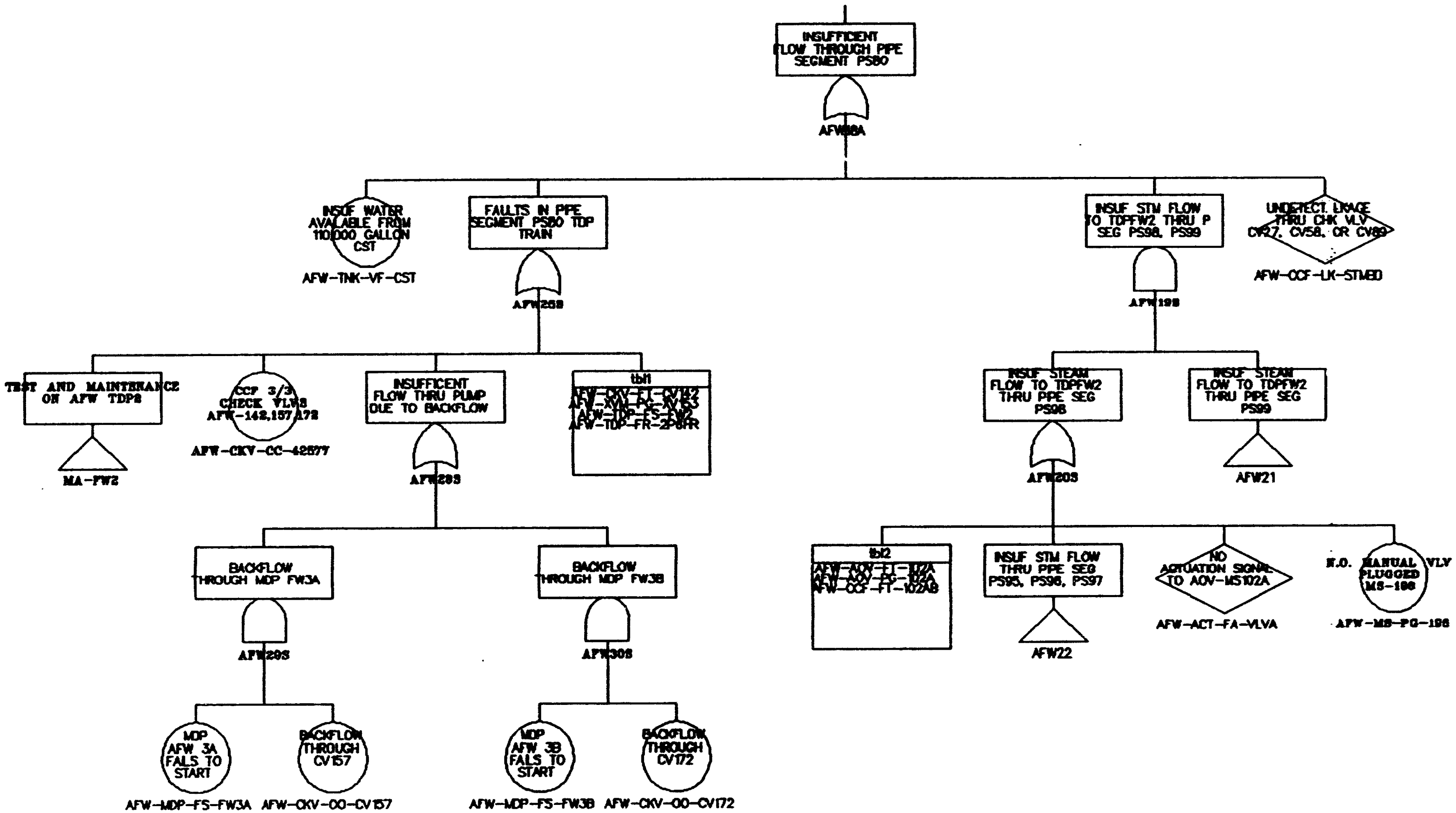
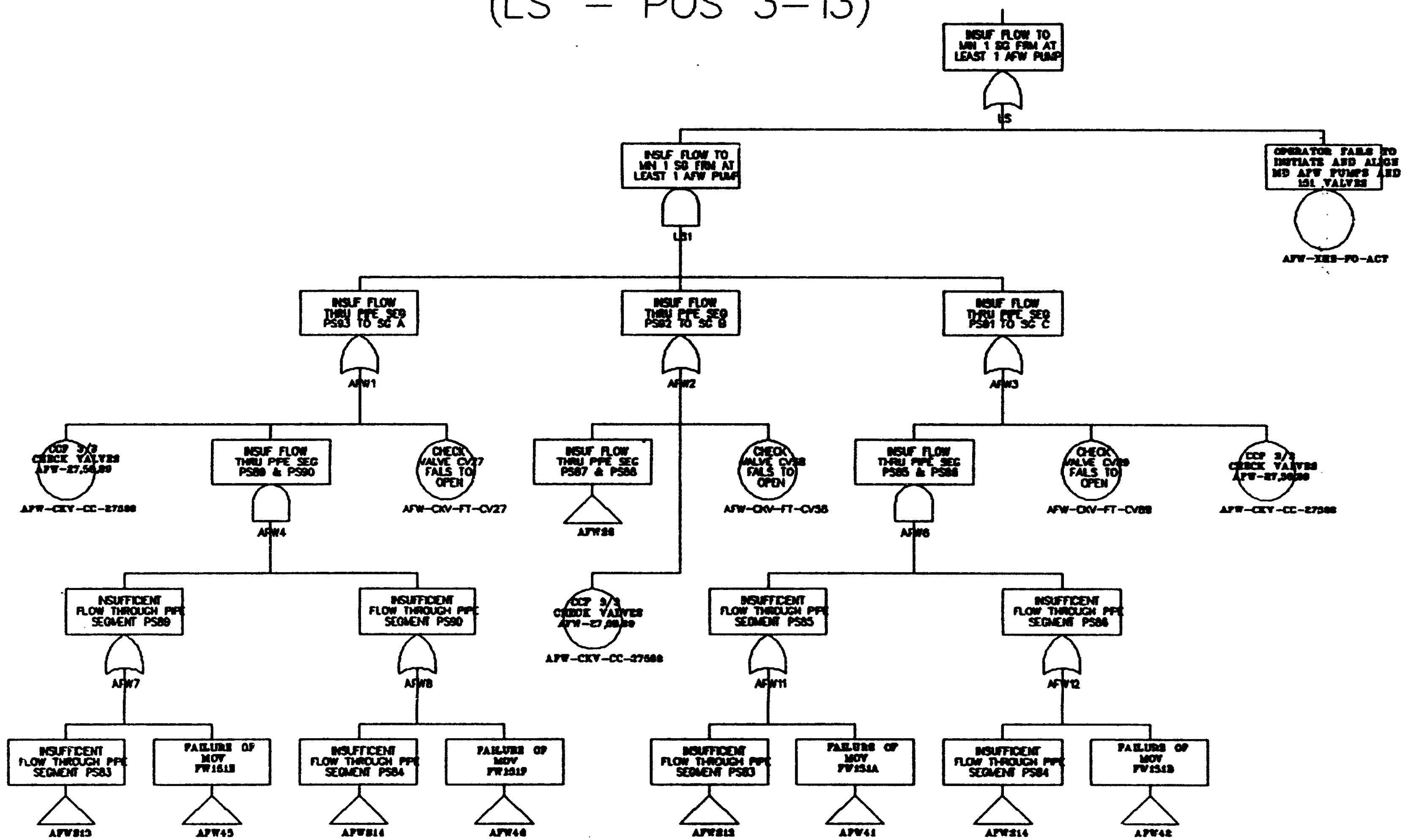


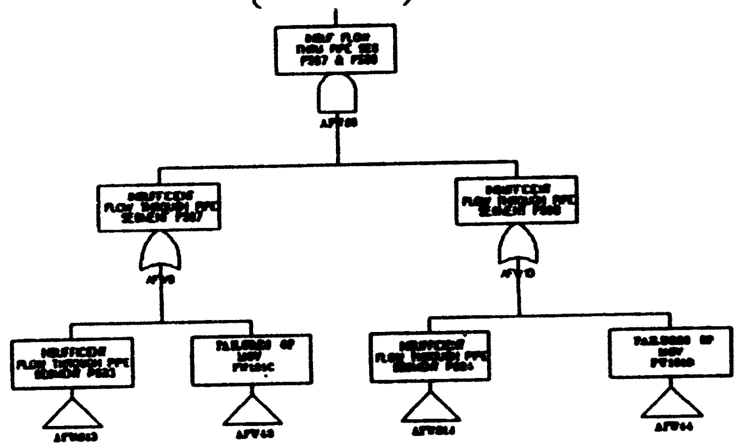
AUXILIARY FEEDWATER TO 1 OF 3 SG (AFWS-1)
(LS - POS 3-13)



PAGE 1 & 9

AUXILIARY FEEDWATER TO 1 OF 3 SG (AFWS-1)

(AFWS5)



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AUXILIARY FEEDWATER TO 1 OF 3 SG (AFWS-1)
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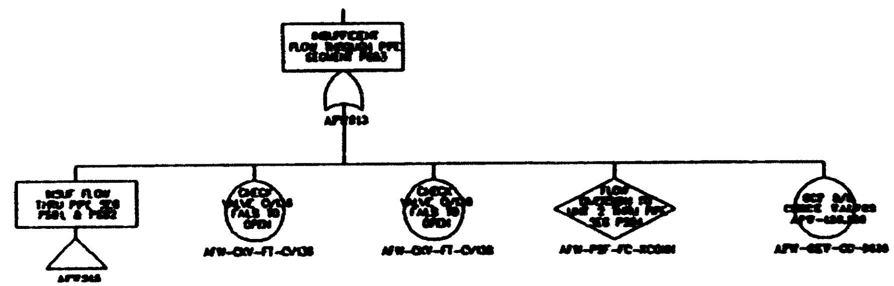

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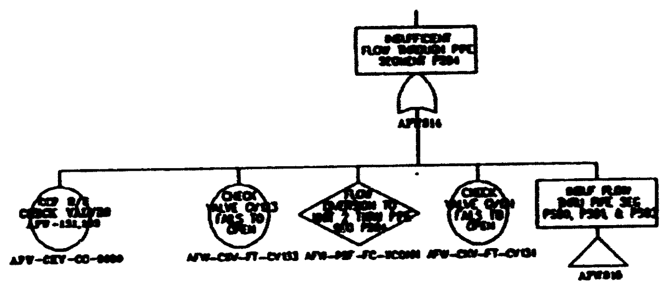
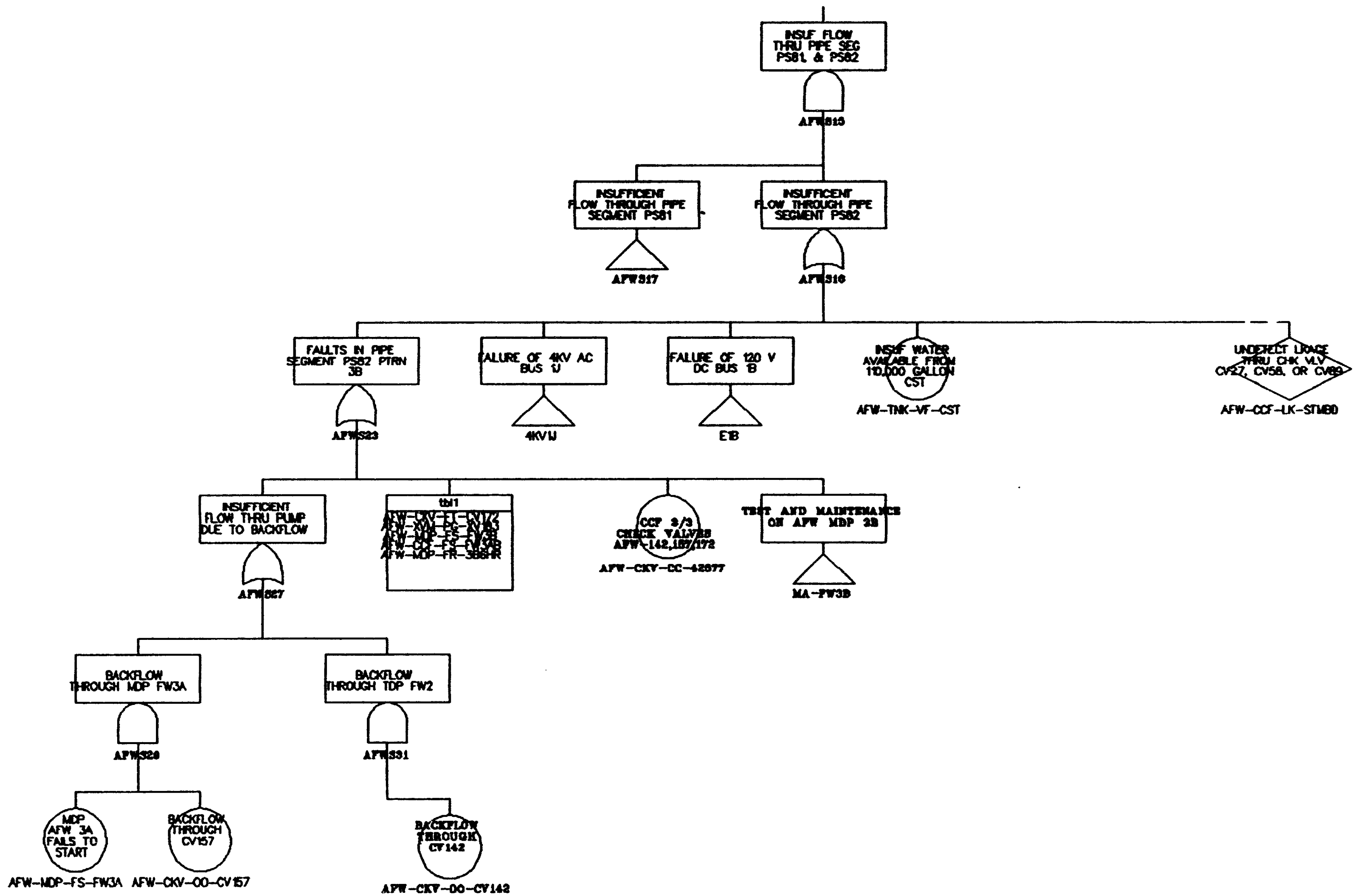


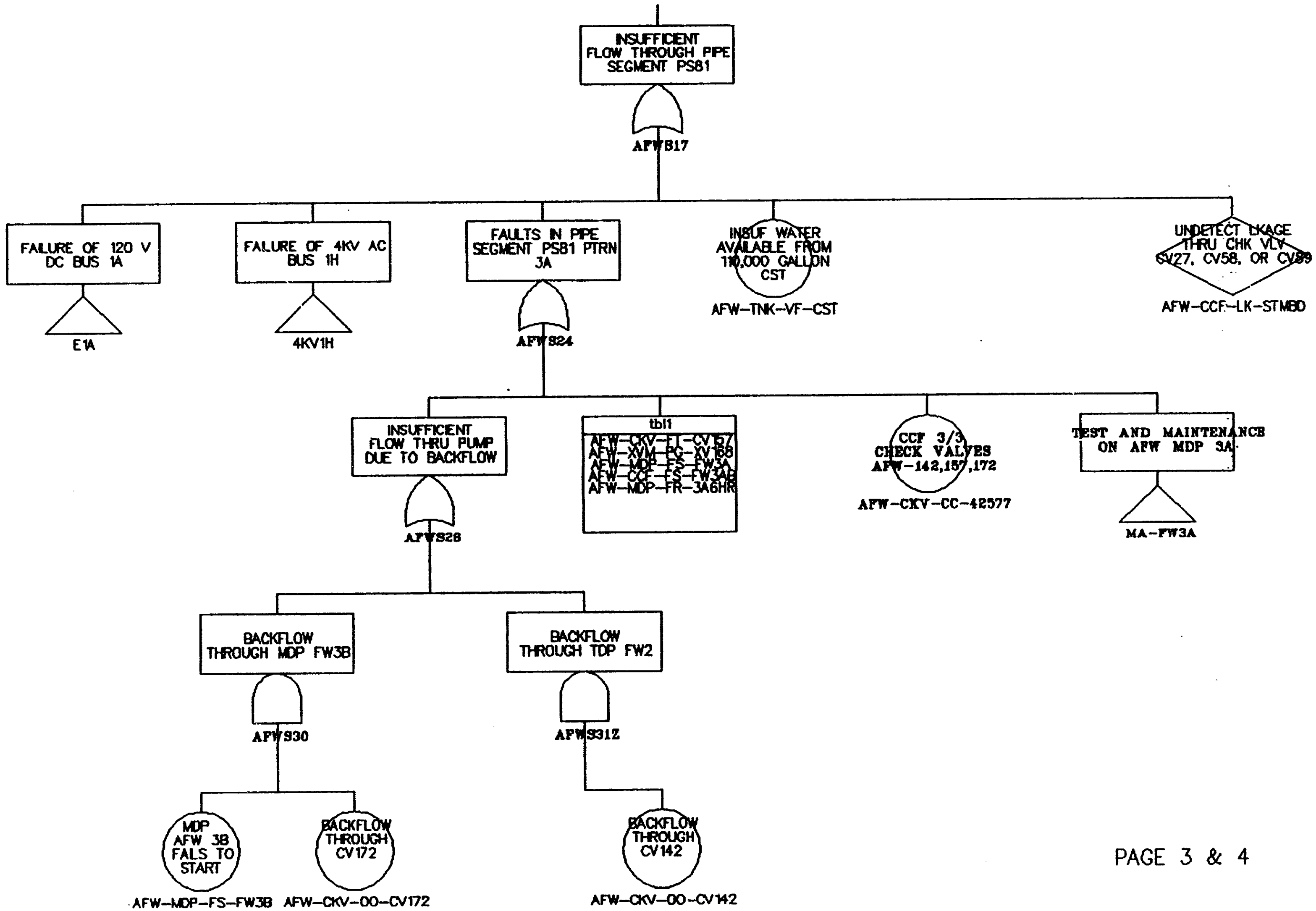
C-42

AUXILIARY FEEDWATER TO 1 OF 3 SG (AFWS-1)

(AFWS15)

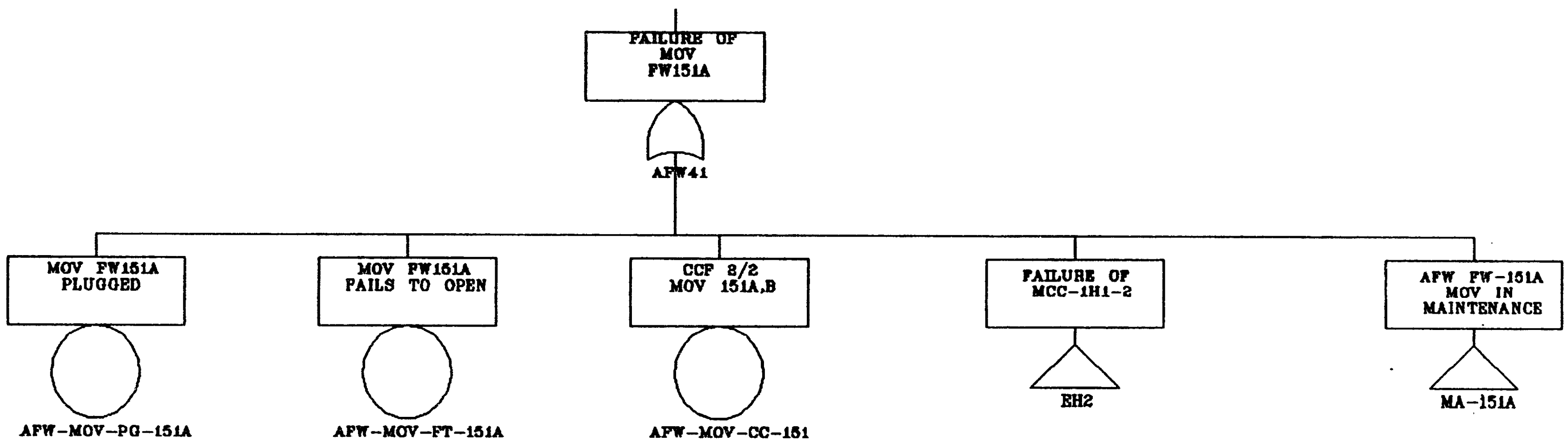


AUXILIARY FEEDWATER TO 1 OF 3 SG (AFWS-1) (AFWS17)

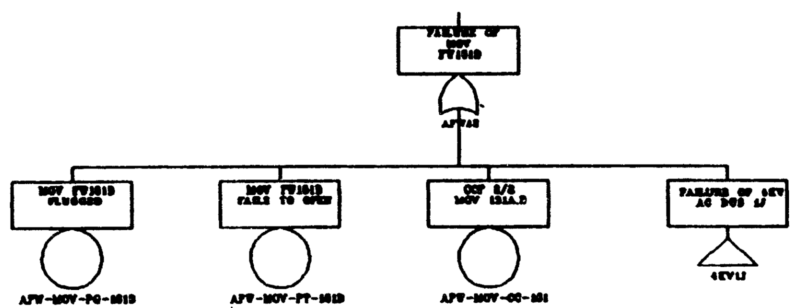


PAGE 3 & 4

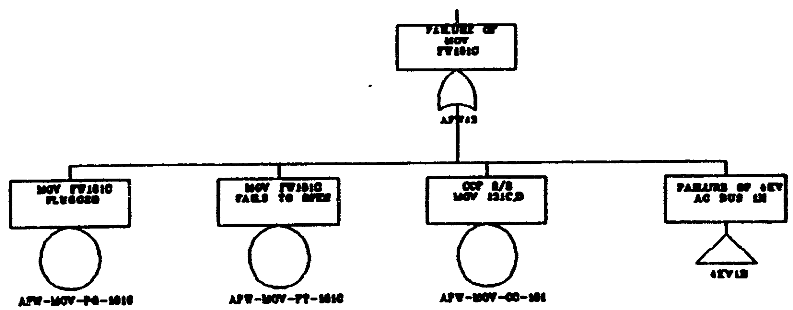
AUXILIARY FEEDWATER - POS 3-13
(AFW41)



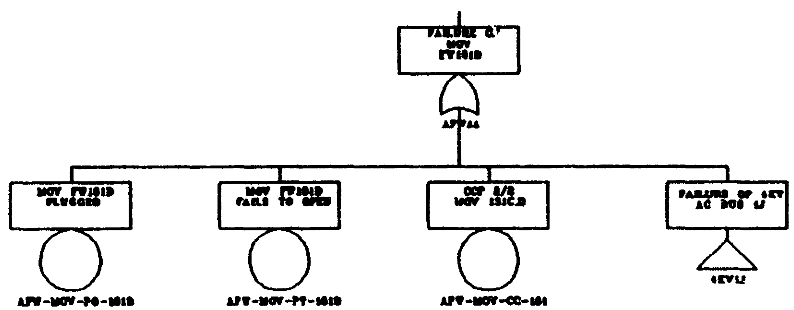
AUXILIARY FEEDWATER – POS 3–13
(AFW42)



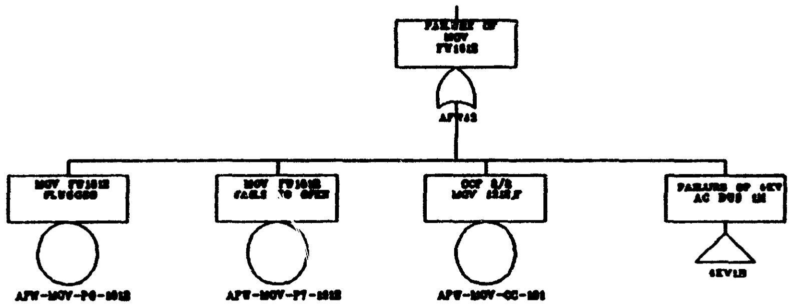
AUXILIARY FEEDWATER – POS 3–13
(AFW43)



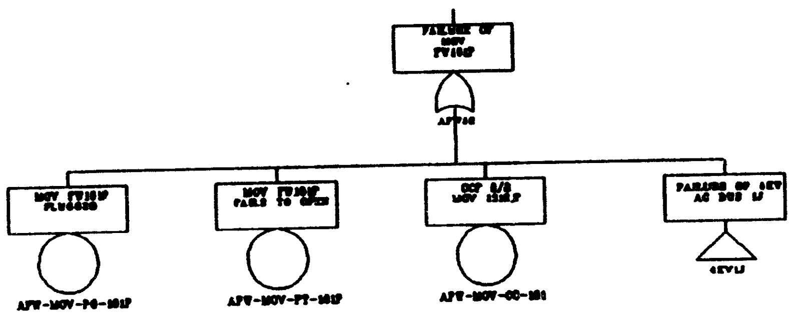
AUXILIARY FEEDWATER – POS 3–13
(AFW44)



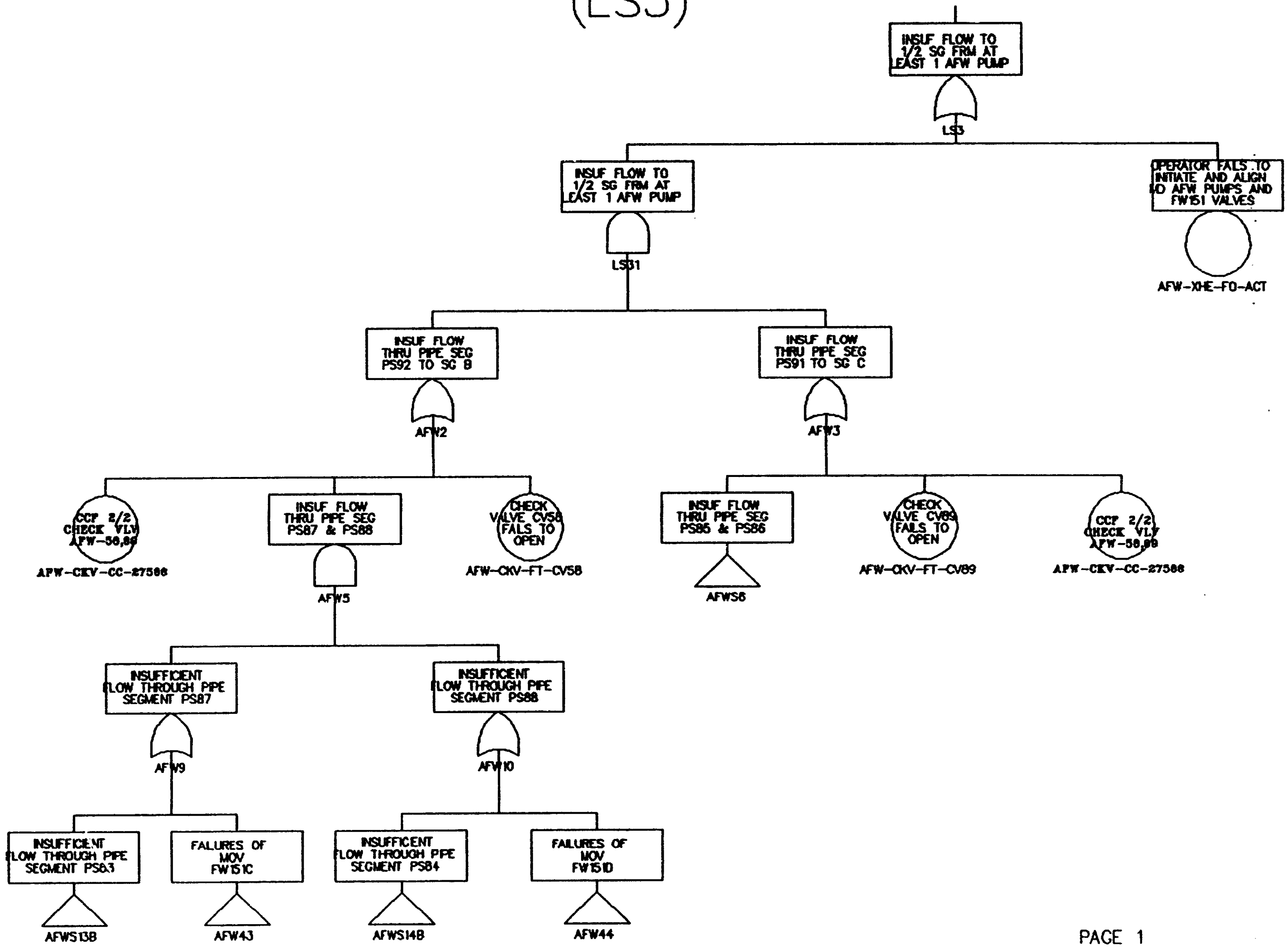
AUXILIARY FEEDWATER – POS 3–13
(AFW45)



AUXILIARY FEEDWATER – POS 3–13
(AFW46)

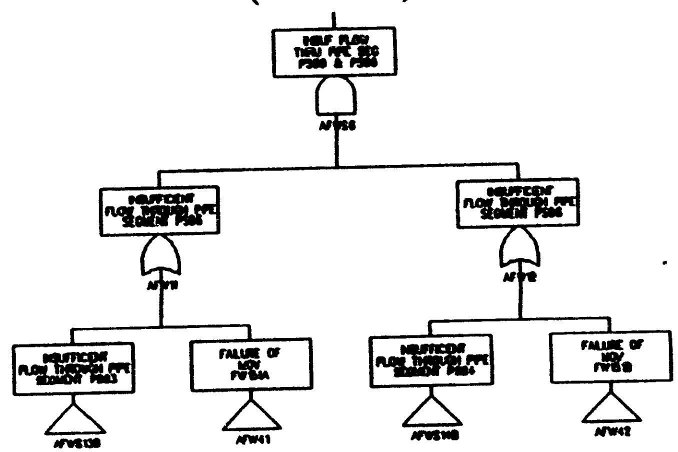


AUXILIARY FEEDWATER TO 1 OF 2 SG (AFWS-3) (LS3)

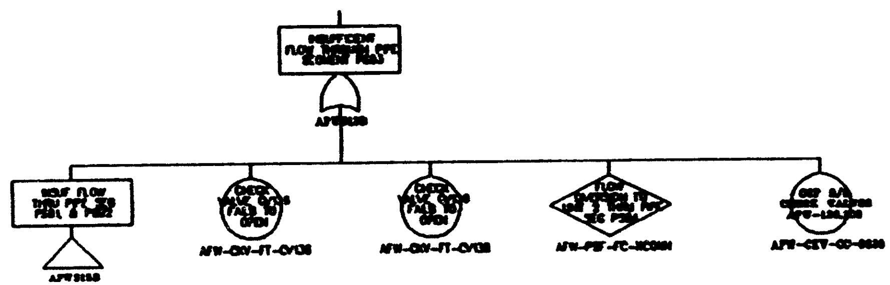


PAGE 1

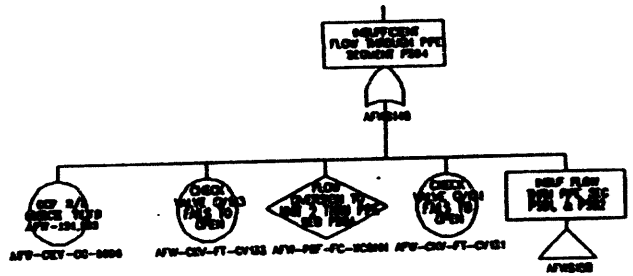
AUXILIARY FEEDWATER TO 1 OF 2 SG (AFWS-3) (AFWS6)



AUXILIARY FEEDWATER TO 1 OF 2 SG (AFWS-3)
(AFWS13B)

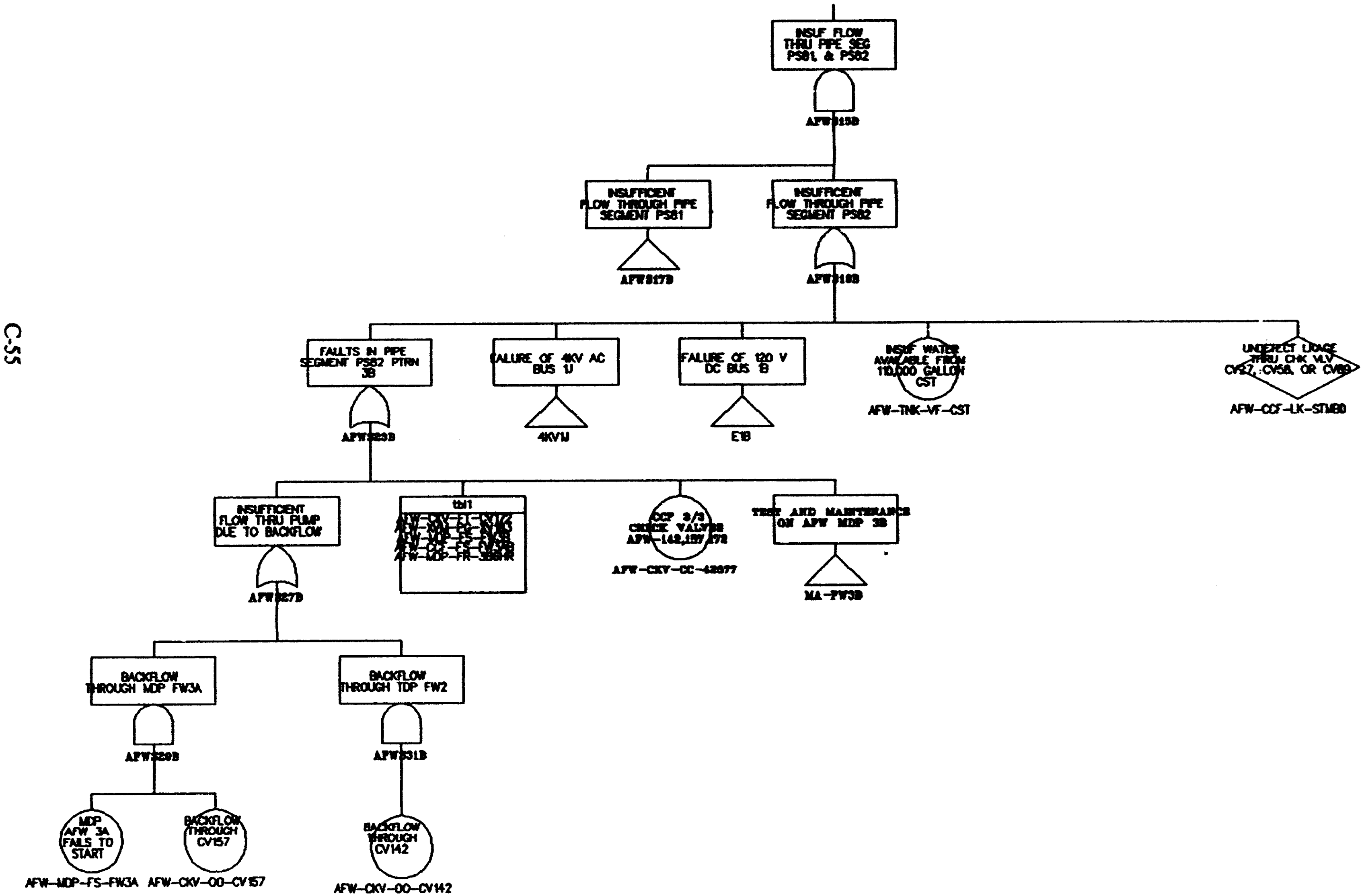


AUXILIARY FEEDWATER TO 1 OF 2 SG (AFWS-3)
(AFWS14B)

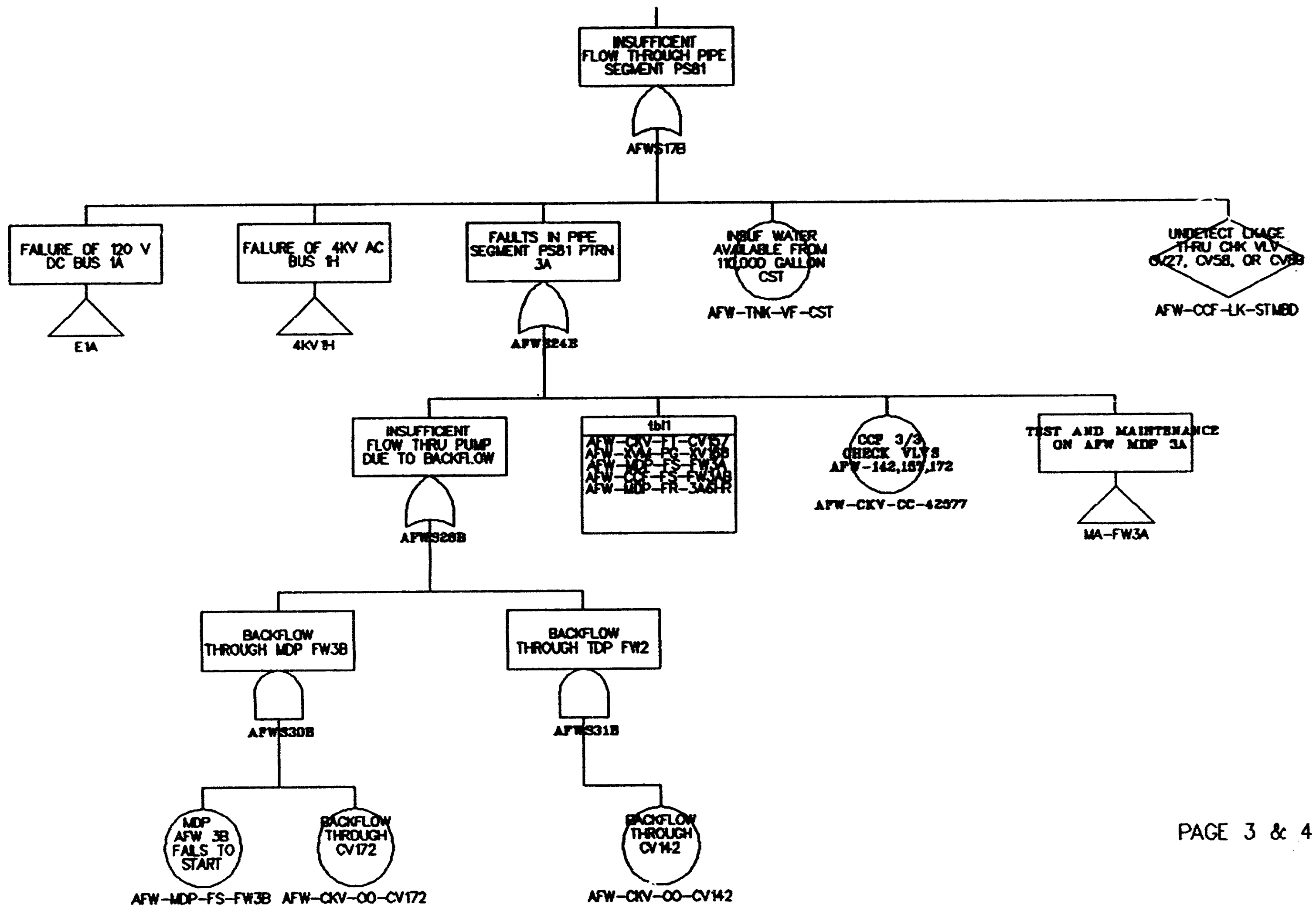


AUXILIARY FEEDWATER TO 1 OF 2 SG (AFWS-3)

(AFWS 15B)

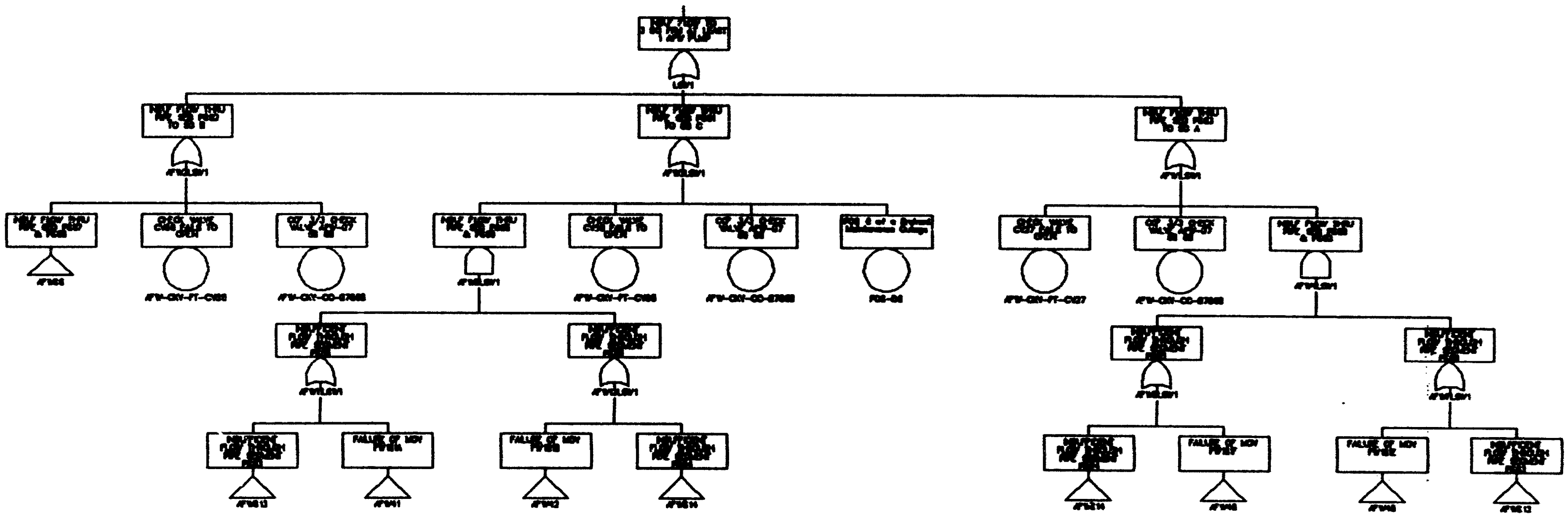


AUXILIARY FEEDWATER TO 1 OF 2 SG (AFWS-3) (AFWS17B)

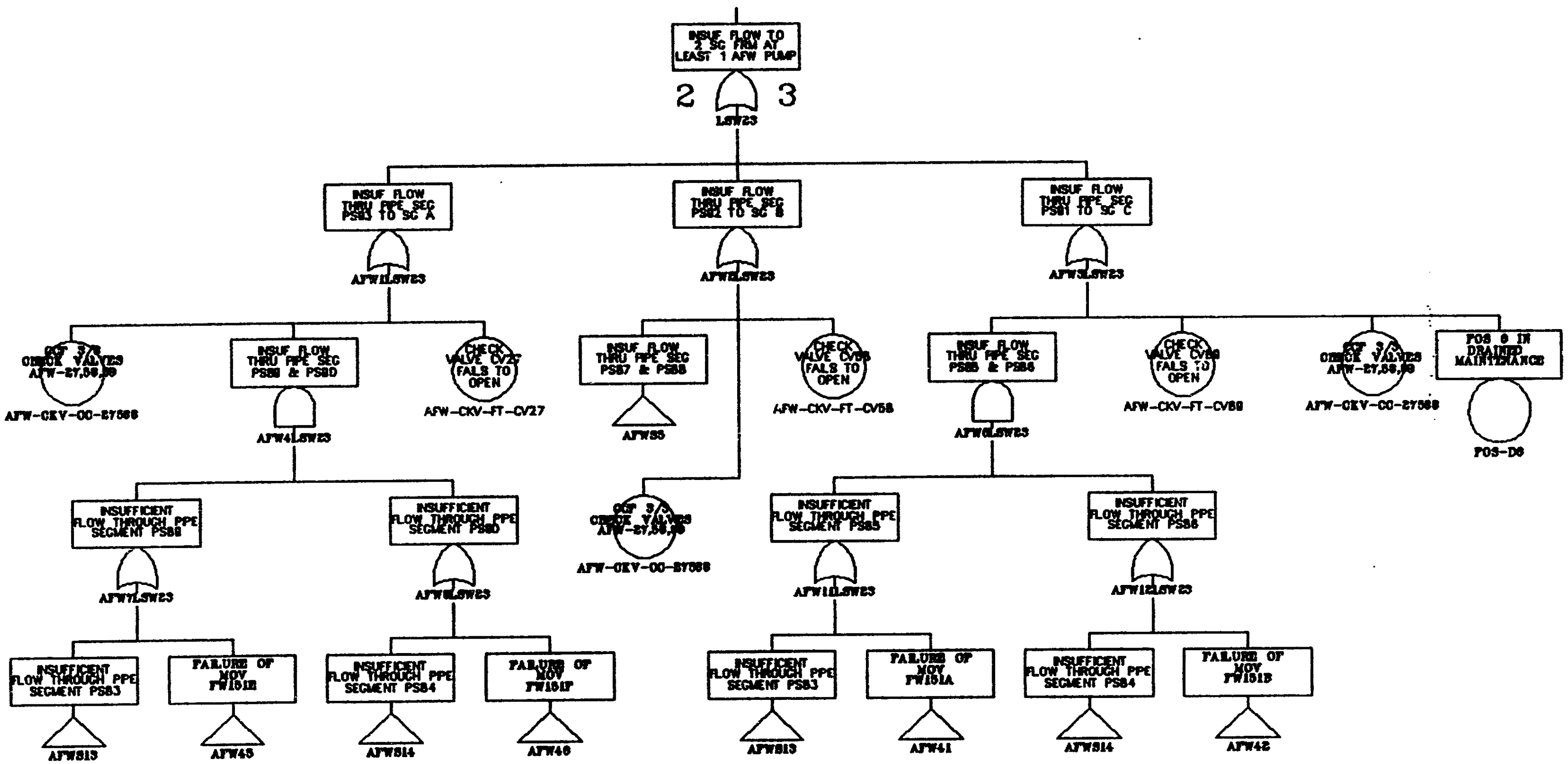


PAGE 3 & 4

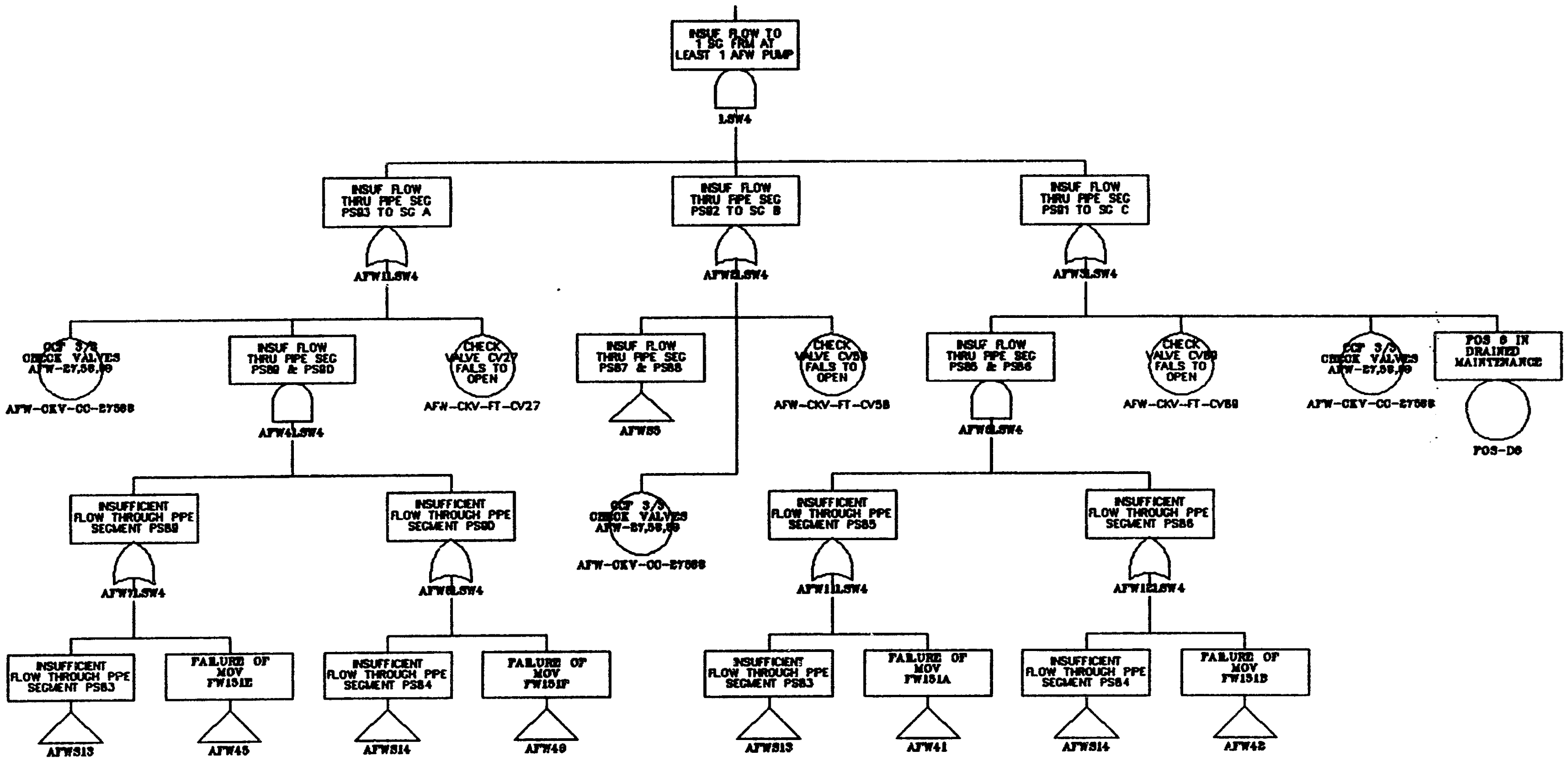
AUXILIARY FEEDWATER TO 3 OF 3 SG
WINDOW 1 - (LSW1)



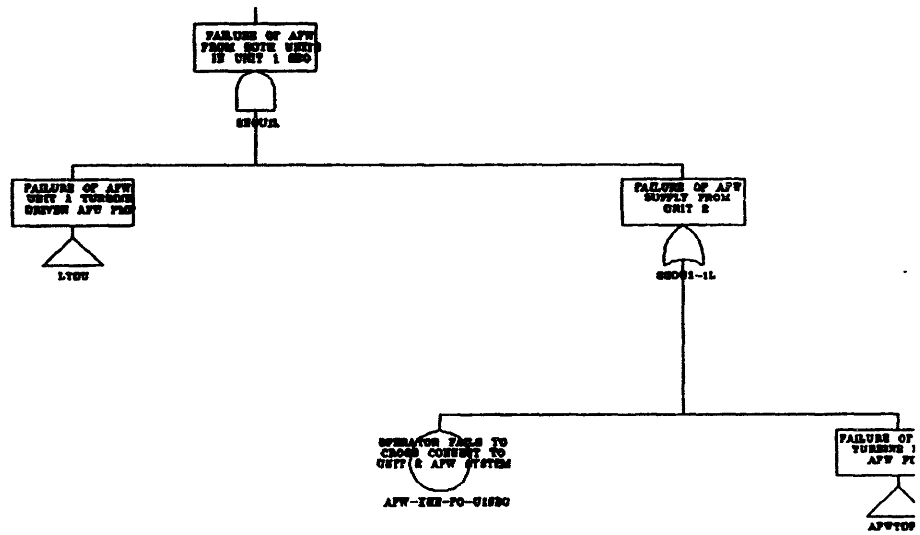
AUXILIARY FEEDWATER TO 2 OF 3 SG
WINDOW 2&3 – (LSW23)



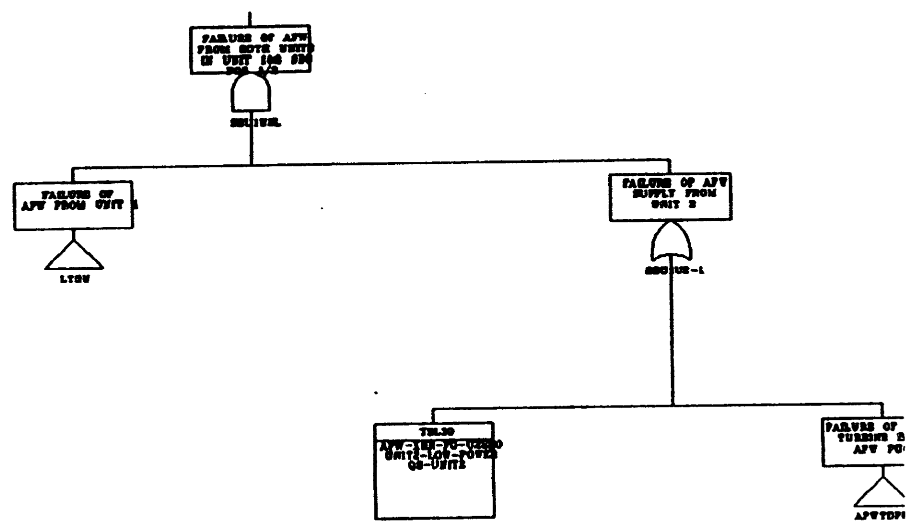
AUXILIARY FEEDWATER TO 1 OF 3 SG
WINDOW 4 – (LSW4)



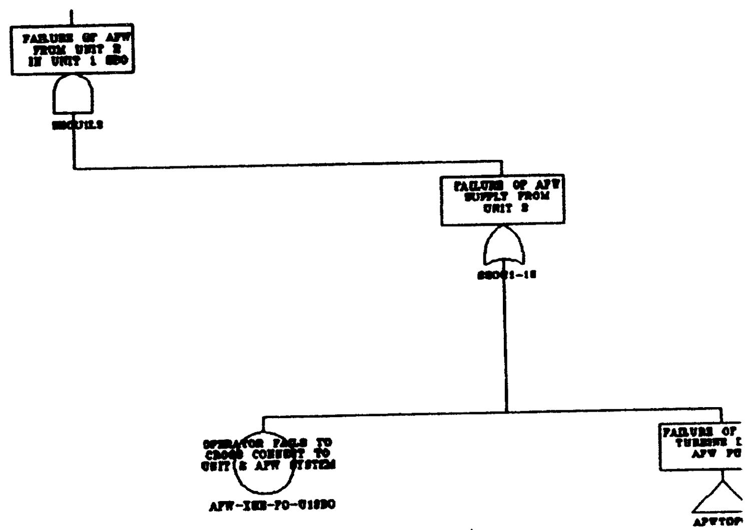
SBO AT UNIT 1 – AFW 1 OF 3 SG (SBOU1–L) – POS 1/2, 14/15



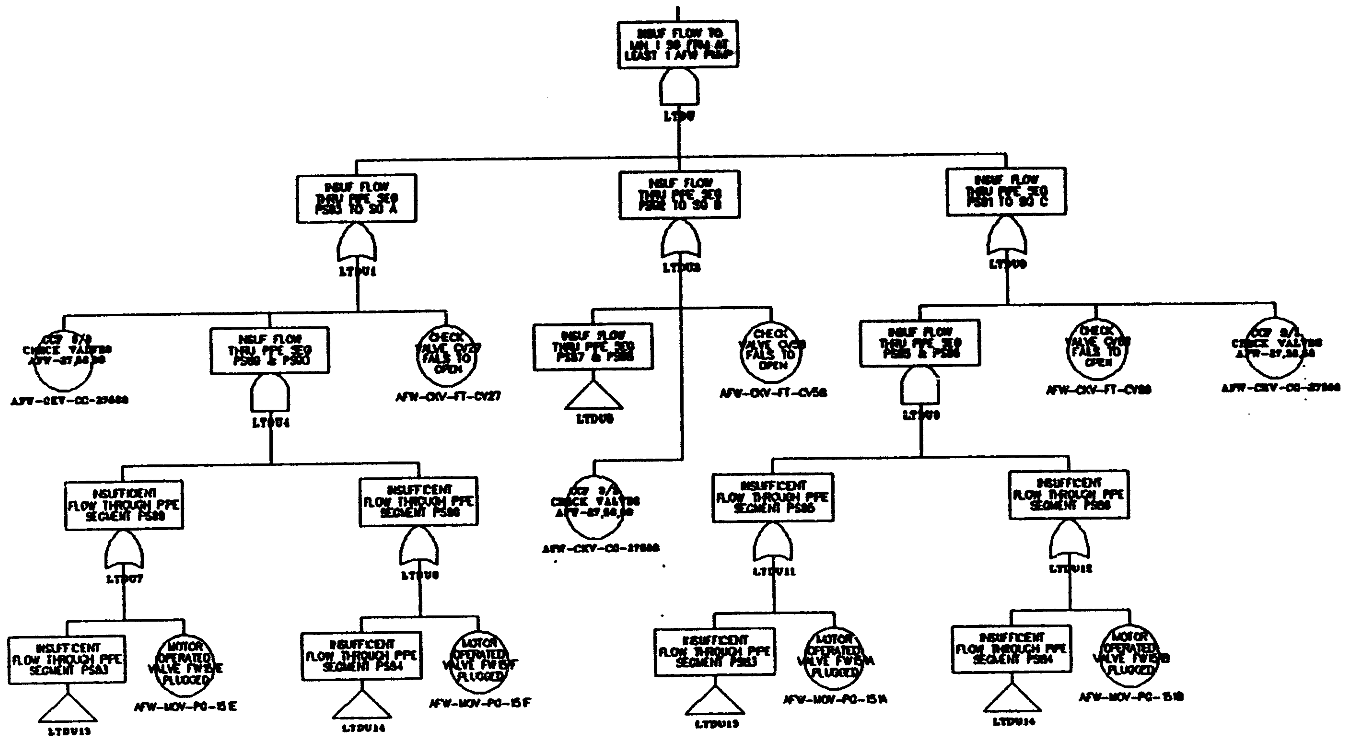
SBO AT UNIT 1&2 – AFW 1 OF 3 SG
(SBOU1U2-L) – POS 1/2, 14/15



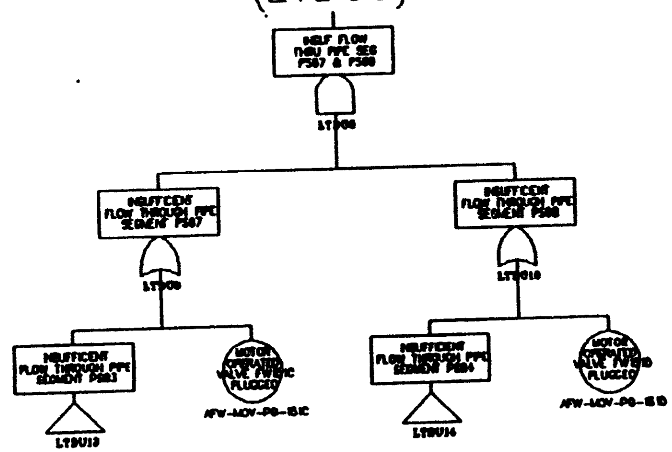
SBO AT UNIT 1 - AFW 1 OF 3 SG
(SBOU1-LS) - POS 3-13



SBO AT UNIT 1 AFW TO 1OF 3 SG (LTDU)
(LTDU)

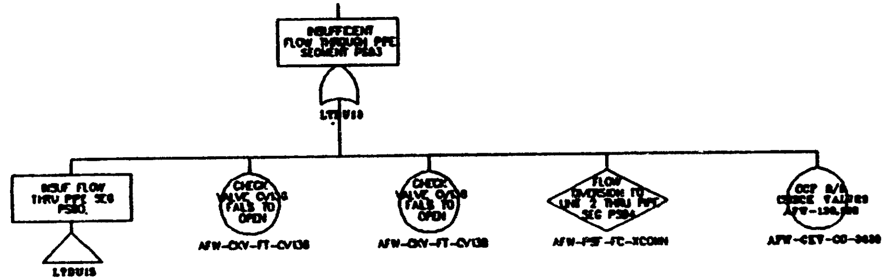


SBO AT UNIT 1 AFW TO 1 OF 3 SG (LTDU)
(LTDU5)



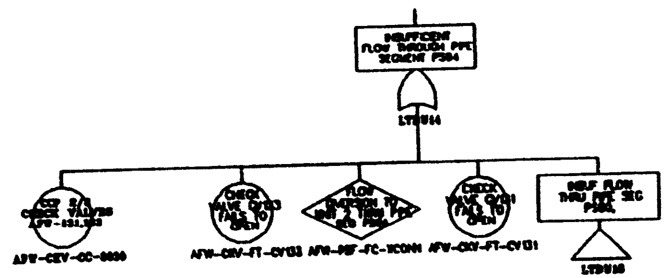
SBO AT UNIT 1 AFW TO 1 OF 3 SG (LTDU)
(LTDU13)

C-65

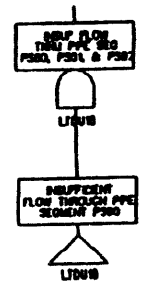


C-66

SBO AT UNIT 1 AFW TO 1 OF 3 SG (LTDU)
(LTDU14)

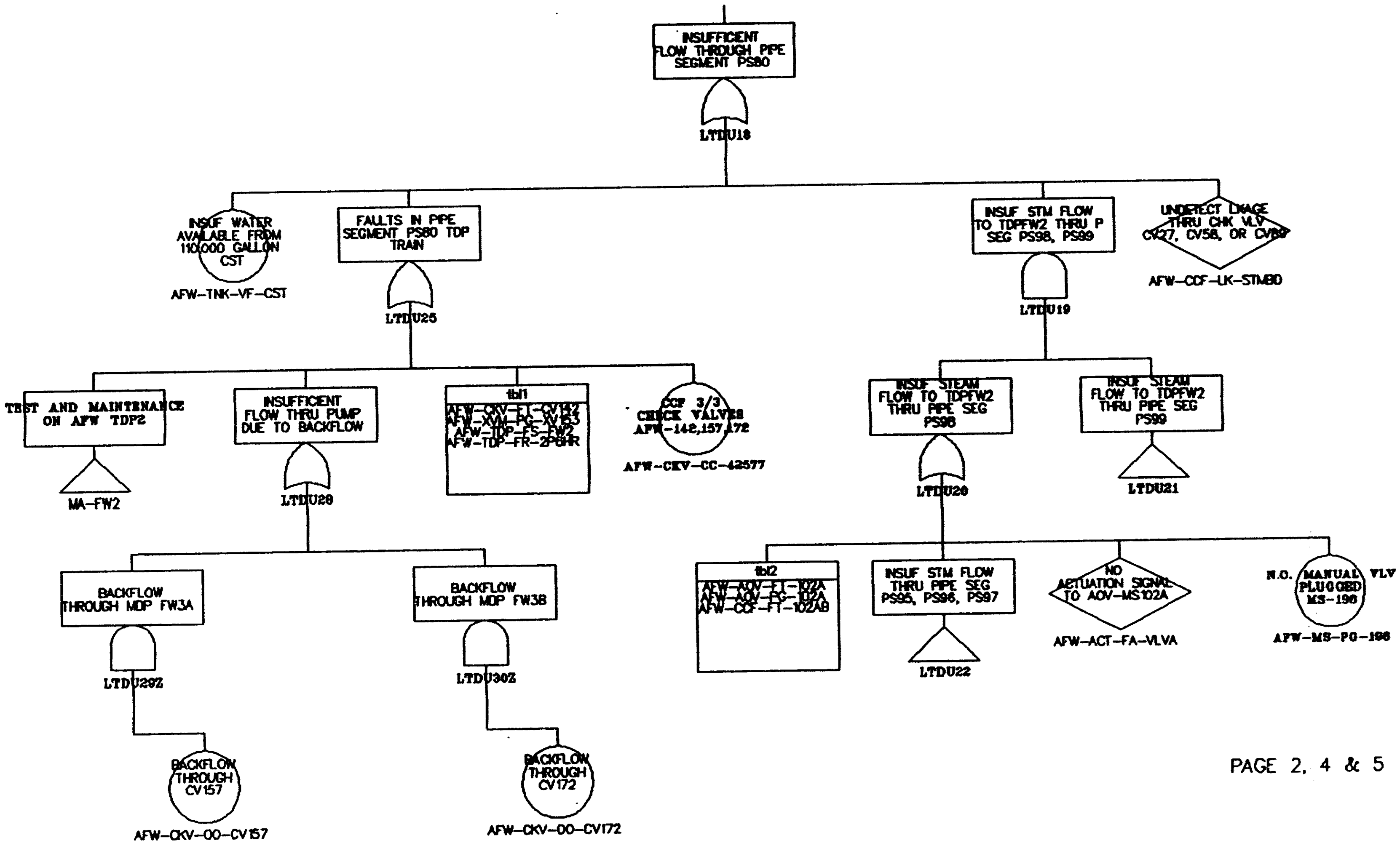


SBO AT UNIT 1 AFW TO 1 OF 3 SG (LTDU)
(LTDU15)



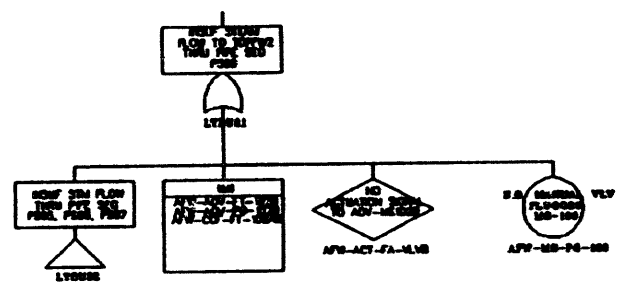
C-67

SBO AT UNIT 1 AFW TO 1 OF 3 SG (LTDU) (LTDU18)

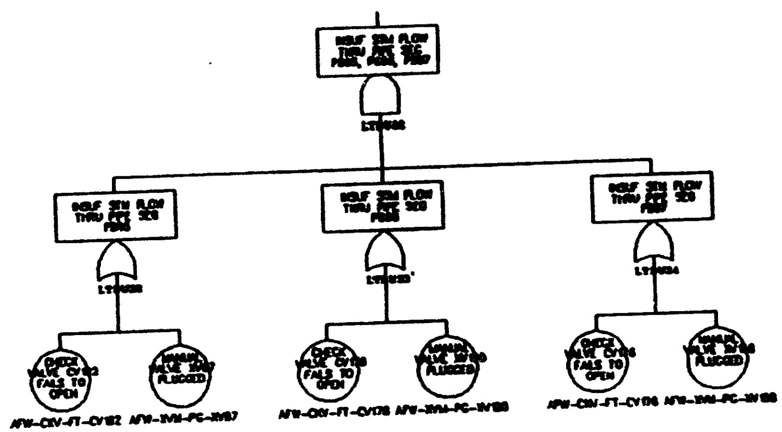


PAGE 2, 4 & 5

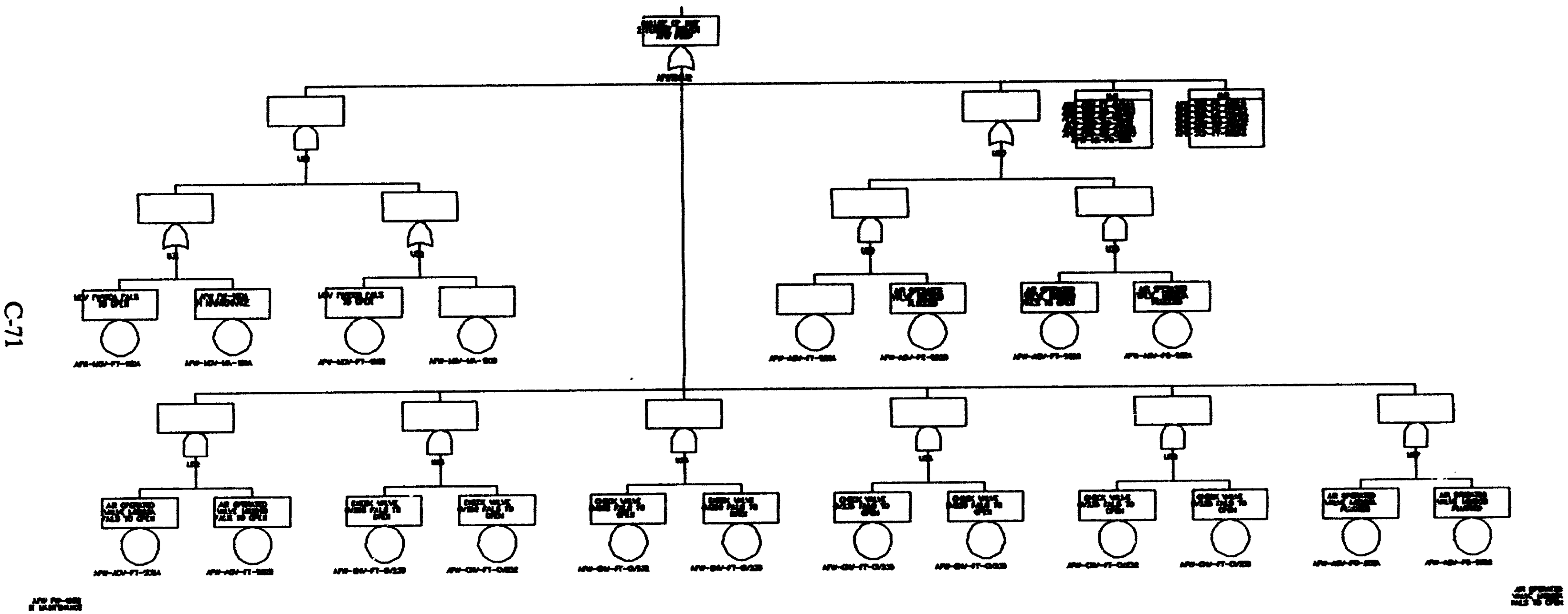
SBO AT UNIT 1 AFW TO 1 OF 3 SG (LTDU)
(LTDU21)



SBO AT UNIT 1 AFW TO 1OF 3 SG (LTDU)
(LTDU22)

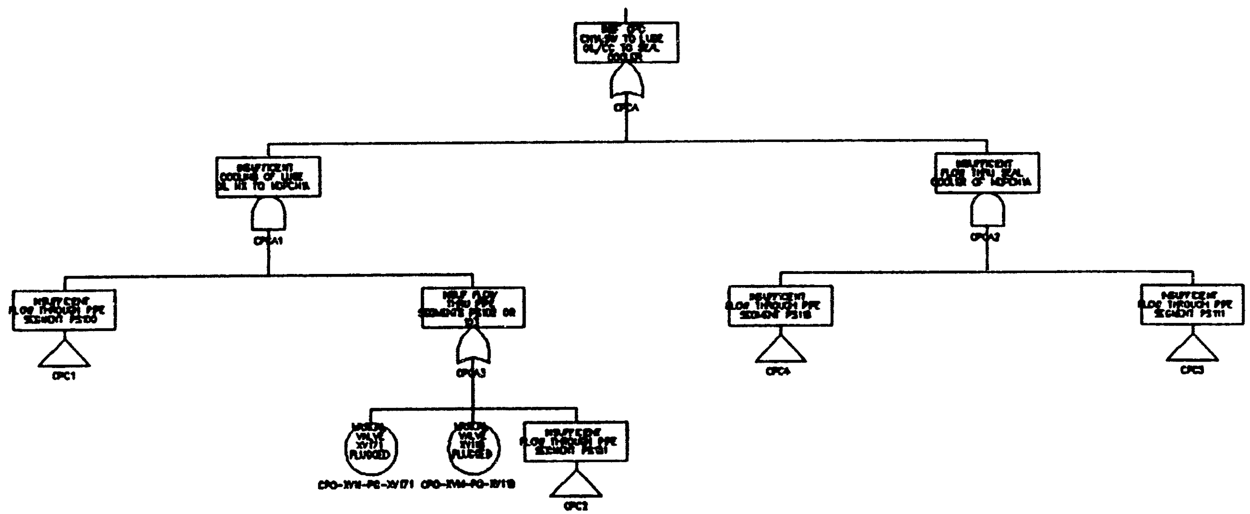


FAILURE OF UNIT 2 TURBINE DRIVEN AFW PUMP

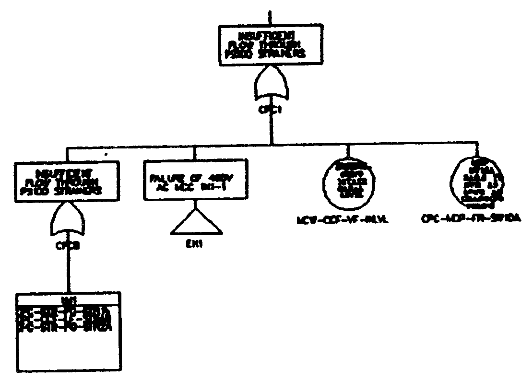


Appendix C.3 Charging Pump Cooling System

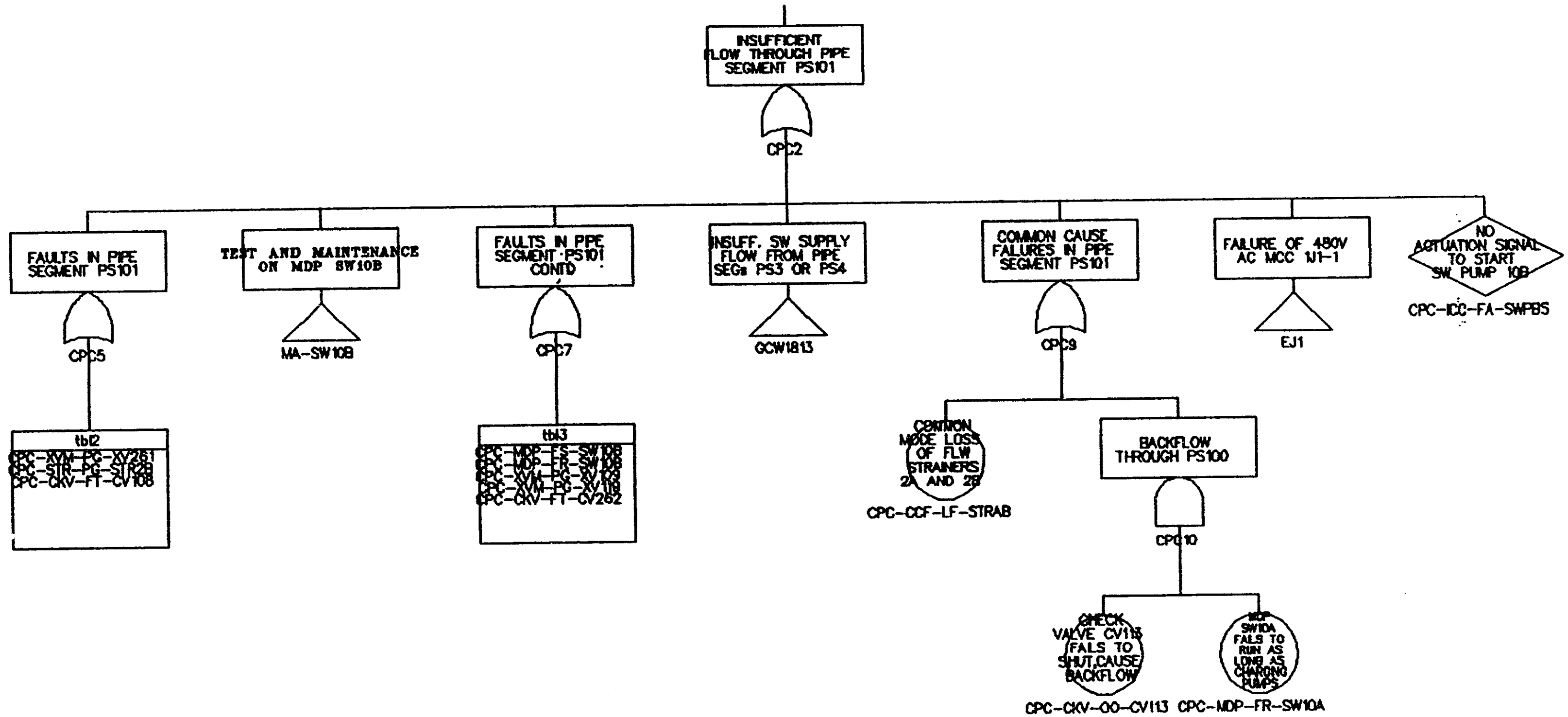
CHARGING PUMP A COOLING (CPCA)
(CPCA)



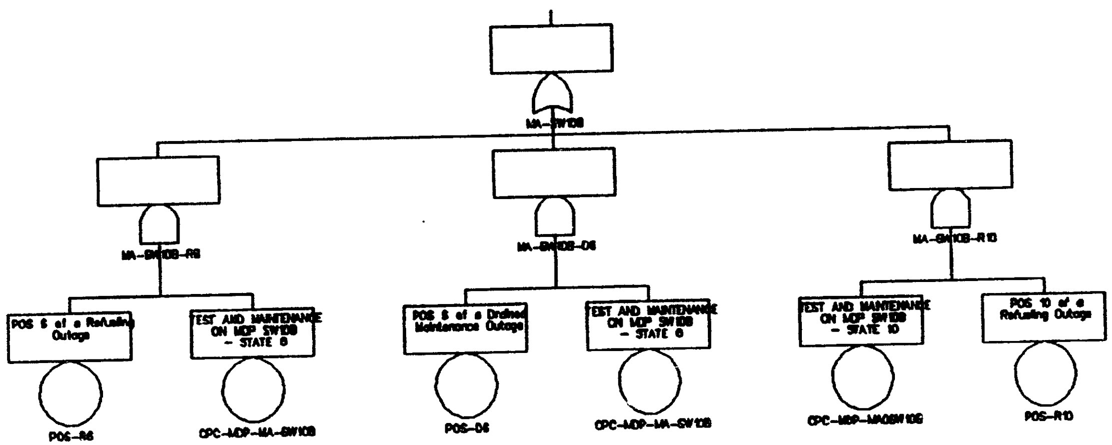
CHARGING PUMP A COOLING (CPCA)
(CPC1)



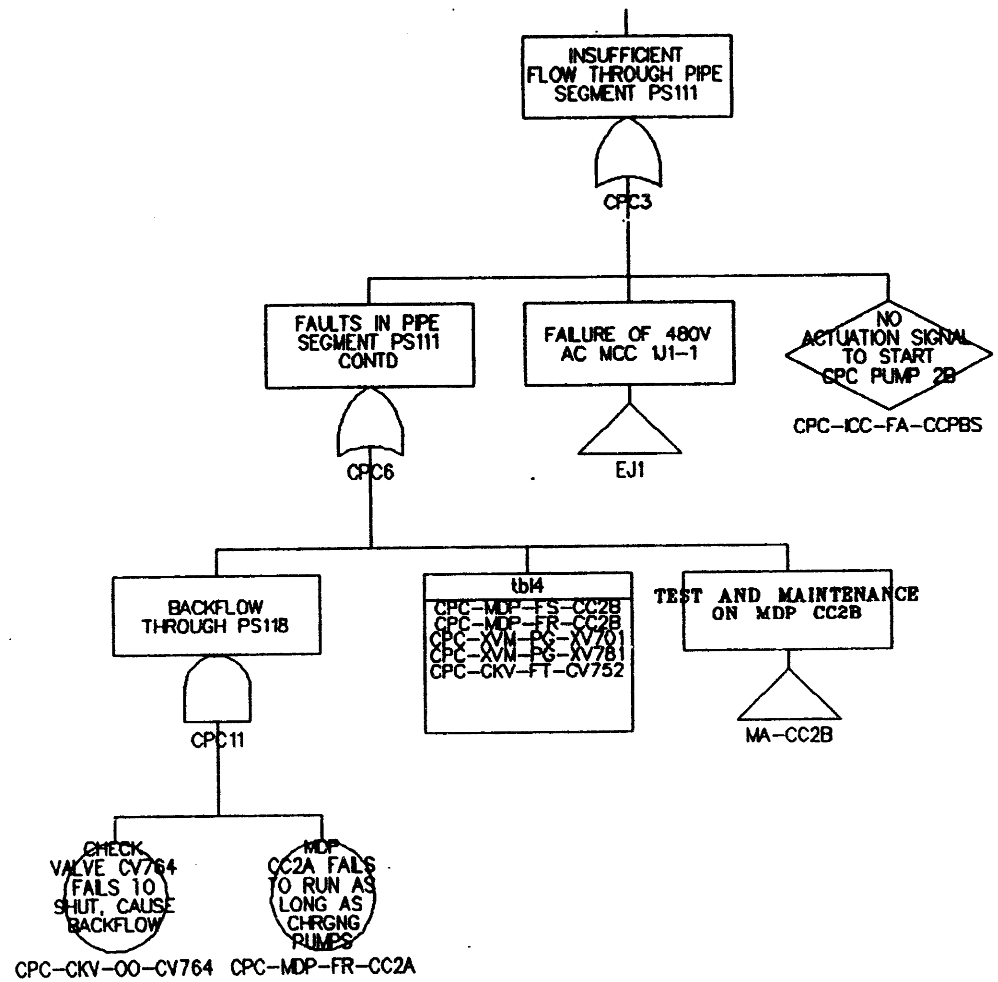
CHARGING PUMP A COOLING (CPCA)
(CPC2)



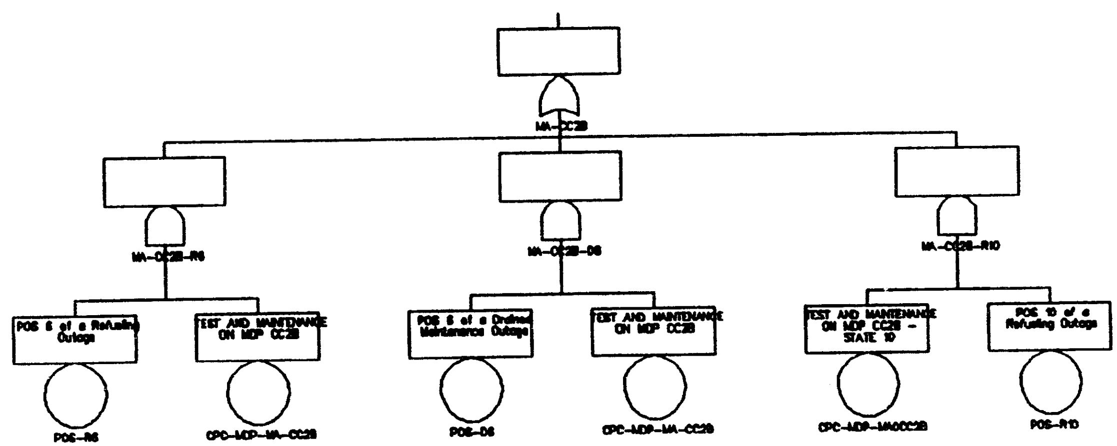
TEST AND MAINTENANCE ON MDP SW10B



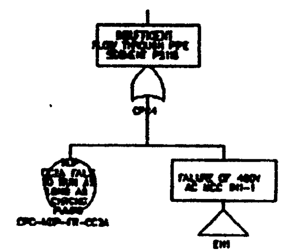
CHARGING PUMP A COOLING (CPC/
(CPC3)



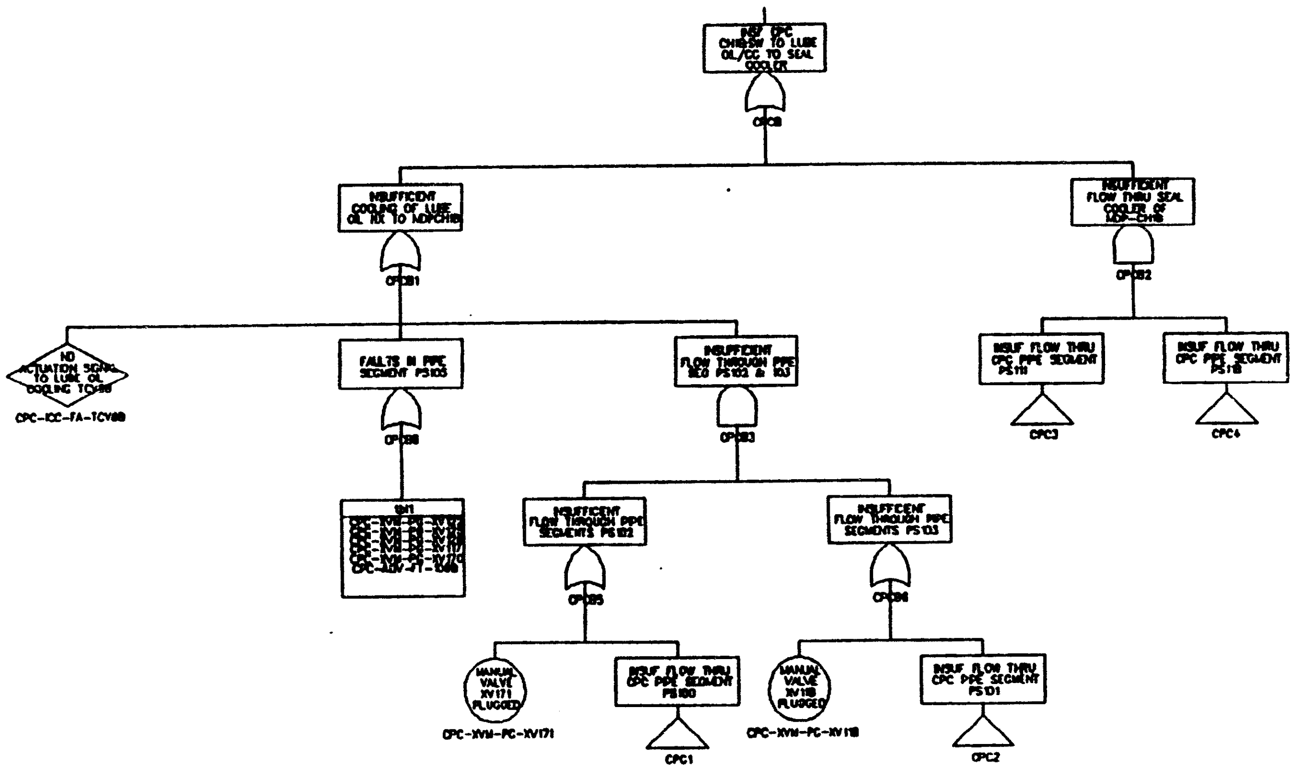
TEST AND MAINTENANCE ON MDP CC2B



CHARGING PUMP A COOLING (CPCA)
(CPC4)

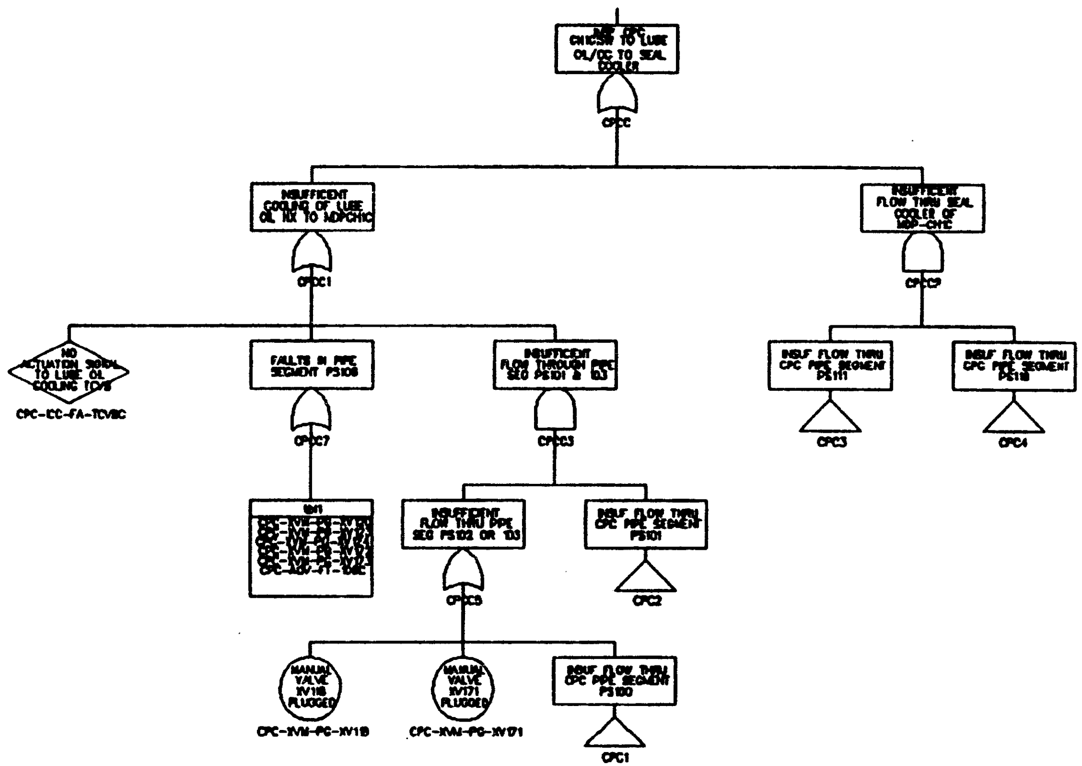


CHARGING PUMP B COOLING (CPCB)
(CPCB)



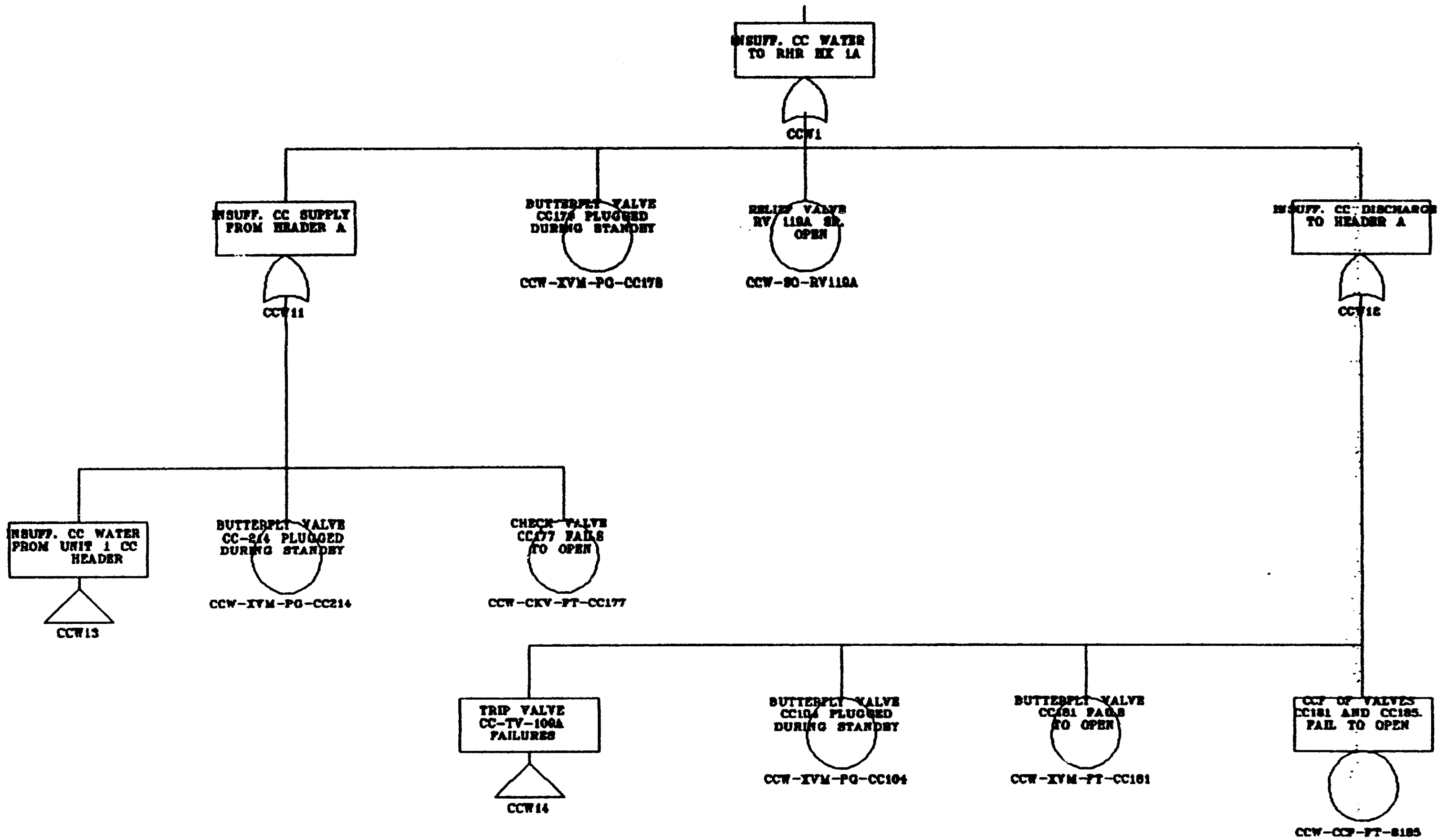
C-80

CHARGING PUMP C COOLING (CPCC)
(CPCC)

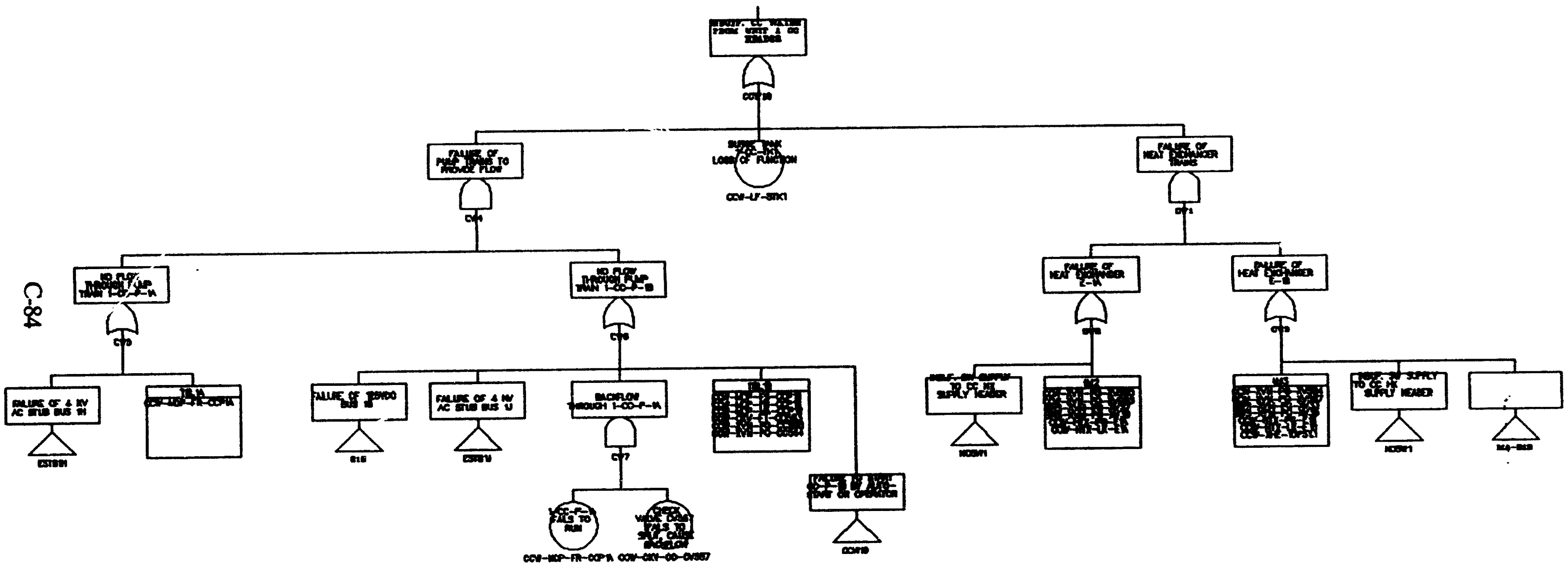


Appendix C.4 Component Cooling Water System

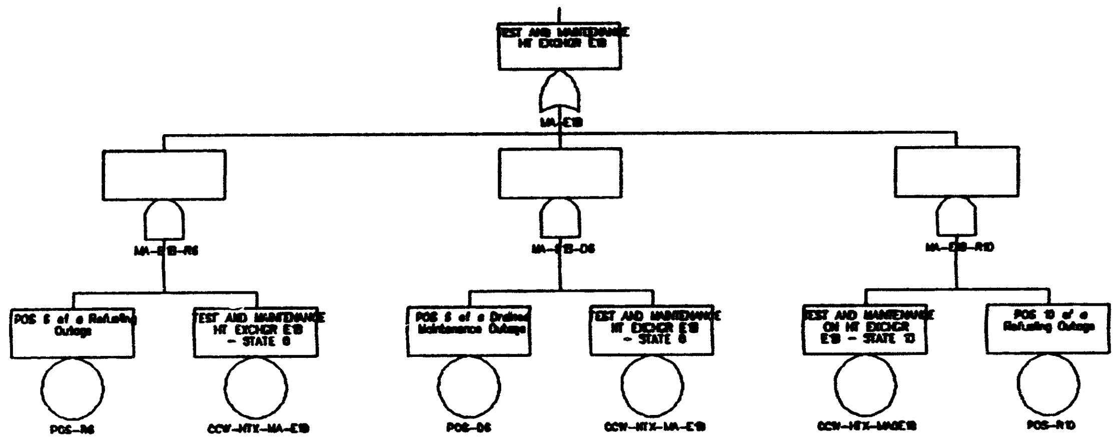
COMPONENT COOLING WATER SYSTEM FAULT TREES
INSUFFICIENT CC WATER TO RHR HX 1A, CCW1



COMPONENT COOLING WATER SYSTEM FAULT TREES
INSUFFICIENT CC WATER FROM UNIT 1 CC HEADER, CCW13

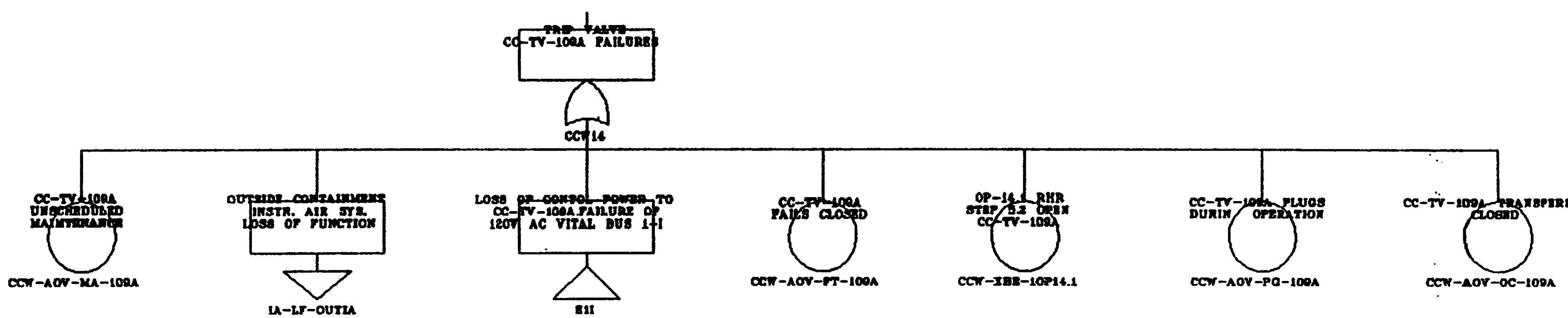


TEST AND MAINTENANCE HT EXCHGR E1B

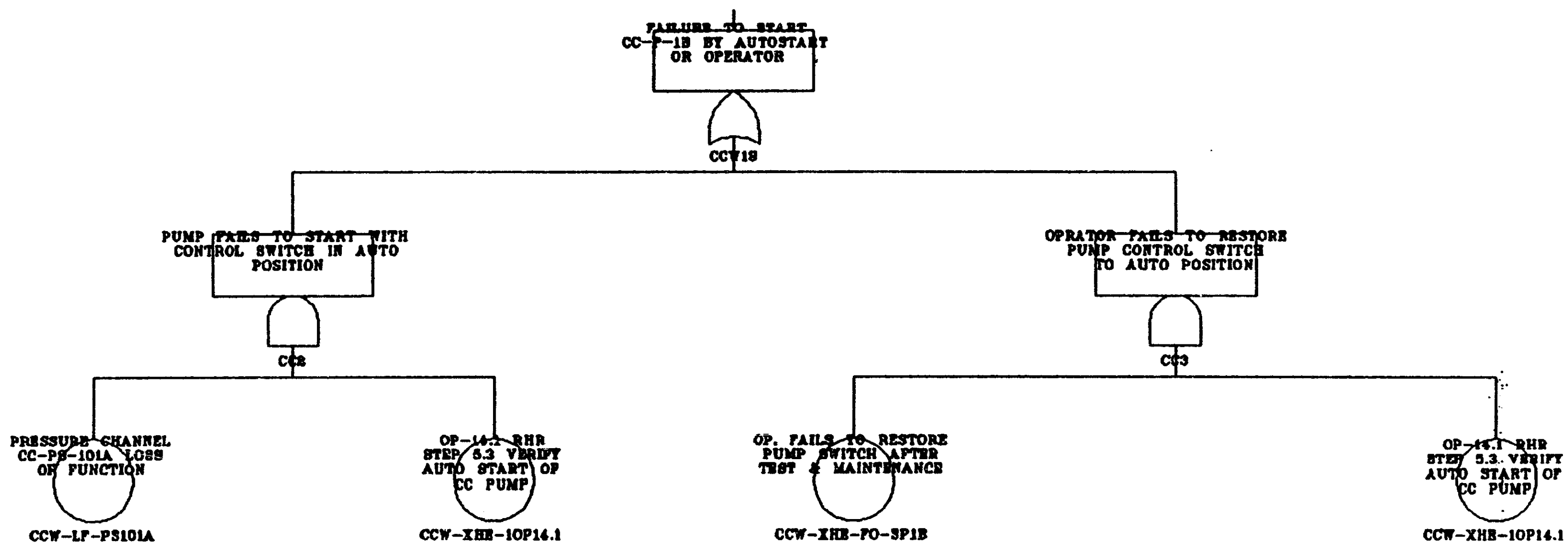


3 of 5

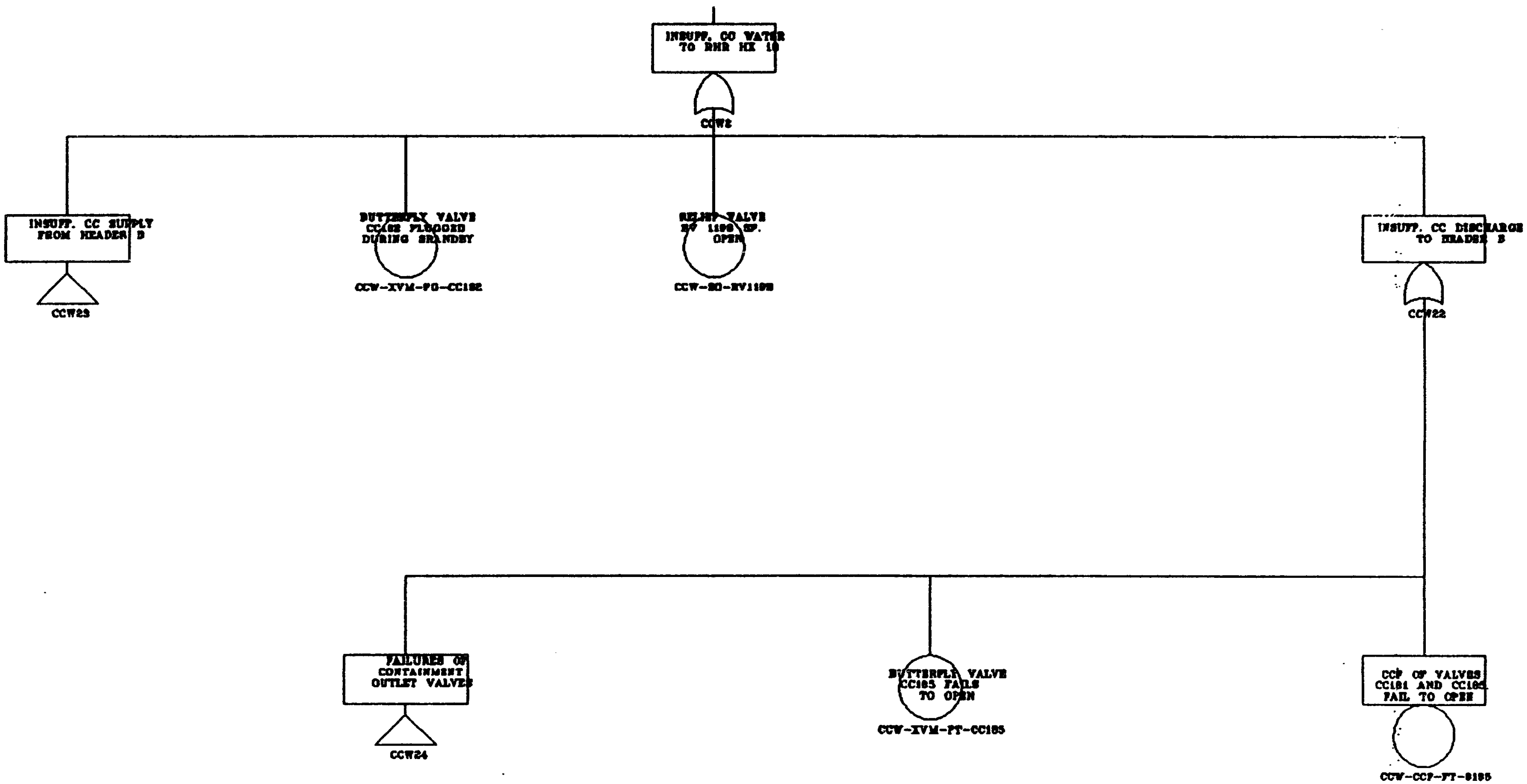
COMPONENT COOLING WATER SYSTEM FAULT TREES
TRIP VALVE CC–TV–109 FAILURES, CCW14



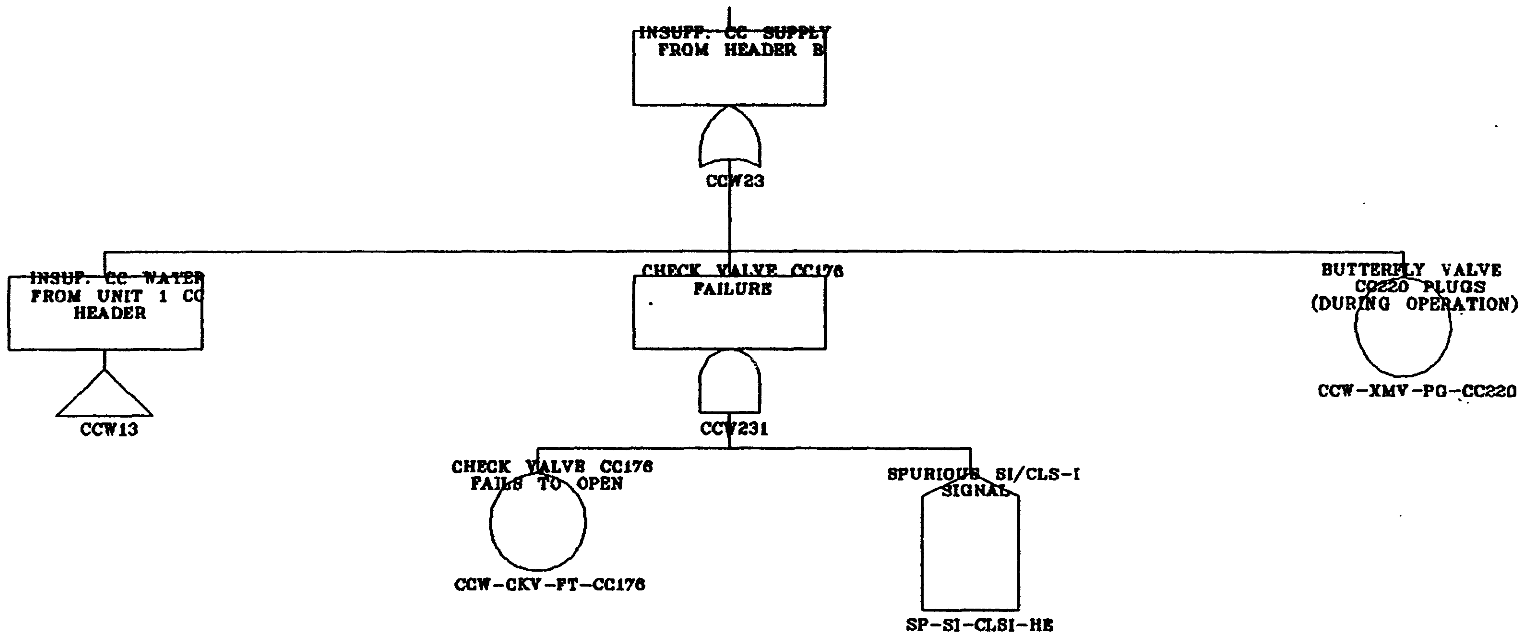
COMPONENT COOLING WATER SYSTEM FAULT TREES
FAILURE TO START CC-P-1B BY AUTOSTART OR OPERATOR, CCW19



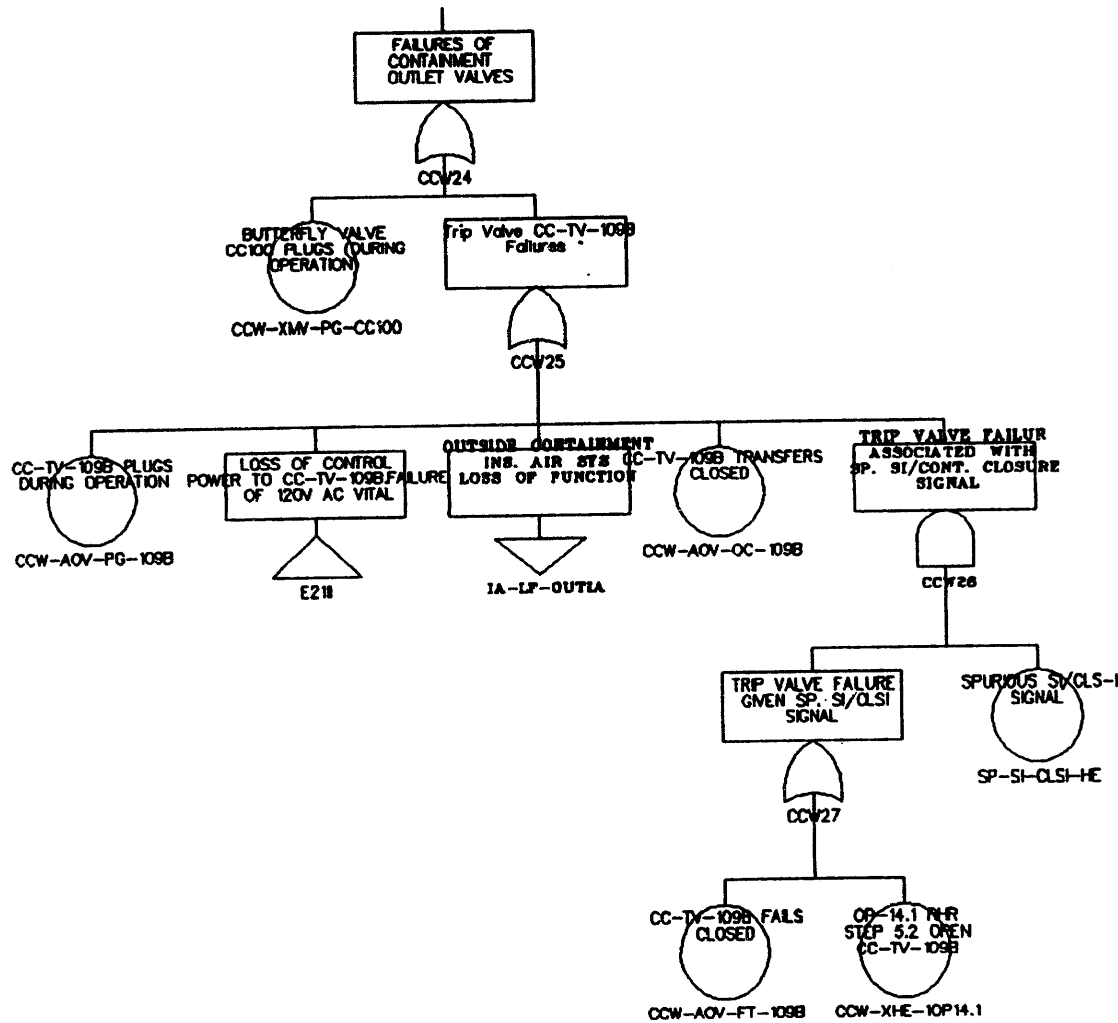
COMPONENT COOLING WATER SYSTEM FAULT TREES
INSUFFICIENT CC WATER TO RHR HX 1B, CCW2



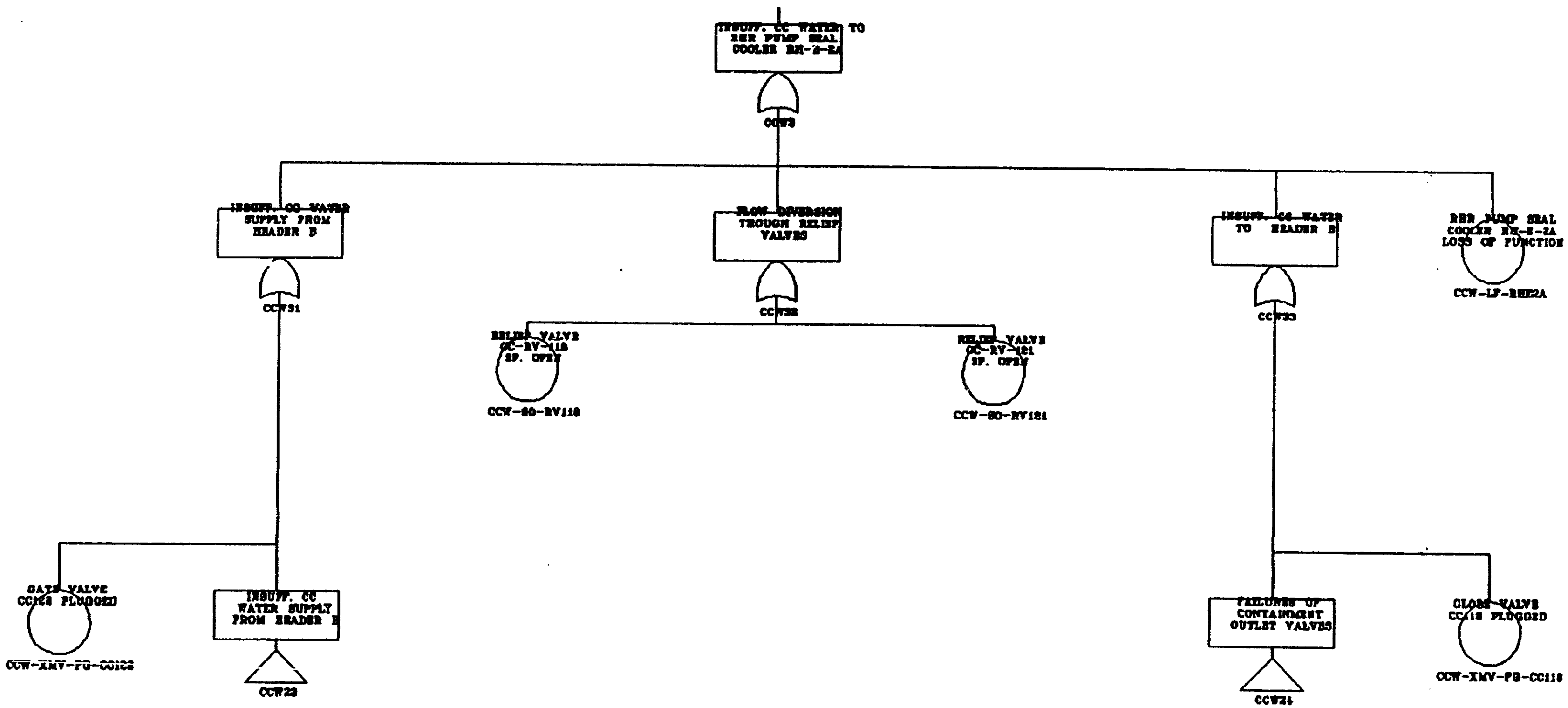
COMPONENT COOLING WATER SYSTEM FAULT TREES
INSUFFICIENT CC WATER SUPPLY FROM HEADER B, CCW23



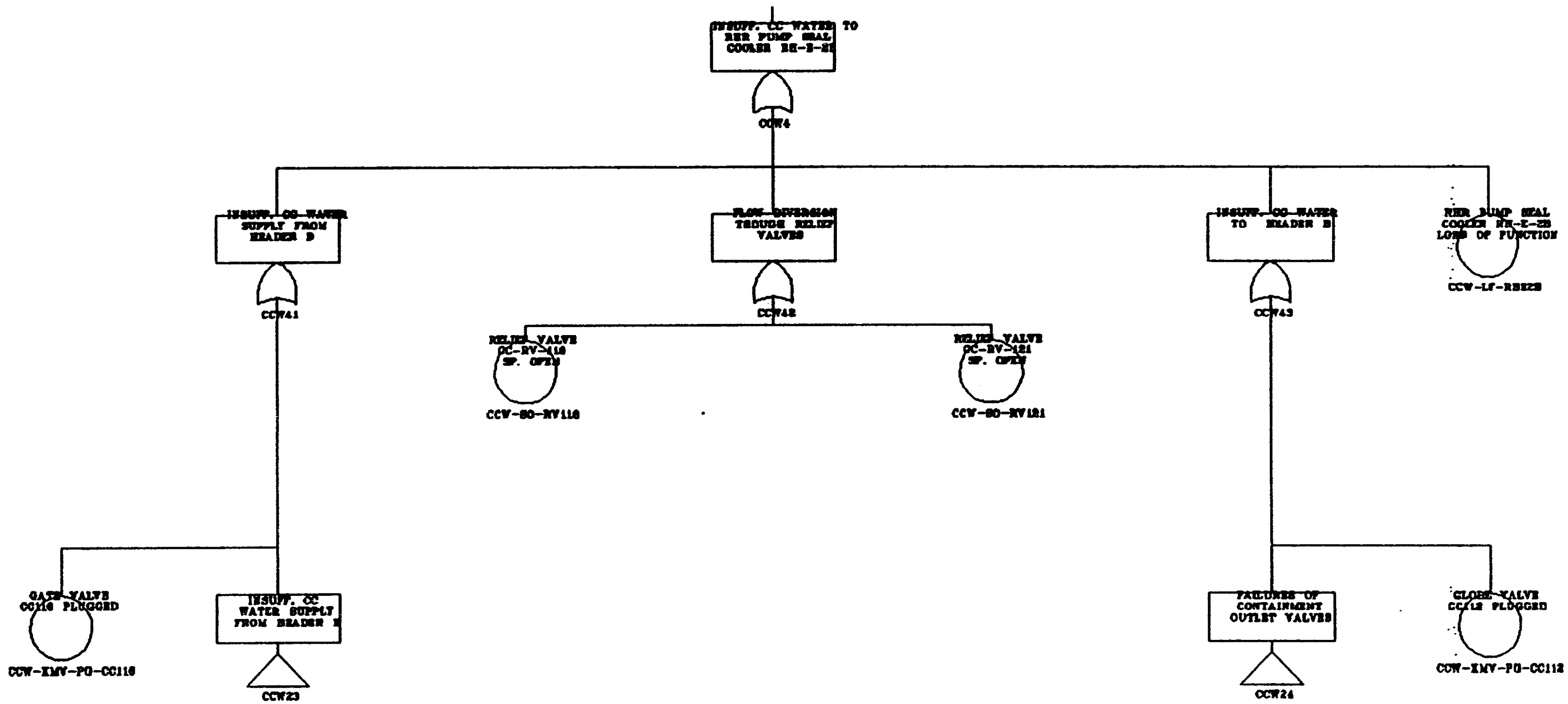
COMPONENT COOLING WATER FAULT TREES, TRIP VALVE CC-TV-109B FAILURES, CCW24



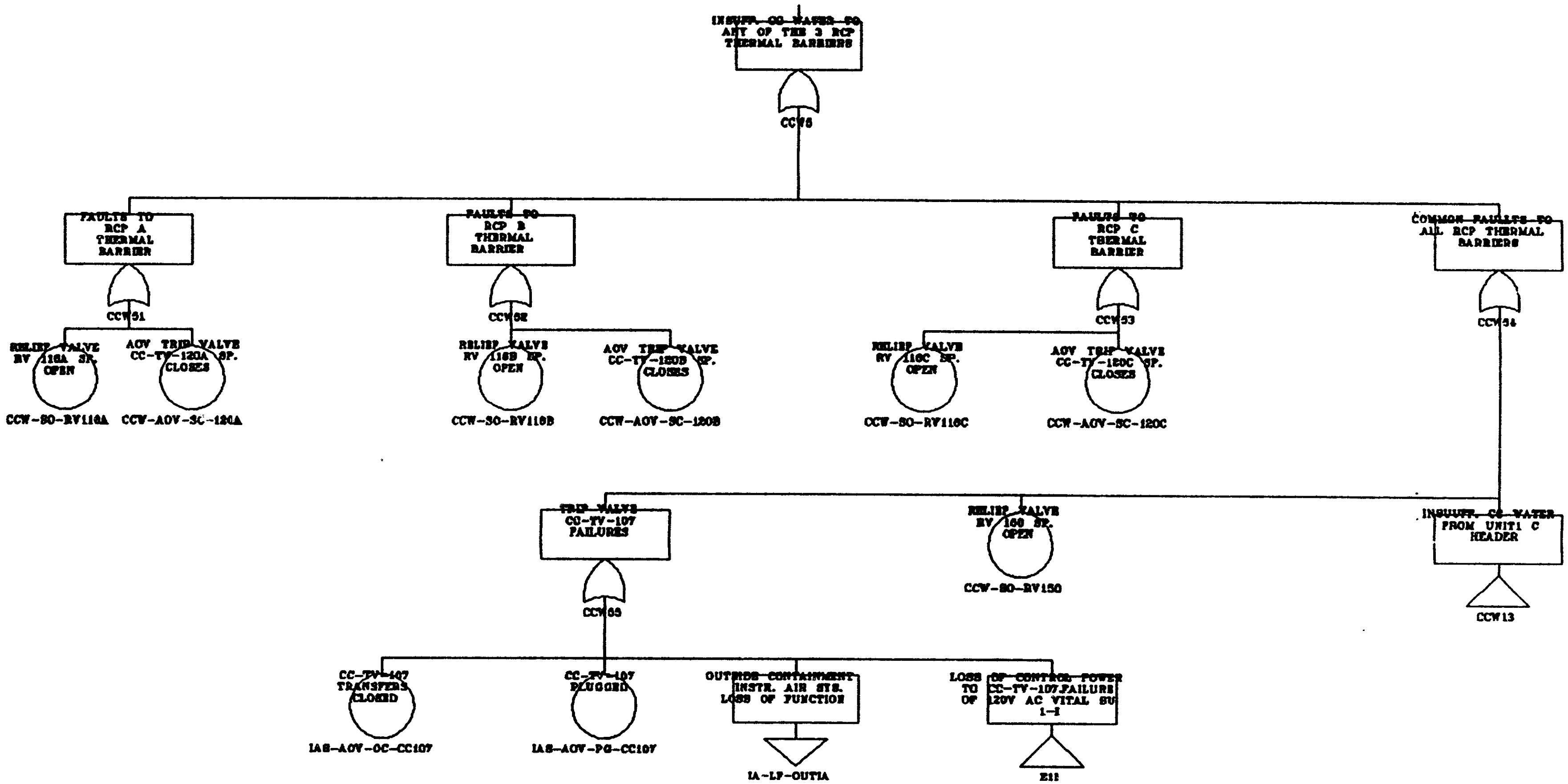
COMPONENT COOLING WATER SYSTEM FAULT TREES
INSUFF. CC WATER TO RHR PUMP COOLER RH–E–2A, CCW3



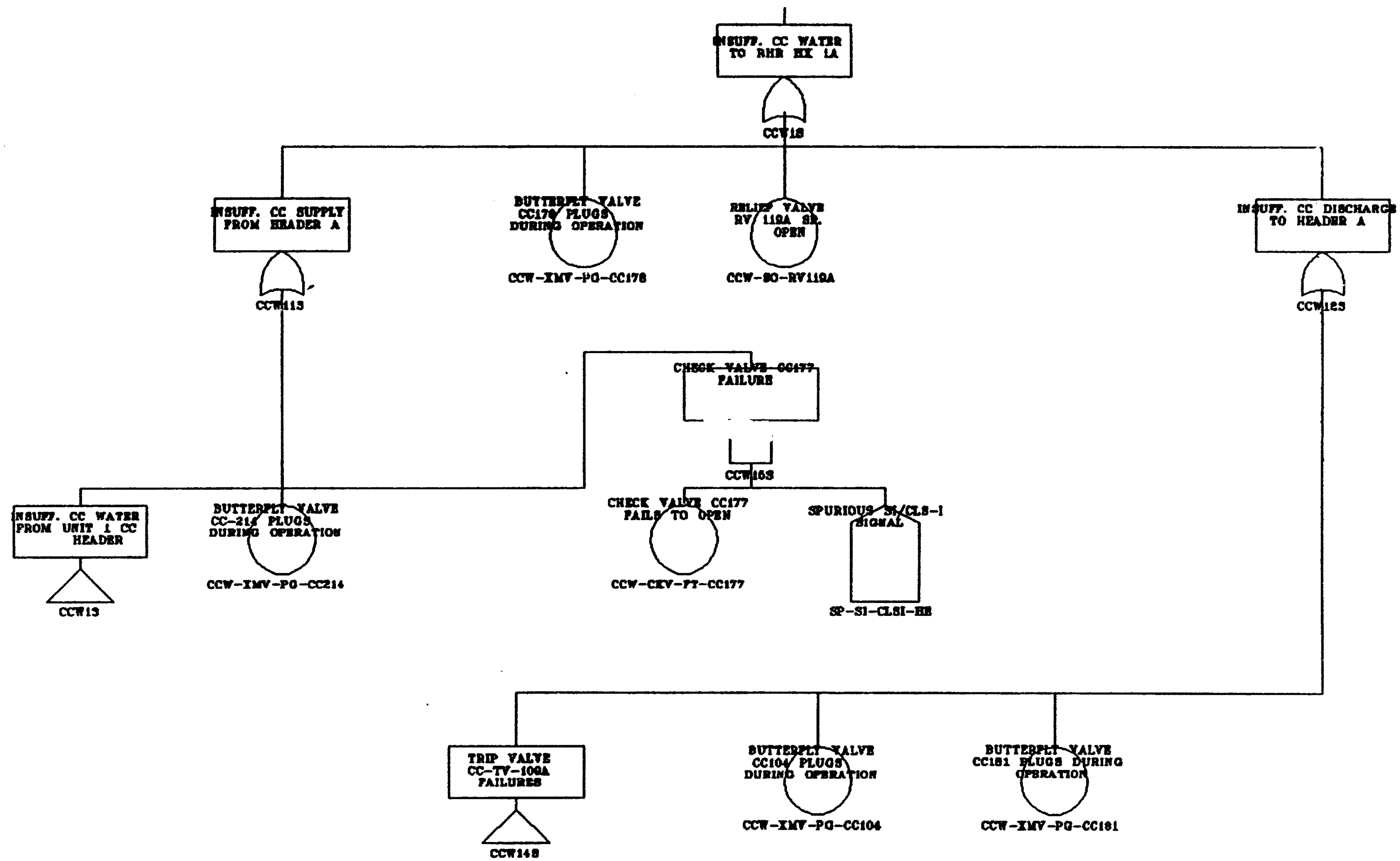
COMPONENT COOLING WATER SYSTEM FAULT TREES
INSUFF. CC WATER TO RHR PUMP COOLER RH-E-2B, CCW4



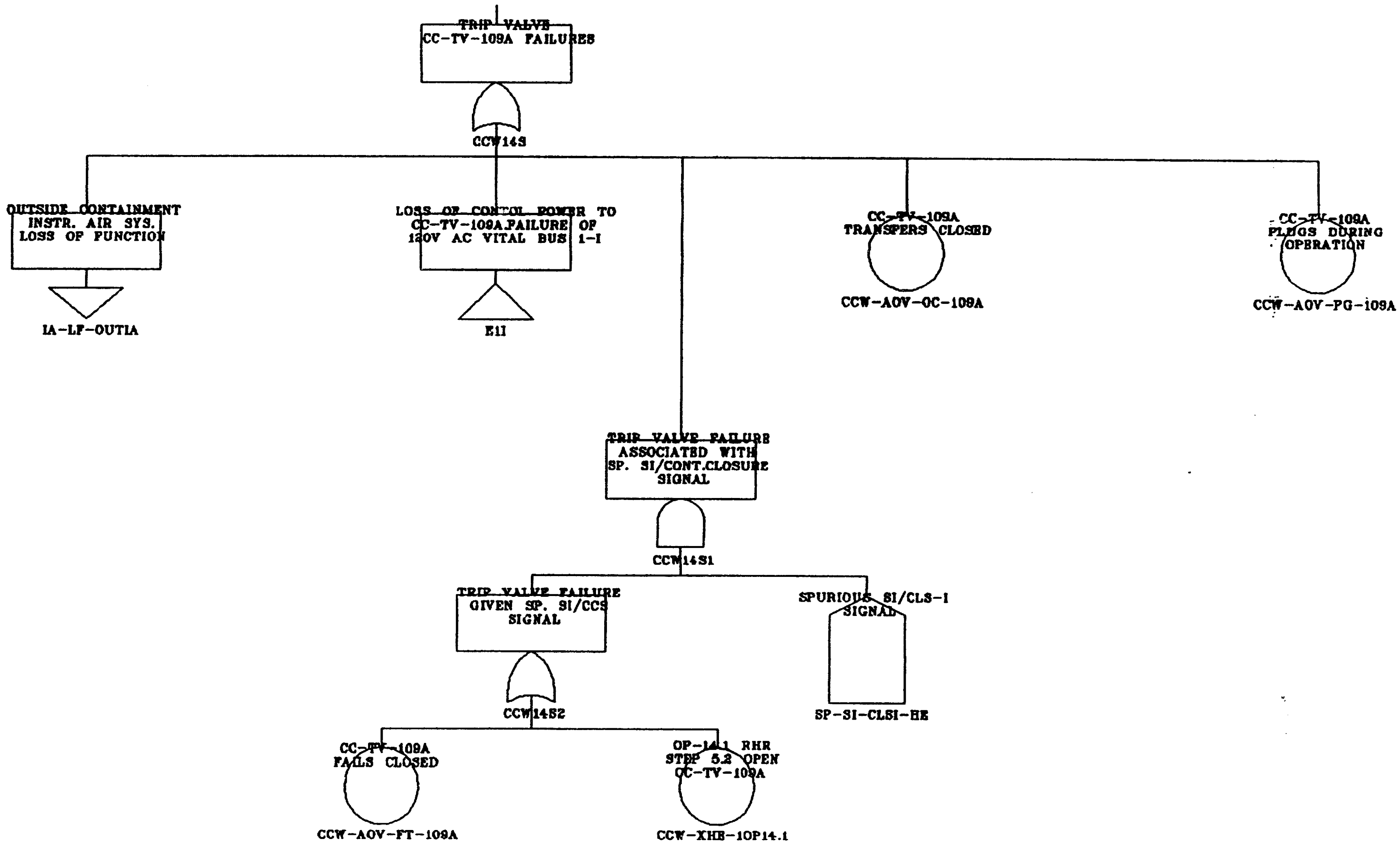
COMPONENT COOLING WATER SYSTEM FAULT TREES
INSUFFICIENT CC WATER TO ANY OF THE 3 RCP
THERMAL BARRIERS, CCW5



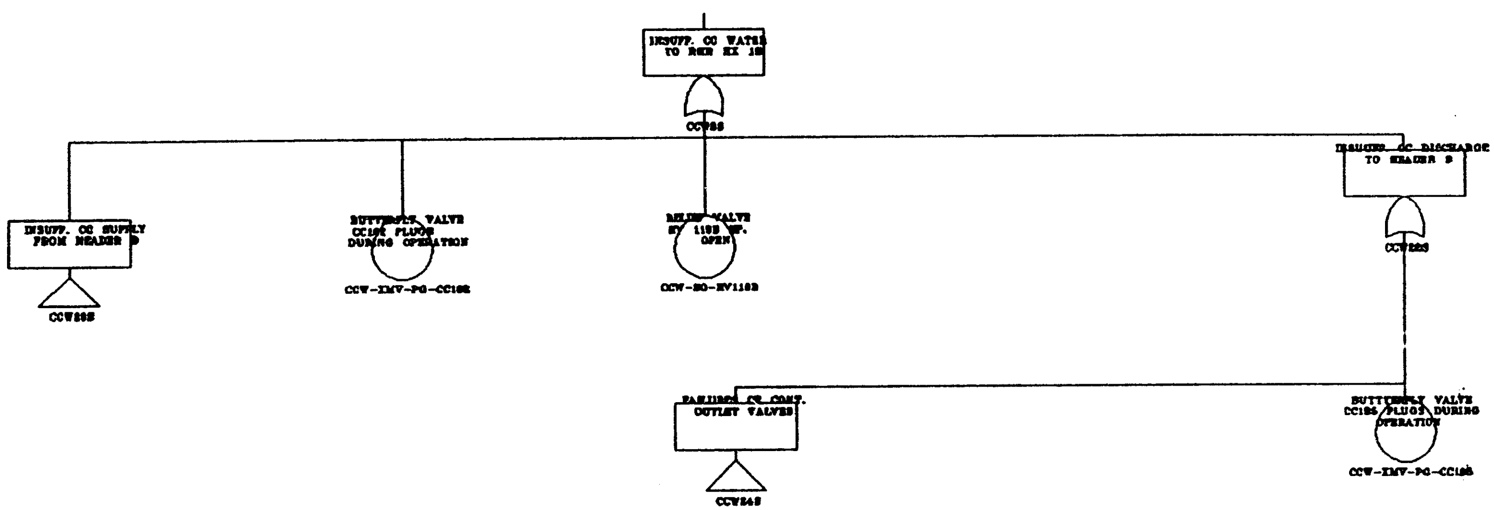
COMPONENT COOLING WATER SYSTEM FAULT TREES
INSUFFICIENT CC WATER TO RHR HX 1A, CCW1S



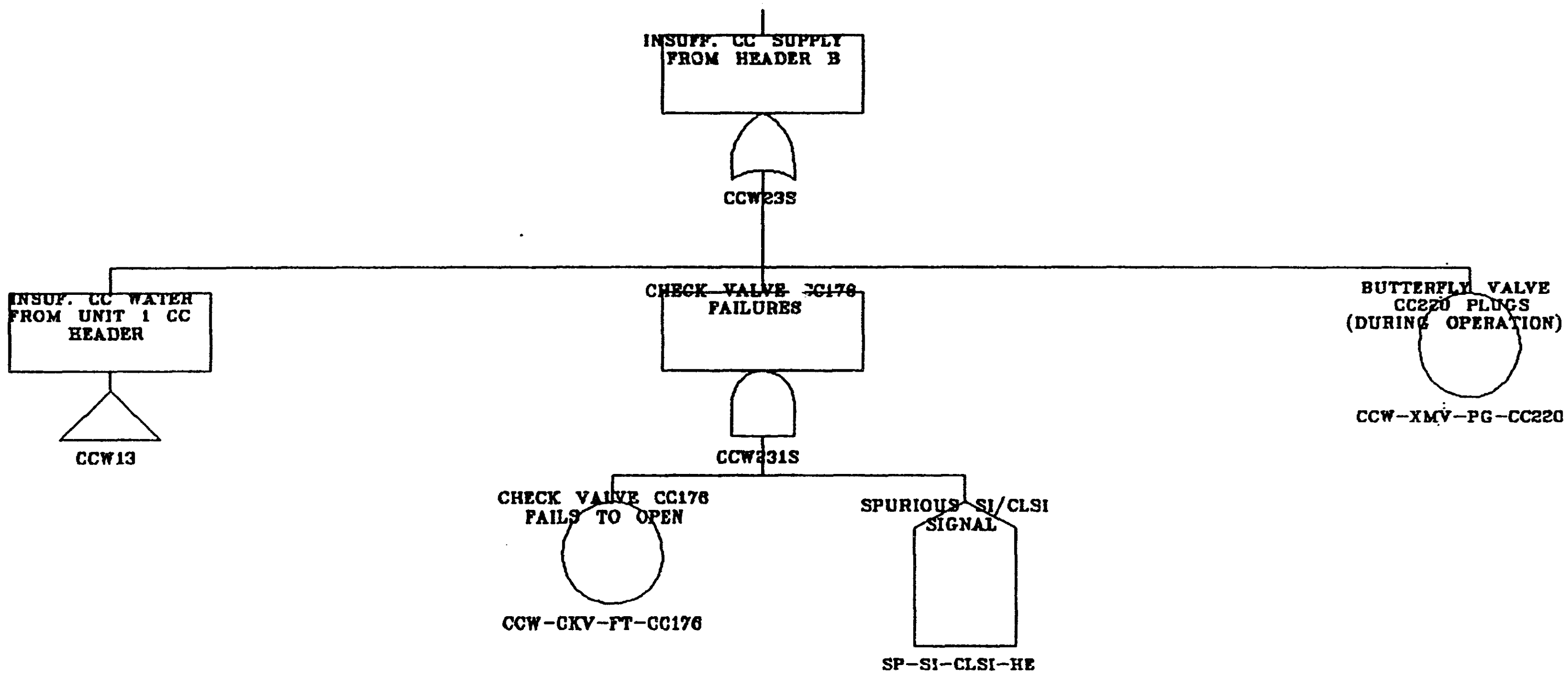
COMPONENT COOLING WATER SYSTEM FAULT TREES
TRIP VALVE CC-TV-109A FAILURES, CCW14S



COMPONENT COOLING WATER SYSTEM FAULT TREES
INSUFFICIENT CC WATER TO RHR HX 1B, CCW2S

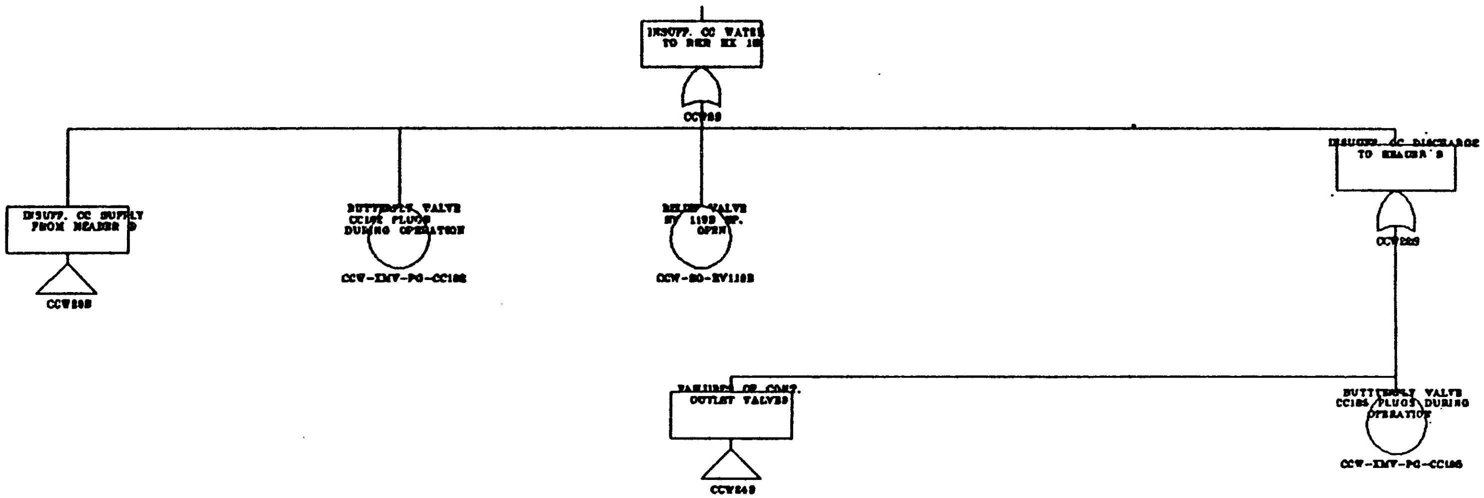


COMPONENT COOLING WATER SYSTEM FAULT TREES
INSUFFICIENT CC WATER SUPPLY FROM HEADER B, CCW23S

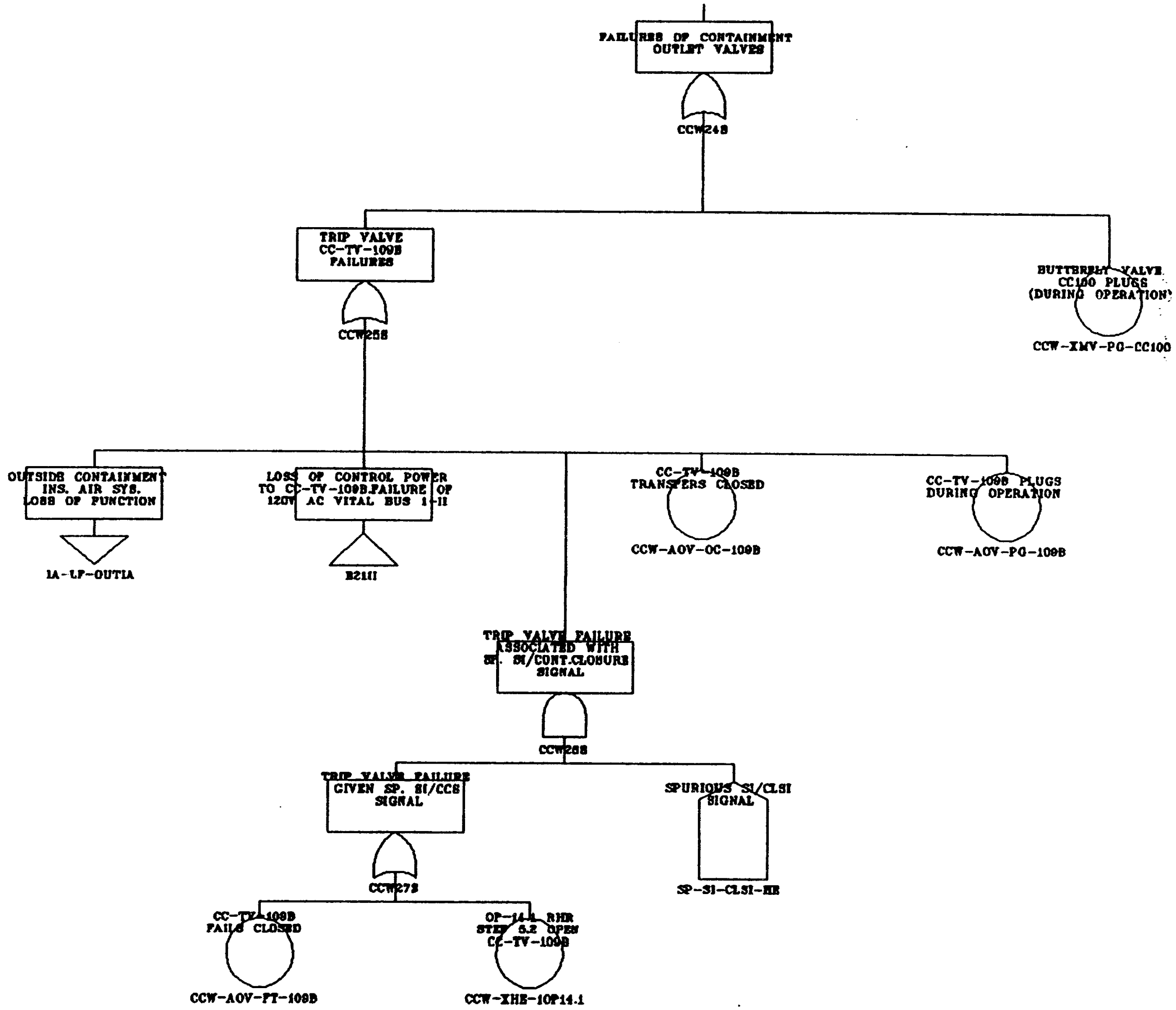


C-98

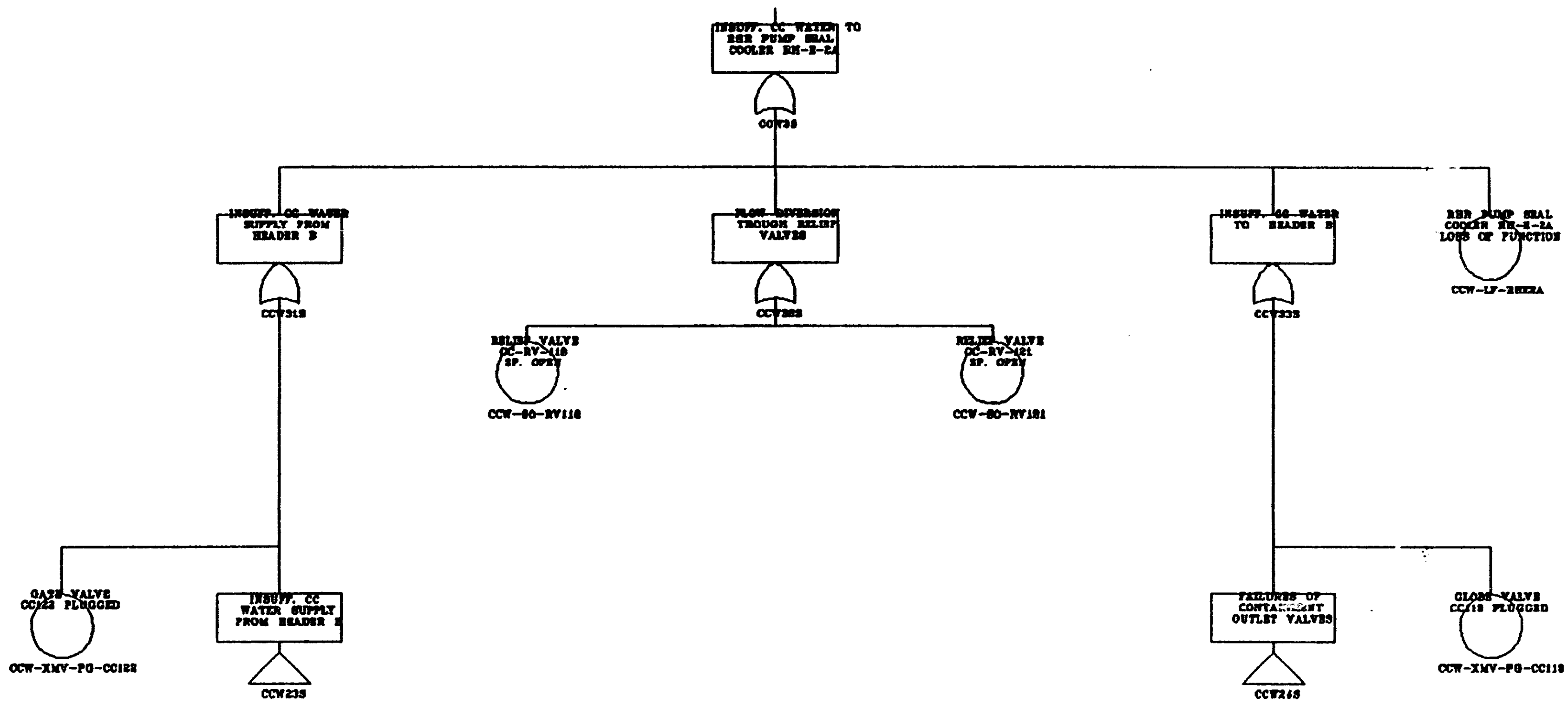
COMPONENT COOLING WATER SYSTEM FAULT TREES
INSUFFICIENT CC WATER TO RHR HX 1B, CCW2S



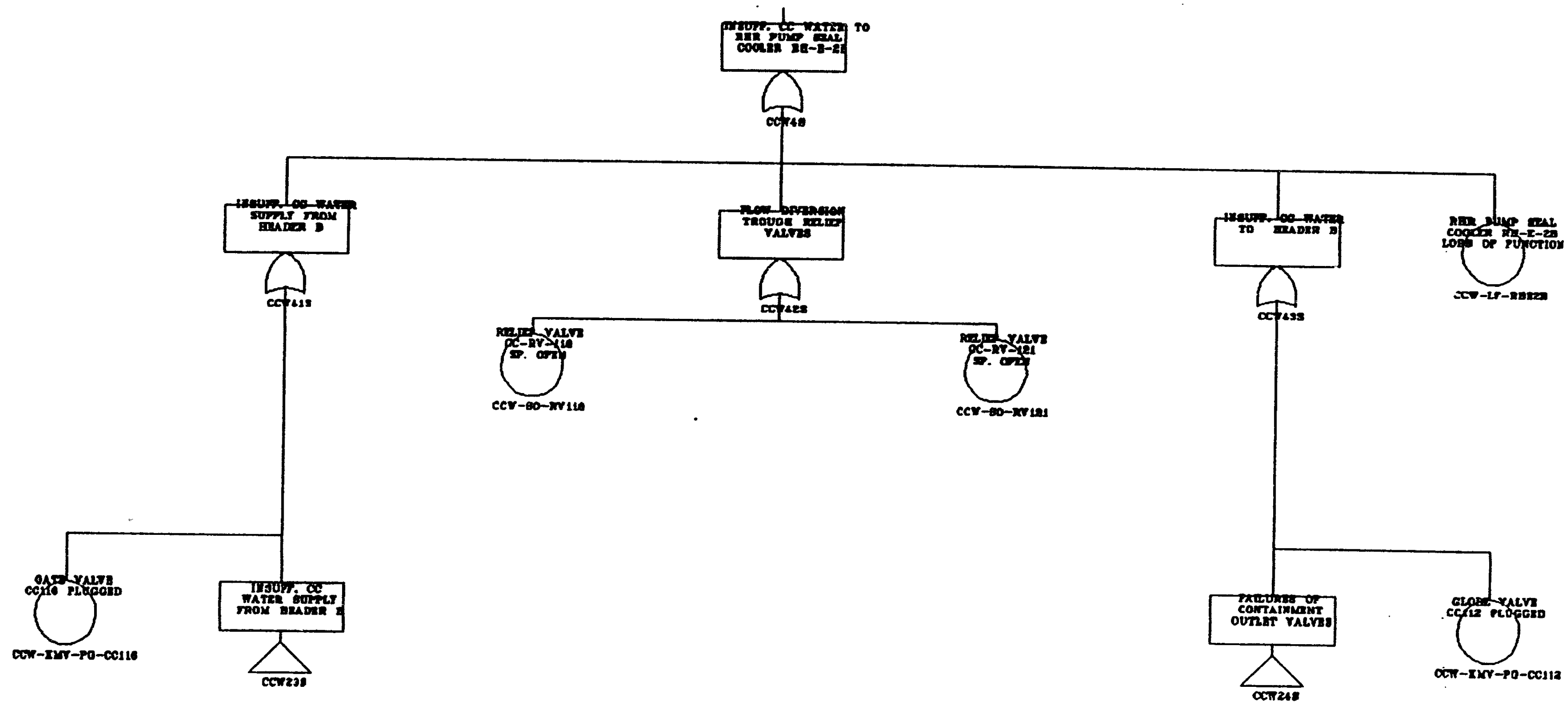
COMPONENT COOLING WATER FAULT TREES
TRIP VALVE CC-TV-109B FAILURES, CCW24S



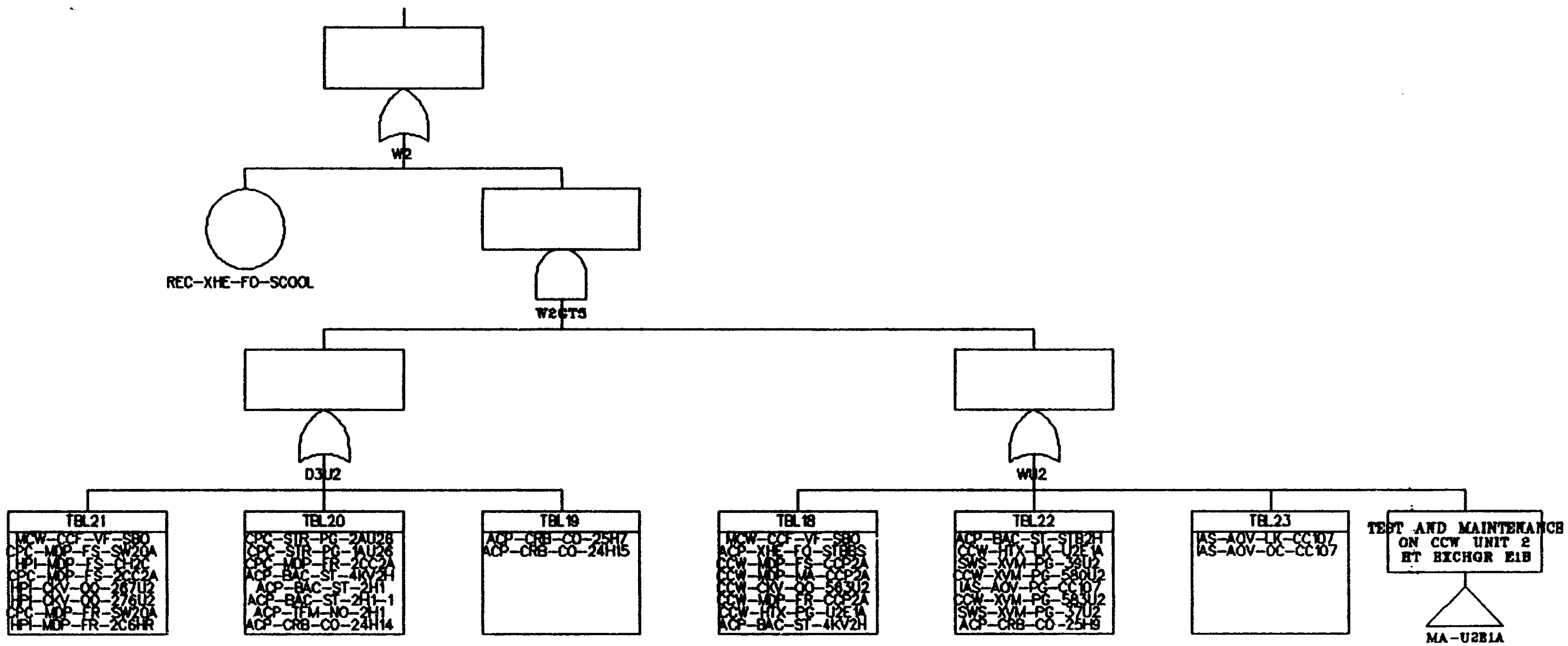
COMPONENT COOLING WATER SYSTEM FAULT TREES
INSUFF. CC WATER TO RHR PUMP COOLER RH-E-2A, CCW3S



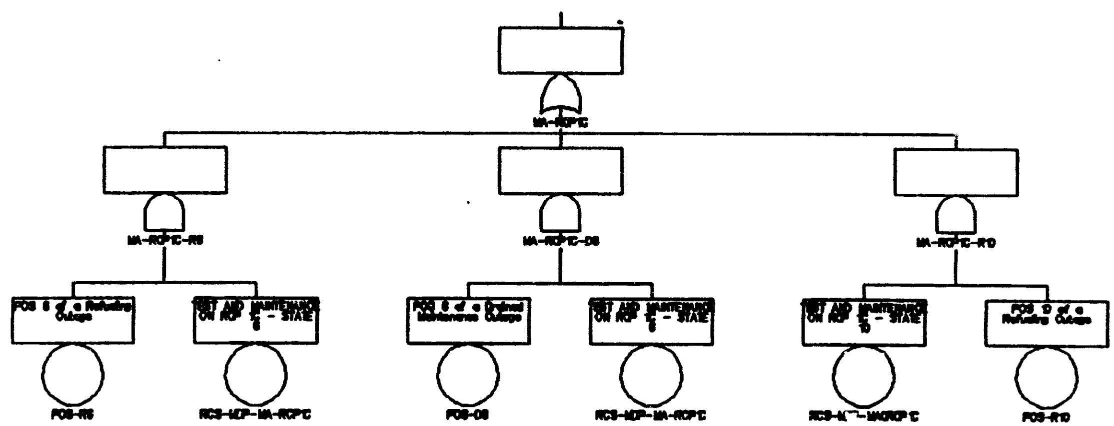
COMPONENT COOLING WATER SYSTEM FAULT TREES
INSUFF. CC WATER TO RHR PUMP COOLER RH-E-2B, CCW4S



FAILURE TO COOL RCS PUMP SEALS FROM UNIT 2 CCW FROM EQUATION ON PAGE B-9

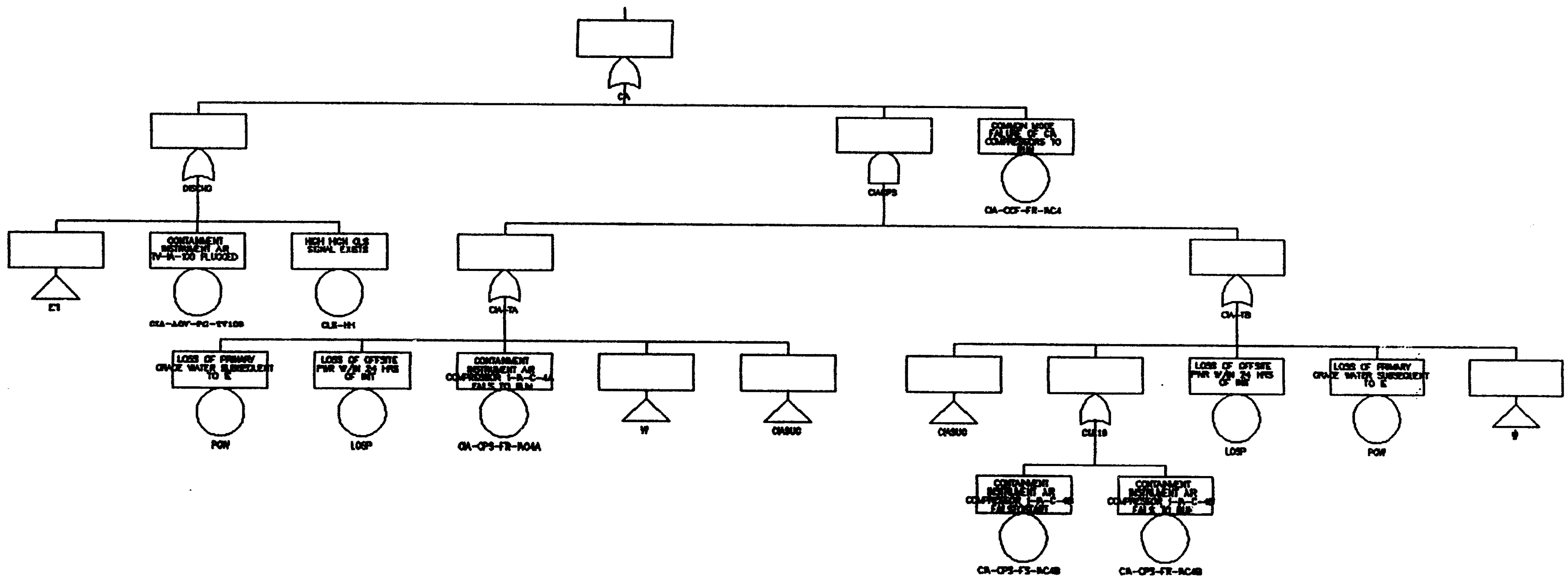


TEST AND MAINTENANCE ON RCP 1C

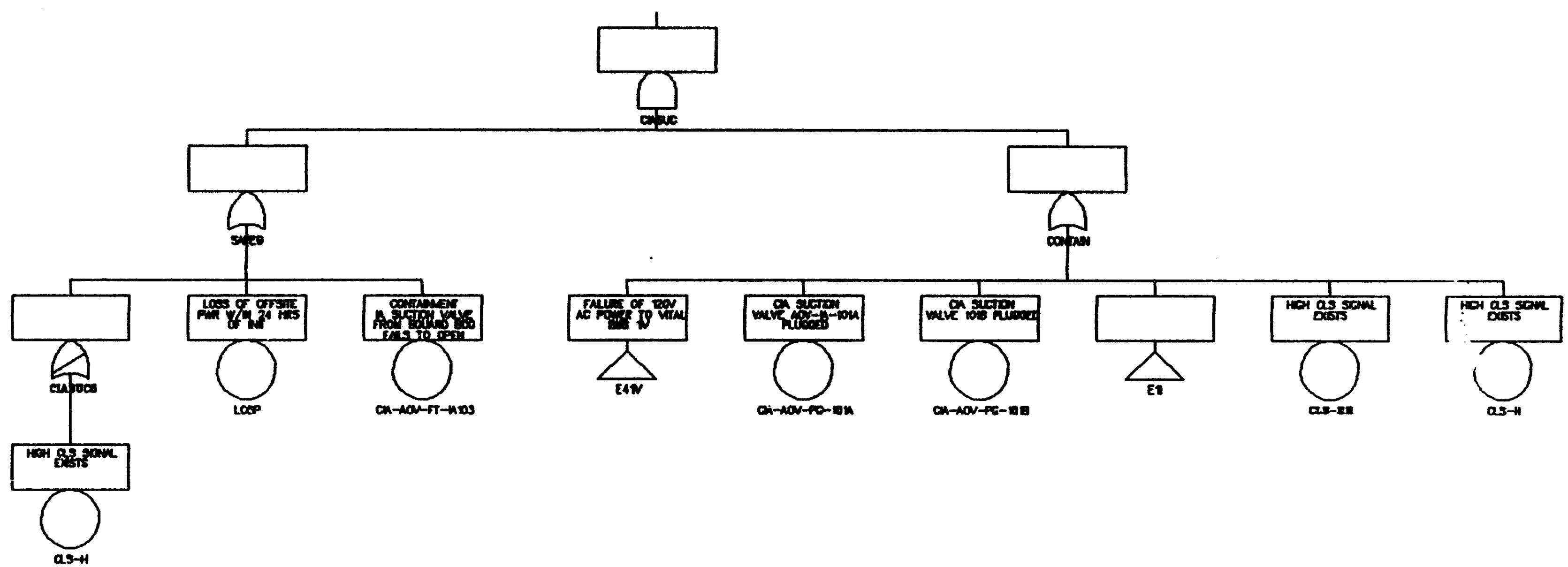


Appendix C.5 Compressed Air System

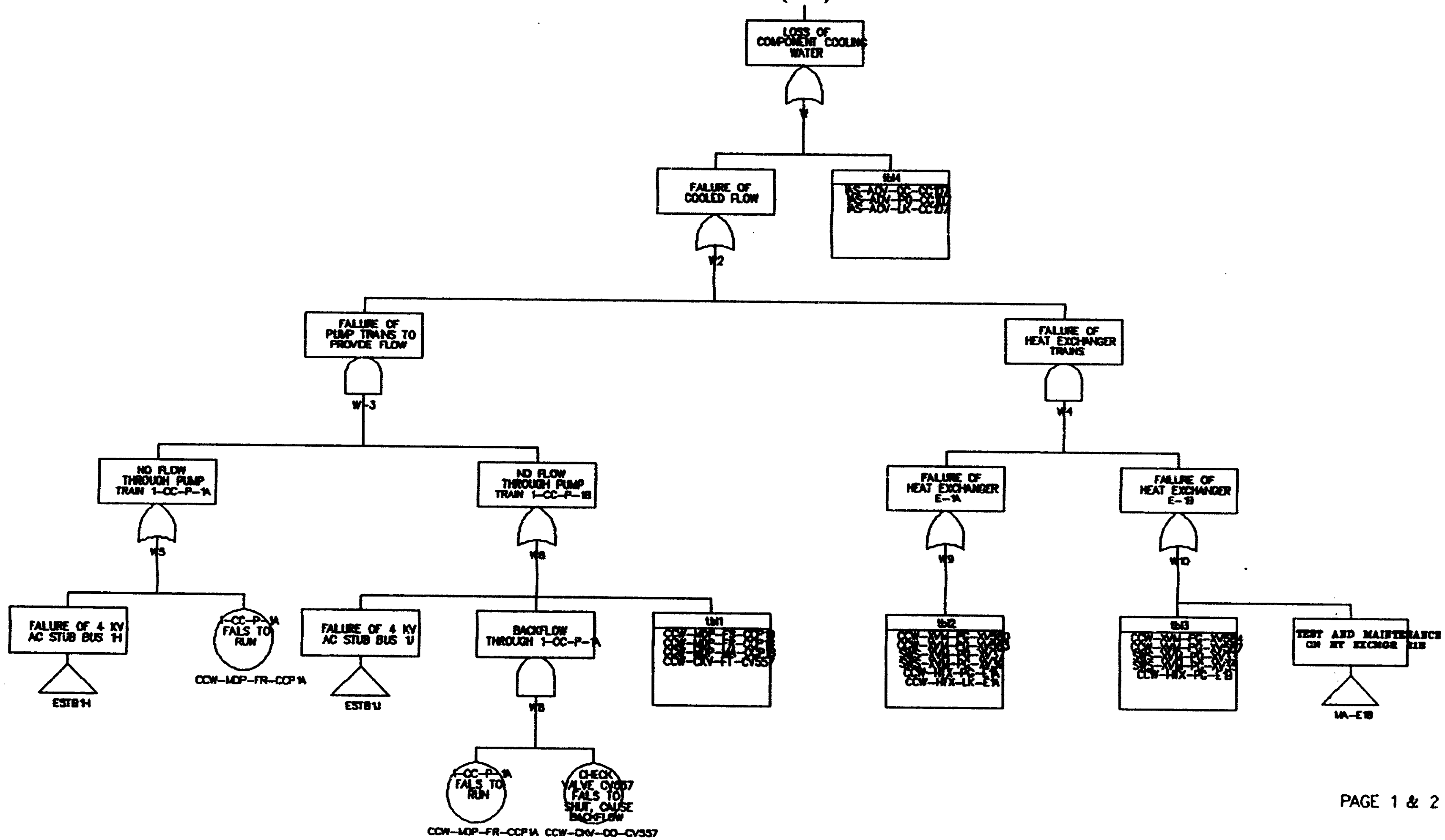
LOSS OF CONTAINMENT IA TOP EVENT =CIA



LOSS OF CIA SUCTION

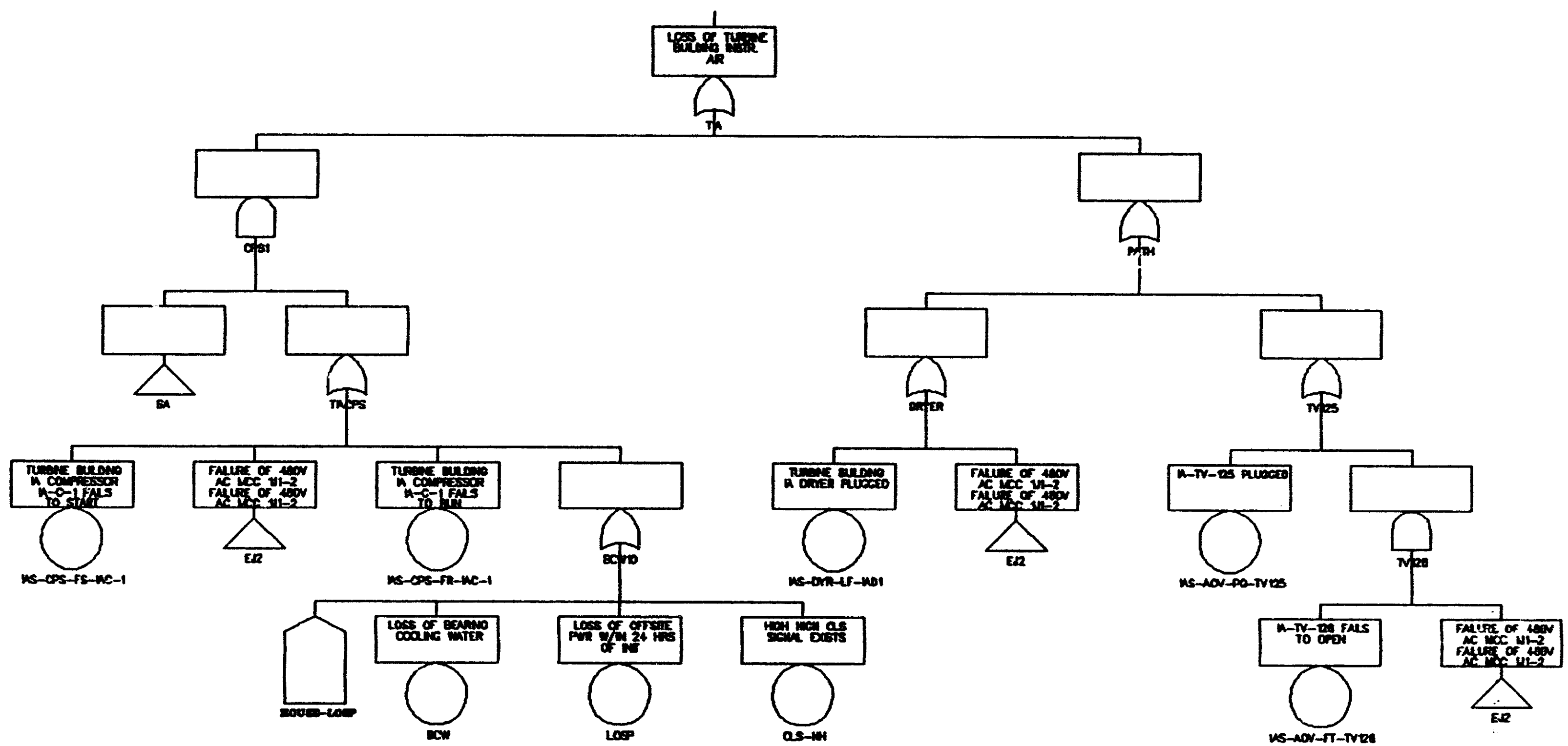


COMPONENT COOLING WATER (CCW1)
(W)

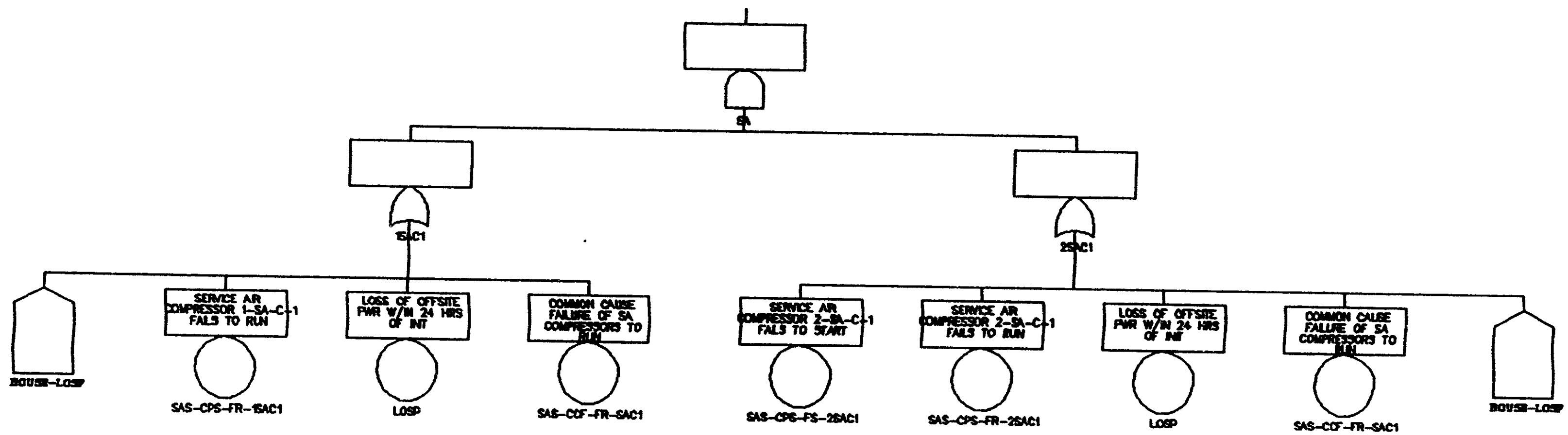


PAGE 1 & 2

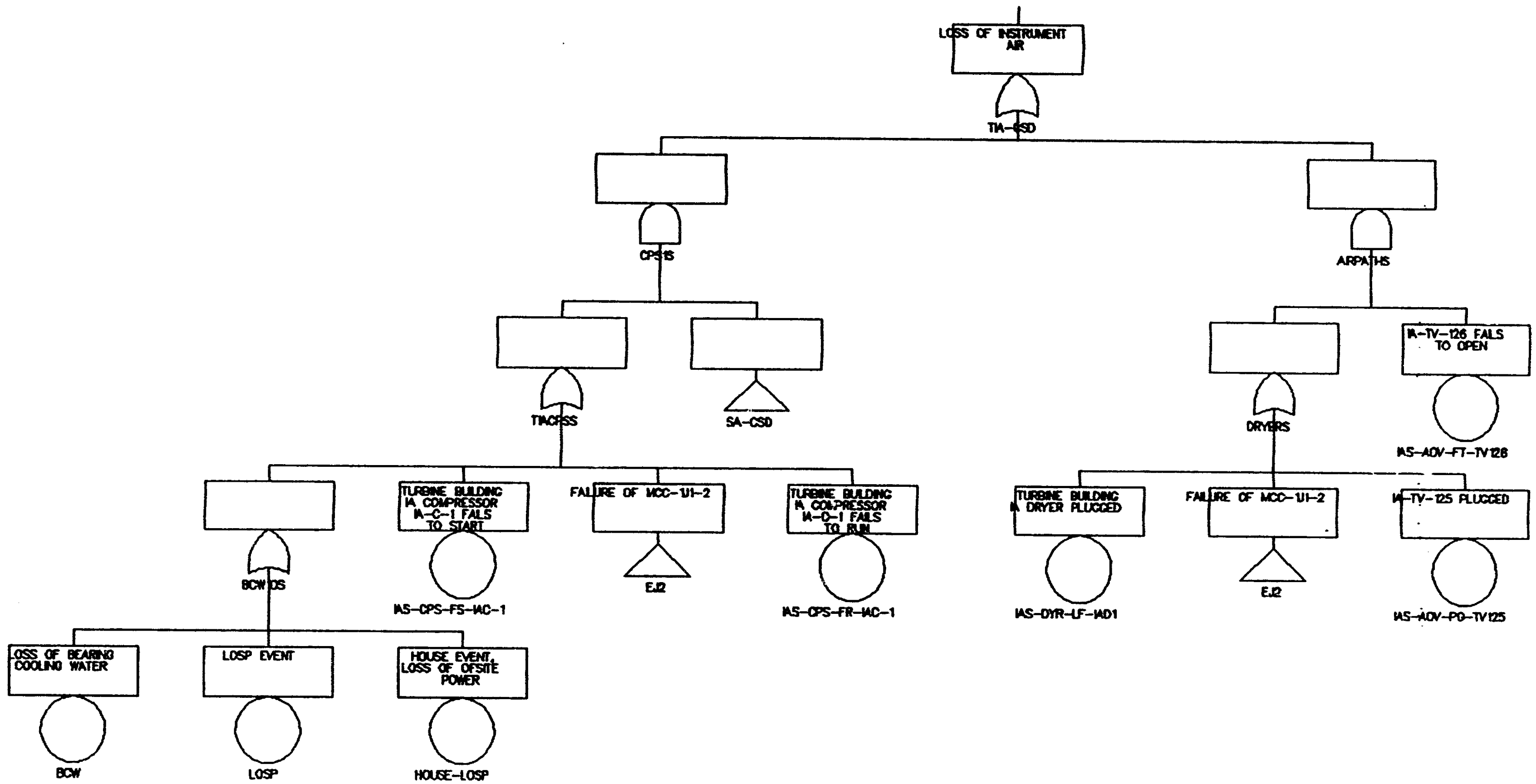
Loss of Turbine Building Instrument Air



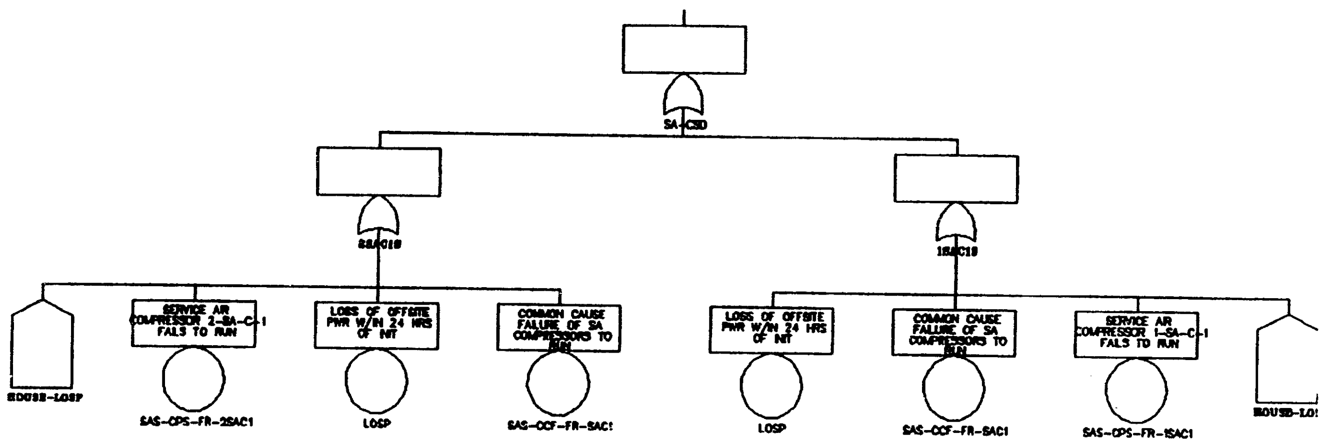
Loss of Both SA Compressors



TURBINE BUILDING INSTRUMENT AIR-CSD



Loss of Both SA Compressors - CSD



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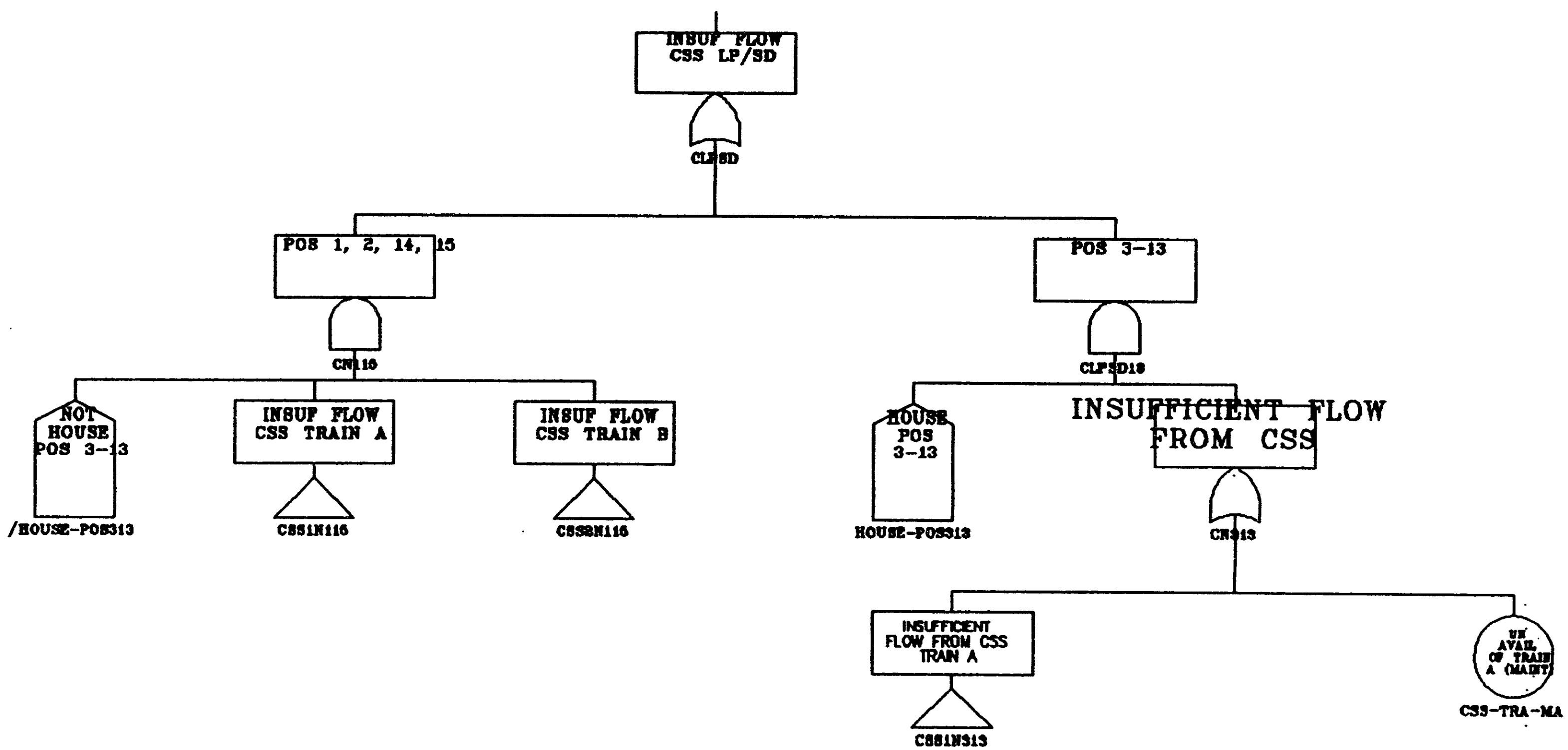
Appendix C.6 Containment Spray System

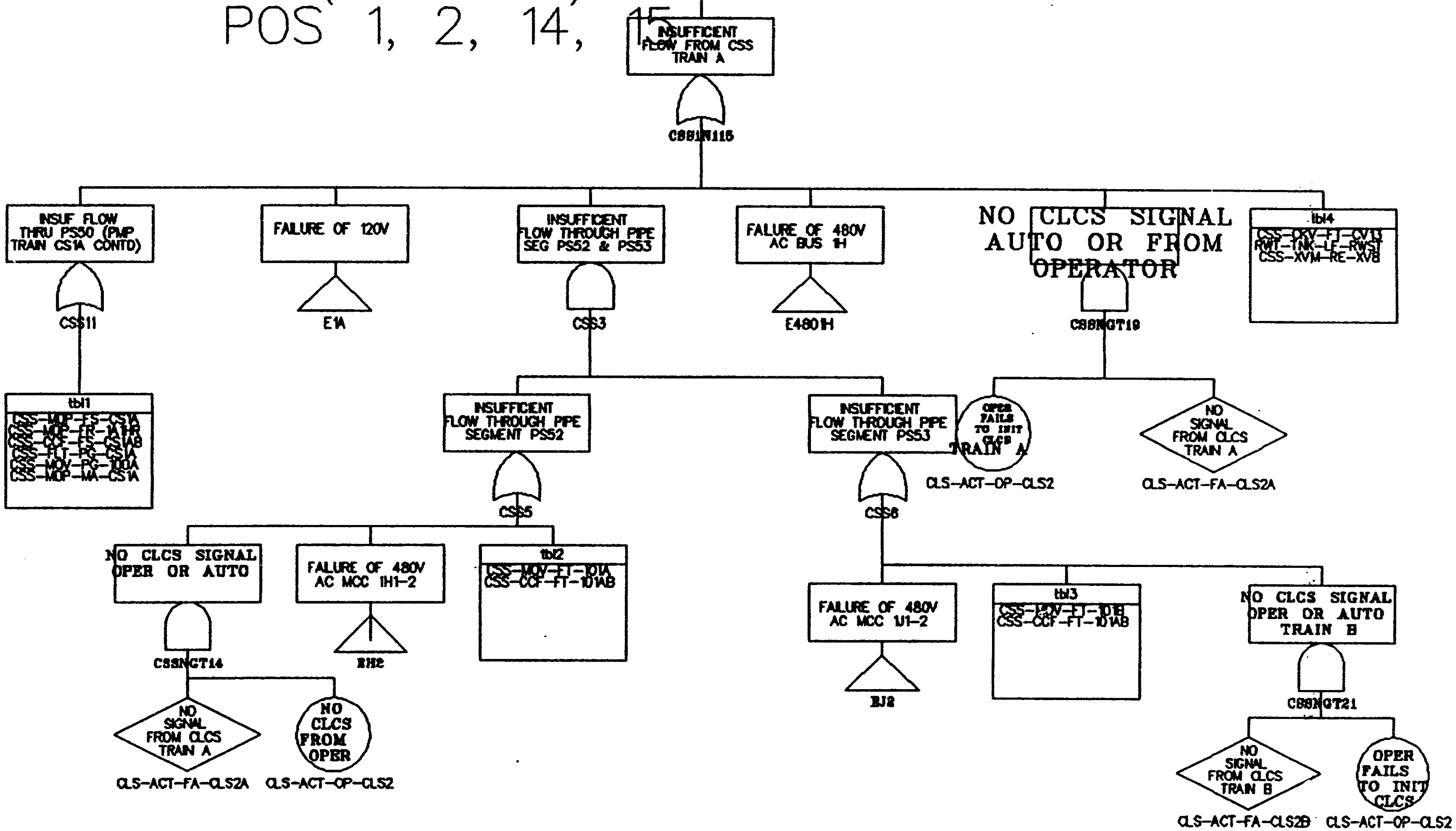
CONTAINMENT SPRAY SYSTEM (CSS)

(6) LOW POWER & S/D



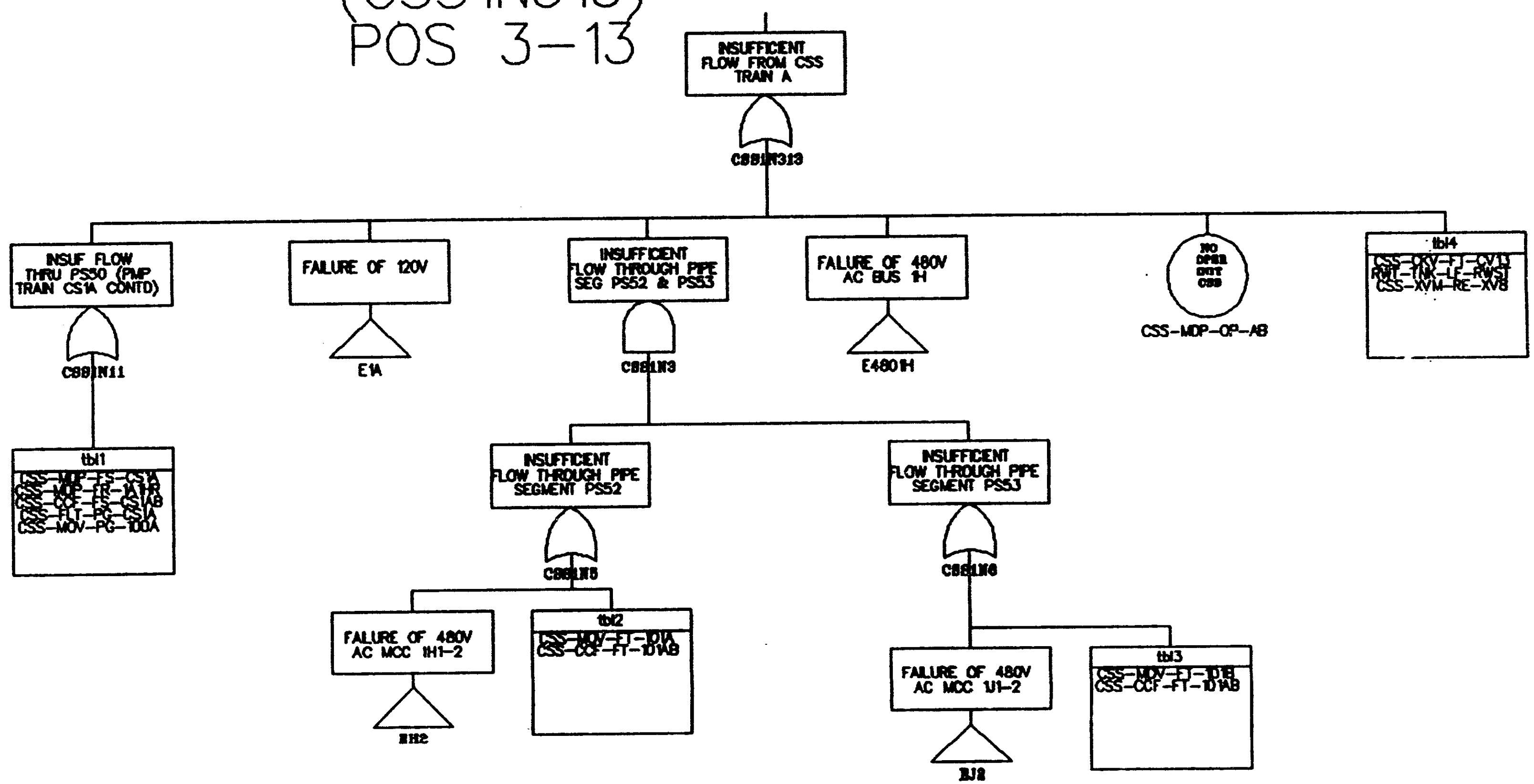
CONTAINMENT SPRAY SYSTEM (CSS)

(CSS1N115)
POS 1, 2, 14, 15

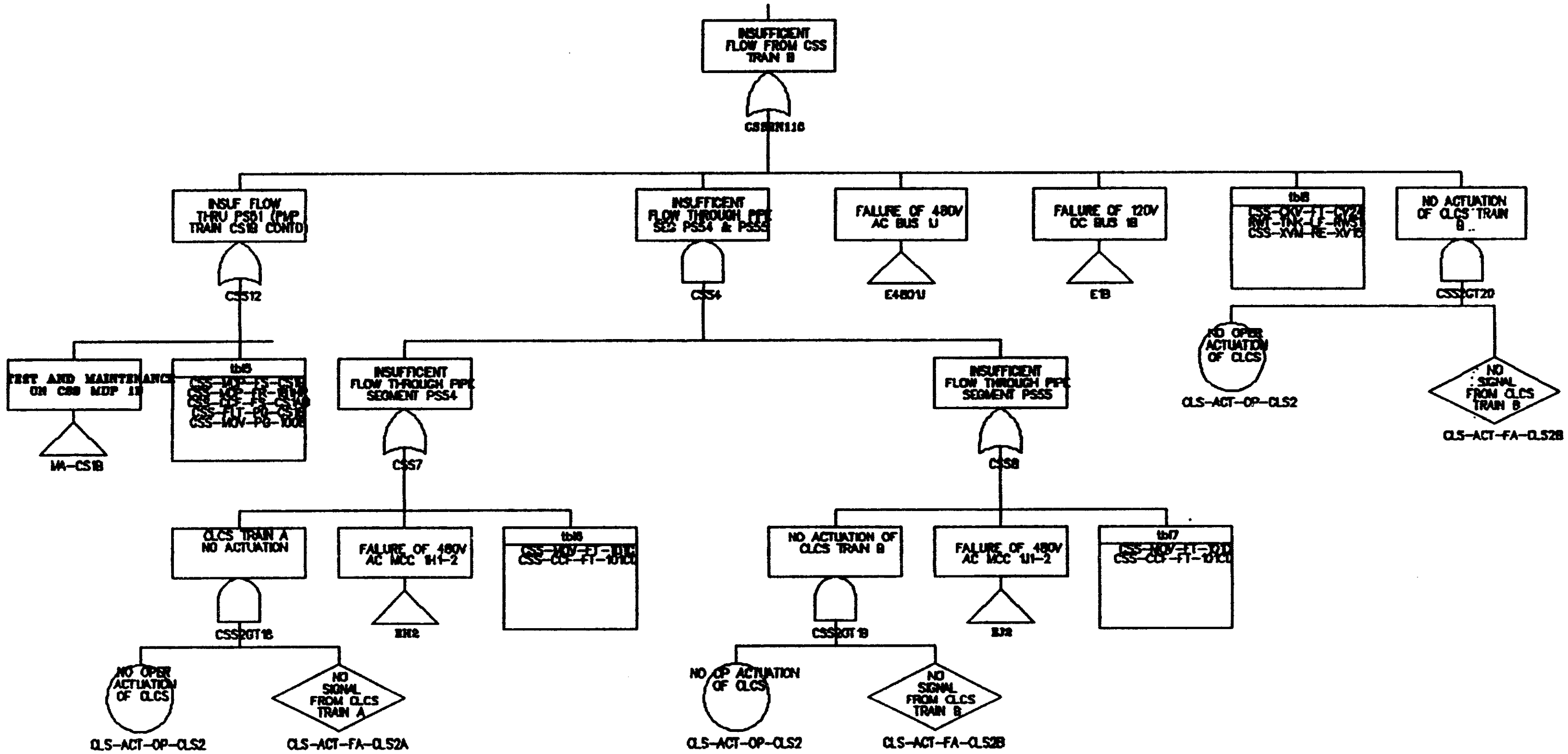


CONTAINMENT SPRAY SYSTEM (CSS)

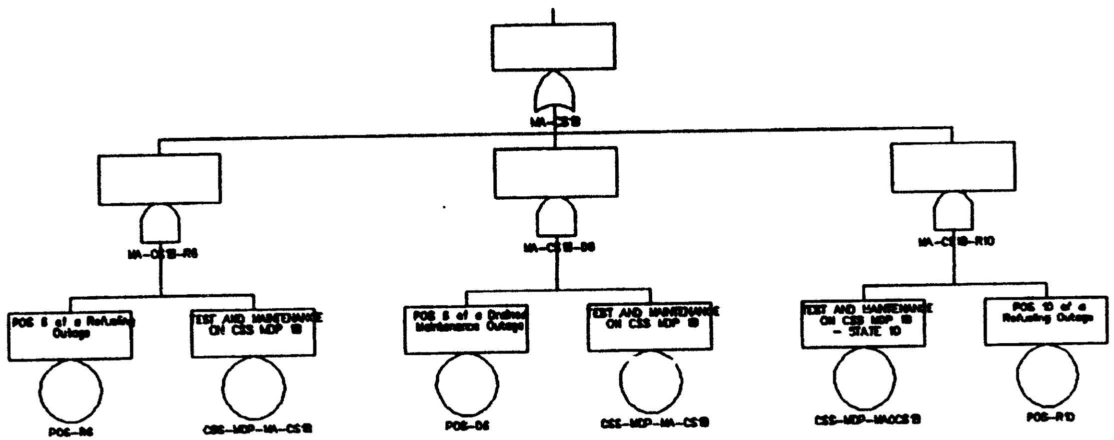
(CSS1N313)
POS 3-13



CONTAINMENT SPRAY SYSTEM (CSS)
(CSS2N115)

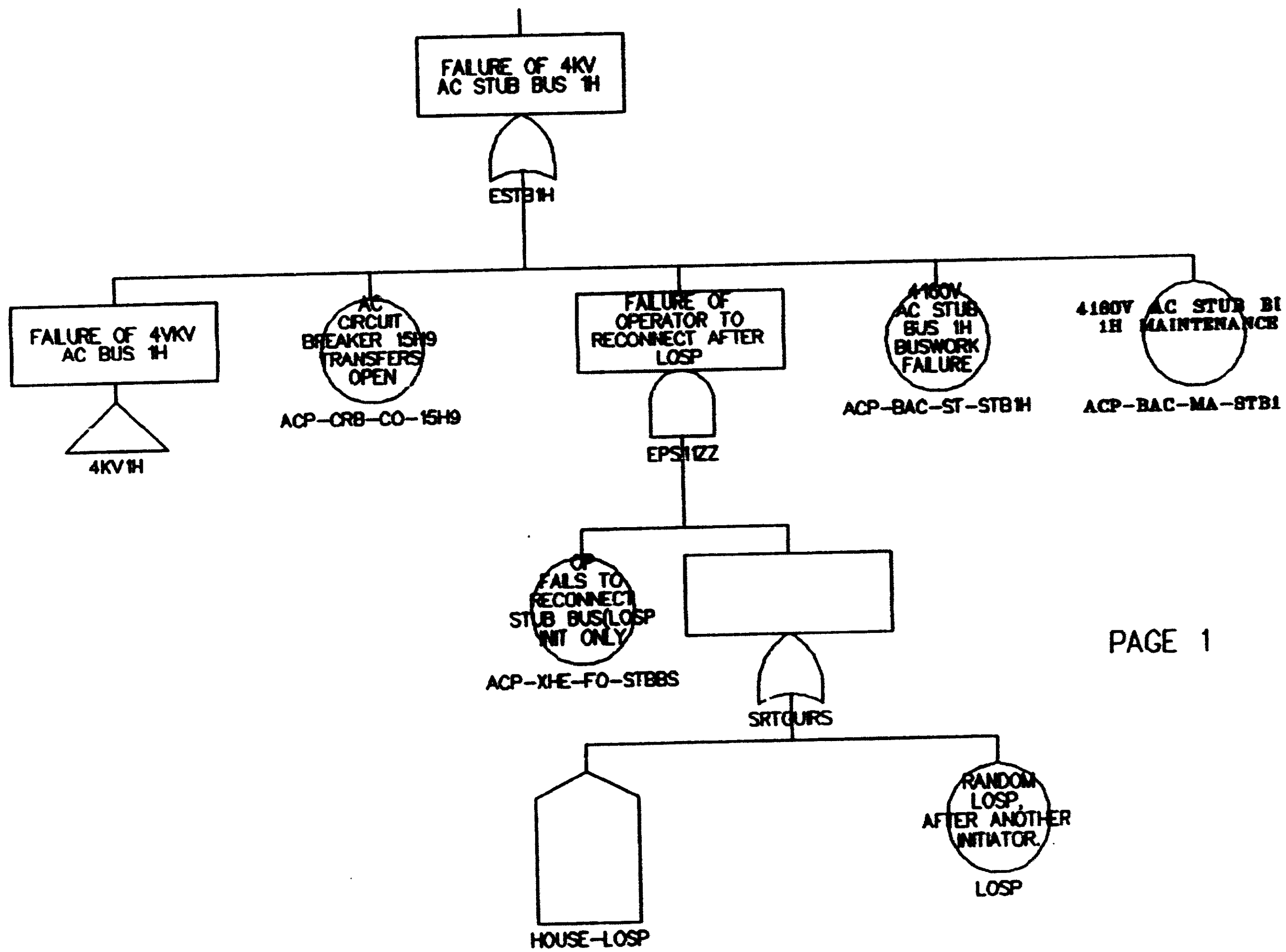


TEST AND MAINTENANCE ON CSS MDP 1B



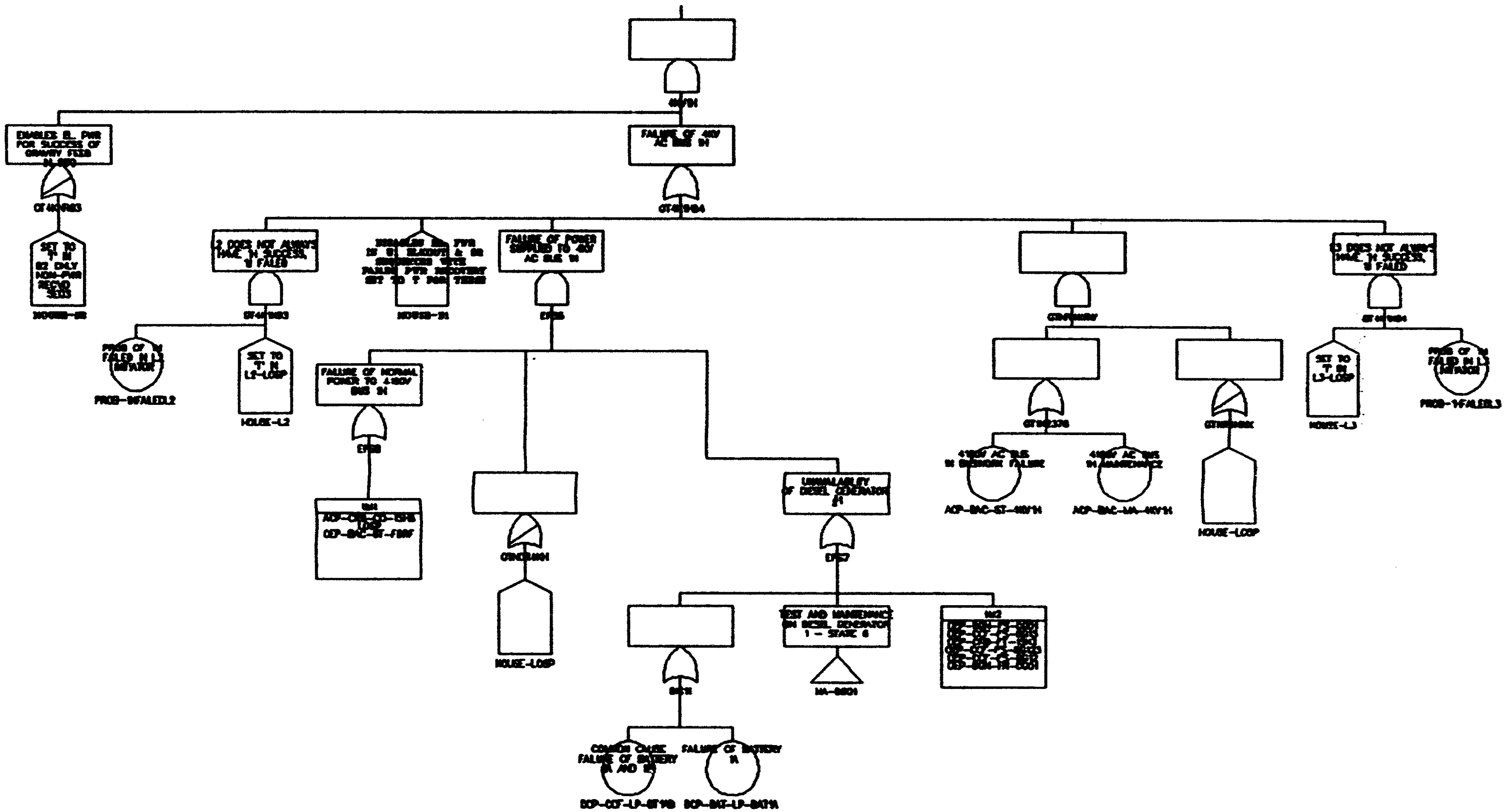
Appendix C.7 Emergency Power System

ELECTRICAL POWER – STUB BUS 1H (ESTB1H)
(ESTB1H)

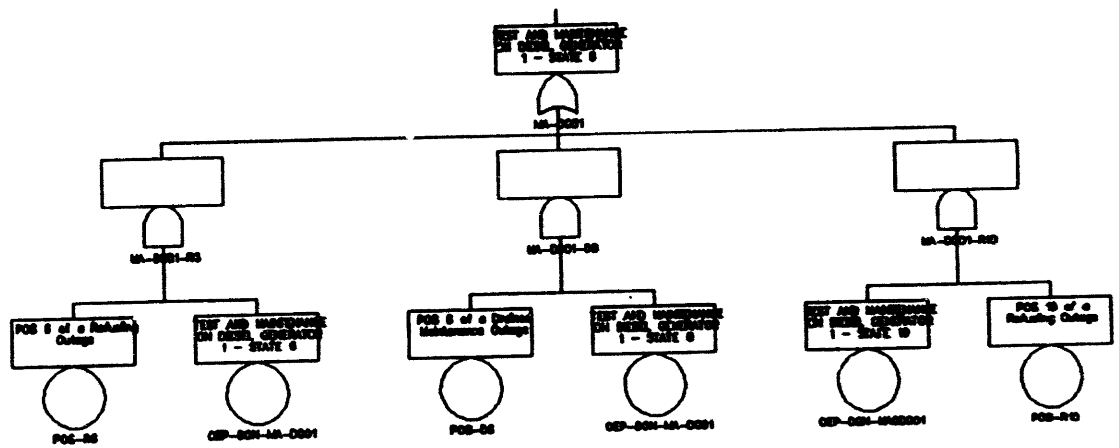


PAGE 1

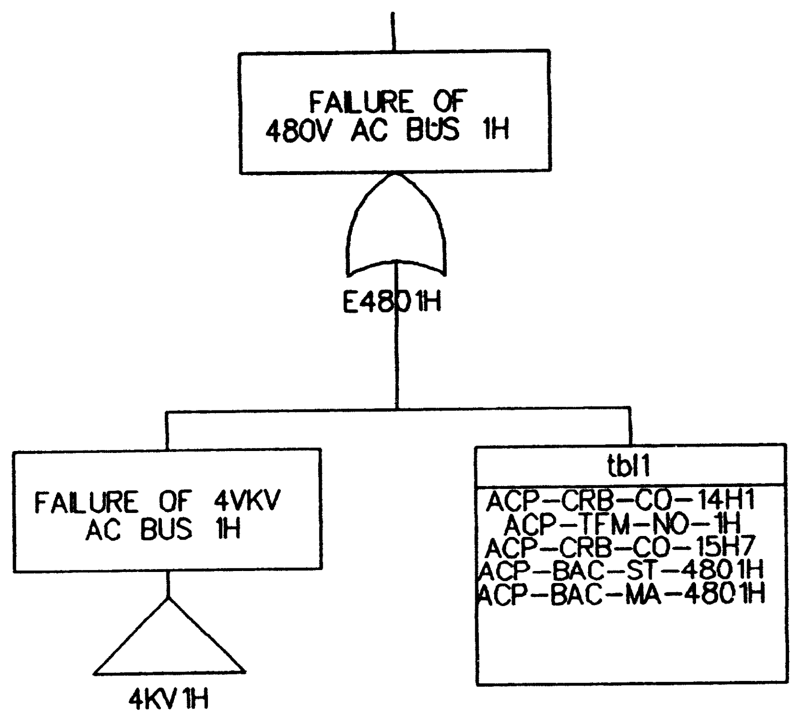
ELECTRICAL POWER – MCC 1H1–1 (4KV1H) (4KV1H)



TEST AND MAINTENANCE ON DIESEL GENERATOR 1

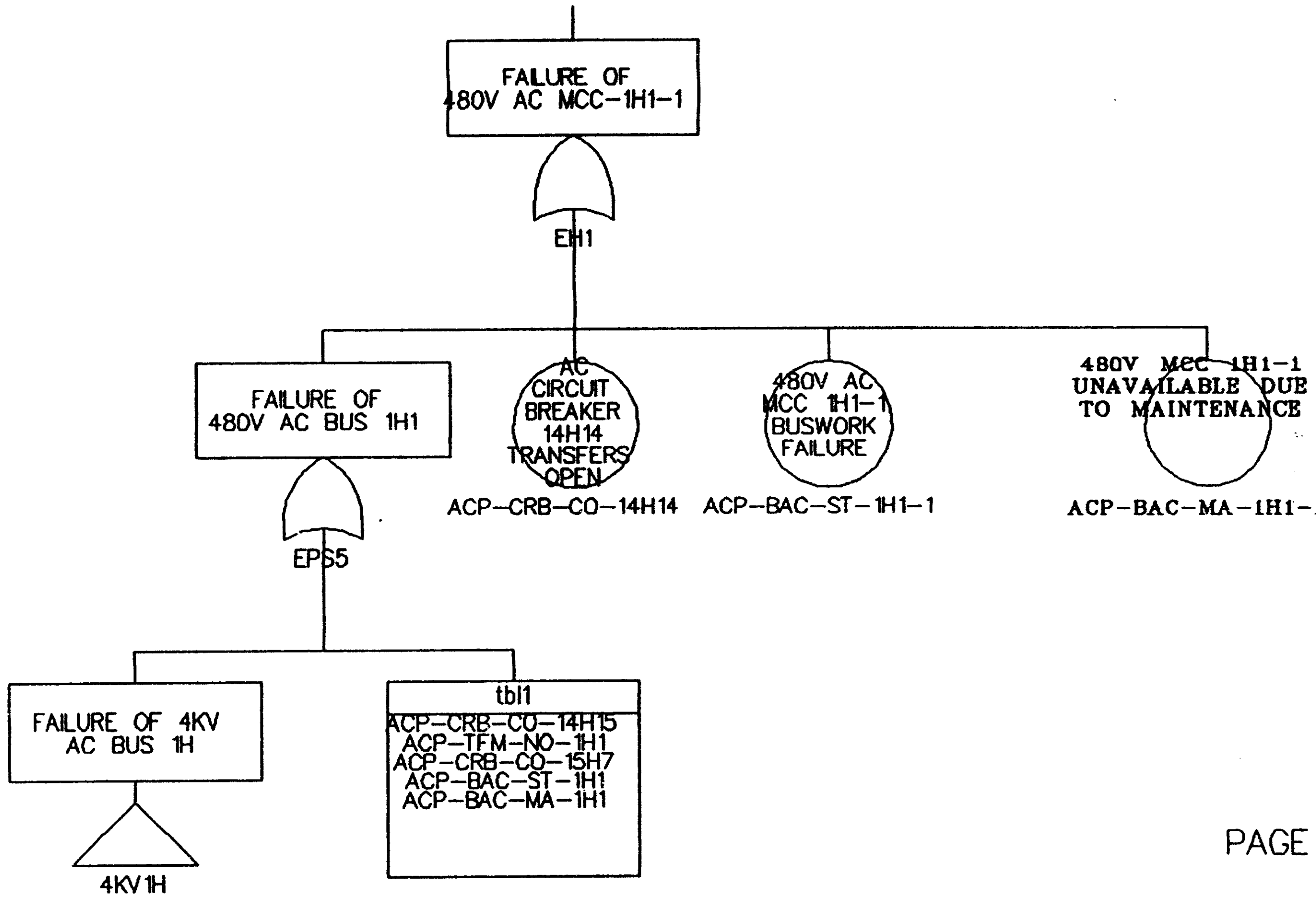


ELECTRICAL POWER – 4801H BUS (E4801H)
(E4801H)



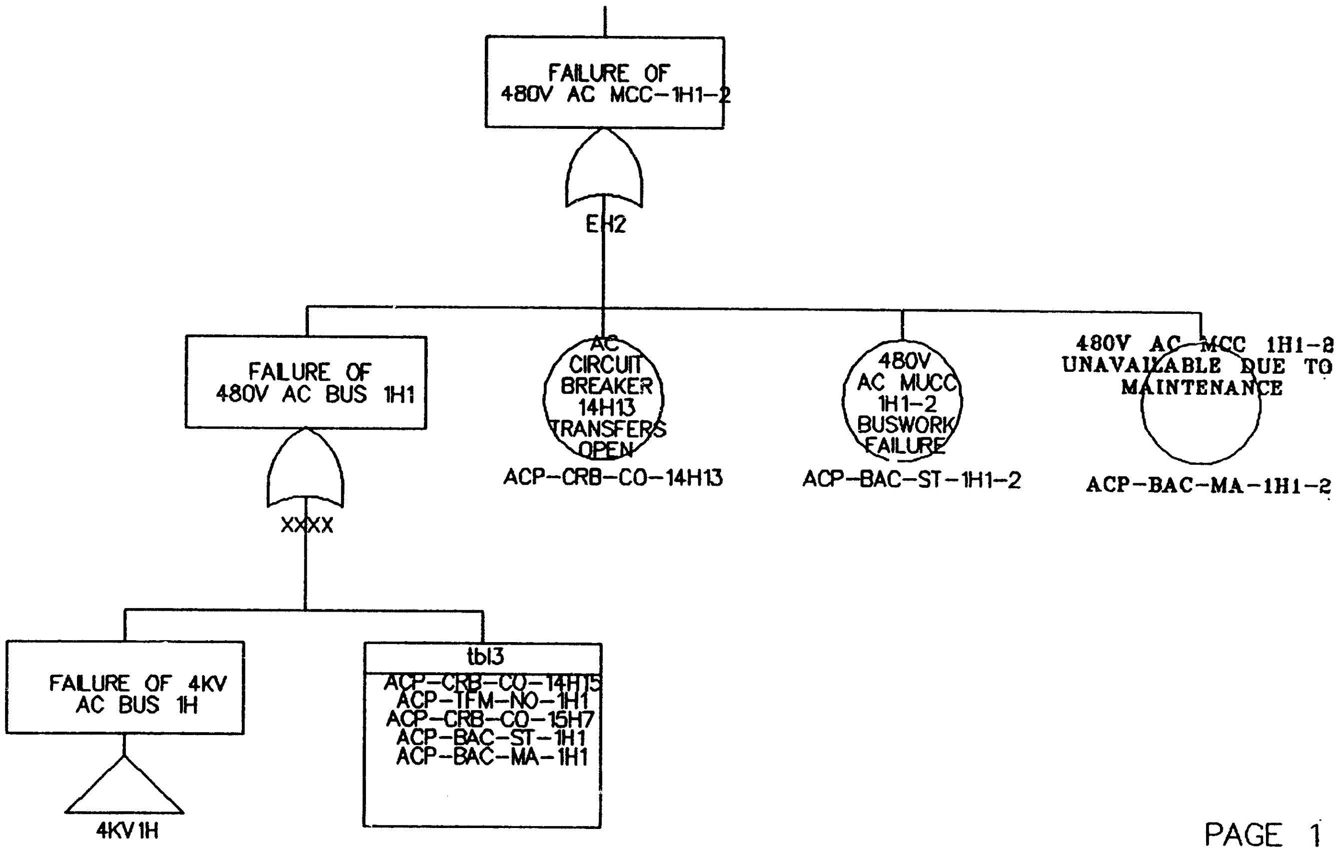
PAGE

ELECTRICAL POWER - MCC 1H1-1 (EH1)
(EH1)



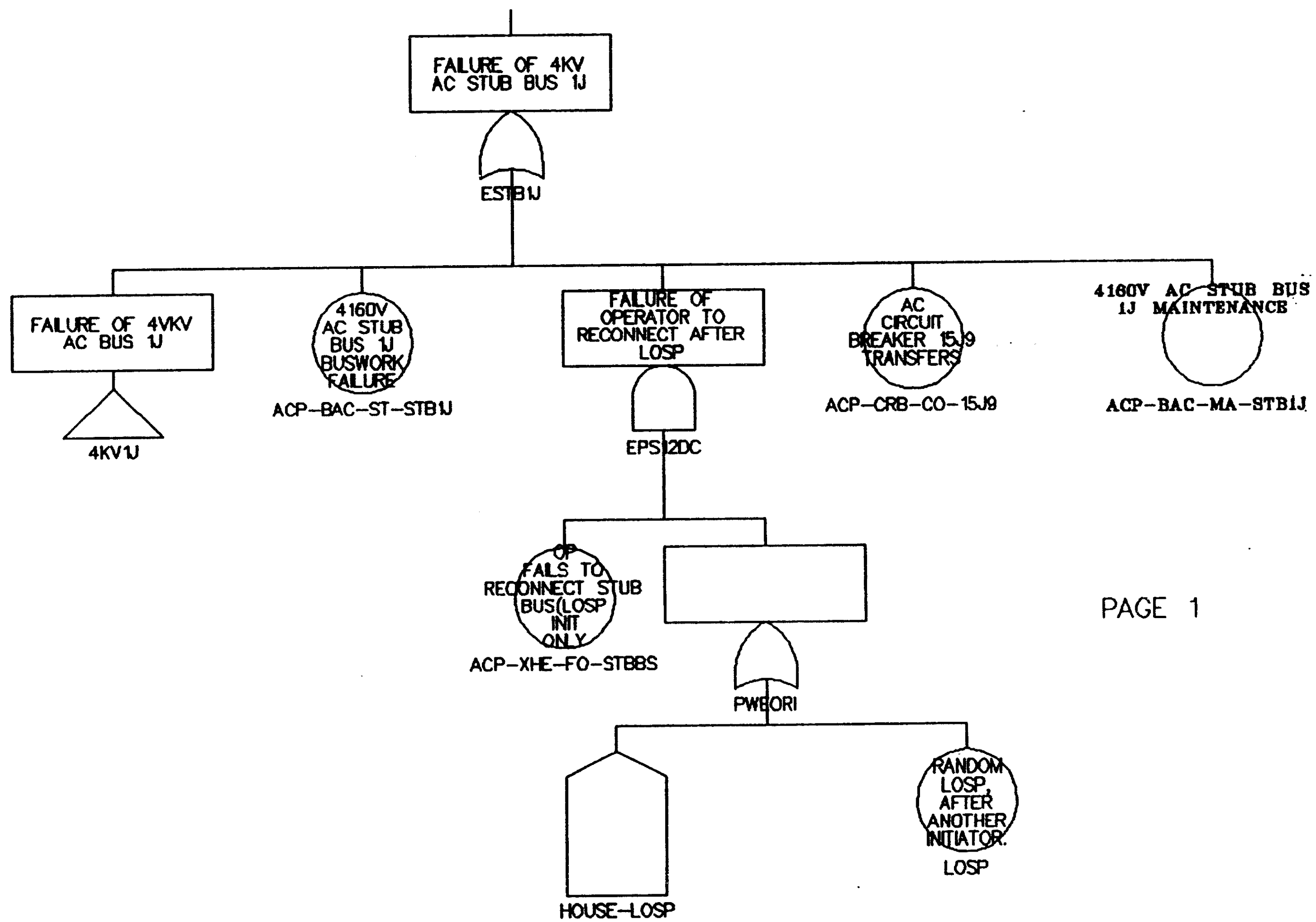
PAGE 1

ELECTRICAL POWER – MCC 1H1–2 (EH2)
(EH2)

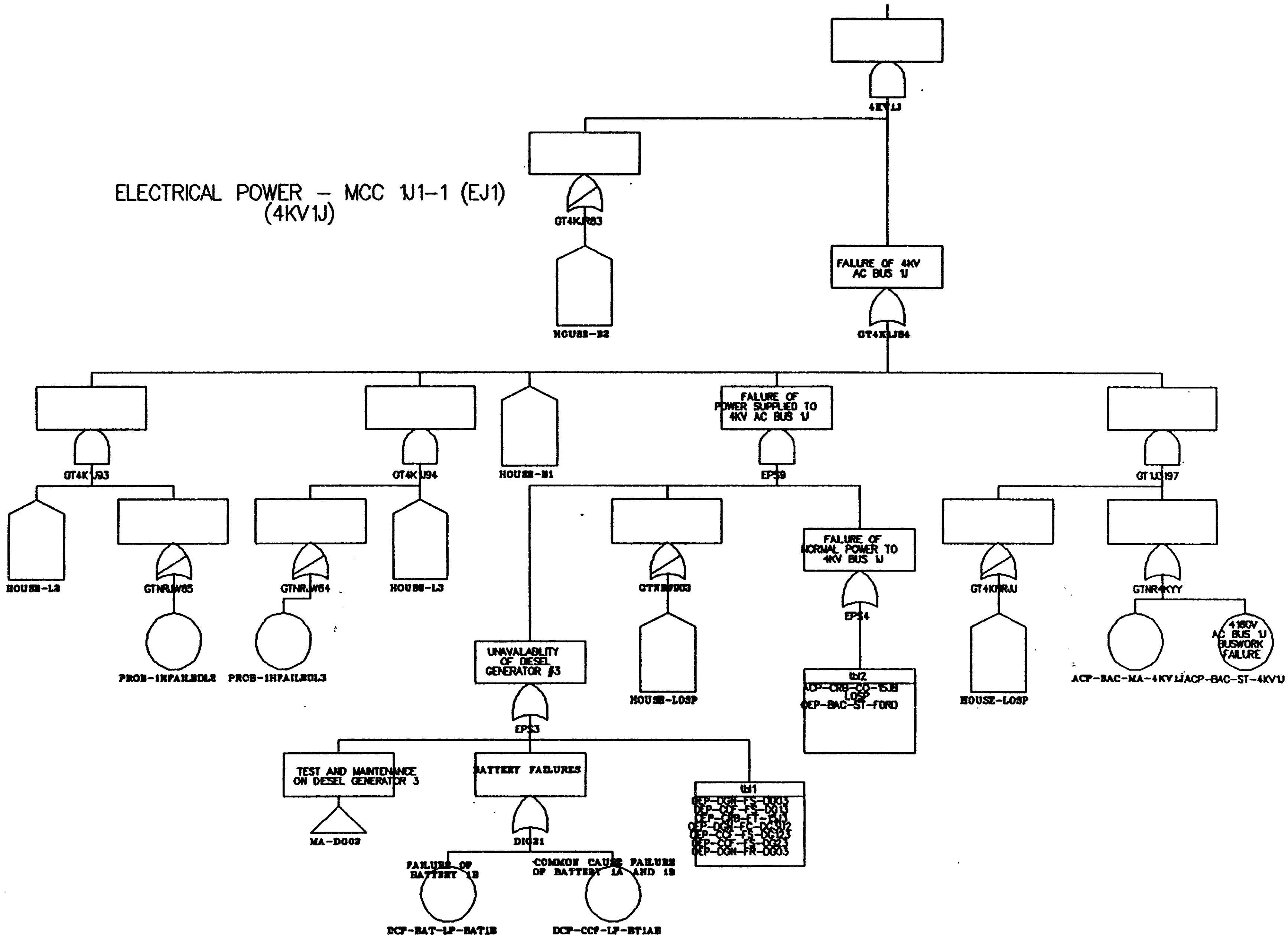


PAGE 1

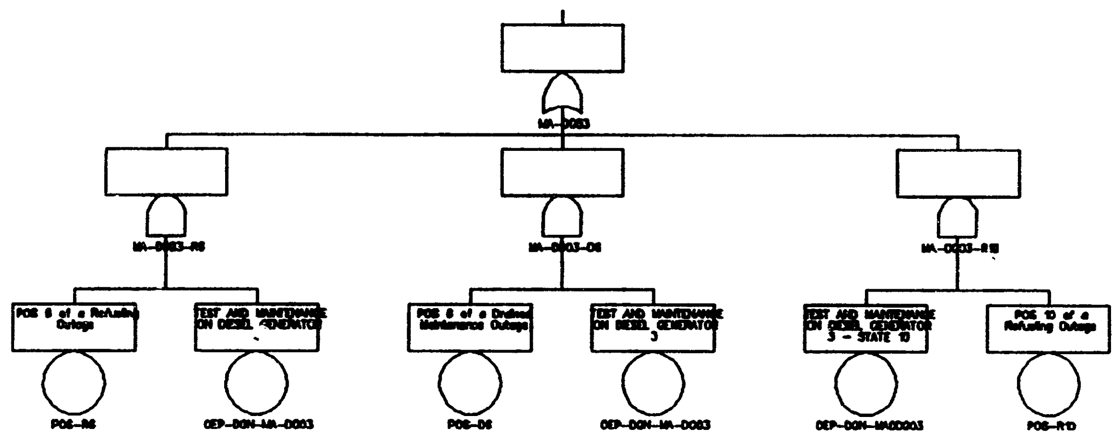
ELECTRICAL POWER – STUB BUS 1J (ESTB1J)
(ESTB1J)



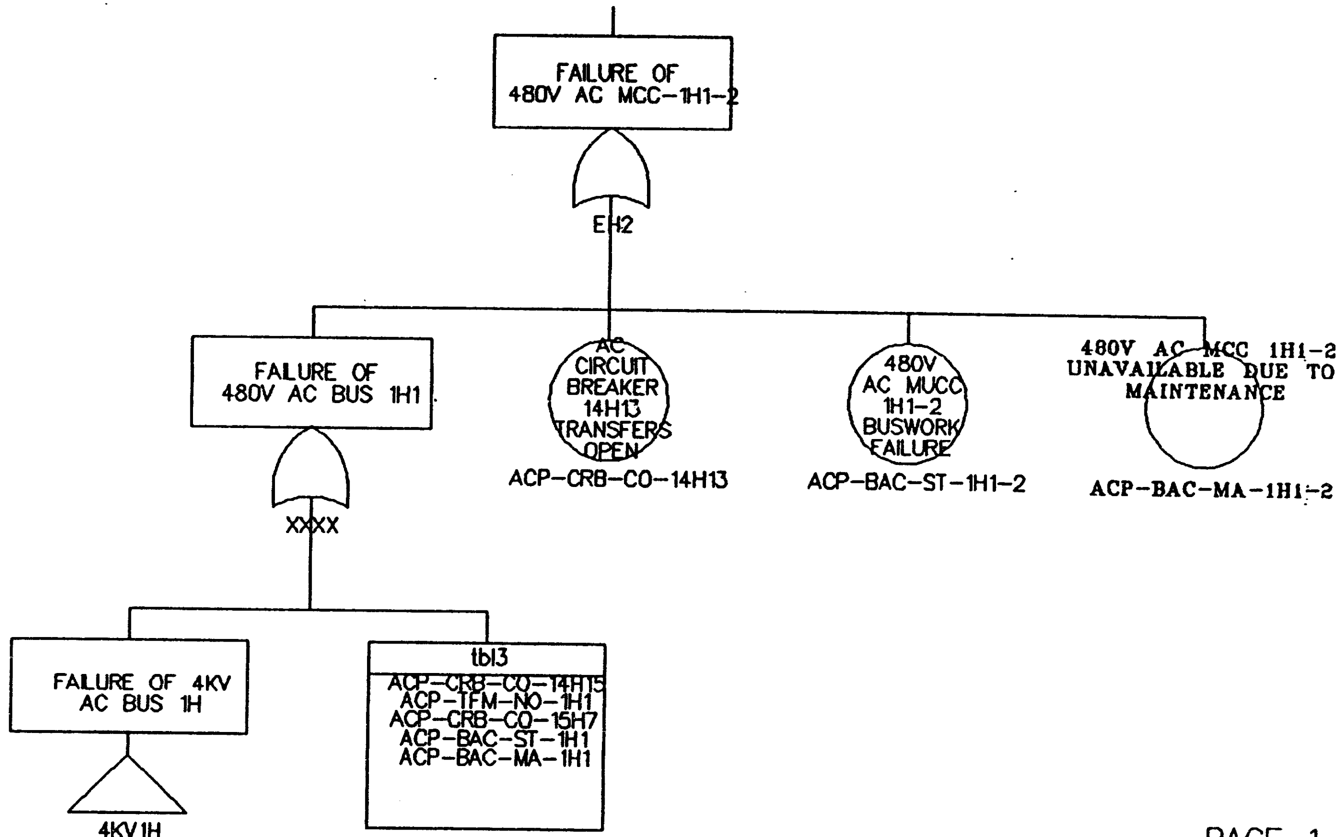
ELECTRICAL POWER – MCC 1J1-1 (EJ1)
(4KV1J)



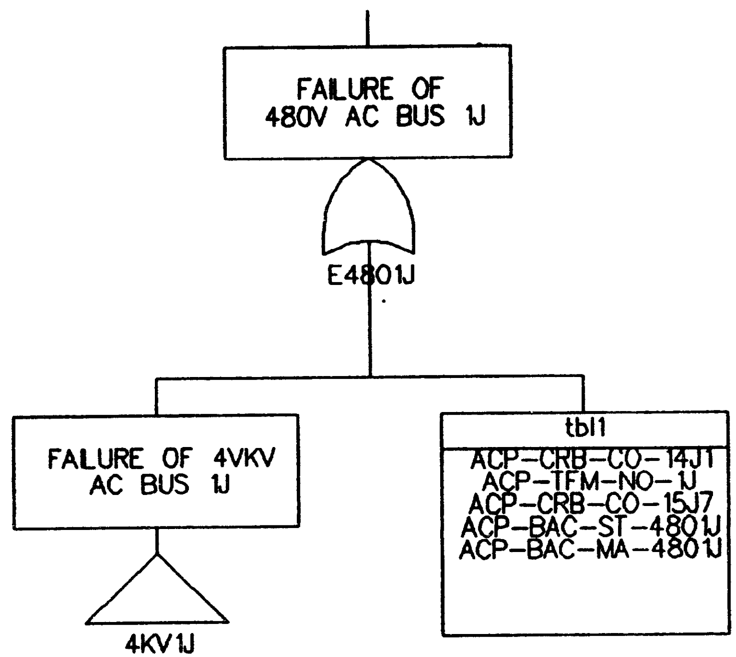
TEST AND MAINTENANCE ON DIESEL GENERATOR 3



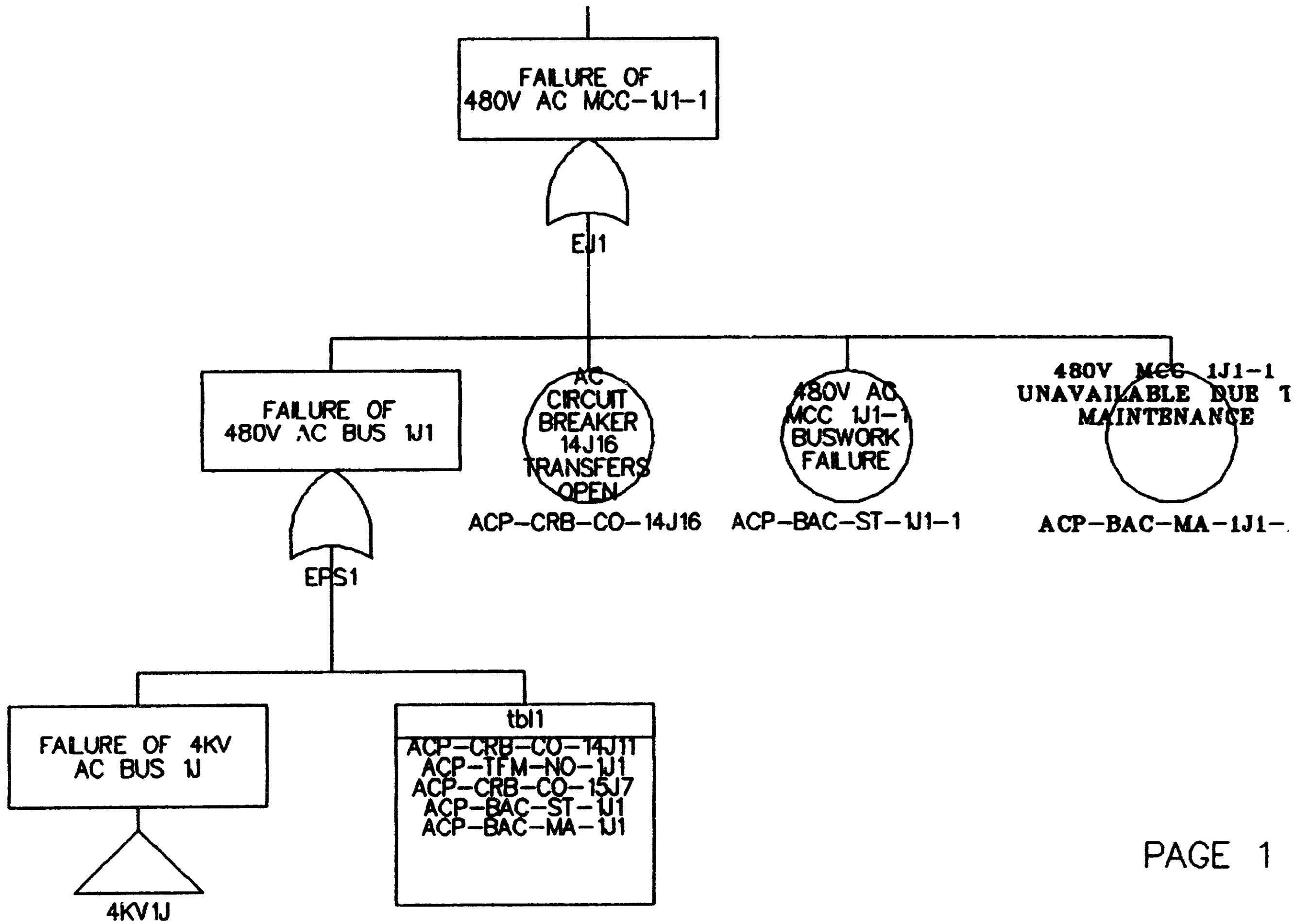
ELECTRICAL POWER - MCC 1H1-2 (EH2) (EH2)



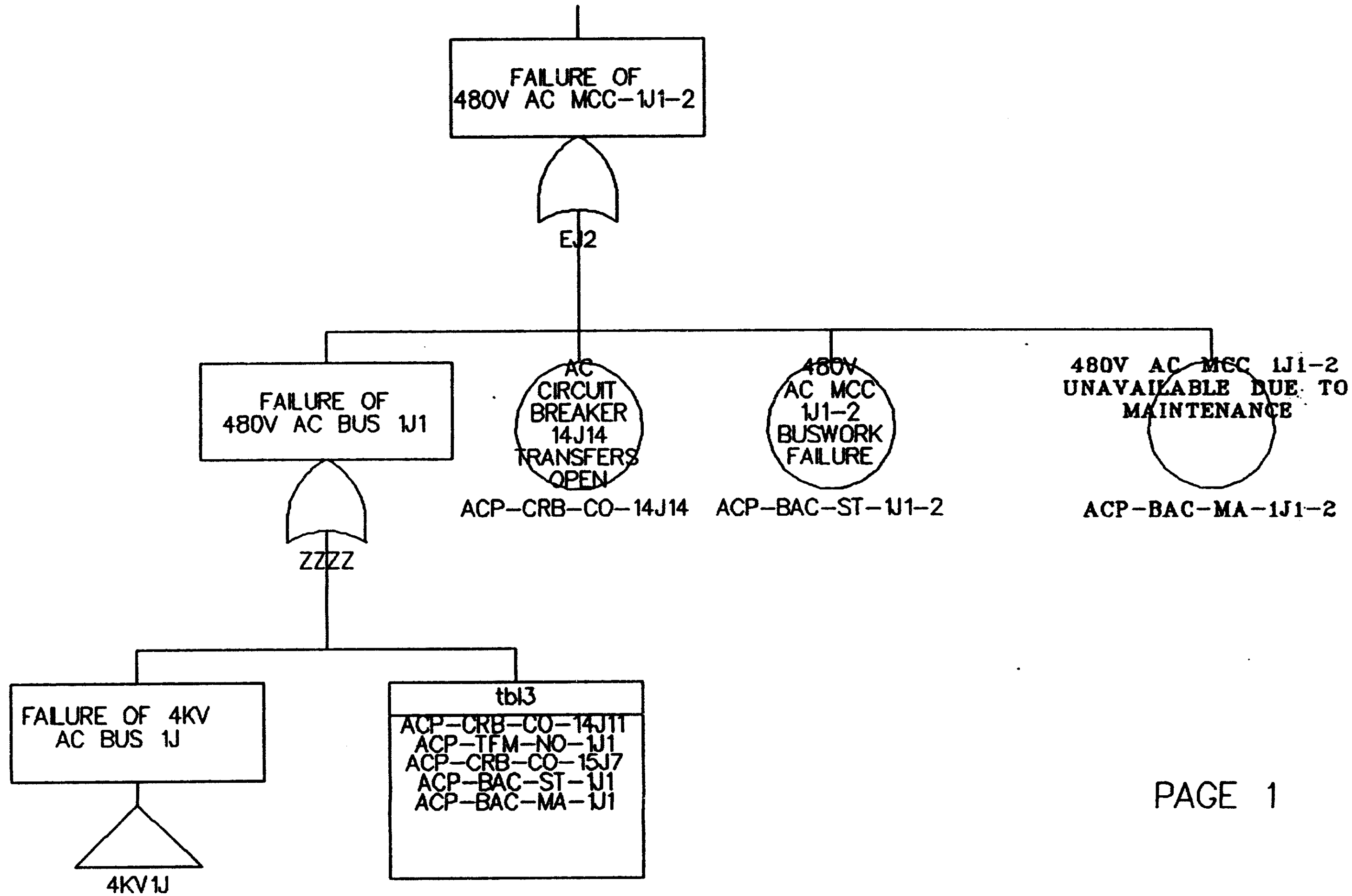
ELECTRICAL POWER – 4801J BUS (E4801J)
(E4801J)



ELECTRICAL POWER - MCC 1J1-1 (EJ1)
(EJ1)

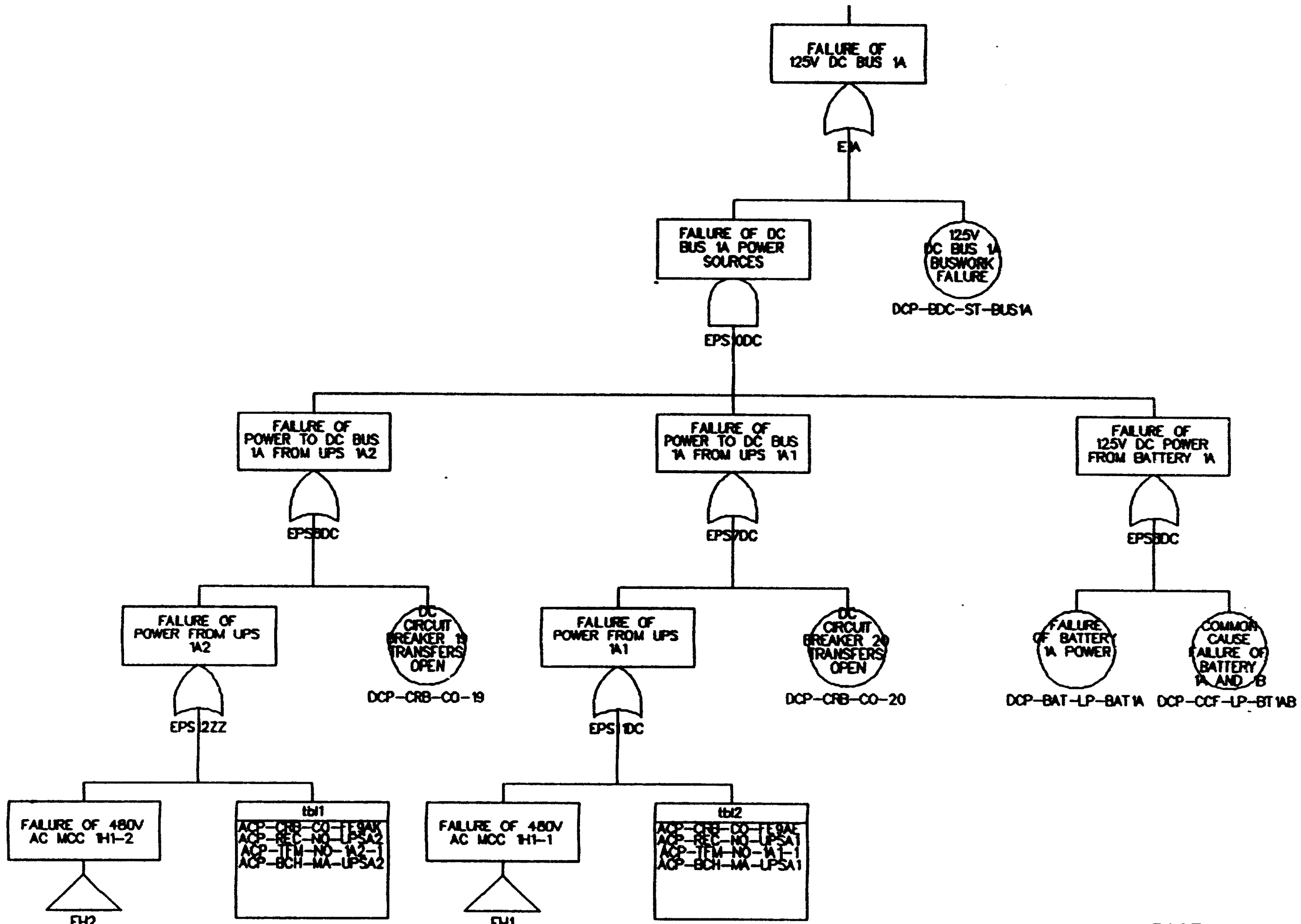


ELECTRICAL POWER – MCC 1J1–2 (EJ2)
(EJ2)

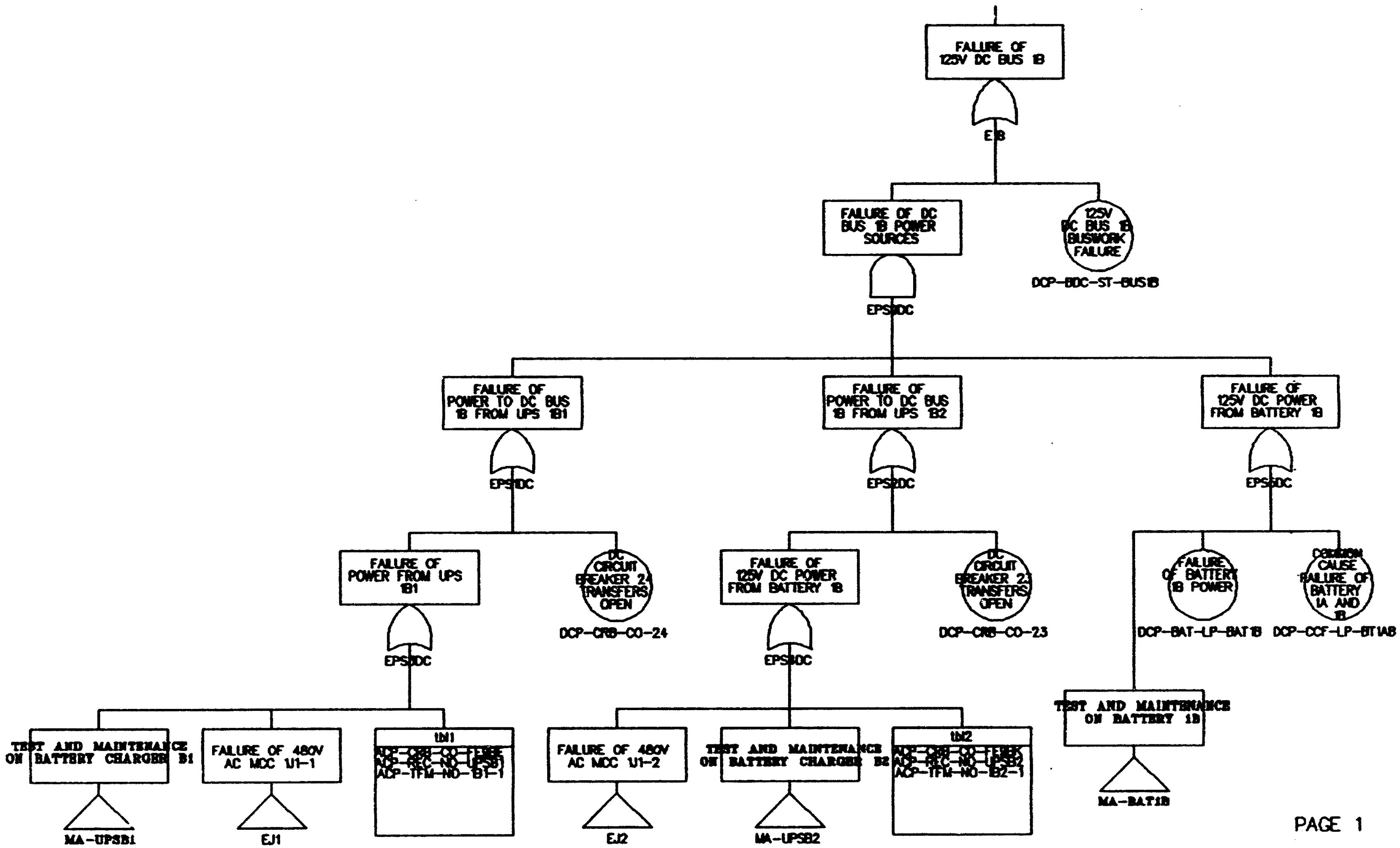


PAGE 1

ELECTRICAL POWER - DC BUS 1A (E1A)
(E1A)

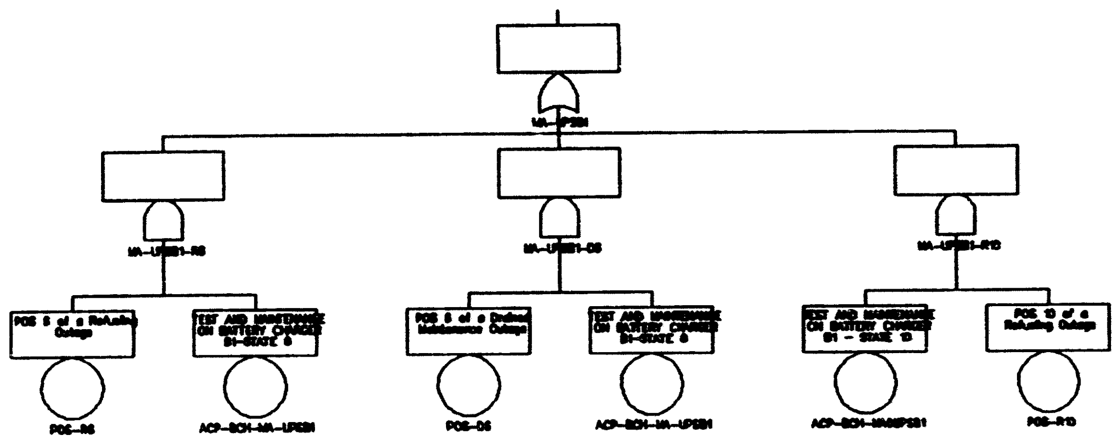


ELECTRICAL POWER - DC BUS 1B (E1B)
(E1B)

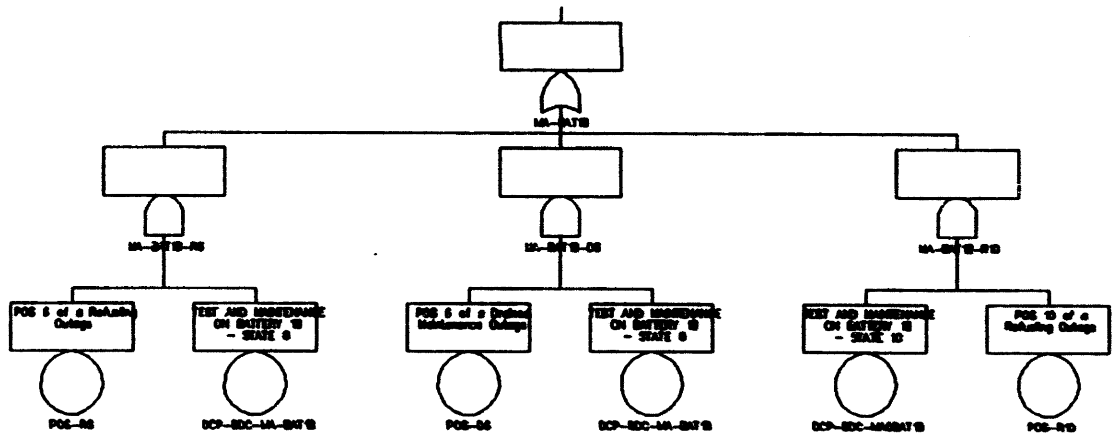


PAGE 1

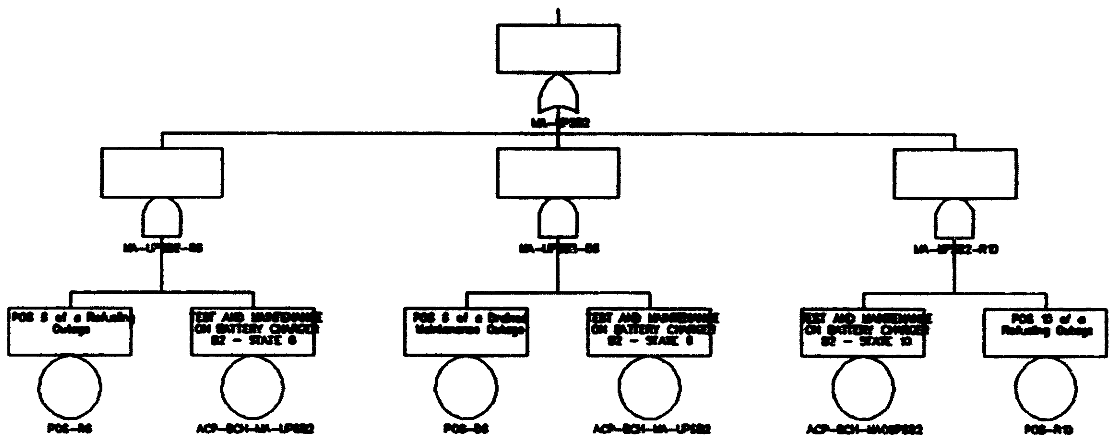
TEST AND MAINTENANCE ON BATTERY CHARGER B1



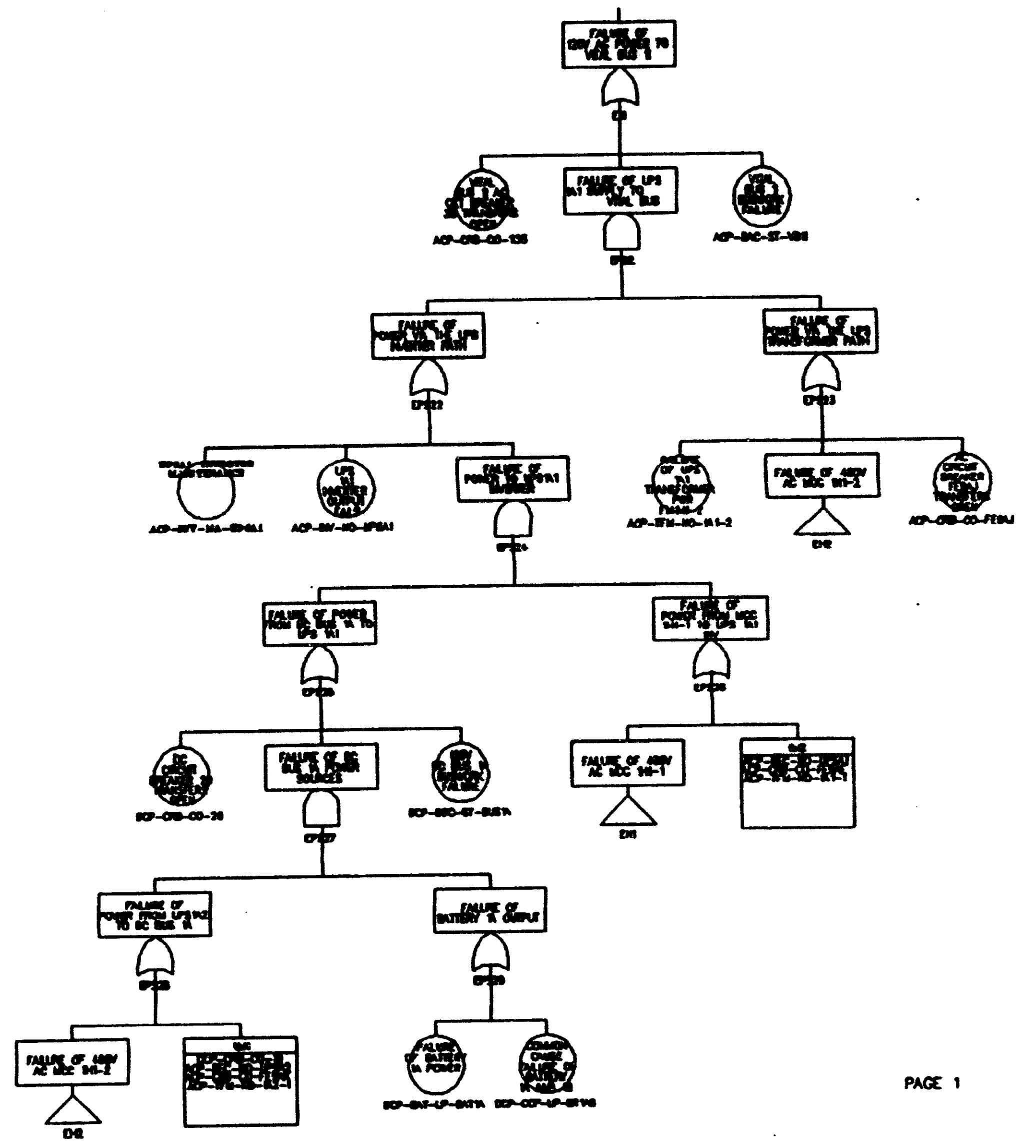
TEST AND MAINTENANCE ON BATTERY 1B



TEST AND MAINTENANCE ON BATTERY CHARGER B2

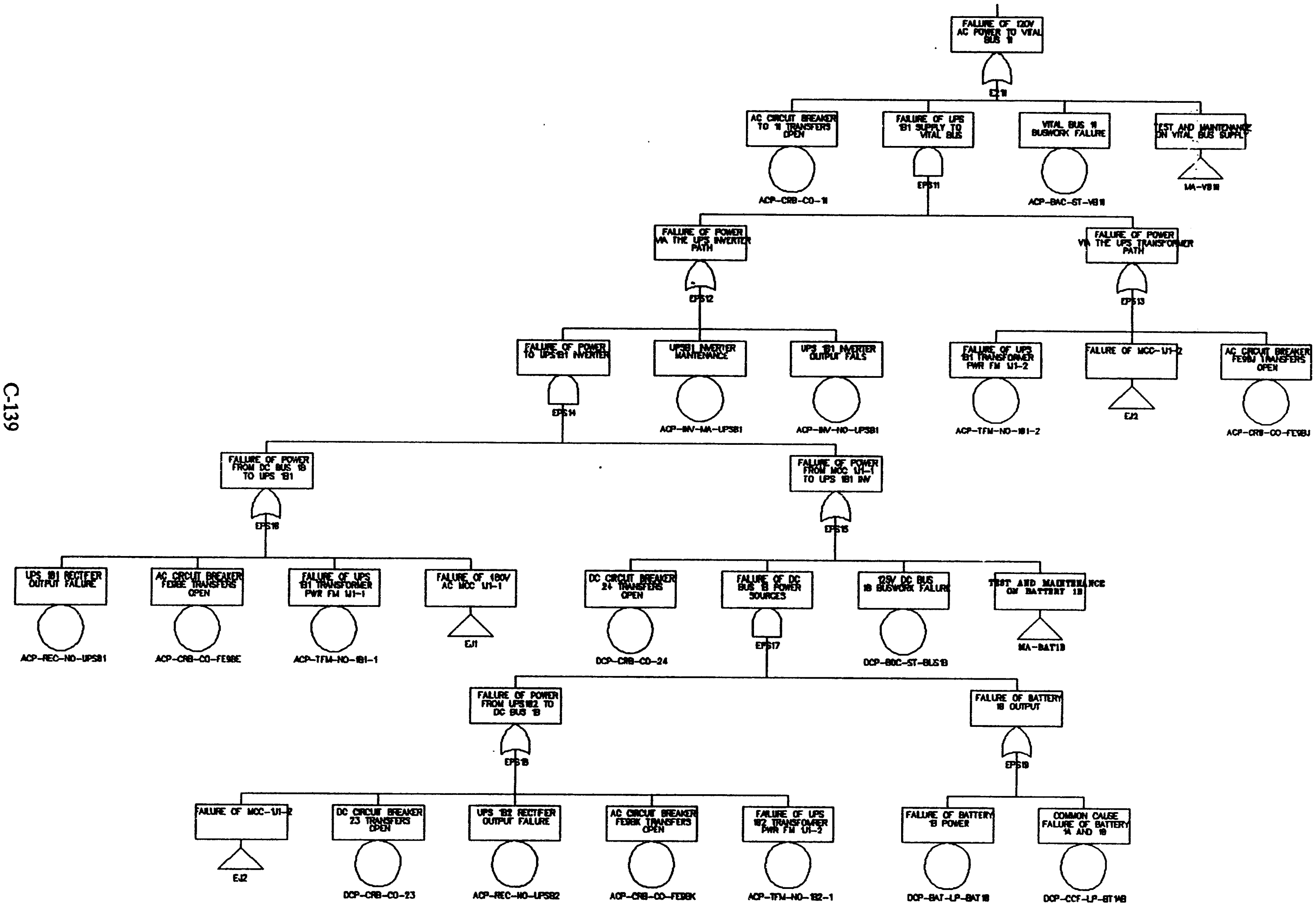


ELECTRICAL POWER - VITAL BUS 1 (E1)
(E1)

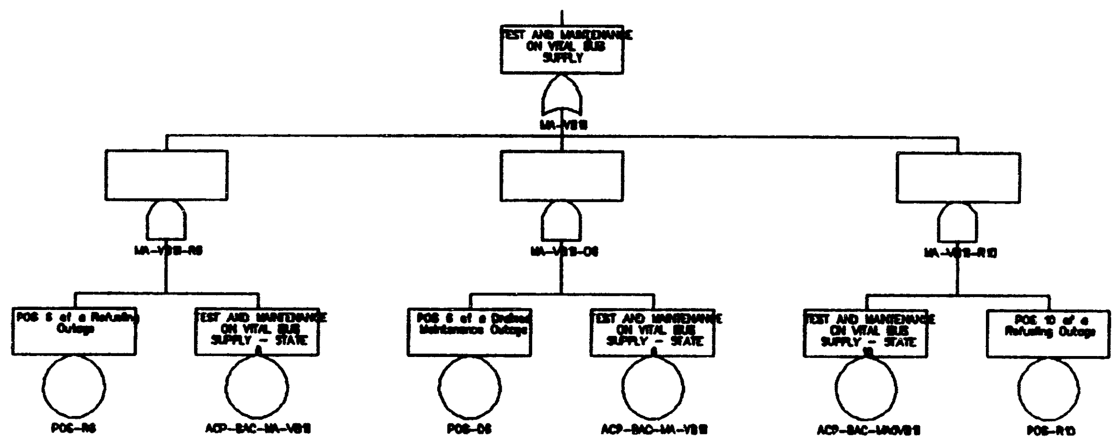


PAGE 1

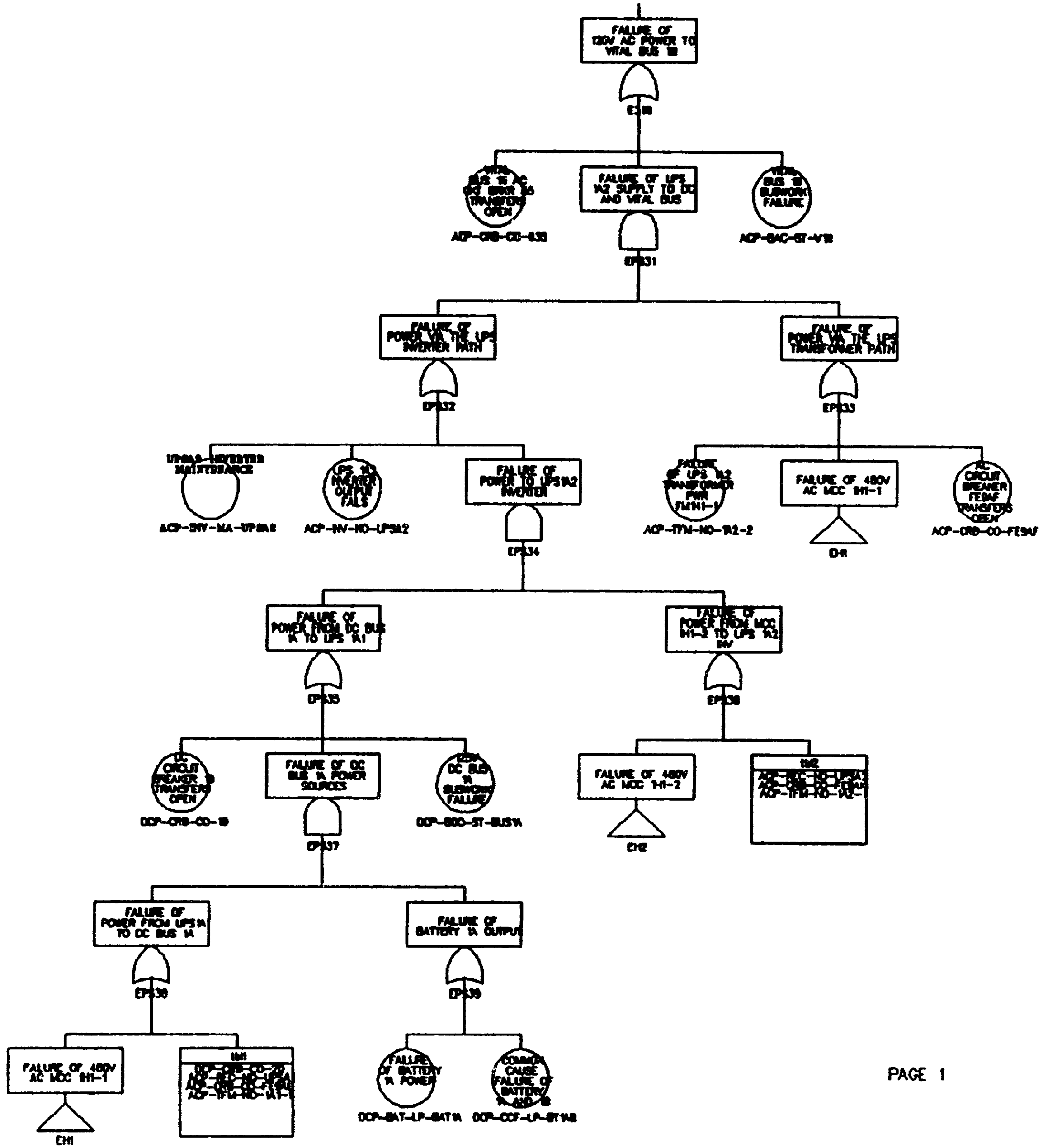
ELECTRICAL POWER – VITAL BUS 1II (E21II)
(E21II)



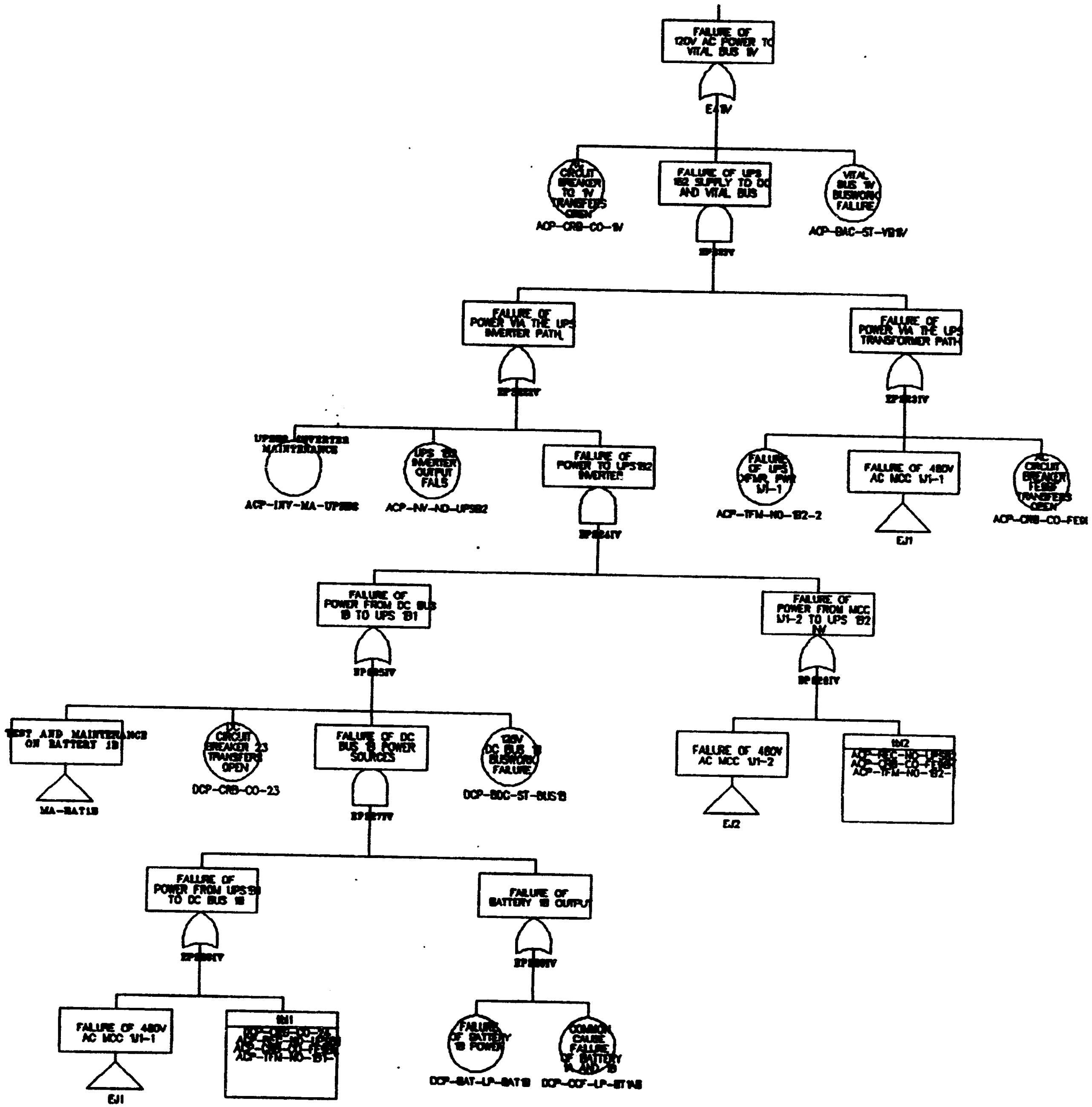
TEST AND MAINTENANCE ON VITAL BUS SUPPLY



ELECTRICAL POWER - VITAL BUS 1III (E31III)
(E31III)

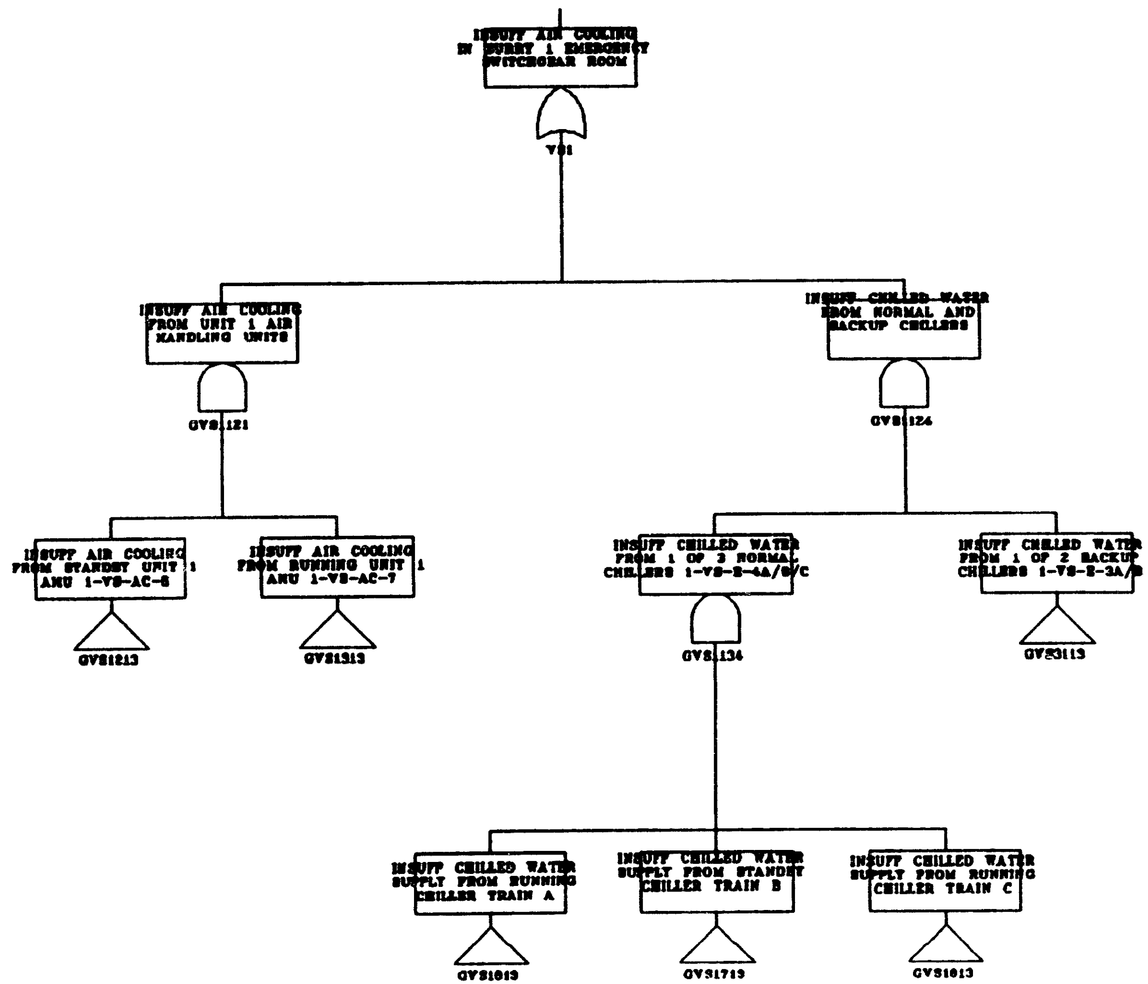


ELECTRICAL POWER – VITAL BUS 1V (E41V)
(E41V)

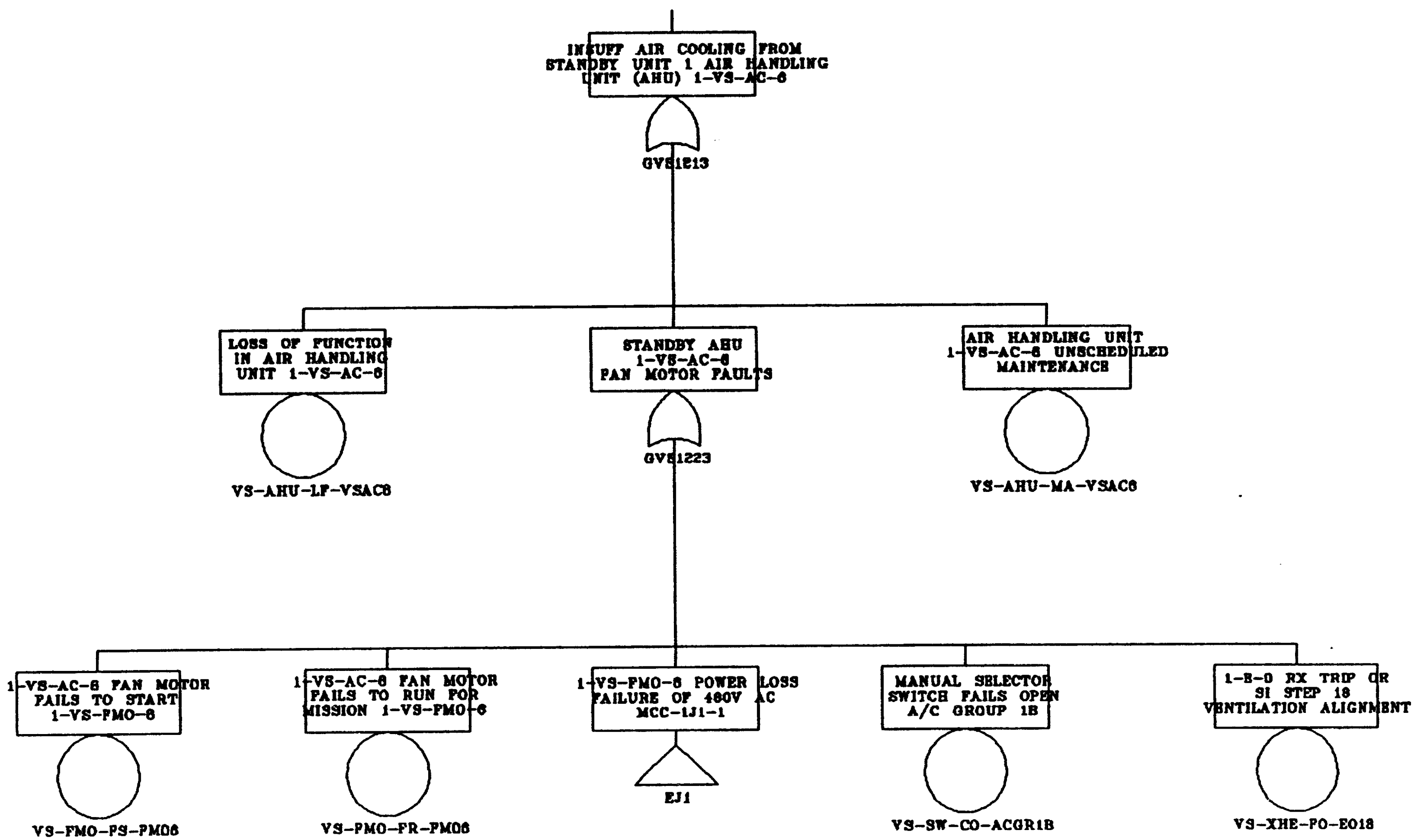


Appendix C.8 Emergency Switchgear Ventilation System

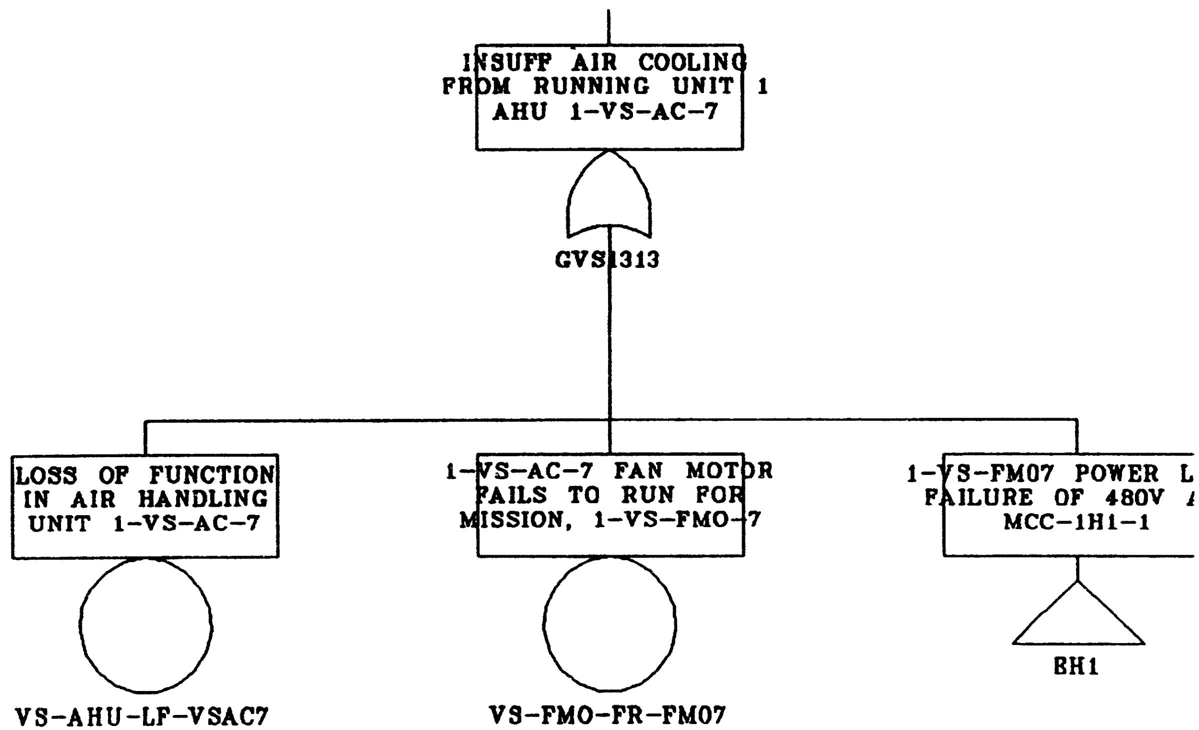
VENTILATION SYSTEM, VS
(EMERGENCY SWITCHGEAR ROOM COOLING)
(VS1)



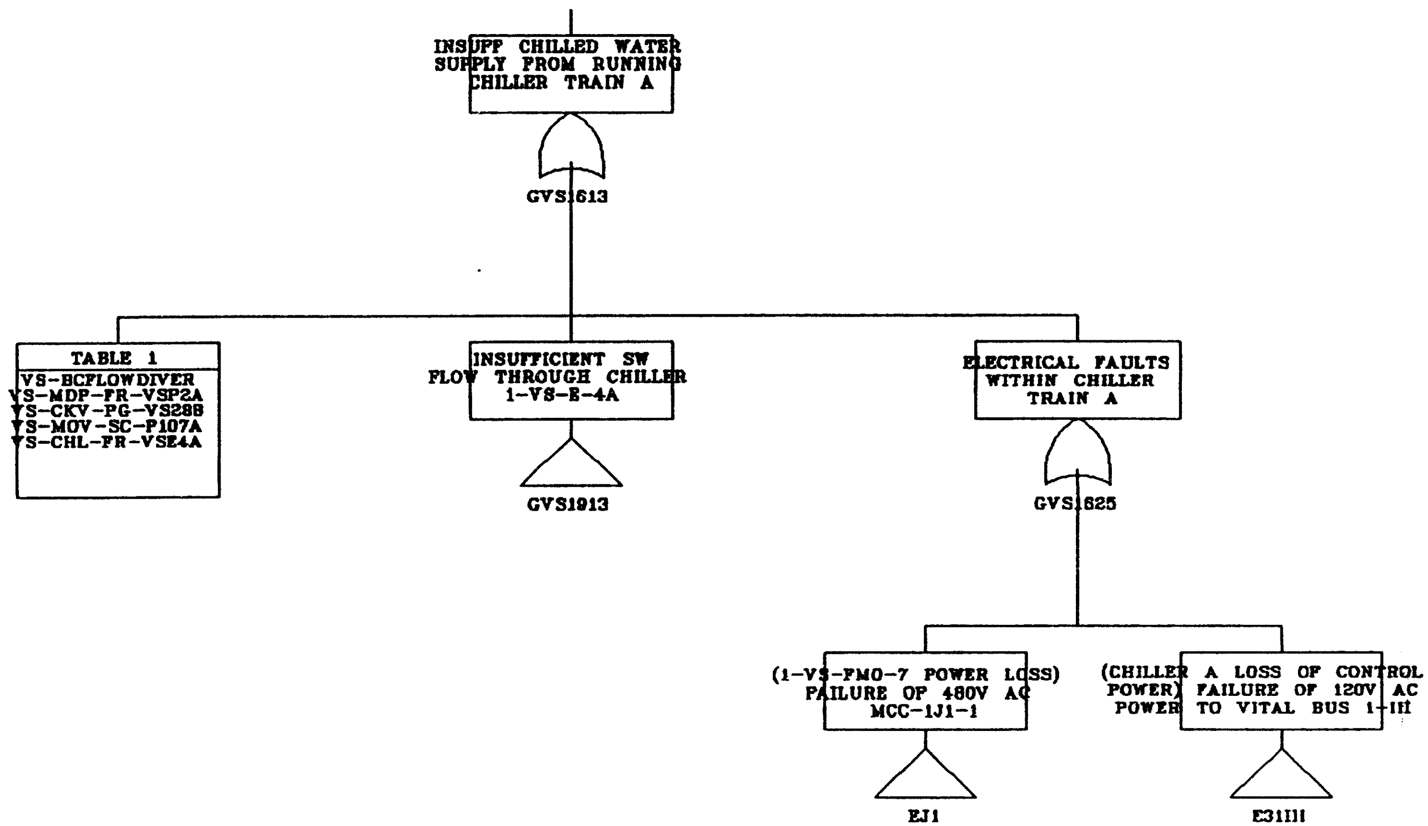
VENTILATION SYSTEM, VS
(EMERGENCY SWITCHGEAR ROOM COOLING)
(GVS1213)



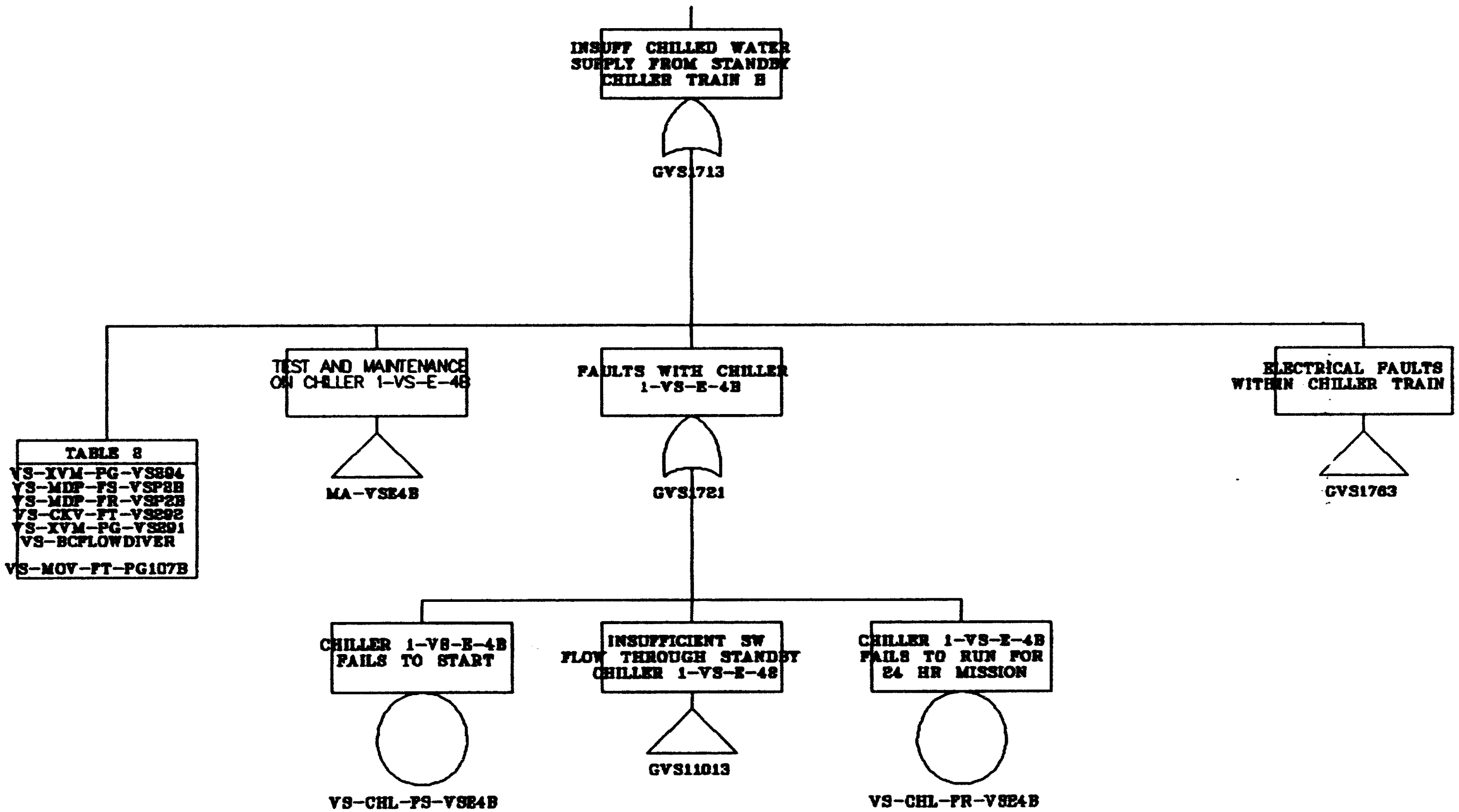
VENTILATION SYSTEM, VS
(EMERGENCY SWITCHGEAR ROOM COOLING)
(GVS1313)



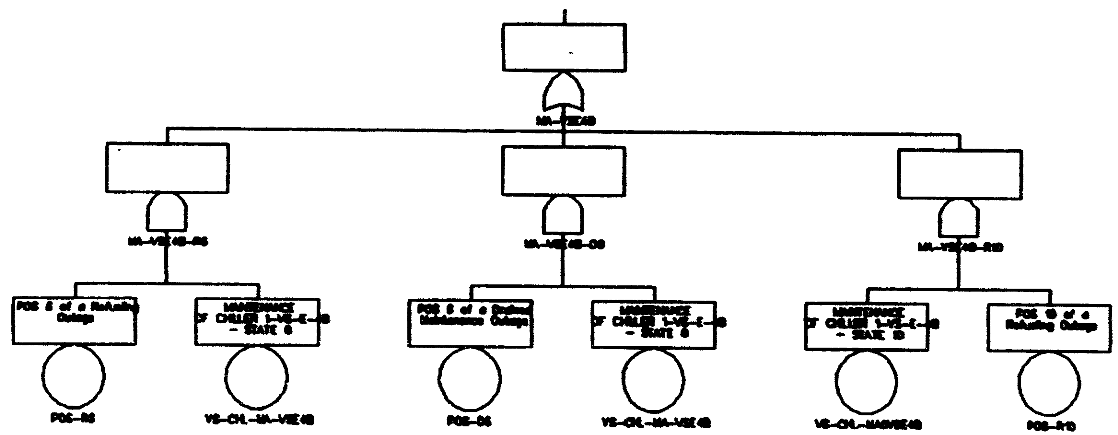
VENTILATION SYSTEM, VS
(EMERGENCY SWITCHGEAR ROOM COOLING)
(GVS1613)



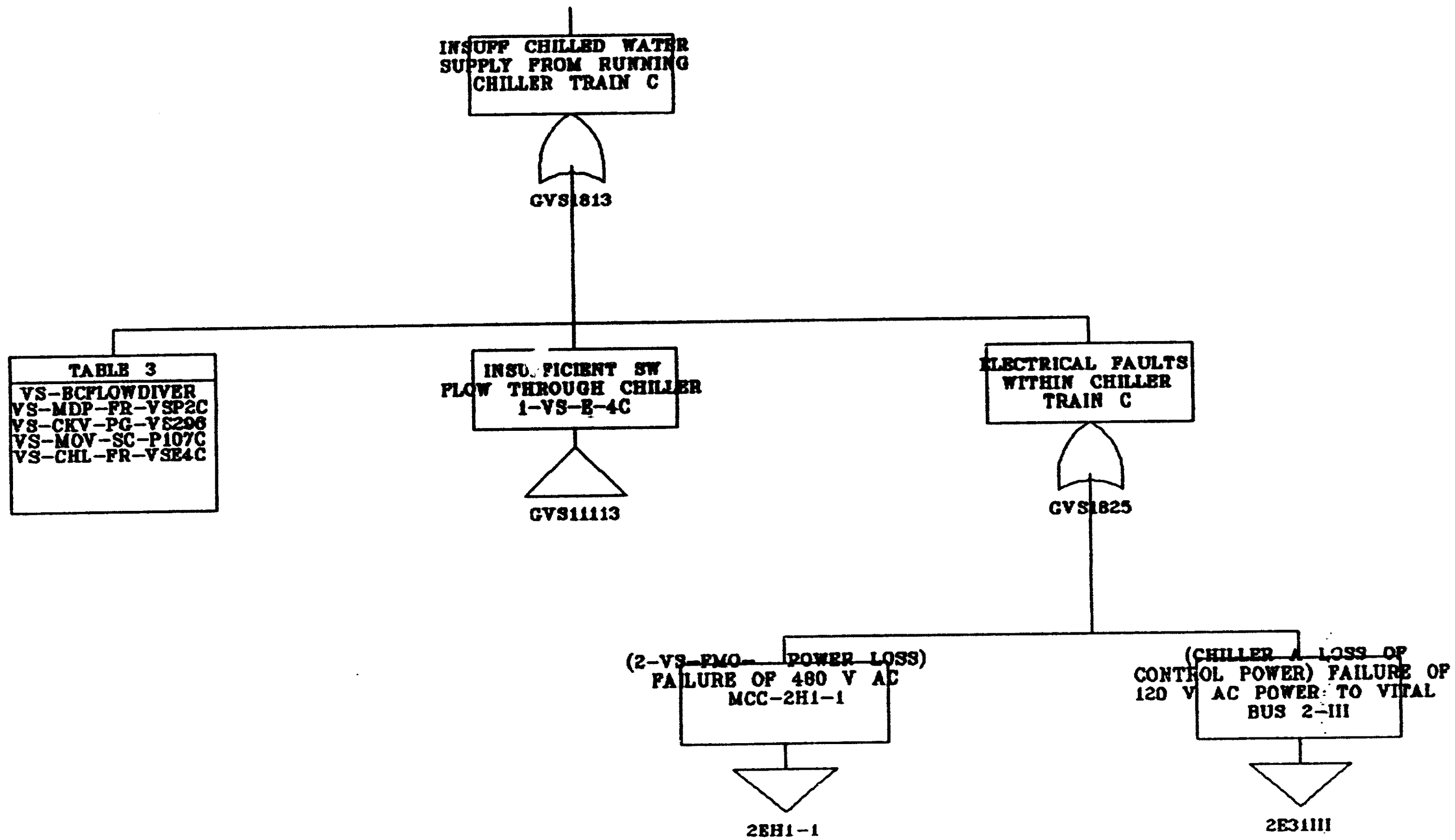
VENTILATION SYSTEM, VS
(EMERGENCY SWITCHGEAR ROOM COOLING)
(GVS1713)



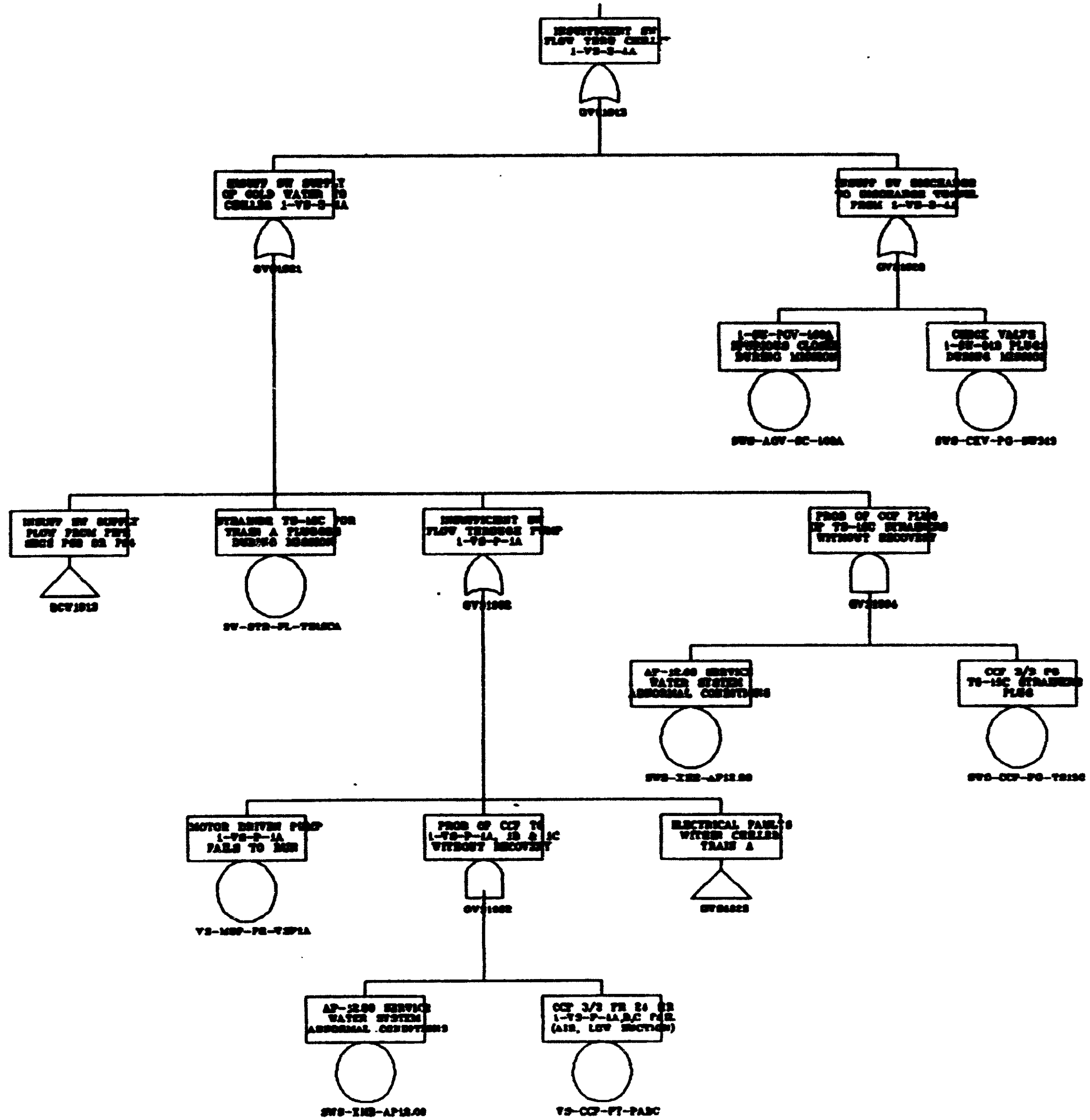
TEST AND MAINTENANCE ON CHILLER 1-VS-E-4B



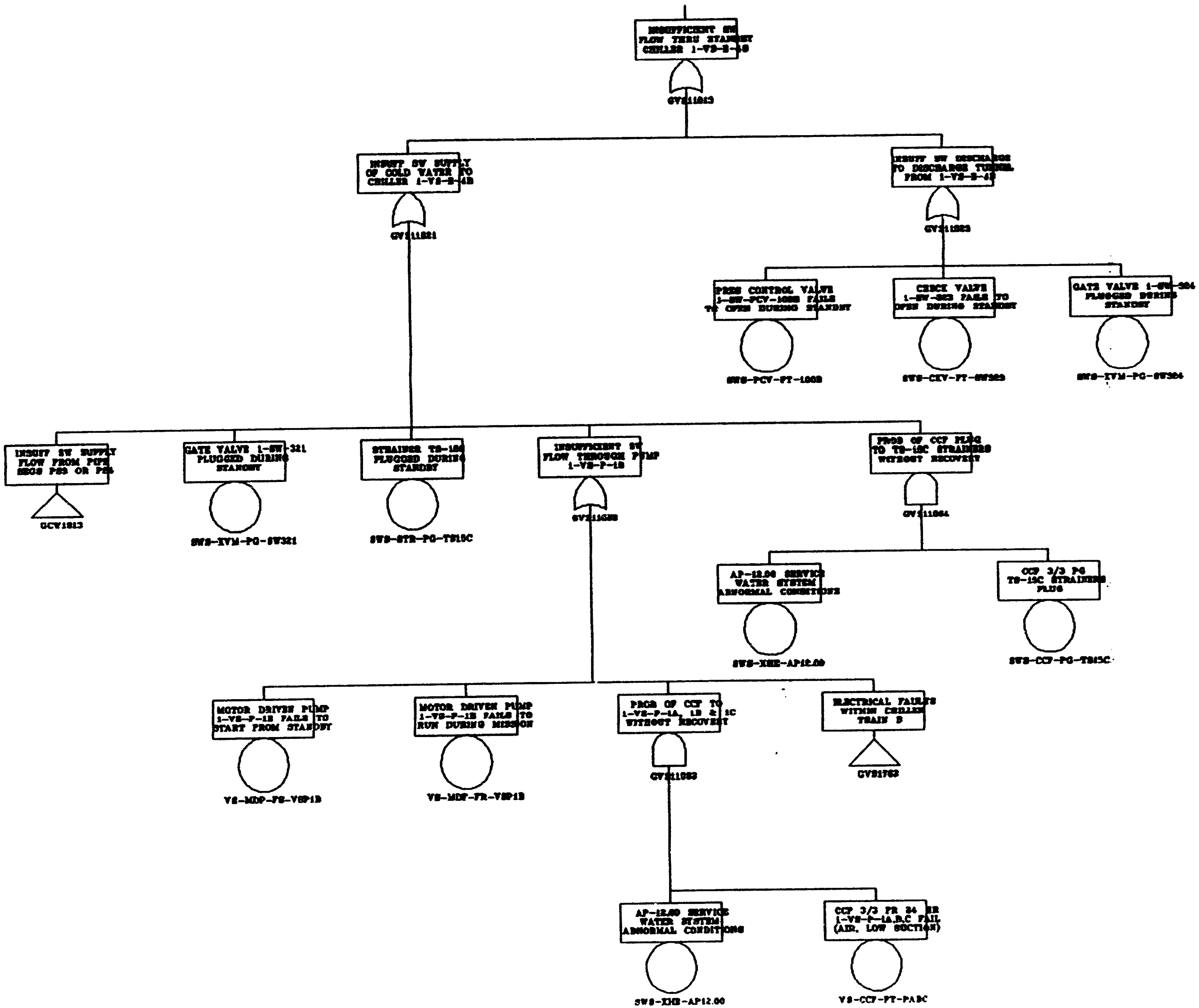
VENTILATION SYSTEM, VS
(EMERGENCY SWITCHGEAR ROOM COOLING)
(GVS1813)



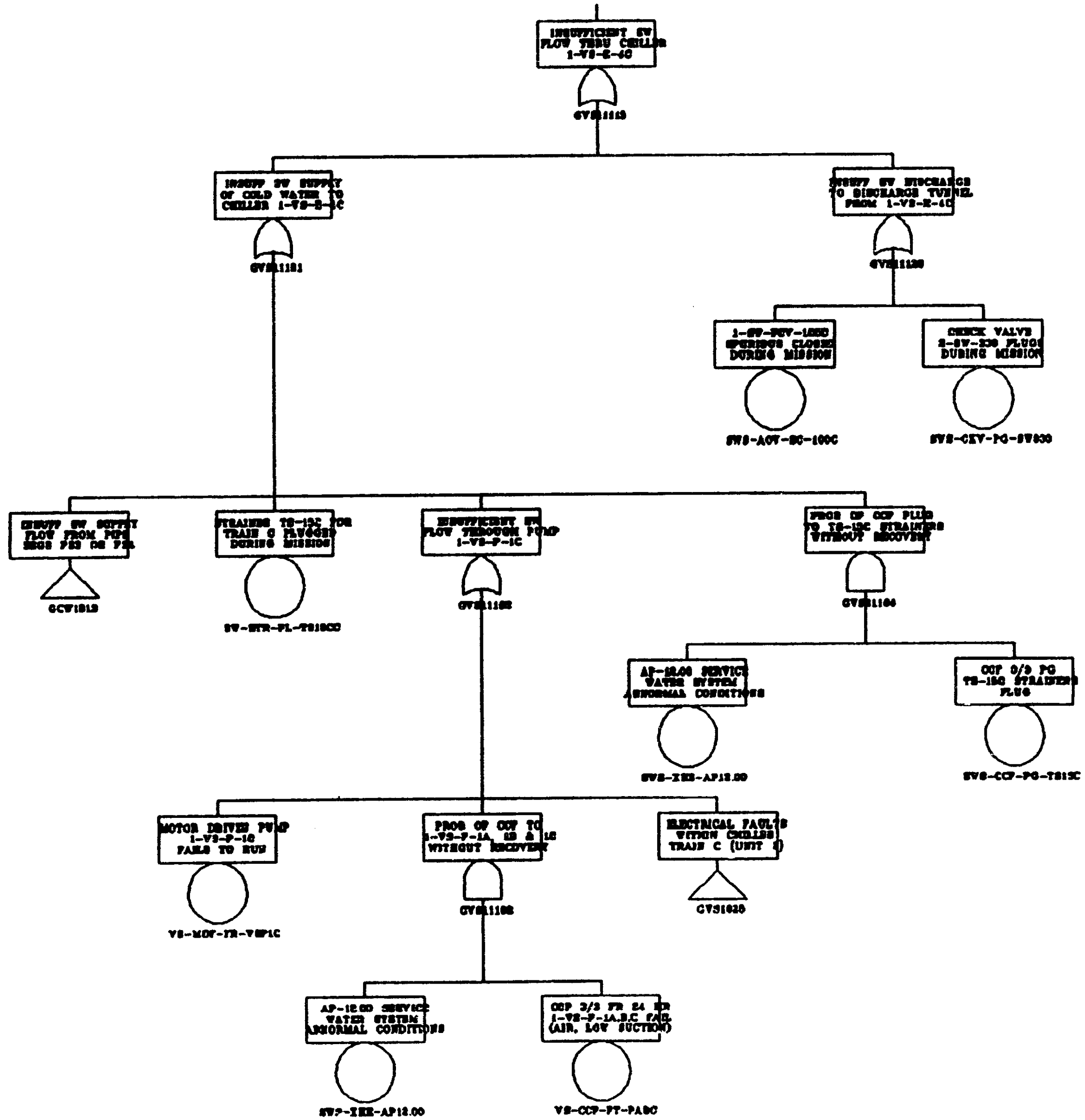
VENTILATION SYSTEM, VS
(EMERGENCY SWITCHGEAR ROOM COOLING)
(GVS1913)



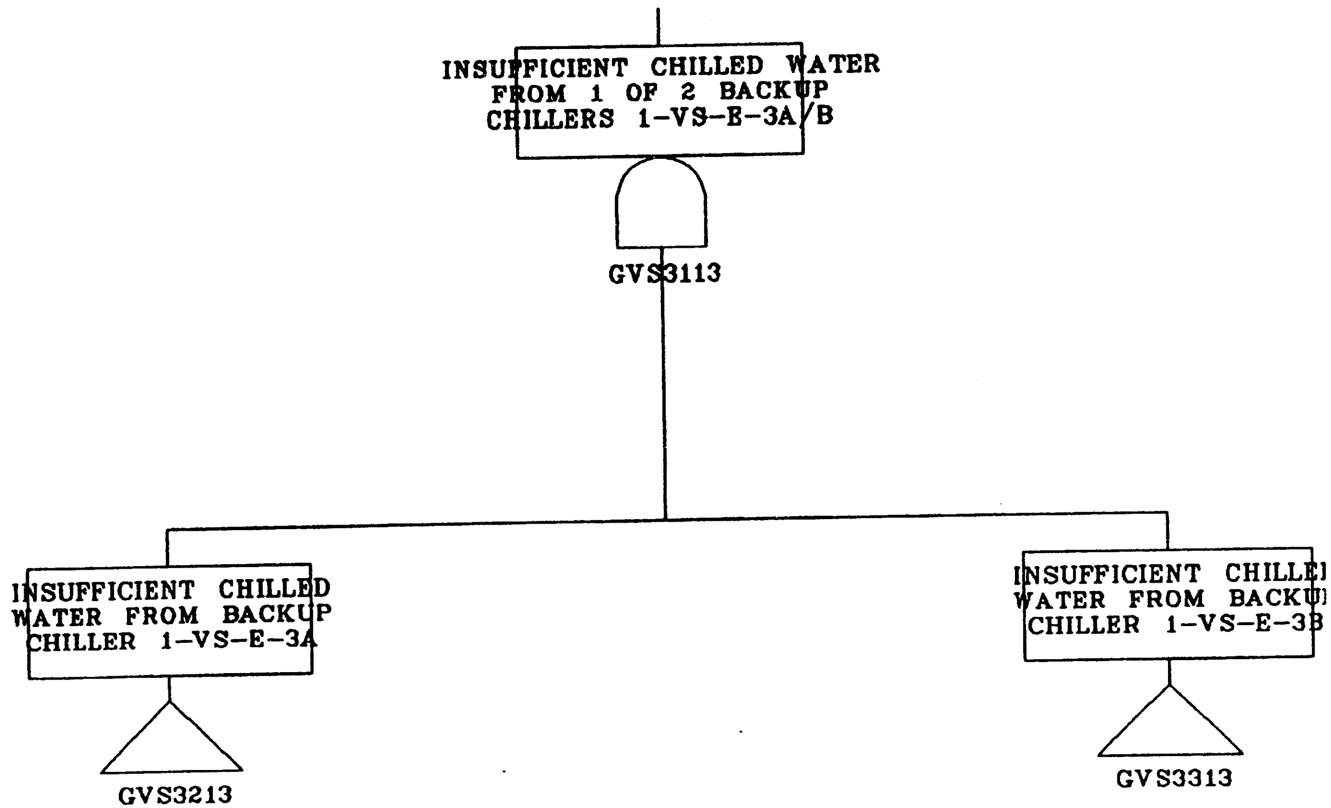
VENTILATION SYSTEM, VS
(EMERGENCY SWITCHGEAR ROOM COOLING)
(GVS11013)



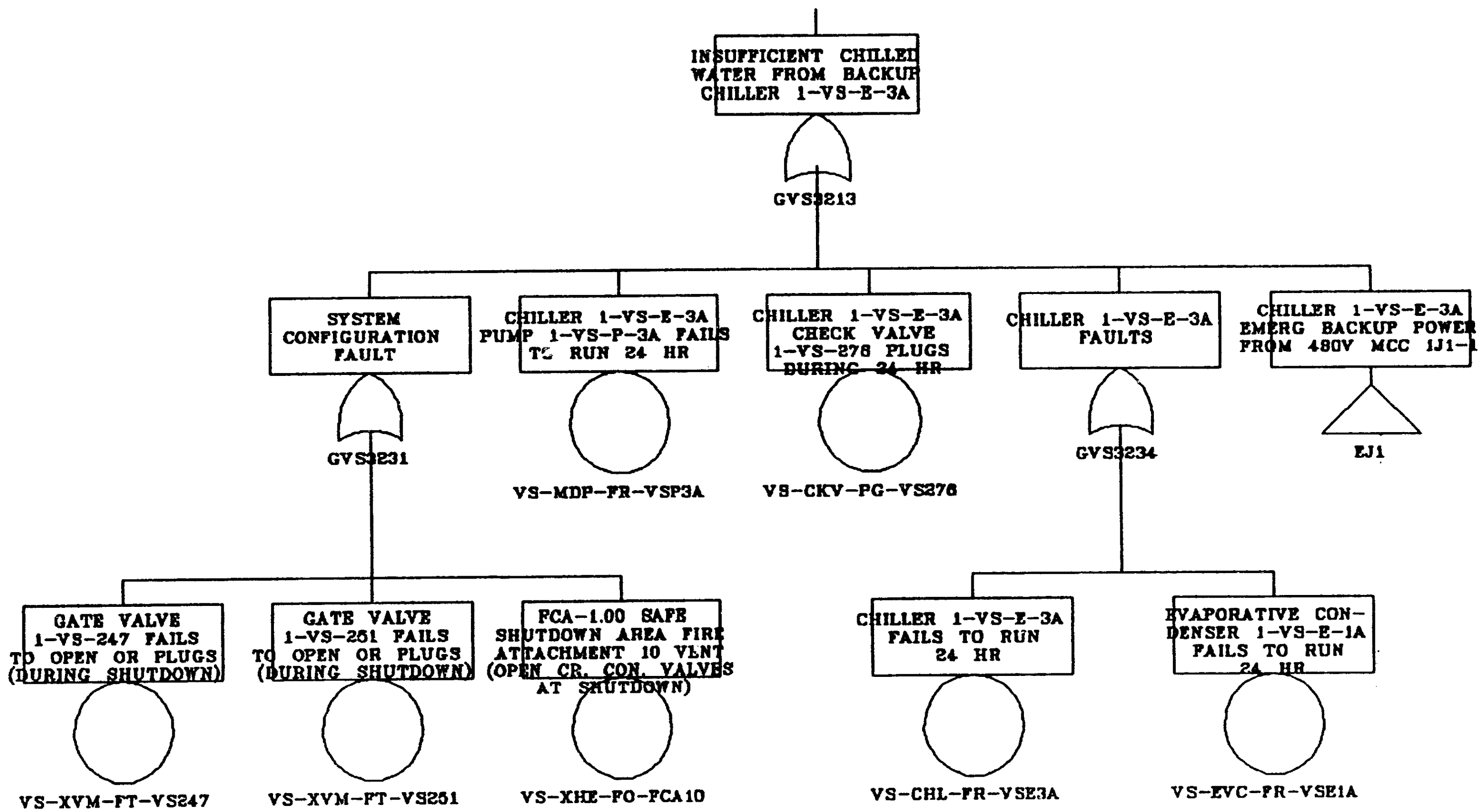
VENTILATION SYSTEM, VS
(EMERGENCY SWITCHGEAR ROOM COOLING)
(GVS11113)



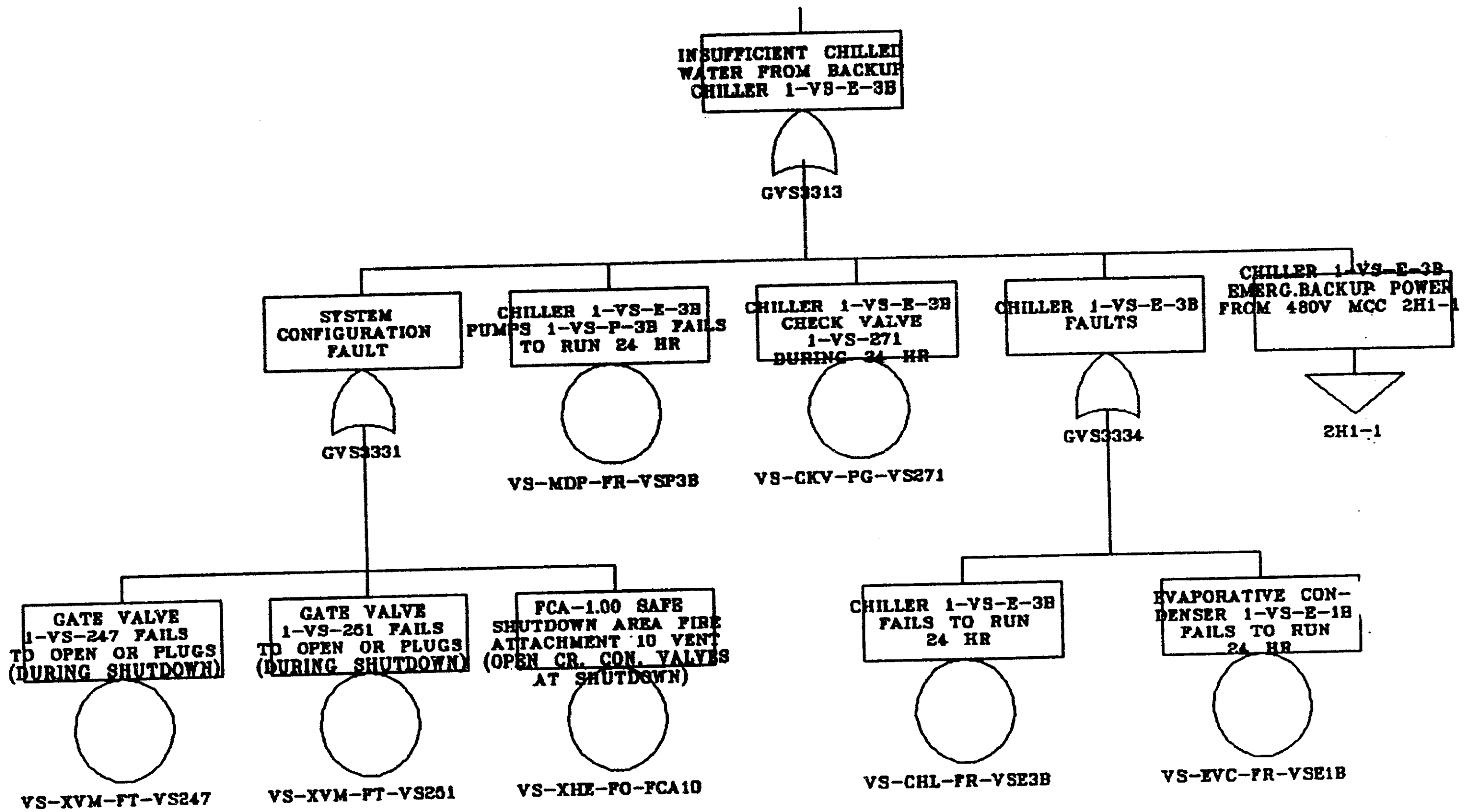
VENTILATION SYSTEM, VS
(EMERGENCY SWITCHGEAR ROOM COOLING)
(GVS3113)



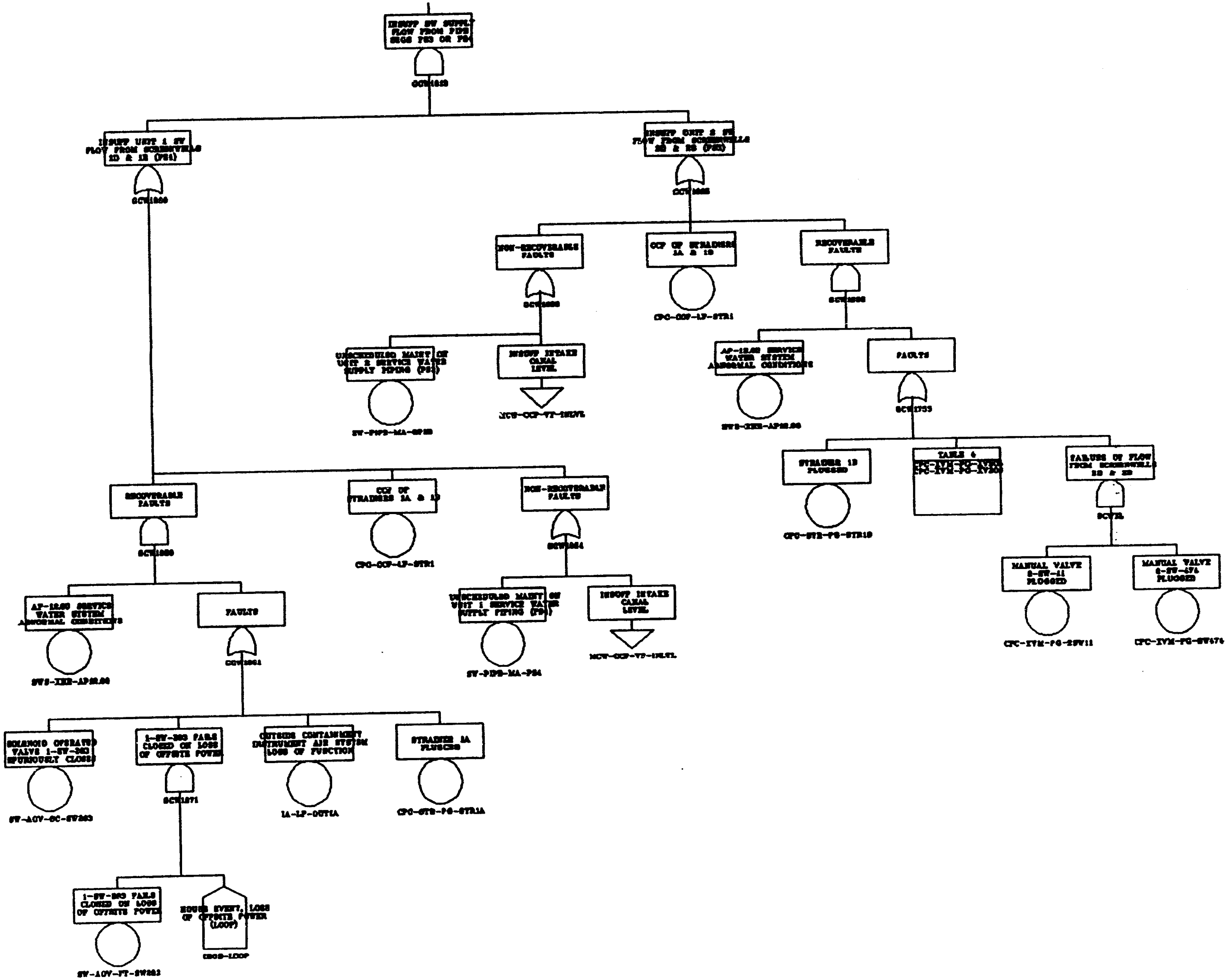
VENTILATION SYSTEM, VS
(EMERGENCY SWITCHGEAR ROOM COOLING)
(GVS3213)



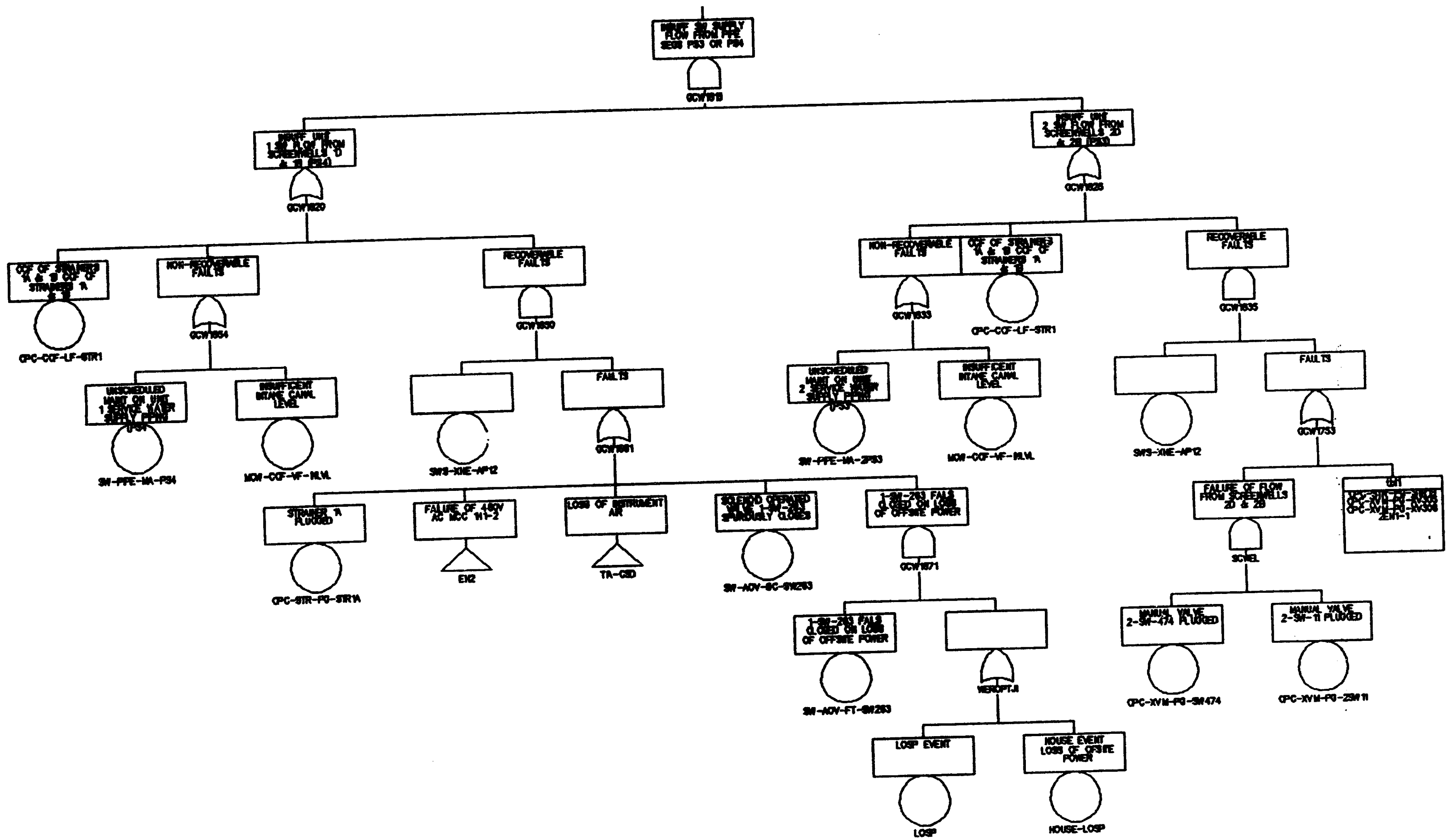
VENTILATION SYSTEM, VS
(EMERGENCY SWITCHGEAR ROOM COOLING)
(GVS3313)



VENTILATION SYSTEM, VS
(SERVICE WATER SYSTEM INTERFACE)
(GCW1813)

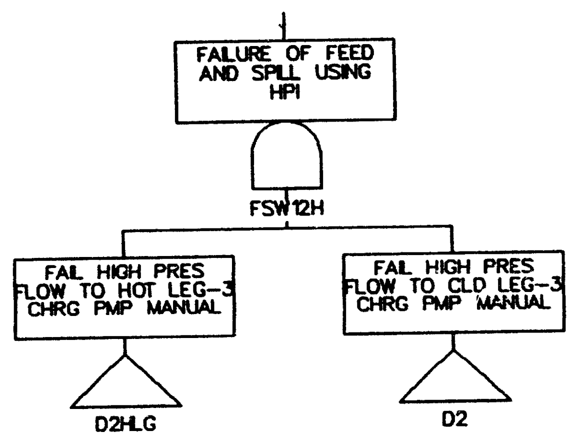


VENTILATION SYSTEM, VS (SERVICE WATER SYSTEM INTERFACE) (GCW1813)

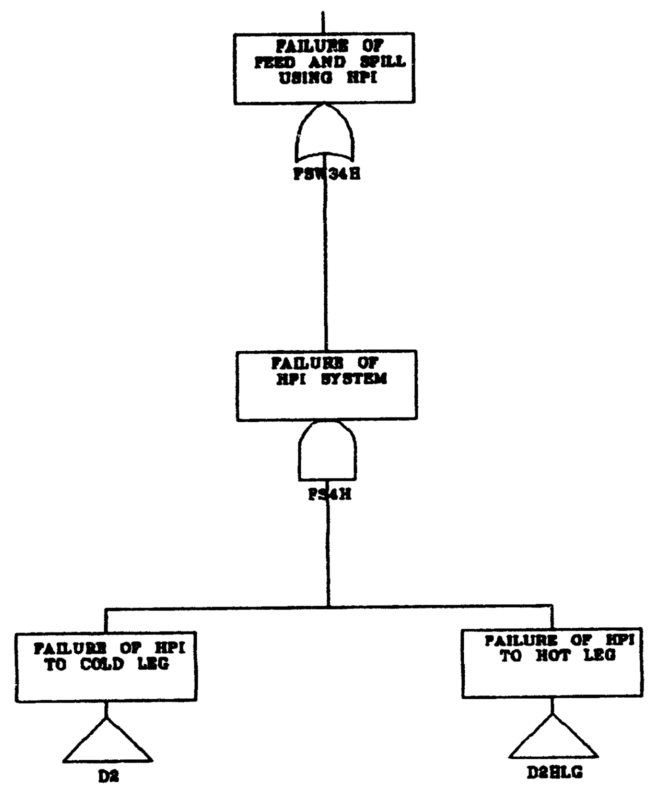


Appendix C.9 High Pressure Injection and Recirculation System

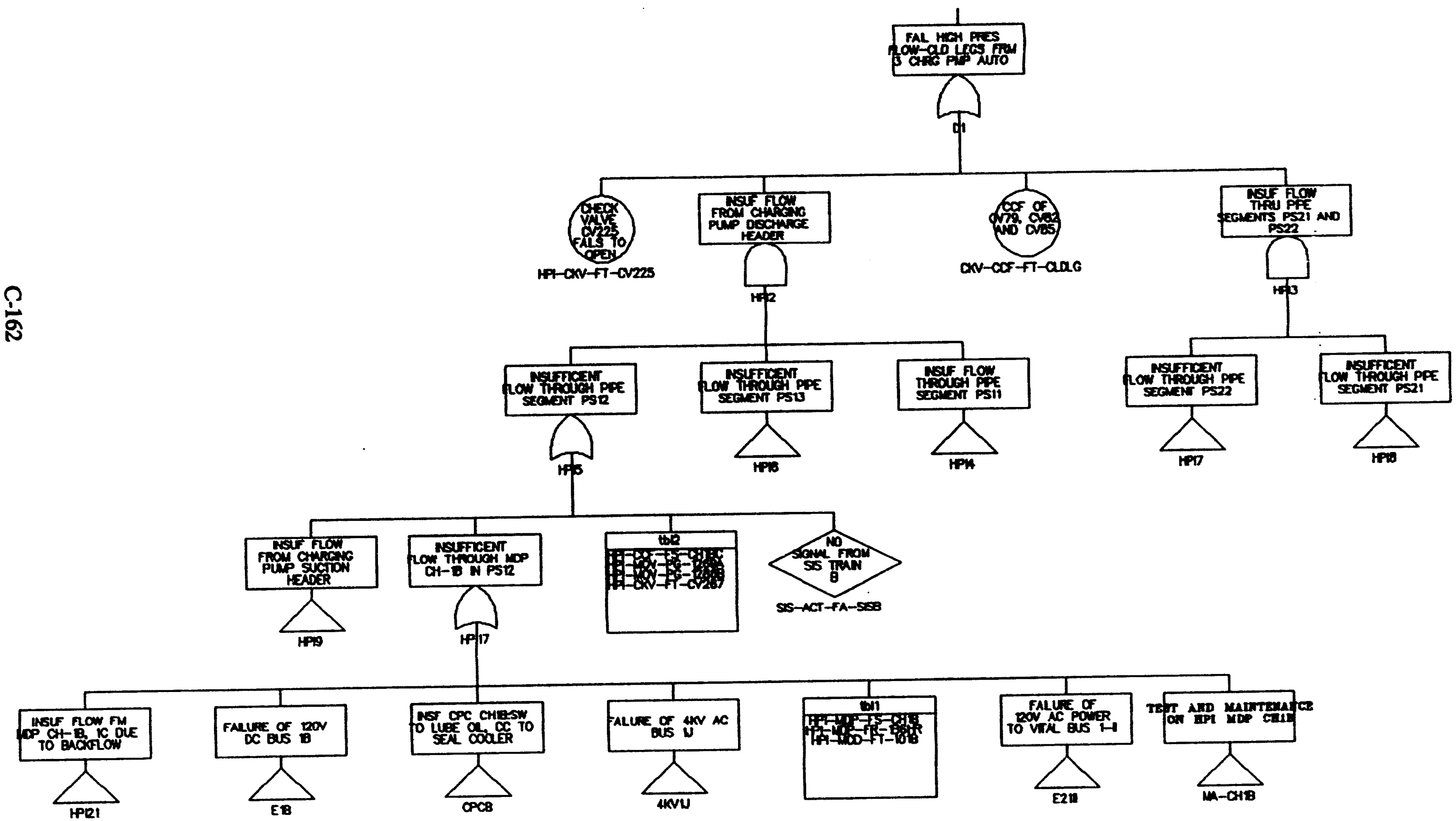
FAILURE OF FEED AND SPILL USING HPI SYSTEM — WINDOW 1&2



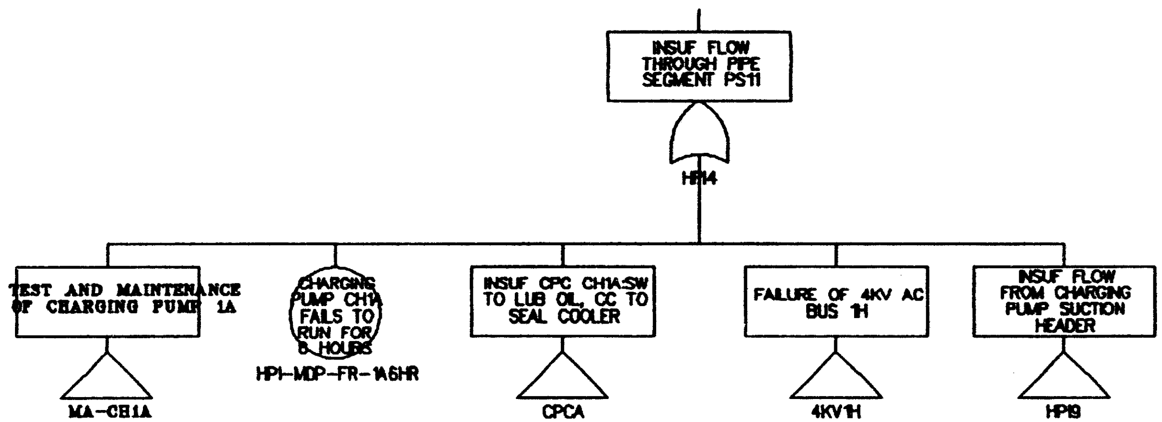
FAILURE OF FEED AND SPILL USING HPI SYSTEM – WINDOW 3&4 (FSW34H)



HIGH PRESSURE INJECTION – AUTOMATIC (D1)
(D1)

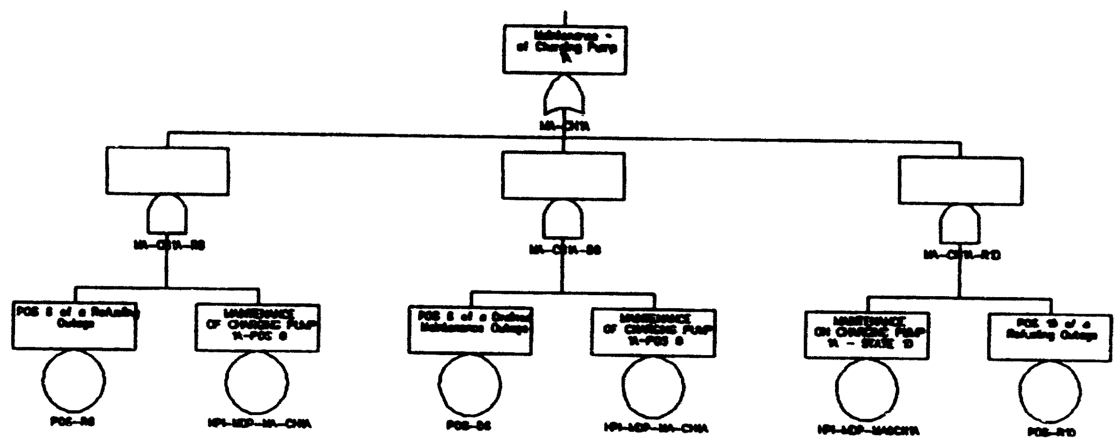


HIGH PRESSURE INJECTION – AUTOMATIC (D1) (HPI4)

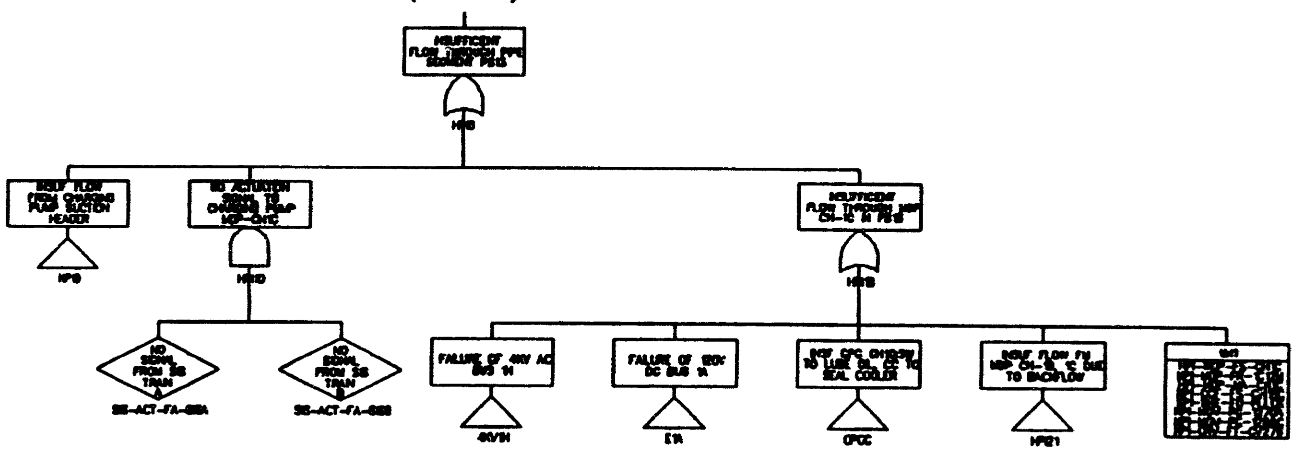


PAGE 1

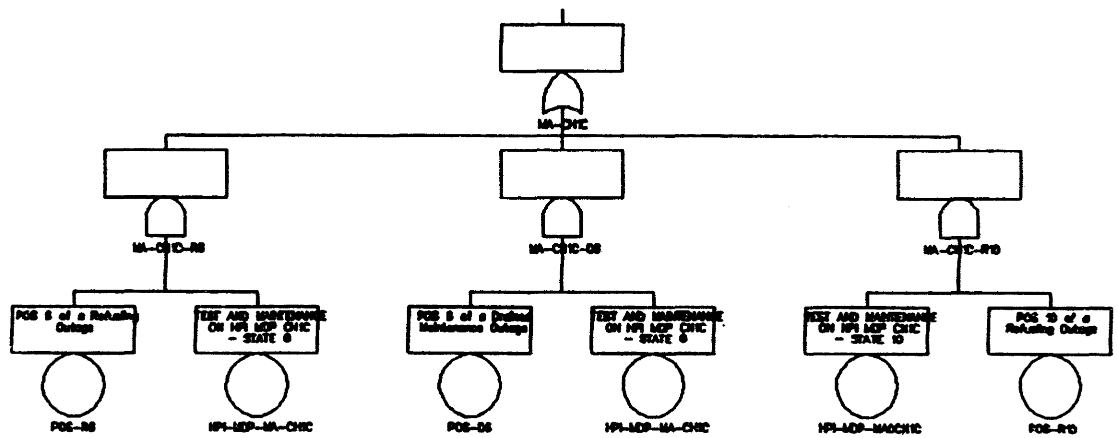
TEST AND MAINTENANCE ON CHARGING PUMP 1A



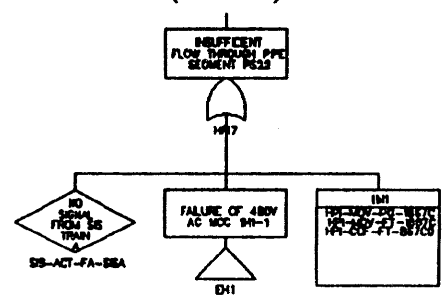
HIGH PRESSURE INJECTION – AUTOMATIC (D1)
(HP16)



TEST AND MAINTENANCE ON HPI MDP CH1C

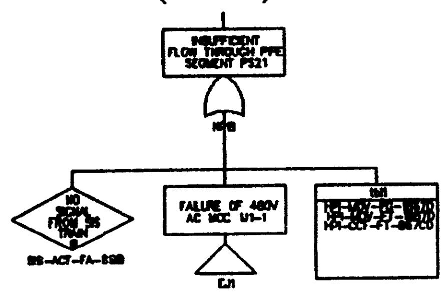


HIGH PRESSURE INJECTION – AUTOMATIC (D1)
(HPI7)



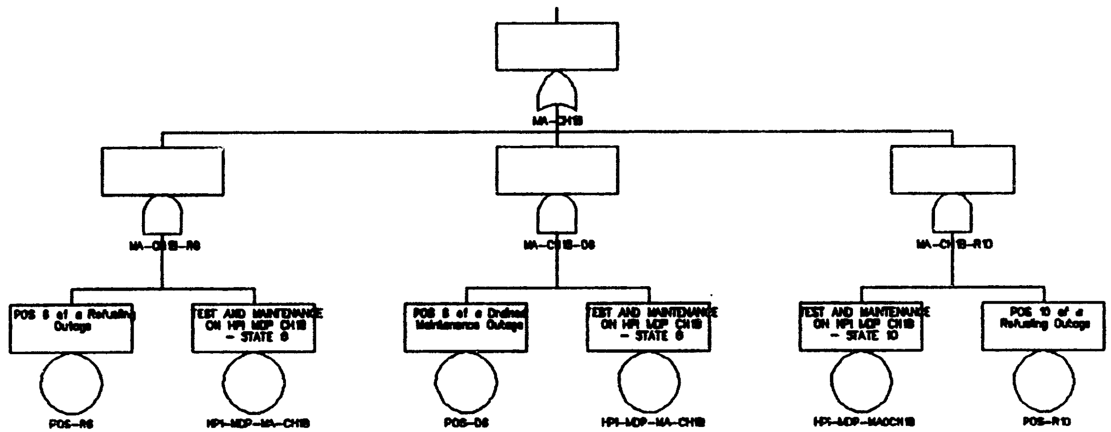
C-167

HIGH PRESSURE INJECTION – AUTOMATIC (D1)
(HPI8)

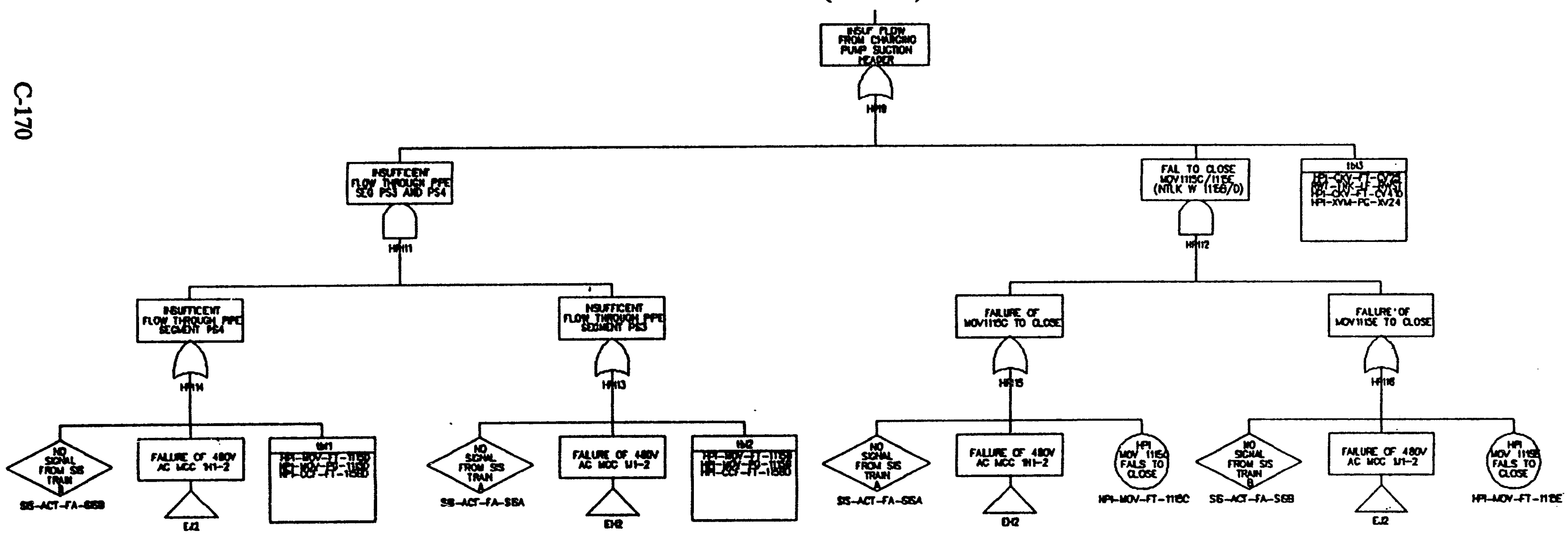


C-168

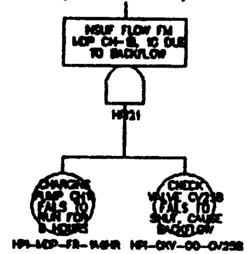
TEST AND MAINTENANCE ON HPI MDP CH1B



HIGH PRESSURE INJECTION – AUTOMATIC (D1)
(HPI9)

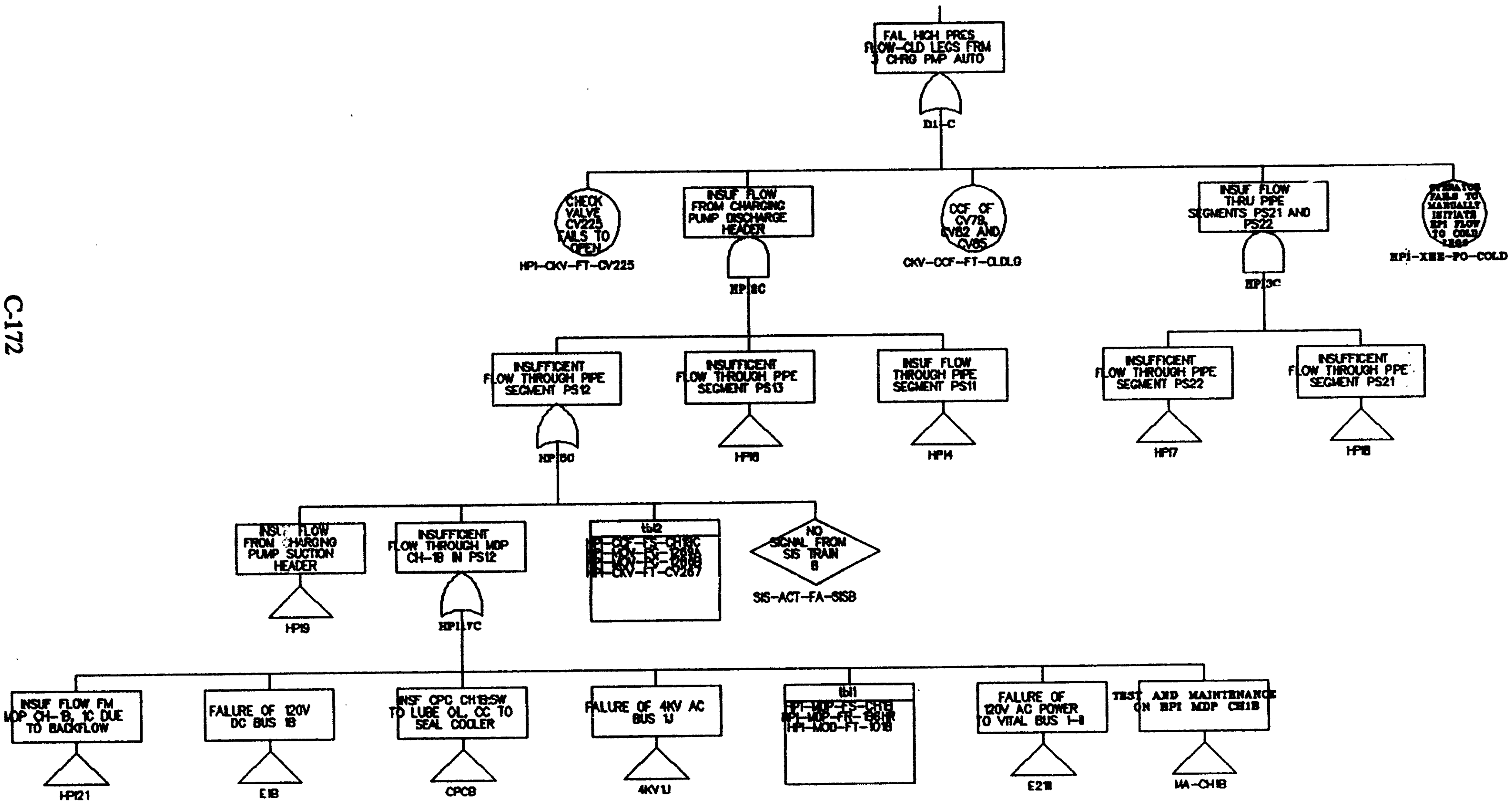


HIGH PRESSURE INJECTION – AUTOMATIC (D1)
(HPI21)

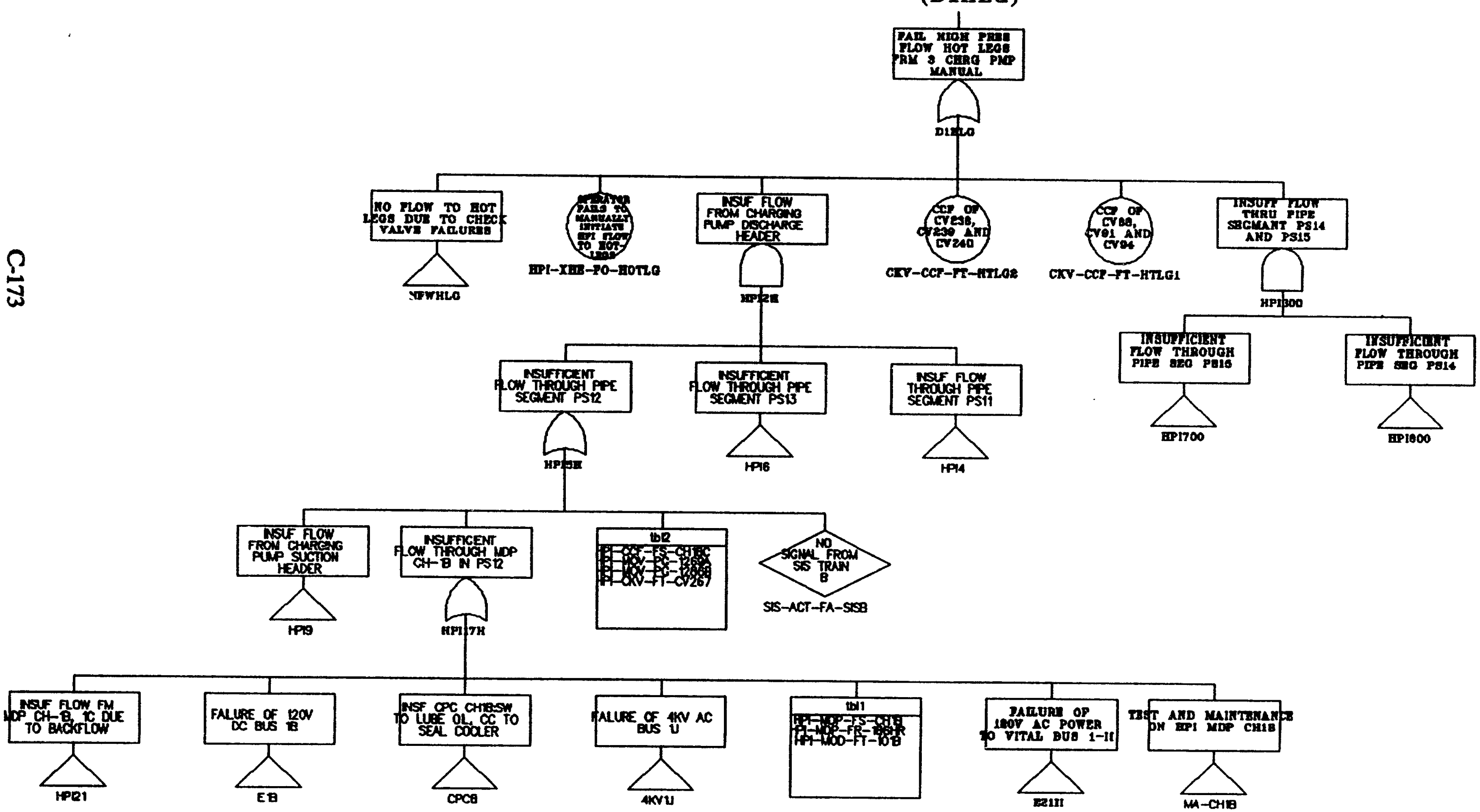


C-171

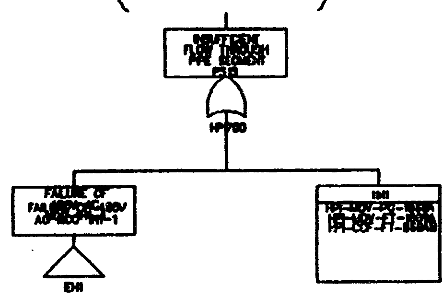
HIGH PRESSURE INJECTION - AUTOMATIC (D1)
(D1-C)



HPI TO HOT LEGS - MANUAL (D1HLG)

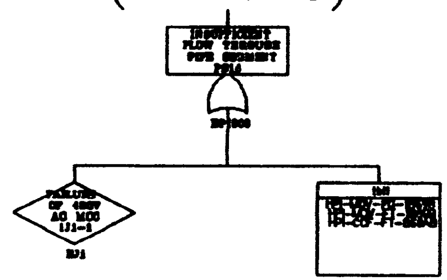


HIGH PRESSURE INJECTION – AUTOMATIC (D1)
(HPI700)



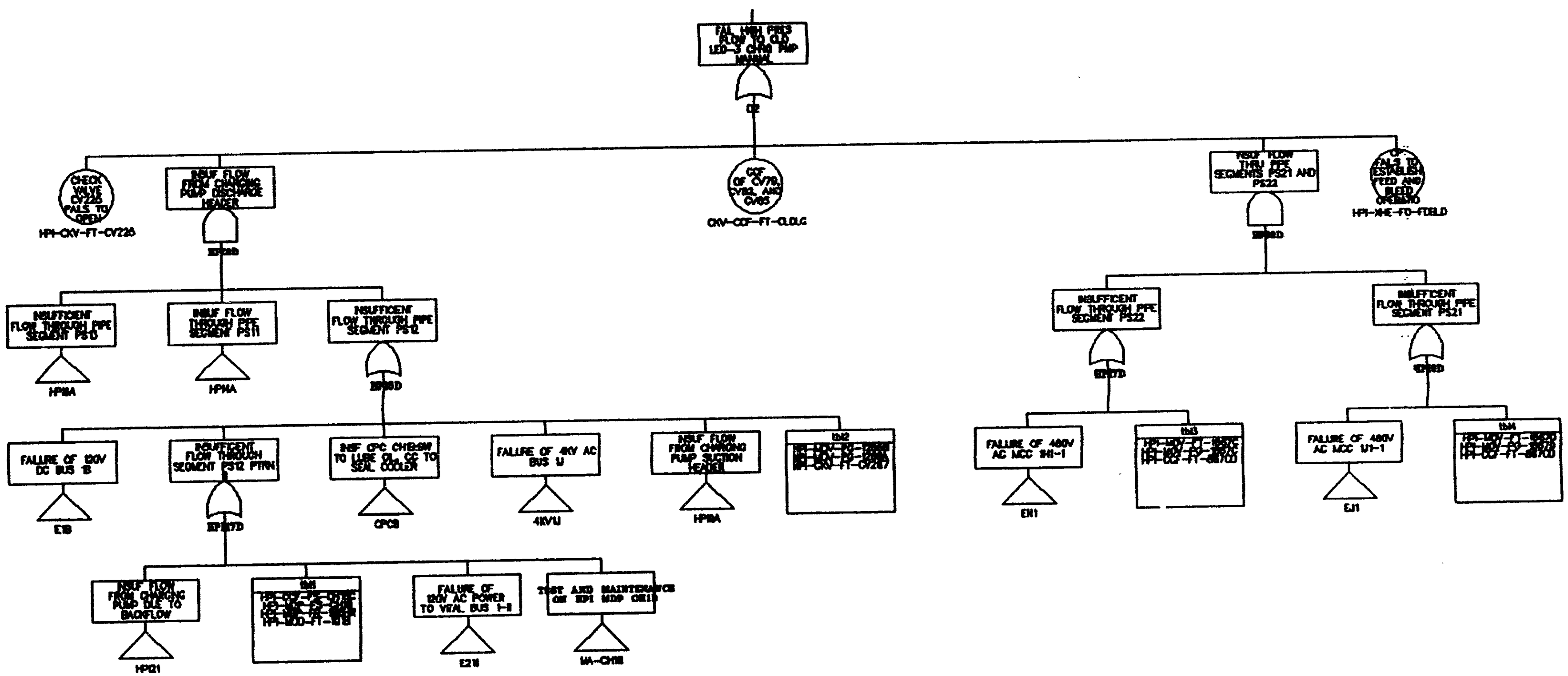
HIGH PRESSURE INJECTION – AUTOMATIC (D1)

(HPI800)

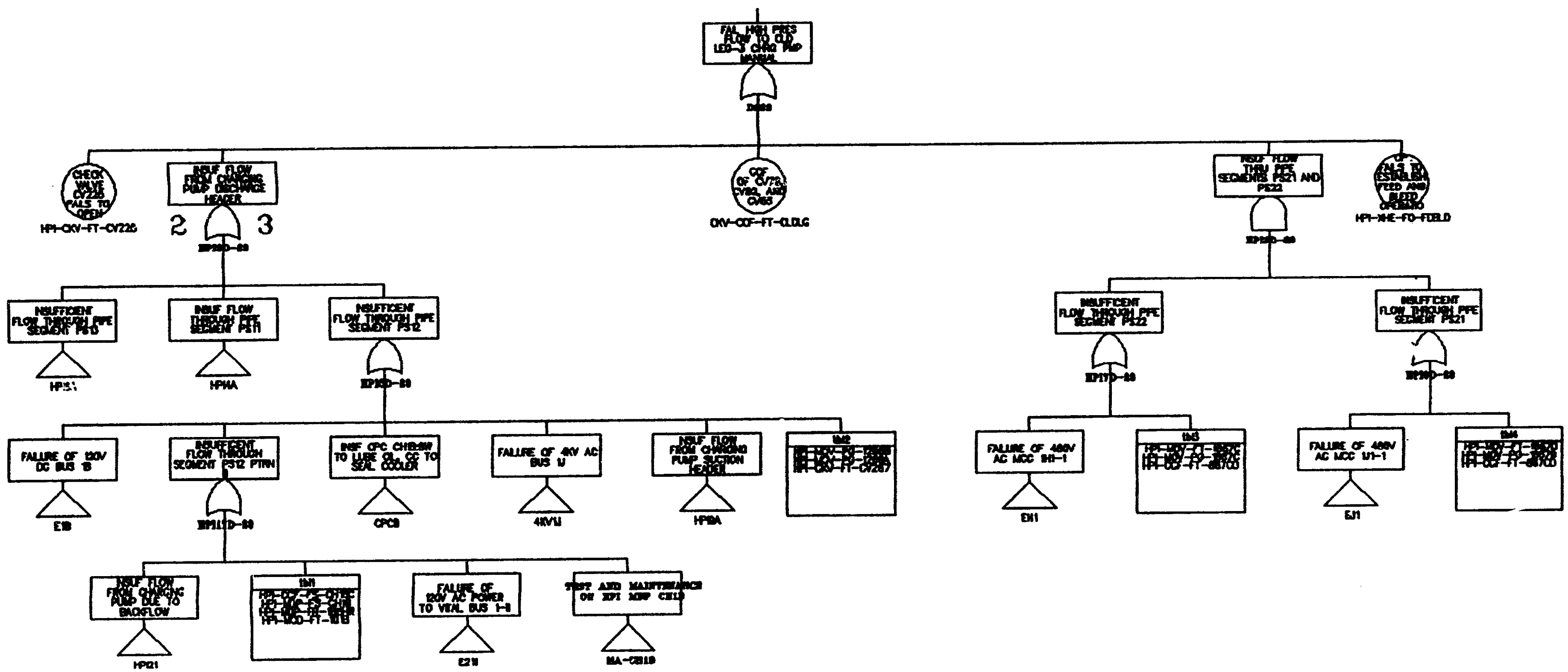


C-175

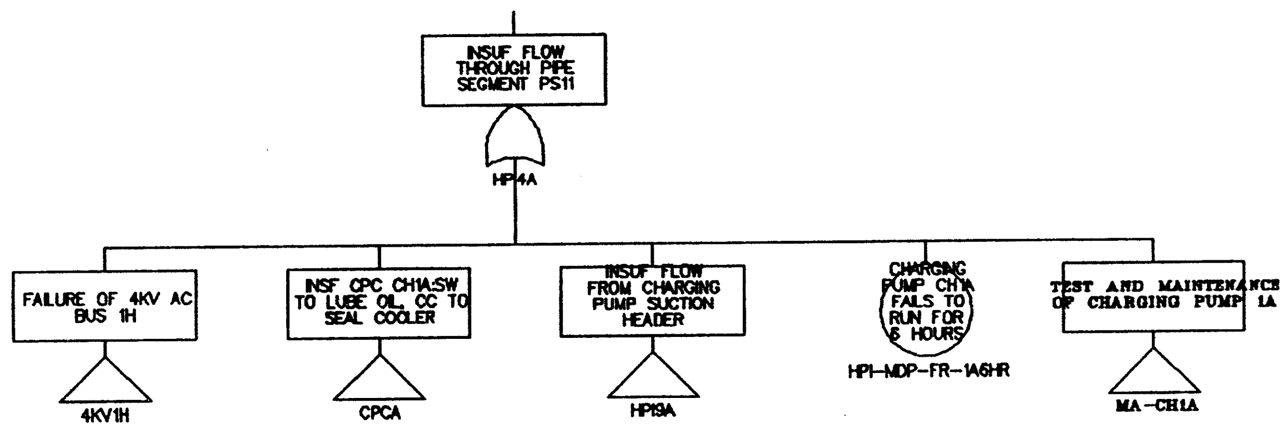
HIGH PRESSURE INJECTION - MANUAL (D2)
(D2)



HIGH PRESSURE INJECTION – MANUAL (D2-23)
(2/3 pumps)

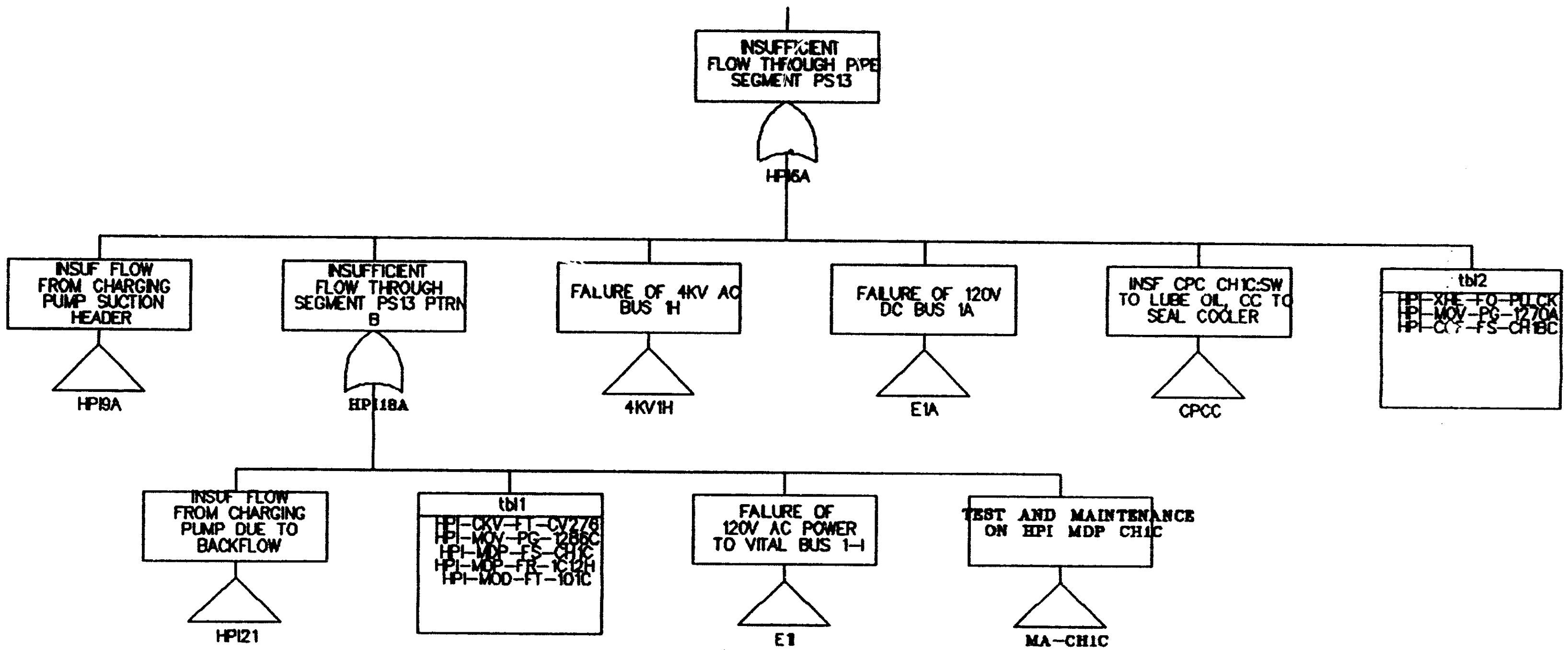


HIGH PRESSURE INJECTION — MANUAL (D2) (HPI4A)

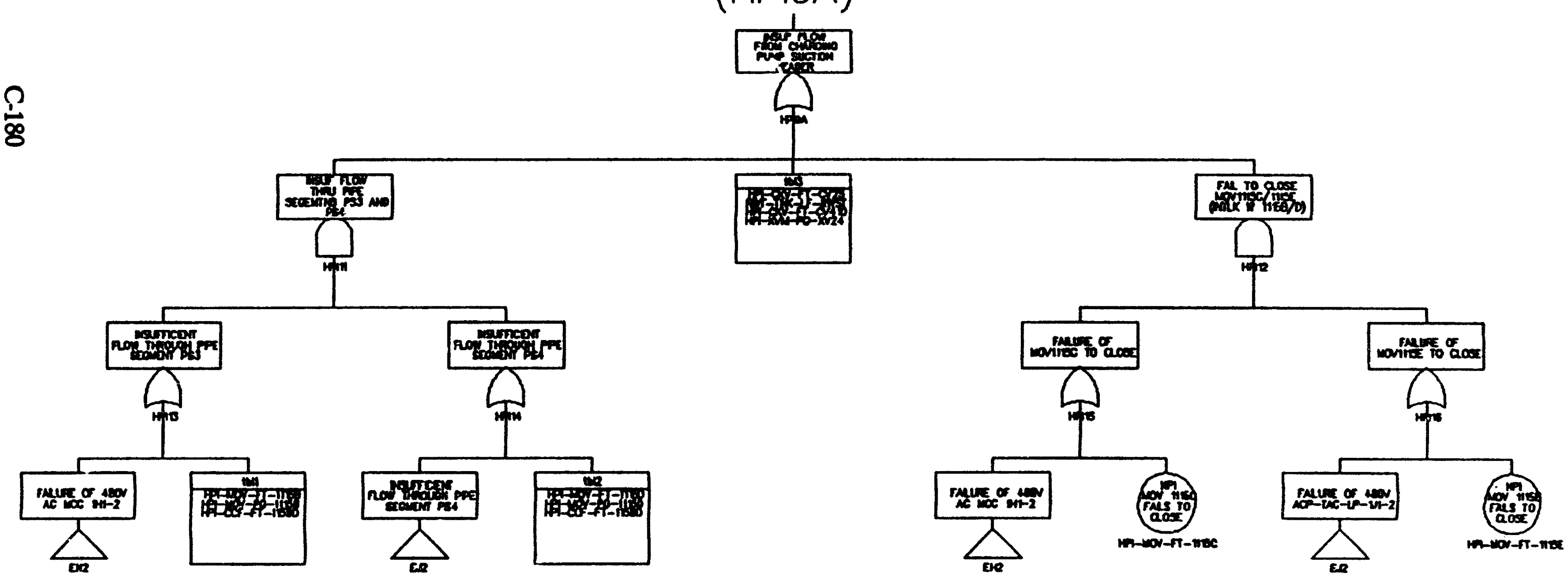


PAGE 1

HIGH PRESSURE INJECTION – MANUAL (D2)
(HPI6A)

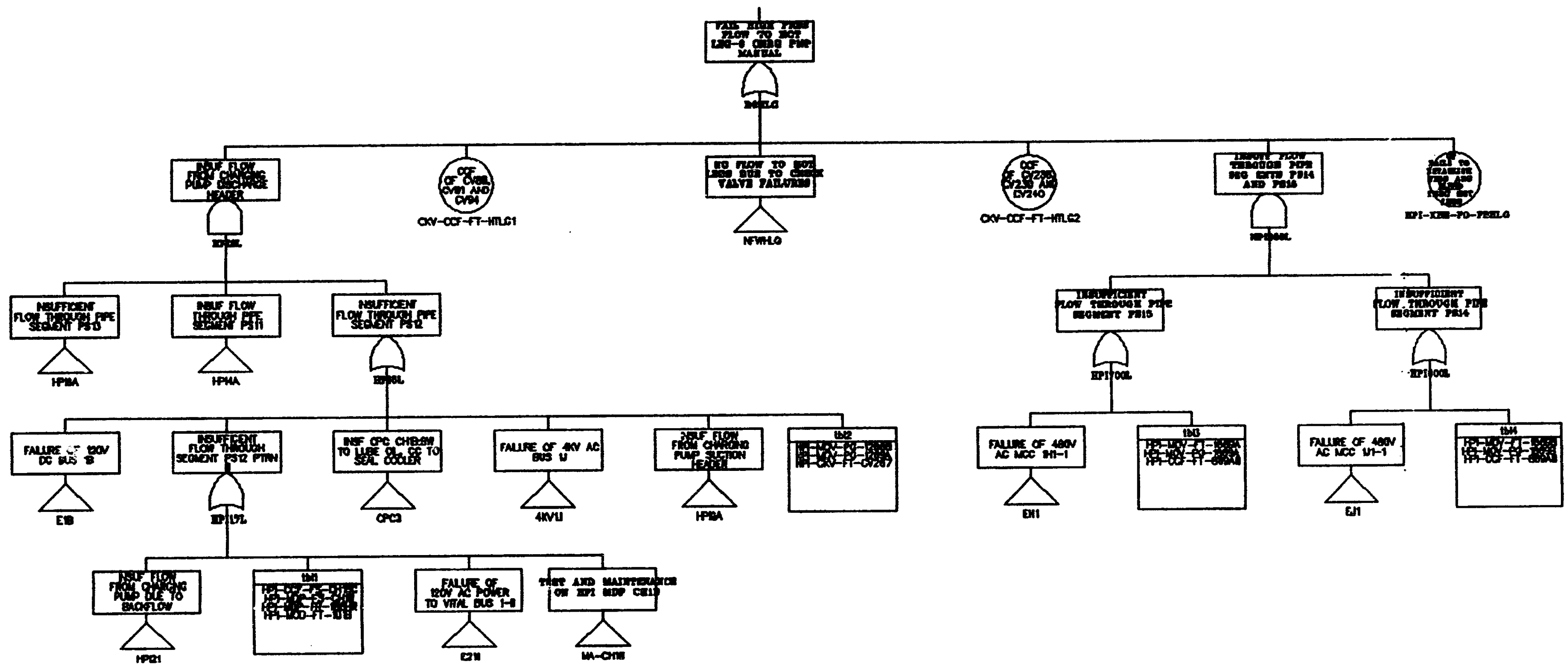


HIGH PRESSURE INJECTION – MANUAL (D2)
(HPI9A)

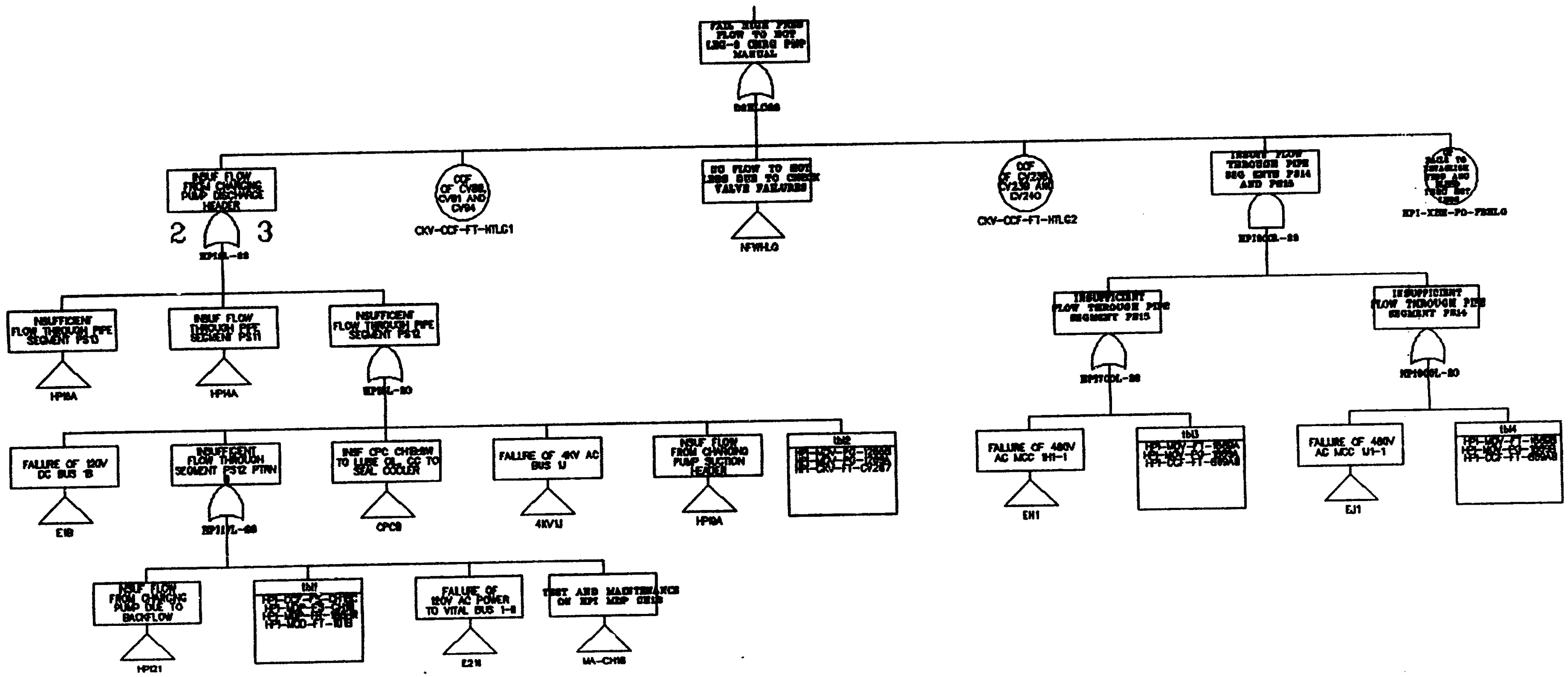


4 of 5

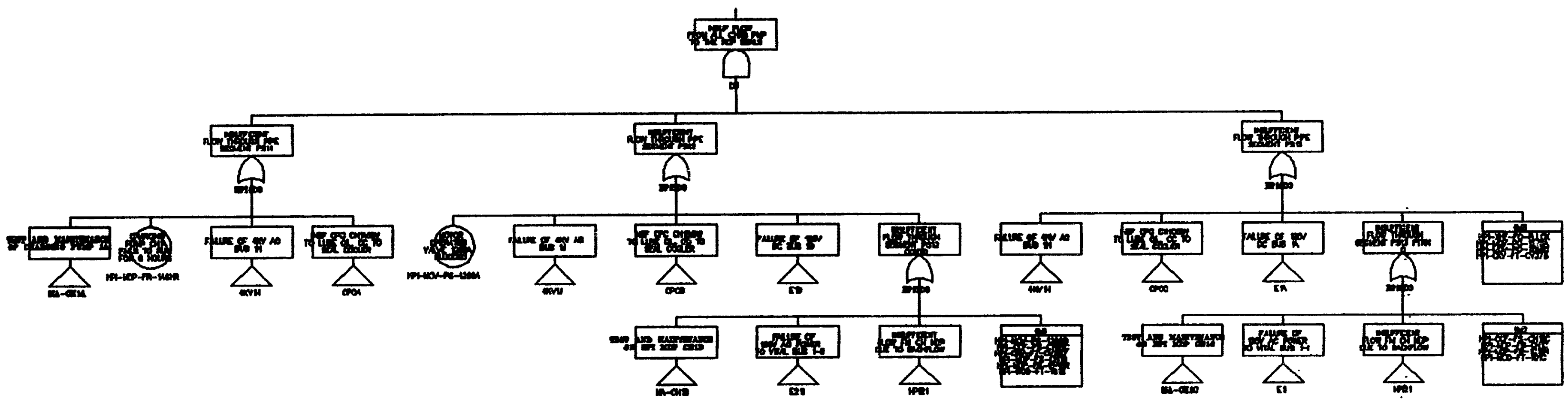
HIGH PRESSURE INJECTION - MANUAL (D2)
(D2HLG)



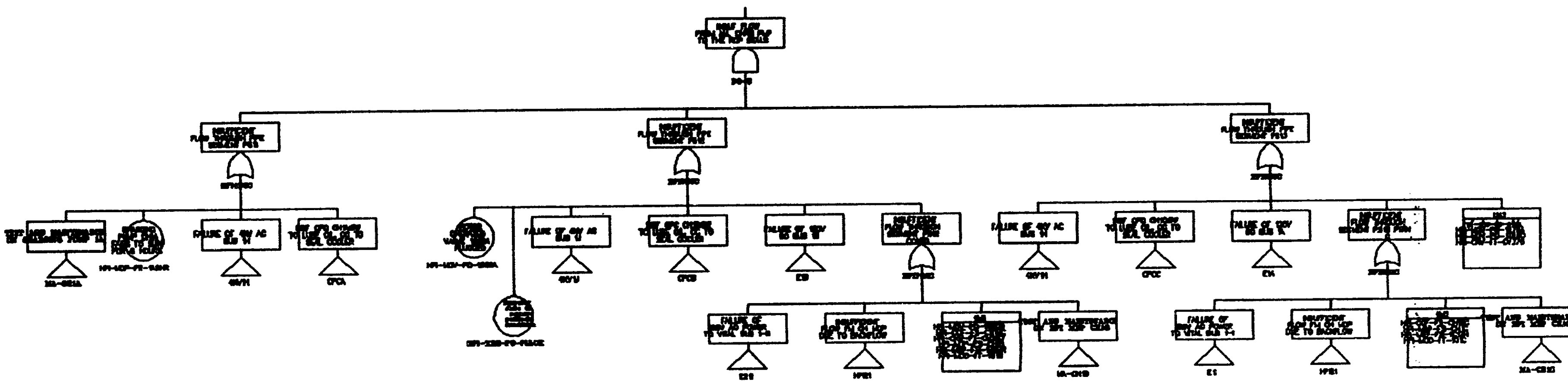
HIGH PRESSURE INJECTION TO HOT LEGS - MANUAL
(D2HLG-23, 2/3 PUMPS)



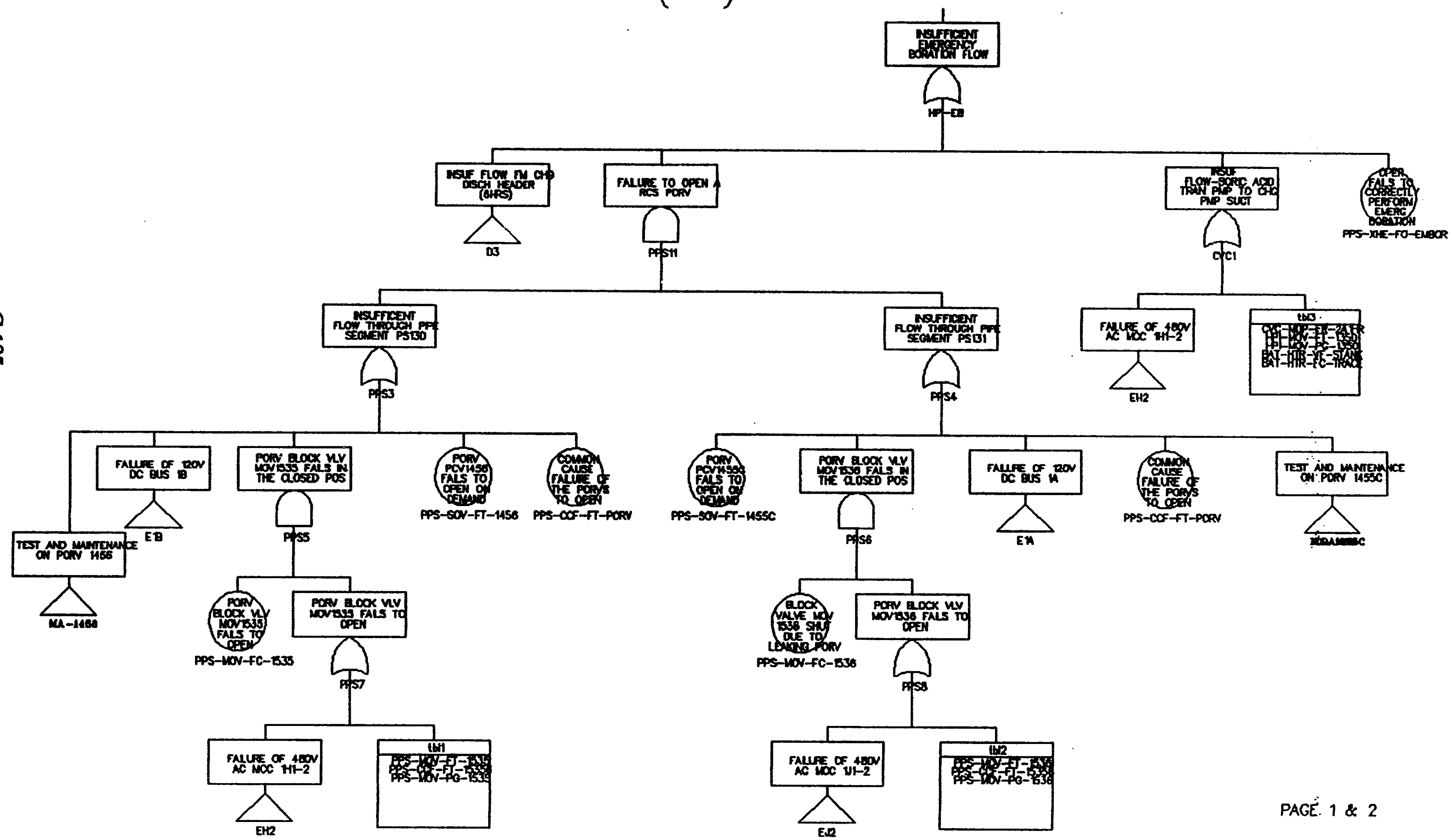
HIGH PRESSURE INJECTION – RCP SEALS (D3)
(D3)



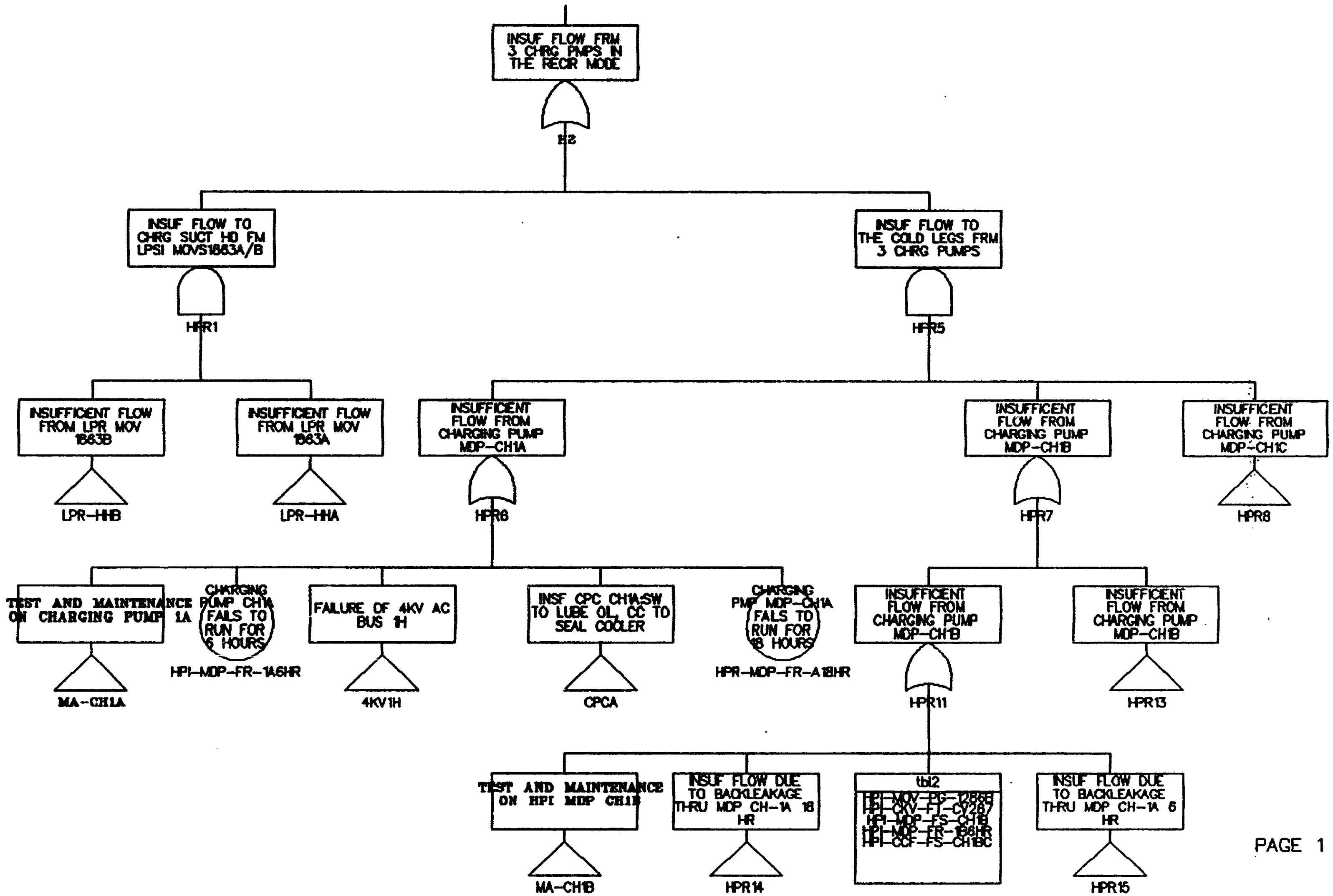
HIGH PRESSURE INJECTION – RCP SEALS (D3)
(D3-C)



HIGH PRESSURE INJECTION – EMERGENCY BORATION (HPI-EB)
(D4)

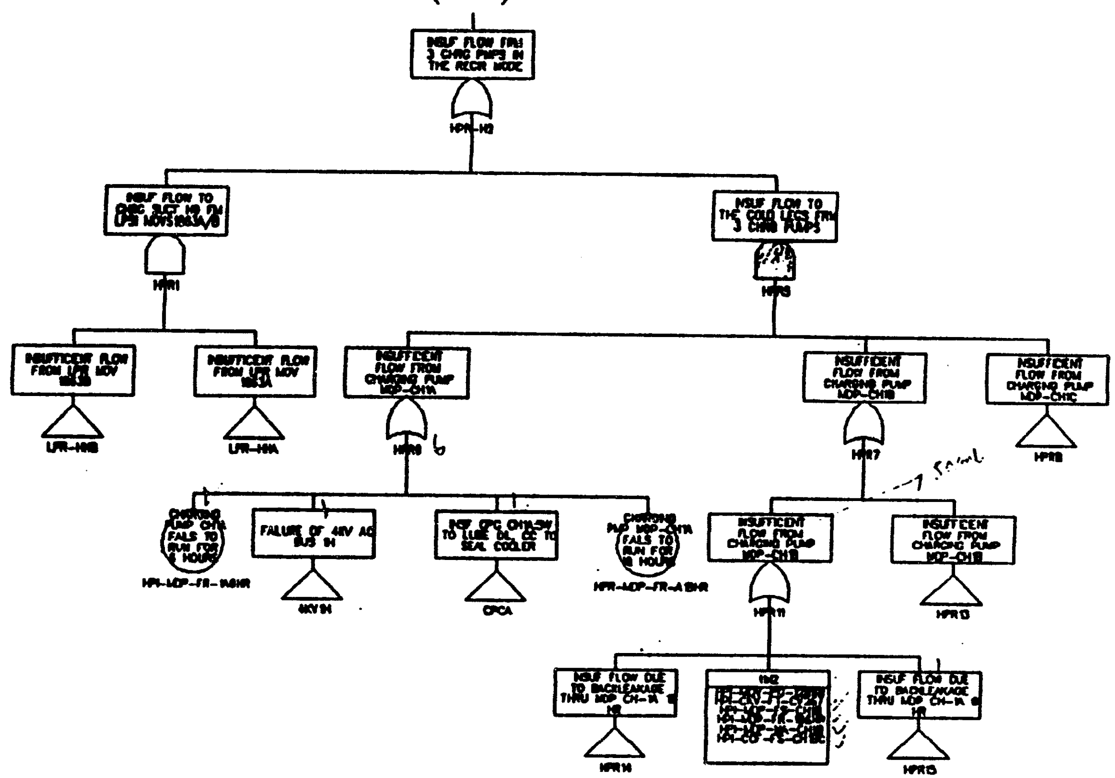


HIGH PRESSURE RECIRCULATION (HPR-H2)
(H2)

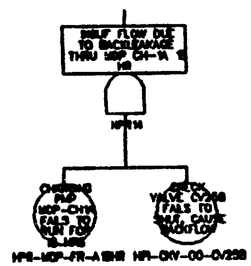


C-187

HIGH PRESSURE RECIRCULATION (HPR-H2)
(H2)

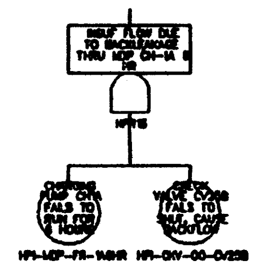


HIGH PRESSURE RECIRCULATION (HPR–H2)
(HPR14)

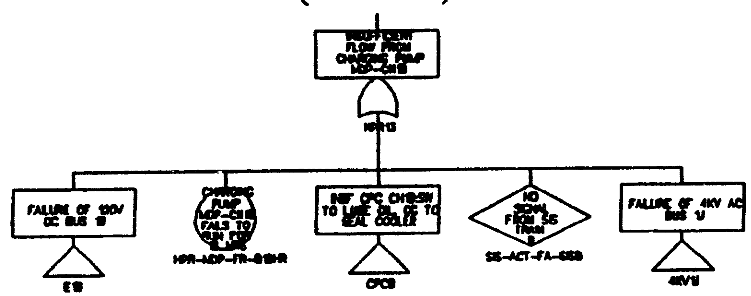


C-188

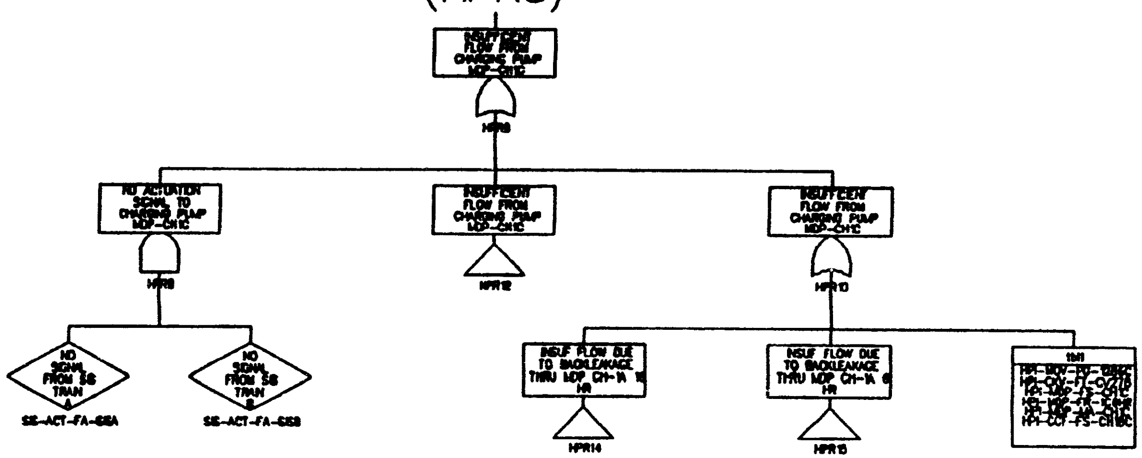
HIGH PRESSURE RECIRCULATION (HPR–H2)
(HPR15)



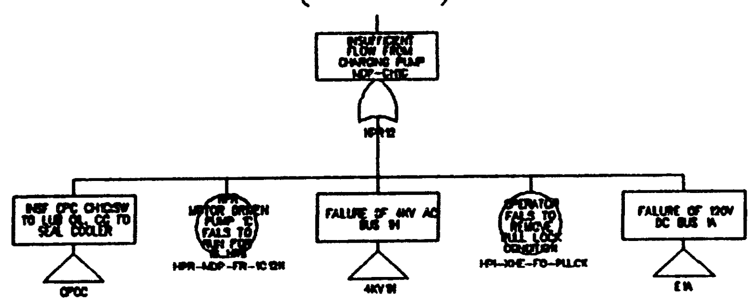
HIGH PRESSURE RECIRCULATION (HPR–H2)
(HPR13)



HIGH PRESSURE RECIRCULATION (HPR-H2)
(HPR8)

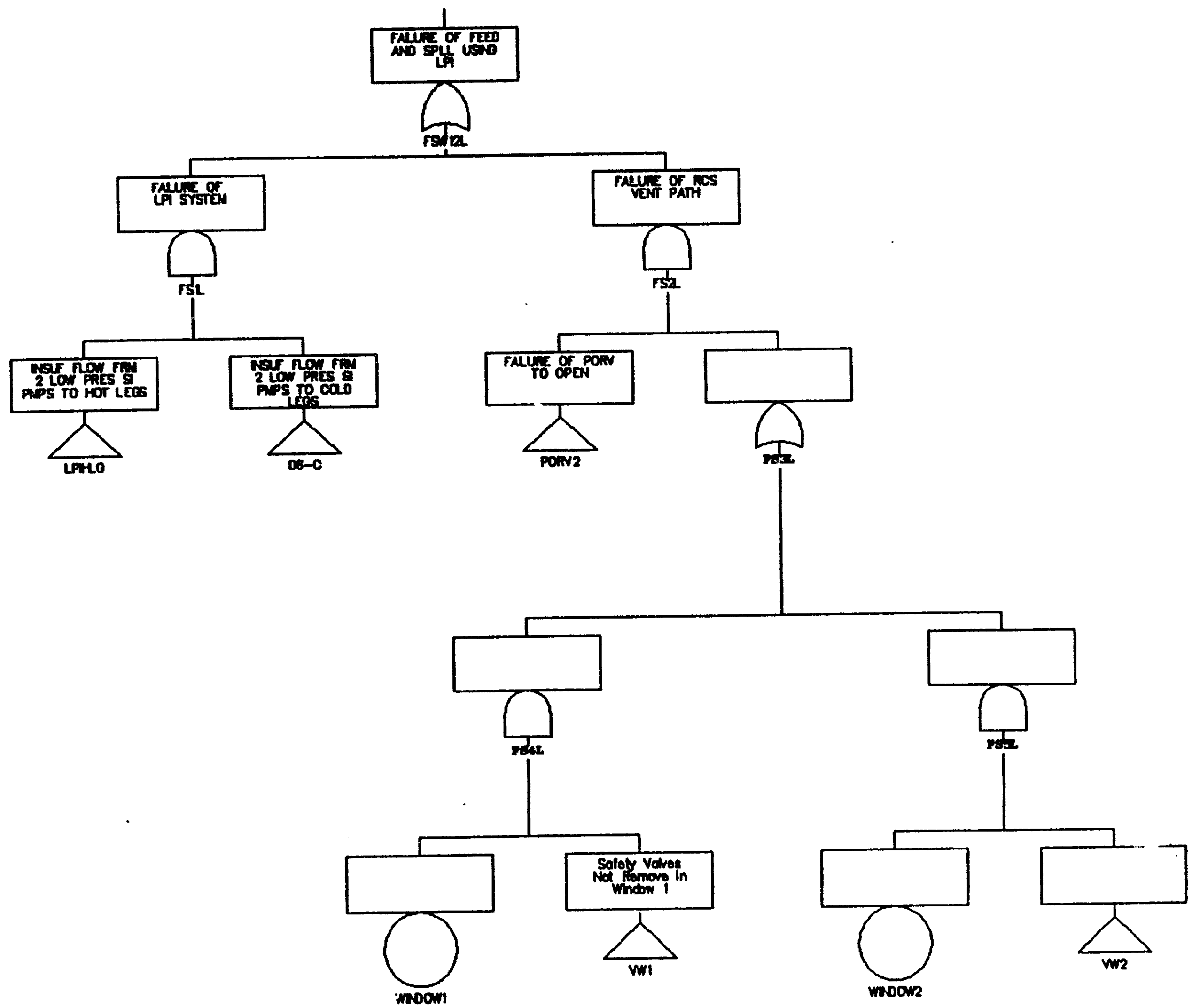


HIGH PRESSURE RECIRCULATION (HPR-H2)
(HPR12)

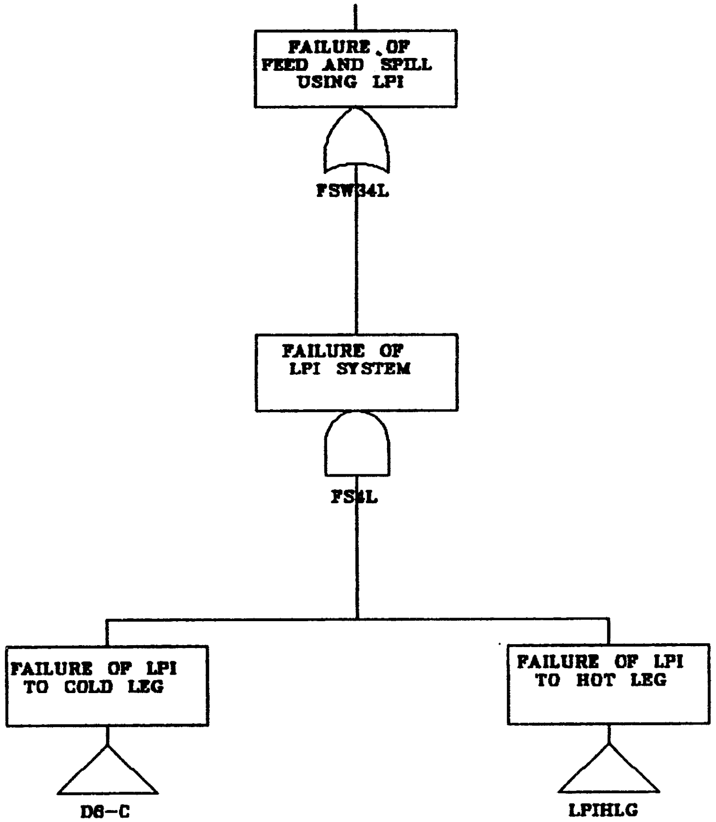


Appendix C.10 Low Pressure Injection and Recirculation System

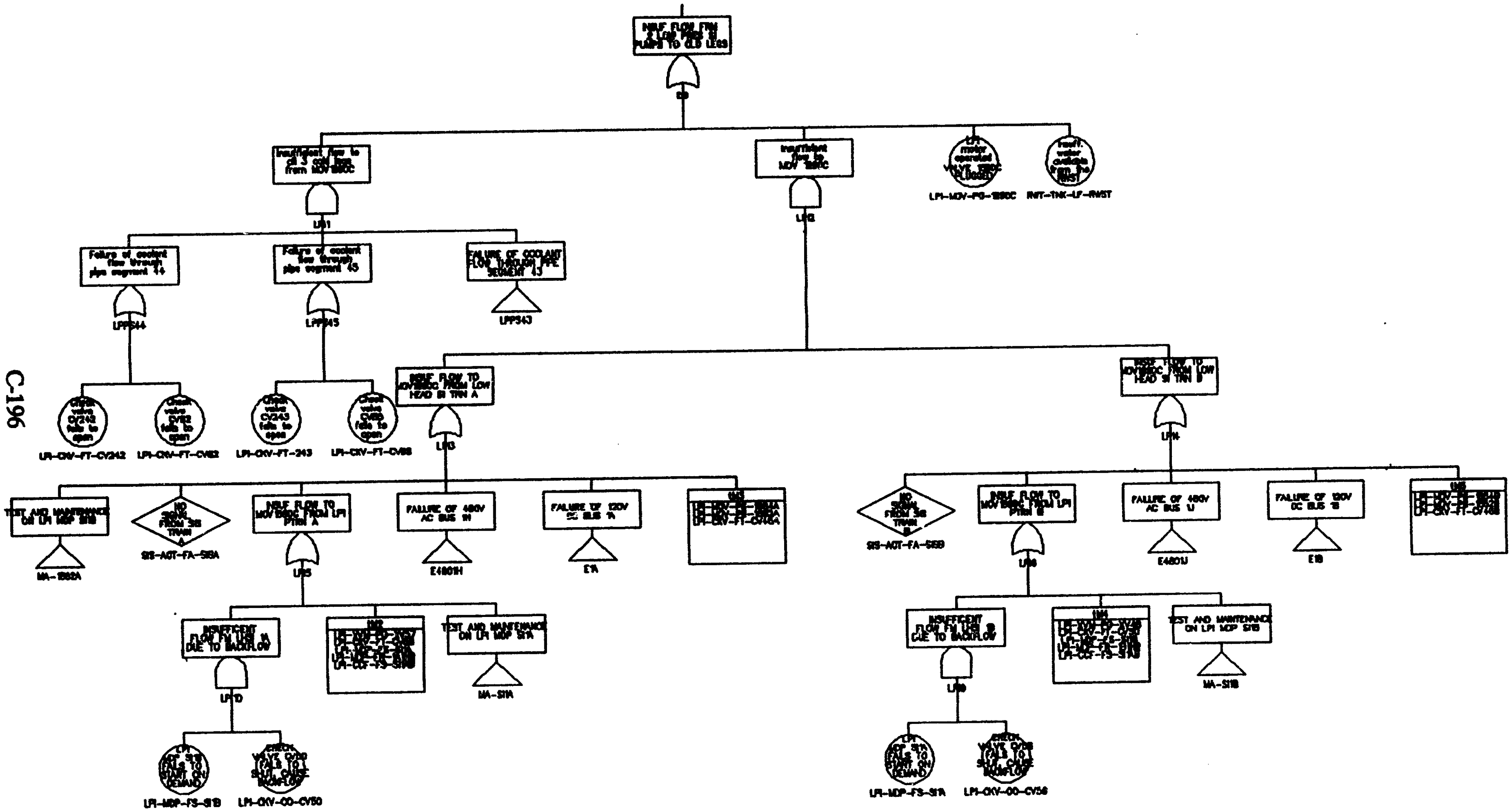
FAILURE OF FEED AND SPILL USING LPI SYSTEM – WINDOW 1&2



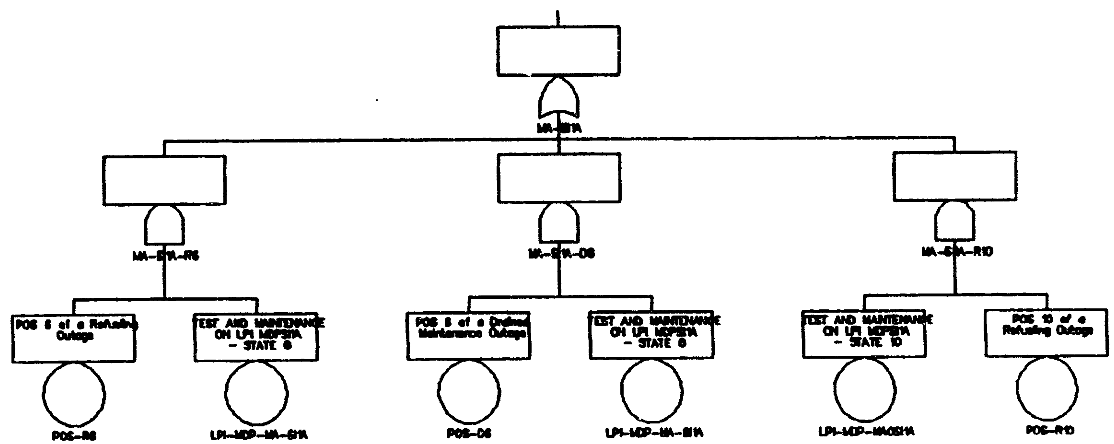
FAILURE OF FEED AND SPILL USING LPI SYSTEM – WINDOW 3&4 (FSW34L)



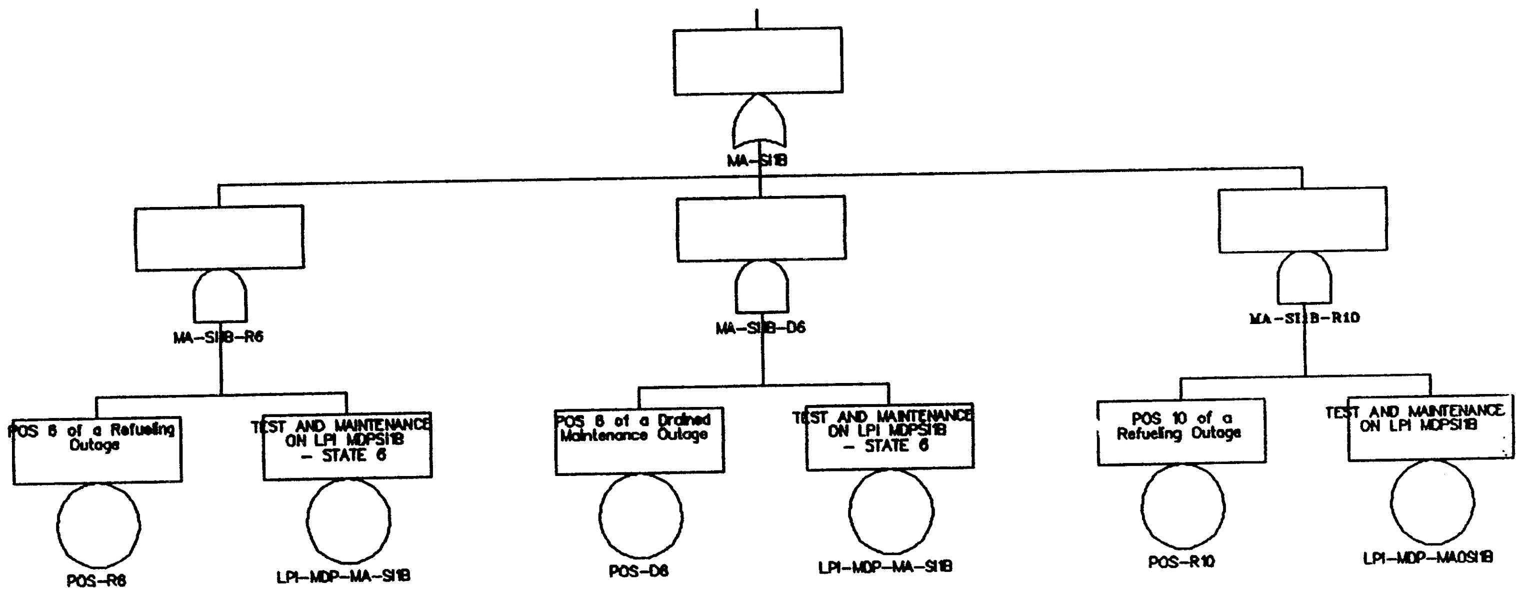
LOW PRESSURE INJECTION (LPI)
(D6)



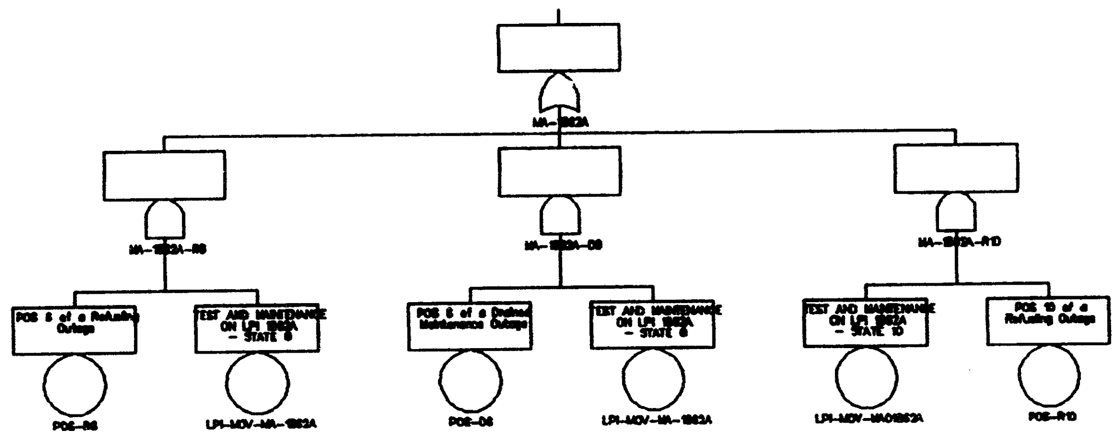
TEST AND MAINTENANCE ON LPI MDPSI1A



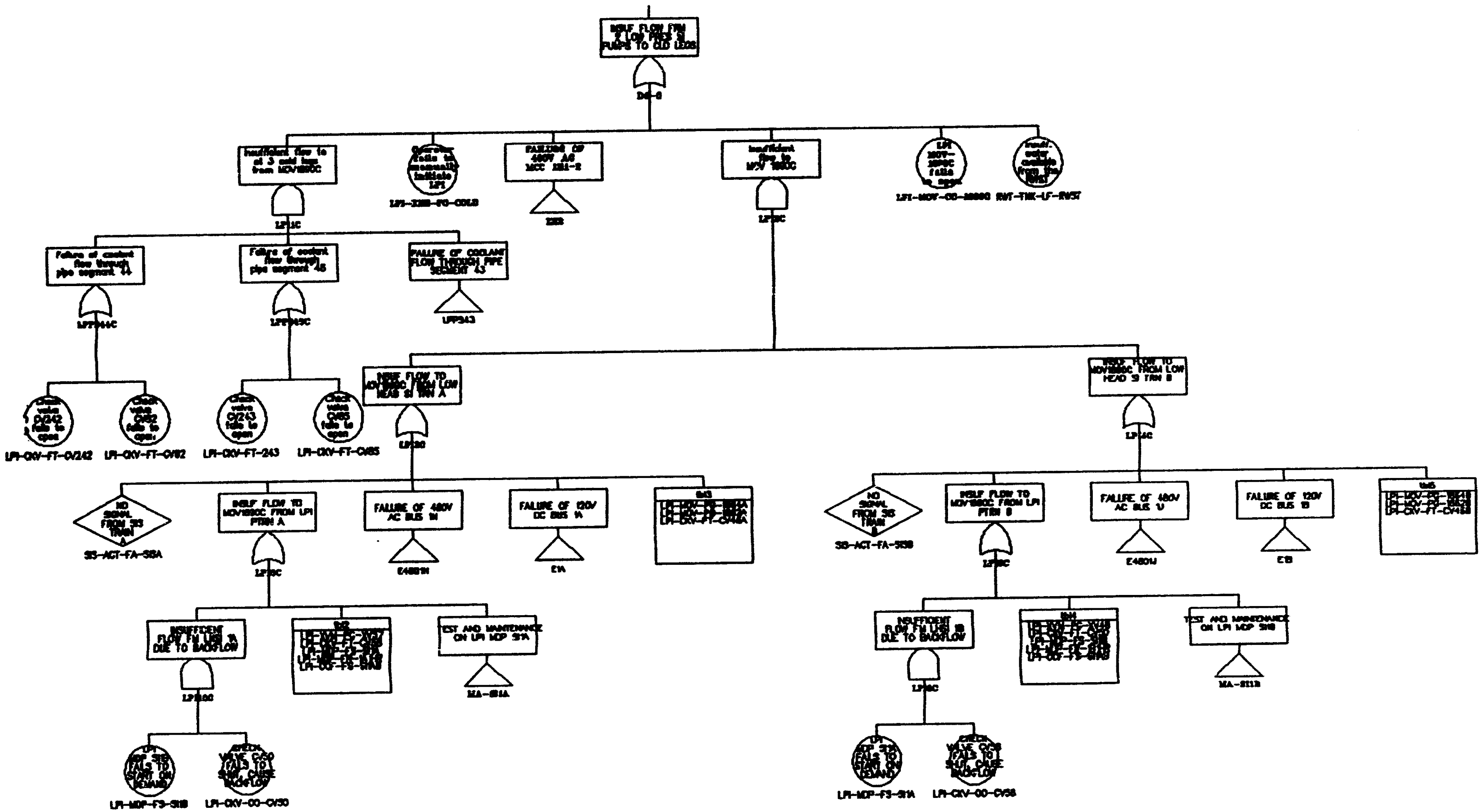
TEST AND MAINTENANCE ON LPI MDPSI1B



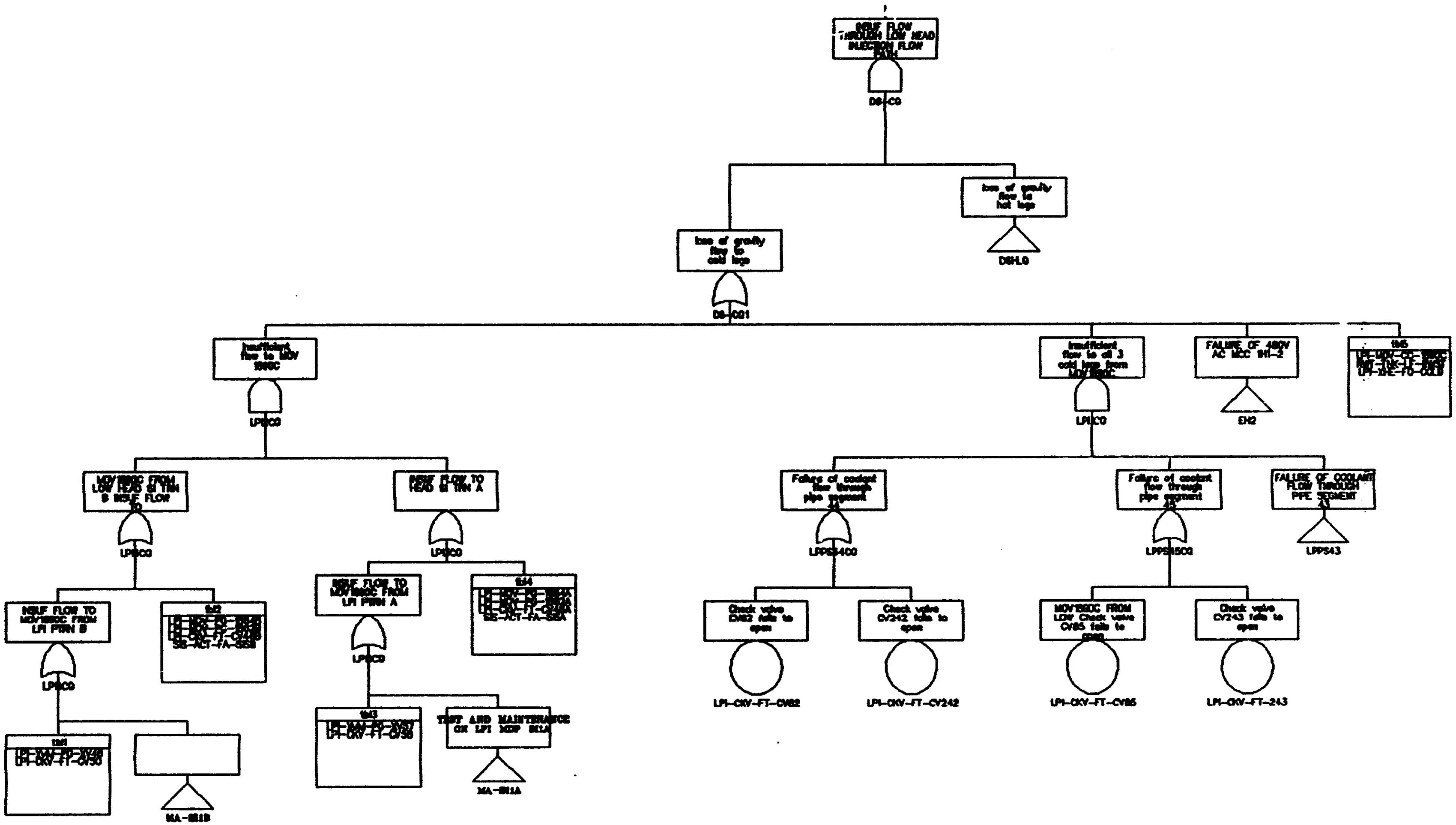
TEST AND MAINTENANCE ON LPI 1862A



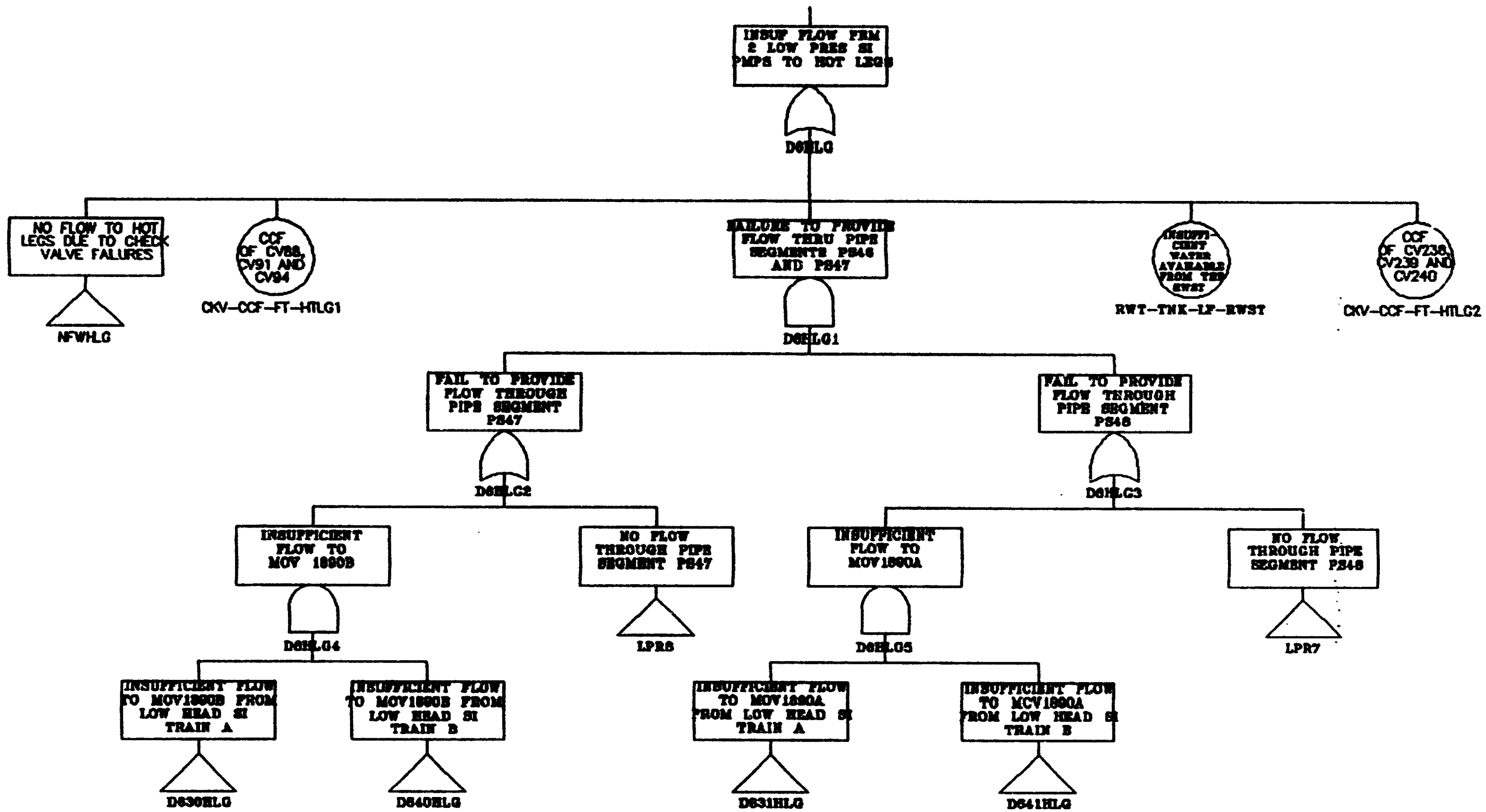
LOW PRESSURE INJECTION (LPI)
(D6-C)



Loss of LPI Flow Path
(D6–CG)

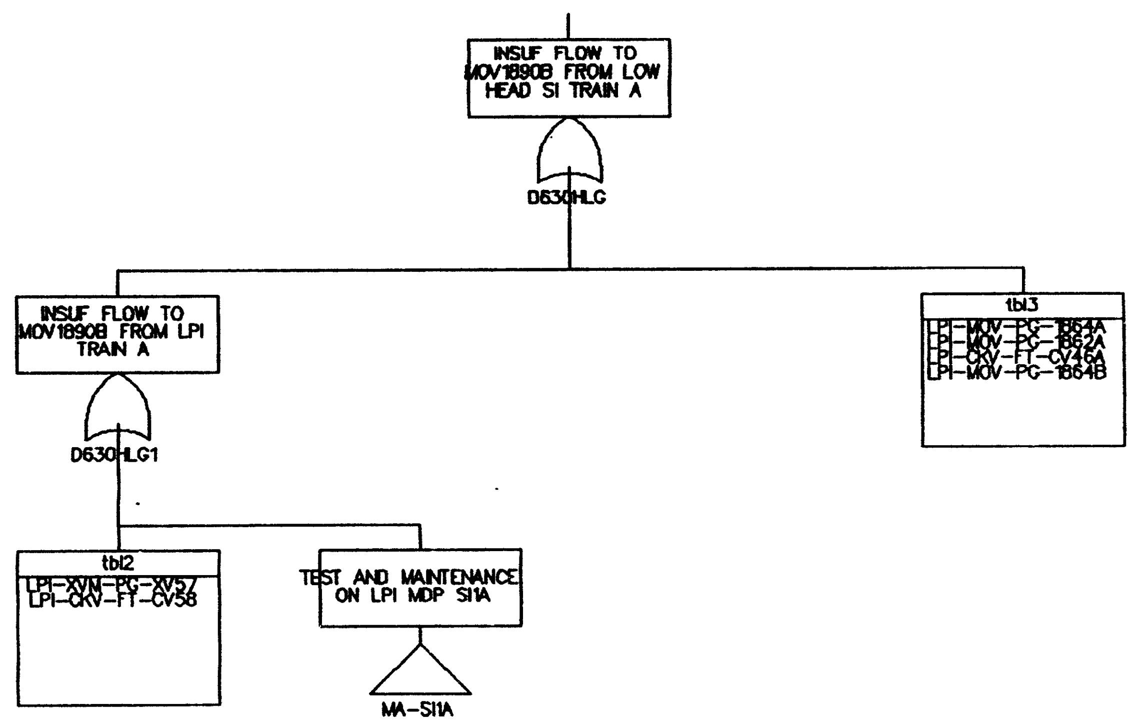


LOW PRESSURE INJECTION PATH TO HOT LEGS
(D6HLG)



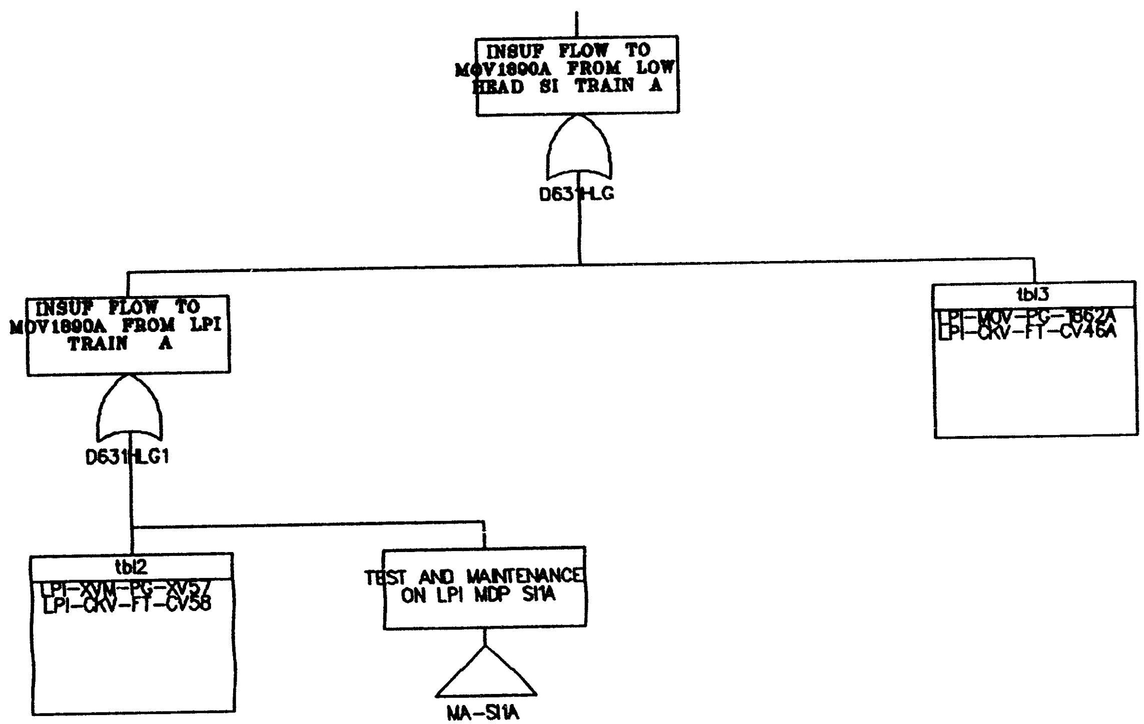
LOW PRESSURE INJECTION TO HOT LEGS

(D630HLG)



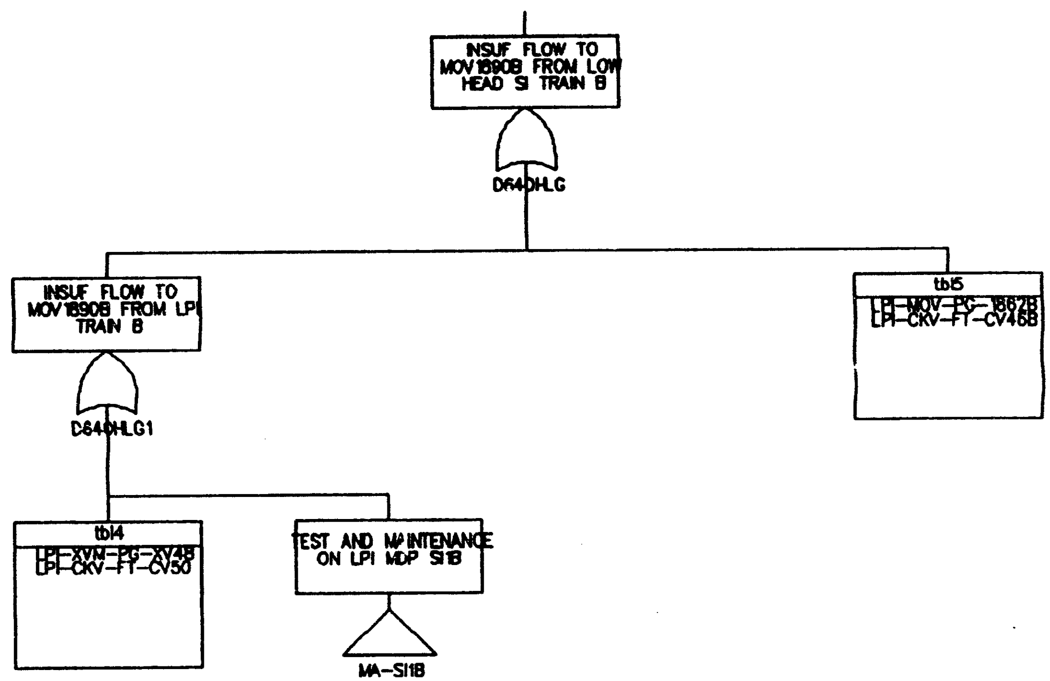
LOW PRESSURE INJECTION TO HOT LEGS

(D631HLG)



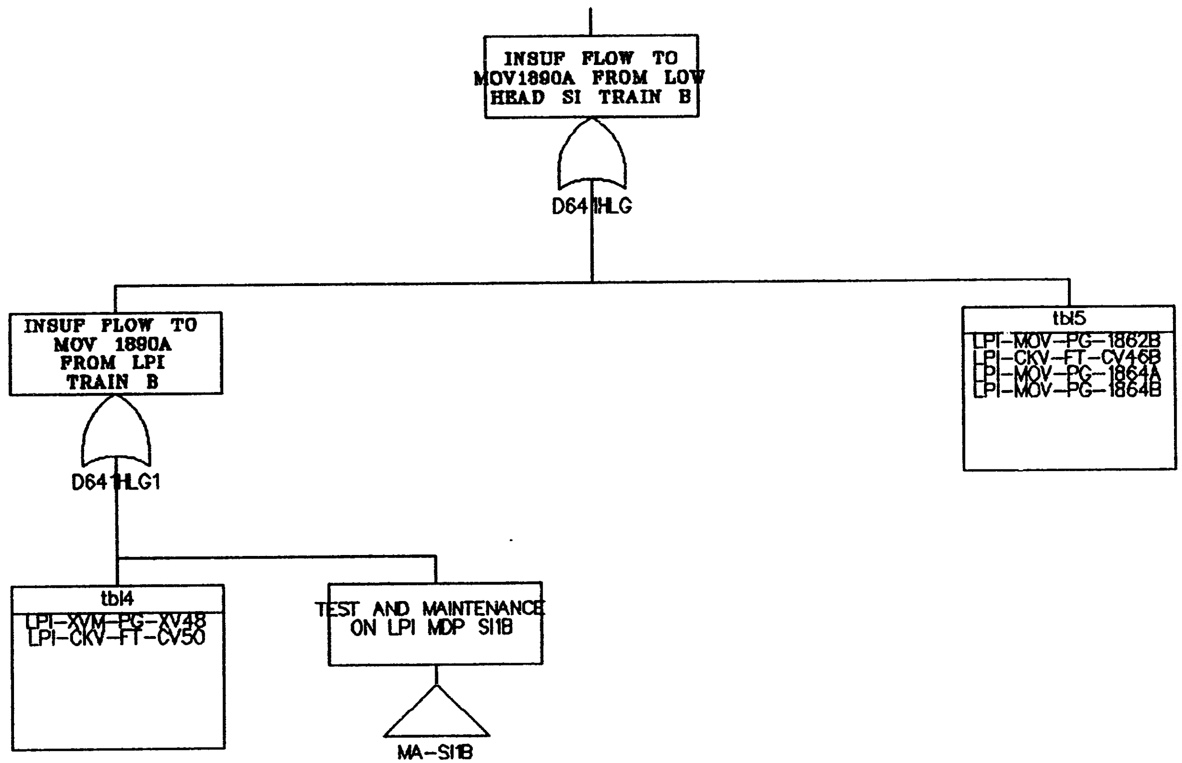
LOW PRESSURE INJECTION TO HOT LEG

(D640HLG)



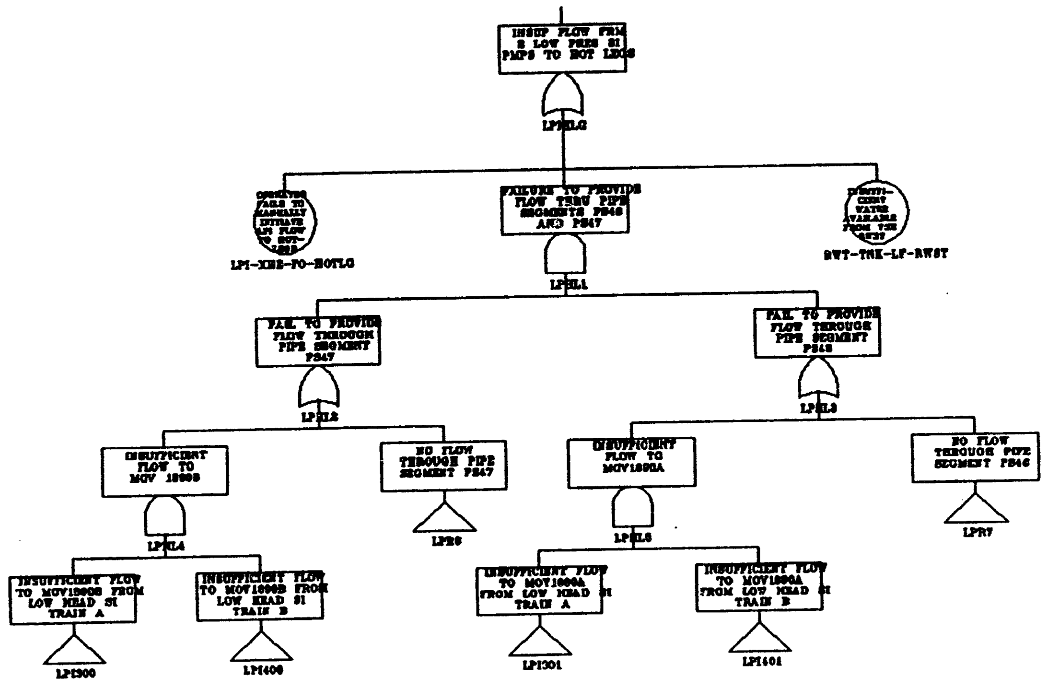
LOW PRESSURE INJECTION TO HOT LEGS

(D641HLG)



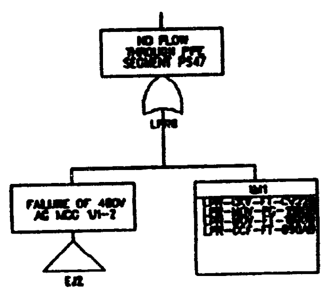
LOW PRESSURE INJECTION TO HOT LEGS (LPIHLG)

LPIHLG



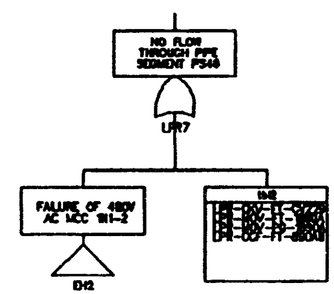
LOW PRESSURE INJECTION TO HOT LEGS (LPIHLG)

LPR6



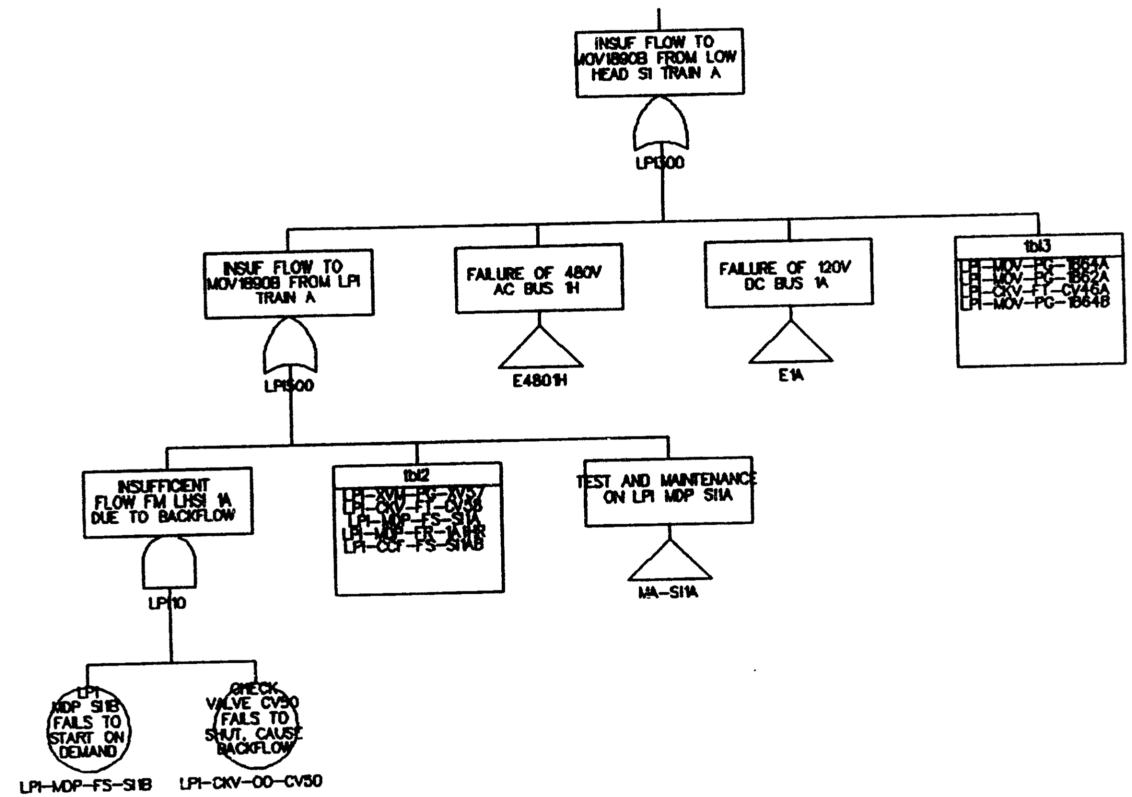
LOW PRESSURE INJECTION TO HOT LEGS (LPIHLG)

LPR7

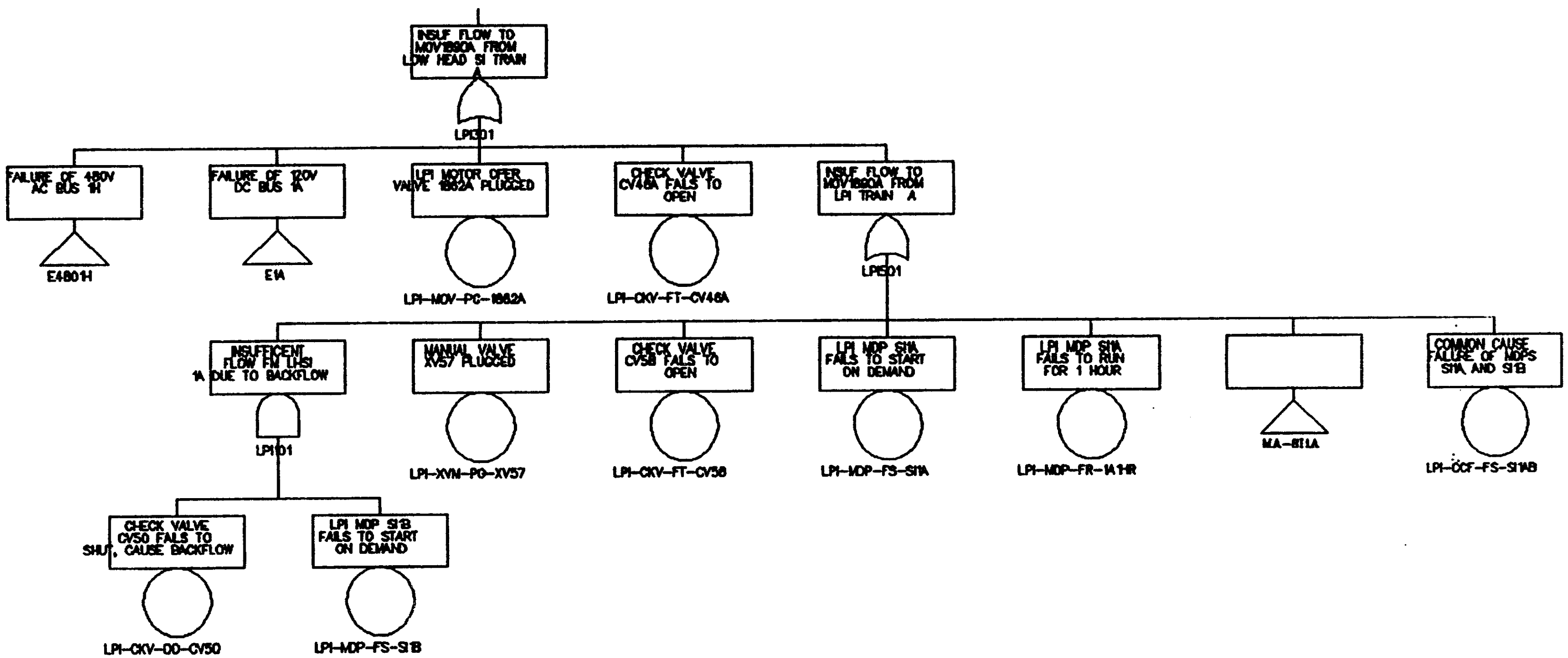


LOW PRESSURE INJECTION TO HOT LEGS (LPIHLG)

LPI300

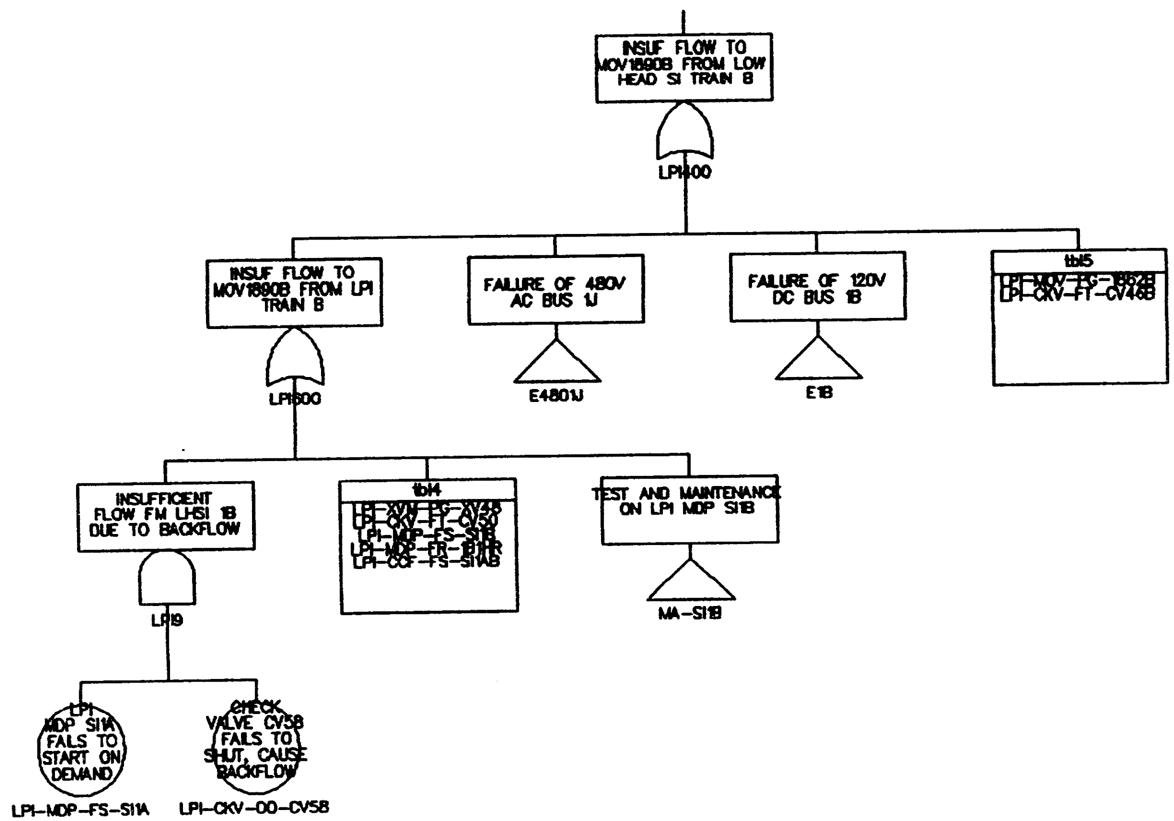


LOW PRESSURE INJECTION TO HOT LEGS (LPIHLG)



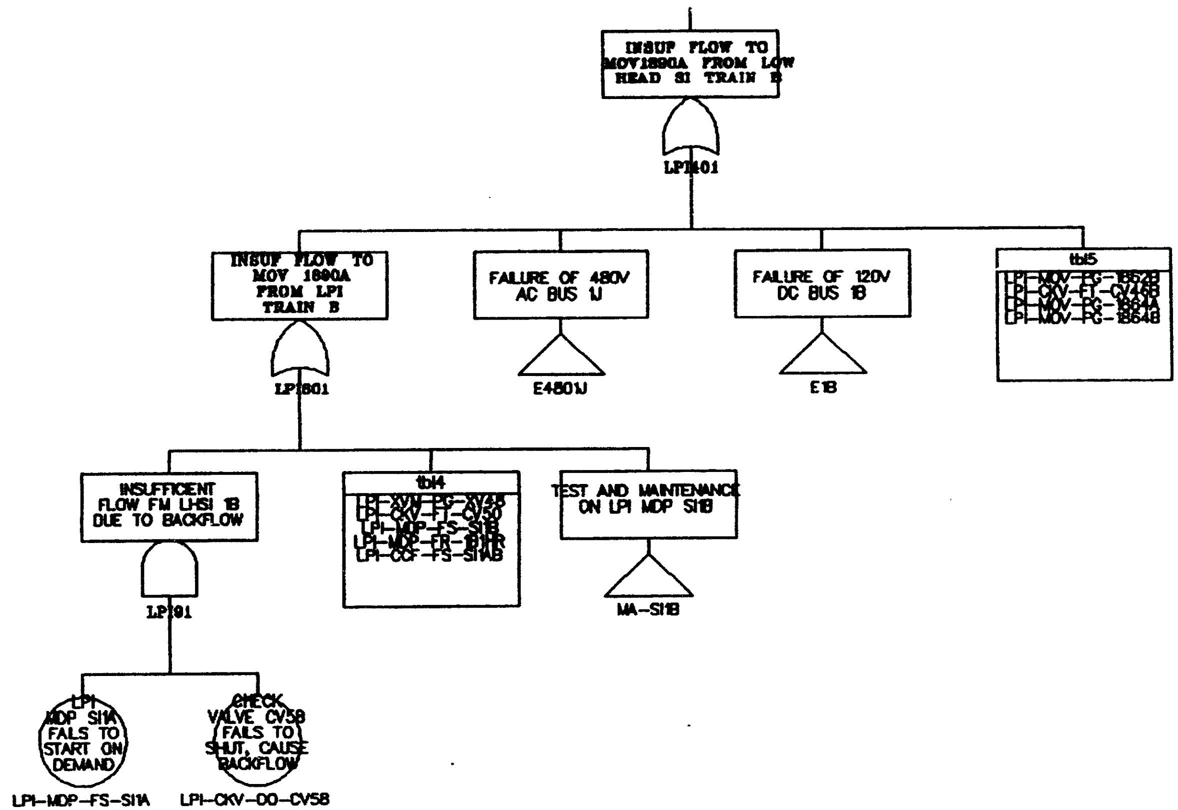
LOW PRESSURE INJECTION TO HOT LEGS (LPIHLG)

LPI400

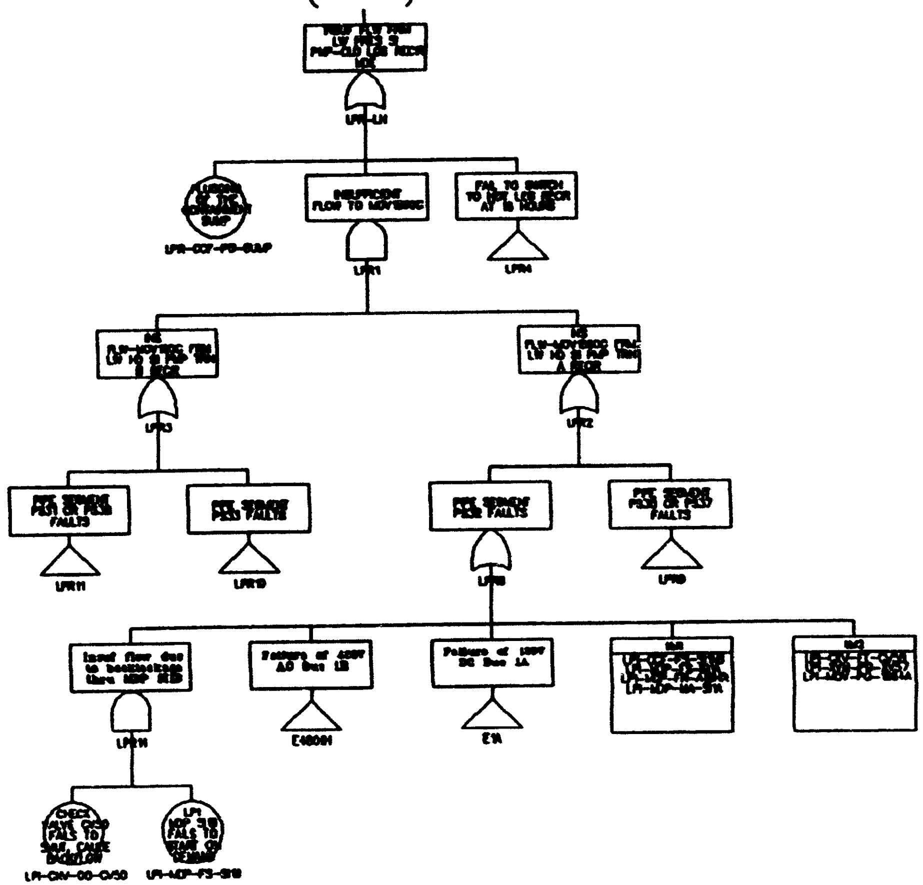


LOW PRESSURE INJECTION TO HOT LEGS (LPIHLG)

LPI401

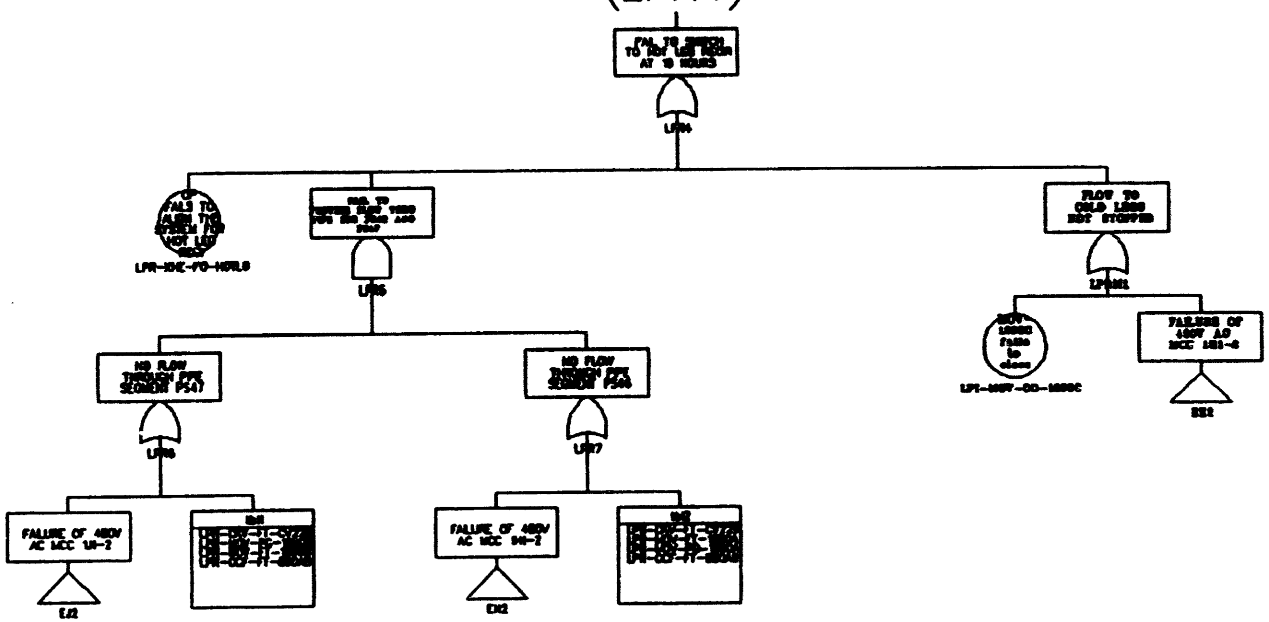


LOW PRESSURE RECIRCULATION – TO RCS (LPR–LH) (HAS)

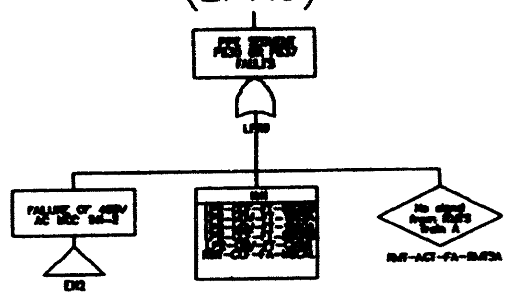


C-215

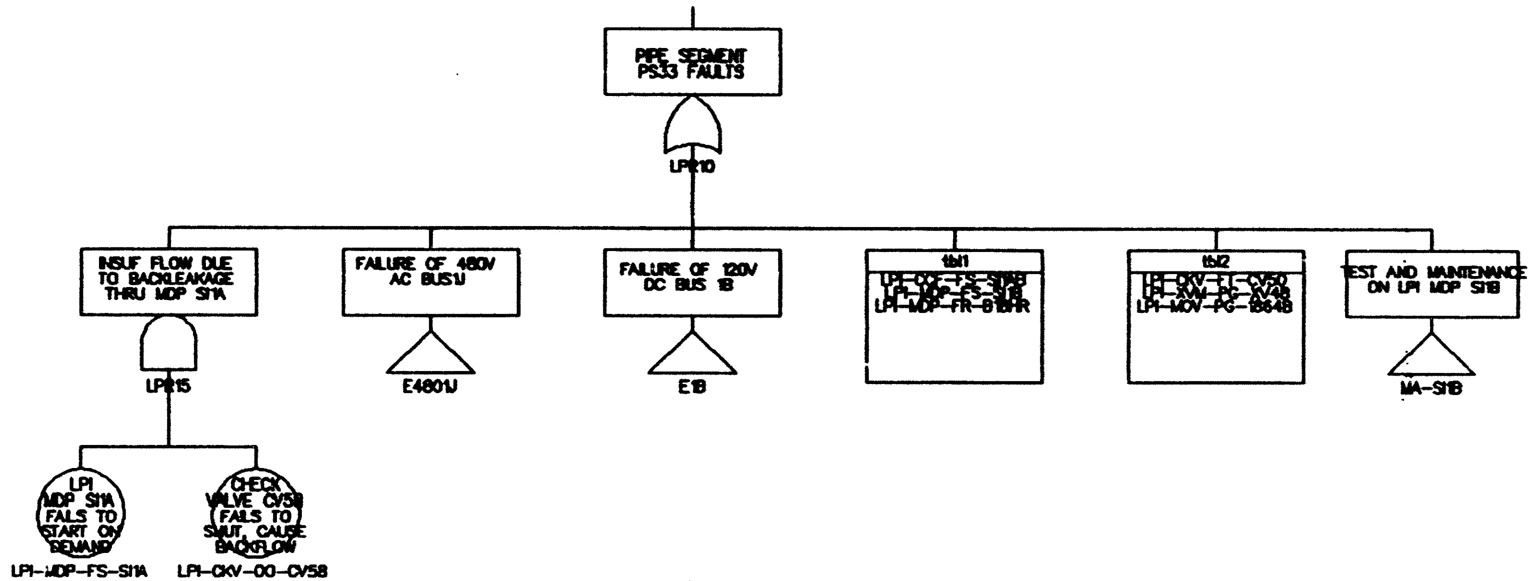
LOW PRESSURE RECIRCULATION – TO RCS (LPR-LH) (LPR4)



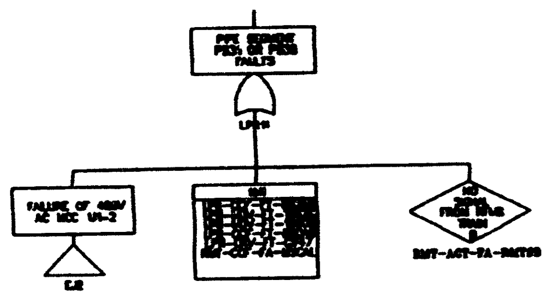
LOW PRESSURE RECIRCULATION – TO RCS (LPR–LH)
(LPR9)



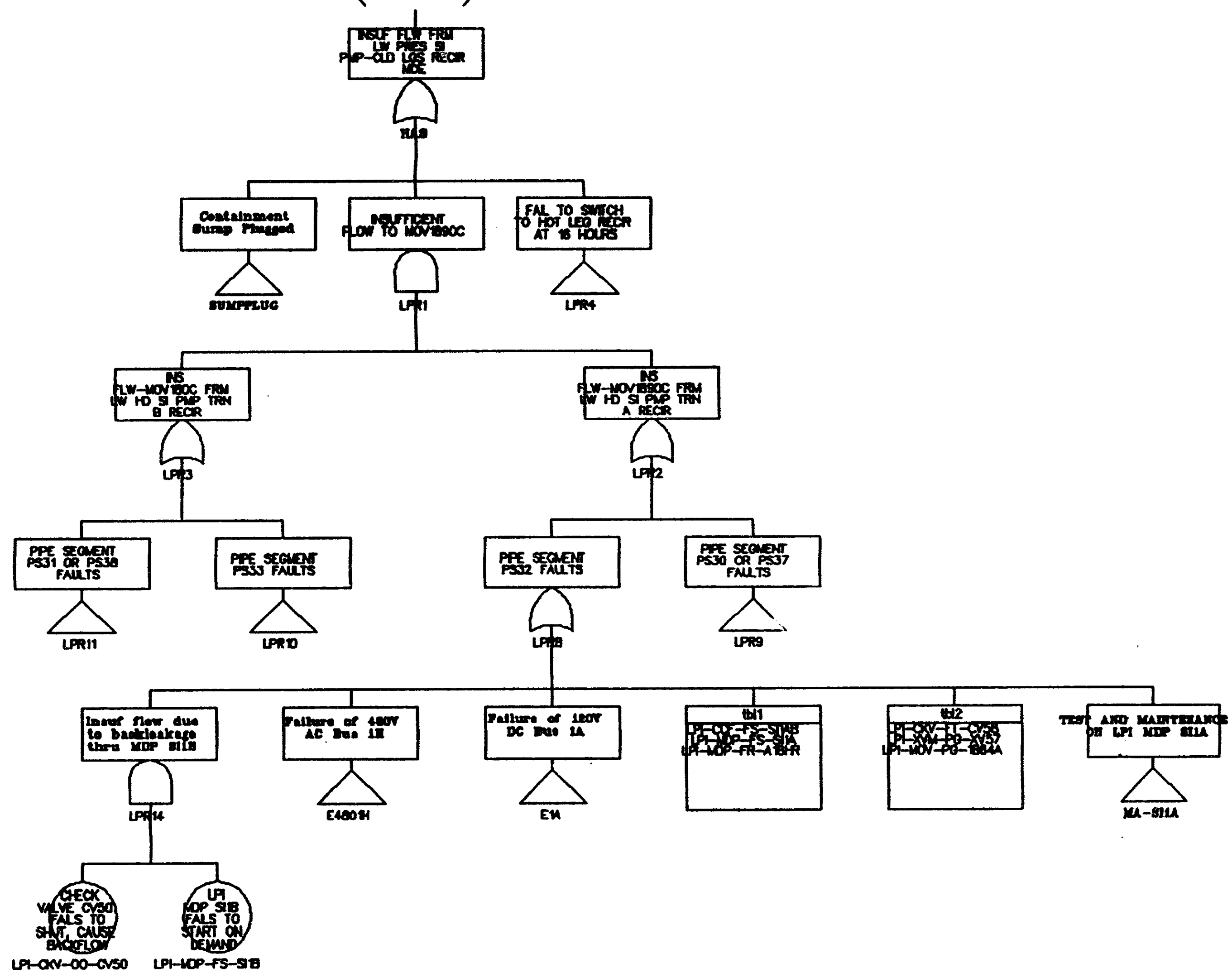
LOW PRESSURE RECIRCULATION – TO RCS (LPR-LH) (LPR10)



LOW PRESSURE RECIRCULATION – TO RCS (LPR–LH)
(LPR11)

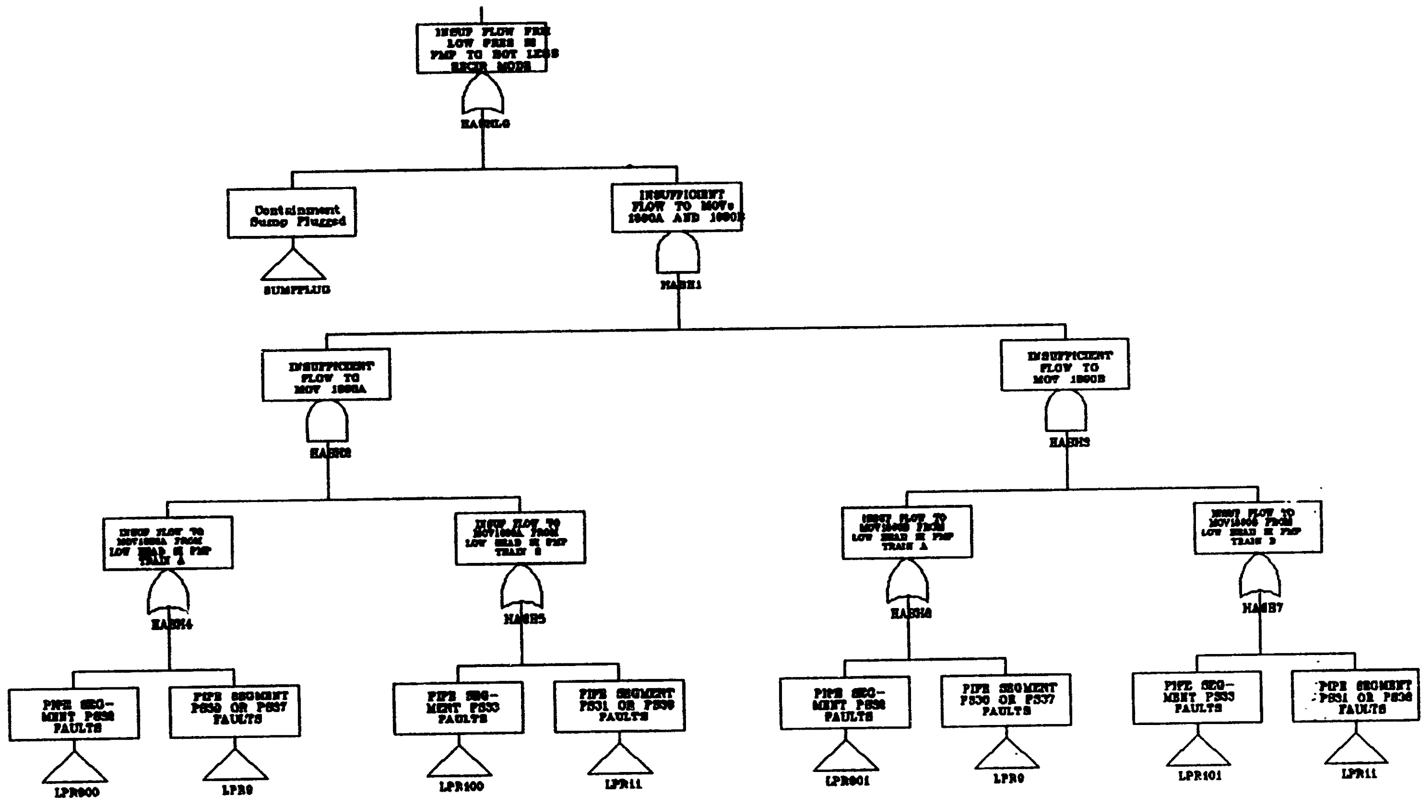


LOW PRESSURE RECIRCULATION – TO RCS (LPR–LH) (HAS)



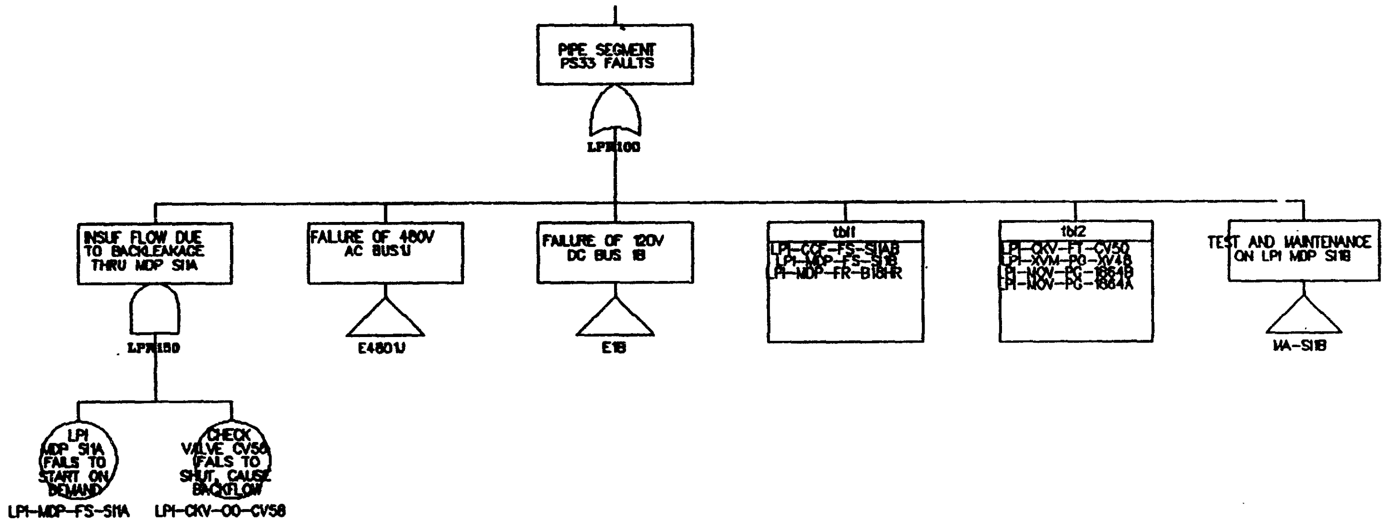
LPI TO HOT LEGS–RECIRCULATION MODE (HASHLG)

HASHLG



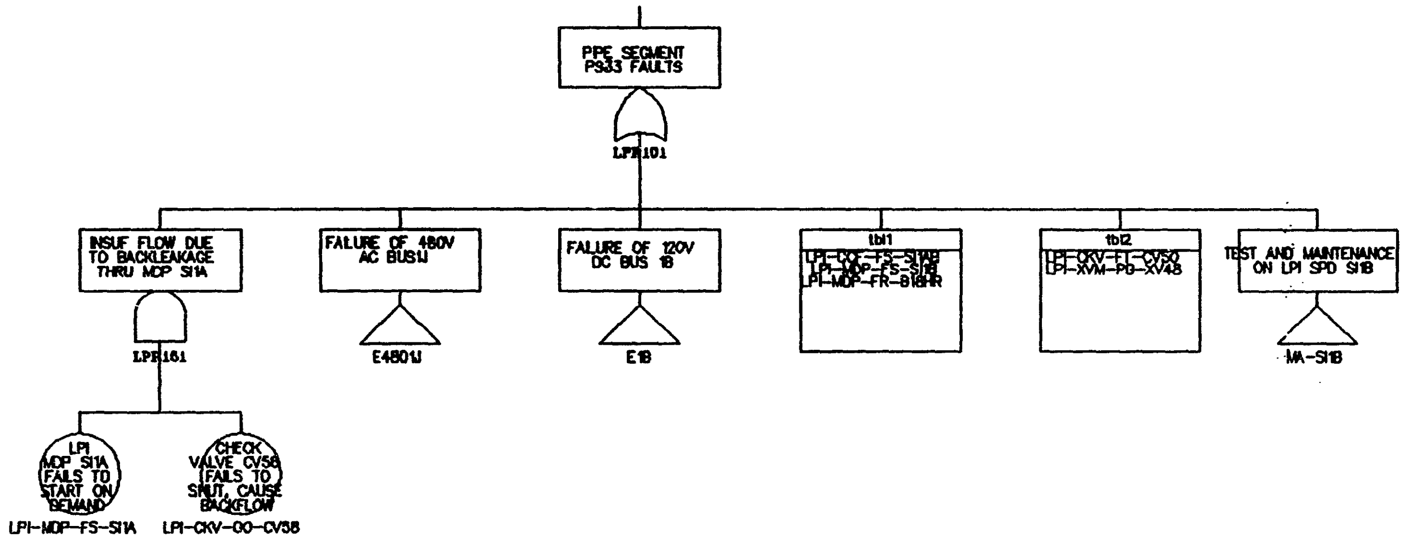
LPI TO HOT LEGS–RECIRCULATION MODE (HASHLG)

LPR100



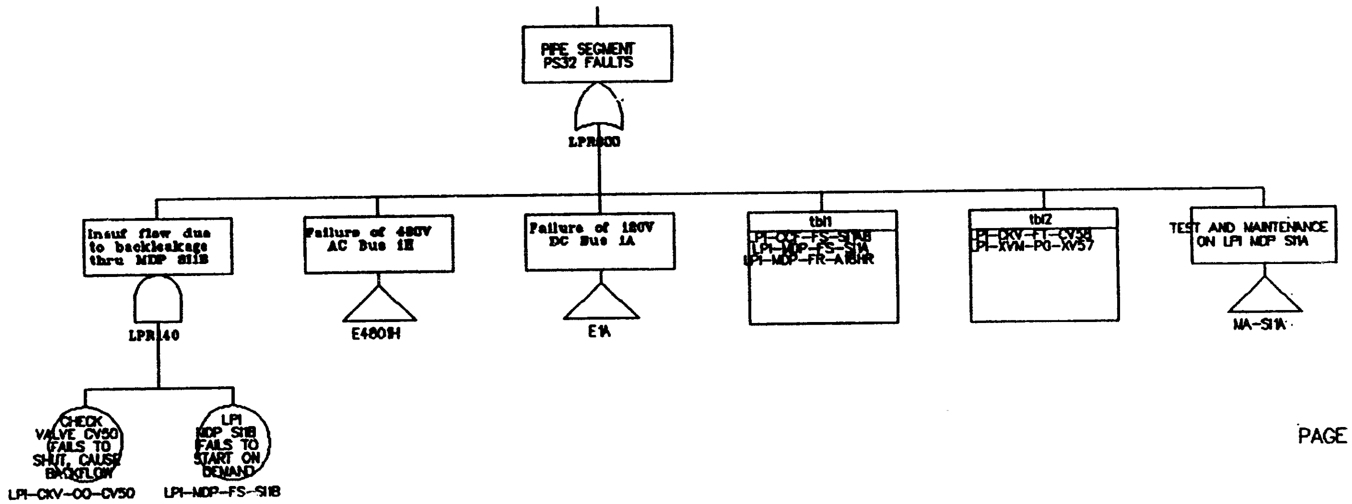
LPI TO HOT LEGS-RECIRCULATION MODE (HASHLG)

LPR101

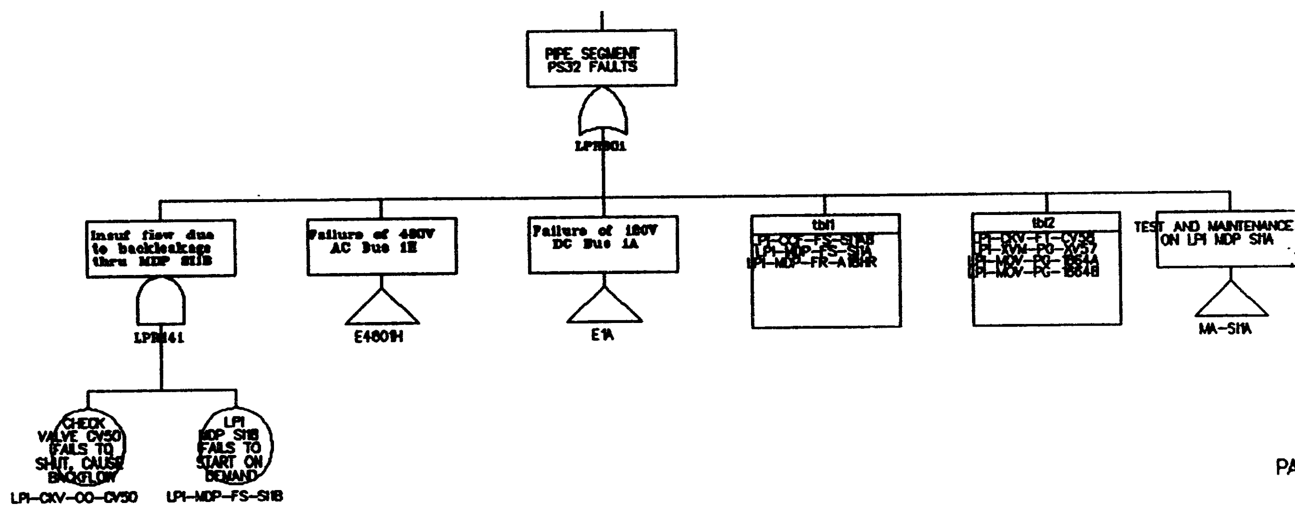


LPI TO HOT LEGS-RECIRCULATION MODE (HASHLG)

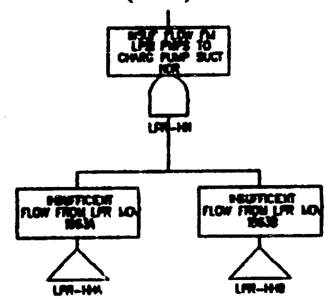
LPR800



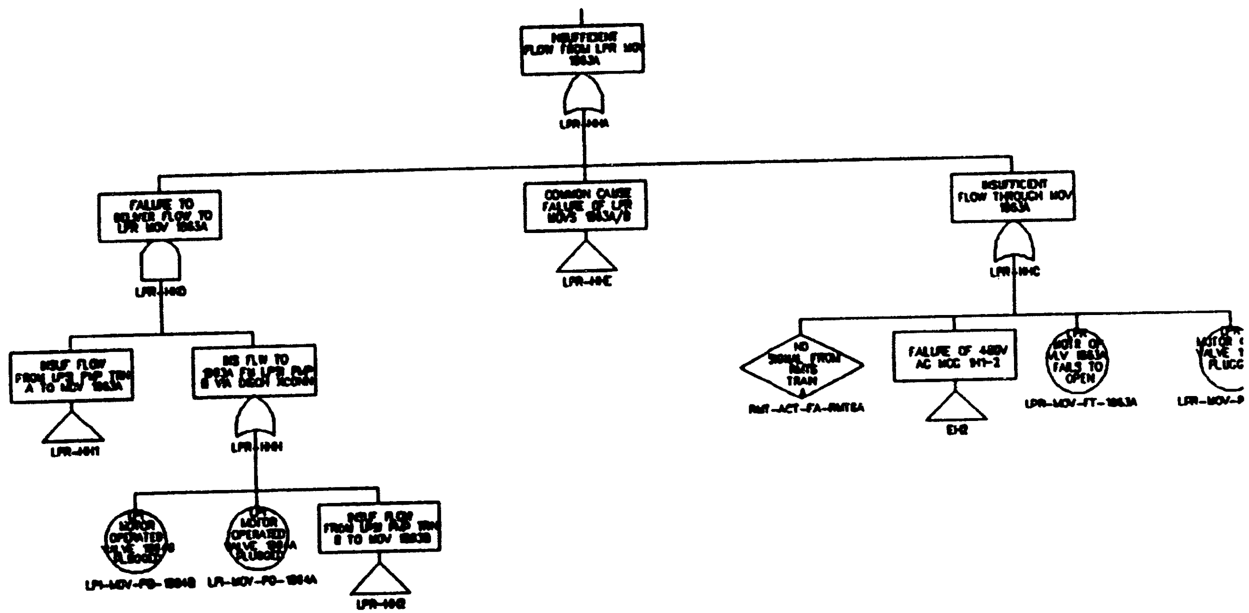
LPI TO HOT LEGS–RECIRCULATION MODE (HASHLG)
LPR801



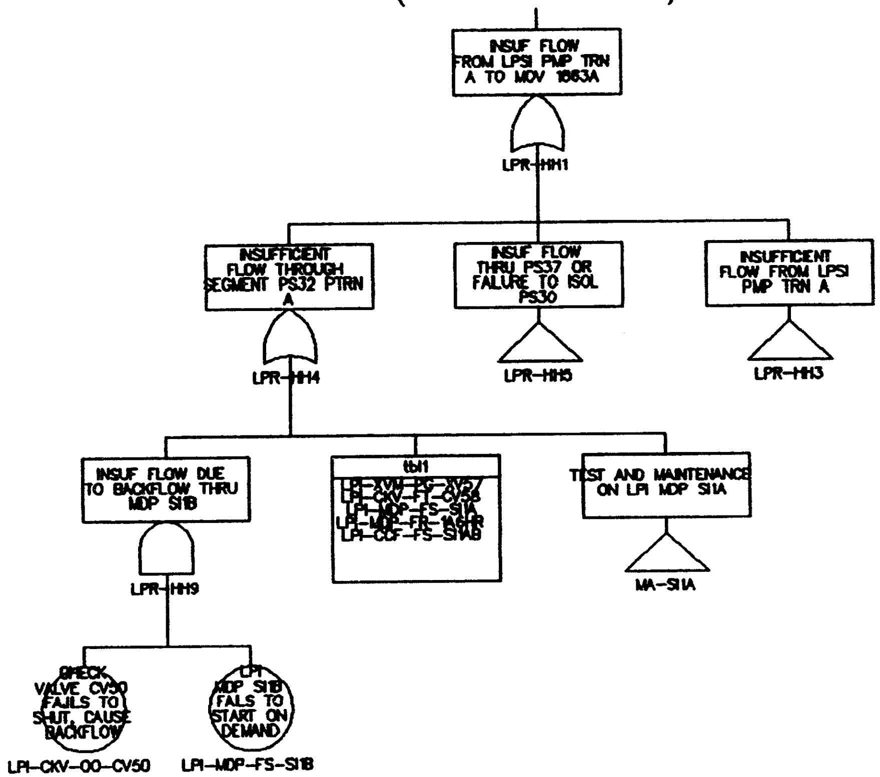
LOW PRESSURE RECIRCULATION - TO HPR (LPR-HH) (H1)



LOW PRESSURE RECIRCULATION – TO HPR (LPR–HH)
(LPR–HHA)

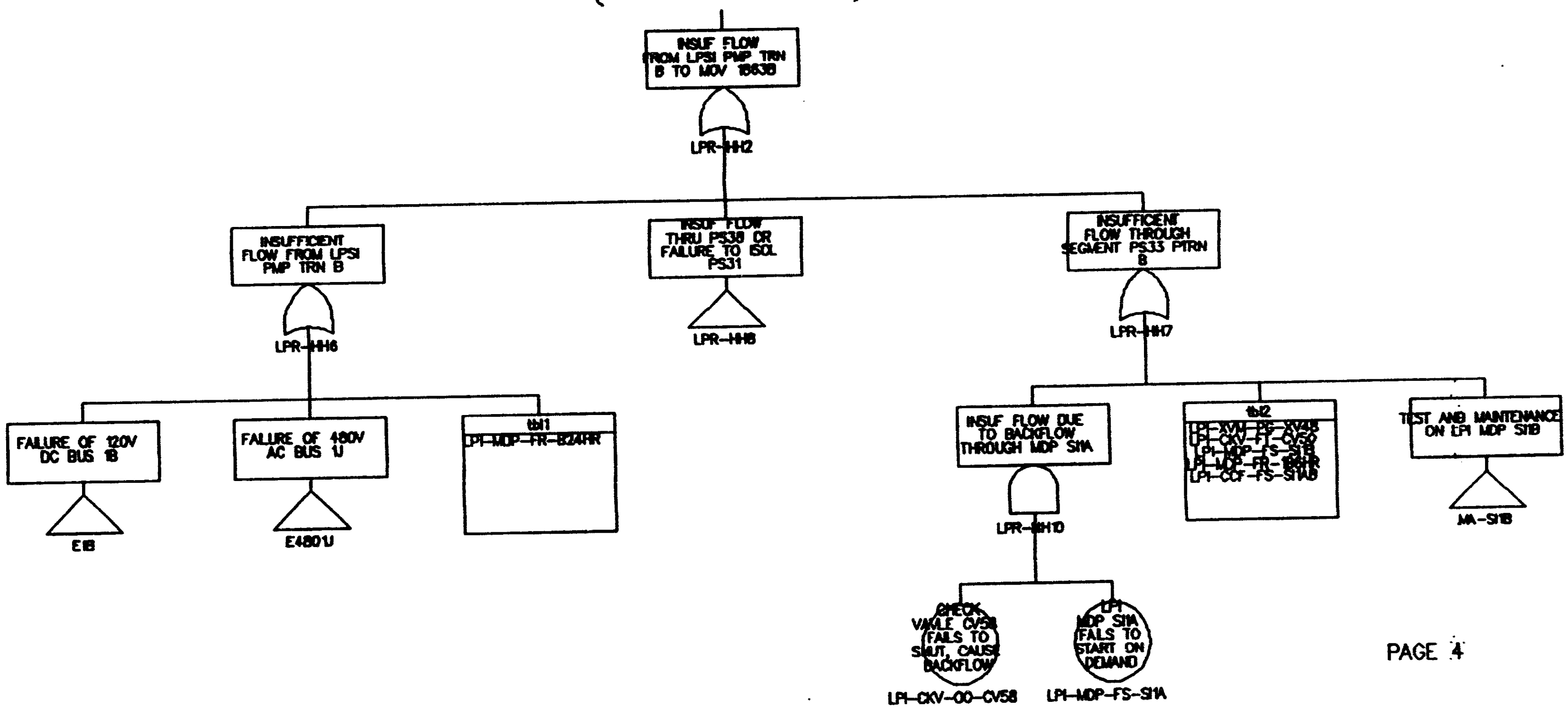


LOW PRESSURE RECIRCULATION – TO HPR (LPR–HH)
(LPR–HH1)



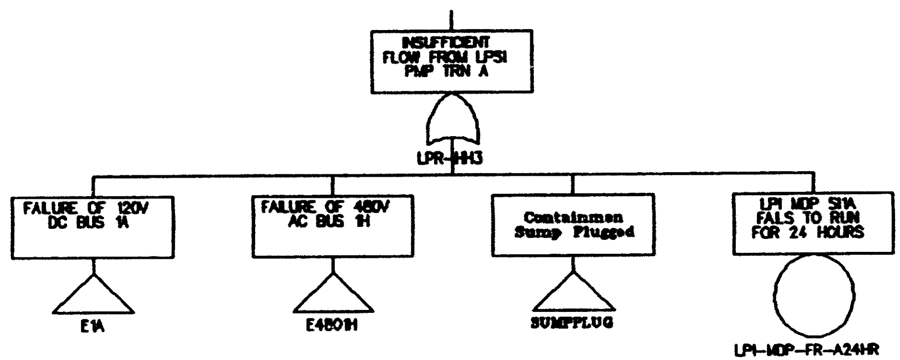
PAGE 2

LOW PRESSURE RECIRCULATION – TO HPR (LPR–HH)
(LPR–HH2)



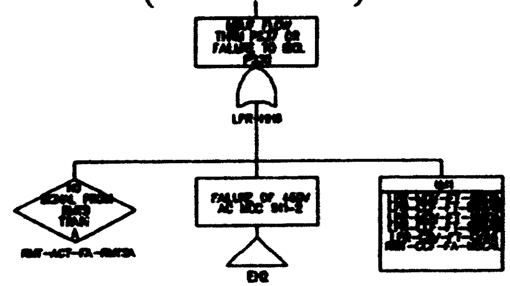
PAGE 4

LOW PRESSURE RECIRCULATION - TO HPR (LPR-HH)



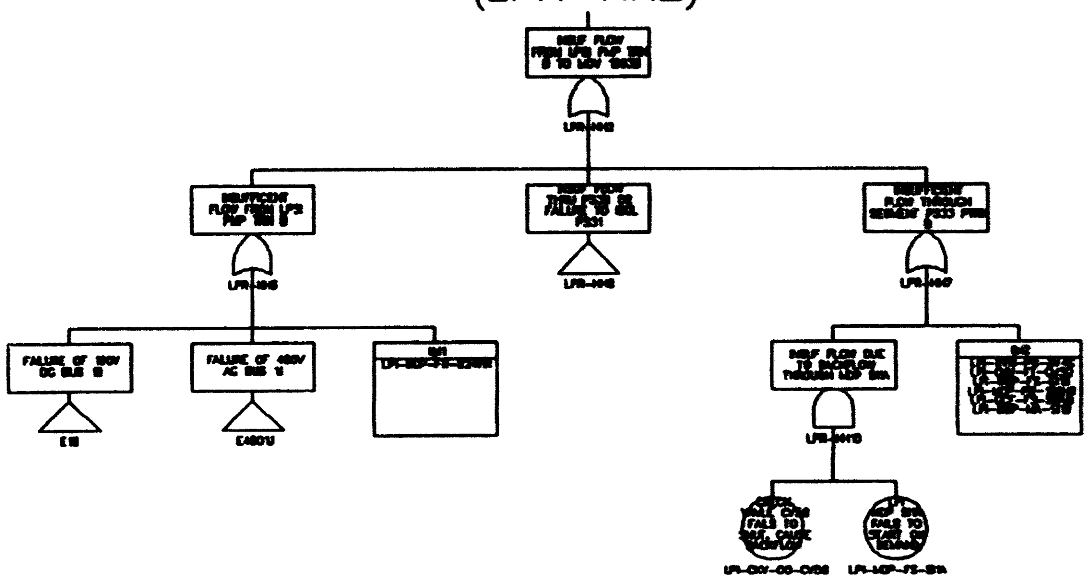
LOW PRESSURE RECIRCULATION – TO HPR (LPR–HH)

(LPR–HH5)

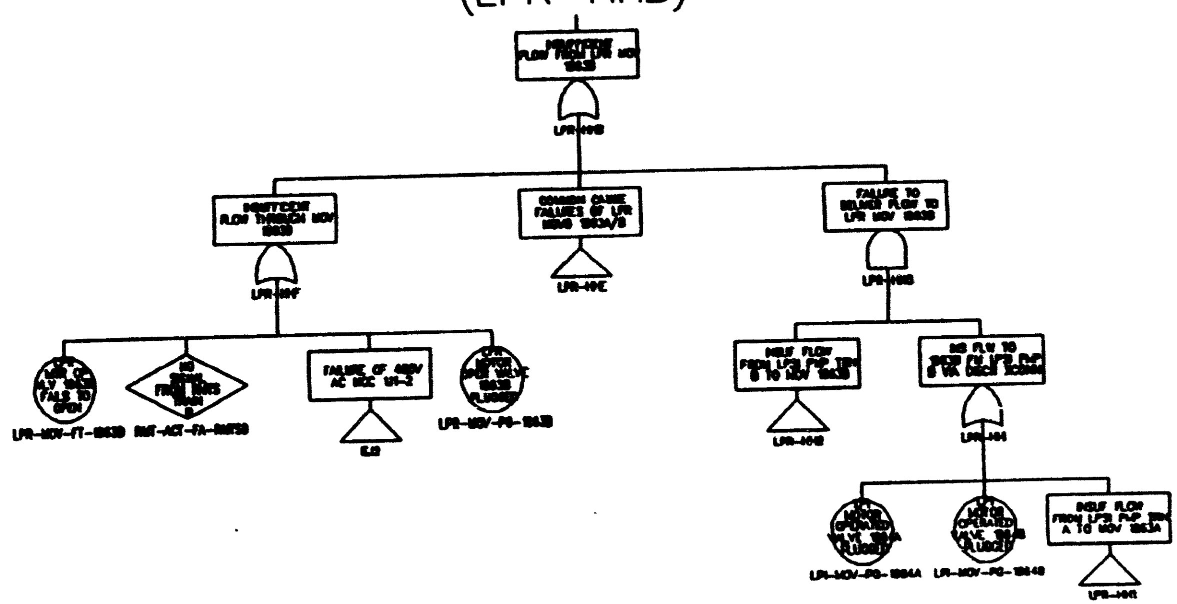


C-231

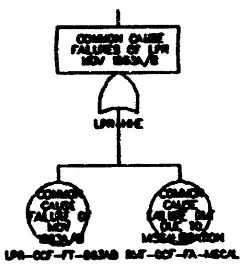
LOW PRESSURE RECIRCULATION – TO HPR (LPR–HH)
(LPR–HH2)



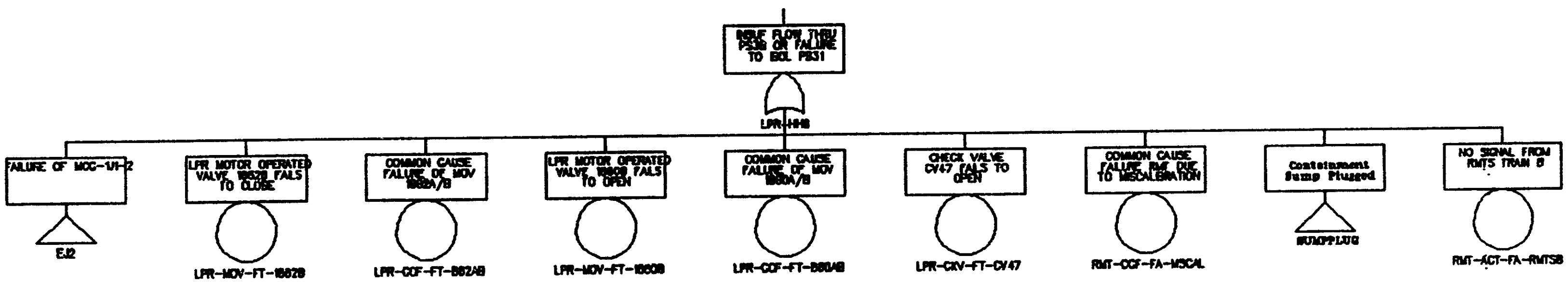
LOW PRESSURE RECIRCULATION – TO HPR (LPR–HH) (LPR–HHB)



LOW PRESSURE RECIRCULATION – TO HPR (LPR–HH)
(LPR–HHE)

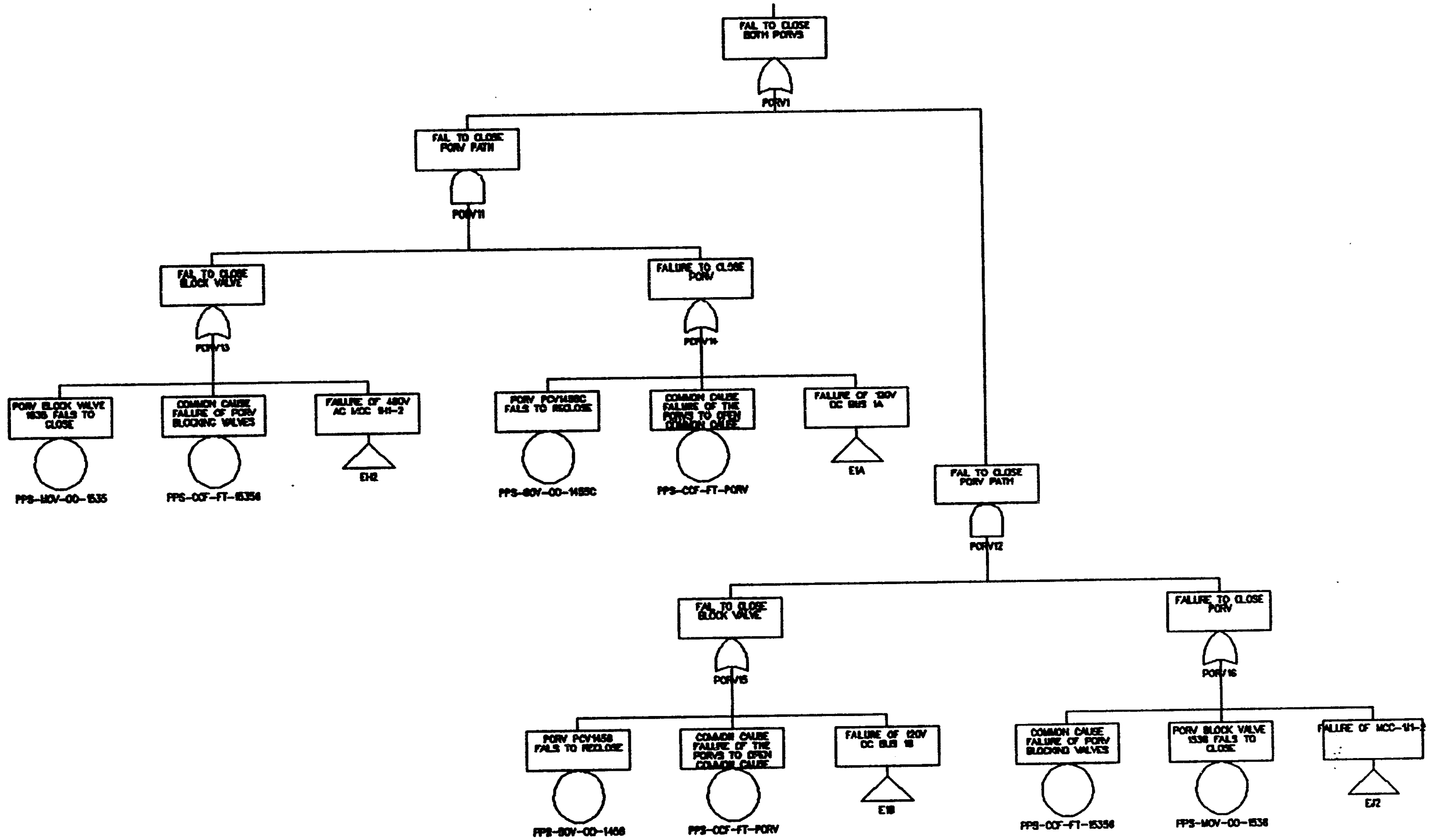


LOW PRESSURE RECIRCULATION – TO HPR (LPR–HH)

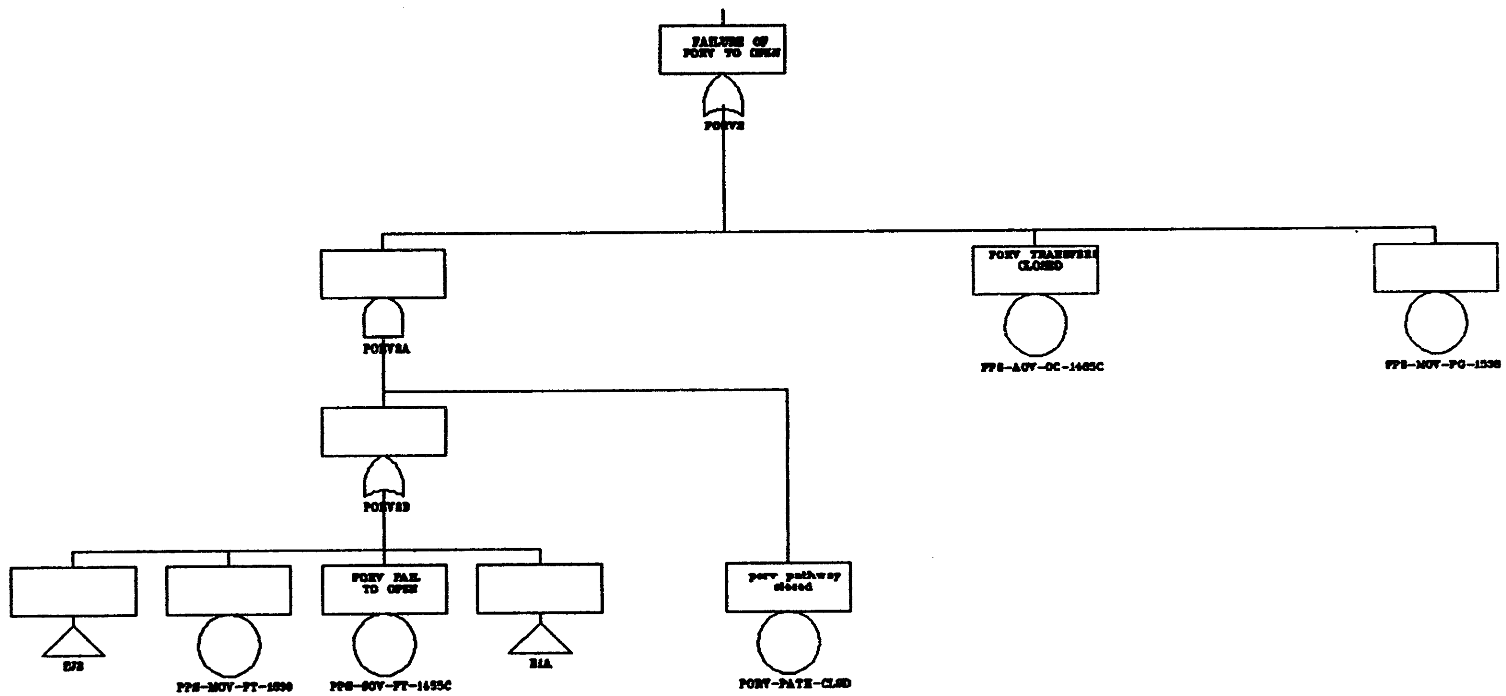


Appendix C.11 Primary Pressure Relief System

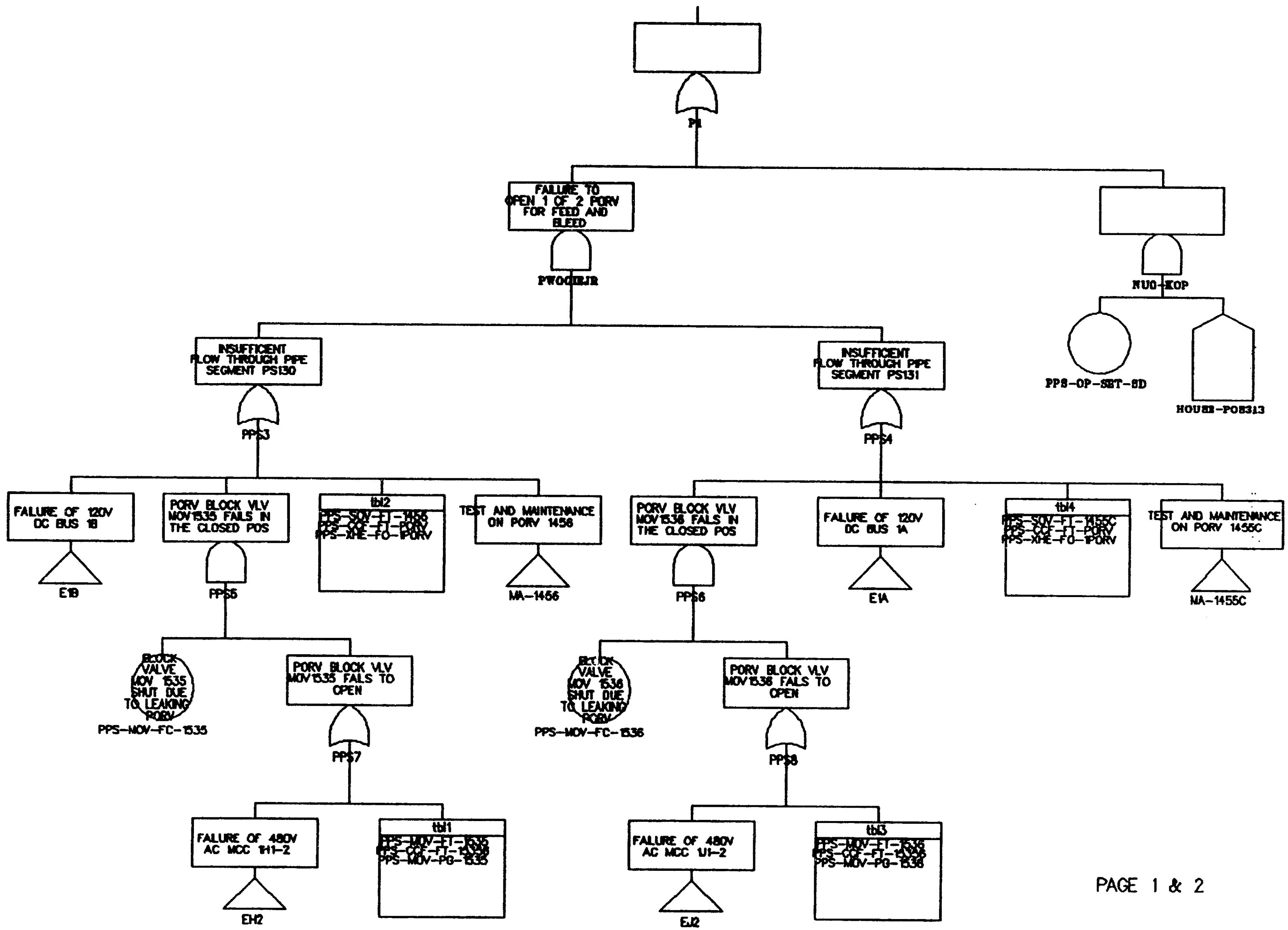
FAILURE TO CLOSE BOTH PORV (PORV1)



PORV FAILS TO OPEN ON DEMAND
(PORV2)

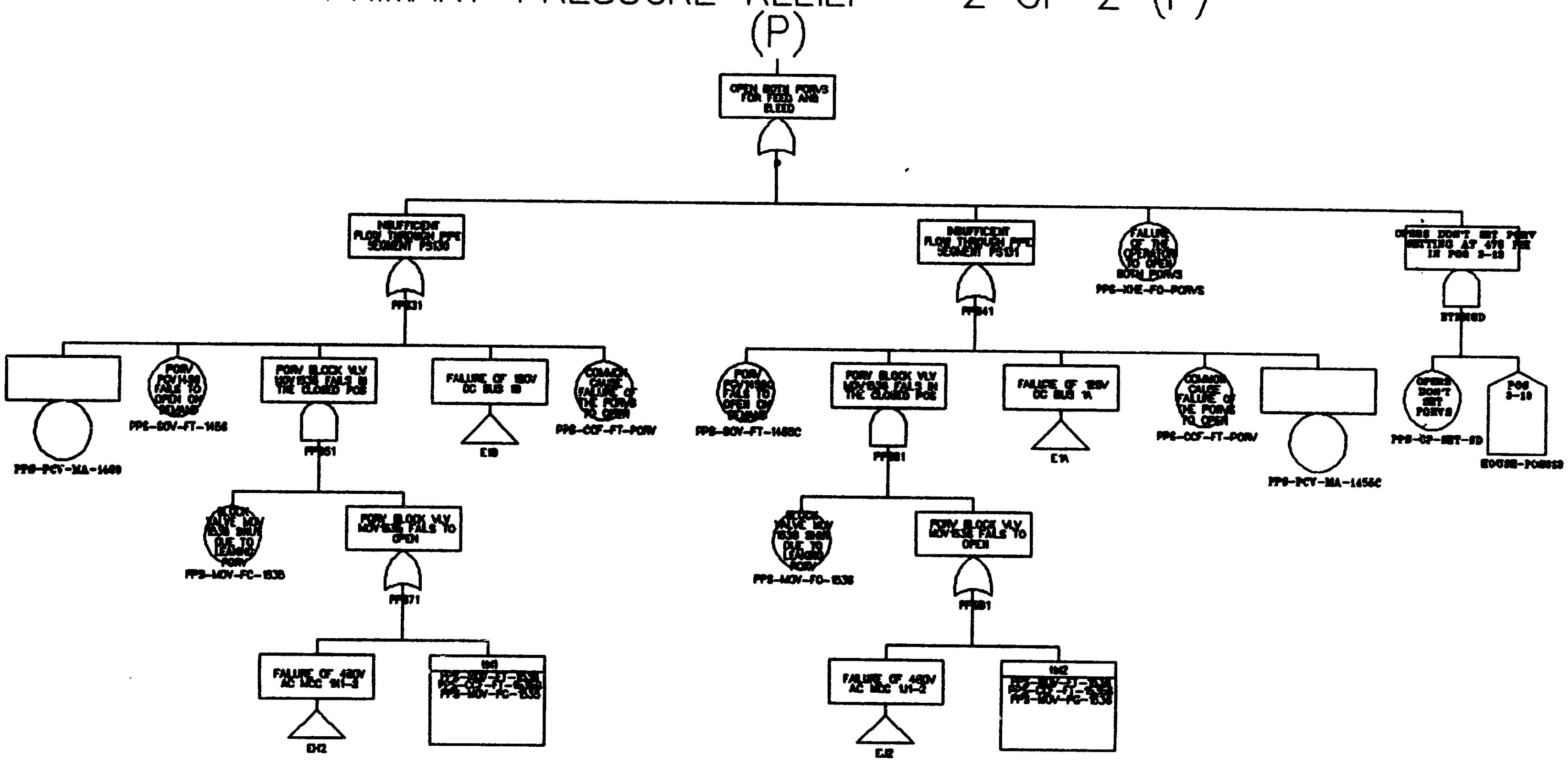


PRIMARY PRESSURE RELIEF - 1 OF 2 (P1)
(P1)

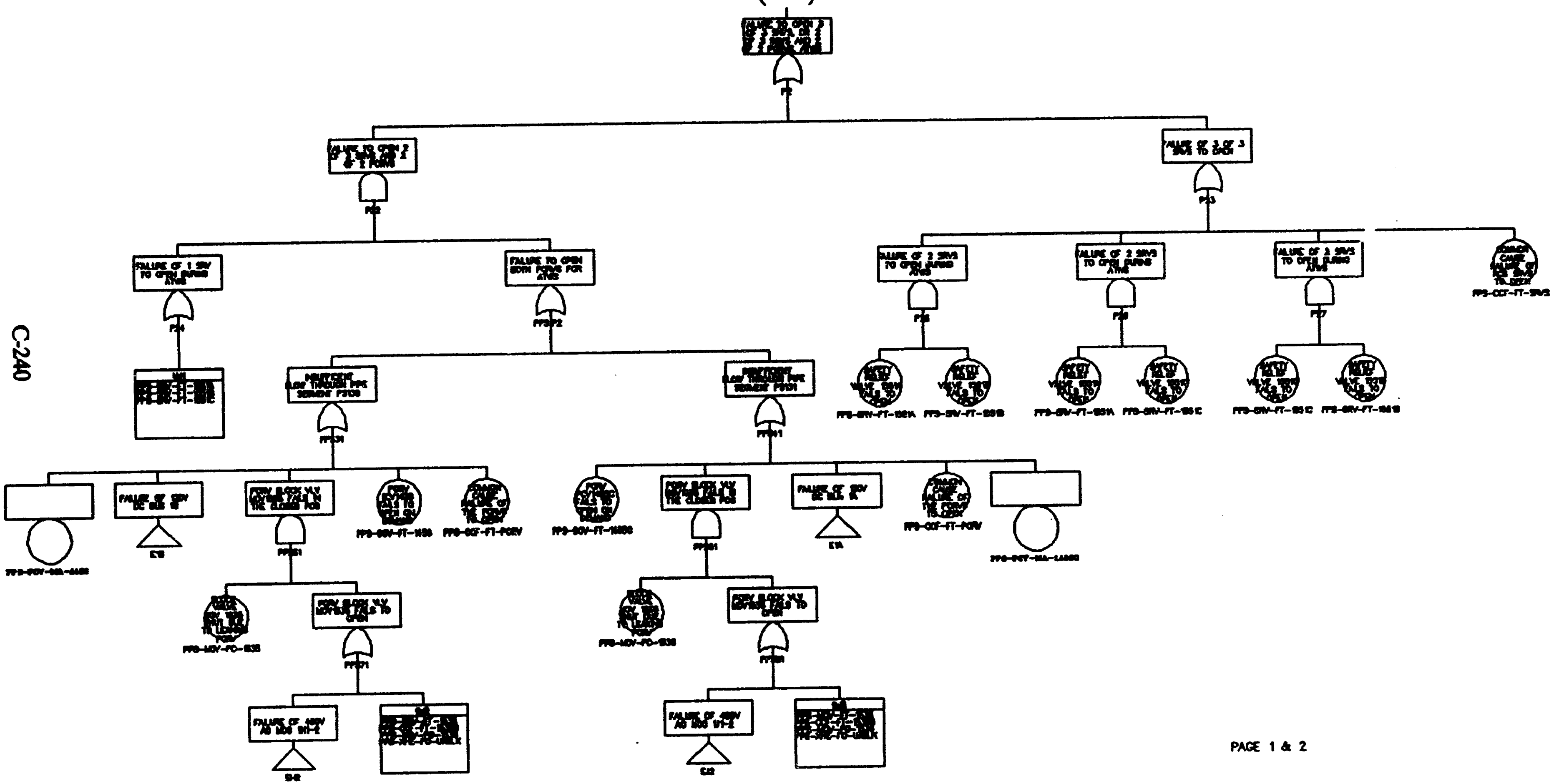


PAGE 1 & 2

PRIMARY PRESSURE RELIEF – 2 OF 2 (P)

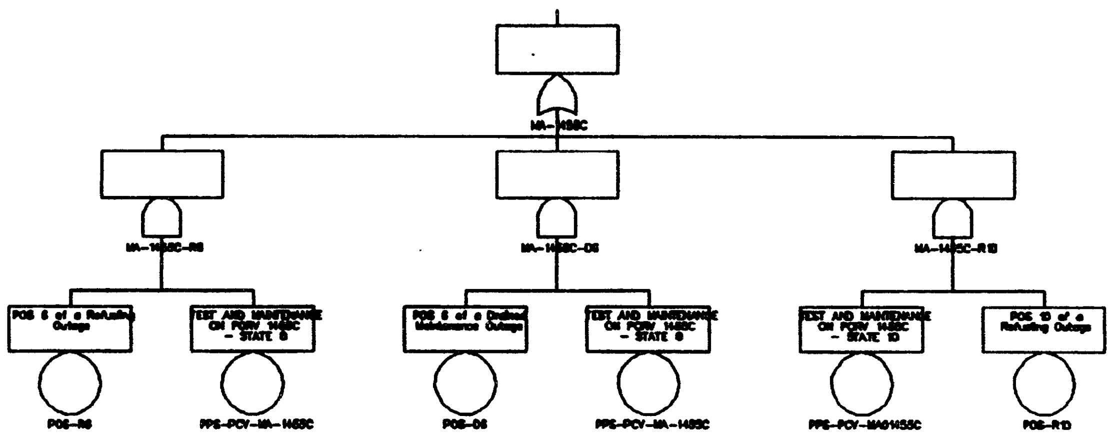


PRIMARY PRESSURE RELIEF – ATWS (P2)
(P2)

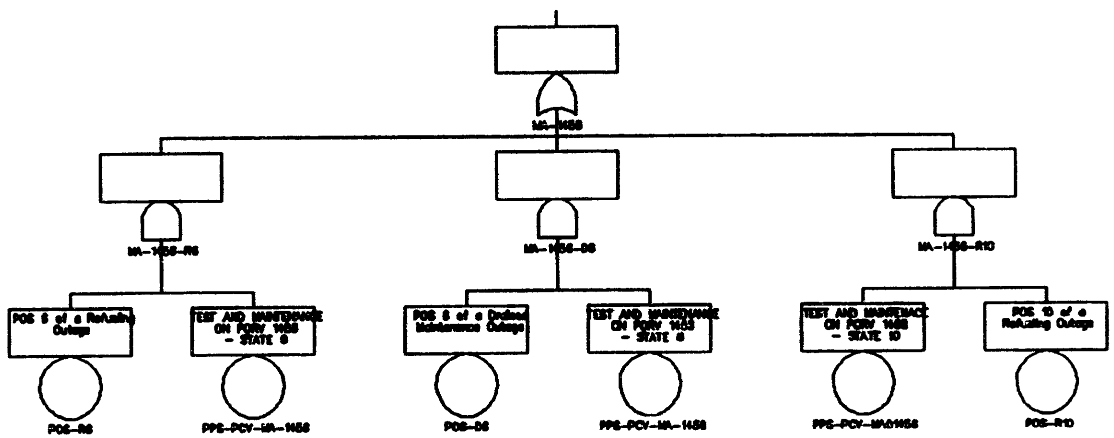


PAGE 1 & 2

TEST AND MAINTENANCE ON PORV 1455C

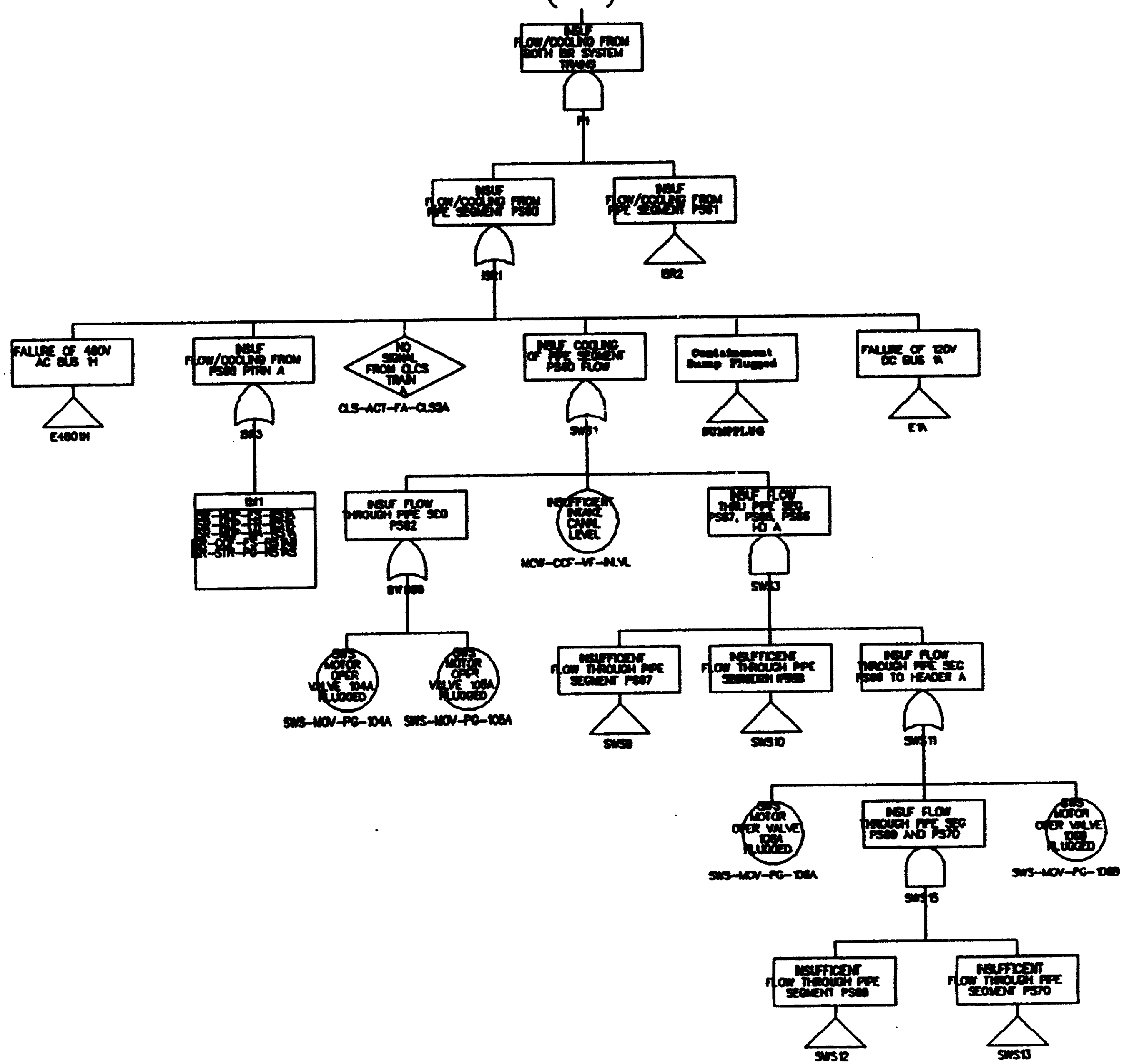


TEST AND MAINTENANCE ON PORV 1456

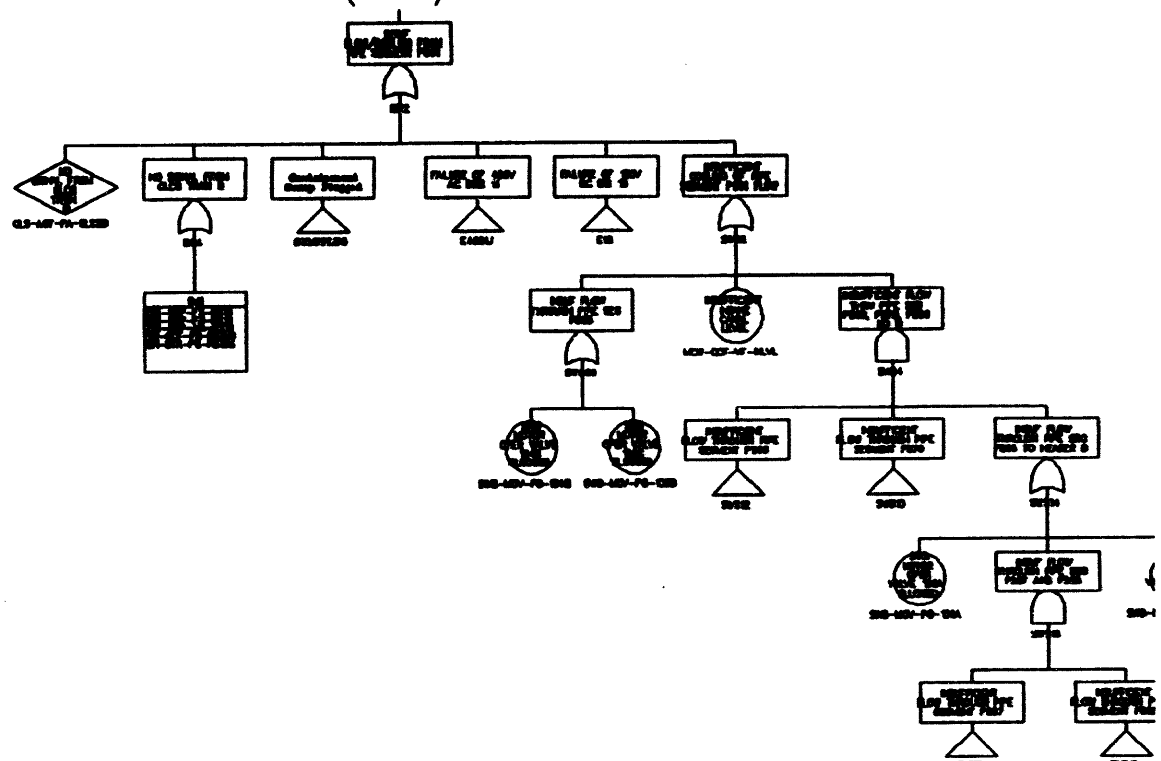


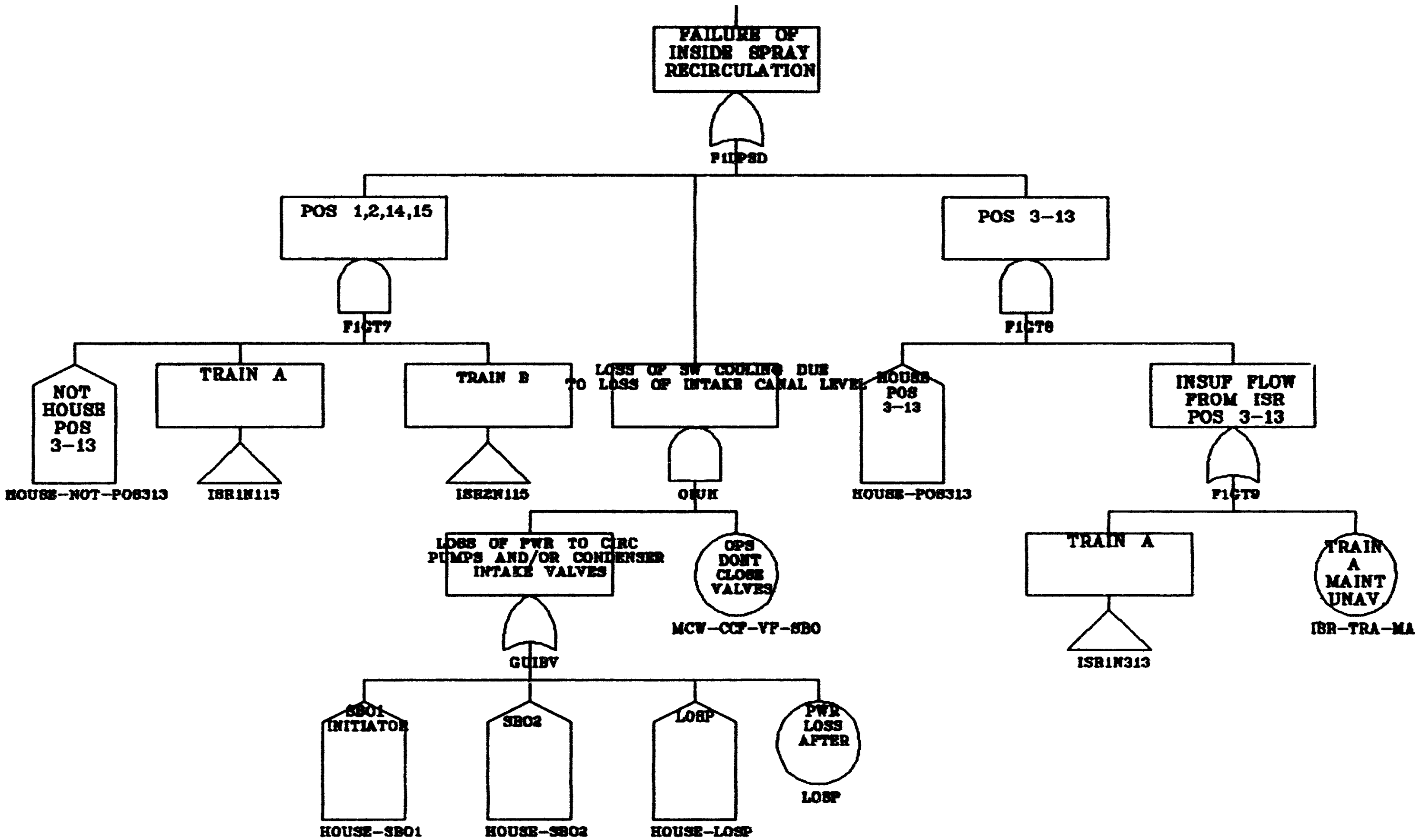
Appendix C.12 Recirculation Spray Systems

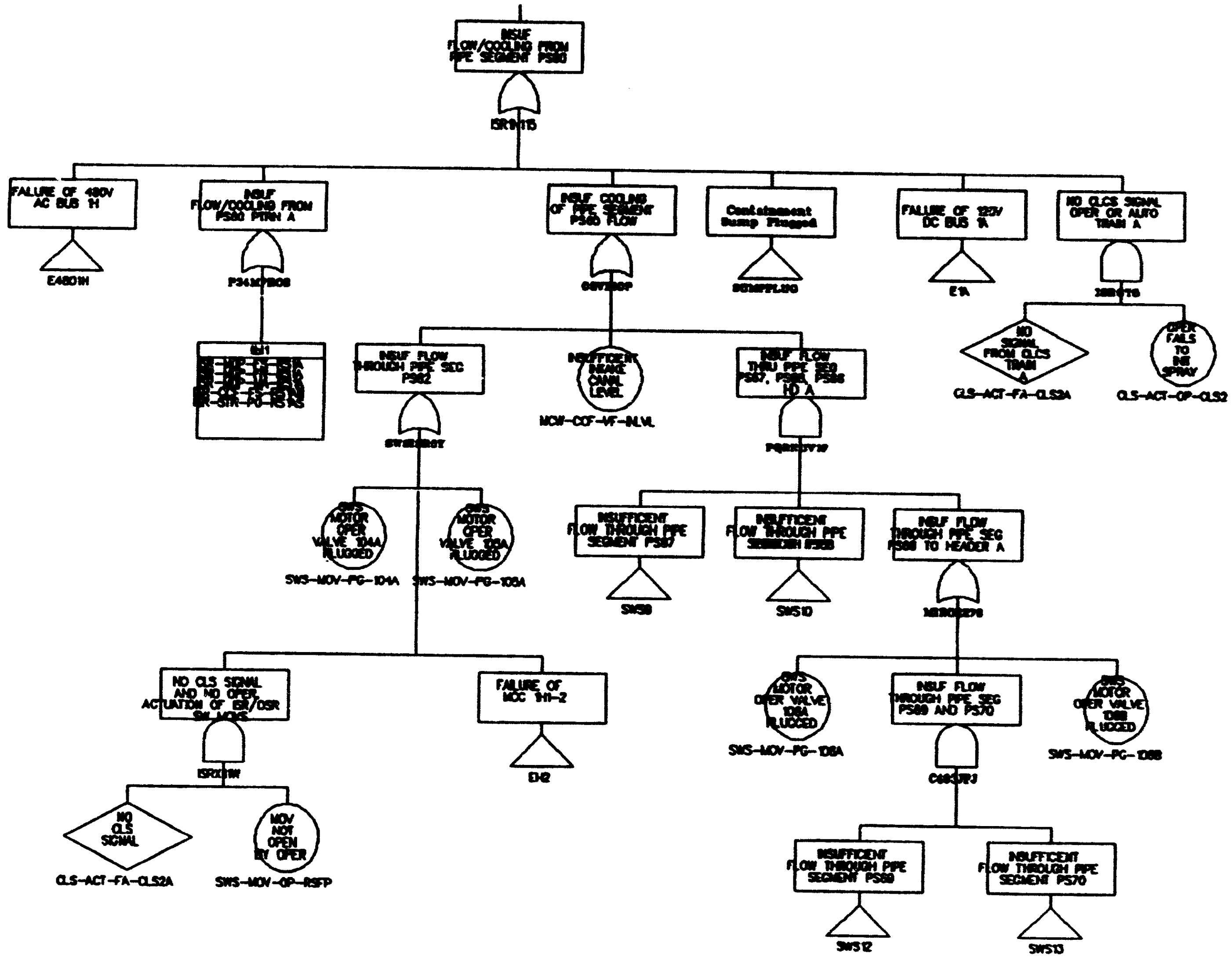
INSIDE SPRAY RECIRCULATION (ISR)
(F1)



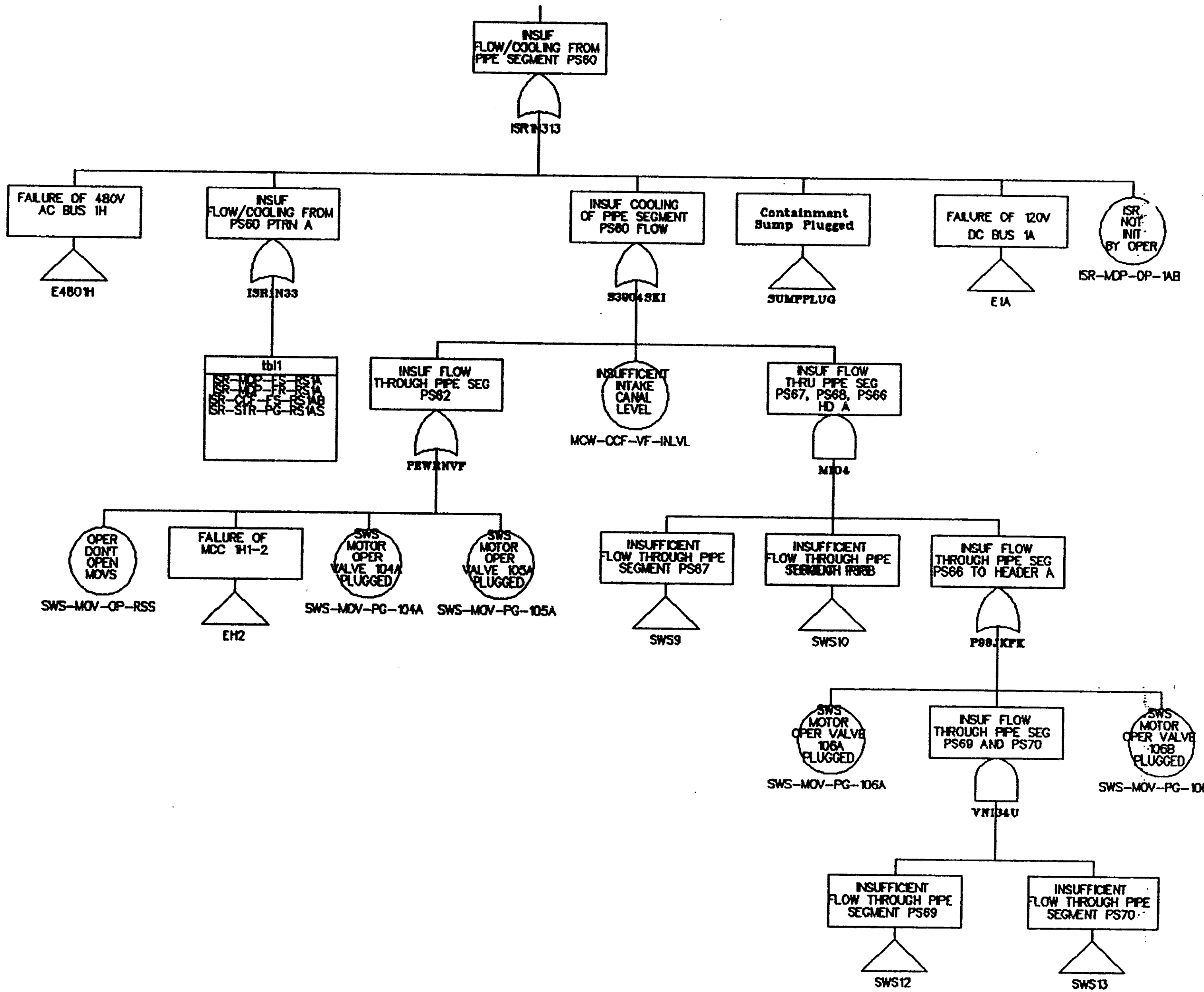
INSIDE SPRAY RECIRCULATION (ISR)
(ISR2)



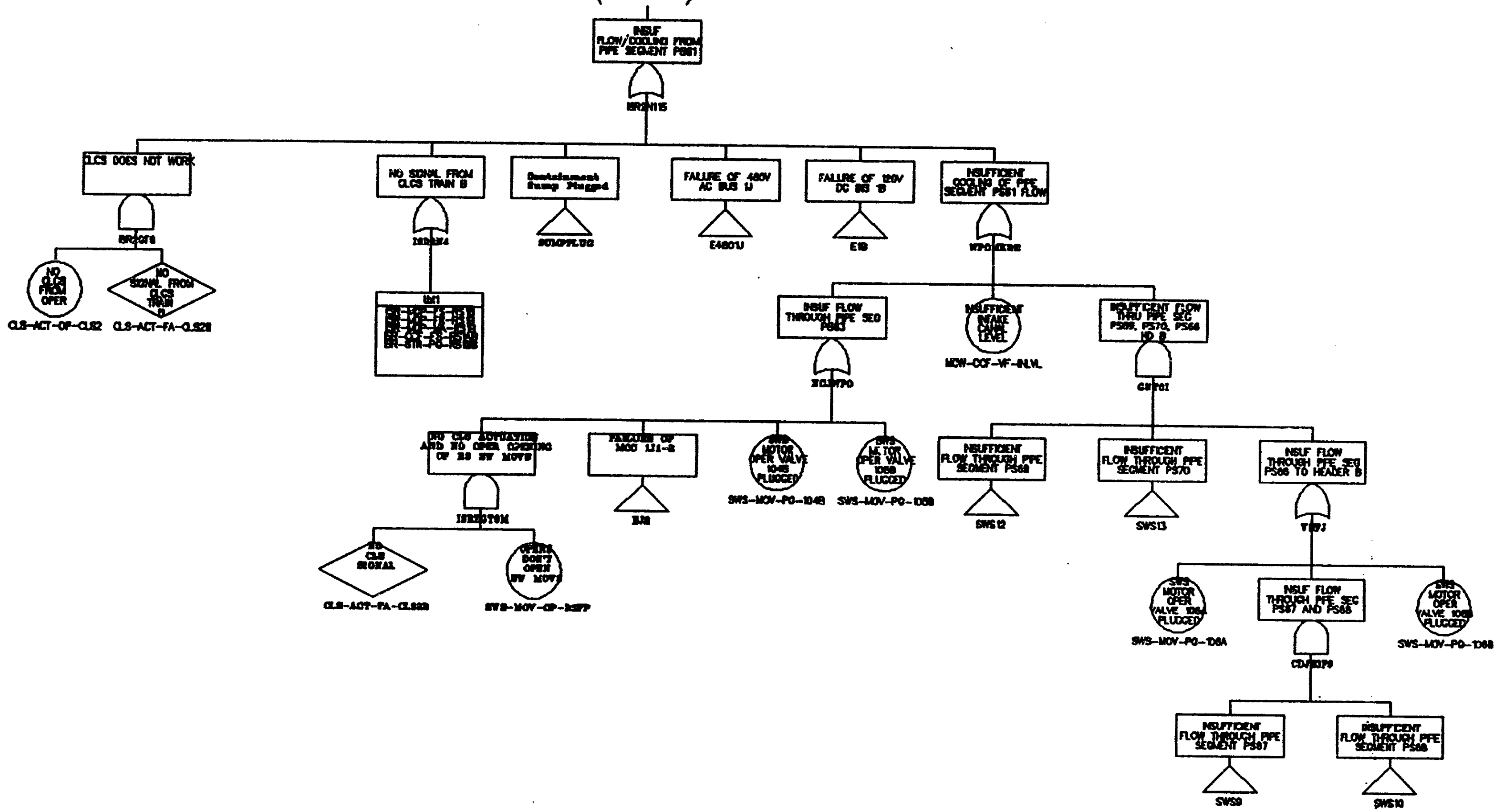

FAILURE OF INSIDE SPRAY RECIRCULATION
F1DPSD
POS 1,2,14,15
F1GT7
LOSS OF SW COOLING DUE TO LOSS OF INTAKE CANAL LEVEL
POS 3-13
F1GT8
NOT HOUSE POS 3-13
HOUSE-NOT-POS313
TRAIN A
ISR1N115
TRAIN B
ISR2N115
GIUH
HOUSE POS 3-13
HOUSE-POS313
INSUF FLOW FROM ISR POS 3-13
F1GT9
LOSS OF PWR TO CIRC PUMPS AND/OR CONDENSER INTAKE VALVES
GUIBV
OPS DONT CLOSE VALVES
MCW-CCF-VF-SBO
TRAIN A
ISR1N313
TRAIN A MAINT UNAV
ISR-TRA-MA
SBO1 INITIATOR
HOUSE-SBO1
SBO2
HOUSE-SBO2
LOSP
HOUSE-LOSP
PWR LOSS AFTER
LOSP

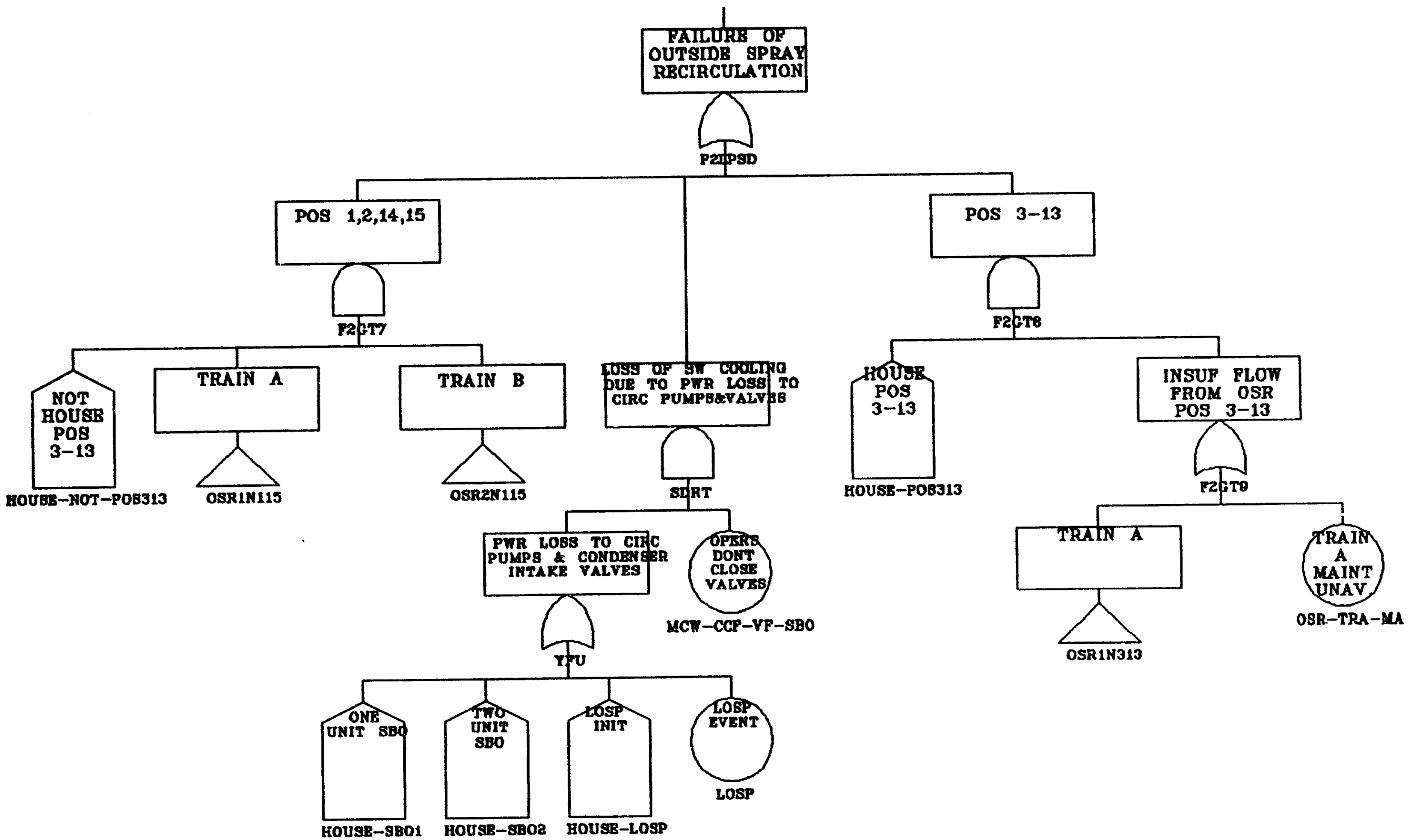


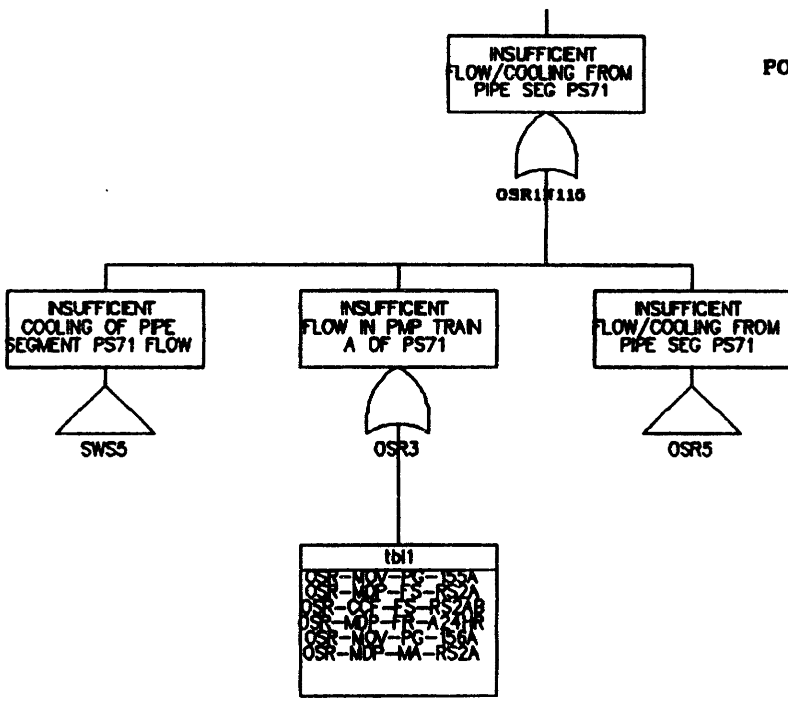
INSUF FLOW/COOLING FROM PIPE SEGMENT PS80
ISR19115
FAILURE OF 480V AC BUS 1H
E4801H
INSUF FLOW/COOLING FROM PS80 PTRN A
INSUF COOLING OF PIPE SEGMENT PS40 FLOW
Containment Sump Plugged
FAILURE OF 125V DC BUS 1A
E1A
NO CLCS SIGNAL OPER OR AUTO TRAIN A
NO SIGNAL FROM CLCS TRAIN A
CLS-ACT-FA-CLS2A
OPER FAILS TO INIT SPRAY
CLS-ACT-OP-CLS2
INSUF FLOW THROUGH PIPE SEC PS82
INSUFFICIENT INTAKE CANAL LEVEL
MCW-COF-VF-INLVL
INSUF FLOW THRU PIPE SEG PS67, PS68, PS86 HD A
SWS MOTOR OPER VALVE 104A PLUGGED
SWS-MOV-PG-104A
SWS MOTOR OPER VALVE 105A PLUGGED
SWS-MOV-PG-105A
INSUFFICIENT FLOW THROUGH PIPE SEGMENT PS67
SWS9
INSUFFICIENT FLOW THROUGH PIPE
SWS10
INSUF FLOW THROUGH PIPE SEG PS68 TO HEADER A
NO CLS SIGNAL AND NO OPER. ACTUATION OF ISR/OSR
FAILURE OF MCC 1H1-2
EH2
SWS MOTOR OPER VALVE 108A PLUGGED
SWS-MOV-PG-108A
INSUF FLOW THROUGH PIPE SEG PS69 AND PS70
SWS MOTOR OPER VALVE 108B PLUGGED
SWS-MOV-PG-108B
NO CLS SIGNAL
CLS-ACT-FA-CLS2A
MOV NOT OPEN BY OPER
SWS-MOV-OP-RSFP
INSUFFICIENT FLOW THROUGH PIPE SEGMENT PS69
SWS12
INSUFFICIENT FLOW THROUGH PIPE SEGMENT PS70
SWS13


INSUF FLOW/COOLING FROM PIPE SEGMENT PS60
ISR1N313
FAILURE OF 480V AC BUS 1H
E4801H
INSUF FLOW/COOLING FROM PS60 PTRN A
ISR1N33
tbl1
ISR-MDP-FS-RS1A
ISR-MDP-FR-RS1A
ISR-CCF-FS-RS1AB
ISR-STR-PG-RS1AS
INSUF COOLING OF PIPE SEGMENT PS60 FLOW
S3904SKI
Containment Sump Plugged
SUMPPLUG
FAILURE OF 120V DC BUS 1A
E1A
ISR NOT INIT BY OPER
ISR-MDP-OP-1AB
INSUF FLOW THROUGH PIPE SEG PS62
PEWRNVF
INSUFFICIENT INTAKE CANAL LEVEL
MCW-CCF-VF-INLVL
INSUF FLOW THRU PIPE SEG PS67, PS68, PS66 HD A
MI04
OPER DONT OPEN MOVS
SWS-MOV-OP-RSS
FAILURE OF MCC 1H1-2
EH2
SWS MOTOR OPER VALVE 104A PLUGGED
SWS-MOV-PG-104A
SWS MOTOR OPER VALVE 105A PLUGGED
SWS-MOV-PG-105A
INSUFFICIENT FLOW THROUGH PIPE SEGMENT PS67
SWS9
INSUFFICIENT FLOW THROUGH PIPE SEGMENT PS68
SWS10
INSUF FLOW THROUGH PIPE SEG PS66 TO HEADER A
PS9JKPK
SWS MOTOR OPER VALVE 106A PLUGGED
SWS-MOV-PG-106A
INSUF FLOW THROUGH PIPE SEG PS69 AND PS70
VNI34U
SWS MOTOR OPER VALVE 106B PLUGGED
SWS-MOV-PG-106B
INSUFFICIENT FLOW THROUGH PIPE SEGMENT PS69
SWS12
INSUFFICIENT FLOW THROUGH PIPE SEGMENT PS70
SWS13

INSIDE SPRAY RECIRCULATION (ISR)
(ISR2)



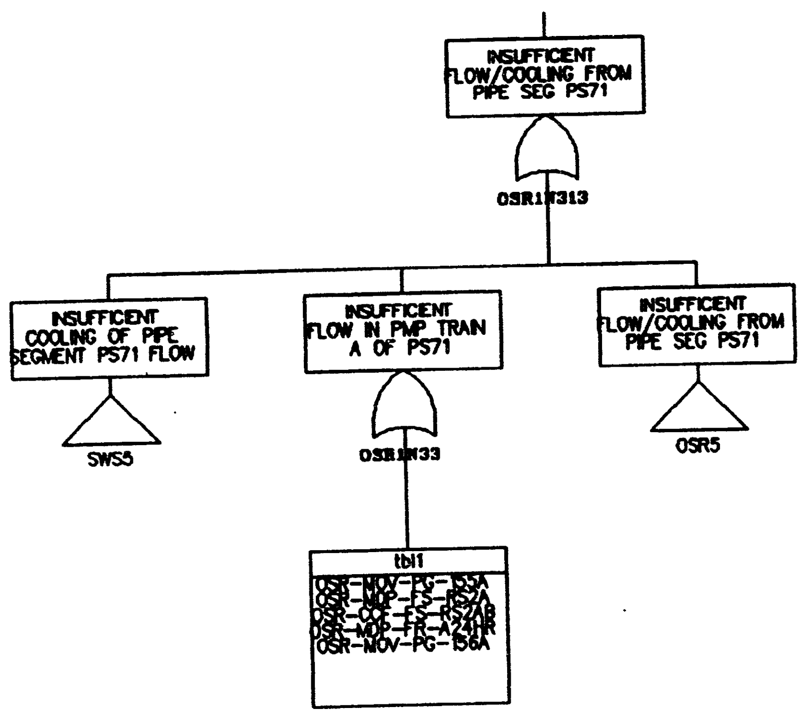

FAILURE OF OUTSIDE SPRAY RECIRCULATION
P2IPSD
POS 1,2,14,15
F2GT7
NOT HOUSE POS 3-13
HOUSE-NOT-POS313
TRAIN A
OSR1N115
TRAIN B
OSR2N115
LOSS OF SW COOLING DUE TO PWR LOSS TO CIRC PUMPS&VALVES
SDRT
PWR LOSS TO CIRC PUMPS & CONDENSER INTAKE VALVES
YFU
ONE UNIT SBO
HOUSE-SBO1
TWO UNIT SBO
HOUSE-SBO2
LOSP INIT
HOUSE-LOSP
LOSP EVENT
LOSP
OPERS DONT CLOSE VALVES
MCW-CCP-VF-SBO
POS 3-13
F2GT8
HOUSE POS 3-13
HOUSE-POS313
INSUF FLOW FROM OSR POS 3-13
F2GT9
TRAIN A
OSR1N313
TRAIN A MAINT UNAV
OSR-TRA-MA



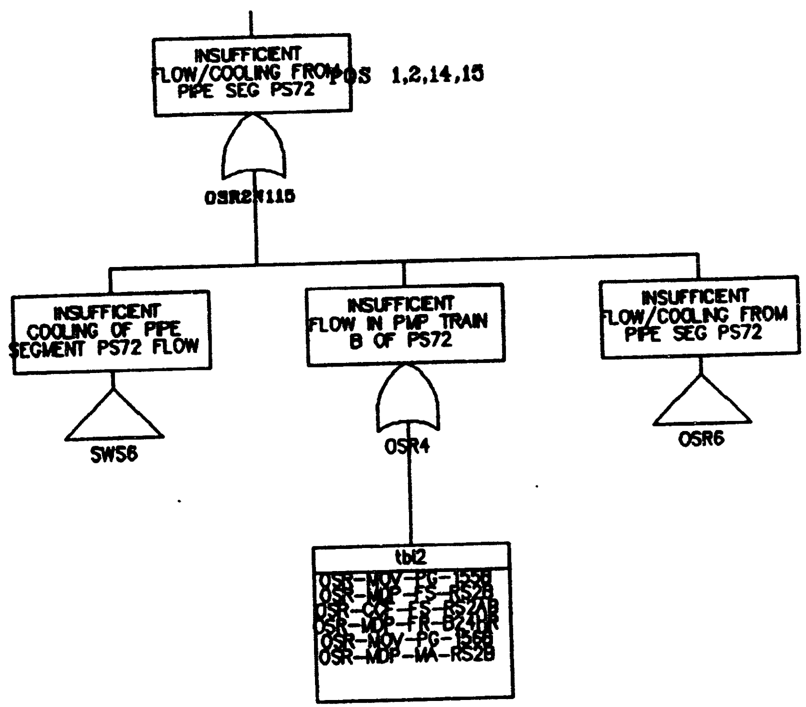
INSUFFICENT FLOW/COOLING FROM PIPE SEG PS71
OSR1N116
INSUFFICENT COOLING OF PIPE SEGMENT PS71 FLOW
INSUFFICENT FLOW IN PMP TRAIN A OF PS71
INSUFFICENT FLOW/COOLING FROM PIPE SEG PS71
SWS5
OSR3
OSR5
tbl1
OSR-MOV-PG-155A
OSR-MDP-FS-RS2A
OSR-CCF-FS-RS2AB
OSR-MDP-FR-A24HR
OSR-MOV-PG-156A
OSR-MDP-MA-RS2A

POS 1,2,14,15

POS 3-13

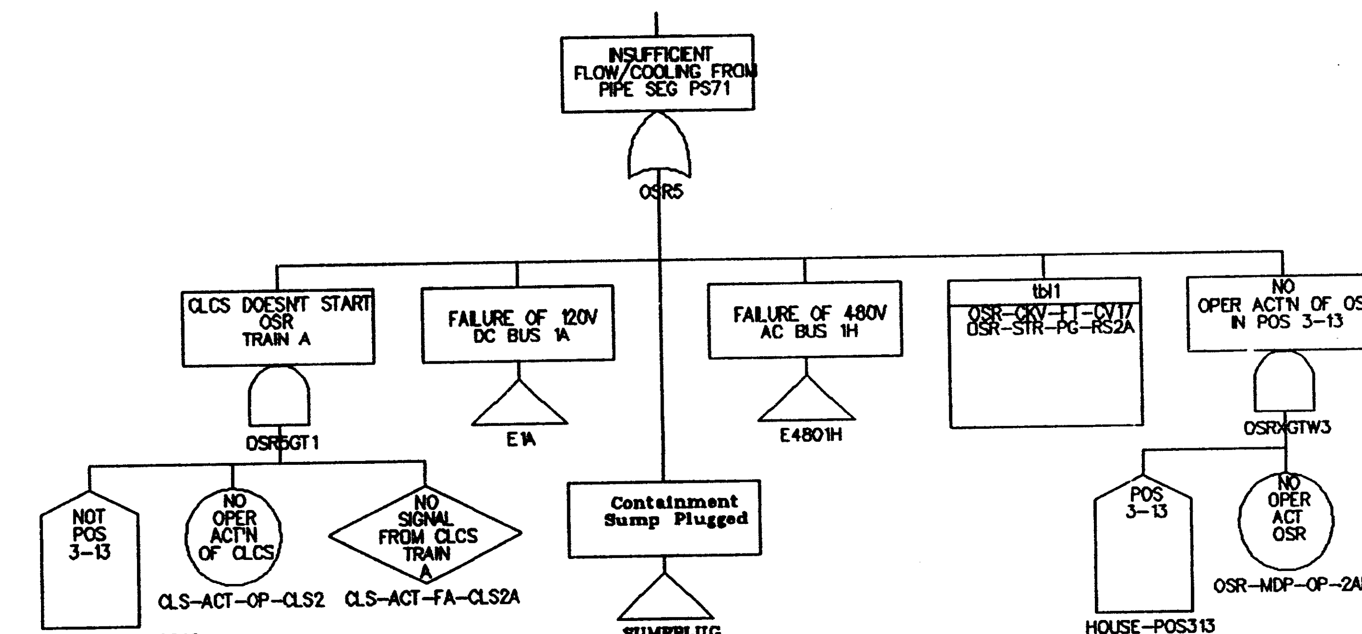


INSUFFICENT FLOW/COOLING FROM PIPE SEG PS71
OSR1N313
INSUFFICENT COOLING OF PIPE SEGMENT PS71 FLOW
SWS5
INSUFFICENT FLOW IN PMP TRAIN A OF PS71
OSR1N33
tbl1
OSR-MOV-PG-155A
OSR-MDP-FS-RS2A
OSR-CCF-FS-RS2AB
OSR-MDP-FR-A24HR
OSR-MOV-PG-156A
INSUFFICENT FLOW/COOLING FROM PIPE SEG PS71
OSR5

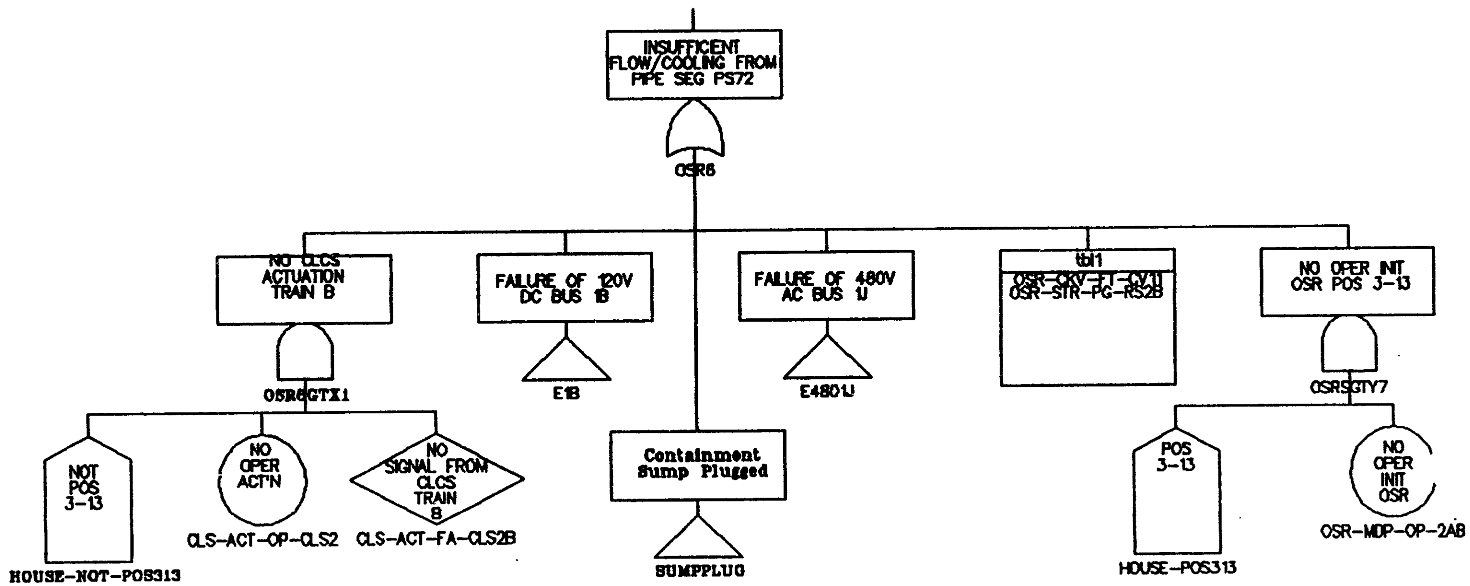


INSUFFICIENT FLOW/COOLING FROM PIPE SEG PS72
POS 1,2,14,15
OSR2N115
INSUFFICENT COOLING OF PIPE SEGMENT PS72 FLOW
SWS6
INSUFFICIENT FLOW IN PMP TRAIN B OF PS72
OSR4
INSUFFICENT FLOW/COOLING FROM PIPE SEG PS72
OSR6
tbl2
OSR-MOV-PG-155B
OSR-MDP-FS-RS2B
OSR-CCF-FS-RS2AB
OSR-MDP-FR-B24DR
OSR-MOV-PG-156B
OSR-MDP-MA-RS2B

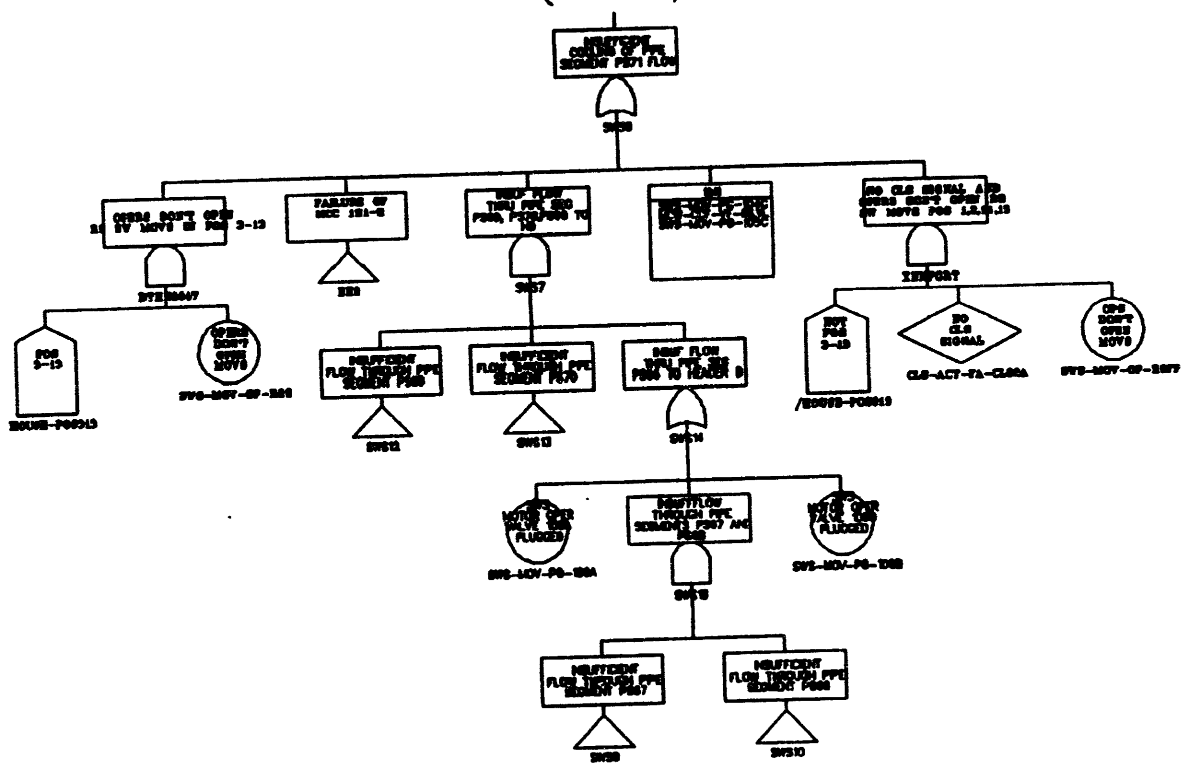
OUTSIDE SPRAY RECIRCULATION (OSR)
(OSR5)



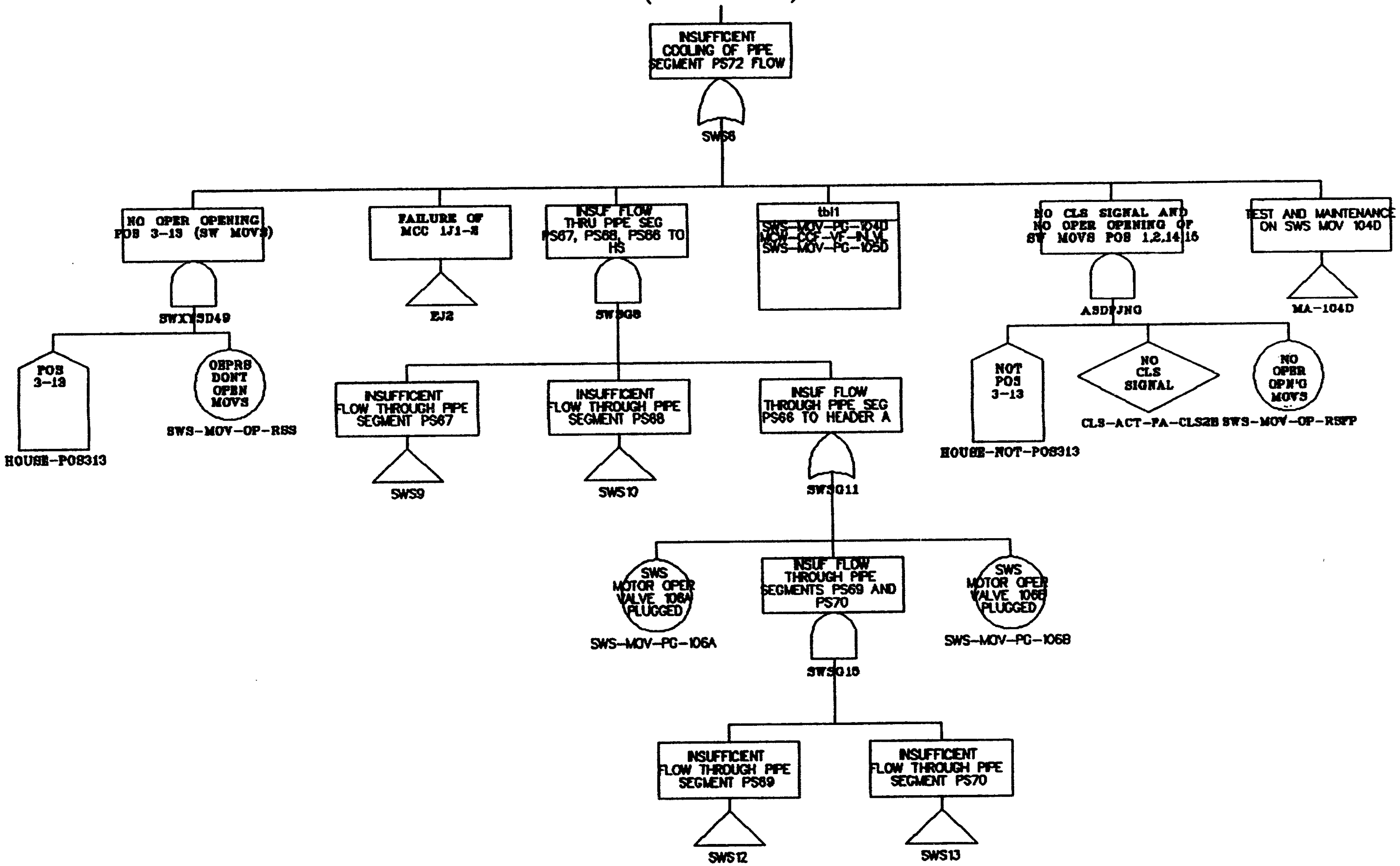
OUTSIDE SPRAY RECIRCULATION (OSR)
(OSR6)



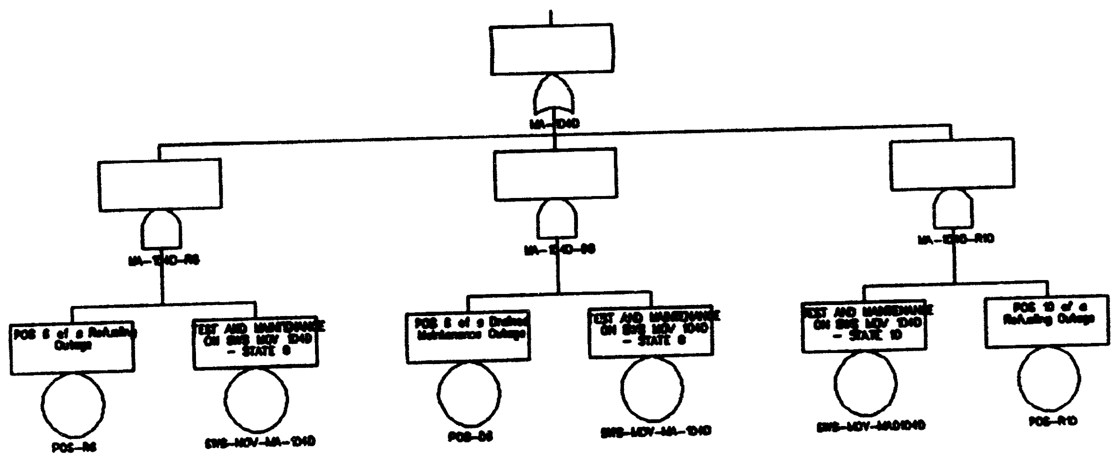
OUTSIDE SPRAY RECIRCULATION (OSR)
(SWS5)



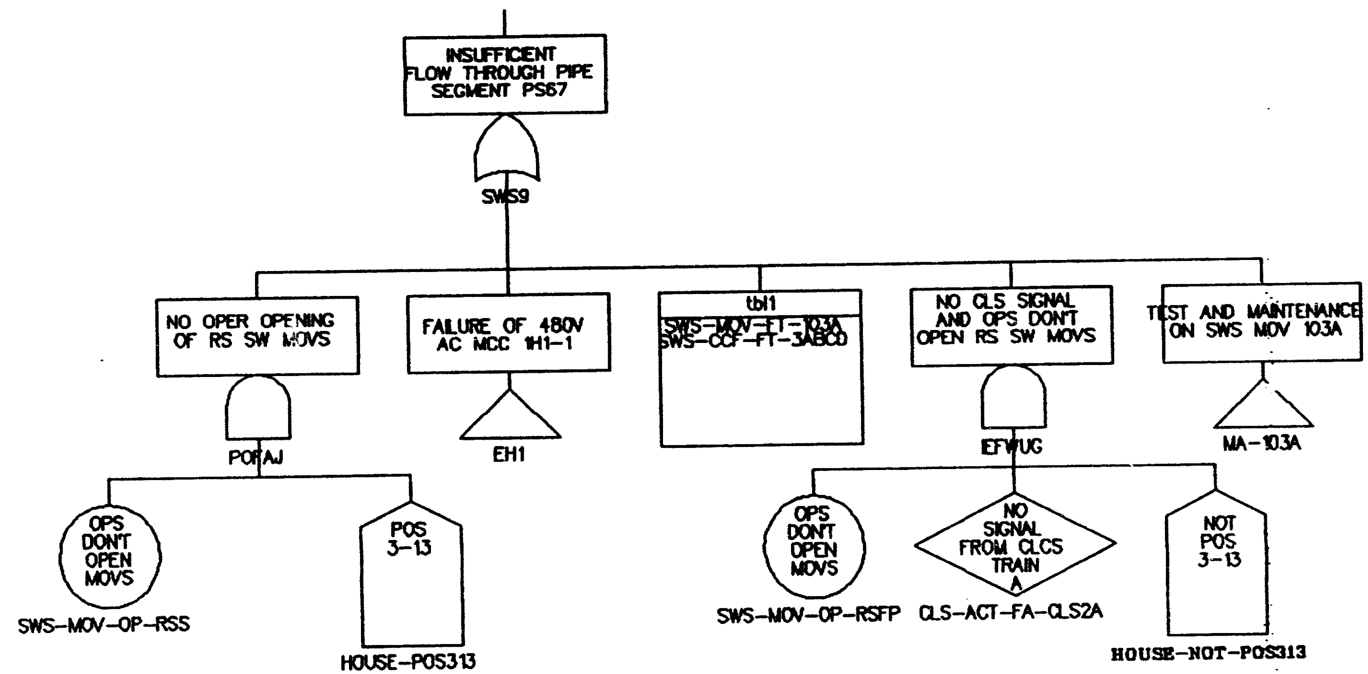
OUTSIDE SPRAY RECIRCULATION (OSR)
(SWS6)



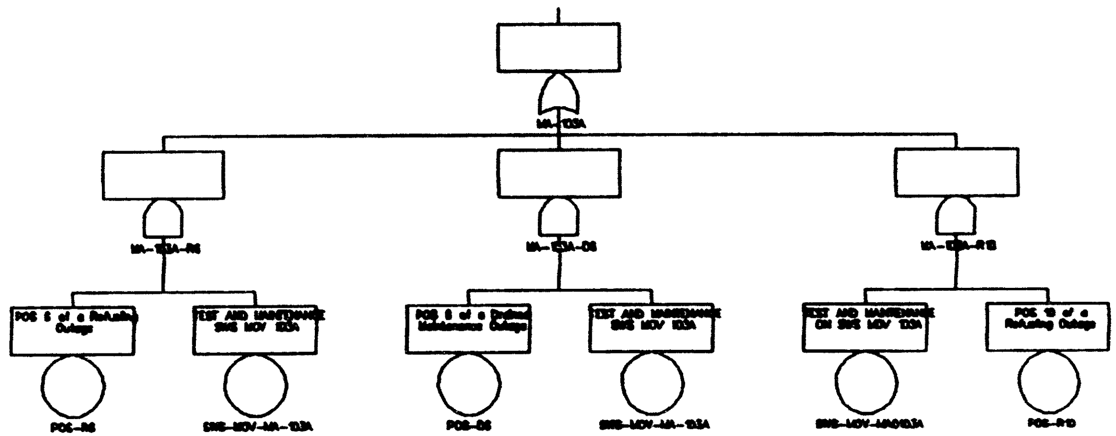
TEST AND MAINTENANCE ON SWS MOV 104D



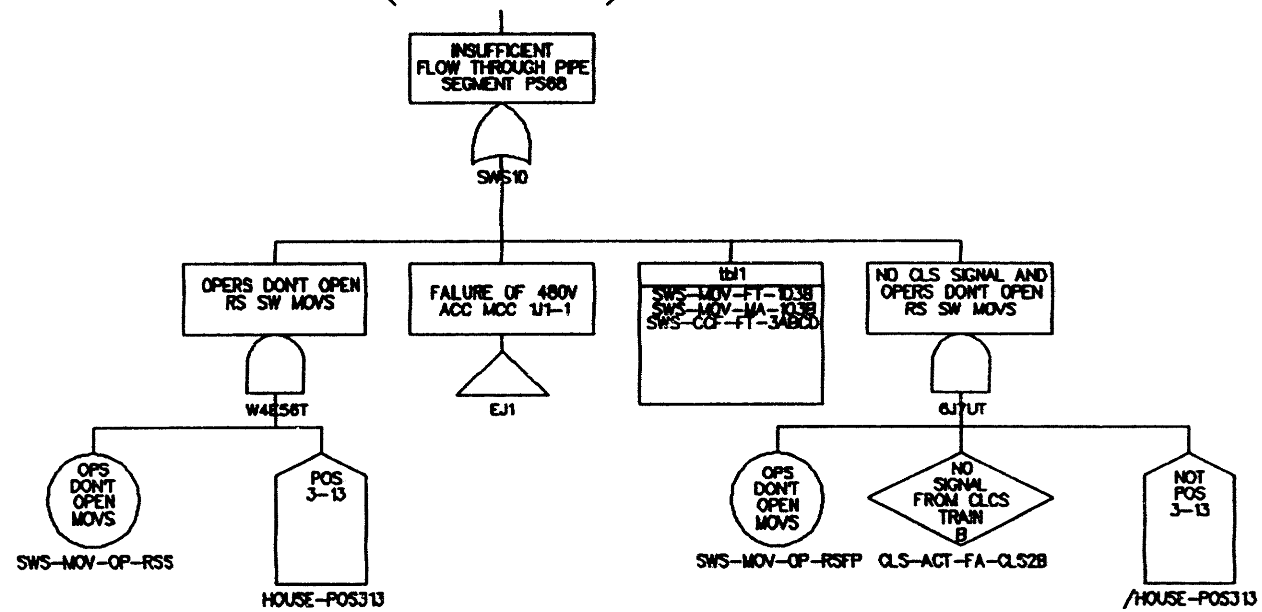
OUTSIDE SPRAY RECIRCULATION (OSR)
(SWS9)



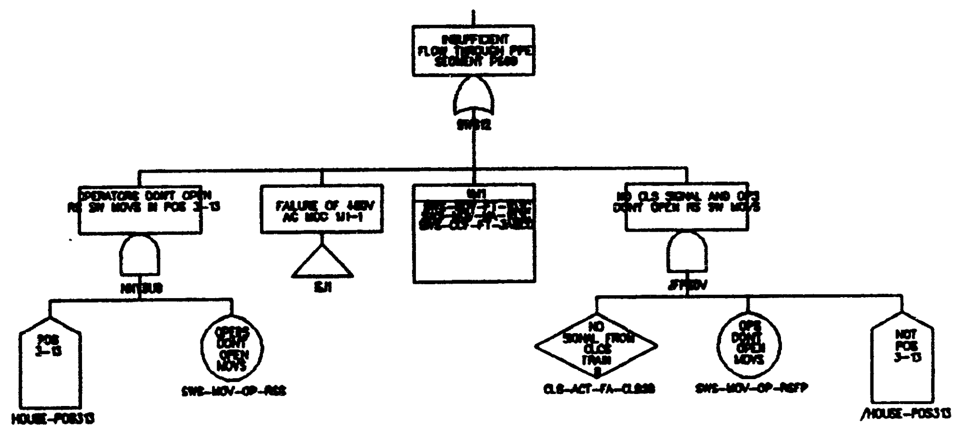
TEST AND MAINTENANCE ON SWS MOV 103A



OUTSIDE SPRAY RECIRCULATION (OSR) (SWS10)

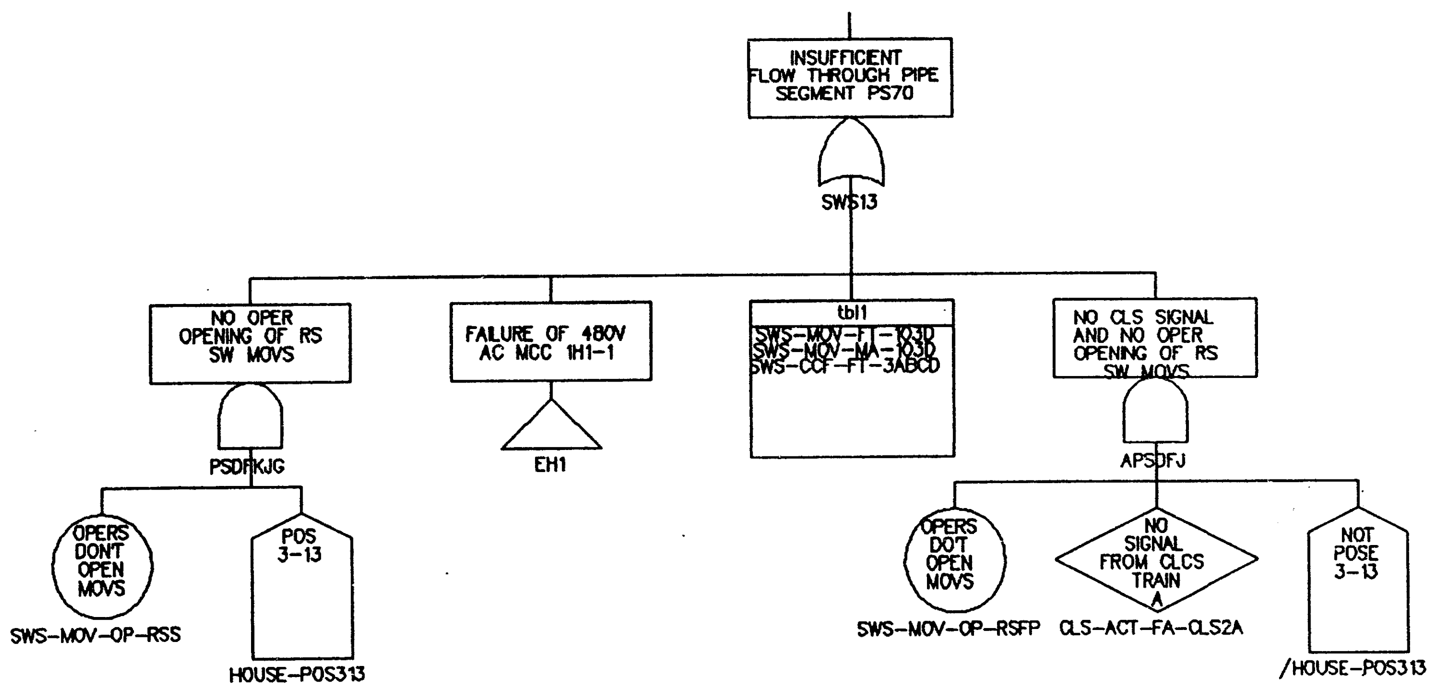


INSIDE SPRAY RECIRCULATION (ISR)
(SWS12)

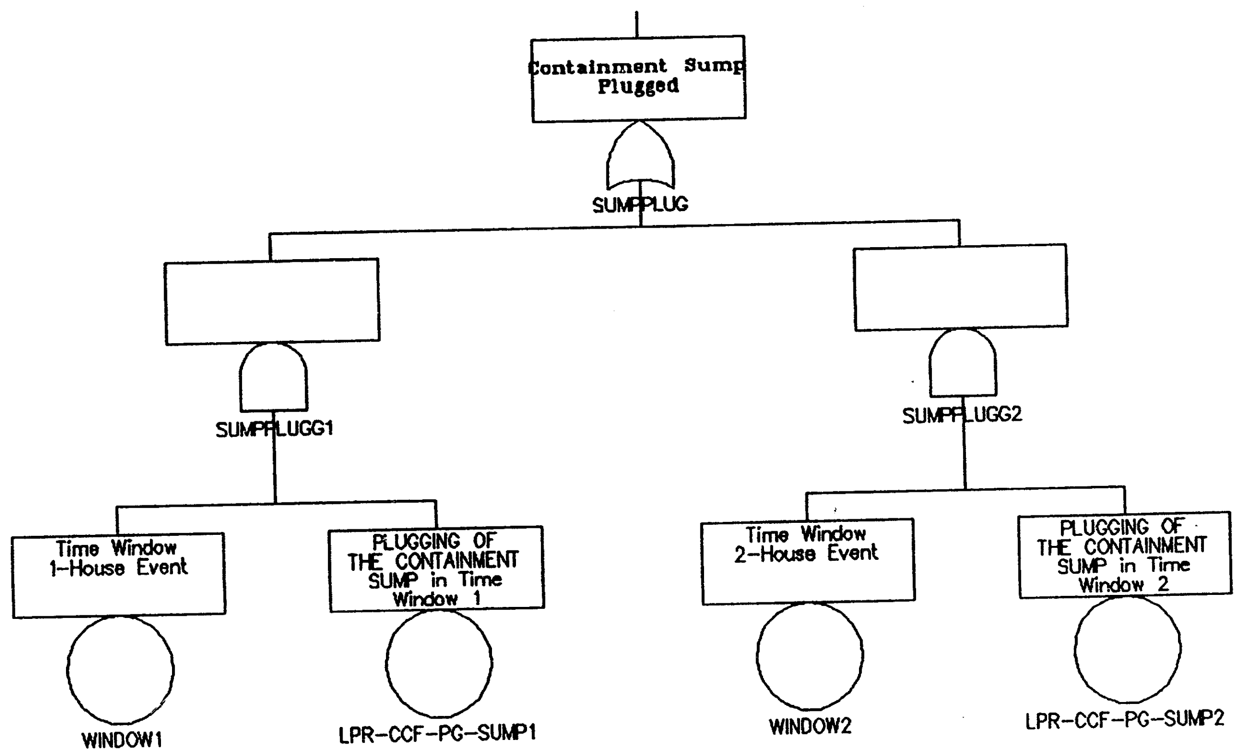


C-262

INSIDE SPRAY RECIRCULATION (ISR) (SWS13)

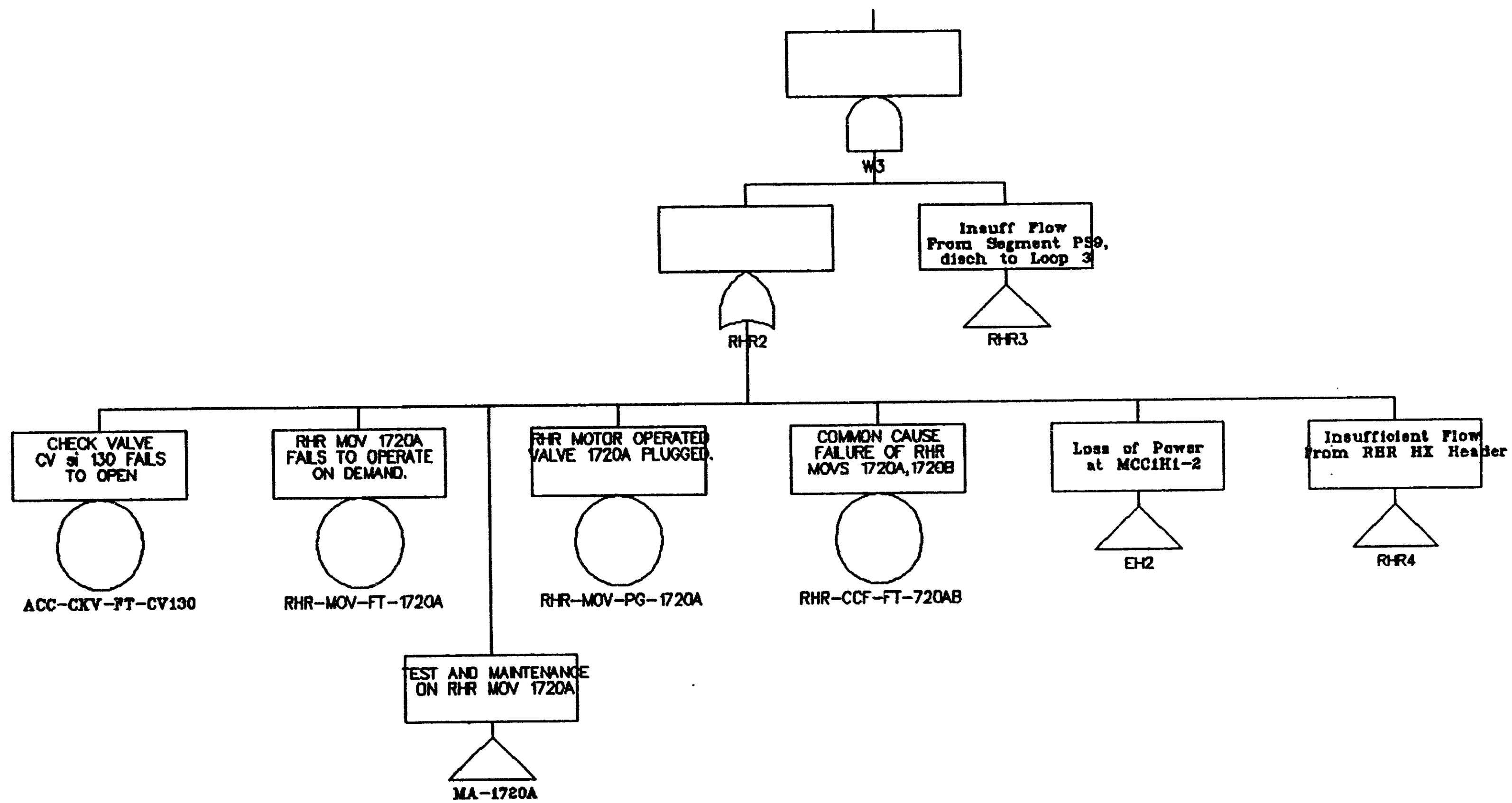


Cotainment Sump is Plugged(causes failure of recirculation)

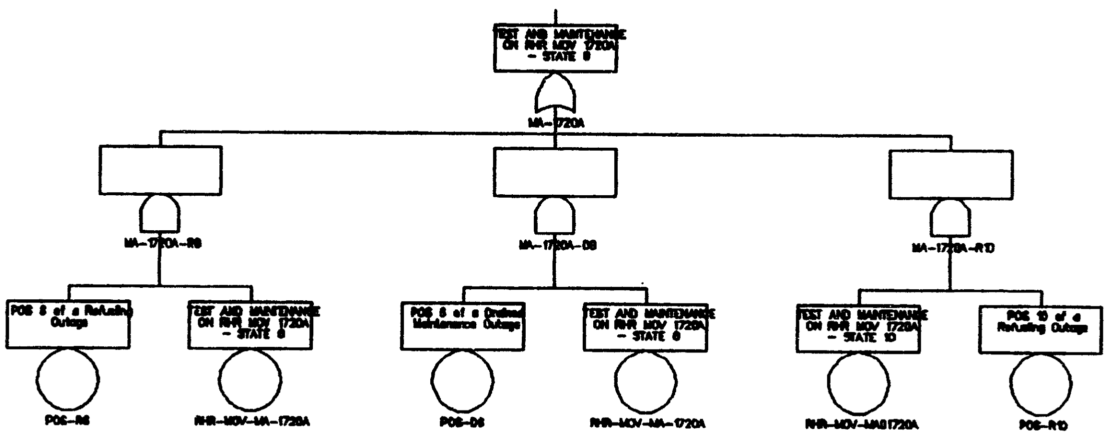


Appendix C.13 Residual Heat Removal Systems

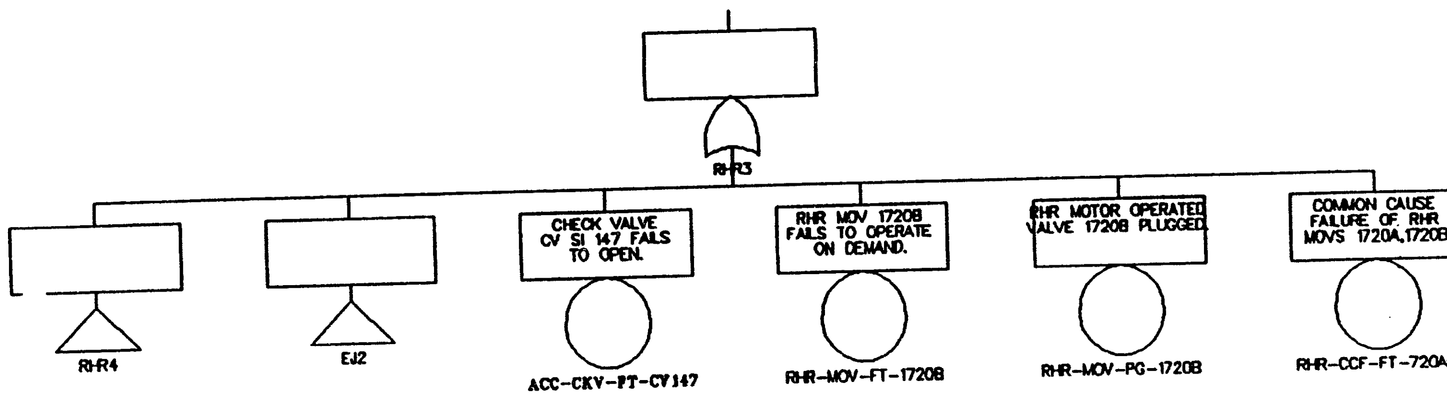
FAILURE OF RHR SYSTEM TO COOL THE REACTOR, 1OF2 (FT W3)



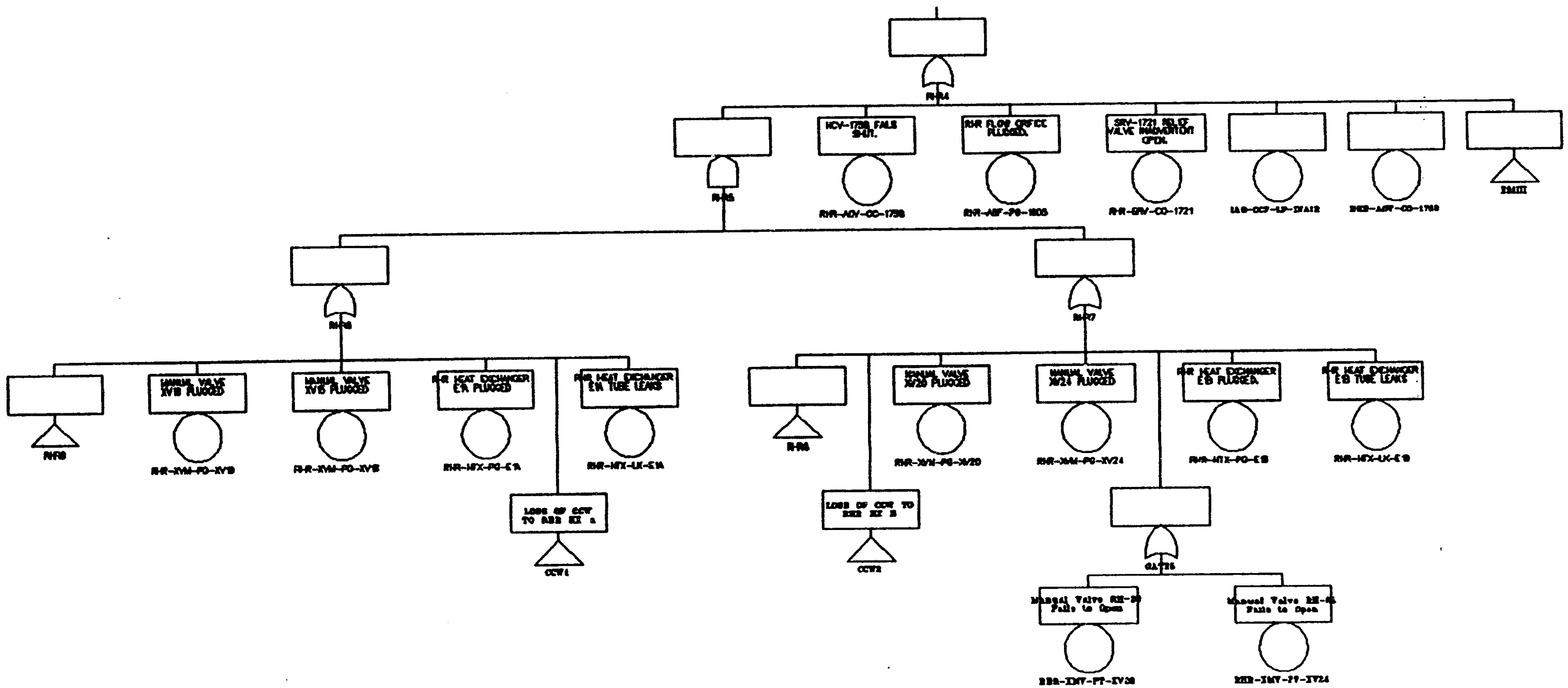
TEST AND MAINTENANCE ON RHR MOV 1720A



INSUFF FLOW FROM SEG PS9, DISCH TO LOOP 3 (FT W3)

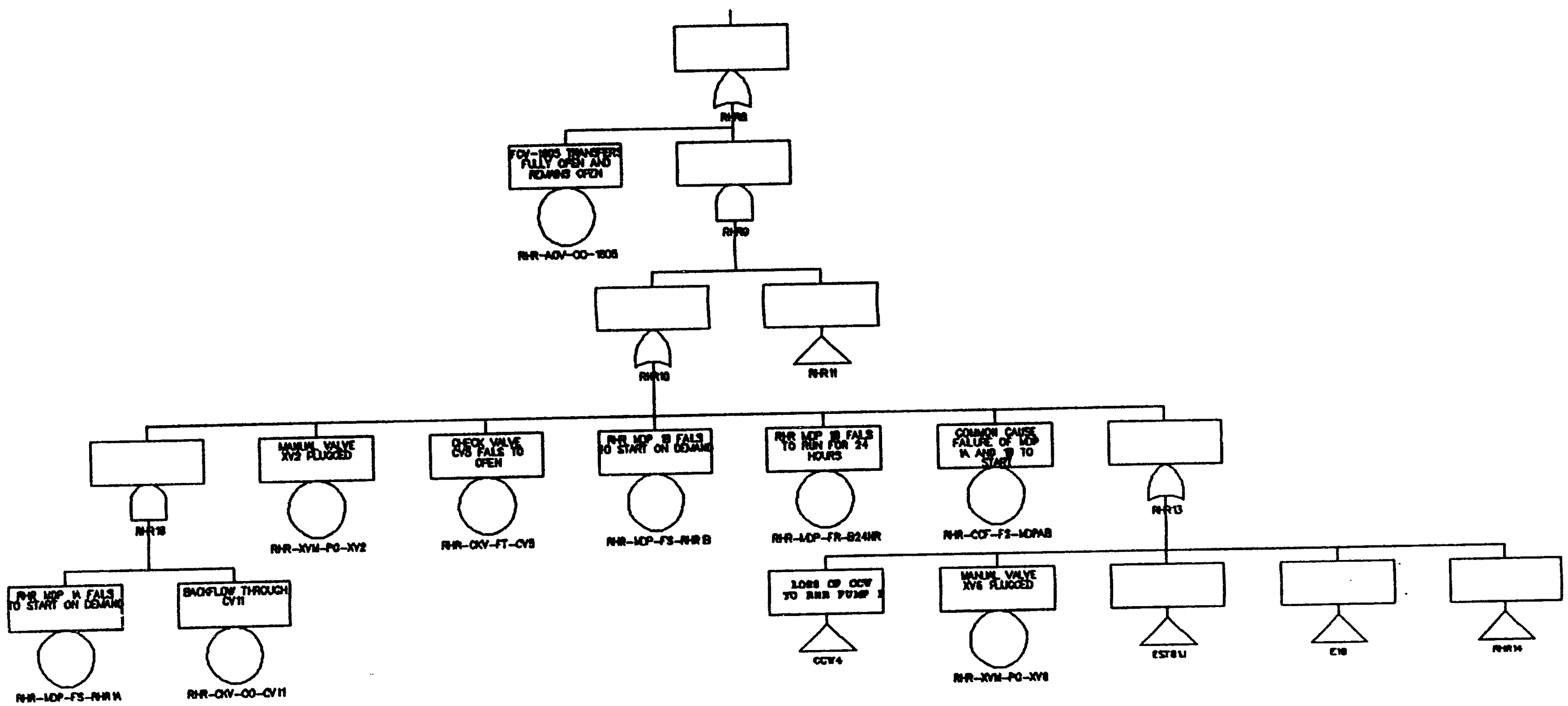


RHR4



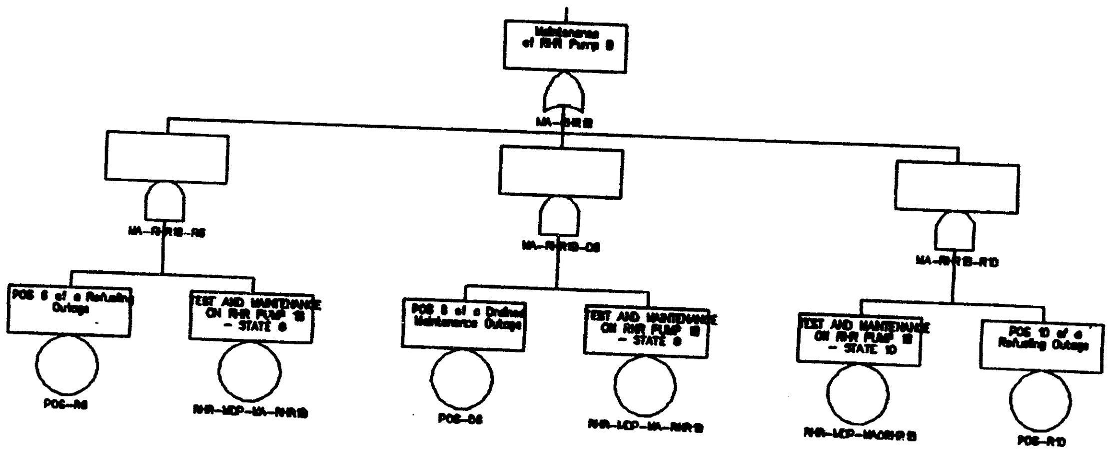
RHR4
HCV-1758 FAILS SHUT.
RHR FLOW ORIFICE PLUGGED.
SRV-1721 RELIEF VALVE INADVERTENT OPEN.
RHR-AOV-CC-1758
RHR-ABF-PG-1805
RHR-SRV-CO-1721
RHR5
RHR6
RHR7
MANUAL VALVE XV18 PLUGGED
MANUAL VALVE XV16 PLUGGED
RHR HEAT EXCHANGER E1A PLUGGED
RHR HEAT EXCHANGER E1A TUBE LEAKS
RHR-XVM-PG-XV18
RHR-XVM-PG-XV16
RHR-HTX-PG-E1A
RHR-HTX-LK-E1A
LOSS OF CCW TO RHR HX A
CCW1
MANUAL VALVE XV20 PLUGGED
MANUAL VALVE XV24 PLUGGED
RHR HEAT EXCHANGER E1B PLUGGED
RHR HEAT EXCHANGER E1B TUBE LEAKS
RHR-XVM-PG-XV20
RHR-XVM-PG-XV24
RHR-HTX-PG-E1B
RHR-HTX-LK-E1B
LOSS OF CCW TO RHR HX B
CCW2
GATE6
Manual Valve RH-30 Fails to Open
Manual Valve RH-24 Fails to Open

RHR8

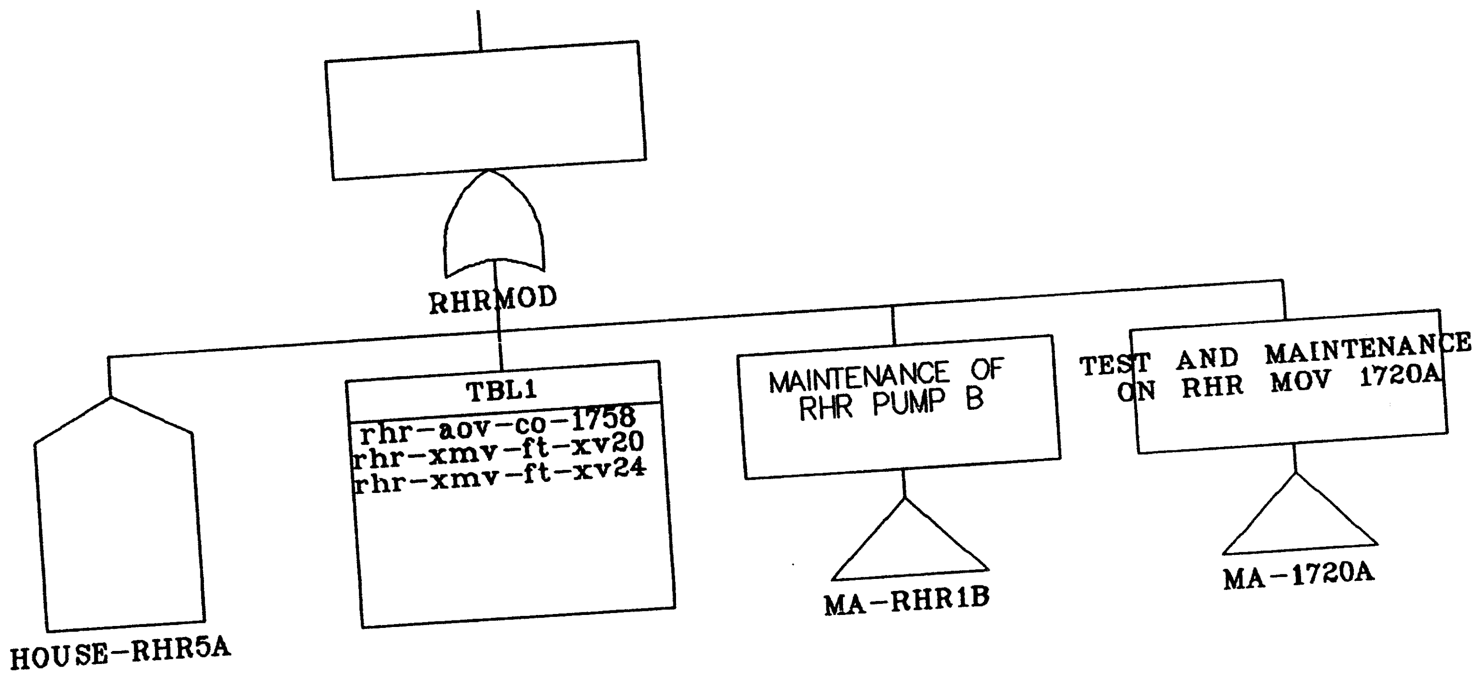


RHR8
FCV-1605 TRANSFERS FULLY OPEN AND REMAINS OPEN
RHR-AOV-OO-1606
RHR9
RHR10
RHR11
MANUAL VALVE XV2 PLUGGED
CHECK VALVE CV5 FAILS TO OPEN
RHR MDP 1B FAILS TO START ON DEMAND
RHR MDP 1B FAILS TO RUN FOR 24 HOURS
COMMON CAUSE FAILURE OF MDP 1A AND 1B TO START
RHR18
RHR-XVM-PG-XV2
RHR-CKV-FT-CV5
RHR-MDP-FS-RHR1B
RHR-MDP-FR-B24HR
RHR-CCF-FS-MDPAB
RHR13
RHR MDP 1A FAILS TO START ON DEMAND
BACKFLOW THROUGH CV11
RHR-MDP-FS-RHR1A
RHR-CKV-OO-CV11
LOSS OF CCW TO RHR PUMP B
MANUAL VALVE XV6 PLUGGED
CCW4
RHR-XVM-PG-XV6
E18
RHR14

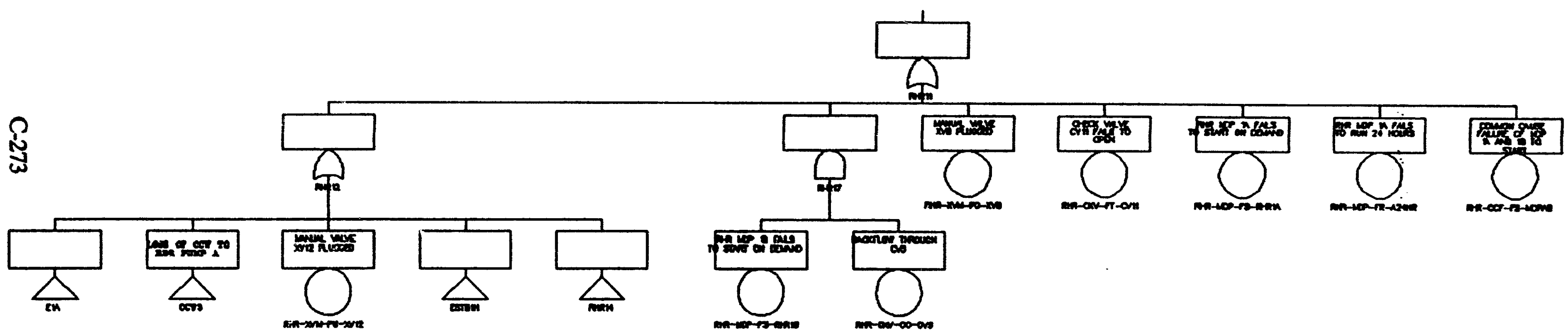
Maintenence of RHR Pump B



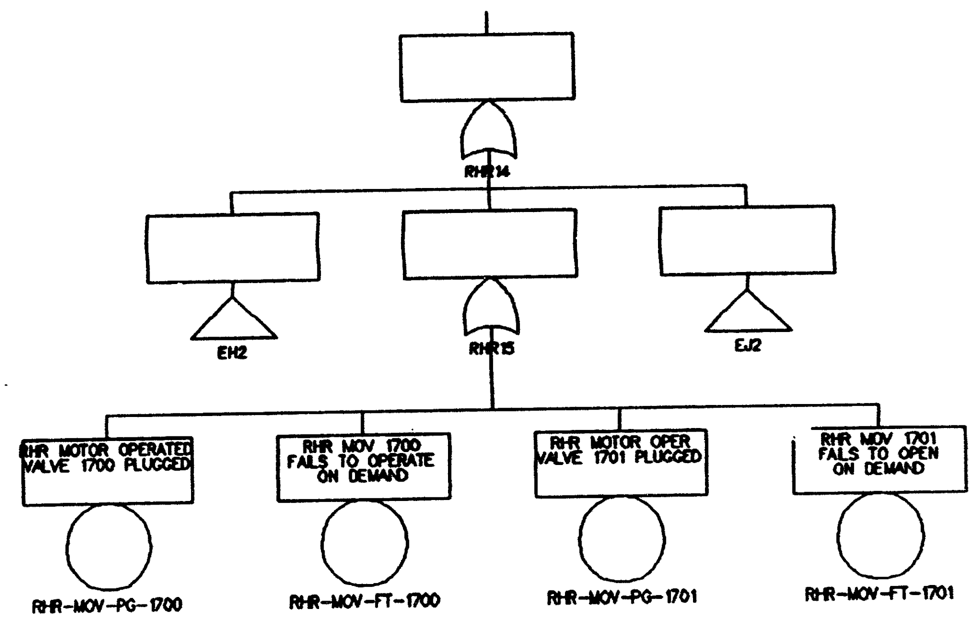
RHRMOD


RHRMOD
HOUSE-RHR5A
TBL1
rhr-aov-co-1758
rhr-xmv-ft-xv20
rhr-xmv-ft-xv24
MAINTENANCE OF RHR PUMP B
MA-RHR1B
TEST AND MAINTENANCE ON RHR MOV 1720A
MA-1720A

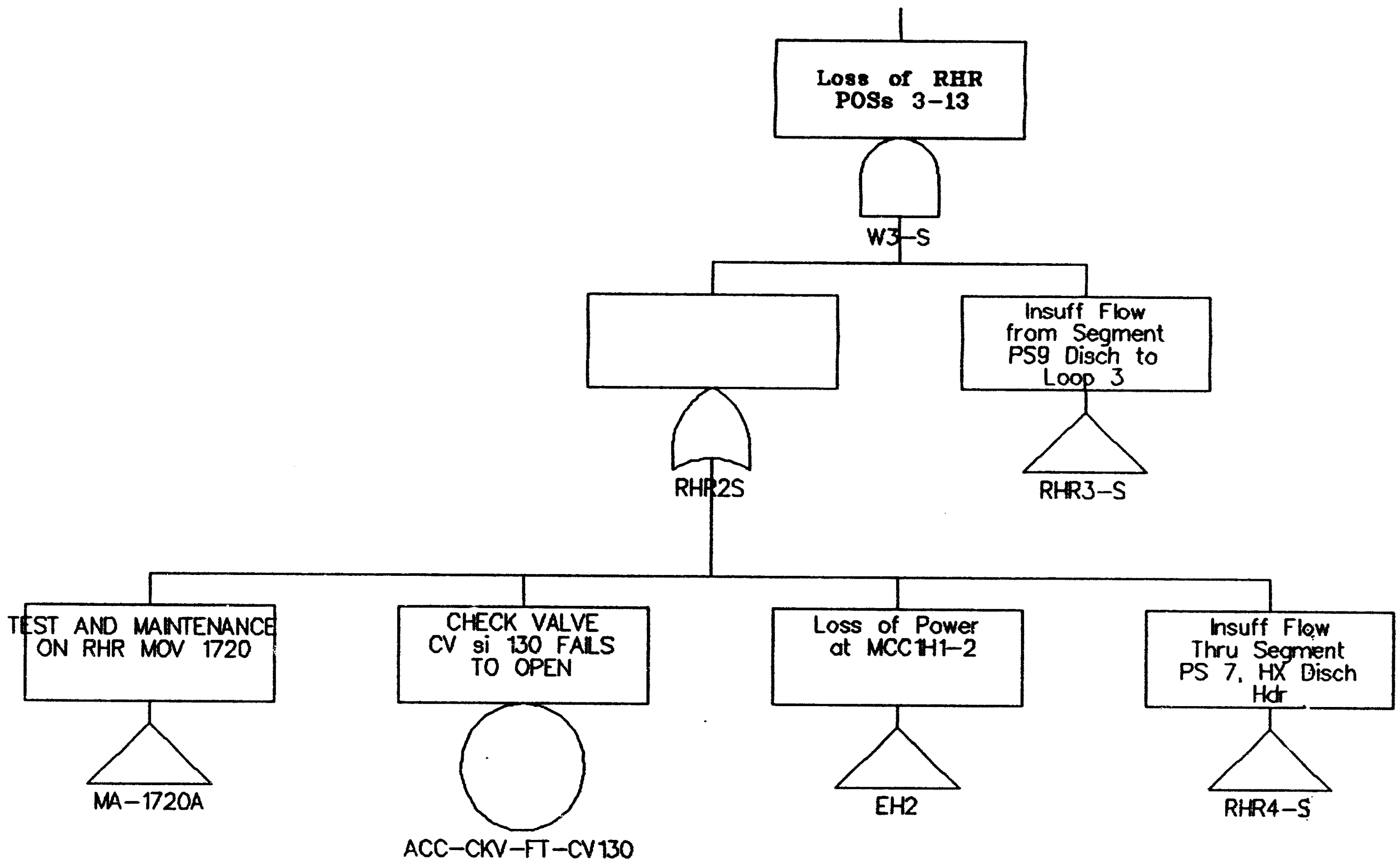
RHR11


RHR12
MANUAL VALVE
RHR14
BACKFLOW THROUGH
CHECK VALVE
TO RUN 24 HOURS

RHR14


RHR14
EH2
RHR15
EJ2
RHR MOTOR OPERATED VALVE 1700 PLUGGED
RHR MOV 1700 FAILS TO OPERATE ON DEMAND
RHR MOTOR OPER VALVE 1701 PLUGGED
RHR MOV 1701 FAILS TO OPEN ON DEMAND
RHR-MOV-PG-1700
RHR-MOV-FT-1700
RHR-MOV-PG-1701
RHR-MOV-FT-1701

W3-S



Loss of RHR POSs 3-13
W3-S
Insuff Flow from Segment PS9 Disch to Loop 3
RHR2S
RHR3-S
TEST AND MAINTENANCE ON RHR MOV 1720
CHECK VALVE CV si 130 FAILS TO OPEN
Loss of Power at MCC1H1-2
Insuff Flow Thru Segment PS 7, HX Disch Hdr
MA-1720A
ACC-CKV-FT-CV130
EH2
RHR4-S

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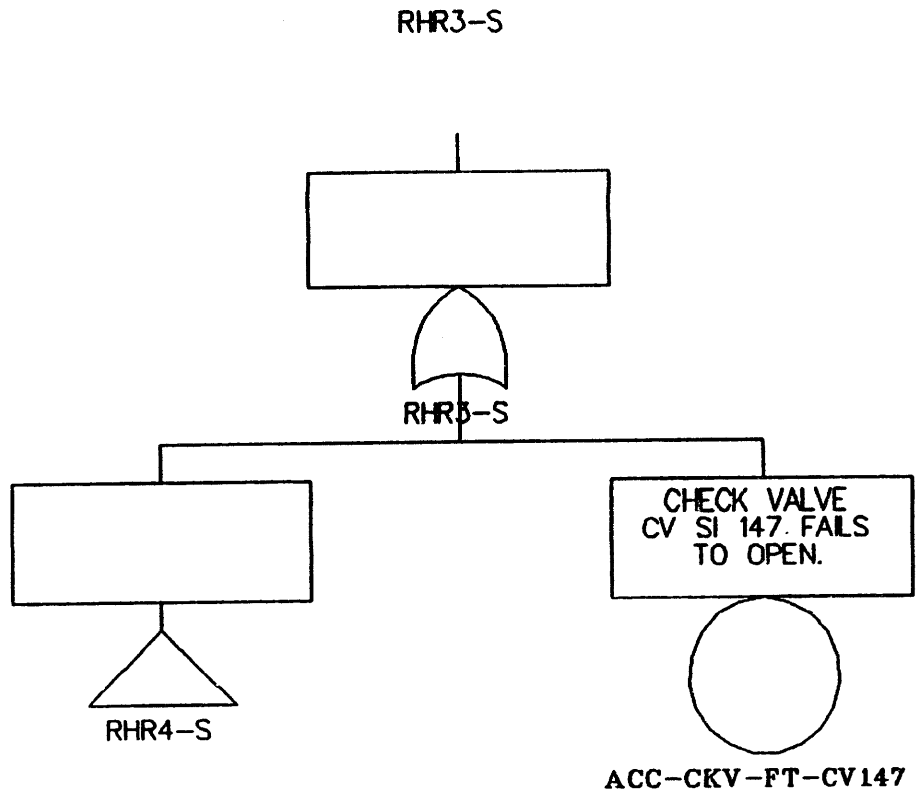
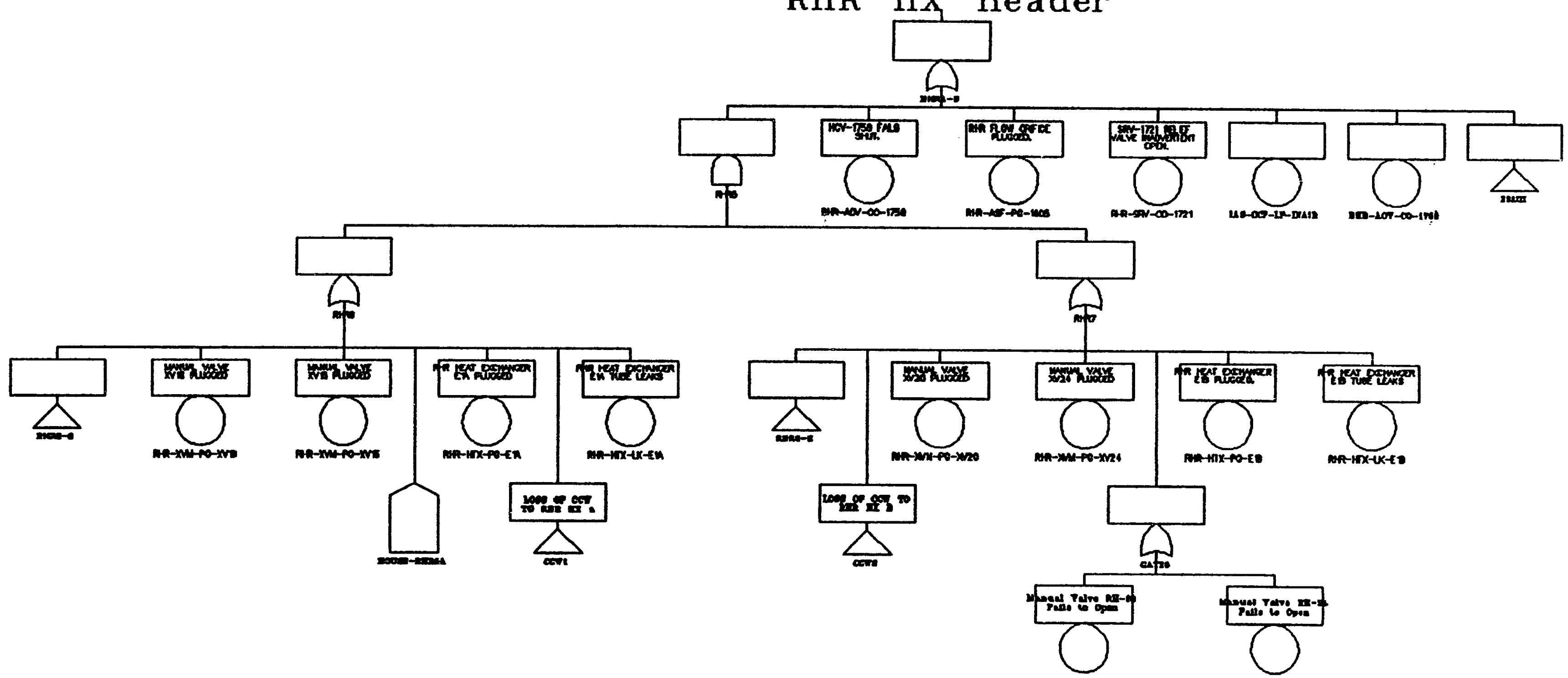
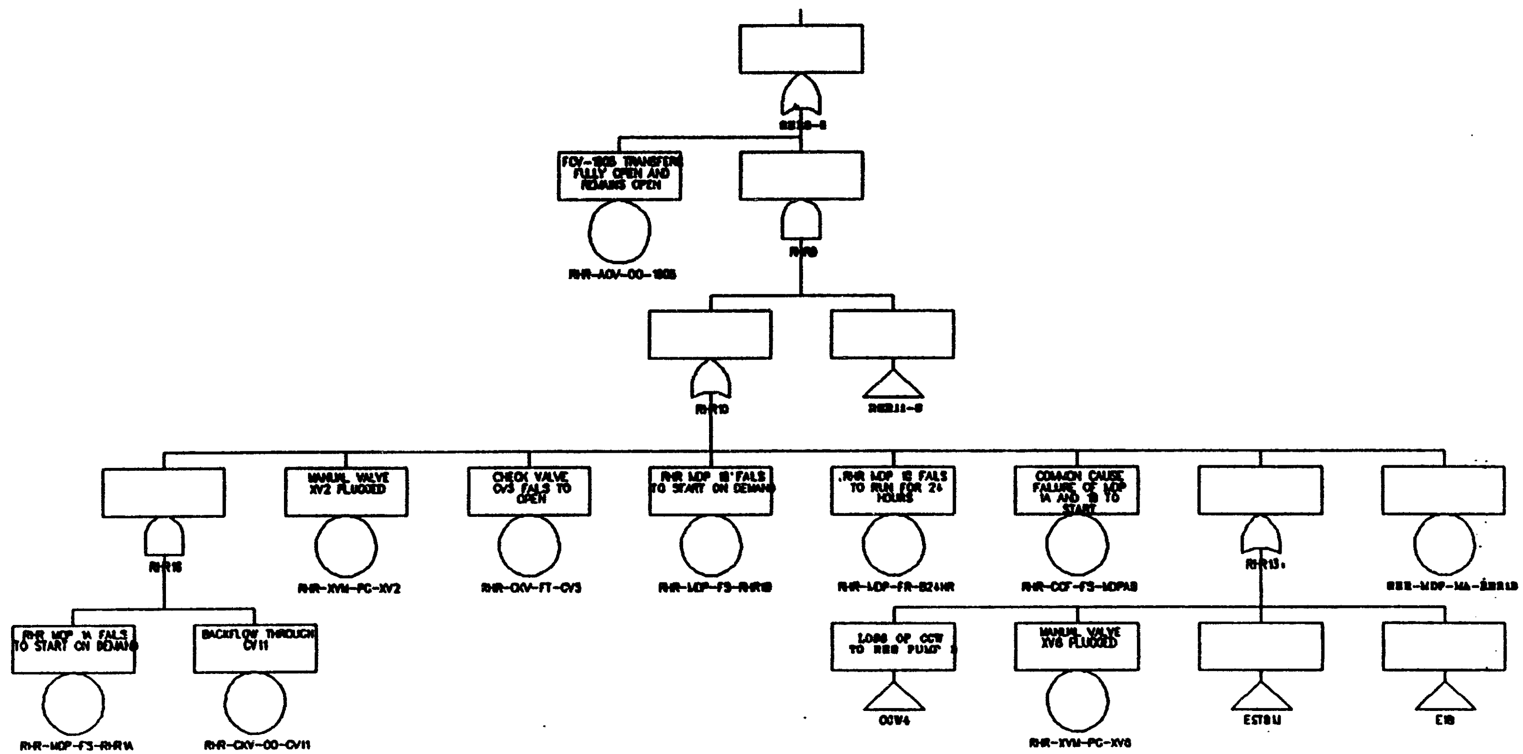

RHR3-S
RHR3-S
CHECK VALVE
CV SI 147 FAILS
TO OPEN.
RHR4-S
ACC-CKV-FT-CV147

RHR4-S

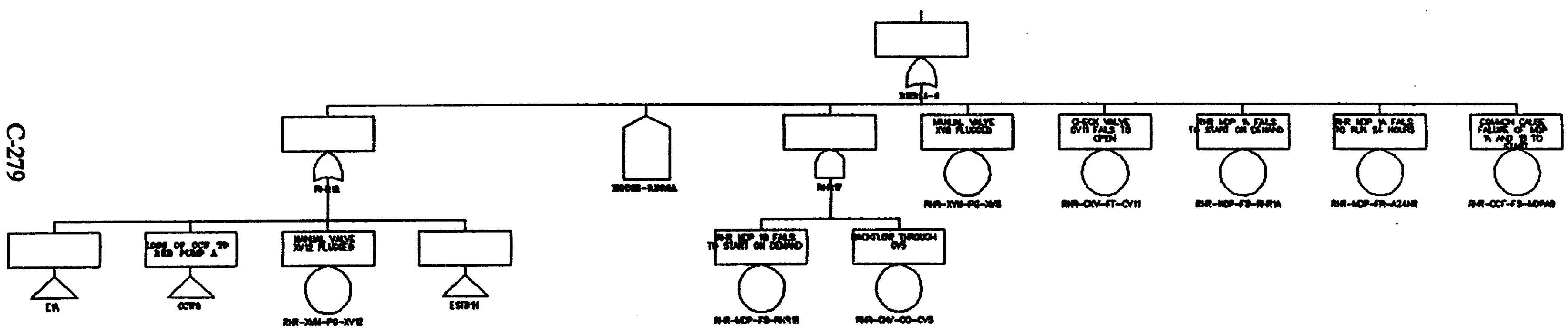
Insufficient Flow from
RHR HX header



RHR8-S


FCV-1805 TRANSFERS FULLY OPEN AND REMAINS OPEN
RHR-AOV-OO-1805
RHR10
MANUAL VALVE XV2 PLUGGED
RHR-XVM-PG-XV2
CHECK VALVE CV3 FAILS TO OPEN
RHR-CKV-FT-CV3
RHR MDP 1B FAILS TO START ON DEMAND
RHR-MDP-FS-RHR1B
RHR MDP 1B FAILS TO RUN FOR 24 HOURS
RHR-MDP-FR-B24HR
COMMON CAUSE FAILURE OF MDP 1A AND 1B TO START
RHR-CCF-FS-MDPAB
RHR16
RHR MDP 1A FAILS TO START ON DEMAND
RHR-MDP-FS-RHR1A
BACKFLOW THROUGH CV11
RHR-CKV-OO-CV11
RHR13
MANUAL VALVE XV6 PLUGGED
RHR-XVM-PG-XV6
CCW4
E1B

RHR11-S

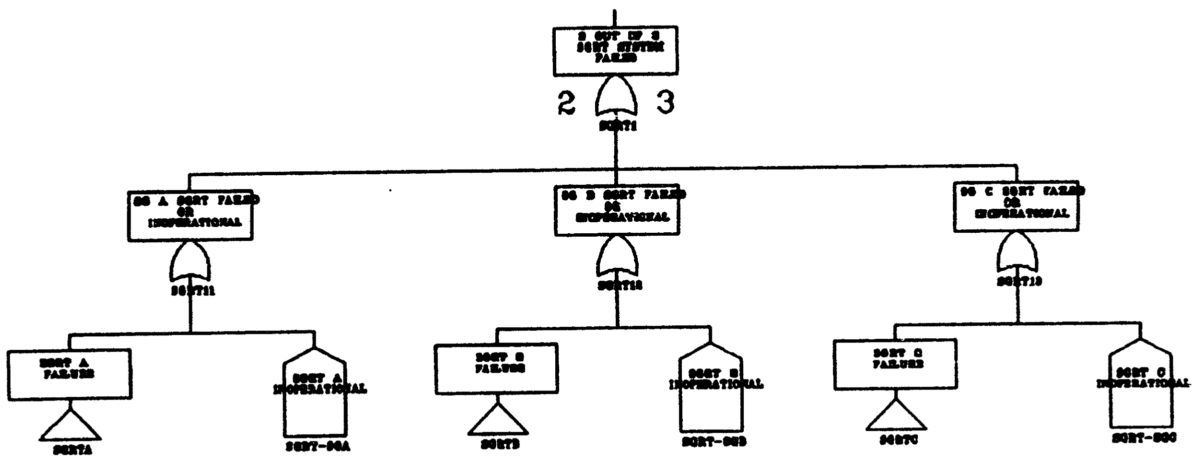


MANUAL VALVE XV8 PLUGGED
RHR-XVM-PG-XV8
CHECK VALVE CV11 FAILS TO OPEN
RHR-CKV-FT-CV11
RHR MDP 1A FAILS TO START ON DEMAND
RHR MDP 1A FAILS TO RUN 24 HOURS
RHR-MDP-FR-A24HR
COMMON CAUSE FAILURE OF MDP 1A AND 1B TO START
RHR MDP 1B FAILS TO START ON DEMAND
BACKFLOW THROUGH CV5
RHR-CKV-OO-CV5
LOSS OF CCW TO RHR PUMP A
MANUAL VALVE XV12 PLUGGED
RHR-XVM-PG-XV12
ESTB1H

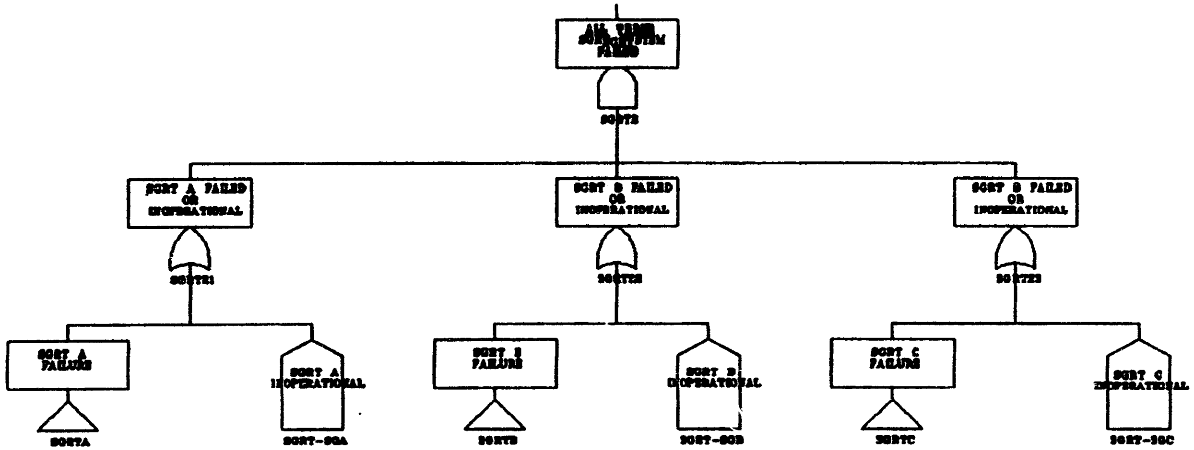
Appendix C.14 Service Water System
(The Fault Trees for the Service Water Components are included in the Fault Trees of those systems that depend on Service Water)
(See App. C.3, C.4, C.8 & C.12)

Appendix C.15 Steam Generator Recirculation and Transfer System

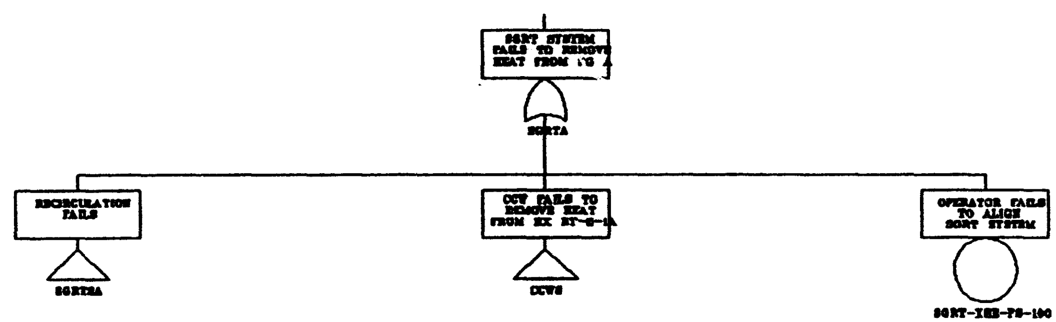
SG RECIRCULATION 2 OUT OF 3
(SGRT1)



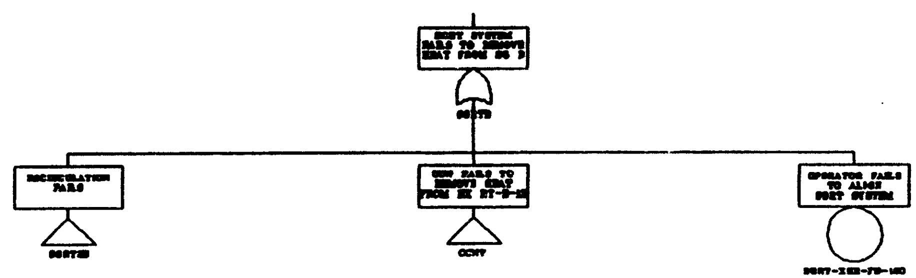
ALL SG RECIRCULATION FAILED
(SGRT2)



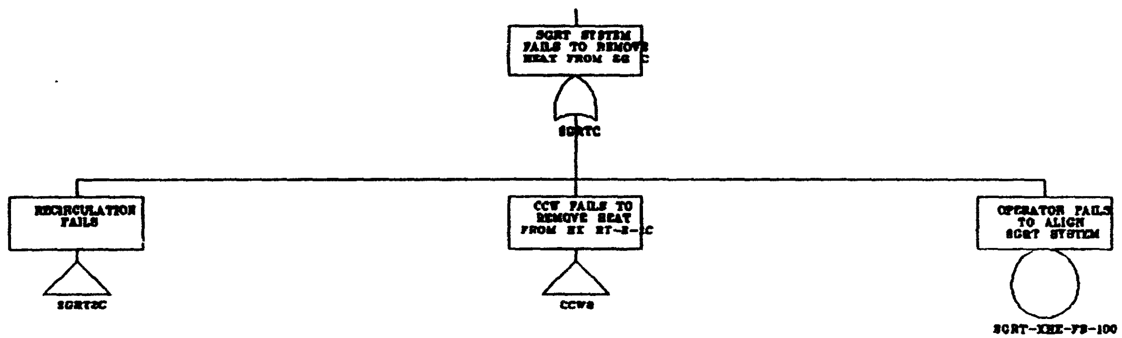
SG RECIRCULATION AND TRANSFER – SG A (SGRTA)



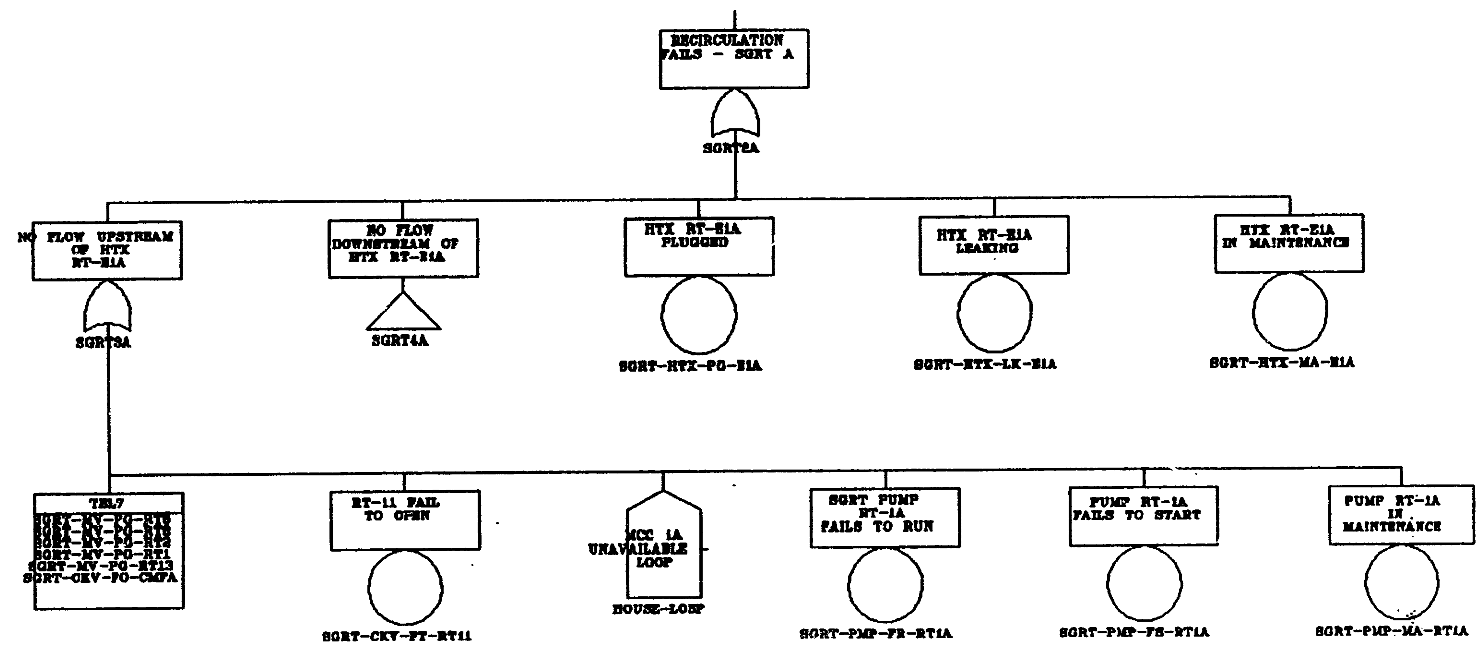
SG RECIRCULATION AND TRANSFER – SG B
(SGRTB)



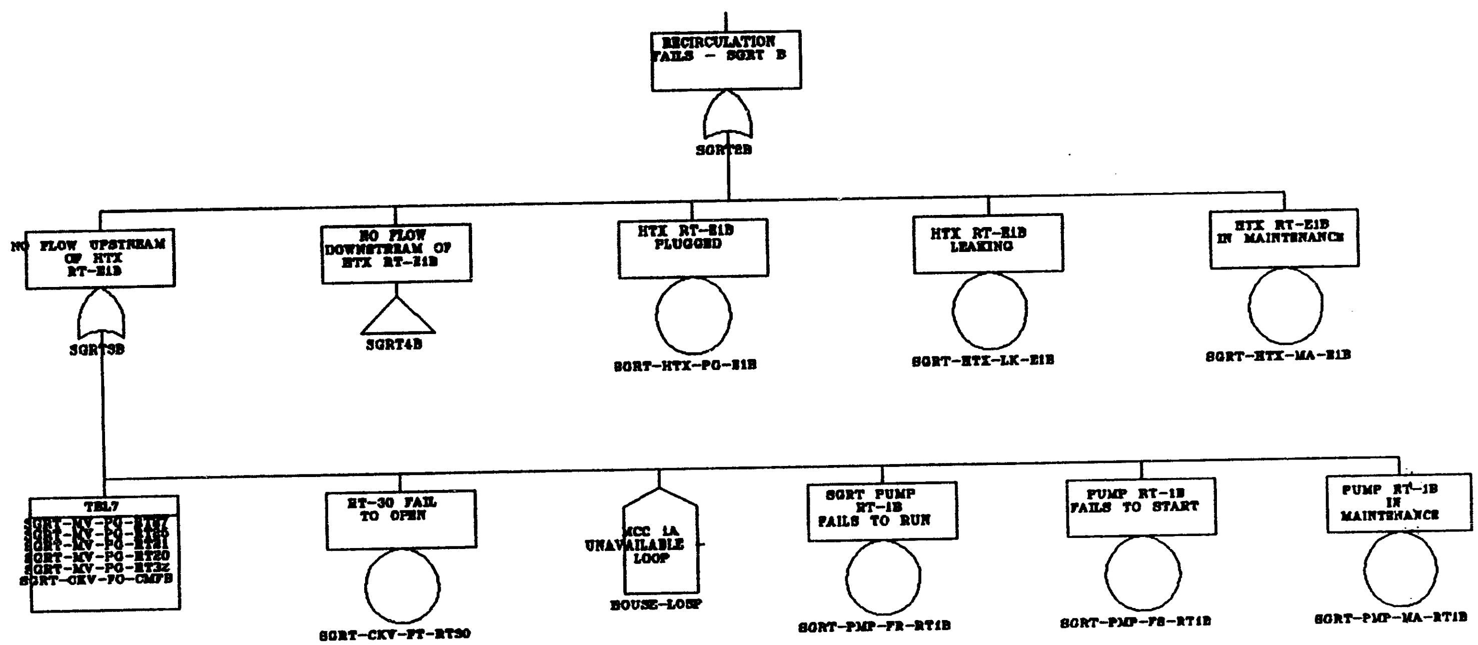
SG RECIRCULATION AND TRANSFER – SG C (SGRTC)



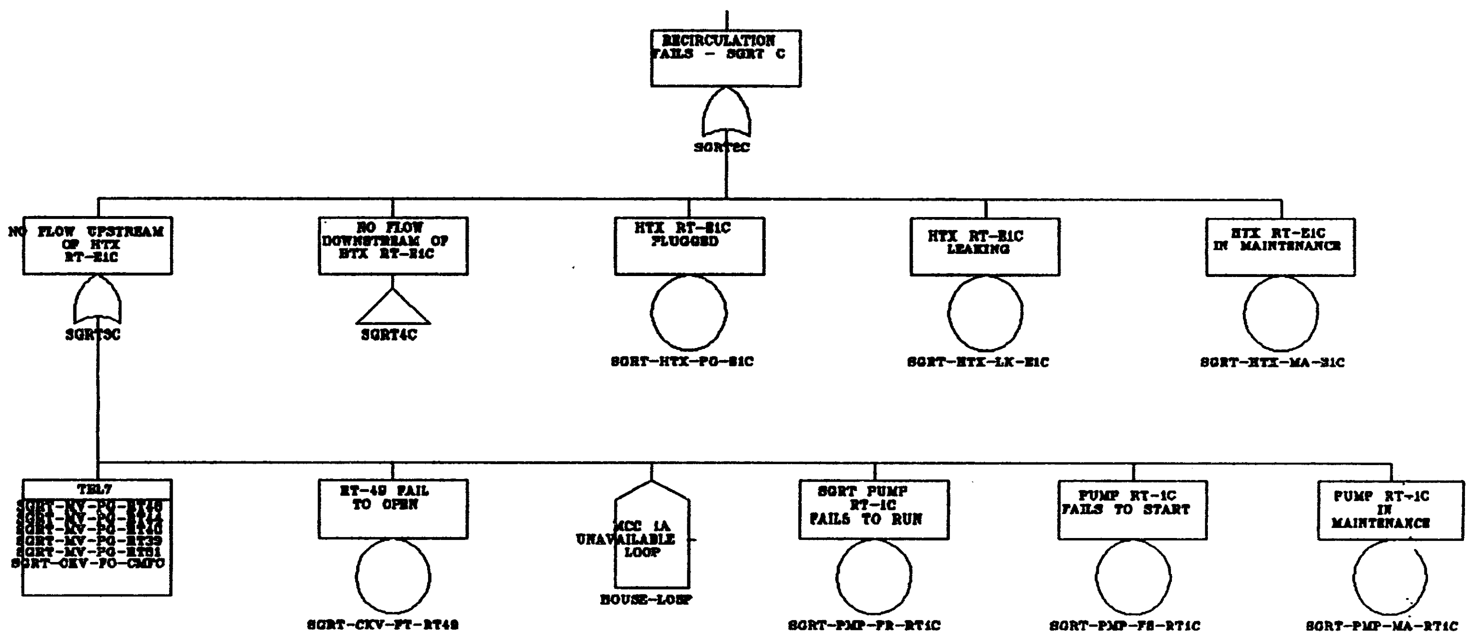
SG RECIRCULATION SYSTEM — SG A (SGRT2A)



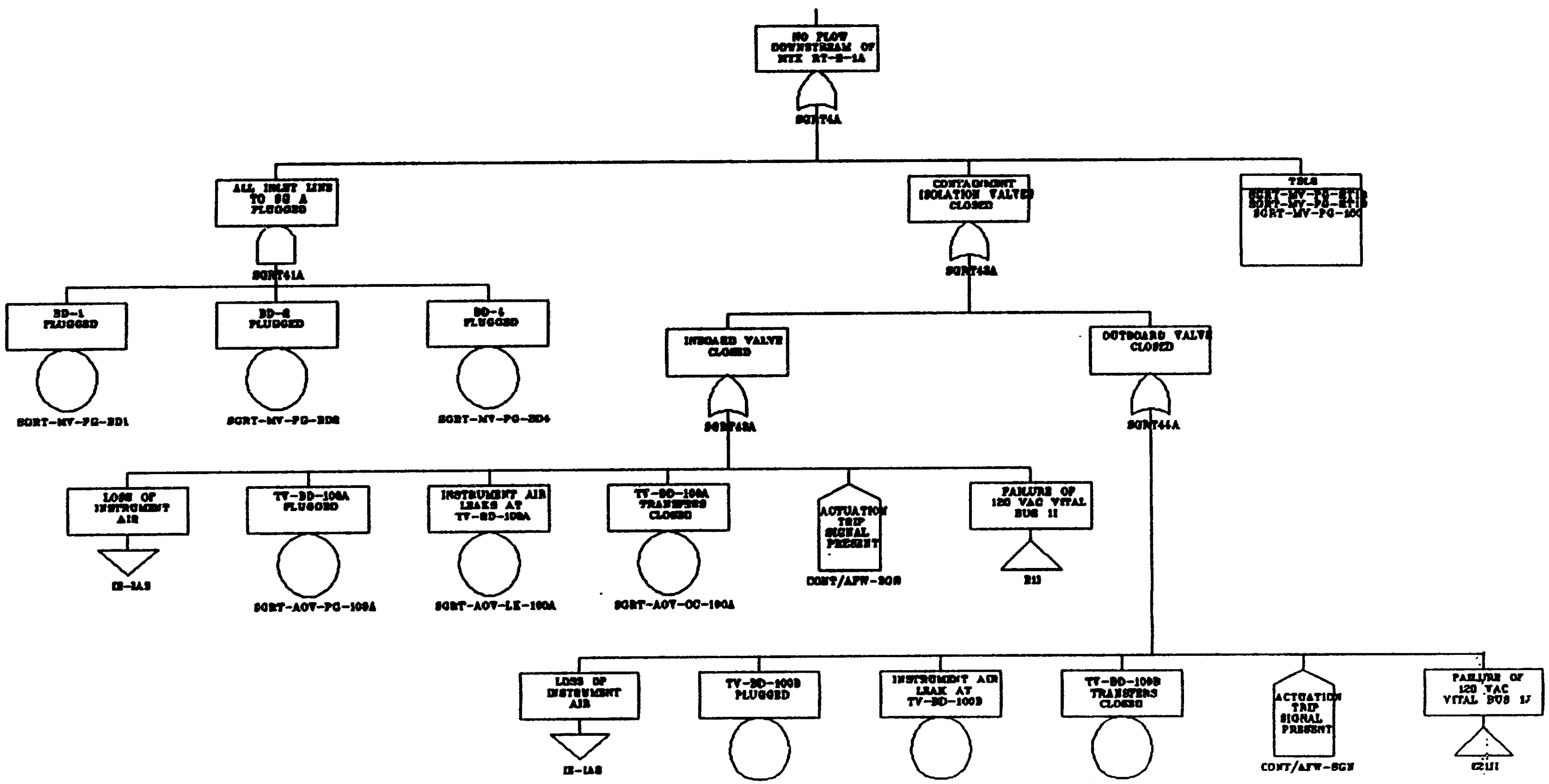
SG RECIRCULATION SYSTEM — SG B (SGRT2B)



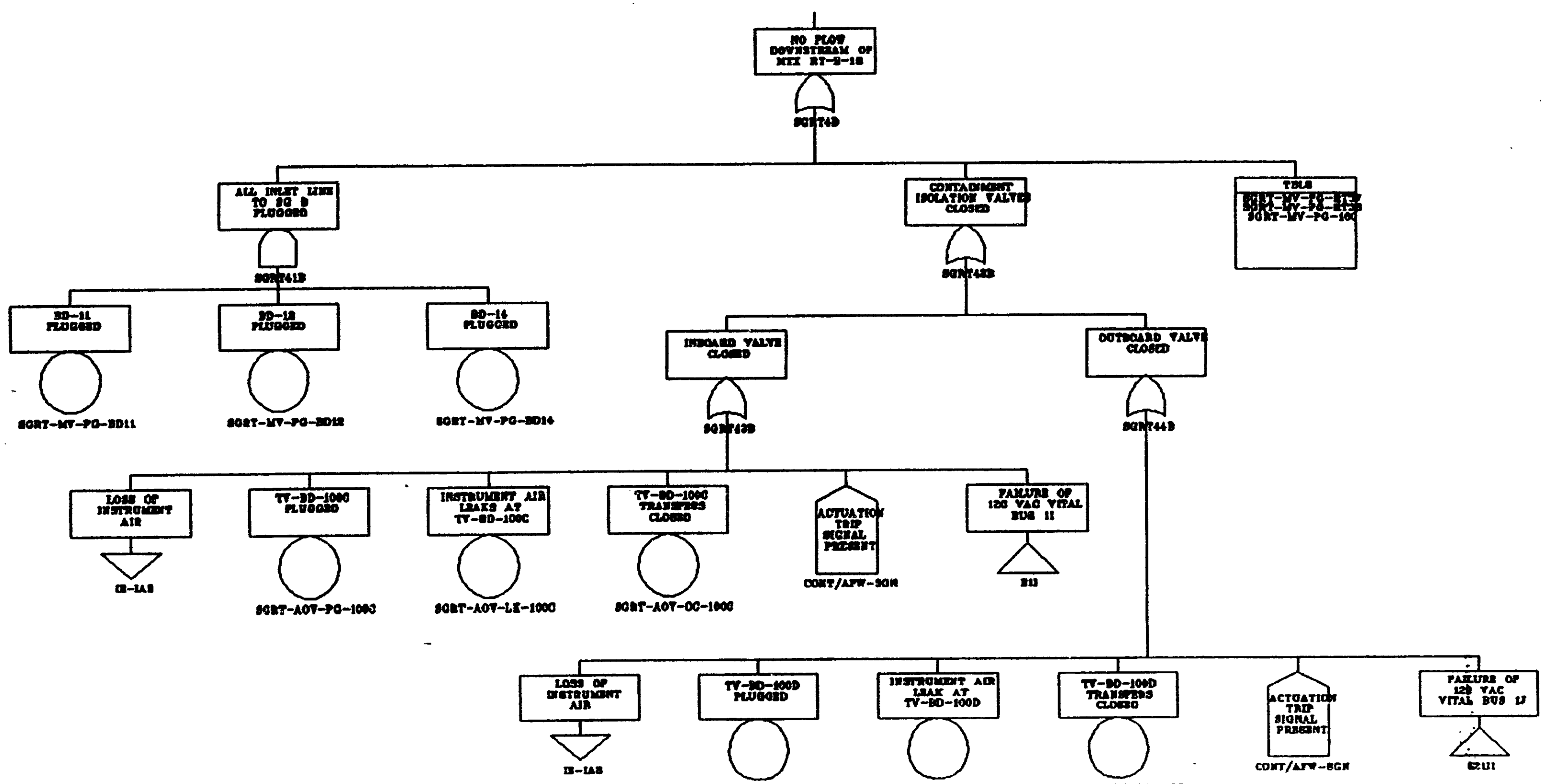
SG RECIRCULATION SYSTEM – SG C (SGRT2C)



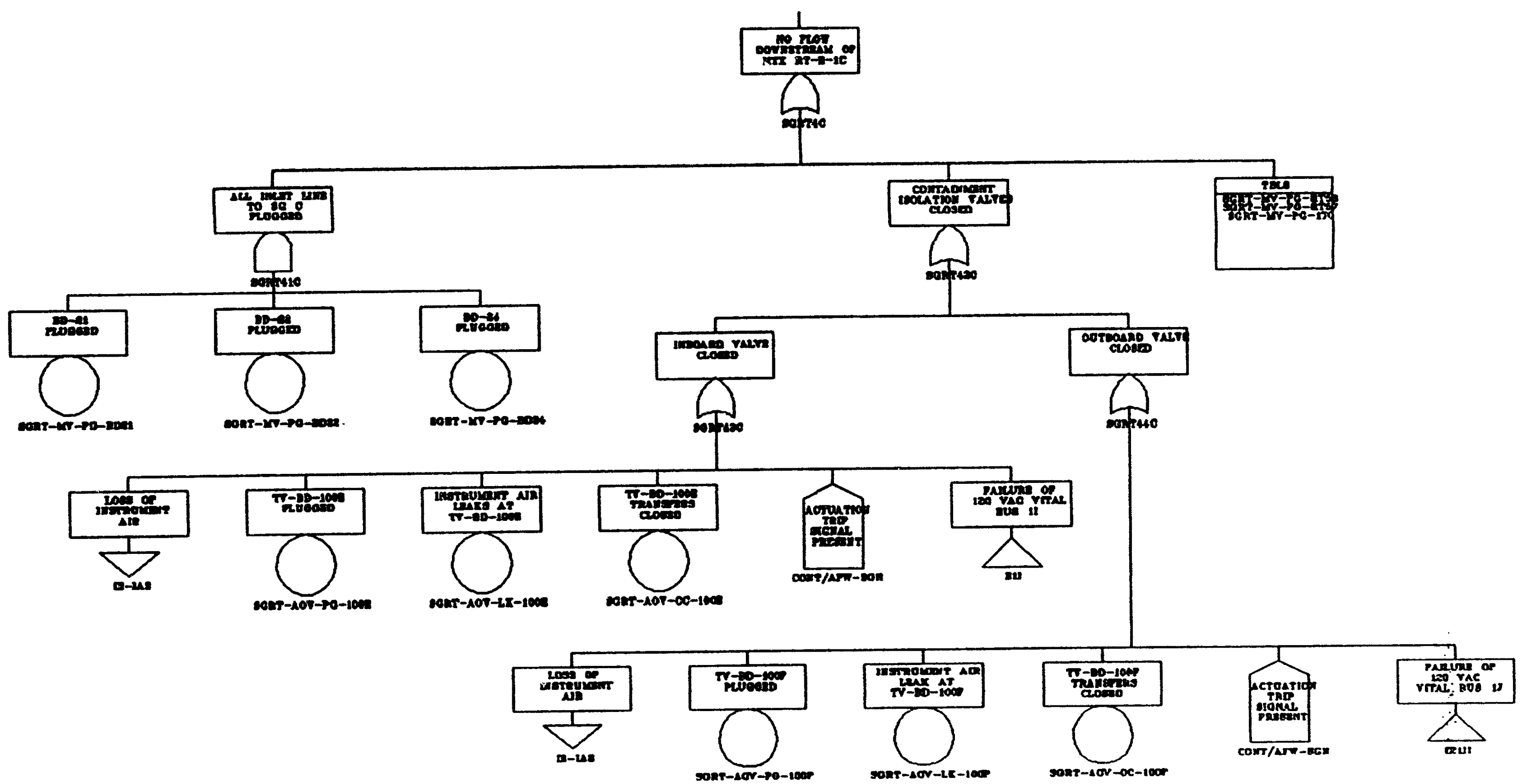
SG RECIRCULATION – SG A
(SGRT4A)



SG RECIRCULATION – SG B
(SGRT4B)

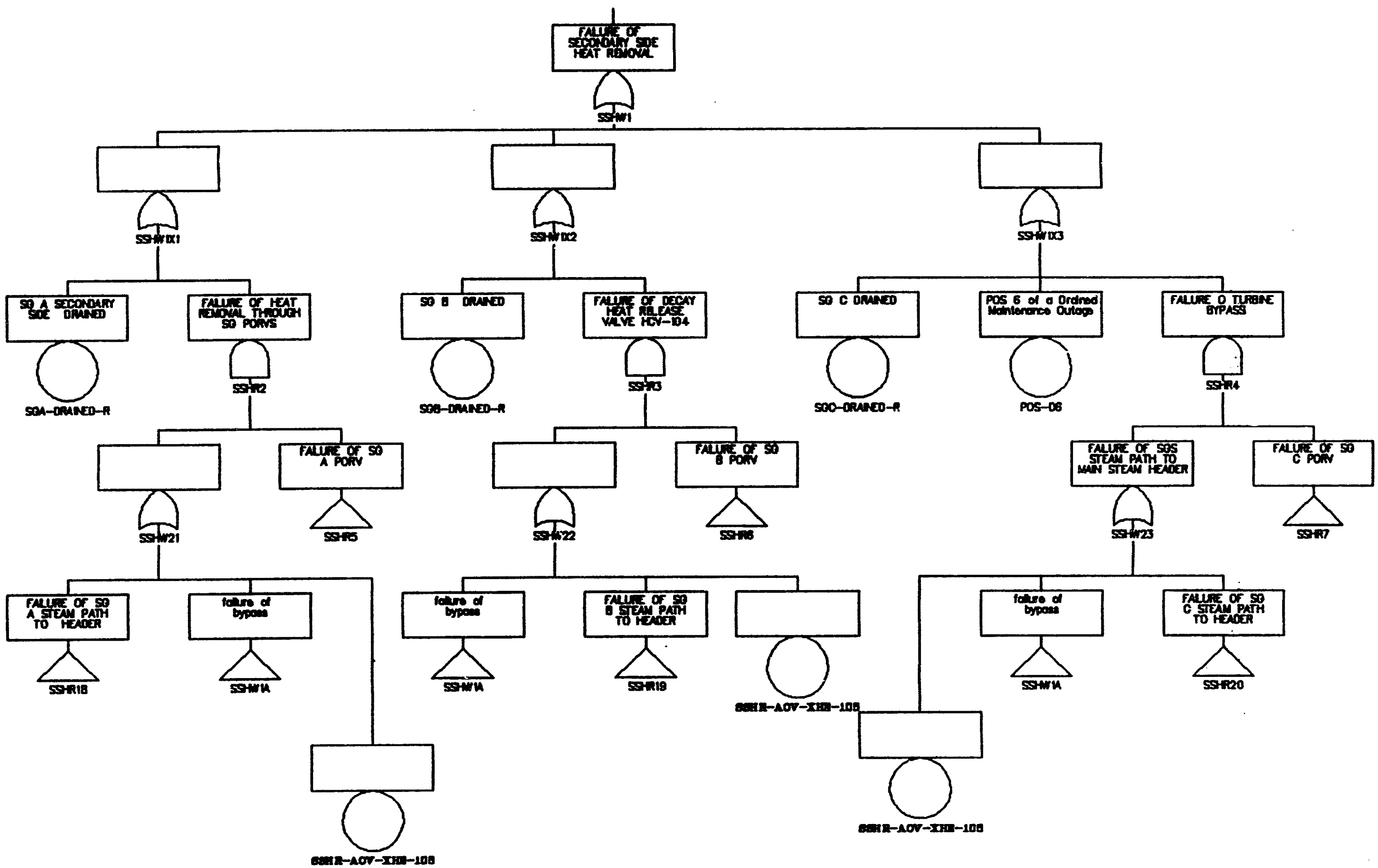


SG RECIRCULATION – SG C
(SGRT4C)

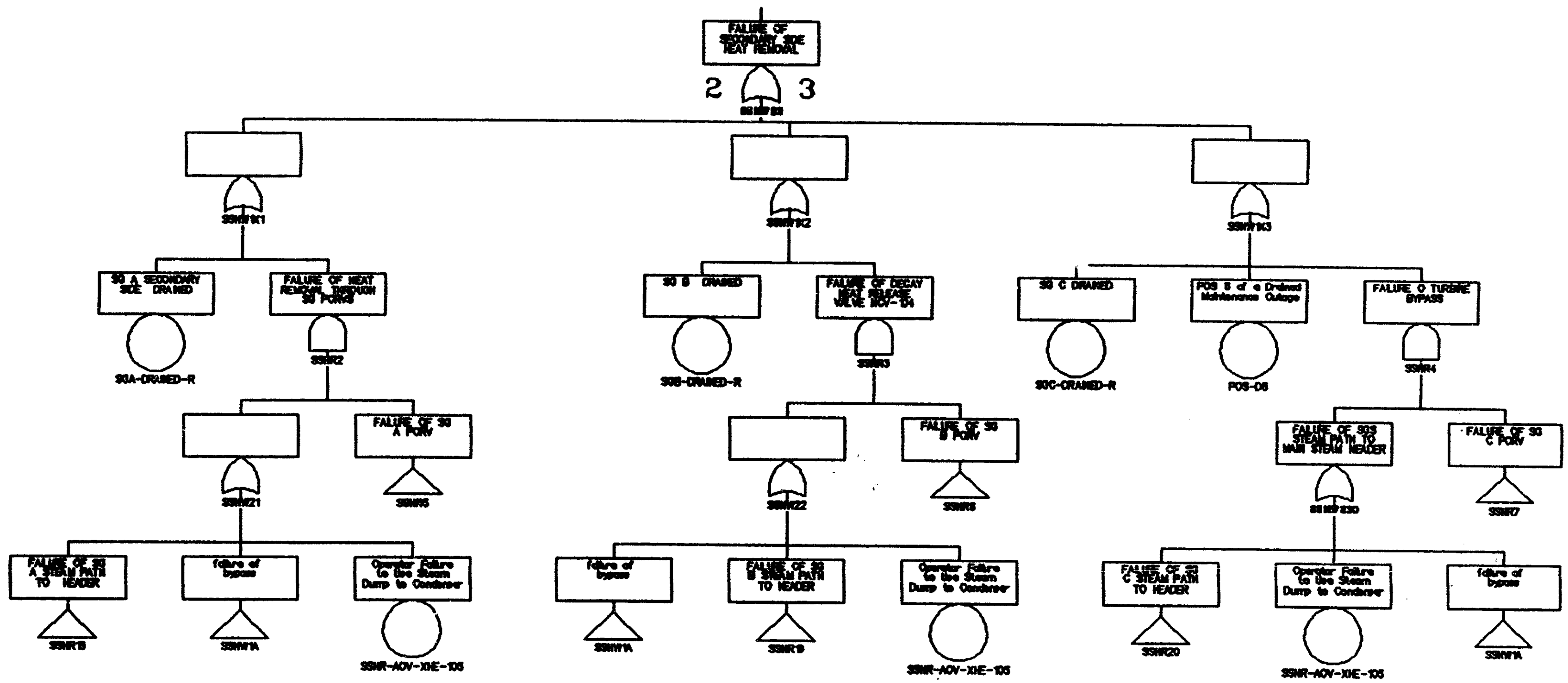


Appendix C.16 Steam Generator Secondary Relief System

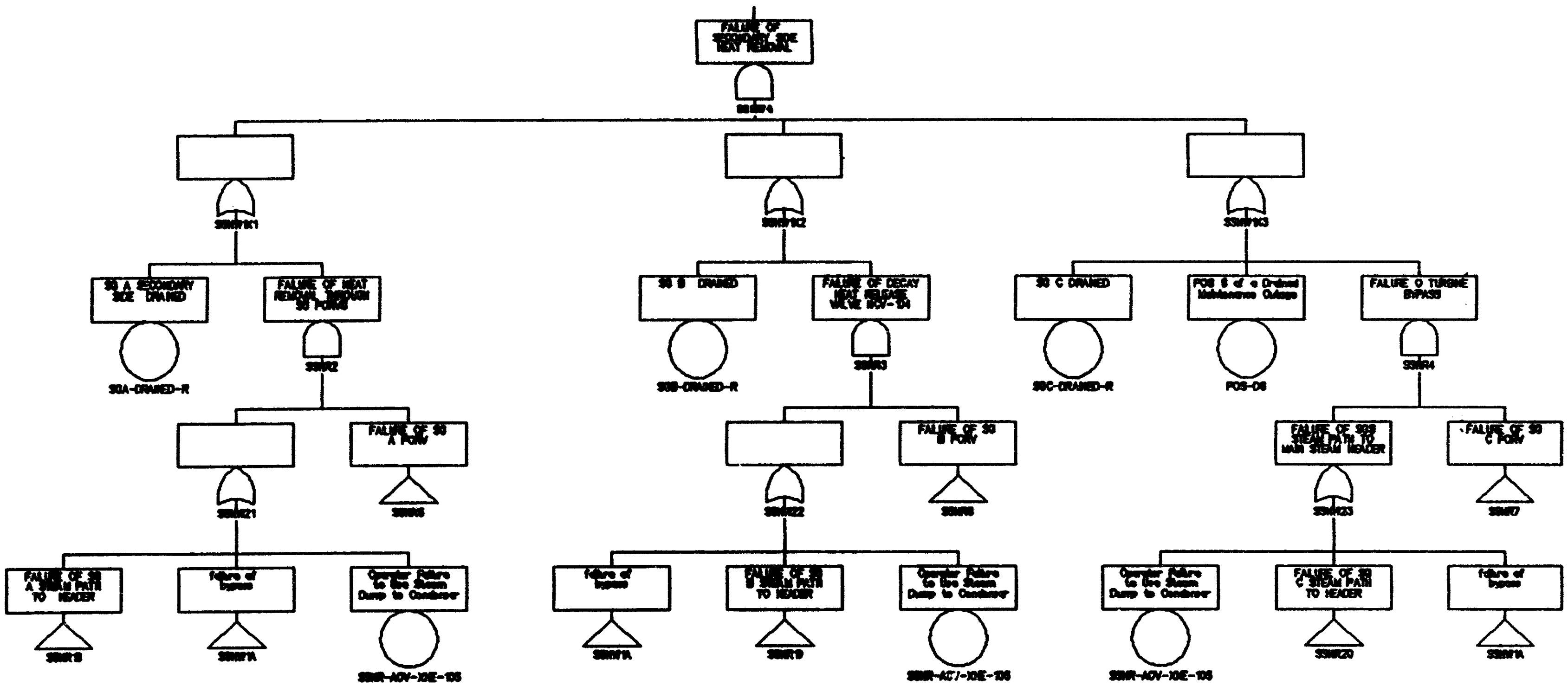
SECONDARY SIDE HEAT REMOVAL FOR REFLUX COOLING WINDOW 1 (SSHW1)



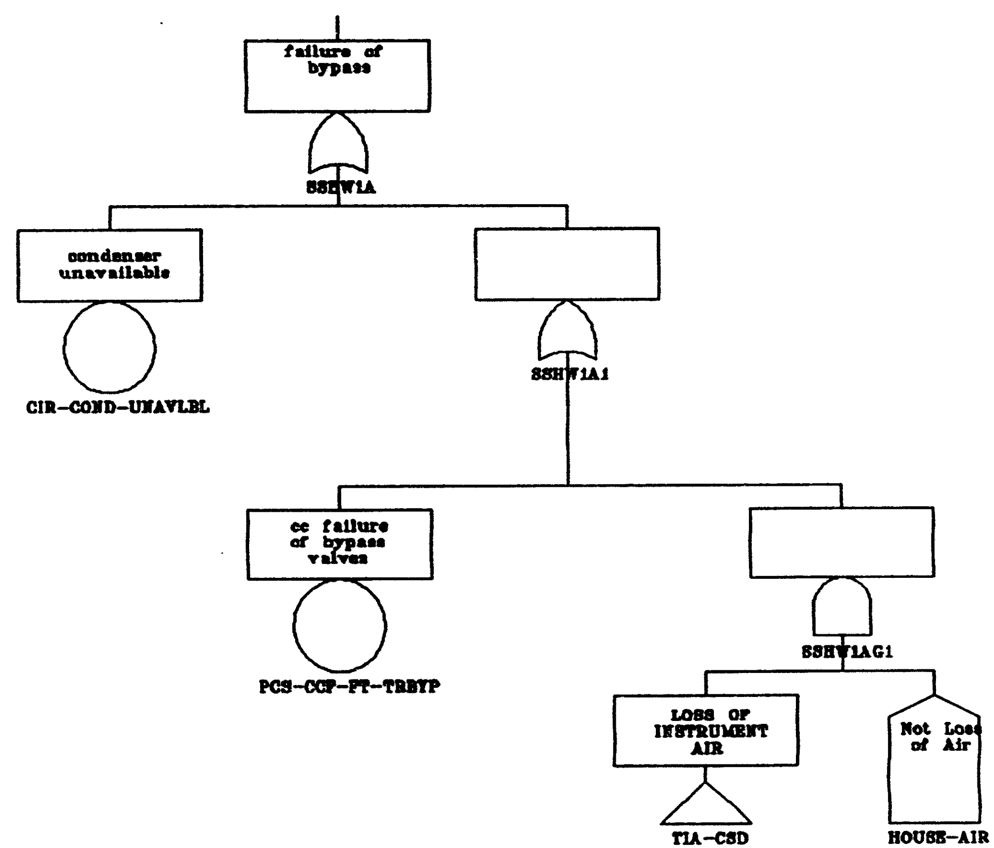
SECONDARY SIDE HEAT REMOVAL FOR REFLUX COOLING WINDOW 2&3 (SSHW23)



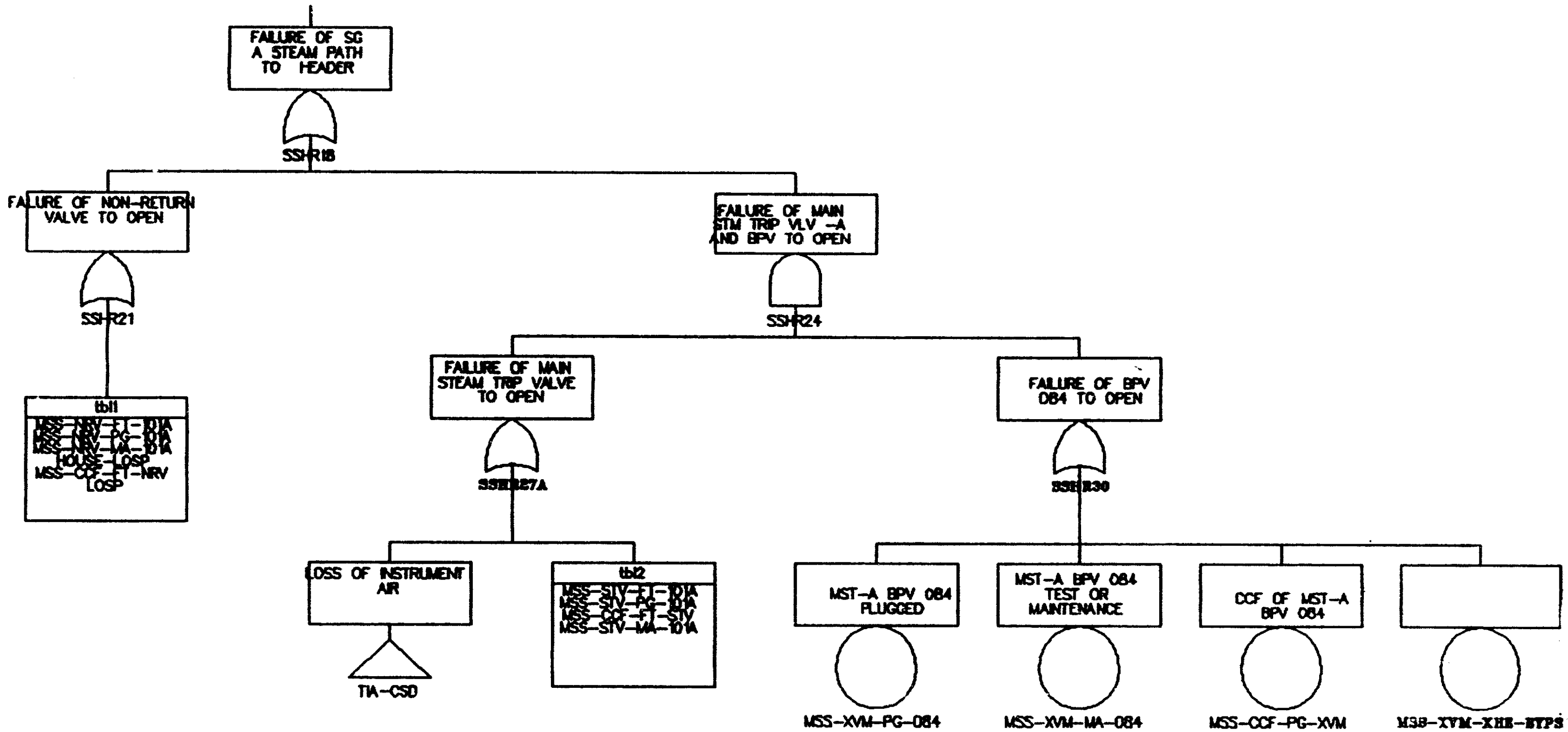
SECONDARY SIDE HEAT REMOVAL FOR REFLUX COOLING WINDOW 4 (SSHW4)



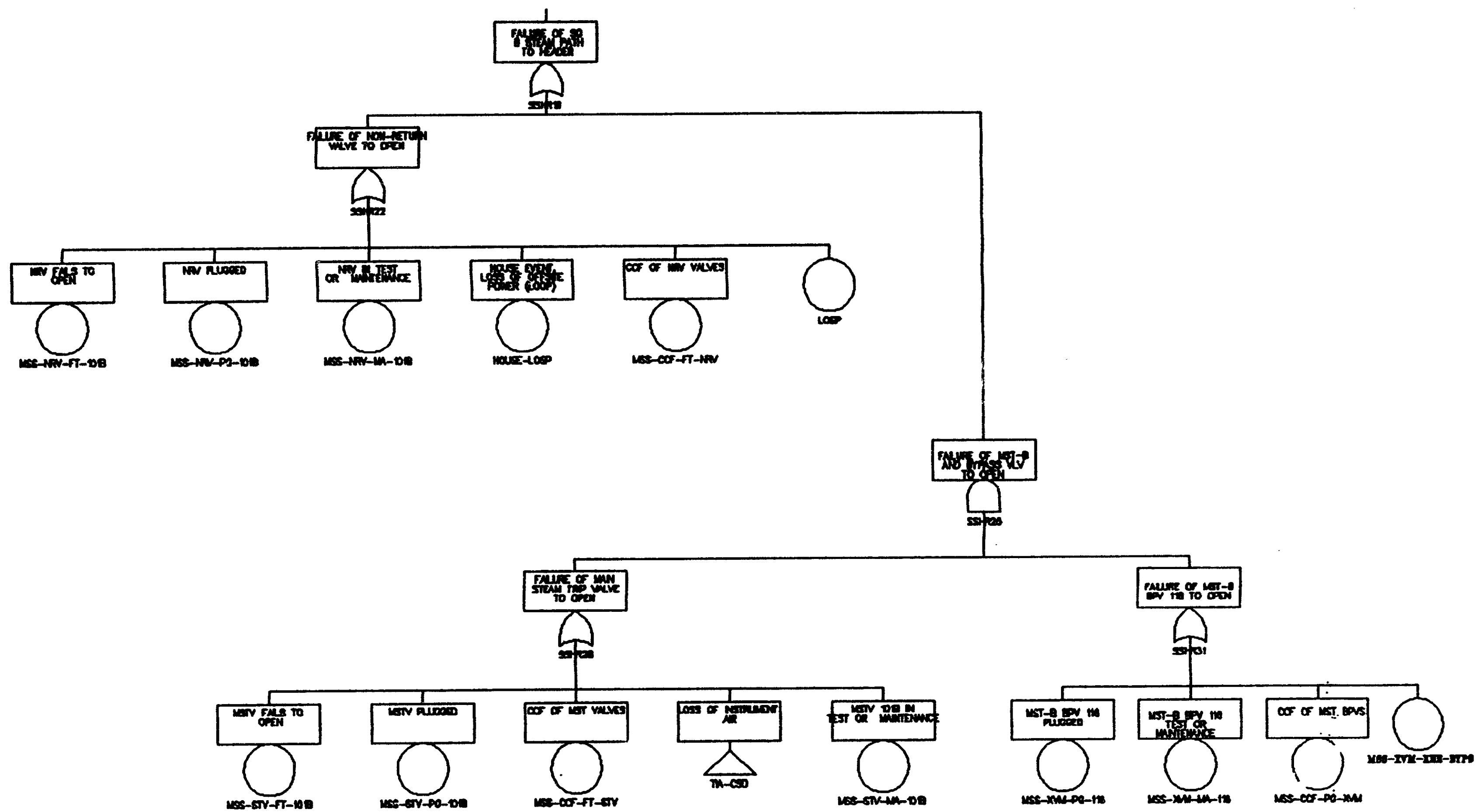
SECONDARY SIDE HEAT REMOVAL FOR REFLUX COOLING (SSHW1A)



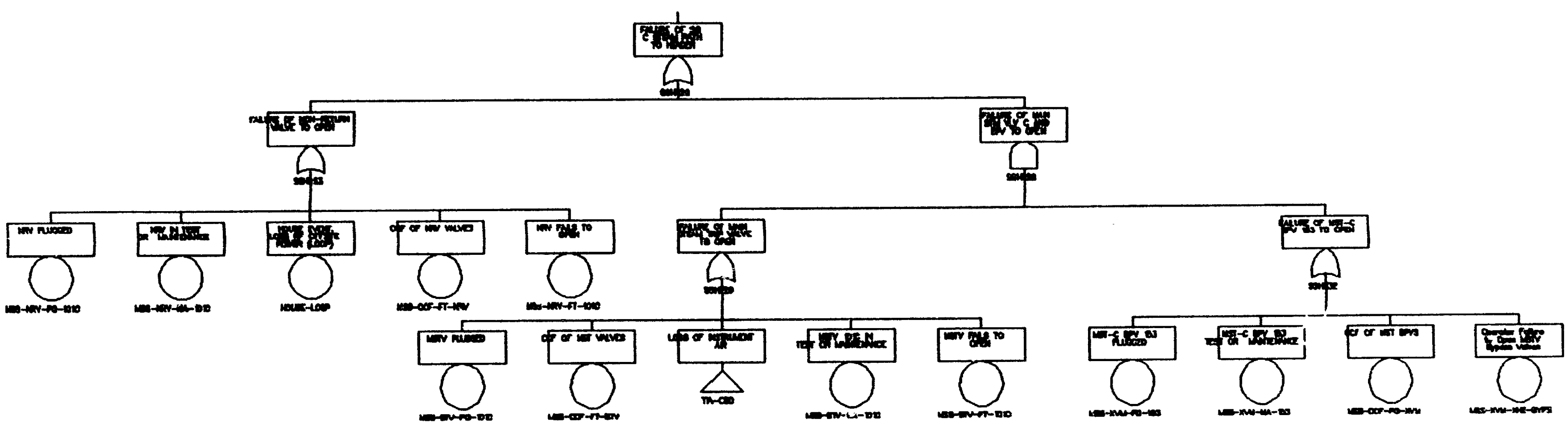
SG A STEAM PATH FAILURE



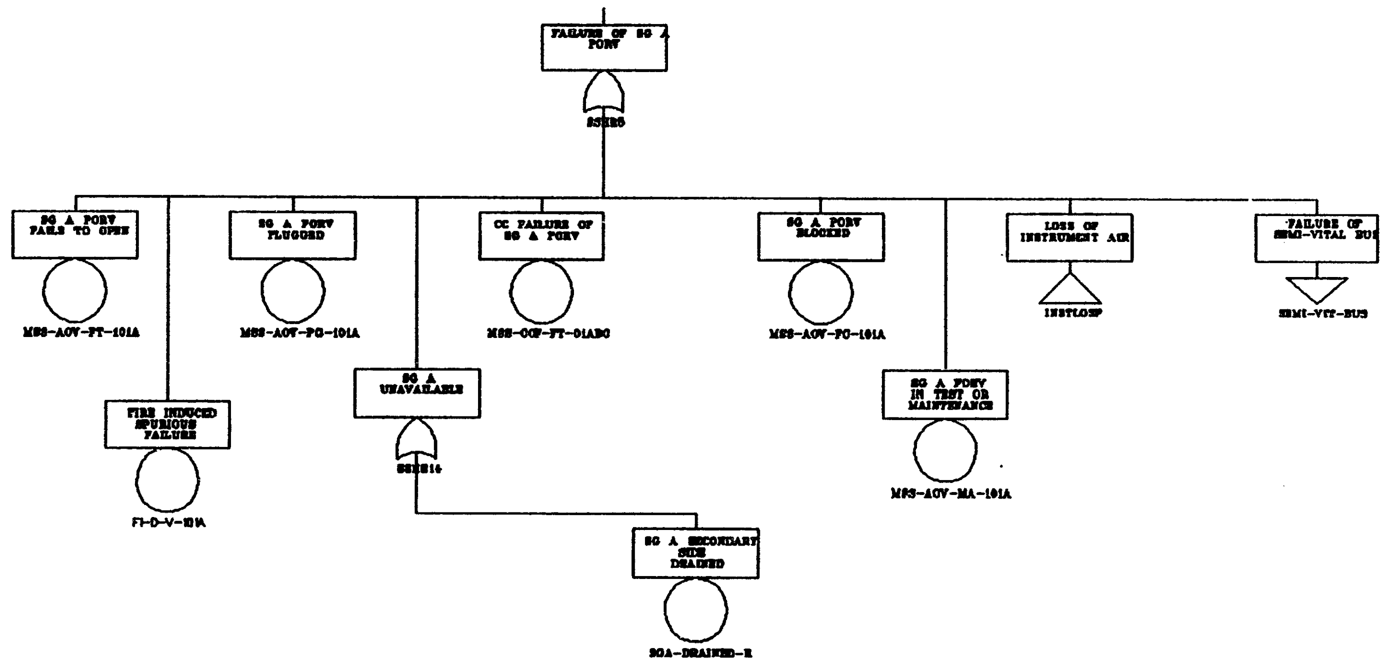
SG B STEAM PATH FAILURE



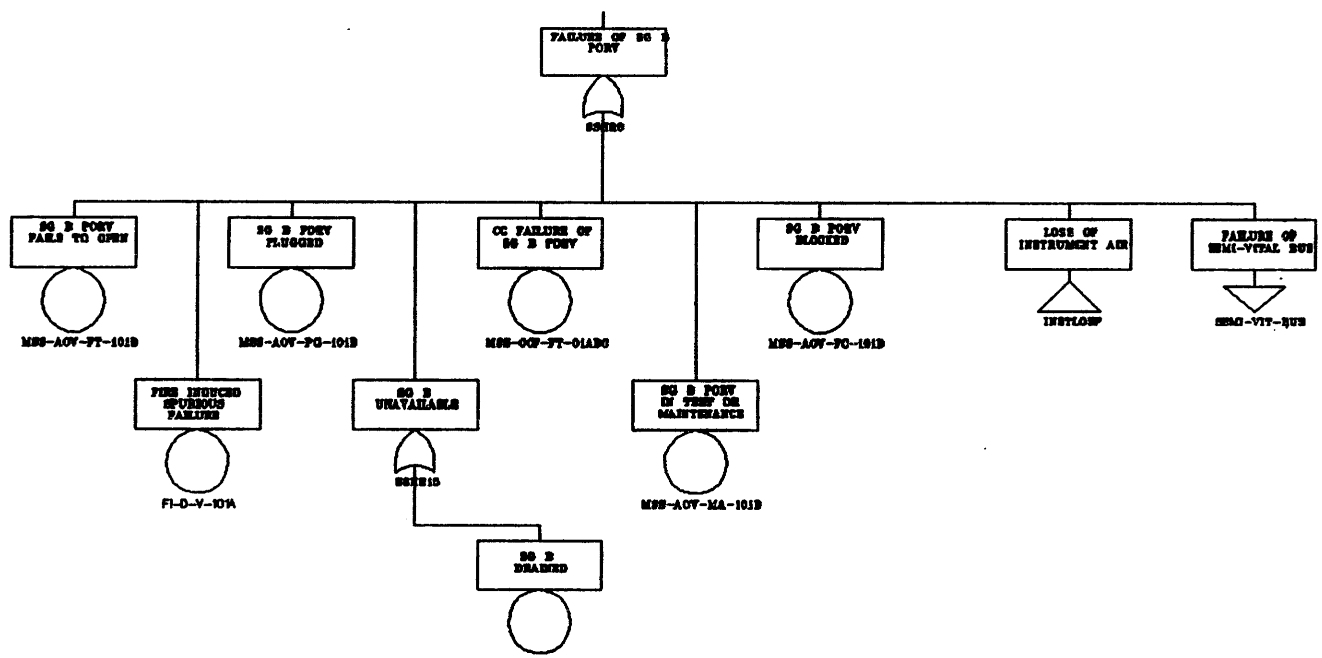
SG C STEAM PATH FAILURE



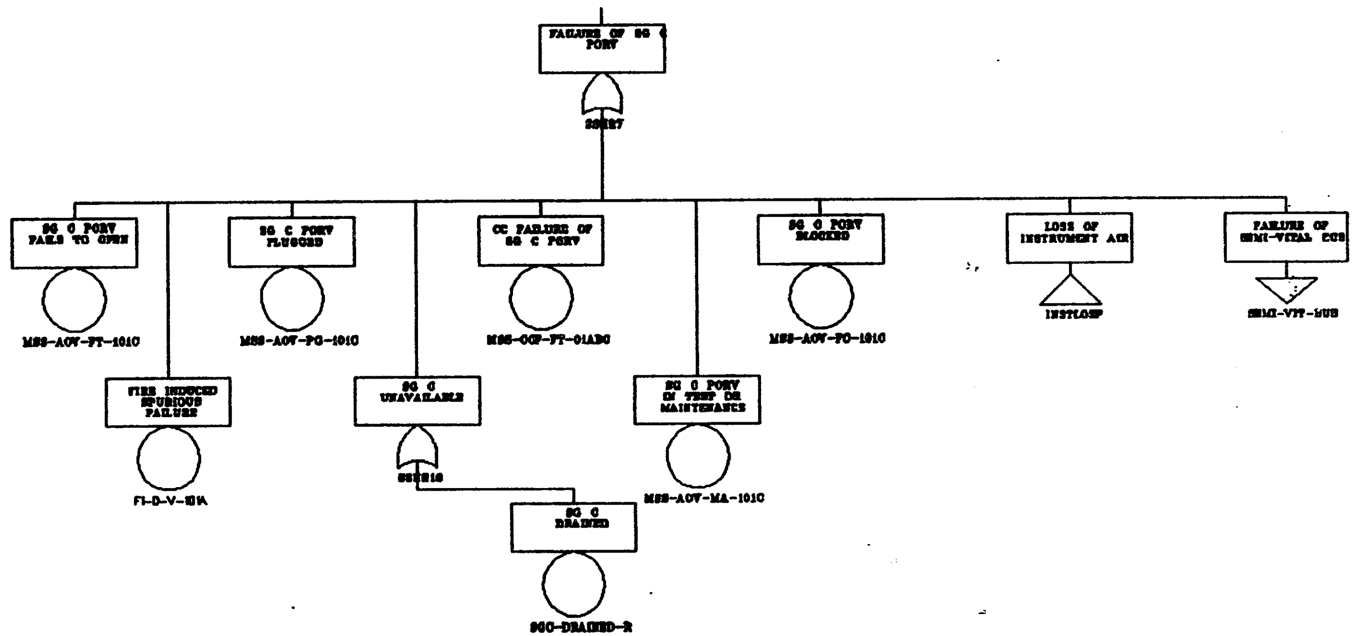
SG A PORV FAILURE



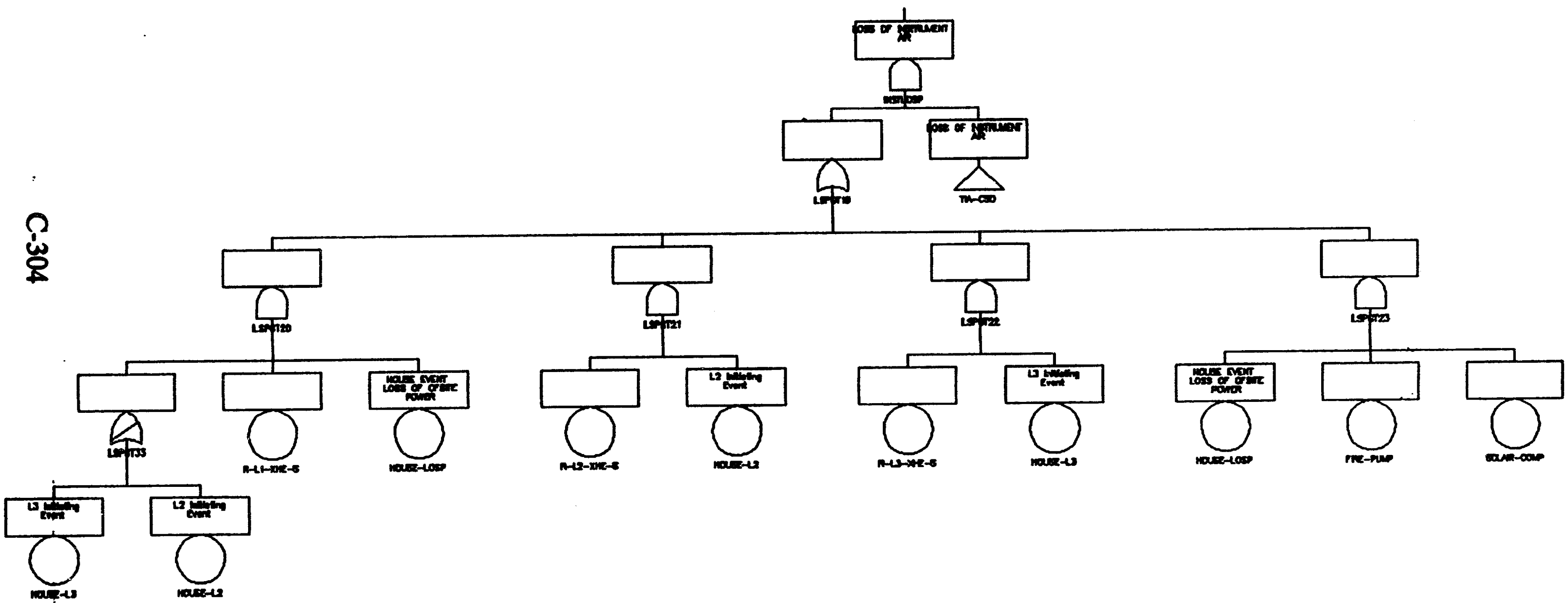
SG B PORV
FAILURE



SG C PORV FAILURE

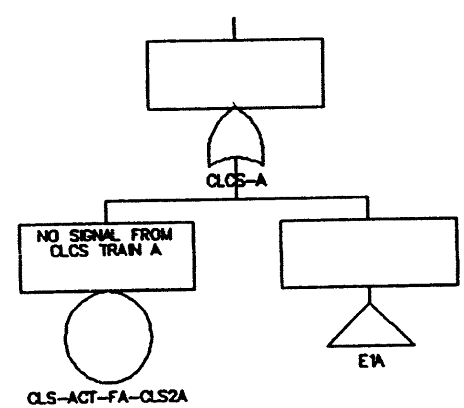


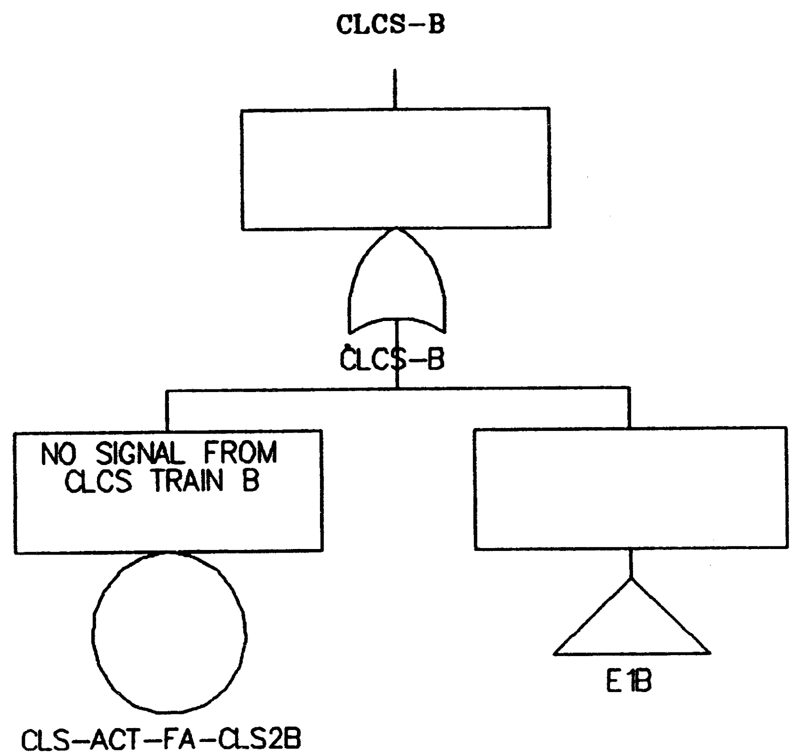
LOSS OF INSTRUMENT AIR



Appendix C.17 Consequence Limiting Control System

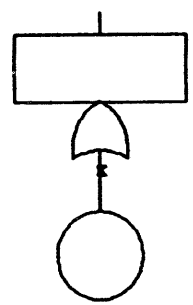
Consequence Limiting Control System Train A




CLCS-B
CLCS-B
NO SIGNAL FROM CLCS TRAIN B
CLS-ACT-FA-CLS2B
E1B

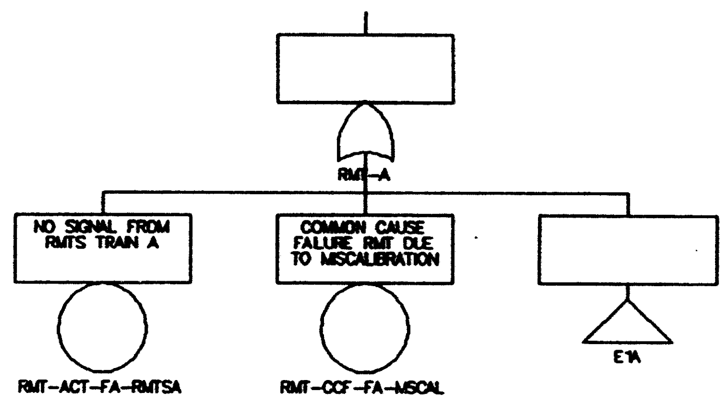
Appendix C.18 Reactor Protection System

FAILURE OF RPS TO SCRAM THE REACTOR

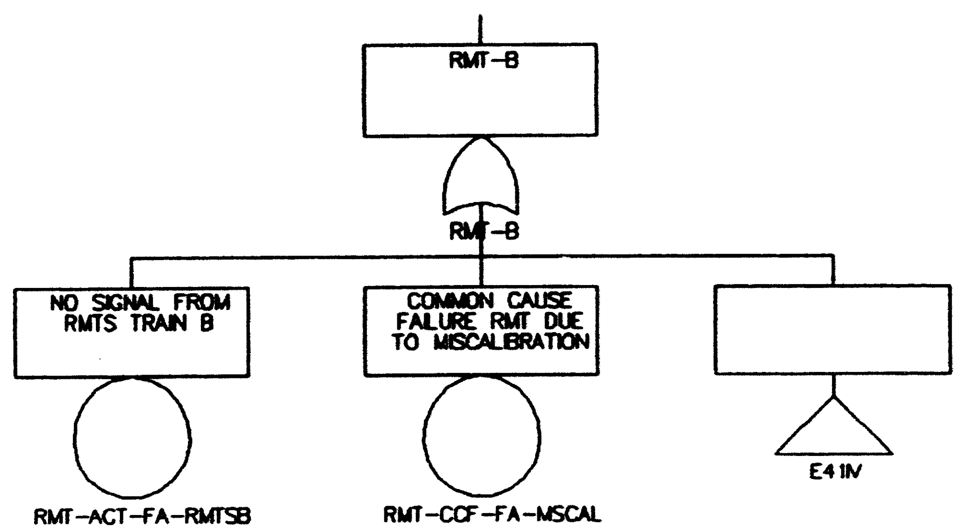


Appendix C.19 Recirculation Mode Transfer System

Recirculation Mode Transfer System Train A



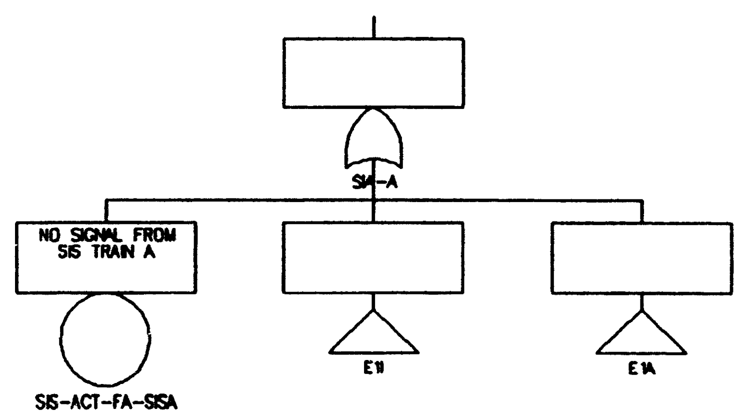
RMT-B



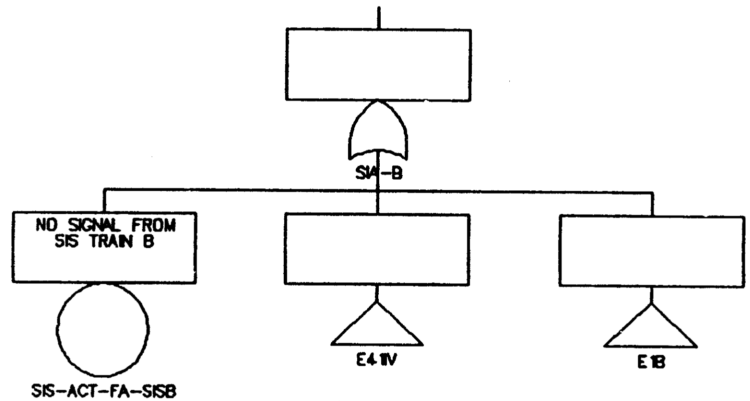
RMT-B
RMT-B
NO SIGNAL FROM RMTS TRAIN B
COMMON CAUSE FAILURE RMT DUE TO MISCALIBRATION
RMT-ACT-FA-RMTSB
RMT-CCF-FA-MSCAL
E41V

Appendix C.20 Safety Injection Actuation System

Safety Injection Actuation System Train



Safety Injection Actuation System Train B



APPENDIX D

Statistical Analysis of Time to Mid-Loop and Duration of Mid-Loop

APPENDIX D

STATISTICAL ANALYSIS OF TIME TO MID-LOOP AND DURATION OF MID-LOOP

PAGE

APPENDIX D.1

Bayesian Analysis of Time to Mid-Loop

D.1 Bayesian Analysis of Time to Mid-loop

This Appendix summarizes a Bayesian analysis of three quantities:

- **the time-to-mid-loop (POS 6)**
- **the time-to-second mid-loop (POS 10)**
- **the duration of mid-loop (POS 6 and POS 10)**

Note that in all three cases, the random variable is assumed to be a shifted lognormal, i.e., the time to mid-loop T = t + t', where t' is the lower bound for T and t is lognormal distributed with density function given by (using the $T_{50,\sigma}$ formulation)

$$f(t \mid T_{50},\sigma) = \frac{1}{\sqrt{2\pi}\,\sigma t}\exp\left\{\frac{1}{2}\left(\frac{\ln(t/T_{50})}{\sigma}\right)^2\right\}$$

The following lists the time shift for each of the POSs:

POS	t'
Pos 6 - Refueling outage	2 days
POS 6 - Drained Maintenance	13 hours
Pos 10 - Regulating outage	2088 hours

These times were estimated using the operating procedures and past plant experience. The rest of this appendix deals with the distibution of t and shows the results for T. Reference [1] is a paper that documents the method used in the analysis in more detail.

TIME TO MID-LOOP DISTRIBUTION

Data for the time to mid-loop consist of population data and Surry-specific data. Regarding the former, it is assumed that the time-to-mid-loop for each plant is lognormally distributed with parameters μ and σ, and that these parameters vary from plant to plant. The population data (generally) consist of experts' "best estimates" and "lower bounds" for each plant-specific distribution. (In some cases, only a "best estimate" is provided.) The "best estimates" are interpreted as medians; the "lower bounds" are interpreted as 5th percentiles.

1) First Stage: Population Variability Surface for T_{50} and σ

Likelihood Functions:

Assume T_{50} and σ are independent, lognormally distributed parameters. Then (for the ith plant):

$$L(T_{50,i})=\frac{1}{\sqrt{2\pi}\,\sigma_{50}T_{50,i}}\exp\left\{\frac{1}{2}\left(\frac{\ln T_{50,i}-\mu_{50}}{\sigma_{50}}\right)^2\right\}$$

$$L(\sigma_i)=\frac{1}{\sqrt{2\pi}\,\sigma_\sigma\sigma_i}\exp\left\{\frac{1}{2}\left(\frac{\ln\sigma_i-\mu_\sigma}{\sigma_\sigma}\right)^2\right\}$$

Prior Distribution (1st Stage):

$$\pi_0(\mu_{50},\sigma_{50},\mu_\sigma,\sigma_\sigma)\propto\frac{1}{\sigma_{50}\sigma_\sigma}$$

Data: Table D.1-1
Posterior Distribution (Characteristics):

	μ_{50}	σ_{50}	μ_σ	σ_σ
Mean	**4.1438**	**0.4971**	**-0.5776**	**0.7729**

Expected Population Variability Surface:

$$g_1(T_{50}) = \iint f(T_{50}|\mu_{50},\sigma_{50})\pi_1(\mu_{50},\sigma_{50})d\mu_{50}d\sigma_{50}$$

$$g_1(\sigma) = \iint f(\sigma|\mu_\sigma,\sigma_\sigma)\pi_1(\mu_\sigma,\sigma_\sigma)d\mu_\sigma d\sigma_\sigma$$

(Note that the f(•) are based on μ and σ, rather than T_{50} and σ.)

$$g_1(T_{50},\sigma) = g_1(T_{50})g_1(\sigma)$$

2) Second Stage: Expected Distribution for Time-To-Mid-loop

The analysis distinguishes between refueling outages and drained maintenance outages.

Likelihood Function:
For the ith data point from Surry,

$$L(T_i|T_{50},\sigma)=\frac{1}{\sqrt{2\pi}\,\sigma t_i}\exp\left\{\frac{1}{2}\left(\frac{\ln(t_i/T_{50})}{\sigma}\right)^2\right\}$$

Prior Distribution (2nd Stage):

$$\pi_1(T_{50},\sigma) = g_1(T_{50},\sigma)$$

Expected Distribution:

$$\bar{f}(t)=\int\int f_T(t|T_{50},\sigma)\pi_2(T_{50},\sigma)dT_{50}d\sigma$$

Refueling Outage:

Data:

Event	Date	Time (h)
R	02/83	184
R	06/83	293
R	02/84	88.1
R	09/84	161
R1 (Unit 2)	03/20/85	239
R2 (Unit 1)	05/10/86	91.9
R3 (Unit 2)	10/04/86	100
R4 (Unit 1)	04/09/88	174
R5 (Unit 1)	09/14/88	315
R6 (Unit 2)	09/10/88	203

Expected Distribution Characteristics (see Figure D.1-1):

Mean 191
5th 78.7
50th 155
95th 422

Drained Maintenance Outage:

Data:

Event	Date	Time (h)
D	10/82	121
D	12/82	44.0
D	06/83	24.0
D	09/83	106
D	12/83	42.1
D	12/83	27.9
D	03/84	37.6
D	10/84	82.5
D1 (Unit 1)	04/29/85	94.8
D2 (Unit 1)	08/06/85	105
D3 (Unit 2)	10/29/85	61.5
D4 (Unit 1)	01/24/86	74.8
D5 (Unit 2)	06/17/86	53.3
D6 (Unit 1)	12/11/86	276
D7 (Unit 2)	12/09/86	1282
D8 (Unit 1)	05/16/87	74.9
D9 (Unit 1)	06/23/87	53.7
D10 (Unit 2)	12/09/87	184
D11 (Unit 2)	05/16/88	291
D12 (Unit 2)	10/12/89	403

Expected Distribution Characteristics (see Figure D.1-1):

Mean190
5th27
50th105
95th618

TIME TO SECOND MID-LOOP (POS 10) DISTRIBUTION

Only Surry-specific data (3 points) are available. (Note that this POS is relevant only for refueling outages.) A straightforward Bayesian approach is used.

Likelihood Function

$$L(t_i|\mu,\sigma)=\frac{1}{\sqrt{2\pi}\,\sigma t_i}\exp\left\{\frac{1}{2}\left(\frac{\ln t_i-\mu}{\sigma}\right)^2\right\}$$

Prior Distribution

$$\pi_0(\mu,\sigma)\propto\frac{1}{\sigma}$$

Expected Distribution

$$f(t) = \iint f_T(t|\mu,\sigma)\pi_1(\mu,\sigma)d\mu d\sigma$$

Data

Event	Date	Time (h)
R1 (Unit 2)	03/20/85	1909
R3 (Unit 2)	10/04/86	934
R6 (Unit 2)	09/10/88	2905

Posterior Distribution Characteristics for t

μ	σ
7.7276	0.53473

Expected Distribution Characteristics for T

Mean2619
5th942
50th2270
95th5471

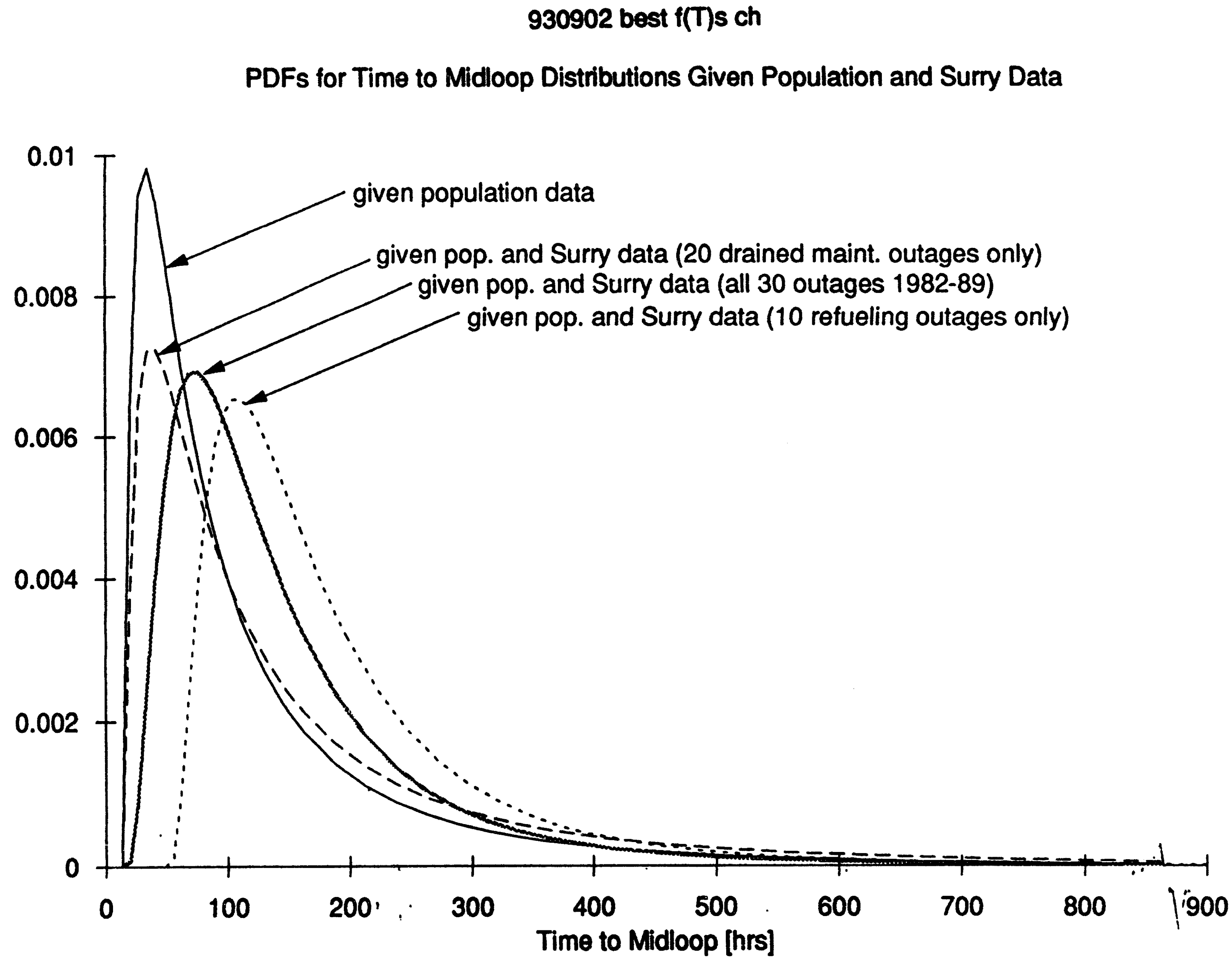


Figure D.1-1 Distributions of Time to Mid-loop

Table D.1-1
Population Data on Time to Mid-loop Based on Responses to Generic Letter 87-12

Plant #	Median (hr)	5th (hr)	95th (hr)
1	84.6	74.8	
2		66	
3	72		
4	72	24	
5		48	
6		56	
7		48	
8	77		
9	120		
10		33	
11		30	
12		44.5	
13		48	
14	121		
15	72		
16		72	
17	52		
18	96		
19		48	
20		99	528
21	65		
22	147	76	
23	50		
24		72	
25		120	
26		23	
27		14	

Table D.1-1 (continued)

Plant #	Median (hr)	5th (hr)	95th (hr)
28	48	24	
29	53		
30	42		
31		34	
32	120	48	
33	106		
34			144
35		50	144
36		51	
37	48		
38	116		
39	56	16	
40	168	72	
41		44	
42		30.5	
43	54	37	
44	108		
45		69	
46		161	

The population data for the time to mid-loop were collected from responses to NRC Information Notice 87-12. The plants were asked to provide information on their time to midloop experiences. The plants provided "typical," minimum and maximum values of the time to mid-loop. In this analysis, these have been interpreted as median, 5th percentile, and 95th percentile values.

Appendix D.2

Bayesian Analysis of Duration of Mid-Loop

D.2 Bayesian Analysis of Mid-loop Duration

MID-LOOP DURATION DISTRIBUTION

Only Surry-specific data are available. Analyses are done for refueling outages and drained maintenance outages. In the case of the former, POS 6 and POS 10 mid-loops are distinguished. A straightforward Bayesian approach is used.

Likelihood Function

$$L(t_i|\mu,\sigma)=\frac{1}{\sqrt{2\pi}\,\sigma t_i}\exp\left\{\frac{1}{2}\left(\frac{\ln t_i-\mu}{\sigma}\right)^2\right\}$$

Prior Distribution

$$\pi_0(\mu,\sigma)\propto\frac{1}{\sigma}$$

Expected Distribution

$$f(t) = \iint f_T(t|\mu,\sigma)\pi_1(\mu,\sigma)\,d\mu\, d\sigma$$

Refueling Outage, POS 6
Data:

Event	Date	Time (h)
R1 (Unit 2)	03/20/85	134
R2 (Unit 1)	05/10/86	61.7
R3 (Unit 2)	10/04/86	41.6
R4 (Unit 1)	04/09/88	79.4
R5 (Unit 1)	09/14/88	100
R6 (Unit 2)	09/10/88	681

Posterior Distribution Characteristics:

	μ	σ
Mean	4.714	1.146
5th	3.923	0.652

50th	4.710	1.046
95th	5.513	1.999
Correlation	0.028	

Expected Distribution Characteristics (hours)

Mean238
5th14.2
50th112
95th876

REFUELING OUTAGE, POS 10
Note that the expected distribution has a reverse J-shaped pdf. Auxiliary MathCAD computations confirm that this is appropriate, even though the joint pdf is μ and σ is unimodal and well-behaved.

Data

Event	Date	Time (h)
R1 (Unit 2)	03/20/85	141
R3 (Unit 2)	10/04/86	52.3
R6 (Unit 2)	09/10/88	452

Posterior Distribution Characteristics

	μ	σ
Mean	5.021	1.593
5th	3.413	0.619
50th	5.011	1.273
95th	6.656	3.798
Correlation	0.039	

Expected Distribution Characteristics

Mean444
5th6.3
50th151
95th2568

DRAINED MAINTENANCE OUTAGE, POS 6

Data

Event	Date	Time (h)
D1 (Unit 1)	04/29/85	153
D2 (Unit 1)	08/06/85	42.5
D3 (Unit 2)	10/29/85	79.4
D4 (Unit 1)	01/24/86	182
D5 (Unit 2)	06/17/86	191
D6 (Unit 1)	12/11/86	1072
D7 (Unit 2)	12/09/86	59.9
D8 (Unit 1)	05/16/87	144
D9 (Unit 1)	06/23/87	10.9
D10 (Unit 2)	12/09/87	28.3
D11 (Unit 2)	05/16/88	206
D12 (Unit 2)	10/12/89	266

Posterior Distribution Characteristics

	μ	σ
Mean	4.692	1.282
5th	4.065	0.892
50th	4.691	1.232
95th	5.318	1.849
Correlation	0.001	

Expected Distribution Characteristics

Mean255
5th11.9
50th109
95th958

Appendix D.3
Recovery Curves for Accident Initiating Events

Appendix D.3 Recovery Curves for Accident Initiating Events

The data that was used in estimating the frequency of initiating events show that the initiating event can be terminated by eliminating their causes. In the event trees, recovery of the following initiating events was modeled as top events in the event trees:

Loss of Offsite Power
Loss of 4 KV Bus
Loss of CCW
Inadvertent Safety Injection
Loss of Vital Bus
Loss of Instrument Air

Recovery of offsite power is discussed in section 4.3.1. The recovery of the rest of the above initiating events was analyzed using a single stage bayesian analysis. The computer code BAYES3D written by N. Siu was used. The recovery time is assumed to be lognormally distributed. The prior distribution of the parameters μ and σ is assumed to be inversely proportional to σ. The likelihood function is the density function of the lognormal distribution. Tables D.3-1 to D.3-5 list the input data and results.

Table D.3-1

Statistical Analysis of Recovery Time of 4KV Bus

Recovery Times of Loss of 4 KV Bus(minutes)		Percentiles of Time to Recovery	
1	9.00	Probability (%)	Percentile (minutes)
2	1.00	5	0.33
3	21.00	10	0.62
4	1.53	15	0.96
5	19.00	20	1.34
6	1.50	25	1.80
7	2.00	30	2.34
8	15.00	35	2.99
9	60.00	40	3.77
10	0.17	45	4.71
11	2.00	50	5.87
12	4.00	55	7.32
13	45.00	60	9.15
14	22.00	65	11.54
15	17.00	70	14.72
		75	19.13
		80	25.68
		85	36.08
		90	55.52
		95	104.87
		Mean=29.09minutes	

Table D.3-2

Statistical Analysis of Recovery Time of CCW

Recovery Times of Loss of CCW (minutes)		Percentiles of Time to Recovery	
		Probability (%)	Percentile (minutes)
1	14.00	5	7.17
2	17.00	10	8.97
3	30.00	15	10.44
		20	11.76
		25	13.04
		30	14.30
		35	15.58
		40	16.90
		45	18.29
		50	19.76
		55	21.35
		60	23.10
		65	25.06
		70	27.30
		75	29.94
		80	33.20
		85	37.42
		90	43.54
		95	54.46
		Mean =26.16	

Table D.3-3

Statistical Analysis of Recovery Time of Inadvertent Safety Injection

Recovery Times of Inadvertent Safety Injection(minutes)		Percentiles of Time to Recovery	
		Probability (%)	Percentile (minutes)
1	5.00	5	0.86
2	15.00	10	1.39
3	23.00	15	1.92
4	9.00	20	2.48
5	2.00	25	3.10
6	150.00	30	3.78
7	2.00	35	4.54
8	50.00	40	5.40
9	2.00	45	6.39
10	3.00	50	7.55
11	5.00	55	8.91
12	2.00	60	10.55
13	7.00	65	12.56
14	5.00	70	15.10
15	19.00	75	18.39
16	6.00	80	22.97
		85	29.67
		90	41.07
		95	66.35
		Mean=18.70	

Table D.3-4

Statistical Analysis of Recovery Time of Loss of Vital Bus

Recovery Times of Loss of Vital Bus(minutes)		Percentiles of Time to Recovery	
		Probability (%)	Percentile (minutes)
1	0.03	5	0.33
2	1.00	10	0.60
3	3.00	15	0.91
4	4.00	20	1.25
5	4.00	25	1.65
6	5.00	30	2.12
7	5.00	35	2.67
8	5.00	40	3.33
9	6.00	45	4.12
10	7.00	50	5.08
11	13.00	55	6.26
12	15.00	60	7.74
13	17.00	65	9.64
14	18.00	70	12.15
15	25.00	75	15.58
16	15.00	80	20.60
		85	28.45
		90	42.84
		95	78.36
		Mean=21.34	

Table D.3-5

Statistical Analysis of Recovery Time of Loss of Instrument Air

Recovery Times of Loss of Vital Bus(minutes)		Percentiles of Time to Recovery	
		Probability (%)	Percentile (minutes)
1	10.00	5	9.32
2	20.00	10	10.68
3	20.00	15	11.70
4	15.00	20	12.58
5	20.00	25	13.40
6	31.00	30	14.17
7	20.00	35	14.93
8	20.00	40	15.68
9	20.00	45	16.45
10	20.00	50	17.24
11	20.00	55	18.07
12	10.00	60	18.95
13	10.00	65	19.91
		70	20.98
		75	22.18
		80	23.62
		85	25.40
		90	27.84
		95	31.89
		Mean=18.55	

APPENDIX D.4

Assessment of Uncertainty Parameters of Basic Events

Appendix D.4 Assessment of Uncertainty Parameters of Basic Events

Frequency of Outages

The uncertainty of the frequency of outages was estimated judgmentally. Table D.4-1 lists the characteristic parameters of the outage frequencies. In chapter 9, the point estimates of the frequencies were calculated at using the Surry plant experience. They are taken to be the mean frequencies of the outages. It was the Surry experience that the time between 2 refueling outages sometimes is as longer as 2 years. Therefore, a frequency of 0.5 per year is quite possible to occur. It was taken to be the 25th percentile of the distribution of the frequency of refueling. That is, the probability that the time between 2 refueling outages is longer than 2 years is 0.25. A lognormal distribution is assumed with these parameters. In the case of drained maintenance, it is the plant experience that a unit may go to drained maintenance twice a year. Therefore, 3 times a year is taken to be an upper bound (95th percentile) of the frequency of drained maintenance.

Another parameter used in the quantification is the fraction(FRAC-POS10) of time that the plant goes to mid-loop operation after refueling is completed in a refueling outage. The review of plant experience found that in 3 out of 6 refueling outages the plant went to the second mid-operation. Therefore, the mean of this fraction is taken to be 0.5. It is assumed to be uniformly distributed between 0 and 1.

Conditional Probability of a Time Window Given That the Initiating Event Occurred in a POS

In order to correctly determine the success criteria for the mitigating functions, the time window approach was developed. Given that the accident initiating event had occurred in a POS, the probability that it occurred in a given time window was determined in section 9.3 using data colloected on time to mid-loop and duration of mid-loop. The uncertainty in the time when the accident occurs is reflected in the probabilities of the time windows. Therefore, the conditional probabilities of the time windows take on single values with no uncertainty parameter. They are listed in Table D.4-2 for the accident initiating events. For all initiating events except over draining to mid-loop(RHR2A), the distribution of the time when the accident occurs is calculated as the time to mid-loop plus the duration of mid-loop times an uniform distribution. For RHR2A, the time when the initiating event occurs is the same as the time to mid-loop.

Maintenance Unavailability

Two types of maintenance events are used, the ones adopted from NUREG-1150 study, and those estimated using plant outage data. For those maintenance evetns of NUREG-1150, the uncertainty data of NUREG-1150 was used. Chapter 9 documents the maintenance data collected from the plant. The uncertainty of these maintenance unavailabilities was derived by judgement using the following rules:

1. If the mean is small, a lognormal distribution with some EF is assumed.

2. If the mean is close to 1, a uniform distribution is assumed. If the mean is larger than 0.5, the upper bound is set to 1. If the mean is lower than 0.5, the upper bound is set to twice the mean.

Table D.4-1

Characteristic Values of Frequency of Outages (per year)

	Mean	Error Factor	5%	50%	95%	μ	σ
Refueling	0.6	1.46	0.40	0.584	0.854	-0.5375	0.2309
Drained Maintenance	1.2	3.22	0.29	0.932	3.00	-0.07	0.7104

Table D.4-2
Conditional Probability that an IE Occurs in the Time Windows
Given it Occurred in the POS

	WINDOW 1	WINDOW 2	WINDOW 3	WINDOW 4
Definition	<= 75 hours	> 75 hours and <= 240 hours	> 240 hours and <= 32 days	> 32days
All IEs except RHR2A				
D6	1.17E-01	0.436	0.375	7.20E-02
R6	1.7E-02	0.543	0.41	3.4E-02
R10	0.0	0.0	0.016	9.84E-01
RHR2A only				
D6	0.31	0.454	0.21	2.6E-02
R6	5.82E-02	0.7	0.24	1.48E-03
R10	0.0	0.0	2.2E-02	0.98

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