EMERGENCY RESPONSE PROCEDURES

(FOR INFORMATION ONLY)*

This material was cooperatively developed for license operator training by the Seabrook Training Center staff, Westinghouse, and the Operations Department.

The text materials and figures were developed for the purpose of instruction and should not be used in plant maintenance or operation.

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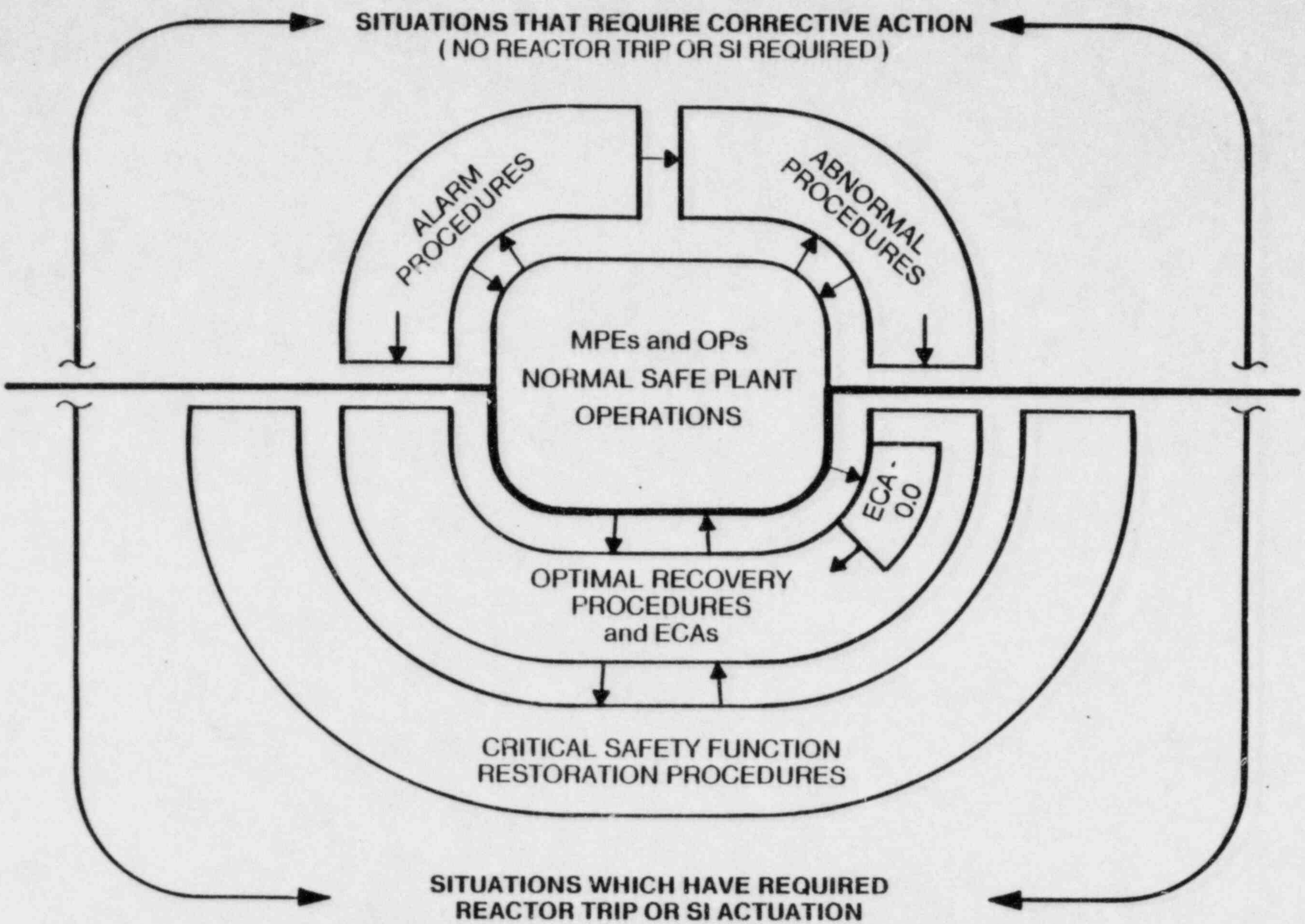
*Controlled Emergency Response Procedures Handouts will be issued at a later date.

INTRODUCTION

TO

EMERGENCY RESPONSE PROCEDURES

- CONSTRUCTION AND USE -



OPERATIONAL PROCEDURE PHILOSOPHY

FIGURE OP (TC Rev 0 3/84)

OBJECTIVES

EMERGENCY PROCEDURE SET

- MUST PROVIDE PROCEDURAL RESPONSES FOR ALL CONCEIVABLE EVENTS WHOSE PROBABILITY OF OCCURENCE EXCEEDS 10^{-8}
- MUST BE RESPONSIVE TO EVENTS AND SYMPTOMS
- MUST BE BASED ON SOLID ANALYSIS TO DETERMINE MOST APPROPRIATE RECOVERY METHOD
- MUST BE VALIDATED AND VERIFIED TO BE CORRECT

EMERGENCY RESPONSE PROCEDURES (ERPs)

COMPONENTS

- OPTIMAL RECOVERY PROCEDURES (ORPs)
- EMERGENCY CONTINGENCY ACTIONS (ECAs)
- CRITICAL SAFETY FUNCTION (CSF) STATUS TREES
- FUNCTION RESTORATION PROCEDURES (FRPs)

OPTIMAL RECOVERY PROCEDURES (ORPs)

OPTIMAL RECOVERY PROCEDURES

- EVENT-SPECIFIC
- EVENT DIAGNOSTICS
- OPERATOR GUIDANCE FOR PLANT RECOVERY FROM KNOWN EVENT/CONDITION STATE
- MAINTENANCE OF CSFs INHERENT IN PROCEDURES
- EQUIPMENT FAILURE CONTINGENCIES AND TRANSITIONS TO FRPs

EMERGENCY CONTINGENCY ACTIONS (ECAs)

EMERGENCY CONTINGENCY ACTIONS

- EVENT-SPECIFIC
- POSSIBLE BUT HIGHLY UNLIKELY EVENTS
- OPERATOR GUIDANCE FOR PLANT RECOVERY
- TRANSITIONS BACK TO ORGs
- MAINTENANCE OF CSFs APPLICABLE
- TRANSITIONS TO FRPs WHEN DIRECTED

CRITICAL SAFETY FUNCTIONS

CRITICAL SAFETY

FUNCTION

AN ACTIVITY WHICH ASSURES THE INTEGRITY OF THE PHYSICAL BARRIERS AGAINST

RADIATION RELEASE

CRITICAL SAFETY FUNCTION SELECTION

- COMPLETE SET
- LIMITED NUMBER
- COMPATIBLE WITH ERP STRUCTURE
- PREVENT BARRIER FAILURE

"DEFENSE IN DEPTH"

(MULTIPLE BARRIERS)

- FUEL MATRIX, FUEL CLAD
- REACTOR COOLANT SYSTEM
- CONTAINMENT
- DISTANCE

CRITICAL SAFETY FUNCTIONS

PRIORITY	FUNCTION	SYMBOL
1)	SUBCRITICALITY	(S)
2)	CORE COOLING	(C)
3)	HEAT SINK	(H)
4)	INTEGRITY	(P)
5)	CONTAINMENT	(Z)
6)	INVENTORY	(I)

CRITICAL SAFETY FUNCTION SET

- MAINTENANCE OF SUBCRITICALITY
- MAINTENANCE OF CORE COOLING
- MAINTENANCE OF A HEAT SINK
- MAINTENANCE OF REACTOR COOLANT SYSTEM INTEGRITY
- MAINTENANCE OF CONTAINMENT INTEGRITY
- CONTROL OF REACTOR COOLANT SYSTEM INVENTORY

SAFETY FUNCTION RELATIONS TO BARRIERS

BARRIERS	SAFETY FUNCTIONS
• FUEL MATRIX	SUBCRITICALITY
• FUEL CLAD	CORE COOLING INVENTORY
• REACTOR COOLANT SYSTEM BOUNDARY	HEAT SINK INTEGRITY INVENTORY
• CONTAINMENT	CONTAINMENT

CRITICAL SAFETY FUNCTION STATUS TREES

STATUS TREE

- MONITORING PLANT SAFETY STATUS TOTALLY INDEPENDENT OF ORPs
- CHALLENGES TO CSFs SYSTEMATICALLY AND EXPLICITLY DIAGNOSED
- APPROPRIATE FRP PRIORITIZED BY STATUS TREES

STATUS TREE CONSTRUCTION

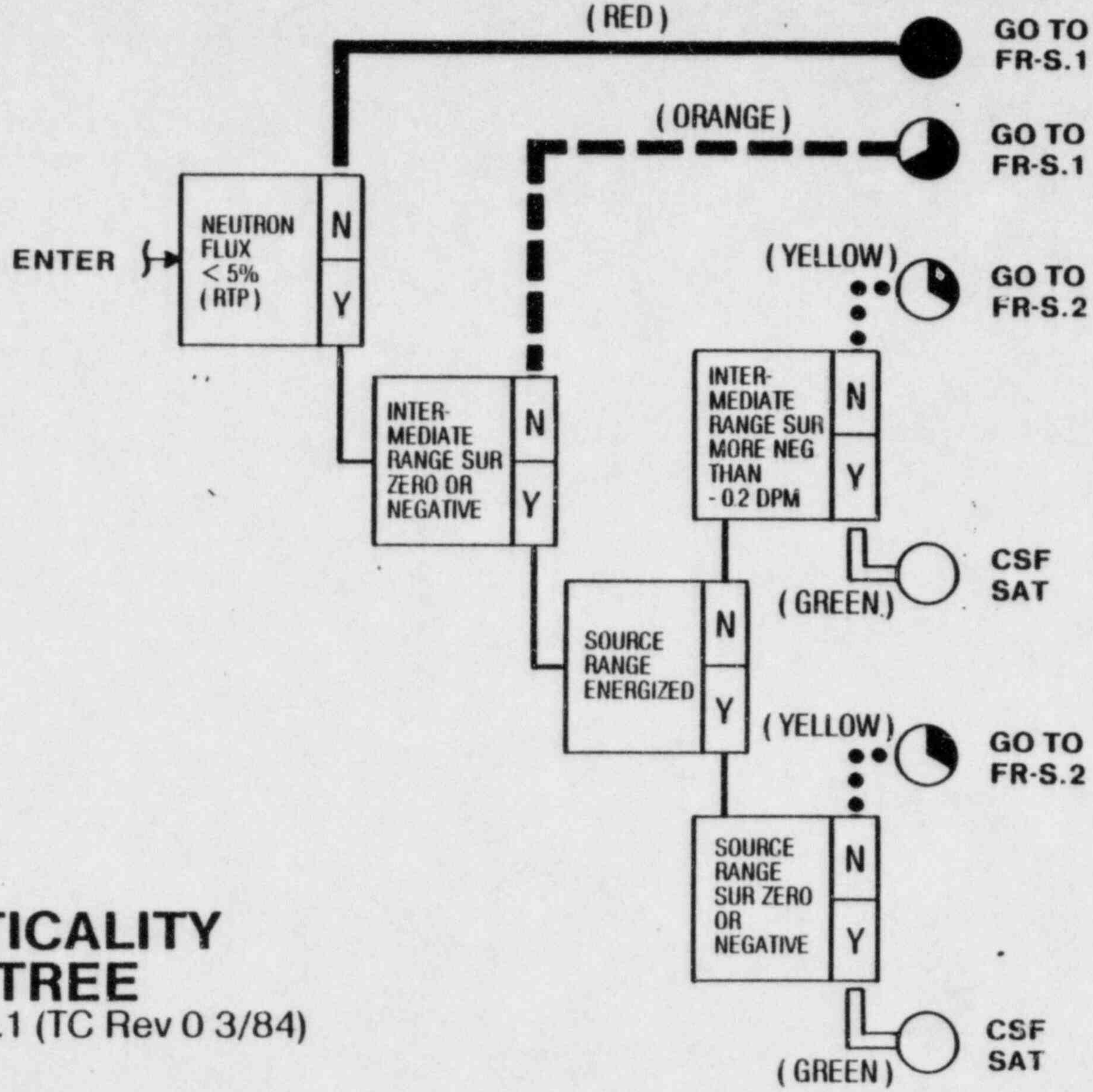
- EACH TREE REPRESENTS ONE CSF

- EACH BRANCH DEFINES A CSF STATUS WITH A UNIQUE COMBINATION OF CONDITIONS

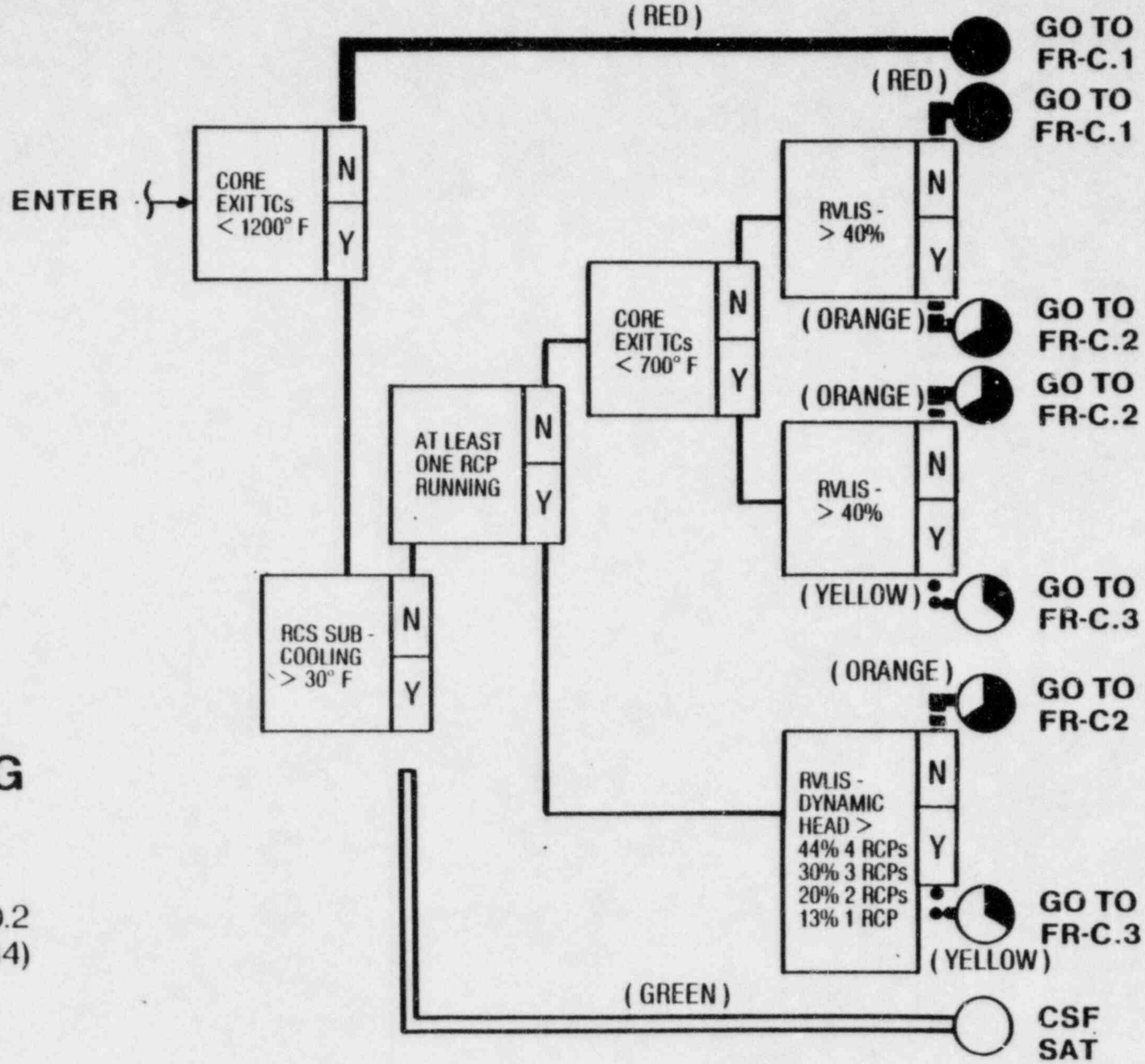
- OPERATOR RESPONSE PRIORITIZED BY:
  - STATUS TREES MONITOR ORDER
  - UNIQUE PATH COLOR
  - UNIQUE PATH INSTRUCTIONS

CSF STATUS COLOR-CODING

COLOR	SIGNIFICANCE
GREEN	• CSF SATISFIED • NO ACTION REQUIRED
YELLOW	• CSF NOT FULLY SATISFIED • ACTION MAY BE NEEDED
ORANGE	• CSF UNDER SEVERE CHALLENGE • PROMPT ACTION NEEDED
RED	• CSF IN JEOPARDY • IMMEDIATE ACTION REQUIRED

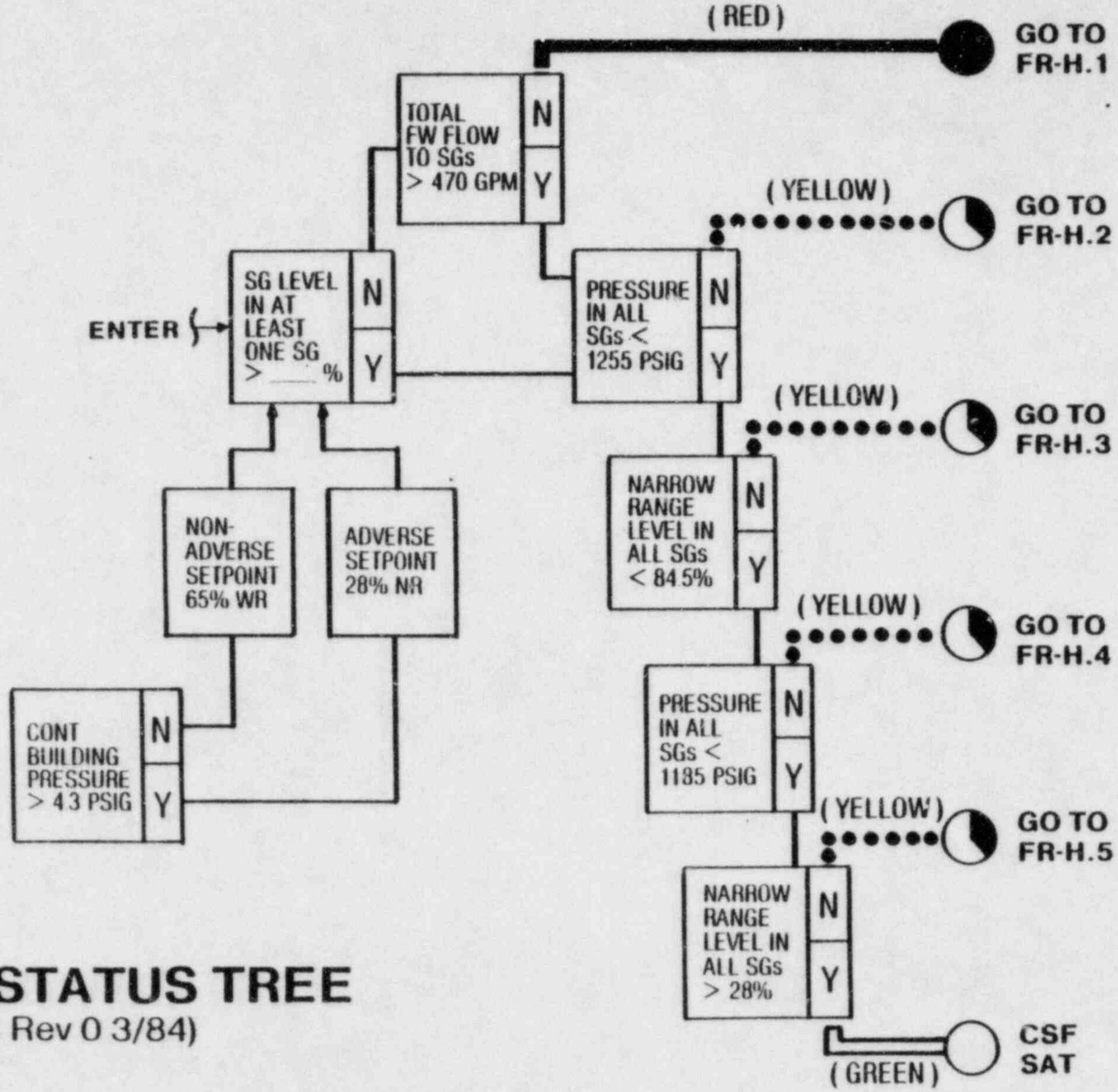


SUBCRITICALITY STATUS TREE
FIGURE OP 0.1 (TC Rev 0 3/84)



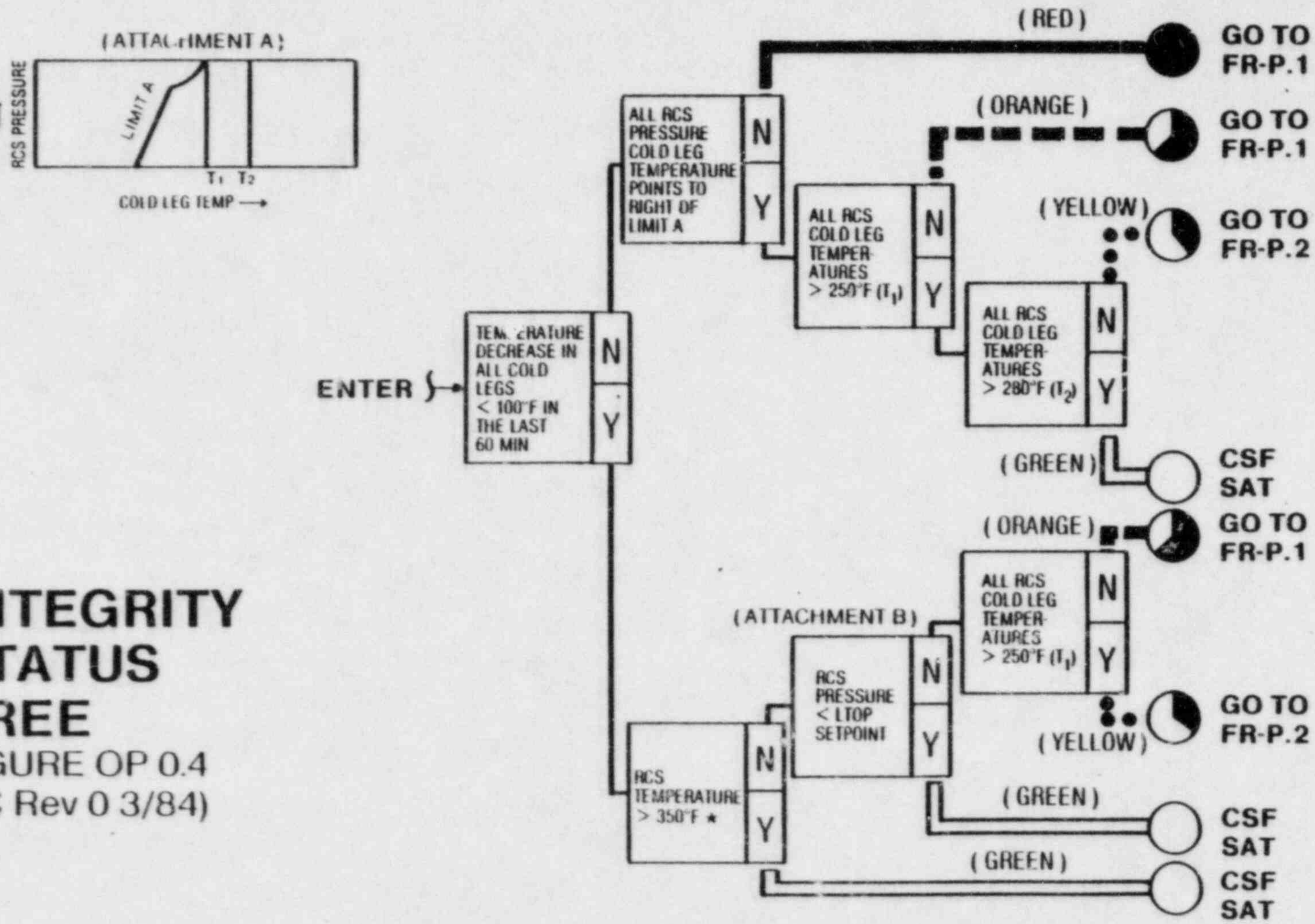
CORE COOLING STATUS TREE

FIGURE OP 0.2
(TC Rev 0 3/84)



HEAT SINK STATUS TREE

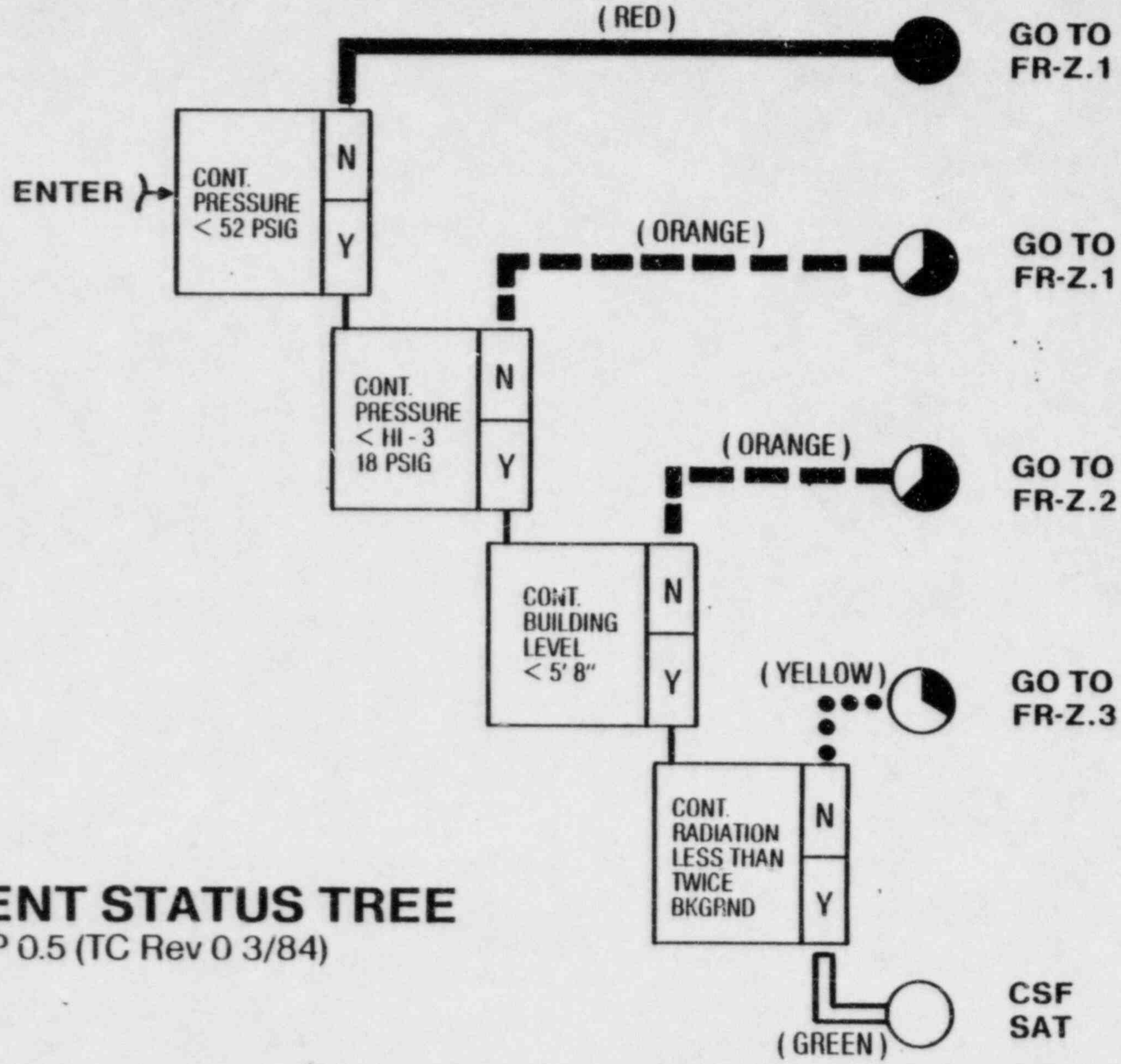
FIGURE OP 0.3 (TC Rev 0 3/84)



INTEGRITY STATUS TREE

FIGURE OP 0.4
(TC Rev 0 3/84)

*ARMING BISTABLE SETPOINT

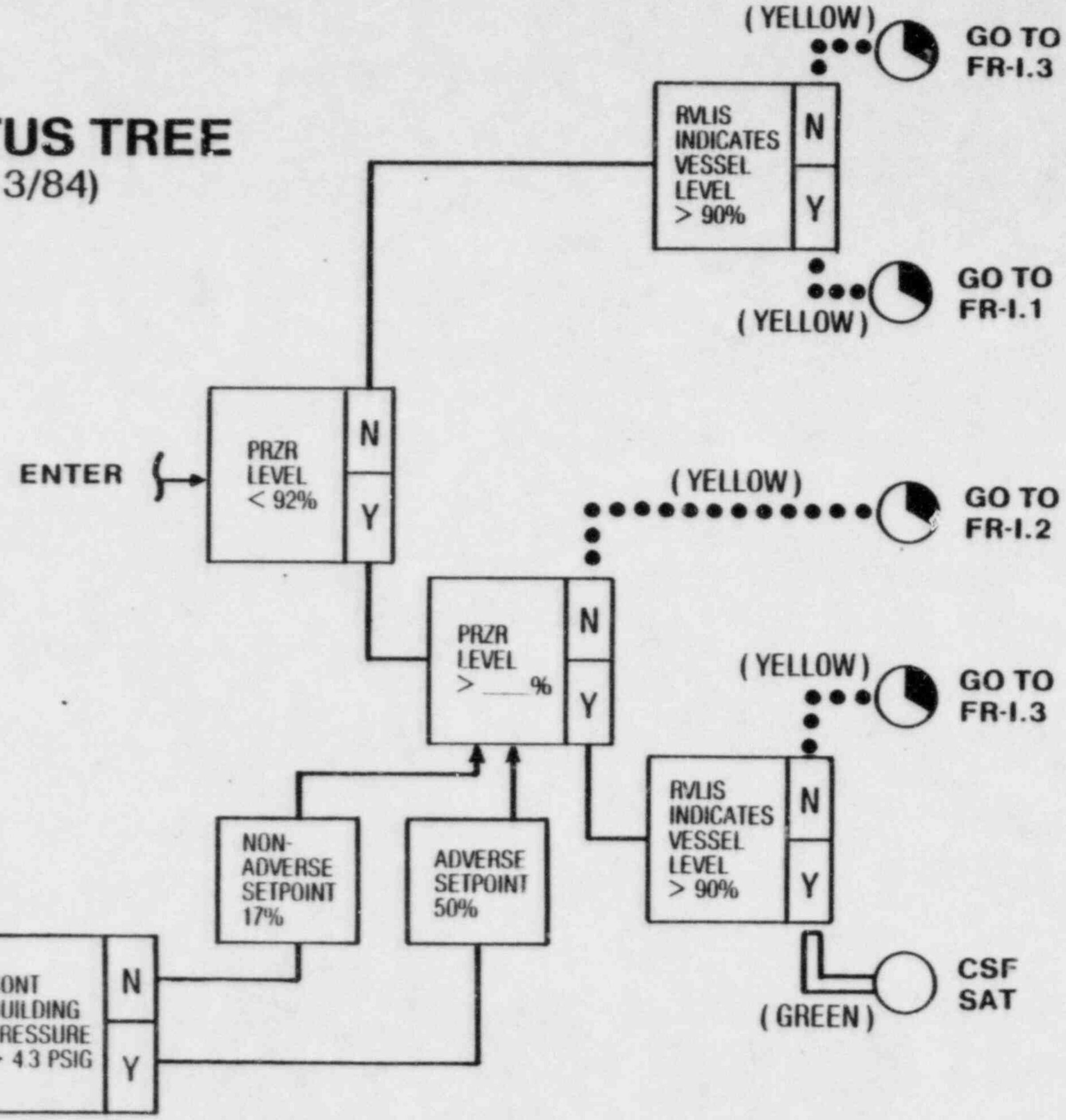


CONTAINMENT STATUS TREE

FIGURE OP 0.5 (TC Rev 0 3/84)

INVENTORY STATUS TREE

FIGURE OP 0.6 (TC Rev 0 3/84)



CRITICAL SAFETY FUNCTIONS

(STATUS TREES AND FRPs)

<u>ADVANTAGES</u>

- INDEPENDENT OF INITIATING EVENT
- GUIDANCE BEYOND DESIGN BASIS

<u>LIMITATIONS</u>

- GENERALLY NOT ADEQUATE FOR PLANT RECOVERY
- SUPPLEMENTED BY EVENT-SPECIFIC RECOVERY PROCEDURES (ORPs)

FUNCTION RESTORATION PROCEDURES

FUNCTION RESTORATION PROCEDURES

- NON-EVENT-SPECIFIC
- STATUS TREES' YELLOW, ORANGE, OR RED TERMINUS COVERED BY PROCEDURES
- DIRECT RESPONSE TO CSFs CHALLENGES
- TRANSITIONS TO ORPs AFTER SAFETY FUNCTION CHALLENGE REMOVED
- COMPREHENSIVE COVERAGE
- ALL CONCEIVABLE CHALLENGES TO CSFs ADDRESSED

SEABROOK STATION

WRITERS GUIDE

FOR

EMERGENCY RESPONSE PROCEDURES

Based in part on the

Westinghouse Owner's Group

Generic Emergency Response Guidelines

Post Validation Program
Revision

January 13, 1984

ERP WRITERS GUIDE
TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

1. Purpose and Scope

The purpose of this document is to provide administrative and technical guidance on the preparation of Emergency Response Procedures. This guide applies to both Optimal Recovery Procedures, Function Restoration Procedures, and Critical Safety Function Status Trees.

2. ERP Designation and Numbering

ERPs specify operator actions to be taken during plant emergency situations to return the plant to a safe stable condition. Each procedure shall be uniquely identified to facilitate preparation, review, use, and subsequent revision.

2.1 Procedure Title

Every separate procedure shall have its own descriptive name which summarizes the scope of that procedure, or states the event(s) which it is intended to mitigate.

2.2 Procedure Numbering

Each separate procedure shall be identified in two ways, i.e.; an alpha-numeric code which is identical to the Westinghouse Owners Group (WOG) numbering method and the plant procedure number.

In order to comply with station manual procedure AQ1.002 and still retain the Human Factors Engineered Systems developed by the Westinghouse Owners Group (WOG), the emergency procedures will be numbered in two ways.

The procedure number must be in accordance with AQ1.002 and will appear in the upper right-hand box of each page. (The WOG identifier will be called the procedure code and will appear in the upper left-hand box of each page.) WOG numbers must contain the same general form that appears in all WOG Procedures including proper positioning of dots and dashes. For example, E-0, ES-0.1, FR-H.1. Operators will learn and use the WOG codes for procedure use. The plant specific procedure numbers will be used exclusively for document control.

Each emergency procedure number will follow AQ1.002 with the first four positions in each of the emergency procedures being the same, that is OS13.

- The fifth position will correspond to the main procedures.

OS13 [0]	E-0 Procedures
OS13 [1]	E-1 Procedures

OS13 $\boxed{2}$ E-2 Procedures

OS13 $\boxed{3}$ E-3 Procedures

OS13 $\boxed{4}$ ECA Procedures

OS13 $\boxed{5}$ FR Procedures and Status Trees

- The sixth position will correspond to the sub-procedures.

OS131 $\boxed{1}$ ES-1.1

OS134 $\boxed{2}$ ECA-2.1 Procedure

This applies to all procedures except the FR Procedures.

- After the decimal in the other procedures the number will correspond to alternate sub-procedures.

OS1340. $\boxed{1}$ Loss of All AC Power Recovery Without SI Required, ECA-0.1

- In the FR Procedures, the sixth position will correspond to the FR category.

OS135 $\boxed{0}$ Status Trees

OS135 $\boxed{1}$ Sub-Criticality Procedures

OS135 $\boxed{2}$ Core Cooling Procedures

OS135 $\boxed{3}$ Heat Sink Procedures

OS135 $\boxed{4}$ Reactor Coolant System Integrity Procedures

OS135 $\boxed{5}$ Containment Integrity Procedures

OS135 $\boxed{6}$ Reactor Coolant Inventory Procedures

- After the decimal in the FR procedures the number will correspond to individual procedure in the appropriate categories.

OS1351. $\boxed{1}$ Response to Nuclear Power Generation/ATWS

OS1352. $\boxed{2}$ Response to Degraded Core Cooling

2.3 Revision Numbering

Revision numbering for the WOG code shall be handled as specified in the generic ERG set. A change in the current revision number of WOG ERG does not mandate that the code revision number also change. Each new revision of the WOG ERGs will be evaluated on a case-by-case basis. If the new ERG revision has sufficient merit to warrant a plant procedure revision, the ERG revision number used as a basis for the plant procedure will be updated in the code block.

Revision numbering for ERPs will be handled in accordance with plant administrative procedures.

2.4 Page Numbering and Identification

Each page of a procedure will be identified by the procedure title, alpha-numeric designator, "Rev." designator, and date in title blocks at the top of the page. Each page number will be specified as "__ of __", centered on the bottom of the page. The last page of instructions will have the word "END" following the last instruction step.

3. Format

The following format is to be applied consistently to all Emergency Response Procedures:

3.1 Procedure Organization

All Optimal Recovery Procedures (ORPs) will have three (3) sections. The Cover Sheet will summarize procedure intent and state either entry symptoms or means of entry. The Operator Actions will comprise the bulk of each procedure and present the actual stepwise guidance. The Operator Action Summary appears on the back side of each page as applicable and provides information which could direct further operator action at any point in the procedure.

3.2 Page Formats

All pages of the Emergency Response Procedures (ERPs) will use the same page structure. This page structure employs a pre-printed border to ensure all margins are correctly maintained, and pre-printed designator boxes and page cues to assure completeness and consistency. (See Figure 1).

The pages for presentation of operator action steps will use a two-column format within the pre-printed border. The left-hand column is designated for operator action, and the right-hand column is designated for contingency actions when the expected response is not obtained. These pages will use pre-printed title blocks above the separate columns (including the "step" column) for uniformity (See Figure 2).

3.3 Instructional Step Numbering

Procedural steps will be numbered as follows:

1. High-level step

    a. Substep

        1) Detailed instructions (if necessary)

Substeps are lettered sequentially according to expected order of performance. If the order of substep performance is not important, the substeps are designated by bullets (•). If the logical OR is used, both choices may be designated by bullets. This same numbering scheme is to be used in both the right and left columns of the guidelines. (See Figure 3).

3.3.1 Immediate Action Steps

For those procedures which can be entered directly based on symptoms, certain initial steps may be designated "immediate actions". This designation implies that those steps may be performed by the operator, based on his memory, without reference to the written procedure. These steps should be limited to verifications, if possible. Immediate action steps are identified by a NOTE (see Section 4.2.4) prior to the first action step.

Example:

NOTE: Steps 1 through 14 are IMMEDIATE ACTION steps.

3.3.2 Continuous Steps

Many of the operator actions provided in a procedure imply continuous performance throughout the remainder of the procedure. This intent is best conveyed by the use of appropriate action verbs such as monitor, maintain, or control.

4. Writing the Procedure

The following format is to be applied consistently when writing Emergency Response Procedures (ERPs):

4.1 Cover Sheet

Each cover sheet will contain two explanatory sections in addition to procedure and page designators. The first will be titled "PURPOSE" and will briefly describe what the procedure is intended to do for the operator. The second section is a summary of those conditions which require entry into the procedure. This section will be titled "SYMPTOMS OR ENTRY CONDITIONS". Certain procedures such as E-0 and ECA-0.0 can be entered purely based on symptoms; for these procedures, a symptom summary is sufficient (see Figure 4). For other procedures which can only be entered by transition from previous procedures, a summary of the entry conditions (and procedure/step) should be provided. (See Figure 5).

4.2 Operator Actions

Steps directing operator action should be written in short and precise language. The statement should present exactly the task which the operator is to perform. The equipment to be operated should be specifically identified, and only those plant parameters should be specified which are presented by instrumentation available in the control room. (If possible, use of qualified instruments is desired.) It is not necessary to state expected results of routine tasks or specify instrument usage if qualified instruments are already identified in the main control room.

All steps are assumed to be performed in sequence unless stated otherwise in a preceding NOTE (see Section 4.2.4). To keep the individual steps limited to a single action, or a small number of related actions, any complex evolution should be broken down into composite parts.

Actions required in a particular step should not be expected to be complete before the next step is begun. If assigned tasks are short, then the expected action will probably be completed prior to continuing. However, if an assigned task is very lengthy, additional steps may be performed prior to completion. If a particular task must be completed prior to continuation, this condition must be stated clearly in that step or substep.

Refer to Figure 6 as an example of the format for presenting operator actions in the following sections.

4.2.1 Instruction Steps, Left-Hand Column

The left-hand column of the two-column format will be used for operator instruction steps and expected responses. The following rules of construction apply:

- High Level Action steps should begin with an appropriate verb, or verb with modifier.
- Expected responses to operator actions are shown in ALL CAPITAL LETTERS.
- If a step requires multiple substeps, then each substep will have its own expected response if applicable.

- If only a single task is required by the step, the high level step contains its own EXPECTED RESPONSE.

- Left-hand column tasks should be specified in sequence as if they could be performed in that manner. The user would normally move down that left-hand column when the expected response to a particular step is obtained.

- When the expected response is not obtained, the user is expected to move to the right-hand column for contingency instructions.

- All procedures should end with a transition to either another guideline or to some normal plant procedure.

4.2.2 Instruction Steps, Right-Hand Column

The right-hand column is used to present contingency actions which are to be taken in the event that a stated condition, event, or task in the left-hand column does not represent or achieve the expected result. Contingency actions will be specified for steps or substeps for which useful alternatives are available. The following rules apply to the right-hand column:

- Contingency actions should identify directions to override automatic controls and to initiate manually what is normally initiated automatically.

- Contingency actions should be numbered consistently with the expected response/action for substeps only. A contingency for a single-task high-level step will not be separately numbered but will appear on the same line as its related step.

- If the right-hand column contains multiple contingency actions for a single high-level action in the left-hand column, the phrase "Perform the following:" should be used as the introductory high-level statement.

- The user is expected to proceed to the next numbered step or substep in the left-hand column after taking contingency action in the right-hand column.

- As a general rule, all contingent transitions to other procedures take place out of the right-hand column. (Pre-planned transitions may be made from the left-hand column.)

- If a contingency action cannot be completed, the user is expected to proceed to the next step or substep in the left-hand column unless specifically instructed otherwise. When writing the procedure, this rule of usage should be considered in wording subsequent left-hand column instructions.

* If a contingency action must be completed prior to continuing, that instruction must appear explicitly in the right-hand column substep.

4.2.3 Use of Logic Terms

The logic terms AND, OR, NOT, IF NOT, WHEN, can NOT, and THEN, are to be used to describe precisely a set of conditions or a sequence of actions. Logic terms will be highlighted for emphasis by capitalizing and underlining. (See Figure 6.)

The two-column format equates to the following logic: "IF NOT the expected response in the left-hand column, THEN perform the contingency action in the right-hand column." The logic terms should not be repeated in the right-hand column contingency. However, the logic terms may be used to introduce a secondary contingency in the right-hand column.

When action steps are contingent upon certain conditions, the step shall begin with the words IF or WHEN followed by a description of those conditions, a comma, the word THEN, and the action to be taken.

IF is used for an unexpected, but possible condition.

WHEN is used for an expected condition.

AND calls attention to combinations of conditions and shall be placed between each condition. If more than two conditions are to be combined, a list format is preferred.

OR implies alternative combinations or conditions. OR means either one, or the other, or both (inclusive).

IF...NOT or IF...can NOT should be used when an operator must respond to the second of two possible conditions. IF should always be used to specify the first condition. (The right-hand column of the two-column format contains an implicit IF NOT.)

4.2.4 Notes and Cautions

Because the present action-step wording is reduced to the minimum essential, certain additional information is sometimes desired, or necessary, and cannot be merely included in a background document. This non-action information is presented as either a NOTE or a CAUTION. (See Figure 6.)

To distinguish this information from action steps, it will extend across the entire page and will immediately precede the step to which it applies. Each category (NOTE or CAUTION) will be preceded by its descriptor in large, bold, letters. Multiple statements included under a single heading shall be separately identified by noting them with bullets (•).

CAUTION denotes some potential hazard to personnel or equipment associated with the following instructional step. A CAUTION may also be used to provide contingent transition based on unfavorable changes in plant conditions. NOTE is used to present advisory or administrative information necessary to support the following action instruction.

As a general rule, neither a CAUTION or NOTE will contain an instruction/operator action step; however, reference may be made to expected actions in progress.

4.2.5 Transitions to Other Procedures or Steps

Certain conditions require the use of a different procedures or step sequence. Transitions are specified by using the words "go to" followed by the procedure designator, title (in CAPITAL LETTERS) and step number.

Transitions shall NOT contain a "return" feature (i.e., perform steps X through Y in some other procedure and then return).

Example: Go to ES-0.1, REACTOR TRIP RESPONSE, Step 1.

Transitions to a different step later in the same procedure are specified in a similar manner.

Example: Go to Step 20.

Transitions to an earlier step in a procedure are specified by using the words "return to".

Example: Return to Step 2.

Transitions to a step which is preceded by a CAUTION or NOTE shall include special wording to assure that the CAUTION or NOTE is observed.

Example: If conditions are NOT satisfied, THEN go to Step 22. OBSERVE CAUTION PRIOR TO STEP 22.

4.2.6 Component Identification

Equipment, controls and displays will be identified in "operator language" terms. Standard abbreviations which may be used throughout the guidelines are listed alphabetically in Table 2. Since similar components are used in both primary and secondary systems, it is always necessary to clarify the location, even if the wording appears redundant.

Example: PCCW vs. SCCW identifies primary component cooling water as distinct from the secondary component cooling water.

4.2.7 Level of Detail

To allow an operator to efficiently execute the action steps in a procedure, all unnecessary detail must be removed. Any information which an operator is expected to know (based on his training and experience) should not be included. Many actuation devices (switches) in the control room are similar, even though the remotely performed functions are not, so certain action verbs listed here are recommended.

- Use "start/stop" for power-driven rotating equipment.
- Use "open/close/throttle" for valves.
- Use "control" to describe a manually maintained process variable (flow, level, temperature, pressure).
- Use "trip/close" for electrical breakers. (PULL-TO-LOCK for breaker switches with a pull-to-lock feature).
- Use "place in standby" to refer to equipment when actuation is to be controlled by automatic logic circuitry.

4.2.8 Figures

If needed to clarify operator action instructions, figures shall be added to a procedure. Any figure used will be constructed to fit within the pre-printed page format (see Figure 1). Certain rules of construction will apply:

- All wording on the figure shall be at least as legible (type size and spacing) as the instruction steps in the guidelines.

- Each figure will occupy a complete page and will be uniquely identified by a figure number and title. The figure number will consist of the procedure designator, without punctuation, followed by a hyphen and an integer.

  Example: Figure E-3-1

- Figure titles will explain the intent or content of the figure.

- The figure number and title will be placed at the top of the page just inside the printed border.

- If the figure is a graph, all the numbers and wording will be horizontal if possible. By convention, the independent variable is plotted on the horizontal (X) axis. Grid line density should be consistent with the resolution expected from the graph. Any labeling required on the graph will have a white (not graph) background. Figure 7 is an example figure showing presentation of a graph.

- All figures for a procedure are numbered sequentially and appear at the end of the procedure. Figure pages are numbered as pages of that procedure. Any figures required for an ATTACHMENT are numbered in sequence with the procedure figures, but have page numbers corresponding to placement in the attachment.

4.2.9 Tables

Tables may be used within the text of a procedure to clearly present a large number of separate options. A table will immediately follow the step or substep which makes use of it. Therefore, it does not require a unique number and title. Any table will be completely enclosed by a distinct outline; if necessary, it may extend into the adjacent column because of this delineation.

All information presented in a table shall be at least as legible (type size and spacing) as the instruction steps in the guideline.

All columns and rows of information in a table will be defined by solid lines.

All column and row headings shall be presented in upper case type.

Absence of a table element will be indicated by a dash.

Figure 8 presents a typical table.

4.2.10 Attachments

Supplementary information or detailed instructions which would unnecessarily complicate the flow of a procedure may be placed in an attachment to that procedure.

Attachments are identified by the title "ATTACHMENT" followed by a single letter designator. This title is centered at the top of a standard format page. The pre-printed title blocks will be the same as for the procedure.

Physically, ATTACHMENTs will be located after any Figures belonging to procedure. Attachments will use a single-column, full-page-width format. Figure 9 is an example ATTACHMENT page.

4.3 Setpoint and Value Study

The "SETPOINT AND VALUE STUDY" is a listing of the setpoints and values used in the ERPs and are plant specific to Seabrook Station. This document provides all applicable setpoints, values, curves and other parameters needed for the ERPs.

The "SETPOINT AND VALUE STUDY" also includes references, assumptions and actual calculations used to derive setpoints and values and will be maintained as a plant controlled safety related document for the life of the plant. This document is updated as necessary with appropriate changes made to ERPs.

4.4 Operator Action Summary

The operator action summary appears on the back of applicable procedure pages and is titled "OPERATOR ACTION SUMMARY FOR E-X SERIES PROCEDURES". It will use a plain page format for distinction.

Each set of operator information will be numbered sequentially and have an explanatory title. The title will be capitalized and underlined for emphasis. This page contains those important actions which can be performed at any step in the procedures. Refer to Figure 10.

5. Status Tree Format

Critical Safety Function Status Trees are presented in the "block" version and all trees in the set use the same format. Similarly, the trees may be oriented either vertically or horizontally on a page, so long as the orientation is consistent over the set. Refer to Figure 11.

Color-coding and/or line-pattern coding shall be used from each last branch point to its terminus.

All text on the Status Trees shall be at least as legible (type size and spacing) as the instruction steps in the procedures. Refer to Table 4 for the color usage legend.

Each status tree shall have at the top of the page, a designator block identical to that used in the standard procedure format, and containing the same information.

Statements shall be worded so that the favorable response is downward. Termini shall be ordered so that REDs are uniformly at the top and GREENs at the bottom. Termini order should be RED - ORANGE - YELLOW - GREEN if possible.

CRT presentation of status trees should conform to this format for consistency.

6. Mechanics of Style

6.1 Spelling

All spelling should be consistent with modern usage as specified in the Oxford Dictionary of the English Language, unabridged version.

6.2 Punctuation

Punctuation should be used only as necessary to aid reading and prevent misunderstanding. Word order should be selected to require a minimum of punctuation. The following rules apply:

- Use a colon to indicate that a list of items is to follow.

  Example: Stop the following equipment:

- Use a comma after conditional phrases for ease of reading.

  Example: IF level exceeds 50%, THEN . . .

- Use parenthesis to indicate alternative items in a guideline.

- Use a period to indicate the end of complete sentences and for indicating the decimal place in numbers.

- Use a dash to separate a required action and its expected response and also to indicate a null table element.

  Example: Verify SI Pump - RUNNING

6.3 Capitalization

Capitalization shall be used in the procedures for emphasis in the following cases:

- Logic terms will be capitalized and underlined.

- Expected responses (left-hand column of instructions) are capitalized.

- Titles of procedures will be completely capitalized whenever referenced within any guideline.

- Operator action steps may be capitalized FOR EMPHASIS.

- Abbreviations (TABLE 2) are commonly capitalized.

- Section headings on operator action summary pages are capitalized and underlined.

6.4 Vocabulary

Words used in the procedures should convey precise meaning to the trained operator. Simple words having few syllables are preferred. These are typical of words in common usage.

Verbs with specific meaning should be used. The verb should exactly define the task expected to be performed by the operator. A list of frequently used verbs is included as Table 3.

Some words have unique meanings as listed below:

manual (manually) - an action performed by the operator in the control room. (The word is used in contrast to an automatic action, which takes place without operator intervention.)

local (locally) - an action performed by an operator outside the control room.

Example: "Locally close valve" means directly turning a handwheel to close a valve.

Inequalities are to be expressed in words rather than symbols: i.e., "greater than, less than". These words are always appropriate for comparing pressures, temperatures, levels and flowrates.

6.5 Numerical Values

All numerical values presented in the procedures should be consistent with what can be read on instruments in the control room (i.e., consistent with instrument scale and range).

The number of significant digits presented should be equal to the reading precision of the operator.

Acceptance values should be stated in such a way that any addition and subtraction operations are avoided, if possible. This is done by stating acceptance values as limits. Examples: 2500 psig maximum, 350°F minimum, between 450°F and 500°F. Tolerances can be expressed by stating the normal value followed by the acceptable range in parenthesis.

Example: 550°F (540°F to 560°F)

Avoid: 550°F ± 10°F if possible

Engineering units should always be specified when presenting numerical values for process parameters. They should be the same as those used on the control room displays.

6.6 Abbreviations and Acronyms

Abbreviations and acronyms should be limited to those commonly used by operators. Table 2 lists the most common ones necessary for these procedures. Abbreviations and acronyms should be used whenever possible to simplify the procedures.

Abbreviations and acronyms from Table 2 will be uniformly capitalized whenever they are used.

7. Printed Format

The final printed format of the procedures will be clear and legible. Final approved versions may be commercially printed at the option of station management.

8. Reproduction

Procedure reproduction will be done on a standard copier, without significant loss of legibility. Uncontrolled copies shall be marked "FOR INFORMATION ONLY" or "UNTESTED" for those procedures which have not been validated and verified on the plant simulator or in actual practice.

TABLE 1

- SEABROOK STATION -

EMERGENCY RESPONSE PROCEDURE INDEX

PROCEDURE NUMBER	TITLE	WOG CODE
OS1300	Reactor Trip or Safety Injection	E-0
OS1300.1	Rediagnosis	ES-0.0
OS1301	Reactor Trip Response	ES-0.1
OS1302	Natural Circulation Cooldown	ES-0.2
OS1303	Natural Circulation Cooldown With Steam Void in Vessel (With RVLIS)	ES-0.3
OS1304	Natural Circulation Cooldown With Steam Void in Vessel (Without RVLIS)	ES-0.4
OS1310	Loss of Reactor or Secondary Coolant	E-1
OS1310.1	SI Termination	ES-1.1
OS1311	Post-LOCA Cooldown and Depressurization	ES-1.2
OS1312	Transfer to Cold Leg Recirculation	ES-1.3
OS1313	Transfer to Hot Leg Recirculation	ES-1.4
OS1320	Faulted Steam Generator Isolation	E-2
OS1330	Steam Generator Tube Rupture	E-3
OS1331	Post-SGTR Cooldown Using Backfill	ES-3.1
OS1332	Post-SGTR Cooldown Using Blowdown	ES-3.2
OS1333	Post-SGTR Cooldown Using Steam Dump	ES-3.3
OS1340	Loss of All AC Power	ECA-0.0
OS1340.1	Loss of All AC Power Recovery Without SI Required	ECA-0.1
OS1340.2	Loss of All AC Power Recovery With SI Required	ECA-0.2
OS1341.1	Loss of Emergency Coolant Recirculation	ECA-1.1
OS1341.2	LOCA Outside Containment	ECA-1.2
OS1342.1	Uncontrolled Depressurization of All Steam Generators	ECA-2.1
OS1343.1	SGTR With Loss of Reactor Coolant - Subcooled Recovery Desired	ECA-3.1
OS1343.2	SGTR With Loss of Reactor Coolant - Saturated Recovery Desired	ECA-3.2
OS1343.3	SGTR Without Pressurizer Pressure Control	ECA-3.3
OS1350.1	Subcriticality (Critical Safety Function Status Tree)	F-0.1
OS1350.2	Core Cooling (Critical Safety Function Status Tree)	F-0.2
OS1350.3	Heat Sink (Critical Safety Function Status Tree)	F-0.3
OS1350.4	Integrity (Critical Safety Function Status Tree)	F-0.4
OS1350.5	Containment (Critical Safety Function Status Tree)	F-0.5
OS1350.6	Inventory (Critical Safety Function Status Tree)	F-0.6
OS1351.1	Response to Nuclear Power Generation/ATWS	FR-S.1
OS1351.2	Response to Loss of Core Shutdown	FR-S.2
OS1352.1	Response to Inadequate Core Cooling	FR-C.1
OS1352.2	Response to Degraded Core Cooling	FR-C.2
OS1352.3	Response to Saturated Core Cooling Condition	FR-C.3
OS1353.1	Response to Loss of Secondary Heat Sink	FR-H.1
OS1353.2	Response to Steam Generator Overpressure	FR-H.2
OS1353.3	Response to Steam Generator High Level	FR-H.3
OS1353.4	Response to Loss of Steam Dump Capabilities	FR-H.4
OS1353.5	Response to Steam Generator Low Level	FR-H.5
OS1354.1	Response to Imminent Pressurized Thermal Shock Conditions	FR-P.1
OS1354.2	Response to Anticipated Pressurized Thermal Shock Conditions	FR-P.2
OS1355.1	Response to High Containment Pressure	FR-Z.1
OS1355.2	Response to Containment Flooding	FR-Z.2
OS1355.3	Response to High Containment Radiation Level	FR-Z.3
OS1356.1	Response to High Pressurizer Level	FR-I.1
OS1356.2	Response to Low Pressurizer Level	FR-I.2
OS1356.3	Response to Voids in Reactor Vessel	FR-I.3

COMMON
ABBREVIATIONS USED IN PROCEDURES

ac	- alternating current (electrical)
EFW	- emergency feedwater
ASDV	- atmospheric steam dump valve
ATWS	- anticipated transient without scram
BA	- boric acid
BAT	- boric acid (storage) tank
BIT	- boron injection tank
BTRS	- boron thermal regeneration system
CCP	- centrifugal charging pump
CCW	- component cooling water (preceded by an S or P)
CRDM	- control rod drive mechanism
CST	- condensate storage tank
CVCS	- chemical and volume control system
CVCT	- chemical volume control tank
dc	- direct current (electrical power and signals)
DG	- diesel generator
DWST	- demineralized water storage tank
EPS	- emergency power sequencer
ECCS	- emergency core cooling system
HP	- high pressure
HX	- heat exchanger
LOCA	- loss of coolant accident
LOP	- loss of power
LP	- low pressure
MCC	- motor control center
MD	- motor driven (in reference to pumps)
MSIV	- main steamline isolation valve
NIS	- nuclear instrumentation system
NR	- narrow range (level indication)
PORV	- power operated relief valve (pressurizer only)
PDP	- positive displacement pump
PRT	- pressurizer relief tank
PRZR	- pressurizer
RAT	- reserve auxiliary transformer
RCP	- reactor coolant pump
RCS	- reactor coolant system
RHR	- residual heat removal
RMO	- remote manual operation (relay designation)
RPV	- reactor pressure vessel
RWST	- refueling water storage tank
RVLIS	- reactor vessel liquid inventory system
SI	- safety injection
SG	- steam generator
SGTR	- steam generator tube rupture
SUR	- startup rate
SW	- service water
TA	- tower actuation
TC	- thermocouple
TD	- turbine driven (in reference to pumps)
TSC	- technical support center
UAT	- unit auxiliary transformer
WPB	- waste processing building
WR	- wide range

TABLE 3

ACTION VERBS

Actuate	To put into action or motion; commonly used to refer to automated, multi-faceted operations. Examples: Actuate S.I., Actuate Phase A, Actuate Containment Spray
Align	To arrange components into a desired configuration. Examples: Align the system for normal charging. Align valves as appropriate.
Block	To inhibit an automatic actuation. Example: Block SI actuation.
Check	To note a condition and compare with some guideline requirement. Example: Check PRZR level - GREATER THAN 20%.
Close	To change the physical position of a mechanical device. Closing a valve prevents fluid flow. Closing a breaker allows electrical current flow.
Complete	To accomplish specified procedure requirements.
Continue	To go on with a particular process. Example: Continue with this procedure.
Control	To manually operate equipment as necessary to satisfy procedure requirements on process parameters - pressure, temperature, level, flow. Example: Control pressurizer level.
Determine	To calculate or evaluate using formula or graphs. Example: Determine maximum venting time.

Energize	To supply electrical energy to (something). Commonly used to describe an electrical bus or other dedicated electrical path. Examples: Energize AC emergency buses. Energize PRZR heaters.
Enter	To insert into or add to.
Establish	To make arrangements for a stated condition. Example: Establish normal pressurizer pressure and level control.
Evaluate	To examine and decide; commonly used in reference to plant conditions and operations. Example: Evaluate plant conditions.
Initiate	To begin a process. Example: Initiate flow to all SGs.
Load	To connect an electrical component or unit to a source of electrical energy. May involve a "start" in certain cases. Example: Load the following equipment on AC equipment buses:
Maintain	To control a given plant parameter to some procedure requirement continuously. Example: Maintain SG level in the narrow range.
Monitor	Similar to "check", except implies a continuous function.
Open	To change the physical position of a mechanical device to the unobstructed position. Opening a valve permits fluid flow. Opening an electrical breaker prevents current flow.
Place-in-standby	To return a piece of equipment to an inactive status but ready for start on demand; commonly used to refer to a mid-position on a switch labeled "AUTO". Example: Stop the pumps and place in standby.

Reset	To remove an active output signal from a retentive logical device even with the input signal still present; commonly used in reference to protection/safeguards logics in which the actuating signal is "locked-in". The RESET allows equipment energized by the initial signal to be de-energized. Examples: Reset SI, Reset Phase A.
Record	To document specified characteristics. Example: Record RCS average temperature.
Sample	To take a representative portion for the purpose of examination; commonly used to refer to chemical or radiological examination. Examples: Sample for RCS boron concentration. Samples for side activity.
Start	To originate motion of an electrical or mechanical device, either directly or by remote control. Example: Start one RCP.
Stop	To terminate motion of an electrical or mechanical device. Example: Stop both diesels.
Throttle	To operate a valve in an intermediate position to obtain a certain flow rate. Example: Throttle flow control valve to establish desired flow.
Trip	To manually activate a semi-automatic feature. Commonly, "trip" is used to refer to component de-activation. Examples: Trip the reactor; trip the turbine. Trip a breaker.
Verify	To observe that <u>expected</u> characteristic or condition exists. Typically the expectation comes from some previous automatic or operator action. Examples: Verify Reactor Trip, Verify SI Pumps - RUNNING.

TABLE 4

STATUS TREE COLOR LEGEND

COLOR CODE	Definition
Green	The critical safety function is satisfied - no operator action is called for.
Yellow	The critical safety function is not fully satisfied - operator action may eventually be needed.
Orange	The critical safety function is under severe challenge - prompt operator action is necessary.
Red	The critical safety function is in jeopardy - immediate operator action is required.

Code:	Symptom/Title:	Procedure No. Revision No./Date:

FIGURE 1

Pre-Printed Page Format

Code:	Symptom/Title:	Procedure No. Revision No./Date:

STEP	ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED

FIGURE 2

Pre-Printed Page (2-Column) Format

STEP	ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED

FIGURE 3

17	Depressurize RCS To Minimize Break Flow And Refill PRZR:	
	a. Normal PRZR spray - AVAILABLE	a. Go to Step 18. OBSERVE CAUTION PRIOR TO STEP 18.
	b. Spray PRZR with maximum available spray until ANY of the following conditions satisfied: • BOTH of the following: 1) RCS pressure - LESS THAN RUPTURED SG PRESSURE 2) PRZR level - GREATER THAN 5% [30% FOR ADVERSE CONTAINMENT] - OR - • PRZR level - GREATER THAN 80% - OR - • RCS subcooling based on core exit TCs - LESS THAN 30°F	
	c. Close spray valve(s)	
	1) Normal spray valves	1) Stop RCP(s) supplying failed spray valve. • RC-PCV-455A RCP-1C • RC-PCV-455B RCP-1A
	d. Go to Step 20. OBSERVE CAUTION PRIOR TO STEP 20	

FIGURE 4

A. PURPOSE

This procedure provides actions to verify proper response of the automatic protection systems following manual or automatic actuation of a reactor trip or safety injection, to assess plant conditions, and to identify the appropriate recovery procedure.

B. SYMPTOMS OR ENTRY CONDITIONS

1. Any symptom that requires a manual reactor trip listed in ATTACHMENT A, if one has not occurred.

2. The following are symptoms of a reactor trip:

   a. Any reactor trip annunciator lit.

   b. Rapid decrease in neutron level indicated by nuclear instrumentation.

   c. All shutdown and control rods are fully inserted. Rod bottom lights are lit.

3. Any symptom that requires a manual reactor trip and safety injection listed in ATTACHMENT B, if one has not occurred.

4. The following are symptoms of a reactor trip and safety injection.

   a. Any SI annunciator or status lamp lit.

   b. ECCS pumps in service.

FIGURE 5

A. PURPOSE

This procedure provides actions to respond to a failure of the steam generator atmospheric steam dump valves (ASDVs) and condenser steam dump valves.

B. SYMPTOMS OR ENTRY CONDITIONS

This procedure is entered from F-0.3, HEAT SINK Critical Safety Function Status Tree on a YELLOW condition.

STEP	ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED

FIGURE 6

STEP	ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED
25	Check If ECCS Flow Should Be Reduced:	
	a. RCS subcooling based on core exit TCs - GREATER THAN 30°F	a. DO NOT STOP ECCS PUMPS. Go to Step 27.
	b. Secondary heat sink: • Total EFW flow to intact SGs - GREATER THAN 470 GPM TOTAL COMBINED FLOW CAPABILITY. - OR - • WR level in at least one intact SG - GREATER THAN 65%	b. IF neither condition satisfied, THEN DO NOT STOP CENTRIFUGAL CHARGING PUMPS OR SI PUMPS. Go to Step 27.
	c. RCS pressure - STABLE OR INCREASING	c. DO NOT STOP ECCS PUMPS. Go to Step 27.
	d. PRZR level - GREATER THAN 5%	d. DO NOT STOP ECCS PUMPS. Try to stabilize RCS pressure with normal spray. Return to Step 25a.
26	Go To ES-1.1, SI TERMINATION, Step 1	
27	Initiate Monitoring Of Critical Safety Function Status Trees	

> CAUTION CST makeup should commence as early as possible to avoid low inventory problems.

STEP	ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED

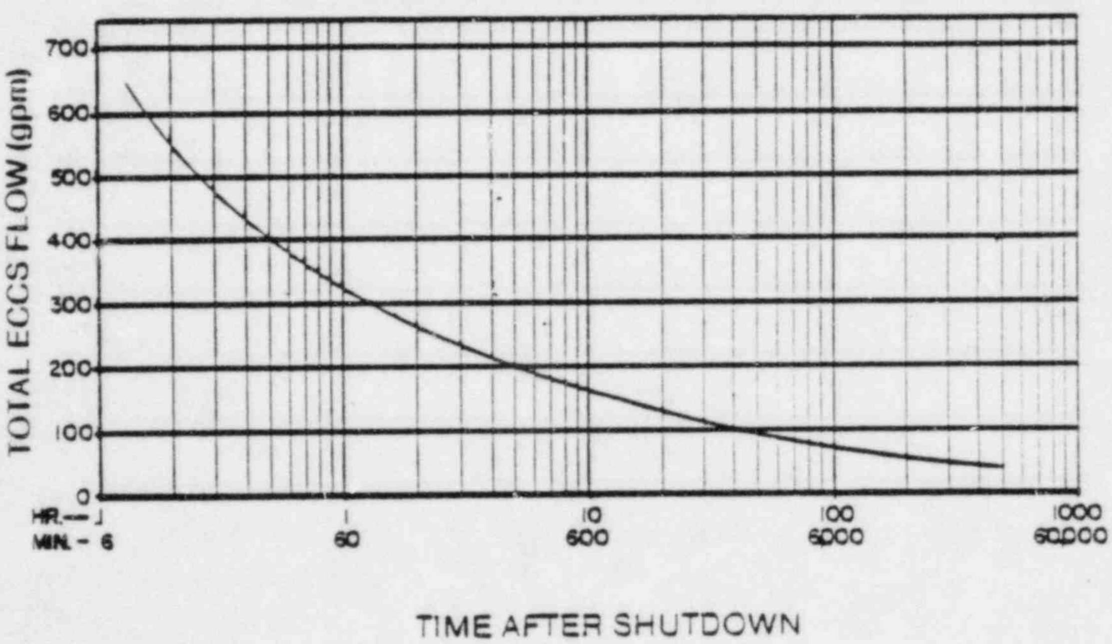
FIGURE 7

FIGURE FR-H.1-1

REQUIRED ECCS FLOW

for

CORE BLEED AND FEED COOLING



STEP	ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED

FIGURE 8

NOTE
- After stopping any ECCS pump, RCS pressure should be allowed to stabilize before stopping another ECCS pump.
- The charging pumps and SI pumps should be stopped on alternate ECCS trains when possible.

20 Check If One CCP Should Be Stopped:

a. Two CCPs - RUNNING — a. Go to Step 21.

b. Determine required RCS subcooling from table:

SI PUMP STATUS	RCS SUBCOOLING (°F)	
	NORMAL CONTAINMENT	ADVERSE CONTAINMENT
NONE RUNNING	91°	91°
ONE RUNNING	57°	57°
TWO RUNNING	50°	50°

c. RCS subcooling based on core exit TCs - GREATER THAN REQUIRED SUBCOOLING — c. DO NOT STOP CCP. Go to Step 23.

d. PRZR level - GREATER THAN 5% [30% FOR ADVERSE CONTAINMENT] — d. DO NOT STOP CCP. Go to Step 23.

e. Stop one CCP

FIGURE 9

ATTACHMENT A

The following conditions support or indicate natural circulation flow:

- RCS subcooling based on core exit TCs - GREATER THAN 30°F
- SG pressures - STABLE OR DECREASING
- RCS hot leg temperatures - STABLE OR DECREASING
- Core exit TCs - STABLE OR DECREASING
- RCS cold leg temperatures - AT SATURATION TEMPERATURE FOR SG PRESSURE
- Loop ΔT - INDICATED

(EXAMPLE ONLY)

FIGURE 10

OPERATOR ACTION SUMMARY FOR E-3 SERIES PROCEDURES

1. SI REINITIATION CRITERIA

Manually operate SI pumps as necessary and go to ECA-3.1, SGTR WITH LOSS OF REACTOR COOLANT - SUBCOOLED RECOVERY DESIRED, Step 1, if EITHER condition listed below occurs:

- RCS subcooling based on core exit TCs - LESS THAN 30°F
- PRZR level - CANNOT BE MAINTAINED GREATER THAN 5% [30% FOR ADVERSE CONTAINMENT]

2. SECONDARY INTEGRITY CRITERIA

Go to E-2, FAULTED STEAM GENERATOR ISOLATION, Step 1, if any SG pressure is decreasing in an uncontrolled manner or has completely depressurized, and has not been isolated, unless needed for RCS cooldown.

3. COLD LEG RECIRCULATION SWITCHOVER CRITERION

Go to ES-1.3, TRANSFER TO COLD LEG RECIRCULATION, Step 1 if RWST level decreases to less than 23.5%.

4. EFW SUPPLY

Commence CST makeup as soon as possible to avoid low inventory problems.

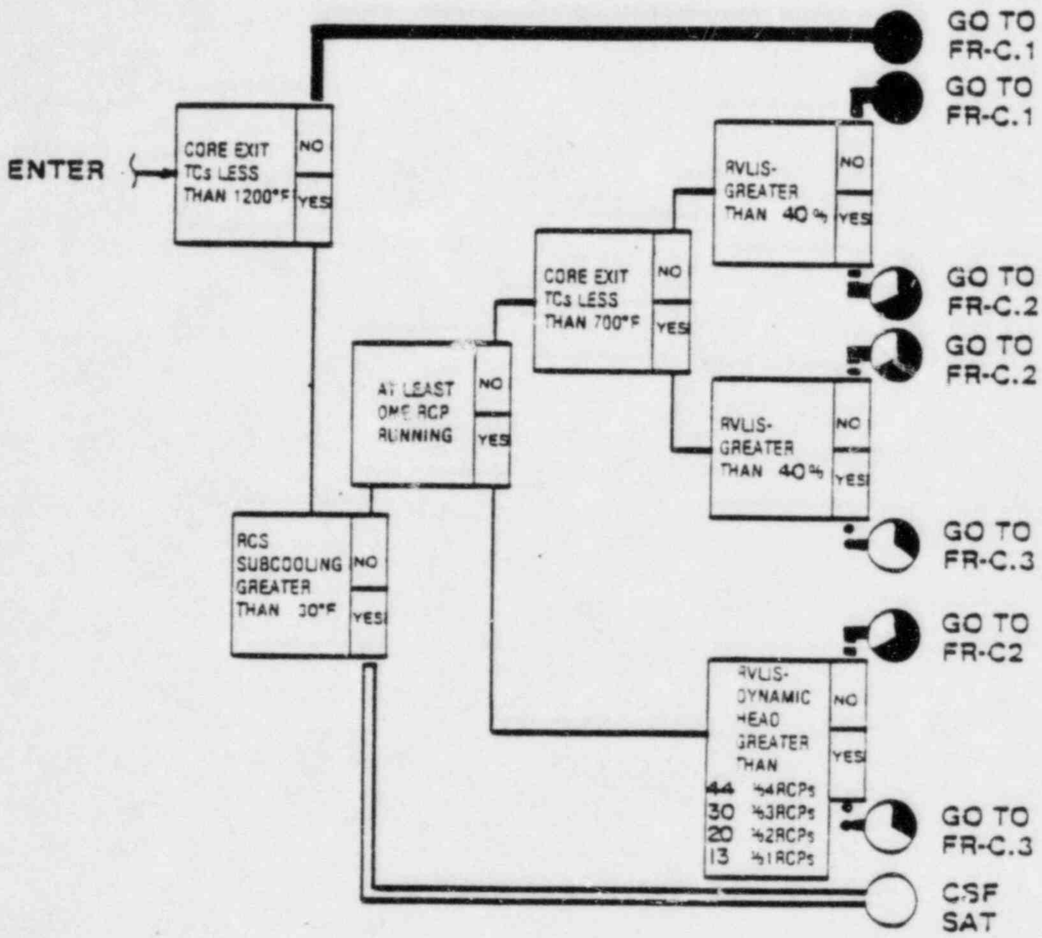
5. RED PATH SUMMARY - ATTACHMENT A

6. KEY CAUTIONS

- Maintain RCS pressure less than ruptured SG(s) ASDV setpoint.
- If a MD EFW pump is running, shut down steam driven EFW pump.

STEP	ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED

FIGURE 11



SEABROOK STATION

USERS GUIDE

FOR

EMERGENCY RESPONSE PROCEDURES

BASED ON THE WESTINGHOUSE

OWNERS GROUP USERS GUIDE

FOR

EMERGENCY RESPONSE GUIDELINES

POST VALIDATION PROGRAM

REVISION

JANUARY 16, 1984

User's Guide for Emergency Response Procedures
at Seabrook Station

TABLE OF CONTENTS

1. INTRODUCTION

The Emergency Response Guidelines (ERGs) developed by the Westinghouse Owners Group (WOG) combined with plant-specific knowledge provided by the Seabrook Station staff, has resulted in a complete set of Emergency Response Procedures (ERPs) for Seabrook Station. The two-column format used to present the ERPs contains implicit rules of usage which supplement the technical instructions. The Critical Safety Function Status Trees have their own format and rules of usage. Priorities have been established between the Optimal Recovery Procedures (ORPs) and Function Restoration Procedures (FRPs) which are intended to direct operator action to the most urgent operational or safety conditions.

Each of these aspects of using the Emergency Response Procedures is presented in detail in the following sections.

2. CONTROL ROOM USAGE OF ERPs

Entry into an individual procedure begins at the cover sheet. The title block presents the unique identifiers for each procedure, and the purpose and entry conditions are described in separate paragraphs.

Individual operator action steps are presented in the two-column format beginning on the following page. Certain special information is also presented, which is emphasized by not following the standard two-column format. This information is of two types:

- NOTES contain administrative or advisory information which supports operator action.

- CAUTIONS contain information about potential hazards to personnel or equipment. They also advise on actions or transitions which may become necessary depending on changes in plant conditions.

Both NOTES and CAUTIONS are introduced by their descriptor, in bold letters, followed by the text extending across the entire page. If multiple items are included after a descriptor, each item is distinguished by a preceding bullet (•).

In general, NOTES and CAUTIONS apply to the step which they precede. A NOTE or CAUTION which precedes the first operator action step may also apply to the entire procedure. One type of NOTE in this category is described below:

1. Several procedures contain steps which are designated as "IMMEDIATE ACTIONS". These steps are intended to be performed, if necessary, without the written procedure being available. These procedures contain a NOTE advising which steps are "immediate action" steps.

After observing any initial NOTES and/or CAUTIONS, the operator proceeds to the first action step. In the two-column format, each step in the left-hand column contains a highlighted high-level statement which describes the task to be performed.

If the high level task requires multiple actions, then subtasks are specified. Following each task or subtask, the <u>expected</u> response or result is given in CAPITAL LETTERS, separated from the task by a dash.

Example: Check Pressurizer Level - INCREASING.

Example: Check if Pressure Boundary is Intact:

a. Check response in all SGs -

• NO SG PRESSURE DECREASING IN AN UNCONTROLLED MANNER
- OR -
• NO SG HAS COMPLETELY DEPRESSURIZED

Expected responses are not supplied for simple control manipulations or actions.

Example: Stop All RCPs.

If sequence of performance is important, then the subtasks are designated by letters (or numbers if finer detail is provided). If sequence of performance is not important, the subtasks are designated by bullets (•).

Only a limited set of action verbs is used in the action steps. These verbs have specific meanings in the context of their usage in the ERPs. (Refer to the verb list in the ERP <u>Writers Guide</u>.)

Action steps are written so that the operator can proceed directly down the left-hand column only. This column contains all the expected conditions, actions, and checks required to accomplish the stated purpose of the procedure.

If however, the expected result or response is <u>not</u> obtained or the action cannot be performed, the operator should move to the right-hand column for contingency instructions. This column is appropriately titled "RESPONSE NOT OBTAINED". Almost all action steps contain some contingency action statement. If one contingency action is appropriate for any of a series of left-hand column subtasks, it is simply stated once as a high level contingency. If a contingency is not provided, then the operator should proceed to the next step or substep in the left-hand column.

Example:

Check CVCT Makeup Control System:	Adjust controls as necessary.
a. Makeup set for GREATER THAN RCS BORON CONCENTRATION	
b. Makeup set for AUTOMATIC	

The two column format thus equates to logical terms which would otherwise be specifically stated: IF the conditions required in the left-hand column are not achieved, THEN go to the right-hand column for contingency instructions. For this reason, the first contingency action does not contain the highlighted logic terms IF and THEN. Subsequent contingency actions are always expressed using the logical construction.

Example:

Verify PRZR Level - GREATER THAN 17%	Control charging flow to maintain PRZR level. IF PRZR level can NOT be maintained, THEN manually operate ECCS pumps as necessary.

After taking the contingency action in the right-hand column, the operator should proceed to the next step or substep in the left-hand column. If the contingency action cannot be performed or is not successful, and further contingency instruction is not provided, the operator should again return to the next step or substep in the left-hand column.

Unless otherwise specified, a required task need not be fully completed before proceeding to the next instruction; it is sufficient to begin a task and have assurance that it is progressing satisfactorily. This assures efficient implementation where steps are very time consuming. In certain cases, where local operator actions are required (outside the control room) a special NOTE may be added to reinforce this rule of procedure usage.

If a particular task must be complete prior to proceeding, the step containing the task will explicitly state that requirement.

Transitions to other procedures or to different steps in the same procedure may be made from either column. Such transitions should be made realizing that preceding NOTES or CAUTIONS are applicable. Any tasks still in progress need not be completed prior to making a transition; however, the requirement to complete the tasks is still present and must not be neglected.

Each procedure ends with either a specific transition to another procedure, if further operator guidance is required, or with the plant being maintained in a steady-state condition. Often in ERPs, the final transition is to "procedure and step in effect". This wording results from the symptom-dependent transitions performed in accordance with rules of usage and not located at a specific procedure and step. "Step in effect" refers to whichever step was being performed when transition was made into the present procedure.

As an example, assume an operator is performing procedure A, when symptoms appear requiring transition to procedure B. While performing procedure B, in accordance with a CAUTION, he finds it necessary to go to procedure C. After completing the actions in C, he returns to the procedure and step from which he entered C, that is, back to procedure B. And after completing procedure B, the operator would return to the procedure and step from which he entered B, in this case, procedure A. (This example assumes that procedures A, B, and C all end with the transition words "Return to Procedure and Step in Effect".)

Several series of procedures have been provided with an OPERATOR ACTION SUMMARY page. This page is located on the back side of the previous procedure page and is always visible to the operator regardless of the procedure step in effect. The OPERATOR ACTION SUMMARY contains several pieces of information or actions which are applicable at any step in the procedure. The most important of these actions are procedure transitions which allow immediate response to new symptoms as they appear. The placement of these transitions on the OPERATOR ACTION SUMMARY page removes any sensitivity to timing from the appearance of subsequent symptoms.

3. EXAMPLE OF PROCEDURE USAGE

The actual process of working through a procedure will be illustrated by using E-2, FAULTED STEAM GENERATOR ISOLATION. It is assumed that the user was directed to Step 1 of this procedure by an instruction in some other procedure.

The user first verifies the designator and title on the cover sheet to assure himself that he is in the proper procedure. The PURPOSE tells him that this procedure will identify and isolate a faulted steam generator. Examination of the SYMPTOMS OR ENTRY CONDITIONS list should produce the procedure from which the transition to E-2 was made in this case.

The first action step of this procedure is preceded by two CAUTIONS. Each separate concern is identified by a bullet (•), and the CAUTION identifier is used only once.

The first CAUTION tells the operator that at least one SG must be maintained available for RCS cooldown.

The second CAUTION tells the operator that any faulted SG or secondary break should remain isolated during subsequent recovery actions unless needed for RCS cooldown. Both CAUTIONS refer to the SG isolation which will take place in the next step(s). The operator is expected to know that "faulted" refers to failure of the secondary pressure boundary, and "isolated" refers to closure of the stem and/or feed flow paths. The CAUTIONS have provided a specific criteria (needed for RCS cooldown) for not isolating, or un-isolating a faulted SG.

The first action in Step 1 is a check of the main steamline isolation and bypass valves on the affected SGs. The expected condition is that the valves are CLOSED. If, in fact, the operator finds the valves closed by whatever means his training requires, he then proceeds to Step 2. If the valves are not closed, or not closed on all the affected SGs, the operator moves to the right-hand column where a contingency instruction tells him to "Manually Close Valves". After performing this action, the operator would return to the next task in the left-hand column, in this case, Step 2.

The Step 2 high-level action is to "Check if SG Pressure Boundary Is Intact" with a more detailed subtask describing how this is to be done: the operator is to "Check Pressures in All SGs". The expected response is "ANY (SG Pressure) STABLE OR INCREASING. If any pressure is stable or increasing, the operator proceeds to the Step 3. If none of the steam generators exhibits a stable or increasing pressure, the operator moves to the right-hand column for contingency instructions. He is told, "IF all SG pressures decreasing in an uncontrolled manner, THEN go to ECA-2.1, UNCONTROLLED DEPRESSURIZATION OF ALL STEAM GENERATORS, Step 1". In order to perform this step, he has to decide if the depressurization is controlled, or not. If it is not controlled, he will leave E-2 and make the required transition to ECA-2.1. If however, the pressure decrease is under his control, in at least one steam generator, he proceeds to the next left-hand column task, Step 3.

Step 3 requires the operator to "Identify Faulted SG(s)" and the more detailed process is described in a substep "Check Pressures in All SGs". Two possible pressure responses are given which will satisfactorily identify a faulted SG: ANY SG PRESSURE (is) DECREASING IN AN UNCONTROLLED MANNER, or ANY SG (is) COMPLETELY DEPRESSURIZED. If either condition is observed, then the intent of the step is satisfied and the faulted SG(s) is (are) identified. The operator moves on to Step 4. If neither condition is observed on any SG, the operator moves to the right-hand column where he is instructed to search for the initiating break (which may have been isolated by MSIV closure) and then to go to Step 5, i.e., skip over Step 4 since no steam generator is required to be isolated.

Step 4 tells the operator to "Isolate Faulted SG(s)" and lists several separate paths which should be isolated. The bullet (•) designator on the separate items implies that isolations can be done in any order. If the isolations are properly performed, the operator proceeds to Step 5. If some aspect of isolation cannot be completed, he moves to the right-hand column where he is instructed to manually close the valves (from the control room), and if that is not successful, to dispatch a (local) operator to close the desired valve(s) or appropriate block valve(s). With the contingency performed or local action initiated, the operator proceeds to Step 5.

The CAUTION prior to Step 5 alerts the operator that EFW system operation will eventually deplete the CST and that makeup will be required. The sooner the better in this case.

Step 5 simply has the operator Check the present level in the condensate storage tank. It is expected to be - GREATER THAN 23 FEET. If level is as expected, the operator proceeds to Step 6. However, if level is less than expected, he moves to the right-hand column where he is instructed to establish CST makeup at the maximum rate. From his training, he will perform this task and then proceed to the left-hand column of Step 6.

Step 6 is a Check for secondary radiation. Detailed performance of the task is presented in sequential subtasks. First, the operator is to "Request Periodic Activity Samples of All SG(s)". This will involve a call out to a local operator, with attendant time delays for sampling and analysis. By rules of usage, the operator can proceed to the next subtask "Check Un-isolated Secondary Radiation Monitors", which he should be able to do from the control room. The third subtask is the conclusion on the "Check" process, "Secondary Radiation - NORMAL". If no abnormal radioactivity is known or detected at that time, the expected response is obtained and the operator proceeds to Step 7. If abnormal radiation is detected on the secondary side of any steam generator, then, by rules of usage, the operator moves to the right-hand column and is instructed to "Go to E-3, etc." and so leaves the E-2 procedure.

Step 7 tells the operator to "Go to E-1, etc." and thus ends the procedure with a transition to some other appropriate procedure.

The highlighted END centered on the page emphasizes that the listing of action steps for E-2 is complete.

In many cases, FIGURES and ATTACHMENTS are included in the procedures to aid the operator and to remove lengthy instructions such as valve alignments from the procedure text. For example, FIGURE E-3-1 in procedure E-3 provides a curve showing the programmed LTOP setpoint for the pressurizer PORVs. ATTACHMENT A in procedure E-3 lists conditions that show positive evidence of natural circulation flow in the RCS.

4. CONTROL ROOM USAGE OF STATUS TREES

Status Trees are a convenient device used to evaluate the current state of predefined CRITICAL SAFETY FUNCTIONS. When the Functions are shown to be satisfied, the plant is safe. Trees ask a series of questions about plant conditions, and in general, each question asked depends on the answer to the previous question. This dependancy results in a branching pattern, which is referred to as a "tree".

There are six different trees, each one evaluating a separate safety aspect of the plant. (Critical Safety Function.) At any given time, a Critical Safety Function status is represented by a single path through its tree. Since each path is unique, it is uniquely labeled at its end point, or terminus. This labeling consists of color and/or line pattern coding of the terminus and last branch line, plus a transition to an appropriate procedure if required by that safety status. If the status is normal for a particular Critical Safety Function, no transition is specified, and the condition is clarified by the words CSF SATISFIED.

Color coding can be either Red, Orange, Yellow, or Green, with Green representing a "Satisfied" safety status. Each non-green color represents an action priority as discussed below.

The six Status Trees are ALWAYS evaluated in the sequence:

PRIORITY	STATUS TREE	CODE
1	Subcriticality	(S)
2	Core Cooling	(C)
3	Heat Sink	(H)
4	Integrity	(P)
5	Containment	(Z)
6	Inventory	(I)

If identical color priorities are found on different trees during monitoring, the required action priority is determined by this sequence. The user begins monitoring with the Subcriticality tree. Entry is at the arrow at the left side of the tree. Questions are answered based on plant conditions at the time, and the appropriate branch line followed to the next question.

An individual status tree evaluation is complete when the user arrives at a color - (or line pattern) - coded terminus. With the exceptions noted below, the color and instructions of the terminus are noted (logged) and the user continues to the next tree in sequence, again entering at the left-hand side arrow.

If any RED terminus is encountered, the operator is required to immediately stop any Optimal Recovery Procedure (ORP) in progress, and to perform the Function Restoration Procedure (FRP) required by the terminus.

If during the performance of any RED - condition FRP, a RED condition of higher priority arises, then the higher priority condition should be addressed first, and the lower priority RED-FRP suspended.

If any ORANGE terminus is encountered, the operator is expected to monitor all of the remaining trees, and then, if no RED is encountered, suspend any ORP in progress and perform the FRP required by the ORANGE terminus.

If, during the performance of an ORANGE - coded FRP, any RED condition or higher priority ORANGE condition arises, then the RED or higher priority ORANGE condition is to be addressed first, and the original ORANGE FRP suspended.

Once a FRP is entered due to a RED or ORANGE condition, that FRP is performed to completion, unless pre-empted by some higher priority condition. It is expected that the actions in the FRP will clear the RED or ORANGE condition before all the operator actions are complete. However, these procedures should be completely performed to the point of the normal transition back to "Procedure and Step in Effect".

Tree monitoring should be continuous if any status coded ORANGE or RED is found to exist. If no condition more serious than YELLOW is encountered, monitoring frequency may be reduced to 10-20 minutes, UNLESS some significant change in plant status occurs.

Monitoring may be terminated after the Reactor Protection System and Engineered Safeguards System are both restored to operable status (SI reset and trip breakers closed). At this point, the operator should no longer be using the ERPs.

A YELLOW terminus does not require immediate operator attention. Frequently it is indicative of an off-normal and/or temporary condition which will be restored to normal status by actions already in progress. In other cases where RED or ORANGE termini are possible, the YELLOW status might provide an early indication of a problem developing. Following FRP implementation, a YELLOW might indicate a residual off-normal condition. The operator is allowed to decide whether or not to implement any YELLOW condition FRP.

Tree monitoring can be done automatically by computer; however, the operator should verify proper automatic status monitoring at least once and as early as possible. This is accomplished by comparing status tree indications with hard wired MCB indicators for appropriate parameters.

5. EXAMPLE OF STATUS TREE USAGE

The actual process of working through the trees will be illustrated by examining the first (Subcriticality) status tree. The user enters the tree at the left-hand arrow and is asked if neutron flux (NIS channels) indication is less than 5%. The possible answers are either "yes" or "no". If indicated power is greater than 5%, then the appropriate answer is "no", so the user would follow the "no" path directly to the terminus and determine that:

- the response priority is RED (immediate response required)
- the appropriate Function Restoration Procedure is FR-S.1.

According to the Rules of Priority, the operator should suspend whichever ORP is being performed and immediately initiate the actions in procedure FR-S.1. Monitoring of the Status Trees may continue for information purposes, but by Rules of Priority, no other higher priority condition can exist. When the actions required by FR-S.1 are complete, the operator is directed to "Return to Procedure and Step in Effect". This allows recovery actions to continue exactly where they were suspended when the RED priority was recognized. This also signals continued monitoring of status trees. In this case, the user and/or operator would know, because of the FR-S.1 actions and checks, that the subcriticality tree would have no status more severe than YELLOW.

If indicated power is less than 5%, then the first question block is answered with a "yes" and the user would follow the "yes" path to the next question block.

In this second block, the user is asked whether the Intermediate Range Startup Rate is zero or negative. If the indicated rate is positive, then the user would follow the "no" response path directly to a terminus and determine that:

- the response priority is ORANGE (prompt response required)
- the appropriate Function Restoration Procedure is FR-S.1.

According to the rules of usage, the remainder of the status trees should be monitored to determine if any RED conditions are present. If no RED status is encountered, then any ORANGE conditions would be reviewed for priority. Since subcriticality is the first status tree, the present ORANGE would be addressed first by rules of priority. Again the operator would suspend whichever ORP was being performed and initiate the actions in procedure FR-S.1. Monitoring of the status trees should continue in order to promptly identify any RED conditions which might arise and take priority. When procedure FR-S.1 is completed, the operator can again return to his normal recovery action at the point where it was suspended - unless other ORANGE conditions require attention first. Again, order of tree sequence would determine ORANGE priority.

If the answer to the second block question were "yes", the user would follow the "yes" path to a third question block.

This time the question is whether the source range is energized. This can easily be answered by checking the detector high voltage indication, or by noting the Source Range beeper. If the Source Range is determined to be not energized, the user follows the "no" path upward to another question block. Now he is asked if the Intermediate Range startup rate is more negative than - .2 DPM. If the indicated startup rate is between zero and - .2 DPM, then the user would follow the "no" path directly to a terminus and find that:

- the response priority is YELLOW (action not required immediately)
- the appropriate Function Restoration Procedure is FR-S.2.

Since the status priority is YELLOW, the user would continue to monitor the remaining trees and deal with any RED or ORANGE priorities which might be encountered. If no other condition coded higher than YELLOW were present, then the operator would decide if the FRP should be performed or delayed. Often, a YELLOW is indicative of an off-normal condition which may be restored to normal status by actions already in progress. At other times, the YELLOW status may be indicative of an abnormality in a single RCS loop - a single SG, for example and may be considered acceptable for the particular accident in progress. Whatever the case, the operator makes the decision about responding to the YELLOW condition.

If the Intermediate Range startup rate is more negative than - .2 DPM, then the user would follow the "yes" path downward to a terminus and find the condition coded GREEN, the annotated "CSF SAT;" the Critical Safety Function - SUBCRITICALITY, is considered satisfied, so the user proceeds to evaluate the next status tree in the sequence.

If the Source Range was found to be energized, in response to the third question block, the user would follow the "yes" path downward to another question block. This time he is asked if the Source Range startup rate is negative or zero. Since the source range signal is normally erratic, it will be necessary for the user to look at a recorder trend of count rate to properly evaluate the startup rate. If positive, the user would follow the "no" path upward to a terminus and find:

- the response priority is YELLOW
- the appropriate Function Restoration Procedure is FR-S.2

The operator would again use his judgement regarding implementation of FR-S.2 while continuing recovery operations and observing the rules of usage for the other status trees.

If the Source Range startup is observed to be negative, the user follows the "yes" path downward out of the question box and finds the condition coded GREEN, the safety function is satisfied. The user would move directly to the next tree in the sequence.

6. CONTROL ROOM USAGE OF THE ERP NETWORK

While the previous sections discussed the separate usage of an individual procedure and evaluation of status trees, this section presents the intended overall usage of this entire ERP network.

Direct entry into the Emergency Response Procedures is limited to TWO SPECIFIC CONDITIONS:

- If at any time a reactor trip or safety injection occurs OR IS REQUIRED, the operator will enter procedure E-0, REACTOR TRIP OR SAFETY INJECTION.
- If at any time a complete loss of power on the AC emergency busses takes place, the operator will enter ECA-0.0, LOSS OF ALL AC POWER. This includes any time during the performance of ANY other ERP.

The entry into E-0 is expected to be the one more frequently used, so is described first:

The operator proceeds through E-0, following the rules of procedure usage as described above, with two possible outcomes:

- He remains in E-0 and is directed by an action step to begin monitoring the status trees.

- OR -

- He transitions to some other procedure, at which point he begins to monitor the status trees.

Monitoring of the status trees takes place in accordance with its own rules of usage, in parallel with the recovery actions being performed by the operator. The monitoring may be done directly by one of the operators in the control room, by some other member of the shift assigned to the control room, or by a dedicated computer routine. The only requirement of the monitoring function is that the operator in charge of recovery actions be immediately informed of RED or ORANGE priority status conditions, and regularly advised of YELLOW and GREEN conditions.

The ORP actions in progress are suspended if either a RED or ORANGE condition is detected on a status tree. No ORP actions are to be performed while a critical safety function is being restored from a RED or ORANGE condition, unless directed by the FRP in effect.

After restoration of any Critical Safety Function from a RED or ORANGE condition, recovery actions may continue when the FRP is complete. Most often, the FRP will return the operator to the suspended ORP. However, at times a FRP will require a transition to a different ORP because of conditions created within the FRP.

Upon continuation of recovery actions, some judgement is required by the operator to avoid inadvertent reinstatement of a RED or ORANGE condition by undoing some critical step in a Function Restoration Procedure. The plant recovery procedures are optimal assuming that equipment is available as required for safety. The appearance of a RED or ORANGE condition implies that some equipment or function required for safety is not available, and by implication, some adjustment may be required in the recovery procedures.

An example might be the establishing of an alternate feed path to the steam generators as required by FR-H.1. With feed flow from either the main feed or condensate system, the operator would NOT want to isolate the main feed line as required by ES-0.1.

Direct entry into ECA-0.0, due to loss of AC power on both (4 KV) safeguards busses is expected to be a rare occurrence. However, once in ECA-0.0, special considerations come into effect. Because none of the electrically powered safeguards equipment used to restore Critical Safety Functions is operable, none of the FRPs can be implemented. A NOTE at the beginning of procedure ECA-0.0 states "CSF Status Trees should be monitored for information only. FRPs should not be implemented". Once in ECA-0.0, the operator performs the required actions, and is not allowed to transition to any other procedure until some form of power is restored to the (4 KV) Safeguards busses. Even then, permission is not granted to implement FRPs until some initial status checks are performed by the operator.

Certain emergency contingency actions (ECA) take precedence over FRPs because of their treatment of specific initiating events. In all such cases, this precedence is identified in a NOTE at the beginning of the ECA procedure.

For example: ECA-2.1 deals with depressurization, loss of level, and resultant feed flow reduction to ALL steam generators. While this condition results in a RED priority on the Heat Sink Status Tree, the referenced procedure, FR-H.1, returns the operator to ECA-2.1 for the preferred treatment of the event. ECA-2.1 contains an introductory CAUTION stating the specific conditions under which FR-H.1 should be implemented.

A more dramatic example is ECA-0.0 which provides the best strategy for maintaining Critical Safety Functions satisfied and protecting barriers until (4 KV) safeguards AC power is restored.

One unique procedure in the ERP set has no transitions or direct entry conditions. It is used purely as an operator aid and is entered based purely on operator judgement. The procedure is ES-0.0, REDIAGNOSIS. It is intended to be used after departure from E-0, only if SI has been actuated. It provides reassurance to the operator that he is in the correct procedure, or provides the necessary transition instruction to get to the correct procedure for the existing symptoms. Operator need for this rediagnosis procedure is limited in the Rev. 1 ERPs, because many of the transitions needed to respond to new symptoms are included in the OPERATOR ACTION SUMMARY. However, its presence can be reassuring to an operator after making several consecutive transitions due to rapidly changing conditions.

ERP usage always ends in one of the following ways:

- Transition to a normal (not an ERP) plant operating procedure (stable).
- Transition to some "appropriate" procedure while on RHR at cold shutdown conditions (stable).
- On cold leg recirculation or hot leg recirculation with longer term recovery actions being determined by the individual utility (stable).

7. MODES OF APPLICABILITY OF THE ERPs

The ERP network was originally written to accommodate transients occurring at a "hot" or "at power" condition. The transients envisioned would result in either Reactor Protection System or Safeguards Systems actuation, with some corresponding, or subsequent, operator action needed. The guidance for operator action is based upon having the safety-related equipment required by Tech Specs for MODE 1 or MODE 2 operation available for his use. For transients initiating during other MODEs of operation, the same complement of equipment cannot be assumed available, so that the detailed instructions within the ERPs may not be applicable. Just as earlier steps in the ERPs generally involve response to the transient, later steps generally relate to getting the plant to a cold shutdown condition. If the plant is already substantially cooled and depressurized, some detailed instructions may not be applicable.

Critical Safety Function monitoring using the Status Trees also assumes a MODE 1 or MODE 2 initial condition, followed by some Protection System actuation, to result in a subcritical reactor. Use of the trees can be extended beyond this original intent, but with an understanding of the intent of each tree. For example, the Heat Sink Tree assumes the steam generators are available for heat removal by steaming. If all reactor decay heat is being removed by the RHR system, the steam generators are not required in their normal capacity. So, SG availability is really not required to be satisfied. Yet the tree would indicate a SG in wet layup to be OK, while one in dry layup would be abnormal.

To clarify the usability of the ERPs for transients originating during other than the assumed initial operating MODES, a detailed review of the entire network has been performed. The results are presented in the following table. In some cases, slight modifications are needed to extend the applicable range of a procedure beyond its original intent.

Procedure Designator	Applicable Modes	Comments
E-0	1, 2, 3	RHR not in service and SI operable
ES-0.0 ED-0.1	1, 2, 3, 4 1, 2	(Assumes trip from power)
ES-0.2 ES-0.3 ES-0.4		Hot (near no load), slight modification required if already in cooldown
E-1 ES-1.1	1, 2, 3	RHR not in service
ES-1.2		RHR not in service, entry is limited by stated conditions
E-2	1, 2, 3, 4	Temp > 212°F
E-3 ES-3.1 ES-3.2 ES-3.3	1, 2, 3, 4	RHR not in service
ECA-0.0 ECA-0.1 ECA-0.2	1, 2, 3, 4	Partly hot and pressurized
ECA-1.1 ECA-1.2		Specific entry conditions provided
ECA-2.1	1, 2, 3, 4	RHR not in service, hot

Procedure Designator	Applicable Modes	Comments
ECA-3.1 ECA-3.2 ECA-3.3	1, 2, 3, 4	RHR not in service
F-0.1, Subcriticality F-0.2 Core Cooling	1-4 1-4	
F-0.3, Heat Sink	1-4	Unless RHR in service
F-0.4, Integrity	1-4	Slight problem with cool-down rate in MODE 4
F-0.5, Containment F-0.6, Inventory	1-4 1-4	
FR-S.1	1-4	(AFW not required if on RHR)
FR-S.2	1-4	
FR-C.1 FR-C.2	1, 2, 3	Partial MODE 4 on SI equipment availability, secondary lineup
FR-C.3	1-4	
FR-H.1	1-4	Bleed and feed may be too soon for MODE 4
FR-H.2	1-4	
FR-H.3	1-4	Except wet layup
FR-H.4	1-4	
FR-H.5	1-4	Except dry layup

Procedure Designator	Applicable Modes	Comments
FR-P.1	1-4	Entry may not be necessary if initial temperature was low
FR-P.2	1-4	
FR-Z.1	1-4	
FR-Z.2	1-4	
FR-Z.3	1-4	
FR-I.1	1-4	Some exceptions if RHR in service
FR-I.2	1-4	Possible exception of SI initiation
FR-I.3	1-4	

Operating MODES as used here has the same definition as the Seabrook Technical Specifications:

MODE	REACTIVITY (Keff)	THERMAL POWER (% RATED, EXCLUDING DECAY HEAT)	AVERAGE COOLANT TEMPERATURE
1. Power Operation	$\geq$ 0.99	> 5	$\geq$ 350°F
2. Startup	$\geq$ 0.99	$\leq$ 5	$\geq$ 350°F
3. Hot Standby	< 0.99	0	$\geq$ 350°F
4. Hot Shutdown	< 0.99	0	350°F>Tavg>200°F
5. Cold Shutdown	< 0.99	0	$\leq$ 200°F

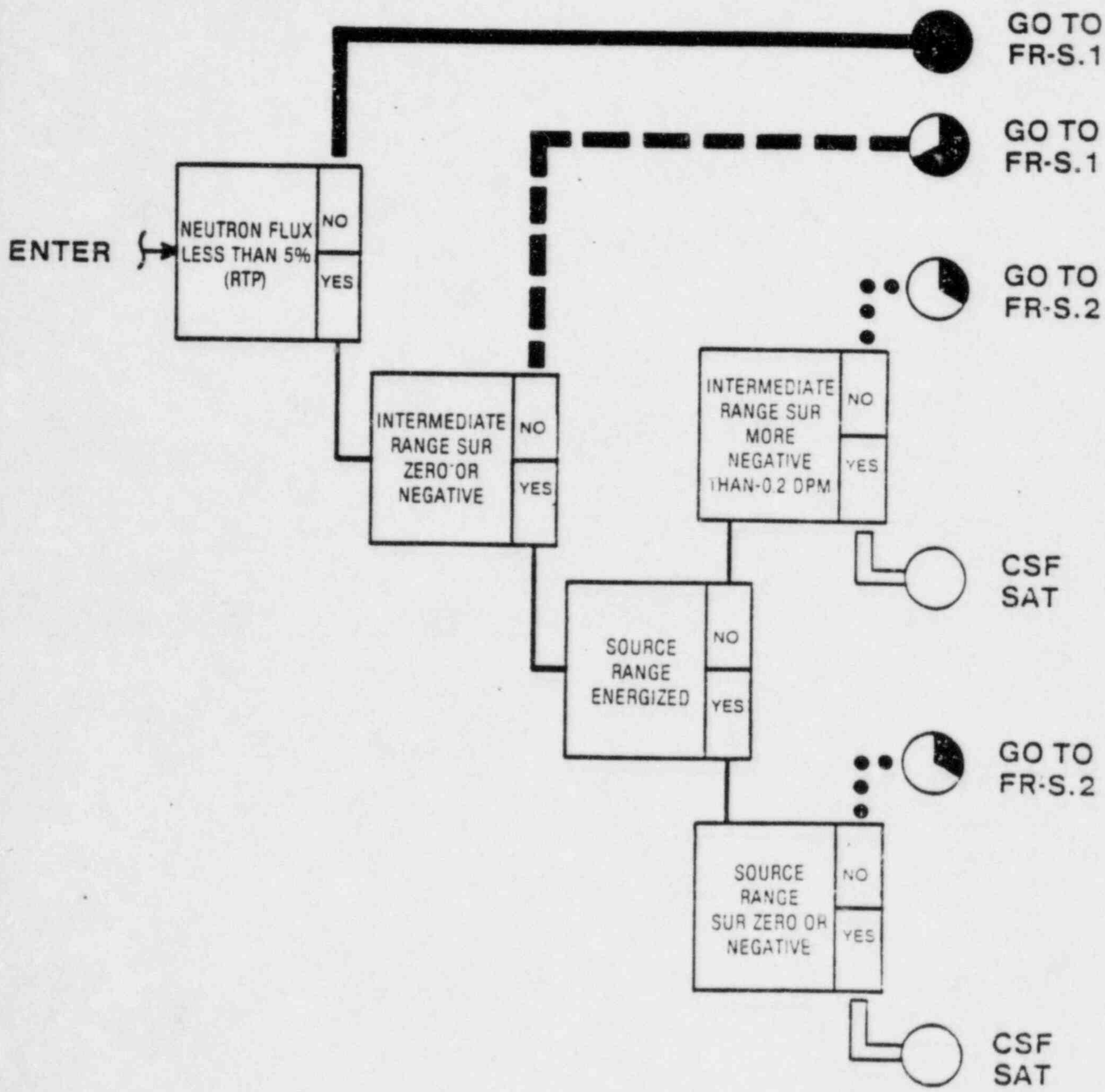
(Mode 6, Refueling, is not considered in the context of ERP applicability.)

EXAMPLE ERP

E-2 FAULTED STEAM GENERATOR ISOLATION

OPERATOR IMMEDIATE ACTIONS
(Must commit to permanent memory)

CODE:	SYMPTOM / TITLE:	PROCEDURE NO. REVISION NO. / DAT.
F-0.1 REV. 1	SUBCRITICALITY STATUS TREE	OS-1350.1 00/10/2/83



EXAMPLE STATUS TREE

A. PURPOSE

This procedure provides actions to identify and isolate a faulted steam generator.

B. SYMPTOMS OR ENTRY CONDITIONS:

This procedure is entered from:

1) E-0, REACTOR TRIP OR SAFETY INJECTION, Step 22 and E-1, LOSS OF REACTOR OR SECONDARY COOLANT, Step 2 with the following symptoms:

   a. Any SG pressure decreasing in an uncontrolled manner

   b. Any SG completely depressurized

2) E-3, STEAM GENERATOR TUBE RUPTURE, Step 6, ECA-3.1, SGTR WITH LOSS OF REACTOR COOLANT - SUBCOOLED RECOVERY DESIRED, Step 8, and ECA-3.2, SGTR WITH LOSS OF REACTOR COOLANT - SATURATED RECOVERY DESIRED, Step 3 when faulted SG isolation is not verified.

3) FR-H.5, RESPONSE TO STEAM GENERATOR LOW LEVEL, Step 3 when the affected SG is diagnosed as faulted.

4) Other procedures whenever a faulted SG is identified.

STEP	ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED

CAUTION
- At least one SG must be maintained available for RCS cooldown.
- Any faulted SG or secondary break should remain isolated during subsequent recovery actions, unless needed for RCS cooldown.

STEP	ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED
1	Check Main Steamline Isolation And Bypass Valves Of Affected SG(s) - CLOSED	Manually close valves.
2	Check If SG Pressure Boundary Is Intact:	
	a. Check pressures in all SGs - ANY STABLE OR INCREASING	a. IF all SG pressures decreasing in an uncontrolled manner, THEN go to ECA-2.1, UNCONTROLLED DEPRESSURIZATION OF ALL STEAM GENERATORS, Step 1.
3	Identify Faulted SG(s):	
	a. Check pressures in all SGs - • ANY SG PRESSURE DECREASING IN AN UNCONTROLLED MANNER - OR - • ANY SG COMPLETELY DEPRESSURIZED	a. Search for initiating break: • Main steamlines • Main feedlines • EFW lines • Steam to EFW turbine • ASDVs • Blowdown Go to Step 5.

STEP	ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED
4	Check Faulted SG(s) Isolated:	Manually close valves. IF valves can NOT be closed, THEN dispatch operator to locally close valves or block valves which are accessible to isolate leak.

a. Main feedline - ISOLATED

b. EFW flow - ISOLATED

c. Steam supply to turbine-driven EFW pump - ISOLATED

- SG-A MS-V127
- SG-B MS-V128

d. SG ASDV - CLOSED

e. Main steam drains - GROUP A CLOSED

f. SG blowdown - ISOLATED

SG	VALVE
A	SB-V9
B	SB-V10
C	SB-V11
D	SB-V12

CAUTION CST makeup should commence as early as possible to avoid low inventory problems.

STEP	ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED
5	Check CST Level - GREATER THAN 23 FEET	Establish makeup to CST at maximum rate.

STEP	ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED
6	Check Secondary Radiation:	
	a. Request periodic liquid activity samples of all SGs:	a. <u>IF</u> SG blowdown can <u>NOT</u> be reestablished, go to Step 6b.
	1) Reset SI	
	2) Reset Phase A isolation	
	3) Reestablish SG blowdown for sampling only	
	a. Locally isolate throttle valves to blowdown tank first, <u>THEN</u> reopen blowdown containment isolation valves	
	b. Check unisolated secondary radiation monitors using RDMS	
	• Main Steamline monitors	
	c. Secondary radiation - NORMAL	c. Go to E-3, STEAM GENERATOR TUBE RUPTURE, Step 1.
7	Go To E-1, LOSS OF REACTOR OR SECONDARY COOLANT, Step 1	

- END -

ATTACHMENT A

RED PATH SUMMARY

SUBCRITICALITY - NEUTRON FLUX GREATER THAN 5% RTP

CORE COOLING - CORE EXIT TCs GREATER THAN 1200°F

\- OR -

CORE EXIT TCs GREATER THAN 700°F AND RVLIS LESS THAN 40% WITH NO RCPs RUNNING

HEAT SINK - SG INVENTORY LESS THAN REQUIRED IN TABLE AND EFW FLOW CAPABILITY LESS THAN 470 GPM TOTAL COMBINED FLOW

NORMAL CONTAINMENT	ADVERSE CONTAINMENT
65% WR	28% NR

INTEGRITY - COLD LEG TEMPERATURE DECREASE GREATER THAN 100°F IN LAST 60 MINUTES AND RCS COLD LEG TEMPERATURE LESS THAN 250°F

CONTAINMENT - CONTAINMENT PRESSURE GREATER THAN 52.0 PSIG

IMMEDIATE ACTIONS

REACTOR TRIP OR SAFETY INJECTION

E-0

STEP	SEQUENCE
1. Verify Reactor Trip	1
2. Verify Turbine Trip	2
3. Verify Power To AC Emergency Busses	3
4. Check If SI Is Actuated	4 (OUT)
5. Verify FW Isolation	
6. Verify Containment Isolation Phase A	
7. Verify EFW Pumps - RUNNING	
8. Verify ECCS Pumps - RUNNING	
9. Verify PCCW Pumps - RUNNING	
10. Verify Ultimate Heat Sink Operation	
11. Verify SW Cooling To DG's	
12. Verify Containment Ventilation Isolation	
13. Check If Main Steamlines Should Be Isolated	
14. Check Containment Pressure - HAS REMAINED LESS THAN HI-3 (18 PSIG) BY PRESSURE RECORDING	

IMMEDIATE ACTIONS

LOSS OF ALL AC POWER

ECA-0.0

STEP	SEQUENCE
1. Verify Reactor Trip	1
2. Verify Turbine Trip	1
3. Check If RCS Is Isolated	1
4. Verify EFW Flow - GREATER THAN 470 GPM TOTAL COMBINED FLOW	1

IMMEDIATE ACTIONS

RESPONSE TO NUCLEAR POWER GENERATION

ATWS

Function Restoration Procedure FR-S.1

STEP	SEQUENCE
1. Verify Reactor Trip	1
2. Verify Turbine Trip	2
3. Check EFW Pumps Running	3
4. Initiate Emergency Boration	4

SELECTED

EMERGENCY RESPONSE PROCEDURES

for

Discussion

Our training thus far has already provided adequate "overview level" discussions for many events and plant symptoms such as LOCA, LOAC, Steamline/ Feedline breaks, ATWS, Inadequate Core Cooling (ICC) and Loss of Heat Sink. Most of this was presented in ECCS and MCD.

However, more time should be spent in other events and symptoms not yet discussed in sufficient detail. This will include Response to Reactor Trip or Safety Injection, more on Natural Circulation Cooldown and SG Tube Rupture Recovery Techniques.

REACTOR TRIP OR SAFETY INJECTION

INTRODUCTION

Procedure E-0, REACTOR TRIP OR SAFETY INJECTION, provides actions to verify proper response of the automatic protection systems following manual or automatic actuation of a reactor trip or safety injection, to assess plant conditions, and to identify the appropriate Optimal Recovery Procedure.

Procedure E-0 is to be entered when any of the following occur:

1) A reactor trip is required as determined by plant specific setpoints or requirements being exceeded.

2) A reactor trip has occurred as determined by the plant annunciators, neutron flux instrumentation, and control rod position indicators.

3) A safety injection is required as determined by plant specific setpoints or requirements being exceeded.

4) A safety injection has occurred as determined by the plant annunciators, SI pump status, or other plant specific means.

Once E-0 is entered, it is not exited until there is a direct transition to an Optimal Recovery Procedure (ORP) as directed by the symptoms being monitored in E-0 or to a Function Restoration Procedure (FRP) as directed by the Critical Safety Function Status Trees or symptoms being monitored in E-0.

DESCRIPTION

Procedure E-0, REACTOR TRIP OR SAFETY INJECTION, provides the operator with the necessary guidance to verify that all automatic actions have occurred as designed and presents the diagnostic sequence to be followed in the identification of the appropriate Optimal Recovery Procedure. These include:

1. ECA-0.0, LOSS OF ALL AC POWER
2. ES-0.1, REACTOR TRIP RESPONSE
3. E-1, LOSS OF REACTOR OR SECONDARY COOLANT
4. E-2, FAULTED STEAM GENERATOR ISOLATION
5. E-3, STEAM GENERATOR TUBE RUPTURE
6. ES-1.1, SI TERMINATION
7. ECA-1.2, LOCA OUTSIDE CONTAINMENT

It is expected that the operator will attempt to take manual actions to correct for anomalous conditions during power operation. Such actions would include taking manual control of the automatic control systems, turning on additional charging pumps, reducing power level, etc. If these types of actions do not alleviate the trend toward a reactor trip or safety injection, the operator is permitted to trip the reactor and, if necessary, actuate safety injection.

The reactor protection equipment is designed to safely shut down the reactor in the event that the anomalous condition cannot be corrected. The safety injection system is designed to provide emergency core cooling water and boration to maintain a safe reactor shutdown condition. The plant safeguards systems operate with offsite electrical power or from onsite emergency diesel-electric power, should offsite power not be available. The operator will enter E-0 on a reactor trip or safety injection, whether the signal was automatic or a result of manual actuation.

Through symptom-based diagnosis, the operator is directed to the proper Optimal Recovery Procedure to facilitate optimal recovery.

Many parameters behave in a similar manner for loss of reactor coolant, secondary coolant and steam generator tube ruptures. For example, RCS pressure drops for all three cases. The symptoms used to diagnose the three major event categories are those most representative of the fault. A break in the secondary is diagnosed by secondary pressure decreasing in an uncontrolled manner or any steam generator completely depressurized. A primary to secondary break is diagnosed by abnormal secondary radiation. A loss of primary coolant into containment is diagnosed by abnormal containment pressure, sump level, or radiation. Abnormalities in both containment pressure and sump level can also occur for a secondary break in containment. For that reason the secondary pressure is checked before the containment conditions in the diagnostic steps to eliminate a secondary break as being the cause of the containment conditions. The rediagnostic capabilities of the subsequent procedures, such as in E-1, LOSS OF REACTOR OR SECONDARY COOLANT, allow for any misdiagnosis to be corrected and the operator to proceed to the proper procedures in the Emergency Response Procedure (ERP) network. If an event is not diagnosed by the primary symptoms, then other symptoms are checked in E-0. If no fault is initially found, the operator will cycle through the diagnostic steps until either a fault is observed or SI termination criteria are met.

REACTOR TRIP OR SAFETY INJECTION

MAJOR ACTION CATEGORIES IN E-0

- Verify Automatic Actions as Initiated by the Protection and Safeguards System

(IMMEDIATE ACTIONS - STEPS 1-14)

Immediate actions are those actions which the operator should be able to perform before opening and reading his emergency procedures. In general, immediate actions are limited to the verification of automatic protection features of the plant. Although the immediate actions should be memorized by the operator, they need not be memorized verbatim. The operator should know them well enough to complete the intent of each step, which is to verify that the automatic actions have occurred. The order in which they should be performed should also be consistent with the step sequence requirements, i.e., the order of the first four steps is important and the rest may be interchanged.

- Identify Appropriate Optimal Recovery Procedure

- Shut Down Unnecessary Equipment and Continue Trying to Identify Appropriate Optimal Recovery Procedure

- Initiate Monitoring of Critical Safety Function Status Trees AT STEP 27 OR WHEN EXITING E-0.

The following are questions which have been frequently asked about E-0, REACTOR TRIP OR SAFETY INJECTION:

Q. When is E-0 normally entered?

A. E-0 is normally entered whenever a reactor trip or safety injection occurs or is required as determined by plant observables.

Q. Can safeguards signals be reset before the procedure step instructs me to reset them?

A. Safeguards signals should only be reset when necessary to manually operate equipment. In the procedures, those steps are generally located before the first step that either stops an ECCS pump or explicitly repositions a valve that receives a safeguards signal. The general philosophy to follow is to only reset safeguards signals when the reset is necessary for manual operation of components.

Q. If the fault is readily apparent, does E-0 have to be performed rather than going directly to the appropriate Optimal Recovery Procedure?

A. Yes, E-0 should be performed. The verification of automatic actions and diagnostics should be performed to ensure the proper checks have been completed prior to the first step of any subsequent procedure. The ERPs are a procedural network organized in a logical order with any one procedure being a sub-part of the whole. To properly execute th ERPs, it is important to start at the beginning and let the transitions direct you through the network.

ES - 0.0 REDIAGNOSIS

PURPOSE OF PROCEDURE

Method For Determining Or Confirming The Most Appropriate Post Accident Recovery Procedure

ENTRY INTO PROCEDURE

Operator Judgement When SI Is Actuated Or Required

REACTOR TRIP RESPONSE

INTRODUCTION

Procedure ES-0.1, REACTOR TRIP RESPONSE, provides the necessary instructions to stabilize and control the plant following a reactor trip without a safety injection. It is entered only from E-0, REACTOR TRIP OR SAFETY INJECTION, Step 4 when an SI is neither actuated nor required. Following the stabilization of the plant, ES-0.1 is exited to either a normal plant procedure for startup or cooldown, or to ES-0.2, NATURAL CIRCULATION COOLDOWN, if a natural circulation cooldown is required.

DESCRIPTION

A reactor trip is a command to shut down a reactor which is either critical or undergoing startup operation. The command is generated by either an automatic protective action initiated when certain setpoints for plant operating parameters are exceeded or by manual initiation by the operator. The generation of a protection demand is appropriately indicated at the annunciator panel. Several automatic actions aimed at ensuring that the core is shutdown and that there is effective decay heat removal follow the occurrence of a reactor trip.

Following a reactor trip from full power, the reactor coolant temperature is reduced from full power temperature to no-load temperature by automatic operation of the condenser steam dump system. If for any reason condenser steam dump capability cannot be obtained, the steam generator atmospheric steam dump valves will automatically modulate. If these do not open, the steam generator code safety valves open to protect the secondary system and by that means remove heat from the primary system. The cooldown to no-load shrinks the water in the RCS and pressurizer level should stabilize automatically at the no-load programmed level. The drop in level results in a reduction in RCS pressure from the nominal 2235 psig. RCS pressure can be expected to drop to about 2000 psig before starting to increase as a result of operation of the pressurizer heaters. For most reactor trips steam generator water level will remain above the top of the U-tubes although it may shrink out of the narrow range indication. Emergency feedwater pumps will start on low-low narrow range SG level to restore SG level into the narrow range. Extensive subcooling of the reactor coolant at the core exit should exist. Forced flow in the RCS will be maintained unless for some reason the reactor coolant pumps have tripped, in which case flow will be by natural circulation.

The station electrical busses would normally be energized by offsite power. If for some reason a station "blackout" (loss of offsite power) occurs, the diesel generators would automatically start and supply power to the blackout loads to stabilize and control the plant. All critical surveillance, control, and safeguards actuation systems are continuously powered from the plant's redundant batteries. All operating elements of the safety-grade systems (ECCS pumps, for example) would have power available from the diesel generators. A number of operating elements for "non-safety-grade" systems and components may not be automatically powered by the diesel generators. These "non-safety-grade" components include some pressurizer heaters, the Startup Feed Pump and the plant air compressors, and should be intentionally repowered as soon as possible since the availability of these components facilitate plant control.

Procedure ES-0.1 deals with the specific actions necessary to stabilize and control the plant following a reactor trip. It also handles reactor trips combined with either a station blackout or a total loss of forced reactor coolant flow.

MAJOR ACTION CATEGORIES IN ES-0.1

- Ensure the Primary System Stabilizes at No-load Conditions

- Ensure the Secondary System Stabilizes at No-load Conditions

- Ensure Necessary Components Have Power Available

- Maintain/Establish Forced Circulation of the RCS

- Maintain Plant in a Stable Condition

KEY UTILITY DECISION POINTS

After the plant is stabilized following a reactor trip, the operating crew would have to determine the next course of action. Generally, if no components necessary for power operation are out of service, the limiting conditions for operation in the Technical Specifications are satisfied, and if the cause of the trip is identified and corrected, then a plant startup would be commenced. If a Technical Specification limiting condition for operation is violated and its action statement requires a cooldown, or a cooldown is necessary to repair non-safety grade components needed for operation, then a plant cooldown is commenced. If a cooldown is required, forced circulation of the RCS is always preferred over a natural circulation cooldown in order to eliminate any concerns about drawing voids in the system and/or incomplete boron mixing. Therefore, attempts should be made to start at least one reactor coolant pump prior to the cooldown, if one is not already running. A natural circulation cooldown should only be performed if absolutely necessary.

NATURAL CIRCULATION COOLDOWN

INTRODUCTION

Upon entry to ES-0.2, NATURAL CIRCULATION COOLDOWN, natural circulation of the RCS has been verified and stable plant conditions are being maintained. The purpose of ES-0.2 is to cool down and depressurize the plant to cold shutdown under natural circulation conditions by dumping steam and subsequent RHR system operation. There should be no accident in progress and cooldown conditions are specified to preclude any upper head void formation.

This procedure is entered from ES-0.1, REACTOR TRIP RESPONSE, Step 13 or ECA-0.1, LOSS OF ALL AC POWER RECOVERY WITHOUT SI REQUIRED, Step 21 when it has been determined that a natural circulation cooldown is required. There are three possible transitions out of this procedure. If SI actuation occurs, a transition to E-0, REACTOR TRIP OR SAFETY INJECTION, should be made. Since it is always desirable to have forced convection heat transfer from the core, the first step of the procedure attempts to start an RCP. If this attempt is successful, a transition to appropriate plant procedures is in order. The third transition occurs if the plant staff determines that a natural circulation cooldown and depressurization must be performed at a rate that may form a steam void in the vessel. At that time a transition to ES-0.3, NATURAL CIRCULATION COOLDOWN WITH STEAM VOID IN VESSEL (WITH RVLIS) or ES-0.4, NATURAL CIRCULATION COOLDOWN WITH STEAM VOID IN VESSEL (WITHOUT RVLIS), should be made.

DESCRIPTION

The objective of ES-0.2, NATURAL CIRCULATION COOLDOWN, is to permit cooldown and depressurization of the RCS without forming voids in the higher-temperature/low-flow portions of the system (e.g., upper head region and steam generator U-tubes). Based on the cooldown/depressurization analysis performed for Westinghouse plants as a result of the St. Lucie Unit 1 plant cooldown using natural circulation (June 11, 1980), certain limitations were determined concerning the maximum cooldown rate and minimum subcooling requirements necessary to prevent void formation.

During the St. Lucie event, it was evident from pressurizer level and primary system pressure response that void formation occurred in the upper head region. Even though old leg temperatures at the time of voiding were highly subcooled, fluid in the upper head was much hotter, relatively stagnant and in poor communication with the rest of the primary system. It has been postulated that the steam bubble in the upper head area was produced when the system pressure dropped below the saturation pressure corresponding to the temperature of the fluid in the upper head.

There are several parameters which can have a significant effect on the formation of voids in the upper head region during natural circulation cooldown/depressurization transients. One such parameter is the magnitude of the flow between the upper downcomer and the upper head. This flow is at a temperature equivalent to that of the cold leg fluid. Hence, this flow directly affects the upper head fluid temperature, which is a second factor that has an effect on the formation of voids in the upper head region. Most currently operating Westinghouse plants under forced flow conditions have an amount of flow into the upper head region which results in an upper head fluid temperature between the cold leg temperature (T_{COLD}) and the hot leg temperature (T_{HOT}). For the natural circulation cooldown analysis the initial upper head temperature for these plants was conservatively chosen as T_{HOT}. Other Westinghouse plants operate with sufficient flow from the upper downcomer to the upper head region to make the upper head fluid temperature equal to the cold leg fluid temperature (T_{COLD}). Both types of plants were analyzed. Seabrook is a T_{COLD} plant.

Another parameter which affects void formation in the upper head region is the cooldown rate of the primary system. Natural circulation cooldown rates of 25°F/hr and 50°F/hr were analyzed for T_{HOT} and T_{COLD} plants, respectively.

A final parameter important in the formation of voids in the upper head is the heat removal rate from the upper head. The two primary means of heat loss are ambient heat losses and heat removal by the control rod drive mechanism (CRDM) fans. The effect of ambient heat losses through the reactor vessel on upper head temperature is small compared to the effect of the CRDM fans. The cooloff rate of the upper head due to ambient heat losses is <u>less than 1°F/hr</u> and was neglected in the analysis. However, metal heat addition to the upper head area from the reactor vessel and upper internals was taken into account.

The CRDM cooling system consists of fans which maintain a suitable atmosphere within the CRDM shroud to protect and prolong the life of the CRDM motors. The system induces cooler containment air into the CRDM shroud and exhausts warmed air through the fans. The CRDM fans remove

8 kw/drive train at full power. For a 4-loop plant with 57 full-length rods, the CRDM fans remove 8 kw x (57) = 456 kw. Based on the heat transfer area of the CRDMs and the volume of coolant under the reactor vessel head, the calculated head cooldown rates with CRDM fans running is 18.5°F/hr @ 600°F and 10°F/hr @ 350°F.

UPPER HEAD FLUID TEMPERATURE
T_{COLD} - 50°/hr COOLDOWN
FIGURE OP 1 (TC Rev 0 3/84)

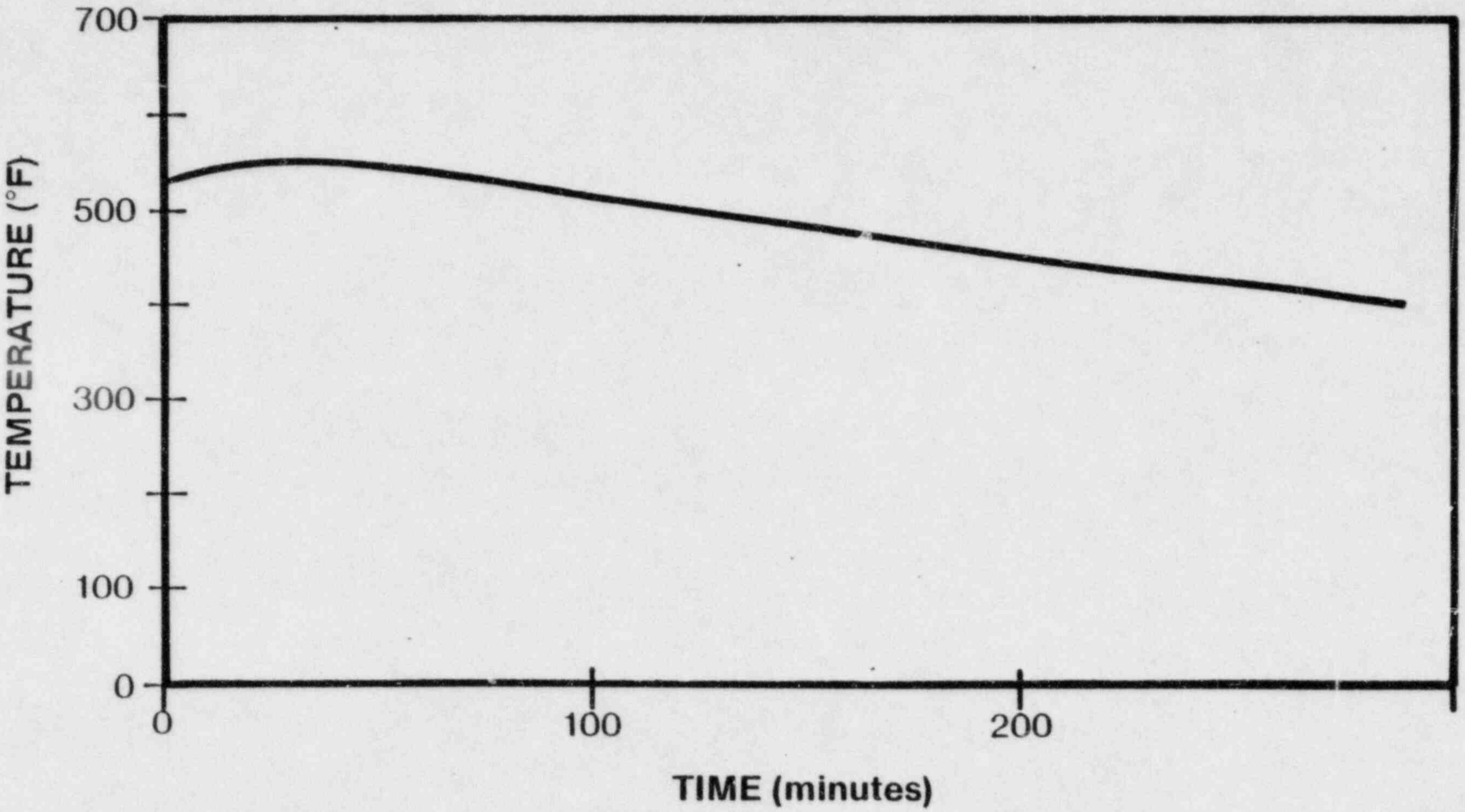


FIGURE 1

In the analysis, natural circulation cooldown was assumed to be initiated at 12 minutes after the RCP trip. With the exception of the pressurizer, the primary system was subcooled when the natural circulation cooldown was initiated. At 12 minutes the difference between the hot and cold leg temperatures was approximately 30°F, the primary system loop flow was approximately 500 lb/sec. and the reactor power (due to decay heat) was 2.3 percent of full power (nominal). The loop flow rate of 500 lb/sec, was approximately 5 percent of full power loop flow. Natural circulation flow has been observed to be between 4.5 percent and 5.0 percent of full power flow at 2.3 percent of nominal power for a Westinghouse 4-loop plant based on calculations and tests.

With forced flow (i.e., with the reactor coolant pumps running) the flow goes from the upper downcomer through the upper head spray nozzles into the upper head region. From the upper head region the flow goes down through the guide tubes into the upper plenum/core region. With the reactor coolant pumps running the vessel pressure distribution is such that flow is forced up the upper head spray nozzles. Within 2 to 4 minutes after the reactor coolant pumps are tripped this flow reverses and goes up the guide tubes into the upper head region and down through the upper head spray nozzles into the upper downcomer. This flow reversal occurs due to the downcomer fluid density being greater than the upper plenum/core fluid density, and the upper plenum/core fluid density being greater than the upper head density. This density variation forces flow up the guide tubes. Because of this flow reversal, upper head temperature rises early in the transient (see Figure 1). The upper head temperature is initially equivalent to the cold leg temperature for T_{COLD} plants. When the spray nozzle/guide tube flow reversal occurs, hotter water from the core is introduced into the upper head area and causes the upper head temperature rise. After this early increase, the upper head temperature steadily decreases.

CONCLUSIONS FOR T_{COLD} PLANTS

The average cooldown rate of the upper head fluid due to a 50°F/hr natural circulation cooldown rate is about 34°F/hr for a T_{COLD} plant. The total upper head cooldown rate due to both natural circulation cooldown and CRDM fans varies from a maximum of 52.5°F/hr to around 44°F/hr when the upper head temperature is cooled to 350°F. Thus, with the CRDM fans operating during the cooldown, a T_{COLD} plant could be cooled and depressurized at a natural circulation cooldown rate of 50°F/hr to the point where the RHR System could be employed for further cooldown, with no void formation occurring in the upper head area. The operator should maintain a minimum of 50°F subcooling during the depressurization (stated in the procedure).

Adding the cooldown rate due to the CRDM fans to that from the natural circulation cooldown is conservative since the additional cooling due to the fans will enhance the density difference between the downcomer and upper head, which in turn increases the guide tube/spray nozzle flow rate.

With the CRDM fans not available, a T_{COLD} plant can be cooled down and depressurized to RHR System conditions at a natural circulation cooldown rate of 50°F/hr with no void formation in the upper head area if the operator maintains a minimum of 100°F subcooling during the depressurization (see Figure 2).

SUBCOOLING MARGIN T_{COLD} - 50 °F/hr COOLDOWN WITHOUT CRDM FANS

FIGURE OP 2 (TC Rev 0 3/84)

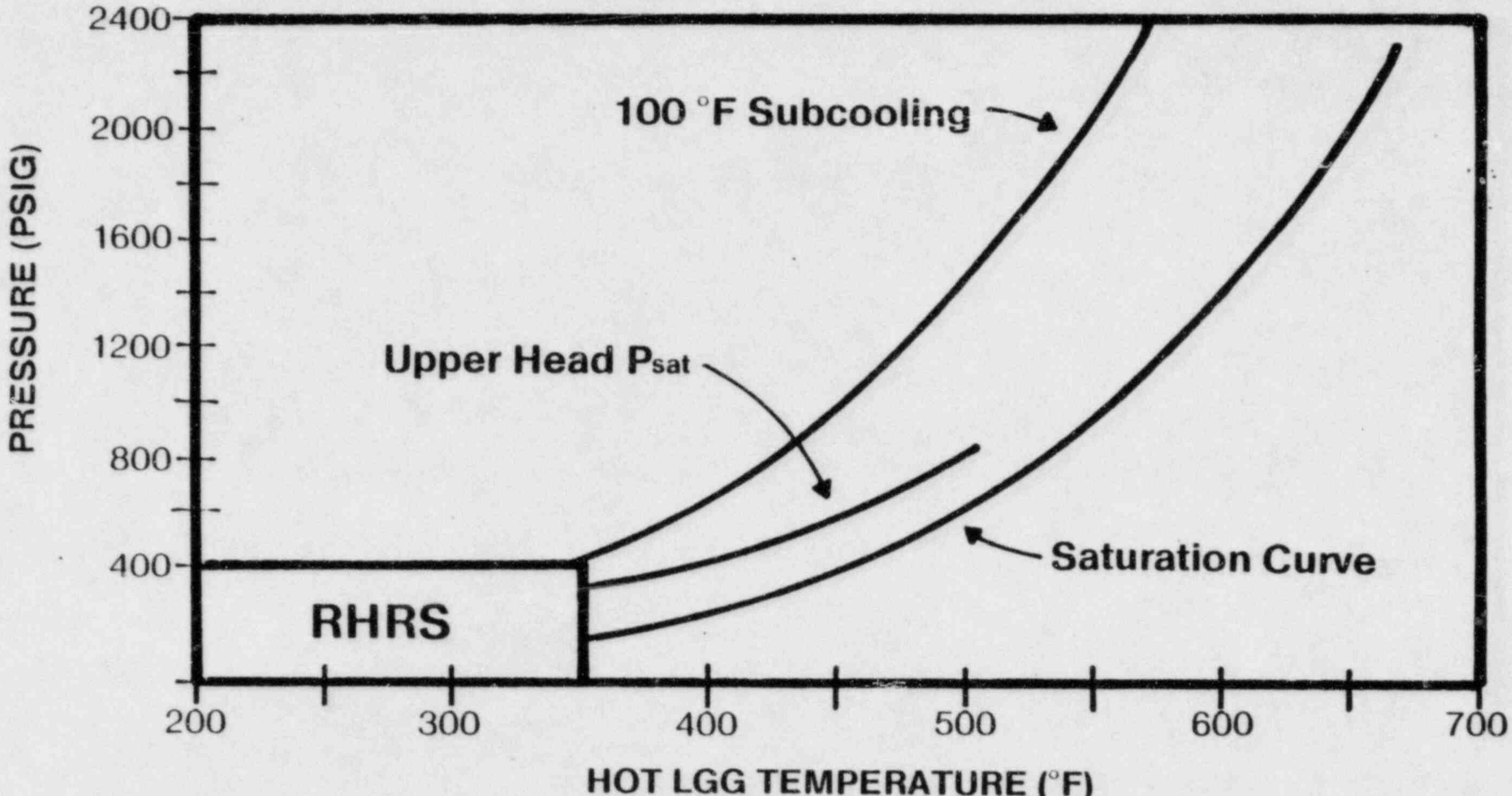


FIGURE 2

MAJOR ACTION CATEGORIES IN ES-0.2

- Try to Start an RCP
- Cool Down and Depressurize RCS With No Upper Head Void Growth
- Lock Out SI System
- Place RHR System in Service
- Cool Down to Cold Shutdown

KEY UTILITY DECISION POINTS

There are four decision points in this procedure when a choice must be made between two or more courses of action. The first decision occurs in the first step as the operator attempts to start an RCP. If he is successful, a decision as to which appropriate plant procedure should be entered is required. A similar situation exists at the end of the procedure. Here cold shutdown has been accomplished and the utility must decide on an appropriate normal or abnormal plant procedure.

The other two decision points involve continuing a fast-paced cooldown and allowing a void to form in the upper head. In the note following step 11 the possibility for transition to either ES-0.3, NATURAL CIRCULATION COOLDOWN WITH STEAM VOID IN VESSEL (WITH RVLIS), or ES-0.4, NATURAL CIRCULATION COOLDOWN WITH STEAM VOID IN VESSEL (WITHOUT RVLIS), exists. This same opportunity to transfer to either of these procedures appears in Step 14.

The preferred method for cooldown under natural circulation conditions is provided in this procedure, ES-0.2, where no upper head void is created. Any decision to continue an expedited cooldown (e.g., due to condensate storage limitations) should be carefully considered before a transition to either ES-0.3 or ES-0.4 is made.

RECOVERY PROCEDURE SUMMARY

ES-0.2: Initial plant setup for a natural circulation cooldown followed by RCS cooldown and depressurization under requirements that avoid any upper head void formation.

ES-0.3: RCS cooldown and depressurization under requirements that allow the potential for upper head void formation, with RVLIS to monitor void growth (initial plant setup for natural circulation cooldown provided by ES-0.2).

ES-0.4: RCS cooldown and depressurization under requirements that allow the potential for upper head void formation, without RVLIS to monitor void growth (initial plant setup for a natural circulation cooldown provided by ES-0.2).

NATURAL CIRCULATION COOLDOWN WITH STEAM VOID IN VESSEL

INTRODUCTION

Upon entry to ES-0.3, NATURAL CIRCULATION COOLDOWN WITH STEAM VOID IN VESSEL (WITH RVLIS), natural circulation of the RCS has been verified and a cooldown/depressurization has been initiated (see procedure ES-0.2, NATURAL CIRCULATION COOLDOWN). The purpose of this procedure is to continue plant cooldown and depressurization to cold shutdown under conditions that allow for the potential formation of a void in the upper head region. There should be no accident in progress and a reactor vessel level system (RVLIS) is available to monitor the size of any vessel void.

This procedure is entered from ES-0.2, NATURAL CIRCULATION COOLDOWN, when it has been determined that a cooldown/depressurization must be performed at a rate that may form a steam void in the vessel. In any case, the first eleven steps of ES-0.2 must be completed prior to entering this procedure.

There are two transitions out of this procedure. The first occurs if SI is actuated. In this instance a transition to E-0 , REACTOR TRIP OR SAFETY INJECTION, should be made. The second transition occurs if forced convection heat transfer can be established. The first step of the procedure attempts to start an RCP. If this attempt is successful a transition to appropriate plant procedures is performed.

DESCRIPTION

The objective of ES-0.3, NATURAL CIRCULATION COOLDOWN WITH STEAM VOID IN VESSEL (WITH RVLIS), is to permit a natural circulation cooldown and depressurization of the RCS while allowing, controlling, and monitoring the formation of voids in the vessel.

During the St. Lucie Unit 1 plant cooldown under natural circulation conditions (June 11, 1980), it was evident that void formation occurred in the upper head region. Using the information obtained from this event and the subsequent analyses performed for Westinghouse plants, the procedure ES-0.3 was developed to enable the operator to perform a natural circulation cooldown/depressurization that permitted upper head void growth, which would be monitored with RVLIS.

If it is necessary to cool down and depressurize the RCS quickly under natural circulation conditions (e.g., due to limited condensate storage), procedure ES-0.3 is the appropriate alternative to ES-0.2 if there is a RVLIS available to monitor void growth. If a rapid RCS cooldown/depressurization is desired in the absence of RVLIS instrumentation, ES-0.4, NATURAL CIRCULATION COOLDOWN WITH STEAM VOID IN VESSEL (WITHOUT RVLIS) is to be used.

Though there is no analysis to support the technique employed in ES-0.3, specific symptoms are relied upon to indicate that void growth is restricted to the upper head/upper plenum region, above the top of the hot legs, so as not to disrupt the natural circulation flow. By maintaining RCS subcooling, controlling pressurizer level, and monitoring RVLIS indications, a maximum cooldown rate of 100°F/HR and a continued RCS depressurization are permitted under natural circulation conditions. If, during the course of the cooldown/depressurization, the RVLIS indicates that void growth is approaching the hot legs, RCS depressurization is stopped and the operator is instructed to repressurize the RCS to collapse the void.

At no time is it appropriate to make a transition to FR-I.3, RESPONSE TO VOIDS IN REACTOR VESSEL, and perform a head venting operation. This is contrary to the intent of procedure ES-0.3 where a vessel void is allowed to exist under controlled conditions while the plant is cooled down and depressurized to cold shutdown. If procedure FR-I.3 was used to vent the vessel head at this time, the steam void would not be eliminated. As pressure decreases (from venting), more water will flash to steam in the head region, replacing the steam that was vented. The void size will remain essentially constant and the net result will be a loss of system inventory. Therefore, procedure FR-I.3 should not be used when cooling down and depressurizing the system with procedure ES-0.3.

It should be noted that although procedure ES-0.3 is the approved guidance for natural circulation cooldown/depressurization with a vessel void, procedure ES-0.2 presents the preferred mode of operation (i.e., no void formation) and should be used whenever possible.

MAJOR ACTION CATEGORIES IN ES-0.3

- Try to Start an RCP

- Cool Down and Depressurize RCS
  While Monitoring Void Growth

Before cooling down and depressurizing the RCS, a pressurizer level is established to accommodate void growth. During the cooldown/depressurization phase, a cooldown rate of less than 100°F/HR is maintained, together with a minimum RCS subcooling. RCS temperature and pressure should also be maintained within Technical Specification cooldown limits. To monitor void growth and maintain pressure control, RVLIS and pressurizer level instrumentation are checked for proper values.

- Lock Out SI System

- Place RHR System in Service

- Cool Down to Cold Shutdown

KEY UTILITY DECISION POINT

The key decision point occurs in Step 4. In the RNO (Response Not Obtained) column a choice must be made between two methods of reducing PRZR level. The first method involves adjusting charging and letdown to reduce system inventory. The second uses the natural phenomenom of inventory shrink during cooldown to lower the PRZR level. Though the use of charging and letdown should be the preferred method, the operators should determine which method is more appropriate considering the circumstances and/or plant equipment available.

NATURAL CIRCULATION COOLDOWN WITH STEAM VOID IN VESSEL (WITHOUT RVLIS)

INTRODUCTION

Upon entry to ES-0.4, NATURAL CIRCULATION COOLDOWN WITH STEAM VOID IN VESSEL (WITHOUT RVLIS), natural circulation of the RCS has been verified and a cooldown/depressurization has been initiated (see procedure ES-0.2, NATURAL CIRCULATION COOLDOWN). The purpose of this procedure is to continue plant cooldown and depressurization to cold shutdown under conditions that allow for the potential formation of a void in the upper head region. There should be no accident in progress and no reactor vessel level system available to monitor the size of any vessel void.

This procedure is entered from ES-0.2, NATURAL CIRCULATION COOLDOWN, when it has been determined that a cooldown/depressurization must be performed at a rate that may form a steam void in the vessel. In any case, the first eleven steps of ES-0.2 must be completed prior to entering this procedure.

There are two transitions out of this procedure. The first occurs if SI is actuated. In this instance a transition to E-0, REACTOR TRIP OR SAFETY INJECTION, should be made. The second transition occurs if an RCP can be started. The first step of the procedure attempts to start an RCP. If this attempt is successful a transition to appropriate plant procedures is performed.

DESCRIPTION

The objective of ES-0.4, NATURAL CIRCULATION COOLDOWN WITH STEAM VOID IN VESSEL (WITHOUT RVLIS), is to permit a natural circulation cooldown and depressurization of the RCS while allowing and controlling the formation of voids in the vessel.

During the St. Lucie Unit 1 plant cooldown under natural circulation conditions (June 11, 1980), it was evident that void formation occurred in the upper head region. Using the information obtained from this event and the subsequent analyses performed for Westinghouse plants, the procedure ES-0.4 was developed to enable the operator to perform a natural circulation cooldown/depressurization with upper head void growth.

If it is necessary to cool down and depressurize the RCS quickly under natural circulation conditions (e.g., due to limited condensate storage), procedure ES-0.4 is the appropriate alternative to ES-0.2 if there is no RVLIS available to monitor void growth. If a rapid RCS cooldown/depressurization is desired and RVLIS instrumentation is available, ES-0.3, NATURAL CIRCULATION COOLDOWN WITH STEAM VOID IN VESSEL (WITH RVLIS) is to be used.

Though there is no analysis to support the technique employed in ES-0.4, specific symptoms are relied upon to indicate that void growth is restricted to the upper head/upper plenum region, above the top of the hot legs, so as not to disrupt the natural circulation flow. The growth of the vessel void is inferred from PRZR level indications. Initially a low PRZR level is established to accommodate void growth.

PRZR level changes from inventory shrinkage and void growth are accounted for separately with a step-by-step cooldown/depressurization technique. This technique is based on the concept of meeting Technical Specification cooldown requirements and not creating a saturated primary system (as measured at the hot legs). The goal is to reach RHR operating conditions in as few steps as possible but with no challenges to the LTOP or saturation curve requirements.

At no time is it appropriate to make a transition to FR-I.3, RESPONSE TO VOIDS IN REACTOR VESSEL, and perform a head venting operation. This is contrary to the intent of procedure ES-0.4 where a vessel void is allowed to exist under controlled conditions while the plant is cooled down and depressurized to cold shutdown. If procedure FR-I.3 was used to vent the vessel head at this time, the steam void would not be eliminated. As pressure decreases (from venting), more water will flash to steam in the head region, replacing the steam that was vented. The void size will remain essentially constant and the net result will be a loss of system inventory. Therefore, procedure FR-I.3 should not be used when cooling down and depressurizing the system with procedure ES-0.4.

It should be noted that although procedure ES-0.4 is the approved guidance for natural circulation cooldown/depressurization with a vessel void, procedure ES-0.2 presents the preferred mode of operation (i.e., no void formation) and should be used whenever possible.

MAJOR ACTION CATEGORIES IN ES-0.4

- Try to Start an RCP

- Cool Down and Depressurize RCS While Controlling Void Growth

Before cooling down and depressurizing the RCS, a pressurizer level is established to accommodate void growth. During the cooldown/depressurization phase, a step-by-step cooldown and depressurization is performed in order not to violate the Technical Specification (LTOP) cooldown curve or the saturation curve limitations. To monitor void growth and maintain pressure control, pressurizer level is maintained below 90%. During RCS depressurization the required RCP seal injection flow is maintained, and charging and letdown flows are balanced for strict control of primary inventory.

- Lock Out SI System

- Place RHR System in Service

- Cool Down to Cold Shutdown

STEAM GENERATOR TUBE RUPTURE

INTRODUCTION

Of all classic accidents, steam generator tube failures have occurred the most frequently. In fact, if previous trends continued, every Westinghouse PWR could expect to experience at least one steam generator tube failure during the lifetime of the plant. Of course, the nuclear industry has implemented many programs to reduce the incidents of tube failures, such as secondary side inspections, improved steam generator designs and water chemistry control, and more reliable eddy current tube inspection techniques. Nevertheless, a steam generator tube failure probably will remain one of the more likely accidents. A steam generator tube failure provides a direct release path for contaminated primary coolant to the environment via the secondary side relief valves. Accumulation of water in the secondary side can also lead to an overfill condition which can severely aggravate the radiological consequences and increase the likelihood of complicating failures. Timely operator intervention is necessary to limit the radiological releases and prevent steam generator overfill. So, to provide the operator with the best possible tools for dealing with these accidents, a series of Optimal Recovery Procedures (ORPs) were developed to address steam generator tube failures (E-3 series). These procedures contain instructions for limiting primary-to-secondary leakage and minimizing radiological releases following tube failures in one or more steam generators.

Unlike other loss of coolant accidents (LOCA), a steam generator tube failure demands substantial operator involvement early in the event. In order to expedite recovery, the ORP hierarchy directs the operator to the E-3 series procedures whenever symptoms of a tube failure exist, such as high secondary side activity or an uncontrollably increasing steam generator water level. In this respect, it is similar to the E-2, "FAULTED STEAM GENERATOR ISOLATION" procedure. However, unlike E-2, the optimal recovery scheme following tube failure strongly depends on coincident failures.

Consequently, the E-3 series procedures must be general enough to address a wide variety of multiple failures, such as tube failures in combination with other LOCAs or secondary side breaks. Yet, the procedures must also be sufficiently specific to ensure prompt operator response.

This apparent conflict was resolved by structuring the E-3 series into procedures which address two major categories of events: 1) those events for which leakage from the RCS can be stopped prior to cold shutdown, and 2) those events for which leakage from the RCS will continue. Events such as tube failures in one or more steam generators, or tube failures in combination with secondary faults in non-ruptured steam generators would belong to this first group. Instructions for responding to this event-type are provided in E-3, "STEAM GENERATOR TUBE RUPTURE", and ECA-3.3, "SGTR WITHOUT PRZR PRESSURE CONTROL". The second group is characterized by multiple events such as tube failures in combination with other LOCAs or a secondary break in a steam generator with failed tubes. The contingency guidelines ECA-3.1, "SGTR WITH LOSS OF REACTOR COOLANT-SUBCOOLED RECOVERY DESIRED", provide guidance for stopping leakage of reactor coolant for this event group. The principle difference between the recovery methods for the two event categories involves termination of SI. For the E-3 recovery, the SI pumps are all stopped concurrently to minimize primary-to-secondary leakage and avoid steam generator overfill.

Since for this event type leakage from the RCS is also terminated, there is no concern of depleting RCS inventory. For the second event group, ECCS pumps are stopped sequentially (ECA-3.3 and ECA-3.2) when conditions indicate that the reduced ECCS flow will be sufficient to maintain adequate coolant inventory.

The E-3 series procedures have been simplified further by incorporating common recovery actions into the E-3 procedure. In general, these actions are limited to identification and isolation, if possible, of the ruptured steam generators. Although other common actions exist it is not certain that they would be completed prior to transitioning from the E-3 procedure. Consequently, some redundancy does exist. With this structure, the E-3 procedure becomes the focal point for the E-3 series. Similarly, entries to the E-3 contingency actions occur only after entry into the E-3 procedure. The symptoms which govern these transitions are based on the expected system response to a steam generator tube rupture and subsequent recovery actions.

The E-3 procedure contains instructions to minimize releases and to terminate primary-to-secondary leakage following tube failures in one or more steam generators. The following sections describe the plant response to a steam generator tube failure and the basis for subsequent recovery actions, and identifies any special knowledge requirements. The causes of tube failures will not be discussed since the mechanism of tube failure once it has occurred does not influence recovery actions.

DESCRIPTION

A steam generator tube rupture event begins as a breach of the primary coolant barrier between the reactor coolant system and the secondary side of the steam generator, i.e., the steam generator tube. Although this relatively thin barrier is designed with substantial safety margin to preclude bursting even when subjected to full primary system pressure, the harsh secondary side environment may attack the steam generator tubes resulting in excessive tube wall thinning or cracking over time. Although improved secondary side chemistry has greatly reduced the frequency of tube failures attributed to chemical corrosion, foreign objects in the steam generator secondary have resulted in relatively rapid tube degradation and eventually tube failure in the previous two events [Prairie Island (1979) and Ginna (1982)].

Since the primary system pressure (nominally 2235 psig) is initially much greater than the steam generator pressures (nominally 1000 psig) reactor coolant flows from the primary into the secondary side of the affected steam generator. In response to this loss of reactor coolant, pressurizer level decreases at a rate which is dependent upon the size and number of failed tubes. RCS pressure also decreases as the steam bubble in the pressurizer expands. For normal operation, charging flow will automatically increase and pressurizer heaters will energize in an effort to stabilize pressure and level. However, if leakage exceeds the capacity of the Chemical and Volume Control System, reactor coolant inventory will continue to decrease and eventually lead to an automatic reactor trip signal on low pressurizer pressure or, possibly, overtemperature - ΔT. Prior to this, normal letdown flow would isolate, and pressurizer heaters would turn off on low pressurizer level.

On the secondary side, leakage of contaminated primary coolant will increase the activity of the secondary coolant resulting in high radiation indications from the air evacuation radiation monitor and steam line radiation monitors. Although these alarms may lag indications of a loss of reactor coolant, depending on the transport time to the radiation monitors, they have sounded nearly simultaneously during past tube failure events and generally provide the earliest diagnosis of a steam generator tube rupture. As primary coolant accumulates in the affected steam generator, normal feedwater flow is automatically reduced to compensate for high steam generator level. Consequently, a mismatch between steam flow from and feedwater flow to the affected steam generator may be observed. This potentially provides early confirmation of a tube failure event and also identifies the affected steam generators. However, such a mismatch may not be noticeable for smaller tube failures because of the relatively large normal feedwater/steam flow rates. The water level in the affected steam generators may not be significantly greater than that of the intact steam generators and may be somewhat erratic prior to reactor trip as the normal feedwater control system automatically compensates for changes in steam flow rate and steam generator level due to primary-to-secondary leakage.

The time between initial tube failure and reactor trip also depends on the leak rate. In most cases sufficient time will be available (greater than 3 minutes) for the operator to perform a limited number of actions to either prevent or prepare for reactor trip. Such actions are likely to include starting additional charging pumps, energizing pressurizer heaters if not done automatically, reducing the load on the turbine, and possibly manual reactor trip. These actions, with the exception of manual reactor trip, will tend to delay an automatic trip signal. In addition, these actions can have a significant effect on the system response following reactor trip which may impact the longer term recovery. For example, as turbine load reduction proceeds, the mismatch between core power and turbine load causes the average coolant temperature (Tavg) to increase until the rod control and steam dump systems actuate to restore programmed Tavg. Although the reference Tavg decreases with turbine load, a period of time may exist when Tavg is greater than nominal full power conditions. If reactor trip occurs during this time, the cooldown of the primary system, when the steam dump system actuates to establish no-load conditions, is enhanced. This may result in a significantly lower minimum RCS pressure following reactor trip which may satisfy the criteria for tripping the RCPs. In addition, the combination of delayed reactor trip and reduced steam flow due to turbine load runback may result in a greater steam generator inventory when recovery actions are initiated. This would reduce the time available to steam generator overfill.

Following reactor trip, core power rapidly decreases to decay heat levels, steam flow to the turbine is terminated, and the steam dump system actuates to establish no-load coolant temperatures in the primary system. Shortly thereafter, the normal feedwater control system throttles feedwater flow in response to reduced steam flow. The RCS pressure decreases more rapidly as sensible energy transfer to the secondary shrinks the reactor coolant and tube rupture flow continues to deplete primary inventory. This decrease in RCS pressure results in a low-low pressurizer pressure SI signal soon after reactor trip. Normal feedwater flow is automatically isolated on the SI signal which also actuates the Emergency

Feedwater. System to deliver flow to all steam generators. Eventually, manual action is required to adjust EFW flow to maintain the steam generator water level on the narrow range span.

Secondary side pressure will increase rapidly after reactor trip as automatic isolation of the turbine momentarily stops steam flow from the steam generators. Normally, automatic steam dump to the condenser would actuate to dissipate energy transferred from the primary, thereby limiting the secondary pressure increase. Since the intact and ruptured steam generators communicate via the main steam header, no significant difference in pressures will be evident at this time. Initially SI flow and EFW flow will absorb decay heat and decrease the reactor coolant temperature below no-load until EFW flow is manually throttled to maintained steam generator level in the narrow range. This will also terminate steam flow and may cause the steam generator pressures to slowly decrease as the cold EFW condenses steam. At low decay heat levels or for multiple tube failures the reactor coolant temperature may continue to decrease even after EFW flow is throttled due to SI flow.

Pressurizer level decreases more rapidly following reactor trip as the reactor coolant shrinks during the post-trip cooldown and primary-to-secondary leakage continues to deplete coolant inventory. Although the minimum pressurizer level is dependent upon a number of parameters, including initial pressurizer level, initial power level, the size of the tube failure, operation of pressurizer heaters, and pre-trip operator actions, it is likely that level will be offscale low when SI is actuated. With SI actuated, the primary system will tend toward a equilibrium condition where break flow and coolant shrinkage are matched by SI flow. If break flow and shrinkage are initially greater than SI flow, pressurizer level and pressure will continue to decrease until quasi-equilibrium conditions are reached. In some cases, such as multiple tube failures or reduced SI capacity, RCS pressure may momentarily decrease to saturation until SI flow and EFW flow cool the primary system below the saturation temperature of the steam generators. Conversely, if SI flow exceeds primary-to-secondary leakage and coolant shrinkage, the pressurizer level and pressure will increase until equilibrium is achieved. The equilibrium RCS pressure depends on the size of the tube failures, capacity of the SI system, and cooldown rate of the primary. However, since leakage from the RCS is a function of both pressure and temperature, no true equilibrium pressure exists unless the reactor coolant temperature also remains constant. Consequently, RCS pressure may continue to slowly decrease until reactor coolant temperatures are stabilized.

The pressurizer may refill to a relatively high level prior to operator intervention if the tube failure is small. However, in the more likely case, pressurizer level will return on span but will equilibrate at a value significantly below nominal level. A point of confusion often noted occurs during simulation of a steam generator tube failure event where pressurizer level continues to increase toward an overfill condition following actuation of the SI system. While admittedly such behavior could occur for small tube failures in high-pressure plants, in some cases this response has been attributed to modelling limitations of the pressurizer. The operator should be aware that although filling of the pressurizer is possible, it is not generally expected. It should also be clear that the reactor coolant temperature trend and operator actions such as throttling EFW flow, will effect the pressurizer level.

As previously mentioned, the steam generator level may drop out of the narrow range following reactor trip. EFW flow, which is automatically actuated on an SI signal or low-low SG level, will begin to refill the steam generators, distributing approximately equal flow to all steam generators.

Since primary-to-secondary leakage adds additional inventory which accumulates in the ruptured steam generators, level should return to the narrow range in those steam generators significantly earlier and will continue to increase more rapidly. This response provides confirmation of a steam generator tube rupture event and also identifies the affected steam generators. Although these symptoms will be evident very soon after reactor trip for larger tube failures, for smaller tube failures in one or more steam generators the steam generator level response may not be noticeably different or may be masked by non-uniform EFW flows. In that case, high radiation indications may be necessary for positive identification of the ruptured steam generator. In such instances, the break flow would be less and, consequently, more time would be available for recovery prior to filling the affected steam generators with water.

SGTR TRANSIENT: OFFSITE POWER UNAVAILABLE

The principle systems/components affected by a coincident station blackout are the steam dump system, Reactor Coolant Pumps (RCPs), and RCS pressure control. The effect of each of these on the system response and recovery is discussed.

The steam dump system is designed to actuate following loss of load or reactor trip to limit the increase in secondary side pressure. Without offsite power available, the steam dump valves, which bypass the turbine to the condenser, will remain closed. Hence, energy transferred from the primary will rapidly increase steam generator pressures after reactor trip until the atmospheric relief valves lift to dissipate this energy. Since the secondary side temperature increase is greater, sensible energy transfer from the primary side following reactor trip is reduced. Consequently, RCS pressure decreases more slowly, so that SI actuation and most attendant automatic actions are delayed.

RCPs trip on a loss of offsite power and a gradual transition to natural circulation flow ensues. The cold leg temperature trends toward the steam generator temperature as the fluid residence time in the tube region increases. Initially, the core temperature rise decreases as core power decays following reactor trip and subsequently increases as RC Loop flow transitions to stable natural circulation. Without RCPs running the upper head region becomes inactive and the fluid temperature in that region will significantly lag that in the active RCS regions. In addition, subsequent actions to isolate the affected steam generators and cool down the intact RCS loops may stagnate the loop. Consequently, the hot leg fluid in that loop may remain significantly warmer than in the unaffected loops. Similarly, SI flow into the stagnant loop cold leg may rapidly decrease the fluid temperature in adjacent regions significantly below the rest of the RCS, as observed during the tube failure event at R. E. Ginna.

RECOVERY/RESTORATION TECHNIQUE

The automatic protection systems are more than sufficient to maintain adequate core cooling even for multiple tube failures. However, extensive operator actions are required to stop primary-to-secondary leakage which, if not terminated expeditiously, could lead to a steam generator overfill condition. The system response to a steam generator tube failure before and immediately after reactor trip has been described. From this description, the symptoms which identify both the tube failure event and the affected steam generators should be evident, including high or increasing secondary side radiation, and steam generator level response. These symptoms provide the basis for diagnostics in the ERPs which are used to direct the operator to the E-3 procedure.

The objectives of the recovery restoration technique incorporated into procedure E-3 are to limit the release of radioactive effluents from the ruptured steam generators, stop primary-to-secondary leakage to prevent steam generator overfill, and restore reactor coolant inventory to ensure adequate core cooling and plant control. Although many other techniques may achieve any one of these goals equally well, the guidance in E-3 presents the best approach for balancing all of these objectives for a wide variety of events. Inherent safety features, such as unambiguous SI termination and reinitiation criteria, guarantee effective recovery actions for credible multiple failure events and proper remedial actions for misdiagnosis or error.

MAJOR ACTION CATEGORIES IN E-3

- Identify and Isolate Ruptured SG(s)
- Establish RCS Subcooling Margin
- Depressurize RCS to Restore Inventory
- Terminate SI to Stop Primary-to-Secondary Leakage
- Prepare for Long Term Cooldown

• <u>Identify and Isolate Ruptured SG(s)</u>

Once a tube failure has been identified, recovery actions begin by isolating steam flow from and stopping feedwater flow to the affected steam generators. In addition to minimizing radiological releases, this also reduces the possibility of filling the affected steam generator with water by 1) minimizing the accumulation of feedwater flow and 2) enabling the operator to establish a pressure differential between the ruptured and intact steam generators as a necessary step toward terminating primary-to-secondary leakage. With steam flow and feedwater flow terminated, the affected steam generator pressure will slowly increase thereafter as primary-to-secondary leakage compresses the steam bubble in the steam generator. Although this response is not demonstrated in the available analysis results, actual plant experience exhibits this behavior. Eventually a steam generator atmospheric steam dump valve would lift unless actions to stop leakage into the affected steam generator are completed.

• <u>Establish RCS Subcooling Margin</u>

After isolation of the ruptured steam generators, the RCS is cooled to less than saturation at the ruptured steam generator pressure by dumping steam from only the intact steam generators. This ensures adequate subcooling in the RCS after depressurization to the ruptured steam generator pressure in subsequent actions. With offsite power available, the normal steam dump system to the condenser provides sufficient capacity to perform this cooldown rapidly. RCS pressure will decrease during this cooldown as shrinkage of the reactor coolant expands the steam bubble in the pressurizer. For multiple tube failures, RCS pressure may decrease to less than the ruptured steam generator pressure as steam voids, which were generated in the RCS during the initial depressurization, condense. Reverse flow, i.e. secondary-to-primary leakage, during this time would reduce the inventory in the ruptured steam generators and delay steam generator overfill.

- <u>Depressurize RCS to Restore Inventory</u>

When the cooldown is completed, SI flow again increases RCS pressure toward an equilibrium value where break flow matches SI flow. Consequently, SI flow must be terminated to stop primary-to-secondary leakage. However, the operator must first ensure adequate coolant inventory. This includes both sufficient reactor coolant subcooling and pressurizer inventory to maintain a reliable pressurizer level indication after SI flow is stopped. Since leakage from the primary side will continue until RCS and ruptured steam generator pressures equalize an "excess" amount of inventory, which depends on RCS pressure, is required before stopping SI flow. To establish sufficient inventory, RCS pressure is decreased by condensing steam in the pressurizer using normal spray. This increases SI flow and reduces break flow which refills the pressurizer.

For multiple tube failures, RCS pressure may decrease below the ruptured steam generator pressure before pressurizer level returns on span. In that case, reverse flow through the failed tubes will supplement SI flow in refilling the pressurizer. Conversely, for smaller tube failures, pressurizer inventory may be sufficient for SI termination prior to depressurizing the RCS so that actions to restore inventory would not be necessary.

• Terminate SI to Stop Primary-to-Secondary Leakage

Previous actions were designed to establish adequate RCS subcooling, secondary side heat sink, and reactor coolant inventory to ensure SI flow is no longer required. When these actions have been completed, SI flow must be stopped to prevent repressurization of the RCS and to terminate primary-to-secondary leakage. With SI flow stopped, residual break flow will reduce RCS pressure to equilibrium with the ruptured steam generator. RCS temperature, pressurizer level, and affected steam generator levels will stabilize.

• Prepare for Long Term Cooldown to Cold Shutdown

Following SI termination, the plant will stabilize near hot shutdown conditions and all immediate safety concerns will have been addressed. At this time a series of operator actions must be performed to prepare the plant for cooldown to cold shutdown conditions. These actions include restoring normal CVCS operation, minimizing the spread of contamination throughout the secondary side, and starting an RCP if necessary to ensure uniform cooldown and boron concentration. The operator must also select the best post-SGTR cooldown method based on an evaluation of the plant status. Considerations for selecting either ES-3.1, POST-SGTR COOLDOWN USING BACKFILL", ES-3.2, "POST-SGTR COOLDOWN USING BLOWDOWN", or ES-3.3, "POST-SGTR COOLDOWN USING STEAM DUMP" are discussed next.

E-3 STEAM GENERATOR TUBE RUPTURE

METHOD OF RECOVERY

- SHOULD RCPs BE STOPPED
- IDENTIFY RUPTURED SG(s)
- ISOLATE RUPTURED SG
- PRZR PORVs AND BLOCK VALVES PROPERLY POSITIONED
- ANY SGs FAULTED
- RESET SI AND ESTABLISH CTMT AIR
- ALL AC BUSSES POWERED FROM OFFSITE
- SECURE RHR PUMPS IF NOT NEEDED
- CHECK RUPTURED SG(s) PRESSURE
- COOLDOWN RCS AT MAXIMUM RATE
- RUPTURED SG PRESSURE STABLE OR INCREASING
- RCS SUBCOOLING ADEQUATE
- DEPRESSURIZE RCS
- SI TERMINATION CRITERIA MET
- CHARGING/LETDOWN ESTABLISHED
- SI FLOW REQUIRED
- MINIMIZE RCS-TO-SECONDARY LEAKAGE
- SHUTDOWN UNNECESSARY PLANT EQUIPMENT (CONDENSATE, HEATER DRAIN)
- GO TO APPROPRIATE POST-SGTR COOLDOWN METHOD

ES-3.1 POST-SGTR COOLDOWN USING BACKFILL

PURPOSE OF PROCEDURE

- FOLLOWING AN SGTR
  - COOLDOWN PLANT TO COLD SHUTDOWN CONDITIONS
  - DEPRESSURIZE THE PLANT
- DEPRESSURIZE RUPTURED SG BY BACKFILL FROM RUPTURED SG TO RCS

ENTRY INTO PROCEDURE

- PLANT STAFF SELECTS BACKFILL METHOD
  - E-3, STEP 38
- BLOWDOWN NOT AVAILABLE AND PLANT STAFF SELECTS BACKFILL METHOD
  - ES-3.2, STEP 9

ES-3.1 POST-SGTR COOLDOWN USING BACKFILL

METHOD OF RECOVERY

- REGAIN PRZR PRESSURE CONTROL
- ISOLATE ACCUMULATORS IF NOT NEEDED
- RCS SDM ADEQUATE
- INTACT SG LEVELS IN NR
- COOLDOWN RCS TO COLD SHUTDOWN
- DEPRESSURIZE RCS TO BACKFILL FROM RUPTURED SG
- PLACE RHR SYSTEM IN SERVICE
- STOP RCPs WHEN REQUIRED
- EVALUATE LONG TERM PLANT STATUS

ES-3.2 POST-SGTR COOLDOWN USING BLOWDOWN

PURPOSE OF PROCEDURE

- FOLLOWING AN SGTR
  - COOLDOWN PLANT TO COLD SHUTDOWN CONDITIONS
  - DEPRESSURIZE THE PLANT
- DEPRESSURIZE RUPTURED SG BY DRAINING WITH BLOWDOWN

ENTRY INTO PROCEDURE

PLANT STAFF SELECTS BLOWDOWN METHOD

- E-3, STEP 38

ES-3.2 POST SGTR COOLDOWN USING BLOWDOWN

METHOD OF RECOVERY

- REGAIN PRZR PRESSURE CONTROL
- ISOLATE ACCUMULATORS IF NOT NEEDED
- RCS SDM ADEQUATE
- INTACT SG LEVELS IN NR
- INITIATE RCS COOLDOWN
- MINIMIZE RCS-TO-SECONDARY LEAKAGE (RCS PRESSURE AND MAKEUP CONTROL)
- ESTABLISH RUPTURED SG BLOWDOWN
- DEPRESSURIZE RCS (MINIMIZE RCS-TO-SECONDARY LEAKAGE)
- STOP RCPs WHEN REQUIRED
- PLACE RHR SYSTEM IN SERVICE
- CONTINUE RCS COOLDOWN TO COLD SHUTDOWN
- EVALUATE LONG TERM PLANT STATUS

ES-3.3 POST-SGTR COOLDOWN USING STEAM DUMP

PURPOSE OF PROCEDURE

- FOLLOWING AN SGTR
  - COOLDOWN PLANT TO COLD SHUTDOWN CONDITIONS
  - DEPRESSURIZE THE PLANT
- DEPRESSURIZE RUPTURED SG BY DUMPING STEAM

ENTRY INTO PROCEDURE

- PLANT STAFF SELECTS STEAM DUMP METHOD
  - E-3, STEP 38
- BLOWDOWN NOT AVAILABLE AND PLANT STAFF SELECTS STEAM DUMP METHOD
  - ES-3.2, STEP 9

ES-3.3 POST-SGTR COOLDOWN USING STEAM DUMP

METHOD OF RECOVERY

- REGAIN PRZR PRESSURE CONTROL
- ISOLATE ACCUMULATORS IF NOT NEEDED
- RCS SDM ADEQUATE
- INTACT SG LEVELS IN NR
- INITIATE RCS COOLDOWN
- MINIMIZE RCS-TO-SECONDARY LEAKAGE (RCS PRESSURE AND MAKEUP CONTROL)
- DUMP STEAM FROM RUPTURED SG
- DEPRESSURIZE RCS (MINIMIZE RCS-TO-SECONDARY LEAKAGE)
- STOP RCPs WHEN REQUIRED
- PLACE RHR SYSTEM IN SERVICE
- CONTINUE RCS COOLDOWN TO COLD SHUTDOWN
- EVALUATE LONG TERM PLANT STATUS

SPECIAL TOPICS

This section of ERP training discusses various topics concerning plant emergency responses that the operator is confronted with in the ORGs, ECAs and FRPs. For the most part, the trained operator is expected to know the capabilities and limitations of plant equipment and what alternatives exist should that equipment be inoperable or ineffective. He is also expected to understand the integrated plant limitations resulting for accident induced transients.

In many cases, a dozen or more variables combine to create potentially dangerous situations for the plant and its equipment. The ERPs are designed to handle these situations in conjunction with the operator. The operator's role consists of observing, monitoring, controlling and deciding (when options are given to accomplish a task). This operator decision responsibility is predicated on the assumption that the operator has the knowledge to select the most appropriate option.

In other cases, the deciding function of the operator is less important. An example of this is the CRITICAL SAFETY FUNCTIONS. When a CSF is challenged, the operator is instructed in detail on a pre-analyzed action to be taken. However, the operator must still be well informed and understand the bases for these mandatory actions and the consequences if prompt actions are not taken.

Special Topics for further discussion include the following:

- SI Termination and Reinitiation Criteria

- RCP Trip Criteria

- RCP Restart Requirements/Interlocks

- RCS Pressure Reduction Methods - Limitations, Advantages/Disadvantages

  1. Normal Spray

  2. PORVs

  3. Auxiliary Spray

- RCS Pressure - Temperature Limitations

- Pressurized Thermal Shock (PTS)

- Hydrogen Venting from RCS

- Loss of Emergency Coolant Recirculation

Background Information

for

SI TERMINATION AND REINITIATION CRITERIA

INTRODUCTION

For the most part, SI (ECCS) Termination and Actuation Criteria is specifically stated in the applicable ERPs in at least one place. However, the operator should know that the criteria can vary depending on the plant status.

DISCUSSION

SI termination conditions, if applicable for a particular ERP, are given in the procedure text at the appropriate step. In cases when automatic SI actuation has occurred from the SSPS, and the RCS proves to be intact, a detailed SI TERMINATION procedure is provided.

IN GENERAL, SI termination can only be done if RCS subcooling is restored and if pressurizer level and pressure control is restored.

SI reinitiation conditions, if applicable for a particular ERP, are given in at least two places in the procedure. One place includes the OPERATOR ACTION SUMMARY which appears on the back side of certain applicable procedure pages. Therefore, it will always be visible to the operator at any step in the procedure.

IN GENERAL, the operator must reinitiate SI if RCS Subcooling decreases to LESS THAN 30°F <u>OR</u> if Pressurizer Level CANNOT BE MAINTAINED IN RANGE.

An example OPERATOR ACTION SUMMARY is provided for reference on the following page.

OPERATOR ACTION SUMMARY FOR E-0 SERIES PROCEDURES

1. RCP TRIP CRITERIA

Trip all RCPs if any conditions listed below occur:

CCPs or SI pumps - AT LEAST ONE RUNNING
- AND -
RCS Subcooling - LESS THAN 30°F

- Phase B containment isolation (loss of PCCW)
- RCP seal ΔP - LESS THAN 220 PSID
- RCP #1 seal leakoff flows - LESS THAN 0.2 GPM

2. SI ACTUATION CRITERIA

Actuate SI and go to E-0, REACTOR TRIP OR SAFETY INJECTION, Step 1, if EITHER condition listed below occurs:

• RCS Subcooling - LESS THAN 30°F
- OR -
• Pressurizer level - CANNOT BE MAINTAINED GREATER THAN 5% [30% FOR ADVERSE CONTAINMENT]

3. EFW SUPPLY

Commence CST makeup as soon as possible to avoid low inventory problems.

4. RED PATH SUMMARY - ATTACHMENT B

5. KEY CAUTIONS

- If SI actuation occurs during this procedure, E-0, REACTOR TRIP OR SAFETY INJECTION, should be performed,
- Do not cooldown plant by overfeeding SGs.
- On natural circulation, RTD bypass temperatures and associated interlocks will be inaccurate.

Background Information

for

REACTOR COOLANT PUMP TRIP CRITERIA

INTRODUCTION

An issue that arose subsequent to the Three Mile Island incident concerned the effect of prolonged operation of the reactor coolant pumps (RCPs) during a small break loss of coolant accident (LOCA). Extensive analyses have been performed for Westinghouse designed PWRs to evaluate the effect of delayed RCP trip during small break LOCAs. These analyses were performed utilizing the Westinghouse Small Break Evaluation Model. In the study, a range of break sizes and locations assuming various RCP trip times was considered.

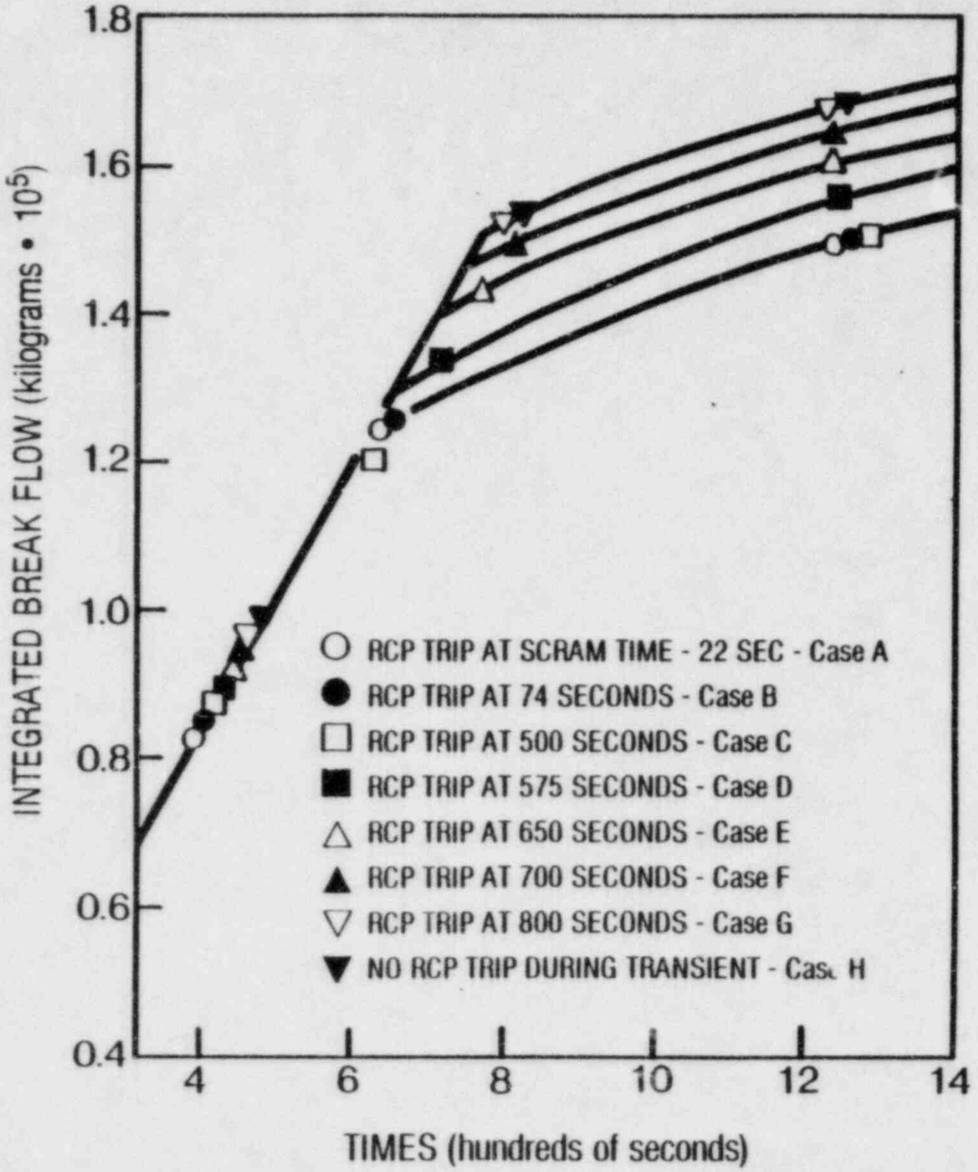
Evaluation of the cases indicate two distinct characteristic behavior modes depending on RCP trip time. This trend is made evident by Figure 1 which presents integrated break discharge mass versus time. The change of slope of each curve of Figure 1 represents a shift in break flow steam quality from nearly zero to one, as the reactor coolant system (RCS) drains to the break elevation. Case A is the FSAR 3 inch break calculation for a 3-loop plant design, which assumes RCP trip at the time of reactor trip. Cases B and C represent analyses in which RCP trip still occurs prior to the time of RCS drain to the break elevation in the FSAR calculation. Figure 1 illustrates that the differences in the integrated break discharge characteristics are insignificant for these cases. Therefore, the liquid mass inventory remaining in the RCS is also comparable, yielding PCTs similar to FSAR Case results, well below the regulatory limit of 2200°F.

Cases D through G represent transients in which the RCPs remain operational beyond the time of RCS drain to the break elevation for Case A and demonstrate significant differences in the integrated break discharge

TOTAL MASS LOSS VS. TIME

(3 loop design
3 inch diameter,
cold leg break)

FIGURE OP (TC Rev 0 3/84)

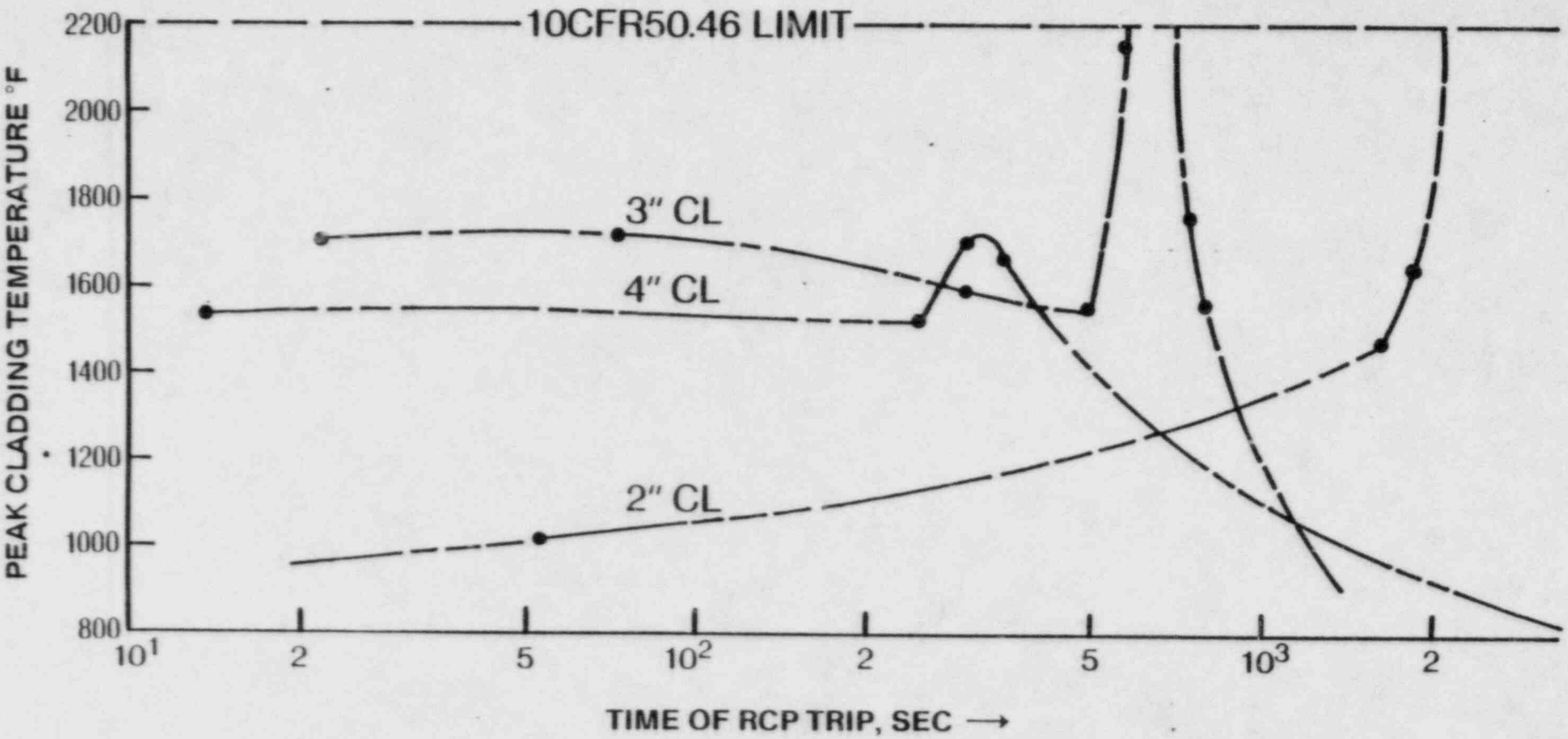


transient. Forced loop flowrates induced by RCP operation maintain the inner vessel mixture level above the hot leg nozzle elevation. This allows for continued circulation of liquid around the loops, providing a source of liquid to the break region. Therefore, as the RCS drains, continued RCP operation prolongs the period of liquid break discharge. The difference in time of the slope change for the delayed RCP trip cases is additional time of liquid break discharge. The prolonging of the liquid break discharge further depletes the liquid mass inventory remaining in the RCS. Immediately following RCP trip for these cases, loop flowrate decreases and phase separation occurs. A rapid reduction in RCS mixture level results, which may partially uncover the fuel. Prolonged RCP operation and the resultant additional liquid mass depletion can greatly affect the core uncovery characteristics. Depending on plant type and break size, an interval of RCP trip times may yield PCTs greater than the FSAR case result. The effect of RCP trip time on calculated PCTs is illustrated in Figure 2.

If RCPs remain operational throughout the transient (Case H of Figure 1) depletion of primary liquid mass is maximized. Nevertheless, PCTs remain well below FSAR Case results due to enhanced core cooling caused by the high core steam flowrates indicative of RCP operation. However, operation of the RCPs continuously post-LOCA cannot be guaranteed and failure of the RCPs may be postulated to occur at any time. <u>The purpose of tripping the RCPs during accident conditions is to prevent unnecessary depletion of RCS water inventory through a small break in the RCS which could lead to severe core uncovery if the RCPs were tripped for some reason later in the accident</u>. The RCPs should be tripped before the RCS inventory is depleted

EFFECT OF PUMP TIME ON PEAK CLADDING TEMPERATURE FOR A THREE LOOP PLANT

FIGURE OP (TC Rev 0 3/84)



to the point where tripping of the pumps causes the break to immediately uncover by allowing the RCS liquid inventory to settle in the low places of the RCS below the break elevation.

It is possible to utilize a conservative criterion to assure that the RCPs are tripped early in a small break LOCA transient. However, the use of this conservative criterion would also result in RCP trip for a steam generator tube rupture (SGTR) and other non-LOCAs for which it is desirable to keep the pumps running. It is desirable to keep the RCPs running during these transients to maintain normal pressure control using pressurizer spray and avoid opening of the pressurizer PORVs for this purpose, to prevent the formation of a stagnant water volume in the upper head region which may flash and form a steam bubble during subsequent cooldown and depressurization, to minimize potential pressurized thermal shock challenges, and to minimize operator actions such as tripping the RCPs and then restarting them later. Thus, it would be beneficial to develop a RCP trip criterion which would ensure pump trip for the range of small break LOCAs where pump trip is required, but would not lead to pump trip for most SGTRs and non-LOCAs. However, it would not be a safety problem if RCP trip should occur for a SGTR or non-LOCA event, since the plant safety systems design and FSAR analysis for these accidents are based on concurrent loss of offsite power, and therefore on RCP trip.

In NRC Generic Letters, the NRC addressed the question of developing RCP trip setpoints which would not require RCP trip for those transients and accidents where forced circulation and pressurizer pressure control is a major aid to the operator, yet would alert the operators to trip the RCPs for those small LOCAs where continued operation or delayed trip might result in core damage. The NRC concluded that the need for RCP trip following a transient or accident should be determined by each plant, considering the Owners Group input, and provided guidance for the development of satisfactory RCP trip setpoints. This guidance indicated that the setpoints should be designed to assure that the RCPs will be tripped for all LOCAs in which RCP trip is considered necessary, but should also ensure continued forced RCS flow during SGTRs up to and including the desig basis tube rupture. The associated evaluation should be capable of demonstrating and justifying that the proposed RCP trip setpoints are adequate for small LOCAs, but will not result in RCP trip for other non-LOCA transients and accidents (e.g., SGTRs).

Thus, it is necessary to establish an RCP trip criterion which can be used to provide an indication for the operator to trip the RCPs following an accident. The criterion must be capable of providing an indication of the need for RCP trip for small break LOCAs, but the criterion should not indicate the need for RCP trip for most SGTR and non-LOCA events

ALTERNATE RCP TRIP CRITERIA

For a small break LOCA, the RCP trip criterion must provide for pump trip before the RCS coolant inventory decreases to the point where the break would be uncovered when the pumps are tripped. Thus, parameters which are indicative of the RCS coolant inventory should be suitable for use as potential RCP trip criteria. The evaluation of alternate RCP trip criteria was limited to the potential criteria which can generally be implemented using existing qualified instrumentation. The alternate RCP trip criteria which were evaluated include RCS pressure, reactor coolant subcooling, and secondary pressure dependent RCS pressure.

In establishing the RCP trip setpoint for any of the potential criteria, the uncertainty in the instrumentation readings must be considered. One of the factors which can affect the instrument uncertainty is environmental conditions. The environmental conditions inside the containment following an accident can vary from normal conditions to the worst case post-accident conditions depending upon the type and severity of the accident. For the purpose of evaluating instrumentation uncertainties, adverse containment conditions have been defined as a pressure of approximately 5 psig or a radiation level of approximately 10^4 R/hr. Based upon instrumentation qualification studies, it has been determined that the normal instrument uncertainties can be used for containment conditions below these limits, but that the uncertainties associated with post-accident containment conditions should be used for pressures or radiation levels above these limits.

Although a major LOCA or secondary break inside containment may result in adverse containment conditions, there are many other non-LOCAs which are not expected to result in adverse containment conditions. In addition, a SGTR is not expected to result in adverse containment conditions. If adverse containment conditions exist, then the instrument uncertainties associated with post-accident containment conditions can be utilized in establishing the RCP trip setpoint, whereas normal instrument uncertainties can be used if adverse containment conditions do not exist. This requires the maintenance of two RCP trip setpoints, with the appropriate one being selected based on an indication of containment conditions. Since most SGTR and non-LOCA events are not expected to result in adverse containment conditions, the lower setpoint based on normal instrument uncertainties will reduce the likelihood of tripping the RCPs for these events.

The three potential RCP trip criteria which have been considered are discussed below.

- RCS PRESSURE CRITERION

The purpose of tripping the RCPs during accident conditions is to prevent unnecessary depletion of RCS water inventory through a small break in the RCS which could lead to severe core uncovery if the RCPs were tripped for some reason later in the accident. RCP operation does not lead to prolonged RCS liquid inventory loss to the break until the time is reached where tripping the RCP causes the break to immediately uncovery by allowing the RCS liquid inventory to settle in the low places of the RCS below the break elevation. The break cannot be uncovered until the steam generator tubes have begun to drain. Also, the steam generator tubes cannot begin draining until saturation pressure is reached at the top of the steam generator tubes. Only then is steam able to reside in the top of the steam generator tubes to volumetrically compensate for the falling liquid level.

Thus, the objective is to trip the RCPs at the time that saturation pressure is reached at the top of the steam generator tubes. The determination of this saturation pressure depends on the conditions in the primary system, the conditions in the steam generator secondary side, and the location and accuracy of the instrumentation used to make the determination.

A bounding decay heat level at 2 minutes after reactor trip will be used as one boundary condition to determine the primary system conditions. The value of decay heat at the time is about 3.5 percent. The RCP heat input to the primary system should also be included. With the RCPs operating, the primary system is able to transfer the 3.5 percent decay heat and RCP heat with a very small ΔT. However, the actual temperatures of the RCS will depend on the conditions in the steam generator secondary side.

The pressure in the steam generator secondary side will depend on the availability of the condenser for steam dump operation and the operability of the secondary ASDVs. The highest operating pressure of the steam generator secondary side will occur if the condenser is not available and the secondary ASDVs are not operable (e.g., loss of air supply) and the steam generator secondary side pressure is established by the safety valves. This is the steam generator secondary side condition that is chosen because with a concurrent small LOCA it will protect for the highest possible saturation pressure. Therefore, the secondary pressure is related to the steam generator safety valve set pressure.

The RCS indicated pressure that will be compared to the secondary pressure must be considered. The RCS wide range pressure which would be used for this purpose is normally measured in the hot leg (e.g., the RHR suction line). There is a pressure drop between the RCS pressure measurement location and the top of the steam generator tubes (where the occurrence of saturation is key), there is a pressure gradient across the steam generator tubes required for heat transfer, and there is a pressure drop from the steam generator to the secondary safety valves. Thus, the RCS pressure for RCP trip should be the secondary pressure established by the steam generator safety valves plus the calculated pressure differential from the secondary safety valves to the RCS pressure measurement location.

The appropriate instrument uncertainties should be added to the RCS pressure value established by the above procedure. For normal containment conditions, the normal instrument uncertainties should be used, whereas with adverse containment conditions, the instrument uncertainties associated with post-accident containment conditions should be used. The resulting pressure is the indicated RCS pressure at which the operator should trip the reactor coolant pumps, depending upon the containment conditions.

- RCS SUBCOOLING CRITERION

As discussed previously, RCP operation following a small break LOCA does not lead to prolonged RCS liquid inventory loss to the break until the time is reached where tripping the RCPs causes the break to immediately uncover. The break cannot be uncovered until a significant amount of voiding has occurred in the RCS. Since it is expected that voiding will occur first at the reactor outlet, it would not be required to trip the RCPs as long as subcooling is maintained in the RCS hot legs. The subcooling indication based on either the hot leg RTDs or the core exit thermocouples can be used for this purpose. To assure that pump trip indication is available before subcooling is actually lost, the instrument uncertainty for the plant subcooling monitor must also be considered. Thus, the RCP trip setpoint using a subcooling monitor would be zero degrees subcooling plus the instrument uncertainty.

The normal instrument uncertainties should be used to determine the RCP trip setpoint for normal containment conditions, and the instrument uncertainties based on post-accident containment conditions should be used to determine the setpoint for adverse containment conditions.

- SECONDARY PRESSURE DEPENDENT RCS PRESSURE CRITERION

In previous sections, an RCS pressure criterion was described to provide for tripping the RCPs at the time when saturation pressure is reached at the top of the steam generator tubes. The method of determining the RCS pressure setpoint is based on the conservative assumption that the secondary pressure is at the steam generator safety valve set pressure.

However, the secondary pressure may actually be less than this value, depending upon the availability of the steam dump system and the secondary ASDVs. With this method, the RCS pressure setpoint will be determined based on the actual steam generator pressure.

EVALUATION OF ALTERNATE RCP TRIP CRITERIA

The results of the small break LOCA analysis demonstrate that the three alternate RCP trip criteria (RCS pressure, RCS subcooling and RCS/secondary ΔP) are essentially equivalent in providing an indication for the operator to trip the pumps during a small break LOCA transient. The results also show that each of the criteria will provide the indication for RCP trip sufficiently early such that more than 2 minutes are available after the RCP trip setpoint is reached for operator action before the time when trip is required. This was demonstrated for each of the RCP trip criteria without considering the effect of instrument uncertainty in determining the RCP trip setpoints. Thus, each of the alternate RCP trip criteria will satisfactorily indicate the need for RCP trip for a small break LOCA for either normal or adverse containment conditions. Because each of the alternate RCP trip criteria are adequate to quickly provide an indication of the need for trip during a small break LOCA, the choice of which criterion to implement at a given plant may therefore be based upon the discrimination capability for SGTRs and non-LOCAs and other plant specific instrumentation considerations.

SELECTION OF RCP TRIP CRITERION

Since it was determined that the three alternate RCP trip criteria are essentially equal in effectiveness in providing indication of the need for pump trip for a small break LOCA, the criteria selection can be based on the capability to prevent a pump trip for SGTRs and non-LOCAs.

EVALUATION OF RCP TRIP CRITERIA DISCRIMINATION CAPABILITY

FOR SEABROOK

	RCP TRIP CRITERIA		
	RCS Pressure	RCS Subcooling	RCS/ Secondary ΔP
Minimum parameter values for SGTR and non-LOCA transients	1753 psia	58°F	685 psi
RCP trip setpoint with normal containment conditions	1390 psia	30°F	--
Does criterion meet discrimination requirement in NRC letters	Yes	Yes	Yes
Companion RCP trip setpoint with adverse containment conditions	1390 psia	30°F	--

At Seabrook, we can use either RCS Pressure or RCS Subcooling. RCS/Secondary ΔP could be used but ΔP is not provided as a hard wired instrument. At this time, the ERPs will use RCS Subcooling as the RCP Trip Criterion unless otherwise stated.

It is very important to point out that SUBCOOLING provides the BASIS for RCP trip, BUT THIS IS NOT THE WHOLE STORY.

The operator MUST NOT trip the RCPs on loss of SUBCOOLING ALONE. Before actually tripping the RCPs, the operator MUST also ensure that AT LEAST ONE CCP OR SI PUMP IS ALSO RUNNING. Remember that the RCPs provide excellent core cooling even if subcooling is zero.

In addition, other factors enter into this criteria such as loss of PCCW cooling to RCP motors, insufficient seal ΔP or low seal leakoff flow.

The RCP TRIP CRITERIA appears in just the E-0 series procedures.

The RCP TRIP CRITERIA for Seabrook is shown on the following page.

RCP TRIP CRITERIA

Trip all RCP's if any of the conditions listed below occur:

- CCP's or SI pumps - AT LEAST ONE RUNNING
  and
- RCS subcooling - LESS THAN 30° F

- Phase B Isolation
- RCP Seal ΔP - LESS THAN 220 PSID
- RCP #1 Seal leakoff flow - LESS THAN 0.2 GPM

Background Information

for

REACTOR COOLANT PUMP RESTART

INTRODUCTION

Many instances occur in the ERPs when the RCPs are shut down due to the specified trip criterion (e.g.; usually SUBCOOLING) or loss of supporting conditions such as 13.8 KV power and loss of PCCW to motors.

Frequently, it may be useful or desired to restart at least one RCP for cooling, plant cooldown, pressurizer spray capability and to mitigate serious situations such as inadequate core cooling or thermal stress in the reactor vessel.

RCP RESTART CRITERIA

RCP restart criteria can be classified in two ways, (e.g.; interlocks and support functions). RCP interlocks are those conditions that HAVE to be fulfilled to permit breaker closure. These consist of;

- Electrical lockouts reset
- RCP Seal ΔP > 220 PSID
- Oil Lift Pressure > 600 PSIG

Other support functions necessary for continuous pump operation are designated support functions and consist of the following;

- PCCW pump operating in loop associated with RCP
- PCCW containment isolation valves open
  1) To RCP motor
  2) To RCP thermal barriers
- Seal injection flow > 6 GPM

Keep in mind that the RCPs can be started without cooling to the motors or the thermal barriers. Typically the motors can only run about ten (10) minutes without cooling after which the bearings will overheat and cause a locked rotor condition or at least an overcurrent trip.

Also keep in mind that some form of seal cooling is necessary, either seal injection or thermal barrier cooling or both. Operation without either will result in seal failure and up to 300 GPM leakage (LOCA) into the containment. In general, it is best to have BOTH seal cooling mechanisms to start an RCP and at least ONE to continue RCP operation.

The operator should KNOW that RCP-1A and RCP-1D are cooled by PCCW Loop A and RCP-1B and RCP-1C are cooled by PCCW Loop B. The operator should also know that Bus 1 supplies RCP-1A and 1B and Bus 2 supplies RCP-1C and 1D. Note that an RCP that drives pressurizer spray is on each 13.8 KV bus.

It is also worth noting that RCP operation with a saturated or highly voided RCS will result in high vibration (shaft and motor frame) and that normal motor current will be less than normal.

Background Information

for

RCS PRESSURE REDUCTION MEASURES

INTRODUCTION

The ERPs contain many steps that require RCS pressure reduction. Mechanisms for RCS pressure reduction include normal pressurizer spray, auxiliary spray and pressurizer PORVs. All three mechanisms have limitations that the operator must be aware of.

NORMAL PRESSURIZER SPRAY

Use of normal pressurizer spray is in general the most desirable pressure reduction mechanism. However, certain RCPs must be running for it to be effective. Single pump operation in the loops with spray connections is the most effective. In addition, running RC-P-1C in loop 3 will yield the best results since the pressurizer surge tap is connected to loop 3 hot leg.

Therefore, a heirarchy of preference for pressurizer spray exists as follows:

1. Run RC-P-1C using loop 3 spray valve - BEST
2. Run RC-P-1A using loop 1 spray valve - GOOD

Running either RC-P-1B or RC-P-1D will not produce good results because the reverse flow in loops one and three will not drive much spray flow up to the pressurizer. This is because of system pressure drops and the orientation of loop one and loop three spray scoops. Recall that the spray scoops add velocity head to the spray lines only if forward loop flow exists.

Although normal pressurizer spray is the best and preferred pressure reduction mechanism, it may be the most difficult to reestablish in some accident scenarios, since it requires possible selected RCP restart which depends on the operability of control grade instrumentation and containment instrument air.

A major advantage associated with normal spray is that it CONSERVES reactor coolant inventory.

PRESSURIZER PORVs

If normal spray is not available, use of one PRZR PORV has priority over auxiliary spray. Auxiliary spray is used as a last resort to minimize thermal shock to the spray nozzles.

Opening one PORV results in a more rapid pressure reduction than normal spray, however, it is slow enough to allow operator action such as blocking SI actuation at P-11.

The PORVs are highly reliable because they are redundant and are operated by safety grade controls without total dependency on air or off-site power.

Use of a PORV will initially result in a loss of RCS inventory. However, this is well within the capability of the CCPs in either the charging or ECCS modes. In fact, in the ECCS mode, the reduction in RCS pressure results in higher ECCS flow into the system.

The major concerns of the operator when using a PORV should focus on successful reclosure of the PORV and the integrity of the PRT.

Since TMI, a lot of effort has been expended to increase valve reliability and to provide positive valve position indication. This, combined with the PORV isolation valve should instill operator confidence.

The PRT is not designed for continuous pressurizer discharge. However, analysis shows that most step (short term) discharges, such as those associated with a cooldown, can be accommodated without opening the rupture disc. The operator can help the situation by ensuring that the PRT cooling system operates, if available, to cool down the PRT liquid between discharges. Another option involves pumping down the PRT in conjunction with spraying RMW. However, remember that increasing the PRT level will compress the nitrogen atmosphere and may worsen the situation.

AUXILIARY SPRAY

Use of auxiliary spray for any other purpose than normal pressurizer cooldown is laced with potential problems that the operator should be familiar with.

First, the auxiliary pressurizer spray system supplies water from the CVCS to the pressurizer spray nozzle. If normal letdown (and charging) through the regenerative HX is NOT in service, the auxiliary spray water will not be PRE-HEATED prior to discharge through the pressurizer spray nozzle. This will cold shock ($\Delta T \approx 550°F$) the nozzle and may cause nozzle failure. Failure in this case means that the nozzle breaks off and takes up residence in the bottom of the pressurizer. Without the nozzle, even normal spray would become less effective.

In Westinghouse NSSSs, the maximum recommended ΔT for auxiliary spray use is 200°F. If it becomes necessary for the operator to use auxiliary spray without letdown preheat, the operator should cut in flow as slowly as possible.

In general, the ERP's attempt to restore charging and letdown first before pressure reduction steps that allow use of the auxiliary spray option.

Secondly, the operator must be aware of flow competition with charging and BIT flow, since flow takes the path of least resistance. If normal charging and letdown are in service (no BIT flow), opening the auxiliary spray valve won't yield much auxiliary spray flow. It may be necessary for the operator to close the normal charging isolation to loops one or four to get auxiliary spray flow. Of more significance is the situation where ECCS is in operation (normal charging and letdown isolated). In this case, the operator would have to isolate BIT flow to obtain auxiliary spray flow. <u>THIS COULD BE A DEFINITE NO-NO!</u> In a case like this, the ERPs specify that the operator use one PORV without the option to use auxiliary spray.

Background Information

for

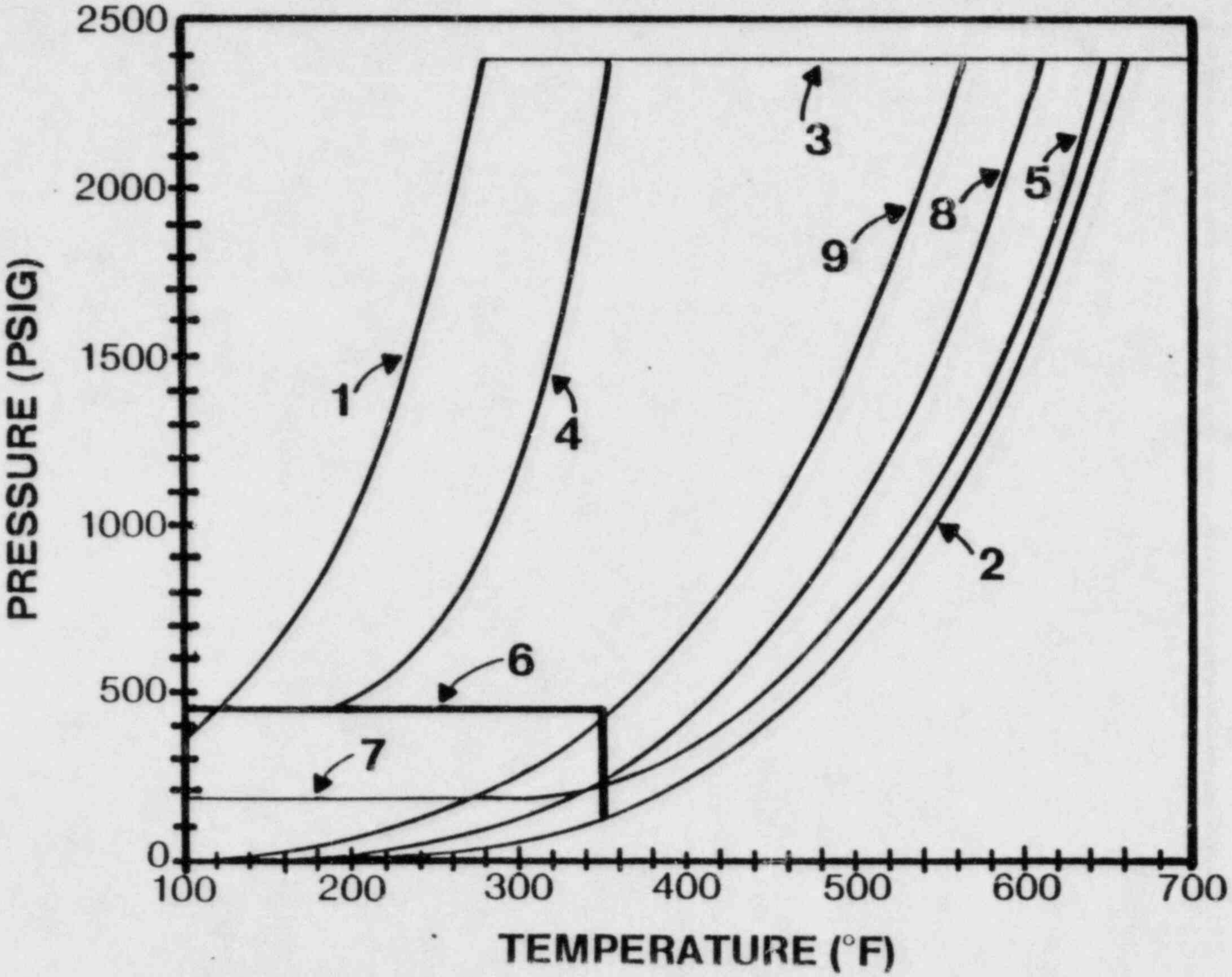
SEABROOK PRESSURE-TEMPERATURE LIMITS

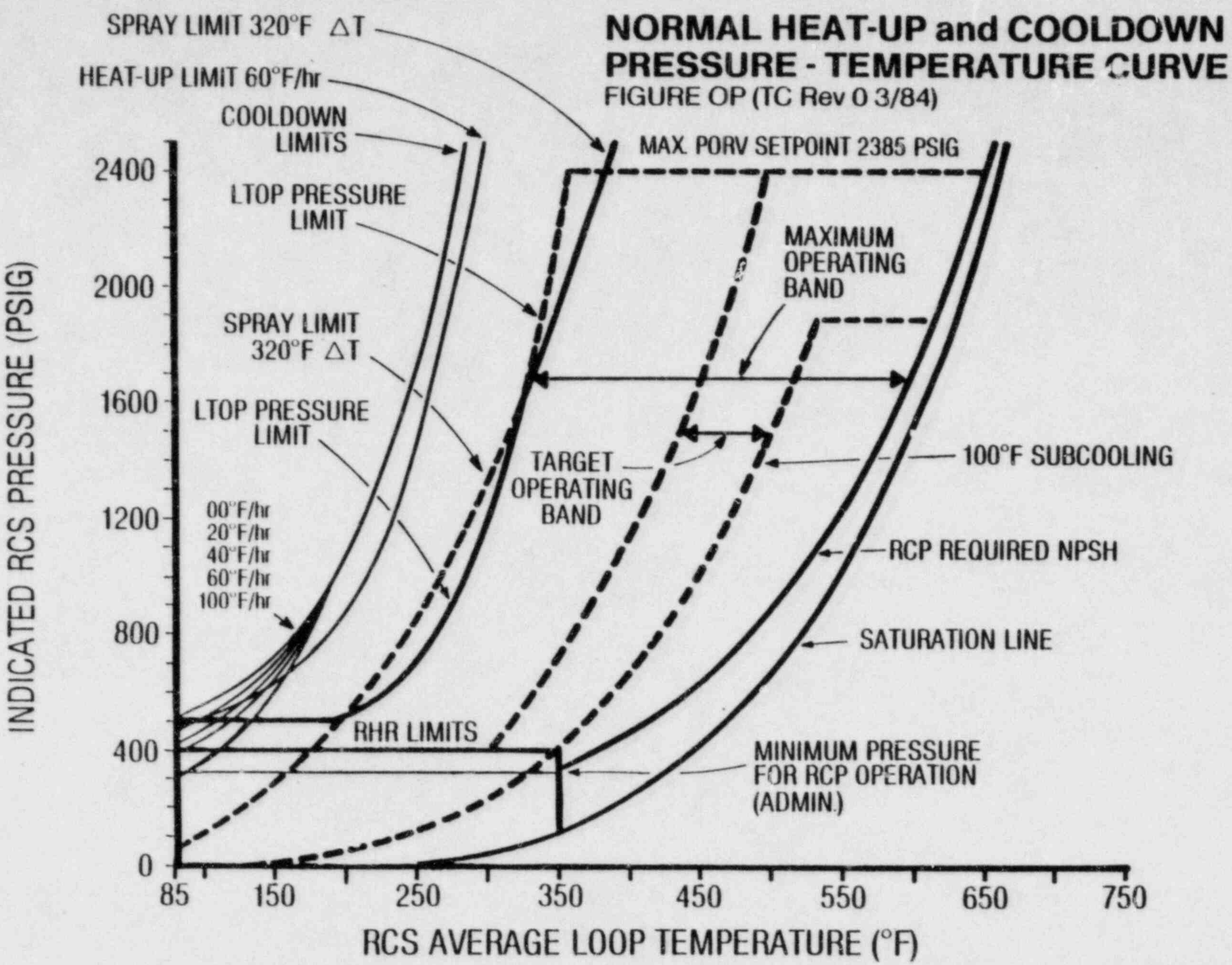
CURVE DESCRIPTION

1. MAXIMUM TECH SPEC COOLDOWN LIMIT @ 100°F/HR
2. RCS SATURATION CURVE
3. MAXIMUM PORV SETPOINT (2385 PSIG)
4. LTOP PROGRAM FOR PORVs
5. RCP NPSH
6. RHR OPERATING LIMITS
7. MINIMUM RCS PRESSURE FOR RCP OPERATION [MAY REQUIRE HIGHER PRESSURE (~ 350 PSIG) TO MEET MINIMUM SEAL LEAKOFF FLOW (0.2 GPM)]
8. 50°F SUBCOOLING LINE
9. 100°F SUBCOOLING LINE

SEABROOK RCS PRESSURE / TEMPERATURE LIMITS

FIGURE OP (TC Rev 0 3/84)




NORMAL HEAT-UP and COOLDOWN
PRESSURE - TEMPERATURE CURVE
FIGURE OP (TC Rev 0 3/84)
SPRAY LIMIT 320°F ΔT
HEAT-UP LIMIT 60°F/hr
COOLDOWN LIMITS
LTOP PRESSURE LIMIT
SPRAY LIMIT 320°F ΔT
LTOP PRESSURE LIMIT
00°F/hr
20°F/hr
40°F/hr
60°F/hr
100°F/hr
MAX. PORV SETPOINT 2385 PSIG
MAXIMUM OPERATING BAND
TARGET OPERATING BAND
100°F SUBCOOLING
RCP REQUIRED NPSH
SATURATION LINE
RHR LIMITS
MINIMUM PRESSURE FOR RCP OPERATION (ADMIN.)
INDICATED RCS PRESSURE (PSIG)
2400
2000
1600
1200
800
400
0
85
150
250
350
450
550
650
750
RCS AVERAGE LOOP TEMPERATURE (°F)

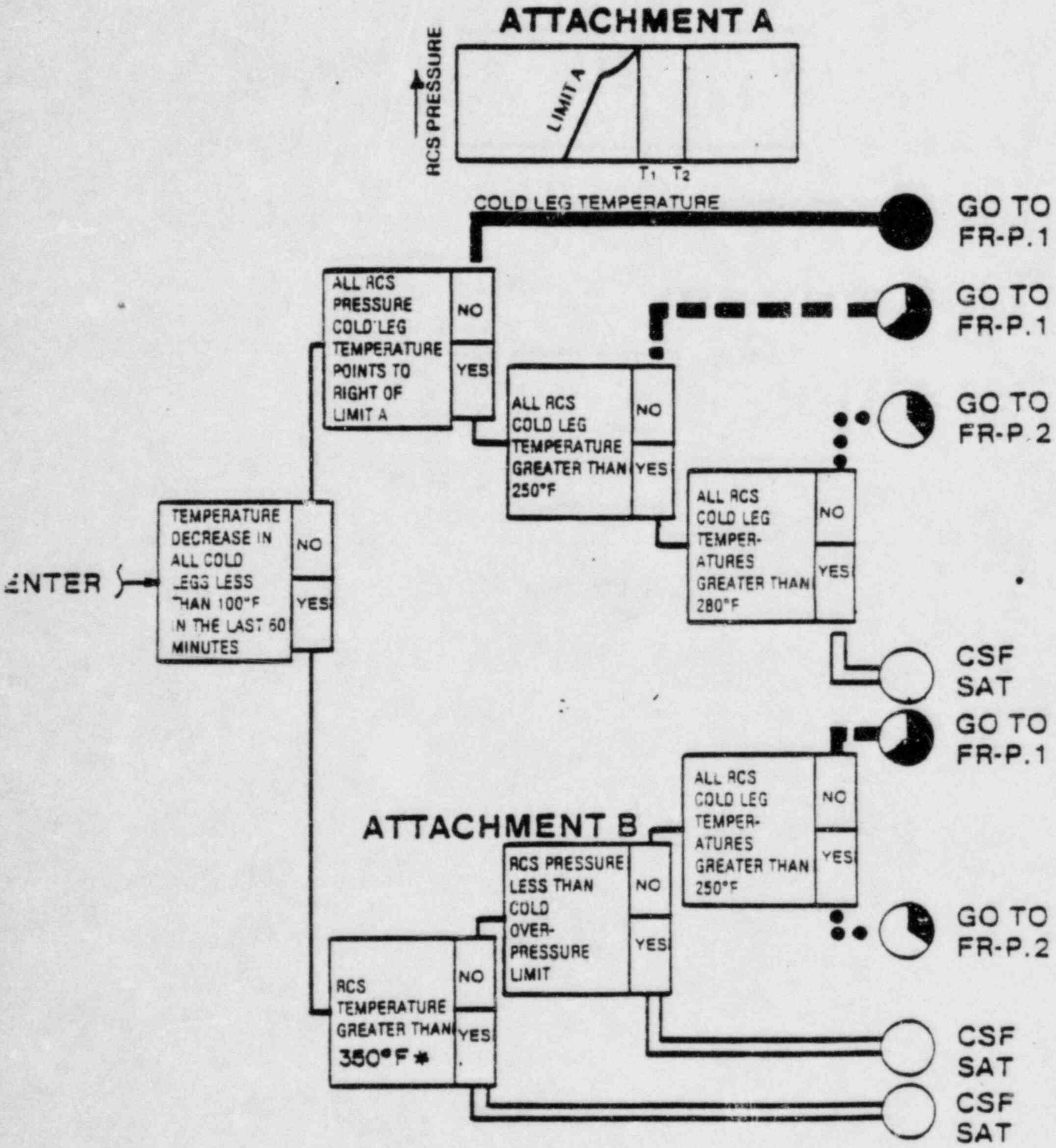
Background Information

for

PRESSURIZED THERMAL SHOCK

FIGURE 13

INTEGRITY STATUS TREE



*ARMING BISTABLE SETPOINT

OPERATOR RESPONSE TO IMMINENT PTS CONDITIONS

The Function Restoration Procedure FR-P.1, "RESPONSE TO IMMINENT PRESSURIZED THERMAL SHOCK CONDITION," provides guidance in the event of an unexpectedly severe RCS cooldown following a reactor trip or safety injection actuation (indicated by the RED or ORANGE terminus of the Integrity Status Tree). The operator is provided with instructions to attempt to prevent further cooldown and to minimize the pressure in the RCS in order to respond to a challenge to reactor vessel integrity. Guidance is also provided on any subsequent RCS cooldown restrictions required to safely achieve cold shutdown conditions.

An event or series of events which leads to a relatively rapid and severe reactor vessel downcomer cooldown can result in a thermal shock to the vessel wall that may lead to the initiation and growth of a small flaw that may already exist in the vessel wall into a larger crack. A growth or extension of such a flaw may lead in some cases (where propagation is not stopped within the wall) to a loss of vessel integrity. The objective of the Integrity Status Tree and its associated Function Restoration Procedures is to enable the operator to identify a potential thermal shock condition and to take action to assure the integrity of the vessel. The basis is to prevent the initiation of a flaw, and in the event the limits set forth are exceeded, specific procedures are given which appropriately restrict operation to prevent further growth of a possible wall crack with concomitant loss of integrity.

The FRP is entered from two separate branches of the Integrity Status Tree, one having a RED terminus signifying a potentially damaying thermal shock condition independent of RCS pressure, with the second having an

ORANGE terminus signifying an imminent approach to the RED condition, depending on subsequent increases in pressure or decreases in temperature. A limited number of scenarios related to single or multiple failures involving LOCA, secondary breaks or steam generator tube rupture may lead to a severe cooling of the entire RCS (e.g., secondary breaks or LOCA) or a local cooling of the cold leg/downcomer area (e.g., LOCA or steam generator tube rupture).

MAJOR ACTION CATEGORIES IN FR-P.1

* Cold leg temperature has exceeded RED or ORANGE LIMITS

- Attempt to Stabilize Temperature

- If Excessive Cooldown Caused By ECCS, THEN:

  1) Terminate ECCS

  - OR -

  2) Start an RCP to mix cold ECCS water with coolant

- Depressurize RCS to Minimum Subcooling

- Temperature SOAK (ANNEAL TO INCREASE DUCTILITY)

- Cooldown at Less Than 50°F/Hr with Maximum of 200°F Subcooling

DISCUSSION

During the fabrication of the vessel or during the operational lifetime of the plant, small flaws may be created in the weld or base metal of the reactor vessel. These flaws can be propagated or extended into larger cracks if very high thermal or pressure (membrane) stresses are imposed on them by RCS transients. A severe thermal shock or a pressurized thermal shock can lead to a brittle fracture of the vessel wall such that a loss of vessel integrity may occur.

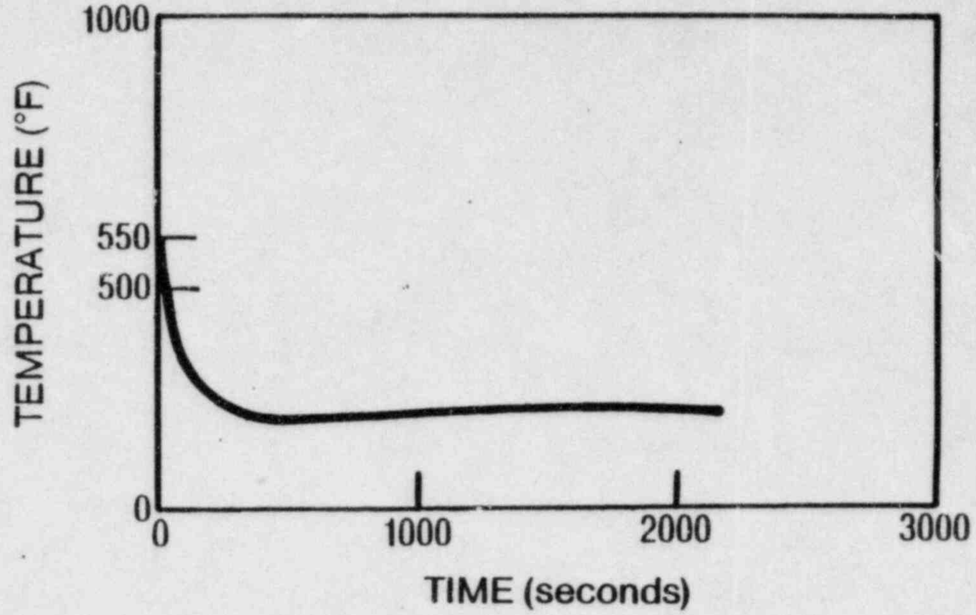
A vessel thermal shock condition exists if a rapid fluid temperature decrease occurs in the downcomer region of the reactor vessel. A temperature difference will then be established through the vessel wall with the inside of the wall initially rapidly cooled while the outside portion remains close to its initial temperature. An example fluid temperature transient is provided in Figure 1 and corresponding wall temperature profiles for various times are provided in Figure 2. As time increases the temperature profile flattens because more of the wall thickness is cooled below the initial system temperature.

The result of the through-wall temperature difference is that a tensile stress is placed on the vessel wall acting to pull open any pre-existing small flaws in welds or base material. Figure 3 is a representation of a flaw at the vessel inner surface and how temperature induced stresses act to extend the flaw into the wall. In addition, when the temperature of the vessel wall decreases, its ability to resist flaw growth also decreases (decreasing fracture toughness). If these conditions occur to a severe enough extent, the pre-existing small flaw may propagate into a larger crack.

In addition to the temperature induced stresses the RCS pressure could act to assist the growth of a flaw. A thermal shock occurring with pressure in the RCS is called pressurized thermal shock (PTS). Figure 3 shows how pressure acts on a flaw and Figure 1 presents an example pressure transient for a typical PTS event.

REACTOR COOLANT PRESSURE & TEMPERATURE FOR A REPRESENTATIVE SEVERE THERMAL TRANSIENT

FIGURE OP 1 (TC Rev 0 3/84)



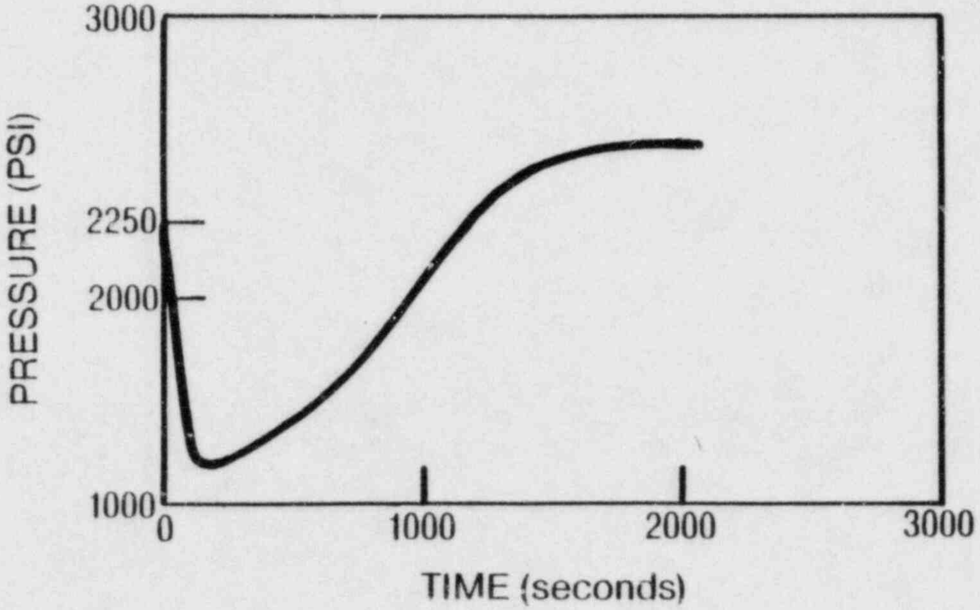


FIGURE 1

VESSEL TEMPERATURE PROFILES

FIGURE OP 2 (TC Rev 0 3/84)

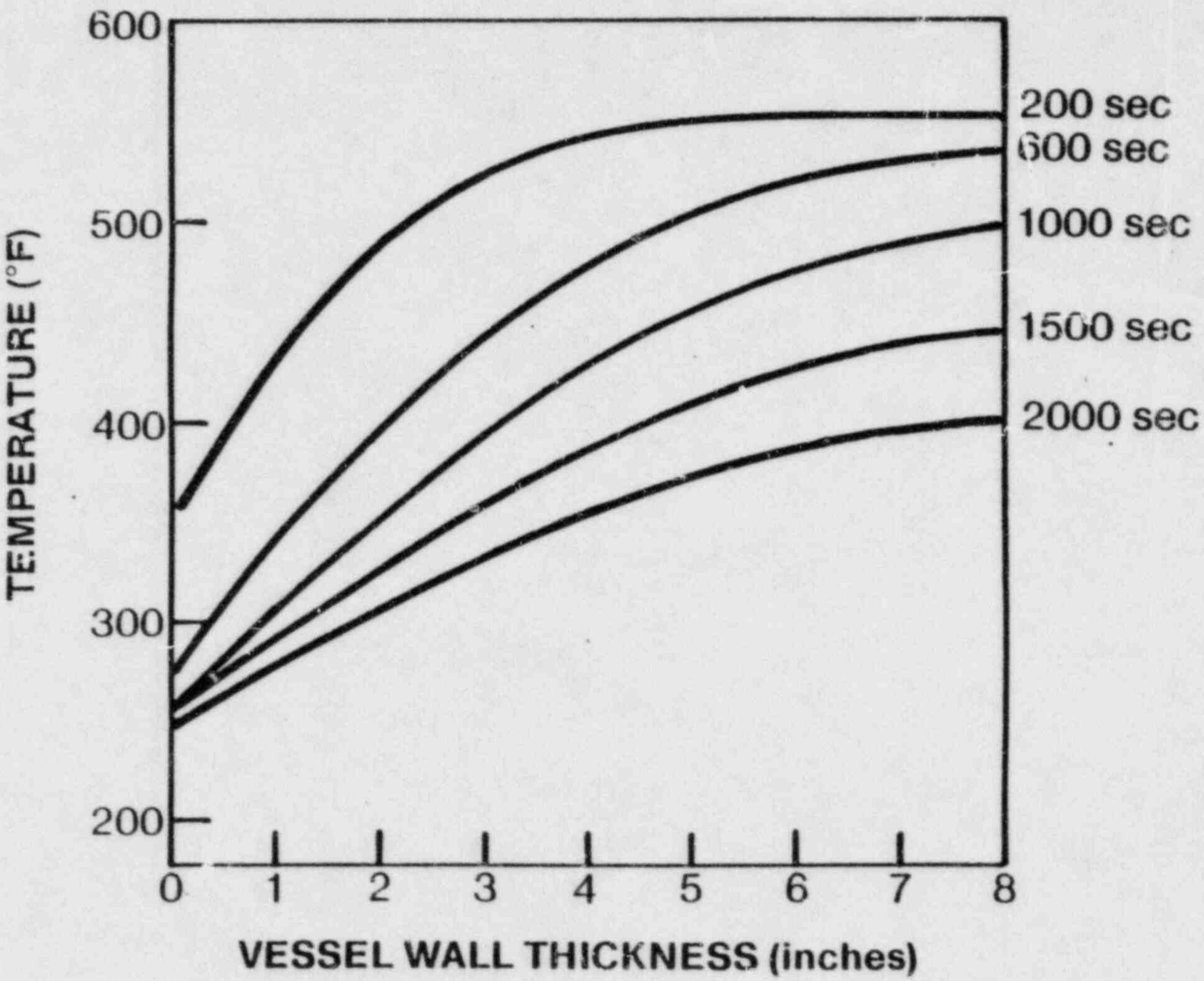
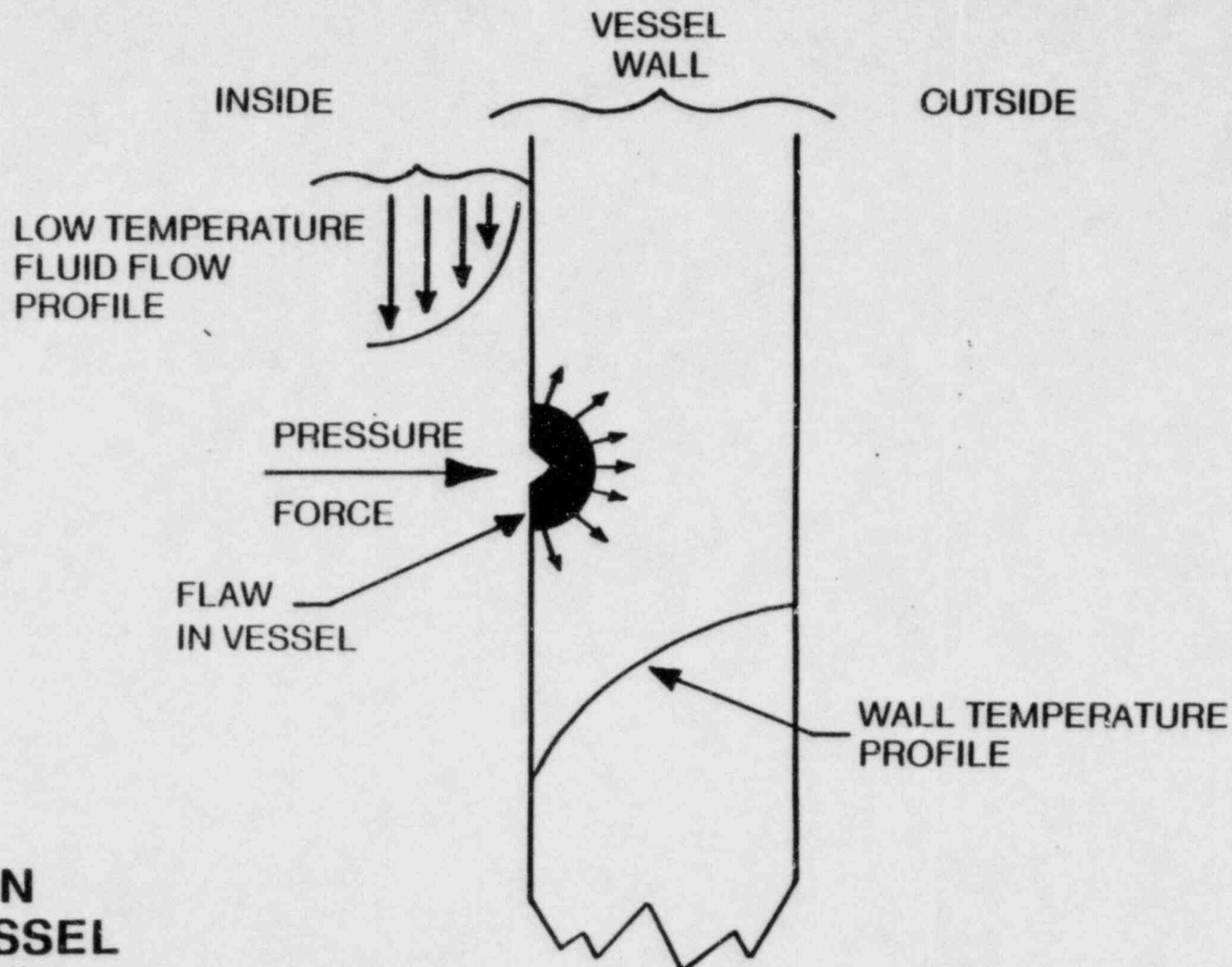


FIGURE 2

FIGURE 3



FLAW PROPAGATION CONDITIONS IN VESSEL

FIGURE OP 3 (TC Rev 0 3/84)

A representation of the combined stress from temperature (thermal stress) and pressure (membrane stress) for the example transient in Figure 1 is shown in Figure 4 where stress profiles at various times into the transient are shown at different wall thickness locations. In some cases a thermal stress alone can be sufficient to propagate a flaw while in other cases significant membrane stress in addition to thermal stress will be required to initiate flaw growth.

In general, whether a small pre-existing flaw will grow is dependent on the rate and amount of RCS cooldown, the RCS pressure, the material properties of the metal and the location, size and geometry of the flaw. In deriving the Integrity Status Tree operational limit each factor has been considered; the assumptions used in development of this limit will be discussed in the following section.

The intent of the Integrity Critical Safety Function RED limit is to define parameters (symptoms) that indicate a challenge is occurring to the Integrity Critical Safety Function, and that immediate operator action is required to address this challenge. Using fracture mechanics analysis techniques and an assumed fluid temperature transient, the minimum pressure at a given temperature required to initiate a flaw, called the allowable pressure, can be calculated and used as a basis for the definition of the RED limit. The other Integrity priority levels (ORANGE, YELLOW, GREEN) will be based in turn on the definition of the RED limit.

A typical ALLOWABLE PRESSURE curve is provided as Figure 6.

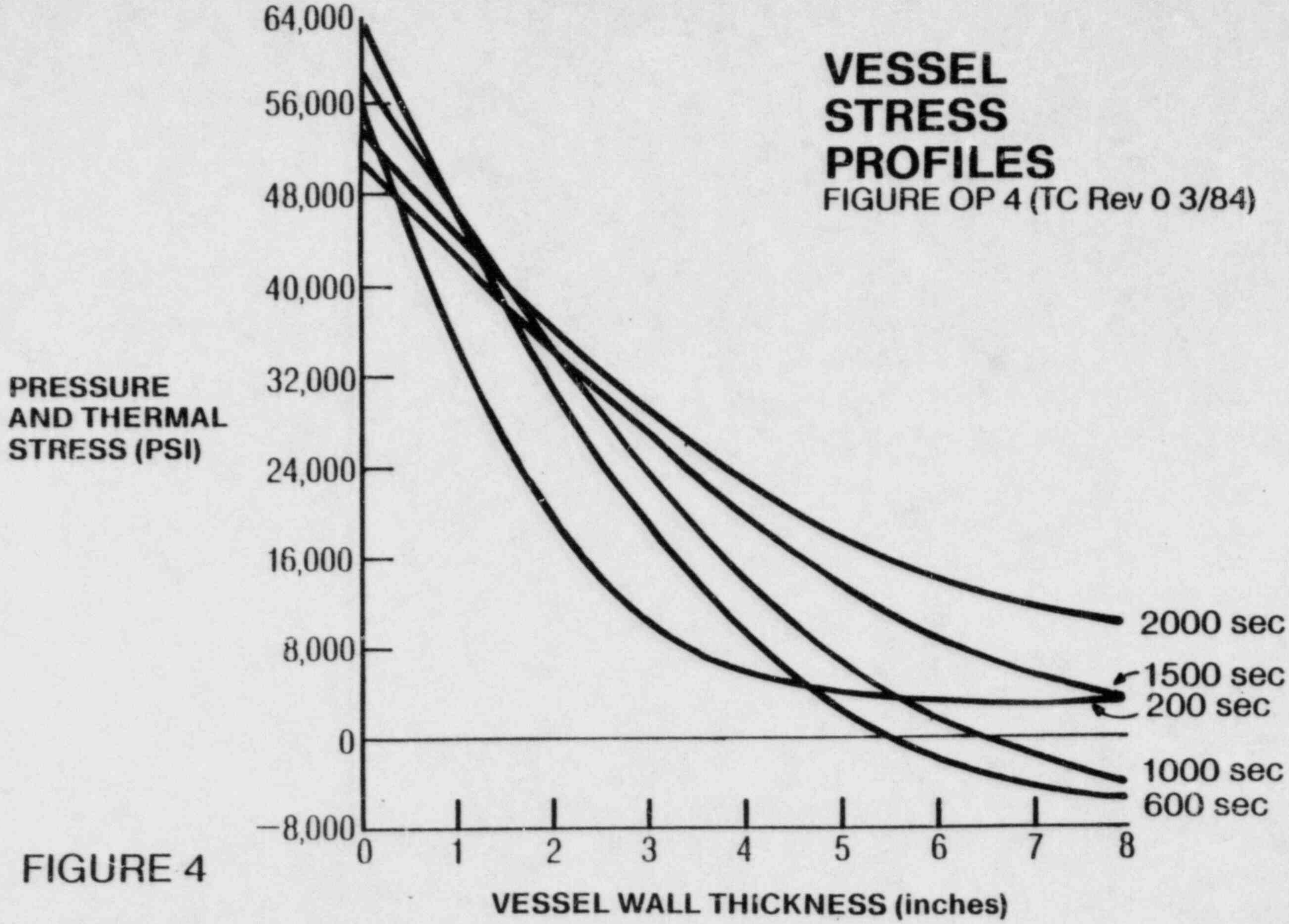

VESSEL
STRESS
PROFILES
FIGURE OP 4 (TC Rev 0 3/84)
PRESSURE
AND THERMAL
STRESS (PSI)
64,000
56,000
48,000
40,000
32,000
24,000
16,000
8,000
0
−8,000
0
1
2
3
4
5
6
7
8
2000 sec
1500 sec
200 sec
1000 sec
600 sec
VESSEL WALL THICKNESS (inches)

FIGURE 4

SELECTION OF RED CONDITION ACTION LEVEL LIMITS

The plant process parameters to be used in monitoring the Integrity Critical Safety Function are RCS pressure an RCS cold leg temperature. RCS pressure is an indication of the pressure in the vessel downcomer region and cold leg temperature is the best available indication of downcomer fluid temperature.

In order to be compatible with the intent of Critical Safety Function Status Tree monitoring the integrity action levels are required to be time independent. Since the severity of a thermal shock is dependent on the rate of RCS cooldown a method is needed to conservatively eliminate rate effects from the symptoms. This is done in calculating the RED limit by assuming a step decrease (or infinite rate drop) in fluid temperature in order to bound all possible cooldown rates.

The method used to define the RED limit is to use in an allowable pressure calculation a step temperature transient assumed to start at a downcomer wall and fluid temperature of 550°F, with fluid temperature then dropping to a lower specified constant temperature. Figure 5 provides a representation of some example temperature transients. Figure 6 presents an example allowable pressure calculation result. For each final temperature assumed, a different allowable pressure curve is generated. A series of minimum allowable pressures each corresponding to a given final temperature assumption is then used to generate a curve which is called the "Step Cooldown Crack Initiation Limit" as shown on Figure 7.

Also includ on Figure 7 is a curve called the "Isothermal Wall Crack Initiation Limit" which is an allowable pressure curve assuming a constant steady-state through-wall temperature, rather than the very extreme

BASIS FOR DEVELOPMENT OF CRACK INITIATION CURVE

FIGURE OP 5 (TC Rev 0 3/84)

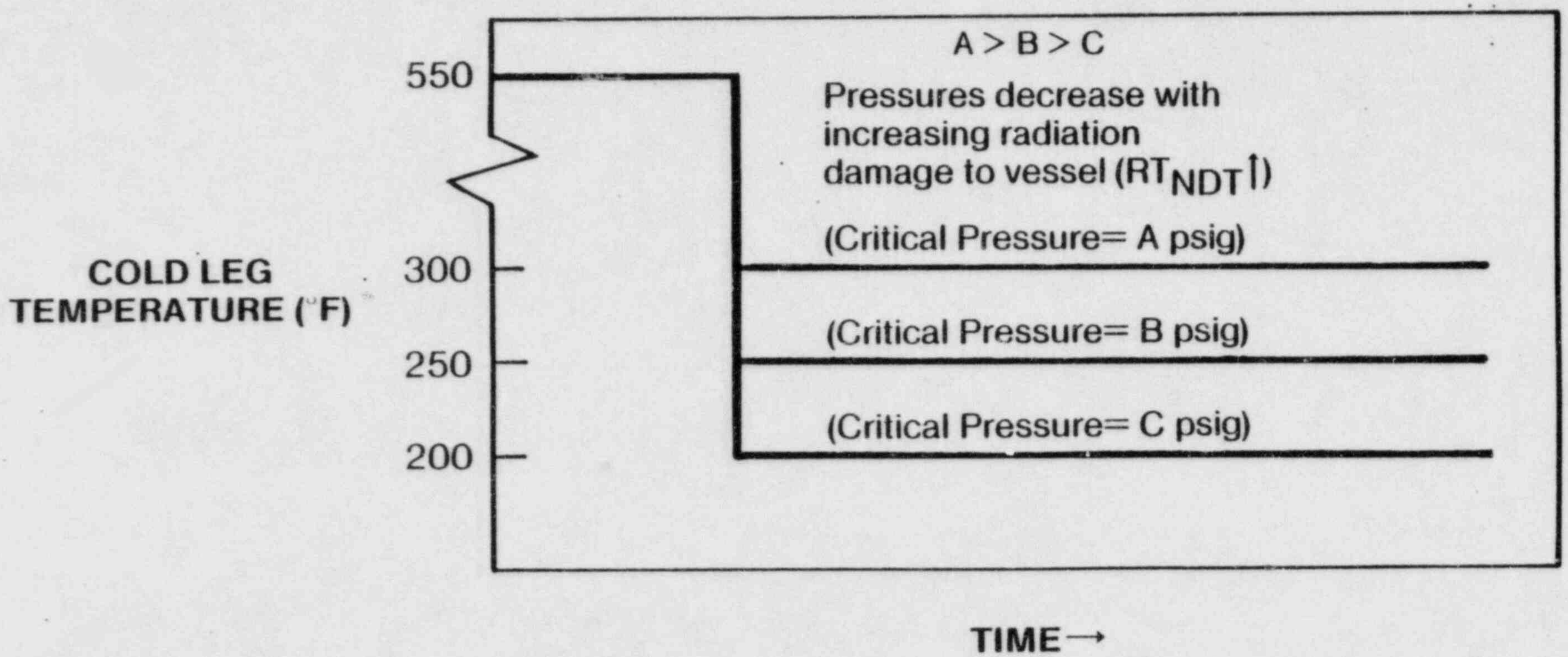


FIGURE 5

EXAMPLE: ALLOWABLE PRESSURE CURVE

FIGURE OP 6 (TC Rev 0 3/84)

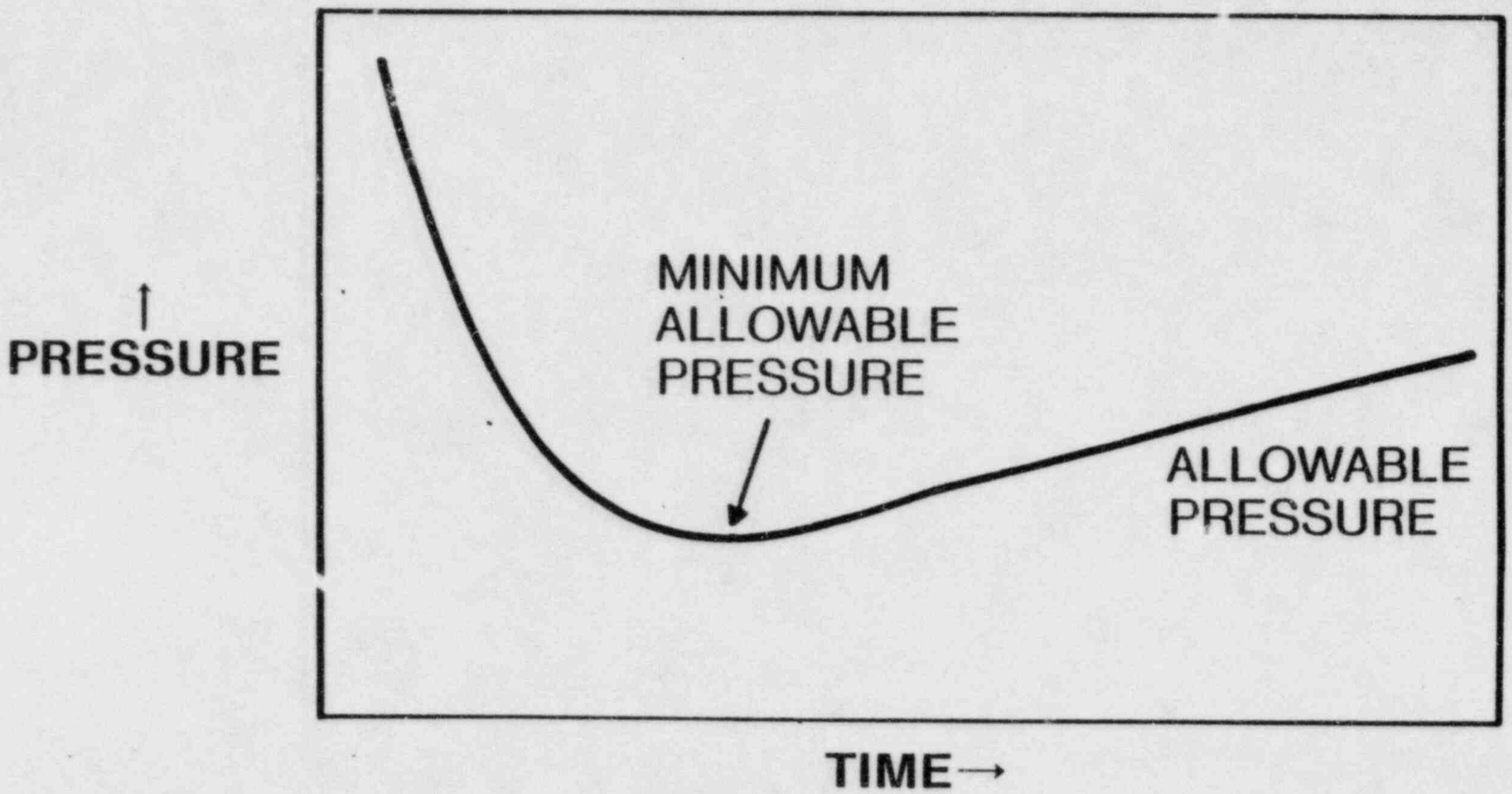


FIGURE 6

situation resulting from the step temperature decrease transient which places the maximum thermally-induced tensile stress on the vessel inner wall.

For the steady state through-wall temperature case, temperature stress is nearly zero, but material fracture toughness, or its resistance to flaw growth, at low temperature is low enough so that excessive pressure alone is calculated to cause flaw initiation. For thick-walled vessels it has been found that this curve is more limiting at high pressure than the "Step Cooldown Crack Initiation Limit." Therefore, the RED Integrity limit has been defined as the lower bound of the "Step Cooldown Crack Initiation Limit" and the "Isothermal Wall Crack Initiation Limit."

The RED pressure-temperature limit line is then conservatively defined as the boundary of a region below which a flaw may initiate and is independent of the time history of the transient. If conditions remain to the right of the RED limit, no initiation of a flaw will occur. If conditions are to the left of this limit the potential for flaw initiation exists and appropriate operator action should be taken to reduce the probability that an existing flaw will propagate through the vessel wall.

The region to the right of the intersection of the "Isothermal Wall Crack Initiation Limit" and the RCS safety valve pressure setpoint plus 3 percent accumulation (2560 psig) is a full repressurization area. In this area a flaw will not initiate at any pressure up to the safety valve setpoint and complete operating flexibility with respect to pressure can be allowed. In permitting this flexibility it is assumed that at least one of the installed code safety valves will operate correctly to limit RCS pressure, if necessary.

The region to the right of the RED limit line and to the left of the "Full Repressurization Limit" line (Figure 7) is an area where a flaw will be calculated to initiate if pressure increases above the RED limit line even at a constant wall temperature. Since pressure can rise in some cases rather quickly, increased operator awareness is warranted in this region.

EXAMPLE CURVE

FIGURE OP 7 (TC Rev 0 3/84)

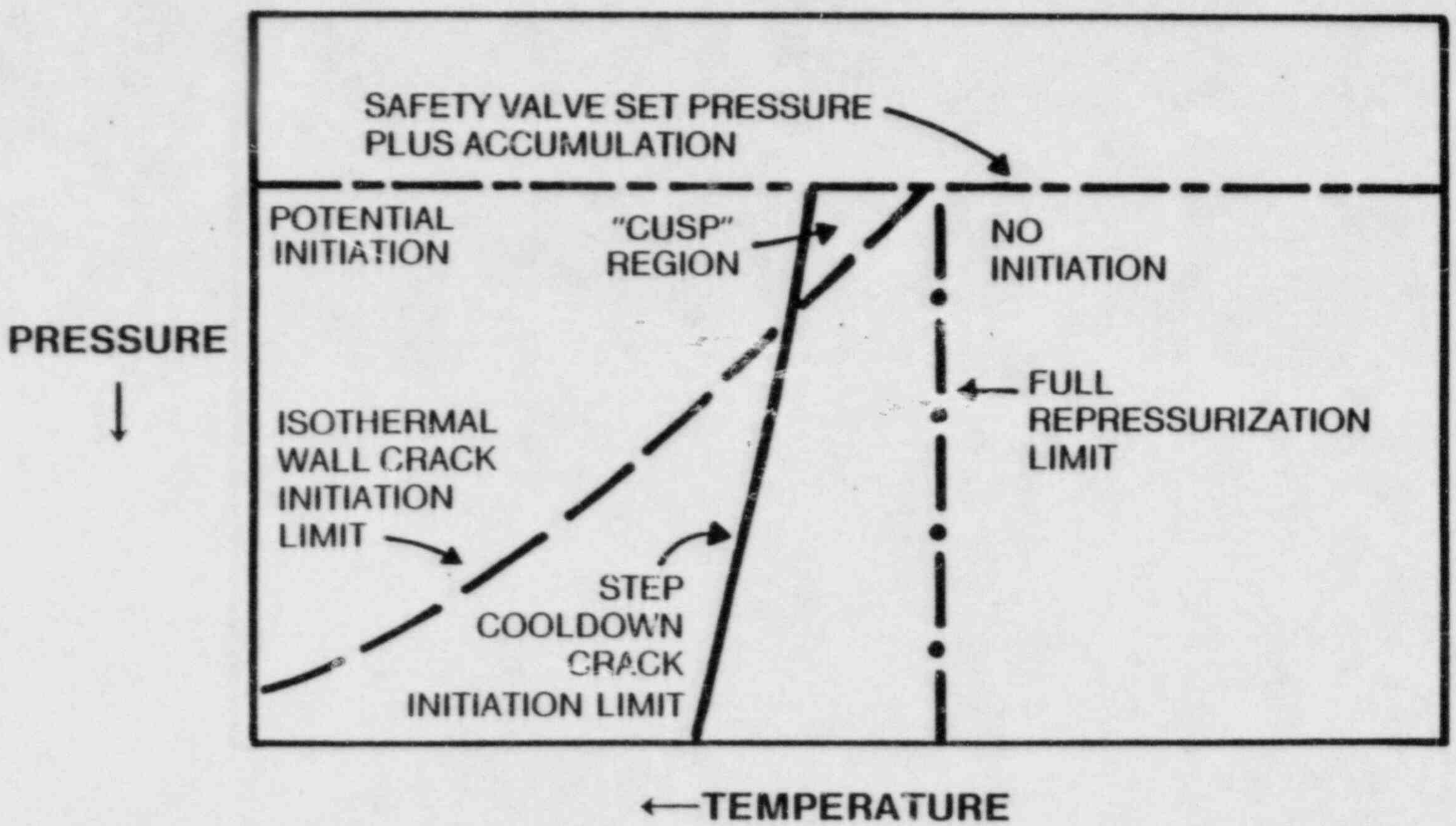


FIGURE 7

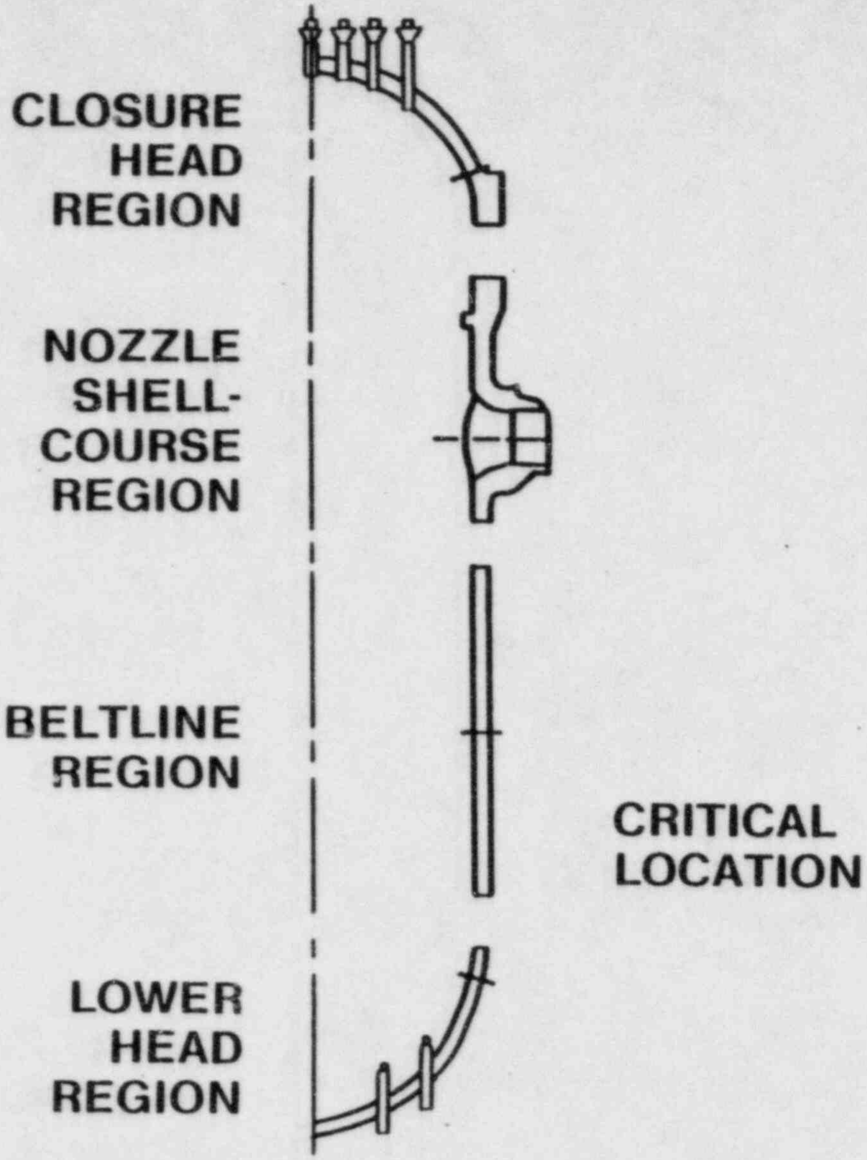
RT_{NDT} CATEGORIES FOR OPERATIONAL LIMITS

The material properties of a given reactor vessel determine the fracture toughness or resistance to flaw initiation of the vessel. The important characteristics of the material are the initial vessel metal and weld composition and the neutron irradiation damage sustained during the life of the vessel. A measure of the fracture toughness of a given material in a specific vessel is its RT_{NDT} (Reference Transition Nil-Ductility Temperature) value. The higher the RT_{NDT} temperature, the lower the fracture toughness of the material and the more susceptable it is to flaw initiation. This parameter, RT_{NDT}, has been generally accepted as the most useful figure-of-merit for evaluating the susceptibility of a reactor pressure vessel to a PTS condition.

The material properties to be assumed are dependent on the plant reactor vessel. Three categories of reactor vessel material have been used to generate generic curves which can be conservatively applied to any Westinghouse nuclear plant vessel. The categories are defined by RT_{NDT} levels for the limiting vessel material as follows:

CATEGORY I	$RT_{NDT} \leq 200°F$ (Seabrook)
CATEGORY II	$200°F < RT_{NDT} \leq 250°F$
CATEGORY III	$250°F < RT_{NDT} \leq 300°F$

The limiting location in the vessel for evaluating severe cooldown effects is generally the downcomer core midplane (beltline) region (Figure 8). This is true because at one or more points around the vessel circumference, at its inner wall, the fluence level (integrated neutron flux due



MAJOR SECTIONS OF A REACTOR PRESSURE VESSEL

FIGURE OP 8 (TC Rev 0 3/84)

FIGURE 8

to core leakage) is the highest of any RCS material. The peak axial flux generally occurs in the core midplane region, and the maximum embrittlement of vessel materials from neutron bombardment therefore occurs on the contiguous vessel beltline. In most vessels, the beltline region also contains either circumferential or longitudinal welds that are the critical locations for assuring the integrity of the vessel. In applying the RED limit for any particular vessel the limiting location is taken to be the location in the vessel beltline with the highest RT_{NDT}. This can be weld material or base metal.

FLAW SIZE AND GEOMETRY

In calculating the RED limit curve all flaw sizes up to an including 0.25 times the vessel wall thickness (1/4 T) have been evaluated. This means that all potential pre-existing flaws in size equal to or less than 1/4 T have been covered by the RED limit generated. Flaws larger than 1/4 T are not expected to exist due to the quality of vessel fabrication and the reliability of in-service inspection techniques.

The geometry of the pre-existing flaw assumed is finite and the analysis technique is consistent with the methods used in standard fracture mechanics calculations.

SELECTION OF ORANGE CONDITION ACTION LEVEL LIMITS

The intent of the ORANGE condition limit of the Integrity Status Tree is to provide a warning area for the operator of an imminent RED condition. In the ORANGE region a flaw is <u>not</u> calculated to initiate, but relatively small and possibly rapid changes in pressure or temperature will result in entry to the RED region where a flaw is calculated to initiate.

For Category I plants the ORANGE limit is defined as the region between the RED region boundary and the "Full Repressurization Limit" line (Figure 7).

LIMITS OF APPLICABILITY

This Function Restoration Procedure is intended to respond to a thermal shock or pressurized thermal shock event. If a normal cooldown is occurring and the cooldown rate limit on the Status Tree is not exceeded, but a subsequent RCS pressurization in violation of the Tech Spec pressure - temperature limits occurs, then it is possible to have an immediate ORANGE or RED indication without an excessive thermal condition. This case is not specifically covered by the procedure, but the actions instructed do address any potential cold overpressure concern by requiring an RCS depressurization. However, the degree of depressurization necessary would be only that needed to return the RCS pressure to within the Tech Spec limits. Also, no soak is required and subsequent RCS cooldown should be within Tech Spec cooldown limits.

Seabrook design includes a Low Temperature Overpressurization Protection (LTOP) system that automatically opens pressurizer PORVs to limit RCS pressure for a given RCS temperature. The programmed LTOP pressure-temperature setpoint maintains RCS pressure within Appendix G (Tech Spec) cooldown limits. The operator should expect LTOP to open the pressurizer PORVs automatically if a large cooldown occurs without a significant decrease in RCS pressure. In addition, a sudden RCS pressure increase without a thermal shock will also result in LTOP operation. See Figure 9.

SEABROOK LTOP SETPOINT PROGRAM

FIGURE OP 9 (TC Rev 0 3/84)

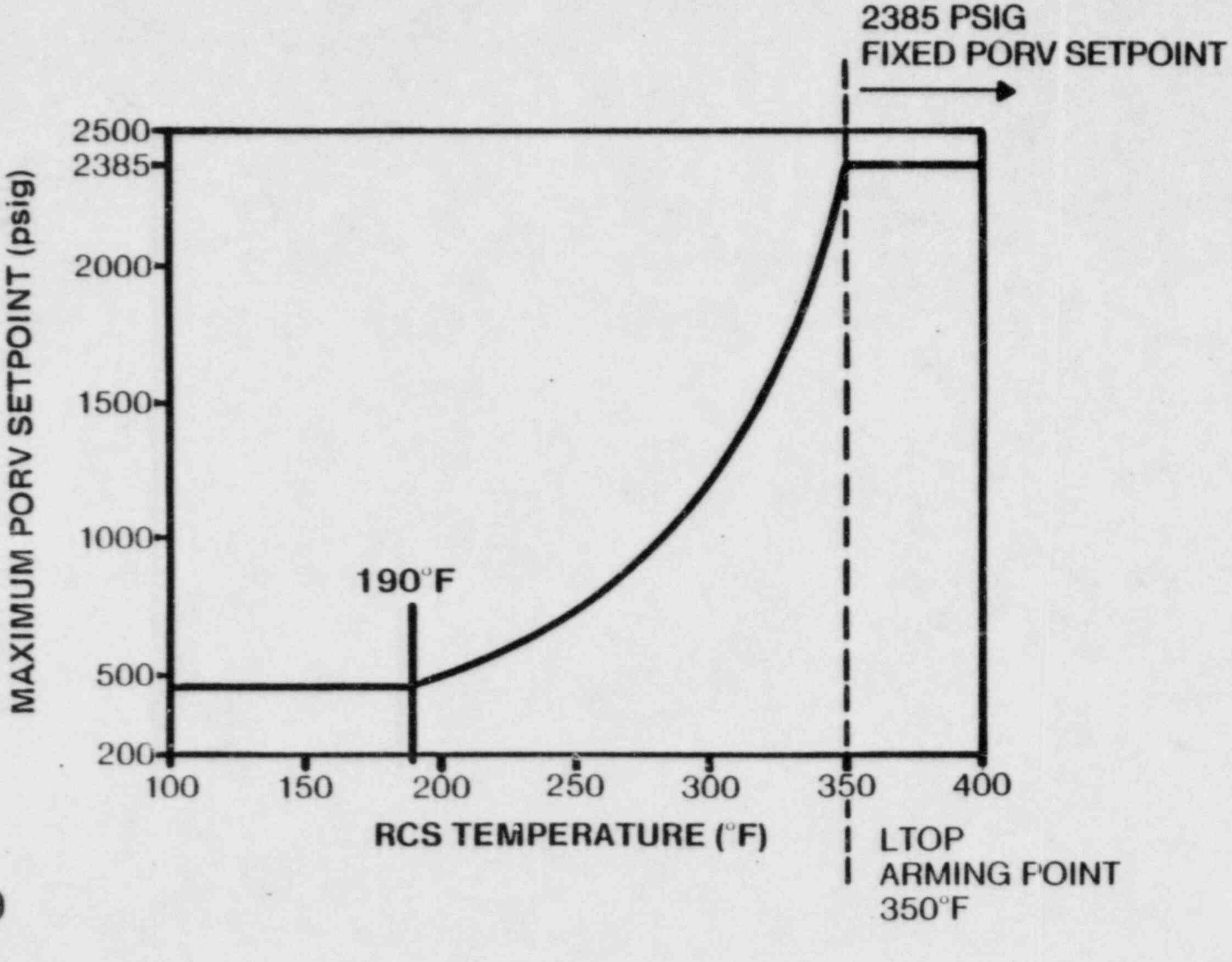


FIGURE 9

SEABROOK STATION - OPERATIONAL LIMITS CURVE

FIGURE OP 11(TC Rev 0 3/84)

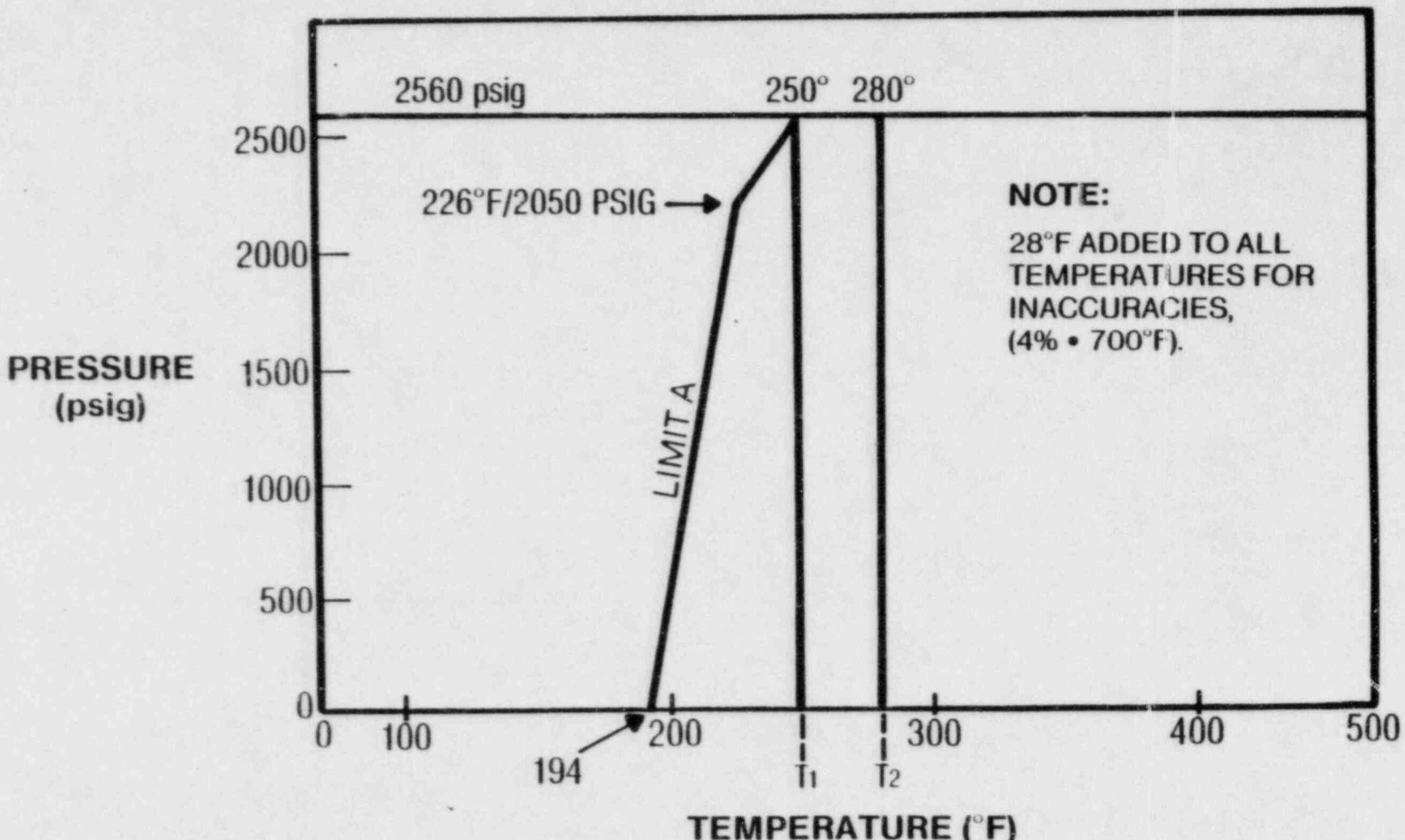


FIGURE 11

SEABROOK STATION-OPERATIONAL LIMITS CURVE WITH SUPERIMPOSED LTOP PROGRAM

FIGURE OP 12 (TC Rev 0 3/84)

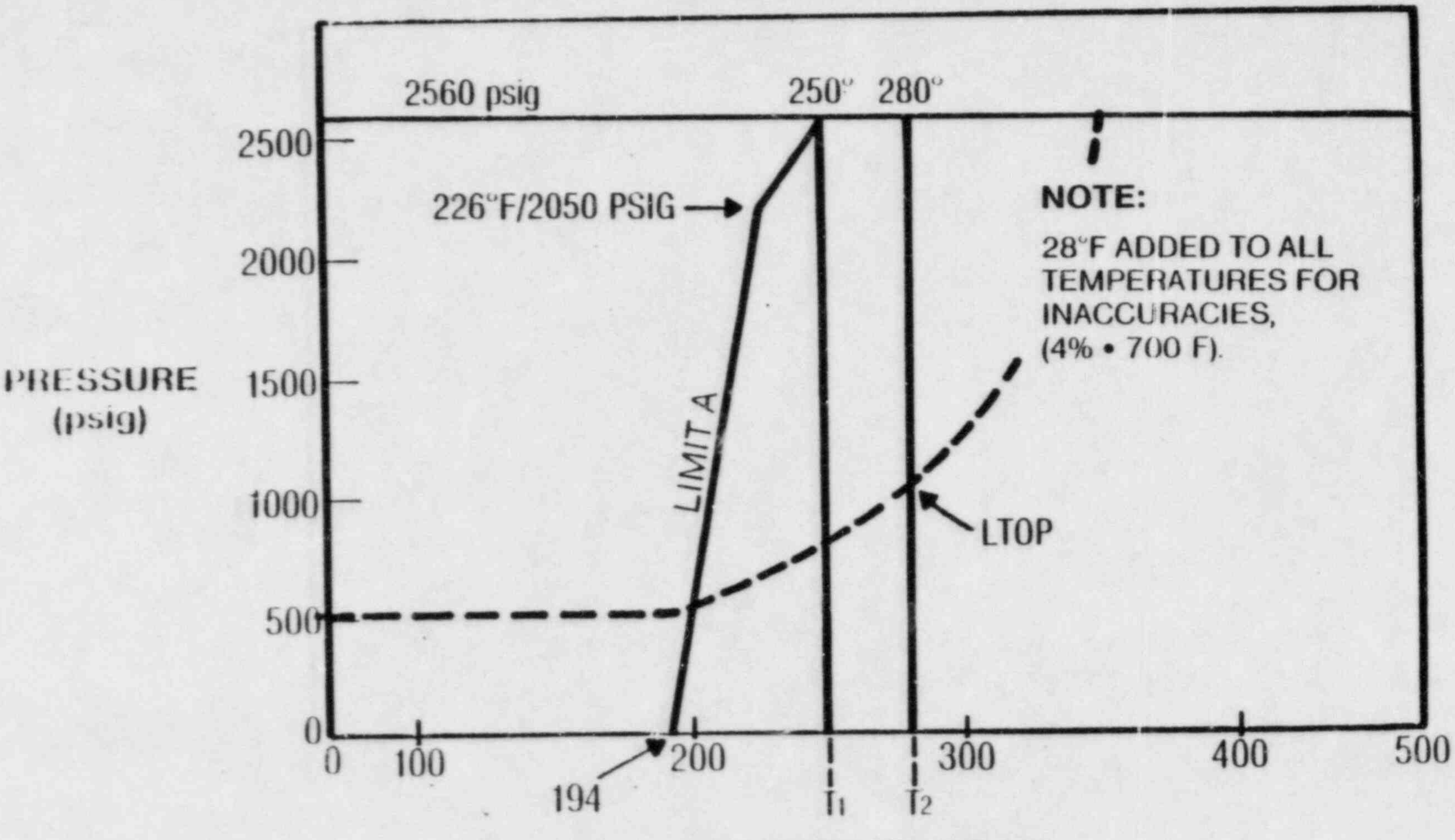


FIGURE 12

INTEGRITY CRITICAL SAFETY FUNCTION
POST - RECOVERY OPERATING RESTRICTIONS

FIGURE OP 14 (TC Rev 0 3/84)

FIGURE 14

Safety Function Status	Limiting Temperature In Transient	Soak Time Required	Cooldown Rate Restriction	Allowable RCS Pressure and Temperature Operating Band
Red	Crack T < Initiation Limit	1 Hour After Stabilizing RCS Temperature	50°F/hour After Soak	Between Minimum Subcooling Curve and 200°F Subcooling Curve
Orange	Crack Initiation < T < 250°F Limit	1Hour After Stabilizing RCS Temperature	50°F/hour After Soak	Between Minimum Subcooling Curve and 200°F Subcooling Curve
Yellow	250°F < T < 280°F	None	100°F/hour	Between Minimum Subcooling Curve and 275°F Subcooling Curve
Green	T > 280°F	None	100°F/hour	Between Minimum Subcooling Curve & Tech. Specification Cooldown Curve

FREQUENT QUESTIONS

The following questions have been commonly asked about procedure FR-P.1, RESPONSE TO IMMINENT PRESSURIZER THERMAL SHOCK CONDITION:

Q. Why are the criteria for SI termination reduced?

A. For the conditions existing when this procedure is entered, there is a high likelihood that SI flow was, at least partly, responsible for the RCS cooldown. It also would act to prevent RCS depressurization, which is a desirable action to reduce pressure stress on the vessel. The criteria assure that adequate core cooling and inventory exist at the present time, and will not be lost in the short term.

Q. What if the depressurization is prematurely stopped because of high PRZR level?

A. Following normal rules of usage, the operator would proceed in the procedure, establish normal letdown, reduce PRZR level, and then check if minimum subcooling had been established. If not, he would return and depressurize further, since PRZR level had been reduced. This process might be repeated.

OPERATOR RESPONSE TO ANTICIPATED PTS CONDITIONS

The Function Restoration Procedure FR-P.2, RESPONSE TO ANTICIPATED PRESSURIZED THERMAL SHOCK CONDITION," provides guidance in the event of an unexpectedly severe RCS cooldown following a reactor trip or safety injection actuation (indicated by the YELLOW terminus of the Integrity Status Tree). The operator is provided with instructions to attempt to prevent further cooldown and with guidance on subsequent cooldown restrictions required to safely achieve cold shutdown conditions.

This FRP is entered from the YELLOW branch of the Integrity Status Tree. The YELLOW branch conditions are defined by a pressure-temperature region as represented in Figure 11. The lower temperature boundary is defined as the upper temperature limit of the ORANGE region (temperature T_l). The upper temperature boundary is defined to be 30°F higher than the lower temperature boundary (temperature T_l).

The minimum size of the YELLOW region temperature difference (30°F) has been chosen to allow time for operator action to prevent entering the ORANGE region. As long as the T_l Limit line is not crossed, the plant can be safely cooled down at up to the Tech Spec maximum rate of 100°F/hr with no SOAK. However, lower cooldown rates are desirable.

MAJOR ACTION CATEGORIES IN FR.P-2

* Cold Leg Temperature has NOT exceeded RED or ORANGE LIMITS but has exceeded YELLOW LIMIT (< 280°F)

- Attempt To Stabilize Temperature
- Continue Only If ECCS Can Be Terminated
- Maintain RCS Pressure Within Pressure-Temperature Limits Of Tech Specs (LTOP)
- Cooldown At Less Than 100°F/Hr With Maximum of 275°F Subcooling

FREQUENT QUESTIONS

The following questions have been commonly asked about procedure FR-P.2, RESPONSE TO ANTICIPATED PRESSURIZED THERMAL SHOCK CONDITION:

Q. Why can't SI be reduced in this procedure?

A. Because FR-P.2 is only reached on YELLOW paths, entry into the procedure is, by rules of usage, at operator discretion. This means that SI reduction, if it were placed in the procedure, could not be counted on by the ORPs to be implemented. It is simpler to allow SI reduction to be performed as part of the normal recovery sequence in the ORPs, and then to perform the subsequent pressure reduction, if needed, in this procedure.

Background Information

for

HYDROGEN VENTING FROM THE RCS

INTRODUCTION

FR-I.3, RESPONSE TO VOIDS IN THE REACTOR VESSEL, is used when a gas void is detected in the reactor vessel, and when the operator determines that it should be removed. Any number of transients can result in a void, whenever saturation conditions exist in the vessel head, or gas is injected into or generated in the RCS. Removal of a void in the reactor vessel should not be attempted until a stable, subcooled RCS exists.

Entry to this function restoration procedure would usually occur through the critical safety function monitoring status trees, specifically from the Reactor Coolant Inventory tree whose branches show pressurizer level at or above normal, and a less than full reactor vessel.

In addition to reactor vessel level, other indirect indications of a void in the RCS (not necessarily in the reactor vessel head) are listed.

- Variations from the normal pressurizer pressure and level response due to normal charging and spraying operations may be observed if a gaseous void exists in the RCS. The pressurizer level may decrease during a RCS pressurization from charging due to gaseous void contraction and level may rise rapidly during a spraying operation due to a gaseous void expansion.

- Gases in the reactor coolant system may result from several types of plant events. An accumulator tank discharge or a core uncovery may result in non-condensible gases (e.g. nitrogen and hydrogen) being trapped in the RCS.

- A rapid RCS cooldown may result in the vessel head temperature being greater than the primary saturation temperature and result in a steam bubble being developed.

The operator should suspect the presence of gases in the RCS if any of the above events occur.

The configuration of the head vent system includes a single connection to the vessel head with series isolation valves in a common line. The common line includes a 3/8" orifice which limits the flowrate to within the makeup capability of the chemical and volume control system. The line is routed to the PRT.

RECOVERY DESCRIPTION

This function restoration procedure describes steps to remove the void. An initial attempt is made to condense the void. This attempt will ultimately succeed if the void is steam. If the void is gaseous, a head vent operation must be performed to remove the void. A general description of the procedure is presented below.

1) The initial step is to record the RCS pressure when this procedure was entered, for future reference.

2) After verifying the SI is not operating, the operator confirms that stable RCS conditions exist.

3) The next set of steps provide guidance to condense a potential steam void. This is done by increasing pressurizer pressure. If this operation is successful, the procedure is complete, and the operator

returns to the procedures in effect. If a void remains, it must be assumed to be a non-condensible gas, and head vent must be initiated.

4) Prior to initiating a head vent, certain conditions must be established to minimize system perturbations when the vent path is opened with a resulting RCS depressurization. The letdown path is isolated to minimize inventory loss. Pressurizer water level is maintained above the heaters, and pressure is adjusted to be at or above the initial RCS pressure. The pressurizer low pressure SI signal is blocked.

5) RCS subcooling is then checked. Since venting will reduce subcooling, 50°F margin should be achieved prior to operating the vent.

6) The final preparations before venting are then made. The containment isolation and ventilation systems are started. <u>The maximum allowable vent time to preclude an unacceptable hydrogen accumulation is determined</u>, and the other vent termination criteria are reviewed.

7) One vent path is opened, then closed when the reactor vessel is full or indicated level is stable, or when one of the other vent termination criteria is met.

8) If the venting was successful, this procedure is exited, after insuring stable pressurizer level. If it was not successful, the vent process is repeated.

DETERMINATION OF VENTING TIME

The amount of hydrogen released by the head vent is limited such that the bulk containment atmospheric concentration does not exceed 3% hydrogen by volume. Therefore, the concentration must be below 3% before any venting can commence. The lower the initial hydrogen concentration is, the longer the head vent operation can continue. After determining the containment hydrogen concentration, the operator must calculate the maximum allowed venting time. The formula and curve needed for this are contained in the procedure. The 3% limit provides assurance of a reasonable margin to a potentially explosive hydrogen concentration inside the containment.

The venting time calculation is presently the only "SIT DOWN AND CALCULATE" value in the ERPs, thus it deserves some attention.

INSTRUCTIONS FOR DETERMINING VENTING TIME

1. Determine Containment Volume at STP = A

$$A = (2.704 \times 10^6 \text{ FT}^3) \times \frac{\text{(Containment Pressure)}}{14.7 \text{ psia}} \times \frac{492°F}{\text{(Containment temperature)}}$$

2. Determine Maximum Hydrogen volume that can be vented = B

$$B = \frac{(3.0\% - \text{Containment Hydrogen Concentration}) \times A}{100\%}$$

3. Determine Hydrogen flow rate as a function of RCS pressure = C

   a. Check RCS pressure

   b. Using Figure FR-I.3-1 read hydrogen flow rate

4. Calculate maximum venting time

$$\text{Maximum venting time} = \frac{B}{C} = \_\_\_\_\_\_\_\_\_\_ \text{ minutes}$$

HYDROGEN FLOW RATE VS. RCS PRESSURE

FIGURE FR-I.3-1 (TC Rev 0 3/84)

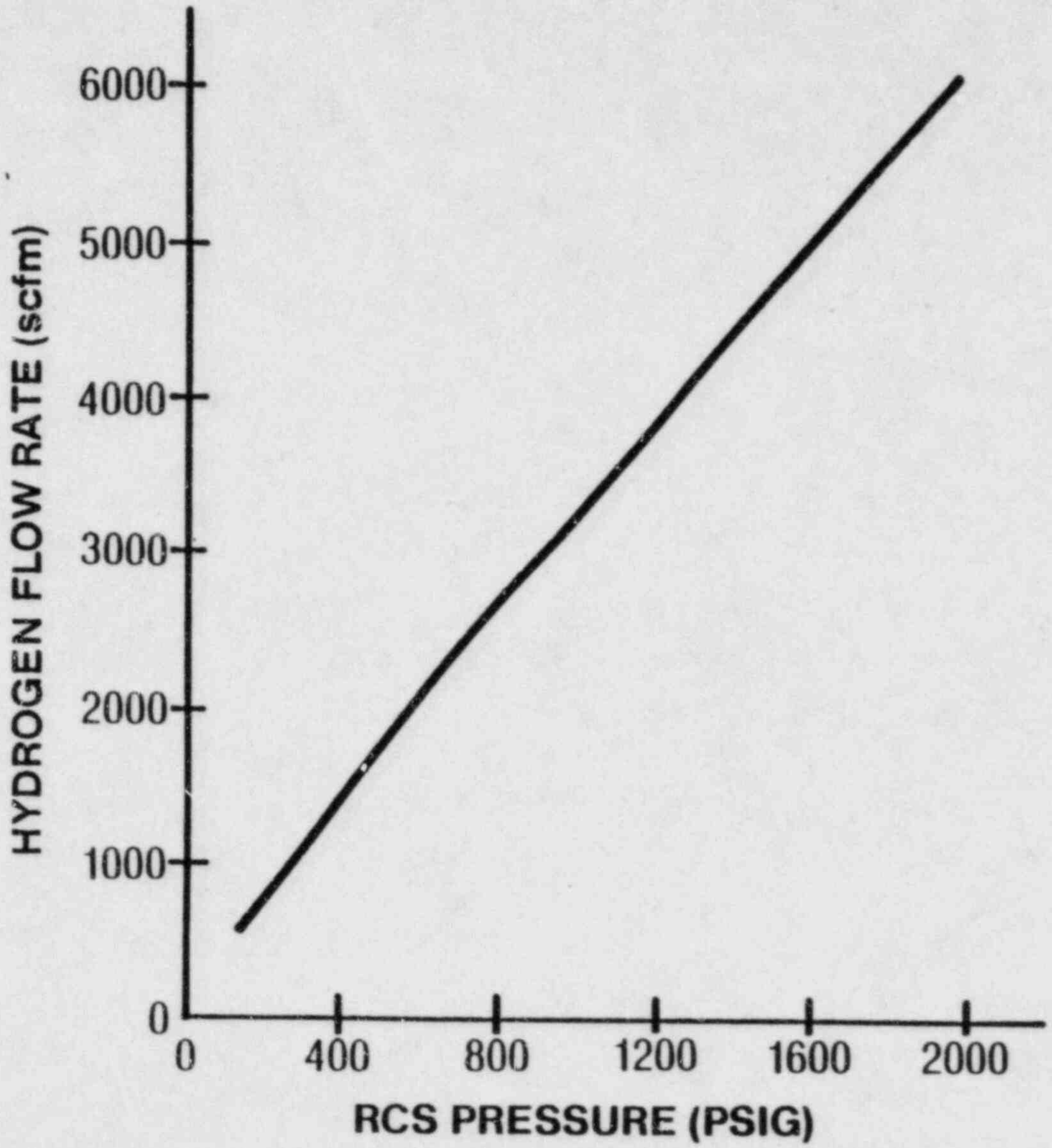


FIGURE FR-I.3-1

VENTING TERMINATION CRITERIA

- Reactor Vessel Full (RVLIS > 90%)
- Containment Hydrogen Concentration Exceeds 3 v/o
- Loss of Subcooling < 30°F
- Pressurizer Level Low (< 20%)
- RCS Pressure Decrease > 200 PSI
- Venting Time Greater Than Calculated
- PRT Rupture Disc Burst

Vent again if necessary if non-condensible void still exists.

Background Information

for

LOSS OF EMERGENCY COOLANT RECIRCULATION

INTRODUCTION

The "Loss of Emergency Coolant Recirculation (ECR) procedure," ECA1.1 has been developed as an Emergency Contingency Action (ECA), and it provides procedural guidance when emergency coolant recirculation capability is lost. Loss of emergency recirculation capability is defined as the loss of the ability to provide the recirculation function following a LOCA: i.e., the loss of the ability to inject fluid from the sump to the RCS using an RHR pump.

DESCRIPTION

The objective of the loss of ECR procedure is threefold: (1) to continue attempts to restore emergency coolant recirculation capability, (2) to delay depletion of the RWST by adding makeup fluid and reducing outflow, and (3) to depressurize the RCS to minimize break flow.

The following are symptoms or indications of loss of ECR capability:

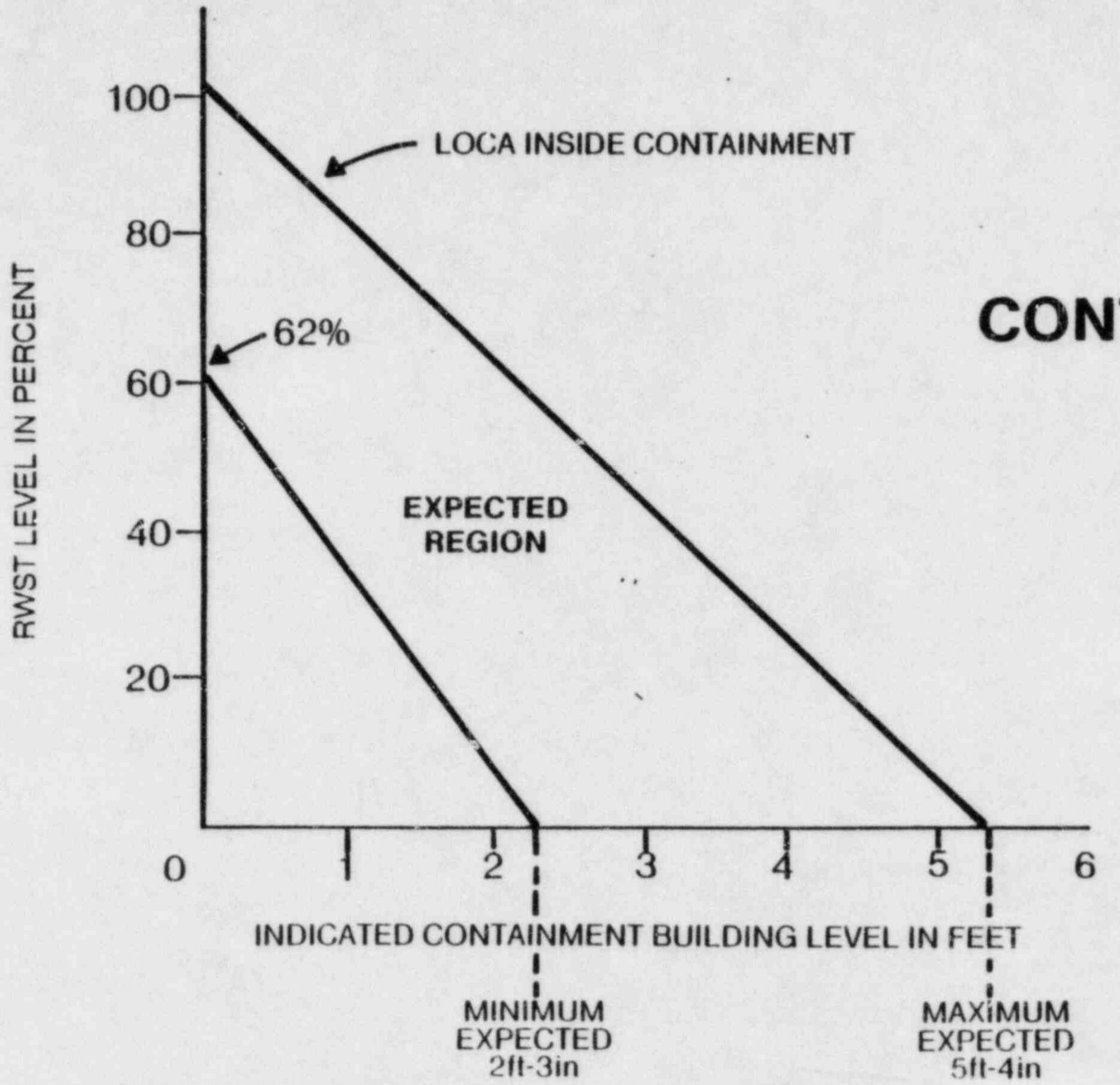
- Loss of BOTH Sump Isolation Valves
- Loss of BOTH RHR pumps
- Inadequate Containment Building Level due to a LOCA Outside Containment

Loss of ECR is potentially severe and could ultimately result in a Class IX event.

To minimize the possibility of getting into this situation, the ERPs contain check steps in procedures that are implemented prior to the need to establish ECR. This is done to give operators time to rectify the situation should equipment be unpowered or if incorrect valve lineups exist.

MAJOR ACTION CATEGORIES IN ECA-1.1

- Continue Efforts To Restore ECR
- Makeup To RWST From RMUS And Spent Fuel Pool
- Reduce ECCS To One Train To Minimize RWST Drawdown
- Operate Containment Spray Pumps Only As Necessary To Keep Containment Pressure Within Safe Limits
- Add Makeup To RCS From Other Sources (Charging from CVCT with RMUS)
- Depressurize SGs And Thus RCS To Inject Accumulators And Minimize Break Flow
- Reduce RCS Makeup To Only That Necessary To Match Decay Heat



CONTAINMENT LEVEL
VS.
RWST LEVEL

FIGURE OP (TC Rev 0 3/84)