BABCOCK & WILCOX
NUCLEAR POWER GENERATION DIVISION

TECHNICAL DOCUMENT

THREE MILE ISLAND

UNIT I

ABNORMAL TRANSIENT OPERATING GUIDELINES

PART I

CAUTION

ATOG PART II MUST BE READ AND UNDERSTOOD PRIOR TO REVIEW OR USE OF PART I.

74-1124158-00

Doc. ID – Serial No., Revision No.

for

GENERAL PUBLIC UTILITIES

By

BABCOCK & WILCOX

THIS DOCUMENT WAS PREPARED FOR GENERAL PUBLIC UTILITIES UNDER MASTER SERVICE CONTRACT NO. 582-7105 (B&W No. 582-7108). ANY USE OF THE INFORMATION CONTAINED HEREIN OTHER THAN UNDER THE EXPRESS CONDITIONS OF SAID CONTRACT IS EXPRESSLY PROHIBITED WITHOUT THE WRITTEN PERMISSION OF THE BABCOCK & WILCOX COMPANY.

8401230549 840109
PDR ADOCK 05000289
P PDR

BABCOCK & WILCOX
NUCLEAR POWER GENERATION DIVISION

RECORD OF REVISION

NUMBER
74-1124518-00

REV. NO.	CHANGE SECT/PARA.	DESCRIPTION/CHANGE AUTHORIZATION
00		Original Issue - B. L. Brooks System Engineering

repared by Benton L Brooks Date April 5, 1983

Reviewed by W A Cell Date 4/11/83

Approved by L H Bowling Date 4/6/83

Approved by D C Faulkner Date 4/13/83

Released by D A Lapin Date 4/6/83

TABLE OF CONTENTS

SECTION	TITLE	TAB NAME
	Abbreviation Glossary	
Section I	Immediate Action	REACTOR TRIP
Section II	Vital System Status Verification	REACTOR TRIP
Section III A	Lack of Adequate Subcooling Margin	SUBCOOLING
Section III B	Lack of Heat Transfer	LACK OF HEAT TRANSFER
Section III C	Excessive Heat Transfer	EXCESSIVE HEAT TRANSFER
Section III D	Steam Generator Tube Rupture	SGTR
CP-101	A Large LOCA Has Occurred and the Core Flood Tanks Are Emptying	COOLDOWN
CP-102	Normal Cooldown	
CP-103	Transient Termination Following an Occurrence That Leaves the RCS Saturated With OTSGs Removing Heat	
CP-104	Transient Termination Following an Occurrence That Leaves the RCS Being Coolded by HPI Cooling	
CP-105	Transient Termination Following an Occurrence That May Require Pressurizer Recovery or Solid Plant Cooldown With OTSGs Removing Heat and RCS Subcooled	
NNI/ICS	Loss of NNI/ICS Power	LOSS OF NNI/ICS
Specific Rules	Specific Rule 1 Specific Rule 2 Specific Rule 3 Specific Rule 4	SPECIFIC RULES
SAD	SAD	
Section ICC	Inadequate Core Cooling	ICC

LIST OF FIGURES

Figures	Title
1	HPI Flow Vs. RC Pressure
2	RC Pressure/Temperature Limits
3	Core Exit Fluid Temeprature For Inadequate Core Cooling

ABBREVIATION GLOSSARY

ADV	Atmospheric Dump Valve
BWST	Borated Water Storage Tank
CFT	Core Flood Tank
CP	Cooldown Procedure
DBA	Design Bases Accident
DH	Decay Heat
DHR	Decay Heat Removal
EFP	Emergency Feed Pump
EFPT	Emergency Feed Pump Turbine
EFW	Emergency Feedwater
ESAS	Engineered Safetyguards Actuation System
FW	Feedwater
H_2	Hydrogen
HPI	High Pressure Injection
ICS	Integrated Control System
IC T/C	Incore Thermocouple
ICW	Intermediate Cooling Water
LPI	Low Pressure Injection
MFW	Main Feedwater
MPT	Minimum Pressurization Temperature
MSIV	Main Steam Isolation Valve
MSSV	Main Steam Safety Valve
N_2	Nitrogen
Nil	Ductility Temperature

ABBREVIATION GLOSSARY (CONT'D)

NR	Narrow Range
NNI	Non-Nuclear Instrumentation
OP	Operating Procedure
OTSG	Once Through Steam Generator
P/T	Pressure vs. Temperature plot for water
Pzr.	Pressurizer
RB	Reactor Building or Containment
RBS	Reactor Building Spray
RCP	Reactor Coolant Pump
RCS	Reactor Coolant System
RTD	Resistance Temperature Detector
SAD	System Auxiliary Diagram
SG	Once Thorough Steam Generator
S/G	Once Trhough Steam Generator
SGTR	Steam Generator Tube Rupture
SLRDS	Steam Line Rupture Detection System
STATUS	Existing Plant Status
SU	Startup
STM-LK	Steam Leaking (Steam Generator)
TBV	Turbine Bypass Valve
Tc	T_{cold}, reactor inlet
T/C	Thermocouple
TH	T_{hot}, reactor outlet
TR	Tube Rupture
WR	Wide Range
Zr	Zirconium

REACTOR TRIP

Section I

IMMEDIATE ACTIONS

Determine whether this is a reactor trip or a forced shutdown situation and proceed below.

REACTOR TRIP	FORCED SHUTDOWN
a. Manually trip the reactor.	a. IF a tube rupture has occurred as indicated by main steam line and/or vacuum pump discharge monitor alarm, THEN go to SGTR Section III.
b. Manually trip the turbine.	b. IF a forced shutdown is required by technical specifications or by other operating documents, THEN shutdown plant to required conditions per normal procedures, starting with OP-1102-04, Power Operation.
c. Immediately go to Section II	c. As soon as the reactor is shut down continue with Section II.

SECTION II

VITAL SYSTEM STATUS VERIFICATION

Verification Column	Remedial Action Column
VERIFY THE FOLLOWING:	IF VERIFICATION CANNOT BE MADE, THEN PERFORM THE FOLLOWING:
1.0 REACTOR POWER DECREASING ON INTERMEDIATE RANGE.	Start HPI taking suction from BWST.
2.0 ALL RODS ON BOTTOM. (EXCEPT APSR)	Begin emergency boration as necessary.
3.0 ALL MAIN TURBINE STOP VALVES SHUT.	Trip EH-P-1A and EH-P-1B.
4.0 NO LETDOWN FLOW.	Close letdown isolation valve MU-V-3.
5.0 FEEDWATER HAS RUNBACK.	Trip both running main feedwater pumps AND verify EFW starts.

Verification Column	Remedial Action Column
VERIFY THE FOLLOWING:	IF VERIFICATION CANNOT BE MADE, PERFORM THE FOLLOWING:
7.0 AT LEAST ONE AUXILIARY TRANSFORMER HAS NORMAL VOLTAGE ON ITS SECONDARY.	a) Start or verify auto start AND loading of diesel generators. b) Verify auto start of EFW AND raise SG levels to 50% with EFW properly throttled (see Specific Rule 3). c) Ensure a makeup pump is started AND RCP seal injection is re-established. d) Verify auto start of: NSCC pump NSRW pump DHCC pump DHRW pump e) If no ESAS actuation, THEN start instrument air compressor. f) Regain OTSG pressure control with ADVs.

Verification Column	Remedial Action Column
VERIFY THE FOLLOWING:	IF VERIFICATION CANNOT BE MADE, THEN PERFORM THE FOLLOWING:
8.0 NO ESAS ALARMS.	RCS 1600 PSIG ALARM ON COMPUTER a) Verify HPI and LPI channels have actuated by noting the colors of component's indicating lamps on the ES status panel. b) Verify makeup tank outlet valve (MU-V-12) closed. c) Close PORV block valve RC-V-2. d) Verify seal injection flow. CTMT 4 PSIG ALARM ON COMPUTER a) Verify HPI, LPI and containment isolation and cooling channels have actuated by noting the colors of component's indicating lamps on the ES status panel. b) Verify makeup tank outlet valve (MU-V-12) closed. c) Close PORV block valve RC-V-2. d) Verify seal injection flow. CTMT 30 PSIG ALARM a) Verify CTMT spray channels have actuated AND throttle RB spray flow to $\leq$ 1200 gpm. b) Verify NaOH and spray valves are open. c) NSCCW and intermediate cooling valves closed.

BABCOCK & WILCOX
NUCLEAR POWER GENERATION DIVISION
TECHNICAL DOCUMENT

NUMBER 74-1124518-00

Verification Column	Remedial Action Column
VERIFY THE FOLLOWING:	IF VERIFICATION CANNOT BE MADE, THEN PERFORM THE FOLLOWING
9.0 NO SLRDS ALARMS.	'A' Side Trip FW-V-5a Closed _____ FW-V-92A Closed _____ FW-V-16A Closed _____ FW-V-17A Closed _____ 'B' Side Trip FW-V-5B Closed _____ FW-V-92B Closed _____ FW-V-16B Closed _____ FW-V-17B Closed _____
10.0 ADEQUATE SUBCOOLING MARGIN	Go to Lack of Subcooling Margin Section III A.
11.0 PROPER PRIMARY TO SECONDARY HEAT TRANSFER EXISTS	FOR LACK OF HEAT TRANSFER go to Lack of Heat Transfer Section III B. FOR EXCESSIVE HEAT TRANSFER go to Excessive Heat Transfer Section III C.

Verification Column	Remedial Action Column
VERFIY THE FOLLOWING:	IF VERFICIATION CANNOT BE MADE, THEN PERFORM THE FOLLOWING:
12.0 NO MAIN STEAM LINE OR CONDENSER VACUUM PUMP RADIATION MONITOR ALARMS.	Go to SGTR Section III D.

13.0 THE PLANT IS STABLE IN A SAFE SUBCOOLED CONDITION WITH PROPER PRIMARY TO SECONDARY HEAT TRANSFER AND NO MAJOR PRIMARY BOUNDARY FAILURES. FURTHER ACTION AT THIS POINT WILL BE AT THE DISCRETION OF STATION MANAGEMENT.

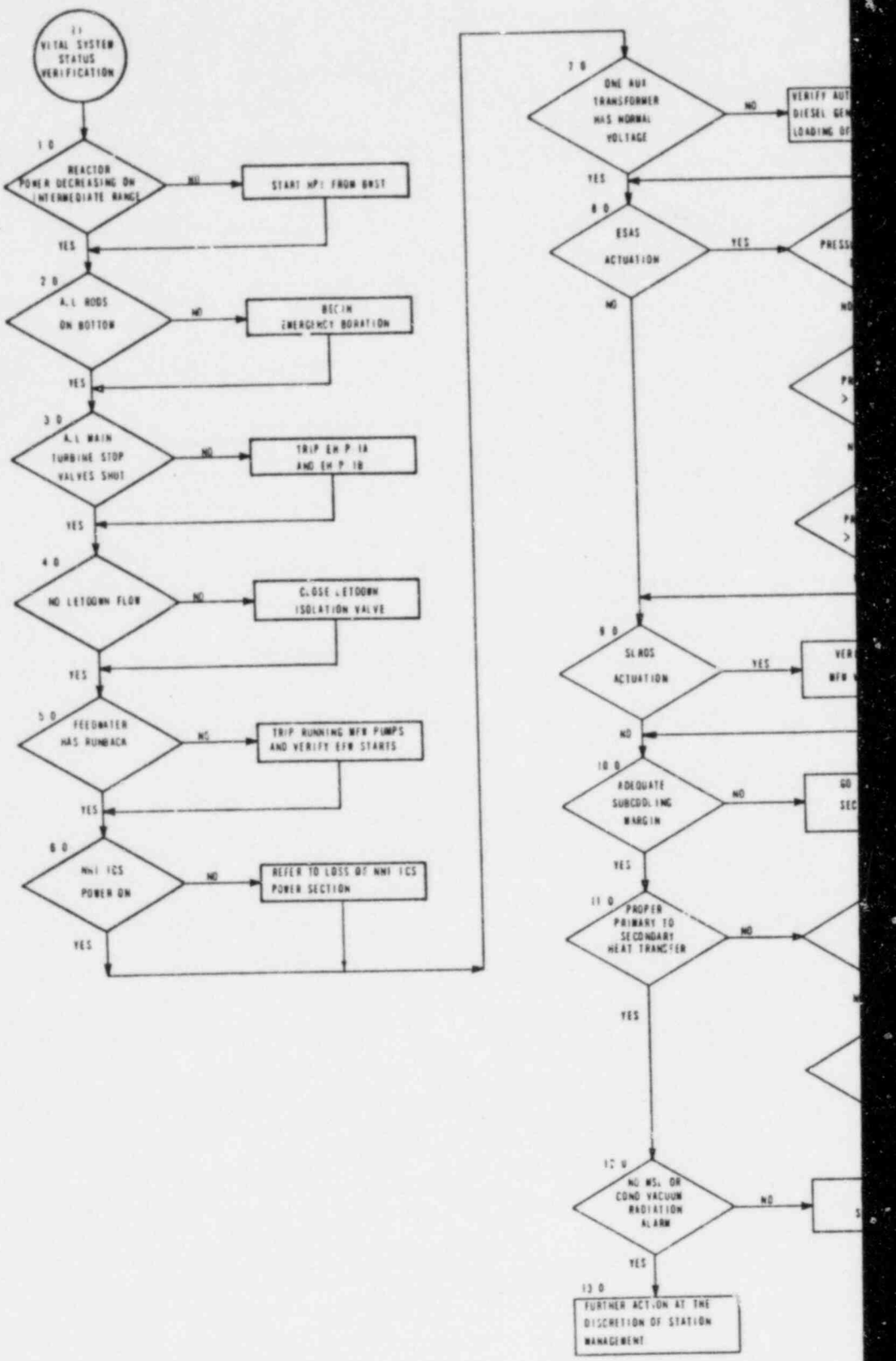
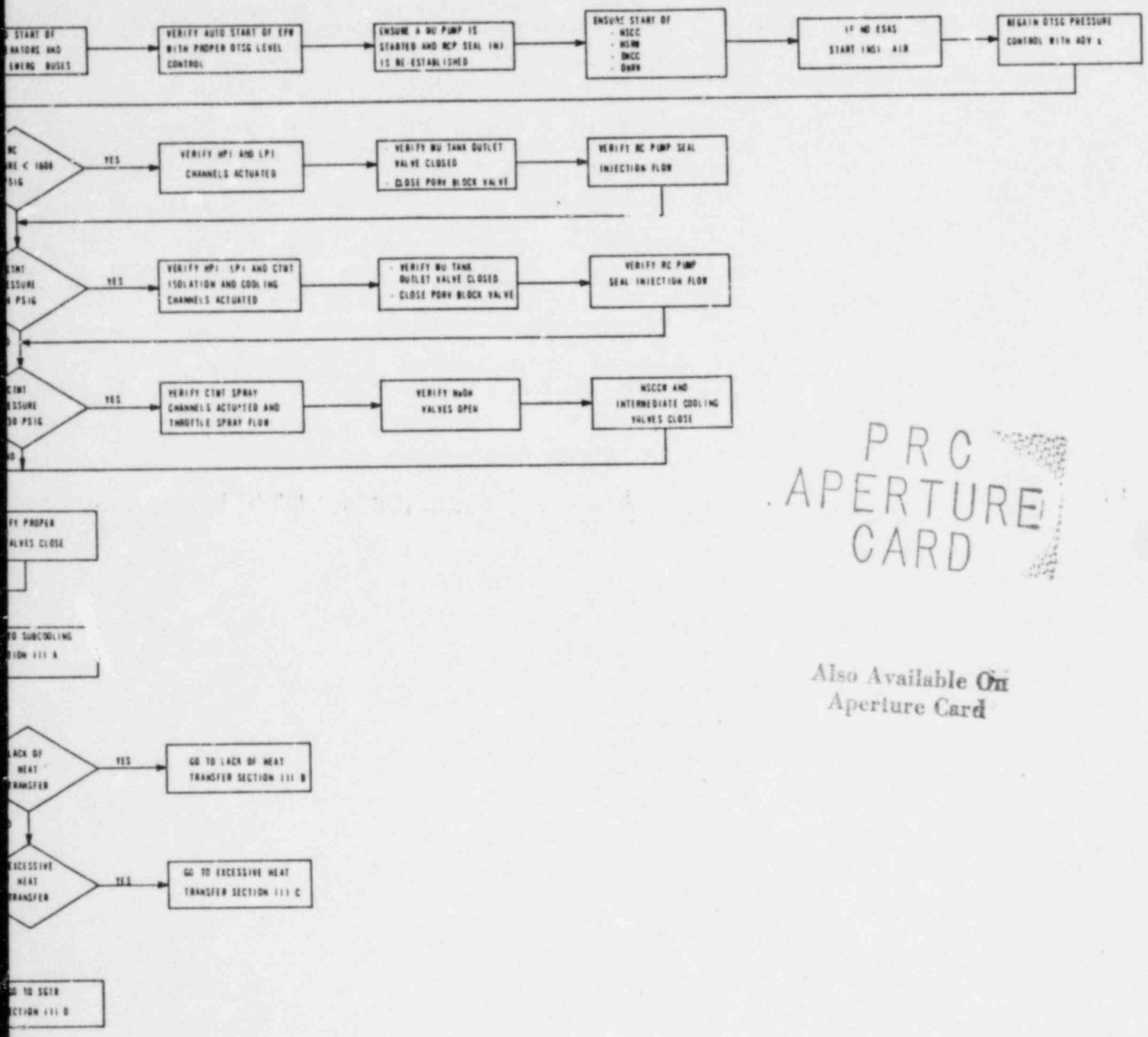

1 0
VITAL SYSTEM STATUS VERIFICATION
1 0
REACTOR POWER DECREASING ON INTERMEDIATE RANGE
NO
START HPI FROM RWST
YES
2 0
ALL RODS ON BOTTOM
NO
BEGIN EMERGENCY BORATION
YES
3 0
ALL MAIN TURBINE STOP VALVES SHUT
NO
TRIP EH P 1A AND EH P 1B
YES
4 0
NO LETDOWN FLOW
NO
CLOSE LETDOWN ISOLATION VALVE
YES
5 0
FEEDWATER HAS RUNBACK
NO
TRIP RUNNING MFW PUMPS AND VERIFY EFW STARTS
YES
6 0
NNI 1CS POWER ON
NO
REFER TO LOSS OF NNI 1CS POWER SECTION
YES
7 0
ONE AUX TRANSFORMER HAS NORMAL VOLTAGE
NO
YES
8 0
ESAS ACTUATION
YES
NO
9 0
SLRDS ACTUATION
YES
NO
10 0
ADEQUATE SUBCOOLING MARGIN
NO
YES
11 0
PROPER PRIMARY TO SECONDARY HEAT TRANSFER
NO
YES
12 0
NO MSL OR COND VACUUM RADIATION ALARM
NO
YES
13 0
FURTHER ACTION AT THE DISCRETION OF STATION MANAGEMENT

Figure II VITAL SYSTEM STATUS VERIFICATION



PRC
APERTURE
CARD

Also Available On
Aperture Card

8401230549-01

SUBCOOLING

SECTION III A

LACK OF ADEQUATE SUBCOOLING MARGIN

FOLLOWUP ACTIONS FOR TREATMENT OF LACK OF ADEQUATE SUBCOOLING MARGIN

1.0 TRIP ALL RCPs.

2.0 INITIATE AND CONTROL HPI.

2.1 See Specific Rules 1 and 2.

3.0 MAINTAIN PROPER OTSG LEVELS.

3.1 IF primary to secondary heat transfer is not excessive, THEN raise OTSG levels to 90-95% on operate range while properly throttling EFW (See Specific Rule 3 and 4).

4.0 IF EXCESSIVE HEAT TRANSFER EXISTS, THEN GO TO EXCESSIVE HEAT TRANSFER SECTION III C, OTHERWISE CONTINUE.

5.0 ISOLATE POSSIBLE LEAKS.

5.1 Close PORV (RC-RV-2) and PORV block valve (RC-V-2).

5.2 Close the pressurizer spray block valves (RC-V-3).

5.3 Verify letdown isolated (MU-V-3 closed).

6.0 IF SUBCOOLING MARGIN HAS BEEN ESTABLISHED, THEN GO TO STEP 12.0, OTHERWISE CONTINUE.

7.0 IF SUPERHEATED, THEN GO TO ICC SECTION, OTHERWISE CONTINUE.

7.1 IF at anytime during the transient the incore T/C temperatures indicate superheated conditions based on the saturation curve of Figure 3, THEN go to Section ICC, OTHERWISE continue.

8.0 IF THE CFTs ARE EMPTYING, THEN GO TO CP-101, OTHERWISE CONTINUE.

STATUS | The Core Flood Tanks emptying is an indication of a major LOCA. CP-101 provides instructions for long-term core cooling following a major LOCA. Do not go to Section III.B. Primary to secondary heat transfer will be lost and cannot be regained.

9.0 IF THERE IS A LACK OF PRIMARY TO SECONDARY HEAT TRANSFER IN EITHER OTSG, THEN GO TO LACK OF HEAT TRANSFER SECTION III B, OTHERWISE CONTINUE.

10.0 IF THERE IS INDICATION OF A SGTR, THEN GO TO SGTR SECTION III D STEP 5.0, OTHERWISE CONTINUE.

11.0 GO TO CP-103.

STATUS | There is primary to secondary heat transfer in both SG(s) without adequate subcooling margin. A small break is indicated. Cooldown with SG(s) can be performed while HPI maintains RCS inventory.

ADEQUATE SUBCOOLING MARGIN HAS BEEN ESTABLISHED

12.0 RESTART RCP AND REESTABLISH PZR SPARY, IF POSSIBLE.

12.1 Start RCPs per OP 1103-06. One per loop is desired.

12.2 Reopen pressurizer spray block valve (RC-V-3) and monitor RCS pressure to ensure that reopening pressurizer spray block valve does not cause depressurization (i.e., failed open pressurizer spray valve or pressurizer spray line break).

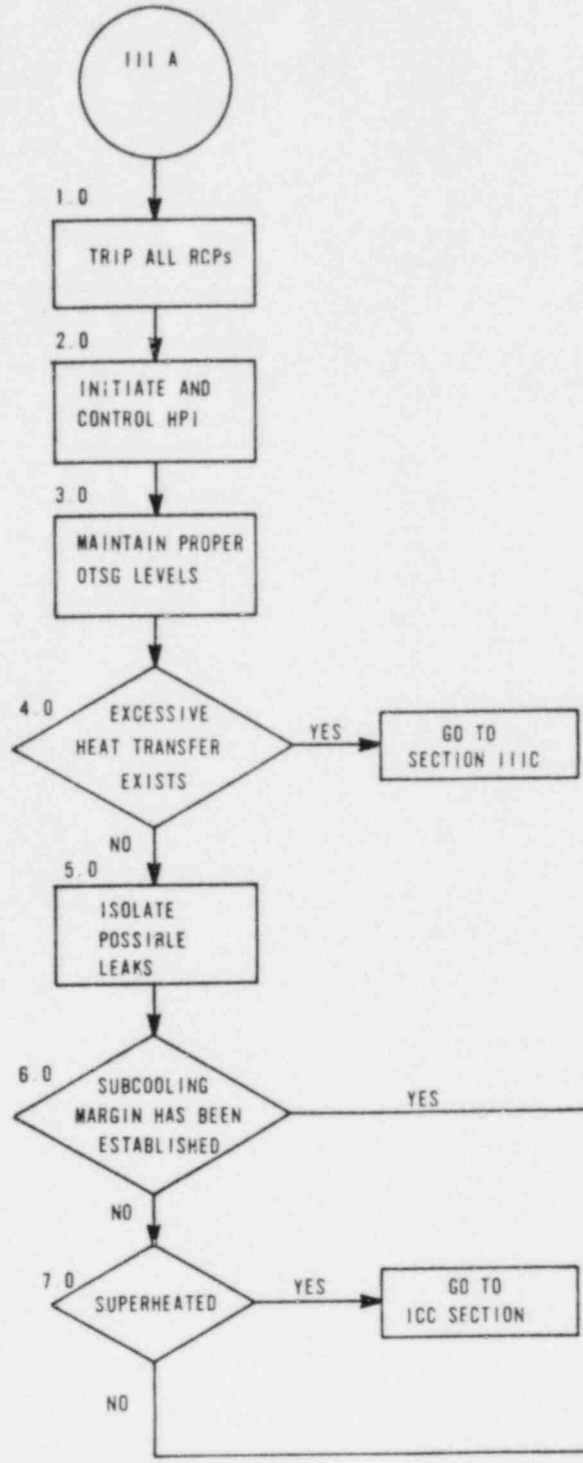
12.3 IF opening the PZR spray block valve causes RC depressurization, THEN reclose the PZR spray block valve.

13.0 IF THERE IS LACK OF PRIMARY TO SECONDARY HEAT TRANSFER THEN GO TO LACK OF HEAT TRANSFER SECTION III B, OTHERWISE CONTINUE.

14.0 IF THERE IS INDICATION OF A SGTR, THEN GO TO SGTR SECTION III D STEP 5.0, OTHERWISE CONTINUE.

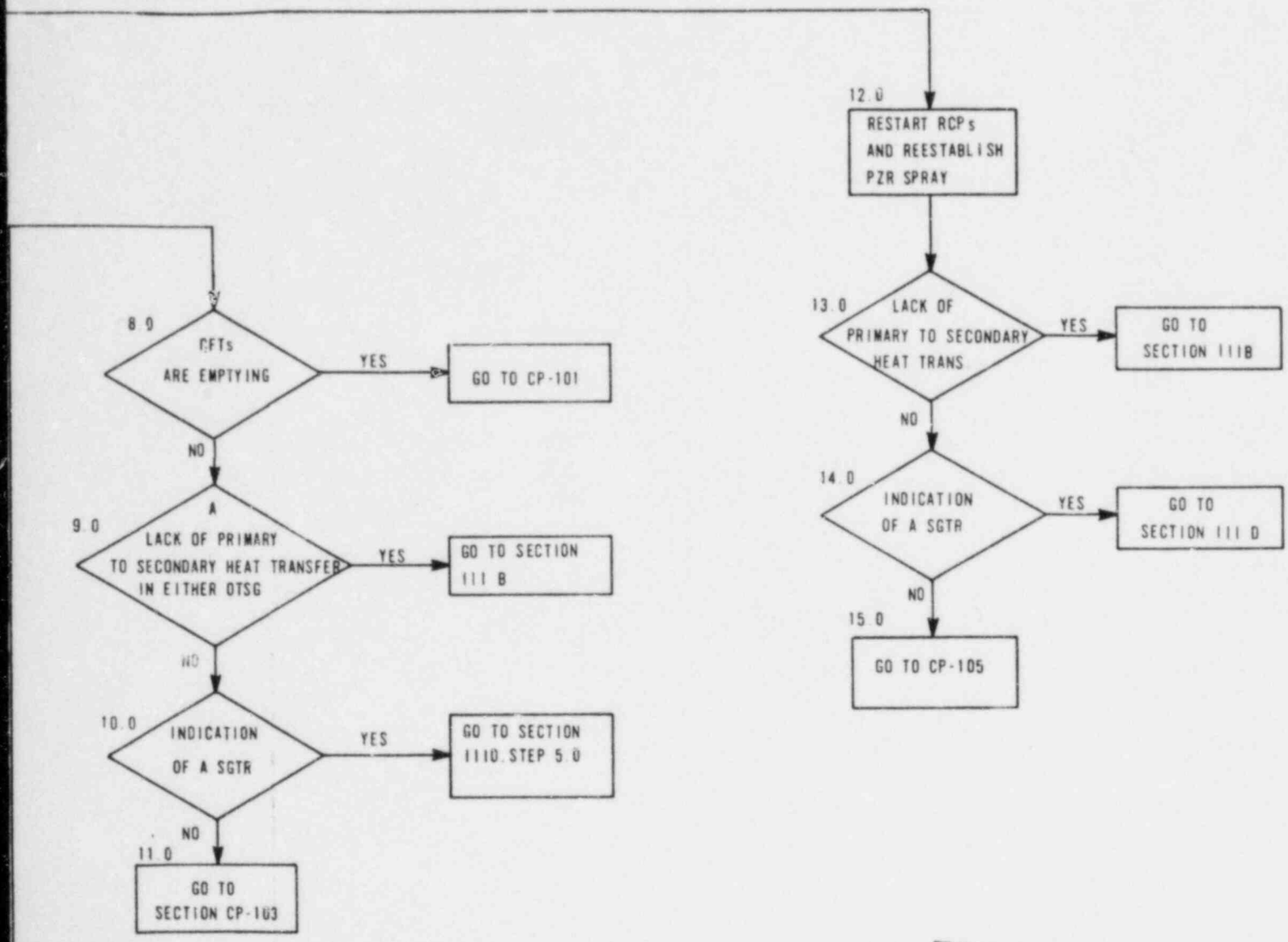
15.0 GO TO CP-105.

STATUS | The RCS is subcooled. There may or may not be a bubble in the pressurizer. OTSG heat transfer is controlled. CP-105 provides instructions either to draw a bubble if necessary and then cooldown normally or to cooldown solid if a bubble cannot be drawn.



PRC APERTURE CARD

Figure III A LACK OF ADEQUATE SUBCOOLING MARGIN



Also Available On Aperture Card

8401230549-02

LACK OF
HEAT TRANSFER

III B

LACK OF HEAT TRANSFER

FOLLOWUP ACTIONS FOR TREATMENT OF LACK OF PRIMARY TO SECONDARY HEAT TRANSFER IN EITHER OTSG

DETERMINE FEEDWATER AVAILABILITY

1.0 IF FEEDWATER IS AVAILABLE, THEN GO TO STEP 7.0, OTHERWISE CONTINUE WITH STEP 2.0.

LACK OF FEEDWATER EITHER SUBCOOLED OR SATURATED

2.0 IF THE RC PRESSURE INCREASES TO THE PORV SETPOINT BEFORE FW IS REESTABLISHED, THEN GO TO STEP 5.0.

3.0 INITIATE FW.

3.1 Feed both OTSGs, with EFW properly throttled to the appropriate SG level (See Specific Rules 3 and 4).

3.2 IF EFW is not available, THEN use main FW.

3.3 IF neither EFW nor MFW is available, THEN attempt to feed one SG from emergency feedwater cross connect to another unit.

3.4 IF the EFW system is not operating properly, THEN refer to the SAD section.

4.0 IF FEEDWATER IS RE-ESTABLISHED, THEN GO TO STEP 7.0, OTHERWISE CONTINUE.

5.0 ESTABLISH HPI COOLING.

5.1 Initiate HPI (See Specific Rule 1).

5.2 Open PORV block valve (RC-V-2).

5.3 Open PORV (RC-RV-2).

5.4 Run one RCP as long as adequate subcooling margin is maintained.

6.0 GO TO CP-104.

STATUS | There is no heat transfer to either OTSG. The OTSGs are dry and the core must be cooled by HPI.

FEEDWATER HAS BEEN REESTABLISHED BUT THERE IS NO HEAT TRANSFER

7.0 MAINTAIN APPROPRIATE OTSG LEVEL.

7.1 See Specific Rule 4.

8.0 IF THE CFTs HAVE EMPTIED, THEN GO TO CP-101, OTHERWISE CONTINUE.

STATUS | The Core Flood Tanks emptying is an indication of a major LOCA, CP-101 provides instructions for long term cooling following a major LOCA. Primary to secondary heat transfer is lost and cannot be regained.

9.0 IF AT ANY TIME WHILE ATTEMPTING TO REESTABLISH HEAT TRANSFER, THE RC PRESSURE INCREASES TO THE PORV SETPOINT, THEN OPEN THE PORV AND WHEN THE RC PRESSURE DROPS TO 100 PSI ABOVE THE OTSG PRESSURE, CLOSE THE PORV.

10.0 LOWER OTSG PRESSURE TO INDUCE HEAT TRANSFER.

10.1 Lower OTSG pressure by adjusting TBVs or ADVs, while maintaining level, until secondary Tsat is 40 to 60F lower than the incore T/C temperature. Maintain this OTSG pressure.

11.0 WHEN HEAT TRANSFER IS REESTABLISHED, THEN GO TO STEP 17.0, UNTIL THEN CONTINUE.

12.0 DETERMINE RCP OPERABILITY. IF RCPs CAN BE BUMPED THEN CONTINUE OTHERWISE INITIATE HPI COOLING AND GO TO CP-104.

STATUS | There is no heat transfer to either OTSG. Natural circulation does not exist and cannot be induced by bumping RCPs. The core must be cooled by HPI cooling.

13.0 USE PUMP BUMPS TO INDUCE HEAT TRANSFER.

13.1 Bump a RCP, which is capable of being started in the loop with the highest level in the OTSG.

13.2 Allow RCS pressure to stabilize within ± 20 psig of new pressure before determining if heat transfer is established.

13.3 WHENEVER Heat Transfer is established, THEN go to Step 17.0, until then, continue.

13.4 Repeat Steps 13.1 and 13.3 for operable RCPs that have not been bumped. Allow 15 minutes between pump bumps. IF all operable RCPs have been bumped and heat transfer has NOT been reestablished, THEN continue with Step 14.0.

14.0 FURTHER LOWER SG PRESSURE TO INDUCE OTSG HEAT TRANSFER.

16.1 Lower OTSG pressure by adjusting TBVs or ADVs while maintaining the appropriate level, until secondary T_{sat} is 90 to 100F lower than incore T/C temperature. Maintain this OTSG pressure.

15.0 START ONE RCP TO INDUCE OTSG HEAT TRANSFER.

17.1 IF at least one hour has passed since reactor trip AND any RCPs are capable of being started, THEN start and run one RCP, preferably in a loop with OTSG level greater than 30".

16.0 IF ADEQUATE HEAT TRANSFER HAS NOT BEEN RE-ESTABLISHED, THEN INITIATE HPI COOLING (IF NOT IN PROGRESS) AND GO TO CP-104, OTHERWISE CONTINUE.

STATUS | There is no heat transfer to either OTSG. Attempts to establish heat transfer by natural circulation and forced flow have failed. The RCS is saturated and the core must be cooled by HPI.

HEAT TRANSFER HAS BEEN REESTABLISHED

17.0 RECOVER FROM HPI COOLING, IF INITIATED

17.1 Close PORV (RC-RV-2).

17.2 IF PORV does not close THEN close PORV block valve RC-V-2.

17.3 Control HPI (See Specific Rule 2.0).

18.0 CONTROL OTSG HEAT TRANSFER RATE.

18.1 Adjust TBV or ADV position to maintain RC temperature at present value.

19.0 IF A SG TUBE RUPTURE IS INDICATED, THEN GO TO SGTR SECTION III D, OTHERWISE CONTINUE.

20.0 IF THERE IS ADEQUATE SUBCOOLING MARGIN, THEN GO TO CP-105.

STATUS | The RC is subcooled. There may or may not be a bubble in the pressurizer. OTSG heat transfer is controlled. CP-105 provides instructions either to draw a bubbble if necessary then cooldown normally or to cooldown solid if a bubble cannot be drawn.

21.0 IF THERE IS A LACK OF ADEQUATE SUBCOOLING MARGIN, THEN GO TO CP-103.

STATUS | The RCS is saturated. A small break is indicated. Cooldown with the SGs can be performed while HPI maintains RCS inventory.

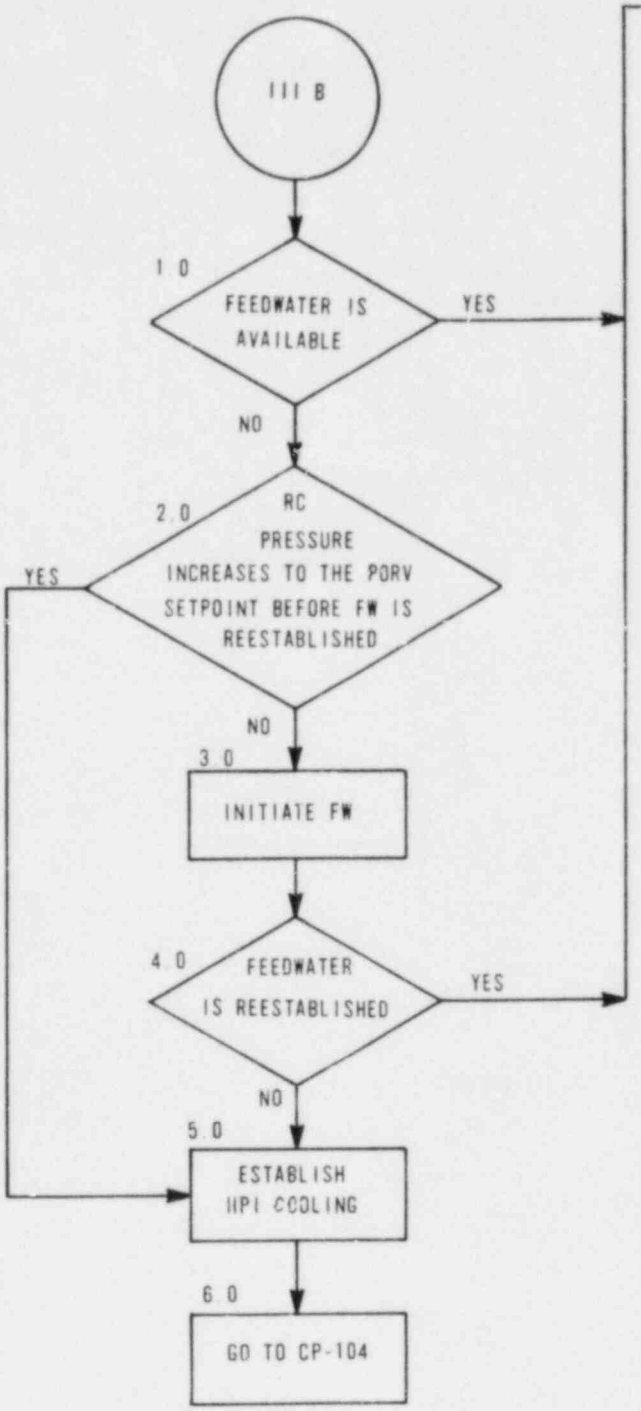
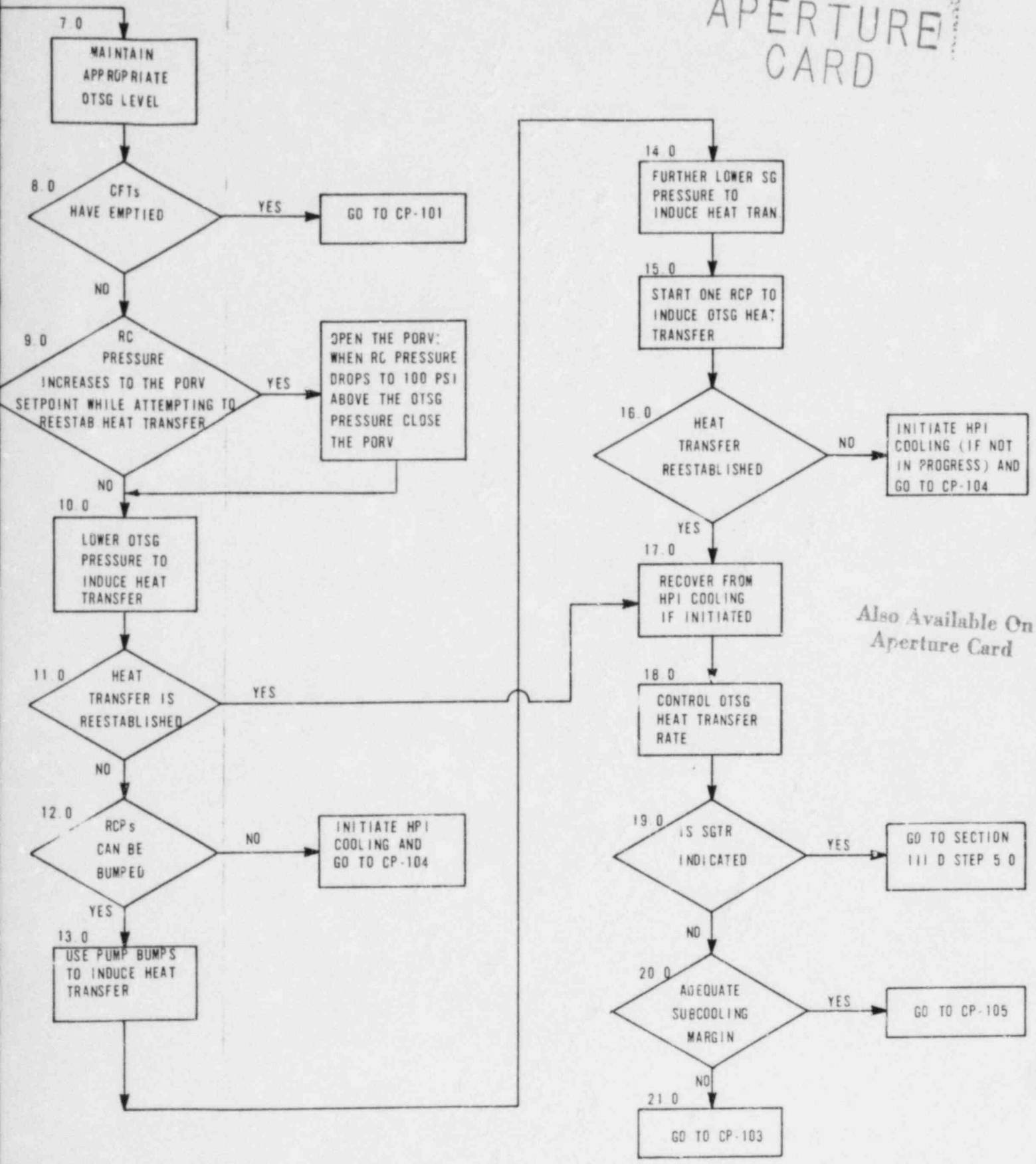

III B
1.0
FEEDWATER IS AVAILABLE
YES
NO
2.0
RC PRESSURE INCREASES TO THE PORV SETPOINT BEFORE FW IS REESTABLISHED
YES
NO
3.0
INITIATE FW
4.0
FEEDWATER IS REESTABLISHED
YES
NO
5.0
ESTABLISH HPI COOLING
6.0
GO TO CP-104

Figure III B LACK OF HEAT TRANSFER

PRC APERTURE CARD



Also Available On Aperture Card

8401230549-03

EXCESSIVE
HEAT TRANSFER

III C

EXCESSIVE HEAT TRANSFER

FOLLOW-UP ACTIONS FOR TREATMENT OF TOO MUCH PRIMARY TO SECONDARY HEAT TRANSFER

1.0 IF PRESSURIZER LEVEL IS BELOW 100" AND RCS PRESSURE IS DECREASING, THEN INCREASE MU AS NECESSARY.

1.1 Open MU-V-14A and MU-V-14B to provide BWST supply.

1.2 Close MU-V-12 to isolate letdown tank supply.

1.3 Start additional MU pump.

1.4 Open MU-V-217 as necessary to maintain pressurizer level above 100 inches.

1.5 If pressurizer level cannot be maintain above 100 THEN initiate full HPI (Specific Rule 1) and control (Specific Rule 2).

2.0 IF IT IS APPARENT WHICH OTSG IS CAUSING THE OVERCOOLING, THEN GO TO STEP 14.0, OTHERWISE CONTINUE WITH STEP 3.0.

OVERCOOLING IS OCCURING FROM AN UNIDENTIFIED OTSG

3.0 ISOLATE BOTH OTSGs.

3.1 IF OTSG operating level is greater than 95% AND increasing THEN:

a. Trip the running MFW pumps.

b. Close and verify closed locally all of the following valves:

Valve	OTSG "A"	OTSG "B"
EFW Control	EF-V30A	EF-V30B

c. Start the motor driven EFW pumps and verify discharge pressure and recirculation flow.

3.2 IF SLRDS has actuated, THEN go to Step 3.4, OTHERWISE continue.

3.3 Place the MFW stop valves in manual to ensure that they remain open.

3.4 Close and verify closed locally all of the following valves:

Valve	OTSG"A"	OTSG "B"
Startup FW Control	FW-V16A	FW-V16B
Main FW Control	FW-V17A	FW-V17B
EFW Control	EF-V30A	EF-V30B
Turbine Bypass	MS-V3A MS-V3C	MS-V3D MS-V3F
ADV	MS-V4A	MS-V4B

3.5 Close all of the following valves:

Main Steam to Emer. FWP	MS-V10A MS-V13A	MS-V10B MS-V13B
Main Steam Isolation	MS-V1A MS-V1B	MS-V1C MS-V1D

III C

EXCESSIVE HEAT TRANSFER

FOLLOW-UP ACTIONS FOR TREATMENT OF TOO MUCH PRIMARY TO SECONDARY HEAT TRANSFER

1.0 IF PRESSURIZER LEVEL IS BELOW 100" AND RCS PRESSURE IS DECREASING, THEN INCREASE MU AS NECESSARY.

- 1.1 Open MU-V-14A and MU-V-14B to provide BWST supply.
- 1.2 Close MU-V-12 to isolate letdown tank supply.
- 1.3 Start additional MU pump.
- 1.4 Open MU-V-217 as necessary to maintain pressurizer level above 100 inches.
- 1.5 If pressurizer level cannot be maintain above 100 THEN initiate full HPI (Specific Rule 1) and control (Specific Rule 2).

2.0 IF IT IS APPARENT WHICH OTSG IS CAUSING THE OVERCOOLING, THEN GO TO STEP 14.0, OTHERWISE CONTINUE WITH STEP 3.0.

OVERCOOLING IS OCCURING FROM AN UNIDENTIFIED OTSG

3.0 ISOLATE BOTH OTSGs.

3.1 IF OTSG operating level is greater than 95% AND increasing THEN:

a. Trip the running MFW pumps.

b. Close and verify closed locally all of the following valves:

Valve	OTSG "A"	OTSG "B"
EFW Control	EF-V30A	EF-V30B

c. Start the motor driven EFW pumps and verify discharge pressure and recirculation flow.

3.2 IF SLRDS has actuated, THEN go to Step 3.4, OTHERWISE continue.

3.3 Place the MFW stop valves in manual to ensure that they remain open.

3.4 Close and verify closed locally all of the following valves:

Valve	OTSG"A"	OTSG "B"
Startup FW Control	FW-V16A	FW-V16B
Main FW Control	FW-V17A	FW-V17B
EFW Control	EF-V30A	EF-V30B
Turbine Bypass	MS-V3A MS-V3C	MS-V3D MS-V3F
ADV	MS-V4A	MS-V4B

3.5 Close all of the following valves:

Main Steam to Emer. FWP	MS-V10A MS-V13A	MS-V10B MS-V13B
Main Steam Isolation	MS-V1A MS-V1B	MS-V1C MS-V1D

4.0 IF OTSG LEVELS AND PRESSURES HAVE STABILIZED OR ARE INCREASING IN BOTH OTSGs, THEN GO TO STEP 10.0.

5.0 IF EITHER OTSG HAS DECREASING LEVEL AND/OR PRESSURE, THEN CONTINUE WITH STEP 6.0.

PRESSURE AND LEVEL ARE STILL DECREASING ON ONE OTSG (NON-ISOLABLE STEAM LEAK)

6.0 REESTABLISH HEAT TRANSFER TO OTSG WITHOUT THE STEAM LEAK.

6.1 OTSG with decreasing level and/or pressure has a steam leak.

6.2 Complete isolation of the steam leaking OTSG by closing its respective valve as follows:

Valve	OTSG"A"	OTSG "B"
MFW Stop	FW-V5A FW-V92A	FW-V5B FW-V92B

6.3 Allow the steam leaking OTSG to boil dry. Heat transfer is being intentionally stopped in the leaking OTSG. DO NOT go to lack of Heat Transfer Section III B.

6.4 Establish MFW to only the OTSG without a steam leak.

6.5 IF MFW is not available, THEN use EFW.

6.6 Adjust TBVs or ADV on OTSG without the steam leak to maintain R temperature at its present value.

6.7 IF the TBVs are not operating properly, THEN refer to the SAD section.

6.8 Control HPI as necessary (see Specific Rule 2).

6.9 IF containment temperature increases above the high RB temperature limit, THEN start 3 RB coolers with maximum cooling water flow.

7.0 IF THERE IS LACK OF ADEQUATE SUBCOOLING MARGIN, THEN GO TO LACK OF SUBCOOLING MARGIN SECTION III A, OTHERWISE CONTINUE.

8.0 IF AN OTSG TUBE RUPTURE IS INDICATED, THEN GO TO SGTR SECTION III D STEP 5.0, OTHERWISE CONTINUE.

9.0 GO TO CP-102.

STATUS | RCS is subcooled with pressure and temperature stable. Only one OTSG is operable and steaming to the condenser or atmopshere.

OVERCOOLING IS OCCURRING FROM ONE APPARENT OTSG

14.0 ISOLATE THE OVERCOOLING OTSG.

14.1 IF OTSG operating level is greater than 95% AND increasing

THEN

a. Trip the running MFW pumps.

b. Close and verify closed locally the respective valves on the overcooling OTSG:

Valve	OTSG"A"	OTSG "B"
EFW Control	EF-V30A	EF-V30B

c. Start the motor driven EFW pumps and verify discharge pressure and recirculation flow.

14.2 IF SLRDS has actuated on the overcooling OTSG, THEN go to Step 14.4, OTHERWISE continue.

14.3 Place the MFW stop valves on the overcooling OTSG in manual to ensure that they remain open.

14.4 Close and verify closed locally the respective valves on the overcooling OTSG:

Valve	OTSG"A"	OTSG "B"
Startup FW Control	FW-V16A	FW-V16B
Main FW Control	FW-V17A	FW-V17B
EFW Control	EF-V30A	EF-V30B
Turbine Bypass	MS-V3A MS-V3C	MS-V3D MS-V3F
ADV	MS-V4A	MS-V4B

14.5 IF the EFW control valve cannot be closed THEN

a. Trip the turbine driven EFW pump.

b. Trip the motor driven EFW pump of the overcooling SG.

c. Close the cross tie to the overcooling SG (EF-V2A for SG "A" or EF-V2B for SG "B").

OVERCOOLING IS OCCURRING FROM ONE APPARENT OTSG

14.0 ISOLATE THE OVERCOOLING OTSG.

14.1 IF OTSG operating level is greater than 95% AND increasing

THEN

a. Trip the running MFW pumps.

b. Close and verify closed locally the respective valves on the overcooling OTSG:

Valve	OTSG"A"	OTSG "B"
EFW Control	EF-V30A	EF-V30B

c. Start the motor driven EFW pumps and verify discharge pressure and recirculation flow.

14.2 IF SLRDS has actuated on the overcooling OTSG, THEN go to Step 14.4, OTHERWISE continue.

14.3 Place the MFW stop valves on the overcooling OTSG in manual to ensure that they remain open.

14.4 Close and verify closed locally the respective valves on the overcooling OTSG:

Valve	OTSG"A"	OTSG "B"
Startup FW Control	FW-V16A	FW-V16B
Main FW Control	FW-V17A	FW-V17B
EFW Control	EF-V30A	EF-V30B
Turbine Bypass	MS-V3A MS-V3C	MS-V3D MS-V3F
ADV	MS-V4A	MS-V4B

14.5 IF the EFW control valve cannot be closed THEN

a. Trip the turbine driven EFW pump.

b. Trip the motor driven EFW pump of the overcooling SG.

c. Close the cross tie to the overcooling SG (EF-V2A for SG "A" or EF-V2B for SG "B").

PRESSURE AND LEVEL ARE STILL DECREASING ON ISOLATED OTSG

17.0 CONTROL HEAT TRANSFER TO OTSG WITHOUT STEAM LEAK.

17.1 Complete isolation of the steam leaking OTSG by closing its respective valves as follows:

Valve	OTSG"A"	OTSG "B"
MFW Stop	FW-V5A FW-V92A	FW-V5B FW-V92B

17.2 Allow the steam leaking OTSG to boil dry. When the generator boils dry, heat transfer on that OTSG will be lost; DO NOT go to Lack of Heat Transfer Section III B.

17.3 Adjust TBVs or ADV on the OTSG without the steam leak to maintain RC temperature at its present value.

17.4 IF the TBVs are not operating properly, THEN refer to the SAD section.

17.5 IF RB temperature increases above the high RB temperature limit THEN start 3 RB coolers with maximum cooling water flow.

17.6 Control HPI as necessary (See Specific Rule 2).

18.0 IF THERE IS LACK OF ADEQUATE SUBCOOLING MARGIN, THEN GO TO LACK OF ADEQUATE SUBCOOLING MARGIN SECTION III A, OTHERWISE CONTINUE.

19.0 IF A OTSG TUBE RUPTURE IS INDICATED, THEN GO TO SGTR SECTION III D, STEP 5.0, OTHERWISE CONTINUE.

20.0 GO TO CP-102.

STATUS | RCS is subcooled with pressure and temperature stable. One OTSG is operable steaming either to condenser or atmosphere.

PRESSURE AND LEVEL ARE STILL DECREASING ON ISOLATED OTSG

17.0 CONTROL HEAT TRANSFER TO OTSG WITHOUT STEAM LEAK.

17.1 Complete isolation of the steam leaking OTSG by closing its respective valves as follows:

Valve	OTSG"A"	OTSG "B"
MFW Stop	FW-V5A FW-V92A	FW-V5B FW-V92B

17.2 Allow the steam leaking OTSG to boil dry. When the generator boils dry, heat transfer on that OTSG will be lost; DO NOT go to Lack of Heat Transfer Section III B.

17.3 Adjust TBVs or ADV on the OTSG without the steam leak to maintain RC temperature at its present value.

17.4 IF the TBVs are not operating properly, THEN refer to the SAD section.

17.5 IF RB temperature increases above the high RB temperature limit THEN start 3 RB coolers with maximum cooling water flow.

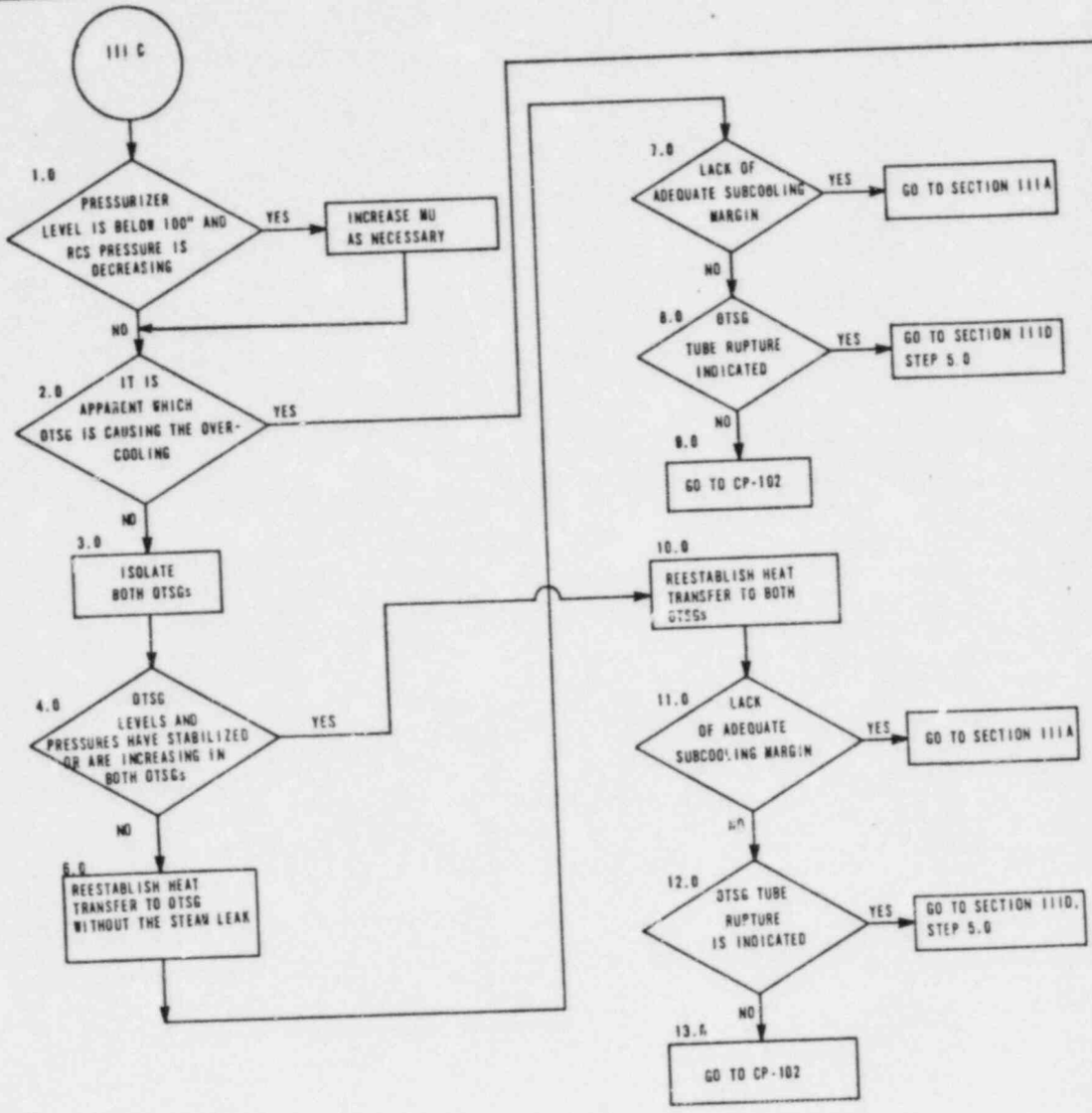
17.6 Control HPI as necessary (See Specific Rule 2).

18.0 IF THERE IS LACK OF ADEQUATE SUBCOOLING MARGIN, THEN GO TO LACK OF ADEQUATE SUBCOOLING MARGIN SECTION III A, OTHERWISE CONTINUE.

19.0 IF A OTSG TUBE RUPTURE IS INDICATED, THEN GO TO SGTR SECTION III D, STEP 5.0, OTHERWISE CONTINUE.

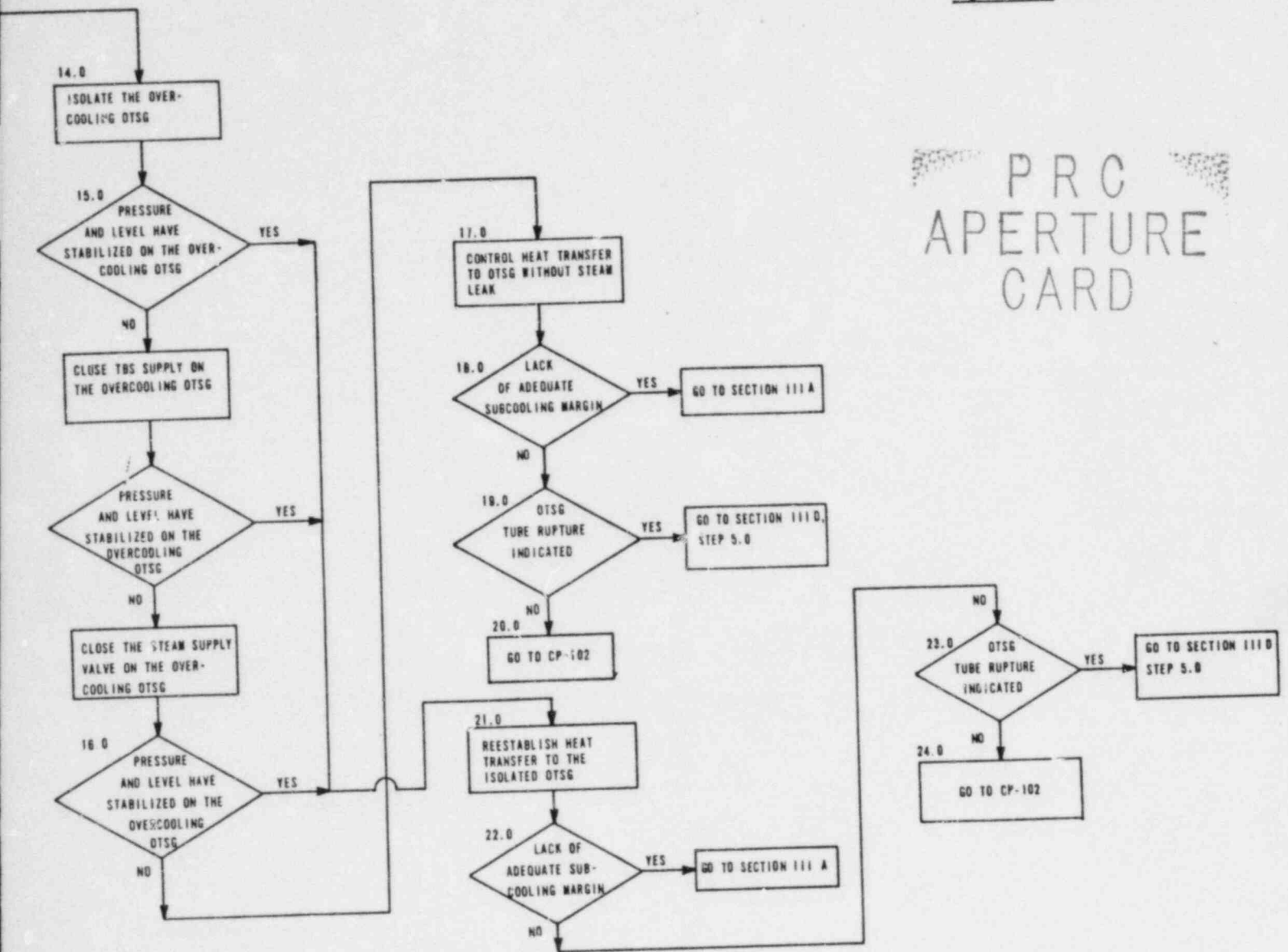
20.0 GO TO CP-102.

STATUS | RCS is subcooled with pressure and temperature stable. One OTSG is operable steaming either to condenser or atmosphere.



74-1124158-00

Figure III C EXCESSIVE HEAT TRANSFER



PRC APERTURE CARD

Also Available On Aperture Card

8401230549 -04

III D
SGTR

FOLLOWUP ACTION FOR OTSG TUBE RUPTURE

1.0 IF THE REACTOR HAS TRIPPED, THEN GO TO STEP 5.0, OTHERWISE CONTINUE.

REACTOR TRIP HAS NOT OCCURRED

2.0 INCREASE MU IF REQUIRED.

2.1 IF normal makeup through MU-V-17 cannot maintain pressurizer level above 200" THEN do the following, OTHERWISE go to Step 3.0.

a. Close MU-V-3 to isolate letdown.

b. Open MU-V-14A and MU-V-14B to provide BWST supply.

c. Close MU-V-12 to isolate letdown tank supply.

d. Start additional MU pump.

e. Open MU-V-217 as necessary to maintain pressurizer level about 150" inches.

2.7 IF pressurizer level cannot be maintained above 150" THEN initiate full HPI (Specific Rule 1).

2.8 IF pressurizer level cannot be maintained at greater than 100", THEN trip the reactor and go to Step 4.0, otherwise continue.

3.0 SHUTDOWN REACTOR.

3.1 Close MU-V43 and observe MU tank guideline.

3.2 Immediately begin power reduction at as fast a rate as can be controlled.

3.3 IF the reactor trips during runback, THEN perform the immediate actions and verifications of Section I and II.

3.4 Determine OTSG with tube leak by surveying steam line radiation, sampling OTSGs, observing OTSG levels and feed rates.

3.5 At approximately 0 MWe:

a. Place the TBVs in manual and control steam pressure to avoid lifting main steam safety valves.

b. Ensure site loads are transferred.

c. Trip turbine/generator then verify the generator breakers open and turbine stop valves close.

d. Reduce reactor power to < 4% then trip reactor.

e. Reduce RCP's to one per loop.

f. Continue with Step 4.0.

REACTOR TRIP HAS OCCURRED

4.0 PERFORM THE IMMEDIATE ACTIONS AND VERIFICATION OF SECTION I AND II.

5.0 CONTROL MU/HPI AS REQUIRED.

5.1 See Specific Rule 2.

6.0 PREPARE FOR COOLDOWN.

6.1 Turn off all pressurizer heaters.

6.2 Ensure that local survey of main steam line is being made to confirm high radiation alarms and verify the tube ruptured OTSG.

6.3 IF HPI was initiated, THEN begin makeup to the BWST.

7.0 IF THE REACTOR COOLANT PUMPS ARE RUNNING, THEN GO TO STEP 16.0, OTHERWISE CONTINUE.

8.0 IF OFFSITE POWER IS AVAILABLE BUT RC PUMPS ARE NOT RUNNING, THEN GO TO STEP 13.0, OTHERWISE CONTINUE.

9.0 IF LOSS-OFFSITE POWER HAS OCCURRED, THEN CONTINUE WITH STEP 10.0.

LOSS OF OFFSITE POWER HAS OCCURRED

10.0 WHEN OFFSITE POWER IS RESTORED, THEN GO TO STEP 13.0, OTHERWISE CONTINUE.

10.1 Restore offsite power as soon as possible.

11.0 BEGIN COOLDOWN AND DEPRESSURIZATION WITH LOSS-OF-OFFSITE POWER.

11.1 Verify that OTSG levels are increasing to the appropriate OTSG level (see Specific Rule 4) with EFW properly throttled (see Specific Rule 3).

11.2 IF an OTSG has an unisolable steam leak, THEN feed the leaking OTSG as necessary (approximately 100 gpm) through the MFW nozzles (or EFW nozzles if MFW not available) to maintain tube-to-shell ΔT less than 150F.

11.3 AS SOON AS the tube ruptured OTSG is identified, feed it as needed to maintain the low level limit, to promote natural circulation, to maintain adequate subcooling margin, or to maintain tube to shell ΔT requirements. Steam the tube ruptured OTSG as necessary to promote natural circulation.

11.4 Load instrument air compressor on diesel generator for air supply to ADVs.

11.5 Depressurize the RCS to as close as possible to the adequate subcooling margin curve by opening the PORV (RC-RV-2). Repeat this process whenever sufficient excess RC subcooling develops (i.e., the RC becomes 30F colder than the subcooling margin) to minimize primary to secondary leakage.

11.6 As quickly as possible, begin cooldown of the RCS with the ADVs initially using both steam generators if they are both operable.

11.7 Initiate a rapid cooldown to 500F (do not exceed a C/D rate of 240 F/hr).

11.8 During the depressurization and cooldown, control the ADVs as necessary to prevent the MSSVs from opening.

12.0 GO TO STEP 17.0.

STATUS | No offsite power is available. The RCS is being depressurized by opening the PORV. The RCS is being cooled with the ADVs.

REACTOR COOLANT PUMPS NOT RUNNING

13.0 WHEN ADEQUATE SUBCOOLING MARGIN IS OBTAINED, THEN RESTART APPROPRIATE RCPs AND GO TO STEP 16.0, OTHERWISE CONTINUE.

13.1 Start one RCP in each loop. IF successful, THEN go to Step 16.0, otherwise continue.

13.2 IF unable to start a RCP in one loop, THEN attempt to start both RCPs in the opposite loop. IF successful, THEN go to Step 16.0, otherwise continue.

13.3 IF only one RCP can be started AND it is in Loop with pzr spray line, THEN go to Step 16.0, otherwise continue.

13.4 IF only one RCP can be started AND it is in loop without pzr spray line THEN leave that RCP running and continue.

14.0 BEGIN COOLDOWN AND DEPRESSURIZATION WITHOUT NORMAL PRESSURIZER SPRAY.

14.1 Verify that OTSG levels are increasing to the appropriate OTSG level (see Specific Rule 4) with feedwater properly throttled (see specific Rule 3).

14.2 IF an OTSG has a steam leak, THEN feed the leaking OTSG as necessary (approximately 100 gpm) through the MFW nozzles (or EFW nozzles if MFW not available) to maintain tube-to-shell ΔT less than 150F.

14.3 AS SOON AS the tube ruptured OTSG is identified, THEN feed it as needed to maintain the low level limit, to promote natural circulation, to maintain adequate subcooling margin, or to maintain tube to shell ΔT requirements. Steam the tube ruptured OTSG as necessary to promote natural circulation and to prevent level from exceeding 95% on the operate range.

14.4 As soon as possible, begin cooldown of the RCS with the TBVs on both steam generators, if possible.

14.5 Initiate a rapid cooldown to 500F (do not exceed a C/D rate of 240 F/hr).

14.6 IF the RCPs cannot be restarted for pressurizer spray flow within 10 minutes after tripping, THEN:

a. Depressurize the RCS to as close as possible to the adequate subcooling margin curve by opening the PORV. Repeat this process whenever sufficient excess RC subcooling develops (i.e. the RC becomes 30F colder than the subcooling margin) to minimize primary to secondary leakage.

b. Continue cooldown of the RCS with the TBVs initially on both steam generators.

c. As soon as possible, restart RCPs per Step 13.0 AND continue with Step 16.0.

d. IF RCPs cannot be restarted, continue with Step 15.0.

15.0 GO TO STEP 17.0.

REACTOR COOLANT PUMPS ARE RUNNING

16.0 BEGIN COOLDOWN AND DEPRESSURIZATION WITH RCPs PROVIDING PRESSURIZER SPRAY.

16.1 Ensure appropriate steam generator level is maintained (see Specific Rule 4). Begin depressurizing the RCS to as close as possible to the adequate subcooling margin curve by opening the pressurizer spray valve (RC-V-1).

16.2 IF a OTSG has an unisolable steam leak, THEN feed the steam, leaking OTSG as necessary (approximately 100 gpm) through the EFW nozzle (or EFW nozzles if MFW not available) to maintain tube-to-shell T less than 100F (150F for emergency cooldown).

16.3 IF the SGTR leak rate is greater than the capacity of one normal MU pump OR the condenser is NOT available OR the SGTR has an unisolable steam leak, THEN initiate a rapid cooldown to 500F (do not exceed a C/D rate of 240 F/hr).

16.4 As quickly as possible, begin cooldown of the RCS with the TBVs initially on BOTH steam generators if possible.

16.5 Continue spraying the pressurizer as necessary to remain as close as possible to the adequate subcooling margin.

16.6 Continue with Step 17.0

COOLDOWN HAS BEGUN USING BOTH OTSGs

17.0 CONTROL THE TUBE RUPTURED OTSG TO PREVENT RADIATION RELEASE.

17.1 During the depressurization and cooldown:

a. Control the TBVs as necessary to prevent the MSSVs from opening.

b. IF the TBVs are not available, THEN use the ADVs to continue the cooldown.

17.2 Terminate discharge from IWTS and IWFS until monitoring and controls are established in accordance with HPP 1699B. Open breakers for the following sump pumps to control discharge to the IWTS (IWFS):

		Unit	MCC
Turbine Bldg. Sump Pumps	SD-P5	10E	1D Turb.
	SD-P2 A	1C	1C Turb.
	SP-P2 B	1E	1D Turb.
Powdex Sump Pumps	SD-P1 A	4D	1A Turb.
	SD-P1 B	4D	1B Turb.

17.3 Notify Health Physics to begin survey of the Intermediate and Turbine Buildings to determine the need for controlled areas. Initiate Emergency Plan if required, as a result of the surveys.

17.4 Notify Unit II Control Room to isolate auxiliary steam cross connect by closing AS-V-23 and its bypass AS-V-209.

18.0 ISOLATE THE TUBE RUPTURED OTSG.

18.1 IF the OTSG without the tube rupture is not operable, THEN go to Step 19.0 and continue cooldown with the tube ruptured OTSG, otherwise continue.

18.2 AS SOON AS the tube ruptured OTSG is identified AND the RCS is below 540F, THEN isolate the tube ruptured OTSG by closing its respective valves as follows:

OTSG A	OTSG B	Valve Name
FW-V16B	FW-V16A	Startup FW Valve
FW-V17A	FW-V17B	MFW Valve
FW-V5A	FW-V5B	MFW Stop Valve
EF-V30A	EF-V30B	EFW Control Valve
MSV-3A	MS-V3D	Turbine Bypass Valve
MSV-3C	MS-V3F	Turbine Bypass Valve
MSV-4A	MSV-4B	Atmospheric Dump Valve
MSV-10A	MSV-10B	Main Steam to Emer. FWP
MSV-13A	MSV-13B	Main Steam to Emer. FWP
MSV-85A	MSV-85B	Relief Valve Support Heati
MSV-1A	MSV-1C	Main Steam Isolation Valve
MSV-1B	MSV-1D	Main Steam Isolation Valve

18.3 Initiate steaming as necessary to maintain the OTSG pressure below 1000 psig and OTSG level below 95% on the operate range on the tube ruptured SG.

18.4 WHEN 500F is reached, THEN continue with Step 19.0.

PLANT IS COOLING DOWN WITH ONE OTSG ISOLATED

19.0 CONTINUE COOLDOWN WITH APPLICABLE LIMITATIONS.

19.1 When the RCS inventory and subcooling can be maintained by the MU system, stop the HPI system and establish normal MU control.

19.2 Continue depressurization and cooldown at the maximum attainable C/D rate without exceeding 100F/hr using the OTSG without the tube rupture.

19.3 Cooldown on the ruptured OTSG if the other OTSG is not operable.

19.4 Decrease the RCS pressure as required to remain as close as possible to the minimum subcooling margin line.

19.5 Bypass SLRDS before OTSG pressure reaches 600 psig.

19.6 IF an unisolable steam line break has occurred, THEN feed that OTSG as necessary (approximately 100 GPM) to provide shell cooling with MFW, use EFW if MFW not available.

19.7 IF tube to shell ΔT approaches 100F (or 150F if emergency condition) THEN slow cooldown as necessary to prevent exceeding the T limit.

IF the tube to shell ΔT exceeds 100F (or 150F if emergency condition) THEN stop the cooldown. Resume cooldown when tube to shell ΔT is less than 100F (or 150 if emergency condition).

19.8 Block HPI before reaching 1600 psig (if not in use) to prevent auto start of HPI.

20.0 CONTINUE NORMAL COOLDOWN PER PROCEDURE 1102-10 USING ONLY ONE OTSG AND OBSERVE THE FOLLOWING PRECAUTIONS:

20.1 Steam the tube ruptured OTSG as necessary to prevent exceeding 95% on the operate range.

20.2 When steaming is no longer possible drain the OTSG as necessary to the condenser to prevent exceeding 95% on the operate range.

20.3 Depressurize the RCS as close to the subcooling margin line as possible to minimize the tube leak rate driving force.

20.4 Feed OTSG as necessary to maintain tube-to-shell $\Delta T < 100F$ (or 150F for emergency condition).

20.5 Maintain powdex cells in operation to remove activity from condensate.

20.6 Continue cooldown and drain RCS as soon as possible to stop the leak.

STATUS | The tube ruptured OTSG has been identified and isolated if possible. The RCS is subcooled and the pressurizer is controlling RCS pressure.

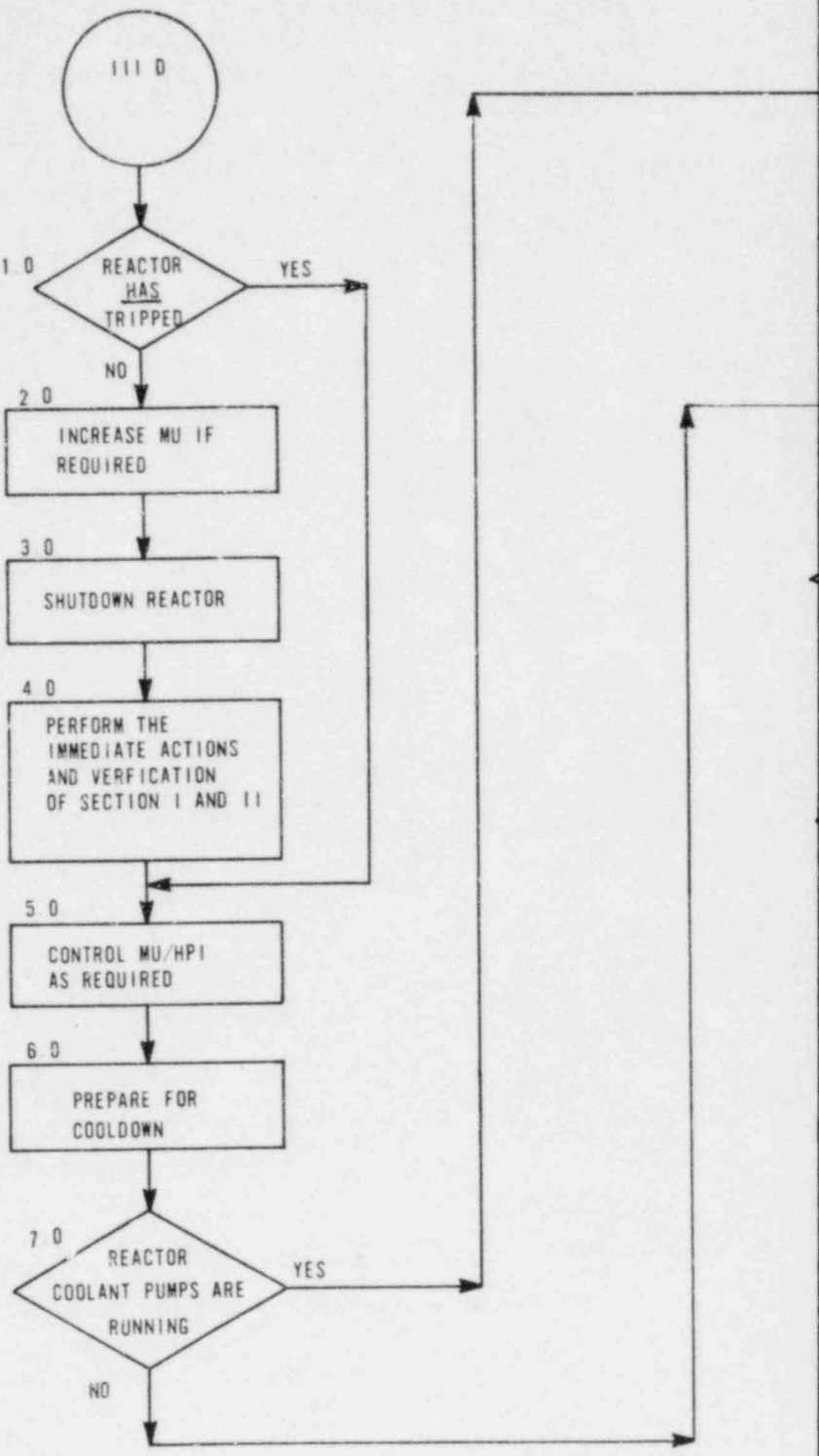
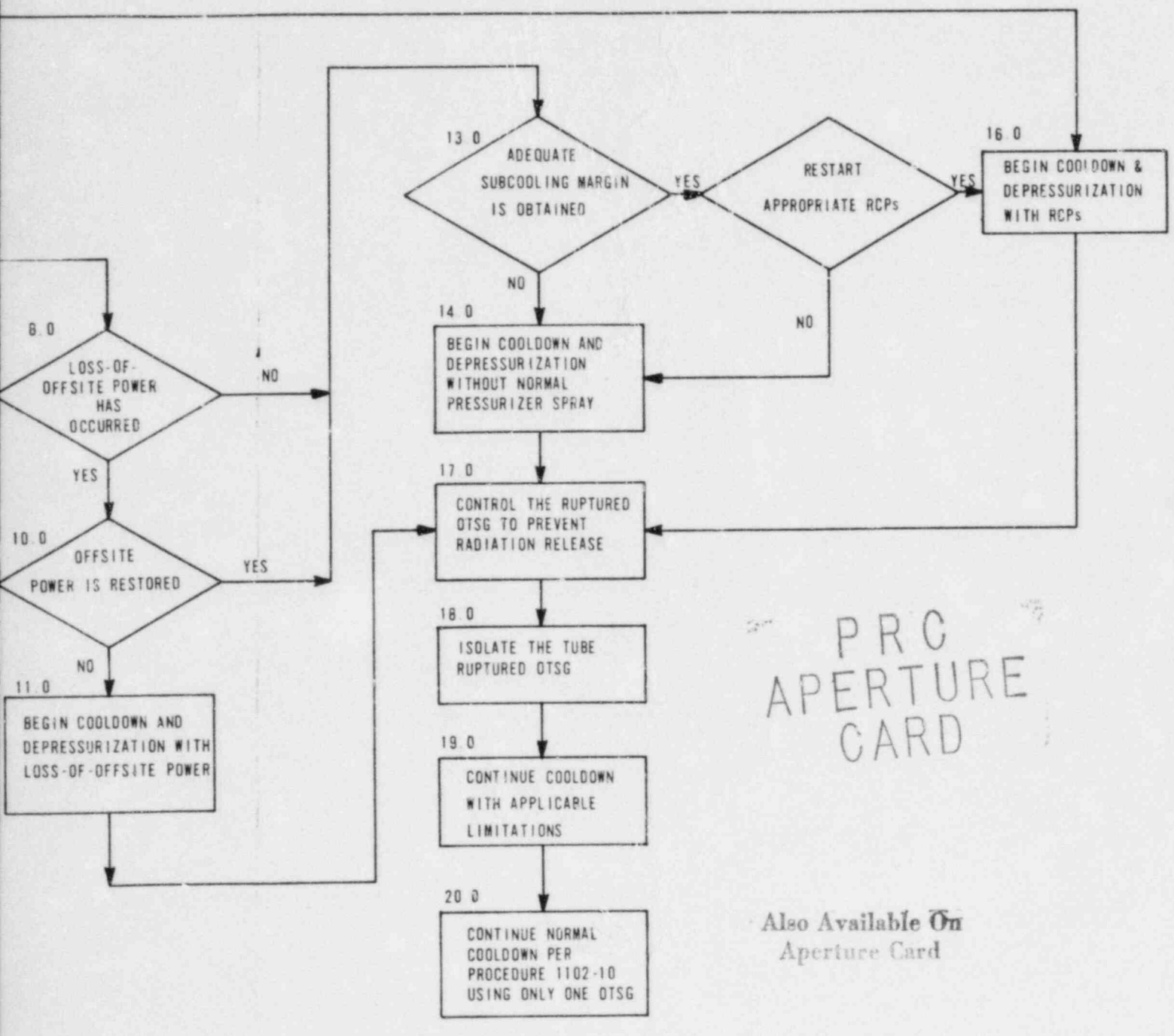

111 0
1.0
REACTOR HAS TRIPPED
YES
NO
2.0
INCREASE MU IF REQUIRED
3.0
SHUTDOWN REACTOR
4.0
PERFORM THE IMMEDIATE ACTIONS AND VERFICATION OF SECTION I AND II
5.0
CONTROL MU/HPI AS REQUIRED
6.0
PREPARE FOR COOLDOWN
7.0
REACTOR COOLANT PUMPS ARE RUNNING
YES
NO

Figure 111 D STEAM GENERATOR TUBE RUPTURE



PRC APERTURE CARD

Also Available On Aperture Card

8401230549-05

CP-101

A LARGE LOCA HAS OCCURRED AND THE CORE FLOOD TANKS ARE EMPTYING

1.0 VERIFY AUTOMATIC SFAS ACTUATION.

1.1 Check SFAS actuation per Section II.

2.0 IF THE RC PRESSURE STABILIZES ABOVE THE MAXIMUM OPERATING PRESSURE FOR LPI THEN:

a. IF adequate primary to secondary heat transfer exists, THEN go to CP-103 OR

b. IF adequate primary to secondary heat transfer does NOT exist, THEN go to CP-104.

3.0 IF LPI FLOW IS IN EXCESS OF 1000 GPM IN EACH INJECTION LINE FOR AT LEAST 20 MINUTES BEFORE THE BWST LEVEL REACHES THE CONTAINMENT SUMP SWITCHOVER LEVEL SETPOINT (36") THEN CONTINUE, OTHERWISE GO TO STEP 7.0.

4.0 STOP HPI.

4.1 Stop HPI pumps.

4.2 Close BWST outlet valves to HPI (MU-V-14A and MU-V-14B).

5.0 WHEN THE BWST LEVEL REACHES THE CONTAINMENT SUMP SWITCHOVER LEVEL SETPOINT (36"), THEN SWITCH LPI SUCTION TO THE CONTAINMENT SUMP.

5.1 Open the containment sump outlet valves (DH-V-6A and DH-V-6B).

5.2 Close the BWST outlet valves to LPI (DH-V-5A and DH-V-5B).

5.3 Assure cooling to the LPI coolers.

6.0 GO TO STEP 9.0.

7.0 WHEN THE BWST LEVEL REACHES THE CONTAINMENT SUMP SWITCHOVER LEVEL (36") THEN SWITCH LPI SUCTION TO THE CONTAINMENT SUMP AND SWITCH THE HPI SUCTION TO THE LPI DISCHARGE.

7.1 Open containment sump outlet valves to LPI (DH-V-5A and DH-V-5B).

7.2 Close the BWST ouclet valves to LPI (DH-V-5A and DH-V-5B).

7.3 Open HPI suction valves from LPI discharge (DH-V-7A and DH-V-7B).

7.4 Close the BWST outlet valves to HPI (MU-V-14A and MU-V-14B).

7.5 Assure cooling to the LPI coolers.

8.0 WHEN HPI/LPI "PIGGYBACK" OPERATION HAS BEEN SUPPLYING AT LEAST 1000 GPM TO EACH LPI INJECTION LINE FOR AT LEAST 20 MINUTES AND DURING THIS 20 MINUTES THE RCS PRESSURE HAS CONTINUOUSLY BEEN LESS THAN THE MAXIMUM PRESSURE FOR LPI OPERATION ALONE, THEN STOP HPI.

8.1 Stop HPI pumps.

8.2 Close HPI suction valves from LPI discharge (DH-V-7A and DH-V-7B).

9.0 ISOLATE MAJOR CONTAINMENT PENETRATIONS.

9.1 IF core cooling is being maintained by the HPI/LPI/CFT systems, THEN stop the EFW pumps AND close the following valves to isolate the SGs.

Valves	SG-A	SG-B
MSIVs	MSV-1A	MSV-1C
MSIVs	MSV-1B	MSV-1D
MFIVs	FWV-92A	FWV-92B

9.2 WHEN:

a. RB pressure increases above 4 psig

OR

b. RCS pressure decreases below 1600 psig

OR

c. RB radiation increases above the high radiation limit, THEN ensure that the containment isolation valves are closed.

10.0 ESTABLISH LONG-TERM LPI COOLING.

10.1 Shut down turbine, feedwater, and steam systems when time permits.

10.2 Close the PORV block valve (RC-V-2).

10.3 Continue LPI cooling until further instructions are given by management.

10.4 Monitor gas and particulate activity and radiation levels to determine if penetration areas and emergency pump rooms are safe for personnel entry.

10.5 Periodically sample RCS fluid for pH, boron and isotopic concentration once stable temperatures are reached. Control pH.

10.6 Monitor containment for hydrogen.

CAUTION

DO NOT ESTABLISH A FLOW PATH IN ANY SYSTEM ISOLATED BY ESAS WITHOUT REVIEW OF THE POTENTIAL RELEASE OF RADIOACTIVE GAS OR LIQUID.

11.0 ESTABLISH BORON DILUTION FLOW TO THE RV.

11.1 When practical but within twenty four hours, establish dilution flow to the RV to prevent boron precipitation.

CP-102

COOLDOWN ON ONE OR TWO SG(s) WITH SUBCOOLED RC AND PZR STEAM BUBBLE

A SMALL PRIMARY BOUNDARY FAILURE MAY EXIST

1.0 RESTART RCPs AND REESTABLISH PZR SPRAY, IF POSSIBLE.

1.1 Start RCPs per OP 1103-06. One per loop is desired.

1.2 Reopen pressurizer spray block valve (RC-V-3) and monitor RCS pressure for 5 to 30 minutes to ensure that reopening pressurizer spray block valve does not cause depressurization (i.e., failed open pressurizer spray valve or pressurizer spray line break).

1.3 IF opening the PZR spray block valve causes RC depressurization, THEN reclose the PZR spray block valve.

2.0 IF NORMAL PZR. SPRAY IS NOT AVAILABLE, THEN USE THE PORV TO DEPRESSURIZE THE RCS.

3.0 IF BOTH SGs ARE IN SERVICE, THEN GO TO STEP 5.0. OTHERWISE CONTINUE.

4.0 PREPARE FOR COOLDOWN WITH A DRY SG.

4.1 Calculate the existing tube-to-shell ΔT for the dry SG.

$$\Delta T = \frac{\Sigma \text{ SG Shell T/C}}{\text{no. of operable T/Cs}} - T_c^{RCS}$$

= _____F. This value must not exceed 100F.

4.2 WHEN the ΔT as determined in Step 4.1 above is less than 100F, THEN open the TBVs or ADVs and commence cooldown. DO NOT exceed 100F tube-to-shell ΔT on the dry SG.

5.0 IF A PRIMARY BOUNDARY FAILURE EXISTS, THEN CONTINUE, OTHERWISE FURTHER ACTIONS AT THIS POINT ARE AT THE DISCRETION OF STATION MANAGEMENT.

6.0 CONTROL HPI FLOW.

6.1 See Specific Rule 2.

7.0 BEGIN SG COOLDOWN OF RCS.

7.1 Increase SG steaming by opening the TBVs or ADVs to cooldown the RCS, while maintaining SG levels per Specific Rules 3 and 4.

7.2 Begin makeup to the BWST with borated water as necessary.

7.3 IF cooling down with a dry SG, THEN slowly feed the dry SG as necessary to maintain 100F tube-to-shell ΔT requirements together with a cooldown rate near 100 F/hr.

7.4 Bypass SLRDS, and ESAS to prevent inadvertent actuation during the cooldown.

7.5 WHEN the RCS pressure falls below 750 psig, THEN close the CFT isolation valves.

8.0 GO TO CP-104 STEP 14.0.

CP-103

SATURATED RC COOLDOWN WITH SG(s) REMOVING HEAT

1.0 CLOSE OR VERIFY CLOSED THE PORV.

2.0 VERIFY THAT LOSS OF SUBCOOLING MARGIN IS BEING TREATED.

1.1 Ensure maximum HPI flow per Specific Rule 1.

1.2 Ensure SG levels are raised to 95% operate range per Specific Rule 4.

3.0 IF THE CFTs ARE EMPTYING (INDICATING A LARGE LOCA), THEN GO TO CP-101.

4.0 IF ADEQUATE PRIMARY TO SECONDARY HEAT TRANSFER CANNOT BE MAINTAINED, THEN GO TO CP-104.

5.0 IF ADEQUATE SUBCOOLING MARGIN IS RESTORED, THEN GO TO CP-105.

6.0 IF AT ANY TIME THE RCS BECOMES SUPERHEATED, THEN GO TO ICC PROCEDURE.

7.0 WHEN RCS PRESSURE REACHES MAXIMUM LPI OPERATING PRESSURE, THEN VERIFY START OR START LPI.

7.1 Ensure LPI recirculation established.

7.2 Start LPI pumps.

7.3 Ensure LPI to RCS valves are open.

7.4 Ensure cooling to LPI coolers.

8.0 COOLDOWN WITH SG(s) TO INITIATE LPI FLOW.

8.1 Increase SG steaming by opening the TBVs or ADVs.

8.2 Verify that SG(s) continue to provide a heat sink for the RCS by:

a. remaining pressurized

AND

b. incore T/Cs decreasing as SG pressure is lowered.

8.3 IF cooling down with a dry SG, THEN feed as necessary to maintain the 100F tube-to-shell ΔT requirement together with a cooldown rate near 100 F/hr.

8.4 Continue saturated cooldown by decreasing SG pressure.

8.5 Bypass SLRDS to prevent inadvertent actuation during the cooldown.

8.6 Ensure that the CFT isolation valves remain open during the saturated cooldown until specifically instructed to close them.

8.7 Begin makeup to the BWST with borated water as necessary.

8.8 Close high point vents (if open) when RC pressure < 150 psig.

9.0 IF LPI FLOW IS IN EXCESS OF 1000 GPM IN EACH INJECTION LINE FOR AT LEAST 20 MINUTES BEFORE THE BWST LEVEL REACHES THE CONTAINMENT SUMP SWITCHOVER LEVEL SETPOINT (36"), THEN CONTINUE, OTHERWISE GO TO STEP 13.0.

10.0 STOP HPI AND ESTABLISH NORMAL MU.

10.1 Establish RCP seal injection with the normal makeup pump taking suction from MU tank AND stop the other HPI pump. Do NOT allow the HPI throttle valves to be closed on a running HPI pump without first establishing recirculation flow.

10.2 If necessary, throttle the LPI flow to balance flow between trains and to maintain flow per pump below the upper flow limit.

10.3 Close CFT isolation valves (CF-T-1A and CF-T-1B).

11.0 WHEN THE BWST LEVEL REACHES THE CONTAINMENT SUMP SWITCHOVER LEVEL SETPOINT (36"), THEN SWITCH LPI SUCTION TO THE CONTAINMENT SUMP.

11.1 Open or verify open the containment sump outlet valves (DH-V-6A and DH-V-6B).

11.2 Close or verify closed the BWST outlet valves to LPI (DH-V-5A and DH-V-5B).

11.3 Place LPI coolers in operation.

11.4 Continue to supply makeup by transferring HPI pump suction from the BWST to the discharge of an LPI pump.

12.0 GO TO STEP 14.0.

13.0 WHEN THE BWST LEVEL REACHES THE CONTAINMENT SUMP SWITCHOVER LEVEL (36"), THEN SWITCH LPI SUCTION TO THE CONTAINMENT SUMP AND SWITCH THE HPI SUCTION TO THE LPI DISCHARGE.

13.1 Open containment sump outlet valves (DH-V-6A and DH-V-6B).

13.2 Close the BWST outlet valves to LPI (DH-V-5A and DH-V-5B).

13.3 Open HPI suction valves from LPI discharge (DH-V-7A and DH-V-7B).

13.4 Close the BWST outlet valves to HPI (MU-V-14A and MU-B-14B).

13.5 Place LPI coolers in operation.

14.0 WHEN HPI/LPI PIGGYBACK OPERATION HAS BEEN SUPPLYING AT LEAST 1000 GPM TO EACH LPI INJECTION LINE FOR 20 MINUTES AND DURING THIS 20 MINUTES THE RCS PRESSURE HAS CONTINUOUSLY BEEN LESS THAN THE MAXIMUM PRESSURE FOR LPI OPERATION ALONE, THEN:

14.1 Establish RCP seal injection with the normal makeup pump in piggyback mode AND stop the other HPI pump. Do NOT allow the HPI throttle valves to be closed on a running HPI pump without first eatablishing recirculation flow.

14.2 If necessary, throttle the LPI valves to balance flow between trains and to maintain flow per pump below the upper flow limit.

14.3 Close CFT isolation valves (CF-T-1A and CF-T-1B).

15.0 CONTINUE COOLDOWN ON LPI SYSTEM.

15.1 Monitor core ΔT by comparing incore T/Cs and DH cooler outlet temperature.

15.2 Continue RCS cooldown to 140F.

16.0 GO TO CP-101 STEP 10.0 TO ESTABLISH LONG TERM COOLING.

CP-104

HPI/PORV - OPEN COOLING WITHOUT SG(s) REMOVING HEAT

1.0 OPEN OR VERIFY OPENED THE PORV AND PORV BLOCK VALVE.

2.0 IF ADEQUATE SUBCOOLING MARGIN DOES NOT EXIST, THEN ENSURE MAXIMUM HPI FLOW.

2.1 See Specific Rule 1.0.

3.0 IF ADEQUATE SUBCOOLING MARGIN EXISTS THEN START ONE RCP AND THROTTLE HPI FLOW.

3.1 See Specific Rule 2.

4.0 IF AT ANY TIME BEFORE ESTABLISHING DHRS AND/OR LPI COOLING.

A. THE INCORE T/Cs INDICATE THAT A SATURATED RCS BECOMES SUBCOOLED AFTER INITIATING HPI/PORV-OPEN COOLING WITH FW AND SGs STILL AVAILABLE,

OR

B. FW TO SGs IS RESTORED AFTER INITIATING HPI/PORV-OPEN COOLING DUE TO A LOSS OF ALL FW,

THEN ATTEMPT TO RESTORE PRIMARY TO SECONDARY HEAT TRANSFER BY PEFORMING THE FOLLOWING STEPS 5.0 THROUGH 11.0. OTHERWISE CONTINUE AT STEP 12.0.

FEEDWATER AVAILABLE

5.0 IF AT ANYTIME, WHILE PERFORMING STEPS 6.0 THROUGH 11.0, PRIMARY TO SECONDARY HEAT TRANSFER IS ESTABLISHED, THEN:

A. IF ADEQUATE SUBCOOLING MARGIN EXISTS, THEN GO TO CP-105.

B. IF ADEQUATE SUBCOOLING MARGIN DOES NOT EXIST, THEN GO TO CP-103.

6.0 RAISE SG LEVEL TO APPROPRIATE LEVEL.

6.1 See Specific Rule 4.

7.0 LOWER SG PRESSURE TO INDUCE PRIMARY TO SECONDARY HEAT TRANSFER.

7.1 Lower SG pressure by adjusting TBVs or ADVs, while maintaining SG level, until secondary Tsat is 40 to 60F lower than incore T/C temperature. Maintain this SG pressure.

8.0 IF AN RCP IS RUNNING OR IF NO RCP(s) CAN BE BUMPED THEN GO TO STEP 12.0, OTHERWISE CONTINUE.

9.0 USE PUMP BUMPS TO INDUCE HEAT TRANSFER.

9.1 Bump a RCP, which is capable of being started, in a loop with SG level at the low level limit or greater.

9.2 Allow RCS pressure to stabilize within ±20 psig of new pressure.

9.3 Repeat Steps 9.1 through 9.2 for operable RCPs that have not been bumped. Allow 15 minutes between pump bumps. IF all operable RCPs have been bumped and heat transfer HAS NOT been reestablished, THEN continue with Step 10.0.

10.0 FURTHER LOWER OTSG PRESSURE TO INDUCE HEAT TRANSFER.

10.1 If heat transfer has not been established then further lower SG pressure by adjusting TBVs or ADVs while maintaining SG level, until secondary T_{sat} is 90F to 110F lower than incore T/C temperature.

11.0 START AN RCP.

11.1 IF at least one hour has passed since reactor trip and any RCPs are capable of being started, THEN start and run one RCP preferably in a loop with SG level greater than 30".

NO PRIMARY TO SECONDARY HEAT TRANSFER

12.0 HPI/PORV-OPEN COOLDOWN TO DHRS AND/OR LPI OPERATION.

12.1 Begin makeup to the BWST with borated water as necessary.

12.2 Bypass SLRDS and SFAS as necessary to prevent inadvertent actuation during the cooldown.

12.3 IF cooldown rate and RCS pressure are being controlled AND adequate subcooling margin exists, THEN close the CFT isolation valves at a RCS pressure between 700 and 675 psig.

12.4 Start both LPI pumps, ensure LPI pump recirculation to the BWST, and open LPI-to-RCS valves.

13.0 IF ADEQUATE SUBCOOLING MARGIN DOES NOT EXIST, THEN GO TO CP-103 STEP 9.0, OTHERWISE CONTINUE.

14.0 IF THE BWST LEVEL REACHES THE CONTAINMENT SUMP SWITCHOVER LEVEL BEFORE THE DHRS CUT-IN CONDITIONS ARE MET, THEN SWITCH LPI PUMP SUCTION TO THE CONTAINMENT SUMP AND SWITCH THE HPI SUCTION TO THE LPI DISCHARGE. OTHERWISE GO TO STEP 16.0.

14.1 Open containment sump outlet valves (DHV-6A and DH-V-6B) for LPI suction.

14.2 Close the BWST outlet valves (DH-V-5A and DH-V-5B) for LPI suction.

14.3 Open the LPI-to-RCS valves.

14.4 Place DH coolers in operation.

14.5 Open HPI suction valves from the LPI discharge (DH-V-7A and DH-V-7B).

14.6 Close BWST outlet valves to HPI (MU-V-14A and MU-V-14B).

14.7 Throttle HPI and LPI flow as necessary.

14.8 Stop RCP(s) if on

15.0 WHEN THE DHRS CUT-IN CONDITIONS ARE MET AND THE FLOW IN A SINGLE LPI INJECTION LINE ALONE IS SUFFICIENT TO MAKE UP RC INVENTORY, THEN PLACE ONE LPI PUMP IN THE DH MODE WHILE THE OTHER LPI PUMP REMAINS IN THE INJECTION MODE AND RECOVER FROM HPI/LPI/PORV-OPEN COOLING AND GO TO STEP 17.0.

15.1 Continue to supply RCP seal injection with HPI/LPI piggyback.

15.2 Establish core cooling with LPI loop A in DH mode.

15.3 Maintain LPI loop B in the injection mode (i.e., taking suction from the RB sump).

15.4 Close the PORV.

15.5 Close the PORV block valve if necessary.

15.6 Establish a bubble in the pzr.

15.7 Stop RCPs if on.

15.8 Go to Step 17.0.

16.0 WHEN THE DHRS CUT-IN CONDITIONS ARE MET, THEN PLACE BOTH LPI PUMPS IN DH MODE AND RECOVER FROM HPI/LPI/PORV-OPEN COOLING.

16.1 At cut-in conditions place both LPI pumps in the DH mode taking suction from the DH drop line, while continuing to supply makeup as necessary with the HPI pumps(s).

16.2 Close the PORV.

16.3 Close a PORV block valve if necessary.

16.4 Establish a bubble in the pzr.

16.5 IF at any time the BWST level reaches the containment sump switchover level, THEN perform the following.

a. Place one LPI train in the injection mode taking suction from the containment sump while the other LPI train remains in the DH mode.

b. Continue to supply makeup by transferring HPI pump suction from the BWST to the discharge of an LPI pump.

16.6 Stop RCP(s) if on.

17.0 CONTINUE COOLDOWN TO COLD SHUTDOWN.

17.1 WHEN the RCS depressurizes to less than 150 psig THEN close or verify closed all high point vents.

17.2 Monitor core ΔT by comparing incore T/Cs and DH cooler outlet temperature.

17.3 Continue RCS cooldown to 140F with core cooling provided by DHRS and RCS pressure controlled by pzr. and LPI/HPI.

CP-105

TRANSIENT TERMINATION WITH SG(s) REMOVING HEAT FOLLOWING AN OCCURRENCE THAT MAY REQUIRE PRESSURIZER RECOVERY OR SOLID PLANT COOLDOWN WITH SUBCOOLED RC

1.0 CLOSE OR VERIFY CLOSED THE PORV AND ALL HIGH POINT VENTS.

2.0 IF THERE IS A BUBBLE IN THE PRESSURIZER, THEN GO TO CP-102 OTHERWISE CONTINUE.

3.0 ESTABLISH A BUBBLE IN THE PZR.

3.1 Turn on all available pzr. heaters.

3.2 Monitor the increase in pzr. water temperature until pzr. temperature reaches saturation for the existing RC pressure. At this point, lower pressurizer level to form a steam bubble.

3.3 When a bubble is established in the pzr., lower pzr. level to approximately 200 inches.

4.0 IF A PRESSURIZER STEAM BUBBLE IS ESTABLISHED., THEN GO TO CP-102. OTHERWISE CONTINUE.

5.0 CONTROL RCS SUBCOOLING WITH HPI AND LETDOWN .

5.1 Control HPI Per Specific Rule 2.

5.2 Establish letdown flow.

5.3 Control HPI/MU letdown flow to maintain as close as possible to the adequate subcooling margin curve of Figure 2.

6.0 GO TO CP-102, STEP 3.0.

LOSS OF NNI/ICS POWER

(This section will be provided by GPU)

SPECIFIC RULES

SPECIFIC RULE 1 - INITIATION OF HPI

I. HPI START RULE FOR LOSS OF SUBCOOLING MARGIN

1.0 If the RC subcooling margin is exceeded then two HPI pumps must be run at full HPI system capacity and the HPI flow balanced.

SPECIFIC RULE 2 - HPI FLOW CONTROL

I. GUIDELINES FOR TERMINATING HPI

1.0 HPI operation may be terminated if the LPI system has been started and has been flowing at a rate in excess of 1000 gpm in each injection line for 20 minutes.

2.0 HPI may be terminated any time the RC subcooling margin is restored AND pressurizer level is above 100 inches and HPI flow rate within MU capacity. Normal makeup should be started.

Exception - If core cooling is provided by HPI cooling.

II. GUIDELINES FOR THROTTLING HPI

1.0 The flowrate of each HPI pump should not be throttled below 40 gpm.

2.0 HPI should be throttled to prevent exceeding the reactor vessel pressure temperature limit of Figure 2 during once through cooling or HPI cooling.

3.0 HPI pump flow should be throttled to prevent the pump flow from exceeding 550 gpm.

4.0 HPI can be throttled anytime the reactor subcooling margin is restored.

SPECIFIC RULE 3 - FEEDWATER THROTTLING METHODS

I. EFW THROTTLING RULES

1.0 If natural circulation has stopped and the SG level is below setpoint, THEN ensure full EFW flow. Do not throttle EFW until natural or forced circulation is verified.

2.0 IF EFW actuation was delayed, THEN ensure full EFW flow. Do not throttle EFW until natural or forced circulation is verified or SG level setpoint reached.

3.0 IF EFW is injecting into only one OTSG, THEN ensure full EFW flow. Do not throttle EFW until natural or forced circulation is verified or SG level setpoint reached.

4.0 Maintain continuous EFW flow until the appropriate level setpoint is reached. Do not allow the OTSG level to decrease if level is still below the appropriate level.

Exception - If excessive primary to secondary heat transfer exists THEN stop EFW flow to the steam generator(s) being over cooled.

II. EFW THROTTLING GUIDELINES

1.0 IF RC temperature is to be stabilized, THEN throttle EFW to maintain OTSG pressure within less than 100 psi below the turbine header pressure setpoint.

2.0 IF a cooldown is required, THEN throttle EFW as necessary to limit the cooldown rate to less than the maximum allowed 100 F/hr.

SPECIFIC RULE 4 - SG LEVEL SETPOINT

I. OTSG LEVEL RULE FOR LOSS OF SUBCOOLING MARGIN

1.0 IF the subcooling margin is lost, THEN levels in the operating OTSGs, must be raised to 95% on the operating range.

Exception - IF the loss of subcooling margin was due to a loss of secondary steam pressure control, THEN do not attempt to raise level in the affected steam generator(s) until steam pressure is regained.

II. GUIDELINES FOR OTSG LEVEL CONTROL

1.0 IF RCPs are running THEN maintain the low level limit of 30" inches on the startup range.

2.0 IF no RCPs are running, THEN maintain 50% on the operate range.

SAD SECTION

System	SAD Dwg. No.
PZR Heaters & PZR Spray	EDS-0116-011-115
Chemical Addition	EDS-0116-011-106
HPI	EDS-0116-011-013
LPI	EDS-0116-011-107
Turbine Bypass	EDS-0116-011-114
Emergency Feedwater	EDS-0116-011-105
Reactor Building Spray	EDS-0116-011-104
Reactor Building Emergency Cooling	EDS-0116-011-111
Reactor Building Isolation	EDS-0116-011-112

SECTION ICC

FOLLOWUP ACTIONS FOR INADEQUATE CORE COOLING

1.0 INITIATE HPI & LPI.

1.1 See Specific Rule 1.

1.2 IF LPI is delivery flow, THEN increase LPI flow to maximum.

2.0 INCREASE SG LEVELS TO 90-95% ON OPERATE RANGE.

3.0 LOWER SG PRESSURE TO INDUCE HEAT TRANSFER.

3.1 Depressurize SG(s) while maintaining level(s) to achieve a 100 F/hr decrease in secondary saturation temperature.

4.0 ENSURE CORE FLOOD TANK ISOLATION VALVES (CF-T-1A and CF-T-2A) ARE OPEN.

5.0 IF RC PRESSURE GOES TO 2300 PSIG, THEN OPEN PORV AND RECLOSE PORV WHEN RC PRESSURE FALLS TO 100 PSIG ABOVE SG PRESSURE.

6.0 TAKE ACTION BASED ON FIGURE 3.

6.1 Average the five highest reading incore T/C temperatures.

6.2 Determine which region of Figure 3 that the RCS is in based on Step 6.1.

6.3 Using the region determined in Step 6.2, take action according to the following table:

REGION	ACTION
Saturated	Go to CP-103
1	Continue Step 1.0 - 6.0 above
2	Go to Step 7.0
3	Go to Step 12.0

INCORE THERMOCOUPLE TEMPERATURE IS IN REGION 2

7.0 START ONE RCP PER LOOP IF POSSIBLE.

7.1 Do not override normal RCP interlocks.

8.0 LOWER SG PRESSURE TO INDUCE HEAT TRANSFER.

8.1 Depressurize operating steam generator(s) as rapidly as possible to 400 psig or further if necessary to achieve a 100F decrease in secondary T-sat but not below steam pressure necessary to power the steam driven EFW pump unless one of the following is available:

a. Steam from aux. boiler.

b. Both motor driven EFWP.

c. Steam from another unit.

8.2 Continue depressurizing SG(s) to maintain 100 F/hr decrease in SG saturation temperature to achieve a 150 psig RCS pressure.

9.0 OPEN ALL HIGH POINT VENT VALVES.

10.0 IF PRIMARY TO SECONDARY HEAT TRANSFER IS NOT ESTABLISHED, THEN OPEN PORV (RC-RV-2) AND PORV BLOCK VALVE (RC-V-2) AND GO TO CP-104.

10.1 Allow RCS to depressurize until HPI/LPI/CFTs return incore thermocouple temperatures to saturation.

10.2 Go to CP-104.

11.0 IF PRIMARY TO SECONDARY HEAT TRANSFER IS ESTABLISHED, THEN GO TO CP-103.

11.1 Maintain the primary to secondary heat transfer by cycling the PORV to keep RCS pressure 25-50 PSI greater than SG pressure.

11.2 Go to CP-103

INCORE THERMOCOUPLE TEMPERATURE IS IN REGION 3

12.0 START ALL RCPs.

12.1 Starting interlocks should be defeated if necessary.

12.2 Do not defeat the overload trip circuit.

13.0 LOWER SG PRESSURE TO INDUCE HEAT TRANSFER.

13.1 Depressurize the operative SG(s) as quickly as possible. Do not go below the minimum steam pressure necessary to power the steam driven EFW pump unless one of the following is available:

a. Steam from aux. boiler.

b. Both motor driven EFWP.

c. Steam from another unit.

14.0 DEPRESSURIZE THE RCS.

14.1 Open the PORV (RC-RV-2) and PORV block valve (RC-V-2) and leave open.

14.2 Depressurize the RCS until LPI restores adequate core cooling.

14.3 Open high point vents.

15.0 WHEN INCORE THERMOCOUPLE TEMPERATURE RETURNS TO THE SATURATION TEMPERATURE FOR THE EXISTING RCS PRESSURE, THEN CONTINUE WITH STEP 16.0.

COOLDOWN FOLLOWING ICC (INCORE TEMPERATURES HAVE BEEN IN REGION 4, NOW SATURATED)

16.0 IF RC PRESSURE < 150 PSIG THEN CLOSE PORV AND HIGH POINT VENTS AND REOPEN THEM IF RC PRESSURE INCREASES ABOVE 150 PSIG.

17.0 DECREASE RUNNING RCPs TO ONE PER LOOP.

18.0 MAINTAIN EFW FLOW. AND SG PRESSURE AS LOW AS POSSIBLE.

18.1 If using turbine driven EFWP, do not reduce SG pressure below the minimum steam pressure necessary to power the steam driven EFW pump until one of the following is available:

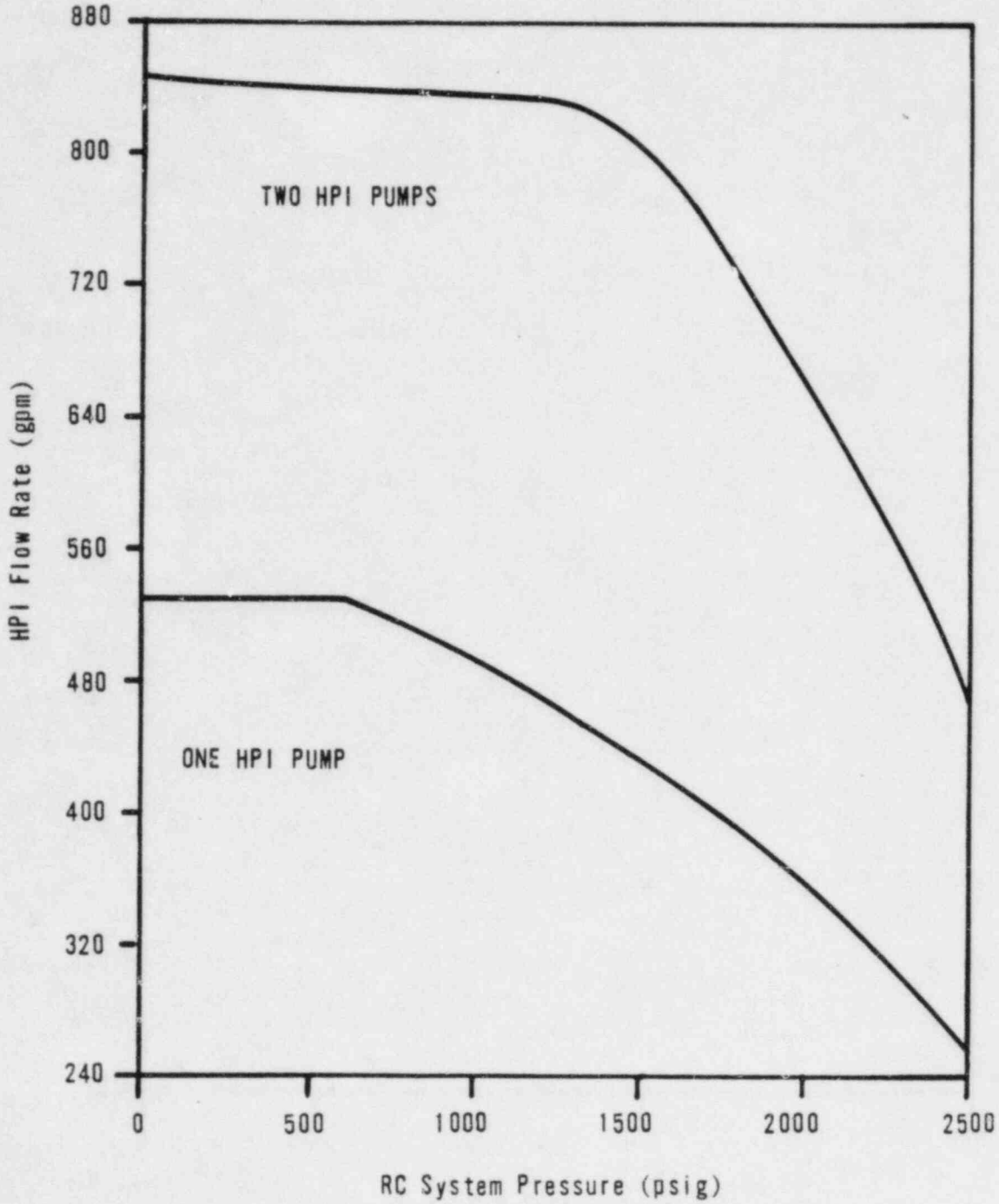
a. Steam from aux. boiler.

b. Both motor driven EFWPs.

c. Steam from another unit.

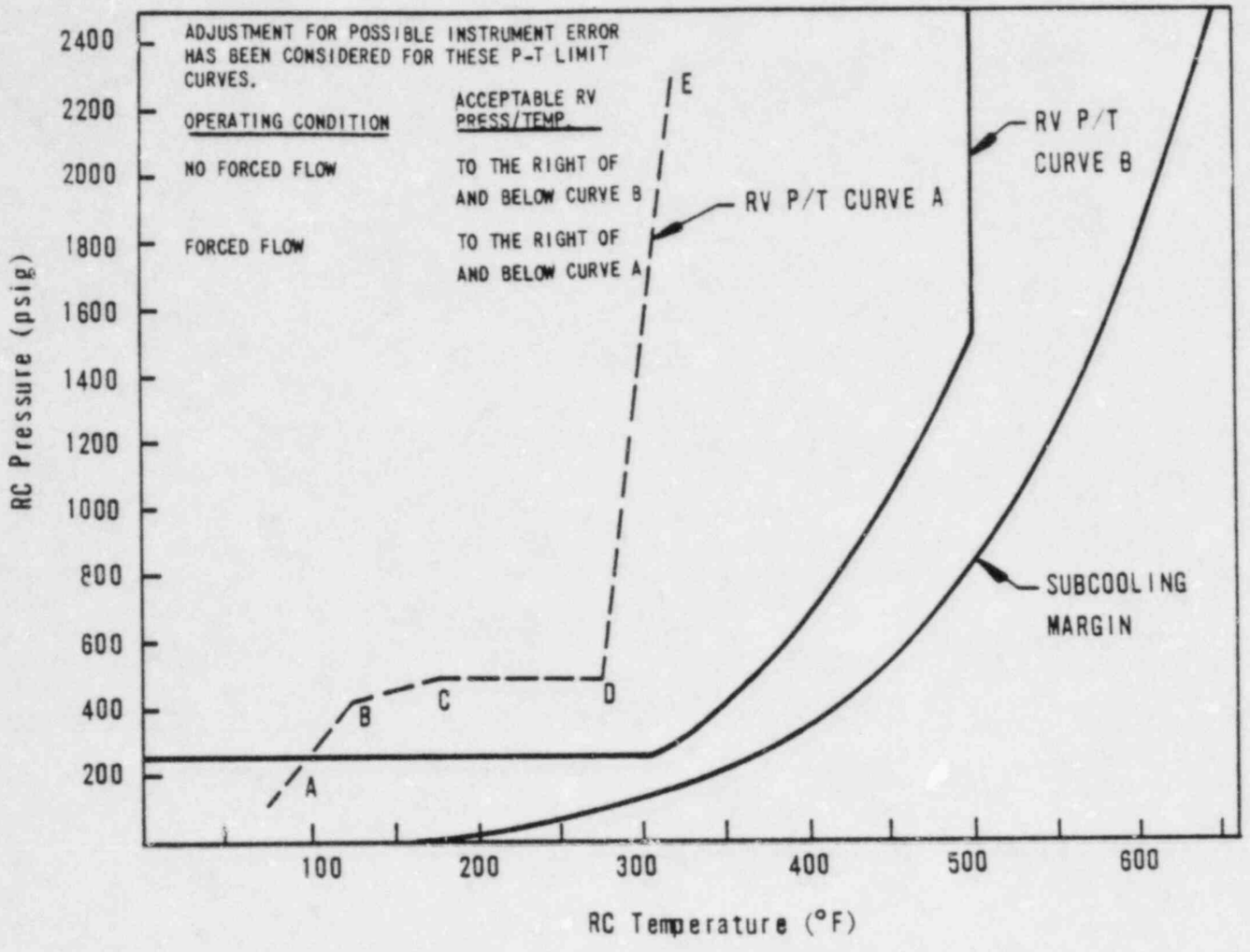
19.0 GO TO CP-103 STEP 4.0.

Figure 1 HPI FLOW VS. RC PRESSURE



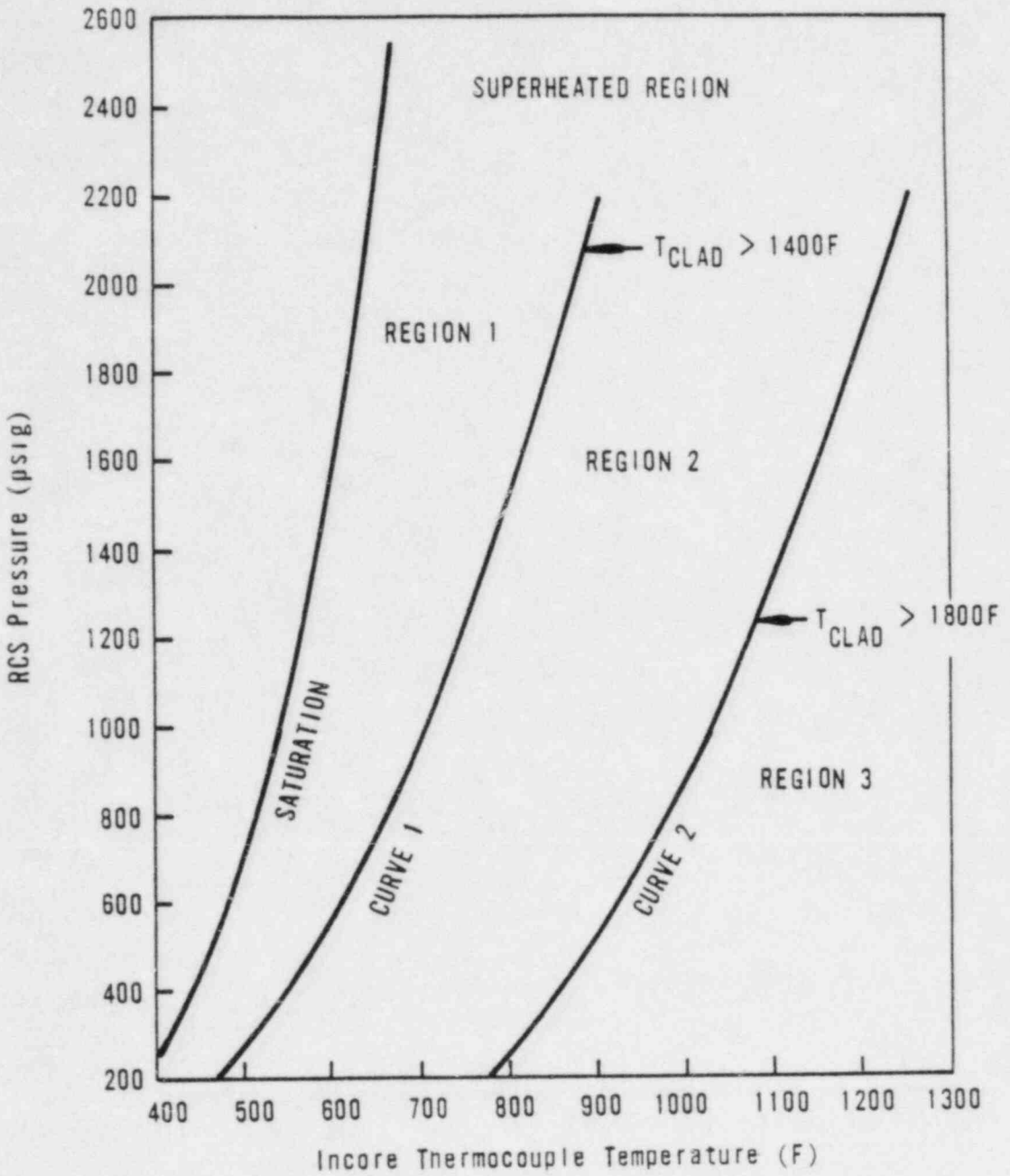
74-1124158-00

Figure 2 RC PRESSURE/TEMPERATURE LIMITS



74-1124158-00

Figure 3 CORE EXIT FLUID TEMPERATURE FOR INADEQUATE CORE COOLING



74-1124158-00

BABCOCK & WILCOX
NUCLEAR POWER GENERATION DIVISION

TECHNICAL DOCUMENT

THREE MILE ISLAND

UNIT I

ABNORMAL TRANSIENT OPERATING GUIDELINES

PART II

VOLUME 1

74-1124158-00

Doc. ID – Serial No., Revision No.

for

GENERAL PUBLIC UTILITIES

By

BABCOCK & WILCOX

THIS DOCUMENT WAS PREPARED FOR GENERAL PUBLIC UTILITIES UNDER MASTER SERVICE CONTRACT NO. 582-7105 (B&W No. 582-7108). ANY USE OF THE INFORMATION CONTAINED HEREIN OTHER THAN UNDER THE EXPRESS CONDITIONS OF SAID CONTRACT IS EXPRESSLY PROHIBITED WITHOUT THE WRITTEN PRERMISSION OF THE BABCOCK & WILCOX COMPANY.

BABCOCK & WILCOX
NUCLEAR POWER GENERATION DIVISION
TECHNICAL DOCUMENT

NUMBER
74-1124158-00

ATOG GUIDELINES
PART II VOLUME I

TITLE	TAB NAME
Introduction	
Chapter A - Basic Heat Transfer	HEAT TRANSFER
Addendum A - Subcooled, Saturated, Superheated Water	A-SUBCOOLING
Addendum B - Natural Circulation	B-NATURAL CIRCULATION
Chapter B - Use of P-T Diagram	P-T DIAGRAM
Chapter C - Abnormal Transient Diagnosis & Mitigation	DIAGNOSIS AND MITIGATION
Chapter D - Backup Cooling Methods	BACKUP COOLING
Chapter E - Best Methods for Equipment Operation	EQUIPMENT OPERATION
Chapter F - Post Transient Stability Determination	STABILITY
Chapter G - Fundamentals of Reactor Building (Containment) Control	RB Control
Chapter H - Use of the Guidelines	USE OF ATOG

VOLUME I FUNDAMENTALS OF REACTOR CONTROL FOR ABNORMAL TRANSIENTS

List of Figures

Figure 1	Fundamental Methods of Heat Transfer Control
Figure 2	Illustration of Parameters Contributing to Natural Circulation Driving Head
Figure 3	Transition to Natural Circulation
Figure 4	DELETED
Figure 5	DELETED
Figure 6	DELETED
Figure 7	DELETED
Figure 8	Forced Circulation Post-Trip Diagram
Figure 9	Natural Circulation Post-Trip Diagram
Figure 10	Typical Response of Major Plant Parameters Following a Reactor Trip
Figure 11	Overcooling Trends (Symmetric)
Figure 12	Overheating Trends
Figure 13	Loss of Subcooled Margin
Figure 14	Asymmetric Overcooling Trends
Figure 15	Loss of Main Feedwater
Figure 16	Small Steam Leak
Figure 17	Excessive Feedwater
Figure 18	Small LOCA in Pressurizer Steam Space
Figure 19	Small LOCA in RCS Water Space
Figure 20	General Plant Transient Mitigation
Figure 21	Transient Mitigation Approach
Figure 22	Overcooling Diagnosis Chart
Figure 23	Overheating Diagnosis Chart
Figure 24a	Loss of All Feedwater (No Operator Action)
Figure 24b	Backup Cooling by HPI for Loss of All Feedwater
Figure 25	RC Pressure/Temperature Limits
Figure 26	Illustration of Loss of Natural Circulation Due to Buildup of Steam in the Reactor Coolant System
Figure 27	Boiler Condenser Cooling
Figure 28	Loss of Natural Circulation - System Refill by HPI
Figure 29	Core Exit Fluid Temperature for Inadequate Core Cooling
Figure 30	HPI Control Logic
Figure 31a	Cooldown on One Steam Generator (Steam Pressure Controlled)
Figure 31b	Cooldown on One Steam Generator (Steam Pressure Not Controlled)
Figure 32	General Approach for Control of the Reactor Building
Figure 33	Reactor Building Trend Temperature Vs Pressure for LOCA
Figure 34	Envelope of Peak Reactor Building Pressure Vs Rupture Sizes With 3 Air Coolers Operating
Figure 35	Reactor Building Pressure Vs Time for the DBA 8.5 ft^2 Rupture With 3 Reactor Building Air Coolers
Figure 36	Hydrogen Generation From Zr-H_2O Reaction
Figure 37	Processes Affecting Site Dose and Containment Hydrogen Concentration

VOLUME I FUNDAMENTALS OF REACTOR CONTROL FOR ABNORMAL TRANSIENTS

List of Figures (Cont'd)

Figure 38	RB Hydrogen Accumulation vs Time Following the Design Basis LOCA (Without Recombiners)
Figure 39	Flammability Limits of Hydrogen-Air-Steam Mixtures
Figure 40	Reactor Building Trend Temperature vs Pressure for RB Hydrogen Burn
Figure 41	TMI-2 Loss of Coolant Accident 3/28/79 Reactor Building Temperature and Pressure
Figure 42	Estimate of Total Hydrogen Volume in RCS of TMI-2
Figure 43	TMI-2 Dome Monitor Readings
Fiugre 44	Reactor Building Radiation Monitor Response Following the CR-3 Loss of Non-Nuclear Instrumentation With HPI Cooling Event, 2-26-80
Fiugre 45	Reactor Building Trend Temperature vs Pressure Steam Line Break

BABCOCK & WILCOX
NUCLEAR POWER GENERATION DIVISION
TECHNICAL DOCUMENT

NUMBER
74-1124158-00

VOLUME I FUNDAMENTALS OF REACTOR CONTROL FOR ABNORMAL TRANSIENTS

List of Tables

Table 1	DELETED
Table 2	Standard Post Trip Actions
Table 3	Actions to Correct Fast Transients
Table 4a	How to Differentiate a LOCA From Other Transients
Table 4b	Symptoms for LOCA's That Can be Located or Isolated
Table 5	Deleted
Table 6	RC Pump Restart Guidelines
Table 7	Summary of Reactor Building Isolation Control Actions
Table 8	Summary of Reactor Building Internal Environment Control Actions

ATOG GUIDELINES PART II

INTRODUCTION

The 3-28-79 accident at the Three Mile Island Nuclear Power Generating Plant has caused the Nuclear Industry's perspective of emergency operation to change. That accident was difficult for the plant operators to handle because several things were happening at once. Loss Of Main Feedwater, Loss of Emergency Feedwater, and Small Break LOCA occurred at the same time. An incorrect interpretation of pressurizer level misled the operators to think the core was covered when it was not. The operators acted on that misleading information and core cooling was stopped when they shut down Emergency High Pressure Injection and the Reactor Coolant Pumps. The combination of multiple failures and incorrect interpretation of information are the two factors which have caused a new perspective of emergency operation to be developed.

In the past, emergency procedures and operator training concentrated on single event accidents. But accidents do not usually happen with only single failures; several things often go wrong at the same time. These guidelines have been developed so the operator can understand what has gone wrong in order to circumvent failures and keep the core cool with the available equipment.

When failures of equipment occur, they frequently cause a change in the heat transfer from the core to the steam generators. When the reactor is operating normally all the heat produced by the core is being removed by the steam generators; primary and secondary system pressures, temperatures, and levels are stable. Heat transfer is balanced. Any transient will cause an upset in the heat transfer from the core to the steam generators. Heat transfer will be affectd in different ways depending on what equipment has operated incorrectly. When the heat transfer changes, the effects will show up in primary and secondary system pressures, temperatures, and levels. Pressures and temperatures are parameters from which three basic symptoms of improper heat transfer can be derived and used to discover what has gone wrong. These guidelines will use those heat transfer symptoms as the source of information for the operator action. Recognition of just three basic heat transfer symptoms will give the knowledge needed so the operator can restore and maintain adequate core cooling. These symptoms are:

1. loss of adequate subcooling margin
2. lack of primary to secondary heat transfer
3. excessive primary to secondary heat transfer.

Part II of the guidelines has two major sections. The first section is entitled "Fundamentals of Reactor Control for Abnormal Transients". This section gives general information about the way heat transfer changes can be used to identify failures. Methods to correct those failures are also given. The second section, "Discussion of Selected Transients", is

divided into several subsections and each subsection covers one specific type of transient. For example, one of the transients to be covered is loss of feedwater. Each one of these specific transients is combined with other equipment failures, and ways of making corrections for multiple failures are given.

Part II, Volume 1

The "Fundamentals of Reactor Control for Abnormal Transient" volume begins with Chapter A on core-to-steam generator heat transfer. Core cooling using the steam generator is the best way to control transients, although other ways can be used. This chapter shows that four principle parameters can be used to control heat transfer. Those parameters are steam generator pressure, steam generator inventory, reactor coolant inventory, and reactor coolant pressure. This chapter also has attachments that discuss: a) Subcooling, Saturation, and Superheating of water and steam, and b) Natural Circulation. This chapter contains important background information about heat transfer; following chapters will use this background to show how abnormal transients can be corrected using a knowledge of basic heat transfer.

Chapter B discusses the use of reactor coolant system pressure-temperature diagrams (P-T). The P-T diagram is used to quickly identify trends when an abnormal transient happens. With this diagram an abnormal transient can be classed as overcooling, overheating, or loss of subcooling. The ability to determine which of these is taking place will narrow down the

possible things that could have failed. Once a choice has been made then a further review of a few other heat transfer parameters will permit a closer focus on the right corrective actions. This approach, using the P-T diagram and a few selected parameters, will help to focus on the corrective actions quicker without the need to review a large number of alarms and indications to determine the individual piece of equipment that has failed.

Chapter C deals with the methods to be used for transient correction. This chapter contains a part called "Immediate Actions" which identifies several actions to take immediately after the transient signal has alarmed regardless of the kind of transient that has occurred. The immediate actions are needed to keep the heat transfer as balanced as possible and to identify the two transients that can rapidly become serious: steam generator tube failures and excessive main feedwater. Of all the transients that can occur these two need fast operator actions. A third transient requiring immediate operator action would be a steam line break inside the intermediate building. However, this event must be handled by a specific site procedure and therefore is not specifically addressed by ATOG.

Transient correction methods are oriented toward restoring the proper balance of heat transfer between the core and the steam generator. The correction methods given in this section show ways of controlling and restoring heat transfer when overcooling, overheating, or loss of subcooling has happened.

Although restoring the balance of heat transfer between the reactor coolant system and the steam generator is the preferred way of controlling transients, it may not always be possible. Chapter D, called "Backup Cooling Methods," shows how to cool the core when the steam generator is not available.

During the course of correcting the plant heat balance, some systems are operated in different ways depending on what has happened. Chapter E on "Best Methods for Equipment Operation" shows the best ways to operate some very important equipment. Special attention is given to RC pumps, HPI, and feedwater control.

Chapter F on "Post Transient Stability Determination" gives some important things to check to see if the plant has stabilized. After stabilization, equipment should be checked or repaired and the plant may be cooled down or kept at hot shutdown as appropriate.

Chapter G discusses the fundamentals of the reactor building control. Chapter H discusses how to use these guidelines.

Part II, Volume 2

The second volume of Part II of the guidelines, entitled "Discussion of Selected Transients," discusses specific individual transients. Along with each transient, additional equipment failures are superimposed. The

effects of these failures are shown and ways to correct the failures are given.

The entire purpose of these guidelines is to give an overview on reactor transients, their diagnosis and control, so future transients will not be as severe as the Three Mile Island accident. Because transients may not follow a planned course, these guidelines provide enough background and understanding so that no matter what happens, the operator will have sufficient understanding to correctly respond to the transient using the principles of heat transfer control.

HEAT TRANSFER

CHAPTER A

BASIC HEAT TRANSFER

Introduction and Summary

This chapter of the guidelines gives the basic principles of heat transfer that are important for removing heat from the core so that it can be properly cooled. The chapter is divided into three parts: 1) "Basic Heat Transfer", 2) Addendum A - "Subcooled, Saturated, Superheated Water", and 3) Addendum B - "Natural Circulation". Addendum A and Addendum B give information on two general subjects. The part on "Basic Heat Transfer" covers two related topics: 1) the general process for heat removal through the steam generators, and 2) the ways the operator can control that heat transfer.

The preferred way to protect the core and prevent fuel failure is to control the rate of heat removal by transferring core heat to the steam generators with subcooled reactor coolant. Other ways to protect the core do exist; they are covered in Chapter D, entitled "Backup Cooling Methods".

To control core heat removal with the steam generator, the operator should balance the heat generated by the core with the heat removal through the steam generators. This chapter discusses the fundamentals of heat transfer control and how the operator applies these fundamentals to get balanced heat removal.

Heat Transfer Equations

The path for heat flow from the core to the steam generator is:

Core heat ⟶ reactor coolant ⟶ steam generator water and steam

The steam generator then releases the heat either to the atmosphere or to the condenser.

The concepts of heat sinks and heat sources are useful. For the first part of the heat transfer path, the core is the heat source and the reactor coolant is the heat sink. When the plant is tripped, the reactor coolant pump heat becomes a significant heat source. For the second part of the heat transfer path, the reactor coolant is the heat source and the steam generator water and steam is the heat sink. The atmosphere and the condenser are heat sinks for the steam from the steam generator. In some unusual cases the reactor coolant can be colder than the steam generator fluid; then the steam generator is a heat source which passes heat to the reactor coolant sink.

Two "kinds" of heat can be transferred to the steam generators:

1. Generated Heat - which includes RC pump work and nuclear heat which is the heat made within the core by the fission process; it includes decay heat
2. Stored Heat - which is the heat of the metal parts of the reactor coolant system and of the reactor coolant fluid.

When the reactor is operating at steady state and heat removal is balanced, the steam generators will remove the nuclear heat and RC pump heat as it is generated and reactor coolant temperatures will not change. In other words the stored heat will stay the same.

If the steam generators remove more heat than the core (including RC pumps) is creating, then they will remove both generated heat and stored heat; reactor coolant temperatures will drop. Normal cooldown is a condition when both generated heat and stored heat are being removed within a specified rate; this is a controlled condition. If too much heat is being removed then it would be called overcooling and corrective actions would have to be taken to bring it under control.

On the other hand, if the steam generators remove less heat than the core and RC pumps are creating, then the generated heat will increase the amount of reactor coolant stored heat; reactor coolant temperatures will increase. Heatup from 0% to 15% power illustrates a controlled example where the stored heat of the reactor coolant is increased by heat addition

from the core nuclear heat and the reactor coolant pumps. If a condition exists where the reactor coolant temperature increases abnormally it is called overheating; corrective actions would have to be taken to bring overheating under control.

Equations can be used to describe the heat transfer path from the core to the steam generators. When the heat transfer is balanced:

Equation 1) $\dot{Q}_{core} = \dot{Q}$ reactor coolant

for the heat transfer path from the core to the reactor coolant

and

Equation 2) $\dot{Q}_{reactor\ coolant} = \dot{Q}$ steam generator fluid

for the heat transfer path from the reactor coolant to the steam and water in the secondary side of the steam generators

$\dot{Q}$ is heat rate - units are BTU/hr.

When heat transfer is balanced all the way from the core to the steam generator, then Equation 1 equals Equation 2. But when heat transfer becomes unbalanced then they will not be equal. Interruptions of the heat transfer path can happen when the reactor coolant is not a good heat sink for the core ($\dot{Q}_{core} \neq \dot{Q}_{reactor\ coolant}$); or when the steam generator fluid is not a good heat sink for the reactor coolant ($\dot{Q}_{reactor\ coolant} \neq \dot{Q}_{steam\ generator\ fluid}$).

The unbalanced condition of concern for core heat transfer to the reactor coolant is when there is not enough heat transfer from the core to the reactor coolant. This can happen only when the reactor coolant is no longer subcooled; for example, when the core is partly covered by water and partly by steam or covered completely by steam; then $\dot{Q}_{core} \neq \dot{Q}_{reactor\ coolant}$. When this happens not enough nuclear heat can be transferred from the core to the reactor coolant and the core will heat up. The stored heat of the fuel clad will increase which will result in increased fuel pin temperatures.

When the steam generator heat flow path becomes unbalanced then the steam generator fluid will remove too much or too little heat from the reactor coolant and cause an overcooling or overheating condition. When this happens during a transient, $\dot{Q}_{reactor\ coolant}$ will increase or decrease depending on the heat removal by the secondary side. The reactor coolant temperatures will change in order that temperature (thermal) equilibrium can be re-established between the primary and secondary side fluids. To show the effects, Equations 1 and 2 can be written to add temperature terms:

Equation 1 ($\dot{Q}_{core} = \dot{Q}_{rc}$) can be written as:

Equation 1a $Q_{core} = \dot{M}_{rc} C_{p_{rc}} (T_h - T_c)$

where: $\dot{M}_{rc}$ = reactor coolant system mass flow rate (lbm/hr)

C_{prc} = specific heat capacity of the reactor coolant (BTU/lbm-F)

T_h = core outlet temeprature (F)

Tc = core inlet temeprature (F)

Equation 2 ($\dot{Q}_{rc} = \dot{Q}_{sg}$) can be expanded as follows:

Equation 2a: $\dot{Q}_{sg} = UA\,\Delta T$

where: U = overall heat transfer coefficient (BTU/hr-ft^2-F)

A = total area of heat transfer surface (ft^2)

ΔT = temperature differential across the heat transfer boundary between the reactor coolant and steam generator fluids (F)

FOOTNOTE

Equations 1a and 2a have been simplified to show the general heat transfer process. To be complete, additional heat transfer terms would have to be included. All of the water that flows through the reactor coolant system loops does not flow through the core and get all the way to the steam generators. Some flow is let down to the makeup system, some goes to the pressurizer spray, and there is some "leakage" through spaces in the internals. This amount of flow is small and it has been ignored for these equations. Also, all the heat of the core does not go to the steam generators; some of it is lost through the piping to the reactor building or through the letdown water. But his amount of heat is small compared to the total amount and it has been neglected. Heat is also added by reactor coolant pumps (as in plant heatup to power operation), but it is small compared to core heat when the reactor is at power (but the reactor coolant pumps are a relatively large heat source after trip or at low power).

Overall heat transfer coefficient is dependent on many factors, including the fluid conditions (primarily density and flowrate) on both sides of the boundary and the properties of the boundary (primarily the thickness and thermal conductivity of the barrier and oxide layers). For this discussion we can assume that the properties of the boundary (steam generator tube walls) remain constant and therefore can be ignored.

The secondary side of the steam generator has three different regions along the tube bundle during power operation: nucleate boiling, film boiling, and superheat. Each region has a different heat transfer coefficient (U), surface area (A), and temperature differential across the tube wall (ΔT). The nucleate boiling region has the highest heat transfer coefficent of the three and accounts for approximately 70-85% of the total heat transfer into the steam generator over the power range. The heat transfer coefficient decreases by a factor of 3 to 10 in the film boiling region and again by another factor of 3 to 10 in the superheat region.

The heat transfer surface areas and ΔT's involved for each of the three regions vary over the power range with the two boiling regions accounting for an increasingly higher percentage of the total heat transfer with increasing power levels. Thus, to determine the effects of transients on secondary heat removal during power operation, the effects in each of the three regions along the tube bundle must be studied.

However, for the purposes of these guidelines, we are primarily concerned with control of heat removal by the steam generators after a reactor trip. After trip the steam generators are essentially at saturation conditions with two basic regions, water and saturated steam (theoretically, some superheat exists after trip but it is negligible). Almost all of the heat transfer occurs in the water region and most of the heat transfer in the water region occurs in the nucleate boiling portion below the steam/water interface. Saturated water is absorbing the latent heat of vaporization and the nucleate boiling provides a much higher heat transfer coefficient (U). Below this level the water is subcooled with a considerably lower heat transfer coefficient, although this heat transfer coefficient is still much higher than exists in the steam space.

Very little heat transfer occurs in the steam space (primary side temperature can be considered equal to T_{hot} throughout the steam space). Even though the area is large, the heat transfer is small due to low steam flow rates and low density with respect to the water region. During forced circulation the ΔT across the tube walls in the steam space is also very small as T_{hot} is close to T_{sat} of the steam. The ΔT is larger between T_{hot} and T_{sat} during natural circulation, but the heat transfer coefficient is even smaller due to the lower primary flowrates.

The major factors affecting heat transfer in the water region are surface area and the ΔT between the primary and secondary sides. Surface area is increased by increasing feedwater flow to raise level. The primary

increase in area takes place in the subcooled water region. Even though most of the heat transfer occurs in the nucleate boiling region, overall heat transfer is increased because the area of the steam space (with a very small heat transfer coefficient) is decreased and replaced by area in the subcooled water region (with a relatively much larger heat transfer coefficient).

The major method of affecting primary to secondary ΔT is on the secondary side by varying steam pressure. When steam pressure is decreased (e.g., by opening turbine bypass valves) saturation temperature also decreases which increases the ΔT across the tube wall. The higher ΔT causes heat transfer ($\dot{Q}_{sg}$) to increase thus cooling the primary side. The ΔT is also affected significantly immediately following reactor trip due to the large drop in main feedwater temperature. However, after the initial drop (to $\sim$ 180F), main feedwater temperature does not change significantly and thus is usually not a major contributor to heat transfer fluctuations.

Of these two factors (surface area and ΔT), ΔT is the major factor. Effects due to surface area are significant only while the surface area is changing. Once a constant water level is maintained, changes in heat transfer are primarily due to changes in ΔT.

Heat transfer can be increased significantly by injecting emergency feedwater through the upper nozzles. The increase in heat transfer is due to two factors. First, the spray of feedwater into the steam space reduces steam pressure similar to the action of pressurizer spray. This reduces

the saturation temperature which increases heat transfer as described previously. Second, where water contacts the tube surfaces in the steam space the heat transfer coefficient is increased, essentially replacing steam area with water area as in the case of raising steam generator level. Emergency feedwater will have a greater cooling effect than main feedwater (for the same flowrate) due to its colder temperature. In addition, the total capacity of the EFW system is more than that required to remove decay heat. Thus, if unthrottled, EFW can cause significant overcooling.

Assuming a minimum adequate level is maintained in the steam generators, variations in steam pressure will have a greater effect on heat transfer than variations in level. The best method to decrease heat transfer is to close the turbine bypass valves and allow the steam generator pressure to increase. Allowing steam generator level to decrease will not have an appreciable effect on heat transfer until the level becomes inadequate (too low for maintaining natural circulation or virtually dry with forced circulation).

In summary, the operator can control primary to secondary heat transfer after reactor trip by controlling two major parameters on the secondary side (assuming the capability of the reactor coolant to transport core heat to the steam generators remains intact). The operator can increase heat transfer by reducing steam pressure or by raising steam generator level. He can decrease heat transfer by allowing the steam generator pressure to increase.

Control of heat transfer requires control of all the parameters in these two equations. Some are fixed by design or properties of fluids; the remainder can be influenced by the operator. The general methods of heat transfer control are discussed next.

Control of Heat Transfer

The preferred way of removing heat from the core is to transfer the heat to the reactor coolant and then transfer the reactor coolant heat to the secondary fluid in the steam generators. Steam generator heat removal is controlled by adjusting steam pressure and feedwater. To keep the core-to-steam generator heat transfer in balance,the heat removal rate from the steam generators must be equal to the heat generation rate of the core. In order to balance the heat removal two very basic conditions must be satisfied: 1) there must be enough liquid reactor coolant in the vessel and piping to transfer the heat to the steam generators, and 2) the steam generator pressure and level (feedwater flow rate) must be balanced at the correct heat removal rate. Figure 1 illustrates these fundamental functions of heat transfer control. Figure 1 also shows the controls that the operator can use to change heat transfer.

The five fundamental functions of heat transfer control are:

- Reactivity control (core heat output control)
- Reactor coolant pressure control
- Reactor coolant inventory control
- Steam generator pressure control
- Steam generator inventory control

When an abnormal transient occurs, one or more of these five functions will be out of control. It is the operator's job to determine which are out of control, and to make corrections to restore the right heat transfer balance so that the core heat can be removed by the steam generators.

1. Reactivity control - Reactivity control is usually taken care of automatically by ICS rod control or by reactor trip. Reactor trip lowers the core heat output to the decay heat level.
2. Reactor Coolant Inventory Control - The link between the core and the steam generator is the reactor coolant. It is the fluid which transports the heat. To do its job best the coolant should be in a liquid state, that is, subcooled. (Discussion of subcooling is given in Addendum A.)
3. Reactor Coolant Pressure Control - The reactor coolant system is pressurized to keep the reactor coolant in a liquid state, i.e., RCS pressure > saturation pressure.

4. Steam Generator Inventory Control - The water-steam inventory in the secondary side of the steam generator is the heat transfer fluid which removes the heat from the reactor coolant. In order for it to remove heat at the correct rate, the amount of fluid and its flow rate through the steam generator must be controlled.

5. Steam Generator Pressure Control - The water temperature of the reactor coolant is best controlled by controlling the pressure of the steam generator. In combination with reactor coolant pressure control, steam generator pressure control will maintain the reactor coolant in a subcooled liquid state.

Each one of these control methods is discussed individually as it relates to heat transfer.

Steam Generator Pressure Control

Heat transfer from the reactor coolant to the steam generators goes to both the steam and water in the generator. After reactor trip, the steam and feedwater in the generator are saturated and changes of steam pressure will cause a direct change in the saturation temperatures of the steam and water. A review of the saturated water and steam properties will show how much the steam and water temperature will change by increasing and decreasing steam pressure. There are situations where the operator controls the steam pressure manually using the turbine bypass valves or the

atmospheric dump valves. When the steam pressure is lowered, the heat transfer from the reactor coolant to the steam generator increases because the steam and water in the steam generator become a colder heat sink causing more heat to flow away from the reactor coolant. Two reasons combine to create the colder heat sink: first, the saturation temperature of the steam and water is reduced by lowering the steam pressure, which causes the rate of boiloff to increase. The increased boiloff takes away more heat. Second, the increased boiloff requires more feedwater flow to be added to maintain level. The feedwater inlet temperature is colder than the water already in the steam generator, thus its addition contributes to the colder sink. Because a colder secondary sink exists, the primary side temperature will drop as heat is transferred.

Steam pressure can be lowered in two ways:

- By opening the steam line and releasing steam (turbine bypass, steam line break, atmospheric dump valves, steam to EFW pump turbine).
- By adding more EFW than is required to remove decay heat.

Steam pressure can also increase; but normally it will only increase from the operating condition to the reactor trip condition where it will be limited by the steam safeties or by the turbine bypass valves, so the effect on reactor coolant temperature is small. But if steam pressure

initially low because of a failure, for example a steam line break, the subsequent increase in reactor coolant temperature could be much larger when the steam break is isolated. After isolation, the reactor coolant adds heat to the generator and causes the steam pressure to increase. Without operator action, the steam pressure would increase to the TBV or MSSV setpoint. The operator can limit the increase in reactor coolant temperature under these conditions by lowering the turbine bypass valve setpoint and keeping steam pressure low.

Steam Generator Inventory Control

Heat transfer from the reactor coolant goes to both the steam and the feedwater in the secondary side of the steam generators. When changes of feedwater flow or steam pressure occur, the volumes occupied by the steam or water will change and the heat transfer will change. For example, when the volume of water increases, it occupies space formerly occupied by steam, so the volume of steam has to decrease. This changes the relative amounts of OTSG tube surface area covered by water and steam. Water has a greater heat capacity than steam does, thus it is a better heat sink for the reactor coolant than steam is. Simply stated there are more pounds of water in a cubic foot to absorb heat than there are of steam. If the water inventory increases, then the generator will become a better heat sink for the reactor coolant; but if the water inventory decreases or is lost, the generator will lose some or all of its ability to absorb heat from the reactor coolant.

For example, after trip when the core heat generation is nearly constant, if the water level in the steam generator is raised rapidly without changing steam pressure, the reactor coolant temperature will drop and stay low until the water inventory reaches a new level and that level is held (i.e., feedwater flowrate is then reduced). Once the new level is fixed, the reactor coolant will reheat and temperatures will return to their former values.

This cooling effect of feedwater is caused by the inlet feedwater temperature, which is colder than the general temperature of the bulk of the fluid in the steam generator. The inlet feedwater temperature allows a colder heat sink to be established in the steam generator.

The steam generator level can, however, be increased slowly after trip without a large drop of reactor coolant temperature by controlling the rate of addition of feedwater.

Too much inventory can also be the result of overfeeding with the Emergency Feedwater System. Even though its flow rate is lower, Emergency Feedwater will have a proportionally larger cooling effect on reactor coolant than main feedwater because:

a) it comes on when the reactor is tripped and core heat is lowest,

b) it is colder ($T_{inlet\ feedwater}$ is less), and

c) it has a steam pressure reduction effect that main feedwater does not normally have

On the other hand, if steam generator inventory is too low (insufficient feedwater or loss of feedwater can lower the water level), the reduced heat sink will not allow the reactor coolant to transfer all of its heat to the steam generator. When the steam generator's heat sink is reduced, the reactor coolant must retain more of the core heat and it will heat up.

For example, if all feedwater is lost, the water in the generator will boil away and only steam will remain to remove heat. But because the steam does not have enough heat capacity, the reactor coolant must retain the core heat and the reactor coolant temperatures will increase. When all feedwater is lost, the reactor coolant pressure will increase to the PORV setpoint and the reactor coolant will eventually become saturated as the core continues to add heat. The steam remaining in the generator will flow out through the steam lines and steam pressure will drop; loss of the steam eliminates the heat sink of the steam generators altogether.

Finally, another part of steam generator inventory control is feedwater temperature. The heat sink of the generators will be affected by an abnormally low feedwater temperature. A reduction of feedwater heating

steam or loss of a feedwater heater will cause reactor coolant temperature to decrease. Usually ICS operation will stabilize the plant, but the decreased feed temperature will cause a change in the heat sink and an increase of heat transfer from the reactor coolant.

The operator should ensure the rate of feedwater addition is controlled properly to maintain the steam generator inventory. Level measurements in the steam generator downcomer give a good indication of the steam generator inventory for control.

Reactor Coolant Inventory Control

Reactor coolant heat transfer can be affected by changes in the mass of fluid in the reactor coolant system or by changes in the density of the reactor coolant.

Several ways exist to vary the mass of reactor coolant: LOCA or small break, and changes in HPI or makeup, RC pump seal injection, seal return, and letdown. Several ways also exist to vary the density of the reactor coolant. As shown by the previous discussions of steam generator pressure and inventory control, changes of the rate of heat transfer from the reactor coolant to the steam generator can cause the reactor coolant to cool down when the steam generators remove too much heat (low steam pressure, too much feedwater); or the reactor coolant can heat up when the steam generators don't remove enough heat (not enough feedwater). These effects cause density changes in the reactor coolant; the coolant contracts or expands accordingly.

Regardless of the cause, changes in inventory in the reactor coolant system have two effects:

1. A loss of mass can affect the ability of the reactor coolant to transport heat from the core to the steam generators. If the RC pumps are not running, steam can collect in the hot legs and block natural circulation. When natural circulation and heat transport stop, then the steam generator temperature will not "set" the temperature of the reactor coolant; T_{cold} will not change when T_{sat-SG} changes.

   If the mass of the reactor coolant system continues to decrease and the core is mostly covered by steam, the mass of the RC will not provide a sufficient heat sink and the core will retain the heat and heatup. Fuel failures can result.

2. A change of mass or density can affect the ability of the pressurizer to provide pressure control of the reactor coolant system (this will be discussed next under Reactor Coolant Pressure Control).

Operator control of reactor coolant inventory requires the ability to balance mass increases or decreases by adding water with makeup or ECCS or removing mass with the letdown. Control of reactor coolant density changes requires control of the steam generator pressure and inventory.

The operator has two indications to determine if the inventory is sufficient for core cooling. Pressurizer level is an accurate measure of the inventory when the reactor coolant is subcooled (except for a rare possibility when free hydrogen gas may exist in the loops; this condition will likely exist only after fuel failures caused by uncovering of the core). The other measure is the incore thermocouples; if these read subcooled or saturation temperature, then enough mass exists in the reactor vessel to cover and cool the core. But the incore thermocouples will not show if the loops are full.

Reactor Coolant Pressure Control

Reactor coolant pressure control is required to keep the reactor coolant subcooled so that the coolant is in the best state to transfer the heat from the core to the steam generators. For most subcooled reactor operations RCS pressure control is provided by the pressurizer. (Reactor coolant pressure control is different for LOCA's and small breaks than for other plant conditions. It is discussed in detail in Appendix F.) Use of pressurizer heaters and spray is the usual way of increasing and decreasing RCS pressure when a steam and water interface exists in the pressurizer. The purpose of the heaters is to maintain the reactor coolant in a subcooled condition by maintaining RCS pressure > saturation pressure; the spray retards pressure increases to limit operation of the pressurizer relief and safety valves. Neither the heaters nor spray have enough capacity to prevent large abrupt pressure changes, but they can moderate small changes. As a backup, the pressurizer vent and/or PORV

can be used to reduce pressure, but this method is not as desirable to use as the spray because it results in releases to the RC drain tank. Frequent use of the pressurizer vent or PORV can result in failure of the drain tank rupture disk.

RCS pressure control by the pressurizer can be lost in two ways:

1. The steam-water interface in the pressurizer can be lost either by draining the pressurizer or if the pressurizer fills solid with water
2. The heaters and spray can fail.

Each of these is discussed below.

Draining the Pressurizer:

If the pressurizer water level drops sufficiently to uncover the heaters, the heaters cannot provide pressure control because no water is available to be boiled by the heaters to create steam.

If the pressurizer drains completely, RCS pressure will then be controlled by the highest fluid temperature in the system. When the pressurizer drains, the reactor coolant system pressure will decrease to the saturation pressure of the reactor coolant in the hot leg. Pressure control will then be controlled indirectly by the steam generator (the steam generator sets the reactor coolant loop hot and cold leg temperatures). Since the hot leg is at the highest temperature the reactor coolant in the hot leg will flash to steam. In effect the hot leg will become a pressurizer.

Filling the Pressurizer:

Spray depressurizes the reactor coolant system by condensing the steam in the pressurizer. If the pressurizer fills with water, the spray cannot be effective for depressurizing, because the steam space is lost.

When the pressurizer fills, the reactor coolant system may or may not lose subcooling and become saturated depending on what caused it to fill. If the filling was caused by HPI or makeup and the steam generator is still removing heat, then the RCS will stay subcooled because the makeup (HPI) pumps will cause the pressure to stay high and the steam generator will keep the temperature controlled. If the filling was caused by heatup and swell because the steam generators were not removing enough heat then the system may become saturated because the heat from the core will go only into the reactor coolant and not out the steam generators.

When the pressurizer fills, either because of heating the reactor coolant or because of too much HPI, water will be lost through the PORV and pressurizer safety valves. This loss is considered to be a LOCA, even if the action was deliberately done.

The operator should not confuse these losses of RCS pressure control with the normal pressure responses during plant transients. Any transient which rapidly decreases pressurizer level will cause a drop in RCS pressure. The rapid decrease in level (except for a LOCA) is caused by a temperature decrease in the RCS. The drop in RCS pressure is caused by the

outsurge from the pressurizer which results in expansion of the pressurizer steam space. Additional coolant will flash to steam in the pressurizer as the steam volume expands, which will reduce the rate of pressure decrease. This flashing of steam, however, has a cooling effect on the remaining coolant in the pressurizer since the latent heat of vaporization is required to convert saturated water to steam. These transients are those rapid enough so that the pressurizer heaters can not keep up with this cooling effect.

Any transient which rapidly increases pressurizer level will cause a concurrent rise in RCS pressure initially. This rise in RCS pressure is usually followed by a decrease in RCS pressure unless the pressurizer heaters can maintain pressure. The rapid increase in level is usually caused by a temperature increase in the RCS. The initial rise in RCS pressure is caused by the compression of the steam volume in the pressurizer, since the insurge acts like a piston. Three things happen to reduce this initial pressure increase: the spray effects start to show up, some of the steam condenses on the water surface, and the cooler water which entered the bottom of the pressurizer mixes with the hotter water which, in turn, increases the condensing action. This cooling of the pressurizer may exceed the capacity of the pressurizer heaters, so that the initial increase in RCS pressure is followed by a large decease in RCS pressure even though pressurizer level is now stable. The operator can anticipate this situation and manually energize the pressurizer heaters when the pressure begins to decrease.

Failure of Spray and/or Heaters:

A failure of the spray or heaters in the pressurizer control system can also cause a loss of pressure control. If the spray fails on and cannot be turned off, the system will depressurize. Depressurization may also occur if the heaters fail in the "off" mode. The reverse is not true; failure of the spray in the "off" mode will only limit the ability to depressurize. Unless something else happens to the plant, pressure increases and decreases will not occur. If the heaters fail "on", pressure increases will not occur because the spray will operate to provide a balance. However, if the spray is not working, then the heaters can cause the system to pressurize and cause coolant (steam) to be lost through the PORV and the pressurizer safety valves; subcooling will not be lost as long as water covers the heaters. When only steam covers the heaters they will no longer raise pressure and subcooling can gradually drop. If the heaters fail "on" when they are uncovered, no water exists to cool them and they will burn out.

Reactivity Control

Reactivity control is usually taken care of automatically by ICS rod control or by reactor trip. Reactor trip lowers the core heat output to the decay heat level. The operator must verify rod insertion and decreasing reactor power to ensure the reactivity control systems function

properly. After the trip no more heat transfer control can be achieved by use of the rods, unless the rods did not fully insert. If one or more rods are stuck out after trip the operator should manually trip them. If one or more rods remain stuck out, the operator should begin emergency boration and a reactivity balance calculation should be performed to ensure a shutdown margin in excess of 1% $\Delta k/k$ is achieved.

Summary

The preceding discussion introduced the concept of reactor-steam generator heat transfer and the balance that heat transfer must have. When an imbalance of heat transfer occurs, its effects will often be transmitted throughout the steam and reactor coolant systems. The purpose of understanding heat transfer is to understand its effects so the operator can diagnose what has gone wrong and correct it. An understanding of the major influences on reactor-steam generator heat transfer control (reactor coolant inventory control, reactor coolant pressure control, steam generator pressure control, steam generator inventory control, and reactivity control) will allow the operator to focus on achieving controlled heat transfer and stable plant conditions without necessitating the identification of specific failures. Thus, an understanding of the principles of heat transfer and the control methods permits a more disciplined approach to abnormal transient diagnosis and correction.

The effects of changing one of the controls will nearly always cause changes in other parts of the system and therefore will require other controls to be changed to balance heat transfer. The controls are interdependent because they affect total heat transfer from core to steam outlet.

Core cooling with the steam generator can occur as long as two conditions exist:

- The reactor coolant can transport the heat. The best way to do this is with subcooled liquid. Reactor Coolant Inventory and Pressure Control contribute towards this.
- The heat removal is controlled by the steam generator. Steam Generator Inventory Control and Pressure Control aid this.

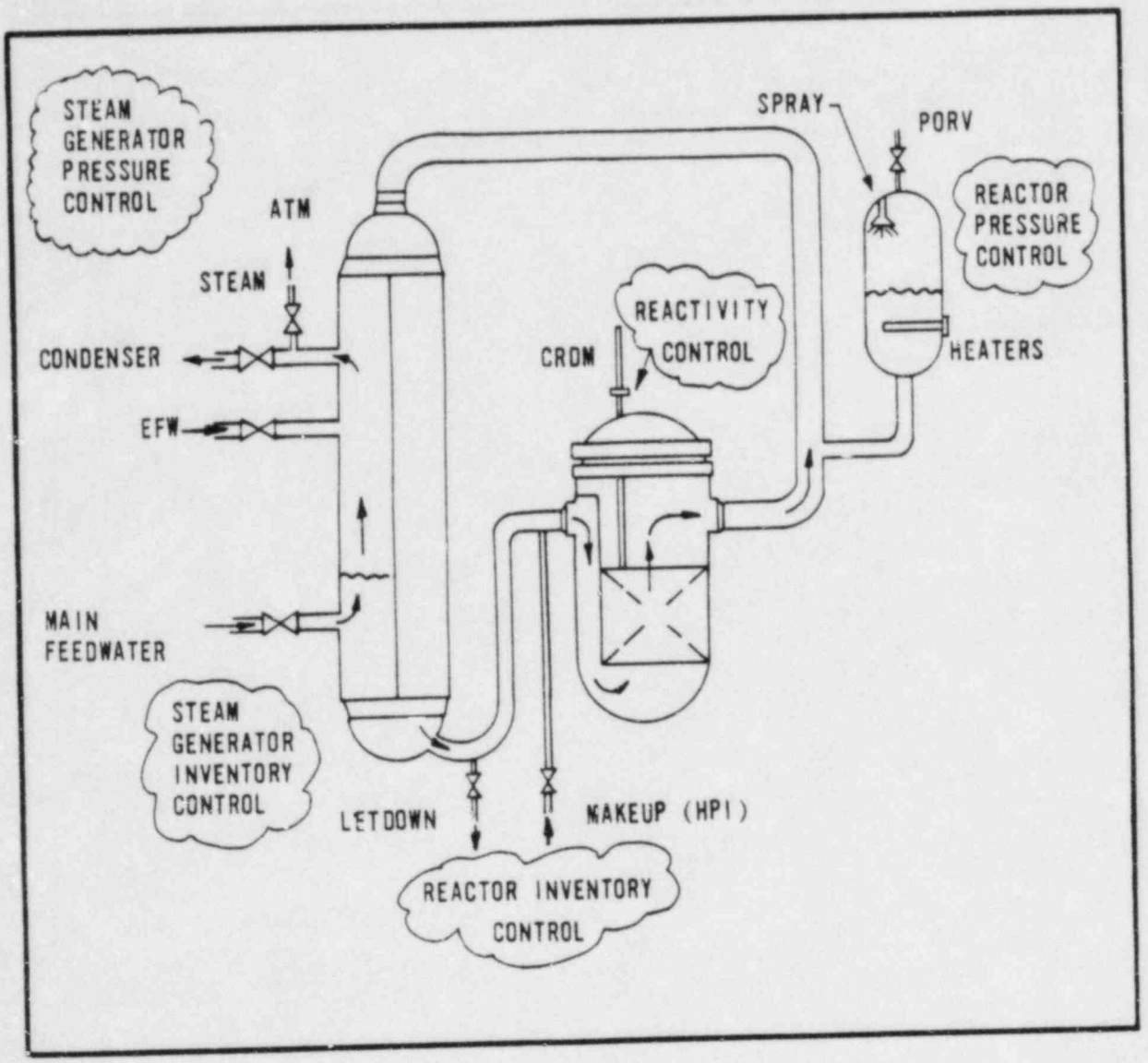
Usually an abnormal transient will be caused by a failure of one or more of the heat transfer controls. The understanding of the control influences allows the operator the freedom of two approaches to abnormal transient correction:

1. He can treat the symptoms by manipulating equipment to regain heat transfer control without knowing exactly which equipment has failed. Consequently, proper heat transfer can be restored quicker and more accurately than if the operator had to hunt for the equipment failure. In some instances, treating the symptoms will also uncover the failed equipment.

2. He can use these control failures as symptoms of poor heat transfer to discover the equipment that has failed and, by doing so, isolate it, remove it from service, or repair the equipment.

Understanding the influence each of these controls has on overall heat transfer will also give an understanding of what the outcome of an action is. All operator actions will have some consequence to heat transfer and a knowledge of the heat transfer will allow judgements to be made about the general effects.

Figure 1 FUNDAMENTAL METHODS OF HEAT TRANSFER CONTROL



ADDENDUM A

(SUBCOOLED, SATURATED, SUPERHEATED WATER)

The state (solid, liquid or gas) of the water in the reactor coolant system or the steam system is determined by the pressure and temperature conditions which exist. The terms subcooled, saturated, and superheated are normally used within operating procedures. These terms mean the following:

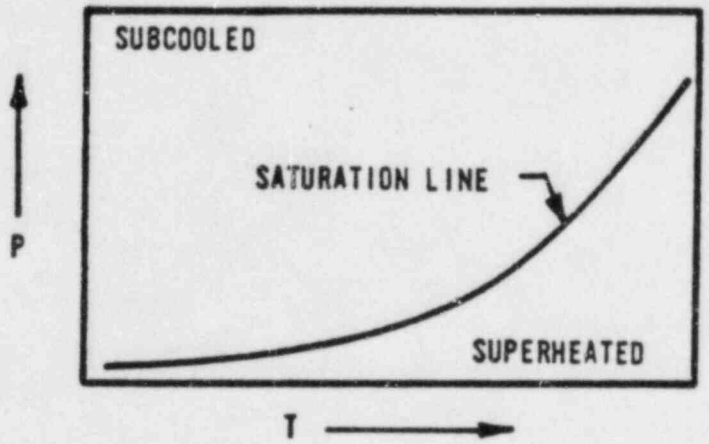
Subcooled: Water can exist only in the liquid state.

Saturated: If heat is added to subcooled water a temperature, for the existing pressure, will be reached where the water can exist either as a liquid or as a gas (steam). At this point, the liquid is called saturated water and the gas is called saturated steam. The liquid and steam states both can exist at this temperature and pressure. Heat must be added to saturated water to change it to saturated steam. Heat must also be removed from saturated steam to change it to saturated water. The heat required to make the change is called the latent heat of vaporization for heat added and the latent heat of condensation for heat removed.

Superheated: Water can exist only in a gaseous or steam state. This state can be distinguished from saturated conditions because the temperature will be higher than the saturation temperature for the existing pressure.

The normal state of the steam coming out of the steam generator is superheated during power operation and saturated after trip.

The state of the reactor coolant can be determined by plotting the RCS pressure and temperature on a pressure-temperature diagram (see below):



P-T conditions which are to the left and above the saturation line are in the subcooled region, and P-T conditions to the right and below the saturation line are in the superheated region.

Subcooling

Subcooled conditions are maintained in the reactor coolant (except pressurizer) during normal operation. During a reactor transient it is desirable to maintain the reactor coolant subcooled. When subcooled:

1. The primary loops are solid water and a water level is present within the pressurizer.
2. The pressurizer water level is a true measurement of RCS inventory. The inventory can be controlled by regulation of pressurizer level by the MU/HPI system and letdown. (NOTE: If non-condensible gases are present in abnormally high concentrations, gas bubbles could form in the RCS high points while the RCS is subcooled. In this case, pressurizer level is not a true measurement of inventory.)
3. The reactor coolant is liquid and is ideal for heat removal from the core and heat transport to the steam generator by either forced or natural circulation.
4. RC pressure can be maintained by the pressurizer and can be regulated by using normal procedures and equipment (spray and heaters).
5. RC temperature can be controlled by the secondary system (with feedwater available) by adjusting feedwater flow and steam pressure.

With no RCP's running, the degree of subcooling shall be determined by the saturation meter (T_{hot} and RCS pressure) or the five highest and operable incore thermocouples and RCS pressure, depending on the ability to establish or verify natural circulation flow (i.e., no flow, use incore thermocouples). Anytime the reactor coolant gets too close to saturation, the HPI system should be turned on full. The reactor coolant is too close

to saturation if it exceeds a subcooling margin limit. This is a limit approximately 20F colder than the saturation curve and is explained in more detail in Chapter B, "Use of the P-T Diagram."

HPI Start Rule: Two HPI pumps should be run at full capacity when:

- The ESAS is automatically actuated OR
- The reactor coolant subcooling margin is lost.

Saturation

A loss of subcooling can occur when the pressurizer drains or when filled solid (if the pressurizer is solid because of HPI and adequate core cooling is provided by the steam generators or HPI flow, then the reactor coolant may stay subcooled). A loss of subcooling can be caused by an overheating or overcooling transient or a loss of reactor coolant. Saturated conditions can exist in isolated pockets of the loop (e.g., within one or both hot leg pipes or the reactor vessel head, but not in cold leg pipes) or within the system as a whole, as would be the case during a major LOCA. Therefore, temperatures should be checked in the hot legs of both loops. When the RCS is saturated, the following things happen:

1. The reactor coolant temperature and pressure will not show whether the saturated fluid is liquid or gas (steam).

2. Voids (steam bubbles or pockets) can exist within the primary system.
3. The pressurizer water level indication is not a true measurement of reactor coolant inventory.
4. If the RC pumps are off, a loss of natural circulation may occur because steam voids can form at the top of the hot legs and block water flow.
5. Normal pressure control by the pressurizer has been lost. The RCS hot leg loops, which have a steam bubble at the top, now work as a pressurizer. RC pressure will be controlled by the highest fluid temperature in the system. The amount of steam can change because of steam condensation by the steam generators, by addition of cold HPI water to compress the steam, or by loss of steam generator heat removal.

Under ideal conditions, subcooling should exist in all parts of the reactor coolant loop to be able to transport heat from the core to the steam generators. However, given the proper conditions, the steam generators can remove heat when the reactor coolant is saturated.

For all events, except a LOCA or a sustained total loss of secondary fluid, saturated conditions should be a temporary effect. For example, if steam generator overcooling causes the pressurizer to drain, saturation will occur, but HPI will start and restore the reactor coolant to a subcooled state.

Superheating

Superheated reactor coolant conditions are to the right and below the saturation line of the P-T diagram. Superheated steam results when the core is uncovered. Heat from the core is passed to the steam and its temperature rises above saturation. When the reactor coolant is superheated the core is cooled by steam. Steam cannot remove enough heat to prevent the core and clad from heating up. Fuel failure may result. Superheated steam indicates Inadequate Core Cooling (ICC).

The only accurate measure of temperature when superheated conditions exist is the incore thermocouples, and they should be used along with hot leg pressure to determine the amount of superheating.

Superheat Rule: The inadequate core cooling procedure must be used anytime superheated conditions exist in the RCS.

Refer to Chapter D, "Backup Cooling Methods", for a discussion of inadequate core cooling.

B- NATURAL
CIRCULATION

ADDENDUM B

NATURAL CIRCULATION

When the reactor coolant pumps are tripped, forced circulation is lost and an alternate method of removing core decay heat must be found. The preferred method is to transport this heat to the steam generators by natural circulation of the reactor coolant. Natural circulation is possible as long as the following requirements are met: 1) a heat source is available to produce warm (low density) water; 2) a heat sink is available to produce cold (high density) water; 3) a flow path (loop) is available connecting the warm and cold water; and 4) the cold water is at a higher elevation than the warm water. Requirements 1, 2 and 3 are met by the following: decay heat in the core is the heat source, water on the secondary side of the steam generators provides a heat sink, and the hot and cold legs connect the two. Requirement 4, "the cold water is above the warm water," involves a concept called thermal center. In reality, heat is transferred continuously as the water moves up through the core and again as it moves down through the steam generator. The thermal center is defined here as the point in the core or the steam generator where the primary water is at average temperature. It can be used to represent the entire column of water in its "average" conditions.

Thermal Center Definition

1. Core thermal center: That elevation in the core which the reactor coolant may be considered to go from T_{cold} to T_{hot} (i.e., for simplification purposes the reactor coolant temperature above the

thermal center can be considered equal to T_{hot}, and the reactor coolant temperature below the thermal center can be considered equal to T_{cold}).

2. Steam generator thermal center: That elevation in the steam generator at which the reactor coolant may be considered to go from T_{hot} to T_{cold} (again, a simplification).

Requirement 4 for natural circulation can be met if the thermal center of the steam generator is at a higher elevation than the thermal center of the core. This will put the "average" cold water above the "average" hot water, the cold water (more dense) will sink, the hot water (less dense) will rise, and there will be circulation.

The rate of natural circulation (gpm) depends on the following things:

- The friction (resistance to flow) of the piping and components around the primary loops: this is determined when the plant is designed and built; the operator has no control over it.
- The strength of the heat source: this depends on the available decay heat, which is a function of past power history and time since the reactor trip. It will, of course, decrease with time after trip. The operator has no control of this after trip except to make sure the reactor is shut down so that the only heat input is decay heat.

- The strength of the heat sink: the colder the heat sink is the more it will be able to cool the primary coolant passing through the steam generator. This will make the water more dense and the natural circulation flowrate will increase. The operator can make the heat sink colder by 1) lowering secondary steam pressure (opening the turbine bypass or ADV's more); this will lower secondary saturation temperature which will increase heat transfer across the tubes; or 2) lower feedwater temperature (for example, shift from main feedwater to emergency feedwater), this will increase the heat transfer across the tubes by providing a larger primary to secondary ΔT.
- Difference in height between the core thermal center and the steam generator thermal center: As the difference in height becomes larger, the natural circulation flow will increase. The core thermal center is fixed, but the operator can control the steam generator thermal center by two methods: 1) most of the heat transfer occurs in the violent boiling area just below the established secondary side water level. Therefore, the operator can raise the thermal center by raising the steam generator water level; 2) the operator can add EFW at the top of the generator. This will put cold feedwater high in the generator and thereby raise the average height (thermal center) of heat removal. This only works <u>while</u> EFW is being added. If EFW flow is stopped, the thermal center will move back down to just below the water level.

In summary, the natural circulation flowrate can be changed by changing the difference in temperature (density) between the hot water and the cold water or by changing the difference in height between the core thermal center and steam generator thermal center. This can be expressed in equation form as:

$$\Delta P_{\text{driving head}} = h_{eff} (\rho_c - \rho_H)$$

where: $\Delta P_{\text{driving head}}$ = available driving head for natural circulation

h_{eff} = distance between core thermal center and steam generator thermal center (effective height)

ρ_c = density of cold water at steam generator thermal center

ρ_H = density of hot water at core thermal center

This is shown graphically in Figure 2.

Natural Circulation (All Other Conditions Normal)

When the reactor coolant pumps are tripped, the operator should check two things to make sure natural circulation is being initiated properly. First, he should make sure the reactor coolant remains subcooled. If it does not, he should make every effort to restore subcooling (the methods for doing this are discussed in Chapter C, "Abnormal Transient Diagnosis and Mitigation"). Second, he should make sure the thermal center is being raised in both steam generators. Normally, automatic equipment will start

EFW and increase level to 50% on the operating range of each steam generator when the RC pumps trip. The operator should monitor this process while keeping the following in mind:

- As long as EFW is flowing at sufficiently high rates into the top of the generator, it is not necessary to get a level in the generator to have natural circulation. If the heat source (decay heat) is high enough, the EFW may come in and boil right off and go out as steam. This is acceptable; the thermal center is high and natural circulation will develop.
- After initiation of EFW the operator should watch steam pressure, pressurizer level, and cold leg temperatures. If necessary, EFW should be throttled to prevent overcooling. Guidelines for throttling EFW are discussed in Chapter E, "Best Methods for Equipment Operation."
- If EFW is not available, natural circulation can be initiated using main feedwater. Again, the level should be raised to 50% on the operating range.

Use main feedwater for anticipatory SG level changes if the required SG level can be established before the RC pumps are tripped.

Figure 3 shows how RCS temperature and pressure, and steam generator temperature and pressure will vary during the transition to natural circulation using EFW. Approximate times for the transient are also included. The times are approximate because the rate of recovery of the steam pressure depends on the amount of decay heat available. When steady state is reached, the cold leg temperatures (T_{cold}) will be just about equal to the saturation temperature in the steam generators. The hot leg temperatures will increase as necessary to develop the driving head required for flow (by developing a density change between T_h and T_c). The best measures to use to see if natural circulation has started are the coupling between T_c and the steam generator pressure, the relationship of T_h and the incore thermocouples, and the temperature difference between T_h and T_c. The plot of T_c vs. steam pressure on the P-T diagram should remain a few degrees to the right of the saturation curve, an average of the five highest incore thermocouples should track T_h within approximately 10F, and the temperature difference between T_h and T_c should be approximately 50F (maximum decay heat). When steam pressure is changed, T_c should follow but a time delay in T_c response (on the order of a few minutes) can be expected due to low loop flow rates. Once natural circulation is established and the higher steam generator levels are reached, the operator must ensure feedwater is available to replace the steam generator water being boiled off removing decay heat and to maintain the RCS subcooled. Transition to natural circulation using MFW will look very similar. The major difference would be less

primary system cooldown (with the same feedwater flow rates) while the SG levels are being established due to higher temperature feedwater and the absence of spray action into the steam space.

Natural circulation flow will regulate itself. That is, as the heat source (decay heat) dies down, the ΔT ($T_h - T_c$) will go down, and there will be less driving head available; therefore, flow will go down.

Natural Circulation - Abnormal Operation

The discussion so far concerned expected or normal natural circulation conditions. That is, the RCS is subcooled, the level in both steam generators is 50% on the operate range, and both steam generators are being steamed. This section will discuss off normal conditions: 1) natural circulation with one OTSG, 2) natural circulation with saturated RCS, and 3) recognition of loss of natural circulation.

One OTSG

There may be times when an operator does not want to steam a generator (SG tube leak) or cannot steam a generator (steam line break and isolated generator is dry). If he is also in natural circulation he can expect the following:

Only T_{hot} in the operating loop will indicate core outlet temperature; T_{cold} on the operating generator will be approximately equal to T_{sat} in the operating steam generator; T_{cold} in the isolated generator will

not be equal to T_{sat} in the isolated generator; it will probably be much colder due to ambient losses and due to seal injection water temperature coming into the idle pumps; (T_h-T_c) on the operating steam generator may be 10F higher than the 50F ΔT expected with two operating SGs. The level in the operating steam generator may have to be raised above 50% to maintain adequate primary to secondary heat transfer. Steady state operation under these conditions is stable and safe. Plant cooldown, however, is complicated because the cooldown of the loop with the isolated steam generator will lag behind the steaming steam generator. If there is water in the isolated steam generator, it will become a heat source instead of a heat sink. If the RC pressure is reduced too fast during cooldown the reactor coolant in the associated hot leg will flash to steam. If this happens, that hot leg will act as a pressurizer and slow down the depressurization during cooldown. This will also slow down the cooldown rate. The operator must carefully watch subcooling in both loops under these conditions and make sure adequate subcooling margin is maintained by regulating the rate of cooldown with steam pressure control of the operating steam generator.

Natural Circulation with a Saturated RCS

A subcooled reactor coolant system is the desired state, however, natural circulation can remove core heat when the RCS is saturated. As long as the four requirements for natural circulation are met, heat will be removed from the core and transferred to the steam generator. The problem with saturated natural circulation is that the operator doesn't know how much

of the reactor coolant is steam and how much is water (see discussion of saturation in Addendum A). If the RCS is losing inventory, steam will form in the hot legs and eventually stop natural circulation flow (this is a violation for the requirement that a flow path exists connecting the hot water and the cold water).

This requirement could also be violated by a large collection of non-condensible gases in top of the hot legs, however, such a collection could only exist following a core uncovery. At that point the operator would be using inadequate core cooling procedures.

Another form of natural circulation could still exist when the hot legs are voided, called boiler-condenser cooling (boiling in the core and condensing in the steam generators) but it requires a higher steam generator level (95% on operator range). This method is discussed in detail in Chapter D, "Backup Cooling Methods."

The point to remember is that primary inventory (mass) is unknown under saturated conditions and, therefore, every effort should be made to keep the RCS subcooled.

Recognition of Loss of Natural Circulation

A loss of natural circulation can occur for various reasons and several indications may be available. If the RCS is subcooled, a loss of natural circulation flow is more than likely a result of inadequate heat removal by the steam generators. The thermal center in the steam generators may

be too low. At low decay heat levels or during single loop cooldown, the SG level(s) may have to be raised above 50% on the operate range to induce or maintain natural circulation flow.

The best single indication of a loss of natural circulation flow when the RCS is subcooled is a divergence developing between the incore thermocouples and T_{hot}. When the flow is lost, the incore thermocouples will begin a continual increase toward saturation. The rate will depend on the decay heat level. T_{hot} indications may also increase but can actually decrease and begin to converge with T_{cold}. In any case, T_{hot} will not increase as rapidly as the incore thermocouples and the two indications will diverge. Another indication of loss of natural circulation is a "decoupling" between T_{cold} and SG pressure. If T_{cold} ceases to follow SG pressure, then natural circulation flow has been lost.

When the RCS is saturated and natural circulation flow is lost, the divergence between T_{hot} and the incore thermocouples may not develop significantly. The best indication of a loss of natrual circulation flow when the RCS is saturted is a trend of incore thermocouple temperature vs. RCS pressure increasing along the saturation curve. Flow can be lost due to low thermal centers in the SG's or blockage due to voids in the RCS. When saturated, SG levels should be maintained at 95% on the operate range and full HPI flow should exist. If voids exist in the RCS, it is possible that boiler-condenser cooling was in progress. As the RCS refills,

cooling in this manner is expected to be lost when the RCS liquid level increases above the SG tubes. However, in this case, natural circulation cooling should be restored by continued refill and by following the actions specified in Part I (pump bumps, reducing SG pressure, etc.). Restoration of natural circulation flow is discussed in Chapter D, "Backup Cooling Methods."

CHAPTER B

USE OF THE P-T DIAGRAM

Introduction

The previous chapter provided the fundamentals of heat transfer control and also presented information about natural circulation, subcooling, saturation and superheating. These basics are the background information needed to diagnose transients and follow through with the correct operator actions. This chapter builds on that information.

The foundation for abnormal transient diagnosis and operator action is the reactor coolant pressure-temperature diagram (P-T) which is used to show how changes of heat transfer affect plant operation. Examples of reactor coolant system pressure and temperature response for normal trips are presented in this chapter; the response is also presented for a few selected abnormal events. These examples show the difference between transients in which all systems and equipment function properly and those which have several failures.

The P-T diagram is used to identify the three basic heat transfer symptoms used in Part I of the guidelines (loss of subcooling margin, lack of heat transfer, and excessive heat transfer). The previous chapter discussed the fundamental heat transfer control functions. If control of one of these functions is lost, it will impact primary to secondary heat transfer and become evident as one of the three basic heat transfer symptoms. For example, a loss of SG inventory control low (loss of feedwater) will

result in lack of heat transfer (overheating). Conversely, a loss of SG inventory control high (too much feedwater) will result in excessive heat transfer (overcooling). When a symptom appears, one or more of fundamental heat transfer control functions are not being controlled properly. Regaining control of these functions will restore controlled core cooling.

The P-T diagram will also be used to monitor actions taken by the operator to see if they are producing the right effects. When equipment failures cannot be found or cannot be fixed, the P-T diagram can be used to follow the effects of operator corrections as the plant is controlled toward the best possible condition.

The diagram may also be used to ensure the plant has stabilized after a transient has been terminated.

Description of the P-T Diagram

Figure 8 shows the P-T diagram with information pertinent to post-trip conditions with forced circulation (one or more RC pumps on). The diagram and plotted parameters allow the operator to determine: 1) the state of the reactor coolant (subcooled, saturated, or superheated), 2) if reactor coolant is circulating in the loops, and 3) if heat transfer from the reactor coolant to the steam generator fluid is excessive, inadequate, or about balanced.

Reactor coolant status is displayed by a plot of hot leg temperature (T_h) vs. RC system pressure. Curves and limit lines are provided to aid in determining when reactor coolant conditions are off-normal rather than "as expected" after trip. Figure 8 shows a primary post-trip "window" where the reactor coolant pressure and hot leg temperature are expected to stabilize after a normal reactor and turbine trip. The size of the window has been compiled from a review of several actual reactor trips (plus computer simulations) with and without equipment failures. Its size is not exact and it is possible for a trip (with minor failures) to end slightly outside the window and still have a stable plant. Some judgement will have to be applied.

The P-T diagram has curves for saturation and subcooled margin. The saturation curve is applicable to both primary and secondary fluids. Above and to the left of the saturation curve is the subcooled water region; below and to the right of the curve is the superheated steam region. The subcooled margin line is only to be used to gauge the condition of the reactor coolant and not the steam generator fluid. Because the reactor coolant conditions can be different from one loop to the other this line must be compared to reactor coolant pressures and temperatures in the hot legs of both loops. The amount of subcooled margin chosen was based on the ability to accurately measure the reactor coolant temperatures and pressures (instrument errors) during degraded reactor building environmental conditions (LOCA or SLB). It also includes an extra 5F to allow for temperature variations from the point of

measurement in the system. This gives assurance that when the reactor coolant is above the margin line it is truly subcooled and has the ability to transport the heat from the core to the steam generators. The subcooling margin shown in ATOC is a typical value. Actual values for subcooling margin are determined by the user based on specific plant equipment.

If the subcooling margin is lost, the assumption should be made that subcooling has been lost. The rule that was given in Addendum A should be invoked (it is repeated here):

HPI Start Rule

Two HPI Pumps should be run at full capacity when:

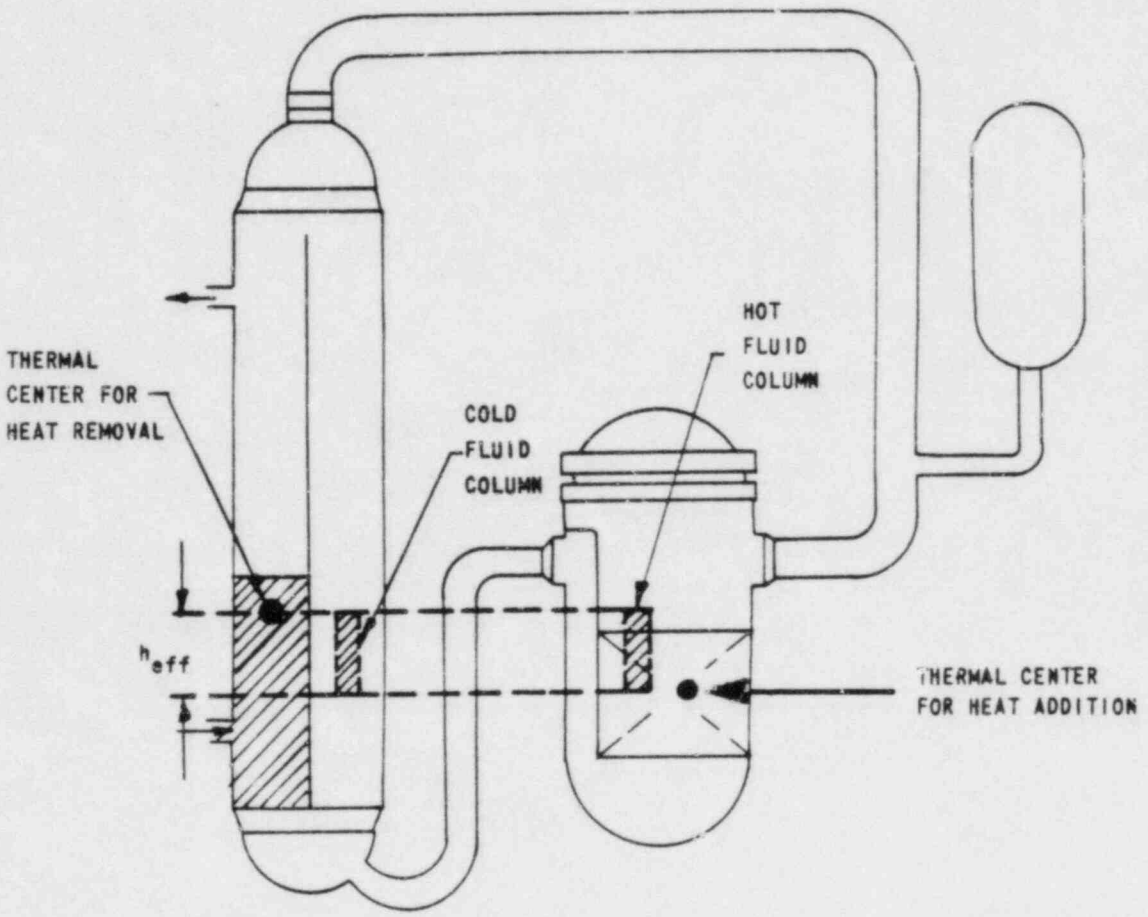
The ESAS is automatically actuated

OR

The reactor coolant subcooling margin is lost.

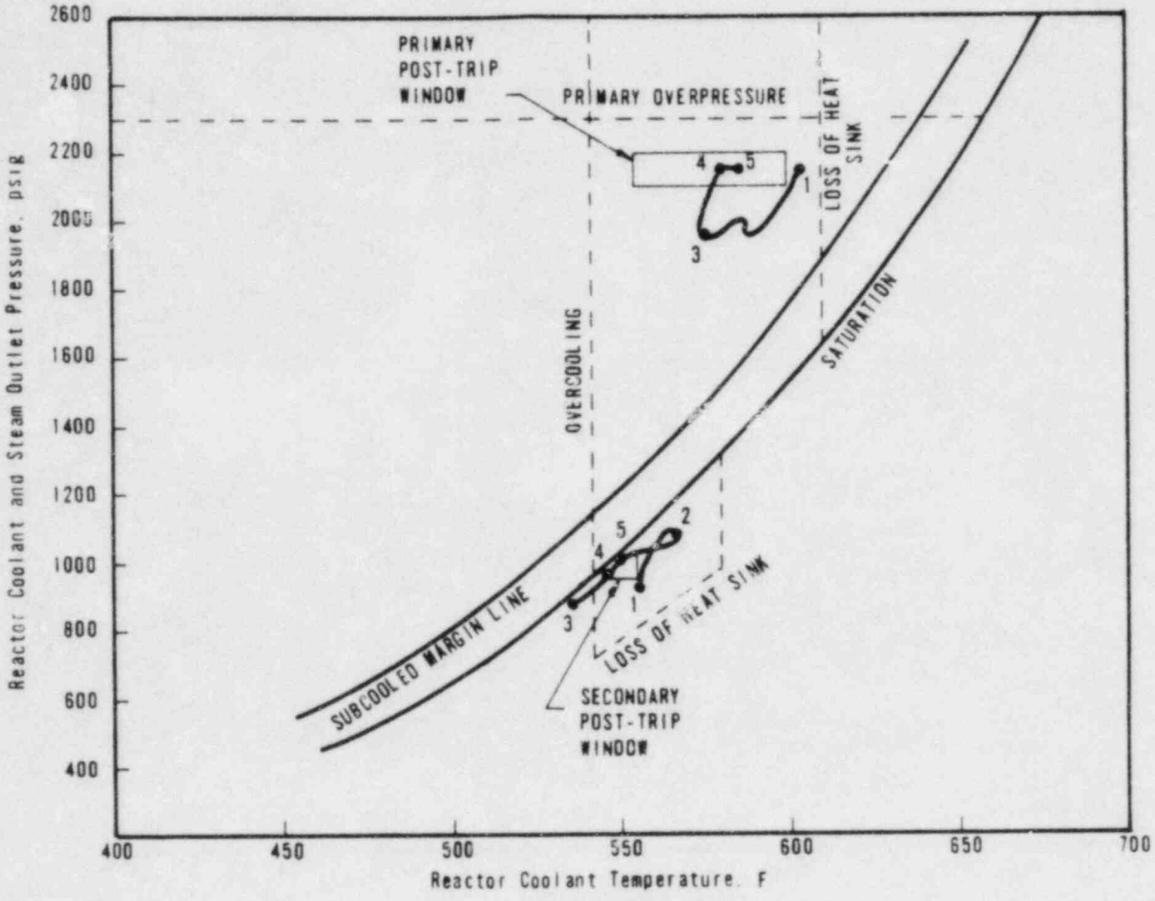
The P-T curves can also be used to monitor and control HPI and RC pump operation. When HPI is initiated it can be throttled only when the allowable subcooling margin is regained. In general, if the RC pumps have been tripped they can be restarted anytime the subcooling margin is regained and an OTSG is available as a heat sink. Exact details of HPI and RC pump control are given in Chapter E, "Best Methods for Equipment Operation".

Figure 2 ILLUSTRATION OF PARAMETERS CONTRIBUTING TO NATURAL CIRCULATION DRIVING HEAD



$$\Delta P_{\text{driving head}} = h_{eff} (\rho_C - \rho_H)$$

Figure 3 TRANSITION TO NATURAL CIRCULATION



Reference Points	Time (Seconds)	Remarks
1	0	RCP's trip; reactor trip.
2	30-60	T_{cold} reaches maximum value.
3	400	OTSG's at required level; RCS pressure at minimum value; recovery of RCS pressure begins.
3-4	>400	Steam pressure being restored by decay heat; ADV's shut.
4-5	>400	RCS pressure normal. OTSG pressure still low due to initial injection of EFW.
5	Depends on available decay heat	Steady state; ADV's relieving steam. Primary $\Delta T \sim 40F$.

P-T DIAGRAM

An indication of the status of heat transfer from the reactor coolant to the secondary system is provided by plotting reactor coolant cold leg temperature (T_c) vs. steam generator pressure. After trip the steam generators are normally at saturation conditions and T_c is slightly greater than saturation temperature (T_{sat}) of the secondary side. Therefore, a plot of T_c vs. steam generator pressure will normally be a few degrees into the region of the P-T diagram to the right of the saturation curve. It is important that the operator study this aspect of the display and become completely familiar with it. If the plot of T_h vs. reactor coolant pressure enters this region, it is superheated and it is an indication of inadequate core cooling, but it is normal for T_c vs. steam generator pressure to track in this region of the diagram. The reason for plotting this derived parameter is that it provides a means to gauge the heat transfer from the primary system to the secondary system. When heat transfer exists, T_c will follow T_{sat} of the steam generator and will remain a few degrees to the right of the saturation curve. A loss of heat transfer will be evident by a trend away from the saturation curve. This will be discussed in more detail later.

Figure 8 also shows a secondary post-trip window where T_c and steam generator pressure are expected to stabilize after a normal reactor and turbine trip. The secondary window is based on the same considerations which set the primary window and thus the same judgements are required to evaluate plant performance.

Typical bounding lines are given on Figure 8 for overcooling, loss of heat sink, and overpressure. These lines are provided only as a basis for identifying the trend of a transient and are not to be construed as absolute limits. They were established in the same manner as the post-trip windows, i.e., most normal reactor and turbine trips will stabilize without exceeding the boundaries established by these lines. Generally, if the transient approaches or exceeds one of these lines, some failure has probably occurred and the operator should begin a diagnosis of the plant. However, some transients can become severe before an abnormal response is evident on the P-T diagram. It is important to note that other parameters that are not displayed on the P-T diagram must also be checked to ensure proper primary to secondary heat transfer. For example, excessive main feedwater will not initially cause noticeable steam generator pressure or temperature reduction and will, at first, be masked by the normal post-trip cooling response. By the time the overcooling becomes evident on the P-T diagram, the pressurizer may be in a nearly-drained condition. Therefore, main feedwater flowrates and steam generator levels must be checked very early following a reactor trip.

Another reason for exercising caution in the use of these boundary lines is that they are based on the expected response following a normal reactor trip from power operation. Therefore they will have little relative meaning for abnormal transients that begin from other plant conditions, such as during a cooldown or after an overcooling transient has been stabilized at a lower pressure and temperature.

The P-T diagram shown in Figure 9 provides the same basic information as Figure 8 except that the primary post-trip window has been enlarged and the primary loss of heat sink line is at a higher temperature to allow for the larger primary system ΔT that exists during natural circulation. The window size and boundary line were derived from the same basic considerations used for Figure 8, thus the same type of judgement should be applied.

Heat Transfer Characteristics Shown by the P-T Diagram

This section will show examples of various transients on the P-T diagram. Both normal and abnormal transients are shown for comparison. The transients to be illustrated include:

- A normal reactor-turbine trip with no failures (Figure 10)
- Examples showing the basic trend of:
  - an overcooling transient (Figure 11)
  - an overheating transient (Figure 12)
  - loss of subcooled margin (Figure 13)
  - asymmetric overcooling (Figure 14)
- Specific transient examples for:
  - overheating due to loss of MFW/EFW (Figure 15)
  - overcooling due to steam leaks (symmetric and asymmetric) (Figure 16)
  - overcooling due to excess FW (Figure 17)
  - loss of subcooling due to LOCA (Figures 18, 19)

These examples are used to show how reactor coolant system pressure and temperature and steam pressure change when different failures cause changes in heat transfer.

P-T Transient - Normal Trip

Figure 10 shows the typical response of both primary and secondary plant parameters following a reactor trip. Individual important parameters are shown as well as the P-T diagram. The shape of the reactor coolant P-T characteristic path from 100% power operation (above 15%) to hot zero power is always like this unless an abnormal transient is in progress. The "dip" of the curve for T_{hot} vs. RCS pressure is due to cooldown of the RCS to near T_{sat} of the steam generators for the turbine bypass system (TBS) setpoint. The cooldown results in coolant shrinkage which causes a pressurizer outsurge and pressure reduction. After the RCS reaches a temperature slightly above T_{sat} of the SG's, the reactor coolant will repressurize and stabilize. Depending on prior power operating history the low point of the "dip" will have different values, but the characteristic shape will always exist when tripping from full power. When the plant trips, the steam pressure will initially rise to the safety valve setpoint and then quickly settle out at the post trip turbine bypass valve setpoint. Cold leg temperature will initially rise as the core ΔT decreases during RC pump coastdown following the sudden drop in core power. T_{cold} will then cool down and settle out at a temperature slightly higher than T_{sat} of the steam generators. Thus the plot of T_{cold} vs. steam pressure will end up a few degrees to the right of the saturation curve in or near the post-trip window.

Indications of a normal trip as shown by the P-T diagram include:

1. Hot and cold leg temperatures will stabilize in 2-3 minutes.
2. Reactor coolant pressure will stabilize in 5 to 6 minutes.
3. T_{cold} will be nearly equal to saturated steam temperature indicating that reactor coolant is transferring heat to the steam generators.
4. Steam pressure will stabilize in 2 to 3 minutes.
5. Reactor coolant subcooled margin will increase.

P-T Characteristics - Abnormal Transient Trends

Figures 11, 12, and 13 show trend indications on the P-T diagram for three basic abnormal transients: overcooling (excessive heat transfer), overheating (inadequate heat transfer), and loss of subcooled margin. Figure 14 shows possible trends for asymmetric overcooling transients induced by excessive heat removal through one steam generator.

These trends, overcooling, overheating, and loss of subcooling, are the first indications to check in transient diagnosis and correction. In the case of overcooling, which can be masked by the normal post-trip response, other parameters such as MFW flow and SG levels, which are not shown on the P-T diagram, must be checked very early in the transient.

An abnormal transient will show different characteristics depending on the failures that may have occurred. Some characteristics of RC pressure and temperature and of steam pressure that show undesired heat transfer on the P-T diagram are:

1. Reactor coolant subcooled margin is lost.

2. Reactor coolant pressure and hot leg temperature will not stabilize and will approach or exceed boundary lines.

   - The trend may be caused by overheating or overcooling. Subcooling may or may not be lost.
   - The trend may be caused by loss of reactor coolant. Subcooling will be lost for all except the very smallest primary side breaks.

3. Steam generator pressure and cold leg temperature will not stabilize and will approach or exceed boundary lines.

   Normally steam pressure will stabilize after trip at the TBV setpoint of 1010 psig and T_{cold} will stabilize at a temperature a few degrees higher than saturation temperature in the steam generator.

   - Steam pressure and T_{cold} may be low due to steam leaks or excessive feedwater. Overcooling will result.
   - Steam pressure and T_{cold} may be low and cross the saturation curve (both loops) due to a large LOCA.
   - Steam pressure may be low with a steady or increasing T_{cold} (trend away from the saturation curve to the right and/or below the curve). This is usually indicative of a loss of heat removal by the steam generator either due to inadequate secondary inventory (LOFW) or loss of primary inventory (small LOCA).

- Overcooling induced by one steam generator or loss of heat removal in one steam generator (asymmetric transients) may be distinguishable by a divergence of the loop plots. It should be noted that less severe overcooling transients may be caused by only one steam generator but not result in a significant divergence between the loop plots. However, when it is not obvious which steam generator is causing the overcooling, following the guidelines in Part I for both steam generators will restore plant stability. Thus, the term "symmetric" overcooling includes failures in one steam generator that are not of sufficient magnitude to be readily identified.

Overcooling (Symmetric) (Figure 11)

Overcooling transients are characterized by RCS temperature decreases significantly below normal post-trip values. Severe overcooling transients may cause drainage of the pressurizer and a loss of subcooled margin. Less severe transients may allow repressurization of the primary system while continuing to cool down the RCS (dashed arrow).

During post-trip conditions when the steam generators are removing decay heat, overcooling transients are caused by malfunctions in the secondary system, either steam leaks or excessive feedwater. If it is not obvious which steam generator is causing the overcooling transient, then both loop plots of T_{cold} vs. steam pressure will decrease along (or slightly below) the saturation curve. Figure 14 shows obvious asymmetric (single steam generator failures) overcooling transients.

Overheating (Figure 12)

Loss of heat transfer to a steam generator causes the secondary trend to move away from the saturation line (further below and/or to the right). Decay heat removal is possible with one steam generator out of service. In such a situation, the inoperable steam generator would indicate a loss of heat transfer while the operating steam generator and the primary trend would remain in or near the normal post-trip windows.

If both steam generators become inoperable, decay heat removal is still possible with high pressure injection. Under these conditions, both steam generators would indicate a loss of heat transfer but the primary trend would show a constant or decreasing temperature.

In the event that all decay heat removal methods are inoperable or inadequate, the primary trend will show an increasing temperature. The total loss of heat sink or overheating event is indicated by the primary trend increasing toward the loss of heat sink and/or primary overpressure boundary lines.

Loss of steam generator heat sink events result from low steam generator level, loss of feedwater flow or loss of natural circulation flow. Total loss of heat sink can result from ineffective heat transfer in both steam generators and inadequate high pressure injection flow.

Loss of Subcooling (Figure 13)

This event is indicated by a constantly decreasing subcooling margin. The primary trend may stabilize on the saturation curve, as in a small break loss of coolant accident, or continue into the superheat region below the saturation line. Loss of subcooling is considered to have occurred when the trend crosses the subcooled margin line.

Loss of subcooling may result from large or small LOCA's (arrow A), a severe overcooling event (arrow B), or a prolonged loss of heat sink (arrow C).

Asymmetric Overcooling (Figure 14)

Asymmetric overcooling transients are defined, for the purpose of this discussion, as overcooling transients caused by one steam generator that result in significantly divergent trends on the P-T diagram between the loop plots for T_{cold} vs. steam pressure (T_{hot} vs. RCS pressure for both loops will usually still track together). It is possible for an overcooling transient caused by both steam generators to appear asymmetric on the P-T diagram due to differences in magnitude of the overcooling caused by each OTSG or differences in instrument errors. It is also possible for an asymmetric transient to appear symmetric. If in doubt, the transient should be handled as symmetric. However, the P-T diagram does have the capability to highlight asymmetric transients and this feature should be utilized when applicable.

During post-trip decay heat removal using the steam generators, overcooling transients will be the result of failure in steam pressure control or inventory control in one or both steam generators. The resultant divergence in the loop plots will be dependent on the type and magnitude of the transient. For example, a large steam leak on one steam generator will cause the affected loop steam pressure and T_{cold} to decrease rapidly as shown by arrow C on Figure 14. The rapid cooling of the primary system will result in the unaffected (non-leaking) steam generator becoming a heat source. Thus, its saturation temperature will be higher than its associated T_{cold} and the plot will cross over into the subcooled region as shown by arrow B. Smaller steam leaks will result in smaller pressure and temperature differentials but the basic pattern would be the same. Since this transient is essentially a one steam generator cooldown with the unaffected steam generator becoming a heat source, T_{cold} in the affected loop will "lead" T_{cold} in the unaffected loop (affected T_{cold} lower the unaffected T_{cold} at any point in time).

A severe excessive main feedwater transient results in the same basic conditions, i.e., one steam generator overcooling with the other steam generator becoming a heat source. However, the pressure in the affected steam generator will not initially decrease significantly due to the compressing action of the rapidly rising water level. Thus, the plot of T_{cold} vs. steam pressure in the affected loop will look like arrow A in Figure 14 while the unaffected loop will follow a path similar to arrow B.

Again, T_{cold} in the affected loop will lead T_{cold} in the unaffected loop. This is true of all single steam generator overcooling transients and is the best indication to check for in determining the affected steam generator.

A severe excessive emergency feedwater transient will appear similar to the steam leak transient on the P-T diagram. Pressure and temperature will decrease on the affected SG (arrow C) due to the colder feedwater temperature and due to the quenching effect of EFW spray into the steam space.

In summary, significant overcooling by one steam generator will usually cause the loop secondary plots (T_{cold} vs. steam pressure) to diverge. The affected steam generator causing the overcooling may have a higher or lower pressure than the unaffected steam generator but will always have a lower associated T_{cold} at any point in time during the transient. The magnitude of the difference depends on the severity of the transient. Thus, if the affected steam generator is not obvious, the transient should be handled as if symmetric (i.e., overcooling caused by both steam generators). In this manner overcooling will be terminated and then subsequent restoration of steam and feedwater control on the good steam generator will provide decay heat removal. Identification of the affected loop can be enhanced by using different plotting methods for each loop (e.g., one solid line and one dashed line, different colors, etc.).

P-T Characteristics - Abnormal Transients - Specific Examples

Figures 15, 16, 17, 18, and 19 show examples of transients which may occur because of failures either on the primary or secondary side. These examples show transients which end as expected and also some that go past the expected point because of additional failures. Those transients which are corrected properly will follow the expected course and will end up in the "post trip window" near the normal post trip end point. When the path goes outside the bounding lines, the transient is defined as abnormal and the direction reactor coolant pressure and temperature move toward can be classified as overheating or overcooling. In combination with overheating or overcooling the reactor coolant temperature and pressure path can also move toward more or less subcooling.

Figure 15 - Loss of Main Feedwater

- 15a) Shows Loss of Main Feedwater with EFW actuated. The important feature of this transient is that the main feedwater heat sink is quickly replaced with an EFW heat sink; the trend looks similar to a normal reactor trip.
- 15b) Shows Loss of Main Feedwater with EFW delayed. Important features of 15b) are: 1) loss of steam pressure with a trend in T_{cold} away from the saturation curve, and 2) the reactor coolant heats up and the primary system repressurizes to the PORV setpoint. This is an indication of lack of primary to secondary heat transfer.

Figure 16 - Small Steam Leak

- 16a) Shows a small steam leak on both steam generators (symmetric). The leak in this example (failed-open TBV) is isolable, but the transient shows the results if unisolable and terminated by allowing both OTSG's to boil dry. The purpose is to show the sequence and timing should unisolable leaks of similar magnitude occur. If the leak is isolated from one or both steam generators, restoration of feedwater and normal TBV or ADV control on the good SG(s) would allow normal post-trip decay heat removal.

- 16b) Shows a small steam leak on only one steam generator (asymmetric). Again, the leak is in the TBS and thus isolable, but, for the same reasons as in 16a, the transient shows termination of the overcooling by allowing the affected steam generator to boil dry and controlling DH removal with the good steam generator. The important feature of this transient is the capability to identify the steam generator with the steam leak by noticing the divergence in secondary (T_{cold} vs. steam pressure) plots and the lower T_{cold} in the affected loop.

Figure 17 - Excessive Feedwater

- This transient is shown to be corrected by ICS operation and looks similar to a normal trip. A transient that continues to run without ICS correction is shown in Appendix A of Part II,

Volume 2. Were the transient to continue, water could enter the steam lines and cause damage but the amount of damage and its effects are not known. The RCS would probably overcool to saturated conditions (i.e., drain the pressurizer) by the time water entered the steam lines.

Figure 18 - Small Break LOCA in the Pressurizer Steam Space

- The important feature of this transient is that water will flow into the pressurizer from the reactor coolant loops. Although the pressurizer will show a level, it is not a good indication of reactor coolant inventory when the reactor coolant is saturated.
- 18a) Shows a LOCA with the break isolated after the accident starts. Refill and repressurization of the reactor coolant system allow a normal cooldown with a pressurizer bubble.
- 18b) Shows a LOCA that is not isolated. A return to a subcooling state would be expected during cooldown. The entire reactor coolant system fills with water. Cooldown after this accident will be with a pressurizer full of water.

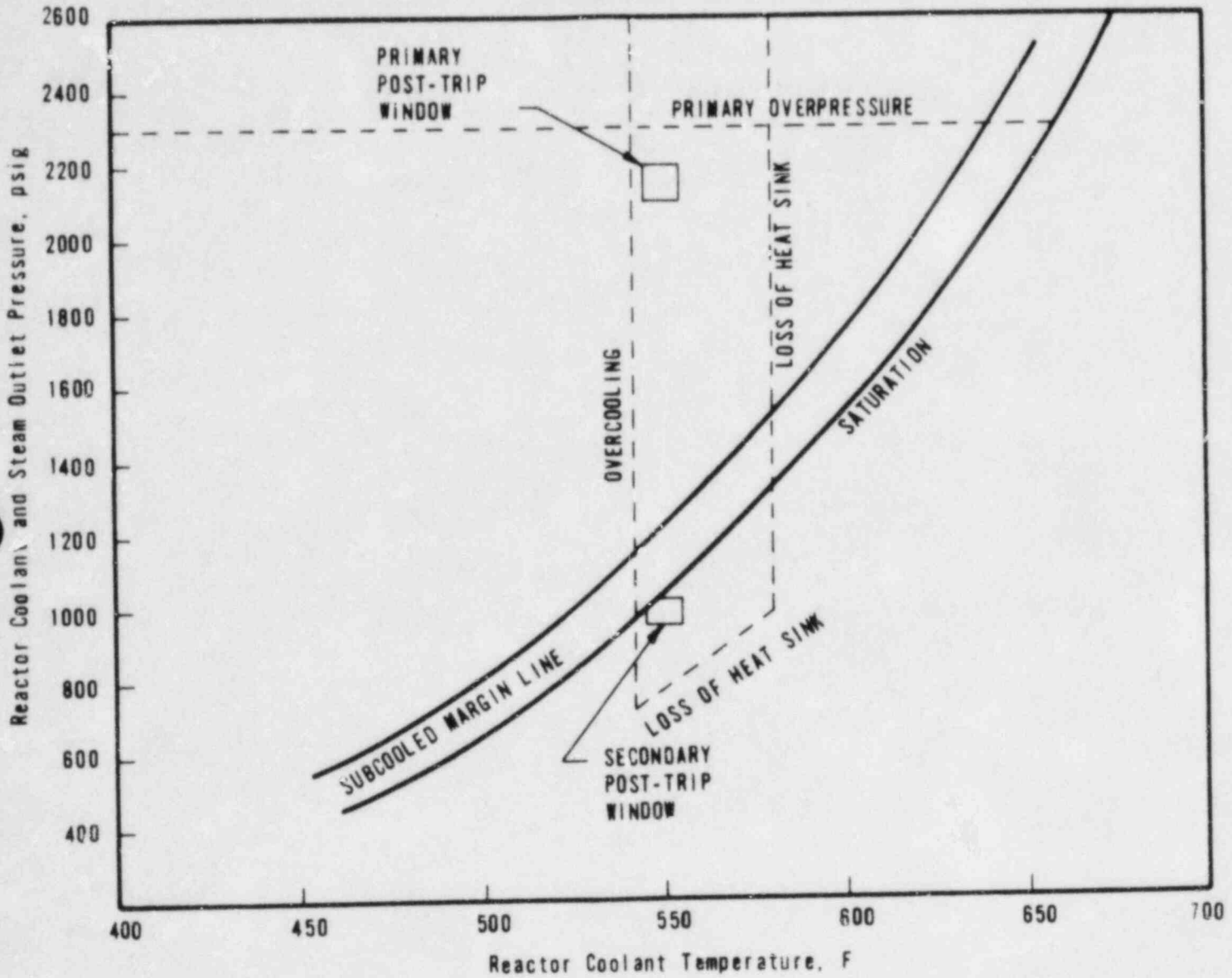
Figure 19 - Small Break LOCA in the RCS Loop Water Space

- This transient is different from Figure 18 because the pressurizer does not fill with water from the loops as a result of the break.

- 19a) Shows a small break with EFW used to remove heat.

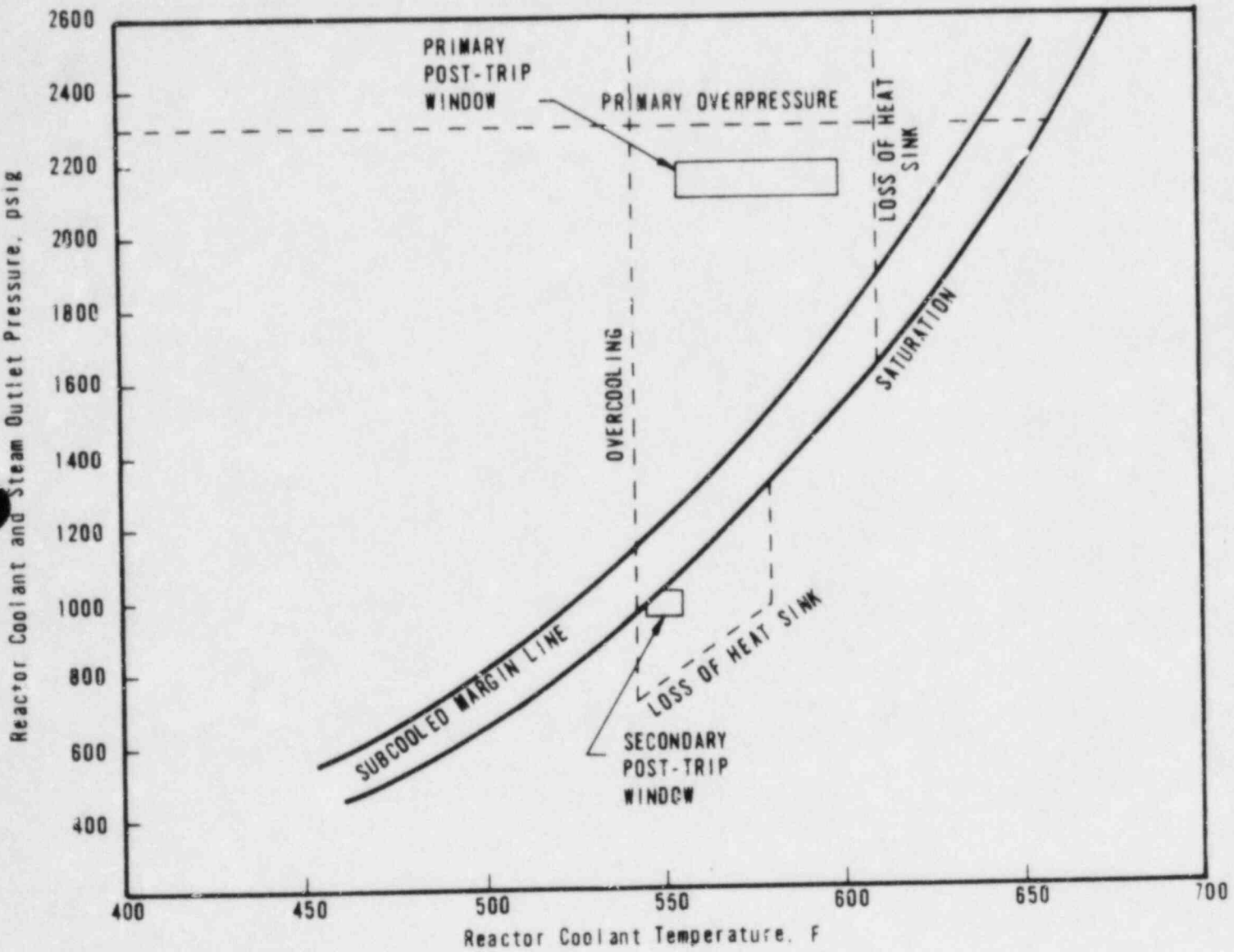
- 19b) Shows the same break with no MFW and EFW delayed. The effect of the heat transfer to the steam generators can be seen by comparing the RC pressures and secondary plots (in 19a and 19b) with and without FW. With no FW the RC system pressurizes to 2500 psi. At this pressure the leak rate is highest and HPI flow is lowest; use of the steam generator helps to reduce the leak flow and increase the HPI flow to cover the core. 19b also shows that steam pressure is lost because no steam generator inventory exists to create steam. When EFW is finally initiated at 1200 seconds, steam pressure is rapidly restored and the RCS begins to cool.

Figure 8 FORCED CIRCULATION POST-TRIP DIAGRAM



74-1124158-00

Figure 9 NATURAL CIRCULATION POST-TRIP DIAGRAM



74-1124158-00

DOCUMENT/ PAGE PULLED

ANO. 8401230549

NO. OF PAGES 1

REASON

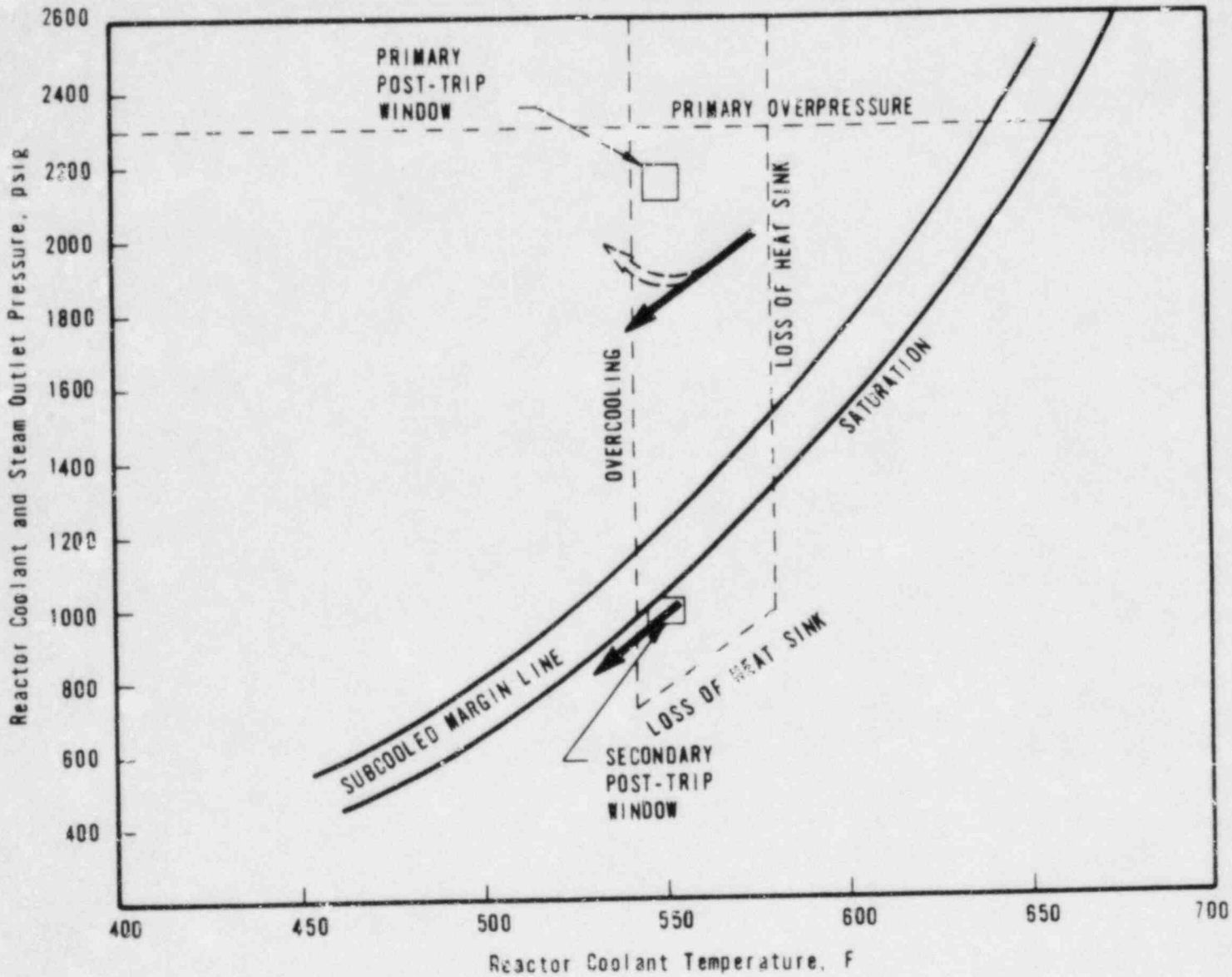
☐ PAGE ILLEGIBLE
☐ HARD COPY FILED AT: PDR CF
OTHER _____

☐ BETTER COPY REQUESTED ON ___/___/___

☑ PAGE TOO LARGE TO FILM
☑ HARD COPY FILED AT: PDR (CF)
OTHER _____

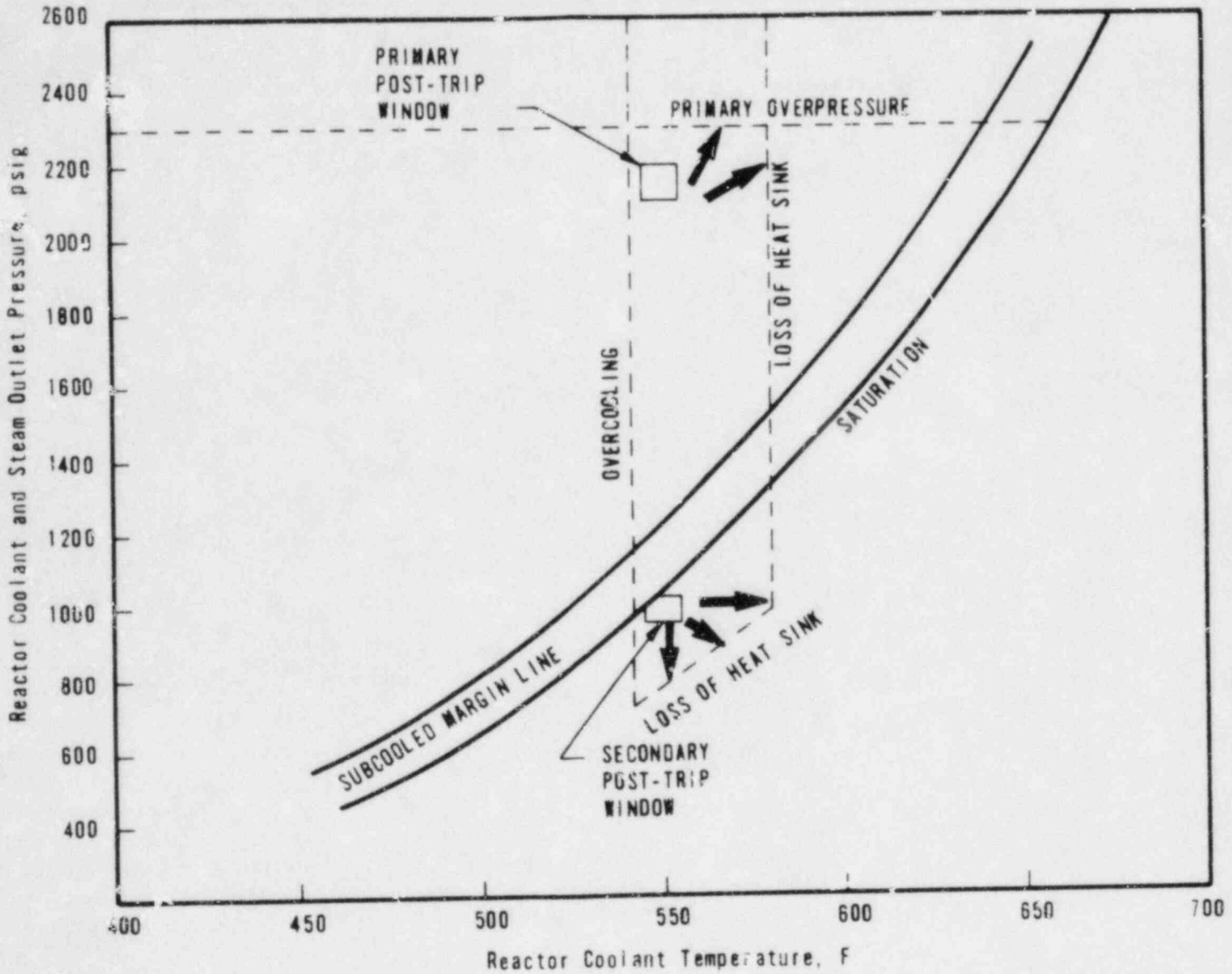
☐ FILMED ON APERTURE CARD NO 8401230549-06

Figure 11 OVERCOOLING TRENDS (SYMMETRIC)



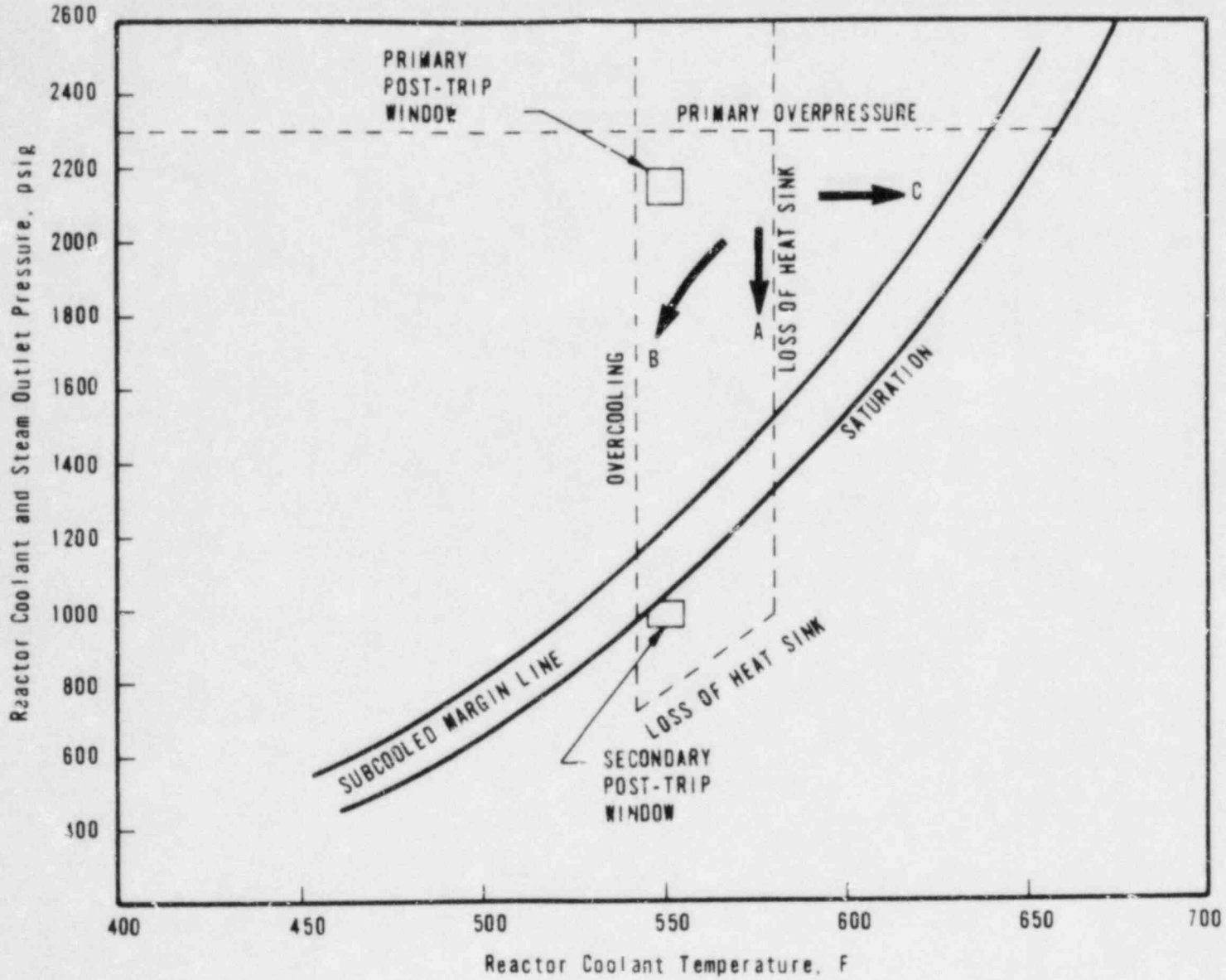
74-1124158-00

Figure 12 OVERHEATING TRENDS



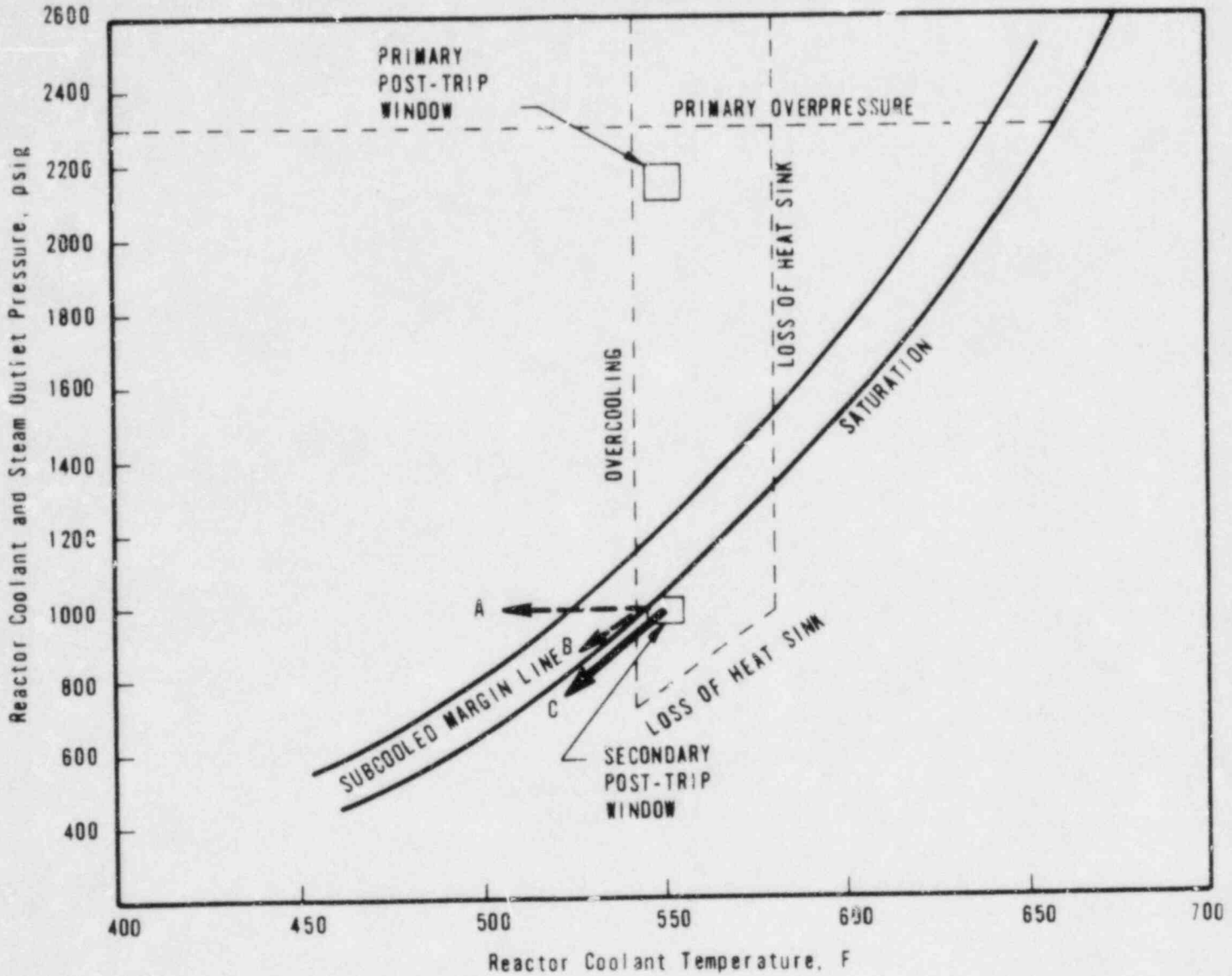
74-1124158-00

Figure 13 LOSS OF SUBCOOLED MARGIN



74-1124158-00

Figure 14 ASYMMETRIC OVERCOOLING TRENDS



74-1124158-00

Figure 15a. LOSS OF MAIN
EFW STARTE

Reference Points	Time (Seconds)	
1	0	Transient starts.
1-2	0-40	RCS P&T decrease d Typical post trip with a correspondi level.
2	40	EFW delivered to b level controlled a
2-3	40-100	System stabilizes the steam generato the saturation tem sure, and pressuri makeup.
3-4	100-600	Pressurizer level RC pressure restor
4	600	STABLE PLANT CONDI

PRO
APERTURE
RD

Figure 15b TOTAL LOSS OF MA

Reference Points	Time (Seconds)	
1-2	0-40	Same as Figure 15
2	4-	EFW fails; no fee steam generator.
2-3	40-100	System continues trend; feedwater
3	100	Steam generators
3-4	100-175	RCS reheats and to secondary heat increases. Trend curve indicates
4	175	PORV lifts and c
4-5	175-620	PORV controls RC to heat up; the conditions. Ste decreases due to
5	620	Pressurizer fill at the PORV or s primary conditio an abnormal cond to maintain core vessel.

Figure 15 LOSS OF MAIN FEEDWATER

FEEDWATER WITH
D WITHIN 40 S

Remarks

Main feedwater pumps trip.

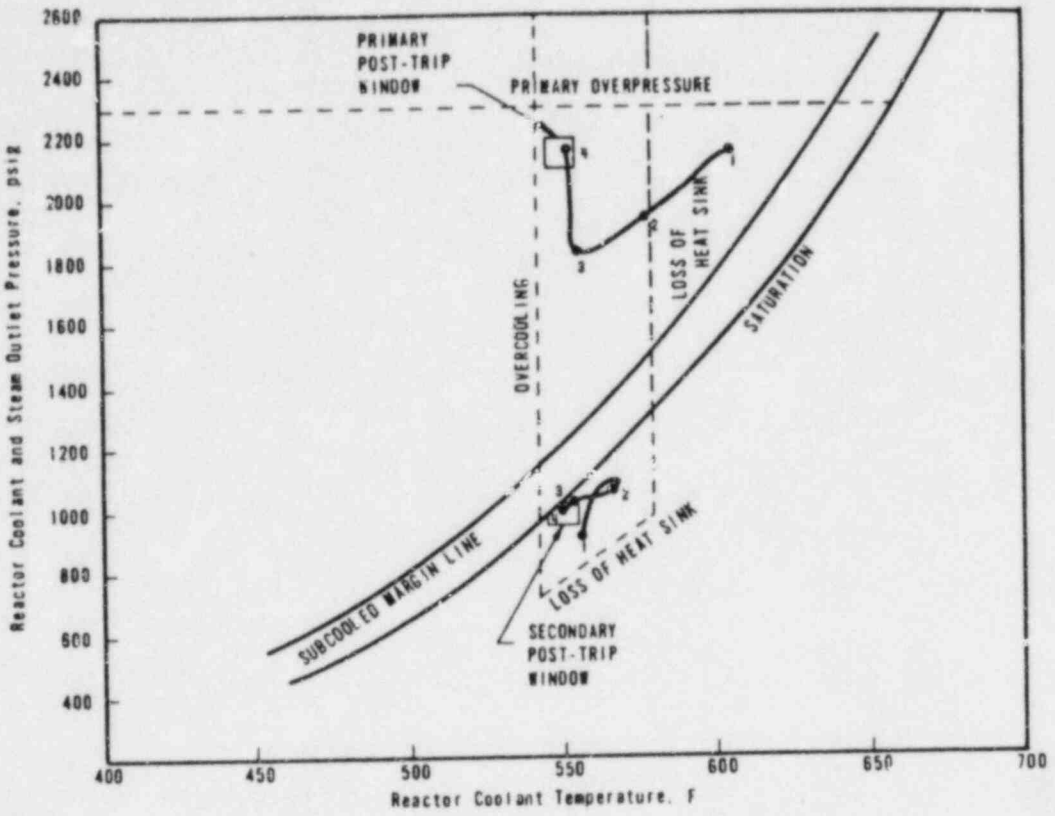
e to loss of fission power.
esponse (overcooling trend)
g decrease in pressurizer

th steam generators, with
low level (RC pumps on).

ith decay heat removal through
s. RC temperature approaches
erature for the secondary pres-
zer level increases because of

restored and steady with normal
ed by the pressurizer heaters.

TIONS.



N AND EMERGENCY FEEDWATER

Remarks

a.

dwater is delivered to either

o exhibit post trip overcooling
inventory is being boiled off.

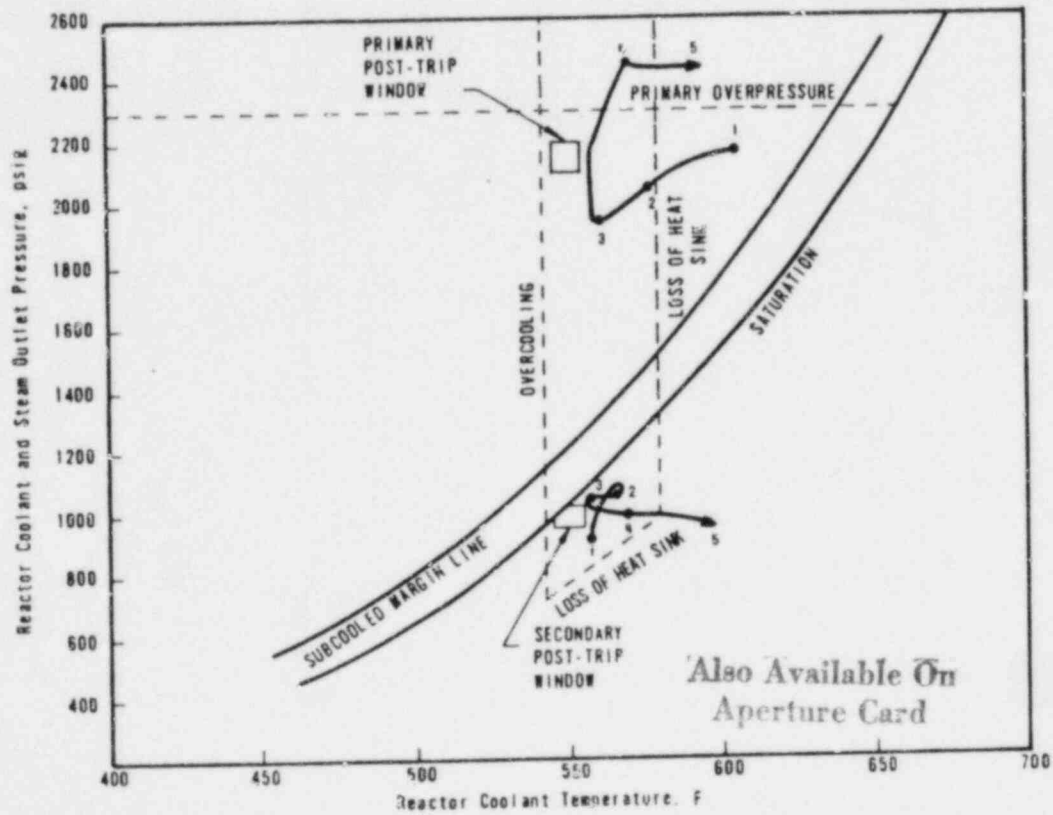
are almost dry.

epressurizes due to loss of primary
transfer. Pressurizer level also
of T_{cold} away from the saturation
oss of secondary heat removal.

cles to control RCS pressure.

pressure. RC temperature continues
rimary system is approaching saturated
m pressure in the dry steam generators
losses to ambient.

with water. RC pressure would stay
fety valve setpoint and saturated
s would develop. Plant is left in
tion; EFW and/or HPI must be established
cooling before water boils out of the



Also Available On
Aperture Card

8401230549-07

Figure 16a. SMALL STEAM LEA

Reference Points	Time (Seconds)	
1	0	Loss of main fe
1-2	0-40	RCS P&T decrease Typical post-tri a corresponding
2	40	E'W delivered to controlled at lo TBV's on both st
2-3	40-60	Overcooling beg sure and RC temp expected post-t
3	60	Operator notice
4	80	Operator isolate attempts to clo operator can re manual TBV or A steam generators shown. Failed cooldown is sho illustrative pu
5	98	If leak and coo HPI at this poi dry.

Figure 16b. SMALL STEAM LEA

Reference Points	Time (Seconds)	
1-2	0-40	Same as Figure 'B" fail open.
2-3	40-60	EFW flow delive due to faster l (T_{cold} vs. stea
3	60	Operator notice and lower T_{cold}
4	80	Operator isolat to close TBV's lated, OTSG 'B' the pressure in restore EFW to

If, as in 16a , the operator wi shown. He will while monitorin

PRC APERTURE CARD

Figure 16 SMALL STEAM LINE BREAK (0.5 FT^2)

X (SYMMETRIC)

Remarks

dwater - anticipatory reactor trip.

due to loss of fission power.
p response (overcooling trend) with
decrease in pressurizer level.

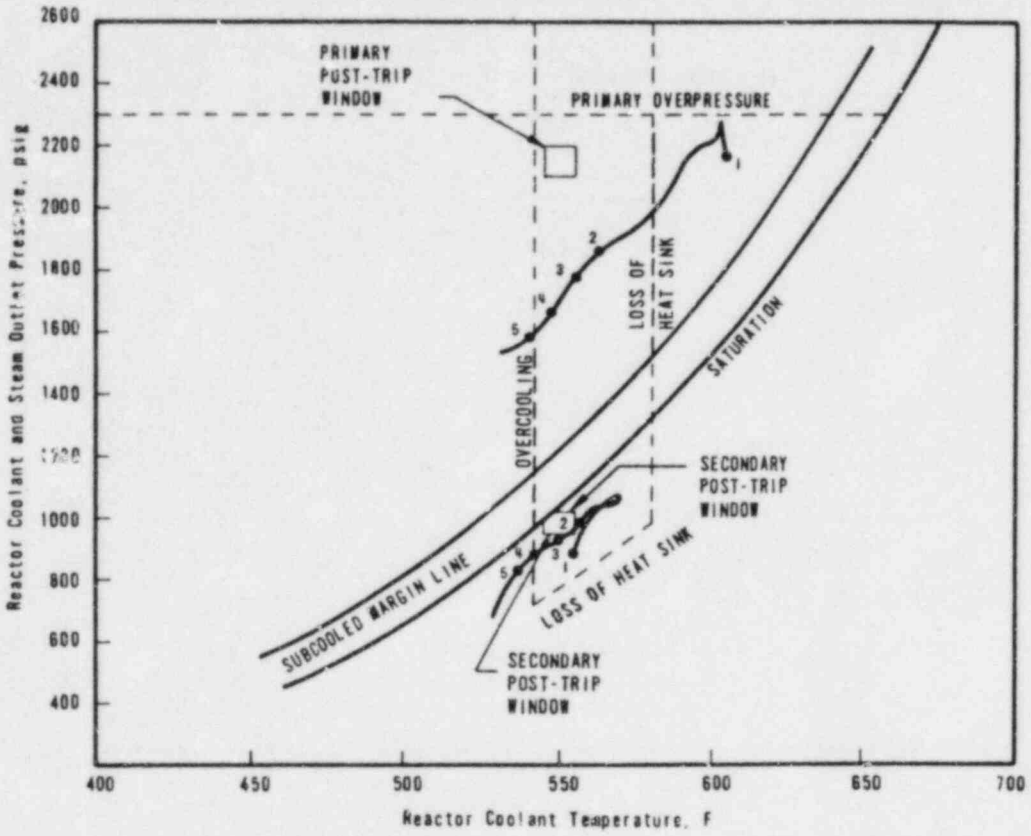
both steam generators with level
w level setpoint (RC pumps on).
eam generators fail open.

ns to become evident as steam pres-
eratures continue to decrease beyond
ip conditions.

overcooling.

s EFW to both steam generators and
e TBV's. If steam leak isolated,
tore EFW and normal DH removal with
V control. If leak(s) unisolable,
will boil dry and depressurize as
pen TBV's are isolable; however,
n to continue as if unisolable for
poses.

down continue, ESAS would initiate
t. Steam generators would be nearly



(ASYMMETRIC)

Remarks

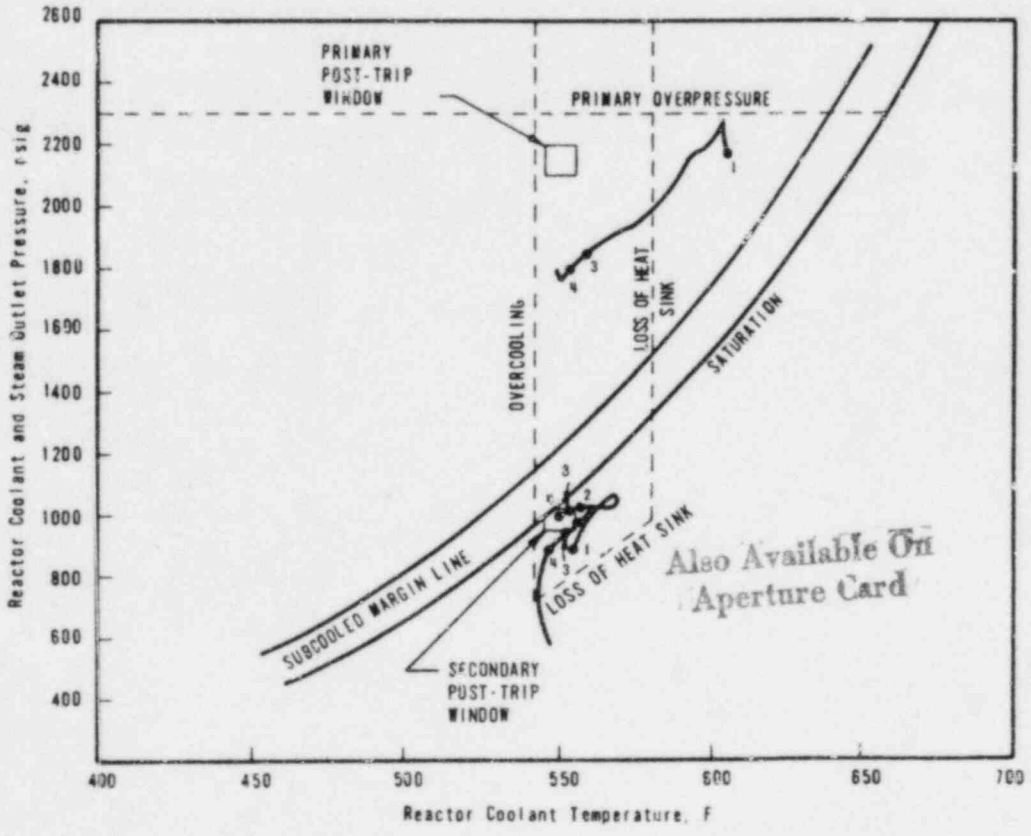
6a. except only TBV's on OTSG

ed to OTSG 'B' before OTSG 'A'
vel decrease. Secondary plots
pressure) begin to diverge.

divergence in secondary plots
in loop B.

s EFW to OTSG 'B' and attempts
n OTSG 'B'. If steam leak iso-
will repressurize to approximately
OTSG 'A' and the operator can
TSG 'B'.

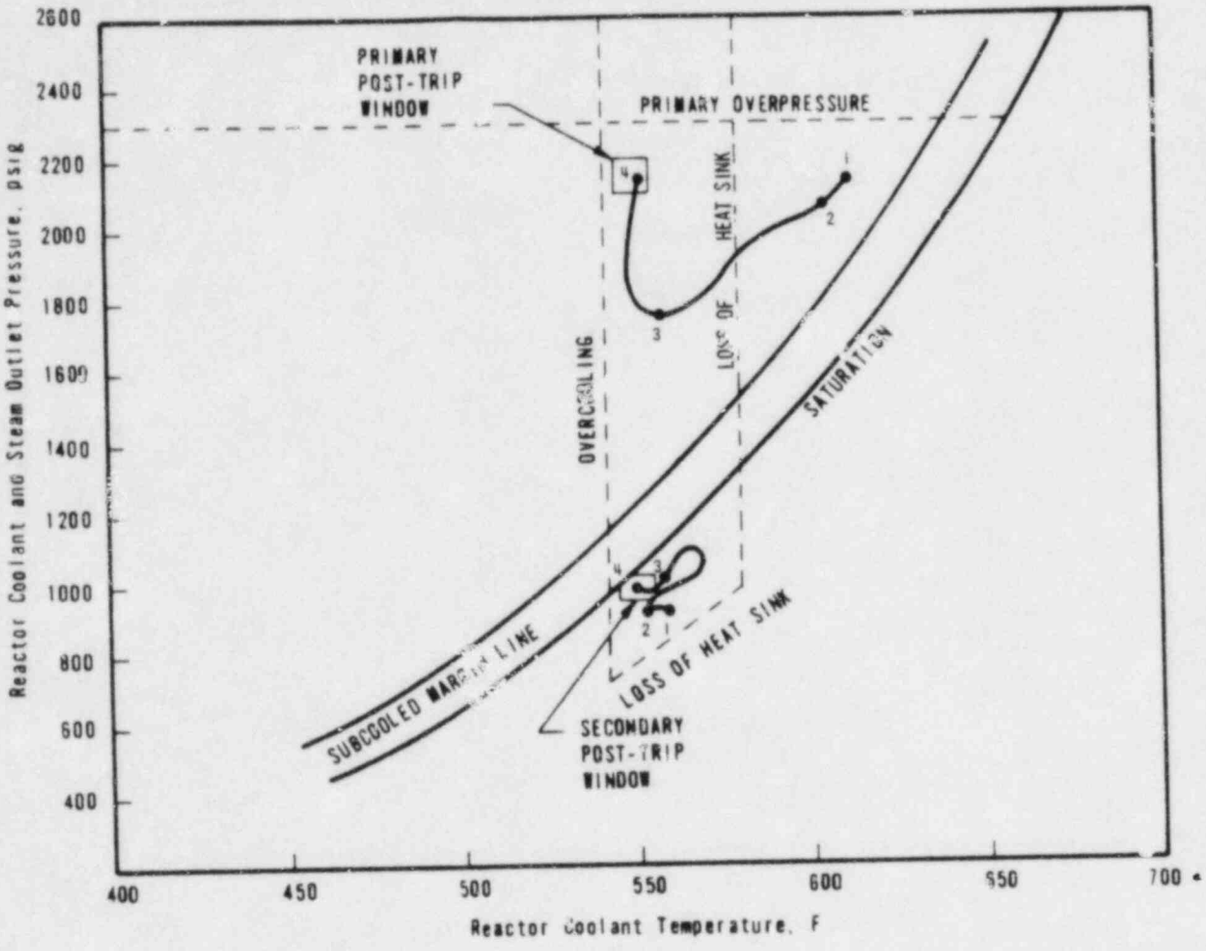
we assume the leak is unisolable,
l allow OTSG 'B' to boil dry as
control DH removal with OTSG 'A'
tube/shell ΔT in OTSG 'B'.



Also Available On
Aperture Card

8401230549-08

Figure 17 EXCESSIVE FEEDWATER



EXCESSIVE MAIN FEEDWATER ADDITION TO ONE STEAM GENERATOR (DURING POWER OPERATION)

Reference Points	Time (Seconds)	Remarks
1	0	With the plant operating at 100% power, a failure of the MFW pump controller allows pump overspeed. Excessive feedwater addition begins to both SG's.
1-2	0-60	Slight overcooling of RCS occurs due to excessive feedwater addition. ICS pulls rods to compensate for reduction of T_{ave}, but rod withdrawal is limited by the high flux limiter.
2	60	Manual reactor trip.
2-3	60-200	RC P&T decreases due to loss of fission power and higher than normal secondary inventory. The ICS initiates a feedwater runback and the MFW addition stops. Pressurizer level decreases because of reactor coolant contraction.
3	200	Minimum pressurizer level reached.
3-4	>200	Normal system pressure restored by operation of MU system and pressurizer heaters.

Figure 18a. STUCK OPEN PORV
TO CLOSE BLOCK

Reference Points	Time (Seconds)	
1	0	PORV assumed to ope
1-2	0-60	Pressure drops due out of PORV. Little occurs. An insurge surizer would occur level would be obse
2	60	Reactor trip on vari
2-3	60-125	RCS P&T decrease du primary to secondar trip-overcooling tr drops. MU can't ke pressure drops.
3	125	Subcooling margin l starts HPI. EFW ac controlled to 50% o
4	185	Hot leg saturates a occurs. Operator a PORV by closing the
4-5	185-600	HPI in combination on the generator tu voids within primar subcooled state and is restored to an i
5	600	Subcooling margin e and restarts RCP's.
5-6	600-700	Operator stops HPI
6	700	STABLE PLANT CONDIT

PRC
APERTURE
CARD

Figure 18b. STUCK OPEN PO

Reference Points	Time (Seconds)	
1-4	0-185	Same as Figure 18a continues, and ope
4-5	185-400	RCS is in two-phas P&T conditions dec stabilize at about increasing as pres
5	400	Pressurizer level changes from steam
5-6	400-1000	RC drain tank disc stable at approxim saturated. HPI ex are slowly being c
6	>1000	Operator initiates to place plant in break a return to during cooldown. quired thereafter

ITH OPERATOR ACTION
VALVE AT ~ 3 MIN.

Remarks

o discharge of pressurizer steam
or no change of RC temperature
of reactor coolant into pres-
and an increase in pressurizer
ved.

able low RC pressure.

to loss of fission power and
heat transfer; general post
nd results. Pressurizer level
p up with the leak, and RC

st; operator trips RC pumps and
ated with level automatically
operate range.

d an insurge into the pressurizer
tion is assumed to isolate the
block valve. LOCA is isolated.

with condensation of the RC steam
es leads to collapse of steam
system. System returns to a
repressurizes as pressurizer level
dicated level.

tablished; operator throttles HPI

nd restarts normal MU and letdown.

IONS.

V (NO ISOLATION)

Remarks

except PORV is not isolated, leak
ator raises OTSG levels to 95%.

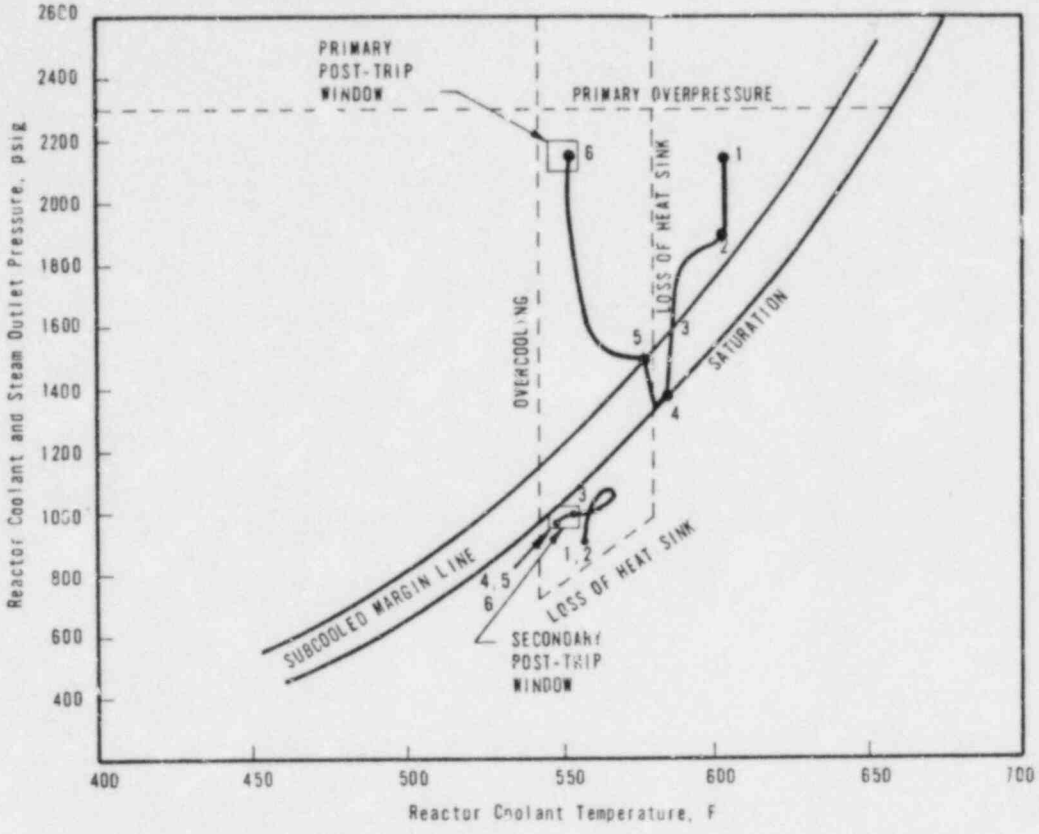
natural circulation condition.
ease along saturation line and
1200 psia. Pressurizer level is
urizer steam space depletes.

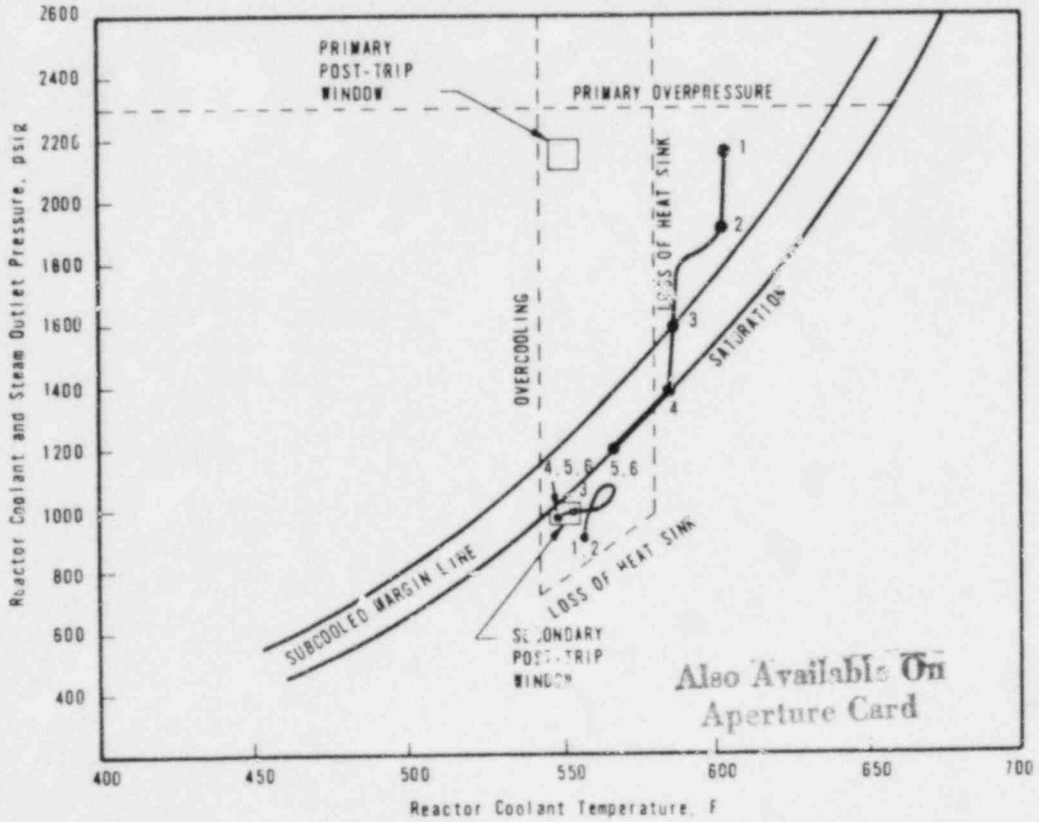
ndicates full scale; leak flow
to a steam-water mixture.

ruptures. Primary system remains
tely 1200 psia with the hot leg
eeds core boil-off and steam voids
ilapsed.

plant cooldown and depressurization
safe condition. For this size
subcooled state would be expected
Solid-water cooldown would be re-
unless PORV is isolated.

Figure 18 SMALL LOCA IN PRESSURIZER STEAM SPACE





Also Available On
Aperture Card

8401230549-09

Figure 19a. 0.01 FT^2 BREAK AT
TO BOTH STEAM GE

Reference Points	Time (Seconds)	
1	0	LOCA occurs at discharg
1-2	0-50	Pressure dr break; pres
2	50	Reactor tri
2-3	50-90	RCS P&T dro mary to sec overcooling cation goes with leak,
3	90	Subcooling starts HPI.
3-4	90-120	EFW actuate it reaches
4	120	Pressurize
4-5	120-600	RCS in two- crease alo mately 122
5	600	Two-phase top of hot generator
5-6	600-1500	RCS repress to reheat tion curve, in size; co possible. transfer to sure. Tren loss of sec
6	1500	Boiler cond is low enou tubes. Ree restores st
6-7	>1500	Pressurizer ration curv side satura plant coold

Figure 19b. 0.01 FT^2 BREA
DELAYED FOR 2

Reference Points	Time (Seconds)	
1-4	0-120	Same as F water has
4-5	120-1200	Steam gen tion line Pressuriz slowly dr
5	1200	Operator initiates generator
5-6	>1200	With EFW RCS P&T d slightly Pressuriz of coolan plant coo

PRC
APERTURE
CARD

PUMP DISCHARGE WITH EFW OPERATION
NERATORS (LOCA IN RCS WATER SPACE)

Remarks

; break is equivalent to 1.35 in OD hole
e of RC pump.

ops due to release of reactor coolant out
surizer level decreases.

p on variable low RC pressure.

ps due to loss of fission power and pri-
ondary heat transfer; general post trip
trend results. Pressurizer level indi-
off scale low. Because MU can't keep up
pressure drops.

margin lost; operator trips RCP's and

d and is automatically raised to 50% (when
50% operator will manually increase to 95%).

drains and hot leg saturates.

phase natural circulation mode. P&T de-
g saturation curve and stabilize at approxi-
psi.

atural circulation stops; steam bubble in
leg prevents liquid carry over to steam
nd steam generator cannot remove heat.

urizes because all heat from core is going
he reactor coolant. RCS stays on the satura-
Steam bubble in hot leg is slowly increasing
ndensation of RCS steam on tubes is not yet
Pressurizer level is increasing. Lack of heat
steam generators causes decay in steam pres-
d of Tcold away from saturation curve indicates
ondary cooling.

enser cooling established; RCS hot leg water level
gh to allow RCS steam to condense on steam generator
stablished heat transfer to steam generators
eam pressure.

level decreases. RCS P&T decrease along satu-
e and will stabilize slightly above secondary
tion conditions. Operator should initiate a
own and depressurization to recover plant.

K AT PUMP DISCHARGE WITH EFW AND HPI
) MINUTES (LOCA IN RCS WATER SPACE)

Remarks

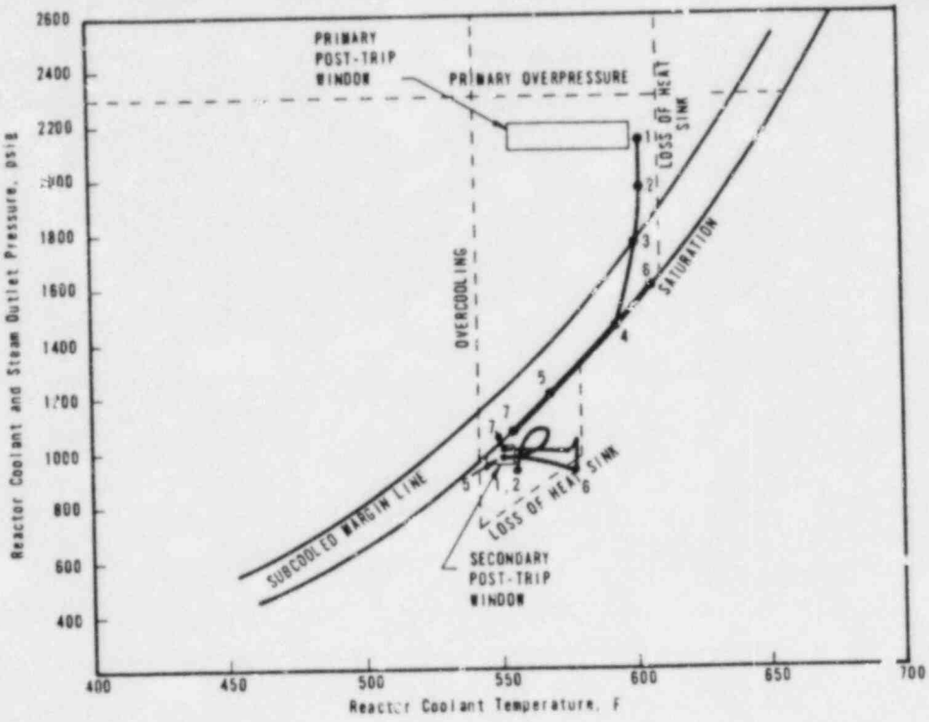
igure 19a. except that a total loss of feed-
occurred and HPI is assumed to fail.

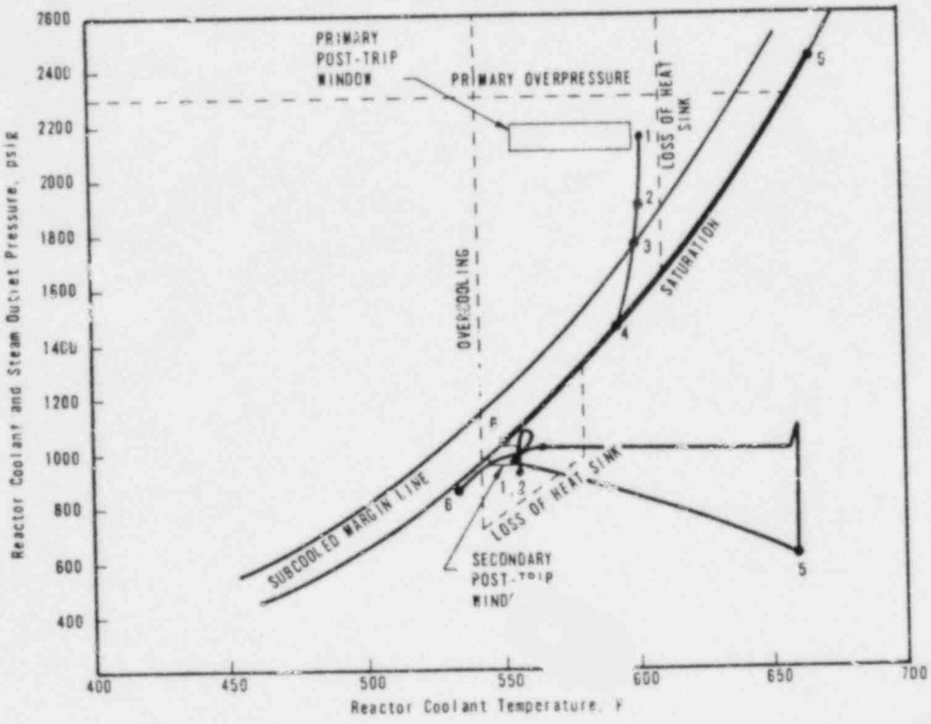
erators boil dry; P&T increase along satura-
due to lack of primary to secondary cooling.
r level is increasing. Steam pressure will
p once inventory is boiled off.

restores EFW system operation and manually
HPI. EFW flow is started to both steam
s and steam pressure is restored.

on, boiler condenser cooling is started. The
rops along saturation curve and will stabilize
above secondary side saturation conditions.
er level drops to zero indication because
t contraction. Operator should initiate a
ldown and depressurization to recover plant.

Figure 19 SMALL LOCA IN RCS WATER SPACE





Also Available On
Aperture Card

8401230549-10

DIAGNOSIS & MITIGATION

CHAPTER C

ABNORMAL TRANSIENT DIAGNOSIS AND MITIGATION

Introduction

This chapter shows how an abnormal transient can be diagnosed and mitigated using the information provided by the P-T diagram and the concepts on heat transfer discussed in the previous chapters. A simplified flow chart of the approach to be used to diagnose and mitigate an abnormal transient is provided in Figure 20A "General Plant Transient Mitigation". It is broken down into a few separate steps although these steps will "blend" together into one continuous process in actual practice. The Abnormal Transient Operating Guidelines are implemented whenever an automatic or manual reactor trip occurs (the operator may have manually tripped the reactor after recognizing something was wrong) or a forced shutdown is necessary.

The guidelines are provided in Part I. They list the appropriate operator actions necessary to mitigate an abnormal transient. They follow the approach outlined in Figure 20A. The guidelines incorporate the following features.

1. Use of the P-T diagram which provides a constant feedback to the operator on his success or failure after taking each step in Part I. This diagram should be checked frequently to make sure things are progressing as expected. It will thus give the operator early indications of subsequent failures that are delayed after the initial event, or

multiple failures that were covered by the predominant event and didn't appear until that one was corrected.

2. The guidelines are constructed such that the operator makes an attempt to correct the problem with a given piece of equipment or system (e.g., AFW to correct loss of main feedwater). If that fails he is instructed to go on to the next available system. This failure of the AFW system is not given priority attention in the body of Part I, protection of the core is.

3. The operator is given frequent present plant status "(STATUS)" aids throughout the procedure to help him maintain proper orientation.

4. If new symptoms appear he is instructed to recycle (go to the section that treats that symptom) to the appropriate part of the procedure.

Immediate Actions

The first block in Figure 20A is the "Immediate Actions" block. The immediate actions should be completed in the first 2-3 minutes. The first action to be made is to determine if a reactor trip has occurred or plant conditions requiring a forced shutdown exist. If a reactor trip has occurred the operator should manually trip the reactor and turbine, then proceed to the next post trip site of the ATOG procedure which is "Vital Systems Status Verifications". However, if plant conditions warrant a forced shutdown, the operator should initiate the appropriate shutdown

procedure. If a reactor trip should occur during the forced shutdown operations, the post-trip ATOG procedures should be implemented.

Vital Systems Status Verification

The next major block on Figure 20A is the Vital Systems Status Verifications. This section requires reviewing specific plant status items including the P-T diagram to determine if they are behaving as they should for a normal reactor trip. If the specific plant status items cannot be verified as performing as expected, the operator should perform the specified remedial actions. The procedures provide specific remedial actions for each plant status item which cannot be verified. The plant status items which are checked first are the normal automatic post trip functions which control core reactivity, primary and secondary inventory, and primary and secondary pressure.

Next the operator must verify the operability of certain power supplies to assure the important plant parameters can be monitored and the power is available to the important control devices. These include pumps, valves, etc., which are needed to safely control the plant and to mitigate abnormal transients. The plant cannot be controlled or abnormal transients mitigated if the control devices do not work. Nor can the plant be safely controlled if the parameters to be controlled are not displayed for diagnosing the plant status.

Next the operator must check to see if any safety system has been initiated and if so that they are operating properly. For example, when the operator notes the presence of a SLRDS alarm he will be directed to verify proper actuation of SLRDS controlled equipment.

Next, the operator needs to check the P-T diagram for a loss of subcooling margin, "overheating" or "overcooling" conditions. Table 2 summarizes generally the plant status items to be checked and the actions to be taken if the items are not as they should be.

The P-T diagram is the foundation for transient diagnosis and for the actions to correct abnormal transients.

When the P-T diagram is checked, the reactor coolant and secondary system P-T parameters should stay within the "post-trip" boundaries. If the plant responds so that these limits are not exceeded then the transient is going "as expected". If the plant does not "go as expected" the P-T parameters should be checked to find out the "type" of abnormal transient so that proper corrective actions can be made to restore the reactor-steam generator heat transfer. Finally, the operator must check to see if there are any steam generator tube ruptures.

If the Vital Systems Status Verification shows everything is alright, then the plant is in a stable subcooled condition with proper primary to

secondary heat transfer and no primary boundary failures. Further action will be at the discretion of the station management.

If one or more items are not alright, the ATOG procedure will direct the operator to make a remedial action. The remedial action may be a finite action such as closing a valve or a "Followup Action".

Followup Action

As shown on Figure 20A, when the P-T diagram indicates a "loss of subcooling margin", "overcooling", or "overheating" exists, the operator must determine which one of the three conditions exist, and then start the appropriate followup actions procedure. These followup actions are first directed at re-establishing the correct amount of steam generator cooling. If it cannot be re-established, then backup cooling methods are to be implemented. (The backup cooling methods are discussed in a separate chapter of Part II).

Once steam generator heat transfer or backup cooling has been established, the plant should be brought to a stable condition for plant cooldown. The condition may be hot or cold depending on the circumstances; a return to the "post-trip" boundaries is not required for plant stability.

Cooldown Procedures

Once a stable plant condition is reached, the plant is cooled down using one of several cooldown procedures depending on the existing stable plant

conditions such as a solid water system or saturated RCS. The ATOG procedures state which cooldown procedure to use. This is discussed in the Post-Transient Stability Chapter of ATOG.

Inadequate Core Cooling

In the event that neither steam generator cooling or backup cooling is established, "Inadequate Core Cooling" will occur. This topic is discussed in the Backup Cooling Chapter.

The remainder of Chapter C discusses the immediate actions for fast transients, checks for transient stabilization, and corrective actions for "overheating" and "overcooling".

Immediate Actions For Fast Transients

Excessive main feedwater requires the operator to quickly terminate feed flow to prevent water spilling into the steam line. Steam generator tube rupture requires fast action to depressurize and begin cooldown to limit the offsite doses.

Table 3 shows the immediate actions to take for these circumstances; some of the actions include checks of equipment indication to see that it is working correctly - other actions are to manipulate controls to operate equipment. Table 2 shows "standard" action; Table 3 shows the actions needed to control "fast" transients.

A steam line break in the intermediate building also requires fast action to terminate the steam release to the intermediate building.

Determination of Transient Stabilization

Although the type of accident may have become evident during the first 2 or 3 minutes of the transient, plant monitoring is required to make sure that the accident is going as expected. Generally, after 2 or 3 minutes, actions have already been taken to stabilize within the "Post Trip Windows" (examples of this were given in the P-T Diagram Chapter). Actions have already been taken to identify the "fast" transients and the systems which should be operating have been checked to make sure that they are working correctly. Further plant monitoring should begin. At this stage (5-7 minutes) the effort should now be to make sure that the plant stabilizes as it should. To do this the P-T diagram is kept under surveillance. If the plots of reactor coolant pressure vs. hot leg temperature and SG pressure vs. cold leg temperature stabilize within the boundary lines, the transient is probably not abnormal and a quick check of the following should be made to ensure system and equipment parameters are within expected values:

Heat Transfer Balance Indicators

- P-T diagram (for RC pressure and temperature and subcooling)
- Pressurizer level
- Steam generator level and pressure

Equipment Status and Operation (depending on what was started)

- Makeup/HPI flow rates and pump status
- Main or emergency feedwater flow rates and pump status
- RC pump operation including cooling water and seal injection service
- Position of important valves (letdown, PORV, feedwater isolation and control valves, pressurizer spray valve)
- Containment isolation and cooling systems
- Power supplies (AC and DC)

Once these reviews are completed, a more thorough check can be conducted and a decision made to determine if the plant is stable. (Refer to Chapter F, "Post Transient Stability Determination".)

But if the first review of the P-T indicates that the plots of reactor coolant pressure vs. hot leg temperature and/or SG pressure vs. cold leg temperature are not going to remain within the boundary lines, then something is wrong with heat transfer and corrective actions are required to bring the heat transfer into balance.

The path for correction is charted and shown on Figure 21, "Transient Mitigation Approach". The chart keys on the three general characteristics displayed on the P-T diagram: overcooling (too much steam generator

heat transfer), overheating (insufficient steam generator heat transfer), and loss of subcooling. The chart is a reference table that ties together a wide variety of information for corrective actions. With the exception of LOCA, corrective actions for all abnormal transients are provided in this section. LOCA is discussed separately in considerable detail in Appendix F of these guidelines.

Corrective Actions for Overcooling (too much steam generator heat transfer)

Figure 22 shows the corrective actions to be taken for overcooling. The chart is largely self-explanatory so only a brief discussion will be given. Information provided by the chart will not be repeated.

Overcooling is always caused by failures on the secondary side. The usual sources of failure are low steam pressure or excessive main or emergency feedwater or by combinations of high feedwater and low pressure. The P-T diagram shown is typical for a more severe case of overcooling; usually excessive feedwater alone (unless severe and not terminated within 2-4 minutes) or small reductions in steam pressure will not cause loss of subcooling. But the general trend shown by the P-T diagram is characteristic of overcooling. Some LOCA's can also cause a loss of steam pressure because the RCS will depressurize, cool and draw heat away from the steam generators; this will be temporary for small breaks.

Once an overcooling trend is exhibited, checks should be made on steam pressure, steam generator level, and main or emergency feedwater flow. If the cause is obvious, then actions to isolate the cause should be taken.

If the subcooling margin is lost during an overcooling transient, the HPI start rule must be used; two HPI pumps must be started.

When the subcooling margin is lost, the RC pumps must be tripped and not restarted until subcooling is restored; a LOCA may have occurred, and its P-T characteristics and overcooling characteristics are similar.

Overcooling transients induced by steam pressure and/or feedwater control failures on only one steam generator may be obvious when T_{cold} vs. steam pressure for both loops are plotted on one P-T diagram. If the magnitude of the overcooling is surficiently large, the two plots should diverge as shown in Figure 22. The "bad" steam generator may be the one with the higher or lower steam pressure depending on the type of transient. However, if the overcooling is significant, T_{cold} in the affected loop will always lead T_{cold} in the loop with the good steam generator (i.e., T_{cold} in the affected loop will be lower). Comparison of feedwater flowrates may also identify the affected SG. If one SG is causing the overcooling, it should have a higher FW flowrate, regardless of whether the overcooling is due to excessive feedwater or loss of steam pressure.

Detection of overcooling due to low steam pressure and determination of which generator has failed, if <u>not</u> obvious, can be done by two methods. The first way is to stop all feedwater <u>when a level exists in both generators</u> (if level exists only in one generator the one without level is likely to be failed). When feedwater is isolated to both generators,

the level should fall at a faster rate in the failed generator. Detection is possible before both generators boil dry and feedwater should be restored to the "good" generator before it dries out. Termination of feedwater should be done by closing valves; pumps should not be stopped but should continue to run on recirculation. A characteristic feature of steam leaks is that the steam generator with the low pressure will transfer the heat from the RCS and lower the RCS temperature; the "good" generator will not. Consequently the RCS temperature can fall below the temperature of the "good" generator. When this occurs the pressure in the good generator will drop below the TBV setpoint, they will close, and steam generator level will drop slowly or not at all. Consequently, one steam generator will retain level, so stopping all feedwater to both generators is not dangerous. However, when one steam generator boils dry, then the remaining generator will begin to transfer heat and level will drop. Feedwater must be restored before it is dry.

The second (but less reliable) way to identify a leaking generator is to compare the rate of drop of steam pressure in both generators. The failed generator will permit steam pressure to fall faster than the good generator will. A differential pressure between the two steam generators of about 100 psi, with the failed generator lower, will show the correct one to isolate. The 100 psi differential will show up rapidly for large leaks and slower for small leaks. A steam leak of about 5% total flow (about equal to one main steam safety valve stuck open) will show this

trend within 3 to 5 minutes. However, this magnitude of pressure differential may exist only for a short duration. Therefore, comparison of level changes in isolated SG's is preferred when the affected SG is not obvious.

It is highly unlikely, but possible, that both SG's have unisolable steam leaks. If this situation occurs, the operator should proceed as follows:

1. Maintain primary to secondary heat transfer by supplying feedwater to both SG's at a very limited rate (flow through the MFW nozzles is preferred to flow thorugh the AFW nozzles), essentially controlling the cooldown rate by feedwater flowrates rather than by adjusting steam pressure. Attempt to stop the steam leak on at least one SG (e.g., gag shut a leaking MSSV, etc.). If heat removal is excessive with two SG's, or if steam flow needs to be stopped from one SG (due to location of the steam leak, to aid repairs, etc.), then

2. Isolate FW to one SG and allow it to boil dry while continuing restrictive feed to the other SG and attempting to maintain level and controlled DH removal. Continue trying to stop the leak on at least one SG. If conrolled DH removal with one SG is not possible, then

3. Initiate HPI cooling, isolate all FW, and allow both SG's to boil dry.

4. Continue attempts to repair or isolate the leak path on at least one SG. When the steam leak is repaired (isolated) on one SG, then use

the repaired SG to restore primary to secondary heat transfer and recover from HPI cooling.

Whenever an overcooling transient occurs, the operator's first goal is to stop the transient and restore controlled core cooling. Once this is accomplished, he should check for indications of a steam generator tube rupture, since the overcooling may have induced excessive stresses on the tubes. Overcooling due to steam leaks is also discussed in Appendix E of Volume 2 and tube ruptures are covered in Appendix C of Volume 2.

During the course of performing the followup actions in Section III of Part I, and after stabilizing the plant after correcting an abnormal transient, the operator should continue monitoring the P-T diagram and key plant parameters. This continuing surveillance will provide feedback on the success of actions taken and allow early recognition of other failures/transients should they occur.

Corrective actions for excessive feedwater are shown on the chart and discussed in Appendix A.

Corrective Actions for Overheating (not enough steam generator heat transfer)

Figure 23 shows the corrective actions to take when the reactor coolant cannot transfer heat to the steam generators. If reactor-to-steam generator heat transfer is not coupled, T_c will trend away from the saturation curve. In general there are three causes of insufficient heat transfer:

- There is no inventory in the steam generator to receive the heat (loss of all feedwater)
- The reactor coolant cannot transport the heat to the generator because there is insufficient inventory (LOCA)
- Circulation has stopped (forced and natural)

Loss of all Feedwater

Overheating when all feedwater is lost can take different paths depending on the decay heat level, when feedwater was lost, and whether HPI was operating before it was lost. The P-T diagram illustrated on Figure 23 shows a total loss of all feedwater immediately after reactor trip from full power, with HPI cooling started when the operator recognized the loss of primary to secondary heat transfer and loss of all feedwater. Regardless of the path, the loss of all feedwater from power operation will exhibit two clear characteristics on the P-T diagram:

- After the normal post-trip cooldown, the RCS will begin to reheat and repressurize beyond the normal post-trip "window" (point 2 on Figure 23) when the SG's boil dry.
- Steam pressure will drop because there is no feedwater and T_{cold} will increase away from the saturation curve.

The corrective actions for this transient are to attempt to restore feedwater; failing to do so, HPI cooling should be started when primary to secondary heat transfer is lost and before the RC pressure reaches the PORV open setpoint. The PORV should be manually opened and two HPI pumps should be started and run at full capacity until the subcooling margin is restored. Then the HPI flow should be throttled. Although the HPI start rule requires that HPI be started when the subcooling margin is lost, the expected path for this transient is that the PORV setpoint is reached before the subcooling margin is lost. Without HPI, primary inventory would be lost out of the PORV for about 30 or 40 minutes before subcooling margin is lost. This could lead to conditions of core uncovery. Therefore, the operator should start HPI when primary to secondary heat transfer is lost to assure core protection rather than waiting until the subcooling margin is lost.

When HPI cooling (with the PORV open) is started under these circumstances, all but one RC pump should be tripped. This will reduce the heat input to the RC. One RC pump should continue to run as long as possible to maintain forced core cooling. When the subcooling margin is lost, all the RC pumps must be tripped. HPI cooling is discussed in more detail in Chapter D, "Backup Cooling Methods."

Continued operation without feedwater, but with HPI cooling, will provide adequate core cooling, but the operator should continue efforts to restore feedwater and primary to secondary heat transfer. When the subcooling

margin (as indicated by incore thermocouples) is restored, the HPI flow should be throttled. A reactor coolant pump should also be restarted at this time. Control of HPI flow to keep the minimum subcooling margin is important to minimize reactor vessel thermal shock. One way thermal shock occurs is when the reactor coolant is subcooled and no circulation exists, because the cold HPI water will slowly flow into the downcomer and flow next to the hot reactor vessel wall. Restart of a reactor coolant pump will thus help prevent thermal shock because it mixes the HPI water and the reactor coolant. (See Figure 25 and Chapter E of this volume for a discussion of HPI throttling and RC pump restart.)

If EFW or MFW is restored while the reactor coolant is saturated and HPI is running, the subcooling margin will be restored and a reactor coolant pump may be restarted.

LOCA

The other condition in which heat transport to the steam generators can be interrupted is during a LOCA. LOCA is discussed in great detail in Appendix F and will not be covered here in detail. However, this section will show how LOCA's are to be identified and will show how to locate those that can be isolated.

Although some small breaks will allow the reactor coolant to transport heat to the steam generators, some will not. The most significant characteristics that show poor heat transfer are an increase of incore T/C along the saturation line even when a steam generator level exists.

Incore T/C is increasing because the reactor coolant is absorbing the core heat and not passing it to the generators. Without RC loop flow, T_c will tend to decrease due to seal injection, HPI and heat loss through the pipe.

Steam pressure will gradually drop because little or no heat is being absorbed. Figure 13 of Appendix F (LOCA) shows this P-T characteristic.

Figure 23 indicates that LOCA's can cause poor heat transfer and includes three references for supporting actions:

(1) Table 4a shows how to distinguish LOCA's from other transients.

(2) Table 4b shows symptoms for LOCA's that can be located and shows which equipment to use for isolation (for those that can be isolated).

(3) Appendix F shows the corrective actions for LOCA's.

Loss of Circulation

Natural circulation can be temporarily interrupted because of reactor coolant contraction after a severe overcooling transient. A long interruption would not be expected since HPI will refill the system and natural circulation will normally restart. Loss of natural circulation would be expected for most LOCA's or for an extended loss of feedwater. Therefore, to restore natural circulation for either of these, the failure must be corrected (feedwater restored) and subcooling should be restored

(to ensure the best natural circulation). Loss of natural circulation heat transfer can be the cause or the result of an overheating condition; therefore, the "overheating" corrective actions include restoration of heat transport as an integral part of the action.

Pressurizer Control System Failures

Two failures of the pressurizer controls can occur that can change RC pressure. These are not serious events because they are slow, but if they are left without correction plant control can become more difficult.

Failure of pressurizer heaters (on) with no spray operation will cause the RC pressure to increase to the PORV setpoint at a constant reactor coolant temperature. (If the spray is operating it will stop the pressure increase.) Steam will be released to the RC drain tank until the heaters are turned off. The normal makeup control will continue to add reactor coolant until the makeup tank level is lost at which time the pressurizer level will begin to drop. Although this is a very slow transient and should be easy to correct (manual cutoff or power disconnect), if it is left unattended the following equipment damage can result:

RC Drain Tank Rupture Disk Failure

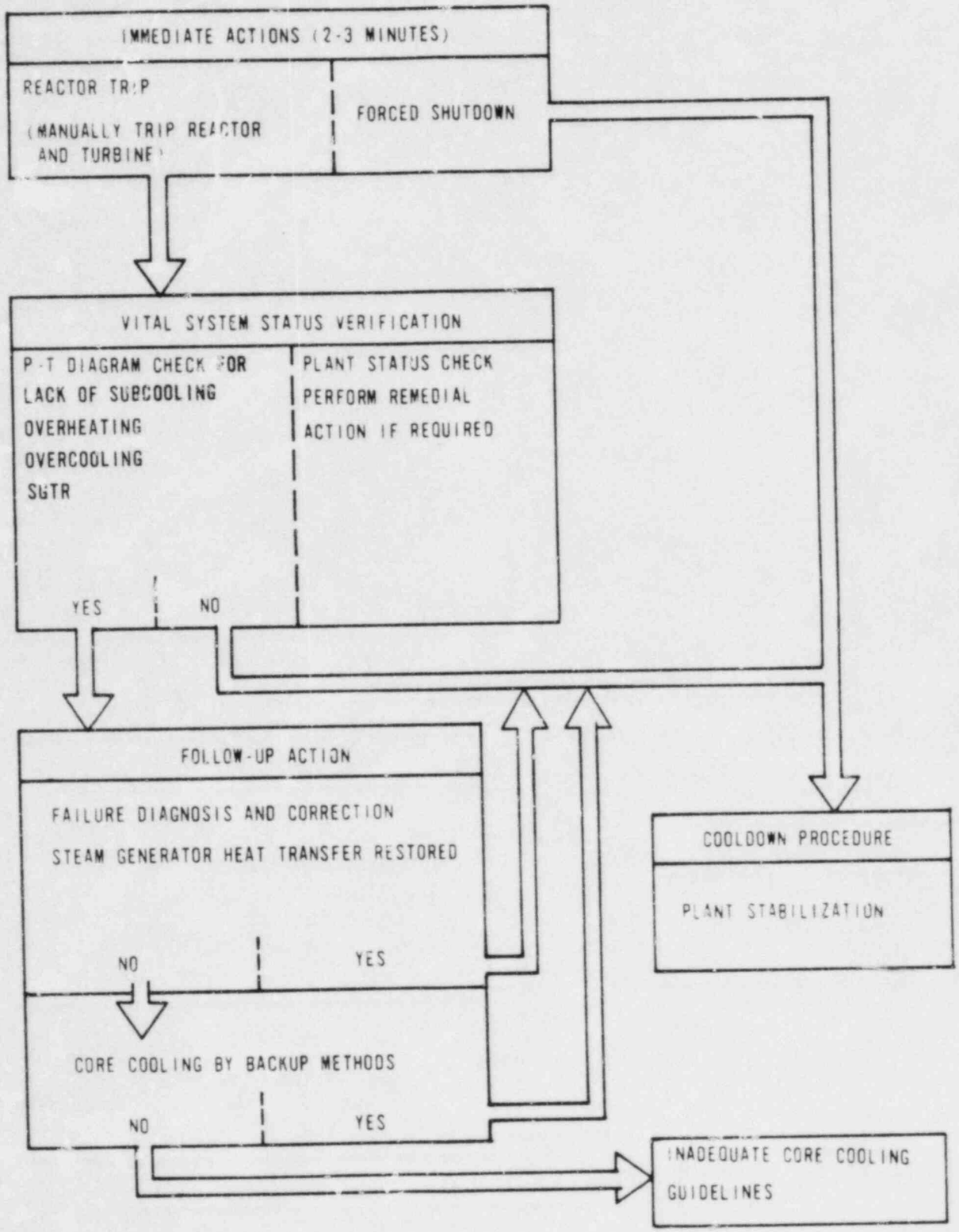
Makeup Pump Failure on Loss of Suction

Heater Burnout when they Uncover

A spray failure (on) will cause a pressure decrease at a constant RC temperature until the reactor coolant becomes saturated. This may be corrected by blocking spray flow.

Neither failure is considered serious because there is ample time for correction. Pressure and pressurizer level alarms will sound far in advance of the time when action is required.

Figure 20 GENERAL PLANT TRANSIENT MITIGATION



74-1124158-00

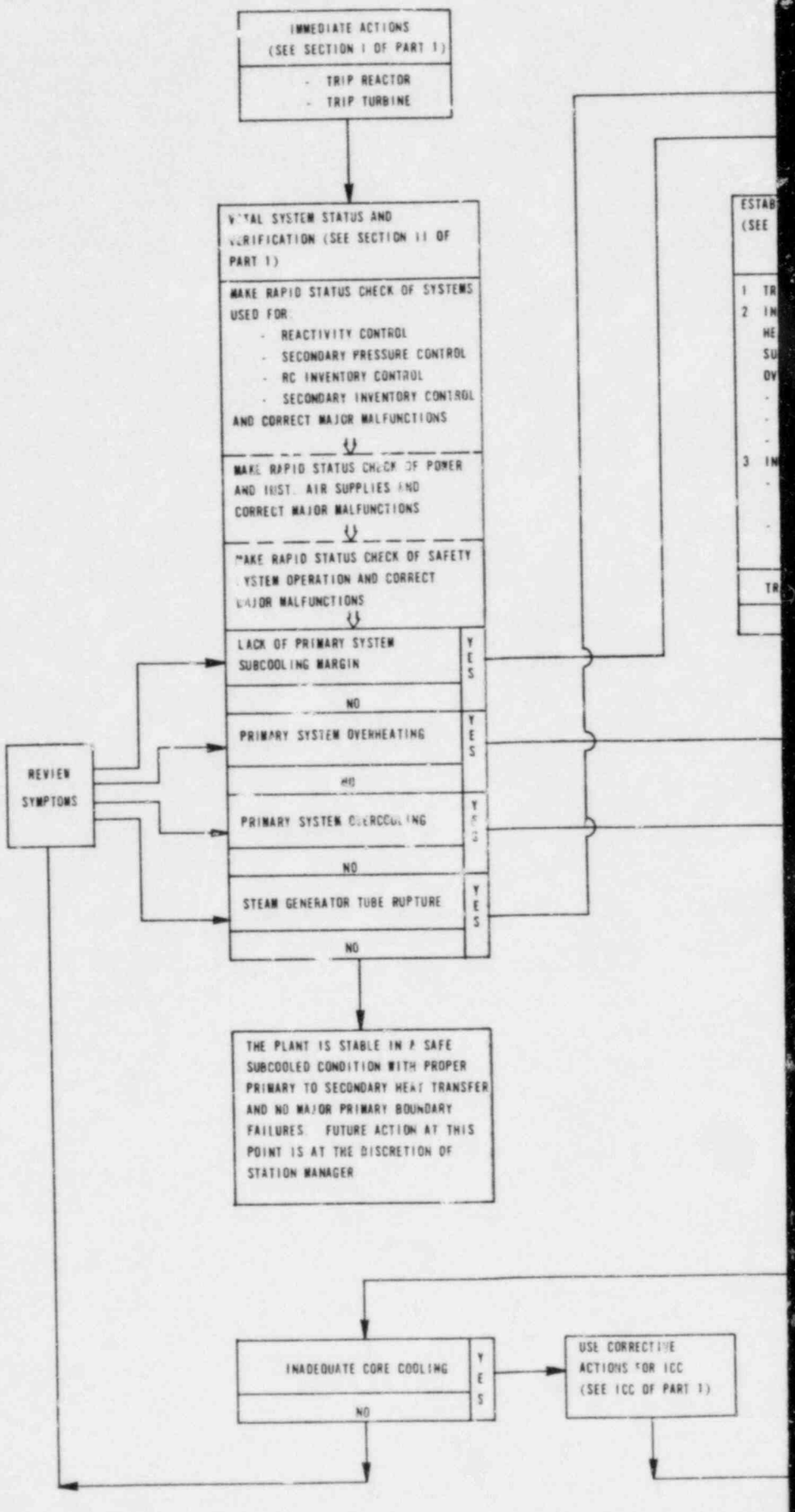
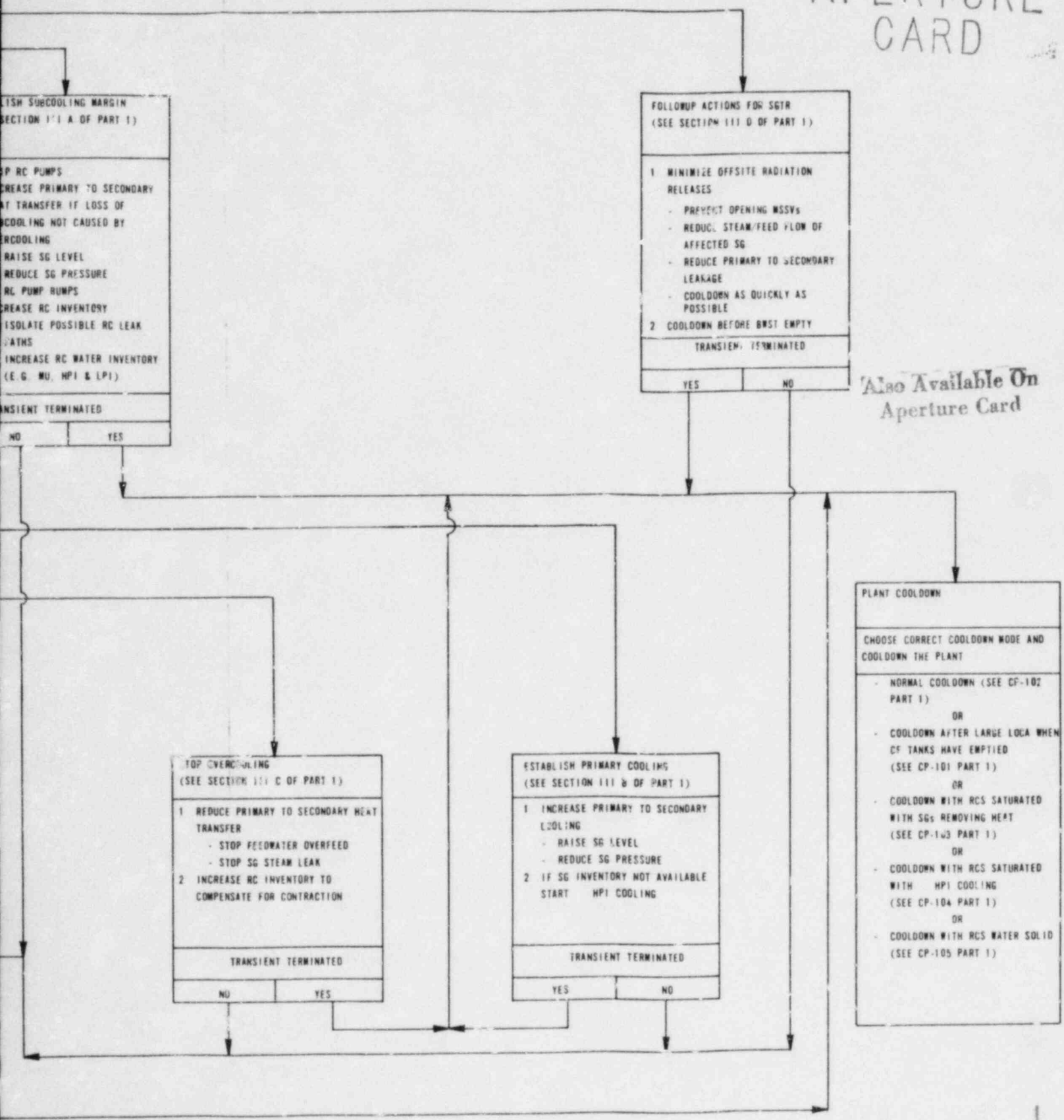

IMMEDIATE ACTIONS
(SEE SECTION I OF PART 1)
- TRIP REACTOR
- TRIP TURBINE
VITAL SYSTEM STATUS AND VERIFICATION (SEE SECTION II OF PART 1)
MAKE RAPID STATUS CHECK OF SYSTEMS USED FOR:
- REACTIVITY CONTROL
- SECONDARY PRESSURE CONTROL
- RC INVENTORY CONTROL
- SECONDARY INVENTORY CONTROL
AND CORRECT MAJOR MALFUNCTIONS
MAKE RAPID STATUS CHECK OF POWER AND INST. AIR SUPPLIES AND CORRECT MAJOR MALFUNCTIONS
MAKE RAPID STATUS CHECK OF SAFETY SYSTEM OPERATION AND CORRECT MAJOR MALFUNCTIONS
LACK OF PRIMARY SYSTEM SUBCOOLING MARGIN
YES
NO
PRIMARY SYSTEM OVERHEATING
YES
NO
PRIMARY SYSTEM OVERCOOLING
YES
NO
STEAM GENERATOR TUBE RUPTURE
YES
NO
REVIEW SYMPTOMS
THE PLANT IS STABLE IN A SAFE SUBCOOLED CONDITION WITH PROPER PRIMARY TO SECONDARY HEAT TRANSFER AND NO MAJOR PRIMARY BOUNDARY FAILURES. FUTURE ACTION AT THIS POINT IS AT THE DISCRETION OF STATION MANAGER
INADEQUATE CORE COOLING
YES
NO
USE CORRECTIVE ACTIONS FOR ICC (SEE ICC OF PART 1)

Figure 21 TRANSIENT MITIGATION APPROACH

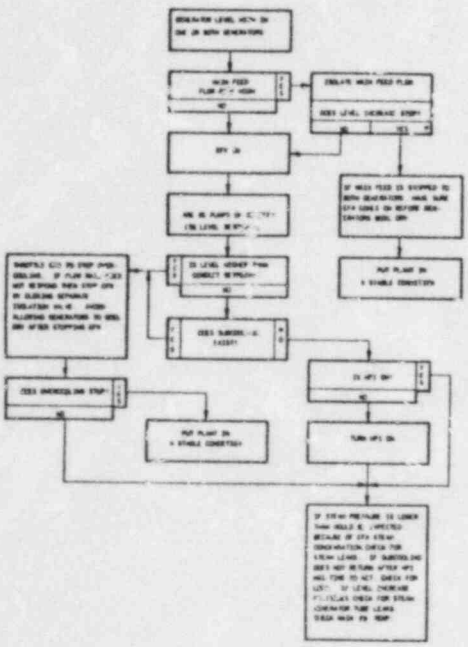
PRC APERTURE CARD



Also Available On Aperture Card

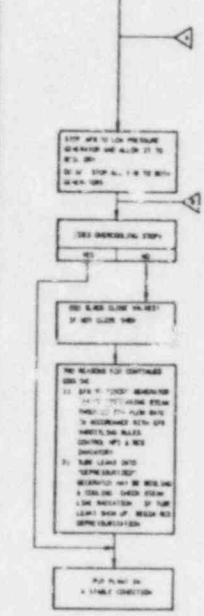
8401230549-11

CORRECTIVE ACTIONS FOR HIGH STEAM GENERATOR LEVEL

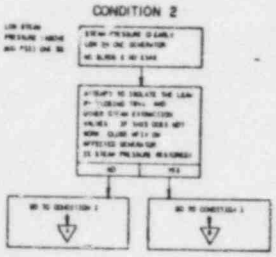


CORRECTIVE ACTIONS FOR L

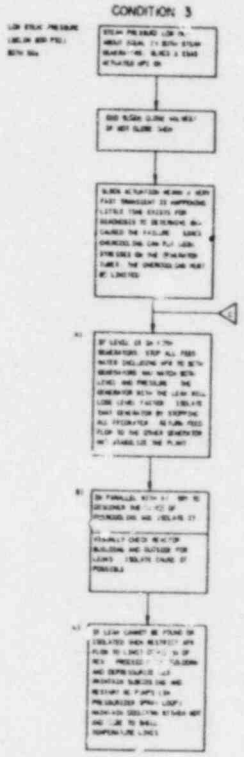
CONDITION 1



CONDITION 2



CONDITION 3



74-1124158-00

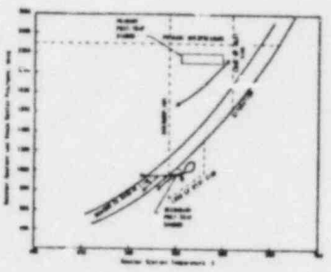
PRC
APERTURE
CARD

Figure 22 OVERCOOLING DIAGNOSIS CHART

OW STEAM PRESSURE

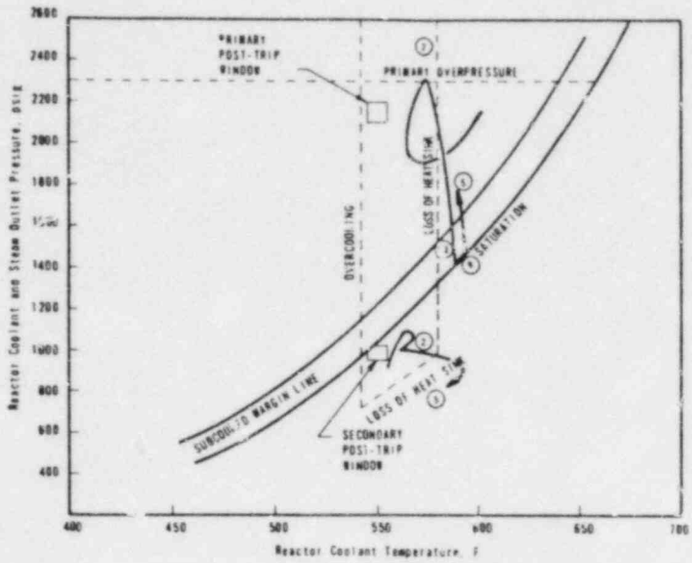
CONDITION 4

TYPICAL P-T DIAGRAM



Also Available On
Aperture Card

8401230549-12



(1) ATTEMPT TO RESTORE MFW OR EFW

(2) START HPI COOLING WHEN PRIMARY TO SECONDARY HEAT TRANSFER IS LOST

STOP ALL BUT ONE RC PUMP TO REDUCE THE REACTOR COOLANT HEAT LOAD

(3) TRIP ALL RC PUMPS ON LOSS OF SUBCOOLING MARGIN

OTHER
SEE "
OPERA
RC PU

(4) SATURATED CONDITIONS WILL EXIST UNTIL FEEDWATER IS RESTORED OR HPI FLOW MATCHES DECAY HEAT

(5) SUBCOOLING MARGIN RESTORED BY HPI COOLING, HPI MUST BE THROTTLED TO PREVENT NOT PROBLEMS

ONE RC PUMP SHOULD BE RESTARTED WHEN SUBCOOLING MARGIN IS REGAINED. A MOMENTARY LOSS OF SUBCOOLING MARGIN MAY OCCUR ON RESTART

OTHER
SEE "
OPERA
AND R

Figure 23 OVERHEATING DIAGNOSIS CHART

OVERHEATING OCCURS WHEN THE REACTOR COOLANT CANNOT TRANSPORT THE CORE HEAT TO THE STEAM GENERATORS FOR HEAT REMOVAL. NATURAL CIRCULATION WILL NORMALLY BE LOST FOR AN EXTENDED TIME (VS BRIEFLY INTERRUPTED). T_{HOT} WILL BE SATURATED (T_{COLD} WILL USUALLY ALSO BE SATURATED). SINCE THE STEAM GENERATOR CANNOT REMOVE HEAT, STEAM PRESSURE AND T_{SAT} S.G. WILL DECREASE. GENERALLY ONLY TWO CONDITIONS WILL PERMIT OVERHEATING: LOCA's AND LOSS OF ALL FEEDWATER.

PRC APERTURE CARD

SEE FIGURE F-13, APPENDIX F, "LOCA"
IN PART II-2 "DISCUSSION OF SELECTED TRANSIENTS"
FOR
A - P-T DIAGRAM CHARACTERISTICS
B - CORRECTIVE ACTIONS

SEE TABLE 4A "HOW TO DISTINGUISH LOCA's FROM OTHER TRANSIENTS"

SEE TABLE 4B "SYMPTOMS FOR LOCA's THAT CAN BE LOCATED OR ISOLATED

REFERENCES:
BEST METHODS FOR EQUIPMENT
TION" FOR HPI COOLING AND
MP TRIP

REFERENCES:
BEST METHODS FOR EQUIPMENT
TION" FOR HPI THROTTLING
C PUMP RESTART

Also Available On
Aperture Card

8401230549-13

PRC
APERTURE
CARD

Plant Status Verificat

1. Reactivity control

   -Reactor power de-
   creasing
   -All rods at in li
   (except APSRs)

2. Secondary pressure
   trolled
   -All Turbine steam
   valves shut

3. RC inventory contr
   -No letdown flow

4. FW inventory contr
   -Feedwater flow no
   excessive

5. Instrumentation ar
   control available
   -Vital DC and AC
   power, emergency
   standby busses ar
   instrument air

6. Low RC pressure or
   high RB pressure

   High high RB press

7. SLRDS actuation

8. Loss of offsite p
   (LOOP)

9. P-T diagram check

   Lack of subcoolin
   margin
   Overheating
   Overcooling

10. Steamline or cond
    vacuum pump radia
    alarm due to SG t
    leak

Table 2 STANDARD POST-TRIP ACTIONS

ion	Operation Action Required	Basis for Action
led	•Start HPI from BWST •Emergency borate	After reactor or turbine trip, the operator should ensure that the fission process is shutdown. The simplest method is to ensure the rods are fully inserted; if not, the operator should manually trip both the turbine and reactor and ensure that a rapid decrease in neutron flux has occurred. Compensation for a stuck rod will have to be by boration to maintain a subcritical margin when the plant is stablized or plant cooldown is required.
mit		
con-	•Manually trip turbine	If steam pressure is allowed to drop below turbine bypass setpoint, the RC will over cool which could lead to emptying pressurizer.
stop		
olled	•Stop letdown flow	When a reactor trip occurs, T_{ave} will decrease due to the loss of core fission power, and an outsurge from the pressurizer will be caused by the contraction of the reactor coolant. The MU control valve will open to increase MU in response to a decrease in pressurizer level. To minimize the potential for a loss of pressurizer level and/or indication, the operator should manually isolate the letdown.
olled t	•Trip MFW pumps •Initiate EFW	Feedwater should be added to maintain steam generator heat removal. Too much feedwater will lead to overcooling of the RCS and water in the steam lines. Water in steam lines could lead to steam line ruptures.
d		
d	•Make use of what is available while trying to re-establish power and air supplies.	Instrumentation is needed to determine what the plant's conditions is to determine if corrective measures are needed and if the corrective actions are effective. Plant controls are needed to be able to correct any adverse plant conditions.
	•Confirm that the HPI and LPI are started. •Verify, by review of ECCS flow indication, that flow exists in the injection lines. •Confirm reactor building isolation. •Confirm reactor building cooling systems start •Trip RC pumps on loss of subcooling margin.	When an ESAS actuation occurs, the operator should assure that at least one train is operative (one pump on) and that flow is present. At this point, HPI/LPI flow balancing is not required, but can be done later.
ure	•Verify RB spray system on	
	•Verify that appropriate MFIVs are closed.	SLRDS design function is to prevent overcooling RCS and release to RB due to steam line break. Upon detection of a steam line break, SLRDS automatically initiates action to close both main feedwater valves (FIVs).
wer	•Verify that at least one emergency diesel generator starts and automatic and manual load sequencing is completed. If only one has started manually, start the other	Upon loss of normal power sources, the two engineered safeguard busses are energized, each powered by its respective diesel generator. Bus load shedding, transfer to the diesel generators, and pickup of critical loads is automatic with ESAS. When a loss of power occurs, the operator should ensure that at least one diesel generator starts. He should try to start the other. Loop without ESAS will require some manual loading of critical loads.
	•EFW actuation - verify that at least one EFW pump is on and flow is delivered when SG level is below the appropriate setpoint. EFW should be stopped to the low pressure steam generator, but maintained to the "good" generator.	The operator should confirm that the above actions are complete by examination of valve position indicators and EFW status and flow. EFW injection should be stopped to the generator with low pressure to prevent overcooling.
		Also Available On Aperture Card
	•Replenish RC inventory	Provide stable core cooling.
	•Regain SG heat removal •Reduce SG heat removal	Provide stable core cooling. Provide stable core cooling.
enser tion ube	•Start immediate cooldown and depressurization of RCS	Reactor coolant has flow path to outside environment via secondary system. Must depressurize RCS to stop tube leak.

8401230549-14

Transient	Operator Action
Excessive feedwater flow	Immediately following reac amine SG levels for excess • If SG level is "high," is still on, stop furth • Allow SG level to decre riate setpoint; then re tion by - Manual control of MFW - EFW addition if MFW isolated.
Steam generator tube rupture	Confirm that radiation mo supports alarm; If necess riate actions for loss of margin or improper primar heat transfer then start cooldown and depressuriza RCS. The cooldown should to cold shutdown.

Table 3 ACTIONS TO CORRECT FAST TRANSIENTS

Also Available On
Aperture Card

Required	Symptoms	Basis for Action
tor trip, ex- ive feedwater. and MFW flow er MFW addition. ease to approp- esume FW addi- W or as been	High steam generator level High feedwater flow	Excessive MFW is the addition of water to the SG at a rate faster than it can be boiled off. It can result in overcooling of the RCS and water spillage into the steam lines must be avoided. Overfill of the SG can occur very rapidly because of the large flow capacity of the MFW system; this is especially true following a reactor trip. Following a reactor trip the operator should assure that MFW runs back. If a FW flow remains high and SG level is increasing, MFW should be controlled (trip pumps). NOTE: Ensure that EFW starts if MFWPs are tripped and throttle EFW to prevent overcooling.
itor reading ary, take approp- subcooling y to secondary an immediate tion of the continue	Steam line or condenser vacuum pump radiation monitor NOTE: Radiation monitors may indicate a tube rupture prior to reactor trip.	Steam generator tube leaks or ruptures are LOCAs which result in contamination of the main steam system and offsite dose release. To minimize the offsite dose release, complete cooldown and depressurization of the RCS is required to reduce the primary to secondary leakage and to prevent unnecessary primary discharge to the atmosphere through the steam generators. Since this is a LOCA, HPI must be kept on if subcooling is lost, but this will keep reactor coolant pressure high and continue the leak. Cooldown is required to lower RC pressure to stop the leak.

PRC
APERTURE
CARD

8401230549-15

Table 4a HOW TO DIFFERENTIATE A LOCA FROM OTHER TRANSIENTS

Unique Characteristics of LOCA's

- Rapid system depressurization to saturated conditions with little or no change of reactor coolant temperature (characteristic of all but the very smallest break)
- Sustained saturation (HPI does not return the reactor to a sub cooled state within 5-10 minutes after actuation)
- Containment radiation (only for breaks in containment)

  NOTE: A steam or feed line leak inside containment will cause high pressure, temperature and humidity but will not cause high radiation.

- Steam pressure, feed flow and steam generator level do not indicate overcooling (this helps to differentiate LOCA's from overcooling transients)
- High steam line radiation alarms (tube leaks only)
- Low makeup tank level (in the absence of all of the above, this indicates a leak outside the containment)

NOTE: LOCA's CAN BE DIFFICULT TO DETECT, ESPECIALLY IF THE BREAKS ARE SMALL. IF THERE IS ANY DOUBT THAT AN ACCIDENT IS A LOCA, ASSUME THAT IT IS AND TAKE APPROPRIATE LOCA ACTIONS UNTIL CLEARLY PROVEN OTHERWISE. THE GENERAL ACTIONS INCLUDE HPI COOLING, RC PUMP TRIP, AND COOLDOWN TO COLD CONDITIONS.

THIS CHART WILL AID IN LOCATI
CAN ALSO BE ISOLATED AND THE
INSIDE CONTAINMENT FROM LOCA
ALWAYS BE LOW. HOWEVER, A LO

Failure	Locating symptoms[a]
Symptoms for LOCAs That Can be Isolated	
Makeup and purification system outside containment and letdown coolers	Low makeup tank level High ICW radiation High ICW surge tank level breaks in letdown coole Local sump levels, radiati
Seal return line and seal return cooler outside containment	Low makeup tank level High NSCC radiation High NSCC surge tank level breaks in seal return c Local sump levels, radiati High seal return flow
Pressurizer electromatic relief valve	Acoustic monitor alarm High RC drain tank level High RC drain tank tempera (These will only be goo the RC drain tank ruptu is good).
Makeup-letdown imbalance (this is not a break but is a loss of coolant)	High makeup tank level Bleed holdup tank level Makeup flow rate, seal inj flow, letdown flow
Decay heat removal line break outside containment (decay heat removal system in operation, plant cooled down)	High or low decay heat rem Low pump suction pressure Local sump and local radia alarms
Decay heat cooler tube leak (decay heat removal system in operation, plant cooled down)	High DHCC surge tank level High DHCC radiation

Table 4b SYMPTOMS FOR LOCA'S THAT CAN BE LOCATED OR ISOLATED

Also Available On
Aperture Card

NG SOME BREAKS; ALL BREAKS CANNOT BE LOCATED. SOME BREAKS WHICH CAN BE LOCATED
LOCA CAN BE STOPPED. IT MAY BE DIFFICULT TO DISTINGUISH SMALL STEAM LINE LEAKS
S; BUILDING ENVIRONMENT WILL CHANGE FOR BOTH, AND THE STEAM PRESSURE WILL NOT
CA WILL CHANGE BUILDING RADIATION LEVELS.

	Isolating hardware	Failure	Locating symptoms[a]
		Symptoms for LOCAs That Cannot be Isolated	
	Letdown valve upstream of coolers[b]	Steam generator tube(s)	High steam line radiation High steam generator level
(for r) on alarms		Pressurizer safety valves	Acoustic monitor alarm High RC drain tank level High RC drain tank temperature (These will only be good while the drain tank rupture disc is good).
	Seal return isolation valve[b]		
(for ooler) on alarms		HPI injection line break	Flow imbalance between injection[d] lines (High flow will be through broken line above RCS pressure of 600 psig; flow may be low through cross-connected line).
	PORV isolation valve		
ture d when re disc		RC pump seal failure	High seal return temperature (~ 350°F) combined with: Low and upper stage pressures are equal and high
	Letdown control valve[b]	RCS instrumentation lines Pressurizer level Pressures RC flow	False low level reading False low pressure False high or low flow compared with known pump operation
ection			
oval flow	Decay heat letdown drop line valve[c]		
tion			
	Cooler isolation valves		

[a] Symptoms or alarms most likely to show location are underlined.

[b] Do not allow makeup tank to drain or operating pump will lose suction and fail.

[c] Inadequate Core Cooling Guidelines for loss of decay heat removal should be implemented.

[d] Break cannot be isolated to prevent loss of reactor coolant and should not be isolated to prevent loss of injection water. The cavitating venturis will limit the loss of injection water and ensure adequate flow to the core with two HPI pumps and valves MU-V16-A-D fully open.

PRC
APERTURE
CARD

8401230549 -16

BACKUP COOLING

CHAPTER D

BACKUP COOLING METHODS

The normal method of core cooling, when the RCS pressure/temperature conditions are above those for DHRS operation, is by transferring heat from the core to the steam generators using subcooled reactor coolant. The flow can be either forced or natural circulation. However, if subcooled heat transfer via the steam generators is lost, two other means of core cooling are available. This section will discuss these backup cooling methods and explain their uses and limitations. The two methods are:

1. HPI cooling
2. Boiler-Condenser Cooling

HPI cooling is when the core is cooled by HPI flow passing through the core (removing core heat) and out a break or open PORV to the containment. This method is used whenever feedwater is not available.

Boiler-Condenser cooling is when reactor coolant is boiled in the core to form steam (removing core heat) which flows through the hot leg pipe to the steam generator where it is condensed. The condensed water returns to the core via the cold leg pipe. In addition, this chapter also discusses how to restore natural circulation heat removal (if lost) and what to do if core cooling is lost causing inadequate core cooling.

Backup Cooling by HPI (For Loss of All Feedwater)

A complete loss of feedwater is not a likely event, but it can occur because of multiple equipment failures or operator error. If primary to secondary heat removal is lost because of the loss of feedwater, it is possible to cool the core by the HPI system until feedwater is restored. The core energy is removed by the reactor coolant (HPI) and released to the reactor building, which serves as the heat sink instead of the steam generator. The core is kept covered and cooled by HPI.

A total loss of all feedwater is illustrated in Figure 24a and is discussed below:

1. With the plant at power, a loss of main feedwater would result in a reactor trip (anticipatory trip on loss of MFW or RPS actuation on high RCS pressure). A loss of all FW could also occur during hot shutdown or plant heatup/cooldown.

2. If emergency feedwater also fails, the secondary side of the steam generators will boil dry and the RCS will then heat up due to decay heat.

3. The reactor coolant will expand into the pressurizer.

NOTE: The rate at which the above occurs will depend upon the initial inventory in the steam generators and the core decay heat level. For example, the RCS heatup rate may be as high as 4F/min with high decay heat or as low as 1F/min with low decay heat following boil off of the SG inventory.

4. RC pressure will increase as the steam space in the pressurizer is compressed due to the insurge of reactor coolant. Steam/water relief through the PORV or the pressurizer safety valves will also occur.

5. The reactor coolant will eventually saturate and boiling will occur throughout the core.

6. Without corrective action, the reactor coolant will slowly be vaporized to steam and relieved to the containment and core damage will result. If feedwater cannot be reestablished before the PORV setpoint is reached then HPI cooling must be established.

To avoid these consequences, the operator should attempt to regain feedwater to at least one steam generator. This includes main feedwater, emergency feedwater and condensate and booster pumps (if steam generator pressure is low enough). If feedwater cannot be regained, he should manually start two HPI pumps and open and leave open the PORV. HPI flow should be balanced to give the maximum flow possible.

The event can be recognized by observation of steam generator level and equipment status checks or through use of the P-T diagram. Figure 24b illustrates the P-T response of the RCS after a loss of main feedwater from 100% power with no EFW but with appropriate operator action.

Figure 24b and the following transient description should be considered as typical. Actual times and sequences (e.g., subcooling could be regained before HPI flow "matches" decay heat) will depend on actual HPI flowrate, DH level, etc. In any case, the "match" point will have occurred when the RCS begins to cool.

When HPI is started, the RCS will eventually go to a water solid condition (subcooled) with RC pressure controlled by a combination of the HPI pump head rise and the relief capability of the PORV. One RC pump should be restarted when the subcooling margin is regained. The time to become water solid depends on the core decay heat level and the number of operating HPI pumps. If core decay heat is high, the reactor coolant will saturate and its pressure will rise along the saturation curve (points 5-6 on Figure 24b). The running RCP should be tripped when subcooling margin is lost. Eventually the system will go to a subcooled water-solid state (points 6-7 on Figure 24b).

When all feedwater is lost, it is very important that two HPI pumps be run until the subcooling margin is restored. One HPI pump is adequate for core heat removal, but the time required for 100% decay heat to decrease to the cooling capacity of one HPI pump is much longer than if two pumps are used. The time for 100% decay heat to decrease to the capacity of one HPI pump is approximately 70 minutes and approximately 8 minutes with two HPI pumps. These approximate times will vary depending on RCS pressure, which determines available HPI flowrate.

When the subcooled margin (based on incore thermocouples) is regained, the operator should start one reactor coolant pump and throttle HPI flow to maintain the reactor coolant subcooled but within equipment design limits, such as the RC Pressure/Temperature Limits of Figure 25, "RCS Pressure/Temperature Limits". If a reactor coolant pump cannot be restarted, the operator should still throttle HPI to maintain an adequate subcooling margin and avoid exceeding the curves of Figure 25. The intent is to run an RC pump to improve thermal mixing and minimize thermal shock to the reactor vessel. However, if the pump is not ready in all respects to be run, it should not be run. Core protection is assured by the HPI cooling.

In summary, HPI cooling will maintain core cooling if secondary heat removal is lost. It is not a normal operating mode for many reasons; three examples are:

1. The PORV will pass large amounts of solid and two phase flow. Since the valve was designed for steam flow it may fail to close when feedwater is reinstated, requiring closing the PORV isolation valve to stop PORV flow.

2. Long-term operation (subcooled water solid operation) is extremely sensitive and must be closely monitored to prevent exceeding equipment design limits (e.g., RC Pressure/Temperature Limits).

3. The degraded containment environment may cause failure or bad readings of instrumentation.

4. The BWST inventory will eventually become depleted requiring HPI/LPI "piggyback" operation taking suction from the containment emergency sump.

   The sump water is poor quality water. Using SG cooling is perferred over using HPI cooling with sump water.

Consequently, feedwater should be restored as quickly as possible so that normal primary to secondary heat transfer can be resumed.

Boiler Condenser Cooling

A subcooled reactor coolant system is the desired state, however, core heat can be removed when the RCS is saturated. The problem with saturated natural circulation is that the operator doesn't know how much of the reactor coolant is steam and how much is water (see discussion of saturation in Addendum A of Chapter A). If the RCS is losing inventory, steam will form in the hot legs and eventually stop natural circulation flow (this is a violation of the subcooled natural circulation requirement that a flow path exists connecting the hot water and the cold water. This could also be violated by a large collection of non-condensible gases in top of the hot legs, however, such a collection should only exist following a core uncovery. At that point the operator would be using inadequate core cooling procedures).

Another form of core heat removal could still exist under these conditions called boiler-condenser cooling (boiling in the core and condensing in the steam generator), but it requires a higher steam generator level (95% on operate range).

Figure 27 illustrates boiler-condenser cooling. In this mode of cooling, water is boiled in the core. The resulting steam flows through the hot leg pipe to the steam generator where the steam is condensed in the cool steam generator tubes. The condensed water flows back to the reactor core. In order to flow back to the core the elevation of the RC water level in the steam generator must be above the elevation of the RC pump

discharge pipe. This will allow the water in the cold leg pipe to flow up and over the RC pump discharge into the core.

The RC steam entering the SG is condensed on the inside tube surface between the RC and SG water level. This tube surface has to be large enough to remove all the latent heat of the steam at the expected RC steam flow rate. The amount of condensing surface is determined by the secondary side water level. The steam generator tubes will condense the RC steam if the cooler feedwater is on the outside of the tubes. To make the condensing surface above the required RC water level high enough, the steam generator water level must be at 95% on the operating range.

The problem with boiler-condenser cooling is the operator does not know the RC water level in the steam generator. Therefore, to assure enough water exists, the operator should have both HPI pumps on at a high capacity.

If a LOCA occurs and the size is such that both steam generator and HPI cooling are needed to remove the core heat but subcooled natural circulation is lost, the RCS will heat up and repressurize causing the pressurizer safety valves to open and relieve RC to the reactor building. This will continue until the RC water level drops below the steam generator feedwater level to expose sufficient condensing surface to the RC steam. With the feedwater level at 95%, the RCS will inherently go into boiler-condenser cooling as the RC level in the steam generators boils

down below the feedwater level to expose the condensing tube surface. HPI flow will be needed to makeup for RC lost out the break.

If emergency feedwater is sprayed into the steam generator, the effective condensing surface of the steam generator tubes is much higher than the loss of subcooling margin level because the EFW spray will be cooling the tube surface above this level. However, if the main feedwater is used to add water to the steam generators, the feedwater enters the bottom of the steam generator so that the only condensing surface is below this level.

If boiler-condenser cooling exists, T_{hot} should be equal to primary T_{sat} and the incore thermocouple temperature and T_{cold} will be equal to the SG saturation temperature.

The point to remember is that primary inventory (mass) is unknown under saturated conditions and, therefore, every effort should be made to keep the RCS subcooled.

Loss of Natural Circulation

When RC pumps are off, heat is removed from the reactor core by natural circulation as discussed in Addendum B. Some transients can lead to a loss of natural circulation but methods exist to restore it if it is lost. The intent of this section is to highlight the recovery measures and to give an understanding of why certain actions are recommended and when they are to be taken. Brief discussions of other issues on natural circulation are also provided.

A loss of natural circulation can occur for three reasons, which are:

Reason 1. Insufficient secondary inventory control (i.e., not enough feedwater)

Reason 2. Formation of steam voids within the hot leg which are of sufficient volume to block water carry over to the steam generator (i.e., not enough reactor coolant).

Reason 3. Blockage of hot leg by non-condensible gases.

The previous section addressed system operation when natural circulation is lost due to insufficient feedwater (Reason 1). The only way to recover natural circulation under that condition is to restore feedwater. Void formation (Reason 2) is more complicated because the reactor coolant system can operate differently depending on what has happened. The two

principal events which lead to void formation are overcooling transients and loss of coolant accidents. For these transients, voids are formed in the following manner:

Overcooling: Too much primary to secondary heat transfer causes a drop of RCS temperature which causes a contraction of fluid inventory, a decrease in reactor coolant pressure, and a loss of pressurizer liquid. Some of the steam in the pressurizer flows into the RC piping and collects in the hot legs. Because the RC pressure drops, some of the reactor coolant may flash and cause void formation in the hot legs.

LOCA: A LOCA results in a loss of RC inventory and a reduced RC pressure. Voids are formed directly as a result of loss of RC inventory and also because of flashing of the reactor coolant as RC pressure drops. The RC temperature does not drop as much as it would for an overcooling event.

Figure 26 illustrates the buildup of steam voids and the formation of a steam bubble in the upper hot leg piping.

The size of the steam bubble will depend on the rate of system overcooling or loss of inventory versus the rate at which HPI adds water

to the RCS to refill it. If HPI flow is large compared to the rate of RC inventory loss no steam bubble will form at all and natural circulation will not be lost.

If a steam bubble does form, its size has a direct effect on primary to secondary heat transfer. If the bubble is big enough such that the hot leg level is at or below the secondary side feedwater level then steam can be condensed within the steam generator tubes and the steam generators can still remove a large amount of decay heat. This is a boiling mode of natural circulation and is illustrated in Figure 27. Boiler-condensing cooling is an expected small break LOCA condition. If the steam bubble is smaller and steam cannot be condensed in the steam generator (see Figure 28) then primary to secondary heat transfer will be much lower. In this condition the RCS may heat up and might repressurize. Several examples of transient conditions that could get into this mode of operation are:

1. Small LOCA's where HPI can match the leak rate (at reduced RCS pressures) and refill the RCS.
2. A severe overcooling event (e.g., major steam line break) in combination with delayed actuation of HPI.
3. A total loss of feedwater, where EFW is restarted after the RCS is in a highly voided condition and the HPI is refilling the RCS.

Figure 27 shows boiler-condenser cooling (boiling in the reactor vessel and condensing in the steam generator) with a saturated hot leg and RCS pressure near the steam generator pressure. For this condition, it is important to ensure that 1) SG level is at 95% on the operating range (to allow the condensed reactor coolant to flow over the cold leg pump elevation and into the core) and, 2) HPI is on at a high capacity (two pumps). A check of containment pressure and temperature conditions should also be made to see if the cause is a LOCA. If LOCA conditions are indicated, an immediate plant cooldown at design rates (100F/hr) should be initiated. The P-T diagram should be monitored to see if subcooled natural circulation returns or boiler-condenser cooling is lost.

If natural circulation has been lost and steam cannot be condensed in the steam generators (that is, the steam bubble is in the top of the hot leg pipe but not low enough to be in the steam generator), the RCS will repressurize. This mode of operation will be indicated (see Figure 28) by saturated hot leg conditions with Reactor Coolant pressure above the steam generator pressure (SG pressure may be dropping due to lack of primary to secondary heat transfer). As indicated in Figure 28, the same actions identified for boiler-condenser cooling apply to this operating mode. In this mode, the HPI is refilling the RCS. During refill, steam in the upper region of the hot leg piping will be compressed and/or condensed as the water level in the loops and steam generator rises. In some cases (i.e., low decay heat with all HPI pumps on) subcooling and natural

circulation will occur with minor increases in RC pressure. Under other circumstances, it may be difficult to fully condense the steam in the hot leg and restore natural circulation. Figure 28 shows the actions to take to restart natural circulation if the steam generator can be used as a heat sink and the RC pumps are available for restart (see the RC pump restart guidelines in the "Best Methods for Equipment Operation" chapter). If the RC pumps are available, pump bumps (short run times of 10 seconds duration) are allowed. This momentary use of forced circulation tries to force reactor coolant steam condensation by mixing it with liquid reactor coolant and by moving the steam into the generator tubes where it can condense. Use of the PORV to limit RCS pressure rise (separately or in conjunction with RCP operation) is also allowed. Limiting the RCS pressure increase will maximize HPI flow. To be effective, the steam generator must be a heat sink to ensure a strong temperature gradient for condensation; the steam generator saturation temperature selected is somewhat arbitrary; it was chosen to ensure a strong temperature gradient for condensation. When the pumps are bumped and steam is condensed, the RCS pressure will drop as much as several hundred psi. HPI flow will increase to help refill of the voids. If natural circulation starts, the RC pressure will stay low; if not, the RCS will repressurize and another pump bump can be used about 15 minutes later (see the pump restart guidelines). This cyclic repressurization could continue for a number of cycles until decay heat is low enough to allow the RCS to become subcooled.

Finally, a LOCA of a certain size could depressurize the RCS below steam generator pressure before it settles to an equilibrium with HPI (HPI will automatically start because this size LOCA will drop pressure below the ESAS setpoint). If this happens, the operator should lower the steam generator pressure (using the TBV's or ADV's) until the saturation temperature on the secondary side is 50F below the primary saturation temperature. This will ensure the steam generators are heat sinks. Other actions are the same as discussed above for boiler-condenser cooling (Figure 27).

Inadequate Core Cooling (ICC)

The first objective of the operator during any abnormal transient is to keep the core cooled. As discussed in Addendum A, core cooling is taking place whenever the reactor coolant is in a subcooled or saturated state and the core is covered. If the reactor coolant becomes superheated, the core has been uncovered and is not being adequately cooled; that is, decay heat is not being removed fast enough and the temperature of the fuel and cladding are increasing. This, in turn, causes the reactor coolant to heat up, flash to steam, and become superheated.

Inadequate core cooling is not expected as long as the ATOG guidelines are followed. However, any reactor transient can become an inadequate core cooling event if enough equipment failures happen. These events have a low probability of occurrence. Some examples where ICC conditions could develop are:

1. Small LOCA with a total failure of the HPI system.

2. Total loss of feedwater (both main and EFW) with a total failure of the HPI system.

3. A total loss of power (including a failure of both emergency generators to start) with a failure of the steam turbine-driven EFW pump to run.

4. During a small break, tripping the RC pumps at a time period when the RC void fraction is about 70% or greater, rather than immediately tripping the RC pumps on a loss of subcooling margin.

The intent of the Inadequate Core Cooling (ICC) guidelines is:

1. To allow the operator to identify when core cooling is inadequate.

2. To provide the operator with a way to estimate the severity of the transient.

3. To identify those systems which are vital so that the operator's attention will be focused on these items in his attempts to re-establish core cooling.

4. To identify some known alternative actions to try to correct or minimize the consequences of the transient until normal cooling can be re-established. These actions are based on the severity of the transient.

ICC is indicated when the reactor coolant pressure and temperature (incore thermocouples) enter the superheat region. This condition can occur with or without forced circulation. If the RC pumps are operating, superheated conditions imply that the reactor coolant is nearly all steam (see Figure 24a- Time IV). That is, the liquid in the RCS has been lost, due to a

leak in the primary system, or boiled off out the safety valve by decay heat, and the steam mass left within the system is not enough to remove core heat even though it is circulated by the RC pumps. When the RC pumps are off, core cooling is accomplished by keeping the core covered with a steam-water mixture. If not enough cooling water (HPI) is supplied to make up for losses, the core will become uncovered and the core exit fluid temperature will become superheated (see Figure 24a - Time IV.)

Superheated temperatures, as indicated by the core exit thermocouples, are ICC symptoms. (NOTE: Incore Thermocouples are the only valid temperature measurement when the RCS is not circulating). These indicators can also be used to estimate how bad the situation is. Analyses have been performed which show the relationship between core exit steam temperature and fuel cladding temperature for various RC pressures (see Figure 29). This figure gives the following information:

Region 1

When the RCS P&T conditions are superheated but to the left of curve 1 on Figure 29, an ICC condition exists but it is not bad enough to cause core damage.

Region 2

If the RCS P&T conditions reach or exceed Curve 1 on Figure 29, the cladding temperature in the high power regions of the core may be 1400F or higher. Above this temperature, there is a chance for rupture of the fuel rod cladding material. A chemical reaction between the cladding and the water at high temperatures also occurs and will add heat to the fuel rods increasing the chances of fuel failure. The clad-water reaction also causes free hydrogen formation which collects in the reactor loops and may escape to the building. The accumulation of hydrogen in the RCS can also block natural circulation when water is added to the RCS.

Region 3

If RCS P&T conditions reach or exceed Curve 2 of Figure 29, the cladding temperatures in the high power regions of the core may be 1800F or higher. This is a very serious condition. At this level of ICC, significant amounts of hydrogen are being formed, and core damage may be unavoidable. Extreme measures are warranted to prevent major core damage.

If an ICC condition develops, the operators should try to get equipment working to supply water to the reactor and/or steam generator. The general strategy during ICC is as follows:

1. To check vital equipment
   - All available HPI should be on with flow into RCS. For a total loss of feedwater, the HPI must be manually started. ESAS will not be actuated automatically since RCS pressure does not decrease.
   - FW should be flowing to at least one steam generator with level at 95% on operating range level instrumentation.
2. Start any backup equipment to correct for problems found in vital equipment check.
   - Start standby MU/HPI pumps.
   - Take suction from any available borated water source.
   - Start MFW if EFW is not operating.
   - Start any backup pumps which can supply water to the steam generator if MFW and EFW are not operating.
3. Minimize the consequences of the event if conditions degrade.
   - Start RC pump to circulate primary system fluid (water or steam) through the core. This action will make available water trapped in the lower region of the reactor vessel and the loops for core cooling (see Figure 24a - TIME IV) and provide improved heat transfer due to forced convection which will provide additional time to restore emergency injection.

- Attempt to decrease RC pressure by opening the PORV to increase the rate of available high pressure injection and open the high point vents to remove noncondensible gases.
- If secondary cooling is available, decrease primary pressure by decreasing SG pressure. This action is directed at making the core flood tanks and LPI system available to restore core cooling.

In general, the ICC strategy depends on operator action to locate and correct the cause of low RCS inventory or to take alternate actions to make backup sources of cooling water available. Some of the actions identified above can be detrimental to major components, and others carry a certain amount of risk, but keeping the core cooled is the first priority. For example, an emergency cooldown/depressurization of the system may impose high thermal stresses on the SG internals; this action can be shown to be acceptable but it challenges the design to its limit. A second example would be the restart of one or more RC pumps. This action carries some risk because later on a pump trip may leave the RCS with less water than before. These risks are small compared to those which could happen with extensive core damage. Because the severity of the ICC condition can be estimated (by using Figure 29), the appropriate actions have been picked so that the risk of the action is small compared to the core consequence if the action is not taken. These actions are outlined below and are based on where the RC pressure-incore thermocouple temperature (P-T/C) combination corresponds to the curves of Figure 29.

Region 1

If the P-T/C combination is between the saturation curve and Curve 1, superheated conditions exist and the operator should:

1. Verify emergency cooling water is being injected through all injection nozzles into the RCS,
2. Initiate any additional sources of cooling water available such as the standby makeup pump,
3. Verify the steam generator level is being maintained at the emergency 95% on the operate range.
4. If steam generator level is not at 95% of operating range, raise level to the 95% level,
5. If the desired steam generator level cannot be achieved, actuate any additional available sources of feedwater.
6. Depressurize the SG(s) to achieve a 100 F/hr decrease in secondary temperature (maintain 95% SG level).
7. Open core flooding line isolation valves if previously isolated.
8. If RC pressure increases to 2300 psig, open the pressurizer PORV to reduce RC pressure and reclose PORV when RC pressure falls to 100 psi above the secondary pressure.

These actions are directed toward depressurization of the RCS to a pressure at which the ECCS water input exceeds core steam generation. The alignment of other sources of cooling water such as the standby MU pump is necessary because the injection of the HPI system alone is not sufficient to exceed core boil off.

Region 2

If the P-T/C combination is between Curve 1 and Curve 2 of Figure 29, the operator should do the following:

1. Start one RC pump in each loop; do not defeat RC pump interlocks.
2. Depressurize the steam generator as rapidly as possible to 400 psig or as far as necessary to achieve a 100F decrease in secondary saturation temperature, but not below the steam pressure necessary for EFW pump turbine operation.
3. Immediately continue the plant cooldown by maintaining a 100F/hr cooldown rate until the secondary saturation temperature is low enough to achieve a 150 psig RC pressure.
4. Open the power operated relief valve (PORV), as necessary, to maintain RCS pressure within 25-50 psig above steam generator pressure. If SG pressure can not be reduced then open and leave open the PORV.
5. Open all high point vents to vent non-condensible gases and aid RCS depressurization and refill until the RCS is 50F subcooled or RCS pressure decreases to 150 psig.

The operator action in starting the RC pumps will provide forced flow core cooling and will reduce the fuel cladding temperatures. The rapid depressurization of the steam generators will help to depressurize the primary system to the point where the core flood tanks will actuate. Stopping the depressurization at 400 psig (or as far as necessary to achieve a reduction in secondary saturation temperature of 100F) will maintain the OTSG tube to shell temperature difference within the design limit. The continued cooldown to 150 psig will reduce the primary system pressure to the point where the Low Pressure Injection System can supply cooling. The opening of the PORV and high point vents will also help to depressurize the primary system and vent non-condensible gases. The PORV should be closed when the primary pressure is within 25 to 50 psi of the secondary pressure and then should be used only as necessary to maintain the primary system pressure at no greater than 50 psi above the secondary system pressure. This method of operation will minimize the loss of water from the primary system through the PORV. The high point vents should not be closed until the RCS is 50F subcooled or RCS pressure decreases to 150 psig.

Region 3

If the P-T/C combination is to the right of Curve 2 of Figure 29, the operator should:

1. Depressurize the steam generators as rapidly as possible down to atmospheric pressure (ensure motor-driven EFW pumps are in operation

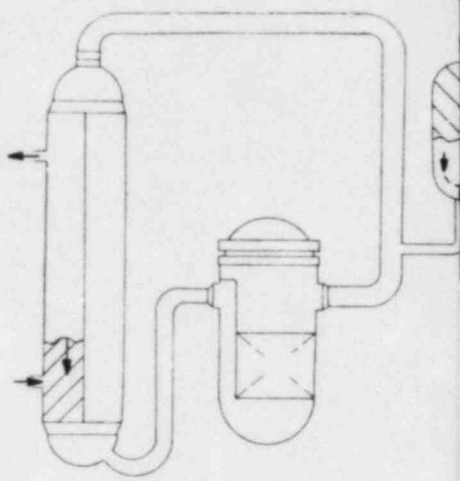
before losing steam supplies to turbine-driven EFW pump or ensure turbine-driven pump is operating on auxiliary steam).

2. Start the remaining RC pumps. Defeat starting interlocks; do not defeat overload trip circuit.
3. Open the PORV and leave it open.
4. Open high point vents if not open.

The goal of these actions is to depressurize the RCS to a level where the core flooding tanks will fully discharge and the LPI system can be actuated thus providing prompt recovering of the core.

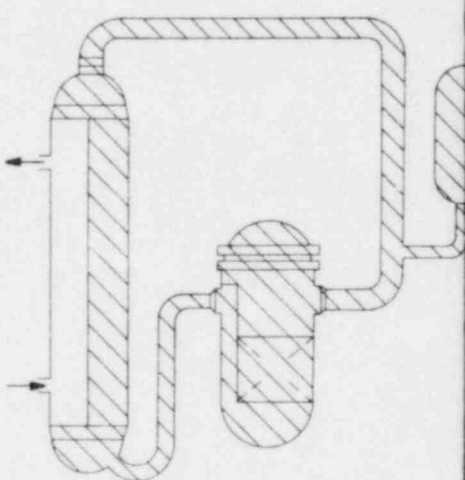
After reaching Curve 2, significant core damage may have occurred which will add significant radioactive contaminants to the reactor coolant and via the PORV to the containment.

Special cooldown precautions need to be followed to contain these contaminants. These include isolating the DH rooms.



TIME I

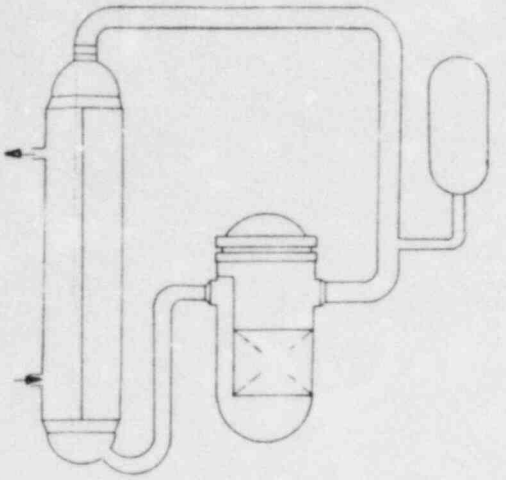
1. LOSS OF FEEDWATER.
2. REACTOR TRIP ON HIGH RCS PRESSURE (OR ANTICIPATORY TR
3. PRESSURIZER LEVEL DECREASES (NORMAL RESPONSE FOLLOWIN REACTOR TRIP) THEN INCREASES BECAUSE OF MU ADDITION A REHEAT OF REACTOR COOLANT.
4. SECONDARY SIDE BOILS DRY.
5. EFW DOES NOT START.
6. RC PRESSURE SHOWS NORMAL POST TRIP RESPONSE THEN INCR AS PRESSURIZER LEVEL IS RESTORED.



TIME IV (RC PUMPS ON)

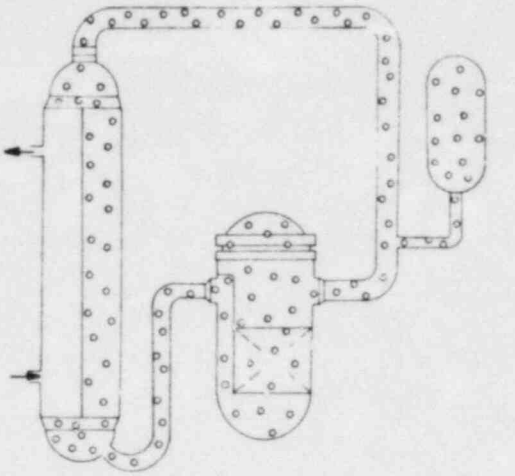
END CONDITION FOR TOTAL LOSS OF FW WITHOUT HPI ACTUATION. SYSTEM WOULD COMPLETELY VOID (STEAM ONLY IN RCS). CORE TEMPERATURE WILL INCREASE AND CAUSE SUPERHEATED STEAM TO FORM. INADEQUATE CORE COOLING CONDITIONS EXIST.

Figure 24a LOSS OF ALL FEEDWATER (NO OPERATOR ACTION)



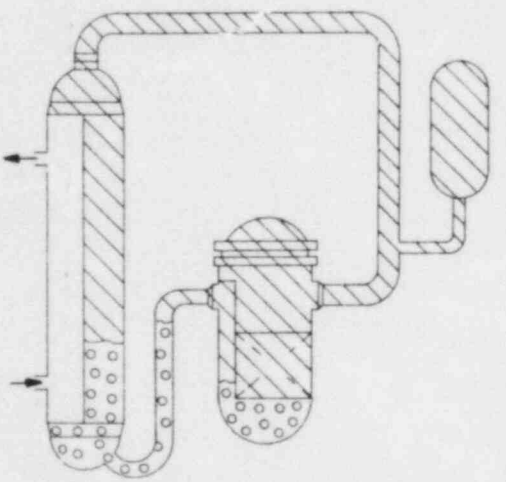
TIME II

1. RC HEATS UP DUE TO LOSS OF SECONDARY HEAT SINK AND EXPANDS INTO PRESSURIZER.
2. RC PRESSURE INCREASES TO PORV SETPOINT. PRESSURIZER STEAM IS EJECTED OUT OF PORV.
3. PRIMARY SYSTEM GOES WATER SOLID (STILL SUBCOOLED) AT 2500 PSIG. CONTINUED HEATUP OF REACTOR COOLANT CAUSES WATER RELIEF OUT OF PORV OR SAFETY VALVES.
4. RC TEMPERATURE IS SLOWLY APPROACHING SATURATED CONDITIONS @ 2500 PSIG.



TIME III

1. RCS GOES SATURATED AT 2500 PSIG.
2. STEAM IS CREATED IN CORE BECAUSE OF BOILING THROUGHOUT THE CORE.
   - IF RC PUMPS ARE RUNNING, STEAM WILL BE DISTRIBUTED AROUND THE LOOP (SEE ABOVE)
   - IF RC PUMPS ARE OFF, THE STEAM WILL SEPARATE FROM THE REACTOR COOLANT AND COLLECT IN THE UPPER REGION AT RV AND HOT LEG.



TIME IV (RC PUMPS OFF)

END CONDITION FOR TOTAL LOSS OF FW WITHOUT HPI ACTUATION. WITH RC PUMPS OFF EARLY IN THE EVENT, REACTOR COOLANT CAN BE TRAPPED IN LOWER REGIONS OF LOOP AND REACTOR VESSEL. CORE WILL HEATUP WHEN MIXTURE LEVEL DROPS BELOW TOP OF FUEL. INADEQUATE CORE COOLING WILL EXIST.

Also Available On
Aperture Card

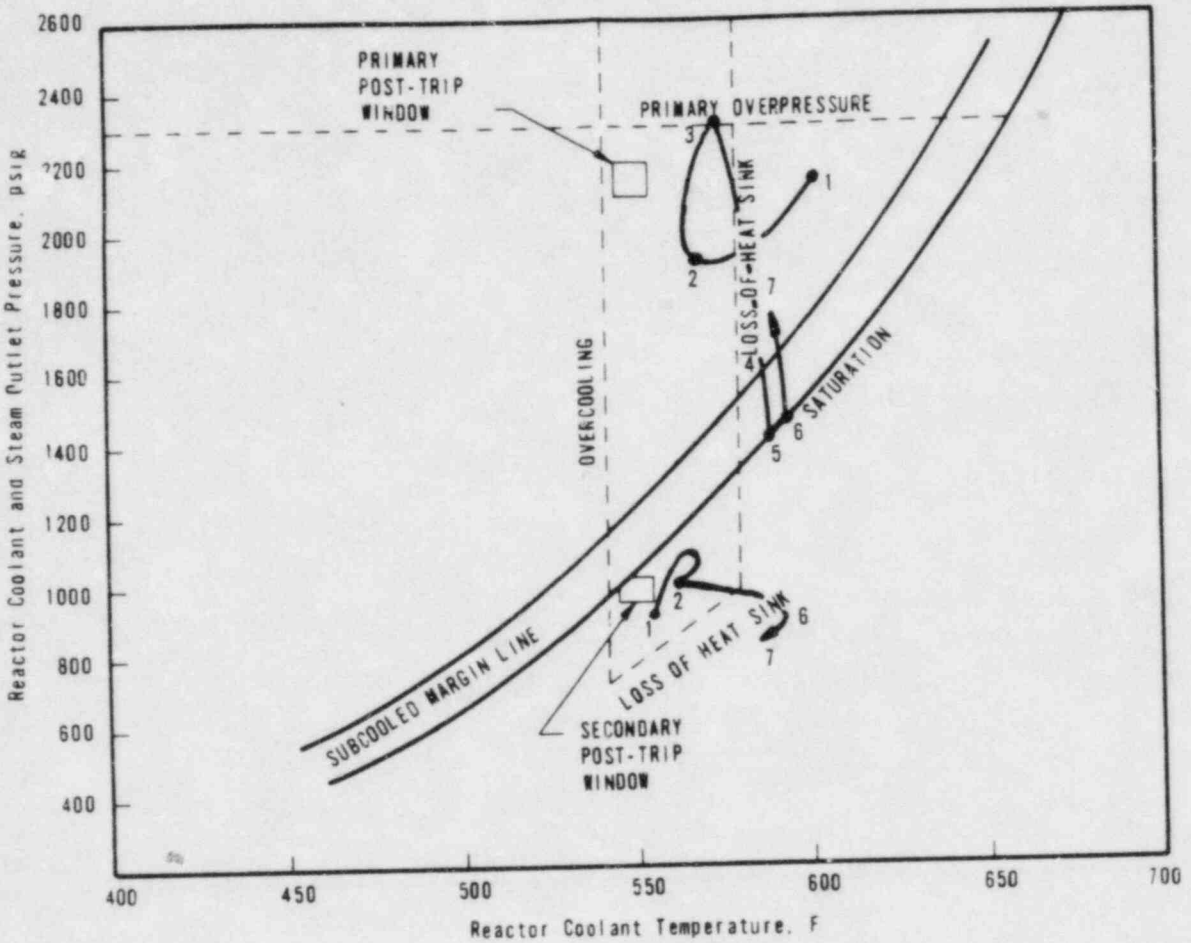
LEGEND

PRIMARY SIDE		SECONDARY SIDE
WATER		WATER
TWO PHASE LIQUID		STEAM
STEAM		

PRC
APERTURE
CARD

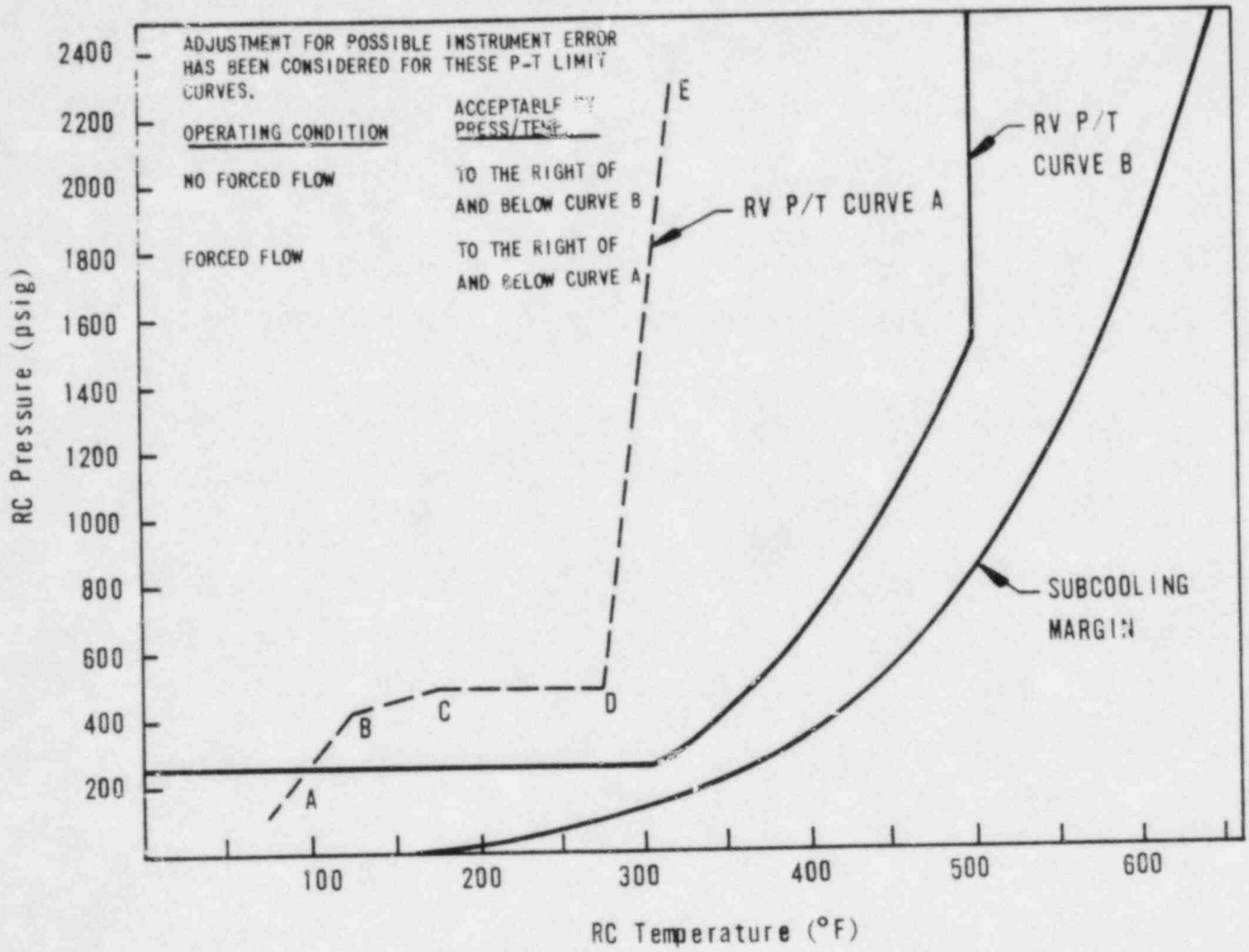
8401230549-17

Figure 24b BACKUP COOLING BY HPI FOR LOSS OF ALL FEEDWATER (WITH OPERATOR ACTION)

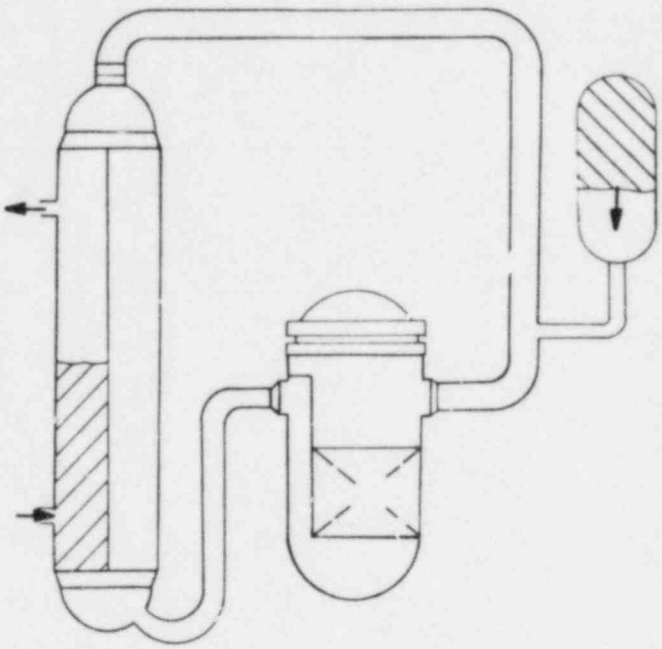


Reference Points	Time (Minutes)	Remarks
1-2	0-1	Reactor tripped on anticipatory loss of feedwater. Normal post-trip cooldown and depressurization in progress. EFW does not initiate.
2	1-2	Steam generators dry. RCS begins to reheat and repressurize due to loss of secondary cooling.
3	3-4	Operator diagnoses loss of heat transfer, opens PORV, starts two HPI pumps and verifies HPI flow.
		RCS begins to depressurize. Operator trips all but one RC pump to reduce heat input
4	5-6	Subcooled margin is lost. Operator trips remaining RC pump.
5	6-7	RCS reaches saturation.
6	7-8	Pressurizer in solid or near solid condition. HPI flow "matches" decay heat and begins to repressurize RCS to subcooled conditions.
7	8-10	RCS subcooled margin restored and RCS is beginning to cool due to HPI flow and PORV release. Operator throttles HPI flow to maintain subcooled conditions and restarts an RC pump to promote thermal mixing of HPI to minimize thermal shock.

Figure 25 RC PRESSURE/TEMPERATURE LIMITS



PRC
APERTURE
CARD



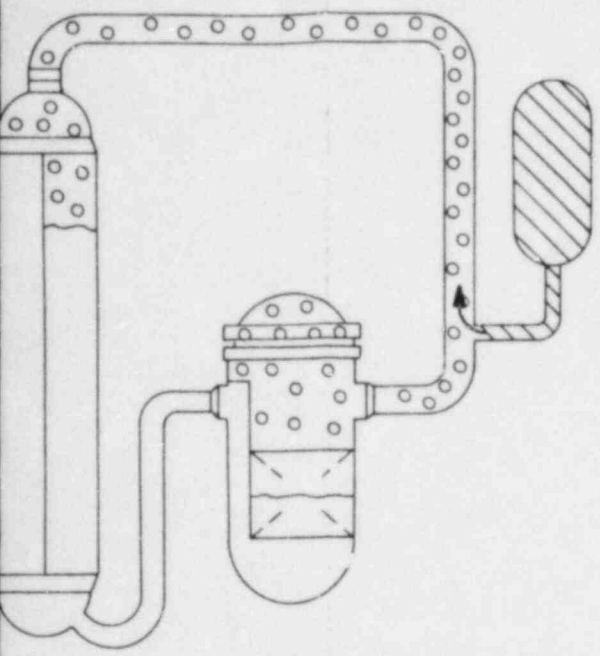
TIME 1

1. DECREASING PRESSURIZER LEVEL BECAUSE OF LOSS OF REACTOR COOLANT (LOCA) OR CONTRACTION OF REACTOR COOLANT (OVERCOOLING).

2. REACTOR TRIP ON LOW REACTOR COOLANT PRESSURE.

3. ESAS ACTUATION ON LOW REACTOR COOLANT PRESSURE
   -HPI ACTUATION

Figure 26 ILLUSTRATION OF LOSS OF NATURAL CIRCULATION DUE TO BUILD UP OF STEAM IN THE REACTOR COOLANT SYSTEM



TIME II

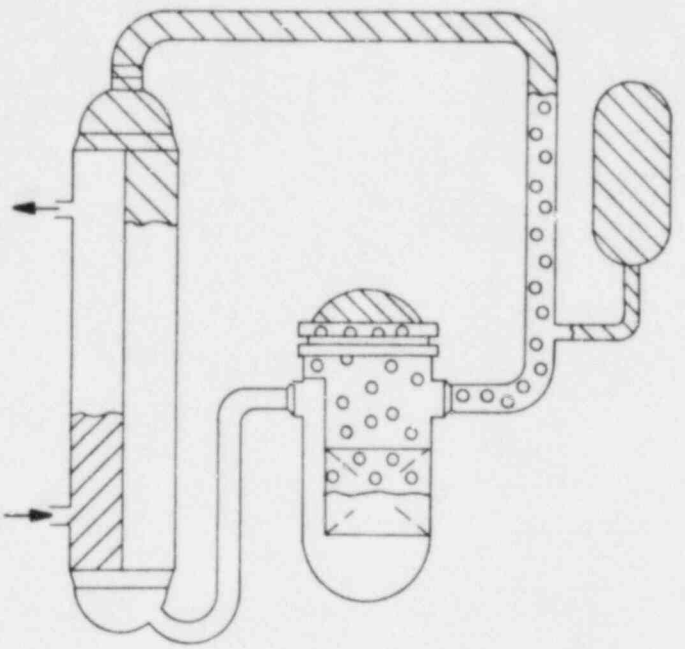
SSURIZER LIQUID VOLUME IS LOST; STEAM FROM PRESSURIZER ENTER RCS LOOPS WHEN THE RCS DEPRESSURIZES.

CTOR COOLANT PRESSURE DROPS TO A VALUE ABOUT EQUAL TO AM GENERATOR PRESSURE. OPERATOR TRIPS RC PUMPS WHEN SUBCOOLED GIN IS LOST. EFW ACTUATES.

AM FORMS IN HOT LEG BECAUSE OF ACCUMULATION OF SURIZER STEAM AND BECAUSE OF FLASHING OF REACTOR ANT. STEAM IS IN THE FORM OF BUBBLES WITHIN RCS.

HASE NATURAL CIRCULATION WILL OCCUR - BOILING MAY JR IN CORE.

SUFFICIENT STEAM IS CREATED, IT WILL START TO COLLECT JPPER REGION OF LOOP BECAUSE STEAM CAN RISE AT A FASTER OCITY THAN WATER.



TIME III

1. STEAM SEPARATES IN UPPER REGIONS OF LOOP
2. 2-PHASE NATURAL CIRCULATION STOPS.
3. SIZE OF THE STEAM BUBBLE DEPENDS ON SEVERITY OF ACCIDENT, HPI FLOWRATE, AND HPI STARTUP TIME.

Also Available On
Aperture Card

LEGEND

PRIMARY SIDE

WATER

TWO PHASE LIQUID

STEAM

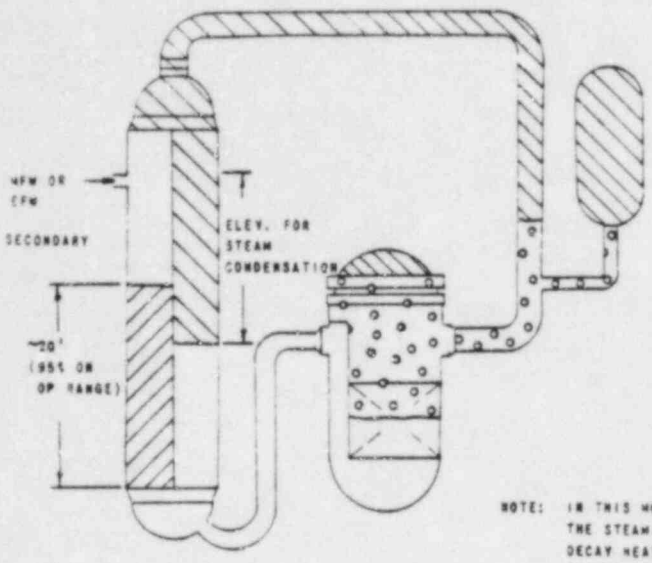
SECONDARY SIDE

WATER

STEAM

8401230549-18

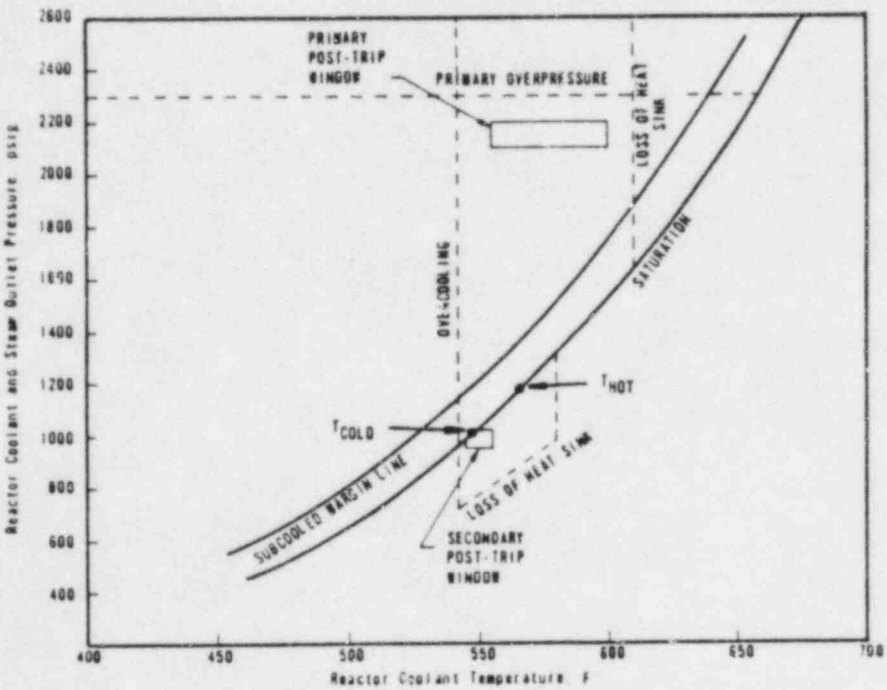
Figure 27 BOILER CONDENSER COOLING



LEGEND

PRIMARY SIDE	SECONDARY SIDE
WATER	WATER
TWO PHASE LIQUID	STEAM
STEAM	

NOTE: IN THIS MODE OF OPERATION THE STEAM GENERATORS CAN REMOVE DECAY HEAT BY CONDENSATION OF PRIMARY COOLANT STEAM. THE STEAM THAT IS CONDENSED KEEPS A WATER LEVEL IN THE STEAM GENERATOR TUBES TO FORCE FLOW UP THE COLD LEG AND INTO THE REACTOR VESSEL.



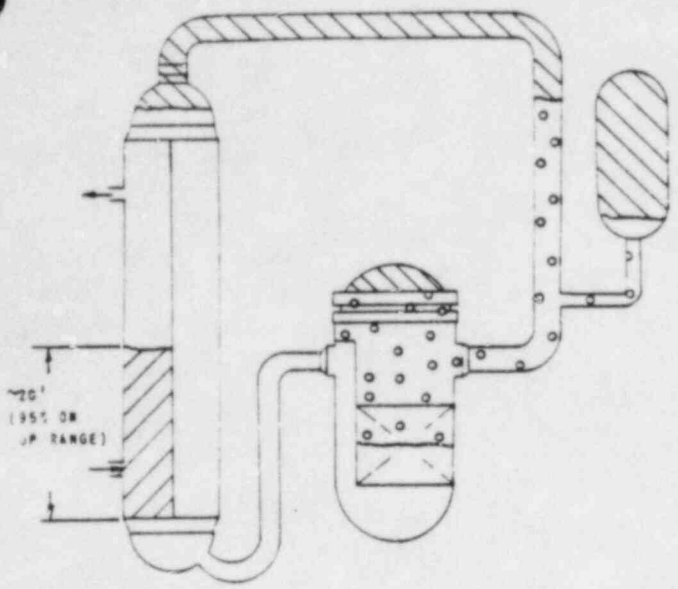
NOTES ON P-T DIAGRAM

1. RC pressures is slightly higher than steam generator pressure.
2. T_{hot} is equal to T_{sat} for existing RC pressure.
3. T_{cold} is equal to T_{sat} for existing steam pressure.

OPERATOR ACTION REQUIRED

1. Turn HPI on to highest flow rate.
2. Verify EFW flow (or start EFW) and raise steam generator level to 95% on Operate Range.
3. Start plant cooldown at 100F/hr.
4. Monitor plant conditions for a loss of boiler condenser cooling or a return to normal natural circulation (subcooling).

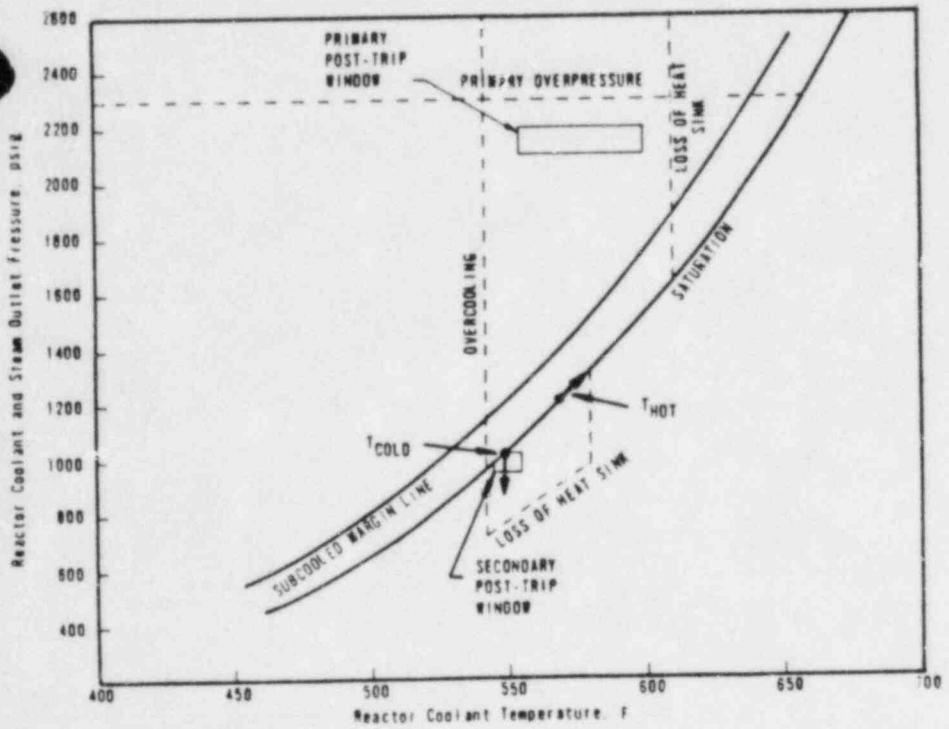
Figure 28 LOSS OF NATURAL CIRCULATION - SYSTEM REFILL BY HPI



LEGEND

PRIMARY SIDE	SECONDARY SIDE
WATER	WATER
TWO PHASE LIQUID	STEAM
STEAM	

NOTE: HPI IS REFILLING THE PRIMARY SYSTEM. THE STEAM GENERATOR CANNOT REMOVE DECAY HEAT BECAUSE THE HOT LEG IS FULL OF STEAM AND FLOW IS BLOCKED.



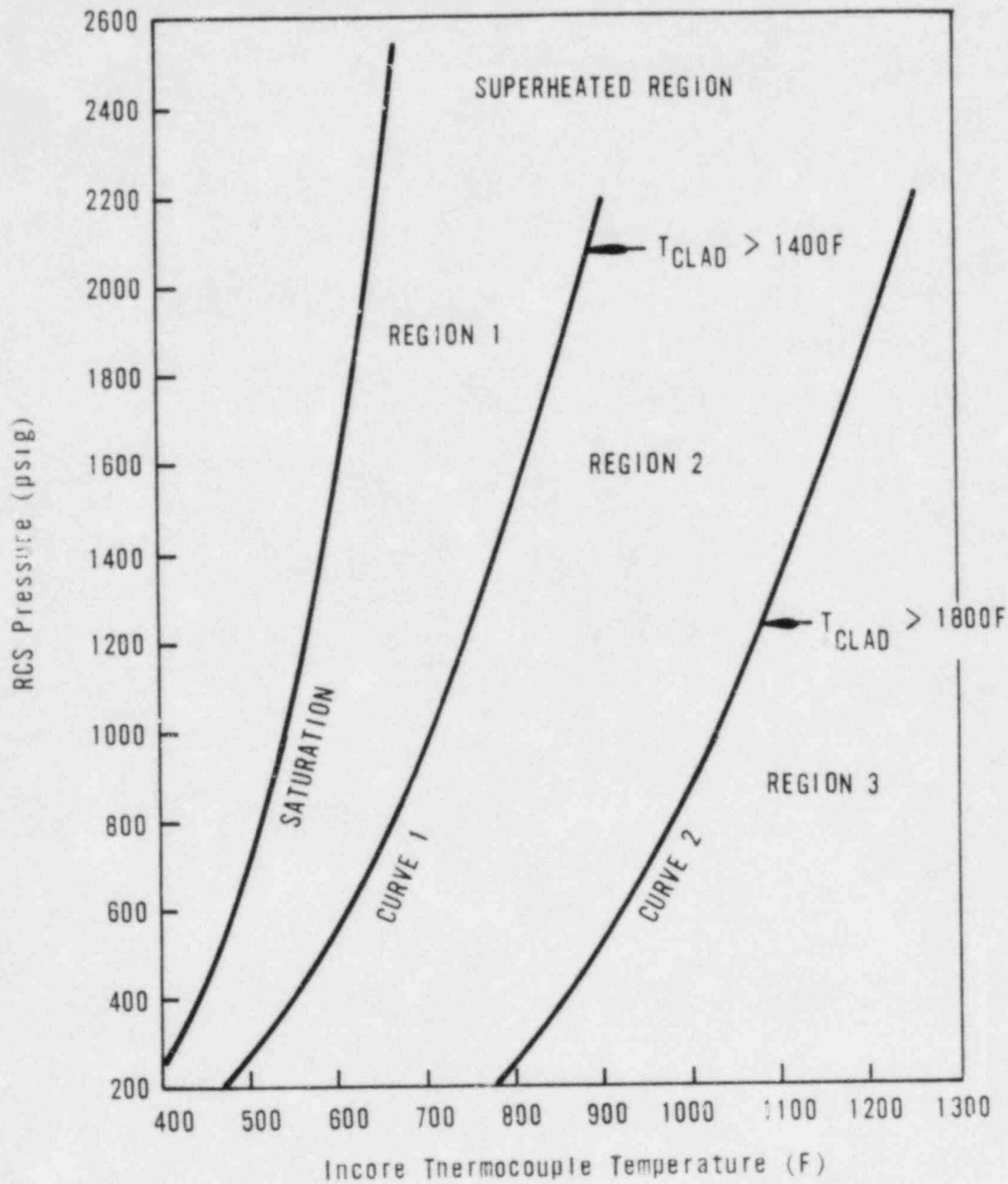
NOTES ON P-T DIAGRAM

1. T_{hot} is equal to T_{sat} for existing RC pressure.
2. RC pressure will increase above steam generator pressure and can go as high as the pressurizer safety valve setpoint (2500 psig).
3. Steam pressure may drop because heat transfer from reactor coolant is low. T_{cold} will remain approximately same value but may drop due to cold HPI and seal injection flow.

OPERATOR ACTION REQUIRED

1. Same as boiler condenser cooling.
2. Establish the steam generators as a heat sink (SG T_{sat} should be about 50F less than the incore thermocouple temperature).
   - Open PORV
   - Bump one RC pump

Figure 29 CORE EXIT FLUID TEMPERATURE FOR INADEQUATE CORE COOLING



EQUIPMENT OPERATION

CHAPTER E

BEST METHODS FOR EQUIPMENT OPERATION

During an abnormal transient the operator has to perform several actions to control different systems. This chapter will show the best ways to do the following things:

- Start and Stop RC Pumps
- Throttle or Terminate HPI
- Throttle or Terminate Emergency Feedwater
- Stop Main Feedwater
- Use the Incore Thermocouples
- Cooldown with One Generator out of Service
- Use of High Point Vents
- Recovery from Loss of LPI Recirculation

RC Pumps

During the course of an abnormal transient the RC pumps may need to be stopped and, at a later time, may be restarted depending on the kind of transient and the conditions of the reactor coolant system.

In general, the reasons for stopping the pumps are:

- To prevent pump damage (e.g., due to inadequate NPSH, loss of CCW etc.)
- To prevent possible core damage if a small break LOCA occurs
- To decrease heat input into the RCS

In general, the reasons a pump should be restarted are:

- To start natural circulation if it has stopped
- To allow a faster rate of cooldown and RCS depressurization
- To provide core cooling if the core has become uncovered (inadequate core cooling)
- Prevent thermal shock of the reactor vessel when the reactor coolant is subcooled without forced circulation.

This section will show the rules and guidelines for stopping and restarting RC pumps.

RC Pump Trip

RC pumps must be tripped during a small break LOCA if the subcooling margin is lost to prevent core damage. If the pumps are kept running they will force steam and water by the break; because the water is forced by the break, more reactor coolant mass will be lost out the break than if the pumps were not running. This can cause insufficient liquid in the RCS. If the pumps are tripped later in the transient, when insufficient liquid remains in the RCS, the steam and water remaining in the vessel and loops will separate (steam will collect in the high points and water will collect in the low points) and not enough water will collect in the vessel leaving the core uncovered so that the core will not be adequately cooled. Core damage can result. Analyses show that a later pump trip can be dangerous, but an early pump trip is safe. However, as long as the pumps continue to run the core will be cooled by the steam and water mixture circulating through the core.

The RC pumps must be tripped upon loss of subcooling margin. A loss of coolant accident will nearly always cause a loss of subcooling margin. Other transients, such as severe overcooling or loss of all feedwater can also cause loss of subcooling margin. Because the effects of failure to immediately trip RC pumps during a LOCA can be very serious, the operator should trip the pumps on the loss of subcooling margin without trying to find out the cause first.

To avoid core damage and RC pump damage, the following rule and associated note is given:

RC PUMP TRIP RULE

The RC pumps shall be tripped immediately whenever the subcooling margin is lost.

NOTE: IT IS ABSOLUTELY MANDATORY TO TRIP THE RC PUMPS IMMEDIATELY BUT IF THE PUMPS ARE NOT TRIPPED IMMEDIATELY (I.E., WITHIN TWO MINUTES) WHEN THE SUBCOOLING MARGIN IS LOST IT IS MANDATORY THAT THEY SHOULD NOT BE TRIPPED AT A LATER TIME. THE OPERATOR MUST MAKE SURE THAT COOLING WATER AND SEAL INJECTION ARE WORKING TO PREVENT PUMP DAMAGE. THESE SERVICES MUST BE MAINTAINED FOR SEVERAL HOURS. IF MECHANICAL DAMAGE TO THE PUMPS IS LIKELY THEN TWO PUMPS (ONE IN EACH LOOP) SHOULD BE STOPPED. THE TWO REMAINING PUMPS MUST BE KEPT RUNNING FOR AT LEAST 7000 SEC. IF THEY FAIL, THE TWO PUMPS WHICH WERE STOPPED SHOULD BE STARTED EVEN IF MECHANICAL DAMAGE IS LIKELY. THE OPERATOR MUST ALSO TRY TO GET AS MUCH HPI FLOW INTO THE RCS AS POSSIBLE.

The RC pumps should be tripped to prevent mechanical damage in all cases except the one noted above and during severe ICC. Mechanical damage is not expected to cause safety problems unless total seal failure occurs.

It is desirable to trip the pumps to prevent mechanical damage in case they must be restarted at a later time. Preserving the pumps for long term cooling or cooldown is desirable, and it is recommended that they be shut down if high vibration or loss of cooling services occurs. Limits on continued pump operation are given in OP 1103-6, 'RCP Operation'. These limits apply to normal and emergency services.

When the RC pumps are tripped to prevent mechanical damage, emergency feedwater will be automatically started and the steam generator level setpoint will be changed to 50% on the operating range. The operator should make sure that natural circulation starts. If only Nuclear Service Closed Cycle (NSCC) cooling water is lost, ten minutes exist to raise the water level (and/or restore NSCC) before the pumps must be tripped. Monitor RC pump stator oil temperatures and trip pumps if limits are exceeded.

If the pumps are tripped on loss of subcooling margin, natural circulation may or may not start depending on the amount of steam in the RCS. Nevertheless, a check on natural circulation is desired. Actions to establish natural circulation when the pumps are tripped because of subcooling margin are given in the pump restart guidelines which follows.

RC Pump Restart

The major reason for restarting the RC pumps is to increase the rate of heat transfer from the core to the steam generators; or if natural circulation has stopped and there is no heat transfer from the core to the steam generators, then a pump bump will help to restart natural circulation. Because the purpose of restarting the pumps is to increase core-to-steam generator heat transfer, it is necessary that the steam generator be available for heat removal. The steam generator will remove heat if: 1) the steam generator saturation temperature is lower than the RCS incore thermocouple temperature - a 50F temperature difference is a good rule of thumb to use, and 2) the steam generator is fed with main or emergency feedwater. It is preferable to start the pumps in the loop with the operating steam generator if only one is in service, and it is best to start the pumps in the loop with the pressurizer spray if possible. Since it is preferable to keep the pumps operable, a pump restart is not desired if mechanical damage can result (except for severe ICC conditions).

One RC pump may be restarted and run to prevent thermal shock when the reactor coolant subcooled margin exists and the core is being cooled by HPI cooling and no circulation exists. For this unusual situation, which can be caused by a prolonged loss of all feedwater, one RC pump may be run even though there is no steam generator cooling. However, it should not be run unless all normal limits and precautions are met. If subcooling margin is lost the RC pump should be stopped.

Inadequate Core Cooling is a condition where the reactor coolant is superheated. This is a condition when core damage could occur. For this condition, exceptions are taken: 1) RC pumps can be restarted if the steam generators are not available, and 2) If severe ICC conditions exist, RC pumps must be restarted even if mechanical damage can occur. For all other cases of pump restart, mechanical damage should be avoided.

Core cooling and plant control are best if the RC pumps are running. Pumps can be restarted after trip if the reactor coolant conditions are right. Therefore, to complement the RC Pump Trip Rule given previously, conditions when the pumps can be restarted are given. The RC pump restart criteria have been chosen to prevent fuel damage if an inadvertent pump trip occurs after restart.

When the RC pumps are restarted the operator should expect to see pressure changes in the RCS as follows:

- If the reactor coolant is subcooled and the pressurizer is filled solid, an abrupt rise in pressure could occur.
- If the reactor coolant is subcooled with a near normal pressurizer level, almost no change in pressure should occur.
- If the reactor coolant is two-phase and saturated, a pressure drop could occur when the heat removal rate of the steam generator increases.

Table 6, "RC Pump Restart Guidelines", shows the conditions when the pumps can be restarted. The table is divided into three parts: subcooled, saturated, and superheated. Guidelines for restart of the pumps in the saturated conditions are dependent on the existence of liquid or two-phase natural circulation. Generally, if natural circulation does not exist the RC pumps are "bumped" to try to start natural circulation; if natural circulation does start then that is a good indication that a large amount of water is in the RCS. "Bump", means to start a pump, observe the starting current drops off to running current, then turn it off.

When a RC pump is "bumped", it will cause hot reactor coolant in the vessel and hot leg to move into the steam generator; and will cause cold water in the steam generator to move into the reactor vessel. This will cause the thermal centers to change causing natural circulation (if enough water is in the RCS). When the RCS is saturated the "bump" may or may not start natural circulation, but it will help to depressurize the RCS by condensing reactor coolant steam in the generators and allow more HPI to flow into the system.

The "bumps" are used only every 15 minutes because: 1) that will limit the liquid flow out of the break and 2) it will take some time for natural circulation to develop and stabilize. Between "bumps" the development of natural circulation can be checked.

Table 6 shows two columns when the RCS is saturated - one with natural circulation and one without. Both show that HPI is on.

When natural circulation exists, the steam generator T_{sat} will be close to the incore thermocouple temperature; if SG T_{sat} is changed, the incore thermocouple temperature will follow. If the incore thermocouple temperature does not change when SG T_{sat} changes, the steam generators are not coupled to the reactor coolant system. Extended saturation with the steam generators available as a heat sink can exist only because of a LOCA or loss of RC inventory control.

For the condition with no natural circulation, the operator is directed to perform several "bumps". If after four bumps natural circulation does not start, then one RC pump should be run for cooldown as long as at least one OTSG is available as a heat sink. Natural circulation will not start when there is not enough water in the RCS. The reasons for allowing RC pump operation in this case, which goes against other requirements that do not permit RC pump operation when the subcooled margin is lost, are that the RCS should be depressurized and placed on the decay heat system before the BWST runs dry (to avoid HPI recirculation from the sump) and that the several "bumps" have consumed an hour since reactor trip. This time has allowed the decay heat load to drop so that a RC pump can be restarted without resulting in core damage if the pump subsequently trips. The HPI system is now capable of adding enough water to make up the flow out of

the break and still remove all of the heat. There is no chance for the core to become uncovered when the RC pumps are run at this time when the HPI system is working.

HPI Control

The HPI system is used for emergency injection of borated water to make up for lost inventory from a small break. It may also be actuated for overcooling and loss of heat sink events. The operator will have to control the flow rate in different ways depending on the cause of its actuation. The general control actions are:

1. Ensure two HPI pumps are running.
2. Verify maximum flow, balanced through all four injection nozzles with loss of subcooling margin.
3. Throttle the flow to prevent runout and cavitation of the HPI pumps at low pressure, if necessary (cavitating venturis should limit flow)
4. Throttle or stop the flow to prevent filling the pressurizer solid when the RCS is subcooled (except during HPI cooling as described in "Backup Cooling Methods").
5. Stop the HPI system when the LPI system is operating
6. Throttle the HPI to prevent exceeding RV brittle fracture limits when the RCS is subcooled.

Each one of these topics will be addressed and the best ways for handling HPI will be shown. The discussion will be divided into two sections: Maximizing HPI Flow, and Throttling HPI.

Maximizing HPI Flow

HPI START RULE:

Two HPI pumps should be run at full capacity when:

- The ESAS is automatically actuated or
- The reactor coolant subcooling margin is lost.

When the HPI system is started for either of these two conditions, its purpose is to remove decay heat either by "once through cooling" or by allowing the reactor coolant to transport heat to the steam generator. "Once through cooling", or HPI cooling occurs when the injection water passes through the core, picks up heat, and exits through a break or the PORV. In order to be most effective, the HPI flow to the core must be the greatest amount possible. One HPI pump will satisfy core cooling requirements, but two HPI pumps are preferred. (Operating three HPI pumps is not required or recommended.)

Balancing the HPI flow is required to ensure that the greatest amount of pumped flow enters the core. When the system is automatically actuated the operator should check the flow indicators on all four injection lines. The cavitating venturis should provide balanced maximum flow. If an injection line reads low flow, the operator should ensure all four injection valves (MU-V16A-D) are fully open.

HPI Throttling

After it is started, the HPI must be run at full capacity until the reactor coolant system conditions allow it to be terminated or throttled. Guidelines for throttling or termination and the reasons are given below:

Guideline 1 for HPI termination:

HPI operation may be terminated if the LPI system has been started and has been flowing at a rate in excess of 1000 gpm in each injection line for 20 minutes.

This condition is applicable to a large LOCA when the RCS depressurizes enough to allow the LPI to flow into the reactor vessel. Since LPI will provide emergency injection at a much greater flow rate than the HPI, HPI can be stopped. The 20-minute delay is used to make sure that the primary system will not repressurize and result in a loss of LPI flow. The minimum flow requirement of 1000 gpm is used to make sure that the injection flow can remove decay heat with no loss of reactor vessel water inventory after HPI is stopped. 1000 gpm flow to each injection line is required to make sure at least 1000 gpm gets into the RCS since a break in one of the two LPI/CFT lines would allow LPI water to be lost out the break and not reach the reactor vessel.

Guideline 2 for HPI termination or throttling:

- HPI may be throttled any time the reactor coolant subcooling margin is restored.
- HPI may be terminated any time the reactor coolant subcooling margin is restored and pressurizer level is on scale "low" (> 100") and increasing and within capacity of normal makeup. Normal makeup and pressurizer level control should be restarted. RCP seal injection should be maintained. The one exception to this guideline is the case where core cooling is provided solely by HPI. In this case HPI can be throttled when the subcooling margin is restored, but should not be stopped until secondary heat removal is established, even though the pressurizer will be solid.

These guidelines apply to both LOCA and non-LOCA transients and are intended to limit the amount of water going into the RCS so that the pressurizer will not fill solid and let water discharge through the pressurizer valves. The pressurizer can fill for two reasons:

- Continued HPI injection
- Reheat and swell of the reactor coolant after an overcooling transient has been stopped.

Although the core will be covered and safe if HPI flow is not throttled, it is desirable but not mandatory to do so. If there is any doubt about throttling HPI flow, then don't do it. If water were allowed to flow through the pressurizer valves, the plant conditions could get worse.

Continued flow through the valves could fill the RC drain tank and cause the rupture disc to fail releasing water to the containment, or the pressurizer valves could fail to reclose and a LOCA would result. The one exception for flow through a pressurizer valve is HPI cooling when the PORV is intentionally opened to provide a once-through cooling path for HPI water. If the reactor coolant was very cold, the repressurization could cause a violation of the RV P/T curve of Figure 25.

An overcooling transient causes the reactor coolant to shrink. If HPI is started additional water is added to the RCS. When the overcooling is stopped, the core heat will cause the reactor coolant and the added water to swell. It can expand enough to fill the pressurizer. In order to limit the amount of filling, the HPI flow should be throttled when the reactor coolant subcooling margin is restored. HPI flow can be stopped when the subcooling margin is restored and an adequate pressurizer level indication is shown. The 100 inch pressurizer level indication was chosen because it is above the pressurizer heater cut-off level.

If the overcooling was severe, throttling HPI alone may not be enough to prevent the pressurizer filling so the reheat of reactor coolant must also be limited. This can be done by lowering steam saturation temperature below the RC cold leg temperature. The operator can monitor the effects of steam pressure by monitoring T_{cold} and pressurizer level and control steam pressure as necessary. The operator should be careful not to lower steam pressure too much or the pressurizer will drain.

Throttling or termination of HPI and lowering steam pressure will keep the RC pressure and temperature from returning to the "post trip window". This is an acceptable end point if the system is stable.

For many events that use the HPI system, subcooled reactor coolant conditions will be returned in the first several minutes. When the reactor coolant subcooling margin is established the following general procedure to control RCS inventory should be followed:

HPI Control After RC Subcooling Margin is Regained

1. Avoid too much subcooling (high RCS pressure). There is a tendency to think that if "adequate" subcooling margin is good, then 200F subcooling must be better. The easiest way to get this excess subcooling is to allow HPI to run unthrottled and raise RCS pressure. This may lead to unnecessary lifting of the primary safety valves (the time between 2200 psig and 2500 psig with two HPI pumps running unthrottled is about 60 seconds). Also, there are transients such as a steam generator tube rupture where the higher RCS pressure makes the transient worse (larger leak rates). Therefore, the operator should throttle HPI and begin to stabilize RCS pressure as soon as the criteria allow.
2. If pressurizer level is off scale low, maintain HPI but reduce the amount of flow that is being added to the RCS.

- If two or more HPI pumps are running, stop all but one pump.

  NOTE: Run the HPI pump which normally supplies seal injection.

  NOTE: Do not decrease HPI flow below low flow limits (40 gpm).

3. If pressurizer level is on scale but below 100 inches, throttle HPI using HPI injection valves and attempt to stabilize pressurizer level.
   - Maintain HPI at the reduced flow rate if pressurizer level and subcooling stabilizes (i.e., HPI is matching a leak).
   - If pressurizer level continues to increase above 100 inches, control HPI per Item 4 below (except during HPI cooling as described in "Backup Cooling Methods").
4. If pressurizer level is increasing and greater than 100 inches (indicated) and HPI flow is within MU system capacity, realign the HPI system into the normal makeup and letdown mode.
   - Monitor reactor coolant subcooling; restart HPI if subcooling margin is lost or pressurizer level decreases below 100 inches.
   - Reset ESAS after HPI has been stopped (if RCS pressure is high enough).

Guideline 3 for HPI termination or throttling

- The HPI must be throttled to prevent pump runout and cavitation damage. The maximum allowable flow per pump is 550 gpm.

This guideline is implemented for pump protection so that core cooling will continue. With the recirculation lines closed the cavitating

venturis should limit total pump flow to approximately 550 gpm even when the RC system is at 500 psig or lower. However, the additional flow through the recirculation lines can result in total pump flow slightly greater than the 550 gpm limit.

Guideline 4 for HPI termination or throttling

- The HPI low flow limit is about 40 gpm. HPI flow should not be throttled below this limit unless MU-V-36/37 are open.

  The total HPI pump flow should stay above 40 gpm.

Pump overheating and damage can occur at very low flows. The total flow is a combination of the recirculation flow and the injected flow.

Guideline 5 for HPI termination or throttling:

- HPI must be throttled to prevent exceeding the RV P-T curve of Figure 25 when the reactor coolant is subcooled.

The RCS pressure/temperature combination must be kept within certain limits to assure reactor vessel integrity. These limits are dependent on whether there is forced flow, or NO forced flow:

Forced Flow

As long as at least one reactor coolant pump (RCP) is running, the RCS pressure and temperature must be kept within the normal technical specification NDT limits (Region I & II of Figure 25).

With at least one RCP running, any cold leg RTD can be used to determine the temperature for comparison to the NDT limit. However, due to back flow in the cold leg pipes without an operating pump, the cold leg RTD in these loops will indicate temperatures slightly lower (~2F) than in the cold leg pipes with running RC pumps due to the relatively cold HPI and seal injection water added to the back flow.

No Forced Flow

If the RC pumps are NOT running, the RC pressure/temperature combination must be kept within the no forced flow region of Figure 25 (Region II). The reactor vessel downcomer temperature will be colder during no flow conditions than during forced flow conditions. The "RV P/T Curve B" of Figure 25 is designed to account for these colder temperatures. These colder temperatures occur because the HPI flow entering the RCS does not completely mix with the reactor coolant as would happen if the RC pump were operating. The HPI water, which can be as low as 40F per Technical Specifications, will enter the cold leg pipe then flow into the RV downcomer to cool the reactor vessel walls. These colder RV temperatures will cause the allowable RV pressure to be lower.

The "Interim Brittle Failure Guideline" requires throttling the HPI flow. This will reduce the thermal shock probability by first reducing the RV pressure and second reducing the HPI cooling of the RV.

The "RV P/T Curve B" of Figure 25 is based on several conservative assumptions; consequently, small violations of this curve are more tolerable than similar violations of the subcooling margin limit. However, if the "RV P/T Curve" is exceeded, the RCS pressure should be reduced to regain the no forced flow operating region as quickly as possible.

a) Monitoring Thermocouple Temperatures

With no RCPs running, the average of the five highest operable incore thermocouples (TC's) temperature readings should be used to determine the RC temperature for Figure 25. This will assure that the subcooling margin is maintained and that the RV P/T curve is not exceeded.

The use of the 5 highest TC's is preferred for the following reasons:

1) The operator monitors the five highest TC's for other reasons (ICC), i.e., the data is available and the operator need not perform additional data reduction.
2) The conservatisms in the thermal shock analysis are more than adequate to support the slightly higher system pressures and slightly lower downcomer temperatures by using the five highest rather than five lowest thermocouple readings.

3) The allowable temperature span between the subcooling margin limit and the RV P/T Curve B of Figure 25 for RCS operation is relatively narrow. Consequently, the operator should use the same instrument for avoiding both limits. If the subcooling margin is determined by averaging the five highest thermocouple readings, the margin to the curve should be determined with the same readings to avoid overlapping limits.

Without a RC pump on and with HPI on, with or without natural circulation, the cold leg temperature detectors cannot measure the RV downcomer temperature. This is because the RC loop flow and HPI flow mix downstream of the temperature detector. The ratio of the HPI flow to RC loop flow is substantial. Consequently, the resulting mixed temperature of the two fluids will be substantially lower than the cold leg temperature indication. The ratio of the two flows will vary with the size of break in the reactor coolant pressure boundary. The larger the break the more the HPI flow and the less the reactor coolant flow.

During natural circulation, the hot leg temperature detector with loop flow can be used to indicate core outlet temperature. However, to simplify the operating instruction the incore thermocouples are to be read, whether or not natural circulation exists. Therefore, the operator does not have to determine if natural circulation exists to switch from one measuring device to another.

If HPI flow does not exist, the operator should use the normal NDT limit curve (RV P/T Curve A of Figure 25) during natural circulation and the cold leg temperature detector in the loop(s) with natural circulation flow.

b) RCS Pressure Control

During water solid operation, throttling the HPI flow is the only method for gradually reducing RCS pressure. Also, without primary to secondary heat transfer, the rate of cooldown is dependent on HPI cooling through the break (opening the PORV is necessary only if the break is so small that RCS pressure begins increasing). Therefore, careful and consistent throttling of HPI flow is the only available means to ensure that the RC pressure/temperature combination remains within the no forced flow operating region of Figure 25.

c) Restoring Natural Circulation

If a RCP cannot be started, natural circulation should be obtained to provide some HPI mixing as well as providing good heat transfer from the primary to secondary coolant. With natural circulation, the cold HPI water will mix with cold leg flow and reduce the thermal shock to the reactor vessel. However, the RC pressure/temperature should still be maintained within the no forced flow operating region of Figure 25. The thermal shock concern is eliminated entirely when RCPs are running and RCS P/T is maintained within tech Spec NDT limits. Therefore, as soon as subcooling margin is obtained in the RCS, a RCP should be restarted. Then the reactor vessel downcomer pressure/temperature should be kept within the normal RV pressure/temperature limit.

HPI VALVE CONTROL

The HPI valves will be used to reduce HPI flow until the RC system pressure becomes low enough to initiate the LPI or DHR system. If a small break exists, the RC pressure may have to be reduced to the LPI operating pressure because of lack of NPSH for DHRS operation. If only a loss of feedwater exists, then the RC pressure need only be reduced to the DHRS operating pressure (unless secondary cooling is re-established) and then the pressurizer power operated relief valve should be closed.

Without feedwater the time to depressurize will depend on the size of the break. The HPI flow will be performing two functions. It will be maintaining system pressure which will be a function of the HPI pump head and the choked flow out the break. It will also be removing decay heat from the core. The amount of decay heat will determine the amount of HPI flow needed and the HPI flow will establish the RC pressure. Consequently, as the decay heat level decreases the HPI flow can be throttled back which will cause the RC pressure to reduce.

With feedwater and the RCS water solid and either forced or natural circulation, the HPI flow to the core is needed only to control pressure. The steam generator will remove heat. Consequently, the RCS can be depressurized much quicker. The steam generator can be used to cool the core as quickly as possible up to the 100F/hr. limit. Simultaneously, the HPI flow will be throttled to maintain the RC pressure within the acceptable P-T limits.

The HPI flow rate should be balanced among all injection nozzles to distribute the HPI flow around the reactor vessel downcomer as much as possible. This will limit localized cooling of the RV.

During plant cooldown a situation may occur where the RC pressure cannot be reduced by throttling HPI flow. This will have been caused by hot water flashing to steam in either of the RC hot leg 180 degree elbows "candy canes" (due to no flow in one or both loops) or in the pressurizer (PORV closed).

The operator should attempt to remove the RC loop steam and hot water by bumping a RC pump in the loop with natural circulation flow. If no natural circulation flow exists any RC pump can be bumped.

With a small break, the HPI can cool the core enough to make the RCS subcooled with choked flow out the break. However, if the break is not in the pressurizer steam space, a steam bubble could form in the pressurizer which will also need to be controlled in order to reduce RC pressure, either by opening the PORV or vent or using pressurizer spray.

These guidelines are summarized in Figure 30.

Feedwater Control

Abnormal transient operation with main or emergency feedwater requires special attention to feedwater control. Failures can cause too much water to be added. Excessive main feedwater addition can fill the steam lines with water (steam lines may fail) and cause undesirable overcooling. If feedwater heating is lost and cold water is added to the steam generator overcooling will be augmented. Excessive emergency feedwater can have the same general effects, but it will cause a more severe cooldown (for the same MFW flowrate) because of the steam pressure reduction effect due to the colder water and where it enters. Both excessive main and emergency feedwater may require that quick actions be taken to stop it. Emergency feedwater may also cause overcooling when the steam generator level is being raised even though no failures have occurred. In order to limit overcooling, emergency feedwater flow should be throttled. This section will recommend the best methods for manual control.

Main Feedwater Overfill

The procedural guidelines in Part I consider various MFW overfill conditions including a very rapid overfill for which the operator is instructed to immediately trip both MFW pumps. This section, however, presents less severe actions that can be taken in the event of slower overfill transients.

To regain control and stop main feedwater overfilling when a failure of the controls occurs (the following gives a series of increasingly more severe actions):

- Close the feedwater isolation valve to the high flow generator. This action is preferred to closing the control valves or running back feedwater with the ICS feedwater demand hand station because those controls may have failed and could have been the reason for the excessive feedwater. Closing the isolation valve cuts off feedwater to only one generator and does not cause a total loss of main feedwater.
- Trip the main feedwater pumps. This is the quickest and surest method of stopping the overfill. It is also the preferred method if the OTSG is overfilling rapidly. This will stop all feedwater to both generators (it will be a loss of feedwater, but since the generators have a large inventory the heatup effects will be delayed). This action can be taken if both generators have excessive feedwater or the other actions do not work.
- Flow should be monitored in all cases; it will show the effects of corrective action faster than level. The corrective actions must be taken within 2-3 minutes to prevent steam generator overfill (water level at the top of the shroud). If all main feedwater has

been stopped, the operator should make sure emergency feedwater starts so it can start to inject when the generator water level boils down to the automatic setpoint.

Emergency Feedwater Overfill

To stop emergency feedwater from filling one steam generator:

- Artempt to close the control valve to high level/high flow steam generator. This may not work if the valve controls have failed.
- Trip the turbine driven EFW pump.
- Trip one motor driven EFW pump (select the motor-driven pump supplying flow to the high level/high flow generator)
- Close the cross connect valve to prevent the pump from supplying flow to the bad generator. If the failed control valve cannot be repaired or operated locally, flow to the affected SG can be initiated as required by cycling the cross-connect valve or the associated motor-driven pump to "batch" feed the generator. This should only be done as necessary to prevent dry-out and to maintain tube/shell ΔT within limits. Normal EFW or MFW flow control should be re-established as soon as possible.

To stop emergency feedwater from filling both steam generators (this condition may happen if power supplies or air supplies are lost to the control valves):

- When steam generator level is high, stop both motor-driven pumps and close both cross-connect valves, allow the steam generator level to drop and reopen the cross-connects. Use the cross-connect valves and the turbine-driven pump to "batch" feed the generators by cycling as necessary. Ensure minimum bypass flow exists for the turbine-driven pump when both cross-connects are shut.

  This approach can be taken until the control valves can be operated normally or manually. Once an operator is stationed at each valve he can position it to maintain level. Infrequent cycles of the cross-connect valves are expected because the steam generator levels will take about 5 to 10 minutes to boil the inventory to a low level.

- If EFW cannot be controlled MFW should be tried. If this is unsuccessful, HPI cooling can be used. This method is not desirable, but it will keep the core cool. Every attempt should be made to maintain EFW to at least one generator, even if the operation is not steady.

EFW Throttling

Anytime EFW flow is actuated and automatically increases steam generator level to 50% on the operating range, it can cause significant overcooling. The 50% level is required to establish natural circulation any time all RC pumps are tripped.

Steam generator level must also be manually increased from 50% to 95% on the operating range when the subcooling margin is lost. The 95% level will permit primary coolant steam condensation during boiler-condenser cooling in case a small break LOCA has happened. Anytime the subcooling margin is lost, the level should be raised to 95% on the operable steam generator(s), i.e., the steam generator(s) without a leak; if the subcooling margin is regained while the level is increasing then the level increase does not need to be continued to the 95% level, but must be raised to 50% if the RC pumps are not running.

Steam Generator Level Rule
Anytime the subcooling margin is lost, levels in the operable steam generators must be raised to 95% on the operating range using EFW flow in accordance with the EFW throttling guidelines.

Exception: If the loss of subcooling margin was due to a loss of secondary steam pressure control, do not attempt to raise level in the affected steam generator(s) until steam pressure control is regained.

Overcooling can result because all EFW flow comes on and injects cold water into the steam space of the generator. As the flow sprays into the steam space it causes steam condensation and a reduction of steam pressure; when the level increases the inventory accumulation is a colder heat sink than is needed to balance decay heat. The combination of the steam pressure reduction and the colder heat sink causes the overcooling.

Addition of EFW at the maximum rate is not needed to achieve stable natural circulation; it is also not necessary to raise the level from 50% to 95% at the highest possible rate. EFW can be throttled to control the level and limit the overcooling. Full flow of EFW is not needed, but continuous flow is. A continuous addition of EFW into the steam space will cause the thermal center for natural circulation to be high in the generator, and continuous addition will cause primary steam condensation. However, if natural circulation is lost (for example, due to a delay in EFW actuation), then EFW flow should not be throttled until natural circulation starts.

It is not mandatory to limit the rate of EFW addition to prevent overcooling, but throttling is preferred to control the plant better. For example, if a severe overcooling transient caused loss of the subcooling margin and the RC pumps were tripped, the addition of EFW at full flow would cause the overcooling transient to be much worse. Throttling is desirable to control the severity of this type of transient.

Guidelines for EFW Throttling:

- EFW may be throttled any time it is started after loss of main FW if it is injecting into both steam generators (EFW should not be throttled when in automatic control with the low level setpoint in effect).
- EFW may be throttled any time after it is started and natural circulation exists in one or both steam generators.
- EFW flows should be throttled to maintain SG pressure within less than 100 psi below the turbine header pressure setpoint.

Rules on EFW Throttling:

- EFW must be turned on full if natural circulation stops and the steam generator level is below the setpoint. It can be throttled when natural circulation starts.
- EFW must be turned on full if its actuation was delayed (and SG level is below setpoint). It can be throttled when natural circulation starts.
- EFW must be turned on full if it is injecting into only one generator and SG level is below setpoint. It can be throttled when natural circulation starts.
- The steam generator level must never be allowed to decrease if level is still below the appropriate setpoint.
- Flow into the steam generators must be continuous at all times until the setpoint is reached.

Steam Generator Level Setpoints:

- 30" on the startup range when one or more RC pumps are operating (low level setpoint).
- 50% on the operating range with two steam generators (it may be necessary to raise the level higher than 50% if only one steam generator is working) when no RC pumps are operating.
- 95% on the operate range when the subcooling margin is lost.

The amount that EFW can be throttled depends on the decay heat load which can vary depending on the prior operating power history. To increase

level, the flow must be greater than that required to remove the decay heat.

Because the decay heat can be different, the amount of flow needed to remove decay heat and increase level is different; therefore, no fixed flow rate can be established. However, the maximum flow rate can be gauged by its effects. Generally, the flow rate should not drop steam pressure by more than about 100 psi below the pressure setpoint. For example, after a trip the turbine bypass set pressure is 1010 psig so the EFW flow should not cause steam pressure to drop below around 900 psig. If the operator has adjusted steam pressure to a different setting, the steam pressure drop should stay within 100 psi of that setting. The 100 psi change in steam pressure is a rule of thumb for limiting the cooling of the RC system.

The effects of EFW throttling can also be seen in pressurizer level (if the reactor coolant is subcooled and is circulating). Pressurizer level indication should be visible and not be allowed to drop out of range because of EFW.

An important objective is to maintain natural circulation. If natural circulation has been previously established and the EFW flow rate is enough to maintain natural circulation, then it is the right flow (if pressurizer level and steam pressure are about right). Generally, natural circulation is established and maintained when T_{hot} is no more than 50F higher than T_{cold}.

EFW should not be throttled if its automatic start is delayed after loss of main feedwater when all RC pumps are off. It also should not be throttled if only one generator is available for heat removal. For either of these conditions natural circulation could be stopped or not started. Small break LOCA primary steam condensation might also be restricted for either situation.

EFW throttling is not mandatory, but is desirable to limit overcooling and possible pressurizer draining. If there is doubt about throttling EFW, then don't do it.

Use of the Incore Thermocouples

The incore thermocouples can be used for a variety of purposes. Information about the incores is given in different chapters. The following summarizes that information:

1. They are used to detect core uncovering. They are the most valid indication of core cooling. If the incore thermocouples clearly indicate superheated conditions, then the actions to counter Inadequate Core Cooling should be taken.
2. They provide an indication of natural circulation. T_{hot} should read within 10F of the incore thermocouples when the plant is subcooled and solid water natural circulation is occurring. When the reactor coolant is saturated the incore thermocouples do not provide a good indication of natural circulation.

3. They provide an indication of NDT margin to RV pressure/temperature limits when no forced circulation exists. The reading of the average of the five highest incore thermocouples displayed should be compared to Curve B on Figure 25, "Subcooling Margin and Reactor Vessel RC Pressure/Temperature Limits." If that number is above Curve B the HPI flow should be throttled or an RC pump started.
4. They are the only valid indication of core outlet conditions when no circulation exists.

Cooldown with One Steam Generator Out of Service

Attempting to cool the plant down using one "good" steam generator can cause excessive thermal stresses in the other "bad" steam generator if it is dry and the cooldown rate is large. Although one steam generator can remove the decay heat and the stored heat needed to cooldown, the dry steam generator is not properly cooled because the shell stays hot.

During normal cooldown the shells of both generators are cooled by liquid in the lower part and by steam in the upper part. When the shell is not cooled and the tubes are cooled by reactor coolant, the tubes can get much colder than the shell causing them to contract relative to the shell. But because the tubesheets hold the tubes in a fixed position and the shell does not shrink the tubes go into tension. If they get cold enough the tension stresses will be greater than the yield stress and they will permanently stretch. If the tubes are cracked, flawed, or thinned they may fail. Consequently, limits are placed on the tube-to-shell ΔT. For

normal cooldown this limit has been conservatively set at 100F. However, in an emergency situation when cooldown is absolutely required the limit can be exceeded up to 150F ΔT, with the understanding that any transient which results in exceeding the design ΔT limit of 100F requires specific stress evaluation before plant restart.

Cooldown with one generator at the highest rate of cooldown should not be done unless it is absolutely necessary. The choices to be made prior to cooldown are:

- Stay at stable hot conditions until the generator is repaired and returned to service.
- Cool down at a slow rate so that the tube-to-shell temperature limit does not exceed the "normal" ΔT limit of 100F.
- Cool down at a more rapid rate, but do not allow the tube-to-shell temperature limit to exceed the "emergency" ΔT limit of 150F.

The need to cool down can be established only after a review of the plant status. There are a limited number of reasons why cooldown may be required; these include:

- LOCA - small or intermediate break LOCA's will require cooldown so that the primary system can be depressurized. Depressurization will slow down or stop the leak rate. Tube leaks or ruptures especially require depressurization to stop the leakage into the steam generator.

- BWST Draining - in conjunction with LOCA, it is desirable to have the plant completely cooled down to avoid recirculation from the containment sump using the HPI system. For tube leaks which do not return water to the sump, it is absolutely required to have the plant depressurized before the BWST drains.
- Condensate tank draining - to avoid using backup service water with poor water chemistry in the steam generator, it is desirable to have the plant on the decay heat removal system before the condensate tank is drained (or be able to return the MFW system to operation).
- Other Transients - most transients will not require cooldown for mitigation, so the plant can be placed in hot shutdown while the "bad" steam generator is repaired.

However, some situations, such as fires, may have left the plant so badly damaged that a decision to cool down is necessary to avoid unknown side effects.

In order to cool the plant down rapidly with one generator out of service it will be necessary to add water to the "bad" generator so the shell can be cooled. If the generator is completely dry, the shell will cool only by heat loss through the insulation to the reactor building; the average shell cooldown rate will be low (around 3-5F per hour). Water addition to the generator will allow the shell to cool faster and the rate will depend on whether a water level can be maintained. If water can accumulate and

cover the lower part of the shell, the average rate of shell cooldown will be about 20F/hr. But if a water level cannot be built and the shell is mostly cooled by steam, then the average rate of shell cooldown will be around 10F/hr. Since the rate of shell cooldown is greatest when water is in contact with it, the preferred way to add water is with the main feedwater system. However, the main feedwater flow rate must be carefully controlled so the tubes do not "overcool".

The cooldown rate of the plant will be limited by the cooldown rate of the shell and the cooldown limit is based on the tube-to-shell ΔT limit. The tube-to-shell limit can be calculated by averaging the five shell thermocouples and subtracting the reactor coolant average temperature (However, in some rare cases T_{ave} might not represent the average tube temperature; these cases can occur if the hot leg is steam bound and no circulation is occurring. If T_{hot} is increasing but T_{cold} is fixed, then T_{cold} should be used rather than T_{ave}.)

To illustrate a plant cooldown, two examples are given. Both of the examples assume that a tube leak has occurred. Therefore, the plant must be cooled down; it cannot stay at hot conditions. The first example shows a tube leak with a generator that can hold pressure but cannot be steamed. In this case a water level can be built to cool the lower part of the shell. The second example shows a tube leak with a generator that cannot hold pressure (a failed steam safety valve could do this). In this case,

a water level cannot be built because of constant steaming (in fact, a water level could be built if the main feedwater system were allowed to operate at high capacity, but the tubes would cool down extremely fast and the tube-to-shell temperature limit would be violated). The examples are illustrated in Figures 31a and 31b.

Both examples follow the recommended procedure for large tube leaks. That is, the plant is runback, depressurized and cooled rapidly from 550F (T_{ave}) to 500F (T_{ave}) at up to 240 F/hr. After that the RCS is cooled down and depressurized at 100F/hr until the "emergency" tube-to-shell limit of 150F is reached. At that time, the cooldown is slowed and follows the cooldown rate of the shell and the tube-to-shell ΔT is the controlling limit. When the plant first reaches the "emergency" tube-to-shell temperature limit of 150F, the RCS pressure will be around 400 to 450 psig and the tube leak rate will be lowered.

The procedure shown in Figure 31a, with a generator that can hold pressure, is to add water to the generator when the first stage of cooldown is completed (i.e., at 500F RCS T_{av}). A water level should be maintained at the appropriate level so the lower portion of the shell is cooled by water. Steam will be created in the generator and will help cool the upper shell. Main feedwater is preferred, but EFW will also be adequate; both must be controlled to prevent overcooling. The cooldown after 150F emergency tube-to-shell limit is reached will be about 20F/hr.

The procedure to be used when steam pressure cannot be maintained is shown in Figure 31b. The RCS should be cooled down at 100 F/hr while slowly adding main feedwater (if possible) or emergency feedwater until the "emergency" tube-to-shell temperature limit is reached. When that limit is reached the cooldown should be halted and the generator slowly fed with main feedwater (if possible) or emergency feedwater. The rate of feedwater flow should initially be around 100 gpm, but actual flow rate will be dictated by the circumstances. A continuous low flow rate is desired rather than an interrupted "batch" feeding rate. Main feedwater will be difficult to control at this low flow rate and it may be necessary to use the startup flow valve.

If the reactor coolant pumps are not operating or have been shut off sometime during the cooldown sequence, natural circulation will not occur in the loop with the generator out of service. If the reactor coolant in that loop is at a high temperature when the RCS depressurization begins, it may flash to steam. The steam will collect in the candy cane and that loop will become a "pressurizer". The system pressure will "hang up" at that pressure, preventing further depressurization. In some cases, not much can be done to prevent this except slowing the rate of cooldown. If possible, one or more RC pumps should be run, at least periodically, to prevent steam voids collecting in the idle loop. If steam does form, and any reactor coolant pump can be "bumped", it will help to mix the fluid so cooldown can continue. If a reactor coolant pump cannot be started, then an alternate method to stimulate circulation and cool the stagnant water can be obtained by spraying EFW on the tubes. If neither

EFW nor RC pumps can be used the cooldown rate will have to be slowed. These actions should be performed only for situations, such as tube ruptures, where it is necessary to continue the cooldown. If continued cooldown isn't required the plant should be held stable with continued natural circulation in the one loop to remove decay heat until the voids in the idle loop are collapsed due to losses to ambient and/or HPI or the idle steam generator is returned to service (i.e., the problem requiring single steam generator cooldown is corrected).

Use of High Point Vents During Inadequate Core Cooling

Following a loss of coolant accident (LOCA), it is necessary to remove the decay heat from the core to prevent cladding damage. Core heat removal is accomplished by supplying cooling water to the core. If the supply of cooling water to the core is decreased or interrupted, a lower mixture level in the core will result. If the upper region of the core uncovers, cooling for these regions will be by heat transfer to superheat steam, which is a "slow" heat transfer process. Continued operation in this mode may result in elevated fuel cladding temperatures with subsequent core damage and possible hydrogen generation due to Zr - H_2O reaction.

During inadequate core cooling, significant hydrogen generation due to metal-water reaction begins when a cladding temperature of 1800F is attained. Therefore, if the operator has indications that the fuel cladding temperature is at or above 1400F (Figure 29), he should open the high point vents at the hot leg and at the vessel head. This is a

precautionary action to prevent noncondensible gases, which are being formed in the core, from accumulating within the steam generator tubes.

The steam generators are expected to be utilized, within the inadequate core cooling procedure, in order to depressurize the primary system allowing subsequent actuation of the core flooding and/or low pressure injection systems. Therefore, concentration of noncondensible gases within the steam generator tubes should be minimized in order not to degrade the steam generator heat removal process.

Opening the high point vents is also somewhat beneficial in relieving the RCS pressure and allowing a greater safety injection flowrate, but this is a limited effect due to the vent's small size.

When the subcooled margin is regained or the RCS depressurizes to the point where the LPI system can be operated, then noncondensible production due to core damage has ceased. The operator can then close the high point vents and continue a "normal" small break cooldown.

Loss of LPI Recirculation Ability

The ability to recirculate water from the reactor building emergency sump can be lost during recirculation or when trying to start recirculation. If this ability is lost, the cause should be determined and flow started as soon as possible. There are two general causes, 1) loss of sump water,

and 2) loss of both flow paths from the sump. Loss of sump water can occur because of:

A. A steam generator tube rupture - A steam generator tube rupture is a LOCA; however, the water which leaks from the RCS does not accumulate in the reactor building sump. Instead, it leaks out of the reactor building via the secondary system. When the BWST is depleted and time has come to transfer to the RB sump, there will be no sump water. This transient must be mitigated as explained elsewhere in these guidelines to prevent the loss of the reactor building sump water.

B. Diluted sump water - Diluted sump water caused by a leak from a non-borated water source, such as the cooling water to the containment emergency coolers or the feedwater system, will make the sump water unusable if the boron concentration becomes too low. The diluted water should not be added to the reactor core because it could allow the reactor to go critical. This would make the core cooling problem worse. This problem must be corrected by adding borated water to the recirculation flow and by stopping the dilution process, e.g., if a feedwater line is adding water to the reactor building, the flow to the broken line should be stopped.

Both sump flow paths can be lost if both the RB emergency sump inlets become clogged or if both the sump valves fail to open. If both of the sump inlets become clogged, it may be possible to back flush the line to clear away any debris that might be covering at least one of the sump line inlets. If both the sump motor operated valves fail to operate remotely, then local manual operation of the valves should be attempted to open at least one of the valves. However, the problem may not be electrical, e.g., the valve stem or disk may be binding, and manual operation of the hand wheel may not work, but some kind of mechanical leverage may be able to open the valves. Local attempts to open these valves may not be possible because of high radiation levels.

If the cause of a loss of sump water or flow path cannot be corrected, the operator should attempt to cool the reactor core with the DHRS. This method of cooling will be successful if the cooling water can flow through the RCS without leaking to the reactor building. To accomplish this, the RCS water must be 1) subcooled to prevent steaming out the break and 2) below the break elevation to stop RCS water from continually leaking to the reactor building and 3) high enough to prevent a vortex formation as water is drawn into the DHRS suction pipe (this would be the same elevation as required for normal DHRS operation when draining the RCS). The RCS water is brought subcooled by increasing the LPI cooling as much as possible. When the RCS pressure drops below the DHRS design pressure, DHRS operation can be initiated and the RCS water level will drop to the break location. The operator should try to start the DHRS even if the RCS

is saturated. This is contrary to instructions given in Appendix F for small break cooldown. Appendix F states normal DHRS can not be started when the RCS is saturated because the DHRS pumps may cavitate. The difference is because plant conditions are not the same. In Appendix F, LPI recirculation is assumed available. However, in this scenario, LPI recirculation is not available causing a more severe situation which allows more severe actions. If the break location is high enough, vortex formation in the DHRS drop line will not occur.

However, if the break elevation is too low, then a vortex will form in the DHRS letdown line and LPI cooling will need to be continued. Vortex formation can be detected by noting LPI pump cavitation and should be continually monitored if RCS water level is unknown, especially when initiating the DHRS with a saturated RCS.

Because of the possibility of vortex formation, the transition from LPI to DHRS cooling should be made cautiously by switching one LPI train at a time from LPI to DHRS mode of operation.

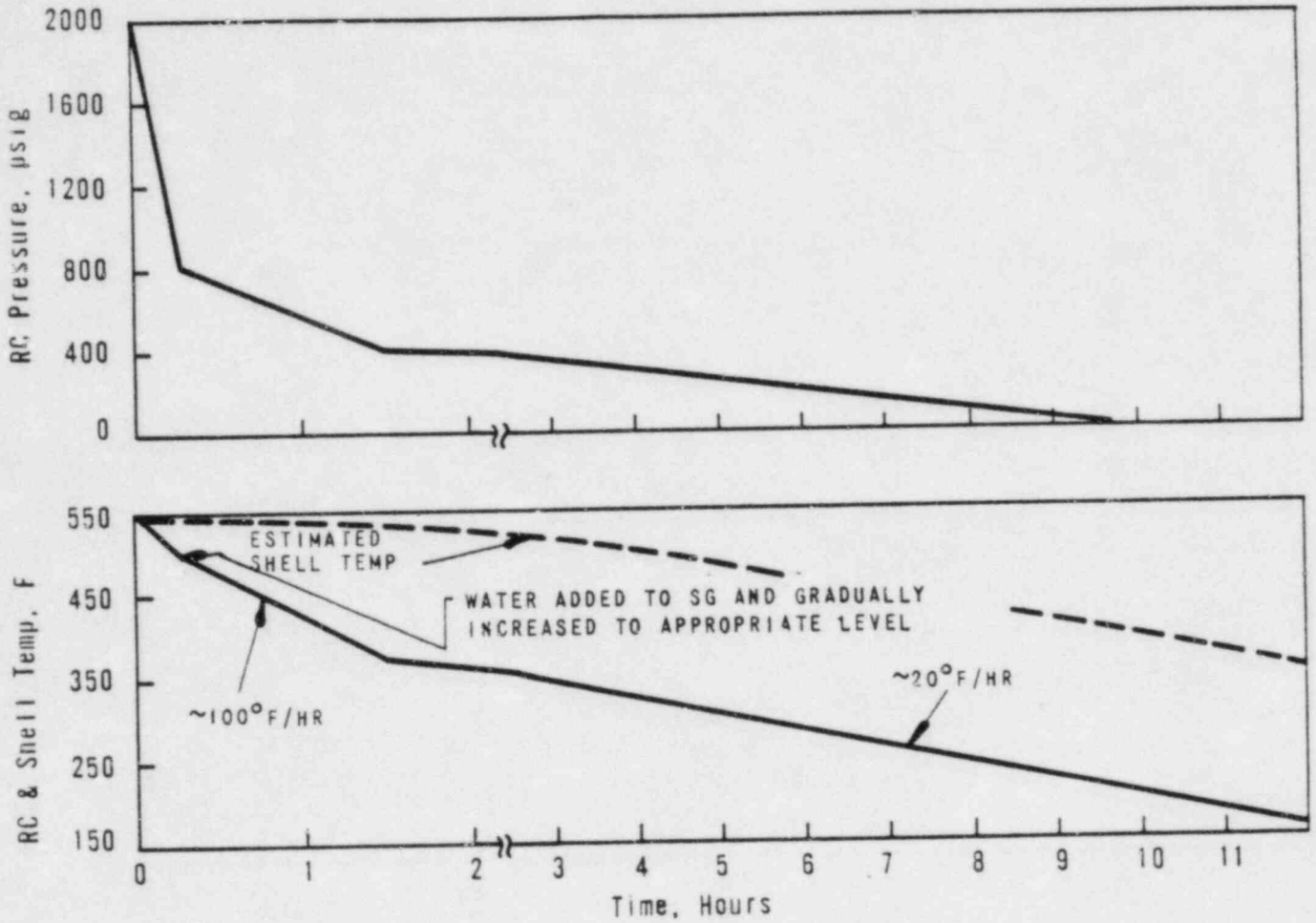
During LPI cooling, water will continually be lost out the break until the water level in the containment increases to the elevation equal to the water level required in the RCS for DHRS operation. This will require more water than that contained in the BWST. Therefore, sources of borated water in addition to the BWST water will need to be used for core cooling. These additional sources will need to be pumped to the reactor vessel

for core cooling until the sump recirculation can be established or the RB is flooded to the RCS level needed for DHRS operation so that the DHRS can be put into operation. If the RB needs to be flooded, the operator should prepare for equipment and instrument failures due to water submerence. For example, the DHRS suction line valves should be opened before they are submerged because after they are submerged they may not operate.

Water may need to be added periodically to makeup for leakage from the RCS and DHRS.

During DHRS operation, the RCS water temperature should be held constant to prevent volumetric water changes which cause the RCS water level to fluctuate. In addition, the RCS water temperature should be held below the boiling point to prevent water loss by steam flowing out the break.

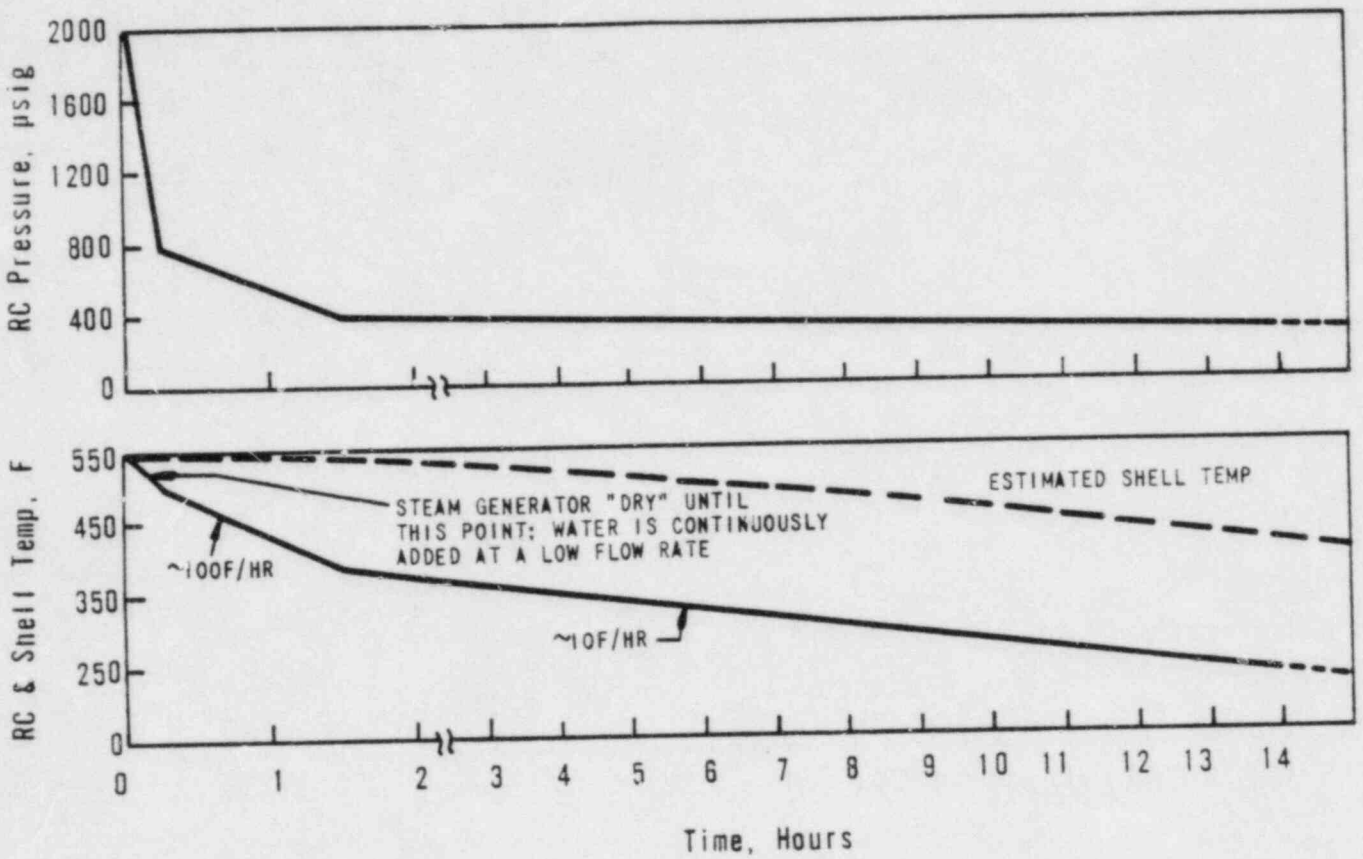
Figure 31a COOLDOWN ON ONE STEAM GENERATOR (STEAM PRESSURE CONTROLLED)



CONDITIONS:

- RC PUMPS ON OR OFF (PROBABLY ON)
- STEAM GENERATOR "ISOLATED" BUT HAS INVENTORY OF WATER ADDED AFTER THE INITIAL DEPRESSURIZATION TO 500°F.

Figure 31b COOLDOWN ON ONE STEAM GENERATOR
(STEAM PRESSURE NOT CONTROLLED)



CONDITIONS:

- RC PUMPS ON OR OFF (PROBABLY ON)
- STEAM LEAK IN GENERATOR; STEAM PRESSURE IS AMBIENT
- SLOW FEEDING OF GENERATOR BEGINS AT ~ 500F - IT IS DOUBTFUL THAT LEVEL WILL BUILD FOR SEVERAL HOURS; LOWER SHELL WILL NOT BE COVERED FOR SOME TIME; SHELL COOLING IS BY STEAM CONDENSATION

DOCUMENT/ PAGE PULLED

ANO. 8401230549

NO. OF PAGES 1

REASON

☐ PAGE ILLEGIBLE

☐ HARD COPY FILED AT: PDR CF

OTHER _____

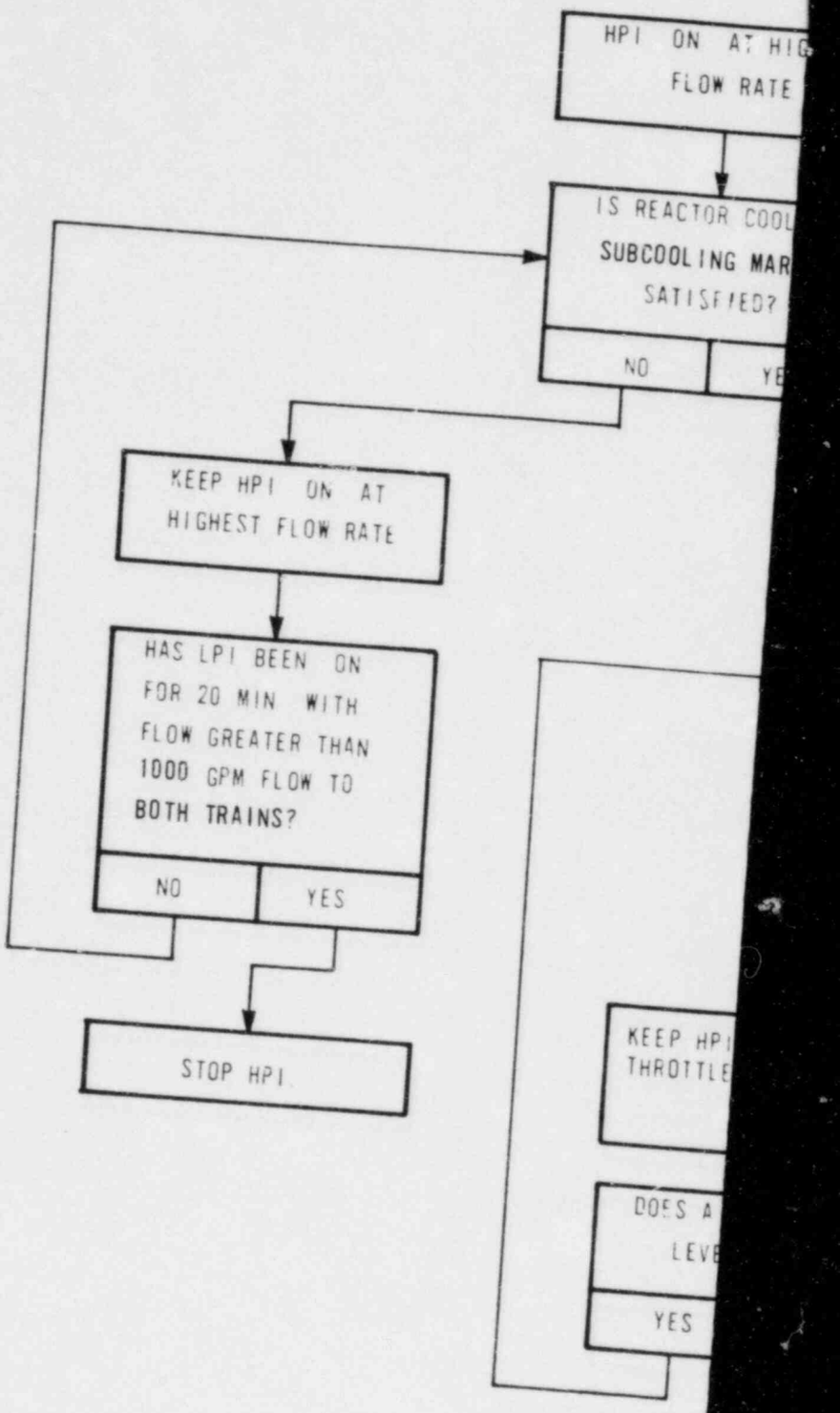
☐ BETTER COPY REQUESTED ON ___/___/___

☒ PAGE TOO LARGE TO FILM

☒ HARD COPY FILED AT: PDR (CF)

OTHER _____

☐ FILMED ON APERTURE CARD NO 8401230549-19


HPI ON AT HIG
FLOW RATE
IS REACTOR COOL
SUBCOOLING MAR
SATISFIED?
NO
YE
KEEP HPI ON AT
HIGHEST FLOW RATE
HAS LPI BEEN ON
FOR 20 MIN WITH
FLOW GREATER THAN
1000 GPM FLOW TO
BOTH TRAINS?
NO
YES
STOP HPI
KEEP HPI
THROTTLE
DOES A
LEVE
YES

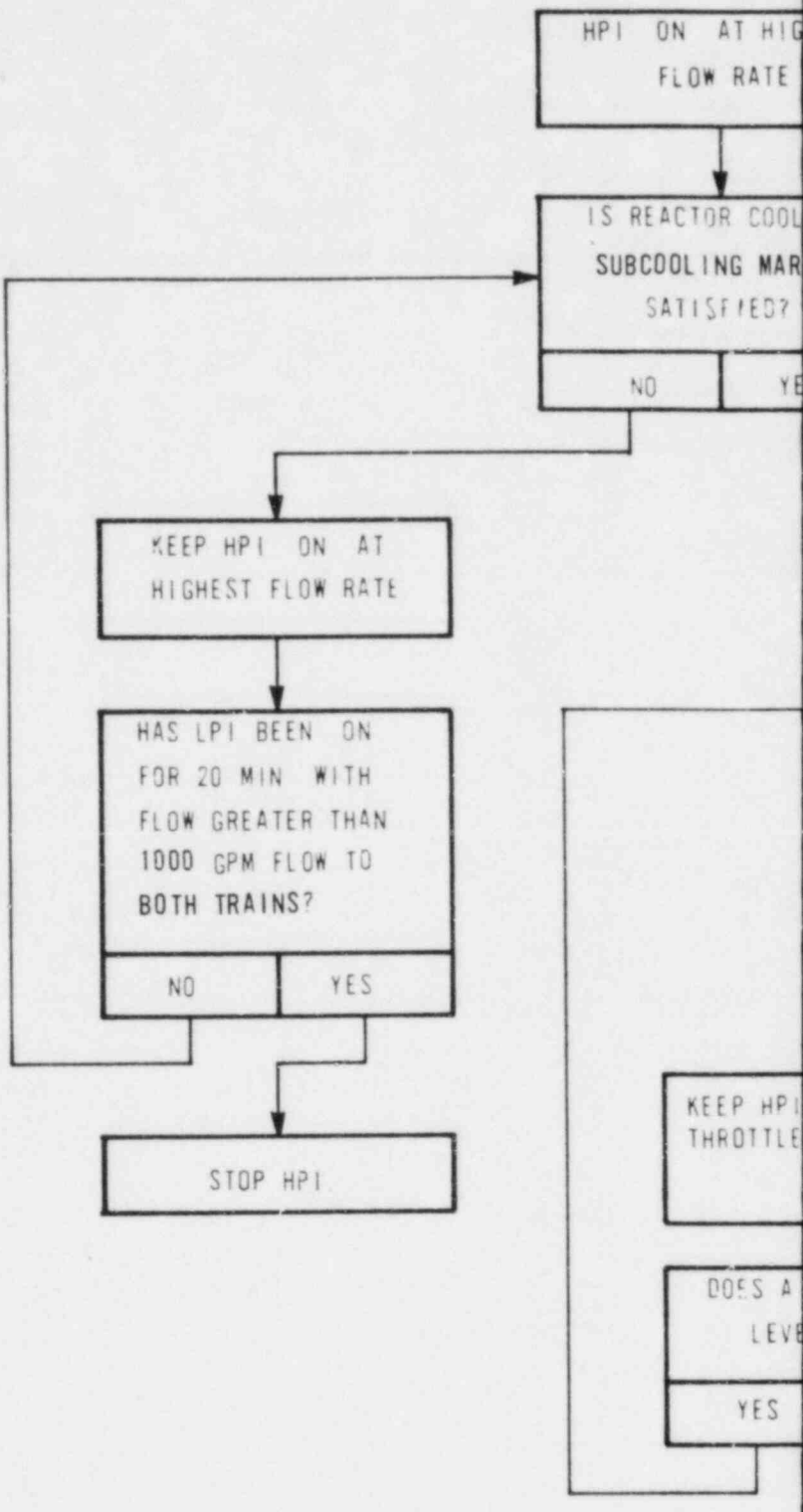
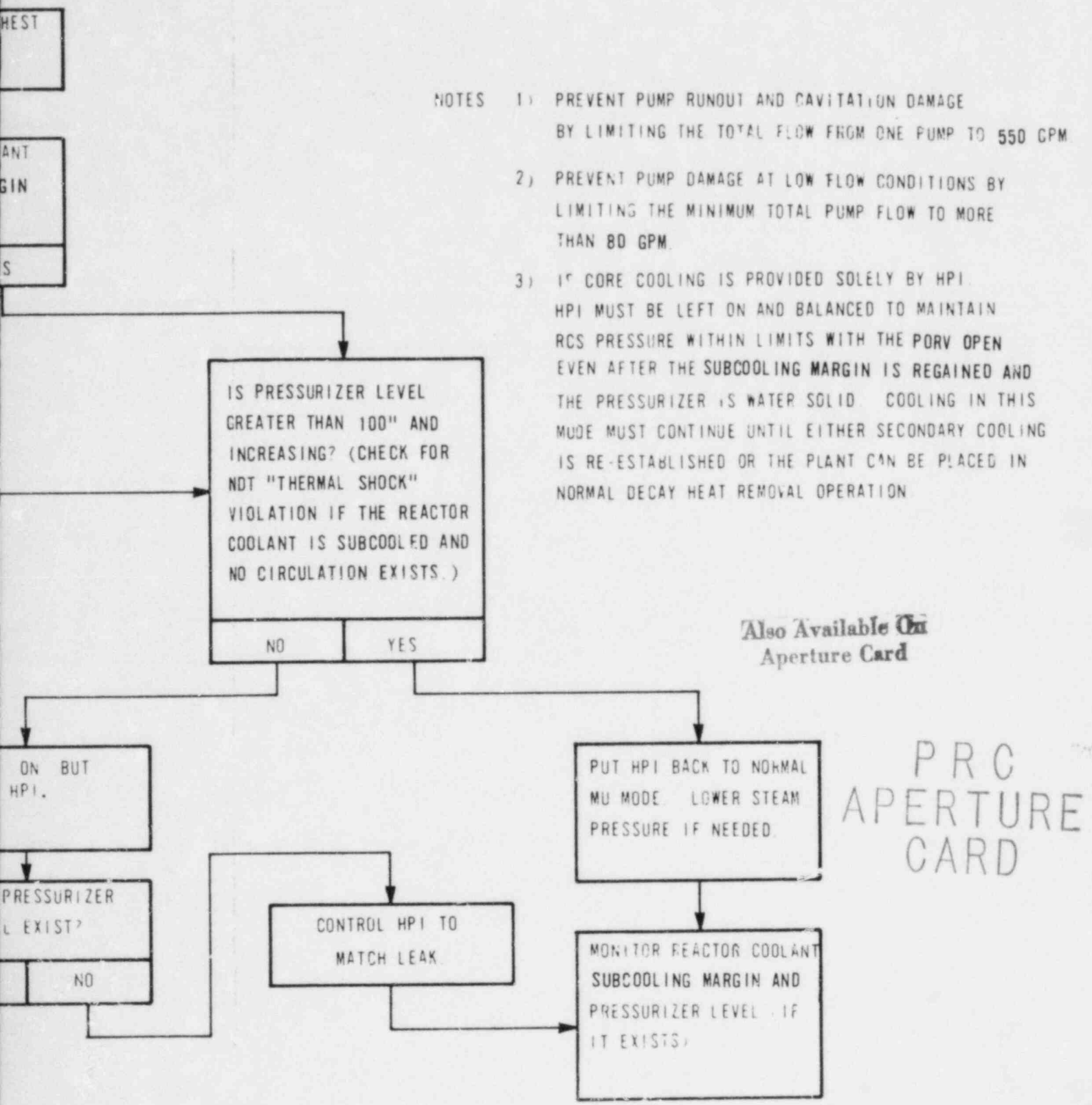

HPI ON AT HIG
FLOW RATE
IS REACTOR COOL
SUBCOOLING MAR
SATISFIED?
NO
YE
KEEP HPI ON AT
HIGHEST FLOW RATE
HAS LPI BEEN ON
FOR 20 MIN WITH
FLOW GREATER THAN
1000 GPM FLOW TO
BOTH TRAINS?
NO
YES
STOP HPI
KEEP HPI
THROTTLE
DOES A
LEVE
YES

Figure 30 HPI CONTROL LOGIC



Also Available On Aperture Card

PRC APERTURE CARD

STABILITY

CHAPTER F

POST ACCIDENT STABILITY DETERMINATION

To determine if the transient has been brought under control four general areas must be checked.

1. Reactivity Control - The reactor must have a subcritical margin of at least 1% $\Delta k/k$.
2. Core Heat Removal Control - The core must be covered and cooled; the heat removal rate is equal to or slightly greater than the core heat generation rate.
3. Radiation Release Control - Release to offsite is terminated.
4. Plant Equipment is Operating Correctly - Equipment to maintain the plant safe and stable is operating and within design duty; equipment failures have been bypassed, isolated or repaired.

Several things around the plant must be checked to make sure these four general rules are being met. The following basic check list defines the more important items. The list is divided into two parts. Part I applies to LOCA's which can be stopped by complete isolation of the leak and to all other transients. Part II applies to LOCA's which cannot be isolated. The difference between the two parts is simple: A reactor leak that cannot be stopped is a transient that cannot be positively terminated. However, a leak can be reduced to the smallest amount possible and become stable for "long term cooling". Steam generator heat removal can be used

for some small leaks but HPI must be kept running to keep the reactor coolant subcooled. Subcooling can be regained for some very small break sizes at a time when the decay heat decreases and HPI is able to refill the RCS loops and add water to the pressurizer.

Part I - All transients except unisolable LOCA's

1. Reactor coolant pressure and temperature are preferably within the "post-trip window" of the P-T diagram; however, pressure and temperature may be anywhere on the P-T diagram within a region bounded by: a) RV pressure/temperature limits, b) the subcooling margin, c) RC pressure upper limit equal to the PORV setpoint minus 100 psi, d) fuel pin compression limits and e) RCP NPSH requirements if applicable. Subcooling will exist in the hot and cold legs of both loops (although T_{cold} will appear slightly superheated since it is plotted vs. steam pressure).
2. The "long term" trend of reactor coolant pressure and temperature is constant or slowly decreasing with time. "Short term" fluctuations of temperature and pressure are small and can be attributed to periodic operations of other equipment (pressurizer heaters, spray, or feedwater).
3. Pressurizer level is within the indicated range.
4. If forced circulation exists (RC pumps on) then reactor coolant T_{av} is about equal to the saturation temperature of the water in the steam generator (or generators) that is removing the heat.

5. If natural circulation exists, $T_{cold\ leg}$ will be about equal to the saturation temperature of the water in the steam generator (or generators) that is removing the heat. The difference between T_{hot} and T_{cold} in the operating loop (or loops) will not exceed 50F to 60F. If only one generator is removing heat the other reactor loop will be subcooled.
6. Steam generator (or generators) level will be at the correct setpoint (either natural or forced circulation setpoint) and will be steady.
7. Steam generator pressure is steady and is below the safety valve opening setpoint.
8. The core is at least 1% $\Delta k/k$ subcritical. If more than one rod did not fully insert the core is at 1% $\Delta k/k$ subcritical on boron alone (assuming all rods out).
9. If the transient caused water to enter the containment (from RCS or steam generator), the containment pressure will return to near original pressure; average containment temperature will be near prior operating temperature; relative humidity will be about 100%.
10. If radioactive water leaks occurred in auxiliary buildings those areas will be sealed and the spillage either trapped or drained to storage tanks.

11. The component failure which caused the transient has been bypassed, isolated,repaired, or otherwise handled so that it no longer compromises plant safety.
12. Components which support plant safety are operating within their qualified range (examples: pumps are operating away from the minimum shutoff flow and have adequate NPSH, throttle valves are near the proper opening, electric motors are in the normal service range, electronic equipment is environmentally protected). If a component is operating off design and future failure is possible, then redundant or alternate equipment is on standby and ready to replace the equipment which might fail.
13. Stored water (condensate tank, BWST) and diesel fuel supplies are adequate for long term use or alternates are readily available.
14. Instrumentation to monitor plant performance is operating correctly. Potential failures of critical instrumentation have been identified and alternate instrumentation is available.

Part II - LOCA's which cannot be isolated

NOTE: With the exception of steam generator tube leaks, all reactor coolant leaks outside the containment can be isolated. Although a tube leak is "inside" the containment a direct path outside the containment exists through the steam lines.

Many of the criteria of Part I apply to this part except that the reactor coolant will not always regain the subcooled margin and operating conditions that depend on subcooling will not apply. The very smallest reactor coolant leaks may allow the reactor coolant system to repressurize (because of continued High Pressure Injection) and some amount of subcooling may be regained, but it is not likely that enough margin will occur. Consequently, the criteria for LOCA stability does not include the subcooling margin. Also, because subcooling may not exist, the hot legs may have steam binding and natural circulation may not exist; therefore, the criteria do not include natural circulation requirements (however, it can exist for very small breaks and should be checked). A reactor-steam generator heat transfer balance cannot usually be accomplished because of saturated (or near saturated) conditions which may not permit the reactor coolant to move the heat from the core to the steam generator, but some heat transfer to the steam generator is possible for small breaks. The steam generator operating level should be at the 95% level for small breaks to permit condensation of primary side steam. Pressurizer level cannot be relied upon if saturation exists.

The most important criterion for LOCA is to keep the core covered. This condition is confirmed by readings of the incore thermocouples and the hot leg RTD's; both should show that the reactor coolant is saturated (or even subcooled) but not superheated.

The continued loss of coolant from a LOCA will not permit the transient to be truly terminated, but the leak rate can be minimized. Lowering RCS pressure is the best way to lower the leak rate. This can be done by loss through the leak, by opening the PORV, or by lowering secondary side pressure. Long term loss of coolant when the RCS is depressurized occurs in two ways: 1) steaming out of the leak because of continued boiling, and 2) water loss because the head of water is above the break and water will "run" out of it. The rate of leak will depend on the system pressure, the decay heat level (which causes boiling), and the elevation of the leak (a leak high in the system will have a lower flow rate than a leak low in the system). The leak rate will also depend on the hole size.

The criteria for stability is that the leak rate is as low as possible and that the flow into the core keeps it covered. It may take a very long time to recover from some LOCA's and during that time there will be two general stages when the leak rate diminishes. The first stage is when the reactor coolant system is depressurized to atmospheric pressure (big breaks will depressurize rapidly, smaller breaks will take longer); the second stage is when the core heat drops so that it cannot boil the water in the reactor vessel. Steaming will stop at that time (which may be as long as several months after the transient). Until the water in the vessel becomes subcooled (incore thermocouples will read less than 212F), the plant must be operated by injecting containment sump water in the recirculation mode or by continuing to inject fresh borated water from

other sources. When the vessel water becomes subcooled the operator has the option to transfer one train of LPI to the decay heat removal mode and keeping the other train on sump recirculation. The reason one train is left on recirculation is that it will keep water above the hot leg suction for decay heat removal. Decay heat removal has the advantage of rapid RCS cooldown, but it must be carefully monitored to make sure the decay heat pump does not lose suction (or it will fail), and to make sure the decay heat pump does not run at shut-off head.

Because the leak may continue a long time until the decay heat system is engaged, an arbitrary definition of stability is given. The following criteria define post-LOCA long term stability:

1. The core is covered. Incore thermocouple readings show saturated or subcooled reactor coolant.
2. ECCS injection is in the "long term cooling" mode. Long term cooling exists when the ECCS is operating with recirculation from the containment emergency sump. (NOTE: A decision may have been made not to transfer but to bring in backup water to refill the BWST. Nevertheless, if recirculation could have been started, "long term cooling" is considered to have started).
3. The reactor coolant system is depressurized to near atmospheric pressure so that the leak rate is as low as possible. The LPI system is used to cool the core . (NOTE: If the break size did not permit

depressurization before the BWST was empty, and HPI "piggyback" recirculation had to be used while further depressurization took place the plant is not considered to be stable until the pressure and leak rate are as low as possible).

4. Steam generator level is at 95% on the operate range and is steady.
5. Reactor coolant pumps are off (operation of RC pumps could move water past the break and increase the leak rate).
6. The following criteria from the previous part also apply: Numbers 7, 8, 9, 10, 11, 12, 13, 14.
7. For the special case of steam generator tube leaks (LOCA's):
   a) Feedwater (main and emergency) has been stopped to the bad generator.
   b) Steam created by boiling the RCS leakage is directed to the condenser (if it is operating).
   c) The plant is on decay heat removal or standby backup borated water sources are available to replenish BWST inventory.

RB CONTROL

CHAPTER G

FUNDAMENTALS OF REACTOR BUILDING CONTROL

1.0 Introduction

The Three Mile Island Accident of 3-28-79 provided some significant insight to reactor building performance. Two separate conditions existed during the TMI-2 accident that lead to a conclusion that a more comprehensive approach should be used for reactor building control to limit radiation releases during abnormal transients.

First, the reactor building pressure remained low for a significant time before reaching 4 psig where automatic reactor building isolation of penetrations could occur. During this time period the core was uncovered and high concentrations of radioactive material were released to the reactor building. The reactor building penetrations that were open did not permit a direct release of reactor building gases to the site. The sump line was open, however, and radioactive liquid was pumped to the auxiliary building.

This scenario illustrates the need for operator action to control radiation releases by controlling the reactor building boundary at all times. Operator action prior to automatic system actuation may be appropriate; operator action may also be needed for conditions when systems used for automatic reactor building isolation control fail, and the automatic isolation requirement exists.

Another condition that existed at TMI was an accumulation of hydrogen in the reactor coolant system. Hydrogen is flammable or explosive under certain conditions and therefore the concentration in the RB must be controlled. This situation illustrates the need to control the reactor building environment to preserve the integrity of the reactor building and its operating equipment.

Operator action is required to control the reactor building environment (radiation, pressure and temperature, H_2, and other physical phenomena) so that:

- Radiation release from the reactor building to the site surroundings is limited to as low as reasonably achievable.
- Radiation release to the auxiliary building atmosphere or fluid systems is limited to as low as reasonably achievable.
- Systems or components inside the reactor building that are used for reactor building control or for core cooling are protected.

The main purpose of the reactor building is to prevent unacceptable releases to the environment of radioactive material leaking from the reactor coolant system. Although the reactor building serves this purpose during normal operation and abnormal transients, this discussion will be limited to abnormal transients. Proper reactor building control during abnormal transients, especially during a Loss of Coolant Accident, will limit the amount of radioactive

material leaking to the environment. The operator must be prepared to take manual control of any automatic control function in the event of a malfunction or to manually actuate a non-automatic control.

2.0 DIAGNOSIS AND CONTROL

The two basic objectives of reactor building control are: reactor building isolation control and reactor building environment control . This section discusses how these objectives are reached by diagnosing and treating reactor building problems.

This chapter will first discuss the general approach (Section 2.1) to diagnosis and control of the reactor building. The following sections (2.2 and 2.3), will be more specific in describing what parameters to monitor, when to take action, and what the action should be. Tables 7 and 8 are a summary of these control actions.

2.1 General Approach for Diagnosis and Control

Following the ATOG instructions, the operator maintains adequate core cooling and then ensures RB control. Adequately cooling the core will limit the H_2 and radiation levels in the reactor building. Inadequate core cooling (ICC) will aggravate the ability to control the reactor building and can require more drastic actions than would otherwise be required. In fact, if ICC occurs the emphasis on reactor building control will become greater because of the greater potential for hydrogen and radiation release.

The need to take action for reactor building control is based primarily on the following symptoms:

- High reactor building pressure.
- High reactor building temperature.
- Low reactor coolant system pressure.
- High reactor building radiation.

The principal reason for use of radiation as a symptom is that it is possible to have high radiation without high building pressure or low reactor coolant system pressure.

Figure 32 illustrates the general approach to be used for reactor building control following an abnormal transient. The following is a discussion of Figure 32.

Abnormal Transients Which Require Additional Reactor Building Control.

The first block on Figure 32 refers to the abnormal transients which require additional mitigating actions (automatic and manual) for reactor building control. These mitigating actions are required especially for reactor building conditions following a LOCA or steam/feedline break. Of these events the LOCA imposes the most difficult problems. A LOCA can result in release of radioactive material, H_2, and acidic water (boric acid); but, a steam or feed line break can only release steam and water unless the

steamline break is concurrent with a SG tube leak. The rate of hydrogen release and accumulation during the LOCA will be gradual unless the Zr-water reaction occurs. However, large amounts of radioactive steam and water will be released to the reactor building even if adequate core cooling is maintained. Either of the above events can cause equipment damage and require repair prior to placing the plant back into service. This section will emphasize the LOCA, but additional discussion of the steam line break and inadequate core cooling (ICC) is included in Section 3.0.

First Line of Defense - Limit Radiation Release by Assuring the Reactor Building Leak Paths are Sealed.

The second block shows the first line of defense against radiation release. Attention should be primarily on isolation of penetrations of non-essential fluid systems used in power operation.

Some examples are:

- Those that should be normally closed, but may not be, such as the pressurizer sample line and the RB air purification and cleanup system.
- Those that could be isolated early by the operator before the setpoints which initiate automatic actions are reached, e.g., the letdown line.
- Paths that can transfer liquid reactor coolant to the auxiliary building such as the RB normal sump drain.

Conversely, paths that should remain open or must be reopened are those needed for core cooling or reactor building control; for example, component cooling water should be available for operating reactor coolant pumps.

Confirmation that isolation is effective is provided by valve operator lights, flow indicators, level indicators, temperature indicators as well as other indirect indications.

Second Line of Defense - Maintain RB Integrity.

The next line of defense is preservation of the reactor building integrity. Pressure and/or temperature can be high within the reactor building for two reasons:

- the mass and energy from the LOCA or steam line break.
- hydrogen burning or detonation.

Containment recirculating air coolers and sprays are used to reduce excessive pressure and temperature caused by mass and energy release. Hydrogen concentration is limited by the hydrogen recombiners and by controlled purging, provided radiation limits are not exceeded.

Third Line of Defense - Eliminate or Reduce the Cause for the Change in the Reactor Building Internal Environment.

The next line of defense is to eliminate or reduce the cause of the change in the reactor building environment to:

- minimize the continued radiation release to the reactor building.
- minimize the continued mass and energy release.
- minimize hydrogen release to the reactor building atmosphere.

Adequate core cooling, in conjuction with RB control, results in the major elimination or reduction of the cause of the adverse RB environment. The third line of defense includes those actions which may not have been included in adequate core cooling or which may now require additional emphasis due to RB control requirements.

For example, following a steam line break inside the RB, the feeding and steaming of the affected SG to assist in RCS cooling would be delayed until the RB environment was back under control unless this steaming was essential to adequate core cooling. This action would result in a very slow RCS cooldown rate (with dry SG) until the affected SG could be trickle fed.

Fourth Line of Defense - Followup to Return the Reactor Building Internal Environment to Normal.

The fourth line of defense is the followup required to restore the RB internal environment to a normal or acceptable set of conditions. This fourth line of defense will limit radiation release by protecting the reactor building control equipment, protecting the RCS heat removal equipment, continued reduction in RB pressure and removal of radiation and hydrogen from the RB atmosphere.

This includes the following:

- Control of reactor building water level to prevent flooding of useful equipment (such as decay heat drop line valves, instrumentation connections, RC pumps, ventilation ducts).
- Control of reactor building water level to ensure adequate sump level so that sump recirculation can occur.
- Control of sump water chemistry (boron concentration and pH) to limit corrosive effects (especially stress corrosion) and enhance removal and retention of radioactivity from the RB atmosphere.
- Control of RB spray into the reactor building to control RB pressure, temperature and airborne radioactive material.
- Control of RB recirculation air coolers to lower RB pressure.
- Control of RB H_2 recombiners and/or H_2 purging to limit the H_2 concentration.

2.2 Reactor Building Isolation Control.

Control of reactor building isolation is the first basic objective of RB control. Reactor building isolation control involves reducing and controlling leakage through the reactor building penetrations following a diagnosis of an abnormal condition. Various partial RB isolations actuate on the following parameters.

1. Following any automatic or manual [low 1600 / high 4] which are open to the containment atmos[phere directly to] the RCS, which are not required f[or operation,] are isolated. The operator must assess the status of the RCS prior to defeating this partial RB isolation.
2. All fluid lines which penetrate the containment, including the normal RB cooling system, are isolated on low RC pressure (1600 psig) or high RB pressure (4 psig).
3. All lines which could transfer high levels of radiation from the containment are isolated for any system whose radiation monitors (located outside the RB) indicate high radiation.
4. All lines used as cooling water support services which are protected from pipe whip, jet impingement and missles are isolated on a high RB pressure of 30 psig.
5. NSCCW and ICCW lines are isolated on either a high RB pressure of 30 psig or an indicated line break coincident with HPI actuation.

6. The main feedwater line on a low pressure OTSG (below 600 psig) is isolated by the SLRDS. Main steam lines must be manually isolated.

2.2.1 Diagnosis

Specific parameters are monitored that will indicate the potential for radiation release from the reactor building. These parameters. as listed earlier in Section 2.1 are:

- High reactor building radiation.
- High reactor building pressure.
- Low RCS pressure.

Each of the three conditions listed above relate to a potential release of radioactive material as follows:

1. High radiation - If the radiation level in the reactor building is above the limit, then a normal amount of RB leakage can release excessive radioactive material. Radiation monitor alarms will indicate an abnormal radiation level in the reactor building atmosphere or line penetrations.

   For an RCS leak rate of 1 gpm, the following gaseous radiation monitor response times are typical:

Coolant Activity	Response Time
1% defective fuel in core	∿ 1 minute
0.1% defective fuel in core	∿ 5 minutes

A leak rate such as the 1 gpm above is usually not an abnormal transient. Any RCS leak rate above normal, however, may be an indication of an incipient LOCA or it may mask other abnormal events.

2. High reactor building pressure - As the reactor building pressure increases, the leak rate of radioactive materials will tend to increase. Some small amount of leakage is expected, based on the results of the RB leak rate test. This leak rate test can be used to estimate expected radiation releases.

3. Low reactor coolant pressure - low reactor coolant pressure indicates a possible LOCA. The LOCA can cause both a high reactor building radiation condition and a high reactor building pressure condition. This combination of high radiation and high pressure increases the potential for an excessive radiation release if there is any RB leakage.

If the RB radiation, RB pressure or RCS pressure (low) exceed the values specified in Tables 7 and 8, the potential for too much radiation release exists and control actions should be taken as specified in these tables.

In addition to the above parameters, the failure of systems circulating reactor coolant outside the reactor building will contribute to the radiation release. This leakage can be monitored by the changes in sump levels in the auxiliary building. Some leakage of these systems is anticipated. The maximum allowed leak rates for normal operation are specified in the technical specifications and the actual leak rates should be known by the shift supervisor so an assessment of abnormal leakage can be made.

Service water or component cooling water systems do not pose a path for radiation release from the reactor building space. They do not carry radioactive fluid and they operate at a pressure which is usually higher than the pressure the reactor building would reach during an abnormal transient. Consequently, radiation would not be expected to flow from the reactor building to the fluid system and out the penetration to the environment.

2.2.2 Isolate Penetrations of Non-Essential Fluid Systems Used in Power Operation.

The only non-essential penetrations not isolated or sealed before power operation are those for fluid systems used in power operation (e.g. reactor coolant letdown). These non-essential penetrations are normally closed automatically if the ESAS is

tripped on either a RCS pressure of 1600 psig or a RB pressure of 4 psig. In addition, many RB penetrations are isolated by both ESAS and non-ESAS signals. For examples, the pressurizer and RC sample lines are isolated on a 4 psig RB pressure signal (ESAS), a reactor trip signal or a high line radiation signal. The ICCW outlet line is isolated on a 30 psig RB pressure signal (redundant non-ESAS) or a low surge tank level trip with a coincident safeguards HPI actuation.

Several lines are designed to be closed manually on high line radiation (e.g., RC pump seal return). Also the operator must be alert to the fact that many abnormal conditions may release radioactive material from the RB before automatic isolation occurs or an isolation valve may fail to close when a signal is received. If there is any evidence of an abnormal amount of radioactive material in either the RB sump or atmosphere, then the penetrations normally isolated automatically should be manually isolated immediately.

In addition to leakage from the RB, a leak of nonborated water into the RB is potentially serious if the ECCS is on recirculation from the RB emergency sump. This leakage can dilute the ECC flow into the reactor and cause a loss of shutdown margin. Therefore the NSCCW and ICCW surge tank levels and differential flows should be monitored and the system leak isolated if possible.

2.2.3 Control With Equipment Failure.

If an automatic isolation valve does not close on the close signal the operator should check its redundant isolation valve to see if it has automatically closed. If at least one valve has closed for each reactor building penetration, then no other immediate action is required. If both valves on a penetration fail to close then the operator should try individual remote operation of one or both or the redundant isolation valves. If neither valve will close, attempts should be made to locally close the isolation valve outside the reactor building. This may not be possible if radiation levels are too high. If the outside isolation valve cannot be locally reached or can be reached but cannot be closed, then a determination should be made of what caused the valve inside the reactor building to fail open and then an attempt made to correct the problem and close the valve. If neither of the redundant isolation valves can be closed, then follow the system out from the penetration to the next set of valves and close them.

2.2.4 Selectively Operate Penetration Isolation Valves.

During abnormal transients, the operator may want to use some of the non-essential fluid system penetrations to help maintain core cooling and to control the reactor building environment. Some of the safety fluid system penetrations may require isolation upon a failure. Consequently, the operator will have to selectively operate the reactor building isolation valves as he chooses

between the need for reactor building isolation and fluid system operations. The decision to open the valves should be accompanied by a conderation of consequences (e.g. the penetration path cannot be reclosed).

The penetrations the operator needs to manipulate can be divided into two groups as follows:

a. The penetrations of non-essential fluid systems used during power operation. These penetrations close automatically on ESAS actuation.

b. The penetrations of essential fluid systems. These penetrations open automatically or remain open upon ESAS actuation. The operator has administrative control of others such as the DHRS suction line.

When the penetrations for non-essential fluid systems are isolated, the operator needs to be aware of what is affected so that he can make appropriate compensation. For example following a reactor trip cooling to the RC drain tank will be isolated. The cooling water to the RC drain tank should be reestablished if PORV or pressurizer safety valve release causes the tank temperature to significantly increase.

If the safety function is required immediately following an abnormal transient, the isolation valves will be automatically opened if ESAS is actuated. If the safety function is not required immediately following an abnormal transient, the isolation valve will not automatically open (e.g. reactor building sample valves).

The RCP seal injection penetration remains open when the RB is isolated and should be left open by the operator. Some isolation valves (e.g. HPI) remain open during power operation, but they still have the automatic valve opening feature just in case they happen to be closed.

The service water penetration valves which supply emergency cooling water to the reactor building air coolers open following a transient requiring reactor building isolation. Reactor building emergency cooler isolation valves are available but require operator action to close. Separate isolation valves are provided for each cooler. These valves are used to isolate cooling water to a cooler should the cooler develop a leak. The service cooling water is not borated, thus any leakage from the cooler would dilute any borated water collected in the sump after a LOCA. Therefore, to prevent boron dilution of the reactor building sump water, the service water to the leaking cooler must be isolated.

2.3 Reactor Building Internal Environment Control.

Control of the reactor building internal environment is the second basic objective of reactor building control.

After an abnormal transient, the environment inside the reactor building can become harsh enough to cause failures of equipment and structures. Other effects include degradation of equipment performance, especially instrumentation.

The reactor building environment needs to be controlled to reduce or eliminate failures of equipment and structures required to control the harsh environment itself and required to control core heat removal. Reactor building control requires controlling the following to bring them within acceptable limits.

a. Reactor building pressure and temperature.

b. Reactor building hydrogen concentration.

c. Reactor building sump chemistry.

d. Reactor building radiation.

e. Reactor building water/sump level.

Control of each of these will now be discussed in more detail.

2.3.1 Reactor Building Pressure and Temperature.

RB atmospheric temperature and pressure are coupled together for a LOCA e.g., if the temperature is reduced the pressure will also be reduced and vice versa. Figure 33 illustrates the RB trend; temperature vs. pressure for a LOCA.

As the LOCA releases steam and water, this mixture heats up the RB atmosphere. The decreasing mixture temperature and increasing RB air temperature will come to equilibrium at a common temperature. This temperature will determine the reactor building pressure. The pressure will be the sum of the pressure due to air and the pressure due to the steam. The partial pressure due to the initial air in the RB is only about 4 psig at 250F, therefore the RB temperature and pressure approximate the saturation values for steam (The RB design pressure is 55 psig.).

With only the air recirculation coolers used to provide building cooling, the peak RB pressure varies between 45 and 50.6 psig for LOCAs between 1.0 and 14.1 ft^2 (double ended hot leg break) in area, with the peak pressure of 50.6 psig due to the 8.5 ft^2 LOCA. Figure 34 shows the envelope of peak RB pressure vs rupture size. These results were obtained from conservative assumptions and therefore actual values are expected to be at least 10% lower. The time required to reach the RB peak pressure varies with

break size. Figure 35 shows RB pressure vs time for the 8.5 ft^2 break.

2.3.1.1 Pressure and Temperature Control.

The reactor building pressure and temperature must be reduced to:

a. Prevent exceeding the design pressure and temperature of the reactor building.

b. Reduce the driving force (ΔP) for reactor building leakage.

c. Prevent equipment damage.

The following combinations of RB safety cooling equipment are the minimum design requirements for pressure and temperature control under LOCA conditions:

- 2 reactor building spray (RBS) trains or,
- 3 reactor building recirculating air coolers or,
- 1 RBS train and 1 reactor building recirculating cooler.

If the high reactor building pressure limit (4 psig) is reached or RCS pressure drops to 1600 psig, the ESAS system will automatically:

a. Start the three RB recirculation air coolers on slow speed.

b. Isolate the RB.

The number of emergency coolers and sprays does not significantly affect the peak RB pressure for a LOCA in which the peak pressure

is reached soon after this equipment is actuated. On the other hand the peak pressure for a small LOCA is very dependent upon the amount of cooling equipment in operation. Large increases in reactor building temperature and pressure may not occur for small LOCAs such as a stuck open PORV. However, radiation will be released to the reactor building. Also the RCS pressure may not drop to the ESAS setpoint for some time. The RB recirculation air coolers may provide sufficient cooling during the SBLOCA such that no RB pressure or temperature transient is detected. The RB atmosphere will be automatically isolated on a high radiation signal unless the operator isolates the RB manually. The operator should try to reduce the amount of energy being released to the reactor building by:

1. Control of feedwater added to a steam generator which has a break inside the reactor building.
2. Increase the heat removal by the LPI cooler (if in operation).
3. Increase the heat removal by the steam generators (if in operation).
4. Isolate any break in the RCS if possible.

If a high RB temperature (120F) is reached or coolers fail to start at a pressure of 4.0 psig, then the operators should start RB coolers as required to bring the pressure and temperature back within limits.

2.3.1.2 Pressure and Temperature Control With Equipment Failures

The primary method of reducing the reactor building pressure and temperature under abnormal conditions is with the reactor building recirculating air coolers. If this equipment fails to keep the reactor building pressure below 30 psig, backup cooling is available with the reactor building spray system. RBS operation should be automatic by the ESAS on a high building pressure of 30 psig. However, manual initiation should be made if the ESAS does not auto actuate the reactor building spray systems.

Reactor building spray for RB pressure reduction following a LOCA may be stopped after the RB pressure is reduced to 4 psig and is decreasing. Figure 35 shows RB pressure vs time for a 8.5 ft^2 LOCA without RB spray. The RBS would cause a reduction in the peak building pressure. RB recirculating air cooler fan operation may be returned to fast speed when the RB pressure is reduced to 4 psig. The operator should not attempt to reduce reactor building pressure by opening the reactor building normal purge valves. The valves may fail open and result in the release of large quantities of radioactive material.

Reactor Building Pressure Rule

Whenever RB pressure $\geq$ 4 psig:

a. Isolate all non-essential RB isolation valves.

(Reopen those required for RCP operation if closed),

b. Start all RB recirculating air coolers on slow speed.

Whenever RB pressure $\geq$ 30 psig:

a. Start both RB spray trains.

Reactor Building Temperature Rule

Whenever the average RB Temperature $\geq$ 120F.

a. Start RB recirculating air coolers as required to maintain temperature below 120F.

2.3.2 Reactor Building Hydrogen Concentration

A significant amount of H_2 generation and release to the RB is expected only following a LOCA or inadequate core cooling (ICC).

If the core is not adequately cooled, the major source of hydrogen can be from the Zr-water reaction. The formula for the reaction of zirconium with steam is:

$$Zr + 2H_2O \rightarrow Z_rO_2 + 2H_2 + Heat$$

The extent of the Zr-water reaction is controlled by the ECCS performance. The amount of H_2 production is strongly dependent upon the fuel cladding temperature. Consequently, if the

operator keeps the core adequately cooled, the Zr-water reaction will be an insignificant source of hydrogen and the most significant source of hydrogen will be from the radiolytic decomposition of water in the reactor vessel and the reactor building sump. Some hydrogen will also come from zinc-boric acid reaction (one pound of zinc will yield 5.5 SCF of H_2) and the initial hydrogen content of the reactor coolant.

The chemically produced H_2 (Zr-water, zinc-boric acid, etc.) is produced within a few hours of a LOCA. The radiolytic H_2 is slowly produced over a long period following the LOCA by the decomposition of water into hydrogen and oxygen.

Figure 37 includes a diagram of the processes affecting containment hydrogen concentration.

If the sources of radiolytic and chemical hydrogen are calculated for the design basis LOCA, a time dependent increase in hydrogen can be determined as shown in Figure 38. This figure is based on a 1.0% Zr-water reaction (the design basis LOCA).

The flammability limits of hydrogen-air-steam mixtures are shown in Figure 39. The lower flammability limit for H_2 is 4.1 vol. %. in dry air. At this concentration, the flame would only propagate upward. Therefore, there would not be any widespread H_2 burning at this concentration. At 9.0 vol. %, in dry air the flame can propagate rapidly in all directions and, at 19.0 vol. %, the H_2 can detonate. A hydrogen and steam mixture of $\geq$ 57 vol. % steam is completely inerted; however, steam mixtures below 15 to 20 vol. % have very little impact on flammability.

If H_2 is released from the reactor coolant system too rapidly, then local concentrations much higher than those above may occur. Thus H_2 burning or deconation may occur with low H_2 releases if the RB atmosphere is not mixed well. H_2 burning will increase RB temperature and pressure. The most significant feature of H_2 burning is a sudden RB pressure spike with a return to a pressure only nominally higher than before the burn. The SG and RCS pressure indications will dip by about the same amount as the RB increases during the H_2 burn since the low pressure side of these transmitters are vented to the containment. The equation is: $2H_2 + O_2 \rightarrow 2H_2O$ + Heat. H_2 detonation causes a more pronounced pressure spike. Figure 40 is the reactor building trend, temperature vs. pressure for RB hydrogen burning.

2.3.2.1 Hydrogen Control

The hydrogen concentration is controlled to limit hydrogen burn or detonation in order to prevent:

a. Equipment damage within the reactor building.

b. Structural damage to the reactor building or penetrations. The reactor building hydrogen concentration must be periodically analyzed following a LOCA or ICC to determine the rate of hydrogen build up in the reactor building.

Hydrogen is controlled to keep the concentration below the value at which it burns ($\sim$ 4.1 vol. %). The primary means of hydrogen control is, of course, maintenance of adequate core cooling. While hydrogen is in the RCS, it does not present an explosive hazard since very little oxygen is present. Since H_2 can interfere with natural circulation cooling, ICC procedures require it to be vented from the RCS and in the case of most LOCAs, any H_2 is released to the RB along with the steam and water.

The first method of H_2 control in the RB is by mixing the RB atmosphere. The RB recirculating air cooler fans are used for mixing. The RBS system also mixes the RB atmosphere when actuated. Mixing will help disperse any local concentration of hydrogen and create a more homogeneous mixture for sampling and purging the hydrogen in the reactor building. All RB fans should

be on to circulate air during sampling or purging to prevent stratifications of H_2 in the RB atmosphere. These fans (above) should be operated even if the reactor building pressure and temperature conditions do not otherwise call for cooler operation.

The second method of hydrogen control is operation of the H_2 recombiners. If the average hydrogen concentration reaches .5 vol. %, the hydrogen recombiners should be started. Figure 41 is a diagram of the H_2 concentration in containment vs time for either one or two recombiners in operation. Operation of the recombiners is controlled manually at their panel outside the RB by controlling electrical current to the recombiner coils. The recombiners are operable at RB pressures up to 10 psig.

2.3.2.2 Hydrogen Control With Equipment Failures

The backup method of hydrogen control is purging. Purging should be started at a hydrogen concentration of 3.0 vol. %. When concentration drops below 2.9%, purging should be terminated. The purging should start at 3.0 vol. % to prevent exceeding 4.1 vol. % while allowing for lack of complete mixing, delays from unfavorable atmospheric conditions and equipment failure or inaccuracies. If hydrogen sample analysis indicates that the volumetric hydrogen concentration has reached 2.5% and is projected to exceed 3.0%, preparations for purging the RB

should commence. The Atmosphere Clean-up system should be started at least four hours prior to purging if RB radiation is high.

The purge rate will vary in accordance with the meteorological conditions and the amount of radioactivity in the RB. Below 3.7 vol. % hydrogen, doses at the site exclusion boundary are limited to 1.5 rem thyroid and .5 rem whole body. If the hydrogen concentration exceeds 3.7 vol.%, then the allowable radiation release rate will be increased by a factor of ten until the hydrogen concentration is again below 3.7 vol. %. However, the hydrogen concentration is not allowed to exceed 4.1 vol. % in the RB. Consequently, if offisite doses are high and an increase in purge rate is projected to be necessary to prevent exceeding the 4.1 vol. % limit, then consideration will be given to evacuating offsite personnel within the Low Population Zone.

If the H_2 concentration exceeds 4.0 vol. % in the RB (based on atmospheric pressure), then one train of the RBS system should be started. When the H_2 concentration exceeds 4.0 vol. %, the recombiner inlets should be diluted with nitrogen gas and the electrical power to the recombiners should be reduced as

necessary to prevent exceeding the maximum recombiner outlet temperature of (value by GPU). The RBS system operation will:

a) Lower the RB pressure (if elevated) so the initial pressure is less in case of H_2 burning,

b) Will cause the pressure spike due to a H_2 burn to be less because of the heat sink provided by the water droplets, and

c) Will <u>not</u> significantly affect the H_2 flammability except to the extent that lowering RB presssure (condensing steam) <u>raises</u> the volume % of H_2 in the RB.

Item C above is the reason why the 4.0 vol. % limit should be based on atmospheric pressure and a dried sample. Otherwise, lowering RB pressure and humidity can create a flammable mixture in the RB where there is none at higher pressure and humidity. It is very important to keep the RBS system on as a heat sink and to keep the RB pressure near atmospheric in the event the H_2 concentration goes above 4.0 vol. %. The operator should not deliberately let the RB pressure rise to keep the H_2 concentration below 4.0 vol. %. If lowering the RB pressure will cause a concentration above 4.0 vol. %, then the operation of equipment in the RB which could provide a spark for H_2 burning should be minimized while lowering RB pressure.

Reactor Building (RB) Hydrogen Rule

Whenever RB hydrogen concentration is $\geq$ .5 vol. %, start the hydrogen recombiners.

Whenever RB hydrogen concentration is $\geq$ 3.0 vol., %, start hydrogen purge to prevent exceeding 4.1 vol. %.

Whenever RB hydrogen concentration is $\geq$ 4.0 vol. %, start one train of the RBS system.

Whenever hydrogen concentration drops below 2.9 vol. %, terminate purging.

2.3.3 Reactor Building Emergency Sump Chemistry

The reactor building emergency sump water boron concentration following a LOCA should not be diluted. This is to assure the recirculation water has sufficient boron to maintain the core subcritical. Boron dilution can be caused if a fluid system leaks nonborated water to the reactor building sump such as a feedwater leak or a leak in the NSCCW. If this occurs the source of nonborated water should be isolated. Boron precipitation in the reactor vessel can also cause a lower boron concentration in the RB sump. The operator should take appropriate actions to prevent boron precipitation in the reactor vessel as discussed in Appendix F.

A RB emergency sump pH limit from > (By GPU) to < (By GPU) is used to limit acid and caustic stress corrosion, respectively. Also, pH control maximizes the iodine removal and retention capability (from the RB atmosphere) of the RB spray system.

2.3.3.1 RB Emergency Sump Chemistry Control

pH

The sodium hydroxide (NaOH) tank is designed to automatically drain down with the BWST and provide initial pH control of the RB sump following RB spray actuation. For a small break LOCA in which the RB spray is not actuated, the NaOH tank will not discharge unless the NaOH valves are manually opened to the DH pump suction.

Boron

If the reactor building sump boron concentration is low the cause may be boron precipitation in the RCS or nonborated fluid systems leaking into the RB, e.g.:

- Main or emergency feedwater leak.
- Steam line leak.
- Service water of CCW leak.

If the low boron concentration limit is reached, boron from the concentrated boric acid storage tank must be added to bring the sump boron concentration back above the low concentration limit. When caustic (NaOH) has been added to the reactor coolant, modified laboratory procedures are required to determine the boron concentration.

2.3.3.2 RB Emergency Sump Chemistry Control With Equipment Failure.

pH - The NaOH tank is designed to drain down prior to BWST depletion regardless of whether one or two RBS trains are in operation.

Boron - The concentrated boric acid storage tank is available to supply additional boric acid to the RB sump via the makeup system in the event of sump dilution.

2.3.4 Reactor Building Radiation

The amount of radioactivity in the reactor building atmosphere or sump following an abnormal transient is dependent upon many factors such as the per cent of defective fuel pins, the power history, time in core life, amount of reactor coolant leaked to the containment and whether the leak was direct (LOCA) or to the SG (tube leak) and then to the RB due to a steam leak. In addition, the equipment which has operated since the transient determines, to some extent, the radioactivity present.

A reduction in the amount of radioactive material in the reactor building atmosphere helps to limit the amount of radioactive material that is released offsite. Figure 37 includes a schematic of processes affecting the site dose.

It is very important to know what radiation levels are in the reactor coolant and reactor building as soon as possible after an abnormal transient. For the LOCA, the NRC has recommended (NUREG-0578) that the reactor coolant and reactor building air be sampled within 1 hour after an accident (LOCA) and that a sample for possible core damage be made in less than 2 hours.

The primary radionuclides of concern are the noble gas nuclides - primarily Kr-85, Kr-88, Xe-132m, Xe-133m and Xe-133 and the iodine nuclides - primarily I-132, I-133, and I-135. The primary means of detecting radiation (μCi/cc and Ci/cc) in the RB atmosphere is with the containment radiation monitors. Before discussing how to control these above nuclides to limit personnel and equipment exposure, some discussion is first included on their behavior in the RB.

2.3.4.1 Behavior of Noble Gases and Iodine Nuclides in the Reactor Building.

The noble gas nuclides will always follow the steam and/or coolant flow and will accumulate wherever there is a gas phase, i.e.,

in the pressurizer steam space, in the makeup tank cover gas, or in the reactor building atmosphere. A significant fraction of all noble gas nuclides will be soluble in the reactor coolant while the system is at a high pressure, but the gas will rapidly leave the liquid upon depressurization. After 10 to 20 minutes at atmospheric pressure, less than a few percent will remain in solution. All noble gases are chemically inert.

The behavior of iodine nuclides is complicated by the fact that the iodine can exist in several different chemical forms, each of which has somewhat different behavior characteristics. Elemental iodine is one of these chemical forms and it constitutes about 85% of the total iodines.

Elemental iodine (I_2) is very volatile, but it will react with water and form Iodide (I) which is very soluble in water in the following manner:

a) $I_2 + H_2O \rightarrow H^+ + I^- + HOI$

The HOI (hypoidous acid) is also somewhat volatile, but it will also react quickly with O_2,if present, in the following manner:

b) $HIO + O_2 \rightarrow IO_3 + H^+$

The IO_3 is also very soluble in water.

If the water is base (pH > 7.0), another reaction becomes more important as follows:

c) $I_2 + OH^- \rightarrow HIO + I^-$

This reaction also has an advantage in that no H^+ is generated as in reactions a) and b).

2.3.4.2 Reactor Building Radiation Control

All noble gases are chemically inert, so there is no effective way to remove them following a reactor accident other than to attempt to contain them and await for decay, which should take 60 to 70 days. After this period, the remaining noble gas activity will have decayed so that it is only a small fraction of the original amount present.

The solubility of I and IO_3 in water is used to remove elemental iodine from the the RB atmosphere. The RBS system, by virtue of the large surface area provided by the liquid droplets, provides an excellent means of absorbing soluble components from the gas phase of the containment atmosphere. If the I and IO_3 can be kept in the RB sump liquid then leakage to the environment can be much better controlled.

Organic and particulate iodine constitute tne other 15% of the total iodines. Particulate iodine is also removed from the RB atmosphere readily by the RBS. Organic iodine (which is mostly methyl iodide - CH_3I) is not removed well by the RBS. However, the charcoal filters in the Atmosphere Clean-up System absorb all forms of iodine.

If an abnormally high radiation level is detected on the containment noble gas detectors, then the operator should:

a) Ensure adequate core cooling.

b) Stop all normal RB purging.

c) Close the normal purge valves, and the RB sump drain valve.

d) Use all available RB fans to mix the RB atmosphere and take samples of the RB atmosphere.

e) Sample the RCS.

f) Check for RCS leakage.

g) Check RB pressure and temperature.

If a high RB radiation alarm is received on the high range containment radiation monitors, then implement the Reactor Building Radiation Rule below:

Reactor Building (RB) Radiation Rule
Whenever RB radiation $\geq$ (By GPU):
a. Isolate all non-essential RB penetrations,
b. Start all RB recirculation air coolers.

2.3.4.3 Reactor Building Radiation Control With Equipment Failure.

In the event of radioactivity in the RB atmosphere and an excessive RB leak rate, all available RB coolers should be operated to reduce the pressure and thus reduce the radiation leakage. The RB spray could also be used to reduce RB pressure and remove iodine from the RB atmosphere prior to a RB pressure of 30 psig. The RB spray should be actuated if the RB radiation release rate is greater than allowable or is projected to be greater than allowable.

2.3.5 Reactor Building Water/Emergency Sump Level

The method of detecting an improper RB water or emergency sump level is by level instrumentation. The volume of borated water in the BWST is designed to provide the correct RB water level for recirculation cooling when the BWST is drained to the low level for LPI pump switch over to the RB emergency sump.

Therefore, high RB water level should not be a problem unless additional water has been added to the reactor building. If this additional water was nonborated, then there will be indication of boron dilution in the RB sump.

2.3.5.1 RB Water/Emergency Sump Level Control

The water level should be maintained high enough for LPI or reactor building spray recirculation flow (NPSH), but not so high that it submerges equipment important to core heat removal or reactor building control. If the water level is at the low level limit, more borated water should be added. The operator should also check for a steam generator tube rupture or some other possible source of water loss such as inadvertent pumping or draining from the sump or break in LPI or spray recirculation line. If water level becomes too high, consideration of lowering it should be made depending on the core cooling method being used (sump recirculation or DHR). The amount of radiation in the sump must also be considered before attempting to remove any of the sump water.

The reactor building water/emergency sump level should be kept between the values shown in Table 8 when recirculating from the emergency sump.

2.3.5.2 RB Water/Emergency Sump Level Control With Equipment Failure

In the event of a failure of the RB emergency sump valves to open or a clogged sump screen following a LOCA, recirculation cooling must be changed to the DHR system with suction from the DH drop line. The decay heat drop line valves will be submerged following a large LOCA. In the event the DHR mode of cooling is required (or desirable), these valves should be opened as soon as RCS pressure will allow after any actuation of the RBS. RB water level following a steam line break is discussed in Section 3.0. A discussion on the loss of LPI recirculation is included in Chapter E, "Best Methods For Equipment Operation".

In the event of a failure of the RB water/emergency sump level, another indication of low sump level is loss of suction and cavitation of a pump taking suction from the emergency sump. Valve lineup, suction fluid temperature, flow rates, etc., should be checked since these symptoms may be a result of a variety of causes. The level of the BWST after ECC injection is also an indication of sump level. Detection of a high RB water level by other than level instrumentation is more difficult and may not be confirmed until submerged equipment is damaged.

3.0 DISCUSSION OF SOME ABNORMAL TRANSIENTS

The preceding discussion has emphasized the LOCA. This section will first discuss some aspects of RB control as it relates to the 3-28-79 accident at the TMI-2 plant (3.1) and the 2-26-80 transient at the CR-3 plant (3.2). This TMI-2 discussion is of special interest since it represents an actual case of a SB LOCA (PORV open) which evolved to inadequate core cooling (ICC). As a result of the ICC, the TMI-2 RB conditions go well past some of the design basis conditions previously discussed.

Also, additional discussion of the steam line break (SLB) and ICC transients is included in Sections 3.3 and 3.4.

3.1 TMI-2 Accident of 3-28-79

3.1.1 RB Pressure and Temperature

Figure 41 is a diagram of the RB pressure and temperature during the first 20 hours after the accident. The PORV was stuck at least partially open during much of the accident. The PORV block valve was closed at approximately 2 hours after turbine trip and the RB temperature dropped off rapidly. The PORV block valve was later reopened and reclosed several times which caused most of the RB temperature cycles between 120 and 180F. RB isolation was actuated at 4 hours. The H_2 burn produced a 28 psig spike

which actuated the RBS. The RBS stayed on several minutes and reduced RB temperature from 170F to 140F.

The RB temperature detectors were too slow to respond to the peak RB temperature at the time of H_2 burning. The peak ambient temperature is believed to have been as high as 1000F for a few seconds in some areas of the RB.

3.1.2 Hydrogen

The amount of hydrogen that was estimated to be in the TMI-2 reactor coolant system is shown in Figure 42. It can be seen that 173,000 SCF was generated in the period between 2 and 4 hours after the accident. At least 63,000 SCF was released into the containment and burned approximately 9 hours 50 minutes after the accident causing the 28 psig pressure pulse inside the reactor building. The remaining hydrogen was slowly removed from the RCS over the next several days by a combination of either venting the pressurizer into the containment, degassing the letdown flow in the makeup tank or by a small leak in the area of the control rod drives. The hydrogen concentration in the reactor building subsequently reached a maximum concentration of 2.3 volume percent on April 3rd (6 days after the accident). A 95 CFM recombiner operated frequently during the period of April 2nd to May 1st and slowly reduced the hydrogen concentration to about 0.8 percent. Estimates of the total Zr-water reaction

range from about 35 to 50% of the fuel cladding. This is in contrast to the 1.0% assumed for the design basis LOCA for TMI-1.

It can be seen that even if all of the plant's waste gas storage tanks were empty, they could only accommodate a small fraction of the hydrogen generated. The hydrogen, while in the reactor coolant system, did not present an explosive hazard. While the RCS pressure was high, the hydrogen occupied a relatively small volume (e.g., 173,000 SCF = 2125 cu. ft. @ 220 psig and 450F).

3.1.3 Equipment Failure in RB

One of the TMI-2 area radiation monitors inside the reactor building, the personnel hatch monitor, was removed during one of the first post-accident reactor building entries for analysis. The results of the analysis showed that a rubber boot on the instrument's cable connection was not on securely; therefore, when the reactor building sprays were on, a drop of water caused a short between two high voltage connections.

The TMI-2 dome monitor also failed. Failures that leave the indicator needle on scale are particularly confusing because they often indicate believable values (e.g., TMI-2 dome monitor indicated a constant 40 R/h after about 2 months of decay, see Figure 43).

A similar problem arose during a different open PORV incident at CR-3 caused by the loss of power to the non-nuclear instrumentation. Since the power supply was a -10 V to +10 V system, the loss of power produced 0 V, which corresponded to a mid-scale reading. The mid-scale reading is usually very close to the normal reading for that process variable, so the operators have difficulty identifying which instruments are functioning properly and which have failed.

3.1.4 Reactor Building Radiation

Figure 43 shows the dome monitor readings following the TMI-2 accident. Several interesting features are shown in this figure.

1. The large dose rate reduction produced by the reactor building sprays.
2. The large increase in dose rate between March 29 and April 2 when the RCS was degassed by venting steam to the reactor building.
3. The increase in dose rate on April 6, when the waste gas tanks were vented into the reactor building.
4. The series of linear decreases in dose rate indicating exponential removal rates, which surprisingly did not relate to radioactive decay but rather to other removal processes (e.g., the large decrease on or about May 1 seemed to relate to operation of the reactor building coolers).

5. The constant dose rate, about 40 R/h, after May 15, is indicative of instrument failure.

The vast majority of the dome monitor reading initially was from Xe-133. A containment gas sample (corrected to 0700, March 31, 1979) contained 755 µCi/ml of which 751 µCi/ml was from XE-133 and Xe-133m. By April 3, 1979, the containment sample had decayed to 29 µCi/ml. Experience has shown (including TMI-2) that the amount of iodine release from the RCS during an accident is orders of magnitude lower than that assumed in the safety analysis provided the release pathway is not dry. The indications are that the solubility of iodine compounds in water (or steam) is much greater than assumed. Measurements showed that only about 2000 Ci of I^{131} were released to the TMI-2 RB atmosphere. This represents only 0.003% of the core inventory. In contrast, about 20% of the core I^{131} inventory was released to the RB sump.

3.2 CR-3 Transient

Figure 44 shows the response of the reactor building dome monitor following a February 26, 1980, transient at the CR-3 plant site. The detector is unshielded and thus showed the correct dose rate response relative to the other detectors in the reactor building. There are several important observations that can be made based on Figure 44.

1. The fuel handling bridge monitor was reading about a factor of 500 lower than the reactor building dome monitor. Apparently, the hot steam and air carried the activity to the top of the reactor building, thus, even though the bridge monitor and dome monitor were both exposed to large gas volumes in the reactor building, there was not enough mixing to prevent radiation dose rates being several orders of magnitude different.
2. The reactor building incore instrument area monitor responded to the decay of the N-16 activity immediately after reactor trip, then eventually climbed to correspond to the dome monitor reading. The decrease in both the dome monitor reading and the reactor building incore instrument area monitor reading corresponds to the mixing rate provided by the reactor building fan-coolers.
3. The core was properly cooled so that no core damage occurred. However, a large amount of radioactive material was released which caused a significant change in the reactor building radiation monitor readings.
4. The reactor buildings at both TMI-2 and CR-3 had significant radiation concentration gradients for several hours and therefore the assumption of a well mixed building atmosphere cannot be justified on the basis of the fan-cooler operation until several hours after a LOCA.

3.3 Steam Line Break (In RB)

A steam line break releases mass and energy to the RB from both SGs until the turbine-generator trips. Then the broken steam line will continue to blow down one SG so long as the SG has level. The operator must verify control of feedwater flow to the SG with the broken steam line to limit the release of mass and energy to the RB. If the feedwater is isolated to the SG with the broken steam line by the main FW isolation system (SLRDS) in the proper manner (at 600 psig), then the maximum amount of mass and energy released into the RB is less than for the worst case LOCA. However, if the SLRDS should fail the feedwater system will continually add feedwater to the SG until manually stopped.

A steam line break inside the RB will release superheated steam into the RB atmosphere. Consequently, when the reactor building air is heated up and the steam is cooled, the two will equalize at a temperature high enough to maintain superheated vapor in the reactor building atmosphere. It will not approximate the steam saturation curve as does the LOCA. Some of the smaller SLBs may cause an elevated RB atmospheric temperature prior to raising the RB pressure sufficiently to actuate the RB spray. The RB spray should be actuated if the RB temperature exceeds the limits of Table 8.

As soon as the blowdown is complete, the reactor decay heat is transferred by the operable SG, so there is no additional decay heat released to the RB as in the case of a LOCA. If the RBS is actuated, the RB pressure and temperature will later tend to approximate the LOCA pressure temperature curve. Figure 45 is a diagram of the general pressure-temperature trend in the RB following a steam line break.

The DH drop line valves will be required to open prior to going on DHR system cooling. If these valves are submerged, then they may not open. This situation is somewhat different than that for a LOCA, since for a LOCA, RB sump recirculation is used until the RCS is depressurized, except for the smaller SB LOCAs. A high RB water level is not expected for these smaller SB LOCAs. The RBS should be shut off after a SLB prior to submerging the DH drop line valves.

3.4 Inadequate Core Cooling (ICC)

The symptom of inadequate core cooling (superheat in the core) is an expected result of a large (> .5 ft^2) LOCA. Under these conditions, however, the ECCS should automatically mitigate the ICC and recover the core with a Zr-water reaction of less than 1% of the fuel cladding. ICC is not an expected part of any other abnormal transient and its occurrence means that the equipment has not operated according to the design basis, either as a

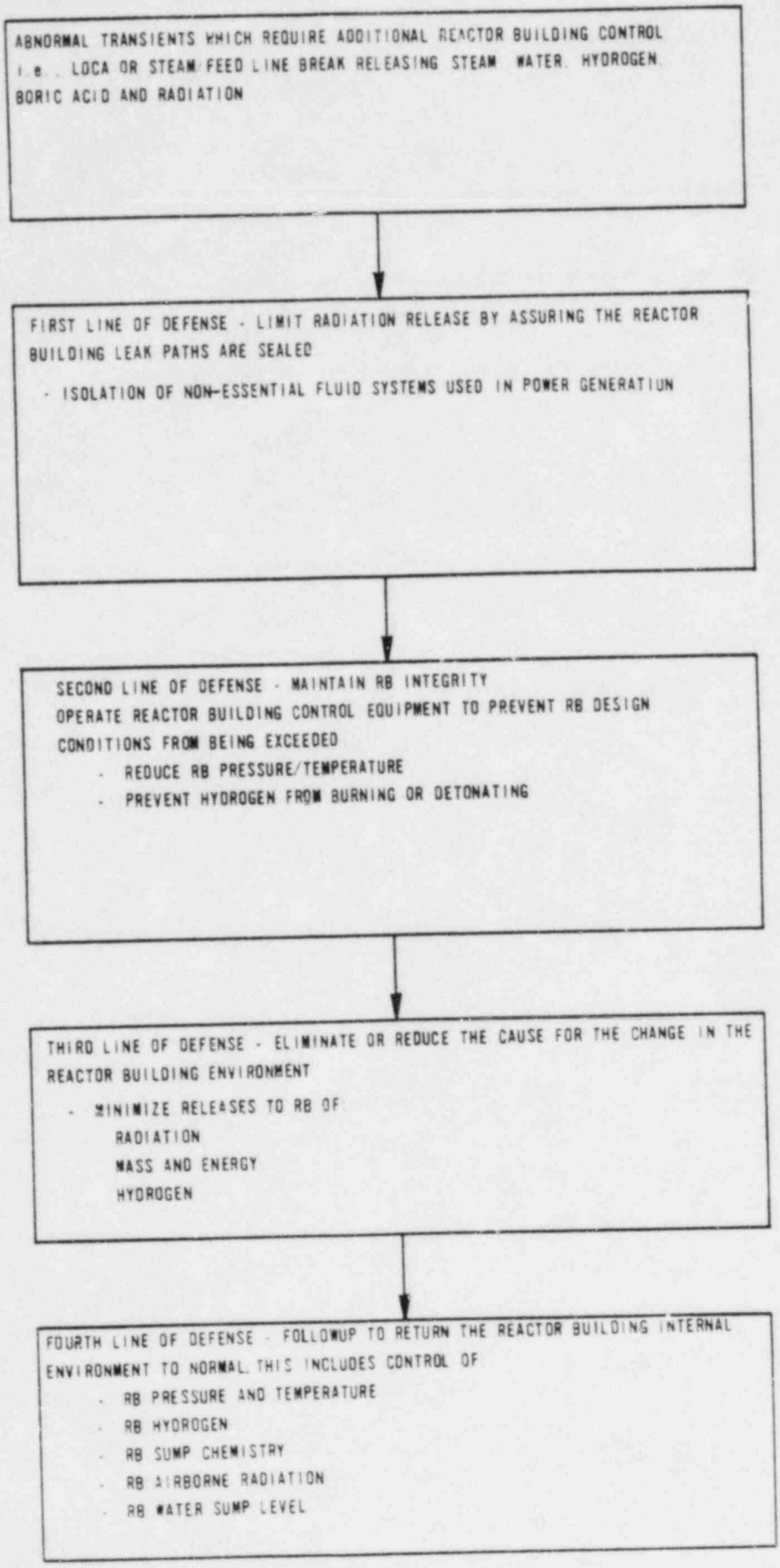
result of personnel error or of multiple equipment failure.

Discussion of ICC is usually associated with recovery from a small LOCA, however ICC conditions can be postulated to result with no RCS boundary break. An example is a total loss of feedwater coupled with no operator action. Mitigation of ICC includes opening the PORV and high point vents and releasing steam, water, radioactivity and H_2 to the RC drain tank and the RB. During the most severe stages of ICC (See Part I, Figure 3, Regions 2 and 3), a large amount of hydrogen may be generated by the zirconium-water reaction in the core. This hydrogen will be vented to the RB through the high point vents. This generation of hydrogen may very well exceed the 1.0% cladding reaction assumed for the design LOCA as discussed in the case of TMI-2. This can occur within hours in contrast to the weeks required for the radiolytic component of hydrogen to peak. Thus hydrogen control becomes a very important part of reactor building control following an ICC event. The hydrogen recombiners and RB recirculation air coolers should be started as soon as there is any indication of ICC. The RB spray should be started if the ICC condition evolves to incore temperatures of 1800F or more (Region 3).

It is very important to sample the RB H_2 concentration soon after an ICC condition is detected and to continue to closely monitor H_2. For some ICC conditions the H_2 recombiners may not be sufficient. RB hydrogen purging may be required within several hours of the ICC. Following recovery from ICC, the venting of H_2 from the RCS to the RB should be controlled to prevent exceeding 4.0 vol. % of H_2 in the RB unless this venting is essential to maintain adequate core cooling.

A severe case of ICC (Region 3) may also result in a large radiation release to the RCS, the RB atmosphere and RB sump. Recirculation into the auxiliary buildings should be minimized under these conditions. If RCS inventory is under control, then an alternative to sump recirculation or DHR system operation is steam generator cooling until the sump radiation levels are allowed to decay.

Figure 32 GENERAL APPROACH FOR CONTROL OF THE REACTOR BUILDING



74-1124158-00

Figure 33 REACTOR BUILDING TREND
TEMPERATURE VS. PRESSURE FOR LOCA

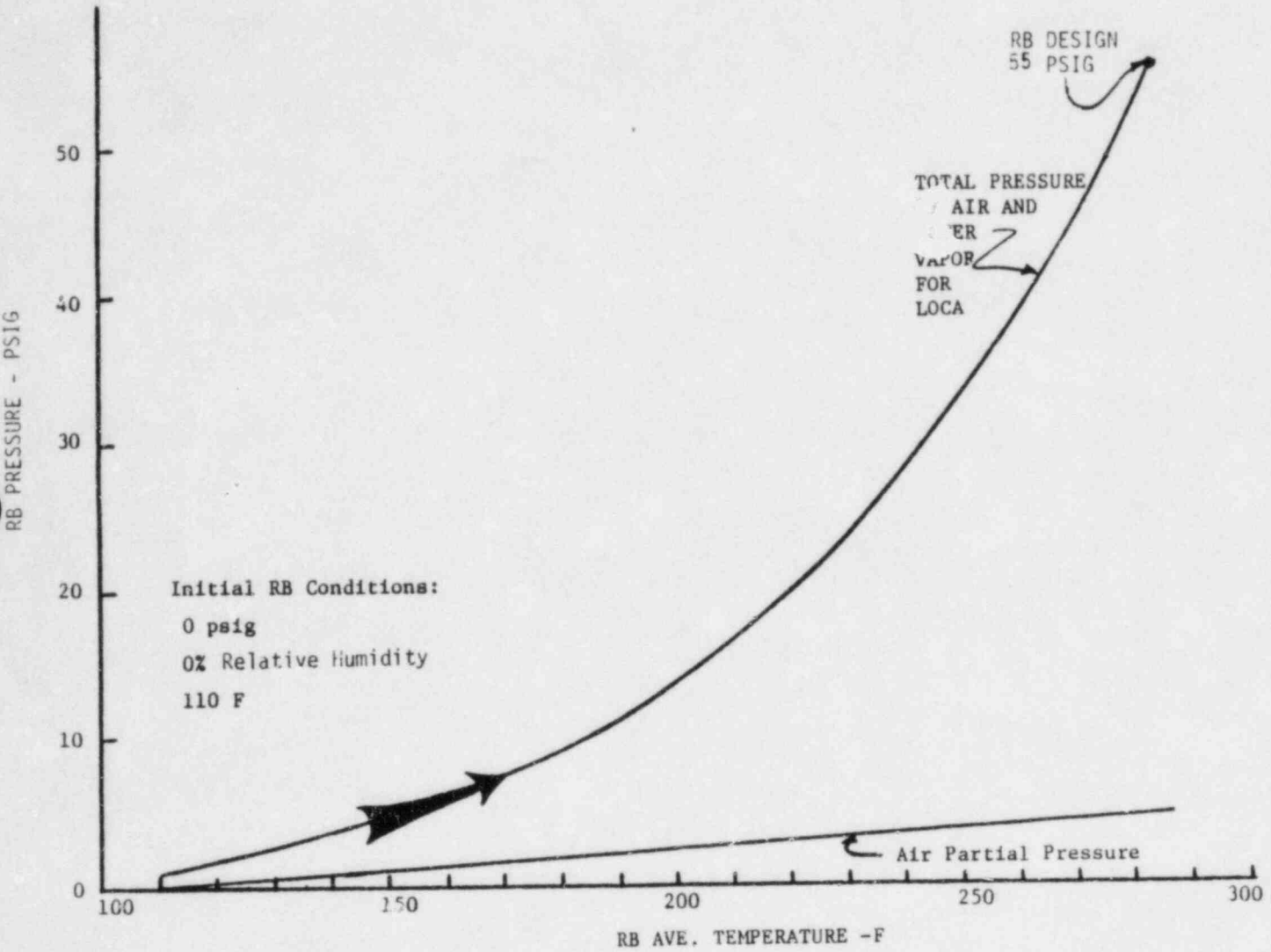


Figure 34 ENVELOPE OF PEAK REACTOR BUILDING PRESSURE VERSUS RUPTURE SIZES WITH 3 AIR COOLERS OPERATING

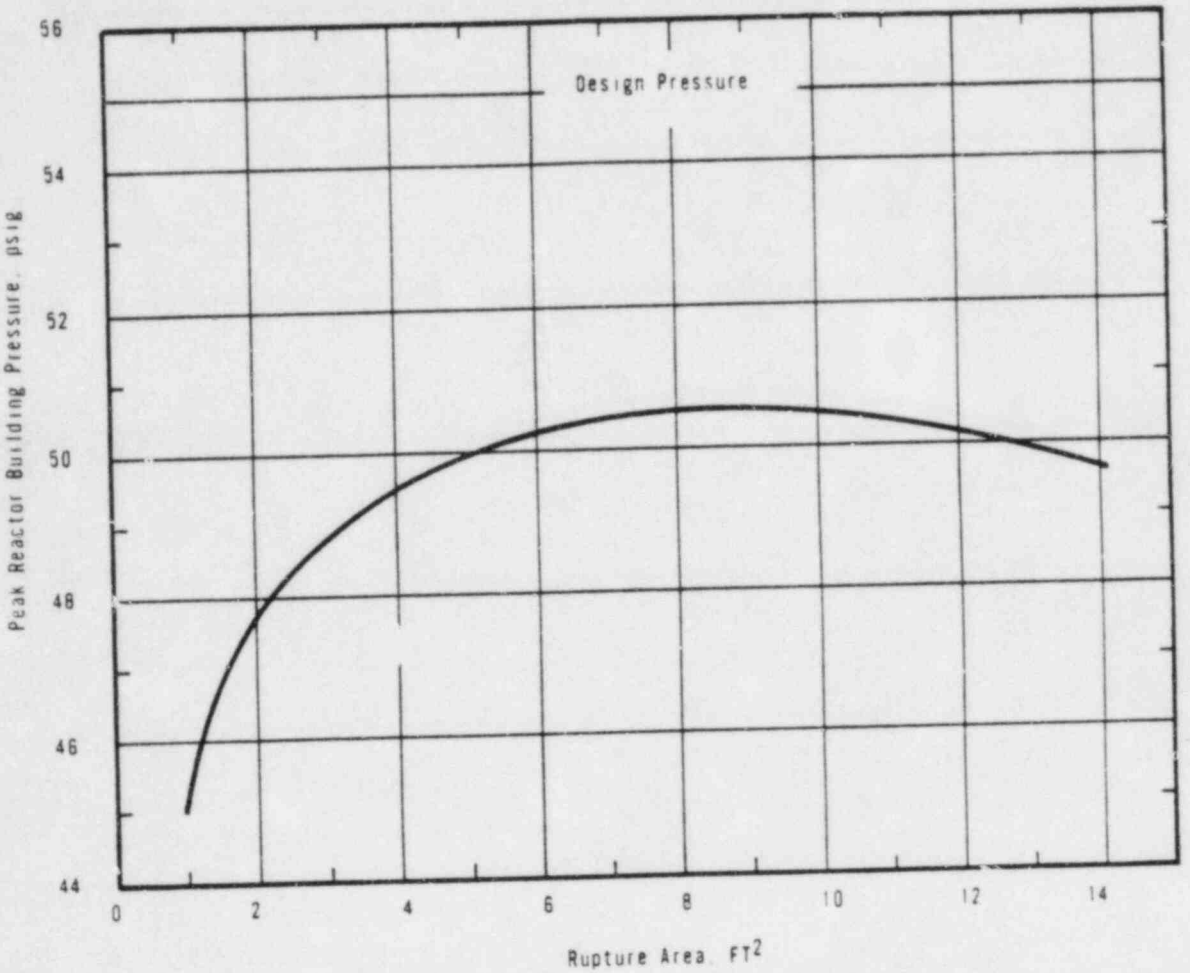


Figure 35 REACTOR BUILDING PRESSURE VERSUS TIME FOR THE DBA 8.5 FT^2 RUPTURE WITH 3 REACTOR BUILDING AIR COOLERS

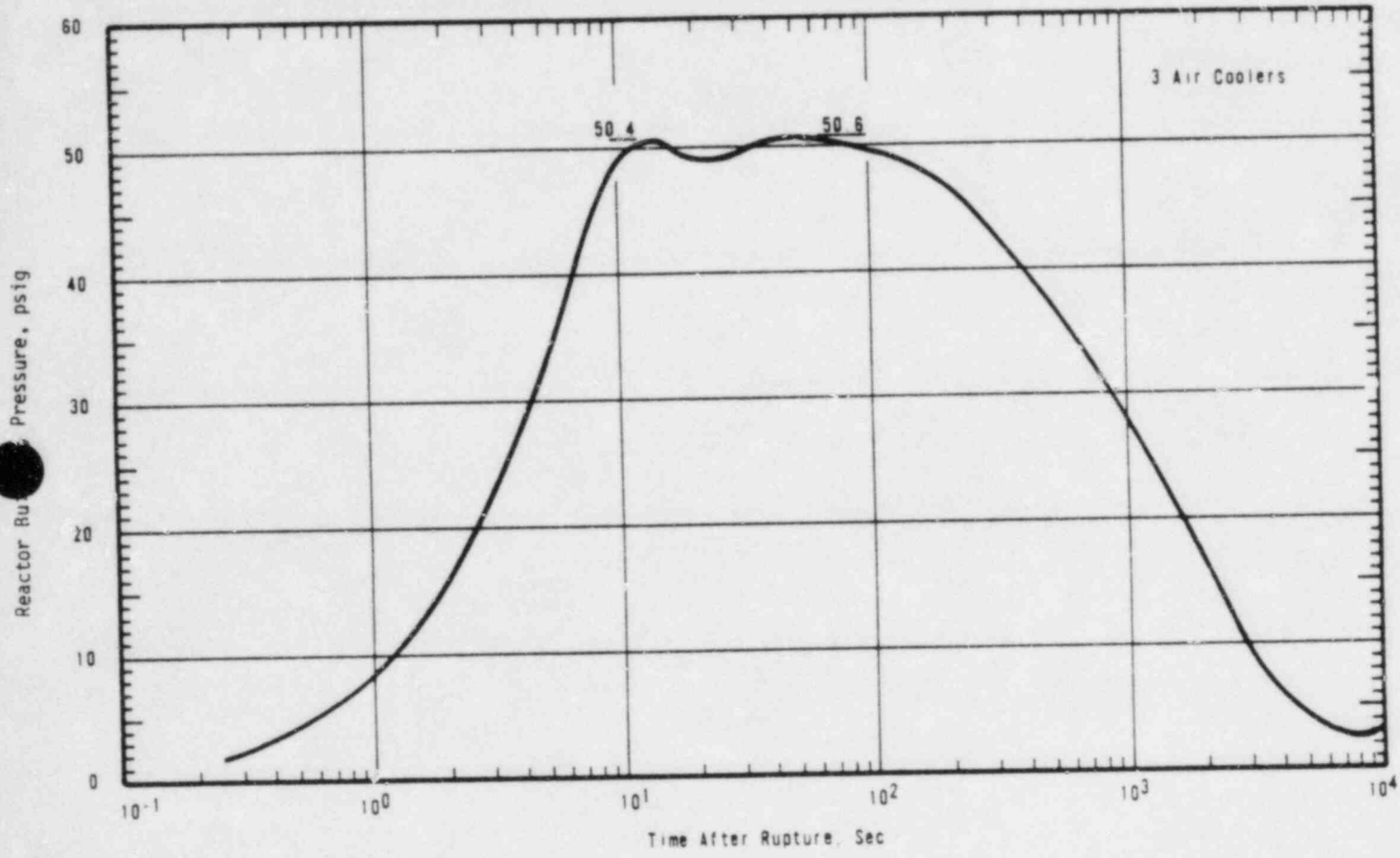
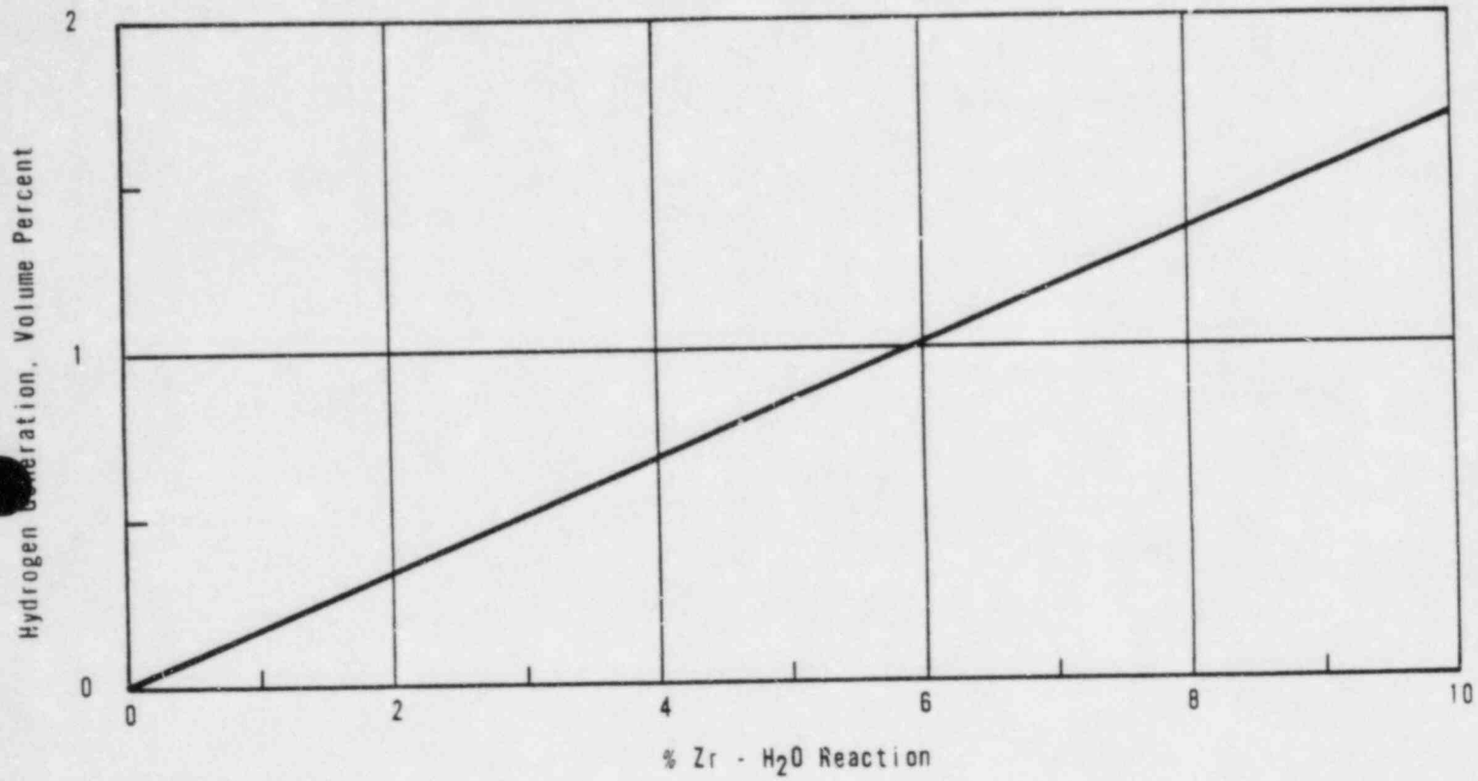


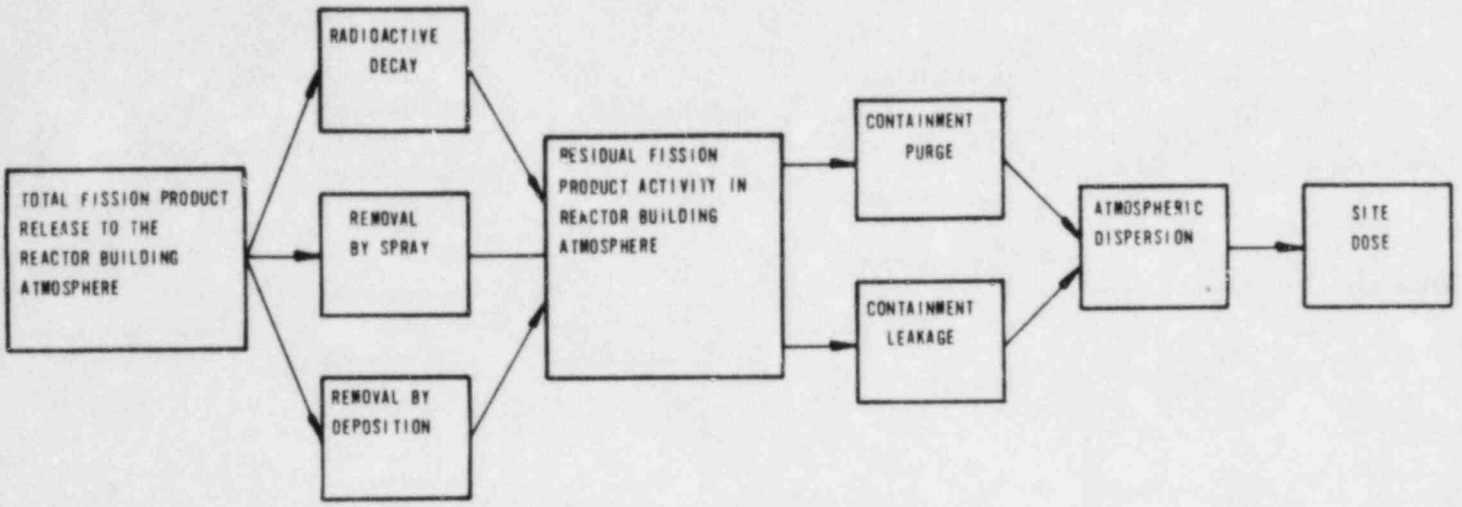
Figure 36 HYDROGEN GENERATION FROM ZR-H_2O REACTION



74-1124158-00

Figure 37 PROCESSES AFFECTING SITE DOSE AND CONTAINMENT HYDROGEN CONCENTRATION

PROCESSES AFFECTING SITE DOSE



PROCESSES AFFECTING CONTAINMENT HYDROGEN CONCENTRATION

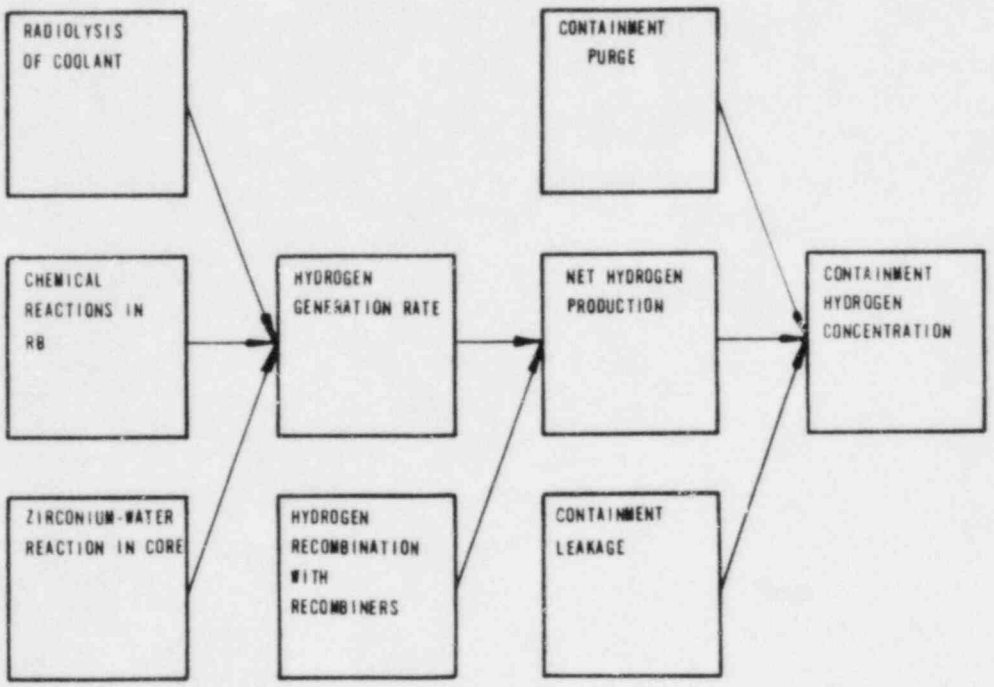
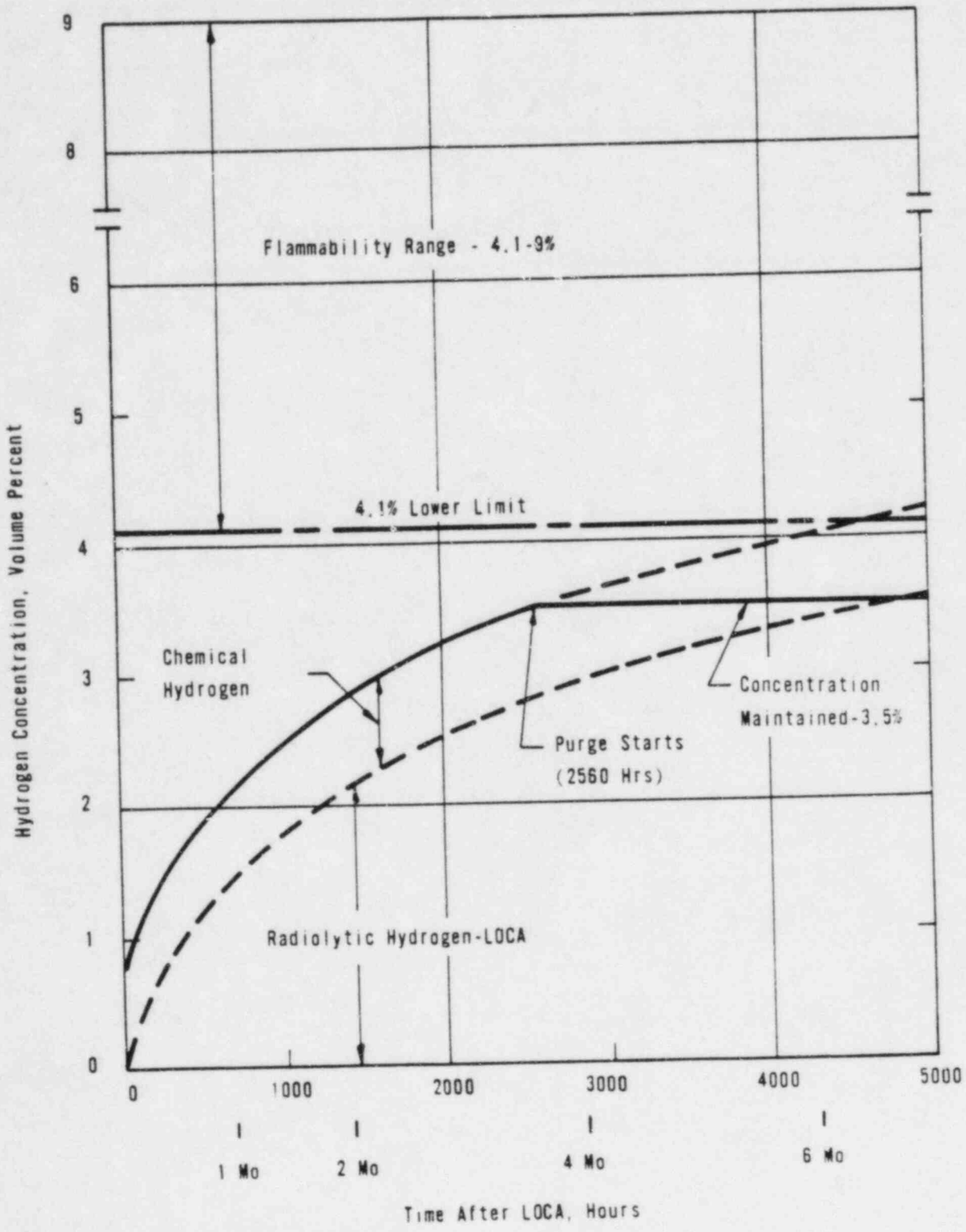
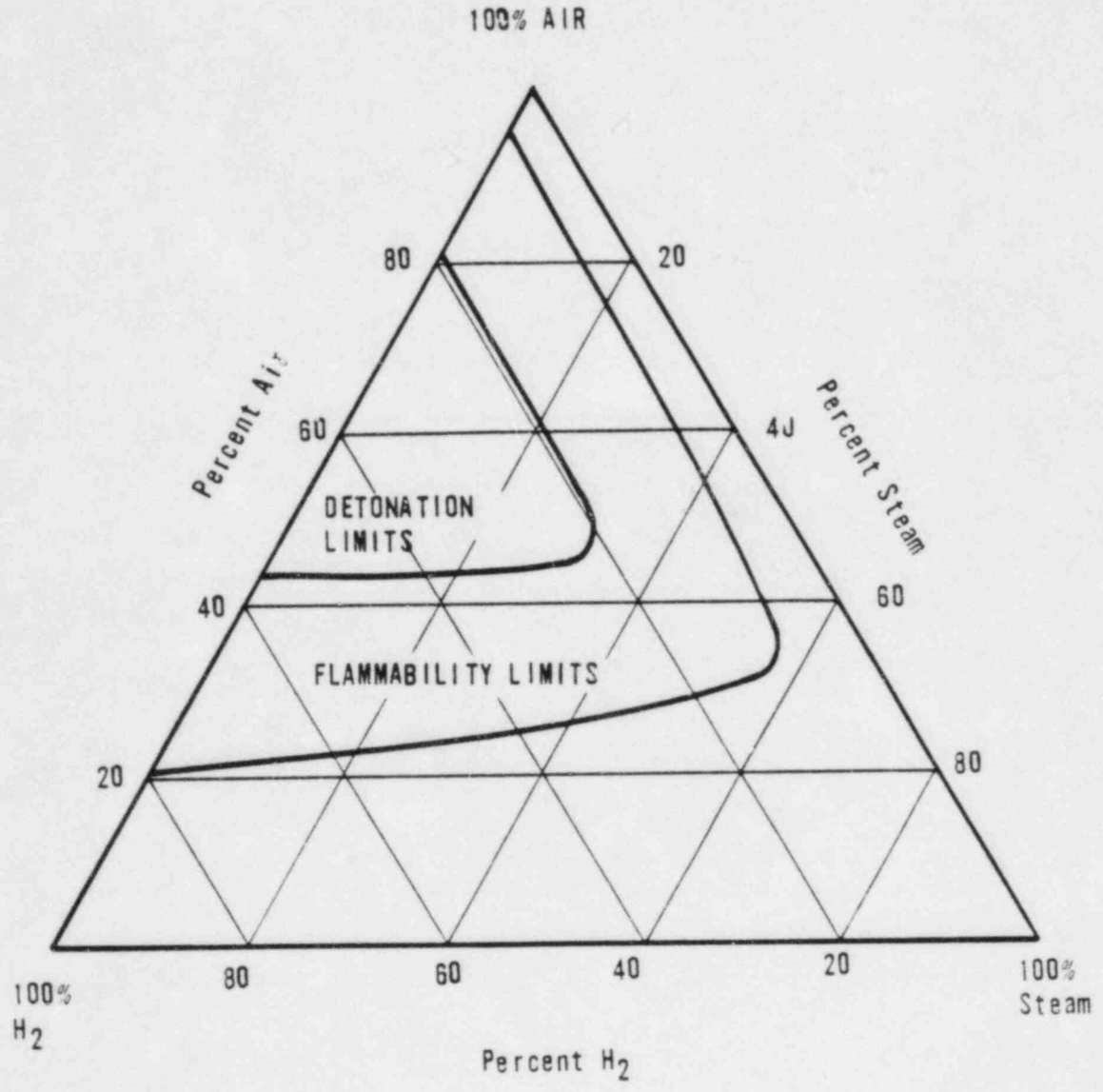


Figure 38 RB HYDROGEN ACCUMULATION VS. TIME FOLLOWING THE DESIGN BASIS LOCA (WITHOUT RECOMBINERS)



74-1124158-00

Figure 39 FLAMMABILITY LIMITS OF HYDROGEN-AIR-STEAM MIXTURES



74-1124158-00

Figure 40 REACTOR BUILDING TREND
TEMPERATURE VS. PRESSURE FOR
RB HYDROGEN BURN

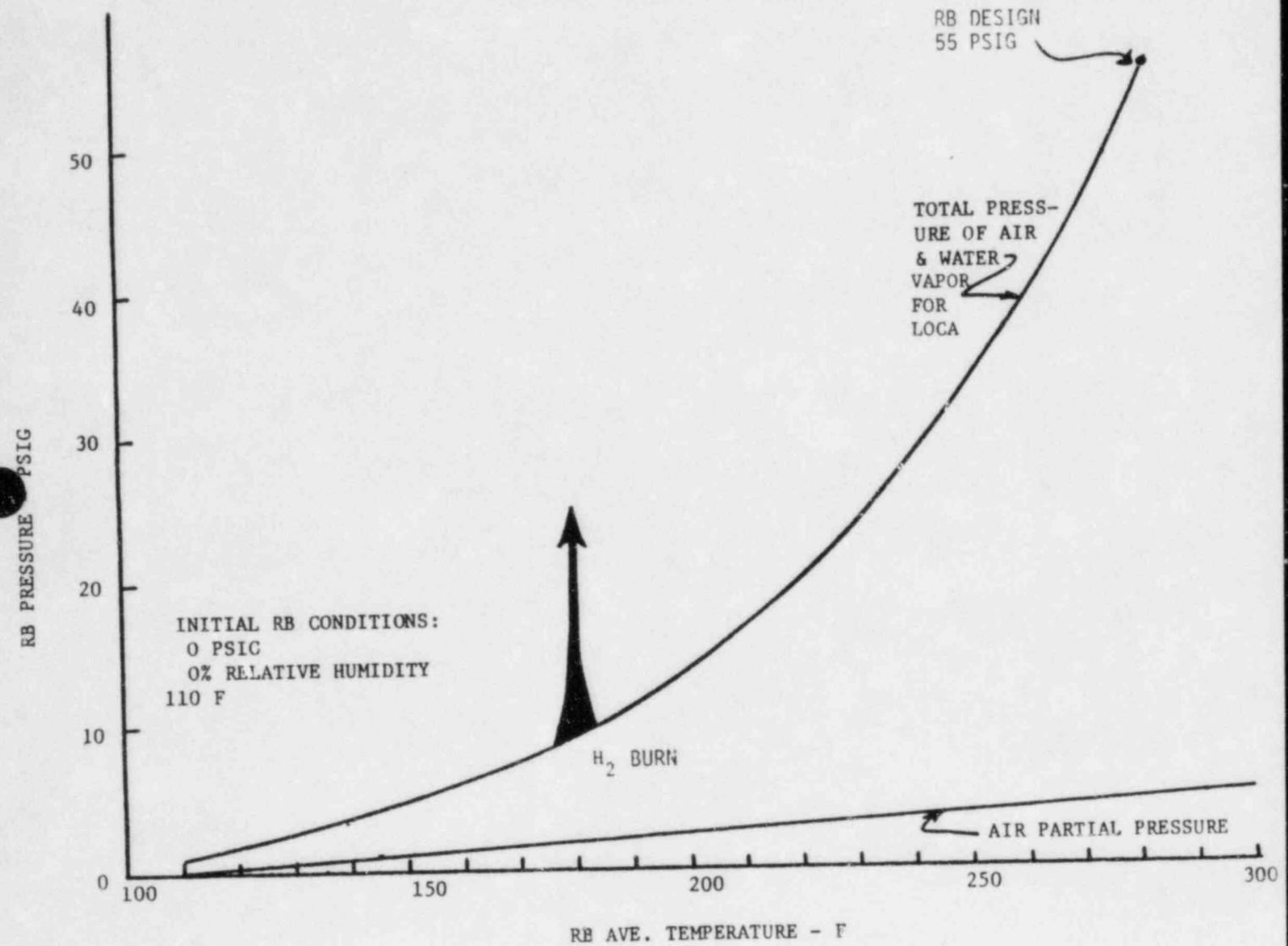
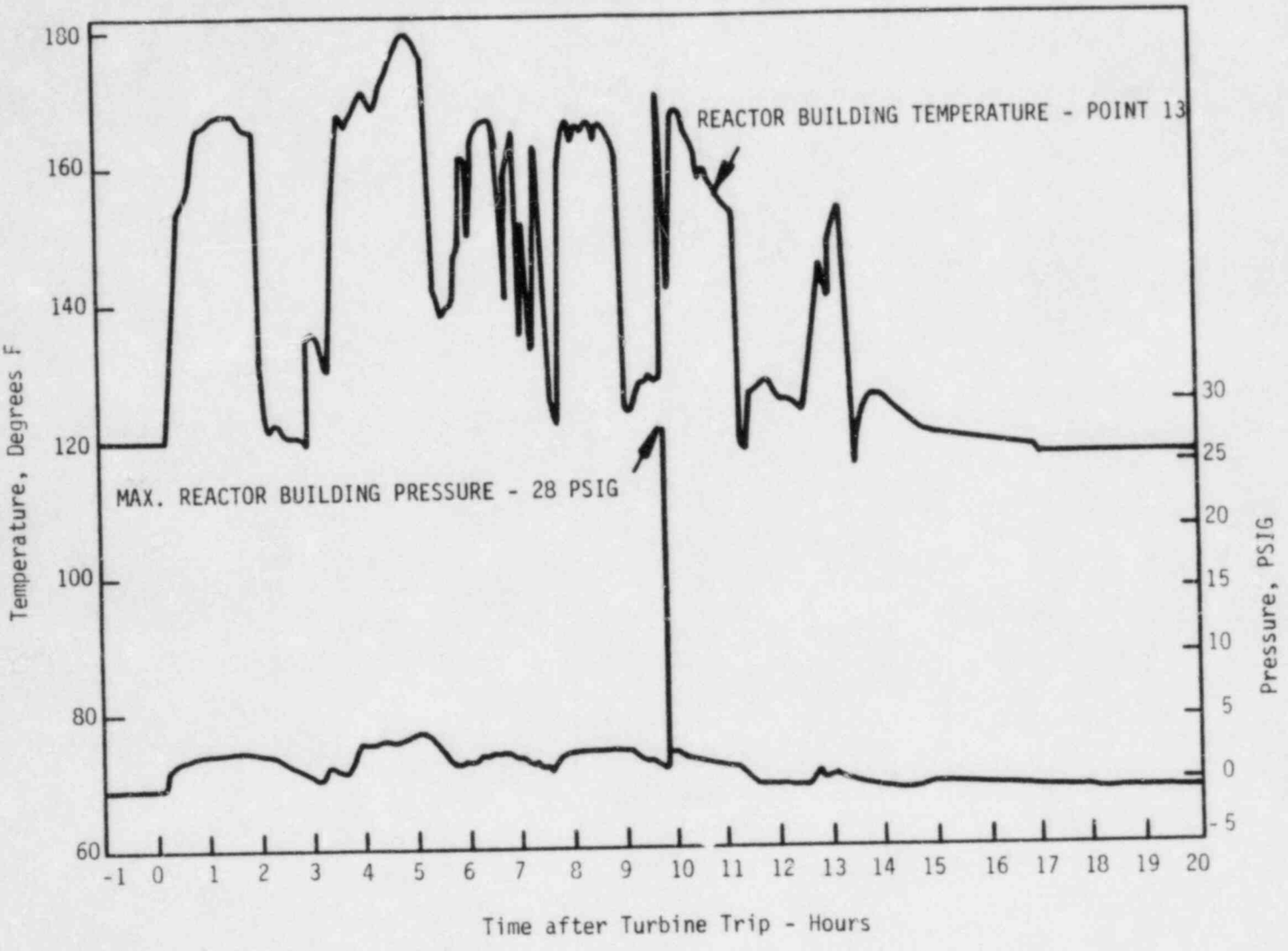
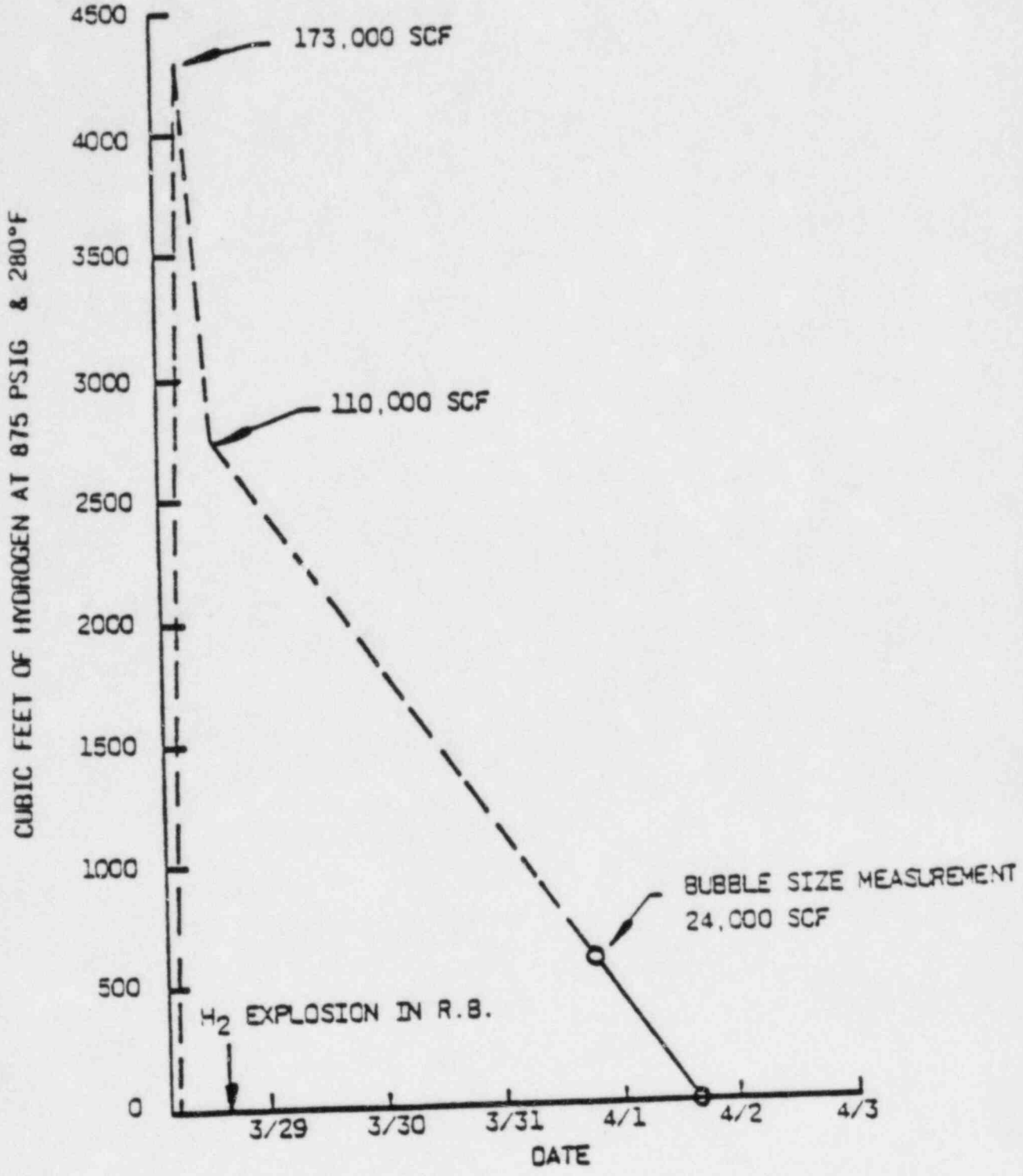


Figure 41 TMI-2 LOSS OF COOLANT ACCIDENT
3/28/79 REACTOR BUILDING
TEMPERATURE AND PRESSURE



74-1124158-00

Figure 42 ESTIMATE OF TOTAL HYDROGEN VOLUME IN RCS OF TMI-2



74-1124158-00

Figure 43 TMI-2 DOME MONITOR READINGS

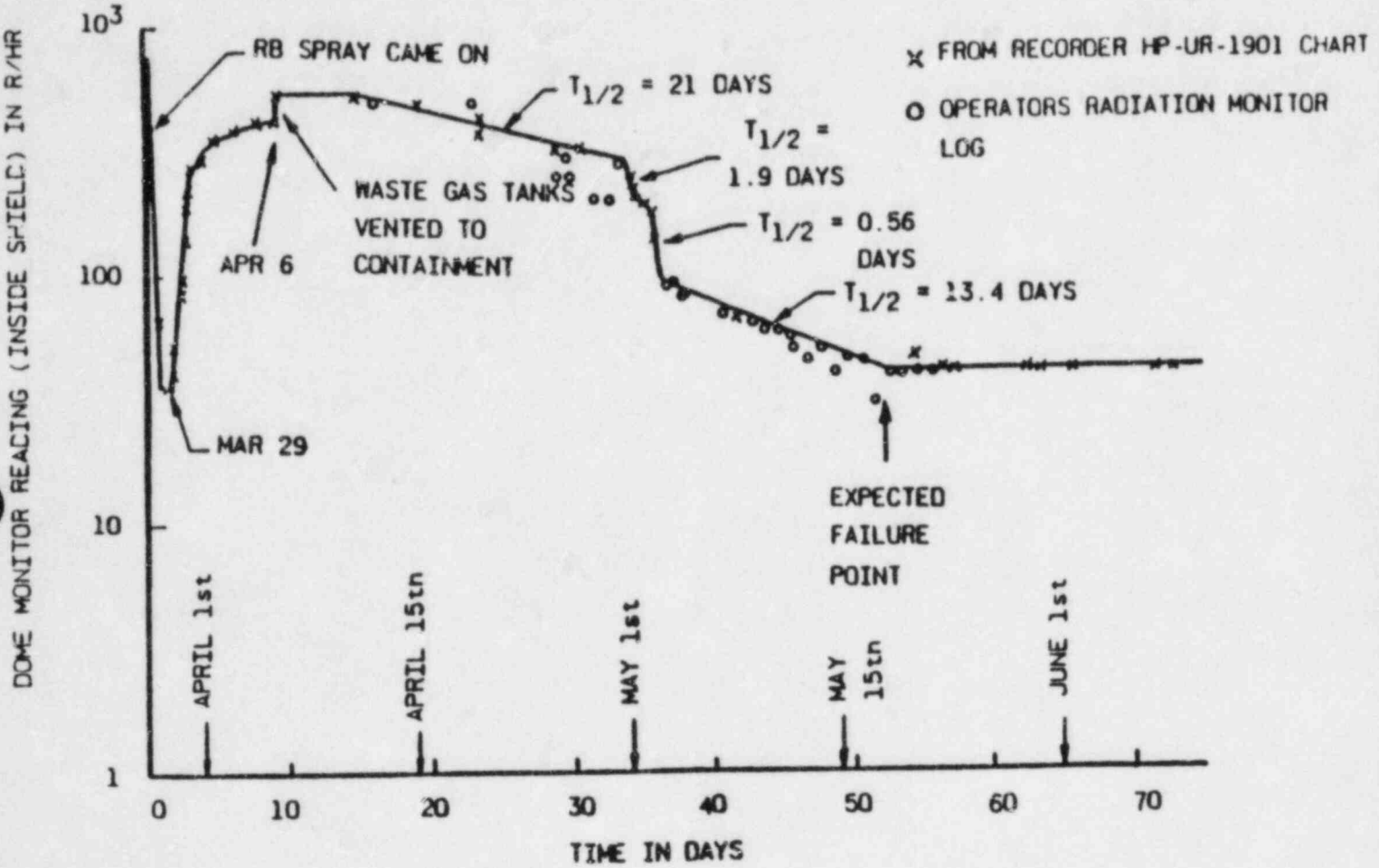


Figure 44 REACTOR BUILDING RADIATION MONITOR RESPONSE FOLLOWING THE CR-3 LOSS OF NON-NUCLEAR INSTRUMENTATION WITH HPI COOLING EVENT, 2-26-80

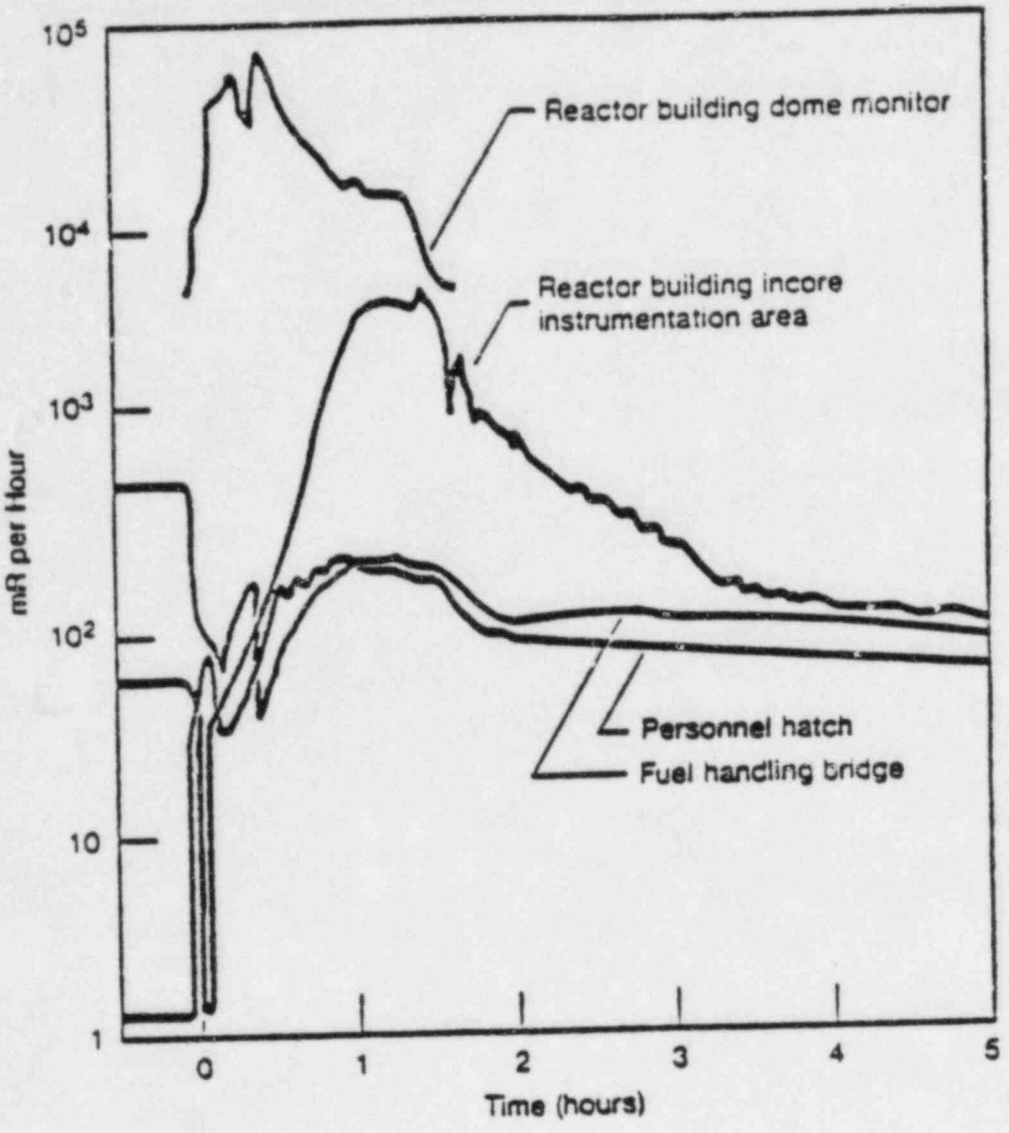


Figure 45 REACTOR BUILDING TREND
TEMPERATURE VS. PRESSURE
STEAM LINE BREAK

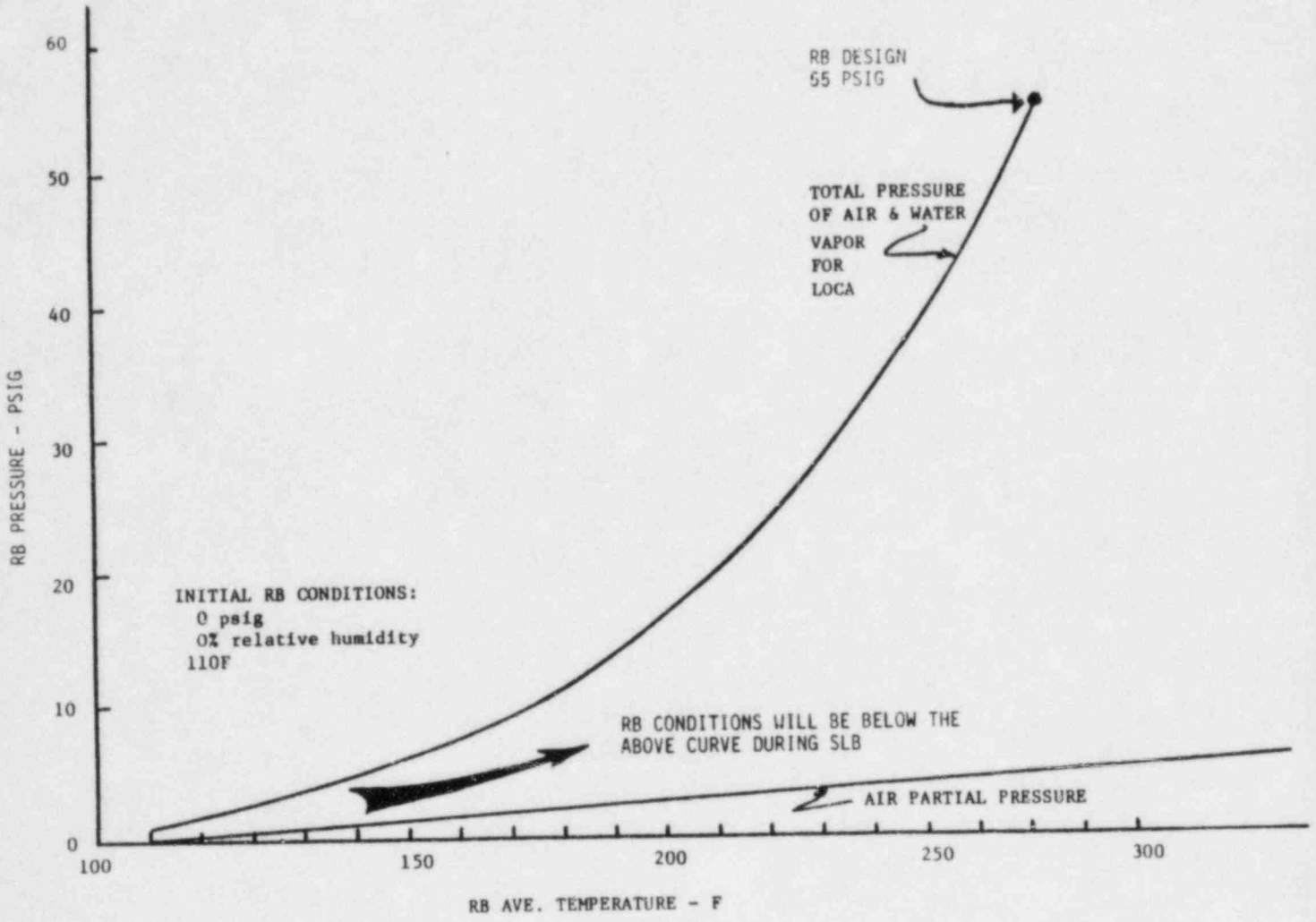


Table 7 SUMMARY OF REACTOR BUILDING ISOLATION CONTROL ACTIONS

PARAMETER	LIMIT	CONTROL ACTION
High RB Pressure or Low RCS Pressure	$\geq$ 4 psig $\leq$ 1600 psig	Verify penetrations of non-essential fluid systems are isolated.
High RB Radiation	(By GPU)	Verify isolation of all lines connecting to RB armosphere.

Table 8 SUMMARY OF REACTOR BUILDING INTERNAL ENVIRONMENT CONTROL ACTIONS
(Sheet 1 of 3)

PARAMETER	LIMIT	CONTROL ACTION
High RB Pressure	≥ 4 psig	Verify 3 RB recirculation air coolers start on slow speed.
High high RB Pressure	≥ 30 psig	- Verify 2 RB spray systems start. - When RB pressure returns to 4 psig, and is decreasing, stop spray.
High RB Temperature	≥ 120F	- Start RB coolers as required to maintain RB temperature below 120F.
High RB Temperature	(By GPU)	- Start the RB spray system as required to maintain RB temperature below this limit.
High RB Radiation	(By GPU)	- Start all RB recirculation air coolers.
High RB Radiation Release Rate	(≥ μc/min By GPU)	- Operate RB spray to lower release rate. - Consider evacuation of Low Population Zone.

Table 8 SUMMARY OF REACTOR BUILDING INTERNAL ENVIRONMENT CONTROL ACTIONS
(Sheet 2 of 3)

PARAMETER	LIMIT	CONTROL ACTION
High RB Hydrogen	$\geq$ 0.5 vol. %	Start H_2 recombiners.
High RB Hydrogen	$\geq$ 3.0 vol%	- Run all RB fans continuously. Start continuous RB purge to prevent exceeding 4.1 vol. %. - Maintain the RB pressure as low as possible with the RB coolers. - Vent H_2 from the RCS only as necessary to maintain adequate core cooling.
High RB Hydrogen	$\geq$ 4.0 vol%	Start one train of the RBS System.
RB Sump pH	(By GPU) to (By GPU)	- Add NaOH as necessary to RB sump to maintain pH above (by GPU).
Low RB Sump Boron	$\leq$ (by GPU) (ppm vs burnup)	- Add boron. - Check for non-borated fluid system leaks into RB. - Check for boron precipitation in RCS.

Table 8 SUMMARY OF REACTOR BUILDING INTERNAL ENVIRONMENT CONTROL ACTIONS
(Sheet 3 of 3)

PARAMETER	LIMIT	CONTROL ACTION
High Level RB Sump	≥ (by GPU) (elevation of equipment not to be submerged)	- Lower sump level if core cooling is assured and radiation levels of sump water are less than (by GPU). - Check for other fluid systems leaking into RB.
Low Level RB Sump (When on sump recirculation)	≤ (by GPU)	- Raise level to between low and high RB sump level limits with borated water. - Check for steam generator tube rupture.
Incore Temperature	Superheat (ICC)	- Start H_2 recombiners and all RB recirculation air coolers.
Incore Temperature	≥ 1800F (ICC-Region 3)	- Start both trains of the RB spray system.

USE OF ATOG

CHAPTER H

USE OF THE GUIDELINES

Philosophy of Part I Organization

Part I is designed for use following any reactor trip or forced shutdown. Its primary purpose is to maintain core cooling and ensure plant stability. A reactor trip, depending on the cause and initial plant conditions, can result in demands on various systems and components (MSSV's, TBV's, EFW, etc.). These demands, coupled with the cause of the trip or forced shutdown, increase the probability that abnormal conditions will develop.

When equipment or system failures occur resulting in an abnormal plant response following a trip, it is not so important to immediately identify the cause as it is to restore stable, controlled conditions. Once the plant has been stabilized, then time exists for failure identification and the decision for future operations (i.e., return to power, remain at existing conditions, or begin controlled cooldown). The main thrust of ATOG, and certainly the most important aspect of dealing with any transient is to maintain adequate core cooling. The most expeditious and positive approach to accomplish this objective is to recognize abnormal conditions when they develop and take appropriate actions to restore stability.

Part I of ATOG contains four basic sections that flow in a logical sequence based on this philosophy. The four sections, in order, are:

a. Section I: Immediate Actions

b. Section II: Vital System Status Verification

c. Section III (A-D): Follow-up Actions for Key Symptoms

d. Cooldown Procedures (including Inadequate Core Cooling)

A two-level format is used in Section III and in the cooldown procedures (including inadequate core cooling). The main steps or headings are designed to provide sufficient information for the supervisor or experienced operator. The sub-steps provide additional detailed information for the operator actually performing the actions as well as a step by step procedure for the less experienced operator. This approach is designed to allow the more experienced operator to follow the procedure more quickly by not requiring him to read detailed information he is already familiar with. The flowcharts for Section III are provided as a visual aid to supplement the text. They do not replace the text, since the detailed information of the sub-steps is not included in the flowcharts. Only the main steps are represented on the flowcharts.

The immediate actions in Section I are those actions taken after every reactor trip regardless of cause (e.g., manually tripping the reactor and turbine). Once the immediate actions have been performed, the next priority is to verify that the reactor is shutdown and that key systems and equipment are available and functioning properly (e.g., NNI/ICS power, turbine stop valves shut, etc.). These items are included in Section II. One abnormal transient (excessive MFW), should it occur, can require

prompt recognition and response by the operator to prevent the possibly severe consequences of water spillover into the steam lines. Therefore, one of the first checks in Section II is the verification that MFW flow has runback. The important items to check early are reactor/turbine trip and MFW flow status. No particular importance should be placed on the sequencing of the other verification steps as long as all of them are performed, except for verification of the four main symptoms discussed below:

Section II also includes obtaining a status of the three main symptoms of abnormal transients (the three basic heat transfer symptoms and the special case for SG tube rupture). However, operator training should emphasize continuous surveillance for indications of off-normal conditions. The four main symptoms are:

1. Lack of adequate subcooled margin
2. Lack of primary to secondary heat transfer (overheating)
3. Excessive primary to secondary heat transfer (overcooling)
4. Indications of steam generator tube rupture.

Recognition of these symptoms is covered in more detail in the "P-T Diagram" and "Abnormal Transient Diagnosis and Mitigation" chapters of this volume. Should any of these symptoms or steam generator tube rupture occur, Section II references the operator to the appropriate follow-up action in Section III of Part I.

Philosophy on the Use of Section III

The order that the symptoms are listed in Section II corresponds to the order of the respective follow-up actions in Section III and is based on the relative priorities of the corrective actions. Lack of adequate subcooling margin is of top priority because core cooling cannot be assured until certain actions are performed. If a lack of adequate subcooling margin occurs, tripping the RC pumps and initiating full HPI flow must be performed quickly. While ICC is the most severe condition of the RCS, it follows after a lack of adequate subcooling margin and the operator would be directed to the ICC section if it should occur. However, if the actions in the lack of adequate subcooling margin can be performed, ICC will not occur. Lack of heat transfer and excessive heat transfer are both second priority symptoms. These two symptoms are equal in priority because they are mutually exclusive conditions. However, excessive heat transfer will require the quickest response by the operators. The SG Tube Rupture is the last priority symptom. The order of the priority for these symptoms can be understood by focusing on the objectives for treating any abnormal transient, which is to maintain adequate core cooling and minimize radiation release. For example, even though a SGTR occurs which can release large amounts of radiation if it is not quickly treated, the lack of adequate subcooling margin and the lack of heat transfer take precedence. This is true because, if adequate core cooling is not maintained, the radiation release would be much greater.

Again, even though it is important to diagnose and treat a steam generator tube rupture as soon as possible, termination of a concurrent overcooling transient takes precedence. This is true because:

1. The overcooling could be the result of a steam leak to atmosphere on the steam generator with the tube rupture, resulting in higher offsite releases.
2. The overcooling increases the tensile stresses on the steam generator tubes which could result in a larger leak size.
3. The contraction of the RCS liquid volume due to the overcooling, especially when compounded by the inventory loss through the tube leak, could result in draining the pressurizer and saturation of the RC loops. Subsequent voiding in the loops can significantly delay the cooldown and thus lead to increased offsite releases.

This discussion of priorities is given to show the logic behind the development of Part I. The important point to remember is that the operator should always be alert for the presence of these symptoms and should always proceed directly to the appropriate section for follow-up actions for a symptom without necessarily waiting to see if a "higher priority" symptom develops. This constant operator surveillance should continue during and after the stabilization of a transient. Some symptoms can mask the presence of others. For example, an overcooling transient can mask the presence of a small LOCA. However, once the overcooling transient is

terminated, the small LOCA should quickly become evident. Abnormal transients can occur at any time and will not always oblige by beginning immediately after a reactor trip. Therefore, continuous surveillance is warranted.

One symptom, lack of adequate subcooling margin, always requires immediate attention. The operator must trip reactor coolant pumps and initiate HPI flow immediately whenever the subcooled margin is lost, regardless of which part of Section III he is currently following. For this reason, the other parts of Section III will either a) reference the operator to Section III.A or b) reiterate the required actions given in Section III.A for loss of subcooling margin.

It can be seen that these symptoms can occur in various combinations and virtually at any time during a transient or subsequent cooldown. Thus it would be very difficult to write a comprehensive procedure that will lead the operator through any possible sequence of events. Where it is known that multiple symptoms are more likely to occur the guidelines will specifically address the possibility. However, to ensure maximum coverage this approach is supplemented by a combination of operator training and procedural guidelines. Recognition of the four basic symptoms and following the appropriate actions of Section III will provide plant stabilization for all single events regardless of cause. Operator training is the key in the recognition and understanding of the basic symptoms. When events

become more complex, either due to additional failures or due to an event progressing to the point of inducing other symptoms (e.g., loss of subcooling margin), operator training is again the key in successful mitigation. The procedural guidelines contain all the necessary information, but the operator must know when to implement the appropriate sections. He does this by careful surveillance of the plant conditions during and following a transient, recognizing the symptoms whenever they occur and going to the appropriate section. In this respect ATOG is somewhat similar to event-oriented procedures in that the operator must recognize a condition and react to it. The difference is that the symptom will always be evident when the failure occurs. The cause (event) will not always be evident. Also, there are just three heat transfer symptoms and the steam generator tube rupture event to recognize as opposed to numerous events.

In addition to recognizing a symptom and implementing the appropriate part of Section III, the operator must also know when to transfer between parts of Section III (for multiple symptoms or incorrect diagnosis) and when to terminate his actions if the problem is corrected. Some basic instructions for the use of Part I can be summarized as follows:

1. Priorities between the parts of Section III:
    a. Loss of subcooling margin always requires immediate attention regardless of which part of Section III is being following (with single exception of raising SG levels noted in 1.c below).

b. Lack of heat transfer or excessive heat transfer must be corrected before actions for SGTR.

c. Excessive heat transfer (overcooling transients) must always be terminated as soon as possible, and before raising SG levels to high level for loss of subcooled margin or actions for SGTR.

2. Follow the appropriate part of Section III for the dominant symptom, unless a "higher priority" symptom (in item 1 above) appears, in which case recycle to the part of Section III for the higher priority symptom.

3. If a reactor trip occurs during a forced shutdown, recycle to Section I.

4. If a major change in equipment status occurs during the performance of a part of Section III or subsequent cooldown, carry out the appropriate actions of Section II (i.e., loss of NNI/ICS power, loss of offsite power, safeguards actuation, etc.). This can be accomplished in parallel with Section III.

5. If it is discovered that an incorrect diagnosis has been made and:

   a. no other symptom exists (e.g., inadvertent entry into Section III because an overshoot after trip was misinterpreted as overcooling), then stabilize plant (e.g., restore heat transfer; don't exit III.C immediately after isolating both SG's) and recycle to Section II; or

b. if a different symptom exists, then recycle to the appropriate part of Section III.

6. If, during the performance of follow-up actions in Section III, the cause of the transient becomes evident and is corrected, then hold at that point and allow the plant to stabilize while checking for other symptoms/problems (e.g., if in the process of isolating both SG's for excessive heat transfer and closing of the TBV's on one SG stops the transient, there is no need to continue isolation of steam and feedwater on both SG's). Similarly, if the intent of a group of actions is satisfied, then continuation of those actions may not be neccesary (e.g., HPI flow can be throttled and SG levels do not need to be raised to the high level once subcooling margin is restored).

7. All normal limits and precautions are applicable during the performance of Part I unless specifically superseded by the ATOG procedure (e.g., the use of pump bumps regardless of NPSH requirements when saturated with SG level). Whenever a step appears in Part I that supersedes a normal limit or precaution, it has been carefully considered and deemed acceptable for plant conditions existing at the point in the procedure (e.g., violation of fuel pin compression limits during a large SGTR). One should not infer, however, that since it is acceptable at one point in the procedure then it is always acceptable to violate the limit or precaution.

As an example on the use of Part I, assume an overcooling transient occurs following a reactor trip that leads to drainage of the pressurizer and a loss of the subcooling margin. When the subcooling margin is lost the operator must quickly perform the actions of III.A which include tripping the reactor coolant pumps and initiating full HPI flow (1.a above). The operator is also required to raise SG levels. These actions are required in the event of a small break LOCA. In this case the LOCA could be masked by the overcooling or induced by the overcooling transient. The overcooling will be caused by either excessive feedwater flow or loss of steam pressure in one or both steam generators. The operator must either regain control of feedwater or isolate the loss of steam pressure (may require isolation of one SG) before proceeding with raising SG levels (1.c above). The intent is to terminate the overcooling first as it could otherwise continue to mask the presence of a small break and, if the loss of subcooling margin was due to <u>just</u> an overcooling event (i.e., no LOCA), then filling the SG's would be exactly the <u>wrong</u> action (it would aggravate the overcooling). Similarly, if the subcooling margin is regained while the operator is filling the SG's, he need not continue to the high level required for small breaks (6 above). The intent of the actions (restore subcooling margin and ensure SG's available for heat removal) has been satisfied. The operator should throttle HPI flow and adjust SG levels to the appropriate setpoint for natural circulation or forced circulation if he has restarted RC pumps. These variations on the use of the guidelines are examples of situations that, if Part I attempted to cover them all, it

would result in a procedure of such bulk and complexity as to render it useless. However, by training the operator so that he understands what the symptoms mean in terms of heat transfer and what is really occurring in the plant, and so that he understands what the guidelines are intended to accomplish, then his educated use of the guidelines will ensure transient termination and plant stability for any event or combination of events.

Another example of proper operator judgement can be shown by again assuming an overcooling transient. The guidelines may tell the operator to completely isolate both SG's (steam and feedwater). This is because Part I is designed to restore plant stability assuming worst case accidents, which, in the case of overcooling, would be an unisolable steam line break. If the operator does not know the cause of the overcooling or even which SG is causing the overcooling then the proper response is to isolate both SG's to stop the transient. With the transient terminated he should then be able to monitor secondary conditions and isolate the problem to one SG so that controlled decay heat removal can be restored using the unaffected SG. However, if he should discover the cause of the transient while he is isolating the SG's (e.g., stuck open TBV's) and isolation of this cause does indeed stop the overcooling, then there is no reason for him to complete the isolation of both SG's. If he understands the purpose of the steps he is taking in following the guidelines, then he will understand when that intent is satisfied and may be able to exit the procedure

at that point rather than arbitrarily following it through to completion. Of course, should he fail to realize that isolation of the TBV's terminated the transient, continuing through the guidelines, including isolation of both SG's for this example, will not cause any significant problem; it is merely unnecessary. Continuing through the procedure will lead to restoration of core cooling using the unaffected SG(s).

Objectives of Section III

In order to promote understanding of the procedural guidelines, this section will address each subsection of Part I, Section III in terms of what the plant conditions are, what are the possible causes, and why the operator is directed to take the specified actions (i.e., what the actions are intended to accomplish). The referenced section of Part I should be followed while reading this section.

Section III.A, Follow-up Actions for Treatment of Lack of Adequate Subcooling Margin

Whenever plant conditions reach or exceed the subcooling margin curve the assumption is that the RCS is saturated. The RCS can become saturated as a result of three basic causes:

i. loss of coolant inventory (LOCA)

ii. overcooling that results in sufficient coolant contraction to drain the pressurizer, or

iii. prolonged loss of heat transfer that allows the RCS to overheat to saturation at high pressure (this cause would be recognized as lack of heat transfer before loss of subcooling and handled in accordance with Section III.B).

The primary objectives of this section are to 1) restore subcooling margin and 2) maintain or restore core cooling. To accomplish these objectives, HPI must be initiated and either secondary heat transfer or HPI cooling must be established.

Two actions are always required whenever the subcooling margin is lost:

1. trip all reactor coolant pumps and
2. initiate full, balanced HPI flow.

These actions are necessary in the event the loss of subcooling margin is due to a small break LOCA. Tripping the RC pumps must be done immediately following the loss of subcooling margin to minimize inventory loss if a small break exists. In addition, if the loss of subcooling margin was the result of an overcooling transient, HPI will compensate for the coolant contraction and restore subcooling. Reestablishing controlled secondary heat removal should then be possible. If the loss of subcooling margin was due to a total loss of feedwater (main and emergency) then full HPI will be needed to establish HPI cooling (in Section III.B). In this case subcooling should also be restored but it may take some additional time until the cooling capacity of the HPI flow exceeds the core heat generation rate.

Raising SG levels should also be done in the event of a small break LOCA. High SG levels will allow condensation of steam voids in the RCS side of the upper tube region to establish boiler-condenser cooling. If the transient was initiated by total loss of feedwater then the operator may not be able to restore feedwater and raise SG levels but after he has established HPI cooling he should continue efforts to restore feedwater. If the transient indicates overcooling then he should not raise level in the affected SG(s) until the overcooling is corrected. This is to prevent further uncontrolled plant cooldown. Actions are also included to isolate possible causes for the loss of primary pressure.

At this point the operator has full HPI flow, the RC pumps are off, he is raising or attempting to raise SG levels, and he has isolated possible causes of the loss of subcooling. Further actions will be determined by the plant response to the actions already taken. The subcooling margin may be restored by HPI or the plant may remain at saturation. In either case, primary to secondary heat transfer may or may not exist.

Subcooling Margin Restored

If the subcooling margin is restored, the operator should restart reactor coolant pumps. This will aid in establishing primary to secondary heat removal if it does not already exist and will provide better mixing of the cold HPI flow to alleviate the thermal shock concern. He will also throttle HPI flow to prevent excessive RCS pressure that could lead to NDT violation and/or unnecessary lifting of the pressurizer safety valves.

If primary to secondary heat transfer does not exist even after the subcooling margin is restored, it is probably due to a lack of feedwater or a blockage of RC flow due to steam voids in the hot legs. The operator will proceed to Section III.B which will provide for restoration of feedwater and primary to secondary heat transfer or establishment of HPI cooling.

If excessive heat transfer exists, the operator will proceed to Section III.C. The operator should also be alert for indications of a small break (refer to Appendix F in Volume 2) as a small break could exist that is within the capacity of the HPI system.

If controlled primary to secondary heat transfer exists then the operator should regulate feedwater flow to establish SG levels at the appropriate setpoint (dependent upon whether RC pumps were restarted). The operator should also control steam pressure to prevent RCS reheating and swell. If the RCS were allowed to reheat, the added inventory from HPI could result in a large pressure increase and possibly a full pressurizer.

Subcooling Margin not Restored

If full HPI flow does not restore the subcooling margin even with heat transfer to the SG's, it is a LOCA. If heat transfer does not exist or exists in only one SG, the operator will proceed to Section III.B to attempt restoration of heat transfer to both SG's. The prolonged period

at saturation may be due to a total loss of feedwater or a small primary break. In either case, restoration of feedwater flow in III.B will aid primary cooling. If, however, the CFT's begin to empty, a large break exists and primary to secondary heat transfer cannot be regained. In this case the operator will go to CP-101 for long term cooling following a major LOCA.

NOTE: Whenever adequate subcooling margin does not exist, the operator should be alert to indications of superheat in the RCS (incore thermocouples read higher than saturation temperature for the existing RCS pressure). If indications of superheat occur, the operator should proceed to the Inadequate Core Cooling (ICC) guidelines.

Summary

The bases for Section III.A can be summarized as follows:

Symptom: RCS pressure-temperature to the right and/or below the subcooling margin curve.

Problems:
a) Possible LOCA
b) Void formation in RCS at saturation can interrupt core cooling

Objectives:
a) Restore subcooling margin
b) Maintain or restore core cooling:
   i. preferably with SG's
   ii. with HPI cooling (after transfer to Section III.B) if SG cooling unavailable

Key Points:
a) Be alert for indications of ICC
b) Lack of subcooled margin can severely hamper primary to secondary heat transfer
c) HPI cooling, while adequate for core cooling, is not a desirable long-term cooling mode. Cooling with one or both SG's must be restored as soon as possible. (HPI cooling is discussed in more detail in the "Backup Cooling Methods" chapter).

Section III.B: Follow-up Actions for Treatment of Lack of Primary to Secondary Heat Transfer in Either OTSG

If adequate subcooling margin exists, the most likely cause for lack of primary to secondary heat transfer is no heat sink (loss of feedwater). The operator will take steps to restore feedwater. If he cannot restore feedwater he will establish HPI cooling and he should reduce the number of running RC pumps to one to minimize heat input to the RCS. This will provide adequate core cooling while he continues efforts to restore feedwater to at least one SG.

Lack of Adequate Subcooling Margin

If, however, adequate subcooling margin does not exist, then the lack of heat transfer could be due to no heat sink (loss of feedwater) and/or no reactor coolant flow (hot leg voiding). The primary objective is to restore core cooling. The preferred method of core cooling is with primary to secondary heat transfer.

If the operator has feedwater flow and a level in at least one OTSG, then the lack of heat transfer is due to lack of RC flow. If the CFT's are emptying, a major LOCA has occurred and there is no benefit in restoring primary to secondary heat transfer. In this case the operator will proceed to the procedure for long term cooling following a major LOCA. If a major LOCA has not occurred, he will attempt to induce natural circulation flow by raising SG level and lowering SG pressure. If this fails,

and RCP's are operable, he will attempt to induce natural circulation flow by bumping an RC pump. With the SG available as a heat sink, bumping an RC pump will force steam voids in the RCS into the SG tubes where they can be collapsed. Fifteen minutes should be allotted between successive pump bumps to allow natural circulation flow to start. If natural circulation flow is still not established after all operable RCP's have been bumped and one hour has passed since the reactor trip, a pump should be started and run, if possible, in a loop with the SG available as a heat sink. The hour limitation is based on allowing decay heat to decrease to a level that the HPI flow can accommodate so that additional inventory loss through the break due to forced flow is no longer a serious concern.

If the RCP's are not operable or FW is not available, he must cool the core with HPI and he will go to CP-104 for HPI cooling. If he is successful in establishing primary to secondary heat transfer then he will go to the appropriate cooldown procedure depending on the degree of subcooling. If the subcooling margin is not restored then a small break probably exists.

Summary

The bases for Section III.B can be summarized as follows:

Symptoms: a) With subcooling margin, symptoms are those indicative of loss of feedwater:

i. RCS reheating and repressurizing after normal post-trip cooldown.

ii. Low or non-existent SG levels and feedwater flowrates.

b) With lack of adequate subcooling margin, symptoms could be as above for loss of feedwater and/or small break symptoms (see Appendix F in Volume 2).

Problems:

a) Lack of core cooling

b) Extended loss of feedwater will lead to saturation and loop voiding-necessitates HPI cooling.

c) Possible LOCA.

Objectives:

a) Maintain or restore subcooling margin.

b) Restore core cooling, preferably using the SG's.

Key Points:

a) Lack of heat transfer with adequate subcooling is more than likely due to total loss of feedwater or insufficient feedwater to induce natural circulation.

b) Every effort must be made to restore primary to secondary heat transfer (unless a Major LOCA occurred). HPI cooling will be adequate for short-term core cooling but is not a stable long-term cooling mode (see HPI cooling section in "Backup Cooling Methods" chapter).

Section III.C: Followup Actions for Treatment of Too Much Primary to Secondary Heat Transfer

Excessive heat transfer is always caused by a failure in the control of secondary side parameters, resulting in a loss of steam pressure or excessive feedwater flow or a combination of both. The overcooling places large thermal stresses on the RCS piping and components and on the steam generators. It can also lead to saturation of the primary system if the RCS contraction is large enough to drain the pressurizer. The primary objective of this section is to terminate the overcooling transient and then to restore controlled decay heat removal.

MU is increased if pressurizer level is low and RCS pressure is decreasing in an effort to prevent drainage of the pressurizer and loss of subcooling margin. If the SG level is > 95% on the operate range, the MFW pumps must be tripped. If the SG level is not excessive the operator will then check to see if the SG causing the overcooling can be identified. The best method to identify the affected SG is to compare T_{cold} temperatures. The loop with a significantly lower T_{cold} is the loop with the affected SG. However, T_{cold} temperatures can be fairly close together even when only one SG is causing the overcooling (refer to the discussion on overcooling transients in the "Diagnosis and Mitigation" chapter). Since the primary objective is to first terminate the transient, both steam generators should be isolated if there is any doubt which SG is affected.

In either case (one or both SG's isolated), the affected SG will either:

a) stabilize in level and pressure if the overcooling was due to excessive feedwater or isolable steam leak, or

b) continue to lose pressure and level due to an unisolable steam leak.

If a), then controlled decay heat removal can be restored using both SG's (being careful not to unisolate a steam leak). If b), then the SG with the steam leak should be allowed to boil dry while decay heat removal is established with the intact SG.

Once controlled decay heat removal is established, the operator should verify adequate subcooling margin exists and then check for indications of a tube rupture (since the tubes have been stressed by the overcooling). If the affected SG was returned to service, then the check for tube rupture can be made using steam line monitors. If the affected SG was left isolated, then the operator should check for indications of a small break LOCA and continued cooling of the RCS by the isolated SG (due to boiloff of tube leakage). It should be noted that identification of a small break LOCA that is not a tube rupture (e.g., RC pump seals) does not preclude the possibility that a tube rupture also exists. The indentified small break LOCA may mask the presence of a tube rupture. The important point is to ensure that the unisolable steam leak is not a source of radioactivity release that is unknown to the operator. If adequate subcooling margin does not exist he should proceed to Section III.A.

Whenever an overcooling transient has been terminated, the operator should hold RCS temperatures at the existing values. If the RCS were allowed to reheat, the added inventory from HPI could result in a large pressure increase and possibly a full pressurizer.

Summary

The bases for Section III.C can be summarized as follows:

Symptoms:
a) Decreasing T_{cold} and/or SG pressures significantly below the normal post-trip cooldown.
b) Possibly high SG level(s) and feedwater flowrate(s).
c) Low RCS pressure and pressurizer level.

Problems:
a) Thermal stresses on RCS components and SG's (tubes).
b) Possible RCS saturation due to pressurizer drainage.
c) Excessive feedwater flow could result in water carryover into the main steam lines.

Objectives:
a) Prevent loss of subcooling margin due to RCS contraction and drainage of the pressurizer.
b) Terminate the overcooling.
c) Reestablish controlled primary to secondary heat transfer.
d) Stop SG overfill.

Key Points:
a) Comparison of loop T_{cold} temperatures is best method for identifying affected SG before SG isolation.
b) Comparison of SG levels and pressures is best method for identifying affected SG after both SG's are isolated.
c) Severe overcooling can induce tube leaks.
d) The RCS should not be allowed to reheat after the transient is cerminated.
e) Unisolable steam leaks require boiling the affected SG dry to stop the overcooling.

Section III.D: Followup Actions for OTSG Tube Rupture

Several concerns exist whenever indications of a steam generator tube rupture become evident. In addition to being a LOCA, the primary inventory lost through the tube leak cannot be recovered for sump recirculation as it would for other LOCA's. Thus, it is important to cooldown and stop the tube leak before makeup capacity (BWST) is lost. However, it is also important to minimize offsite releases. Therefore, if at all possible, it is desirable to perform a controlled power runback and reactor shutdown at a power level less than the capacity of the TBV's rather than trip the reactor at high power. This prevents lifting of the safety valves on the SG with the tube leak which helps reduce overall releases to the atmosphere. Thus the primary objectives in mitigating a tube rupture are to minimize offsite releases and total tube leakage by performing an orderly but expedient shutdown and cooldown. Opening the TBV's before tripping the turbine and reactor (when power is less than total TBV capacity) will prevent lifting of the main steam safety valves.

Reactor Trip

If a reactor trip should occur or be required because the tube leakage exceeds makeup capacity, then it is important to ensure proper plant response, particularly with respect to steam and feedwater control. If a loss of subcooling margin occurs the RC pumps must be tripped and full HPI initiated. These actions are required for the same reason as in any

small break but, in addition, it is very important with a tube rupture to prevent void formation in the hot legs which could block coolant flow and severely hamper the cooldown rate. It is also very important to terminate excessive heat transfer should it occur. Uncontrolled cooldown could also result in void formation in the hot legs and could overstress the SG tubes resulting in larger leak rates. Thus, if excessive heat transfer is indicated, the operator is directed to Section III.C to correct the condition before continuing in Section III.D.

During the period that the operator is performing the shutdown or stabilizing the plant after a trip, a survey of the steam lines should be made to verify which SG has the tube rupture. It is desirable to isolate the affected SG as soon as possible after primary temperature is low enough to preclude lifting of the main steam safety valves.

Cooldown Methods

Two basic cooldown methods are provided for tube ruptures, designated here as "normal" and "emergency". The method to be used is determined by the tube leak rate and the existing plant status. The differences between the methods are:

	Normal	Emergency
1) Cooldown rate	100F/hr	240F/hr to 500F; 100F/hr below 500F
2) Tube/shell ΔT limit	100F	150F
3) Fuel pin compression limit	Applies	May be violated, if necessary

The factors determining use of the "normal" cooldown method are:

1) Tube leak rate within capacity of makeup system (minimal rate of BWST depletion).
2) Condenser available
3) RC pumps available
4) No unisolable steam leak in the steam generator with a tube rupture

All four conditions must exist to use the normal cooldown. If any one condition is not met, the emergency cooldown method must be used. If, during the performance of the emergency cooldown, all three conditions are satisfied then the normal cooldown can be used. Conversely, if during the performance of the normal cooldown, any one of the conditions is no longer satisfied, then the cooldown must be switched to the emergency method. In either case, the SG with the tube rupture should be isolated as soon as it is identified and T_{hot} is < 540F (to prevent lifting the steam safeties on the SG with the tube leak).

Loss of Offsite Power/RC Pumps Not Running

A loss of offsite power can significantly impact the mitigation of a tube rupture and therefore power should be restored as quickly as possible. While power is unavailable a natural circulation cooldown will be required. It will be necessary to periodically steam the SG with the tube leak during a natural circulation cooldown to maintain loop circulation and avoid hot leg flashing in that loop. Void formation in the hot leg would hamper the cooldown due to the inability to depressurize the RCS (the hot leg would act as a surge volume). With the condenser not

available, steaming of the affected SG would have to be done directly to atmosphere thus increasing offsite releases.

In addition, while RC pumps are not available, RCS pressure reduction must be accomplished using the pressurizer relief. This is a less desirable method since it repeatedly challenges the relief valve, results in additional inventory loss, and may degrade the reactor building environment. The cyclic operation between the subcooling margin and 30F more subcooled than the subcooling margin is a compromise between the need to limit the cycles on the relief valve and the need to maintain as low a pressure as possible to minimize the tube leakage rate.

RC Pumps Running

With RC pumps available, steaming of the affected SG can be reduced to the minimum necessary to keep the steam pressure less than 1000 psig and the level less than 95% on the operate range. This is required to prevent lifting of the steam safeties and atmospheric dump valves (additional release to atmosphere) and to prevent water spillover into the steam lines. Forced circulation will prevent the formation of steam voids in the idle (non-steaming) loop.

RCS pressure control is better with RC pumps and spray available. Therefore, spray should be used as necessary to maintain the RCS pressure as close as possible to the minimum subcooling margin to minimize the leak rate.

Continued Cooldown and Isolation of the Affected SG

The plant is not stable after a tube rupture until the tube leakage has been stopped. This will require cooldown and depressurization and DHRS operation to the point where the RCS can be drained to below the elevation of the tube leak. Therefore, the cooldown should progress as expediently as possible.

Once the affected SG has been isolated, it should only be fed and/or steamed as necessary to maintain steam pressure < 1000 psig and level < 95% on the operate range and to maintain the tube/shell Δ T within the limits. Excessive tube/shell ΔT could result in a higher leak rate due to the increased tensile stress on the failed tube. In addition, as previously stated, steaming of the isolated SG may be required during a natural circulation cooldown to prevent void formation in the hot leg.

Summary

Symptoms:
a) high radiation in steam lines and/or condenser vacuum pump radiation monitor
b) LOCA symptoms (decreasing pressure, unaccountable RCS inventory loss, etc.)

Problems:
a) SG tube rupture/LOCA
b) unrecoverable RCS inventory loss (i.e., not available for sump recirculation)
c) offsite releases

Objectives:
a) minimize offsite releases
b) terminate leakage before BWST depletion
c) maintain core cooling/expedient cooldown and depressurization

Key Points:
a) transient (leakage) not terminated until RCS cooled, depressurized, and drained below tube leak elevation
b) LOOP/natural circulation cooldown will probably result in higher offsite releases due to greater need to steam the affected SG to the atmosphere
c) natural circulation cooldown necessitates use of PORV to reduce RCS pressure

Cooldown Procedures/Inadequate Core Cooling

The objective of these guidelines is to maintain adequate core cooling by terminating transients and stabilizing the plants with controlled decay heat removal. Once stable conditions are achieved, further plant cooldown can be accomplished by existing plant procedures. However, the end conditions at stabilization following the execution of the guidelines will not necessarily coincide with the entry conditions for plant cooldown procedures. Therefore, procedures are provided in Part I to accomplish the transition from the guidelines to the plant procedures. Five cooldown procedures are provided to cover five possible end conditions:

1) Cooldown following a large LOCA
2) Normal cooldown
3) Saturated cooldown with primary to secondary heat transfer

4) HPI cooling

5) Solid plant cooldown/recovery from solid plant with primary to secondary transfer.

A sixth procedure is provided for the special case of Inadequate Core Cooling (ICC). The philosophy and the objectives of the actions for ICC are discussed in detail in the "Backup Cooling Methods" chapter in Volume 1 of Part II.

At the end of the section containing the five cooldown procedures (immediately before the ICC section) are specific rules. These rules are provided in a separate section to avoid repetition throughout Section III of the guidelines. These rules apply wherever they are referenced in Section III. Specific rules are provided to cover:

1) Initiation of HPI

2) HPI flow control

3) Feedwater throttling methods

4) SG level setpoint.

In addition, three figures are provided at the back of Part I for easy reference during the use of the guidelines. These figures provide:

1) HPI flow vs. RCS pressure

2) RV pressure-temperature limits

3) Incore thermocouple temperature for ICC

Operator Aids

In addition to the guidelines in Part I and the training material in Part

II, two other developments of the ATOG program can provide significant assistance to the operator during the mitigation of abnormal transients: the pressure-temperature (P-T) display and the System Auxiliary Diagrams (SADs). The ATOG user should provide for full utilization of these aids in the implementation of the guidelines.

P-T Display

The information required to identify and track the symptoms discussed previously is already available in the control room. However, it consists of discrete displays for reactor coolant system hot and cold leg temperatures, reactor coolant system pressure and steam generator pressure. This format requires mental integration on the part of the operator to quickly assess plant cooling status using individual displays and the steam tables. Thus, the problem is how these variables could best be displayed in real time to give the operator a simple and logical method of monitoring the symptoms of interest. The solution developed in ATOG was the use of a P-T display on a cathode ray tube (CRT). The display continuously shows the primary subcooling margin and the dynamic relationship of the primary to secondary heat transfer. The particulars of the display format and identification of the symptoms is discussed in detail in the "P-T Diagram" chapter. This section will discuss the various functions the display can perform to aid the operator.

Symptom Identification

The primary purpose for developing the P-T display is to provide the means

for the operator to monitor the plant response following a reactor trip or during a forced shutdown to verify normal response and to quickly identify abnormal response should it occur. The "P-T Diagram" chapter describes the normal post trip cooldown of the RCS and the various trends that can develop when the response is abnormal. With the P-T display the operator can quickly recognize the loss of subcooled margin, lack of heat transfer or excessive heat transfer and proceed directly to the appropriate section of Part I to restore plant stability and core cooling.

Response Verification

The P-T display also provides positive feedback to the operator on the response of the plant to his actions. For example, after the loss of subcooling margin, the operator can easily determine the effectiveness of full HPI flow by monitoring the P-T display and determine when to throttle HPI flow if the subcooling margin is restored.

Controlling Within Limits

Certain operations require that the operator control the primary system within specified P-T regions that can readily be displayed on the P-T diagram. For example, the guidelines for a natural circulation cooldown with a tube rupture require maintaining RCS pressure between subcooling margin line and 30F more subcooled than the subcooling margin line. If the operator has the capability to select this 30F curve for display on the CRT (the subcooling margin line is already displayed) then he has a simple, convenient format for monitoring the cooldown and ensuring

compliance with the limits. Many other examples exist, including uses during normal plant cooldowns and heatups (e.g., fuel pin compression limits, NDT limits, etc.).

Power Operation

The CRT format is readily adaptable for displaying plant status information during normal power operation. Some examples for such usage are the reactor protection system pressure-temperature trip envelope (shown in the "P-T Diagram" chapter) and power imbalance envelope. However, if the ATOG CRT is used for these displays, they should be of a secondary nature with the CRT automatically reverting to the ATOG P-T display on reactor trip.

Backup for the CRT

It can readily be seen that the availability of a P-T display improves the flow of information to the operator and enhances the use of Part I. Effort should be made in the implementation of CRT displays to provide high reliability.

However, control room personnel should allow for the possibility that the CRT displays are unavailable when needed. Provisions should be made to facilitate hand plotting of the parameters on a P-T diagram similar to the diagrams depicted herein. Hand plotting is quick enough to provide data which can be used for plant control. The format of the diagram for hand plotting (with the saturation and subcooled margin lines pre-drawn) would allow for trend diagnosis and still be a significant improvement over mental assimilation of discrete data displays.

System Auxiliary Diagrams

System Auxiliary Diagrams (SADs) were developed in the ATOG program to identify supporting systems essential to the operation of systems having direct input to plant response. They also identify instrumentation required to verify proper operation of supporting systems.

The SADs serve as a useful aid in the event that a critical system fails. For example, the operator may be required to initiate HPI. In the highly unlikely event that a total loss of HPI occurs, the associated SAD can be used as a rapid troubleshooting aid to restore HPI operation. The SAD for HPI shows HPI in the center and various arrows pointing toward HPI which identify everything required to make HPI initiation successful. Pump power supplies, required cooling/lube oil sources, major inline valve positions, ventilation cooling, etc., are all identified along with available instrumentation to verify proper operation of the HPI system. Only those items that are within the operators ability to control and can be accomplished quickly are included. Corrections that are longer term (e.g., replacing a pump impeller) are omitted.

Since troubleshooting will be performed by roving operators or maintenance groups, the SADs are packaged separately as opposed to being contained in the ATOG volumes. However, the appropriate SADs are referenced in Part I where applicable. Station management will determine the availability and use of the SADs.

SADs have been developed for the following systems and components:

1. Main feedwater system (loss of flow).
2. Auxiliary Feedwater System (loss of flow).
3. Steam line components (loss of steam pressure).
    a. Turbine bypass valves
    b. Main steam safety valves
    c. Atmospheric dump valves
    d. Turbine controls
4. ECCS Systems (failure to deliver water).
    a. Makeup
    b. HPI
    c. LPI
5. Reactor Building cooling systems (failure to depressurize containment)
    a. Reactor building spray
    b. Reactor building coolers
6. Reactor building isolation (failure to isolate).
7. Chemical addition.
8. Components for RC pressure control
    a. Pressurizer heaters
    b. Pressurizer spray

Rationale for ATOG Development

Plant safety analyses, in the FSAR, define a boundary inside which the plant must be operated to protect the public. If the boundary is approached, the RPS will shut the reactor down; or if a Limiting Condition of Operation (LCO) is exceeded, (i.e., a system would not be operable when needed during a transient), then the operator, if required, will shut the plant down. The rules and regulations that can seem very confusing really boil down to operating the reactor within the boundary of the safety analyses. Further, if the limits of any of the safety evaluation criteria are approached, then the boundary of the safety analysis could be violated and the reactor will be shutdown by RPS or operator action. Therefore, something we cannot see (safety analyses boundary) is translated into observable parameters (RPS trips and LCOs) that the operator can respond to. So, with this model, we can see how the reactor operator responds to the various regulations with respect to plant operations.

We will now take a look at how the plant operator responds to a plant transient with the multiple (event oriented) procedure method.

Let's suppose that a small reactor coolant system leaks occurs (∿15 gpm). Per Section III of T. S., the operator must shutdown the reactor. Further, he will address the emergency procedure called "Loss of reactor coolant/reactor coolant pressure" (LOCA). We will call this procedure EP #1. Now, during the orderly shutdown of the reactor, the leak gets worse and the reactor trips on the variable pressure/temperature trip. At this

point, the operator will address the "reactor trip" emergency procedure. We will call this procedure EP #2. We can see that even in this simple demonstration, the operator ends up in two different procedures at the same time, having started from the same place and treating the same problem. This kind of procedural method is called the event oriented method because the operator takes actions based on triggering events.

Event #1 was the reactor coolant system leak of 15 gpm. Event #2 was the reactor trip. In this kind of system, a multitude of event-triggered emergency procedures are used to identify the appropriate operator action.

The operator must identify the event that has occurred and follow the specified action. The treatment of many problems can require the use of several procedures at the same time. This forces the operator to read many procedures simultaneously and integrate them into useful tools. This should not be required. At TMI-2, the first event that occurred was loss of feedwater (LOFW). This lead to a "reactor trip" (Event #2). The PORV failed open after the initial high RC pressure causing Event #3, LOCA. All of this occurred in 2 minutes.

So now, the operator is forced to address three procedures that are designed to handle different problems and he must do it simultaneously. This type of procedureal method is confusing and inherently defeats concise and efficient handling of transients. Besides being confusing, this method has another weakness. If one defines 100 events and provides

100 emergency procedures, and undefined event 101 occurs, then no procedure is available.

Event Vs Symptom

This brings us to the Abnormal Transient Operating Guideline Program (ATOG). This program was designed to alleviate the multiple emergency procedure method (event oriented) described above and to answer concerns of NUREG-0578. This procedural method is known as a "symptom" oriented approach. We will start our discussion by understanding the difference between an event and a symptom. An event is the cause of a problem and a symptom is the effect of the problem. This can best be understood by looking at some simple examples. Let us consider a small LOCA. The event is the pressure boundary failure and the effect is reduction of reactor coolant subcooling margin. Another example is steam line break. (SLB). The SLB is the event and excessive primary to secondary heat transfer (overcooling) is the symptom. A symptom is more readily discernable than an event. A symptom can be read from some kind of indicator; an event can not.

Symptomatic Approach

ATOG is designed to maintain adequate core cooling subsequent to reactor trips and forced shutdowns. Four symptoms have been identified and must be memorized by the operator. They are:

1. Loss of subcooling margin
2. Lack of primary to secondary heat transfer
3. Excessive primary to secondary heat transfer
4. Steam generator tube rupture.

These symptoms, if treated, will help maintain the integrity of the reactor coolant system and limit the offsite dose rates by keeping the core cooled. In this method (symptomatic), we are concerned with identifying symptoms - not events. So, it doesn't matter what the event was that propagated the symptom, as long as we identify the symptom and treat it. For example, if the seal oil supply unit failed causing loss of H_2 cooling to the generator, a turbine trip could occur caused by high stator temperature. Assume that in the ensuing transient a main steam relief valve fails to reseat properly. Even though loss of seal oil supply is not a defined event, a symptom (overcooling) will occur. Therefore, the operator identifies the symptom and treats it. This approach is indeed a symptom oriented one where no matter what event challenges the system, the operator will identify a symptom that arises and maintain core cooling. So, then, the problem of defining events goes away because this system can handle an infinite number of events. Events that have <u>not been foreseen or analyzed</u> have been brought into the scope of identification (symptom) and hence treatment. At some time, the operator will still have to recognize what failures have occurred in order to correct the problem that caused the symptoms.

Single Procedure Method

One of the goals of ATOG stated above is to alleviate the confusion caused by the muliple emergency procedure method. You may already see how this is inherently so by having one procedure which addresses the four symptoms.

After the operator identifies either an LCO violation (forced shutdown) or the RPS trips, he needs to address only one procedure no matter what the event was that caused the symptom. You can see how this eliminates the confusion of having to address a myriad of procedures.

Application of ATOG Method

Now that we have seen how the symptom oriented ATOG works from a conceptual point of view, let's take a more practical look at it by applying it to the TMI-2 occurrence. The first thing that happened was a complete loss of feedwater causing an RCS pressure escalation resulting in reactor trip and subsequent failed open PORV (LOCA).

When the LOFW occurred, some plant parameters approached their boundary due to rising reactor coolant pressure.

The RPS tripped the reactor at this point and the parameters began to return to normal. However, the PORV failed open (LOCA) causing RC pressure to drop (DNBR concern).

Once again, some plant boundaries were approached but now the ECCS started and began to return the parameters to normal. Then an error was made and the ECCS was turned off. The parameters again approached their boundary and indeed violated it resulting in fuel cladding failure. The violation was caused by exceeding an LCO (ECCS system operable). After this, no other defined event occurred to key the operator that an error was made and the reactor system was in trouble.

Applying the symptom oriented approach to this scenario results in a different outcome. Inherent in ATOG is a self-diagnosing feature. The operator is trained to identify the four symptoms and is directed to do so by ATOG in a reccuring way. Therefore, a symptom will not go unnoticed even if the symptoms change or are delayed in their appearance.

When the ECCS was secured at this point, the symptom, inadequate subcooling margin, would appear. As long as a symptom exists certain actions will be taken. In the case of inadequate subcooling margin, the operator is directed to start the ECCS. At this point, the operator would realize his mistake and initiate the ECCS. In this way, ATOG can handle any unforeseen and unanalyzed events that are of a lesser magnitude than the design basis events used to generate the safety analysis boundary.

Analysis Incorporated Into Procedure

ATOG has incorporated into it transient analysis performed by B&W. This transient analysis differs from earlier analysis in that it looks at events that are lesser in magnitude than design basis events and looks at them for a longer period of time in various degraded modes. This provides operational guidance in areas not previously looked at. This background analysis has been prepared in such a way as to be compatible with operator training. It includes easily understood writing and illustrations that will lend themselves readily to the plant training programs.

Operator Aids

Three basic symptoms of abnormal heat transfer can be detected by evaluating primary and secondary system pressures and temperatures. Loss of subcooling will be indicated by the saturation margin meters and by the relationship between system pressure and hot leg and incore thermocouples. Excessive heat transfer is indicated by cold leg temperature, and lack of heat transfer is reflected by hot leg and incore thermocouples and the relationship between steam generator pressure and cold leg temperature.

An integrated plot of these parameters provides an alternate display which can aid in this diagnosis. Plots of primary pressure vs hot leg temperature and steam generator pressure vs cold leg temperature produce trends which are characteristic of normal plant response or which reflect the abnormal heat transfer conditions which exist. This pressure-temperature plot, either hand drawn or automatically displayed on a CRT, supplements

the existing control room instrumentation as a real-time monitoring and diagnositic aid.

Normal Vs Abnormal

The name "Abnormal Transient Operating Guideline" implies that a condition of abnormality has been considered. This is indeed so and a condition of normal parameters has been outlined on the CRT display. So, when the RO views the CRT subsequent to a reactor trip and sees that the prescribed parameters are within the normal envelope, he immediately knows that the transient was normal. If, however, the parameters are not within the normal envelope, the transient has been abnormal and ATOG will guide the operator to successful mitigation of the occurrence and recovery to stable, safe conditions.

BABCOCK & WILCOX
NUCLEAR POWER GENERATION DIVISION

TECHNICAL DOCUMENT

THREE MILE ISLAND

UNIT I

ABNORMAL TRANSIENT OPERATING GUIDELINES

PART II

VOLUME 2

74-1124158-00

Doc. ID – Serial No., Revision No.

for

GENERAL PUBLIC UTILITIES

By

BABCOCK & WILCOX

THIS DOCUMENT WAS PREPARED FOR GENERAL PUBLIC UTILITIES UNDER MASTER SERVICE CONTRACT NO. 582-7105 (B&W No. 582-7108). ANY USE OF THE INFORMATION CONTAINED HEREIN OTHER THAN UNDER THE EXPRESS CONDITIONS OF SAID CONTRACT IS EXPRESSLY PROHIBITED WITHOUT THE WRITTEN PRERMISSION OF THE BABCOCK & WILCOX COMPANY.

DISCUSSION OF SELECTED TRANSIENTS

INTRODUCTION

To develop the ATOG approach to integrated plant transient control six initiating events were studied. The results of these studies are given as examples:

1. Excessive Main Feedwater
2. Loss of Main Feedwater
3. Steam Generator Tube Ruptures
4. Loss of Offsite Power
5. Small Steam Leak
6. Loss of Coolant Transient (LOCA)

These events show how the procedures of Part I are applied to specific transients and they amplify the general guidance given by the first volume of Part II. After reviewing these individual transients in detail, the operator should be able to see that regardless of (1) the initial event, (2) whether or not he can immediately identify the initial event or, (3) how many additional failures occur, he can keep the core and the plant in a safe condition by following Part I of these guidelines.

Each appendix discusses the plant designed response to its initiating event and, if available, gives an example of an actual transient. The discussion points out what operator actions are required and how Part I directs the operator to those actions.

Next is a review of the initial event compounded with other equipment failures. These are generally broken down into the failures of the fundamental methods of heat transfer control that are important to that event. Again the appropriate operator actions for that particular sequence of failures are given. Part I is referenced so that the operator can see how the basic procedure covers many multiple failures.

Each appendix contains a logic diagram which is a summary sheet for the transient being discussed. It is a simplified event tree which has been modified to show how correct operator actions will influence the outcome of the transient. The central vertical block diagram is the initiating event without additional failures. The failure paths branch out to the right and the left. The details on the diagram show identifying symptoms, including P-T, the corrective actions, and the limits to be considered for each additional failure that might occur. References are made to the appropriate parts of Part I and Part II. Nearly every kind of plant condition is covered either in the initiating event path or in the branches. Even if the initiating event is different from the examples, the principles to be used are the same, and therefore these examples illustrate how various other plant conditions can be handled.

Plots of various parameter trends are also provided. The times can only be approximate because they vary with such things as decay heat, initial power level and the size of the leak involved. However, they will give the operator a feel for the timing involved in these transients.

The operator should give special attention to the sections on LOCA and steam generator tube rupture because very detailed information has been prepared for these two events.

ATOG GUIDELINES

PART II VOLUME 2

Title		Tab Name
Introduction		
Appendix A	Excessive Main Feedwater	EXCESSIVE MFW
Appendix B	Loss of Main Feedwater	LOSS OF FW
Appendix C	Steam Generator Tube Ruptures	SGTR
Appendix D	Loss of Offsite Power	LOOP
Appendix E	Small Steam Leak	STEAM LEAK
Appendix F	Loss of Coolant Accidents	LOCA

VOLUME II DISCUSSION OF SELECTED TRANSIENTS

LIST OF FIGURES

FIGURE NUMBER	TITLE
A-1	Excessive Feedwater Terminated by ICS
A-2	Excessive Feedwater Not Terminated by ICS
A-3	Actual Plant Response During an Excessive Main Feedwater Transient (RCS and Feed Flow Parameters)
A-4	Actual Plant Response During an Excessive Main Feedwater Transient (Steam Generator Parameters)
A-5	Typical Excessive Feedwater Transient
A-6	Time Relationship of Key Parameters
A-7	Excessive Feedwater Logic Diagram
B-1	Loss of Feedwater (Initial Stage)
B-2	Loss of Feedwater (Mid Stage)
B-3	Loss of Feedwater (Final Stage)
B-4	Time Relationship of Loss of Main Feedwater with Failures
B-5	Loss of Feedwater Logic Diagram
C-1	Deleted
C-2	Typical System Response for Large SGTR Which Results in a Reactor Trip
C-3	Steam Generator Tube Rupture Logic Diagram
C-4	RCS Cooldown Using PORV
D-1	Loss of Offsite Power - 2/22/75 Loop A RC Temperatures vs. Time
D-2	Loss of Offsite Power - 2/22/75 Loop B RC Temperatures vs. Time

FIGURE NUMBER	TITLE
D-3	Loss of Offsite Power - 2/22/75 Loop A Pressure vs. Time
D-4	Loss of Offsite Power - 2/22/75 OTSG Full Range Level vs. Time
D-5	Loss of Offsite Power - 2/22/75 OTSG Steam Pressure vs. Time
D-6	Loss of Offsite Power - 2/22/75 Steam Pressure vs. Time
D-7	Typical Parameter Trends for LOOP
D-8	Typical Parameter Trends for LOOP/Loss of Secondary Inventory Control (Low)
D-9	Loss of Offsite Power Logic Diagram
D-10	Typical Loss of Offsite Power P-T Response
E-1	Small Steam Leak
E-2	Typical Small Steam Line Break Transient
E-3	Time Relationship of Key Parameters
E-4	Small Steam Leak Logic Diagram
F-1	Fluid History During a Large Break
F-2	System Response for Large Break in Cold Leg Piping
F-3	System Response for Large Break in Hot Leg Piping
F-4	Typical System Response During Flow Circulation Phase of a Small Break
F-5a	System Response for Small Break Which Continually Depressurizes the RCS (0.5 ft^2 Break in Cold Leg Pipe)
F-5b	System Response for Small Break Which Continually Depressurizes the RCS (0.1 ft^2 Cold Leg Break)

FIGURE NUMBERS	TITLE
F-6	System Response for Small Break Which Stabilizes At Secondary Side Pressure
F-7	System Response for Small Break Which Repressurizes in a Saturated State
F-8	System Response for Small Break Which Depressurizes the RCS Without Feedwater
F-9	System Response for Small Break That Stabilizes at High RCS Pressure Without Feedwater
F-10	System Response for Small Break That Repressurizes If Feedwater Is Lost
F-11	System Response for Small Break Within Pressurizer Steam Space
F-12	Post LOCA Corrective Action for Lack of Adequate Subcooled Margin
F-13	Post LOCA Corrective Action for Lack of Primary to Secondary Heat Transfer

VOLUME 2 DISCUSSION OF SELECTED TRANSIENTS

LIST OF TABLES

Table Number	TITLE
C-1	Ways to Detect a SGTR
C-2	Deleted.
C-3	Effects of Failures on Steam Generator Tube Leak Control
F-1	General Post-LOCA Corrective Action to Maintain Core Cooling
F-2	How to Distinguish LOCA's from Other Transients
F-3	Summary of General LOCA Symptoms
F-4	Symptoms for LOCA's That Can Be Located or Isolated
F-5	Summary of Long Term Cooling Actions

EXCESSIVE MFW

APPENDIX A

EXCESSIVE MAIN FEEDWATER

1.0 GENERAL TRANSIENT DESCRIPTION

Excessive main feedwater is a failure to control secondary inventory. It is an overcooling transient that results in too much primary to secondary heat transfer and without proper operator action, can result in steam generator overfill.

Excessive main feedwater is defined as the sustained addition of more water to the steam generator than can be boiled off by the available core heat to make superheated steam. This mismatch between heat source and heat sink will cause the steam generator level to rise and will cool the reactor coolant down. The severity and rapidity of the transient will vary with the size of the mismatch. Under worst case conditions (i.e., maximum mismatch) the excessive main feedwater flow must be terminated within two minutes to prevent water spillage into the steam lines. Thus, this is a transient that may require fast operator action.

As the reactor coolant temperature decreases, the RCS water volume will shrink, dropping pressurizer level. This in turn causes RCS pressure to drop. In the secondary side, while at power, the excessive feedwater will cause a loss of superheat and may cause a slight reduction of steam pressure. A reactor trip may occur on low pressure or high flux. If a trip occurs and the excessive

feedwater continues, the mismatch will be much larger (less core heat) and the steam generator fill rate and RCS cooldown rate will increase. If the shrinkage of the RCS water volume is sufficient to drain the pressurizer, the RCS will rapidly approach saturation conditions and ESAS will actuate. A loss of subcooling margin will require that the RC pumps be tripped and EFW be started. EFW flow will make the overcooling of the primary system worse. However, EFW flow can be throttled to obtain a gradual increase in SG level and thereby limit the overcooling. If the loss of subcooling margin is caused only by the overcooling, it will be temporary. When the subcooling margin is restored, HPI can be throttled and RC pumps can be restarted.

If the excessive addition of feedwater to the steam generator is not stopped, water will spill into the steam lines. The GPU analysis indicates the steam system will maintain its integrity with water spillage. Nevertheless, it is very desirable to terminate the feedwater transient before spillage occurs. In addition, it is highly desirable to stop the RCS cooldown before the pressurizer is drained and ESAS actuates. This will significantly reduce the magnitude of the transient and number of operator actions required, as well as limit challenges of protection systems and allow for quicker recovery to stable plant conditions.

In general, main feedwater overfeed can happen in four ways:

1. A failure of the Feedwater Control System to run back after reactor trip.
2. An operator error of feedwater control while in manual.
3. Equipment failure when the plant is in automatic operation.
4 Improper ICS tuning.

Excessive feedwater can occur at any time the main feedwater system is in operation. The plant may be tripped or at power. The steam generators will fill at different rates depending on what the plant power level is when the high flow begins. The rate of fill of the generator will be greater when the reactor is at low power (or tripped) than at high power. The overcooling effects on the reactor coolant system will be greater at low power. The reasons are that at low power less core heat exists to boil off the additional feedwater and the feedwater system (valves and pumps) has a lot of capacity left to overmatch the low reactor power. At full load, the valves and pumps are near full capacity and cannot open much more to increase feed flow.

Because the effects of excessive feedwater are different across the power range and because it can be caused by different failures, the rate of the Reactor Coolant System response will be different depending on what has happened. But all excessive feedwater additions will look similar.

The P-T curve and sequence of events shown in Figure A-1 depict a typical main feedwater transient that is terminated by the ICS before water enters the steam lines or the pressurizer is drained. The transient shown is also applicable if terminated early by the operator.

The P-T curve and sequence of events shown in Figure A-2 depict an excessive main feedwater transient that is not terminated before water enters the steamlines or before the pressurizer is drained. The transient is initiated by a reactor trip from 100% power with a failure of feedwater to runback on the A steam generator.

Several important points should be noted regarding this transient:

- The affected steam generator can fill very rapidly, in this case approximately two minutes after the reactor trip. Thus, if the failure causing the excessive feedwater condition is not corrected by the ICS, the operator has little time available to prevent spillage into the steam lines.

- If the subcooling margin is lost, the operator is required to trip the RC pumps and raise OTSG levels to 95% on the operate range with EFW. The additional cooling from EFW would worsen the transient.

However, the operator should throttle EFW flow to obtain a gradual level increase. (See Part II, Chapter E "Best Methods for Equipment Operation".)

- Excessive MFW flow to OTSG A was allowed to continue for almost two minutes after the steam generator was full. Thus a significant quantity of water was spilled into the steam lines.
- Even though the ESAS started HPI before the pressurizer was empty, the HPI flow was not sufficient to overcome the shrinkage due to the cooldown and the pressurizer was drained.
- Once the overcooling transient has been terminated, the RCS will reheat and the water volume will swell. Since a large quantity of cold HPI water was added to the RCS, the operator must act to prevent the pressurizer from going solid. This will be discussed in more detail later.
- The overcooling transient and affected steam generator, for this large of a feedwater mismatch, should be quickly obvious after trip by checking feedwater flowrates, SG levels, and noting the divergence in plots of T_{cold} vs. steam pressure.

Actual Plant Excessive Feedwater

On 3/18/77, an excessive feedwater transient occurred at an operating plant. The transient was not serious and the plant ended in a good condition because the operator recognized what was going on and took control quickly and the excessive feedwater was terminated automatically by the ICS after reactor trip. The steam generator did not fill and spill water into the steam lines; that is the most important limit for this transient. The operator also turned HPI on and prevented the pressurizer from draining and that is another important limit. Because the cooldown was stopped early in this transient, the operator did not have to take drastic action to prevent filling the pressurizer solid due to reactor coolant reheating. After trip, the HPI flow was throttled.

The plant was operating at 75% in a power escalation sequence. Because of the power escalation sequence, the overpower trip setpoint was set at 85%. The overfeeding started because main feedwater pump "A" failed and went to full speed.

The plant data shows main feedwater abruptly increasing to full flow on generator "A" and within about 30 to 45 seconds, its affects appear in other signals: "A" generator level goes up, Tav drops (because of the increased heat transfer), pressurizer level drops (because of shrinkage due to lowered Tav), and RC pressure lowers (because of the lowered pressurizer level). These

parameters are shown in Figures A-3 and A-4. When Tav began to drop, the ICS pulled rods to try and keep temperatures steady. The operator sensed the change in plant conditions almost immediately and quickly diagnosed the problem and took the appropriate action. He tried to cut back feed flow. He did this by manually reducing the feedwater demand; this did not work (more about this later). He then put rod control into manual to try to raise Tav, and he also started HPI to stabilize the pressurizer level. The reactor then tripped at 85% power because of the low overpower trip setting. When the reactor tripped, the ICS BTU limits ran feedwater back and controlled the feedwater on level; because of the high steam generator level, the "A" startup feedwater valve closed stopping the excessive feedwater transient. The "B" generator startup valve controlled to maintain the "B" OTSG level after trip. When the plant tripped, the large inventory of cold water in the "A" generator cooled down the reactor coolant considerably (illustrating the effect on core heat removal due to the boil-off of the extra inventory in the generator). The reactor steam generator heat transfer interplay is shown well by this example. After the trip, the reactor pressure increased and the pressurizer level increased; this is largely due to HPI.

A look at steam pressure (Figure A-4) shows a very slight reduction (before trip) because of the cooling and condensing effect of the excessive feedwater on the steam in the generator.

This illustrates the magnitude of steam pressure loss to be expected because of excessive feedwater; a greater loss would indicate an additional failure that the operator would have to correct. The reason "A" pressure is lower than "B" after trip is mostly because of one mis-set safety valve; the water in the generator would have some pressure reduction effect, but it would be small. The lower steam pressure did have some effect on overcooling, but because it was only about 100 psi low, the effect was small.

This steam pressure loss was mostly an inconvenience; if it had been greater (about 200 psi), the pressurizer could have drained.

When the transient was over, the "A" steam generator was about half full. It took about two minutes to increase the level about 200 inches; most of the filling took place before trip when a high reactor power (75% to 85%) was available to boil the water off. The steam generator level increase was about 150" during this time (or about 3/4 of the total increase). If a main feedwater failure had occurred after trip, the rate of level rise would have been much faster. Excessive feedwater is probably the one transient the operator must react to faster than any other transient. The steam generator can fill and water can spill into the steam lines in as little as 2 to 4 minutes (after trip). The operator must

act fast to stop feedwater and the equipment he chooses to use is important. He should understand that the equipment he elects to use may be the component that failed causing excessive feedwater and therefore may not respond. Thus he must be prepared to switch to an alternate device if necessary to terminate feed flow.

When the operator tried to correct this transient, he made the right choice of action: cut back feedwater. But the equipment he used did not respond. He used the ICS feedwater demand to try to run back the feed pump and valves. A post trip review showed that the feedpump controller had failed. It was essentially dead, and no signal would have made it respond. The Main Feedwater System is complex. About 20 different equipment failures (operator error with the feedwater control in manual can also happen) could result in an excessive feedwater transient. The ICS can have several failures. The transient can be too fast to try to figure out what failure has occurred. Therefore, the best way to correct a very fast overfill is to use the direct controls to trip both main feedwater pumps. Adequate time will be available to regain MFW or EFW to at least one SG.

Tripping both MFW pumps is the fastest method to stop excessive MFW flow and should prevent water entering the steam lines for even the most severe MFW transient. However, for much slower fill rates, or if a pump should fail to trip, the operator should

isolate feedwater to the SG with the high, increasing level by closing the MFW control and isolation valves.

Figures A-3 and A-4 show actual plant data from the above transient. Note the large disparity between levels and feedwater flowrates for the two steam generators . This magnitude of mismatch should, and did, facilitate rapid recognition and response by the operator.

2.0 OPERATOR ACTIONS SUMMARY

Immediate Actions

- Attempt to close feedline isolation valves if the overfill is slow and the affected generator is obvious.
- Trip running MFW pumps to stop fast overfills.
- Start EFW and verify operation; control EFW to limit overcooling.
- Increase MU flow to the RCS if pressurizer level is less than 100" and RCS pressure is decreasing.
- Follow remainder of Part I, Section III.C.

Identifying Symptoms

- Excessive feedwater is an overcooling transient as shown in Figure A-5.

- Other identifying symptoms to distinguish excessive feedwater from other overcooling transients are:
  - High steam generator level
  - High main feedwater flowrate

NOTE: Rapid excessive feedwater transients, e.g., large MFW flowrate after reactor trip, will result in the pressure being in a near-drained condition by the time T_h/pressure exceed the overcooling boundary. Drainage and RCS saturation will occur very quickly after the overcooling boundary is exceeded (dotted path in Figure A-5) and water will enter the steam lines. Therefore, it is very important that the operator recognize the overcooling transient before the overcooling boundary is exceeded by checking MFW flowrates and SG levels. He should discover that excessive feedwater is in progress in Step 5.0 of Part I, Section II, "Vital System Status Verification".

The previous section discussed some of the many possible examples for excessive main feedwater transients. However, it can be seen from that discussion that the primary transient of concern is the rapid filling of a steam generator that is not automatically terminated early by the ICS. SLRDS actuation will occur too late to prevent water in the steam lines and drainage of the pressurizer and

may occur on the "good" steam generator only. Therefore, such a transient requires rapid response by the operator. In addition, the operator must exercise caution whenever feedwater is in manual control to prevent large feedwater mismatches from developing. Historically, oversights while in manual control have been a significant contributor to the frequency of excessive feedwater transients.

This section will discuss how operator actions in accordance with Part I will terminate the overcooling transient and provide recovery to stable shutdown conditions. The assumed transient will be the same as that used for the second transient discussed in the previous section. A reactor trip occurs (for whatever reasons) and the ICS fails to close the feedwater valves for the "A" steam generator and thus allows a continuous excessive feedwater flow to that generator on the order of 5×10^6 lbm/hr. This transient was selected because the ICS will not correct the excessive feedwater addition and the "B" MFP will continue to provide flow to the "A" steam generator longer if uncorrected since water in the "A" side steam lines will not affect operation of the "B" MFP turbine.

After performing the immediate actions of Part I, Section I, the operator will verify vital system status in accordance with Section II. Step 5.0 of Section II requires the operator to verify that feedwater has runback. He should check steam generator levels and

feedwater flow rates and note that level and flow for the OTSG "A" are high. The corrective action noted is to trip the running feedwater pumps and verify proper operation of the EFW system. These actions will terminate the excessive feedwater and return the plant to stable conditions.

However, for illustrative purposes it is assumed the operator fails to note the abnormal conditions at this time. Step 11.0 of Section II requires the operator to verify that primary to secondary heat transfer is not excessive. The operator should note by RCS response on the P-T diagram that an overcooling transient is in progress and therefore primary to secondary heat transfer is excessive. He does not need to concern himself at this time whether the overcooling is due to excessive feedwater or loss of steam pressure control. The procedure directs him to Section III.C (Excessive Heat Transfer) of Part I.

Step 1.0 of III.C requires the operator to increase MU if pressurizer level goes below 100" and RCS pressure is decreasing. While full HPI flow will not maintain pressurizer level during this magnitude of shrinkage due to overcooling, it will slow down the rate of pressurizer level decrease and provide additional time for the operator to terminate the overcooling transient before the pressurizer drains (see Figure A-6).

If it is obvious which steam generator has excessive feedwater, the operator will isolate that generator and will terminate the transient. He can then restore FW to the isolated steam generator while controlling DH removal with the good steam generator. The affected steam generator may be obvious by observing MFW flowrates and SG levels. In addition, if the overcooling is severe, T_{cold} in the affected loop may be significantly lower than T_{cold} in the unaffected loop with divergent steam pressures (see Figure A-2). Divergent steam pressures alone will not conclusively identify the affected OTSG but a significantly lower T_{cold} will. If it is not obvious which steam generator is causing the overcooling, the operator will isolate both SG's and monitor levels and pressures to determine the affected SG.

In this case, OTSG "A" level is high indicating excessive feedwater had occurred. Therefore the operator will restore FW and controlled primary to secondary heat transfer. Maintaining RCS temperature at the present value by lowering the TBV setpoint will prevent filling the pressurizer solid due to RCS reheating and swell and is especially important since RCS inventory has been increased due to HPI. However, HPI is still in progress and should be throttled or stopped when the Subcooling Margin is satisfied. Establishing EFW flow to maintain OTSG levels will restore stable primary to secondary heat transfer.

If the operator follows the guidelines in an expeditious manner and performs the actions such that MFW is isolated within one to two minutes following reactor trip, he will probably prevent water entering the steam lines and drainage of the pressurizer. In fact, the RCS will probably stay within the overcooling line and recovery to stable shutdown conditions can be quickly achieved. If, however, the cooldown is allowed to continue to the point of pressurizer drainage, the RCS will rapidly approach saturation conditions and further operator actions and precautions are in order.

When the subcooling margin is lost the operator will trip the RC pumps, start full HPI, verify EFW initiates and begin to raise SG levels if the overcooling condition has not yet been recognized. For this particular transient these actions will worsen the overcooling by removing pump heat input and adding cold EFW (decreasing the heat source and increasing the heat sink). However, the operator should immediately throttle EFW flow to obtain a steady, gradual increase in SG level thus minimizing the overcooling due to EFW. (See "Best Methods for Equipment Operation" in Volume I of Part II, Chapter E).

With EFW throttled steam pressure should not decrease significantly. By this time the operator should recognize the overcooling transient. He will follow Section III.C of Part I and terminate the excessive MFW.

With the overcooling transient terminated, HPI flow will overcome the shrinkage of the RCS and rapidly recover RCS pressure and pressurizer level. The operator must again respond to prevent HPI refill, and reactor coolant swelling due to reheating, from filling the pressurizer. He should perform the following actions:

- Lower the TBV setpoint to a value near the corresponding saturation pressure for the existing cold leg temperature. This will limit RCS heatup and thus limit the resultant swell of the RCS inventory.
- Throttle HPI as soon as the subcooling margin is regained. This action will reduce the injection rate and allow a more gradual, stable recovery of pressurizer level. Throttling should be accomplished by using one HPI pump (preferably the normal makeup pump).
- When pressurizer level returns on-scale low (with the RCS above the subcooled margin) and is increasing above 100" the operator should terminate HPI and realign for normal makeup/letdown operation.
- If desired, the operator can return the plant to normal post-trip conditions by gradually increasing the TBV setpoint and regulating RCS pressure with makeup, letdown, and pressurizer heaters. He should also restart two RCP's once the subcooling margin is restored.

NOTE: Overcooling transients that result in a large decrease in pressurizer level may have a relatively long-term impact on RCS pressure control after the transient is terminated. The insurge due to HPI and RCS reheat and swell will cause pressure to increase due to compressing action but may leave the pressurizer with a large volume of subcooled water. This can cause pressure to settle out at a lower value and it will take some time for the pressurizer heaters to restore saturated conditions at a higher pressure. Subsequent outsurges during this time will have a larger than normal pressure reduction effect due to the lack of saturated water available to flash to steam.

The excessive feedwater transients discussed herein all involve a reactor trip. If a feedwater excursion occurs while at power that does not result in an automatic reactor trip, the operator should attempt to locate the failure causing excessive feedwater and correct it while at power if possible. A manual reactor trip at this time would result in a much larger mismatch between heat source and heat sink and thus make the transient more severe.

3.0 EXCESSIVE MAIN FEEDWATER WITH OTHER PLANT FAILURES

Introduction

The previous section described excessive main feedwater in general, but did not discuss other failures that might also happen at the same time. This section will show what symptoms to look for when other equipment fails and will show what steps the operator should take to restore the heat transfer from the core to the steam generators. The event that was chosen for simulation starts with the reactor at 100% power; a failure in the feedwater system allows main feed to run away in one generator; automatic ICS corrective action to control main feedwater does not happen; the plant is tripped automatically on high flux or low pressure, and excessive feedwater continues. All the data that is shown starts from the time of plant trip.

Remember that all feedwater transients will not start from high power. They may look different than the examples used. The reason for these examples is to provide understanding, so close study of the effects is required.

Branch Discussion

Figure A-7 has separate failure branches for loss of reactor coolant inventory control (high and low), loss of secondary inventory control (high and low), and loss of secondary pressure control. Significant failures in RC pressure control, such as those due to overcooling or excessive HPI, are adequately covered by these branches; therefore separate branches specifically for loss of RC pressure control are not shown. Minor failures, such as loss of pressurizer heaters, are discussed at the end of the main transient path. This section will discuss each of these additional failure branches and illustrate how operator actions in accordance with the procedures in Part I and with the "Best Methods for Equipment Operation" in Part II, Chapter E, will restore proper control of the parameter in question.

These branches are structured to address the particular function failure in question even though the excessive feedwater transient may still be in progress. However, since some additional failures result in further overcooling of the RCS, actions to correct such failures may also correct the excessive feedwater condition. In any case, it should be understood that Figure A-7 and this discussion

are provided as tools to promote familiarity with expected plant responses. Another valuable tool to facilitate operator recognition and identification of overcooling transients is Figure 22, "Overcooling Diagnosis Chart," in Volume 1, Part II, Chapter C. The operator should become familiar with this chart.

Figure A-6 is provided to show key distinguishing parameters for excessive main feedwater that have a time dependency important to the operator in identifying both the type and severity of transient. The parameter plots show typical responses to a large excessive main feedwater transient. Arrows, where used, show the effect of other failures and operator actions on the time relationship.

One item of particular note on Figure A-6 is the effect of large excessive feedwater transients on steam pressure in the unaffected generator. The pressure is reduced because the primary system has been cooled so rapidly that the unaffected SG becomes, temporarily, a heat source and loses heat (and thus pressure) to the primary system.

Loss of Reactor Coolant Inventory Control (High)

A loss of reactor inventory control (high) exists whenever makeup or HPI flows are excessive causing the pressurizer to fill and overpressurizing the RCS for the existing plant conditions. Severe excessive feedwater transients involving large mismatches between feed

flow and primary heat input will result in RCS cooldowns and shrinkages that cannot be compensated for by full HPI flow. Thus, while the excessive feedwater transient is in progress, pressurizer level will continue to drop, although full HPI flow will slow the rate of level drop. This can be seen in Figure A-6 where manual initiation of HPI when the subcooling margin is lost shifts the curves for RCS pressure and pressurizer level to the right, i.e., more time is available before pressurizer drainage occurs. However, for smaller feedwater transients, and when the excessive feedwater has been terminated, full HPI flow will more than compensate for the coolant shrinkage and result in a rapid increase in pressurizer level and RCS pressure. Rapid operator response will be required to prevent a solid pressurizer and RCS overpressurization.

The operator should perform the following actions to restore proper RCS inventory and pressure control:

1) Throttle HPI as soon as the subcooled margin is restored and RCS pressure is increasing. Throttling should be accomplished using one HPI pump (preferably the normal makeup pump).
2) If the RCS is reheating and thus swelling, lower the TBV (or ADV if the TBV's are isolated) setpoint to a value near the corresponding saturation pressure for the existing cold leg temperature. This will stop the RCS heatup and swell. If

desired, the operator can then gradually increase the setpoint to allow a gradual heatup while controlling pressurizer level.

3) When pressurizer level returns on-scale low (with the RCS above the subcooled margin) and is instructed above 100", the operator should terminate HPI and realign for normal makeup/letdown operation.

NOTE: Throughout Part I the operator is instructed to throttle HPI as soon as the subcooling margin is restored and to reduce TBV or ADV setpoints to maintain RC temperature. Thus, adhering to these guidelines will prevent a loss of RCS inventory control. This is discussed in more detail in Volume 1 of Part II, Chapter E., "Best Methods for Equipment Operation."

Loss of Reactor Coolant Inventory Control (Low)

A loss of reactor inventory control (low) exists whenever makeup or HPI flow is insufficient to overcome a primary leak rate or the coolant contraction rate, resulting in drainage of the pressurizer. As stated previously, full HPI flow will be insufficient to maintain pressurizer level during severe excessive main feedwater transients, but will rapidly refill and repressurize the RCS once the overcooling is terminated.

If the overcooling is terminated before the pressurizer empties, the RCS will reheat and the resultant swell will restore pressurizer level. If the overcooling continues, ESAS will actuate and HPI will initiate. If the subcooling margin is lost, the operator will trip the RC pumps and EFW will start.

Control of EFW to attain and maintain 95% level on the operate range will provide adequate core cooling (refer to boiler condenser cooling in Chapter D of Volume 1) while the problem with HPI is being corrected. The operator should throttle the EFW flowrate to obtain gradual SG level increases and limit further overcooling.

Following the actions specified in III.A of Part I will restore primary system inventory control and subcooled margin.

Loss of Secondary Inventory Control (High)

A loss of secondary inventory control (high) due to excessive EFW is very similar to the main initiating event covered in this section (excessive main feedwater). However, there are basic differences in definition and plant response. Excessive EFW can occur simultaneous with excessive MFW or after excessive MFW has stopped.

Whenever EFW initiates it will provide more flow than can be boiled off and is needed to raise SG levels to the appropriate setpoint in a controlled manner. However, if the rate at which EFW builds SG levels is excessive the primary system will be overcooled.

Excessive emergency feedwater will depressurize the affected SG to a much larger extent than excessive main feedwater. This is due to the condensing action introduced by spraying EFW in near the top of the tube bundle (into the steam space) and due to the lower EFW temperatures.

Thus, even when the EFW system performs as designed, it can cause overcooling of the primary system, particularly when achieving the natural circulation level setpoint (50% operate range) with low decay heat. Therefore, the operator should throttle EFW to obtain a gradual increase in SG levels and to maintain SG pressures. This will minimize the overcooling effects on the primary system. This action should only be required when the natural circulation setpoint is in effect since EFW cannot cause significant overcooling while attaining the low level setpoint for forced circulation.

Should EFW flow control fail, the operator should recognize the overcooling as well as high EFW flow and SG level higher than the appropriate setpoint. Following the actions in Part I, Section III.C for excessive primary to secondary heat transfer will terminate the excessive EFW. III.C requires the operator to close the EFW regulating valves. The operator should not restore EFW to the generator with high level until the failure causing excessive EFW has been identified and corrected. Restoration of EFW to the "good" generator will provide DH removal. The operator should assure that at least one motor-driven pump and the turbine-driven pump are aligned to feed the good generator.

Figure A-6 shows the impact of excessive main feedwater overcooling compounded by overcooling due to excessive EFW. The curves for RCS pressure and pressurizer level will shift to the left, i.e., pressure reduction and drainage of the pressurizer will occur faster.

Loss of Secondary Inventory Control (Low)

A loss of secondary inventory control (low) exists whenever too little feedwater is being supplied to the steam generators resulting in too little primary to secondary heat transfer and overheating of the RCS. Should a total loss of both main and emergency feedwater subsequently occur, the operator will have more time available

for corrective actions due to initial SG inventory increase caused by the excessive main feedwater transient. A detailed discussion is provided in Appendix B, "Loss of Main Feedwater".

Loss of Steam Pressure Control

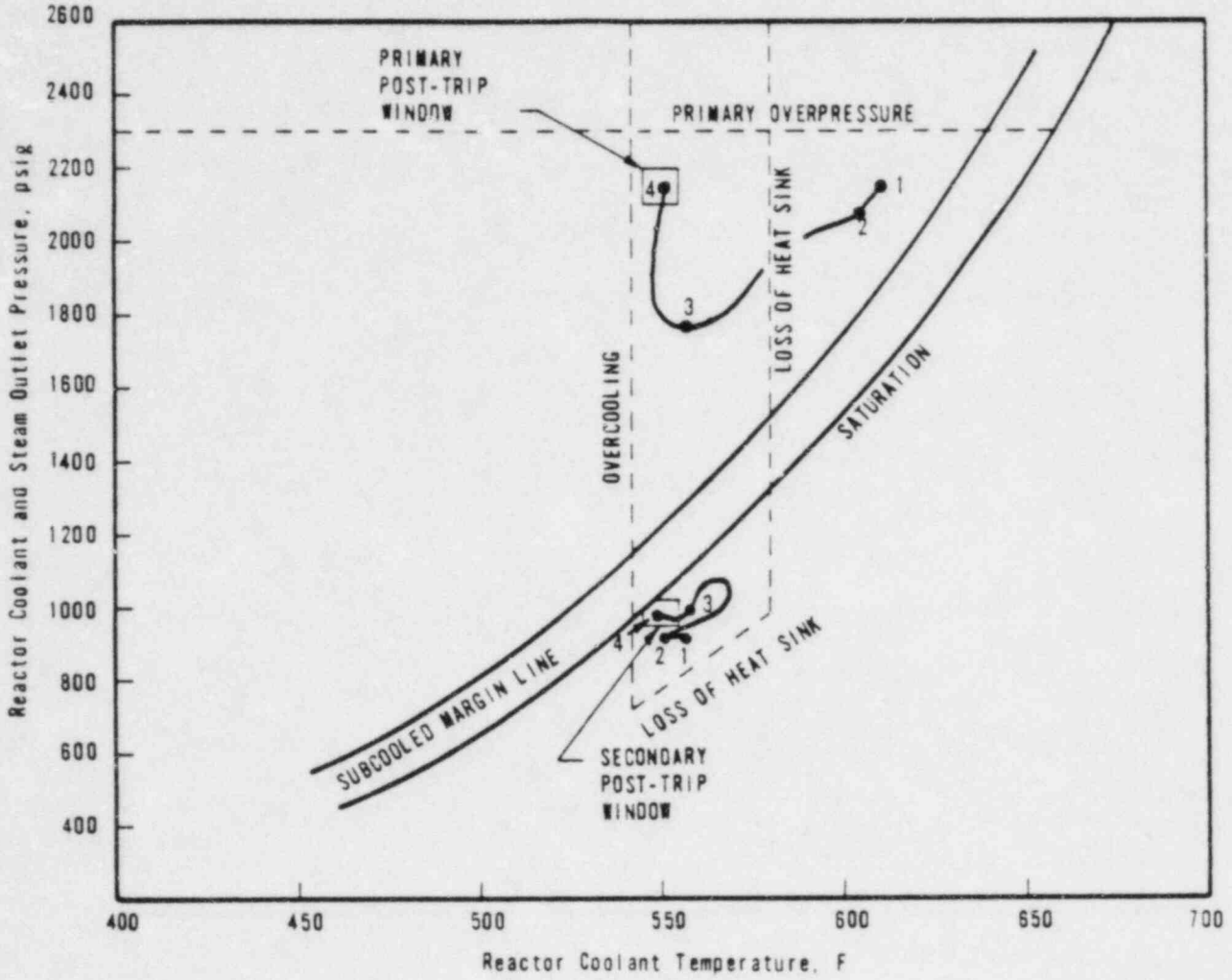
A loss of steam pressure control exists whenever one or both steam generators undergo a pressure reduction significantly below the TBV reseat setpoint. It is an overcooling transient and will look similar (on the P-T diagram) to an excessive feedwater transient. It can be caused by excessive emergency feedwater (discussed earlier) or by an unplanned steam flow through stuck open valves or a pipe break. Improper EFW flow control will also result in a SG pressure reduction.

If the steam generator with the steam leak is not obvious, the operator will isolate both SG's and then monitor their respective levels and pressures. If both SG's stabilize, indicating the steam leakage path has been isolated, he can restore EFW to both. If only one SG stabilizes he will restore EFW to that SG for DH removal and allow the broken SG to boil dry. In the event that neither SG stabilizes, the operator must pick one for DH removal while trying to locate the leakage path. For example, one SG may be broken and the other may have a leaking MSSV or ADV.

It should be noted that the overcooling caused by the excessive feedwater coupled with the overcooling due to loss of secondary pressure

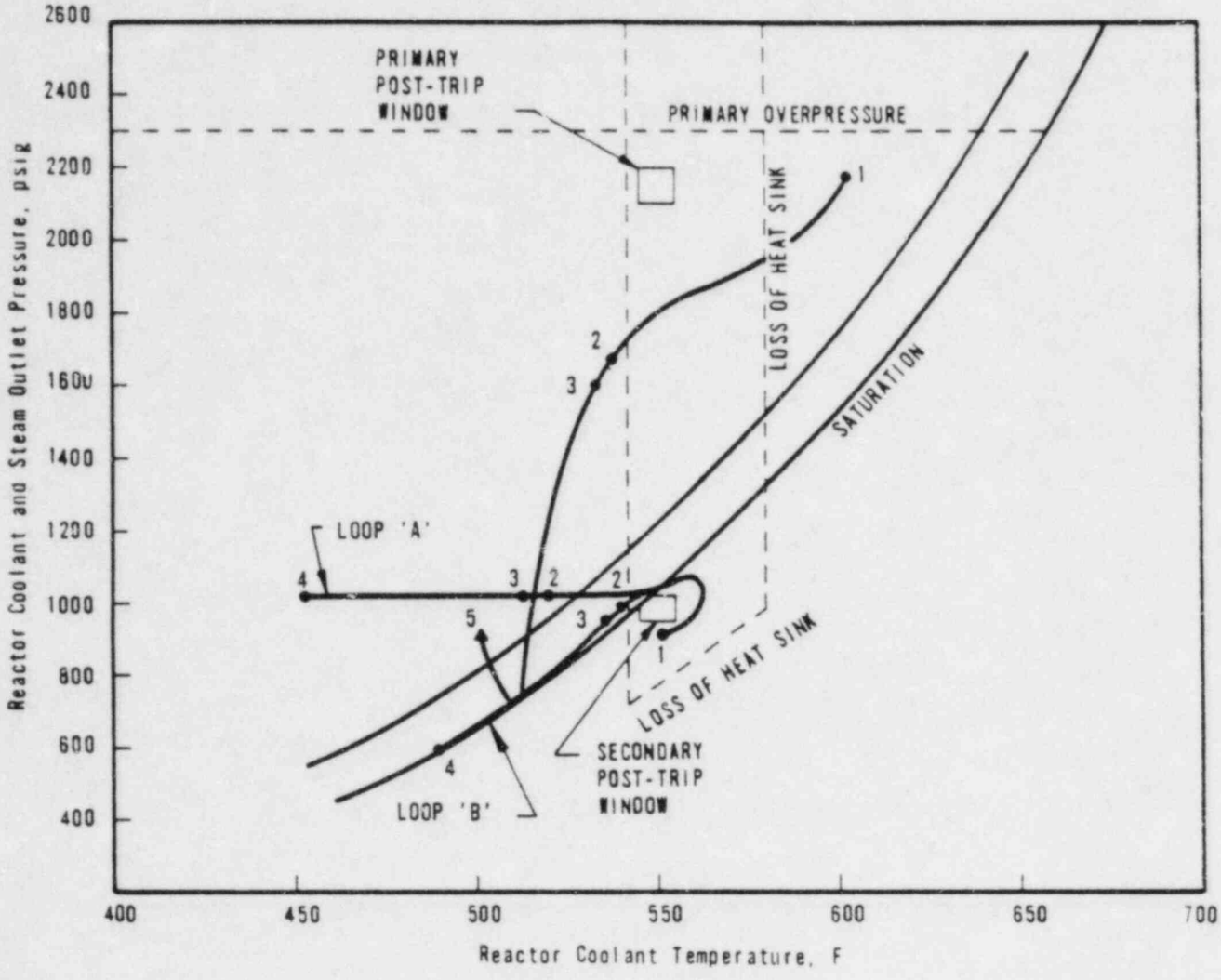
control may be too rapid and too severe to prevent pressurizer drainage and saturation of the RCS. Figure A-6 shows the impact of excessive feedwater overcooling compounded by overcooling due to loss of steam pressure control. The curves for RCS pressure and pressurizer level will shift to the left, i.e., pressure reduction and drainage of the pressurizer will occur faster. When the overcooling transient is terminated, the operator must react to prevent overpressurization of the RCS and possible violation of NDT limits.

Figure A-1 EXCESSIVE FEEDWATER TERMINATED BY BY ICS



Reference Points	Time (Seconds)	Remarks
1	0	Excessive feedwater addition begins.
1-2	0-60	Slight overcooling of RCS occurs due to excessive feedwater addition. ICS pulls rods to compensate for reduction of Tave.
2	60	Reactor trip on high flux or low pressure. (Note: Depending on severity and power history, a reactor trip may or may not occur.)
2-3	60-200	RC P&T decrease due to loss of fission power and higher than normal secondary inventory. The ICS initiates a feedwater runback and the MFW addition stops. Pressurizer level decreases because of reactor coolant contraction.
3	200	Minimum pressurizer level reached.
3-4	>200	Normal system pressure restored by RCS reheating, operation of MU system, and pressurizer heaters.

Figure A-2 EXCESSIVE FEEDWATER NOT TERMINATED BY ICS



Reference Points	Time (Seconds)	Remarks
1	0	Reactor trip from 100%. ICS fails to run back MFW to OTSG 'A'.
2	107	OTSG 'A' full.
3	120	ESAS actuates HPI but overcooling causes pressurizer to empty. RCS rapidly approaches saturation. On loss of subcooling margin, the operator trips RC pumps and EFW starts.
4	211	RCS cooling causes OTSG "B" pressure to decrease. The operator notices the high OTSG 'A' level and continuing MFW flow to OTSG 'A' and stops MFW addition to OTSG 'A'.
5	300	The excessive MFW has terminated and EFW is controlling SG level to 50% on the operate range. Refill of the pressurizer by HPI has begun to repressurize the RCS and subcooling is regained.

Figure A-3 ACTUAL PLANT RESPONSE DURING AN EXCESSIVE MAIN FEEDWATER TRANSIENT

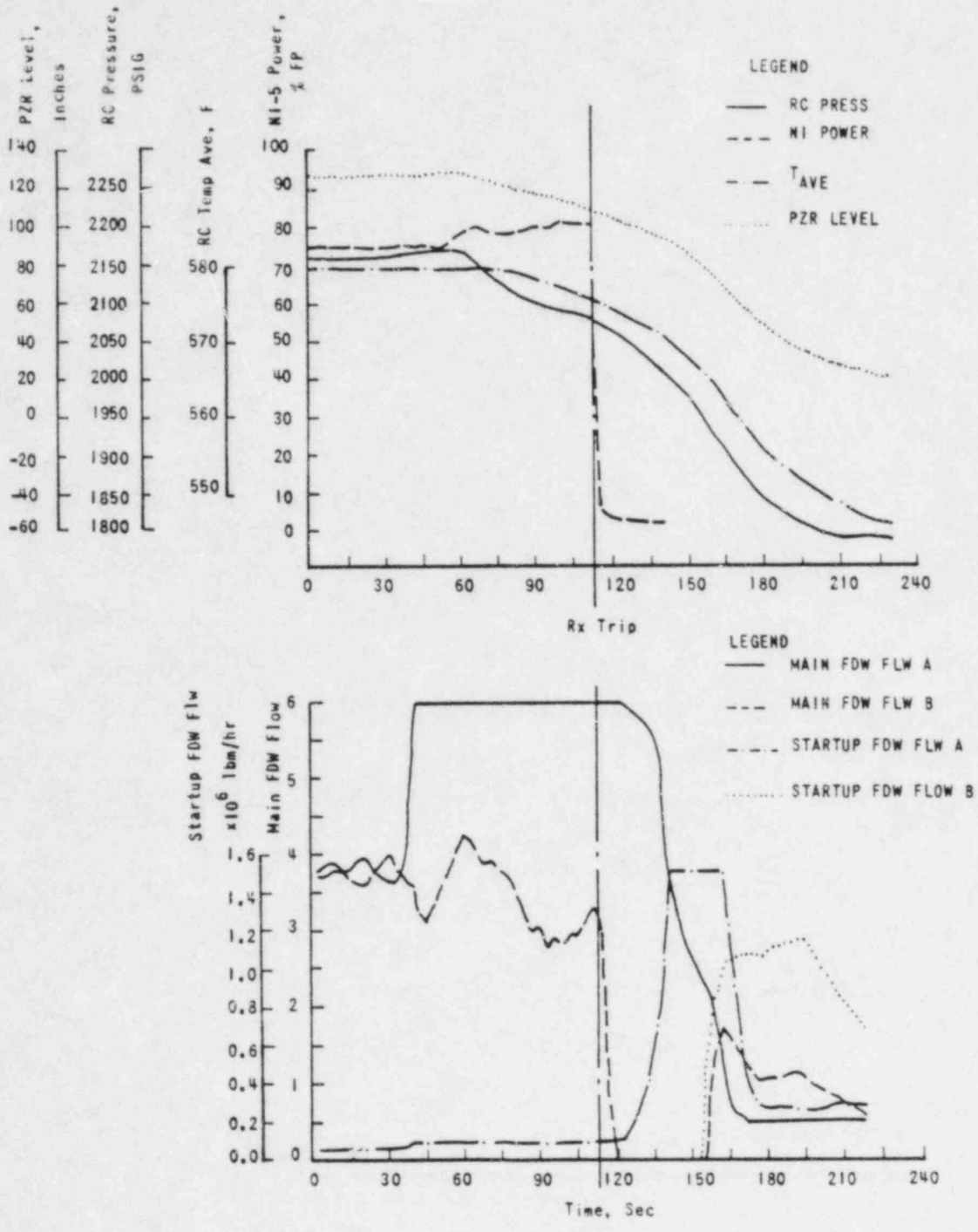


Figure A-4 ACTUAL PLANT RESPONSE DURING AN EXCESSIVE MAIN FEEDWATER TRANSIENT

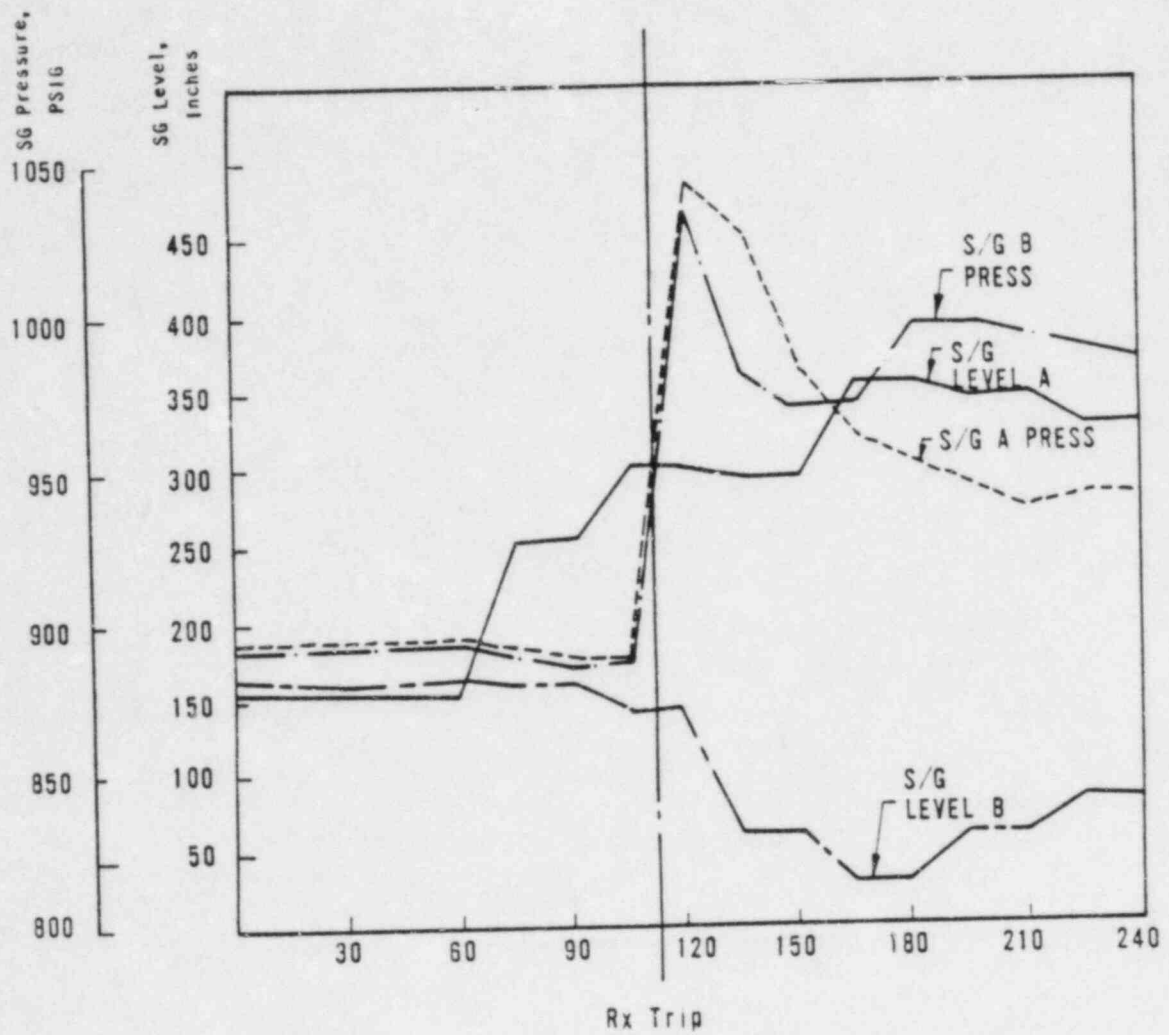
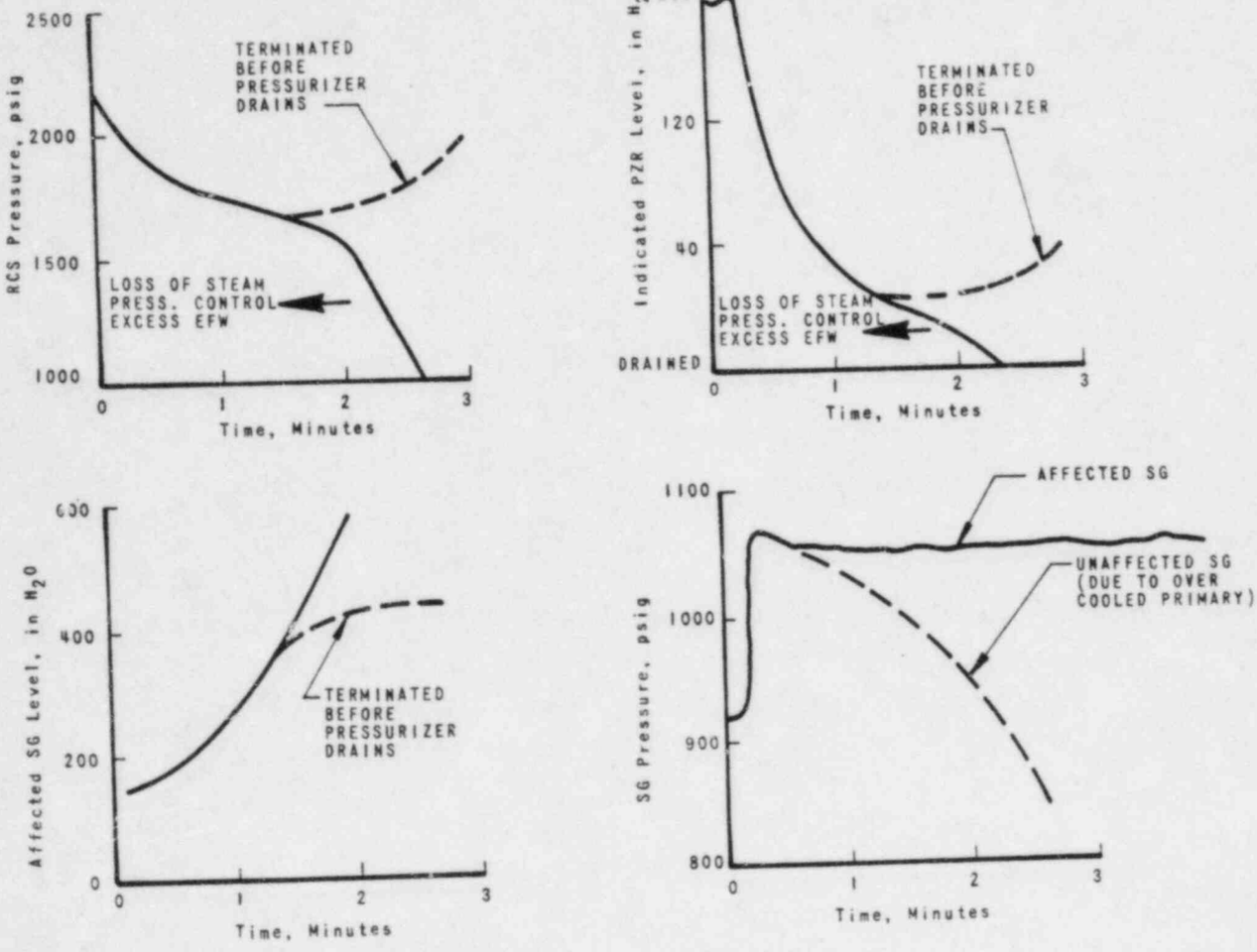


Figure A-6 TIME RELATIONSHIP OF KEY PARAMETERS



APPENDIX B

LOSS OF MAIN FEEDWATER

1.0 GENERAL TRANSIENT DESCRIPTION

Loss of main feedwater is a failure to control secondary inventory.

Loss of Main Feedwater (LOFW) is not by itself a severe transient. The plant was designed to respond automatically to this event so that the important plant parameters, like RC pressure and temperature, will stay within acceptable limits.

However, when main feedwater is lost, some important backup systems like the Emergency Feedwater System are called into play. If these backup systems fail to function correctly, a much more severe transient may start. The important plant parameters may go outside their limits and the operator will have to step in to control them. So even though loss of main feedwater is not by itself a bad transient, it can be the starting point for some severe abnormal transient.

This section will discuss what can cause a loss of feedwater and how the plant will respond.

Causes for a Loss of Main Feedwater

The most common cause for a loss of main feedwater is a trip of the main feedwater pumps which can result from a number of automatic

pump turbine trips. Trip of both main feedwater pumps is significant because it causes an anticipatory reactor trip. The anticipatory trip helps reduce the severity of the transient because it quickly drops the production of heat in the reactor core. Without the anticipatory trip, the core will continue to produce heat for up to 8 seconds after a LOFW before the reactor trips on high RC pressure.

LOFW can also be caused by inadvertent closure of the main feedwater control valves, the main feedwater isolation valves, or by a feedwater line break. If these failures occur, they will not result in an anticipatory trip. However, they are much less likely than both main feedwater pumps tripping. So for the remainder of this discussion, we will assume that the LOFW has been caused by a main feedwater pump trip and that an anticipatory reactor trip also occurs.

Plant Behavior Following a LOFW

For the first few seconds following a LOFW, RC pressure, pressurizer level and steam pressure all "spike" upwards. This happens because, within a second after the main feedwater pumps trip, the reactor and turbine also trip, and the effects of the turbine trip are seen more quickly than the reactor trip. The turbine trip causes steam pressure to increase and reduces primary to secondary heat removal. The reactor coolant gets hotter and expands slightly causing an increase in pressure and pressurizer level. On the P-T diagram of Figure

B-1, this initial spike is shown (greatly exaggerated) to indicate its direction. In actual practice the spike is so small and so quick that the operator probably won't see it. (Note: Only for the case where there is no anticipatory trip does the spike become significant. In that case RC pressure will rise to 2300 psig before causing a reactor trip).

When the reactor trips, the loss of power generation in the core ends the overheating spike. As the steam generator inventory is boiled away, heat is removed from the secondary side faster than it is being supplied by decay heat in the core and the RCS cools. This part of the transient takes much longer and will probably be the first system behavior observed by the operator. The P-T diagram of Figure B-2 shows the trend that he will see. Reactor coolant pressure, temperature and pressurizer level will fall as a result of the RCS cooling down. Pressurizer heaters will come on and makeup flow will automatically increase.

Steam generator levels in both generators will continue to drop as the inventory is boiled away. At the same time, steam pressure will peak as the main steam safety valves lift. After the excess energy has been vented, steam pressure drops and these valves close. The turbine bypass valves will control steam pressure near the 1010 psig setpoint.

Because the reactor trip and turbine trip occur so quickly after the main feedwater pumps trip, the transient up to this point will look almost identical to a normal reactor trip. For positive identification of a LOFW, the operator must rely on other indications such as the main feedwater pumps have tripped or the emergency feedwater pumps have been turned on. Main feedwater flow rate is a fast indication which also should be checked.

The emergency feedwater pumps are actuated early in the transient, but no EFW flow will occur until the steam generator levels have dropped to the low level setpoint. When this occurs, the EFW flow will be automatically controlled to maintain a nearly constant level and the heat removed from the steam generator will closely match the core decay heat. When this happens, RC temperature will remain nearly constant. Pressurizer level will slowly increase in response to the additional makeup flow, and operation of the pressurizer heaters will cause RC pressure to go up. This represents the final stage of the LOFW transient as the system approaches its desired post-trip conditions. The P-T diagram of Figure B-3 shows the expected system behavior during this period.

2.0 OPERATOR ACTIONS SUMMARY

Immediate Actions

- Confirm emergency feedwater system is providing feedwater flow to the steam generators. If not, start EFW pumps and check EFW valve alignment. Control EFW flow rate to prevent overcooling (EFW throttling should only be necessary when all RC pumps are off and the higher level setpoint for natural circulation is in effect.)

Identifying Symptoms

- Main Feedwater Flow Rate
- Main Feedwater Pumps Tripped Alarm
- EFW controlling OTSG levels

NOTE: The RC pressure and temperature behavior is almost identical to a "normal" reactor trip.

If the plant responds normally, there is no need for the operator to take any immediate actions other than his normal post-trip response (Part I, Sections I and II). If the loss of main feedwater is compounded by other failures, Sections I and II of Part I will help the operator identify these situations and take the appropriate actions.

3.0 LOSS OF MAIN FEEDWATER WITH OTHER PLANT FAILURES

Introduction

The previous section describes the loss of main feedwater without additional plant failures. The plant is designed to automatically

handle the simple loss of main feedwater events without immediate operator action (although to limit overcooling effects when in natural circulation the operator should control EFW when it starts). However, a number of other plant failures can also occur at the same time which will compound the LOFW event and increase the complexity of the transient. These compound events require operator recognition and corrective action to mitigate the transient. This section will show what symptoms to look for when other equipment fails and will show what steps the operator should take to restore the heat transfer from the core to the steam generators.

There are three significant secondary system failures which may compound the loss of main feedwater event. These are:

- Loss of Secondary Inventory Control (Low)
- Loss of Secondary Inventory Control (High)
- Loss of Secondary Pressure Control (Low)

These events are shown on the Loss of Feedwater Logic Diagram (Figure B-5) and are discussed separately below.

Loss of Secondary Inventory Control (Low)

Loss of main feedwater is already a loss of secondary inventory control. If the LOFW is compounded by a failure of the EFW system, the steam generators will dry out and a loss of heat transfer will result.

The operator can recognize the total loss of feedwater by the lack of both MFW and EFW flow indication on the flowmeters and by the low steam generator level which will be decreasing below 30 inches on the startup range. Secondary steam pressure will decrease below the post-trip setpoint of 1010 psig once the steam generator dries out and can no longer produce enough steam to hold the setpoint pressure. Also, by following the steps in Part I, Sections I and II, the operator will identify that inadequate primary to secondary heat transfer exists at Step 11.0 of Part I, Section II. This step directs him to Section III.B of Part I where instructions for establishing HPI cooling, if necessary to protect the reactor core, and for restoring proper primary to secondary heat transfer are given. Use of HPI cooling protects the core while providing the operator the time necessary to correct EFW and/or MFW problems and restore feedwater to at least one steam generator. HPI cooling should be started when the loss of heat transfer is noted (T_{cold} increases to the right of the saturation curve and steam pressure drops as shown on Figure B-5) and before the RC pressure reaches the PORV setpoint. When HPI cooling is started, all but one RC pump should be tripped; if the subcooling margin is lost the remaining RC pump should be stopped. After HPI cooling has been established, the operator should continue attempts to feed at least one SG from any available source.

Figure B-4 is provided to show how RC hot leg temperature and RC pressure typically change as a function of time. On a loss of main feedwater with no EFW both RC temperature and pressure respond initially like a normal LOFW trip but then within minutes both parameters increase due to the inadequate primary-to-secondary heat transfer.

Loss of Secondary Inventory Control (High)

The loss of main feedwater may be compounded by a failure in the EFW system resulting in EFW overfeed. This is an overcooling event because too much primary to secondary heat transfer occurs; however, it is different from the excessive feedwater event of Appendix A because main feedwater has tripped off and cannot be causing the overfeed. Therefore, the overfeed from this transient will be much slower.

Excessive emergency feedwater can be recognized by the following symptoms:

- High steam generator level in one or both generators
- Continuous EFW feed flow indication above the correct level setpoint in one or both generators
- Falling steam generator pressure in the "bad" (overfed) OTSG

By following the instructions in Part I, Sections I and II, the operator will identify the excessive primary to secondary heat transfer at Step 11.0 of Section II. This step directs him to Part I, Section III C. Following those actions will terminate the excessive EFW. A more detailed discussion of Loss of Secondary Inventory Control (High) is provided in Appendix A.

Figure B-4 shows the behavior of RC hot leg temperature and RC pressure versus time for the LOFW event compounded by excessive EFW. Steam pressure will decrease in both OTSG's and RC cold leg temperature will follow steam generator T_{sat} throughout the transient. If only one SG is being overfed, it may be distinguishable as shown on the EFW overfeed branch of Figure B-5.

Loss of Secondary Pressure Control (Low)

A loss of main feedwater event may also be compounded by a loss of secondary pressure control. The loss of secondary pressure control can be caused by such things as a turbine bypass valve or a main steam relief valve failing in an open position. Any of these initiating causes will result in an overcooling transient.

Symptoms of a loss of secondary pressure control caused by steam leakage through an open safety or turbine bypass valve are: (1) rapidly falling steam generator pressure in both OTSG's with the "bad" generator pressure falling more rapidly; After a few minutes the "bad"

generator pressure may be as much as 200 psi lower than the good generator pressure, and (2) low steam generator level in the "bad" generator and/or higher EFW flow to the "bad" generator.

The operator should follow the instructions in Part I, Sections I and II. Step 11.0 in Section II will identify the overcooling event and direct him to Section III C which provides the explicit instructions for identifying and dealing with the steam leakage.

These steps include isolating all feedwater to the "bad" OTSG by closing the control or isolation valves and verifying the TBV's and ADV's are closed, and, if the leak cannot be isolated, then boiling the "bad" OTSG dry.

With a loss of secondary pressure control caused by a stuck open turbine bypass valve, ADV, or main steam safety valve, the reactor coolant hot leg temperature and pressure decrease very rapidly. The time dependence of these parameters for a stuck open MSSV is shown in Figure B-4.

Figure B-1 LOSS OF FEEDWATER (INITIAL STAGE)

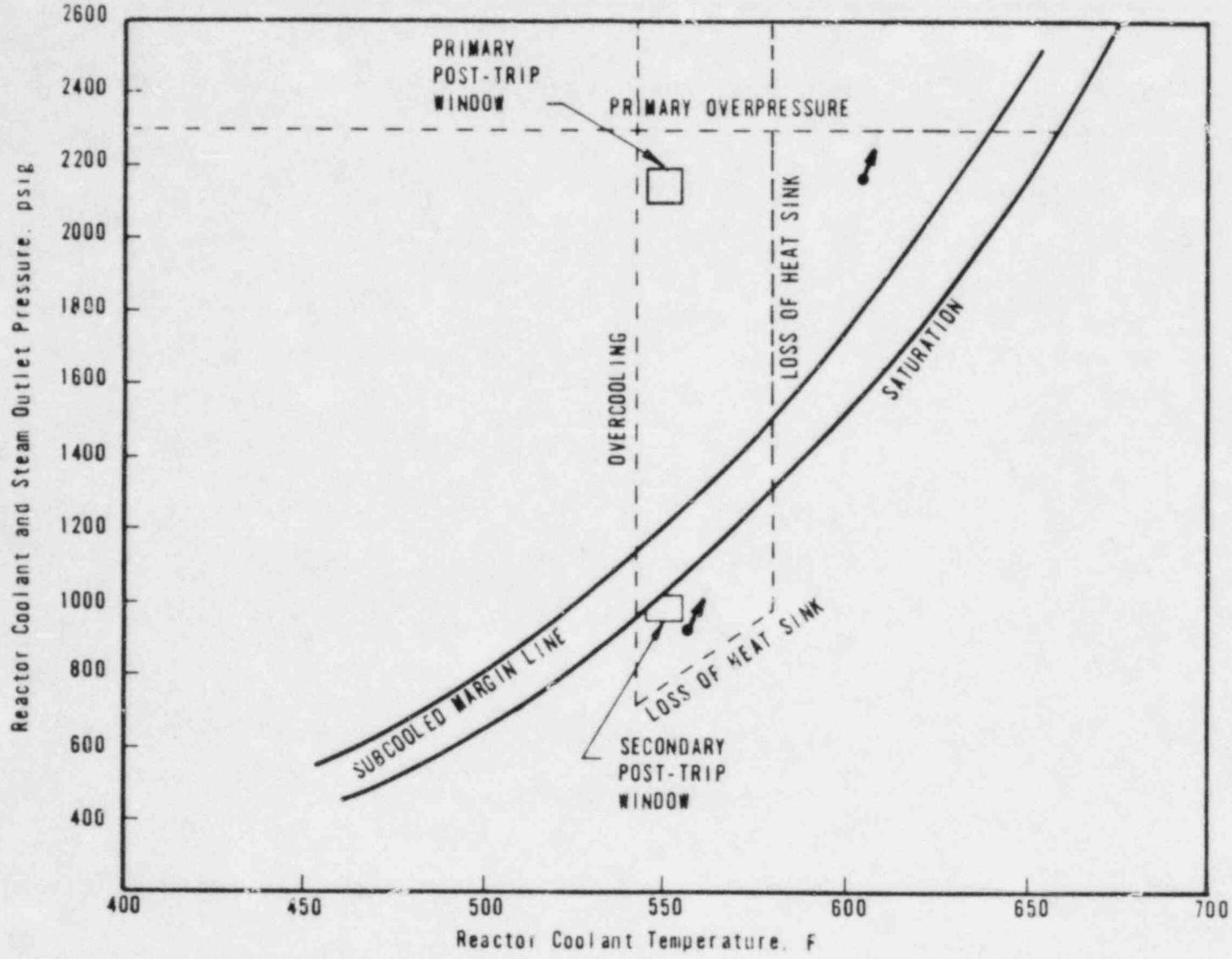


Figure B-2 LOSS OF FEEDWATER (MIDDLE STAGE)

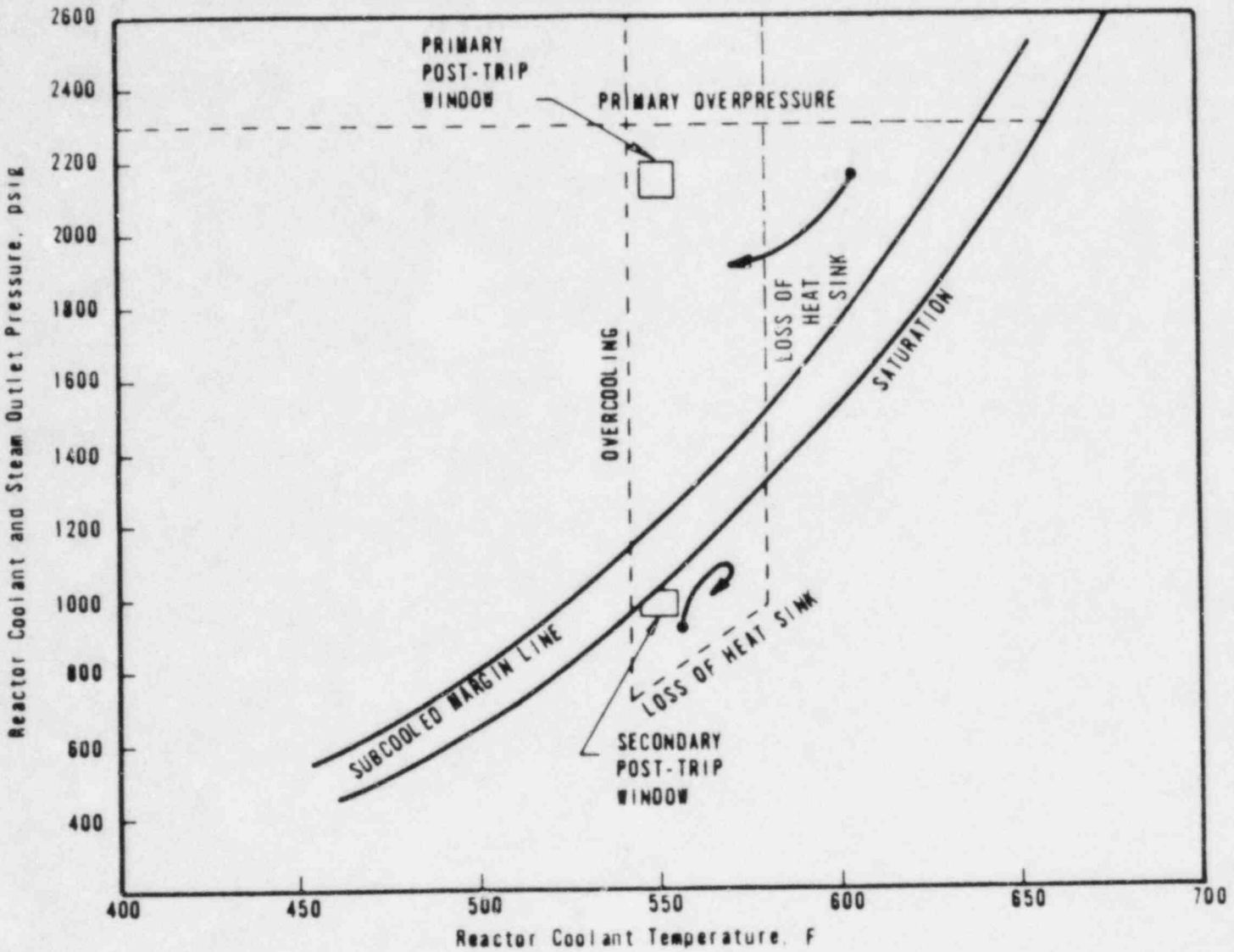


Figure B-3 LOSS OF FEEDWATER (FINAL STAGE)

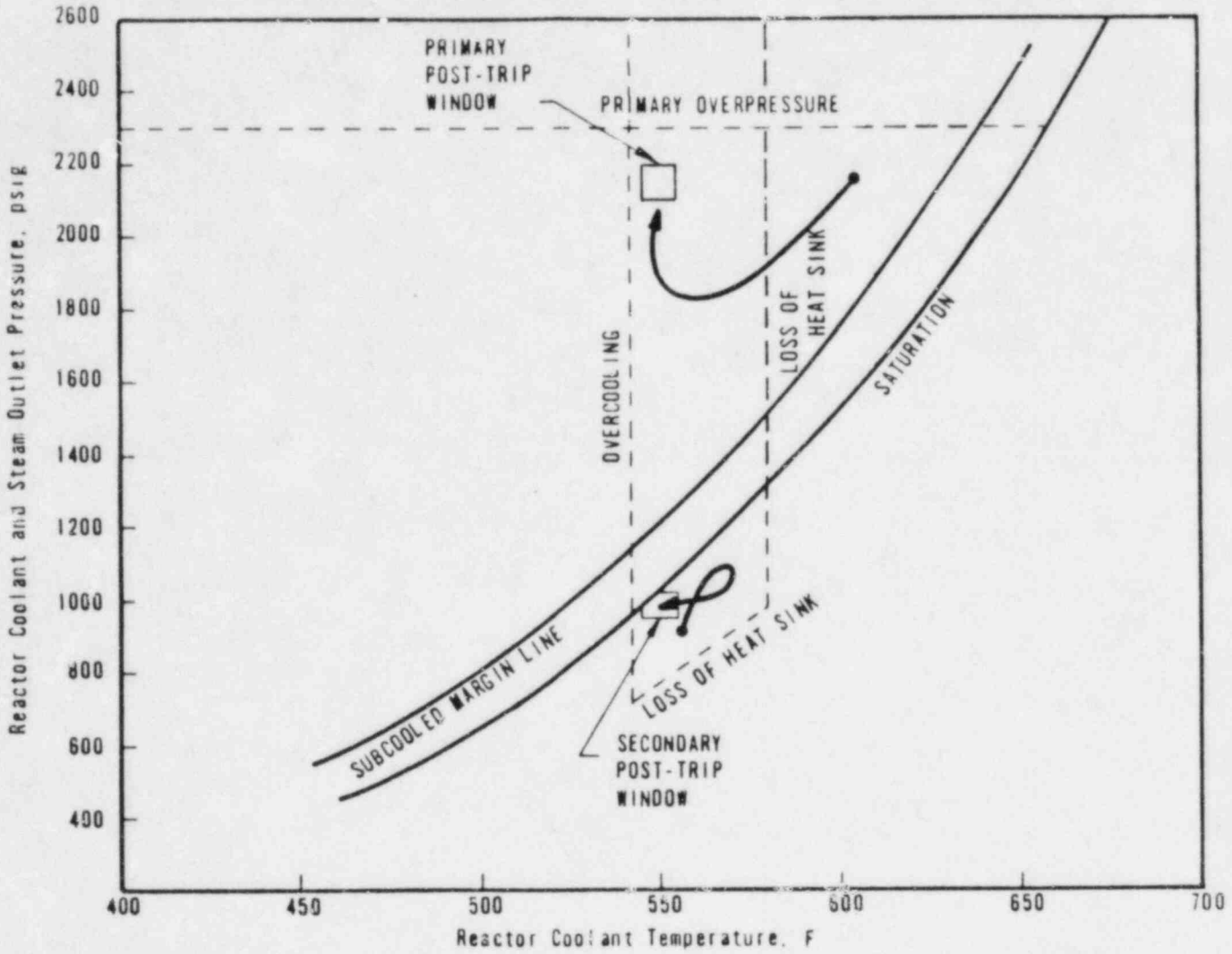
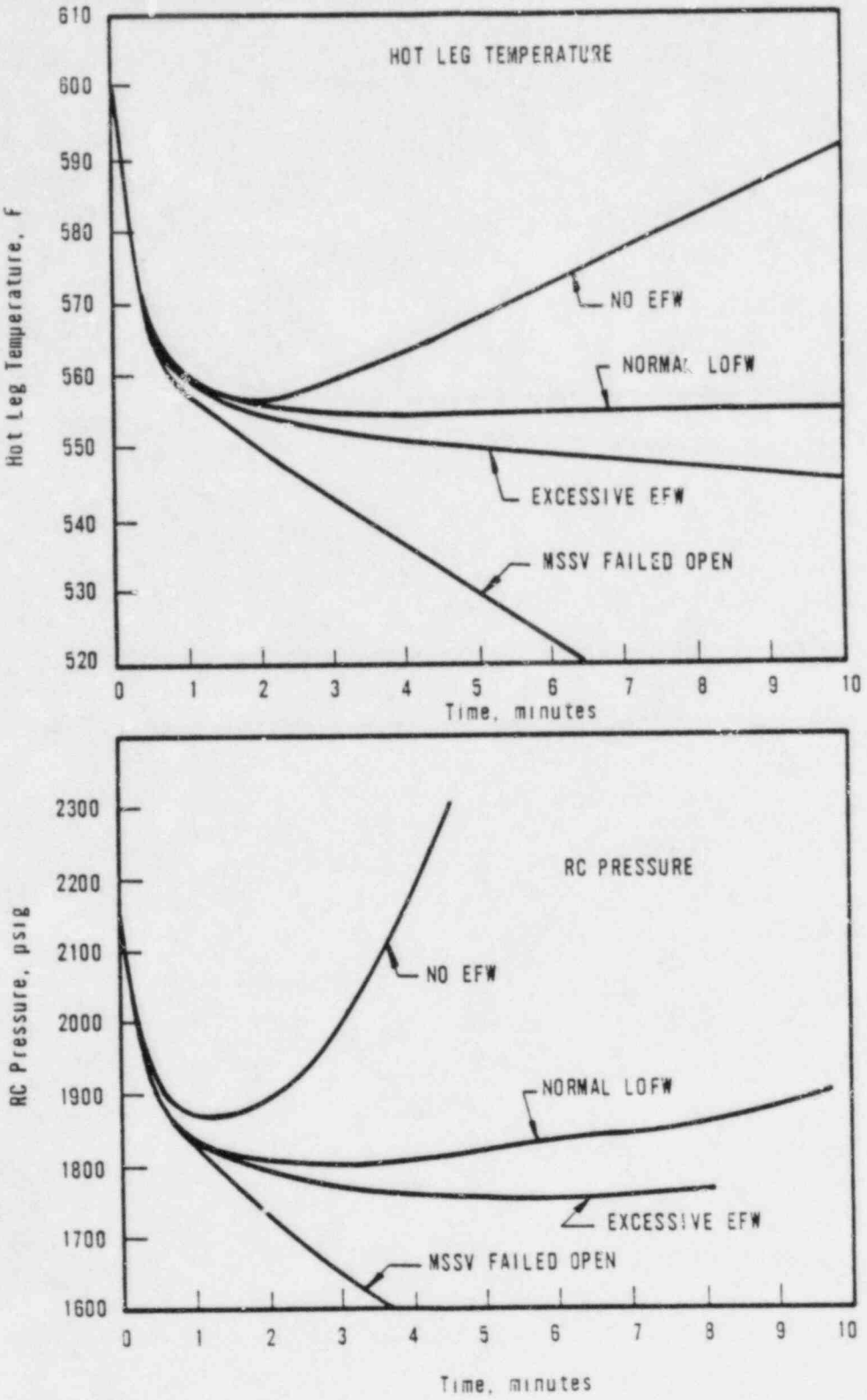


Figure B-4 TIME RELATIONSHIP OF LOSS OF MAIN FEEDWATER WITH FAILURES



74-1124158-00

APPENDIX C

STEAM GENERATOR TUBE RUPTURE (SGTR)

1.0 INTRODUCTION

A SGTR is a loss-of-coolant accident (LOCA) that allows reactor coolant to leak into the secondary side of the once through steam generator (OTSG) where it is released into the steam plant. A SGTR contaminates the secondary plant and can lead to significant offsite releases if steam from the affected steam generator(s) is released to the environment. It can have the complications associated with a normal small break LOCA (see Appendix F).

A SGTR is a loss of integrity of the steam generator tubes. It can be a small leak of one tube or failures of more than one tube. SG tube failure can be caused by corrosion (bad water chemistry), excessive thermal or hydraulic loadings during severe plant transients, or mechanical wear due to foreign objects in the primary or secondary system. Tube failure can occur by itself or it can be combined with another severe plant transient.

The leak rate during a SGTR can be small (a few gpm) or quite large (several hundred gpm). The major factors which influence the leak rate of reactor coolant into the steam generators are:

1. The number of defective tubes,
2. The size (break area) of the tube failure(s), and
3. The pressure and temperature conditions in the primary and secondary systems.

Small leaks with leak rates less than 20 gpm are more frequently encountered than large tube ruptures. For a complete severance of one SG tube, a leak rate of approximately 400 gpm at normal steam pressure and temperature conditions would be expected. SGTR events with high leak rates have occurred at commercial nuclear plants.

The leak from a failed tube cannot be isolated and reactor coolant will continue to be lost until the plant is completely cooled and depressurized and the primary system loops have been drained. Hot shutdown is not a safe end condition for a SGTR.

The requirement to maintain an RCS subcooling margin will prevent the equalization of the primary and affected OTSG pressures. The primary to secondary elevation difference will also prevent termination of the tube leak until the RCS is drained. Therefore, a rapid plant cooldown and depressurization is required for transient mitigation. Higher RCS pressures result in higher tube leak flows and ultimately higher offsite releases, so early detection and diagnosis of this accident is very important.

The RCS must be at cold shutdown before the BWST is depleted because recirculation from the sump is not possible; all injection water is lost through the broken SG tube. Therefore, the RCS cooldown and depressurization must be initiated as soon as safely possible. A tube leak is a LOCA, therefore LOCA symptoms will be treated (e.g., start HPI and trip RCP's on loss of subcooling margin). However, some special actions are required for this unique transient: 1) the leak rate through the tube will increase as subcooling margin increases, therefore a minimum subcooling margin should be maintained, and 2) delays in cooldown and depressurization must be avoided.

Delays of cooldown and depressurization can happen if failures occur in plant systems in addition to the tube leak. To minimize delays in the RCS cooldown and depressurization, the failures may have to be corrected during the cooldown.

This appendix will show characteristics of and corrective actions for large and small tube leaks rates, with and without additional failures.

2.0 GENERAL OPERATOR ACTIONS

The most important stages in the treatment of steam generator tube leaks are to:

1. Diagnose that a SGTR is in progress and identify which steam generator has the leak.
2. Bring the plant to a stable, zero power condition by:
   - Performing a plant runback, or
   - Performing the Immediate Actions and Status Verification of Part I if a reactor trip occurs.
3. Rapidly cool down and depressurize the RCS so that the RCS pressure is below the main steam safety valve setpoint.
4. Once the RCS temperature is approximately 540F, isolate feedwater to the generator with the tube leak. Bypass the SLRDS signal to maintain or allow restoration of feedwater to OTSG's during RCS cooldown. Isolate all steam extraction lines from the steam generator with the tube leak except the turbine bypass line. Leak rates of 5-20 gpm are small and will probably not fill the generator before complete plant cooldown if RCPs are running. Slightly larger leaks can be accommodated depending on the time it takes to completely cool down. Isolation of the generator will help minimize contamination of the secondary plant and the cleanup efforts associated with it. For all large leaks and small leaks

without RCP operation, secondary plant contamination will occur because the generator with the leak will have to be steamed periodically to prevent filling. The operator should make every effort to limit the degree of contamination in the balance of plant without inhibiting mitigation of the SGTR event. This includes isolation of the MFW and EFW pump turbines, and Steam Heated Post Supply system.

5. If additional component failures have occurred which will a) limit plant depressurization with the spray or PORV, or b) prevent the use of both generators, then repair or bypass the failures if possible.
6. Cooldown and depressurize the plant to cold shutdown conditions while maintaining the reactor coolant subcooled and minimizing the offsite releases.
7. During small leaks, addition of feedwater prevents large tube to shell ΔT's and loss of internal recirculation of the OTSG.

These steps are shown in the block diagram (Figure C-1). The text follows the outline of the diagram. The first part of the text shows actions for tube leaks without failures; actions to take if other failures occur with the tube rupture are discussed in Section 9.0.

SGTR's are unique LOCA's; therefore, the SGTR procedures by themselves contain the corrective actions.

Figure C-3, which is at the end of this appendix, summarizes the general operator actions for a SGTR. Sheet 1 of Figure C-3 summarizes those actions required to identify the transient and to bring the plant to a stable zero power condition and Sheet 2 addresses plant cooldown. Table C-3 outlines actions to minimize offsite releases for SGTR's with additional equipment failures. These figures should be studied as a supplement to the following sections.

3.0 EVENT DETECTION

The first stage for correction of steam generator tube leaks is prompt detection and determining which generator has the leak. It is mandatory to know that a tube rupture has occurred and it is very important to know which generator is affected. Table C-1 summarizes the ways a SGTR and the affected steam generator can be detected. Secondary plant radiation levels are the best and most timely indicators of a SGTR. The other SGTR symptoms (LOCA or asymmetric high water level with zero feedwater addition in one generator) are best used as back up methods in case the plant's radiation detection equipment is inoperative. Figure C-2 shows the P-T diagram and a sequence of events for a large tube leak without operator intervention prior to trip; as expected, the tube leak looks like a small break LOCA (see Appendix F).

4.0 PLANT CONTROL AT POWER FOLLOWING A SGTR

The second stage for mitigation of a SGTR is to stabilize reactor coolant (RC) pressure and pressurizer level so that the plant may be run back without tripping. Tube leaks will result in decreases in RC pressure and pressurizer level. The makeup (MU) system will automatically increase MU flow to stabilize pressurizer level and the pressurizer heaters will come on to restore RC pressure. Makeup tank level will drop, but must not be allowed to drain. Action must be taken to supply the makeup tank with a water supply with a boron concentration equal to or greater than RCS boron concentration. Larger tube leaks or a complete rupture of a tube will require opening MU-V-217 and starting a second makeup pump or manual initiation of HPI. Action to start HPI should be taken if pressurizer level cannot be maintained with MU. Shift HPI pump suction to BWST if unable to maintain makeup tank level. If the leak rate is greater than the MU or HPI flow rate, the reactor should be manually tripped if the pressurizer level goes below 100 inches to prevent a subsequent automatic reactor trip from draining the pressurizer. A complete severence of one OTSG tube (approximately 400 gpm) will result in a reactor trip in approximately 10 minutes if the operator does not initiate HPI (refer to Figure C-2). For tube ruptures with a flow greater than approximately 700 gpm (more than one tube ruptured), the rate of RCS depressurization will be too rapid to prevent a reactor trip, even with initiation of full HPI. Letdown should be secured as rapidly as possible (prior to

reactor trip) for all SGTR's. If a reactor trip has already occurred, verify automatic isolation of letdown.

Once RC pressure and pressurizer level have been stabilized ("normal" plant conditions) by any of the above actions, the third stage of actions (Section 5.0) should be followed. By achieving RC pressure and inventory control, the plant may be run back. If a reactor trip does occur, the minimum RC subcooling margin and pressurizer level must be reestablished. Actions to be taken are discussed in Section 5.0.

5.0 PLANT CONTROL TO HOT ZERO POWER (See Sheet 1 of Figure C-3)

The third stage for correcting a SGTR is to bring the plant to hot standby (unless the leak is large enough to depressurize the plant to a low pressure and automatically trip the plant). Depending on the leak size and other factors, the plant may be runback or it may trip. It is preferable to run back as much as possible, even if a reactor trip is imminent, to avoid or limit lifting the steam safeties and releasing radioactive steam to the environment. Tube leaks can occur alone or other plant failures can occur at the same time. If other plant failures occur at the same time, it may be difficult to establish hot shutdown and then proceed with cooldown and depressurization. Generally, but not always, the best course to follow, if possible, is to fix the other failures while taking actions to cool the plant down. This section will show how to establish hot shutdown and prepare for cooldown with tube leaks only. Treatment of other failures will be given in a later portion of the text (Section 9.0).

Action should be initiated to stablize pressurizer level and RCS pressure while conducting a plant runback at as fast a rate as can be controlled to below 12% power without tripping. RCS inventory should be closely watched during the plant runback and subsequent cooldown.

Below 12% power the turbine bypass capacity is sufficient to avoid lifting the steam safeties if the plant trips.

At approximately 0 MWe:

1. Place TBV's in manual and control steam pressure to avoid lifting the main steam safety valves.
2. Ensure site loads are transferred.
3. Trip the turbine generators then verify the generator breakers open and turbine stop valves close.
4. Reduce reactor power to < 4% then trip the reactor.
5. Reduce operating RCP's to one per loop.

If pressurizer level has not been maintained and a reactor trip should occur, there is a good chance that the pressurizer will drain, ESAS will actuate on low RCS pressure, and the reactor coolant subcooled margin will be lost. If this happens, the operator's actions are to:

1. Ensure full HPI flow.
2. Trip the RC pumps immediately following the loss of subcooled margin.
3. Ensure that EFW flow is established and controlled.
4. Throttle HPI once the reactor coolant subcooled margin is regained and maintain pressurizer level at 100 inches or greater.

Once the reactor is shutdown and the turbine is offline, immediately begin cooldown and depressurization as described in the following sections.

6.0 INITIAL COOLDOWN AND DEPRESSURIZATION

Once the plant has been brought to a hot zero power condition and a vital system status verification has been made, a cooldown and depressurization of the RCS should be started with both OTSGs (unless one was isolated due to a steam leak) while maintaining the reactor coolant with a minimum subcooled margin.

This action is required to minimize the offsite releases because:

1. By reducing RCS pressure, the primary-to-secondary leakage will decrease and
2. By decreasing RCS temperature and steam pressure, radioactive steam release through the steam safety valves is less likely.

The objective of the initial cooldown is to bring the RCS temperature to a value ($\leq$ 540F) that corresponds to a saturation pressure which is below the main steam safety setpoint. This action will prevent inadvertent lifting of the main steam safety valves and the resulting atmospheric radiation releases. Below 540F, the SG with the tube rupture can be isolated without lifting the MSSVs. The selection of the cooldown method to be used (normal or emergency) is discussed in Section 8.0.

The plant cooldown and depressurization should be continued immediately to cold shutdown conditions. The primary-to-secondary leak will not stop completely until the loops are drained.

Prior to and during the cooldown and stabilization period, the operator should check the status of several things so that he can decide on the best method for cooldown.

1. Determine if the tube leak is small or large. For a small tube leak, normal (with two MU pumps and letdown isolated) will maintain pressurizer level. If normal makeup cannot maintain pressurizer level the tube leak is large.

2. Determine if the condenser is available.

3. Determine the availability of both OTSG's.
   a. Which OTSG's can be feed.
   b. Which OTSG has the tube leak.
   c. Which OTSG's can be steamed.

4. Determine which RC pumps are operable. If tripped and the RC conditions permit, restart one pump per loop as soon as possible.

7.0 ISOLATION OF AFFECTED OTSG

During the cooldown and depressurization of the plant, isolation of the affected steam generator is recommended once the reactor coolant temperature decreases below 540F. Below this temperature, steam pressure will be below the secondary safety valve lift setpoints and reactor coolant subcooling requirements can be met. Isolation is defined as:

1. Stopping MFW and EFW flow to the affected steam generator except as needed to maintain the low level limit, to promote natural circulation, to maintain adequate subcooling margin or to maintain tube to shell ΔT requirements.
2. Stopping steaming of the affected steam generator except as necessary to promote natural circulation or to maintain the steam generator pressure below 1000 psig and level below 95% on the operate range.
3. If the condenser is available, the TBV's should be used if steaming is needed. Therefore, the TBV's should be closed (until needed) but the steam flow path upstream of the TBV's should remain open and available.
4. If the condenser is not available, the ADV's will have to be utilized or the RCS must be cooled down by HPI cooling (very slow).
5. Switch the emergency feed pump and other steam supplies to the unaffected OTSG.

The SLRDS signal should be bypassed during cooldown to prevent isolation of feedwater. Feedwater should always be available to the unaffected OTSG for RCS cooldown. Although feedwater may be temporarily isolated to the affected (ruptured) OTSG, it may be required during certain periods of the RCS cooldown and depressurization to cold shutdown. For example, feedwater addition to either OTSG would be required in case of RCP trip where the level must be raised to establish natural circulation.

The reactor coolant which leaks into the steam generator may eventually require steaming to limit the water accumulation in the generator. Steaming must be done when 95% on the operator range is reached. Steaming may also be needed to maintain natural circulation so that a reasonable rate of RCS cooldown to cold shutdown can be achieved. The decision to steam should be based on the actual situation; RCS cooling, steam generator level, tube-to-shell ΔT, and the need to add feedwater for natural circulation will help make this decision.

Small leaks will not provide enough water to the generator to maintain a minimum level and therefore periodic feeding will be required to keep the shell cool and rate of cooldown constant. Large leaks will provide enough water without feedwater addition. Feedwater may be initially required to establish and maintain natural circulation in the loop with the tube leak. A decision to

add feedwater must be based on the actual plant situation; RCS cooling, steam generator level, tube-to-shell ΔT, and the natural circulation condition will help make this decision.

If the plant is in natural circulation, feedwater addition and steaming will be required from both loops to prevent the reactor coolant in either loop from going saturated in the "candy cane" of the hot leg and forming a steam bubble which will interrupt natural circulation and prevent depressurization. Further plant cooldown and depressurization will be significantly reduced.

Although the intent of isolation is to "bottle up" the affected OTSG and to use it as a storage tank for the additional reactor coolant that escapes during the remainder of the plant cooldown and depressurization, total isolation is not always possible. For large tube leaks steaming may be required; feedwater may have to be added for some other situations. Level control in the steam generator and a high rate of RCS cooldown will provide a lower radioactive release for large leaks than a slow cooldown. A fast rate of cooldown will limit the total water that leaks into the steam generator, limiting the offsite releases. A timely cooldown will also allow the plant to be brought to a cold, depressurized condition before the BWST is drained. Therefore, a rapid rate of cooldown (100F/hr) should take priority over isolation of the OTSG for large tube leaks. For smaller tube leaks were the transient is well under control (i.e., low rate of SG level increase, adequate, BWST inventory etc.), the

SG with the tube rupture should not be steamed for the sole purpose of achieving a 100F/hr cooldown.

Specific isolation actions for various plant conditions are addressed below (additional failures that may occur are covered in Section 9.0):

A. Small Leaks With RC Pumps Running

Small SG tube leaks are events where the loss of reactor coolant is within the capacity of the normal makeup system at system operating pressure with two makeup pumps on and letdown isolated. For this condition, the reactor coolant pumps will force circulation through the isolated loop so it will not stagnate and flash; a continuous uninterrupted cooldown with the other generator is mandatory. The cooldown rate should be close to normal, but the tube-to-shell temperature difference should be monitored and maintained within normal limits (100F) to avoid excessive tube stress. Feed addition should be as required to maintain level at the low level limits to keep the lower shell covered. A continuous depressurization of the RCS is required to maintain a minimum subcooling margin while proceeding with RCS cooldown. If heat removal does become interrupted, then a path to the condenser from the affected OTSG should be opened to prevent radioactive release through the safety valves or ADV's of the isolated generator.

Intermittent feeding to the isolated generator may be required to maintain a minimum water level for a minor tube leak. A leak of this size may not be large enough to fill the generator before the cooldown and depressurization are completed; however, the leak rate and the steam generator level should be monitored at all times. If the level increases or the leak rate changes, the generator may have to be steamed (preferably to the condenser). Steaming of the affected OTSG may be desired at lower RC temperatures to maintain a reasonable rate of cooling depending on existing plant conditions (e.g. low BWST inventory). (COOLDOWN METHOD 1 should be used for the entire transient if the condenser and RCP's are available - See Figure C-3, Sheet 2.)

B. Small Leaks With RCP's Off

Intermittent or minimal continuous feeding and steaming may be required to maintain natural circulation in the affected loop and to prevent stagnation and flashing in the RCS. The cooldown rate should be as large as possible up to 100F/hr. Pressurizer level should be maintained. The tube-to-shell temperature difference should be maintained within the emergency limits (150F). Continuous feeding and steaming of the affected OTSG, at low flow rates, may be required to maintain natural circulation and the tube-to-shell limits. Cooldown Method 2 should be used. (See Figure C-3, Sheet 2)

C. Large Leaks/Ruptures with RCP's On or Off

If the tube leak is large enough, the affected OTSG will contribute significantly to RCS cooling. The best approach is to steam the affected OTSG at a rate adequate to maintain a constant level. The rate of cooling (100 F/hr) can then be controlled by steaming the unaffected OTSG. If the affected OTSG begins to fill, steaming should be increased to limit level to 95% on the operate range. The rate of RCS cooling may be temporarily exceeded to achieve level control. Once the 95% level is reached, continuous steaming of the leaking OTSG, without feedwater addition, will be required to maintain a constant rate of RCS cooling and to prevent overfill. Toward the latter stages of the cooldown, the affected OTSG may begin to fill because the boiloff needed to remove decay heat is less than the leakage from the RCS into the OTSG. If this occurs, most of the heat removal should be transferred to the affected OTSG. Intermittent feeding and steaming of the unaffected OTSG may be required to maintain natural circulation (if RCP's are tripped), 100 F/hr cooling, and the emergency tube-to-shell limit. Cooldown Method 2 should be used. (See Figure C-3, Sheet 2.)

8.0 COOLDOWN AND DEPRESSURIZATION TO COLD SHUTDOWN

The final step for mitigating tube leaks is to bring the plant to a completely depressurized condition. The tube leak rate will be the lowest when the RCS pressure is approximately equal to the steam generator pressure. To achieve this condition, the RCS must be depressurized so that the decay heat removal system can be started. The RCS subcooling requirements will not allow equalization of RCS and secondary system pressures while the steam generator is removing heat. When the decay heat removal system is started for heat removal, the steam pressure can be allowed to remain slightly higher than the RCS pressure. Reverse leakage will occur, but the effect is minimal if this condition is not maintained for extended periods of time.

Although the leak flow will be lowest when the RCS is placed on the decay heat removal system, further cooldown and depressurization is required. Since the elevation of the hot leg "candy cane" is always higher than the tube leak, elevation head will cause the leak to continue. Special actions for handling the leak after the decay heat system is placed in the decay heat removal mode of operation will be described in Section 11.0.

Control of plant depressurization is needed to bring the plant to cold conditions; methods of depressurization are described in Section 11.0.

The approach chosen for cooldown to the decay heat removal system will depend on the conditions of the plant at the start of cooldown. To determine the method of cooldown the leak size, condenser availability, RC pump availability, and other factors must be known.

The following subsection describes the various factors to be considered for final cooldown:

8.1 Selection of Plant Cooldown Method

Figure C-3 shows the three methods of plant cooldown to be selected. There are two basic cooldown rates shown in this figure; "normal" and "emergency". The "emergency" approach applies to an RCS cooldown when either one or two generators are available.

A "Normal" cooldown is defined by limits as:

- For the entire cooldown a close-to-normal cooldown rate is used ($\leq$ 100F/hr)
- Tube-to-shell temperature limits do not exceed 100F
- Fuel compression limits are not violated deliberately

An "Emergency" cooldown is defined by limits as:

- Tube-to-shell temperature limits do not exceed 150F
- Fuel compression limits may be deliberately violated
- The RC temperature should be dropped to 500F as fast as possible (not to exceed 240 F/hr)
- After 500F is reached the cooldown rate should be as close to 100F/hr., as long as that rate can be held. Steaming of both OTSG's will be required at lower RCS temperatures. The cooldown rate should be reduced when the tube-to-shell temperature limit approaches 150F (unless there is danger of running out of BWST inventory).

The cooldown method is selected primarily based on four conditions: leak size, RCP status, availability of the condenser, and steam line integrity on the SG with the tube leak. These four conditions take into account the severity of the event. If the leak is large or the condenser is not available, offsite releases will be large and the emergency approach is chosen. Small leaks with the condenser and RCP's available will not allow a significant release so a normal approach is selected.

Method 1 (near "normal" cooldown) is selected when:

a. The condenser is available, and

b. The tube leak is small, and

c. The RC Pumps are operating.

d. The SG with the tube leak does not have an unisolable steam leak.

Note that all conditions must be satisfied to use the "normal" method.

Method 1 is a "normal" cooldown except that the affected OTSG is isolated when the reactor coolant temperature is reduced to less than 540F. It should be used for SGTR's where the leak rate is small (well within the capacity of the MU system). For this mode, all normal plant equipment or systems (condenser, RC pumps, pressurizer sprays, etc.) must be available. The plant should be cooled within normal plant cooldown limits (fuel compression limits, 100F tube-to-shell ΔT's, etc.). This cooldown method will most likely be preceded by a plant runback since the leak rate is small. This cooldown method is the most likely condition which will be faced, based on tube failure histories with the OTSG.

The entire cooldown should be by the single operating generator. To cooldown with one generator under these conditions the following apply:

1. RC Pumps will keep circulation in both loops; if all RC Pumps were off the reactor coolant in the isolated generator would flash and prevent cooldown and depressurization. The RC

Pumps also allow spray depressurization which is more controllable than PORV depressurization.

2. The leak is small enough and the cooldown is fast enough with one generator so that the water accumulation in the isolated generator will not build up and require steaming to lower the water level. The generator can truly be used to store the leaking reactor coolant. The level should still be closely monitored and steaming should be started if the water level approaches 95% on the operate range.

3. Continuous heat removal by the single generator is needed. The single generator will not only remove heat from the reactor coolant and core but also from the secondary fluid in the isolated generator, which acts as a heat source. At lower RC temperatures, the additional heat removal requirements on the good OTSG may result in a significant reduction in the rate of RCS cooling. If the rate of cooling is significantly reduced or interrupted, the isolated generator TBV's should be opened to increase RCS heat removal, if a higher rate of cooldown is needed to prevent BWST depletion or to prevent overfill of the affected OTSG. Bypass the SLRDS to prevent inadvertent isolation of feedwater during RCS cooldown.

4. Depressurization should be controlled so that it closely follows the subcooled margin curve. A minimum reactor coolant subcooled margin should be maintained so that the leak rate is as small as possible (However, do not violate RCP NPSH requirements).

5. Feedwater to the ruptured generator should be isolated after the appropriate level is established. The SG will be cooled as heat is removed from the generator and shell heat will reduce in the region contacted by the water in the generator. Steam generator tube-to-shell ΔT should be monitored and normal limits maintained. The rate of cooldown should be controlled to maintain normal limits.

The "emergency" method is selected when:

a. the condenser is not available, or

b. the leak is large, or

c. the RCP's are not available or

d. An unisolable steam leak exists on the OTSG with the tube leak.

Note that if either one of the above conditions exists, the "emergency" method must be used.

Figure C-3 shows emergency methods for conditions when one generator or both generators are available.

The cooldown method 2 shown in Figure C-3 is to be used for a SGTR when HPI must be used to makeup for the leak rate and both steam generators are available and removing heat when the plant cooldown is initiated. This cooldown method can be preceded by a reactor runback or by an automatic reactor trip (if the SGTR is large or other equipment failures occur). The general actions used for this cooldown method are as follows:

1. Once the plant has been rapidly cooled down and depressurized to about 500F and 1000 psig, pressurizer level has been stabilized, and the feedwater and steam on the SGTR have been isolated:
   - If the condenser is not available, the ADV's must be controlled manually to continue the cooldown. If the condenser is available, then the TBV's should be used.
   - If the RC Pumps were tripped on loss of subcooling margin, one RC pump per loop should be restarted if conditions permit; restart of the pump in the spray loop taking precedence to make the pressurizer spray is available (See Pump Restart Criteria in Part II "Best Methods of Equipment operation). If the RC pumps cannot be restarted then the PORV must be used for depressurization.

2. From 500F and 1000 psig, continue the plant cooldown and depressurization at up to 100F/hr with the unaffected OTSG, using the affected OTSG only as required, until the decay heat system can be started.
   - Maintain the RCS as close as possible to the subcooling margin to minimize the leak. Do not violate RCP NPSH requirements if RCP's running.
   - Monitor the water level in the isolated SG and initiate steaming if the water level rises above 95% on the operate range.

- If the leak does not provide enough water to keep a minimum level (natural circulation or forced level as appropriate), then feed the ruptured generator as required.
- If the plant is in natural circulation, both generators must be fed and steamed as necessary to maintain natural circulation in both loops.
- Monitor tube-to-shell limits and slow the plant cooldown so as not exceed a ΔT of 150F (See Part II, "Cooldown With One Steam Generator Out of Service".).
- Bypass the SLRDS to prevent inadvertent isolation of feedwater.

3. After the decay heat removal system has been started, continue to cooldown and depressurize to cold shutdown so the loops can be drained and repairs started.

The above cooldown procedure is an emergency measure. Its goal is to get the plant to a depressurized state as quickly as possible to stop the leak and minimize offsite releases. In this method, fuel compression limits do not apply. Method 2 can be applied when all plant systems are available or under more degraded conditions such as a loss of offsite power. Figure C-3 outlines this cooldown method; it shows the ways the plant can be controlled and identifies monitoring and corrective actions which are unique to a SGTR.

Method 3 cooldown is identical to Method 2 except that only one steam generator is available for heat removal when the plant cooldown is started. As indicated in Figure C-3, this could result from equipment failures that result in a loss of feedwater to one OTSG or a loss of steam pressure control on one OTSG. The failed steam generator may or may not contain the SGTR. The actions required for Method 3 are the same as Method 2 except that isolation of the affected SG at less than 540F may not be possible. For Method 3, significant offsite releases can occur under some failure modes. Figure C-3 outlines this third cooldown method and the circumstances when large offsite releases could occur.

Since the Method 3 "one generator cooldown" can only come about because of failures, it will be discussed in more detail in the following sections which address failures.

A summary of the SGTR conditions and appropriate cooldown methods follows:

SGTR Conditions	Cooldown	Comments
Normal		
Small Leak RCP's On (No Unisolable Steam Leak and Condenser Available)	Method 1	Isolate Affected OTSG
Emergency		
Small Leak RCP's Off (and/or Unisolable Steam Leak or Condenser Unavailable)	Method 2	Isolate Affected OTSG
Large Leak RCP's On	Method 2	Isolate Affected OTSG
Large Leak RCP's Off	Method 2	Isolate Affected OTSG
One Generator Cooldown	Method 3	Refer to Section 9.0

9.0 PLANT CONTROL FOR TUBE LEAKS WITH OTHER FAILURES

Some plant equipment failures, in addition to the tube leak, can make plant control very difficult. Some failures will make it difficult to establish a stable condition for cooldown; some will cause the cooldown rate to be much slower than desired. Some failures can cause the offsite releases to be large. Some failures can be repaired or bypassed and some cannot. All of the failures that can make plant control difficult will be of two kinds:

- Those that limit the heat removal of the steam generator(s) (these failures will limit the ability to establish hot standby and will limit the cooldown rate).
- Those that limit the ability to depressurize the RCS (these failures will limit the depressurization rate and may require the cooldown rate be limited in order to stay within RV pressure-temperature limits).

Table C-3 summarizes the major failures and the actions required to correct them. The general approach for correcting other equipment failures that occur in addition to the tube leak is as follows:

- As quickly as possible:
  a. Depressurize and cool the reactor coolant system (if possible) and bring the system to the point where the RCS pressure is below the setpoint of the steam safety valves. Most failures will not prevent this step and may even cause the depressurization.

b. Diagnose the additional failures in accordance with the principles shown elsewhere in these guidelines.

- Correct the failure prior to or during the final cooldown to cold shutdown. Do not delay the cooldown even if the failure limits the rate of RCS cooling and depressurization. Details of the effects of and corrections for failures are shown in Tables C-2 and C-3.
- If the failures cannot be corrected to enable both generators to be used or the RCS cannot be depressurized with use of the pressurizer spray, vent or the PORV, then the cooldown will be difficult. In general, these kinds of failures are limited to:

  a. Failure of a main steam safety valve (open). This will not allow a normal rate of feedwater addition, because excessive RCS cooldown rates will result.

     Turbine bypass failures may be corrected by isolating the failed valve(s) and do not apply; MSSV failures cannot be isolated. The plant must be cooled down with the remaining generator even if it has the leaky tube. Radiation dose release may be high if the open steam valve is in the same generator as the tube leak. Failure of a steam safety valve (open) will not allow a "normal" rate of feedwater addition (excessive RCS cooling rates will result). During cooldown, the generator with the low pressure must be

continuously fed at approximately 50,000 lbm/hr, preferably through the main feedwater nozzles. Bypass the SLRDS to maintain the availability of MFW to the failed OTSG. Feeding the OTSG will maintain cooling of the lower shell and keep the tube-to-shell temperature difference within limits. If the generator is completely depressurized, care must be exercised when feeding. A flow path through the start-up feed regulating valve or their manual bypass can be used to achieve low feed flow rates (~100 gpm). If the RCP's are tripped, it is important to provide some feeding of the depressurized generator to establish or maintain natural circulation. If the steam failure is in the affected (ruptured) generator and the leak flow is large, the tube leak will usually provide adequate cooling. Unlike most other transients in which feeding a depressurized generator is not recommended, a SGTR requires RCS cooldown to terminate the transient; therefore, careful feeding of a depressurized generator is allowed.

Steam leaks will most likely occur outside containment and be caused by valve failures rather than piping failures (TBV, MSSV's, etc). If the steam leak occurs inside containment, it will likely be a piping failure in a steam, feed, or drain line. If the steam failure is on the steam generator with the tube leak and is inside the containment,

the reactor coolant from the tube leak will be returned to the containment sump. Although adverse containment conditions may result, the offsite releases will be minimal after the RC temperature reaches 540 F.

b. A loss of all feedwater to one OTSG will normally require cooldown on the remaining generator. The rate of RCS cooling must be slow to prevent violation of the tube-to-shell temperature limits on the OTSG without feedwater. If the RCP's are tripped, the rate of cooling will be even slower; reactor coolant will not naturally circulate in the idle loop. The stagnant loop must be closely monitored for saturation in the hot leg. Releases offsite will be significant because of the slow rate of RCS cooling and depressurization. Every effort should be made to realign feedwater to both generators. If realignment cannot be achieved, the BWST inventory should be replenished to avoid loss of injection water. If feedwater is lost to the ruptured OTSG and large leak flows are present, the leak will provide enough feedwater to maintain cooling of the affected OTSG.

c. Pressurizer failures (e.g., open or leaking valves) may require constant HPI to maintain subcooling. Failures in the pressurizer steam space will cause HPI to fill the pressurizer.

RCS depressurization from this solid water condition will require throttling of HPI without loss of subcooling. The BWST inventory should be carefully monitored when this mode of depressurization is utilized for extended periods of time.

d. Total loss of feedwater (MFW and EFW) will require a solid water cooldown without the benefit of secondary heat removal. Attempts should be made to obtain feedwater from any available source. For cases of this type which require excessive cooldown times, BWST inventory should be carefully monitored. HPI inventory from the BWST will flow into the affected OTSG and ultimately be released offsite. It will not be returned to the reactor building sump and cannot be reclaimed. Therefore, backup water supplies for the BWST may be necessary and should be prepared. Offsite releases will be very significant.

10.0 LIMITS FOR RCS COOLDOWN

The following is a summary of the basic limits which the operator should be aware of while proceeding with the RCS cooldown for all SGTR's:

1. The maximum allowed cooldown rate is 100 F/hr for small leaks with the condenser available, RC pumps running, and SGTR does not have an unisolable steam leak. Cooldown rate is as close to 100 F/hr as possible except where tube-to-shell temperature limits restrict cooldown rate. Overcooling should be avoided and the pressurizer should not be allowed to drain. If the plant is on natural circulation, the cooldown rate should be reduced to avoid RCS voiding (the recognition of void formation is discussed in Part II, Volume 1 of the ATOG). Cooling with both OTSG's may be required, at least periodically, to maintain natural circulation.

2. The minimum subcooling margin should be maintained. Excessive subcooling should be avoided to keep a minimum leak rate. However, at lower pressures and temperatures when RC pumps are operating, the RC pump NPSH requirements may become more restrictive and should not be violated while pumps are operating.

3. Normal tube-to-shell temperature limits (100F) apply to the case of small tube leaks, no unisolable steam leaks, RC Pumps running, and the condenser available. Emergency tube to shell temperature limits (150F) apply to all other situations, except:

The emergency limits may be violated at management discretion, if loss of core cooling injection water is imminent (BWST draining). The steam generators are likely to be unusable if the emergency limits are violated, however, core cooling takes priority.

4. Fuel compression limits apply to the case of small tube leaks, no unisolable steam leaks, RC Pumps running, and the condenser available; they may be violated for other cases.
5. The plant should be completely cooled down and depressurized before the BWST is drained. Simply placing the decay heat removal system into operation is not adequate.
6. It is desirable to place the plant on the decay heat removal system before the condensate storage tank is depleted and poor quality backup water is injected into the steam generator.

11.0 SPECIAL TOPICS RELATED TO COOLDOWN

11.1 Ways to Depressurize the RCS

Two ways are available to depressurize the primary system. The first way is to use the pressurizer spray, and the second is to vent the pressurizer using the vent or PORV. Use of the pressurizer spray is the preferred method since vent and PORV operation can result in a drain tank disc rupture, abnormal reactor building pressure and temperature, and additional RB cleanup efforts. Pressurizer spray also provides better control in comparison to cyclic PORV operation.

RCP operation should be maintained whenever possible to maintain pressurizer spray. (Refer to Table C-3, Sheet 3 of 3, for spray flow vs. RCP combinations). Refer to Figure C-3, Sheet 2, for a P-T diagram of the RC cooldown and depressurization using the pressurizer spray.

If the RCP's have been tripped, the RCP's should be restarted as soon as the restart criteria are satisfied (refer to RCP restart guidelines in "Best Methods for Equipment Operation"). The RCP's should be restarted (with preference to spray) in the following order:

1. One RCP in each loop.
2. Two RCP's in one loop.
3. One RCP in loop with pzr spray line.
4. One RCP in loop without pzr spray line.

The performance of the RC pump motor and seal cooling systems should also be periodically monitored to ensure that the pumps can be continuously run until the decay heat removal system is placed into a cooling mode of operation. Operation of the RCP's not only allows the pressurizer spray to be used but:

- May eliminate the need to add feedwater to the affected OTSG to sustain natural circulation.
- Provides a faster rate of RCS cooldown due to better mixing of the reactor coolant.
- Prevents significant void formation that otherwise could occur during natural circulation cooldown on one OTSG.

If an RCP operating combination must be selected which only provides a limited amount of spray flow (refer to failure Table C-3, RC pressure 1), periodic use of the pressurizer vent and/or PORV may be used to augment spray depressurization. PORV, vent and spray depressurization is preferable to use of the PORV alone.

In the event the pressurizer spray is off or the RC pumps cannot be restarted, the pressurizer vent or PORV must be used to depressurize the plant. In general, it will not be possible to open the vent or PORV and maintain pressurizer level and pressure control. Instead, cyclic operation (open-shut) will be necessary. The best way to maintain plant control is to continue the RCS cooldown and depressurize with the vent or PORV in a sawtooth manner between the subcooling margin and a temperature around 30F colder than the subcooling margin line, as shown on the P-T diagram of Figure C-4. This minimizes excessive RC subcooling while providing room to depressurize.

When the PORV is opened, pressurizer conditions should be closely monitored. As the pressure drops some of the water in the pressurizer with flash to steam which would caused level to decrease. However, the expansion of the liquid volume may have a greater offset casuing pressurizer level to increase. Makeup and letdown flow should be adjusted as necessary to maintain an adequate pressurizer water inventory.

Also when the PORV is opened, monitor the drain tank conditions and if possible, adjust the PORV "open" time to prevent failure of the rupture disc. However, RCS cooldown and depressurization take precedence over drain tank disc rupture.

11.2 Placing The Decay Heat Removal System into Operation

Once the plant has been cooled down and depressurized, the decay heat removal system (DHRS) is used for final cooldown and depressurization. The cooldown should still continue as fast as possible (up to 100 F/hr). Special actions must be taken for tube leaks when the decay heat system is actuated to continue SGTR mitigation

1. As a general rule, if the RCS is saturated (which will occur only if several tubes are failed), it may not be possible to place the DHRS into operation; (liquid level above the drop line is not known and a loss of decay heat suction would cause pump cavitation). However, if it is definitely known that no LOCA other than a tube leak exists, the decay heat removal system can be placed into operation. The reason is that the leak location is such that liquid will be trapped in the lower parts of the hot leg. The RC pump elevation will trap water between the pump and the vessel. When the RCS is saturated and the decay heat system is engaged,

the decay heat pumps must be locally monitored for cavitation. The pumps must be shut down qucikly after loss of suction to prevent cavitation damages.

2. One decay heat pump should be aligned in the decay heat removal mode; the other in the injection mode from the BWST.

Decay heat removal system startup after forced circulation cooldown: (The following options may be available):

1. Continue RC pump operation until the hot leg temperature is lower than 212F (one pump in each loop is adequate) to prevent RC flashing in hot legs if not adequately cooled or
2. Place the decay heat removal system into operation at a higher temperature. After the DHRS is placed into operation, stop the RC pumps, monitor hot leg temperatures for saturation, and control cooldown rate to avoid saturation. If saturation occurs, "bump" a pump. A slight pressure rise may occur.

Decay heat removal startup after natural circulation cooldown:

In general, the steps are similar to the forced circulation method; however, it is not likely that the hot leg reactor coolant can be cooled to 212F using the steam

generators, consequently hot leg flashing is more likely. To avoid hot leg flashing:

- Just before placing the DHRS into operation "bump" a pump, if possible.

or

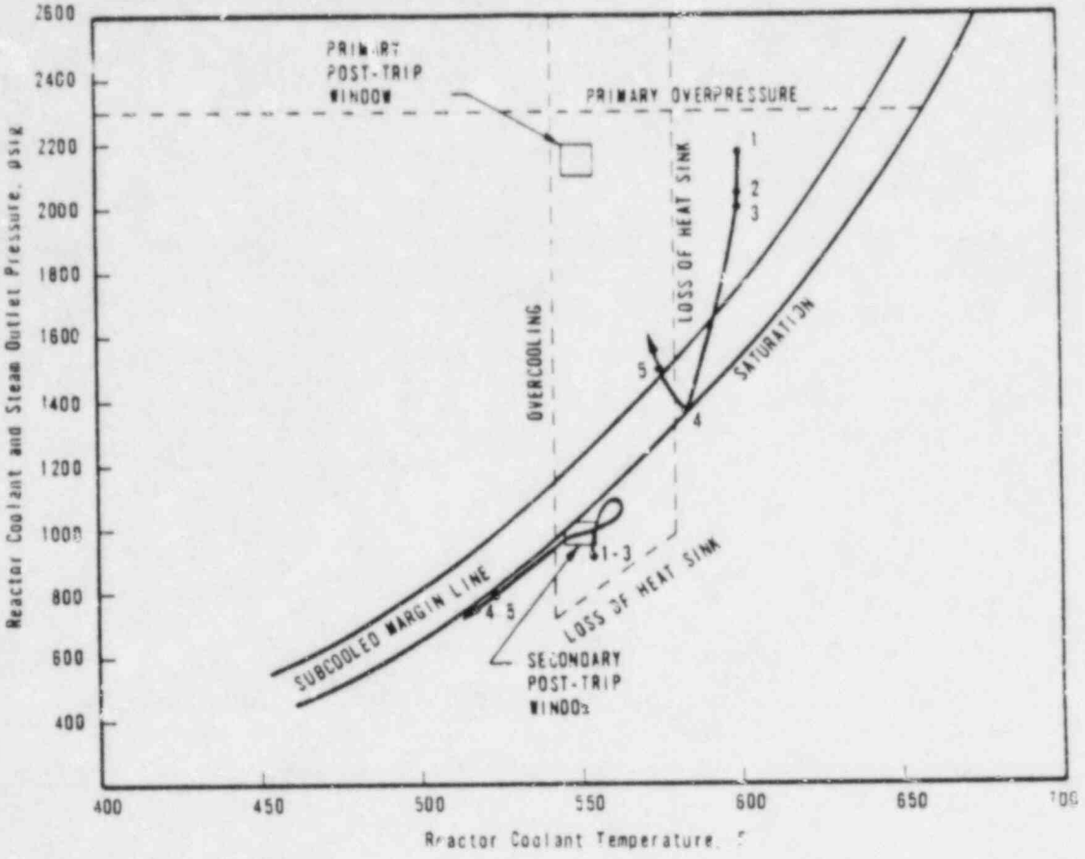
- When the decay heat system is placed into operation, control the rate of cooldown and further depressurization to avoid hot leg saturation.

Operator Actions During DHRS Operation:

- Isolate the steam generator with the tube leak at the steam and feed lines. Steam pressure may rise for a short time, but thereafter will drop since the reactor coolant temperature will be lower than the steam generator liquid temperature; lack of heat transfer into the generator will not permit steam pressure to build up.
- Add nitrogen to the isolated steam generator to provide a slight overpressure. When the RCS is completely depressurized, the nitrogen pressure should be about 2-3 psi greater than RCS pressure.
- Do not isolate the remaining generator; it may have to be used for heat removal if the RCS repressurizes and reheats.
- Since the hot leg is at a higher elevation than the steam generator, a small leak rate can occur into the

generator after the RCS is depressurized. Liquid can be allowed to accumulate in the isolated generator as long as continued heat removal occurs and reheat and repressurization is avoided. It may be desirable to manually drain liquid accumulation to avoid complete filling (600 inches on the wide range level) if a radioactive waste reservoir is available. Draining should not be performed above the design pressure of the waste systems.

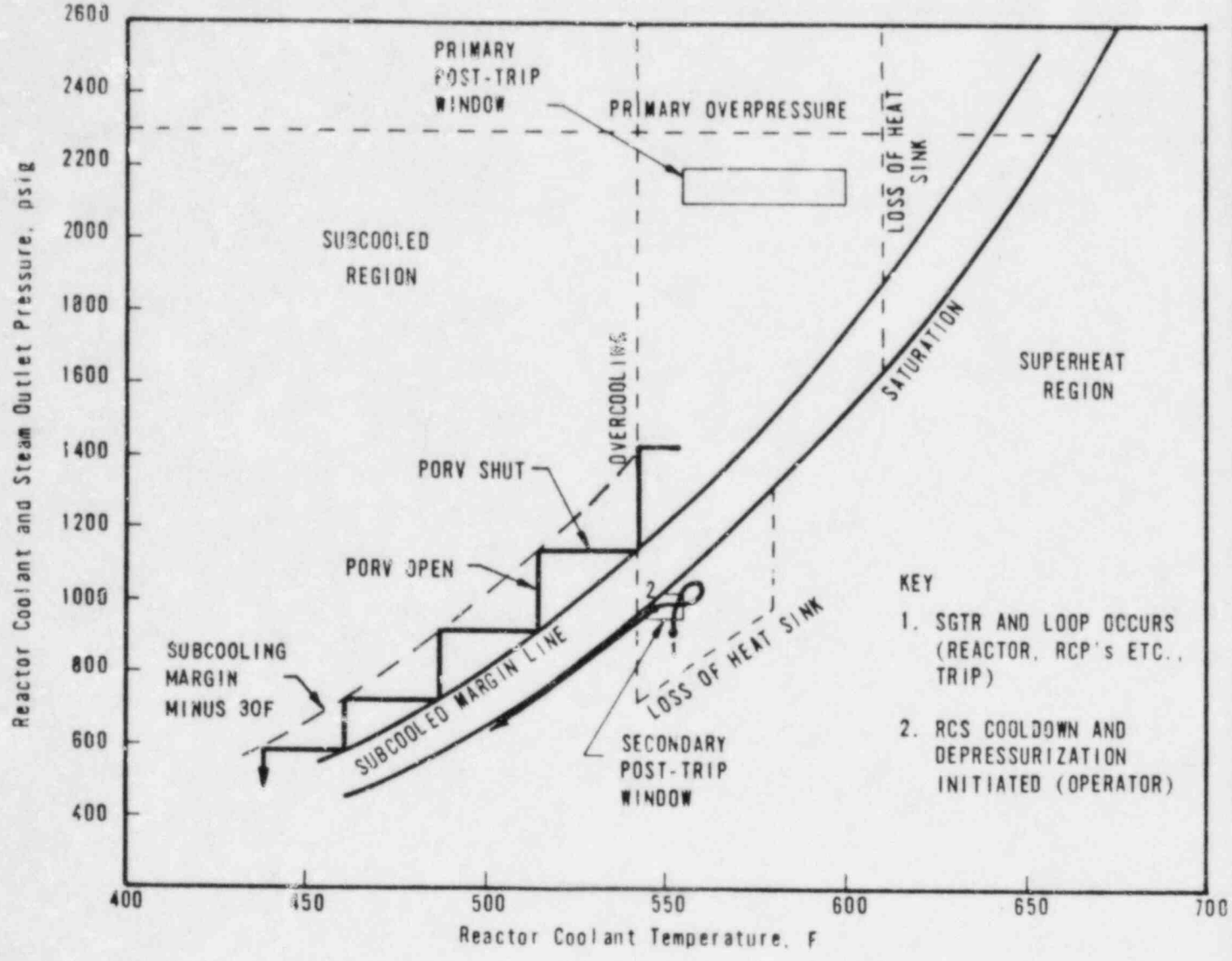
Figure C-2 TYPICAL STEAM RESPONSE FOR LARGE SGTR WHICH RESULTS IN A REACTOR TRIP



Reference Points	Time (Seconds)	Remarks
1	0	A SGTR occurs from 100% FP. (Initial leak rate ~ 400 gpm)
1-2	0-440	RC pressure and pressurizer level slowly drop. • Pressurizer heaters come on; • High MU flow alarm occurs (approximately 160 gpm) Steam line and condenser radiation alarms sound.
2	300	Pressurizer level falls below 80 inches; pressurizer heaters turn off automatically.
2-3	300-660	RC pressure and pressurizer level continue to drop because the leak rate exceeds MU (no operator action assumed)
3	650	Reactor trips on variable low pressure (P_{RCS} ~ 2000 psig).
3-4	660-680	The turbine trips; MFW runs back; the reactor coolant subcooled margin is lost (RC pump trip required); ESAS actuated on low RC pressure; HPI starts.
4	680	The pressurizer completely drains and the reactor coolant is saturated.
4-5	680-900	The RC pumps are tripped and EFW starts. The operator throttles EFW to prevent overcooling. The reactor coolant subcooled margin is reestablished, and the operator throttles HPI to stablize pressurizer level and system repressurization.
5	>900	The plant is stable with decay heat being removed by natural circulation. The RC pumps can be restarted and a plant cooldown and depressurization can be initiated. A minimum subcooled margin is maintained to keep RC pressure and leak rate low.

74-1124158-00

Figure C-4 RCS COOLDOWN USING PORV



74-1124158-00

Table C-1 WAYS TO DETECT A SGTR

1. Abnormal Radiation Level in Steam Plant • High readings and alarm of condenser vacuum pump discharge radiation monitor • High readings and alarm of main steam line radiation monitors.	The secondary plant radiation monitors give the best indication of a primary to secondary leak. They are effective when both the SGTR is the only transient and when a SGTR occurs along with another transient. Both the steam line and condenser radiation monitor will indicate a SGTR; but, the individual steam line monitors will show which steam generator is leaking. Typically, a condenser radiation alarm and an alarm on one of the steam line monitors will sound if a SGTR occurs. NOTE: A local frisk of the steam lines using portable equipment can also be done to find the affected OTSG.
2. LOCA Symptoms • Decreasing RCS Pressure • Decreasing Pressurizer Level • High MU FLow (or HPI initiation) • Low Makeup Tank Level	The LOCA symptoms depend on the size of the SGTR (leak rate) and may not show up immediately if the leak rate is within the capacity of the normal MU system. These symptoms are best utilized as confirmatory indicators of a SGTR. NOTE: A SGTR can be distinguished from a normal small break LOCA in that normal RB conditions (Pressure, temperature, and radiation) should exist unless additional equipment failures occur.
3. Asymmetric SG Conditions • Increasing water level with zero feedwater addition.	Once the plant is tripped, asymmetric OTSG water levels may develop. When feedwater is stopped and water level is at or above the appropriate control setpoint, the water level in the affected OTSG may continue to rise because of the primary to secondary leakage. This method of detection should be used only as a backup because it is effective only for very large leak rates. For small leaks asymmetric water level conditions will not develop; the reactor coolant will simply boil off as if it were normal feedwater. The differences in indicated feedwater flows between the unaffected and affected OTSG will not be significant enough to detect unless the leak is large and the reactor has tripped.
• High activity levels or boron concentrations in the secondary water inventory.	The affected OTSG can also be identified by drawing an OTSG water sample. The affected OTSG will contain some activity and boron due to the presence of reactor coolant. This method of detection is time consuming and requires action outside the control room. Coolant sampling becomes less effective as the transient evolves and the reactor coolant is mixed with the secondary coolant.

LOOP

APPENDIX D

LOSS OF OFFSITE POWER

1.0 GENERAL TRANSIENT DESCRIPTION

Loss of offsite power is a failure to provide power to the plant auxiliaries from an offsite source. It is not an "abnormal" transient or a failure to control the plant unless coincident failures occur.

This transient is initiated by the plant separating from the grid due to a grid upset. The unit auxiliaries are powered by the main generator through the auxiliary transformers during both normal operation and grid separation. Therefore, power is still supplied to all plant auxiliaries and the ICS (by design) begins to run the plant back to 15% power.

Since the turbine was supplying 100% power and "house loads" are only about 4% full power, the turbine protection system must partially close the turbine throttle valves to prevent overspeed. This results in a sudden increase in secondary pressure and temperature and consequently an increase in primary pressure and temperature. The steam produced during the runback will be dumped to the turbine through the turbine throttle valves, to the condenser through the turbine bypass system, and to the atmosphere through the atmospheric dump valves.

With the present pressurizer power operated relief valve setpoint (2450 psig) and high pressure trip setpoint (2300 psig), the plant will trip during the runback. All power will be lost to the plant auxiliaries except those components loaded on the 125V DC battery banks

The 1D and 1E 4KV ES bus feeder breakers trip when loss of power is detected by the bus under voltage relays. The under voltage relays also start the diesel generators.

When the diesel generator is up to speed and voltage the diesel breakers close, and power is restored to the ES buses. Some loads automatically start; however, essential loads must be verified and/or started by the operator. The operator must start a makeup pump and restore seal injection.

Because the reactor coolant pumps have lost power, natural circulation must be used for decay heat removal. To assure natural circulation is established both the steam driven and electric driven emergency feedwater pumps are automatically started (the electric driven pumps have a 5 second delayed start after the diesel generator energizes the 1D and 1E buses). Water from both the steam and motor driven EFW pumps will be automatically directed to the steam generators. EFW is desirable when establishing natural

circulation because it enters at the top of the OTSG and will provide a higher thermal center for heat removal.

However, the injection of EFW from the EFW pumps into the top of the OTSG's will slowly quench or condense the steam. As a result, the OTSG steam pressure will decrease at a rate dependent on the EFW flow rate and the decay heat rate.

Therefore, EFW should be throttled by the operator to prevent this overcooling of the RCS. Following the EFW throttling guidelines the operator should throttle flow such that:

1. OTSG level is continuously increasing; and
2. Steam pressure does not decrease more than 100 psi below its target value.

The main condenser stops operating after a loss of offsite power (LOOP) because the circulating water pumps are not powered.

Because of this, the ICS will isolate the condenser (i.e., stop the turbine bypass steam flow to the condenser) and shift pressure control to the atmospheric dump valves (ADVs). The steam safeties will reseat in less than a minute after the LOOP and thereafter the ADVs (if air supply is available to the valve operator) will relieve steam to the atmosphere as necessary.

As the plant approaches steady state, the OTSC level will reach its setpoint and EFW flow will modulate to maintain this level. Steam pressure and temperature will return to the ADV setpoint and ADVs will relieve steam to the atmosphere. Primary temperature will increase slightly as steam temperature increases. Primary pressure will also increase as makeup flow raises pressurizer level to its normal setpoint. When secondary pressure has increased to the ADV setpoint and pressurizer level is at its post trip setpoint, primary to secondary heat transfer will again be equal and the plant will be at steady state.

Actual Plant Loss of Offsite Power

On February 22, 1975, Arkansas Nuclear One, Unit 1, was operating at 100% power when a storm blew down a 500 kv transmission line near Little Rock, Arkansas. This resulted in a loss of offsite power.

The reactor, and consequently, the turbine generator, tripped due to under voltage to the control rod drive breakers. The reactor did not trip on high RC pressure as would be expected. The control rod drives are normally powered from startup transformer #1 and make a transfer to the auxiliary transformer upon LOOP. During this trip there apparently was a momentary delay in this transfer and the control rods fell into the core. Buses H-1, H-2, and A-1 transferred to startup transfer #1 which had lost power due to the LOOP. Bus A-2 transferred to startup transformer #2.

Following the reactor trip, the reactor coolant and main feedwater pumps tripped placing the plant in a natural circulation mode. The diesel generator (DG1) started automatically and emergency feedwater and makeup flow was initiated in about 30 seconds after the LOOP. After approximately 4-1/2 minutes bus H1, H2, and A1 were switched to startup transformer #2 which was powered and one RC pump was started in each loop.

Figures D-1 through D-5 show the plant data. Figures D-4 and D-5 show the OTSG full range level and steam pressure versus time. Since OTSG level was slowly decreasing, the EFW flowrate was probably very small. Although the OTSG level should be raised to 50% on the operate range after a LOOP, the failure to do so in this case did not adversely affect the transient for the first five minutes. However, failure to raise the level for an extended period of time could possibly have led to possible loss of natural circulation.

The slow oscillations in steam pressure are probably due to the steam safety valves lifting and blowing down. Steam pressure leveled off at about 1010 psig which is the setpoint of their ADVs.

Figure D-1 and D-2 show the hot and cold leg temperatures versus time for loops A and B. The initial decrease in RC temperature after trip is followed by a slow rise in the hot leg temperature. The hot leg temperature should be approximately 20-40F higher than

the cold leg when natural circulation is developed. The cold leg temperature will approach the saturation temperature of the steam pressure.

Figure D-3 shows the loop A RC pressure versus time after trip. After an initial decrease due to T_{ave} decrease following a reactor trip, the pressure begins to increase. This is caused by the injection of makeup and the reactor coolant expansion due to the increasing hot leg temperature.

Figure D-6 is a P-T diagram of the ANO LOOP of February 22, 1975. This plot is similar to but not exactly the same as Figure D-10. Since the plant tripped on loss of power to the control rod drives, there was no initial spike in pressure.

Figure D-10 shows a temporary increase in both pressure and temperature before OTSG level reaches 50%. This increase is due to the increase in the ΔT required to establish natural circulation. The plant data for the February 22, 1975 LOOP does not show a similar trend. This difference is due to the long time interval used between plant data points.

2.0 OPERATOR ACTIONS SUMMARY WITH NO OTHER PLANT FAILURES

Major Operator Action

- Verify both diesel generators have started and are loading.
- Verify EFW has started to both OTSG's then throttle flow to both OTSG's such that:
  a. OTSG level is increasing to 50% on operate range and
  b. Steam pressure does not fall more than 100 psi below its target value.
- Start a MU pump, establish makeup and RCP seal injection
- Restore instrument air supply

Identifying Symptoms

- A loss of offsite power is a failure to provide power to the plant auxiliairies from the offsite source. It is not a failure to control the plant unless additional failures occur. A typical P-T plot for a loss of offsite power is shown in Figure D-10.
- Other identifying symptoms to help distinguish a LOOP from other transients are:
  - RC and MFW pump trip
  - Loss of voltage indication on 230 kv bus
  - Trip of condensate and circulating water pumps
  - Automatic start of diesel generators

Discussion

This section will discuss how actions in accordance with Part I of ATOG will help the operator recognize a loss of offsite power and obtain a stable shutdown after it occurs.

An operator using the guidelines for the event described would first perform the Immediate Actions of Part I, section I; then go to Section II, Vital System Status Verification. The first verification which might require action is to verify that letdown is stopped. The letdown flow should be automatically isolated on a reactor trip. If not it should be manually isolated. Step 5.0 requires the operator to verify that feedwater has runback. However, both MFW pumps will trip after a LOOP and EFW will be automatically initiated. Therefore, the operator does not need to take any remedial action at Step 5.0.

Step 7.0 is the crucial step for diagnosis of a LOOP. At least one auxiliary transformer should have normal voltage on its secondary. If not, a LOOP has occurred.

The remedial actions to be taken for Step 7 include

a. Start or verify the auto start and loading of the diesel generators (automatic);
b. Raise OTSG operate level to 50% (automatic) while throttling EFW (manual); and

c. Restart at least one makeup pump and provide seal injection to the RCP's (manual).

d. Verify auto start of the important plant cooling water systems.

e. Get instrument air operating.

f. Control SG pressure with ADVs.

3.0 LOSS OF OFFSITE AC POWER WITH OTHER PLANT FAILURES

Introduction

The previous section described loss of offsite power with no coincident failures. This section will show what symptoms indicate other equipment has failed and what steps the operator should take to correct the heat transfer from the core to the steam generators.

In addition to a possible failure of one of the major control functions discussed throughout these guidelines, both diesel generators can fail to start after a LOOP. While this is not one of these control functions, it can result in loss of RC Inventory and Pressure Control.

Branch Discussion

The loss of Offsite Power Logic Diagram (Figure D-9) has separate failure branches for loss of reactor inventory control (low and high), loss of secondary inventory control (high and low), loss of primary pressure control (low), and loss of secondary pressure control (low), and loss of all power except batteries. This section will discuss each of these additional failure branches and illustrate how operator actions in accordance with procedures in Part I will restore proper control of the parameter in question.

Figures D-7 and D-8 show typical primary and secondary pressure and pressurizer and OTSG full range level trends for each of the failure branches.

Loss or Reactor Inventory Control (Low)

A loss of reactor inventory (low) exists whenever makeup or HPI is insufficient to overcome a primary leak rate. The most probable primary leak is a failure to stop letdown, after a reactor trip. The letdown isolation valve should automatically close on a reactor trip.

The makeup pump busses are automatically loaded onto the diesel generators. However, the operator will need to manually start the pumps. If he does not do so, the pressurizer will drain unless letdown is isolated. This is especially likely if excessive EFW occurs and overcools the primary.

In either of the above cases (excessive letdown or inadequate makeup), the symptoms will be the same, decreasing pressurizer level and pressure with eventual draining of the pressurizer. The primary pressure will then quickly approach the saturation pressure of the primary temperature [illegible] long as the hottest primary temperature has been maintained belo[illegible] (which has a saturation pressure of 1600 psig), ESAS will actuate HPI.

The appropriate actions for an operator to regain control of primary inventory are as follows:

- Isolate letdown
- Restore and increase makeup
- If subcooling margin lost initiate HPI
- If the cause is an excessive cooldown, eliminate cause of cooldown. (i.e., throttle feedwater, isolate the stuck open steam line valve, etc.)

Following the remedial action of Part I will correct the problem. If subcooling is lost the operator can use III A to regain inventory control.

Loss or Reactor Inventory Control (High)

A loss of reactor inventory control (high) can result from excessive makeup or HPI. These can happen by:

1. Pressurizer level is controlled by varying makeup using the make-up control valve, therefore excessive makeup can occur by the failure of the makeup control valve (in an open position) or failure of inputs into the valve (i.e., erroneous pressurizer level measurements).

2. If HPI is initiated, the operator should throttle the flow when the subcooling margin is regained. If he does not, excessive HPI can occur.

An operator using ATOG, Part I, section II only, would not be able to directly diagnose excessive makeup. However, a slowly increasing pressurizer level will indicate the problem. Several indications, such as high makeup flow and pressurizer level alarms, are available to assist him. It should be emphasized that excessive makeup is an extremely slow transient and there should be ample time for the operator to recognize and correct the problem.

If HPI has been started automatically or manually due to loss of subcooling margin, Section III A of Part I will direct the operator to throttle the HPI once subcooling margin has been regained.

Figure D-7 shows typical parameter trends for loss of reactor inventory control (high).

The actions the operator can take to regain control of the reactor inventory are as follows:

1. Throttle or stop makeup using inline valves.
2. Increase letdown to maximum by opening both the letdown cooler isolation valve and bypass valve.
   Caution: Verify cooling water flow to the letdown coolers.

3. Trip the makeup pumps.

   Caution: The makeup pumps should only be tripped after all other actions have failed to stop the excessive makeup.

   Tripping the makeup pumps makes RCP seal injection unavailable.

Loss of Secondary Inventory Control (Low)

A loss of secondary inventory control (low) exists whenever there is too little EFW being injected into the steam generators to remove the decay heat output of the core. This can result from such things as:

1. The steam and motor driven EFW pumps have failed to start.
2. EFW control valves have failed to open if closed.

The symptoms will be typical of a loss of primary to secondary heat transfer. OTSG level will decrease with eventual dry out of both OTSGs. RC temperature will increase along with a rise in pressurizer level and pressure. (See Figure D-8.) Some RC flow may continue even after the OTSGs are dry (i.e., not removing any heat). The increasing hot leg temperature maintains a density difference between cold and hot legs. However, this is not stable natural circulation nor does this flow adequately cool the core for long periods of time.

At Step 11.0 of Part I, Section II, the operator will see that primary to secondary heat transfer has been lost. Step 11.0 will direct him to follow Section III B for loss of heat transfer. EFW will be regained or the plant will be placed into HPI cooling and brought to a stable shutdown.

Loss of Secondary Inventory (High)

A loss of secondary inventory (high) exists whenever significantly more emergency feedwater is being injected into one or both steam generators than is required to remove the existing decay heat. The symptoms and corrective actions for excessive EFW are discussed in Appendix A and will not be repeated here. However, it should be emphasized that draining of the pressurizer due to overcooling may result in void formation in the primary. This may lead to an accumulation of steam at the top of each hot leg and a stopping of natural circulation cooling. Chapter D, "Backup Cooling Methods" of Part II discusses methods of recovery from this condition.

Loss of Primary Pressure Control (Low)

During a LOOP, a loss of primary pressure control (low) can be the result of:

(1) Power being lost to all presurizer heaters.

(2) The pressurizer draining.

Certain pressurizer heaters can be manually loaded on the diesel powered bus after a LOOP. These heaters (totalling 126 kW) are designed only to compensate for ambient heat losses at normal RCS operating temperature. If all heaters are lost, the steam bubble in the pressurizer will cool and condense. Eventually the bubble will collapse, the pressurizer will fill and pressurizer pressure control will be lost.

An operator using Part I, Section II, will not immediately diagnose the loss of heaters. However, this is a very slow process and the operator should have ample time to diagnose the event using the P-T diagram. The required operator actions are to regain the pressurizer heaters, cooldown the RCS or increase makeup to compensate for the collapsing steam bubble.

The pressurizer may drain on an overcooling event (excessive EFW or stuck open steam line valve). If it does, control of primary pressure will be lost. RCS pressure will then approach the saturation pressure of the primary temperature. As long as the hottest primary temperature is less than 606F (saturation pressure equals 1500 psig), ESAS will actuate and HPI will begin.

An operator using Part I, Section II, will diagnose the overcooling at Step 11.0. Section III C will then instruct him on how to stop the overcooling and terminate the transient.

Loss of Steam Pressure Control (Low)

A loss of steam pressure control exists whenever one or both steam generators undergo a pressure reduction significantly below the ADV setpoint. This is an overcooling transient and will look similar (on the P-T diagram) to the small steam line break transient discussed in Appendix E. There is nothing unique about loss of this control function due to being coupled with a loss of offsite power; therefore, it should be identified and treated as discussed in Appendix E.

Loss of All Power Except Batteries

A loss of all power (or station blackout) exists when both diesel generators fail to start after a LOOP. Thereafter, the only power available to the plant auxiliaries are the 125V DC battery banks. This results in a loss of power to the following major components:

- The motor driven EFW pump
- All makeup pumps
- Pressurizer heaters
- Instrument air compressor (However, a manual start 5 HP DC air compressor is available for operation of the EFW system valves and ADVs. Also two hours air supply available to limited components.)

This event is one of the most serious that can happen to a pressurized water reactor. The main feedwater pumps have tripped placing the plant into a loss of main feedwater transient. The plant relies on only the steam driven EFW pump for the injection of EFW into the steam generator for natural circulation. The HPI pumps are not powered and thus HPI cooling cannot be initiated.

This situation cannot be maintained indefinitely because of the limited lifetime of the batteries, the lack of primary inventory control and a finite supply of good quality secondary water. Therefore, the operator should get at least one diesel generator running so that makeup can be remotely initiated and controlled.

Since the pressurizer heaters and makeup pumps have lost power, the operator has little control of primary pressure or inventory. Any voids that form in the primary will tend to accumulate in the hot leg and obstruct natural circulation. Therefore, the plant may wind up in the boiler-condenser mode. The operator should monitor natural circulation and, if necessary, raise the steam generator levels to 95% on the operate range.

An operator using the guidelines for a LOOP with no diesel generators would first perform the immediate actions of Part I, Section I and verify vital system status in Section II. At

Step 7.0 he will be directed to start the diesel generators and initiate emergency feedwater. These are the two most important steps he can take to regain control of the plant. In the long run, offsite power must be regained or a diesel generator started before primary inventory control is lost.

Figure D-1 LOSS OF OFFSITE POWER - 2/22/75
LOOP A RC TEMPERATURE VS. TIME

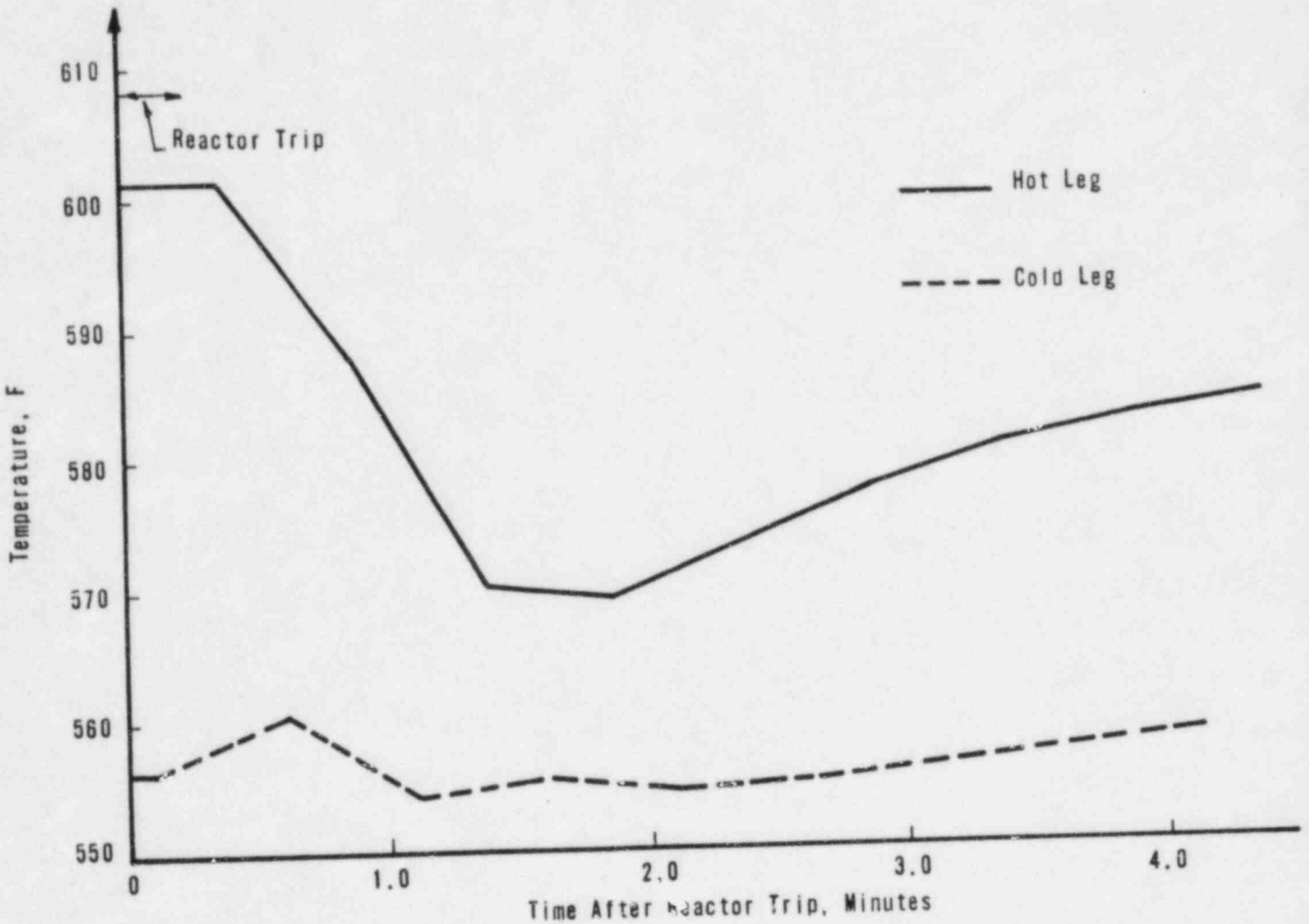
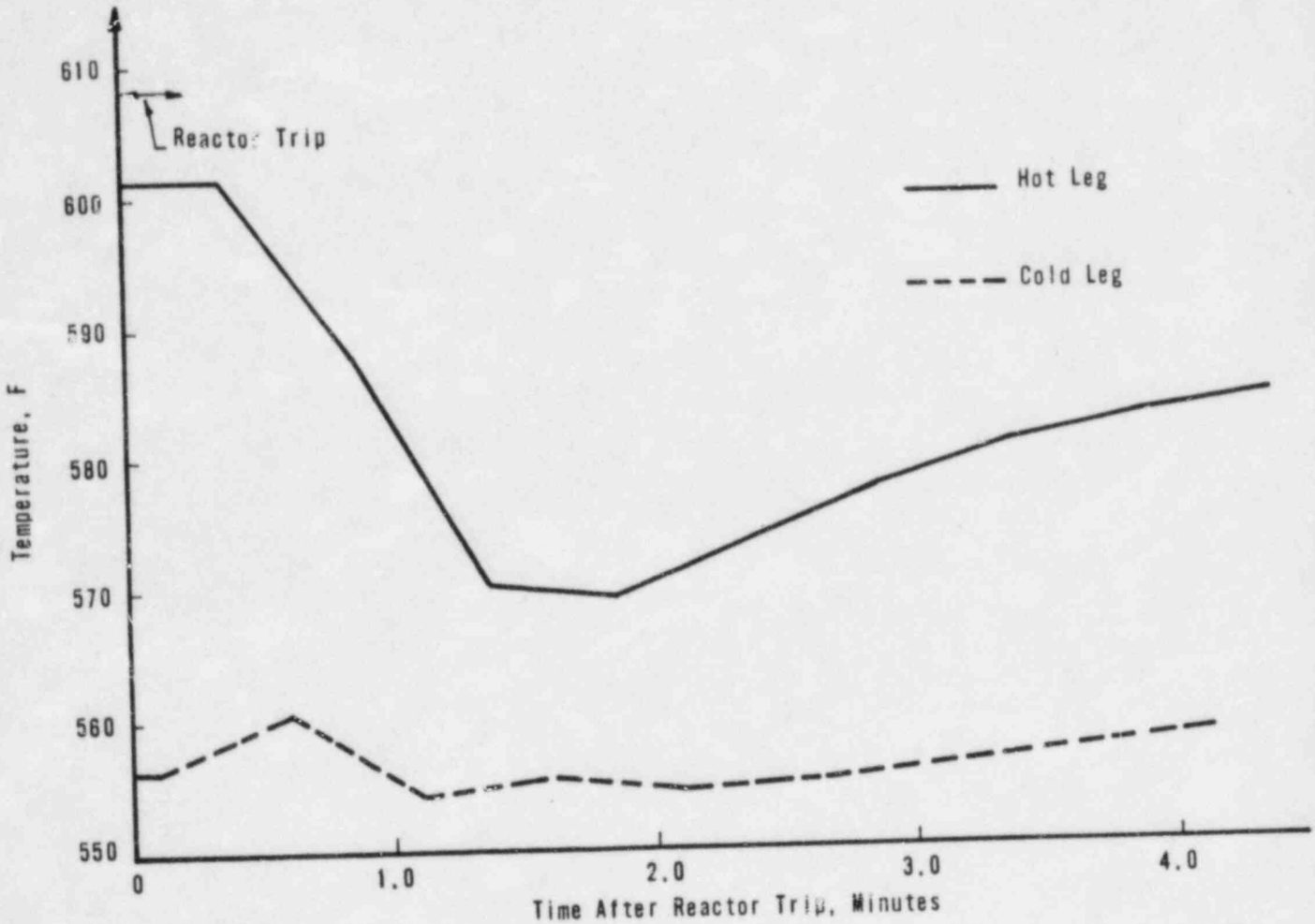
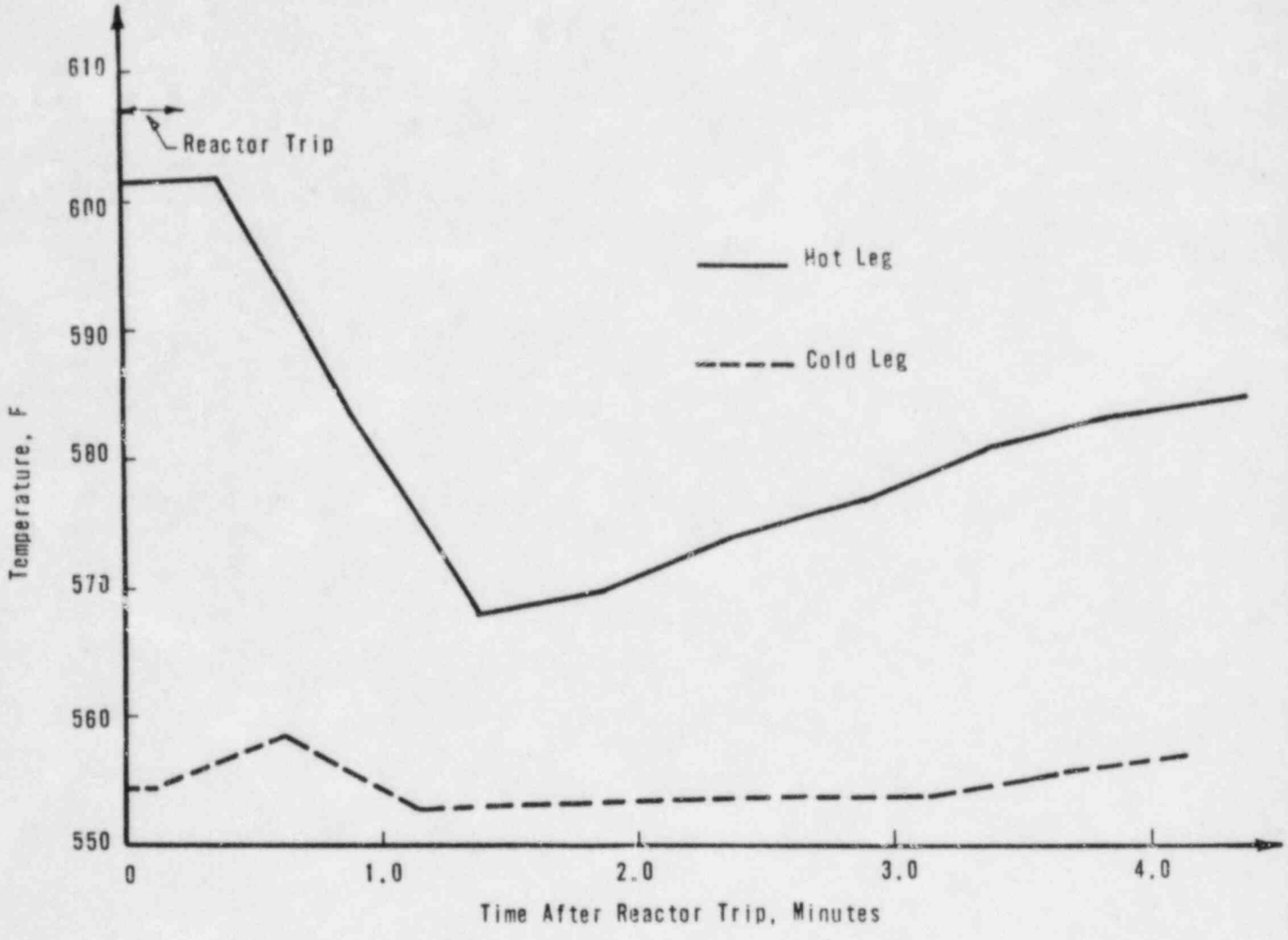


Figure D-1 LOSS OF OFFSITE POWER - 2/22/75
LOOP A RC TEMPERATURE VS. TIME



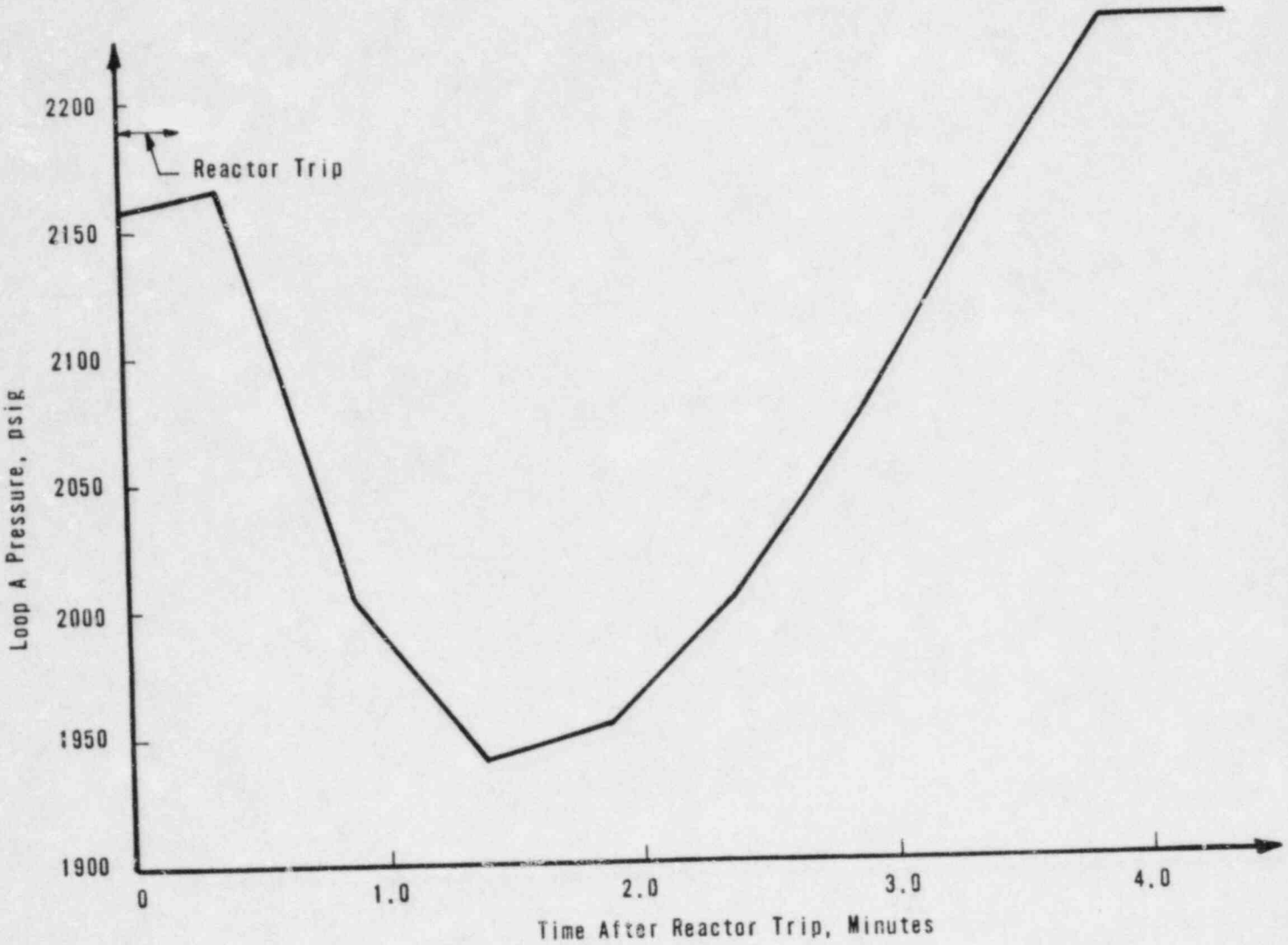
74-1124158-00

Figure D-2 LOSS OF OFFSITE POWER - 2/22/75
LOOP B RC TEMPERATURE VS. TIME



74-1124158-00

Figure D-3 LOSS OF OFFSITE POWER - 2/22/75
LOOP A PRESSURE VS. TIME



74-1124158-00

Figure D-4 LOSS OF OFFSITE POWER - 2/22/75
OTSG FULL RANGE LEVEL VS. TIME

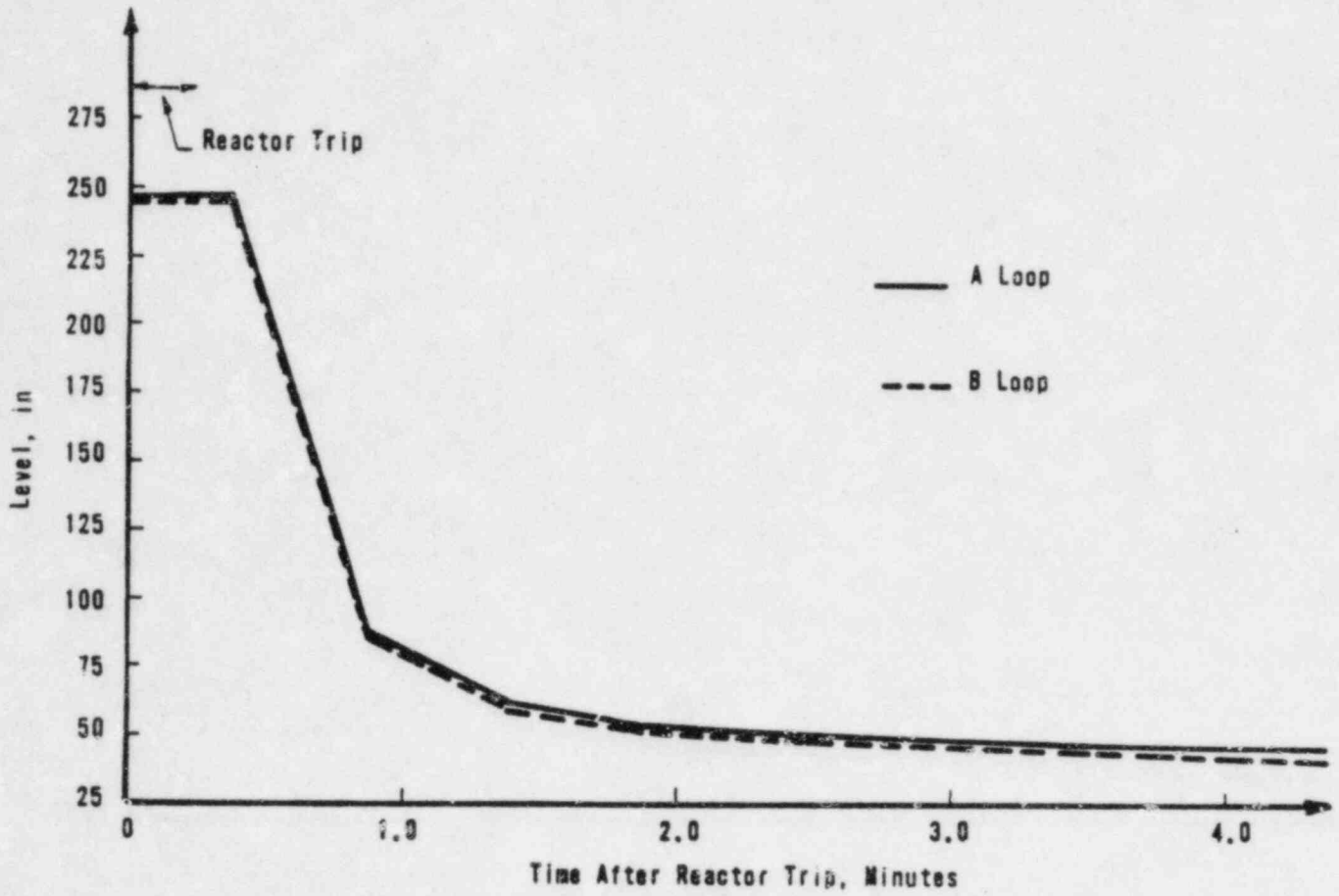
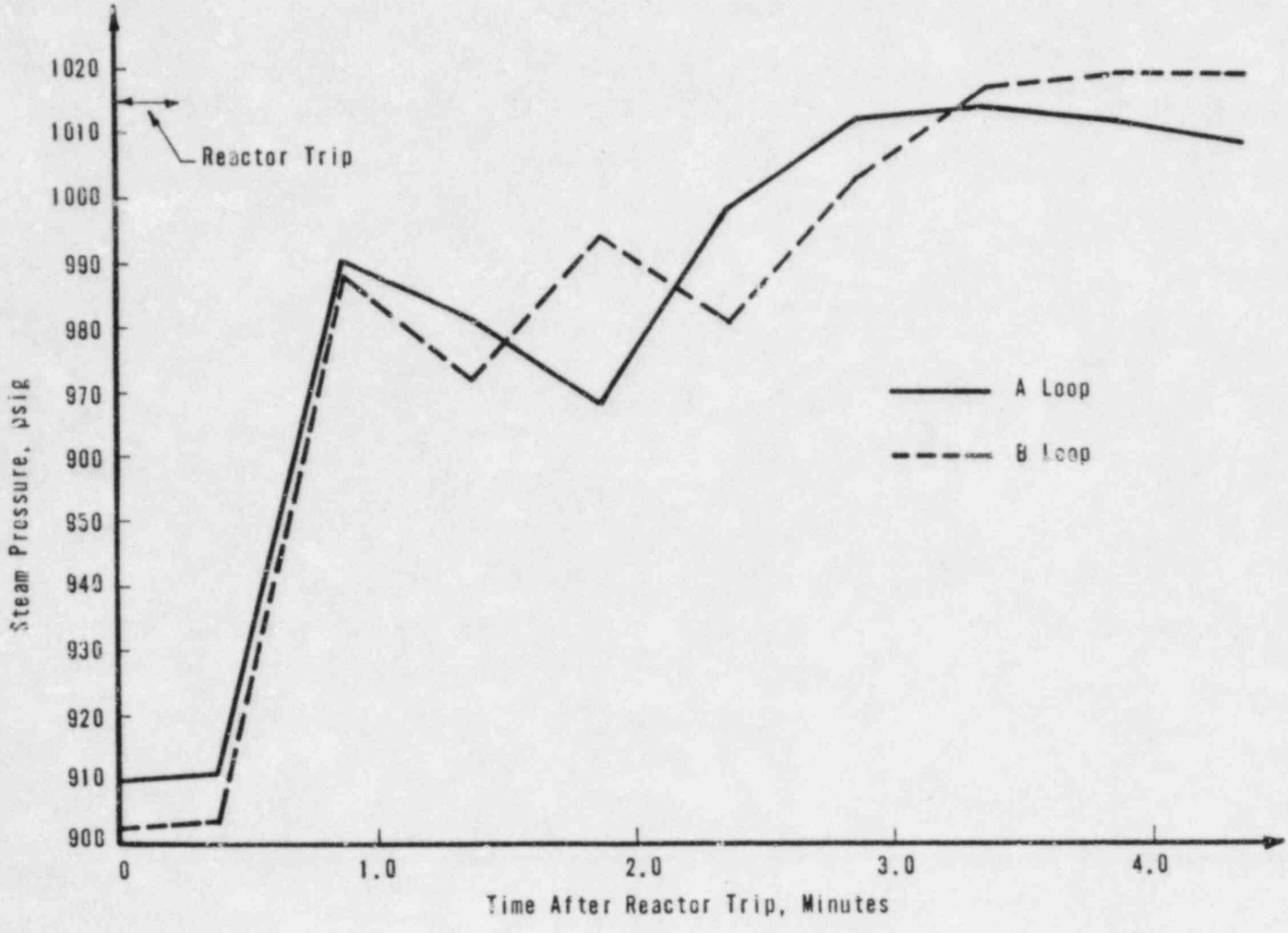
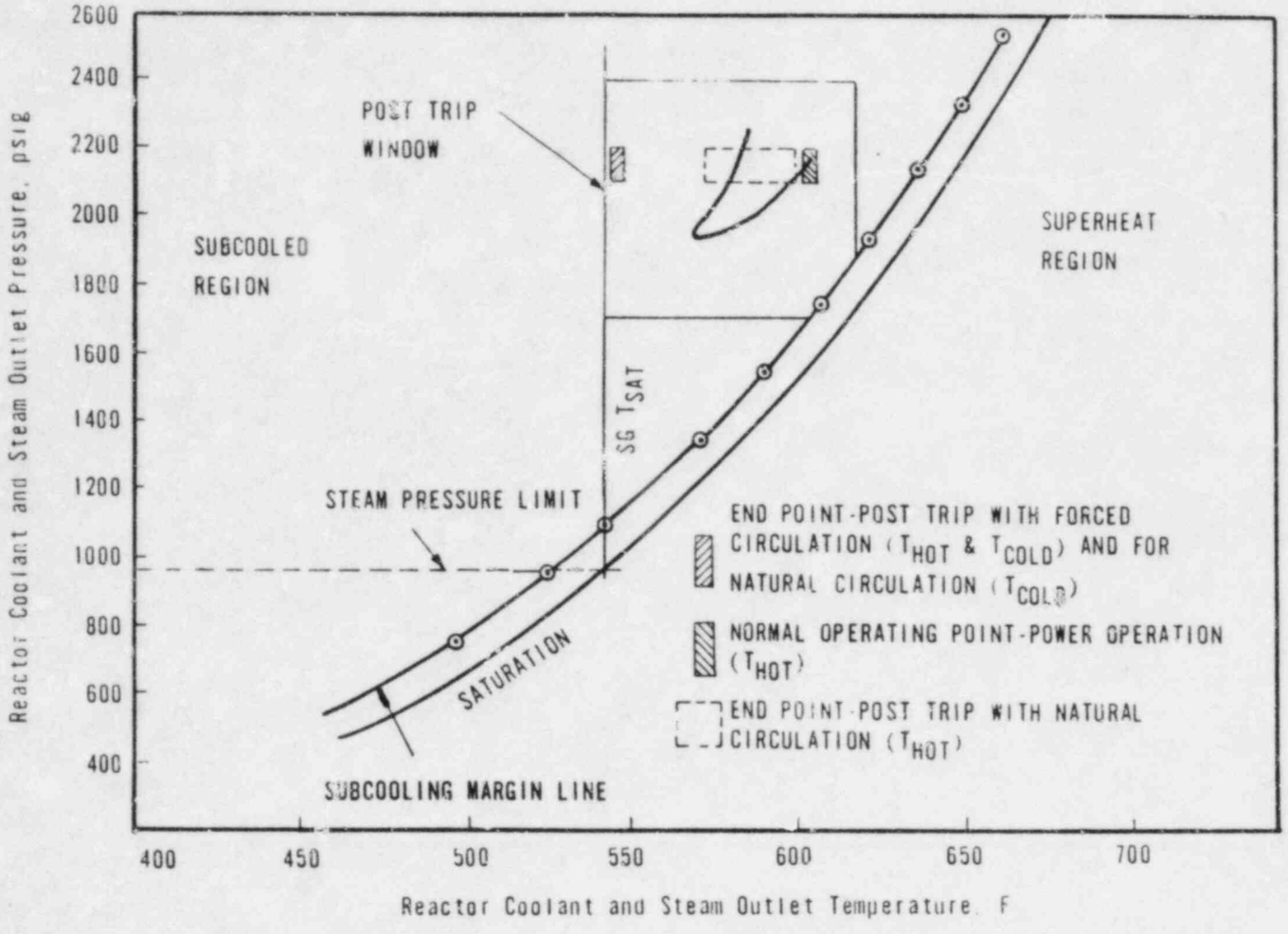


Figure D-5 LOSS OF OFFSITE POWER - 2/22/75
OTSG STEAM PRESSURE VS. TIME



74-1124158-00

Figure D-6 LOSS OF OFFSITE POWER - 2/22/75



74-1124158-00

Figure D-7 TYPICAL PARAMETER TRENDS FOR LOOP

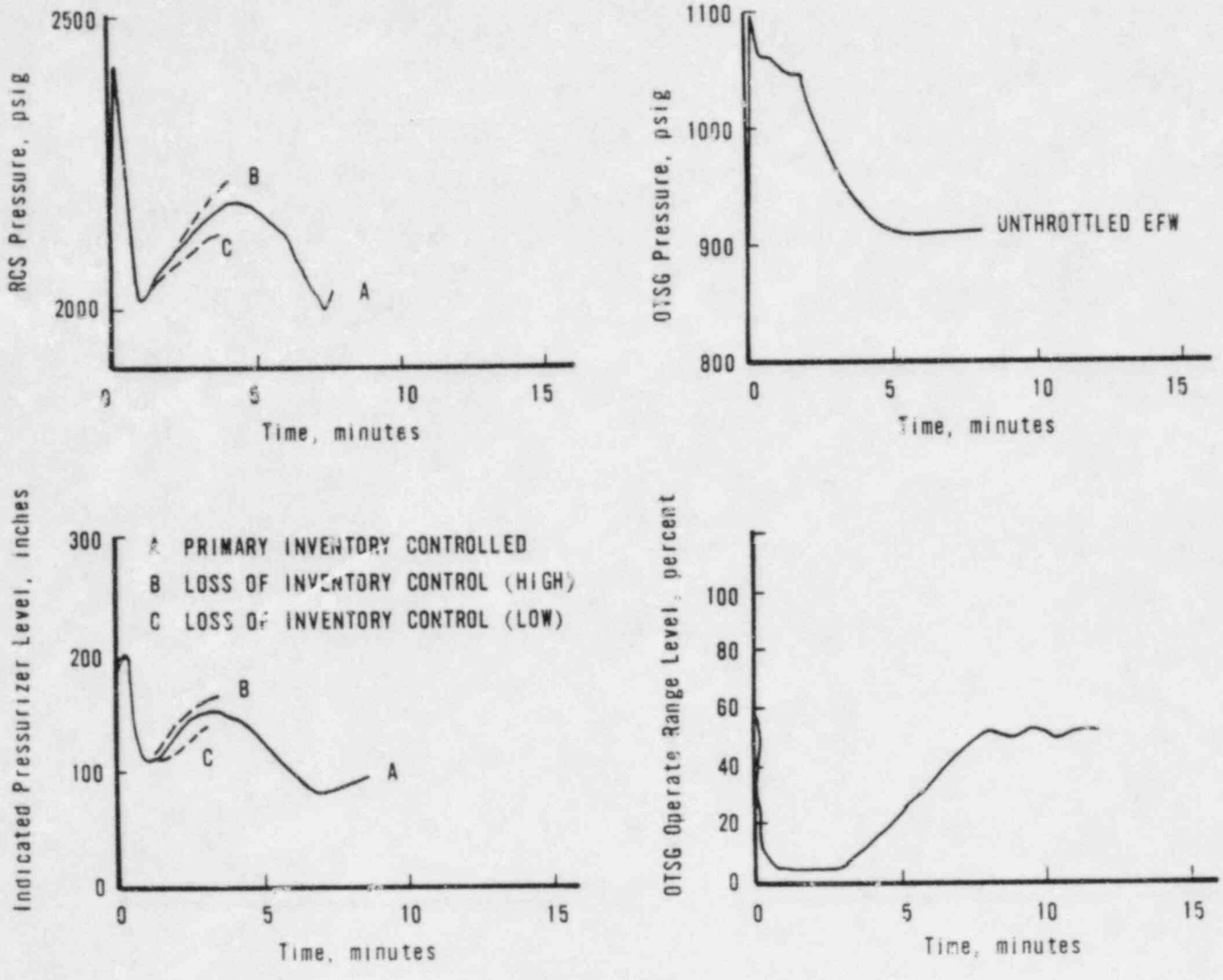


Figure D-8 TYPICAL PARAMETER TRENDS FOR LOOP/LOSS OF SECONDARY INVENTORY CONTROL (LOW)

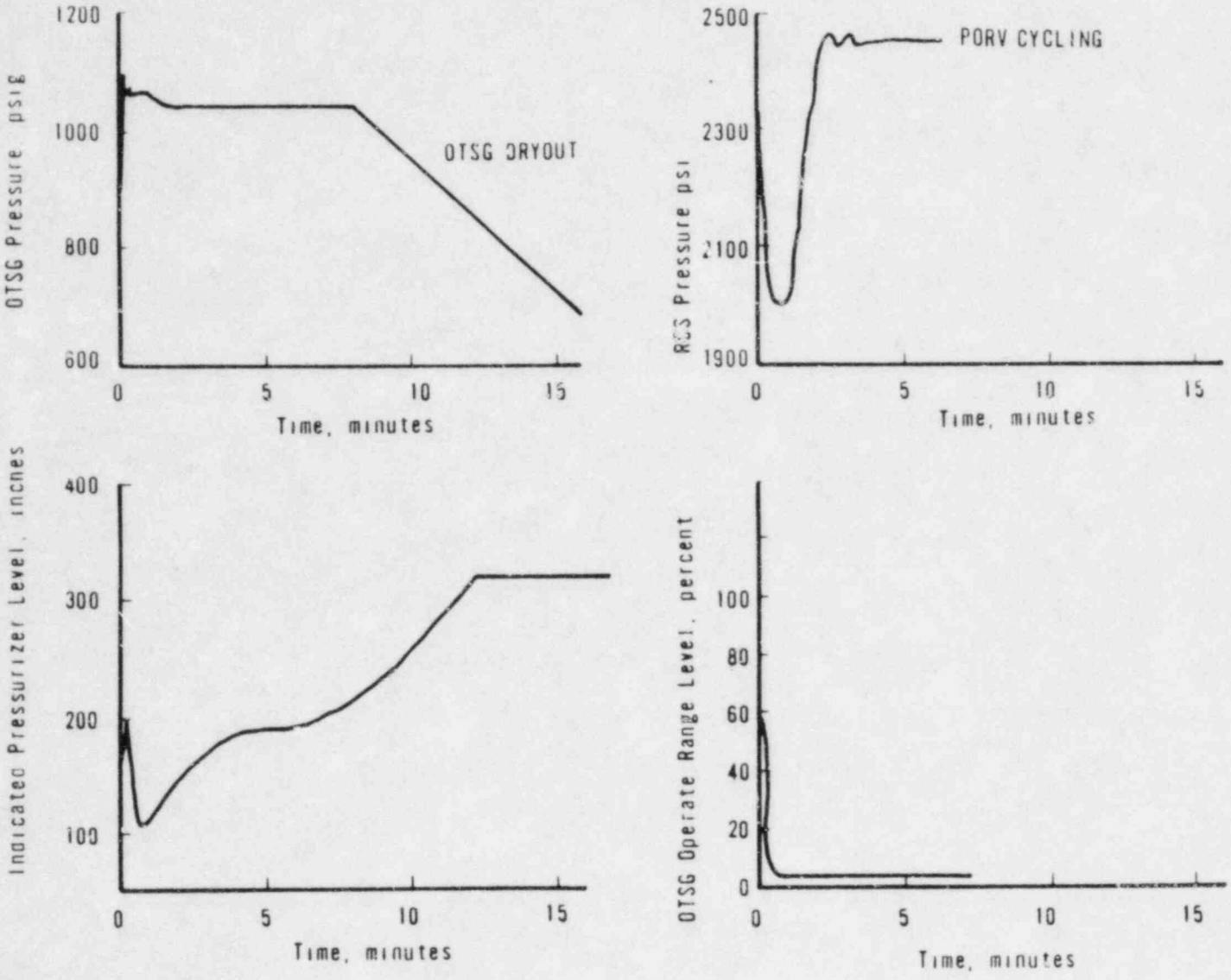
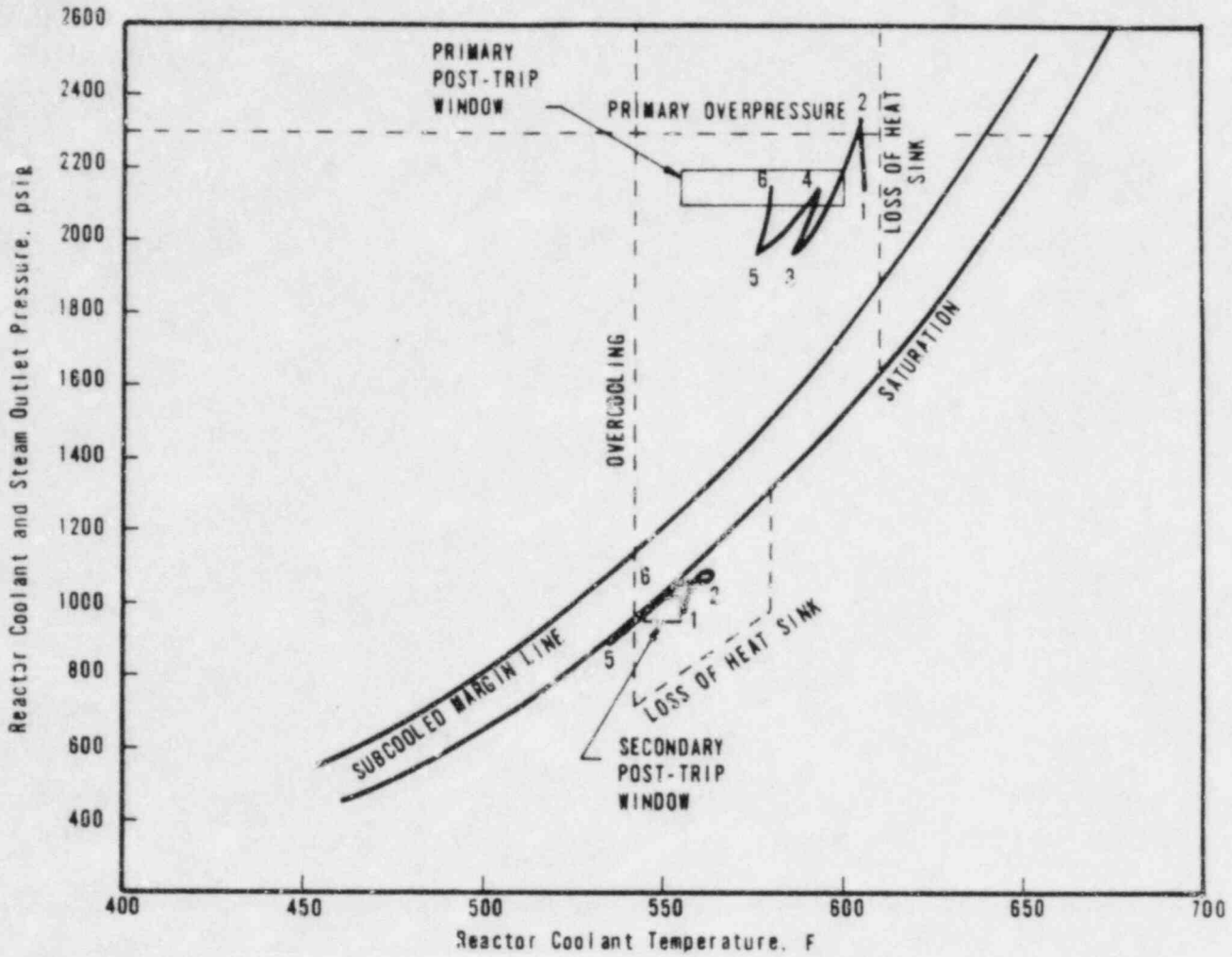


Figure D-10 TYPICAL LOSS OF OFFSITE POWER P-T RESPONSE



Reference Points	Time (Seconds)	Remarks
1	0	Plant separates from grid.
1-2	0-15	Reactor trips on high pressure. Diesel generators begin loading within 15 seconds after reactor trip.
2-3	15-75	Plant cools down as steam is relieved to atmosphere by ADV's and steam safety valves.
3-4	75-240	T_{hot} increases to develop required temperature difference for natural circulation.
4-5	240-480	RCS is cooled by natural circulation. Steam pressure is dropping due to quenching affects of EFW.
5	480	OTSG levels reach 50% on the operate range.
5-6	>480	Steam pressure, T_{av} and RCS pressure return to normal post-trip values as decay heat adds energy to the system.

STEAM LEAK

APPENDIX E

SMALL STEAM LEAK

1.0 GENERAL TRANSIENT DESCRIPTION

A small steam leak is a failure to control secondary pressure. It is an overcooling transient that results in too much primary to secondary heat transfer.

A small steam leak is defined as loss of steam up to about 22.5% of full flow (six failed open turbine bypass valves). Larger steam leaks could exist only with piping failures; these are not as likely as component failures. However, the basic principles and sequence of events to be discussed also apply to larger breaks.

The steam leak causes a power mismatch between the heat source (the core) and the heat sink (the steam generators) and will cool the reactor coolant down. The ICS will pull rods to increase core power and maintain T_{av}. If initially the plant is operating at much less than full power, the plant will stabilize with reactor power greater than megawatt demand by an amount equal to the size of the steam leak. Depending on the leak location and size the operator may be able to locate and isolate the leak without tripping. For example, if the leak results from a stuck open TBV, the mass flow through the leak goes to the condenser and the plant could operate indefinitely.

The only indication will be the reactor-turbine power mismatch. An atmospheric leak will require makeup to prevent the hotwell from draining. Hotwell level and condensate level as well as visual inspection will indicate the leak. If, however, the leak is inside containment, an ESAS signal on high RB pressure will occur. ESAS actuation will happen in about ten minutes for a leak equivalent to 1% full flow and in about twenty seconds for a leak equivalent to 15% full flow. (Assuming initial RB pressure = 0 psig and temeprature = 120F.)

If the plant is initially near full power, the steam leak may result in a reactor trip on high flux. Small leaks will not cause a reactor trip (up to about 3% flow) if the reactor is at high power. After trip the RCS will continue to cooldown and depressurize due to the leak. The rate of cooldown will depend on prior power history (decay heat level) and the size of the leak.

Small steam leaks do not result in rapid overcooling and the reactor coolant temperature drop will not be severe. If no additional failures occur and the leak can be isolated by the operator then the plant may recover from a leak without losing the subcooling margin. If the steam leak cannot be isolated the operator must stop MFW and EFW to the affected SG to prevent overcooling the RCS and losing condensate inventory. The SLRDS will automatically isolate MFW to a SG if its pressure drops to 600 psig. It does not isolate EFW. If the steam pressure is reduced low enough to actuate SLRDS, the RCS

will probably have cooled low enough to depressurize the RC to ca. a loss of subcooling margin. The operator will be required to trip the RC pumps which will actuate EFW. This will allow full EFW flow to the OTSGs causing additional cooling of the RCS if the EFW flow is not throttled. The EFW control valve will auto control the SG level to the 50% on the operate range if the RC pumps are tripped. The EFW throttling rule should be followed. HPI will probably also be actuated by a low RCS pressure and will recover RCS shrinkage, although temporary drainage of the pressurizer may occur. After the leak is isolated, the operator would have to take manual control of HPI and the ADV's (or TBV's) to limit the RCS refill by limiting the reactor coolant reheat and swell while maintaining RC subcooling.

The following transient example is based on a leak equivalent to 15% full flow and occurs with maximum decay heat. A larger leak or lower decay heat levels would result in a faster cooldown rate and could cause RCS saturation.

SLRDS actuation will not isolate the leak from the broken SG but will isolate MFW flow to the broken steam generator and allow it to boil dry. Other failures may occur which will require operator action. These are discussed in Section 3.0 of this appendix. The operator should become familiar with the "Overcooling Diagnosis Chart", in Part II, "Diagnosis and Mitigation".

The P-T curve and sequence of events shown in Figure E-1 depicts a typical small steam leak transient (stuck open TBV) that is terminated by operator actions.

2.0 OPERATOR ACTIONS SUMMARY

Initial Operator Actions

- Increase MU if pressurizer level is less than 100" and RCS pressure is decreasing.
- If the leaking generator is obvious it should be isolated; but if it is not obvious the next two steps will help identify it.
- Close TBV's and ADV's.
- Stop all feedwater to both SG's; watch levels; the generator with the fastest level decrease is leaking; isolate it and restart feedwater to the generator(s) which repressurize.
- Follow remainder of Part I, Section III.C.
- Limit RCS reheat and swell.

Identifying Symptoms

Small steam leak is an overcooling transient as shown in Figure E-2. (Solid line for secondary plot shows both RC loops for symmetric leaks and RC loop for asymmetric leak. Dashed line shows unaffected (non-leaking) RC loop for asymmetric leak)

Other key parameters to distinguish small steam leaks from other transients are:

- Reactor building pressure increase if leak inside RB
- Low condensate storage tank level
- Decreasing level and pressure in one or both SG's with feedwater isolated*
- Near normal or low SG levels with feedwater addition.

*NOTE: Excess MFW can cause a slightly reduced steam pressure in the unaffected SG; excess EFW can cause a large reduction of steam pressure in the affected SG; however, in both cases the SG with reduced pressure should have steady or increasing level indicating that inventory is not being lost.

This section will present an example of a small steam leak and discuss how operator actions in accordance with Part I will terminate the transient and provide recovery to stable shutdown conditions. The assumed transient will be the same shown in the previous section, i.e., failed open TBVs from 100% full power.

A failure of four TBVs in the open position results in approximately 15% excess steam flow. The reactor will trip on high flux within about eighteen seconds, the turbine will trip, and the ICS will run back MFW. After the operator performs the immediate actions in Pa I, Section I, he will verify vital system status in accordance with Section II. Steam pressure in both steam generators and T_{cold} in both loops will decrease fairly quickly (≃ 100 seconds) below the normal secondary post-trip window. In Step 11.0 of Section II the operator should note that primary to secondary heat transfer is excessive by observing lower than normal steam pressures and the overcooling trend indicated by the response on the P-T diagram. (Refer to Figure E-2.) The procedure directs the operator to Section III.C.

Step 1.0 in III.C requires the operator to increase makeup if pressurizer level is below 100" and RCS pressure is decreasing. For this transient pressurizer level will go below 100" within about 40 secords (see Figure E-3, "Time Relationship of Key Parameters") after trip. If low RC pressure ESAS actuates, full HPI flow will more than compensate for the reactor coolant contraction rate for this size leak; therefore, pressurizer refill and RCS repressurization should begin to occur even before the steam leak is isolated. However, a temporary loss of indicated pressurizer level may be expected.

Subsequent steps will effectively isolate the steam generators from most failures that would cause overcooling. III C requires the operator to place the TBV's and ADV's in manual and close them. Successful completion of this step will terminate the overcooling transient in this case by isolating the leak. If this action is done quickly enough the subcooling margin will not be lost, the RC pumps will not be tripped and MFW will establish the low level SG setpoint. If the failure of the TBV's was such that it prevented manual closure, the operator would recognize the failure and realize the cause for overcooling. Since the TBV's are failed open on both SG's he would have to close both MS-V8A and 8B to isolate the leak. Once the leak is isolated, the operator can restore FW to both SG's and use the ADV's for steam pressure control and DH removal.

Subcooling margin was not lost, therefore the RC pumps remained on and FW will be establishing the low level setpoint. When this low setpoint is in effect the operator does not need to throttle FW to obtain a gradual level increase. Full FW flow until the low setpoint is reached will not significantly contribute to further overcooling.

Once the steam leak and overcooling has been terminated, the operator must perform a few actions to regain RCS inventory and pressure control. At this stage in the transient he still has HPI flow and the RCS is slowly reheating and will continue to reheat until steam pressure increases to the ADV setpoint. The actions he should take are given in the procedure and are as follows:

- Maintain RCS temperature at the present value by adjusting the ADV's on both SG's. Closure of MSV-8A and 8B has isolated the TBVs. The HPI flow has increased the RCS inventory; therefore, if the RCS is allowed to reheat to normal post trip conditions a very high pressurizer level and possibly a full pressurizer will occur.
- Throttle HPI when the subcooling margin is restored. In this particular transient, the subcooling margin was not lost and RCS pressure began to increase before the leak was isolated. Therefore, the operator could have throttled HPI as soon as RCS pressure began to increase.

- When pressurizer level returns to 100 inches and is increasing (and the RCS is above the subcooled margin) the operator should terminate HPI and realign for normal makeup/letdown operation.

NOTE: Overcooling transients that result in a large decrease in pressurizer level may have a relatively long-term impact on RCS pressure control after the transient is terminated. The insurge due to HPI and RCS reheat and swell will cause pressure to increase due to compressing action but may leave the pressurizer with a large volume of subcooled water. This can cause pressure to settle out at a lower value and it will take some time for the pressurizer heaters to restore saturated conditions at a higher pressure. Subsequent outsurges during this time will have a larger than normal pressure reduction effect due to the lack of saturated water available to flash to steam.

In the previous example, the operator followed the procedure in Part I and terminated the transient in a timely manner. However, the steam leak was isolable and the plant could be returned to a fairly normal shutdown condition with steam pressure control by the ADV's.

The transient of most concern for the operator is an unisolable leak in one SG upstream of the MSIV's and steam extraction line isolation valve (MS-V2A or 2B). HPI actuation by ESAS would still occur and SLRDS actuation would ensure that main feedwater flow is terminated to the SG with the steam leak. However, SLRDS could also terminate main feedwater flow to the good SG if the cooldown of the RCS was severe enough to lower steam pressure in the good SG to the SLRDS setpoint. In this case the operator must take action to assure main FW or EFW is supplied to the good SG. If EFW is auto actuated the operator must take action to isolate EFW flow to the leaking SG and allow the leaking SG to boil dry. He would then return to stable shutdown conditions by controlling DH removal with the good SG.

If the leaking SG cannot be identified, the operator will stop all feedwater to both SG's, close all the TBV's, ADV's and MSIV's. If the leak stops he will reestablish FW to both SG's. If the leak continues he will then allow the leaking SG to boil dry and restart feedwater for DH removal with the good SG. EFW should be stopped by closing the control valves; the pumps should not be stopped. Stopping all feedwater is not dangerous as long as it is restarted before both steam generators dry out.

3.0 SMALL STEAM LEAK WITH OTHER PLANT FAILURES

Introduction

The previous section described small steam leaks in general, but did not discuss other failures that might also happen at the same time. This section will show what symptoms to look for when other equipment fails and will show what steps the operator should take to restore the heat transfer from the core to the steam generators.

Figure E-4, "Small Steam Leak Logic Diagram", condenses the event tree into the main transient path and branches for the major failures that can occur in addition to the main transient. The P-T diagrams are shown in Figure E-4. The effects on other parameters is shown in Figure E-3, "Time Relationship of Key Parameters".

The event that was chosen for simulation starts with the reactor at power. A small steam leak occurs that may or may not result in a reactor trip on high flux. If a trip does not occur, the plant will stabilize with a power mismatch with the possible conditions given in Note 1 on Figure E-4. The main path assumes a reactor trip does occur. All the data that is shown starts from the time of reactor trip. The failures are shown to occur when a component has to operate (for example, after a reactor trip the ICS should automatically run back MFW; the failure shown is that MFW does not run back).

It must be remembered that all steam leaks will not look exactly like the examples used. The primary purpose of these examples is to promote operator familiarity with the symptoms and effects of steam leaks.

Branch Discussion

Figure E-4 has separate failure branches for loss of reactor inventory control (high and low), loss of secondary inventory control (high and low), and loss of secondary pressure control (low). (Minor failures, such as loss of pressurizer heaters, have relatively little impact on the overall transient. The operator has time to diagnose and correct such failures; therefore they are not shown.) Another valuable tool to facilitate operator recognition and identification of overcooling transients is Figure 22, "Overcooling Diagnosis Chart", in Part III, Section I.C, "Diagnosis and Mitigation". The operator should become familiar with this chart.

Figure E-3 is provided to show key distinguishing parameters for small steam leaks that have a time dependency important to the operator in identifying both the type and severity of transient. The parameter plots show typical responses to a steam leak equivalent to 15% full flow (2 TBV's on each OTSG failed open) with automatic HPI actuation. Arrows, where used, show the effect of other failures and of operator actions on the time relationship.

Loss of Reactor Inventory Control (High)

A loss of reactor inventory control (high) exists whenever makeup or HPI flows are excessive causing the pressurizer to fill and overpresurize the RCS for the existing plant conditions. Steam leaks ranging in size up to approximately 15% of full flow, assuming maximum decay heat, will not cause overcooling and RCS contraction rates greater than the full capacity of the HPI system. Therefore, pressurizer refill and RCS repressurization should begin to occur even before the steam leak is isolated (refer to Figure E-1 and sequence of events in Section 1.0 of this appendix). Larger steam leaks or lower decay heat levels would result in a faster cooldown rate and could cause RCS saturation even with full HPI flow. However, for smaller steam leaks and when the overcooling has been terminated, full HPI flow will more than compensate for the coolant shrinkage and result in a rapid increase in pressurizer level and RCS pressure. Rapid operator response will be required to prevent a solid pressurizer and RCS overpressurization.

Loss of Reactor Inventory Control (Low)

A loss of reactor inventory control (low) exists whenever makeup or HPI flow is insufficient to overcome the primary leak rate or (as in this case) the coolant contraction rate, resulting in drainage of the pressurizer.

Again, as in Appendix A, too little makeup or HPI flow is not a major concern for this particular transient. If the overcooling is terminated before the pressurizer empties, the RCS will reheat and the resultant swell will restore pressurizer level. If the overcooling continued, ESAS will actuate and HPI will automatically initiate.

Following the actions specified in III.A.1 Part I will restore primary system inventory control and subcooled margin.

Loss of Secondary Inventory Control (High)

A loss of secondary inventory control (high) exists whenever significantly more feedwater (main or emergency) is being injected into one or both steam generators than is required by existing plant conditions. It is an overcooling transient and response on the P-T diagram is very similar to that of a small steam leak. Excessive main feedwater can be distinguished from small steam leaks by high MFW flowrates and high SG levels. Large feedwater mismatches can cause more severe effects on the RCS than small steam leaks and must be corrected much faster. A detailed discussion of excessive main feedwater is contained in Appednix A.

Excessive main feedwater was defined in Appendix A as basically supplying more feedwater than could be boiled off to make superheated steam. The definition for excessive emergency feedwater differs slightly in that 1) the steam generator is at saturation conditions and 2) more importantly, whenever EFW initiates it must provide more flow than can be boiled off

in order to raise SG levels to the appropriate setpoint. However, the rate at which EFW builds SG levels can be excessive and overcool the primary system. The operator should throttle EFW in accordance with the guidelines in "Best Methods for Equipment Operation."

In addition, excessive emergency feedwater can cause depressurization of the affected SG to a much larger extent than excessive main feedwater. This is due to the condensing action introduced by spraying EFW in near the top of the tube bundle (into the steam space) and due to the lower EFW temperatures.

Should the EFW flow be excessive, the operator should recognize the overcooling as well as high EFW flow. Following the actions in Part I, Section III for excessive primary to secondary heat transfer will terminate the excessive EFW.

Figure E-3 shows the impact of small steam leak overcooling compounded by overcooling due to excessive feedwater. The curves for RCS pressure and pressurizer level will shift to the left, i.e., pressure reduction and drainage of the pressurizer will occur faster. Excessive EFW will also cause the steam pressure curve to shift to the left.

Loss of Secondary Inventory Control (Low)

A loss of secondary inventory control (low) exists whenever too little feedwater is being supplied to the steam generators resulting in too little primary to secondary heat transfer and overheating of the RCS. The operator should recognize this condition by low feedwater flow rates and low SG levels.

The operator may be required, by the procedures in Part I, to isolate all feedwater in order to determine which SG is leaking. However, he will also by procedure immediately restore feedwater to the good SG as soon as the broken SG is identified and isolated.

Total Loss of Steam Pressure Control

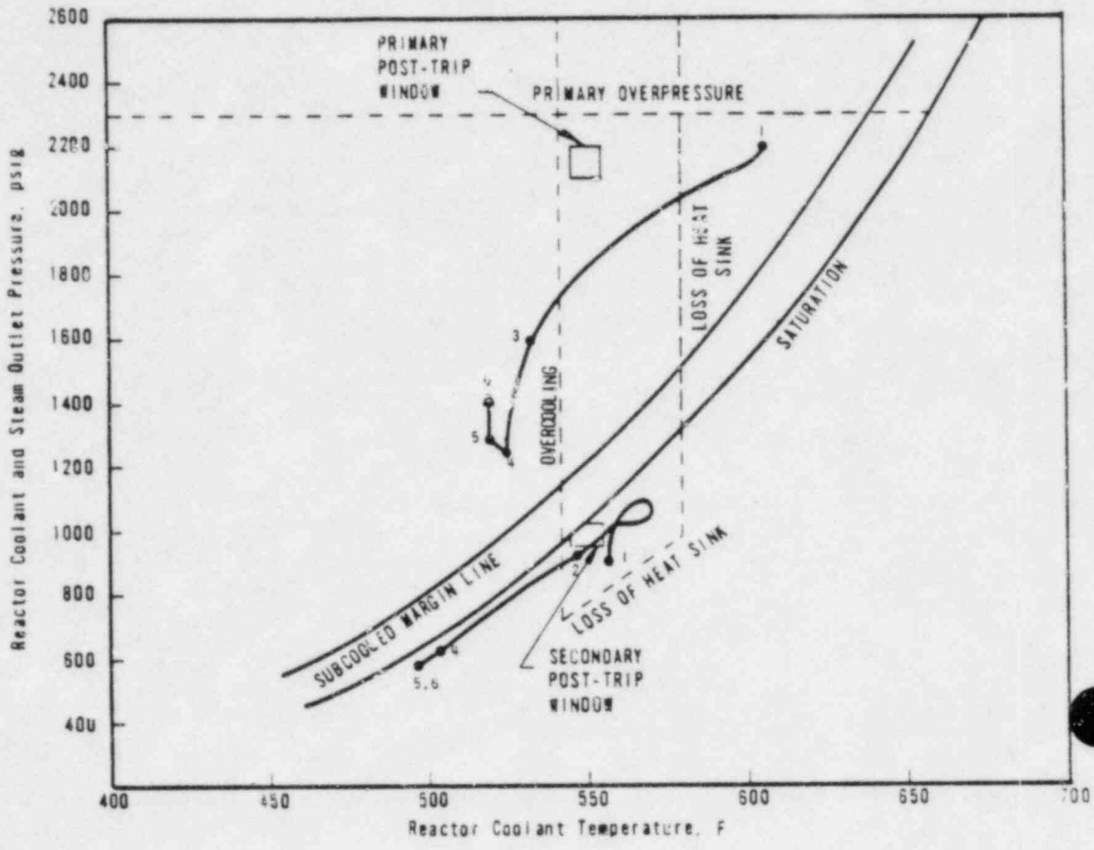
A total loss of steam pressure control exists whenever an unisolable steam leak exists in both steam generators.

If the conditions exists, the operator should perform the following:

1. Maintain primary to secondary heat transfer by supplying feedwater to both SGs at a very limited rate while attempting to stop the steam leak on at least one SG (e.g. manually isolate stuck open ADV, Gag shut MSSV etc.). If heat removal is excessive with two SGs or steam flow needs to be stopped from a SG (due to the location of steam leak, SGTR, to aid repairs, steam leak in the reactor building, etc.) then,

2. Isolate FW to one SG and allow it to boil dry while continuing restrictive feed to the other SG and attemtping to maintain level and controlled DH removal. Continue trying to stop the leak on at least one SG. If controlled DH removal on one SG is not possible then,
3. Initiate HPI cooling and allow both SGs to boil dry.
4. Continue to try to repair the steam leak of at least one SG. When steam leak is repaired in one SG then use repaired SG to restore SG DH removal.

Figure E-1 SMALL STEAM LEAK



Reference Points	Time (Seconds)	Remarks
1	0	Two TBVs on each OTSG fail open from 100% full power allowing 15% of full power steam flow.
1-2	0-100	Reactor trip on high flux (~ 18 seconds), turbine trip, ICS runs back MFW, makeup valve goes wide open.
2	100	First indication of overcooling on P-T diagram occurs as both T_{cold}/steam pressure plots continue to decrease below secondary post-trip window.
3	190	Pressurizer drained; ESAS trip on low RC pressure, starts HPI.
4	250	RCS pressure begins to increase; operator throttles back on HPI.
5	270	SLRDS actuates isolating MFW to both SG's; operator isolates leak by manually closing TBV's or by closing MS-V8A and 8B, overrides SLRDS, and restores feedwater to both SG's.
6	330	Operator adjusts ADV (TBV's if available) setpoint to stop heatup. When pressurizer level > 100" and increasing, operator will stop HPI and realign for normal makeup and letdown.

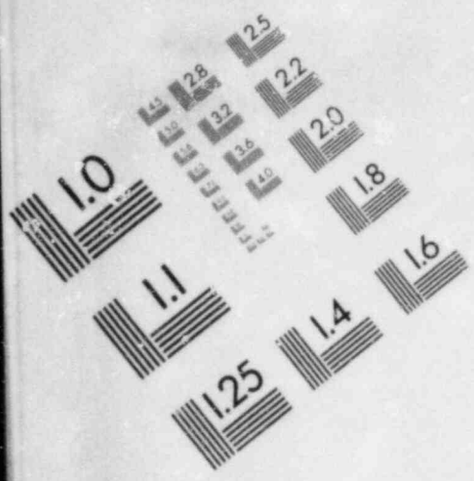
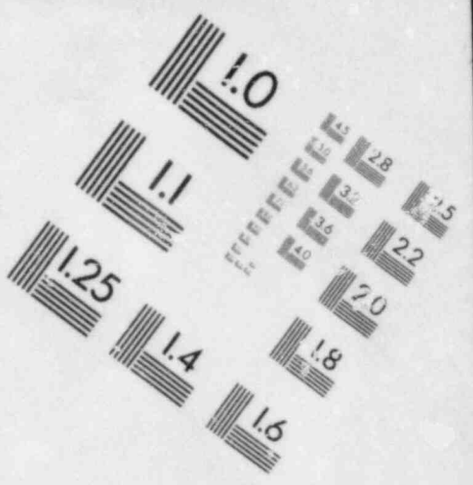
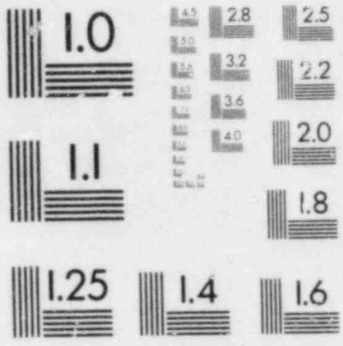
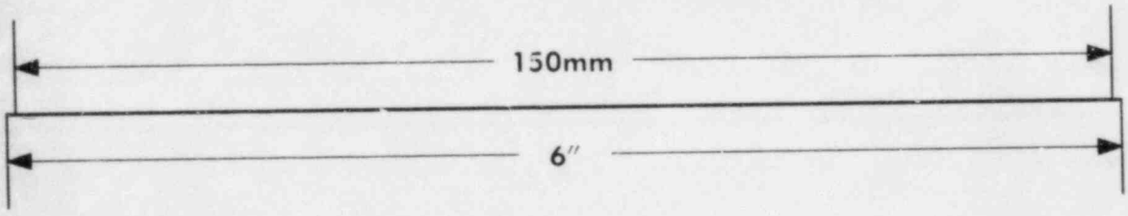
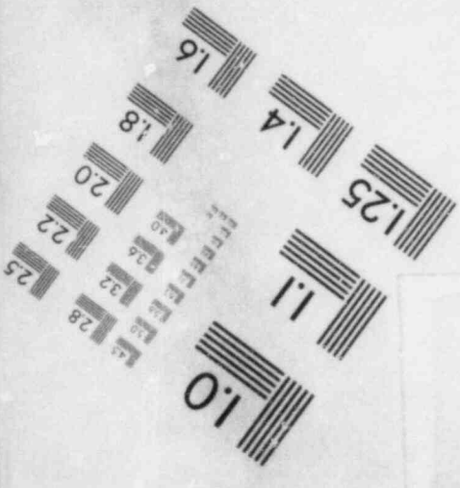


IMAGE EVALUATION TEST TARGET (MT-3)









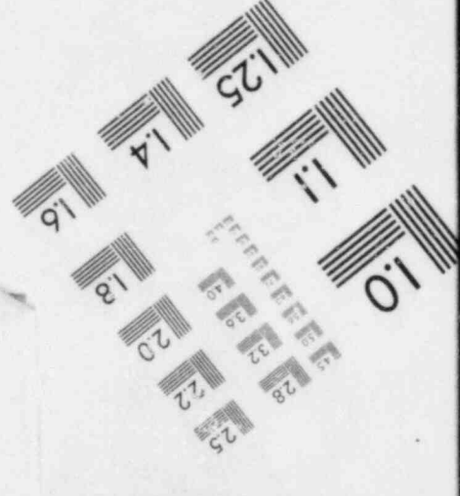
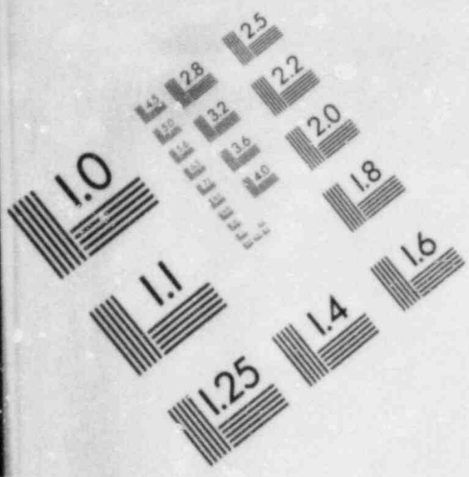
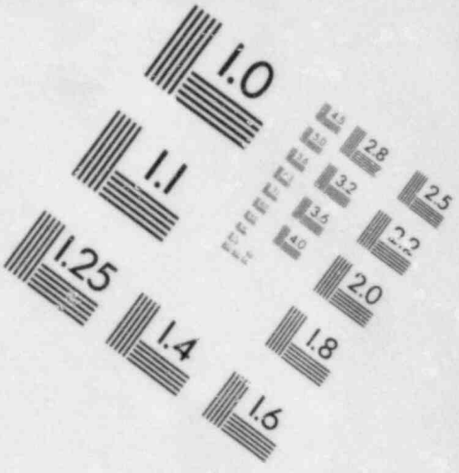
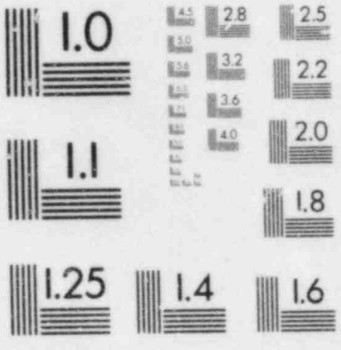
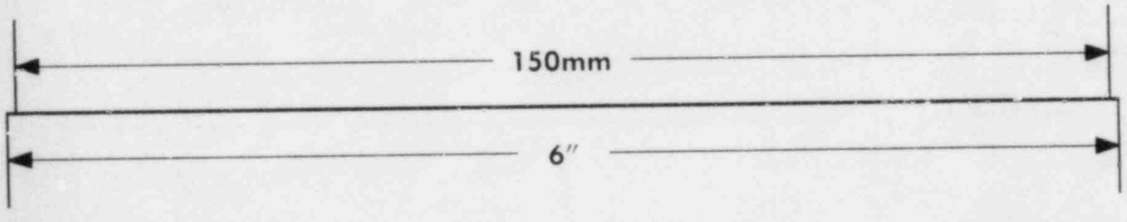


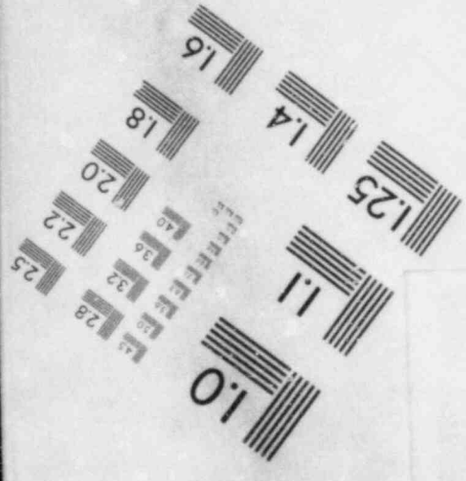
IMAGE EVALUATION TEST TARGET (MT-3)











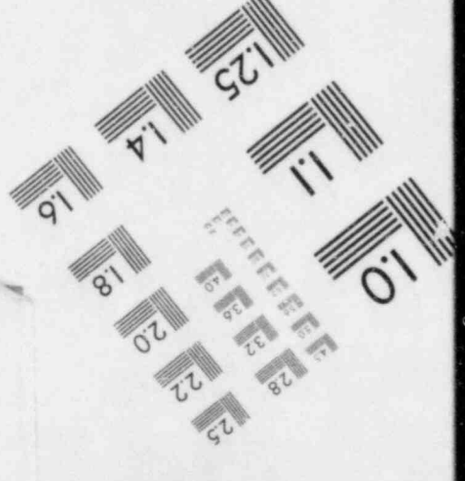


Figure E-2 TYPICAL SMALL STEAM LEAK TRANSIENT

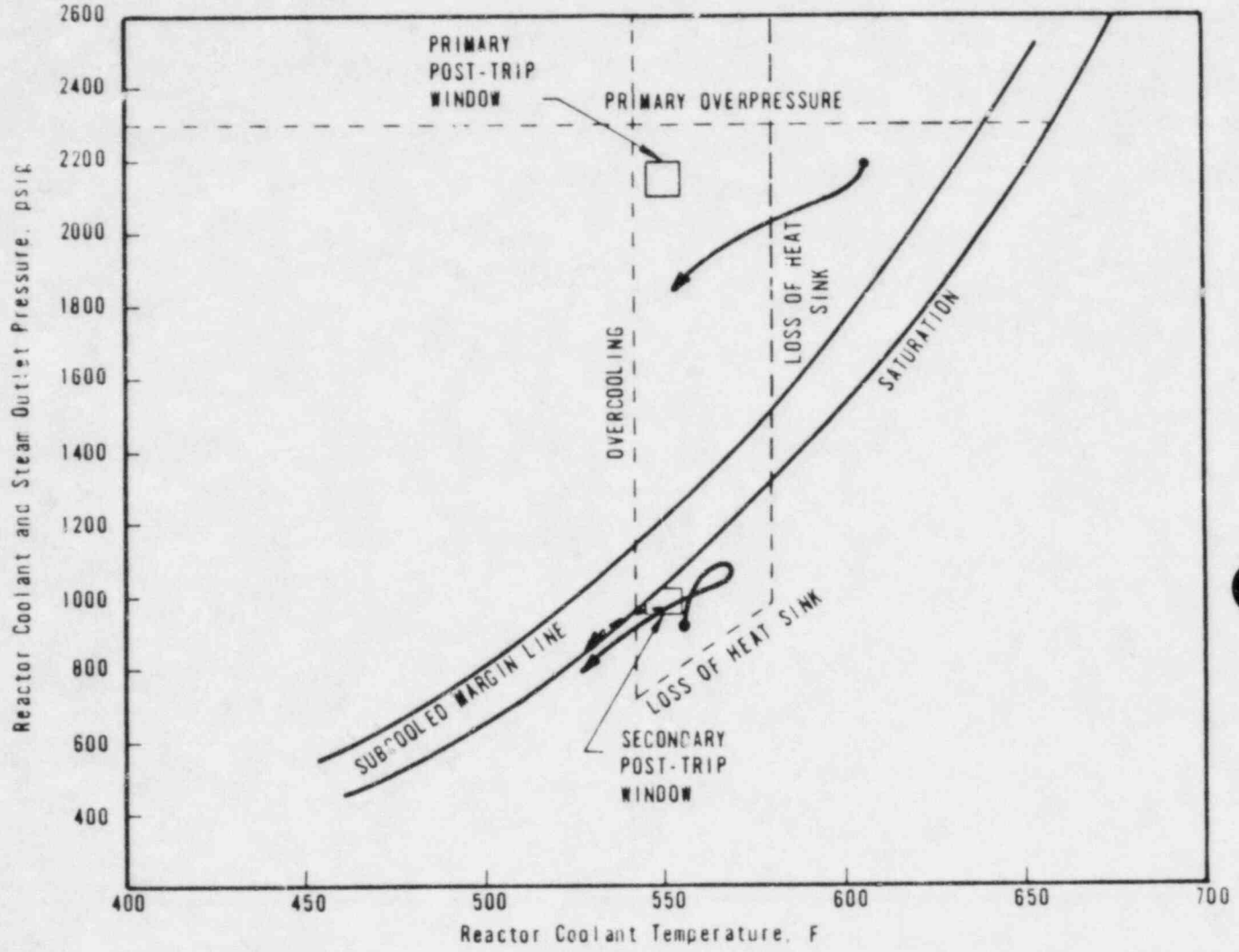
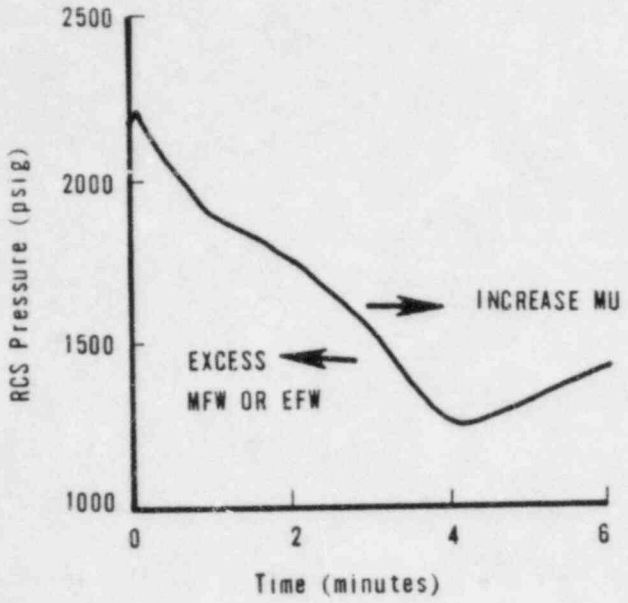
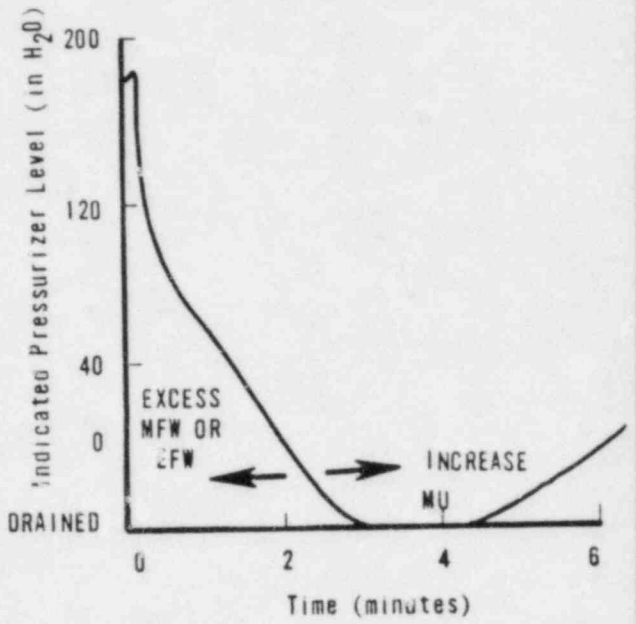
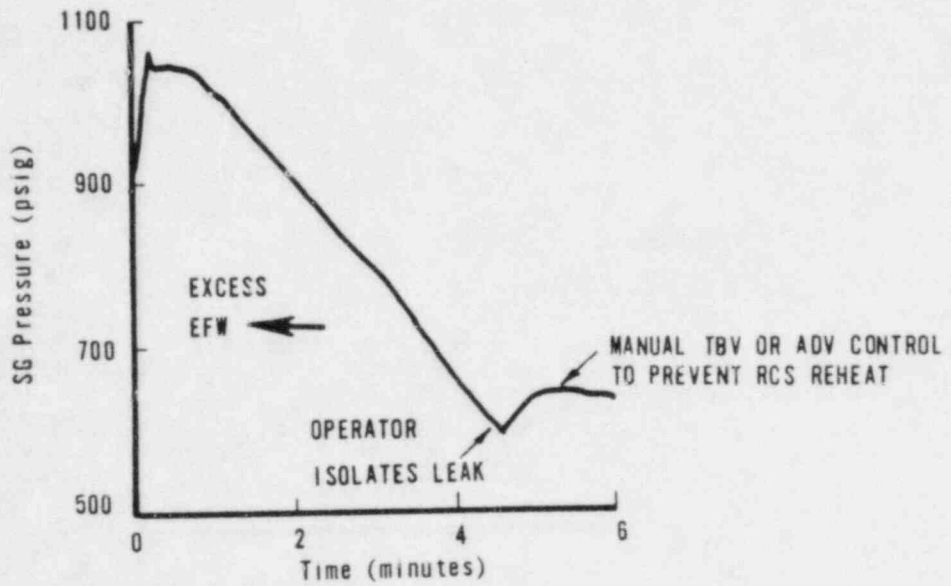
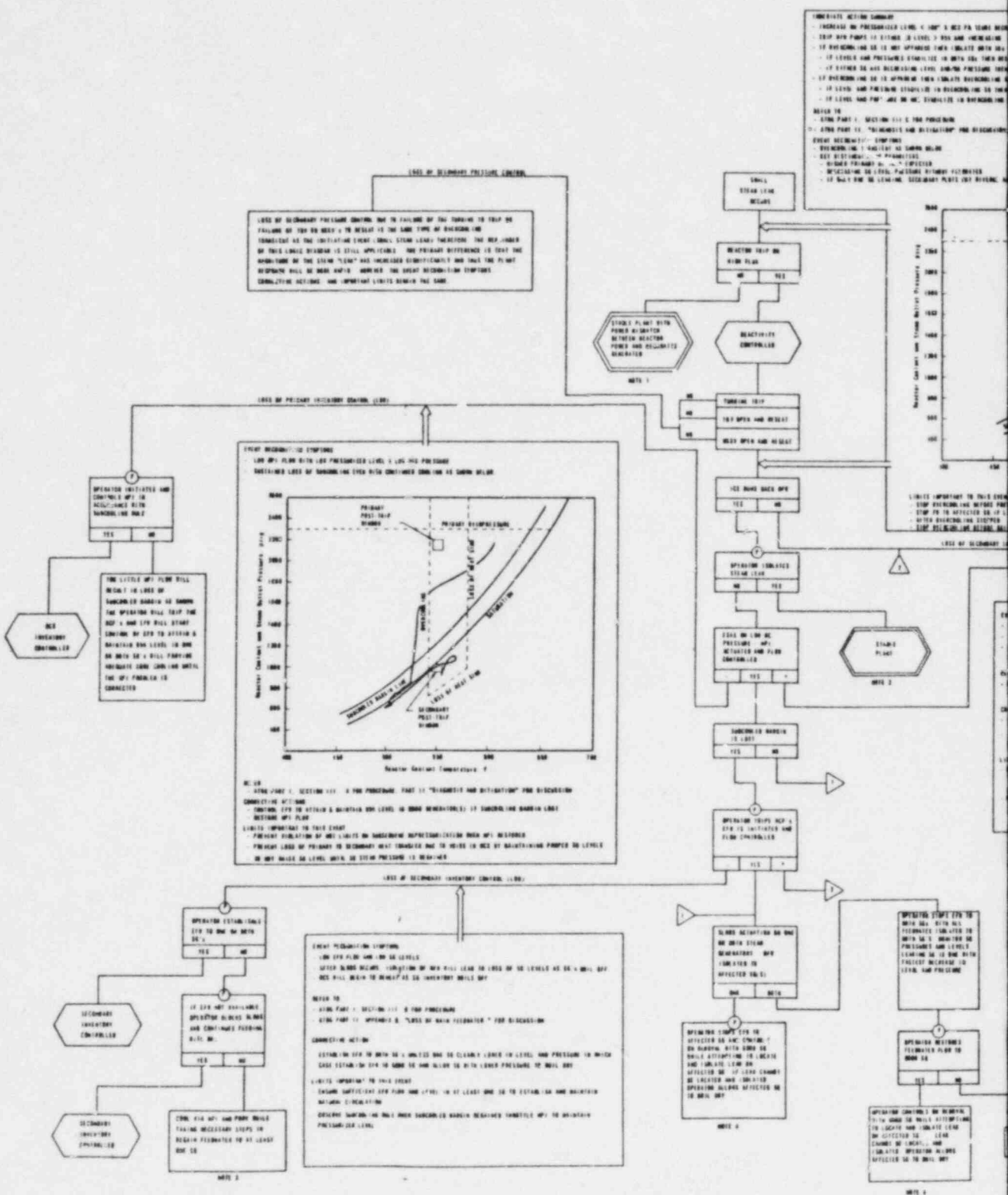


Figure E-3 TIME RELATIONSHIP OF KEY PARAMETERS



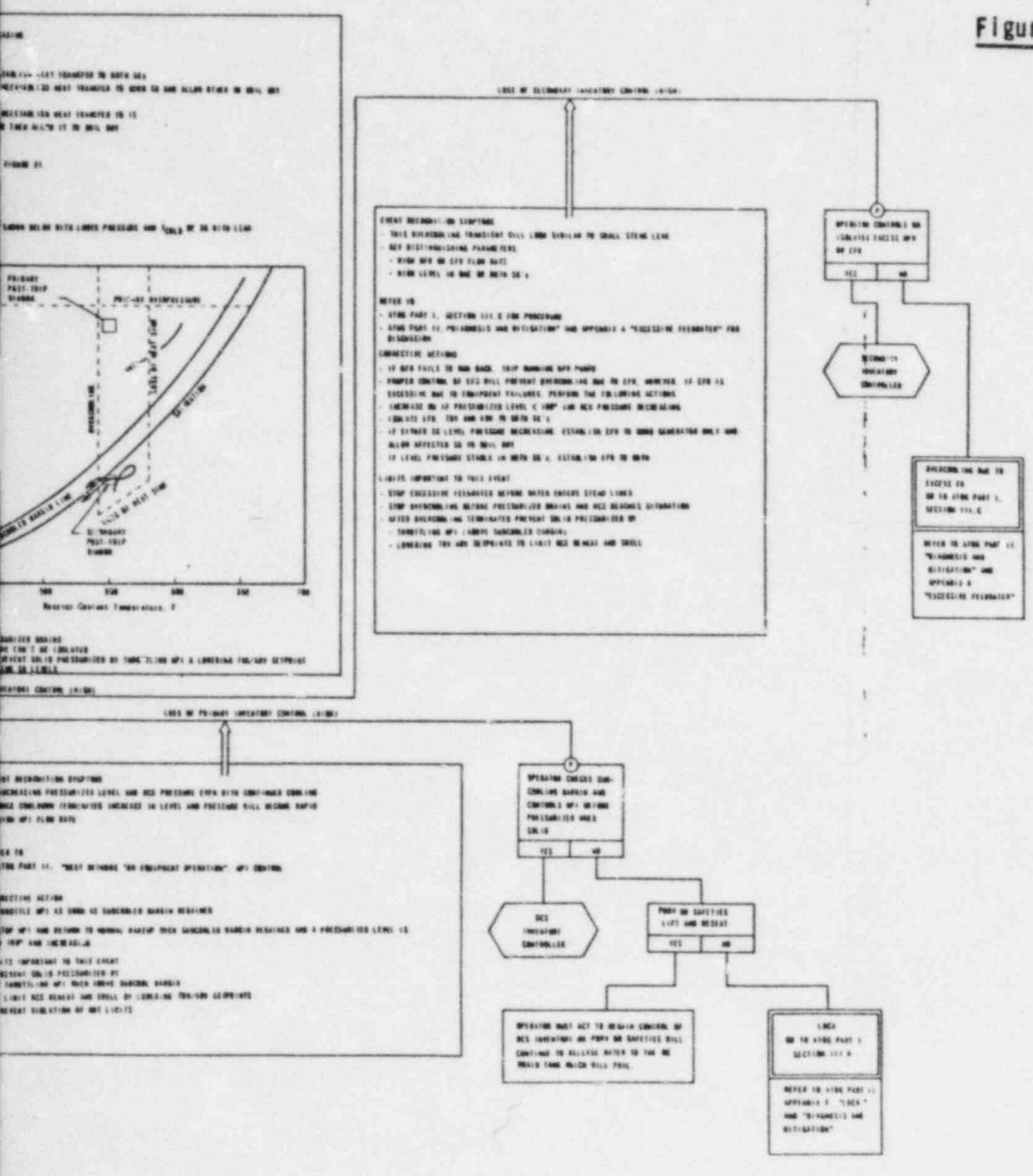






74-1124158-00

Figure E-4 SMALL STEAM LEAK LOGIC DIAGRAM



PRC
APERTURE
CARD

NOTES

1. IF SMALL STEAM LEAKAGE PATH IS THROUGH TBS VALVES PLANT MAY OPERATE WITH POWER REDUCTION INDEFINITELY WHILE SOURCE OF LEAKAGE IS BEING LOCATED AND ISOLATED. IF LEAKAGE PATH IS OTHER THAN TBV BUT OUTSIDE OF RB A GRADUAL DECREASE IN SECONDARY WATER INVENTORY WILL OCCUR. IF LEAKAGE PATH IS INSIDE RB, CONTAINMENT TEMPERATURE AND PRESSURE WILL INCREASE. THE ESAS 4 PSIG TRIP SETPOINT CAN BE REACHED IN ~ 30 SECONDS FOR A 150 GPM LEAK.

2. AT THESE POINTS "STABLE PLANT" DENOTES FACT THAT OVERCOOLING DUE TO SMALL STEAM LEAK HAS BEEN TERMINATED AND PROPER PRIMARY TO SECONDARY HEAT TRANSFER HAS BEEN ESTABLISHED. HOWEVER THE OPERATOR STILL NEEDS TO RE-ESTABLISH NORMAL PRIMARY SYSTEM INVENTORY CONTROL BY:
   - THROTTLING HPI WHEN SUBCOOLED MARGIN RESTORED
   - IF NECESSARY, REDUCING TBV LO HDR SETPOINT TO LOWEST MSL REHEAT AND SWELL
   - TERMINATE HPI AND RE-ALIGN FOR NORMAL MAKEUP/LETDOWN OPERATION WHEN RCS IS ABOVE SUBCOOLED MARGIN AND PRESSURIZER LEVEL IS 100" AND INCREASING.
   - THROTTLE EFW FLOW TO OBTAIN A GRADUAL SG LEVEL INCREASE TO THE APPROPRIATE LEVEL SETPOINT
   - IF IN NATURAL CIRCULATION, THE OPERATOR SHOULD RESTART AN RCP WHEN SUBCOOLED MARGIN IS RESTORED

3. THE OPERATOR WILL PERFORM THE FOLLOWING ACTIONS TO STABILIZE THE PLANT DURING HPI COOLING:
   - WHILE ON HPI COOLING MONITOR INCORE THERMOCOUPLES TO MINIMIZE THERMAL SHOCK.
   - RE-ESTABLISH EFW TO AT LEAST 24K SG
   - THROTTLE HPI WHEN SUBCOOLED MARGIN RESTORED
   - USE PRESSURIZER HEATERS TO DRAW A BUBBLE AND RESTORE RCS PRESSURE CONTROL
   - ISOLATE PORV AND CONTINUE NORMAL PLANT COOLDOWN

4. WITH UNISOLABLE STEAM LEAK IN ONE SG, THREE MAJOR CONCERNS EXIST:
   - BLOWDOWN OF REMAINING INVENTORY IN LEAKING SG COULD RESULT IN SLOWS ACTUATION ON GOOD SG. THEREFORE OPERATOR SHOULD BLOCK SLOWS ON GOOD SG.
   - IF LEAK IS IN RB, ESAS ACTUATION ON HIGH RB PRESSURE IS LIKELY. IF HIGH-HIGH RB PRESSURE (3.30 PSIG) ACTUATION OCCURS, COOLING WATER TO RCP'S WILL BE ISOLATED. OPERATOR SHOULD TAKE STEPS TO PREVENT LOSS OF COOLING WATER OR RESTORE IT IF ISOLATION HAS ALREADY OCCURRED.
   - TUBE SHELL AT DP SHOULD NOT BE ALLOWED TO EXCEED LIMIT DURING SUBSEQUENT ONE SG COOLDOWN. LIMITED FEEDWATER FLOW MAY BE ADMITTED TO AFFECTED SG PERIODICALLY TO MAINTAIN AT WITHIN LIMIT.

Also Available On
Aperture Card

8401230549 -21

APPENDIX F

LOSS OF COOLANT ACCIDENTS

1.0 Introduction

A loss of coolant accident (LOCA) is defined as any event during which reactor coolant escapes due to loss of integrity of the primary coolant system. A LOCA can occur at any time (power operation, cooldown, heatup, cold shutdown) and can be either an initiating event or a result of another accident. Usually LOCA's release reactor coolant to the containment environment; however, there are some LOCA's which can release reactor coolant to the secondary plant (steam generator tube leaks) or to the auxiliary building (leaks in the MU, letdown, or decay heat removal systems).

LOCA's directly affect one of the five fundamental principles of reactor operation: "RCS Inventory Control". The loss of reactor coolant reduces the plant's ability to transport the core's heat to the steam generators. If the lost reactor coolant is not replaced, core cooling will be lost and fuel damage may occur. The Emergency Core Cooling Systems (ECCS) consisting of the High Pressure Injection (HPI), Low Pressure Injection (LPI), and Core Flooding Tanks are used to supply emergency core cooling water to prevent fuel damage. The emergency feedwater system is also used for core heat removal and RCS depressurization for some sizes of small break LOCA's.

Some of the major factors which affect response to a LOCA as follows:

A. A wide range of leak sizes is possible:

The rate at which reactor coolant is lost from the primary system depends on the break size through which the reactor coolant can pass. LOCA's can range from small leak rates (leaking pressurizer relief or safety valves, leaking RC pump seals, cracks or breaks in instrumentation lines connected to the primary system) to large losses of reactor coolant due to cracks in or a severance of the RCS piping or its attachments (letdown line, HPI lines, decay heat drop line).

B. Abnormal system conditions are a natural consequence of the event:

When reactor coolant is lost at a rate greater than it is replaced, pressurizer level will be lost, the reactor coolant will become saturated, a loss of normal natural circulation (assuming the RCP's are tripped) is inevitable and boiler-condenser cooling may be the only means by which the steam generators can remove energy from the reactor coolant. For many LOCA's these conditions are temporary and can be prevented by isolation of the leak. For LOCA's which cannot be isolated, the evolution of the transient to abnormal conditions is unavoidable.

C. Steam generator heat removal may be degraded:

The transport of core heat to the steam generators may be severely reduced depending upon the size of the LOCA. Steam generator heat removal is needed for some small breaks, even though the break itself also removes energy from the primary system and uses the reactor building as a heat sink. If the break is large enough the steam generator is not needed as a heat sink. In some large breaks the RCS depressurizes below steam pressure, and the steam generator can even be a heat source if the temperature of the secondary inventory is higher than that of the reactor coolant.

D. Maintenance of hot shutdown is not a safe end condition in most cases:

Some LOCA's can be isolated and the loss of reactor coolant stopped and therefore hot shutdown is a safe condition. However, when isolation is not possible the loss of reactor coolant cannot be stopped. Then the RCS must be depressurized to reduce the leak, increase the ECCS flowrate, engage the LPI system and establish long term cooling. It is also desirable to depressurize before the BWST is empty to avoid HPI piggyback operation so that sump water does not need to be pumped by the HPI pumps. Debrie in the RB sump water is more harmful to the HPI pumps than to the LPI pumps. The RB sump water may be highly radioative, therefore its transfer through fluid systems should be limited. Depressurization is also desirable to engage the LPI

system so the steam generators do not have to be used with river water when the condensate tank empties. Depressurization is required for the tube leaks to limit the offsite doses and to avoid emptying the BWST (tube leakage is not returned to the sump and recirculation is not possible).

E. The containment environment will degrade:

If the break is inside the containment (most breaks will be) reactor coolant water and steam will collect in the reactor building. The pressure, temperature and radiation levels in the reactor building will increase, and use of emergency building cooling systems may be necessary. In addition to maintenance of core cooling, the operator must also control the reactor building environment to prevent or limit offsite radiation releases. Control of the environment is also desired to prevent equipment damage. Containment isolation is required to limit the offsite doses. The remaining portions of this appendix will describe the response of the RCS for the full spectrum of LOCA's, the general approach to accident mitigation and establishment of long term cooling, how the ECCS and other equipment are best used, and also outline control limits which apply to plant recovery.

2.0 LOCA CONCEPTS

Loss of coolant accidents are classified in three categories:

1. Large Break
2. Small Break
3. Small Leak

These categories are used because the response of the RCS is different. Each category will be discussed separately.

2.1 Large Breaks

A large break is a major failure of the primary system pressure boundary which continually and rapidly depressurizes the reactor coolant to where LPI flow is initiated. This is a design basis event that establishes the size of the core flood tanks, the size of the LPI flow rate and the size of the containment cooling systems (sprays and coolers). A large break LOCA has never occurred at a commercial nuclear power plant.

As a rule of thumb, a LOCA with a break area greater than that of a 10-inch diameter hole is a large break. For breaks of this size or larger, the plant transient can be broken down into three distinct phases: blowdown, refill, and reflood.

Blowdown: Blowdown is a rapid depressurization of the primary system as reactor coolant escapes in large quantities. Large pressure gradients are created in the primary system and low pressure zones are created at or near the break. These pressure gradients disrupt the normal flow patterns within the primary system, and the reactor coolant will be

drawn to the break (low pressure zone) from all regions of the primary system. The reactor coolant will saturate and change to steam due to system depressurization and core heat removal.

Blowdown ends when the primary system and the containment pressures are the same; the loss of reactor coolant stops. From start to finish, the blowdown period can be from 20 to 200 seconds depending upon the break size and location. At the end of blowdown, the reactor coolant system will contain very little water and will be mostly steam.

During blowdown, RC pressure drops rapidly and falls below the secondary side pressure within a few seconds. The steam generators become a heat source as opposed to a heat sink because the temperature of the reactor coolant will be less than the secondary feedwater temperature. The steam generators remove heat only as long as the primary temperature is above the secondary temperature. Steam pressure will hang up initially and then slowly decrease as energy from the secondary is slowly transferred to the primary system.

Blowdown causes a reactor trip, and the fission process is shutdown to the decay heat level. But, because large quantities of steam are produced, the core will heat up;

the fuel and cladding temperature will rise until cooling systems recover the core with water.

During blowdown the HPI and LPI systems are actuated, and the core flood tanks discharge when the primary system pressure drops below 600 psig. These emergency core cooling systems have little or no impact on the blowdown phase of a large break. The blowdown transient is too fast, and the cooling water that does enter the primary system is "swept out" the break along with the reactor coolant. The ECCS systems restore core cooling during the second and third phase of a large break.

The blowdown also has a severe impact on the reactor building. Rapid increase in the containment pressure, temperature, and radiation levels occur. The emergency coolers and sprays are started by the ESAS signals, and water will accumulate in the reactor building emergency sump. The reactor building becomes the heat sink for the energy originally contained in the primary system.

Figure F-1 shows the primary system response during the blowdown transient of a large break.

Refill: At the end of blowdown the primary system is at a low pressure, and little or no water is left in it (see end

condition in Figure F-1). However, the CFT's, the LPI and the HPI will be adding water to the system. The emergency injection water entering the system accumulates and begins to refill the reactor vessel. Refill is defined as the time required to refill the reactor vessel lower head up to bottom of the fuel (see end of refill in Figure F-1). This is a short time (10-12 seconds) and for smaller breaks a refill period may not occur if enough water remains in the reactor vessel.

The refill phase of a large break cannot be detected by any plant instrumentation. As shown in Figure F-1, no water exists in the core during refill and the core will heat up until ECCS water enters the core. When the core is uncovered the hot zircaloy clad chemically reacts with the oxygen of the steam to give zirc oxide and release hydrogen. Hydrogen may accumulate in the loop or it may be vented through the break or high point vent to the containment.

Reflood: The last phase of a large break is called reflood. During reflood, water from the ECCS refloods the RV up to the elevation of the inlet nozzles and refills the system up to the elevation of the break. This is a slow process because a lot of the emergency cooling water is boiled off as it enters the core since decay heat levels are still high.

Within 5 to 10 minutes the core will be recovered with water and the fuel clad temperatures reduced to within a few degrees of the saturation temperature (the core exit thermocouples should show approximately saturated conditions). Core cooling thereafter is maintained by continuously adding injection water from the low pressure injection system so that the core remains covered by water. The CFT will empty, and the HPI system can be secured (see Guidelines for HPI termination in "Best Methods for Equipment Operation") after LPI has been stable for twenty minutes.

Figure F-1 shows the reflood phase. Two examples are given: one for a large break at a high location in the system and one for a large break low in the system.

During the reflood phase, additional steam is created by:

a) boiling of emergency injection water in the core,

b) boiling of emergency injection water due to heat from the hot metal components, and

c) boiling of emergency injection due to heat transferred from the secondary side of the steam generators (this is a source of additional steam only if primary side water re-enters the tube region of the steam generators).

This steam is vented out the break to the reactor building. The reactor building pressure and temperature conditions may rise during the early stages of reflood. When decay heat and the heat from the hot metal and steam generators drop, the steam release rate will decrease and the reactor building pressure and temperature will decrease as the sprays and coolers can remove more heat than is being released.

Figures F-2 and F-3 give a summary of the expected response (P-T diagram) of the RCS during large hot and cold leg breaks. The diagrams also outline the sequence of events. At the end of blowdown, the reactor coolant is in a saturated condition at or near the containment pressure. Thereafter, the core outlet thermocouples should be used to check the core outlet temperature for saturation. At the end of the blowdown the core outlet thermocouples may indicate superheated conditions since the core may be completely void of water. As the ECCS refloods the reactor vessel, the fuel rods will be quenched and the core outlet temperature should return to saturation.

2.2 Small Breaks

The second category of LOCA's are small breaks. The depressurization is much slower, the mass is lost at a lower flowrate, and the core cooling can be maintained throughout the transient as long as the ECCS is operating.

Small Leak				Large Break
Breaks for which the leak rate is within the capacity of the MU system (area approximately equal to that of a 3/8" hole)	<	SMALL BREAK	<	(Area approximately equal to or greater than that of a 10 in. diameter hole).

Small breaks include cracks in the primary system piping, breaks of lines attached to the RCS (HPI lines, letdown line, spray line), and failed open pressurizer relief or safety valves. The reference hole sizes given above are not exact boundaries for small breaks. They are given only as physical reference points to promote a feel for the spread in break size for this category of LOCA's. The response of the RCS during a LOCA is actually a better way to gauge whether a specified LOCA is a small leak, small break, or a large break.

A small break transient is characterized by a slow depressurization relative to large breaks. Flow conditions in the RCS change gradually and smoothly, and temperature and pressure gradients between different places in the primary system tend to be small. Rather than the distinct blowdown, refill, and reflood phases associated with large breaks, small breaks have a period of relatively high loop flow followed by a period of relatively low or no loop flow. The no loop flow conditions are a semi-stable period where circulation stops and the steam separates from the water. When the steam and water separate the reactor coolant system is in a "boiling pot" mode.

Figure F-4 shows a small break, including P-T responses and sequence of events. Early in the transient reactor coolant will circulate from the core to the steam generator, and the steam generator will remove heat. This part of the transient is called the "flow circulation" phase. Flow can be a combination of forced flow (while the RC pumps operate and coast down), subcooled natural circulation and two-phase natural circulation. For very small breaks natural circulation (normal or two phase) will not be lost, and the primary system will return to a subcooled state. For "larger" small breaks, the flow circulation phase will end almost immediately after the RC pumps are tripped. For all small breaks, core cooling is maintained during the "flow circulation" phase.

After the "flow circulation" portion of a small break, the reactor coolant "settles out". The water falls by gravity and collects in the lower regions, and the steam bubbles up through the water and collects in the high points of the system. If the RC saturation temperature is below the secondary side temperature a "boiling pot" cooling will exist.

In this condition the ECCS water added to the core boils and the steam vented flows out the break. The SG does not provide any cooling.

If The RC temperature is above the secondary side temperature boiler-condenser cooling will coincide with the boiling pot cooling. The core water level will vary depending on:

- Break Size
- Break Location
- Primary to Secondary Heat Transfer (steam generator cooling)
- Number HPI/LPI Pumps Operating
- Decay Heat Levels

These variables will cause the response characteristics of the RCS to change in different ways. The effects of these variables will be discused next.

To illustrate the effects of break size, steam generator cooling and the other small break variables, the following five categories will be considered:

1. Small breaks large enough to depressurize the RCS
2. Small breaks which stabilize at approximately secondary side pressure
3. Small breaks which may repressurize in a saturated condition
4. Small breaks without primary to secondary heat transfer
5. Small breaks within the pressurizer steam space

These discussions will also highlight the effects of break size on the "flow circulation" phase of a small break.

Small Breaks Large Enough to Depressurize the RCS Below the Secondary Side Presure With FW Available

At the "large" end of the small break spectrum, the breaks release enough mass and energy from the system such that the primary system will continually depressurize to a stable low pressure condition. For these breaks the "flow circulation" period is over very rapidly. RCS pressure will also drop very rapidly below the secondary side pressure. Therefore, for these breaks primary to secondary heat transfer does not play a vital role in the accident. During the "boiling pot" period, the water levels in the system will quickly drop to the elevation of the break. When the water level drops below the break elevation, the rate of RCS depressurization will increase

This change in rate is due to the change in break flow from liquid to steam. Steam release through a given size break wil depressurize the RCS at a faster rate than water release due to both an increase in volumetric flow rate and an increase in energy lost out the break. Thereafter the water levels within the system will decrease until emergency cooling water flowrate exceeds the rate of water boiloff in the core. The net amount of water in the system will then increase slowly, and the water levels in the system will gradually build back up to the break elevation. For small breaks of this size the primary system will never refill water above the break.

Figures F-5a and F-5b show two examples of the system P-T response up to the time where the lowest system water levels occur. These figures show that these breaks depend upon the HPI and CFT's to maintain adequate water in the system to keep the core covered. When the system finally depressurizes, LPI increases the water level up to the break elevation. The steam generators provide very little cooling for this size of break and are not very important for accident mitigation.

Small Breaks Which Stabilize At Approximately Secondary Side Pressure With FW Available

When the break size is smaller than that of the previous example, the leak rate and consequently the energy removal rate of the break decreases (the break removes energy when reactor coolant escapes). These smaller breaks cannot remove energy from the primary system fast enough to allow a continuous RCS depressurization. Following the "flow circulation" portion of the transient, the system will stabilize at or near the secondary side pressure. For these breaks, the steam generators can remove a significant amount of the core's decay heat by condensing primary system steam within the tube region. Steam generator operation is important for these break sizes. To promote reactor coolant steam condensation (commonly called boiler condenser cooling) and to reduce RCS pressure, the SG water levels should be increased (preferably with EFW) to 95% on the operate range. This must be done manually and is one of the more important operator actions.

The system response for small breaks within this size range is illustrated in Figure F-6. As shown in Figure F-6, the "flow circulation period" is short-lived, and the system stabilizes slightly above steam generator pressure. Because the RCS pressure remains high, HPI is the only means by which emergency cooling water can be supplied to make up for inventory loss until the system depressurizes further. Since the generators are removing heat from

the RCS by condensing steam, another important operator action will be to begin a plant cooldown and depressurization by decreasing steam pressure. The primary system will depressurize because more steam will be condensed. As system pressure is decreased the ECCS system will flow at a higher rate, and filling the PC system becomes more likely. During the refill, RCS pressure may stabilize or increase slightly (while still saturated) as the RCS water level covers the condensing surface in the steam generators. For this break size range, a refill and repressurization is not likely until the RCS pressure has been lowered to the LPI pressure. Repressurization of the RCS when the RC is in a saturated state will be more likely for the next category of breaks in the small break range.

Small Breaks Which May Repressurize in a Saturated Condition With FW Available

For the sizes smaller than the two previous examples the loss of reactor coolant mass and energy is sufficient to initially depressurize the RCS and results in enough steam formation to interrupt loop circulation. When the flow stops and the reactor coolant "settles out", the RCS may gradually repressurize. The repressurization occurs because the break alone is not large enough to depressurize the RCS and the reactor coolant steam in the hot leg cannot be condensed because the reactor coolant water level is higher than the tubes. The primary system can repressurize as high as the pressurizer safey valve setpoint. Once enough RCS inventory has been lost and the reactor coolant water level drops below the EFW injection level, reactor coolant steam will condense on the tube and the reactor coolant pressure will drop to the steam generator pressure. Figure F-6 illustrates this repressurization behavior as it would be observed on a P-T diagram. During the repressurization phase, pressurizer level may return on scale, as shown in Figure F-7, because the reactor coolant is heating up and expanding. For more severe cases, the pressurizer level may go off scale high. Because the reactor coolant is saturated, HPI flow should not be throttled. Two HPI pumps should be kept on full, and the PORV should be opened if RCS pressure increases above the PORV pressure setpoint. The PORV should be closed when the RC pressure drops to within 100 psi of the SG pressure.

Summary

The previous three examples highlighted the importance of small break size and steam generator cooling and showed how these two variables interplayed to change the reactor coolant system pressure. The reactor coolant system pressure is one of the most important factors in small break control. When the reactor coolant system pressure is high the leak flow will be high and the HPI flowrate will be low. The steam generator is valuable because it condenses reactor coolant steam and lowers the RCS pressure. To get the best effect steam generator level should be raised and EFW flow continuously run until the steam generator level is at 95% on the operate range.

Although decay heat level and HPI flow rate were not specifically addressed for their effects, their influence is important. As the decay heat level lowers with time (or if it was low at the start) the heat input to the reactor coolant is reduced and the HPI flow can more easily "match" decay heat. Pressure will fall quicker with lower decay heat levels than with high. HPI flowrate is important because it will keep the core covered and cooled when two HPI pumps are running. One pump will take much longer to match decay heat and if the system pressure is high the flowrate will be very low; steam generator cooling is desirable to reduce the RCS pressure to get more HPI.

The next three examples will repeat the first three, except that steam generator cooling is not available. The final example will illustrate the importance of break location.

Small Break Without Primary to Secondary Heat Transfer

Steam generator heat transfer becomes more and more important as the break size gets smaller. This is due to the inability of the break to remove decay heat by release of reactor coolant. Without primary to secondary heat transfer, the RCS is more likely to repressurize or to depressurize more slowly. Figures F-8 to F-10 show system responses for three different break sizes. These break sizes are approximately the same as previously illustrated; those had steam generator cooling and these do not.

Figure F-8 shows the size where the break is large enough to continually decrease RCS pressure. For these breaks, which can depressurize the RCS below the normal secondary side pressure, the loss of secondary inventory has little or no effect on the transient. Core cooling is maintained by the ECCS. Because these breaks are fairly large, pressurizer level would rapidly fall and remain off-scale low.

Figure F-9 shows the next size smaller break. The RCS quickly depressurizes; the HPI's are actuated; and the RC pumps are tripped when the reactor coolant subcooled margin is lost. Pressurizer level also goes off-scale low. When flow circulation stops and the steam and water separate, the RCS pressure hangs up. RC pressure would normally drop to the secondary side pressure if primary to secondary heat transfer were available. If feedwater is restored and primary to secondary heat transfer established, the RCS pressure would drop and boiler condenser cooling would start.

Figure F-10 shows the smallest break size. ESAS may not be automatically actuated and the RCS repressurizes when the secondary inventory is boiled off. It is possible for the RCS to repressurize to the pressure setpoints of the PORV or the pressurizer safety valves and for pressurizer level to go off-scale high. For any break size without secondary side heat remvoal, the operator should actuate the HPI (if not already on) and open the PORV. The RC pumps should also be tripped if the RC subcooled margin is lost. The RCS is being cooled by "HPI Cooling". Figure F-10 shows a transient where no operator actions are taken for the first 20 minutes. After 20 minutes, Figure F-10 shows the effects of restoring feedwater and starting HPI. The RCS depressurization causes an outsurge from the pressurizer. A complete loss of pressurizer level may result. Thereafter, the system response is similar to that of a small break with primary to secondary heat transfer.

Small Breaks Within the Pressurizer Steam Space

For small breaks within the pressurizer, the system pressure-temperature response will be similar to small breaks not in the pressurizer steam space. The initial depressurization will be faster because steam, rather than water, is released (steam has a higher volumetric flow rate than water does). The big difference for pressurizer breaks is the response of pressurizer level. Figure F-11 shows a P-T diagram and transient pressure and pressurizer level histories for a stuck open PORV. As shown in Figure F-11, pressurizer level initially rises; this is due to the pressure reduction in the pressurizer and an insurge into the pressurizer from the RCS prior to reactor trip. Once the reactor trips, the reactor coolant contraction (normal post trip response) causes a decrease in pressurizer level. Because RC pressure is dropping, flashing occurs in the hot leg (saturation), and the steam bubbles expand and force water into the pressurizer. The pressurizer subsequently fills and will remain full for the remainder of the transient. In the long term, the pressurizer may contain a two-phase mixture, and the indicated level may show that the pressurizer is only partly full. This peculiar behavior is the main reason that pressurizer level cannot be relied on to measure reactor coolant inventory until the reactor coolant is subcooled (and free of non-condensible gases). If the break in the pressurizer is fairly small and can't be isolated, the HPI can refill the system and the pressurizer can be water solid and subcooled. This would not be the expected response for a stuck open PORV since the PORV can be isolated. For these cases, attempts to draw a pressurizer steam bubble will fail, and a solid water cooldown will be necessary.

2.3 Small Leaks

Small leaks are within the capacity of the normal makeup system. Several possible occurrences which could fall in this category are leaking pressurizer safety or relief valves, leaking RC pump seals or tiny cracks in the primary system piping or attachments (instrument lines, RTD hotwells, or auxiliary system lines). This category would correspond to a 3/8 inch or less diameter hole in the primary system.

When the leakage rate is very small, there is no impact on the primary or secondary system. These small-small leaks are discovered due to the necessity to add water to the makeup tank more frequently than normal or from leak rate calculations. The action required is in the Technical Specifications.

At the upper end of the leak rate for small leaks, more direct symptoms may be observed, such as

1. Excessive MU Flow
2. Decreasing pressurizer level and pressure
3. Reactor trip
4. Containment radiation

These symptoms would likely exist when the leak, combined with letdown flow, is greater than the capacity of the MU system. After letdown isolation on reactor trip, makeup flow would equal or exceed the leak rate. This transient is very slow, but pressurizer low level and

pressure (before letdown isolation) and makeup tank low level alarms show the imbalance in reactor inventory control. There is time to increase the makeup rate to the RCS and stop letdown. Subcooling should not be lost; but if a reactor trip occurs, the pressurizer might drain (due to normal post-trip cooldown and lower than normal pressurizer level) and HPI will be started. The plant can be cooled down in a near normal manner unless a small leak in the pressurizer steam space occurs which is greater than the steam production capacity of the pressurizer heaters. If the steam release rate is greater than the steam production capacity of the pressurizer heaters, the pressurizer will fill and a solid water cooldown will be necessary if the leak is unisolable.

3.0 POST LOCA - PLANT CONTROL

The primary objectives during a LOCA are to maintain core cooling, to cooldown and depressurize, and to establish a stable long-term cooling mode. Maintenance of core cooling is the first priority and is achieved through operation of the ECCS. Maintenance of core cooling will limit fuel damage and thereby limit radiation release. With essentially no actions other than verifying the rods fully inserted following a reactor trip and tripping the reactor coolant pumps on loss of subcooling, the core can be cooled by ensuring that the ECCS works when required and can be run continuously until their safety function is satisfied. In addition to ensuring core cooling, the operator must make sure that containment cooling is working and that long-term cooling is established. The general things to be done after a LOCA are:

Core Cooling

1. Actuate HPI on loss of subcooled margin (if not automatically actuated).
2. Trip RC pumps on loss of subcooled margin.
3. Verify automatic start and injection flow rate of LPI and HPI after ESAS.
4. Balance LPI and HPI as necessary.
5. Verify that Core Flood Tanks release when RC pressure drops below 600 psig. For small leaks isolate CFT's after discharge to prevent N_2 from entering RCS.

6. Locate and, if possible, isolate the break (check for steam generator tube leaks and leaks inside or outside containment).
7. Control steam pressure and raise steam generator level to 95% on the operate range if the reactor coolant subcooled margin is lost (except for the "bad" generator for tube ruptures) for small breaks. If a large LOCA has occurred, isolate and let both generators dry out.

Containment Control

8. Refer to Chapter G in Volume 1 of Part II.

Long Term Cooling

9. Switch the suction of the LPI to the reactor building emergency sump when the BWST low level is reached. If the RCS is not depressurized enough to use LPI, place the HPI in piggyback on the LPI and use recirculation from the sump for injection.
10. For large breaks in the sump recirculation mode, stop one LPI train and leave one running so long as the incore thermocouples indicate the core is cooled. This will preserve one pump in case it is needed later. Continue to monitor LPI flow.
11. Take actions to prevent boron precipitation.

For large breaks, maintenance of core cooling leads directly to a stable long-term cooling mode because the break is large enough to depressurize the RCS and secondary pressure and inventory control have little or no effect on the course of the accident.

For small breaks, core cooling can be maintained using two HPI's. The core will be cooled, but reactor coolant will continue to be lost in large quantities as long as the RCS is at high pressure. Depressurization and cooldown using the steam generator is necessary to decrease the leak and to allow for a potential refill of the primary system. Depressurization to cold conditions is essential for tube leaks because all the BWST water is lost out of the leak and cannot be recirculated from the sump; the plant must be placed on the decay heat removal system before the BWST drains.

In the following sections, the general approach to accident mitigation (core cooling) and establishment of long-term cooling using the Abnormal Transient Operating Guidelines will be outlined for loss-of-coolant accidents. The full spectrum of LOCA's will be addressed with the exception of the very small breaks or leaks which would typically never result in loss of reactor coolant subcooled margin. For these transients, the loss of reactor coolant can be matched by the normal makeup system or the HPI system; and plant control is essentially no different than any other abnormal transient which results in a reactor trip followed by a plant cooldown and depressurization.

General Overview

Table F-1 outlines the general approach to post-LOCA plant control from a core cooling standpoint. This sequential breakdown of operator

actions has many of the same features described in the accident mitigation chapter for non-LOCA's except that actions to cool down the plant and to establish long-term cooling that are unique to LOCA have been included. If a LOCA can be located and isolated, however, the plant can be stabilized at or near a hot shutdown condition since the loss of reactor coolant has been stopped. Although not shown in Table F-1, the containment environment must also be controlled; both short and long term actions from a containment integrity standpoint are discussed in Volume 1, Part II, Chapter G.

3.1 Immediate Actions and Vital System Status Checks

The operator actions required during the first 2-3 minutes of a LOCA are identical to those for any abnormal event. These actions include the immediate actions and verification that systems are working properly as outlined in the Accident Mitigation Chapter. For LOCA's, some of the required actions are of special significance:

1. Verification that ESAS starts HPI and LPI and that containment cooling and isolation have occurred.
2. Trip RC pumps if the reactor coolant subcooled margin is lost.

The ESAS initiates and aligns the HPI and LPI systems for emergency injection, starts emergency containment cooling systems (sprays and fan coolers) for high pressure containment conditions, and isolates non-vital containment penetrations to limit offsite dose releases. Tripping the RC Pumps, as explained in the chapter on Best Methods for Equipment Operation, is a preventive action specifically for a small break. If the RC pumps are tripped on loss of reactor coolant subcooling margin, enough reactor coolant will be retained within the primary system (not lost out the break) and HPI will maintain the core covered and cooled. Both loss of subcooling margin and ESAS actuation are alarmed (visually and audibly) in the control room to alert the operator of the plant's status. By verifying that the ESAS actuated systems automatically start (or by applying corrective actions in the event of failure in ESAS actuated systems) and tripping the RC pumps, the operator ensures:

1. Adequate core cooling.
2. Containment integrity so that the offsite doses will be within acceptable limits.

3.2 Monitoring

During and immediately following the immediate actions, the P-T diagram and other parameters should be monitored to determine if the abnormal transient is a LOCA and not some other transient. Many overcooling transients will look like small breaks, and all small break LOCA's will not look the same. In some cases, a LOCA can only be determined by showing that some other transient is not in progress. Usually the transients that can be eliminated readily are overcooling transients; these can often be eliminated by reviewing steam pressure, secondary water level, and feed flows.

The operator should compare the examples of this section with other transients. LOCA's do have some unique characteristics; these are shown in Table F-2. (This is Table 4a from the "Abnormal Transient Diagnosis and Mitigation" chapter, repeated here for convenient reference.)

For most LOCA's the general symptoms shown in Table F-2 will be apparent, and other indications will supply additional evidence that a LOCA is in progress. Table F-3 scopes the characteristics of a wide range of LOCA break sizes and summarizes the other evidence to be used to diagnose that a LOCA is occurring. Table F-3 includes both the pressure-temperature response characteristics and other event or plant symptoms for the complete spectrum of LOCA's. Some LOCA's can be isolated. Table F-4 gives symptoms for LOCA's that can be located and isolated. (This is Table 4b from the "Abnormal Transient Diagnosis and Mitigation" chapter repeated here for convenient reference.)

Some LOCA's (such as large breaks) have such distinctive characteristics that a quick diagnosis is assured. For small LOCA's the event may not be properly diagnosed for some time into the event, but core cooling is assured so long as the ECCS systems are flowing fully and the RC pumps are tripped on loss of subcooled margin. The symptoms in Tables F-2, F-3 and F-4 should be studied because some LOCA's can be isolated and the loss of reactor coolant stopped.

3.3 Corrective Actions for LOCA's - Introduction

As outlined in the Accident Mitigation chapter, the actions to be taken in response to abnormal plant symptoms are aimed at restoring and controlling primary-to-secondary heat transfer or starting backup cooling methods. For LOCA's, in addition to restoring primary-to-secondary heat transfer, an RCS cooldown and depressurization must be started. The plant is not in a stable condition until it is depressurized and the ECCS systems are aligned for long-term cooling (unless the break is isolated). For large breaks, the plant will depressurize quickly and only actions to establish and maintain long-term cooling are required.

Three symptoms for which operator actions are based during any abnormal event are:

1. Lack of Adequate Subcooled Margin
2. Lack of Primary to Secondary Heat Transfer (overheating)
3. Too much Primary to Secondary Heat Transfer (overcooling)

During a LOCA all of the above symptoms can exist at some time during the transient. Lack of adequate subcooling and/or lack of primary to secondary heat transfer are the expected symptoms, because the loss of reactor coolant will result in saturated conditions and impede the transport of core heat to the steam generators. The following sections will show how to control the RCS for LOCA, and ensure isolation, and establish long-term cooling.

Corrective Actions for LOCA's - Loss of Subcooling Margin

Figure F-12 outlines the symptoms of and general actions for a lack of subcooling margin for a LOCA. Tripping the RC Pumps is a preventive action for small breaks as discussed previously, and manual HPI actuation serves as a backup to the normal start feature provided by the ESAS. Verification of the HPI flows is a general action to be taken following HPI actuation at any time, and is required to ensure that the greatest amount of pumped flow enters the core. The chapter on "Best Methods for Equipment Operation" outlines specific ways to correct abnormal HPI flows. The third action in Figure F-12 is raising the steam generator water level to 95% on the operate range. Controlling the water level high in the steam generator is required for small LOCA when the pumps are tripped because it aids boiler condenser cooling (boiling in the vessel and condensing in the steam generator) for decay heat removal and can help to establish natural circulation. When raising the water level in the steam generators, full emergency feedwater flow is not required. EFW should be throttled and the water level raised in a continuous and controlled manner as described in the "Best Methods for Equipment Operation" chapter. The last action, which is to attempt to locate and isolate the break, should be taken whenever a LOCA is suspected. Typically, the PORV and block valve should be routinely closed under these conditions as a precautionary measure. In addition, Table F-4 also outlines symptoms of other specific LOCA's which can be located and shows how they can be isolated. By performing the four actions

(graphically displayed in Figure F-12), core cooling is assured for the full spectrum of small breaks. If the reactor coolant returns to a subcooled state due to break isolation or system refill by HPI, the plant can be cooled down in a near normal manner if no other abnormal plant symptoms exist. If saturated conditions persist with heat transfer to the steam generators (see example P-T diagram on Figure F-12), additional evidence to support an additional LOCA diagnosis should be gathered (see Tables F-2 and F-3). With evidence to confirm or suspect a LOCA, an immediate cooldown of the system to establish a stable long-term cooling mode should be started. If lack of primary to secondary heat transfer (overheating) exists, these conditions must be treated to restore use of the steam generators for plant cooldown.

Corrective Actions for LOCA's with Lack of Primary-to-Secondary Heat Transfer

Figure F-13 outlines the symptoms of and general corrective actions for a lack of primary to secondary heat transfer (overheating) during a LOCA. Actions are shown for two types of overheating transients. The first type (right-hand portion of Figure F-13) is overheating due to a loss of secondary inventory (no feedwater), and the corrective action is to use HPI cooling (open PORV with two HPI pumps on) until feedwater is restored. The second type is overheating due to reverse heat transfer (RC pressure drops below secondary pressure) or due to loss of steam condensing surface in the steam generators as the primary system refills. For reverse heat transfer symptoms (i.e. SG T_{sat} > RC temperature) to exist, a fairly "large" small break must be in progress because the break is large enough to depressurize the plant. For these LOCA's the primary and secondary systems can be recoupled by lowering steam pressure. If RC pressure follows steam pressure, small break cooldown procedures should be followed to establish long-term cooling. For plant symptoms which imply a lack of primary to secondary heat transfer due to the inability to condense steam in the generator tubes, methods are available to stimulate a return to "normal" natural circulation. The method used to start natural circulation is to lower steam saturation temperature about 50F below the incore thermocouple temperature and bump an RC pump (see pump restart criteria in the "Best Methods for Equipment Operation" chapter). When the pump is bumped, RCS pressure will drop to secondary pressure as primary steam is swept into and condenses in the

steam generator tubes. As a result of the reduction in primary system pressure, the HPI can add more water to the primary system and the system may refill and establish natural circulation. If the primary and secondary heat transfer is not established after four successive pump bumps, steam temperature should be dropped until it is 100F below the incore thermocouple temperature. A RC pump should be started and run continuously. After these actions, a cooldown can be started to establish a stable long-term cooling mode. If the RC pumps are not available, the PORV can be opened (HPI cooling) to minimize the RCS pressure increase and to increase HPI flow when lack of primary to secondary heat transfer symptoms exist.

Corrective Actions for LOCA's with Overcooling

LOCA's are not overcooling events. Nevertheless, the P-T response of the RCS during a LOCA can resemble a severe overcooling event (too much primary to secondary heat transfer) initially because the reactor coolant pressure and temperature will drop to saturation (although usually at a higher temperature than with overcooling transients) and steam pressure can also be low. Low steam pressure in both steam generators is possible (without equipment failures) because LOCA's can block the primary to secondary heat transfer process. This similarity between non-LOCA and LOCA events will be short-lived because the non-LOCA overcooling event will return to a subcooled condition fairly rapidly after HPI is actuated.

Figure 22 in the Abnormal Transient Diagnosis and Mitigation chapter outlines diagnostic techniques and corrective actions for excessive primary to secondary heat transfer. Corrective actions are identified for high steam generator level (too much feedwater) and low steam pressure conditions. These actions are also appropriate for LOCA's because equipment failures can occur in conjunction with a LOCA to cause excessive heat transfer, even when the reactor coolant is saturated. If steam pressure or feedwater control in one steam generator is lost, that steam generator can be isolated and allowed to boil dry since adequate core cooling capability is maintained with the other OTSG.

3.4 Cooldown for LOCA's - General

The actions identified in Figures F-12 and F-13 and Figure 22 of the Abnormal Transient Diagnosis and Mitigation chapter allow the operator to maintain the plant in a safe condition; but since the plant is still at high pressure, the leak will continue (unless it has been isolated). Cooldown and depressurization is required. At this point into the accident, the conditions can be one of the following:

1. Isolated LOCA with the plant at hot shutdown (forced or natural circulation).
2. Small break with HPI "on" and
   a. Subcooled coolant conditions with primary to secondary heat transfer (RC pumps "on" or "off");
   b. Saturated coolant conditions with primary to secondary heat transfer (RC pumps "on", restarted when treating lack of primary to secondary heat transfer, or "off"); or
   c. Saturated coolant conditions (RC pumps "off") with no primary to secondary heat transfer (HPI cooling).
3. Large break with the primary system completely depressurized.

Steam generator heat transfer will permit a better cooldown and depressurization and minimize the amount of reactor coolant spilled to the containment but the plant can be depressurized without it. Large breaks do not require depressurization, but long term cooling must be established. The following section will discuss cooldown from each of these conditions.

Small Break Cooldown (With Primary to Secondary Heat Transfer)

a. Subcooled Cooldown

If the reactor coolant has adequate subcooled margin, the plant can be cooled in a near normal manner to get on the decay heat removal system for long-term cooling. The RC Pumps should be started (see RC Pump restart guidelines) if the plant is in a subcooled natural circulation condition on at least one generator. With RC Pumps running and the reactor coolant subcooled, the steam generator water levels can also be controlled at the normal low level limits. If the LOCA has been isolated, a pressurizer bubble can be drawn and cooldown can proceed normally. If the LOCA is not isolated and not in the pressurizer, a pressurizer bubble can be drawn using the pressurizer heaters. The HPI injection system must be throttled to match the leak and to maintain the reactor coolant subcooled as the plant is cooled and depressurized.

If the LOCA is in the pressurizer, a solid water cooldown is necessary because RC pressure is controlled by the discharge pressure of the HPI pumps. To maintain plant control, HPI flow must be reduced slowly to reduce RCS pressure and coordinated with RCS temperature control (by the secondary system) to maintain desirable cooldown limits. Tight control of HPI is necessary at low RC temperatures to avoid a sudden flow increase and subsequent increase in system pressure.

For plant cooldown (with or without a pressurizer steam bubble) the depletion rate of BWST should be monitored. If low BWST levels occur, the LPI pumps must be aligned to take suction from the reactor building sump and the HPI-LPI systems aligned in the piggyback mode (HPI pumps take suction from discharge of the LPI pumps) so as to maintain continuous RCS inventory control. The CFT's may also be isolated if the plant is cooled down in a subcooled state.

b. Saturated Cooldown

For some small breaks, a plant cooldown with saturated reactor coolant conditions will be necessary. In this mode, the steam pressure controls the reactor coolant temperature and RCS pressure. Pressurizer bubble control is not possible when the RCS is saturated. When steam pressure is reduced, the RCS pressure will drop as long as primary steam can be condensed in the steam generator tube region. For saturated cooldown, a high steam generator level is required and the HPI cannot be throttled as long as the subcooling margin is lost. The RCS may refill and reestablish subcooling during saturated plant cooldown because (1) the leak flow decreases and HPI flow increases as RCS pressure is reduced, and (2) decay heat is slowly dropping. If the RC Pumps are off, the need to apply corrective action for loss of primary to secondary heat transfer (see left side of Figure F-13) may again be necessary. BWST level should be monitored and, if it gets low, the ECCS should be realigned to draw from the sump to maintain continuous HPI injection. If the RCS remains in a

saturated condition, the CFT isolation valves should not be closed unless the tank's water volume has been depleted. The plant cooldown and depressurization should be continued to acquire approximately 150 psig to establish long-term cooling.

When 150 psig is reached the normal decay heat removal system can be engaged if the reactor coolant is subcooled. The normal decay heat removal system cannot be engaged if the reactor coolant is saturated, because water level may not exist at the hot leg suction nozzle. When subcooled with the normal decay heat removal system started up, continued makeup either from the HPI or from the LPI (aligned to the sump or BWST) will probably be required. If the LPI is used for makeup, then one string will have to be aligned to the sump or BWST and the other aligned in the "normal" decay heat removal mode. Cooling in this configuration is required until the reactor coolant temperature is below 212F. At that time the additional makeup can be stopped if the break location is above the hot leg suction of the decay heat drop line. If it is below this level or it is not known where the break is, makeup should continue.

Small Break Cooldown (Without Primary to Secondary Heat Transfer, HPI Cooling)

If a LOCA occurs and primary to secondary heat transfer is not possible due to a total loss of feedwater, HPI cooling is used to maintain the core cooled. Generally, as discussed in the Backup Cooling Methods chapter, this is not a preferred method of plant

control and alternative actions to restore primary to secondary heat transfer should be started at once. Should long-term reliance on HPI cooling be necessary, the operator's primary responsibilities while the system is saturated are:

1. To open the PORV and leave it open.
2. To monitor the performance of the HPI system and realign the HPI in piggyback with LPI to draw from the sump on recirculation if the BWST runs out.

With saturated conditions and no primary to secondary heat transfer, it is not possible to make the plant depressurize if the steam cannot be vented. Depending on the break size and location, the number of HPI pumps operating, and the plant decay heat level, some different system trends that can occur are:

1. A slow but continuous depressurization as decay heat drops.
2. Repressurization to the PORV or pressurizer code safety valve setpoint followed by a slow depressurization as decay heat drops.
3. Either of the above followed by reestablishment of subcooled conditions when the decay heat gets low enough not to boil the ECCS flow or SG cooling is reestablished.

Should the RCS return to a subcooled condition, HPI flow can then be throttled to slowly depressurize the plant as the reactor coolant temperature drops. Because there is little or no circulation within

the RCS, the incore thermocouples must be used to gauge the reactor coolant subcooling margin. The HPI flow must be carefully controlled to maintain the primary pressure and temperature conditions to the left of the subcooling margin curve but to the right of the RV brittle fracture limits (see Figure 25 of Part II, Volume I) until the DHR system can be engaged.

HPI cooling will eventually allow establishment of a long-term cooling mode where the DHR System (normal or LPI mode) can be used to keep the core cooled. This mode of core cooling (HPI cooling) should be maintained only until alternate means of cooling are possible.

3.5 Long Term Cooling

Long-term cooling is defined as the time after a LOCA when on Decay Heat Removal System, or on RB sump recirculation with the BWST empty.

Table F-5 presents a summary of actions required to establish and maintain long-term cooling following a LOCA.

1 Establish Long-Term Cooling

To establish long-term cooling after a small break, the decay heat removal system can be aligned with one train in the decay heat removal mode (subcooled only) and the other train in the LPI mode (possibly with HPI piggyback from the sump or from the BWST). If the system is saturated, recirculation from the sump in the LPI mode (possibly with HPI piggyback) establishes long-term cooling. To establish long-term cooling for large breaks, the LPI system is placed in the recirculation mode from the sump.

Boron Precipitation

Within twenty-four hours after a LOCA, actions should be taken to preclude the possibility of boron precipitation. If the RCS is subcooled and one DHR train is successfully operating in the normal decay heat removal mode, then no further actions are required to prevent boron precipitation. However, if the RCS is not subcooled, other actions will be required. With a large hole in certain areas of the RCS, the reactor can, acting like a distiller, boil off almost pure steam and leave impurities (mostly boron) to concentrate in the vessel. If enough boron accumulates, core flow blockage might occur. To limit the boron concentration, the following steps should be taken:

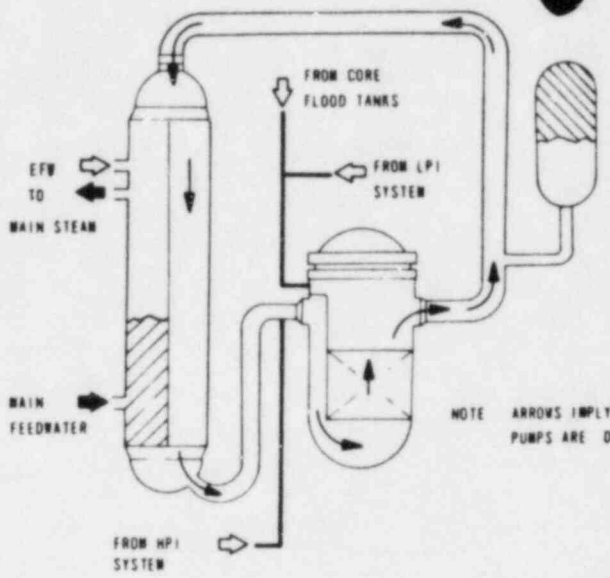
1. If using one LPI train for normal DHR removal is not possible, open the DH drop line to one LPI train to establish gravity draining from the hot leg to the reactor building emergency sump (i.e., backflow through one sump suction line). This will pull

injection flow through the core at a rate equal to the drain flow rate. The other LPI train should remain in the sump recirculation mode.

2. If Step 1 is not successful, open the auxiliary spray to the pressurizer. This will route relatively diluted injection water to the area above the core. The flow path is through the auxiliary spray line into the pressurizer, out of the pressurizer through the surge line into the hot leg and then into the vessel.

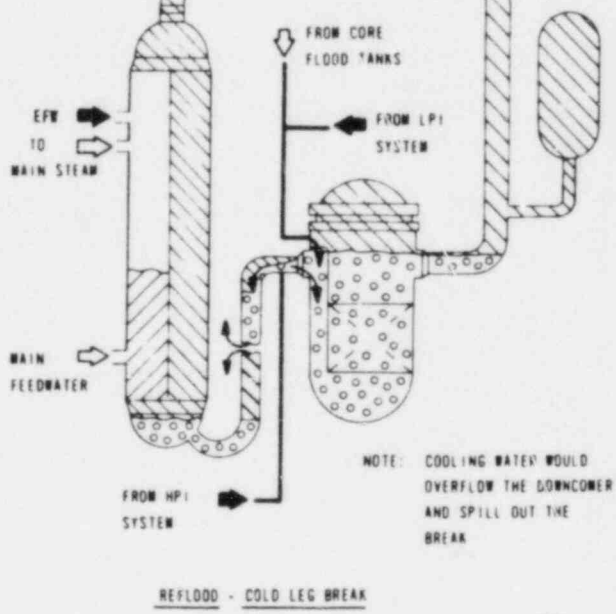
Preserving the LPI System for Long Term

If a large break LOCA has occurred, or if a small break LOCA has occurred that is in a location that does not permit use of the decay heat system in the normal mode (for core cooling or prevention of boron precipitation), it may be desirable to take one decay heat pump out of service to preserve it for the future (so it can be placed back in use if the operating train develops problems). One decay heat pump can be removed from service safely if sump recirculation is in progress and the LPI flow in each train (from the remaining pump through the cross-connect line) is equal to or greater than 1000 gpm.



PRE LOCA INITIAL CONDITION

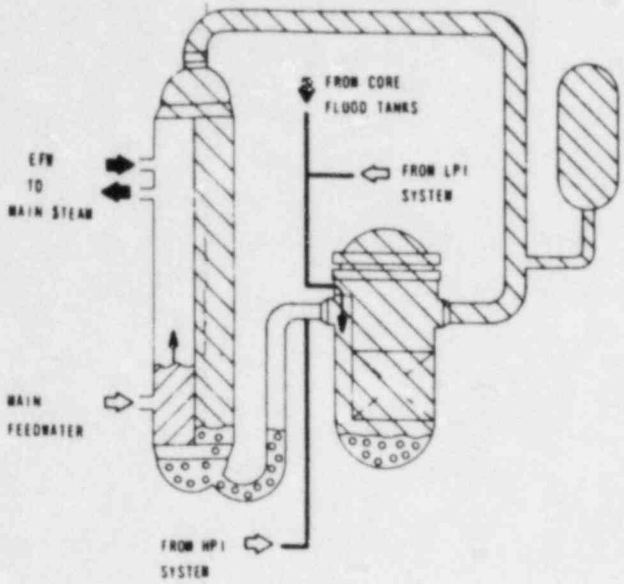
RCS INVENTORY IS NORMAL WITH THE REACTOR AT POWER AND THE RC PUMPS 'ON'.



REFLOOD - COLD LEG BREAK

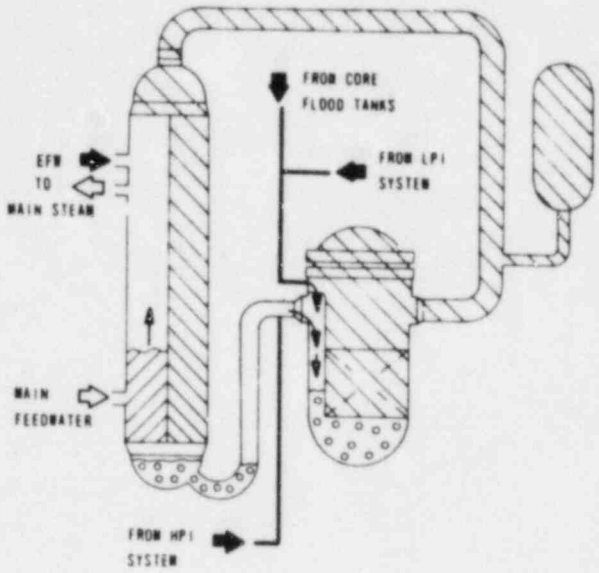
DURING REFLOOD THE
RESTORES CORE COOL
OF THE BREAK THE
PROVIDES THE COOLIN
WILL BE MAINTAINED

Figure F-1 FLUID HISTORY DURING A LARGE BREAK



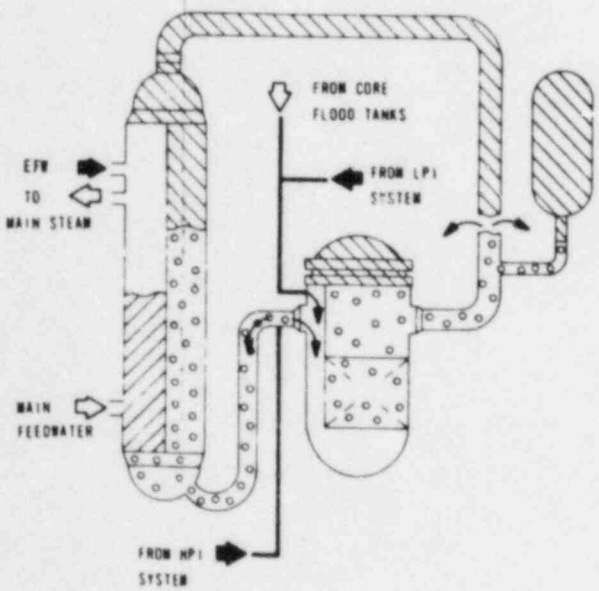
END OF BLOWDOWN

A LARGE BREAK HAS OCCURRED AND NEARLY ALL OF THE INITIAL REACTOR COOLANT INVENTORY HAS ESCAPED TO THE RB. BLOWDOWN LASTS ANYWHERE FROM 20 200 SECONDS DEPENDING ON THE BREAK SIZE AND ENDS WHEN THE RCS AND RB PRESSURES EQUALIZE. AT THE END OF BLOWDOWN THE CFT'S WILL BE OPERATIVE AND THE HPI/LPI SYSTEMS WILL BE FUNCTIONAL WITHIN 35 SECONDS FOLLOWING ESAS ACTUATION



END OF REFILL

THE ECCS HAS REFILLED THE REACTOR VESSEL UP TO THE BOTTOM OF THE CORE REGION.



REFLOOD - HOT LEG BREAK

Also Available On
Aperture Card

LEGEND

PRIMARY SIDE	SECONDARY SIDE
WATER	WATER
TWO PHASE LIQUID	STEAM
STEAM	

SYSTEM 'ON'

SYSTEM 'OFF'

PRC
APERTURE
CARD

ECCS FLOODS THE REACTOR VESSEL WITH WATER,
NG, AND REFILLS THE SYSTEM UP TO THE ELEVATION
CFT's EMPTY DURING REFLOOD, AND THE LPI SYSTEM
WATER TO REFILL THE SYSTEM. CORE COOLING
S LONG AS LPI FLOW IS CONTINUED

8401230549-22

DOUBLE-ENDED COLD LEG BREAK AT DISCHARGE OF RC PUM

REFERENCE POINTS	TIME (SECONDS)	REMARKS
1	0.0	LOCA OCCURS WITH THE PLANT INITIALLY AT 100%
2	< 1.0	RCS PRESSURE DROPS TO RPS TRIP SETPOINT AND
3	< 1.0	SUBCOOLING MARGIN IS LOST.
4	< 1.0	ESAS ACTUATED ON LOW RC PRESSURE. HPI AND L WITHIN 35 SECONDS.
5	< 1.0	THE REACTOR COOLANT SATURATES IN THE HOT LEG
6	12.0	RCS PRESSURE DROPS BELOW SECONDARY SIDE PRES SOURCE INSTEAD OF A HEAT SINK
7	17.0	RCS PRESSURE DROPS TO 600 PSIG AND BORATED W TO ENTER THE REACTOR VESSEL.
8	24.0	THE END OF BLOWDOWN IS REACHED AS THE RCS AN PRESSURE (~ 20-40 PSIG). THE RCS IS ESSENTI EXISTS) AND THE CORE OUTLET THERMOCOUPLES WO CONDITIONS.
9	35.0	END OF REFILL. THE RV HAS BEEN REFILLED UP CORE. AT THIS TIME, THE HPI AND LP STEMS
10	50.0	THE CFT WATER VOLUME IS DEPLETED.
11	380.0	THE CORE IS RECOVERED BY WATER AND THE FUEL TERMINATED. THE CORE EXIT THERMOCOUPLES RET

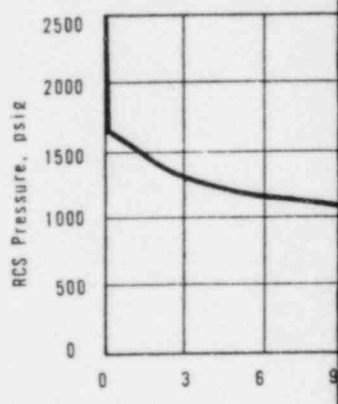
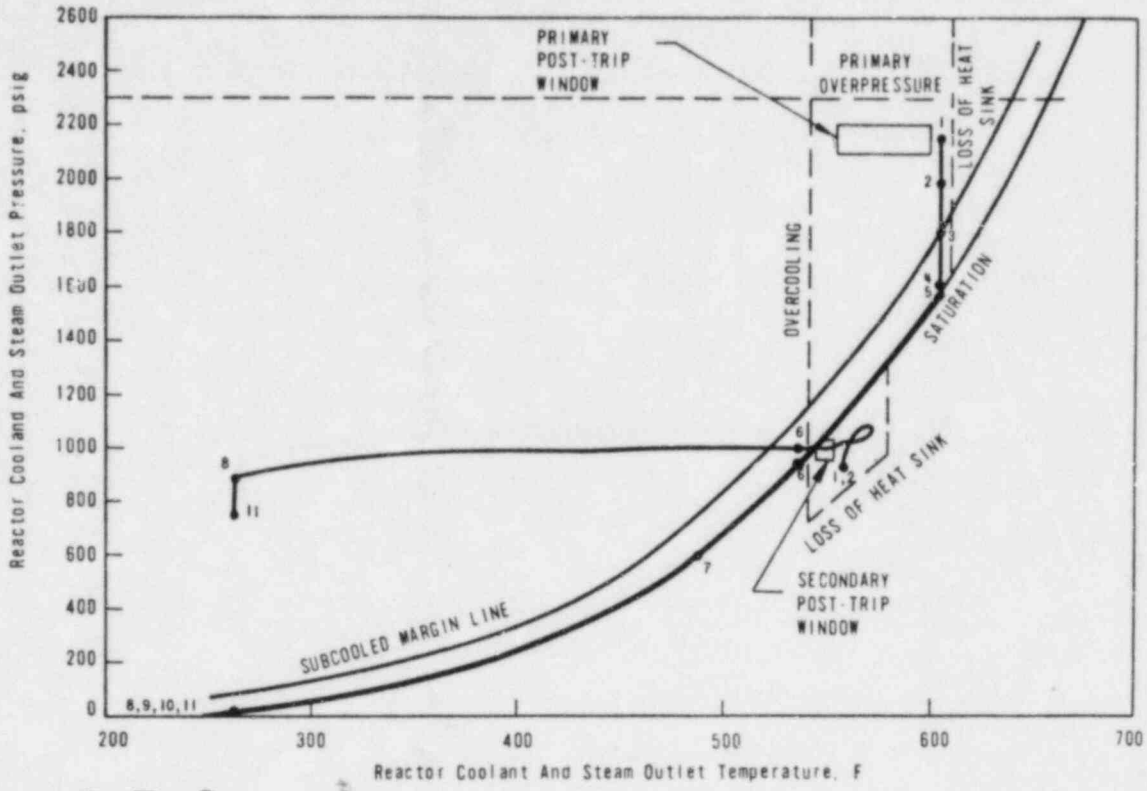


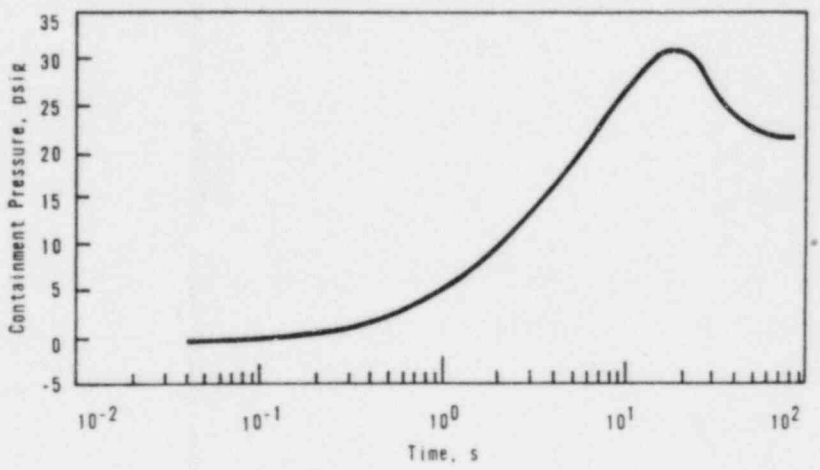
Figure F-2 SYSTEM RESPONSE FOR LARGE BREAK IN COLD LEG PIPING



PRC APERTURE CARD

Also Available On Aperture Card





8401230549-23

REFERENCE POINTS	TIME (SECONDS)	REMARKS
1	0.0	LOCA OCCURS WITH THE PLANT INITIALLY AT 100% POWER
2	<1.0	RCS PRESSURE DROPS TO RPS TRIP SETPOINT AN[redacted]CTO
3	<1.0	SUBCOOLING MARGIN IS LOST.
4	.0	ESAS ACTUATED ON LOW RC PRESSURE. HPI AND LPI WILL BECOME OPERATIVE WITHIN 35 SECONDS.
5	<1.0	THE REACTOR COOLANT SATURATES IN THE HOT LEGS.
6	4.0	RCS PRESSURE DROPS BELOW SECONDARY SIDE PRESSURE; TH A HEAT SOURCE INSTEAD OF A HEAT SINK.
7	9.0	RCS PRESSURE DROPS TO 600 PSIG AND BORATED WATER FRO TO ENTER THE REACTOR VESSEL.
8	18	THE END OF BLOWDOWN IS REACHED AS THE RCS AND CONTAI PRESSURE (~ 20-40 PSIG). THE RCS IS ESSENTIALLY VOI WATER EXISTS) AND THE CORE OUTLET THERMOCOUPLES WOUL SUPERHEATED CONDITIONS
9	19	END OF REFILL. THE RV HAS BEEN REFILLED UP TO THE B CORE. AT THIS TIME, THE HPI AND LPI SYSTEMS ARE [illegible]
10	30	THE CFT WATER VOLUME IS DEPLETED.
11	350	THE CORE IS RECOVERED BY WATER AND THE FUEL'S TEMPER TERMINATED. THE CORE EXIT THERMOCOUPLES RETURN TO S

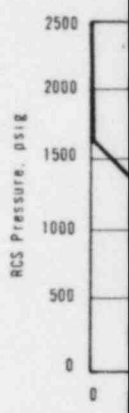
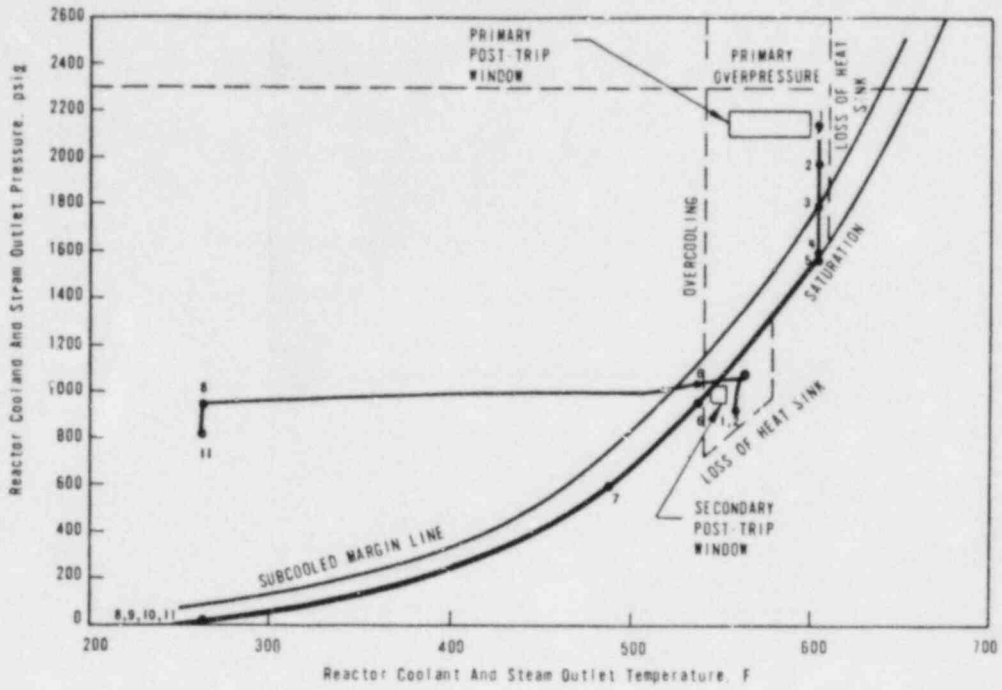


Figure F-3 SYSTEM RESPONSE FOR LARGE BREAK IN HOT LEG PIPING



INITIATED.

E SG'S BECOME

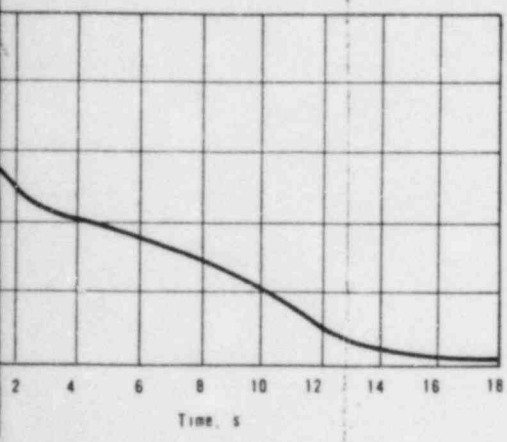
THE CFTs BEGINS

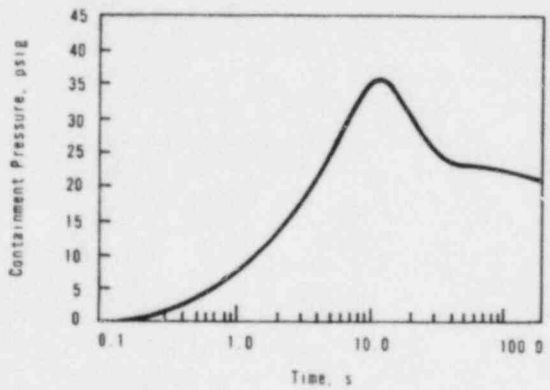
NMENT EQUALIZE IN
(LITTLE OR NO
INDICATE

TTOM OF THE ACTIVE
Y OPERATIVE.

ATURE EXCURSION IS
ATURATED CONDITIONS.

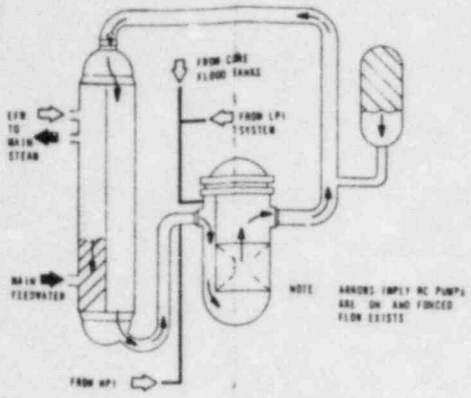
Also Available On
Aperture Card

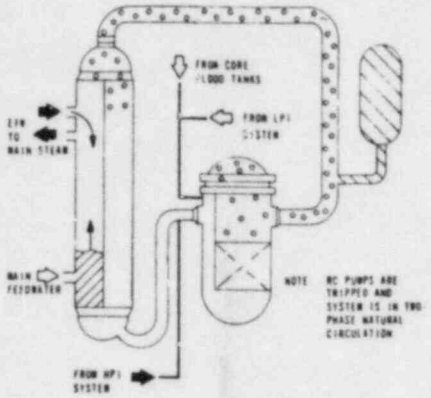


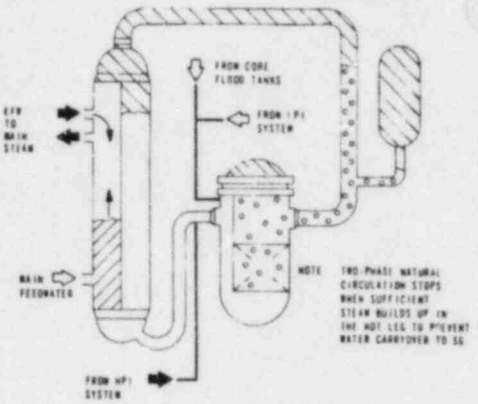


PRC
APERTURE
CARD

Figure F-4 TYPICAL SYSTEM RESPONSE DURING FLOW CIRCULATION PHASE OF A SMALL BREAK







TYPICAL SYSTEM RESPONSE UP TO REACTOR TRIP (POINTS 1 TO 2 ON P-T DIAGRAM)

1. THE SMALL BREAK OCCURS AND SUBCOOLED REACTOR COOLANT IS LOST AT A FASTER RATE THAN CAN BE SUPPLIED BY THE MU SYSTEM.
2. PRESSURIZER LEVEL DROPS AND RC PRESSURE DECREASES AS THE PRESSURIZER STEAM SPACE EXPANDS. LITTLE OR NO CHANGE OCCURS IN THE REACTOR COOLANT TEMPERATURE. THE REACTOR COOLANT REMAINS SUBCOOLED.
3. THE REACTOR TRIPS ON VARIABLE TEMPERATURE AND PRESSURE (DIAGONAL PORTION OF THE RPS TRIP ENVELOPE). RAPS THE RODS ENTER THE CORE AND SHUT DOWN THE FISSION PROCESS. CORE POWER DROPS TO DECAY HEAT LEVELS.
4. THE TURBINE TRIPS. AND A MAIN FEEDWATER RUNBACK TO CONTROL SG LEVEL AT THE LOW LEVEL LIMIT BY THE ICS IS STARTED.
5. THE REACTOR COOLANT TEMPERATURE DROPS (SIMILAR TO THAT WHICH OCCURS AFTER ANY REACTOR TRIP). AN INCREASE IN THE OUTSURGE FROM THE PRESSURIZER OCCURS TO COMPENSATE FOR TEMPERATURE REDUCTION (SHRINKAGE) OF THE REACTOR COOLANT. AND PRESSURIZER LEVEL AND RC PRESSURE CONTINUE TO DROP.

POST-TRIP EVOLUTION TO TWO-PHASE NATURAL CIRCULATION (POINTS 2 TO 3 ON P-T DIAGRAM)

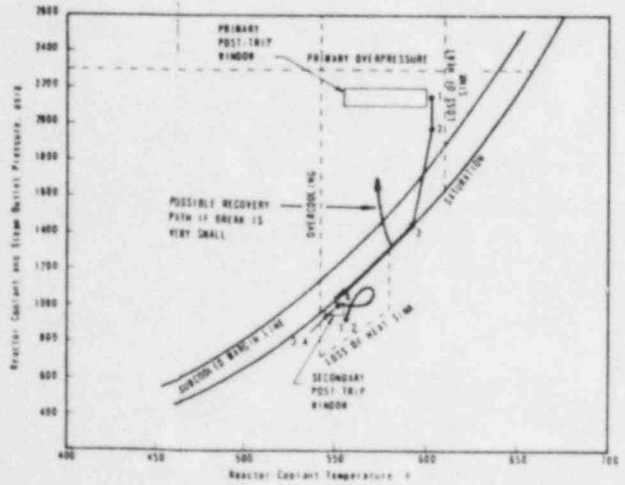
1. RCS PRESSURE AND PRESSURIZER LEVEL CONTINUE TO DROP DUE TO THE LOSS OF REACTOR COOLANT AND RCS CONTRACTION FOLLOWING THE REACTOR TRIP.
2. BECAUSE REACTOR COOLANT IS BEING LOST. RCS PRESSURE DROPS FASTER THAN NORMAL. AS A RESULT. THE REACTOR COOLANT SUBCOOLING MARGIN IS LOST. ESAS IS ACTUATED ON LOW RCS PRESSURE. THE PRESSURIZER EMPTIES. AND THE HOT LEG SATURATES.
3. HPI IS STARTED. THE RC PUMPS ARE TRIPPED MANUALLY. EFW IS AUTOMATICALLY STARTED WHEN THE RC PUMPS ARE TRIPPED. AND THE PRESSURIZER LEVEL GOES OFF SCALE LOW.
4. RCS FLOW DECREASES TO NATURAL CIRCULATION LEVELS AS THE PUMPS COAST DOWN.
5. STEAM BEGINS TO COLLECT IN THE PRIMARY SYSTEM LOOPS.
   - STEAM ENTERS THE HOT LEG FROM THE PRESSURIZER.
   - SOME OF THE REACTOR COOLANT FLASHES TO STEAM BECAUSE THE SYSTEM PRESSURE IS DROPPING.
   - STEAM CAN POSSIBLY BE FORMED IN THE CORE IF THE REACTOR COOLANT IN THE CORE SATURATES AND BOILING OCCURS.
6. TWO-PHASE NATURAL CIRCULATION IS IN PROGRESS.

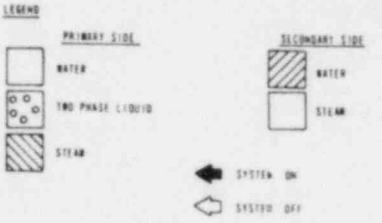
NOTE: AT THIS POINT INTO A SMALL BREAK. THE SYSTEM RESPONSE CAN GO IN TWO DIRECTIONS. IF THE BREAK IS VERY SMALL. THE STEAM WITHIN THE PRIMARY SYSTEM CAN BE CONDENSED WITHIN THE STEAM GENERATOR OR BY COLD HPI WATER. AND THE REACTOR COOLANT CAN BE RETURNED TO A SUBCOOLED STATE. ONCE THE REACTOR COOLANT SUBCOOLING MARGIN IS ESTABLISHED. THE HPI CAN BE THROTTLED AND A HOT SHUT DOWN CONDITION CAN BE ACHIEVED. IF THE BREAK IS SOMEWHAT LARGER. ADDITIONAL STEAM WILL BE FORMED (SEE NEXT SEQUENCE).

SYSTEM RESPONSE TO THE END OF THE "FLOW CIRCULATION" PHASE (POINTS 3 TO 4 ON P-T DIAGRAM)

1. THE RCS PRESSURE IS SLOWLY DROPPING AND APPROACHING THE SATURATION PRESSURE AND TEMPERATURE OF THE STEAM GENERATORS.
2. ADDITIONAL STEAM IS FORMED. AND THE STEAM AND WATER START TO SEPARATE (i.e. STEAM CAN RISE FASTER BECAUSE IT IS LIGHTER).
3. STEAM WILL START TO ACCUMULATE IN LARGE AMOUNTS IN THE HIGH POINTS IN THE SYSTEM (UPPER HEAD OF REACTOR VESSEL AND UPPER HOT LEG PIPING).
4. AS STEAM COLLECTS IN THE UPPER HOT LEG PIPING. THE TWO-PHASE NATURAL CIRCULATION FLOW DROPS. THIS ENCOURAGES BOILING IN THE CORE AND MORE STEAM PRODUCTION.
5. THE VOLUME OF THE HOT LEG OCCUPIED BY STEAM GROWS. AND THE UPPER HOT LEG 180° FLOORS BECOME COMPLETELY OCCUPIED BY STEAM.
6. TWO-PHASE NATURAL CIRCULATION STOPS AS WATER IS NO LONGER CAPABLE OF FLOWING UP THE HOT LEG PIPING AND INTO THE STEAM GENERATORS.
7. THE "FLOW CIRCULATION" PHASE IS OVER.

Also Available On Aperture Card





PRC APERTURE CARD

8401230549-25

0.5 FT^2 BREAK IN COLD LEG PIPE

REFERENCE POINTS	TIME (SECONDS)	REMAR
1	0	LOCA OCCURS WITH REACTOR INIT AT EQUIVALENT TO 9.5 INCH DIAMETER HOLE.
1-2	0-.2	PRESSURE DROPS DUE TO RELEASE OF REAC THE BREAK.
2	0.2	RPS TRIP SETPOINT IS REACHED; A REACT INITIATED.
2-3	0.2-0.5	BREAK IS LARGE ENOUGH TO DEPRESSURIZE SATURATED CONDITIONS BEFORE PRESSURIZ WITHIN 0.5 SEC. ESAS IS ACTUATED AND SHOULD BE TRIPPED BECAUSE SUBCOOLING
3	0.5	HOT LEG SATURATES.
3-4	0.5-40	RC PUMPS ARE TRIPPED AND EFW IS ACTUA TO DEPRESSURIZE IN A SATURATED STATE DELIVER FLOW TO THE RCS.
4	40	THE "FLOW CIRCULATION" PERIOD ENDS, AN SIDE PRESSURE AND TEMPERATURE DROP BEL AND TEMPERATURE OF THE SG's. THE SG's SOURCE.
4-5	40-110	BOTH THE HOT AND COLD LEG ARE SATURATE CONTINUES TO DROP.
5	110	RC PRESSURE HAS DROPPED TO 600 PSIG AN ADDING WATER TO REACTOR VESSEL.
5-6	110-200	RCS PRESSURE CONTINUES TO DROP.
6	200	RCS PRESSURE IS BELOW 200 PSIG AND THE TO DELIVER FLOW TO THE REACTOR VESSEL.
7	>200	THE RCS BEGINS TO REFILL BACK TO THE E BREAK. CORE COOLING WILL BE MAINTAINED IS CONTINUED.

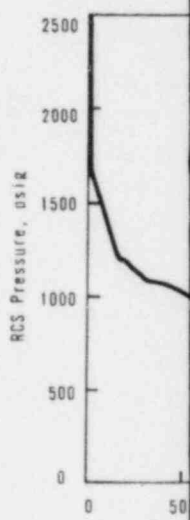
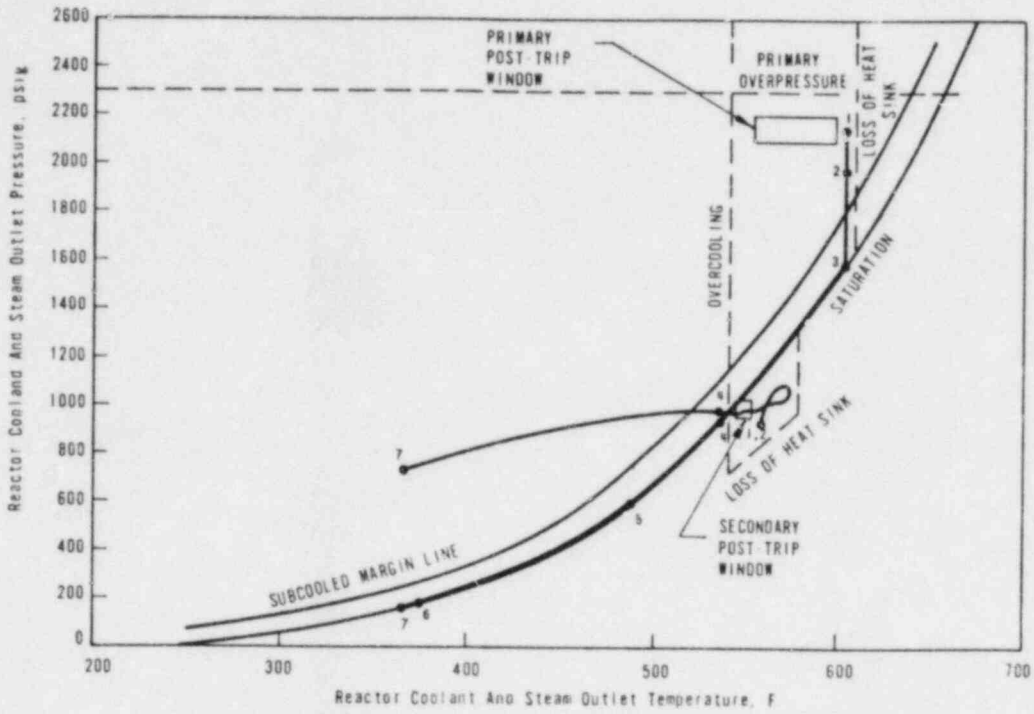
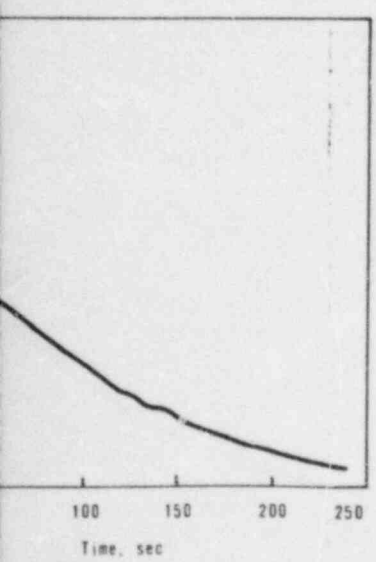
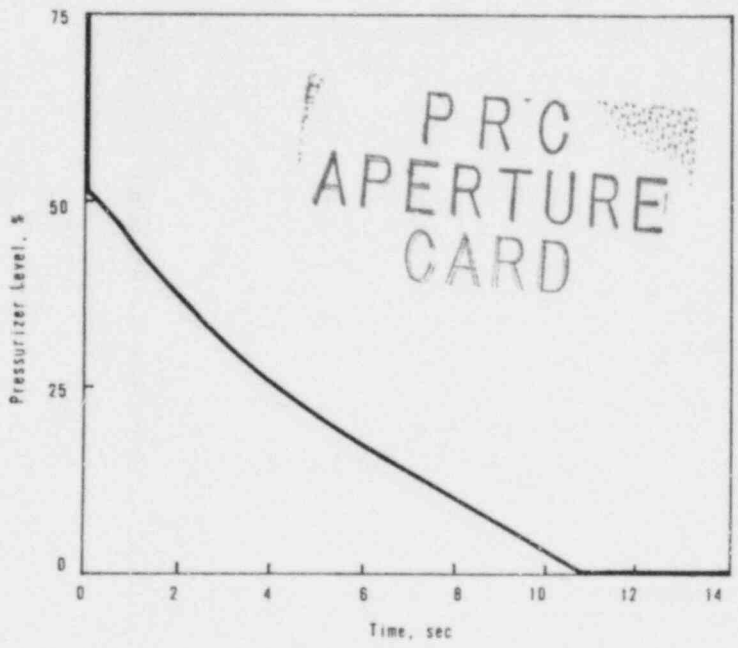


Figure F-5a SYSTEM RESPONSE FOR SMALL BREAK WHICH CONTINUALLY DEPRESSURIZES THE RCS (0.5 FT^2 BREAK IN COLD LEG PIPE)



Also Available On
Aperture Card





PRC
APERTURE
CARD

8401230549-26

0.1 FT^2 COLD LEG BREA

REFERENCE POINTS	TIME (SECONDS)	
1	0	LOCA OCCURS WITH REACTOR INIT TO 4.3 INCH DIAMETER HOLE.
1-2	0-5.0	RCS PRESSURE AND PRESSURIZER COOLANT OUT THE BREAK.
2	5.0	RPS TRIP SETPOINT IS REACHED;
2-3	5-18	RCS DEPRESSURIZES TO SATURATED RC PRESSURE; AND THE PRESSURI
3	18	PRESSURIZER IS COMPLETELY EMPT
3-4	18-140	THE RCS CONTINUES TO DEPRESSUR IS ACTUATED; AND TWO-PHASE NAT
4	140	THE "FLOW CIRCULATION" PHASE E
4-5	140-270	THE RCS CONTINUES TO DEPRESSUR EFW INJECTION AND REDUCED PRIM
5	270	PRIMARY PRESSURE DROPS BELOW TH ARE NOW A HEAT SOURCE.
5-6	270-910	RCS PRESSURE CONTINUES TO DROP.
6	910	RCS PRESSURE HAS DROPPED TO 600 WATER TO THE REACTOR VESSEL.
7	>910	THE RCS WILL CONTINUE TO DEPRES BECOMES OPERATIVE.

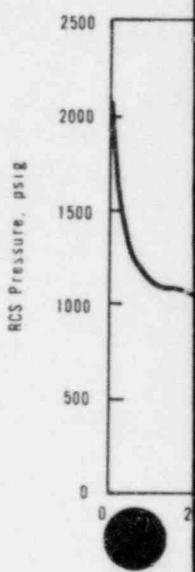


Figure F-5b SYSTEM RESPONSE FOR SMALL BREAK WHICH CONTINUALLY DEPRESSURIZES THE RCS (0.1 FT^2 COLD LEG BREAK)

REMARKS

ALLY AT POWER. BREAK IS EQUIVALENT

EVEL DROP DUE TO LOSS OF REACTOR

REACTOR TRIPS.

CONDITIONS: ESAS IS ACTUATED ON LOW
ER EMPTIES.

Y AND THE HOT LEG IS SATURATED.

ZE. THE RC PUMPS ARE TRIPPED; EFW
URAL CIRCULATION EVOLVES.

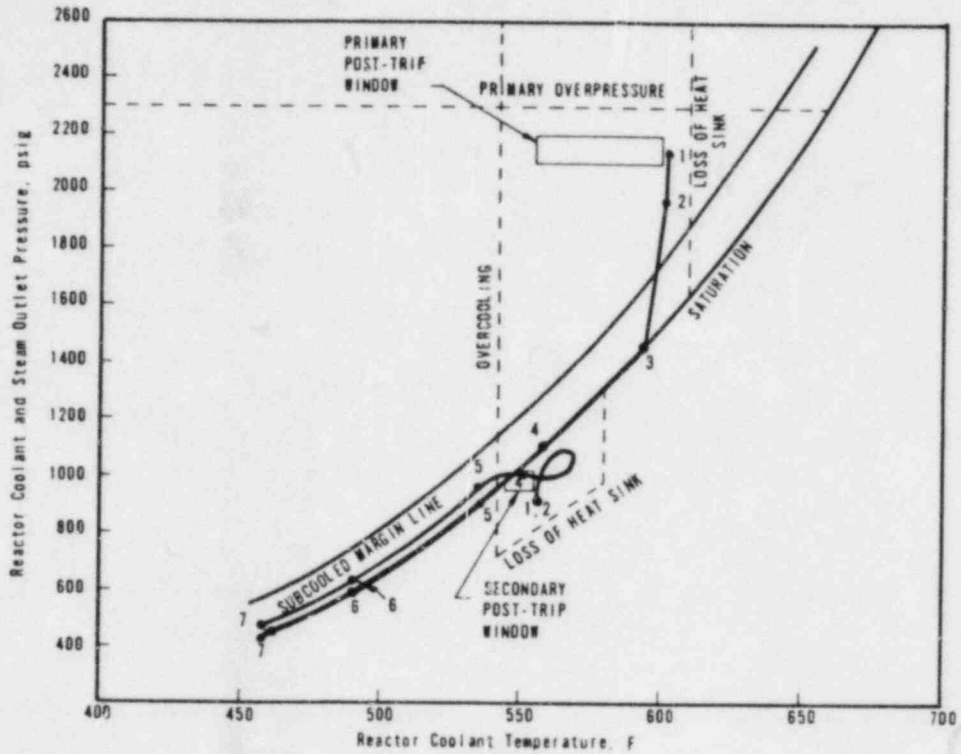
NDS; THE RCS IS IN BOILER CONDENSER COOLING.

ZE. STEAM PRESSURE DROPS DUE TO
RY TO SECONDARY HEAT TRANSFER.

E SECONDARY PRESSURE. THE SG'S

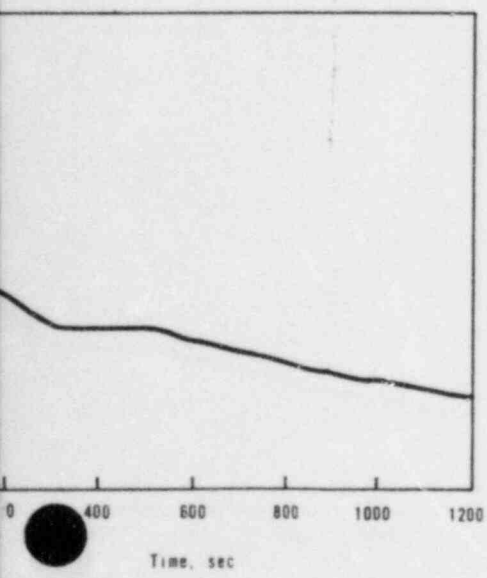
PSIG AND THE CFT'S BEGIN ADDING

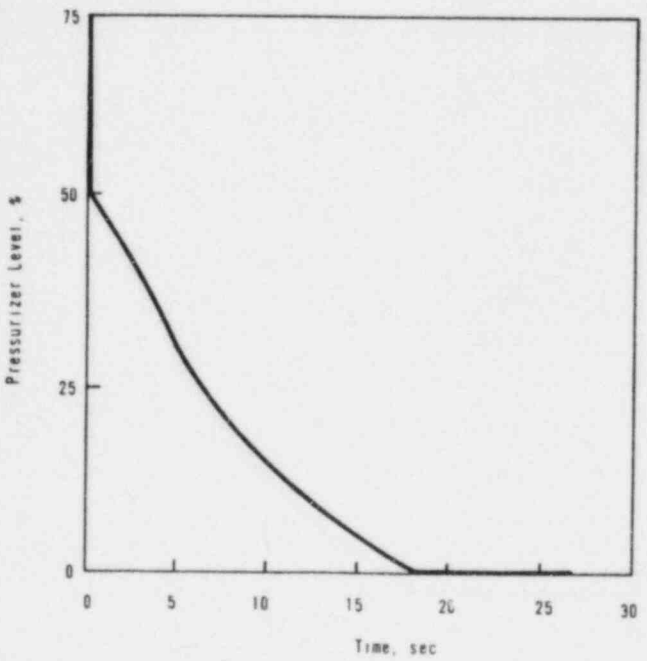
SURIZE SLOWLY UNTIL THE LPI SYSTEM



PRC APERTURE CARD

Also Available On Aperture Card





8401230549-27

0.04 FT^2 COLD LEG [redacted]

REFERENCE POINTS	TIME (SECONDS)	
1	0	LOCA OCCURS WITH REACTOR INITIALLY AT POWER; DIAMETER HOLE.
1-2	0-15	RCS PRESSURE AND PRESSURIZER LEVEL DROP DUE
2	15	PRESSURE DROPS TO RPS SETPOINT; THE REACTOR
2-3	15-23	RCS PRESSURE CONTINUES TO DROP AND SUBCOOLIN IS REQUIRED.
3	23	ESAS ACTUATED ON LOW RC PRESSURE.
3-4	23-30	THE PRESSURIZER EMPTIES AND THE HOT LEG COND
4	30	HOT LEG SATURATES.
4-5	30-340	THE RC PUMPS ARE TRIPPED; EFW IS ACTUATED; AN CONTINUES TO BE TRANSPORTED FROM THE CORE TO CIRCULATION. RCS PRESSURE AND TEMPERATURE AR SIDE SATURATION CONDITIONS.
5	340	THE FLOW CIRCULATION PHASE ENDS; THE SYSTEM I
6	>340	THE RCS STABILIZES AT OR NEAR SECONDARY SIDE SLOWLY RAISED TO 95% ON OPERATE RANGE. THE RC FOR A LONG TIME PERIOD AND THEN BEGIN A SLOW DECAY HEAT DROPS.

NOTE: OPERATOR ACTION TO COOLDOWN THE PLANT S A LONG-TERM COOLING MODE.

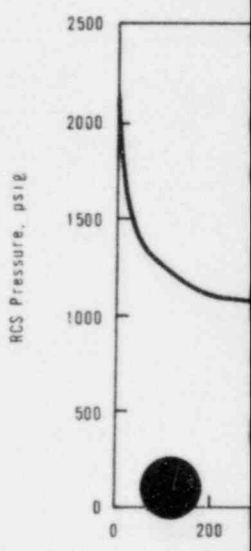


Figure F-6 SYSTEM RESPONSE FOR SMALL BREAK WHICH STABILIZES AT SECONDARY SIDE PRESSURE

REMARKS

BREAK IS EQUIVALENT TO 2.7 INCH

TO THE LOSS OF REACTOR COOLANT.

TRIPS.

MARGIN IS LOST. AN RC PUMP TRIP

TIONS APPROACH SATURATION.

HEAT

THE SG BY TWO-PHASE NATURAL

SLOWLY APPROACHING THE SECONDARY

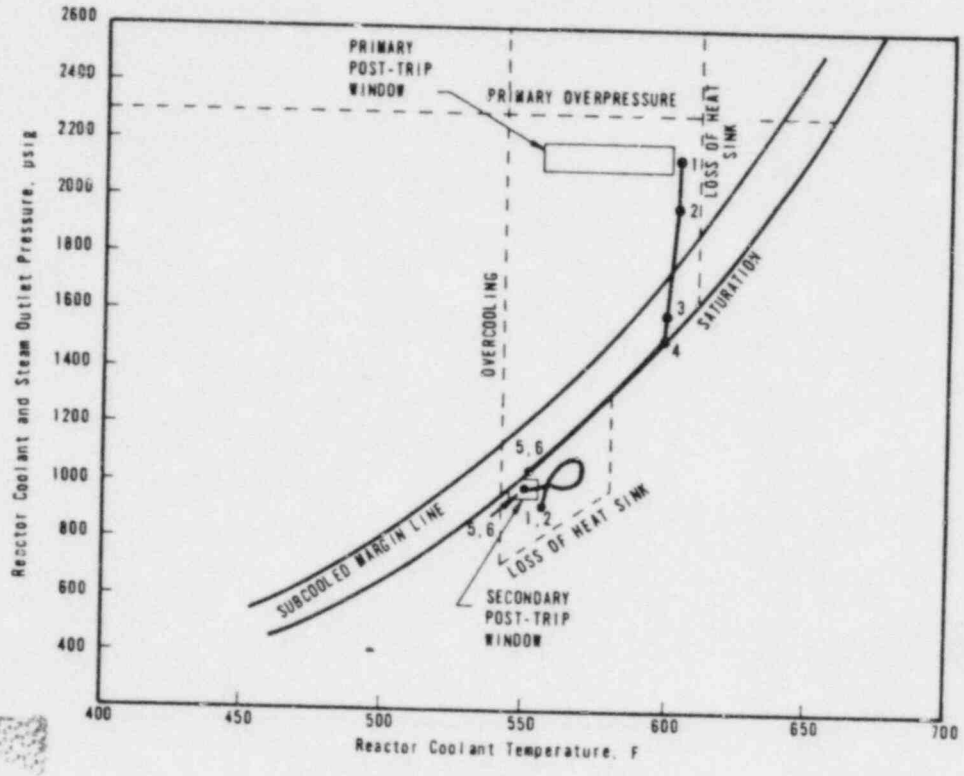
IN A BOILER CONDENSER COOLING.

ONDITIONS. OTSG LEVELS SHOULD BE

S WILL REMAIN IN THIS CONDITION

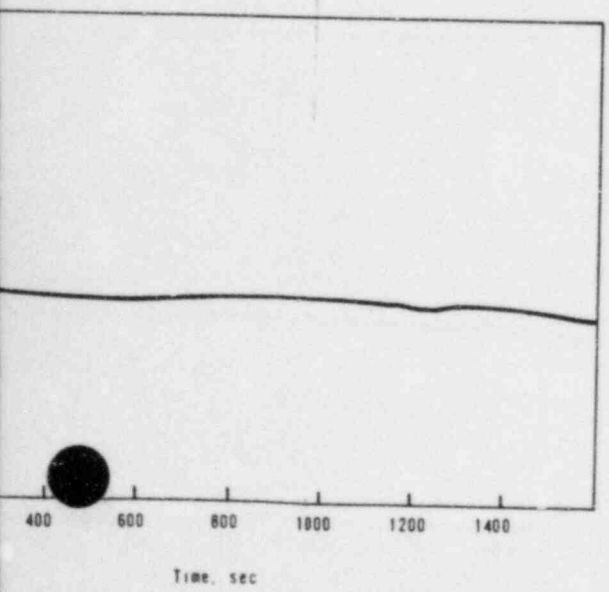
OLDOWN AND DEPRESSURIZATION AS

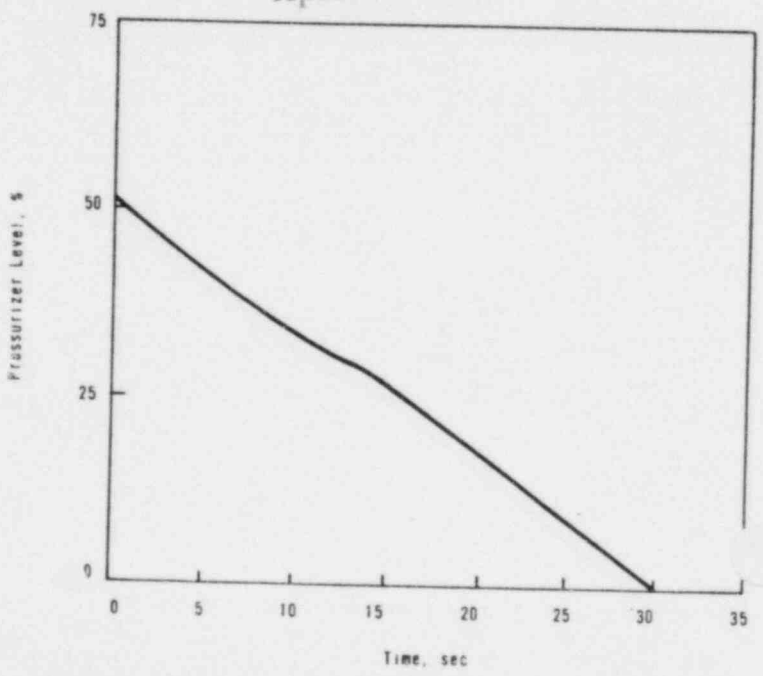
HOULD INITIATED TO ACHIEVE



PRC APERTURE CARD

Also Available On Aperture Card





0.01 FT^2

REFERENCE POINTS	TIME (SECONDS)	
1	0	LOCA OCCURS WITH REACTO TO 1.35 INCH DIAMETER H
1-2	0-50	RCS PRESSURE AND PRESSU COOLANT.
2	50	PRESSURE DROPS TO RPS
2-3	50-80	RCS PRESSURE CONTINUES MARGIN IS LOST (PUMP T
3	80	ESAS ACTUATION ON LOW
3-4	80-100	HOT LEG APPROACHES SAT THE RC PUMPS ARE TRIPP
4	100	THE HOT LEGS ARE SATUR
4-5	100-600	RCS IS IN TWO-PHASE NA
5	600	THE "FLOW CIRCULATION" SECONDARY HEAT TRANSFE IN SG TUBES IS NOT POS
5-6	600-1250	RCS REPRESSURIZES BECA GENERATORS. STEAM BUB SIZE REACTOR COOLANT REPRESSURIZE
6	1500	STEAM CONDENSATION STA
6-7	>1500	BOILER CONDENSER COOLI PRESSURE AND TEMPERATU SATURATION CONDITIONS.

Figure F-7 SYSTEM RESPONSE FOR SMALL BREAK WHICH REPRESSURIZES IN A SATURATED STATE

PRC APERTURE CARD

BREAK AT PUMP DISCHARGE

REMARKS

R INITIALLY AT POWER; BREAK IS EQUIVALENT
OLE.

RIZER LEVEL DROP DUE TO THE LOSS OF REACTOR

RIP SETPOINT; THE REACTOR TRIPS.

TO DROP; THE REACTOR COOLANT SUBCOOLING
IP REQUIRED).

CS PRESSURE.

RATED CONDITIONS AS THE PRESSURIZER EMPTIES.
D AND EFW FLOW IS ACTUATED.

TED.

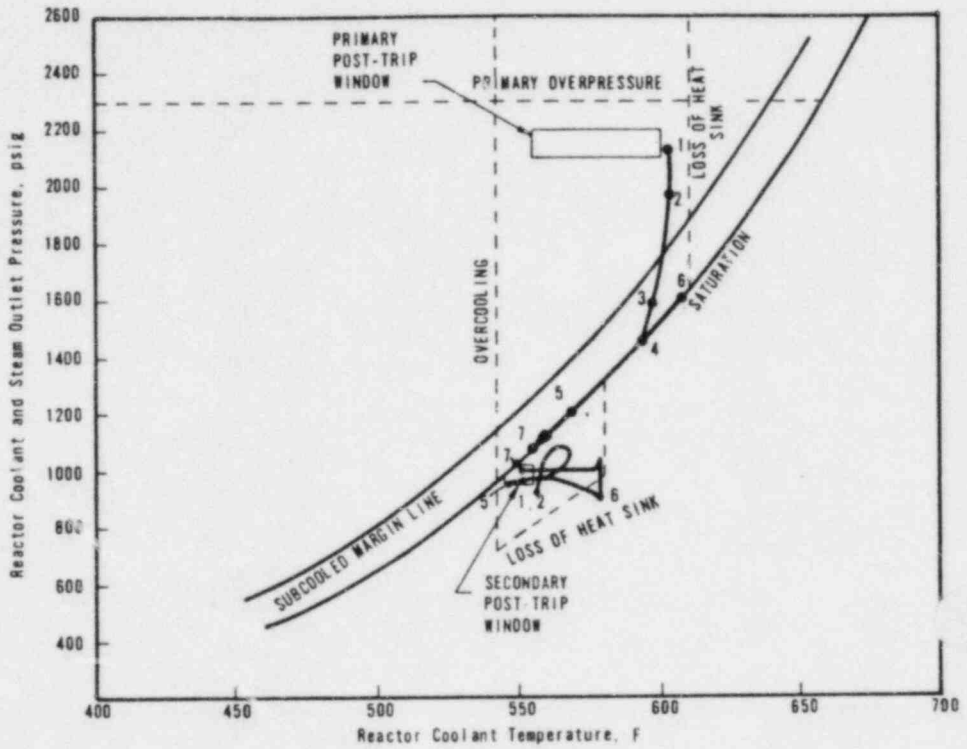
URAL CIRCULATION.

PHASE STOPS; A LOSS OF PRIMARY TO
OCCURS BECAUSE STEAM CONDENSATION
IBLE.

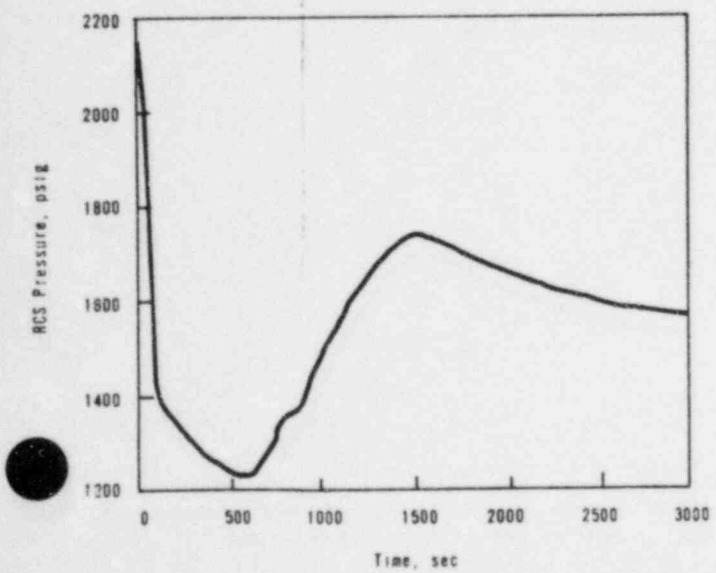
SE NO CORE HEAT CAN BE REMOVED BY STEAM
LE IN HOT LEG PIPING IS SLOWLY GROWING IN
EXPAND INTO THE PRESSURIZER AS THE SYSTEM

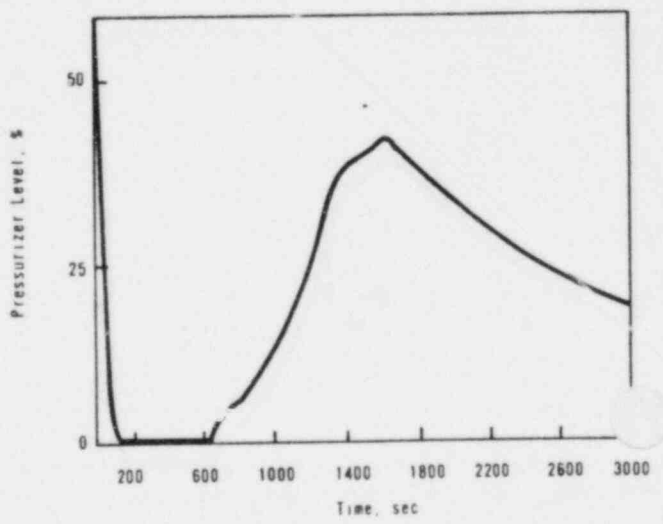
RTS IN SG TUBES.

NG IS ESTABLISHED; AND THE PRIMARY SYSTEM
RE SLOWLY DECREASE TO THE SECONDARY SIDE



Also Available On Aperture Card





8401230549-29

0.07 FT^2 BREAK WITHOUT EFW

REFERENCE POINTS	TIME (SECONDS)	
1	0	LOCA OCCURS WITH REACTOR INITIALLY IS EQUIVALENT TO 3.6 INCH DIAMETER
1-2	0-10	RCS PRESSURE AND PRESSURIZER LEVEL OF REACTOR COOLANT.
2	10	RCS PRESSURE DROPS TO RPS TRIP SET TRIPS.
2-3	10-24	AS RCS PRESSURE DROPS, THE REACTOR MARGIN IS LOST (RC PUMP TRIP IS RE ACTUATED ON LOW RCS PRESSURE.
3	24	THE HOT LEG SATURATES.
3-4	24-150	THE RCS SLOWLY DEPRESSURIZES; THE RESIDUAL FEEDWATER IS SLOWLY BOILE
4	150	SG COOLING IS ESSENTIALLY LOST.
4-5	150-1200	THE RCS CONTINUES TO SLOWLY DEPRES BREAK CAN REMOVE DECAY HEAT BY REL COOLANT TO THE RB. RCS PRESSURE D SECONDARY PRESSURE AND SG's BECOME
5	1200	RCS PRESSURE HAS DROPPED TO 600 PS TO ADD WATER TO THE REACTOR VESSEL
5-6	>1200	THE RCS CONTINUES TO DEPRESSURIZE IN PROGRESS.

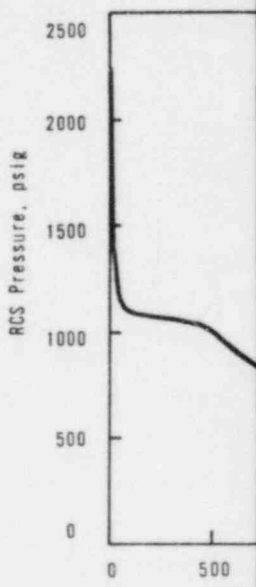
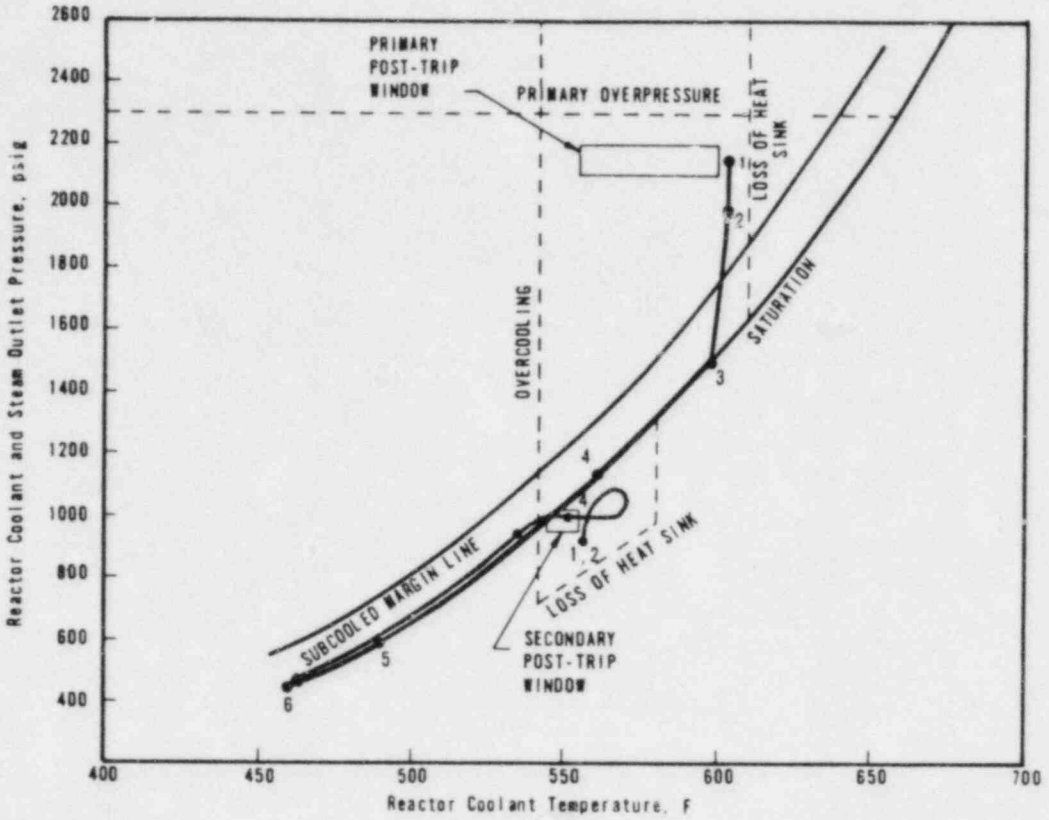


Figure F-8 SYSTEM RESPONSE FOR SMALL BREAK WHICH DEPRESSURIZES THE RCS WITHOUT FEEDWATER



AT POWER; BREAK
HOLE.

DROP DUE TO LOSS

POINT; THE REACTOR

COOLANT SUBCOOLED
QUIRED) AND ESAS IS

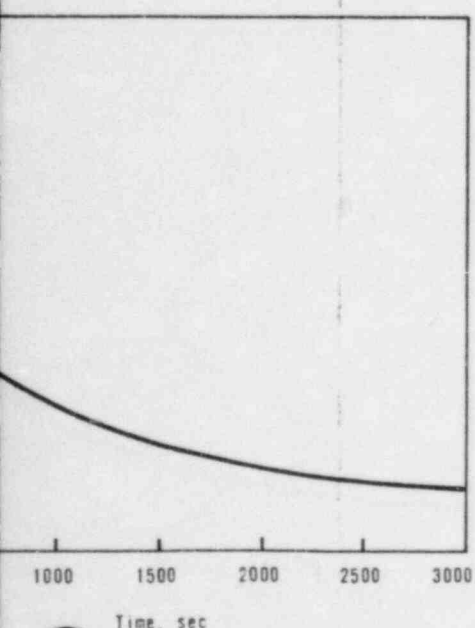
RC PUMPS ARE TRIPPED;
D OFF.

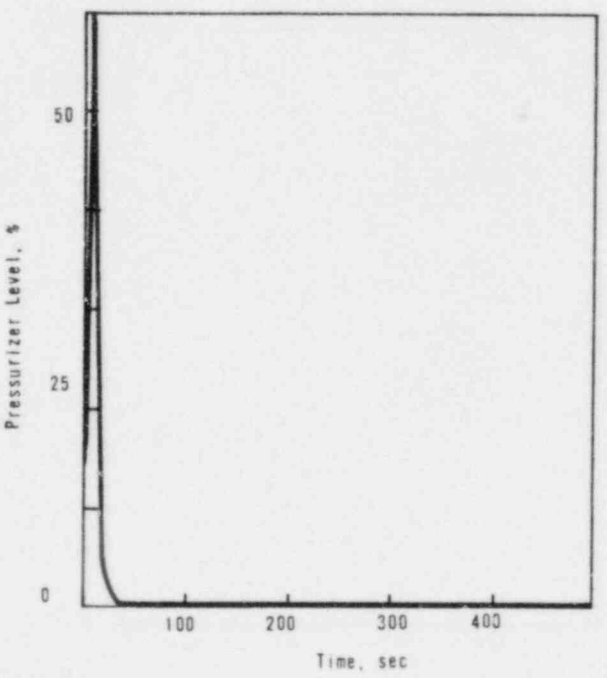
SURIZE BECAUSE THE
EASING REACTOR
ECREASES BELOW
A HEAT SOURCE.

IG; THE CFT BEGINS

WITH HPI COOLING

Also Available On
Aperture Card





PRC
APERTURE
CARD

8401230549-30

REFERENCE POINTS	TIME (SECONDS)	
1	0.0	LOCA OCCURS WITH REACT TO 1.9 INCH DIAMETER H
1-2	0-29	RCS PRESSURE AND PRESS COOLANT.
2	29	RCS PRESSURE DROPS TO
2-3	29-60	AS RCS PRESSURE DROPS, LOST; THE RC PUMPS AR RCS PRESSURE.
3	60	HOT LEG SATURATES.
3-4	60-250	THE RCS STABILIZES IN BOIL DRY.
4	250	SG COOLING IS ESSENTI T_{COLD} INCREASES TO RC SG's SLOWLY LOSE PRES
5	>250	THE RCS HANGS UP IN P ENOUGH TO CONTINUALL IS BEING COOLED BY H COOLDOWN AND DEPRESS

Figure F-9 SYSTEM RESPONSE FOR SMALL BREAK THAT STABILIZES AT HIGH RCS PRESSURE WITHOUT FEEDWATER

2 FT^2 BREAK AT PUMP DISCHARGE
(NO EMERGENCY FEEDWATER)

REMARKS

OR INITIALLY AT POWER. BREAK IS EQUIVALENT
DLE.

URIZER LEVEL DROP DUE TO LOSS OF REACTOR

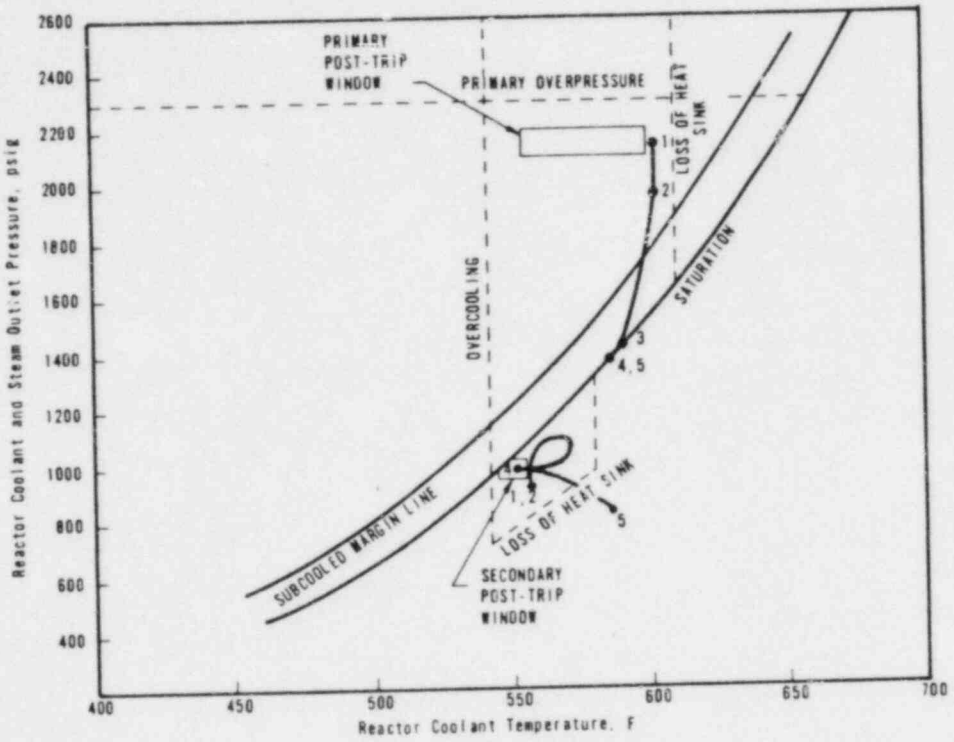
RPS TRIP SETPOINT; THE REACTOR TRIPS.

THE REACTOR COOLANT SUBCOOLED MARGIN IS
TRIPPED AND ESAS IS ACTUATED ON LOW

PRESSURE AND THE STEAM GENERATORS SLOWLY

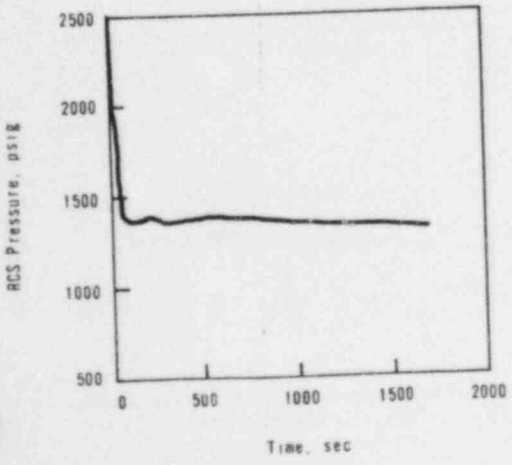
ALLY LOST.
S SATURATION TEMPERATURE.
SURE.

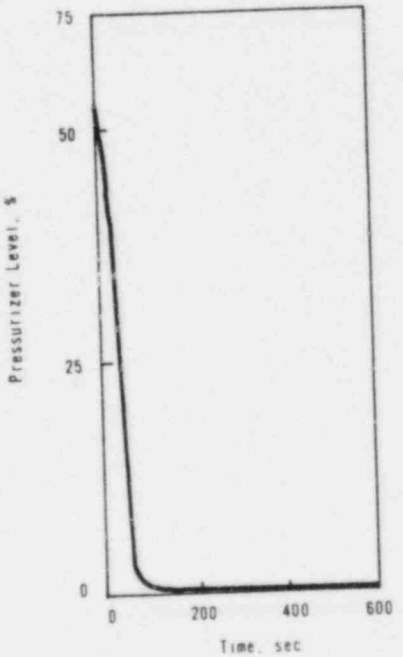
RESSURE AS THE BREAK IS NOT LARGE
DEPRESSURIZE THE SYSTEM. THE CORE
I COOLING. THE PLANT WILL SLOWLY
RIZE AS DECAY HEAT DROPS.



Also Available On
Aperture Card

PRC
APERTURE
CARD

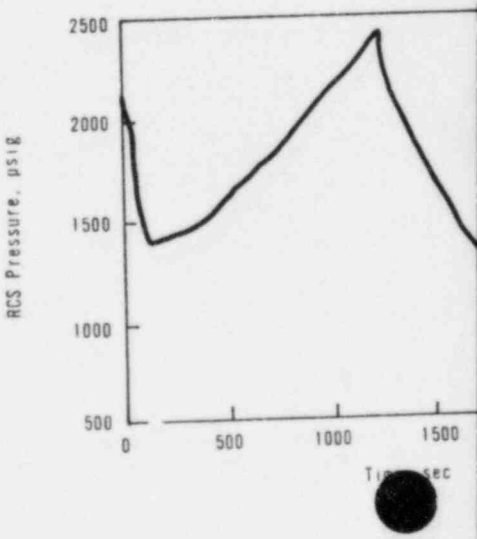




8401230549-31

0.01 ft^2 BREAK AT PUMP DISC[illegible]
(BOTH HPI AND EFW ARE ASSUMED TO
BE DELAYED FOR 20 MINUTES)

REFERENCE POINT	TIME (SECONDS)	REMARKS
1	0.0	LOCA OCCURS WITH REACTOR INITIALLY AT POW TO 1.35 INCH DIAMETER HOLE.
1-2	0-50	RCS PRESSURE AND PRESSURIZER LEVEL DROP D COOLANT.
2	50	RCS PRESSURE DROPS TO RPS TRIP SETPOINT; OF OFFSITE POWER OCCURS, AND THE RC PUMPS EFW FAILS TO START.
2-3	50-120	AS RCS PRESSURE DROPS, THE REACTOR COOLA LOST AND ESAS IS ACTUATED ON LOW RCS PRE TO FAIL.
3	120	HOT LEG SATURATES.
3-4	120-280	SG'S SLOWLY BOIL DRY.
4	280	SG COOLING IS ESSENTIALLY LOST.
4-5	280-1200	RCS REPRESSURIZES DUE TO LACK OF PRIMARY AND THE BREAK'S INABILITY TO REMOVE END TOO SMALL TO KEEP THE SYSTEM PRESSURE DO
5	1200	OPERATOR ACTION TO START EFW AN[illegible] IS
5-6	>1200	BOILER CONDENSER COOLING IS EST[illegible]RED TO THE SECONDARY SIDE SATURATION CONDIT



PRC APERTURE CARD

ER; BREAK IS EQUIVALENT

UE TO THE LOSS OF REACTOR

THE REACTOR TRIPS. LOSS
AND MAIN FEED ARE LOST.

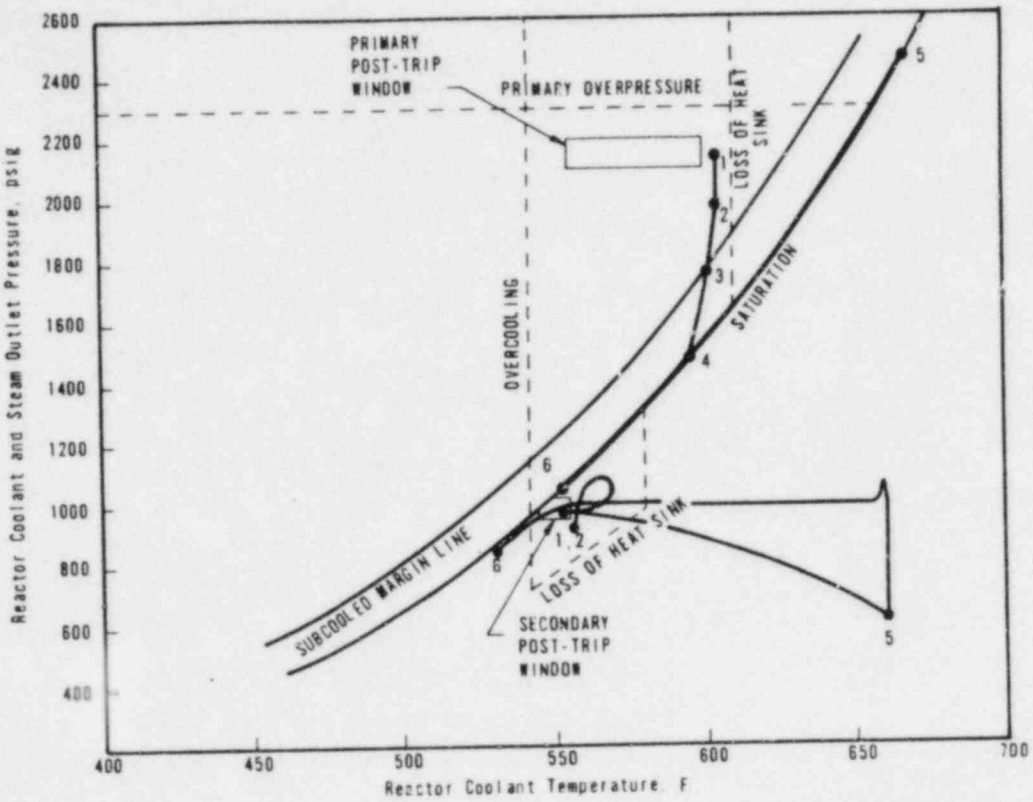
NT SUBCOOLING MARGIN IS
SSURE. HPI IS ASSUMED

TO SECONDARY HEAT TRANSFER
UGH ENERGY (I.E., BREAK IS
N).

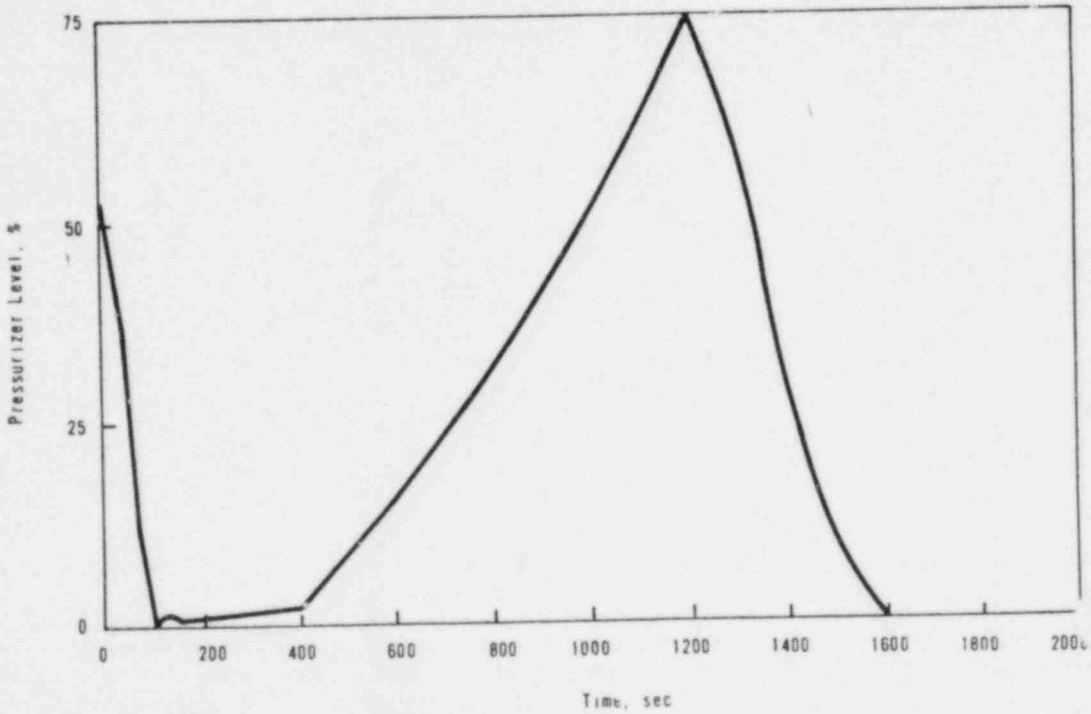
ASSU
AN RCS SLOWLY DEPRESSURIZES
ONS

2000 2500

Figure F-10 SYSTEM RESPONSE FOR SMALL BREAK THAT REPRESSURIZES IF FEEDWATER IS LOST



Also Available On
Aperture Card



8401230549-32

REFERENCE POINTS	TIME (SECONDS)	
1	0	LOCA OCCURS W[redacted]CT IS EQUIVALENT [redacted]OUT
1-2	0-60	RCS PRESSURE DROPS AS T OUT THE BREAK. PRESSU
2	60	PRESSURE DROPS TO THE
2-3	60-185	AS RCS PRESSURE DROPS, IS LOST (RC PUMP TRIP RCS PRESSURE.
3	185	THE HOT LEG SATURATES.
3-4	185-490	RCS IS IN TWO-PHASE NA CONDITIONS DECREASE AL 1200 PSI. PRESSURIZER DEPLETED.
4	490	THE PRESSURIZER FILLS.
4-5	>490	SYSTEM STABILIZES AT A CIRCULATION IS NEVER L TO A SUBCOOLED STATE. COOLDOWN WOULD BE REQU

STUCK OPEN PORV

REMARKS

R LY AT PUWER, STUCK OPEN PORV
A CH DIAMETER HOLE.

HE PRESSURIZER STEAM SPACE IS VENTED
IZER LEVEL INCREASES.

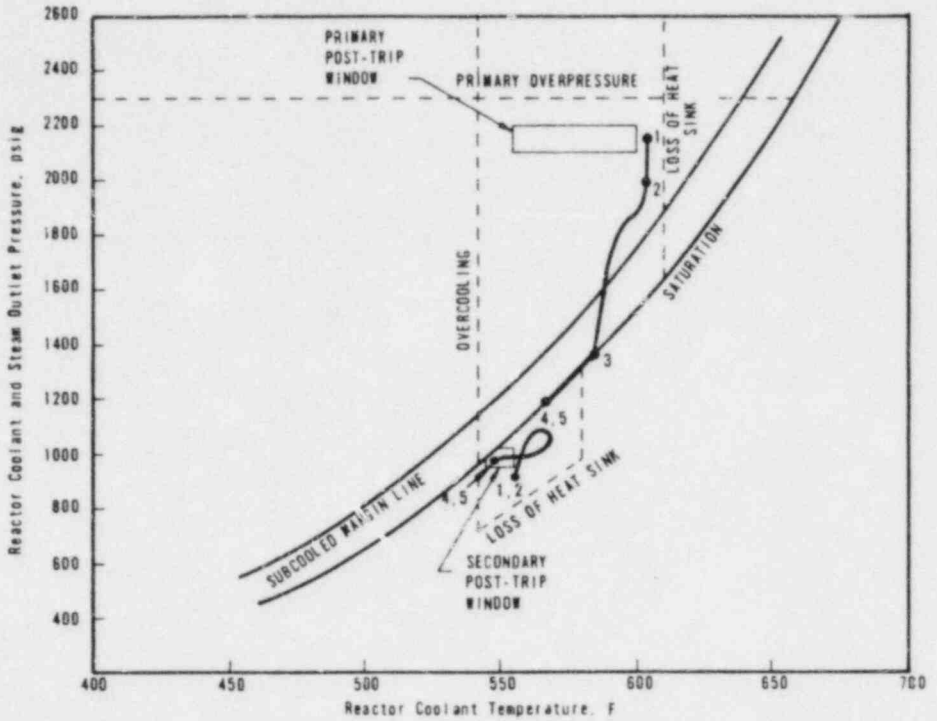
PS TRIP SETPOINT; THE REACTOR TRIPS.

THE REACTOR COOLANT SUBCOOLING MARGIN
S REQUIRED), AND ESAS IS ACTUATED ON LOW

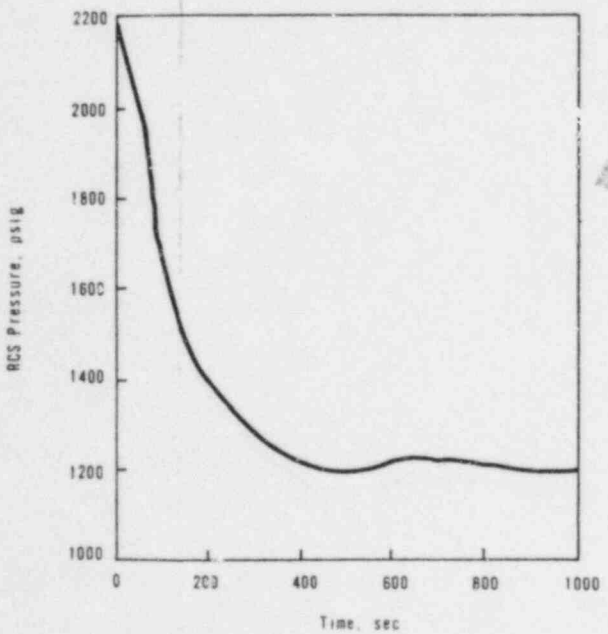
URAL CIRCULATION. PRESSURE AND TEMPERATURE
NG THE SATURATION CURVE AND STABILIZE AT ABOUT
LEVELS ARE INCREASING AS THE STEAM SPACE IS

OUT 1200 PSI, AND TWO-PHASE NATURAL
ST. HPI WILL EVENTUALLY RETURN THE SYSTEM
ITHOUT ISOLATION OF THE PORV, A SOLID WATER
KED.

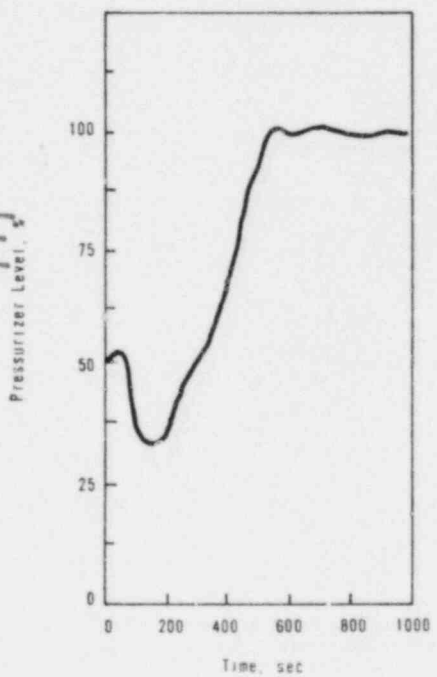
Figure F-11 SYSTEM RESPONSE FOR SMALL BREAK WITHIN PRESSURIZER STEAM SPACE



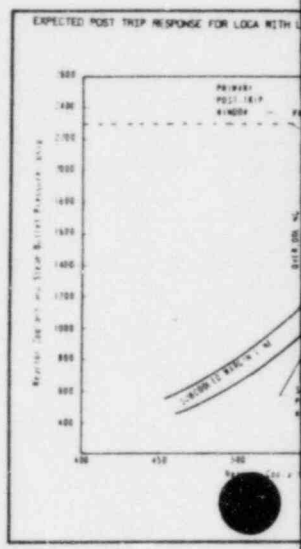
Also Available On
Aperture Card



PRC
APERTURE
CARD

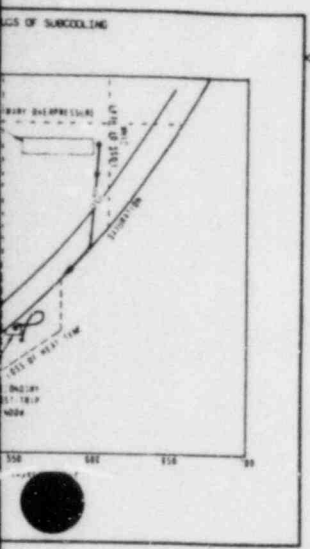


8401230549-33



GO TO PLANT COOLDOWN PROCEDURE FOR
SUBCOOLED CONDITIONS WITH A SMALL BREAK

Figure F-12 POST-LOCA CORRECTIVE ACTION FOR LACK OF ADEQUATE SUBCOOLING MARGIN



LACK OF ADEQUATE SUBCOOLED MARGIN

*1. TRIP RC PUMPS
*2. CONFIRM 2-HPI ON AT MAX. CAPACITY & BALANCE FLOWS
*3. CONFIRM EFW 'ON' & RAISE LEVEL TO 95%
4. ATTEMPT TO LOCATE AND ISOLATE THE LOCA (SEE TABLE F-4)

EXCESSIVE HEAT TRANSFER? YES / NO

YES → TREAT OVERCOOLING PER PROCEDURE SEE FIG 22

NO → ISOLATE POSSIBLE LEAKS

SUBCOOLED MARGIN? YES / NO

YES → THROTTLE HPI (TEE BEST METHODS FOR EQUIPMENT OPERATION)

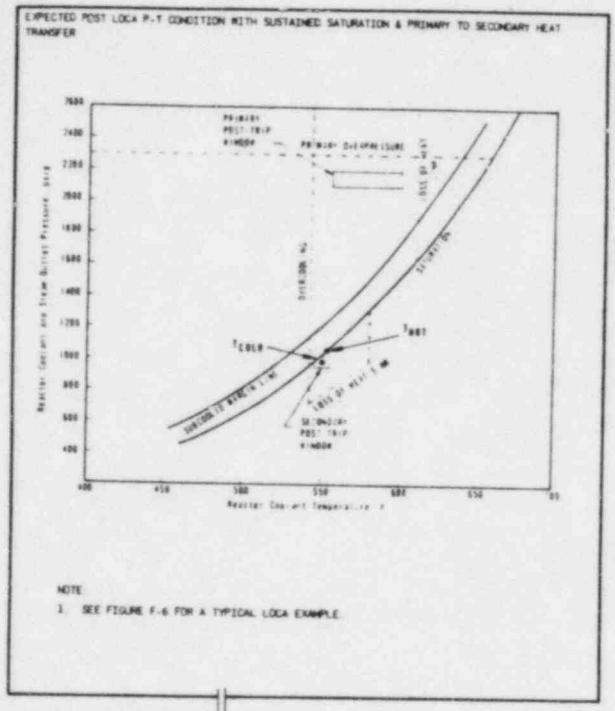
OVERHEATING? NO / YES

YES → TREAT OVERHEATING PER PROCEDURE (SEE FIGURES 23 F-13)

NO → HEAT TRANSFER IN BOTH SG*? YES / NO

YES → GO TO PLANT COOLDOWN PROCEDURE FOR SATURATED CONDITION WITH A SMALL BREAK

NO → GO TO LACK OF PRIMARY TO SECONDARY HT TRANSFER (GO TO FIGURE F-13)



NOTE
1. SEE FIGURE F-6 FOR A TYPICAL LOCA EXAMPLE

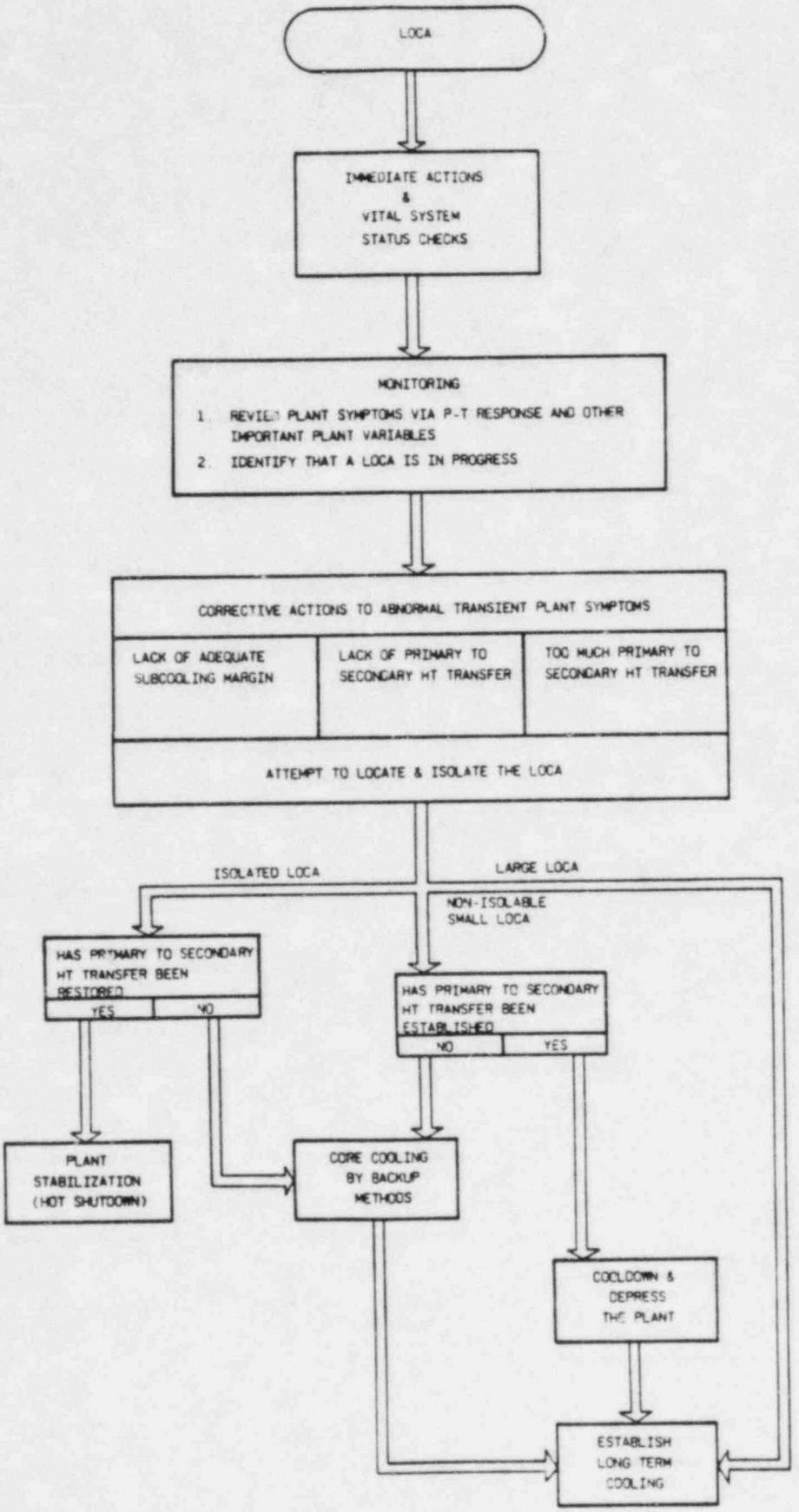
*FOR MORE DETAILS, GO TO ATOG PART II BEST METHODS OF EQUIPMENT OPERATION

Also Available On Aperture Card

PRC APERTURE CARD

8401230549-34

Table F-1 GENERAL POST-LOCA CORRECTIVE ACTION TO MAINTAIN CORE COOLING



74-1124158-00

Table F-2 HOW TO DISTINGUISH LOCA'S FROM OTHER TRANSIENTS

Unique Characteristics of LOCA's

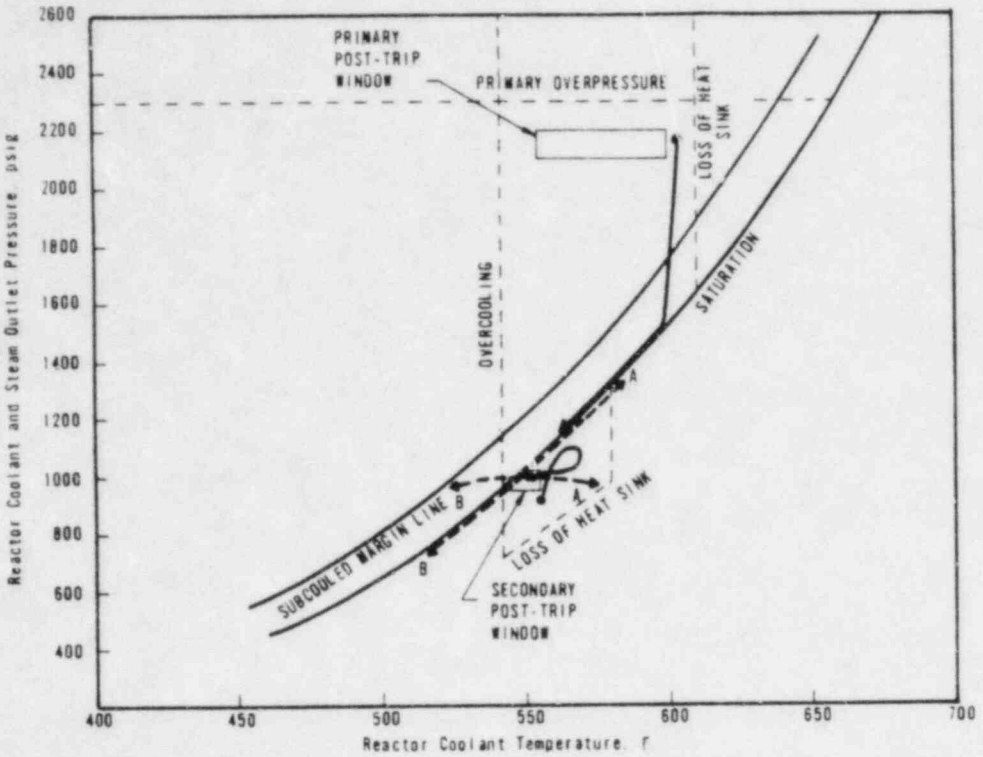
- Rapid system depressurization to saturated conditions with little or no change of reactor coolant temperature (characteristic of all but the very smallest breaks)
- Sustained saturation (HPI does not return the reactor to a subcooled state within 5-10 minutes after actuation)
- Containment radiation (only for breaks in containment)

  NOTE: A steam or feed line leak inside containment will cause high pressure, temperature and humidity but will not cause high radiation.
- Steam pressure, feed flow and steam generator level do not indicate overcooling (this helps to differentiate LOCA's from overcooling transients)
- High steam line radiation alarms (tube leaks only)
- Low makeup tank level (in the absence of all of the above, this indicates a leak outside the containment)

NOTE: LOCA's CAN BE DIFFICULT TO DETECT, ESPECIALLY IF THE BREAKS ARE SMALL. IF THERE IS ANY DOUBT THAT AN ACCIDENT IS A LOCA, ASSUME THAT IT IS AND TAKE APPROPRIATE LOCA ACTIONS UNTIL CLEARLY PROVEN OTHERWISE. THE GENERAL ACTIONS INCLUDE HPI COOLING, RC PUMP TRIP, AND COOLDOWN TO COLD CONDITIONS.

Table F-3 SUMMARY OF GENERAL LOCA SYMPTOMS

A. INITIAL P-T DIAGRAM CHARACTERISTICS



a. Rapid system depressurization to saturated reactor coolant conditions.

b. Sustained saturation (i.e., HPI does not return the reactor coolant to a subcooled state within 5-10 minutes).

B. POSSIBLE EVENTS OR OTHER PLANT LEVEL SYMPTOMS (EXTRACTED FROM LOCA CONCEPTS SECTION)

		SMALL LEAK	SMALL BREAK Small	SMALL BREAK Large	LARGE BREAK
1.	Excessive Makeup	X	-	-	-
2.	Decreasing Pressurizer Level and Pressure***	X	X	X	X
3.	Reactor Trip	X	X	X	X
4.	ES Actuation (Low RC Pressure)		X	X	X
5.	Loss of Subcooled Margin		X	X	X
6.	Lack of Primary to Secondary Heat Transfer (System Repressurization along Saturation Curve, T_{cold} vs. Steam Press. Trend to Right of Saturation Curve) (Arrows 'A' above)		X		
7.	Reverse Primary to Secondary Heat Transfer (Arrows 'B' above)			X	X
8.	Rapid Depletion of CFTs				X
9.	Rapid Drop in RCS Pressure to where LPI System becomes Operative				X
10.	Rapid Increase in RB Pressure and Temperature*			X	X
11.	Increasing RB Radiation Levels*	X	X	X	X
12.	Inadequate Core Cooling Symptoms**				X

*Degraded RB conditions can occur for other events such as steam or feedwater line breaks inside RB. These non-LOCA events would not have high RB radiation levels. High RB radiation levels are thus a good indicator that a LOCA is in progress.

**For large breaks, the incore thermocouples can indicate superheated coolant conditions from approximately the end of blowdown to up to 10 minutes into the reflood portion of the event. This is an expected condition. Because the RC pressure is reduced to where the LPI system is fully operational, actions specified for ICC are not required. The core's temperature excursion will be terminated when CFT and HPI water refloods the reactor vessel.

***Break in pressurizer steam space will cause level to increase.

Table F-5 SUMMARY OF LONG TERM COOLING ACTIONS

ACTIONS TO MAINTAIN CORE COOLING

1. ECCS Alignments

   a. For saturated reactor coolant conditions (RCS pressure $\leq$ 150 psig):

      When BWST reaches low level limit, transfer suction of LPI pumps to containment sump.

      If LPI flow in each train is $\geq$ 1000 gpm, HPI can be stopped. If LPI flow in each train can be maintained $\geq$ 1000 gpm with one LPI pump, the other LPI pump can be stopped to preserve it for future use.

      If neither or only one LPI train flow is $\geq$1000 gpm, run two HPI pumps in the piggyback mode.

   b. For subcooled reactor coolant conditions (RCS temperature $\leq$ 280F):

      If both LPI pumps are operative, place one LPI train in normal decay heat removal mode. Cool down to 100F with decay heat coolers.

      If only one LPI pump is operative, maintain SG cooling. Control RCS inventory using HPI with suction from BWST or in piggyback mode. Start normal decay heat removal when second LPI pump becomes available.

2. Start Action within 24 Hours to prevent boron precipitation following large breaks.

   a. Try to establish normal decay heat removal if two LPI pumps are available, or

   b. Establish gravity draining from the hot leg to the reactor emergency sump, or

   c. Start the auxiliary spray to the pressurizer.