CEN-152

NORTHEAST UTILITIES

THE CONNECTICUT LIGHT AND POWER COMPANY
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NORTHEAST UTILITIES SERVICE COMPANY
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May 8, 1984
RWW-84-33

Mr. D. G. Eisenhut
Director, Division of Licensing
Office of Nuclear Reactor Regulation
U.S. Nuclear Regulatory Commission
Washington, DC 20555

Subject: Transmittal of CEN-152, Revision 02, "Combustion Engineering Emergency Procedure Guidelines"

References:
(A) D. G. Eisenhut, NRC letter dated July 29, 1983 to R. W. Wells, Chairman, CE Owners Group; Subject: Safety Evaluation of Emergency Procedure Guidelines
(B) R. W. Wells, CE Owners Group letter dated October 28, 1983 to D. G. Eisenhut, NRC; Subject: CEOG Response to EPG 90-Day Action Requirements
(C) Letter from R. W. Wells, CEOG to H. R. Denton, NRC, "Communications Between the CEOG and the NRC", dated October 19, 1982
(D) R. W. Wells, CEOG letter dated November 22, 1982 to D. G. Eisenhut, NRC, Transmitting Report CEN-152, Revision 01, CE Emergency Procedure Guidelines
(E) R. W. Wells, CEOG letter dated February 28, 1984, to D. G. Eisenhut, NRC, Transmitting Report (CEN-268, "Justification of Trip Two/Leave Two Reactor Coolant Pump Trip Strategy During Transients

Dear Mr. Eisenhut:

The purpose of this letter is to transmit to you the subject report. This report was prepared by Combustion Engineering (CE) for the CE Owners Group (CEOG) in partial response to your request stated in Reference (A). This submittal provides emergency procedure guidance improvements in the areas of the Reactor Vessel Level Monitoring System (RVLMS), reactor coolant pump (RCP) operating strategy, and selected long-term EPG issues from Reference (A). The CEOG made a commitment to provide this submittal in Reference (B).

This transmittal by the CEOG is made in order to assist you and the CEOG members in reaching resolution of requirement I.C.I for CE designed nuclear steam supply systems. The transmittal is made according to the terms stated in Reference (C), a copy of which is attached for your convenience. In particular, this submittal is not applicable to any individual licensee or license applicant until the submittal is

referenced by that licensee or license applicant for use on his docket. Please send copies of any correspondence concerning this submittal to individuals identified in the attached list.

The emergency procedure guidelines contained in the enclosed report, CEN-152, Revision 2, are intended to update guidelines contained in report CEN-152, Revision 1 which was transmitted to you by Reference (D). The updated guidelines incorporate information on the use of the RVLMS, the trip two/leave two RCP trip strategy described in report CEN-268 which was submitted to the NRC by Reference (E), and four of the long-term EPG issues identified in Reference (A). The four issues addressed are reactor coolant system upper head voids, charging pump operation, safety injection maximization, and steam generator tube rupture safety function criteria. Discussions to obtain resolution on the remaining long-term issues are currently underway between the CEOG and the NRC staff.

The CEOG authorized the creation of report CEN-152, Revision 02 in response to NRC requirements for changes to the emergency procedure guidelines. The CEOG maintains control of report CEN-152 and will consider additional revisions as the need dictates. As Reference (B) indicates, additional long-term EPG issues are expected to be addressed in a third revision of CEN-152 to be issued in 1985.

Very truly yours,

Rik W. Wells, Chairman
CE Owners Group

RWW/djr
Enclosures: CEN-152, Revision 02, "CE Emergency Procedure Guidelines" (Five copies are included.)

COMBUSTION ENGINEERING
EMERGENCY PROCEDURE GUIDELINES

Prepared for the C-E Owners Group

CEN-152 Rev. 02

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ABSTRACT

This report has been prepared by Combustion Engineering, Inc. for the C-E Owners Group in response to the NRC Safety Evaluation Report (SER) on CEN-152 Revision 01 and to Three Mile Island (TMI) Action Item II.K.3.5. This report also continues the response to NUREG-0737, Item I.C.1, which was previously provided by CEN-152, Revision 01. This report contains revised generic Emergency Procedure Guidelines which supersede those contained in Combustion Engineering Emergency Procedure Guidelines, CEN-152, Revision 01. It also contains supporting information on the development of the Guidelines.

The remainder of the change package consists of new "Record of Revisions" and "List of Effective Pages" for the foreword section of CEN-152. A new "Table of Contents" pages will be supplied if necessary. The changes in the text of CEN-152 will be page insertions with the change identified by vertical lines and a letter which identifies the change package.

The EPGs may be revised by reissue of the entire set or by revised pages. If new pages are issued, the page is identified by the current revision followed by a sequentially assigned letter suffix. When a major revision occurs a new book will be issued as a new revision number. Change between major revisions will be issued as page changes only.

Revision and Control of C-E Emergency Procedure Guidelines, CEN-152

Changes to the EPGs must be controlled to ensure each document holder has the latest revision and that the control copy of each holder is the same as every other holder. This will be accomplished by following the guidelines in this section. When a change is required one package is sent to each of the document holders and Combustion Engineering Document Control Department. Each holder is responsible for making additional copies.

A master control copy will be maintained in the CEOG Project Office and it will remain as the reference copy for all others.

When a change is transmitted to document holders, a Change Control Sheet will summarize the pertinent information in the change and is retained as a permanent part of the EPG. It is to be placed in the Foreword following the previous change. Each sheet will be sequentially numbered.

Each recipient will insert the change(s) into the control copy of CEN-152 according to instructions on a second Change Control Sheet 2. After the change(s) is (are) completed, Sheet 2 is placed after Sheet 1 of the same change and is signed by the person who entered the change. The enclosed form, which is signed as verification that the change has been entered, is then returned to the CEOG Project Office at Combustion Engineering. This receipt informs the CEOG Project Office that each document holder has received the change package and has entered it into the control copy. These reciepts will be retained by the CEOG Project Office as part of the permanent records of the changes which are made to CEN-152. C

COMBUSTION ENGINEERING EMERGENCY PROCEDURE GUIDELINES

CEN-152

Change Control Sheet 1

Change Package A

Revision: 02 Date: August 1985

1. EPG Sections Affected: 5, 6, 7, 9, 10, Appendix A, Foreword

2. Subject of Change:

   CEN-152 Appendix A and Changes to CEN-152

3. Summary of reason for change:

   Response to NRC Questions on or CEN-152, Rev. 02 relating to RVLMS, CETs etc.

   Incorporate CEN-152 Change Control

4. Change correspondence record (letter number and/or copies attached):

   SE-84-576, December 12, 1984; P.R. Nelson to Operations Subcommittee, C-E Owners Group

COMBUSTION ENGINEERING EMERGENCY PROCEDURE GUIDELINES

CEN-152

Change Control Sheet 2

Change Package A

Instructions

1. Place "Revision and Control of C-E Emergency Procedures Guidelines, CEN-152" in Foreword section of CEN-152. Rev. 02 (4 pages)
2. Replace Record of Revisions Rev. 02 with Record of Revisions Rev. 02A
3. Replace old List of Effective Pages with new List of Effective Pages.
4. Replace old page v with new page v in Table of Contents
5. Replace page 5-10 Rev.02 with page 5-10, Rev.02A
6. Replace page 5-70 Rev.02 with page 5-70, Rev.02A
7. Replace page 6-10 Rev.02 with page 6-10, Rev.02A
8. Replace page 6-62 Rev.02 with page 6-62, Rev.02A
9. Replace page 7-9 Rev.02 with page 7-9, Rev.02A
10. Replace page 7-55 Rev.02 with page 7-55, Rev.02A
11. Replace page 9-8 Rev.02 with page 9-8, Rev.02A
12. Replace page 9-42 Rev.02 with page 9-42, Rev.02A
13. Replace page 10-108 Rev.02 with page 10-108, Rev.02A
14. Replace page 10-134 Rev.02 with page 10-134, Rev.02A
15. Replace page 10-146 Rev.02 with page 10-146, Rev.02A
16. Replace page 10-162 Rev.02 with page 10-162, Rev.02A
17. Replace page 10-178 Rev.02 with page 10-178, Rev.02A
18. Replace page 10-197 Rev.02 with page 10-197, Rev.02A
19. Place Appendix "A" after Chapter 14

Change entered P Pierringer

Date 10/28/85

COMBUSTION ENGINEERING EMERGENCY PROCEDURE GUIDELINES

CEN-152

Change Control Sheet 1

Change Package B

Revision: 02   Date: August 1985

1. EPG Sections Affected: Foreword, Table of Contents, 6

2. Subject of Change:

   Wording correction

3. Summary of reason for change:

   Correct wording in step 27b of SGTR ORG from "cooldown using the isolated steam generator" to "cooldown using the unisolated (least affected) steam generator" and from "atmospheric dump on the isolated" to "atmospheric dump on the unisolated (least affected) steam generator."

4. Change correspondence record (letter number and/or copies attached):

   CE-OG-1118, May 7, 1985, J.H. Hutton to C-E Owners Group

COMBUSTION ENGINEERING EMERGENCY PROCEDURE GUIDELINES

CEN-152

Change Control Sheet 2

Change Package B

Instructions

1. Relace Record of Revisions, Rev. 02A with Record of Revisions, Rev. 02B
2. Replace old "List of Effective Pages" with new "List of Effective Pages".
3. Replace old page v with new page v in Table of Contents
4. Replace page 6-8 Rev. 02 with page 6-8 Rev. 02B

Change entered Reinger

Date 10/28/85

COMBUSTION ENGINEERING EMERGENCY PROCEDURE GUIDELINES

CEN-152

Change Control Sheet 1

Change Package C

Revision: 02 Date: August 1985

1. EPG Sections Affected: 5,6,7,9,10,12, Appendix A

2. Subject of Change:

   a. Void elimination guidance
   b. Average CET temperature

3. Summary of reason for change:

   a. Change void elimination criteria per Rev. 02 SER so voids are eliminated prior to heat removal being inhibited.
   b. Change Appendix A to include "Example Algorithm for Determining Average Core Exit Thermocouple Temperature."

4. Change correspondence record (letter number and/or copies attached):

COMBUSTION ENGINEERING EMERGENCY PROCEDURE GUIDELINES

CEN-152

Change Control Sheet 2

Change Package C

Instructions

1. Replace "Revision and Controls" of C-E Emergency Procedure Guidelines, CEN-152, Rev. 02A with Rev. 02C.
2. Replace "Record of Revisions" Rev 02B with "Record of Revisions" Rev 02C.
3. Replace "List of Effective Pages" Rev 02B with "List of Effective Pages" Rev 02C.
4. Replace page 5-15 Rev 02 with page 5-15 Rev 02C.
5. Replace page 6-14 Rev 02 with page 6-14 Rev 02C.
6. Replace page 6-15 Rev 02 with page 6-15 Rev 02C.
7. Replace page 7-12 Rev 02 with page 7-12 Rev 02C.
8. Replace page 9-11 Rev 02 with page 9-11 Rev 02C.
9. Replace page 10-80 Rev 02 with page 10-80 Rev 02C.
10. Replace page 10-108 Rev 02A with page 10-108 Rev 02C.
11. Replace page 10-111 Rev 02 with page 10-111 Rev 02C.
12. Replace page 10-134 Rev 02A with page 10-134 Rev 02C.
13. Replace page 10-146 Rev 02A with page 10-146 Rev 02C.
14. Replace page 10-150 Rev 02 with page 10-150 Rev 02C.
15. Replace page 10-157 Rev 02 with page 10-157 Rev 02C.
16. Replace page 10-166 Rev 02 with page 10-166 Rev 02C.
17. Replace page 10-178 Rev 02A with page 10-178 Rev 02C.
18. Replace Appendix A page iii with Appendix A page iii Rev 02C.
19. Replace Appendix A page 4 with Appendix A page 4 Rev 02C.
20. Replace Appendix A page 6 with Appendix A page 6 Rev 02C.
21. Replace Appendix A page 7 with Appendix A page 7 Rev 02C.
22. Replace Appendix A page 9 with Appendix A page 9 Rev 02C.
23. Replace Appendix A page 10 with Appendix A page 10 Rev 02C.
24. Replace Appendix A page 11 with Appendix A page 11 Rev 02C.
25. Replace Appendix A page 12 with Appendix A page 12 Rev 02C.
26. Replace Appendix A page 13 with Appendix A page 13 Rev 02C.
27. Remove old page 54 of Appendix A and insert pages 54 Rev 02C through 64 Rev 02C at the end of Appendix A.

Change entered *P. Pieringer*

Date *10/28/85*

COMBUSTION ENGINEERING

Emergency Procedure Guidelines

(CEN-152)

Record of Revisions

Revision Number	Date
00	June, 1981
01	November, 1982
02	May, 1984
02A	August, 1985
02B	August, 1985
02C	September, 1985

COMBUSTION ENGINEERING

Emergency Procedure Guidelines

CEN-152

List of Effective Pages

SECTION	PAGE NUMBERS	REVISION	DATE
1.0	1-1 through 1-56	02	May, 1984
2.0	2-1 through 2-15	02	May, 1984
3.0	3-1 through 3-9	02	May, 1984
4.0	4-1 through 4-29	02	May, 1984
5.0	5-1 through 5-9	02	May, 1984
	5-10	02A	Sept., 1985
	5-11 through 5-14	02	May, 1984
	5-15	02C	August, 1985
	5-16 through 5-69	02	May, 1984
	5-70	02A	August, 1985
	5-71 through 5-86	02	May, 1984
6.0	6-1 through 6-7	02	May, 1984
	6-8	02B	August, 1985
	6-9	02	May, 1984
	6-10	02A	August, 1985
	6-11, 6-12, 6-13	02	May, 1984
	6-14, 6-15	02C	Sept., 1985
	6-16 through 6-61	02	May, 1984
	6-62	02A	August, 1985
	6-63 through 6-78	02	May, 1984
7.0	7-1 through 7-8	02	May, 1984
	7-9	02A	August, 1985
	7-10, 7-11	02	May, 1984
	7-12	02C	Sept., 1985
	7-13 through 7-54	02	May, 1984
	7-55	02A	August, 1985
	7-56 through 7-69	02	May, 1984
8.0	8-1 through 8-57	02	May, 1984
9.0	9-1 through 9-7	02	May, 1984
	9-8	02A	August, 1985
	9-9,9,10	02	May, 1984
	9-11	02C	Sept., 1985
	9-12 through 9-41	02	May, 1984
	9-42	02A	August, 1985
	9-43 through 9-53	02	May, 1984
10.0	10-1 through 10-79	02	May, 1984
	10-80	02C	Sept., 1985
	10-81 through 10-107	02	May, 1984
	10-108	02C	Sept., 1985
	10-109, 10-110	02	May, 1984
	10-111	02C	Sept., 1985

COMBUSTION ENGINEERING

Emergency Procedure Guidelines

CEN-152

List of Effective Pages

SECTION	PAGE NUMBERS	REVISION	DATE
10.0	10-112 through 10-133	02	May, 1984
	10-134	02C	Sept., 1985
	10-135 through 10-145	02	May, 1984
	10-146	02C	Sept., 1985
	10-147 through 10-149	02	May, 1984
	10-150	02C	Sept., 1985
	10-151 through 10-156	02	May, 1984
	10-157	02C	Sept., 1985
	10-158 through 10-161	02	May, 1984
	10-162	02A	August, 1985
	10-163 through 10-165	02	May, 1984
	10-166	02C	Sept., 1985
	10-167 through 10-177	02	May, 1984
	10-178	02C	Sept., 1985
	10-179 through 10-196	02	May, 1984
	10-197	02A	August, 1985
	10-198 through 10-221	02	May, 1984
11.0	11-10 through 11-7	02	May, 1984
12.0	12-1 through 12-29	02	May, 1984
	12-30	02	May,1984
	12-31 through 12-58	02	May, 1984
13.0	13-1 through 13-7	02	May, 1984
14.0	14-1 through 14-3	02	May, 1984
Appendix A	i,ii	02A	August, 1985
	iii	02C	Sept., 1985
	1 through 3	02A	August, 1985
	4	02C	Sept., 1985
	5	02A	August, 1985
	6, 7	02C	Sept., 1985
	8	02A	August, 1985
	9 through 13	02C	Sept., 1985
	14 through 53	02A	August, 1985
	54 through 64	02C	Sept., 1985

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1.0 INTRODUCTION

1.1 PURPOSE

The objective of this report is to provide a description of the Combustion Engineering Owners Group (CEOG) emergency procedure guideline system. This report contains the methodology used to develop and validate the emergency procedure guidelines (EPGs), and information on guideline implementation. Revision 01 of this report was provided in response to Nuclear Regulatory Commission (NRC) requirements set forth in NUREG-0737, Item I.C.1. Revision 02 is being provided in response to the NRC Safety Evaluation Report (SER) on Revision 01 (Reference, 14.21) and in support of the resolution of Three Mile Island (TMI) Action Item II.K.3.5 regarding reactor coolant pump (RCP) trip strategy. Justification of the "Trip 2/Leave 2 RCP Trip Strategy During Transients" is provided in Reference 14.22.

1.2 BACKGROUND

Following the Three Mile Island Unit 2 (TMI-2) incident, the NRC established requirements addressing their objective to improve the quality of operational information for dealing with emergency events.

Following the TMI-2 incident, IE Bulletin 79-06C, "Nuclear Incident at Three Mile Island - Supplement", was issued. IE Bulletin 79-06C required that analyses and operator guidance pertaining to small break loss of coolant accidents (LOCA) and inadequate core cooling (ICC) be developed. The following CEOG sponsored reports dealing with selected multiple failures and systematic failure analyses provided responses to IE Bulletin 79-06C:

1) CEN-114-NP Amendment 1-NP, "Review of Small Break Transients In Combustion Engineering Nuclear Steam Supply Systems"

2) CEN-115-NP Amendment 1-NP, "Response to NRC IE Bulletin 79-06C, Items 2 and 3, for Combustion Engineering Nuclear Steam Supply Systems"

3) CEN-117, "Inadequate Core Cooling, A Response to NRC IE Bulletin 79-06C, Item 5, for Combustion Engineering Nuclear Steam Supply Systems".

Then, NUREG-0578, "TMI-2 Lessons Learned Task Force Status Report and Short Term Recommendations", was issued. That document contained the NRC's short-term recommendations on improving the analyses of design basis and off-normal transients and the procedures for handling such transients. The implementation of these recommendations was made a requirement by the NRC's Office of Nuclear Reactor Regulation (NRR) in letters which were issued on September 13 and 27, October 10 and 30, and November 9, 1979.

CEN-128, entitled "Response of Combustion Engineering Nuclear Steam Supply System to Transients and Accidents", was submitted by the CEOG in response to NUREG-0578. CEN-128 contains the information required by NUREG-0578 including the results of improved and extended best estimate analyses of design basis and off-normal transients and the corresponding emergency procedure guidelines.

In May 1980, NUREG-0660, "NRC Action Plan Developed as a Result of the TMI-2 Accident," was issued. NUREG-0660 lists, by task, all of the NRC's TMI related action plan recommendations. Task I.C.1 of NUREG-0660 discusses operational guidance issues. The objective of Task I.C.1 was to conduct a short-term program of best estimate accident analysis and procedures revision.

The revisions recommended by NUREG-0660 are part of an ongoing three phase program for emergency guidance improvement initiated by NUREG-0578. Item I.C.9. of NUREG-0660 discusses future activities in this area by stating:

> "The NRC will develop a long-term program plan that will integrate and expand on current efforts in the writing, reviewing, and monitoring of plant procedures. Studies to be considered in the plan will include how best to write plant procedures to assure that the wording of procedures is clear and concise; that the content of procedures reflects both

engineering thinking and operating practicalities; and that the format of procedures is clear, including clear diagnostic instructions for identifying the particular abnormal conditions confronting the operator."

NUREG-0737, "Clarification of TMI Action Plan Requirements", which was issued in October of 1980 provided clarification of some TMI-related action plan requirements and specified schedules for implementation. Item I.C.1 of NUREG-0737 clarified the action plan recommendations that had previously been set forth in NUREG-0660. The report contained herein was first prepared in response to NUREG-0737, Item I.C.1. An evaluation of CEOG compliance to NUREG-0737, and subsequent regulatory initiatives, is provided in Section 1.3.

The initial submittal in response to I.C.1 of NUREG-0737 was contained in CEN-152, Revision 00, "Combustion Engineering Emergency Procedure Guidelines", and CEN-156, Revision 00, "Combustion Engineering Emergency Procedure Guidelines Development. The NRC provided comments on this submittal in an Eisenhut letter dated September 15, 1981. Revision 01 to CEN-152 was submitted in response to the NRC comments on Revision 00.

The NRC issued a Safety Evaluation Report (SER) on CEN-152 Revision 01 on July 29, 1983. The NRC concluded that the C-E Emergency Procedure Guideline program provided improved guidance for emergency operating procedure development and was acceptable for plant specific implementation. The SEP identified a number of items associated with the guidelines which required further consideration by the CEOG. CEN-152 Revision 02 addresses several items specified in the SER (e.g., voiding, RCS heat removal capability, safety injection maximization, and charging pump operation). Also included in Revision 02 is guidance on use of the Reactor Vessel Level Monitoring System (RVLMS) and a new strategy for RCP operation during depressurization events. This revised RCP operating strategy was developed in resolving NUREG-0737, Item II.K.3.5.

1.3 SUMMARY OF NUREG-0737 Item I.C.1 REQUIREMENTS AND RESPONSES

Item I.C.1 OF NUREG-0737 states that the Office of Nuclear Reactor Regulation has required licensees of operating plants, applicants for operating licenses, and licensees of plants under construction to:

1) perform analyses of transients and accidents including multiple failures
2) prepare emergency procedure guidelines
3) upgrade emergency procedures, including procedures for operating with natural circulation conditions
4) conduct operator retraining

Part of the response to NUREG-0737 includes expanded analyses of transients and accidents including multiple failures. Some of the analyses of transients and accidents which support the EPGs were performed per the requirements of NUREG-0578 and are contained in CEN-128. Certain other technical items have been analyzed in response to NRC requirements issued after NUREG-0660. More recent technical developments and corresponding analyses are detailed in section 1.7. The results of all these analyses have been used to respond to the requirements set forth in NUREG-0737, Item I.C.1, which deal with emergency procedure guideline development.

Figure 1-1 is a cross reference of issues originating in various NRC documents and the corresponding responses.

The information presented in this report complies with those requirements in Item I.C.1 associated with the development of emergency procedure guidelines. The work was performed by C-E on behalf of the CEOG.

Figure 1-1

SUMMARY OF
ISSUES - REFERENCES - RESOLUTIONS

ISSUE		REFERENCE	CEOG RESOLUTION
1.	Range of Initiating Events		
	A. FSAR Events	NUREG-0737 Item I.C.1	CEN-152 Optimal Recovery Guidelines provided for LOCA, SGTR, LOFC, ESDE, RT, LOF
	B. Loss of Instrumentation	NUREG-0737 Item I.C.1	Specific loss of instrumentation busses procedures developed on a plant specific basis.
	C. Natural Phenomena	September 15 NRC letter	Not explicitly addressed - rationale discussed in CEN-152 (Revision 01).
2.	Justification for the Approach to EPG Development	NUREG-0737 Item I.C.1	CEN-152 (Revision 01)

Figure 1-1 (Cont'd)

SUMMARY OF
ISSUES - REFERENCES - RESOLUTIONS

	ISSUE	REFERENCE	COEG RESOLUTION
3.	Identification of Plant Resources	NUREG-0737 Item I.C.1	CEN-152 (Revision 01) Resource Assessment Trees are provided in Functional Recovery Guideline and alternative actions are provided in Optimal Recovery Guidelines.
4.	Multiple and Consequential Failure Considerations	NUREG-0737 Item I.C.1	CEN-152 (Revision 01) Guidance to deal with multiple failures generated through workshop process - Reported in CEN-152 (Revision 01).
5.	Include Diagnostic Information to Aid in Implementation of Correct Procedure for Event in Progress	September 15 NRC letter	CEN-152 (Revision 01) Safety Function Status Check-Break Identification Charts-Diagnostic Aids.
6.	Use of Instrumentation to Identify Adequate Core Cooling	NUREG-0737 Item II.F.2	CEN-117, CEN-152
7.	Include Information for Determining Adequacy of Core Cooling	September 15 NRC letter	CEN-152 Safety Function Status Check.

Figure 1-1 (Cont'd)

SUMMARY OF
ISSUES - REFERENCES - RESOLUTIONS

	ISSUE	REFERENCE	CEOG RESOLUTION
8.	Identify Phenomena in Guideline Supporting Analysis		
	A. Reactor Head Voiding due to Rapid Cooldowns	NUREG-0737 Item I.C.1	CEN-152 Guidance relative to void management is provided in relevant EPGs.
	B. Steam Generator Stratification	NUREG-0737 Item I.C.1	Response in CEOG letter to NRC dated 1/30/81, question 10.
	C. Operator Errors During Long Term Cooling	NUREG-0737 Item I.C.1	CEN-152 Safety Function Status Checks and Functional Recovery Guideline.
9.	Include Information on Implementation of Guidelines	September 15 NRC letter	CEN-152 Implementation section.
10.	Improve Guidelines to Clarify and Emphasize Functional Recovery Side	September 15 NRC letter	CEN-152 Functional Recovery Guideline.

Figure 1-1 (Cont'd)

SUMMARY OF

ISSUES - REFERENCES - RESOLUTIONS

ISSUE	REFERENCE	CEOG RESOLUTION
11. Submit Description of Methodology Used to Develop Guidelines	NUREG-0737 Item I.C.1	CEN-152 CEN-156 (Revision 00)
12. Analyses Supporting Guideline Development	NUREG-0737 Item I.C.1	CEN-128, CEN-114, CEN-115 CEN-117, CENPD-254, CEN-154, CEN-189, CEN-199
13. Description of Applicability of Generic Results to Plant Specific Applications	NUREG-0737 Item I.C.1	CEN-152 Implementation section.
14. Provide Guidance Addressing the use of the Reactor Vessel Level Monitoring System (RVLMS)	SER on CEN-152 Revision 01	CEN-152 (Revision 02)
15. SER Long Term Items	SER on CEN-152 Revision 01	CEN-152 (Revision 02) (selected long term issues).
16. Develop RCP Trip Strategy	NUREG-0737 Item II.K.3.5 and Generic Letters No. 83-10a and 83-10b	CEN-268 CEN-152 (Revision 02) Implementation guidance.

1.4 EXPLANATION OF MAJOR TERMS

Provided in this section are some important terms useful to the understanding of the overview presented in the next few sections.

1.4.1 *Safety Functions*

A safety function is any condition or action needed to either prevent core damage or minimize radiation releases to the general public. If all safety functions are fulfilled, the safety of the public is preserved.

1.4.2 *Emergency Procedure Guidelines*

Emergency procedure guidelines provide technical guidance for the development of plant specific emergency operating procedures. These guidelines provide the actions necessary for mitigation of plant events that necessitate a reactor trip.

1.4.3 *Optimal Recovery Guidelines*

Optimal recovery guidelines provide the technical basis for plant specific emergency operating procedures which the operator would use to treat a specific set of symptoms. Optimal recovery guidelines are written to strategically address a specific set of symptoms. Each set of symptoms usually corresponds to a specific event or class of events (e.g. LOCA, SGTR) causing the transient or accident.

1.4.4 *Functional Recovery Guideline*

The functional recovery guideline provides the technical basis for a plant specific functional recovery emergency operating procedure which the operator would use to verify the adequacy of all critical safety functions and to restore and maintain those functions when degraded. A functional recovery procedure (and the guideline on which it is based) is written in such a way that the operator need not diagnose an event in order to establish and maintain a safe plant configuration.

1.4.5 *Emergency Operating Procedures*

Emergency operating procedures are a plant specific document based on emergency procedure guidelines containing all the steps needed to take the plant from the post-reactor trip state to a safe, stable condition. Emergency operating procedures use a specific format for clarity of procedural actions, control room personnel interactions, and compatibility with the design of the control room.

1.4.6 *Verification*

Verification is the process by which the technical information in emergency procedures is demonstrated to be accurate and complete. Verification may consist of technical analyses, workshops, or technical review. The outcome of the verification process is emergency operating procedures which are technically sound and complete.

1.4.7 *Validation*

Validation is the process by which emergency operating procedures are demonstrated to be useable by the operators. Validation is accomplished through workshops, control room walkthroughs, or by exercising the emergency operating procedures on simulators.

1.5 OVERVIEW OF EPG SYSTEM

The C-E Owners' Group effort to produce the C-E Emergency Procedure Guidelines is the continuation of an intense effort initiated in 1979. A consistent goal of the program has been to provide the best available technical information to be used for writing plant specific emergency operating procedures. The product, Combustion Engineering Emergency Procedure Guidelines (hereafter referred to as EPGs), represents a balanced approach to providing operator guidance. The first step in developing the EPGs was to evaluate existing plant procedures and to evaluate current programs related to this subject.

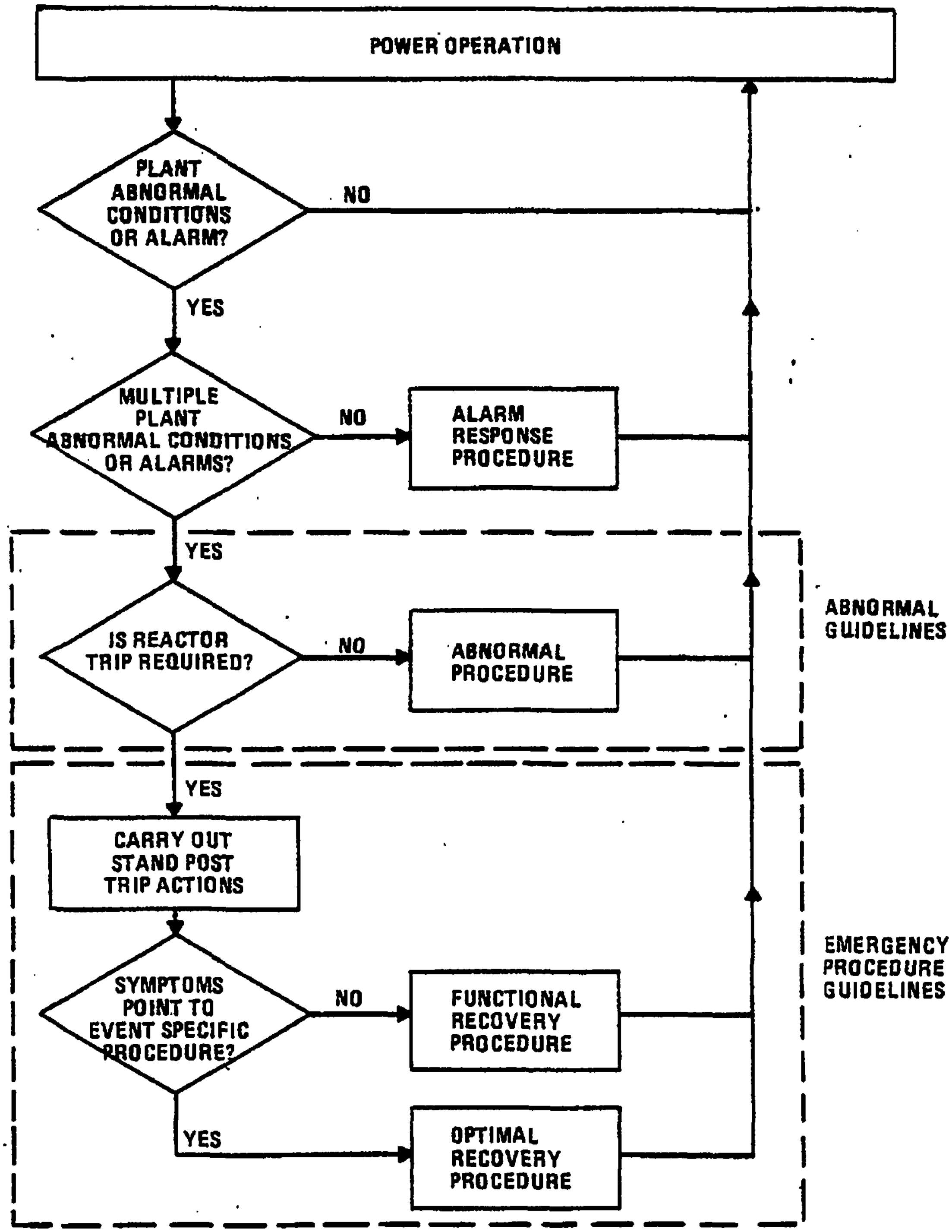
Each plant already has an extensive network of procedures. Emergency Operating Procedures must be coordinated with these existing procedures. The content and scope of the emergency operating procedures developed from EPGs should be designed to interface with, but neither overlap nor duplicate, plant procedures (other than the emergency procedures they are intended to replace). The EPGs are designed to be used independently and cross referencing is minimized. Cross referencing is appropriate only when the other guideline entry conditions are achieved during the course of operation (e.g., when Shutdown Cooling System entry conditions are established, then initiate it per operating instructions). The EPGs do not cover information related to overall operation of the power plant site during emergency conditions because that subject is covered by the Site Emergency plan.

1.5.1 EPG System Structure and Rationale

The EPGs are a collection of the best available technical information to be used for writing emergency operating procedures. An understanding of what constitutes an emergency is a prerequisite to deciding what information is to be collected and in which format that information is to be arranged. For the purpose of these EPGs, an emergency event is distinguished from other off-normal plant operations by virtue of its severity; it is sufficiently severe that a reactor trip is either activated or required immediately to properly mitigate the event. Figure 1-2 depicts the distinction between emergency operating procedures based on these guidelines and other off-normal procedures.

FIGURE 1-2

SEQUENCE OF DECISIONS FOR OFF-NORMAL OPERATIONS



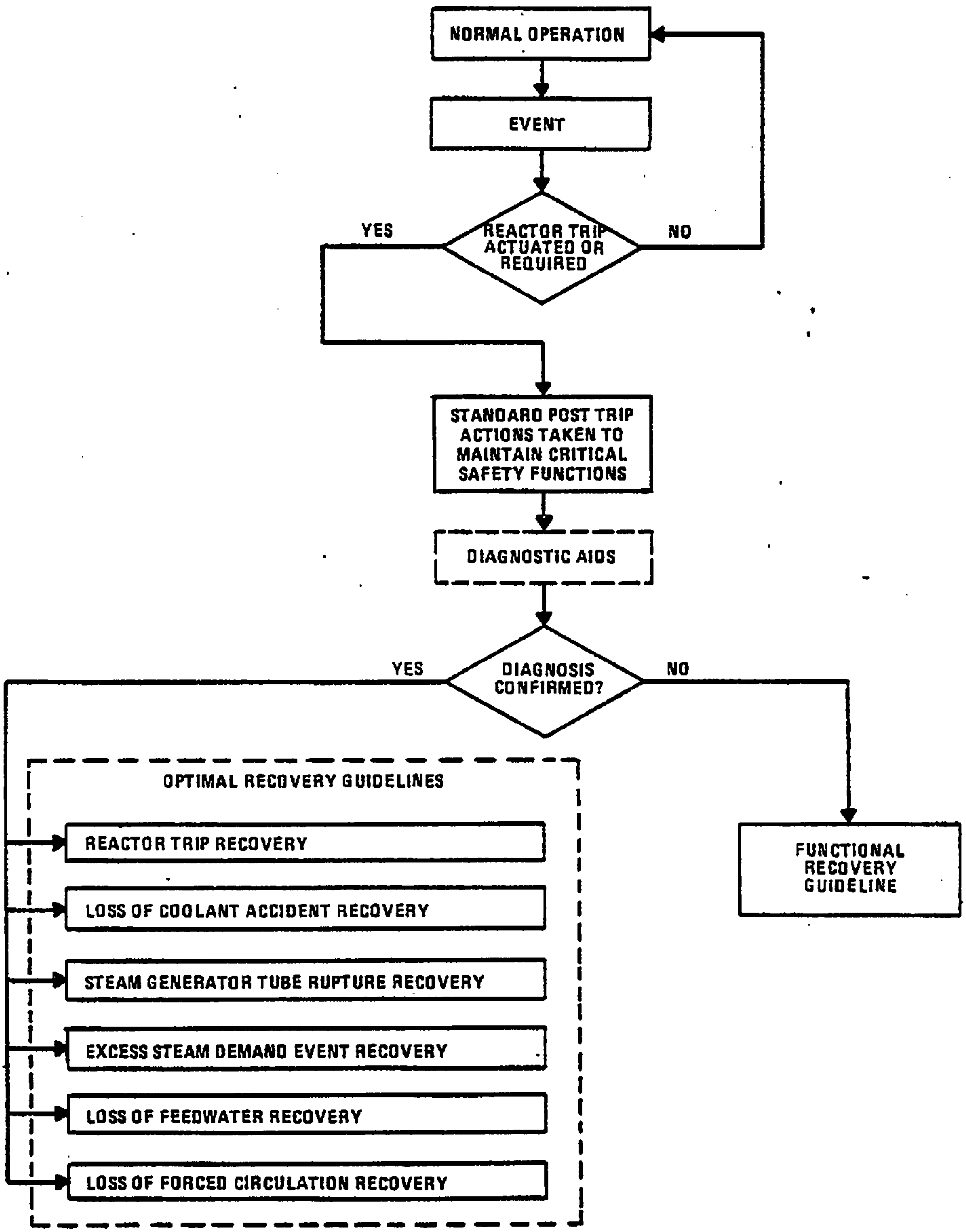
Emergency events can be divided into two kinds. For the first kind, the operators can ascertain the general type of the event by recognizing its correlated symptom set from control board indications and their knowledge of the plant and recent operating history. For these events where an accurate diagnosis can be made, it is highly desirable to provide mitigating guidance which is selected and sequenced to strategically address that symptom set. Since these types of events have been well analyzed and understood (e.g., LOCA, SGTR), it is possible to write the emergency procedure guidelines to optimize the recovery (i.e., minimize release of radiation, minimize system leakage, reduce risk of core damage, reduce post accident recovery time to full power, etc.). For ease of use, these events have been grouped into classes of events (e.g., large and small break LOCAs are covered by one guideline). In the second kind of emergency, the operators are unable to identify a recognizable symptom set for the disturbance. This may be due to errors in symptom assessment by the operators, multiple, simultaneous failures in the plant, the occurrence of an heretofore unanalyzed event or instrumentation failures which distort the symptom picture.

Emergency procedure guidelines must provide guidance for both kinds of emergencies. Thus, when a reactor trip occurs or should occur, the operators can refer to guidance which will provide a safe response whether or not a symptom set is identified. EPGs written to treat specific symptoms are called Optimal Recovery Guidelines. The EPG which provides guidance for undiagnosed events for which a reactor trip is required is called the Functional Recovery Guideline.

Figure 1-3 illustrates the system of EPGs. The Standard Post Trip Actions section is the entry for the EPGs. It is performed following all reactor trips (automatically or manually initiated). Its purpose is to evaluate the status of each safety function and provide immediate actions which can be quickly and easily performed to improve the status of functions in jeopardy. Following the Standard Post Trip Actions, diagnostic actions are performed to determine the symptom set corresponding to the type of event which is transpiring. Depending on the operators' ability to diagnose, they will then select either an Optimal Recovery Guideline or the Functional Recovery Guideline.

FIGURE 1-3

OVERVIEW OF THE EMERGENCY PROCEDURE GUIDELINE SYSTEM



The design of any system of EPGs must recognize that eventually in the course of an emergency it will become necessary for the operator to specify what resources are available. This is so because the operators must know what systems and equipment are available for use either in contirued operation or in taking the plant to cold conditions. A system of EPGs must also recognize the possibility of a misdiagnosis by the operators and make provisions for detecting and recovering from such misdiagnoses. If the operators have selected the FRG because they cannot diagnose, the FRG provides action steps to bring the plant to a safe, stable condition followed by a diagnosis section which permits the operator to systematically determine what has happened, what resources are available and which optimal recovery guideline (if any) is best suited to managing the emergency. At this point, transfer to an optimal recovery guideline (ORG) is recommended. Naturally, the operators would start at the beginning of any ORG implemented to ensure all the relevant actions have been or are taken.

Each ORG contains a section which requires the operator to confirm the diagnosis and continually review the status of safety functions by use of the safety function status check. If the diagnosis is not confirmed or if the safety function criteria are not met, the operators then implement the FRG. Thus, if the symptoms are not responding to treatment as anticipated or if the core is not being adequately cooled, the ORG is exited and the Functional Recovery Guideline is implemented.

Natural phenomena and other disasters are implicitly addressed in this system since all the possible consequences of such a phenomenon (e.g. break in RCS pressure boundary, loss of vital auxiliaries) which affect the NSSS are addressed explicitly. Even if such a phenomenon results in multiple, major consequences, the FRG would provide systematic guidance for managing such a casualty. Therefore, since it is not possible to predict in advance what the consequences to the NSSS would be of a tornado or an aircraft crash, and since all possible consequences are covered by the EPGs, these phenomena need not be explicitly addressed. Plant specific procedures exist for managing non-NSSS systems and equipment in the event of certain natural phenomena or man-made disasters.

The CEN-152 guidelines are designed as the basis for emergency operating procedures which provide guidance for operating the NSSS to mitigate emergency events. Where possible and necessary, guidance is provided for operating equipment which is closely associated with but not part of the NSSS (e.g., the turbine generator). This delimiting of scope is in recognition of the network of procedures existing at each plant which deals with non-NSSS systems and equipment (i.e. balance of plant). The guidelines are generally written in a narrative format and do not go into greater detail than system level information. This preserves their generic nature and permits each utility to write emergency operating procedures from the EPGs in a format which is most useful to them.

Guidance for the management of degraded core conditions is not included in these guidelines because there is an insufficient analytical base for this guidance. This issue is the subject of an ongoing industry effort and the results of that effort will be included at the discretion of the CEOG.

1.5.2 *Safety Functions*

1.5.2.1 *The Concept of Safety Functions*

The concept of safety functions introduces a systematic approach to plant operations based on a hierarchy of protective actions. The protective actions are directed at mitigating the consequences of an event and, once fulfilled, ensure proper control of the event which is occurring. A safety function is defined as a condition or action that prevents core damage or minimizes radiation release to the public. A complete set of safety functions needs to be fulfilled to ensure proper operator control of the event and public safety. The actions which ensure fulfillment of a safety function may result from automatic or manual actuations of systems, from passive system performance, from natural feedback inherent in the plant design, or when the operator follows guidance established in an event recovery guideline. To accomplish safety functions, the operator does not have to know what event has occurred. He/she does need to know what safety functions need to be accomplished, how to accomplish the safety functions and what criteria show the safety function is being accomplished.

To ensure proper control of the plant at anytime during operation, there are ten safety functions which must be fulfilled. All are directed at mitigating an event and containing and/or controlling radioactivity releases. These safety functions can be grouped into four major classes as follows:

1. anti-core melt safety functions
2. containment integrity safety functions
3. indirect radioactive release safety function
4. maintenance of vital auxiliaries needed to support the other safety functions

The anti-core melt safety function class contains five safety functions:

1. reactivity control
2. RCS inventory control
3. RCS pressure control
4. core heat removal
5. reactor coolant system heat removal

The purpose of the first anti-core melt safety function, reactivity control, is to shut the reactor down and keep it shut down, thereby reducing the amount of heat generated in the core. The purpose of reactor coolant system (RCS) pressure and inventory control is to keep the core covered with an effective coolant medium. RCS pressure and inventory control are interdependent in a PWR design. That is, actions taken to effect inventory control will affect pressure control and vice versa. The purpose of the fourth anti-core melt safety function, core heat removal, is to remove the decay heat generated in the core and transfer it to a location where it can be removed from the RCS. The final anti-core melt safety function is RCS heat removal. The purpose of this safety function is to transfer heat from the primary system coolant to another heat sink.

The containment integrity safety function class contains three safety functions:

1. containment isolation
2. containment temperature and pressure control
3. containment combustible gas control

The primary objective of these safety functions is to prevent major radioactive release from the containment by maintaining the integrity of the containment structure. Accomplishing the first safety function, containment isolation, assists in maintaining containment integrity by ensuring that all normal containment penetrations not required for accident mitigation are closed off when necessary. The purpose of the containment temperature and pressure control safety function is to prevent overstressing the containment structure and to prevent damage to other equipment in the containment resulting from a hostile environment. The purpose of the combustible gas control is to prevent containment overstress caused by explosion of hydrogen gas inside containment.

The third safety function class has one safety function associated with it: indirect radioactive release. The purpose of indirect radioactive release control is to prevent radioactive releases to the environment (gaseous, solid, and liquid, including radioactive coolant) from sources outside containment. These sources include the spent fuel pool and the radioactive waste handling and storage facilities. The systems used to control releases from these sources include the radiation monitoring system, the spent fuel pool cooling system, and the waste management and processing systems. In mitigating the types of emergencies for which CEN-152 provides guidance, the indirect radioactive release safety function does not come into play. Consequently, operator actions necessary for control of the indirect radioactive release safety function are not found in CEN-152.

The fourth safety function class likewise includes only one safety function: maintenance of vital auxiliaries. The systems used to accomplish the eight other safety functions addressed in CEN-152 are all supported by the maintenance of vital auxiliaries safety function. In general, support systems provide service such as instrument air needed for opening and closing valves, electric power for valve operation, pump motors, and operating instruments,

and an ultimate heat sink to which RCS and core heat can be transferred. Of greatest impact to the operator actions associated with CEN-152 is vital AC and DC power. AC and DC power must be maintained in order to successfully accomplish the other safety functions in a straightforward manner.

1.5.2.2 *Safety Function Hierarchy*

The safety function concept incorporates a principle of safety function hierarchy. Some safety functions have precedence over others as far as their sequence of implementation during an event. Figure 1-4 summarizes the hierarchy of safety functions as standardized in the CEN-152 guidance.

Reactivity control is the most important since it responds most quickly to changes in plant conditions. Similarly, RCS inventory control must be satisfied before core heat removal can be effected (i.e., there must be a medium to remove heat) and, in general, loss of inventory can occur within a shorter time frame than that required for core heat removal. This hierarchy concept is important in the design of systems used to fulfill each function and has also been employed in developing emergency guidance.

All the guidelines identify, for the particular plant state, each of the 9 safety functions (in the hierarchy of Figure 1-4) and criteria which reflects accomplishment of each of the safety functions.. The safety functions are provided as a complete set so the operator can monitor the plant to verify that the ultimate goal, the health and safety of the public, is provided. * Application of the concept of safety functions in a restructured format is acceptable as long as: (1) the representation contains actions and criteria necessary to control and fulfill the nine (9) individual safety functions; (2) it is consistent with the safety function hierarchy of CEN-152; and (3) the ultimate goal of preserving the health and safety of the public is ensured. Figure 1-5 shows various arrangements of the safety functions, with each level representing another way in which the ultimate goal is supported. Further evaluation of each level reveals that the safety function set which comprises the particular level is a representation of all the actions necessary to provide for public health and safety during an emergency event. In other words, a subset consisting of a rearrangement or combination of safety

FIGURE 1-4

SAFETY FUNCTION HIERARCHY

REACTIVITY CONTROL

MAINTENANCE OF VITAL AUXILIARIES (AC AND DC POWER)

RCS INVENTORY CONTROL

RCS PRESSURE CONTROL

CORE HEAT REMOVAL

RCS HEAT REMOVAL

CONTAINMENT ISOLATION

CONTAINMENT TEMPERATURE AND PRESSURE CONTROL

COMBUSTIBLE GAS CONTROL

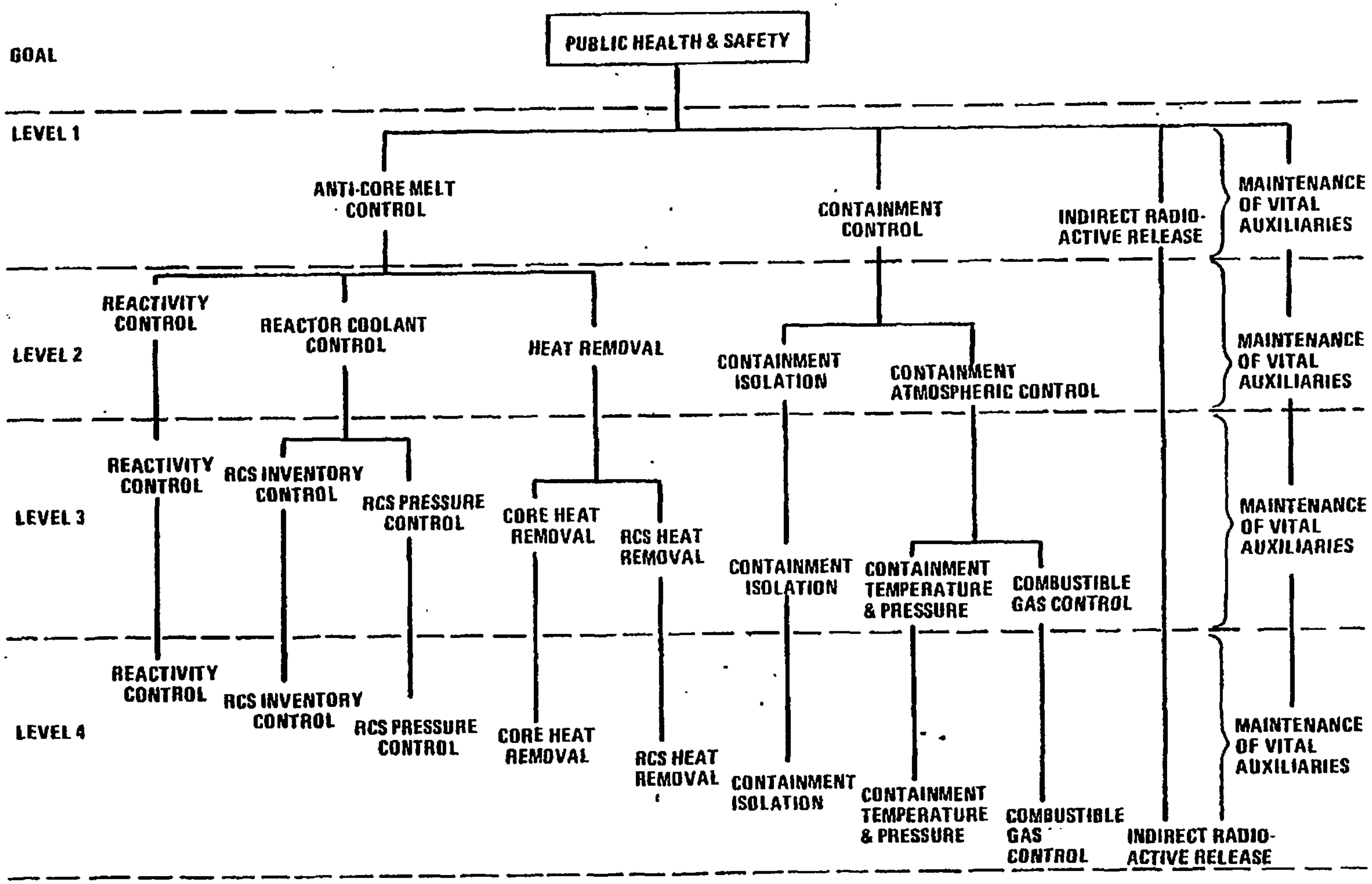
functions can achieve the same goal as the set which contains each safety function individually. This is especially true if the subset or rearrangement is enhanced by use of a particular control room operator aid, such as the CFMS, SPDS, etc.

Because safety functions are a complete set of actions or conditions which will provide public safety, they form the foundation of all emergency guidance. In the Optimal Recovery Guidelines (ORGs), specific events such as LOCA or Excess Steam Demand Event (ESDE) are addressed. Because each event affects diverse parts of the plant, proper mitigation of different events will emphasize different safety functions. For example, in a major LOCA, RCS pressure and inventory control are the two safety functions of immediate concern. Therefore, the operator actions are sequenced to achieve control of these two functions first using equipment designed for that purpose. Nonetheless, since all safety functions must be fulfilled to provide public safety, each ORG addresses all the safety functions. In preparing emergency procedure guidelines, the nine safety functions are used to audit the guidance to ensure that sufficient action steps to cover all relevant safety functions exist. Each ORG also includes a safety function status check chart which is used by the operator to continually determine whether the safety functions are being adequately fulfilled during the course of the event.

The Functional Recovery Guideline (FRG) is used by the operator when a diagnosis is not possible, when the Optimal Recovery Guideline is not adequate (as judged by the safety function status check in each ORG) or when the guideline in use is inappropriate. The FRG's structure includes an expanded version of the safety function status check which is used by the operator to continually check the status of each safety function. For those functions which are found to be in jeopardy, possible success paths are provided along with directions for implementing each and criteria by which successful safety functions restoration is judged. For this guideline the safety functions actually form the main structure of the guideline.

FIGURE 1-5

SAFETY FUNCTION CLASSIFICATIONS



1.5.2.3 *Success Paths*

Nuclear power plants are designed such that each safety function has multiple means of fulfillment. In other words, there exists for each function more than one system or way to fulfill a safety function. Each is called a success path. For example, reactivity control can be achieved by inserting control rods or by increasing RCS boron concentration. With respect to the latter, there are several methods of increasing RCS boron concentration. It is important that the operator be aware of the various success paths associated with each safety function.

During any emergency event, the operator needs information on plant state. This monitoring of plant state leads to identification of the safety functions in jeopardy and to identification of systems available to accomplish the safety functions. The CEN-152 emergency guidance clearly indicates the alternate ways of performing each function by providing success path oriented guidance.

1.6 PRINCIPLES OF EPG DEVELOPMENT

In the course of the development of the guidelines, certain principles were developed and adhered to, to ensure that the final products conformed to generally acknowledged rules for operational guidance, and to ensure that the rationale for the overall EPG system was preserved throughout. The following three sections describe and explain these principles.

1.6.1 *Principles of Standard Post Trip Actions*

The purpose of the Standard Post Trip Actions is to provide the entry point for all EPGs. That is, an emergency is defined as any off-normal event which actuates or requires a reactor trip (RT) to properly mitigate the event. This definition is consistent with the NUREG 0899 definition and with industry operating practice. Therefore, this emergency procedure guideline contains as its first operator action a check of safety functions against acceptance criteria, followed by standard actions and alternative actions which can be taken easily and quickly to restore those functions in jeopardy. The Standard Post Trip Actions actually serve three purposes:

1) All relevant safety functions are checked against acceptance criteria to give the operator a complete status as regards plant safety. The criteria are chosen to be easily accessible from the control boards and to require no interpretation or interpolation by the operator.

2) The check of safety functions provides the operator with objective decision criteria as to whether action is required in the short term to restore plant safety. This permits crisp, reliable decision making and precludes unnecessary operator action.

3) As further explained below, the status check discriminates between an uncomplicated reactor trip (e.g., one caused by technician error) and other more complex events. The safety function criteria are chosen to be consistent with the plant conditions which would prevail only in the short term after a simple and uncomplicated

reactor trip. Thus, if there are other failures which require attention, the criteria in the status check will not be satisfied, signaling that more than a simple RT has occurred.

The Standard Post Trip Actions are presented in a format chosen for ease of presentation and understanding. The relationship of function to criteria to actions is immediately apparent. The safety function assessment and accompanying immediate actions are prioritized according to two factors. The first factor is the importance to safety in terms of the consequences of not fulfilling that function and in terms of the time associated with that function. Thus, reactivity control is of first priority since shutting down the reactor is foremost in importance to safety and reactivity responds very quickly. The second factor in prioritizing relates to the natural order of steps in the control room. Since turbine trip and reactor trip are generally interlocked and since a turbine trip quickly results in automatic rearrangement of the electrical distribution system, and also since electrical power is a prerequisite to almost all other actions, it is important to check the status of electric power early in the sequence of actions. This has been confirmed in workshops, simulator experiments, and operator interviews.

It should be stressed that the Standard Post Trip Actions (SPTAs) EPG contains the only immediate actions in the entire system of EPGs. The purposes for this are to acknowledge the standard post trip actions which are performed by operators following any reactor trip, and to standardize a safety function approach to any event which causes a reactor trip. The latter is most important since the entire EPG system is designed to institute a functional approach to casualty management. The SPTAs clearly reflect this intent.

Additional principles which were adhered to during the development of the SPTA EPG are as follows:

1. The statements should be clear and concise to facilitate memorization by the operator.

2. The statements should be prioritized.

3. Multiple action statements should be avoided.

4. Conditional action statements should be clearly identified with the contingencies spelled out.

5. Cross referencing to other guidelines should be avoided.

The level of detail in the Standard Post Trip Actions guideline is consistent with the other EPGs and with the intent of providing generic guidelines. The level of technical information extends to the system level only. Action statements are sufficiently detailed to indicate the system(s) to be used, including any important supporting systems but do not provide detailed, step by step guidance for starting or stopping systems or components.

1.6.2 *Principles of Optimal Recovery Guidelines*

1.6.2.1 *Optimal Recovery Guideline Structure*

Optimal Recovery Guidelines (ORG) are those guidelines written to address specific symptom sets. In order to minimize the number of guidelines, and thereby avoid operator confusion, those events which are difficult to distinguish from each other in the short term (e.g., inadvertently opened atmospheric steam dump valve and steam line break) or which have similar effects on the NSSS over time are grouped into classes of events. The classes of events considered are:

1) Reactor Trip (RT)
2) Loss of Coolant Accident (LOCA)
3) Steam Generator Tube Rupture (SGTR)
4) Excess Steam Demand Event (ESDE)
5) Loss of Feedwater (LOF)
6) Loss of Forced Circulation (LOFC)

Each ORG consists of the following sections:

a) Purpose
b) Entry Conditions
c) Operator Actions
d) Supplementary Information
e) Safety Function Status Check
f) Bases

PURPOSE

The purpose section provides a brief statement of the condition(s) for which the subject guideline is intended to be used.

ENTRY CONDITIONS

Entry conditions are chosen to reflect those conditions which are most likely to exist following the trip and which reflect the trends which may exist for some time into the event.

The entry conditions section contains parameters and indications which an operator is expected to utilize in identifying and confirming the event. These conditions were written with the following points in mind:

1. Priority should be given to conditions which appear first during the initial phases of an event or which are most important with respect to associated consequences.

2. Indications listed should be readily available to the operator. For example, pressurizer level is used instead of RCS inventory since pressurizer level can be read directly and RCS inventory must be derived.

3. If several indications are available for the same symptom, the best indication should be selected and used.

OPERATOR ACTIONS

The operator actions provide the operator with event specific guidance starting at the point at which the Standard Post Trip Actions leave off. Operator actions also tend to contain more explanation and cover a greater range of possible failures and alternative actions. Thus, operator actions for a particular event diverge from those for other events. The purpose of the operator actions is to provide steps which would place the plant in a stable condition, permit problems to be corrected, and allow recovery operations to commence. Depending on the event, the final plant condition could be hot standby, hot shutdown, or cold shutdown.

In appropriate places, the primary success path plus any alternative success paths for accomplishing the intended function are included in the operator action steps. Where more than one success path is provided, the order of preference is indicated.

The operator actions section consists of those actions required to place the plant in a configuration from which either recovery can be accomplished or a long-term shutdown can be achieved. This section was written with the following points in mind:

1. The statements should be clear and concise to avoid confusion.
2. The statements should be prioritized.
3. Multiple action statements should be avoided.
4. Conditional action statements should be clearly identified with contingency actions specified.
5. If more than one equally acceptable action sequence exists, the simpler one is preferred.
6. Cross referencing to other procedures should be avoided.
7. Action statements are provided in a narrative form to permit the utility to implement in plant specific procedures the most useful format.
8. Action statement content should be limited to system level information. This is consistent with the intent of providing generic guidance and is sufficient to ensure accurate implementation in plant specific procedures.

9. The completion of operator actions must result in a plant condition which allows recovery operations to commence (return to operation, repair, clean-up, etc.).
10. Alternative success path actions should be provided.

Generous use of charts and diagrams is made for the EPGs. Charts and diagrams quickly and accurately deliver a large amount of technical information without the need to read long explanatory narratives. Charts and diagrams in their plant specific form are intended to be implemented in plant specific procedures as appropriate.

Charts and diagrams were developed with the following points in mind:

1. Each figure or table or chart will have a title.
2. Axes on graphs should be clearly labeled.
3. Explanatory notes on graphs and figures should be kept to a minimum.
4. In general, a left to right, top to bottom flow is followed.
5. Figures and graphs should be uncluttered and legible.
6. The purpose or intention of the graph or figure should be immediately apparent to trained personnel.
7. Units of measurements should be clear.

SAFETY FUNCTION STATUS CHECK

Each Optimal Recovery Guideline (ORG) has its own safety function status check (SFSC) which must be used whenever an ORG is in use. The purpose of the SFSC is to continually verify the adequacy of safety functions. This is accomplished by comparing control board indications to safety function acceptance criteria tailored for each class of event. By satisfying the SFSC acceptance criteria, the operating staff is assured that the actions being taken are maintaining the plant in a safe condition. On the other hand, if SFSC criteria are not satisfied, the operators are promptly alerted to the situation. In this case the operators will take corrective actions to satisfy the safety functions, implement another ORG, or exit to the Functional Recovery Guideline. The SFSC is designed to be used by the Shift Supervisor, Shift Technical Advisor, or other person available to provide an independent assessment of the status of safety functions.

BASES

Each guideline contains a bases section. The bases section is a dialogue between the guideline preparer and the procedure writer. It is not intended that the bases appear in the detailed, plant specific EOP but rather that it be used in preparing EOPs and in operator training. The guideline preparer can draw upon a large amount of information on the event including plant data, licensing analysis, realistic transient analysis, incident reports, sequence of events diagrams, and operating experience. The bases presents a condensed form of this information for the procedure writer and the operators. There is sufficient detail in the explanations without burdening the operators with specific analytical data.

The bases section provides technical information that increases the operators' ability to identify the event, understand the plant response to an event, and understand the corrective actions he or she is expected to take. The following points are addressed in the bases section:

1. A brief overview of the event is presented.

2. The general characteristics and possible causes of the event are discussed.

3. The potential effect of the event on the reactor, plant equipment, and the environment is noted.

4. The bases section includes a detailed discussion of the range and trend of plant responses to an event or class of events. The following list contains examples of the significant plant parameters that are considered:

   Reactor Power
   RCS Temperature
   Pressurizer Pressure
   Pressurizer Level

Steam Generator Level
Steam Generator Pressure
Reactor Vessel Inventory

5. Trending of key parameters that can be used to classify the event and determine its severity is explained. These are parameters (such as those listed in 4 above) which operators frequently evaluate during an event.

6. The bases section describes the objective of the recovery actions (automatic and manual) taken in response to the event, and why these actions are taken (e.g. which safety function is being dealt with). To this end the bases section corresponds step by step to the guideline steps.

7. The immediate and long range goals of the actions (i.e., strategy) of each guideline are explained. Each bases section contains a set of strategy charts which pictorialize the sequence of guideline goals for that event and which identify the steps that correspond to the strategy goals.

8. Preferred and alternate success paths to accomplish essential functions are included.

9. The basis for the safety function status check (including the criteria chosen for each function) is explained.

1.6.2.2 *Use of ORGs*

ORGs are used to treat specific symptom sets which have occurred following a reactor trip and which are identifiable or diagnosable by the operators. Each ORG is designed to accommodate minor concurrent failures which do not present major complications (e.g., failure of the automatic pressurizer level control system). The Standard Post Trip Actions are performed before an ORG is reached. If a specific symptom set can be identified, the operators will then

select the appropriate ORG and implement the recovery actions. The goal of the recovery actions is to place the plant in a safe, stable condition either in a position to return to power operations or to cool the plant down in order that repairs can be made.

The emphasis in the Optimal Recovery Guideline section is on treatment of a set of symptoms according to an optimal strategy, as contrasted to treatment of a specific event. One of the first recovery actions will be to assess the safety functions against specific criteria using the safety function status check. This serves a dual purpose. First, it is a check to verify that all relevant safety functions are being fulfilled as anticipated in best estimate analysis and by engineering judgement. Second, it provides a check on diagnostic accuracy. This essential feature provides a correction process. If the treatment in use is adequately treating the symptoms, then the treatment is continued. If the treatment is inadequate, either because new information (symptoms) appears that is not covered in the guideline, or because the observed symptoms are not properly responding, each ORG has a step which requires the operators to exit the ORG and implement the FRG. The checking process using the safety function status check continues as long as the guideline is in use. This is the way the EPG system manages multiple, significant failures, or misdiagnosed or undiagnosable symptom sets. The FRG is designed to provide guidance for managing any event which results in or requires a reactor trip.

Operator actions are selected and sequenced to address all relevant safety functions in their order of importance to treating that symptom picture. Where appropriate, alternate success path actions are included for use when primary success paths have been unsuccessful. Each ORG has two types of strategy charts included in the bases section which pictorially depict the intended strategy for managing the event. One chart indicates the fundamental strategy being applied for event recovery and the second is a more detailed chart which correlates the guideline steps to each strategy element.

1.6.3 *Principles of the Functional Recovery Guideline*

1.6.3.1 *Functional Recovery Guideline Structure*

The functional recovery guideline (FRG) is the EPG used to combat off-normal symptom pictures which result in a reactor trip and which cannot be quickly or easily diagnosed by the operators. It may also be used to mitigate symptoms for which the operators have initially selected an ORG but subsequently discovered that they had misdiagnosed or that the ORG was not adequately treating symptoms as anticipated.

The FRG consists of the following sections:

a) Safety Function Status Check
b) Resource Assessment Trees
c) Operator Action Guidelines
d) Long Term Actions
e) Bases

SAFETY FUNCTION STATUS CHECK

The safety function status check is the entry point for the FRG. It is used to assess the status of each safety function. The safety function status check is structured to facilitate the selection of appropriate operator actions which will restore those functions in jeopardy. Since safety functions are a complete set of the actions or conditions which will provide for plant and public safety, an EPG which maintains or achieves all of the functions is an effective vehicle for preserving plant safety. Therefore, the FRG is oriented to detecting out of specification safety functions and providing multiple recovery actions to restore those functions.

The safety function status check lists the safety functions which must be checked in an emergency. This list differs slightly from that in section 1.5.2. RCS heat removal and core heat removal are combined in this assessment chart because the success paths used to achieve these two functions are the

same. Also, since the criteria and resource tree actions associated with each of these success paths are identical for both function, it makes sense to combine the functions to eliminate the redundancy of listing each separately.

RCS inventory control and RCS pressure control reflect the two possible trends of the parameters and the different success paths and acceptance criteria associated with each (high and low conditions).

The safety function status check lists the success paths associated with each function. These are the success paths common to C-E plants which can be identified at the generic EPG level. Listing the success paths permits the operator to select the safety function criteria appropriate to the success path in use. For any given function, the appropriate criteria to use are those associated with the lowest success path on the list which is in use. After having performed the Standard Post Trip Actions and having attempted to diagnose the plant condition, the operator will be generally aware of what equipment is running and, therefore, which success paths are in use. If not, the chart will assist in surveying the plant status. For completeness, all success paths are listed for each function. This feature requires that there be some redundancy between the Standard Post Trip Actions and the functional guideline. Nevertheless, the Functional Recovery Guideline must provide all the resources available to the operator in order to give the operator the widest latitude. Furthermore, because some of the success paths and their methods of use may be plant specific, a somewhat redundant listing will permit utilities to arrange this information in a fashion most suitable to them in their plant specific emergency operating procedures. Success paths are shown on each resource assessment tree in left to right orientation with those paths on the left corresponding to plant conditions which would result from an uncomplicated reactor trip. Moving to the right the paths correspond to progressively more degraded plant conditions. The path having the highest priority for implementation are those which correspond to the current plant conditions (e.g., the safety injection system (SIS) success path on inventory control is used to manage inventory in a LOCA).

Also contained in the safety function status check are the acceptance criteria for each function. The acceptance criteria are organized such that each success path has its respective criteria next to it. The criteria are selected to define minimum acceptable system conditions, for that success path. Thus, the combination of the acceptance criteria for all the safety functions of those success paths in use (i.e., the current plant lineup) defines an acceptable plant state.

Each safety function listed in the safety function status check also contains reference to its respective resource assessment tree. Resource assessment trees provide a pictorial representation of all the plant resources available (at a generic level) for satisfying that safety function. These trees are utilized if the corresponding safety function does not meet its success criteria.

The safety function status check in the FRG is not only the entry point for the FRG, it is also used to continually verify the adequacy of safety functions. This review is accomplished anytime the FRG is in use.

While each ORG has its own safety function status check which must be used whenever the ORG is in use, the FRG safety function status check could also be used by a shift supervisor, shift technical advisor or comparable person during any event as a backup means of verifying the adequacy of safety functions.

RESOURCE ASSESSMENT TREES

Resource assessment trees are pictorial representations of the generic resources available to fulfill each safety function. The trees are intended to assist the operator in evaluating plant resources available to fulfill jeopardized safety functions. A pictorial representation was chosen for the EPG resource trees because of its simplicity and clarity (and also for its compatibility with CRT display). It relies minimally on reading and verbal comprehension and serves as a quick method to jog the operator's memory regarding the systems and components used to fulfill each function. The detailed and overall knowledge of these systems and components and their proper operation is already available to the operator from training and experience.

Each limb of a tree starts at the top with the name of the function, then (working down) the name of the success path (mode), then the plant conditions and equipment used in that path (conditions, source, motive, power), then the success criteria for that path, and finally, the number of the recovery guideline associated with that path.

In constructing these trees, a number of principles were generally observed to obtain a uniform and useful tree:

1. Each success path identified on the tree had to be generic and be capable of independently satisfying that safety function. This is not to say that each path must be used independently of other paths or that it must be able to satisfy the function under all plant conditions. It merely must be able to satisfy the function independently under some plant conditions.

2. All the safety functions are assessed before any other actions are taken. If it is found that the primary or first success path is adequately maintaining control of each of the safety functions (in other words, the criteria are being met), then the operator may exit

the functional recovery guideline and implement the reactor trip recovery guideline. This is true because the criteria for those success paths bound the expected parameters for an uncomplicated trip.

3. The resource assessment trees provided are structured to show the intended priority (left to right) of implementation of success paths. Note that more than one success path may be employed for each safety function in order to satisfy the acceptance criteria of the last path (to the right) in use. Also note that the path with the highest priority is the path which corresponds to current plant conditions (e.g., the SIS is designed to manage inventory control problems resulting from a LOCA). Those associated with progressively more degraded plant conditions are arranged from left to right. The path which should be used is the one which corresponds to the current plant conditions and which can (either alone or in combination with other paths) maintain the function.

4. Two rules were used to order the components/conditions from top to bottom in each path. The first priority rule is to arrange components according to the usual flow path in the plant since this is most familiar and logical. The second rule was to attempt to place the most restrictive component, or RCS conditions or limits, towards the top of the limb. In this way, if the RCS or equipment did not meet this condition, it would spare the operator from reviewing the rest of the limb for availability.

5. The limbs are not intended to be detailed representations of plant systems. They are intended only to serve as an aid to the operator in determining the availability of resources. The limits shown inside each component are intended to provide only the most essential, minimum requirements for path availability. All limits can be read directly (without interpretation) from control board indications in the control room.

6. Based on engineering judgement, the minimum amount of information was included for each limb which would assure path availability. That is, if the minimum requirements expressed by the limits in the limb were met, then there is a reasonably high probability that the path will be available. It would be unlikely, therefore, that the operator would get to the recovery action guideline associated with the limb only to discover that the path was not available. In practice, by the time the operator begins to implement the functional guideline, he/she is largely aware of which systems and components are available.

7. The symbols for components use standard size and shape coding developed by C-E for use on CRT displays.

8. The success criteria that appear at the bottom of each limb are the same criteria which appear on the FRG safety function status chart. Therefore, if the criteria for any given limb are met, then the corresponding function is fulfilled.

When this success path information is implemented in plant specific emergency operating procedures, utilities will have the flexibility of changing this pictorial format to some other format. What is necessary is that each utility provide equivalent information in some usable format.

RECOVERY GUIDELINES

Each limb in each resource assessment tree has a corresponding recovery guideline which provides guidance on the implementation of that success path. Because different success paths may utilize the same equipment, more than one success path may reference the same guideline. The guidelines are numbered according to the function they serve. For example, HR-2 is the second recovery guideline associated with heat removal.

Each recovery guideline has the following structure:

1. Name and number of the guideline
2. The recovery action steps for that path
3. The success criteria for that path
4. Supplementary information for use of that path

It is important in using the FRG that the success path recovery guidelines be used since the supplementary information associated with each path provide the restrictions associated with that path. That is, the supplementary information alerts the operator to possible misuse of a path or to a condition which may lead to a defeat of that path. This supplementary information is not contained elsewhere in the FRG.

LONG TERM ACTIONS

The long term actions section of the FRG is designed to ensure that the operator continues to periodically verify the adequate maintenance of safety functions, assesses the status of the plant, implements the appropriate ORG if conditions warrant, and determines the necessity, feasibility, and/or urgency to perform a cooldown to cold shutdown conditions.

BASES

The bases section for the FRG serves the same purpose as the bases section for optimal recovery guidelines (ORG) discussed in section 1.6.2 and follows similar format and content ground rules. The bases describe in detail the rationale for each step or portion of the FRG.

1.6.3.2 Use of the Functional Recovery Guideline (FRG)

The following gives a brief description of the intended use of the FRG once it is implemented in a plant specific procedure.

The Standard Post Trip Actions (SPTA) would always be completed prior to entry into the FRG. The FRG may be entered directly after completion of the SPTAs if a diagnosis is not possible. The FRG might also be entered from an ORG if an ORG had been initially selected by the operator but was subsequently found to be inadequate. The safety function status check in each ORG is used to judge this adequacy. If the safety function criteria are not satisfied at any time, then the operator is directed to use the FRG.

The entry point for the FRG is the safety function status check. The operator reviews the status of all safety functions first by checking control board indications against the acceptance criteria for the success paths in use. For each safety function, the acceptance criteria for the highest numbered success path in use are the appropriate criteria to use. For example, if RCS inventory control is the safety function in question and success paths IC-1 (CVCS) and IC-2 (SIS) are both currently in use, the acceptance criteria for success path IC-2 must be satisfied. This would continue to be true until the SIS was secured and the CVCS was the sole success path in use. The operator notes which safety functions do not meet their appropriate acceptance criteria. These safety functions are in jeopardy. Note that the acceptance criteria for the first success path for each safety function generally correspond to the symptoms of an uncomplicated reactor trip.

Then, beginning with the first safety function which is in jeopardy, the operator reviews the resource assessment tree to ascertain the availability of resources. Working from left to right on the tree the operator reviews each path to determine its availability and whether or not it is already operating. If it is operating, the operator checks the acceptance criteria to see if the safety function is now being satisfied. If the safety function is satisfied, the operator goes on to the next safety function in jeopardy. If the success path was not operating but is available (as indicated by meeting the component or condition limits noted on each path), the operator implements the recovery guideline referenced for that path. If the acceptance criteria associated with that path are now satisfied, the operator goes on to the next safety function in jeopardy. If the acceptance criteria are not satisfied, the operator goes to the next success path to the right on the tree and continues

implementing paths until the safety function is satisfied. Note that it is possible and desirable in many cases, to use more than one success path at a time. Even if more than one path is in use, the acceptance criteria by which the fulfillment of the safety function is judged are those for the highest numbered path in use.

If all the success paths on a resource assessment tree have been implemented and none of their respective acceptance criteria are met, then each resource tree has a caution which requires the operator to refer to the "Continuing Actions" section. The operator is required to continue to work on this safety function and to pursue other jeopardized safety functions simultaneously.

Once all safety functions have been satisfied, the operator goes to the Long Term Actions to attempt to evaluate plant status, determine a diagnosis and decide on future actions.

Concurrently with taking steps to restore jeopardized safety functions and after all safety functions are satisfied, the control room team is using the FRG safety function status check to continually review the status of safety functions. As the event progresses and/or as new success paths are available, the operator may have to shift to the new acceptance criteria which correspond to these paths. This periodic review may reveal that some safety function is in jeopardy and requires further operator action.

1.7 RECENT TECHNICAL DEVELOPMENTS INCLUDED IN EPGs

Several technical issues have arisen during the course of the development of the EPGs which have affected the content of the EPGs. These merit a brief discussion to describe the technical issue and to clarify their impact on and to demonstrate their inclusion in the EPGs. The issues discussed are:

- 1.7.1. Pressurized Thermal Shock
- 1.7.2. Inadequate Core Cooling
- 1.7.3. RCS Voiding
- 1.7.4. Reactor Coolant Pump Termination and Restart Criteria
- 1.7.5. Reactor Vessel Level Monitoring

1.7.1 Pressurized Thermal Shock

NRC NUREG-0737 Item II.K.2.13 requires utilities to analyze the "thermal mechanical conditions in the reactor vessel during the recovery from small breaks with an extended loss of feedwater". The NRC concern deals with the potential for thermal shock of the reactor vessel resulting from cold safety injection flow and possible non-ductile failure of the reactor vessel upon repressurization.

Typically, a Pressurized Thermal Shock (PTS) transient is characterized by a rapid uncontrolled RCS cooldown and depressurization followed by a repressurization. The thermal shock transient combined with the RCS repressurization may cause thermal and pressure stresses which could result in crack initiation within the reactor vessel. The degree to which any reactor vessel would be affected by a PTS transient depends on the physical strength properties and neutron induced embrittlement of the vessel, pre-existing flaws in the vessel, and the severity of the transient.

Events other than the one identified in Item II.K.2.13 can result in a PTS concern. Excess steam demand events are of particular concern because of the severity of the cooldown phase. In general, a PTS situation may occur any time an overcooling transient is followed or accompanied by an RCS repressurization.

When a potential for a PTS transient exists, the operator goals are first, to control the overcooling transient where possible and second, to limit the repressurization of the RCS. Primary emphasis must ultimately be placed on prevention of excessive pressurization since the initial cooldown transient is not always controllable and the cooldown thermal stresses alone will not violate the pressure boundary.

To ensure that the guidelines adequately address PTS, a systematic evaluation of the guidelines with respect to PTS was conducted. The following paragraphs contain a summary of the results of this evaluation.

The potential for pressurized thermal shock of a reactor vessel is reduced if the coolant temperature and pressure are maintained within acceptable limits (Figure 1-6). The PTS concern arises in situations where a low temperature has occurred due to cooldown in excess of Technical Specification limits accompanied by a high pressure. A convenient way to define acceptable combinations of low temperature and high pressure is to define an upper limit on coolant subcooling. Since we are also concerned about minimum subcooling, the combination of upper and lower subcooling limits is used to define a band of pressure and temperature conditions within which the RCS should be maintained. The upper and lower subcooling limitations are illustrated in Figure 1-6 which is included in each guideline as an operator aid.

The lower limit on subcooling which is currently contained in the C-E Emergency Procedure Guidelines is nominally 20°F. The numerical value of this limit is based on engineering judgement. If 20°F subcooling cannot be maintained, the emergency procedure guidelines instruct that high pressure safety injection (HPSI) pumps must be operating until the coolant subcooling is nominally 20°F and there are indications of adequate inventory (along with other specified conditions).

Pressurized thermal shock considerations dictate that the high pressure safety injection pumps and charging pumps be turned off when the pressurizer water level reaches some specified high limit value in order to avoid filling the pressurizer solid and overpressurizing the reactor coolant system (i.e.,

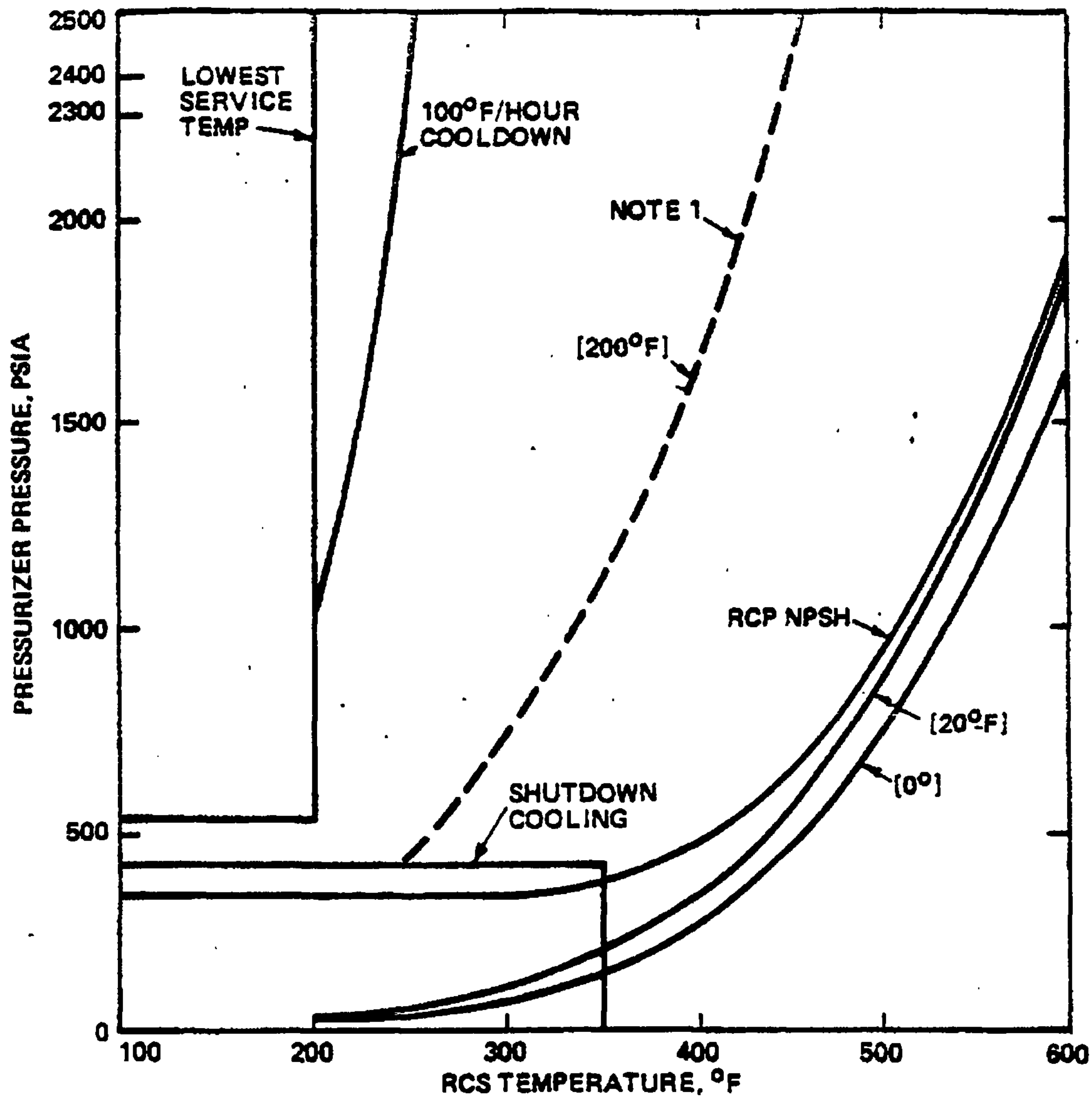
greater than 200°F subcooling). C-E judges that the instructions on maintenance of minimum subcooling for adequate core cooling should prevail over PTS considerations. Therefore, the guidance calls for continued running of the HPSI pumps until 20°F subcooling is achieved regardless of pressurizer level.

An upper cooling limit has been developed using engineering judgement based on existing plant thermal-hydraulic and fracture mechanics analyses. This upper limit of subcooling is nominally 200°F. When pressurized thermal shock is not a concern, a 100°F/hr cooldown curve provides the maximum pressure-temperature limit for the RCS. The guidelines caution the operator to monitor RCS temperature and pressure throughout all phases of the cooldown in order to avoid exceeding this cooldown rate. However, when pressurized thermal shock is a concern, a more limiting maximum RCS pressure-temperature limit is imposed. A 200°F subcooling curve supercedes the 100°F/hr curve anytime the RCS has experienced an uncontrolled cooldown which causes RCS temperature to go below 500°F. This limit is judged to provide a sufficient operating band for the operator while requiring the pressure stresses to be maintained at a safe level.

The upper limit was developed with the understanding that due to the inability of the operator to control the initial cooldown transient in all cases, it is conceivable that the limit may be violated during the first part of the transient. The operator's goal is to restore the plant to the acceptable band of pressure and temperature as soon as possible. This is accomplished by depressurizing, either by using pressurizer sprays or by terminating or throttling HPSI or charging. This approach is acceptable since thermal stresses resulting from the initial transient will not breach the reactor vessel. Therefore, the operator's efforts are directed at depressurizing or preventing repressurization.

Figure 1-6

TYPICAL POST ACCIDENT PRESSURE-TEMPERATURE LIMITS(2)



NOTES: (1) THIS CURVE SUPERSEDES THE 100°F/HOUR COOLDOWN CURVE ANYTIME THE RCS HAS EXPERIENCED AN UNCONTROLLED COOLDOWN WHICH CAUSES RCS TEMPERATURE TO GO BELOW 500°F

(2) THESE CURVES MUST BE ADJUSTED FOR INSTRUMENT INACCURACIES

(3) COLOR CODE

RED - PARAMETER IN EXCESS OF LIMITS

ORANGE - PARAMETER IN DANGER OF EXCEEDING LIMITS

YELLOW - PARAMETER OUTSIDE OF OPTIMAL RANGE, BUT STILL WITHIN LIMITS

GREEN - PARAMETER IN OPTIMAL RANGE OF VALUES

To accomplish the above, the following additional guidance has been provided to the operator. For each guideline, the operator is directed to maintain the RCS within acceptable RCS pressure and temperature limits. The acceptable pressure and temperature limits are provided in each guideline in the form of a figure shown here as Figure 1-6. The Excess Steam Demand Event guideline requires the operator to stabilize plant temperature and pressure following the uncontrollable cooldown. If the ESDE is unisolable, then the operator is directed to stop feed to the affected steam generator in order to terminate the cooldown.

In addition, each guideline has supplementary information which warns of the following conditions:

1. Solid water operation of the pressurizer may make it difficult to control RCS pressure and therefore should be avoided unless 20°F of subcooling cannot be maintained in the RCS.

2. If the initial cooldown rate exceeds Technical Specification limits, there may be a potential for Pressurized Thermal Shock (PTS) of the reactor vessel, unless Post Accident Pressure/Temperature Limits are maintained.

1.7.2 *Inadequate Core Cooling*

The subject of inadequate core cooling (ICC) has received much interest since TMI. During the TMI accident, there was a substantial period of time during which the reactor core was inadequately cooled, and the operators failed to take appropriate actions to correct the condition. It is generally considered that sufficient instrumentation indications were available to recognize the inadequate core cooling condition. However, operator training and plant emergency operating procedures did not prepare the operators to recognize inadequate core cooling and to respond properly.

A major goal in the development of these guidelines has been to provide guidance to maintain an adequately cooled core and to alert the operator if

the actions being performed are not effective. This goal has been achieved in a number of ways. These are highlighted below. Detailed explanations of each are found elsewhere in this document.

1. Explicit criteria for stopping safety systems (e.g., SIS) is included. For example, the termination criteria for the safety injection system ensures that RCS inventory, pressure and heat removal, [and reactor vessel level], meet specified conditions before the system may be turned off.

2. Each Optimal Recovery Guideline is built around a strategy which minimizes the likelihood of an inadequately cooled core.

3. Safety function status checks are provided to alert the operator if the actions being taken are ineffective or inappropriate, thus averting an ICC situation. A detailed explanation of safety function status checks is found in section 1.6.

4. A Functional Recovery Guideline (FRG) is provided for situations where the optimal recovery guidelines (i.e., LOCA, SGTR, etc.) are not effective. A detailed explanation of the FRG is found in section 1.6.3.

5. Studies have been performed to determine whether instrumentation is available to monitor the approach to, existence of, and recovery from ICC. In general, existing instrumentation, proven reliable under operating conditions (i.e., Subcooled Margin Monitor, Core Exit Thermocouples, Pressurizer Level), are adequate for this purpose. In combination with new Reactor Vessel Level Monitoring Systems (RVLMS), which provide corroborative indications of reactor vessel liquid inventory and liquid inventory trending, sufficient instrumentation is available to provide the operator with diverse means to directly observe core cooling conditions.

The guidance provided herein is designed to minimize the likelihood of an ICC condition. However, should such a condition develop sufficient information is provided to allow the operator to recognize and deal with it. This would likely be accomplished using the Functional Recovery Guideline and the resource assessment trees which help the operator identify systems available to mitigate adverse conditions for the various safety functions. This guidance also enables the operator to make the necessary assessments in an orderly manner, prioritizing the various success paths he/she could follow. However, guidance for the management of degraded core conditions is not included. There is an insufficient analytical base for this guidance. An industry effort is ongoing in this area and the results will be evaluated by the CEOG when available and included if appropriate.

1.7.3 *RCS Voiding*

NRC NUREG-0737 Item II.K.2.17 requires that each utility analyze the potential for voiding in the RCS. A response has been prepared by C-E in a generic program sponsored by the CEOG. Additional work is ongoing on this issue. A summary of this work's impact on the EPG system to date follows.

Voids in the RCS may be formed as a result of not maintaining pressure control and losing the minimum required subcooling margin. Those system conditions affecting void formation over which an operator may have control include the rate of RCS depressurization, the rate of cooling of the RCS fluid and the flow distribution in the RCS. Depressurization and cooling obviously relate to the state (amount of subcooling) of the RCS fluid. Loss of subcooling leads to saturated fluid which implies voids in the RCS. Flow distribution refers to the fact that the fluid state in all parts of the RCS may not be uniform if there is inadequate flow in some regions. Thus, a loop in which the steam generator is isolated when no reactor coolant pumps (RCP) are running may be at higher temperatures than the rest of the RCS if a cooldown is in progress. Similarly, the temperatures in the reactor vessel head region may be higher than the rest of the RCS since there is little exchange of fluid between the head region and the other parts of the RCS without RCPs running. The operator must be aware of this potential and monitor for indications of

reactor vessel voiding (e.g., very slow depressurization rate, subcooled margin monitor, pressurizer level, [RVLMS indication]). The voided area in the reactor vessel head may act as a pressurizer, thus creating difficulty in RCS pressure reduction and subsequent entry into shutdown cooling system (SCS) operation.

The potential for RCS voiding exists during normal operating transients, natural circulation cooldown transients, and accident transients. During normal operating transients, voids in the RCS are highly unlikely since the proper operation of the pressurizer pressure control system will maintain the subcooling margin for all normal transients.

A natural circulation cooldown may result in reactor vessel upper head or stagnant loop voiding. Maintaining subcooling with respect to hot leg temperature when RCPs are running will generally suffice to prevent any portion of the RCS from voiding. However, RCS voids may be formed while maintaining steam generator heat removal in natural circulation for the following cases:

1. Depressurization during natural circulation cooldown so that the stagnant reactor vessel upper head region reaches saturation.

2. An asymmetric natural circulation cooldown which results in stagnated flow in one steam generator loop (e.g., steam generator isolated due to tube rupture or ESDE).

3. A loss of reactor coolant system pressure control and, therefore, subcooling.

In addition to natural circulation cooldowns, accident transients which result in rapid depressurization (ESDE, SGTR, LOCA) to saturation conditions throughout the RCS may result in some voiding. For large LOCAs in which depressurization to very low pressures (less than 300 psia) occurs rapidly and pressure control is not regained, voiding of the RCS is not a concern as long as the core is kept covered by the SIS injection fluid. For small LOCAs (where steam generator cooling is important for heat removal) and SGTRs and ESDEs (where

the RCS is refilled by the SIS and charging), if RCPs are restarted, voids will be eliminated much more quickly than under natural circulation conditions. If natural circulation is the mode of cooling, then voids may form or grow as discussed under natural circulation above.

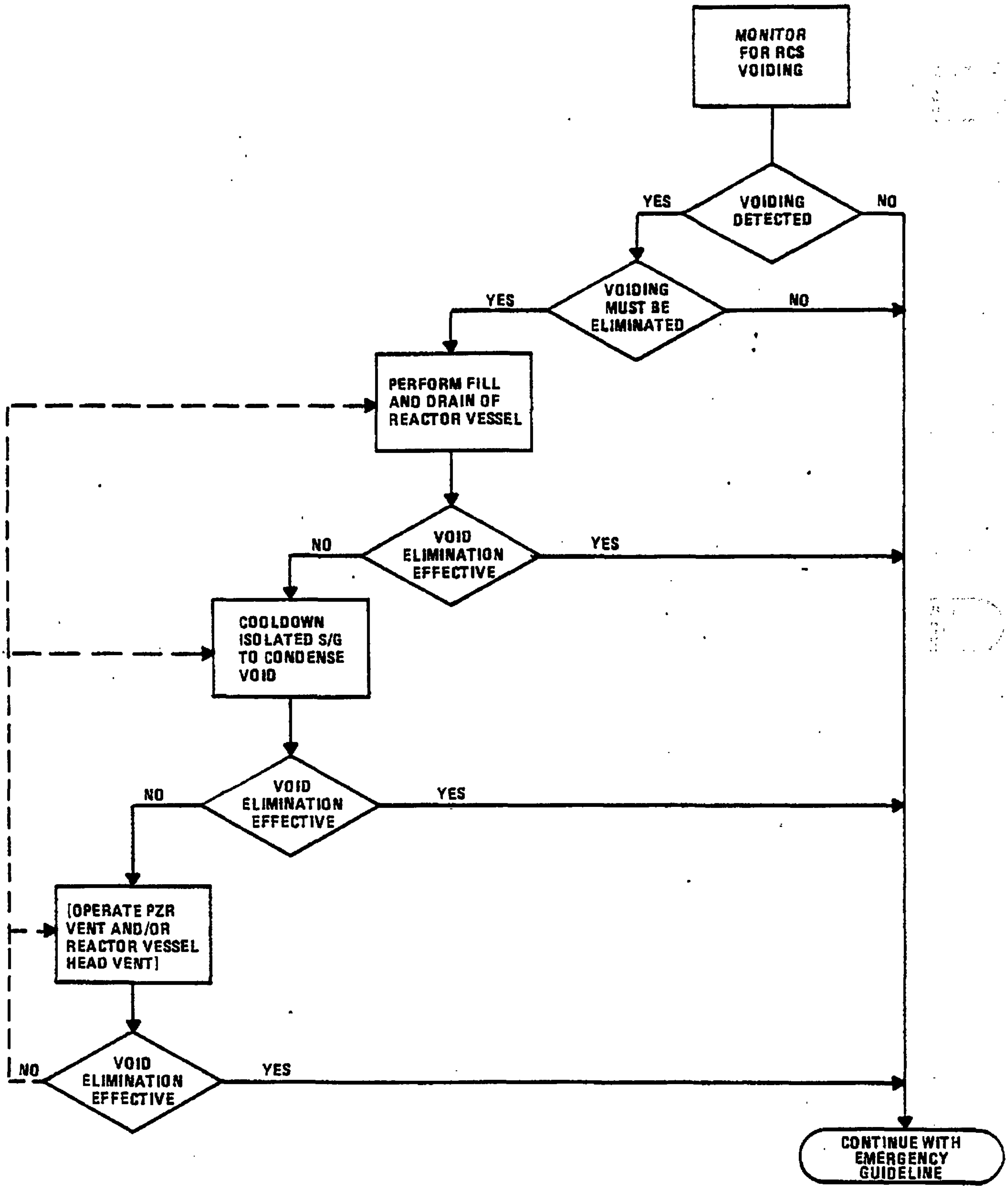
Voids in the RCS may also be formed of non-condensible gases. The largest potential source of gas would result from clad oxidation and fission product release which would occur following long-term core uncovery. Gas pockets might also result from the evolution of dissolved gases accompanying a depressurization of the RCS. This latter would be a relatively small amount of gas. Another source of gas which might be significant is the safety injection tanks (SITs). The cover gas (nitrogen) in the SITs might be released into the RCS if the operator failed to isolate the SITs as required in each EPG.

RCS voiding is most likely to present operational problems to the operator while attempting to depressurize for entry into SCS operation. The guidance for detection and management of voids appears in each section where entry into SCS operation is discussed. Voiding guidance has been incorporated into certain guidelines in the manner shown on Figure 1-7.

1.7.4 *Reactor Coolant Pump (RCP) Termination and Restart Criteria*

The requirement to terminate RCP operation has been the subject of considerable analytical work based on post-TMI concerns. The results of the CEOG sponsored analytical work, which served as a basis for the RCP trip strategy incorporated in Rev. 01, is recorded in CEN-114P, Amendment 1-P, "Review of Small Break Transients in Combustion Engineering Nuclear Steam Supply Systems", and in CEN-115P, "Response to NRC IE Bulletin 79-06C Items 2 and 3 for Combustion Engineering Nuclear Steam Supply Systems". More recently, actual events in operating plants have demonstrated that plant control is improved if RCPs continue to operate for depressurizaton events which do not result in significant loss of RCS inventory (e.g., SGTRs and ESDEs). The NRC issued a requirement for utilities to develop an RCP operating strategy which would optimize the recovery from depressurization events.

FIGURE 1-7
VOID ELIMINATION FLOW CHART



Prolonged RCP operation during LOCAs of certain size and location could increase the severity of the event. Conservative licensing analysis has indicated that for a limited range of break sizes in the bottom of the hot leg, continued RCP operation can result in greater loss of RCS inventory than if RCPs were not running. This could result in decreased core cooling capability. For LOCA's in this break size range, it is very desirable to turn off all RCPs to minimize inventory loss.

On the other hand, forced circulation is generally desirable for all other events (except large break LOCAs). Forced circulation facilitates the recovery process by preventing reactor vessel head voids, providing forced cooling of an isolated steam generator, providing main pressurizer sprays, and preventing thermal stratification throughout the RCS.

Given these considerations, a desirable strategy for operating RCPs would be one that:

1) ensures the tripping of all RCPs for large break LOCAs and small break LOCAs in the break size range of concern.

2) maximizes the probability of running at least one RCP in each loop for all other events. Since conservative licensing analysis yields acceptable results for all design basis events without RCPs operating, an RCP strategy which occassionally results in tripping all RCPs for some non-LOCA events is still acceptable.

Since ESDEs, LOCAs and SGTRs, in addition to a number of anticipated operational occurrences, may result in RCS depressurization accompanied by similar trends for other key RCS parameters, diagnosis during the first minutes of a transient may be difficult. Even if a LOCA can be correctly diagnosed, the operator will not generally be able to identify the size and location of an RCS break. Therefore, the RCP strategy should permit the operator to decide the proper operation of the RCPs without relying heavily on the accuracy of operator diagnosis.

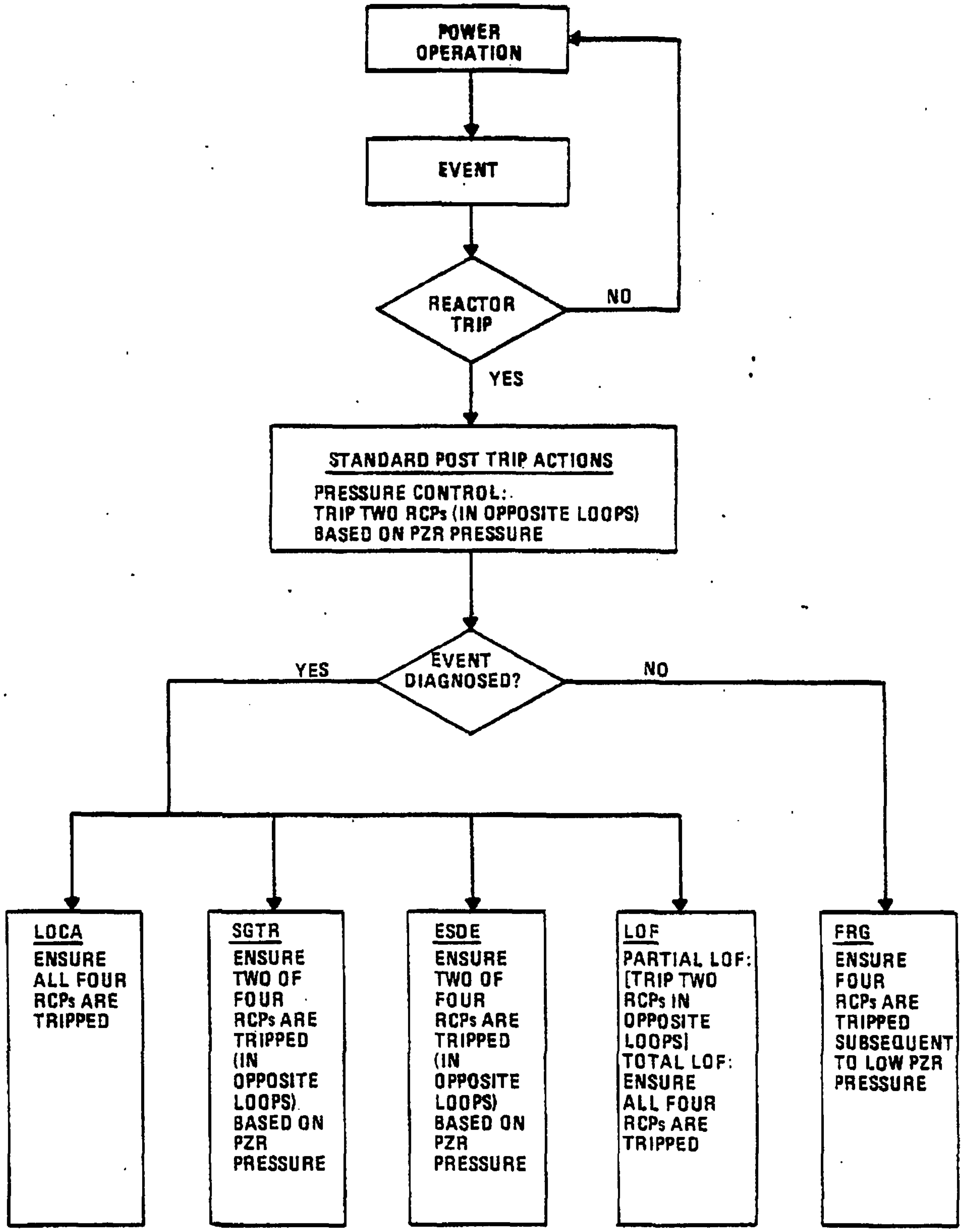
A generic RCP trip scheme has been incorporated in the guideline which result in the tripping of all four RCPs for LOCAs and which allows the continued operation of at least two RCPs (in opposite loops) for many non-LOCA events. Once the operator has determined that a LOCA is the cause of the depressurization event, then all four RCPs are tripped if pressurizer pressure is less than [1300 psia] and an SIAS has occurred. This occurs after the LOCA diagnosis is confirmed in order to prevent the premature securing of all forced coolant flow. An SIAS is coupled with the [1300 psia] criterion in the decision logic in order to make the distinction between a controlled depressurization and an uncontrolled depressurization, where the latter causes an SIAS.

The RCP operating strategy for a total loss of feedwater (LOF) event has not changed. All four RCPs are required to be tripped in order to minimize heat input to the RCS. For a partial LOF, two RCPs (in opposite loops) may be tripped in order to minimize unnecessary heat input to the RCS, especially if there is any difficulty in maintaining RCS heat removal.

Since, for all events, RCS control is easier and more effective with RCPs running (especially under accident conditions), it is desirable to restart them whenever possible. The restart criteria have been chosen to ensure that relevant RCS parameters are under control and that RCP operation under these conditions will not be detrimental (e.g., result in undesirable inventory loss). Pressurizer level and pressure can be expected to decrease when restarting RCPs due to loop shrinkage and/or steam void condensation.

FIGURE 1-8

RCP TRIP STRATEGY IMPLEMENTATION



1.7.5 *Overview of Reactor Vessel Level Monitoring System*

The accident at TMI, as well as several other industry incidents, have brought to light the advantage of being able to monitor the liquid level in the Reactor Vessel. The TMI accident would have very likely been less severe if the operators had been adequately trained to recognize indications of voiding in the reactor vessel upper head and, consequently, not secured safety injection. This probably would have prevented the conditions which then allowed the core to become uncovered. In reaction to this event, NUREG-0737 Item II.F.2 identified the usefulness of a Reactor Vessel Level Monitoring System (RVLMS) which would be operational for post-accident indication and also required the installation of such an instrument. The industry responded with the development two primary instruments to measure liquid levels in Reactor Vessels; the Heated Junction Thermocouple and the Differential Pressure Detector.

There are a number of factors relating to the design and operation of reactor vessel level monitoring systems which increase the difficulty of designing a system which is accurate under all post-accident conditions. Due to mechanical design differences in reactors, it was necessary to design different systems to account for the plant differences. Plants already operating required a backfit system while plants under construction could be changed to accommodate a design which was not dependent on already existing structures. In other words, internal structural changes in operating plants were ruled out due to excessive contamination and radiation levels while plants under construction could be modified internally. Systems also had to be designed to respond to various accidents, e.g., small and large break LOCAs, ESDEs and SGTRs. The various RCS responses during the accidents are not the same, an evaluation of the reactor vessel level monitoring system (RVLMS) (generic term) response using best estimate analysis had to be made, and the system design had to consider the conclusions of the analyses for all accidents. One other major item which was considered was the RCS and RVLMS response for various RCP operating configurations. Due to upper guide structure design, there are mechanical restrictions to flow above the fuel alignment plate which

could bias the RVLMS response when RCPs are operating. The RCP operating configuration also has different effects on the various RVLMS designs. When RCPs are operating, the quality of the pumped fluid has an effect on the RVLMS response and this also has to be taken into account. A substantial amount of analysis and testing was performed to arrive at designs which gave the best information under the accident conditions which were most critical with respect to reactor vessel voiding.

The RVLMS is most useful when RCPs are not operating because the level indication is not biased. However, even under conditions when the RCPs are operating, valuable trending information of reactor vessel inventory is available to the operators.

1.8 RELATIONSHIP OF EPGs TO NEW CONTROL ROOM OPERATOR AIDS

The design of the system of EPGs is deliberately fashioned to permit integration with new control room operator aids. Specifically, the control room aids which have been installed, or may be installed in the future, are the subcooled margin monitor (SMM); the safety parameter display system (SPDS), the reactor vessel level monitoring system (RVLMS), and the Critical Function Monitoring System (CFMS).

For example, the safety function status checks contained in both optimal and functional recovery guidelines require that the operator check safety function criteria against control board parameters to assess the adequacy of core cooling and the effectiveness of mitigation measures. The parameters chosen for comparison on these safety function status check were deliberately selected from the list of parameters identified for inclusion on the SPDS.

In a similar vein, the criteria for the various safety function status checks are organized around the same safety functions used in the CFMS. Thus, the CFMS could be used as an automated means of checking the status of safety functions during accident mitigation. This unburdens the operators of this role and permits the machine processing of considerably more plant data in assessing the safety functions.

STANDARD POST TRIP ACTIONS

Prepared by
COMBUSTION ENGINEERING, INC.
for the
C-E Owners Group

only 5 ENTRY CONDITIONS LISTED per INPO RECOMMENDATIONS
Basis DOCUMENT provides additional ALARMS/INDICATIONS

Entry Conditions See Deviation 0-50

1. See Dev. 0-51
2. See Dev. 0-52
3. See Dev. 0-53
4. Covered in step B.
5. See Dev. 0-54
6. See Dev 0-54

PURPOSE

This guideline provides the immediate operator actions which must be accomplished after an automatic or manually initiated reactor trip. These actions are necessary to ensure the plant is placed in a stable, safe condition or that the plant is configured to respond to a continuing emergency. This is the entry guideline for the entire EPG system. This guideline provides technical information to be used by utilities in developing a plant specific procedure.

ENTRY CONDITIONS

Any symptom(s) of a Reactor Trip

1. [Reactor trip alarm]
2. CEA bottom lights on
3. Rapid decrease in reactor power
4. Reactor trip circuit breakers open
5. [RPS trip setpoint exceeded]
6. [Other plant specific symptoms, insert here]

1. COVERED BY ¶ 1 AND 2 IN SCOPE SECTION. ALSO COVERED IN TRAINING

2.

a. COVERED BY STEP IV.A.3. PROMPT DROP IS MORE CONSERVATIVE AND DEFINITIVE INDICATION OF A. REACTOR TRIP
See Dev 0-55

b. INCORPORATED IN safety function status check - Reactivity control. OTHER SAFETY QUALIFIED INDICATIONS USED IN place of SUR BECAUSE of better Reliability.
See Dev. 0-56

c PROCEDURE step is more CONSERVATIVE. See BASIS IV. A. 2 of the standard post trip Actions
See Dev 0-57

1. COVERED BY ¶ 1 AND 2 IN SCOPE SECTION

2.

a. INCORPORATED AS IV.A.1 I.A.W. NRC STAFF POSITION of Dec. 2, 83 (Divis. of Licensing office of NRR) See ¶ 3 of BASIS

b. Requires OPERATOR TO leave control Room or direct plant operator to perform action. This step ommitted in favor of tripping CEDM MG set which can be done from control Room.

c. included AS IV A.1 alternate Action

d. N/A

e. included as Alternate action IV.A.2

Instructions	*Contingency Actions*
1. Verify all safety function acceptance criteria are satisfied.	1. If any criteria are not satisfied, Then perform the necessary contingency actions.

Reactivity Control

2. Verify reactivity control is established by the following:	2. If reactivity control is not established, Then do the following as necessary:
a. Reactor power decreasing *and*	*a.* Manually trip the reactor
b. [Negative startup rate] *and*	*b.* Open the reactor trip breakers
c. No more than one CEA bottom light not lit.	*c.* Deenergize the CEA motor generator
	d. [Plant specific methods, insert here]
	e. If more than one CEA not inserted, Then borate the plant in accordance with technical specifications.

3 Power Supply Availability confirmed by SFSC. 4KV Buses checked as an immediate action.	3.
a. Covered by C.3A a (maintenance of S/G pressure) and C.3.b. (Tcold) See Deviation O-1	a. Covered by Alt. Action C31 (Shut MSIV's)
b. See EOP Deviation sheet O-2 See EOP Bases section FD.	b. 2 independent system are available to open output breakers. Therefore step is omitted. EOP 1 verifies actions occurred. See Deviation O-2
c. No auto transfer available. SMECO power available but outside time frame of immediate actions	c. Included as Alt. Action F3D.
D. Additional vital Auxiliaries (other than power supplies) are monitored in safety function status check.	D. N/A

Instructions	*Contingency Actions*

Maintenance of Vital Auxiliaries
(AC & DC Power)

3. Verify plant electrical power requirements are satisfied by the following:	3. If electrical power requirements are not satisfied, Then do the following as necessary:
a. Main turbine tripped *and*	a. Trip the turbine
b. Generator output breakers open *and*	b. Open the generator output breaker
c. [Station loads transferred offsite] *and*	c. Ensure the diesel(s) are started
d. [Plant specific methods, insert here].	d. [Plant specific methods, insert here].

SEE EOP DEVIATION SHEET 0-3 ~~1X~~ for safety function classification deviation

4

a. IMPLEMENTED IN STEP B.1

b. included in step B.3

4

a. included in alt. act ~~alt~~ 1

b. IMPLEMENTED IN ALT. ACTION 1

c. N/A

Instructions	*Contingency Actions*
RCS Inventory Control	
4. Verify RCS inventory control is established by the following:	4. If RCS inventory control is not established, Then do the following as necessary:
a. Pressurizer level in the range [35 to 245"] *and*	a. Verify proper operation of the PLCS
b. The RCS is at least [20°F] subcooled.	b. Take manual control of charging and letdown
	c. [Plant specific methods, insert here].

5 included in step B.2

5.

a. included as alt. action B.2.1

b. included as alt. action B.2.1

c. included in alternate action B.2.3

d. included in alt. action B.2.3

e. PORV's added in alt. action B.2.2

Instructions	*Contingency Actions*

RCS Pressure Control

5. Verify RCS pressure control is established by pressurizer pressure in the range [1700 to 2350 psia].

5. If RCS pressure control is not established, Then do the following as necessary:

   a. Verify proper operation of the PPCS

   b. Take manual control of pressurizer heaters and spray

   c. If pressurizer pressure decreases to [1600 psia], Then ensure an SIAS is initiated

   d. If pressurizer pressure decreases to less than [1300 psia] following an SIAS, Then trip 2 RCPs (in opposite loops)

   e. [Plant specific methods, insert here].

SEE EOP deviation 0-5 for safety function classification deviation

6. a Included in RCS & Core heat removal SF check c.

b Included in RCS & Core heat removal SF check

c. Included as step B3. SPTA. Not included in Step c to limit repetition

a-d See EOP deviation Sheet 0-6

Instructions | Contingency Actions

Core Heat Removal

Instructions

6. Verify core heat removal via forced circulation by the following:

   a. At least one RCP is operating

   and

   b. $T_H - T_C$ is less than [10°F]

   and

   c. The RCS is at least [20°F] subcooled.

Contingency Actions

6. If forced circulation core heat removal is not possible, Then verify natural circulation is developing by:

   a. Loop ΔT ($T_H - T_C$) is less than normal full power ΔT

   b. No abnormal difference between T_H RTDs [and CETs]

   c. RCS subcooling greater than or equal to [20°F]

   d. [Plant specific information, insert here].

7.

a. included in step C.1 AND C.2

b. covered by step C.3.b,
SEE Deviation 0-7

c. Covered by step C.3.a. more Conservative Limit used because of the controlling effect primary temperature has on S/G pressure.

a. included in ~~in~~
Alt. action 21

b. ~~inherent in step C.3.a AND ...~~
~~Because tight limits on S/G pressure AND RCS temperature are used, the Atmospheric Dumps AND TURB. Bypass valves must work correctly per Design of Rx Reg System. If THESE BANDS CANNOT BE MAINTAINED the OPERATOR TAKES ACTION TO DETERMINE why.~~ ACTION added IN STEP 3.1 alternate action based ON feedback from operators

c. ~~ALT. ACTION C.3 Limits S/G pressure decrease to 800 psia (RCS temperature of ≈ 518°F). This in turn limits the drop in RCS temperature which limits Reactivity addition~~

c. Included as alternate action 32

d. N/A

Instructions	*Contingency Actions*
	RCS *Heat Removal*
7. Verify RCS heat removal by the following:	7. If RCS heat removal is not maintained, Then do the following as necessary:
a. At least one S/G has level: i) within the normal level band with feedwater available to maintain level or ii) being or restored by a feedwater flow greater than [150 gpm] *and*	*a.* Verify [main or auxiliary] feed is controlling S/G level *b.* Verify the steam dump system is operating properly *c.* If S/G pressure decreases to [500 psia], Then verify actuation of an MSIS
b. RCS T_{ave} is less than [545°F] *and*	*d.* [Plant specific methods, insert here].
c. S/G pressure is greater than [500 psia].	

Containment Environment in lieu of Containment Isolation
See EOP deviation sheet. 0-8

8.

a. Included in step ~~D.1~~ E.1 AND SAFETY FUNCTION STATUS CHECK

a Included as Alt-Action ~~D~~ E.II.

b. See deviation sheet 0-9

c. N/A.

b. Included in step ~~D~~ E.3.

c. Included in Step ~~E~~ F.2

Instructions	*Contingency Actions*

Containment Isolation

Instructions

8. Verify normal containment integrity by:

   a. Containment pressure less than [1.5 psig]
      and

   b. No containment area radiation monitors alarming
      and

   c. No steam plant radiation alarms.

Contingency Actions

8. If containment integrity is not indicated, Then do the following as necessary:

   a. If containment pressure is greater than [4 psig], Then ensure a CIAS

   b. If steam plant radiation levels are above the alarm setpoint, Then refer to the SGTR EPG

   c. [Plant specific methods, insert here].

9. Included in Containment Environment. See deviation sheet 0-10

a. Included in Step ~~D~~E.2.

b. Included in Step ~~D~~E.1
Set point is more conservative and consistant with Calvert Cliffs administrative limit.

a. Not included see deviation sheet, 0-11

b. (1) Included in step ~~D~~E.11 (b)
(2) Not included. See Deviation Sheet 0-12

c. N/A.

Instructions / *Contingency Actions*

Containment Temperature & Pressure

Instructions

9. Verify normal containment temperature and pressure parameters by the following:

   a. Containment temperature less than [120°F]

      and

   b. Containment pressure less than [1.5 psig]

Contingency Actions

9. If normal containment temperature and pressure parameters are not indicated, Then do the following as necessary:

   a. [Verify proper functioning of containment coolers]

   b. If containment pressure is greater than [10 psig], Then verify containment spray is operating with header flow greater than [1500 gpm]

   c. [Plant specific methods, insert here].

Safety function included under Containment Environment
See Deviation Sheet 0-10

10. Not included See deviation sheet. 0-13. 10 N/A.

11. Included as step G 11. Included as step G

Instructions	*Contingency Actions*
	Containment Combustible Gas Control
10. Verify normal containment combustible gas concentration by hydrogen concentration less than [2%].	10. If normal containment combustible gas concentration is not indicated, Then [Plant specific methods, insert here].
11. Verify all safety function criteria are satisfied and the event is an uncomplicated reactor trip, Then implement the Reactor Trip Recovery Guideline.	11. If all safety function criteria are not satisfied, Then more than a simple reactor trip has occurred and the following guidance must be utilized: a. If a diagnosis is apparent, Then implement the appropriate Optimal Recovery Guideline b. If a diagnosis is not possible, Then implement the Functional Recovery Guideline.

BASES

This is the entry guideline for the EPG System. This guideline is used for any event which actuates or requires a reactor trip. It is intended that the operator check each function and perform the contingency actions if necessary. The criteria are selected from best estimate analysis to reflect the range for each parameter which would be expected following an uncomplicated reactor trip. The recovery actions are selected to reflect the need to verify the actuation of automatic systems which may occur and to include other appropriate post trip actions which will ready the plant to respond to any event.

Standard Post Trip Actions (SPTAs) are organized around those critical safety functions which must be satisfied when a reactor trip is actuated or required, in order to ensure the plant is placed in a stable, safe condition or that the plant is configured to further respond to a continuing casualty. In order to provide for this, the operator is given specific, unambiguous acceptance criteria which can be evaluated without interpolation directly from the control room instruments. These criteria are located under the "instructions" heading. These criteria (and the range of the numerical criteria) are chosen from generic, best estimate analyses to bound the expected conditions which would follow an uncomplicated reactor trip. Thus, checking the acceptance criteria serves two purposes: if the criteria are met, then this serves as a verification that the function is being fulfilled; second, the meeting of the criteria is a diagnostic indicator (i.e., meeting all of the acceptance criteria implies that nothing more serious than an uncomplicated reactor trip has occurred). If the acceptance criteria are not met, then this serves as a cue to perform the appropriate contingency actions located under the heading of the same name. These actions are chosen to reflect the verification of expected automatic system responses and the usual, easy to accomplish actions which operators always take in response to a trip. With regard to the latter actions, a generic list of these was prepared from operator interviews, review of existing emergency procedures, and simulator experimental and validation efforts.

The reactivity control function is designed to ensure a shutdown reactor in order to reduce heat input to the RCS. The reactivity control criteria are chosen to reflect those reactor conditions which would prevail during the first ten minutes following a trip. Negative startup rate is bracketed to reflect the fact that startup rate instrumentation is either inaccessible or inadequate at some plants. No more than one CEA stuck out is chosen as the cutoff point in the third criterion since it is a core design criterion that the reactor will still shutdown even with the most reactive rod stuck out. Contingency actions a) through d) are directed to inserting the CEAs. Criterion c) and contingency action e) reflect the generic technical specification requirement to borate should more than one CEA not be fully inserted.

Maintenance of vital auxiliaries is chosen as the next function to address since the items included here relate to the alignment of the electrical system. The electrical system is essential to the fulfillment of succeeding functions. The criteria reflect the automatic disconnect of the main turbine generator and transfer of power to offsite which should occur immediately upon a trip. Contingency actions are chosen to remedy the failure of automatic system responses.

RCS inventory and pressure are next in order of priority due to their importance to core cooling and their potential for rapid change. RCS inventory control is intended to ensure an adequate amount of fluid to remove decay heat. On an uncomplicated trip, the pressurizer will retain some indicated level (even though the pressurizer heaters may be deenergized briefly on low pressurizer level) which is acknowledged in the criteria. The upper limit of pressurizer level expressed is based on avoiding solid water operations and bounds the highest level observed in best estimate analysis. Contingency actions are selected to restore proper operation of the normal inventory control system (the PLCS) and, failing that, to ensure control of inventory using manual control of charging and letdown.

RCS pressure control relates to the maintenance of subcooled fluid in the RCS in order to adequately remove decay heat. Best estimate analyses reveal that for an uncomplicated reactor trip, pressure will remain within the limits

expressed in the criteria. The limits are adequate to ensure RCS inventory subcooling and to prevent lifting a primary relief or safety valve. Contingency actions are directed at restoring RCS pressure control with the PPCS. Failing that, actions are directed at restoring or maintaining pressure with manual control of pressurizer heaters and spray, or the safety injection system.

Core heat removal is related to circulating cooling fluid in the proper state through the core to remove decay heat. The criteria assume RCPs are running (as they would be following an uncomplicated trip) thereby providing the small loop ΔT expected with decay heat. Subcooling is concerned with maintaining adequate fluid conditions surrounding the core. Contingency actions are directed at removing heat through the steam generators using natural circulation.

RCS heat removal is next in priority because the parameters associated with it are concerned mostly with steam generators, which are the primary means of removing heat from the RCS. Furthermore, steam generator level and pressure also have the potential for rapid change. Criteria a) and c) refer to ensuring the presence of an operable steam generator for removing heat. A lower level for the steam generator is not specified since it is not uncommon for level to briefly transit below the indicating range for plants with only narrow range steam generator level indication. RCS average loop temperature (criterion b) below some predetermined value is indicative that steam generators are in fact removing heat. The contingency actions relate to restoring feed or steam flow to a steam generator or to ensuring isolation of a faulted steam generator.

Containment isolation serves to contain radionuclides inside the containment building. The criteria selected are designed to ensure that containment integrity is maintained. High containment pressure or containment/steam plant radiation alarms are indications that more than an uncomplicated reactor trip has occurred. Contingency actions are designed to ensure that the containment is isolated when necessary and the SGTR EPG is implemented if an SGTR is indicated.

Containment temperature and pressure control has as its goal the preservation of the containment building boundary by preventing or minimizing pressure excursions. Since containment pressure and temperature are not expected to change noticeably for an uncomplicated reactor trip, the criteria are selected to be sensitive to any change. Contingency actions focus on restoring or initiating containment cooling either with the cooling fans or, if necessary, with the containment spray system.

Containment combustible gas control serves to alert the operator of a potentially dangerous buildup of hydrogen. No increase in containment hydrogen concentration is expected following an uncomplicated reactor trip. Specific limits and contingency actions are plant specific items which will be detailed during the writing of the utilities' emergency operating procedures.

3.0 *DIAGNOSTIC AIDS*

By the time the diagnostic aids are consulted, the operator has already completed the Standard Post Trip Actions (SPTAs) in response to a reactor trip and any other concurrent plant problem symptoms. The operator has already made an initial evaluation of plant status and has either observed or attempted to initiate a reactor trip. Because the Standard Post Trip Actions also constitute a check of the safety functions, the operator is also now aware of the status of safety functions. If no functions were in jeopardy, that is, all of the safety functions met their respective acceptance criteria, then nothing more than an uncomplicated reactor trip has occurred. If one or more safety functions did not meet the acceptance criteria of the SPTAs, then the operator must attempt to identify a symptom set which provides entry to an ORG. The diagnostic aids contained herein are intended to provide examples of the kinds of aids utilities may use to assist operators in selecting an appropriate procedure during the first several minutes after a reactor trip.

Diagnostic aids have been developed to assist the operator in logically selecting a procedure. Figures 3-1, 3-2, and 3-3 are examples of aids which have been developed with operator input and considerable engineering effort. These examples serve only to quickly identify procedures for use with events which are not complicated by significant, multiple failures or confusing symptom configurations. Minor system failure will not impair the use of these diagnostic aids in distinguishing symptom sets. To go much beyond the complexity of the samples provided will require too much operator time and may hinder the operator in performing the required actions in a timely manner. Each utility will decide, based on their own training programs and other plant specific considerations, what form this diagnostic section will take in their plant specific procedures.

Figures 3-1 and 3-3 are simplified flow charts which can be used to assist the operator in organizing plant symptoms to decide which procedure to employ (i.e., which major class of event is occurring). These charts are intended only to assist in selecting a procedure. While they could be expanded to

cover a greater variety of symptom combinations, they are purposely kept simple for ease of use. Therefore, minor control system or component failures are not included.

Figure 3-2 is another form of diagnostic aid. It is intended to be a follow on from the Standard Post Trip Actions such that, for those safety functions which the operator identified as being in jeopardy, additional parameters (column labeled PARAMETER DEVIATIONS) are looked at to narrow down and distinguish the possible events. The operator should first look at the safety function which appears to be most in jeopardy (e.g., the dominant problem may be RCS pressure control) and then look at one or two additional parameters normally associated with other safety functions to assist in diagnosis. After looking at the confirming parameters for all of the safety functions in jeopardy, the operator should be able to select a symptom set and an appropriate procedure. Once again, minor control system or component failures (e.g., failure of the pressurizer pressure control system) will generally not prevent the use of this diagnostic aid in selecting a procedure.

A particular ORG would be entered after the operator has completed the Standard Post Trip Actions and has been able to make a diagnosis. The ORG will efficiently mitigate the event if it has been properly diagnosed and is not severely complicated by multiple failures. The key in conduct of an optimal procedure is providing a correction process. In essence, this correction process continuously checks symptoms using the ORG safety function status check. If the treatment in use is adequately treating the symptoms, then the treatment is continued. If the treatment is inadequate, either because new information on symptoms appears that is not covered in the procedure, or because the observed symptoms are not properly responding (as judged by the safety function status check), then a transfer is made to a more appropriate treatment. The checking process is continued as long as the emergency procedures are in use. If identification of a symptom set were not possible, or if the event were not being mitigated by the use of a particular ORG, the operator would implement the Functional Recovery Guideline (Section 10.0).

FIGURE 3-1

POSSIBLE VERSION OF THE REACTOR TRIP DIAGNOSTIC FOR IDENTIFICATION OF UNCOMPLICATED MAJOR EVENT PROCEDURES

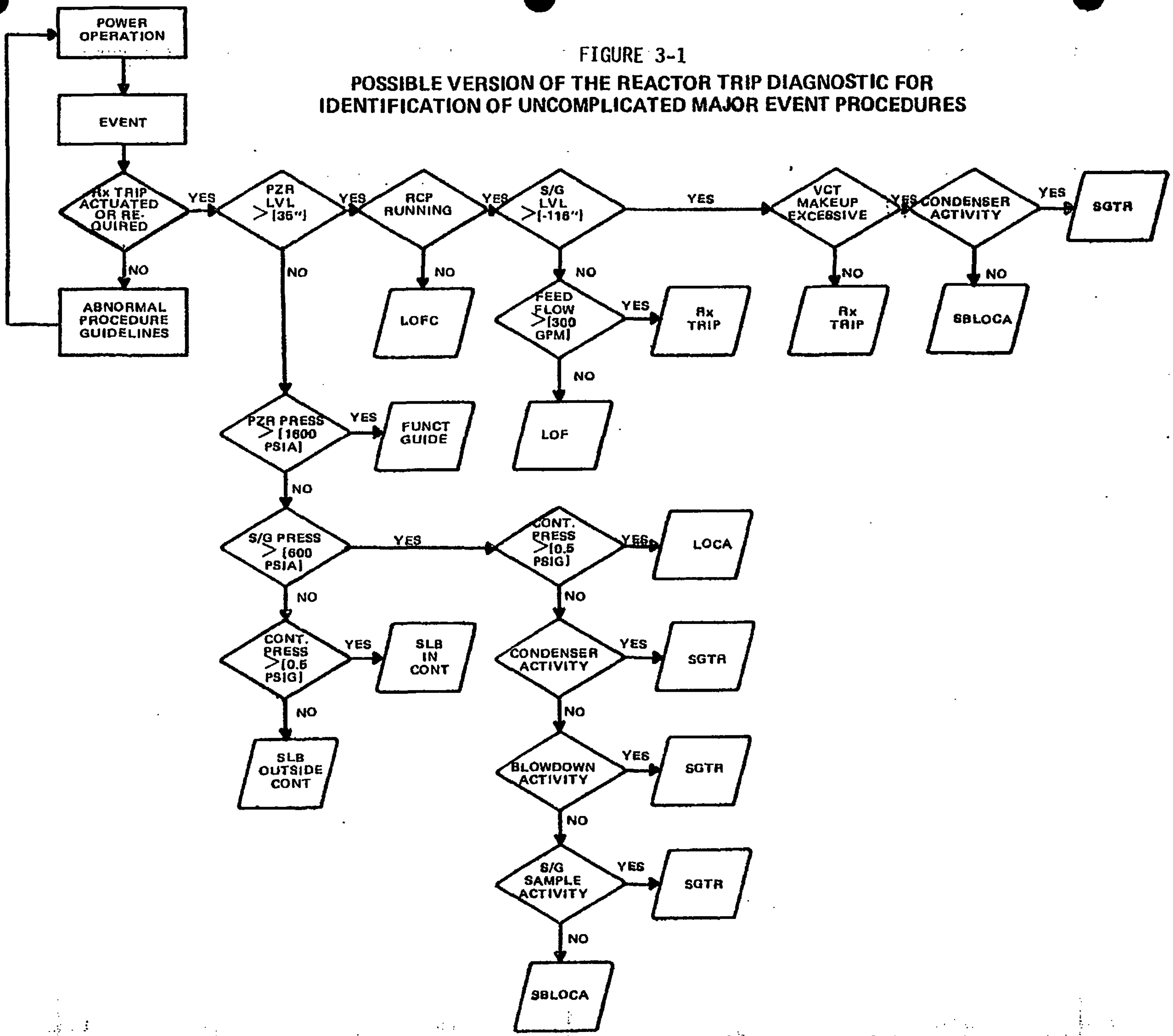


FIGURE 3-2

POSSIBLE VERSION OF THE REACTOR TRIP DIAGNOSTIC

FUNCTION NOT SATISFIED	PARAMETER DEVIATIONS	POSSIBLE EVENT
REACTIVITY CONTROL	Power > [$10^{-(X)}$%] with RCS temp. increasing	Rx not shutdown Consider implementing FUNCTIONAL RECOVERY GUIDELINE
RCS INVENTORY CONTROL	Pzr. level decreasing or not recovering or recovering very slowly with HPSI on with S/G press. & level constant or increasing	Consider LOCA/SGTR
	Pzr. level decreasing or not recovering with S/G press. & level decreasing and not recovering	Consider ESDE
RCS PRESSURE CONTROL	Pzr. press decreasing or low and subcooled margin decreasing with S/G press constant or increasing	Consider LOCA/SGTR
	Pzr. press decreasing or low with S/G pressure and level decreasing or low and subcooled margin decreasing	Consider ESDE
CORE HEAT REMOVAL	T_h-T_c > [10°F] with S/G dp < [X psid]	Consider LOFC
RCS HEAT REMOVAL	S/G level < [-116"] or feed flow = 0 with S/G press decreasing	Consider LOF
	S/G press & level decreasing and not recovering with adequate S/G feed	Consider ESDE

FIGURE 3-2 (Continued)
POSSIBLE VERSION OF THE REACTOR TRIP DIAGNOSTIC

FUNCTION NOT SATISFIED	PARAMETER DEVIATIONS	POSSIBLE EVENT
CONTAINMENT ISOLATION	Containment sump level increasing with no containment radiation	Consider ESDE
	Containment sump level increasing with containment radiation increasing	Consider LOCA
CONTAINMENT TEMPERATURE AND PRESSURE CONTROL	Containment pressure increasing without increase in steam plant radiation monitor	Consider LOCA/ESDE
	Containment pressure normal with increase in steam plant radiation monitor	Consider SGTR

FIGURE 3-3a

ALTERNATE VERSION DIAGNOSTIC PROCESS

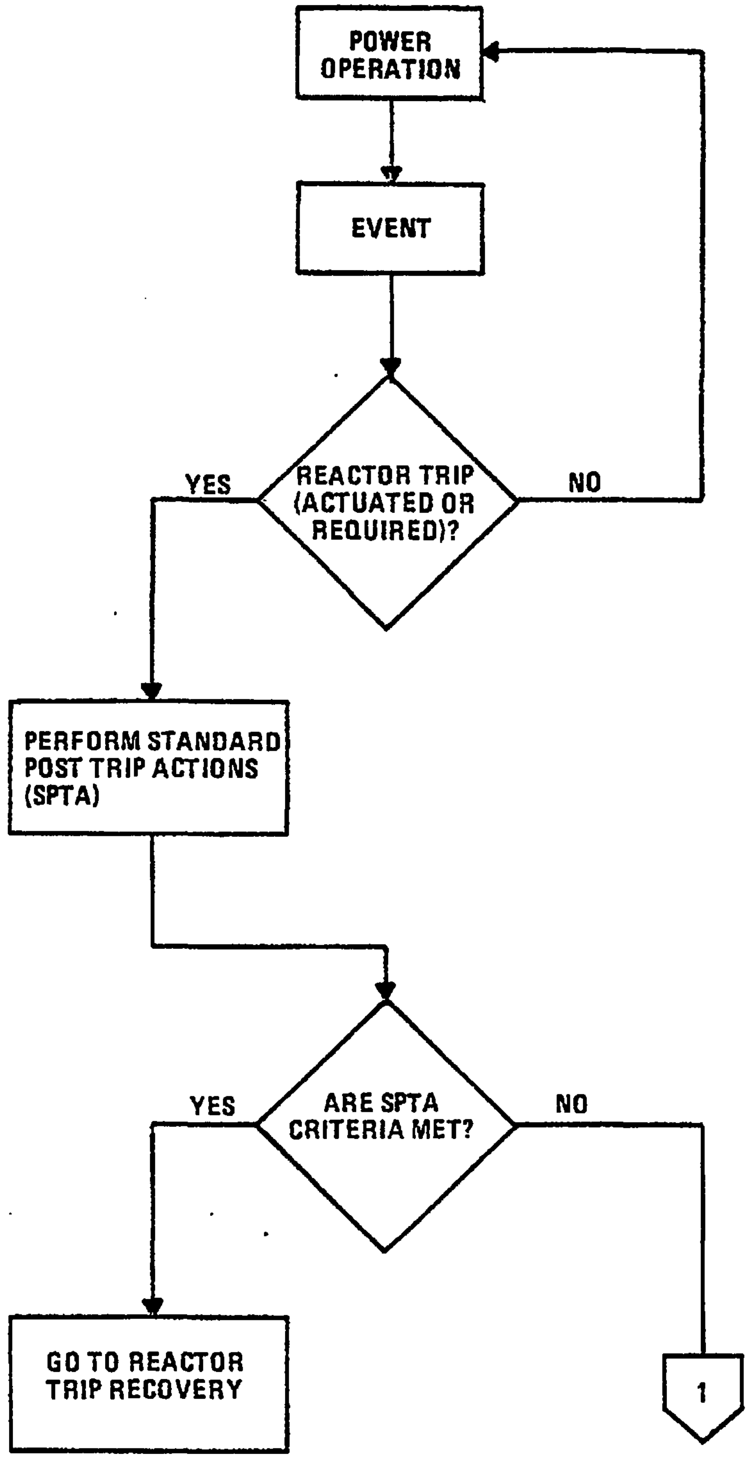


FIGURE 3-3b

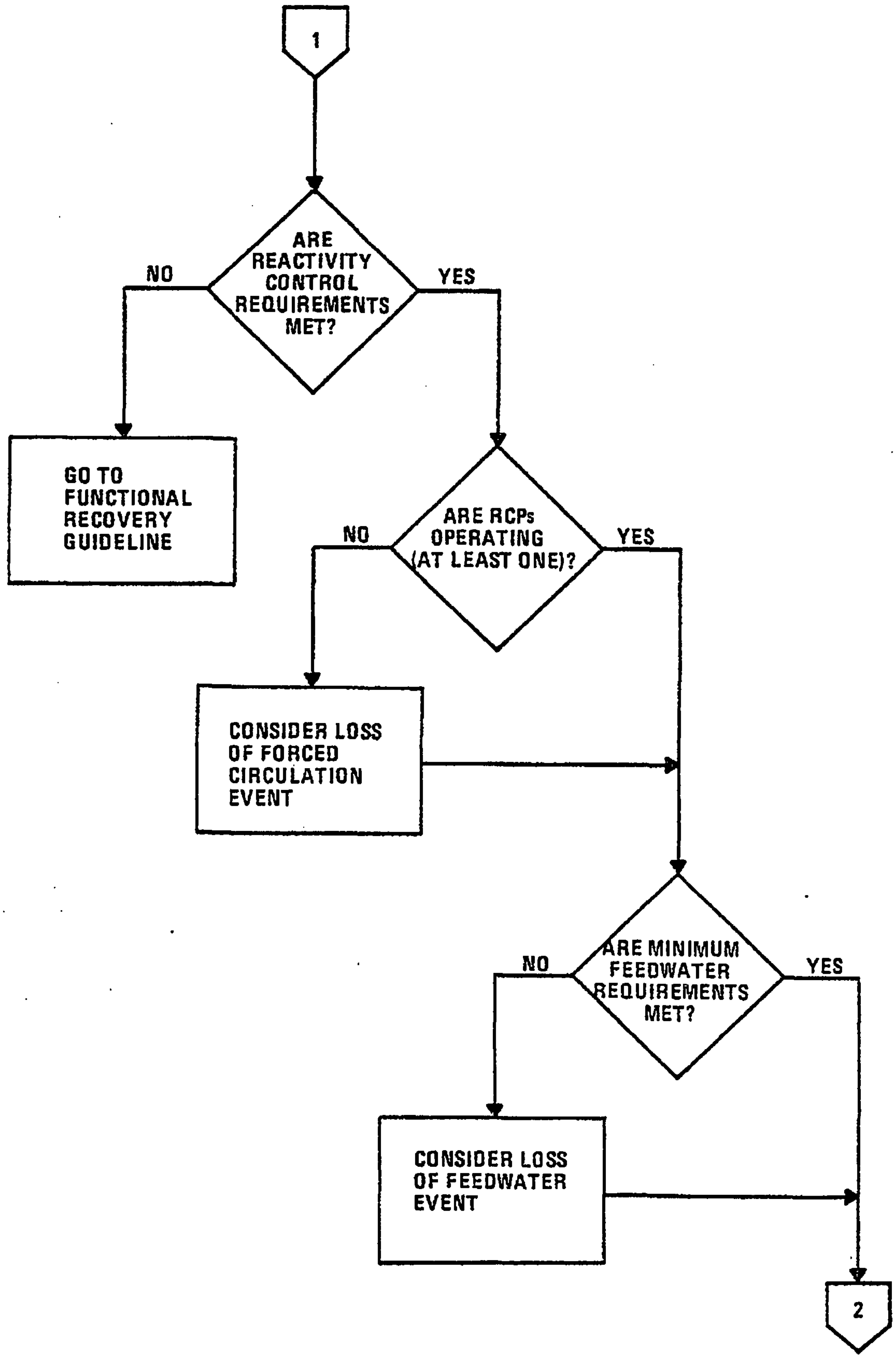

1
ARE REACTIVITY CONTROL REQUIREMENTS MET?
NO
YES
GO TO FUNCTIONAL RECOVERY GUIDELINE
ARE RCPs OPERATING (AT LEAST ONE)?
NO
YES
CONSIDER LOSS OF FORCED CIRCULATION EVENT
ARE MINIMUM FEEDWATER REQUIREMENTS MET?
NO
YES
CONSIDER LOSS OF FEEDWATER EVENT
2

FIGURE 3-3c

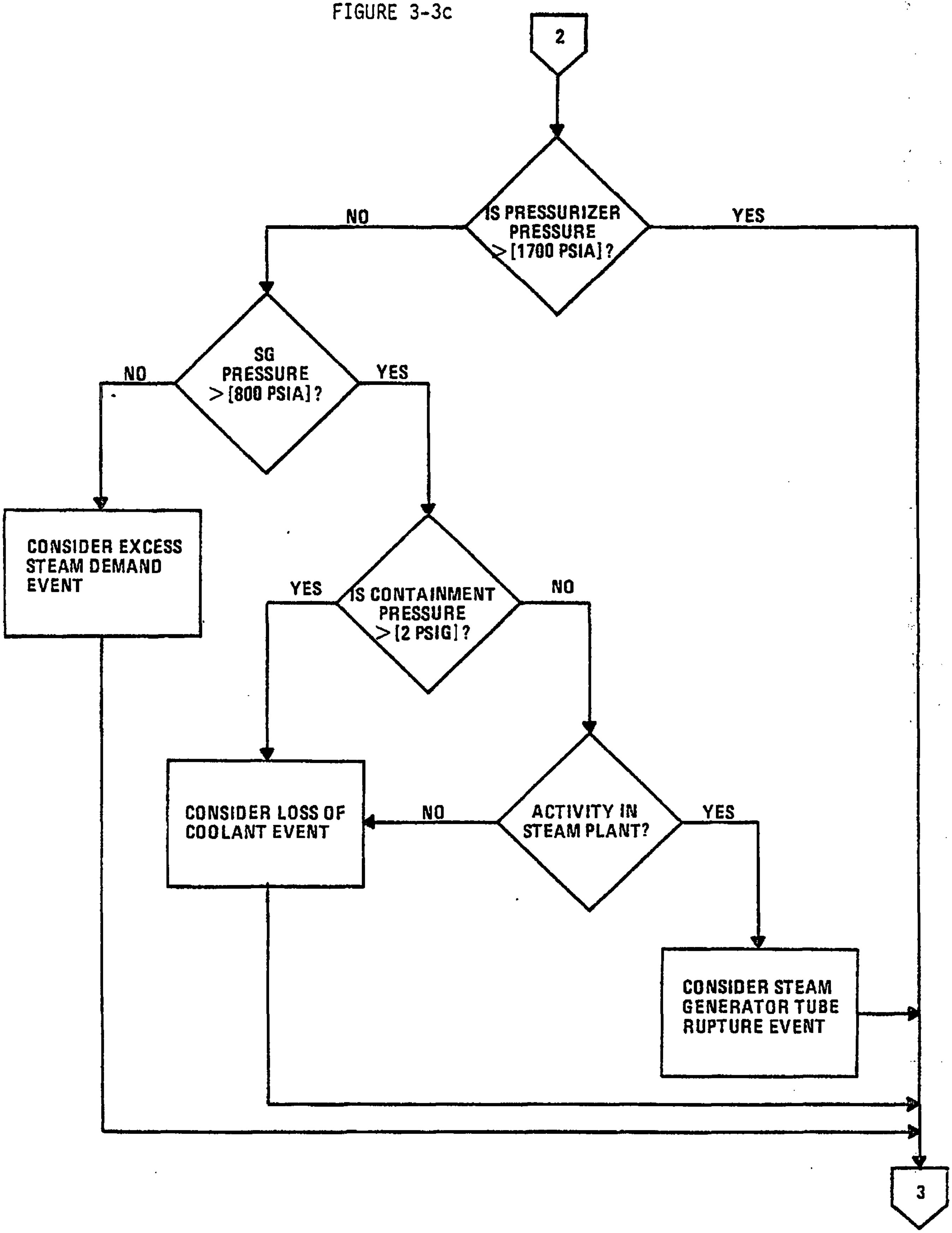
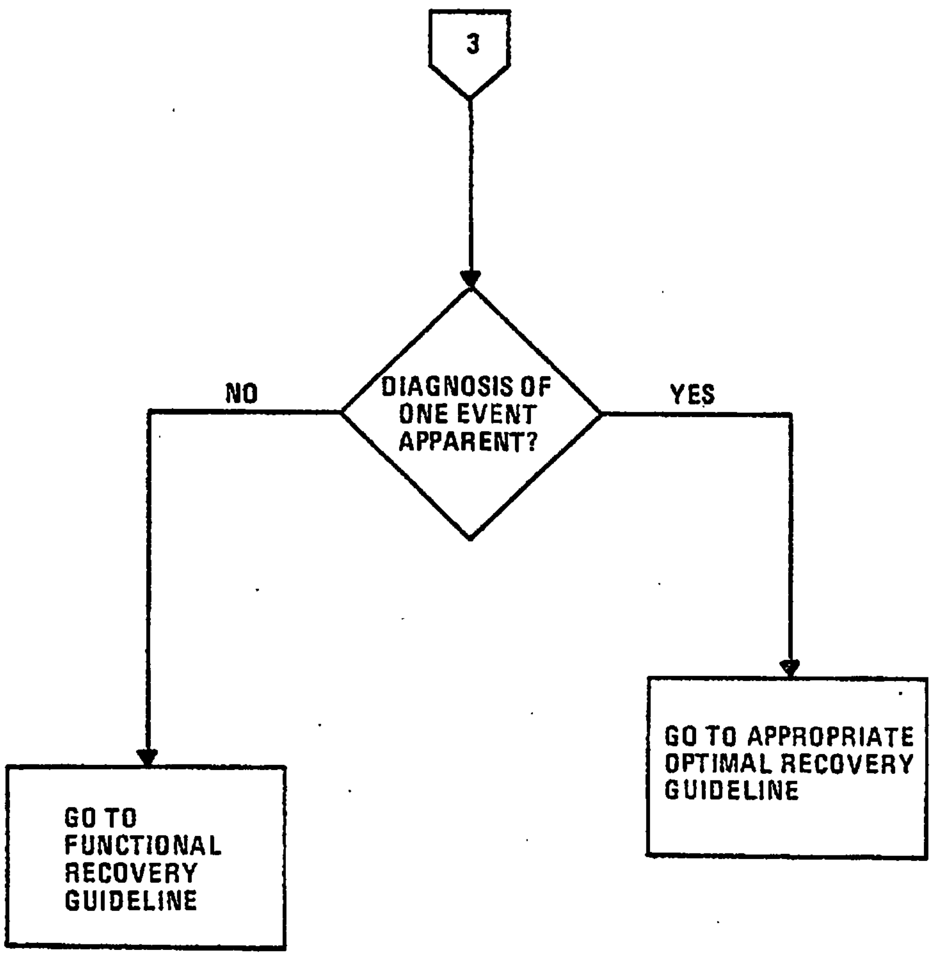

2
IS PRESSURIZER PRESSURE > [1700 PSIA] ?
NO
YES
SG PRESSURE > [800 PSIA] ?
NO
YES
CONSIDER EXCESS STEAM DEMAND EVENT
IS CONTAINMENT PRESSURE > [2 PSIG] ?
YES
NO
CONSIDER LOSS OF COOLANT EVENT
ACTIVITY IN STEAM PLANT?
NO
YES
CONSIDER STEAM GENERATOR TUBE RUPTURE EVENT
3

FIGURE 3-3d


3
DIAGNOSIS OF ONE EVENT APPARENT?
NO
YES
GO TO FUNCTIONAL RECOVERY GUIDELINE
GO TO APPROPRIATE OPTIMAL RECOVERY GUIDELINE

REACTOR TRIP
RECOVERY GUIDELINE

Prepared by
COMBUSTION ENGINEERING, INC.
for the
C-E Owners Group

PURPOSE

This guideline provides the operator actions which must be accomplished subsequent to a relatively uncomplicated reactor trip. The actions in this guideline are necessary to ensure that the plant is placed in a stable, safe condition.

ENTRY CONDITIONS

1. The Standard Post Trip Actions have been performed

and

2. Plant conditions indicate that an uncomplicated reactor trip has occurred.

① IMPLEMENTED IN STEP A.

② IMPLEMENTED IN STEP B.

③ SEE DEVIATION SHEET 1-1.

④ IMPLEMENTED IN STEP ~~D~~ E AND ALTERNATE ACTION ~~D1~~ E.1

⑤ ADDED STEP ~~E~~ D, SEE DEVIATION SHEET 1-2

⑥ IMPLEMENTED IN STEP F

OPERATOR ACTIONS

1. Verify that the Standard Post Trip Actions have been performed.

*2. Verify that the safety function criteria are being satisfied by comparing control board parameters to the criteria in the Safety Function Status Check.

*3. If the safety functions are satisfied, Then continue with the actions of this guideline.
If the diagnosis of an uncomplicated RT is found to be in error and another event is diagnosed, Then implement the correct recovery guideline.
If a diagnosis cannot be made, Then implement the Functional Recovery Guideline.

4. Verify that the PLCS is automatically maintaining or restoring pressurizer level.
If not, manually operate charging and letdown to restore and maintain normal pressurizer level.

5. Verify that the PPCS is automatically maintaining or restoring RCS pressure within the limits of Figure 4-1.
If not, manually control pressurizer heaters and/or spray to control pressurizer pressure.

6. Verify turbine bypass valves are controlling steam generator pressure [900-950 psia].
If condenser vacuum is lost, the turbine bypass system is unavailable, or the MSIVs are closed, Then use the atmospheric dump valves to control steam generator pressure.

* Step performed continuously.

⑦ IMPLEMENTED IN STEP G.

⑧ SEE DEVIATION SHEET 1-3. ADDED STEP J.

7. Restore and maintain steam generator level in the normal band using [main or auxiliary] feedwater.

8. Maintain the plant in a stabilized condition and evaluate the need for a plant cooldown based on plant conditions, availability of auxiliary systems, and condensate inventory. If required, conduct a plant cooldown and enter shutdown cooling.

① Accomplished by SFSC.

② implemented be precaution C.

③ See Deviation sheet 1-4

④ EOP 1 does not direct c/o to be established. Procedures which direct such action do contain cooldown limitations

⑤ implemented by precaution A

⑥ See Deviation sheet 1-5

SUPPLEMENTARY INFORMATION

This section contains items which should be considered when implementing EPGs and preparing plant specific EOPs. The items should be implemented as precautions, cautions or notes or in the EOP training program.

1. Pressurizer level should be closely monitored since it normally decreases to, or near, the pressurizer heater cutoff level following a reactor trip.

2. All available indications should be used to aid in evaluating plant conditions since the accident may cause irregularities in a particular instrument reading. Instrumentation readings must be corroborated when one or more confirmatory indications are available.

3. A plant cooldown and entry into shutdown cooling (if necessary) should be conducted prior to depleting the condensate storage.

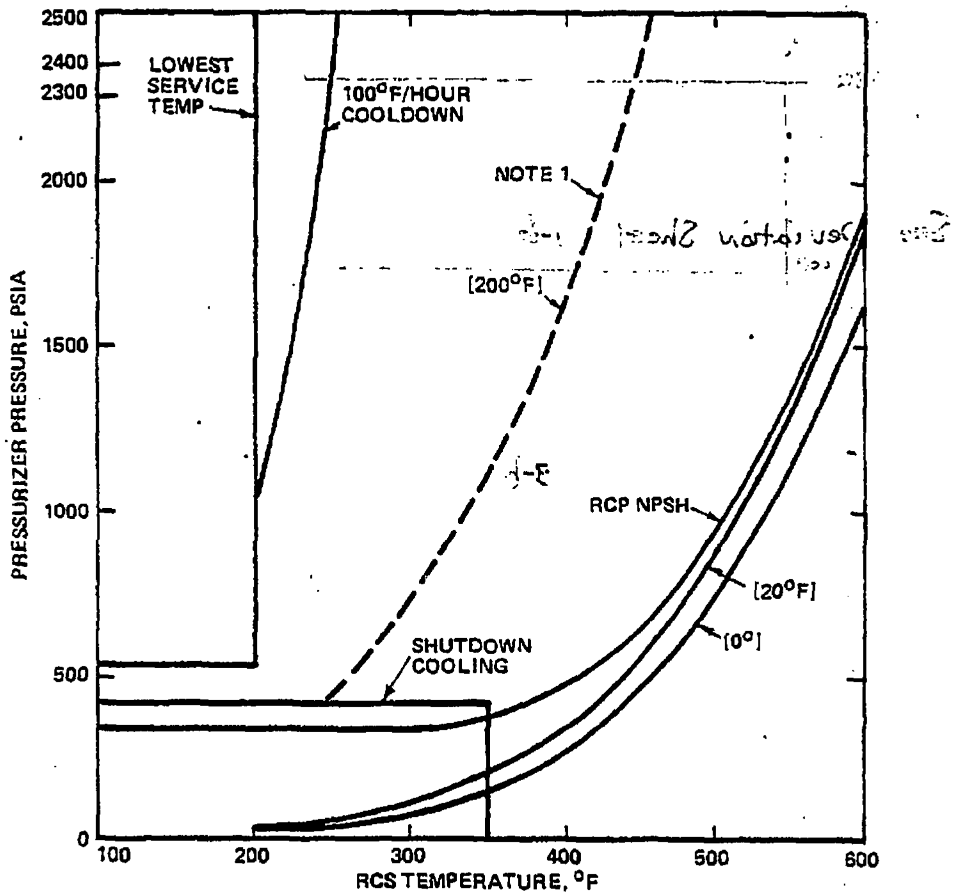
4. During all phases of the cooldown, RCS temperature and pressure should be monitored to avoid exceeding a cooldown rate greater than Technical Specification limitations.

5. Do not place systems in "manual" unless misoperation in "automatic" is apparent. Systems placed in "manual" must be checked frequently to ensure proper operation.

6. If the initial cooldown rate exceeds Technical Specification Limits, then there may be a potential for pressurized thermal shock (PTS) of the reactor vessel. Post accident pressure/temperature should be maintained within the limits of Figure 4-1.

FIGURE 4-1

TYPICAL POST ACCIDENT PRESSURE-TEMPERATURE LIMITS(2)



NOTES: (1) THIS CURVE SUPERSEDES THE 100°F/HOUR COOLDOWN CURVE ANYTIME THE RCS HAS EXPERIENCED AN UNCONTROLLED COOLDOWN WHICH CAUSES RCS TEMPERATURE TO GO BELOW 500°F

(2) THESE CURVES MUST BE ADJUSTED FOR INSTRUMENT INACCURACIES

(3) COLOR CODE

RED - PARAMETER IN EXCESS OF LIMITS
ORANGE - PARAMETER IN DANGER OF EXCEEDING LIMITS
YELLOW - PARAMETER OUTSIDE OF OPTIMAL RANGE, BUT STILL WITHIN LIMITS
GREEN - PARAMETER IN OPTIMAL RANGE OF VALUES

1. All items covered under Reactivity control SFSC

1.a See Deviation. 0-55

1. b. See Deviation 1-36

1.c. Deviation 0-14

2 MAINTENANCE of VITAL auxilliaries accomplished as 4th item IN SFSC.

Deviation 1-43

3 All items a AND c covered under Press/INV SFSC. RVLMS is NOT INSTALLED. See Deviation 1-6 for item 3b.

3a. See Deviation. 0-64

c. See Deviation 0-65

d. See Deviation 1-44

SAFETY FUNCTION STATUS CHECK

Safety Function	Acceptance Criteria
1. Reactivity Control	1.a. Reactor power decreasing *and* > b. [Negative Startup Rate] *and* c. Not more than 1 CEA bottom light not lit or borated per Tech. Specs.
2. Maintenance of Vital Auxiliaries (AC and DC Power)	2. [Plant specific criteria, insert here].
3. RCS Inventory Control	3.a. Pressurizer level is [35 to 245"] *and* b. Charging and letdown are maintaining or restoring pressurizer level *and* c. The RCS is at least [20°F] subcooled *and* d. [No reactor vessel voiding as indicated by the RVLMS].

4. ITem a. covered IN Press/INV SFSC. see DeviaTION 1-7 for item b
See Deviation 0-67

5. All items covered in CORE/RCS heat removal SFSC
a. See Deviation 1-45
b. see Deviation 0-65

6. All items covered in CORE/RCS heat removal SFSC
a. See Deviation 1-46
b. See Deviation 0-7 + 1-47

SAFETY FUNCTION STATUS CHECK

Safety Function	*Acceptance Criteria*
4. *RCS Pressure Control*	4.a. Pressurizer pressure is [1700 to 2350 psia] *and* b. Pressurizer heaters and spray are maintaining or restoring pressure within P/T limits of Figure 4-1.
5. *Core Heat Removal*	5.a. $T_H - T_C$ is less than [10°F] *and* b. The RCS is at least [20°F] subcooled.
6. *RCS Heat Removal*	6.a. At least one S/G has level: i) within normal level band with feedwater available to maintain level or ii) being restored by feedwater flow greater than [150 gpm] *and* b. RCS T_{ave} is less than [545°F].

7. Items 7a and 7b covered in Containment Environment SFSC.
Item 7C covered in RADIOACTIVITY CONTROL SFSC
See Deviation 0-76.

8 all items covered in Containment Environment SFSC

9 See Deviation sheet 1-8

SAFETY FUNCTION STATUS CHECK

Safety Function	*Acceptance Criteria*
7. *Containment Isolation*	7.a. Containment pressure less than [1.5 psig] *and* b. No containment area radiation alarms *and* c. No steam plant activity alarms.
8. *Containment Temperature & Pressure Control*	8.a. Containment temperature less than [120°F] *and* b. Containment pressure less than [1.5 psig].
9. *Containment Combustible Gas Control*	9. H_2 concentration less than [2%].

BASES

The bases section of the reactor trip (RT) recovery guideline describes the RT transient in relation to the actions which the operator takes during an RT recovery. The purpose of the bases section is to provide the operators with information which will enable them to understand the reasons for, and the consequences of, the actions they take during an RT.

Characterization of a Reactor Trip

A reactor trip is a shutdown of the reactor accomplished by the rapid insertion of the control element assemblies (CEAs). It is automatically initiated by the reactor protective system when certain continuously monitored parameters exceed predetermined setpoints, or it can be initiated manually by the operator if plant conditions warrant. A malfunction in the reactor protective system may also cause a reactor trip signal.

A reactor trip may be the result of automatic action initiated by the reactor protective system in response to any of the following typical parameters:

a) High reactor power.
b) Low pressurizer pressure.
c) Low reactor coolant flow.
d) Low steam generator level.
e) Low steam generator pressure.
f) High pressurizer pressure.
g) [Thermal margin/low pressure.]
h) High containment pressure.
i) Turbine trip.
j) [Core protection calculator trip].

[A reactor trip will also result due to an automatic or manual turbine trip at full power conditions.] A turbine trip is necessary if a condition detrimental to continued turbine operation develops.

Safety Function Affected

A reactor trip results in a decrease of primary system heat generation to decay heat. It is an automatic safety action performed for reactivity control and does not directly challenge the maintenance of any safety function required to place the plant in a stable condition. However, all safety functions should be monitored to assure public safety or to detect failures which may lead to unsafe conditions.

Trending of Key Parameters

Reactor Power (*Fig. 4-2*)

As a result of the reactor trip initiation, the control element assemblies (CEAs) will be rapidly inserted. Steam flow to the turbine generator will be terminated, the turbine generator output breakers will open and the feedwater flow will automatically ramp down to [5%] flow position. A rapid decrease in reactor power and a negative startup rate will be observed. This rapid decrease is followed by a decrease in indicated power (approximately -1/3 decades per minute) until the subcritical multiplication level is reached. Indicated power will stabilize at the subcritical multiplication level and decrease slowly over a period of hours.

RCS Temperature (*Fig. 4-3*)

Initially, feedwater temperature decreases sharply due to steam heating to the feedwater heaters (440°F to about 200°F feedwater temperature) or due to actuation of auxiliary feed (may be as low as 40°F). Heat from the RCS is absorbed by the cooler feedwater supplied to the steam generators. At power, there is a large differential between RCS T_{ave} and average steam generator temperature. Following the trip of the reactor and the turbine, the heat transfer rate from the RCS to the steam generator decreases to decay heat removal and the RCS to steam generator ΔT decreases to a few degrees. As a new equilibrium is achieved, the combined effect of the cooler feedwater and the steam generator heating up to an average temperature closer to RCS

temperature results in a net heat extraction from the RCS. Loop differentials between hot and cold leg temperatures will drop to less than ten degrees and RCS average temperature will decrease to the hot zero power temperature controlled by the turbine bypass system.

Reactor Vessel Level

For an uncomplicated reactor trip, it is expected that the reactor vessel will remain full. The subcooled margin in the RCS loops is typically 50°F or higher, and RVUH subcooling margins can be significantly lower than that for the RCS loops but still high enough to prevent voids from forming. At steady state conditions, the upper head region is about 1°F cooler than the core exit temperature and, therefore, the subcooled margin of the RVUH is essentially equal to that of the hot leg. Under transient conditions, with RCPs running, there is a time lag between the change in the core exit temperature and the change in RVUH temperature to approximately the same temperature. Under RCS cooling transients up to [75°F/hour], the time lag is small enough so that the subcooling margin in the RVUH will not allow voids to form.

Pressurizer Pressure and Level (*Fig. 4-4, 4-5*)

Pressurizer pressure and level will initially decrease due to the lowering of RCS temperature. However, this effect will usually be tempered by operation of pressurizer heaters and charging pumps to restore level to the programmed hot zero power band.

Steam Generator Pressure (*Fig. 4-6*)

Steam generator pressure will usually increase. Since heat is being removed from the RCS but not from the steam generator (except for the cooling from the feed), the steam generator heats up to decrease RCS to steam generator differential temperature. Steam generator pressure increases as temperature increases. As steam generator pressure increases, the turbine bypass valves and/or atmospheric dump valves will usually open to control steam generator pressure at hot standby pressure (which is above normal 100% power steam generator pressure).

Steam Generator Level (*Fig. 4-7*)

After a reactor trip the steam generator level decreases rapidly. This is explained as follows. Steam generator level is inferred from the steam generator downcomer level. During normal 100% power operation, the steam generator has a recirculation ratio of approximately 4 to 1 (ratio of water returning to the downcomer from the dryers and separators to feedwater entering the downcomer). This accounts for a major portion of the water level entering the downcomer. When steam flow is stopped by the turbine trip, recirculation stops. The reduced flowrate into the downcomer results in reduced head losses through the downcomer and up the riser section. The downcomer water level, and thus the steam generator indicated level, both drop. This drop in level will occur even before the feedwater system automatically readjusts.

Plant operators should be cautioned not to overreact to this lowered level in the steam generators. Excessive feeding of the steam generator with cooler feed to recover level results in RCS temperatures being driven down below the desired no load value. This could cause pressurizer level to fall to a point where the pressurizer is drained. RCS pressure will then drop until the safety injection system is actuated. This complicates the recovery from a simple reactor trip considerably.

FIGURE 4-2
REPRESENTATIVE REACTOR TRIP
REACTOR POWER

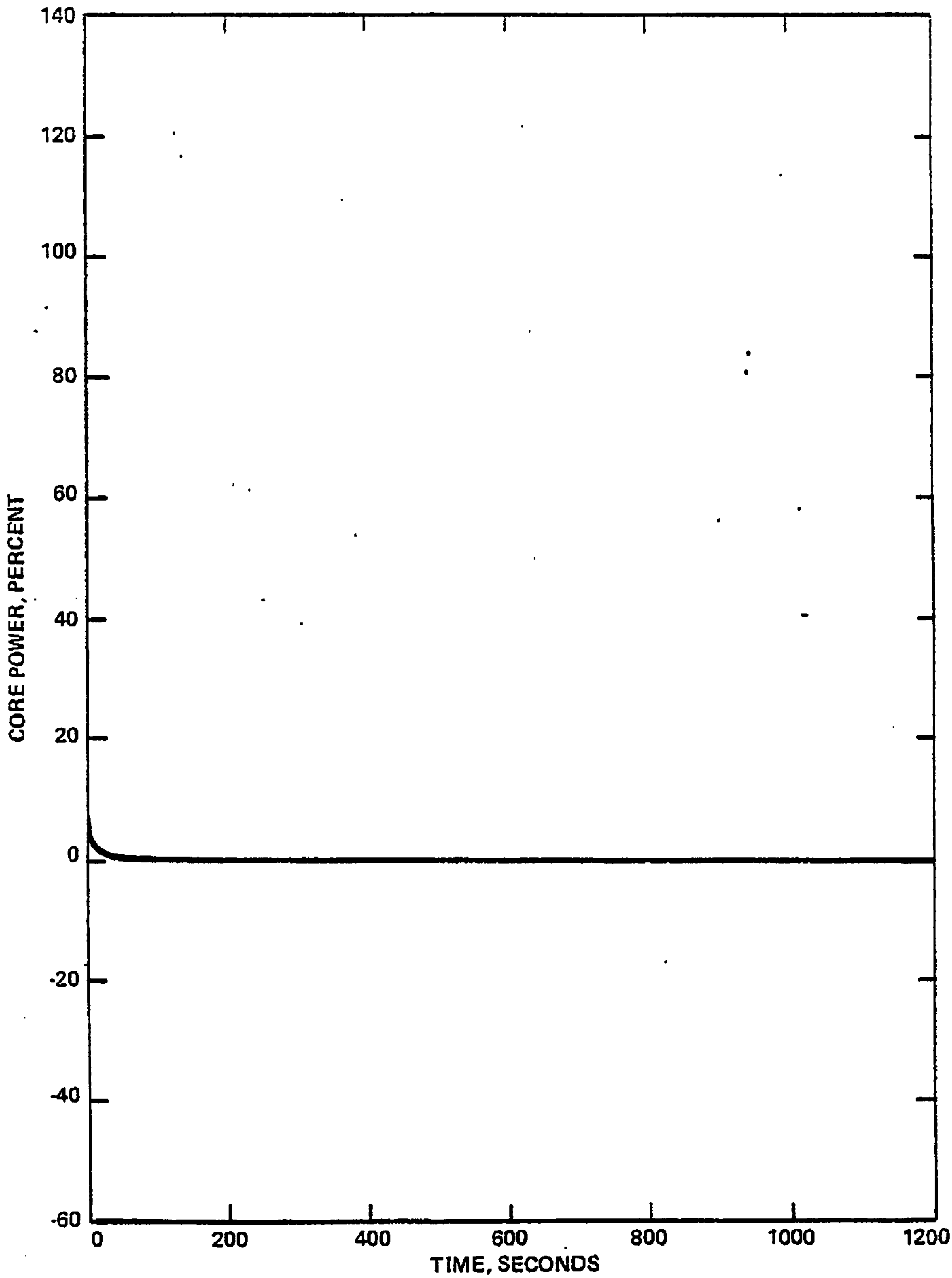


FIGURE 4-3
REPRESENTATIVE REACTOR TRIP
RCS WIDE RANGE TEMPERATURES

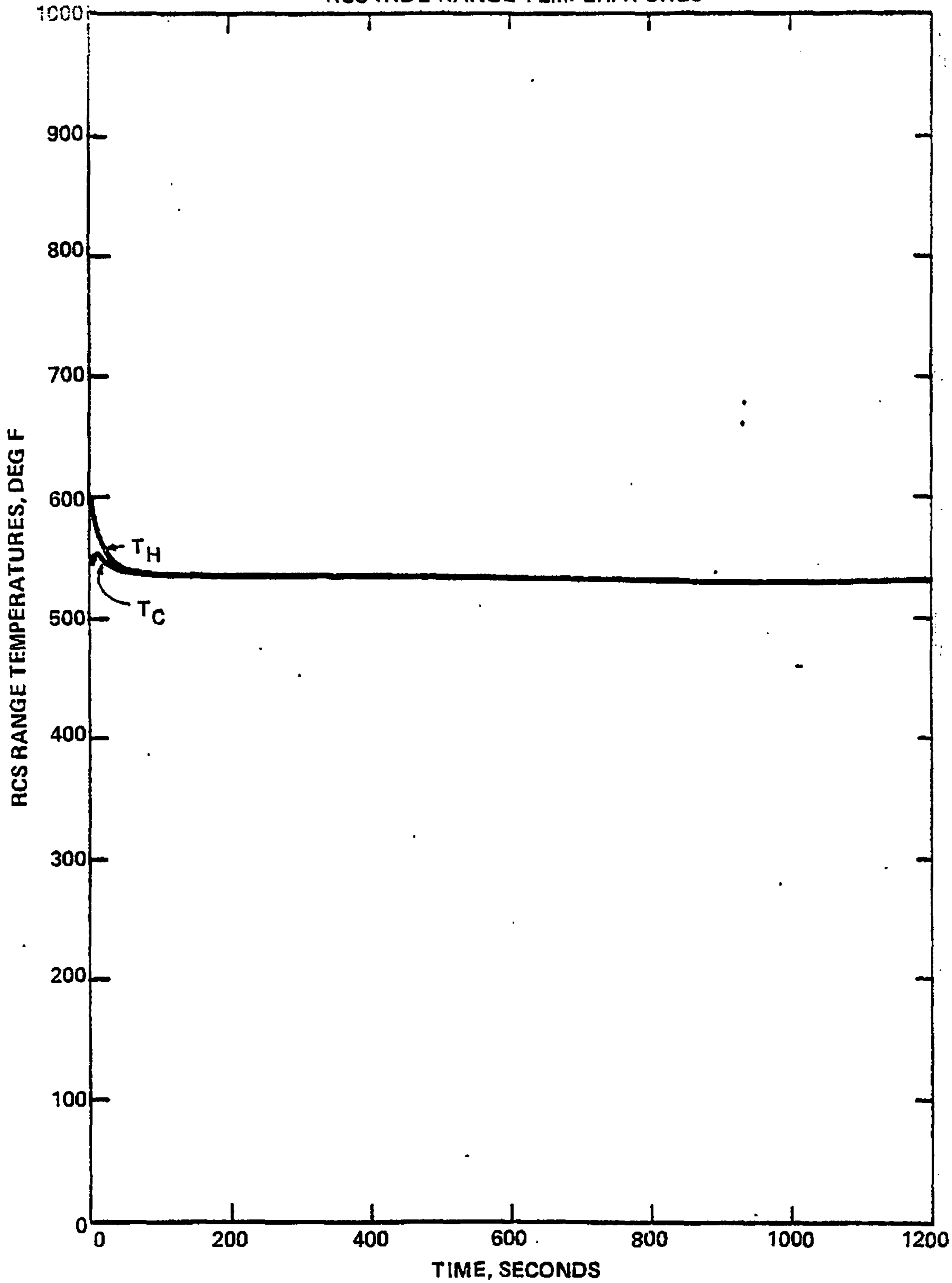


FIGURE 4-4

REPRESENTATIVE REACTOR TRIP
PZR WIDE RANGE PRESSURE

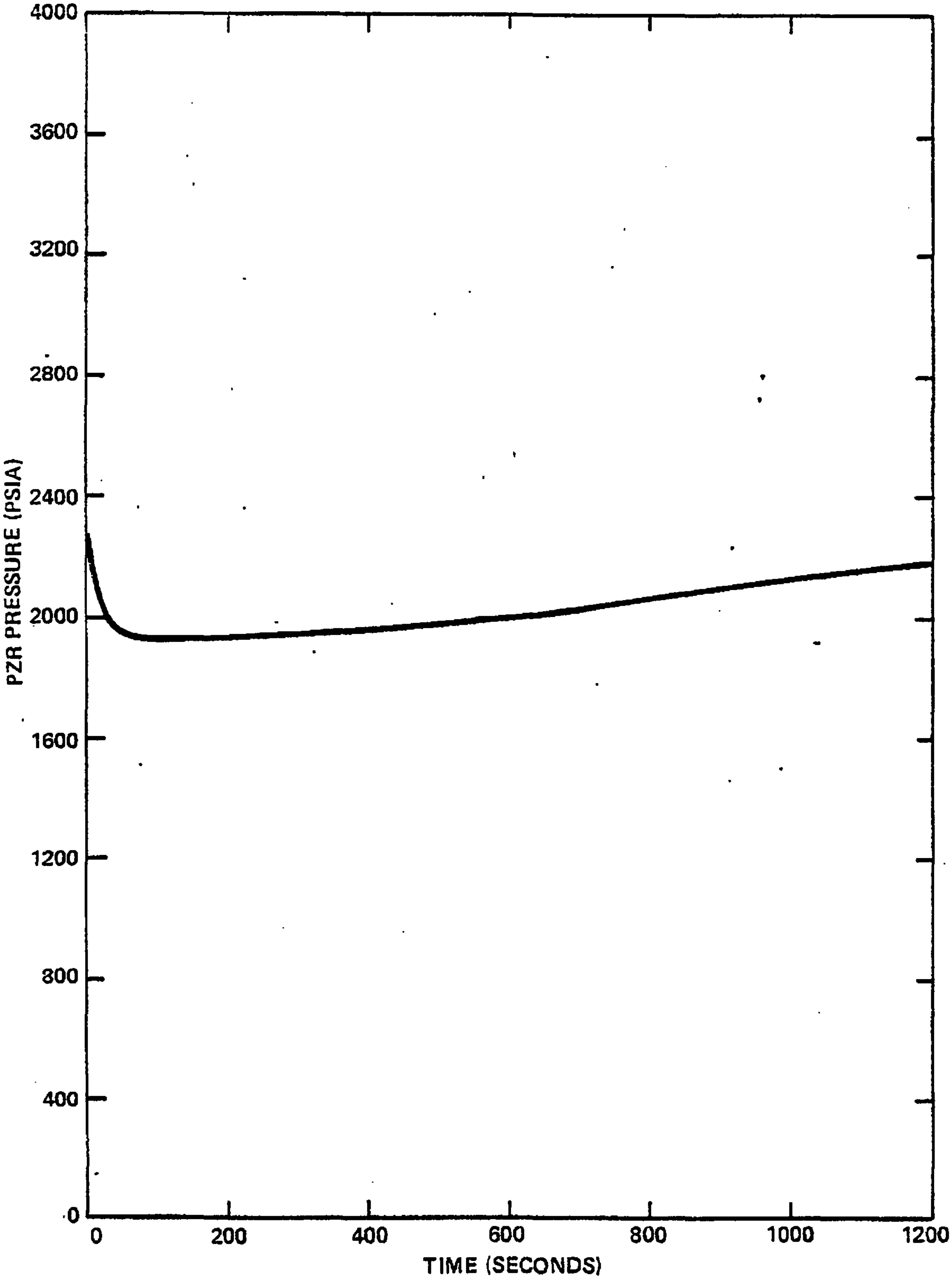


FIGURE 4-5

REPRESENTATIVE REACTOR TRIP
PZR LEVEL

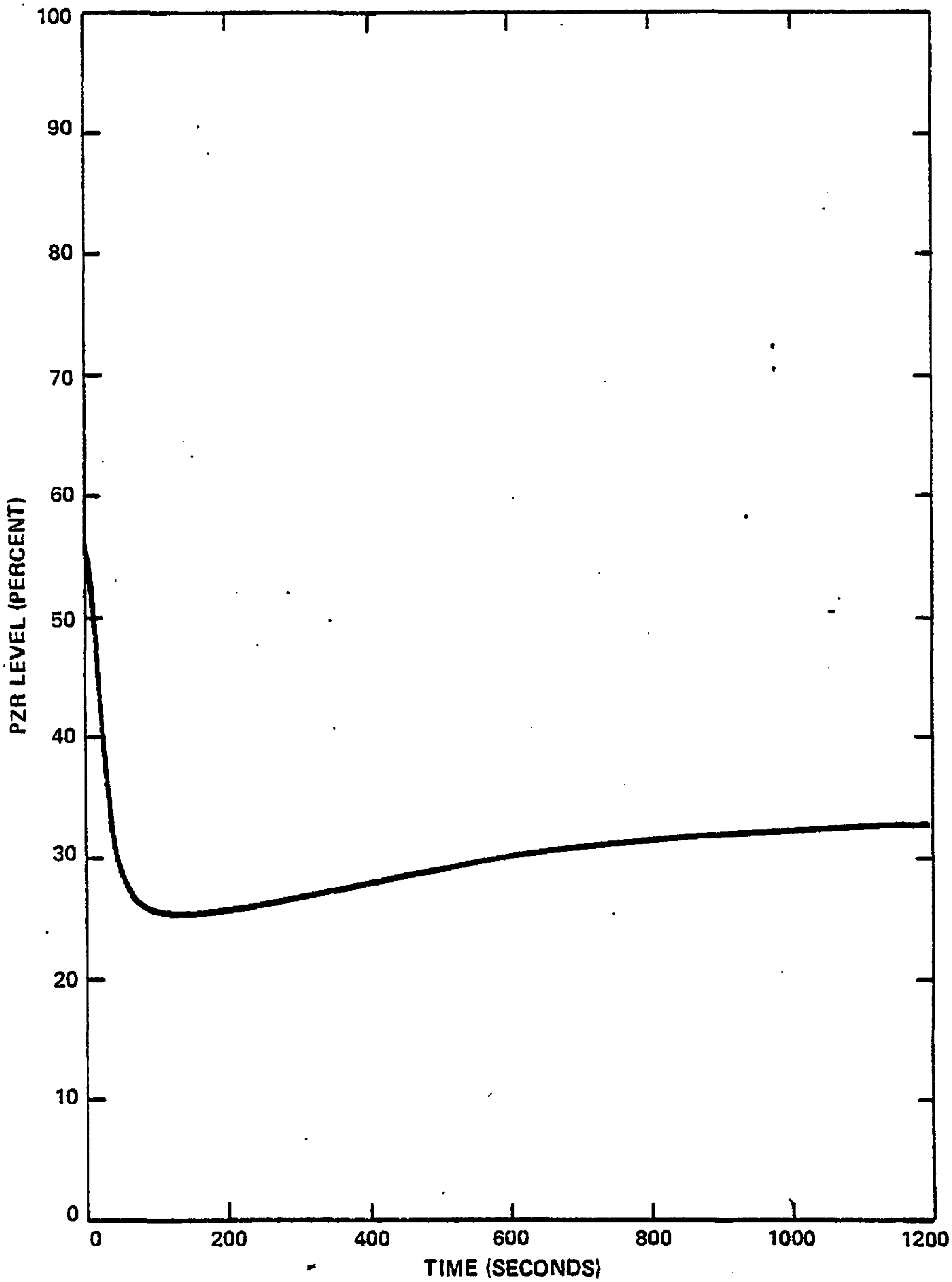


FIGURE 4-6

REPRESENTATIVE REACTOR TRIP
STEAM GENERATOR PRESSURE

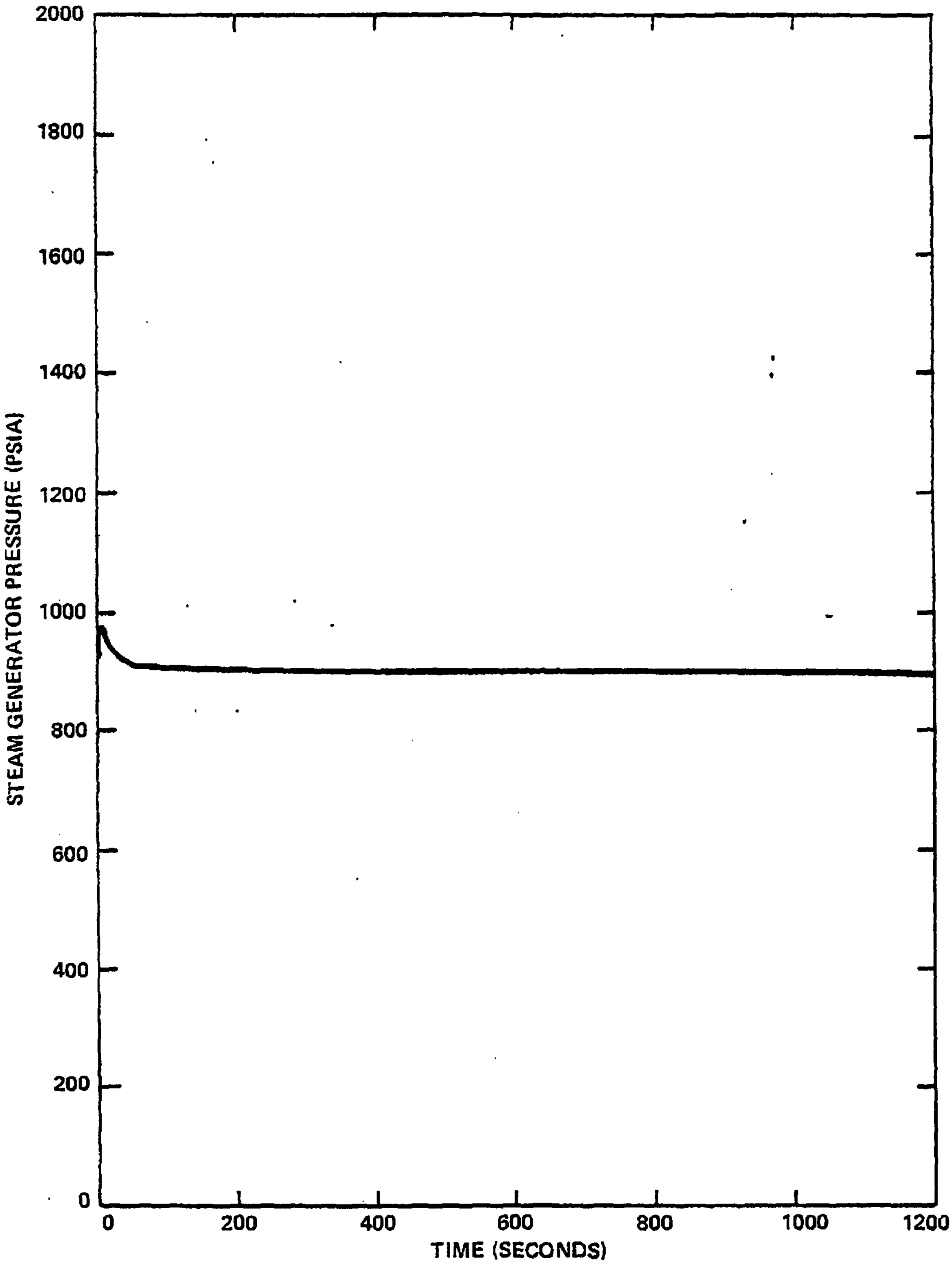
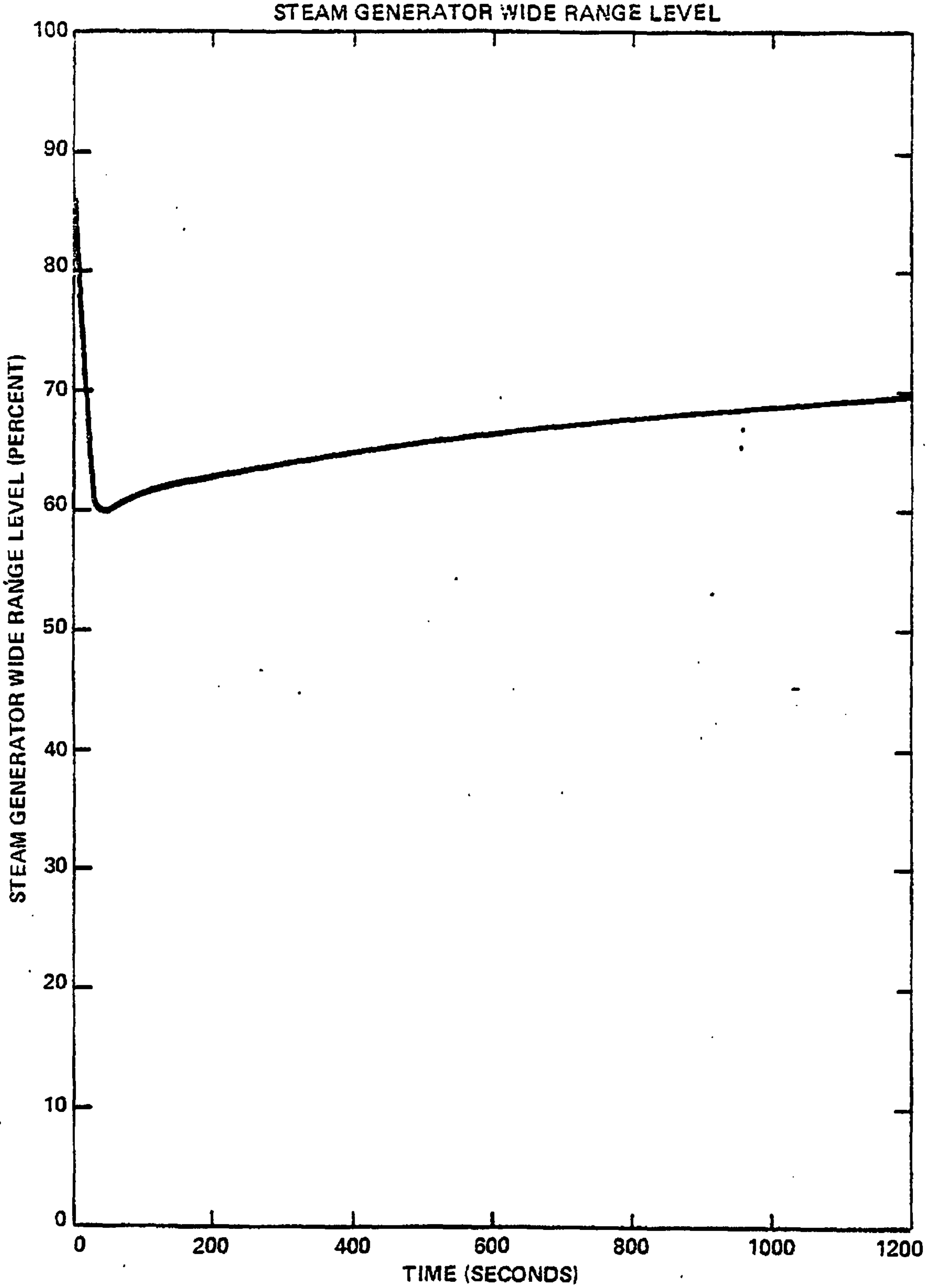


FIGURE 4-7

REPRESENTATIVE REACTOR TRIP
STEAM GENERATOR WIDE RANGE LEVEL



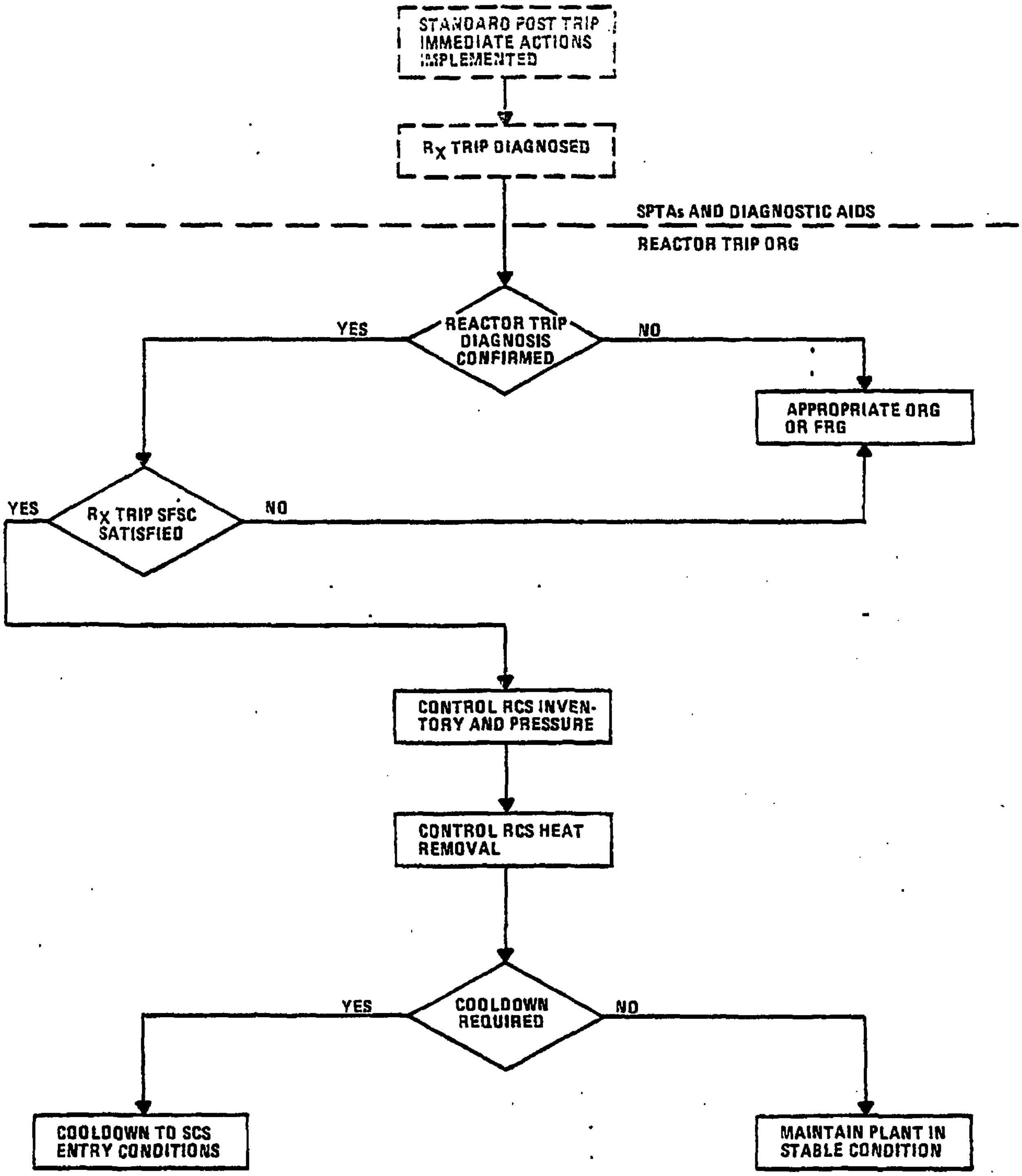
Guideline Strategy and Information Flow

Figure 4-8 provides a summary description of the Reactor Trip (RT) Recovery Guideline strategy and information flow. Prior to implementing the actions provided in the RT Recovery Guideline, the operator would have performed the Standard Post Trip Actions and concluded that an uncomplicated reactor trip had occurred. In the RT Recovery Guideline the operator begins using the safety function status check to confirm that the plant is recovering. RT Recovery actions provide instructions on regaining and maintaining RCS pressure, inventory control, and RCS heat removal.

A more detailed RT strategy chart (refer to Figure 4-10) is detailed later. It lists the guideline steps which correspond to each strategy objective. Steps which are performed at any time during the course of the event are shown by affixed asterisks.

FIGURE 4-8

REACTOR TRIP



Bases for Operator Actions

The operator actions are directed at bringing the plant to a safe, stable condition following an uncomplicated reactor trip and ensures that a proper heat sink for the reactor is being maintained.

1. The execution of all standard post trip actions is verified. This assures that the safety functions have been initially attended to.

2. The operator is required to continually verify that safety functions are being satisfied by comparing control board parameters to the criteria in the Safety Function Status Check. This ensures that the safety functions are being satisfied and the core is being adequately cooled.

3. If the safety functions are satisfied, then this procedure is adequately mitigating the effects of the RT which are occurring. Thus, the implementation of the remaining actions of this guideline is continued. If the diagnosis of an uncomplicated reactor trip is found to be in error (i.e., any of the safety functions are not being satisfied), then the procedure is not adequately mitigating the event. If another event is diagnosed, the operator exits the RT guideline and implements the appropriate guideline. If a diagnosis cannot be made, then the Functional Recovery Guideline (FRG) is implemented. The FRG is functionally oriented and will ensure all safety functions are attended to regardless of what event(s) is occurring.

4. The PLCS is verified to be automatically controlling or restoring pressurizer level. If not, charging and letdown are operated manually to ensure pressurizer level is being maintained. This action verifies that the RCS inventory control safety function is being performed.

5. The PPCS is verified to be automatically controlling or restoring RCS pressure within the limits of Figure 4-1. If not, pressurizer heaters and main (preferred) or auxiliary spray are operated manually to control pressurizer pressure. This action verifies that the RCS pressure control safety function is being performed.

6. Steam generator pressure should be controlled by the turbine bypass system. If condenser vacuum is lost, the turbine bypass system is not available, or the MSIVs have closed, then the atmospheric dump valves must be used to control steam generator pressure. This action prevents the secondary safety valves from opening and is necessary for maintaining RCS heat removal.

7. Steam generator level is restored and controlled in the normal level band using [main or auxiliary] feedwater to provide for RCS heat removal.

8. At this point, the plant status should be evaluated. If necessary, a cooldown and depressurization to SCS entry conditions should be started until finally, SCS is commenced.

Safety Function Status Checks

Figure 4-9 provides the bases for the RT Safety Function Status Check. The Safety Function Status Check is designed to ensure that the operator is using the correct procedure, and the actions of that procedure are satisfying all relevant safety functions and maintaining adequate core cooling.

SAFETY FUNCTION STATUS CHECK BASES
REACTOR TRIP
Figure 4-9a

The safety functions listed below and their respective criteria are those used to confirm the adequacy of the RT Guideline in mitigating the event.

SAFETY FUNCTION	ACCEPTANCE CRITERIA	INDICATION	RANGE	BASES
Reactivity Control	Reactor Power Decreasing and [Negative Startup Rate] and Not more than 1 CEA Bottom Light Not Lit or Borated per Tech Specs	Power Range Power Rate CEA Status Display	[0-125%] [-1 → 7 dpm] On/Off Light for each CEA	For all emergency events, the reactor must be shutdown. The criteria that no more than one CEA be stuck out or the RCS be borated observes typical Technical Specification requirements.
Maintenance of Vital Auxiliaries (AC & DC Power)	[<-----------------------------------Plant Specific----------------------------------->]			
RCS Inventory Control	[35"] ≤ Pressurizer Level ≤ [245"] and Charging and Letdown are being operated manually or automatically to maintain or restore pressurizer level	Pressurizer Level	[0"-350"]	A value of [245"] ([70%] of range) was chosen as an upper limit for pressurizer level to account for instrument inaccuracies and other uncertainties. A value of [35"] ([10%] of range) was chosen as a lower limit to account for instrument inaccuracy.
	and RCS ≥ [20°F] Subcooled and [No reactor vessel voiding as indicated by the RVLMS]	[RVLMS]	[0-100%]	A [20°F] subcooling margin coexisting with a pressurizer level in the range [35" to 245"] indicates adequate RCS inventory control via a saturated bubble in the pressurizer.

SAFETY FUNCTION STATUS CHECK BASES
REACTOR TRIP
Figure 4-9b

The safety functions listed below and their respective criteria are those used to confirm the adequacy of the RT Guideline in mitigating the event.

SAFETY FUNCTION	ACCEPTANCE CRITERIA	INDICATION	RANGE	BASES
RCS Inventory Control (Cont'd)				An uncomplicated reactor trip should not result in reactor vessel voiding.
RCS Pressure Control	[1700 psia] < Pressurizer Pressure < [2350 psia] <u>and</u> Pressurizer heaters and spray are being operated manually or automatically to maintain or restore pressurizer pressure to within the limits of the P/T curves, Figure 4-1.	Pressurizer Pressure	[1500-2500 psia]/ [0-1600 psia]	[1700 psia] corresponds to the SIAS alarm setpoint. [2350 psia] is the high pressure alarm setpoint. Best estimate analysis shows that the selected events will fall within the above range.
Core Heat Removal	$T_H - T_C$ < [10°F] <u>and</u> RCS ≥ [20°F] subcooled	T_H T_C [Subcooled Margin Monitor]	[520°-610°F] [0°-600°F] [0°-100°F]	Best estimate analysis demonstrates that S/G ΔT will be less than [10°F] in the steaming loop with RCPs running and at least one S/G steaming. [20°F] subcooled margin is based on engineering judgement to assure adequate core cooling accounting for temperature variations in the RCS. Best Estimate analysis shows that the noted events will fall in the selected ranges.

SAFETY FUNCTION STATUS CHECK BASES
REACTOR TRIP
Figure 4-9c

The safety functions listed below and their respective criteria are those used to confirm the adequacy of the RT Guideline in mitigating the event.

SAFETY FUNCTION	ACCEPTANCE CRITERIA	INDICATION	RANGE	BASES
RCS Heat Removal	a) At least one S/G has level: i) within the normal level band with feedwater available to maintain the level or ii) being restored by a feedwater flow > [150 gpm] and b). RCS T_{ave} is < [545°F]	Steam Generator Level	[+63.5" - (-)116.5"]	Decay heat levels may not be high enough to require a feedwater flow of [150 gpm]. If this is the case, once steam generator level is returned to the zero power level band and feedwater remains available to maintain that level, then RCS heat removal is being satisfied. [545°F] is based on control program for atmospheric dump valves and turbine bypass valves, and best estimate analysis.
Containment Isolation	Containment Pressure < [1.5 psig]	Containment Pressure	[0-60 psig] [0-15 psig]	[1.5 psig] is based on the containment pressure alarm. It is not expected, for the selected events, that containment pressure will increase to the alarm setpoint.
	and			
	No Containment Area Radiation Monitors Alarming	Containment Area Radiation Monitors	Alarming - Not Alarming	During an uncomplicated reactor trip there should be no radiation in containment. The indicators should not be alarming.
	and			
	No Steam Plant Activity Monitors Alarming	Steam Plant Radiation Monitors	Alarming - Not Alarming	Steam plant activity is an indication of an SGTR and is not anticipated for a RT.

SAFETY FUNCTION STATUS CHECK BASES
REACTOR TRIP
Figure 4-9d

The safety functions listed below and their respective criteria are those used to confirm the adequacy of the RT Guideline in mitigating the event.

SAFETY FUNCTION	ACCEPTANCE CRITERIA	INDICATION	RANGE	BASES
Containment Temperature and Pressure Control	Containment Pressure < [1.5 psig]	Containment Pressure	[0-60 psig] [0-15 psig]	[1.5 psig] is based on the containment pressure alarm. It is not expected, for the selected events, that containment pressure will increase to the alarm setpoint.
	<u>and</u>			
	Containment Temperature < [120°F]	Containment Temperature	[50°-300°F]	Maximum normal expected average containment air temperature.
Containment Combustible Gas Control	H_2 < [2%]	[<------------------Plant Specific----------------------->]		

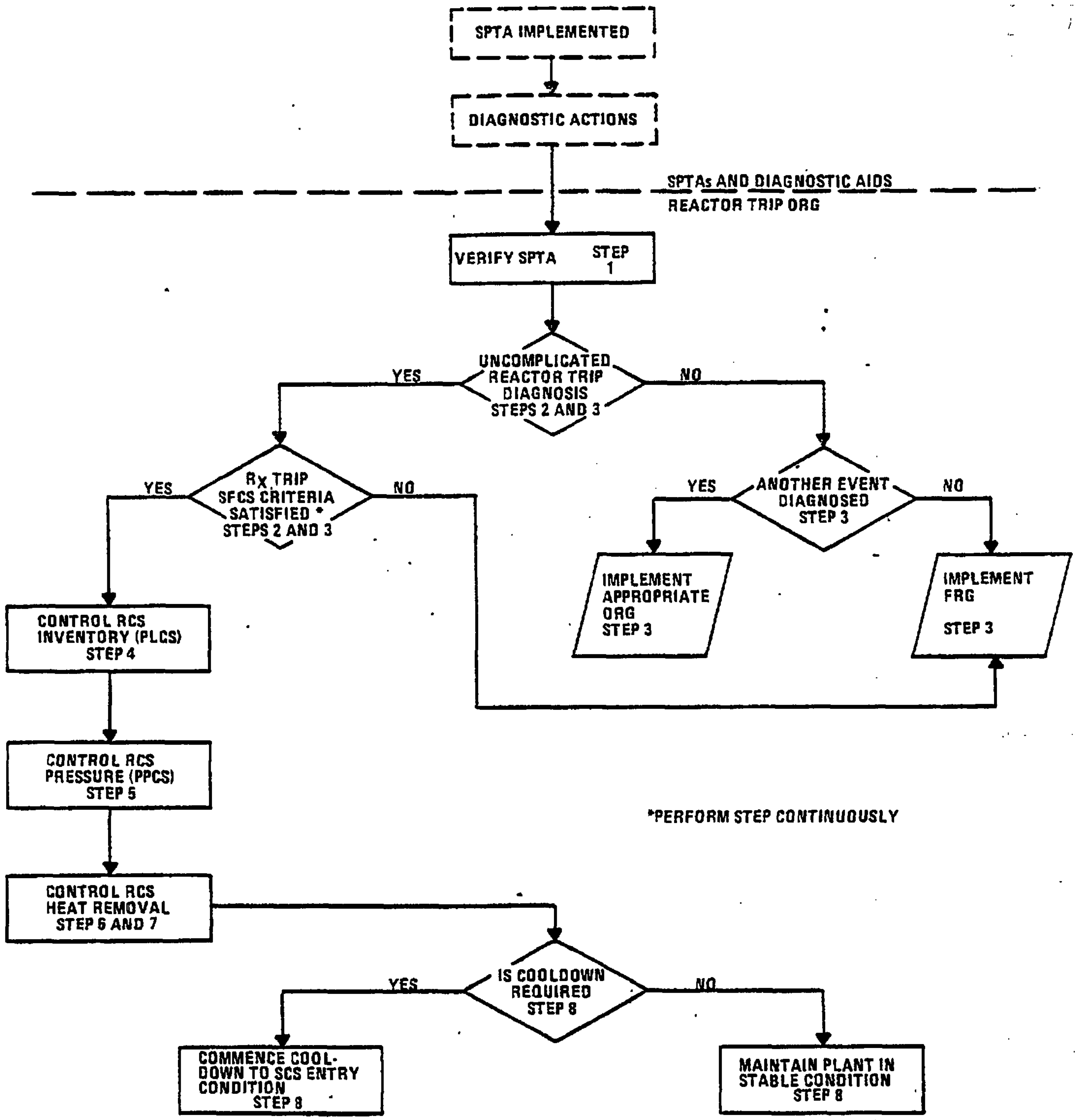
Event Strategy

This section contains the RT operator actions strategy flow chart Figure 4-10. The flow chart pictorially depicts the strategy around which the RT guideline is built. It is intended to assist the reader in understanding the intent of the guideline writer and for use in training. Operators should understand what the major objectives of the guideline are in order to permit them to evaluate their progress toward those goals.

The strategy charts show the recovery guideline strategy in detail and lists the guideline steps which correspond to each strategy objective. Some steps in the guideline may be performed at any time during the course of an event. These steps are shown by affixed asterisks.

FIGURE 4-10

STRATEGY CHART FOR REACTOR TRIP



LOSS OF COOLANT ACCIDENT
RECOVERY GUIDELINE

Prepared by
COMBUSTION ENGINEERING, INC.
for the
C-E Owners Group

PURPOSE

This guideline provides operator actions which must be accomplished in the event of a loss of coolant accident. The actions in this guideline are necessary to ensure that the plant is placed in a stable, safe condition. This guideline provides technical information to be used by utilities in developing a plant specific procedure.

ENTRY CONDITIONS

1. The Standard Post Trip Actions have been performed

and

2. Plant conditions indicate that a loss of coolant accident has occurred. Any one of the following may be present:

   a) Pressurizer level low (for a break in the pressurizer the level may be high).
   b) Safety injection system (SIS) actuated automatically.
   c) Increase in containment pressure, temperature, radiation, humidity and containment sump level.
   d) High quench tank level, temperature, or pressure.
   e) [Other plant specific symptoms, insert here.]

① Implemented in STEP A

② Implemented in STEP B

③ SEE DEVIATION 5-1

④ See Deviation 5-2

⑤ SEE DEVIATION 5-2

⑥ IMPLEMENTED IN STEP C
See Deviation 0-69

⑦ IMPLEMENTED IN STEP B

⑧ SEE DEVIATION 5-2.

OPERATOR ACTIONS

1. Verify that the Standard Post Trip Actions have been performed.

2. Confirm the diagnosis of a loss of coolant accident by:

   [a) Referring to the Break Identification Chart (Figure 5-2)

   and

   b) Verifying the Safety Function Status Check criteria are satisfied.]

3. Sample both steam generators for activity.

*4. If the diagnosis indicates that an SGTR or an ESDE has occurred, Then exit the LOCA Guideline and implement the actions of the SGTR or ESDE guideline.

*5. If the initial diagnosis of an LOCA is confirmed, Then continue with the actions of this guideline.
If not, implement the Functional Recovery Guideline.

*6. If pressurizer pressure decreases to less than [1300 psia] following an SIAS, Then ensure all four RCPs are tripped.

*7. Verify that all safety functions are being satisfied by comparing control board parameters to the criteria in the Safety Function Status Check.

*8. If the safety functions are satisfied, Then continue with the actions of this guideline.
If not, implement the Function Recovery Guideline.

* Step Performed Continuously

(9) See Deviation 5-3

(10) SIAS starts all SI and charging pumps. STEP E implements this guideline STEP BY verifying that SIAS has initiated

(11) Implemented by step D
Deviation 5-47

(12) IMPLEMENTED BY STEP T. SEE DEVIATION 5-4 for sequence VARIATION Deviation 2-39, 40, 41

9. Record the time of day.

*10. Take steps to ensure maximum safety injection (Figure 5-3) and charging flow to the RCS by:

   a) restoring electrical power to valves and pumps,
   b) restoring correct SIS valve lineup if misaligned,
   c) restoring other necessary auxiliary systems,
   d) starting idle SIS and charging pumps.

11. Attempt to isolate the leak by performing the following:

   a) [If pressurizer pressure is below 2400 psia, then verify that the PORVs are closed. If not, manually close the PORVs or close the PORV block valves.]

   b) Verify that the letdown line is isolated. If necessary, manually close the letdown isolation valves.

   c) Verify sample lines are isolated. If necessary, manually isolate sample lines.

   d) [If there are other possible sources of leakage that can be rapidly and remotely isolated, then insert that information here.]

*12. If the RCPs were stopped, Then determine whether RCP restart criteria are met by the following:

   a) At least one steam generator is available for removing heat from the RCS
   b) Pressurizer level is greater than [200"] and not decreasing

* Step performed continuously.

(13). Implemented in STEP T. See DEVIATION 5-4 FOR sequence VARIATION
Deviation 2-42, 5-49

(14) Implemented in STEP G Deviation 2-43

(15) Implemented by SFSC. ALSO, see referenced steps in guideline

c) The RCS is at least [20°F] subcooled (Figure 5-1)

d) [Other criteria satisfied per RCP operating instructions].

√*13. If RCP restart criteria are met, Then do the following:

a) Start all available HPSI and charging pumps, or verify their operation

b) Start one RCP in each loop

c) [Ensure proper RCP operation by monitoring RCP amperage and pump NPSH. NPSH is determined by pressurizer pressure and corresponding T_c on Figure 5-1].

d) Operate HPSI (Figure 5-3) and charging pumps until pressurizer level is greater than [100"] and SIS termination criteria are met.

√*14. If all RCPs have been stopped, Then verify natural circulation flow is being maintained in at least one loop. The following criteria must be met to demonstrate adequate natural circulation flow:

a) Loop ΔT (T_H - T_C) less than normal full power ΔT

b) Cold leg temperatures constant or decreasing

c) Hot leg temperatures stable (i.e., not steadily increasing) or decreasing

d) No abnormal differences between T_H RTDs [and core exit thermocouples].

*15. If the criteria of step 14 are not met, Then ensure RCS pressure and inventory (steps 20 and 21) and S/G steaming and feed (step 22) are being controlled properly. Ref steps which Ref other steps

*16. If all RCPs have stopped and inventory and pressure are not being controlled, Then two phase natural circulation cooling along with break heat removal maintain the heat removal process. In this mode the operator performs the following:

* Step Performed Continuously.

16a. implemented in step E

16b. implemented by HEAT Removal SFSC

16C. IMPLEMENTED BY STEP G AND HEAT REMOVAL SFSC
Dev 5-50

17. IMPLEMENTED IN STEP P
Dev 3-34

18. IMPLEMENTED IN STEP P. SEE DEVIATION 5-5

19. IMPLEMENTED IN STEP F
Deviation 5-51

20. Procedure is organized to minimize Referencing. IT Does this by assuming the leak is not isolated. If the leak is isolated the recovery is accomplished in an AOP.

21 See comments for step 20

a) Verify that all available charging pumps and the SIS is operating to restore inventory control per Figure 5-3
b) [Verify CET temperature < 700°F]
c) Verify that at least one steam generator has level:
   i) within the normal level band with feedwater available to maintain the level

   or

   ii) being restored by a feed water flow > [150 gpm]

*17. If the SIS is operating, Then it may be throttled or stopped, one train at a time, if the following criteria are satisfied:

a) RCS is at least [20°F] subcooled (Figure 5-1)
b) Pressurizer level is greater than [100"] and not decreasing,
c) At least one steam generator is available for removing heat from the RCS
d) [The RVLMS indicates the core is covered].

*18. If the criteria of step 17 cannot be maintained after the SIS has been stopped, Then the SIS must be restarted.

*19. Verify containment isolation at [4 psig] or [other plant specific criteria]. (Be alert to the loss of RCP cooling water and loss of other auxiliaries which may occur.)

20. If the leak has not been isolated, Then go to step 27 and perform steps 27 through 47.

21. If the leak has been isolated, Then go to step 22 and perform steps 22 through 26.

* Step Performed Continuously.

22. SEE DEVIATION 5-6

23. SEE DEVIATION 5-6

24. SEE DEVIATION 5-6

25. SEE DEVIATION 5-6 + 4-48

26. SEE DEVIATION 5-6

27. see comment for step 20

28. IMPLEMENTED IN STEP G
Dev. 5-52

22. Verify that the PPCS is automatically maintaining or restoring RCS pressure within the limits of Figure 5-1.
If not, manually operate pressurizer heaters and main (preferred) or auxiliary spray to control pressurizer pressure.

23. Verify that the PLCS is automatically maintaining or restoring pressurizer level.
If not, manually operate charging and letdown to restore and maintain normal pressurizer level.

24. Maintain RCS cooling by supplying [main or auxiliary] feedwater to the steam generators and discharging steam, preferably to the condenser, via the turbine bypass valves or, if the condenser is unavailable, to atmosphere via the atmospheric dump valves.

25. If plant conditions permit, Then bypass automatic initiation of [MSIS, CIAS, CSAS and SIAS by lowering the setpoint as the cooldown and depressurization proceed].

26. Evaluate the need for a plant cooldown based on plant status, auxiliary systems availability, and condensate inventory. If a cooldown is not required, Then maintain the plant in a stabilized condition.
If conditions require a cooldown, Then conduct a cooldown to SCS initiation conditions per normal operating instructions.
If voiding inhibits depressurization to SCS entry pressure, Then refer to steps 40 and 41.

27. If the break has not been isolated, Then perform steps 28 through 47.

28. Commence a rapid cooldown. Cooldown to at least [300°F] at a rate within the Technical Specification Limits by (listed in order of preference):

29. IMPLEMENTED IN SFSC. See DEVIATION 5-7.

30. IMPLEMENTED IN STEP I.
Dev. 5-53

31. Implemented in STEP K
Dev 5-54

32 Implemented in step L
5-55, 56

33. Implemented in step L

a) the turbine bypass system and [main or auxiliary] feedwater,

or

b) the atmospheric dump valves and [main or auxiliary] feedwater.

*29. Monitor the condensate inventory during the cooldown to ensure an adequate supply. Refer to Figures 5-4 and 5-5.

30. Restore and maintain pressurizer level in the indicating range ([35 to 245"]) unless it is necessary to go solid to restore RCS subcooling, by (listed in order or preference):

a) Control of charging and letdown

or

b) Operating and/or throttling SIS.

31. [If the charging pumps are taking suction from a concentrated boron source, Then realign suction to the RWT or other suitable source within 1 hour after the start of the loss of coolant accident.]

*32. Monitor [refueling water tank] level. If the [refueling water tank] level falls to [10%], Then verify initiation of recirculation. If necessary, manually initiate recirculation with one SIS train at a time [and close RWT outlet valves to the safety injection system].

*33. If the HPSI pumps are delivering less than [30 gpm] per pump during recirculation, Then turn off one charging pump at a time and then one HPSI pump (turn off the HPSI pump with the lower indicated flow) at a time until the remaining HPSI pumps are delivering more than [30 gpm] per pump. At least one HPSI pump should be kept operating at all times unless SIS termination criteria of step 17 are met.

* Step performed continuously.

34. Implemented in SFSC

35. Implemented in step m
Dev 5-57

36. Implemented in step G.
5-58

37. Implemented in step V
5-59, 60

38. Implemented in step V and W. See deviation 5-8.

*34. [Monitor containment radiation levels in order to evaluate environmental releases. It may be desirable to reduce airborne radiation levels in the containment to minimize environmental releases.]

35. If the CSAS has been actuated and containment pressure subsequently falls below [7 psig], Then containment spray should be terminated. Upon termination, the CSS must be realigned and reset for automatic actuation. The CSS may be manually restarted to control iodine levels in the containment.

36. If plant conditions permit, Then bypass automatic initiation of [MSIS by lowering the setpoint as the cooldown and depressurization proceed.]

37. At [2-4 hours] after the start of the loss of coolant event, the alignment of the [SIS] for simultaneous hot and cold leg injection should be made, unless the criteria of step 38 can be met before the [4 hour] time limit. In that case, go to step 38. Verify SIS flow per Figure 5-3.

*38. Determine if the conditions for entering shutdown cooling system operation can be established by the following criteria:

a) Pressurizer level is greater than [100"] and constant or increasing
b) The RCS is at least [20°F] subcooled
c) RCS activity level within [plant specific limits]
d) Condensate inventory adequate per Figures 5-4 and 5-5.
e) [Other plant specific information insert here, (e.g., component cooling water, instrument air, valve control power).]

* Step performed continuously.

39. Implemented in alternate action W

40 IMPLEMENTED IN ALTERNATE ACTION T
5-61

41 IMPLEMENTED IN ALTERNATE ACTION T
5-61 + 62

*39. If the criteria in step 38 are satisfied, Then shutdown cooling system operation is allowable when the RCS has been depressurized to at least [300 psia] and cooled down to at least [300°F].

a) [Realign the SIS for cold leg injection]
b) If necessary, cool the RCS to < [300°F].
c) If necessary, depressurize the RCS to < [300 psia] by:
   i) use of auxiliary spray
   ii) stopping charging pumps, or stopping or throttling HPSI pumps

*40. If the above actions fail to depressurize the RCS, Then a void should be suspected. The operator should monitor for the presence of voids. If voiding inhibits RCS depressurization to SCS entry pressure, Then an attempt at eliminating the voiding should be made.

Voiding in the RCS may be indicated by any of the following indications, parameter changes, or trends:

a) letdown flow greater than charging flow,
b) pressurizer level increasing significantly greater than expected while operating pressurizer spray,
c) [the RVLMS indicates that voiding is present in the reactor vessel],
d) [HJTC unheated thermocouple temperature indicates saturated conditions in the reactor vessel upper head]. A
e) [other indications, insert here].

*41. If voiding should be eliminated, Then proceed as follows:

a) verify letdown is isolated,
b) stop the depressurization and, if required, repressurize the RCS to ≥ [20°F] subcooling,

* Step performed continuously.

42 IMPLEMENTED IN STEP W AND X .
S-63

43 Implemented in STEP U. SEE DEVIATION 5-9

44 Implemented in STEP U. see DEVIATION 5-9

45 Implemented in step X. see DEVIATION 5-10

c) pressurize and depressurize the RCS within the limits of Figure 5-1 by operating pressurizer heaters and spray (preferred method) or HPSI and charging pumps (alternative method). Monitor pressurizer level [and the RVLMS] for trending of RCS inventory.

d) if indications of unacceptable RCS voiding continue, and voiding is suspected to exist in the (isolated) steam generator tubes, then cool the (isolated) steam generator (by steaming or blowdown, and/or feeding) to condense the steam generator tube bundle void. Monitor pressurizer level for trending of RCS inventory.

e) if indications of unacceptable RCS voiding continue, then [operate the pressurizer vent and/or the reactor vessel head vent to] clear trapped non-condensible gases. Monitor pressurizer level [and/or the RVLMS] for trending of RCS inventory.

42. When SCS entry conditions (RCS pressure $\leq$ [300 psia] and RCS $T_H \leq$ [300°F]) are established, Then initiate SCS operation per operating instructions.

43. [Isolate, vent, or drain the safety injection tanks (SITs) at 250 psia RCS pressure.]

→44. [Initiate the low temperature overpressurization (LTOP) system at 275°F.]

45. If shutdown cooling system operation is not possible, Then continue simultaneous hot and cold leg injection and maintain RCS heat removal using the following methods (listed in order of preference):

a) If the condenser and the [main or auxiliary] feedwater system is available, then maintain RCS heat removal by using the turbine bypass system.

b) If the condenser or turbine bypass system is not available, then maintain RCS heat removal by way of the atmospheric dump valves using either the [main or auxiliary] feedwater system.

46 See Deviation 5-11

47 See Deviation 5-12. CST level monitored in SFSC

c) [Maintain steam generator cooling using alternate methods of secondary feedwater supply while discharging steam to the condenser or atmosphere.]

*46. [If the RCS heat removal methods of step 45 are not adequate to maintain the RCS subcooled, Then establish once through cooling by the following:

a) Realign the SIS for cold leg injection
b) Verify HPSI and charging pumps are operating (or start them)
c) Open both pressurizer PORVs.]

*47. If the condensate inventory for any of the heat removal methods of step 45 becomes limiting, Then reevaluate the conditions in step 38 and then, if appropriate, implement steps 38 through 44.

* Step performed continuously.

1. IMPLEMENTED THROUGH OUT PROCEDURE WHERE cooldown guidance is provided

2. IMPLEMENTED IN PRECAUTIONS A AND B

3. IMPLEMENTED IN PRECAUTIONS C AND D

4. IMPLEMENTED AS A PREREQUISITE FOR INITIATING SDC. SEE STEPS W AND X

5. IMPLEMENTED IN PRECAUTION G

6. IMPLEMENTED BY STEP L

SUPPLEMENTARY INFORMATION

This section contains items which should be considered when implementing EPGs and preparing plant specific EOPs. The items should be implemented as precautions, cautions, notes, or in the EOP training program.

1. During all phases of the cooldown, monitor RCS temperature and pressure to avoid exceeding a maximum cooldown rate greater than Technical Specification Limitations.

2. Do not place systems in "manual" unless misoperation in "automatic" is apparent. Systems placed in "manual" must be checked frequently to ensure proper operation.

3. All available indications should be used to aid in the evaluation of plant conditions since the accident may cause irregularities in a particular instrument reading. Instrument readings must be corroborated when one or more confirmatory indications are available.

4. If there is a high radioactivity level in the reactor coolant system, then circulation of this fluid through the SCS may result in high area radioactivity readings in the [auxiliary building]. The activity level of the RCS should be determined prior to initiating SCS flow.

5. For small breaks in the RCS where the steam generators are important for heat removal, one steam generator must be used for this purpose even if primary to secondary leaks are detected. Use the unaffected steam generator, or the least affected steam generator, if both have primary to secondary leaks.

6. The operator should be cautioned against prematurely initiating an RAS. This manual action should not be taken unless an automatic RAS is required.

7. STEPS within procedure DIRECT THAT SUBCOOLING BE MAINTAINED BETWEEN 30 AND 200°F IF POSSIBLE. Since excessive Cooldown Rates followed by repressurization is NOT TYPICAL OF A LOCA NO FURTHER CONTROLS WERE CONSIDERED NECESSARY

8. IMPLEMENTED BY PRECAUTION H AND STEP Z.

9. SEE DEVIATION 5-13.

10. IMPLEMENTED IN PRECAUTION I

11 SEE DEVIATION 5-14

12. IMPLEMENTED BY PRECAUTION C. Also subcooling is calculated using CET Temperature AND THE SFSC USES CET

13. Implemented IN STEP T. CONDENSATE AVAILABILITY MONITORED IN SFSC

7. If the initial cooldown rate exceeds Technical Specification Limits, then there may be a potential for pressurized thermal shock (PTS) of the reactor vessel. Post Accident Pressure/Temperature Limits should be maintained within the limits of Figure 5-1.

8. Minimize the number of auxiliary spray cycles whenever the temperature differential between the spray water and the pressurizer is greater than [200°F] in order to minimize the increase in the spray nozzle thermal stress accumulation factor. Every such cycle must be recorded in accordance with Technical Specification Limitations.

9. [Monitor quench tank parameters since any sustained operation of the PORVs may burst the tank's rupture disc.]

10. Verification of an RCS temperature response to a plant change during natural circulation cannot be accomplished until approximately 5 to 15 minutes following the action due to increased loop cycle times.

11. Solid water operation of the pressurizer should be avoided unless [20°F] of subcooling cannot be maintained in the RCS (Figure 5-1). If the RCS is solid, closely monitor any makeup or draining, and any system heatup or cooldown, to avoid any unfavorable rapid pressure excursions.

12. Hot leg and cold leg RTD temperature indication may be influenced by charging pump or SIS injection water temperatures. Use multiple RTD indications [and/or CET indications] for temperature when injection is occurring.

13. During the process of establishing entry conditions (RCS pressure and temperature) for SCS operation, it may be necessary to eliminate or reduce the size of the steam void in the reactor head. Ensure sufficient condensate availability to continue steam generator heat removal until the RCS pressure and temperature are reduced sufficiently, and SCS operation is accomplished.

14. See Deviation 5-15

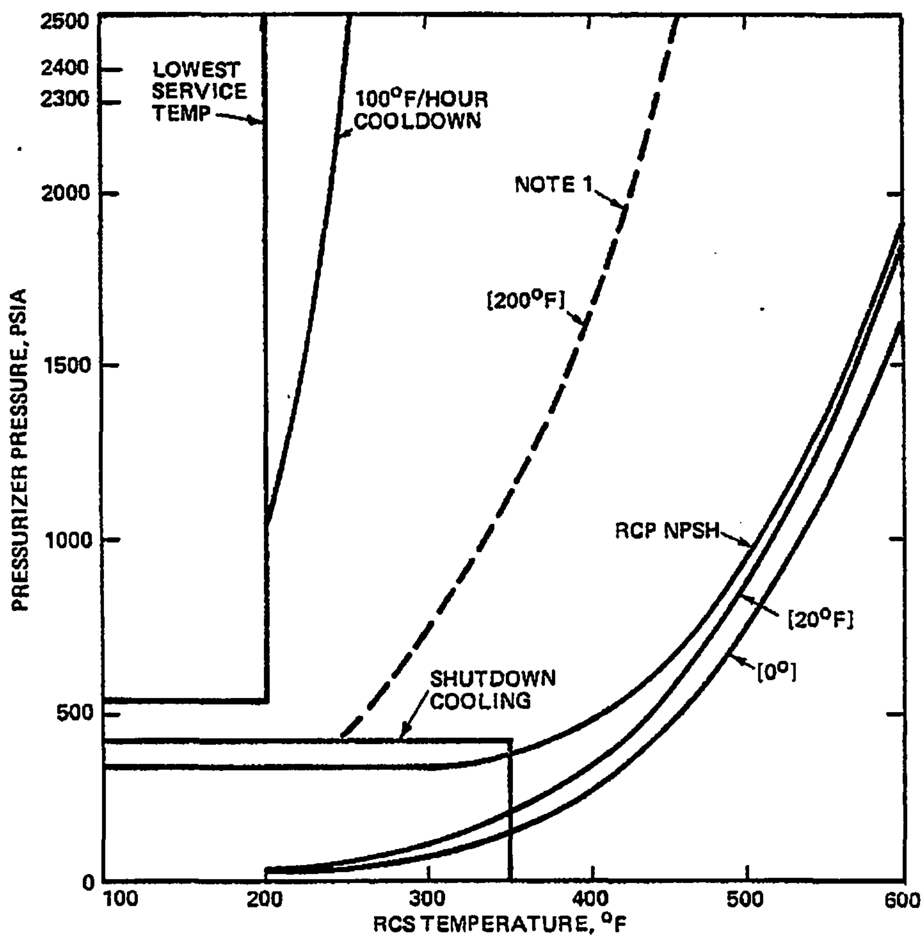
15. Monitoring heat removal continuously is accomplished in SFSC. Step T provides direction for monitoring voids and reducing/eliminating voids.

14. When a void exists in the reactor vessel, and RCPs are not operating, the RVLMS provides an accurate indication of reactor vessel liquid inventory. When a void exists in the reactor vessel, and RCPs are operating, it is not possible to obtain an accurate reactor vessel liquid level indication due to the effect of the RCP induced pressure head on the RVLMS. The indicated level also differs for different RVLMS designs under these conditions. Information concerning reactor vessel liquid inventory trending may still be discerned. However, the operator is cautioned not to rely solely on the RVLMS indication when RCPs are operating.

15. The operator should continuously monitor for the presence of RCS voiding and take steps to eliminate voiding any time voiding causes the heat removal or inventory control safety functions to begin to be threatened. C
Void elimination should be started soon enough to ensure heat removal and inventory control are not lost.

FIGURE 5-1

TYPICAL POST ACCIDENT PRESSURE-TEMPERATURE LIMITS(2)



NOTES: (1) THIS CURVE SUPERSEDES THE 100°F/HOUR COOLDOWN CURVE ANYTIME THE RCS HAS EXPERIENCED AN UNCONTROLLED COOLDOWN WHICH CAUSES RCS TEMPERATURE TO GO BELOW 500°F

(2) THESE CURVES MUST BE ADJUSTED FOR INSTRUMENT INACCURACIES

(3) COLOR CODE

RED -	PARAMETER IN EXCESS OF LIMITS
ORANGE -	PARAMETER IN DANGER OF EXCEEDING LIMITS
YELLOW -	PARAMETER OUTSIDE OF OPTIMAL RANGE, BUT STILL WITHIN LIMITS
GREEN -	PARAMETER IN OPTIMAL RANGE OF VALUES

BREAK IDENTIFICATION CHART

FIGURE 5-2

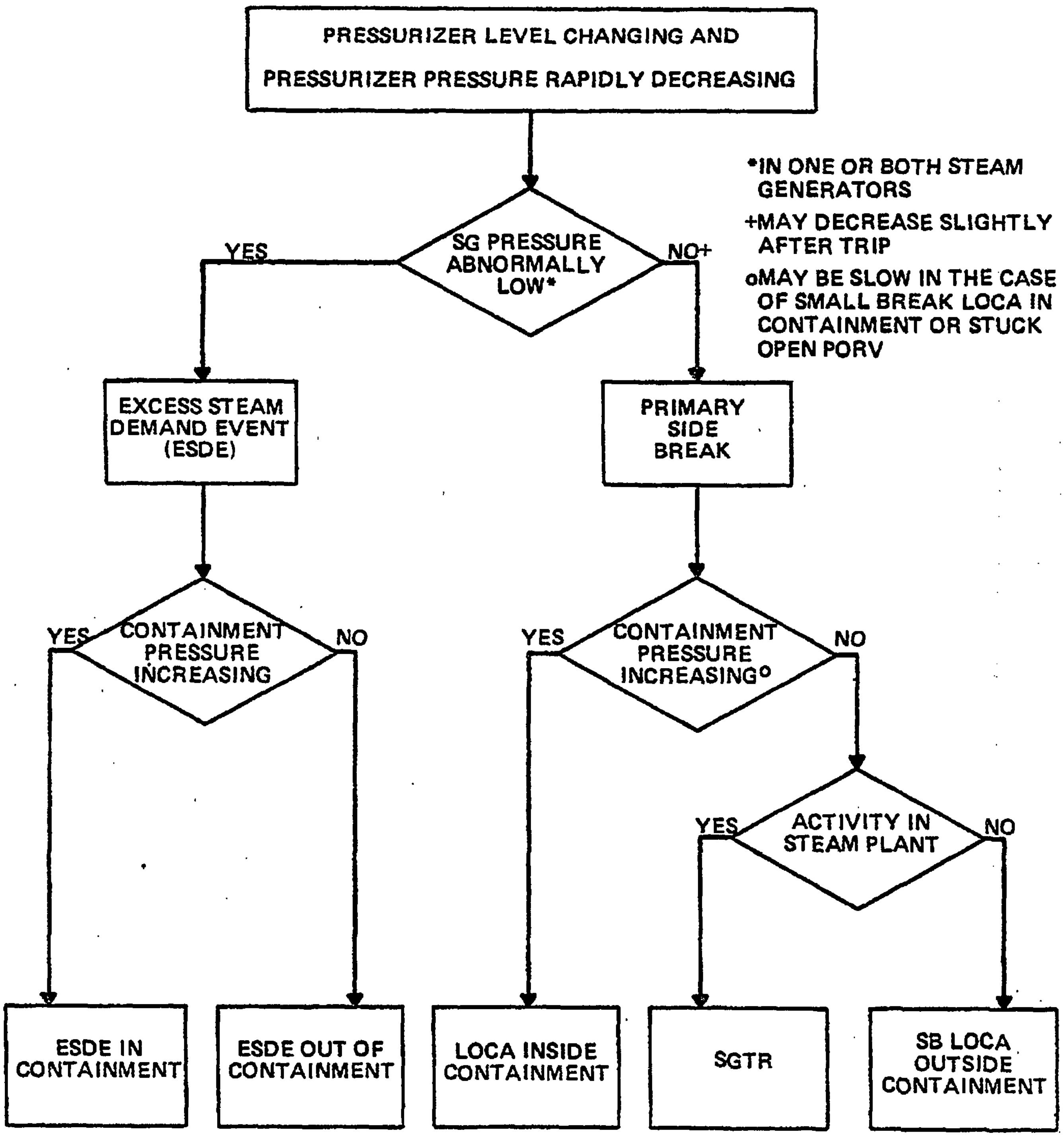
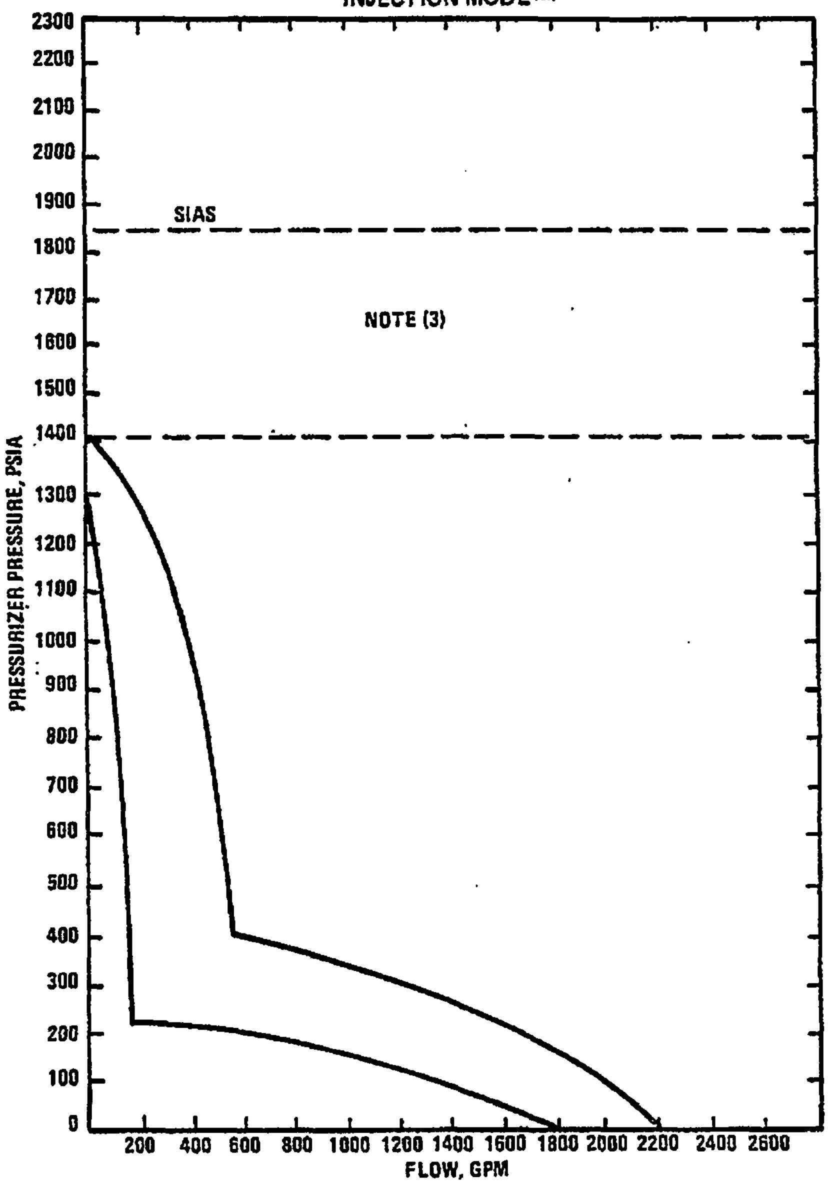


FIGURE 5-3

TYPICAL ACCEPTABLE SIS FLOW vs RCS PRESSURE(1)
INJECTION MODE(2)



NOTES:
(1) SEE IMPLEMENTATION SECTION FOR DEVELOPMENT OF PLANT SPECIFIC CURVE
(2) FOR HOT AND COLD LEG INJECTION MODE, THE LPSI PUMPS ARE NOT REQUIRED TO BE OPERATING. THE HPSI PUMP FLOW IS DIVIDED EQUALLY BETWEEN THE HOT AND COLD LEGS
(3) BELOW SIAS PRESSURE, SAFETY INJECTION SYSTEM (SIS) PUMPS WILL BE OPERATING BUT THERE WILL BE NO INJECTION FLOW UNTIL SYSTEM PRESSURE FALLS BELOW THE SHUTOFF HEAD OF ANY SIS PUMP
(4) COLOR CODE
  - RED - PARAMETER IN EXCESS OF LIMITS
  - YELLOW - PARAMETER OUTSIDE OF OPTIMAL RANGE, BUT STILL WITHIN LIMITS
  - GREEN - PARAMETER IN OPTIMAL RANGE OF VALUES

FIGURE 5-4
TYPICAL FEEDWATER CAPACITY vs TIME REMAINING UNTIL SHUTDOWN COOLING REQUIRED

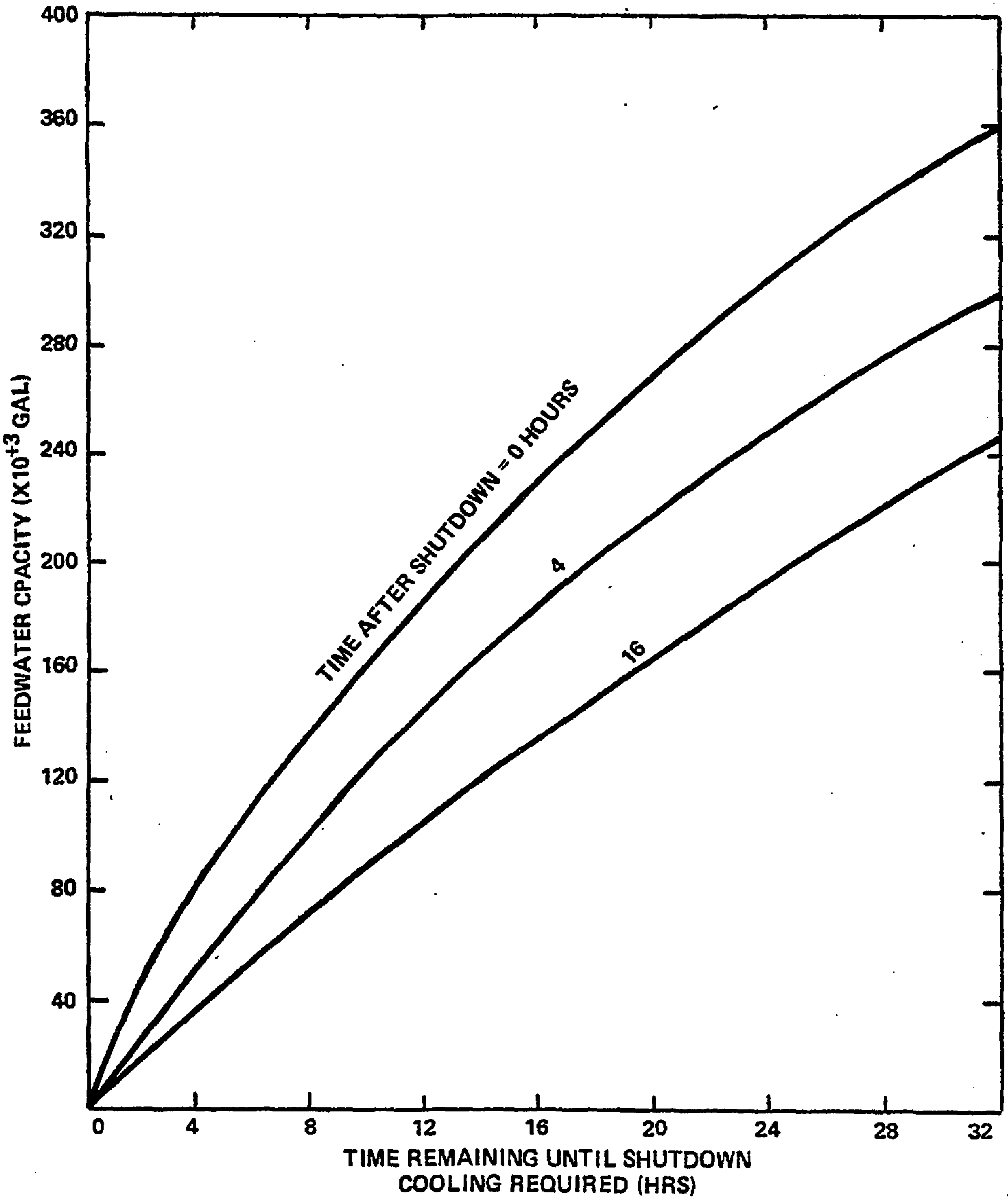
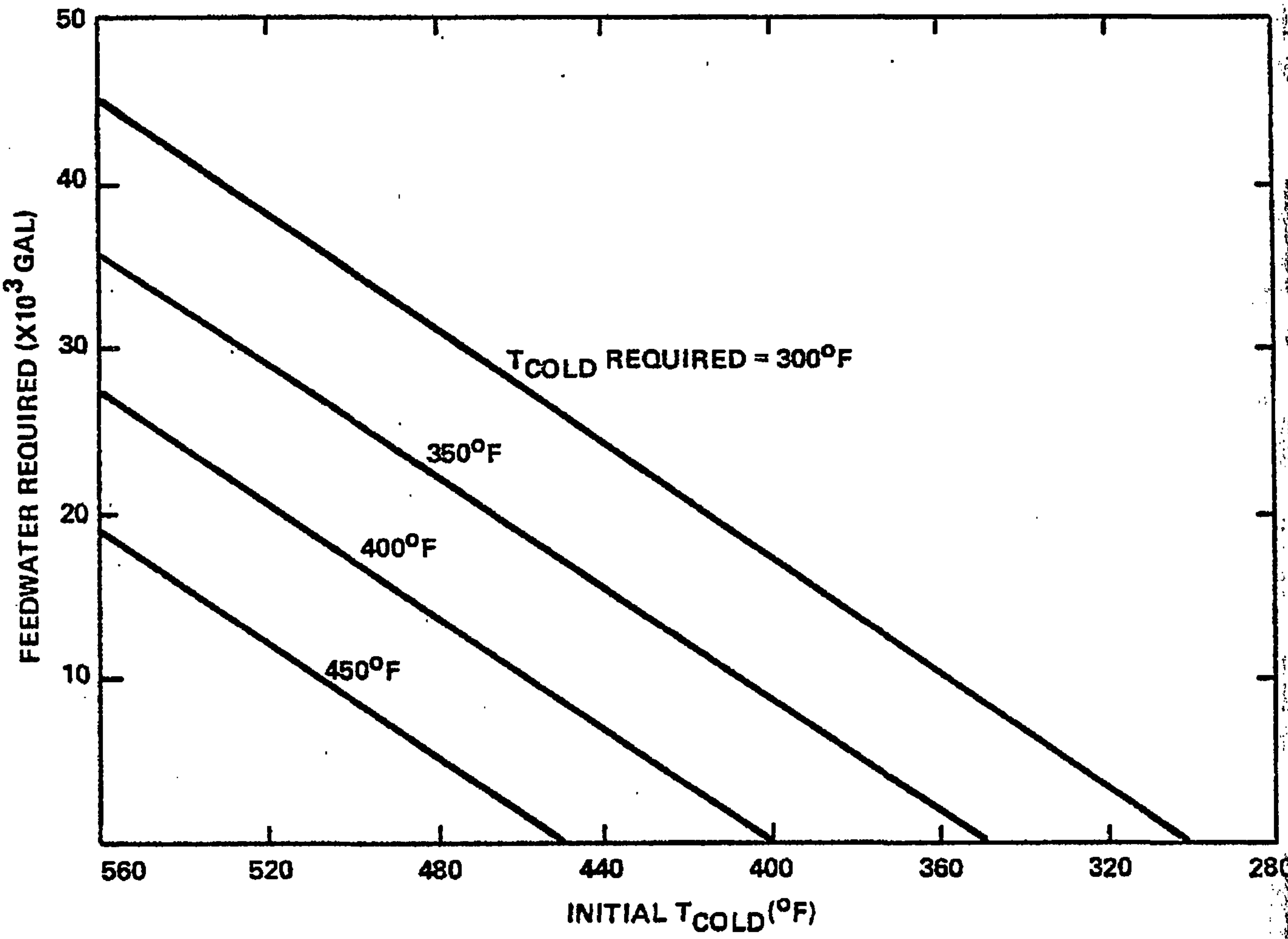


FIGURE 5-5

TYPICAL FEEDWATER REQUIRED FOR SENSIBLE HEAT REMOVAL
T_{COLD} (REQUIRED) vs T_{COLD} (INITIAL)



1. All items covered under Reactivity Control SFSC.

2. Included as 4th function of SFSC

3. Level and subcooling acceptance criteria are included in SFSC. See Deviation 5-16 for equipment operation verification

SAFETY FUNCTION STATUS CHECK

Safety Function	Acceptance Criteria
1. Reactivity Control	1.a. Reactor power decreasing *and* b. [Negative Startup Rate] *and* c. Not more than 1 CEA bottom light not lit or borated per Tech Specs.
2. Maintenance of Vital Auxiliaries (AC and DC Power)	2. [Plant specific criteria, insert here].
3. RCS Inventory Control	3.a. If pressurizer level is [35 to 245"], Then: i) charging and letdown are being operated automatically, or manually, to maintain or restore pressurizer level and ii) the RCS is at least [20°F] subcooled and iii) [the RVLMS indicates the core is covered] *or* b. If pressurizer level is less than [35"], Then [all available charging pumps are operating and]

4. See DEVIATION 5-17

5 CET used in place of THOT because of affects charging and SI temperature can have on the RTDs

SAFETY FUNCTION STATUS CHECK (Cont'd)

Safety Function	Acceptance Criteria
3. RCS Inventory Control (Cont'd)	the SIS pump(s) are injecting water into the RCS per Figure 5-3.
4. RCS Pressure Control	4.a. If pressurizer pressure is greater than or equal to [1600 psia], Then either pressurizer heaters and spray, or charging pumps and SIS pumps, are being operated automatically, or manually, to maintain or restore pressurizer pressure within the limits of Figure 5-1. or b. If pressurizer pressure is less than [1600 psia], Then [all available charging pumps are operating and] the SIS pump(s) are injecting water into the RCS per Figure 5-3 (unless SIS termination criteria are met).
5. Core Heat Removal	5. T_H RTD [and Core Exit Thermocouple] temperatures less than [700°F].

6. LEVEL CRITERIA CONTAINED IN SFSC. ~~8~~ SEE DEVIATION 5-18 for feedwater flow, TAVE, AND charging/SI Deviations

7 Implemented by step F AND BY THE CONTAINMENT ENVIRONMENT AND RADIATION CONTROL SFSC's. see Deviation 5-19 for CONTAINMENT ISOLATION Safety function DEVIATION

8.

SAFETY FUNCTION STATUS CHECK (Cont'd)

Safety Function	*Acceptance Criteria*
6. *RCS Heat Removal*	6.a. At least one steam generator has level: i) within the normal level band with feedwater available to maintain level or ii) being restored by feedwater flow greater than [150 gpm]. and b. RCS T_{ave} is less than [545°F] and controlled *or* c. [All available charging pumps are operating and] the SIS pump(s) are injecting water into the RCS per Figure 5-3 (unless SIS termination criteria are met).
7. *Containment Isolation*	7.a. i) Containment pressure less than [4 psig] and ii) No containment area radiation monitors alarming and iii) No steam plant activity monitors alarming *or* b. CIAS present or manually initiated.

8. IMPLEMENTED IN CONTAINMENT ENVIRONMENT SFSC. SEE DEVIATION 5-20 for spray flow DEVIATION.

9. implemented in Containment environment safety function status check

SAFETY FUNCTION STATUS CHECK (Cont'd)

Safety Function	*Acceptance Criteria*
8. *Containment Temperature & Pressure*	8.a. i) Containment temperature less than [240°F] and ii) Containment pressure less than [10 psig] *or* b. Containment spray flow greater than [1500 gpm].
9. *Containment Combustible Gas Control*	9.a. H_2 concentration less than [2%] *or* b. [Hydrogen recombiners in operation].

BASES

The bases section of the loss of coolant accident (LOCA) emergency procedure guideline describes the LOCA transient in relation to the actions which the operator takes during an LOCA. The purpose of the bases section is to provide the operators with information which will enable them to understand the reasons for, and the consequences of, the actions they take during an LOCA.

Characterization of an LOCA

An LOCA is an accident which is caused by a break in the reactor coolant system (RCS) pressure boundary. The break can be as large as a double ended guillotine break in the hot leg or as small as a break which results in a loss of RCS fluid at a rate that is just in excess of the available charging capacity of the plant.

Small and large break LOCAs differ in their effect on the post-LOCA RCS heat removal process. For a large break the only path necessary for RCS heat removal in both the short and long term, is the break flow with core boiloff. For small breaks, heat removal via the flow out the break is not sufficient to provide cooling, and therefore steam generator heat removal is required. The guidelines take this into account with the decisions which must be made. Although distinct small and large break LOCA information is contained in the bases section of this guideline, the action steps to be used during the actual emergency do not require the operator to distinguish between break sizes.

An LOCA is characterized by an initial decrease in RCS pressure and inventory. Subsequent RCS inventory and pressure response depends on the size of the break. For large breaks inside containment, an increase in containment temperature and pressure occurs relatively soon after the LOCA. However, a small LOCA or stuck open PORV may not be detectable on containment temperature and pressure instruments in the short term. The actions taken by the operator during an LOCA, and more detailed descriptions of LOCA response, are provided in the following sections.

Safety Functions Affected

The LOCA primarily affects RCS inventory and pressure control, and RCS and core heat removal. To a lesser degree, reactivity control, containment isolation, and containment temperature and pressure control are also affected. All safety functions should be monitored to assure public safety or detect failures which might lead to unsafe conditions.

RCS inventory control is initially lost since the break flow rate exceeds the available charging pump capacity. For small breaks, RCS inventory control is regained via injection from the high pressure safety injection (HPSI) pumps [and the charging pumps]. It is maintained in the long-term by injection from these pumps. For large breaks, inventory control is regained through the injection of water into the RCS by the safety injection tanks (SITs) and the low pressure safety injection (LPSI) pumps. It is maintained in the long-term through the recirculation of sump water through the RCS by the HPSI pumps. Note that for large breaks, the RCS may not totally refill and pressurizer level may not be regained. If the large break is unisolable, injection is required continually to make up for the loss out the break and to prevent boron precipitation.

RCS pressure control is initially lost since the RCS depressurizes as a result of the loss of inventory out the break. For large breaks, the RCS depressurizes in 10 seconds to 3 minutes to pressures typically below 300 psia. In the case of the largest breaks, the RCS pressure will reach equilibrium with containment pressure, and will be nearly equal to that pressure. Because of the size of the break, the operator never regains direct control of RCS pressure and the RCS remains depressurized. For small breaks, the RCS depressurizes during the short-term (10 to 30 minutes) to an equilibrium condition with the steam generators. It then continues to depressurize as the operator cools down the steam generators. Pressure control is regained when the safety injection system (SIS) refills the RCS and pressurizer level is regained. Once pressure control is regained, subsequent small break post-LOCA operator actions which are associated with pressure control are (1) decreasing RCS pressure by means of auxiliary sprays, (2) controlling HPSI pumps and charging, (3) heat removal via the steam generators in order to establish shutdown

cooling entry conditions and, (4) isolating or depressurizing the SITs. For small break LOCAs, during the period of time when the RCS is refilling (pressure control has not yet been achieved), there may be significant voiding in the RCS. The voided areas may be located in the reactor vessel head region [as indicated by the RVLMS], the RCS loops, or the steam generator u-tubes, and may be made up of steam or non-condensible gases. Steam voids may occur from fluid flashing in local hot spots within the RCS. The presence of small amounts of non-condensibles may be present from sources such as gases evolving from the primary coolant and pressurizer vapor space. [If their presence is detected in the RCS the reactor vessel head vent may be operated.] The presence of non-condensible gases in the steam generator tubes is characterized by a decrease in primary to secondary heat removal capability. RCS heat removal is not jeopardized by the presence of non-condensibles until a significant number of steam generator tubes are blocked. A significant number of tubes will not be blocked unless there is considerable oxidation of fuel cladding, and this is not expected for the small break LOCA, unless significant core uncovery occurs.

There are two paths initially available for RCS heat removal: heat transfer to the secondary side via the steam generators, and heat transfer via the fluid flowing out the break. Large break LOCAs have sufficient fluid flowing out the break to provide adequate heat removal without relying on steam generators. Small break LOCAs do not have sufficient fluid flowing out of the break to provide adequate heat removal. Therefore, steam generator heat removal is required in addition to break flow for adequate heat removal.

The large break LOCA heat removal process is not complex. For cold leg breaks the SIS refills the reactor vessel (RV) and provides only enough fluid to the core to match boil off. The excess injected fluid spills out of the cold leg break. The steam from core boil off passes out the hot leg and through the steam generators on its way out the cold leg break. For the hot leg break, the injected water builds up in the cold legs and provides the core with water for boil off heat removal and some single phase cooling. In the long term, heat removal is provided by simultaneous hot and cold leg injection. This

process provides heat removal for either hot or cold leg large break LOCAs while providing the added benefit of ensuring adequate flushing of the RV to avoid buildup of non-volatile materials produced in the boil off cooling process. Figures 5-6 and 5-7 illustrate the heat removal process for large break LOCAs.

The small break LOCA heat removal process is more complex than that described above for the large break. In the short-term, after the RCPs are tripped, core heat removal is maintained by natural circulation. Since the break is not large enough to adequately remove the heat, heat removal via a steam generator is required. This requires that the operator maintain feedwater (either main or auxiliary) to the steam generators and control steam flow from the steam generators via the turbine bypass system or the atmospheric dump valves. Figures 5-8 and 5-9 illustrate the heat removal process for typical small break LOCAs. The typical percentage of required RCS heat removed by the steam generators for various break sizes is illustrated in Figures 5-10 and 5-11.

The small break natural circulation process can take different forms. These forms include single phase natural circulation and a more complex two phase natural circulation. The simplest form of natural circulation is single phase, liquid cooling. Single phase natural circulation is possible for cases where RCS inventory and pressure are controlled. Single phase cooling transports heat using the same flow path involved in forced circulation cooling with the liquid density difference between SG and RV driving the flow. Two phase natural circulation involving steam and water is more complex and can take several forms, which depends on the amount of decay heat, the amount of inventory and pressure control degradation, the break size and the status of the SIS and the steam generators. One form of two phase natural circulation is known as reflux. In the reflux process, steam leaves the core region and travels to the steam generator via the hot leg; the steam is condensed in the steam generator before reaching the top of the "U" tubes and flows back to the core via the hot leg where it is once again turned to steam. Another two phase natural circulation process is similar to reflux but differs in that the steam from the core goes past the steam generator "U" bend and is condensed in the tubes on the cold leg side; thus condensate flows back to the core via the cold leg. A combination of the two processes is also possible.

FIGURE 5-6

HEAT REMOVAL VIA
LARGE HOT LEG BREAK

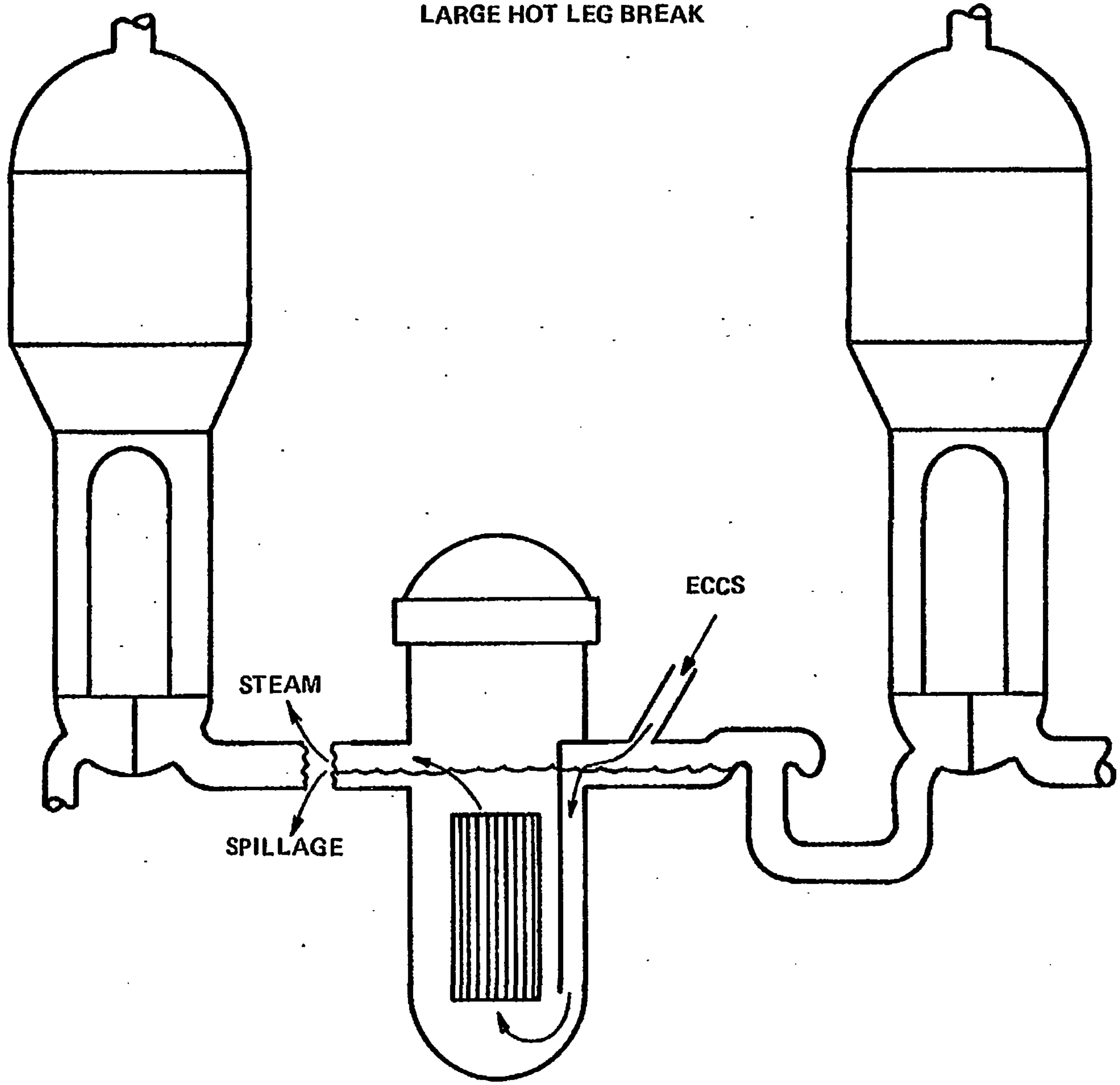


FIGURE 5-7

HEAT REMOVAL VIA
LARGE COLD LEG BREAK

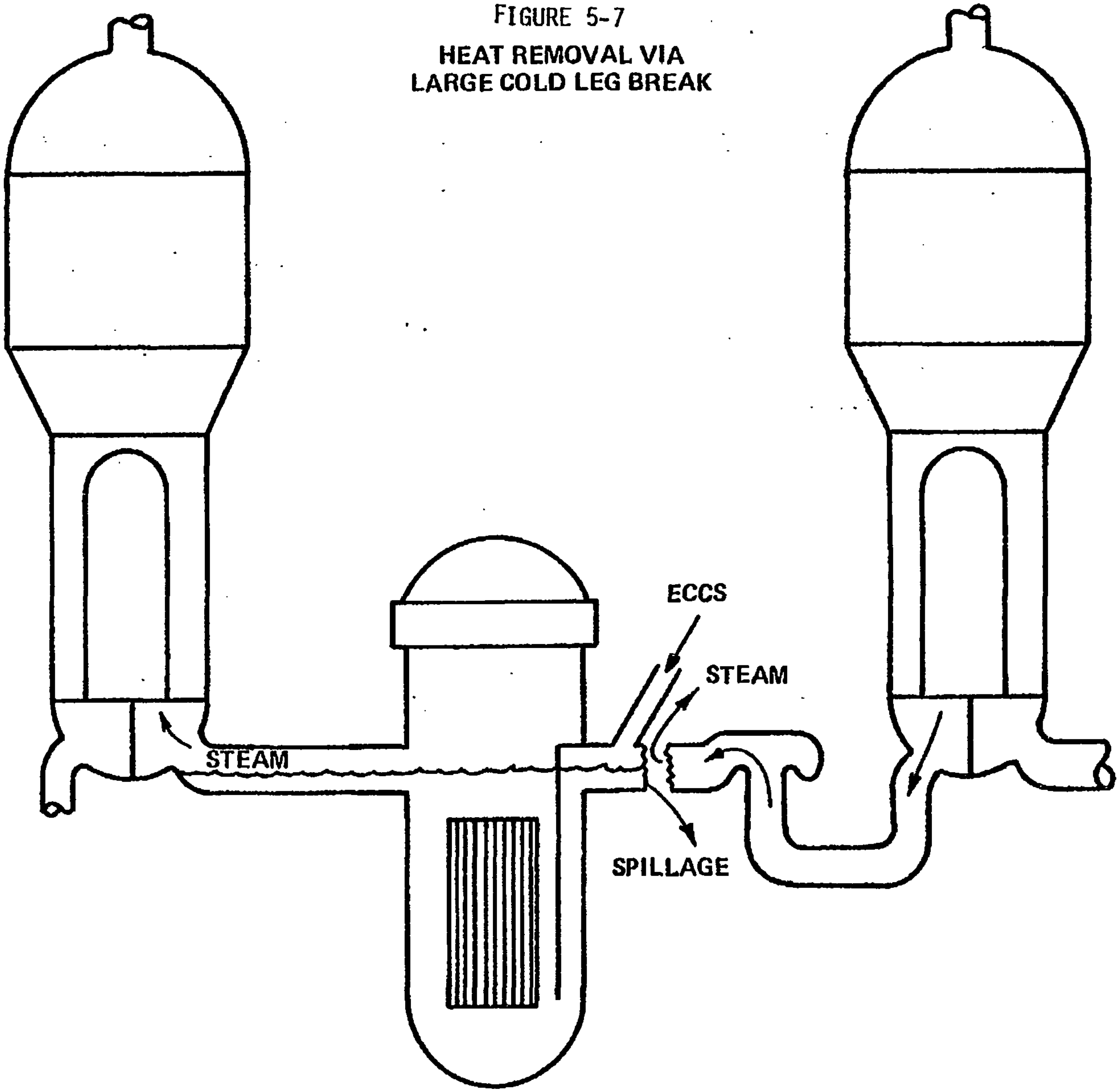


FIGURE 5-8
HEAT REMOVAL VIA SMALL BREAK
(RCS FILLED)

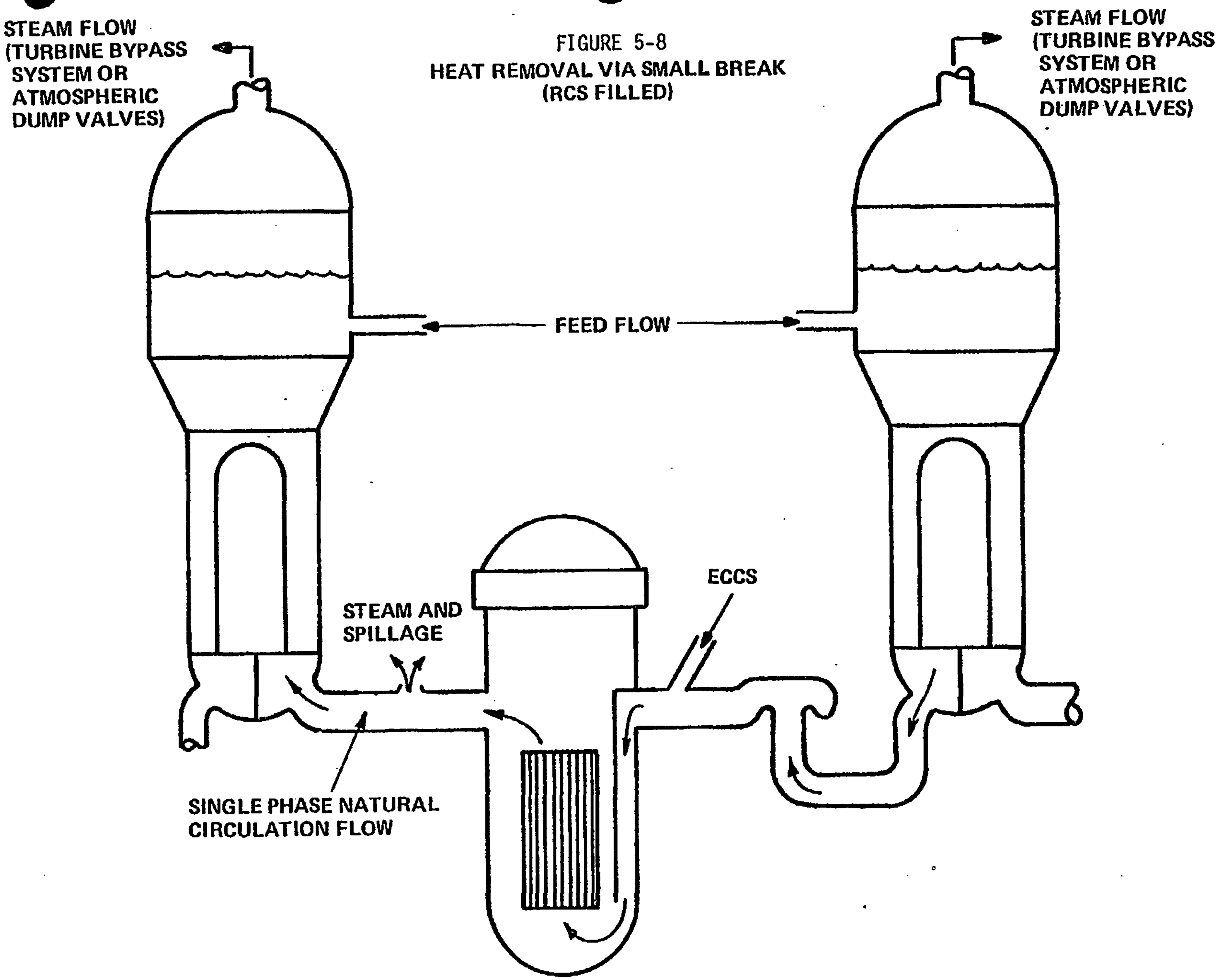


FIGURE 5-9
HEAT REMOVAL VIA SMALL BREAK
(REFLUX COOLING)

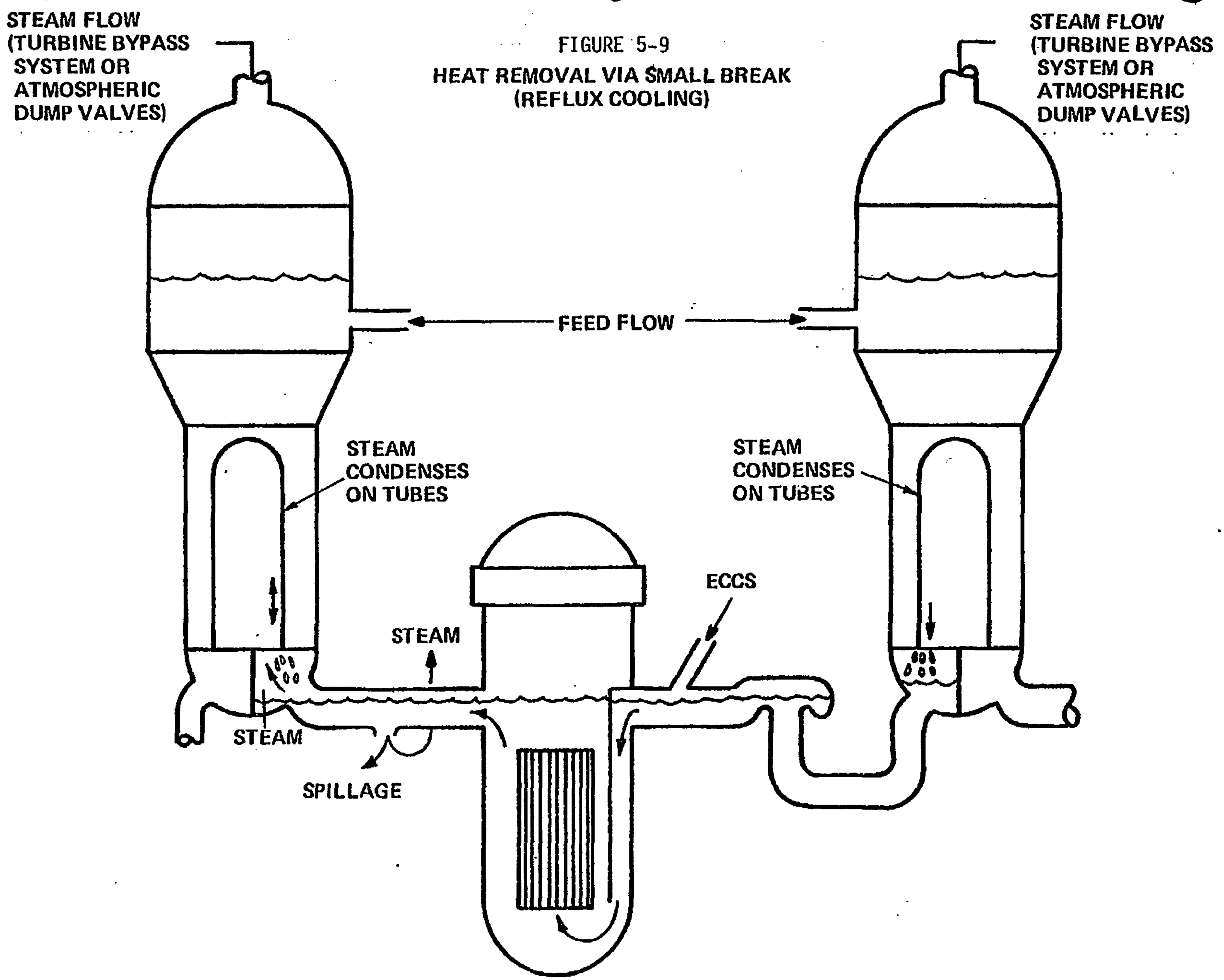


FIGURE 5-10

BREAK DIAMETER vs % OF DECAY HEAT REMOVED BY STEAM GENERATORS

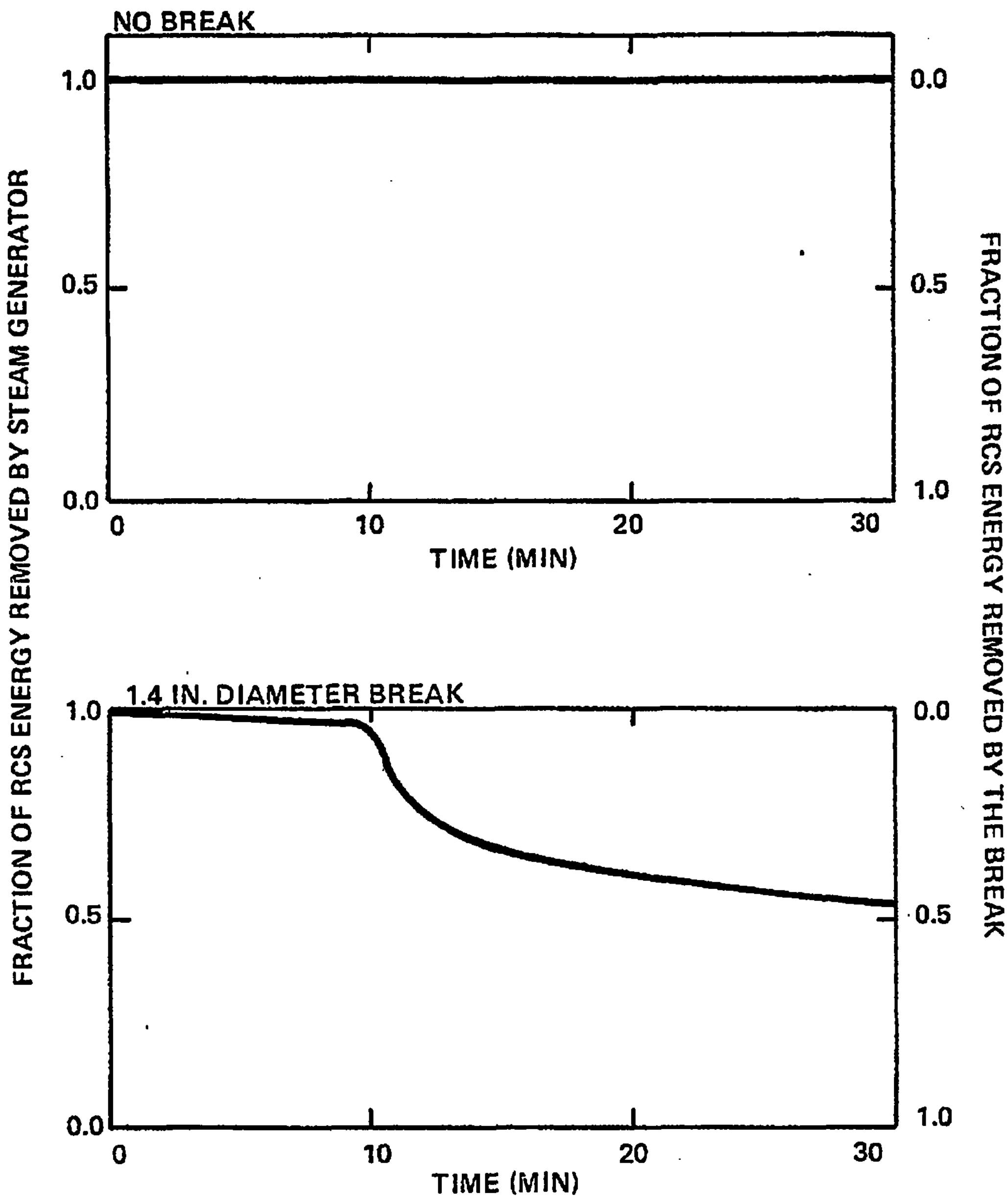
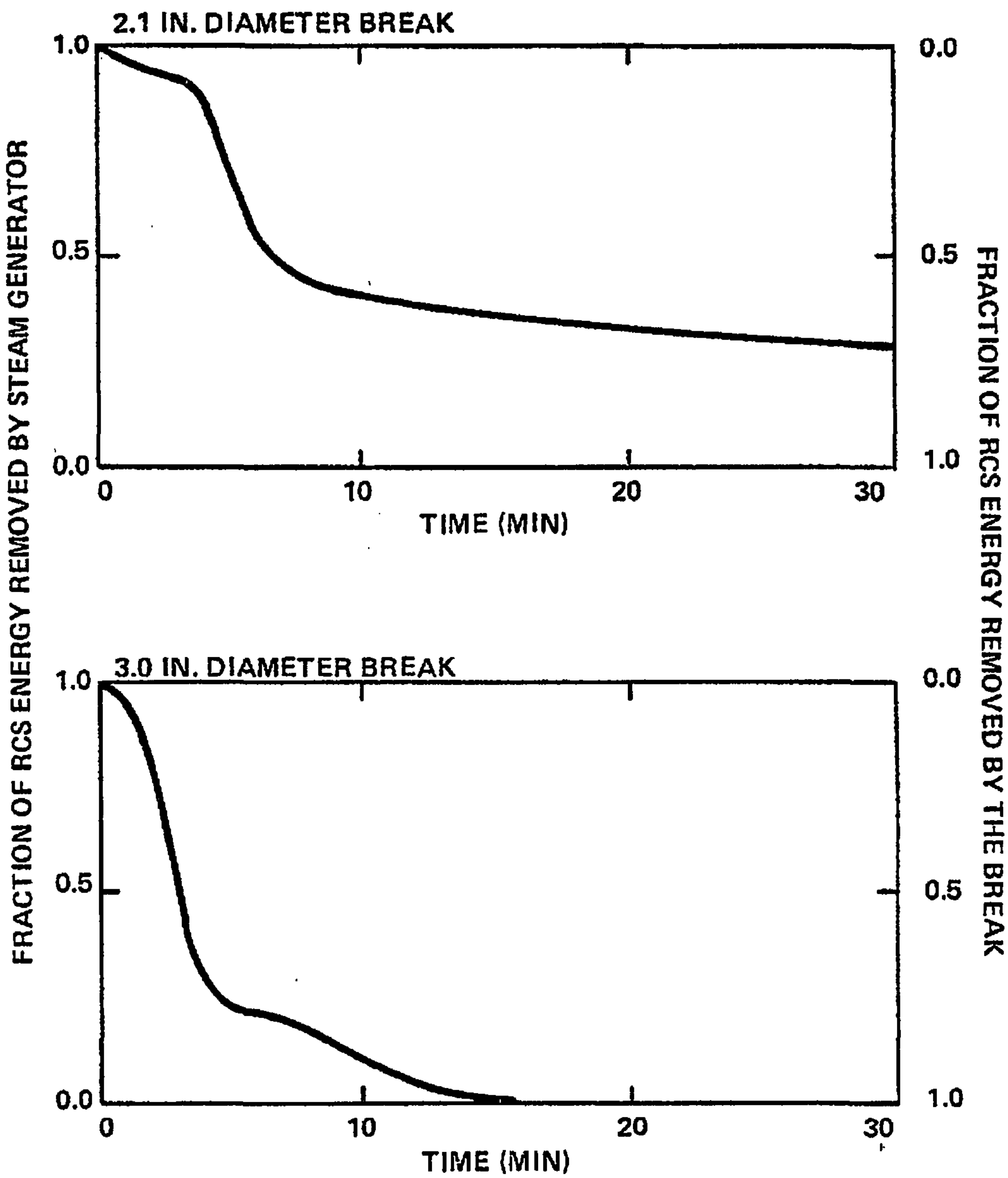


FIGURE 5-11

BREAK DIAMETER vs % OF DECAY HEAT REMOVED BY STEAM GENERATORS



The operator has adequate instrumentation to monitor natural circulation for the single phase liquid natural circulation process. The RCS temperature instrumentation, and loop ΔT can be used along with other information to confirm that the single phase natural circulation process is effective. The natural circulation processes involving two phase cooling are complex and varied enough so that RCS loop ΔT may not be a meaningful indication of adequate natural circulation cooling. The guidelines are written to alert the operator to use explicit acceptance criteria for natural circulation only when RCS inventory and pressure are controlled.

For cases where two phase natural circulation cooling is the heat removal process, the operator relies upon maintaining the steam generator heat removal process and the strict rules that require the SIS to remain operating to restore inventory control. In addition, the core exit thermocouple temperature and T_H indication are important in monitoring heat removal during two phase natural circulation cooling. As long as these temperatures remain within acceptable limits they indicate that heat removal and inventory functions are being satisfied.

The transition from single phase liquid natural circulation cooling to the reflux mode can occur quickly for larger small breaks, or can occur more slowly for the smaller small breaks. The operator should be aware that this transition may cause confusing temperature indications as the RCS loop ΔTs readjust to reflect the transition in progress. The emphasis in the guideline is to continue the steam generator heat removal process, continue restoring inventory control, and to continue monitoring the core exit thermocouples to confirm the heat removal process is adequate.

Once RCS pressure and temperature are reduced, RCS heat removal is provided by the shutdown cooling system. [In the event that the feedwater supply to the steam generator is exhausted and/or unavailable and the SCS is inoperable, the PORVs are opened to ensure that the flow from the SIS is available for RCS heat removal purposes.]

Short-term reactivity control is accomplished by the negative moderator affects for large breaks and by the reactor trip for small breaks. The reactor trip decreases core heat generation to decay heat levels which aids in the control of heat removal. Long-term reactivity control is accomplished through injection of borated water by the safety injection system and the charging pumps.

If the LOCA occurs inside containment, then containment temperature and pressure control is accomplished by action of the containment spray system. Containment isolation occurs either automatically, or is performed manually, after an evaluation of containment conditions (i.e., containment activity levels, temperature and pressure) is made.

Trending of Key Parameters (Representative of small break LOCAs)

Reactor Power (Figure 5-12)

The reactor will have tripped on thermal margin/low pressure, and reactor power will be decreasing as a result of the reactor trip. Additional negative reactivity insertion will be provided by moderator voiding, and boron addition by charging pump and/or SIS flow.

RCS Temperature (Figures 5-13, 5-14)

Following the reactor trip, RCS temperature initially decreases for all size LOCAs due to the reduction in heat input into the RCS, and due to the heat removed out the break and by the steam generators.

Pressurizer Pressure (Figure 5-15)

Pressurizer pressure initially decreases due to the loss of coolant and reactor power reduction following reactor trip.

Pressurizer Level (Figure 5-16)

Pressurizer level may decrease or increase. For breaks not located in the pressurizer, the pressurizer will empty and, depending on the size of the break, not refill during the course of the accident. Breaks located in the pressurizer may lead to increased pressurizer level since water from the hot leg flows into the pressurizer surge line while significant voiding of the RCS loop is occurring. If there is a break on or near the pressurizer level instruments, this may cause this instrument to be grossly inaccurate and misrepresent pressurizer level (high or low).

For small break LOCAs where the pressurizer refills as a result of SIS injection, pressurizer level may not be representative of RCS inventory or core coverage. As indicated above, the depressurization associated with a leak in the RCS will usually result in the formation of voids in RCS hot spots

(reactor vessel head, hot legs, S/G tube bundle). The growth or persistance of these voids, after refill of the pressurizer by the SIS, may cause pressurizer level to increase or remain constant in spite of continuing loss of inventory through the break.

Reactor Vessel Level (Figure 5-17)

Some degree of voiding is expected for LOCAs but the extent and duration is largely dependent on break size and location. Most small break (SB) LOCA events will not result in core uncovery without some other failure occurring concurrently. Some small breaks can lead to some core uncovery. However, when HPSI delivery is established, the core will be covered. For very small breaks the RCS will repressurize to slightly below the shut-off head of the HPSI pumps and voiding will not uncover the core. For large breaks the RCS saturates almost immediately and voids start to form. Core uncovery is expected in the short term but RCS pressure decrease is also very rapid and SIS flow restores core cooling.

Steam Generator Pressure (Figure 5-18)

Steam generator pressure may increase or remain constant in the short-term if the break is small. However, for all sized LOCAs, steam generator pressure will usually decrease in the long term as a result of operator action.

Steam Generator Level (Figure 5-19)

Steam generator level will decrease rapidly following the reactor trip and then increase to the hot standby level. Level may then remain constant or increase somewhat based on automatic or manual control of feedwater.

FIGURE 5-12

REPRESENTATIVE LOCA
REACTOR POWER

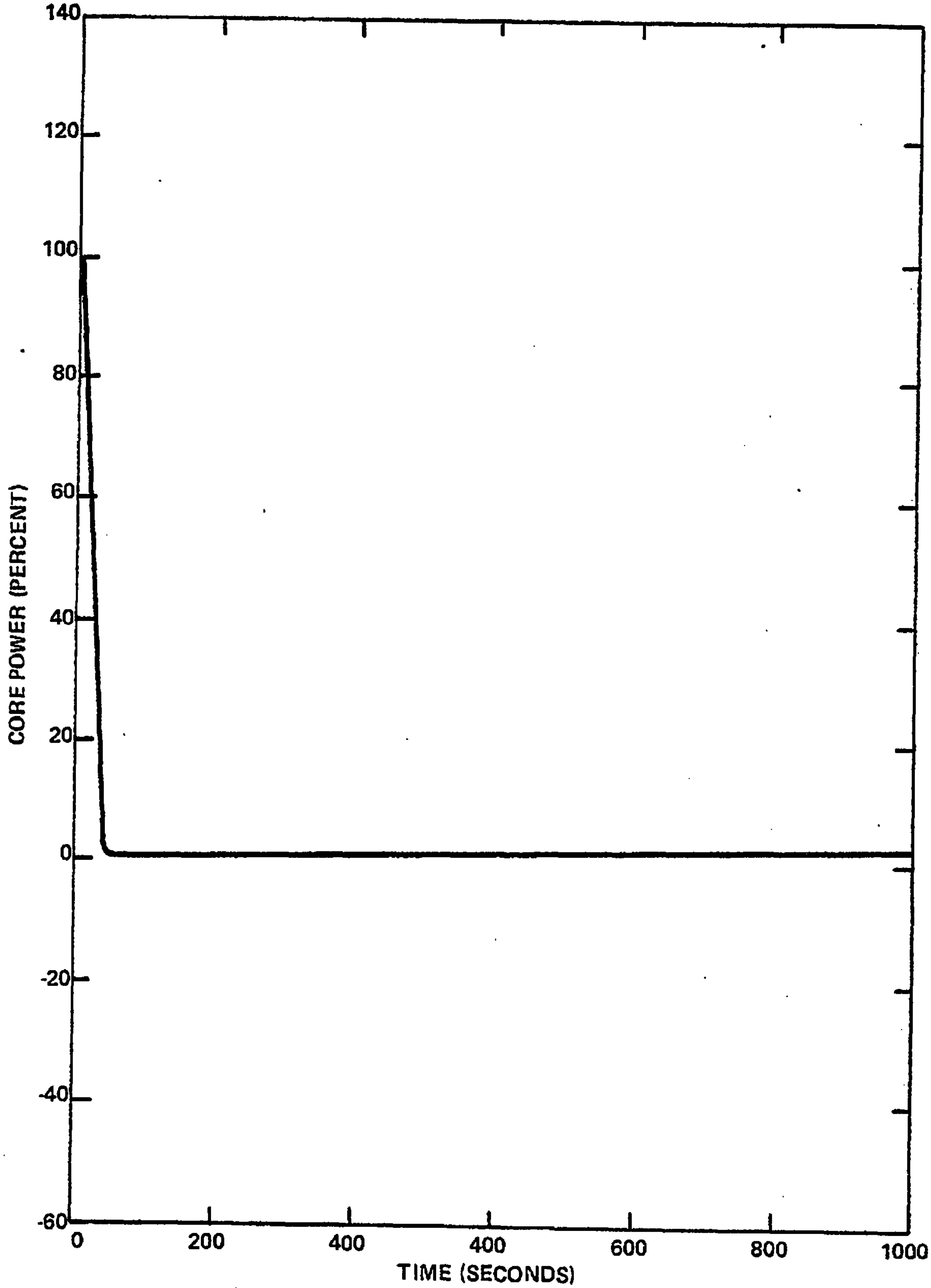


FIGURE 5-13
REPRESENTATIVE LOCA
RCS HOT LEG TEMPERATURE

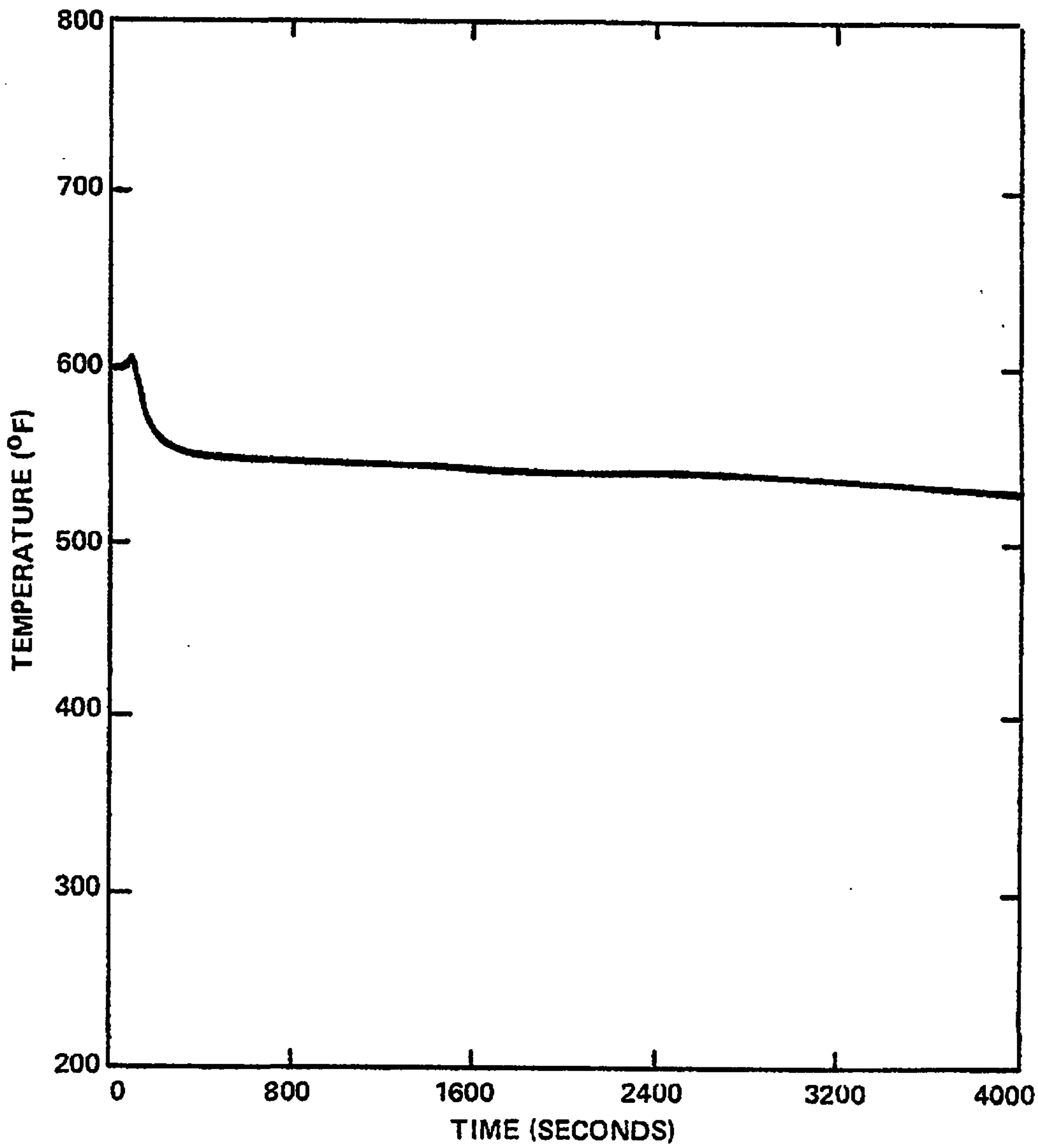


FIGURE 5-14

REPRESENTATIVE LOCA
RCS COLD LEG TEMPERATURE

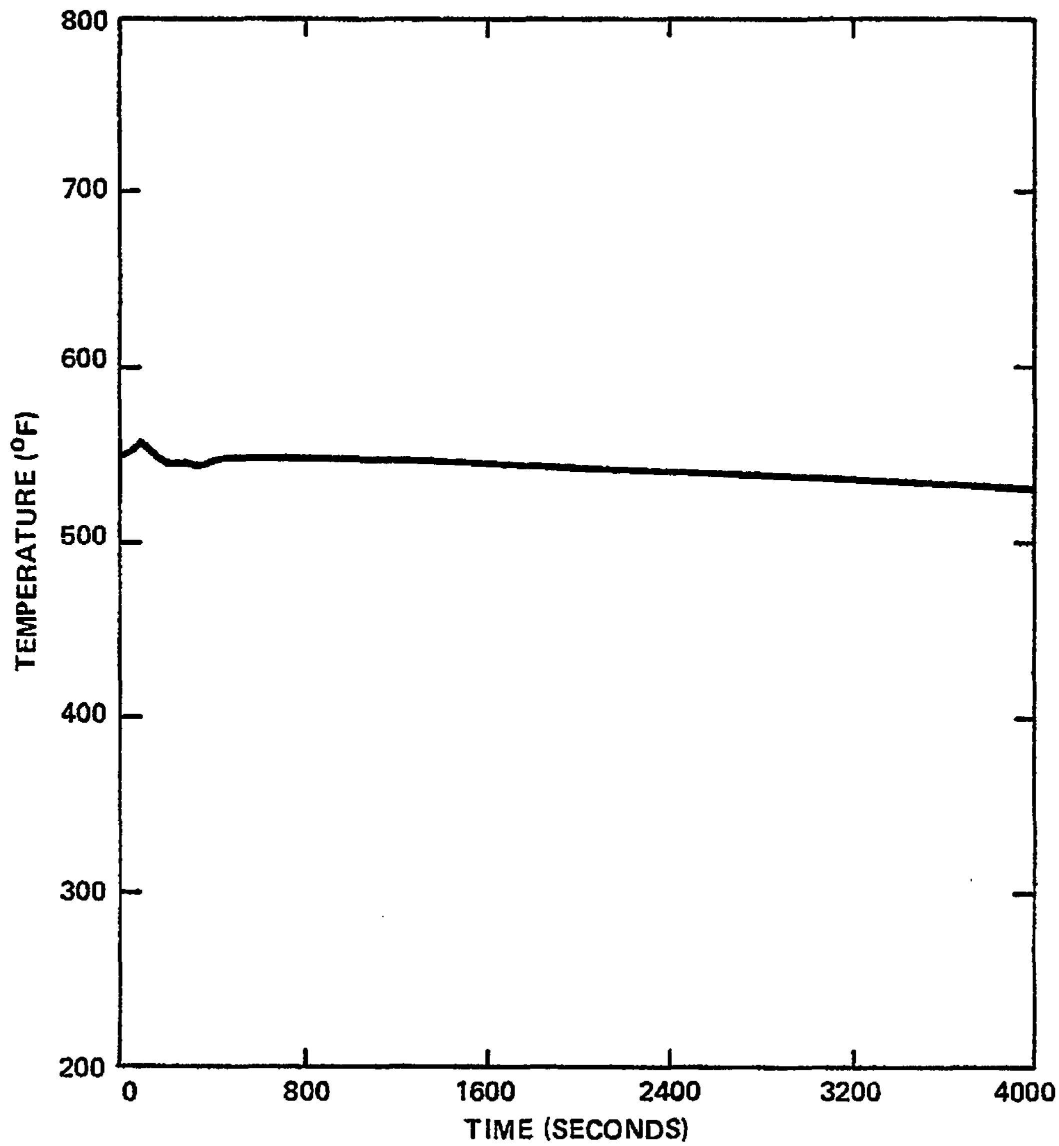


FIGURE 5-15
REPRESENTATIVE LOCA
PRESSURIZER PRESSURE

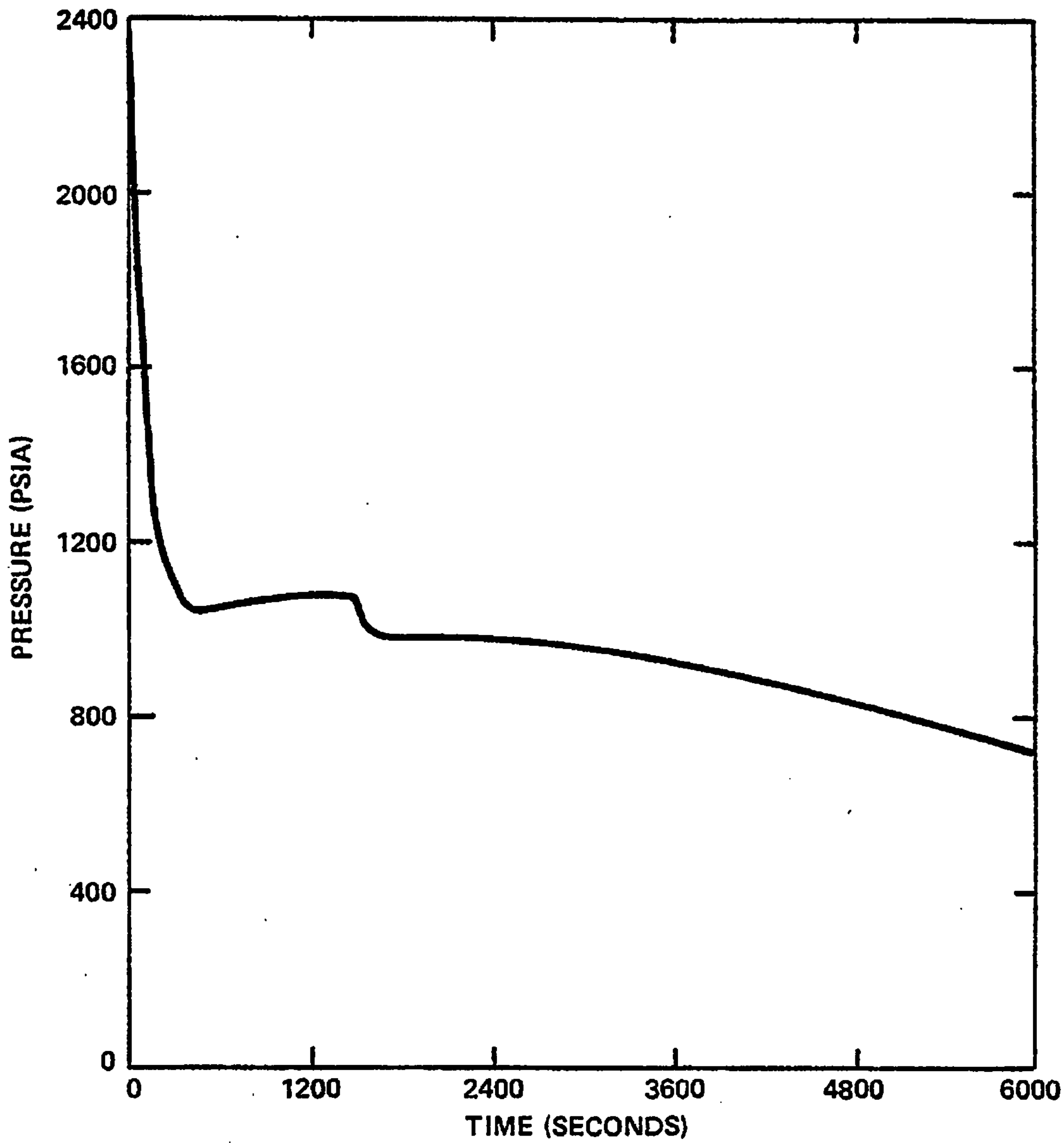


FIGURE 5-16

REPRESENTATIVE LOCA
PRESSURIZER LEVEL

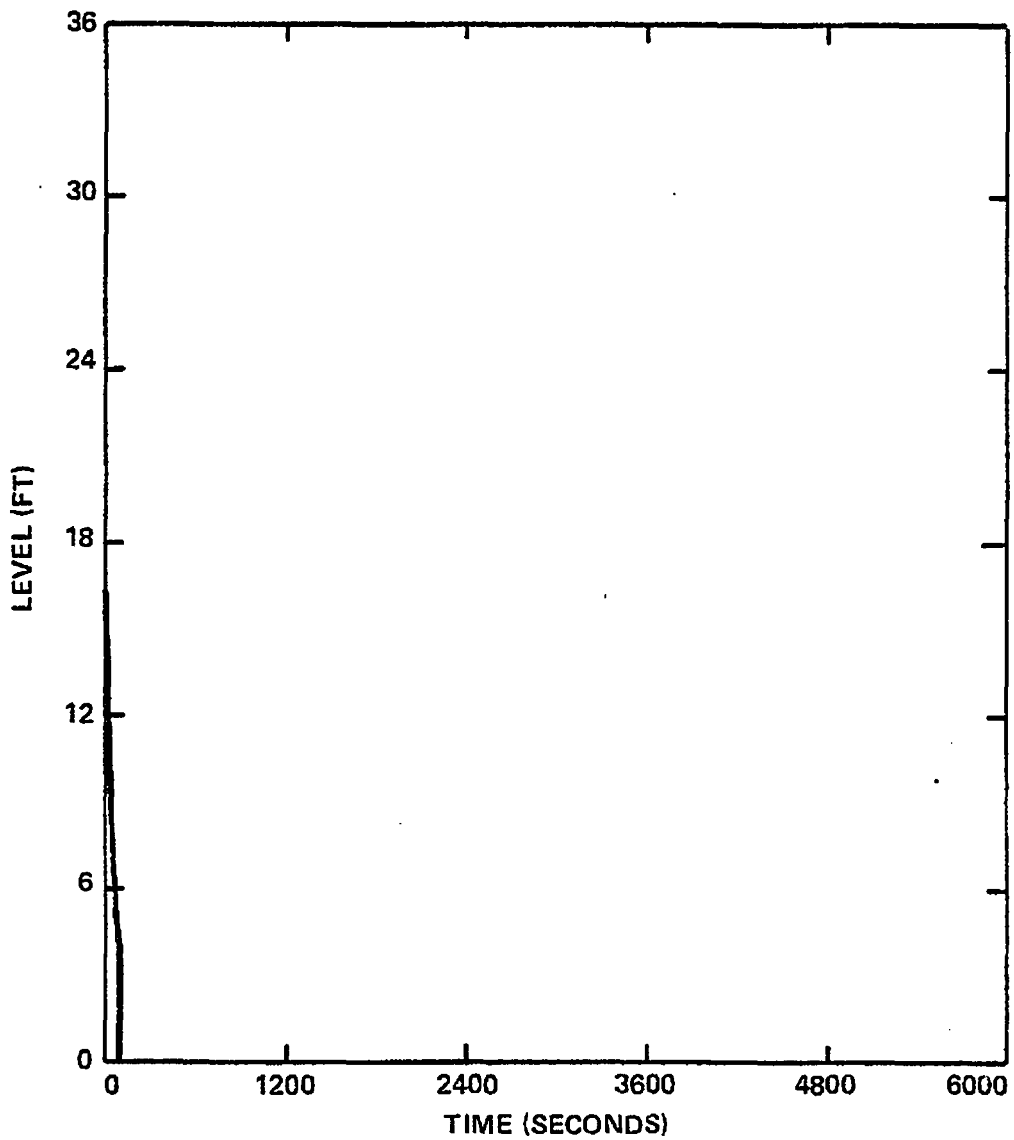


FIGURE 5-17
REPRESENTATIVE LOCA
REACTOR VESSEL LEVEL

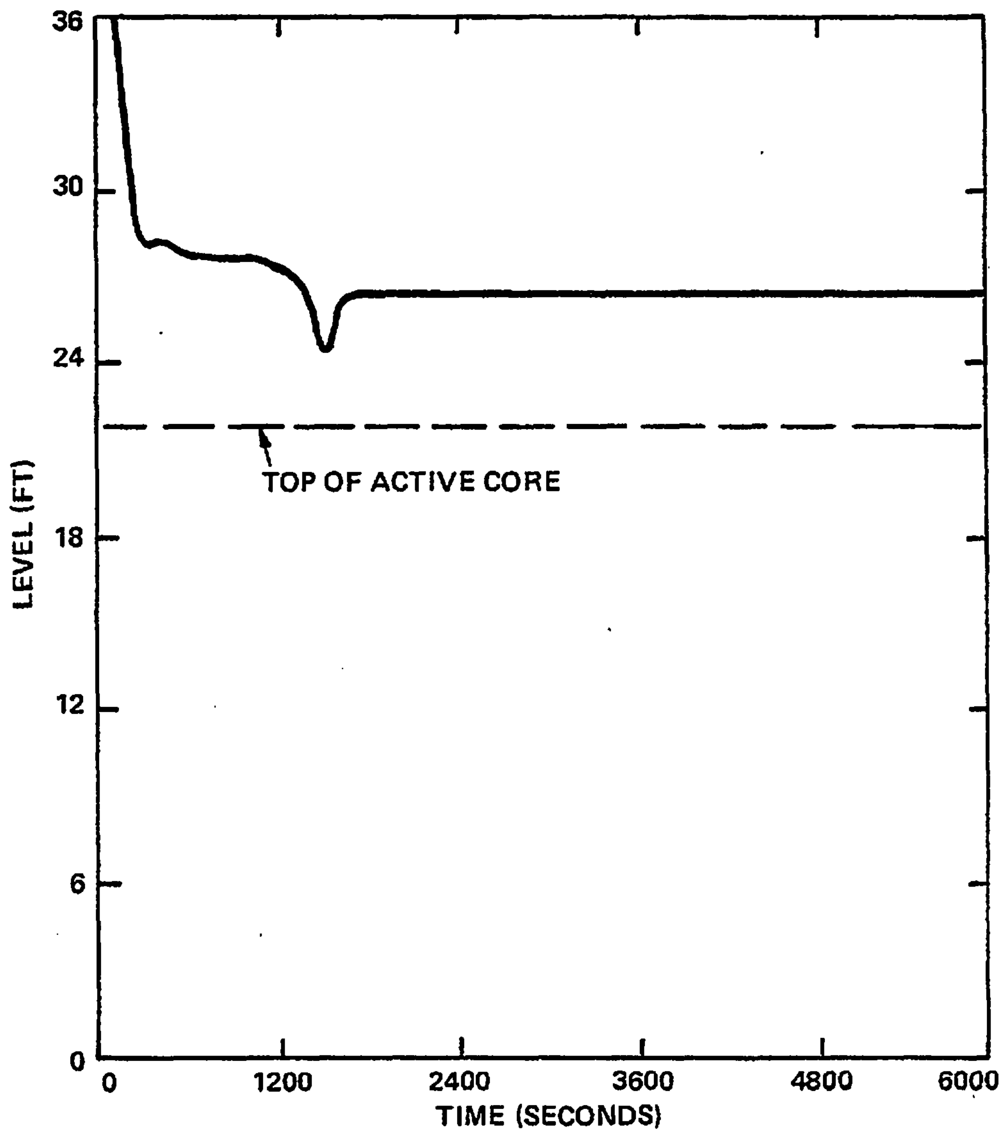


FIGURE 5-18

REPRESENTATIVE LOCA
STEAM GENERATOR SECONDARY SIDE PRESSURE

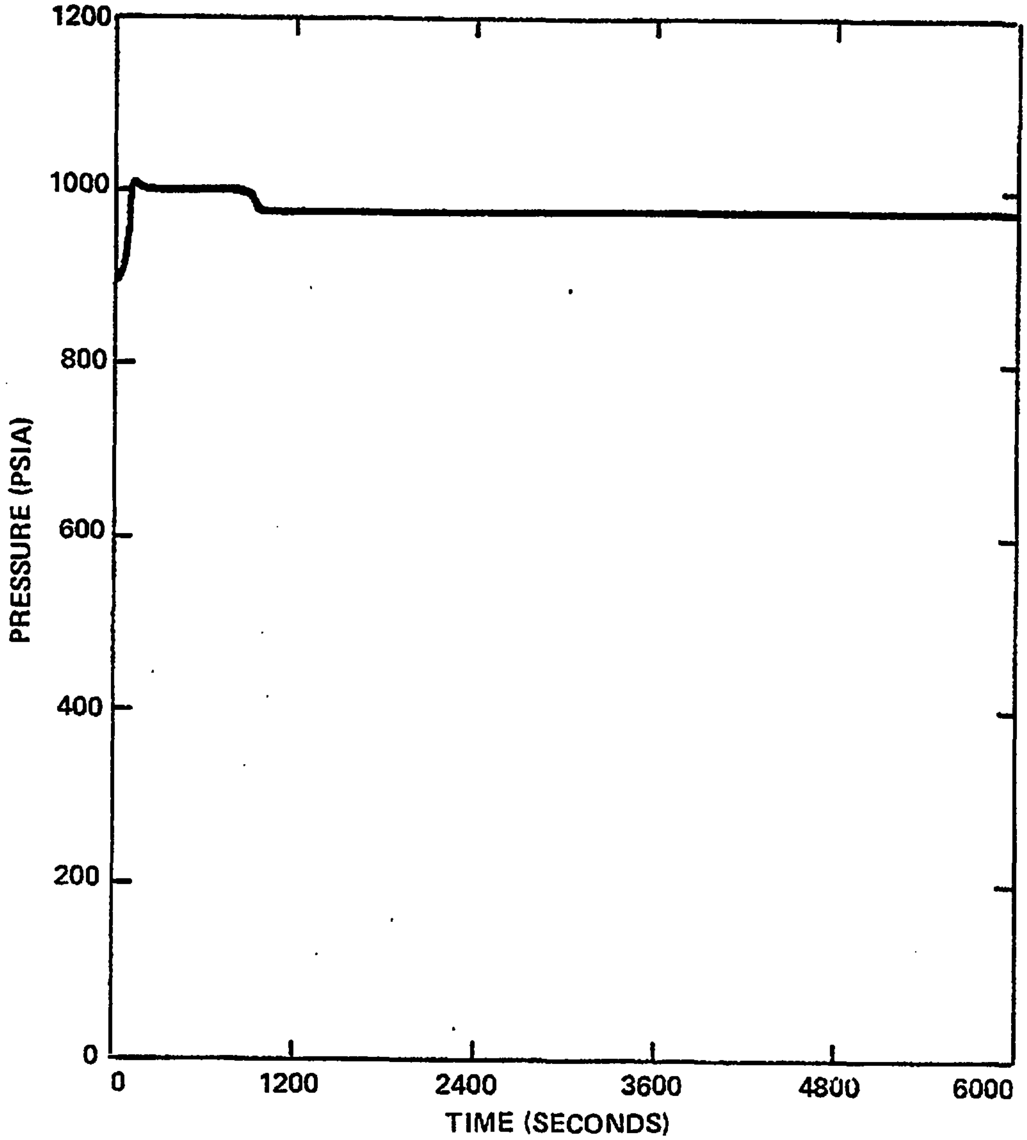
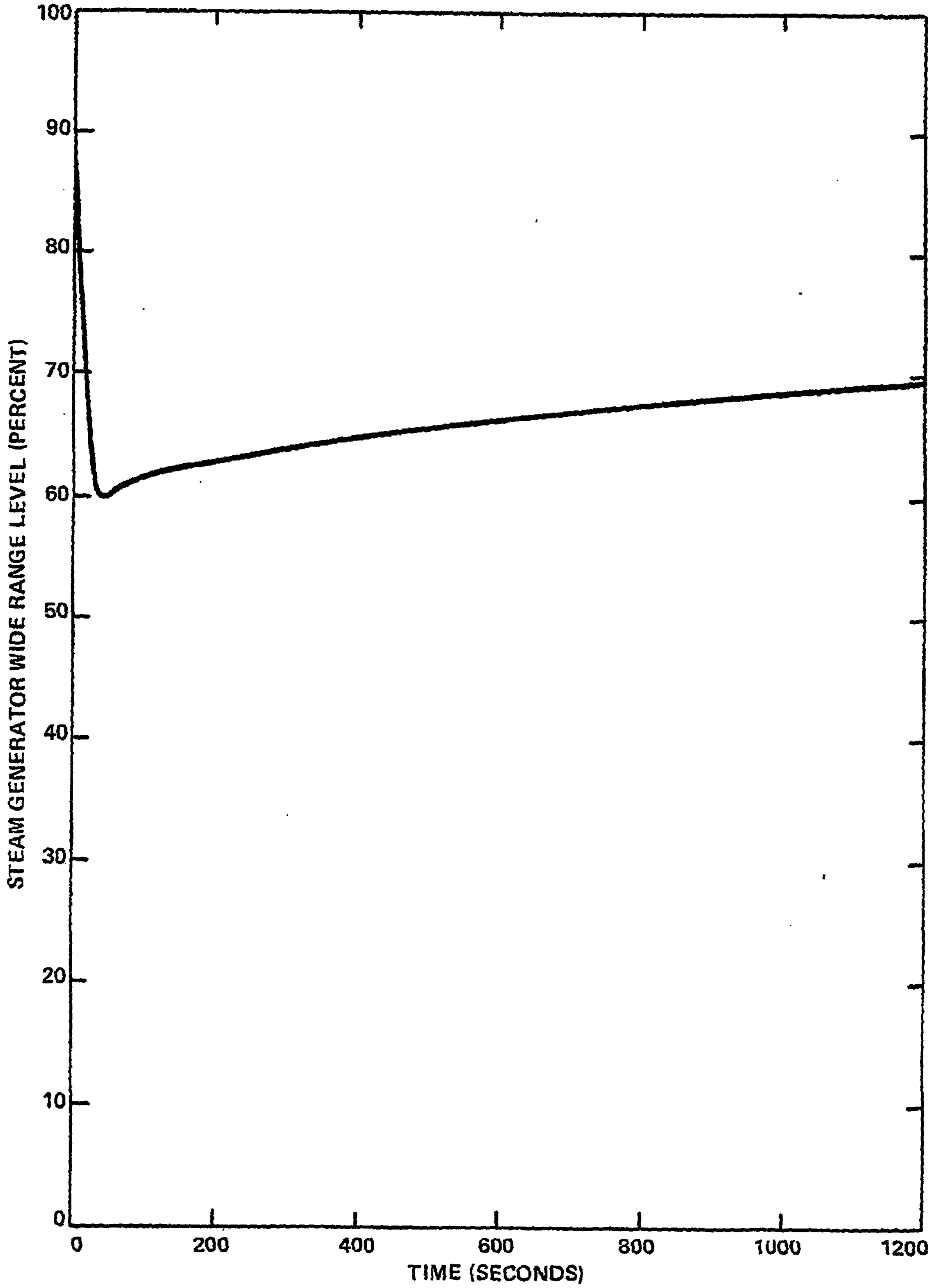


FIGURE 5-19

REPRESENTATIVE LOCA
STEAM GENERATOR WIDE RANGE LEVEL



Guideline Strategy and Information Flow

Figure 5-20 provides a summary description of the LOCA Recovery Guideline's strategy and information flow. Prior to implementing the actions provided in the LOCA Recovery Guideline, the operator would have performed the standard post trip actions and diagnosed the event. In the LOCA Recovery Guideline, the operator begins using the safety function status check to confirm that the plant is recovering. The next steps provide instructions on establishing those conditions immediately necessary for effectively combatting an LOCA. Specifically, the operator maximizes safety injection flow to the RCS and attempts to isolate the leak.

The next group of steps provide instructions on RCP restart criteria, natural circulation, SIS, and containment isolation. These steps are illustrated on Figure 5-20. Following the instructions on RCP operation, natural circulation, SIS, and containment isolation, the flow of information breaks into two paths. One path addresses regaining normal control of the plant for an isolated leak while the other path provides instructions for addressing the unisolated leak.

A more detailed chart illustrates the recovery guideline strategy and lists the guideline steps which correspond to each strategy objective. Those steps discussed above which are performed at any time during the course of the event are affixed with asterisks. Refer to Figure 5-25.

FIGURE 5-20a

LOSS OF COOLANT ACCIDENT STRATEGY CHART

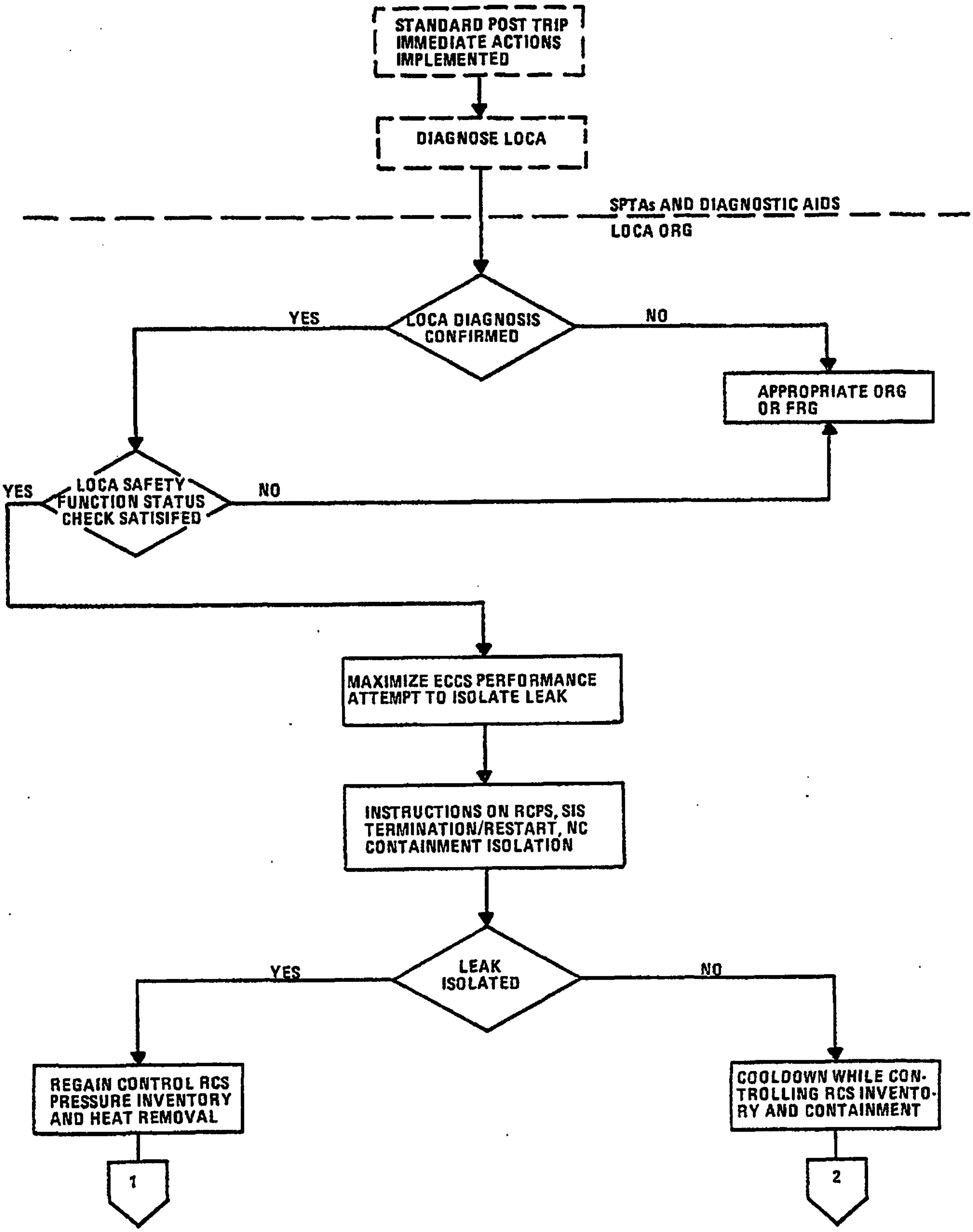
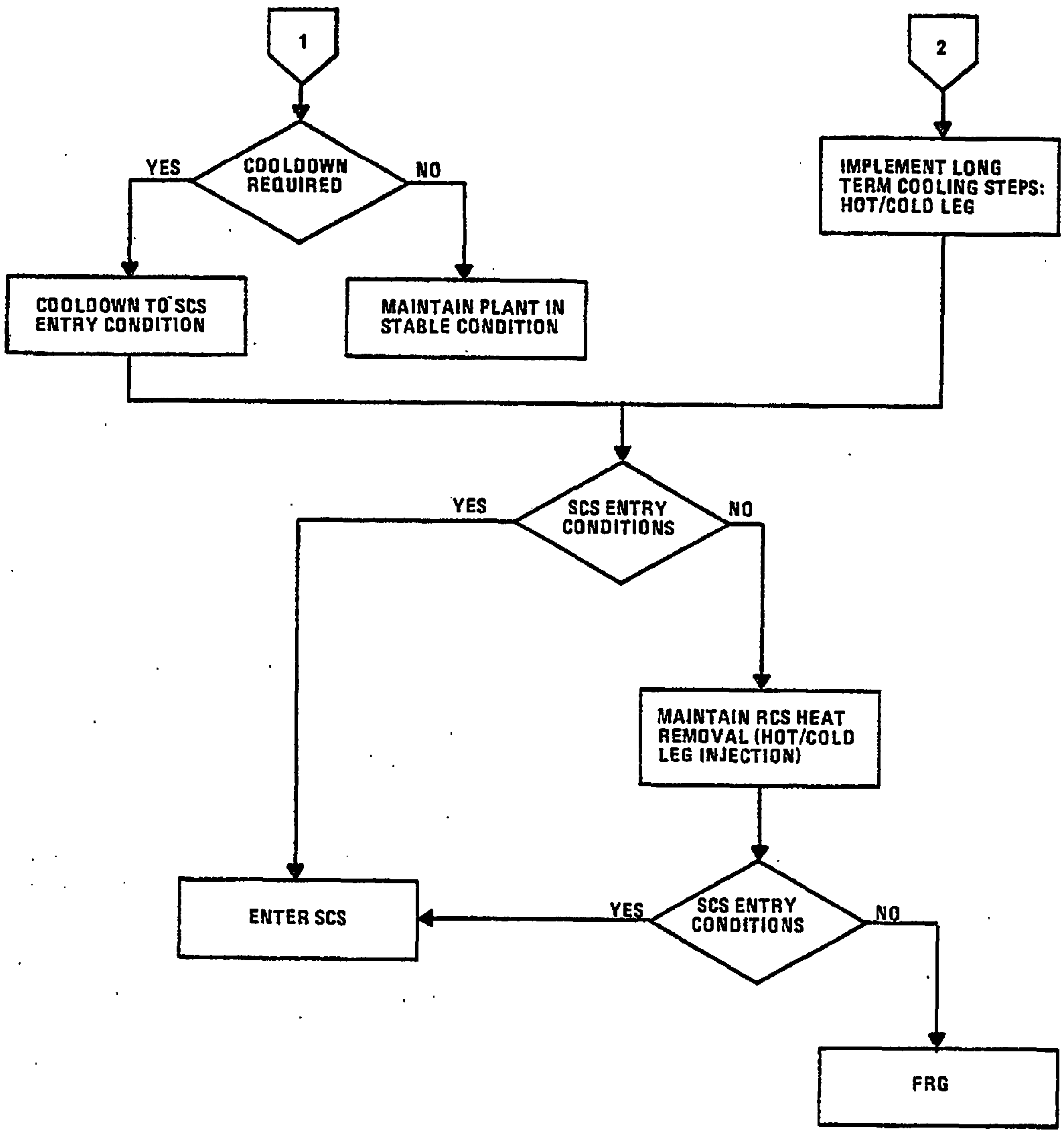


FIGURE 5-20b

LOSS OF COOLANT ACCIDENT STRATEGY CHART



Bases Operator Actions

The operator actions are directed toward recovering the plant from the LOCA, and placing it in a safe, stable condition. One of two paths are followed, depending upon whether or not the break has been isolated.

1. The execution of all standard post trip actions is verified. This assures that all safety functions have been initially attended to.

2. The diagnosis of a loss of coolant accident should be confirmed by using [the Break Identification Chart (Figure 5-2) and by verifying that the safety functions are being satisfied by comparing control board parameters to the acceptance criteria in the Safety Function Status Check. In particular, the operator should note the status of RCS subcooling and containment and steam plant activity. These parameters provide a means of discriminating between LOCAs and SGTRs/ESDEs. For most LOCAs, the RCS reaches saturation condition and containment activity monitors may be alarming but steam plant activity monitors should not be alarming. For an SGTR, steam plant activity monitors may be alarming but containment activity monitors should not be alarming. For ESDEs, neither steam plant or containment activity monitors should be alarming. For plants which exhibit S/G tube leakage, however, steam plant or containment activity monitors may alarm during ESDEs. These actions ensure the proper procedure is being used to mitigate the effects of an LOCA.]

3. Sample both steam generators for activity. This will assist in confirming the diagnosis made in step 2.

4. If the diagnosis indicates that an SGTR or an ESDE has occurred, then the LOCA Guideline is exited and the actions of the proper guideline are implemented. This step allows the operator to switch to the proper guideline for those events similar to LOCAs which may have occurred. LOCAs, ESDEs, and SGTRs have similar initial symptoms and could be confused early in the event.

5. If the initial diagnosis of a LOCA is confirmed, then the operator continues with the actions of this guideline.

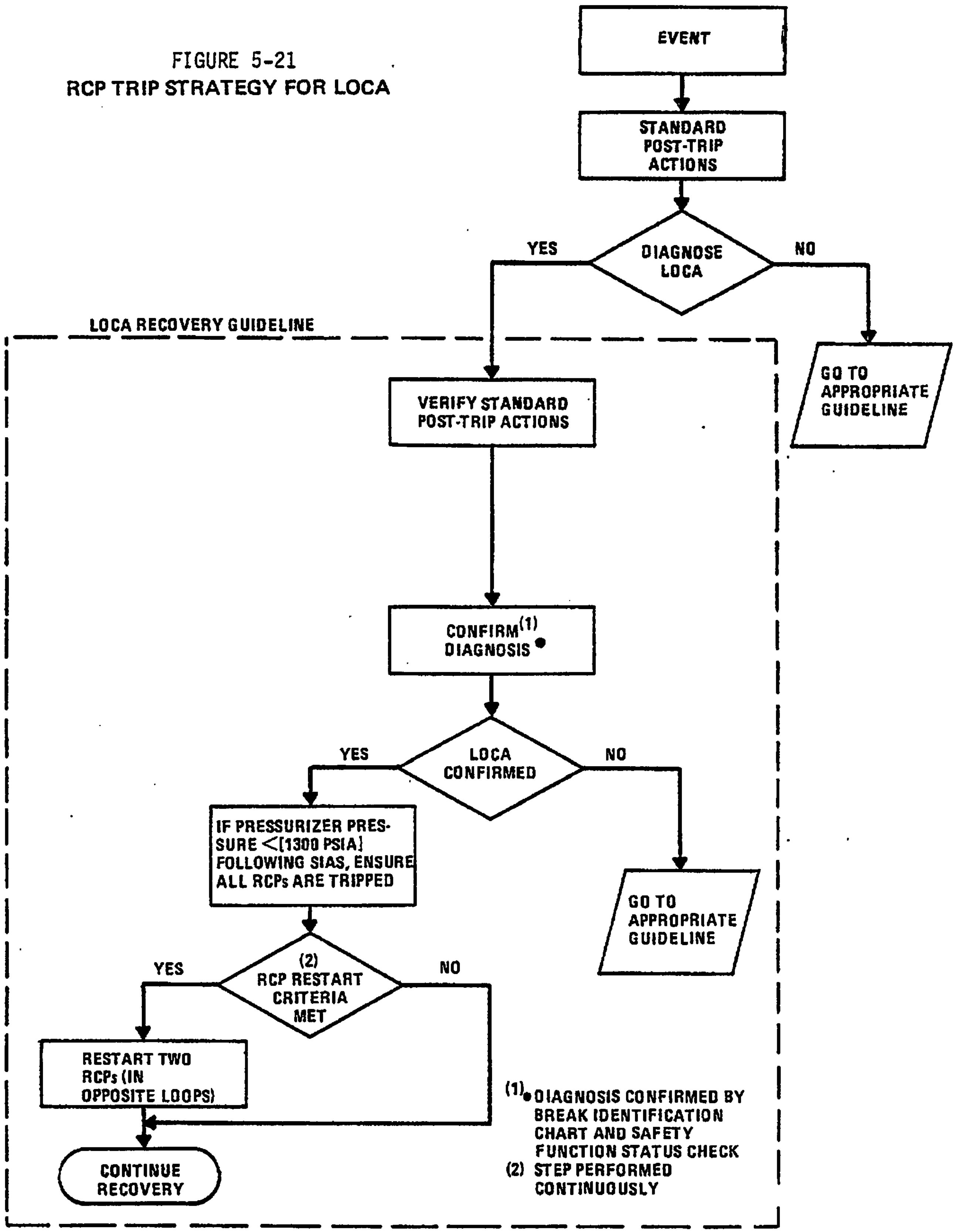
If the diagnosis is not confirmed, then the operator is directed to implement the Functional Recovery Guideline. The Functional Recovery Guideline is functionally oriented and will ensure that all safety functions are attended to regardless of what event(s) is occurring.

6. This step contains guidance regarding the RCP operating strategy for an LOCA (see Figure 5-21). A generic RCP trip strategy has been developed which, in general, results in the tripping of all four RCPs for depressurization events determined to be LOCAs, but allows the continued operation of two RCPs (in opposite loops) for diagnosed, non-LOCA, depressurization events. For undiagnosed events, where the Functional Recovery Guideline is implemented, the RCP trip strategy is identical to that followed in the LOCA guideline.

   Once the operator implements the LOCA recovery guideline, and the LOCA is confirmed, if pressurizer pressure goes below [1300 psia] following receipt of an SIAS, then all four RCPs must be tripped. Two RCPs may have been tripped already in the Standard Post Trip Actions. In this case, the operator would simply trip the remaining two RCPs. Tripping all four RCPs ensures a conservative approach to event recovery. Prolonged RCP operation during LOCAs of certain size and location could result in increasing the severity of the event. Analysis has indicated that for a break in the bottom of the hot leg, continued RCP operation may result in greater loss of RCS inventory than if RCPs were stopped. This could result in decreased core cooling capability. Since the operators may not know the size or location of the break, they are instructed to trip all RCPs for LOCA depressurization events and all non-diagnosed (i.e., Functional Recovery Guideline implemented) depressurization events.

7. The operator is required to continually verify that all safety functions are being satisfied by comparing control board parameters to the acceptance criteria of the Safety Function Status Check. This ensures that all safety functions are being satisfied and the core is being adequately cooled.

FIGURE 5-21
RCP TRIP STRATEGY FOR LOCA



8. If all of the safety functions are satisfied, then this procedure is adequately mitigating the effects of the LOCA which is occurring. Therefore, the implementation of the remaining actions of this guideline is continued.

If the safety functions and their respective acceptance criteria are not satisfied, then the operator is required to leave the LOCA guideline and implement the Functional Recovery Guideline. The FRG is functionally oriented and will ensure all safety functions are attended to regardless of what event(s) is occurring.

9. The operator records the time of day, since several of the follow-up actions need to be performed within a defined time window relative to the start of the accident. Recorded automatically on data log.

10. An LOCA will result in actuation of safety injection. The RCS pressure will respond during the accident according to the break size. Safety injection system flow rate will follow the RCS pressure according to the SIS delivery curves (see Figures 5-22 and 5-23). The SIS and charging flowrate should be checked and maximized relative to RCS pressure to enhance RCS inventory replenishment and/or core heat removal. Specific steps such as restoring electrical power, correcting valve lineups, restoring necessary auxiliary systems, and starting all available pumps will also serve to enhance RCS inventory replenishment and/or core heat removal.

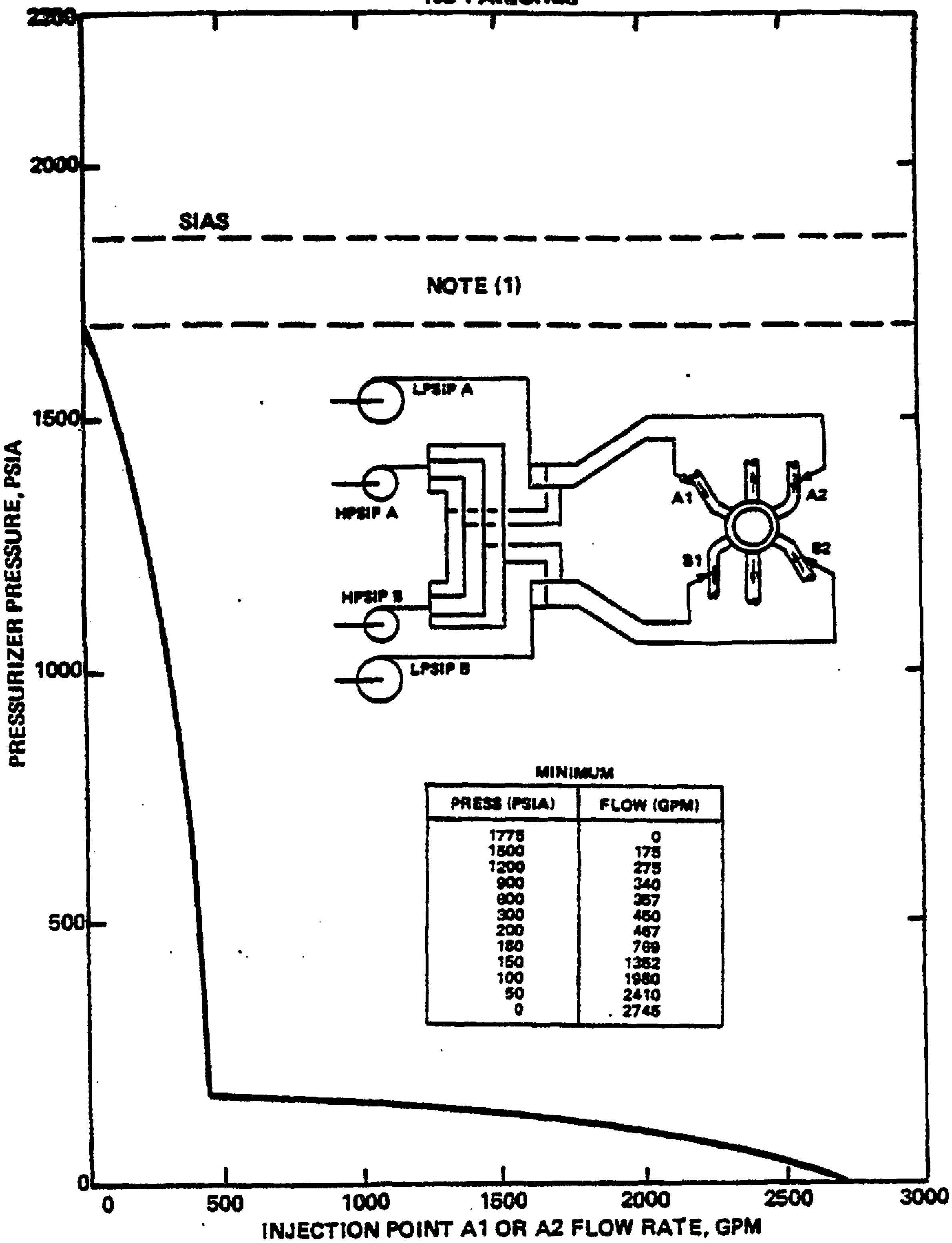
11. Attempt to isolate the leak by performing the following:

    a) [The PORVs are not expected to open on an LOCA. However, if they are a cause of the LOCA and pressurizer pressure is below 2400 psia, the PORVs should be closed. If necessary, the PORV block valves must be closed to maintain RCS inventory.]

    b) Letdown is isolated to possibly isolate the break or to preclude loss of RCS inventory to the CVCS.

FIGURE 5-22

TYPICAL SAFETY INJECTION DELIVERY CURVES
NO FAILURES



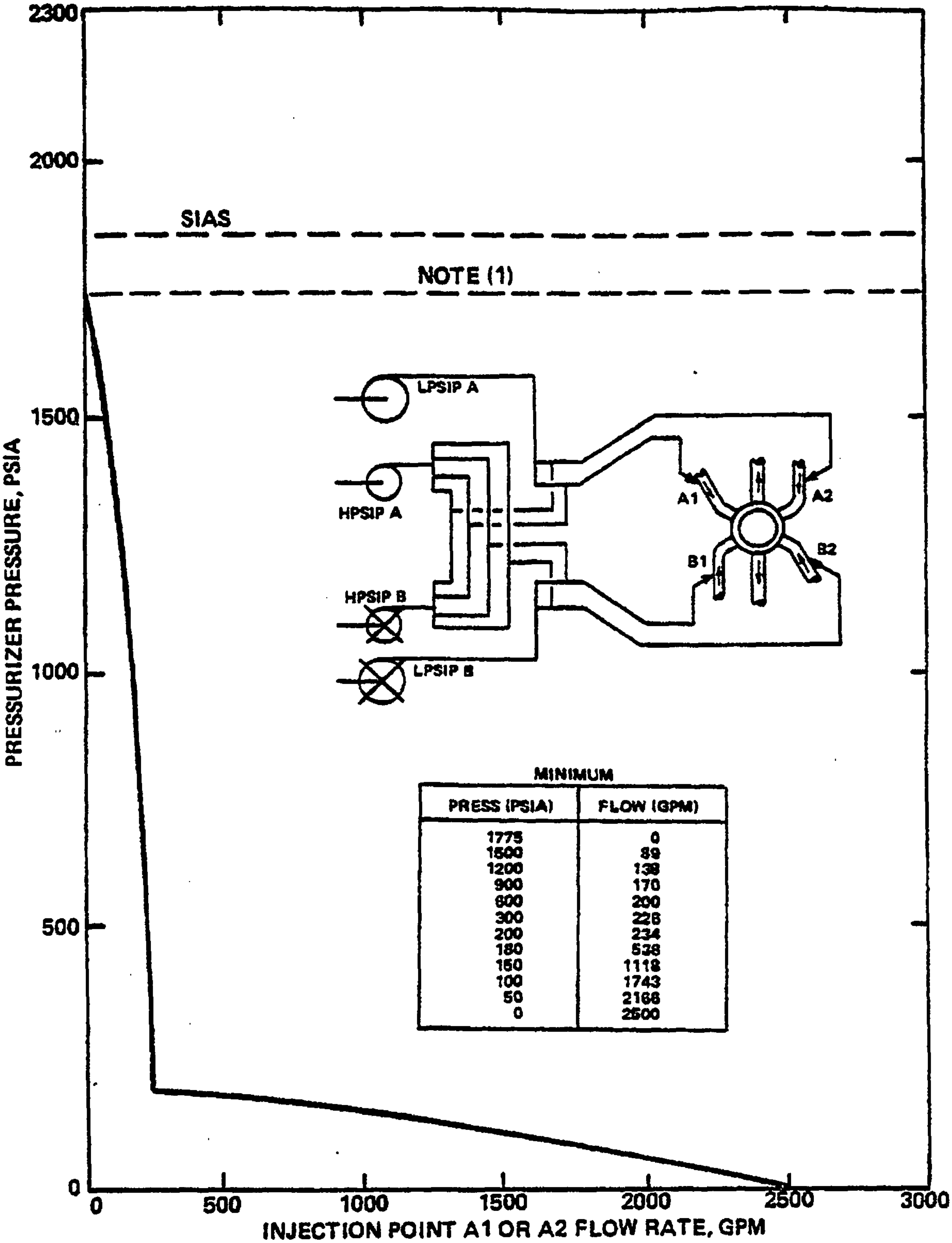
MINIMUM

PRESS (PSIA)	FLOW (GPM)
1775	0
1500	175
1200	275
900	340
600	357
300	450
200	467
180	769
150	1352
100	1980
50	2410
0	2745

NOTE: (1) BELOW SIAS PRESSURE, SAFETY INJECTION SYSTEM (SIS) PUMPS WILL BE OPERATING, BUT THERE WILL BE NO INJECTION FLOW UNTIL SYSTEM PRESSURE FALLS BELOW THE SHUTOFF HEAD PRESSURE OF ANY SIS PUMP

FIGURE 5-23

TYPICAL SAFETY INJECTION DELIVERY
FAILURE CONDITIONS - LOSS OF ONE EMERGENCY GENERATOR



MINIMUM

PRESS (PSIA)	FLOW (GPM)
1775	0
1500	89
1200	138
900	170
600	200
300	228
200	234
180	538
150	1118
100	1743
50	2168
0	2500

NOTE: (1) BELOW SIAS PRESSURE, SAFETY INJECTION SYSTEM (SIS) PUMPS WILL BE OPERATING, BUT THERE WILL BE NO INJECTION FLOW UNTIL SYSTEM PRESSURE FALLS BELOW THE SHUTOFF HEAD PRESSURE OF ANY SIS PUMP

c) RCS sampling should be terminated and all sampling lines should be isolated. If necessary, this isolation should be performed manually. Isolating sampling lines minimizes the possibility of inadvertent personnel exposure, and minimizes RCS inventory losses.

d) [All other sources of leakage which can be rapidly and remotely isolated are isolated in order to minimize RCS inventory losses and to possibly isolate the break. This should be done rapidly, because the operator should be focusing his attention on recovering the plant from the LOCA.]

12. If the RCPs have been stopped, then operation of two RCPs in opposite loops should be attempted if the RCP restart criteria are met. This action ensures continued forced circulation of coolant through the core, cooling of the RV head region, and provides the capability for the normal mode of pressurizer spray, condenses RCS steam voids, and removes non-condensible gases from the S/G tube bundle. Furthermore, this action enhances the strategy to obtain an uncomplicated cooldown, since a forced circulation cooldown is preferred to a natural circulation cooldown whenever possible during recovery from an LOCA. Only one reactor coolant pump in each loop should be operated in order to minimize heat input to the RCS.

Determine whether RCP restart criteria are met by the following:

a) At least one steam generator is available for removing heat from the RCS. A steam generator having feed flow and removing heat from the RCS is an indication that primary to secondary heat removal is being maintained.

b) Pressurizer level is greater than [200"] and not decreasing. With pressurizer level at the high end of the operating band, the possibility of draining the pressurizer due to loop shrinkage and/or steam void condensation is minimized and there is a greater likelihood of keeping the pressurizer heaters covered. This will assist in maintaining positive RCS pressure control. The criterion of pressurizer level not decreasing implies that RCS inventory control has been established.

c) The RCS is greater than or equal to [20°F] subcooled. A subcooled condition taken in conjunction with (b) above indicates that inventory control has been established.

d) [All plant specific RCP operating criteria are satisfied before the RCPs are restarted to prevent damage to RCPs. Following automatic or operator initiated containment isolation, reinstatement of component cooling water to the RCPs should be considered in order to ensure adequate RCP cooling].

13. Upon restarting two RCPs in opposite loops, pressurizer level and pressure may decrease due to loop shrinkage and/or void condensation. It is possible that this action will drain the pressurizer. Steam voids present in the reactor vessel will condense upon restarting RCPs. [The RVLMS should be monitored for the trending of reactor vessel liquid level. This trending information may be correlated to pressurizer level decrease.] RCP operation with a drained pressurizer may continue provided certain actions are taken and certain criteria are satisfied.

    The following constitute the actions to be taken, and the criteria to be satisfied, when restarting RCPs:

    a) Start all available HPSI and charging pumps, or verify their operation. This serves to compensate for pressurizer level and pressure decrease.

    b) Start one RCP in each loop.

    c) [Ensure proper RCP operation by monitoring RCP amperage and pump NPSH. NPSH is determined by pressurizer pressure and corresponding T_c on Figure 5-1].

    d) Operate all available HPSI and charging pumps until pressurizer level is greater than [100"] and SIS termination criteria are met.

14. If all RCP operation is terminated, and inventory and pressure are controlled, then natural circulation is monitored by heat removal via at least one steam generator. Natural circulation flow stabilizes within 5-15 minutes after the RCPs were tripped if there is adequate inventory in the RCS.

The RCS temperature response during natural circulation will usually be slow (5-15 minutes) as compared to a normal forced flow system response time of 6-12 seconds, since the coolant loop cycle time will be significantly longer.

When single phase natural circulation is established in at least one loop the RCS indicates all of the following conditions:

a) Loop ΔT ($T_H - T_c$) less than normal full power ΔT;
b) Cold leg temperatures constant or decreasing;
c) Hot leg temperatures stable (i.e., not steadily increasing) or decreasing;
d) No abnormal differences between T_H RTDs [and core exit thermocouples]. Hot leg RTD temperature should be consistent with the [core exit thermocouples]. Adequate natural circulation flow ensures that [core exit thermocouple] temperatures will be approximately equal to the hot leg RTD temperatures within the bounds of the instrument's inaccuracies. An abnormal difference between T_H and the [CETs] is greater than [10°F].

15. If the criteria listed above are not satisfied, then natural circulation in the RCS is not effectively transferring heat from the core to the steam generators. Both RCS Heat Removal and Core Heat Removal Safety Functions may become jeopardized if the above criteria continue to be violated. Operators should ensure that RCS pressure and inventory, and S/G steaming and feed, are being controlled properly to prevent violation of a safety function, which would require a transfer from this guideline to the Functional Recovery Guideline.

16. Natural circulation is governed by decay heat, component elevations, primary to secondary heat transfer, loop flow resistance, and voiding. Component elevations on C-E plants are such that satisfactory natural circulation decay heat removal is obtained by fluid density differences between the core region and the steam generator tubes.

The small break natural circulation process can take different forms. These forms include single phase natural circulation and a more complex two phase natural circulation. The simplest form of natural circulation is single phase, liquid cooling. Single phase natural circulation is possible for cases where RCS inventory and pressure are controlled. Single phase cooling transports heat using the same flow path involved in forced circulation cooling with the liquid density difference between SG and RV driving the flow. Two phase natural circulation involving steam and water is more complex and can take several forms, which depends on the amount of decay heat, the amount of inventory and pressure control degradation, the break size and the status of the SIS and the steam generators. One form of two phase natural circulation is known as reflux. In the reflux process, steam leaves the core region and travels to the steam generator via the hot leg; the steam is condensed in the steam generator before reaching the top of the "U" tubes and flows back to the core via the hot leg where it is once again turned to steam. Another two phase natural circulation process is similar to reflux but differs in that the steam from the core goes past the steam generator "U" bend and is condensed in the tubes on the cold leg side; thus condensate flows back to the core via the cold leg. A combination of the two reflux processes is also possible.

The operator has adequate instrumentation to monitor natural circulation for the single phase liquid natural circulation process. The RCS temperature instrumentation, namely loop ΔT can be used along with other information to confirm that the single phase natural circulation process is effective. The natural circulation processes involving two phase cooling are complex and varied enough so that RCS loop ΔT may not be a

meaningful indication of adequate natural circulation cooling. The guidelines are written to alert the operator to use explicit acceptance criteria for natural circulation only when RCS inventory and pressure are controlled.

For cases where two phase natural circulation cooling is the heat removal process, the operator performs the following:

a) Verify that all available charging pumps and the SIS is operating to restore inventory control per Figure 5-3
b) [Verify CET temperature < 700°F]
c) Verify that at least one steam generator is either:
   i) within the normal level band with feedwater available to maintain the level

   <u>or</u>

   ii) being restored by a feed water flow > [150 gpm]

The transition from single phase liquid natural circulation cooling to the two phase modes can occur quickly for larger small breaks, or can occur more slowly for the smaller small breaks. The operator should be aware that this transition may cause confusing temperature indications as the RCS loop ΔTs readjust to reflect the transition in process. The emphasis in the guideline is to continue the steam generator heat removal process, continue restoring inventory control, and to continue monitoring the hot leg RTDs and core exit thermocouples to confirm the heat removal process is adequate.

17. If an SIAS has been initiated and the SIS is operating, then it must continue to operate at full capacity until SIS termination criteria are met. For most LOCAs, the SIS will run continuously for a long period of time while RCS inventory, pressure, and heat removal control are being regained. In some cases, control of these three functions is not regained during the accident (i.e., largest breaks) and the SIS runs for the duration of the recovery period. Early termination is expected only when the SIAS was spurious, or if the leak was identified and promptly isolated (e.g., by blocking a stuck open PORV).

Termination of SIS should be sequenced by stopping one pump at a time while observing the termination criteria. Throttling of HPSI flow is also permissible if the following criteria are satisfied:

a) RCS is at least [20°F] subcooled (Figure 5-1). Establishing [20°F] of subcooling ensures the fluid in the core is subcooled, and provides sufficient margin for establishing flow should the [20°F] subcooling deteriorate when SIS flow is secured. Voids may exist in some parts of the RCS (e.g., reactor vessel head [as determined by the RVLMS]), but these are permissible as long as core heat removal is maintained.

b) Pressurizer level is greater than [100"], and not decreasing. A pressurizer level greater than [100"] and not decreasing in conjunction with criterion a) above is an indication that RCS inventory control has been established.

c) At least one steam generator is available for removing heat from the RCS. Steam generator availability requires having feed flow and steam flow which are indications that primary to secondary heat removal is possible.

d) [The RVLMS indicates the core is covered. An indication of core coverage, in conjunction with the above, serves as an additional indication that RCS inventory control has been established].

If SIS termination criteria are met, then the operator may either terminate or throttle the SIS. The operator may decide to throttle, rather than terminate the SIS, if the SIS is to be used to control pressurizer level or plant pressure. A general assessment of the SIS performance can be made from the control room. The operator should confirm that all available charging pumps are operating and that at least one train, and preferably both trains, of SIS are operating and that system delivery rate is consistent with RCS pressure as shown in Figures 5-22 and 5-23. Injection flow rates to each cold leg should be approximately equal; departures from this would indicate a closed flow path or some system spillage that is in addition to the LOCA.

18. If the criteria of step 15 cannot be maintained, then the SIS pumps must be restarted.

19. The operator verifies that containment is isolated at the appropriate automatic setpoints or if containment conditions required isolation. Containment conditions which might require containment isolation would be high radiation levels on containment area radiation monitors. Each plant should develop criteria for containment isolation to be identified in the procedure. Operators should be alert to the loss of auxiliaries to the containment (in particular RCP cooling water) which may occur with containment isolation.

20. In step 11, the operator attempted to isolate the leak. This step was followed by steps containing instructions on RCP restart, natural circulation, SIS, and containment isolation. Those instructions are followed regardless of whether the attempt at isolation was successful. At this point in the guideline, the strategy follows two parallel paths. If the break has not been isolated, the operator is required to go to the section of this procedure which contains recovery actions for those conditions (steps 27-47). If the operator is not certain that the leak is isolated, he/she must proceed as if the leak is not isolated. Positive means of ensuring that a leak is isolated include visual verification, such as direct or remote observation (e.g., in a television monitor). Direct observation is possible for leaks inside and outside of containment, although leaks inside containment are directly observable only if personnel are inside containment at the LOCAs onset.

21. If the break has been isolated, then the following actions (steps 22-26) are aimed at stabilizing the plant.

22. The PPCS is verified to be automatically maintaining or restoring RCS pressure within the limits of Figure 5-1. If not, pressurizer heaters and main spray (preferred) or auxiliary spray are manually controlled to restore pressurizer pressure. The intent of this action verifies that a safety function is being performed: RCS pressure control. Maintaining RCS pressure and temperature within the limits of Figure 5-1 allows for adequate core cooling and minimizes the PTS concerns.

23. The PLCS is verified to be automatically maintaining or controlling pressurizer level. If not, charging and letdown are operated manually to ensure pressurizer level is being maintained. This action verifies that a safety function is being performed: RCS inventory control.

24. RCS cooling must be maintained during the recovery from the LOCA by continually supplying [main or auxiliary] feedwater to the steam generators. Steam discharge should be continued. This activity should be performed preferentially by steam discharge to the condenser via the turbine bypass system. If the condenser or turbine bypass system is not available, the next order of priority for discharging steam would be to use the atmospheric dump valves. Use of the atmospheric dump valves may have the potential for release of activity to the environment. Consequently, it is less desirable to use the atmospheric dump valves for radiological release considerations.

25. During a controlled cooldown and depressurization, the automatic operation of certain safeguard systems is undesirable. [Therefore, the setpoint of CIAS, SIAS, CSAS and MSIS must be manually reset (lowered)] as the cooldown progresses to ensure that automatic engineered safeguards protection remains available until the RCS is cooled down and depressurized.

26. The plant status should be evaluated. If cooldown and depressurization are desired, then this action should be performed until SCS entry conditions are established. A cooldown and depressurization should be performed via either forced circulation (preferred) or natural circulation. SCS operation should be commenced per normal SCS operating instructions once SCS entry conditions are achieved. If voiding inhibits depressurization to SCS entry pressure, then refer to steps 40 and 41.

27. If the break has not been isolated, then the following actions are directed toward reestablishing RCS inventory control while maintaining RCS heat removal.

28. A rapid plant cooldown via the steam generators, is beneficial for all LOCAs, particularly small breaks. For small breaks, the steam generators are the major heat sink for RCS heat removal. An aggressive cooldown (while holding the cooldown rate within Technical Specification Limitations) improves RCS heat removal by enhancing natural circulation and reflux boiling. Furthermore, an aggressive cooldown hastens the depressurization of the RCS. This results in higher safety injection flows which aid in regaining RCS inventory control. Figures 5-22 and 5-23 show typical SIS flowrates as a function of RCS pressure.

    For the largest breaks, the RCS depressurizes to an equilibrium pressure with the containment. In this condition, the RCS fluid is at a lower temperature than that of the steam generators. The steam generators, therefore, act as a heat source, superheating any steam in the RCS which may be flowing through the S/Gs to the break. By cooling down the steam generators, heat input to the RCS is reduced.

29. The available condensate inventory should be monitored, and replenished from available sources as necessary to continually provide a source for a secondary heat sink. Examples of alternate sources of condensate are nonseismic tanks, fire mains, lake water supplies, potable tanks, etc. Plant specific alternate sources of feedwater should be identified and cited in the procedure. The condensate required to either maintain the plant at hot standby or cooldown may be determined from Figure 5-4 and 5-5.

30. Once pressurizer level is restored it should be maintained at the normal shutdown reference level (if possible) by one of the following methods:

    a) Preferentially, by control of charging and letdown,

    <u>or</u>

    b) Operation and/or throttling of the HPSI pumps.

    If the normal shutdown reference level is not maintained, then a pressurizer level of [35 to 245"] with a saturated bubble in the pressurizer should be maintained to avoid losing pressure control. If pressurizer level drops below the top of the pressurizer heaters, then pressurizer heater operation will be interlocked off for overheating protection. It

may be necessary to exceed [245"] pressurizer level if the operator is attempting to restore RCS subcooling since pressurizer heaters may be unavailable and solid water operation may be necessary to achieve subcooling.

Once the pressurizer water temperature varies from the normal hot standby temperature, the instrument indication on the normal pressurizer level channel will begin to deviate (i.e., decalibrate) from the true pressurizer level. At this time, the operator should use plant cooldown correction curves to determine the true pressurizer water level. A cold calibrated pressurizer instrument channel is provided. This channel can be used as a quick reference during the plant cooldown.

31. Suction for the charging pumps should be realigned, within [1 hour] after the start of the loss of coolant accident from the concentrated boron source to the [RWT or any other plant specific suitable source]. Proper shutdown margin must be maintained.

    This realignment from a concentrated boron source to a dilute source is made in order to avoid the possibility of boric acid precipitation in the core which may occur for large breaks. For large breaks, the reactor vessel refills only to the elevation of the break. Borated water is injected into the reactor vessel via the charging and safety injection pumps and pure steam is boiled away. This may result in boric acid being concentrated in the reactor vessel. Switching suction of the charging pump to a dilute source helps limit the excessive buildup of boric acid in the reactor vessel while still allowing for sufficient long-term reactivity control.

32. If the [refueling water tank] level falls to [10%], then initiation of recirculation should be verified. If necessary, recirculation should be initiated manually one SIS train at a time. Recirculation is actuated either automatically or manually in order to maintain a continuous flow of safety injection fluid to the RCS (required for inventory control) and a continuous flow of containment spray water (required for containment

temperature and pressure control). [If the automatic or manual initiation of the RAS does not automatically close RWT outlet valves, these must be manually closed to isolate the RWT from the SIS pumps. Furthermore, sump level should be checked prior to and at the time of transfer of suction sources. An LOCA outside of containment could result in inadequate containment sump inventory to allow recirculation. The operator should monitor an increasing trend in containment sump level that corresponds to the decreasing trend in RWT level. These actions prevent the inadvertent air binding of the safety injection pumps.]

The operator should be cautioned against prematurely initiating an RAS. A possible complication of a premature RAS is the pumps' suction being aligned to a dry sump, consequently air binding the pumps and losing both heat removal loops. In addition, for events where high containment pressure is present, the check valves in the [RWT] outlet line may be forced shut and the [RWT] fluid will remain unavailable while the containment is pressurized.

33. After the switch to recirculation, the HPSI pump flows are monitored in order to ensure that HPSI pump minimum flow requirements for pump protection are met, and to avert any possible permanent HPSI pump damage. If they are not met, the operator should turn off the charging pumps one at a time until the minimum flow requirements are met. If they are still not met with all the charging pumps off and two HPSI pumps operating, the operator turns off the HPSI pump with the lower flow. One HPSI pump should be left operating at all times, unless the criteria of step 17 are met.

34. [To minimize the radionuclide releases to the environment following an RCS boundary break and/or core damage, it is desirable to keep the radionuclides inside the containment. Iodine is the nuclide of greatest concern. The iodine removal system (IRS) operates in conjunction with the containment spray system (CSS) to remove iodine from the containment atmosphere. Since iodine may be released to the containment atmosphere at various times following event initiation, (e.g., released directly

from the core in a large LOCA evolved from iodine plated out on containment surfaces; or released during reactor vessel venting to the containment) and since the CSS is activated automatically on containment pressure, its actuation may not correspond to the time of peak containment iodine levels (if it is actuated at all). Therefore, the CSS may be run to reduce containment airborne iodine to acceptable or minimum levels unless the following indicate otherwise:

1. If there were a leak in containment below sump water level, it might be more desirable to leave the iodine atmospherically suspended.

2. If sump water is highly radioactive, it may not be desirable to circulate it outside the containment.

For those IRS's using hydrazine, it may be necessary to further increase sump water pH (beyond that achieved by trisodium phosphate in the sump) to increase long-term (4 hours post-LOCA) iodine retention in the sump. An alternate method of adding a pH buffer (typically sodium hydroxide) is by establishing a flowpath with the charging pumps].

35. Before terminating containment spray, the operator must verify that containment pressure is below [7 psig]. Termination may be useful to recover from the LOCA since continuous use of the containment sprays may impact the operation of equipment inside containment. Since the containment pressure may increase again, the containment spray system should be realigned for automatic operation after it is terminated. The spray system may also be required to operate in conjunction with the iodine removal system in the event of an iodine buildup in containment.

36. During a controlled cooldown and depressurization the automatic initiation of an MSIS is undesirable, particularly when primary to secondary heat transfer is via the steam generators. [Therefore, the MSIS setpoint must be manually reset as the cooldown progresses to ensure that automatic engineered safeguards protection for an MSIS remains available until the RCS is cooled down and depressurized].

37. Simultaneous hot and cold leg injection is used for both small break and large break LOCAs at [2-4 hours] after the start of the LOCA. In this mode, the HPSI pumps discharge lines are realigned so that the total injection flow is divided equally between the hot and cold legs. Refer to Figure 5-22. Simultaneous injection into the hot and cold legs is used as the mechanism to prevent the precipitation of boric acid in the reactor vessel following a break that is too large to allow the RCS to refill. Injecting to both sides of the reactor vessel ensures that fluid from the reactor vessel (where the boric acid is being concentrated) flows out the break regardless of the break location and is replenished with a dilute solution of borated water from the other side of the reactor vessel. The action is taken no sooner than [2 hours] after the LOCA since the fluid injected to the hot leg may be entrained in the steam being released from the core and hence possibly diverted from reaching the reactor vessel. After [2 hours], the core decay heat has dropped sufficiently so that there is insufficient steam velocity to entrain the fluid being injected to the hot leg. The action is taken no later than [4 hours] after the LOCA in order to ensure that the buildup of boric acid is terminated well before the potential for boric acid precipitation occurs. Even though the action is required only for large breaks, it is taken for any LOCA so that the operator need not be required to distinguish between large and small breaks early in the transient. Simultaneous hot and cold leg injection is not required for small breaks because the buildup of boric acid is terminated when the RCS is refilled. Once the RCS is refilled, the boric acid is dispersed throughout the RCS via natural circulation. If entry into shutdown cooling system operation is anticipated before the [4 hour] limit, and the criteria of step 38 are met, then the realignment to hot/cold leg injection is unnecessary. In that case, go to step 38.

38. For certain sized breaks (small breaks), entry into shutdown cooling is desired, and may be necessary, if steam generator heat removal is lost. The shutdown cooling system is utilized if certain plant conditions exist.

If refilling of the RCS is at all possible, then the time necessary to refill the RCS and regain control of pressure and inventory depends on break size, break location, RCS cooldown rate and the number of HPSI pumps and charging pumps actuated. With only one HPSI pump actuated, for a break of about 3 inch diameter, located on the bottom of the cold leg, it may take as long as [8 hours] to refill the RCS. With all injection pumps operable, the time is about [1 hour].

The operator should determine if SCS operation criteria are met. If pressurizer level is stable, the pressurizer and/or HPSI pumps are maintaining system pressure such that RCS hot and cold leg temperatures are at least [20°F] below saturation temperature for pressurizer pressure, and the steam generators are available (steam flow and feed flow) to reduce the RCS temperature to the shutdown cooling entry value, SCS operation may be appropriate if the SCS is available. Before the SCS is operated, RCS activity levels must be determined since the RCS fluid will now be circulated outside of the containment building. The operator must decide whether to circulate high activity RCS coolant outside containment if high activity is present and such circulation has the potential for release to the environment. If the potential for significant releases exists, it may be more desirable to continue cooling with the steam generator. The condensate inventory must be checked to ensure that the supply is sufficient to cool down the plant to SCS entry conditions or continue cooling the RCS. Condensate inventory adequacy is plant specific and should be determined according to Figure 5-4 and 5-5. Other plant specific prerequisites for SCS operation must be considered (e.g., component cooling water, instrument air and valve control power).

39. If SCS operation is determined to be appropriate per step 38, then the SIS is aligned for cold leg injection and the RCS is cooled down and depressurized as follows. If necessary, RCS hot leg temperature should be cooled to at least [300°F] and depressurized to at least [300 psia]. The RCS is depressurized to at least [300 psia] or less by using auxiliary spray. Depressurization may also be accomplished by stopping charging pumps, or stopping or throttling HPSI pumps. If auxiliary spray is used, then the difference between the pressurizer temperature and the auxiliary spray water temperature should be maintained below [200°F] if

possible. If RCS inventory control is satisfactory, then auxiliary spray water temperature may be increased by increasing letdown flow or reducing charging flow which will increase the regenerative heat exchanger outlet temperature. Other plant specific methods to increase auxiliary spray water temperature may be used. If auxiliary spray is used when a [200°F] or more difference exists, then such a cycle must be recorded as per Technical Specifications. The number of such cycles should be minimized. Another operational alternative for the RCS pressure reduction is to throttle the HPSI pumps and adjust charging pump flow (if the pressurizer is solid) to maintain level and control pressure.

40. If the above actions fail to depressurize the RCS, then a void should be suspected. Any time it is found that voiding inhibits RCS depressurization to SCS entry pressure, when SCS operation is desired, then an attempt at elimination of the voiding should be made.

The operator should monitor for the presence of voids. Voiding in the RCS may be indicated by any of the following indications, parameter changes, or trends:

a) letdown flow greater than charging flow,
b) pressurizer level increasing significantly greater than expected while operating pressurizer spray,
c) [the RVLMS indicates that voiding is present in the reactor vessel],
d) [HJTC unheated thermocouple temperature indicates saturated conditions in the reactor vessel upper head]. A
e) [other indications insert here].

41. If voiding should be eliminated, then proceed as follows:

a) letdown is isolated or verified to be isolated to minimize further inventory loss,

b) the depressurization is stopped to prevent further growth of the void and, if required, the RCS is repressurized to $\geq$ [20°F] subcooling,

c) pressurizing and depressurizing the RCS within the limits of Figure 5-1 may condense the void. Pressurizing has the effect of filling the voided portion of the RCS with cooler fluid which will remove heat from the region. Subsequent depressurization and a repeating of this process several times will cool and condense the steam void. In the case of a void in the reactor vessel, the pressurization/depressurization cycle will produce a fill and drain of the reactor vessel. The pressurization/depressurization cycle may be accomplished using pressurizer heaters and spray (preferred method) or the SIS/charging system (alternative method). Monitor pressurizer level [and the RVLMS] for trending of RCS inventory. This will assist the operator in assessing the effectiveness of void elimination.

d) if indications of unacceptable RCS voiding continue, and voiding is suspected to exist in the (isolated) steam generator tubes, then cool the (isolated) steam generator (by steaming or blowdown, and/or feeding) to condense the tube bundle void. This will be effective for condensing steam voids but will not have an effect on non-condensible gases trapped in the tube bundle. A buildup of non-condensible gases in the tube bundles will not hinder natural circulation event with a large number of the tube blocked. This is due to the small amount of heat transfer area required for the removal of decay heat. Monitor pressurizer level for trending of RCS inventory. This will assist the operator in assessing the effectiveness of void elimination.

e) if indications of unacceptable RCS voiding continue, then voiding may be caused by non-condensible gases. [Operate the pressurizer vent and/or the reactor vessel head vent to clear trapped non-condensible gases.] Monitor pressurizer level [and/or the RVLMS] for trending of RCS inventory. This will assist the operator in assessing the effectiveness of void elimination.

42. When SCS entry conditions (RCS pressure $\leq$ [300 psia] and RCS $T_H \leq$ [300°F]) are established, then the SCS is placed in service.

43. The safety injection tanks must be vented, drained, or their discharge valves shut at an RCS pressure of [250 psia] to prevent the nitrogen cover gas from discharging into the RCS when the RCS pressure is reduced.

44. [LTOP protection is instituted below 275°F to protect the primary pressure boundary from low temperature brittle fracture.]

45. If RCS pressure and inventory control have not been established, then the break may be too large to assure proper suction pressure to the SCS pumps. Therefore, the SCS is not operated. However, in this event there is assurance that the continuation of simultaneous hot and cold leg injection in a recirculation mode will both cool the core and flush the reactor vessel.

If SCS operation is not appropriate due to the above mentioned conditions, or if the system is not available, then it is desirable to continue RCS heat removal via the steam generators until no further steam is generated. Steam generator heat removal is preferentially maintained using [main or auxiliary] feedwater and steam is discharged suing the turbine bypass system via the condenser. Alternatively, if the turbine bypass system or condenser are unavailable, steam generator heat removal is maintained using [main or auxiliary] feedwater and steam is discharged via the atmospheric dump valves. If [main or auxiliary] feedwater are unavailable, alternate supplies of feedwater should be employed. Examples of alternate sources of feedwater are fire pumps, condensate pumps, temporary water transfer pumps, etc. These alternate sources of feedwater should be indicated in the plant emergency procedures.

46. [If subcooling conditions, as indicated by CETs, cannot be maintained, then the pressurizer PORV may be opened and the charging and SIS aligned for cold leg injection to obtain once-through cooling. For heat removal purposes the charging system must remain operating (for plants both with and without pressurizer PORVs) even if the RCS is in an overpressurized condition.]

47. If heat removal is being maintained using any of the methods listed in step 45, then the operator should periodically verify that condensate inventory is adequate. If at any time, the cooling water supply for the heat removal alternative in use becomes limiting, the operator would implement the next alternative in step 45 which is available. Finally, a reevaluation of the conditions necessary for SCS operation may be made. This includes such things as RCS radioactivity levels (if the SCS is otherwise available), or the activities necessary to restore the SCS for use. If use of the SCS is appropriate or feasible, steps 38 through 44 are implemented.

Safety Function Status Check

Figure 5-24 provides the bases for the LOCA Safety Function Status Check. The Safety Function Status Check is designed to ensure that the operator is using the correct procedure, and the actions of that procedure are satisfying all relevant safety functions and maintaining adequate core cooling.

The safety function status check provides a systematic approach to determine if the LOCA EPG is appropriate, and more importantly, if the plant condition is satisfactory. Safety functions have been used throughout the guideline system as a structure for storing and using operational information. When the plant is in a normal condition each safety function can be explicitly shown to be satisfied. For example, inventory control can be demonstrated by conducting simple tests with charging and pressurizer spray and heaters. The safety function status check acceptance criteria for inventory control when the plant is normal can be direct and explicit. When the plant has been damaged, some of the safety functions are not easily shown to be under control. For example, inventory control in an LOCA can not be tested for as easily as it can be when the plant is normal. The safety function status check acceptance criteria for inventory control in a LOCA relies on implicit information. Since tests with charging, pressurizer spray and heaters would not be valid, the inventory control acceptance criteria is based on knowing that the systems intended to provide inventory control (i.e., SIS) are functioning. In addition, the acceptance criteria for other functions must be used in conjunction with inventory acceptance criteria to arrive at the conclusion that the plant status is satisfactory.

SAFETY FUNCTION STATUS CHECK BASES
LOSS OF COOLANT ACCIDENT
Figure 5-24a

The safety functions listed below and their respective criteria are those used to confirm the adequacy of the LOCA Guideline in mitigating the event.

SAFETY FUNCTION	ACCEPTANCE CRITERIA	INDICATION	RANGE	BASES
Reactivity Control	Reactor Power Decreasing and [Negative Startup Rate] and Not more than 1 CEA Bottom Light Not Lit or Borated per Tech Specs	Power Range Power Rate CEA Status Display	[0-125%] [-1 → 7 dpm] On/Off Light for Each CEA	For all emergency events, the reactor must be shutdown. The criteria that no more than one CEA be stuck out or the RCS be borated observes typical technical specification requirements.
Maintenance of Vital Auxiliaries (AC & DC Power)	[<--Plant Specific----------------------------------->]			
RCS Inventory Control	If [35"] ≤ Pressurizer Level ≤ [245"]; Then: charging and letdown are being operated manually or automatically to control pressurizer level and RCS ≥ [20°F] Subcooled and [The RVLMS indicates the core is covered] or If Pressurizer Level < [35"]; Then:	Pressurizer Level [RVLMS]	[0-350"] [0-100%]	A value of [245"] ([70%] of range) was chosen as an upper limit for pressurizer level to account for instrument accuracies and other uncertainties. A value of [35"] ([10%] or range) was chosen as a lower limit to account for instrument accuracy. A [20°F] subcooling margin coexisting with a pressurizer level of [35 to 245"] indicates adequate RCS inventory control via a saturated bubble in the pressurizer.

(continued)

SAFETY FUNCTION STATUS CHECK BASES
LOSS OF COOLANT ACCIDENT
Figure 5-24b

The safety functions listed below and their respective criteria are those used to confirm the adequacy of the LOCA Guideline in mitigating the event.

SAFETY FUNCTION	ACCEPTANCE CRITERIA	INDICATION	RANGE	BASES
RCS Inventory Control (Cont'd)	[All available charging pumps are operating and] the SIS pump(s) are injecting water into the RCS per Figure 5-3			An RVLMS indication that the core is covered taken in conjunction with [20°F] subcooling is an additional indication of adequate RCS inventory control. * For cases where RCS inventory is badly degraded the SIS operation provides implicit assurance that control is being regained. At RCS pressures greater than the shutoff head of the SIS, the use of all available charging pumps is emphasized. <u>All available</u> charging pumps is emphasized because until pressure lowers, this will be the sole means of injecting water into the RCS.
RCS Pressure Control	If Pressurizer Pressure ≥ [1600 psia], Then either pressurizer heaters and spray or charging and SIS pumps are being operated automatically or manually to maintain or restore pressurizer pressure within the limits of the P/T curves, Figure 5-1 <u>or</u>	Pressurizer Pressure	[1500-2500 psia]/ [0-1600 psia]	[1600 psia] is the SIAS setpoint. The range of the selected events are very broad, therefore the acceptance criteria is written to cover the expected range which may result from the events noted.

SAFETY FUNCTION STATUS CHECK BASES
LOSS OF COOLANT ACCIDENT
Figure 5-24c

The safety functions listed below and their respective criteria are those used to confirm the adequacy of the LOCA Guideline in mitigating the event.

SAFETY FUNCTION	ACCEPTANCE CRITERIA	INDICATION	RANGE	BASES
RCS Pressure Control (Cont'd)	If Pressurizer Pressure < [1600 psia], Then [all available charging pumps are operating and] the SIS pump(s) are injecting water into the RCS per Figure 5-3 (unless SIS termination criteria are met).			
Core Heat Removal	T_H RTDs [and Core Exit Thermocouples] < [700°F]	[Core Exit Thermocouples] T_H RTDs	[0-1600°F] [465-615°F]	Since the saturation temperature corresponding to the RCS safety valve setpoints is less than 700°F, an indicated temperature greater than 700°F on the [CETs] represents a superheat condition in the RCS which can only occur with core uncovery. Core uncovery results from a loss of RCS inventory which generally results from two accident scenarios: LOCA or loss of steam generators as a heat sink. LOCA results directly in a loss of inventory. Very small break LOCAs will not result in depressurization much below the HPSI pump shutoff head. For these small break LOCAs, superheat is indicative of core uncovery occurs at high pressure. For large break LOCAs which result in rapid depressurization (Continued)

SAFETY FUNCTION STATUS CHECK BASES
LOSS OF COOLANT ACCIDENT
Figure 5-24d

The safety functions listed below and their respective criteria are those used to confirm the adequacy of the LOCA Guideline in mitigating the event.

SAFETY FUNCTION	ACCEPTANCE CRITERIA	INDICATION	RANGE	BASES
Core Heat Removal (Continued)				to less than 300 psia, superheat which is indicative of core uncovery occurs at low pressure. A loss of inventory (leading to core uncovery) can also result from a loss of S/G heat sink which causes RCS pressure to rise high enough to lift the [PORVs] and pressurizer safeties. Core uncovery and, therefore, superheat on the [CETs] indicate an advanced phase in the approach to inadequate core cooling and are undesirable. If at anytime superheat is approached or indicated, the operator should review the effectiveness of earlier measures and take all possible steps to restore the inventory to at least a core covered condition as indicated by saturation or subcooling on the [CETs], Subcooled Margin Monitor, [or as an indication of core coverage on the RVLMS]. [700°F] is the plant specific temperature as read on the T_H RTDs [and core exit thermocouples (CETs)] which represents the maximum temperature anticipated during accident mitigation. It is chosen based on engineering judgement and is intended to (Continued)

SAFETY FUNCTION STATUS CHECK BASES
LOSS OF COOLANT ACCIDENT
Figure 5-24e

The safety functions listed below and their respective criteria are those used to confirm the adequacy of the LOCA Guideline in mitigating the event.

SAFETY FUNCTION	ACCEPTANCE CRITERIA	INDICATION	RANGE	BASES
Core Heat Removal (Continued)				bound predicted, indicated temperatures for an LOCA with no multiple equipment failures or coincident accidents. Superheat on the T_H RTDs [and CETs] is indicative of core uncovery and short term core uncovery is predicted for worst case scenarios.
RCS Heat Removal	a) At least one S/G has level: i) within the normal level band with feedwater available to maintain the level or ii) being restored by a feedwater flow > [150 gpm] and	Steam Generator Level	[+63.5" - (-)116.5"]	Decay heat levels may not be high enough to require a feedwater flow of [150 gpm]. If this is the case once steam generator level is returned to the zero power level band and feedwater remains available to maintain that level, then the S/G contribution to RCS heat removal is being satisfied.
	b) RCS Tave is < [545°F] and controlled or	Tave	[520°F-610°F]	[545°F] is based on not lifting a steam generator safety valve.
	c) [All available charging pumps are operating and] the SIS pump(s) are injecting water into the RCS per Figure 5-3 (unless SIS termination criteria are met).			RCS heat removal can occur by once through cooling either through the [PORV] or by cooling through the break combined with steam generator cooling.

SAFETY FUNCTION STATUS CHECK BASES
LOSS OF COOLANT ACCIDENT
Figure 5-24f

The safety functions listed below and their respective criteria are those used to confirm the adequacy of the LOCA Guideline in mitigating the event.

SAFETY FUNCTION	ACCEPTANCE CRITERIA	INDICATION	RANGE	BASES
Containment Isolation	a. i) Containment Pressure < [4 psig]	Containment Pressure	[0-60 psig]	[4 psig] is the CIAS setpoint. If pressure does exceed [4 psig], containment isolation valves should shut (i.e., CIAS should be present).
	and			
	ii) No containment area radiation monitors alarming	Containment Area Rad Monitors	Alarming/Not Alarming	Steam plant activity is an indication of an SGTR and is not anticipated for a LOCA regardless of containment conditions.
	and			
	iii) No steam plant activity monitors alarming	Steam Plant Activity Monitors	Alarming/Not Alarming	The containment should usually be isolated if containment area radiation monitors alarming.
	or			
	b. CIAS should be present or manually initiated	Containment Isolation Valve Position Indicators	Open/Shut	

SAFETY FUNCTION STATUS CHECK BASES
LOSS OF COOLANT ACCIDENT
Figure 5-24g

The safety functions listed below and their respective criteria are those used to confirm the adequacy of the LOCA Guideline in mitigating the event.

SAFETY FUNCTION	ACCEPTANCE CRITERIA	INDICATION	RANGE	BASES
Containment Temperature and Pressure Control	a. i) Containment Temperature < [240°F]	Containment Dome Temperature	[50-300°F]	[240°F] corresponds to the maximum containment temperature expected below [10 psig].
	and			
	ii) Containment Pressure < [10 psig]	Containment Pressure	[0-60 psig] [0-15 psig]	[10 psig] is based on CSAS setpoint.
	or			
	b. Containment Spray Flow > [1500 gpm]	Containment Spray Flow	[0-5000 gpm]	During the selected event, containment temperature and pressure may exceed these limits if the break is inside containment. If this happens, a CSAS should be present and the CSP should be injecting spray solution at [1500 gpm].
Containment Combustible Gas Control	H_2 < [2%]	<--------------[Plant Specific]-------------->		
	or			
	[Hydrogen Recombiners in operation]	[On/Off]		[In the long term, containment hydrogen levels may rise above X%. At any level greater than X% the hydrogen recombiners should be operating to maintain the hydrogen concentration below flammable/explosive limits].

Event Strategy

This section contains the detailed LOCA operator actions strategy flow chart, Figure 5-25. The flow chart pictorially depicts the strategy around which the LOCA guideline is built. It is intended to assist the reader in understanding the intent of the guideline writer and for use in training. Operators should understand the major objectives of the guideline in order to facilitate their progress toward the guideline goals.

The strategy charts show the recovery guideline strategy in detail and list the guideline steps which correspond to each strategy objective. Some steps in the guideline may be performed at any time during the course of an event. These steps are shown by affixed asterisks. The dashed boxes above the line indicate the lead-in steps performed by the operator prior to entering this recovery guideline.

Figure 5-25a

LOSS OF COOLANT ACCIDENT RECOVERY STRATEGY CHART

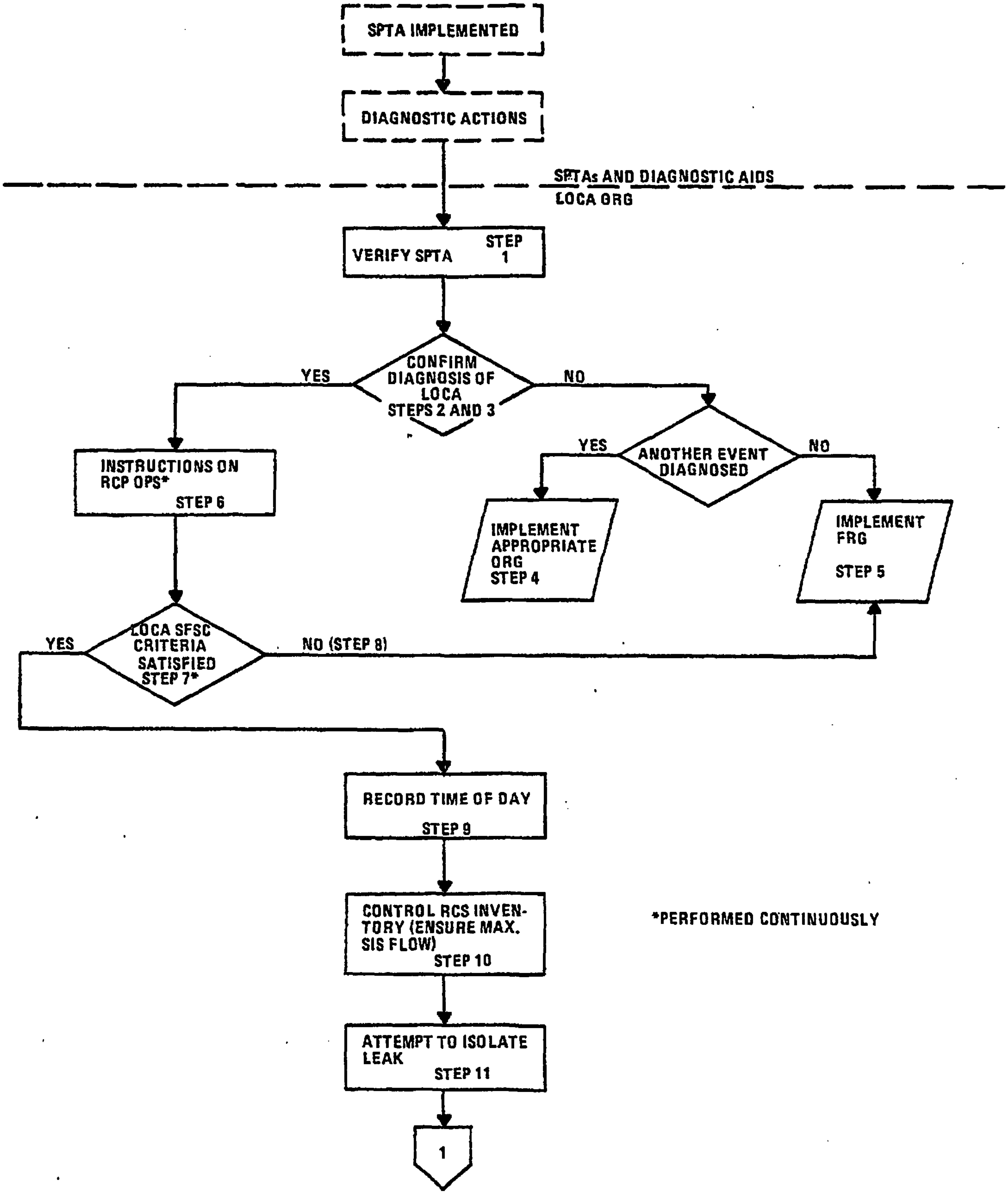


FIGURE 5-25b

LOSS OF COOLANT ACCIDENT RECOVERY STRATEGY CHART

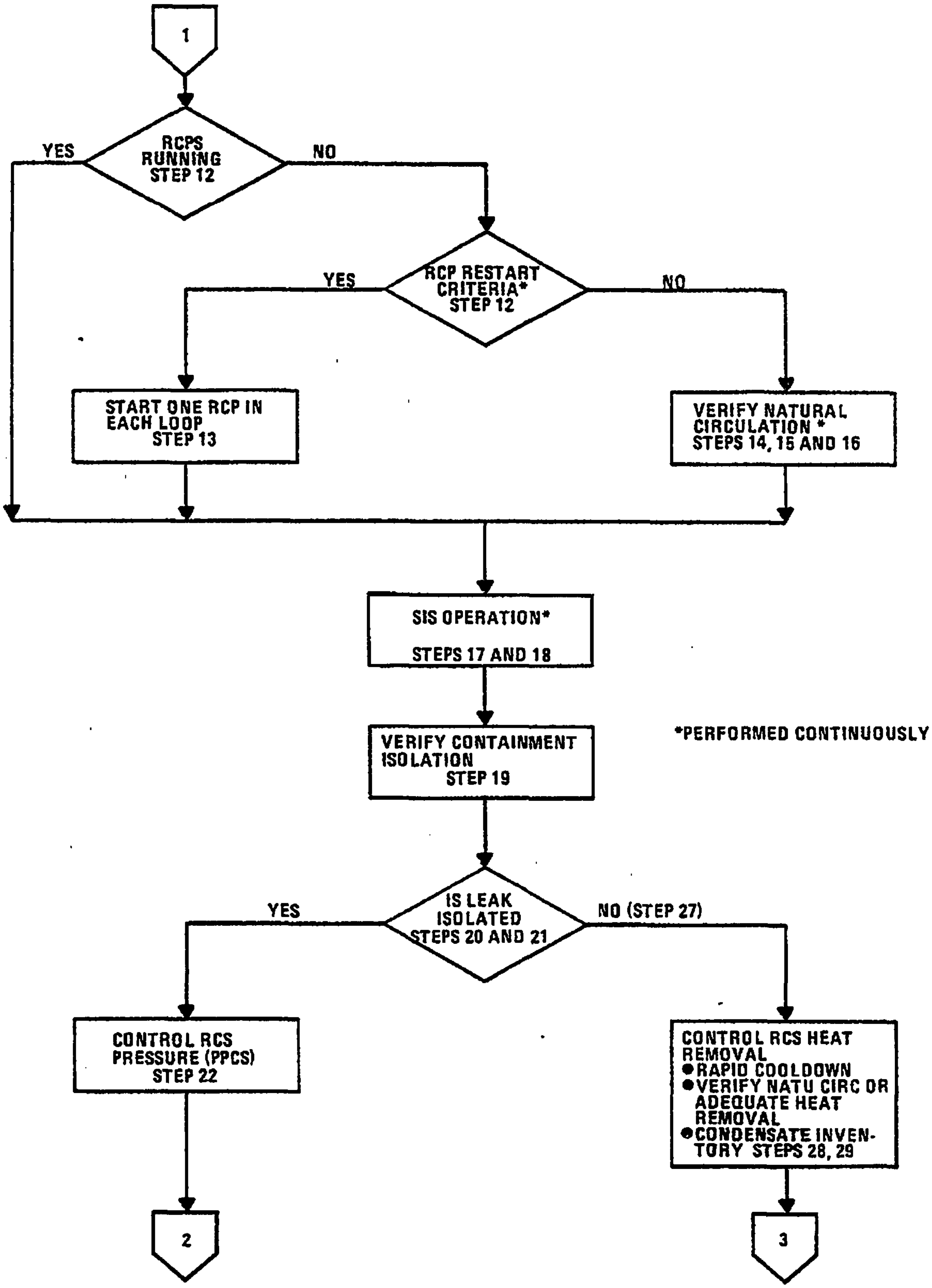


FIGURE 5-25c
LOSS OF COOLANT ACCIDENT RECOVERY STRATEGY CHART

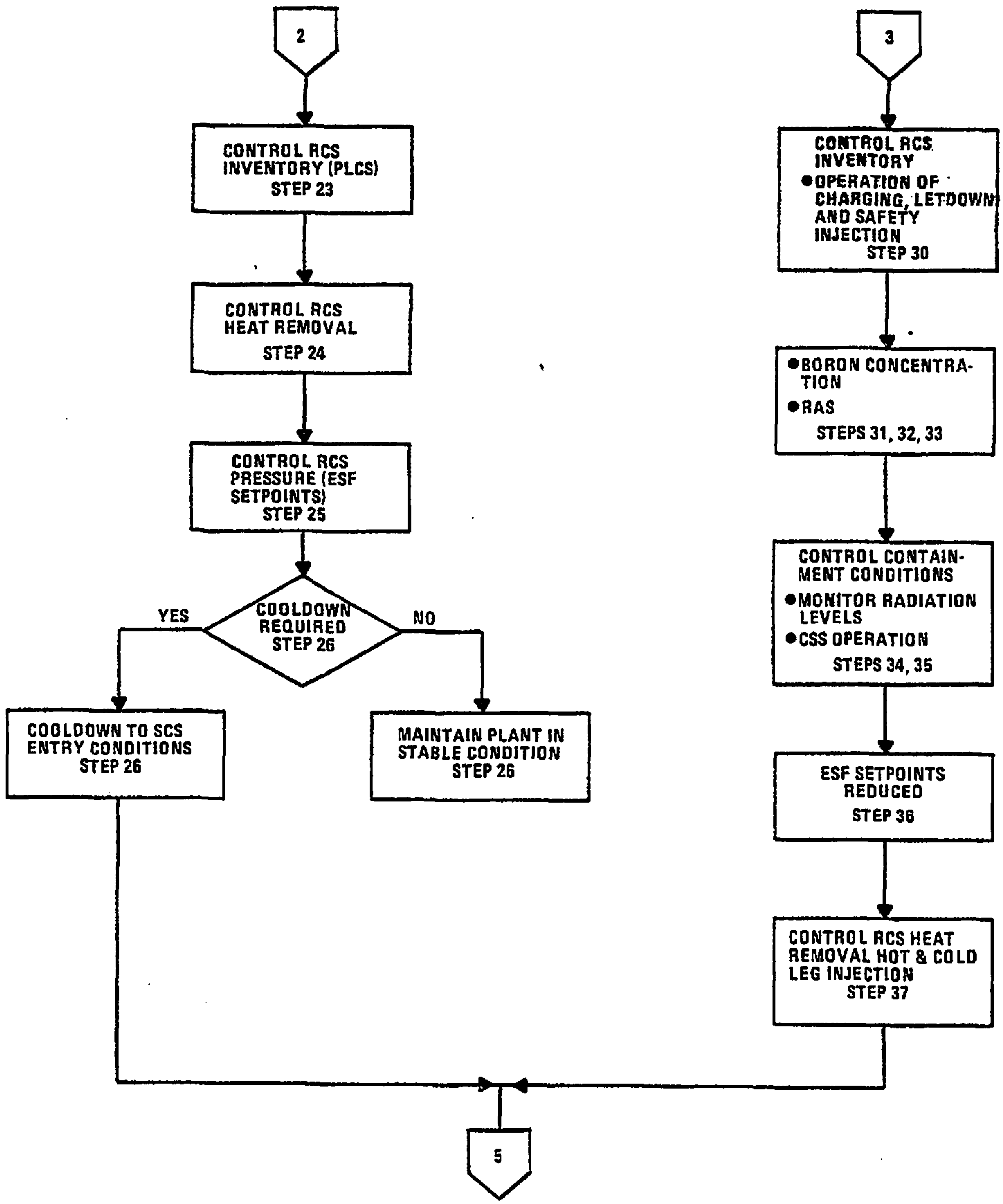
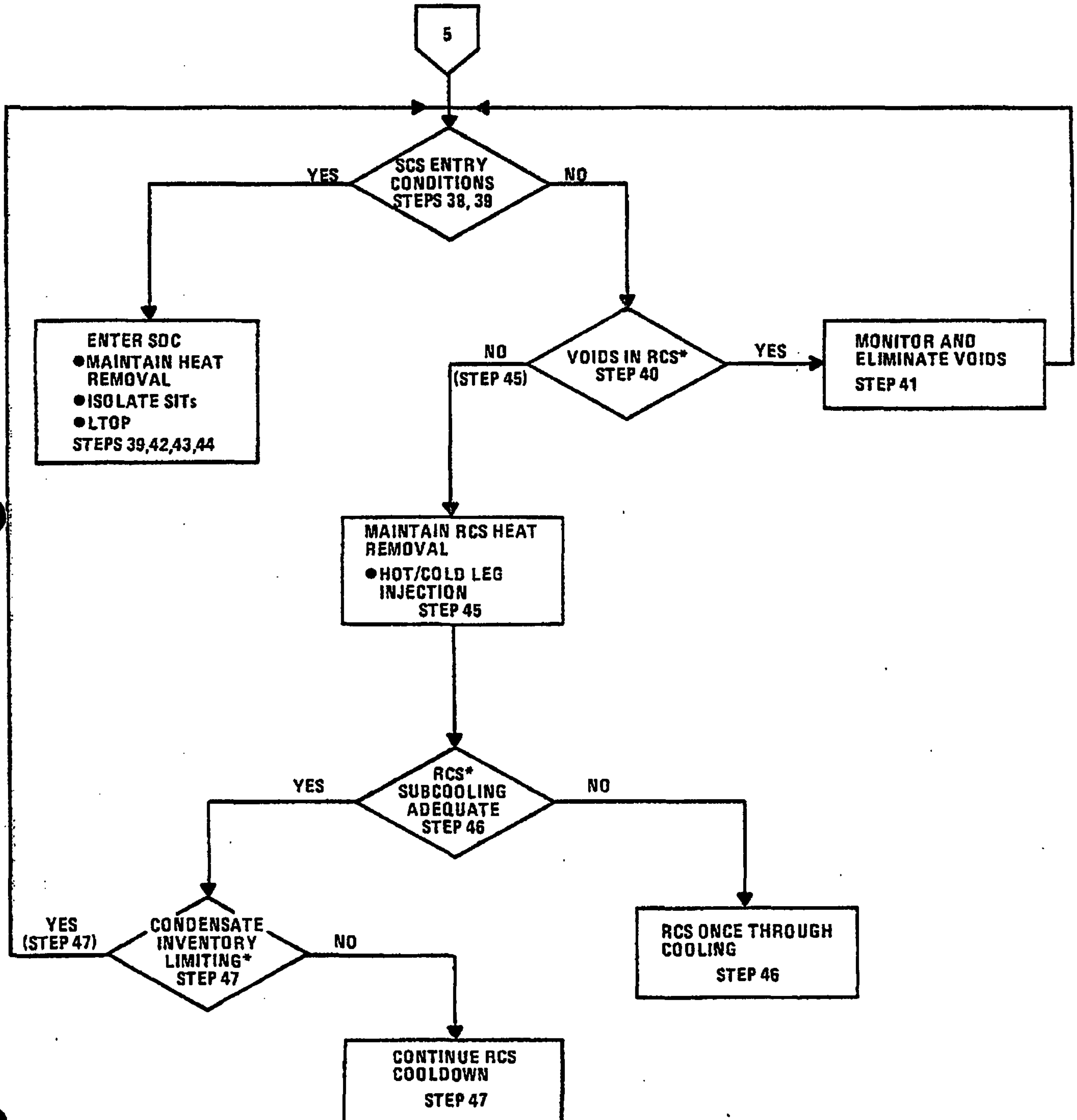


FIGURE 5-25d

LOSS OF COOLANT ACCIDENT RECOVERY STRATEGY CHART



*PERFORMED CONTINUOUSLY

STEAM GENERATOR TUBE RUPTURE RECOVERY GUIDELINE

Prepared by
COMBUSTION ENGINEERING, INC.
for the
C-E Owners Group

PURPOSE

This guideline provides operator actions which must be accomplished in the event of a steam generator tube rupture. The actions in this guideline are necessary to ensure the plant is placed in a stable, safe condition. This guideline provides technical information to be used by utilities in developing a plant specific procedure.

ENTRY CONDITIONS

1. The Standard Post Trip Actions have been performed.

and

2. Plant conditions indicate that a steam generator tube rupture has occurred. Any one, or more, of the following may be present:

   a. Air ejector high activity alarm.

   b. Steam generator blowdown high activity alarm.

   c. High activity and conductivity in steam generator liquid sample.

   d. Increasing steam generator level.

   e. [Other plant specific symptoms, insert here.]

1. IMPLEMENTED IN STEP A

2. IMPLEMENTED IN STEP B

3. IMPLEMENTED IN STEP K

4 SEE DEVIATION 6-1

5 SEE DEVIATION 6-1

6 IMPLEMENTED IN STEP O
Dev O-69

7 IMPLEMENTED IN STEP O
O-69

8 IMPLEMENTED IN STEP B

OPERATOR ACTIONS

1. Verify that the Standard Post Trip Actions have been performed. ✓

2. Confirm the diagnosis of a steam generator tube rupture by:

   [a) Referring the the Break Identification Chart (Figure 6-2)

   and

   b) Verifying the Safety Function Status Check criteria are satisfied]. ✓

3. Sample both steam generators for activity.

*4. If the diagnosis indicates that an LOCA or an ESDE has occurred, Then exit the SGTR Guideline and implement the actions of the ESDE or LOCA Guideline.

*5. If the initial diagnosis of an SGTR is confirmed, Then continue with the actions of this guideline.
If not, implement the Functional Recovery Guideline.

*6. If pressurizer pressure decreases to less than [1300 psia] following an SIAS, Then ensure two of four RCPs are tripped (in opposite loops). ✓

*7. [If RCP operating limits are not satisfied, Then trip the remaining two RCPs]. ✓

*8. Verify that the safety functions are being satisfied by comparing control board parameters to the acceptance criteria of the Safety Function Status Check.

* Step performed continuously.

9. SEE DEVIATION 6-1

10. IMPLEMENTED IN STEP C
Dev 6-38+37

11. IMPLEMENTED IN STEPS G, H, K
Dev 6-39

12. IMPLEMENTED IN STEP N

*9. If the safety functions from the Safety Function Status Check are satisfied, Then continue with the actions of this guideline.
If not, implement the Functional Recovery Guideline.

10. Verify that the RCS hot leg temperature is less than [525°F] in order to minimize the possibility of lifting steam generator safeties after isolating a steam generator.
If the RCS hot leg temperature is greater than [525°F], Then cooldown the RCS by (listed in order of preference):

a) If the condenser, turbine bypass system, and [main or auxiliary] feedwater system are available, Then commence the cooldown by using the turbine bypass system and [main or auxiliary] feedwater.

or

b) If the condenser or turbine bypass system is not available, Then commence a reactor plant cooldown using the atmospheric dump valves and [main or auxiliary] feedwater.

11. Determine which steam generator has the tube rupture by performing the following:

a) Monitor and/or sample steam generators for activity. ✓
b) Monitor main steam piping for activity. ✗ ✓
c) [Other plant specific indications, insert here.] ✓

12. Isolate the steam generator with higher activity, higher radiation levels or increasing water level by performing the following: ✓

* Step performed continuously.

13 SEE DEVIATION 6-2

14 SEE DEVIATION 6-2

15 DIRECTION PROVIDED IN SCOPE ~~SECT~~ION OF PROCEDURE. ACTION STEPS are also written to imply the MOST affected S/G is ~~to~~ ISOLATED

16 IMPLEMENTED IN STEP AB
Dev 2-39 + 2-40

a) Close the main steam isolation valve.
b) Verify the main steam isolation valve bypass valve is closed.
c) Close the atmospheric dump valve and align to the manual mode.
d) Close the main feedwater isolation valve.
e) Isolate steam generator blowdown.
f) [Close the auxiliary feedwater isolation valves including the steam driven pump steam supply valve associated with the steam generator being isolated.]
g) Isolate vents, drains, exhausts, and bleedoffs from the steam system and turbine building sumps.
h) [Other plant specific information, insert here.]

13. Verify the correct S/G is isolated by checking radiation indications, and possible steam generator level increase, and by sampling techniques.

14. If the wrong steam generator has been isolated, Then unisolate that generator and isolate the affected steam generator.

15. If both generators are affected, Then the steam generator with the highest radioactivity should be isolated.

*16. If the RCPs were stopped, Then one RCP in each loop should be restarted if possible. Determine whether RCP restart criteria ar met by the following:

a) The unaffected steam generator (or the least affected, if both steam generators have leaks) is available (feed and steam flow) for removing heat from the RCS,
b) Pressurizer level is greater than [200"] and not decreasing,
c) The RCS is at least [20°F] subcooled (Figure 6-1)

* Step performed continuously.

17 IMPLEMENTED BY STEP AB
Dev 2-42

18 IMPLEMENTED BY STEP A
Dev 2-43

19 IMPLEMENTED BY SFSC. ALSO SEE REFERENCED GUIDELINE STEPS

d) [Other criteria satisfied per RCP operating instructions.] ✓

*17. If RCP restart criteria are met, Then do the following:

a) Start all available HPSI and charging pumps, or verify their operation.
b) Start one RCP in each loop.
c) [Ensure proper RCP operation by monitoring RCP amperage and pump NPSH. NPSH is determined by pressurizer pressure and corresponding T_C on Figure 6-1]. ✓
d) Operate HPSI (Figure 6-3) and charging pumps until pressurizer level is greater than [100"] and SIS termination criteria are met.

*18. If all RCPs have been stopped, affected S/G ? inventory and pressure are being controlled, and the steam generators are being used for heat removal, Then natural circulation flow is being maintained in at least one loop. The following criteria must be met to demonstrate adequate natural circulation flow:

a) Loop ΔT (T_H - T_C) less than normal full power ΔT. ✓
b) Cold leg temperatures constant or decreasing
c) Hot leg temperatures stable (i.e., not steadily increasing) or decreasing slowly
d) No abnormal differences between T_H RTDs and [core exit thermocouples].

*19. If the criteria of step 18 are not met, Then ensure RCS pressure and inventory (steps 20 and 26), and S/G steaming and feed (step 27), are being controlled properly. ✓

* Step performed continuously.

20. Implemented by step L. SEE DEVIATION 6-3

21. implemented by step S
Dev. 3-34

22. IMPLEMENTED BY STEP S

23. SEE DEVIATION 6-4

24 implemented IN steps AC, AD, AE, AF, AG
6-40

*20. If pressurizer level is less than [35"], Then take steps to ensure maximum safety injection (Figure 6-3) and charging flow to the RCS by:

a) restoring electrical power to valves and pumps,
b) restoring correct SIS valve lineup if misaligned,
c) restoring other necessary auxiliary systems,
d) starting idle SIS and charging pumps.

*21. If the SIS is operating, Then it may be throttled or stopped, one train at a time, if the following conditions are satisfied:

a) RCS is at least [20°F] subcooled (Figure 6-1)
b) Pressurizer level is greater than [100"] and constant or increasing,
c) At least one steam generator is available (feed and steam flow) for removing heat from the RCS. ✓
d) [The RVLMS indicates the core is covered.]

*22. If the criteria of step 21 cannot be maintained after the SIS has been stopped, Then the SIS must be restarted. ✓

23. If the SIS termination criteria are met and the isolated steam generator is still overfilling with primary fluid, Then stop the running HPSI pumps. ✓

*24. Prevent overfilling of the isolated steam generator through periodic draining to the [radioactive waste system] or, if draining is not feasible or sufficient, then dump steam from the affected steam generator to the condenser. ✓ What happens if condenser unavailable

Also in NC/Condenser not available limited to one ADV

if can achieve a CDR of 100°/h then RCS - Temp of < 500°F

will ensure LR ~ 0 ΔP RCS-SG ~0-50psid maintain 30°F S.C

* Step performed continuously.

25 IMPLEMENTED IN STEP V. PERIODIC sampling is done to ensure any dilution (from PZR or S/G) THAT MAY OCCUR DOES NOT CHALLENGE THE SHUTDOWN margin

26 IMPLEMENTED IN STEPS P, AC, AH

27 implemented IN STEP P

28 IMPLEMENTED IN STEP W

25. Sample the RCS for radioactivity and boron concentration. Calculate and add sufficient boron to the RCS to raise the entire RCS (including the mass in the pressurizer) to the shutdown margin required by Technical Specifications.

26. Decrease and then control RCS pressure slightly above (0-100 psid) the isolated steam generator pressure and below [1000 psia]. Throughout the event, including cooldown, maintain the RCS within acceptable Post-Accident Pressure/Temperature Limits of Figure 6-1 by the following methods of RCS depressurization:

    a) Main spray
    b) Auxiliary Spray
    c) Throttling HPSI pump(s)

27. Resume an orderly reactor plant cooldown in accordance with Technical Specification limits with forced circulation (preferred) or natural circulation by:

    a) If the condenser and either the [main or auxiliary] feedwater system are available, cooldown by using the turbine bypass system.

    or

    b) If the condenser or turbine bypass system are not available, then cooldown using the unisolated (least affected) steam generator by way of the atmospheric dump on the unisolated (least affected) steam generator, and using either the [main or the auxiliary] feedwater system.

28. Sample the condensate and other connecting systems, including turbine building sumps, for activity which may have been transferred from the affected steam generator(s).

* Step performed continuously.

29. IMPLEMENTED IN SFSC (noble gas monitor on main vent)

30. IMPLEMENTED IN STEP AB

31 implemented in CORE AND RCS heat removal SFSC. See Deviation 6-5

32 implemented in step L. See Deviation 6-6

33 implemented by steps D, F, CIS AND CSAS DO NOT HAVE bypasses since they only initiate on containment pressure
Dev 4-48

34 IMPLEMENTED IN STEP P. SEE DEVIATION 6-7
[redacted]

*29. Observe the [turbine] and [auxiliary] building ventilation systems' radiation monitors and any other applicable radiation monitors. Take corrective actions, if necessary, in accordance with plant Technical Specification Limitations.

30. When conditions permit, Then restart one RCP in each loop to establish cooling of the isolated steam generator and continue RCS cooldown and depressurization to SCS initiation conditions. Refer to steps 16 and 17 for RCP restart criteria. If RCP restart criteria are not met, then go to step 38.

*31. Monitor the condensate inventory during the cooldown, in order to ensure an adequate supply. Refer to Figures 6-4 and 6-5.

*32. Maintain pressurizer level in the indicating range, [35 to 245"] (unless it is necessary to go solid to restore RCS subcooling) by (listed in order of preference):

a) Control charging and letdown

or

b) Operating and/or throttling SIS.

33. If plant conditions permit, Then bypass automatic initiation of [MSIS, CIAS, CSAS and SIAS by lowering the setpoint as the cooldown and depressurization proceeds].

*34. If the above actions fail to depressurize the RCS, Then a void should be suspected. The operator should monitor for the presence of voids. If voiding inhibits RCS depressurization to SCS entry pressure, Then an attempt at eliminating the voiding should be made.

* Step performed continuously.

35. IMPLEMENTED IN STEP P. SEE DEVIATION 6-7 for S/G TUBE VOIDING ACTIONS

Voiding in the RCS may be indicated by any of the following indications, parameter changes, or trends:

a) letdown flow greater than charging flow,
b) pressurizer level increasing significantly greater than expected while operating pressurizer spray,
c) [the RVLMS indicates that voiding is present in the reactor vessel],
d) [HJTC unheated thermocouple temperature indicates saturated conditions in the reactor vessel upper head]. A
e) [other indications insert here].

*35. If voiding should be eliminated, Then proceed as follows:

a) verify letdown is isolated,
b) stop the depressurization and, if required, repressurize the RCS to ≥[20°F] subcooling,
c) pressurize and depressurize the RCS within the limits of Figure 6-1 by operating pressurizer heaters and spray (preferred method) or HPSI and charging pumps (alternative method). Monitor pressurizer level [and the RVLMS] for trending of RCS inventory.
d) if indications of unacceptable RCS voiding continue, and voiding is suspected to exist in the (isolated) steam generator tubes, then cool the (isolated) steam generator (by steaming or blowdown, and/or feeding) to condense the steam generator tube bundle void. Monitor pressurizer level for trending of RCS inventory.
e) if indications of unacceptable RCS voiding continue, then [operate the pressurizer vent and/or the reactor vessel head vent to] clear trapped non-condensible gases. Monitor pressurizer level [and/or the RVLMS] for trending of RCS inventory.

* Step performed continuously.

36. IMPLEMENTED IN STEP AI

37. STEP Accomplished in OP-5 OR AOP-3E DEPENDING ON whether RCPs are AVAILABLE. STEP AI REFERENCES THESE PROCEDURES

38. see step 37 above

39. IMPLEMENTED IN STEPS P AND Q AND IN AOP 3E

40. heat Removal verified in safety function status check. see Referenced steps for implementation information.

41 implemented in SFSC

42 implemented in STEP Q. SEE DEVIATION 6-6 for solid plant operations

43 Direction for bypassing ESFAS are provided early in the event in steps D, F. IF Bypassing can be Accomplished it will be done then. Consequently further direction in the cooldown is not required.

44

*36. When the RCS is cooled to at least [300°F] and depressurized to at least [300 psia], Then initiate shutdown cooling per the SCS operating instructions.

37. [Isolate, vent, or drain the safety injection tanks at 250 psia.] ✓

38. [Initiate the low temperature overpressurization system at 275°F.] ✓

39. If necessary, a natural circulation cooldown is performed by the steps in the remainder of the guideline.

*40. During the cooldown and depressurization to SCS entry conditions natural circulation heat removal is maintained. Refer to steps 18 and 19. If voiding inhibits depressurization to SCS entry conditions, then refer to step 34.

*41. Monitor the condensate inventory during the cooldown, in order to ensure an adequate supply. Refer to Figures 6-4 and 6-5. ✓

*42. Maintain pressurizer level in the indicating range [35 to 245"] (unless it is necessary to go solid to restore RCS subcooling) by (listed in order of preference):

a) Control charging and letdown

or

b) Operating and/or throttling SIS.

43. If plant conditions permit, Then bypass automatic initiation of [MSIS, CIAS, CSAS and SIAS by lowering the setpoint as the cooldown and depressurization proceeds]. ✓

* Step performed continuously.

44. IMPLEMENTED BY STEP Q AND STEP AC AND STEP AH

45. SEE DEVIATION 6-7

46. Implemented in OP-5 OR AOP-3E depending on whether RCPs are available. STEP AI References these procedures.

47 see STEP 46

48 see STEP 46

44. Maintain the RCS pressure slightly above that of the affected S/G and within the acceptable Post Accident Pressure/Temperature Limits (Figure 6-1) during the cooldown by:

    a) Controlling RCS heat removal via the unaffected or least affected steam generator

    and

    b) Controlling RCS pressure using the following methods (listed in order of priority):
        i) Pressurizer heater and auxiliary spray
        ii) Charging and letdown
        iii) HPSI pumps

45. Remove heat from the isolated S/G during the cooldown by one of the following methods (listed in order of priority):

    a) feed and bleed using main or auxiliary feedwater and steam generator blowdown
    b) [other plant specific methods, insert here].

46. When the RCS is cooled to at least [300°F] and depressurized to at least [300 psia], Then initiate shutdown cooling per the SCS operating instructions.

47. [Isolate, vent, or drain the safety injection tanks at 250 psia RCS pressure.]

48. [Initiate the low temperature overpressurization system at 275°F.]

1. SEE DEVIATION 6-8

2. implemented IN STEP H. ADDITIONAL DIRECTION IS NOT warranted

3. implemented in step Q. ADDITIONAL DIRECTION IS NOT WARRANTED

4. implemented in steps H AND K. ADDITIONAL DIRECTION IS NOT warranted

5. implemented in precaution D

6 implemented in precaution A AND B

SUPPLEMENTARY INFORMATION

This section contains items which should be considered when implementing EPGs and preparing plant specific EOPs. The items should be implemented as precautions, cautions, notes, or in the EOP training program.

1. To minimize the unmonitored release of radioactivity, use of the atmospheric steam dump valves on the affected steam generator should be minimized.

2. To reduce the release of potentially radioactive steam from turbine driven pump exhausts, motor driven auxiliary or main feedwater pumps should be used. If the motor driven pumps are not available, steam from the intact steam generator should be used to drive the turbine driven auxiliary feed pump.

3. During all phases of the cooldown, RCS temperature and pressure should be monitored to avoid exceeding a maximum cooldown rate greater than Technical Specification Limitations.

4. Automatic feedwater modulation may mask the expected steam generator level increase due to a steam generator tube rupture.

5. If the faulted steam generator has been isolated and the cooldown is proceeding via natural circulation, an inverted ΔT (i.e., T_C greater than T_H) may be observed in the idle loop. This is due to a small amount of basis reverse heat transfer in the isolated steam generator and will have no effect on natural circulation flow in the intact steam generator.

6. Do not place systems in "manual" unless misoperation in "automatic" is apparent. Systems placed in "manual" must be checked frequently to ensure proper operation.

7. implemented in Precaution C

8. implemented in step Q ADDITIONAL DIRECTION NOT WARRANTED

9 See Deviation 6-9

10 implemented in Precaution F. See Deviation 6-10

11 See Deviation 6-11

12 see Deviation 6-12

13 implemented in step P. Additional direction not warranted.

7. All available indication should be used to aid in diagnosing the event since the accident may cause irregularities in a particular instrument reading. Instrument readings must be corroborated when one or more confirmatory indications are available.

8. If the initial cooldown rate exceeds Technical Specification Limits, there may be a potential for pressurized thermal shock (PTS) of the reactor vessel. Post-Accident Pressure/Temperature Limits of Figure 6-1 should be maintained.

9. Solid water operation of the pressurizer should be avoided unless [20°F] of subcooling cannot be maintained in the RCS (Figure 6-1). If the RCS is solid, closely monitor any makeup or draining and any system heatup or cooldown to avoid any unfavorable rapid pressure excursions.

10. Minimize the number of cycles or pressurizer auxiliary spray whenever the temperature differential between the spray water and the pressurizer is greater than [200°F] in order to minimize the increase in the spray nozzle thermal stress accumulation factor. Every such cycle must be recorded in accordance with Technical Specification Limitations.

11. If restarting reactor coolant pumps, consideration should be given to choosing pump combinations which will maximize pressurizer spray flow.

12. [Monitor quench tank parameters since any sustained operation of the PORVs may burst the tank's rupture disc.]

13. The operator should continuously monitor for the presence of RCS voiding and take steps to eliminate voiding any time voiding causes the heat removal or inventory control safety functions to begin to be threatened. Void elimination should be started soon enough to ensure heat removal and inventory control are not lost. C

14. See deviation 6-13

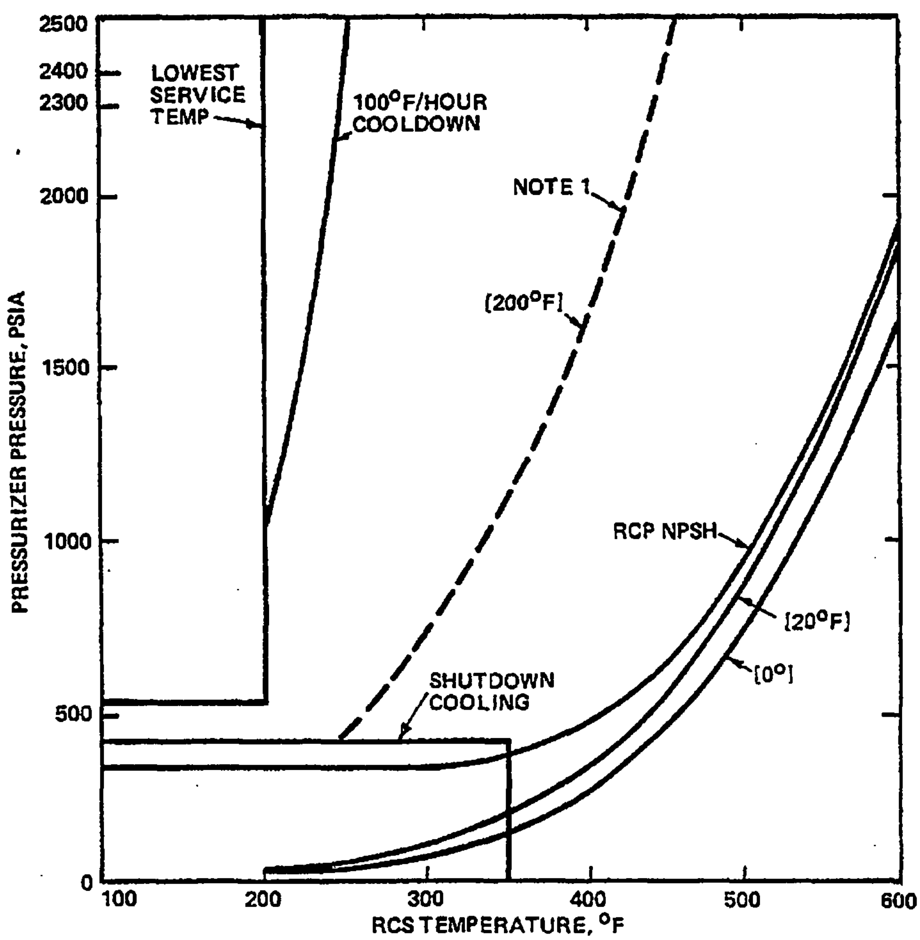
15 implemented by step P. Additional guidance not warranted

14. When a void exists in the reactor vessel, and RCPs are not operating, the RVLMS provides an accurate indication of reactor vessel liquid inventory. When a void exists in the reactor vessel, and RCPs are operating, it is not possible to obtain an accurate reactor vessel liquid level indication due to the effect of the RCP induced pressure head on the RVLMS. The indicated level also differs for different RVLMS designs under these conditions. Information concerning reactor vessel liquid inventory trending may still be discerned. However, the operator is cautioned not to rely solely on the RVLMS indication when RCPs are operating.

15. The operator should continuously monitor for the presence of RCS voiding and take steps to eliminate voiding any time voiding causes the heat removal or inventory control safety functions begin to be threatened. Void elimination should be started soon enough to ensure heat removal and inventory control are not lost. C

FIGURE 6-1

TYPICAL POST ACCIDENT PRESSURE-TEMPERATURE LIMITS(2)



NOTES: (1) THIS CURVE SUPERSEDES THE 100°F/HOUR COOLDOWN CURVE ANYTIME THE RCS HAS EXPERIENCED AN UNCONTROLLED COOLDOWN WHICH CAUSES RCS TEMPERATURE TO GO BELOW 500°F
(2) THESE CURVES MUST BE ADJUSTED FOR INSTRUMENT INACCURACIES
(3) COLOR CODE
RED - PARAMETER IN EXCESS OF LIMITS
ORANGE - PARAMETER IN DANGER OF EXCEEDING LIMITS
YELLOW - PARAMETER OUTSIDE OF OPTIMAL RANGE, BUT STILL WITHIN LIMITS
GREEN - PARAMETER IN OPTIMAL RANGE OF VALUES

BREAK IDENTIFICATION CHART

FIGURE 6-2

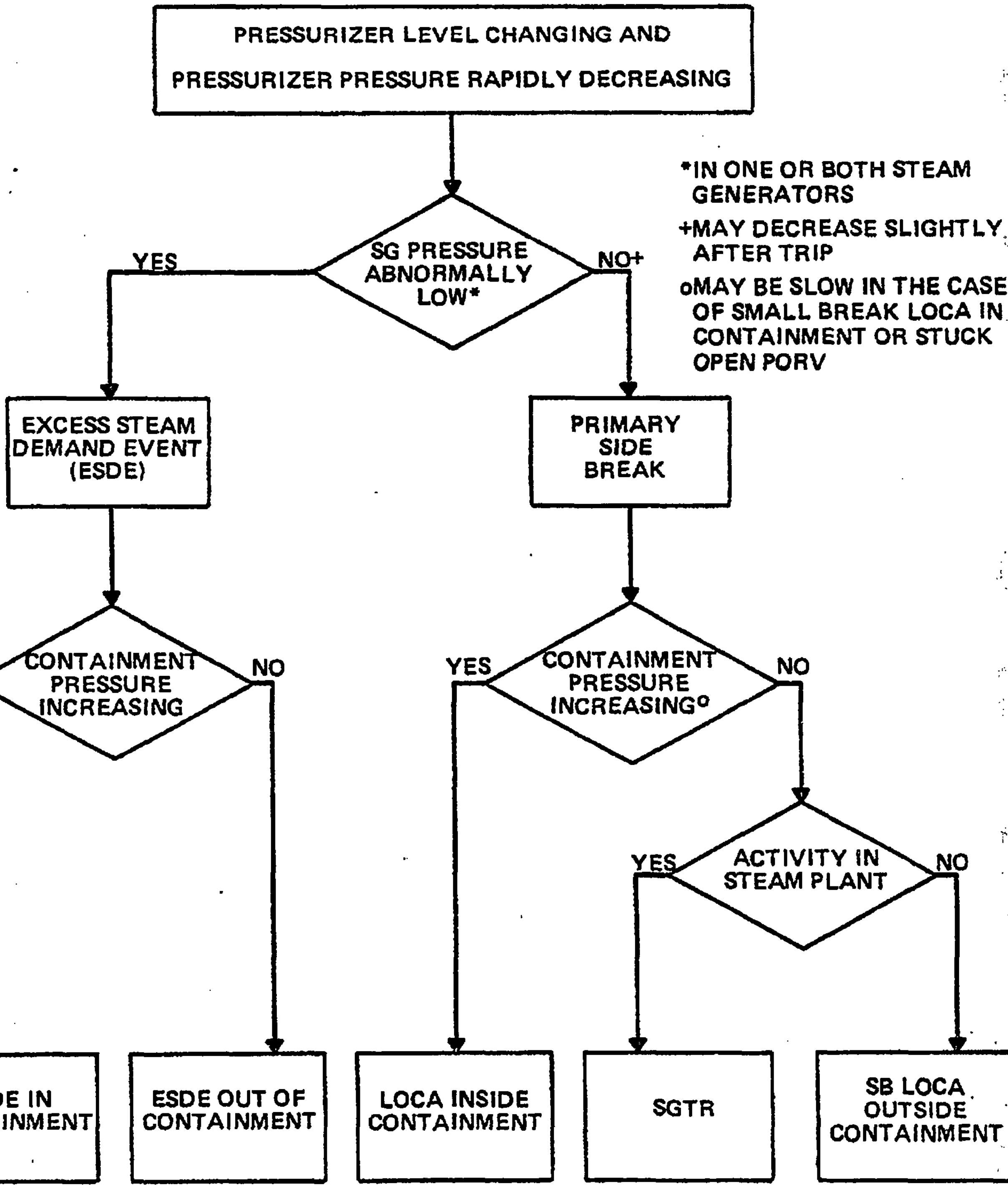
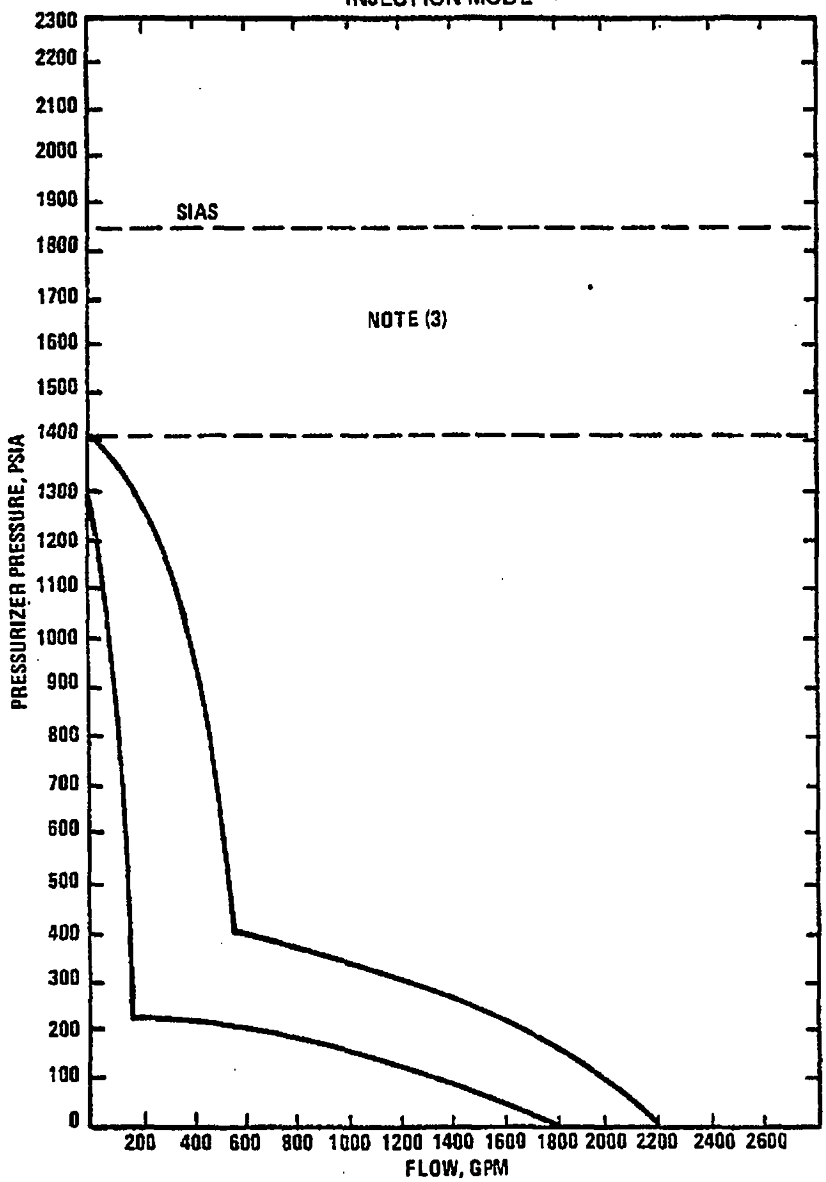


FIGURE 6-3

TYPICAL ACCEPTABLE SIS FLOW vs RCS PRESSURE(1)
INJECTION MODE(2)



NOTES:
(1) SEE IMPLEMENTATION SECTION FOR DEVELOPMENT OF PLANT SPECIFIC CURVE
(2) FOR HOT AND COLD LEG INJECTION MODE, THE LPSI PUMPS ARE NOT REQUIRED TO BE OPERATING. THE HPSI PUMP FLOW IS DIVIDED EQUALLY BETWEEN THE HOT AND COLD LEGS
(3) BELOW SIAS PRESSURE, SAFETY INJECTION SYSTEM (SIS) PUMPS WILL BE OPERATING BUT THERE WILL BE NO INJECTION FLOW UNTIL SYSTEM PRESSURE FALLS BELOW THE SHUTOFF HEAD OF ANY SIS PUMP
(4) COLOR CODE
RED - PARAMETER IN EXCESS OF LIMITS
YELLOW - PARAMETER OUTSIDE OF OPTIMAL RANGE, BUT STILL WITHIN LIMITS
GREEN - PARAMETER IN OPTIMAL RANGE OF VALUES

TYPICAL FEEDWATER CAPACITY vs TIME REMAINING UNTIL SHUTDOWN COOLING REQUIRED

FIGURE 6-4

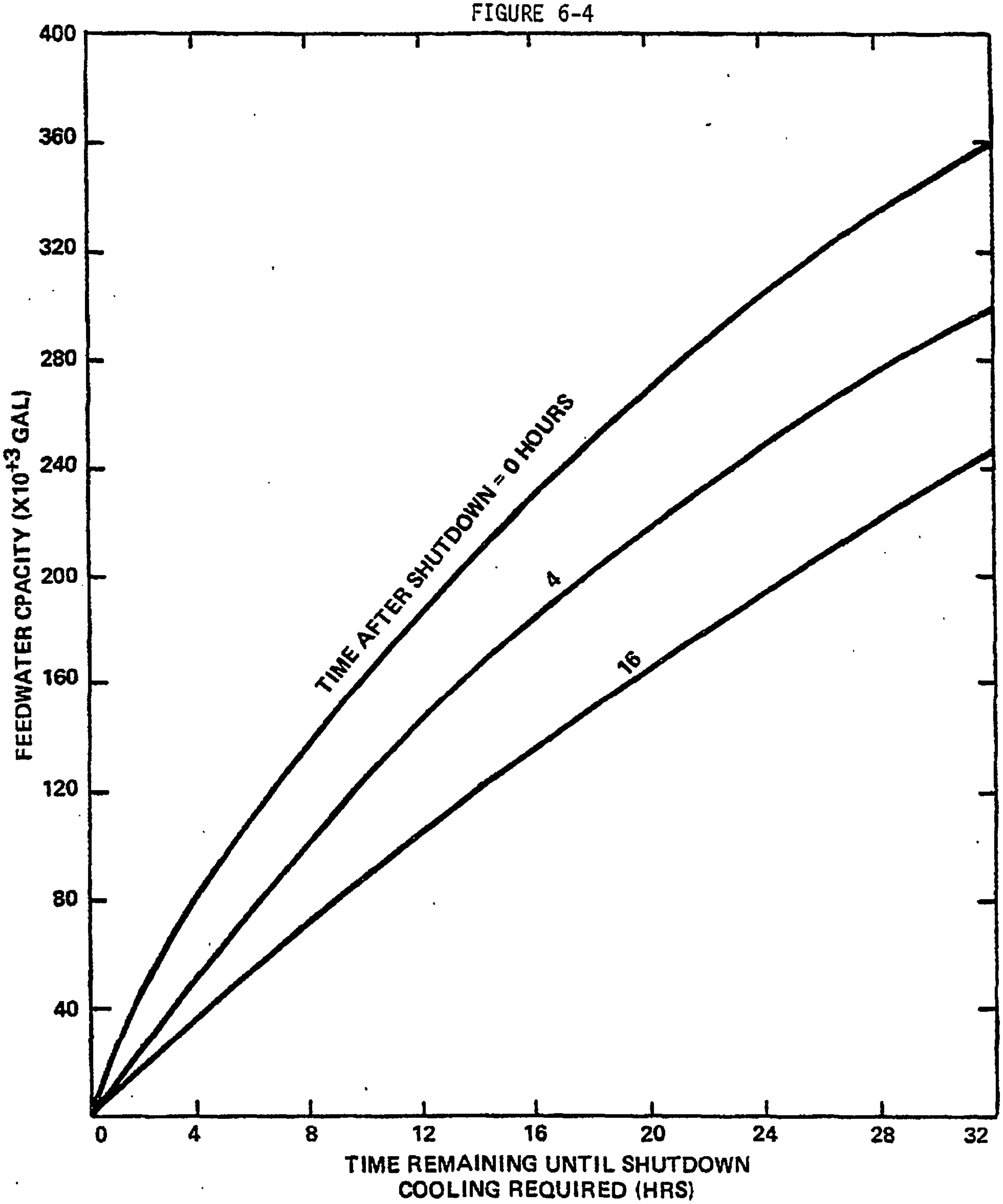
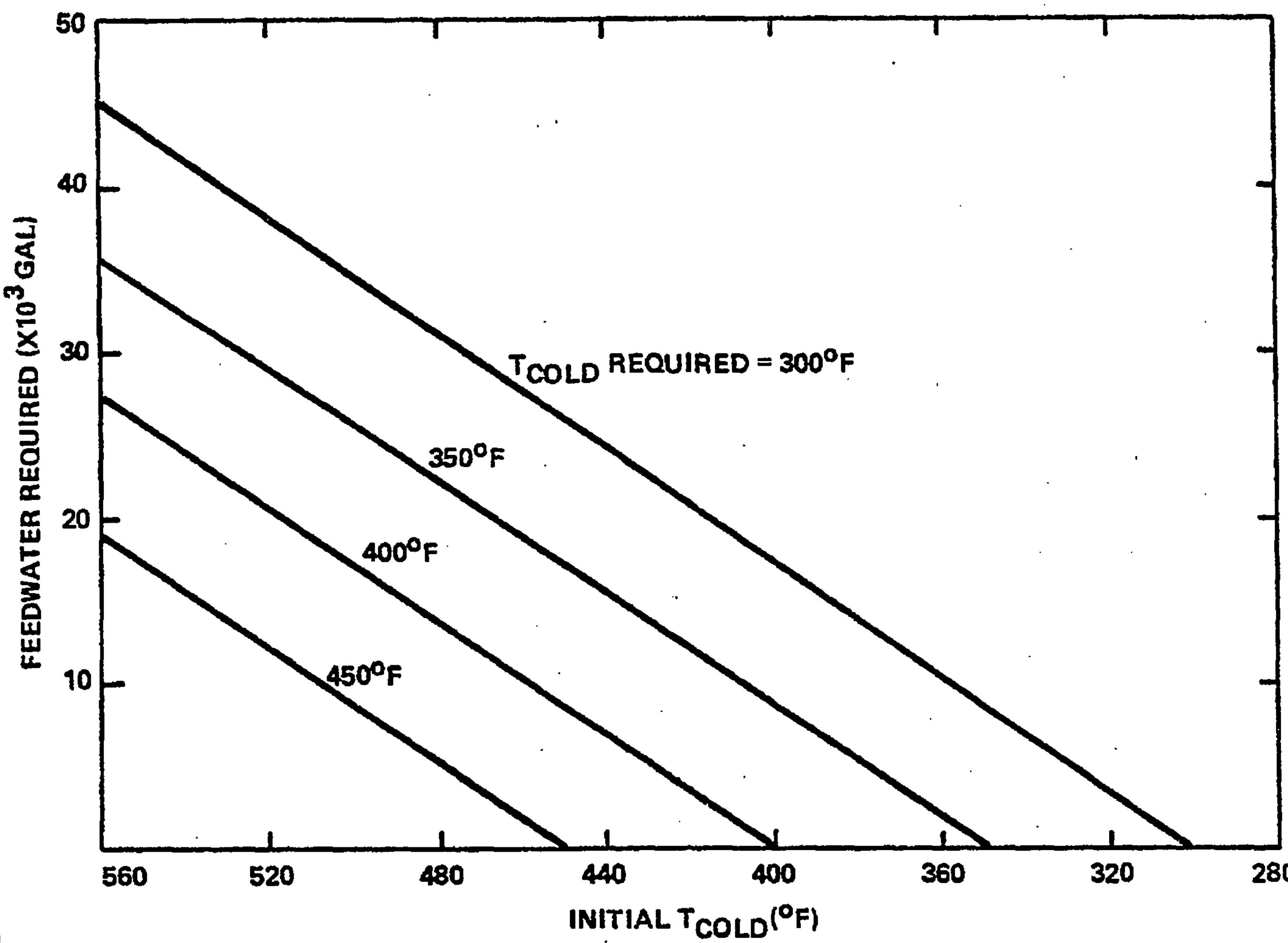


FIGURE 6-5

TYPICAL FEEDWATER REQUIRED FOR SENSIBLE HEAT REMOVAL
T_{COLD} (REQUIRED) vs T_{COLD} (INITIAL)



1. All items covered under Reactivity control SFSC

2. included as 4th function of SFSC

3. Level and subcooling acceptance criteria included in SFSC. See Deviation 6-14 for equipment operation verification.

SAFETY FUNCTION STATUS CHECK

Safety Function	*Acceptance Criteria*
1. *Reactivity Control*	1.a. Reactor power decreasing *and* b. [Negative Startup Rate] *and* c. No more than 1 CEA bottom light not lit or borated per Tech Specs.
2. *Maintenance of Vital Auxiliaries (AC and DC Power)*	2. [Plant specific criteria, insert here].
3. *RCS Inventory Control*	3.a. If pressurizer level is [35 to 245"], Then: i) Charging and letdown are being operated automatically, or manually, to maintain or restore pressurizer level and ii) the RCS is at least [20°F] subcooled and iii) [the RVLMS indicates the core is covered] *or*

4. See deviation 6-15

5

SAFETY FUNCTION STATUS CHECK

Safety Function	Acceptance Criteria
	b. If pressurizer level is less than [35"], Then: i) [all available charging pumps are operating and] the SIS pump(s) is injecting water into the RCS per Figure 6-3 and ii) [the RVLMS indicates the core is covered].
4. RCS Pressure Control	4.a. If pressurizer pressure is greater than or equal to [1600 psia], Then pressurizer heaters and spray are being operated automatically, or manually, to maintain or restore pressurizer pressure within the limits of Figure 6-1. or b. If pressurizer pressure is less than [1600 psia], Then [all available charging pumps are operating and] the SIS pump(s) are injecting water into the RCS per Figure 6-3 (unless SIS termination criteria are met).

5. see Deviation 6-17

6. Level criteria contained in SFSC, see Deviation 6-16 for feedwater flow, TAVE,

7. Implemented in Containment Environment SFSC

SAFETY FUNCTION STATUS CHECK

Safety Function	Acceptance Criteria
5. *Core Heat Removal*	5. T_H RTD [and Core Exit Thermocouple] temperatures less than [600°F].
6. *RCS Heat Removal*	6.a. The unaffected steam generator has level: i) within the normal level band with feedwater available to maintain level or ii) being restored by feedwater flow greater than [150 gpm] *and* b. RCS T_{ave} is less than [525°F] and controlled.
7. *Containment Isolation*	7.a. Containment pressure less than [1.5 psig] *and* b. No containment area radiation monitors alarming.

8. implemented in Containment environment SFSC

9. implemented in Containment environment SFSC....

SAFETY FUNCTION STATUS CHECK

Safety Function	*Acceptance Criteria*
8. *Containment Temperature and Pressure Control*	8.a. Containment temperature less than [120°F] *and* b. Containment pressure less than [1.5 psig] *and* c. No abnormal containment sump levels
9. *Containment Combustible Gas Control*	9. H_2 concentration less than [2%].

BASES

The bases section of the steam generator tube rupture (SGTR) recovery guideline describes the SGTR transient in relation to the actions which the operator takes during an SGTR. The purpose of the bases section is to provide the operators with information which will enable them to understand the reasons for and the consequences of the actions they take during a SGTR.

Characterization of a SGTR Event

The steam generator tube rupture accident is a penetration of the barrier between the reactor coolant system (RCS) and the main steam system. The penetration can range from the failure of an etch pit, a small crack in a U-tube or weld joining the U-tube to the tube sheet, to a single tube double-ended rupture to multiple ruptures in one generator or simultaneous ruptures in both generators. A steam generator tube inside diameter is 0.67 inches. A complete severance of a tube which allows reactor coolant to flow out both ends has an equivalent flow area of approximately 0.7 square inches. This size may be compared to 0.072 square inches, the smallest hole which is classified as a loss of coolant. The loss of coolant flowrate for a steam generator tube rupture differs from the classic loss of coolant accident in that the backpressure opposing flow is the steam generator pressure instead of the containment pressure.

For the double ended rupture of one steam generator tube, without operator action, the reactor trip is expected within 15 minutes after rupture. Multiple tube failures could result in a more rapid plant response. Ruptures within charging system capacity will not result in a continuously decreasing pressurizer level and pressure, since the automatic operation of the PLCS may stop the decrease. An automatic reactor trip may not occur and a controlled reactor shutdown should be performed using the appropriate non-emergency procedures.

A steam generator tube rupture is characterized by specific parameters that may be noted in the control room. Some of these indications are:

a) Radiation monitors indicating an increase in activity levels at the air ejector discharge, at the steam generator blowdown lines, at the turbine or auxiliary building ventilation monitors, at the stack monitor, and/or in the steam generator liquid sample.

b) Decreasing level in the volume control tank.

c) An unaccounted increase in the charging and/or a decrease in the letdown system flowrates.

d) Relatively constant temperature and power indications prior to reactor trip or operator intervention.

e) Steam generator water level either remains relatively constant (indicating a small rupture) or increases slowly (indicating a large rupture) due to the primary to secondary leakage incurred.

f) Containment temperature and pressure remain unchanged.

Safety Functions Affected

The steam generator tube rupture accident directly affects two safety functions. One is RCS inventory control. The second safety function affected is containment isolation since the reactor coolant boundary has been broken and control of the spread of contamination is provided by secondary plant alignment and isolation. All safety functions should be monitored to assure public safety.

The general goals related to controlling RCS inventory and radionuclide containment are met by controlling leakage between the primary and secondary systems and, after isolating the leaking steam generator, by avoiding opening its safety valves. Primary to secondary leakage is minimized by minimizing

RCS inventory

$\Delta P_{SG/RCS}$ = 900 psid   leak rate ~ 750 gpm

Pressurizer level 1 inch ≡ 30 gall.

∴ PL ↓ 25 inch / min

assuming min letdown / max m.u ~ 21 inch/min

~ 10 min to empty Pressurizer with m.u.

Leak rate from Break near Hot leg   modified D'arcy formula

" " " " " Cold leg

the pressure differential between the reactor coolant system and the steam generators. The steam generator safety valves can be lifted in two ways. Adding heat to the steam generator causes steam generator pressure to increase, which in turn causes the safety valves to lift. A second way to lift steam generator safety valves is to have RCS leakage into the steam generator with the RCS pressure greater than the steam generator safety valve setpoint. This second process has a time delay built into it. The pressure drop across the steam generator ~~turbine~~ rupture keeps the steam generator from seeing high (tube) RCS pressure until the steam generator fills sufficiently to drive steam generator pressure up. The optimum response to control RCS inventory and radionuclide containment is to minimize RCS and steam generator pressure differential as soon as possible while bringing RCS pressure down below the steam generator safety valve setpoint and to control RCS temperature to preclude lifting steam generator safety valves by heat transfer to the steam generators.

RCS inventory control is affected in the following manner. The rupture size determines when an automatic reactor trip occurs. For example, the inventory loss out a double-ended tube rupture will exceed the total maximum charging flow into the RCS. Consequently, pressurizer level and pressure decrease and a reactor trip occurs. Pressure and level fall rapidly following the trip, usually emptying the pressurizer and initiating an SIAS. If the pressurizer level decreases to less than [35 inches], all heaters are deenergized due to low pressurizer level. RCS inventory loss is controlled by minimizing the differential pressure between the RCS and the steam generators. Inventory control for the SGTR is dependent on RCS and steam generator pressure control.

Radionuclide containment is the second safety function challenged by the SGTR. In addition to the loss of reactor coolant caused by a steam generator tube rupture, fission products and activated corrosion products normally suspended in the reactor coolant will be transferred from the primary to the secondary plant. Steam plant vents and exhausts provide a potential path to the environment for the radioactive products. The transfer of fission and activated corrosion products from the RCS to the affected steam generator will result in increased levels of activity in the steam generator liquid sample. A high

radiation alarm could occur in the steam generator blowdown monitoring system. Activated products (mostly noble gases) will be carried into the steam plant by the main steam flow. The non-condensible gases may eventually be exhausted to the environment by way of the stack via the air ejector exhaust and may alarm the radiation monitoring system. As a result of gases being emitted and the build-up of activity in the affected steam generator general area radiation levels in the turbine and auxiliary building will increase and may cause area radiation monitors to alarm. Ventilation exhaust and stack monitors may also alarm. For double ended tube ruptures, the expected order of alarms is: air ejector, blowdown, ventilation and stack monitors. For small tube leaks, the first indication may be a high activity level in the steam generator liquid sample.

In this SGTR recovery guideline, radionuclide containment control is accomplished in several stages. The steps to detect and isolate the damaged steam generator are provided. Even before this, a step is provided which cools the RCS so that once the damaged steam generator is isolated, the RCS cannot transfer enough heat into it to cause its safety valves to open. The actions to control RCS inventory combined with control of RCS pressure also preclude release through the steam generator safety valves.

RCS temperature	RCS temperature can only decrease if RCS heat removal is greater than decay ht production

Trending of Key Parameters

Reactor Power (*Figure 6-6*)

In response to a steam generator tube rupture, reactor power initially remains constant. Ruptures exceeding the capacity of the available charging pumps will result in a reactor trip on [thermal margin/low pressure] in a time dependent on the size of the rupture.

RCS Temperature (*Figure 6-7*)

The RCS temperatures remain relatively constant until the reactor trips. Following the reactor trip, the RCS hot and cold leg temperatures will decrease to approximately the hot standby values if reactor coolant pumps are running. If all reactor coolant pumps are stopped, RCS temperatures are expected to stabilize near hot zero power values with hot leg temperature less than fifty degrees greater than cold leg temperature in the loop or loops with natural circulation flow established.

Pressurizer Pressure (*Figure 6-8*)

Pressurizer pressure response is dependent on the severity of the tube rupture. For small ruptures the pressure will remain relatively constant due to the ability of the PPCS to mitigate the loss. For more extensive ruptures, a continual and sometimes rapid decrease in pressure will be seen, and without operator action a [thermal margin/low pressure] reactor trip will occur. If pressure continues to fall and goes below the SIAS setpoint and subsequently below the HPSI pump shut-off head, the SIS is expected to restore RCS pressure and inventory control.

Pressurizer Level (*Figure 6-9*)

Pressurizer level will remain relatively constant for small ruptures due to the ability of the PLCS to make up for inventory losses. For larger tube ruptures, a slowly decreasing level will be seen. If the ruptures are large

enough to cause the level to fall below the heater cutout setpoint, the subsequent pressure decrease will cause an SIAS and inventory control is expected to be restored.

Reactor Vessel Level (*Figure 6-10*)

For tube ruptures which are small enough so that the PPCS and PLCS can make up the pressure and inventory decreases, no RVUH voiding is expected. The loss of primary coolant for a double-ended rupture of one tube will result in constantly decreasing pressure and level. Voids will form in the RVUH if the RCS pressure reaches the saturation pressure of the hottest RCS temperature. The void is not expected to drop below the RCS hot leg however, due to inventory replacement via the SIS.

Steam Generator Pressure (*Figure 6-11*)

Steam generator pressure remains relatively constant until reactor trip. The reactor trip causes a turbine trip, and the reduced steam demand causes a slight dip and then a rapid rise in steam generator pressure. The turbine bypass system automatically actuates to control main steam pressure. The pressure is eventually reduced to the hot standby value (which is higher than operating steam generator pressure at full power).

Steam Generator Level (*Figure 6-12*)

Following the reactor trip, the level in both steam generators will shrink to the usual post trip level. Steam generator water level will be relatively unaffected for small ruptures. Large ruptures usually cause a slow increase in level in the affected steam generator if level control is in the manual mode. Otherwise S/G level will remain relatively unchanged. In general, level experiences a sharp decrease following the reactor trip and turbine trip, followed by a steady increase due to the rupture and feedwater control system until the hot zero power level is reached. If the rupture is large enough, especially after the affected steam generator has been isolated, level may increase enough in the affected steam generator to fill the steam generator unless appropriate actions are taken.

FIGURE 6-6

REPRESENTATIVE SGTR EVENT CHARACTERISTICS
REACTOR POWER

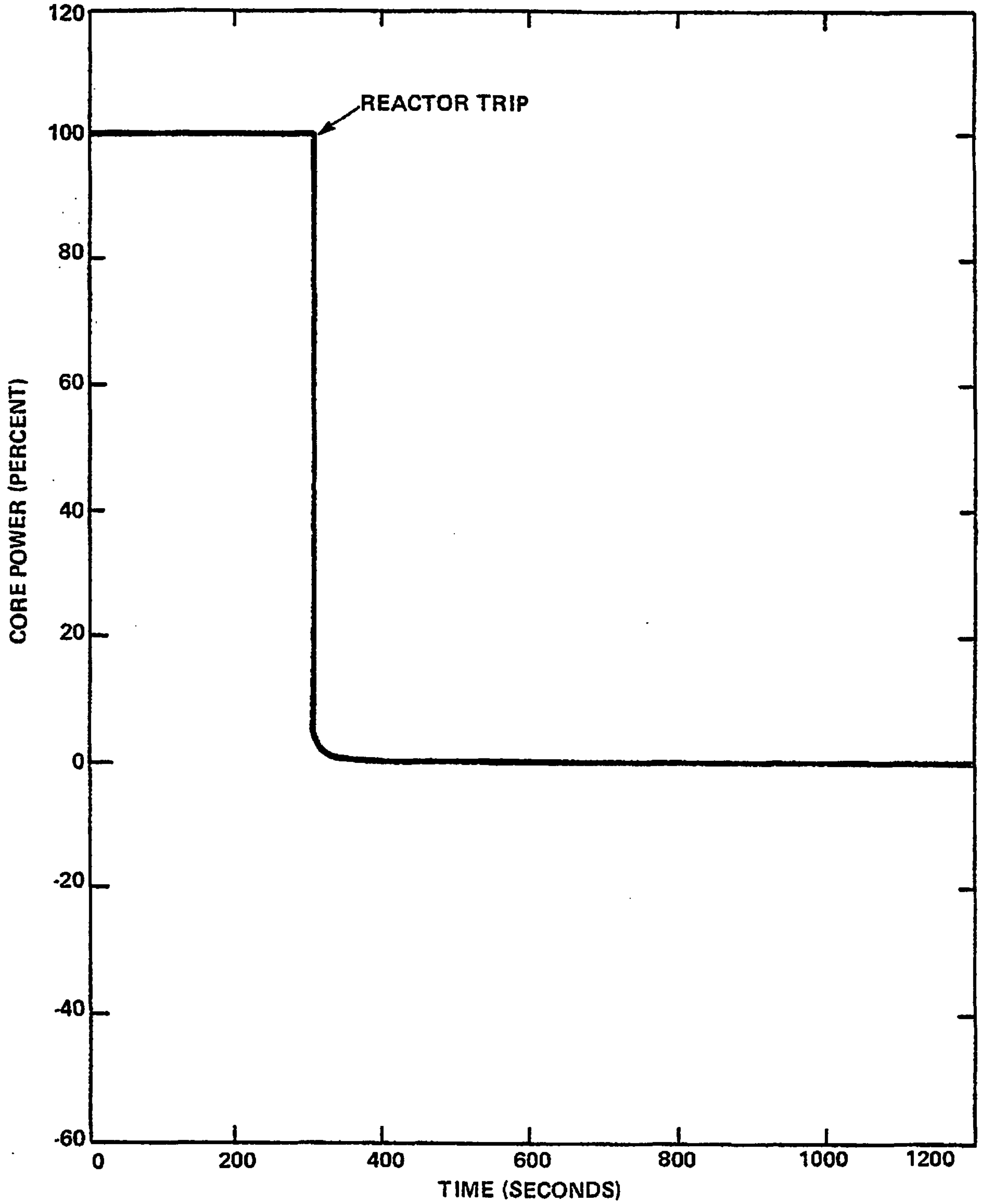


FIGURE 6-7

REPRESENTATIVE STEAM GENERATOR TUBE RUPTURE
RCS NARROW RANGE TEMPERATURES

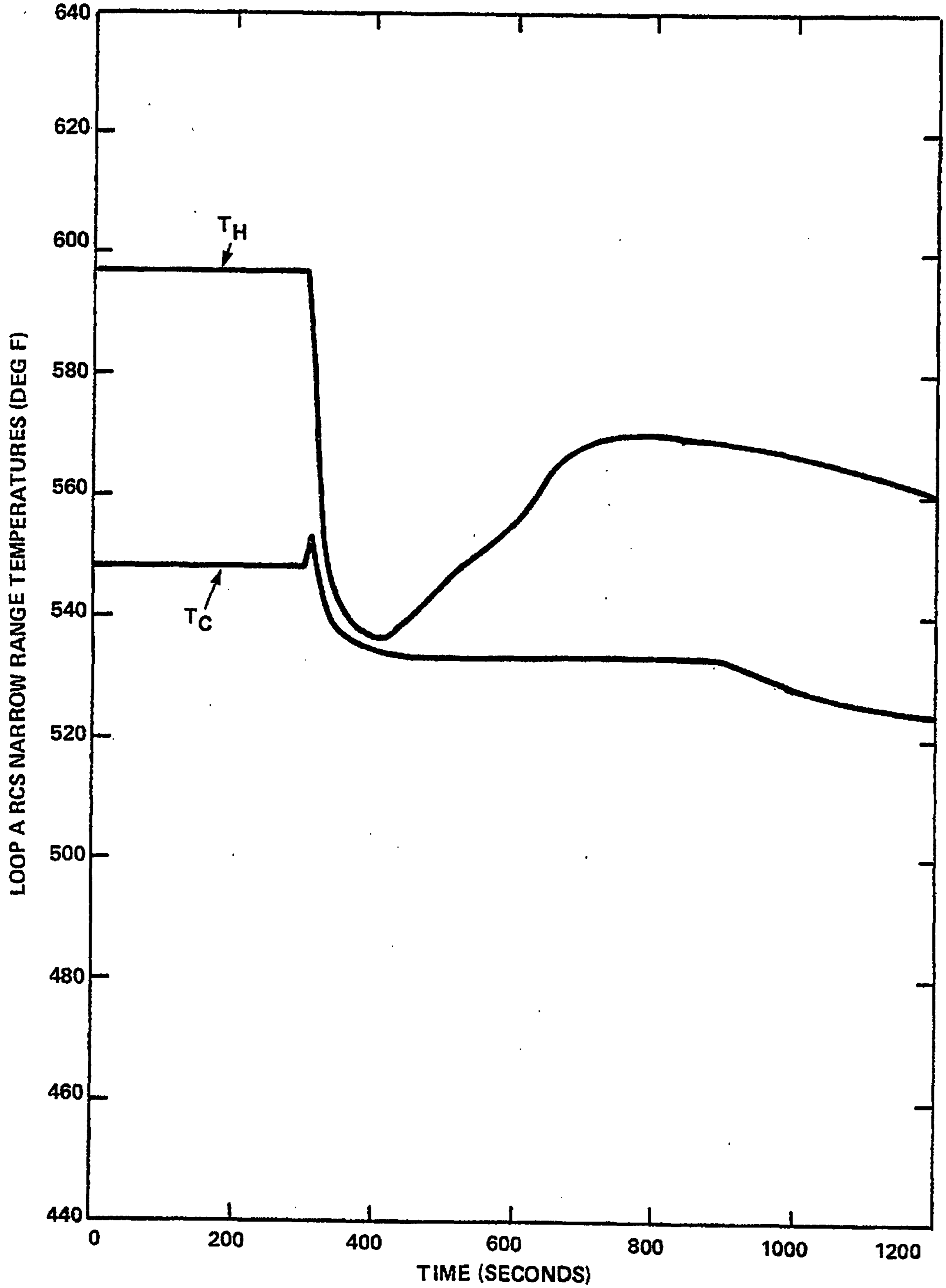


FIGURE 6-8

REPRESENTATIVE SGTR EVENT CHARACTERISTICS
PRESSURIZER WIDE RANGE PRESSURE

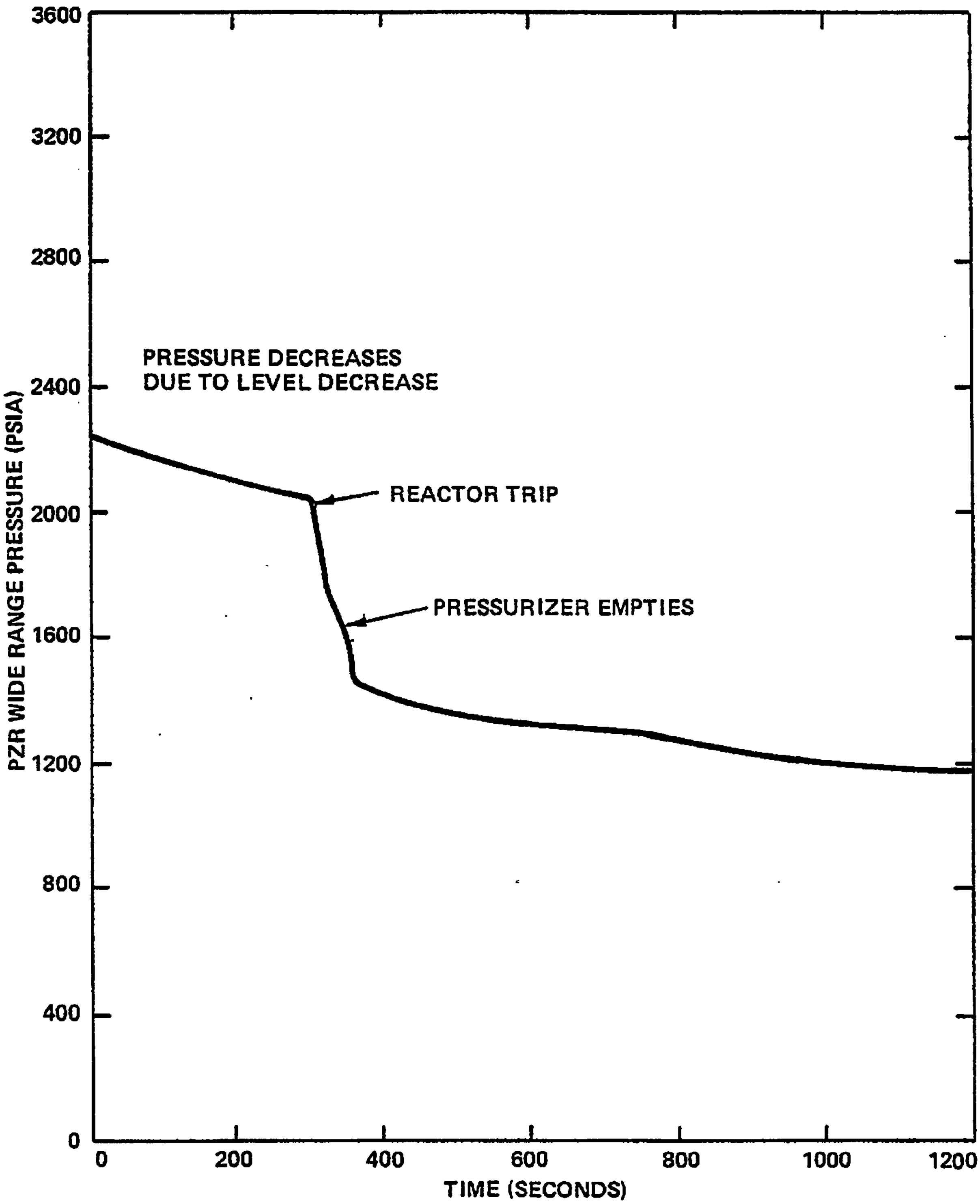


FIGURE 6-9

REPRESENTATIVE SGTR EVENT CHARACTERISTICS
PRESSURIZER LEVEL

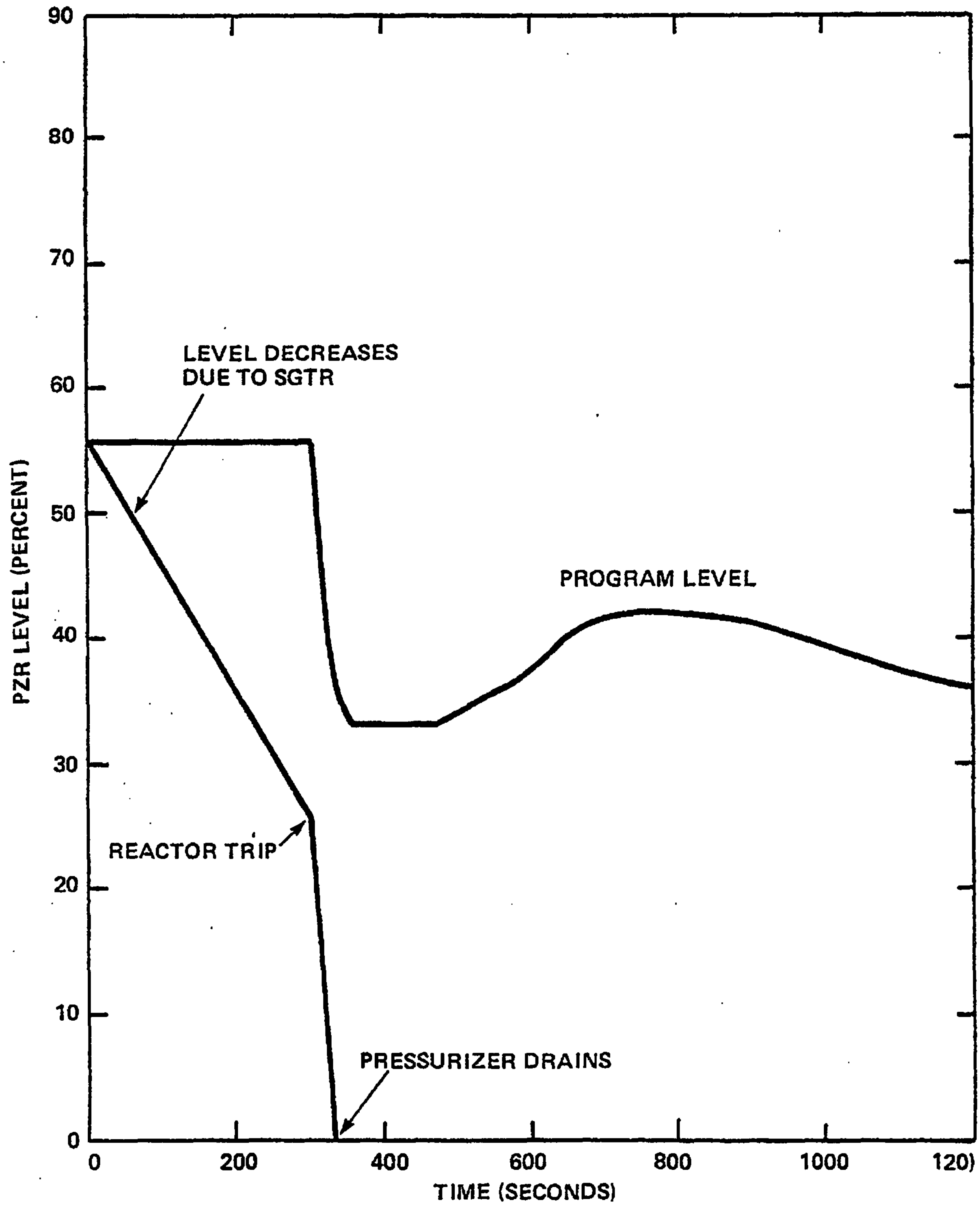


FIGURE 6-10
REPRESENTATIVE STEAM GENERATOR TUBE RUPTURE

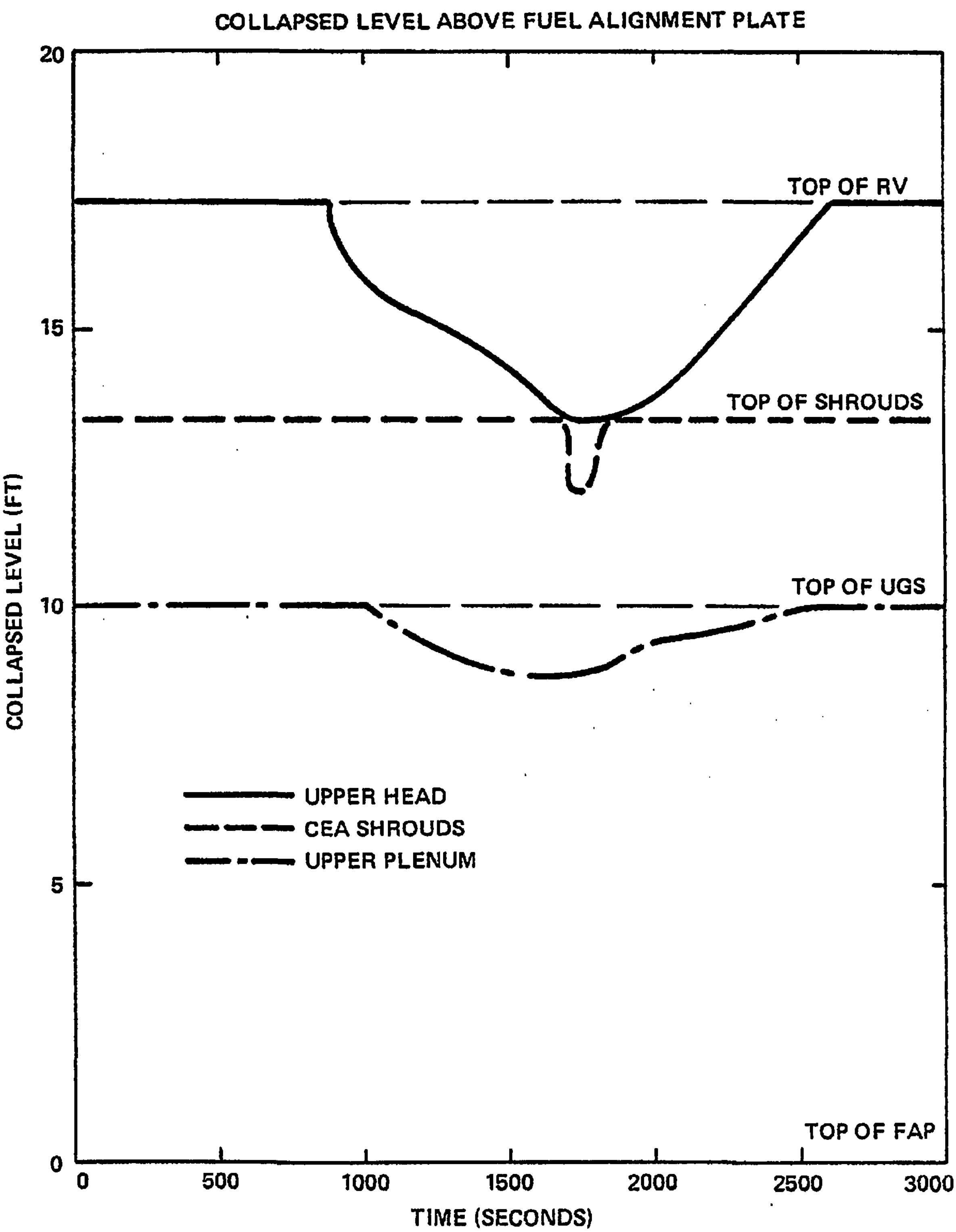


FIGURE 6-11

REPRESENTATIVE SGTR EVENT CHARACTERISTICS
AFFECTED STEAM GENERATOR PRESSURE

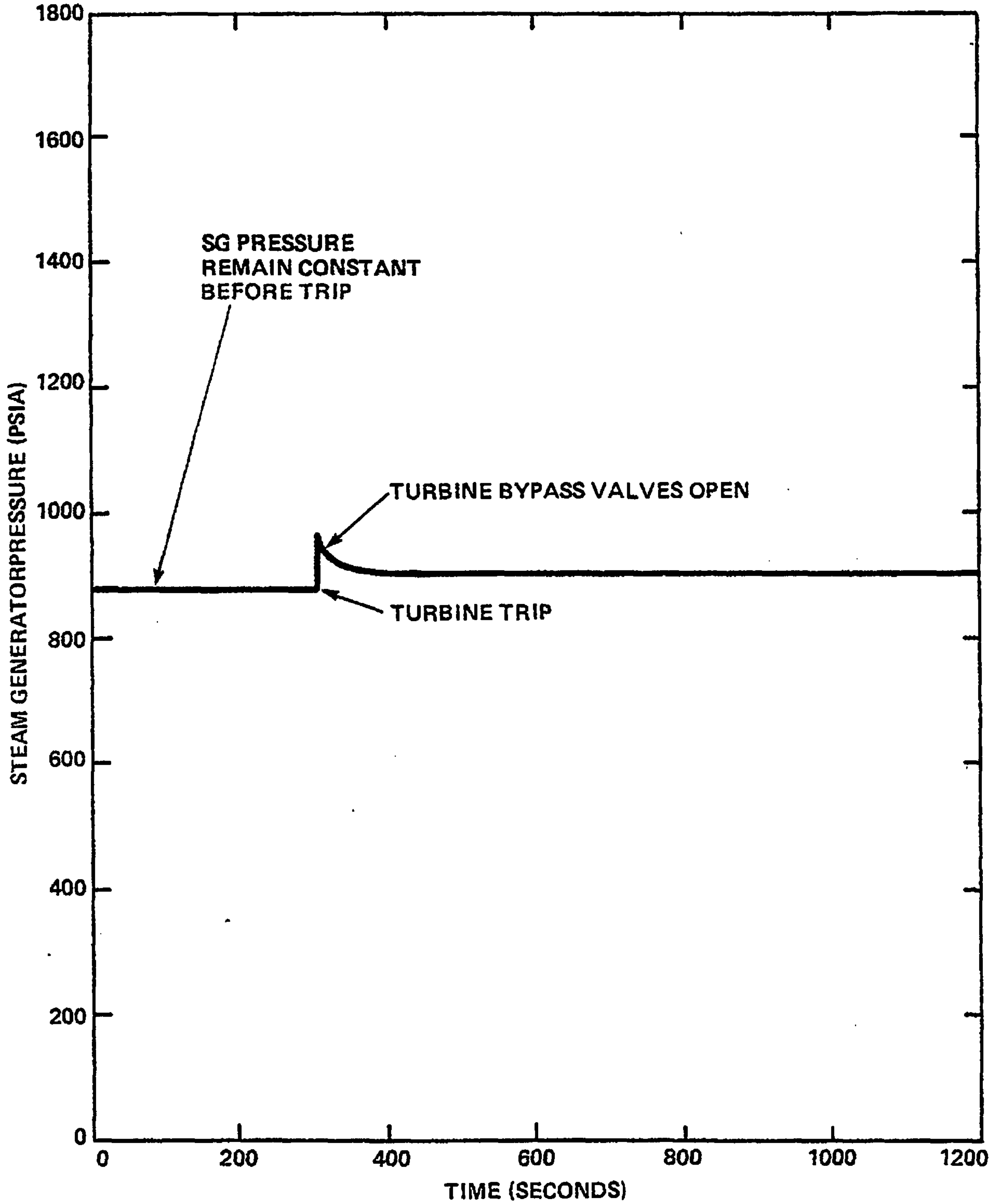
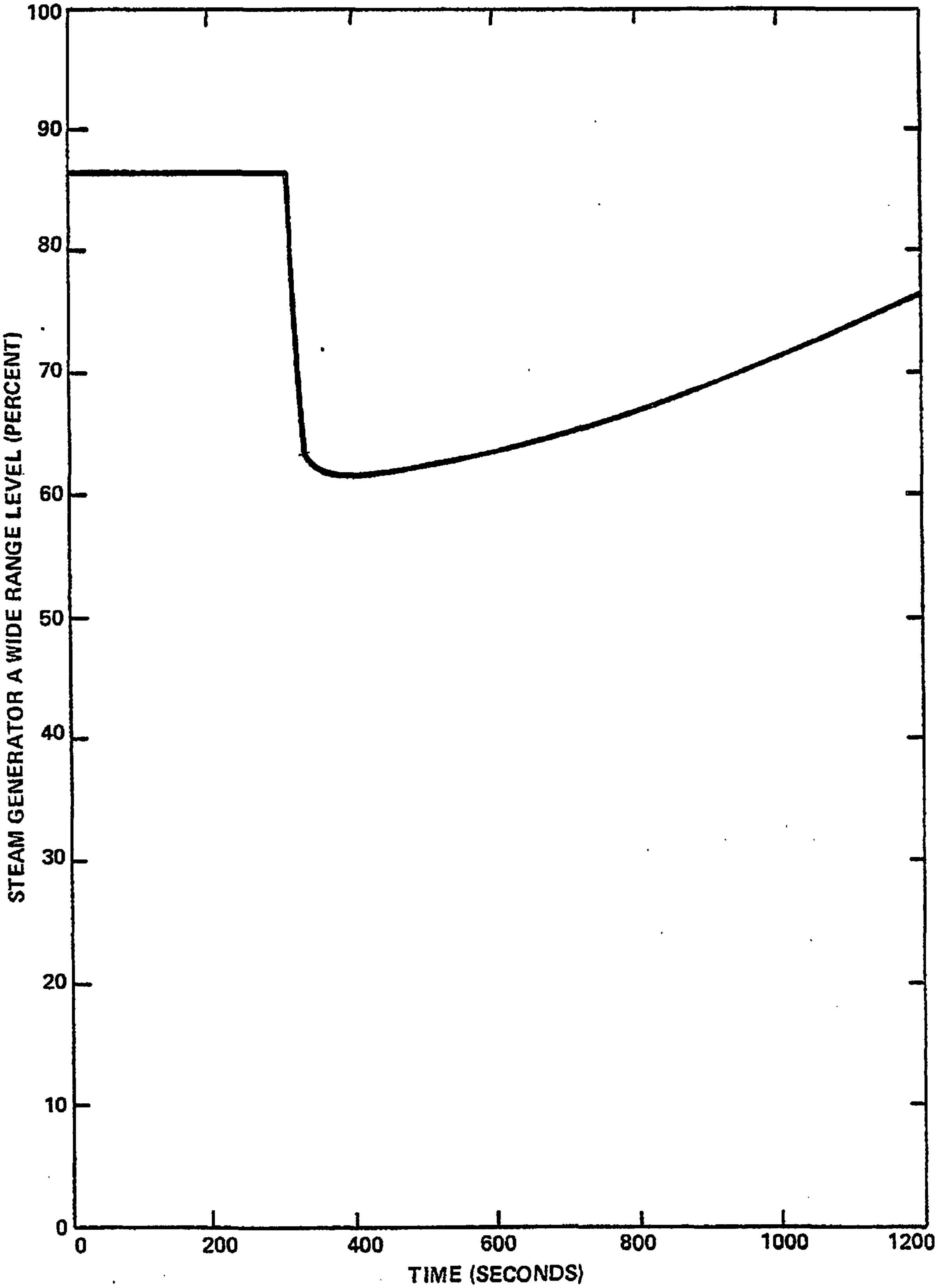


FIGURE 6-12

REPRESENTATIVE STEAM GENERATOR TUBE RUPTURE
AFFECTED STEAM GENERATOR WIDE RANGE LEVEL



Guideline Strategy and Information Flow

Figure 6-13 provides the reader with a summary description of the SGTR Recovery Guideline strategy and information flow.

Prior to implementing the actions provided in the guideline, the operator would have performed the Standard Post Trip Actions and diagnosed the event. In the SGTR Recovery Guideline the operator begins using the safety function status check to confirm that the plant is recovering. The first step of this guideline requires a verification that these steps have taken place. The next steps in the sequence require a cooldown to reduce steam generator saturation pressure below the S/G safety setpoint, detecting which S/G is leaking and isolating it. This is done to prevent radionuclide release to the environment via the safety valves.

The next group of steps provide instructions on RCP restart, natural circulation, SIS, and S/G level control. These steps are illustrated on Figure 6-13. Subsequent steps deal with minimizing leak flow and performing an RCS cooldown. A more detailed chart illustrates the recovery guideline strategy and lists the guideline steps which are performed at any time during the course of the event by use of affixed asterisks. Refer to Figure 6-20.

FIGURE 6-13a

STEAM GENERATOR TUBE RUPTURE

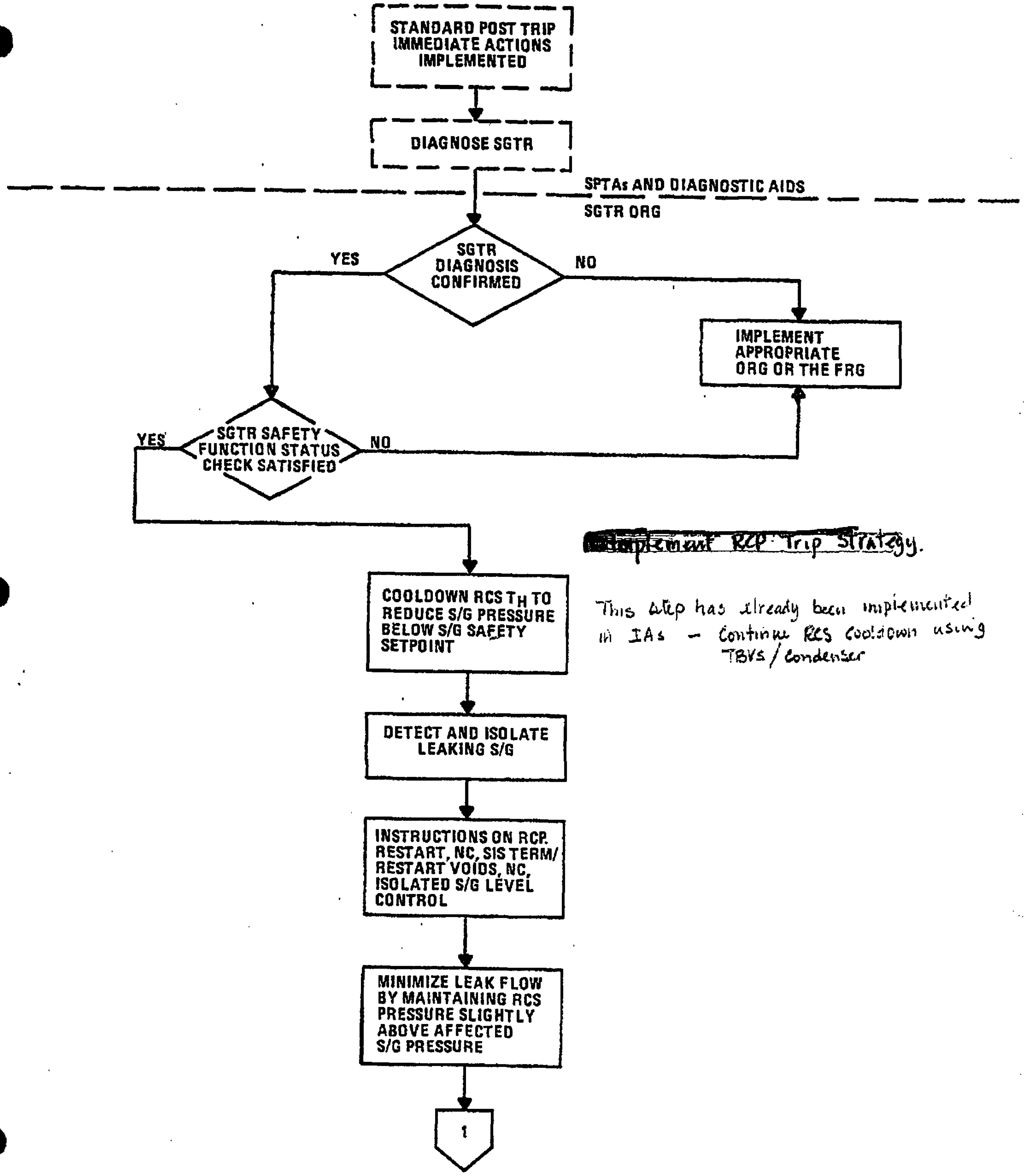
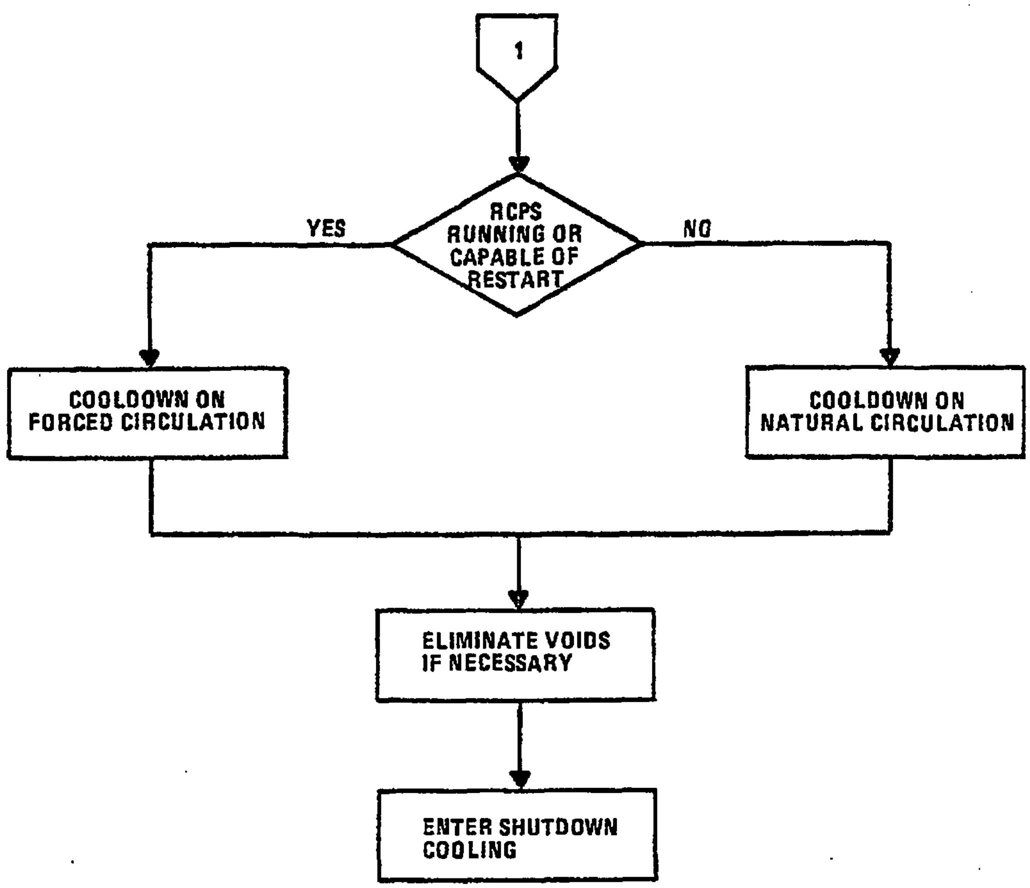


FIGURE 6-13b
STEAM GENERATOR TUBE RUPTURE



Bases Operator Actions

The operator actions are directed at placing the plant in a stable condition following the reactor trip, ensuring that a proper heat sink for the reactor is being maintained, and minimizing radiation release.

1. The execution of all standard post trip actions is verified. This assures that all safety functions have been initially attended to.

2. The diagnosis of a steam generator tube rupture should be confirmed using [the Break Identification Chart (Figure 6-2) and by verifying that the safety functions are being satisfied by comparing control board parameters to the acceptance criteria in the Safety Function Status Check. In particular, the operator should note the status of RCS subcooling and containment and steam plant activity. These parameters provide a means of discriminating between SGTRs and LOCAs/ESDEs. For an SGTR, steam plant activity monitors may be alarming but containment activity monitors should not be alarming. For most LOCAs, the RCS reaches saturation condition and containment activity monitors may be alarming but steam plant activity monitors should not be alarming. For ESDEs, neither steam plant or containment activity monitors should be alarming. For plants which exhibit S/G tube leakage, however, steam plant or containment activity monitors may alarm during ESDEs. This action is a method for verifying the proper procedure is being used to mitigate the effects of an SGTR and all safety functions are being satisfied.]

3. Sample both steam generators for activity. This will assist in confirming the diagnosis made in step 2.

4. If the diagnosis indicates that an LOCA or an ESDE has occurred, then the SGTR Guideline is exited and the actions of the proper guideline are implemented. This allows the operator to switch to the proper guideline for those events similar to an SGTR which may be occurring. LOCAs, ESDEs, and SGTRs have similar initial symptoms and could be confused early in the event.

5. If the initial diagnosis of an SGTR is confirmed, then the operator continues with the actions of this guideline. If the diagnosis is not confirmed, then the operator is directed to implement the Functional Recovery Guideline. The Functional Recovery Guideline is functionally oriented and will ensure all safety functions are attended to regardless of what event(s) is occurring.

6. Step numbers 6 and 7 contain guidance regarding the RCP operating strategy for an SGTR (Figure 6-14). A generic RCP trip strategy has been developed which, in general, results in the tripping of all four RCPs for depressurization events determined to be LOCAs, but allows the continued operator of two RCPs (in opposite loops) for diagnosed, non-LOCA, depressurization events. For undiagnosed events, where the Functional Recovery Guideline is implemented, the RCP trip strategy is identical to that followed in the LOCA guideline.

   There are two significant operational aspects regarding the RCP trip scheme for an SGTR. The first results in the operator tripping two RCPs (in opposite loops) if pressurizer pressure decreases to less than [1300 psia] following an SIAS. This may occur in the Standard Post Trip Ations and, in this case, the operator would simply verify that two RCPs (in opposite loops) have been tripped. If the operator cannot confirm that an SGTR has occurred, and the Functional Recovery Guideline is implemented, then the RCP trip strategy is identical to that followed in the LOCA guideline (i.e., if in the FRG and pressurizer pressure decreases to less than [1300 psia] following an SIAS, then all four RCPs must be tripped). If the depressurization event can be diagnosed and is determined to be other than an LOCA (i.e., ESDE or SGTR), then only two RCPs (in opposite loops) are required to be tripped. This gives the operator maximum flexibility in plant control (because a normal plant cooldown can be performed) while still ensuring a conservative approach to event recovery.

FIGURE 6-14a

RCP TRIP STRATEGY FOR SGTR

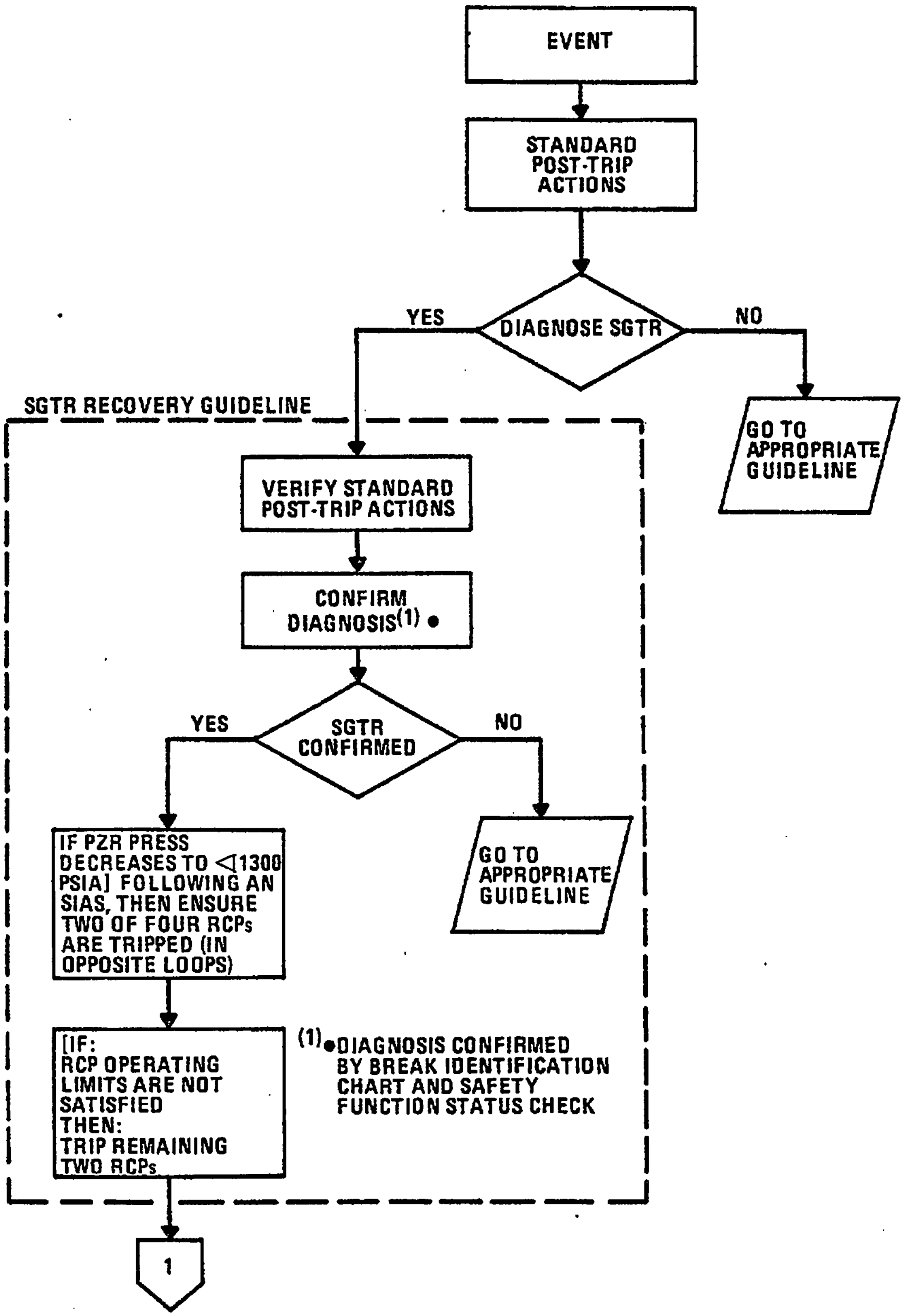
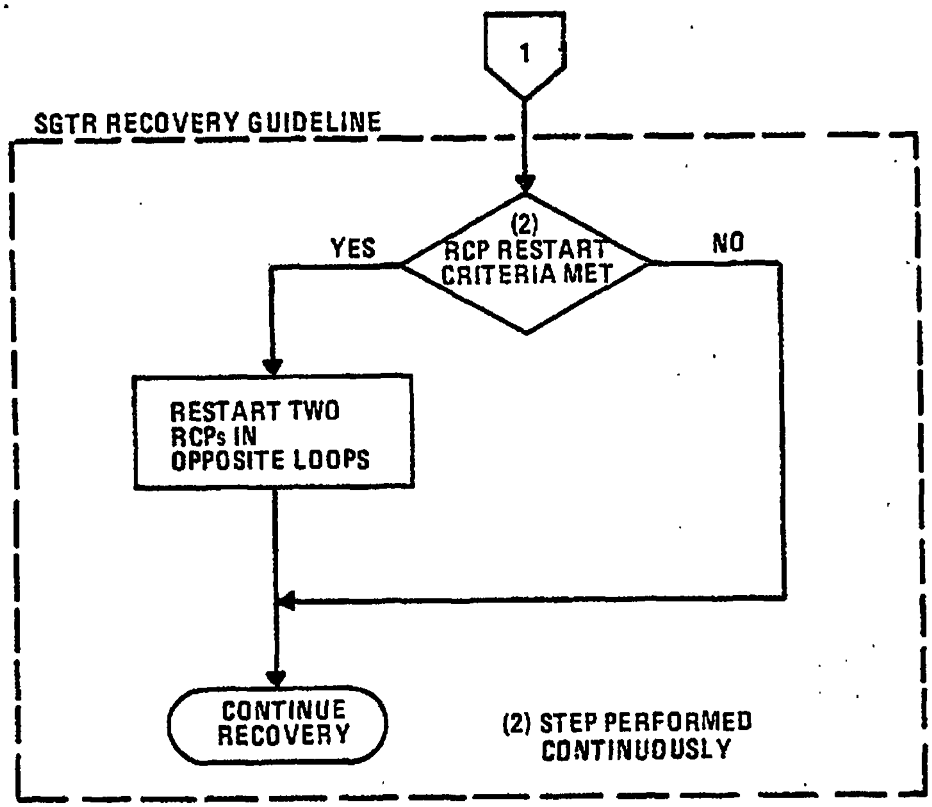


FIGURE 6-14b


1
SGTR RECOVERY GUIDELINE
(2) RCP RESTART CRITERIA MET
YES
NO
RESTART TWO RCPs IN OPPOSITE LOOPS
CONTINUE RECOVERY
(2) STEP PERFORMED CONTINUOUSLY

7. [The second aspect of the RCP operating strategy results in tripping the final two RCPs if RCP operating limits are not satisfied. The RCPs may be operating in a pressure-reduced RCS and, in some cases, degraded containment conditions are also possible. This could result in the loss of vital RCP auxiliaries. The operator must continuously monitor RCP operating limits (e.g., temperatures, seal flow, oil pressures, NPSH, motor amperage, vibration) and trip the remaining two RCPs if concerned about RCP operating equipment integrity. Plant specific RCP operating limits should appear in this step, either directly or, by referencing the applicable operating instructions.]

8. The operator is required to continually verify that all safety functions are being satisfied by comparing control board parameters to the criteria of the Safety Function Status Check. This ensures that all relevant safety functions are being satisfied and the core is being adequately cooled.

9. If all the safety functions from the Safety Function Status Check are satisfied, then this procedure is adequately mitigating the effects of the SGTR which is occurring. Therefore, the implementation of the remaining actions of this guideline is continued.

   If the safety functions are not being satisfied, then the procedure is not adequately mitigating the event. The operator is required to leave the SGTR guideline and implement the Functional Recovery Guideline. This guideline is functionally oriented and will ensure all safety functions are attended to regardless of what event(s) is occurring.

10. The goal of this step is to verify that the RCS temperature has been decreased to less than [525°F] so that the RCS heat inventory is not available to cause secondary safety valves to lift. If RCS hot leg temperature is not less than [525°F] the operator will manually cool the plant down. This action should be performed preferentially by feeding the steam generators with [main or auxiliary] feedwater and dumping steam

If NC is not effective in cooling RV head region for S/G tube rupture why do we put ourselves into the situation in EOP-3 Loss of Auxiliary F.W.

RCS needs to be depressurized to the point where it just exceeds S/G pressure to reduce leakage and prevents water welding of S/G with possible lifting of safties.

to the condenser via manual control of the turbine bypass system. If the condenser or turbine bypass system is not available, the next order of priority for discharging steam would be to use the atmospheric dump valves. It is less desirable to use the atmospheric dump valves to cooldown the RCS because of the unmonitored release of activity to the environment.

This step is presented before the leaking steam generator has been identified and isolated. This step is most easily accomplished when RCPs are operating and when one or more steam generators are providing cooling. If all RCPs have been tripped and natural circulation is the heat removal process, then it is necessary to cooldown both steam generator to provide uniform RCS cooling. Therefore, if forced circulation is available this step can be done in parallel with steps 11 and 12, detecting and isolating the affected steam generator. If forced circulation is not available this step should be done in parallel with step 11, but completed before going on to step 12.

Natural circulation cooldown of the RCS is not effective for cooling the RC head region. If natural circulation cooling provides the reduction of T_H to less than [525°F], heat transfer to the steam generator from the RCS loops will not cause lifting the secondary safety valves. However, the energy stored in the RV head region and pressurizer has to be dealt with to bring RCS pressure close to steam generator pressure to minimize leakage into the steam generator and to preclude steam generator safety valve opening due to filling the steam generator and high RCS pressure. Controlling RCS pressure with the pressurizer and with an uncooled RV head region is addressed in a later step.

11. The steam generator with the tube rupture should be determined by performing the following steps. These steps include:

    a) Monitoring and/or sampling the steam generators for activity
    b) Monitoring the main steam piping for activity
    c) [If appropriate, specific plant instructions for determining which steam generator is affected should be performed].

This action assists in the containment isolation safety function by identifying the proper steam generator for isolation.

12. The steam generator with higher activity, higher radiation levels, or increasing water level should be isolated. Reducing RCS temperature to below the saturation temperature associated with the lowest pressure setpoint of the steam generator safety valves is one of the actions necessary to prevent opening a direct path to the environment for radionuclides after steam generator isolation. Steam generator isolation is an attempt to reestablish the containment isolation safety function.

    The affected steam generator is isolated as follows:

    a) The main steam isolation valve is closed.
    b) The main steam isolation valve bypass valve is verified closed.
    c) [The atmospheric steam dump valve is closed and aligned to the manual mode].
    d) The main feedwater isolation valve is closed.
    e) Steam generator blowdown is isolated.
    f) [The auxiliary feedwater isolation valves are closed, including the steam driven pump steam supply valve associated with the steam generator being isolated].
    g) Vents, drains, exhausts, and bleedoffs from the steam system and turbine building sumps are isolated. This completes the isolation of the radionuclides still in the secondary system to prevent further releases to the environment.
    h) [Any additional plant specific methods for isolating the steam generators should be implemented].

13. Once the steam generator has been isolated, isolation of the correct (affected) steam generator should be verified by checking radiation indications, sampling, and noting any possible increase in the isolated steam generator level. This provides feedback that the correct steam generator has been isolated.

14. If the wrong steam generator has been isolated then it should be unisolated and the affected steam generator should be isolated.

15. If both generators are affected, then the steam generator with the highest radiation indications should be isolated for radiological considerations. This minimizes the potential of releasing radioactivity to the environment.

16. If all RCPs have been stopped, then operation of two RCPs (in opposite loops) should be attempted if RCP restart criteria are met. This action ensures continued forced circulation of coolant through the core, cooling of the RV head region, provides the capability for the normal mode of pressurizer spray, condenses RCS steam voids, and removes non-condensible gases from the S/G tube bundle. Furthermore, this action enhances the strategy to obtain an uncomplicated cooldown, since a forced circulation cooldown is preferred to a natural circulation cooldown whenever possible during recovery from an SGTR. Only one reactor coolant pump in each loop should be operated to minimize heat input to the RCS.

    Determine whether RCP restart criteria are met by the following:

    a) The unaffected steam generator (or the least affected, if both S/Gs have leaks) is available for removing heat from the RCS. A steam generator having feed flow and removing heat from the RCS is an indication that primary to secondary heat removal is being maintained.

    b) Pressurizer level is greater than [200"] and not decreasing. With pressurizer level at the high end of the operating band, the possibility of draining the pressurizer due to loop shrinkage and/or steam void condensation is minimized and there is a greater likelihood of keeping the pressurizer heaters covered. This will assist in maintaining positive RCS pressure control. The criterion of pressurizer level not decreasing implies that RCS inventory control has been established.

c) The RCS is greater than or equal to [20°F] subcooled. A subcooled condition in the RCS taken in conjunction with b) above indicates that the inventory and pressure are being controlled.

d) [All plant specific RCP operating criteria are satisfied before the RCPs are restarted to prevent damage to RCPs. Following automatic or operator initiated containment isolation, reinstatement of component cooling water to the RCPs should be considered in order to ensure adequate RCP cooling.]

17. Upon restarting two RCPs in opposite loops, pressurizer level and pressure may decrease due to loop shrinkage and/or void condensation. It is possible that this action will drain the pressurizer. Steam voids present in the reactor vessel will condense upon restarting RCPs. [The RVLMS should be monitored for the <u>trending</u> of reactor vessel liquid level. This trending information may be correlated to pressurizer level decrease.] RCP operation with a drained pressurizer may continue provided certain actions are taken and certain criteria are satisfied.

    The following constitute the actions to be taken and the criteria to be satisfied when restarting RCPs:

    a) Start all available HPSI and charging pumps, or verify their operation. This serves to compensate for pressurizer level and pressure decrease.

    b) Start one RCP in each loop.

    c) [Ensure proper RCP operation by monitoring RCP amperage and pump NPSH. NPSH is determined by pressurizer pressure and corresponding T_c on Figure 6-1].

    d) Operate all available HPSI and charging pumps until pressurizer level is greater than [100"] and SIS termination criteria are met.

18. If all RCP operation is terminated and inventory and pressure are controlled, then natural circulation is monitored by heat removal via at least one steam generator. Natural circulation flow should occur within 5-15 minutes after the RCPs were tripped if there is adequate inventory in the RCS. Natural circulation heat removal is illustrated in Figure 6-15.

Natural circulation is governed by decay heat, component elevations, primary to secondary heat transfer, loop flow resistance, and voiding. Component elevations on C-E plants are such that satisfactory natural circulation decay heat removal is obtained by fluid density differences between the core region and the steam generator tubes.

The operator has adequate instrumentation to monitor natural circulation for the single phase liquid natural circulation process. The RCS temperature instrumentation, namely loop ΔT, can be used along with other information to confirm that the single phase natural circulation process is effective. The natural circulation process involving two phase cooling is complex and varied enough so that RCS loop ΔT may not be a meaningful indication of adequate natural circulation cooling. The guidelines are written to alert the operator to use explicit acceptance criteria for natural circulation only when RCS inventory and pressure are controlled.

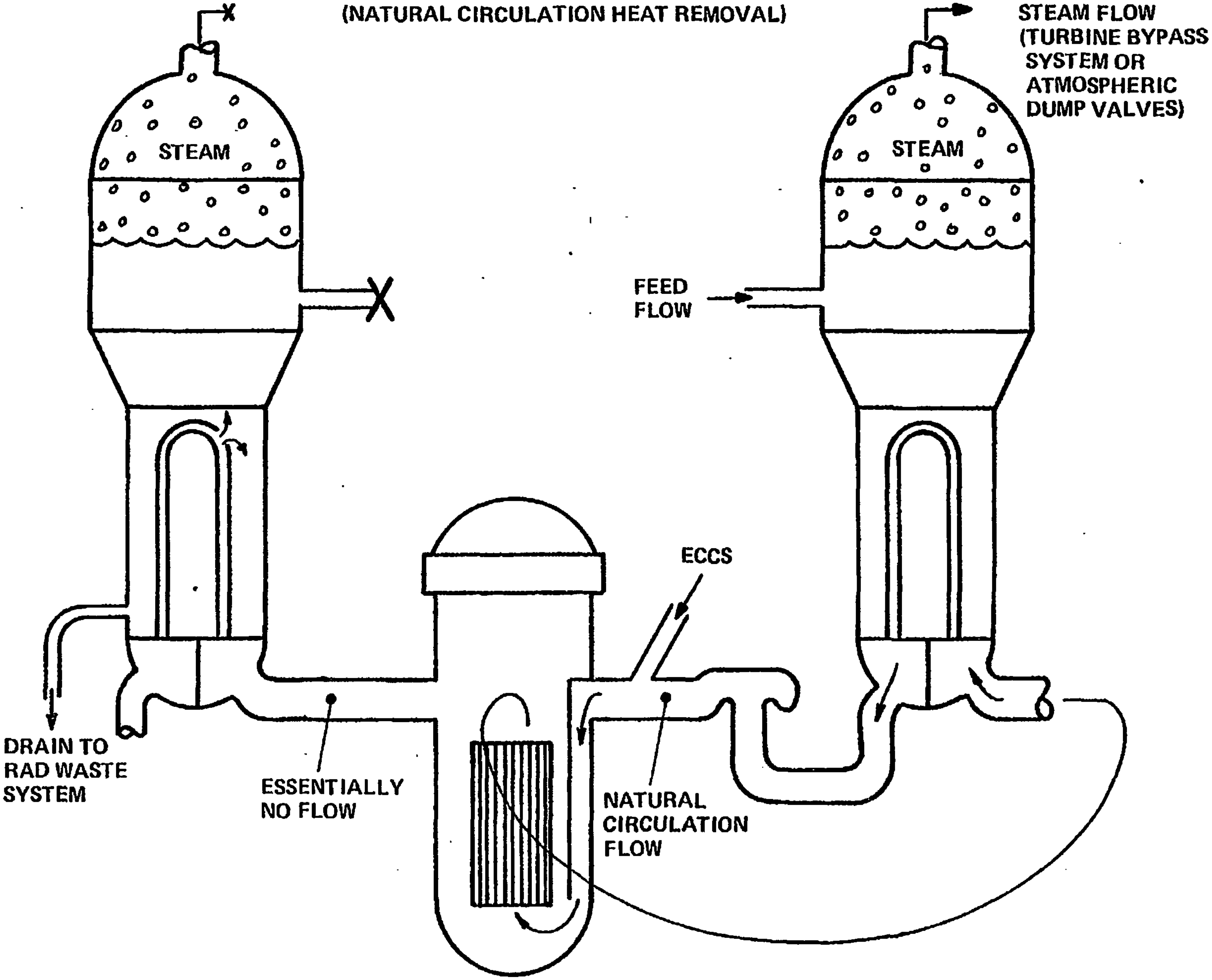
The RCS temperature response during natural circulation will usually be slow (5-15 minutes) as compared to a normal forced flow system response time of 6-12 seconds, since the coolant loop cycle time will be significantly larger.

When single phase circulation is established in at least one loop the RCS indicates all of the following conditions:

a) Loop ΔT (T_H - T_C) less than normal full power ΔT
b) Cold leg temperatures constant or decreasing
c) Hot leg temperatures stable (i.e., not steadily increasing) or decreasing;

FIGURE 6-15

STEAM GENERATOR TUBE RUPTURE
(NATURAL CIRCULATION HEAT REMOVAL)



d) No abnormal differences between T_H RTDs and [core exit thermocouples]. Hot leg RTD temperature should be consistent with the core exit thermocouples. Adequate natural circulation flow ensures that [core exit thermocouple] temperatures will be approximately equal to the hot leg RTDs temperature within the bounds of the instrument's inaccuracies. An abnormal difference between T_H and the [CETs] is greater than [10°F].

19. If the criteria listed in step 18 are not met, then natural circulation in the RCS is not effectively transferring heat from the core to the steam generators. Both RCS and Core Heat Removal Safety Functions may become jeopardized if any of the above criteria continue to be violated. Operators should ensure that RCS pressure and inventory, and S/G steaming and feed, are being controlled properly to prevent violation of a safety function, which would require a transfer from this guideline to the Functional Recovery Guideline.

20. An SGTR may result in actuation of safety injection. If inventory control is not established (i.e., pressurizer level is less than [35"]), then <u>all</u> available charging pumps and <u>at least</u> one train of the SIS should be operating (until SIS termination criteria are met). SIS flowrate will vary according to RCS pressure. SIS and charging pump flowrates should be checked and SIS pump flowrates maximized relative to RCS pressure to enhance RCS inventory replenishment and/or core heat removal (see Figure 6-3). Other steps designed to ensure maximum injection of water into the RCS include; restoration of electrical power and auxiliary systems, ensuring correct valve lineups, and starting idle pumps.

21. If an SIAS has been initiated and the SIS is operating, then it must continue to operate at full capacity until SIS termination criteria are met. Termination of SIS should be sequenced by stopping one pump at a time while observing the termination criteria. Throttling of HPSI flow is permissible. SIS termination criteria are:

a) RCS is at least [20°F] subcooled (Figure 6-1). Establishing [20°F] of subcooling ensures the fluid in the core is subcooled, and provides sufficient margin for establishing flow should the [20°F] subcooling deteriorate when SIS flow is secured. Voids may exist in some parts of the RCS (e.g., reactor vessel head [as determined by the RVLMS], but these are permissible as long as core heat removal is maintained).

b) Pressurizer level is greater than [100"] and not decreasing. A pressurizer level greater than [100"] and not decreasing, in conjunction with criterion a) above, is an indication that RCS inventory control has been established.

c) At least one steam generator is available for removing heat from the RCS. Steam generator availability requires having feed flow and steam flow which are indications that primary to secondary heat removal is possible.

d) [The RVLMS indicates the core is covered. An indication of core coverage in conjunction with the above, serves as an additional indication that RCS inventory control has been established.]

If SIS termination criteria are met, then the operator may either terminate or throttle the SIS. The operator may decide to throttle rather than terminate if the SIS is to be used to control pressurizer level or plant pressure. A general assessment of the SIS performance can be made from the control room. The operator should confirm that at least one train and preferably both trains of SIS are operating and that system delivery rate is consistent with RCS pressure as shown in Figures 6-16 and 6-17. Injection flow rates to each cold leg should be approximately equal; departures from this would indicate a closed flow path or some system leakage that is in addition to the SGTR.

22. If the criteria of step 21 cannot be maintained, then the SIS must be restarted.

23. If the SIS termination criteria are met and the isolated steam generator is still overfilling with primary fluid, then stop the running HPSI pumps. Terminating the HPSI pumps, if SIS termination criteria are met, may prevent overfilling the affected steam generator(s) and challenging a secondary safety.

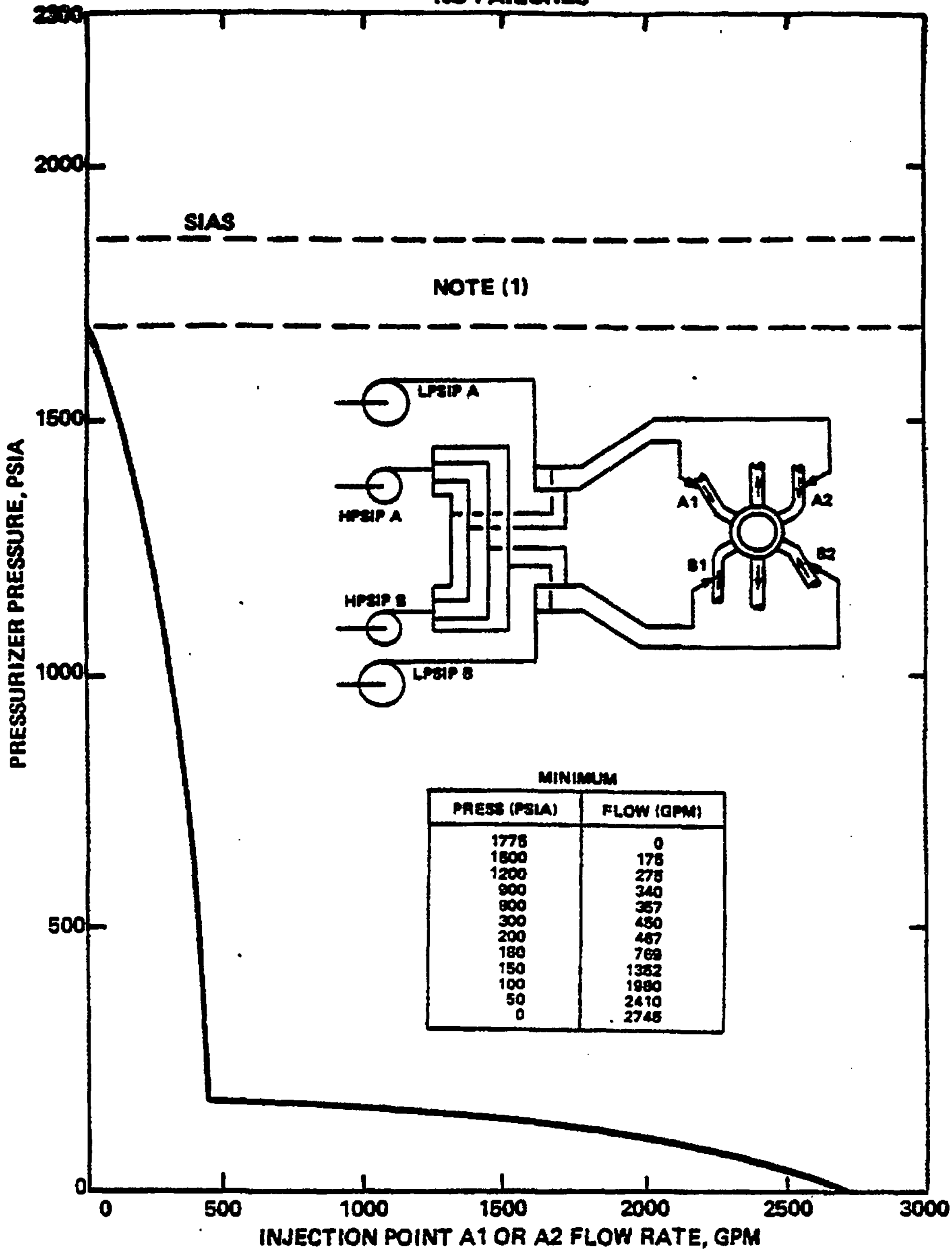
24. Overfilling of the isolated steam generator should be prevented by reducing the level periodically by draining to the [radioactive waste system]. The potential exists for flow of reactor coolant via the tube rupture into the isolated steam generator and filling the steam generator steam space and the main steam piping to the MSIV. This presents an undesirable spread of contamination and potential mainsteam piping support snubber damage. Draining to the [radiation waste system] will minimize the spread of contamination. If time and circumstances permit, snubber damage may be forestalled by snubber pinning per plant specific procedures. If the generator draining is not feasible or is insufficient, then steaming the generator to the condenser will minimize radioactivity release through the S/G safeties. Water hammer damage should be avoided by not reopening the affected MSIV while a significant amount of water remains in the main steam piping.

25. The RCS is sampled for activity and boron concentration and is borated to achieve the required shutdown margin per Technical Specifications. The sample identifies whether reactor coolant dilution has occurred and provides the chemistry information needed for borating to the required boration concentration. This activity identifies whether boron concentration is sufficient to aid in reactivity control. If there is low flow, or no flow in the RCS, then a boron sample may not be indicative of actual boron concentration.

26. The general goals associated with RCS pressure control are providing subcooling to support the core heat removal process, avoiding overpressure situations for PTS and RT_{NDT} considerations, minimizing the pressure differential between the steam generator and the RCS to minimize the leakage and controlling RCS pressure so that it is below the steam generator safety valve setpoints. This step addresses steam generator to RCS pressure differential and RCS depressurization.

FIGURE 6-16

TYPICAL SAFETY INJECTION DELIVERY CURVES
NO FAILURES



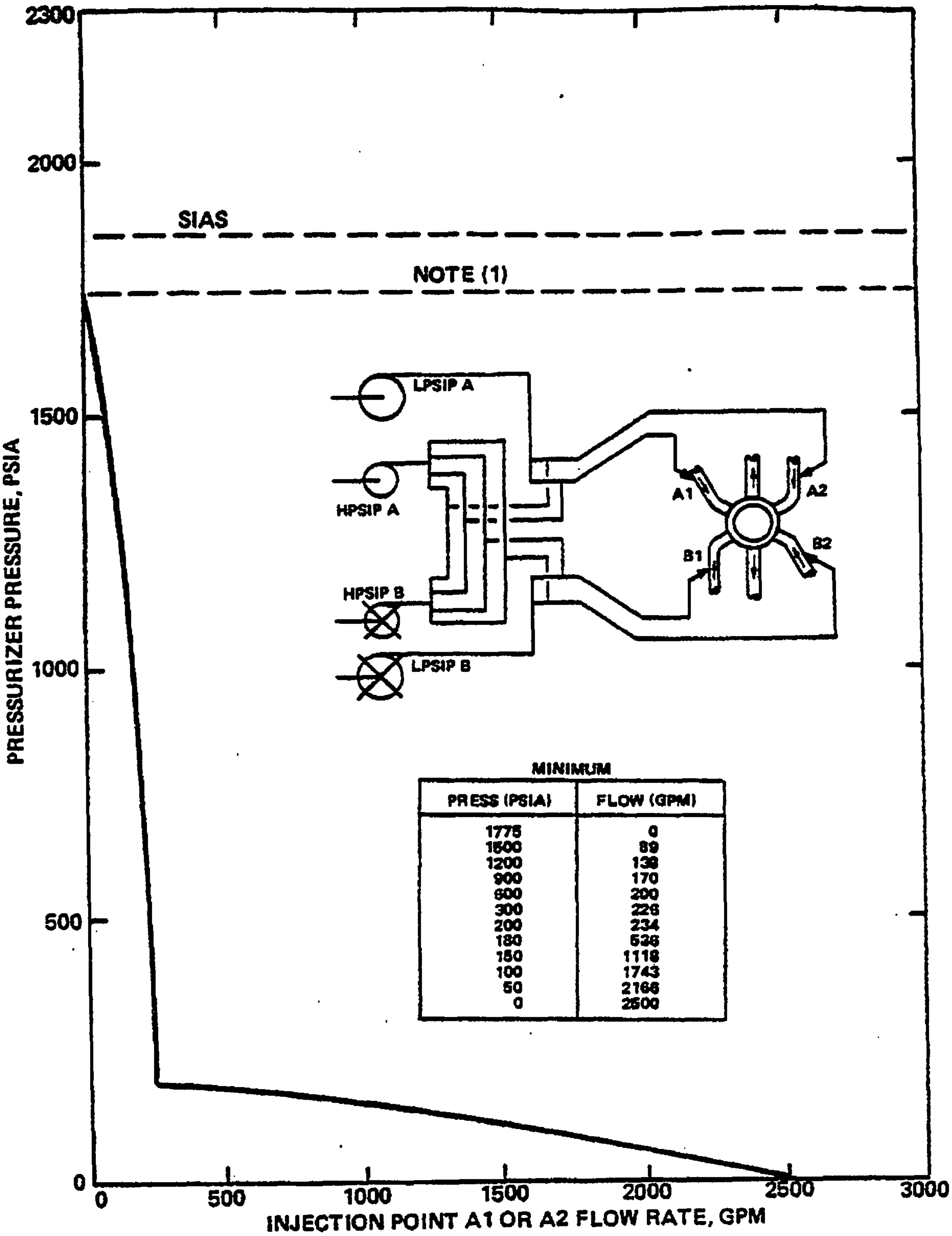
MINIMUM

PRESS (PSIA)	FLOW (GPM)
1775	0
1500	175
1200	275
900	340
600	357
300	450
200	467
180	769
150	1352
100	1980
50	2410
0	2745

NOTE: (1) BELOW SIAS PRESSURE, SAFETY INJECTION SYSTEM (SIS) PUMPS WILL BE OPERATING, BUT THERE WILL BE NO INJECTION FLOW UNTIL SYSTEM PRESSURE FALLS BELOW THE SHUTOFF HEAD PRESSURE OF ANY SIS PUMP

FIGURE 6-17

TYPICAL SAFETY INJECTION DELIVERY FAILURE CONDITIONS - LOSS OF ONE EMERGENCY GENERATOR



MINIMUM

PRESS (PSIA)	FLOW (GPM)
1775	0
1500	89
1200	138
900	170
600	200
300	226
200	234
180	536
150	1118
100	1743
50	2166
0	2500

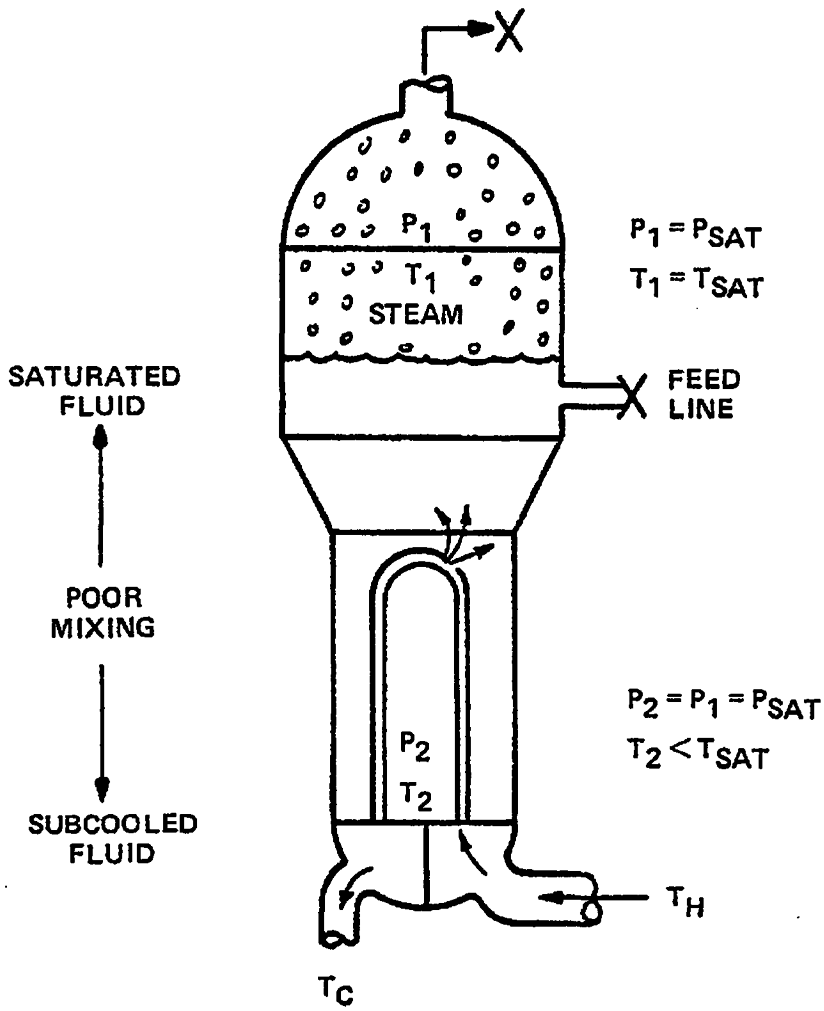
NOTE: (1) BELOW SIAS PRESSURE, SAFETY INJECTION SYSTEM (SIS) PUMPS WILL BE OPERATING, BUT THERE WILL BE NO INJECTION FLOW UNTIL SYSTEM PRESSURE FALLS BELOW THE SHUTOFF HEAD PRESSURE OF ANY SIS PUMP

Maintaining the RCS pressure (0-100 psid) above the affected steam generator pressure and also below the steam generator safety valve setpoint by using main spray (preferred) or auxiliary spray or throttling HPSI pumps will minimize the loss of primary fluid to the secondary side, minimize potential releases of radiation to the environment and loss of RCS inventory. This will also preclude secondary fluid from diluting primary fluid. The strategy for the SGTR event includes keeping or restoring forced circulation. The condition of [20°F] subcooling and minimum pressure required for operating RCPs may cause the operator to hold RCS pressure above secondary pressure by the amount needed to provide this subcooling. The need for [20°F] subcooling takes precedent over the goal of bringing primary pressure to a point slightly above secondary pressure. Note that during the forced circulation cooldown process the isolated steam generator may cool faster in the lower regions (see Figure 6-18). The isolated SG steam space will lag in the cooldown and cause the fluid in the lower regions to be subcooled. If the tube rupture is located in this subcooled region, as it most likely will be, then primary fluid can be at the same pressure as secondary fluid and also be subcooled. This is a desirable situation because the goal of keeping primary pressure slightly above secondary pressures is more easily met while the [20°F] subcooling and RCP NPSH is provided. As noted above, the goals of operating RCP's and [20°F] primary subcooling take precedent over keeping primary pressure slightly above secondary pressures.

RCS pressure control will be complicated if only natural circulation is available for heat removal. Natural circulation is ineffective for cooling the RV head region. This region may become the pressurizing source for the RCS. Steps 34 and 35 provide guidance on void detection and elimination. If RCP operation has been terminated before RCS cool-down and depressurization, or if RCPs cannot be restarted, then a voided RV head region that is pressurizing the RCS is dealt with in steps 34 and 35.

FIGURE 6-18

ISOLATED STEAM GENERATOR WITH TUBE RUPTURE



Maintaining RCS pressure within the acceptable limits of Figure 6-1 helps to assure adequate core cooling by ensuring the core is covered (as indicated by subcooling in the RCS) and minimize concern for pressurized thermal shock by keeping plant pressure below the [200°F] subcooling limit.

27. An orderly cooldown and depressurization is resumed with the unisolated steam generator by preferentially using the [main or auxiliary] feedwater systems in conjunction with the turbine bypass system. If the condenser or turbine bypass system is not available, the next order of priority for steam discharge is using the atmospheric dump valves, but the usage of this method is minimized due to the radiological release considerations described earlier.

28. The condensate and all other connecting systems, including the turbine building sumps, should be sampled for activity that may have been transferred from the affected steam generator(s). These samples aid in determining the extent of contamination throughout the plant systems.

29. The [turbine] and [auxiliary] building ventilation systems' radiation monitors, and any other applicable radiation monitors, should be continually observed. Corrective actions, if necessary, should be taken in accordance with plant Technical Specification Limitations.

30. If conditions permit, restart an RCP in each loop to establish cooling of the isolated steam generator and continue RCS cooldown and depressurization to SCS initiation conditions. Refer to steps 16 and 17 for restarting RCPs. If restart criteria are not satisfied go to step 38.

    This event will require that the affected steam generator be isolated continuously from the RCS as a heat sink (i.e., all feedwater and steam flow in and out of that steam generator stopped). During forced flow conditions in the RCS, when one steam generator must be isolated, sufficient heat transfer occurs to maintain the isolated steam generator at the same relative temperature as the operating RCS loop. However, with no RCPs operating, there usually will be no natural circulation flow

through the isolated steam generator and RCS loop, leaving those components in a hot stagnant condition. This condition by itself will not usually affect core cooling via natural circulation in the unisolated steam generator and RCS loop. As long as reactivity control, RCS pressure control, RCS inventory control, and RCS heat removal are properly maintained in the operating loop, sufficient natural circulation flow will be maintained through the core and operating loop.

However, a hot isolated steam generator presents a problem when trying to depressurize the RCS (e.g., to initiate shutdown cooling). Depressurization of the RCS below the isolated steam generator's saturation pressure could void large portions of the isolated RCS loop which could cause the isolated steam generator to act as a pressurizer and delay depressurization to the shutdown cooling initiation pressure. Thus, an isolated steam generator should be cooled down along with the RCS. The preferred method of cooling an isolated steam generator is to start an RCP, if one is available. Forced reactor coolant circulation through an isolated steam generator will provide adequate heat transfer to maintain the isolated steam generator's temperature approximately (within 20°F) the same as the operating steam generator's temperature. RCP restart criteria must be met prior to starting RCPs.

31. The available condensate inventory should be continually monitored, and replenished from available sources as necessary to provide a source for a secondary heat sink. Examples of alternate sources of condensate are nonseismic tanks, fire mains, lake water supplies, potable tanks, etc. Plant specific alternate sources of feedwater should be identified and cited in the procedure. The condensate required to either maintain the plant at hot standby or cooldown may be determined from Figure 6-4 and 6-5.

32. Once pressurizer level is restored it should be maintained at the normal shutdown reference level (if possible) by one of the following methods:

    a) Preferentially, by control of charging and letdown,

    <u>or</u>

    b) Operation and/or throttling of the HPSI pumps.

If the normal shutdown reference level is not maintained, then a pressurizer level of [35 to 245"] should be maintained to avoid losing pressure control with a saturated bubble in the pressurizer. If pressurizer level drops below the top of the pressurizer heaters, pressurizer heater operating will be interlocked off for heater protection. It may be necessary to exceed [245"] pressurizer level if the operator is attempting to restore RCS subcooling since pressurizer heaters may be unavailable or solid water operation may be necessary to achieve subcooling.

Once the pressurizer water temperature varies from the normal hot standby temperature, the instrument indication on the normal pressurizer level channel will begin to deviate (i.e., decalibrate) from the true pressurizer level. At this time, the operator should use plant cooldown correction curves (which should be available to the operator in plant specific procedures) to determine the true pressurizer water level. A cold calibrated pressurizer instrument channel is provided. This channel can be used as a quick reference during the plant cooldown.

33. During a controlled cooldown and depressurization the automatic operation of certain safeguard systems, is undesirable. [Therefore, the setpoints of SIAS, CSAS, CIAS, and MSIS must be manually reset (lowered) as the cooldown progresses to ensure that automatic engineered safeguards protection remains available until the RCS is cooled down and depressurized.]

34. If the above actions fail to depressurize the RCS, then a void should be suspected. Any time it is found that voiding inhibits RCS depressurization to SCS entry pressure, when SCS operation is desired, then an attempt at elimination of the voiding should be made.

    The operator should monitor for the presence of voids. Voiding in the RCS may be indicated by any of the following indications, parameter changes, or trends:

a) letdown flow greater than charging flow,

b) pressurizer level increasing significantly greater than expected while operating pressurizer spray,

c) [the RVLMS indicates that voiding is present in the reactor vessel],

d) [HJTC unheated thermocouple temperature indicates saturated conditions in the reactor vessel upper head].

e) [Other indications insert here]. A

35. If voiding should be eliminated, then proceed as follows:

a) Letdown is isolated or verified to be isolated to minimize further inventory loss,

b) The depressurization is stopped to prevent further growth of the void and, if required, the RCS is repressurized to $\geq$[20°F] subcooling,

c) Pressurizing and depressurizing the RCS within the limits of Figure 5-1 may condense the void. Pressurizing has the effect of filling the voided portion of the RCS with cooler fluid which will remove heat from the region. Subsequent depressurization and a repeating of this process several times will cool and condense the steam void. In this case of a void in the reactor vessel, the pressurization/depressurization on cycle will preclude a fill and drain of the reactor vessel. The pressurization/depressurization cycle may be accomplished using pressurizer heaters and spray (preferred method) or the SIS/charging system (alternative method). Monitor pressurizer level [and the RVLMS] for trending of RCS inventory. This will assist the operator in assessing the effectiveness of void elimination.

d) If indications of unacceptable RCS voiding continue, and voiding is suspected to exist in the (isolated) steam generator tubes, then cool the (isolated) steam generator (by steaming or blowdown, and/or feeding) to condense the tube bundle void. This will be effective for condensing steam voids but will not have an effect on non-condensible gases trapped in the tube bundle. A buildup of non-con-

densible gases in the tube bundles will not hinder natural circulation even with a large number of the tube blocked. This is due to the small amount of heat transfer area required for the removal of decay heat. Monitor pressurizer level for trending of RCS inventory. This will assist the operator in assessing the effectiveness of void elimination.

e) If indications of unacceptable RCS voiding continue, then voiding may be caused by non-condensible gases. [Operate the pressurizer vent and/or the reactor vessel head vent to clear trapped non-condensible gases.] Monitor pressurizer level [and/or the RVLMS] for trending of RCS inventory. This will assist the operator in assessing the effectiveness of void elimination.

36. When the RCS is cooled to at least [300°F] and depressurized to at least [300 psia], shutdown cooling should be initiated per plant specific operating instructions. If significant voiding is present in the isolated loop the SCS should be aligned to the subcooled loop. This activity places the plant in an operational mode where a complete cooldown and depressurization of the plant can take place.

37. [The safety injection tanks should be isolated, vented, or drained at 250 psig to avoid introducing their nitrogen cover gas into the RCS and increasing the severity of the event.]

38. [LTOP protection is instituted below 275°F to protect the primary pressure boundary from low temperature brittle fracture.]

39. If required, a natural circulation plant cooldown to SCS initiation conditions should be conducted according to the following action steps.

40. During the cooldown and depressurization to SCS entry conditions natural circulation heat removal is maintained. Refer to step 18. If voiding inhibits depressurization to SCS entry conditions, then refer to step 35.

41. The available condensate inventory should be continually monitored, and replenished from available sources as necessary to provide a source for a secondary heat sink. Examples of alternate sources of condensate are nonseismic tanks, fire mains, lake water supplies, potable tanks, etc. Plant specific alternate sources of feedwater should be identified and cited in the procedure. The condensate required to either maintain the plant at hot standby or cooldown may be determined from Figure 6-4 and 6-5.

42. Once pressurizer level is restored it should be maintained at the normal shutdown reference level (if possible) by one of the following methods:

    a) Preferentially, by control of charging and letdown,

    or

    b) Operation and/or throttling of the HPSI pumps.

    If the normal shutdown reference level is not maintained, then a pressurizer level of [35 to 245"] should be maintained to avoid losing pressure control with a saturated bubble in the pressurizer. If pressurizer level drops below the top of the pressurizer heaters, pressurizer heater operating will be interlocked off for heater protection. It may be necessary to exceed [245"] pressurizer level if the operator is attempting to restore RCS subcooling since pressurizer heaters may be unavailable or solid water operation may be necessary to achieve subcooling.

    Once the pressurizer water temperature varies from the normal hot standby temperature, the instrument indication on the normal pressurizer level channel will begin to deviate (i.e., decalibrate) from the true pressurizer level. At this time, the operator should use plant cooldown correction curves (which should be available to the operator in plant specific procedures) to determine the true pressurizer water level. A cold calibrated pressurizer instrument channel is provided. This channel can be used as a quick reference during the plant cooldown.

43. During a controlled cooldown and depressurization the automatic operation of certain safeguard systems, is undesirable. [Therefore, the setpoints of SIAS, CSAS, CIAS, and MSIS must be manually reset (lowered) as the cooldown progresses to ensure that automatic engineered safeguards protection remains available until the RCS is cooled down and depressurized.]

44. During the cooldown maintain the RCS pressure slightly above (0-100 psid) that of the affected S/G and within the acceptable Post Accident Pressure/Temperature Limits (Figure 6-1) by

    a) Controlling RCS heat removal via the unisolated steam generator

    <u>and</u>

    b) Controlling RCS pressure using the following methods (listed in order of priority):
       i) Pressurizer heaters and auxiliary spray
       ii) Charging and letdown
       iii) HPSI pumps

The bases for maintaining the RCS pressure and temperature within the acceptable range of the P/T limit curve (Figure 6-1) is that it will prevent excessive repressurization of the RCS leading to a PTS concern while still allowing the operator the ability to ensure adequate core cooling.

45. During the natural circulation cooldown remove heat from the isolated steam generator by one of the following methods (listed in order of priority).

    a) feed and bleed using main or auxiliary feedwater and steam generator blowdown.
    b) [other plant specific methods, insert here]

During normal forced flow conditions in the RCS, when one steam generator must be isolated, sufficient heat transfer occurs to maintain the isolated steam generator at the same relative temperature as the operating RCS loop. However, with no RCPs operating, there usually will be no natural circulation flow through the isolated steam generator and RCS loop, leaving those components in a hot stagnant condition. This condition by itself will not usually effect core cooling via natural circulation in the unisolated steam generator and RCS loop. As long as reactivity control, RCS pressure control, RCS inventory control, and RCS heat removal are properly maintained in the operating loop, sufficient natural circulation flow will be maintained through the core and operating loop.

However, a hot isolated steam generator presents a problem when trying to depressurize the RCS (e.g., to initiate shutdown cooling). Depressurization of the RCS below the isolated steam generator's saturation pressure could quickly void large portions of the isolated RCS loop which could lead to interruption of the natural circulation cooling established in the operating RCS loop or could cause the isolated steam generator to act like a pressurizer and prevent further depressurization to the shutdown cooling initiation pressure. Thus, an isolated steam generator must be cooled down before shutdown cooling can be aligned. The preferred method for heat removal during natural circulation is to feed and bleed the isolated steam generator using normal feed supply and steam generator blowdown. This method permits cooldown control by regulation of the feed and drain rates. Draining and then refilling is not preferred since the transient from this process is difficult to control. Plant specific procedures should be developed for this process. Consideration should be given to control of the contaminated fluid.

46. When the RCS is cooled to at least [300°F] and depressurized to at least [300 psia], shutdown cooling should be initiated per plant specific operating instructions. If significant voiding is present in the isolated loop the SCS should be aligned to the subcooled loop. This activity places the plant in an operational mode where a complete cooldown and depressurization of the plant can take place.

47. [The safety injection tanks should be isolated, vented, or drained at 250 psig to avoid introducing their nitrogen cover gas into the RCS and increasing the severity of the event.]

48. [LTOP protection is instituted below 275°F to protect the primary pressure boundary from low temperature brittle fracture.]

Safety Function Status Checks

Figure 6-19 provides the bases for the SGTR Safety Function Status Check. The Safety Function Status Check is designed to ensure that the operator is using the correct procedure, and the actions of that procedure are satisfying all relevant safety functions and maintaining adequate core cooling.

The safety function status check provides a systematic approach to determine if the SGTR Recovery Guideline is appropriate, and more importantly, if the plan condition is satisfactory. Safety functions have been used throughout the guideline system as a structure for storing and using operational information. When the plant is in a normal condition each safety function can be explicitly shown to be satisfied. For example, inventory control can be demonstrated by conducting simple tests with charging and pressurizer spray and heaters. The safety function status check acceptance criteria for inventory control when the plant is normal can be direct and explicit. When the plant has been damaged, some of the safety functions are not easily shown to be under control. For example, inventory control in a SGTR, is not easily tested for as it is when the plant is normal. The safety function status check acceptance criteria for inventory control in a SGTR relies on implicit information. Since tests with charging, pressurizer spray and heaters would not be conclusive or may only shown trending, the inventory control acceptance criteria is based on knowing that the systems intended to provide inventory control (i.e., SIS), are functioning. In addition, the acceptance criteria for other functions must be used in conjunction with inventory acceptance criteria to arrive at the conclusion that the plant status is satisfactory.

SAFETY FUNCTION STATUS CHECK BASES
STEAM GENERATOR TUBE RUPTURE
Figure 6-19a

The safety functions listed below and their respective criteria are those used to confirm the adequacy of the SGTR Guideline in mitigating the event.

SAFETY FUNCTION	ACCEPTANCE CRITERIA	INDICATION	RANGE	BASES
Reactivity Control	Reactor Power Decreasing and [Negative Startup Rate] and Not more than 1 CEA Bottom Light Not Lit or Borated per Tech Specs.	Power Range Power Rate CEA Status Display	[0-125%] [-1 → 7 dpm] On/Off Light for Each CEA	For all emergency events, the reactor must be shutdown. The criteria that no more than one CEA be stuck out or the RCS borated observes typical technical specification requirements.
Maintenance of Vital Auxiliaries (AC & DC Power)	[<--------------------------------Plant Specific--->]			
RCS Inventory Control	If [35"] < Pressurizer Level ≤ [245"]; Then: charging and letdown are being operated manually or automatically to control pressurizer level and RCS ≥ [20°F] Subcooled and [the RVLMS indicates the core is covered] or	Pressurizer Level	[0-350"]	A value of [245"] ([70%] of range) was chosen as an upper limit for pressurizer level to account for instrument accuracies and other uncertainties. A value of [35"] ([10%] of range) was chosen as a lower limit to account for instrument accuracy. A [20°F] subcooling margin coexisting with a pressurizer level between [35"] and [245"] indicates adequate RCS inventory control via a saturated bubble in the pressurizer.

SAFETY FUNCTION STATUS CHECK BASES
STEAM GENERATOR TUBE RUPTURE
Figure 6-19b

The safety functions listed below and their respective criteria are those used to confirm the adequacy of the SGTR Guideline in mitigating the event.

SAFETY FUNCTION	ACCEPTANCE CRITERIA	INDICATION	RANGE	BASES
	If Pressurizer Level < [35"]; Then: [all available charging pumps are operating and] the SIS pump(s) are injecting water into the RCS per Figure 6-3. and [the RVLMS indicates the core is covered]	[RVLMS	[0-100%]	An RVLMS indication that the core is covered taken in conjunction with [20°F] subcooling is an additional indication that RCS inventory is under control.
RCS Pressure Control	If Pressurizer Pressure ≥ [1600 psia], pressurizer heaters and spray are being operated manually or automatically to maintain or restore pressurizer pressure within the limits of the P/T curves per Figure 6-1. or If Pressurizer Pressure < [1600 psia], [all available charging pumps are operating and] the SIS pump(s) are injecting water into the RCS per Figure 6-3, (unless SIS termination criteria are met).	Pressurizer Pressure	[1500 - 2500 psia]/ [0-1600 psia]	[1600 psia] is the SIAS setpoint. The range of the selected events are very broad, therefore the acceptance criteria is written to cover the expected range which may result from the events noted.

SAFETY FUNCTION STATUS CHECK BASES
STEAM GENERATOR TUBE RUPTURE
Figure 6-19c

The safety functions listed below and their respective criteria are those used to confirm the adequacy of the SGTR Guideline in mitigating the event.

SAFETY FUNCTION	ACCEPTANCE CRITERIA	INDICATION	RANGE	BASES
Core Heat Removal	T_H RTDs [and Core Exit Thermocouples] < [600°F]	[Core Exit Thermocouples]	[0 - 1600°F]	The basis for the CET temperature limit during the use of optimal recovery procedures other than LOCA is the indication that the event specific recovery strategy is not effective in core heat removal performance. For the optimal recovery guidelines other than LOCA, heat is normally removed from the RCS by the steam generators. The value of the CET temperature will be governed by steam generator conditions (i.e., pressure and temperature). In general, $Tc \cong T_{SG}$ and CET temperature will be Tc + core ΔT. Normally this core ΔT is expected to be approximately [25°F] during single phase natural circulation conditions. For forced RCS flow conditions $T_{SG} \cong Tc \cong T_H \cong$ CET temperature. The design secondary system pressure is [1100] psia. The corresponding saturation temperature is 556.3°F. By adding [43.7°F] to account for thermocouple inaccuracy and the ΔT between Tc and CET, the value of [600°F] is reached.

SAFETY FUNCTION STATUS CHECK BASES
STEAM GENERATOR TUBE RUPTURE
Figure 6-19c

The safety functions listed below and their respective criteria are those used to confirm the adequacy of the SGTR Guideline in mitigating the event.

SAFETY FUNCTION	ACCEPTANCE CRITERIA	INDICATION	RANGE	BASES
RCS Heat Removal	a) Unaffected S/G level is: i) Within the normal level band with feedwater maintaining level or ii) being restored by a feedwater flow > [150 gpm]	Steam Generator Level	[+63.5" - (-) 116.5"]	Decay heat levels may not be high enough to require a feedwater flow of [150 gpm]. If this is the case, one steam generator level is returned to the zero power level band and feedwater remains available to maintain that level, then the S/G contribution to RCS heat removal is being satisfied.
	<u>and</u>			
	b) RCS T_{ave} <u>is</u> < [525°F]	T_{ave} indicator	[520°-610°F]	[525°F] is based on control program for ADVs and steam generator dump bypass valves and best estimate analysis.
Containment Isolation	Containment Pressure < [1.5 psig]	Containment pressure	[0-60 psig]	[1.5 psig] is based on containment pressure alarm. It is not expected for the selected events that containment pressure will increase to the alarm setpoint.
	<u>and</u>			
	No Containment Radiation Monitors Alarming	Containment Radiation Monitor	Alarming/ Not Alarming	No radiation is anticipated in the containment for an SGTR.

SAFETY FUNCTION STATUS CHECK BASES
STEAM GENERATOR TUBE RUPTURE
Figure 6-19c

The safety functions listed below and their respective criteria are those used to confirm the adequacy of the SGTR Guideline in mitigating the event.

SAFETY FUNCTION	ACCEPTANCE CRITERIA	INDICATION	RANGE	BASES
Containment Temp. and Pressure Control	Containment Temperature < [120°F]	Containment Temperature	[50-300°F]	[120°F] is the highest expected normal containment temperature.
	and			
	Containment Pressure < [1.5 psig]	Containment Pressure	[0-60 psig] [0-15 psig]	[1.5 psig] is based on containment pressure alarm. If it not expected for the selected events that containment pressure will increase to the alarm setpoint.
	and			
	No abnormal containment sump levels			
Containment Combustible Gas Control	H_2 < [2%]	[<-------------------Plant Specific------------------------>]		

Event Strategy

This section contains the SGTR operator actions strategy flow chart. The flow chart depicts the strategy around which the SGTR guideline is built. It is intended to assist the procedure writer in understanding the intent of the guideline and for use in training. Operators should understand what the major objectives of the guideline are in order to facilitate their progress toward those goals.

The strategy chart shows the recovery guideline strategy in detail and lists the guideline steps which correspond to each strategy objective. Some steps in the guideline may be performed at any time during the course of an event. These steps are shown by the affixed asterisks. The dashed boxes above the line indicate the lead-in steps performed by the operator prior to entering this recovery guideline.

p. 6-26 Suggests 2 SFs are threatened by SGTR V13:- RCS Inventory & Containment Integrity

Why then is there no mention of RCS inventory until page 6-76. Surely if RCS pressure/inventory is low reduction of TH and trying to restart RCPs prior to stabilizing RCS inventory is a little cavalier

FIGURE 6-20a

STRATEGY CHART FOR STEAM GENERATOR TUBE RUPTURE

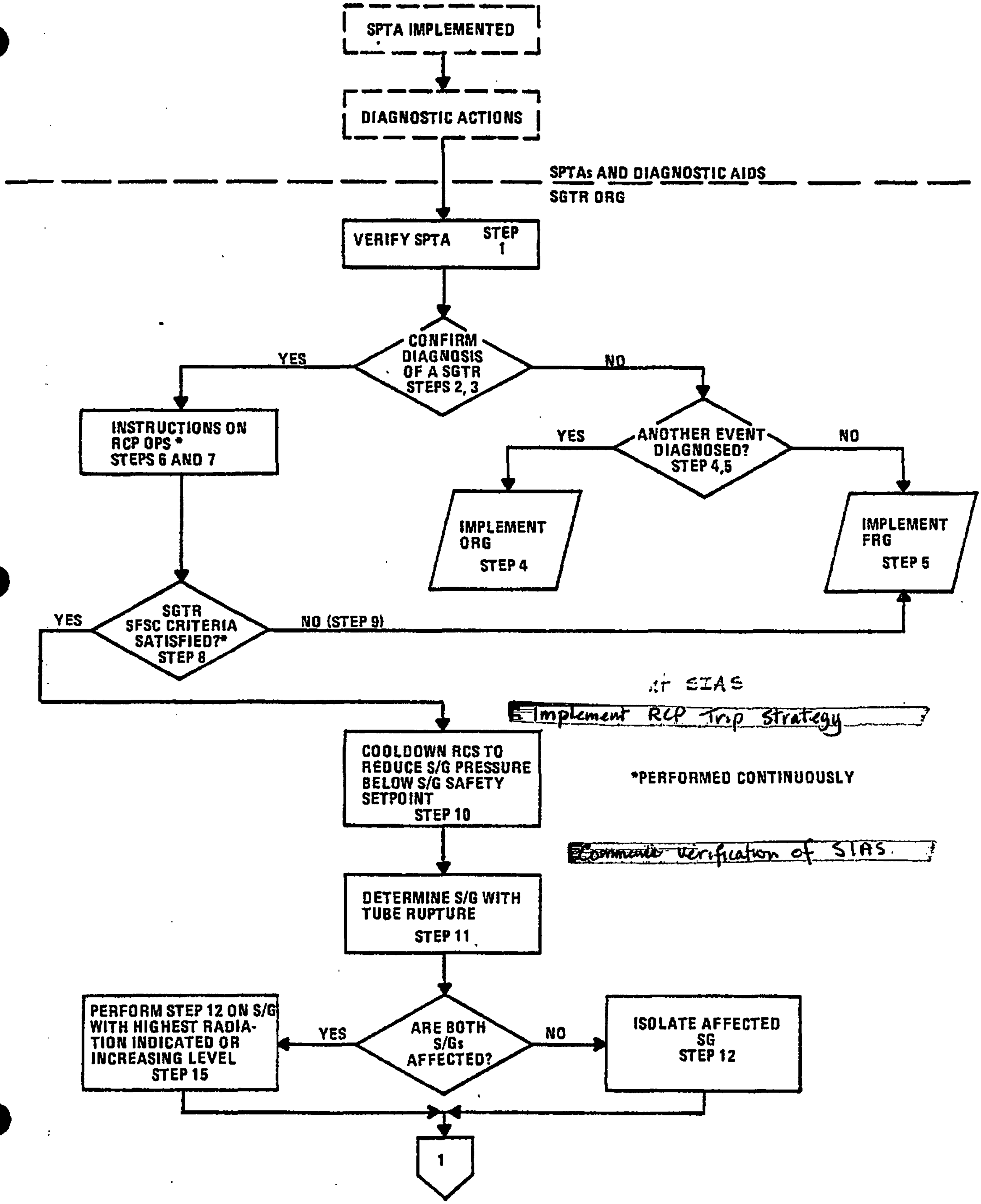


FIGURE 6-20b

STRATEGY CHART FOR STEAM GENERATOR TUBE RUPTURE

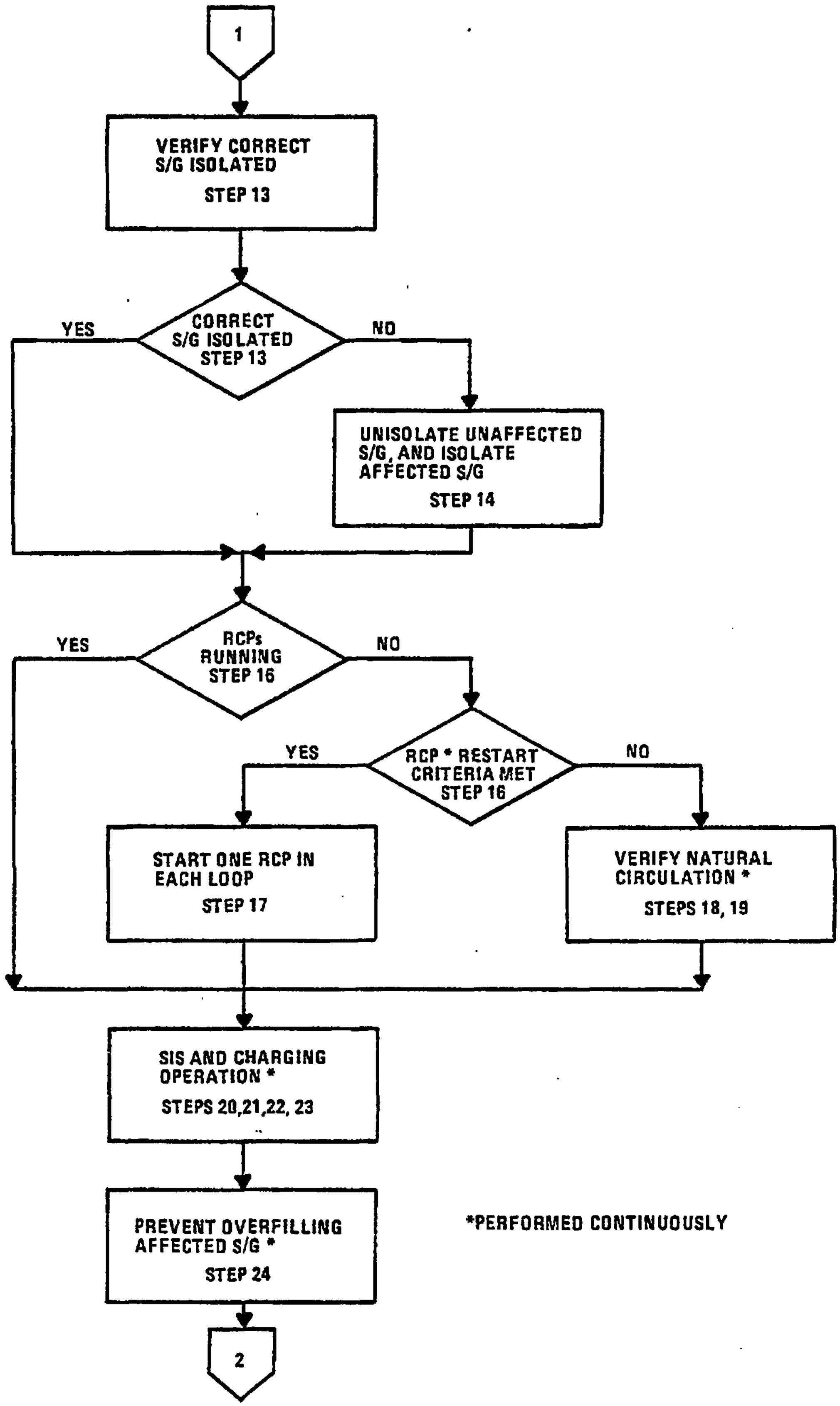


FIGURE 6-20c

STRATEGY CHART FOR STEAM GENERATOR TUBE RUPTURE

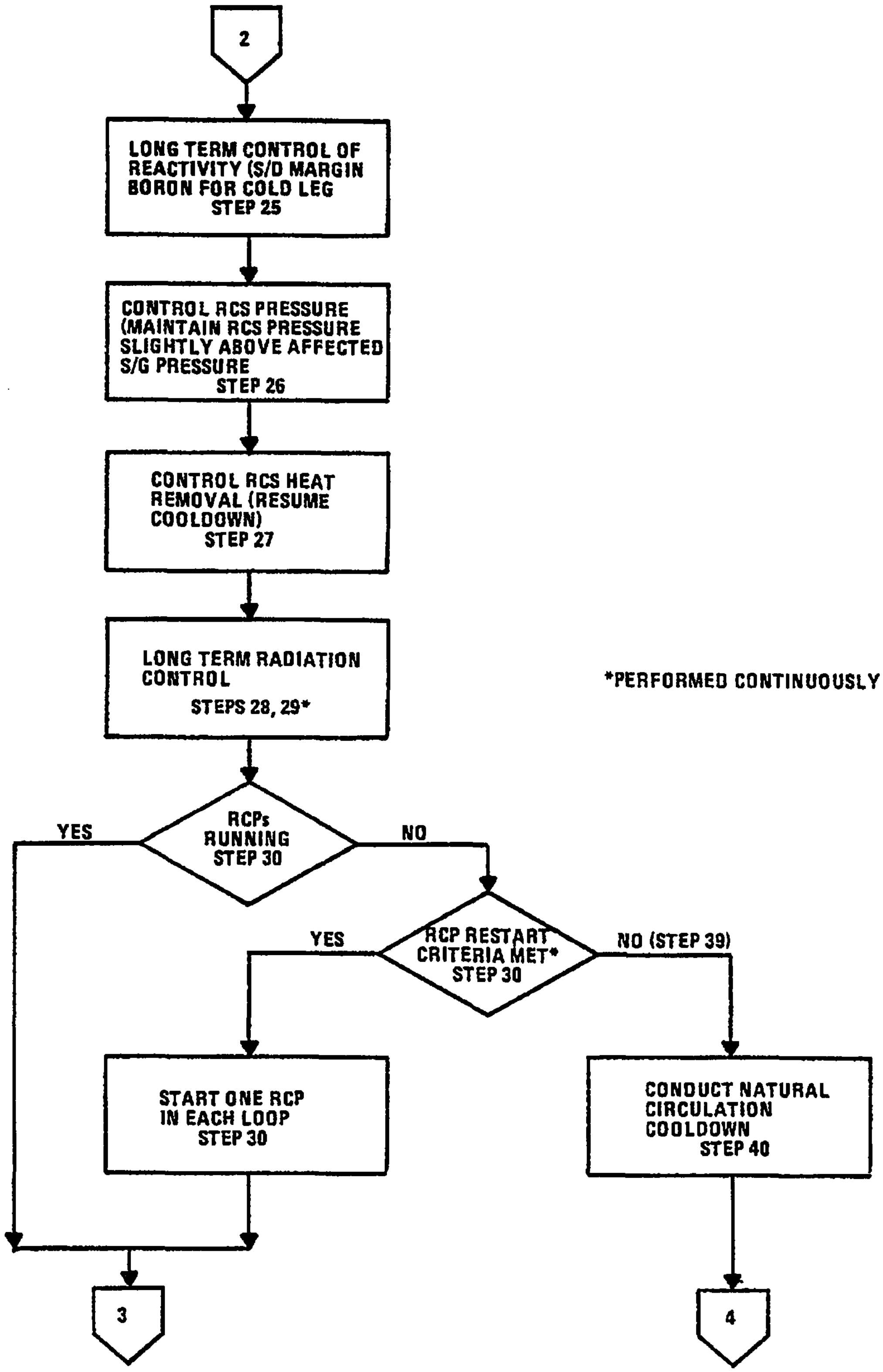
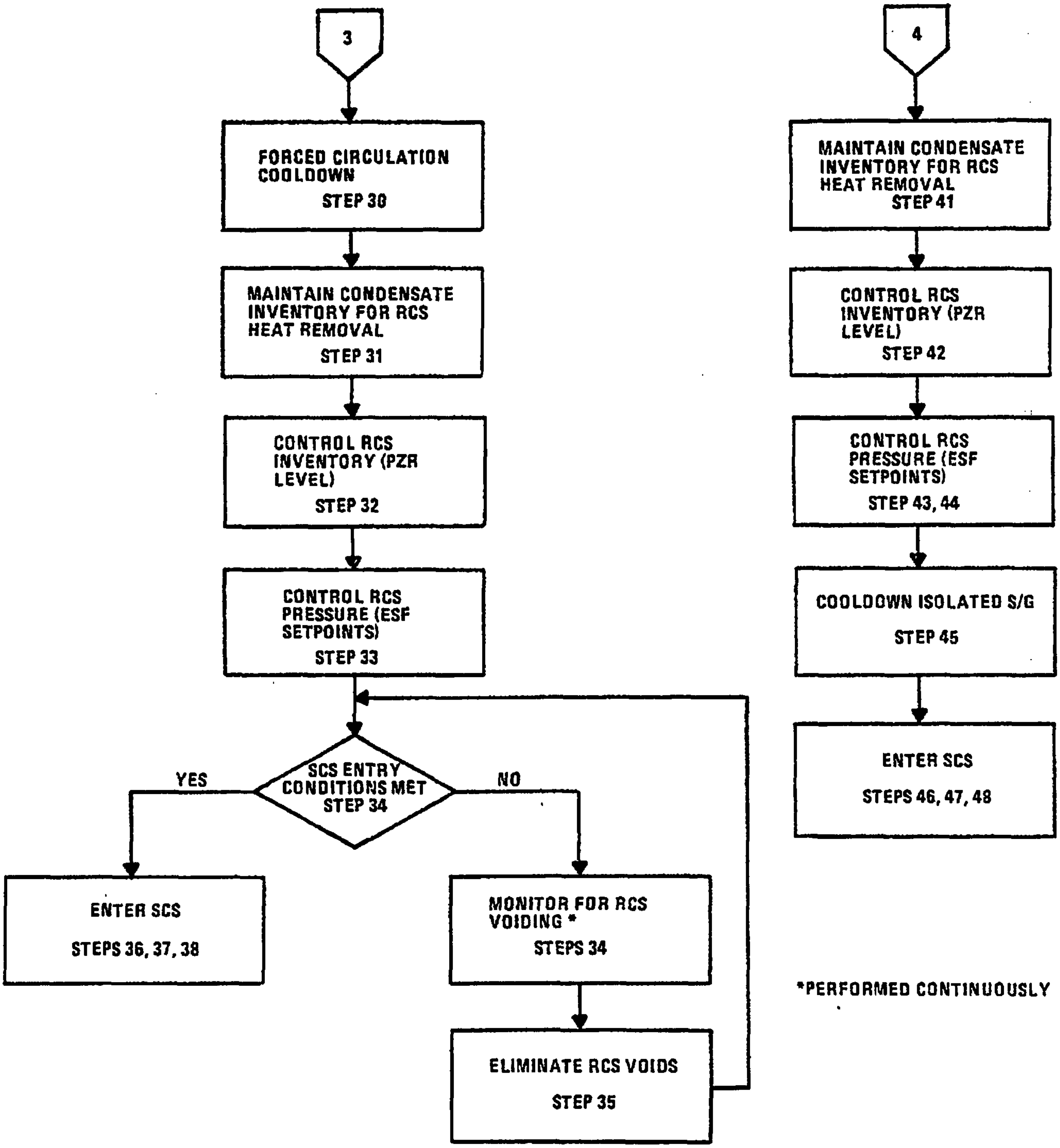


FIGURE 6-20d
STRATEGY CHART FOR STEAM GENERATOR TUBE RUPTURE



EXCESS STEAM DEMAND EVENT RECOVERY GUIDELINE

Prepared by
COMBUSTION ENGINEERING, INC.
for the
C-E Owners Group

PURPOSE

This guideline provides operator actions which must be accomplished in the event of an Excess Steam Demand Event (ESDE). The actions in this guideline are necessary to ensure the plant is placed in a safe, stable condition. This guideline provides technical information to be used by the utilities in developing a plant specific procedure.

ENTRY CONDITIONS

1. The Standard Post Trip Actions have been performed.

   and

2. Plant conditions indicate that an Excess Steam Demand Event has occurred. Any one, or more, of the following may be present.

   a. Loud noise indicative of a high energy steam line break.
   b. Decreasing RCS average temperature caused by the increased RCS heat removal.
   c. Increase in feedwater flow until main feedwater isolation valves are closed on MSIS.
   d. Possible increase in containment temperature, pressure, humidity, and sump level.
   e. [Other plant specific symptoms, insert here.]

1. Implemented in STEP A

2. Implemented in STEP B

3. SEE DEVIATION 4-1

4. SEE DEVIATION 4-2

5. SEE DEVIATION 4-2

6. IMPLEMENTED BY STEP E
See Deviation 0-69

7. IMPLEMENTED BY STEP E
See Deviation 0-69

8. IMPLEMENTED IN STEP B

OPERATOR ACTIONS

1. Verify that the Standard Post Trip Actions have been performed.

2. Confirm the diagnosis of an Excess Steam Demand Event by:

   [a) Referring to the Break Identification Chart (Figure 7-2)

   and

   b) Verifying the Safety Function Status Check criteria are satisfied].

3. Sample both steam generators for activity.

*4. If the diagnosis indicates that an LOCA or SGTR has occurred, Then exit the ESDE Recovery Guideline and implement the actions of the SGTR or LOCA Recovery Guideline.

*5. If the initial diagnosis of an ESDE is confirmed, Then continue with the actions of this guideline.
If not, implement the Functional Recovery Guideline.

*6. If pressurizer pressure decreases to less than [1300 psia] following an SIAS, Then ensure two of four RCPs are tripped (in opposite loops).

*7. [If RCP operating limits are not satisfied, Then trip the remaining two RCPs].

*8. Verify that the safety functions are being satisfied by comparing control board parameters to the criteria of the Safety Function Status Check.

* Step performed continuously.

9. See Deviation 4-2

10. Implemented by step D. See Deviation 4-3.

11 IMPLEMENTED BY STEP C. See Deviation 4-4 and 4-3

12. See Deviation 4-5

13. IMPLEMENTED BY STEPS F, H, AND I
See Dev 4-43

*9. If the safety functions from the Safety Function Status Check are satisfied, Then continue with the actions of this guideline.
If not, implement the Functional Recovery Guideline.

10. Identify the affected steam generator by comparison of steam pressures, cold leg temperature differences, and steam generator level.
If the event is on the steam generator side of the MSIVs, Then the generator with the lower, or decreasing, steam pressure, cold leg temperature and level subsequent to an MSIS is the affected steam generator.

11. Isolate the affected steam generator by performing the following actions:

a) Close the main steam isolation valve and verify the bypass valve is closed on the affected steam generator.
b) Close, or verify closed, the atmospheric dump valve(s) on the affected steam generator.
c) Isolate all (main and auxiliary) feedwater to the affected steam generator.
d) Isolate the affected steam generator vents and drains.
e) [Other plant specific information, insert here.]

12. If both steam generators are affected, Then isolate the steam generator with the worse ESDE, if it can be determined, and attempt to maintain RCS heat removal capability via one steam generator.

*13. If pressurizer level is less than [35"], Then take steps to maximize RCS boration by ensuring maximum safety injection and charging flow to the RCS. This is accomplished by:

* Step performed continuously.

14. Implemented BY STEP L

15. implemented in STEP L

16. implemented IN STEP K AND O

17. implemented BY STEPS G, J (causes loss of RCP cooling), AND Z

18. Implemented by step V
Den- 4-46

a) Verifying electrical power to valves and pumps.
b) Verifying correct SIS valve lineup (if misaligned).
c) Verifying other necessary auxiliary systems operational.
d) Starting idle SIS and charging pumps.

*14. If the SIS is operating, Then it may be throttled, or stopped one train at a time, if the following conditions are satisfied:

a) RCS is at least [20°F] subcooled (Figure 7-1).
b) Pressurizer level is greater than [100"] and not decreasing.
c) The unaffected steam generator (or the least affected, if both steam generators are affected) is available for RCS heat removal.
d) [The RVLMS indicates the core is covered.]

*15. If the criteria of step 14 cannot be maintained after the SIS has been stopped, Then the SIS must be restarted.

16. Operate the turbine bypass valves (preferred method if the condenser is available), or atmospheric steam dump valves, to stabilize RCS temperature.

17. Verify containment isolation at [4 psig] or [other plant specific criteria]. Be alert to the loss of RCP cooling water and loss of other auxiliaries which may occur. In particular, consider unisolating letdown, if it is available.

*18. If containment pressure falls below [7 psig] following operation of the CSS, Then containment spray may be terminated. Upon termination, the CSS must be realigned for automatic operation.

* Step performed continuously.

19 IMPLEMENTED BY STEPS N AND P

20 ~~Im~~ See Deviation 4-6

21 IMPLEMENTED BY STEP O
Dev. 4-47

22 See Deviation 4-7

23 Implemented by steps H, I, and Q. The AOP (3F) also directs BORATION.

24 Implemented by step AC.
See Dev 2-39 and 2-40

19. Manually control pressurizer heaters and spray (main spray preferred) after pressurizer level returns to the indicating range, to restore pressurizer pressure within the limits of Figure 7-1.

20. Verify that the PLCS is automatically maintaining or restoring pressurizer level.
    If not, manually operate charging and letdown to restore and maintain normal pressurizer level.

21. Verify that the steam generator level in the unisolated steam generator is being restored, or maintained, using [main or auxiliary] feedwater.

22. Evaluate the need for a plant cooldown based on plant status, auxiliary systems availability and condensate inventory.
    If a cooldown is not required, Then maintain the plant in a stable condition.
    If conditions require a cooldown, Then conduct a cooldown to SCS initiation conditions. Perform steps 23 through 37.

23. Borate the RCS to obtain, and then maintain, the proper boron concentration per Technical Specification Limitations. Continue borating during the cooldown to maintain sufficient shutdown margin.

*24. If all RCPs were stopped, Then one RCP in each loop should be restarted if possible.

    Determine whether RCP restart criteria are met by the following:

* Step performed continuously.

25. IMPLEMENTED BY STEP AC
See Dev 2-41 and 2-42

26. IMPLEMENTED BY STEP R
See Dev. 2-43

27 Implementy by the safety function status check

a) The unaffected steam generator (or the least affected, if both steam generators are affected) is available for RCS heat removal.
b) Pressurizer level greater than [200"] and not decreasing.
c) The RCS is at least [20°F] subcooled (Figure 7-1).
d) [Other criteria satisfied per RCP operating instructions.]

*25. If RCP restart criteria are met, Then do the following:

a) Start one RCP in each loop.
b) [Ensure proper RCP operation by monitoring RCP amperage and pump NPSH. NPSH is determined by pressurizer pressure and corresponding Tc on Figure 7-1.]
c) Operate HPSI (Figure 7-3) and charging pumps, and letdown, as necessary to maintain pressurizer level [100 to 200"].

*26. If all RCPs have been stopped, Then verify natural circulation flow is maintained in the unisolated loop. The following criteria must be met in order to demonstrate adequate natural circulation flow:

a) Loop ΔT (T_H - T_C) less than normal full power ΔT
b) Cold leg temperatures constant or increasing
c) Hot leg temperatures stable (i.e., not steadily increasing) or decreasing
d) No abnormal differences between T_H RTDs [and CETs].

*27. If the criteria listed above are not met, Then ensure RCS pressure (step 19) and inventory (step 20), and S/G steaming and feeding (step 21), are being controlled properly.

* Step performed continuously.

28. Implemented by step AD. See Deviation 4-8 and 4-49

29. Implemented by step AD. See Deviation 4-8

30. Implemented in SFSC

31. See Deviation 4-8 for cooldown period. Step f implements requirement during accident.
See Dev 4-48

32 See Deviation 4-8

28. Perform an RCS cooldown. Cooldown to at least [300°F] at a rate within Technical Specification Limits by (listed in order of preference):

    a) Cooldown using the turbine bypass system and [main or auxiliary] feedwater,

    or

    b) Cooldown using the atmospheric dump valves and [main or auxiliary] feedwater.

29. Depressurize the RCS to at least [300 psia] while maintaining the RCS within the acceptable Post Accident Pressure/Temperature Limits (Figure 7-1) by:

    1) Controlling RCS heat removal within technical specification limits via the unisolated steam generator

    and

    2) Controlling RCS pressure using the following methods (listed in order of preference):
        i) Pressurizer heaters and spray (preferred) or auxiliary spray
        ii) Charging and letdown
        iii) HPSI pumps [and PORVs]

30. Monitor the available condensate inventory and replenish from alternate sources as required during the cooldown.. Refer to Figures 7-4 and 7-5.

31. If plant conditions permit, Then bypass automatic initiation of [MSIS, CIAS, CSAS and SIAS by lowering the setpoint as the cooldown and depressurization proceed.]

32. Maintain pressurizer level in the range [35 to 245"], unless solid operation is necessary to restore RCS subcooling. This should be accomplished by (listed in order of preference):

33 Implemented by step S. Direction also contained in
AOP 3F See Deviation 4-49

34 Implemented by step T. Direction Also contained in AOP 3F
See Deviation 4-50

a) Control charging and letdown.
b) Operating and/or throttling HPSI pumps.

*33. If the above actions fail to depressurize the RCS, Then a void should be suspected. The operator should monitor for the presence of voids. If voiding inhibits RCS depressurization to SCS entry pressure, Then an attempt at eliminating the voiding should be made.

Voiding in the RCS may be indicated by any of the following indications, parameter changes, or trends:

a) letdown flow greater than charging flow,
b) pressurizer level increasing significantly greater than expected while operating pressurizer spray,
c) [the RVLMS indicates that voiding is present in the reactor vessel],
d) [HJTC unheated thermocouple temperature indicates saturated conditions in the reactor vessel upper head]. A
e) [other indications insert here].

*34. If voiding should be eliminated, Then proceed as follows:

a) verify letdown is isolated,
b) stop the depressurization and, if required, repressurize the RCS to ≥ [20°F] subcooling,
c) pressurize and depressurize the RCS within the limits of Figure 7-1 by operating pressurizer heaters and spray (preferred method) or HPSI and charging pumps (alternative method). Monitor pressurizer level [and the RVLMS] for trending of RCS inventory.
d) if indications of unacceptable RCS voiding continue, and voiding is suspected to exist in the (isolated) steam generator tubes, then cool the (isolated) steam generator (by steaming or blowdown, and/or feeding) to condense the steam generator tube bundle void. Monitor pressurizer level for trending of RCS inventory.

* Step performed continuously.

35. See Deviation 4-8

36. See Deviation 4-8

37. See Deviation 4.8

e) if indications of unacceptable RCS voiding continue, then [operate the pressurizer vent and/or the reactor vessel head vent to] clear trapped non-condensible gases. Monitor pressurizer level [and/or the RVLMS] for trending of RCS inventory.

35. When SCS entry conditions (RCS pressure ≤ [300 psia] and RCS T_H ≤ [300 °F]) are established, initiate SCS operation per operating instructions.

36. [Isolate, vent or drain the safety injection tanks (SITs) at an RCS pressure of 250 psia.]

37. [Initiate the low temperature overpressurization (LTOP) system at 275°F].

(1) Implemented as a note in step V.

(2) Cooldown rate limitations included in steps where controllable cooldowns occur

(3) Implemented in precautions A and B

(4) Implemented in precaution C

(5) Implemented as a caution in step N

(6) See deviation 4-9

SUPPLEMENTARY INFORMATION

This section contains items which should be considered when implementing EPGs and preparing plant specific EOPs. The items should be implemented as precautions, cautions or notes or in the EOP training program.

1. Lengthy operation of the containment spray system may jeopardize the operation of equipment which would be desirable later in the event. Early consideration should be given to termination of spray operation.

2. During all phases of cooldown, monitor RCS temperature and pressure to avoid exceeding a maximum cooldown rate greater than Technical Specification Limitations.

3. Do not place systems in "manual" unless misoperation in automatic is apparent. Systems placed in "manual" must be checked frequently to ensure proper operation.

4. All available indications should be used to aid in diagnosing the event since the accident may cause irregularities in a particular instrument reading. Instrument readings must be corroborated when one or more confirmatory indications are available.

5. If the initial cooldown rate exceeds Technical Specification Limits, there may be a potential for pressurized thermal shock (PTS) of the reactor vessel. Post Accident Pressure/Temperature Limits of Figure 7-1 should be maintained.

6. Solid water operation of the pressurizer should be avoided unless [20°F] of subcooling cannot be maintained in the RCS (Figure 7-1). If the RCS is solid, closely monitor any makeup or draining and any system heatup or cooldown to avoid any unfavorable rapid pressure excursions.

(7) Implemented in Precaution E. ~~Be~~ See Deviation 4-10

(8) Implemented in SFSC for pressure and INVENTORY PARAMETERS. SEE DEVIATION 4-11.

(9) RVLMS NOT INSTALLED yet. See DEVIATION 4-17

(10) IMPLEMENTED IN STEPS S AND T

7. Minimize the number of cycles or pressurizer auxiliary spray whenever the temperature differential between the spray water and the pressurizer is greater than [200°F] in order to minimize the increase in the spray nozzle thermal stress accumulation factor. Every such cycle must be recorded in accordance with Technical Specification Limitations.

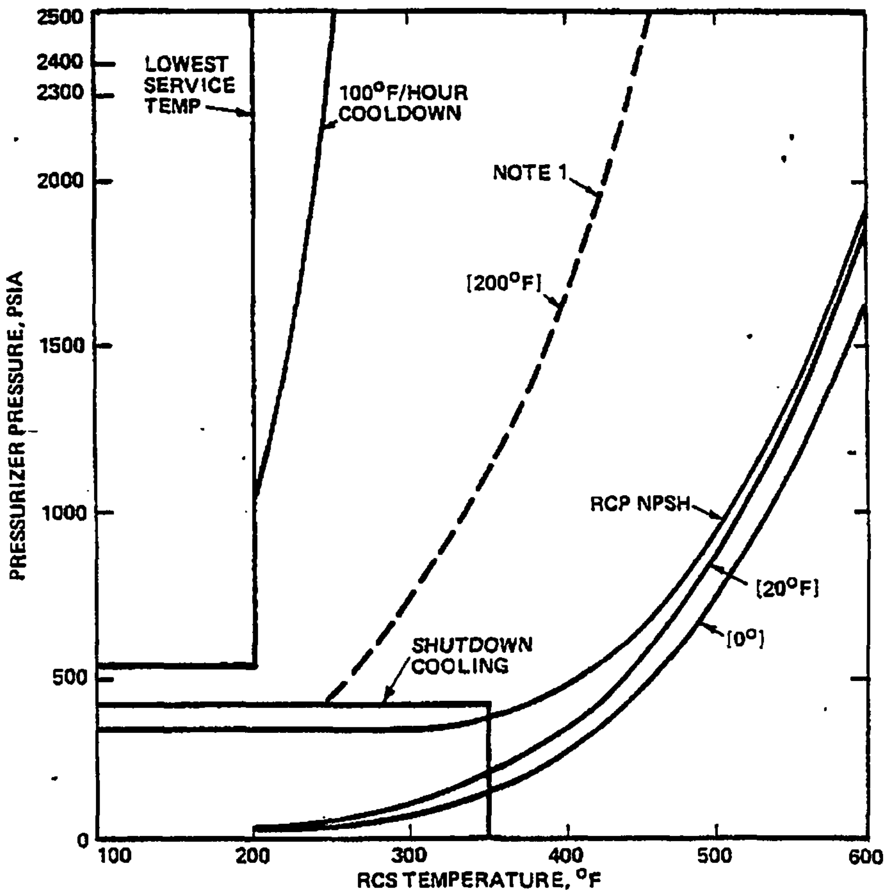
8. [Monitor quench tank parameters since any sustained operation of the PORVs may burst the tank's rupture disc.]

9. When a void exists in the reactor vessel, and RCPs are not operating, the RVLMS provides an accurate indication of reactor vessel liquid inventory. When a void exists in the reactor vessel, and RCPs are operating, it is not possible to obtain an accurate reactor vessel liquid level indication due to the effect of the RCP induced pressure head on the RVLMS. The indicated level also differs for different RVLMS designs under these conditions. Information concerning reactor vessel liquid inventory trending may still be discerned. However, the operator is cautioned not to rely solely on the RVLMS indication when RCPs are operating.

10. The operator should continuously monitor for the presence of RCS voiding and take steps to eliminate voiding any time voiding causes the heat removal or inventory control safety functions to begin to be threatened. Void elimination should be started soon enough to ensure heat removal and inventory control are not lost. C

FIGURE 7-1

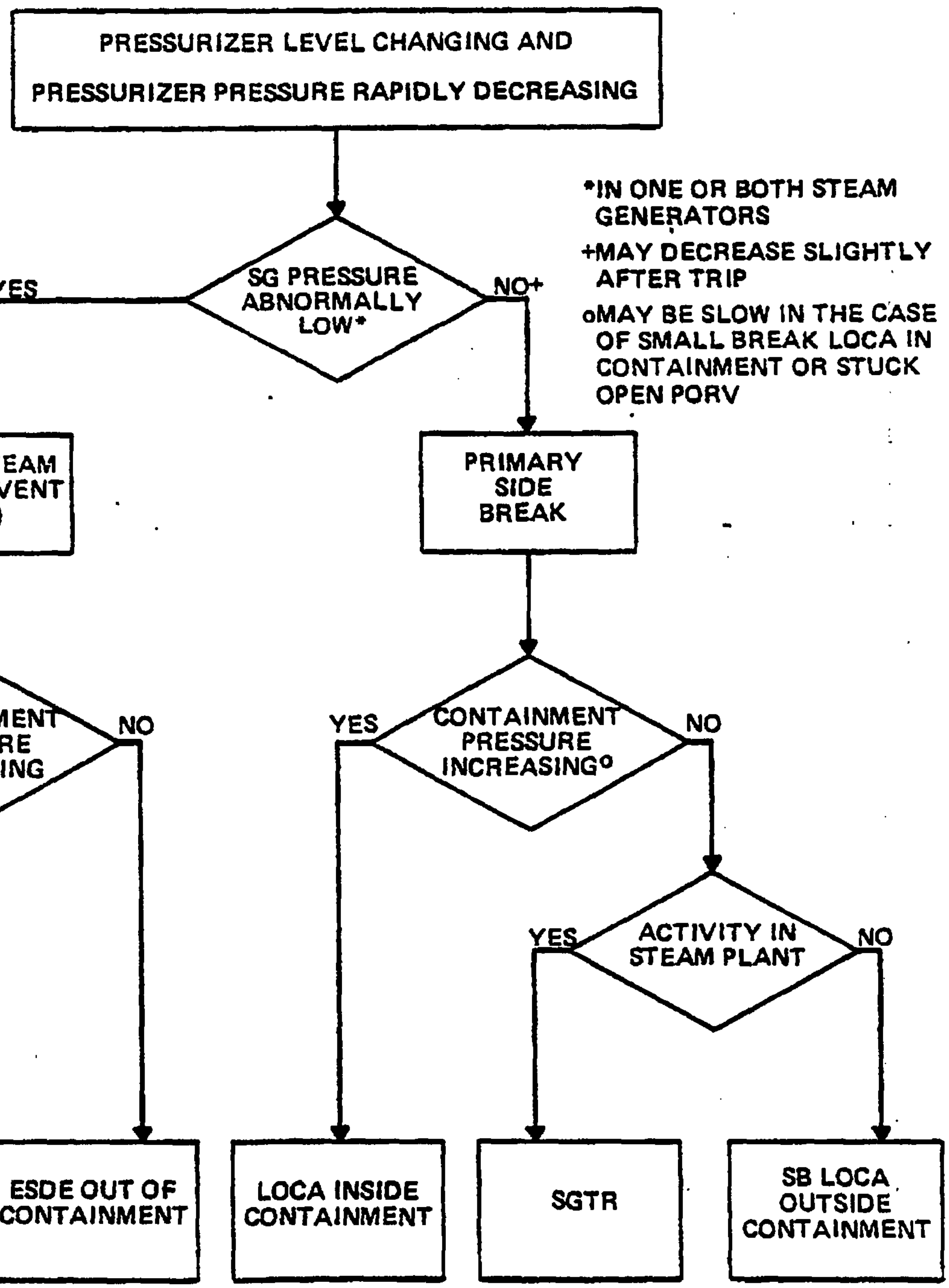
TYPICAL POST ACCIDENT PRESSURE-TEMPERATURE LIMITS(2)



NOTES: (1) THIS CURVE SUPERSEDES THE 100°F/HOUR COOLDOWN CURVE ANYTIME THE RCS HAS EXPERIENCED AN UNCONTROLLED COOLDOWN WHICH CAUSES RCS TEMPERATURE TO GO BELOW 500°F
(2) THESE CURVES MUST BE ADJUSTED FOR INSTRUMENT INACCURACIES
(3) COLOR CODE
- RED - PARAMETER IN EXCESS OF LIMITS
- ORANGE - PARAMETER IN DANGER OF EXCEEDING LIMITS
- YELLOW - PARAMETER OUTSIDE OF OPTIMAL RANGE, BUT STILL WITHIN LIMITS
- GREEN - PARAMETER IN OPTIMAL RANGE OF VALUES

BREAK IDENTIFICATION CHART

FIGURE 7-2



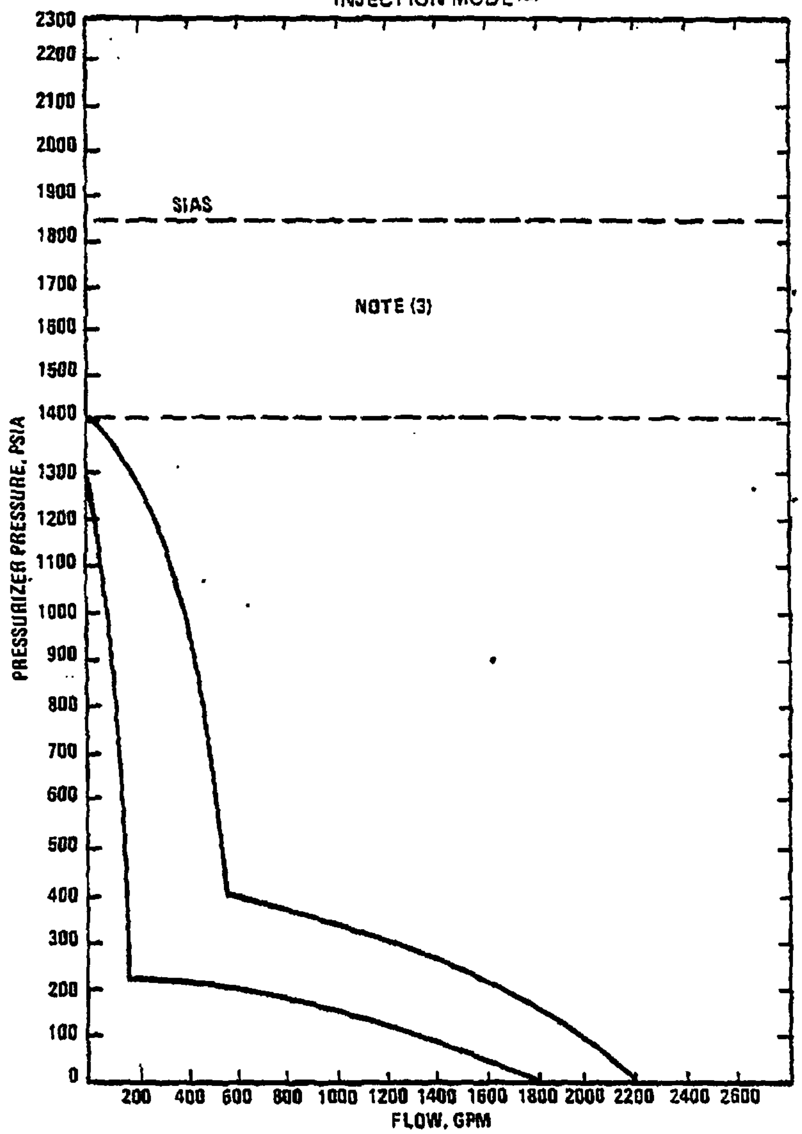
*IN ONE OR BOTH STEAM GENERATORS

+MAY DECREASE SLIGHTLY AFTER TRIP

oMAY BE SLOW IN THE CASE OF SMALL BREAK LOCA IN CONTAINMENT OR STUCK OPEN PORV

FIGURE 7-3

TYPICAL ACCEPTABLE SIS FLOW vs RCS PRESSURE(1)
INJECTION MODE(2)



NOTES:
(1) SEE IMPLEMENTATION SECTION FOR DEVELOPMENT OF PLANT SPECIFIC CURVE
(2) FOR HOT AND COLD LEG INJECTION MODE, THE LPSI PUMPS ARE NOT REQUIRED TO BE OPERATING. THE HPSI PUMP FLOW IS DIVIDED EQUALLY BETWEEN THE HOT AND COLD LEGS
(3) BELOW SIAS PRESSURE, SAFETY INJECTION SYSTEM (SIS) PUMPS WILL BE OPERATING BUT THERE WILL BE NO INJECTION FLOW UNTIL SYSTEM PRESSURE FALLS BELOW THE SHUTOFF HEAD OF ANY SIS PUMP
(4) COLOR CODE
RED - PARAMETER IN EXCESS OF LIMITS
YELLOW - PARAMETER OUTSIDE OF OPTIMAL RANGE, BUT STILL WITHIN LIMITS
GREEN - PARAMETER IN OPTIMAL RANGE OF VALUES

TYPICAL FEEDWATER CAPACITY vs TIME REMAINING UNTIL SHUTDOWN COOLING REQUIRED
FIGURE 7-4

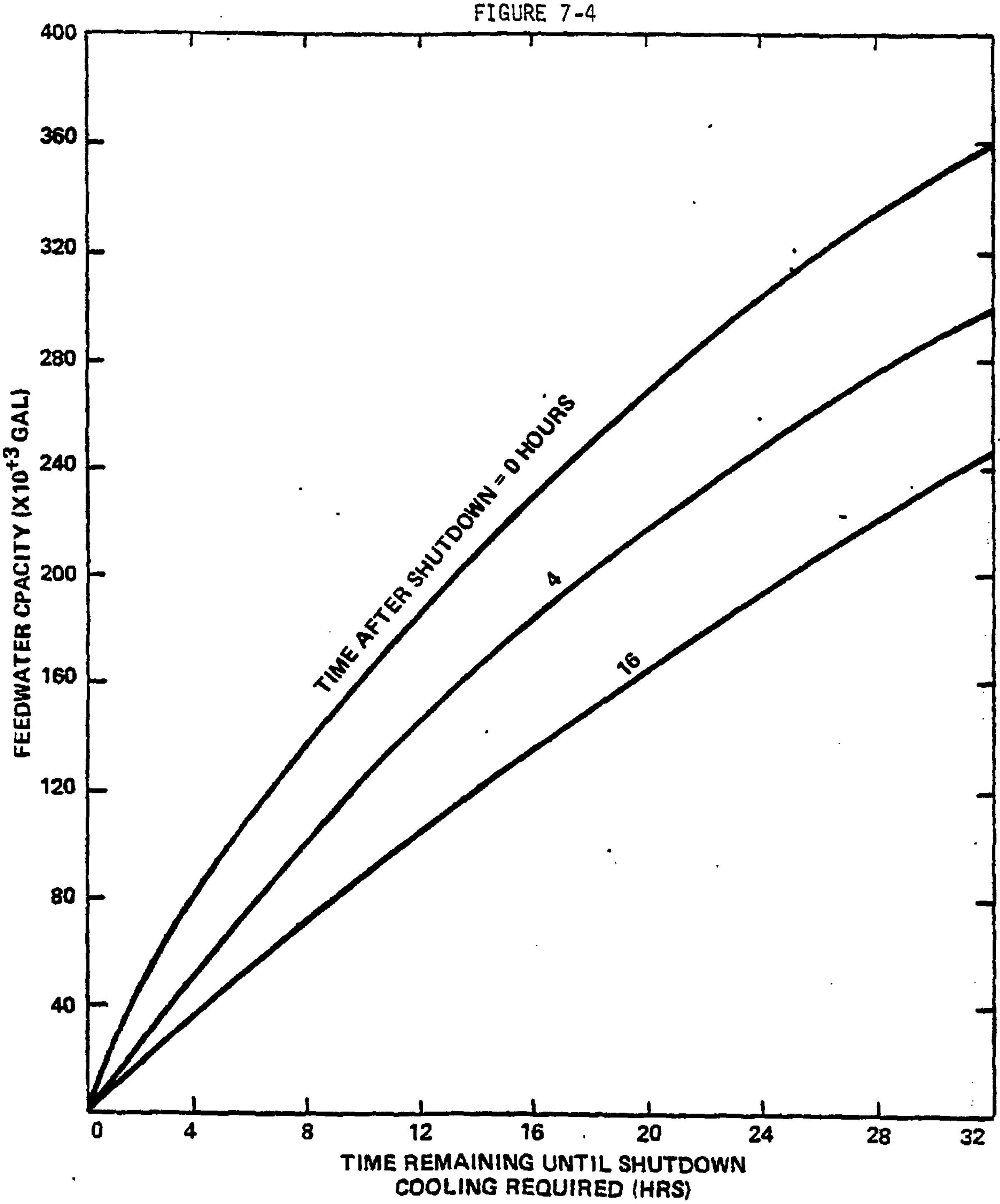
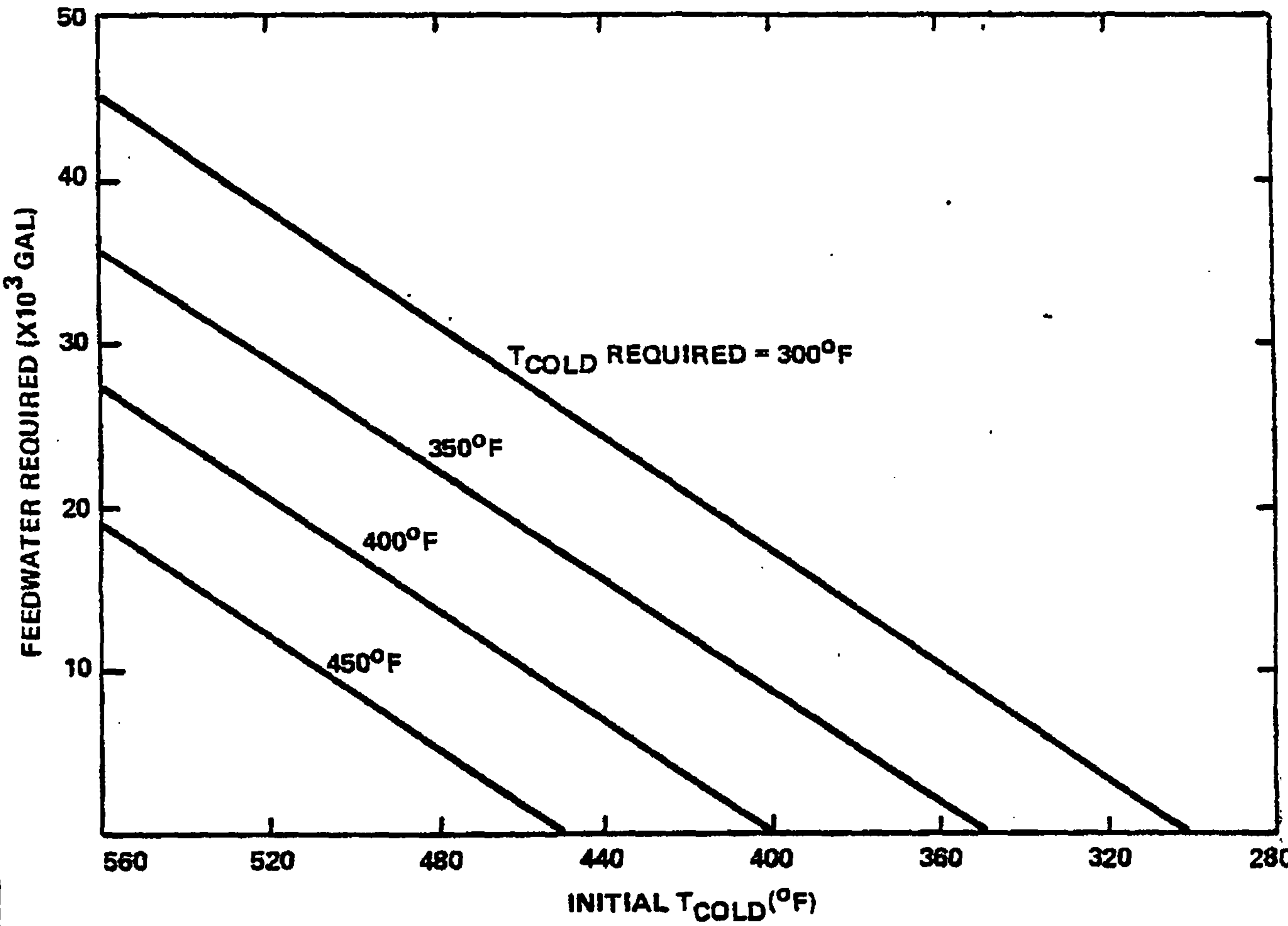


FIGURE 7-5

TYPICAL FEEDWATER REQUIRED FOR SENSIBLE HEAT REMOVAL
T_{COLD} (REQUIRED) vs T_{COLD} (INITIAL)



① ALL ITEMS COVERED UNDER REACTIVITY CONTROL SFSC

② INCLUDED AS 4th FUNCTION IN SFSC.

SAFETY FUNCTION STATUS CHECK

Safety Function	Acceptance Criteria
1. Reactivity Control	1.a. Reactor power decreasing *and* b. [Negative Startup Rate] *and* c. Not more than 1 CEA bottom light not lit or borated per Tech Specs.
2. Maintenance of Vital Auxiliaries (AC and DC Power)	2. [Plant specific criteria, insert here].

③ LEVEL AND SUBCOOLING ACCEPTANCE CRITERIA are included in SFSC. See Deviation 4-12 FOR Deviation ON equipment operation verification.

SAFETY FUNCTION STATUS CHECK (Cont'd)

Safety Function	Acceptance Criteria
3. RCS Inventory Control	3.a. If pressurizer level is [35 to 245"], Then: i) Charging and letdown are being operated automatically or manually to maintain or restore pressurizer level and ii) the RCS is at least [20°F] subcooled and iii) [the RVLMS indicates the core is covered] or b. If pressurizer level is less than [35"], Then: i) [the RVLMS indicates the core is covered] and ii) [all available charging pumps are operating and] the SIS pump(s) are injecting water into the RCS per Figure 7-3.

(4) PRESSURE CRITERIA are included in the SFSC. See DEVIATION 4-13 for Deviation on equipment operation verification.

(5) IMPLEMENTED IN CORE/RCS heat removal SFSC

SAFETY FUNCTION STATUS CHECK (Cont'd)

Safety Function	Acceptance Criteria
4. RCS Pressure Control	4.a. If pressurizer pressure is greater than or equal to [1600 psia], Then pressurizer heaters and spray are being operated automatically or manually to maintain or restore pressurizer pressure within the limits of Figure 7-1. *or* b. If pressurizer pressure is less than [1600 psia], Then [all available charging pumps are operating and] the SIS pump(s) are injecting water into the RCS per Figure 7-3 (unless SIS termination criteria are met).
5. Core Heat Removal	5.a. T_H RTD [and Core Exit Thermocouple] temperatures less than [600°F]. *and* b. The RCS is at least [20°F] subcooled.

⑥ LEVEL CRITERIA CONTAINED IN SFSC. See Deviation 4-14 for feedwater flow and TAVE deviations

⑦ Implemented in Containment ENVIRONMENT AND RADIATION CONTROL SFSC. See Deviation 4-15 for WIDER BAND ON Cont. press.

SAFETY FUNCTION STATUS CHECK

Safety Function	Acceptance Criteria
6. RCS Heat Removal	6.a. The unaffected steam generator has level: i) within the normal level band with feedwater available to maintain level or ii) being restored by feedwater flow greater than [150 gpm] *and* b. RCS T_{ave} is less than [525°F] and controlled.
7. Containment Isolation	7.a. i) Containment pressure less than [4 psig] and ii) No containment area radiation monitors alarming. and iii) No steam plant activity monitors alarming. *or* b. CIAS present or manually initiated.

(8) Implemented in CONTAINMENT ENVIRONMENT SESC. See Deviation 4-16 FOR CONTAINMENT spray flow deviation.

(9) IMPLEMENTED IN CONTAINMENT ENVIRONMENT SESC

SAFETY FUNCTION STATUS CHECK

Safety Function	Acceptance Criteria
8. *Containment Temperature and Pressure Control*	8.a. i) Containment temperature less than [240°F] and ii) Containment pressure less than [10 psig] *or* b. Containment spray flow greater than [1500 gpm].
9. *Containment Combustible Gas Control*	9. H_2 concentration less than [2%].

BASES

The bases section of the Excess Steam Demand Event (ESDE) recovery guideline describes the ESDE transient in relation to the actions which the operator takes during an ESDE. The purpose of the bases section is to provide the operators with information which will enable them to understand the reasons for, and the consequences of, the actions they take during an ESDE.

Characterization of an ESDE

An Excess Steam Demand Event (ESDE) is any event which leads to an unexpected, rapid increase in steam generator steam flow or loss of steam generator inventory that requires and/or results in a reactor trip or exceeds the control capability of the reactor regulating system, pressurizer pressure control system and/or pressurizer level control system. Some of the possible causes include:

a) Rupture or break in a main steam line.

b) Rupture or break of a main, or auxiliary, feedwater line downstream of the last check valve (break upstream of the last check valve in a feedwater line is considered a loss of feedwater event).

c) Inadvertent opening of main steam system valve(s) (i.e., atmospheric dumps, turbine bypass, etc.).

d) Stuck open steam generator safety valve.

The following parameters usually characterize an ESDE:

a) Increased steam flow from the steam generators.

b) Decreasing steam generator pressure and water level (initially, there may be level swell).

c) Decreasing RCS average temperature causing a decrease in pressurizer pressure and water level.

d) Reactor trip caused by [thermal margin or CPC], high core power, low steam generator water level, low pressurizer pressure, low steam generator pressure, or high containment pressure (if ESDE within containment).

e) SIAS may be generated from low pressurizer pressure or high containment pressure (if ESDE within the containment).

f) A CIAS, CSAS, and MSIS may be generated on high containment pressure (if ESDE within the containment).

g) Possible increase in containment pressure, temperature, humidity, or containment sump level.

Safety Functions Affected

An excess steam demand event, depending on the cause, will mostly affect the safety functions reactivity control, RCS heat removal, and containment temperature and pressure control (for events inside containment). However, all safety functions should be monitored to assure public safety, or to detect failures which might lead to unsafe conditions.

A significantly large ESDE usually results in excess steam flow on the secondary side which will lead to a reactor trip. This decrease in reactor heat input (due to reactor trip), combined with the increase in steam generator heat removal due to the excess steam flow, rapidly reduces RCS temperature. A reduction in RCS temperature causes an apparent inventory decrease due to volume contraction, a system pressure decrease, and possible RCS voiding. The inventory shrinkage will usually cause an SIAS if the pressurizer empties. This shrinkage will be restored by subsequent RCS heatup and/or the safety injection system and charging pumps. Care should be taken while the inventory is being increased that the RCS does not go solid.

If a significant ESDE occurs inside containment, the steam flow will result in an increase in containment pressure and temperature. The threat to containment integrity is mitigated by a CIAS when pressure exceeds [4 psig] and a CSAS when pressure exceeds [10 psig]. If containment isolation and containment spray do not occur automatically, they are initiated manually after an evaluation of containment conditions (i.e., containment pressure and temperature) is made.

As steam generator pressure decreases due to the energy loss, an MSIS will occur and isolate the main steam line from the steam generator. If the event is occurring downstream of the MSIVs, then the blowdown will be terminated.

Trending of Key Parameters

Reactor Power (*Figure 7-6*)

In response to the reduction in moderator temperature, reactor power will initially increase until an RPS setpoint is reached by one of the following: [thermal margin or CPC], low steam generator pressure, high containment pressure, low steam generator water level, or low pressurizer pressure. As the steam generator blowdown continues to reduce moderator temperature, there exists a possibility of a return to criticality.

RCS Temperature (*Figures 7-7 and 7-8*)

Prior to the reactor trip, RCS temperature will decrease because heat removed by the ESDE and the turbine exceeds heat produced by the core. After the reactor has tripped, heat removal by the ESDE will exceed decay heat, causing further cooling of the RCS.

Pressurizer Pressure (*Figure 7-9*)

Pressurizer pressure will decrease after the ESDE due to the decrease in RCS temperature and the corresponding RCS volume contraction. Pressure may decrease to hot leg temperature saturation pressure depending on the magnitude of the RCS cooldown.

Pressurizer Level (*Figure 7-10*)

Pressurizer level will decrease due to lower RCS temperature after the Reactor Trip. For large excess steam demands the pressurizer may empty completely before inventory control can be regained.

Reactor Vessel Level (*Figure 7-11*)

Void formation can occur in the RVUH for ESDE or other overcooling events which are large enough to cause the pressurizer to empty. When the pressurizer empties, pressurizer heaters are deenergized and voids begin forming in

the RVUH. The RCS pressure decreases until it equals the saturation pressure associated with the hottest point in the RCS (which is the RVUH). Saturated liquid in the RVUH will continue to flash to steam until the affected steam generator experiences dryout and RCS repressurization is established. For the most severe excess steam demand events the rate of RCS cooldown can be severe enough so that RVUH voids are formed before the pressurizer empties.

Steam Generator Pressure (*Figures 7-12 and 7-13*)

Following an ESDE, the pressure in the affected steam generator will decrease due to the decrease in resistance caused by the break. The pressure in the unaffected steam generator will initially increase after the MSIS and then decrease as RCS temperature decreases. If the cause of the ESDE is located downstream of the MSIVs, the pressure in both steam generators will equalize after an MSIS.

Steam Generator Level (*Figures 7-14 and 7-15*)

Following an ESDE, the level in both the affected and unaffected steam generators will initially increase due to swell and then decrease, as the feedwater level control system will not be able to keep up with steam flow. Following an MSIS the level in both steam generators will increase if the ESDE occurred downstream of the MSIV. If the ESDE occurred upstream of the MSIV, the level in the affected steam generator will continue to decrease while the level in the unaffected steam generator increases. If the event is a feedwater line break, steam generator water level decreases in the affected steam generator without an initial swell [until the feedring is uncovered] while the unaffected steam generator level will usually remain relatively constant.

FIGURE 7-6
REPRESENTATIVE MSLB OUTSIDE CONT. UPSTREAM OF MSIV
CORE POWER

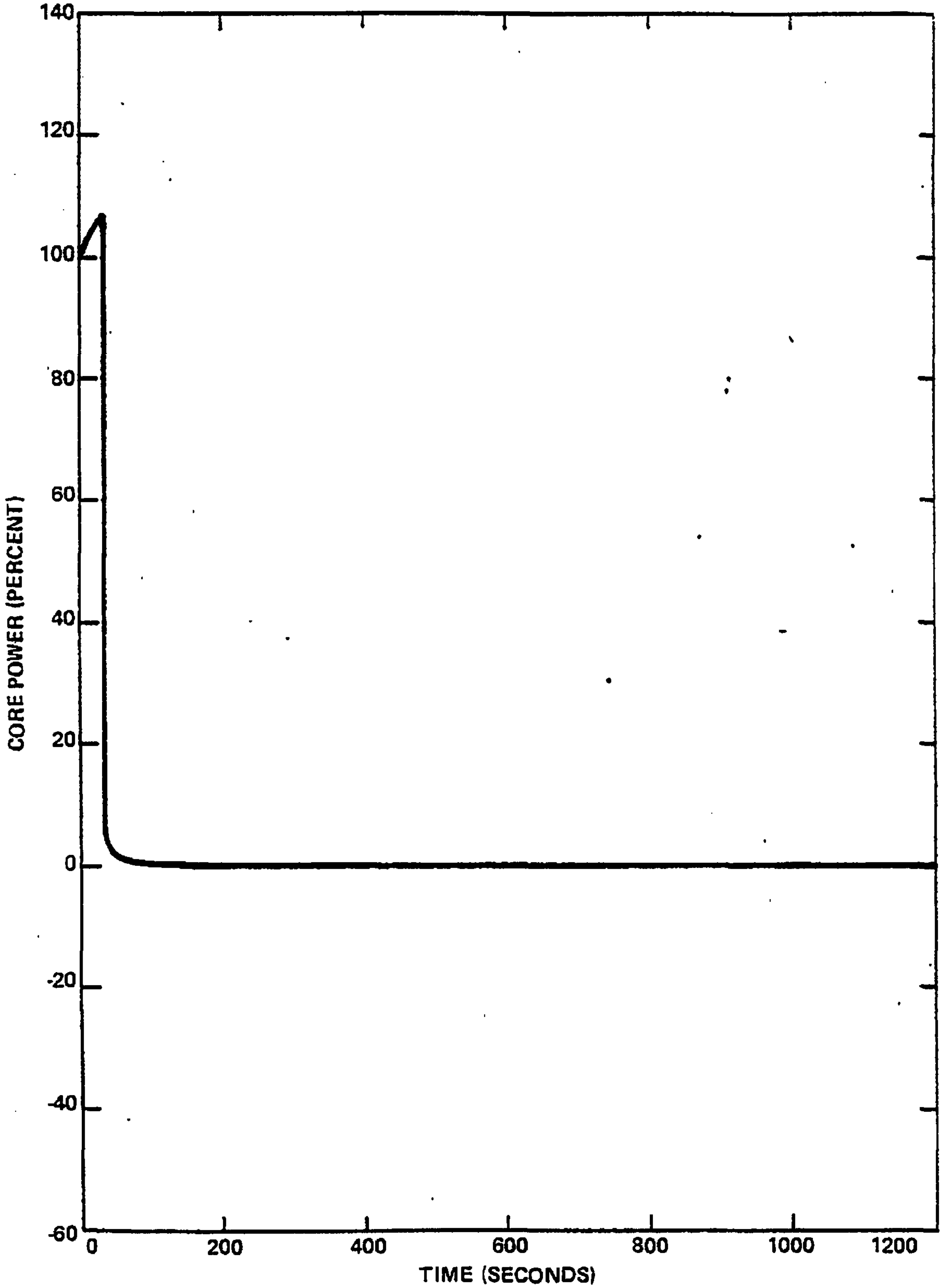


FIGURE 7-7

REPRESENTATIVE MSLB OUTSIDE CONT. UPSTREAM OF MSIV
UNAFFECTED LOOP RCS WIDE RANGE TEMPERATURES

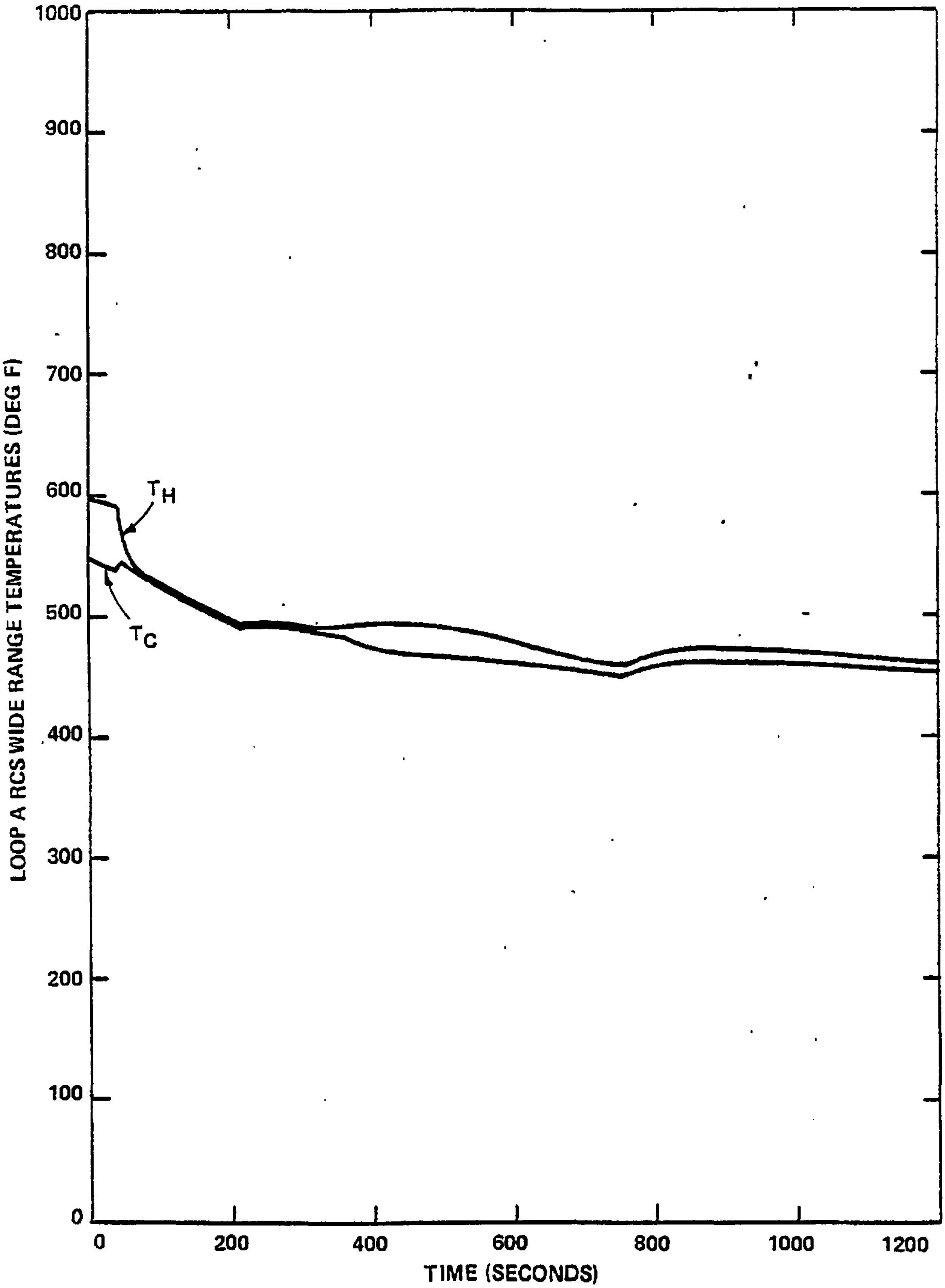


FIGURE 7-8

REPRESENTATIVE MSLB OUTSIDE CONT. UPSTREAM OF MSIV
AFFECTED LOOP RCS WIDE RANGE TEMPERATURES

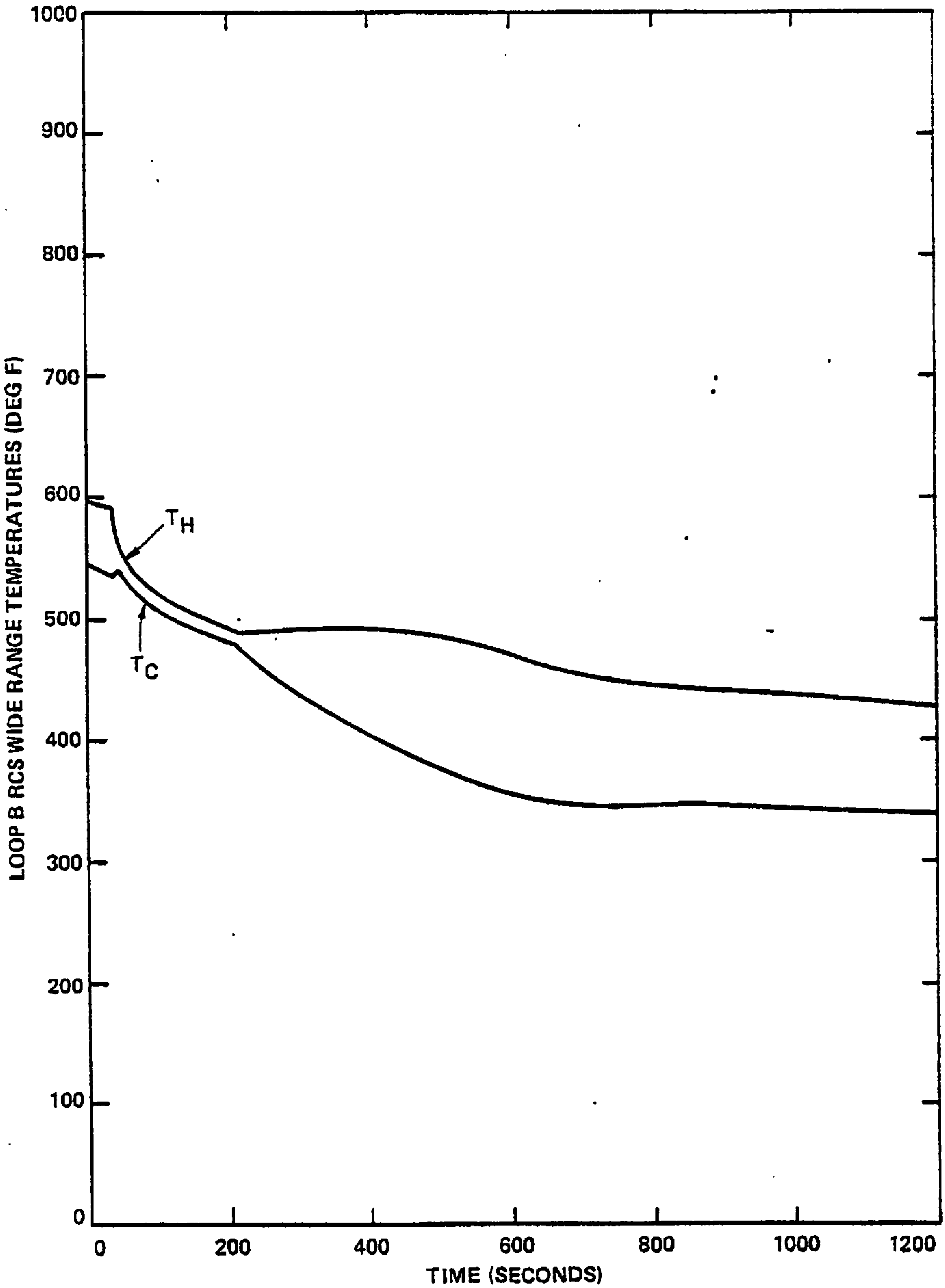


FIGURE 7-9

REPRESENTATIVE MSLB OUTSIDE CONT. UPSTREAM OF MSIV
PZR WIDE RANGE PRESSURE

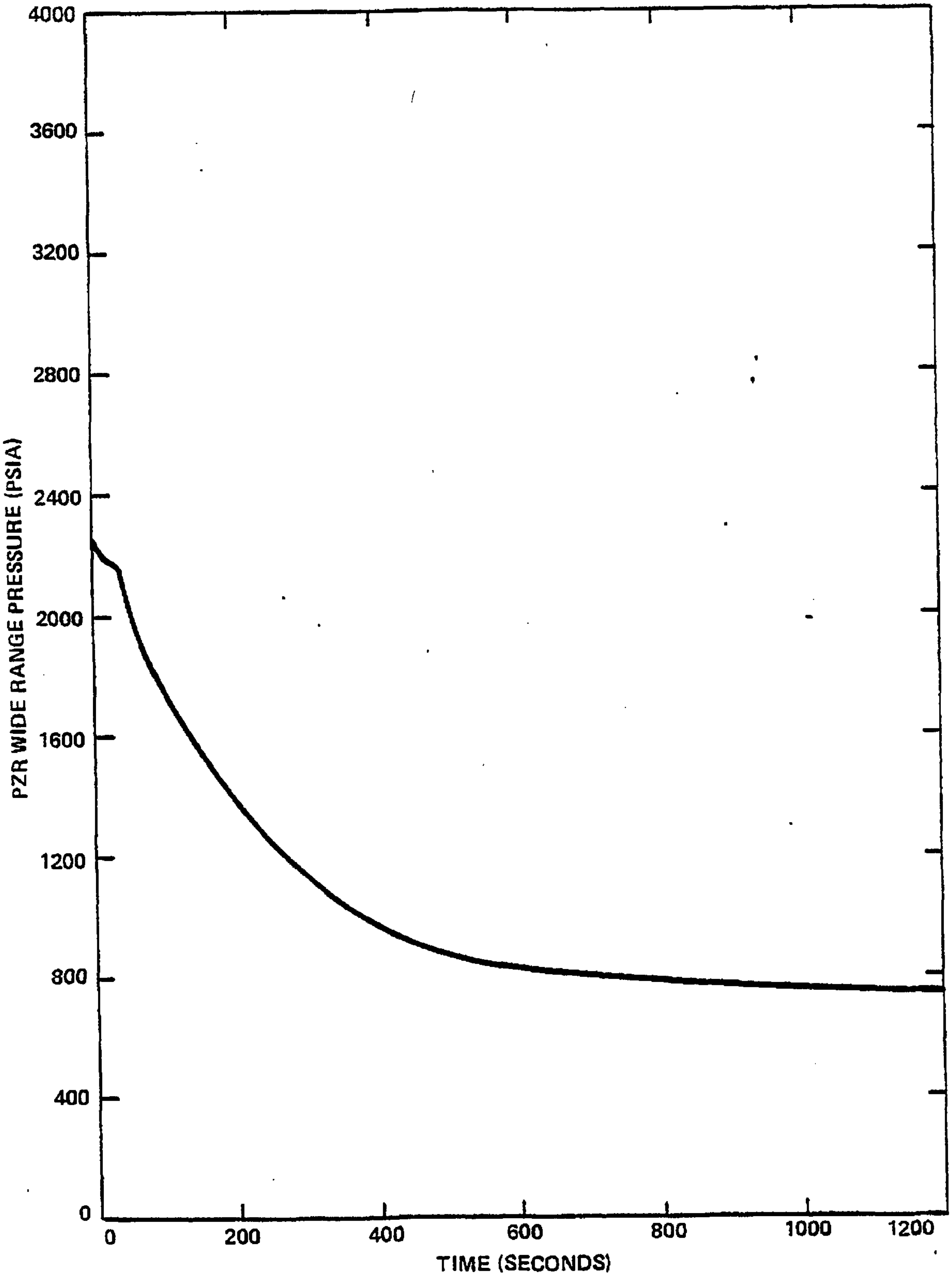


FIGURE 7-10

REPRESENTATIVE MSLB OUTSIDE CONT. UPSTREAM OF MSIV
PZR LEVEL

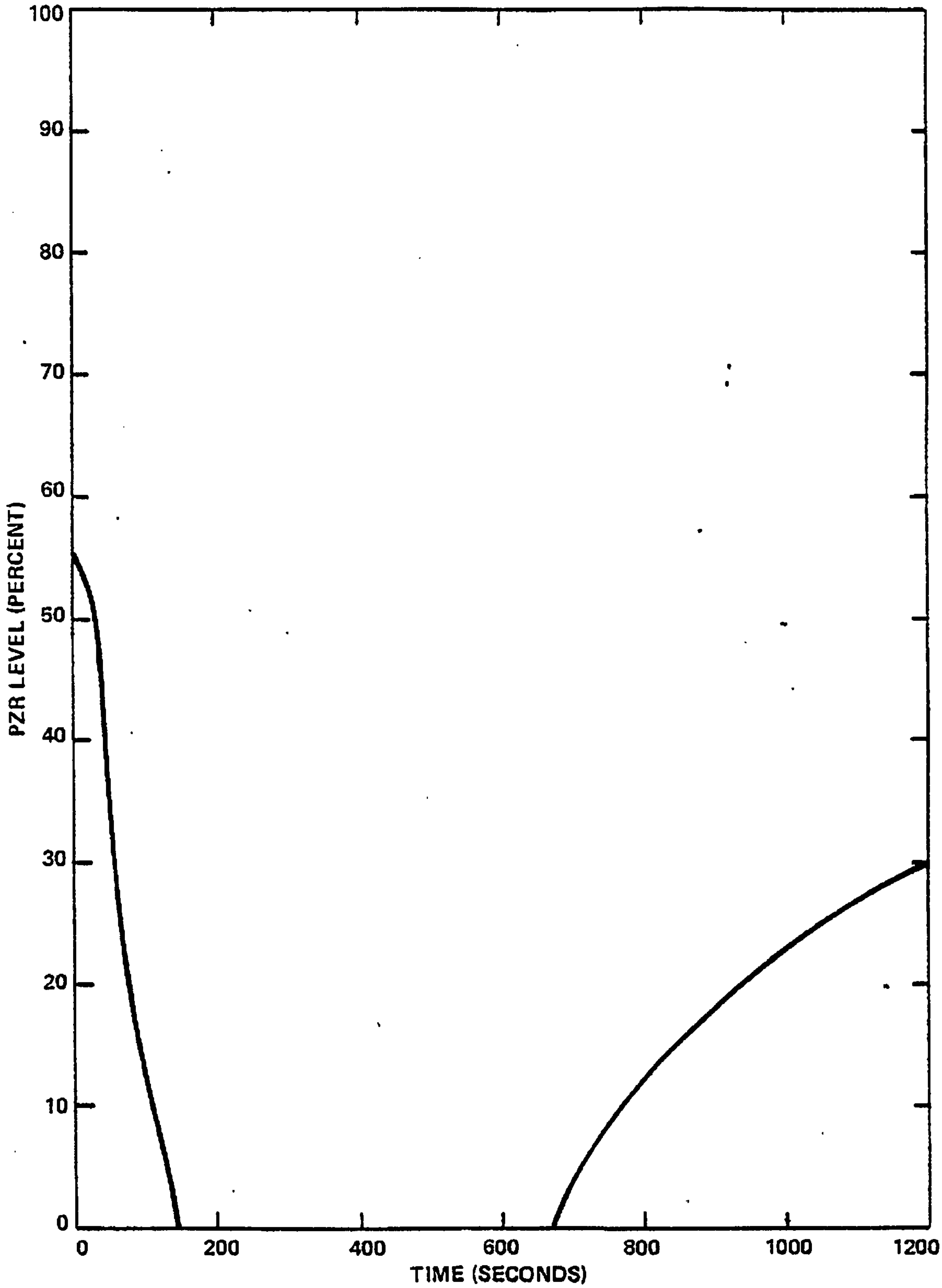


FIGURE 7-11

REPRESENTATIVE EXCESS STEAM DEMAND EVENT
REACTOR VESSEL LIQUID VOLUME vs TIME

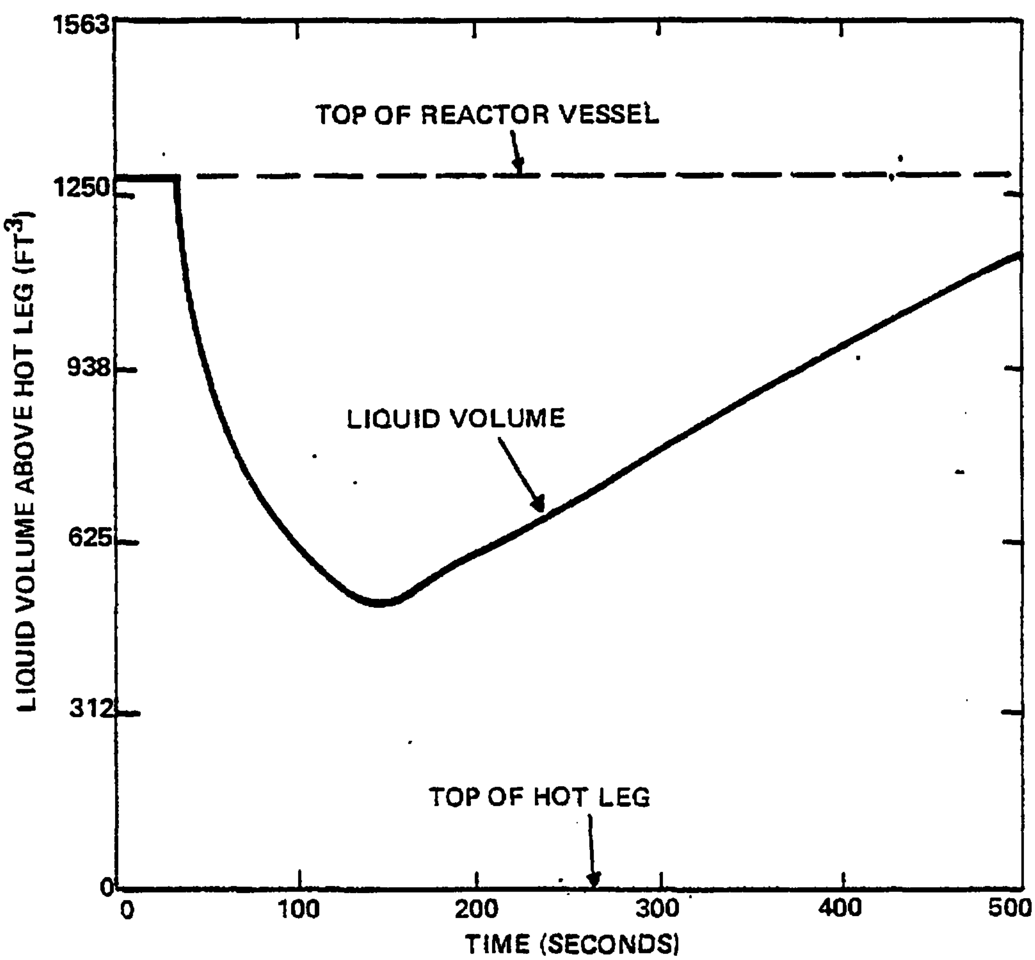


FIGURE 7-12
REPRESENTATIVE MSLB OUTSIDE CONT. UPSTREAM OF MSIV
UNAFFECTED STEAM GENERATOR PRESSURE

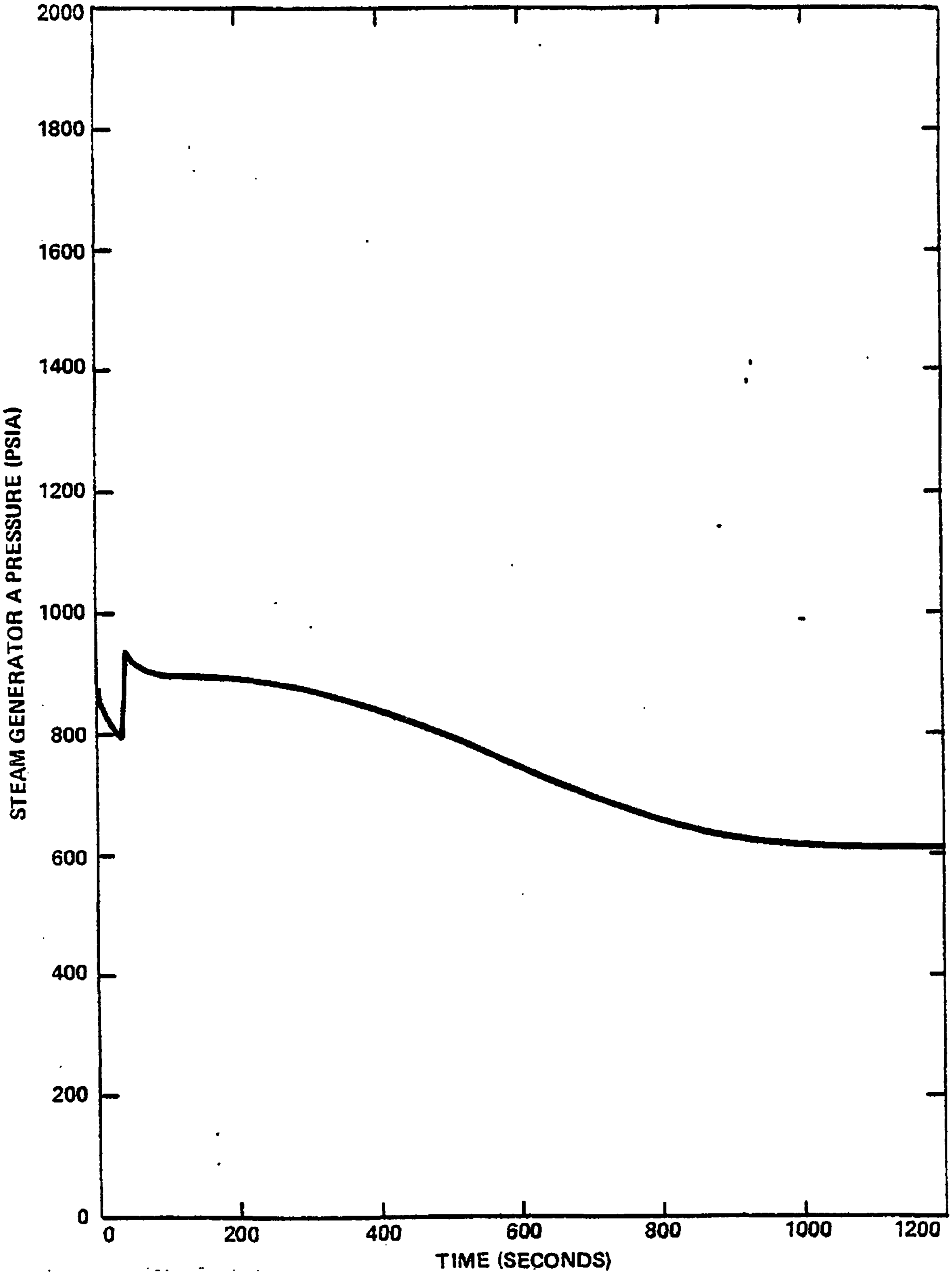


FIGURE 7-13
REPRESENTATIVE MSLB OUTSIDE CONT. UPSTREAM OF MSIV
AFFECTED STEAM GENERATOR PRESSURE

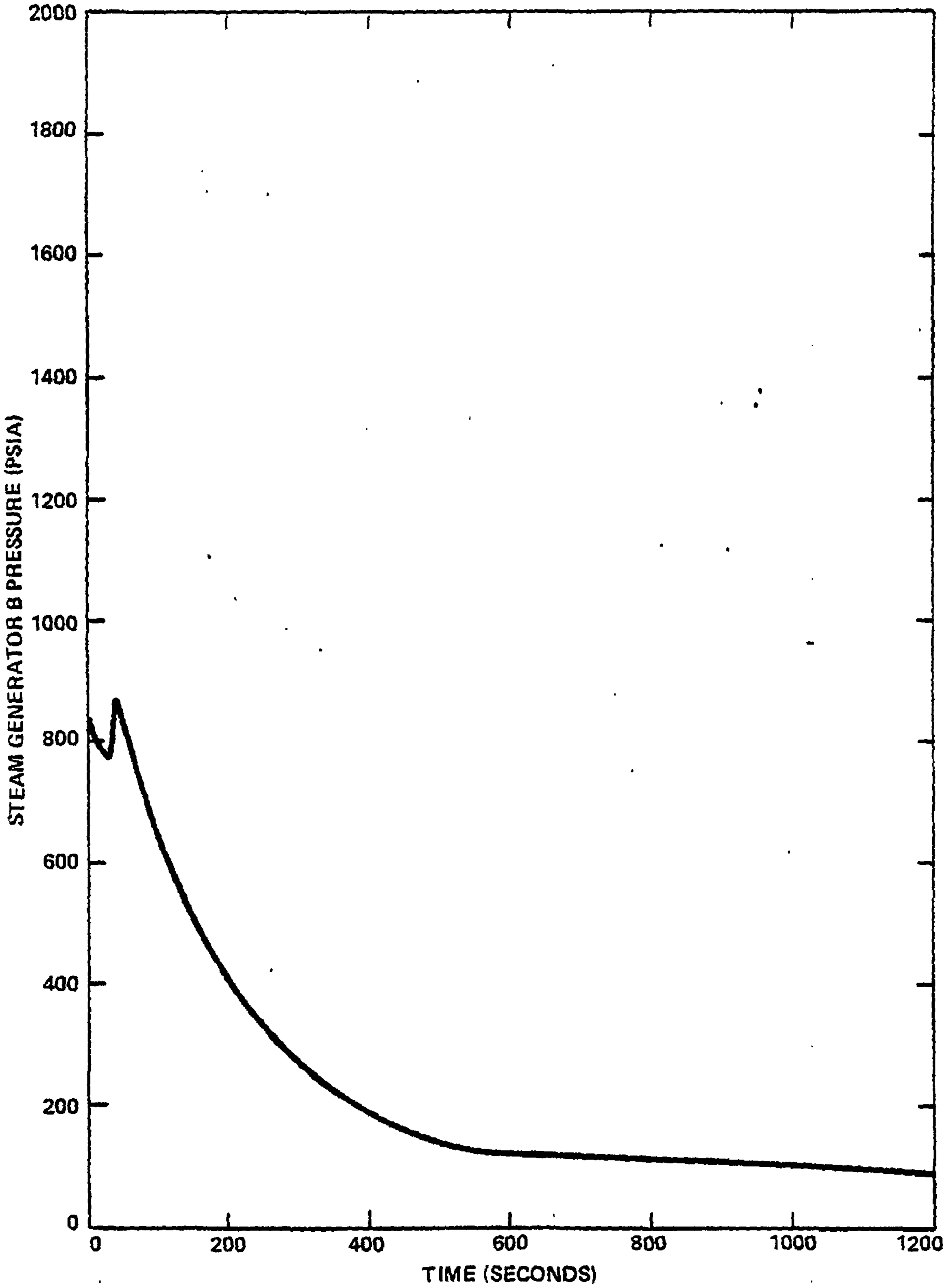


FIGURE 7-14

REPRESENTATIVE MSLB OUTSIDE CONT. UPSTREAM OF MSIV
UNAFFECTED STEAM GENERATOR WIDE RANGE LEVEL

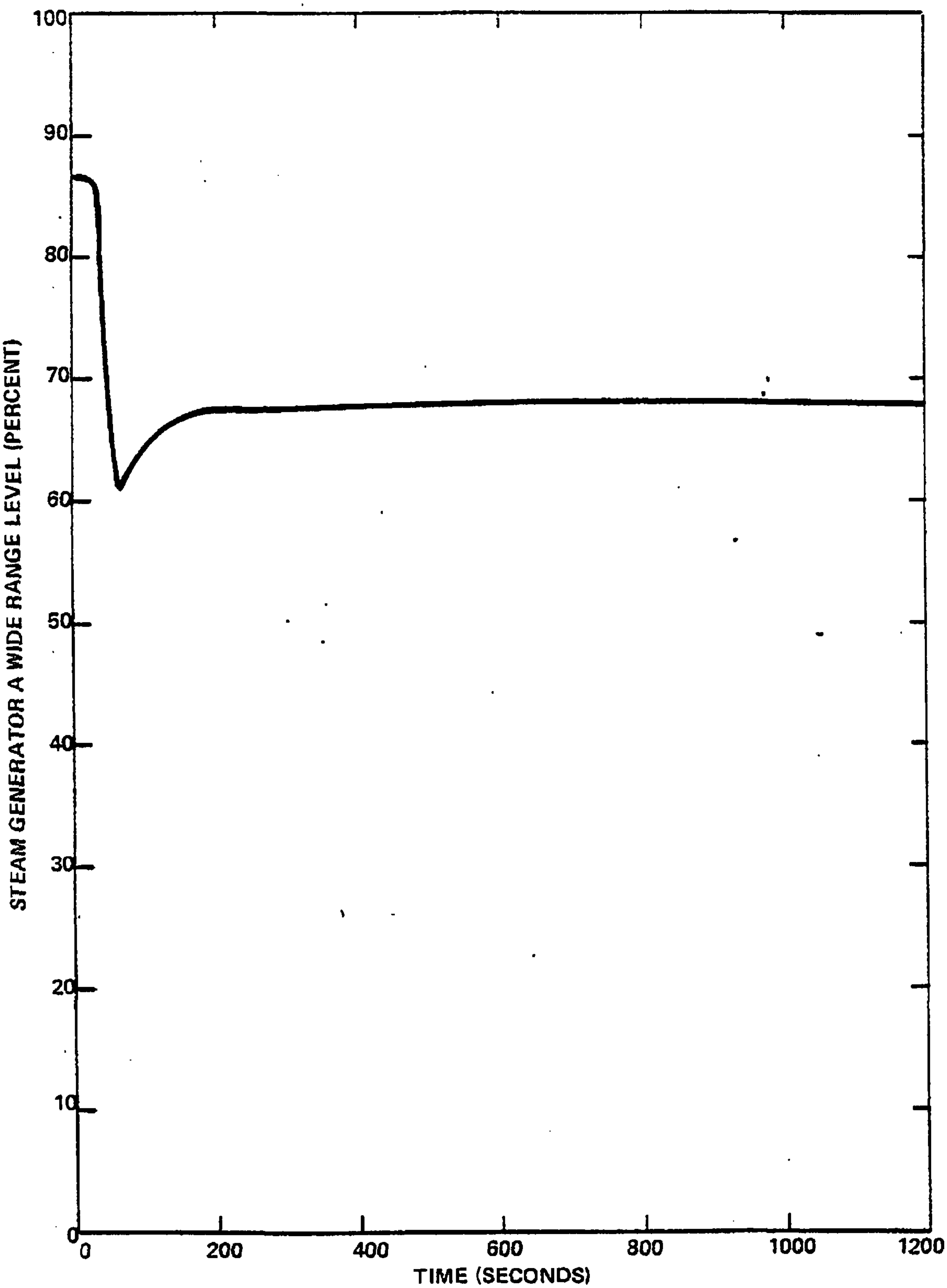
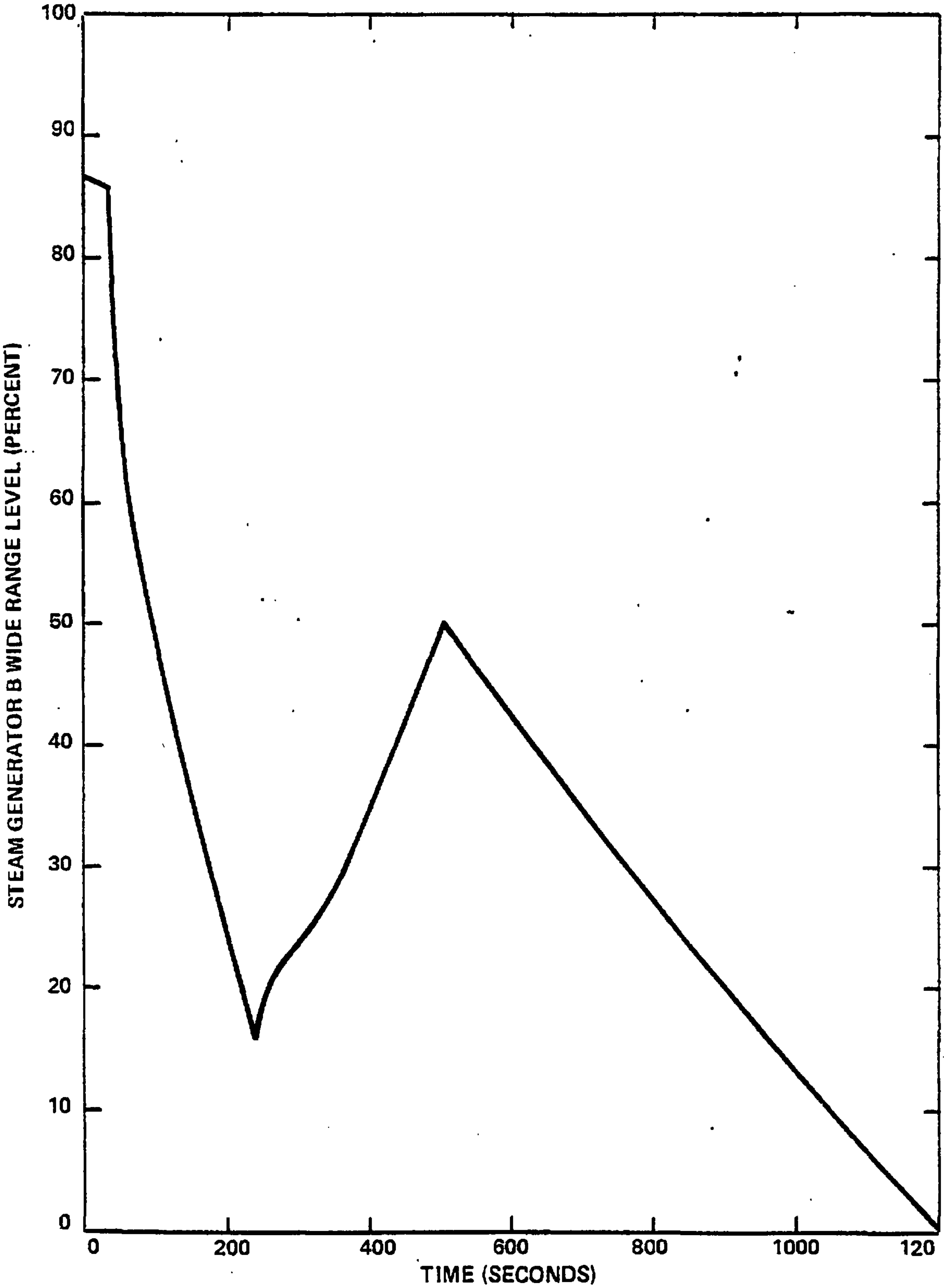


FIGURE 7-15

REPRESENTATIVE MSLB OUTSIDE CONT. UPSTREAM OF MSIV
AFFECTED STEAM GENERATOR WIDE RANGE LEVEL



Guideline Strategy and Information Flow

Figure 7-16 provides a summary description of the ESDE Recovery Guideline's strategy and information flow. Prior to implementing the actions provided in the ESDE Recovery Guideline, the operator would have performed the standard post trip actions and diagnosed the event. The first actions encountered in the ESDE Recovery Guideline require a verification that these actions have taken place and require the operator to use the safety function status check to confirm that the plant is recovering. The next steps provide instructions on establishing those conditions necessary for effectively recovering from an ESDE. The operator makes an identification of the affected steam generator and attempts to isolate it.

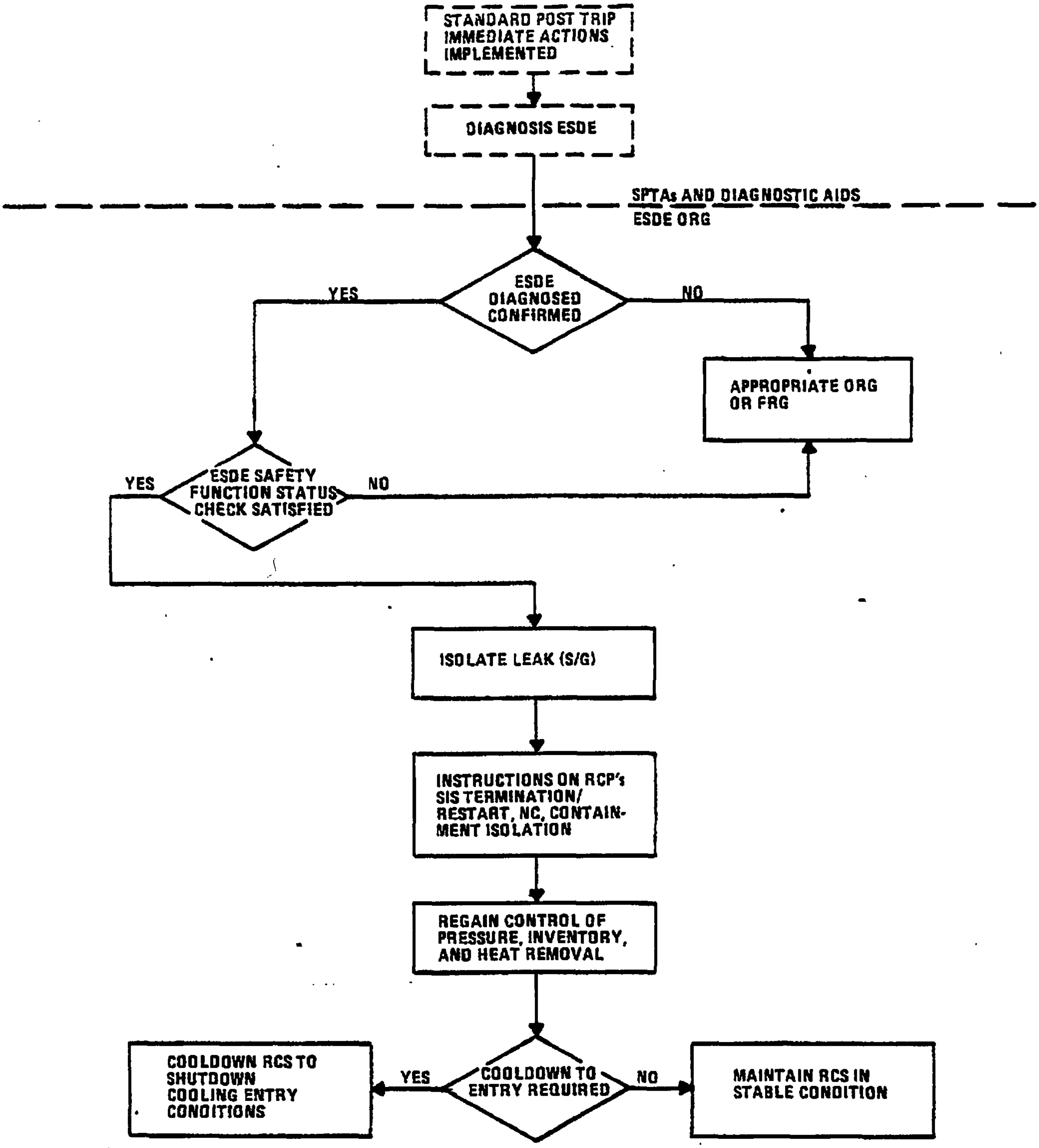
The next group of steps provide instructions on SIS, stabilizing RCS temperature, and containment isolation. These steps are illustrated on Figure 7-16.

Following these instructions, the flow of information proceeds towards regaining control and stabilizing RCS pressure, inventory and heat removal. The necessity of a cooldown is determined next. Once this is done the flow of information breaks into two paths. One path addresses maintaining plant conditions while the other path provides information on performing a plant cooldown.

A more detailed chart illustrates the recovery guideline strategy and lists the guideline steps which correspond to each strategy objective. Refer to Figure 7-19.

FIGURE 7-16

EXCESS STEAM DEMAND EVENT RECOVERY STRATEGY CHART



Bases Operator Actions

The operator actions are directed toward determining the cause of the excess steam demand event (ESDE), isolating that part of the system, and returning the plant to a stable, controlled condition.

1. Execution of all standard post trip actions is verified. This assures that all safety functions have been initially attended to.

2. The diagnosis of an Excess Steam Demand Event should be confirmed using [the Break Identification Chart (Figure 7-2), and the safety functions must be verified by comparing control board parameters to the acceptance criteria in the Safety Function Status Check. In particular, the operator should note the status of RCS subcooling and containment and steam plant activity. These parameters provide a means of discriminating between ESDEs and LOCAs/SGTRs. For ESDEs, neither steam plant or containment activity monitors should be alarming. ESDEs which occur in plants with existing S/G tube leakage, or which cause a concurrent S/G tube rupture, may result in steam plant or containment activity alarms, depending on the location of the event. For most LOCAs, containment activity monitors may be alarming but steam plant activity monitors should not be alarming. For an SGTR, steam plant activity monitors may be alarming but containment activity monitors should not be alarming. These actions ensure the proper guideline is being used to mitigate the effects of an ESDE and that all safety functions are being satisfied].

3. Sample both steam generators for activity. This will assist in confirming the diagnosis made in step 2.

4. If the Break Identification Chart indicates that an SGTR or an LOCA has occurred, then the ESDE Recovery Guideline is exited and, the actions of the proper guideline are implemented. This allows the operator to switch to the proper guideline for those events similar to ESDE which may be occurring. LOCAs, ESDEs, and SGTRs have similar initial symptoms and could be confused early in the event.

5. If the initial diagnosis of an ESDE is confirmed, then the operator continues with the actions of this guideline. If a correct diagnosis is not confirmed, then the operation is directed to implement the Functional Recovery Guideline. The Functional Recovery Guideline is functionally oriented and will ensure that all safety functions are attended to regardless of what event(s) is occurring.

6. Steps 6 and 7 contain guidance regarding the RCP operating strategy for an ESDE. (Figure 7-17). A generic RCP trip strategy has been developed which results in the tripping of all four RCPs for depressurization events determined to be LOCAs, but allows the continued operation of two RCPs (in opposite loops) for diagnosed, non-LOCA, depressurization events. For undiagnosed events, where the Functional Recovery Guideline is implemented, the RCP trip strategy is identical to that followed in the LOCA guideline.

   There are two significant operational aspects regarding the RCP trip scheme for an ESDE. The first results in the operator tripping two RCPs (in opposite loops) if pressurizer pressure decreases to less than [1300 psia] following an SIAS. This may occur in the Standard Post Trip Actions and, in this case, the operator would simply verify that two RCPs (in opposite loops) have been tripped. If the operator cannot confirm that an ESDE has occurred, and the Functional Recovery Guideline is implemented, then the RCP trip strategy is identical to that followed in the LOCA guideline (i.e., if in the FRG and pressurizer pressure decreases to less than [1300 psia] following an SIAS, then all four RCPs must be tripped). If the depressurization event can be diagnosed and is determined to be other than an LOCA (i.e., ESDE or SGTR), then only two RCPs (in opposite loops) are required to be tripped. This gives the operator maximum flexibility in plant control (because a normal plant cooldown can be performed) while still ensuring a conservative approach to event recovery.

Figure 7-17a
RCP TRIP STRATEGY FOR ESDE

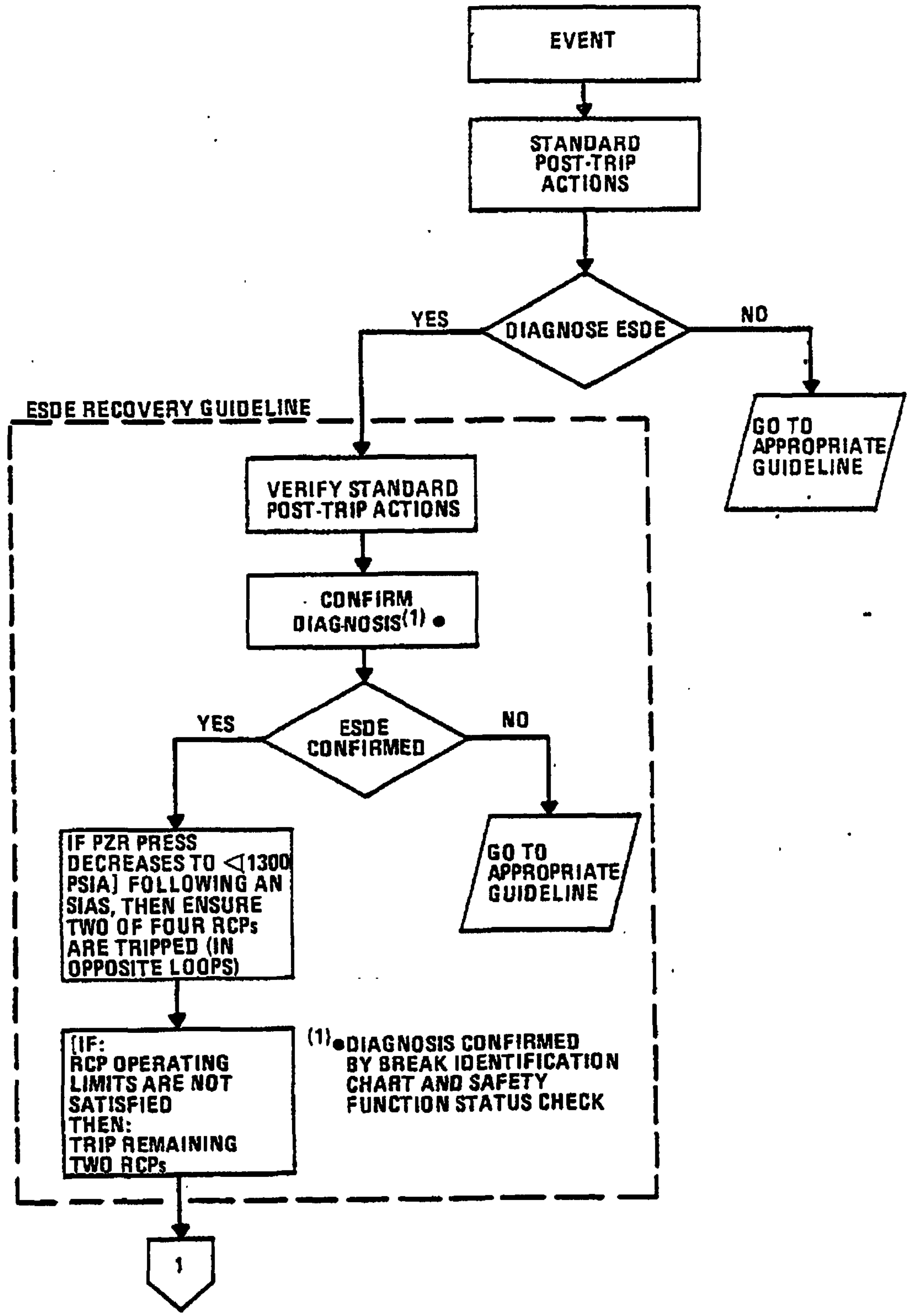
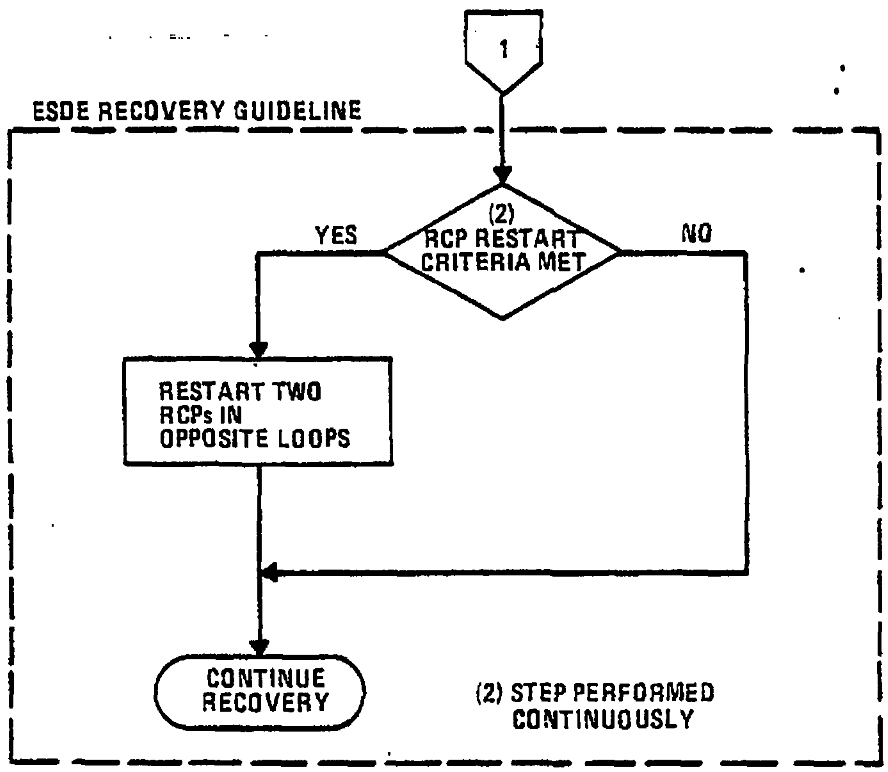


FIGURE 7-17b


ESDE RECOVERY GUIDELINE
1
(2)
RCP RESTART
CRITERIA MET
YES
NO
RESTART TWO
RCPs IN
OPPOSITE LOOPS
CONTINUE
RECOVERY
(2) STEP PERFORMED
CONTINUOUSLY

7. [The second aspect of the RCP operating strategy results in tripping the final two RCPs if RCP operating limits are not satisfied. The RCPs may be operating in a pressure-reduced RCS and, in some cases, degraded containment conditions are also possible. This could result in the loss of vital RCP auxiliaries. The operator must continuously monitor RCP operating limits (e.g., temperatures, seal flow, oil pressures, NPSH, motor amperage, vibration) and trip the remaining two RCPs if concerned about RCP operating equipment integrity. Plant specific RCP operating limits should appear in this step, either directly or, by referencing the applicable operating instruction].

8. The operator is required to continually verify that all relevant safety functions are being satisfied by comparing control board parameters to the criteria of the Safety Function Status Check. This ensures that safety functions are being satisfied and the core is being adequately cooled.

9. If all of the safety functions from the Safety Function Status Check are satisfied, then this procedure is adequately mitigating the effects of the ESDE which is occurring. Therefore, the implementation of the remaining actions of this guideline is continued.

   If the safety functions are not being satisfied, then the procedure is not adequately mitigating the occurring event. The operator is required to leave the ESDE recovery guideline and implement the Functional Recovery Guideline. This guideline is functionally oriented and will ensure all safety functions are attended to regardless of what event(s) is occurring.

10. Identify the affected steam generator by comparison of steam pressures, cold leg temperature differences and steam generator level. If the ESDE is not isolable (e.g., a break inside containment will still be producing steam flow after the MSIVs are shut), the steam generator with the reduced loop T_c, lower steam pressure, and lower steam generator level is the affected steam generator. These differences between affected and

unaffected steam generators will be more pronounced after MSIS isolation. If the ESDE is downstream of the MSIVs and the MSIS occurs, both steam generators' pressure and loop temperatures should approach approximately the same values and then start to increase.

11. Isolate the affected steam generator to stop the uncontrolled plant cooldown and to stabilize the plant.

    The affected steam generator is isolated as follows:

    a) the main steam isolation valve is closed and the main steam isolation valve bypass valve is verified closed
    b) the atmospheric dump valve(s) on the affected steam generator is verified closed
    c) feedwater isolation valves are closed
    d) steam generator blowdown valves are closed
    e) vent and drain valves are closed
    f) [other plant specific information should be inserted here].

12. If both steam generators are found to be affected, then isolate the steam generator with the worse ESDE, if it can be determined, and attempt to maintain RCS heat removal capability via one steam generator. This action is designed to mitigate the uncontrolled cooldown and ready the plant for event recovery.

13. Significant ESDEs may reduce RCS temperature by as much as [250°F] due to increased RCS heat removal. Due to the effects of the moderator temperature coefficient, this cooldown adds positive reactivity to the core and can possibly result in a return to criticality subsequent to the reactor trip. To ensure that the core remains subcritical, it is necessary to maximize RCS boration during the initial stages of severe ESDEs. The charging and safety injection systems should accomplish this automatically. An ESDE may result in the actuation of safety injection. If the transient causes pressurizer level to go below [35"], then [all available charging pumps should be operating and] the SIS pump(s) should be injecting water into the RCS per Figure 7-3 (unless SIS termination criteria are met).

In attempting to maximize RCS boration and to restore pressurizer pressure and level, the safety injection and charging systems should be operating. The following steps will assist in ensuring proper system operation:

a) verify electrical power to valves and pumps
b) verify correct SIS valve lineup (if misaligned)
c) verify other necessary auxiliary systems operational
d) start idle SIS and charging pumps

It must be noted, however, that charging and safety injection can result in excess RCS inventory, possible filling of the pressurizer to a solid condition, and a PTS concern upon RCS heat up, fluid expansion, and subsequent RCS pressure excursion. Operators must be aware of these concerns and terminate the SIS when termination criteria are met.

14. If an SIAS has been initiated, and the SIS is operating, then it must continue to operate at full capacity until SIS termination criteria are met. Termination of SIS should be sequenced by stopping one pump at a time while observing the termination criteria. Throttling of HPSI flow is permissible if it is feasible. SIS termination criteria are:

a) RCS is at least [20°F] subcooled (Figure 7-1). Establishing [20°F] of subcooling ensures the fluid surrounding the core is subcooled and provides margin for reestablishing flow should the [20°F] of subcooling deteriorate when SIS flow is secured. Voids may exist in some parts of the RCS (e.g., reactor vessel head), but these are permissible as long as core heat removal is maintained.

b) Pressurizer level is greater than [100"] and not decreasing. A pressurizer level greater than [100"] and not decreasing, in conjunction with criterion a) above, is an indication that RCS inventory control has been established.

c) At least one steam generator is available for removing heat from the RCS. Steam generator availability requires having feed flow and steam flow, which are indications that primary to secondary heat removal is possible.

d) [The RVLMS indicates the core is covered. An indication of core coverage, in conjunction with the above, serves as an additional indication that RCS inventory control has been established.]

15. If the criteria of step 14 cannot be maintained, then the SIS pumps must be restarted in order to satisfy the criteria.

16. RCS temperature is stabilized (i.e., no heatup or cooldown) using the turbine bypass system (the preferred method if the turbine bypass system and the main condenser are available) or the atmospheric steam dump valves to control RCS temperature. This action leads to control of RCS and core heat removal in order to preclude heatup and repressurization of the RCS for PTS considerations and to minimize or secure any further cooldown of the RCS in excess of Technical Specification limits.

17. The operator verifies that containment is isolated at the appropriate automatic setpoints if containment conditions require. Each plant should develop criteria for containment isolation to be identified in the procedure. Operators should be alert to the loss of auxiliaries to the containment (in particular RCP cooling water) which may occur with containment isolation. Reestablishing letdown should also be considered if it is available. This will enable the operator to better control RCS inventory during a possible RCS heatup and subsequent fluid expansion. This action can minimize the possibility of PTS.

18. Before terminating containment spray, the operator must verify that containment pressure is below [7 psig]. Termination may be useful to recover from the ESDE since continuous use of the containment sprays may impact the operation of equipment inside containment.

19. Pressurizer heaters and main (preferred), or auxiliary spray, are operated manually to control pressurizer pressure within the limits of Figure 7-1. As a result of the initial transient, the RCS may be outside the limits of Figure 7-1. The operator must restore the RCS to within these limits. This action attempts to establish RCS pressure control, allows for adequate cooling and minimizes the PTS concern.

20. The PLCS is verified to be automatically maintaining or restoring pressurizer level. If not, charging and letdown are operated manually to ensure pressurizer level is being maintained. This action is designed to reestablish RCS inventory control.

21. Steam generator level is maintained or restored in the unisolated steam generator. This provides a means of maintaining core cooling and, if necessary, cooling down the reactor.

22. The plant must be maintained in a stable condition based on auxiliary systems availability. One concern the operator must have is the remaining supply of feedwater. If the available condensate appears to be marginally adequate, a plant cooldown within Technical Specification Limitations should be commenced immediately in order to avoid running out of existing condensate before the shutdown cooling system can be placed into operation. The condensate required may be determined from Figures 7-4 and 7-5. The cooldown is performed according to steps 23 through 37.

23. The plant should be borated per Technical Specification limits for reactivity control purposes. If letdown is not available, it may not be possible to borate the RCS to the cold shutdown RCS boron concentration prior to commencing the cooldown if there is limited makeup space available in the pressurizer. If this is the case, the operator should borate the RCS to the minimum shutdown margin corresponding to T_c (per Technical Specifications). During the cooldown, as RCS shrinkage provides more space in the pressurizer, the operator should borate to maintain the minimum shutdown margin until the cold shutdown boron concentration is achieved. Note that if a 75°F/hr. cooldown rate is maintained, charging capacity [3 pumps running] will not be able to keep pressurizer level constant during the initial stages of the cooldown. Therefore, pressurizer level will lower and additional space will be available in the RCS for boration.

24. The preferred method of cooling an isolated steam generator is to start one RCP in each loop. Forced reactor coolant circulation through an isolated steam generator will provide adequate heat transfer to maintain the isolated steam generator's temperature approximately the same as the operating steam generator's temperature.

    If all RCPs have been stopped, then operation of two RCPs (in opposite loops) should be attempted to ensure continued forced circulation of coolant through the core, cooling of the RV head region, provides the capability for the normal mode of pressurizer spray, condenses RCS steam voids, and removes non-condensible gases from the S/G tube bundle. Furthermore, this action enhances the strategy to obtain an uncomplicated cooldown, since a forced circulation cooldown is preferred to a natural circulation cooldown whenever possible during a recovery from an ESDE. However, only one reactor coolant pump in each loop should be operated to minimize heat input to the RCS.

    Determine whether RCP restart criteria are met by the following:

    a) The unaffected steam generator (or least affected, if both steam generators are affected) is available for removing heat from the RCS. A steam generator having feed flow and removing heat from the

RCS is an indication that primary to secondary heat removal is being maintained.

b) Pressurizer level is greater than [200"] and not decreasing. A pressurizer level above [200"] provides the operator with a margin for maintaining plant control during an ESDE. A level of [200"] provides a margin above the heaters to offset the possible pressurizer level decrease due to loop shrinkage and/or steam void condensation.

c) The RCS is greater than or equal to [20°F] subcooled. A subcooled condition, taken in conjunction with (b) above, indicates that inventory control has been established.

d) [All plant specific RCP operating criteria should be satisfied before the RCPs are restarted to prevent damage to RCPs. Following automatic or operator initiated containment isolation, reinstatement of component cooling water to the RCPs should be considered in order to ensure adequate RCP cooling.]

25. Upon restarting two RCPs in opposite loops, pressurizer level and pressure may decrease due to loop shrinkage and/or void condensation. It is possible that this action will drain the pressurizer. Steam voids present in the reactor vessel will condense upon restarting RCPs. [The RVLMS should be monitored for the trending of reactor vessel liquid level. This trending information may be correlated to pressurizer level decrease.] RCP operation with a drained pressurizer may continue provided certain actions are taken and certain criteria are satisfied.

The following constitute the actions to be taken, and the criteria to be satisfied, when restarting RCPs:

a) Start one RCP in each loop.

b) [Ensure proper RCP operation by monitoring RCP amperage and pump NPSH. NPSH is determined by pressurizer pressure and corresponding T_c on Figure 7-1].

c) Operate HPSI pumps, charging pumps, and letdown as necessary to maintain pressurizer level [100 to 200"]. This action will ensure that pressurizer heaters remain covered but will minimize the amount of water added to the RCS.

26. If all RCP operation is terminated and when inventory and pressure are controlled, then natural circulation is monitored by heat removal via the unaffected steam generator. Natural circulation flow should occur within 5-15 minutes after the RCPs were tripped if there is adequate inventory in the RCS.

The RCS temperature response during natural circulation will be slow (5-15 minutes) as compared to a normal forced flow system response time of 6-12 seconds, since the coolant loop cycle time will be significantly larger.

When single phase natural circulation flow is established in at least one loop, the RCS should indicate the following conditions:

a) Loop ΔT ($T_H - T_c$) less than normal full power ΔT
b) Cold leg temperatures constant or decreasing
c) Hot leg temperatures stable (i.e., not steadily increasing) or decreasing steadily
d) No abnormal differences between T_H RTDs [and core exit thermocouples]. Hot leg RTD temperature should be consistent with the [core exit thermocouples]. Adequate natural circulation flow ensures that [core exit thermocouple] temperatures will be approximately equal to the hot leg RTDs temperature within the bounds of the instrument's inaccuracies. An abnormal difference between T_H [and the CETs] is greater than [10°F].

Natural circulation is governed by decay heat, component elevations, primary to secondary heat transfer, loop flow resistance, and voiding. Component elevations on C-E plant are such that satisfactory natural circulation decay heat removal is obtained by fluid density differences between the core region and the steam generator tube sheet.

27. If the criteria listed in step 26 are not met, then natural circulation in the RCS is not effectively transferring heat from the core to the steam generators. Both RCS and Core Heat Removal Safety Functions may become jeopardized if any of the above criteria continue to be violated. Operators should ensure that RCS pressure and inventory, and S/G steaming and feed, are being controlled properly to prevent violation of a safety function, which would require a transfer from this guideline to the Functional Recovery Guideline.

28. The RCS cooldown should be commenced by performing steps a) or b) below:

    a) The preferred method for cooling down the RCS is by feeding the steam generators with [main or auxiliary] feedwater and discharging steam using the turbine bypass system. This method can only be implemented if the condenser is available.

    b) If the condenser is not available, an RCS cooldown should be commenced using [main or auxiliary] feedwater and dumping steam using the atmospheric steam dump valves. Using atmospheric dump valves to cooldown a steam generator with a leaking tube(s) is undesirable due to the releases of radioactivity to atmosphere.

    The cooldown proceeds to at least [300°F] at a rate within Technical Specification Limits.

29. Depressurize the RCS to at least [300 psia] while maintaining the RCS pressure and temperature within the acceptable range of the P/T limit curve (Figure 7-1). This will ensure adequate core cooling but allow for operator actions (such as termination of HPSI or charging flow) which prevent excessive repressurization of the RCS and may lead to a pressurized thermal shock (PTS) concern. The operator has two basic methods to maintain RCS pressure and temperature within the acceptable range of the P/T curve. These methods are (1) control the RCS heat removal (i.e., cooldown rate) and (2) control RCS pressure using pressurizer heaters and spray, charging and letdown, HPSI pumps and/or [PORVs].

The operator will choose which method, or combination of methods, is to be used based on existing plant conditions as no two events are likely to follow the same scenario. For example, if the main condenser were not available and the only method for RCS heat removal was the atmospheric dump valves, then the choice would be to remove RCS heat at the rate consistent with the atmospheric dump valve capacity within Technical Specification limits. On the other hand, if the main condenser is available, then the preferred method would be to control the RCS heat removal using the TBS at the cooldown rate specified per Technical Specification. RCS pressure would be controlled by using pressurizer heaters and spray to maintain RCS pressure within acceptable P/T curve limits. As many variables will exist, the operator must use judgement based on the existing plant conditions as to the best method to maintain the RCS within the desired P/T curve limits to minimize PTS concerns and provide for adequate core cooling.

30. The available condensate inventory should be monitored and replenished from available sources as necessary to continually provide a source for a secondary heat sink. Examples of alternate sources of condensate are non-seismic tanks, fire mains, lake water supplies, potable tanks, etc. Plant specific alternate sources of feedwater should be identified and cited in the procedure. The condensate required to either maintain the plant at hot standby or cooldown may be determined from Figures 7-4 and 7-5.

31. During a controlled cooldown and depressurization, the automatic operation of certain safeguard systems is undesirable. [If they have not already actuated, the setpoints of SIAS, CSAS, CIAS and MSIS should be manually reset (lowered) as the cooldown progresses to ensure that automatic engineered safeguards protection remains available until the RCS is cooled down and depressurized.]

32. The pressurizer level should be maintained [35 to 245"] throughout the cooldown by the following methods:

a) Preferentially, the pressurizer level is maintained by control of charging and letdown.

b) Operation of the HPSI pumps is the next order of priority for maintaining pressurizer level.

If the normal shutdown reference level is not maintained, a pressurizer level of [35 to 245"] along with RCS subcooling ≥ [20°F] should be maintained to avoid losing pressure control with the saturated bubble in the pressurizer. If the pressurizer level drops below the top of the pressurizer heaters, pressurizer heater operation will be interlocked off for overheating protection. A plant cooldown can be performed without a pressurizer level within the above preferred level indications as long as adequate primary pressure control is being maintained. However, pressurizer level should be brought back to normal as soon as possible.

Once the pressurizer water temperature varies from the normal hot standby temperature, the instrument indication on the normal pressurizer level channel will begin to deviate (i.e., decalibrate) from the true pressurizer level. At this time, the operator should use plant cooldown correction curves to determine the true pressurizer water level. A cold calibrated pressurizer instrument channel is provided. This channel can be used as a quick reference during the plant cooldown. The actual pressurizer water level during pressurizer cooldown will be between the level indicated on the cold calibrated channel (which reads low) and the level indicated on the hot calibrated channel (which reads high).

33. If the above actions fail to depressurize the RCS, then a void should be suspected. Any time it is found that voiding inhibits RCS depressurization to SCS entry pressure, when SCS operation is desired, then an attempt at elimination of the voiding should be made.

The operator should monitor for the presence of voids. Voiding in the RCS may be indicated by any of the following indications, parameter changes, or trends:

a) letdown flow greater than charging flow,

b) pressurizer level increasing significantly greater than expected while operating pressurizer spray,

c) [the RVLMS indicates that voiding is present in the reactor vessel],

d) [HJTC unheated thermocouple temperature indicates saturated conditions in the reactor vessel upper head]. A

e) If desired, a confirmation of the results obtained from the above, or a first check for voiding in the RCS, may be obtained by performing the following test. This test is a good indication of voiding for a closed RCS (i.e., no leaks). It may not be possible to perform every step of the voiding test due to system availability, loss of electrical power, etc. In all cases, the operators must determine the validity of the test based upon their knowledge of plant operation and system response. Pressurizer level and pressure must be stabilized prior to performing the following test in order to provide valid results.

i) Start an additional charging pump to demonstrate that pressurizer level responds as expected:

increase of [2 inches/min.] per charging pump (approximately)

ii) Activate pressurizer heaters and demonstrate that the pressurizer pressure instrumentation responds as expected:

increase of [15 psi/min] (approximately)

iii) Activate pressurizer spray and demonstrate that the pressurizer instrumentation responds as expected.

decrease of [26 psi/min] (approximately)

If pressurizer parameters meet the above criteria and subcooling is within the limits of Figure 7-1 then significant voiding does not exist. If pressurizer parameters do not meet the above criteria, then voiding is indicated.

34. If voiding should be eliminated, then proceed as follows:

a) Letdown is isolated or verified to be isolated to minimize further inventory loss,

b) The depressurization is stopped to prevent further growth of the void and, if required, the RCS is repressurized to ≥[20°F] subcooling,

c) Pressurizing and depressurizing the RCS within the limits of Figure 7-1 may condense the void. Pressurizing and the effect of filling the voided portion of the RCS with cooler fluid which will remove heat from the region. Subsequent depressurization and a repeating of this process several times will cool and condense the steam void. In the case of a void in the reactor vessel, the pressurization/depressurization on cycle will produce a fill and drain of the reactor vessel. The pressurization/depressurization cycle may be accomplished using pressurizer heaters and spray (preferred method) or the SIS/charging system (alternative method). Monitor pressurizer level [and the RVLMS] for trending of RCS inventory. This will assist the operator in assessing the effectiveness of void elimination.

d) If indications of unacceptable RCS voiding continue, and voiding is suspected to exist in the (isolated) steam generator tubes, then cool the (isolated) steam generator (by steaming or blowdown, and/or feeding) to condense the tube bundle void. This will be effective for condensing steam voids but will not have an effect on non-condensible gases trapped in the tube bundle. A buildup of non-condensible gases in the tube bundles will not hinder natural circulation even with a large number of the tubes blocked. This is due to the small amount of heat transfer area required for the removal of decay heat. Monitor pressurizer level for trending of RCS inventory. This will assist the operator in assessing the effectiveness of void elimination.

e) If indications of unacceptable RCS voiding continue, then voiding may be caused by non-condensible gases. [Operate the pressurizer vent and/or the reactor vessel head vent to clear trapped non-condensible gases.] Monitor pressurizer level [and/or the RVLMS] for trending of RCS inventory. This will assist the operator in assessing the effectiveness of void elimination.

35. When SCS entry conditions (RCS pressure ≤ [300 psia] and RCS T_H ≤ [300°F] are established, the SCS is placed in service.

36. The safety injection tanks must be vented or drained, or their discharge valves shut at an RCS pressure of [250 psia] to prevent the nitrogen cover gas from discharging into the RCS when the RCS pressure is reduced.

37. [LTOP protection is instituted below 275°F to protect the primary pressure boundary from low temperature brittle fracture.]

Safety Function Status Checks

Figure 7-18 provides the bases for the ESDE Safety Function Status Check. The Safety Function Status Check is designed to ensure that the operator is using the correct procedure, and the actions of that procedure are satisfying all relevant safety functions and maintaining adequate core cooling.

The safety function status check provides a systematic approach to determine if the ESDE Recovery Guideline is appropriate and, more importantly, if the plant condition is satisfactory. Safety functions have been used throughout the guideline system as a structure for storing and using operational information. When the plant is in a normal condition each safety function can be explicitly shown to be satisfied. For example, inventory control can be demonstrated by conducting simple tests with charging and pressurizer spray and heaters. The safety function status check acceptance criteria for inventory control when the plant is normal can be direct and explicit. When the plant has been damaged, some of the safety functions are not as easily shown to be under control. For example, inventory control during an LOCA is not as easily tested for as it is when the plant is normal. The safety function status check acceptance criteria for inventory control in a LOCA relies on implicit information. Since tests with charging, pressurizer spray and heaters would not be valid, the inventory control acceptance criteria is based on knowing that the systems intended to provide inventory control (i.e., the SIS) are functioning. In addition, the acceptance criteria for other functions must be used in conjunction with the inventory control acceptance criteria in order to arrive at the conclusion that the plant status is satisfactory.

SAFETY FUNCTION STATUS CHECK BASES
EXCESS STEAM DEMAND EVENT
Figure 7-18a

The safety functions listed below and their respective criteria are those used to confirm the adequacy of the ESDE Guideline in mitigating the event.

SAFETY FUNCTION	ACCEPTANCE CRITERIA	INDICATION	RANGE	BASES
Reactivity Control	Reactor Power Decreasing and [Negative Startup Rate] and Not more than 1 CEA Bottom Light Not Lit or Borated per Tech Specs.	Power Range Power Rate CEA Status Display	[0-125%] [-1 → 7 dpm] On/Off Light for Each CEA	For all emergency events, the reactor must be shutdown. The criteria that no more than one CEA be stuck out or the RCS borated observes typical technical specification requirements.
Maintenance of Vital Auxiliaries (AC & DC Power)	[<----------------------------------Plant Specific--->]			
RCS Inventory Control	If [35"] ≤ Pressurizer Level ≤ [245"]; Then: charging and letdown are being operated automatically or manually to maintain or restore pressurizer level. and RCS ≥ [20°F] subcooled and [the RVLMS indicates the core is covered] or	Pressurizer Level [RVLMS]	[0"-350"] [0-100%]	A value of [245"] (70%]) of range was chosen as an upper limit for pressurizer level to account for instrument accuracies and other uncertainties. A value of [35"] ([10%]) of range was chosen as a lower limit to account for instrument accuracy. A [20°F] subcooling margin coexisting with a pressurizer level [35 to 245"] indicates adequate RCS pressure control via a saturated bubble in the pressurizer.

SAFETY FUNCTION STATUS CHECK BASES
EXCESS STEAM DEMAND EVENT
Figure 7-18b

The safety functions listed below and their respective criteria are those used to confirm the adequacy of the ESDE Guideline in mitigating the event.

SAFETY FUNCTION	ACCEPTANCE CRITERIA	INDICATION	RANGE	BASES
RCS Inventory Control (Cont'd)	If Pressurizer Level < [35"]; Then: [the RVLMS indicates the core is covered.] and [all available charging pumps are operating, and] the SIS pump(s) are injecting water into the RCS per Figure 7-3.			An RVLMS indication that the core is covered, taken in conjunction with [20°F] subcooling, is an additional indication that RCS inventory control has been established.
RCS Pressure Control	If Pressurizer Pressure ≥ [1600 psia], pressurizer heaters and spray are being operated manually or automatically to maintain or restore pressurizer pressure within the limits of the P/T curves (Figure 7-1) _or_	Pressurizer Pressure	[1500 - 2500 psia]/ [0-1600 psia]	[1600 psia] is the SIAS setpoint. The range of the selected events are very broad, therefore the acceptance criteria is written to cover the expected range which may result from the events noted.

SAFETY FUNCTION STATUS CHECK BASES
EXCESS STEAM DEMAND EVENT
Figure 7-18c

The safety functions listed below and their respective criteria are those used to confirm the adequacy of the ESDE Guideline in mitigating the event.

SAFETY FUNCTION	ACCEPTANCE CRITERIA	INDICATION	RANGE	BASES
RCS Pressure Control (Cont'd)	If Pressurizer pressure < [1600 psia], [at least one charging pump is operating and] the SIS pump(s) are injecting water into the RCS per Figure 7-3, (unless SIS termination criteria are met).			
Core Heat Removal	T_H RTDs [and Core Exit Thermocouples] < [600°F]	[Core Exit Thermocouples] T_H RTDs	[0°-1600°F] [465°-665°F]	The basis for the [CET] temperature limit during the use of optimal recovery procedures other than LOCA is the indication that the event specific recovery strategy is not effective. The value of [CET] temperature indicates core heat removal performance. For the optimal recovery guidelines other than LOCA, heat is normally removed from the RCS by the steam generators. The value of the [CET] temperature will be governed by steam generator conditions (i.e., pressure and temperature). In general $T_c \cong T_{SG}$ and [CET] temperature will be T_c + core ΔT. Normally this core ΔT is expected to be approximately 25°F during single phase natural circulation conditions. For forced RCS flow conditions $T_{SG} \cong T_c \cong T_H \cong$ [CET] temperature.

SAFETY FUNCTION STATUS CHECK BASES
EXCESS STEAM DEMAND EVENT
Figure 7-18d

The safety functions listed below and their respective criteria are those used to confirm the adequacy of the ESDE Guideline in mitigating the event.

SAFETY FUNCTION	ACCEPTANCE CRITERIA	INDICATION	RANGE	BASES
Core Heat Removal (Cont'd)	<u>and</u> The RCS ≥ [20°F] subcooled	[Subcooled Margin Monitor]	[0° - 100°F]	The design secondary system pressure is [1100 psia]. The corresponding saturation temperature is 556.3°F. By adding 43.7°F to account for thermocouple inaccuracy and the ΔT between Tc and [CET], the value of [600°F] is reached. The value of [20°F] subcooling is based on keeping the core covered and thus ensuring adequate core cooling. If the core is covered with fluid, the RCS will indicate subcooled conditions.
RCS Heat Removal	The unaffected S/G has level: a) within the normal level band with feedwater available to maintain the level or b) being restored by a feedwater flow > [150 gpm] and RCS Tave is < [525°F] and controlled	Steam Generator Level	[+63.5" - (-)116.5"]	Decay heat levels may not be high enough to require a feedwater flow of [150 gpm]. Once steam generator level is returned to the zero power level band and feedwater remains available to maintain that level, then the SIS contribution to RCS heat removal is being satisfied. [525°F] is based on not lifting a steam generator safety valve.

SAFETY FUNCTION STATUS CHECK BASES
EXCESS STEAM DEMAND EVENT
Figure 7-18e

The safety functions listed below and their respective criteria are those used to confirm the adequacy of the ESDE Guideline in mitigating the event.

SAFETY FUNCTION	ACCEPTANCE CRITERIA	INDICATION	RANGE	BASES
Containment Isolation	Containment pressure < [4 psig]	Containment Pressure	[0-60 psig]	During ESDEs, it is not expected that there will be radiation inside containment or in the steam plant. The monitors should not be alarming [4 psig] is the CIAS setpoint. If pressure goes above [4 psig], containment isolation valves should shut (i.e., CIAS should be present).
	and			
	No containment area radiation monitors alarming	Containment Area Radiation Monitors	Alarming/ Not Alarming	
	and			
	No steam plant activity monitors alarming	Steam Plant Act Monitors	Alarming/ Not Alarming	
	<u>or</u>			
	CIAS present or manually initiated.	Containment Isolation Valve Position Indication	Shut/Open	
Containment Temperature and Pressure	Containment Temperature < [240°F]	Containment Temperature	[50°-300°F]	[10 psig] is based on CSAS setpoint.
	and			
	Containment Pressure < [10 psig]	Containment Pressure	[0-60 psig] [0-15 psig]	[240°F] corresponds to the saturation temperature for [10 psig].
	<u>or</u>			
	Containment Spray Flow > [1500 gpm]	Containment Spray Flow	[0-5000 gpm]	During the selected event, containment temperature and pressure may exceed these limits if the break is inside containment. If this happens, a CSAS should be present and the CSP should be injected spray solution at [1500 gpm].

SAFETY FUNCTION STATUS CHECK BASES
EXCESS STEAM DEMAND EVENT
Figure 7-18f

The safety functions listed below and their respective criteria are those used to confirm the adequacy of the ESDE Guideline in mitigating the event.

SAFETY FUNCTION	ACCEPTANCE CRITERIA	INDICATION	RANGE	BASES
Containment Combustible Gas Control	H_2 < [2%]	[<------------------------Plant Specific---------------------------->]		

Event Strategy

This section contains the detailed ESDE recovery actions strategy flow chart Figure 7-19. The flow chart pictorially depicts the strategy around which the ESDE guideline is built. It is intended to assist the procedure writer in understanding the intent of the guideline and for use in training. Operators should understand the major objectives of the guideline in order to facilitate their progress toward the guideline goals.

The strategy flow chart shows the recovery guideline strategy in detail and lists the guideline steps which correspond to each strategy objective. Some steps in the guideline may be performed at any time during the course of an event. Those steps which have an asterisk next to the step number can be performed at any time during the event.

FIGURE 7-19a
STRATEGY CHART FOR EXCESS STEAM DEMAND EVENT

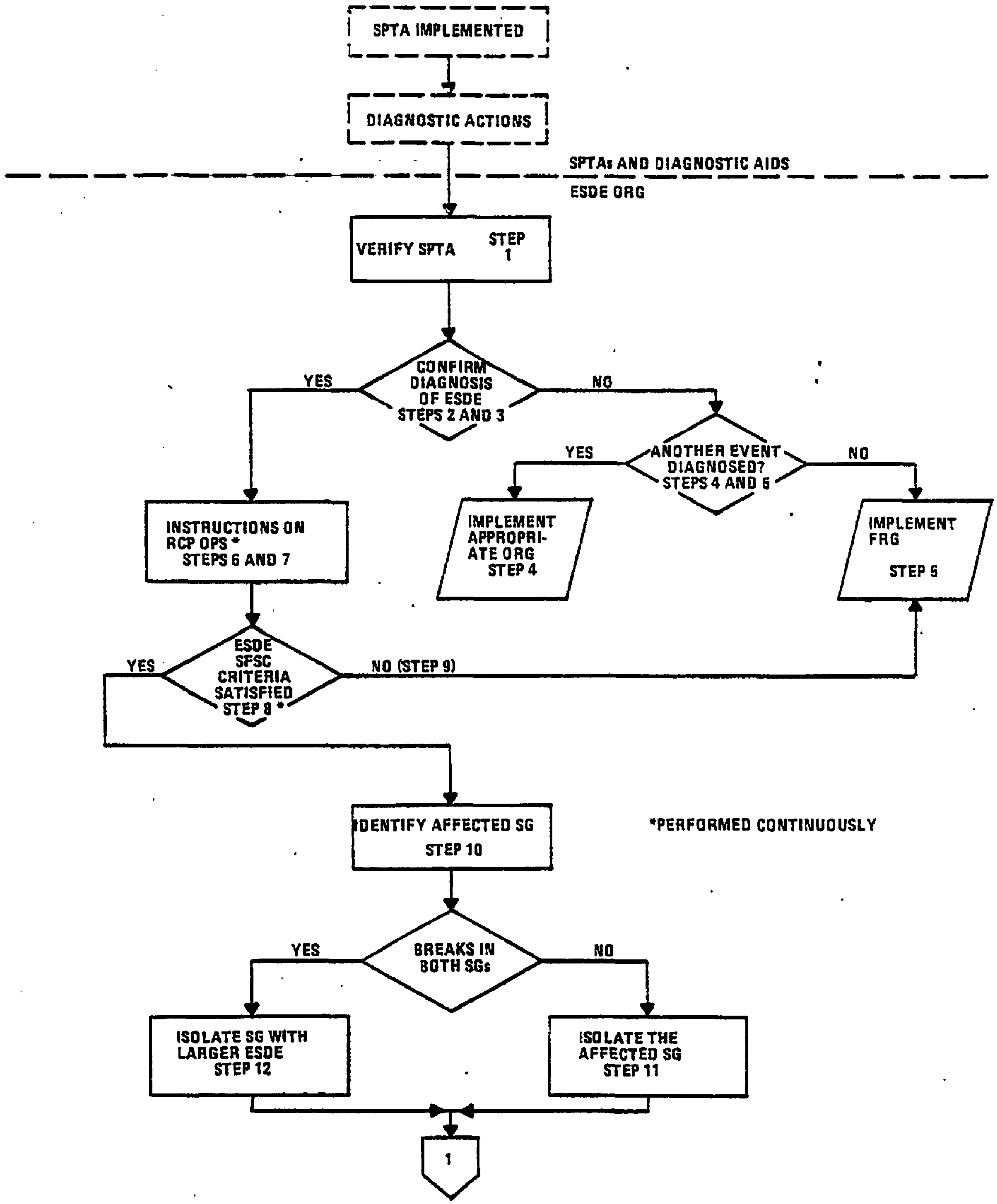


FIGURE 7-19b
STRATEGY CHART FOR EXCESS STEAM DEMAND EVENT

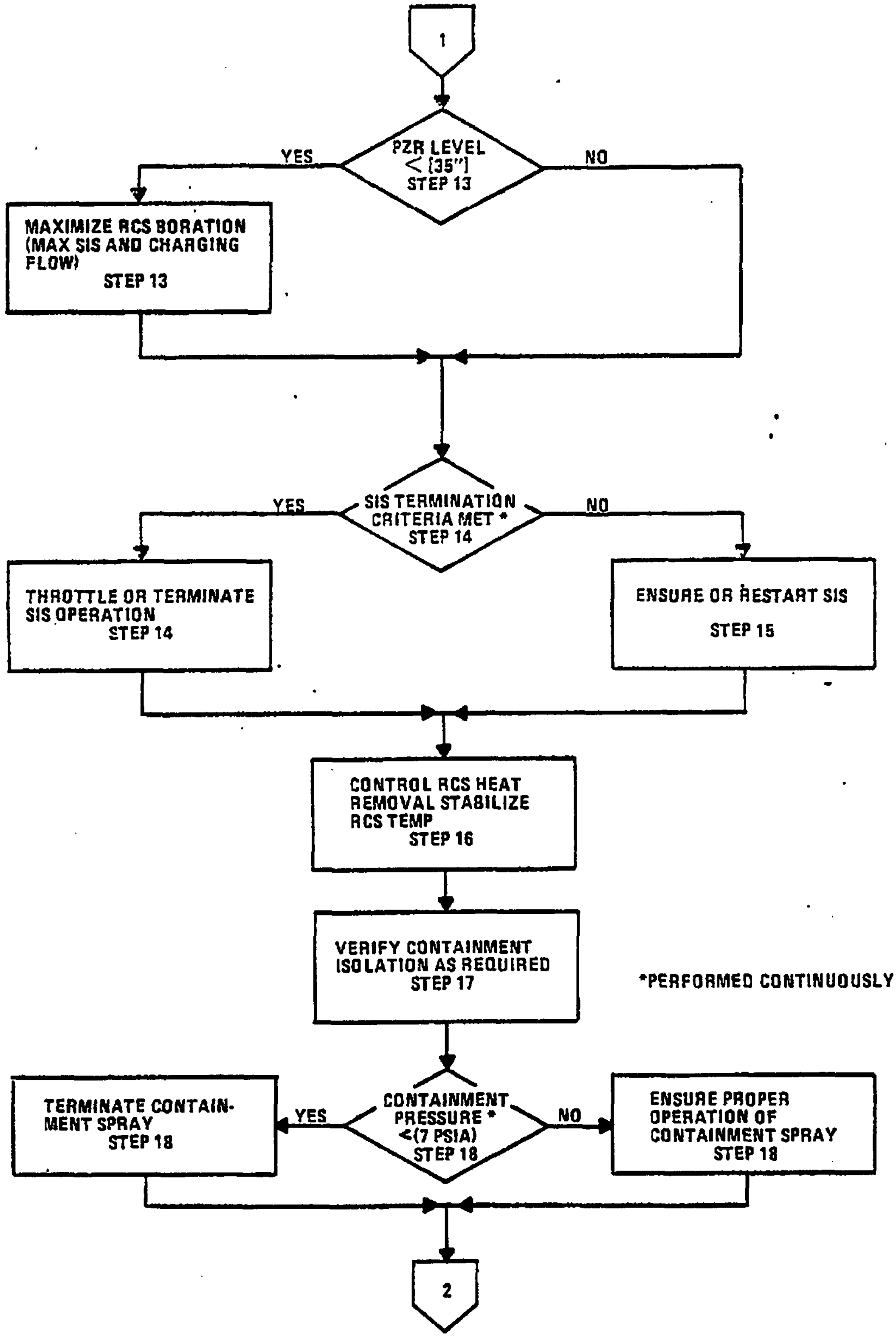


FIGURE 7-19c

STRATEGY CHART FOR EXCESS STEAM DEMAND EVENT

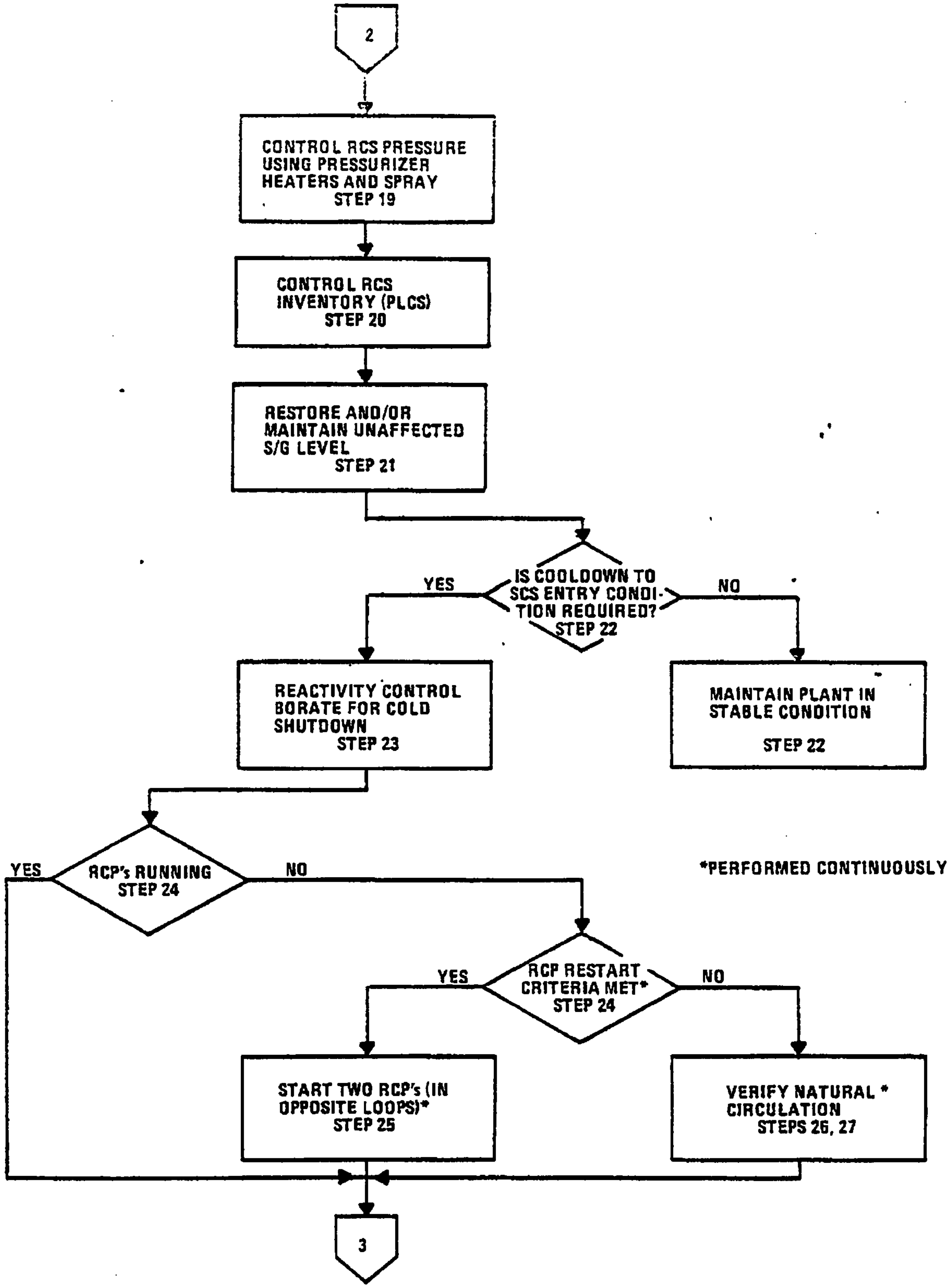
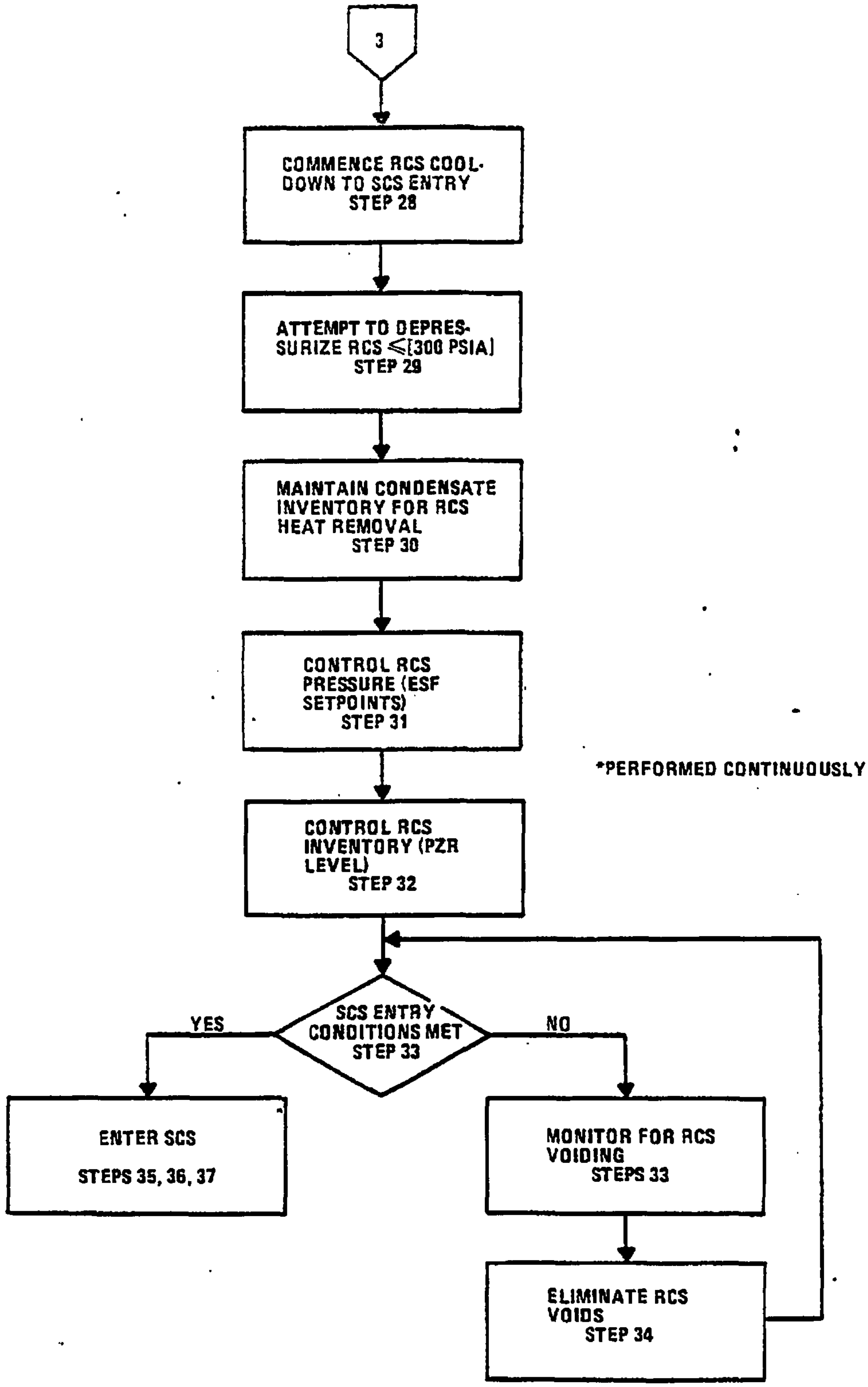


FIGURE 7-19d

STRATEGY CHART FOR EXCESS STEAM DEMAND EVENT



LOSS OF FEEDWATER RECOVERY GUIDELINE

Prepared by
COMBUSTION ENGINEERING, INC.
for the
C-E Owners Group

2. See Deviation J-29

Purpose

This guideline provides operator actions which must be accomplished in the event of a Loss of Feedwater (LOF). The actions in this guideline are necessary to ensure the plant is placed in a stable, safe condition. This guideline provides technical information to be used by the utilities in developing a plant specific procedure.

Entry Conditions

1. The Standard Post Trip Actions have been performed

and

2. Plant conditions indicate that a Loss of Feedwater event has occurred. Any one or more of the following may be present.

   a. Decreasing steam generator water level or alarm.
   b. Main feedwater pump trip alarm.
   c. Low main feedwater pump flow (possible high flow for a feedwater line break).
   d. Low main feedwater pump suction pressure.
   e. [Other plant specific symptoms, insert here.]

1. IMPLEMENTED BY STEP A

2. IMPLEMENTED BY STEP B

3. See DEVIATION 3-1

4. See Deviation 3-2

5. S/G PRESSURE AND LEVEL ARE CONTINUALLY monitored in the SFSC. Limits are maintained as tight as possible on all parameters contained in the SFSC so that CONDITIONS outside the assumptions of the procedure are identified. The operator uses these safety function responses to diagnosis the event and the acceptance criteria for each function in turn confirms his diagnosis. Thus while the procedure doesn't specifically provide the diagnostic direction of this step, the EOP STRUCTURE ENSURES that failures affecting safety functions ARE observed AND acted upon.

Also the plant specific procedure focuses operator attention immediately on the AFW system because of its reliability. Main Feed restoration is left as a lower priority

6. Implemented by step B

OPERATOR ACTIONS

1. Verify that the Standard Post Trip Actions have been performed.

2. Confirm the diagnosis of an LOF event by [verifying the Safety Function Status Check acceptance criteria are satisfied].

*3. If the diagnosis of an LOF is confirmed, Then continue with the actions of this guideline.
If not, implement the Functional Recovery Guideline.

4. [Trip two RCPs (in opposite loops)].

5. Determine whether the cause of the loss of feedwater is a result of a feedwater line break or a feedwater system abnormality by monitoring steam generator pressure and level.
If a feedwater line break is suspected, Then attempt to isolate the break.

   a) If the feedwater line break is unisolable from the steam generator, then exit this guideline and implement the Excess Steam Demand Event Guideline.
   b) If the feedwater line break has been isolated, then proceed with the actions within this guideline.
   c) If a feedwater system abnormality exists, then continue with this guideline.

*6. Verify that the safety functions are being satisfied by comparing control board parameters to the acceptance criteria in the Safety Function Status Check.

* Step performed continuously.

7. SEE Deviation 3-1

8. Implemented by STEPS G, J

9. CCNPP uses seperate aux feed Ring which operating experience indicates is not susceptible to water hammer under AFW flow rates

See Deviation 3-36

10. Administrative - No comment Required

11. ADMINISTRATIVE - NO COMMENT REQUIRED

12. Implemented by STEP M

See Deviation 3-30

*7. If all safety functions from the Safety Function Status Check are satisfied, Then continue with the recovery actions of this guideline. If not, implement the Functional Recovery Guideline.

*8. Take actions to restore the [main or auxiliary] feedwater system to operation.

*9. [If the auxiliary feedwater system (AFW) is started, Then perform the following to prevent steam generator feed ring damage:

a) If S/G water level is above the feed ring, Then stop redundant AFW pumps, restore S/G level, and maintain it in the normal level band.

b) If indicated steam generator water level is below the feed ring, Then:

i) Stop redundant AFW pumps and limit feedwater flow rate to 150 gpm per affected steam generator until an increase in S/G level has been observed, or until continuous feedwater flow to the S/G has been maintained for five minutes.

ii) Modulate AFW flow rate as necessary to restore and maintain S/G water level in the normal level band.]

10. If feedwater has been restored, Then perform steps 12 through 17.

11. If feedwater has not been restored, Then perform steps 18 through 29.

12. Verify turbine bypass valves are controlling steam generator pressure at [900 psia], or lower, depending on RCS conditions.
If condenser vacuum is lost, or the turbine bypass system is unavailable, or if the MSIVs are closed, Then the atmospheric dump valves must be used to control steam generator pressure.

* Step performed continuously.

13 IMPLEMENTED BY STEP M. ~250 inch is Required to terminate feed AND bleed since that level represents a suitable level to support natural circulation.

See Deviation 3-31

14. SEE DEVIATION 3-3

15. IMPLEMENTED BY STEP Z. SEE DEVIATION 3-4

16. Implemented BY STEP Z. SEE DEVIATION 3-4

17. IMPLEMENTED BY STEP Z AND AA

18. IMPLEMENTED BY STEPS C, E, F, K, J

*13. Maintain or restore steam generator level to the normal level band using [main or auxiliary] feedwater.

14. If the auxiliary feedwater system is being used, Then ensure the condensate inventory is adequate per Figures 8-3 and 8-4.

*15. Verify that the PPCS is automatically maintaining or restoring RCS pressure within the limits of Figure 8-1.
If not, manually control pressurizer heaters and main spray (preferred), or auxiliary spray, to restore pressurizer pressure.

*16. Verify that the PLCS is automatically maintaining or restoring pressurizer level in the hot zero power reference band.
If not, manually operate charging and letdown to restore and maintain normal pressurizer level.

*17. Maintain the plant in a stabilized condition and evaluate the need for a plant cooldown based on plant conditions, auxiliary systems availability and condensate inventory (Figures 8-3 and 8-4).
If conditions require a cooldown, Then conduct a cooldown to SCS initiation conditions per normal operating instructions.

*18. If all feedwater (main and auxiliary) is lost, Then conduct the following actions:

a) Stop all RCPs
b) Isolate steam generator blowdown, secondary sampling and any non-vital steam discharge.

* Step performed continuously.

19. IMPLEMENTED BY STEP K

20. IMPLEMENTED BY STEP N

21 Implemented BY STEP N. See Deviation 3-5

22. Implemented in step J

23 Implemented in steps M and N

c) Continue actions to regain either main or auxiliary feedwater system operation. If the auxiliary feedwater system is being used, Then ensure that the condensate inventory is adequate.

d) [If other methods are available for steam generator heat removal, then insert that information here].

19. [If feed to at least one steam generator cannot be restored, Then establish once through cooling by:

a) starting all available charging pumps and the HPSI pumps aligned for cold leg injection

b) opening the PORVs].

20. If the SIS is operating, Then it may be throttled or stopped, one train at a time, if the following conditions are satisfied:

a) The RCS is at least [20°F] subcooled (Figure 8-1),

b) Pressurizer level is greater than [100"] and not decreasing,

c) At least one steam generator is available (feed and steam flow) for removing heat from the RCS,

d) [The RVLMS indicates the core is covered].

*21. If the criteria of step 20 cannot be maintained after the SIS has been stopped, Then the SIS must be restarted.

22. [If other methods are available for heat removal from the RCS, Then insert that information here.]

23. If feedwater is regained, Then use either turbine bypass or atmospheric dump valves to dump steam. Stop one-through-cooling if in use.

* Step performed continuously.

24. implemented in STEP AA
See Deviation 2-39 + 2-40

25. implemented in STEP AA
See Deviation ~~2-40~~ 2-42

26. implemented in STEP O

*24. If all RCPs were stopped, Then two RCPs (in opposite loops) should be restarted if possible.

Determine whether RCP restart criteria are met by the following:

a) At least one steam generator has feedwater restored and is available to remove heat from the RCS,
b) Pressurizer level is greater than [200"] and not decreasing,
c) The RCS is at least [20°F] subcooled (Figure 8-7)
d) [Other criteria satisfied per RCP operating instructions].

*25. If RCP restart criteria are met, Then do the following:

a) Start one RCP in each loop
b) [Ensure proper RCP operation by monitoring RCP amperage and pump NPSH. NPSH is determined by pressurizer pressure and corresponding T_c on Figure 8-1]
c) Operate HPSI (Figure 8-2) and charging pumps until pressurizer level is greater than [100"] and SIS termination criteria are met.

*26. If all RCPs have been stopped, Then verify natural circulation flow in at least one loop. The following criteria must be met in order to demonstrate adequate natural circulation flow:

a) Loop ΔT (T_H - T_c) less than full power ΔT,
b) Cold leg temperatures constant or decreasing,
c) Hot leg temperatures stable (i.e., not steadily increasing) or decreasing slowly,
d) No abnormal differences between T_H RTDs [and core exit thermocouples].

* Step performed continuously.

27. IMPLEMENTED IN STEP Z AND SFSC

28. IMPLEMENTED IN STEP Z

29. IMPLEMENTED IN STEPS Z, AA, AND AB

27. If the criteria of step 26 are not met, Then ensure RCS pressure (step 15) and inventory (step 16) are being controlled properly. Feedwater, however, must be restored to at least one S/G for continued natural circulation.

*28. Maintain the RCS within the acceptable Post Accident Pressure/ Temperature Limits (Figure 8-1) by using the following (listed in order of preference):

   a) pressurizer heaters and main spray
   b) pressurizer heaters and auxiliary spray
   c) all available charging and HPSI pumps [and PORVs].

29. Maintain the plant in a stabilized condition and evaluate the need for a plant cooldown based on plant conditions, systems availability and, if feedwater is regained, condensate inventory (per Figures 8-3 and 8-4). If required, conduct a plant cooldown within Technical Specification Limits and enter shutdown cooling.

* Step performed continuously.

1. Implemented in STEP M AND PRECAUTION F

2. Implemented in SFSC

3. Implemented in PRECAUTION A AND B

4. Implemented in PRECAUTION C

5. Implemented by subcooling limits in steps D, K, N AND Z cooldown RATE limitation provided in step J M AN Q. Additionally feed AND bleed procedure is implemented before S/Gs are completely dry to minimize the possibility of having to feed a dry S/G

6. Implemented in precautions D and E.

SUPPLEMENTARY INFORMATION

This section contains items which should be considered when implementing EPGs and preparing plant specific EOPs. The items should be implemented as precautions, cautions, notes or in the EOP training program.

1. The operator should not add feedwater to a dry steam generator if another steam generator still contains water. Re-establish feedwater only to the steam generator that is not dry. If both steam generators become dry, refill only one steam generator to reinitiate core cooling.

2. During all phases of the cooldown, monitor RCS temperature and pressure to avoid exceeding a cooldown rate greater than Technical Specification Limitations.

3. Do not place system in "manual" unless misoperation in "automatic" is apparent. Systems placed in "manual" must be checked frequently to ensure proper operation.

4. All available indications should be used to aid in evaluating plant conditions since the accident may cause irregularities in a particular instrument reading. Instrument readings must be corroborated when one or more confirmatory indications are available.

5. If the initial cooldown rate exceeds Technical Specification Limits, there may be a potential for pressurized thermal shock (PTS) of the reactor vessel. Post Accident Pressure/Temperature Limits of (Figure 8-1) should be maintained.

6. Solid water operation of the pressurizer should be avoided unless [20°F] of subcooling cannot be maintained in the RCS (Figure 8-1). If the RCS is solid, closely monitor any makeup or draining and any system heatup or cooldown to avoid any unfavorable rapid pressure excursions.

7. Implemented in precaution G. transient log entry directed in step AC

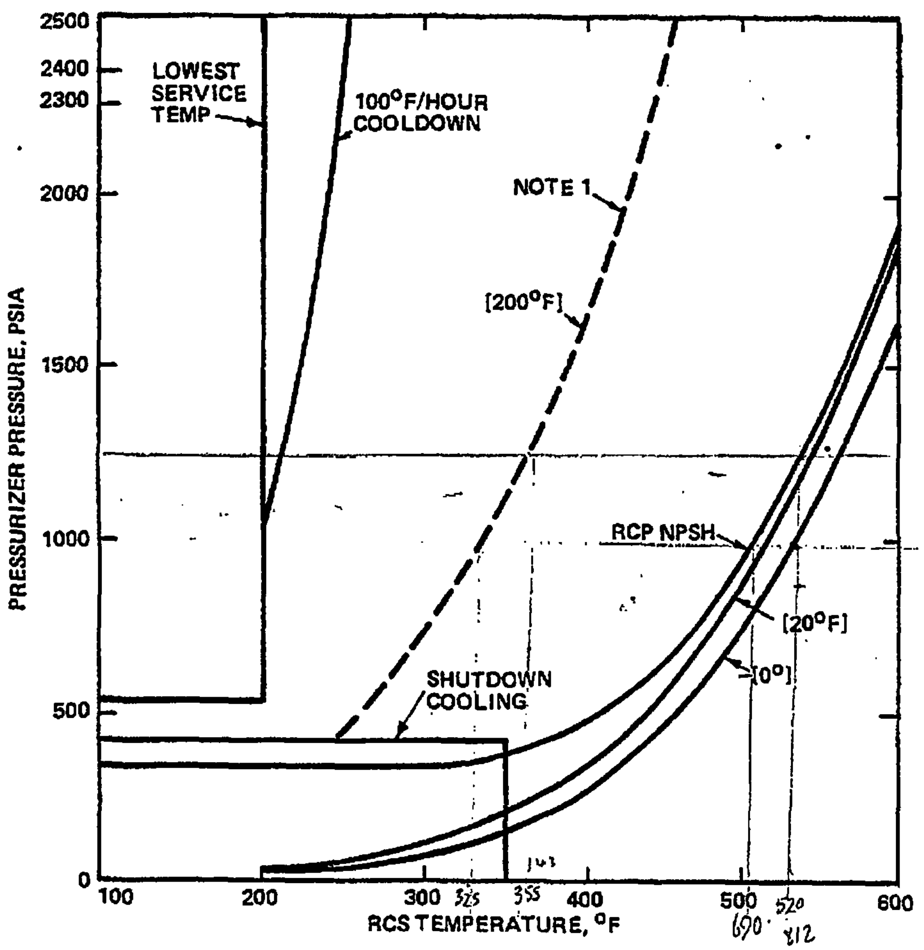
8. Implemented in SFSC

7. Minimize the number of cycles of pressurizer auxiliary spray whenever the temperature differential between the spray water and the pressurizer is greater than [200°F] in order to minimize the increase in the spray nozzle thermal stress accumulation factor. Every such cycle must be recorded in accordance with Technical Specification Limitations.

8. [Monitor quench tank parameters since any sustained operation of the PORVs may burst the tanks rupture disc.]

FIGURE 8-1

TYPICAL POST ACCIDENT PRESSURE-TEMPERATURE LIMITS(2)



NOTES: (1) THIS CURVE SUPERSEDES THE 100°F/HOUR COOLDOWN CURVE ANYTIME THE RCS HAS EXPERIENCED AN UNCONTROLLED COOLDOWN WHICH CAUSES RCS TEMPERATURE TO GO BELOW 500°F

(2) THESE CURVES MUST BE ADJUSTED FOR INSTRUMENT INACCURACIES

(3) COLOR CODE

RED - PARAMETER IN EXCESS OF LIMITS

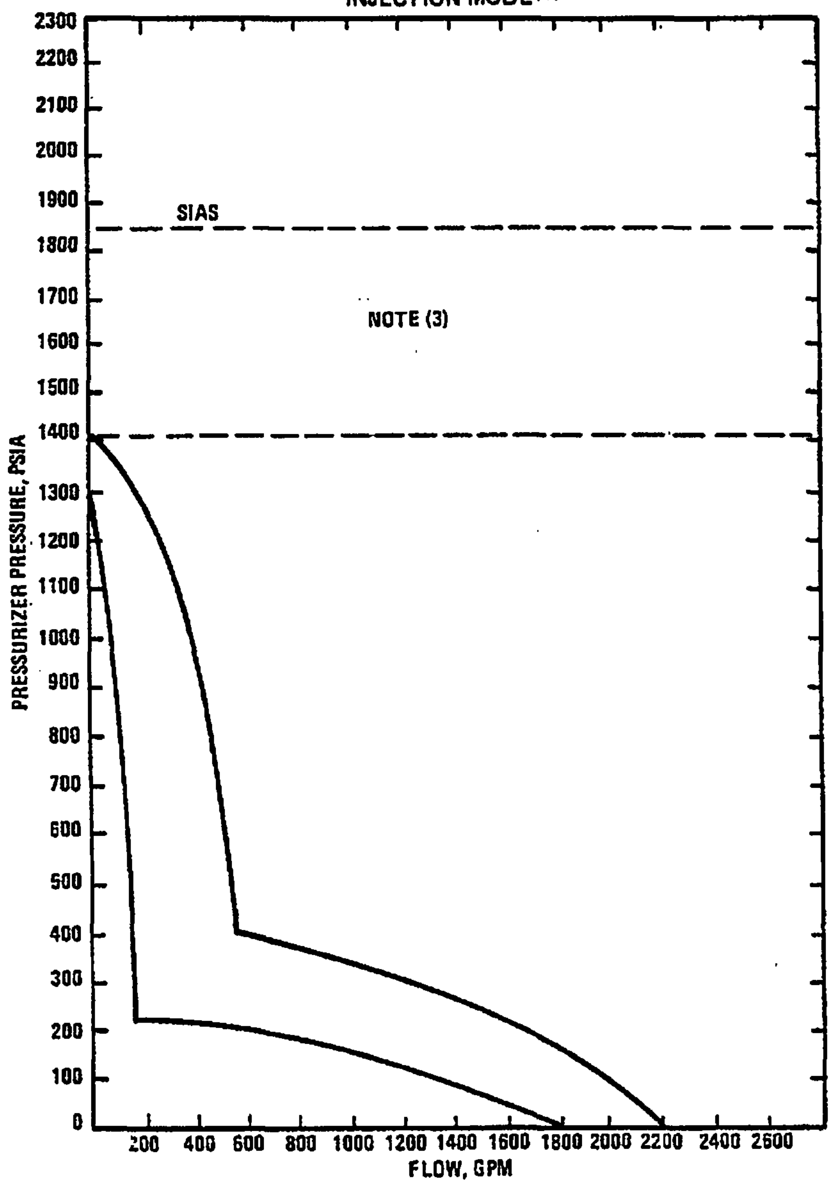
ORANGE - PARAMETER IN DANGER OF EXCEEDING LIMITS

YELLOW - PARAMETER OUTSIDE OF OPTIMAL RANGE, BUT STILL WITHIN LIMITS

GREEN - PARAMETER IN OPTIMAL RANGE OF VALUES

FIGURE 8-2

TYPICAL ACCEPTABLE SIS FLOW vs RCS PRESSURE(1)
INJECTION MODE(2)



NOTES:
(1) SEE IMPLEMENTATION SECTION FOR DEVELOPMENT OF PLANT SPECIFIC CURVE
(2) FOR HOT AND COLD LEG INJECTION MODE, THE LPSI PUMPS ARE NOT REQUIRED TO BE OPERATING. THE HPSI PUMP FLOW IS DIVIDED EQUALLY BETWEEN THE HOT AND COLD LEGS
(3) BELOW SIAS PRESSURE, SAFETY INJECTION SYSTEM (SIS) PUMPS WILL BE OPERATING BUT THERE WILL BE NO INJECTION FLOW UNTIL SYSTEM PRESSURE FALLS BELOW THE SHUTOFF HEAD OF ANY SIS PUMP
(4) COLOR CODE
  - RED - PARAMETER IN EXCESS OF LIMITS
  - YELLOW - PARAMETER OUTSIDE OF OPTIMAL RANGE, BUT STILL WITHIN LIMITS
  - GREEN - PARAMETER IN OPTIMAL RANGE OF VALUES

TYPICAL FEEDWATER CAPACITY vs TIME REMAINING UNTIL SHUTDOWN COOLING REQUIRED

FIGURE 8-3

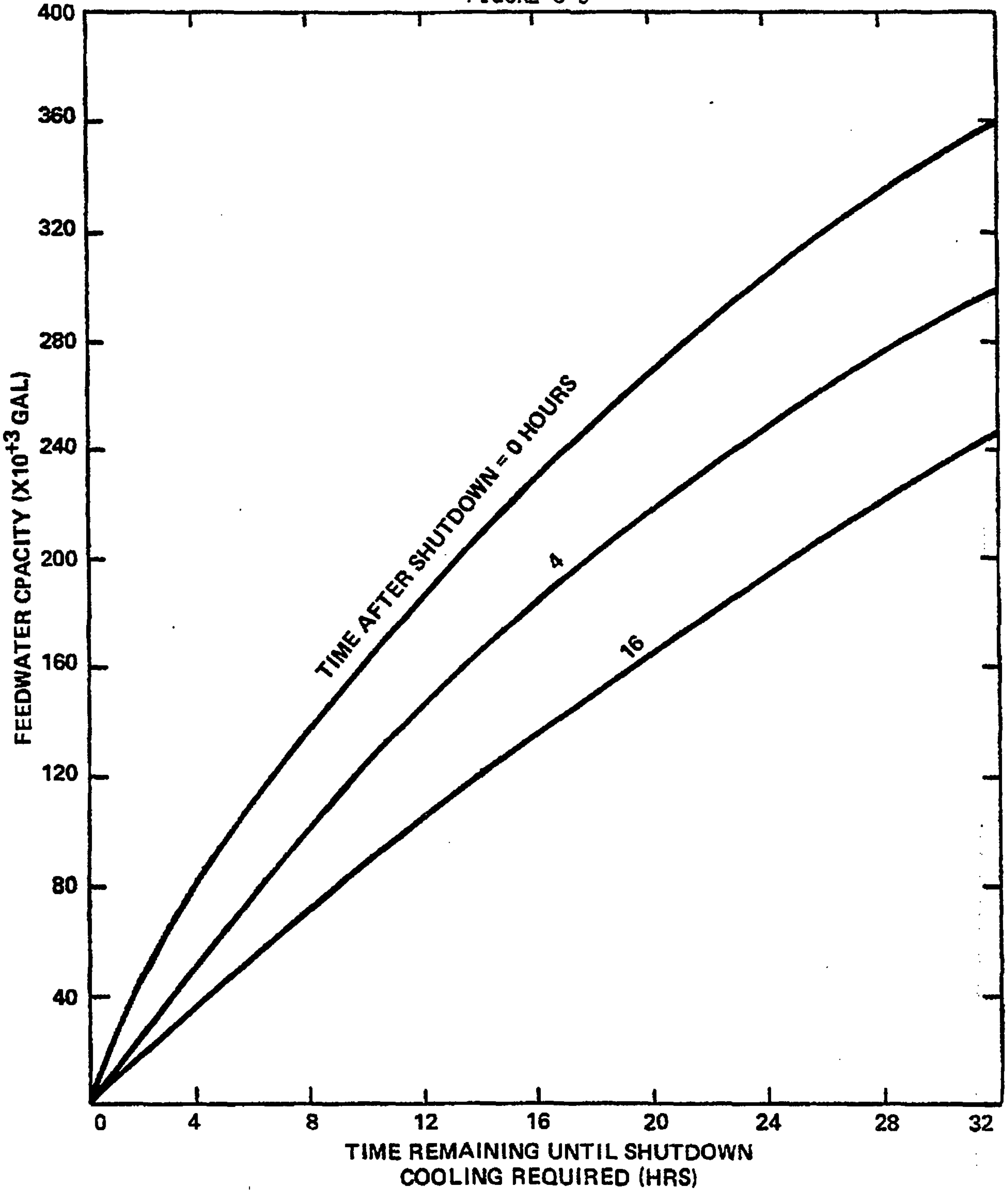
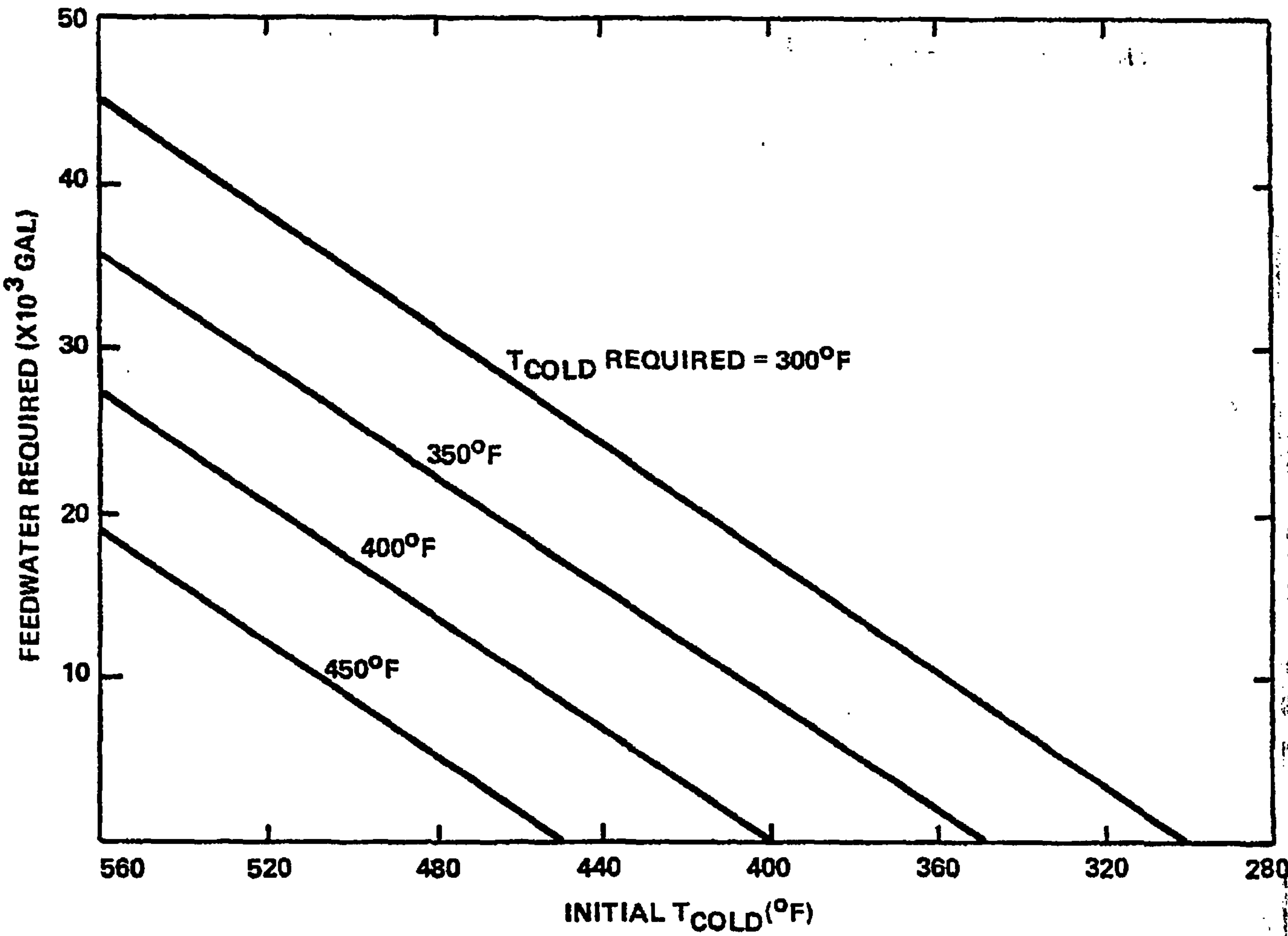


FIGURE 8-4

TYPICAL FEEDWATER REQUIRED FOR SENSIBLE HEAT REMOVAL
T_{COLD} (REQUIRED) vs T_{COLD} (INITIAL)



1. ALL ITEMS COVERED UNDER REACTIVITY CONTROL SFSC

2. included AS 4th function of SFSC

3a. Limits included in Press/Inv. SFSC
see Deviation 3-6 for equipment operability checks

SAFETY FUNCTION STATUS CHECK

Safety Function	*Acceptance Criteria*
1. *Reactivity Control*	1.a. Reactor power decreasing *and* b. [Negative Startup Rate] *and* c. Not more than 1 CEA bottom light not lit or borated per Tech Specs.
2. *Maintenance of Vital Auxiliaries (AC and DC Power)*	2. [Plant specific criteria, insert here].
3. *RCS Inventory Control*	3.a. If pressurizer level is [35 to 245"], Then: i) charging and letdown are being operated automatically, or manually, to maintain or restore pressurizer level and ii) the RCS is at least [20°F] subcooled and iii) [the RVLMS indicates the core is covered] *or*

3b. SEE DEVIATION 3-7

4. Pressure acceptance criteria are included in the SFSC but the assement of proper equipment operation over various pressure bands is not addressed. See Deviation 3-8.

SAFETY FUNCTION STATUS CHECK (Cont'd)

Safety Function	*Acceptance Criteria*
3. *RCS Inventory Control (Cont'd)*	b. If pressurizer level is less than [35"], Then: i) [the RVLMS indicates the core is covered] and ii) [all available charging pumps are operating and] the SIS pump(s) are injecting water into the RCS per Figure 8-2.
4. *RCS Pressure Control*	4.a. If pressurizer pressure is less than [2350 psia] and greater than or equal to [1600 psia], Then pressurizer heaters and spray are being operated automatically, or manually, to maintain or restore pressurizer pressure*. *or* b. If pressurizer pressure is less than [1600 psia], Then [all available charging pumps are operating and] the SIS pump(s) are injecting water into the RCS per Figure 8-2 (unless SIS termination criteria are met).

* Not applicable if in once-through cooling.

5. ALL ITems covered under CORE/RCS HEAT Removal SFSC

6. ALL ITems covered UNder CORE/RCS HEAT Removal SFSC

SAFETY FUNCTION STATUS CHECK

Safety Function	Acceptance Criteria
5. Core Heat Removal	5.a. If not in once-through cooling, Then: i) RCS T_{ave} less than [545°F] and ii) the RCS is at least [20°F] subcooled or b. If in once-through cooling, Then the RCS is at least [0°F] subcooled.
6. RCS Heat Removal	6.a. RCS T_{ave} is less than [545°F]* and b. Loop ΔT for at least one steam generator is: i) Less than [10°F] for forced circulation* or ii) Less than [50°F] for natural circulation*

* Not applicable if in once-through cooling.

7 All items covered under Containment Environment and Radiation control.

8. all items addressed under containment Environment

SAFETY FUNCTION STATUS CHECK (*Cont'd*)

Safety Function	*Acceptance Criteria*
7. *Containment Isolation*	7.a. Containment pressure less than [1.5 psig]* *and* b. No containment area radiation monitors alarming*. *and* c. No steam plant activity monitors alarming.
8. *Containment Temperature and Pressure Control*	8.a. Containment temperature less than [215°F]* *and* b. Containment pressure less than [1.5 psig]*
9. *Containment Combustible Gas Control*	9. Hydrogen concentration less than [2%].

* Not applicable if in once-through cooling.

BASES

The bases section of the loss of feedwater (LOF) recovery guideline describes the LOP transient in relation to the actions which the operator takes during a LOF. The purpose of the bases section is to provide the operators with information which will enable them to understand the reasons for, and the consequences of, the actions they take during a LOF.

Characterization of a Loss of Feedwater Event

A loss of feedwater results from a loss of main feedwater, auxiliary feedwater or both, to the steam generators. Some possible causes for a loss of feedwater include:

a) Loss, or cavitation, of all main feedwater pumps.
b) Malfunction of the feedwater control system which closes the main feedwater control valves.
c) Inadvertent isolation, or blockage, of the feedwater flow path.
d) Malfunction of the condensate system.
e) Feedwater line break (loss of feedwater resulting from a feedwater line break which is not isolable from the steam generator is covered under excess steam demand event).

A loss of feedwater is characterized by specific parameters that may be indicated in the control room. Some of these indications are:

a) Decreasing steam generator water level. The existence of this condition may be noticed by an alarm in the control room.
b) Increasing steam generator pressure before a reactor trip, followed by a decreasing and stabilizing trend.
c) Increasing pressurizer level and pressure before a reactor trip, followed by a decreasing and stabilizing trend.
d) Reactor trip generated on low steam generator water level.
e) Auxiliary feedwater actuation signal (AFAS) generated on low steam generator water level.

f) Turbine/generator tripped.

g) Low main feedwater pump flow/suction pressure, resulting in a main feedwater pump trip alarm. (The main feedwater pump flow may possibly be high if there is a feedwater line break.)

h) Containment pressure may increase if a feedwater line breaks inside containment. In addition, possible increase in containment pressure, temperature, humidity, or containment sump level.

i) A feedwater line break outside containment may be indicated by noise.

j) Possible equipment operational irregularities, such as a loss of feedwater control indication, a failure of the feedwater flow control valves, or a closure of a main feedwater system isolation valve.

k) Possible steam flow vs. feedwater flow mismatch noted.

Safety Functions Affected

A loss of all feedwater, if not corrected, results in a loss of the steam generator's ability to remove heat from the RCS. Operator actions should be directed towards conserving the available steam generator secondary water inventory and reestablishing feedwater flow to the steam generators so that RCS heat removal capability is maintained or restored. All safety functions should be monitored to assure public safety, or to detect changes in the plant conditions which could lead to unsafe conditions.

In addition to RCS heat removal, other safety functions may be affected in the following manner. The loss of all feedwater flow to the steam generators while steaming causes level in the steam generator to decrease. If the level decreases below the top of the generator tube bundle, heat transfer in the steam generator is progressively less and RCS temperature will begin to increase. RCS temperature also increases because cooler feedwater is no longer being added to the steam generators, thereby raising overall steam generator temperature. The rate of level decrease and RCS temperature increase is a function of reactor power. The rate of decrease is also dependent on the rate of feedwater loss or the size of the feedwater line break. As water level decreases below the reactor trip setpoint, a reactor trip (reactivity control) will occur, accompanied by a turbine trip, and rapidly decreasing RCS temperatures (to the hot zero power setpoint), pressurizer level and pressure. At high reactor powers, the reactor trip will occur within approximately 15-30 seconds after the loss of all feedwater. Following the reactor trip, the turbine bypass valves (TBVs) will usually control steam generator pressure at the hot zero power setpoint. If the TBVs are unavailable, steam pressure may be controlled by the ADVs (if they are automatically actuated or if the operator opens them) or by the steam generator safety valves. RCS temperature will be controlled at a value slightly above that corresponding to steam generator saturation conditions until a substantial portion of the tube bundle in each S/G is uncovered. At this point, RCS temperature will begin to increase. If the steam generators boil dry, RCS temperature would rise rapidly. When saturation conditions in the RCS reach the setpoints for the pressurizer safeties, RCS inventory will be lost out of

the safeties (loss of RCS inventory control). If RCS inventory loss continues at a high pressure, core uncovery may occur with corresponding severe consequences. The high pressure in the RCS will prevent RCS inventory replinishment via the SIS, thus, operation of charging pumps will be the lone means of injecting water into the RCS.

Trending of Key Parameters

Reactor Power (*Figure 8-5*)

When the level in one or both steam generators falls below the reactor trip setpoint, the reactor will trip. At high powers, this will occur in 15-30 seconds.

The main turbine generator will trip concurrently with the reactor trip. If the operator is able to conclude that a loss of feedwater has occurred before the reactor has tripped, he/she should immediately trip the reactor, (even before steam generator water level drops to the low level trip setpoint) in order to conserve the available steam generator water inventory.

RCS Temperature (*Figure 8-6*)

RCS temperature may increase before the trip. After the trip, RCS temperatures will usually decrease to approximately the hot zero power setpoint. If steam generator water level begins to drop below the top of the heat transfer tubes, the RCS heat transfer surface is reduced and RCS temperature increases. If the generators boil dry, RCS temperature will increase dramatically.

Pressurizer Pressure (*Figure 8-7*)

Pressurizer pressure will initially increase prior to a reactor trip due to the RCS heatup and then decrease after the trip.

Pressurizer Level (*Figure 8-8*)

Coincident with RCS temperature increases prior to reactor trip there will be an increased pressurizer level. The level will decrease post trip as heat is removed from the RCS. When the S/Gs boil dry, RCS heat removal is no longer being maintained and pressurizer level will increase in conjunction with RCS temperature increases.

Reactor Vessel Level

Voiding is not expected to occur during Loss of Feedwater transients since the RCS heats up and RCS inventory is not expected to be lost unless [PORVs] or pressurizer safety relief valves open. If RCS inventory loss continues at a high rate because of a loss of heat sink, voiding could eventually cause core uncovery because system pressure is above HPSI shut off head. If feedwater is restored, voiding should not occur.

Steam Generator Pressure (*Figure 8-9*)

Initially, the pressure in the steam generators will increase as feedwater flow to the steam generators is lost because the heat required to heat the cool feedwater now causes S/G temperature to increase. Following the reactor trip, S/G pressure will usually go up to the TBV control setpoint. If steaming continues with the steam vent path left open, and without feedwater, steam generator pressure will eventually begin to decrease as the steam generator boils dry.

Steam Generator Level (*Figure 8-10*)

A loss of feedwater to the steam generator will result in a decreasing steam generator level. This decrease usually causes a reactor trip. If steaming continues without feedwater, the S/G tube bundle will uncover and, eventually, the steam generator will boil dry.

FIGURE 8-5

REPRESENTATIVE TOTAL LOSS OF MAIN FEEDWATER FLOW REACTOR POWER

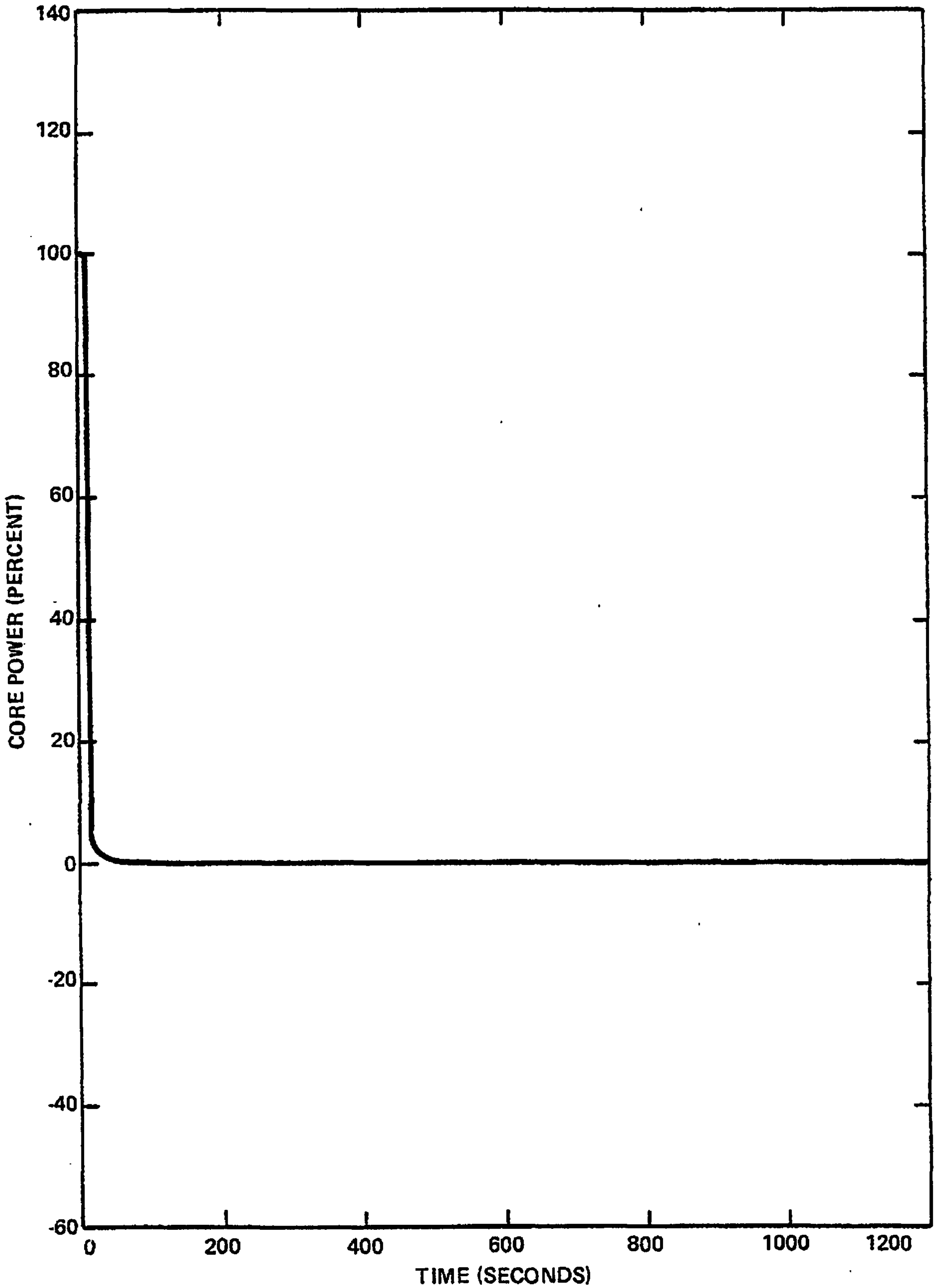


FIGURE 8-6

REPRESENTATIVE TOTAL LOSS OF MAIN FEEDWATER FLOW
RCS TEMPERATURES vs TIME

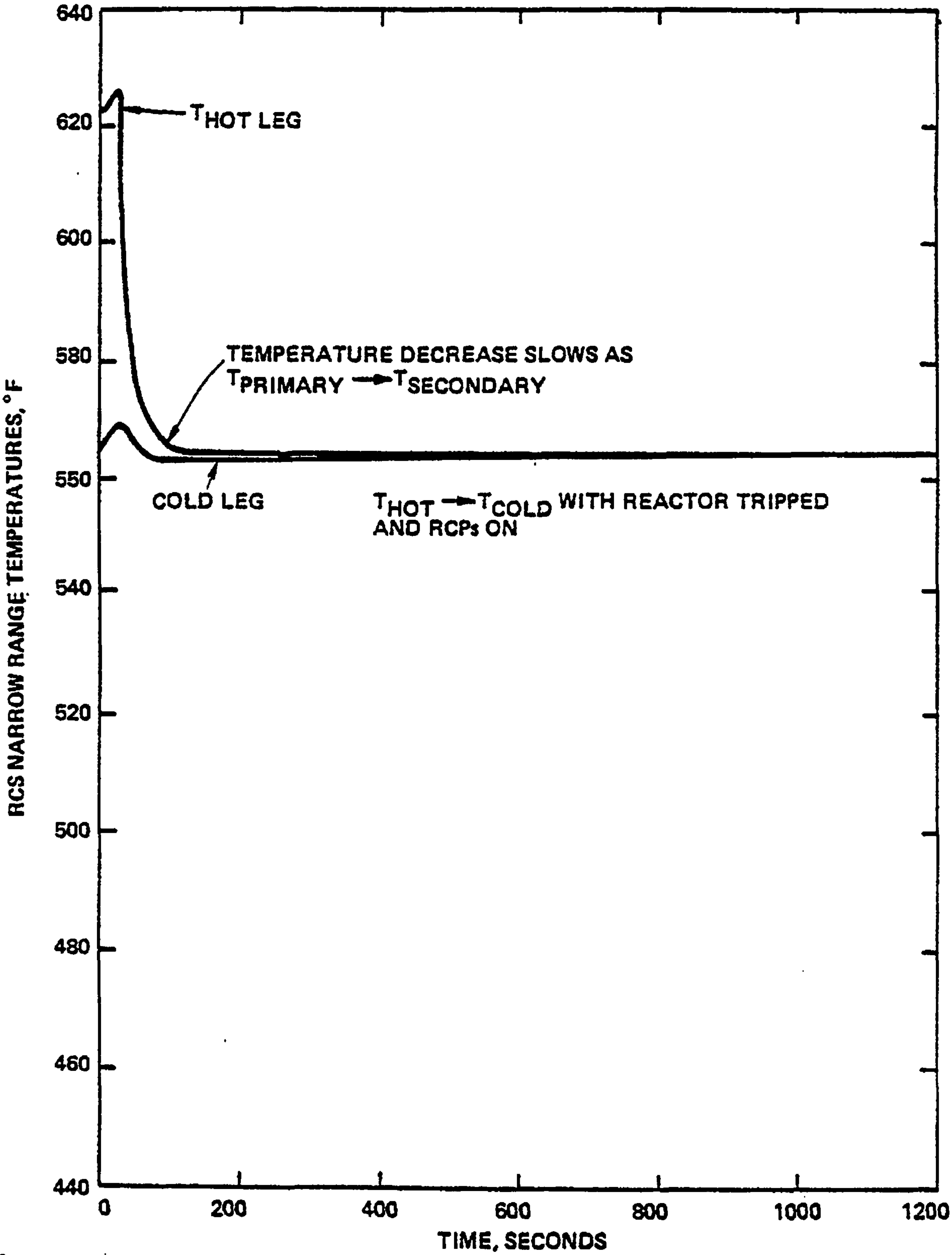


FIGURE 8-7

REPRESENTATIVE TOTAL LOSS OF MAIN FEEDWATER FLOW
PRESSURIZER PRESSURE vs TIME

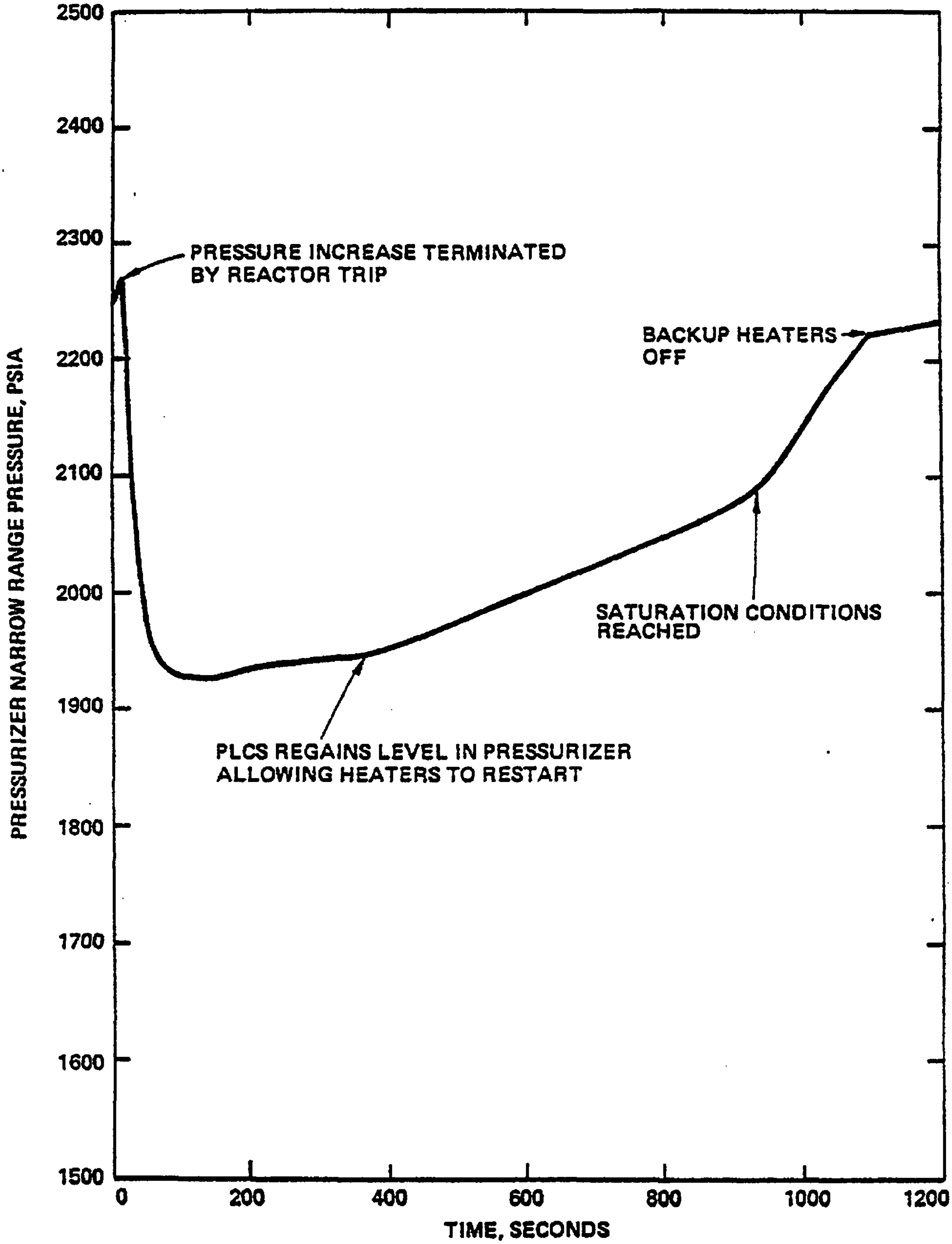


FIGURE 8-8

REPRESENTATIVE TOTAL LOSS OF MAIN FEEDWATER FLOW
PRESSURIZER LEVEL vs TIME

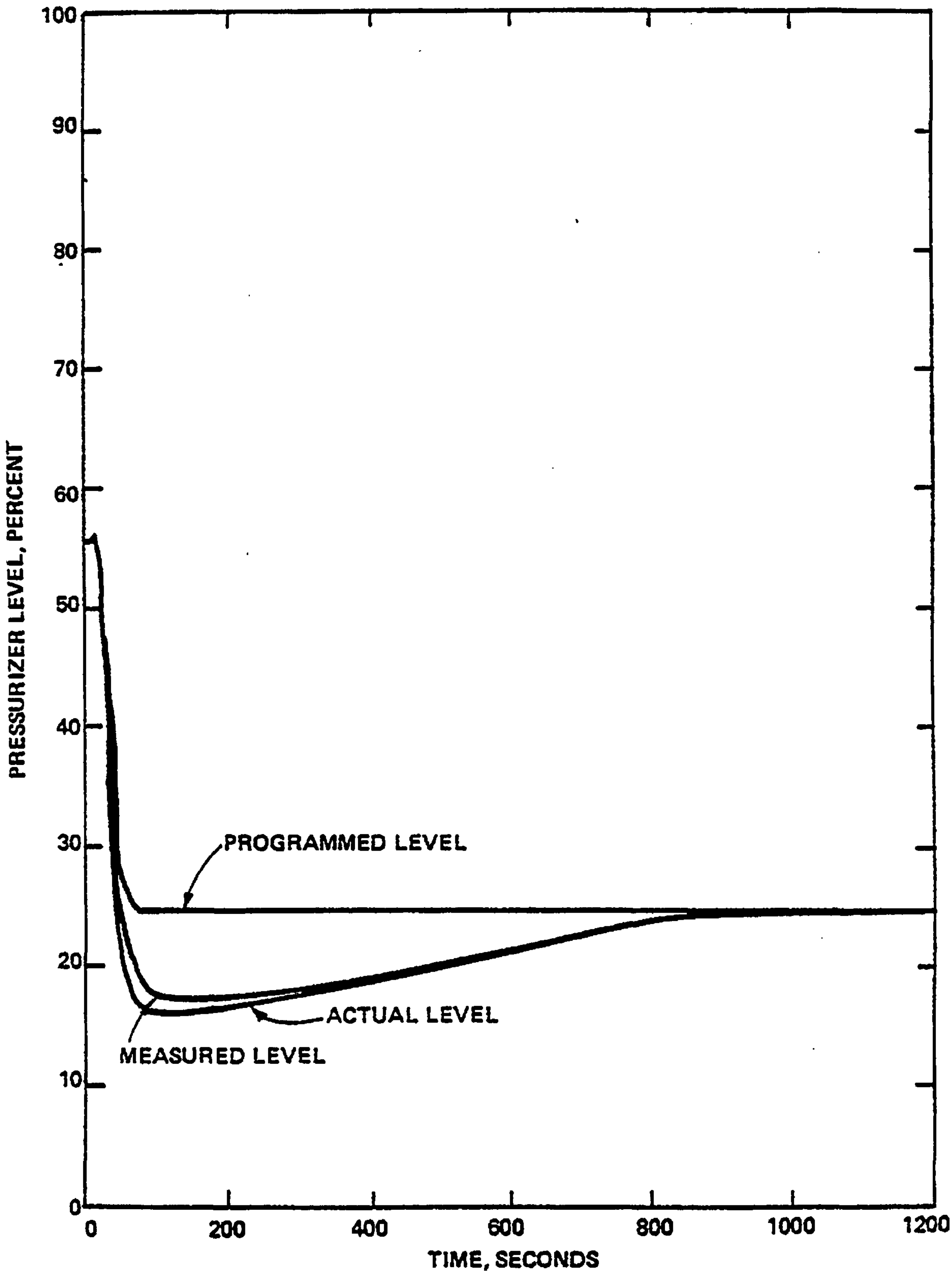


FIGURE 8-9
REPRESENTATIVE TOTAL LOSS OF MAIN FEEDWATER FLOW
STEAM GENERATOR PRESSURE vs TIME

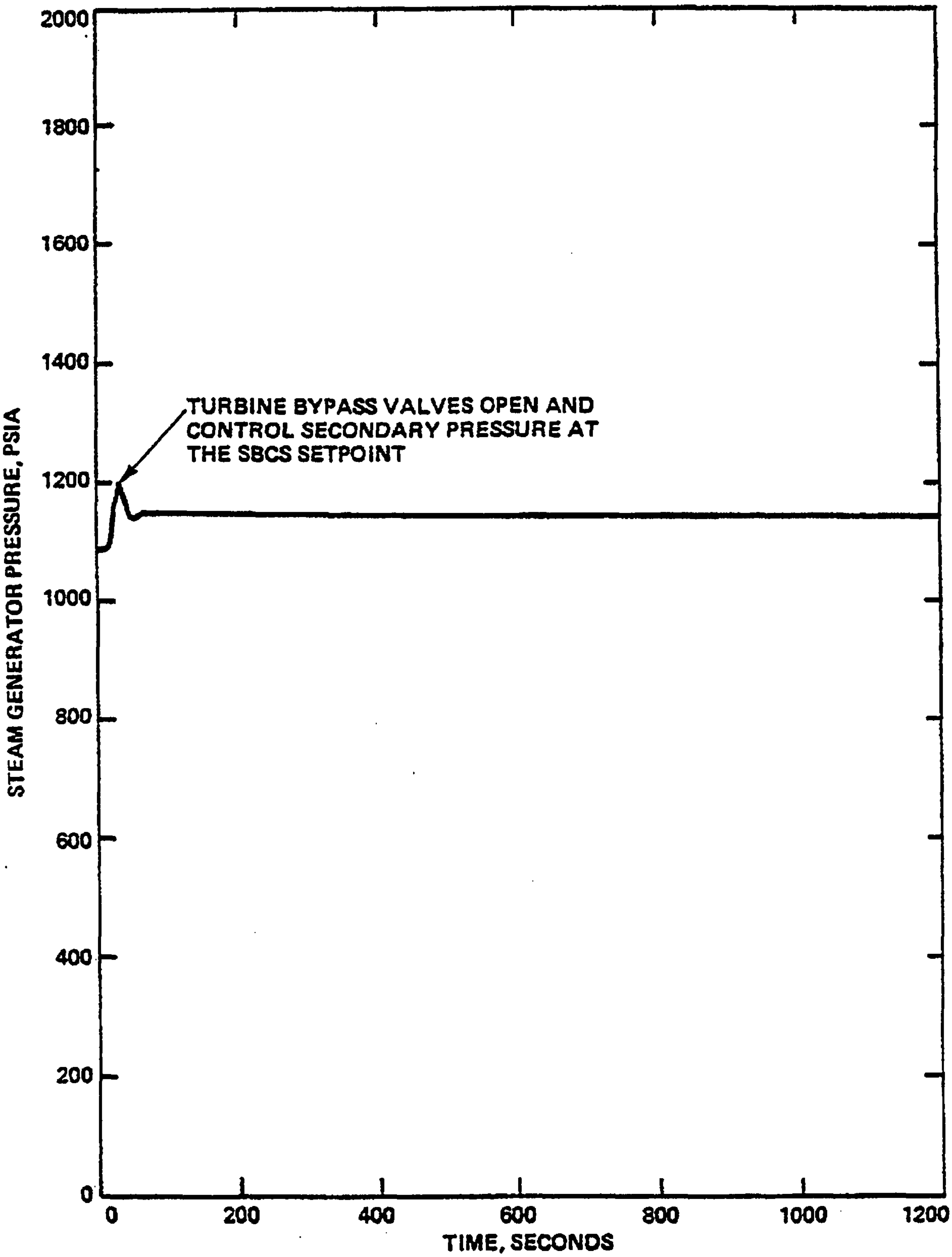
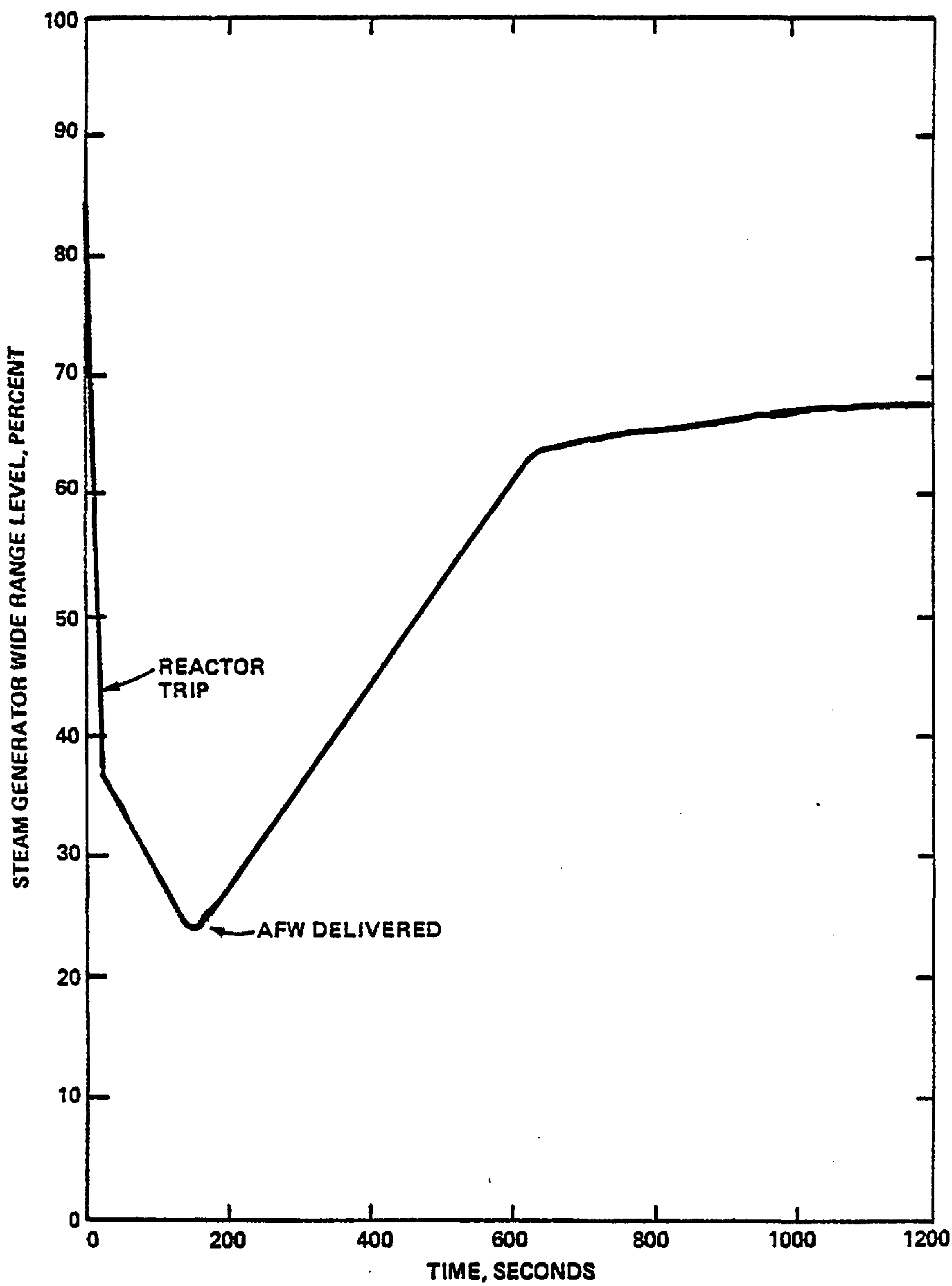


FIGURE 8-10
TOTAL LOSS OF MAIN FEEDWATER FLOW
STEAM GENERATOR LEVEL vs TIME



Guideline Strategy and Information Flow

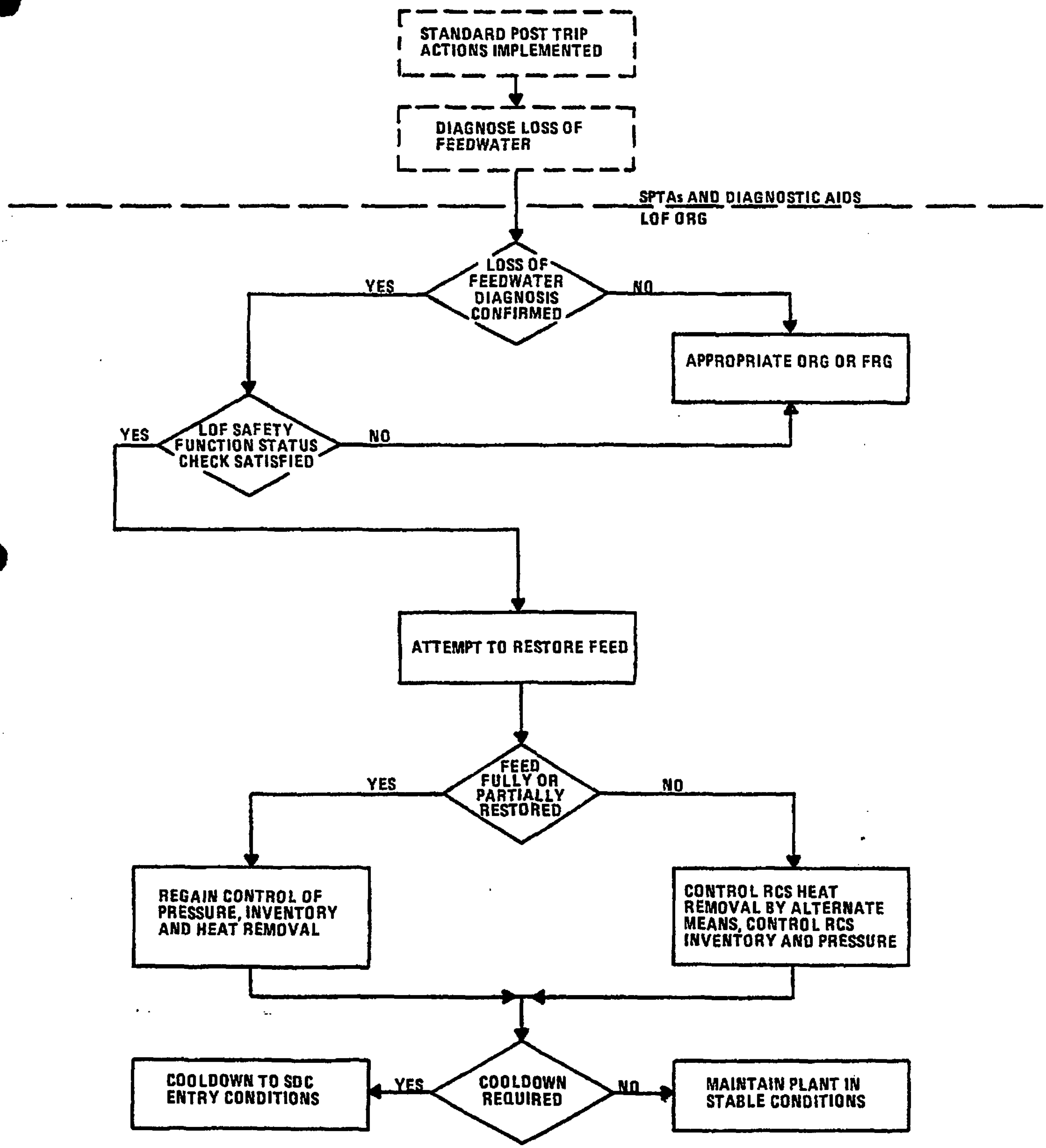
Figure 8-11 has been included to provide the reader with a summary description of the LOF Recovery Guideline strategy and information flow. Prior to implementing the actions provided in the LOF Recovery Guideline, the operator would have performed the standard post trip actions and diagnosed the event. The first two actions encountered in the LOF Recovery Guideline require a verification that these actions have taken place. The steps following the verification are an attempt to restore a feedwater supply to the affected steam generator(s).

The next group of steps provide instructions on RCP termination/restart and natural circulation. These steps are illustrated in Figure 8-11. Subsequent steps are split between two paths. The preferred path deals with recovery after feed is restored. The other path provides instructions on cooling using alternate means such as once-thru-cooling, charging, SIS, and [PORVs], while continuing efforts to regain feedwater.

A more detailed chart (Figure 8-17) illustrates the recovery guideline strategy and lists the guideline steps which correspond to each strategy objective.

FIGURE 8-11

LOSS OF FEEDWATER



Bases Operator Actions

The operator actions are directed towards determining the cause of the loss of feedwater, regaining feedwater system operation and, if this is not possible, removing heat from the RCS and conducting an orderly cooldown.

1. The execution of all standard post trip actions is verified. This assures that all safety functions have been initially attended to.

2. The diagnosis of an LOF event is confirmed by [verifying that the Safety Function Status Check criteria are being satisfied. This action ensures that the proper procedure is being used in mitigating the effects of an LOF and all relevant safety functions are being satisfied].

3. If the diagnosis of an LOF is confirmed, then the operator continues with the actions of this guideline. If a correct diagnosis is not confirmed, then the operator is directed to implement the Functional Recovery Guideline. The Functional Recovery Guideline is functionally oriented and will ensure all safety functions are attended to regardless of what event(s) is occurring.

4. [A loss of feedwater event may result in a reduction, or total loss of the ability of the steam generator(s) to remove heat from the RCS. Heat input to the RCS may be minimized by tripping two RCPs (in opposite loops). This enhances the recovery from an LOF event in two ways. Firstly, heat input to the RCS is minimized in an event in which RCS heat removal is of prime concern. Secondly, the action allows for continued operation of 2 RCPs in order to maintain normal pressurizer spray flow and forced primary circulation which are preferred for efficient plant cooldown once main or auxiliary feed flow is restored]. (Figure 8-12).

FIGURE 8-12a

RCP TRIP STRATEGY FOR LOF

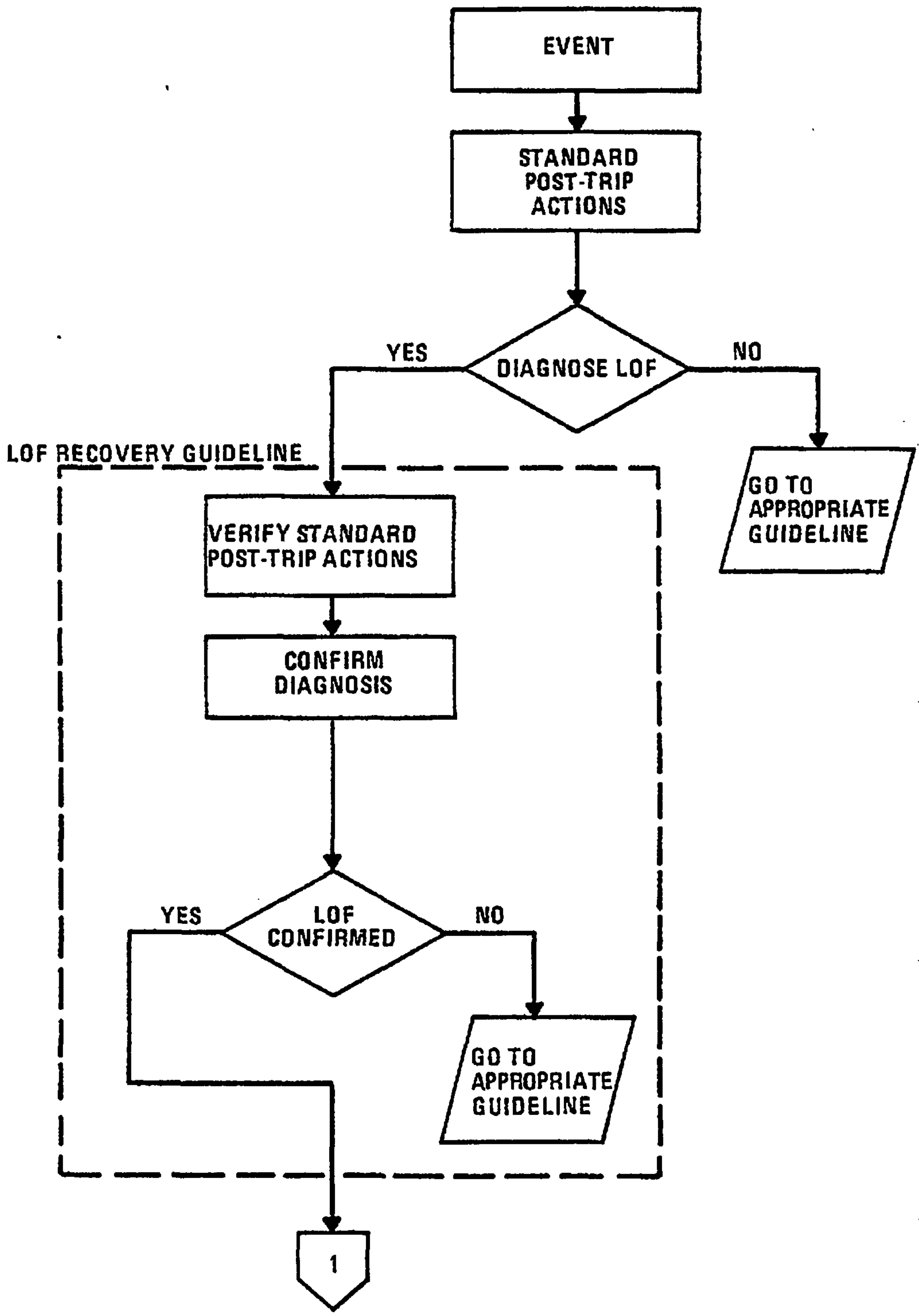
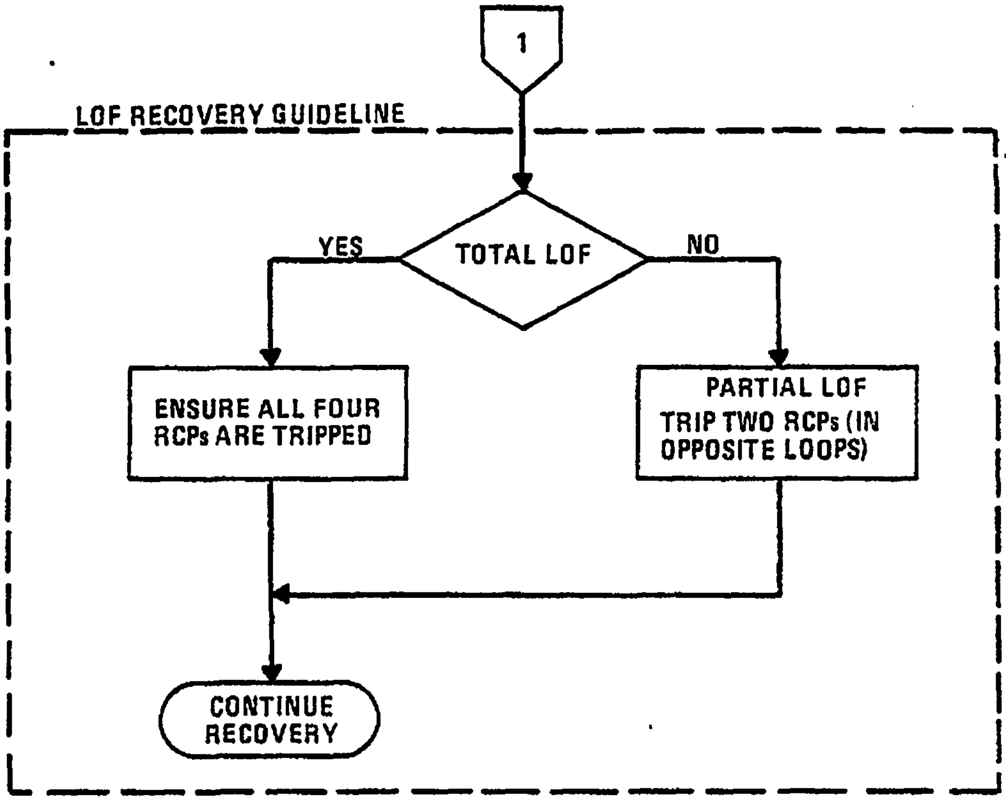


FIGURE 8-12b


1
LOF RECOVERY GUIDELINE
TOTAL LOF
YES
NO
ENSURE ALL FOUR RCPs ARE TRIPPED
PARTIAL LOF
TRIP TWO RCPs (IN OPPOSITE LOOPS)
CONTINUE RECOVERY

5. If a main feedwater line break is suspected, then the operator should try to isolate the feedwater line break from the steam generators by any plant-specific methods possible (i.e., closing main feedwater isolation valves, main feedwater regulating valves, etc.). A feedwater line break upstream of the check valves at the inlet to the steam generator should automatically be isolated from the steam generator.

   If the feedwater line break cannot be isolated from the steam generator, then it will continue to blowdown water until the steam generator boils dry. This results in an uncontrolled cooldown of the RCS. When the operator determines that a feedwater line break is unisolable, the Excess Steam Demand Event Recovery Guideline should be immediately followed for all further actions. If a main feedwater line break has not occurred, or the break is isolated from the steam generator, then the operator should proceed with the recovery actions of this guideline.

   If the loss of feedwater flow is only partial and is discovered before the reactor trip, then the operator may attempt to reduce reactor power to a level within the reduced capacity of the operating feedwater supply equipment. This course of action is allowable only if the operator has positively concluded that the loss of feedwater is only partial. In this case, the operator would be implementing the actions of an abnormal, not an emergency, guideline.

6. The operator is required to continually verify that the safety functions are being satisfied by comparing control board parameters to the criteria of the Safety Function Status Check. This ensures that all relevant safety functions are being satisfied and the core is being adequately cooled.

7. If all the safety functions from the Safety Function Status Check are satisfied, then this procedure is adequately mitigating the effects of the LOF. Therefore, the implementation of the remaining action of this guideline are continued.

If all relevant safety functions are not being satisfied, then the procedure is not adequately mitigating the occurring event. The operator is required to leave the LOF guideline and implement the Functional Recovery Guideline. This guideline is functionally oriented and will ensure all safety functions are attended to regardless of what event(s) is occurring.

8. The operator should attempt to restore the correct operation of the [main or auxiliary] feedwater system by restoring electrical power, operating valves, starting pumps or restoring other important auxiliary systems in order to provide a primary decay heat sink for a controlled reactor cooldown.

   The steam generator level should be increased at a rate consistent with both the decay heat removal rate and desired cooldown rate to prevent exceeding Technical Specifications or causing an unnecessary depressurization. Because decay heat and power history will vary over core life, the operator must use judgement in feeding the steam generator. If the refill rate is too fast, the RCS temperature can easily be driven below the desired no load value. Consequently, pressurizer level may fall to the point where the pressurizer is drained and the safety injection system is actuated.

9. [To avoid damage to the steam generator feed ring the operator should control the auxiliary feedwater system, if it is started. If feedwater flow has been interrupted and is regained and if steam generator level is below the feed ring, the operator should limit feedwater flow to 150 gpm for five minutes. Steam generator water level should be restored to the normal band as soon as possible.

   There is not analytical correlation between feedwater flow rate and the conditions to preclude feed ring failure. A flow rate of 150 gpm has been recommended as a procedural limit based on the fact that no significant water hammer has been observed during testing or operation with flow rates of that order. Additionally, 150 gpm has been traditionally

accepted as a flow limit by industry and the NRC for water hammer protection. The five minute duration of this limited flow is conservatively based on twice the refill time for the 350 gallon feed ring. In the event that refilling of portions of the main feedwater piping must be considered, this time would have to be adjusted accordingly.]

10. If feedwater has been restored, then go to step 12 and perform steps 12 through 17. These steps are directed at stabilizing the plant and recovering from an LOF.

11. If feedwater has not been restored, then go to step 18 and perform steps 18 through 29. These steps are directed at combatting a total LOF.

12. Steam generator pressure should be controlled by the turbine bypass system at [900 psia] or less depending on current RCS temperature. The goal is to stabilize RCS temperature and remove decay heat. If condenser vacuum is lost, the turbine bypass system is not available, or if the MSIVs have closed, the atmospheric dump valves must be used to control steam generator pressure. This action is performed to maintain steam generator pressure below the secondary safety valve setpoints, preventing them from opening, and allow a controlled RCS heat removal process using the steam generators.

13. Steam generator level is controlled in the normal level band using [main or auxiliary] feedwater to provide for RCS heat removal.

14. The auxiliary feedwater source is the condensate storage tank. If the auxiliary feedwater system is being used, the inventory in the condensate storage tank must be verified to be adequate. This can be determined from Figures 8-3 and 8-4. Alternate sources of condensate must be investigated. These alternate sources must be identified in plant specific procedures. Examples of alternate sources of condensate are non-seismic tanks, fire mains, lake water supplies, potable tanks, etc.

15. The PPCS is verified to be automatically controlling or restoring RCS pressure within the limits of Figure 8-1. If not, pressurizer heaters or main spray (preferred) or auxiliary spray are operated manually to control pressurizer pressure. This action verifies that the RCS pressure control safety function is being satisfied.

16. The PLCS is verified to be automatically controlling or restoring pressurizer level in the hot zero power reference band. If not, charging and letdown are operated manually to ensure pressurizer level is being maintained. This action verifies that the RCS inventory control safety function is being satisfied.

17. The plant should be maintained in a stable condition based on auxiliary systems availability. One concern the operator must have, is the remaining supply of feedwater. Condensate inventory adequacy is determined according to Figures 8-3 and 8-4. If the available condensate appears to be marginally adequate, a plant cooldown within Technical Specification limitations should be commenced immediately in order to avoid running out of existing condensate before the shutdown cooling system can be placed into operation. Otherwise, a cooldown may be initiated at a time which depends upon restoration of any other necessary vital auxiliaries. Cooldown is conducted in accordance with the normal plant cooldown procedure.

18. If all feedwater is lost (both main and auxiliary) to both steam generators, then certain actions should be performed to keep the plant in a stable condition. These actions are:

    a) To minimize heat input into the RCS, stop all RCPs.

    b) If operating, the steam generator blowdown system, secondary sampling system or any other nonvital secondary discharge must be secured. Until feedwater is reestablished, the steam generator water inventories must be conserved.

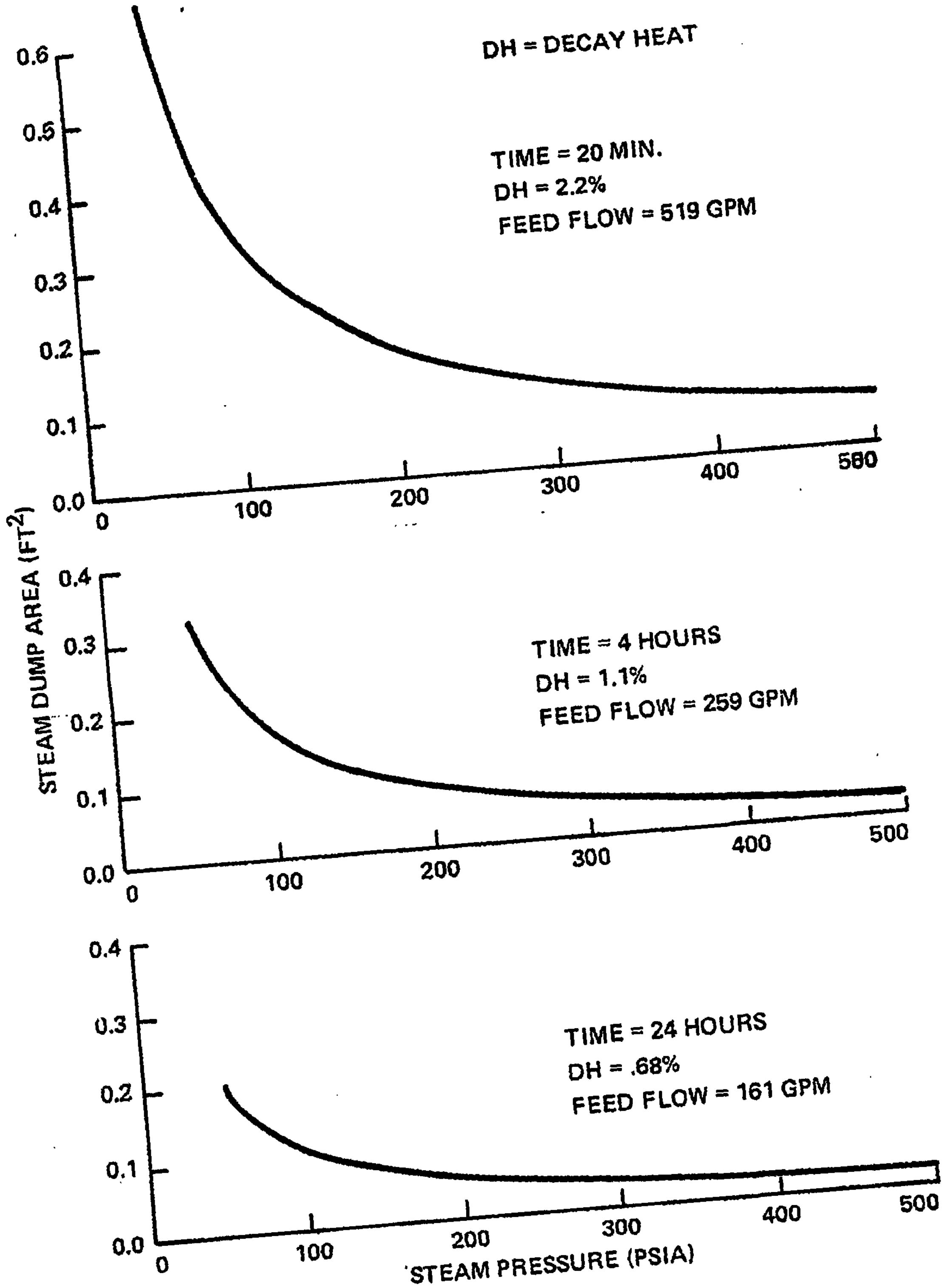
c) Continue to attempt to restore main or auxiliary feedwater system operation. Such attempts may include restoration of vital auxiliaries like instrument air, electrical power, and/or instrumentation. They may also include manual operation of valves or other equipment that is normally operated remotely.

d) If both main and auxiliary feedwater cannot be restored to either steam generator, then all plant specific sources of feedwater which could be made available to replace steam generator boil-off should be implemented. Examples of alternate sources of feedwater are fire pumps, condensate pumps, portable pumps, etc. When developing plant procedures, alternate sources of feedwater should be identified and their use should be indicated in the procedures. Guidelines on steam generator depressurization should be developed for those cases when the operator is relying on low pressure sources of feedwater as a backup feedwater supply. Figure 8-13 provides an example of the type of information that must be developed on a plant specific basis. The figure provides a typical required steam generator dump area to remove heat from the steam generator for various times after shutdown. The required heat removal, compared to the available heat removal capacity (i.e., atmospheric dump valves), provides the technical basis for which guidance may be developed on steam generator depressurization to permit use of alternate sources of feedwater.

19. [As a last resort, cooling of the core is attempted by core flushing. All available charging pumps are started, the SIS is aligned for cold leg injection, and the PORVs are opened. Core flushing is from the cold legs, through the core, and out the PORVs. It is most important to keep the core covered in this mode of cooling. Core coverage is indicated by [the RVLMS], RCS subcooling $\geq$ [0°F] on RCS temperature indication (in particular, the [CETs]). If superheat is indicated or approached, the operator should attempt to maximize makeup to the RCS using charging and SIS pumps. Lowering RCS pressure will usually increase SIS flow].

FIGURE 8-13

REQUIRED STEAM DUMP AREA vs STEAM PRESSURE
3800 MW CLASS PLANT



LOF

20. If an SIAS has been initiated and the SIS is operating, then it must continue to operate at full capacity until SIS termination criteria are met. Termination of SIS should be sequenced by stopping one pump at a time while observing the termination criteria. Throttling of HPSI flow is permissible if it is feasible. SIS termination criteria are:

a) RCS is at least [20°F] subcooled (Figure 8-14). Establishing [20°F] of subcooling ensures the fluid in the core is subcooled, and provides sufficient margin for establishing flow should the [20°F] subcooling deteriorate when SIS flow is secured. Voids may exist in some parts of the RCS (e.g., reactor vessel head), but these are permissible as long as core heat removal is maintained.

b) Pressurizer level is greater than [100"] and not decreasing. A pressurizer level greater than [100"] and not decreasing in conjunction with criterion a) above is an indication that RCS inventory control has been established.

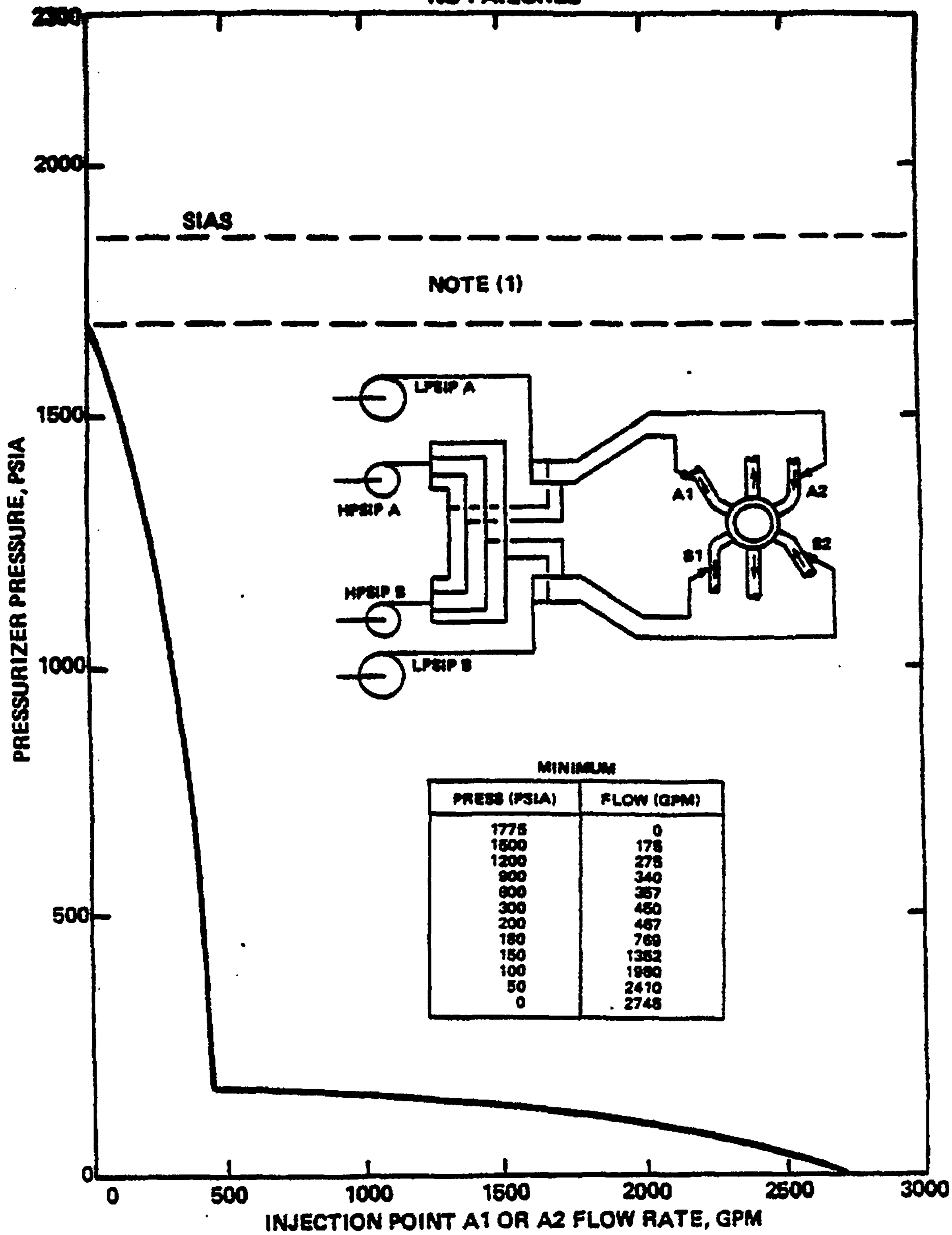
c) At least one steam generator is available for removing heat from the RCS. Steam generator availability requires having feedwater flow and steam flow which are indications that primary to secondary heat removal is possible.

d) [The RVLMS indicates the core is covered. An indication of core coverage in conjunction with the above, serves as an additional indication that RCS inventory control has been established.]

If the criteria are met, then the operator may either terminate or throttle the SIS. The operator may decide to throttle rather than terminate if the SIS is to be used to control pressurizer level or plant pressure. A general assessment of the SIS performance can be made from the control room. The operator should confirm that at least one train and preferably both trains of SIS are operating and that system delivery rate is consistent with RCS pressure as shown in Figures 8-14 or 8-15. Injection flow rates to each cold leg should be approximately equal.

FIGURE 8-14

TYPICAL SAFETY INJECTION DELIVERY CURVES
NO FAILURES



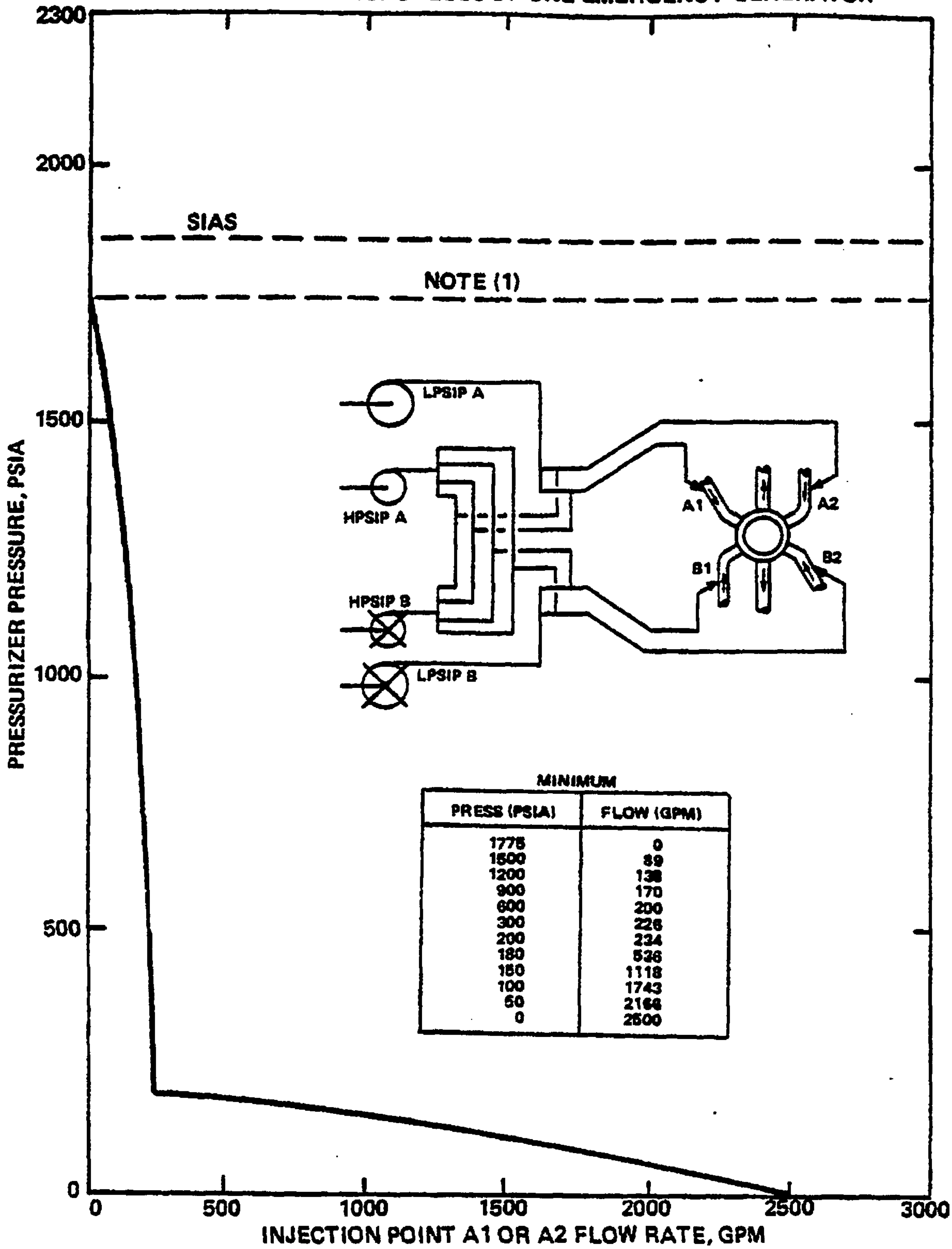
MINIMUM

PRESS (PSIA)	FLOW (GPM)
1775	0
1500	175
1200	275
900	340
600	357
300	450
200	467
180	769
150	1362
100	1980
50	2410
0	2745

NOTE: (1) BELOW SIAS PRESSURE, SAFETY INJECTION SYSTEM (SIS) PUMPS WILL BE OPERATING, BUT THERE WILL BE NO INJECTION FLOW UNTIL SYSTEM PRESSURE FALLS BELOW THE SHUTOFF HEAD PRESSURE OF ANY SIS PUMP

FIGURE 8-15

TYPICAL SAFETY INJECTION DELIVERY
FAILURE CONDITIONS - LOSS OF ONE EMERGENCY GENERATOR



MINIMUM

PRESS (PSIA)	FLOW (GPM)
1775	0
1500	89
1200	138
900	170
600	200
300	226
200	234
180	526
150	1118
100	1743
50	2166
0	2500

NOTE: (1) BELOW SIAS PRESSURE, SAFETY INJECTION SYSTEM (SIS) PUMPS WILL BE OPERATING, BUT THERE WILL BE NO INJECTION FLOW UNTIL SYSTEM PRESSURE FALLS BELOW THE SHUTOFF HEAD PRESSURE OF ANY SIS PUMP

21. If the criteria of step 20 cannot be maintained after SIS termination, then the SIS must be restarted.

22. [If other methods are available for RCS heat removal purposes, then they should be appraised and if possible implemented. Examples might be alternate once-through cooling paths such as drain valves, pressurizer vents, etc. These should be indicated in the procedures.]

23. If feedwater is regained, then maintain RCS heat removal by removing steam via the turbine bypass valves, or if the condenser is not available, via the atmospheric dump valves from at least one steam generator.

    Once-through-cooling (or plant-specific alternate cooling method) is stopped as soon as RCS heat removal is established via at least one steam generator and one steam generator has the capability of removing decay heat.

24. If all RCPs have been stopped, then operation of two RCPs (in opposite loops) should be attempted if feedwater can be restored to at least one S/G. This will ensure continued forced circulation of coolant through the core and will provide the capability for the normal mode of pressurizer spray. However, only one RCP in each loop should be operated to minimize heat input to the RCS.

    Determine whether RCP restart criteria are met by the following:

    a) At least one steam generator has feedwater restored and is available for removing heat from the RCS. A steam generator having feed flow and removing heat from the RCS is an indication that primary to secondary heat removal is being maintained.

    b) Pressurizer level is greater than [200"] and not decreasing. With pressurizer level at the high end of the operating band, the possibility of draining the pressurizer due to loop shrinkage and/or steam void condensation is minimized and there is a greater likeli-

hood of keeping the pressurizer heaters covered. This will assist in maintaining positive RCS pressure control. The criterion of pressurizer level not decreasing implies that RCS inventory control has been established.

c) The RCS is greater than or equal to [20°F] subcooled. An RCS subcooled condition taken in conjunction with (b) above indicates that inventory and pressure are being controlled.

d) [All plant specific RCP operating criteria are satisfied before the RCPs are restarted to protect the RCPs from damage. Following automatic or operator initiated containment isolation, reinstatement of component cooling water to the RCPs should be considered in order to ensure adequate RCP cooling.]

25. Upon restarting two RCPs in opposite loops, pressurizer level and pressure may decrease due to loop shrinkage and/or void condensation. It is possible that this action will drain the pressurizer. Steam voids, if present in the reactor vessel, will condense upon restarting RCPs. [The RVLMS should be monitored for the trending of reactor vessel liquid level. This trending information may be correlated to pressurizer level decrease.] RCP operation with a drained pressurizer may continue provided certain actions are taken and certain criteria are satisfied.

The following constitute the actions to be taken and the criteria to be satisfied when restarting RCPS:

a) Start one RCP in each loop.

b) [Ensure proper RCP operation by monitoring RCP amperage and pump NPSH. NPSH is determined by pressurizer pressure and corresponding T_c on Figure 8-1.]

c) Operate all available HPSI and charging pumps until pressurizer level is greater than [100"] and SIS termination criteria are met.

26. If all RCP operation is terminated and when inventory and pressure are controlled, then natural circulation is maintained by heat removal via at least one steam generator. Natural circulation flow should occur within 5-15 minutes after the RCPs were tripped if there is adequate inventory in the RCS.

The RCS temperature response during natural circulation will usually be slow (5-15 minutes) as compared to a normal forced flow system response time of 6-12 seconds, since the coolant loop cycle time will be significantly larger.

When single phase natural circulation is established in at least one loop, the RCS indicates the following conditions:

a) Loop ΔT (T_H - T_C) less than normal full power ΔT
b) Cold leg temperatures constant or decreasing
c) Hot leg temperatures stable (i.e., not steadily increasing) or decreasing slowly
d) No abnormal differences between T_H RTDs [and core exit thermocouples]. Hot leg RTD temperature should be consistent with the [core exit thermocouples]. Adequate natural circulation flow ensures that core exit thermocouples temperatures will be approximately equal to the hot leg RTDs temperature within the bounds of the instrument's inaccuracies. An abnormal difference between T_H and the [CETs] is [10°F].

Natural circulation is governed by decay heat, component elevations, primary to secondary heat transfer, loop flow resistance, and voiding. Component elevations on C-E plants are such that satisfactory natural circulation decay heat removal is obtained by fluid density differences between the core region and the steam generator tubes.

The operator has adequate instrumentation to monitor natural circulation for the single phase liquid natural circulation process. The RCS temperature instrumentation, namely loop ΔT can be used along with other information to confirm that the single phase natural circulation process is effective.

27. If the criteria of step 26 are not met, then natural circulation is not effectively transferring heat from the core to the steam generators. If feedwater has been regained or sufficient inventory is available in at least one S/G, then ensure RCS pressure and inventory are being controlled properly. Feedwater, however, must be restored to at least one S/G in order to establish or continue the natural circulation heat removal process. Both the RCS and Core Heat Removal Safety Functions may be jeopardized if the criteria of step 26 continue to be violated.

28. The bases for maintaining the RCS pressure and temperature within the acceptable range of the P/T limit curve (Figure 8-1) is that it provides for adequate core cooling by requiring the maintenance of minimum subcooling and it minimizes the reactor vessel stresses of concern for pressurized thermal shock by specifying a maximum subcooling value. Operator actions such as termination of HPSI or charging flow may be required to prevent the excessive repressurization (> [200°F] subcooling) of the RCS which is of concern for PTS.

29. The plant should be maintained in a stable condition. Based on auxiliary systems availability and plant conditions, and, if feedwater is regained, condensate inventory, evaluate the need for a plant cooldown. If required, conduct a plant cooldown within Technical Specification Limits and enter shutdown cooling.

    One concern the operator must have if feedwater is restored is the remaining supply of feedwater. Refer to Figures 8-3 and 8-4. If the available condensate appears to be marginally adequate, a plant cooldown within Technical Specification Limitations should be commenced immediately in order to avoid running out of existing condensate before the shutdown cooling system can be placed into operation. Otherwise, a cooldown may be initiated in a more deliberate manner depending on the restoration of desirable vital auxiliaries.

Safety Function Status Checks

Figure 8-16 provides a bases for the LOF Safety Function Status Check. The Safety Function Status Check charts are designed to ensure that the operator is using the correct guideline, and the actions of that guideline are satisfying all relevant safety functions and maintaining adequate core cooling.

The safety function status check provides a systematic approach to determine if the LOF recovery guideline is appropriate, and more importantly, if the plant conditions is satisfactory. Safety functions have been used throughout the guideline system as a structure for storing and using operational information. When the plant is in a normal condition each safety function can be explicitly shown to be satisfied.

SAFETY FUNCTION STATUS CHECK BASES
LOSS OF FEEDWATER
Figure 8-16a

The safety functions listed below and their respective criteria are those used to confirm the adequacy of the LOF Guideline in mitigating the event.

SAFETY FUNCTION	ACCEPTANCE CRITERIA	INDICATION	RANGE	BASES
Reactivity Control	Reactor Power Decreasing and [Negative Startup Rate] and Not more than 1 CEA Bottom Light Not Lit or Borated per Tech Specs	Power Range Power Rate CEA Status Display	[0 - 125%] [-1 → 7 dpm] On/Off Light for each CEA	For all emergency events, the reactor must be shutdown. The criteria that no more than one CEA be stuck out or the RCS borated observes typical technical specification requirements.
Maintenance of Vital Auxiliaries (AC & DC Power)	[<----------------Plant Specific---------------->]			
RCS Inventory Control	If [35"] ≤ Pressurizer Level ≤ [245"]; Then: charging and letdown are being operated manually or automatically to control pressurizer level and RCS > [20°F] subcooled and [the RVLMS indicates the core is covered] or	Pressurizer Level [RVLMS]	[0 - 350"] [0 - 100%]	A value of [245"] ([70%] of range) was chosen as an upper limit for pressurizer level to account for instrument accuracies and other uncertainties. A value of [35"] ([10%] of range) was chosen as a lower limit to account for instrument accuracy. A [20°F] subcooling margin coexisting with a pressurizer level between [35"] and [245"] indicates adequate RCS inventory control via a saturated bubble in the pressurizer.

SAFETY FUNCTION STATUS CHECK BASES
LOSS OF FEEDWATER
Figure 8-16b

The safety functions listed below and their respective criteria are those used to confirm the adequacy of the LOF Guideline in mitigating the event.

SAFETY FUNCTION	ACCEPTANCE CRITERIA	INDICATION	RANGE	BASES
RCS Inventory Control (Cont'd)	If Pressurizer Level < [35"]; Then: [The RVLMS indicates the core is covered] and [all available charging pumps are operating and] the SIS pump(s) are injecting water into the RCS per Figure 8-2.			An RVLMS indication that the core is covered, taken in conjunction with [20°F] subcooling is an additional indication that RCS inventory control has been established.
RCS Pressure Control	If pressurizer pressure < [2350 psia] and ≥ [1600 psia] then pressurizer heaters and spray are being operated manually or automatically to control pressurizer pressure* or If PZR Pressure < [1600 psia]; Then all available charging pumps are operating and] the SIS pump(s) are injecting water into the RCS per Figure 8-2 (unless SIS termination criteria are met).	Pressurizer Pressure	[1500-2500 psia]/ [0-1600 psia]	[2350 is the high pressure alarm setpoint. Best estimate analysis shows that a LOF can be maintained within the above range.

* Not applicable if in once-through cooling.

SAFETY FUNCTION STATUS CHECK BASES
LOSS OF FEEDWATER
Figure 8-16c

The safety functions listed below and their respective criteria are those used to confirm the adequacy of the LOF Guideline in mitigating the event.

SAFETY FUNCTION	ACCEPTANCE CRITERIA	INDICATION	RANGE	BASES
Core Heat Removal	If not in once-through cooling, Then: RCS T_{ave} < [545°F]* and RCS Subcooled ≥ [20°F]* <u>or</u> If in once-through cooling; Then RCS Subcooling ≥ [0°F][by CET]	RCS T_{ave} [Subcooled Margin Monitor [Core Exit Thermocouples]	[520 - 610°F] [0 - 100°F] [0-1600°F]	[545°F] is based on control program for ADVs and steam dump bypass, and best estimate analysis values. [20°F] subcooled margin is based on engineering judgement to assure adequate core cooling accounting for temperature variations in the RCS. Best estimate analysis shows that the noted events will fall in the selected ranges. Subcooled margin > [0°F] is based on keeping the core covered while in once-through cooling since superheat on the [CETs] is indicative of core uncovery.
RCS Heat Removal	RCS T_{ave} < [545°F]* <u>and</u> Loop ΔT in at least one S/G is: <[10°F] for forced circulation* or ΔT < [50°F] for natural circulation*	T_H T_C		Loop ΔT on at least one operable steam generator which is appropriate for the existing RCS flow mode is indicative of adequate S/G heat removal.

* Not applicable if in once-through cooling.

SAFETY FUNCTION STATUS CHECK BASES
LOSS OF FEEDWATER
Figure 8-16d

The safety functions listed below and their respective criteria are those used to confirm the adequacy of the LOF Guideline in mitigating the event.

SAFETY FUNCTION	ACCEPTANCE CRITERIA	INDICATION	RANGE	BASES
Containment Isolation	Containment Pressure < [1.5 psig]*	Containment Pressure	[0 - 60 psig] [0 - 15 psig]	[1.5 psig] is based on the containment pressure alarm. It is not expected, for the selected events, that containment pressure will increase to the alarm setpoint. During a LOF it is not expected that there will be radiation inside containment or in the steam plant. The containment area monitors should not be alarming (unless once-through cooling is in use).
	and			
	No containment area radiation monitors alarming*	Containment Area Rad. Monitors	Alarming/ Not Alarming	
	and			
	No steam plant radiation monitors alarming	Steam Plant Rad. Monitors	Alarming/ Not Alarming	
Containment Temperature and Pressure Control	Containment Temperature < [215°F]*	Containment Temperature	[50-300°F]	The maximum normal expected average containment air temperature.
	and			
	Containment Pressure < [1.5 psig]*	Containment Pressure	[0-60 psig] [0-15 psig]	[1.5 psig] is based on containment pressure alarm. It is not expected for the selected events that containment pressure will increase to the alarm setpoint.
Containment Combustible Gas Control	H_2 < [2%]	[<-------------------Plant Specific	--------------------------------	------>]

* Not applicable if in once-through cooling.

Event Strategy

This section contains the detailed LOF recovery actions strategy chart (Figure 8-17). The chart depicts the strategy around which the LOF guideline is built. It is intended to assist the procedure writer in understanding the intent of the guideline and for use in training. Operators should understand the major objectives of the guideline in order to facilitate their progress toward the guideline goals.

The strategy charts show the recovery guideline strategy in detail and lists the guideline steps which correspond to each strategy objective. Some steps in the guideline may be performed at any time during the course of an event. These steps are shown by affixed asterisks. The dashed boxes above the line indicate the lead-in steps performed by the operator prior to entering this recovery guideline.

FIGURE 8-17a
STRATEGY CHART FOR LOSS OF FEEDWATER

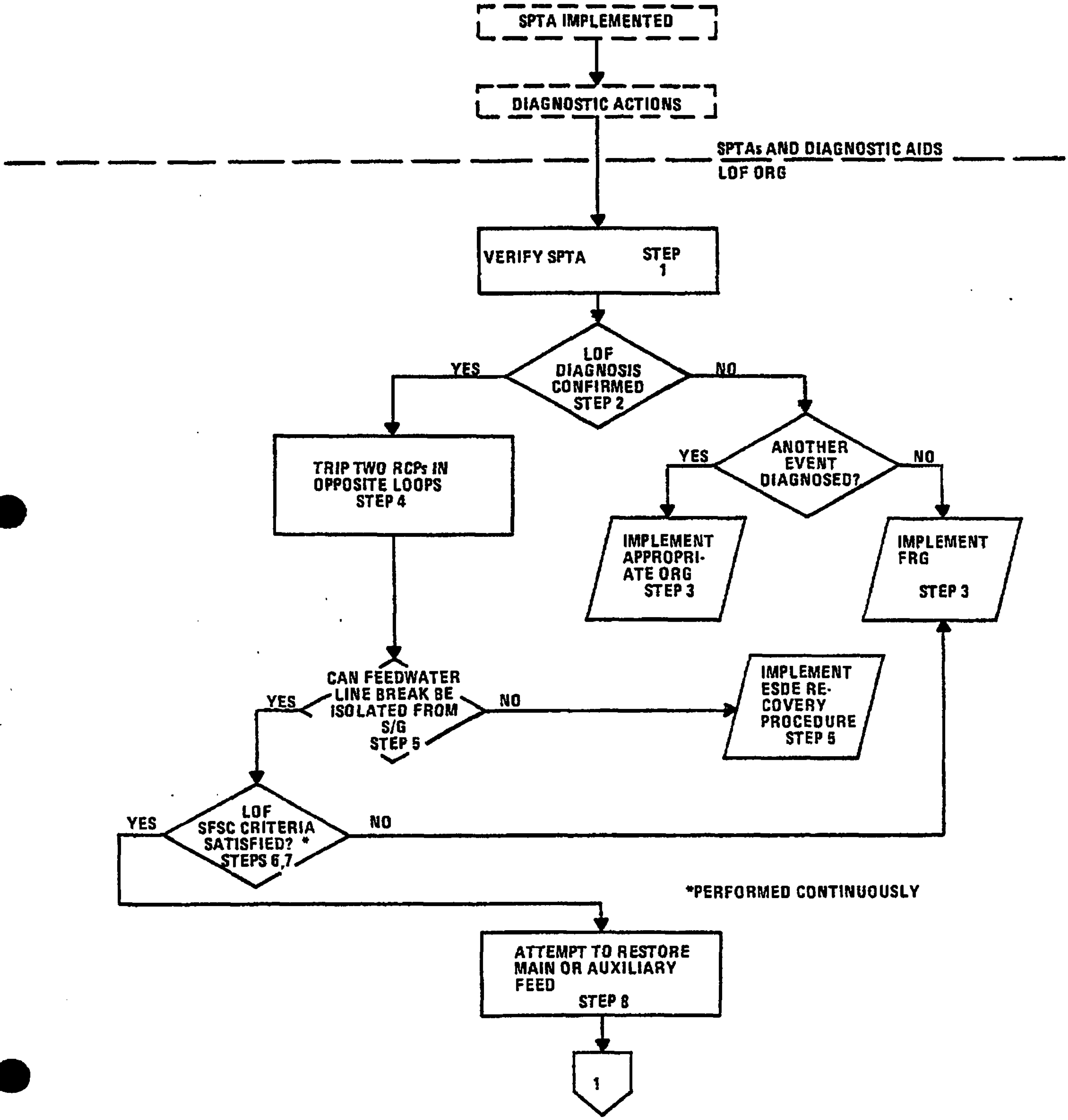


FIGURE 8-17b

STRATEGY CHART FOR LOSS OF FEEDWATER

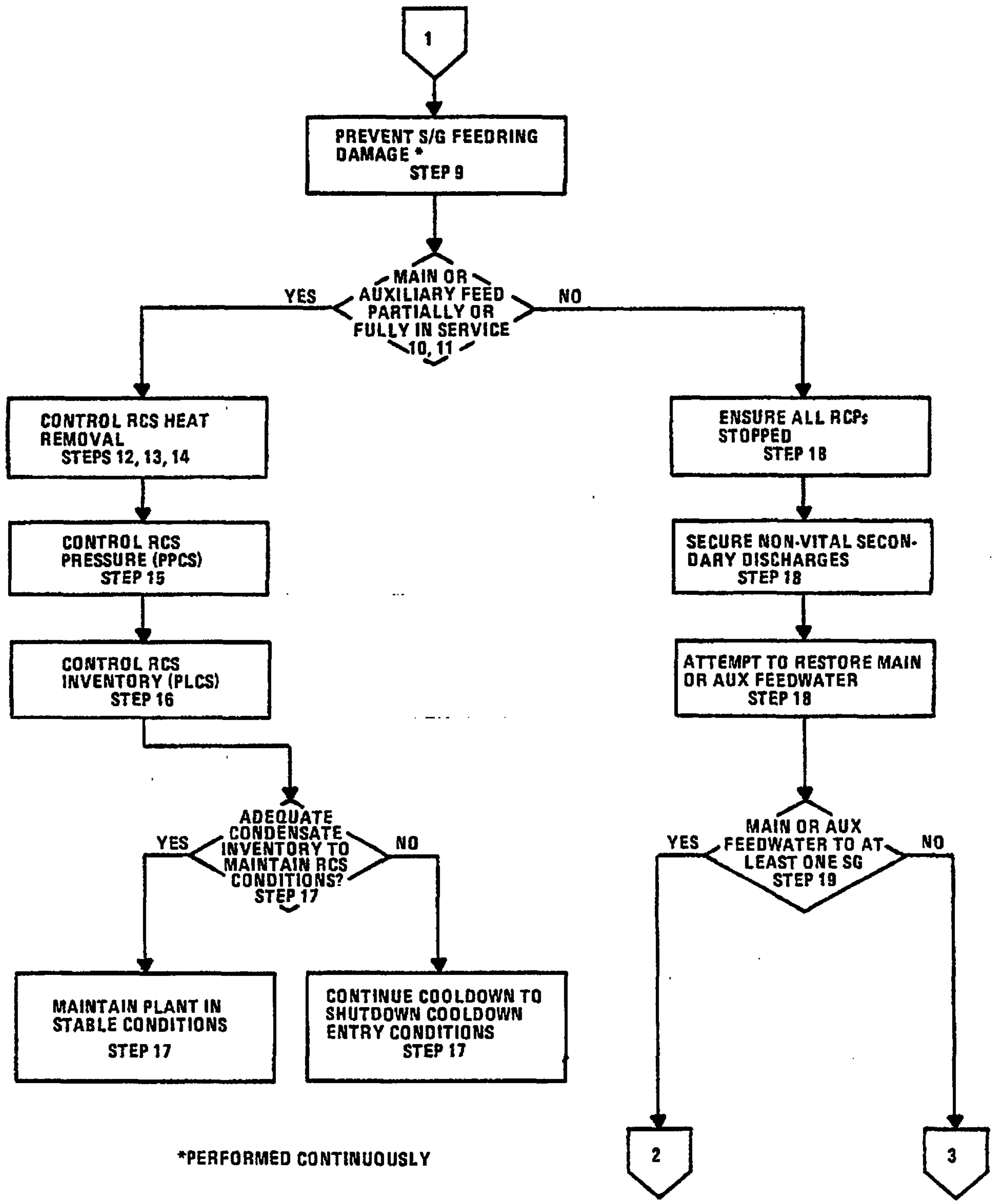
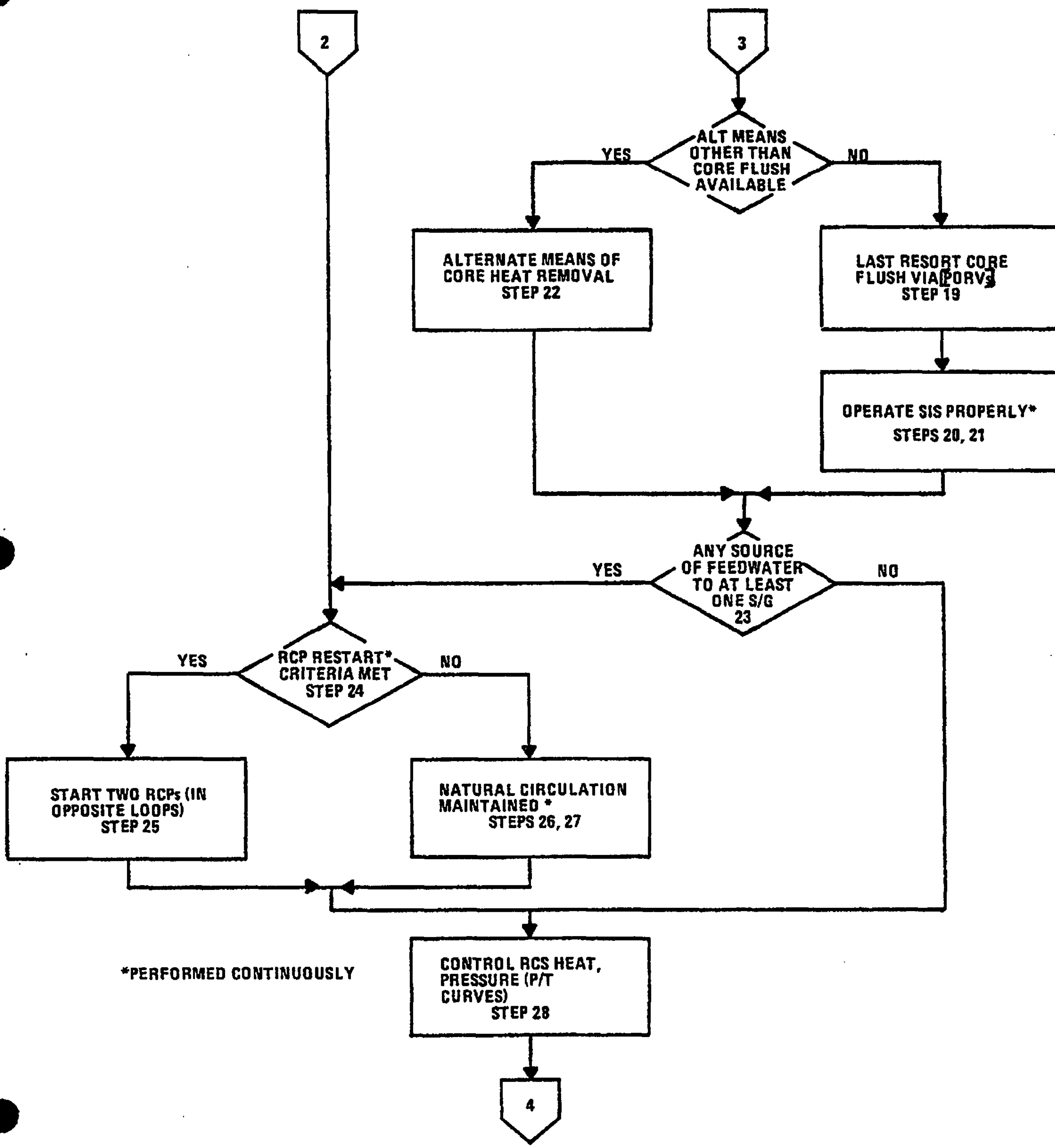
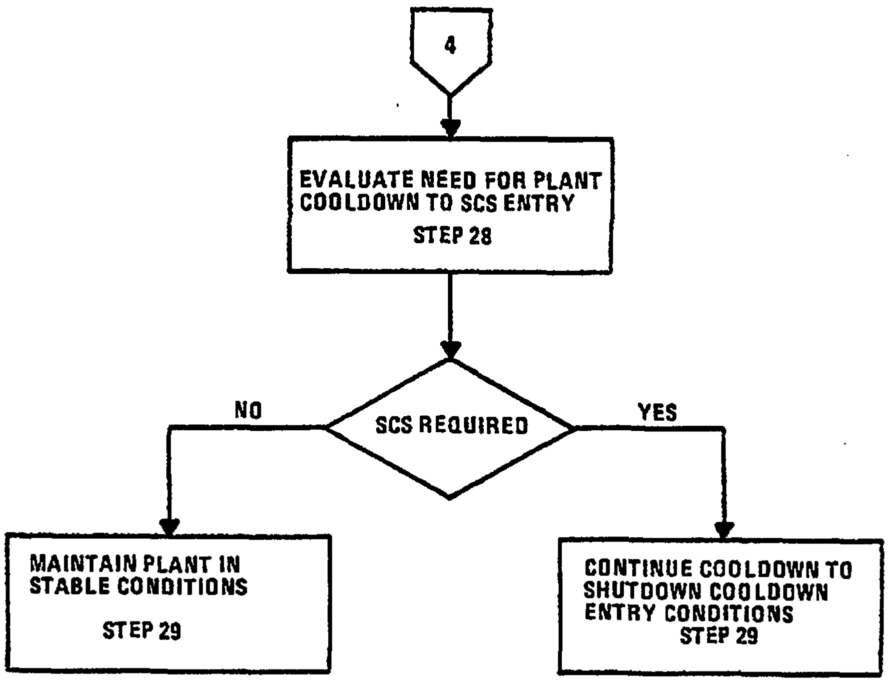


FIGURE 8-17c
STRATEGY CHART FOR LOSS OF FEEDWATER



*PERFORMED CONTINUOUSLY

FIGURE 8-17d
STRATEGY CHART FOR LOSS OF FEEDWATER



LOSS OF FORCED CIRCULATION RECOVERY GUIDELINE

Prepared by
COMBUSTION ENGINEERING, INC.
for the
C-E Owners Group

2. See Deviation 2-38.

PURPOSE

This guideline provides operator actions which must be accomplished in the event of a Loss of Forced Circulation (LOFC). The actions in this guideline are necessary to ensure the plant is placed in a stable, safe condition. This guideline provides technical information to be used by the utilities in developing a plant specific procedure.

ENTRY CONDITIONS

1. The Standard Post Trip Actions have been performed

and

2. Plant conditions indicate that a loss of forced circulation has occurred. Any one or more of the following may be present:

   a. RCP trouble alarms
   b. No RCP delta-P.
   c. Low RCS flow indications.
   d. Decreasing steam generator delta-P.
   e. [Other plant specific symptoms, insert here.]

1. IMPLEMENTED BY STEP A

2. IMPLEMENTED BY STEP B

3. SEE DEVIATION SHEET 2-2

4. IMPLEMENTED BY STEP B

5. SEE DEVIATION SHEET 2-2

6. IMPLEMENTED BY STEP V. SEE DEVIATION 2-3 for sequence variation

   a.

   b. See Deviation 2-39

   c. See Deviation 2-40

   d.

OPERATOR ACTIONS

1. Verify that the Standard Post Trip Actions have been performed.

2. Confirm the diagnosis of an LOFC event [by verifying the Safety Function Status Check criteria are satisfied].

3. If the diagnosis of an LOFC event is confirmed, Then continue with the actions of this guideline.
   If not, implement the Functional Recovery Guideline. TRAINING + SFSC

*4. Verify that the safety functions are being satisfied by comparing control board parameters to the criteria of the Safety Function Status Check. TRAINING + SFSC SECTION

*5. If the safety functions from the Safety Function Status Check are satisfied, Then continue with the actions of this guideline. TRAINING
   If not, implement the Functional Recovery Guideline. + SFSC

*6. With all RCPs stopped, Then two RCPs (in opposite loops) should be restarted if possible.

   Determine whether RCP restart criteria are met by the following:

   a) At least one steam generator is available for removing heat from the RCS,
   b) Pressurizer level is greater than [200"] and not decreasing,
   c) The RCS is at least [20°F] subcooled (Figure 9-1),
   d) [Other criteria satisfied per RCP operating instructions.]

* Step performed continuously.

7. IMPLEMENTED BY STEP V, SEE DEVIATION 2-3 FOR SEQUENCE VARIATION
c. See Deviation 2-42
8. SEE DEVIATION 2-4

9. SEE DEVIATION 2-4

10. SEE DEVIATION 2-5 . ADDED DIRECTION IN STEP Y.

11. IMPLEMENTED BY STEP H.
See Deviation 2-43

*7. If RCP restart criteria are met, Then do the following:

a) Start one RCP in each loop.
b) [Ensure proper RCP operation by monitoring RCP amperage and pump NPSH. NPSH is determined by pressurizer pressure and corresponding T_c on Figure 9-1.]
c) Operate HPSI and charging pumps until pressurizer level is greater than [100"] and SIS termination criteria are met.

*8. If the SIS is operating, Then it may be throttled or stopped, one train at a time, if the following conditions are satisfied:

a) The RCS is at least [20°F] subcooled (Figure 9-1),
b) Pressurizer level is greater than [100"] and not decreasing,
c) At least one steam generator is available (feed and steam flow) for removing heat from the RCS,
d) [The RVLMS indicates the core is covered].

*9. If the criteria of step 8 cannot be maintained after the SIS has been stopped, Then the SIS must be restarted.

*10. If RCPs are restarted, Then exit this guideline and go to the Reactor Trip Recovery Guideline.

*11. When all RCPs have been stopped, Then verify that natural circulation flow is maintained in at least one loop. The following criteria must be met to demonstrate adequate natural circulation flow:

a) Loop ΔT (T_H - T_c) less than normal full power ΔT.
b) Cold leg temperatures constant or decreasing.

* Step performed continuously.

12. IMPLEMENTED BY SFSC, STEP C, STEP G, STEP J, STEP L, STEP M

13. IMPLEMENTED BY STEP J

14. IMPLEMENTED BY STEP L

15. Implemented by STEP C. Using the condenser is NOT AN alternative because of the loss of power assumption
See Deviation Z-44

16. IMPLEMENTED BY STEP W AND STEP X.

c) Hot leg temperatures stable (i.e., not steadily increasing) or decreasing.

d) No abnormal differences between T_H RTDs [and core exit thermocouples].

*12. If the criteria listed in step 11 are not met, Then ensure RCS pressure and inventory (steps 13 and 14) and S/G steaming and feeding (step 15), are being controlled properly.

13. Verify that the PPCS is automatically maintaining or restoring RCS pressure within the limits of Figure 9-1.
If not, manually operate heaters or spray to control pressurizer pressure within the limits of Figure 9-1.

14. Verify that the PLCS is automatically maintaining or restoring pressurizer level to the hot zero power band.
If not, manually operate charging and letdown to restore and maintain normal pressurizer level.

15. Maintain RCS cooling by supplying [main or auxiliary] feedwater to the steam generators and discharging steam preferrably to the condenser via the turbine bypass valves, or if the condenser is unavailable, to atmosphere via the atmospheric dump valves.

16. Evaluate the need for a plant cooldown based on plant status, auxiliary systems availability, and condensate inventory (Figures 9-3 and 9-4).
If conditions require a cooldown, Then conduct a plant cooldown to SCS initiation conditions as addressed in steps 17 through 29.
If a cooldown is not required, Then maintain the plant in a stabilized condition.

* Step performed continuously.

17 See DEVIATION 2-6. IMPLEMENTED BY STEP D OF AOP 3F
a. See Deviation 2-44

18. IN Hot Standby NAT. CIRC. flow is VERIFIED PERIODICALLY by the SFSC. See DEVIATION 2-6 for the requirement DURING C/D.

19. IMPLEMENTED BY STEPS P AND Q. STEP L PROVIDES A NOTE THAT ADDRESSES THE POTENTIAL FOR NOT BEING ABLE TO REACH HOT S/D BORON CONCENTRATION WHEN LETDOWN IS NOT AVAILABLE. SEE DEVIATION 2-7 FOR HOT VS. COLD BORON CONCENTRATIONS.

20. See DEVIATION 2-6, 2-7. IMPLEMENTED BY STEP C OF AOP 3F

17. Commence an RCS cooldown in accordance with Technical Specification Limitations by performing one of the following (listed in order of preference):

    a) If the condenser and turbine bypass system are available, Then commence the cooldown using the turbine bypass system and [main or auxiliary] feedwater.

    b) If the condenser of the turbine bypass system are not available, Then commence the cooldown using the atmospheric dump valves and [main or auxiliary] feedwater.

*18. Verify natural circulation flow in at least one loop throughout the cooldown process. Refer to steps 11 and 12.

*19. Borate the plant in accordance with Technical Specification Limitations. If letdown is inoperable, Then it may not be possible to borate to the cold shutdown RCS boron concentration. In this case borate to the minimum shutdown margin required by Technical Specifications. Periodically borate during the cooldown as necessary to maintain adequate shutdown margin.

20. Perform one of the following steps to avoid RCS boron dilution and loss of shutdown margin by pressurizer outsurge during the cooldown (listed in order of preference):

    a) Calculate and add sufficient boron to the RCS to raise the entire RCS (including the mass in the pressurizer) to cold shutdown conditions.

* Step performed continuously.

21. IMPLEMENTED BY STEP E OF AOP 3F, SEE DEVIATION 2-6

22. IMPLEMENTED BY STEPS J, K of AOP 3F. see DEVIATION 2-6
See Deviation 3-45

23 IMPLEMENTED BY STEPS L, M AND N OF AOP 3F. See DEVIATION 2-6
WHILE IN HOT STANDBY, CONDENSATE INVENTORY IS CHECKED
By STEP W AND THE HEAT REMOVAL SFSC IN THE EOP

24 IMPLEMENTED BY STEP L OF EOP 2. DIRECTION FOR PZR LEVEL
CONTROL DURING COOLDOWN PROVIDED IN AOP 3F STEP F
See Deviation 0-64

b) If letdown is available, Then use auxiliary spray to increase and maintain pressurizer boron concentration to within [50 ppm] of RCS concentration using heaters to control pressurizer pressure.

c) If letdown is not available, Then use auxiliary spray and pressurizer heaters to control pressurizer pressure and increase RCS boron concentration to [50 ppm] greater than that required for minimum shutdown margin.

21. Maintain the RCS pressure within the acceptable Post Accident Pressure/ Temperature Limits (Figure 9-1) during the cooldown by:

a) Controlling RCS heat removal via the steam generators

and

b) Controlling RCS pressure using (listed in order of preference):

i) Pressurizer heaters and auxiliary spray

ii) Charging and letdown

iii) HPSI pumps

iv) [Pressurizer fill and drain method]

22. If plant conditions permit, Then bypass automatic initiation of [MSIS, CIAS CSAS and SIAS by lowering the setpoint] as the cooldown and depressurization proceeds.

*23. Monitor the available condensate inventory (Figures 9-3 and 9-4), during the cooldown and replenish from alternate sources as required.

24. Maintain pressurizer level in the range [35 to 245"], unless solid operation is necessary to restore RCS subcooling. This should be accomplished by (listed in order of preference):

* Step performed continuously.

25. SEE DEVIATION 2-8. IMPLEMENTED BY ~~STEP~~ I OF AOP 3F

26. IMPLEMENTED BY STEP G OF AOP 3F

27. IMPLEMENTED BY STEP H OF AOP 3F.

a) Control charging and letdown
b) Operating and/or throttling HPSI pumps.

25. If a steam generator was isolated, Then cool the isolated steam generator as necessary to prevent isolated loop void formation by:

a) Feeding and bleeding the isolated steam generator with feedwater,

or

b) Feeding and steaming the isolated S/G to the condenser (preferred) or to atmosphere.

*26. If the above actions fail to depressurize the RCS, Then a void should be suspected. The operator should monitor for the presence of voids. If voiding inhibits RCS depressurization to SCS entry pressure, Then an attempt at eliminating the voiding should be made.

Voiding in the RCS may be indicated by any of the following indications, parameter changes, or trends:

a) letdown flow greater than charging flow,
b) pressurizer level increasing significantly greater than expected while operating pressurizer spray,
c) [the RVLMS indicates that voiding is present in the reactor vessel],
d) [HJTC unheated thermocouple temperature indicates saturated conditions in the reactor vessel upper head]. A
e) [other indications insert here].

*27. If voiding should be eliminated, Then proceed as follows:

a) verify letdown is isolated,
b) stop the depressurization and, if required, repressurize the RCS to $\geq$ [20°F] subcooling,

* Step performed continuously.

27d. IMPLEMENTED BY STEP I OF AOP 3F

28. IMPLEMENTED BY STEP R AND U OF AOP 3F

29. IMLEMENTED BY STEP T of AOP 3F

30 IMPLEMENTED BY STEP T of AOP 3F.

c) pressurize and depressurize the RCS within the limits of Figure 9-1 by operating pressurizer heaters and spray (preferred method) or HPSI and charging pumps (alternative method). Monitor pressurizer level [and the RVLMS] for trending of RCS inventory.

d) if indications of unacceptable RCS voiding continue, and voiding is suspected to exist in the (isolated) steam generator tubes, then cool the (isolated) steam generator (by steaming or blowdown, and/or feeding) to condense the steam generator tube bundle void. Monitor pressurizer level for trending of RCS inventory.

e) if indications of unacceptable RCS voiding continue, then [operate the pressurizer vent and/or the reactor vessel head vent to] clear trapped non-condensible gases. Monitor pressurizer level [and/or the RVLMS] for trending of RCS inventory.

28. When SCS entry conditions (RCS pressure $\leq$ [300 psia] and RCS $T_H \leq$ [300°F] are established, Then initiate SCS operation per operating instructions.

29. [Initiate the low temperature overpressurization (LTOP) system at 275°F.]

30. [Isolate, vent, or drain the safety injection tanks (SITs) at 250 psia RCS pressure.]

1. IMPLEMENTED BY NOTE IN STEP C

2. IMPLEMENTED BY PRECAUTION A AND NOTE IN STEP C

3. IMPLEMENTED IN PRECAUTION C

4. SEE DEVIATION 2-9

5. IMPLEMENTED BY PRECAUTION D. TRANSIENT LOG ENTRIES ARE DIRECTED IN STEP Y

SUPPLEMENTARY INFORMATION

This section contains items which should be considered when implementing EPGs and preparing plant specific EOPs. The items should be implemented as precautions, cautions, notes, or in the EOP training program.

1. Natural circulation flow cannot be verified until the RCPs have stopped coasting down after being tripped. IN procedure

2. Verification of an RCS temperature response to a plant change cannot be accomplished until approximately 5 to 15 minutes following the action due to increased loop cycle times during natural circulation.

3. After the required shutdown boron concentration is attained in the RCS, makeup water added to the RCS during the cooldown should be at least the same boron concentration as in the RCS to prevent any dilution of RCS boron concentration.

4. Once the pressurizer cooldown has begun, pressurizer level indication decalibration will occur. The indication on the normal pressurizer level indication will begin to deviate from the true pressurizer level. The operator should use correction curves to find the true pressurizer water level. A cold calibrated pressurizer level indication is also available for lower pressurizer temperatures.

5. Minimize the number of cycles of pressurizer auxiliary spray whenever the temperature differential between the spray water and the pressurizer is greater than [200°F] in order to minimize the increase in the spray nozzle thermal stress accumulation factor. Every such cycle must be recorded in accordance with Technical Specification Limitations.

6. IMPLEMENTED BY PRECAUTION B

7. IMPLEMENTED BY PRECAUTION E

8. SEE DEVIATION, 2-10

9. IMPLEMENTED BY SFSC

6. If cooling down by natural circulation with an isolated steam generator, an inverted ΔT (i.e., T_C higher than T_H) may be observed in the idle loop. This is due to a small amount of reverse heat transfer in the isolated steam generator and will have no affect on natural circulation flow in the intact steam generator.

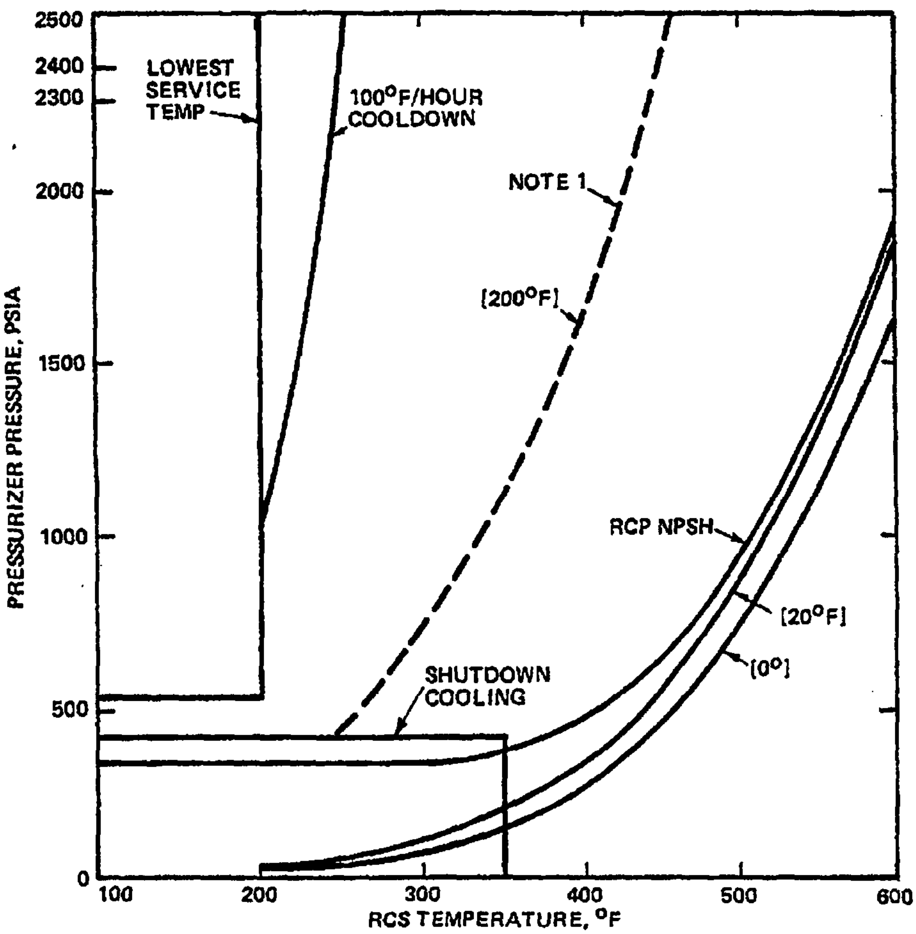
7. All available indications should be used to aid in evaluating plant conditions since the accident may cause irregularities in a particular instrument reading. Instrument readings should be corroborated when one or more confirmatory indications are available.

8. When a void exists in the reactor vessel and RCPs are not operating, the RVLMS provides an accurate indication of reactor vessel liquid inventory. When a void exists in the reactor vessel and RCPs are operating, it is not possible to obtain an accurate reactor vessel liquid level indication due to the effect of the RCP induced pressure head on the RVLMS. The indicated level also differs for different RVLMS designs under these conditions. Information concerning reactor vessel liquid inventory trending may still be discerned. However, the operator is cautioned not to rely solely on the RVLMS indication when RCPs are operating.

9. The operator should continuously monitor for the presence of RCS voiding and take steps to eliminate voiding any time voiding causes the heat removal or inventory control safety functions to begin to be threatened. Void elimination should be started soon enough to ensure heat removal and inventory control are not lost. C

FIGURE 9-1

TYPICAL POST ACCIDENT PRESSURE-TEMPERATURE LIMITS(2)



NOTES: (1) THIS CURVE SUPERSEDES THE 100°F/HOUR COOLDOWN CURVE ANYTIME THE RCS HAS EXPERIENCED AN UNCONTROLLED COOLDOWN WHICH CAUSES RCS TEMPERATURE TO GO BELOW 500°F

(2) THESE CURVES MUST BE ADJUSTED FOR INSTRUMENT INACCURACIES

(3) COLOR CODE

RED - PARAMETER IN EXCESS OF LIMITS

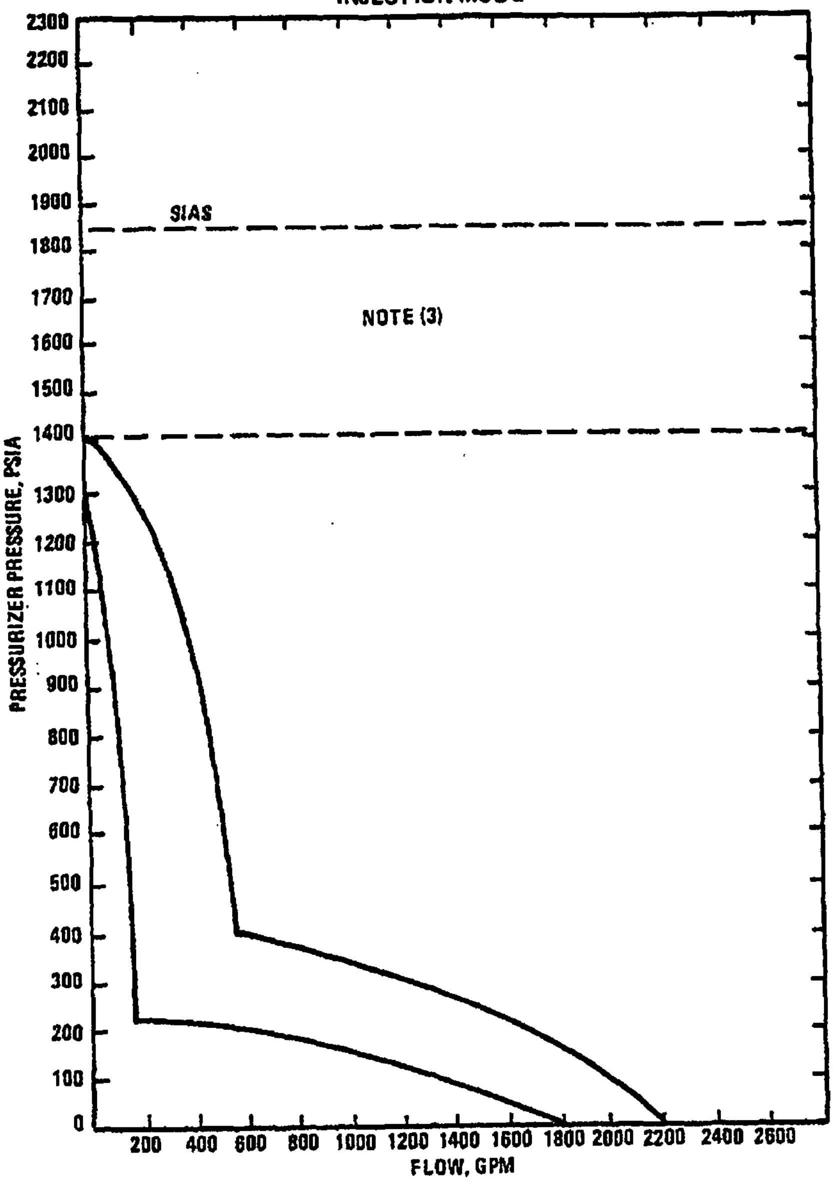
ORANGE - PARAMETER IN DANGER OF EXCEEDING LIMITS

YELLOW - PARAMETER OUTSIDE OF OPTIMAL RANGE, BUT STILL WITHIN LIMITS

GREEN - PARAMETER IN OPTIMAL RANGE OF VALUES

FIGURE 9-2

TYPICAL ACCEPTABLE SIS FLOW vs RCS PRESSURE[1]
INJECTION MODE[2]



NOTES:
(1) SEE IMPLEMENTATION SECTION FOR DEVELOPMENT OF PLANT SPECIFIC CURVE
(2) FOR HOT AND COLD LEG INJECTION MODE, THE LPSI PUMPS ARE NOT REQUIRED TO BE OPERATING. THE HPSI PUMP FLOW IS DIVIDED EQUALLY BETWEEN THE HOT AND COLD LEGS
(3) BELOW SIAS PRESSURE, SAFETY INJECTION SYSTEM (SIS) PUMPS WILL BE OPERATING BUT THERE WILL BE NO INJECTION FLOW UNTIL SYSTEM PRESSURE FALLS BELOW THE SHUTOFF HEAD OF ANY SIS PUMP
(4) COLOR CODE
    RED - PARAMETER IN EXCESS OF LIMITS
    YELLOW - PARAMETER OUTSIDE OF OPTIMAL RANGE, BUT STILL WITHIN LIMITS
    GREEN - PARAMETER IN OPTIMAL RANGE OF VALUES

TYPICAL FEEDWATER CAPACITY vs TIME REMAINING UNTIL SHUTDOWN COOLING REQUIRED
FIGURE 9-3

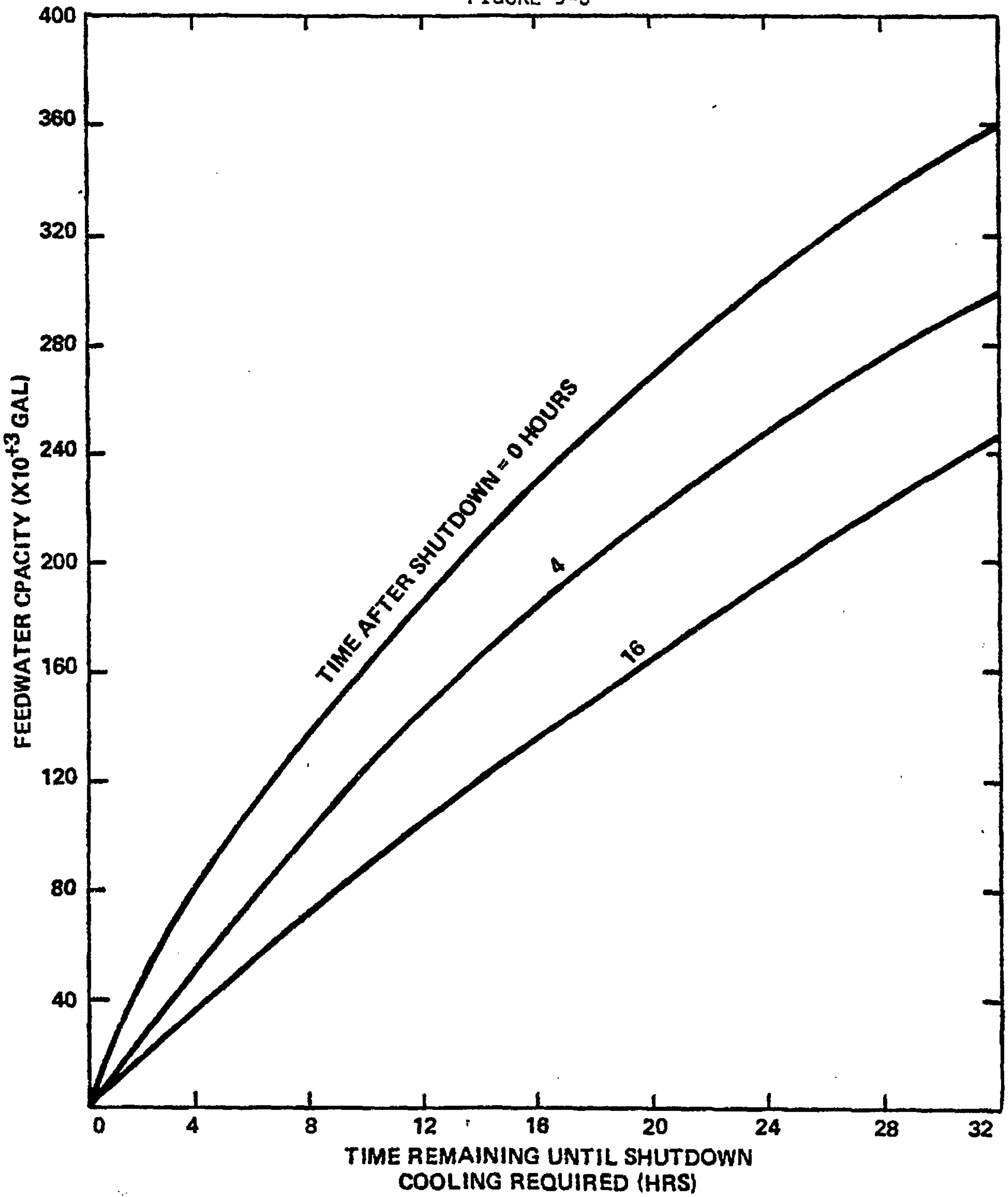
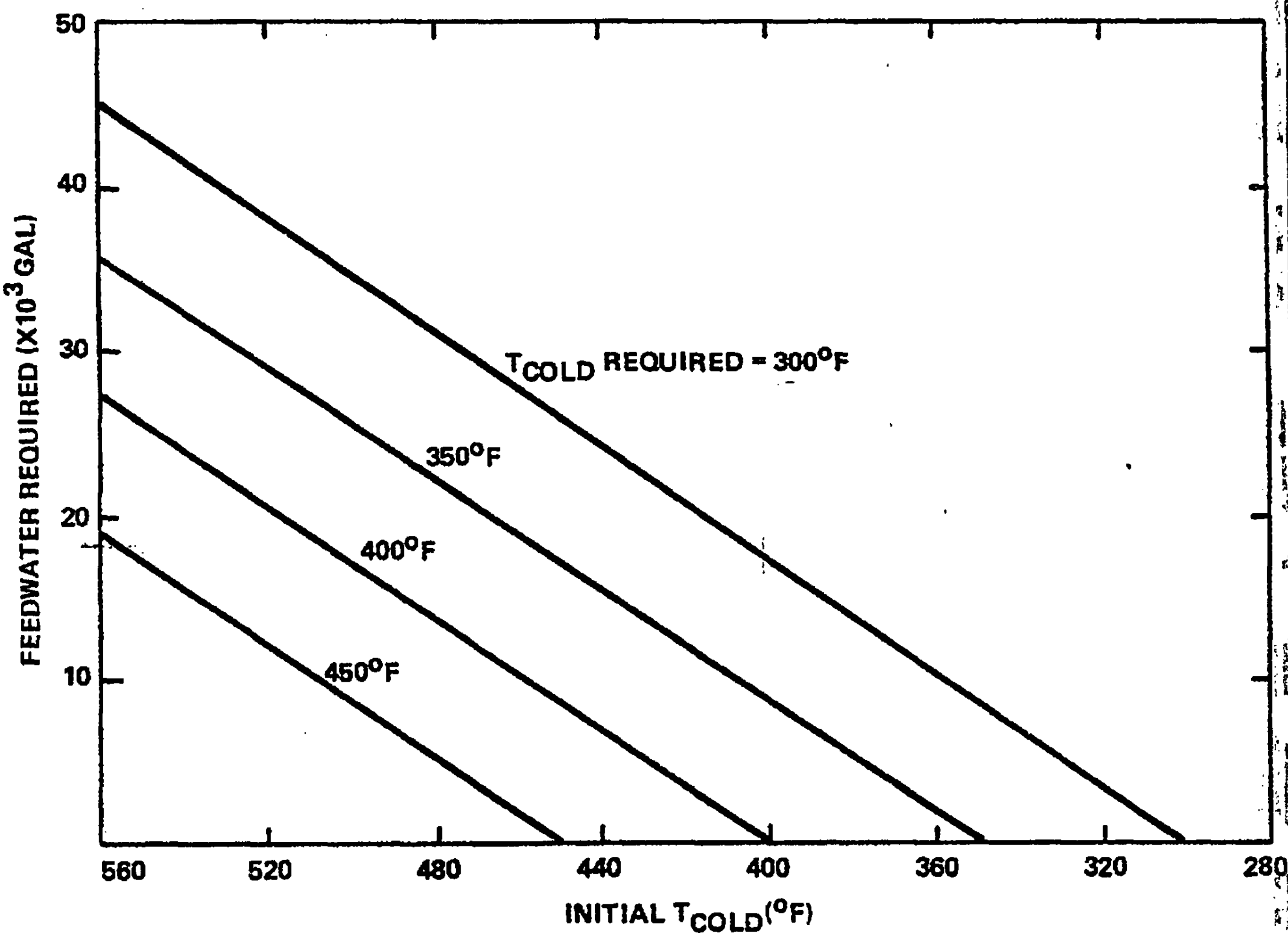


FIGURE 9-4

TYPICAL FEEDWATER REQUIRED FOR SENSIBLE HEAT REMOVAL
T_{COLD} (REQUIRED) vs T_{COLD} (INITIAL)



1. ALL ITEMS COVERED UNDER REACTIVITY CONTROL SFSC

a.

b. see Deviation 1-36

c.

2. INCLUDED AS 4th FUNCTION OF SFSC
See Deviation 1-43 except h.

3. ITEMS a AND C COVERED UNDER PRESS/INV SFSC. RVLMS IS NOT INSTALLED. SEE DEVIATION 2-11 FOR ITEM 3B

SAFETY FUNCTION STATUS CHECK

Safety Function	*Acceptance Criteria*
1. *Reactivity Control*	1.a. Reactor power decreasing *and* b. [Negative Startup Rate] *and* c. Not more than 1 CEA bottom light not lit or borated per Tech Specs.
2. *Maintenance of Vital Auxiliaries (AC and DC Power)*	2. [Plant specific criteria, insert here].
3. *RCS Inventory Control*	3.a. Pressurizer level is [35" to 245"], *and* b. Charging and letdown are being operated automatically or manually to maintain or restore pressurizer level *and* c. The RCS is at least [20°F] subcooled *and* d. [The RVLMS indicates the core is covered].

4. Item a covered in PRESS/INV SFSC ; see Deviation 2-12 for item b

5a covered in RCS/CORE HEAT Removal SFSC

5b covered in PRESS/INV SFSC

6a Level limits contained in RCS/Core HEAT Removal SFSC. Specific criteria ensure one of the feed systems is working

6b Temperature limits contained in RCS/core HEAT Removal function.

SAFETY FUNCTION STATUS CHECK

Safety Function	Acceptance Criteria
4. RCS Pressure Control	4.a. Pressurizer pressure is [1600 to 2350 psia] *and* b. Pressurizer heaters and spray are being operated automatically or manually to maintain or restore pressurizer pressure within the limits of Figure 9-1.
5. Core Heat Removal	5.a. RCS T_{ave} less than [545°F] *and* b. The RCS is at least [20°F] subcooled.
6. RCS Heat Removal	6.a. At least one steam generator has level: i) within the normal level band with feedwater available to maintain level or ii) being restored by feedwater flow greater than [150 gpm] *and* b. RCS T_{ave} is less than [545°F] and controlled.

7. COVERED IN CONTAINMENT ENVIRONMENT AND RADIATION CONTROL SAFETY FUNCTIONS status checks

8. COVERED IN CONTAINMENT ENVIRONMENT safety function status check

9. See DEVIATION 2-13

SAFETY FUNCTION STATUS CHECK

Safety Function	Acceptance Criteria
7. Containment Isolation	7.a. Containment pressure less than [1.5 psig] *and* b. No containment area radiation monitors alarming. *and* c. No process radiation alarms. *and* d. No steam plant activity monitors alarming.
8. Containment Temperature and Pressure Control	8.a. Containment temperature less than [120°F] *and* b. Containment pressure less than [1.5 psig]
9. Containment Combustible Gas Control	9. Hydrogen concentration less than [2%].

BASES

The bases section of the loss of forced circulation (LOFC) recovery guideline describes the LOFC transient in relation to the actions which the operator takes during an LOFC. The purpose of the bases section is to provide the operators with information which will enable them to understand the reasons for, and the consequences of, the actions they take during an LOFC.

Characterization of a Loss of Forced Circulation

A loss of forced circulation will result from a loss of one or more reactor coolant pumps (RCPs). An RCP failure could result from any number of mechanical failures in the pump or motor, from a loss of electrical power, or the RCP may be manually tripped for pump protection purposes. This guideline is designed to provide guidance for complete loss of forced circulation. A partial loss of forced circulation is covered by the Reactor Trip Recovery Guideline.

RCP forced circulation and heat transfer from primary to secondary via the steam generators is the preferred method of residual heat removal whenever plant temperatures and pressure are above the shutdown cooling system entry conditions. If the RCPs are unavailable, the natural circulation capability of all C-E plants provides a backup means for core cooling using the steam generators.

A complete loss of RCP flow can be characterized by reactor turbine and generator trips accompanied by low steam generator ΔPs or RCP ΔPs in the affected loops. Depending on the type of failure, there will also be RCP trouble alarms or abnormal RCP motor currents. The RCS primary loop flow meters will indicate low RCS flow.

Safety Functions Affected

While no safety functions are directly challenged for an uncomplicated loss of forced circulation, all safety functions must be maintained while establishing

and maintaining natural circulation core cooling in hot standby conditions or during a natural circulation plant cooldown. Particularly important are reactivity control, RCS pressure control, RCS inventory control, core heat removal, and RCS heat removal. Failure to maintain any one of these safety functions could lead to an interruption of adequate natural circulation flow or core cooling.

Trending of Key Parameters

Reactor Power (*Figure 9-5*)

Immediately following the failure of one or more RCPs, a reactor and turbine trip will be initiated due to a low reactor coolant flow trip at [95%] flow. The reactor trip causes power to decrease.

RCS Temperature (*Figure 9-6*)

The reactor trip will cause a reduction in RCS temperatures, because RCS heat generation (decay heat) is less than heat removal by the steam generators.

Pressurizer Pressure (*Figure 9-7*)

Pressurizer pressure will decrease following the low flow reactor trip due to decreasing RCS temperature.

Pressurizer Level (*Figure 9-8*)

Pressurizer level will decrease also following the low flow reactor trip. This is due to RCS inventory shrinkage and pressurizer outsurge due to decreasing RCS temperature.

Reactor Vessel Level

No reactor vessel voiding is expected to occur during a loss of forced circulation accident as long as plant control is maintained.

Steam Generator Pressure (*Figure 9-9*)

Once the turbine control valves go shut following the turbine trip, steam generator pressure increases rapidly. With the turbine control valves shut steam demand by the turbine ceases. Pressure will continue to increase until the steam generators achieve equilibrium with the RCS at the setpoint of the Turbine Bypass Valves.

Steam Generator Level (*Figure 9-10*)

The main feedwater system will ramp down to [5%] flow to prevent overfilling the steam generators. Steam generator level will begin to decrease rapidly to the zero power band because of the shrinkage which occurs after the closure of the turbine stop valves following the turbine trip.

FIGURE 9-5

REPRESENTATIVE LOFC
REACTOR POWER

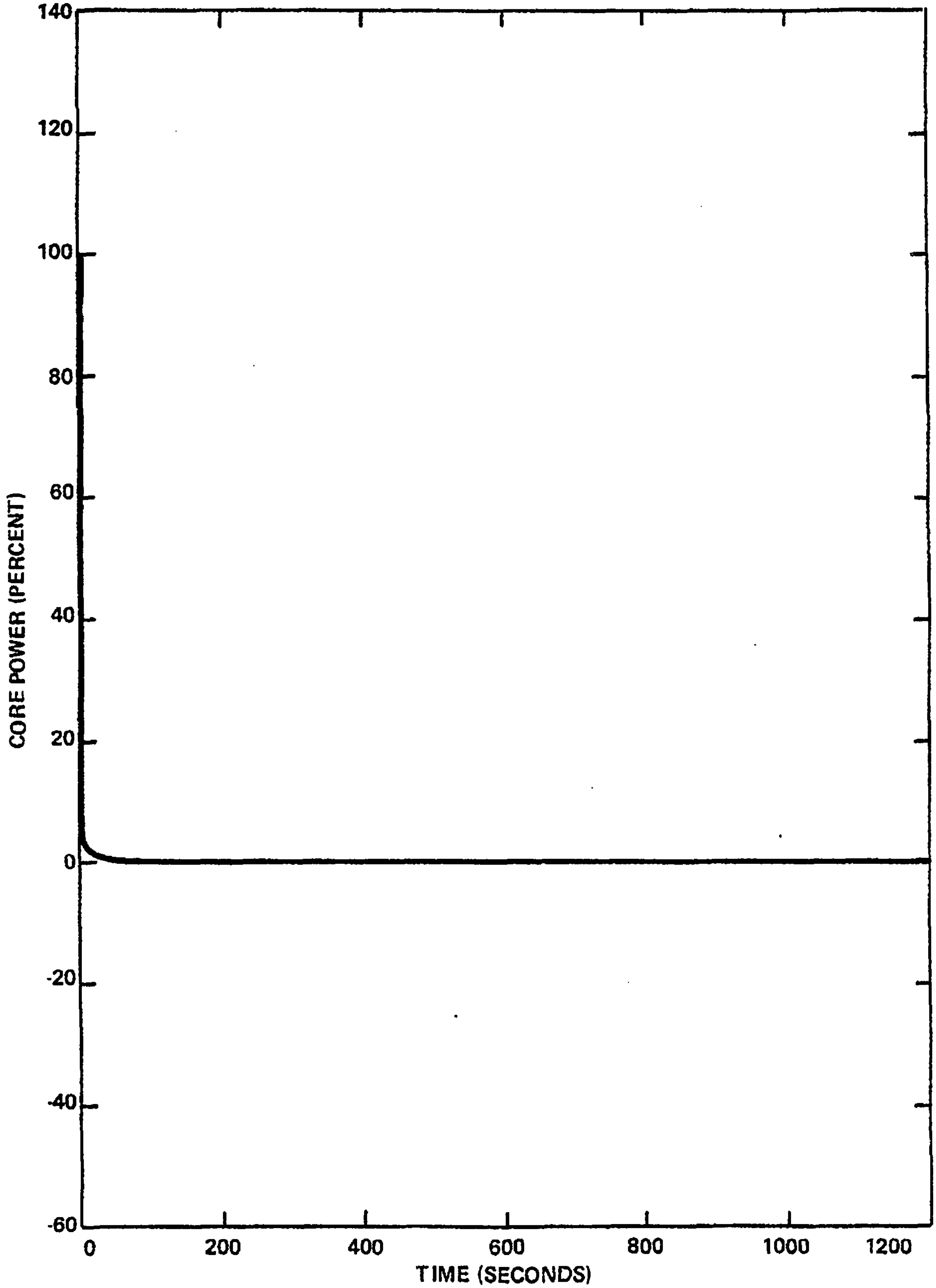


FIGURE 9-6
REPRESENTATIVE LOFC
LOOP RCS NARROW RANGE TEMPERATURES

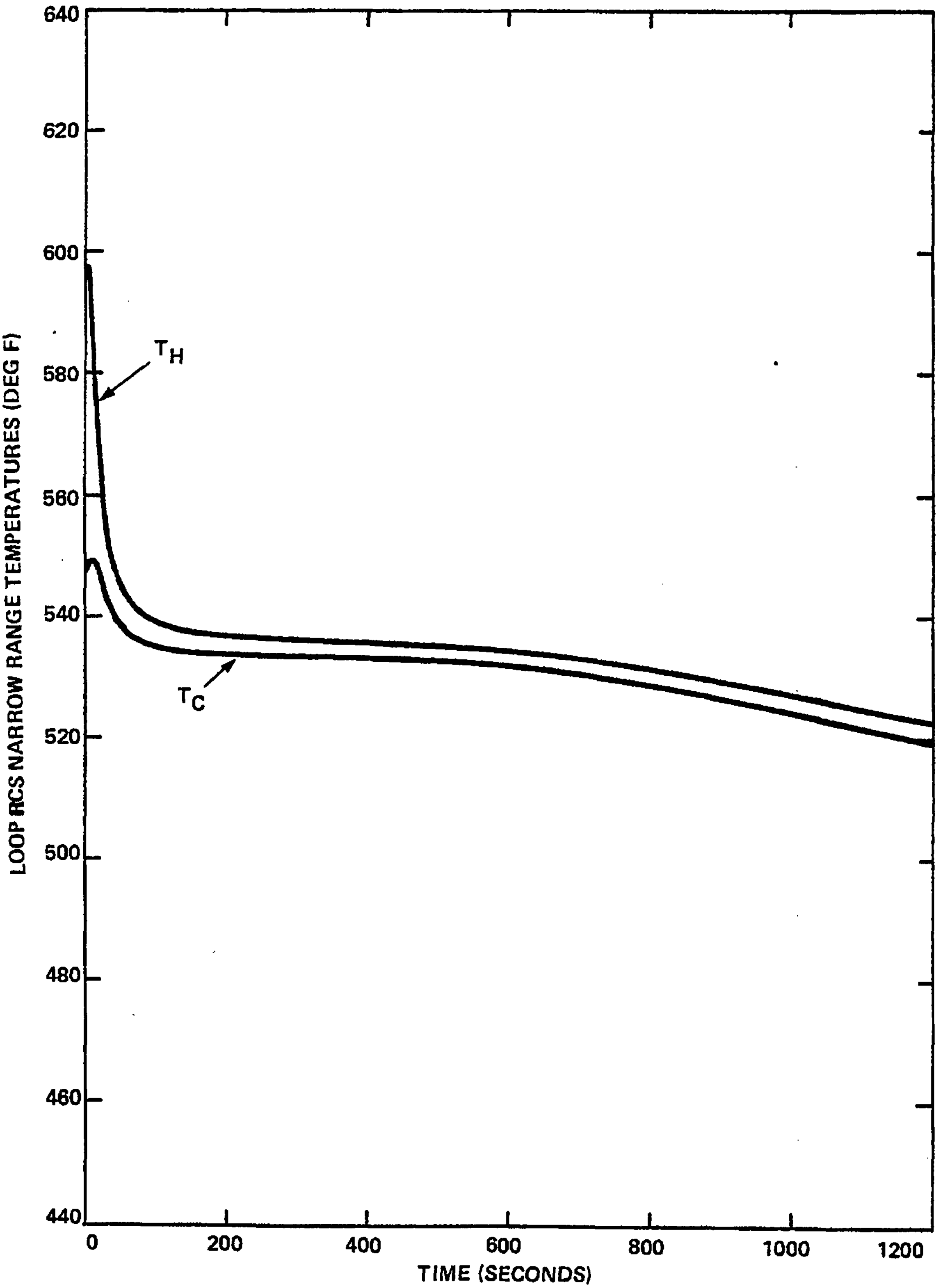


FIGURE 9-7
REPRESENTATIVE LOFC
PZR NARROW RANGE PRESSURE

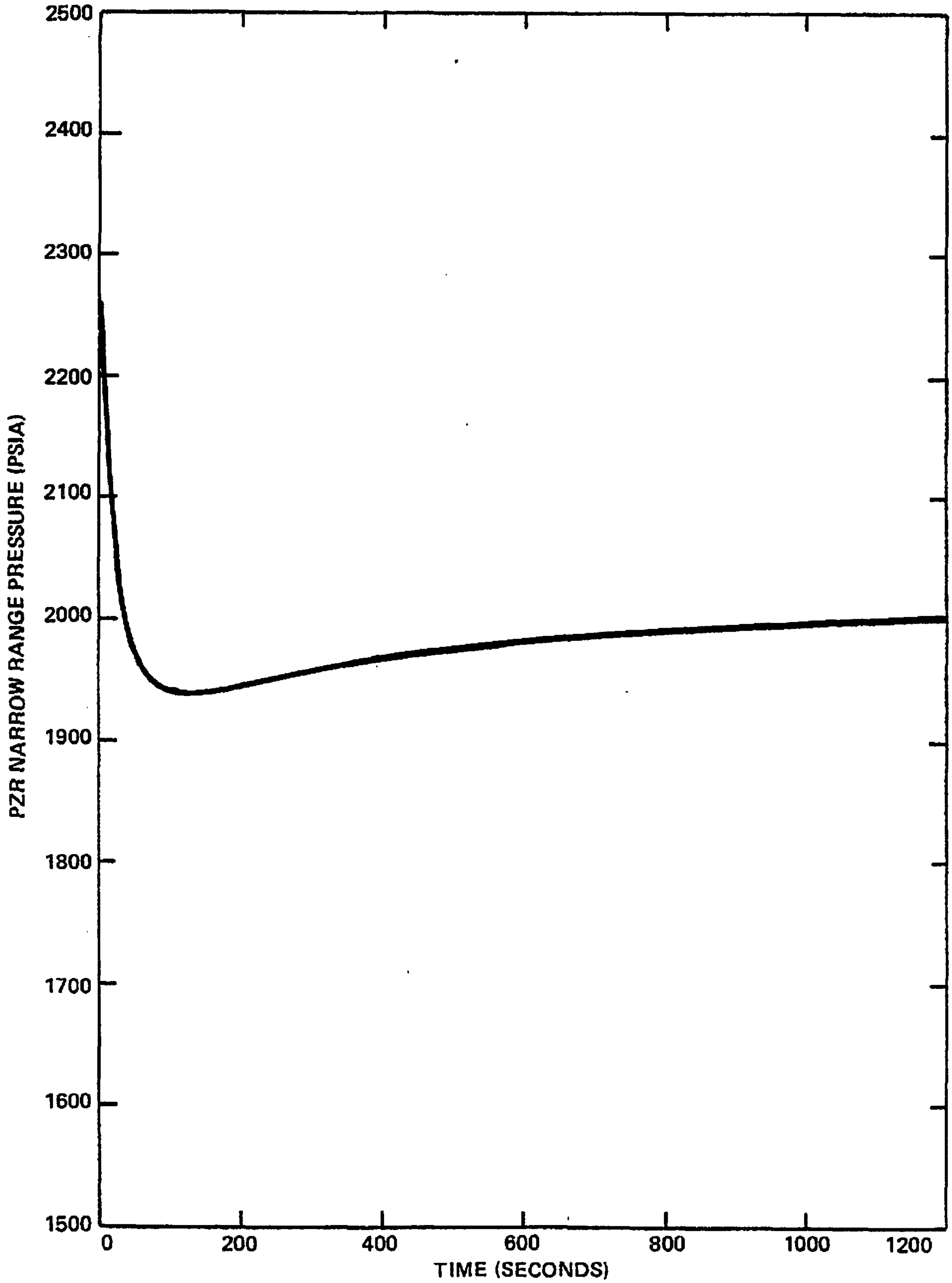


FIGURE 9-8
REPRESENTATIVE LOFC
PZR LEVEL

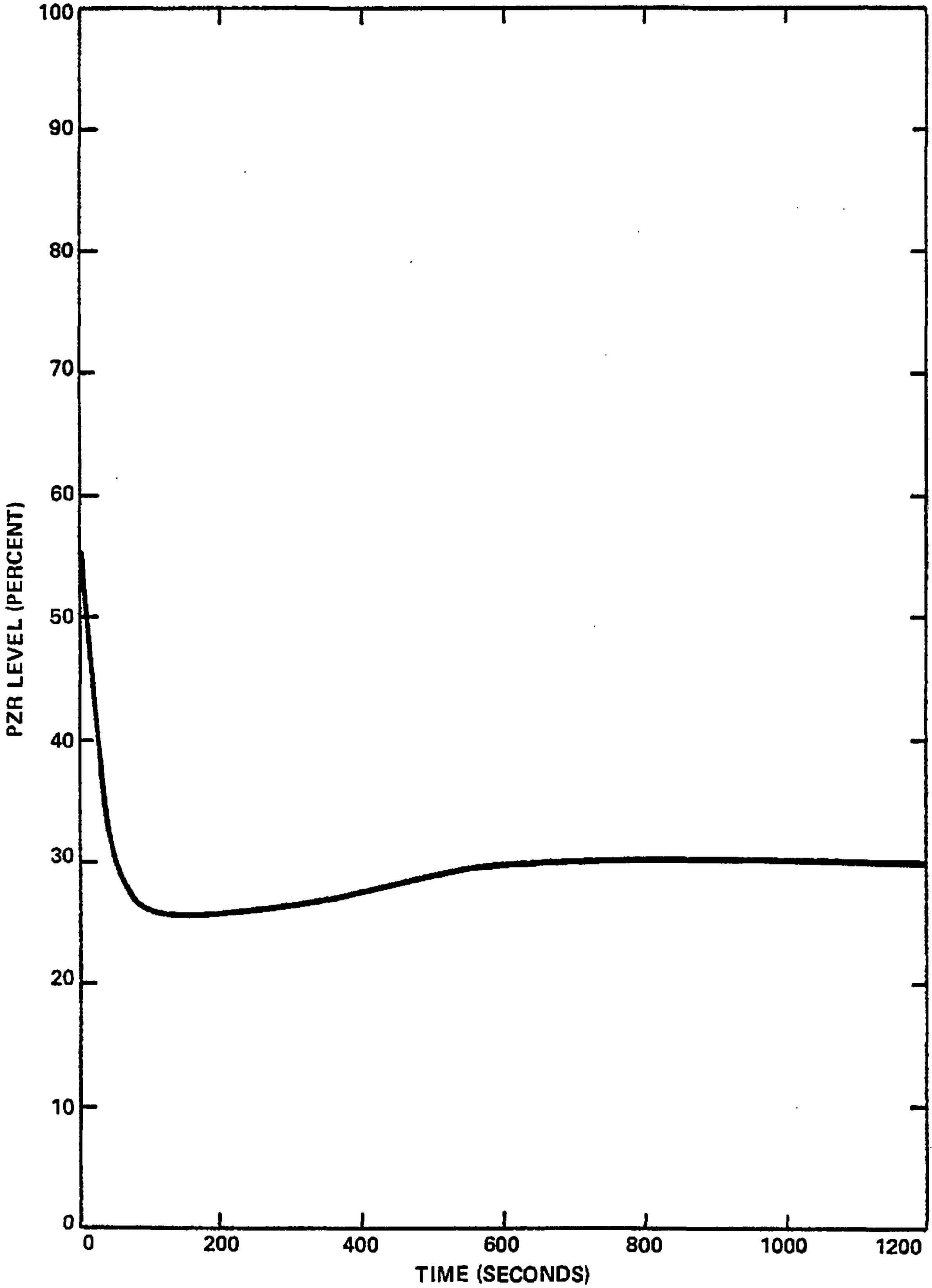


FIGURE 9-9

REPRESENTATIVE LOFC
STEAM GENERATOR PRESSURE

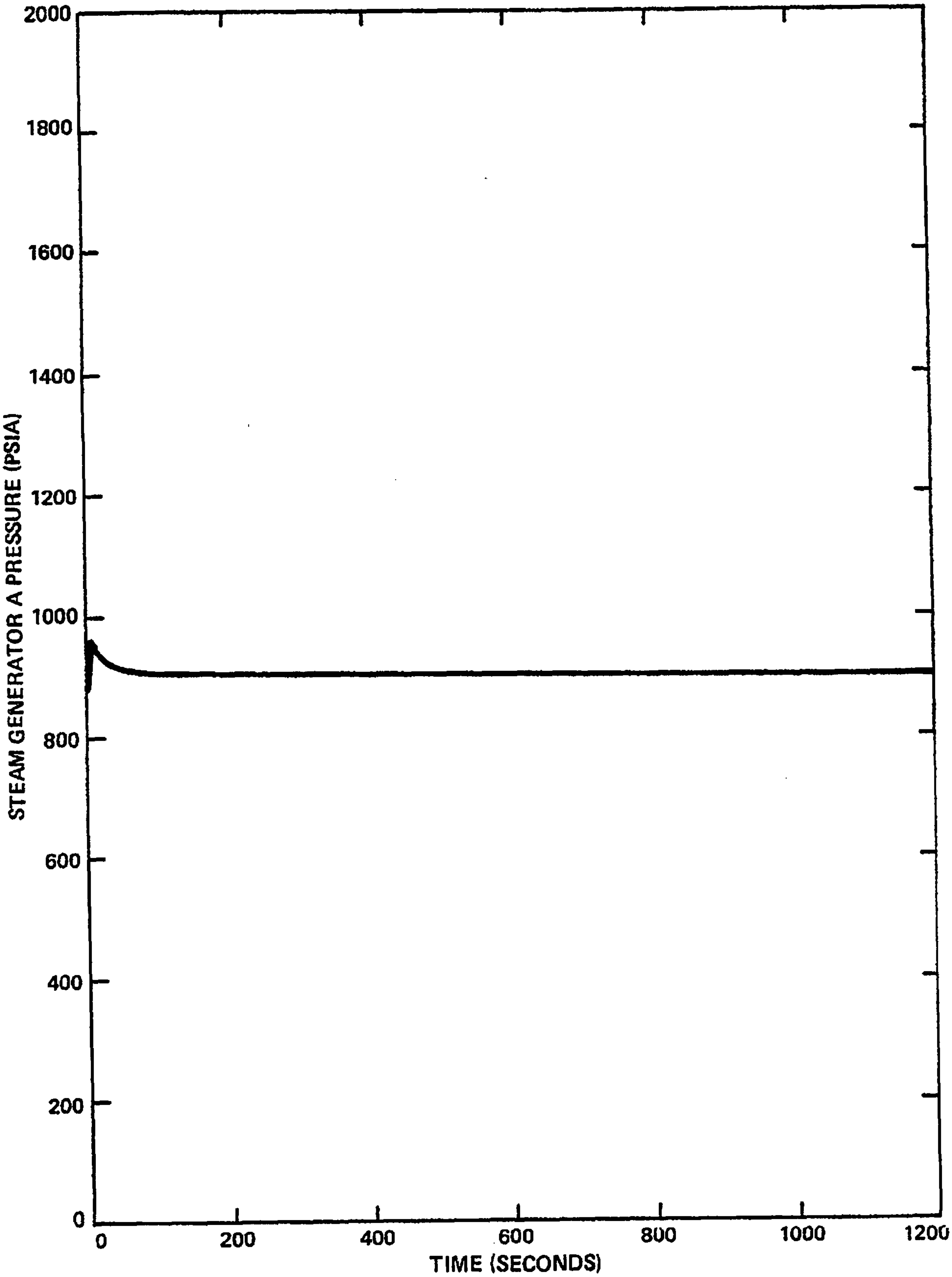
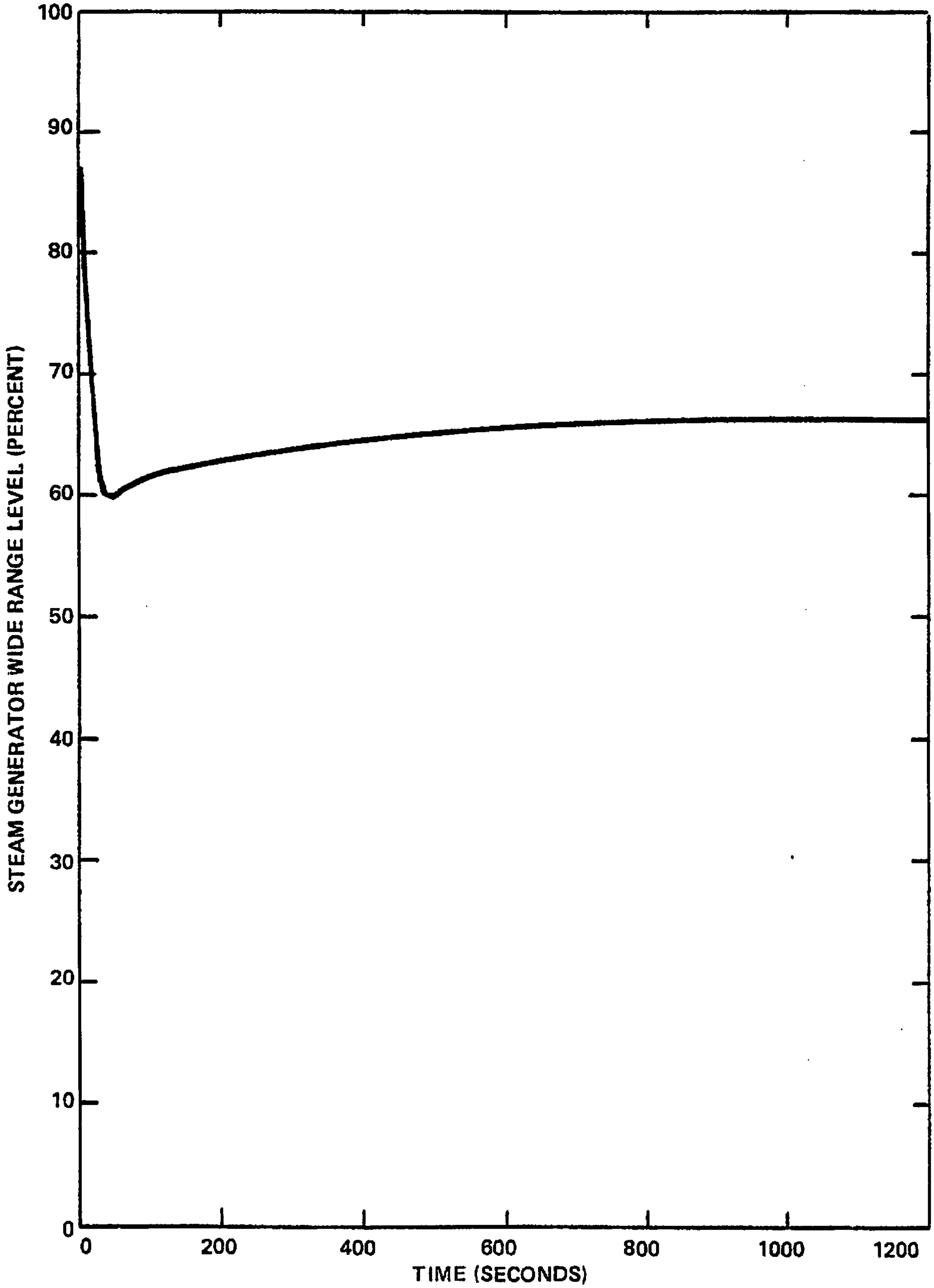


FIGURE 9-10

REPRESENTATIVE LOFC
STEAM GENERATOR WIDE RANGE LEVEL



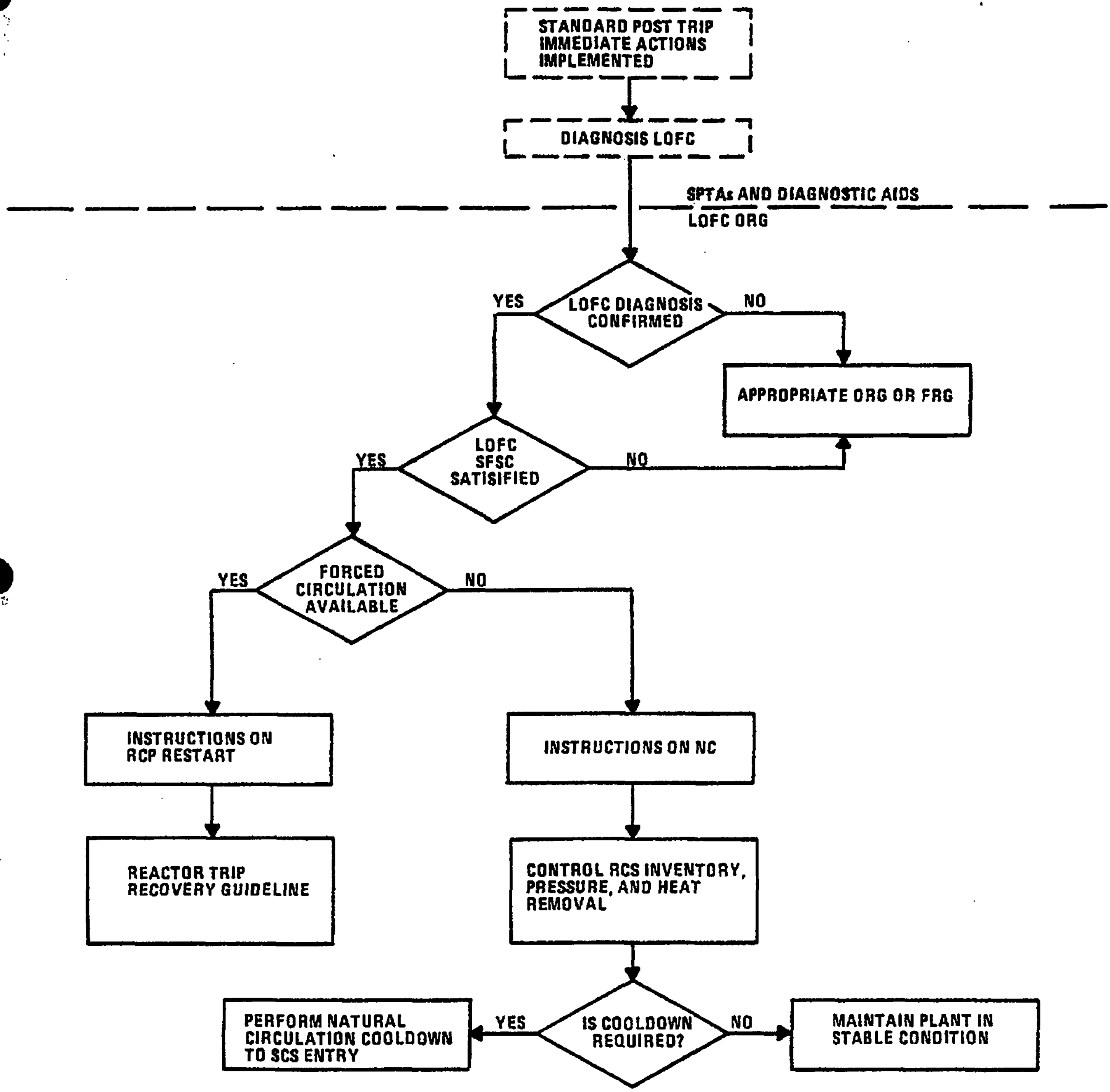
Guideline Strategy

Figure 9-11, provides a summary of the LOFC Recovery Guideline's strategy. Prior to implementing the actions provided in the LOFC Recovery Guideline, the operator would have completed the standard post trip actions and diagnosed the event. In the LOFC Recovery Guideline the operator begins by using the safety function status check to confirm that the plant is recovering. The next group of steps provide instructions on RCP restart criteria, SIS termination/restart, and natural circulation. These steps are illustrated on Figure 9-11.

Following the instructions on RCPs, SIS, and natural circulation, the flow of information proceeds toward stabilizing plant conditions. Once a determination is made on SCS operation, the flow of information breaks into two paths. One path addresses maintaining plant conditions while the other provides information on performing a natural circulation cooldown.

A more detailed chart illustrates the recovery guideline strategy and lists the guideline steps which correspond to each strategy objective. Those steps which are performed at any time during the course of the event are shown by affixed asterisks. Refer to Figure 9-14.

FIGURE 9-11
LOSS OF FORCED CIRCULATION STRATEGY CHART



Bases Operator Actions

The operator actions are directed at achieving two objectives:

a) establishing, maintaining and verifying natural circulation conditions in the RCS if all RCPs are stopped;

b) if necessary, performing a natural circulation cooldown.

1. The execution of all standard post trip actions is verified. This assures that all safety functions have been initially attended to.

2. The diagnosis of an LOFC event is confirmed [by verifying that the Safety Function Status Check criteria are being met]. This action ensures the procedure being used is mitigating the effects of an LOFC and all relevant safety functions are being satisfied.

3. If the diagnosis of an LOFC is confirmed, then the operator continues with the actions of this guideline.

   If a correct diagnosis is not confirmed, then the operator is directed to implement the Functional Recovery Guideline. The Functional Recovery Guideline is functionally oriented and will ensure all safety functions are attended to regardless of what event(s) is occurring.

4. The operator is required to continually verify that the safety functions are being satisfied by comparing control board parameters to the criteria of the Safety Function Status Check. This verifies that all relevant safety functions are being satisfied and the core is being adequately cooled.

5. If all the safety functions from the Safety Function Status Check are satisfied, then this guideline is adequately mitigating the effects of the LOFC which is occurring. Therefore, the implementation of the remaining actions of this guideline is continued.

If all relevant safety functions are not being satisfied, then the guideline is not adequately mitigating the occurring event. The operator is required to leave the LOFC guideline and implement the Functional Recovery Guideline. This guideline is functionally oriented and will ensure all safety functions are attended to regardless of what event(s) is occurring.

6. With all RCPs stopped, then operation of two RCPs (in opposite loops) should be attempted if the RCP restart criteria are met. Only one reactor coolant pump in each loop needs to be operated to minimize heat input to the RCS.

Determine whether RCP restart criteria are met by the following:

a) At least one steam generator is available for removing heat from the RCS. A steam generator having feed flow and removing heat from the RCS is an indication that primary to secondary heat removal is being maintained.

b) Pressurizer level is greater than [200"] and not decreasing. A higher pressurizer level will minimize the possibility of draining the pressurizer due to loop shrinkage and/or steam void condensation is minimized and there is a greater likelihood of keeping the pressurizer heaters covered. This will assist in maintaining positive RCS pressure control. The criterion of pressurizer level not decreasing implies that RCS inventory control has been established.

how is condensation minimized? How does it occur? Isn't the concern here the propagation of the void RATHER THAN THE CONDENSATION of it?

c) The RCS is greater than or equal to [20°F] subcooled. A subcooled condition taken in conjunction with (b) above indicates that inventory control has been established.

d) [All plant specific RCP operating criteria are satisfied before the RCPs are restarted to prevent damage to RCP operation and damage resulting from abnormal operating conditions. Following automatic

or operator initiated containment isolation, reinstatement of component cooling water to the RCPs should be considered in order to ensure adequate RCP cooling.]

7. Upon restarting two RCPs in opposite loops, pressurizer level and pressure may decrease due to loop shrinkage and/or void condensation. It is possible that this action will drain the pressurizer. Steam voids present in the reactor vessel will condense upon restarting RCPs. [The RVLMS should be monitored for the trending of reactor vessel liquid level. This trending information may be correlated to pressurizer level decrease.] RCP operation with a drained pressurizer may continue provided certain actions are taken and certain criteria are satisfied.

   The following constitute the actions to be taken and the criteria to be satisfied when restarting RCPs:

   a) Start one RCP in each loop.

   b) [Ensure proper RCP operation by monitoring RCP amperage and pump NPSH. NPSH is determined by pressurizer pressure and corresponding T_c on Figure 9-1.]

   c) Operate all available HPSI and charging pumps until pressurizer level is greater than [100"] and SIS termination criteria are met.

8. If the SIS is operating, then it must continue to operate until SIS termination criteria are met. Termination of SIS should be sequenced by stopping one pump at a time while observing the termination criteria. Throttling of HPSI flow is permissible if it is feasible. SIS termination criteria are:

   a) RCS is at least [20°F] subcooled (Figure 9-1). Establishing [20°F] of subcooling ensures the fluid surrounding the core is subcooled and provides margin for reestablishing flow should the [20°F] of

subcooling deteriorate when SIS flow is secured. Voids may exist in some parts of the RCS (e.g., reactor vessel head), but these are permissible as long as core heat removal is maintained.

b) Pressurizer level is greater than [100"] and constant or increasing. A pressurizer level greater than [100"] and constant or increasing in conjunction with criterion a) above is an indication that RCS inventory control has been established.

c) At least one steam generator is available for removing heat from the RCS. Steam generator availability requires having feed flow and steam flow which are indications that primary to secondary heat removal is possible.

d) [The RVLMS indicates the core is covered. An indication of core coverage, in conjunction with the above, serves as an additional indication that RCS inventory control has been established.]

9. If the criteria of step 8 cannot be maintained after the SIS has been stopped, then the SIS must be restarted.

10. If RCPs are restarted, then the natural circulation guidance contained in this guideline is no longer required. The operator should go to the Reactor Trip Recovery Guideline.

11. With all RCP operation terminated, inventory and pressure being controlled, and the steam generator(s) being used for heat removal, then natural circulation is maintained by heat removal via at least one steam generator. Natural circulation flow should occur within (5-15 minutes) after the RCPs were tripped if there is adequate inventory in the RCS.

    When single phase liquid natural circulation flow is established in at least one loop, the RCS indicates the following conditions:

a) Loop ΔT (T_H - T_C) less than normal full power ΔT;
b) Cold leg temperatures constant or decreasing;
c) Hot leg temperatures stable (i.e., not steadily increasing) or decreasing slowly;
d) No abnormal differences between T_H RTDs [and core exit thermocouples].

Hot leg RTD temperature should be consistent with the [core exit thermocouples]. Adequate natural circulation flow ensures that [core exit thermocouple] temperatures will be approximately equal to the hot leg RTDs temperature within the bounds of the instruments' inaccuracies. An abnormal difference between T_H [and the CETs] is greater than [10°F].

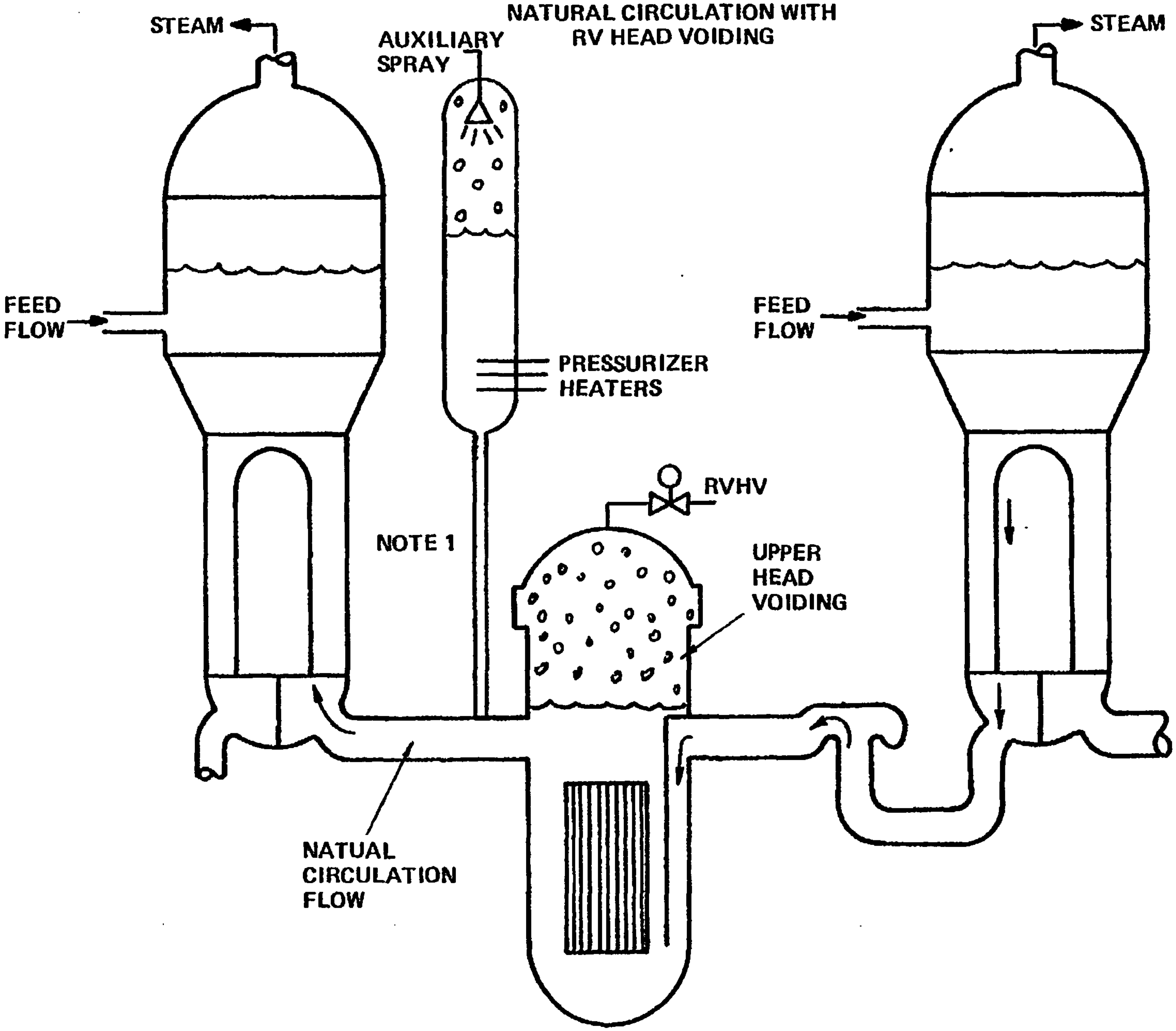
Natural circulation is governed by decay heat, component elevations, primary to secondary heat transfer, loop flow resistance, and voiding. Component elevations on C-E plants are such that satisfactory natural circulation decay heat removal is obtained by density differences between the bottom of the core and the top of the steam generator tube sheet. An additional contribution to natural circulation flow rate is the density difference obtained as the coolant passes through the steam generator U-tubes. Figure 9-12 depicts reactor vessel upper head voiding under natural circulation conditions. If voiding inhibits RCS depressurization to SCS entry conditions, then refer to steps 26 and 27.

12. If the criteria listed in step 11 are not met, then ensure that the systems required to support natural circulation are functioning properly. Specifically, verify that RCS inventory (step 13), RCS pressure (step 14), and S/G steaming and feeding (step 15) are being controlled properly.

13. The PPCS is verified to be automatically maintaining or restoring RCS pressure within the limits of Figure 9-1 (Post Accident Pressure/Temperature Limits). If not, heaters or auxiliary spray are manually controlled to restore pressurizer pressure. The intent of this action verifies that a safety function is being performed: controlling RCS pressure. Maintaining RCS pressure and temperature within the limits of Figure 9-1 allows for adequate core cooling and minimizes the PTS concerns.

FIGURE 9-12

NATURAL CIRCULATION WITH RV HEAD VOIDING



NOTE (1): THE STEAM GENERATOR TUBES ARE AN AREA WHERE VOIDING IS POSSIBLE IF THE GENERATOR HAS BEEN ISOLATED DURING A LOFC

14. The PLCS is verified to be automatically controlling or restoring pressurizer level to the hot zero power band. If not, charging and letdown are operated manually to ensure pressurizer level is being maintained. This action verifies that the RCS inventory control safety function is being performed. Pressurizer level should normally be maintained at the normal shutdown reference level throughout the plant cooldown if a cooldown is necessary. The normal shutdown reference level (plant specific) may or may not be the same as the hot zero-power pressurizer reference level. If letdown is not available, pressurizer level may be allowed to vary over the full range ([35 to 245"]) of the pressurizer as long as care is taken not to go solid. A [20°F] subcooling margin should coexist with a pressurizer level of [35 to 245"] to assure adequate RCS pressure control via a saturated bubble in the pressurizer. Level should be maintained above [100"] if possible to permit pressurizer heater operation.

    If pressurizer level drops below the top of the pressurizer heaters, then pressurizer heater operation will be interlocked off for overheating protection. It may be necessary to exceed [245"] pressurizer level if the operator is attempting to restore RCS subcooling since pressurizer heaters may be unavailable or solid water operation may be necessary to achieve subcooling.

15. Maintain or restore steam generator level in the steam generators in the hot zero power band using the [main or auxiliary] feedwater system. This provides for RCS heat removal and a means of cooling down the RCS. Steam generator pressure should be controlled by the turbine bypass system. If condenser vacuum is lost, the turbine bypass system is not available, or if the MSIVs have closed, the atmospheric dump valves must be used to control steam generator pressure. This action prevents the secondary safety valves from opening and is also necessary for maintaining RCS heat removal.

16. The plant should be maintained in a stable condition based on auxiliary systems availability. One concern the operator must have is the remaining supply of feedwater. If the available condensate appears to be

marginally adequate, a plant cooldown within Technical Specification Limitations should be commenced immediately in order to avoid running out of existing condensate before the shutdown cooling system can be placed into operation. The condensate required may be determined from Figures 9-14 and 9-15. If necessary a natural circulation cooldown to SCS initiation conditions is conducted. Perform steps 14 through 26.

17. The RCS cooldown should be commenced in accordance with Technical Specification limits by performing step a) or b) below (listed in order of preference):

    a) The RCS is cooled down by feeding the steam generators with [main or auxiliary] feedwater and discharging steam using the turbine bypass system. This method can only be implemented if the condenser is available.

    b) If the condenser is not available, then an RCS cooldown should be commenced using [main or auxiliary] feedwater and dumping steam using the atmospheric steam dump valves. Using atmospheric dump valves to cooldown a steam generator causes a depletion of condensate and, therefore, it could be more limiting than using the turbine bypass system.

18. During the cooldown, adequate natural circulation flow in at least one loop should be verified. Refer to steps 11 and 12.

19. The plant should be borated to Technical Specification Limitation for reactivity control purposes. If letdown is not available, it may not be possible to borate the RCS to the cold shutdown RCS boron condition prior to commencing the cooldown due to the limited makeup space available in the pressurizer. If this is the case, the operator should borate the RCS to the minimum shutdown margin corresponding to T_C (per Technical Specifications). During the cooldown, as RCS shrinkage provides more space in the pressurizer, the operator should continuously or periodically borate to maintain the minimum shutdown margin until the cold shutdown boron

concentration is achieved. Note that if a 75°F/hr. cooldown rate is maintained, charging capacity (3 pumps running) may not be able to keep pressurizer level constant during the initial stages of the cooldown.

20. During the cooldown, shrinkage of RCS inventory due to cooling may cause outsurge of pressurizer fluid. Since this fluid is not directly borated by charging flow, it may be at a lower boron concentration than the RCS loops and therefore may dilute the loops and the vessel somewhat. In order to avoid this possible loss of shutdown margin, perform the following actions (listed in order of preference):

    a) Sufficient boron is added prior to commencing the cooldown to borate the entire RCS (including the mass in the pressurizer) to cold shutdown boron concentration (per Technical Specifications). Therefore, even if the pressurizer is relatively dilute and outsurges into the RCS loop, boron concentration will not drop below the cold shutdown concentration.

    b) If letdown is available, then sufficient heaters are energized to permit continuous auxiliary spray into the pressurizer without dropping RCS pressure. With pressurizer level head constant by letdown, the pressurizer is borated to within [50] ppm of RCS loop concentration using auxiliary spray.

    c) If letdown is not available, then the RCS is borated to [50 ppm] greater than the minimum shutdown margin corresponding to T_C (per Technical specifications). As space becomes available in the pressurizer due to RCS cooldown shrinkage, additional boron is charged to the RCS to maintain minimum shutdown margin corresponding to T_C. Of course, the use of auxiliary sprays to depressurize will also increase pressurizer boron concentration.

21. The bases for maintaining the RCS pressure and temperature within the acceptable range of the P/T limit curve (Figure 9-1) during the cooldown is that it will allow the operator to ensure adequate core cooling by maintaining minimum subcooling and will also require operator actions

(such as termination of HPSI or charging flow) which prevent excessive repressurization of the RCS. Excessive repressurization (i.e., > [200°F] subcooling) may result in reactor vessels stresses in the range of concern for pressurized thermal shock.

Maintaining pressurizer pressure as high as possible within the limits of Figure 9-1 will minimize the chances of void formation in areas of low flow. The operator has two basic methods to maintain RCS pressure and temperature within the acceptable range of the P/T curve. These methods are: (1) control RCS heat removal (i.e., cooldown rate) and (2) control RCS pressure suing pressurizer heaters and spray, charging and letdown, and [pressurizer fill and drain].

The operator will choose which method or combination of methods to be used based on existing plant conditions, as no two events are likely to follow the same scenario. For example, if the main condenser was not available and the only method for RCS heat removal is the atmospheric dump valves, then the choice would be toe remove RCS heat at the rate consistent with technical specifications and the atmospheric dump valve capacity. Pressurizer pressure would be controlled by use of pressurizer heaters and auxiliary spray (preferred) or by maintaining the required HPSI or charging pump flow rate to maintain the RCS pressure within acceptable P/T curve limits.

On the other hand if the main condenser is available the preferred method would be to control the RCS heat removal at a rate allowed by Technical Specification Limits using the turbine bypass valve. At the same time RCS pressure would be controlled by using auxiliary spray (preferred) and pressurizer heaters or a combination of HPSI and charging pumps to obtain a RCS pressure within acceptable P/T curve limits.

As many variables will exist, the operator must use judgement based on the existing plant conditions as to the best method to maintain the RCS within the desired P/T curve limits to minimize PTS concerns and provide for adequate core cooling.

22. During a controlled cooldown and depressurization the automatic operation of certain safeguard systems is undesirable. [Therefore, the setpoints of SIAS, CSAS, CIAS and MSIS must be manually reset (lowered) as the cooldown progresses to ensure that automatic engineered safeguards protection remains available until the RCS is cooled down and depressurized.]

23. Throughout the cooldown, the available condensate inventory should be monitored and replenished from available sources to provide a source for a secondary heat sink. Condensate inventory requirements should be determined according to Figures 9-3 and 9-4. Examples of alternate sources of condensate are non-seismic tanks, fire mains, ultimate cooling water supplies, potable tanks, etc. Plant specific alternate sources of feedwater should be identified and cited in the guideline.

24. The pressurizer level should be maintained in the normal shutdown reference band [35 to 245"] throughout the cooldown by the following methods:

    a) Preferentially, the pressurizer level is maintained by control of charging and letdown.
    b) Operation of the HPSI pumps is the next order of priority for maintaining pressurizer level.

    If the normal shutdown reference level is not maintained, a pressurizer level of [35 to 245"] along with RCS subcooling $\geq$ [20°F] should be maintained to avoid losing pressure control with the saturated bubble in the pressurizer. If the pressurizer level drops below the top of the pressurizer heaters, pressurizer heater operation will be interlocked off for overheating protection. A plant cooldown can be performed without a pressurizer level within the above preferred level indications as long as adequate primary pressure control is being maintained. However, pressurizer level should be brought back to normal as soon as possible.

Once the pressurizer water temperature varies from the normal hot standby temperature, the instrument indication on the normal pressurizer level channel will begin to deviate (i.e., decalibrate) from the true pressurizer level. At this time, the operator should use plant cooldown correction curves to determine the true pressurizer water level. A cold calibrated pressurizer instrument channel is provided. This channel can be used as a quick reference during the plant cooldown. The actual pressurizer water level during pressurizer cooldown will be between the level indicated on the cold calibrated channel (which reads low) and the level indicated on the hot calibrated channel (which reads high).

25. Equipment malfunctions may require that one steam generator be isolated continuously from the RCS, as a heat sink (i.e., all feedwater and steam flow in and out of that steam generator stopped). During forced flow conditions when one steam generator must be isolated as a heat sink, sufficient heat transfer occurs to maintain the isolated steam generator at the same relative temperature a the operating RCS loop. However, with no RCPs operating, conditions may result which can stop natural circulation flow through the isolated steam generator and RCS loop, leaving those components in a hot stagnant condition. This condition by itself will not necessarily affect core cooling via natural circulation int he unisolated steam generator. As long as reactivity control, RCS pressure control, RCS inventory control, and RCS heat removal are properly maintained in the operating loop, sufficient natural circulation flow will be maintained through the core and operating loop.

    However, a hot isolated steam generator presents an undesirable situation when trying to depressurize the RCS (e.g., to initiate shutdown cooling). Depressurization of the RCS below the isolated steam generator's saturation pressure could void portions of the isolated RCS loop which could cause the isolated steam generator to act like a pressurizer and hinder the depressurization to the shutdown cooling initiation pressure. Thus, an isolated steam generator should usually be cooled down along with the RCS.

26. If the above actions fail to depressurize the RCS, then a void should be suspected. Any time it is found that voiding hinders RCS depressurization to SCS entry pressure, when SCS operation is desired, then an attempt at elimination of the voiding should be made.

The operator should monitor for the presence of voids. Voiding in the RCS may be indicated by any of the following indications, parameter changes, or trends:

a) letdown flow greater than charging flow,
b) pressurizer level increasing significantly greater than expected while operating pressurizer spray,
c) [the RVLMS indicates that voiding is present in the reactor vessel],
d) [HJTC unheated thermocouple temperature indicates saturated conditions in the reactor vessel upper head]. A
e) If desired, a confirmation of the results obtained from the above, or a first check for voiding in the RCS, may b obtained by performing the following test. This test is a good indication of voiding for a closed RCS (i.e., no leaks). It may not be possible to perform every step of the voiding test due to system availability, loss of electrical power, etc. In all cases, the operators must determine the validity of the test based upon their knowledge of plant operation and system response. Pressurizer level and pressure must be stabilized prior to performing the following test in order to provide valid results.

   i) Start an additional charging pump to demonstrate that pressurizer level responds as expected:

      increase of [2 inches/min.] per charging pump (approximately)

   ii) Activate pressurizer heaters and demonstrate that the pressurizer pressure instrumentation responds as expected:

      increase of [15 psi/min] (approximately)

iii) Activate pressurizer spray and demonstrate that the pressurizer instrumentation responds as expected.

decrease of [26 psi/min] (approximately)

If pressurizer parameters meet the above criteria and subcooling is within the limits of Figure 9-1, then significant voiding does not exist. If pressurizer parameters do not meet the above criteria, then voiding is indicated.

27. If voiding should be eliminated, then proceed as follows:

a) Letdown is isolated or verified to be isolated to minimize further inventory loss,

b) The depressurization is stopped to prevent further growth of the void and, if required, the RCS is repressurized to ≥ [20°F] subcooling,

c) Pressurizing and depressurizing the RCS within the limits of Figure 9-1 may condense the void. Pressurizing has the effect of filling the voided portion of the RCS with cooler fluid which will remove heat from the region. Subsequent depressurization and a repeating of this process several times will cool and condense the steam void. In the case of a void in the reactor vessel, the pressurization/depressurization on cycle will produce a fill and drain of the reactor vessel. The pressurization/depressurization cycle may be accomplished using pressurizer heaters and spray (preferred method) or the SIS/charging system (alternative method). Monitor pressurizer level [and the RVLMS] for trending of RCS inventory. This will assist the operator in assessing the effectiveness of void elimination.

d) If indications of unacceptable RCS voiding continue, and voiding is suspected to exist in the (isolated) steam generator tubes, then cool the (isolated) steam generator (by steaming or blowdown, and/or

feeding) to condense the tube bundle void. This will be effective for condensing steam voids but will not have an effect on non-condensible gases trapped in the tube bundle. A buildup of non-condensible gases in the tube bundles will not hinder natural circulation even with a large number of the tubes blocked. This is due to the small amount of heat transfer area required for the removal of decay heat. Monitor pressurizer level for trending of RCS inventory. This will assist the operator in assessing the effectiveness of void elimination.

e) If indications of unacceptable RCS voiding continue, then voiding may be caused by non-condensible gases. [Operate the pressurizer vent and/or the reactor vessel head vent to clear trapped non-condensible gases.] Monitor pressurizer level [and/or the RVLMS] for trending of RCS inventory. This will assist the operator is assessing the effectiveness of void elimination.

28. When SCS entry conditions (RCS pressure $\leq$ [300 psia] and RCS $T_H \leq$ [300°F] are established, then the SCS is placed in service.

29. [LTOP protection is instituted below 275°F to protect the primary pressure boundary from low temperature brittle fracture.]

30. [The safety injection tanks must b vented or drained, or their discharge valves shut as an RCS pressure of 250 psia to prevent the nitrogen cover gas from discharging into the RCS when the RCS pressure is reduced.]

Safety Function Status Checks

Figure 9-13 provides a bases for the LOFC Safety Function Status Check. The Safety Function Status Check is designed to ensure that the operator is using the correct guideline, and the actions of that guideline are satisfying all relevant safety functions and maintaining adequate core cooling.

The safety function status check provides a systematic approach to determine if the LOFC EPG chosen is appropriate and, more importantly, if the plant condition is satisfactory.

SAFETY FUNCTION STATUS CHECK BASES
LOSS OF FORCED CIRCULATION
Figure 9-13a

The safety functions listed below and their respective criteria are those used to confirm the adequacy of the LOFC Guideline in mitigating the event.

SAFETY FUNCTION	ACCEPTANCE CRITERIA	INDICATION	RANGE	BASES
Reactivity Control	Reactor Power Decreasing and [Negative Startup Rate] and Not more than 1 CEA Bottom Light Not Lit or Borated per Tech Specs	Power Range Power Rate CEA Status Display	[0 - 125%] [-1 + 7 dpm] On/Off Light for each CEA	For all emergency events, the reactor must be shutdown. The criteria that no more than one CEA be stuck out or the RCS borated borated observes typical technical specification requirements.
Maintenance of Vital Auxiliaries (AC & DC Power)	[<--------------------------------Plant Specific-------------------------------->]			
RCS Inventory Control	[35"] ≤ Pressurizer Level ≤ [245"] and charging and letdown are being operated manually or automatically to maintain or restore pressurizer level and RCS ≥ [20°F] subcooled and [The RVLMS indicates the core is covered]	Pressurizer Level [RVLMS]	[0 - 350"] [0 - 100%]	Don't we anticipate a void with the current methodology A value of [245"] ([70%]) of range was chosen as an upper limit for pressurizer level to account for instrument accuracies and other uncertainties. A value of [35"] ([10%]) of range was chosen as a lower limit to account for instrument accuracy. A [20°F] subcooling margin coexisting with a pressurizer level between [35"] and [245"] indicates adequate RCS inventory control via a saturated bubble in the pressurizer. An RVLMS indication that the core is covered, taken in conjunction with [20°F] subcooling is an additional indication that RCS inventory control has been established.

SAFETY FUNCTION STATUS CHECK BASES
LOSS OF FORCED CIRCULATION
Figure 9-13b

The safety functions listed below and their respective criteria are those used to confirm the adequacy of the LOFC Guideline in mitigating the event.

SAFETY FUNCTION	ACCEPTANCE CRITERIA	INDICATION	RANGE	BASES
RCS Pressure Control	[1600 psia] $\leq$ Pressurizer Pressure < [2350 psia], <u>and</u> pressurizer heaters and spray are being operated manually or automatically to maintain or restore pressurizer pressure within the limits of the P/T curves, Figure 9-1.	Pressurizer Pressure	[1500 - 2500 psia]/ [0-1600 psia]	[2350 psia] is the high pressure alarm setpoint. Best estimate analysis shows that the selected events will fall within the above range.
Core Heat Removal	RCS T_{ave} < [545°F] <u>and</u>	RCS T_{ave}	[520°-610°F]	[545°F] is based on not lifting the steam generator secondary safety valves.
	RCS $\geq$ [20°F] subcooled	[Subcooled Margin Monitor]	[0° - 100°F]	[20°F] subcooled margin is based on engineering judgement to assure adequate core cooling accounting for temperature variations in the RCS. Best estimate analysis shows that the noted events will fall in the selected ranges.
RCS Heat Removal	At least one S/G has level: i) within the normal level band with feedwater available to maintain level or ii) being restored by a feedwater flow > [150 gpm] <u>and</u>	Steam Generator Level	[+63.5 - (1) 116.5"]	Decay heat levels may not be high enough to require a feedwater flow of [150 gpm]. If this is the case, once steam generator level is returned to the zero power level band and feedwater remains available to maintain that level, then RCS heat removal is being satisfied.

SAFETY FUNCTION STATUS CHECK BASES
LOSS OF FORCED CIRCULATION
Figure 9-13c

The safety functions listed below and their respective criteria are those used to confirm the adequacy of the LOFC Guideline in mitigating the event.

SAFETY FUNCTION	ACCEPTANCE CRITERIA	INDICATION	RANGE	BASES
RCS Heat Removal (Cont'd)	RCS T_{ave} is < [545°F] and controlled.			[545°F] is based on not lifting the steam generator secondary safety valves.
Containment Isolation	Containment Pressure < [1.5 psig] and	Containment Pressure	[0-60 psig] [0-15 psig]	[1.5 psig] is based on the containment pressure alarm. It is not expected for the selected events that containment pressure will increase to the alarm setpoint.
	No Containment Area Radiation Monitors Alarming and	Containment Area Radiation Monitors	Alarming/ Not Alarming	During an LOFC it is not expected that there will be radiation inside containment or detected on the process radiation monitors. The monitors should not be alarming.
	No Process Area Radiation Monitors Alarming and	Process Radiation Monitors	Alarming/ Not Alarming	
	No Steam Plant Activity Monitors Alarming	Steam Plant Radiation Monitors	Alarming/ Not Alarming	Steam plant activity is an indication of an SGTR and is not anticipated for an LOFC.
Containment Temperature and Pressure Control	Containment Temperature < [215°F] and	Containment Temperature	[50°-300°F]	[215°F] is the maximum normal expected average containment air temperature.
	Containment Pressure < [1.5 psig]	Containment Pressure	[0-60 psig] [0-15 psig]	[1.5 psig] is based on containment pressure alarm. It is not expected for the selected events that containment pressure will increase to the alarm setpoint.

SAFETY FUNCTION STATUS CHECK BASES
LOSS OF FORCED CIRCULATION
Figure 9-13d

The safety functions listed below and their respective criteria are those used to confirm the adequacy of the LOFC Guideline in mitigating the event.

SAFETY FUNCTION	ACCEPTANCE CRITERIA	INDICATION	RANGE	BASES
Containment Combustible Gas Control	H_2 < [2%]	[<----------------------Plant Specific------------------------------>]		

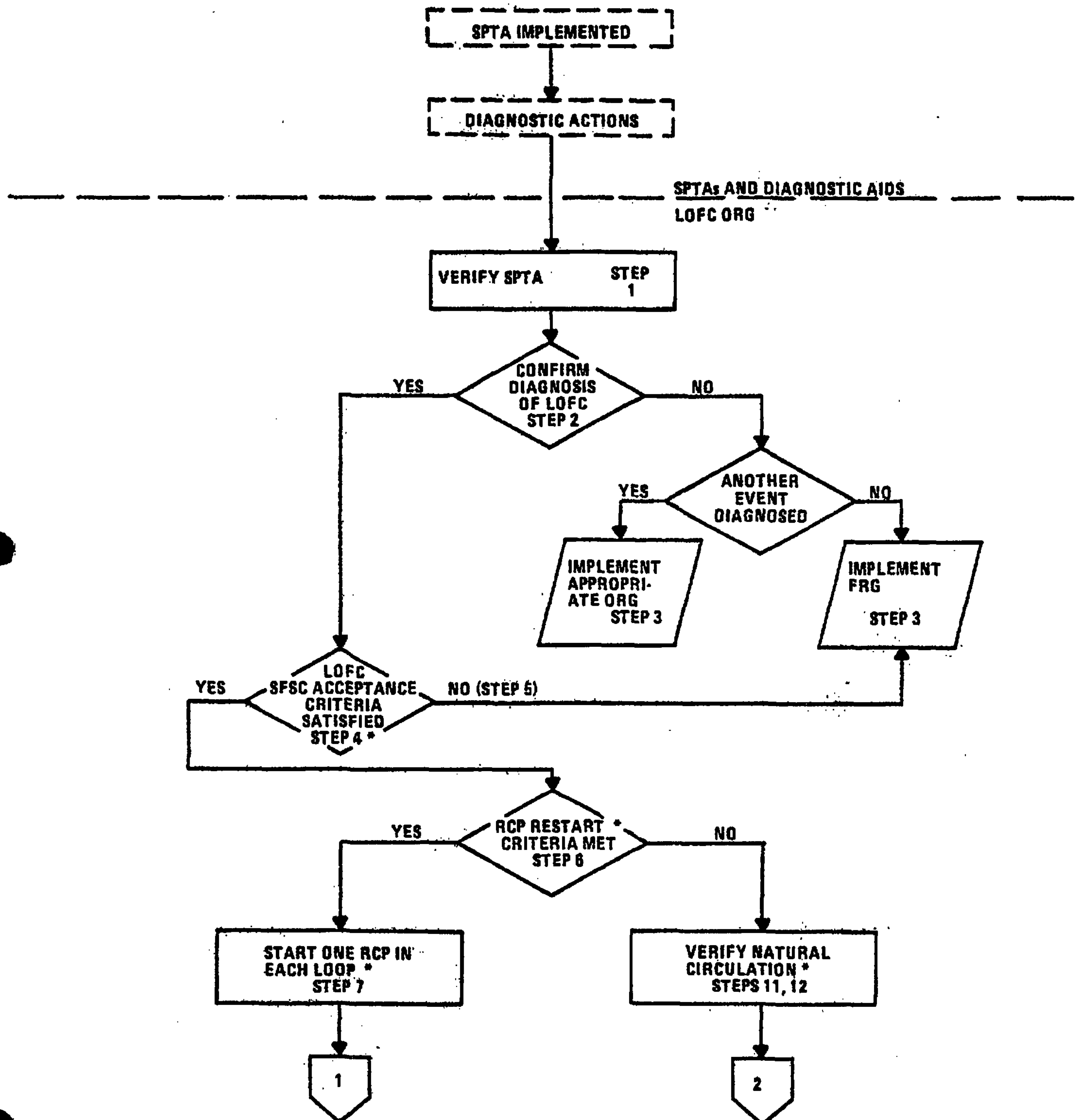
Event Strategy

This section contains the detailed LOFC recovery actions strategy charts (Figure 9-14). The chart depicts the strategy around which the LOFC guideline is built. They are intended to assist the procedure writer in understanding the intent of the guideline and for use in training. Operators should understand what the major objectives of the guideline are in order to facilitate their progress toward the guideline goals.

The strategy charts show the recovery guideline strategy in detail. Steps of the guideline which may be performed at any time during the course of an event are shown by affixed asterisks. The dashed boxes above the line indicate the lead-in steps performed by the operator prior to entering this recovery guideline.

FIGURE 9-14a

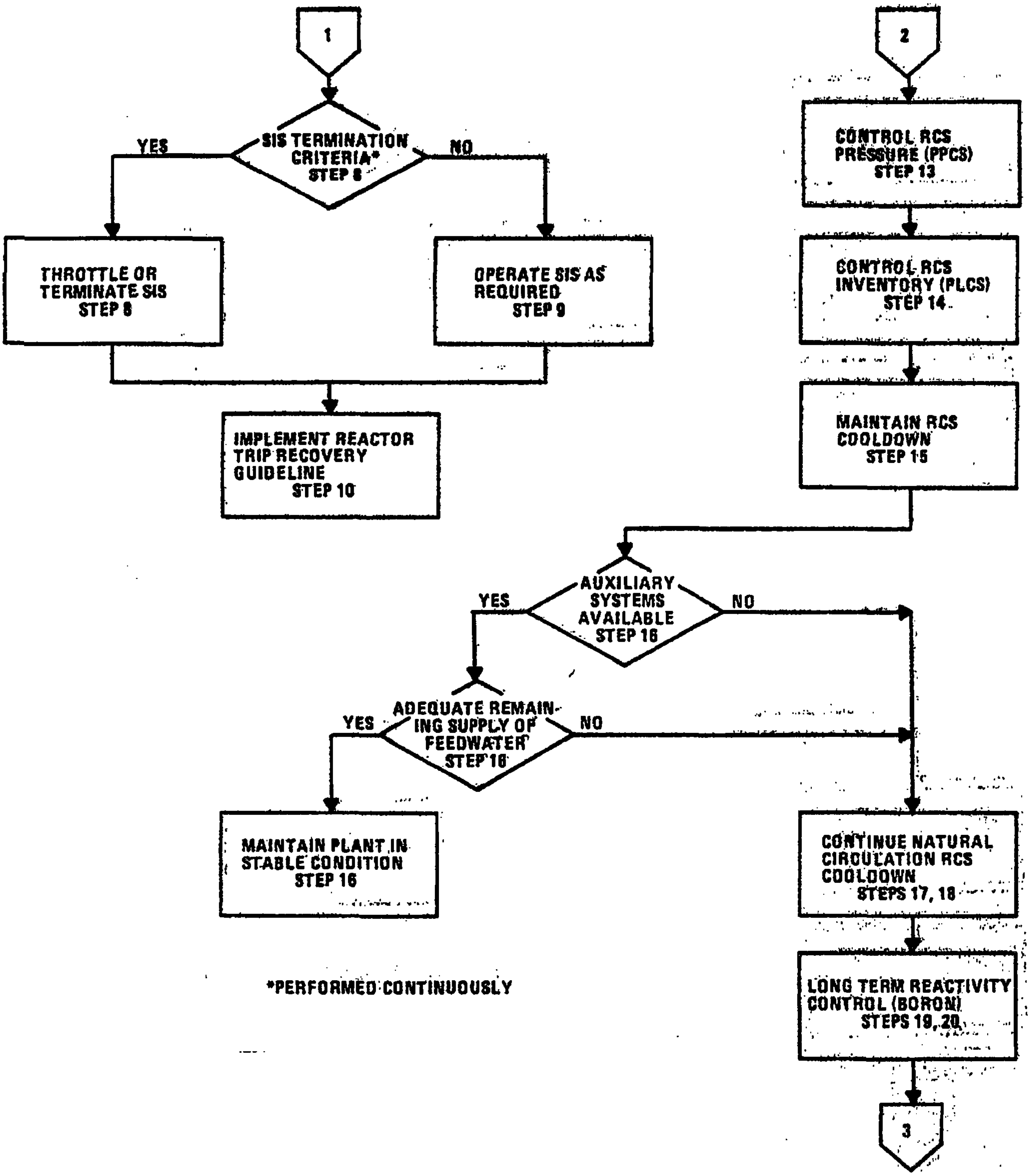
STRATEGY CHART FOR LOSS OF FORCED CIRCULATION



*PERFORMED CONTINUOUSLY

FIGURE 9-14b

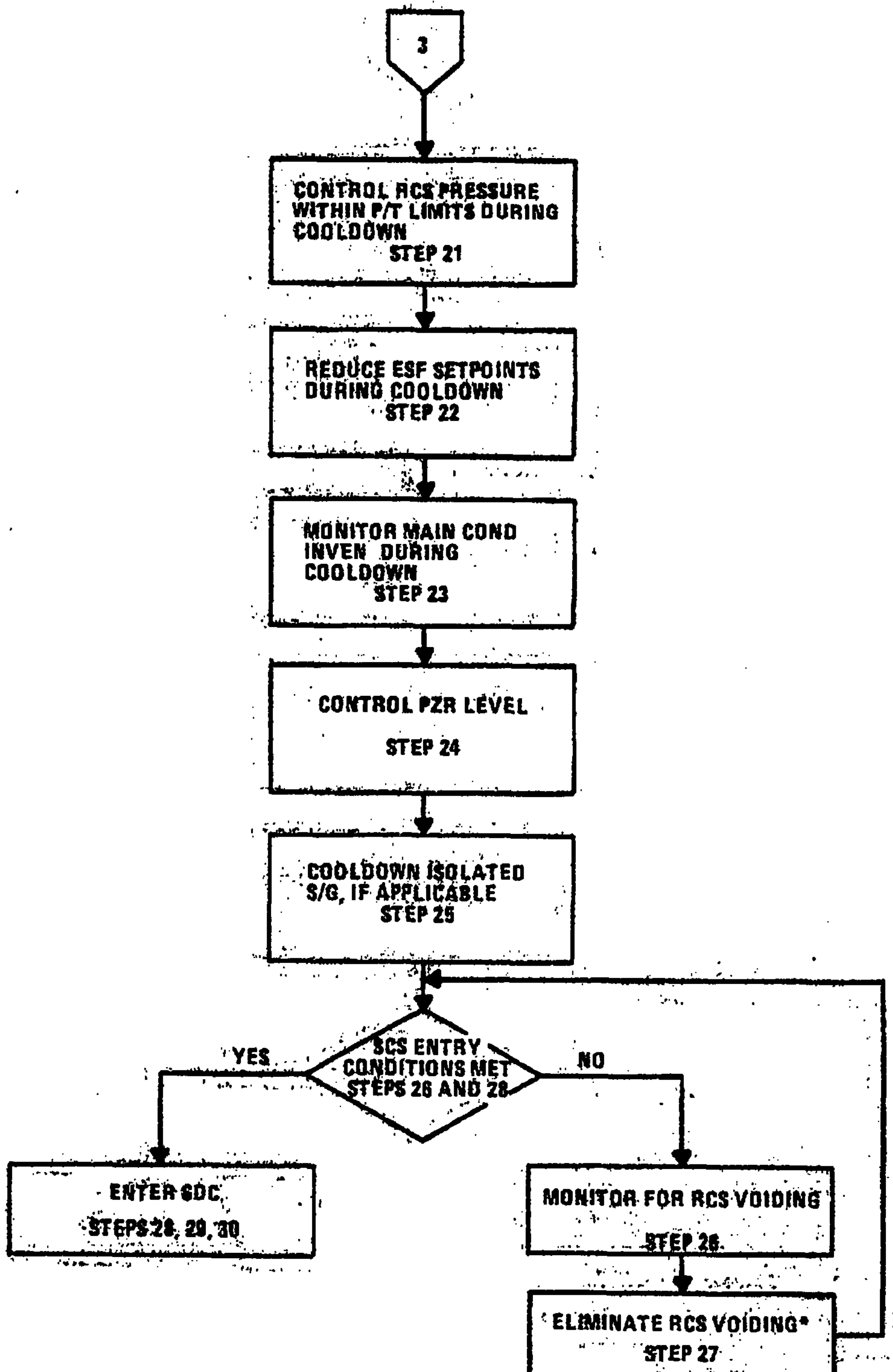
STRATEGY CHART FOR LOSS OF FORCED CIRCULATION



*PERFORMED CONTINUOUSLY

FIGURE 9-14c

STRATEGY CHART FOR LOSS OF FORCED CIRCULATION (Continued)



*PERFORMED CONTINUOUSLY

FUNCTIONAL RECOVERY GUIDELINE

Prepared by
COMBUSTION ENGINEERING, INC.
for the
C-E Owners Group

1. Implemented in Section II. A

2. Implemented in Section II A – C. See Deviation Sheet 8-1 concerning guideline step 2C.

PURPOSE

This guideline provides systematic operator actions for events in which a diagnosis is not possible, or for which emergency guidance is not available. The actions of this guideline are necessary to ensure that the plant is placed in a stable, safe condition. This guideline provides technical information to be used in developing a plant specific functional recovery procedure.

ENTRY CONDITIONS

1. The Standard Post Trip Actions have been performed

and

2. Any of the following conditions may be present:

   a. A reactor trip, and unusual concurrent symptoms, with no immediately apparent diagnosis or cause.

   b. Any condition, or pattern of symptoms, which the operator considers serious and, for which abnormal, or emergency guidance cannot be identified.

   c. Actions taken in an Optimal Recovery Guideline are not satisfying the acceptance criteria in the safety function status check.

1. IMPLEMENTED BY SECTION II. SINCE PERFORMANCE of the IMMEDIATE POST TRIP ACTIONS IS REQUIRED AS AN INITIAL CONDITION NO further DIRECTION to complete these ACTIONS IS required.

2. Implemented by the safety function status check from the optimum Recovery PROCEDURE being USED prior to implementing EOP 8 AND BY THE SFSC IN EOP 8. OPERATORS ARE Also trained to start the New SFSC after a New procedure is implemented (STA Accomplishes this function)

3. Implemented by section IX. See Deviation 8-2 concerning Resource Assessment trees.

4. implemented in Section V.B.3 AND VI.B.3

5. implemented in SECTION IX.

6. See DEVIATION 8-2.

7. Implemented in SECTION I AND section XI except operators ARE not directed to a specific procedure. The diagnosis made after the safety function ARE stabilized DETERMINES which procedure is used. Since it is expected that it would take a serious combination of events to cause the implementation of EOP 8, The Reactor trip Recovery guideline would probably not be the APPLICABLE PROCEDURE.

OPERATOR ACTIONS

1. Verify that the Standard Post Trip Actions have been performed.

2. Identify the status of safety functions using the Safety Function Status Check. This is done by identifying the success path(s) currently in use for each safety function and then checking the appropriate acceptance criteria.

3. Assess all safety functions before going to Resource Assessment Trees.

*4. If pressurizer pressure decreases to less than [1300 psia] following an SIAS, Then ensure all RCPs are tripped.

*5. Assess the status of each safety function whenever the Functional Recovery Guideline is in use. Verify that all safety functions are being satisfied, or identify those in jeopardy, by comparing control board parameters to the acceptance criteria of the Safety Function Status Check.

*6. Identify plant resources, or success paths, which can be used to fulfill each safety function that is not being satisfied. Refer to Figures 10-8 through 10-15.

7. If the first success path is being used for all safety functions of the Safety Function Status Check, and the acceptance criteria for all paths are satisfied, Then implement the Reactor Trip Recovery guideline.

* Step performed continuously.

8. SEE DEVIATION 8-3

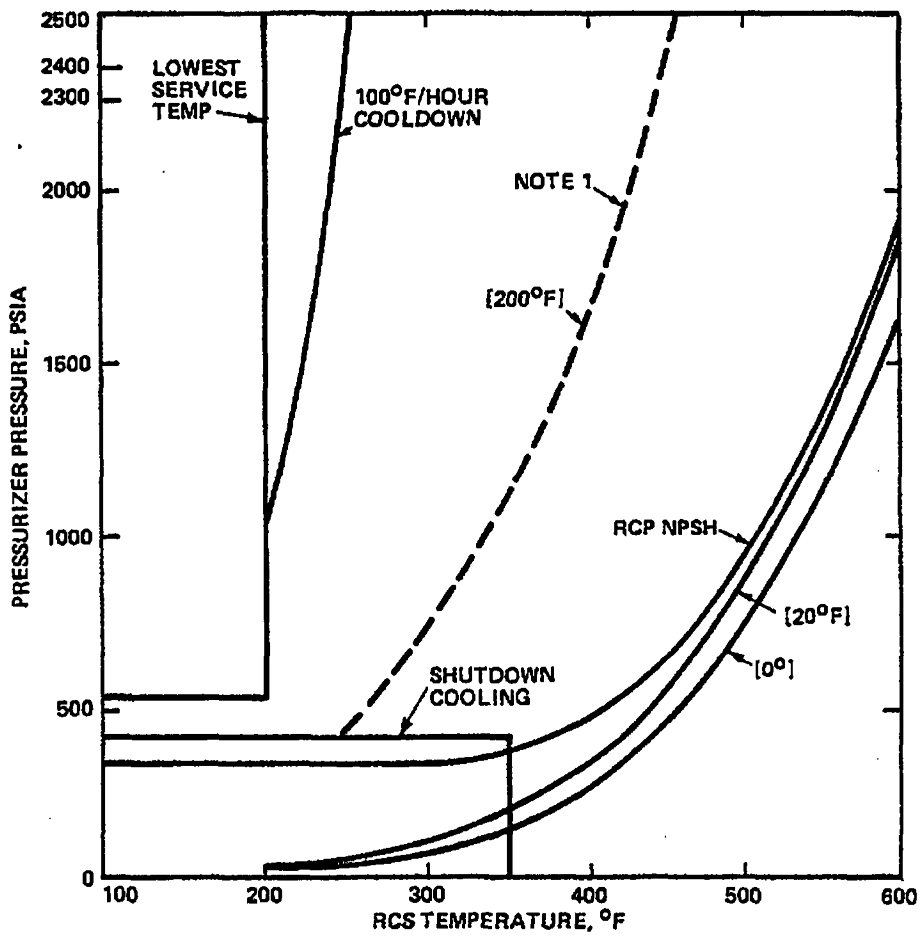
9. Implemented by TRAINING, section I, section XI, ~~and~~ the various optimum recovery procedures AND the OI AND OPs.

*8. Perform the appropriate operator action guidelines associated with the identified success path.

9. Implement the Long Term Actions when all safety functions are being satisfied.

* Step performed continuously.

TYPICAL POST ACCIDENT PRESSURE-TEMPERATURE LIMITS(2)



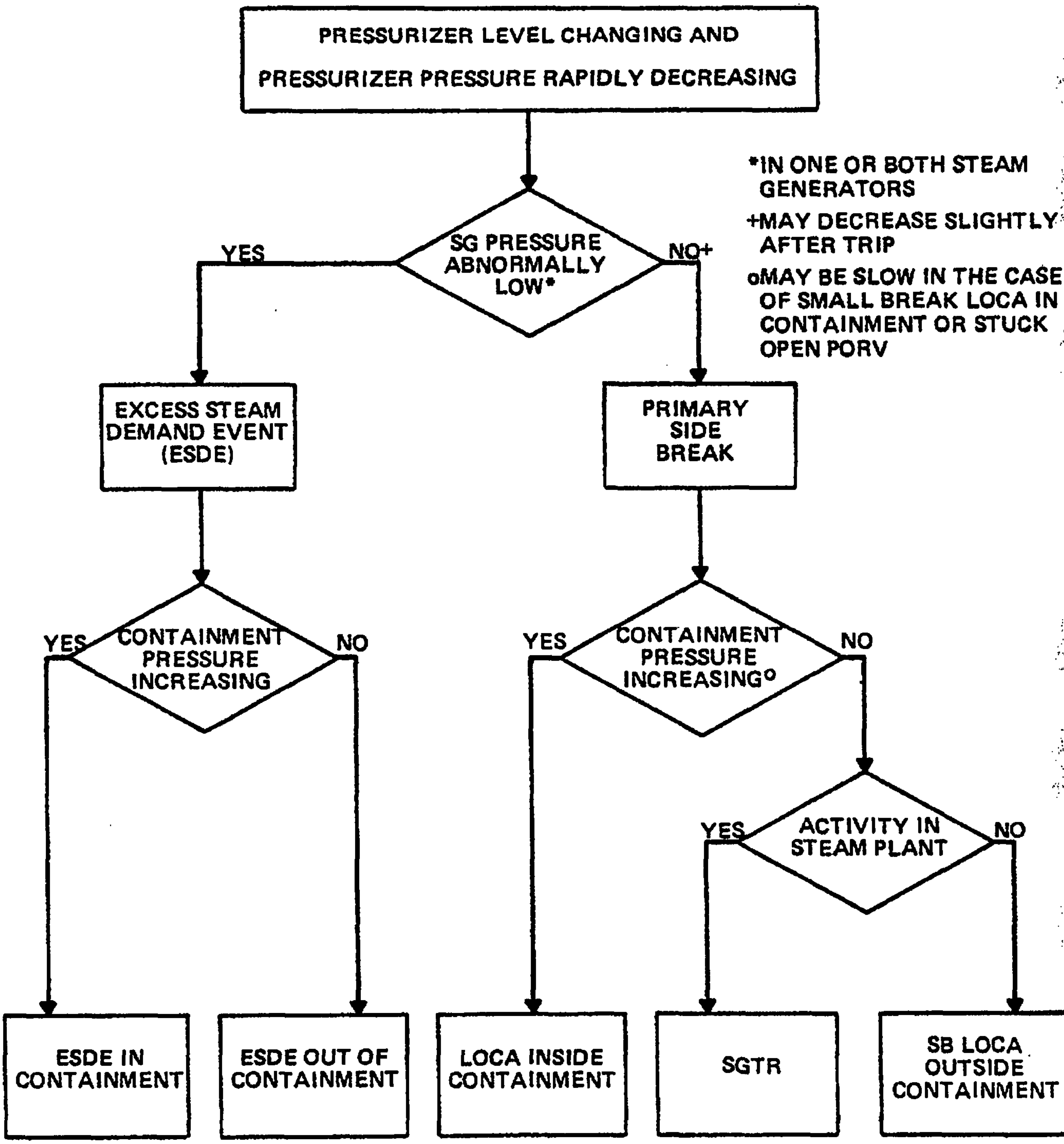
NOTES: (1) THIS CURVE SUPERSEDES THE 100°F/HOUR COOLDOWN CURVE ANYTIME THE RCS HAS EXPERIENCED AN UNCONTROLLED COOLDOWN WHICH CAUSES RCS TEMPERATURE TO GO BELOW 500°F

(2) THESE CURVES MUST BE ADJUSTED FOR INSTRUMENT INACCURACIES

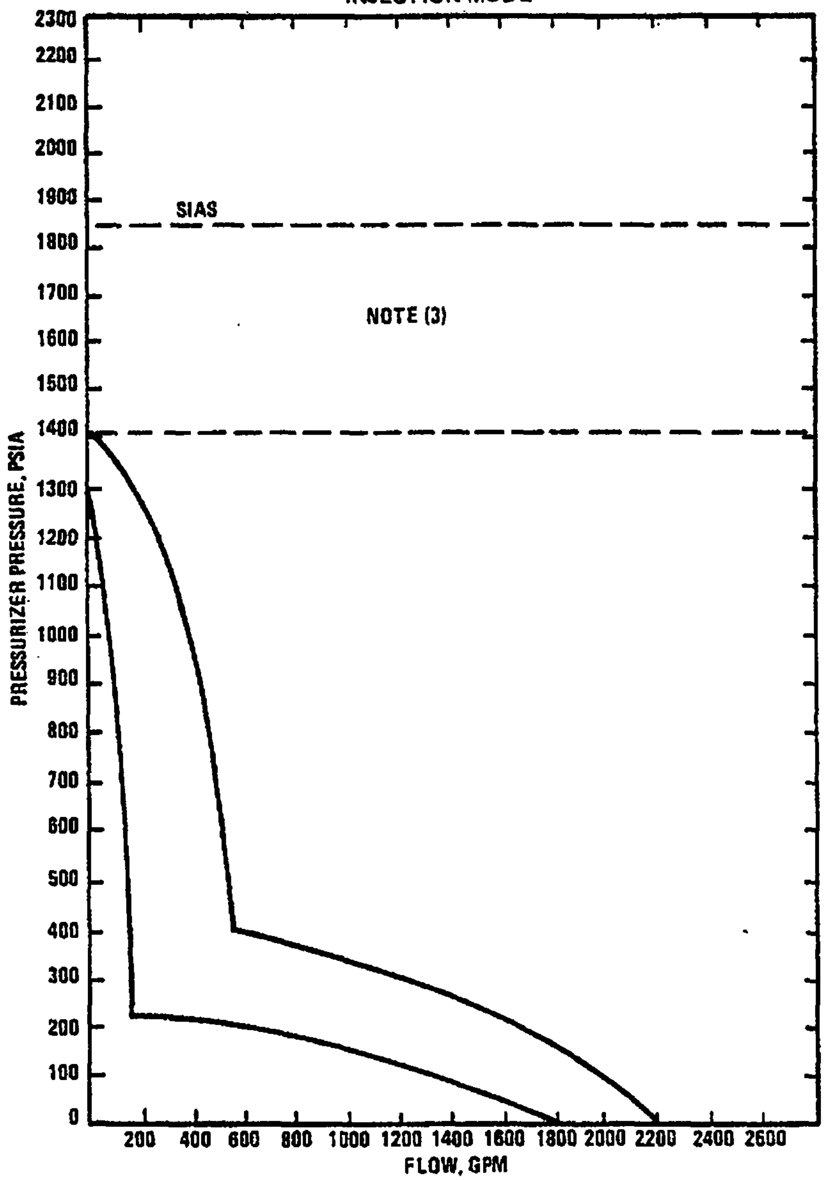
(3) COLOR CODE

RED - PARAMETER IN EXCESS OF LIMITS
ORANGE - PARAMETER IN DANGER OF EXCEEDING LIMITS
YELLOW - PARAMETER OUTSIDE OF OPTIMAL RANGE, BUT STILL WITHIN LIMITS
GREEN - PARAMETER IN OPTIMAL RANGE OF VALUES

BREAK IDENTIFICATION CHART

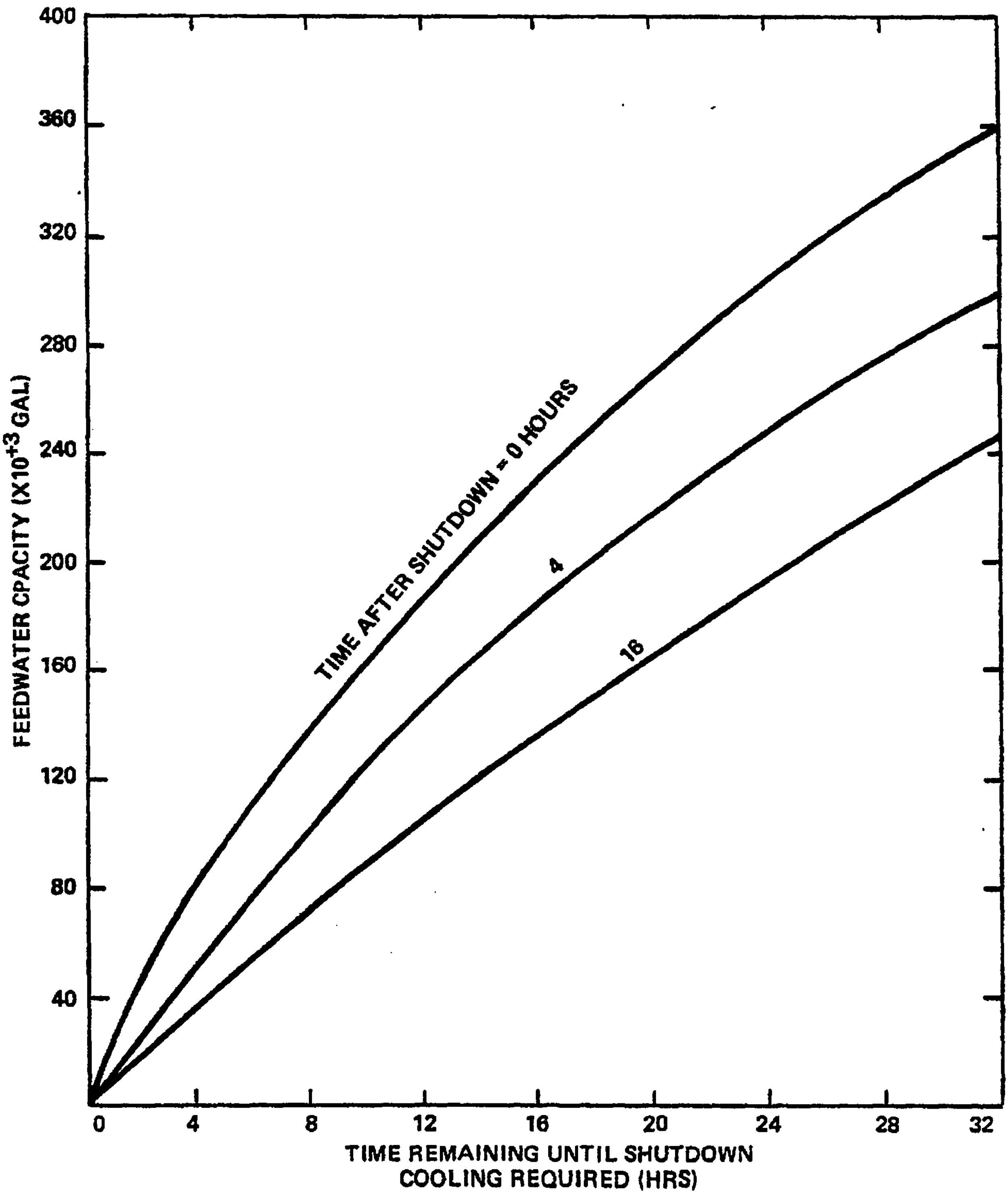


TYPICAL ACCEPTABLE SIS FLOW vs RCS PRESSURE(1)
INJECTION MODE(2)

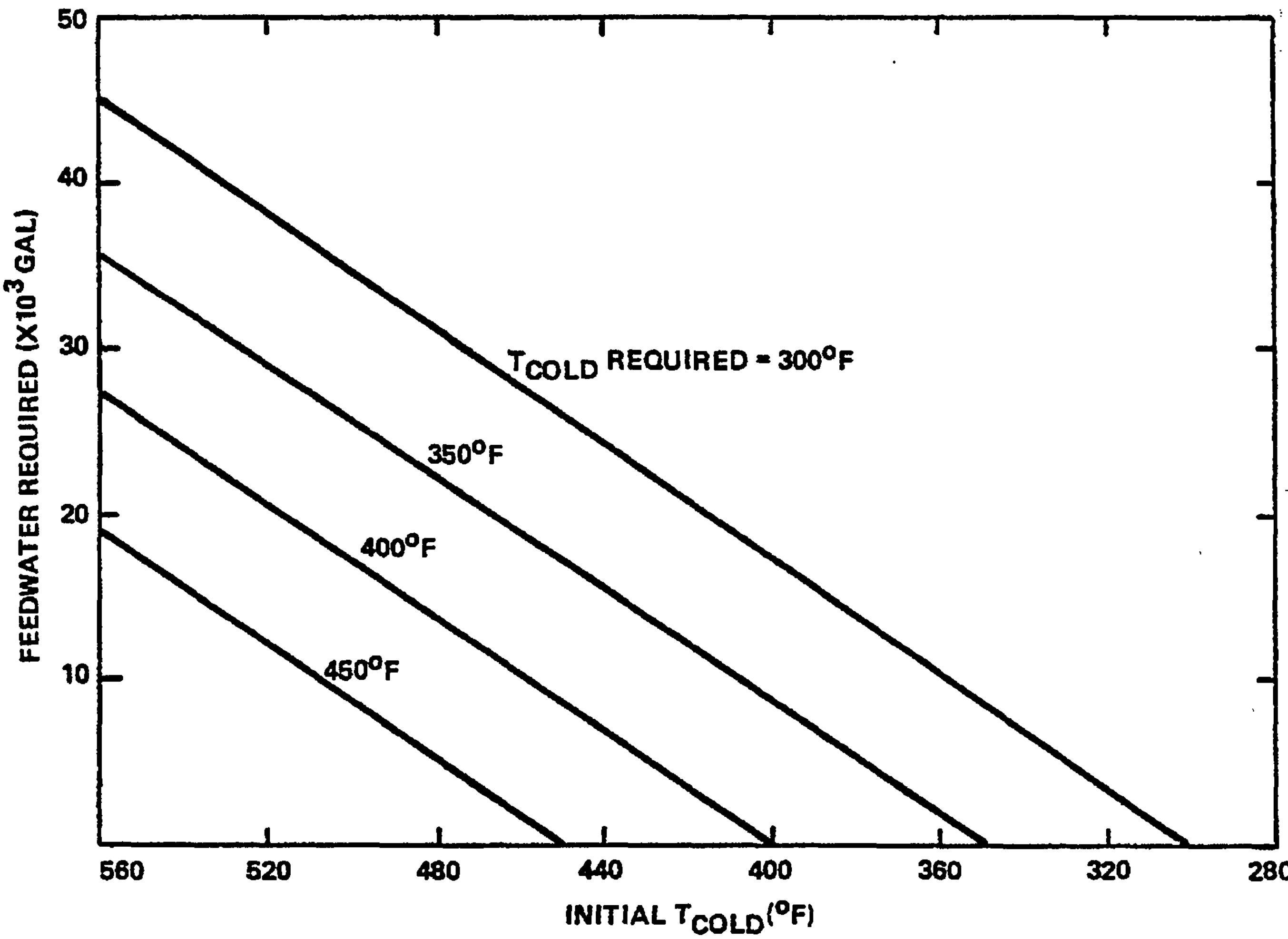


NOTES:
(1) SEE IMPLEMENTATION SECTION FOR DEVELOPMENT OF PLANT SPECIFIC CURVE
(2) FOR HOT AND COLD LEG INJECTION MODE, THE LPSI PUMPS ARE NOT REQUIRED TO BE OPERATING. THE HPSI PUMP FLOW IS DIVIDED EQUALLY BETWEEN THE HOT AND COLD LEGS
(3) BELOW SIAS PRESSURE, SAFETY INJECTION SYSTEM (SIS) PUMPS WILL BE OPERATING BUT THERE WILL BE NO INJECTION FLOW UNTIL SYSTEM PRESSURE FALLS BELOW THE SHUTOFF HEAD OF ANY SIS PUMP
(4) COLOR CODE
    RED - PARAMETER IN EXCESS OF LIMITS
    YELLOW - PARAMETER OUTSIDE OF OPTIMAL RANGE, BUT STILL WITHIN LIMITS
    GREEN - PARAMETER IN OPTIMAL RANGE OF VALUES

TYPICAL FEEDWATER CAPACITY vs TIME REMAINING UNTIL SHUTDOWN COOLING REQUIRED



TYPICAL FEEDWATER REQUIRED FOR SENSIBLE HEAT REMOVAL
T_{COLD} (REQUIRED) vs T_{COLD} (INITIAL)



Bases for Operator Actions

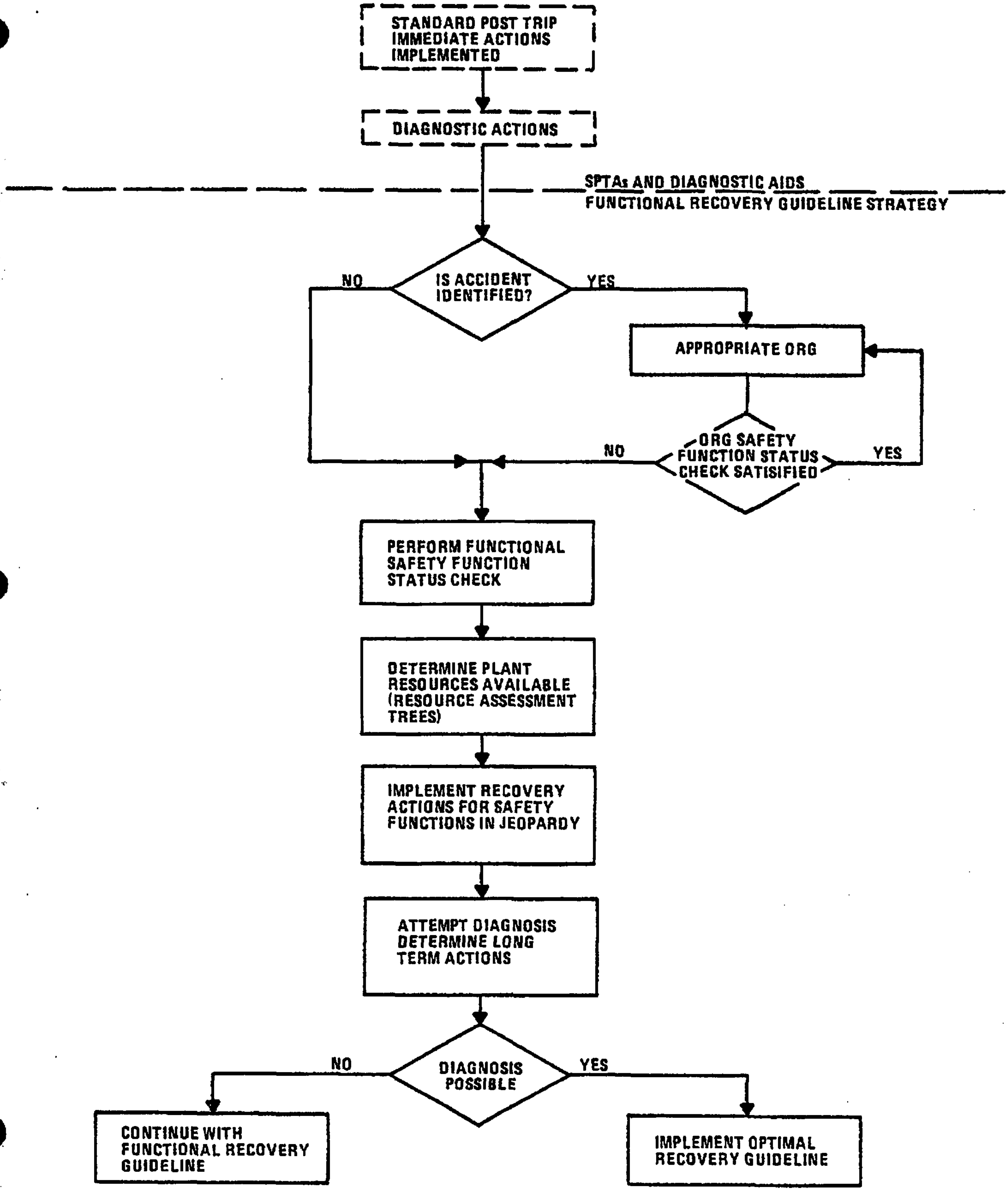
1. The execution of all standard post trip actions is verified. This assures that all safety functions have been initially attended to.

2. A basic strategy flow chart for the functional recovery guideline is shown in Figure 10-6. The entry point to the FRG is the Safety Function Status Check. The primary purpose of this check is to provide an assessment of all relevant safety funtions. Since the FRG may be used for a wide variety of events, it is not possible to know in advance which success path will be the primary one for each safety function or which safety function will be most affected. Since more than one path may be in use for each safety function, the operator should use the acceptance criteria for the highest numbered path in use (e.g., if RCS Inventory Control success paths IC-1 (CVCS) and IC-2 (SIS) are both in use, then the acceptance criteria for IC-2 must be satisfied).

3. All of the safety functions are assessed before any other actions are taken. By using the Safety Function Status Check to check all safety functions, the operator identifies the plant status and trends in the following manner. Safety functions are assessed in order of their priority as discussed previously. The acceptance criteria which are used to judge the status of each safety function are organized around the success paths for each function. Since each path uses, or may use, different technical means of achieving a safety function, the criteria for judging the success of that path are specific to the technical means. Also, in order to facilitate operator use, the criteria chosen are parameters which can be read directly from the control board. Thus, reactivity control criteria related to CEAs uses CEA bottom lights and that related to borating uses indications of reactor power and boron addition rate.

   If it is found that the lowest numbered success path is adequately maintaining control for each safety function (in other words, the acceptance criteria are being met), then the operator may exit the functional

FIGURE 10-6
STRATEGY CHART FOR FUNCTIONAL RECOVERY GUIDELINE



recovery guideline and implement the reactor trip recovery guideline. This is possible because the criteria for those success paths bound the expected parameters for an uncomplicated reactor trip.

4. This step contains guidance regarding the RCP operating strategy when implementing the Functional Recovery Guideline (FRG). The generic RCP trip strategy which follows is identical to the guidance provided for RCP operation during an LOCA. (Figure 10-7).

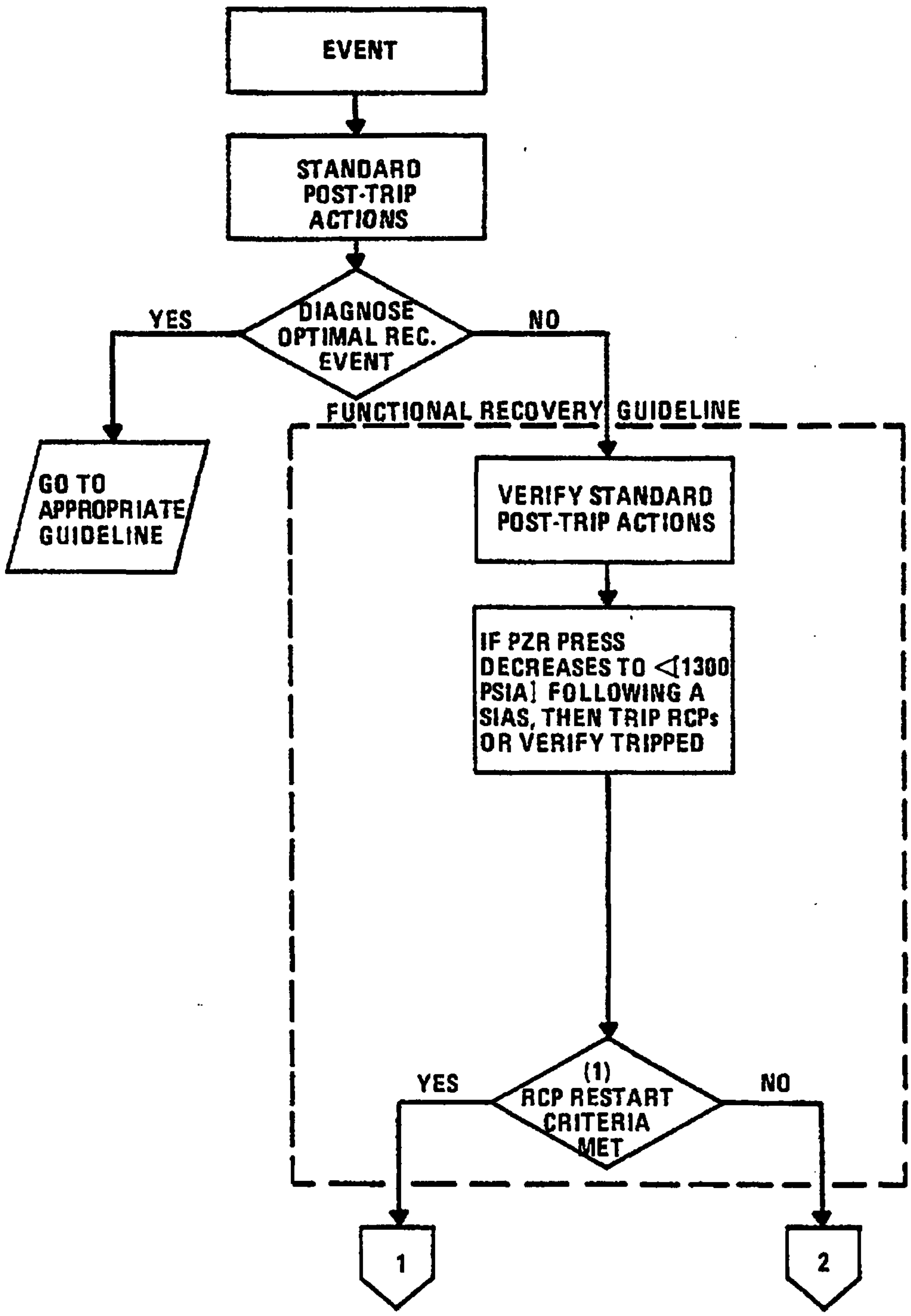
   Once the operator implements the FRG, if pressurizer pressure goes below [1300 psia] following receipt of an SIAS, then all four RCPs must be tripped. Two RCPs may have been tripped already in the Standard Post Trip Actions. In this case, the operator would simply trip the remaining two RCPs. Since prolonged RCP operation during LOCAs of certain size and location could result in increasing the severity of the event, tripping all four RCPs ensures a conservative approach to event recovery. This is due to the fact that when the operators implement the FRG they have not determined what event is occurring. An LOCA may be the lone event which is occurring or it may be occurring in conjunction with other event(s). Since operators cannot be sure what event is occurring, they are instructed to trip all RCPs whenever implementing the FRG and pressurizer pressure decreases to less than [1300 psia] following an SIAS. This is a conservative approach designed to satisfy worst case analysis.

5. The operator is required to continually verify that all relevant safety functions are being satisfied by comparing control board parameters to the acceptance criteria of the Safety Function Status Check. This ensures that the status of all relevant safety functions is being monitored and that the appropriate success path acceptance criteria are being used as the plant lineup and conditions change.

   If all safety functions are satisfied, then the success paths in use are adequately mitigating the effects of the event which is occurring. Therefore, the implementation or use of those success paths is continued.

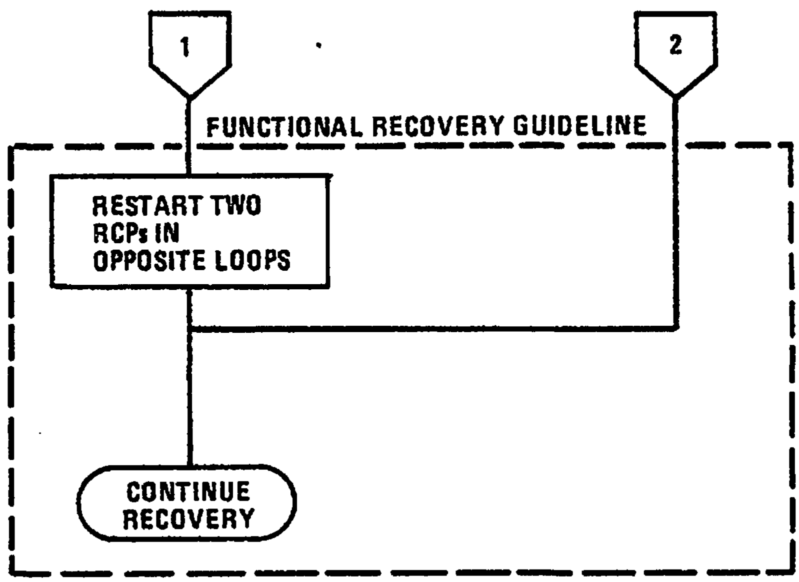
FIGURE 10-7a

RCP TRIP STRATEGY FOR FUNCTIONAL RECOVERY GUIDELINE



(1) STEP PERFORMED CONTINUOUSLY

FIGURE 10-7b


1
2
FUNCTIONAL RECOVERY GUIDELINE
RESTART TWO RCPs IN OPPOSITE LOOPS
CONTINUE RECOVERY

6. If all safety functions are not being satisfied, then the success path in use is not adequately mitigating the occurring event. The operator is required to refer to the resource assessment tree for the function in jeopardy and attempt to use the next success path available for the unsatisfied function in order to mitigate the effects of the event.

   For each safety function not being satisfied, the operator can identify plant resources or success paths by referring to the resource assessment trees. The resource assessment trees (Figures 10-8 through 10-15) provide information to the operator to assist in a determination of the availability of plant resources to be used to satisfy safety functions. The resource assessment trees provided are structured to show the intended priority (left to right) for implementation of success paths. Note, that more than one success path may be employed for each safety function in order to satisfy the acceptance criteria of the highest numbered success path in use. Each plant resource assessment tree pictorializes all of the generic resources available for fulfilling a safety function. Limits have been developed for each component of the success path which permit the operator to interrogate the control board to decide if that success path is available. Once an available path has been identifed, the tree refers the operator to an operator action guideline.

7. If equipment restoration or repair, or changes in plant status permit the use of the first success path then the operator may elect to implement them. If the acceptance criteria for all success paths are satisified and the lowest numbered success paths are the only currently in use then, the RT Recovery Guideline should be implemented.

   The format provided by Figures 10-8 through 10-15 is not meant to be prescriptive. Implementation of the information provided by the figures will vary according to individual utility needs and desires. Certain principles were applied in generating each of the resource assessment trees. These are explained in greater detail in section 1.0.

8. The operator performs the operator action guidelines for the success paths to be implemented in order to satisfy the safety functions in jeopardy.

   The success path operator actions sections contains specific actions to implement success paths for each safety function. Also provided are acceptance criteria for safety functions and specific supplementary information. Additional contingency guidance is provided for situations where the safety functions are not being satisfied even after implementing the available success paths (plant resources). The bases for the operator action guidelines for each success path follow their corresponding operator actions section.

   The operator actions guidelines provide step-by-step operational guidance, acceptance criteria for determining the successful control of a safety function, and associated supplementary information, all of which are necessary to implement the success paths identified on the resource assessment trees. Each operator action guideline contains all the actions necessary (on a generic basis) for recovering control of a jeopardized safety function. Acceptance criteria are included for determining the degree of success achieved. Additional guidance is provided which aids the operators in determining their next course of action. For instance, if control of the safety function is achieved, they may be instructed to proceed to the next safety function in jeopardy. Alternatively, they may be told to implement another success path in the case when the current path is inadequate. If all safety functions are being fulfilled, they may choose to go to the Long Term Actions section of the Functional Recovery Guideline. Supplementary information which applies to the particular operator action guideline in use are listed at the end of each section.

9. When all safety functions are satisfied the operator implements the Long Term Actions and attempts to systematically evaluate the plant status to determine, if possible, what the cause of the emergency was, what course of action to take (e.g., proceed to cold shutdown) and what further emergency operating guidance is available.

In the Long Term Actions, the operator continues to verify the adequate maintenance of safety functions, assesses the status of the plant and if possible, implements an optimal recovery guideline.

SAFETY FUNCTION STATUS CHECK

Safety Function	*Associated Resource Tree*
1. REACTIVITY CONTROL ----------------------------------	Tree A

Success Path Currently In Use	*Acceptance Criteria*
a. CEA Insertion	a.i) Not more than 1 CEA bottom light not lit. and Reactor Power Decreasing *or* ii) Reactor power less than than [$10^{-(X)}$%] and constant or decreasing
b. Boration Using CVCS	b.i) Boron addition rate greater than [40 gpm] and Reactor Power Decreasing *or* ii) Reactor power less than [$10^{-(X)}$%] and constant or decreasing

SAFETY FUNCTION STATUS CHECK (Cont'd)

Safety Function	Associated Resource Tree
1. REACTIVITY CONTROL (Cont'd)	Tree A

Success Path Currently In Use	Acceptance Criteria
c. Boration Using SIS	c.i) Boron addition rate greater than [40 gpm] and Reactor power decreasing *or* ii) Reactor power less than [$10^{-(X)}$%] and constant or decreasing
d. CEA Drive Down	d.i) Not more than 1 CEA bottom light not lit and Reactor power decreasing *or* ii) Reactor power less than [$10^{-(X)}$%] and constant or decreasing

SAFETY FUNCTION STATUS CHECK (Cont'd)

Safety Function	*Associated Resource Tree*
2. MAINTENANCE OF VITAL AUXILIARIES (AC & DC POWER) ------------------	Tree 8

Success Path Currently In Use	*Acceptance Criteria*

[<----------------------Plant Specific Information------------------------>]

SAFETY FUNCTION STATUS CHECK (Cont'd)

Safety Function	*Associated Resource Tree*
3. RCS INVENTORY CONTROL ------------------------------	Tree C

Success Path Currently In Use	*Acceptance Criteria*
a. CVCS	a.i) Pressurizer level is [35 to 245"*] *and* ii) The RCS is at least [20°F] sub-cooled [by CET] *and* iii) [The RVLMS indicates the core is covered].
b. SIS	b.i) [All available charging pumps are operating and] the SIS pump(s) are injecting water into the RCS per Figure 10-3 (unless SIS termination criteria are met). *and* ii) [The RVLMS indicates the core is covered].

* If the RCS is in a solid condition for pressure control, then the limit of [245"] may be exceeded.

SAFETY FUNCTION STATUS CHECK (Cont'd)

Safety Function	Associated Resource Tree
4. RCS PRESSURE CONTROL	Tree D

Success Path Currently In Use	Acceptance Criteria
a. Manual Control of Pressurizer Heaters and/or Spray	a. Pressurizer pressure is within the limits of the Post Accident Accident P-T Curves (Figure 10-1).
b. CVCS	b. Pressurizer pressure is within the limits of the Post Accident P-T Curves (Figure 10-1).
c. SIS	c. [All available charging pumps are operating and] the SIS pump(s) are injecting water into the RCS per Figure 10-3 (unless SIS termination criteria are met).

SAFETY FUNCTION STATUS CHECK (Cont'd)

Safety Function	*Associated Resource Tree*
4. RCS PRESSURE CONTROL (Cont'd) ----------------------	Tree D

Success Path Currently In Use	*Acceptance Criteria*
d. Forced Circulation with ADV or TBS Control.	d. Pressurizer pressure is within the limits of the Post Accident P-T Curves of Figure 10-1.
e. Natural Circulation with ADV or TBS Control	e. Pressurizer pressure is within the limits of the Post Accident P-T Curves of Figure 10-1.
f. [PORVs]	f. [Pressurizer pressure is: i) less than 2340 psia *and* ii) within the limits of the Post Accident P-T Curves of Figure 10-1].

SAFETY FUNCTION STATUS CHECK (Cont'd)

Safety Function — *Associated Resource Tree*

5. RCS AND CORE HEAT REMOVAL -------------------------- Tree E

Success Path Currently In Use	*Acceptance Criteria*
a. Forced Circulation, No SIS Operation	*a.i)* At least one S/G has level: - within the normal level band with feedwater available to maintain the level or - being restored by a feedwater flow greater than [150 gpm]. *and* *ii)* $T_H - T_c$ is less than [10°F] and not increasing *and* *iii)* T_{ave} is less than [545°F] and not increasing *and* *iv)* The RCS is at least [20°F] subcooled [by CET] *and* v) [No reactor vessel voiding as indicated by the RVLMS].

SAFETY FUNCTION STATUS CHECK (Cont'd)

Safety Function	*Associated Resource Tree*
5. RCS AND CORE HEAT REMOVAL (Cont'd) -------------------	Tree E

Success Path Currently In Use	*Acceptance Criteria*
b. Natural Circulation, No SIS Operation	b.i) At least one S/G has level:

- within the normal level band with feedwater available to maintain the level

or

- being restored by a feedwater flow greater than [150 gpm].

and

ii) $T_H - T_c$ less than [50°F] and not increasing

and

iii) T_{ave} is less than [545°F] and not increasing

and

iv) The RCS is at least [20°F] subcooled [by CET].

SAFETY FUNCTION STATUS CHECK (Cont'd)

Safety Function		*Associated Resource Tree*
5.	RCS AND CORE HEAT REMOVAL (Cont'd) -------------------	Tree E

Success Path Currently In Use	*Acceptance Criteria*
c. S/G Heat Sink with SIS Operating	c.*i*) At least one S/G has level: - within the normal level band with feedwater available to maintain the level or - being restored by a feedwater flow greater than [150 gpm]. *and* *ii*) [CET] temperature less than [700°F] or decreasing *and* *iii*) [All available charging pumps are operating and] the SIS pump(s) are injecting water into the RCS per Figure 10-3 (unless SIS termination criteria are met).

SAFETY FUNCTION STATUS CHECK (Cont'd)

Safety Function	*Associated Resource Tree*
5. RCS AND CORE HEAT REMOVAL (Cont'd) ------------------	Tree E

Success Path Currently In Use	*Acceptance Criteria*
d. Once-Through-Cooling	d.i) [CET] temperature less than [700°F] or decreasing *and* ii) [All available charging pumps are operating and] the SIS pump(s) are injecting water into the RCS per Figure 10-3 (unless SIS termination criteria are met). *and* iii) Pressurizer pressure is less than [1300 psia] or decreasing.
e. Shutdown Cooling System	e. Normal SCS Parameters

SAFETY FUNCTION STATUS CHECK (Cont'd)

Safety Function	*Associated Resource Tree*
6. CONTAINMENT ISOLATION ----------------------------	Tree F

Success Path Currently In Use	*Acceptance Criteria*
a. Manual Isolation	a.i) No steam plant activity alarms and No containment radiation alarms and Containment pressure less than [4 psig] *or* ii) Each containment penetration not required to be open has an isolation valve closed.

SAFETY FUNCTION STATUS CHECK (*Cont'd*)

Safety Function		*Associated Resource Tree*
7.	CONTAINMENT TEMPERATURE & PRESSURE CONTROL	Tree G

Success Path Currently In Use	*Acceptance Criteria*
a. Containment Fans	a.i) Containment temperature less than [240°F] *and* ii) Containment pressure less than [1.5 psig]
b. Containment Spray	b.i) Containment spray flow greater than [1500 gpm] (per spray header) *and* ii) Containment temperature and pressure constant or decreasing

SAFETY FUNCTION STATUS CHECK (Cont'd)

Safety Function	*Associated Resource Tree*
8. CONTAINMENT COMBUSTIBLE GAS CONTROL	Tree H

Success Path Currently In Use	*Acceptance Criteria*
a. [Plant specific methods, insert here]	a. Hydrogen concentration less than [2%].

SAFETY FUNCTION STATUS CHECK BASES

SUCCESS PATH CURRENTLY IN USE	ACCEPTANCE CRITERIA	INDICATION	RANGE	BASES
1. *SAFETY FUNCTION:* REACTIVITY CONTROL				
A) CEA Insertion	A) Not more than 1 CEA bottom light not lit and Reactor power is decreasing. or Rx power < $[10^{-(X)}\%]$ and constant or decreasing	CEA Status Display	On/Off Light for each CEA	The criteria here reflect the Tech Spec requirement that no more than one CEA be stuck out. This criterion, occurring with decreasing reactor power ensures that reactivity is under control. Reactor shutdown may also be assured by the minimum boration rate accompanied by decreasing reactor power or a constant reactor power less than that at the maximum expected sub-critical multiplication level. Since procedures require boration prior to cooldown, these criteria are adequate to ensure shutdown.
B) Boration using CVCS	B) Boron addition rate > [40 gpm.] and Reactor power is decreasing. or Rx power < $[10^{-(X)}\%]$ and constant or decreasing	CVCS Flowrate Power Range	[0-150 gpm] $[10^{-7} - 10^{2}\%]$	
C) Boration using SIS	C) Boron addition rate > [40 gpm] and Reactor power is decreasing or Rx power < $[10^{-(X)}\%]$ and constant or decreasing	HPSI Flowrate	[0-300 gpm]	

SAFETY FUNCTION STATUS CHECK BASES

SUCCESS PATH CURRENTLY IN USE	ACCEPTANCE CRITERIA	INDICATION	RANGE	BASES
1. *SAFETY FUNCTION:* REACTIVITY CONTROL (CONT'D)				
D) CEA Drive Down	D) Not more than 1 CEA bottom light not lit. and Reactor power is decreasing or Rx power $\leq$ [$10^{-(X)}$%] and constant or decreasing			
2. *SAFETY FUNCTION:* MAINTENACE OF VITAL AUXILIARIES (AC & DC POWER)				
[<------Plant Specific Information------>]				
3. *SAFETY FUNCTION:* RCS INVENTORY CONTROL				
A) CVCS	A) [35"] $\leq$ Pressurizer Level $\leq$ [245"]* and The RCS is at least [20°F] subcooled [by CET] and [The RVLMS indicates the the core is covered]	Pressurizer Level	[0-350"]	A value of [245"] of range was choosen as an upper limit for pressurizer level to account for instrument accuracies and other uncertainties. A value of [35"] of range was chosen as a lower limit to account for instrument accuracy. These values bound the limits of best estimate analysis.

*If the RCS is in a solid condtion for pressure control, then the limit of [245"] may be exceeded.

SAFETY FUNCTION STATUS CHECK BASES

SUCCESS PATH CURRENTLY IN USE	ACCEPTANCE CRITERIA	INDICATION	RANGE	BASES
3. *SAFETY FUNCTION:* RCS INVENTORY CONTROL (CONT'D)				
B) SIS	B) [All available charging pumps are operating and] SIS pump(s) are injecting water into the RCS per Fig. 10-3 (unless SIS termination criteria are met). and [The RVLMS indicates the core is covered]	[Core Exit Thermocouples]	[0-1600°F]	The value of [20°F] subcooling is based on keeping the core covered and thus ensuring adequate core cooling. If the core is covered with subcooled fluid, the RCS will not indicate super-heated conditions.
		Pressurizer Pressure	[1500-2500 psia] [0-1600 psia]	When the SIS is operating, its performance adequacy is judged by observing its delivery flow versus RCS pressure.
		SIS Flow	HPSI [0-300 gpm] LPSI [0-2000 gpm]	
		[RVLMS]	[0-100%]	An RVLMS indication that the core is covered, taken in conjunction with the other criteria, serves as an additional indication of adequate RCS inventory control.
4. *SAFETY FUNCTION:* RCS PRESSURE CONTROL				
A) Manual Control of Pressurizer Heaters and/or Spray	A) Pzr Pressure is within the limits of the Post Accident P-T Curves. (Figure 10-1)	[Subcooled Margin Monitor]	[0-100°F]	RCS subcooling of at least [20°F] ensures a liquid state of the coolant for effective heat removal properties. When the SIS is operating, its performance adequacy is judged by observing its delivery flow versus RCS pressure.
B) CVCS	B) Pzr Pressure is within the limits of the Post Accident P-T Curves. (Figure 10-1)	[Core Exit Thermocouples]	[0-1600°F]	

SAFETY FUNCTION STATUS CHECK BASES

SUCCESS PATH CURRENTLY IN USE	ACCEPTANCE CRITERIA	INDICATION	RANGE	BASES
4. *SAFETY FUNCTION:* RCS PRESSURE CONTROL (CONT'D)				
C) SIS	C) [All available charging pumps are operating and] the SIS pump(s) are injecting water into the RCS per Figure 10-3 (unless SIS termination criteria are met).	SIS Flow	HPSI [0-300 gpm] LPSI [0-2000 gpm]	
D) Forced Circulation with ADV or TBS Control	D) Pressurizer pressure is within the limits of the Post Accident P-T curves of Figure 10-1.	Pressurizer Pressure	[1500-2500 gpm] [0-1600 psia]	
E) Natural Circulation with ADV or TBS Control	E) Pressurizer pressure is within the limits of the Post Accident P-T curves of Figure 10-1.			Maintaining the RCS within the P-T curves ensures adequate core cooling and minimizes the chance of PTS.
F) [PORVs]	F) [Pressurizer pressure is: less than 2340 psia and constant or decreasing <u>and</u> Within the limits of the Post Accident P-T curves of Figure 10-1].			[2340 psia] is 10 psi below the high pressure alarm setpoint. A review of best estimate analysis shows that the selected events will fall below [2340] psia.

SAFETY FUNCTION STATUS CHECK BASES

SUCCESS PATH CURRENTLY IN USE	ACCEPTANCE CRITERIA	INDICATION	RANGE	BASES
5. *SAFETY FUNCTION:* RCS AND CORE HEAT REMOVAL				
A) Forced Circulation, No SIS Operation	A) At least one S/G has level: within the normal level band with feedwater available to maintain the level or being restored by a feed-water flow > [150 gpm]	Steam Generator Level	[+163.5 - (-)116.5]"	Decay heat levels may not be high enough to require a feedwater flow of [150 gpm]. If this is the case, once steam generator level is returned to the normal level band and feedwater remains available to maintain that level, then the S/G contribution to RCS heat removal is being satisfied.
		T_{ave}	[520-610°F]	
		T_H	[515-615°F]	
		T_c	[515-615°F]	[150 gpm] feed flow is based on operating experience. Feed flow is used instead of a minimum level since even on an uncomplicated reactor trip level may go below the instrument ranges. Operators use flow, S/G pressure and RCS temperatures to verify the S/G is intact and that level will recover.
	and	Feed Flow	[0-1500 gpm]	
	T_h-T_c < [10°F] and not increasing	[Subcooled Margin Monitor]	[0-100°F]	
	and			
	T_{ave} < [545°F] and not increasing			ΔT < [10°F] is verified by best estimate analysis to be the maximum ΔT expected for minimum forced circulation with maximum decay heat.
	and			
	The RCS is at least [20°F] subcooled [by CET]			RCS subcooling of at least [20°F] ensures a liquid state of the coolant for effective heat removal properties. Subcooling of [200°F] is based on PTS criteria.
	and			
	[No reactor vessel voiding as indicated by the RVLMS]	[RVLMS]	[0-100%]	[545°F] is based on control program for ADVs and steam generator dump bypass valves and best estimate analysis.

SAFETY FUNCTION STATUS CHECK BASES

SUCCESS PATH CURRENTLY IN USE	ACCEPTANCE CRITERIA	INDICATION	RANGE	BASES
5. *SAFETY FUNCTION:* RCS AND CORE HEAT REMOVAL (CONT'D)				
B) Natural Circulation, No SIS Operation	B) At least one S/G has level:			An RVLMS indication of no reactor vessel voiding taken in conjunction with other criteria, serves as an additional indication of adequate RCS and core heat removal.
	within the normal level band with feedwater available to maintain the level	Steam Generator Level	[163.5 - (-)116.5]"	
	or being restored by a feedwater flow > [150 gpm]	Feed Flow	[0-1500 gpm]	Decay heat levels may not be high enough to require a feedwater flow of [150 gpm]. If this is the case, once steam generator level is returned to the normal level band and feedwater remains available to maintain that level then RCS heat removal is possible.
	and T_H-T_C < [50°F] and not increasing			[50°F] is based on best estimate analysis which reveals that [50°F] ΔT will not be exceeded for for cooldown with maximum decay heat and one steam generator isolated with cooldown rate < 75°F/hr.
	and T_{ave} < [545°F] and not increasing			[545°F] is based on control program for ADVs and steam generator dump bypass valves and best estimate analysis.
	and The RCS is at least [20°F] subcooled [by CET].			Subcooling ≥ [20°F] is necessary to assure an adequate medium for core heat transfer. [200°F] is a limit based on PTS considerations.

SAFETY FUNCTION STATUS CHECK BASES

SUCCESS PATH CURRENTLY IN USE	ACCEPTANCE CRITERIA	INDICATION	RANGE	BASES
5. *SAFETY FUNCTION:* RCS AND CORE HEAT REMOVAL (CONT'D)				
	At least one S/G has level: within the normal level band with feedwater available to maintain the level	Pressurizer Pressure	[1500-2500 psia] [0-1600 psia]	Adequate S/G performance is indicated by level in the normal band or being restored with feed-water available.
		Steam Generator Level		When SIS is operating, its performance adequacy is judged by comparing expected to observed delivery flow versus RCS pressure.
	or		[163.5-(-)116.5"]	
	being restored by a feedwater flow > [150 gpm]	Feed Flow	[0-1500 gpm]	
C) S/G Heat Sink with SIS Operating	C) <u>and</u>			
	[CET] temperature < [700°F] or decreasing	[Core Exit Thermo-couple]		
	<u>and</u>		[0-1600°F]	
	[All available charging pumps are operating and] the SIS pump(s) are in-jecting water into the RCS per Figure 10-3 (unless SIS termination criteria are met).	SIS Flowrate	HPSI [0-300 gpm] LPSI [0-2000 gpm]	

SAFETY FUNCTION STATUS CHECK BASES

5. *SAFETY FUNCTION:* RCS AND CORE HEAT REMOVAL (CONT'D)

SUCCESS PATH CURRENTLY IN USE	ACCEPTANCE CRITERIA	INDICATION	RANGE	BASES
D) Once-Through-Cooling	D) [CET] temperature < [700°F] or decreasing and [All available charging pumps are operating and] the SIS pump(s) are injecting water into the RCS per Figure 10-3 (unless SIS termination criteria are met). and RCS pressure < [1300 psia] or decreasing.	Pressurizer Pressure [Core Exit Thermocouples] SIS Flow	[1500-2500 psia] [0-1600 psia] [0-1600°F] HPSI [0-300 gpm] LPSI [0-2000 gpm]	[700°F] is the plant specific temperature as read on the T_H RTDs [and core exit thermocouples (CETs)] which represents the maximum temperature anticipated during accident mitigation for an LOCA with no multiple equipment failures. Temperatures greater than [700°F] on the CETs represent a superheat condition in the RCS which can only occur with core uncovery. Short term core uncovery is predicted for worst case scenarios. Hence [700°F] may be expected in an accident scenario, but recovery actions either manual or automatic being maximized will result in decreasing core temperatures. When cooling by once through cooling through the [PORVs], RCS pressure should be less than the shutoff head of the HPSI pumps ([1300 psia]). If greater than [1300 psia], then a decreasing trend indicates theat pressure should drop below [1300 psia] When SIS is operating, its performance adequacy is judged by comparing expected to observed delivery flow versus RCS pressure.
E) Shutdown Cooling System	E) Normal SCS parameters			

SAFETY FUNCTION STATUS CHECK BASES

SUCCESS PATH CURRENTLY IN USE	ACCEPTANCE CRITERIA	INDICATION	RANGE	BASES
6. *SAFETY FUNCTION:* CONTAINMENT ISOLATION				
A) Manual Isolation	A) No steam plant activity alarms and No containment radiation alarms and Containment Pressure < [4 psig] or Each containment penetration not required to be open has an isolation valve closed.	Containment Pressure	[0-60 psig] [0-15 psig]	[4 psig] is the CIAS setpoint. If pressure goes above [4 psig], containment isolation valves should shut (i.e., CIAS should be present).
		Containment Isolation valve Position Indication	Open-Shut	
		Containment Radiation alarms	Alarming/Not Alarming	Radiation alarms may also indicate the need for containment isolation. Steam plant activity alarm may indicate a steam generator tube rupture and require isolating a S/G.
		Steam Plant Radiation Alarms	Alarming/Not Alarming	
7. *SAFETY FUNCTION:* CONTAINMENT TEMPERATURE AND PRESSURE CONTROL				
A) Containment Fans	A) Containment Temperature < [240°F] and Containment Pressure < [1.5 psig]	Containment Dome Temperature	[50-300°F]	[1.5 psig] is based on containment pressure alarm It is not expected for the selected events that containment pressure will increase to the alarm setpoint unless there is an energy release into containment.
		Containment Pressure	[0-60 psig] [0-15 psig]	

SAFETY FUNCTION STATUS CHECK BASES

SUCCESS PATH CURRENTLY IN USE	ACCEPTANCE CRITERIA	INDICATION	RANGE	BASES
7. *SAFETY FUNCTION:* CONTAINMENT TEMPERATURE AND PRESSURE CONTROL (CONT'D)				
B) Containment Spray	B) Containment spray flow > [1500 gpm] (per spray header) and Containment temperature and pressure constant or decreasing	Containment Spray Flow	[0-5000 gpm]	[240°F] is the maximum expected containment temperature for the selected events. It is not expected that containment temperature will increase to [240°F] unless there is an energy release. During the selected event, containment temperature and pressure may exceed these limits if the break is inside containment. If this happens, a CSAS should be present and the CSPs should be pumping spray solution at [1500 gpm].
8. *SAFETY FUNCTION:* CONTAINMENT COMBUSTIBLE GAS CONTROL				
A) [Plant specific methods, insert here]	A) H_2 < [2%]	H_2 Analyzer	[Plant Specific]	H_2 in the containment is indicative of a primary system leak to containment and may be indicative of core damage. The explosive hazard which may exist in the containment may present a threat to containment integrity. 2% H_2 is 50% of the flammability concentration in air.

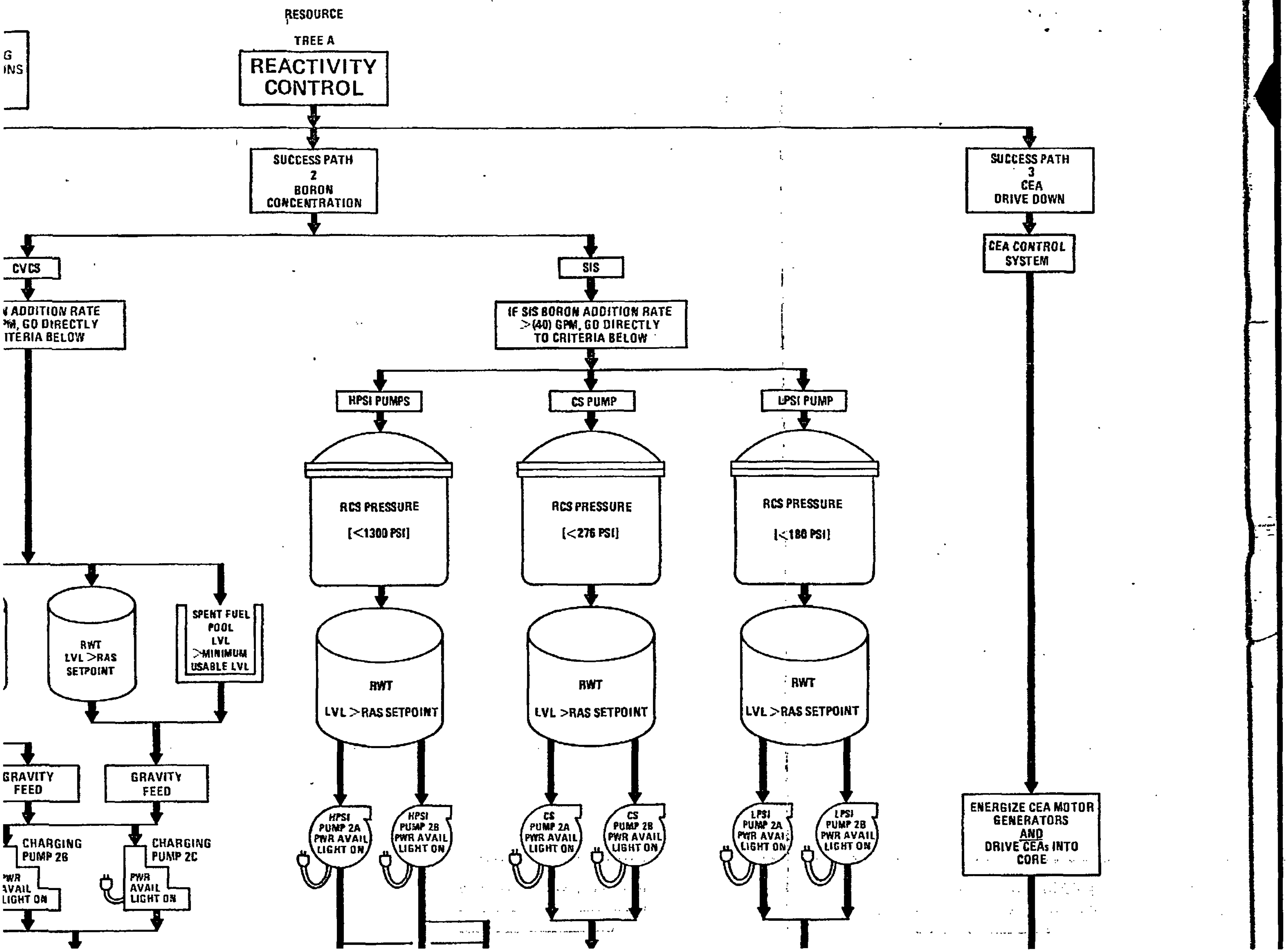
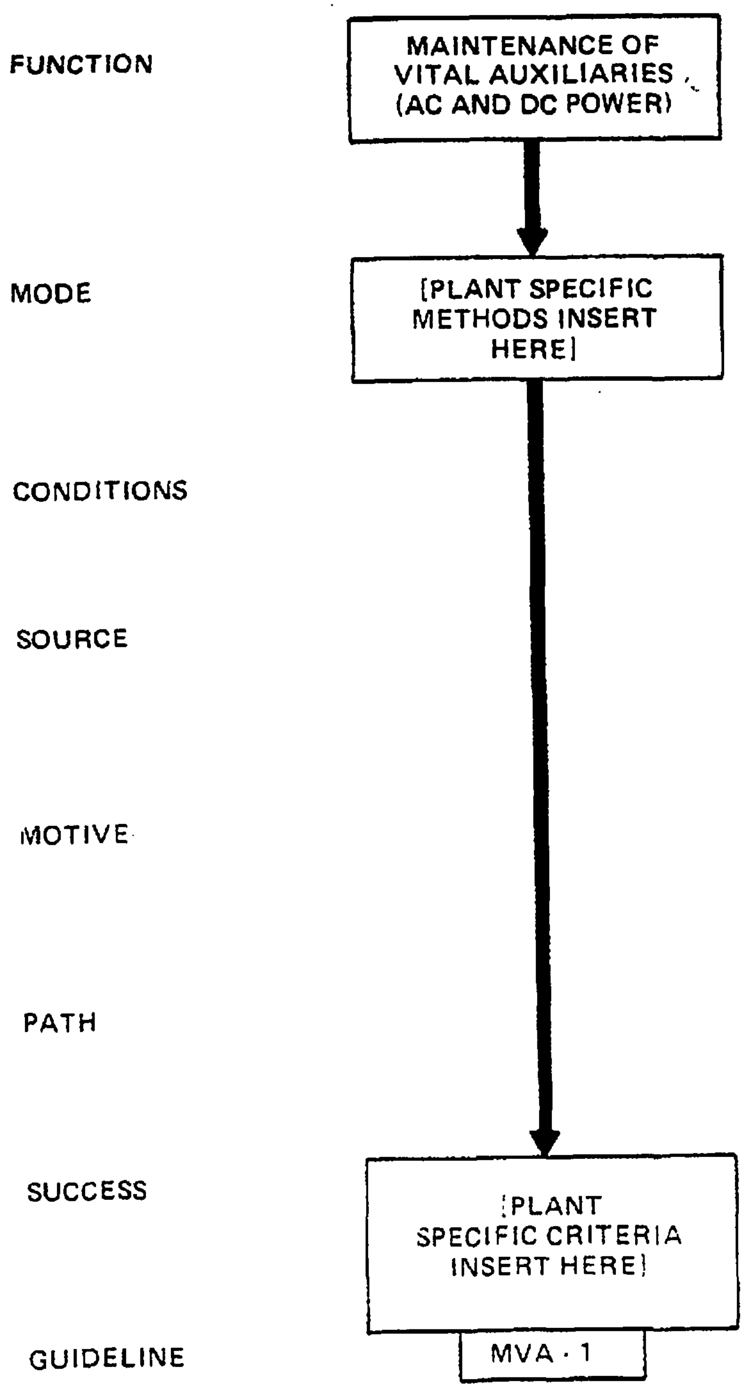
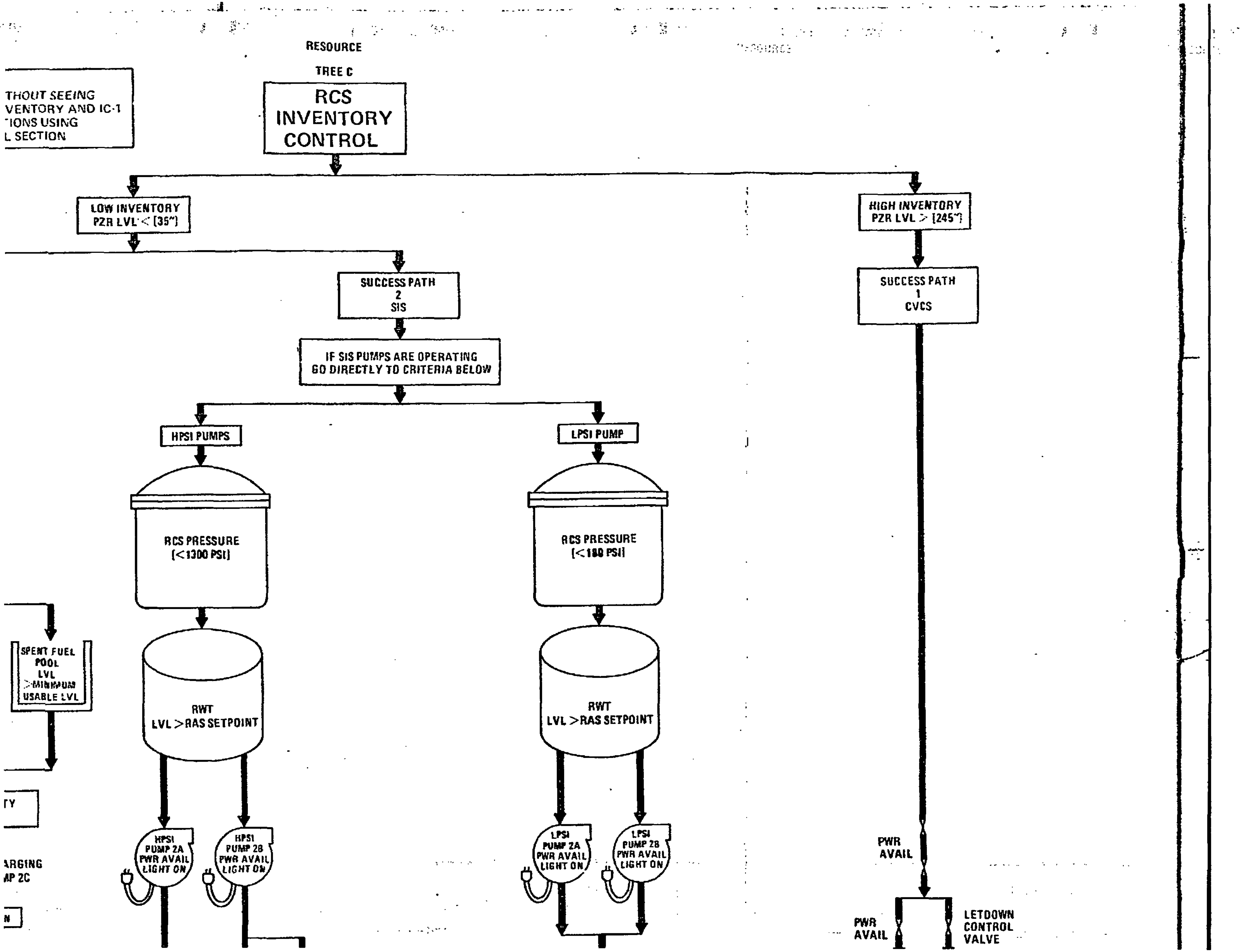

RESOURCE
TREE A
REACTIVITY CONTROL
SUCCESS PATH 2 BORON CONCENTRATION
SUCCESS PATH 3 CEA DRIVE DOWN
CVCS
SIS
CEA CONTROL SYSTEM
IF SIS BORON ADDITION RATE >(40) GPM, GO DIRECTLY TO CRITERIA BELOW
HPSI PUMPS
CS PUMP
LPSI PUMP
RCS PRESSURE [<1300 PSI]
RCS PRESSURE [<276 PSI]
RCS PRESSURE [<180 PSI]
RWT LVL >RAS SETPOINT
SPENT FUEL POOL LVL >MINIMUM USABLE LVL
GRAVITY FEED
CHARGING PUMP 2B
CHARGING PUMP 2C
PWR AVAIL LIGHT ON
HPSI PUMP 2A PWR AVAIL LIGHT ON
HPSI PUMP 2B PWR AVAIL LIGHT ON
CS PUMP 2A PWR AVAIL LIGHT ON
CS PUMP 2B PWR AVAIL LIGHT ON
LPSI PUMP 2A PWR AVAIL LIGHT ON
LPSI PUMP 2B PWR AVAIL LIGHT ON
ENERGIZE CEA MOTOR GENERATORS AND DRIVE CEAs INTO CORE

FIGURE 10-9

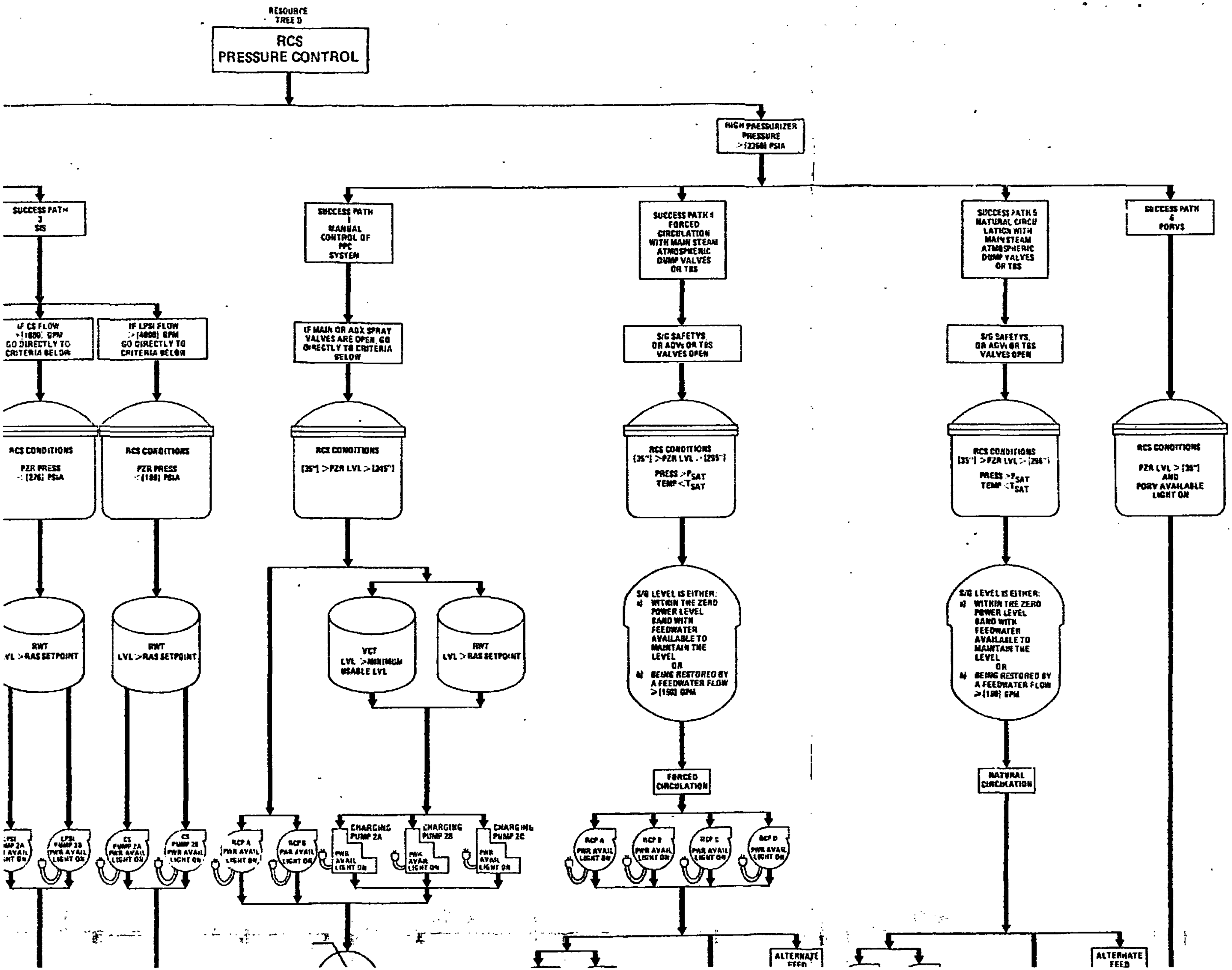
RESOURCE

TREE B





RESOURCE
TREE C
RCS INVENTORY CONTROL
THOUT SEEING
VENTORY AND IC-1
IONS USING
L SECTION
LOW INVENTORY PZR LVL < [35"]
HIGH INVENTORY PZR LVL > [245"]
SUCCESS PATH 2 SIS
SUCCESS PATH 1 CVCS
IF SIS PUMPS ARE OPERATING GO DIRECTLY TO CRITERIA BELOW
HPSI PUMPS
LPSI PUMP
RCS PRESSURE [<1300 PSI]
RCS PRESSURE [<180 PSI]
RWT LVL > RAS SETPOINT
RWT LVL > RAS SETPOINT
SPENT FUEL POOL LVL > MINIMUM USABLE LVL
TY
ARGING
MP 2C
N
HPSI PUMP 2A PWR AVAIL LIGHT ON
HPSI PUMP 2B PWR AVAIL LIGHT ON
LPSI PUMP 2A PWR AVAIL LIGHT ON
LPSI PUMP 2B PWR AVAIL LIGHT ON
PWR AVAIL
PWR AVAIL
LETDOWN CONTROL VALVE



RESOURCE TREE D
RCS PRESSURE CONTROL
HIGH PRESSURIZER PRESSURE >[2360] PSIA
SUCCESS PATH 3 SIS
SUCCESS PATH 1 MANUAL CONTROL OF PPC SYSTEM
SUCCESS PATH 4 FORCED CIRCULATION WITH MAIN STEAM ATMOSPHERIC DUMP VALVES OR TBS
SUCCESS PATH 5 NATURAL CIRCULATION WITH MAIN STEAM ATMOSPHERIC DUMP VALVES OR TBS
SUCCESS PATH 6 PORVS
IF CS FLOW >[1800] GPM GO DIRECTLY TO CRITERIA BELOW
IF LPSI FLOW >[4000] GPM GO DIRECTLY TO CRITERIA BELOW
IF MAIN OR AUX SPRAY VALVES ARE OPEN, GO DIRECTLY TO CRITERIA BELOW
S/G SAFETYS, OR ADVs OR TBS VALVES OPEN
S/G SAFETYS, OR ADVs OR TBS VALVES OPEN
RCS CONDITIONS PZR PRESS <[276] PSIA
RCS CONDITIONS PZR PRESS <[180] PSIA
RCS CONDITIONS [35"] > PZR LVL > [245"]
RCS CONDITIONS [35"] > PZR LVL < [295"] PRESS > P SAT TEMP < T SAT
RCS CONDITIONS [35"] > PZR LVL < [295"] PRESS > P SAT TEMP < T SAT
RCS CONDITIONS PZR LVL > [36"] AND PORV AVAILABLE LIGHT ON
RWT LVL > RAS SETPOINT
RWT LVL > RAS SETPOINT
VCT LVL > MINIMUM USABLE LVL
RWT LVL > RAS SETPOINT
S/G LEVEL IS EITHER: a) WITHIN THE ZERO POWER LEVEL BAND WITH FEEDWATER AVAILABLE TO MAINTAIN THE LEVEL OR b) BEING RESTORED BY A FEEDWATER FLOW >[150] GPM
S/G LEVEL IS EITHER: a) WITHIN THE ZERO POWER LEVEL BAND WITH FEEDWATER AVAILABLE TO MAINTAIN THE LEVEL OR b) BEING RESTORED BY A FEEDWATER FLOW >[150] GPM
FORCED CIRCULATION
NATURAL CIRCULATION
LPSI PUMP 2A PWR AVAIL LIGHT ON
LPSI PUMP 2B PWR AVAIL LIGHT ON
CS PUMP 2A PWR AVAIL LIGHT ON
CS PUMP 2B PWR AVAIL LIGHT ON
RCP A PWR AVAIL LIGHT ON
RCP B PWR AVAIL LIGHT ON
CHARGING PUMP 2A PWR AVAIL LIGHT ON
CHARGING PUMP 2B PWR AVAIL LIGHT ON
CHARGING PUMP 2C PWR AVAIL LIGHT ON
RCP A PWR AVAIL LIGHT ON
RCP B PWR AVAIL LIGHT ON
RCP C PWR AVAIL LIGHT ON
RCP D PWR AVAIL LIGHT ON
ALTERNATE FEED
ALTERNATE FEED

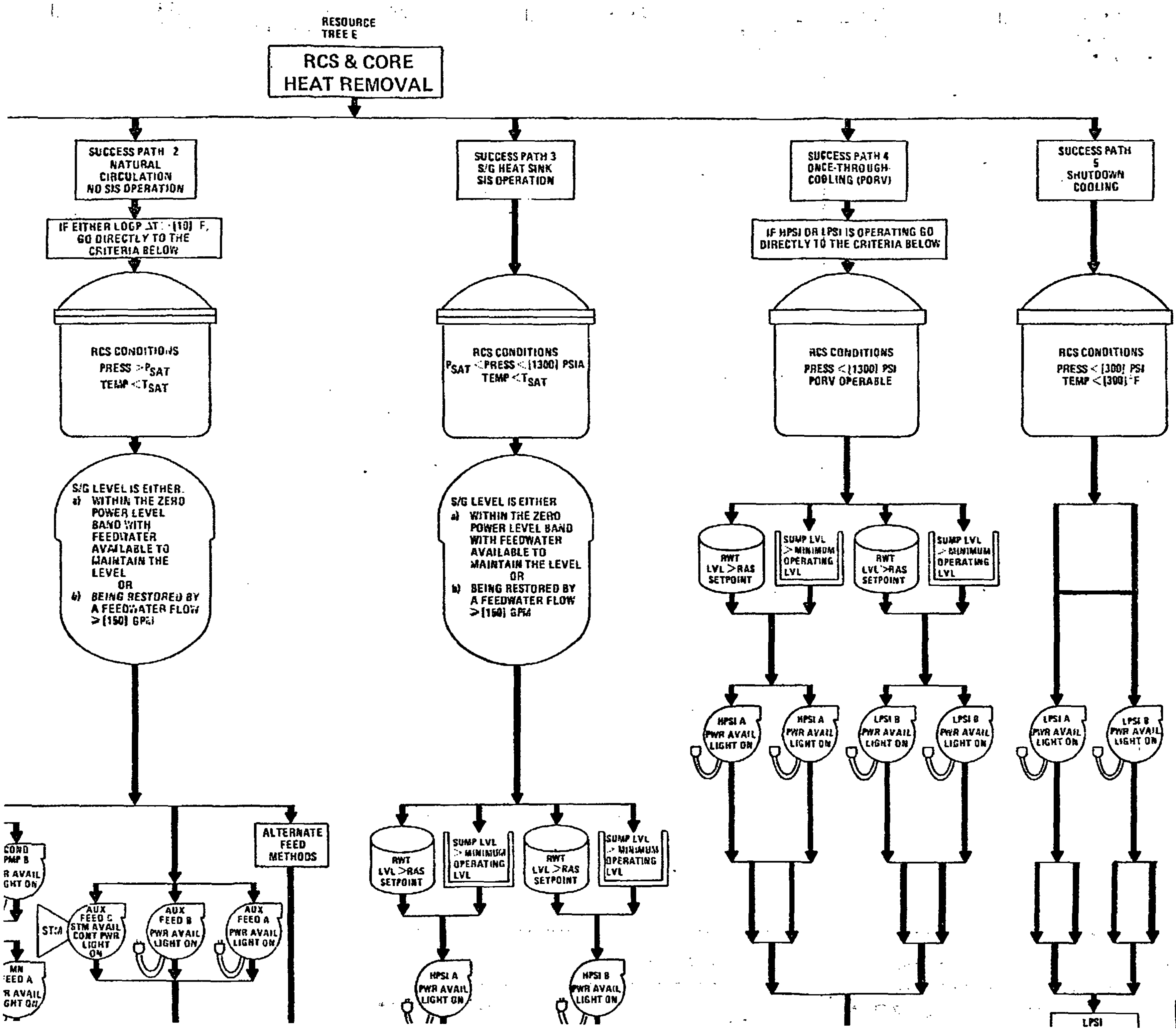


FIGURE 10-12

RESOURCE TREE ____ E

FIGURE 10-13 RESOURCE TREE F

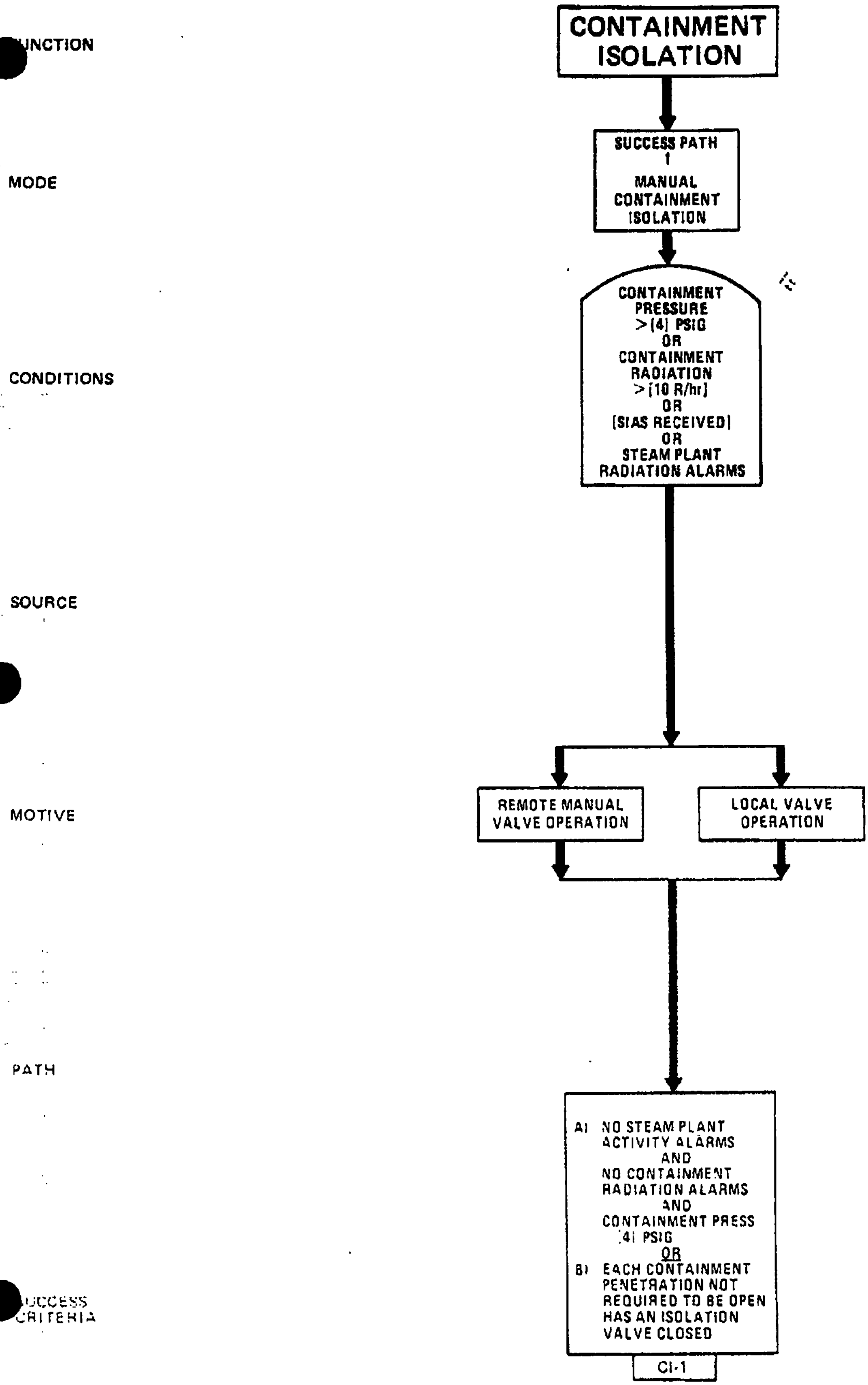


FIGURE 10-8

RESOURCE TREE F

CONTAINMENT ISOLATION

FIGURE 10-14 RESOURCE TREE G

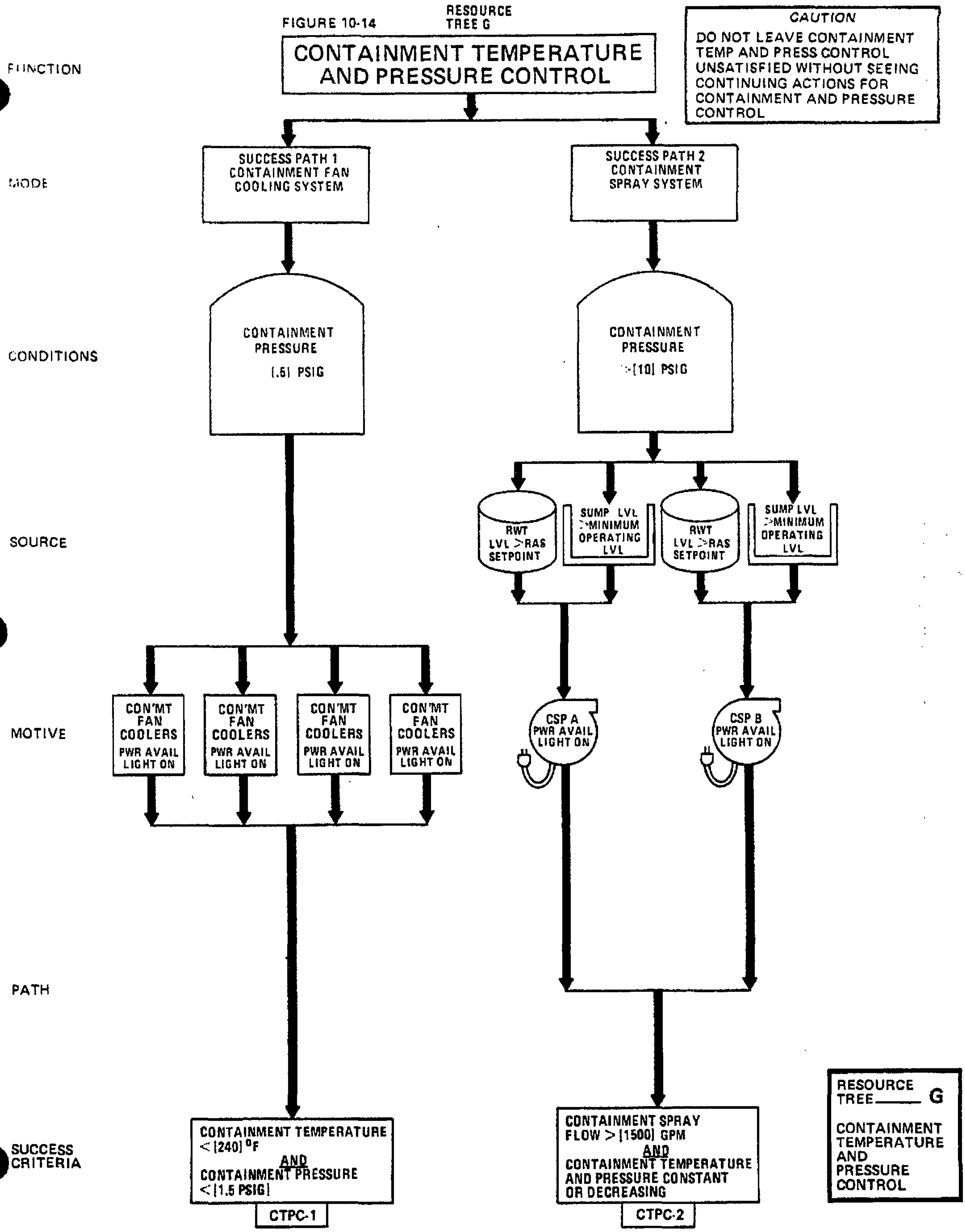
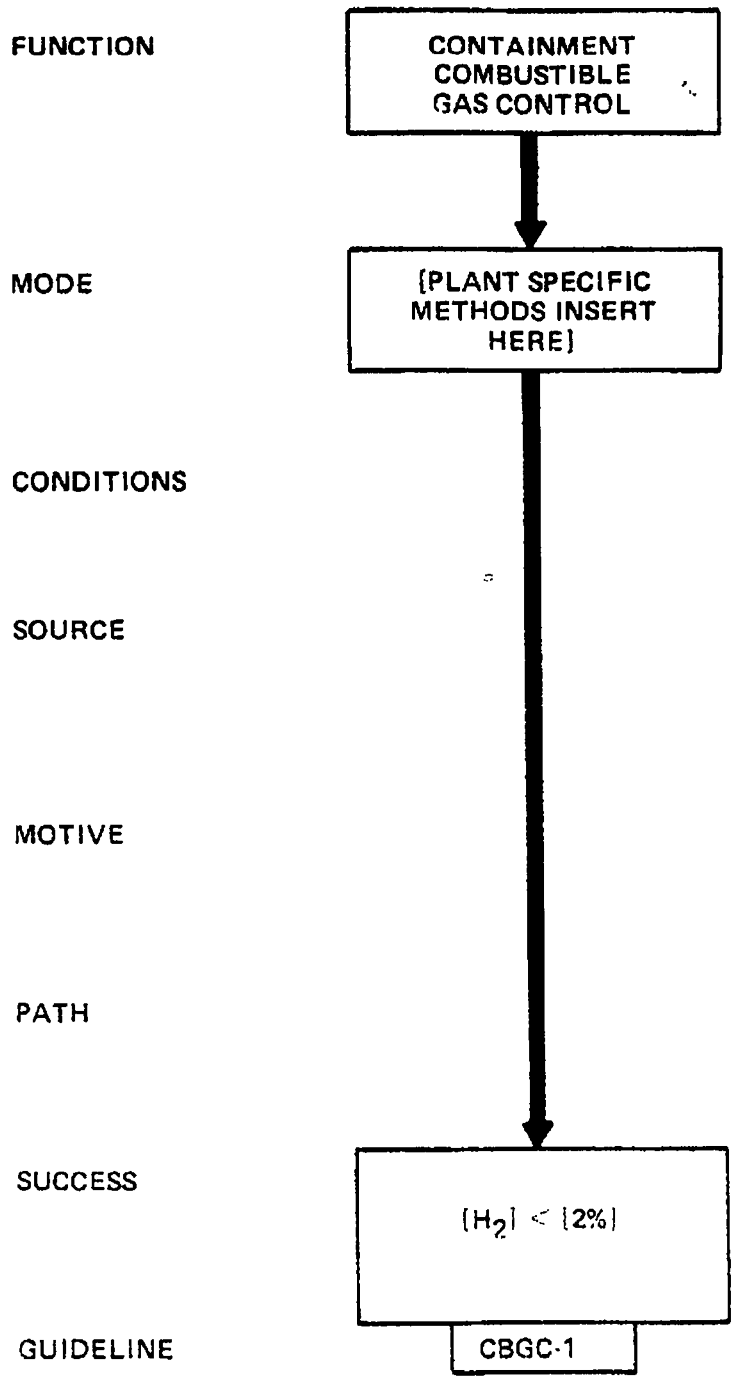


FIGURE 10-15

RESOURCE

TREE H



SAFETY FUNCTION: Reactivity Control
SUCCESS PATH: CEA Insertion; RC-1
RESOURCE TREE: Tree A

OPERATOR ACTIONS

1. Maintain RCS temperature constant (if possible), until reactivity control is established, in order to prevent power increases following the initial transient.

2. Attempt to manually insert the CEAs into the core by the following:

   a) Push all manual CEA trip buttons
   b) Open all CEA trip breakers
   c) Deenergize all CEA drive motor generators
   d) [Other plant specific methods, insert here].

Acceptance Criteria for Success Path: RC-1

1. Reactivity Control is satisfied if:

   a. Not more than 1 CEA bottom light is not lit
   and
   Reactor power is decreasing
   or
   b. Reactor power is less than [$10^{-(X)}$%] and constant or decreasing.

   If the above criteria are met Then proceed to the next safety function in jeopardy.
   If all safety functions are being satisfied, Then implement the Long Term Actions.

2. If the above criteria are not met, Then proceed to the next appropriate success path on Resource Tree A.

1 Implemented IN SECTION III B

2. IMPLEMENTED IN Precaution IV. A.1

3. IMPLEMENTED IN Precaution IV. A.2 AND A.3

4. Step IV B 3 DIRECTS THAT SHUTDOWN MARGIN Be ESTABLISHED using either the RWT OR BAST. IN AN EOP-8 SCENERIO the line up is maintained this way because of the uncertainty surrounding the event. Recovery. Procedures that would be used for long term operation provide the direction recommended IN this step

5. IMPLEMENTED IN SECTION IV. A.4

6 SEE DEVIATION 8-6

SUPPLEMENTARY INFORMATION: RC-1

This section contains items which should be considered when implementing EPGs and preparing plant specific EOPs. The items should be implemented as precautions, cautions, notes, or in the EOP training program.

1. All available indications should be used to aid in an evaluation of plant conditions since the accident may cause irregularities in a particular instrument reading. Instrument readings must be corroborated when one or more confirmatory indications are available.

2. It may not be possible to control other safety functions if reactivity control is in jeopardy.

3. Changes in RCS temperature affecting reactivity must be minimized until a shutdown margin per Technical Specification Limits is achieved in order to prevent core restart.

4. After required shutdown boron concentration is attained in the RCS, makeup water added to the RCS should be at least the same boron concentration as in the RCS to prevent RCS dilution.

5. Main or auxiliary pressurizer spray should be used as necessary to equalize the pressurizer and RCS loop water boron concentration as a change is made to the RCS boron concentration. If pressurizer spray is not available, RCS boron concentration should be increased. This avoids an RCS dilution below minimum shutdown requirements caused later by a possible pressurizer outsurge.

6. Solid water operation of the pressurizer may make it difficult to control RCS pressure and therefore should be avoided unless [20°F] of subcooling cannot be maintained in the RCS (Figure 10-1). If the RCS is solid, closely monitor any makeup or draining and any system heatup or cooldown to avoid any unfavorable rapid pressure excursions.

7. See Deviation 8-7

7. If an initial cooldown rate exceeds Technical Specification Limits, there may be a potential for pressurized thermal shock (PTS) of the reactor vessel, unless Post Accident Pressure/Temperature Limits are maintained (Figure 10-1).

1. Included as precaution IV.A.2. See Deviation 8-4

2. Implemented in STEP IV. B.3

1a implemented in Reactivity SFSC

1b Reactor power decreasing contained in Reactivity Control SFSC. See Deviation sheet 8-5 for power level and additional administrative actions.

SAFETY FUNCTION: Reactivity Control
SUCCESS PATH: Boration using CVCS; RC-2
RESOURCE TREE: Tree A

OPERATOR ACTIONS

1. Maintain RCS temperature constant (if possible), until reactivity control is established, in order to prevent power increases following the initial transient.

2. Commence maximum boration using the CVCS to achieve shutdown margin in accordance with Technical Specification Limits. Perform the following actions:

   a) Align all available charging pumps to take a suction from the [boric acid makeup tanks using either gravity feed or the boric acid makeup pumps, or from the RWT or spent fuel pool using gravity feed].

   b) Charge to the RCS using the normal charging lines. If the normal charging lines are not available, then line up to charge to the RCS through the HPSI header.

   c) Manually operate charging pumps and letdown to maintain pressurizer level [35 to 245"].

Acceptance Criteria for Success Path: RC-2

1. Reactivity Control is satisfied if:

   a. Boron addition rate is greater than [40 gpm]
      and
      Reactor power is decreasing.
      or
   b. Reactor power is less than [$10^{-(X)}$%] and constant or decreasing

2. See Deviation Sheet 8-2

If the above criteria are satisfied, Then proceed to the next safety function in jeopardy.

If all safety functions are being satisfied, Then implement the Long Term Actions.

2. If the above criteria are not met, Then proceed to the next appropriate success path on Resource Tree A.

1. implemented in precaution IV.A.2 AND A.3

2. STEP IV B.3 DIRECTS THAT SHUTDOWN MARGIN BE ESTABLISHED USING either the RWT OR BAST. IN AN EOP 8 scenerio the lineup is maintained this way because of the uncertainty surrounding the event. Procedures that would be used for long term operation provide the direction recommended in this step.

3. implemented in section IV.A.4

4. implemented in section III.B

5. implemented in precaution IV.a.1

6. See Deviation 8-6

SUPPLEMENTARY INFORMATION: RC-2

This section contains items which should be considered when implementing EPGs and preparing plant specific EOPs. The items should be implemented as precautions, cautions, notes, or in the EOP training program.

1. Changes in RCS temperature affecting reactivity must be minimized until a shutdown margin per Technical Specification Limits is achieved in order to prevent core restart.

2. After a shutdown boron concentration is attained in the RCS, makeup water added to the RCS should be of at least the same boron concentration in the RCS in order to prevent RCS dilution.

3. Main, or auxiliary, pressurizer spray should be used as necessary to equalize the pressurizer and RCS loop water boron concentration as a change is made to the RCS boron concentration. If pressurizer spray is not available, RCS boron concentration should be increased. This avoids an RCS dilution below minimum requirements caused later by a possible pressurizer outsurge.

4. All available indications should be used to aid in an evaluation of plant conditions since the accident may cause irregularities in a particular instrument reading. Instrument readings must be corroborated when one or more confirmatory indications are available.

5. It may not be possible to control other safety functions if reactivity control is in jeopardy.

6. Solid water operation of the pressurizer may make it difficult to control RCS pressure and therefore should be avoided unless [20°F] of subcooling cannot be maintained in the RCS (Figure 10-1). If the RCS is solid, closely monitor any makeup or draining and any system heatup or cooldown in order to avoid any unfavorable rapid pressure excursions.

7. See Deviation 8-7

8. SEE DEVIATION 8-8

7. Continuously monitor RCS temperature and pressure to avoid exceeding a heat removal rate greater than Technical Specification Limitations. If the heat removal rate exceeds Technical Specification Limits, there may be a potential for pressurized thermal shock (PTS) of the reactor vessel unless Post Accident Pressure/Temperature Limits are maintained (Figure 10-1).

8. Charging from the concentrated boron source should not continue past [1 hour] after event initiation unless required for reactivity control. This is to preclude boron precipitation in the core. Suction should be shifted to the lower concentration source.

1. Included as precaution IV.A.2 See deviation 8-4

2. SEE DEVIATION 8-9

3. SEE DEVIATION 8-10

4. SEE DEVIATION 8-10

SAFETY FUNCTION: Reactivity Control
SUCCESS PATH: Boration using SIS; RC-3
RESOURCE TREE: Tree A

OPERATOR ACTIONS

1. Maintain RCS temperature constant (if possible), until reactivity control is established, in order to prevent power increases following the initial transient.

2. If pressurizer pressure decreases to [1600 psia, or if containment pressure increases to 4 psig], Then verify initiation of an SIAS. If necessary, manually initiate an SIAS and/or depressurize the RCS to permit SIS injection. This action is primarily to ensure that RCS inventory, pressure, and heat removal are being maintained. However, this will also provide another method of boration at reduced RCS pressures:

   a) [If RCS pressure 01300 psia, then the HPSI pumps may be effective]
   b) [If RCS pressure <276 psia, then the CS pumps may be effective]
   c) [If RCS pressure <180 psia, then the LPSI pumps may be effective].

3. If the Technical Specification shutdown margin is achieved, Then the SIS may be throttled, or stopped one train at a time, if the following conditions are also satisfied:

   a) RCS is at least [20°F] subcooled (Figure 10-1),
   b) Pressurizer level is greater than [100"] and constant or increasing,
   c) At least one steam generator is available (feed and steam flow) for removing heat from the RCS
   d) [The RVLMS indicates the core is covered].

4. If the criteria of step 3 cannot be maintained after the SIS has been stopped, Then the SIS must be restarted.

1A. implemented in Reactivity SFSC

1B. Reactor power decreasing is contained in Reactivity control SFSC
SEE Deviation sheet 8-5 for power level and additional administrative actions.

2. See Deviation sheet 8-2

Acceptance Criteria for Success Path: RC-3

1. Reactivity Control is satisfied if:

   a. Boron addition rate is greater than [40 gpm]

      and

      Reactor power is decreasing

      or

   b. Reactor power is less than [$10^{-(X)}$%] and constant or decreasing

   If the above criteria are satisfied, Then proceed to the next safety function in jeopardy.

   If all safety functions are being satisfied, Then implement the Long Term Actions.

2. If the above criteria are not satisfied, Then proceed to the next appropriate success path on Resource Tree A.

1. implemented in SECTION III. B

2. implemented in PRECAUTION IV.a.1

3. IMPLEMENTED IN SECTION III. A.

4. SEE DEVIATION 8-7

5. SEE DEVIATION 8-6

SUPPLEMENTARY INFORMATION: RC-3

This section contains items which should be considered when implementing EPGs and preparing specific EOPs. The items should be implemented as precautions, cautions, notes, or in the EOP training program.

1. All available indications should be used to aid in evaluation plant conditions since the accident may cause irregularities in a particular instrument reading. Instrument readings must be corroborated when one or more confirmatory indications are available. Hot and cold leg RTDs may be influenced by the cooler SIS injection and should be checked against each other.

2. It may not be possible to control other safety functions if reactivity control is in jeopardy.

3. Do not place system in "manual" unless misoperation in "automatic" is apparent. Systems placed in "manual" must be checked frequently to ensure proper operation.

4. Continuously monitor RCS temperature and pressure to avoid exceeding a heat removal rate greater than Technical Specification Limitations. If the heat removal rate exceeds Technical Specification Limits, there may be a potential for pressurized thermal shock (PTS) of the reactor vessel unless Post Accident Pressure/Temperature Limits are maintained (Figure 10-1).

5. Solid water operation of the pressurizer may make is difficult to control RCS pressure and therefore should be avoided unless [20°F] of subcooling cannot be maintained in the RCS (Figure 10-1). If the RCS is solid, closely monitor any makeup or draining and any system heatup or cooldown to avoid any unfavorable rapid pressure excursion.

6. Implemented IN PRECAUTION IV.a.2 AND A.3

7. IMPLEMENTED IN SECTION IV. A.4

8. STEP IV B.3 DIRECTS THAT SHUTDOWN MARGIN BE ESTABLISHED USING EITHER THE RWT OR BAST. IN AN EOP 8 SCENERIO THE LINEUP IS MAINTAINED THIS WAY because OF THE UNCERTAINTY SURROUNDING THE EVENT. PROCEDURES THAT WOULD ~~WI~~ BE USED FOR LONG TERM OPERATION PROVIDE THE DIRECTION RECOMMENDED IN THIS STEP.

6. Changes in RCS temperature affecting reactivity must be minimized until a shutdown margin per Technical Specification Limits is achieved in order to prevent core restart.

7. Main or auxiliary pressurizer spray should be used as necessary to equalize the pressurizer and RCS loop water boron concentration as a change is made to the RCS boron concentration. If pressurizer spray is not available, RCS boron concentration should be increased. This avoids an RCS dilution below minimum shutdown requirements by a possible pressurizer outsurge.

8. After a shutdown boron concentration is attained in the RCS, makeup water added to the RCS should be at least the same boron concentration as the RCS to prevent RCS dilution.

1. SEE DEVIATION 8-4, Included AS Precaution IV.A.2

2. SEE DEVIATION 8-11.

1A. IMPLEMENTED IN REACTIVITY SFSC

1B. REACTOR POWER decreasing IN CONTAINED IN REACTIVITY CONTROL SFSC. See DEVIATION SHEET 8-5 FOR power LEVEL AND ADDITIONAL ADMINISTRATIVE ACTIONS

2. See Deviation SHEET 8-17

SAFETY FUNCTION: Reactivity Control
SUCCESS PATH: CEA Drive Down; RC-4
RESOURCE TREE: Tree A

OPERATOR ACTIONS

1. Maintain RCS temperature constant (if possible), until reactivity control is established, in order to prevent power increases following the initial transient.

2. [Re-energize the CEA drive mechanisms and manually jog and/or drive the CEA's into the core using the normal rod motion controls.]

Acceptance Criteria for Success Path: RC-4

1. Reactivity Control is satisfied if:

   a. Not more than 1 CEA bottom light is not lit
      and
      Reactor power is decreasing
      or
   b. Reactor Power is less than [$10^{-(X)}$%] and constant or decreasing

   If the criteria above are met, Then proceed to the next safety function in jeopardy.
   If all safety functions are being satisfied, Then implement the Long Term Actions.

2. If the above criteria are not met, Then proceed to the Continuing Actions for Reactivity Control.

1. IMPLEMENTED IN SECTION III. B

2. IMPLEMENTED IN PRECAUTION IV.a.1

SUPPLEMENTARY INFORMATION: RC-4

This section contains items which should be considered when implementing EPGs and preparing plant specific EOPs. The items should be implemented as precautions, cautions, notes, or in the EOP training program.

1. All available indications should be used to aid in evaluation plant conditions since the accident may cause irregularities in a particular instrument reading. Instrument readings must be corroborated when one or more confirmatory indications are available.

2. It may not be possible to control other safety functions if reactivity control is in jeopardy.

Continuing Actions for Reactivity Control

If the acceptance criteria are not met, Then reactivity control is still in jeopardy. THE OPERATOR SHOULD NOT LEAVE REACTIVITY CONTROL UNTIL THIS SAFETY FUNCTION IS FULFILLED. The operator may, if necessary, pursue other urgent safety functions but must continue to attempt to establish reactivity control using the following:

a) Attempt to energize, or restore, other vital auxiliaries to necessary components on the reactivity control success paths.

b) Attempt manual operation of inoperative valves.

c) Attempt to lower plant pressure to permit SIS pump injection of boric acid. Consideration should be given to the effect on RCS subcooling and core cooling which such an action will cause.

Bases for Reactivity Control

A loss of reactivity control can be characterized by the insertion of inadequate negative reactivity to shutdown the reactor. This loss may be identified by indication on two or more safety grade instrument channels that a plant parameter has exceeded its normal reactor trip setpoint. This requires a manual or an automatic trip. If an automatic trip has not been initiated, then manual insertion of all of the CEAs is attempted. Specific symptoms for a loss of reactivity control depend on what actions are being taken to obtain reactivity control, and include any one, or a combination of the following:

a) more than 1 CEA bottom light not lit
b) reactor power not decreasing as expected.
c) startup rate indication $\geq$ 0 DPM
d) boron concentration less than required per Technical Specifications
e) RCS temperature increasing more rapidly than expected for decay heat production

The cause of the loss of reactivity control may range from a Reactor Protection System (RPS) failure in automatically initiating a reactor trip when required, to the inability to manually insert the CEA's, or to a failure in controlling reactivity through the use of boration (possibly due to a boration equipment malfunction). Failure of the RPS to cause a reactor trip has traditionally been referred to as "Anticipated Transient Without Scram" (ATWS). Analysis has shown that the sooner operator actions are taken to restore reactivity control, the more beneficial they will be towards mitigating the consequences of such an event.

The loss of reactivity control may affect other safety functions. Because insufficient negative reactivity is added to the core following the initiating event, heat in excess of the decay heat being produced will continue to be added to the RCS. For example, the RCS heat removal safety function can be affected by continued heat addition if an adequate heat sink is unavailable.

If main feedwater has been lost, the auxiliary feedwater flow (which is generally sized for decay heat only) may not be sufficient to maintain steam generator level. Continued steaming of the steam generators via the turbine, the ADVs, the turbine bypass valves, and/or the steam generator safety valves may result in steam generator dry out and subsequent loss of heat sink.

There are a large number of scenarios which may occur concurrently with a loss of reactivity control. The operator may be faced with the loss of one, or a combination of other safety functions. The most limiting case analyzed involves an ATWS event with a continuing loss of feedwater. Since the secondary system can no longer remove all of the heat generated in the reactor core, the RCS temperature and pressure will increase. If the steam generator secondary water inventory can be restored during the event, the RCS temperature and pressure excursion can be minimized. However, if it can be avoided, the steam generator should not be steamed to control RCS temperature and pressure in the early stages of this event. Steaming will increase the rate of steam generator dry out if feedwater is not available. The resulting RCS pressure excursion will be more severe since the dry out occurs earlier in the transient. Increasing temperature and pressure may result in the pressurizer relief and/or safety valves opening. Further increases in RCS temperature can cause expansion of the reactor coolant which will increase pressurizer level and may cause the plant to go solid. RCS pressure may increase enough to allow coolant leakage through the reactor vessel flange "O" ring seal. Reactor power is reduced due to the negative moderator coefficient feedback caused by the increasing RCS temperature and significant decrease in moderator density. This negative reactivity addition is what limits the consequences of a loss of reactivity control event coincident with a loss of feedwater.

The following success paths are directed at placing the plant in a stable, safe condition following a loss of reactivity control. Reactivity control may be accomplished by any of the following methods:

- RC-1: Reactivity Control via CEA Insertion
- RC-2: Reactivity Control via Boration Using CVCS
- RC-3: Reactivity Control via Boration Using SIS
- RC-4: Reactivity Control via CEA Drive Down

The bases for the operator actions required for implementing each of the above success paths are detailed as follows:

RC-1: *Reactivity Control via CEA Insertion*

Inserting the control rods into the core is the preferred method of reactivity control. If the CEA's have not been inserted automatically, then methods available to manually insert the CEA's must be exercised. Reactivity control is regained in the shortest time frame possible by a rapid insertion of the CEAs.

Operator Actions

1. To prevent reactor power increases following the initial transient, RCS temperature is maintained constant (if possible) until reactivity control is satisfied. Temperature is maintained constant, instead of being reduced, to prevent reactor power increases due to the negative moderator temperature coefficient.

2. An attempt is made to manually insert the CEAs into the core. This is done by performing the following:

   a) Manual trip buttons are pushed
   b) CEA trip breakers are opened
   c) Control rod drive motor generators are deenergized
   d) [If other methods are available to insert CEAs, that information is inserted here].

   These actions are performed to deenergize the CEA's.

After implementing the above actions, reactivity control is satisfied if:

a. Not more than one CEA bottom light is not lit

and

Reactor power is decreasing

<u>or</u>

b. Reactor power is less than [$10^{-(X)}$%] and constant or decreasing

For all emergency events, the reactor must be shutdown. The Technical Specification requirement is that not more than 1 rod be stuck out. If more than 1 rod is stuck out, the RCS must be borated to compensate. Boration is also necessary to assist the CEAs if RCS cooldown has occurred. Reactivity control using boration is identified and discussed in the next two success paths, RC-2 and 3. Insertion of CEAs is adequate to keep the reactor shutdown even after some cooldown. Decreasing reactor power is a second positive indication of reactivity control. Constant reactor power at less than [$10^{-(X)}$%], or decreasing reactor power, acknowledges that power will only decrease until the subcritical multiplication level is reached, then it will decrease very slowly. [$10^{-(X)}$%] is the plant specific maximum value expected for subcritical multiplication level following extended full power operation.

RC-2: *Reactivity Control via Boration Using CVCS*

In the case where the control rods do not insert, or where additional negative reactivity is needed to compensate for temperature effects, reactivity control can be accomplished by boron injection. Borated water can be added to the RCS using the charging and boric acid addition portions of the CVCS.

Operator Actions

1. To prevent reactor power increases following the initial transient, RCS temperature is maintained constant (if possible) until reactivity control is satisfied. Temperature is maintained constant, instead of being reduced, to prevent reactor power increases due to the negative moderator temperature coefficient.

2. Maximum boration is commenced using the CVCS to achieve shutdown margin in accordance with Technical Specification Limits. The following actions are performed.

    a) All available charging pumps are aligned to take a suction from the [boric acid makeup tanks using either gravity feed or the boric acid makeup pumps, or from the RWT or spent fuel pool using gravity feed].

    b) The charging pumps are aligned to the normal charging header. If the normal charging lines are not available, line up to charge to the RCS through the HPSI header.

    c) Charging pumps and letdown are manually operated to maintain pressurizer level [35 to 245"].

    The charging pumps are aligned to discharge the contents of the [boric acid makeup tanks] (primary source of boric acid to the RCS and core). The [boric acid makeup tank] contents may reach the suction of the charging pumps via gravity feed or via the boric acid makeup pumps.

These sources should usually not be used past [1 hour] after event initiation (unless required for reactivity control) to prevent boron precipitation. Boron precipitation is only a concern if charging from the concentrated source has been continuous since event initiation. This is the preferred method for boron addition. Alternative sources for boron are the [RWT] and the [spent fuel pool]. If the normal charging path is unavailable, the charging pumps may be lined up to discharge to the RCS through the HPSI header. Pressurizer level should be maintained throughout by regulating charging into the RCS (manual operation of charging pumps) and bleed off from the RCS (letdown line).

Operation of the charging system also affects RCS inventory and pressure control. When operating the charging system, the operator should maintain plant pressure and temperature within the limits of Figure 10-1.

During a cooldown, shrinkage of RCS inventory due to cooling may cause outsurge of pressurizer fluid. Since this fluid is not directly borated by charging flow, it may be at a lower boron concentration than the RCS loops and/or therefore, may dilute the loops and the reactor vessel. This same concern exists during a natural circulation cooldown with respect to the reactor vessel upper head. With no RCPs operating, there is little interaction between RCS fluid and coolant in the upper head. The boron concentration may be lower in the upper head causing loop and vessel dilution if voiding occurs. In order to avoid this loss of shutdown margin, one of the following actions should be accomplished (listed in order of preference):

a) Sufficient boron is added prior to commencing the cooldown to borate the entire RCS (including the mass in the pressurizer) to cold shutdown boron concentration (per Technical Specifications). Therefore, even if the pressurizer (or reactor vessel upper head region) is relatively dilute and outsurges into the RCS loop, boron concentration will not drop below the cold shutdown concentration.

b) If letdown is available, then sufficient heaters are energized to permit continuous auxiliary spray into the pressurizer without dropping RCS pressure. With pressurizer level held constant by letdown, the pressurizer is borated to within [50 ppm] of RCS loop concentration using auxiliary spray is shown by RCS sampling.

c) If letdown is not available, then the RCS is borated to [50 ppm] greater than the minimum shutdown margin corresponding to T_c (per Technical Specifications). As more volume becomes available in the pressurizer due to RCS cooldown shrinkage, additional boron is charged to the RCS to maintain minimum shutdown margin corresponding to T_c. The use of pressurizer spray to depressurize will also increase pressurizer boron concentration.

After implementing the above actions, reactivity control is satisfied if:

a. Boron addition rate is greater than [40 gpm]

and

Reactor power is decreasing

<u>or</u>

b. Reactor power is less than [$10^{-(X)}$%] and constant or decreasing.

RC-3: *Reactivity Control via Boration Using SIS*

In the case where the control rods do not insert or where additional negative reactivity is needed to compensate for temperature effects, reactivity control can be accomplished by boron injection. The safety injection system can add borated water to the RCS from the RWT when pressure is less than the shut off head for the SIS pumps. (HPSI pump [1300 psia], [CS pump 276 psia], LPSI pump [180 psia]).

Operator Actions

1. To prevent reactor power increases following the initial transient, RCS temperature is maintained constant (if possible) until reactivity control is satisfied. Temperature is maintained constant, instead of being reduced, to prevent reactor power increases due to the negative moderator temperature coefficient.

2. If pressurizer pressure decreases to [1600 psia, or if containment pressure increases to 4 psig], then initiation of an SIAS must be verified. If necessary, SIAS is manually initiated. This action is primarily to ensure that RCS inventory, pressure, and heat removal are being maintained. However, this will also provide another method of boration at reduced RCS pressure:

   a) [If RCS pressure < 1300 psia, then the HPSI pumps may be effective]
   b) [If RCS pressure < 276 psia, then the CS pumps may be effective]
   c) [If RCS pressure < 180 psia, then the LPSI pumps may be effective]

3. If an SIAS has been initiated and the SIS is operating, then it must continue to operate at full capacity until the Technical Specification shutdown margin is achieved and SIS termination criteria are met. Early termination is expected only for steam line breaks, a spurious SIAS, or if an RCS leak is identified and promptly isolated (e.g., a stuck open PORV is blocked). Termination of SIS should be sequenced by stopping one pump at a time while observing the termination criteria. Throttling of HPSI flow is permissible if it is feasible. SIS termination criteria are:

a) The RCS is at least [20°F] subcooled (Figure 10-1). Establishing [20°F] of subcooling ensures the fluid in the core is subcooled, and provides sufficient margin for establishing flow should the [20°F] subcooling deteriorate when SIS flow is secured. Voids may exist in some parts of the RCS (e.g., reactor vessel head), but these are permissible as long as core heat removal is maintained.

b) Pressurizer level is greater than [100"], and constant or increasing. A pressurizer level greater than [100"] and constant or increasing in conjunction with criterion a) above is an indication that RCS inventory control has been established.

c) At least one steam generator is available of removing heat from the RCS. Steam generator availability requires having feed flow and steam flow, which are indications that primary to secondary heat removal is possible.

d) [The RVLMS indicates the core is covered. An indication of core coverage, taken in conjunction with the above, serves as an additional indication that RCS inventory control has been established].

If the above criteria are met, the operator may either terminate or throttle the SIS. The operator may decide to throttle rather than terminate if the SIS is to be used to control pressurizer level or plant pressure. A general assessment of the SIS performance can be made from the control room. The operator should confirm that at least one train, and preferably both trains of SIS are operating and that system delivery rate is consistent with RCS pressure as shown in Figure 10-3. Injection flow rates to each cold leg should be approximately equal. Departures from this would indicate a closed flow path or some system spillage.

4. If the criteria of step 3 cannot be maintained, then the SIS pumps must be restarted.

After implementing the above actions, reactivity control is satisfied if:

a. Boron addition rate is greater than [40 gpm]

and

Reactor power is decreasing

<u>or</u>

b. Reactor power is less than [$10^{-(X)}$%] and constant or decreasing.

RC-4: *Reactivity Control via CEA Drive Down*

If reactivity control has not been regained by deenergizing the CEAs or by boron addition, then re-energize the CEA's to manually drive them in.

Operator Actions

1. To prevent reactor power increases following the initial transient, RCS temperature is maintained constant (if possible) until reactivity control is satisfied. Temperature is maintained constant, instead of being reduced, in order to prevent reactor power increases due to the negative moderator temperature coefficient.

2. The CEA drive mechanisms have been deenergized in RC-1 in an attempt to quickly insert them. If this effort and boration have failed to gain reactivity control, then re-energize the CEA drive mechanism and jog and/or drive the CEAs into the core.

After implementation of the above actions, reactivity control is satisfied if:

a. Not more than 1 CEA bottom light is not lit
and
Reactor power is decreasing
<u>or</u>
b. Reactor power is less than [$10^{-(X)}$%] and constant or decreasing

Continuing Actions for Reactivity Control

If reactivity control is not established, then the operator should continue to work on establishing reactivity control. It may not be possible to control other safety functions while reactivity contrtol is not established. However, if other safety functions urgently need attention, then the operator may attempt to satisfy them while continuing to work on reactivity control.

SAFETY FUNCTION: Maintenance of Vital Auxiliaries (AC & DC Power)
SUCCESS PATH: [Plant Specific Method; Insert Here]; MVA-1
RESOURCE TREE: Tree B

OPERATOR ACTIONS

1. [Plant Specific actions, insert here]

Acceptance Criteria for Maintenance of Vital Auxiliaries (AC & DC Power): MVA-1

1. [Plant specific criteria, insert here]

Bases for Maintenance of Vital Auxiliaries (AC & DC Power)

MVA-1: *Maintenance of Vital Auxiliaries (AC & DC Power)*

The Maintenance of Vital Auxiliaries safety function supports all systems which are utilized to satisfy the safety functions in the FRG Safety Function Status Check. These support systems provide such services as instrument air needed for opening and closing valves, electric power for valve operation, pump and motor operation and instrument indication, and an ultimate heat sink to which RCS and core heat can be transferred. Of greatest impact to operator actions is vital AC and DC power. AC and DC power must be maintained in order to continue to satisfy other safety functions.

Operator Actions

1. [Plant specific actions, insert here].

After implementing the above action(s), Maintenance of Vital Auxiliaries is satisfied if:

[Plant specific criteria, insert here].

SAFETY FUNCTION: RCS Inventory Control
SUCCESS PATH: CVCS; IC-1
RESOURCE TREE: Tree C

OPERATOR ACTIONS

1. Verify that the PLCS is functioning properly to restore pressurizer level.
   If not, manually operate charging and letdown to restore, and maintain, pressurizer level.

2. If operating charging pumps to restore pressurizer level, Then verify adequate suction sources.
   If necessary, use the [VCT, boric acid storage tanks, spent fuel pool, and RWT].

3. If the high RCS inventory appears to be caused by excessive RCS voiding, Then refer to the RCS and Core Heat Removal Safety Function.

Acceptance Criteria for Success Path: IC-1

1. Inventory Control is satisfied if:

   a. Pressurizer level is [35 to 245"*]
      and
   b. The RCS is at least [20°F] subcooled [by CET]
      and
   c. [The RVLMS indicates the core is covered].

* If the RCS is in a solid condition for pressure control, then the limit of [245"] may be exceeded.

see DEVIATION 8-17 ~~for~~ administrative actions

2. See Deviation 8-2

If the above criteria are met, Then proceed to the next safety function in jeopardy.

If all safety functions are being satisfied, Then implement the Long Term Actions.

2. If the above criteria are not met, Then proceed to the next appropriate success path on Resource Tree C.

1. IMPLEMENTED IN V.A.2

2. IMPLEMENTED IN GENERAL PRECAUTION III.B.

3. IMPLEMENTED IN GENERAL PRECAUTION III.A

4 implemented in V.B.4 AND V.B.5 AND V.B.6. See deviation 8-14

5 implemented by training

6. Implemented in precaution V.A.1, See Deviation 8-15

SUPPLEMENTARY INFORMATION: IC-1

This section contains items which should be considered when implementing EPGs and preparing plant specific EOPs. The items should be implemented as precautions, cautions, notes, or in the EOP training program.

1. Solid water operation of the pressurizer may make it difficult to control RCS pressure, and therefore should be avoided unless [20°F] of subcooling cannot be maintained in the RCS (Figure 10-1). If the RCS is solid, closely monitor any makeup or draining and any system heatup or cooldown to avoid any unfavorable rapid pressure excursions.

2. All available indications should be used to aid in evaluating plant conditions since the accident may cause irregularities in a particular instrument reading. Instrument readings must be corroborated when one or more confirmatory indications are available.

3. Do not place system in "manual" unless misoperation in "automatic" is apparent. Systems placed in "manual" must be checked frequently to ensure proper operation.

4. The operator should be cautioned against prematurely initiating an RAS. The operator should verify that RWT level has reached [10%] and that the containment sump has adequate fluid for SIS suction before shifting to recirculation. This manual action should not be taken unless an automatic RAS is required.

5. Steam plant radiation alarms usually indicate a steam generator tube leak which may result in loss of RCS inventory.

6. Charging from the concentrated boron source should not continue past [1 hour] after event initiation unless required for reactivity control. This is to preclude boron precipitation. Charging pump suction should be shifted to the lower concentration source.

7. implemented in precaution V.A.4

8. See deviation 8-16

9. Implemented in step VI.B.4

7. Indications of high RCS inventory may be caused by the displacement of water from voided areas of the RCS. Operators must be aware of this and understand that operation of letdown in this situation may lower RCS pressure and, subsequently, increase RCS voiding.

8. When a void exists in the reactor vessel, and RCPs are not operating, the RVLMS provides an accurate indication of reactor vessel liquid inventory. When a void exists in the reactor vessel, and RCPs are operating, it is not possible to obtain an accurate reactor vessel liquid level indication due to the effect of the RCP induced pressure head on the RVLMS. The indicated level also differs from different RVLMS designs under these conditions. Information concerning reactor vessel liquid inventory trending may still be discerned. However, the operator is cautioned not to rely solely on the RVLMS indication when RCPs are operating.

9. The operator should continuously monitor for the presence of RCS voiding and take steps to eliminate voiding any time voiding causes the heat removal or inventory control safety functions to begin to be threatened. Void elimination should be started soon enough to ensure heat removal and inventory control are not lost. C

1. IMPLEMENTED BY STEP V.B.2

2. IMPLEMENTED BY STEP V.B.3

3. IMPLEMENTED BY STEPS V.B.4, V.B.5, V.B.6

4. See Deviation sheet 8-10

SAFETY FUNCTION: RCS Inventory Control
SUCCESS PATH: SIS; IC-2
RESOURCE TREE: Tree C

OPERATOR ACTIONS

*1. If pressurizer pressure decreases to [1600 psia, or if containment pressure increases to 4 psig], Then verify that an SIAS has been initiated.
If an SIAS has not been initiated automatically, Then manually initiate an SIAS.

*2. If pressurizer pressure decreases to less than [1300 psia] following an SIAS, Then ensure all RCPs are tripped.

*3. If pressurizer level is less than [35"], Then take steps to ensure maximum safety injection (Figure 10-3) and charging flow to the RCS by:

a) restoring electrical power to valves and pumps,
b) restoring correct SIS valve lineup if misaligned,
c) restoring other necessary auxiliary systems,
d) starting idle SIS and charging pumps.

*4. If the SIS is operating, Then it may be throttled, or stopped one train at a time, if the following conditions are satisfied:

a) RCS is at least [20°F] subcooled (Figure 10-1),
b) Pressurizer level is greater than [100"] and constant or increasing,
c) At least one steam generator is available (feed and steam flow) for removing heat from the RCS.
d) [The RVLMS indicates the core is covered].

* Step performed continuously.

5. See Deviation Sheet 8-10

6. Implemented by steps V.B.2, V.B.4, V.B.5, V.B.6

7. Implemented by step V.B.6

1A. Implemented in Press/Inv. SFSC

1B. See Deviation 8-13. See Deviation 8-17 for administrative actions

2. See Deviation 8-17

*5. If the criteria of step 4 cannot be maintained after the SIS has been stopped, Then the SIS must be restarted.

*6. Monitor the [refueling water tank] level.
If the refueling water tank level falls to [10%], Then verify automatic actuation of recirculation.
If necessary, manually actuate recirculation one SIS train at a time [and close RWT outlet valves to the safety injection system].

*7. If the HPSI pumps are delivering less than [30 gpm] per pump during recirculation, Then turn off one charging pump at a time until the HPSI pumps are delivering more than [30 gpm] per pump. If the minimum HPSI pump delivery flow is still not met with all charging pumps off, Then turn off the HPSI pump with the lower indicated flow.

Acceptance Criteria For Success Path: IC-2

1. Inventory Control is satisfied if:

    a. [All available charging pumps are operating and] the SIS pump(s) are injecting water into the RCS per Figure 10-3 (unless SIS termination criteria are met).

    and

    b. [The RVLMS indicates the core is covered].

    If the above criteria are met, Then proceed to the next safety function in jeopardy.
    If all safety functions are being satisfied, Then implement the Long Term Actions.

2. If the above criteria are not met, Then proceed to the Continuing Actions for Inventory Control.

* Step performed continuously.

1. IMPLEMENTED IN V.A.2

2. IMPLEMENTED IN III.B

3. implemented in III.A

4. IMPLEMENTED IN V.B.4, V.B.5, AND V.B.6. See Deviation 8-14

5. implemented by training

SUPPLEMENTARY INFORMATION: IC-2

This section contains items which should be considered when implementing EPGs and preparing plant specific EOPs. The items should be implemented as precautions, cautions, notes, or in the EOP training program.

1. Solid water operation of the pressurizer may make it difficult to control RCS pressure, and therefore should be avoided unless [20°F] of subcooling cannot be maintained in the RCS (Figure 10-1). If the RCS is solid, closely monitor any makeup or draining and any system heatup or cooldown to avoid any unfavorable rapid pressure excursions.

2. All available indications should be used to aid in evaluating plant conditions since the accident may cause irregularities in a particular instrument reading. Instrument readings must be corroborated when one or more confirmatory indications are available. Hot and cold leg RTDs may be influenced by cold SIS injection and should be checked against each other.

3. Do not place system in "manual" unless misoperation in "automatic" is apparent. Systems placed in "manual" must be checked frequently to ensure proper operation.

4. The operator should be cautioned against prematurely initiating an RAS. The operator should verify that RWT level has reached [10%] and that the containment sump has adequate fluid for SIS suction before shifting to recirculation. This manual action should not be taken unless an automatic RAS is required.

5. Steam plant radiation alarms usually indicate a steam generator tube leak which may result in loss of RCS inventory.

Continuing Actions for Inventory Control

If the acceptance criteria are not met, Then RCS inventory control is still in jeopardy. The operator must continue attempting to establish RCS inventory control while pursuing other jeopardized safety functions. Evaluate further actions using the following:

a) Rate of change of inventory and potential for damage to the RCS
b) The urgency of other jeopardized safety functions
c) The feasibility of restoring function to a success path by:
   i) restoring the vital auxiliaries necessary to operate components or systems in the success paths
   ii) manual operation of valves
   iii) use of alternate components to implement a success path.

Bases for RCS Inventory Control

The purpose of maintaining RCS inventory control is to provide a medium for the removal of decay heat. To do this, RCS inventory is maintained between the minimum volume required to keep the core covered with an effective coolant medium and the maximum level desirable for operational purposes (i.e., to prevent solid plant operations with its attendant pressure control problems).

Many plant conditions may result in a loss of inventory control. A break in the primary system piping, a stuck open relief valve, or a failure in the system used for normal fluid addition to the RCS are some examples of possible causes of low inventory. A high inventory situation may result from excessive fluid addition from the CVCS or SIS, RCS fluid expansion due to an uncontrolled heat addition, or from RCS voiding.

The methods available for RCS inventory control also affect RCS pressure control. For example, a high pressure situation may result from excessive RCS inventory. On the other hand, a high RCS pressure may hinder the achievement of RCS inventory control since the SIS pumps (for most plants) are centrifugal with relatively low shutoff heads.

To achieve control of RCS inventory, the following methods are available:

IC-1: RCS Inventory Control via CVCS
IC-2: RCS Inventory Control via SIS

The bases for the recovery actions required for implementing each of the methods listed above are detailed as follows:

IC-1: *RCS Inventory Control via CVCS*

Operator Actions

1. The PLCS is verified to be functioning to restore pressurizer level to the hot zero power band. If not, charging and letdown are operated manually to restore and maintain pressurizer level [35 to 245"].

   Limiting letdown while maximizing charging flow may be adequate to make up for an insufficient RCS inventory condition. Conversely, maximizing letdown and minimizing charging flow may suffice in lowering a high RCS inventory condition.

   It is necessary that the operator check that pressurizer level is within an acceptable range, that there is adequate RCS subcooling, [and that there is no significant reactor vessel voiding as indicated by the RVLMS], to verify that RCS inventory is being controlled. If pressurizer level is not being maintained automatically, the operator has an alternate means of control by manually operating the charging pumps and letdown flowrate to regulate inventory into and out of the RCS.

2. Adequate suction sources to the charging pumps are verified. If necessary, the [VCT, boric acid storage tanks, RWT and spent fuel pool are used].

   The source(s) of water for use in controlling RCS inventory depend on the total amount of fluid necessary for make up to the RCS and the time frame over which the fluid must be introduced. The volume control tank is the primary source of fluid for RCS makeup. If necessary, for the cases where RCS inventory losses are being incurred, the contents of the [boric acid makeup tanks, the refueling water tank and the spent fuel pool] may be used as backup sources of makeup water.

3. A high pressurizer level indication may be the result of RCS voiding. If this is the case, the actions concerning letdown in Step 1 may either have minimal effect on indicated pressurizer level or result in an even higher indicated pressurizer level. (The void expands upon pressure decrease with a resulting distribution of RCS fluid into the pressurizer). The presence of such an RCS void may be the result of inadequate RCS/core heat removal or the presence of non-condensible gases. If a high indicated RCS inventory appears to be caused by excessive RCS voiding, then RCS/core heat removal is more in jeopardy than the RCS Inventory Control Safety Function. The RCS and Core Heat Removal Safety Function Success Paths should be referred to in order to eliminate the voiding. [The RVLMS indication may provide confirmation of this voiding, if voiding is present in the Reactor Vessel].

After implementing the above actions, RCS Inventory Control is satisfied if:

a. Pressurizer level is [35 to 245"]

<u>and</u>

b. The RCS is at least [20°F] subcooled [by CET]

<u>and</u>

c. [The RVLMS indicates the core is covered]

*If the RCS is in a solid condition for pressure control, then the limit of [245"] may be exceeded].

Successful control of RCS inventory may be verified by pressurizer level being restored to [35 to 245"], RCS subcooling $\geq$ [20°F], [and the RVLMS indicating the core is covered]. The basis for meeting this acceptance criteria is dependent upon whether a low or high inventory situation exists. For the low inventory situation a value of [35"] is chosen as a lower pressurizer level limit to ensure that level is being restored to within the pressurizer level instrument indicating range. It is normally desirable to maintain pressurizer level >[100"] to allow for operation of pressurizer heaters. The value of

[245"] was chosen as an upper limit for pressurizer level to limit refill and provide margin to solid RCS conditions, accounting for instrument accuracies and other uncertainties. [20°F] subcooling, pressurizer level [35" to 245"], [and the RVLMS indicating core coverage], are indications of adequate RCS inventory control. In some cases, it may be necessary to fill the pressurizer solid in order to achieve subcooling. If such is the case, then the upper limit on pressurizer level may be exceeded.

Once the pressurizer water temperature varies from the normal hot standby temperature, the instrument indication on the normal pressurizer level channel will begin to deviate (i.e. decalibrate) from the true pressurizer level. At this time, the operator should use the plant cooldown correction curves to determine the true pressurizer water level. A cold calibrated pressurizer instrument channel is provided. This channel can be used as a quick reference during the plant cooldown. The actual pressurizer water level during pressurizer cooldown will be between the level indicated on the cold calibrated channel (which reads low) and the level indicated on the hot calibrated channel (which reads high).

IC-2: *Inventory Control via SIS*

If charging flow and operation of letdown is not satisfying the acceptance criteria of IC-1, then additional makeup fluid may be added by utilizing the SIS.

Operator Actions

1. SIS operation must be verified if pressurizer pressure decreases to [1600 psia, or if containment pressure increases to 4 psig]. If safety injection system operation has not commenced automatically when RCS pressure is below [1600 psia], it must be manually actuated. This action allows the RWT inventory to discharge into the RCS. An insufficient RCS inventory may be associated with a loss of coolant accident, a steam generator tube rupture, a control system malfunction or an excessive heat removal event. Operation of the SIS also affects RCS pressure. When operating the SIS the operator must attempt to maintain or restore pressure to within the limits of Figure 10-1. If at least [20°F] subcooling cannot be maintained, the SIS is kept running for core cooling considerations regardless of pressurizer level.

2. If pressurizer pressure goes below [1300 psia] following receipt of an SIAS, then all four RCPs must be tripped. Two RCPs may have been tripped already in the Standard Post Trip Actions. In this case, the operator would simply trip the remaining two RCPs. Since prolonged RCP operation during LOCAs of certain size and location could result in increasing the severity of the event, tripping all four RCPs ensures a conservative approach to event recovery. This is due to the fact that, when the operators implement the FRG they have not determined what event is occurring. An LOCA may be the lone event which is occurring or it may be occurring in conjunction with other event(s). Since operators cannot be sure what event is occurring, they are instructed to trip all RCPs whenever they are implementing the FRG and pressurizer pressure decreases to less than [1300 psia] following an SIAS. This is a conservative approach designed to satisfy worst case analysis.

3. If inventory control is not established (i.e., pressurizer level is less than [35"]), then all available charging pumps and at least one train of the SIS should be operating (until SIS termination criteria are met). SIS flowrate will vary according to RCS pressure. SIS and charging pump flowrates should be checked and SIS pump flowrates maximized relative to RCS pressure to enhance RCS inventory replenishment and/or core heat removal.

4. If an SIAS has been initiated and the SIS is operating, it must continue to operate at full capacity until SIS termination criteria are met. For most LOCAs the SIS will run continuously for a long period of time while RCS inventory, pressure, and heat removal control are being regained. In some cases control by normal means of these three functions is not regained during the accident (i.e., largest breaks) and the SIS runs for at/or least for the duration of the recovery period. Early termination is expected only for small break LOCAs, for an excess steam demand event, a spurious SIAS, or if any leak is identified and promptly isolated (e.g., a stuck open PORV is blocked).

   Termination of SIS should be sequenced by stopping one pump at at time while observing the termination criteria. Throttling of HPSI flow is permissible if it is feasible. SIS termination criteria are:

   a) The RCS is at least [20°F] subcooled (Figure 10-1). Establishing [20°F] of subcooling ensures the fluid in the core is subcooled, and provides sufficient margin for establishing flow should the [20°F] subcooling deteriorate when SIS flow is secured. Voids may exist in some parts of the RCS (e.g., reactor vessel head), but these are permissible as long as core heat removal is maintained.

   b) Pressurizer level is greater than [100"], and constant or increasing. A pressurizer level greater than [100"] and constant or increasing in conjunction with criterion a) above is an indication that RCS inventory control has been established.

c) At least one steam generator is available for removing heat from the RCS. Steam generator availability requires having feed flow and steam flow which are indications that primary to secondary heat removal is possible.

d) [The RVLMS indicates the core is covered. An indication of core coverage, in conjunction with the above criteria, serves as an additional indication that RCS inventory control has been established].

If the criteria are met, the operator may either terminate or throttle the SIS. The operator may decide to throttle rather than terminate if the SIS is to be used to control pressurizer level or plant pressure. A general assessment of the SIS performance can be made from the control room. The operator should confirm that at least one train and preferably both trains of SIS are operating and that system delivery rate is consistent with RCS pressure as shown in Figure 10-3. Injection flow rates to each cold leg should be approximately equal; departures from this would indicate a closed flow path or some system spillage that is in addition to the LOCA.

5. If the criteria of step 4 cannot be maintained, then the SIS pumps must be restarted.

6. If the [refueling water tank] level falls to [10%], then initiation of recirculation should be verified. If necessary, recirculation should be initiated manually one SIS train at a time. Recirculation is actuated either automatically or manually in order to maintain a continuous flow of safety injection fluid to the RCS (required for inventory control) and a continuous flow of containment spray water (required for containment temperature and pressure control). [If the automatic or manual initiation of the RAS does not automatically close RWT outlet valves, these must be manually closed to isolate the RWT from the SIS pumps. Furthermore, sump level should be checked prior to and during the transfer of suction sources. An LOCA outside of containment could result in inade-

quate containment sump inventory to allow recirculation. The operator should monitor an increasing trend in containment sump level that corresponds to the decreasing trend in RWT level. These actions prevent the inadvertent air binding of the safety injection pumps.]

The operator should be cautioned against prematurely initiating an RAS. A possible complication of a premature RAS is the pumps' suction being aligned to a dry sump, consequently air binding the pumps and losing both heat removal loops. In addition, for events where high containment pressure is present, the check valves in the RWT outlet line may be forced shut and the RWT fluid will remain unavailable while the containment is pressurized unless the containment can be isolated and the SIS suction piping depressurized.

7. After the switch to recirculation, the HPSI pump flows are monitored in order to ensure that HPSI pump miniflow requirements are met to avert possible pump damage. If they are not met, the operator should turn off the charging pumps one at a time until the miniflow requirements are met. If they are still not met with all the charging pumps off and two HPSI pumps are operating, the operator turns off the pump with the lower flow. One HPSI pump should be left operating at all times, unless the criteria of step 4 are met.

After implementing the above actions, RCS Inventory Control is satisfied if:

a. [All available charging pumps are operating and] the SIS pump(s) are injecting water into the RCS per Figure 10-3 (unless SIS termination criteria are met).

and

b. [The RVLMS indicates the core is covered]

These criteria ensure that the core is covered and that all possible means of injecting water into the RCS are being implemented.

Continuing Actions For Inventory Control

If RCS Inventory Control is still in jeopardy, then the operator must continue attempting RCS Inventory control while attending to other safety functions in jeopardy. The evaluation of the urgency of RCS Inventory Control should be based on rate of change of inventory and potential for damage to the RCS, the urgency of other safety functions in jeopardy, and the feasibility of restoring equipment to restore success paths. Clearly, if inventory trends are threatening core uncovery, the operator must take all possible steps to restore inventory. This may involve the manipulation of other safety functions. (e.g., RCS pressure reduction, perhaps by RCS heat removal, to lower RCS pressure below the shutoff head of the SIS pumps).

SAFETY FUNCTION: RCS Pressure Control
SUCCESS PATH: Manual Control of Pressurizer Heaters and/or Spray; PC-1
RESOURCE TREE: Tree D

OPERATOR ACTIONS

1. Manually operate pressurizer heaters and/or spray to restore pressurizer pressure to within the limits of the Post Accident P-T Curves (Figure 10-1).

*2. If pressurizer pressure is restored to within the limits of Figure 10-1, the normal pressure band is desired, and the PPCS is functioning properly, Then shift the PPCS to automatic control if desired.

Acceptance Criteria for Success Path: PC-1

1. Pressure Control is satisfied if:

   Pressurizer pressure is within the limits of the Post Accident P-T Curves (Figure 10-1).

   If the above criteria are met, Then proceed to the next safety function in jeopardy.
   If all safety functions are being satisfied, Then implement the Long Term Actions.

2. If the above criteria are not met, Then proceed to the next appropriate success path on Resource Tree D.

*Step Performed Continuously

1. implemented in Precaution V.A.3

2. implemented in General Precaution III.B

3. implemented in Precaution V.A.2

SUPPLEMENTARY INFORMATION: PC-1

This section contains items which should be considered when implementing EPGs and preparing plant specific EOPs. The items should be implemented as precautions, cautions, notes, or in the EOP training program.

1. Continuously monitor RCS temperature and pressure to avoid exceeding a heat removal rate greater than Technical Specification Limitations. If the heat removal rate exceeds Technical Specification Limits, there may be a potential for pressurized thermal shock (PTS) of the reactor vessel unless Post Accident Pressure/Temperature Limits are maintained (Figure 10-1).

2. All available indications should be used to aid in evaluation of plant conditions since the accident may cause irregularities in a particular instrument reading. Instrument readings must be corroborated when one or more confirmatory indications are available.

3. Solid water operation of the pressurizer may make it difficult to control RCS pressure and, therefore, should be avoided unless [20°F] of subcooling cannot be maintained in the RCS (Figure 10-1). If the RCS is solid, closely monitor any makeup or draining, and any system heatup or cooldown, to avoid any unfavorable rapid pressure excursions.

1. implemented in V.B.1

2. implemented in V.B.7

3. implemented in V.B.4

1. implemented in PRESS/INV SFSC ; see Deviation 8-17 for Administrative actions

2. See Deviation 8-12

SAFETY FUNCTION: RCS Pressure Control
SUCCESS PATH: CVCS; PC-2
RESOURCE TREE: Tree D

OPERATOR ACTIONS

1. Verify that the PLCS is automatically maintaining, or restoring, pressurizer level.
   If not, manually operate charging and letdown to restore, and maintain, pressurizer level.

2. If RCS subcooling of at least [20°F] cannot be maintained, Then take the pressurizer solid (if possible) to establish RCS pressure control.

3. Verify adequate suction sources from the (listed in order of priority) VCT, [BAMT, RWT, or Spent Fuel Pool] to the charging pumps.

Acceptance Criteria for Success Path: PC-2

1. Pressure Control is satisfied if:

   Pressurizer pressure is within the limits of the Post Accident P-T Curves (Figure 10-1).

   If the above criteria are met, Then proceed to the next safety function in jeopardy.
   If all safety functions are being satisfied, Then implement the Long Term Actions.

2. If the above criteria are not met, Then proceed to the next appropriate success path on Resource Tree D.

1. IMPLEMENTED IN GENERAL PRECAUTION III. A

2. IMPLEMENTED IN GENERAL PRECAUTION III. B

3. implemented in V. A. 3

4. implemented in V. A. 2

SUPPLEMENTARY INFORMATION: PC-2

This section contains items which should be considered when implementing EPGs and preparing plant specific EOPs. The items should be implemented as precautions, cautions, notes, or in the EOP training program.

1. Do not place systems in "manual" unless misoperation in "automatic" is apparent. Systems placed in "manual" must be checked frequently to ensure proper operation.

2. All available indications should be used to aid in evaluation of plant conditions since the accident may cause irregularities in a particular instrument reading. Instrument readings must be corroborated when one or more confirmatory indications are available.

3. Continuously monitor RCS temperature and pressure to avoid exceeding a heat removal rate greater than Technical Specification Limitations. If the heat removal rate exceeds Technical Specification Limits, there may be a potential for pressurized thermal shock (PTS) of the reactor vessel unless Post Accident Pressure/Temperature Limits are maintained (Figure 10-1).

4. Solid water operation of the pressurizer may make it difficult to control RCS pressure and, therefore, should be avoided unless [20°F] of subcooling cannot be maintained in the RCS (Figure 10-1). If the RCS is solid, closely monitor any makeup or draining, and any system heatup or cooldown, to avoid any unfavorable rapid pressure excursions.

1. IMPLEMENTED IN V.B.2. see Deviation 8-33 for containment pressure SIAS actuation

2. implemented IN V.B.3

3. See DEVIATION sheet 8-10

4. See Deviation sheet 8-10

5. implemented in step V.B.7

SAFETY FUNCTION: RCS Pressure Control
SUCCESS PATH: SIS; PC-3
RESOURCE TREE: Tree D

OPERATOR ACTIONS

*1. If pressurizer pressure decreases to [1600 psia, or if containment pressure increases to 4 psig], Then verify that an SIAS has been initiated.
If not, manually initiate an SIAS.

*2. If pressurizer pressure decreases to less than [1300 psia] following an SIAS, Then ensure all RCPs are tripped.

*3. If the SIS is operating, Then it may be throttled or stopped, one train at a time, if the following criteria are satisfied:

a) The RCS is at least [20°F] subcooled
b) Pressurizer level is greater than [100"] and constant or increasing
c) At least one steam generator is available (feed and steam flow) for removing heat from the RCS
d) [The RVLMS indicates the core is covered].

*4. If the criteria of step 3 cannot be maintained after the SIS has been stopped, Then the SIS must be restarted.

5. If RCS subcooling of at least [20°F] cannot be maintained, Then take the pressurizer solid (if possible) to establish RCS pressure control.

* Step performed continuously.

6. IMPLEMENTED BY STEPS V.B.2, V.B.4, V.B.5, V.B.6

7. implemented by step V.B.6

1. IMPLEMENTED IN PRESS/INV safety function. See Deviation 8-17 for ADMINISTRATIVE ACTIONS

2. See Deviation 8-17

*6. Monitor [refueling water tank] level.
If the [refueling water tank] level falls to [10%], Then verify initiation of recirculation.
If necessary, Then manually initiate recirculation one train at a time [and close RWT outlet valves to the safety injection system].

*7. If the HPSI pumps are delivering less than [30 gpm] per pump during recirculation, Then turn off one charging pump at a time until the HPSI pump(s) are delivering more than [30 gpm] per pump.
If the minimum HPSI pump delivery flow is still not met with all charging pumps off, Then turn off the HPSI pump with the lower indicated flow.

Acceptance Criteria for RCS Pressure Control: PC-3

1. Pressure Control is satisfied if:

   [All available charging pumps are operating and] the SIS pump(s) are injecting water into the RCS per Figure 10-3 (unless SIS termination criteria are met).

   If the above criterion is met, Then proceed to the next safety function in jeopardy.
   If all safety functions are being satisfied, Then implement the Long Term Actions.

2. If the above criterion is not met, Then proceed to the Continuing Actions for RCS Pressure Control.

* Step performed continuously.

1. IMPLEMENTED IN GENERAL PRECAUTION III.A

2. IMPLEMENTED IN GENERAL PRECAUTION III.B

3. IMPLEMENTED IN V.A.3

4 implemented in V.A.2

5. implemented IN V.B.4, V.B.5, AND V.B.6. Containment level is periodically checked in CONTAINMENT ENVIRONMENT SFSC.

SUPPLEMENTARY INFORMATION: PC-3

This section contains items which should be considered when implementing EPGs and preparing plant specific EOPs. The items should be implemented as precautions, cautions, notes, or in the EOP training program.

1. Do not place system in "manual" unless misoperation in "automatic" is apparent. Systems placed in "manual" must be checked frequently to ensure proper operation.

2. All available indications should be used to aid in the evaluation of plant conditions since the accident may cause irregularities in a particular instrument reading. Instrument readings must be corroborated when one or more confirmatory indications are available. Hot and cold leg RTDs may be influenced by the cooler SIS injection and should be checked against each other.

3. Continuously monitor RCS temperature and pressure to avoid exceeding a heat removal rate greater than Technical Specification Limitations. If the heat removal rate exceeds Technical Specification Limits, there may be a potential for pressurized thermal shock (PTS) of the reactor vessel unless Post Accident Pressure/Temperature Limits are maintained (Figure 10-1).

4. Solid water operation of the pressurizer may make it difficult to control RCS pressure and therefore should be avoided unless [20°F] of subcooling cannot be maintained in the RCS. If the RCS is solid, closely monitor any makeup or draining and any system heatup or cooldown to avoid any unfavorable rapid pressure excursions.

5. The operator should be cautioned against prematurely initiating an RAS. The operator should also check containment sump level to verify adequate suction for the SIS prior to shifting to recirculation.

1. implemented in IV. B. 3, IV. B. 5. See Deviation 8-18 for differences in location in procedure.

2. IMPLEMENTED IN V. B. 7

3. implemented in V. B. 7. see Deviation 8-19 concerning plant cooldown.

4. IMPLEMENTED IN VI. B. 7. SEE Deviation 8-20 concerning AFW waterhammer see Deviation 8-23 concerning location differences,

SAFETY FUNCTION: RCS Pressure Control
SUCCESS PATH: Forced Circulation with ADV or TBS Control; PC-4
RESOURCE TREE: Tree D

OPERATOR ACTIONS

*1. Borate the plant as necessary, while cooling down, in order to maintain shutdown margin per Technical Specification Limits (refer to RC-2 and RC-3).

2. Allow pressurizer level to lower (maintaining level [35 to 245"]) while cooling down in order to aid the depressurization.

3. Perform an orderly plant cooldown/depressurization in order to meet the acceptance criteria of this success path by performing one of the following:

   a) If the condenser, and either [main or auxiliary] feedwater systems are available, then cooldown and depressurize using the turbine bypass system

   or

   b) If the condenser or turbine bypass systems are not available, then cooldown and depressurize using at least one steam generator via the atmospheric dump valve(s) and either [main or auxiliary] feedwater.

*4. [If the auxiliary feedwater system (AFW) is started, Then perform the following to prevent S/G feed ring damage:

   a) If S/G water level is above the feed ring, then stop redundant AFW pumps, restore S/G level, and maintain it in the normal level band.

* Step performed continuously.

5A. Implemented in section VI.B.5

5B. pressure is DICTATED BY THE DEGREE of SUBCOOLING. STEP V. B.7 PROVIDES DIRECTION FOR SUBCOOLING CONTROL. SEE DEVIATION 8-21

5C. See Deviation 8-22

5d. IMPLEMENTED IN STEP VI.B.7

5e implemented in step VI.B.8
SEE DEVIATON 8-23 CONCERNING LOCATION DIFFERENCES ON 5d AND e

6. DIRECTION IS PROVIDED IN STEP VI.4 for the use of PORVs as a heat removal method when all feed water is lost. See DEVIATION 8-23 for location difference. AUTOMATIC PORV Response for pure pressure control is Addressed in step V.2

7. Implemented in RCS/CORE HEAT Removal SFSC

b) If feedwater flow to an S/G has been interrupted, and indicated S/G water level is below the feed ring, then:

   i) Stop redundant AFW pumps and limit feedwater flow rate to 150 gpm per affected S/G until an increase in S/G level has been observed, or until continuous feedwater flow has been maintained for five minutes.

   ii) Modulate AFW flow rate as necessary to restore, and maintain, S/G water level to the normal level band.]

*5. If all feedwater (main and auxiliary) is lost, Then conduct the following:

a) Stop all RCPs
b) Stop the depressurization
c) Isolate steam generator blowdown, secondary sampling, and any non-vital steam discharge.
d) Take actions to regain [main or auxiliary] feedwater system operation.
e) [If other sources of water are available for steam generator heat removal, insert that information here.]

*6. If feedwater cannot be regained, and pressurizer sprays (main and auxiliary) are not available, Then go to PC-6, RCS Pressure Control via [PORVs].

*7. If the auxiliary feedwater system is being used, Then ensure an adequate supply of condensate exists (refer to Figures 10-4 and 10-5).

* Step performed continuously.

1. implemented in press/INV SFSC. See DEVIATION 8-17 for Administrative actions.

2. See DEVIATION 8-2

Acceptance Criteria for RCS Pressure Control: PC-4

1. Pressure Control is satisfied if:

   Pressurizer pressure is within the limits of the Post Accident P-T Curves of Figure 10-1.

   If the above criteria are met, Then proceed to the next safety function in jeopardy.
   If all safety functions are being satisfied, Then implement the Long Term Actions.

2. If the above criteria are not met, Then proceed to the next appropriate success path on Resource Tree D.

1. IMPLEMENTED IN GENERAL PRECAUTION III.A

2. IMPLEMENTED IN GENERAL PRECAUTION III.B

3. IMPLEMENTED IN V.A.3

4. IMPLEMENTED IN V.A.2

5. IMPLEMENTED IN VI.A.2. SEE DEVIATION 8-23 ~~FOR~~ LOCATION

SUPPLEMENTARY INFORMATION: PC-4

This section contains items which should be considered when implementing EPGs and preparing plant specific EOPs. The times should be implemented as precautions, cautions, notes, or in the EOP training program.

1. Do not place systems in "manual" unless misoperation in "automatic" is apparent. Systems placed in "manual" must be checked frequently to ensure proper operation.

2. All available indications should be used to aid in the evaluation of plant conditions since the accident may cause irregularities in a particular instrument reading. Instrument readings must be corroborated when one or more confirmatory indications are available.

3. Continuously monitor RCS temperature and pressure to avoid exceeding a maximum heat removal rate greater than Technical Specification Limitations. If the heat removal rate exceeds Technical Specification Limits, there may be a potential for pressurized thermal shock (PTS) of the reactor vessel, unless Post-Accident Pressure/Temperature Limits are maintained (Figure 10-1).

4. Solid water operation of the pressurizer may make it difficult to control RCS pressure and therefore should be avoided unless [20°F] of subcooling cannot be maintained in the RCS (Figure 10-1). If the RCS is solid, closely monitor any makeup or draining and any system heatup or cooldown to avoid any unfavorable pressure excursion.

5. The operator should not add feedwater to a dry steam generator if another steam generator still contains water. Re-establish feedwater only to the steam generator that is not dry. If both steam generators become dry, refill only one steam generator to reinitiate core cooling.

1. IMPLEMENTED IN IV.B.3 AND IV.B.5. See DEVIATION 8-18 for differences IN LOCATION IN PROCEDURE.

2. IMPLEMENTED IN V.B.7

3. IMPLEMENTED IN VI.B.4. SEE DEVIATION 8-24

4 IMPLEMENTED IN VI.B.4. SEE DEVIATION 8-24

SAFETY FUNCTION: RCS Pressure Control
SUCCESS PATH: Natural Circulation with ADV or TBS control; PC-5
RESOURCE TREE: Tree D

OPERATOR ACTIONS

*1. Borate the plant as necessary, while cooling down, in order to maintain shutdown margin per Technical Specification Limit (refer to RC-2 and RC-3).

2. Allow pressurizer level to lower (maintaining level [35 to 245"]) while cooling down in order to aid the depressurization.

*3. Determine whether RCP restart criteria are met by the following:

   a) At least one steam generator (feed and steam flow) is available for RCS heat removal
   b) Pressurizer level is greater than [200"] and not decreasing,
   c) The RCS is at least [20°F] subcooled (Figure 10-1)
   d) [Other criteria satisfied per RCP operating instructions].

*4. If RCP restart criteria are met, Then do the following:

   a) Start one RCP in each loop
   b) [Ensure proper RCP operation by monitoring RCP amperage and pump NPSH. NPSH is determined by pressurizer pressure and corresponding T_c on Figure 10-1].
   c) Operate HPSI (Figure 10-3) and charging pumps until pressurizer level is greater than [100"] and SIS termination criteria are met.

* Step performed continuously.

5. See Deviation 8-17

6. Implemented in VI.B.4. See Deviation 8-25 for location difference.

7. RCS inventory; S/G feeding and steaming are checked regardless of whether ~~s~~ natural circulation conditions exist. Section V is dedicated to inventory control. S/G steaming and feeding are addressed in sections VI.B.6 and VI.B.7. Steaming and feeding are discussed under core/RCS heat removal since they are more applicable to that function than press/INV.

8. Use of the turb bypass system and/or the atmospheric dumps is directed in section VI.B.6. They are discussed in this section since they are more applicable to heat removal than the press/INV. function.

*5. If at least one RCP has been restarted in a loop with a S/G having feed and steam flow capability, Then go to PC-4, Forced Circulation with ADV or TBS Control.

*6. If all RCPs are stopped, Then verify that natural circulation is being maintained in at least one loop by the following:

a) Loop ΔT ($T_H - T_C$) less than normal full power ΔT
b) Cold leg temperatures constant or decreasing
c) Hot leg temperatures stable (i.e., not steadily increasing) or decreasing slowly
d) No abnormal differences between T_H RTDs and [core exit thermocouples].

*7. If the criteria of step 6 are not met, Then ensure RCS inventory, and S/G steaming and feeding, are being controlled properly.

8. Perform an orderly plant cooldown/depressurization in order to meet the acceptance criteria of this success path by performing one of the following:

a) If the condenser, and either [main or auxiliary] feedwater systems are available, then cooldown and depressurize using the turbine bypass system.

or

b) If the condenser or turbine bypass systems are not available, then cooldown and depressurize using at least one steam generator via the atmospheric dump valve(s) and either [main or auxiliary] feedwater.

*Step performed continuously.

9. implemented in VI.B.7. See Deviation 8-20 concerning AFW waterhammer. See Deviation 8-23 concerning location differences.

10 implemented in RCS heat removal SFSC

11a) pressure is dictated by the degree of subcooling. STEP V.B.7 provides direction for subcooling control. See Deviation 8.21

11b See Deviation 8-22

11c implemented in step VI.B.7

11d implemented in step VI.B.8
See deviation 8-23 for location difference on 11c and D

12 Direction is provided in step IV.4 for the use of PORVs as a heat removal method when all feedwater is lost. See deviation 8-23 for location difference. Automatic PORV response for pure pressure control is addressed in step V.2.

*9. [If the auxiliary feedwater system (AFW) is started, Then perform the following to prevent S/G feed ring damage:

a) If S/G water level is above the feed ring, then stop redundant AFW pumps, restore S/G level, and maintain it in the normal level band.

b) If feedwater flow to an S/G has been interrupted and indicated S/G water level is below the feed ring, then:

   i) Stop redundant AFW pumps and limit feedwater flow rate to 150 gpm per affected S/G until an increase in S/G level has been observed, or until continuous feedwater flow has been maintained for five minutes.

   ii) Modulate AFW flow rate as necessary to restore, and maintain, S/G water level to the normal level band].

*10. If the auxiliary feedwater system is being used, Then ensure an adequate supply of condensate exists (refer to Figures 10-4 and 10-5).

*11. If all feedwater (main and auxiliary) is lost, Then conduct the following:

Stop all RCP's

a) Stop the depressurization

b) Isolate steam generator blowdown, secondary sampling, and any non-vital steam discharge.

c) Take actions to regain [main or auxiliary] feedwater system operation.

d) [If other sources of water are available for steam generator heat removal, then insert that information here].

*12. If feedwater cannot be regained in at least one operable steam generator, Then go to PC-6, RCS Pressure Control via [PORVs].

* Step performed continuously.

13. SEE DEVIATION 8-26

14. IMPLEMENTED IN STEP VI.B.4. SEE DEVIATION 8-27 FOR LOCATION DIFFERENCE.

15. IMPLEMENTED IN STEP VI.B.4, SEE DEVIATION 8-27 FOR LOCATION DIFFERENCE.

13. If one steam generator was isolated, and primary to secondary leakage is suspected; Then unisolate and steam the affected S/G to the condenser to prevent overfilling due to the primary to secondary leakage.

*14. Monitor for the presence of RCS voiding and take steps to eliminate voiding any time voiding jeopardizes RCS heat removal via natural circulation. Voiding in the RCS may be indicated by any of the following indications, parameter changes, or trends: C

a) letdown flow greater than charging flow,
b) pressurizer level increasing significantly greater than expected while operating pressurizer spray,
c) [the RVLMS indicates that voiding is present in the reactor vessel],
d) [the HJTC unheated thermocouple temperature indicates saturated conditions in the reactor vessel upper head].
e) [other indications insert here]. A

*15. If voiding should be eliminated, Then proceed as follows:

a) verify letdown is isolated,
b) stop the depressurization and, if required, repressurize the RCS to $\geq$ [20°F] subcooling,
c) pressurize and depressurize the RCS within the limits of Figure 10-1 by operating pressurizer heaters and spray (preferred method) or HPSI and charging pumps (alternative method). Monitor pressurizer level [and the RVLMS] for trending of RCS inventory.
d) if indications of unacceptable RCS voiding continue, and voiding is suspected to exist in the (isolated) steam generator tubes, then cool the (isolated) steam generator (by steaming or blowdown, and/or feeding) to condense the steam generator tube bundle void. Monitor pressurizer level for trending of RCS inventory.
e) if indications of unacceptable RCS voiding continue, then [operate the pressurizer vent and/or the reactor vessel head vent to] clear trapped non-condensible gases. Monitor pressurizer level [and/or the RVLMS] for trending of RCS inventory.

*Step Performed Continuously

1. Implemented in SFSC for Pressure and inventory parameters.
see Deviation 8-17 for administrative actions.

2. See Deviation 8-2

Acceptance Criteria for RCS Pressure Control: PC-5

1. Pressure Control is satisfied if:

   Pressurizer pressure is within the limits of the Post Accident P-T Curves of Figure 10-1.

   If the above criteria are met, Then proceed to the next safety function in jeopardy.
   If all safety functions are being satisfied, Then implement the Long Term Actions.

2. If the above criteria are not met, Then proceed to the next appropriate success path on Resource Tree D.

1. IMPLEMENTED IN GENERAL PRECAUTION III.A

2. IMPLEMENTED IN GENERAL PRECAUTION III.B

3. implemented in STEP V.A.3.

4. implemented in STEP V.A.2 .

5. implemented in precaution VI.A3 AND in step VI.B.4. SEE DEVIATION 8-25 FOR LOCATION DIFFERENCE.

SUPPLEMENTARY INFORMATION: PC-5

This section contains items which should be considered when implementing EPGs and preparing plant specific EOPs. the items should be implemented as precautions, cautions, notes, or in the EOP training program.

1. Do not place systems in "manual" unless misoperation in "automatic" is apparent. Systems placed in "manual" must be checked frequently to ensure proper operation.

2. All available indications should be used to aid in the evaluation of plant conditions since the accident may cause irregularities in a particular instrument reading. Instrument readings must be corroborated when one or more confirmatory indications are available.

3. Continuously monitor RCS temperature and pressure to avoid exceeding a heat removal rate greater than Technical Specification Limitations. If the heat removal rate exceeds Technical Specification Limits, there may be a potential for pressurized thermal shock (PTS) of the reactor vessel, unless Post-Accident Pressure/Temperature Limits are maintained (Figure 10-1).

4. Solid water operation of the pressurizer may make it difficult to control RCS pressure and therefore should be avoided unless [20°F] of subcooling cannot be maintained in the RCS (Figure 10-1). If the RCS is solid, closely monitor any makeup or draining, and any system heatup or cooldown, to avoid any unfavorable pressure excursions.

5. Natural circulation flow should not be verified until the RCPs have stopped coasting down after being tripped.

6. IMPLEMENTED IN PRECAUTION VI. A3. See DEVIATION 8-25 FOR LOCATION DIFFERENCE.

7. implemented in precaution VI.A.4. SEE DEVIATION 8-25 FOR LOCATION DIFFERENCE.

8. implemented in precaution VI.A.2. SEE DEVIATION 8-28

9. See Deviation 8-16

10. Implemented in step VI.B.4. See DEVIATION 8-27 for location difference.

6. Verification of temperature responses to a plant change cannot be accomplished until approximately 5 to 15 minutes following the action due to increased loop cycle times during natural circulation.

7. When RCS heat removal is conducted by natural circulation with an isolated steam generator, an inverted ΔT (i.e., T_c higher then T_h) may be observed in the idle loop. This is due to a small amount of reverse heat transfer in the isolated steam generator and will have no affect on natural circulation flow in the operating steam generator loop.

8. The operator should not add feedwater to a dry steam generator if another steam generator still contains water. Re-establish feedwater only to the steam generator that is not dry. If both steam generators become dry, refill only one steam generator to reinitiate core cooling.

9. When a void exists in the reactor vessel, and RCPs are not operating, the RVLMS provides an accurate indication of reactor vessel liquid inventory. When a void exists in the reactor vessel, and RCPs are operating, it is not possible to obtain an accurate reactor vessel liquid level indication due to the effect of the RCP induced pressure head on the RVLMS. The indicated level also differs for different RVLMS designs under these conditions. Information concerning reactor vessel liquid inventory trending may still be discerned. However, operators are cautioned not to rely solely on the RVLMS indication when RCPs are operating.

10. The operator should continuously monitor for the presence of RCS voiding and take steps to eliminate voiding any time voiding causes the heat removal or inventory control safety functions to begin to be threatened. Void elimination should be started soon enough to ensure heat removal and inventory control are not lost. C

1. implemented in steps VI.B.2 ; VI.B.7

2. implemented in step VI.B.2

3. IMPLEMENTED IN STEP VI.B.3

1. implemented in SFSC of pressure/inventory parameters.
   see DEVIATION 8-17 for ADMINISTRATIVE ACTIONS.

SAFETY FUNCTION: RCS Pressure Control
SUCCESS PATH: [PORVs]; PC-6
RESOURCE TREE: Tree D

OPERATOR ACTIONS

1. Verify the [PORVs] open automatically at [2400 psia].
   If the [PORVs] do not open, Then manually open them and reduce pressurizer pressure to less than [2340 psia] and within the limits of Figure 10-1.

*2. If pressurizer pressure decreases to [1600 psia, or if containment pressure increases to 4 psig], Then verify that an SIAS has been initiated.
   If not, manually initiate SIS operation.

*3. If pressurizer pressure decreases to less than [1300 psia] following an SIAS, Then ensure all RCPs are tripped.

Acceptance Criteria for RCS Pressure Control: PC-6

1. Pressure Control is satisfied if [pressurizer pressure is:

   a. less than [2340 psia] and constant or decreasing
   and
   b. within the Post Accident P-T limits of Figure 10-1.]

If the above criteria are met, Then proceed to the next safety function in jeopardy.
If all safety functions are being satisfied, Then implement the Long Term Actions.

* Step performed continuously.

2. See Deviation 8-2

2. If the above criteria are not met, Then proceed to the Continuing Actions for RCS Pressure Control.

1. implemented in general precaution III.A

2. implemented in general precaution III.B

3 implemented in step V.A.2

4. implemented in step V.A.3

5. SEE DEVIATION 8-29

SUPPLEMENTARY INFORMATION: PC-6

This section contains items which should be considered when implementing EPGs and preparing plant specific EOPs. The items should be implemented as precautions, cautions, notes, or in the EOP training program.

1. Do not place a system in "manual" unless misoperation in "automatic" is apparent. Systems placed in "manual" must be checked frequently to ensure proper operation.

2. All available indications should be used to aid in evaluation of plant conditions since the accident may cause irregularities in a particular instrument reading. Instrument readings must be corroborated when one or more confirmatory indications are available.

3. Solid water operation of the pressurizer may make it difficult to control RCS pressure and therefore should be avoided unless [20°F] of subcooling cannot be maintained in the RCS (Figure 10-1). If the RCS is solid, closely monitor any makeup or draining and any system heatup or cooldown to avoid any unfavorable pressure excursions.

4. Continuously monitor RCS temperature and pressure to avoid exceeding a heat removal rate greater than Technical Specification Limitations. If the heat removal rate exceeds Technical Specification Limits, there may be a potential for pressurized thermal shock (PTS) of the reactor vessel unless Post Accident Pressure/Temperature Limits are maintained (Figure 10-1).

5. [Monitor quench tank parameters since any sustained operation of the PORVs may burst the tank's rupture disc.]

Continuing Actions for RCS Pressure Control

If RCS Pressure Control is still in jeopardy, then the operator must continue attempting RCS Pressure Control while working on other jeopardized safety functions. RCS Pressure Control measures should be based on the following considerations:

a) Rate of change of pressure and potential for damage to the RCS.
b) The urgency of other jeopardized safety functions.
c) The feasibility of restoring function to a success path by:
   i) restoring the vital auxiliaries necessary to operate components or systems in the success paths
   ii) manual operation of valves
   iii) use of alternate components to implement a success path.

Bases for RCS Pressure Control

The purpose of establishing RCS pressure control is to maintain the RCS subcooled in order to provide an adequate cooling medium for the core, and to prevent the loss of inventory out of a relief valve thereby preventing release of radioactive liquid to the containment and possibly to the atmosphere. Controlling RCS pressure within the limits of Figure 10-1 is also desirable to minimize the potential for pressurized thermal shock.

There are many conditions that could cause a loss of pressure control. A breach in the RCS piping, a stuck open relief valve, failure of the PPCS, loss of heat sink, or the failure of CEAs to insert during a reactor trip condition are some examples of ways that RCS pressure control can be lost. Pressure control is closely related to inventory control and core heat removal. Changes in inventory will generally result in RCS pressure changes and excessive RCS pressure may prevent introduction of makeup water to the RCS. Similarly, the maintenance of an adequate cooling medium around the core for core heat removal is dependent on maintaining subcooling.

The operator actions are directed at placing the plant in a stable, safe condition following a loss of pressure control. Pressure control may be accomplished by any of the following methods:

- PC-1: RCS Pressure Control via Manual Control of Pressurizer Heaters and/or Spray
- PC-2: RCS Pressure Control via CVCS
- PC-3: RCS Pressure Control via SIS
- PC-4: RCS Pressure Control via Forced Circulation with ADV or TBS Control
- PC-5: RCS Pressure Control via Natural Circulation with ADV or TBS Control
- PC-6: RCS Pressure Control via [PORVs]

The bases for the operator actions required to implement the above success paths are detailed as follows:

PC-1: *RCS Pressure Control via Manual Control of Pressurizer Heaters and/or Spray*

The automatic operation of the PPCS is the normal mode for pressure control. In this mode, it is only necessary that the operator periodically check that pressure is being maintained within the normal range to verify that RCS pressure is being controlled. However, the normal operating range of pressure may not be within the limits of Figure 10-1. Therefore, the operator is directed to take manual control of heaters and spray to restore and maintain plant pressure.

Operator Actions

1. Pressurizer heaters and/or (main or auxiliary) spray are operated manually to restore, and maintain pressure within the limits of (Figure 10-1). This action ensures that RCS pressure control is being restored.

2. If pressurizer pressure is restored to within the limits of Figure 10-1, the normal pressure band is desired, and the PPCS is functioning properly, then shift the PPCS to automatic control.

After implementing the above actions, RCS pressure control is satisfied if:

Pressurizer pressure is and within the limits of the Post Accident P-T Curves (Figure 10-1).

Observing the Post Accident P-T limits (including subcooling limits) minimizes pressurized thermal shock concerns and ensures a subcooled cooling medium around the core.

PC-2: *RCS Pressure Control via CVCS*

Pressure control using the charging system is effective as follows: raising pressurizer level above heater cutout will permit the use of heaters to form a steam bubble to control pressure; if there is a steam bubble in the pressurizer, then increasing pressurizer level will tend to compress the bubble and raise pressure; or if the pressurizer is taken solid, then addition of further fluid will increase pressure. The pressurizer should not be taken solid unless [20°F] of subcooling cannot be maintained. If solid, the operator should closely monitor any makeup or draining and any system heat up or cooldown to avoid an excessive pressure excursion.

Operator Actions

1. The PLCS is verified to be maintaining or restoring pressurizer level. If not, charging and letdown are manually operated to attempt to restore and maintain level [35 to 245"]. It is desirable to maintain level above the pressurizer heater cutout ([100"]) in order to permit pressure control using the heaters. Raising pressurizer level with a steam bubble in the pressurizer will tend to increase pressure.

2. If RCS subcooling of at least [20°F] cannot be maintained (which may occur if pressurizer heaters are not available), then the pressurizer is taken solid (if possible) to establish RCS pressure control.

3. Adequate suction sources to the charging pumps are verified. Usually, the VCT [and RWT] are used. The source(s) of water for use in controlling RCS pressure depend on the total amount of fluid necessary to add to the RCS and the time frame over which the fluid must be introduced. The volume control tank is the primary source of fluid for RCS makeup. For the case where RCS inventory losses are being incurred, the contents of [the boric acid makeup tank, the refueling water tank, and the spent fuel pool] may be used as another secondary source of makeup water.

After implementing the above actions, RCS pressure control is satisfied if:

Pressurizer pressure is within the limits of the Post Accident P-T Curves (Figure 10-1).

This criterion assures a subcooled heat transfer medium and that reactor vessel pressure stresses are below those of concern for PTS.

PC-3: *RCS Pressure Control via SIS*

If pressure control is not obtained via the CVCS, then the SIS may be used, if pressure is low enough, to restore inventory and allow pressure to be controlled.

Operator Actions

1. SIS operation must be verified if pressurizer pressure decreases to [1600 psia, or if containment pressure increases to 4 psig]. If safety injection system operation has not commenced automatically on high containment pressure [4 psig] or when RCS pressure is below [1600 psia], then it must be manually actuated. This action restores inventory so that pressure can be controlled by use of either pressurizer heaters and spray or by using the discharge head of the SIS pumps.

2. If pressurizer pressure goes below [1300 psia] following receipt of an SIAS, then all four RCPS must be tripped. Two RCPs may have been tripped already in the Standard Post Trip Actions. In this case, the operator would simply trip the remaining two RCPs. Since prolonged RCP operation during LOCAs of certain size and location could result in increasing the severity of the event, tripping all four RCPs ensures a conservative approach to event recovery. This is due to the fact that, when the operators implement the FRG they have not determined what event is occurring. An LOCA may be the lone event which is occurring or it may be occurring in conjunction with other event(s). Since operators cannot be sure what event is occurring, they are instructed to trip all RCPs whenever they are implementing the FRG and pressurizer pressure decreases to less than [1300 psia] following an SIAS. This is a conservative approach designed to satisfy worst case analysis.

3. If an SIAS has been initiated and the SIS is operating, it must continue to operate at full capacity until SIS termination criteria are met. For most LOCAs, the SIS will run continuously for a long period of time while

RCS inventory, pressure, and heat removal control are being regained. In some cases, control of these three functions is not regained during the accident (i.e. largest breaks) and SIS runs at least for the duration of the recovery period. Early termination is expected only for a small break LOCA, for a steam line break, spurious SIAS, or if the leak is identified and promptly isolated (e.g., a stuck open PORV is blocked).

Termination of SIS should be sequenced by stopping one pump at a time while observing the termination criteria. Throttling of HPSI flow is permissible if it is feasible. These criteria are:

a) RCS is at least [20°F] subcooled (Figure 10-1). Establishing [20°F] of subcooling ensures the fluid in the core is subcooled, and provides sufficient margin for establishing flow should the [20°F] subcooling deteriorate when SIS flow is secured. Voids may exist in some parts of the RCS (e.g. reactor vessel head), but these are permissible as long as core heat removal is maintained.

b) Pressurizer level is greater than [100"], and constant or increasing. A pressurizer level greater than [100"] and constant or increasing in conjunction with criterion a) above is an indication that RCS inventory control has been established.

c) At least one steam generator is available for removing heat from the RCS. Steam generator availability requires having feed flow and steam flow which are indications that primary to secondary heat removal is possible.

d) [The RVLMS indicates the core is covered. An indication of core coverage, in conjunction with the above criteria, serves as an additional indication that RCS inventory control has been established].

If the above criteria are met, the operator may either terminate or throttle the SIS. The operator may decide to throttle rather than terminate if the SIS is to be used to control pressurizer level or plant pressure. A general assessment of the SIS performance can be made from the control room. The operator should confirm that at least one train and preferably both trains of SIS are operating and that system delivery rate is consistent with RCS pressure as shown in Figure 10-3. Injection flow rates to each cold leg should be approximately equal; departures from this would indicate a closed flow path or some system spillage that is in addition to the LOCA.

4. If the criteria of step 3 cannot be maintained, then the SIS pumps must be restarted.

5. If RCS subcooling of at least [20°F] cannot be maintained, then the SIS should be used to take the pressurizer solid, if possible, in order to establish RCS pressure control.

6. If the [refueling water tank] levels falls to [10%], then initiation of recirculation should be verified. If necessary, recirculation should be initiated manually one SIS train at a time. Recirculation is actuated either automatically or manually in order to maintain a continuous flow of safety injection fluid to the RCS (required for inventory control) and a continuous flow of containment spray water (required for containment temperature and pressure control). [If the automatic or manual initiation of the RAS does not automatically close RWT outlet valves, these must be manually closed to isolate the RWT from the SIS pumps. Furthermore, sump level should be checked prior to and at the transfer of suction sources. A LOCA outside of containment could result in inadequate containment sump inventory to allow recirculation. The operator should monitor an increasing trend in containment sump level that corresponds to the decreasing trend in RWT level. These actions prevent the inadvertent air binding of the safety injection pumps.]

The operator should be cautioned against prematurely initiating an RAS. A possible complication of a premature RAS is the pumps' suction being aligned to a dry sump, consequently air binding the pumps and loosing both heat removal loops. In addition, for events where high containment pressure is present, the check valves in the RWT outlet line may be forced shut and the RWT fluid will remain unavailable while the containment is pressurized unless the containment can be isolated and the SIS suction piping depressurized.

7. After the switch to recirculation, the HPSI pump flows are monitored in order to ensure that HPSI pump miniflow requirements are met to avert any possible permanent HPSI pump damage. If they are met, the operator should turn off the charging pumps and/or the HPSI pumps one at a time until the miniflow requirements are met. If they are still not met with all the charging pumps off and two HPSI pumps are operating, the operator turns off the HPSI pump with the lower flow. One HPSI pump should be left operating at all times, unless the criteria of step 3 are met.

After implementing the above actions, RCS Pressure Control is satisfied if:

[All available charging pumps are operating and] the SIS pumps are injecting water into the RCS per Figure 10-3 (unless SIS termination criteria are met).

PC-4: *RCS Pressure Control via Forced Circulation with ADV or TBS Control*

If pressure cannot be reduced using the spray system, then RCS pressure can be reduced by removing heat using the RCPs and steam generators (if RCPs are available). This method may be effective by removing energy from steam generators, thereby preventing steam generators from causing a steam bubble to form in the tube bundle; or by removing energy from the RCS causing a contraction in RCS fluid and lowering of pressurizer level. Lowering of pressurizer level will result in depressurization in the range of [0-300 psia] by decompression of the pressurizer steam bubble.

Operator Actions

1. During a cooldown, the RCS is borated as necessary (success paths RC-2 and RC-3) to maintain shutdown margin per Technical Specifications.

2. RCS inventory is controlled so as to permit pressurizer level to lower during RCS fluid concentration. This drop in level results in pressurizer bubble decompression which in turns results in RCS depressurization. It is also possible to cool the pressurizer gradually by filling the pressurizer with cooler loop fluid by charging to the loop. The level is then allowed to drop due to cooldown contraction and then refilled with cooler loop fluid. Repeated fillings will cool the pressurizer metal and steam bubble resulting in gradual depressurization.

3. RCS depressurization should occur by feeding the steam generators with main or auxiliary feedwater and dumping steam to the condenser via the turbine bypass system. If the condenser or turbine bypass system is not available, steam should be discharged through the atmospheric dump valves.

   The use of atmospheric dump valves may have the potential for an unmonitored release of activity to the environment. If it is suspected that a steam generator(s) has tube leaks, then depressurization should be performed using the unaffected or least unaffected generator.

4. [To avoid damage to the steam generator feed ring the operator should control the auxiliary feed system.

If feed flow has not been interrupted, the feed ring is assumed to be filled and the operator should maintain S/G water level in the normal level.

If feed flow has ben interrupted and steam generator level is below the feed ring, then the operator should limit feedwater flow to 150 gpm for five minutes, or until an increase in S/G level has been observed.

There is no analytical correlation between feedwater flow rate and the conditions to preclude feed ring failure. A flow rate of 150 gpm has been recommended as a procedural limit based on the face that no significant water hammer has been observed during testing or operation with flow rates of that order. Additionally, 150 gpm has been traditionally accepted as a flow limit by industry and the NRC for water hammer protection. The five minute duration of this limited flow is conservatively based on twice the refill time for the 350 gallon feed ring. In the event that refilling of portions of the main feedwater piping must be considered this time would have to be adjusted accordingly.]

5. If all feedwater is lost (both main and auxiliary), then perform the following to keep the plant in a stable condition:

   a) Stop all RCPs to minimize heat input to the RCS.

   b) Any cooldown/depressurization is stopped to minimize steam discharge and conserve S/G inventories.

   c) If in operation, the steam generator blowdown system, secondary sampling system or any other nonvital secondary discharge must be secured. Until feedwater is reestablished, the steam generator water inventories must be conserved.

d) The operator should attempt to restore the operation of the main or auxiliary feedwater system to provide a primary decay heat sink for a controlled depressurization to meet the success criteria of this recovery action guideline.

A moderate rate of increase in steam generator water level is sufficient to restore S/G level. If the refill rate is too fast, excessive cooldown of the RCS and shrinkage of RCS inventory may result. Consequently, pressurizer level may fall below that required to maintain a bubble for pressure control. An adequate feed rate for restoring steam generator level is determined by operating experience.

e) [If both the main and auxiliary feedwater cannot be restored, then all plant specific sources of feedwater which could be made available to replace steam generator boil-off should be implemented. Examples of alternate sources of feedwater are fire pumps, condensate pumps, portable pumps, etc. When developing plant specific procedures, alternate sources of feedwater should be identified and their use should be indicated in the procedures. Guidelines on steam generator depressurization should be developed for those cases when the operator is relying on low pressure sources of feedwater as a backup feedwater supply.]

6. If feedwater is not available, then steam generators will not be available. Therefore, forced or natural circulation will not be effective for removing heat and, therefore, for reducing pressure. The operator is directed to another success path ([PORVs]) which does not rely on feedwater.

7. The available condensate inventory should be monitored and replenished from available sources as necessary to continually provide a source for a secondary heat sink. Examples of alternate sources of condensate are nonseismic tanks, fire mains, lake water supplies, potable tanks, etc. Plant specific alternate sources of feedwater should be identified and cited in the plant specific procedure.

After implementing the above actions, RCS Pressure control is satisfied if:

Pressurizer pressure is within the Post Accident P-T Curves of Figure 10-1.

RCS conditions within the limits of Figure 10-1 minimize PTS concern and assure a subcooled core cooling medium.

PC-5: *RCS Pressure Control via Natural Circulation with ADV or TBS Control*

If pressure cannot be reduced using the pressurizer sprays, and RCPs are not available, then RCS pressure can be reduced by removing heat via natural circulation and steam generators. This method may be effective by removing energy from steam generators, thereby preventing steam generators from causing a steam bubble to form in the tube bundle; or by removing energy from the RCS causing a contraction in RCS fluid and lowering of pressurizer level. Lowering of pressurizer level will result in depressurization in the range of [0-300 psia] by decompression of the pressurizer steam bubble.

Regions of little flow (e.g., reactor vessel head, idle steam generator) will not be cooled during natural circulation and may void if RCS pressure is lowered below the saturation pressure for these hotter regions. If voiding occurs, more RCS cooling will be required in order to effect a given depressurization. In the extreme, RCS pressure may lower to the saturation pressure value corresponding to the hottest fluid in the loops and reactor vessel.

Operator Actions

1. During any cooldown, the RCS is borated as necessary (success paths RC-2 and RC-3) to maintain shutdown margin per Technical Specifications.

2. RCS inventory is controlled so as to permit pressurizer level to lower during RCS fluid contraction. This drop in level results in pressurizer bubble decompression which in turn results in RCS depressurization.

   It is also possible to cool the pressurizer gradually by filling the pressurizer with cooler loop fluid by charging to the loop. The level is then allowed to drop due to cooldown contraction and then refilled with cooler loop fluid. Repeated fillings will cool the pressurizer metal and steam bubble resulting in gradual depressurization.

3. With all RCPs stopped, then operation of two RCPs (in opposite loops) should be attempted if the RCP restart criteria are met. Only one reactor coolant pump in each loop should be operated to minimize heat input to the RCS.

Determine whether RCP restart criteria are met by the following:

a) At least one steam generator is available for removing heat from the RCS. A steam generator having feed flow and removing heat from the RCS is an indication that primary to secondary heat removal is being maintained.

b) Pressurizer level is greater than [200"] and not decreasing. A higher pressurizer level will minimize the possibility of draining the pressurizer due to loop shrinkage and/or steam void condensation is minimized and there is a greater likelihood of keeping the pressurizer heaters covered. This will assist in maintaining positive RCS pressure control. The criterion of pressurizer level not decreasing implies that RCS inventory control has been established.

c) The RCS is greater than or equal to [20°F] subcooled. A subcooled condition taken in conjunction with (b) above indicates that inventory control has been established.

d) [All plant specific RCP operating criteria are satisfied before the RCPs are restarted to prevent damage to RCP operation and damage resulting from abnormal operating conditions. Following automatic or operator initiated containment isolation, reinstatement of component cooling water to the RCPs should be considered in order to ensure adequate RCP cooling.]

4. Upon restarting two RCPs in opposite loops, pressurizer level and pressure may decrease due to loop shrinkage and/or void condensation. It is possible that this action will drain the pressurizer. Steam voids

present in the reactor vessel will condense upon restarting RCPs. [The RVLMS should be monitored for the <u>trending</u> of reactor vessel liquid level. This trending information may be correlated to pressurizer level decrease.] RCP operation with a drained pressurizer may continue provided certain actions are taken and certain criteria are satisfied.

The following constitute the actions to be taken and the criteria to be satisfied when restarting RCPs:

a) Start one RCP in each loop.

b) [Ensure proper RCP operation by monitoring RCP amperage and pump NPSH. NPSH is determined by pressurizer pressure and corresponding T_c on Figure 9-1.]

c) Operate all available HPSI and charging pumps until pressurizer level is greater than [100"] and SIS termination criteria are met.

5. If at least one RCP has been restarted in a loop with a S/G having feed and steam flow capability, then the Forced Circulation with ADV or TBS Control Success Path should be used for Pressure Control.

6. If all RCP operation is terminated, then natural circulation is monitored by heat removal via at least one steam generator. Natural circulation flow should occur within 5-15 minutes after the RCPs were tripped if there is adequate inventory in the RCS.

   The RCS temperature response during natural circulation will usually be slow (5-15 minutes) as compared to a normal forced flow system response time of 6-12 seconds, since the coolant loop cycle time will be significantly larger.

   When single phase natural circulation is established in at least one loop the RCS indicates the following:

a) Loop ΔT (T_H - T_C) less than normal full power ΔT;
b) Cold leg temperatures constant or decreasing;
c) Hot leg temperatures stable (i.e. not steadily increasing) or slowly decreasing;
d) No abnormal differences between T_H RTDs and [core exit thermocouples]. Hot leg RTD temperatures should be consistent with the [core exit thermocouples]. Adequate natural circulation flow ensures that core exit thermocouples temperatures will be approximately equal to the hot leg RTDs temperature within the bounds of the instrument's inaccuracies. An abnormal difference between T_H and [the CETs] is greater than [10°F].

Natural circulation is governed by decay heat, component elevations, primary to secondary heat transfer, loop flow resistance, and voiding. Component elevations on C-E plants are such that satisfactory natural circulation decay heat removal is obtained by fluid density differences between the core region and the steam generator tubes.

7. If the criteria of step 6 are not met, then ensure RCS inventory, and S/G steaming and feeding being controlled properly.

8. Reactor plant depressurization should be performed preferentially by feeding the steam generators with main or auxiliary feedwater and dumping steam to the condenser via the turbine bypass system. If the condenser or turbine bypass system is not available, steam should be discharged through the atmospheric dump valves.

   The use of atmospheric dump valves may have the potential for release of activity to the environment. If it is suspected that a steam generator may be affected by a tube rupture, the natural circulation cooldown and depressurization should be performed using the unaffected or least affected generator.

9. [To avoid damage to the steam generator feed ring the operator should control the auxiliary feed system.
If feed flow has not been interrupted, then the feed ring is assumed to be filled and the operator should maintain S/G water level in the normal level band.
If feed flow has been interrupted and steam generator level is below the feed ring, then the operator should limit feedwater flow to 150 gpm for five minutes, or until an increase in S/G level has been observed.
There is no analytical correlation between feedwater flow rate and the conditions to preclude feed ring failure. A flow rate of 150 gpm has been recommended as a procedural limit based on the fact that no significant water hammer has been observed during testing or operation with flow rates of that order. Additionally, 150 gpm has been traditionally accepted as a flow limit by industry and the NRC for water hammer protection. The five minute duration of this limited flow is conservatively based on twice the refill time for the 350 gallon feed ring. In the event that refilling of portions of the main feedwater piping must be considered this time would have to be adjusted accordingly.]

10. The available condensate inventory should be monitored and replenished from available sources as necessary to continually provide a source for a secondary heat sink. Examples of alternate sources of condensate are non-seismic tanks, fire mains, lake water supplies, potable tanks, etc. Plant specific alternate sources of feedwater should be identified and cited in the plant specific procedure.

11. If all feedwater is lost (both main and auxiliary), then perform the following to keep the plant in a stable condition:

    a) To conserve steam generator inventory, any cooldown/depressurization is stopped.

b) If in operation, the steam generator blowdown system, secondary sampling system or any other nonvital secondary discharge must be secured. Until feedwater is reestablished, the steam generator water inventories must be conserved.

c) The operator should attempt to restore the correct operation of the main or auxiliary feedwater system to provide a primary decay heat sink for a controlled depressurization to meet the success criteria of this recovery action guideline.

A moderate rate of increase in steam generator water level is sufficient to restore S/G level. If the refill rate is too fast, excessive cooldown of the RCS and shrinkage of RCS inventory may result. Consequently, the pressurizer level may fall below that required to maintain a bubble for pressure control. An adequate rate for restoring S/G level is determined by operating experience.

d) [If both main and auxiliary feedwater cannot be restored, then all plant specific sources of feedwater which could be made available to replace steam generator boil-off should be implemented. Examples of alternate sources of feedwater are fire pumps, condensate pumps, portable pumps, etc. When developing plant procedures, alternate sources of feedwater should be identified and their use should be indicated in the plant specific procedures. Guidelines on steam generator depressurization should be developed for those cases when the operator is relying on low pressure sources of feedwater as a backup feedwater supply.]

12. If no feedwater is available, then the operator is directed to another success path ([PORVs]) which does not require feedwater.

13. If it is suspected that the isolated S/G has a tube leak and it appears that primary to secondary leakage will overfill the affected steam generator and lift secondary safeties or atmospheric dump valves, then the affected steam generator may be steamed to the condenser to reduce

fluid inventory and pressure. Consideration should be given to the fact that the steam from this S/G will be contaminated and will contaminate the secondary condenser, with possible activity release to atmosphere.

14. The operator should continuously monitor for the presence of RCS voiding and take steps to eliminate voiding any time voiding jeopardizes RCS heat removal via natural circulation. Voiding in the RCS may be indicated by any of the following indications, parameter changes, or trends: C

a) letdown flow greater than charging flow,
b) pressurizer level increasing significantly greater than expected while operating pressurizer spray,
c) [the RVLMS indicates that voiding is present in the reactor vessel],
d) [the HJTC unheated thermocouple temperature indicates saturated condition in the reactor vessel upper head]. A
e) [other indications insert here]

15. If voiding should be eliminated, then proceed as follows:

a) Letdown is isolated or verified to be isolated to minimize further inventory loss,
b) The depressurization is stopped to prevent further growth of the void and, if required, the RCS is repressurized to ≥[20°F] subcooling.
c) Pressurizing and depressurizing the RCS within the limits of Figure 10-1 may condense the void. Pressurizing has the effect of filling the voided portion of the RCS with cooler fluid which will remove heat from the region. Subsequent depressurization and a repeating of this process several times will cool and condense the steam void. In the case of a void in the reactor vessel, the pressurization/depressurization on cycle will produce a fill and drain of the reactor vessel. The pressurization/depressurization cycle may be accomplished using pressurizer heaters and spray (preferred method) or the SIS/charging system (alternative method). Monitor pressurizer level [and the RVLMS] for trending of RCS inventory. This will assist the operator in assessing the effectiveness of void elimination.

fluid inventory and pressure. Consideration should be given to the fact that the steam from this S/G will be contaminated and will contaminate the secondary condenser, with possible activity release to atmosphere.

14. The operator should continuously monitor for the presence of RCS voiding and take steps to eliminate voiding any time voiding jeopardizes RCS heat removal via natural circulation. Voiding in the RCS may be indicated by any of the following indications, parameter changes, or trends:

    a) letdown flow greater than charging flow,
    b) pressurizer level increasing significantly greater than expected while operating pressurizer spray,
    c) [the RVLMS indicates that voiding is present in the reactor vessel],
    d) [HJTC unheated thermocouple temperature indicates saturated condition in the reactor vessel upper head].
    e) [other indications insert here]

A

15. If voiding should be eliminated, then proceed as follows:

    a) Letdown is isolated or verified to be isolated to minimize further inventory loss,
    b) The depressurization is stopped to prevent further growth of the void and, if required, the RCS is repressurized to ≥[20°F] subcooling.
    c) Pressurizing and depressurizing the RCS within the limits of Figure 10-1 may condense the void. Pressurizing has the effect of filling the voided portion of the RCS with cooler fluid which will remove heat from the region. Subsequent depressurization and a repeating of this process several times will cool and condense the steam void. In the case of a void in the reactor vessel, the pressurization/depressurization on cycle will produce a fill and drain of the reactor vessel. The pressurization/depressurization cycle may be accomplished using pressurizer heaters and spray (preferred method) or the SIS/charging system (alternative method). Monitor pressurizer level [and the RVLMS] for trending of RCS inventory. This will assist the operator in assessing the effectiveness of void elimination.

d) If indications of unacceptable RCS voiding continue, and voiding is suspected to exist in the (isolated) steam generator tubes, then cool the (isolated) steam generator (by steaming or blowdown, and/or feeding) to condense the tube bundle void. This will be effective for condensing steam voids but will not have an effect on non-condensible gases trapped in the tube bundle. A buildup of non-condensible gases in the tube bundles will not hinder natural circulation even with a large number of the tubes blocked. This is due to the small amount of heat transfer area required for the removal of decay heat. Monitor pressurizer level for trending of RCS inventory. This will assist the operator in assessing the effectiveness of void elimination.

e) If indications of unacceptable RCS voiding continue, then voiding may be caused by non-condensible gases. [Operate the pressurizer vent and/or the reactor vessel head vent to clear trapped non-condensible gases.] Monitor pressurizer level [and/or the RVLMS] for trending of RCS inventory. This will assist the operator in assessing the effectiveness of void elimination.

After implementing the above actions, RCS Pressure Control is satisfied if:

Pressurizer pressure is within the limits of the Post Accident P-T Curves of Figure 10-1.

RCS conditions within the limits of Figure 10-1 minimize PTS concern and assure a subcooled core cooling medium.

PC-6: *RCS Pressure Control via [PORV's]*

The [PORV's] may be used to relieve RCS pressure by manually opening them to provide bleed off from the RCS to the quench tank.

Operator Actions

1. The [PORV's] are verified to automatically open at [2400 psia]. If [PORV's] have not opened, they are manually opened and pressure is reduced to <[2340 psia] and to within the limits of Fig. 10-1. The [PORVs] may be manually operated at any plant pressure to lower pressure as an alternative to pressurizer spray and other pressure reducing success paths.

2. SIS operation must be verified if pressurizer pressure decreases to [1600 psia, or if containment pressure increases to 4 psig]. If safety injection system operation has not commenced automatically on high containment pressure [4 psig] or when RCS pressure is below [1600 psig], then it must be manually actuated. This action restores inventory so that pressure can be controlled by use of either pressurizer heaters and spray or by using the discharge head of the SIS.

3. If pressurizer pressure goes below [1300 psia] following receipt of an SIAS, then all four RCPs must be tripped. Two RCPs may have been tripped already in the Standard Post Trip Actions. In this case, the operator would simply trip the remaining two RCPs. Since prolonged RCP operation during LOCAs of certain size and location could result in increasing the severity of the event, tripping all four RCPs ensures a conservative approach to event recovery. This is due to the fact that, when the operators implement the FRG they have not determined what event is occurring. An LOCA may be the lone event which is occurring or it may be occurring in conjunction with other event(s). Since operators cannot be

sure what event is occurring, they are instructed to trip all RCPs whenever they are implementing the FRG and pressurizer pressure decreases to less than [1300 psia] following an SIAS. This is a conservative approach designed to satisfy worst case analysis.

After implementing of the above actions, RCS Pressure Control is satisfied if [pressurizer pressure is:

a. less than [2340 psia] and constant or decreasing

<u>and</u>

b. within the limits of the Post Accident P-T limits of Figure 10-1.]

The value [2340 psia] is the high pressure alarm setpoint. Best estimate analysis shows that analyzed events will fall within the above range. It also provides some margin to primary safety valve setpoints. RCS conditions within the limits of Figure 10-1 ensures a subcooled heat transfer medium for the core and minimizes PTS concerns.

Continuing Actions For Pressure Control

If RCS pressure control is still in jeopardy, then the operator must continue attempting RCS pressure control while pursuing other safety functions in jeopardy.

SAFETY FUNCTION: RCS and Core Heat Removal
SUCCESS PATH: Forced Circulation, No SIS Operation; HR-1
RESOURCE TREE: Tree E

OPERATOR ACTIONS

*1. Borate the plant as necessary, while cooling down, in order to maintain shutdown margin per Technical Specification Limits (Refer to RC-2 and RC-3). SK control

2. Perform an orderly plant cooldown/depressurization in order to meet the acceptance criteria of this success path by performing one of the following:

   a) If the condenser, and either [main or auxiliary] feedwater systems are available, then cooldown and depressurize using the turbine bypass system

   or

   b) If the condenser or turbine bypass systems are not available, then cooldown and depressurize using at least one steam generator via the atmospheric dump valve(s) and either [main or auxiliary] feedwater.

*3. [If the auxiliary feedwater system (AFW) is started, Then perform the following to prevent steam generator feed ring damage:

   a) If S/G water level is above the feed ring, then stop redundant AFW pumps, restore S/G level, and maintain it in the normal level band.
   b) If feedwater flow to an S/G has been interrupted and indicated S/G water level is below the feed ring, then:

* Step performed continuously.

4. IMPLEMENTED IN STEP VI.B.5. SEE DEVIATION 8-22.

5. IMPLEMENTED IN STEP VI.B.4. PROCEDURE DOES NOT CONTAIN ADMINISTRATIVE DIRECTIONS such as that contained in the step (per THE EOP writer's guide). TRAINING is USED TO ENSURE OPERATORS are FAMILIAR with the content of each procedure, and the possible success paths AVAILable to handle each safety function.

6. implemented IN step VI.B.7 AND SAFETY FUNCTION STATUS CHECK

i) Stop redundant AFW pumps and limit feedwater flow rate to 150 gpm per affected S/G until an increase in S/G level has been observed, or until continuous feedwater flow has been maintained for five minutes.

ii) Modulate AFW flow rate as necessary to restore, and maintain, S/G water level to the normal level band].

*4. If all feedwater (main and auxiliary) is lost, Then conduct the following:

a) Stop all RCPs w/ VARIATION

b) Stop the cooldown

c) Secure steam generator blowdown, secondary sampling, and any non-vital steam discharge.

d) Take actions to regain [main or auxiliary] feedwater system operation.

e) [If other sources of water are available for steam generator heat removal, then insert that information here.]

*5. If feedwater cannot be regained, Then go to HR-4, RCS and Core Heat Removal via Once-Through-Cooling.

*6. If the auxiliary feedwater system is being used, Then ensure an adequate supply of condensate exists (Refer to Figures 10-4 and 10-5). SFSC

* Step performed continuously.

1a. implemented in safety function status check for core/RCS heat Removal. SEE DEVIATION 8-31 FOR FEEDWATER FLOW.

1b. implemented in SFSC for core/RCS heat removal.

1c See Deviation 8-31

1d implemented in SFSC for PRESS/INV parameters

1e See Deviation 8-27

for ADMINISTRATIVE ACTIONS SEE DEVIATION 8-17

2. SEE DEVIATION 8-2

Acceptance Criteria for RCS and Core Heat Removal: HR-1

1. RCS and Core Heat Removal is satisfied if:

   a. At least one S/G has level:
      i) within the normal level band with feedwater available to maintain level
      or
      ii) being restored by a feedwater flow greater than [150 gpm]
      and
   b. $T_H - T_C$ is less than [10°F] and not increasing
      and
   c. T_{ave} is less than [545°F] and not increasing
      and
   d. The RCS is at least [20°F] subcooled [by CET]
      and
   e. [No reactor vessel voiding as indicated by the RVLMS].

   If the above criteria are met, Then proceed to the next safety function in jeopardy.
   If all safety functions are being satisfied, Then implement the Long Term Actions.

2. If the above criteria are not met, Then proceed to the next appropriate success path on Resource Tree E.

1. IMPLEMENTED IN GENERAL PRECAUTION III.A

2. IMPLEMENTED IN GENERAL PRECAUTION III.B

3. implemented in SFSC for RCS/core heat removal, and press/inv (Requirement to be w/in P-T curves), AND PRECAUTION VI.A.1.

4. See DEVIATION 8-32

5. implemented IN VI.A.2

SUPPLEMENTARY INFORMATION: HR-1

This section contains items which should be considered when implementing EPGs and preparing plant specific EOPs. The items should be implemented as precautions, cautions, notes, or in the EOP training program.

1. Do not place system "manual" unless misoperation in "automatic" is apparent. Systems placed in "manual" must be checked frequently to ensure proper operation.

2. All available indications should be used to aid in the evaluation of plant conditions since the accident may cause irregularities in a particular instrument reading. Instrument readings must be corroborated when one or more confirmatory indications are available.

3. Continuously monitor RCS temperature and pressure to avoid exceeding a heat removal rate greater than Technical Specification Limitations. If the heat removal rate exceeds Technical Specification Limits, there may be a potential for pressurized thermal shock (PTS) of the reactor vessel, unless Post Accident Pressure/Temperature Limits are maintained (Figure 10-1).

done by safety function

4. Solid water operation of the pressurizer may make it difficult to control RCS pressure and therefore should be avoided unless [20°F] of subcooling cannot be maintained in the RCS (Figure 10-1). If the RCS is solid, closely monitor any makeup or draining and any system heatup or cooldown to avoid any unfavorable pressure excursions.

press control

5. The operator should not add feedwater to a dry steam generator if another steam generator still contains water. Re-establish feedwater only to the steam generator that is not dry. If both steam generators become dry, then refill only one steam generator to reinitiate core cooling.

1. IMPLEMENTED IN IV.B.3 AND IV.B.5. See DEVIATION 8-18 for differences IN LOCATION IN procedure.

2. implemented in VI.B.4

3. IMPLEMENTED IN VI.B.4

SAFETY FUNCTION: RCS and Core Heat Removal
SUCCESS PATH: Natural Circulation, No SIS Operation; HR-2
RESOURCE TREE: Tree E

OPERATOR ACTIONS

*1. Borate the plant as necessary, while cooling down, in order to maintain shutdown margin per Technical Specification Limits (refer to RC-2 and RC-3). ṘK control

*2. Determine whether RCP restart criteria are met by the following:

   a) At least one steam generator (feed and steam flow) is available for RCS heat removal.
   b) Pressurizer level greater than [200"] and not decreasing
   c) The RCS is at least [20°F] subcooled (Figure 10-1)
   d) [Other criteria satisfied per RCP operating instructions].

*3. If RCP restart criteria are met, Then do the following:

   a) Start one RCP in each loop
   b) [Ensure proper RCP operation by monitoring RCP amperage and pump NPSH. NPSH is determined by pressurizer pressure and corresponding T_c on Figure 10-1].
   c) Operate all available charging pumps until pressurizer level is greater than [100"]. INVENTORY function

* Step performed continuously.

4. See Deviation 8-17

5. implemented in VI.B.4

6. IMPLEMENTED IN SFSC Regardless of whether natural circulation has been CONFIRMED.

7. IMPLEMENTED IN STEPS VI.B.6, VI.B.7, VI.B.9

*4. If at least one RCP has been restarted in a loop with a S/G having feed and steam flow capability, Then go to HR-1, Forced Circulation, No SIS Operation.

*5. If all RCPs are tripped, Then verify that natural circulation is being maintained in at least one loop by the following:

a) Loop ΔT (T_H - T_C) less than normal full power ΔT
b) Cold leg temperatures constant or decreasing
c) Hot leg temperatures stable (i.e., not steadily increasing) or decreasing slowly
d) No abnormal differences between T_H RTDs and [core exit thermocouples].

*6. If the criteria of step 5 are not met, Then ensure RCS inventory and pressure, and S/G steaming and feeding, are being controlled properly.

7. Perform an orderly plant cooldown/depressurization in order to meet the acceptance criteria of this success path by performing one of the following:

a) If the condenser, and either [main or auxiliary] feedwater systems are available, then cooldown and depressurize using the turbine bypass system

or

b) If the condenser or turbine bypass systems are not available, then cooldown and depressurize using at least one steam generator via the atmospheric dump valve(s) and either [main or auxiliary] feedwater.

* Step performed continuously.

8. see DEVIATION 8-20

9 implemented in step VI.B.7 and SFSC

10. implemented in step VI.B.5. see DEVIATION 8-22

#.

*8. [If the auxiliary feedwater system (AFW) is started, Then perform the following to prevent S/G feed ring damage:

a) If S/G water level is above the feed ring, then stop redundant AFW pumps, restore S/G level, and maintain it in the normal level band.

b) If feedwater flow to an S/G has been interrupted and indicated S/G water level is below the feed ring, then:

i) Stop redundant AFW pumps and limit feedwater flow rate to 150 gpm per affected S/G until an increase in S/G level has been observed, or until continuous feedwater flow has been maintained for five minutes.

ii) Modulate AFW flow rate as necessary to restore, and maintain, S/G water level to the normal level band].

*9. If the auxiliary feedwater system is being used, Then ensure that an adequate supply of condensate exists (refer to Figures 10-4 and 10-5).

*10. If all feedwater (main and auxiliary) is lost, Then conduct the following:

If you knew this the event based procedure would be implemented

a) Stop the cooldown ?

b) Isolate steam generator blowdown, secondary sampling and any non-vital steam discharge.

c) Take actions to regain [main or auxiliary] feedwater system operation.

d) [If other sources of water are available for steam generator heat removal, then insert that information here].

* Step performed continuously.

11. implemented in step IV.B.4. Procedure does not contain administrative directions such as that contained in this step (per the EOP writer's guide). Training is used to ensure operators are familiar with the content of each procedure, and the possible success paths available to handle each safety function.

12. See Deviation 8-26

13. implemented in step VI.B.4

14. implemented in step VI.B.4

*11. If feedwater cannot be regained, Then go to HR-4, RCS and Core Heat Removal via Once-Through-Cooling.

12. If one steam generator was isolated, and primary to secondary leakage is suspected, Then unisolate and steam the affected S/G to the condenser to prevent overfilling due to the primary to secondary leakage.

*13. Monitor for the presence of RCS voiding and take steps to eliminate voiding any time voiding jeopardizes natural circulation heat removal. Voiding in the RCS may be indicated by any of the following indications, parameter changes, or trends: C

a) letdown flow greater than charging flow,
b) pressurizer level increasing significantly greater than expected while operating pressurizer spray,
c) [the RVLMS indicates that voiding is present in the reactor vessel]
d) [HJTC unheated thermocouple temperature indicates saturated conditions in the reactor vessel upper head]. A
e) [Other indications insert here].

*14. If voiding should be eliminated, Then proceed as follows:

a) verify letdown is isolated,
b) stop the depressurization and, if required, repressurize the RCS to $\geq$ [20°F] subcooling,
c) pressurize and depressurize the RCS within the limits of Figure 10-1 by operating pressurizer heaters and spray (preferred method) or HPSI and charging pumps (alternative method). Monitor pressurizer level [and the RVLMS for trending of RCS inventory].
d) if indications of unacceptable RCS voiding continue, and voiding is suspected to exist in the (isolated) steam generator tubes, then cool the (isolated) steam generator (by steaming or blowdown, and/or feeding) to condense the steam generator tube bundle void. Monitor pressurizer level for trending of RCS inventory.

* Step performed continuously.

e) if indications of unacceptable RCS voiding continue, then [operate the pressurizer vent and/or the reactor vessel head vent to] clear trapped non-condensible gases. Monitor pressurizer level [and/or the RVLMS] for trending of RCS inventory.

1a. IMPLEMENTED IN SFSC CHECK FOR CORE/RCS HEAT REMOVAL. SEE DEVIATION 8-31 FOR FEEDWATER FLOW.

1b. IMPLEMENTED IN SFSC FOR CORE/RCS HEAT REMOVAL.

1c. SEE DEVIATION 8-31

1d. IMPLEMENTED IN SFSC FOR PRESS/INV CONTROL

FOR ADMINISTRATIVE ACTIONS SEE DEVIATION 8-17

2. SEE DEVIATION 8-2

Acceptance Criteria for RCS and Core Heat Removal: HR-2

1. RCS and Core Heat Removal is satisfied if:

    a) At least one S/G has level:
        i) within the normal level band with feedwater available to maintain level

        or

        ii) being restored by a feedwater flow greater than [150 gpm]

        and

    b) $T_H - T_c$ is less than [50°F] and not increasing

        and

    c) T_{ave} is less than [545°F] and not increasing

        and

    d) The RCS is at least [20°F] subcooled [by CET].

    If the above criteria are met, Then proceed to the next safety function in jeopardy.
    If all safety functions are being satisfied, Then implement the Long Term Actions.

2. If the above criteria are not met, Then proceed to the next appropriate success path on Resource Tree E.

1. implemented IN PRECaution VI.A.3 AND STEP VI.B.4.

2. implemented in Precaution VI.A.3

3. IMPLEMENTED IN PRECAUTION VI.A.1

4. implemented in precaution VI.A.4

5. implemented in general precaution III.B

SUPPLEMENTARY INFORMATION: HR-2

This section contains items which should be considered when implementing EPGs and preparing plant specific EOPs. The times should be implemented as precautions, cautions, notes, or in the EOP training program.

1. Natural circulation flow should not be verified until the RCPs have stopped coasting down after being tripped. PROC. INCORPORATES 10 M TIME DELAY

2. Verification of temperature responses to a plant change cannot be accomplished until approximately 5 to 15 minutes following the action due to increased loop cycle times during natural circulation.

3. Continuously monitor RCS temperature and pressure to avoid exceeding a heat removal rate greater than Technical Specification Limitations. If the heat removal rate exceeds Technical Specification Limits, there may be a potential for pressurized thermal shock (PTS) of the reactor vessel unless Post-Accident Pressure/Temperature Limits are maintained (Figure 10-1).

4. If cooling down by natural circulation with an isolated steam generator, an inverted ΔT (i.e., T_c higher than T_h) may be observed in the idle loop. This is due to a small amount of reverse heat transfer in the isolated steam generator and will have no affect on natural circulation flow in the operating stem generator loop.

5. All available indications should be used to aid in the evaluation of plant conditions since the accident may cause irregularities in a particular instrument reading. Instrument readings must be corroborated when one or more confirmatory indications are available.

6. implemented IN precaution V.A.2. SEE DEVIATION 8-32 FOR LOCATION DIFFERENCE.

7 See DEVIATION 8-16

8. implemented IN STEP VI.B.4

6. Solid water operation of the pressurizer may make it difficult to control RCS pressure and therefore should be avoided unless [20°F] of subcooling cannot be maintained in the RCS (Figure 10-1). If the RCS is solid, closely monitor any makeup or drainage and any system heatup or cooldown to avoid any unfavorable pressure excursions. *included under press. cont.*

7. When a void exists in the reactor vessel, and RCPs are not operating, the RVLMS provides an accurate indication of reactor vessel liquid inventory. when a void exists in the reactor vessel, and RCPs are operating, it is not possible to obtain an accurate reactor vessel liquid level indication due to the effect of the RCP induced pressure head on the RVLMS. The indicated level also differs from different RVLMS designs under these conditions. Information concerning reactor vessel liquid inventory trending may still be discerned. However, operators are cautioned not to rely solely on the RVLMS indication when RCPs are operating. *not currently installed*

8. The operator should continuously monitor for the presence of RCS voiding and take steps to eliminate voiding any time voiding causes the heat removal or inventory control safety functions to begin to be threatened. Void elimination should be started soon enough to ensure heat removal and inventory control are not lost. C

1. implemented in step V.B.2 and VIII.B.1. See Deviation 8-34 for location difference.

2. implemented in step VI.B.3

3. see Deviation 8-35

4. see Deviation 8-35

5. implemented in step VI.B.4

SAFETY FUNCTION: RCS and Core Heat Removal

SUCCESS PATH: S/G Heat Sink, SIS Operation; HR-3

RESOURCE TREE: Tree E

OPERATOR ACTIONS

*1. If pressurizer pressure decreases to [1600 psia, or if containment pressure increases to 4 psig], Then verify that an SIAS has been initiated.
If the SIAS has not initiated automatically, Then manually initiate an SIAS.

*2. If pressurizer pressure decreases to less than [1300 psia] (1740 trip 2) following an SIAS, Then ensure all RCPs are tripped. (trip remaining)

*3. If the SIS is operating, Then it may be throttled or stopped, one train at a time, if the following criteria are satisfied:

(This is just done in FRG. Need to go to event proc. for actual recovery — FRG should keep these on all the way to SDC)

a) The RCS is at least [20°F] subcooled
b) Pressurizer level is greater than [100"] and constant or increasing
c) At least one steam generator is available (feed and steam flow) for removing heat from the RCS
d) [The RVLMS indicates the core is covered].

*4. If the criteria of step 3 cannot be maintained after the SIS has been stopped, Then the SIS must be restarted.

*5. If all RCPs were stopped, Then one RCP in each loop should be restarted if possible.

Determine whether RCP restart criteria are met by the following:

* Step performed continuously.

6. implemented IN STEP VI.B.4

7. IMPLEMENTED IN STEP VI.B.4

8. IMPLEMENTED BY SFSC. THE STA is directed by procedure and training to perform the SFSC ~ every 10 minutes. This action implements the intent of step 8. Repetition of administrative requirements within a procedure is contrary to the writer's guide. This guideline is used to ensure the procedures are as directly related to plant control as possible.

9. implemented in steps VI.B.6 AND VI.B.9

a) At least one steam generator (feed and steam flow) is available for RCS heat removal
b) Pressurizer level is greater than [200"] and not decreasing
c) The RCS is at least [20°F] subcooled (Figure 10-1)
d) [Other criteria satisfied per RCP operating instructions].

*6. If RCP restart criteria are met, Then do the following:

a) Start one RCP in each loop
b) [Ensure proper RCP operation by monitoring RCP amperage and pump NPSH. NPSH is determined by pressurizer pressure and corresponding T_C on Figure 10-1].
c) Operate HPSI (Figure 10-3) and charging pumps until pressurizer level is greater than [100"] and SIS termination criteria are met.

*7. If all RCPs are stopped, Then verify that natural circulation is being maintained in at least one loop by the following:

a) Loop ΔT (T_H - T_C) less than normal full power ΔT
b) Cold leg temperatures constant or decreasing
c) Hot leg temperatures stable (i.e., not steadily increasing) or decreasing slowly
d) No abnormal differences between T_H RTDs and [core exit thermocouples].

*8. If the criteria of step 7 are not met, Then ensure RCS inventory and pressure, and S/G steaming and feeding, are being controlled properly.

9. Perform an orderly plant cooldown/depressurization in order to meet the acceptance criteria of this success path by performing one of the following:

* Step performed continuously.

10. SEE DEVIATION 8-20.

11. implemented in RCS/CORE HEAT REMOVAL SFSC.

12. implemented in step VI.B.5; STEP 12E implemented in VI.B.7 AND VI.B.8

a) If the condenser, and either [main or auxiliary] feedwater systems are available, then cooldown and depressurize using the turbine bypass system.

<u>or</u>

b) If the condenser or turbine bypass systems are not available, then cooldown and depressurize using at least one steam generator via the atmospheric dump valve(s) and either [main or auxiliary] feedwater.

*10. [<u>If</u> the auxiliary feedwater system (AFW) is started, <u>Then</u> perform the following to prevent S/G feed ring damage: ✓

a) If S/G water level is above the feed ring, then stop redundant AFW pumps, restore S/G level, and maintain it in the normal level band.

b) If feedwater flow to an S/G has been interrupted and indicated S/G water level is below the feed ring, then:

i) Stop redundant AFW pumps and limit feedwater flow rate to 150 gpm per affected S/G until an increase in S/G level has been observed, or until continuous feedwater flow has been maintained for five minutes.

ii) Modulate AFW flow rate as necessary to restore, and maintain, S/G water level to the normal level band].

*11. <u>If</u> the auxiliary feedwater system is being used, <u>Then</u> ensure an adequate supply of condensate exists (refer to Figures 10-4 and 10-5). ✓

*12. <u>If</u> all feedwater (main and auxiliary) is lost, <u>Then</u> conduct the following: event specific ?

a) Stop all RCPs

b) Stop the cooldown

* Step performed continuously.

13. SEE DEVIATION 8-36

14. IMPLEMENTED IN V.B.2. See DEVIATION 8-37 for location difference.

15 implemented in V.B.6. see DEVIATION 8-37 for location difference.

c) Isolate S/G blowdown, secondary sampling, and any non-vital steam discharge

d) Take action to regain [main or auxiliary] feedwater system operation

e) [If other sources of water are available for steam generator heat removal, then insert that information here].

*13. If feedwater cannot be regained in at least one operable steam generator, then go to HR-4, RCS and Core Heat Removal via Once-Through-Cooling. ✓

*14. Monitor [refueling water tank] level.
If the [refueling water tank] level falls to [10%], Then verify initiation of recirculation. CONT. INVENTORY SF.

- If necessary, manually initiate recirculation one SIS train at a time [and close RWT outlet valves to the safety injection system].

*15. If the HPSI pumps are delivering less than [30 gpm] per pump during recirculation, Then turn off one charging pump at a time until the HPSI pumps are delivering more than [30 gpm] per pump. If the minimum HPSI pumps delivery flow is still not met with all charging pumps off, then turn off the HPSI pump with the lower indicated flow. INVENTORY ?

* Step Performed Continuously

1a. IMPLEMENTED IN SFSC FOR CORE/RCS HEAT REMOVAL. SEE DEVIATION 8-31 FOR feedwater flow.

1b. implemented in core/RCS heat removal SFSC

1c. implemented in press/INV. SFSC

FOR ADMINISTRATIVE ACTIONS SEE DEVIATION 8-17

2. See deviation 8-2

Acceptance Criteria for RCS and Core Heat Removal: HR-3

1. RCS and Core Heat Removal is satisfied if:

   a) At least one S/G has level:
      i) within the normal level band with feedwater available to maintain level

      or

      ii) being restored by a feedwater flow rate greater than [150 gpm].

      and

   b) [CET] temperature less than [700°F] or decreasing

      and

   c) [All available charging pumps are operating and] the SIS pump(s) are injecting water into the RCS per Figure 10-3 (unless SIS termination criteria are met).

   If the above criteria are met, Then proceed to the next safety function in jeopardy.
   If all safety functions are being satisfied, Then implement the Long Term Actions.

2. If the above criteria are not met, Then proceed to the next appropriate success path on Resource Tree E.

* Step performed continuously.

1. Implemented in GENERAL Precaution III.A

2. Implemented in GENERAL Precaution III.B. see DEVIATION 8-41 for RTD effects

3. Implemented in step V.A.2. See DEVIATION 8-32 FOR LOCATION difference.

4. implemented in V.B.4, V.B.5, AND V.B.6. Containment level is periodically checked in Containment ENVIRONMENT SFSC, see DEVIATION 8-37 for location difference.

5. See DEVIATION 8-16

SUPPLEMENTARY INFORMATION: HR-3

This section contains items which should be considered when implementing EPGs and preparing plant specific EOPs. The items should be implemented as precautions, cautions, notes, or in the EOP training program.

1. Do not place system in "manual" unless misoperation in "automatic" is apparent. Systems placed in "manual" must be checked frequently to ensure proper operation.

2. All available indications should be used to aid in evaluation of plant conditions since the accident may cause irregularities in a particular instrument reading. Instrument readings must be corroborated when one or more confirmatory indications are available. Hot and cold leg RTDs may be influenced by the cold SIS injection and should be checked against each other.

3. Solid water operation of the pressurizer may make it difficult to control RCS pressure and therefore should be avoided unless [20°F] of subcooling cannot be maintained in the RCS. If the RCS is solid, closely monitor any makeup or draining and any system heatup or cooldown to avoid any unfavorable pressure excursions. contained in PRESS/INV funct.

4. The operator should be cautioned against prematurely initiating an RAS. The operator should check containment sump level to ensure adequate suction for the SIS before switching to recirculation. This manual action should not be taken unless an automatic RAS is required. cont. in proc.

5. When a void exists in the reactor vessel, and RCPs are not operating, the RVLMS provides an accurate indication of reactor vessel liquid inventory. not installed
When a void exists in the reactor vessel, and RCPs are operating, it is not possible to obtain an accurate reactor vessel liquid level indication

6. implemented in step VI.B.4

due to the effect of the RCP induced pressure head on the RVLMS. The indicated level also differs from different RVLMS designs under these conditions. Information concerning reactor vessel liquid inventory trending can still be discerned. However, operators are cautioned not to rely solely on the RVLMS indication when RCPs are operating.

6. The operator should continuously monitor for the presence of RCS voiding and take steps to eliminate voiding any time voiding causes the heat removal or inventory control safety functions to begin to be threatened. Void elimination should be started soon enough to ensure heat removal and inventory control are not lost. C

1. implemented in step V.B.2 AND VIII.B.1, See Deviation 8-34 for LOCATION difference..

2. implemented in VI.B.3.

3. implemented in STEP VI.B.4

4. SEE DEVIATION 8-38

SAFETY FUNCTION: RCS and Core Heat Removal
SUCCESS PATH: Once-Through-Cooling; HR-4
RESOURCE TREE: Tree E

OPERATOR ACTIONS

*1. If pressurizer pressure decreases to [1600 psia, or if containment pressure increases to 4 psig], Then verify that an SIAS has been initiated.
If the SIAS has not initiated automatically, Then manually initiate an SIAS.

*2. If pressurizer pressure decreases to less than [1300 psia] following an SIAS, Then ensure all RCPs are tripped.

3. Establish once-through-cooling through the [PORVs] (or, if present, through a break in the RCS boundary) by performing the following:

a) Ensure all RCPs are stopped
b) Start all available HPSI and charging pumps
c) Open the [PORVs].

*4. If the following criteria are satisfied, Then SIS operation may be terminated (thus securing once through cooling): CONT. IN PRESS/INV

a) [CET] temperature is less than [700°F]
b) The RCS is at least [20°F] subcooled
c) At least one steam generator is available (feed and steam flow) for removing heat from the RCS
d) [The RVLMS indicates the core is covered].

* Step performed continuously.

5. see deviation 8-38

6. implemented in V.B.2. See Deviation 8-37 for location difference

7. implemented in V.B.6. See Deviation 8-37 for location difference

*5. If the criteria of step 4 cannot be maintained after the SIS has been stopped, Then the SIS must be restarted.

*6. Monitor [refueling water tank (RWT)] level. press/INV
If the [RWT] level falls to [10%], Then verify initiation of recirculation.
If necessary, manually initiate recirculation one train at a time [and close RWT outlet valves to the safety injection system].

*7. If the HPSI pumps are deliverying less than [30 gpm] per pump during recirculation, Then turn off one charging pump at a time until the HPSI pumps are delivered more than [30 gpm] per pump. If the minimum HPSI pump delivery flow is still not met with all charging pumps off, then turn off the HPSI pump with the lower indicated flow. press/INV.

* Step performed continuously.

1A. IMPLEMENTED IN CORE/RCS HEAT REMOVAL SFSC

1B. IMPLEMENTED IN PRESS/INV SFSC

FOR ADMINISTRATIVE ACTIONS SEE DEVIATION 8-17

2 SEE DEVIATION 8-2.

Acceptance Criteria for RCS and Core Heat Removal: HR-4

1. RCS and Core Heat Removal is satisfied if:

   a) [CET] temperature is less than [700°F] or decreasing

   and

   b) [All available charging pumps are operating and] the SIS pump(s) are injecting water into the RCS per Figure 10-3 (unless SIS termination criteria are met)

   and

   c) Pressurizer pressure is less than [1300 psia] or decreasing.

   If the above criteria are met, Then proceed to the next safety function in jeopardy.
   If all safety functions are being satisfied, Then implement the Long Term Actions.

2. If the above criteria are not met, Then re-evaluate the availability of success paths HR-1, 2, and 3, and refer to Continuing Actions for RCS and Core Heat Removal.

1. implemented in General Precaution III.A.

2. implemented in GENERAL PRECAUTION III.B. see DEVIATION 8-41 for RTD effects

3. implemented in V.A.2. See DEVIATION 8-32 FOR LOCATION DIFFERENCE.

4 implemented in V.B.4, V.B.5, V.B.6. Containment level is periodically checked in Containment Environment SFSC. See Deviation 8-37 for LOCATION difference.

SUPPLEMENTARY INFORMATION: HR-4

This section contains items which should be considered when implementing EPGs and preparing plant specific EOPs. The items should be implemented as precautions, cautions, notes, or in the EOP training program.

1. Do not place system in "manual" unless misoperation in "automatic" is apparent. Systems placed in "manual" must be checked frequently to ensure proper operation.

2. All available indications should be used to aid in evaluation of plant conditions since the accident may cause irregularities in a particular instrument reading. Instrument readings must be corroborated when one or more confirmatory indications are available. Hot and cold leg RTDs may be influenced by the cold SIS injection and should be checked against each other.

3. Solid water operation of the pressurizer may make it difficult to control RCS pressure and therefore should be avoided unless [20°F] of subcooling cannot be maintained in the RCS. If the RCS is solid, closely monitor any makeup or draining and any system heatup or cooldown to avoid any unfavorable pressure excursions. press/INV

4. The operator should be cautioned against prematurely initiating an RAS. The operator should check containment sump level to ensure adequate suction for theSIS before switching to recirculation. This manual action should not be taken unless an automatic RAS is required. PRESS/INV

1. implemented in step VI.B.II. See Deviation 8-39 FOR CRITERIA

2. implemented in VI.B.4

SAFETY FUNCTION: RCS and Core Heat Removal
SUCCESS PATH: Shutdown Cooling System; HR-5
RESOURCE TREE: Tree E

OPERATOR ACTIONS

*1. If the following criteria are met, Then initiate shutdown cooling per SCS operating instructions:

a) RCS T_H is cooled down to at least [300°F]
b) The RCS is depressurized to at least [300 psia]
c) Pressurizer level is greater than [100"] and not decreasing
d) The RCS is at least [20°F] subcooled
e) RCS activity level within [appropriate limits]
f) [Other plant specific criteria, insert here].

*2. If voiding inhibits RCS depressurization to SCS entry pressure, Then an attempt at eliminating the voiding should be made. included as a result of N.C

Voiding in the RCS may be indicated by any of the following indications, parameter changes, or trends:

a) letdown flow greater than charging flow,
b) pressurizer level increasing significantly greater than expected while operating pressurizer spray,
c) [the RVLMS indicates that voiding is present in the reactor vessel],
d) [HJTC unheated thermocouple temperature indicates saturated conditions in the reactor vessel upper head].
e) [other indications insert here]. A

* Step performed continuously.

3. implemented in step VI.B.4

4 implemented in step VI.B.11

5 implemented in OP-5

6 implemented in OP-5

*3. If voiding should be eliminated, Then proceed as follows:

included as a funct. of NAT. CIRC

a) verify letdown is isolated,
b) stop the depressurization and, if required, repressurize the RCS to $\geq$ [20°F] subcooling,
c) pressurize and depressurize the RCS within the limits of Figure 10-1 by operating pressurizer heaters and spray (preferred method) or HPSI and charging pumps (alternative method). Monitor pressurizer level [and the RVLMS] for trending of RCS inventory.
d) if indications of unacceptable RCS voiding continue, and voiding is suspected to exist in the (isolated) steam generator tubes, then cool the (isolated) steam generator (by steaming or blowdown, and/or feeding) to condense the steam generator tube bundle void. Monitor pressurizer level for trending of RCS inventory.
e) if indications of unacceptable RCS voiding continue, then operate the pressurizer vent and/or the reactor vessel head vent to] clear trapped non-condensible gases. Monitor pressurizer level [and/or the RVLMS] for trending of RCS inventory.

4. When SCS entry conditions (RCS pressure $\leq$ [300 psia] and RCS $T_H \leq$ [300°F] are established, Then initiate SCS operation per operating instructions. press/inv func

5. [Initiate the low temperature overpressurization (LTOP) system at 275°F].

6. [Isolate, vent, or drain the safety injection tanks (SITs) at 250 psia ? RCS pressure].

* Step performed continuously.

1. See Deviation 8-40. For Administrative actions see Deviation 8-17

2. see DEVIATION 8-2

Acceptance Criteria for RCS and Core Heat Removal: HR-5

1. RCS and Core Heat Removal is satisfied if:

   Normal Shutdown Cooling System parameters exist.

   If the above criterion is met, Then proceed to the next safety function in jeopardy.
   If all safety functions are being satisfied, Then implement the Long Term Actions.

2. If the above criteria are not met, Then re-evaluate the feasibility of SCS operation and consider implementing success paths HR-1, 2, 3 or 4. Refer to Continuing Actions for RCS and Core Heat Removal.

1. IMPLEMENTED IN GENERAL PRECAUTION III.A.

2. IMPLEMENTED IN GENERAL PRECAUTION III.B. See Deviation 8-41 for RTD effects.

3. implemented IN step V.A.2. See Deviation 8-32 for location difference.

4. implemented IN V.B.4, V.B.5, V.B.6. Containment level is periodically checked in the Containment Environment SFSC. SEE DEVIATION 8-37 FOR LOCATION DIFFERENCE.

5. See Deviation 8-16.

SUPPLEMENTARY INFORMATION: HR-5

This section contains items which should be considered when implementing EPGs and preparing plant specific EOPs. The items should be implemented as precautions, cautions, notes, or in the EOP training program.

1. Do not place system in "manual" unless misoperation in "automatic" is apparent. Systems placed in "manual" must be checked frequently to ensure proper operation.

2. All available indications should be used to aid in evaluation of plant conditions since the accident may cause irregularities in a particular instrument reading. Instrument readings must be corroborated when one or more confirmatory indications are available. Hot and cold leg RTDs may be influenced by the cold SIS injection and should be checked against each other.

3. Solid water operation of the pressurizer may make it difficult to control RCS pressure and therefore should be avoided unless [20°F] of subcooling cannot be maintained in the RCS. If the RCS is solid, closely monitor any makeup or draining and any system heatup or cooldown to avoid any unfavorable pressure excursions.

4. The operator should be cautioned against prematurely initiating an RAS. The operator should check containment sump level to ensure adequate suction for the SIS before switching to recirculation. This manual action should not be taken unless an automatic RAS is required.

5. When a void exists in the reactor vessel, and RCPs are not operating, the RVLMS provides an accurate indication of reactor vessel liquid inventory. When a void exists in the reactor vessel, and RCPs are operating, it is not possible to obtain an accurate reactor vessel liquid level indication

6. implemented in step VI.B.4.

due to the effect of the RCP induced pressure head on the RVLMS. The indicated level also differs from different RVLMS designs under these conditions. Information concerning reactor vessel liquid inventory trending may still be discerned. However, operators are cautioned not to rely solely on the RVLMS indication when RCPs are operating.

6. The operator should continuously monitor for the presence of RCS voiding and take steps to eliminate voiding any time voiding causes the heat removal or inventory control safety functions to begin to be threatened. Void elimination should be started soon enough to ensure heat removal and inventory control are not lost. C

Continuing Actions for RCS and Core Heat Removal

1. If the RCS and Core Heat Removal safety function is still in jeopardy, then the operator must pursue the heat removal and other jeopardized safety functions simultaneously. If the HPSI and/or LPSI pumps are delivering flow to the RCS per Figure 10-3, then the operator should evaluate the need and feasibility of transferring additional heat through the steam generators by:

   a) restoring the vital auxiliaries necessary to feed one or both steam generators
   b) using alternate means (e.g., fire water pumps, non-grade A condensate, etc.) to feed the S/Gs
   c) alternate means of operating steam dumps or turbine bypass valves or other steam outlets.

2. If the HPSI and/or LPSI pumps are not delivering adequate flow to the RCS, then the operator should evaluate ways of implementing one of the RCS and core heat removal success paths by considering:

   a) restoring necessary vital auxiliaries (control air, electrical, diesel generator, etc.) to regain needed components or subsystems
   b) manual operation of failed remotely operable valves
   c) alternate sources of water for S/G or RCS makeup
   d) alternate means of steam discharge from the steam generators.

Bases for RCS and Core Heat Removal

The purpose of the RCS and Core Heat Removal safety function is to remove the decay heat generated in the core and transfer it to the RCS fluid, where it can be transferred to the secondary system or some other heat sink.

To achieve control of RCS and Core Heat Removal, and to continually provide a heat sink for residual heat removal, the following methods are available:

- HR-1: RCS and Core Removal via Forced Circulation, No SIS Operation
- HR-2: RCS and Core Removal via Natural Circulation, No SIS Operation
- HR-3: RCS and Core Heat Removal via S/G Heat Sink, SIS Operation
- HR-4: RCS and Core Heat Removal via Once-Through-Cooling
- HR-5: RCS and Core Heat Removal via Shutdown Cooling System

The bases for the operator actions required to implement the above success paths are detailed as follows:

HR-1: *RCS and Core Heat Removal via Forced Circulation, No SIS Operation*

Reactor coolant pump forced circulation is the preferred method for RCS heat removal. The reactor coolant absorbs the core heat and transfers this heat to the steam generators providing for the RCS and core heat removal safety function. This requires that at least one steam generator be available to act as a heat sink. The heat is transferred to the secondary system fluid supplied by the main or auxiliary feedwater systems.

Operator Actions

1. During any cooldown, the RCS is borated as necessary (success paths RC-2 and RC-3) to maintain shutdown margin per Technical Specifications.

2. RCS and core heat removal should be performed by feeding at least one steam generator with main or auxiliary feedwater and dumping steam to the condenser via the turbine bypass system. If the condenser or turbine bypass system is not available, the next order of priority of discharging steam would be to use the atmospheric dump valves.

   The use of atmospheric dump valves may have the potential for release of activity to the environment. If it is suspected that a steam generator(s) may be affected by a tube rupture, as indicated by area radiation monitor and/or other symptoms, then S/G cooling should be performed using the unaffected or least affected generator.

3. [To avoid damage to the steam generator feed ring the operator should control the auxiliary feed system.
   If feed flow has not been interrupted, then the feed ring is assumed to be filled and the operator should maintain S/G water level in the normal band.
   If feed flow has been interrupted and steam generator level is below the feed ring, then the operator should limit feedwater flow to 150 gpm per affected S/G for five minutes, or until an increase in S/G level has been observed.

There is no analytical correlation between feedwater flow rate and the conditions to preclude feed ring failure. A flow rate of 150 gpm has been recommended as a procedural limit based on the face that no significant water hammer has been observed during testing or operation with flow rates of that order. Additionally, 150 gpm has been traditionally accepted as a flow limit by industry and the NRC for water hammer protection. The five minute duration of this limited flow is conservatively based on twice the refill time for the 350 gallon feed ring. In the event that refilling of portions of the main feedwater piping must be considered this time would have to be adjusted accordingly.]

4. If all feedwater is lost (both main and auxiliary), then certain activities should be performed to keep the plant in a stable condition. These activities are listed below.

   a) Stop all RCPs to minimize heat input to the RCS.
   b) To conserve steam generator inventory, any cooldown is stopped.
   c) If in operation, the steam generator blowdown system, secondary sampling system or any other nonvital secondary discharge must be secured. Until feedwater is reestablished, the steam generator water inventories must be conserved.
   d) The operator should attempt to restore the correct operation of the main or auxiliary feedwater system to provide a primary decay heat sink for a controlled reactor heat removal to meet the success criteria of this recovery action guideline.

      A moderate rate of increase in steam generator water level is sufficient to restore S/G level. If the refill rate is too fast, excessive cooldown and RCS inventory shrinkage may result. An adequate refill rate may be determined by operating experience.
   e) [If both main and auxiliary feedwater cannot be restored, then all plant specific sources of feedwater which could be made available to replace steam generator water which has boiled off. Examples of alternate sources of feedwater are fire pumps, condensate pumps,

portable pumps, etc. When developing plant procedures, alternate sources of feedwater should be identified and their use should be indicated in the procedures. Guidelines on steam generator depressurization should be developed for those cases when the operator is relying on low pressure sources of feedwater as a backup feedwater supply.]

5. If feed cannot be regained, then the operator is directed to a core cooling success path which does not rely on feedwater, [specifically the use of PORVs in once-through-cooling.]

6. The available condensate inventory should be monitored and replenished from available sources as necessary to continually provide a source for a secondary heat sink. Example of alternate sources of condensate are nonseismic tanks, fire mains, lake water supplies, potable tanks, etc. Plant specific alternate sources of feedwater should be identified and cited in plant specific procedure.

After implementing the above actions, RCS and Core Heat Removal is satisfied if:

a) At least one S/G has level:
   i) within the normal level band with feedwater available to maintain the level

   or

   ii) being restored by a feedwater flow > [150 gpm]

   and

b) $T_h - T_c$ < [10°F] and not increasing

   and

c) T_{ave} < [545°F] and not increasing

   and

d) The RCS is at least [20°F] subcooled [by CET]

   and

e) [No reactor vessel voiding as indicated by the RVLMS]

A steam generator with adequate level or indications that it is intact, a core ΔT <[10°F], T_{ave} < [545°F], adequate RCS subcooling, and no reactor vessel voiding, comprise adequate indication that heat is being properly removed from the core and the RCS. Operators use feed flow, steam flow and RCS temperature response to verify the S/G is being effective as a heat removal mechanism and that the level will recover if it went below the indication range.

$\Delta T \leq$ [10°F] is verified by best estimate analysis to be the maximum ΔT expected for minimum forced circulation with maximum decay heat. RCS subcooling greater than or equal to [20°F] ensures a liquid state of the coolant for effective heat removal properties. Subcooling less than [200°F] is based on PTS criteria. With RCPs operating, and the above criteria satisfied, there should be no reactor vessel voiding.

HR-2: *RCS and Core Heat Removal via Natural Circulation, No SIS Operation*

In the absence of forced reactor coolant flow, the core can still be cooled by natural circulation induced by a temperature differential between the steam generators and the core. This method also requires that the steam generators be available to act as a heat sink. Heat is transferred to the secondary system water supplied by the main or auxiliary feedwater systems.

Operator Actions

1. During any cooldown, the RCS is borated as necessary (success paths RC-2 and RC-3) to maintain shutdown margin per Technical Specifications.

2. Determine whether RCP restart criteria are met by the following:

   a) At least one steam generator is available for removing heat from the RCS, thus providing an RCS heat removal function. This includes feedwater available for removing heat from the generator and a method for removing steam (e.g. atmospheric dump valves, etc.).

   b) Pressurizer level is greater than [200"] and not decreasing. With pressurizer level at the high end of the operating band, the possibility of draining the pressurizer due to loop shrinkage and/or steam void condensation is minimized and there is a greater likelihood of keeping the pressurizer heaters covered. This will assist in maintaining positive RCS pressure control. The criterion of pressurizer level not decreasing implies that RCS inventory control has been established.

   c) The RCS is greater than or equal to [20°F] subcooled. A subcooled condition in the RCS in conjunction with (b) above indicates that pressure and inventory are being controlled.

   d) [All plant specific RCP operating criteria are satisfied before the RCPs are restarted to prevent damage to RCPs. Following automatic

or operator initiated containment isolation, reinstatement of component cooling water to the RCPs should be considered in order to ensure adequate RCP cooling].

3. Upon restarting two RCPs in opposite loops, pressurizer level and pressure may decrease due to loop shrinkage and/or void condensation. It is possible that this action will drain the pressurizer. Steam voids present in the reactor vessel will condense upon restarting RCPs. [The RVLMS should be monitored for the trending of reactor vessel liquid level. This trending information may be correlated to pressurizer level decrease.] RCP operation with a drained pressurizer may continue provided certain actions are taken and certain criteria are satisfied.

   The following constitute the actions to be taken and the criteria to be satisfied when restarting RCPs:

   a) Start one RCP in each loop.

   b) [Ensure proper RCP operation by monitoring RCP amperage and pump NPSH. NPSH is determined by pressurizer pressure and corresponding T_c on Figure 10-1.]

   c) Operate all available charging pumps until pressurizer level is greater than [100"]. This serves to compensate for pressurizer level and pressure decrease.

4. If at least one RCP has been restarted in a loop with a S/G having feed and steam flow capability, then the Heat Removal Safety Function Success Path utilizing Forced Circulation (HR-1) should be implemented.

5. If all RCP operation is terminated and when inventory and pressure are controlled, then natural circulation is monitored by heat removal via at least one steam generator. Natural circulation flow should occur within 5-15 minutes after the RCPs were tripped. The RCS temperature response during natural circulation will usually be slow (5-15 minutes) as

compared to a normal forced flow system response time of 6-12 seconds, since the coolant loop cycle time will be significantly larger.

When single phase natural circulation is established in at least one loop the RCS indicates all of the following conditions:

a) Loop ΔT (T_H - T_C) less than normal full power ΔT;
b) Cold leg temperatures constant or decreasing;
c) Hot leg temperatures stable (i.e. not steadily increasing) or slowly decreasing;
d) No abnormal differences between T_H RTDs and [core exit thermocouples]. Hot leg RTD temperature should be consistent with the [core exit thermocouples]. Adequate natural circulation flow ensures that [core exit thermocouple] temperatures will be approximately equal to the hot leg RTDs temperature within the bounds of the instrument's inaccuracies. An abnormal difference between T_H and the [CETs] is greater than [10°F].

Natural circulation is governed by decay heat, component elevations, primary to secondary heat transfer, loop flow resistance, and voiding. Component elevations on C-E plants are such that satisfactory natural circulation decay heat removal is obtained by fluid density differences between the core region and the steam generator tubes.

6. If the criteria of step 5 are not met, then RCS inventory and pressure, and S/G steaming and feeding should be properly controlled to attempt establishing natural circulation.

7. RCS and core heat removal should be performed by feeding the steam generators with main or auxiliary feedwater and dumping steam to the condenser via the turbine bypass system. If the condenser or turbine bypass system is not available, the next order of priority for discharging steam would be to use the atmospheric dump valves.

The use of the atmospheric dump valves may have the potential for release of activity to the environment. If it is suspected that a steam generator may be affected by a tube rupture, then natural circulation should be performed using the unaffected or least affected generator.

8. [To avoid damage to the steam generator feed ring the operator would control the auxiliary feed system.

   If feed flow has not been interrupted, then the feed ring is assumed to be filled and the operator should maintain S/G water level in the hot zero power band.

   If feed flow has been interrupted and steam generator level is below the feed ring the operator should limit feedwater flow to 150 gpm per affected S/G for five minutes, or until an increase in S/G level has been observed.

   There is no analytical correlation between feedwater flow rate and the conditions to preclude feed ring failure. A flow rate of 150 gpm has been recommended as a procedural limit based on the face that no significant water hammer has been observed during testing or operation with flow rates of that order. Additionally, 150 gpm has been traditionally accepted as a flow limit by industry and the NRC for water hammer protection. The five minute duration of this limited flow is conservatively based on twice the refill time for the 350 gallon feed ring. In the event that refilling of portions of the main feedwater piping must be considered this time would have to be adjusted accordingly.]

9. The available condensate inventory should be monitored and replenished from available sources as necessary to continually provide a source for a secondary heat sink. Example of alternate sources of condensate are nonseismic tanks, fire mains, lake water supplies, potable tanks, etc. Plant specific alternate sources of feedwater should be identified and cited in the plant specific procedure.

10. If all feedwater is lost (both main and auxiliary), then certain activities should be performed to keep the plant in a stable condition. These activities are listed below.

a) To conserve steam generator inventory, any cooldown is stopped.

b) If in operation, then the steam generator blowdown system, secondary sampling system or any other nonvital secondary discharge must be secured. Until feedwater is reestablished, the steam generator water inventories must be conserved.

c) The operator should attempt to restore the correct operation of the main or auxiliary feedwater system to provide a primary decay heat sink for controlled RCS and Core Heat Removal to meet the acceptance criteria of this operator action guideline.

A moderate rate of increase in steam generator water level is sufficient to restore S/G level. If the refill rate is too fast, the RCS temperature can be reduced too fast and RCS inventory shrinkage can be excessive (i.e. the pressurizer may be emptied). An adequate refill rate can be determined by operator experience.

d) If both main and auxiliary feedwater cannot be restored, then all point specific sources of feedwater which could be made available to replace steam generator boil-off should be implemented. Examples of alternate sources of feedwater are fire pumps, condensate pumps, portable pumps, etc. When developing plant specific plant procedures, alternate sources of feedwater should be identified and their use should be indicated in the procedures. Guidelines on steam generator depressurization should be developed for those cases when the operator is relying on low pressure sources of feedwater as a backup feedwater supply.

11. If feedwater cannot be regained, then the operator is directed to a core heat removal success path that does not rely on feedwater. [Specifically the use of PORVs for once-through-cooling.]

12. If it is suspected that an isolated S/G has a tube leak and it appears that primary to secondary leakage will overfill the affected steam generator and lift secondary safeties or atmospheric dump valves, then the affected steam generator may be steamed to the condenser to reduce fluid inventory and pressure.

13. The operator should monitor for the presence of voids and take steps to eliminate voiding any time voiding jeopardizes natural circulation. Voiding in the RCS may be indicated by any of the following indications, parameter changes, or trends: C

    a) letdown flow greater than charging flow,
    b) pressurizer level increasing significantly greater than expected while operating pressurizer spray,
    c) [the RVLMS indicates that voiding is present in the reactor vessel],
    d) [the HJTC unheated thermocouple temperature indicates saturated conditions in the reactor vessel upper head]. A
    e) [other indications, insert here]

14. If voiding should be eliminated, then proceed as follows:

    a) Letdown is isolated or verified to be isolated to minimize further inventory loss,
    b) The depressurization is stopped to prevent further growth of the void and, if required, the RCS is repressurized to $\geq$ [20°F] subcooling,
    c) Pressurizing and depressurizing the RCS within the limits of Figure 10-1 may condense the void. Pressurizing has the effect of filling the voided portion of the RCS with cooler fluid which will remove heat from the region. Subsequent depressurization and a repeating of this process several times will cool and condense the steam void. In the case of a void in the reactor vessel, the pressurization/depressurization on cycle will produce a fill and drain of the

reactor vessel. The pressurization/depressurization cycle may be accomplished using pressurizer heaters and spray (preferred method) or the SIS/charging system (alternative method). Monitor pressurizer level [and the RVLMS] for trending of RCS inventory. This will assist the operator in assessing the effectiveness of void elimination.

d) If indications of unacceptable RCS voiding continue, and voiding is suspected to exist in the (isolated) steam generator tubes, then cool the (isolated) steam generator (by steaming or blowdown, and/or feeding) to condense the tube bundle void. This will be effective for condensing steam voids but will not have an effect on non-condensible gases trapped in the tube bundle. A buildup of non-condensible gases in the tube bundles will not hinder natural circulation even with a large number of the tubes blocked. This is due to the small amount of heat transfer area required for the removal of decay heat. Monitor pressurizer level for trending of RCS inventory. This will assist the operator in assessing the effectiveness of void elimination.

e) If indications of unacceptable RCS voiding continue, then voiding may be caused by non-condensible gases. [Operate the pressurizer vent and/or the reactor vessel head vent to clear trapped non-condensible gases.] Monitor pressurizer level [and/or the RVLMS] for trending of RCS inventory. This will assist the operator in assessing the effectiveness of void elimination.

After implementing the above actions, RCS and Core Heat Removal is satisfied if:

a) At least one S/G has level:
   i) within the normal level band with feedwater available to maintain the level
   or
   ii) being restored by a feedwater flow > [150 gpm]
   <u>and</u>

b) $T_h - T_c$ <[50°F] and not increasing
   <u>and</u>

c) T_{ave} <[545°F] and not increasing
   <u>and</u>

d) The RCS is at least [20°F] subcooled [by CET]

Best estimate analysis reveals that loop differential temperature for natural circulation will be less than [50°F] ($T_H - T_C$) in the operating loop for the full range of decay heat. Proper loop ΔT accompanied by average operating loop temperature below the saturation temperature corresponding to the lowest S/G safety setpoint ([545°F]) and indications that at least one S/G is removing heat are adequate confirmation of RCS and Core Heat Removal. [20°F] subcooling assures a subcooled heat transfer medium for the core.

HR-3: *RCS and Core Heat Removal via S/G Heat Sink, SIS Operation*

In some instances, RCS and Core Heat Removal may be a combination of steam generator heat removal and heat removal by venting energy out of an RCS opening such as a break or a stuck open [PORV]. If the break is large enough, all necessary heat removal may occur by venting energy out the break. In such a case, success path HR-4 would be adequate. The small break LOCA heat removal process requires the use of SIS and steam generators.

The small break LOCA heat removal process is complex. In the short-term after the RCPs are tripped, core heat removal is maintained by natural circulation. Since the break is not large enough to adequately remove the heat, heat removal via a steam generator is required. This requires that the operator maintain feedwater (either main or auxiliary) to the steam generators and control steam flow from the steam generators via the turbine bypass system or the atmospheric dump valves.

The small break natural circulation process can take different forms. These forms include single phase and two phase natural circulation. The simplest form of natural circulation is single phase, liquid cooling. single phase natural circulation is possible for cases where RCS inventory and pressure are controlled. Single phase cooling transports heat in the active steam generator loop using the same flow path as in forced circulation. The driving force for the natural circulation is the fluid density difference between the steam generator and the core. Two phase natural circulation involving steam and water is more complex and can take several forms. The form taken depends on the amount of decay heat needed to be removed, the amount of inventory and pressure control degradation, the break size, the status of SIS, and the status of steam generators. One form of two phase natural circulation is known as reflux. In the reflux process steam leaves the core region and travels to the steam generator via the hot leg; the steam is condensed in the steam generator before reaching the top of the "U" tubes and flows back to the core via the hot leg where it is once again turned to steam. Another two phase natural circulation process is that in which the steam from the core

goes past the steam generator "U" bend and is condensed in the "U" tubes on the cold leg side; thus condensate flows back to the core via the cold leg. A combination of the two processes is also possible.

The operator has adequate instrumentation to monitor natural circulation for the single phase, liquid natural circulation process. The RCS loop ΔT in the active steam generator loop(s) can be used along with other information to confirm that the single phase natural circulation process is effective. The reflux process involving two phase cooling is complex and varied enough so that RCS loop ΔT may not be a meaningful indication of adequate natural circulation cooling. The guidelines are written to alert the operator to use the traditional acceptance criteria for natural circulation only when RCS inventory and pressure are controlled.

For cases where two phase reflux cooling is the heat removal process, the operator monitors the adequacy of cooling by monitoring the steam generator heat removal. In addition, the [core exit thermocouple] temperature and T_H indication are equally important in monitoring heat removal during the two phase reflux cooling. As long as these temperatures remain within acceptable limits they indicate that heat removal and inventory functions are being satisfied.

The transition from single phase liquid natural circulation cooling to two phase reflux mode can occur quickly for larger small breaks, or can occur more slowly in an event for the smaller breaks. The operator should be aware that this transition may cause confusing temperatures indications as the RCS loop ΔTs readjust to reflect the transition in process. The emphasis in the guideline is to continue the steam generator heat removal process, continue restoring inventory control, and to continue monitoring the [core exit thermocouples] to confirm the heat removal process is adequate.

Operator Actions

1. SIS operation must be verified if pressurizer pressure decreases to [1600 psia, or if containment pressure increases to 4 psig]. If safety injec-

tion system operation has not commenced automatically when RCS pressure is below [1600 psia], it must be manually actuated. This action allows the RWT inventory to discharge into the RCS. An insufficient RCS inventory may be associated with a loss of coolant accident, a steam generator tube rupture, a control system malfunction or an excessive heat removal event. Safety injection system flow rate will follow the RCS pressure according to the SIS delivery curves (see Figure 10-3). The SIS and charging flowrate should be checked and maximized relative to RCS pressure to enhance RCS inventory replenishment and/or core heat removal.

2. If pressurizer pressure goes below [1300 psia] following receipt of an SIAS, then all four RCPs must be tripped. Two RCPs may have been tripped already in the Standard Post Trip Actions. In this case, the operator would simply trip the remaining two RCPs. Since prolonged RCP operation during LOCAs of certain size and location could result in increasing the severity of the event, tripping all four RCPs ensures a conservative approach to event recovery. This is due to the fact that, when the operators implement the FRG they have not determined what event is occurring. An LOCA may be the lone event which is occurring or it may be occurring in conjunction with other event(s). Since operators cannot be sure what event is occurring, they are instructed to trip all RCPs whenever they are implementing the FRG and pressurizer pressure decreases to less than [1300 psia] following an SIAS. This is a conservative approach designed to satisfy worst case analysis.

If an SIAS has been initiated and the SIS is operating, then it must continue to operate at full capacity until SIS termination criteria are met. For most LOCAs the SIS will run continuously for a long period of time while RCS inventory, pressure, and heat removal control are being regained. In some cases control of these three functions is not regained during the accident and SIS runs at least for the duration of the recovery period. Early termination is expected only for a steam line break, a spurious SIAS or if the leak is identified and promptly isolated (e.g., a stuck open PORV is blocked).

3. Termination of SIS should be sequenced by stopping one pump at a time while observing the termination criteria. Throttling of HPSI flow is permissible if it is feasible. SIS termination criteria are:

   a) RCS is at least [20°F] subcooled (Figure 10-1). Establishing [20°F] of subcooling ensures the fluid in the core is subcooled, and provides sufficient margin for establishing flow should the [20°F] subcooling deteriorate when SIS flow is secured. Voids may exist in some parts of the RCS (e.g. reactor vessel head), but these are permissible as long as core heat removal is maintained.

   b) Pressurizer level is greater than [100"], and constant or increasing. A pressurizer level greater than [100"] and constant or increasing in conjunction with criterion a) above is an indication that RCS inventory control has been established.

   c) At least one steam generator is available of removing heat from the RCS. Steam generator availability requires having feed flow and steam flow which are indications that primary to secondary heat removal is possible.

   d) [The RVLMS indicates the core is covered. An indication of core coverage, in conjunction with the above criteria, serves as an additional indication that RCS heat removal control has been established.

If the above criteria are met, the operator may either terminate or throttle the SIS. The operator may decide to throttle rather than terminate if the SIS is to be used to control pressurizer level or plant pressure. A general assessment of the SIS performance can be made from the control room. The operator should confirm that at least one train and preferably both trains of SIS are operating and that system delivery rate is consistent with RCS pressure as shown in Figure 10-1. Injection flow reates to each cold leg should be approximately equal; departures from this would indicate a closed flow path or some system spillage.

4. If the criteria of step 3 cannot be maintained, then the SIS pumps must be restarted.

5. With all RCPs stopped, then operation of two RCPs (in opposite loops) should be attempted if the RCP restart criteria are met. Only one reactor coolant pump in each loop should be operated to minimize heat input to the RCS.

   Determine whether RCP restart criteria are met by the following:

   a) At least one steam generator is available for removing heat from the RCS. A steam generator having feed flow and removing heat from the RCS is an indication that primary to secondary heat removal is being maintained.

   b) Pressurizer level is greater than [200"] and not decreasing. A higher pressurizer level will minimize the possibility of draining the pressurizer due to loop shrinkage and/or steam void condensation is minimized and there is a greater likelihood of keeping the pressurizer heaters covered. This will assist in maintaining positive RCS pressure control. The criterion of pressurizer level not decreasing implies that RCS inventory control has been established.

   c) The RCS is greater than or equal to [20°F] subcooled. A subcooled condition taken in conjunction with (b) above indicates that inventory control has been established.

   d) [All plant specific RCP operating criteria are satisfied before the RCPs are restarted to prevent damage to RCP operation and damage resulting from abnormal operating conditions. Following automatic or operator initiated containment isolation, reinstatement of component cooling water to the RCPs should be considered in order to ensure adequate RCP cooling.]

6. Upon restarting two RCPs in opposite loops, pressurizer level and pressure may decrease due to loop shrinkage and/or void condensation. It is possible that this action will drain the pressurizer. Steam voids present in the reactor vessel will condense upon restarting RCPs. [The RVLMS should be monitored for the trending of reactor vessel liquid level. This trending information may be correlated to pressurizer level decrease.] RCP operation with a drained pressurizer may continue provided certain actions are taken and certain criteria are satisfied.

   The following constitute the actions to be taken and the criteria to be satisfied when restarting RCPs:

   a) Start one RCP in each loop.

   b) [Ensure proper RCP operation by monitoring RCP amperage and pump NPSH. NPSH is determined by pressurizer pressure and corresponding T_C on Figure 10-1.]

   c) Operate all available HPSI and charging pumps until pressurizer level is restored to greater than [100"] and SIS termination criteria are met.

7. If all RCPs are stopped, then verify that natural circulation is being maintained in at least one loop by the following:

   a) Loop ΔT (T_H - T_C) less than normal full power ΔT;
   b) Cold leg temperatures constant or decreasing;
   c) Hot leg temperatures stable (i.e. not steadily increasing) or slowly decreasing;
   d) No abnormal differences between T_H RTDs and [core exit thermocouples]. Hot leg RTD temperature should be consistent with the core exit thermocouples. Adequate natural circulation flow ensures that [core exit thermocouple] temperatures will be approximately equal to the hot leg RTDs temperature within the

bounds of the instrument's inaccuracies. An abnormal difference between T_H and the [CETs] is greater than [10°F].

Natural circulation is governed by decay heat, component elevations, primary to secondary heat transfer, loop flow resistance, and voiding. Component elevations on C-E plants are such that satisfactory natural circulation decay heat removal is obtained by fluid density differences between the core region and the steam generator tubes. Natural circulation flow should occur within 5-15 minutes after the RCPs were tripped. The RCS temperature response during natural circulation will usually be slow (5-15 minutes) as compared to forced flow system response time of 6-12 seconds.

8. If the criteria of step 7 are not met, then ensure RCS inventory and pressure, and S/G steaming and feeding are being controlled properly, in an attempt to establish and maintain one or multi-phase natural circulation.

9. Steam generator heat removal should be performed by feeding the steam generators with main or auxiliary feedwater and dumping steam to the condenser via the turbine bypass system. If the condenser or turbine bypass system is not available, the next order of priority for discharging steam would be to use the atmospheric dump valves.

10. [To avoid damage to the steam generator feed ring the operator should control the auxiliary feed system.
If feed flow has not been interrupted, then the feed ring is assumed to be filled and the operator should maintain S/G water level in the hot zero power band.
If feed flow has been interrupted and steam generator level is below the feed ring the operator should limit feedwater flow to 150 gpm per affected S/G for five minutes, or until an increase in S/G level has been observed.

There is no analytical correlation between feedwater flow rate and the conditions to preclude feed ring failure. A flow rate of 150 gpm has been recommended as a procedural limit based on the face that no significant water hammer has been observed during testing or operation with flow rates of that order. Additionally, 150 gpm has been traditionally accepted as a flow limit by industry and the NRC for water protection. The five minute duration of this limited flow is conservatively based on twice the refill time for the 350 gallon feed ring. In the event that refilling of portions of the main feedwater piping must be considered this time would have to be adjusted accordingly.]

11. The available condensate inventory should be monitored and replenished from available sources as necessary to continually provide a source for a secondary heat sink. Example of alternate sources of condensate are nonseismic tanks, fire mains, lake water supplies, potable tanks, etc. Plant specific alternate sources of feedwater should be identified and cited in the plant specific procedure.

12. If all feedwater is lost (both main and auxiliary), then certain activities should be performed to keep the plant in a stable condition. These activities are listed below.

    a) Stop all RCPs to minimize heat input to the RCS.

    b) To conserve steam generator inventory, any cooldown is stopped.

    c) If in operation, the steam generator blowdown system, secondary sampling system or any other nonvital secondary discharge must be secured. Until feedwater is reestablished, the steam generator water inventories must be conserved.

    d) The operator should attempt to restore the correct operation of the main or auxiliary feedwater system to provide a primary decay heat sink for a controlled RCS and Core Heat Removal to meet the success criteria of this recovery action guideline.

A moderate rate of increase in steam generator water level is sufficient to restore S/G level. If the refill rate is too fast, excessive cooldown of the RCS and shrinkage of RCS inventory may result. Consequently, the pressurizer level may fall below that required to maintain a bubble for pressure control. An adequate rate for restoring S/G level is determined by operating experience.

e) If both main and auxiliary feedwater cannot be restored, then all plant specific sources of feedwater which could be made available to replace steam generator boil-off should be implemented. Examples of alternate sources of feedwater are fire pumps, condensate pumps, portable pumps, etc. When developing plant procedures, alternate sources of feedwater should be identified and their use should be indicated in the plant specific procedures. Guidelines on steam generator depressurization should be developed for those cases when the operator is relying on low pressure sources of feedwater as a backup feedwater supply.

13. If no feedwater is available, then the operator is directed to another heat removal success path ([PORVs]) which does not require feedwater.

14. If the [refueling water tank] level falls to [10%], then initiation of recirculation should be verified. If necessary, recirculation should be initiated manually one SIS train at a time. Recirculation is actuated either automatically or manually in order to maintain a continuous flow of safety injection fluid to the RCS (required for inventory control) and a continuous flow of containment spray water (required for containment temperature and pressure control). [If the automatic or manual initiation of the RAS does not automatically close RWT outlet valves, these must be manually closed to isolate the RWT from the SIS pumps. Furthermore, sump level should be checked prior to and at the transfer of suction sources. An LOCA outside of containment could result in inadequate containment sump inventory to allow recirculation. The operator should monitor an increasing trend in containment sump level

that corresponds to the decreasing trend in RWT level. These actions prevent the inadvertent air binding of the safety injection pumps.]

The operator should be cautioned against prematurely initiating an RAS. A possible complication of a premature RAS is the pumps' suction being aligned to a dry sump, consequently air binding the pumps and loosing both heat removal loops. In addition, for events where high containment pressure is present, the check valves in the RWT outlet line may be forced shut and the RWT fluid will remain unavailable while the containment is pressurized unless the containment can be isolated and the SIS suction piping depressurized.

15. After the switch to recirculation, the HPSI pump flows are monitored in order to ensure that HPSI pump miniflow requirements are met to avert any possible permanent HPSI pump damage. If they are not met, the operator should turn off the charging pumps one at a time until the miniflow requirements are met. If they are still not met with all the charging pumps off and two HPSI pumps are operating the operator turns off the HPSI pump with the lower flow. One HPSI pump should be left operating at all times, unless SIS termination criteria are met.

After implementing the above actions, RCS and Core Heat Removal is satisfied if:

a) At least one steam generator has level:
   i) within the normal level band with feedwater available to maintain the level

   or

   ii) being restored by feedwater flow > [150 gpm]

   and

b) [CET] temperatures <[700°F] or decreasing

   and

   [All available charging pumps are operating and] the

c) SIS pump(s) are injecting water into the RCS per Figure 10-3 (unless SIS termination criteria are met).

When the SIS is operating, it should be delivering flow which corresponds to RCS pressure. If delivery flow is equal to or greater than that of Figure 10-3, then SIS performance is adequate. [700°F] is the plant specific temperature which will not be exceeded if accident recovery is proceeding as anticipated. If [CET] temperatures are > [700°F], then a decreasing trend indicates accident mitigation. At least one steam generator level in the normal band or being restored is indication of the ability to remove heat through the steam generator(s).

HR-4: *RCS and Core Heat Removal via Once Through Cooling*

If steam generators are not available, heat can be removed from the core by a flushing SIS flow through the core and discharging into the containment through a pressure boundary opening such as a primary relief valve (or a break in the RCS if there is one).

Operator Actions

1. If pressurizer pressure decreases to [1600 psia or, if containment pressure increases to 4 psig], then SIAS initiation should be verified. If it has not occurred, then manually initiate an SIS.

2. If pressurizer pressure goes below [1300 psia] following receipt of an SIAS, then all four RCPs must be tripped. Two RCPs may have been tripped already in the Standard Post Trip Actions. In this case, the operator would simply trip the remaining two RCPs. Since prolonged RCP operation during LOCAs of certain size and location could result in increasing the severity of the event, tripping all four RCPs ensures a conservative approach to event recovery. This is due to the fact that, when the operators implement the FRG they have not determined what event is occurring. An LOCA may be the lone event which is occurring or it may be occurring in conjunction with other event(s). Since operators cannot be sure what event is occurring, they are instructed to trip all RCPs whenever they are implementing the FRG and pressurizer pressure decreases to less than [1300 psia] following an SIAS. This is a conservative approach designed to safety worst case analysis.

3. Once-through-cooling through an RCS pressure boundary opening is established in the following manner. All operating RCPs are stopped since an LOCA or sustained opening of the [PORVs] will probably result in saturation conditions in the RCS which is not a desirable fluid condition for RCP operation. All available SIS and charging pumps are started and the [PORV's] are opened (unless there is already an adequate opening in the RCS for once-through-cooling as there would be if a large break had

occurred). This provides the path and motive force for core flushing and will reduce RCS temperature since cooler safety injection fluid is replacing the hot RCS fluid leaving through the opening. This cooling could also take place through a break in the RCS boundary. An adequate size break for adequate core cooling usually results in an initial RCS depressurization to below 300 psia.

4. If once through cooling has been established, then the SIS must continue to operate unless the following criteria are satisfied:

   a) [CET] temperature is less than [700°F]

   b) RCS is at least [20°F] subcooled (Figure 10-1). Establishing [20°F] subcooling prevents void formation in the core when SIS flow is terminated, and provides sufficient margin for establishing flow should the [20°F] subcooling deteriorate when SIS flow is secured. The [200°] subcooled limit minimizes the effects of PTS.

   c) Pressurizer level is greater than [100"] and is constant or increasing. A pressurizer level greater than [100"] and responding normally ensures the RCS inventory control has been established.

   d) At least one steam generator is available for removing heat from the RCS. A steam generator available for removing heat from the RCS ensures that primary to secondary heat removal is being maintained. A steam generator available includes feedwater available for removing heat from the generator and a method for removing steam (e.g. atmospheric dump valves, etc).

5. The SIS must be restarted if the criteria in step 4 cannot be maintained. This provides a sufficient margin for restoring once-through-cooling and minimizes the possibility of void formation in the core.

6. If the [refueling water tank] levels falls to [10%], then initiation of recirculation should be verified. If necessary, recirculation should be

initiated manually one SIS train at a time. Recirculation is actuated either automatically or manually in order to maintain a continuous flow of safety injection fluid to the RCS (required for inventory control) and a continuous flow of containment spray water (required for containment temperature and pressure control). [If the automatic or manual initiation of the RAS does not automatically close RWT outlet valves, these must be manually closed to isolate the RWT from the ECCS pumps. Furthermore, sump level should be checked prior to and during the transfer of suction sources. An LOCA outside of containment could result in inadequate containment sump inventory to allow recirculation. The operator should monitor an increasing trend in containment sump level that corresponds to the decreasing trend in RWT level. These actions prevent the inadvertent air binding of the safety injection pumps.]

The operator should be cautioned against prematurely initiating an RAS. A possible complication of a premature RAS is the pumps' suction being aligned to a dry sump, consequently air binding the pumps and loosing both heat removal loops. In addition, for events where high containment pressure is present, the check valves in the RWT outlet line may be forced shut and the RWT fluid will remain unavailable while the containment is pressurized unless the containment can be isolated and the SIS suction piping depressurized. ?

7. After the switch to recirculation, the HPSI pump flows are monitored in order to ensure that HPSI pump miniflow requirements are met to avert any possible permanent pump damage. If they are not met, the operator should turn off the charging pumps or HPSI pumps (turn off the HPSI pump with the lower flow) one at a time until the miniflow requirements are met. One HPSI pump should be left operating at all times unless SIS termination criteria are met (Step 3).

After implementing the above actions, RCS and Core Heat Removal is satisfied if:

a) [Core exit thermocouple] temperature < [700°F] or decreasing

<u>and</u>

b) [All available charging pumps are operating and] the SIS pump(s) are injecting water into the RCS per Figure 10-3 (unless SI termination criteria are met)

<u>and</u>

c) Pressurizer pressure is less than [1300 psia] or decreasing

SIS performance is judged by comparing delivery flow to RCS pressure. If flow is equal to or greater than that shown on Figure 10-3, SIS performance is adequate. [700°F] is a plant specific temperature which corresponds to the highest temperature which will not be exceeded if accident mitigation is proceeding as expected. If [CET] temperatures are greater than [700°F], then a decreasing trend is indicative of recovery. RCS pressure less than the HPSI pump shutoff head ([1300 psia]) or decreasing is indicative of conditions where SIS can deliver to the RCS.

HR-5: *RCS and Core Heat Removal via the Shutdown Cooling System*

If the RCS is cooled to at least [300°F] and depressurized to at least [300 psia], then it may be possible to use the SCS for RCS heat removal.

Operator Actions

1. The operator should determine if SCS operation criteria are met. If pressurizer level is stable (greater than [100"], the pressurizer and/or HPSI pumps are maintaining system pressure such that RCS hot and cold leg temperatures are at least [20°F] below saturation temperatures for pressurizer pressure, and the steam generators are available (steam flow and feed flow) to reduce the RCS temperature to the shutdown cooling entry value, SCS operation may be appropriate if the SCS is available. Before the SCS is operated, RCS activity levels must be determined since the RCS fluid will not be circulated outside of the containment building. The operator must decide whether to circulate high activity RCS coolant outside containment if high activity is present and such calibration has the potential for release to the environment. If the potential for significant releases exists, it may be more desirable to continue cooling with the steam generator. The condensate inventory must be checked to ensure that the supply is sufficient to cool down the plant to SCS entry conditions or continue cooling the RCS. Other plant specific prerequisites for SCS operations must be considered (e.g. component cooling water, instrument air and valve control power).

   If SCS operation is determined to be appropriate, then the SIS (if operating) is aligned for cold leg injection and the RCS is cooled down and depressurized as follows. If necessary, RCS hot leg temperature should be cooled to at least [300°F] and depressurized to at least [300 psia]. The RCS is depressurized to [300 psia] or less by using auxiliary spray. Depressurization may also be accomplished by stopping charging pumps, or stopping or throttling HPSI pumps. If auxiliary spray is used, the difference between the pressurizer temperature and the auxiliary spray water temperature should be maintained below [200°F] if possible.

If RCS inventory control is satisfactory, auxiliary spray water temperature may be increased by increasing letdown flow or reducing charging flow which will increase the regenerative heat exchanger outlet temperature. Other plant specific methods to increase auxiliary spray water temperature may be used. If auxiliary spray is used when a [200°F] or more difference exists, then such a cycle must be recorded as per Technical Specifications. The number of such cycles should be minimized. [Another operational alternative for the RCS pressure reduction is to throttle the HPSI pumps and adjust charging pump flow (if the pressurized is solid) to maintain level and control pressure.]

2. Any time it is found that voiding is causing the RCS to remain pressurized above the SCS entry pressure, when SCS operation is desired, then an attempt at elimination of the voiding should be made.

   The operator should monitor for the presence of voids. Voiding in the RCS may be indicated by any of the following indications, parameter changes, or trends:

   a) letdown flow greater than charging flow,
   b) pressurizer level increasing significantly greater than expected while operating pressurizer spray,
   c) [the RVLMS indicates that voiding is present in the reactor vessel].
   d) [HJTC unheated thermocouple temperature indicates saturated conditions in the reactor vessel upper head]. A

3. If voiding should be eliminated, then proceed as follows:

   a) Letdown is isolated or verified to be isolated to minimize further inventory loss,
   b) The depressurization is stopped to prevent further growth of the void and, if required, the RCS is repressurized to $\geq$[20°F] subcooling.

c) Pressurizing and depressurizing the RCS within the limits of Figure 10-1 may condense the void. Pressurizing has the effect of filling the voided portion of the RCS with cooler fluid which will remove heat from the region. Subsequent depressurization and a repeating of this process several times will cool and condense the steam void. In the case of a void in the reactor vessel, the pressurization/depressurization on cycle will produce a fill and drain of the reactor vessel. The pressurization/depressurization cycle may be accomplished using pressurizer heaters and spray (preferred level [and the RVLMS] for trending of RCS inventory. This will assist the operator in assessing the effectiveness of void elimination.

d) If indications of unacceptable RCS voiding continue, and voiding is suspected to exist in the (isolated) steam generator tubes, then cool the (isolated) steam generator (by steaming or blowdown, and/or feeding) to condense the tube bundle void. This will be effective for condensing steam voids but will not have an effect on non-condensible gases trapped in the tube bundle. A buildup of non-condensible gases in the tube bundle will not hinder natural circulation even with a large number of the tubes blocked. This is due to the small amount of heat transfer area required for the removal of decay heat. Monitor pressurizer level for trending of RCS inventory. This will assist the operator in assessing the effectiveness of void elimination.

e) If indications of unacceptable RCS voiding continue, then voiding may be caused by non-condensible gases. [Operate the pressurizer vent and/or the reactor vessel head vent to clear trapped non-condensible gases.] Monitor pressurizer level [and/or the RVLMS] for trending of RCS inventory. This will assist the operator in assessing the effectiveness of void elimination.

4. When SCS entry conditions (RCS pressure $\leq$[300 psia] and RCS T_H $\leq$[300°F] are established, then SCS operation is initiated per plant specific operating instructions.

5. [The safety injection tanks should be isolated, vented, or drained at a RCS pressure of 250 psig to avoid introducing their nitrogen cover gas into the RCS and increasing the severity of the event.]

6. [LTOP protection is instituted below 275°F to protect the primary pressure boundary from low temperature brittle fracture.]

After implementing the above actions, RCS and Core Heat Removal is satisfied if:

normal shutdown cooling system parameters exist.

That is, heat exchanger ΔTs, cooling water flows pump discharge heads, etc. are expected for the plant conditions.

Continuing Actions for RCS and Core Heat Removal

If the RCS and Core Heat Removal safety function is still in jeopardy, then the operator must pursue RCS and Core Heat Removal and other jeopardized functions simultaneously. If the HPSI and/or LPSI pumps are delivering flow to the RCS per Figure 10-3, then the operator should evaluate the need and feasibility of transferring additional heat through the steam generators by:

a) restoring the vital auxiliaries necessary to feed one or both steam generators
b) using alternate means (e.g. fire water pump, non-grade A condensate, etc.) to feed the S/G's
c) alternate means of operating steam dumps or turbine bypass valves or other steam outlets.

If the HPSI and/or LPSI pumps are not delivering adequate flow to the RCS, then the operator should evaluate ways of implementing one of the RCS and core heat removal success paths by considering:

a) restoring necessary vital auxiliaries (control air, electrical, diesel generator, etc.) to regain needed components or subsystems
b) manual operation of failed remotely operable valves
c) alternate success of water for S/G or RCS makeup
d) alternate means of steam discharge from the steam generators.

SAFETY FUNCTIONS: Containment Isolation
SUCCESS PATH: Manual Isolation; CI-1
RESOURCE TREE: Tree F

OPERATOR ACTIONS

*1. If containment pressure increases to [4 psig, or if pressurizer pressure decreases to 1600 psig], Then verify initiation of containment isolation. If required automatic initiation has not occurred or if containment radiation levels exceed [plant specific limits], Then manually initiate containment isolation.

2. If containment isolation valves are not closed, Then attempt to close these valves remote manually, or local manually, as appropriate.

3. If activity is detected in the steam plant, Then the operator should identify the leaking steam generator(s), and attempt to isolate the steam generator if plant conditions permit.

Acceptance Criteria for Containment Isolation: CI-1

1. Containment Isolation is satisfied if:

   a. No steam plant activity alarms
      and
      No containment radiation alarms
      and
      Containment pressure is less than [4 psig]
      or
   b. Each containment penetration not required to be open has an isolation valve closed.

*Step Performed Continuously.

See DEVIATION 8-17 for ADMINISTRATIVE actions.

2 See DEVIATION 8-2

If the above criteria are satisfied, Then proceed to the next safety function in jeopardy.
If all safety functions are being satisfied, Then implement the Long Term Actions.

2. If the above criteria are not met, Then proceed to the Continuing Actions for Containment Isolation.

1 SEE DEVIATION 8-45

2. Implemented in PRECAUTIÓN VII . A . 1

SUPPLEMENTARY INFORMATION: CI-1

This section contains items which should be considered when implementing EPGs and preparing plant specific EOPs. The items should be implemented as precautions, cautions, notes, or in the EOP training program.

1. The closing of some containment isolation valves may cause the isolation of vital auxiliaries (i.e. instrument air for valve opening/closing, component cooling water to the RCPs or SCS, sampling, N_2 supply, letdown, blowdown) which could lead to equipment damage.

2. Local radioactivity levels should be determined before attempting any local manual valve closure. Appropriate precautions should be taken if high radiation levels exist.

Continuing Actions for Containment Isolation

If the acceptance criteria are not met, then containment isolation is still in jeopardy. The operator must continue attempting to satisfy containment isolation based on the following considerations:

a) The urgency of other safety functions in jeopardy.
b) The risk to plant personnel and the public of leaving certain penetrations unisolated.
c) The feasibility of isolating the penetration by alternate methods.

Bases for Containment Isolation

The containment isolation safety function is the closure of those valves required to isolate the containment following an event characterized by an increase in containment pressure and/or radioactivity levels, or an increased risk of release of activity through a steam generator with leaking tubes. A containment isolation excludes the isolation of those lines penetrating the containment serving to mitigate the accident.

To achieve isolation of those lines penetrating containment that are not required for operation of the engineered safety feature and other systems in order to minimize a release of radioactive materials to the atmosphere, the following method is available:

CI-1: Containment Isolation via Manual Isolation

The bases for the operator actions required for implementing the methods listed above are detailed as follows:

CI-1: *Containment Isolation via Manual Isolation*

Containment isolation is necessitated when a risk to plant personnel and/or the public exists from leaving containment penetrations unisolated. This may include the potential release of radionuclides from a steam generator with leaking tubes.

Operator Actions

1. If containment pressure increases to [4 psig, or if pressurizer pressure decreases to 1600 psia], then the automatic initiation of containment isolation is verified. If containment radiation exceed plant specific limits, the containment should be isolated. If it is necessary to close the containment isolation valves by manually initiating a containment isolation actuation signal, this action is taken. At some plants, containment isolation is actuated on a pressurizer pressure decrease to [1600 psia] or containment radiation alarms.

2. If the containment isolation actuation signal (either automatic or remote manual) has failed to cause a closure of the required isolation valves, then they are manually closed by all means possible.

3. If activity is detected in the steam plant, then this usually means that at least one steam generator has tube leaks. The operator should attempt to identify the affected (or most affected, if both S/Gs have leaks) by sampling and other plant specific means. If the steam generator is not required to remove heat from the RCS (i.e. the other steam generator is available or some other heat removal path is available), that steam generator (or the most contaminated steam generator, if both are leaking) should be isolated. The operator must weigh the impact on RCS and Core Heat Removal of removing an S/G from operation against the potential for release of radionuclides to the environment.

After implementing the above actions, Containment Isolation is satisfied if there are:

a) No steam plant activity alarms

and

No containment radiation alarms

and

Containment pressure <[4 psig]

<u>or</u>

b) Each containment penetration not required to be open has an isolation valve closed.

[4 psig] is the plant specific CIAS setpoint. Each plant should specify which containment radiation levels or alarm setpoints warrant containment isolation. If a plant has an automatic CIAS on containment radiation, this value should be used as the criterion. Activity in the steam is usually a symptom requiring steam generator isolation. Containment penetrations required for essential services such as cooling water to the RCPs or SIS function need not be isolated when containment isolation is called for. The operator must be alert to the possibility that any unisolated penetration may be a potential path for release of fission products.

Continuing Actions For Containment Isolation

If containment isolation is still in jeopardy, then the operator must evaluate whether to continue attempting to satisfy containment isolation or go to the next safety function in jeopardy, while continuing to attempt restoration of containment isolation. This decision should be based on risk to plant personnel and the public, the urgency of other safety functions in jeopardy, and the feasibility of restoring equipment to restore success paths.

SAFETY FUNCTION: Containment Temperature and Pressure Control
SUCCESS PATH: Containment Fans; CTPC-1
RESOURCE TREE: Tree G

OPERATOR ACTIONS

*1. [Verify automatic operation of the containment fan cooling system at the plant specific setpoint. If at least 2 containment fans are not running in slow, Then they should be started manually].

2. Ensure cooling water is aligned to the containment fan cooling system.

Acceptance Criteria for Containment Temperature and Pressure Control: CTPC-1

1. Containment Temperature and Pressure Control is satisfied if:

   a. Containment temperature is less than [240°F]
   and
   b. Containment pressure is less than [1.5 psig]

   If the above criteria are met, Then proceed to the next safety function in jeopardy.
   If all safety functions are being satisfied, Then implement the Long Term Actions.

2. If the above criteria are not met, Then proceed to CTPC-2 on Resource Tree G.

*Step Performed Continuously.

1. implemented in STEP VIII.B.1. TRAINING ENSURES THAT ANY automatic initiation failure is backed up by manual initiation. This philosophy is not repeated after each Automatic action in order to simplify the procedure

2. SEE DEVIATION 8-46. USE OF CONTAINMENT SPRAY for Iodine Removal is addressed in section VIII.D.

1. Implemented in CONT. ENVIRONMENT SAFETY FUNCTION STATUS CHECK. SEE DEVIATION 8-17 FOR ADMINISTRATIVE ACTIONS.

SAFETY FUNCTION: Containment Temperature and Pressure Control
SUCCESS PATH: Containment Spray; CTPC-2
RESOURCE TREE: Tree G

OPERATOR ACTIONS

*1. If containment pressure increases to [10 psig], Then verify actuation of a CSAS.
If containment spray does not initiate automatically, Then manually initiate containment spray.

2. If a CSAS has been actuated and containment pressure subsequently falls below [7 psig], Then containment spray may be terminated. Upon termination it must be realigned for automatic operation. [It may be desirable to operate containment spray to control containment atmospheric iodine concentrations].

Acceptance Criteria for Containment Temperature and Pressure Control; CTPC-2

1. Containment Temperature and Pressure Control is satisfied if:

   a. Containment spray flow is greater than [1500 gpm] (per spray header)

   and

   b. Containment temperature and pressure are constant or decreasing.

If the above criteria are met, Then proceed to the next safety function in jeopardy.

*Step Performed Continuously.

2. SEE DEVIATION 8-2.

If all safety functions are being satisfied, Then implement the Long Term Actions.

2. If the above criteria are not met, Then proceed to Continuing Actions for Containment Temperature and Pressure Control.

Continuing Actions for Containment Temperature and Pressure Control

If Containment Temperature and Pressure Control is not satisfied, then the operator must go on to other jeopardized safety functions and continue pursuing this safety function based on these considerations:

a) Rate of change of containment temperature and pressure, and potential for damage, to the containment.
b) The urgency of other jeopardized safety functions.
c) The feasibility of restoring function to a success path by:
   i) restoring the vital auxiliaries necessary to operate components or systems in the success paths
   ii) manual operation of valves
   iii) use of alternate components to implement a success path.

Bases for Containment Temperature and Pressure Control

The purpose of the Containment Temperature and Pressure control safety function is to prevent damage to the containment building which provides a barrier to fission product release to the general public.

To achieve control of containment temperature and pressure, the following two methods are available:

CTPC-1: Containment Temperature and Pressure Control via Containment Fans, No Containment Spray

CTPC-2: Containment Temperature and Pressure Control via the Containment Spray and/or Containment Fans

The bases for the operator actions required for implementing each of the methods listed are detailed as follows:

CTPC-1: *Containment Temperature and Pressure Control via Containment Fans, No Containment Spray*

Heat may be removed from the containment to reduce temperature and, subsequently, pressure by use of the containment fan cooling system.

Operator Actions

1. The containment fan cooling system removes heat from the containment by passing containment air through heat exchangers cooled by the component cooling water system. [Two fan coolers running on slow are required to provide post-accident heat removal capability. Each plant should enter the required containment fan cooling scheme for their plant for accident conditions. These two fans should start automatically. If not, they should be started manually and run on slow.]

2. Cooling water, supplied to the containment fan cooling system, is required to ensure that a heat sink is available for removing the containment heat blown by the fan coolers. Once, the heat is absorbed by the component cooling water system, it may be transferred outside containment to an ultimate heat since (cooling towers, spray pond, etc).

After implementing the above actions, Containment Temperature and Pressure Control is satisfied if:

a. Containment temperature <[240°F]

and

b. Containment pressure <[1.5 psig]

For any event, containment pressure and temperature should ideally be below these limits. However, if they are not, the operator must continue pursuing achievement of this function by engaging the operation of additional containment temperature and pressure reducing equipment and systems.

CTPC-2: *Containment Temperature and Pressure Control via Containment Spray and/or Containment Fans*

The containment spray system removes heat from the containment by spraying water droplets throughout the containment atmosphere. This condenses steam and cools the air, subsequently reducing containment pressure.

Operator Actions

1. Operation of this system is required once containment pressure increases to [10 psig]. Operation should commence automatically upon receipt of a containment spray actuation signal; otherwise a manual CSAS should be initiated. In the event a manual CSAS does not start containment spray system operation, the system should be aligned and the pumps started manually.

2. Before terminating containment spray, the operator must verify that containment pressure is below [7 psig]. Termination may be useful to recover from the LOCA since continuous use of the containment sprays may impact the operation of equipment inside containment. Since the containment pressure may increase again, the containment spray system should be realigned for automatic operation when it is terminated. [Containment Spray System operation may also be desirable when in conjunction with the iodine removal system in the event of an iodine buildup in containment. To minimize the radionuclide releases to the environment following an RCS boundary break and/or core damage, it is desirable to keep the radionuclides inside the containment. Iodine is the nuclide of greatest concern. The iodine removal system (IRS) may be aided by the containment spray system (CSS) to remove iodine from the containment atmosphere. Since iodine may be released to the containment atmosphere at various times following event initiations, (e.g., released directly from the core in a large LOCA; reevolved from iodine plated out on containment surfaces; or released during reactor vessel venting to the containment) and since the CSS is activated automatically on containment pressure, its actuation may not correspond to the time of peak

containment iodine levels (if it is actuated at all). The CSS may be run to reduce containment airborne iodine to acceptable or minimum levels unless the following indicate otherwise:]

[1. If there were a leak in containment below sump water level, it might be more desirable to leave the iodine atmospherically suspended.

2. If sump water is highly radioactive, it may not be desirable to circulate it outside the containment.]

[For those IRS's using hydrazine, it may be necessary to further increase sump water pH (beyond that achieved by trisodium phosphate in the sump) to increase long-term (4 hours post-LOCA) iodine retention in the sump. An alternate method of adding a pH buffer (typically sodium hydroxide) is by establishing a flowpath with the charging pumps.]

After implementing the above actions, Containment Temperature and Pressure Control is satisfied if:

a. Containment spray flow is greater than [1500 gpm] (per spray header)

<u>and</u>

b. Containment temperature and pressure are constant or decreasing.

Continuing Actions For Containment Temperature/Pressure Control

If containment temperature and pressure are not being controlled, then the operator must continue pursuing satisfaction of this function as well as other jeopardized safety functions.

SAFETY FUNCTION: Containment Combustible Gas Control
SUCCESS PATH: [Plant Specific Method, Insert Here]; CCGC-1
RESOURCE TREE: Tree H

OPERATOR ACTIONS

1. [Plant specific actions, insert here].

Acceptance Criteria for Containment Combustible Gas Control; CCGC-1:

Hydrogen concentration is less than [2%].

If the above criterion is satisfied, Then proceed to the next safety function in jeopardy.
If all safety functions are being satisfied, Then implement the Long Term Actions.

Bases for Containment Combustible Gas Control

CCGC-1: *Containment Combustible Gas Control*

Operator Actions

1. [Plant specific actions, insert here]

After implementing the above action(s), Containment Combustible Gas Control is satisfied if:

Hydrogen concentration is <[2%].

A hydrogen concentration of 2% is 50% of the flammability concentration in air. Hydrogen in the containment is indicative of a primary system leak into containment and may also be indicative of core damage. The explosive hazard which may exist in the containment could present a threat to containment integrity.

LONG TERM ACTIONS

In this section the operator continues to periodically verify the adequate maintenance of safety functions, assesses the status of the plant, and implements the appropriate optimal recovery guideline, if possible.

*1. Compare plant indications against the acceptance criteria of the FRG Safety Functions Status Check for the success paths currently in use for each safety function.
If any success paths do not meet the acceptance criteria, Then go to the appropriate resource assessment tree to fulfill the jeopardized safety function.

*2. Verify present plant status. This entails the identification of the following:

a) Present RCS conditions (inventory, temperature, pressure, radioactivity levels, etc.)
b) Success paths in use for fulfilling each safety function
c) Adequacy of core cooling
d) Plant area radiation levels
e) Rates of radioactivity release to the environment

*3. If a specific event (e.g., LOCA, LOFC, LOF, etc.), or the cause of the transient, can be identified, Then further guidance for casualty management may be found in an Optimal Recovery Guideline (ORG).

4. Do not discontinue implementing a success path unless another equivalent path has been verified ready for implementation.

*Step Performed Continuously.

*5. Determine whether a cooldown to cold shutdown is necessary and if it is, is it feasible and/or urgent. Consider the following:

a) Available condensate inventory and ability to replenish inventory
b) Rate of release of radioactivity to the environment
c) Failed equipment, or conditions, which may prevent or inhibit a cooldown (e.g., loss of all pressurizer sprays, inability to dump steam, RCS voiding)
d) Availability of electrical power to key equipment (e.g., diesel generator, offsite power, battery endurance)
e) Other vital auxiliaries such as control air, cooling water, etc.
f) Availability and desirability of the shutdown cooling system (e.g., considering the ability to depressurize the RCS, adequacy of RCS inventory for LPSI pump suction, desirability of circulating highly radioactive coolant outside containment, etc.)
g) Personnel available, including technical support center and offsite engineering

*Step Performed Continuously

11.0 CEOG EPG VALIDATION

11.1 Introduction

This section discusses the various activities conducted by the CEOG to validate the CEOG Emergency Procedure Guidelines. Validation of generic technical guidelines is defined as any formal activities conducted to determine the technical adequacy of the guidelines. The CEOG considers that it has conducted the validation of these guidelines in four distinct ways:

1. Workshops
2. C-E Internal Technical Review
3. CEOG Review
4. Simulator Validation

Of course, the technical review conducted by the NRC could also be considered to be part of the process of assuring the technical adequacy of the EPGs, but that will not be documented here.

11.2 Workshops

A number of workshops (or technical review meetings) have been conducted for the EPGs. These have taken place over a period of two years and have been consistently attended by C-E and CEOG personnel with a wide variety of design, analysis, training and operational expertise. A major objective of the workshops was to systematically evaluate failures of systems used in mitigating events. Engineering judgement was used to decide the limit on the number of multiple failures considered for each event.

The first series of workshops reviewed the EPGs and supporting best estimate analysis (this material is contained in CEN-128, "Response of C-E NSSS to Transients and Accidents") which constituted the CEOG response to Section 2.1.9 of NUREG-0578, "TMI-2 Lessons Learned Task Force Status Report and

Short-Term Recommendations". Three workshops of three days each reviewed CEN-128 before its submittal to the NRC. These meetings essentially conducted a line-by-line review of the guidelines. The meetings were attended by operations personnel from CEOG member utilities and design and analysis personnel from C-E.

Following the submission of CEN-128, the workshop process was used a second time to review and comment on improved emergency procedure guidelines based on the currently NRC-approved LOCA guidelines, the C-E ICC operational guidance and the emergency procedure guidelines in CEN-128. These improved guidelines were designed to address multiple plant failures and to meet the requirement of Item I.C.1 of NUREG-0737, "Clarification of the TMI Action Plan". The new guidelines were contained in CEN-152, Revision 0, C-E Emergency Procedure Guidelines.

Four CEOG workshops that were held during the first four months of 1981 provided information that included:

1. A critique of the event scenarios considered by or included in the development of each emergency procedure guideline;
2. An identification and/or verification of expected equipment, instrument or operator responses identified in the guidelines;
3. An evaluation of the operator reaction to the guidelines and their feedback for further improvement;
4. An evaluation of the generic applicability of the guidelines and related training materials;
5. Plant specific operational information related to events and malfunctions beyond that considered in the typical plant design basis.

The information developed at a workshop was documented as an output of the workshop process. Immediately following a workshop, the documentation was issued to the participants to allow them to assess its accuracy and to provide feedback on the proposed use of their information. Proposed changes and additions to the emergency procedure guidelines and training information were addressed at the beginning of the following workshop session.

The CEOG workshops were each held for a three day period. Experts from C-E and C-E Owners Group member utilities participated. Personnel attended from the design, analytical, procedure development, and operational areas.

From the design area, C-E provided personnel experienced in the design, procurement, installation, and initial operation of each NSSS sold by C-E. Their experience included knowledge of emergency safeguards and auxiliary components and systems. Their expertise included:

1. An equipment-level understanding of component and system functional capabilities and their relationships to connected systems;
2. An understanding of component and system design bases;
3. Feedback of field operations from all operating C-E plants;
4. Related operating experiences (e.g., Navy, Army).

From the analytical area, personnel from C-E provided background transient and accident information for incorporation in the guidelines. This information included:

1. Evaluation and simulation results of probable event scenarios (greater than 10^{-6}/yr), including multiple equipment failures or operator errors;
2. Related sequence of events diagrams (SEDs) showing the step by step success paths for automatic and operator initiated equipment operation required to accomplish each safety function, as well as any alternative paths available;
3. Related lists of the minimum required responses of various mitigating systems, the expected ranges and trending of parameter variations, and the expected response to control room instrumentation throughout the event.

From the procedure development area, C-E and utility representatives provided the basis for the format and content of the improved emergency procedure guidelines. This information included:

1. A justification of the overall format and detailed format (order of presentation, use of charts, etc.) of the guidelines;
2. An evaluation of the level of detail and volume of information presented to the operators;
3. An evaluation of the relationship of the emergency procedure guidelines to existing guidelines, standards, etc.;
4. Direct input based on their experience in generating guidelines and interacting with operators.

From the operations area, the utilities with C-E NSSSs provided the operators' point of view. Their input included:

1. A critique of the event scenarios considered or included in the development of each emergency procedure guideline;
2. An identification and/or verification of expected equipment, instrument, or operator responses identified in the guidelines;
3. An evaluation of the anticipated operator reaction to the guidelines and feedback for further improvement;
4. An evaluation of the generic applicability of the guidelines and related training material.

A set of "What If" questions was developed and distributed for each guideline prior to the discussion of the guideline in the workshops. The questions dealt with both the technical content and the format of the respective guideline. The technically oriented "What If" questions stimulated discussion on the adequacy of the guidelines in the area of multiple failures.

A typical workshop meeting would begin with an overview of the three day agenda. The attendance included both C-E and the utility personnel and totaled approximately twenty-five people. Because of the number of questions involved, the workshop was divided into three groups. The "What If" questions would be equally divided among the groups. Each group would address the assigned questions and would also critique one of the major areas of the guidelines. These critiques provided discussions on the consistency of information among the different sections of the guidelines, along with a check

on consistency for the various guidelines. After completing the questions, the three groups would meet as a whole and present the resolutions for their respective questions. If the full group was not satisfied with an individual group's response, further discussion would be generated and the question resolved.

Another set of workshops took place when an adequate agenda was realized during development efforts. The first of this workshop series took place in the fall of 1981 and continued through the first two quarters of 1982. Each workshop typically lasted two days and was attended by design, analysis and training personnel from C-E and operations personnel from CEOG member utilities.

The topics of these workshops were as follows:

November, 1981: Current NRC regulations and proposed regulations and their impact on EPG development.

January, 1982:

1) Restructuring the EPG system such that the reactor trip guideline became the entry point to the EPG system from where a diagnosis is attempted and either optimal or functional recovery guidelines are accessed.

2) Clarification of the scope and use of the safety function status charts.

3) Restructuring the EPG system such that the actions necessary to respond to an "anticipated transient without scram" (ATWS) event are included in the reactor trip guideline and in the Reactivity Control section of the functional recovery guideline (a separate ATWS guideline will not be included).

4) Responding to technical comments resulting from the Operations Subcommittee review of the guideline package.

5) CEOG responses to the September 15, 1981 NRC comments on the EPGs.

March, 1982:

1) CEOG detailed review of EPG changes performed by C-E.
2) CEOG approval of an EPG simulator validation plan.

April, 1982:

1) CEOG technical review of draft EPGs to be submitted to NRC on April 30, 1982.
2) CEOG review of simulator validation results and approval of incorporation of results in the EPGs.

11.3 C-E Internal Technical Review

As noted in Section 1.0, considerable technical investigation preceded the development of the CEOG EPGs. Further technical development has proceeded in parallel with EPG development. In order to ensure complete and correct incorporation of this technical information in the EPGs, a technical review of the EPGs was conducted by experts in relevant fields within C-E. Experienced engineers familiar with the EPGs from the workshop process conducted the review. These experts were in the LOCA analysis, non-LOCA safety analysis, RCS design, mechanical design, auxiliary systems design, and training groups.

11.4 CEOG Review

In parallel with the C-E Internal Technical Review, CEOG member utilities conducted a technical review. This review was performed by operations personnel not intimately involved with the EPG development, thus providing a fresh look at the EPGs.

11.5 *Simulator Validation*

The final form of validation employed with the EPGs was obtained through exercising on a full scope simulator. The purpose of the simulator validation was to test the technical completeness and correctness of the EPGs in a realistic setting. Simulator validation took place in five phases:

1. Planning
2. Preparation and Training
3. Simulator Walkthrough
4. Simulator Drills
5. Evaluation and Incorporation of Results

12.0 IMPLEMENTATION

12.1 INTRODUCTION

The purpose of this section is to provide guidance to the procedure writers to assist in implementation of the CEOG EPGs. The process for development of Emergency Operating Procedures (EOPs) has been given much attention in the industry. NRC guidance related to this subject is contained in NUREG-0899. The Institute for Nuclear Power Operations (INPO) established the Emergency Operating Procedures Implementation Assistance Program and published several industry documents related to implementation. The theme of these documents is to provide direction for translation of technical guidelines into EOPs using existing plant documentation.

12.2 PROCESS FOR EPG IMPLEMENTATION

Step 1: Establish Implementation Plan

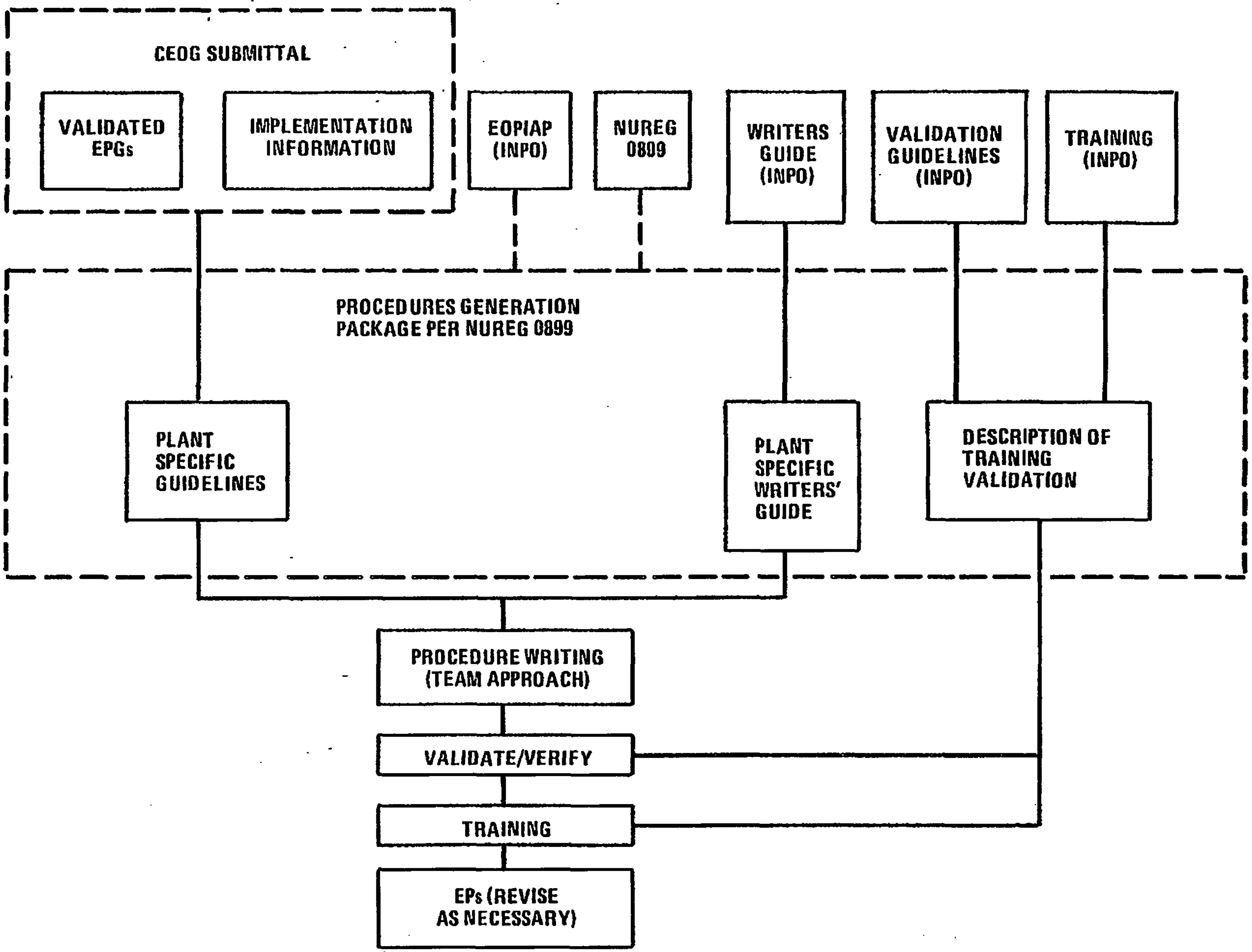
The purpose of an emergency procedure implementation plan is to formalize the process for converting generic guidance into an EOP format for application at a specific utility. The method used will vary in approach for a given utility, but the goal is a common one. That goal is to effectively translate the generic C-E Emergency Procedure Guidelines into a usable, plant specific form. Usable means that the results are technically sound, coherent in presentation, operationally compatible, and acceptable to the operating staff.

The generic plan contained in this document provides a necessary degree of freedom of application. While the elements of this plan are based on the current industry and regulatory guidance, it is designed to accommodate desired variations within the scope of what is acceptable for implementation of plant specific EOPs.

Figure 12-1 illustrates the major activities and products for a typical implementation plan.

FIGURE 12-1

TYPICAL IMPLEMENTATION PLAN



Step 2: Prepare Plant Specific Writer's Guide

Using generic writer's guides available throughout the industry, a plant specific writer's guide is prepared. Procedure writing based on the principles outlined in the writer's guide will result in the development of an EOP system that complies with the current regulatory requirements for ensuring proper mitigation of, and recovery from, emergency events. Examples of the items that should be considered by the writer's guide are:

- General Guidance
- Presentation of Information and Readability
- Organization of EOPs
- Format of EOPs
- Style of Expression and Presentation
- Content of EOPs
- Control Room Staffing and Division of Responsibilities

Step 3: Establish Procedure Writing Team

Figure 12-2 illustrates the flowpath and major blocks of information that are required for detailed procedure writing activities. Care must be taken to select an EOP writing team that, in the aggregate, is knowledgeable of the EPG development process, human factors principles, plant design and operations, and has suitable writing abilities. In addition, EOP writers should be knowledgeable of existing plant procedures, the safety function concept, and the EOP writer's guide.

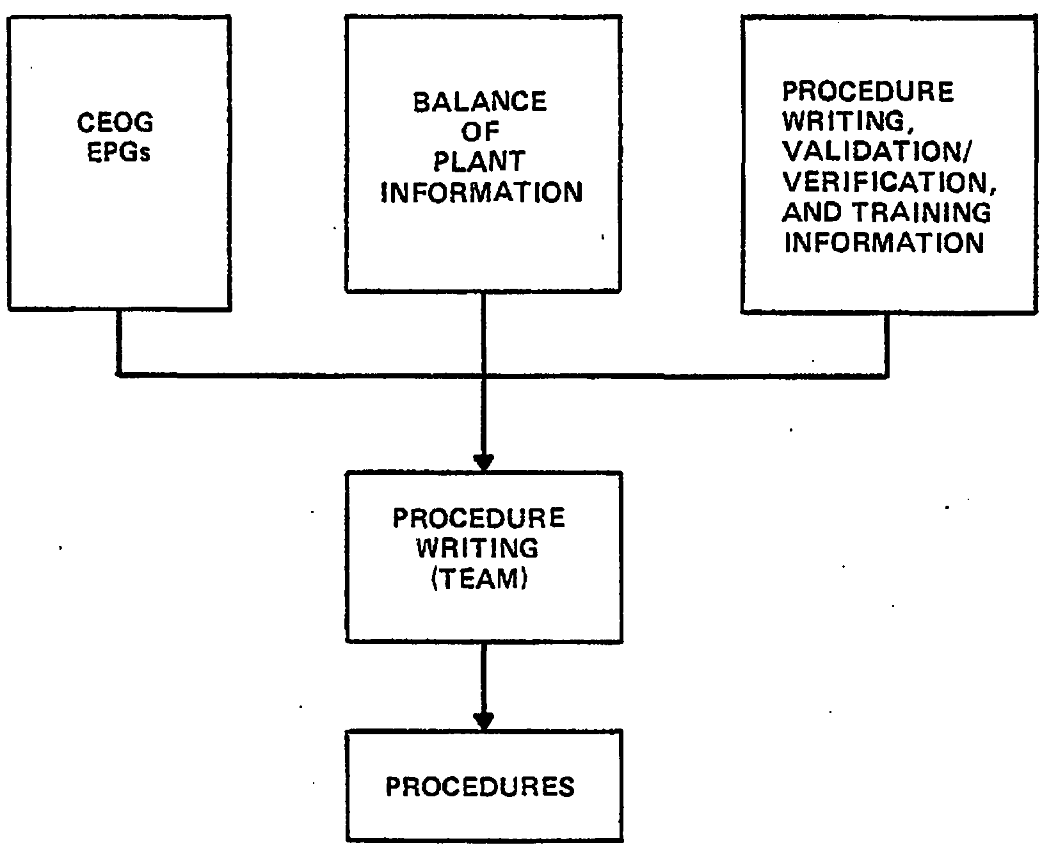
Step 4: Develop Data Base

The foundation for effective EOPs is accurate and detailed information, much of which is plant specific. One of the first activities of this plan is to establish a complete data base. The data base consists of technical information. The data base will be developed from utility documents which include:

FIGURE 12-2

EMERGENCY PROCEDURES DEVELOPMENT

OVERVIEW OF PROCESS



a) most recent P&IDs,
b) most recent electrical wiring diagrams and interconnecting wiring diagrams,
c) a complete set of existing normal, abnormal and emergency procedures,
d) general arrangement drawings,
e) some systems descriptions,
f) Technical Specifications (future or up to date),
g) technical manuals,
h) Final Safety Analysis Report (FSAR),
i) plant specific transient analyses,
j) NRC documents (NUREGS, Notices, Bulletins, etc.)
k) operating experience reports,
l) Plant Design Change Requests,
m) licensing commitment letters,
n) EPG's presented in CEN-152, "The Combustion Engineering Emergency Procedure Guidelines".

Step 5: Conduct Procedure Writing

EOP writing should be conducted as directed by the utility writer's guide using the procedure writing team. The product will be high quality emergency procedures which are ready to be validated. While there is a certain amount of flexibility in converting generic EPGs to plant specific EOPs, there are certain elements that must be preserved. These are outlined in detail in Section 12.3

Step 6: Verify EOPs

Verification is an evaluation of the technical correctness of the incorporation of plant-specific and generic information into plant-specific EOPs. The evaluation should take the form of a documented comparison of the data base documents and plant equipment including the control room layout to the plant specific EOPs. The data base documents include those listed in Section 12.2 Step 4 of this plan. Areas of interest in the process include:

- the accurate and complete translation of the EPGs
- the inclusion of all applicable EPG information
- the accurate reference to plant equipment
- the orderly and efficient flow of the EOPs
- the adherence to the precepts of the writer's guide
- the limitations of the operator with respect to task demands

The process should be conducted by one, or a combination, of the following:

- Control room walk-through
- Workshop review
- Desktop walk-through

Step 7: Validate EOPs

Validation is the process where the EOPs are checked to determine if they are usable during emergency conditions. By verifying that EOPs can be successfully used by operators during simulated events, assurance is provided that the same holds true should a real emergency occur. In essence, validation is a verification of the EOPs during dynamic conditions. The validation consists of operating crews using the EOPs during simulated events. The usefulness of the EOPs is determined by direct observation and debriefings. It is desirable to perform this exercise on a plant specific simulator, although a generic simulator, workshops, or desktop reviews may also be used.

In performing the EOP validation, it is first necessary to construct accident scenarios. There are two major considerations here. The number of scenarios should be large enough to sufficiently test the EOPs, but they must be designed to be within the capability of the simulator. Figure 12-3 lists typical scenario titles.

Any discrepancies identified during the process must be resolved.

Figure 12-3

TYPICAL VALIDATION SCENARIOS

- Turbine Trip
- Reactor Trip (2 CEAs stuck out, letdown valve failure)
- Loss of Condenser Vacuum
- Loss of Main Feedwater (100% power)
- Loss of Main Feedwater (30% power)
- Excess Feedwater Flow
- Loss of One Reactor Coolant Pump (high vibration)
- Loss of Primary Coolant (small break)
- Loss of Primary Coolant (large break)
- Steam Generator Tube Rupture
- Steam Generator Tube Rupture (leak in other steam generator)
- Turbine Trip (stuck open turbine bypass valve)
- Excess Steam Demand Event (large steam line break)
- Loss of All Feedwater
- Excess Steam Demand Event (with concurrent tube rupture in same steam generator)

Step 8: Conduct Training

The operations staff, and other support staff, must be trained in the effective use of the EOPs prior to implementation. This will be done in accordance with the plant as established in the procedures generation package.

Step 9: Establish Administrative Control

The EOP system will be incorporated into the established document control system except as noted in this plan which addresses:

- Revision, review, and approvals
- Distribution
- Supporting documentation
- Experience feedback

12.3 ESSENTIAL ELEMENTS OF EPGs

The CEOG has expended considerable time and resources in developing the emergency procedure guidelines contained in this report. While it is necessary to allow for a certain amount of flexibility in converting EPGs to EOPs, there are certain elements that must be retained in order to maintain the basic intent of the EPGs. In other words, if a participating utility wishes to reference CEN-152, Combustion Engineering Emergency Procedure Guidelines, certain elements must be preserved and any deviations from these elements must be documented and justified. This section details those required elements.

The elements of the EPG system that must be preserved in the development of an EOP system are:

- EPG system structure
- Event Strategy
- Safety Function Concept
- Safety Function Status Checks
- Success Paths

These fundamental elements are described in the context of implementation in the following sections.

12.3.1 *Preservation of the EPG System Structure*

The structure of the EOPs should be based on key principles that have been identified in various industry documents. These key elements have been addressed in the C-E EPGs and provide a suitable approach to format structure. An overview of the EPG structure is illustrated in Figure 12-4.

The major elements in the structure of the EPGs are:

1) Standard Post Trip Actions (SPTA)
2) Diagnostic Aids
3) Optimal Recovery Guidelines (ORG)
4) Functional Recovery Guidelines (FRG)

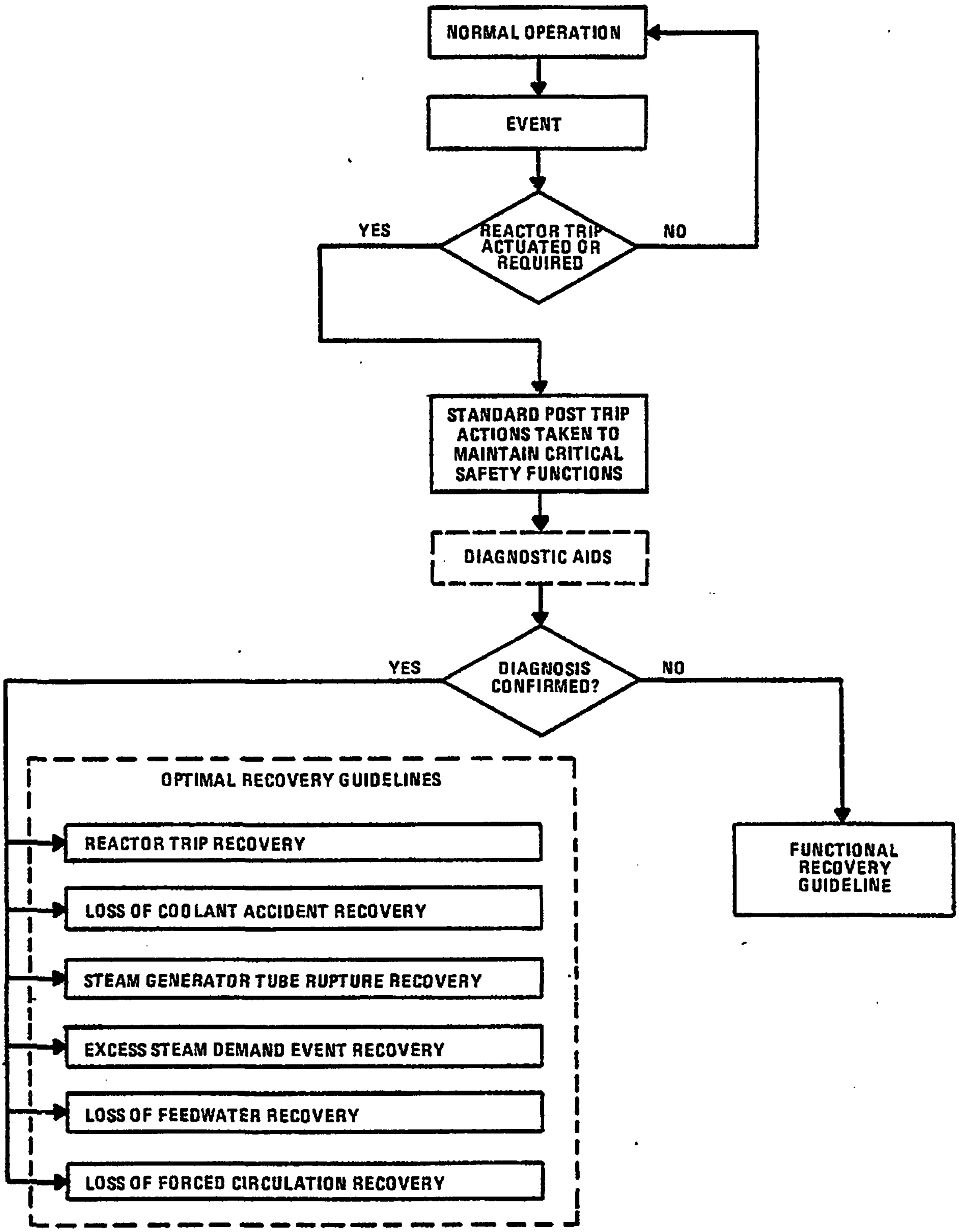
The Standard Post Trip Actions consist of a procedure for evaluating the status of each safety function along with standard post-trip actions which can be quickly and easily performed to improve the status of functions in jeopardy.

Following the Standard Post Trip Actions, Diagnostic Aids may be provided to assist the operators in determining the type of event which is transpiring. Depending on the operators' ability to diagnose, they will then select either an Optimal Recovery Procedure (ORP) or the Functional Recovery Procedure (FRP). The form of the diagnostic aids is the utility's preference. The EPGs provide some examples in Section 3.0 and also make use of break identification charts and safety function status checks.

ORPs will provide guidance which is event specific and contains all actions necessary for recovery of the plant from a specific initiating condition. If the operators have selected the FRP because they cannot diagnose the event, it will provide action steps, based on the control of safety functions, to bring the plant to a safe, stable condition. Each ORP should consist of the following sections:

Figure 12-4

OVERVIEW OF THE EMERGENCY PROCEDURE GUIDELINE SYSTEM



a) Purpose
b) Entry Conditions
c) Operator Actions
d) Supplementary Information
e) Safety Function Status Checks
f) Bases

12.3.2 *Preservation of Event Strategy*

Considerable effort was expended developing the strategy for each EPG. The strategy was based on the best available technical information and consideration of safety functions. Guideline strategy is the mechanism for decision making, for action step sequence, and to some extent, content. Each ORG contains two strategy charts (one general, one detailed). Both charts illustrate the functional and temporal aspects in the careful design of the EPGs. Figure 12-5 provides an example of a strategy chart. The strategy that is illustrated in each ORG serves as a benchmark during implementation.

12.3.3 *Preservation of Safety Function Concept*

A safety function is defined as one or more processes, or conditions, that prevent core melt or minimize radiation releases to the general public. These may result from automatic or manual actuations of systems, from passive system performance, or from natural feedback inherent in the plant design. Taken together, the safety functions comprise a complete set of processes, or conditions, which must occur to ensure public safety.

The safety function concept incorporates a principle of safety function hierarchy to help the operator mitigate the consequences of an event. Some safety functions have precedence over others as far as implementing actions associated with safety function fulfillment. Figure 12-6 summarizes the hierarchy of safety functions as standardized in the CEN-152 guidance. Application of the safety functions concept in a restructured format is acceptable as long as the format contains actions and criteria necessary to control, and fulfill, the individual safety functions. The safety function hierarchy of CEN-152 must be preserved. The ultimate goal is preserving the health and safety of the public.

Figure 12-5

EXCESS STEAM DEMAND EVENT RECOVERY STRATEGY CHART

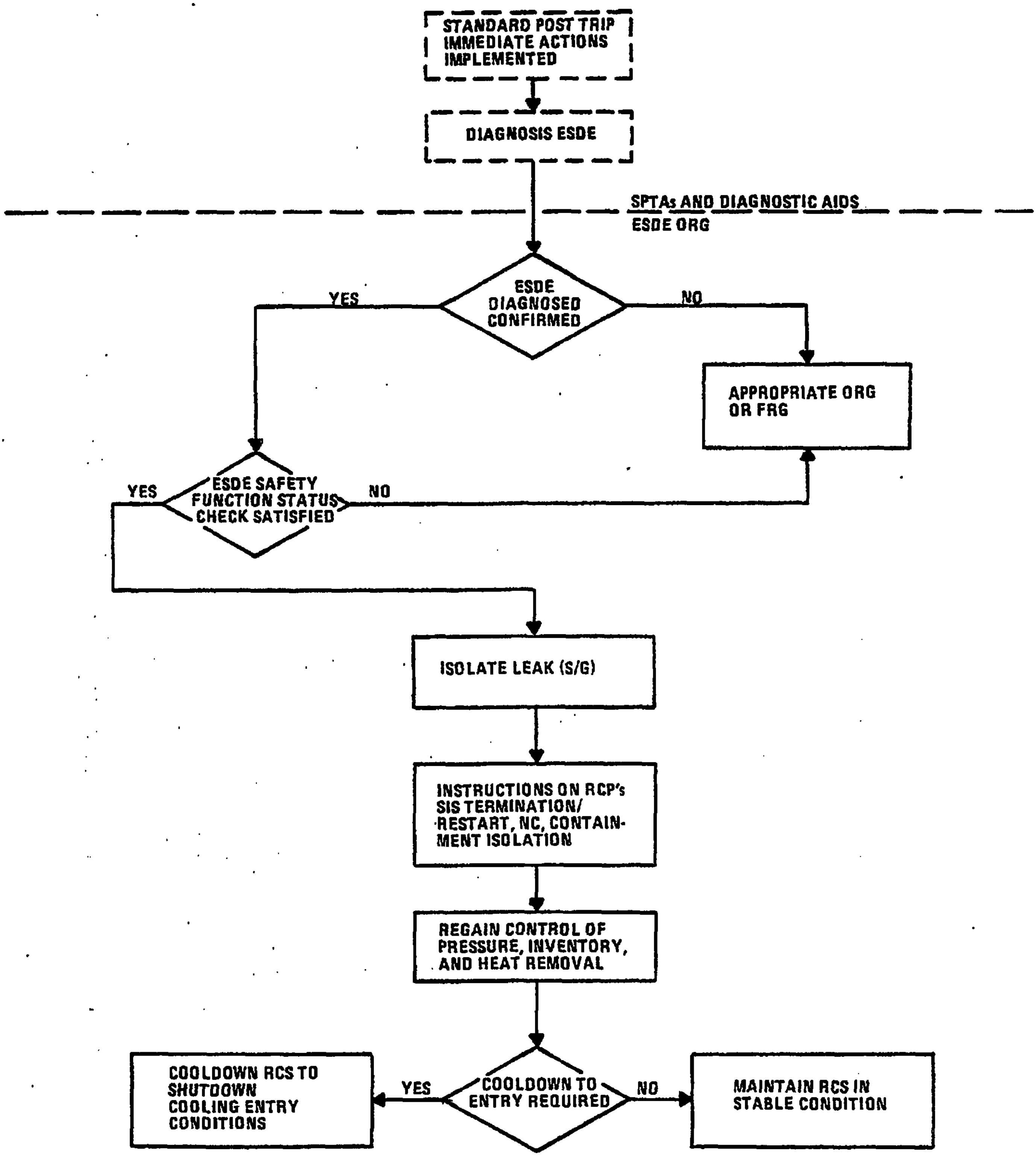


Figure 12-6
SAFETY FUNCTION HIERARCHY

REACTIVITY CONTROL

MAINTENANCE OF VITAL AUXILIARIES (AC AND DC POWER)

RCS INVENTORY CONTROL

RCS PRESSURE CONTROL

CORE HEAT REMOVAL

RCS HEAT REMOVAL

CONTAINMENT ISOLATION

CONTAINMENT TEMPERATURE AND PRESSURE CONTROL

CONTAINMENT COMBUSTIBLE GAS CONTROL

Because safety functions are a complete set of all actions, or conditions, which will ensure public safety, they form the foundation of all emergency guidance.

In preparing procedure guidelines, the safety functions can be used to audit the guidance to ensure that sufficient action steps to cover all relevant safety functions exist.

12.3.4 *Preservation of Safety Function Status Checks*

Each guideline of the EPG system contains safety function status checks. These have been provided to assist the control room team in maintaining an overview of the plant while conducting the detailed activities required by the guidelines. Emergency procedures must provide a mechanism which ensures that the operators maintain an overview perspective of the plant. Safety function status checks have been provided for this purpose.

Each ORG includes a safety function status check which is used by the operator to continually determine whether the safety functions are being adequately fulfilled during the course of the event. Each ORG safety function status check acceptance criteria are unique to that diagnosed event.

The FRG structure includes an expanded version of the Safety Function Status Check format found in each ORG, which is used by the operator to continually check the status of each safety function. Acceptance criteria for each alternate safety function success path are listed. If the criteria for a particular safety function can not be met, then further guidance can be found in the applicable resource assessment tree.

12.3.5 *Preservation of Success Paths*

Each safety function has more than one means of fulfillment. In other words, there exists for each function more than one system or means of achieving safety function acceptance criteria. Each of these means is termed a success path. For example, reactivity control can be achieved by inserting control

rods or by increasing RCS boron concentration. With respect to the latter, there are several methods of increasing RCS boron concentration. It is important that the operator be aware of the various success paths associated with each safety function. Emergency procedures must clearly indicate the alternate means of satisfying each safety function.

12.4 C-E RECOMMENDATIONS FOR EPG IMPLEMENTATION

General Considerations

Emergency procedures shall interface with, but not excessively overlap, the actions and scope of other emergency procedures and the plant procedure systems. Plant procedures needed for support of the EOPs must be revised as necessary prior to implementation of the new EOP system. Established procedures that are not needed due to EOP development should be eliminated.

Properly written procedures must be tailored to those who will use them and the environment in which they will be used. Procedures must accommodate the operators with consideration for range of capabilities of the operator, the number of available operators, and for the range of task demands on the operator. For example, some tasks require the operator to become the feedback in the control loop (e.g., manual control of pressurizer level with the CVCS), thereby demanding considerable attention to the task. Therefore, EOPs should make minimum use of tasks which require considerable vigilance and discourage the removal of systems from automatic control. EOPs must be usable by trained personnel with a wide range of operating experience. EOPs must provide adequate detail for the inexperienced operator while not distracting the experienced operator with excessive information.

Format

Operator actions are selected and sequenced to address all relevant safety functions in their order of importance to the event. Where appropriate, alternate success path actions are included for use when primary success paths have been unsuccessful. The page structure of each EOP should give consideration for the following:

- Title
- Page layout
- Procedure identification
- Step numbering
- Highlighting of imperative information
- Placekeeping aids
- Type style
- Information density

The following basic styles for EOPs are typically discussed:

1) Layered
2) Columnar
3) Narrative
4) Tabular
5) Pictorial (Logic Chart, Flow Chart, Resource Tree)

Each of these has application to different sections of the EOPs. Each style is roughly distinguishable by spacing and level of detail. The spectrum of applicable styles is encompassed by columnar on one side and narrative on the other, with various shades of the layered format in between. A narrative style provides instructions in sentence or short phrase form. Columnar information is generally presented as key words and/or phrases which are left margin justified. Layered uses a combination of key words and phrases in an indented format such that greater detail is included in indented steps. This allows the most experienced operators to follow the left most information while less experienced personnel can get more detail as they need it from the indented paragraphs. Narrative is considered the style with the greatest amount of detail. Some operations personnel consider this style "too wordy" for efficient use as action steps in EOPs. Columnar information is generally not detailed and takes the form of a list.

Maximum use of charts and diagrams should be made throughout the EOPs. Charts and diagrams quickly, and accurately, deliver a large amount of technical information without the need to read long explanatory narratives. They are generally considered applicable for diagnostic aids, operating curves, and the human factored display of complex information.

Style also refers to the vocabulary used in writing procedures. The following goals are desirable:

1) Common nuclear power industry nomenclature should be used,
2) Specific, unambiguous words should be used,
3) Established site terminology should be used,
4) ------------------------

WARNING, CAUTION, NOTE
Statements should be
clearly emphasized

The placement of supplementary information (warning, caution, note) statements can be determined by evaluating the importance, and the applicability, of the statement. Some supplementary information may apply to the entire procedure and may be included in a supplementary information section for the entire procedure. Some of the supplementary information statements, will require placement in the action statements section as well due to their impact on specific actions during an event.

12.5 *DEVELOPMENT OF PLANT-SPECIFIC INFORMATION*

Combustion Engineering developed an Emergency Procedure Guideline system on a generic basis for the CEOG utilities. Generic guidelines were necessary because the Nuclear Steam Supply System (NSSS) and Balance of Plant (BOP) Systems vary from one plant to another. Information, other than the curves in Sections 12.5.1, .2, and .3, which is plant specific in nature, has been enclosed by a set of brackets, [ ]. In order to use these guidelines to write the plant specific emergency procedures, all the information enclosed by brackets and the plant specific curves, must be developed. This section provides information to assist in determining the required information.

12.5.1 *Derivation of RCS Pressure-Temperature Limit Curves*

Post-Accident RCS Pressure-Temperature limits are intended to define acceptable combinations of temperature and pressure. A convenient way to define

acceptable combinations of low temperature and high pressure is to define an upper limit on coolant subcooling. The combination of this upper limit on coolant subcooling for PTS considerations, and a lower subcooling limit for core cooling, defines a band of conditions within which the coolant should be maintained.

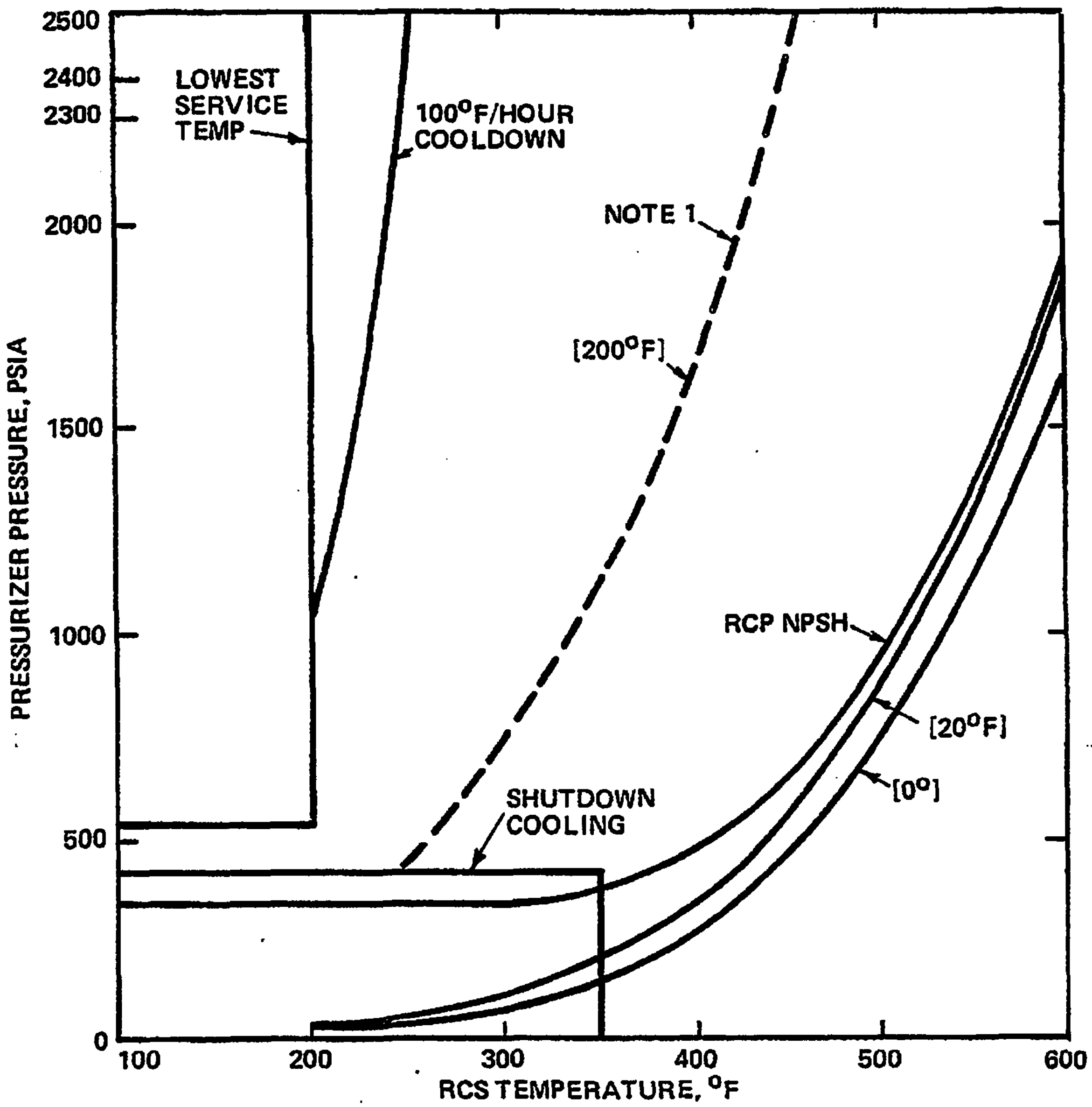
The lower limit on subcooling which is currently contained in the C-E emergency procedure guidelines is, nominally, 20°F. The numerical value of this limit is based on engineering judgement. The reason for having such a limit is to assure that no void formation occurs in the reactor core in order to assure adequate core cooling. Thus, the emergency procedure guidelines instruct that high pressure safety injection pumps must be operating until the coolant subcooling is at least 20°F (along with other specified conditions).

An upper subcooling limit has been developed using engineering judgement based on existing plant thermal-hydraulic and fracture mechanics analyses. It is suggested that the upper limit of subcooling be, nominally, 200°F. This limit is judged to provide a sufficient operating band in order not to interfere with the operator's ability to control the plant. However, analyses have not been conducted to confirm that maintaining subcooling below this upper limit will entirely eliminate the possibility of pressurized thermal shock.

A pressurized thermal shock transient is defined here as an overcooling transient which causes RCS temperature to go below 500°F. The dashed line on Figure 12-7 illustrates the maximum subcooled limit that must be used whenever an overcooling transient, as described above, occurs.

The upper limit was developed with the understanding that, due to the inability of an operator to control the initial cooldown transient in all cases, it is conceivable that the lower limit would be violated during the first part of the transient. Examples of excess steam demand event (ESDE) analyses performed for a generic C-E plant, illustrated in Figures 12-8 and 12-9, show that these transients do not result in a subcooled margin of greater than 200°F during the event. The plots are linear representations of trends that occur between significant time steps. It should be noted that severe ESDEs are sensitive to operator actions and that the figures included here are based on reasonable operator responses.

Figure 12-7
TYPICAL POST ACCIDENT PRESSURE-TEMPERATURE LIMITS(2)



NOTES: (1) THIS CURVE SUPERSEDES THE 100°F/HOUR COOLDOWN CURVE ANYTIME THE RCS HAS EXPERIENCED AN UNCONTROLLED COOLDOWN WHICH CAUSES RCS TEMPERATURE TO GO BELOW 500°F
(2) THESE CURVES MUST BE ADJUSTED FOR INSTRUMENT INACCURACIES
(3) COLOR CODE
RED - PARAMETER IN EXCESS OF LIMITS
ORANGE - PARAMETER IN DANGER OF EXCEEDING LIMITS
YELLOW - PARAMETER OUTSIDE OF OPTIMAL RANGE, BUT STILL WITHIN LIMITS
GREEN - PARAMETER IN OPTIMAL RANGE OF VALUES

FIGURE 12-8
ESDE IN CONTAINMENT

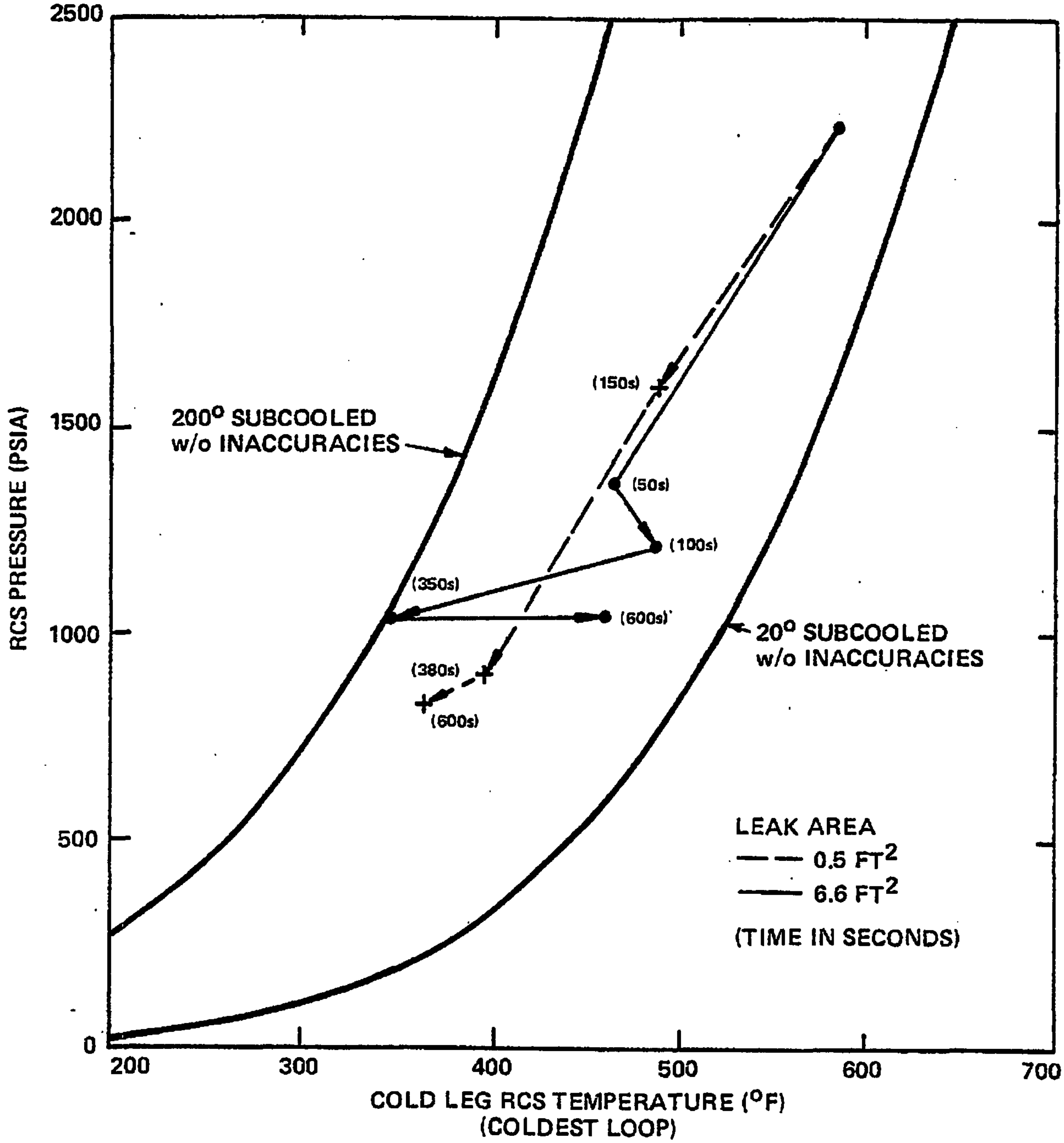
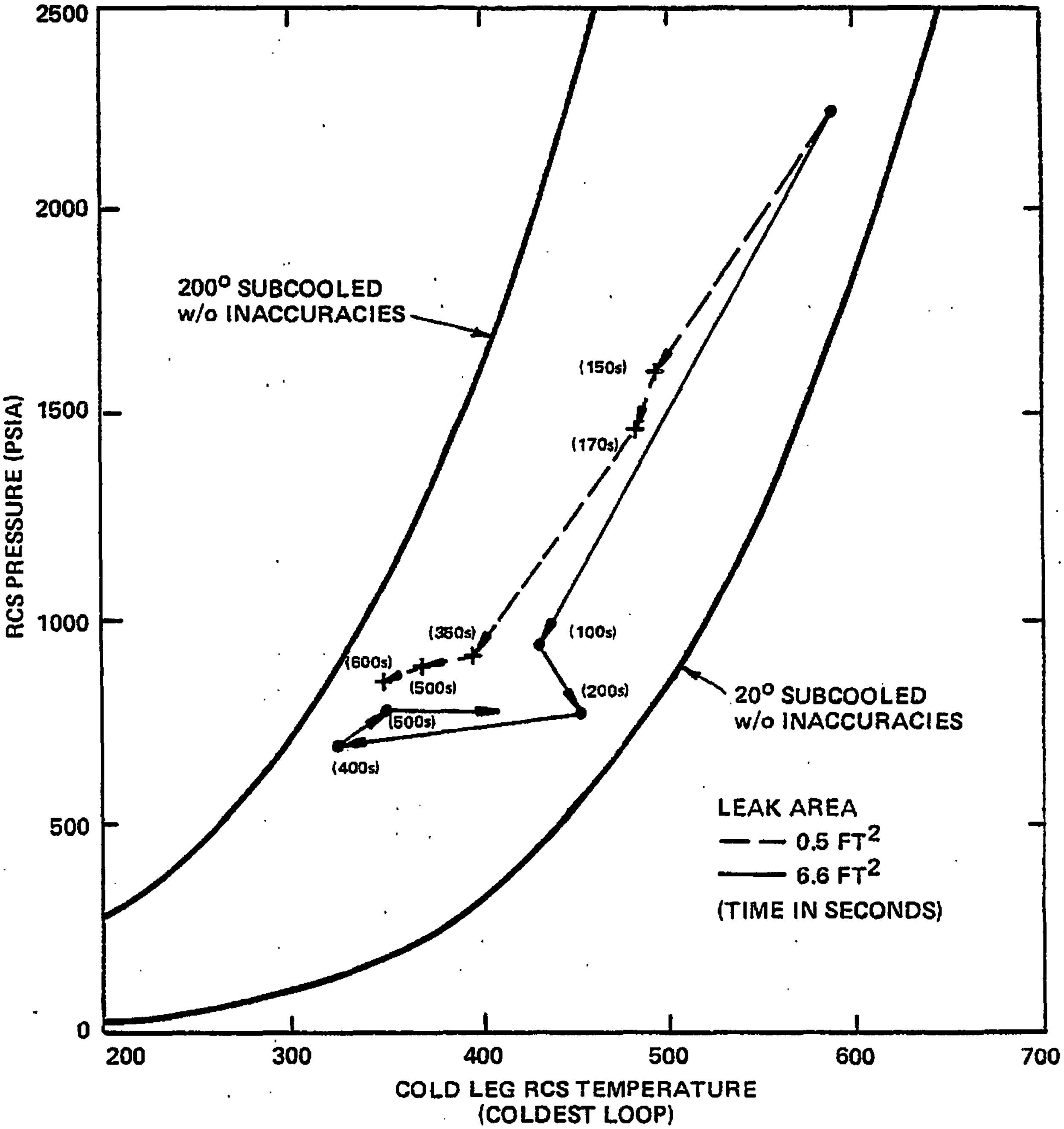


FIGURE 12-9
ESDE OUTSIDE CONTAINMENT



The thermal stress imposed on the vessel during an overcooling transient, when combined with the stress due to the RCS pressure, could result in crack initiation within the reactor vessel. The degree to which any reactor vessel will be affected by PTS will vary depending on the vessel age, vessel composition, neutron embrittlement, and other factors.

Pressurized thermal shock considerations require that high pressure safety injection pumps and charging pumps be turned off, and letdown be reinitiated, when the pressurizer water level reaches some specified value in order to avoid filling the pressurizer and hence overpressurizing the reactor coolant system. However, any conflict between maintaining PTS limits, and maintaining adequate core cooling, must be settled in favor of maintaining adequate core cooling.

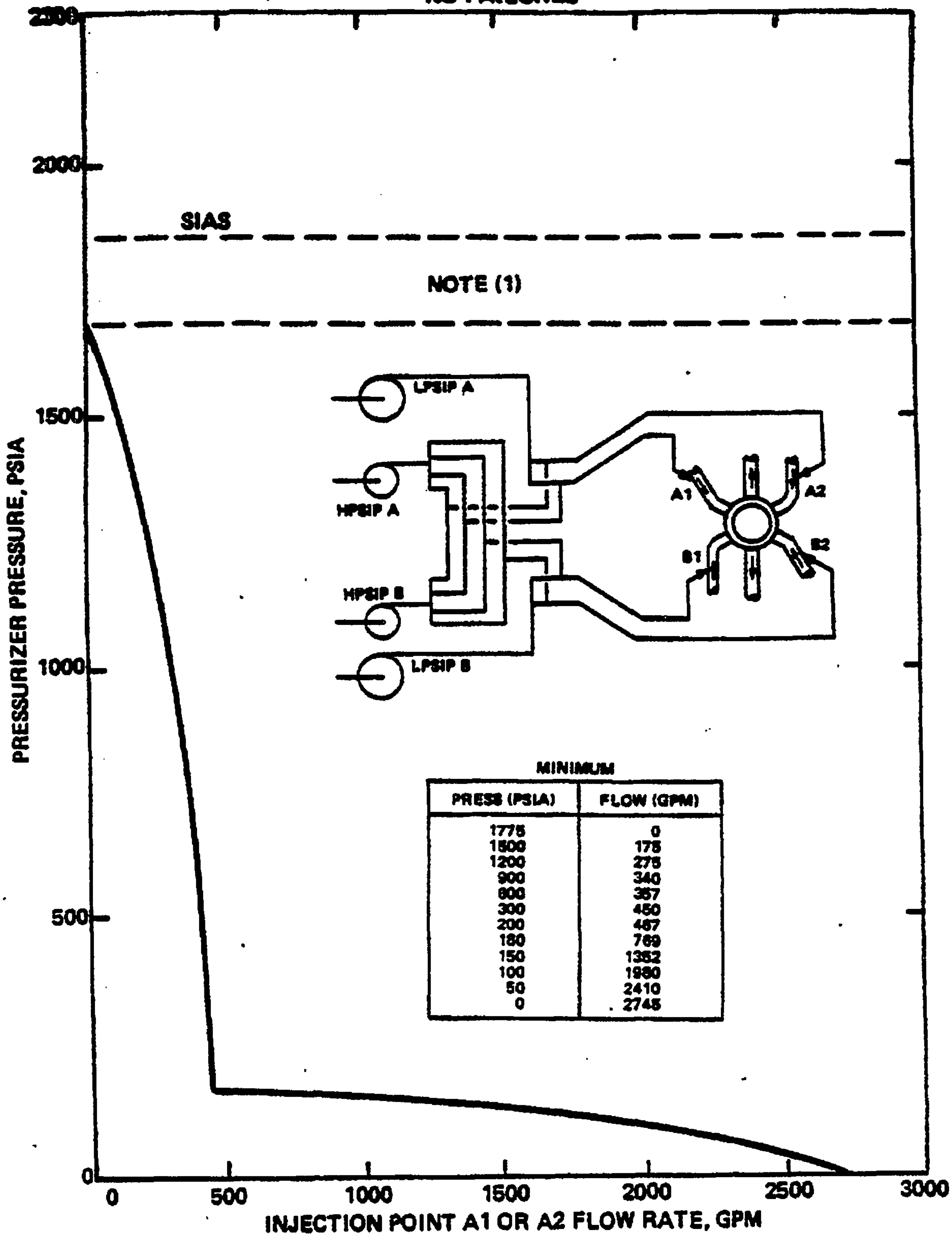
12.5.2 *Derivation of SIS Delivery Curves*

The safety injection system (SIS) may be started manually or automatically during an emergency. Once started, it must continue to run at full flow until specific criteria are satisfied which deal with RCS inventory control, RCS pressure control, and RCS heat removal. After the criteria are met, the SIS may be throttled or terminated. While the SIS is operating, the system's performance must be monitored by checking actual flow against some form of calculated system delivery curve. This curve must be plant specific due to differences in SIS configurations and components, and in the placement of safety injection flow instruments, from plant to plant.

Taking SIS component and instrumentation configurations, and human factors, into account, the emergency operating procedure writing team may deem monitoring specific SIS injection points essential. Figure 12-10 illustrates typical SIS cold leg injection point flow with no SIS component failures. Figure 12-11 illustrates typical SIS cold leg injection point flow when loss of one of the emergency generators has occurred. On the other hand, the emergency operating procedure writing team may deem that an SIS delivery curve representing total acceptable SIS flow (both minimum and maximum values) is more practical and usable. Figure 12-12 illustrates a typical minimum acceptable flow performance for one train of a safety injection system. The flow of two

Figure 12-10

TYPICAL SAFETY INJECTION DELIVERY CURVES
NO FAILURES

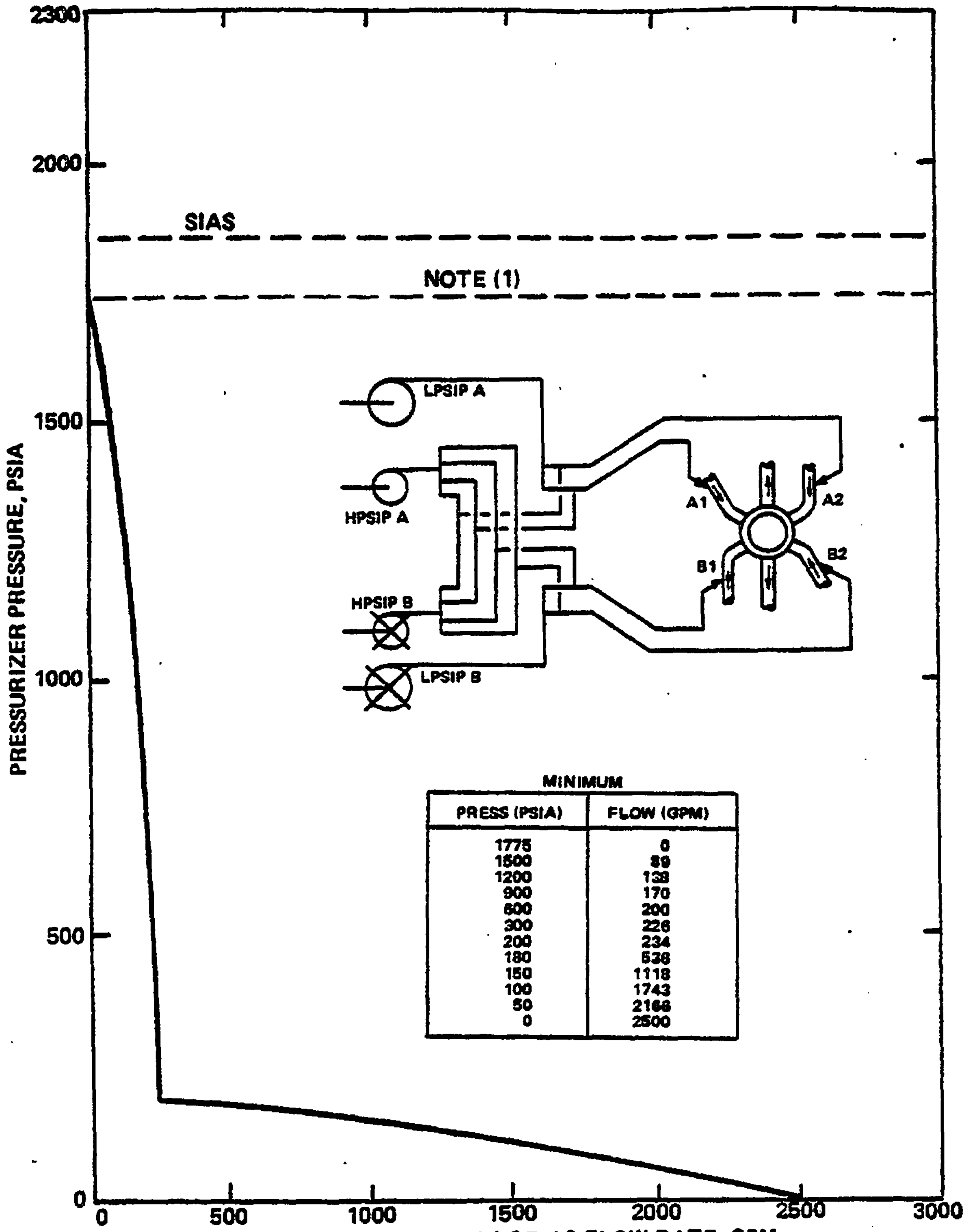


MINIMUM

PRESS (PSIA)	FLOW (GPM)
1775	0
1500	175
1200	275
900	340
600	357
300	450
200	467
180	769
150	1352
100	1980
50	2410
0	2745

NOTE: (1) BELOW SIAS PRESSURE, SAFETY INJECTION SYSTEM (SIS) PUMPS WILL BE OPERATING, BUT THERE WILL BE NO INJECTION FLOW UNTIL SYSTEM PRESSURE FALLS BELOW THE SHUTOFF HEAD PRESSURE OF ANY SIS PUMP

Figure 12-11
TYPICAL SAFETY INJECTION DELIVERY
FAILURE CONDITIONS - LOSS OF ONE EMERGENCY GENERATOR

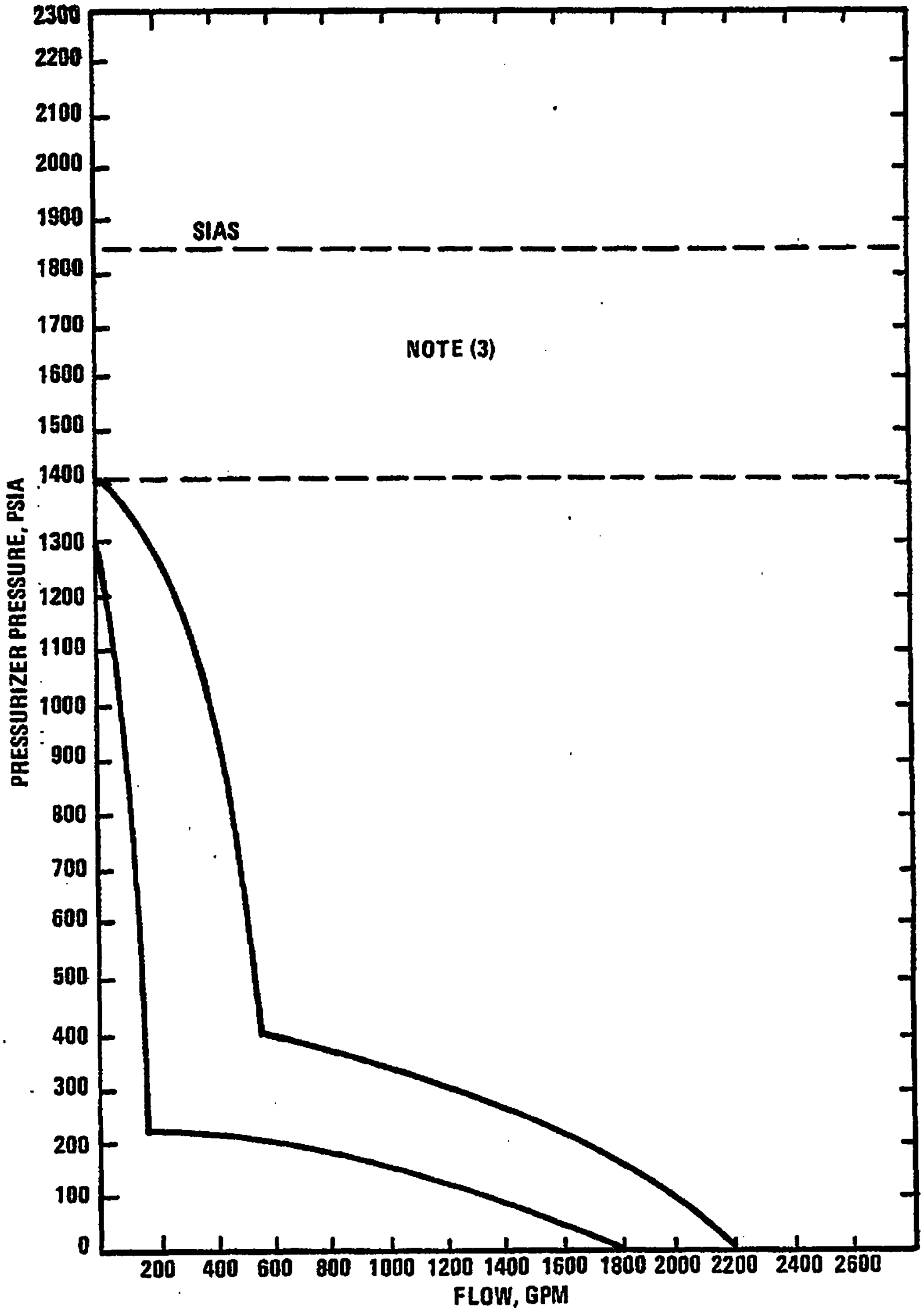


MINIMUM

PRESS (PSIA)	FLOW (GPM)
1775	0
1500	89
1200	138
900	170
600	200
300	226
200	234
180	538
150	1118
100	1743
50	2168
0	2500

NOTE: (1) BELOW SIAS PRESSURE, SAFETY INJECTION SYSTEM (SIS) PUMPS WILL BE OPERATING, BUT THERE WILL BE NO INJECTION FLOW UNTIL SYSTEM PRESSURE FALLS BELOW THE SHUTOFF HEAD PRESSURE OF ANY SIS PUMP

Figure 12-12
TYPICAL ACCEPTABLE SIS FLOW vs RCS PRESSURE[1]
INJECTION MODE[2]



NOTES:
(1) SEE IMPLEMENTATION SECTION FOR DEVELOPMENT OF PLANT SPECIFIC CURVE
(2) FOR HOT AND COLD LEG INJECTION MODE, THE LPSI PUMPS ARE NOT REQUIRED TO BE OPERATING. THE HPSI PUMP FLOW IS DIVIDED EQUALLY BETWEEN THE HOT AND COLD LEGS
(3) BELOW SIAS PRESSURE, SAFETY INJECTION SYSTEM (SIS) PUMPS WILL BE OPERATING BUT THERE WILL BE NO INJECTION FLOW UNTIL SYSTEM PRESSURE FALLS BELOW THE SHUTOFF HEAD OF ANY SIS PUMP
(4) COLOR CODE
    RED - PARAMETER IN EXCESS OF LIMITS
    YELLOW - PARAMETER OUTSIDE OF OPTIMAL RANGE, BUT STILL WITHIN LIMITS
    GREEN - PARAMETER IN OPTIMAL RANGE OF VALUES

centrifugal pumps, one high pressure and one low pressure, are plotted versus pressurizer pressure. The data for these delivery curves are generated by calculations which are based on the experimentally measured pump head curve (manufacturers test reports) and the calculated head loss associated with the discharge header piping leading to the RCS. The RCS pressure must be adjusted to account for the pressurizer elevation head to plot pressurizer pressure versus SIS flow. Plant-specific curves must be based upon plant-specific instrumentation. Procedure writers must decide which (and how many) instruments will be monitored to ensure minimally acceptable SIS performance. The specific flow and pressure instruments to be monitored should be indicated on the curve as well as information on how to interpret, or combine, flows from HPSI and LPSI subsystems in order to enter the curve.

For the LOCA emergency procedure, long term core cooling considerations must be taken into account. The requirements, entry conditions, and actions of SIS simultaneous hot/cold leg injection are among these considerations. However, the curves of Figures 12-10, 12-11, and 12-12 do not display expected, or required, SIS flow rates during simultaneous SIS hot/cold leg injection. It is suggested that a separate plant-specific curve be developed for monitoring hot and cold leg injection. The same considerations apply to this curve as for the cold leg injection mode curve. Procedure writers should select, in advance, the instruments to be monitored and develop and annotate the curves accordingly.

12.5.3 *Derivation of Condensate Inventory Curves*

The following statement is found in those guidelines in which an assessment of condensate inventory determines a course of action:

> The available condensate inventory should be monitored, and replenished from available sources as necessary to continually provide a source for a secondary heat sink. Examples of alternate sources of condensate are nonseismic tanks, fire mains, lake water supplies, potable tanks, etc. Plant-specific alternate sources of feedwater should be identified and cited in the procedure. The condensate required to either maintain the plant at hot standby or cooldown may be determined from Figures 12-13 and 12-14.

Figures 12-13 and 12-14 are the types of figures that could be used in determining how much condensate is required while a plant is being cooled by auxiliary feedwater.

Figure 12-13 represents the amount of condensate required in removing decay heat for a specific duration of time before the shutdown cooling system must be used due to the remaining condensate inventory being inadequate. Each curve reflects a different time after shutdown (in hours). Curves representing intermediate time segments may be added.

Figure 12-14 provides the operator with an indication of how much condensate is required to remove system sensible heat while cooling down the plant to a desired cold leg temperature from an initial cold leg temperature. Figure 12-13 and Figure 12-14 must be used together to calculate the condensate inventory required for decay heat and sensible heat removal for a given cooldown.

The intent of condensate inventory information, whether it is presented in graphical, nomograph, or other forms, is to enable the operating staff to determine whether sufficient inventory exists for the planned actions. It should give the operator information in a timely manner such that, if a cooldown is required, enough condensate will be available to carry it out. In the unlikely event that enough condensate does not exist for a cooldown to shutdown cooling entry condition, the operator(s) can plan accordingly to maximize the time to establish alternate sources of condensate.

The inventory from those plant-specific alternate sources of condensate must be designated in the procedure (i.e., nonseismic tanks, fire mains, lake water supplies, potable tanks, etc.). Through use of Figures 12-13 and 12-14, the operations staff can evaluate condensate availability and select an appropriate course of action for the plant conditions which exist.

12.5.4 *Determination of Representative Core Exit Thermocouples Temperature*

The typical arrangement of core exit thermocouples (CETs) is an array of about 45 instruments distributed about the core in the incore instrumentation sheaths. Typically, the reading from each CET is displayed separately on a

Figure 12-13

TYPICAL FEEDWATER CAPACITY FOR DECAY HEAT REMOVAL VERSUS TIME UNTIL SHUTDOWN COOLING REQUIRED

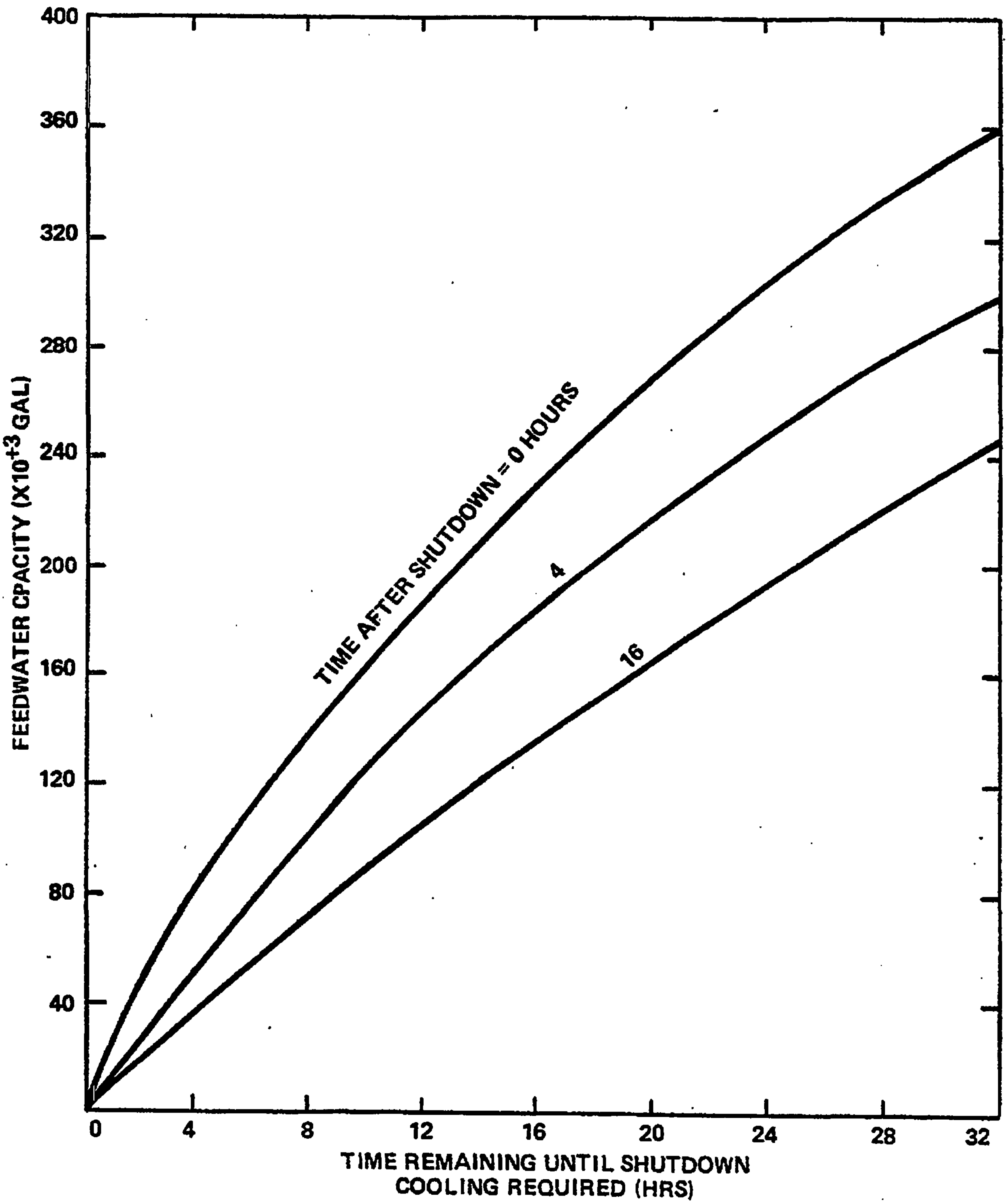
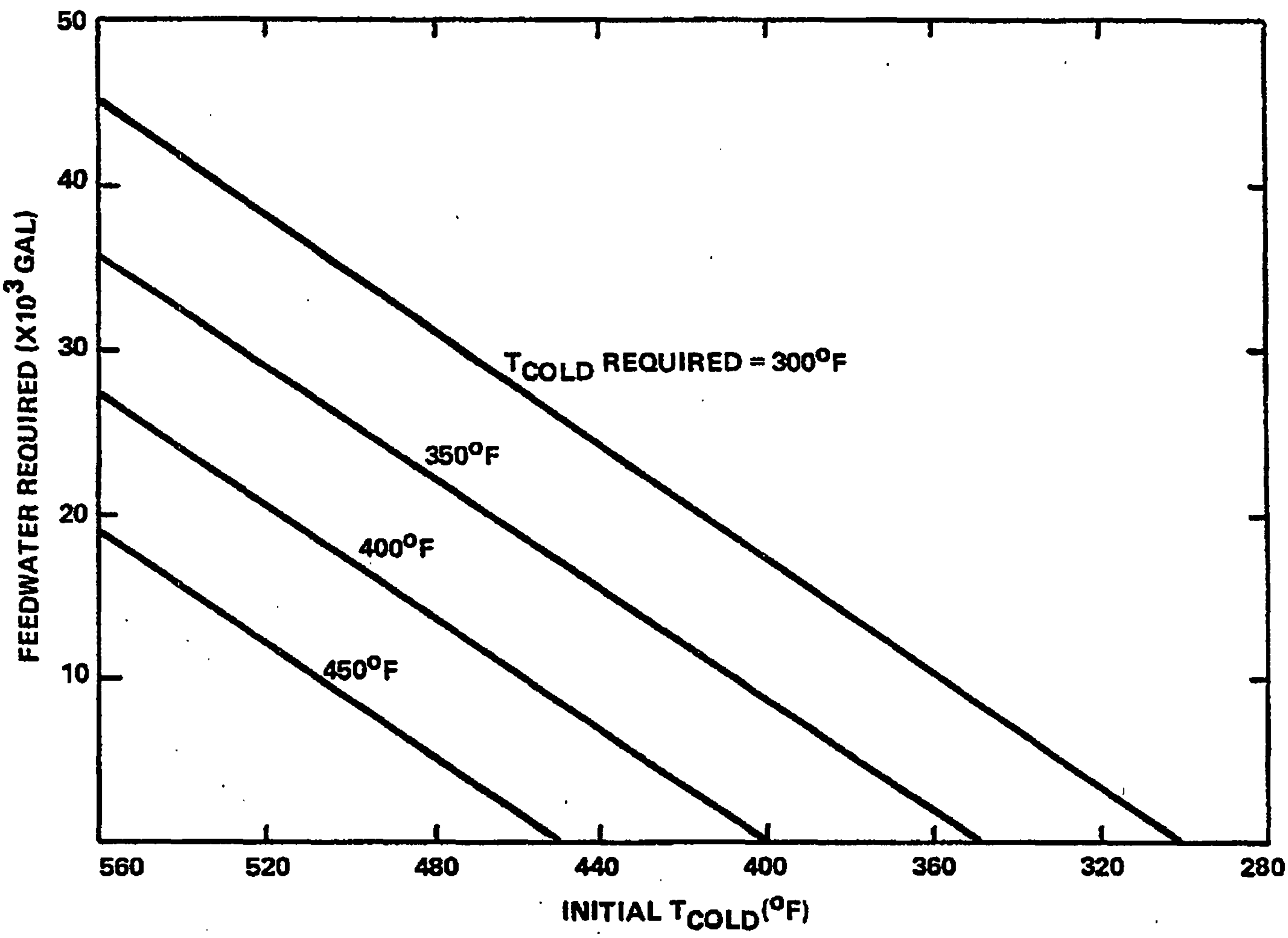


Figure 12-14

TYPICAL FEEDWATER REQUIRED FOR SENSIBLE HEAT REMOVAL BETWEEN T_{COLD} (REQUIRED VS T_{COLD} (INITIAL)



CRT, or printed individually on a computer printout. The CETs are designed to provide core exit temperature indication for monitoring approach to inadequate core cooling, but operational considerations are necessary to use CETs effectively. Among these operational factors are the varying performance of CETs with varying primary coolant conditions, and the probability of a wide disparity among the indicated values of the CETs during normal plant operating conditions.

During forced circulation conditions, CET and T_H indication should be about the same, with roughly equal response times. However, during natural circulation flow conditions, CETs may not be representative of core exit plenum temperature. Under saturated and superheated steam conditions, the CETs should respond to changes in core cooling. Baseline tests for comparison of CET to T_H indication may provide information during forced and NC flow conditions for use with the emergency procedures such that, an operator could identify unexpected temperature anomalies between T_H and CET instruments.

The incorporation of CET monitoring into emergency operating procedures is even more complicated because under normal operating conditions, a wide variance among CET readings may exist. These differences can be attributed to failure of instrumentation (the CETs may fail high or low), thermocouple inaccuracy, indication of temperature profile within the core, or a combination of these reasons. However, where CET monitoring is specified in the emergency procedure guidelines, the operator is required to use a specific, representative CET temperature (a representative CET temperature would also be required for identifying unexpected temperature anomalies between T_H and CET instruments). A simple averaging of the CET indicators may yield an unconservative representative temperature. An overly low representative temperature would underestimate the fuel heatup. An overly high representative temperature could prompt the operator to maintain RCS pressure higher than desired (e.g., aggravating inventory loss, resulting in larger offsite doses, etc. during a steam generator tube rupture accident). Baseline information may provide information for the development of a scheme for deciding which CETs to reference for use with the emergency procedures. This scheme may take the form of a plant computer algorithm which would filter out faulty CET indications during the process of deriving a representative CET temperature.

12.5.5 *Development of Plant-Specific Data*

The Emergency Procedure Guidelines are generic by design to provide information on C-E NSSS and other BOP designs for implementation into EOPs at CEOG member utilities. NSSS and BOP systems vary from plant to plant so that some of the information must be developed on a plant-specific basis. Plant-specific information is identified by brackets throughout the EPG system. The plant-specific information has been compiled, and is presented in this section, with reference to its location in the EPGs along with information to help the procedure writer develop the required bracketed information for a specific plant.

FIGURE 12-15
AFFECTED GUIDELINE STEPS

EXAMPLES OF RECOVERY ACTION REQUIRING PLANT SPECIFIC DATA	SPTA	RT	LOCA	SGTR	LOF	ESDE	LOFC	FRG	SOURCE OF PLANT SPECIFIC DATA
a) Rx Power Decreasing and b) [Negative Startup Rate] and c) Not more than 1 CEA bottom light not lit	*	*	*	*	*	*	*		b) If it is not possible to read a negative startup rate from the control room, remove this information.
IF NOT a) Manually trip the reactor or b) Open the Rx trip breakers or c) [Deenergize the CEA motor generator] or d) [Plant specific methods] and e) If more than 1 CEA not inserted borate the plant in accordance with Technical Specifications	*							*	c) The plant specific method for deenergizing the CEA motor generator should be inserted here. d) Any plant specific methods (e.g., open individual CEA breakers) for CEA insertion should be inserted here.
b) [Maintenance of Vital Auxiliaries]	*								The maintenance of vital auxiliaries deals with balance of plant and is very plant specific; therefore, the plant may want to expand this area.

FIGURE 12-15 (Cont'd)

EXAMPLES OF RECOVERY ACTION REQUIRING PLANT SPECIFIC DATA	SPTA	RT	LOCA	SGTR	LOF	ESDE	LOFC	FRG	SOURCE OF PLANT SPECIFIC DATA
	AFFECTED GUIDELINE STEPS								
a) Main turbine tripped and b) Generator output breaker open and c) [Station loads transferred offsite] and d) [Plant specific]	*								c) The plant specific indication of loads being transferred offsite should be inserted here. d) Include any other plant specific information on the maintenance of vital auxiliaries here (i.e., valve control power, component cooling water, etc.)
IF NOT a) Trip the turbine or b) Open generator output breakers or c) Transfer loads offsite or verify diesel started or d) [Plant specific]	*								d) Include the immediate actions necessary to insure the actions in (d) above are satisfied.
[35"] ≤ Pzr lvl ≤ [245"] and RCS ≥ [20°F] subcooled	*	*	*	*	*	*	*	*	The [35"] corresponds to the minimum dependable pressurizer level. The [245"] corresponds to the maximum dependable pressurizer level prior to going solid. For the plant specific value, instrument inaccuracies may be added to the [20°F]. The [20°F] value is based on engineering judgement to maintain the core surrounded by subcooled fluid.

FIGURE 12-15 (Cont'd)

EXAMPLES OF RECOVERY ACTION REQUIRING PLANT SPECIFIC DATA	SPTA	RT	LOCA	SGTR	LOF	ESDE	LOFC	FRG	SOURCE OF PLANT SPECIFIC DATA
	AFFECTED GUIDELINE STEPS								
If pressurizer pressure decreases to less than [1300 psia] following an SIAS, then ensure all four RCPs are tripped.			*					*	For the methodology and results of analysis to determine at what pressure the RCPs should be tripped, see CEN-268, January 1984.
If pressurizer pressure decreases to less than [1300 psia] following an SIAS then trip two RCPs (in opposite loops) or verify that two RCPs (in opposite loops) have been tripped.				*		*			For the methodology and results of analysis to determine at what pressure the RCPs should be tripped, see CEN-268, January 1984.
If RCP operating limits are not satisfied, then trip the remaining two RCPs.				*		*			Plant specific RCP operating limits should be inserted.
If Pzr pressure decreases to < [1300 psia] following an SIAS, then trip 2 RCPs (in opposite loops).	*								For the methodology and results of analysis to determine at what pressure the RCPs should tripped, see CEN-268, January 1984.
IF NOT b) If pressurizer pressure decreases to [1600 psia, or if containment pressure increases to 4 psig], verify that an SIAS has been initiated. If not, manually initiate SIS operation.	*							*	Insert the SIAS setpoint if it is not [1600 psia]. If the plant does not receive a SIAS from containment pressure, remove this statement. Insert the CIAS/SIAS setpoint if it is not [4 psig].

FIGURE 12-15 (Cont'd)

EXAMPLES OF RECOVERY ACTION REQUIRING PLANT SPECIFIC DATA	SPTA	RT	LOCA	SGTR	LOF	ESDE	LOFC	FRG	SOURCE OF PLANT SPECIFIC DATA
	AFFECTED GUIDELINE STEPS								
a) [1700 psia] < Pzr press < [2350 psia]	*	*			*	*			[1700 psia] corresponds to the SIAS alarm setpoint; insert the plant specific setpoint. [2350 psia] corresponds to the high pressure alarm setpoint, insert the plant specific setpoint.
a) S/G level is: within the normal level band with feedwater available to maintain the level or being restored by a feedwater flow > [150 gpm] and b) RCS T_{ave} < [545°F] and c) S/G press > [500 psia] (If S/G pressure falls to < [500 psia], ensure an MSIS will be initiated.)	*								a) The [150 gpm] feed flow corresponds to feed flow to recover steam generator level, make up for the steaming rate and not cause excessive cooldown rate. The plant specific flow should be based on present guidance and plant operating experience. b) [545°F] is based on the control program for ADVs. The plant specific temperature should be substituted for [545°F]. c) [500 psia] is based on the MSIS setpoint. The plant specific setpoint should be substituted for [500 psia].

FIGURE 12-15 (Cont'd)

EXAMPLES OF RECOVERY ACTION REQUIRING PLANT SPECIFIC DATA	SPTA	RT	LOCA	SGTR	LOF	ESDE	LOFC	FRG	SOURCE OF PLANT SPECIFIC DATA
	AFFECTED GUIDELINE STEPS								
<u>IF NOT</u> a) Verify [main or auxiliary feed] is controlling S/G level and steam dump system operating <u>or</u> b) If S/G pressure decreases to [500 psia], verify the MSIS <u>closes</u> [the MSIVs].	*								a) Main or auxiliary feedwater are bracketed throughout the EPGs because the preference is plant specific. Each plant should decide from present operating practice and experience which would be the preferred method of feeding the steam generators. b) [500 psia] has previously been addressed. The MSIV is the abbreviation for Main Steam Isolation Valve. Insert the plant specific abbreviation.
a) $T_H - T_C$ < [10°F] <u>and</u> b) RCS subcooling ≥ [20°F] subcooling.	*	*			*		*	*	a) A ΔT of [10°F] is the maximum ΔT expected for minimum forced circulation with maximum decay heat. The plant specific ΔT should be based on operational experience and plant specific analysis. b) The subcooling limit of [20°F] has previously been addressed.
<u>IF NOT</u> a) [Verify proper functioning of containment coolers] <u>or</u> b) If containment pressure > [10 psig], verify containment spray is running with header flow > [1500 gpm].	*								a) If the plant does not rely on containment coolers delete this statement. b) [10 psig] is the CSAS setpoint. The plant specific CSAS setpoint should be inserted here. [1500 gpm] is the expected flow of the CSS. The plant specific CSS flow should be inserted.

FIGURE 12-15 (Cont'd)

EXAMPLES OF RECOVERY ACTION REQUIRING PLANT SPECIFIC DATA	SPTA	RT	LOCA	SGTR	LOF	ESDE	LOFC	FRG	SOURCE OF PLANT SPECIFIC DATA
	AFFECTED GUIDELINE STEPS								
IF NOT b) If containment press > [4 psig], verify CIAS.	*								[4 psig] is the CIAS setpoint. The plant specific setpoint should be inserted.
Containment Pressure < [1.5 psig] and Containment temperature < [240°F]	*	*		*	*		*	*	[1.5 psig] is based on the maximum containment pressure expected during normal plant operation (surveillance). It is not expected for the events listed that containment pressure will increase to this value. The plant specific value to be used as safety function acceptance criterion for containment temperature should be selected based on the maximum Tech. Spec. limit during normal operation.
[A reactor trip will also result due to an automatic or manual turbine trip at full power conditions.] A turbine trip is called for if a condition detrimental to continued turbine operation develops.		*							If a turbine trip does not cause a reactor trip, delete this statement.
The main feedwater system will ramp down to [5%] flow to prevent overfilling the steam generators.		*							If the plant does not ramp down main feedwater to [5%] flow, insert the proper plant specific number.

FIGURE 12-15 (Cont'd)

EXAMPLES OF RECOVERY ACTION REQUIRING PLANT SPECIFIC DATA	AFFECTED GUIDELINE STEPS SPTA	RT	LOCA	SGTR	LOF	ESDE	LOFC	FRG	SOURCE OF PLANT SPECIFIC DATA
H_2 < [2%]		*	*	*	*	*	*	*	The detection and control of H_2 gas is very plant specific, therefore each plant should develop its own limits based on the equipment available. Limit of 2% suggested (50% of flammability limit).
Steam generator level is restored and controlled using [main or auxiliary] feedwater to provide for RCS heat removal		*	*	*	*			*	Main and auxiliary feedwater has previously been addressed.
Minimize the number of cycles of pressurizer auxiliary spray whenever the temperature differential between the spray water and pressurizer is greater than [200°F] in order to minimize the increase in the spray nozzle thermal stress accumulation factor. Every such cycle must be recorded in accordance with technical specification limitations.		*	*	*	*	*	*		The plant specific limit on differential temperature may be found in the Technical Specifications. The plant specific limit should be substituted for the [200°F].
a) If pressurizer pressure ≥ [1600 psia], either heaters and pressurizer spray or charging and SIS pumps are being operated manually or automatically to maintain or restore pressurizer pressure within P-T limits of Figure 5-1. or b) If pressurizer pressure < [1600 psia], [at least one charging pump and] at least one SIS pump are operating and the SIS pump(s) are injecting water into the RCS per Figure 5-3, (unless the SIS termination criteria are met).			*	*		*			a) [1600 psia] has previously been addressed. b) If charging pumps are unavailable (i.e., no-vital power or no charging pumps installed), delete reference to charging pumps.

FIGURE 12-15 (Cont'd)

EXAMPLES OF RECOVERY ACTION REQUIRING PLANT SPECIFIC DATA	SPTA	RT	LOCA	SGTR	LOF	ESDE	LOFC	FRG	SOURCE OF PLANT SPECIFIC DATA
a) Containment Pressure < [10 psig] <u>and</u> Containment Temperature < [240°F] <u>or</u> b) Containment Spray Flow > [1500 gpm]			*			*		*	a) [10 psig] is the CSAS setpoint. The plant specific setpoint should be inserted here. The plant specific value to be used as safety function acceptance criterion for containment temperature must be selected based on the maximum average air temperature in the containment for the events listed. For a LOCA, the value inserted should represent the maximum containment temperature expected or allowed to be present without requiring the containment spray system to run. This may be a containment temperature required by technical specifications. The requirements for the steam line break safety function status check criterion should follow the same rationale as for the LOCA criterion. If temperature detector position or instrument errors will cause significant deviations from the average temperature, then appropriate adjustments to the acceptance limit should be considered. b) During the events listed, containment temperature and pressure may exceed these limits if the break is inside containment. If this happens, a CSAS should be present and the CSS should be injecting spray solution at [1500 gpm]. The plant specific value for CSS flow should be inserted.

FIGURE 12-15 (Cont'd)

EXAMPLES OF RECOVERY ACTION REQUIRING PLANT SPECIFIC DATA	SPTA	RT	LOCA	SGTR	LOF	ESDE	LOFC	FRG	SOURCE OF PLANT SPECIFIC DATA
	AFFECTED GUIDELINE STEPS								
RCS inventory control is initially lost since the break flow rate exceeds the available charging pump capacity of the plant. For small breaks, RCS inventory control is regained via injection from the high pressure safety injection (HPSI) pumps [and the charging pumps].			*						If charging pump flow is not credited in safety analysis, this statement may be deleted.
(VOIDS) [If their presence is detected in the RCS, the reactor vessel head vent may be operated].		*		*		*	*		For plants without an operational reactor vessel head vent, delete this statement.
[In the event that the feedwater supply to the steam generator is exhausted and/or unavailable and the SCS is inoperable, the PORVs are opened to ensure that the flow from the SIS is available for RCS heat removal purposes.]					*			*	Plants without PORVs delete this statement.

FIGURE 12-15 (Cont'd)

EXAMPLES OF RECOVERY ACTION REQUIRING PLANT SPECIFIC DATA	SPTA	RT	LOCA	SGTR	LOF	ESDE	LOFC	FRG	SOURCE OF PLANT SPECIFIC DATA
No abnormal differences between T_H RTDs and [core exit thermocouples]. Hot leg RTD temperature should be consistent with the [core exit thermocouples]. Adequate natural circulation flow ensures that [core exit thermocouple] temperatures will be approximately equal to the hot leg RTDs temperature within the bounds of the instrument's inaccuracies. An abnormal difference between T_H and [the CETs] is greater than [10°F].			*	*	*	*	*	*	10°F is judged to be a reasonable value based on the combined instrument accuracies of CETs and RTDs (T_H). Other plant specific values may be substituted if desired.
If the RCPs were stopped, then one RCP in each loop may be restarted if the following criteria are satisfied: a) At least one steam generator is available for removing heat from the RCS, b) Pressurizer level is greater than [200"] and not decreasing, c) The RCS is at least [20°F] subcooled, d) [Other criteria satisfied per RCP operating instructions.]			*	*	*	*	*	*	a) Having a steam generator with the capability of feed flow and steam flow serves as an indication that primary to secondary heat removal is possible. b) A pressurizer level must be established such that sufficient inventory is available to make up for the possible collapse of pressurizer level. When determining the plant-specific pressurizer level for RCP restart criteria, consider the possible consequences during non-inventory loss events. Specifically, for an ESDE, charging and SIS contributions may be minimized in order to reduce the possibility of filling the pressurizer solid and the subsequent PTS concern. c) The subcooling limit of [20°F] has previously been addressed.

The column headings SPTA through FRG are printed under the spanning heading AFFECTED GUIDELINE STEPS.

FIGURE 12-15 (Cont'd)

EXAMPLES OF RECOVERY ACTION REQUIRING PLANT SPECIFIC DATA	AFFECTED GUIDELINE STEPS SPTA	RT	LOCA	SGTR	LOF	ESDE	LOFC	FRG	SOURCE OF PLANT SPECIFIC DATA
									d) Any criteria which must be met to prevent RCP damage or damage from RCP operation should be inserted here. (i.e., component cooling water, lift oil pump, power available indications, etc.).
[Monitor quench tank parameters since any sustained operation of the PORVs may burst the tank's rupture disc.]			*	*	*	*	*	*	If the plant does not have PORVs, delete this precaution.
If the SIS is operating, it may be throttled or stopped if all of the following conditions are satisfied: a) RCS is at least [20°F] subcooled, b) Pressurizer level is greater than [100"] and constant or increasing, c) At least one steam generator is available for removing heat from the RCS. d) [The RVLMS indicates the core is covered]			*	*	*	*		*	a) The subcooling limit of [20°F] has previously been addressed. b) The [100"] pressurizer level corresponds to a level just above pressurizer heater cutouts. The plant specific number should be inserted. When determining the plant-specific pressurizer level for SIS termination criteria, consider the possible consequences during non-inventory loss events. Specifically, for an ESDE, charging and SIS contributions may be minimized in order to reduce the possibility of filling the pressureizer solid and the subsequent PTS concern. c) Having a steam generator with the capability of feed flow and steam flow serves as an indication that primary to secondary heat transfer is possible.

FIGURE 12-15 (Cont'd)

EXAMPLES OF RECOVERY ACTION REQUIRING PLANT SPECIFIC DATA	SPTA	RT	LOCA	SGTR	LOF	ESDE	LOFC	FRG	SOURCE OF PLANT SPECIFIC DATA
									d) If the plant does not have an RVLMS, delete this step.
RCS Refill [8 hours] [1 hour]			*						Information used only for background. [8 hours to refill the RCS is based on 3" diameter break on the bottom of a cold leg with one HPSI pump operable. [One hour] is based on all HPSI pump operable for the same break.
i) Start an additional charging pump to demonstrate that pressurizer level responds as expected; increase of [2 inches/min.] per charging pump (approximately). ii) Activate pressurizer heaters and demonstrate that the pressurizer pressure instrumentation responds as expected: increase of [15 psi/min] (approximately) iii) Activate pressurizer auxiliary spray and demonstrate that the pressurizer instrumentation responds as expected: decrease of [26 psi/min.] (approximately).			*	*				*	[2 inches/min.] per charging pump is based on the expected pressurizer level rate change for each charging pump (i.e., if level is decreasing at 1 inch/min., starting one pump should result in level rate of change of 1 inch/min. increasing). [15 psi/min.] increase for heaters and [26 psi/min.] decrease for auxiliary sprays are similarly derived.
[If plant conditions permit, bypass automatic initiation of MSIS, CSAS, and SIAS by lowering the setpoint as the cooldown and depressurization proceeds.]			*	*		*	*		List the plant specific method of varying or bypassing the signal (i.e., opening a circuit breaker).

(The heading "AFFECTED GUIDELINE STEPS" spans the eight columns SPTA through FRG.)

FIGURE 12-15 (Cont'd)

EXAMPLES OF RECOVERY ACTION REQUIRING PLANT SPECIFIC DATA	AFFECTED GUIDELINE STEPS SPTA	RT	LOCA	SGTR	LOF	ESDE	LOFC	FRG	SOURCE OF PLANT SPECIFIC DATA
[If the charging pumps are taking suction from a concentrated boron source, realign suction to the RWT or other suitable source within 1 hour after the start of the loss of coolant accident.]			*						The time limit to realign charging pump suction to the RWT is based on injecting enough boron to ensure the plant is safely shutdown but minimizing the potential of boron precipitation. For more guidance on boron precipitation see your plant specific long term cooling evaluation.
[If the refueling water tank level falls to 10%, verify initiation of recirculation. If necessary, manually initiate recirculation and close RWT outlet valves to the safety injection system.]			*					*	The plant specific setpoint for RAS actuation on low RWT level should be inserted in place of the [10%] shown. If the plant does not have automatic closure of RWT outlet valves, the operator should be instructed to close them. If the plant has automatic closure of RWT outlet valves, the operator should be instructed to verify that valves have closed.
If the HPSI pumps are delivering less than [30 gpm] per pump during recirculation, turn off one charging pump or one HPSI pump (turn of the HPSI pump with the lower indicated flow) at a time until the HPSI pumps are delivering more than [30 gpm] per pump.			*					*	The [30 gpm] represents HPSI minimum flow requirements. The plant specific requirements should be inserted in its place.

FIGURE 12-15 (Cont'd)

EXAMPLES OF RECOVERY ACTION REQUIRING PLANT SPECIFIC DATA	SPTA	RT	LOCA	SGTR	LOF	ESDE	LOFC	FRG	SOURCE OF PLANT SPECIFIC DATA
Commence a rapid cooldown. Cooldown to less than [300°F] at a rate within the technical specification limits by one of the following methods (listed in order of preference): a) The turbine bypass system and [main or auxiliary] feedwater, or b) The atmospheric dump valves and [main or auxiliary] feedwater			*		*	*			[300°F] corresponds to SCS entry temperature. The plant specific value should be inserted here.
If the CSAS has been actuated and containment pressure subsequently falls below [7 psig], containment spray should be terminated. Upon termination the CSS must be realigned and reset for automatic actuation. The CSS may be manually restarted to control iodine levels in the containment.			*			*		*	[7 psig] corresponds to the CSAS reset point. The plant specific value should be inserted here.
At [2-4 hours] after the start of the loss of coolant event, align the SIS for hot or cold leg injection.			*						The time post LOCA to align for hot/cold leg injection is based on plant specific long term cooling analysis. The maximum [4 hours] time is based on the minimum time for RCS boron concentration to reach the established precipitation level without flushing. The minimum [2 hours] is based on the maximum time to achieve effective hot leg flushing. This is the time when hot leg steam flow falls below that flow which can entrain injected water. Therefore replace [2-4] with values from plant specific long term cooling analysis.

FIGURE 12-15 (Cont'd)

EXAMPLES OF RECOVERY ACTION REQUIRING PLANT SPECIFIC DATA	SPTA	RT	LOCA	SGTR	LOF	ESDE	LOFC	FRG	SOURCE OF PLANT SPECIFIC DATA
	AFFECTED GUIDELINE STEPS								
Determine if the conditions for entering shutdown cooling system operation can be established by the following criteria:			*					*	a&b) The pressurizer level of [100"] and subcooling of [20°F] has previously been addressed.
a) Pressurizer level is greater than [100"] and controlled			*						c) To determine the permissible RCS activity levels for entry into shutdown cooling (SDC), a plant specific analysis should be performed. This analysis must assure that, for the maximum RCS activity for SDC, plant limits for site boundary dose or personnel exposure are not exceeded. As a minimum the analysis should take into account the following: What areas of the plant will the SDC system contaminate (e.g., pump room, auxiliary building)? What are the possible release paths from these areas to the site boundary (e.g., ventilation systems) and how much will be released? Which of these areas must plant personnel enter (e.g., to perform valve alignments) How long will personnel be in these areas How many personnel are available to enter these areas? What support equipment may be lost as a result of SDC system contamination?
b) The RCS is at least [20°F] subcooled									
c) RCS activity level within [appropriate limits]									
d) [Other plant specific information, insert here]									d) Any additional plant specific criteria required to be satisfied to initiate SDC should be inserted here.

FIGURE 12-15 (Cont'd)

EXAMPLES OF RECOVERY ACTION REQUIRING PLANT SPECIFIC DATA	AFFECTED GUIDELINE STEPS: SPTA	RT	LOCA	SGTR	LOF	ESDE	LOFC	FRG	SOURCE OF PLANT SPECIFIC DATA
If the criteria in step 37 are satisfied, shutdown cooling operation is possible, and allowable when RCS pressure and temperature are less than [300 psia] and [300°F]. Realign the [SIS] for cold leg injection and initiate shutdown cooling per the operating instruction.			*	*		*	*	*	If systems in addition to the SIS are used for hot/cold injection, insert the name of the system(s) here. (e.g., CVCS, SCS, etc.)
[Isolate, vent, or drain the safety injection tanks (SITs) at 250 psia RCS pressure].			*	*		*	*	*	The [250 psia] represents the pressure for isolating the SITs for plants with 200 psig SIT (for plants with 600 psig SIT, the pressure for isolating the SIT will be between 650 and 700 psig) during normal plant cooldown. The plant specific number should be inserted here.
[Initiate the low temperature overpressurization (LTOP) systems at 275°F]			*	*		*	*	*	Include operator actions required to initiate LTOP and the plant specific LTOP setpoint for [275°F].
[If pressurizer pressure is below 2350 psia, verify that the PORVs are closed. If not, manually isolate the PORVs or close the PORV block valves]			*					*	If the plant does not have PORVs, or pressurizer vents, delete these statements. If the plant has PORVs or pressurizer vents, substitute the plant specific PORV reset setpoint for the [2350 psia] setpoint listed.
[If there are other possible sources of leakage that can be rapidly and remotely isolated, insert that information here]			*						Any sources of RCS leakage which can be rapidly and remotely isolated from the control room should be listed here.

FIGURE 12-15 (Cont'd)

EXAMPLES OF RECOVERY ACTION REQUIRING PLANT SPECIFIC DATA	SPTA	RT	LOCA	SGTR	LOF	ESDE	LOFC	FRG	SOURCE OF PLANT SPECIFIC DATA
	AFFECTED GUIDELINE STEPS								
Continually observe the [turbine and auxiliary building] ventilation systems' radiation monitors and any other applicable radiation monitors. Take corrective actions if necessary, in accordance with plant technical specification limitations.			*	*					The plant specific nomenclature for the equivalent of a turbine and/or auxiliary building should be inserted as applicable. (Any building in which primary inventory could enter should be included, i.e., HPSI, LPSI pump room or turbine room).
[Core Exit Thermocouples] < [700°F]			*						[700°F] is based on preventing core damage. The plant specific number should be developed based on [CET] location and plant specific accident analysis.
[Monitor containment radiation levels in order to evaluate environmental releases. It may be desirable to reduce airborne radiation levels in the containment to minimize environmental releases].			*					*	Insert containment radiation monitoring equipment and action levels which must be decided by plant management.
[If appropriate plant specific instructions for determining which S/G is affected should be performed.]				*					Any plant specific methods (e.g., portable radiation monitors, etc.) for determining which S/G has a tube rupture should be inserted here).

FIGURE 12-15 (Cont'd)

EXAMPLES OF RECOVERY ACTION REQUIRING PLANT SPECIFIC DATA	SPTA	RT	LOCA	SGTR	LOF	ESDE	LOFC	FRG	SOURCE OF PLANT SPECIFIC DATA
	AFFECTED GUIDELINE STEPS								
After the RCS hot leg temperature has been reduced to [525°F], isolate the steam generator with higher activity, higher radiation levels or increasing water level by performing all of the following:				*		*			The [525°F] corresponds to the saturation temperature of the lowest S/G relief valve setpoint pressure. The plant specific number should be inserted. See section 12.5.1 for methodology to calculate instrument error.
a) Close the main steam isolation valve.									
b) Verify the main steam isolation bypass valve is closed.									545°F - 10°F (margin) - expected increase after S/G isolation
c) Close the atmospheric dump valve.									- 10°F (expected) - increase in N/C ΔT after isolation =
d) Close the main feedwater isolation valve.									525°F
e) Isolate steam generator blowdown.									
f) [Close the auxiliary feedwater isolation valves including the steam driven pump steam supply valve associated with the steam generator being isolated.]									f) If the plant does not have a steam driven pump delete references to them.
g) Isolate vents, drains, exhausts, and bleedoffs from the steam system and turbine building sumps.									
h) [Other plant specific information, inert here.]									h) Any additional plant specific steps to isolate an S/G should be inserted here.
Prevent overfilling of the affected steam generator through periodic draining to the radioactive waste system or, if draining is not possible, dump steam from the affected steam generator to the condenser.				*					Plant specific information may include drain rates and tank capacities. Steam generator draining will be limited by systems design capacities and process flow rates.

FIGURE 12-15 (Cont'd)

EXAMPLES OF RECOVERY ACTION REQUIRING PLANT SPECIFIC DATA	SPTA	RT	LOCA	SGTR	LOF	ESDE	LOFC	FRG	SOURCE OF PLANT SPECIFIC DATA
	AFFECTED GUIDELINE STEPS								
To prevent lifting steam generator safeties after isolating a steam generator, cooldown the RCS until the RCS hot leg temperature is less than [525°F].				*					See previous page, concerning RCS hot leg temperature of [525°F].
[If previous efforts have not eliminated the void, it is suspected to be non-condensible gases. Operate the reactor vessel head vent as necessary to eliminate the gases.]				*		*	*		If the plant does not have reactor vessel head vents, delete this statement.
[Plant specific indications of voiding]				*		*	*		Any plant specific indications of RCS voiding should be inserted here (e.g., reactor vessel level monitor, etc.)
[200°F] subcooling				*					Refer to Section 12.5.1
[If the auxiliary feedwater system (AFW) is started, perform the following to prevent steam generator feed ring damage: a) If S/G level is above the feed ring, stop redundant AFW pumps and restore and maintain S/G level to the normal level band].					*				This statement applies to those plants that introduce auxiliary feedwater (AFW) through the S/G feedring. Plants utilizing economizer S/G or S/G with separate AFW nozzles should delete this and replace with any post trip feeding requirements already in place.

FIGURE 12-15 (Cont'd)

EXAMPLES OF RECOVERY ACTION REQUIRING PLANT SPECIFIC DATA	SPTA	RT	LOCA	SGTR	LOF	ESDE	LOFC	FRG	SOURCE OF PLANT SPECIFIC DATA
	AFFECTED GUIDELINE STEPS								
b) [If indicated steam generator water level is below the feed ring, then: i) Stop redundant AFW pumps and limit feedwater flow rate to 150 gpm per affected steam generator until an increase in S/G level has been observed, or until continuous feedwater flow to the S/G has been maintained for five minutes. ii) Modulate AFW flow rate as necessary to restore and maintain S/G water level in the normal level band.]					*				A flowrate of [150 gpm] has been recommended as aprocedural limit based on the fact that no significant water hammer has been observed during testing or operation with flow rates of that order. Additionally, 150 gpm has been traditionally accepted as a flow limit by industry and the NRC for water hammer protection. The five minute duration of this limited flow is conservatively based on twice the refil time for the 350 gal. feedring. In the event that refilling of portions of the main feedwate piping must be considered this time would have to be adjusted accordingly.
[Plant specific methods for S/G heat removal]					*			*	Alternate sources of S/G feedwater must be included in plant-specific procedures. Example of alternate sources are non-seismic tanks, fire mains, potable tanks, etc. Guidelines on steam generator depressurization should be developed for those cases when low pressure sources of feedwater must be used.
[If feed to at least one steam generator cannot be restored, establish once through cooling by: a) Stopping all remaining operating RCPs b) Starting the HPSI and charging pumps c) Opening the PORVs]					*			*	c) If the plant is not capable of once through cooling (i.e., no PORVs or pzr vent valves) or the specific plant procedure writing tea does not wish to use this option, delete this statement.

FIGURE 12-15 (Cont'd)

EXAMPLES OF RECOVERY ACTION REQUIRING PLANT SPECIFIC DATA	SPTA	RT	LOCA	SGTR	LOF	ESDE	LOFC	FRG	SOURCE OF PLANT SPECIFIC DATA
	AFFECTED GUIDELINE STEPS								
[If other methods are available for heat removal from the RCS, insert that information here.]					*				Any additional plant specific methods for removing heat from the RCS may be inserted here. Examples are drain valves, pressurizer vents, etc.
Solid water operation of the pressurizer should be avoided unless [20°F] of subcooling cannot be maintained in the RCS (Figure 7-1). If the RCS is solid, closely monitor any makeup or draining and any system heatup or cooldown to avoid any unfavorable rapid pressure excursions.					*	*		*	[20°F] subcooling has previously been addressed
To avoid RCS boron dilution and loss of shutdown margin by pressurizer outsurge during the cooldown, perform one of the following steps listed in order of preference: a) Calculate and add sufficient boron to RCS to raise the entire RCS (including the mass in the pressurizer to cold shutdown conditions. b) If letdown is available, use auxiliary spray to increase and maintain pressurizer boron concentration to within [50 ppm] of RCS concentration using heaters to control pressurizer pressure.							*		b) The allowable concentration difference between the pressurizer and the RCS depends on the following: 1) RCS volume 2) Pressurizer volume 3) Boron coefficient of reactivity; for the purposes of this concern α_B varies with core life and RCS temperature. 4) Minimum shutdown margin. The dilution of the RCS by a pressurizer outsurge must not result in a core reactivity that exceeds the minimum required shutdown margin. Each plant must develop an allowable concentration difference.

FIGURE 12-15 (Cont'd)

EXAMPLES OF RECOVERY ACTION REQUIRING PLANT SPECIFIC DATA	AFFECTED GUIDELINE STEPS: SPTA	RT	LOCA	SGTR	LOF	ESDE	LOFC	FRG	SOURCE OF PLANT SPECIFIC DATA
c) If letdown is not available, use auxiliary spray and pressurizer heaters to control pressurizer pressure and increase RCS boron concentration to [50 ppm] greater than that required for minimum shutdown margin.							*		c) If it is not possible to accomplish a) or b) above, increase RCS boron concentration to a concentration that would maintain the minimum shutdown margin after a pressurizer outsurge with a postulated worst case pressurizer boron concentration.
Low Reactor coolant flow trip at [95%] flow.							*		Insert low flow reactor trip setpoint.
[20°F] ≤ RCS subcooling								*	[20°F] RCS subcooling has previously been addressed.
[If all feedwater is lost and pressurizer sprays (main and auxiliary) are not available, go to PC-6. Control of RCS pressure using [PORVs].]								*	If the plant does not have PORVs, delete this statement and replace step 2 of the success criteria in PC-6 with step 2 of the success criteria in PC-7.
Boron addition rate > [40 gpm] and reactor power decreasing								*	[40 gpm] is based on plant technical specification and charging pump capacity. The plant specific flow rate should be inserted in place of [40 gpm].
[Re-energize the CEA drive mechanisms and manually jog and/or drive the CEAs into the core using the normal rod motion controls].								*	If the CEA drive pull down force is not expected to drive a stuck rod into the core, delete this step. This step applies only to plants with magnetic jack type CEDMs.

FIGURE 12-15 (Cont'd)

EXAMPLES OF RECOVERY ACTION REQUIRING PLANT SPECIFIC DATA	SPTA	RT	LOCA	SGTR	LOF	ESDE	LOFC	FRG	SOURCE OF PLANT SPECIFIC DATA
(HPSI pump [1300 psia], CS pump [270 psia], LPSI pump [180 psia]).								*	The plant specific shut off head for the pumps listed should be inserted.
If necessary, the VCT, [boric acid storage tanks, RWT and spent fuel pool are used].								*	If the plant's charging system is not capable of taking a suction on any of the list sources, delete them. If there are other sources of boron available, insert them here.
Reactor power < [$10^{-(X)}$%] and constant or decreasing.								*	"X" should be slightly greater than the highest subcritical multiplication expected after extended full power operation, i.e., if power has been transitted below [10^{-X}%] power, this is assurance that the reactor is currently shutdown while power is relatively constant.
[If feedwater cannot be regained, go to HR-3, RCS and core heat removal using once through cooling].								*	If the plant is not capable of once through cooling (i.e., no PORVs or prz vent valves) delete this statement.
[Verify automatic operation of the containment fan cooling system. If at least 2 containment fans are not running in slow they should be started manually].								*	If the plant's containment fan cooling system does not meet the containment cooling requirements in the FSAR with [2 fans in slow speed], replace "2 containment fans" with the appropriate number and speed of the fans.

FIGURE 12-15 (Cont'd)

EXAMPLES OF RECOVERY ACTION REQUIRING PLANT SPECIFIC DATA	SPTA	RT	LOCA	SGTR	LOF	ESDE	LOFC	FRG	SOURCE OF PLANT SPECIFIC DATA
	AFFECTED GUIDELINE STEPS								
[The RVLMS indicates the core is covered].			*	*	*	*	*	*	Delete reference to [RVLMS] for plants not having RVLMS.
[No reactor vessel voiding as indicated by the RVLMS].		*							Delete reference to [RVLMS] for plants not having an RVLMS.
[The RVLMS indicates that voiding is present in the reactor vessel.]			*	*		*	*	*	Delete reference to [RVLMS] for plants not having RVLMS.
When a void exists in the reactor vessel and RCPs are not operating, the RVLMS provides an accurate indication of reactor vessel level inventory. When a void exists in the reactor vessel, and RCPs are operating, it is not possible to obtain an accurate reactor vessel liquid level indication due to the effect of RCP induced pressure head on RVLMS. The indicated level also differs for RVLMS designs under these conditions. Important information concerning reactor vessel liquid inventory trending can still be discerned, however, and used in plant operations.			*	*		*	*	*	Delete reference to [RVLMS] for plants not having RVLMS.
Hydrogen recombiners in operation			*	*					Delete reference for plants not having containment hydrogen recombiners.

FIGURE 12-15 (Cont'd)

EXAMPLES OF RECOVERY ACTION REQUIRING PLANT SPECIFIC DATA	AFFECTED GUIDELINE STEPS SPTA	RT	LOCA	SGTR	LOF	ESDE	LOFC	FRG	SOURCE OF PLANT SPECIFIC DATA
[The RVLMS should be monitored for the trending of reactor vessel liquid level. This trending information may be correlated to pressurizer level decrease].			*	*	*	*	*	*	Delete for plants not having [RVLMS].
Monitor pressurizer level [and the RVLMS] for trending of RCS inventory.				*			*	*	Delete reference to [RVLMS] for plants not having RVLMS.
[Monitor quench tank parameters since any sustained operation of the PORVs may burst the tanks rupture disc.			*	*	*	*		*	Delete reference to [PORVs] for plants not having PORVs.
[For those IRS's using hydrazine, it may be necessary to further increase sump water pH (beyond that achieved by trisodium phosphate in the sump) to increase long-term (4 hours post-LOCA) iodine retention in the sump. An alternate method of adding a pH buffer (typically sodium hydroxide) is by establishing a flowpath with the charging pumps.								*	Delete reference to use of [hydrazine for IRS] if not applicable to the specific plant.

FIGURE 12-15 (Cont'd)

EXAMPLES OF RECOVERY ACTION REQUIRING PLANT SPECIFIC DATA	SPTA	RT	LOCA	SGTR	LOF	ESDE	LOFC	FRG	SOURCE OF PLANT SPECIFIC DATA
	AFFECTED GUIDELINE STEPS								
During the cooldown maintain RCS pressure slightly above (0-100 psid) that of the affected S/G and within the acceptable post accident pressure/temperature limits (Figure 6-1) by:				*					
a) Controlling RCS heat removal via the unaffected or least affected steam generator									
and									
b) Controlling RCS pressure using the following methods									
i) Pressurizer heaters and main or auxiliary spray									
ii) Charging and letdown									
iii)HPSI pumps									
iv) [PORVs]									b) iv) If the plant does not have [PORVs], or does not wish to use this option, delete it.
v) [Pressurizer vent]									v) If the plant does not have [pressurizer vents], or does not wish to use this option, delete it.
vi) [Pressurizer fill and drain]									vi) If the plant is not capable of the operation pressurizer "fill and drain" or does not wish to use this option, delete it. It if does, additional guidelines should be developed and included here.

FIGURE 12-15 (Cont'd)

EXAMPLES OF RECOVERY ACTION REQUIRING PLANT SPECIFIC DATA	AFFECTED GUIDELINE STEPS: SPTA	RT	LOCA	SGTR	LOF	ESDE	LOFC	FRG	SOURCE OF PLANT SPECIFIC DATA
Verify turbine bypass valves are controlling steam generator pressure at [900 psia]. If condenser vacuum is lost, the turbine bypass system is unavailable, or if the MSIVs are closed, the atmospheric dump valves must be used to control steam generator pressure.		*			*				The [900 psia] represents the post trip controlling setpoint for S/G pressure by the turbine bypass system. This action prevents the secondary relief valves from opening. The plant specific number should be inserted.
If in once-through cooling, subcooled margin $\geq$ [0°F] by [CET].					*				The value of [0°F] subcooling is based on keeping the core covered and thus ensuring adequate core cooling. If the core is covered with fluid, the RCS will not indicate superheated conditions.
Loop ΔT < [50°F]					*				[50°F] encompasses the maximum expected ΔT for NC flow conditions based on 100% power ΔT.

13.0 GLOSSARY

13.1 ACRONYMS AND ABBREVIATIONS

ACC.....Adequate core cooling
ADV.....Atmospheric dump valve
AFW.....Auxiliary feedwater
ATWS....Anticipated transient without SCRAM
BOP.....Balance of plant
CCGC....Containment combustible gas control
CCW.....Component cooling water
C-E.....Combustion Engineering
CEA.....Control element assembly
CEDM....Control element drive mechanism
CEOG....Combustion Engineering Owners Group
CET.....Core exit thermocouple
CI......Containment isolation
CIAS....Containment isolation actuation signal
CSAS....Containment spray actuation signal
CSS.....Containment spray system
CTPC....Containment temperature and pressure control
CVCS....Chemical volume control system
DPM.....Decades per minute
ECCS....Emergency core cooling system
EPG.....Emergency procedure guidelines
ESDE....Excess Steam Demand Event
°F......Degrees Farenheit
FRG.....Functional recovery guideline
FSAR....Final Safety Analysis Report
GAL.....Gallons
GPM.....Gallons per minute
HPSI....High pressure safety injection
HR......Heat removal
HRS.....Hours
IC......Inventory control

List of Acronyms and Abbreviations (Cont'd)

ICC.....Inadequate core cooling
IRS.....Iodine removal system
LOCA....Loss of coolant accident
LOF.....Loss of feedwater
LOFC....Loss of forced circulation
LPSI....Low pressure safety injection
LTOP....Low temperature overpressurization protection
MSIS....Main steam isolation signal
MSIV....Main steam isolation valve
MSLB....Main steam line break
MSSV....Main steam safety valve
MVA.....Maintenance of vital auxiliaries
NC......Natural circulation
NPSH....Net positive suction head
NRC.....Nuclear Regulatory Commission
NSSS....Nuclear steam supply system
ORG.....Optimal recovery guideline
PC......Pressure control
PLCS....Pressurizer level control system
PORV....Power operated relief valve
PPCS....Pressurizer pressure control system
PSIA....Pounds per square inch, absolute
PSIG....Pounds per square inch, gage
P-T.....Pressure-Temperature
PTS.....Pressurized thermal shock
PZR.....Pressurizer
RAS.....Recirculation actuation signal
RC......Reactivity control
RCP.....Reactor coolant pump
RCS.....Reactor coolant system
RPS.....Reactor protective system
RT......Reactor trip
RTD.....Resistance temperature detectors
RV......Reactor vessel

List of Acronyms and Abbreviations (Cont'd)

RWT.....Refueling water tank
Rx......Reactor
SBLOCA..Small break loss of coolant accident
SCS.....Shutdown cooling system
SED.....Sequence of events diagram
SFSC....Safety function status check
S/G.....Steam generator
SGTR....Steam generator tube rupture
SIAS....Safety injection actuation signal
SIS.....Safety injection system
SIT.....Safety injection tank
SLB.....Steam line break
SMM.....Subcooled margin monitor
SPTA....Standard post trip actions
T_{avg}....Average reactor coolant system temperature
TEV.....Turbine bypass valve
T_C......Reactor coolant system cold leg temperature
T_H......Reactor coolant system hot leg temperature
TMI-2...Three Mile Island Unit 2
VCT.....Volume control tank

13.2 DEFINITION OF TERMS

Concurrent Steps	-	Action steps which are performed at the same time. Each concurrent step is identified to provide assurance that the total of all actions required is within the control room manpower requirements.
Conditional Steps	-	Action steps which are performed only if prior actions have taken place or certain stated plant conditions exist.
Emergency Procedure Guideline	-	An emergency procedure guideline is a document containing steps which need to be taken in order to take the plant from the post-reactor trip state to an acceptable safe plant state or to event termination. Emergency procedure guidelines are the translation of engineering data derived from transient and accident analyses into operational guidance. The information is presented in such a way that can be expanded into Emergency Operating Procedures.
Entry Conditions	-	Visual or audible indications discernable from the control room, or locally within the plant, which are characteristic of a particular reactor plant emergency type.
Equally Acceptable Steps	-	Equally acceptable steps are two or more steps that achieve an equivalent goal. The operator is directed to one action path and informed of alternative action paths to take in case of a failure in the preferred path.

Functional Recovery Guideline - A functional recovery guideline provides the operator guidance on how to verify the adequacy of safety functions and restore and maintain those functions when they are degraded. A functional recovery guideline is written in such a way that the operator need not diagnose an event in order to maintain the plant in a safe configuration.

Immediate Operator Actions - Actions taken to stop further degradation of existing conditions and to mitigate their consequences. These actions also provide time to allow the operator to evaluate the situation. Operators normally memorize these actions and perform them without having to refer to an EOP. These actions are included in the EOPs and their execution is verified.

Long-Term - That time following the initial transient when the plant has stabilized and the safety functions are being maintained. The time frame can vary based on the specific event.

Nonsequential Steps - Action steps that may be carried out at any time during an event without reference to a specific sequence of actions. EPG strategy charts identify these nonsequential steps with asterisks.

Operator Actions - The action steps used to return the plant to a stable and safe condition.

Recurrent Steps - Actions steps which are done repeatedly while the event is being mitigated. These steps usually contain information explaining the frequency and conditions for performing the required action.

Safety Function	-	Safety functions are the actions or conditions needed to prevent core melt or minimize radiation releases to the general public.
Sequential Steps	-	A group of two or more action steps whose sequential performance is highly desirable or required to achieve their objective. Nonsequential steps may be interspersed as necessary throughout a group of sequential steps as long as they do not disturb the objective of the sequential group. EPG strategy charts identify action sequences.
Symptoms	-	Visual or audible indications discernable from the control room or locally within the plant which are used to identify the state of the plant.
Time Dependent Steps	-	Action steps which contain a specific time reference for the operator so that the step can be acted on at the proper time.
Validation	-	Validation is a particular method used to confirm that the technical guidance contained in the emergency procedure guideline system is practicable. The validation process stresses the systems' effectiveness, as tested by actual experience (simulator exercises), or as measured by a realistic approach in its intended use (control room walk throughs, desk top reviews). Validation of the emergency procedure guideline system ensures it can be used, and that it is useful.

Verification - Verification is the process by which the technical guidance in the emergency procedure guideline system is proved to be accurate and complete. Verification may occur through an investigation of the technical guidance (analyses), comparison (review of existing procedures), or corroboration by operations personnel. The outcome of the verification process is an emergency procedure guideline system which is technically sound.

Verification Steps - Action steps used to determine whether desired plant state exists as a result of previous action steps or changing plant conditions.

Verify - When used in an EPG recovery action, "verify" means that the operator will either observe specific plant conditions indicated in the step or will take the appropriate actions to establish those conditions.

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APPENDIX A
TO
CEN-152 REVISION 02

RESPONSE TO NRC QUESTIONS
ON CEN-152 REV. 02

NOVEMBER 1984

TABLE OF CONTENTS

C

1.0 PURPOSE

The purpose of this Appendix is to provide information which is intended to resolve comments from the NRC Core Performance Branch on CEN-152 Revision 02. Submittal of this Appendix is intended to satisfy NRC concerns on the inadequate core cooling portion of Revision 02. This Appendix contains information on the measurement of subcooling margin as calculated by core-exit thermocouples and hot leg temperature indications, the determination of mean core exit thermocouple temperature, and the Combustion Engineering Heated Junction Thermocouple System. The CEOG committment on providing this information is detailed in Section 2.0.

Additional guidance which has resulted during resolution of the NRC comments will be integrated into Revision 03 to CEN-152. However, the steps which are affected and the specific revisions to these steps are contained within this Appendix for information.

2.0 BACKGROUND

On May 8, 1984, the Combustion Engineering Owners Group (CEOG) transmitted Revision 02 of CEN-152, "Combustion Engineering Emergency Procedure Guidelines" to the NRC (Reference 5.1). Revision 02 was prepared by Combustion Engineering (C-E) in partial response to the Safety Evaluation Report (SER) received on Revision 01 of CEN-152. The submittal provided emergency procedure guidance improvements in the areas of Reactor Vessel Level Monitoring System, reactor coolant pump (RCP) operating strategy, and selected long-term issues as described in the Safety Evaluation Report of Revision 01.

Representatives of the NRC Procedures and Systems Review Branch (PSRB) and Core Performance Branch (CPB) called C-E on June 14 with four questions about the Reactor Vessel Level Monitoring System guidance contained in Revision 02. Five comments, including some of the questions previously responded to, were telecopied to C-E by the NRC on July 24 (Reference 5.2). The telecon stated that although the NRC has not completed the review of CEN-152, Revision 02, the Core Performance Branch found the ICC portion of the guidelines acceptable subject to satisfactory resolution of five (5) comments.

On June 27 a conference call was held with the NRC. Responses to the five questions were discussed. The CEOG agreed to provide written responses in the form of a change package to Revision 02 of CEN-152. This document was informally sent to the NRC for preliminary review on August 7, 1984. On August 29, C-E/CEOG met with the NRC to discuss the responses. As a result, the CEOG proposed to modify the draft response. C-E and the NRC agreed that two questions were fully addressed if certain slight modifications were made to the preliminary responses, two questions needed further resolution, and one question did not require a response by the C-E Owners Group. It was agreed that a write-up could be developed to resolve the remaining two questions.

Section 3.0 of this Appendix constitutes the resolution of NRC CPB/PSRB questions on CEN-152, Revision 02. It contains responses to all five questions as was mutually agreed at the August 29, 1984 C-E/CEOG/NRC meeting.

3.0 NRC QUESTIONS AND RESPONSES

The following are the questions as they were telecopied to C-E on July 24, 1984. Responses to each of the questions are also contained in this section.

3.1 Question 1

Question

At numerous points throughout the guidelines an acceptable criterion is indicated as RCS $\geq$20°F subcooled. Initially, the subcooling margin was measured using the reactor vessel pressure and the hot leg coolant temperature, usually with an RTD (T_H). It is presumed that the indicated acceptance margin refers to the T_H measurements of SMM. For near normal conditions or slowly proceeding transients, particularly with main coolant pumps running, this measurement is adequate. A statement to this effect appears on page 4-12 of the guidelines.

The procedures encompass a wide range of emergency conditions which include pumps not running, and more rapid transients. Under such conditions there is typically a significantly larger temperature difference between the hot leg (T_H) and the core exit or upper head. Since these hot areas are where voiding is likely to occur first and the subcooling margin will be the least, it would seem advisable to include in the procedures appropriate reference to SMM as calculated by core-exit thermocouples (CET) and upper head (UH) thermocouples. The guidelines include only 2 or 3 instances in the Functional Recovery Guidelines where CET calculated SMM is to be used.

All approved EOP guidelines pertaining to final ICC instrumentation rely on a CET calculated SMM, and CE plants using heated junction thermocouples (HJTC) also have the capability to calculate upper head (UH) SMM. It is recommended that the most sensitive indication of low SMM and potential voiding be used where appropriate in the guidelines; that is, where significant differences between UH, CET, and T_H temperatures are expected.

Response

Conceptually, reactor coolant subcooling is used for three different purposes in the EPGs. The manner, specific region, and inputs for determining coolant subcooling to be used depend to a large extent on the specific purpose intended. Coolant subcooling is used in the following ways in the EPGs:

(1) It is one of several parameters (all of which must be satisfied) used to verify adequate core cooling.

(2) It is one of several parameters (any of which may occur) used to determine when and where voiding is occurring in the reactor coolant system.

(3) It is the primary parameter used to validate pressurizer level indication as representative of total RCS inventory. That is, if the RCS is subcooled throughout (using all available indications), then pressurizer level provides a good indication of acceptable RCS inventory.

Subcooling can be calculated or displayed for a number of regions within the RCS (refer to Figure 1). The pressure input for the calculation is from a suitable pressurizer pressure transmitter in all cases. The temperture input can be from loop T_C (4), loop T_H (2), HJTC temperature, RVUH RTDs, or core exit thermocouples (typically 40-60 averaged to provide a temperature to be used (see response to question 2). The extent to which subcooling is automatically displayed is quite plant specific. | C

In addition to the purpose for which the subcooling is to be used, another factor in determining which subcooling input to use (i.e., temperature input) is the mode of RCS core heat removal being employed. There are five modes of core heat removal addressed in the emergency procedure guidelines. They are:

(1) Forced circulation using RCPs

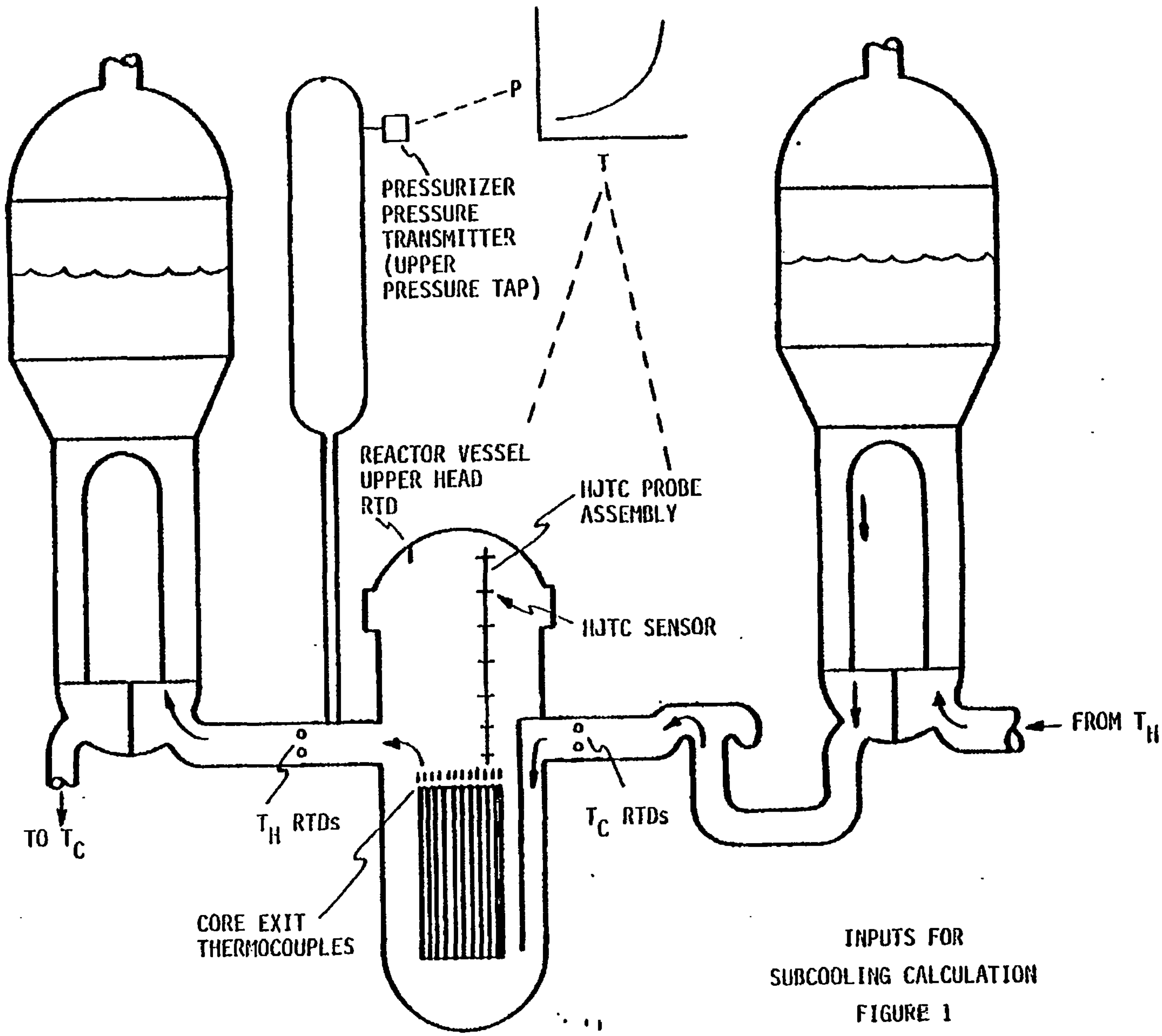
(2) Natural circulation (single phase)

(3) Once through cooling (feed and bleed using PORVs, or SIS flow through the core and out a break)

(4) Reflux cooling (two phase)

(5) Shutdown Cooling System operation

Table 1 provides a summary of the inputs for the subcooling calculation for the three purposes and the five modes of core heat removal. In all cases, all other subcooling values are consulted for corroboration, and/or confirmation of expected trends.



INPUTS FOR
SUBCOOLING CALCULATION
FIGURE 1

TABLE 1

SUBCOOLING INPUTS: HEAT REMOVAL MODE VS. PURPOSE

PURPOSE

MODE OF HEAT REMOVAL

	Core Cooling	Void Detection	Pressurizer * Level Validation
Forced Circulation (using RCPs)	loop T_H	lowest subcooling value calculated	T_H
Natural Circulation (single phase)	average CET	lowest subcooling value calculated	average CET
Once through cooling (feed and bleed using PORVs, or SIS flow through the core and out a break)	average CET	lowest subcooling value calculated	average CET
Reflux cooling (2 phase N/C)	average CET	lowest subcooling value calculated	N/A
Shutdown Cooling operation	average CET	lowest subcooling value calculated	average CET

* PRESSURIZER LEVEL MAY NOT BE VALID WHEN PORV's ARE OPEN

The bases for subcooling parameter selection follows.

Core Cooling and Pressurizer Level Validation

During forced circulation, the operator should use the lowest indicated subcooling value available. It is expected that this value will be based on loop T_H. Representative CET, loop T_C, HJTC and reactor vessel head RTD temperatures (if available) are expected to indicate lower temperatures (higher subcooling) than loop T_H. T_C will indicate lower because of S/G heat removal. CET, HJTC, and reactor vessel head temperatures will read lower because they are partly exposed to cooler core bypass flow.

During forced circulation conditions, CET and T_H indication have roughly equal response times. On most C-E designed plants (2700 MWt and 3410 MWt), the CETs are located 10-20 inches above the active fuel and inside in-core instrument (ICI) tubes. Because of their location inside the ICI tubes, the CETs are exposed to a mixture of core exit fluid and core bypass fluid during forced circulation. Since the core bypass fluid is cooler than core exit temperature, it is common that mean CET temperature reads lower (up to 25°F) than the loop T_H RTD indication during forced circulation (see Table 2). On other C-E designs (System 80 and others), the CETs are more directly exposed to core exit fluid and the difference between T_H and CET readings is expected to be less during forced circulation. Reactor vessel upper head RTDs are similarly exposed to cooler core bypass flows.

Typically, the subcooled margin monitor (SMM) (whether self-contained or integrated with SPDS) develops a minimum loop subcooling indication based on an auctioneered lowest indicated pressurizer pressure, and an auctioneered highest T_H and T_C. On some plants, subcooling is also developed for the HJTC and/or the RV upper head RTD as well as the CETs. Thus, the SMM is ideal for monitoring minimum subcooling during forced circulation.

When conditions other than forced circulation exist, subcooling should be monitored using pressurizer pressure and average CET temperature. Examples of this use of the average CET temperature are the 20° subcooling criterion for pressurizer level validation as part of RCP restart and SIS termination steps. C

TABLE 2

COMPARISON OF MEASURED AVERAGE
CORE EXIT FLUID TEMPERATURES*

Plant

	BG&E Unit 1	BG&E Unit 2	Arkansas	Maine Yankee	St. Lucie Unit 1
% Full Power	100	100	100	95	75
RTD	594	594	605	597	597
Averaged CET Output	587	586	599	597	555

*Based on data obtained from June 1981 to December 1981.

The CETs provide the best indication of fluid conditions adjacent to the core. The CETs do not rely on loop flow (as do the RTDs) for detecting fluid conditions adjacent to the core. With no flow in the loops, the loop RTDs may not provide adequate indication of core fluid conditions. Generally, subcooling will not be stable until the RCS is full (hot and cold legs filled and a level in the pressurizer - although RVUH voids may exist). Use of the HJTC or RVUH RTD is not recommended as input when monitoring for the most conservative indication of subcooling in the RCS since the loops may be adequately subcooled while the RVUH is saturated. The HJTC or RVUH RTD can provide a corroborative indication of a loss of subcooling in the upper head. Use of the average CET temperature to monitor minimum subcooling will permit the operator to stop or throttle SIS (in order to prevent excessive refill or repressurization) while restoring forced or natural circulation. Note that some SPDS designs provide a readout of minimum subcooling based on the average CET temperature. |C |C

During single phase natural circulation, data from plants have shown that CET temperatures are distributed over a narrow range and that CET temperatures closely track T_H RTD indication in the operating loops.

<u>Voiding</u>

When monitoring for voiding in the RCS, the operators should use the lowest indicated or calculated value of subcooling. During natural circulation, it is expected that voiding may occur in the reactor vessel upper head (as described in the Loss of Forced Circulation Guideline Bases Section, page 9-42).

The use of HJTC temperature (unheated thermocouples) and/or reactor vessel upper head RTD in conjunction with pressurizer pressure provides valuable information about coolant subcooling in the reactor vessel upper head. Typically, direct indication is available from the three uppermost HJTC sensors. Loss of subcooling provides the first indication of either voiding or approach to voiding in the RVUH. HJTC level indication is a direct means of determining voiding in the RVUH once it has occurred.

3.2 Question 2

Question

The guidelines refer only to CET temperatures and do not suggest which or how many of the CETs should be used for acceptance of condition of procedural guidelines. This may be a plant specific concern, but general guidance may also be in order.

Response

Where CET monitoring is specified in the emergency procedure guidelines, the operator is required to use a specific, average CET temperature (e.g., an average CET temperature is required for identifying unexpected temperature anomalies between T_H and CET instruments). Experience and baseline data for each plant will provide information for deciding which CETs to reference for use with the emergency operating procedures. This may take the form of operator selection and interpretation or a plant computer algorithm which deletes faulty CET indications during the process of deriving the average CET temperature. The scheme which is selected should take into account: C C

1. The distribution of the CETs so that an adequate sampling of CETs in each quadrant is effected;

2. The possibility that some CETs may be in error (not correctly indicate core exit temperatures) due to condensate runback;

3. The exclusion of CETs which are suspected to have failed or are likely in error by virtue of their large deviation from the average CET temperature.

Once a method for selecting the average CET temperature has been developed, then appropriate plant-specific EOP limits for CET temperature can be determined. Since transient analyses (licensing and best estimate) typically use an average or high average CET temperature, limits should be C

selected to account for any difference which may exits between the average CET temperature and the CET limits prescribed by the analyses. An example of an algorithm which determines an average CET temperature, from which a plant specific computer algorithm could be generated, is represented by the flow chart identified as Figure 20. (See Section 5.0). C

3.3 Question 3

Question

The HJTC systems have generally been accepted by the NRC for Reactor Vessel Level Measuring Systems (RVLMS) on a generic basis. It would seem appropriate to include generic guidance on interpreting the level information display, particularly where dynamic conditions may cause difficulty of interpretation. "Important information concerning reactor vessel liquid inventory trending....." (see page 6-15, Item 14; page 9-11, Item 8; and others) requires a considerable guidance for interpretation of indications, which is not included in the EPGs. The guidance should be applicable to both split and angle HJTC probe users.

Response

See Sections 4.7 and 4.8 for response.

3.4 Question 4

Question

A few phrases are used repeatedly in the EPGs which require considerable interpretation of indications for which no specific guidance is given:

"....voiding is present...." or ".... no voiding is present...." No guidance is given for this interpretation, including no advice or selection of the most sensitive indicator (see Item 1 above).

"....core is covered...." While plant specific, this guidance is a bit vague in relation to instrument indications and especially to allowing margin for approach to core uncovery.

"....follow inventory trend...." (see Item 3 above).

"....indication of unacceptable RCS voiding...." No definition of "unacceptable" voiding is suggested.

<u>Response</u>

Section 4, "Additional information on the HJTC" provides information which responds to this question. The location of additional or more specific information which responds to each of the concerns of Question 4 is identified below.

"....voiding is present...." or "....no voiding is present...." No guidance is given for this interpretation, including no advice or selection of the most sensitive indicator.

Refer to the response to Question 1, CEN-152 (Revision 02) Section 1.7.6 and Sections 4.5 and 4.9.3 of this Appendix.

"....core is covered...." While plant specific, this guidance is a bit vague in relation to instrument indications and especially to allowing margin for approach to core uncovery.

Refer to Sections 4.5 and 4.9.3 of this Appendix.

"....follow inventory trend...." (see Item 3 above).

Refer to CEN-152 (revision 02) Section 1.7.5 and Sections 4.7, 4.8 and 4.9 of this Appendix.

"....indication of unacceptable RCS voiding...." No definition of "unacceptable" voiding is suggested.

Refer to the response to Question 1, CEN-152 (Revision 02) Section 1.7.3, CEN-152 (Revision 02) Page 9-42 (Step 26) and Sections 4.5 and 4.93. of this Appendix.

3.5 Question 5

Question

The guidelines are based on plant conditions most appropriate for C-E designed plants, and contain very little information regarding interpretation of specific instrumentation, such as the HJTC level probes. Plants of other manufacture, such as Westinghouse, using HJTCs may need to use guidelines developed for their plant types and interpret the instrument indications in relation to their own plant conditions.

Response

Based on a telephone conversation which took place on July 30, 1984, this was renamed an observation rather than a questions. No response required.

4.0 ADDITIONAL INFORMATION ON THE HJTC

4.1 INTRODUCTION

NRC requirements for ICC instrumentation are summarized in NUREG-0737, Item II.F.2. NUREG-0737 requires most operating reactors and applicants for operating reactors to install instrumentation for detecting reactor vessel water level. The Heated Junction Thermocouple (HJTC) system is a reactor vessel level measurement system developed by Combustion Engineering (C-E). The HJTC supplements other inadequate core cooling (ICC) instrumentation which in concert provide unambiguous, easy-to-interpret indication of inadequate core cooling.

This information package contains a general description of the HJTC System, including generic guidance on interpreting the level information display, particularly where dynamic conditions influence the displayed information.

4.2 INSTRUMENT FUNCTION

The HJTC can provide meaningful information to the operator from initial occurrence of saturation conditions to the approach to and recovery from ICC. The HJTC is also an effective corroborative indication of the results of corrective actions made by the reactor operator.

The principle function of the HJTC is to determine and display the water inventory in the reactor vessel above the fuel alignment plate. The HJTC is designed to measure both single phase and two phase reactor coolant system (RCS) conditions. Single phase conditions are expected during steady state operations and transients which do not result in rapid depressurization of the RCS. Two phase steam-water mixtures may exist in the RCS during transients involving the loss or shrinkage of reactor coolant system inventory. During those transients, pressure in the RCS may drop to a point where steam voids are formed in the coolant in the upper head, resulting in a steam-water mixture. The HJTC is designed to

indicate the collapsed water level of the steam-water mixture, which is the level the water would form if the steam-water mixture were separated completely to an all vapor (steam) region and an all liquid (water) region.

4.3 INSTRUMENT DESIGN

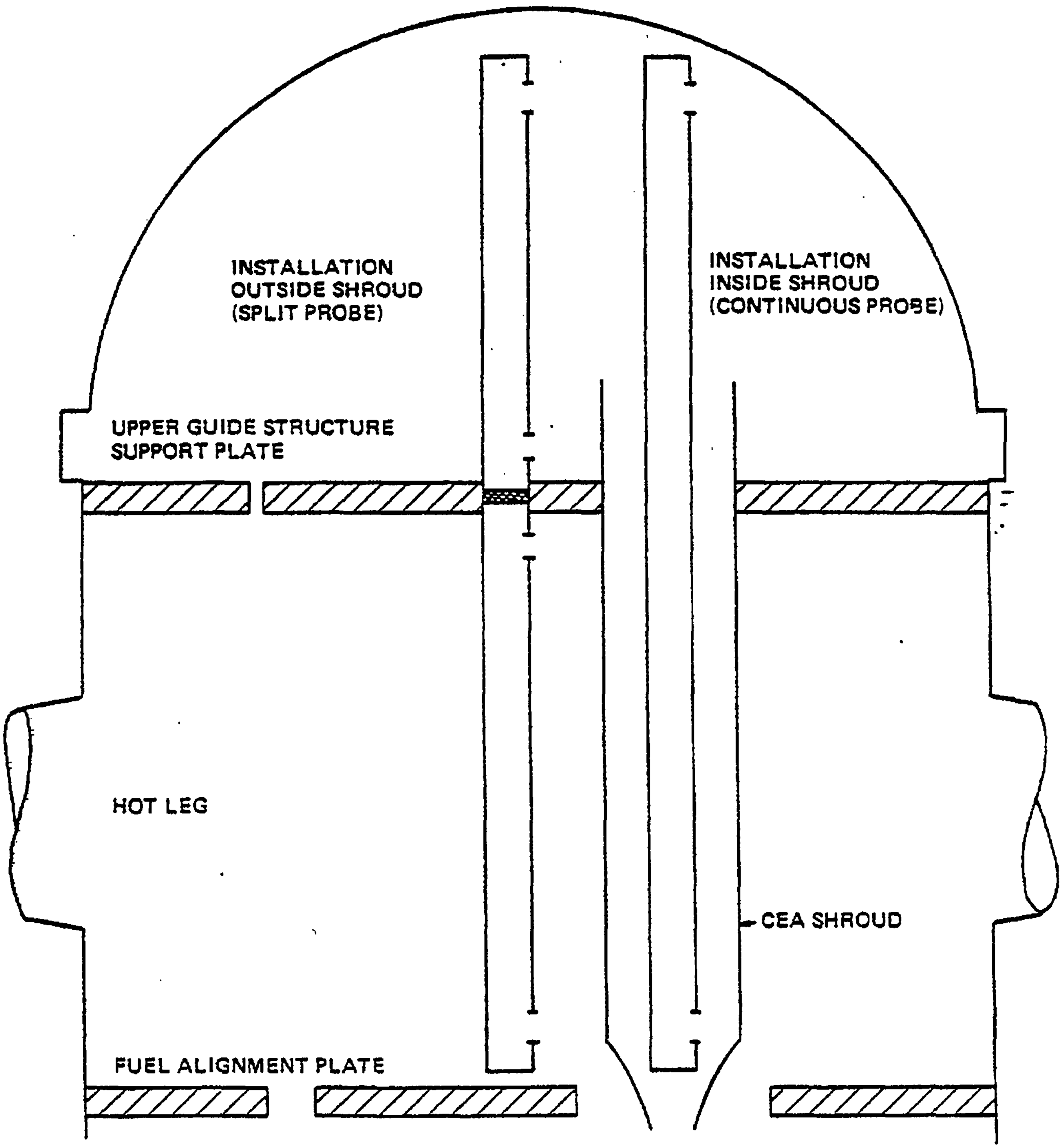
4.3.1 Single Probe vs. Split Probe

There are two design variations of the HJTC probe assembly: a full length probe (called continuous probe) and a split probe design. Two HJTC designs were developed because of different installation requirements and geometrical differences between the upper head and upper plenum regions of various plants. The continuous probe is used for installation within a control element assembly (CEA) shroud of a 2700 MWt C-E PWR, while the split probe is used for installation outside of a CEA shroud in 3410 MWt and System 80 class C-E plants and in non-C-E plants (see Figure 2).

The split probe configuration is simply two single probes, each with fewer HJTC sensors and shorter in length than the full length configuration. The split probe HJTC was designed for the following purpose. In many nuclear reactors, reactor internal structures divide the region above the core into separate liquid compartments. These compartments are isolated from each other to the extent that only limited hydraulic communication occurs. Generally, there are two regions which exist. They are termed "upper head" and "upper plenum". Because of the physical separation, inventory depletion could occur differently in the upper head and plenum. For plants with this physical separation, C-E has devised a split-probe HJTC design which utilizes a divider disk located at the elevation of the upper guide structure support plate to create two separate hydraulic units, one in the upper head and one in the upper plenum. The portion of the HJTC located in the upper head region will measure

FIGURE 2

TYPICAL SENSOR INSTALLATIONS



the liquid fraction of that region. Similarly, the portion of the HJTC in the upper plenum measures the liquid fraction in the plenum region.

The operator's display for the split probe design distinguishes between percent level in the upper head and plenum. The operator's display for the continuous probe design consists of level measurement over the complete span from the fuel alignment plate to the upper head.

4.3.2 HJTC Probe Assembly

The HJTC probe assembly consists of three principal parts. They are:

- o Sensor(s)
- o Separator tube
- o Seal plug

A schematic of the probe assembly is shown in Figure 3.

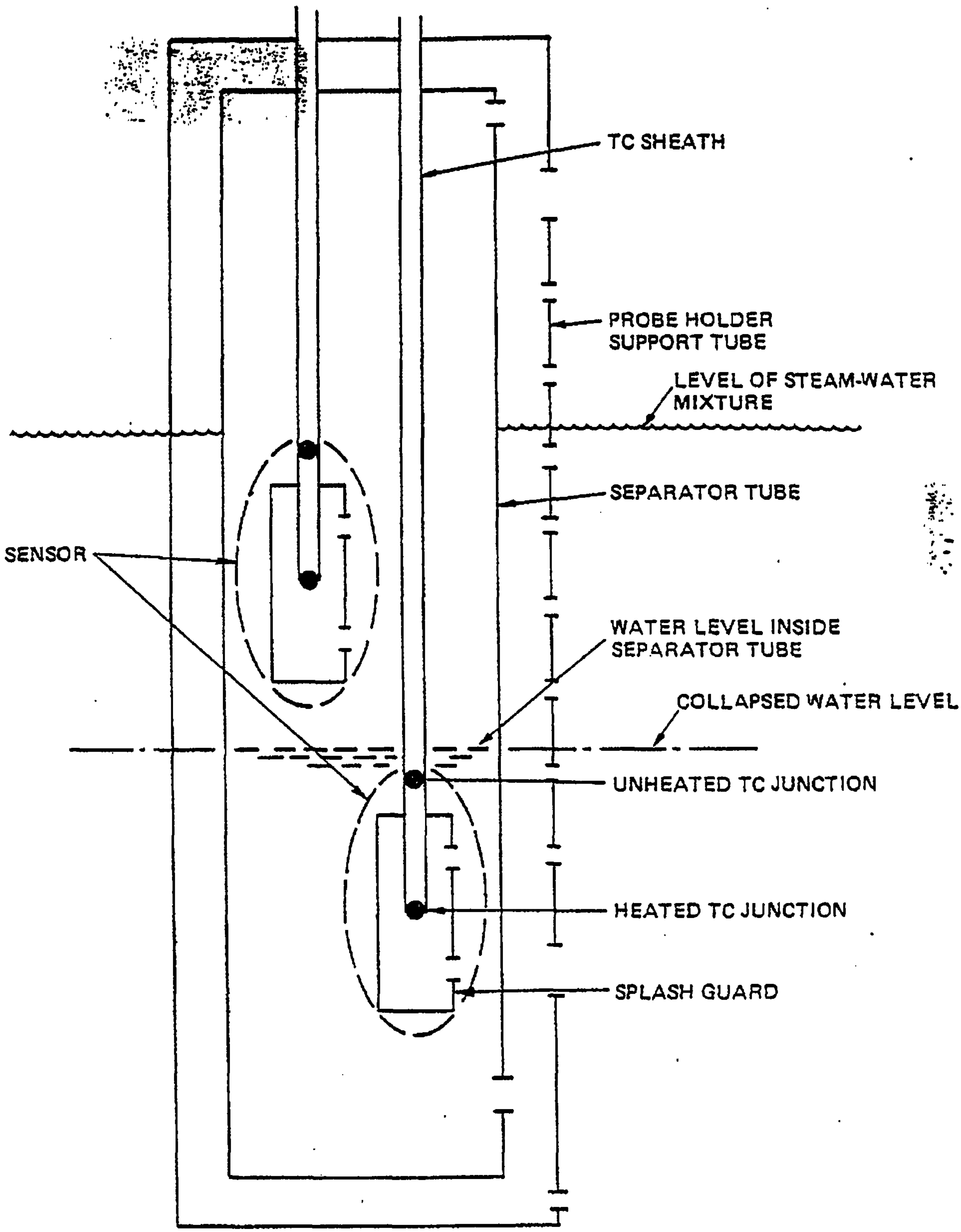
Sensor(s)

The HJTC sensor is the mechanical/electrical interface between reactor vessel level and a transmitted electrical signal. Electrically, each sensor consists of a pair of thermocouples and a resistance heater. The lower of the two thermocouples is encircled by the resistance heater. The lower thermocouple is designated as the heated thermocouple and the upper thermocouple is designated as the unheated thermocouple.

Each sensor has a splash guard. The splash guard is a small cylindrical sleeve, with small side holes at the top and bottom, that is slipped over the sensor sheath during construction. The splash guard is positioned so that the entire heated thermocouple zone is

FIGURE. 3

C-E HJTC PROBE ASSEMBLY



inside the guard. The purpose of the splash guard is to allow liquid to drain or flood the heated zone during changes in vessel level without allowing water droplets or moisture running down the sheath to affect the sensor's performance when the sensor is uncovered. Comparison of the heated thermocouple's electrical output to that of the unheated thermocouple, in the covered and uncovered states, provides information on the existence of fluid in the area of a sensor.

The HJTC probe consists of a string of eight sensors. This string of sensors allows an interpretation of the trending of liquid level in the reactor vessel.

Separator Tube

The second major component of the HJTC probe assembly is the separator tube. The separator tube filters out (or separates) vapor bubbles from a two-phase vapor and liquid mixture. The bubbles, which form in the core region and migrate upward towards the two-phase mixture surface, cause the two-phase mixture to swell. This swelling places the surface of the two-phase mixture higher than the surface of the mixture if the bubbles were collapsed. Since the collapsed level is the more conservative measure of liquid inventory, the separator tube allows the HJTC sensors to monitor it without introducing the ambiguities of swelling.

The separator tube, in conjunction with the structural probe holder support tube, provide a means by which only collapsed liquid level is monitored. The separator tube is a cylinder which has side holes only at the bottom and top. The side holes of the separator tube are shielded from the direct ingress of bubbles by the judicious placement of holes and slots in the probe holder support tube (see Figure 3). Therefore, a solid column of liquid in the separator tube allows for the measurement of the liquid fraction that exists over its span.

As described earlier, for plants with a physical separation between the upper plenum and upper head regions, the separator tube is split into two hydraulically independent zones. This split is physically located in line with the internal structure which divides the upper head from the upper plenum. The portion of the separator tube located in the upper head region contains the column of liquid which allows for the measurement of the liquid fraction of that region. Similarly, the portion of the separator tube in the upper plenum measures the liquid fraction in the plenum region.

Seal Plug

The third component of the HJTC probe assembly is the seal plug. The seal plug seals the HJTC probe assembly to the pressure boundary and internally seals each one of the sensor sheaths (see Figure 4).

Above the seal plug, each sensor sheath terminates in a small electrical receptacle. Each of the eight (8) electrical receptacles have a sensor number designation between 1 through 8. The receptacles mate with corresponding plugs on field cables. The receptacles, by design, are vertically staggered over at least four (4) elevations; however as many as eight (8) elevations may exist. The receptacle elevations correspond to the placement of sensors within the vessel. For example, the sensor receptacle having the longest field cable will be attached to the highest sensor within the reactor vessel.

4.4 HJTC PRINCIPLES OF OPERATION

A single HJTC sensor consists of two electrically opposed thermocouple junctions, one of which is surrounded by a heating element. The temperature difference between the heated and unheated junctions provides an indication of the heat removal capability of the surrounding fluid, which can be directly correlated to the state of the fluid (liquid vs. steam). When the HJTC sensor is immersed in liquid, the surface heat transfer

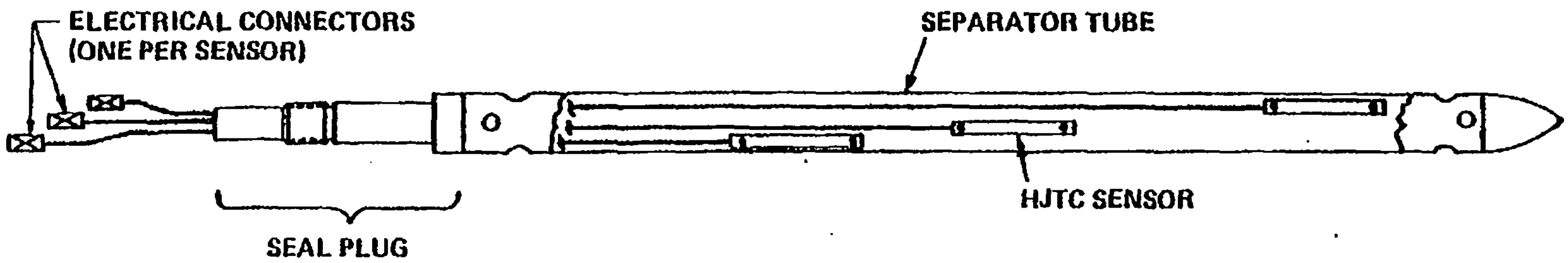


FIGURE 4

HEATED JUNCTION THERMOCOUPLE
PROBE ASSEMBLY, ILLUSTRATING THE SEAL PLUG

coefficient is high, and the heated junction is cooled to near the temperature of the surrounding fluid. The unheated junction is at the same temperature as the surrounding fluid. Thus, the temperature difference between heated and unheated junctions is low. When surrounded by steam, the HJTC sensor's heat transfer ability is much lower. The heated junction does not efficiently transfer heat to the surrounding medium, and consequently the temperature difference between the heated and unheated pair increases.

Since a liquid environment results in a relatively low temperature difference between heated and unheated pairs, and a steam environment causes the opposite effect, the magnitude of the temperature difference between thermocouple pairs can be used to determine whether the sensor is surrounded by liquid or steam. When the temperature difference between the heated and unheated junctions exceeds a predetermined value, the sensor is identified by the microprocessor as being uncovered. This information is displayed to the operating team, alerting them that a void exists in the reactor vessel head.

Once a sensor becomes uncovered, the final temperature that the heated junction reaches depends on the sensor heater power. A higher heater power results in an excessively high heated junction thermocouple temperature and possible sensor damage. A high heater power is desirable, however, to minimize the system response time. Therefore, a sensor heater power control system is used to limit the heated junction temperature and differential temperature below a maximum value. This is done by uniformly reducing the power applied to all sensors after: (1) the temperature of any heated junction reaches a predetermined value, or (2) the temperature difference between heated and unheated junctions reaches a predetermined value. This power cutback system allows the highest possible heater power to be used while still providing protection against excessively high heated thermocouple temperatures and sensor damage.

As stated previously, a sensor is identified as uncovered when the temperature difference between heated and unheated thermocouple pairs

exceeds a predetermined value. A sensor is also considered to be uncovered if the unheated junction temperature exceeds a predetermined value. The purpose of this logic is to maintain an uncovered indication when the temperature of the heated junction thermocouple is high enough so that sensor heater power is completely cutoff. This situation is possible when the temperature of the environment is very high. In this case, the unheated junction and heated junction (without power) would not supply the microprocessor with a sufficiently high temperature differential to result in display information identifying that particular sensor as being uncovered.

4.5 SENSOR PLACEMENT

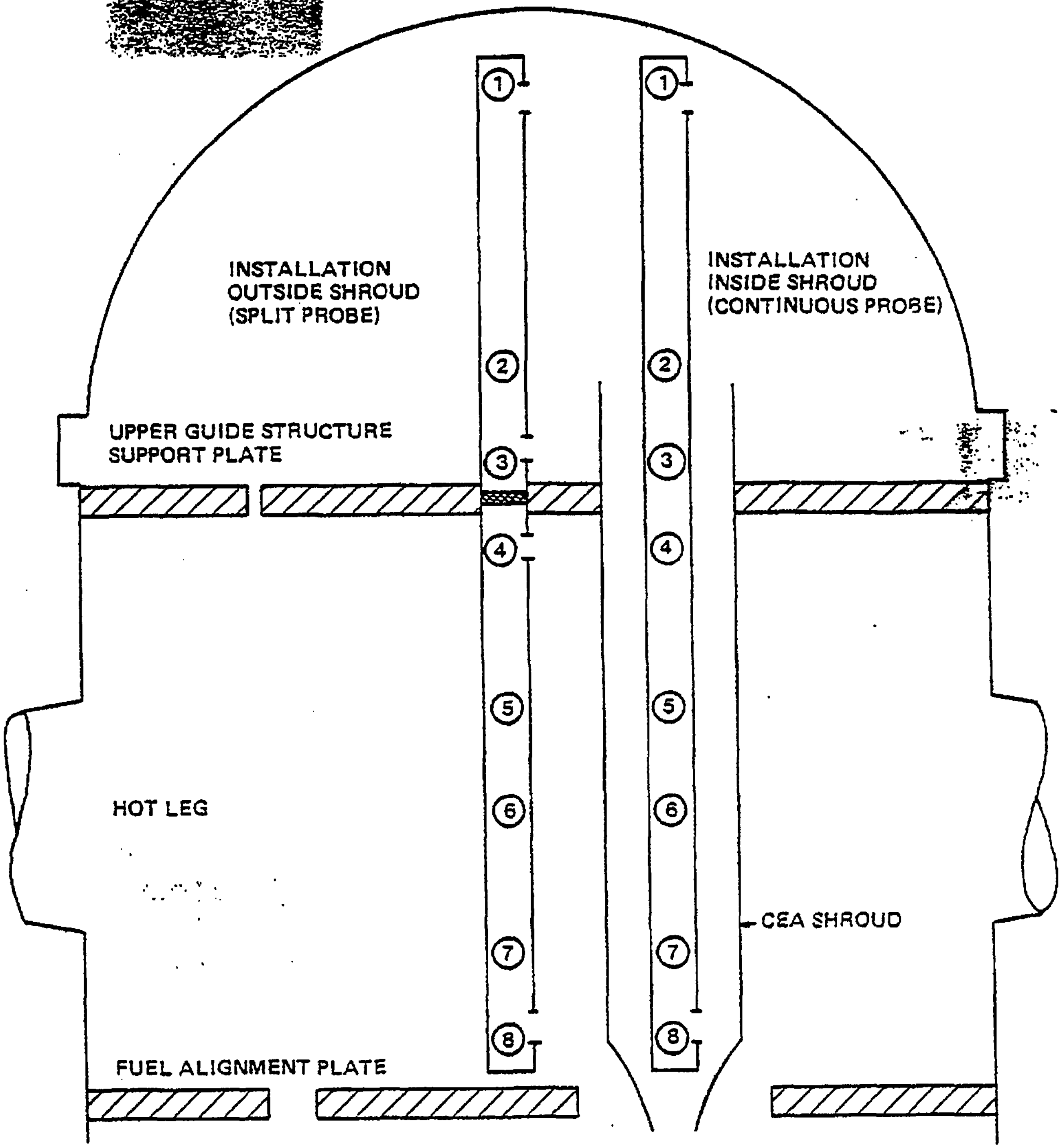
Two HJTC probes are installed in each reactor vessel (RV). These probes are identical to provide redundant level indications. The following description provides the basis for placement of the eight HJTC sensors within each probe. The HJTC sensor locations refer to the location of the heated thermocouple; the unheated thermocouple junction is located 4-1/2 inches above the heated thermocouple junctions.

Two sensor pairs are located in the uppermost position possible in the upper head and upper plenum regions. Refer to sensors 1 and 4 on Figure 5. These sensor positions indicate the earliest formation of a void space in each region. Two sensors (one in each region) are located as low as practical to indicate voiding in that region. Refer to sensors 3 and 8 on Figure 5.

There are three sensors located at the elevation of the hot leg: one at the top of the hot leg (sensor 5), one at the centerline of the hot leg (sensor 6), and one at the bottom of the hot leg (sensor 7). The sensor location at the top of the hot leg indicates the filling of the hot legs and, therefore, the capacity for single-phase natural circulation. The sensors located at the centerline and bottom elevations of the hot leg provide the reactor operator with more detailed information in this region.

FIGURE 5
TYPICAL SENSOR LOCATIONS

[redacted]



The eighth sensor is positioned to provide continuity in water level indication. The location of this sensor varies for each HJTC system design based on RV geometry and engineering judgement. A typical location for sensor 2 is shown on Figure 5.

An illustration of the sensor incremental percent levels and the liquid level indication for each sensor is presented in Figure 6 for a hypothetical region with three sensors. The process operates in reverse during times of increasing level.

4.6 INSTRUMENT DISPLAY

There are two types of control room displays associated with the HJTC system. The standard panel display is a digital readout from a control panel insert. An alternate display is provided as part of C-E's Qualified Safety Parameter Display System (QSPDS) package. Both displays, though different in appearance, provide indications of percent reactor vessel level.

The standard panel display uses a four (4) digit indicator to present percent level for the split-probe design, or percent level and reactor vessel liquid temperature for the single probe design. The orientation of switches and display information is provided on Figures 7 and 8. The four (4) digit display is used in conjunction with three (3) switches on the panel insert to provide the operator with a range of information (see Table 3). Operation of the panel insert switches and the assessment of corresponding display information is also described in Table 3.

The QSPDS display presents a pictorial representation of the core. This is illustrated on Figure 10. The QSPDS also provides individual HJTC temperatures. This is illustrated on Figure 9.

FIGURE 6

EXAMPLE OF HJTC SYSTEM SENSOR RESPONSE
(UPPER SPLIT-PROBE)

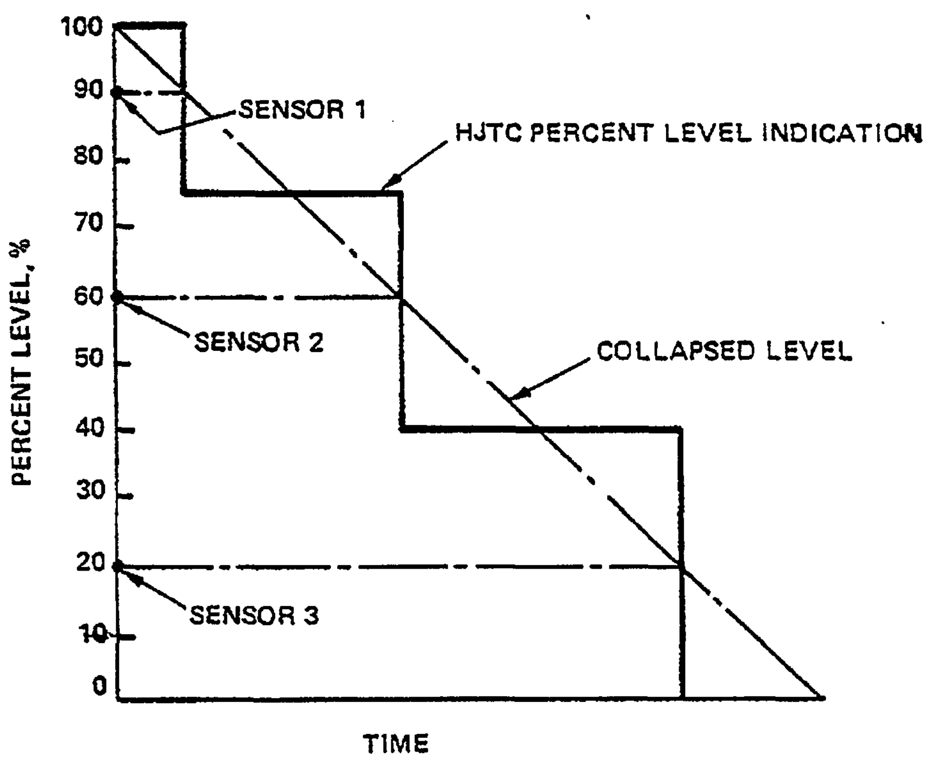


FIGURE 7

PANEL INSERT

SINGLE PROBE DISPLAY

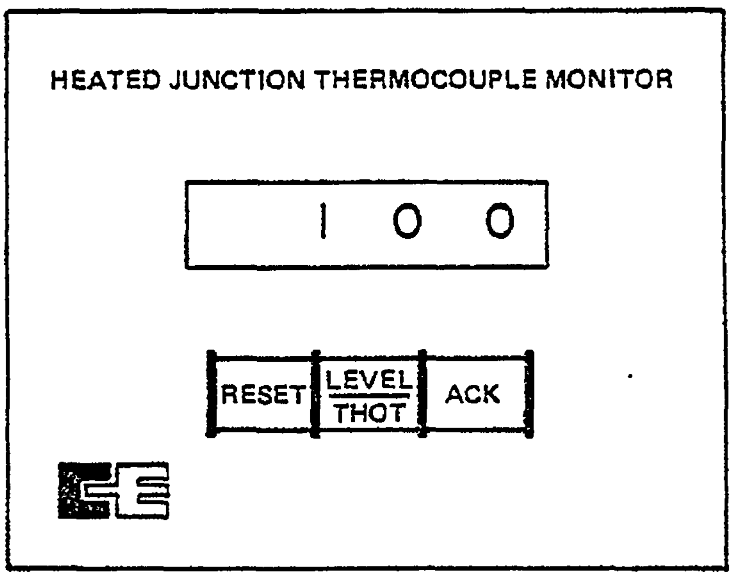
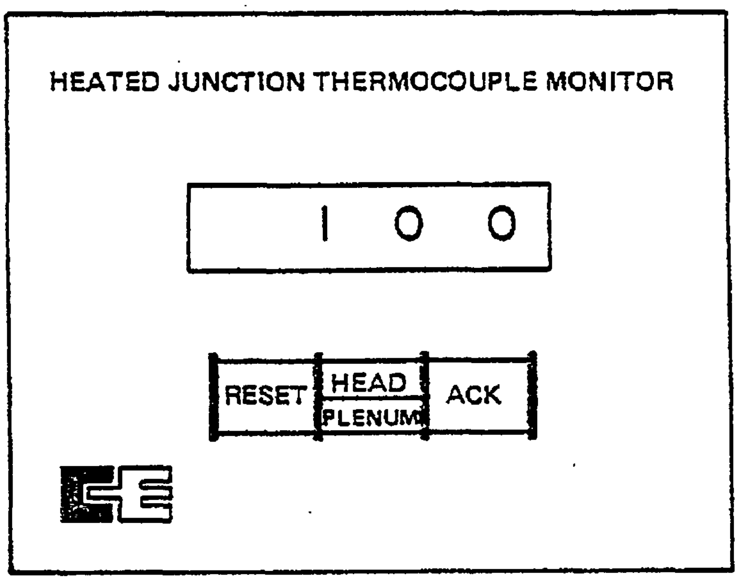


FIGURE 8

PANEL INSERT

SPLIT PROBE DISPLAY



The percent level analog output is usually sent to a trend recorder so as to keep a permanent level trend history. In addition to the analog output, 3 auditory alarms are associated with the HJTC. One alarm notifies the control room staff if the HJTC system stops operating. The second and third alarms are activated when the level drops below 100% in the head and plenum regions respectively. A simplified diagram (Figure 11) shows the indications from the HJTC which are available to the control room operating staff.

4.7 EFFECTS OF REACTOR COOLANT PUMP (RCP) OPERATION ON HJTC PERFORMANCE

The operation of the RCPs during a transient has two principal effects. The first is the production of a frothy, two-phase, steam/water mixture surrounding the HJTC probe. The second is the production of pressure gradients in the reactor vessel above the reactor core which influence the distribution of water within that region.

A frothy, two-phase mixture produced by operating RCPs has no adverse influence on the HJTC measurement since the prcte splash guard and separator tube are designed to separate the mixture into components.

The pressure gradients induced by RCP operation can influence the ability of the HJTC to accurately indicate the liquid inventory above the FAP in either one of two ways. The effect depends upon the plant and type of HJTC installation. In plants which use the continuous probe HJTC, RCP operation during accident conditions may result in temporary liquid inventory redistribution between the upper plenum/upper head and the CEA shroud regions. In plants that use the split-probe HJTCS design, extended RCP operation can produce pressure gradients within the upper plenum region which could affect the indicated level.

4.7.1 Effect of RCP Operation on Continuous Probe Response

During normal plant operation, the RCPs force a small amount of coolant flow through the CEA shrouds. The CEA shrouds extend below

TABLE 3
PANEL INSERT OPERATION

SWITCH	DISPLAY(S)	FUNCTION
RESET	SWITCH LIGHT OFF	DEPRESSED - RESETS SYSTEM AND CLEARS ALL BUFFERS
	SWITCH LIGHT ON	NOT DEPRESSED - PROCESSOR IS RUNNING
HEAD/PLENUM (SPLIT PROBE)	SWITCH LIT (TOP) 'HEAD' DIGITAL DISPLAY 0-100 (%)	MONITORS LEVEL IN THE REACTOR VESSEL HEAD
	SWITCH LIT (BOTTOM) 'PLENUM' DIGITAL DISPLAY 0-100 (%)	MONITORS LEVEL IN THE REACTOR VESSEL UPPER PLENUM
LEVEL/THOT (SINGLE PROBE)	SWITCH LIT (TOP) 'LEVEL' DIGITAL DISPLAY 0-100 (%)	MONITORS LEVEL IN THE REACTOR VESSEL HEAD
	SWITCH LIT (BOTTOM) 'THOT' DIGITAL DISPLAY 32-2300 (°F)	DISPLAYS HIGHEST TEMPERATURE OF THE TOP THREE (3) UNHEATED THERMOCOUPLES
ACK	SWITCH LIGHT OFF	NO HJTC ERROS OR ALARMS EXIST
	FLASHING DIGITAL DISPLAY	AN UNACKNOWLEDGED ALARM OR ERROR CONDITION EXISTS
	SWITCH LIGHT ON	AN ACKNOWLEDGED ALARM OR ERROR CONDITION LIGHT REMAINS LIT AS LONG AS ERROR OR ALARM CONDITIONS EXIST
HEAD/PLENUM (SPLIT PROBE) LEVEL/THOT (SINGLE PROBE)	DIGITAL DISPLAY BLINKING DECIMAL POINT	TEST MODE - DISPLAYS ALL ERRORS THAT EXIST (DISPLAYING ERROR CODE)

TABLE 3 (CONT.)

HJTC MEASURED PARAMETERS		
— SPLIT PROBE —		
PARAMETER	RANGE	PURPOSE
REACTOR VESSEL UPPER HEAD LEVEL	0 - 100%	MONITOR LEVEL IN THE REACTOR VESSEL ABOVE THE UPPER GUIDE STRUCTURE SUPPORT PLATE.
REACTOR VESSEL UPPER PLENUM LEVEL	0 - 100%	MONITOR LEVEL IN THE REACTOR VESSEL ABOVE THE FUEL ALIGNMENT PLATE AND BELOW THE UPPER GUIDE STRUCTURE SUPPORT PLATE.
— SINGLE PROBE —		
REACTOR VESSEL LEVEL	0 - 100%	MONITOR LEVEL IN THE REACTOR VESSEL HEAD ABOVE THE FUEL ALIGNMENT PLATE
T_{HOT}	32 - 2300°F	MONITOR TEMPERATURE IN THE UPPER AREAS OF THE REACTOR VESSEL HEAD.

FIGURE 9

QSPDS DISPLAY
HJTC TEMPERATURE

HJTC TEMPERATURES (DEG F)

	UNHEATED	HEATED	DIFFERENTIAL
1	611	759	147
2	609	759	149
3	589	761	171
4	610	759	140
5	610	760	149
6	610	758	147
7	613	760	147
8	610	760	149

HEATER CONTROL SIGNAL 1	100%	FULL POWER
HEATER CONTROL SIGNAL 2	100%	FULL POWER

REACTOR VESSEL LEVEL

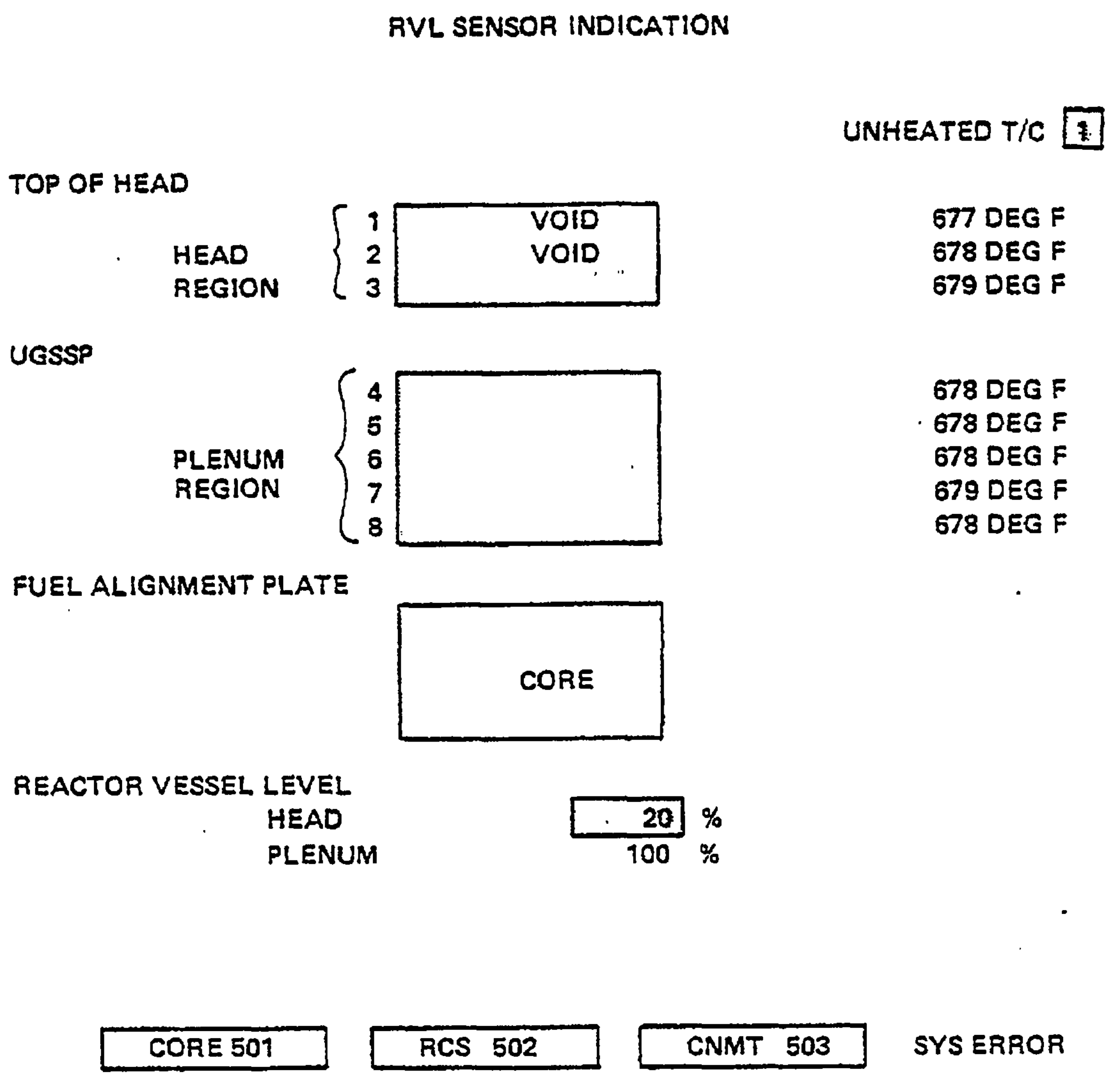
HEAD	100%
PLENUM	100%

CORE 501 | RCS 502 | CNMT 503 | SYS ERROR

FIGURE 10

QSPDS DISPLAY

REACTOR VESSEL LEVEL



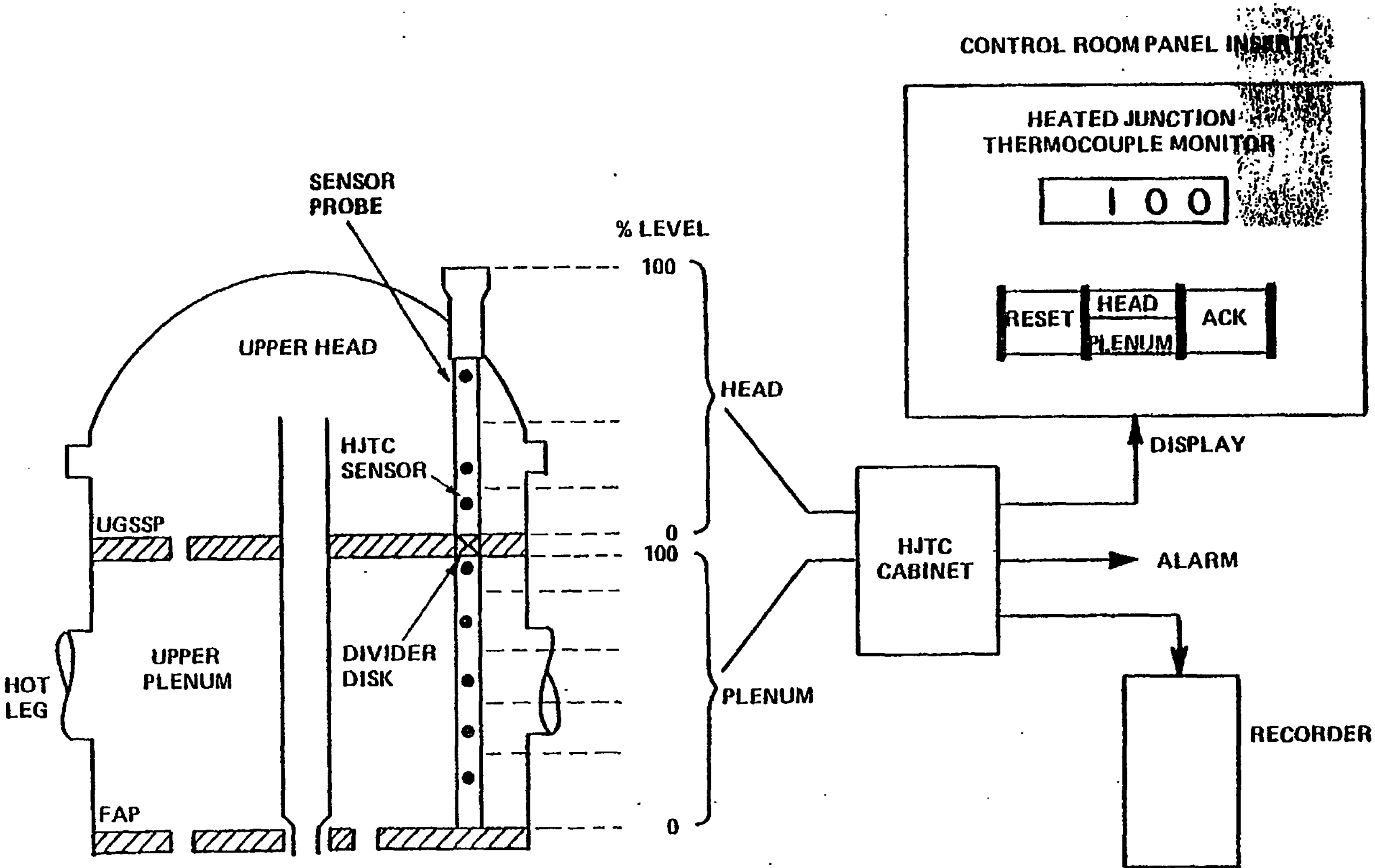


FIGURE 11
SIMPLIFIED DIAGRAM
(HJTC SPLIT PROBE)

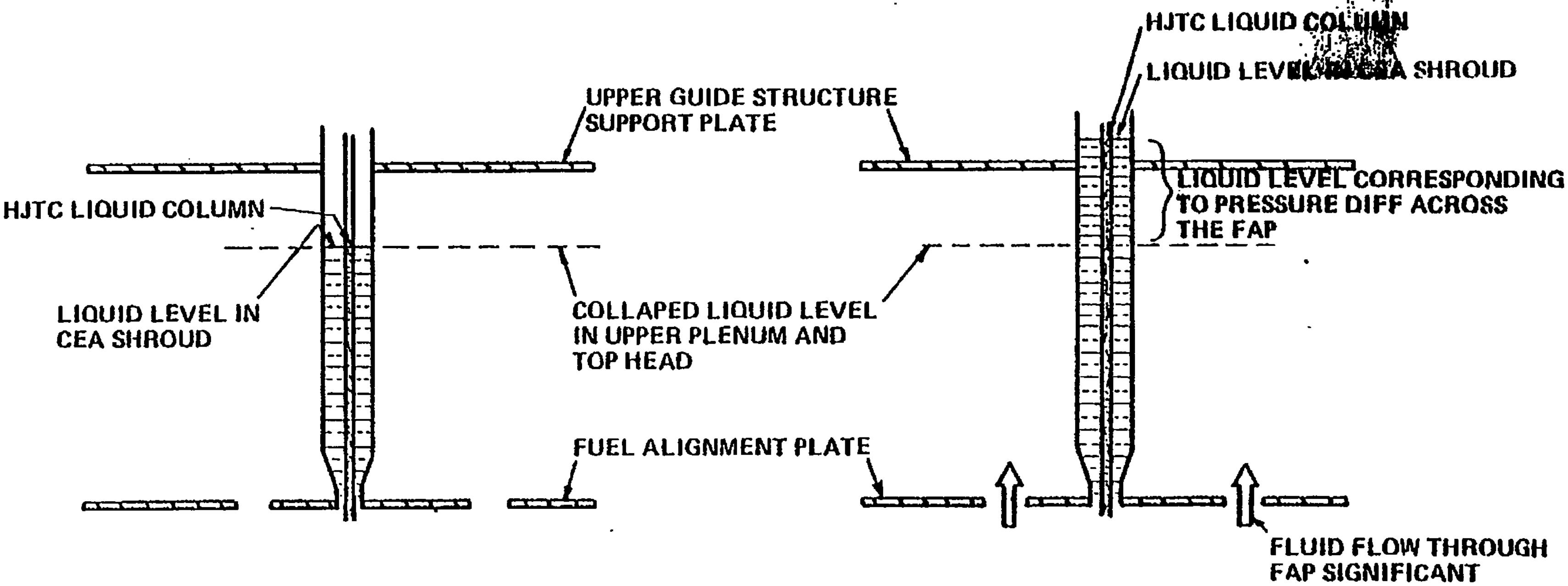
the FAP, which is normally at a higher pressure (about 4 to 6 psi) than the upper plenum. This produces a small flow of liquid up through the shroud into the upper head and down through the upper guide structure support plate (UGSSP) into the upper plenum. As a result of the small flow rates involved, the pressure losses in the shrouds are small and the pressures below the FAP and above the UGSSP (upper head) are nearly in hydrostatic balance.

Following an event leading to an inventory loss (e.g., LOCA) and assuming all RCPs are turned off as required by current emergency operating guidance, the pressure difference across the FAP rapidly diminishes. Consequently, the pressure difference across the FAP is insufficient to maintain a significant liquid flow through the CEA shroud, and more importantly, cannot significantly increase the liquid level inside the shroud. Thus, the CEA shroud liquid level and upper plenum/upper head collapsed liquid level are equal related. The HJTC provides a highly reliable and unbiased indication of inventory above the FAP in this situation.

Continued RCP operation during an inventory loss or shrinkage event (e.g., SGTR, SLB) results in a redistribution of liquid from the upper plenum and upper head into the CEA shrouds. This is shown on Figure 12. Once the collapsed liquid level drops below the top elevation of the CEA shroud, the liquid level in the CEA shroud begins to exceed the collapsed liquid level of the surrounding plenum. The degree of mismatch between the two liquid levels is determined based on the height of the CEA shroud and the instantaneous magnitude of the fuel alignment plate pressure drop. The liquid level mismatch is proportional to the number of RCPs operating, with the maximum mismatch expected for 4 pump operation. For this case, the HJTC only provides the operator with information on the <u>trending</u> of reactor vessel inventory.

FIGURE 12

EFFECT OF PUMP OPERATION ON HJTC LIQUID COLUMN FOR CONTINUOUS PROBE HJTC INSTALLATION



(A) RCPs NOT OPERATING

(B) RCPs OPERATING

Summarizing, if no RCPs are running, the continuous probe HJTC provides accurate information regarding the level of RCS inventory above the fuel alignment plate. If the RCPs are operating, the operator is provided with trending information on reactor vessel inventory and indicated level will tend to exceed actual level.

4.7.2 RCP Effect on Split-Probe Response

The split-probe HJTC installation consists of a single HJTC separator tube hydraulically divided into two tubes at the UGSSP elevation. The upper probe section monitors the collapsed liquid level in the upper head and the lower probe section monitors the collapsed liquid level in the upper plenum.

The HJTC measurement in the upper head region is not affected by the operation of the RCPs. This is a consequence of the relatively high hydraulic resistance of the UGSSP and extremely low fluid flows expected into the upper head. Thus, the collapsed liquid level in the upper head region is closely approximated by the collapsed liquid level within the upper probe section of the HJTC at all times, regardless of RCP status.

The effect of RCP operation on the lower section (upper plenum of the split-probe HJTC) is as follows. As long as the RCPs are operating effectively and pumping high density fluid, significant pressure gradients will exist in the upper plenum. These effects are of little consequence to the overall reactor vessel inventory distribution. However, these pressure gradients will influence the performance of the split-probe HJTC which is placed directly within the reactor vessel upper plenum. During normal reactor operation, coolant flow forced through the FAP enters the reactor vessel upper plenum as a number of high velocity fluid jets. These jets are fully or partially dissipated within the upper plenum, producing a net positive static pressure (pressure recovery) difference between the top (just below UGSSP) and bottom (just above the FAP) of the

upper plenum. Thus, the pressure near the UGSSP may be slightly higher than near the FAP and the hydrostatic balance between the HJTC probe and upper plenum may result in a collapsed level inside the HJTC which is depressed below the upper plenum collapsed liquid level by the head equivalent to the jet pressure recovery. A representation of this typical mismatch between the liquid level in the HJTC and the upper plenum collapsed liquid level is presented in Figure 13.

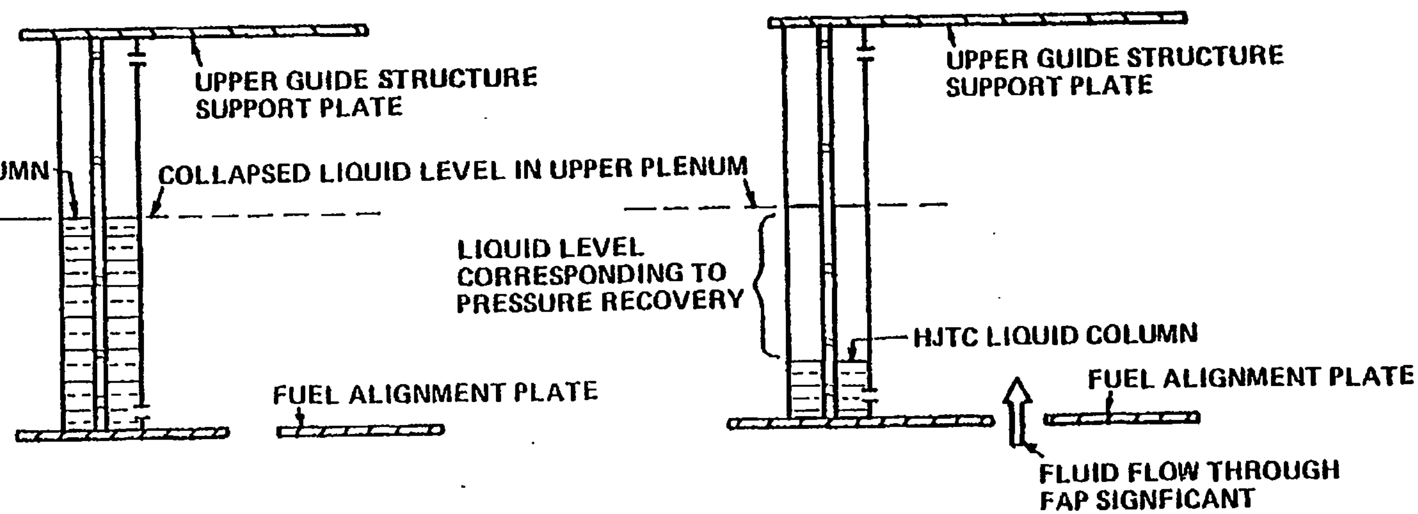
Summarizing, the upper probe section of the split probe HJTC is not affected by RCP operation and provides an accurate reactor vessel liquid level measurement to the operating team. The reactor vessel level measured in the lower section of the HJTC probe in the region between the fuel alignment plate and upper guide structure support plate (upper plenum) is affected by RCP operation. The separate tube level is depressed below the actual level in the reactor vessel when RCPs are running and the information available to the operating team reflects this bias. In this case, the operating team is provided only with information on the trending of liquid level in the RCS.

4.7.3 Factors Affecting RCP Induced Biases

Collapsed liquid level biases for continuous and split probe HJTCS, which are induced by RCP operation, are influenced by three key factors. First is the number of RCPs in operation. The more RCPs operating, the greater the mismatch between actual and displayed level. Second, the density of the primary system coolant has an impact on the collapse liquid level bias. The density of the fluid pumped by the reactor coolant pumps has effects on the pressure difference across the fuel alignment plate (affecting the continuous probe HJTC response) and pressure gradient in the upper plenum (affecting the split probe HJTC) response. Lastly, the geometry of the upper plenum and the plant-specific location of the HJTC probe

FIGURE 13

EFFECT OF PUMP OPERATION ON HJTC LIQUID COLUMN FOR SPLIT-PROBE HJTC INSTALLATION



(A) RCPs NOT OPERATING

(B) RCPs OPERATING

influences the collapsed liquid level bias, since the position of the probe and characteristics of the surrounding fluid due to RCP operation are directly related to HJTC performance.

4.8 HJTC RESPONSE TO VARIOUS EVENTS

The fluid environment following a loss of inventory or inventory shrinkage event is characterized by:

(1) The type and severity of the event
(2) The RCP operating strategy employed*, and
(3) To a lesser extent, the design (MWt size) of the plant

Consequently, the expected hydraulic condition of the reactor vessel, and corresponding HJTC response for certain transient events can only be defined in a general sense. This section provides typical examples of HJTC responses to LOCA, SGTR and SLB transients for both continuous probe and split probe installations. The purpose of providing this information is to present HJTC liquid levels indicative of what may be seen by the operating team in the control room. A range of best estimate computer cases were run to simulate the reactor coolant system response to SGTR, SLBs and LOCAs with the RCPs operating in the same scheme as required in the EPGs. Those curves which show the lowest expected reactor vessel level for each event were chosen for inclusion in this report, since they best illustrate the response for the HJTC display.

*The RCP operating strategy in the Combustion Engineering Emergency Procedure Guidelines is one that:

1) ensures tripping of all RCPs for all LOCAs, and
2) allows the continued operating of at least two RCPs in opposite loops for other RCS inventory loss and shrinkage events (e.g., steam line breaks and steam generator tube ruptures).

4.8.1 HJTC Performance Following a Loss of Coolant Event

The continuous probe HJTC response to a LOCA is presented in Figure 14. The collapsed liquid level in the CEA shrouds closely follows the collapsed level in the upper head and upper plenum after the initial RCS decompression. Thus, without the RCPs operating, the continuous probe HJTC provides an unambiguous indication of the liquid inventory above the FAP.

The split-probe HJTC response to a LOCA is given in Figure 15. The split-probe HJTC also yields an accurate indication of the liquid level above the FAP.

4.8.2 HJTC Performance Following a Steam Generator Tube Rupture

The continuous probe HJTC response following a SGTR with four RCPs off followed by two RCPs restarted is provided in Figure 16. RCP operation during the SGTR transients analyzed is shown not to adversely affect the HJTC level indication. This Figure also shows the HJTC response to void collapse. When the two RCPs are restarted at maximum void, the level inside the shrouds swells rapidly to the top of the shrouds as is indicated by the HJTC.

The response of a split-probe HJTC to a SGTR with two RCPs restarted at maximum void is shown in Figure 17. The split-probe HJTC provides a good indication of the liquid inventory in the upper head and upper plenum.

4.8.3 HJTC Performance Following a Steam Line Break

The HJTC response to a large SLB with two RCPs operating in a typical 3410 MWt plant is given in Figure 18. The reactor operator can follow the formation of the void space in the RV from the upper head into the upper plenum. The recovery of the liquid level in the RV, enhanced by RCP operation, is also well displayed by the split-probe design.

FIGURE 14

LOSS OF COOLANT ACCIDENT (LARGE BREAK)
(COLD LEG BREAK)
4 RCPs TRIPPED
[redacted] CONTINUOUS PROBE HJTC RESPONSE
(2700 MWT PLANT)

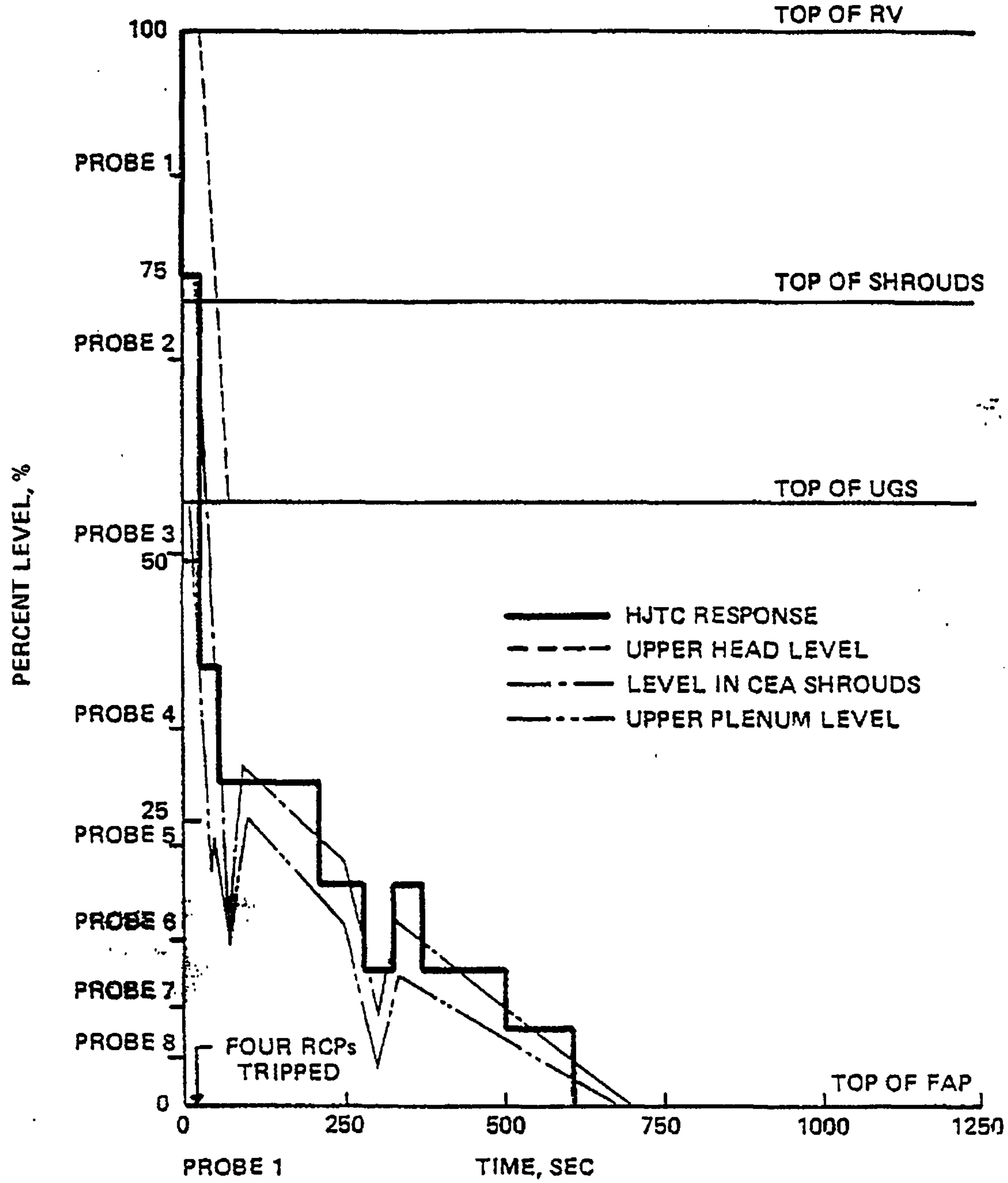


FIGURE 15

LOSS OF COOLANT ACCIDENT
(COLD LEG BREAK)
4 RCPs TRIPPED
SPLIT PROBE HJTC RESPONSE
(3410 MWT PLANT)

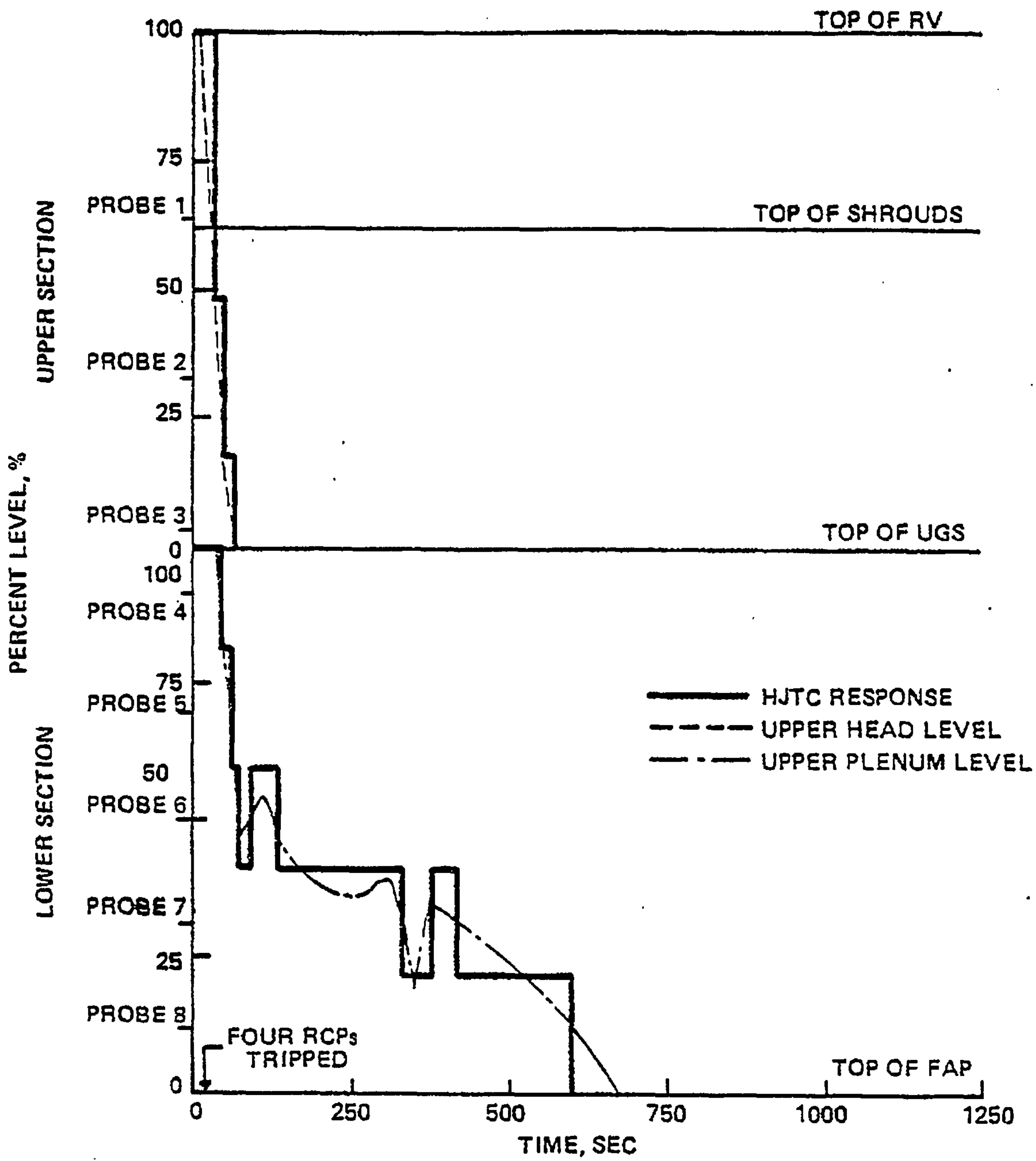


FIGURE 16

STEAM GENERATOR TUBE RUPTURE
4 RCPs TRIPPED
2 RCPs RESTARTED AT MAXIMUM VOID
CONTINUOUS PROBE HJTC RESPONSE
(2700 MWT PLANT)

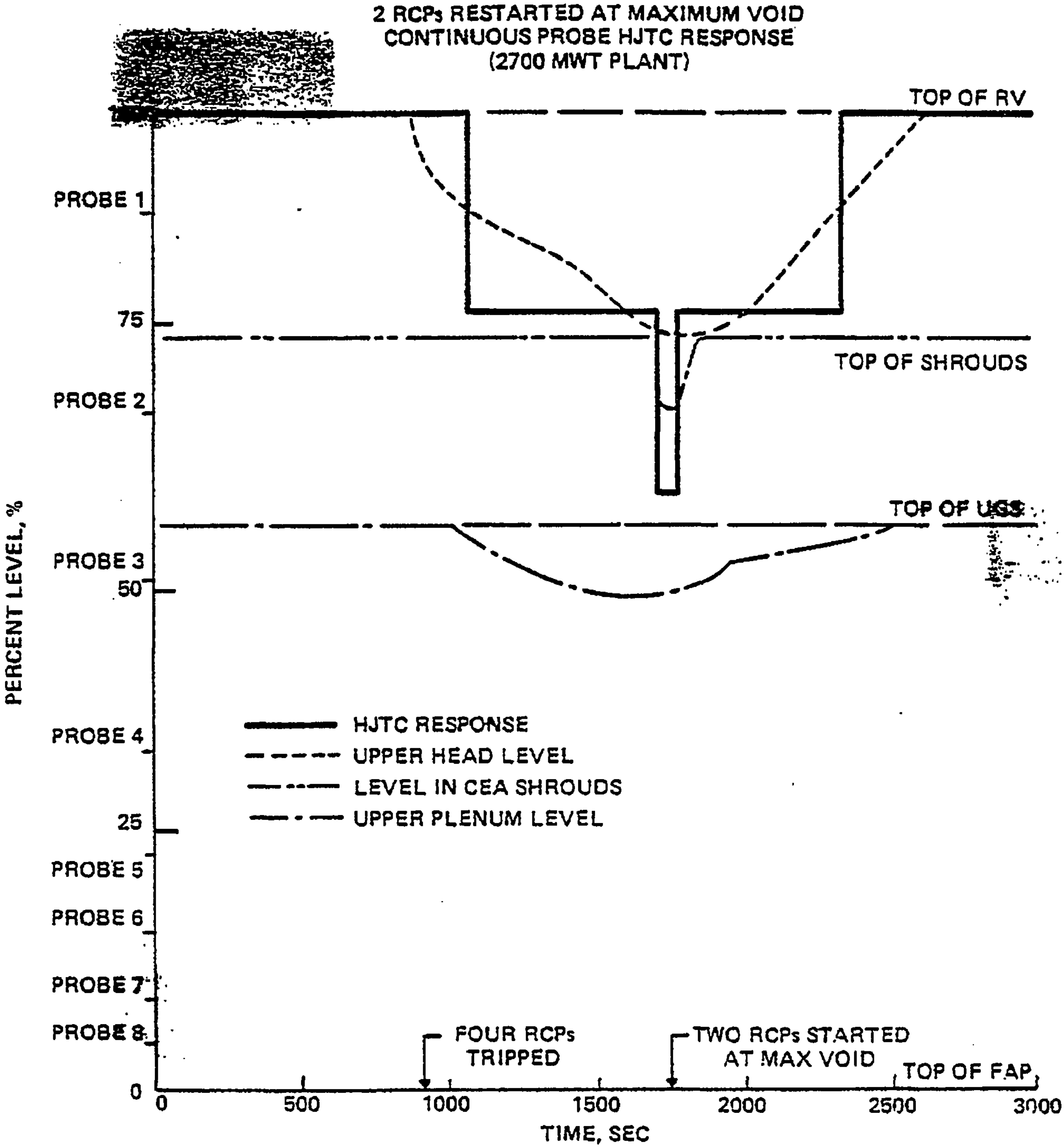


FIGURE 17

STEAM GENERATOR TUBE RUPTURE
4 RCPs TRIPPED
2 RCPs RESTARTED AT MAXIMUM VOID
SPLIT PROBE HJTC RESPONSE
(3410 MWT PLANT)

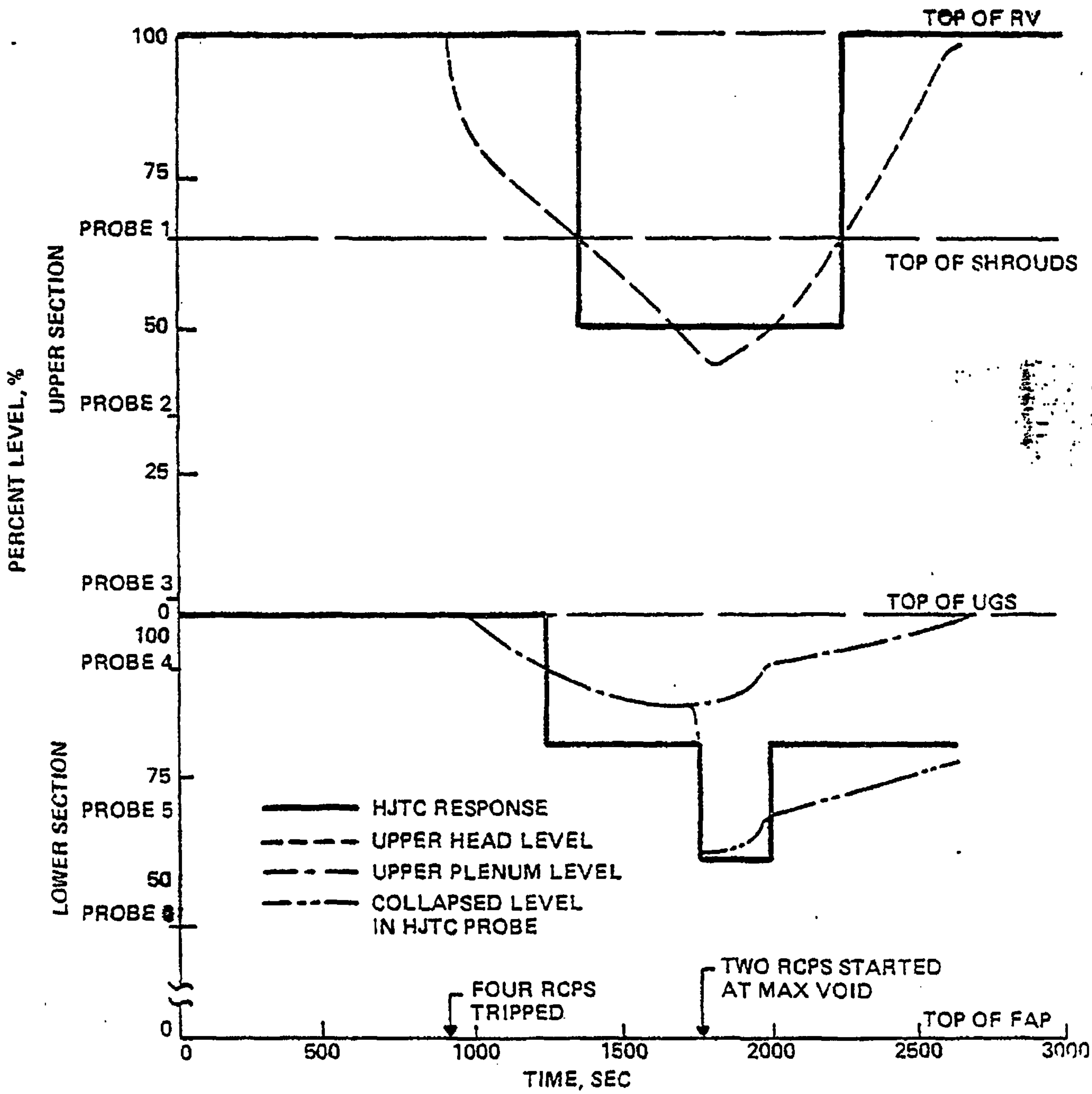
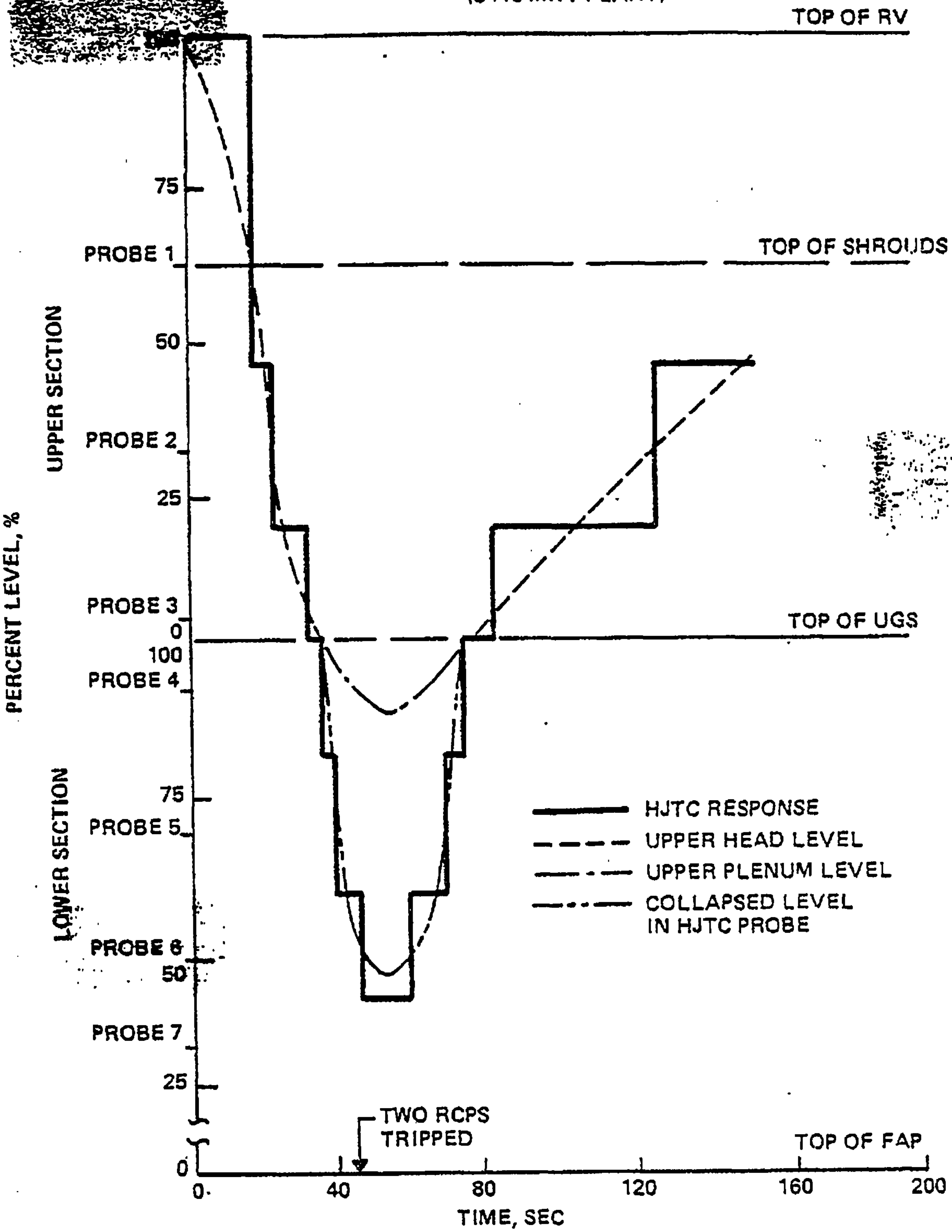


FIGURE 18

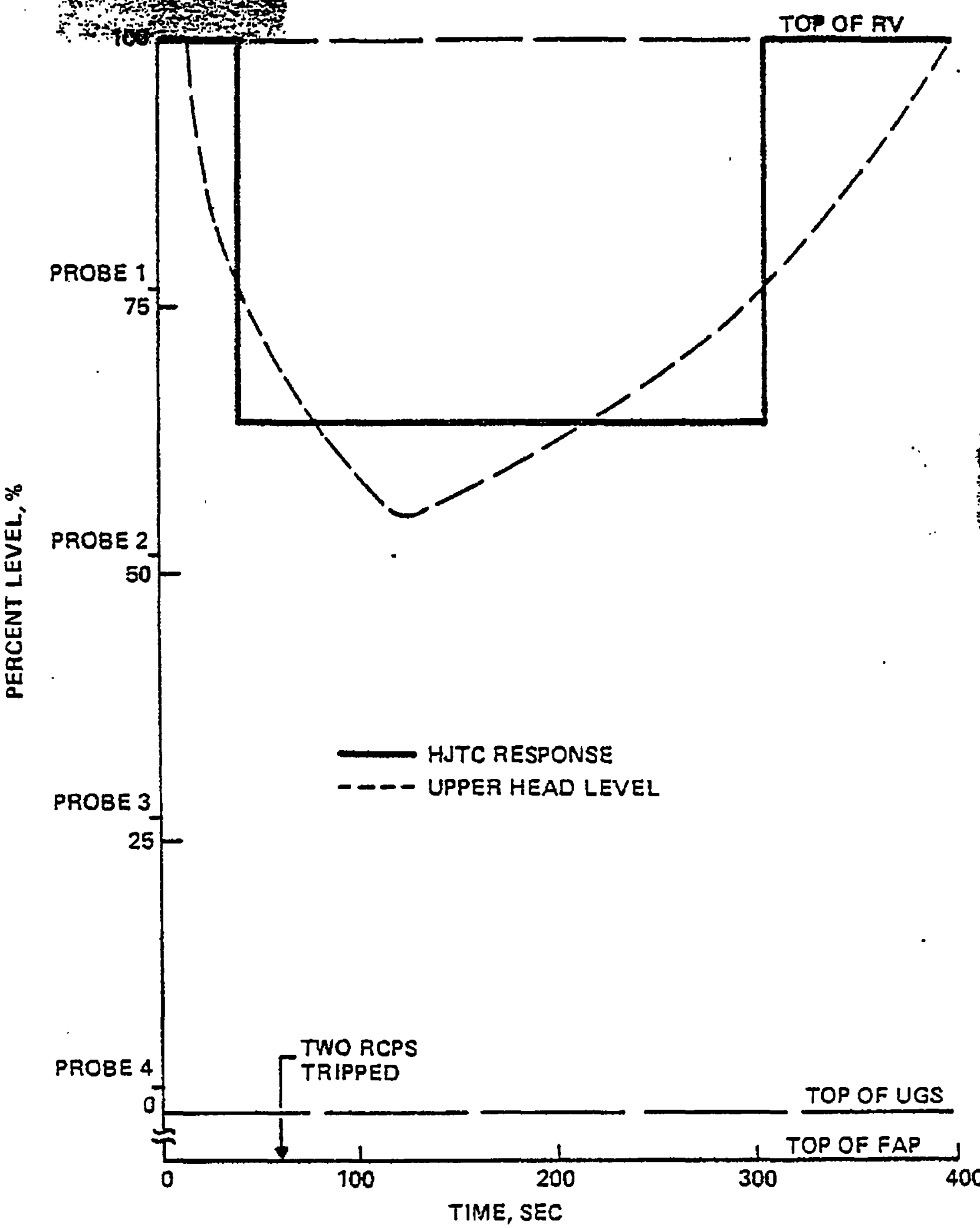
LARGE STEAM LINE BREAK
2 RCPs TRIPPED
SPLIT PROBE HJTC RESPONSE
(3410 MWT PLANT)



The split-probe HJTC response to a large SLB in Sys 80 plants with two RCPs tripped is provided in Figure 19. The amount of voiding in the RV does not fall below the UGSSP due to the large volume of the upper head. The upper section of the HJTC provides a good indication of the collapsed level in the upper head. Since no voids occur in the upper plenum region, the lower section of the HJTC indicates a full level during the transient.

FIGURE 19

LARGE STEAM LINE BREAK
2 RCPs TRIPPED
SPLIT PROBE HJTC RESPONSE
(SYSTEM 80 PLANT)



4.9 OPERATOR USE OF THE HJTC

4.9.1 Normal Plant Operation

Operator interaction with the HJTC system during normal operations will primarily be to confirm that the HJTC is functioning properly. No reactor vessel head (and for the split probe design, plenum) voiding should be indicated. Temperature measurements of the HJTC sensors should compare to other independent temperatures (i.e., measured by the core exit thermocouples and T_H).

HJTC indications can be used to track vessel level during the drain and refill for refueling operations. Additionally, the water level indicated by the HJTC can be compared to independent reference leg water level indications to provide sensor response time testing data for comparison purposes.

4.9.2 Abnormal Plant Operation

An abnormal event is a plant event which causes certain safety functions to be challenged, but can be corrected without tripping the reactor. Voiding in the reactor vessel is not expected to occur during an abnormal event. Consequently, operator interaction with the HJTC system will be limited to verifying that the HJTC remains operational and that head voiding does not exist.

4.9.3 Emergency Plant Operations

During emergency plant operations display information from the HJTC system is valuable:

- As a corroborative diagnostic tool for determining the event which is occurring.

- In assessing the status of the safety functions (both initially and continuously).

- During any event which might cause voiding, as a comparison of actual trending against expected trending (as presented in Section 4.8).

- When following the trend of void growth and collapse during operations requiring a fill and drain of the upper head.

- In providing feedback information on the operation of safety systems which combat the effects of an inventory loss or shrinkage event (e.g., safety injection system).

- For a corroborative indication of saturated conditions in the upper head using the unheated HJTC sensor temperatures for calculating subcooling.

- In corroborating the approach to, or recovery from inadequate core cooling.

4.9.4 Revised Operator Guidance

During discussions with the NRC regarding the five questions, it was agreed that C-E would review the EPGs for possible improvements for the use of the HJTC/RVLMS. C-E has performed this review and has concluded that HJTC temperature (from the unheated sensors) converted to coolant subcooling using pressurizer pressure can provide an additional indication of voiding in the reactor vessel upper head. Note that any of the parameter changes listed might be an indication of voiding. If any one of the parameter changes occurs, the other indications should be checked as available for corroboration.

Revision 03 of CEN-152 will reflect this change. In the interim, plants utilizing CEN-152 Revision 02 should incorporate the following information.

In the CEOG Emergency Procedure Guidelines, when monitoring for voiding, the following substep should be added:

....[HJTC temperature indicates saturated conditions in the reactor vessel upper head]

An example of how this substep is integrated into the EPGs follows:

a) Control charging and letdown
b) Operating and/or throttling HPSI pumps.

25. If a steam generator was isolated, Then cool the isolated steam generator as necessary to prevent isolated loop void formation by:

a) Feeding and bleeding the isolated steam generator with feedwater,

or

b) Feeding and steaming the isolated S/G to the condenser (preferred) or to atmosphere.

*26. If the above actions fail to depressurize the RCS, Then a void should be suspected. The operator should monitor for the presence of voids. If voiding inhibits RCS depressurization to SCS entry pressure, Then an attempt at eliminating the voiding should be made.

Voiding in the RCS may be indicated by any of the following indications, parameter changes, or trends:

a) letdown flow greater than charging flow,
b) pressurizer level increasing significantly greater than expected while operating pressurizer spray,
c) [the RVLMS indicates that voiding is present in the reactor vessel],
e ~~d~~) [other indications insert here].
d) [HJTC unheated thermocouple temperature indicates saturated conditions in the reactor vessel upper head]

*27. If voiding should be eliminated, Then proceed as follows:

a) verify letdown is isolated,
b) stop the depressurization and, if required, repressurize the RCS to ≥ [20°F] subcooling,

* Step performed continuously.

4.10 SUMMARY

The Heated Junction Thermocouple System is a reactor vessel level measurement system developed by Combustion Engineering. There are two design variations; the continuous probe and the split probe design. Two HJTC designs were developed because of different installation requirements of various plants. Both the continuous probe and split probe HJTC designs provide meaningful information to the reactor operating team in the control room. The HJTC measures void fraction above the fuel alignment plate by sensing a temperature difference between the heated and unheated thermocouples in each sensor pair. Sensors are placed within each HJTC probe in a way which provides continuity in water level indication that is useful information for an operating team.

Operation of the RCPs introduces a bias in the water level measured by the HJTC. For the continuous probe design, indicated water level is greater than actual level. For the split probe design, the affect is the opposite. Thus, trending information on reactor vessel level is provided to the operating team while the RCPs are operating during an emergency event. This mismatch does not impede the operator's ability to verify void size, or monitor void growth (or collapse).

During LOCAs, the HJTC yields an accurate indication of liquid level above the fuel alignment plate. During RCS inventory loss or inventory shrinkage events when the reactor coolant pumps are operating (e.g., SLBs or SGTRs), the operator is provided with a good indication of RCS liquid inventory, along with valuable inventory trending information.

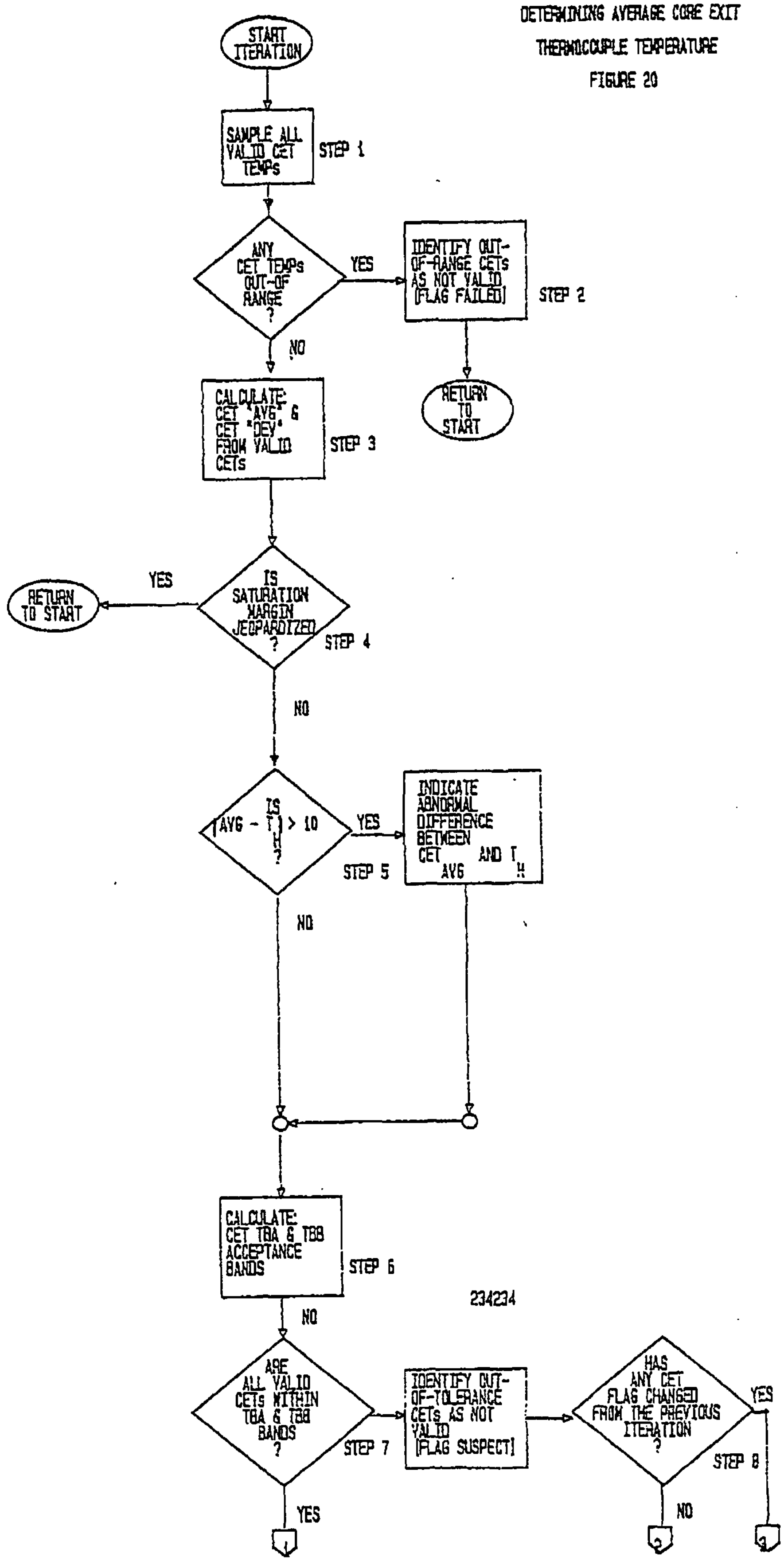
5.0 EXAMPLE ALGORITHM FOR DETERMINING AVERAGE CORE EXIT THERMOCOUPLE TEMPERATURE

This section contains a generic algorithm suitable for development of a plant specific computer algorithm, a manual procedure by which an operator can determine an average CET temperature, and a technical description for each. This algorithm is designed for use with the Emergency Procedure Guidelines and is not intended to replace any existing CET algorithms. C

5.1 An Average CET Temperature Algorithm

This particular algorithm provides an average CET temperature and a method of determining failed and suspect CETs. Figure 20 illustrates this algorithm in a flow chart format. Each step identified on the flow chart correlates to a technical description of the step and the logic applied.

AN ALGORITHM FOR
DETERMINING AVERAGE CORE EXIT
THERMOCOUPLE TEMPERATURE
FIGURE 20



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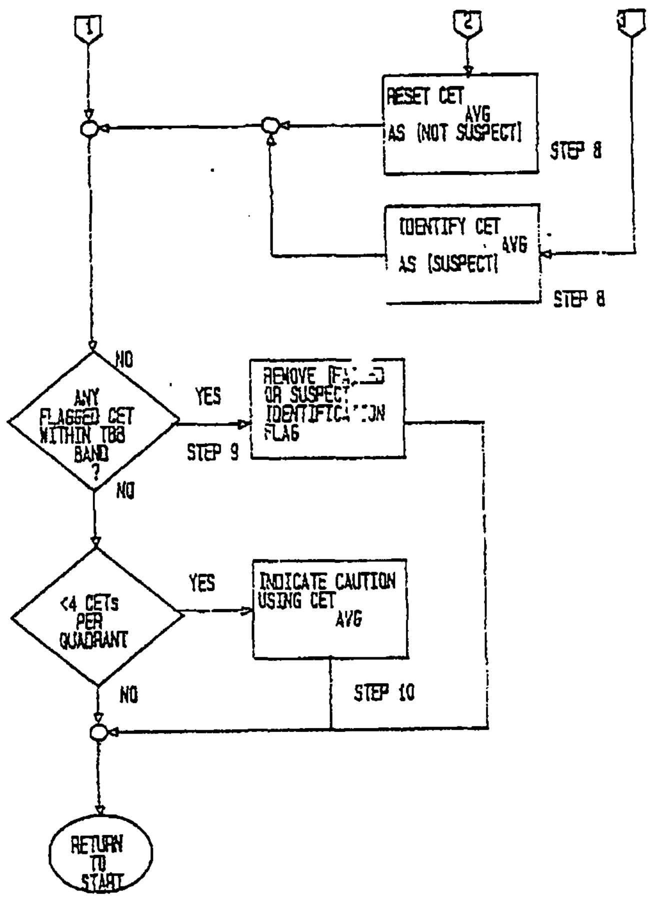
AN ALGORITHM FOR
DETERMINING AVERAGE
CORE EXIT THERMOCOUPLE TEMPERATURE

FIGURE 20



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5.1.1 <u>Description</u>

1. The typical arrangement of core exit thermocouples (CETs) is an array of about 45 instruments distributed about the core in the incore instrumentation sheaths. This algorithm samples all CETs and evaluates the validity of each measurement during each iteration. During each iteration, only the CETs which are valid after the previous iteration's evaluation processes are considered.

2. The CET measurements are first evaluated to identify and exclude failed CETs. This is accomplished by establishing out-of-range limits, typically [32°F] and [2300°F]. These values correspond to the thermocouple reference junction temperature, and the maximum CET temperature measurement required by NRC regulations, respectively. CETs which are out-of-range are uniquely identified or "flagged" as invalid. These CETs will not be used in the su.sequent interations unless the criterion of Step 9 is sat:sfied. C

3. Calculate the mean or average value and the standard deviation of the valid CET temperatures, using the following equations:

$$AVG = \frac{\sum_{i=1}^{n} T_i}{n}$$

$$DEV = \left[\frac{\sum_{i=1}^{n}(T_i - AVG)^2}{n-1}\right]^{1/2}$$

where: n = number of valid CET inputs
T_i = the ith valid CET temperature
AVG = average temperature of valid CETs
DEV = standard deviation of the valid samples.

The standard deviation is used in the determination of suspect CETs.

4. If either the average CET temperature (CET_{AVG}) from the previous iteration or the hot leg RTDs indicate that the reactor coolant system is less than [10°F] subcooled, then the evaluation for suspect CETs is not performed, since a wide distribution of CET temperatures can be expected. This step identifies the departure from the single phase liquid state for which steps 5 through 8 apply.

5. For single phase liquid conditions in the RCS, the CET_{AVG} value is compared to the more accurate RCS hot leg RTDs. The hottest RCS temperature is used to evaluate the validity of the CET measurements and a difference of more than [10°F] is flagged as abnormal. C

6. For single phase liquid conditions in the RCS, this algorithm uses Chanvenet's criterion to determine an acceptable deviation band (TBA) from which suspicious CET temperatures can be identified and excluded. This step determines a value for TBA that is approximately two standard deviations from the AVG value. TBA is determined by the following equation:

$$TBA = AVG \pm A(DEV)$$

where the value for the constant "A" is determined by the value of n (see Table 3).

Table 3

Approximate Number of Valid CET temperatures n	Ratio of Maximum Deviation From the Standard Deviation (DEV) A
10	1.96
15	2.13
25	2.33
50	2.57

This algorithm also uses a fixed tolerance band (TBB) to allow the inclusion of CET values just outside the TBA band if the TBA values determined reflect a narrow distribution. TBB is determined by the following equation:

$$TBB = AVG \pm [10°F]$$

C

7. For single phase liquid conditions, all of the valid CET temperatures are evaluated against the TBA and TBB bands. If the CET value falls outside of both bands, then the CET is identified as "suspect" and will not be considered valid in subsequent iterations unless the criterion of step 9 is satisfied.

8. While the CET algorithm is engaged in the recursive process of rejecting failed and suspect CET inputs, the average CET temperature may be incorrect due to bad input data. Therefore, all CETs which have been identified as "failed" or "suspect" during the present iteration are compared to the CET's identified as "failed" or "suspect" in the preceding iteration. If there is a difference between iterations, then the average CET temperature is identified as suspicious.

9. Any CET identified as "failed" or "suspect" is re-evaluated against the TBB band. Those CETs falling inside the fixed tolerance band will have the "failed" or "suspect flag" removed, and will again be included with the valid sample in Step 1. This step ensures that only valid CET temperatures are re-introduced into the calculation process.

10. NUREG-0737 requires that the CET complement consist of four CETs per quadrant. This provides a caution if this condition is not satisfied. In this case, the operators should monitor all of the non-failed CETs.

5.2 A Manual Procedure of the Average CET Temperature Algorithm

The algorithm described in Section 5.1 has been abbreviated for the purpose of providing a timely approximation of average CET temperature by use of a manual procedure. This procedure can be accomplished within 5 minutes with a standard calculation to manually determine an average CET value. Each step identified in the manual procedure correlates to a technical description of the step and/or the logic applied. C

5.2.1:

A Manual Procedure for the "Determination of Average CET Temperature"

Instructions	*Contingency Actions*
1. Record 2 CET temperatures from each quadrant of the core.	1.
2. Verify all values recorded are within the range of [32°F to 2300°F].	2. Discard any out-of-range values and record a CET temperature from the respective quadrant to replace it.
3. Determine the average temperature	3.

$$T_{avg} = \frac{\sum_{i=1}^{8} T_i}{8}$$

4. Verify all values recorded are within [±10°F] of the CET average temperature.	4. Any recorded CET temperature outside the [±10°F] band is not a valid temperature, therefore, the average CET temperature calculated should be interpreted as suspicious and subsequently recalculated with a different CET temperature from the respective quadrant.

C

5.2.2 Description

1. A sample of eight (8) CET values is used to determine an average CET temperature. The sample size consists of two CET values from each quadrant of the core which are in the operators opinion represents the temperatures of the quadrant.

   Reference 6.4, Section 6.7 indicate that a minimum number of thermocouples needed in an actual PWR based only on thermal-hydraulic considerations is four : one per core quadrant. For an actual CET sample, additional thermocouple readings are desirable and provide redundancy and self consistency checks.

2. The CET measurements are first evaluated to identify and exclude failed CETs. This is accomplished by establishing out-of-range limits, typically [32°F] and [2300°F]. These values correspond to the thermocouple reference junction temperature, and the maximum CET temperature measurement of the instrument, respectively. CETs which are out-of-range will be excluded from the calculation and another valid value from the respective quadrant will be recorded.

3. Calculate the mean or average value of the CET temperatures sampled using the following equation:

$$AVG = \frac{\sum_{i=1}^{8} T_i}{8}$$

where: T_i = the ith valid CET temperature
AVG = average temperature of valid CETs

C

4. This procedure uses only the fixed tolerance band of [±10°F] which considers all values within [10°F] of the T_{avg} value as valid. All of the CET temperatures used in the calculation should be verified to be within [10°F] of T_{AVG}. Any values that do not meet this criterion should be replaced with different values (from the same quadrant) and T_{AVG} should be recalculated. C

6.0 REFERENCES

6.1 Letter #RWW-84-33, R.W. Wells to D.G. Eisenhut Subject: Transmittal of CEN-152, Revision 02, "Combustion Engineering Emergency Procedure Guidelines" dated May 8, 1984.

6.2 Telecopy from T. Greene, NRC PSRB to Peter Nelson, C-E Subject: Comments Related to ICC portion of CEN-152 Revision 02, dated July 24, 1984.

6.3 Letter #WS05-85-04-017, John A. Zwolinski to R.W. Wells Subject: Supplement 1 to Safety Evaluation Report for CEN-152, "Combustion Engineering Emergency Procedure Guidelines" dated April 16, 1985.

6.4 CE-NPSD-212, Performance Evaluation of Core Exit Thermocouples as Inadequate Core Cooling Instrumentation, Combustion Engineering, Inc., March 1983.

C