BABCOCK & WILCOX
UTILITY POWER GENERATION DIVISION

TECHNICAL DOCUMENT

BELLEFONTE NUCLEAR PLANT

UNITS 1 & 2

ABNORMAL TRANSIENT OPERATING GUIDELINES

PART II

VOLUME 1

APPROVED WITH CORRECTION
AS NOTED
This approval does NOT relieve the Contractor from any responsibility for errors in the correctness of the drawings, details and dimensions. Drawings corrected as noted herein, are approved for construction.
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ATOG GUIDELINES PART II

INTRODUCTION

The accident in March, 1979, at the Three Mile Island Nuclear Power Generating Plant, has caused the Nuclear Industry's perspective of emergency operation to change. That accident was difficult for the plant operators to handle because several things were happening at once. Loss of Main Feedwater, Loss of Emergency Feedwater, and Small Break LOCA occurred at the same time. An incorrect interpretation of pressurizer level misled the operators to think the core was covered when it was not. The operators acted on that misleading information and core cooling was stopped when they shut down Emergency High Pressure Injection and the Reactor Coolant Pumps. The combination of multiple failures and incorrect interpretation of information are the two factors which have caused a new perspective of emergency operation to be developed.

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

When failures of equipment occur, they frequently cause a change in the heat transfer from the core to the steam generators. When the reactor is

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

Correlation Between Part I and Part II

Use of symptom-oriented procedures involves a different approach to plant control and requires a shift in emphasis in operator training. The operator is no longer limited by, nor is he required to solely rely on, the designer's foresight in providing the key alarms and indications for every conceivable event that could occur. The symptom approach of Part I will work, regardless of the event. By training on the ATOG approach, the operator will have a thorough understanding of heat transfer, plant control, and the various options available for controlled core cooling when

systems and equipment fail. Part II of ATOG was written to provide the basis for this understanding with the intent that it be used as part of the operator training program.

Part II, Volume 1

Volume 1, "Fundamentals of Reactor Control for Abnormal Transients," provides the basic background necessary for understanding heat transfer and builds on this information to enable the operator to recognize abnormal conditions when they develop and take the appropriate actions to correct them. Volume 1 covers primarily information regarding the heat transfer process, including subcooling and natural circulation. Volume 1 also shows how to use the P-T diagram and this knowledge of heat transfer to diagnose abnormal transients and mitigate them.

The preferred method of core cooling is with controlled primary to secondary heat transfer, and many abnormal transients involve restoring a balance to this heat removal path. However, this is not always possible; therefore, Volume 1 discusses core cooling methods when the steam generators are not available.

Volume 1 also covers operational methods for key systems (feedwater, HPI, etc.) and equipment for various conditions, provides guidance on verification of plant stability, discusses the fundamentals of reactor building control, and provides instructions on the use of the guidelines.

Volume 1 contains a considerable amount of information and should be studied periodically for optimum comprehension and retention. Three major points should be kept in mind when reading Volume 1:

1. Understanding heat transfer is essential.
2. Relationship of symptoms and control functions.
3. Differentiating between rules and guidelines.

Heat Transfer

One aspect of plant control and the use of ATOG cannot be overstressed: the importance of understanding heat transfer and primary pressure-temperature relationships. A thorough grasp of the heat transfer process and P-T relationships will enable the operator to:

- recognize abnormal conditions (symptoms)
- evaluate plant response to corrective actions
- implement backup cooling methods when needed

Although virtually any event or combination of events could conceivably occur, they all present the common threat of disrupting core cooling. Thus, the major thrust of ATOG is to maintain some form of controlled core cooling, whether it be by the steam generators or ECC systems. Simply put, understanding heat transfer allows recognition of symptoms of abnormal transients. Recognition of symptoms allows implementation of the appropriate sections of Part I. Implementation of the appropriate sections of Part I and verification of plant response allows stabilization and restoration of controlled core cooling.

Symptoms and Control Functions

Section III of Part I of the guidelines is divided into four main sections to address the three basic heat transfer symptoms (lack of subcooling margin, overheating, and overcooling) and the special case of SG tube rupture. Part II discusses the importance of heat transfer "control functions". These control functions are:

1. RC inventory
2. RC pressure
3. SG inventory
4. SG pressure

A fifth control function, reactivity, is also important in heat transfer considerations. However, reactivity is quickly controlled by reducing core power to the decay heat level by automatic reactor trip, manual reactor trip, and/or emergency boration.

If control of one of these four functions is lost, it will impact primary to secondary heat transfer and become evident as one of the three symptoms. For example, a loss of SG inventory control low (loss of feedwater) will result in a loss of primary to secondary heat transfer (overheating). Conversely, a loss of SG inventory control high (too much feedwater) will result in excessive primary to secondary heat transfer (overcooling).

When a symptom appears, one or more of these functions are not being controlled properly.

Rules and Guidelines

Volume 1 provides guidance on the operation of systems and equipment for many conditions and various events. When an action must always be taken for the conditions specified, it is called a rule and is enclosed in a box for emphasis. For example, the RC pumps must always be tripped whenever the subcooling margin is lost; therefore, it becomes the RC pump trip rule. (Note: If the subcooling margin is lost while the RC pressure is below the low RC pressure ESFAS setpoint or the RB pressure is above the high RB pressure ESFAS setpoint, the RC pumps will be tripped automatically otherwise, a manual RC pump trip is necessary.)

Whenever specified actions are recommended, but not mandatory, they are considered guidelines. For example, Table 6 in Volume 1 provides guidelines for RC pump operation for different plant conditions.

ATOG was designed for maximum flexibility in order to address the spectrum of conceivable transients. Therefore, rules have been kept to the minimum necessary. The user should remember, however, that the guidelines are also important and should be followed whenever they are applicable and feasible.

Part II, Volume 2

Volume 2, "Discussion of Selected Transients," provides detailed coverage of four specific initiating events. Since the ATOG concept is a break from the traditional event-oriented approach, Volume 2 was structured in the event-oriented approach to meet the following objectives:

1. Validate the ATOG Concept

Most operators involved in the initial implementation of the ATOG concept will be experienced with use of event-oriented procedures and may understandably be resistant to a different approach. Volume 1 discusses ATOG in a general overview manner and, standing alone, may not fully promote user confidence in the concept.

Therefore, Volume 2 is provided to give examples of representative events and how the use of ATOG will lead to successful mitigation. Although the event is given, the diagnosis and mitigation is written with the assumption that the operator (in the example) is unaware of the specific cause.

In addition, the discussion on each transient demonstrates successful mitigation of events compounded by other failures using the same basic ATOG procedure. This highlights the relative simplicity of using a single, comprehensive procedure as opposed to several discrete procedures.

Design bases accident analyses performed for FSAR Chapter 15 events employ conservatisms (e.g., 1.2 ANS decay heat curves) to establish margins of safety for limiting design conditions. In addition, these analyses assume worst possible initial conditions, hot channel peaking factors, etc.

The transients (except LOCA) depicted in Volume 2 are derived from more realistic analyses than previously used for design bases accident analyses. Thus these transient discussions should give the operator a better feel for how the plant would actually respond should similar conditions occur. (05)

2. Amplify Volume 1

The structure of Volume 2 provides a ready vehicle for conveying more detailed information about transient types (e.g., overcooling) and peculiarities and complexities of specific events. This is especially true for the appendices covering SG tube rupture and small break LOCA. These two events are unique in that they cannot be quickly terminated and stabilized. They impact many facets of plant operation and their mitigation is highly dependent on specific conditions at the time of occurrence (including the size of the leak). Consequently, considerably more event specific information is provided in these two appendices.

The entire purpose of these guidelines is to give an overview on reactor transients, their diagnosis and control, so transients as severe as the Three Mile Island accident will be prevented. Because transients will not follow a planned course, anything can happen. Consequently, a symptom-oriented approach is necessary to ensure transient control.

These guidelines should provide enough background and understanding so that no matter what happens, the operator will have sufficient understanding to correctly respond to the transient using the principles of heat transfer control.

CHAPTER A

BASIC HEAT TRANSFER

Introduction and Summary

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

The preferred way to protect the core and prevent fuel failure is to control the rate of heat removal by transferring core heat to the steam generators. Other ways to protect the core do exist; they are covered in a later chapter entitled "Backup Cooling Methods".

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

Heat Transfer Equations

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

Core heat ⟶ reactor coolant

Reactor coolant heat ⟶ steam generator water and steam

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

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

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

1. Generated Heat-which includes RC pump work and nuclear heat, which is the heat made within the core by the fission process; it includes decay heat.

2. Heat from the metal and water - which is the energy of the metal parts of the reactor coolant system and of the reactor coolant.

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

If the steam generators remove more heat than the core and RC pumps are creating, then they will remove both generated heat and stored heat; reactor coolant temperatures will drop. Normal cooldown is a condition when both generated heat and stored heat are being removed within a specified rate; this is a controlled condition. If the condition (cooldown rate) is abnormal or not controlled, then it would be called <u>overcooling</u> and corrective actions would have to be taken to bring it under control.

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

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

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

Equation 1) $\dot{Q}_{core} = \dot{Q}$ reactor coolant for the heat transfer path from the core to the reactor coolant

and

Equation 2) $\dot{Q}_{reactor\ coolant} = \dot{Q}$ steam generator fluid for the heat transfer path from the reactor coolant to the steam and water in the secondary side of the steam generators

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

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

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

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

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

<u>Equation 1a</u> $\dot{Q}_{core} = \dot{M}_{rc} Cp_{rc} (T_h - T_c)$

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

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

T_h = core outlet temperature (F)

T_c = core inlet temperature (F)

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

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

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

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

ΔT = temperature differential across the heat transfer boundary (F)

FOOTNOTE

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

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

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

The secondary side of the steam generator has four different regions along the tube bundle during power operation: subcooled liquid, nucleate boiling, film boiling, and superheat. Each region has a different heat transfer coefficient (U), surface area (A), and temperature differential across the tube wall (ΔT). The nucleate boiling region has the highest heat transfer coefficient of the four and accounts for approximately 70-85% of the total heat transfer into the steam generator over the power range.

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

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

Very little heat transfer occurs in the steam space without AFW spray (primary side temperature can be considered equal to hot leg temperature (T_{hot}) throughout the steam space). Even though the area is large, the heat transfer coefficient is small due to low steam flow rates and low density with respect to the water region. During forced circulation the ΔT across the tube walls in the steam space is also very small as T_{hot} is close to the saturation temperature (T_{sat}) of the steam. The ΔT is larger between T_{hot} and T_{sat} during natural circulation but the heat transfer coefficient is even smaller due to the lower reactor coolant flowrates.

The major factors affecting heat transfer in the water region are changes in surface area and the ΔT between the primary and secondary sides. Surface area is increased by increasing feedwater flow to raise level. The primary increase in area initially takes place in the subcooled water region. Even though most of the heat transfer occurs in the nucleate boiling region, overall heat transfer is increased because the area of the steam space (with a very small heat transfer coefficient) is decreased and replaced by area in the subcooled water region (with a relatively much larger heat transfer coefficient). This increase in heat transfer is transitory; i.e., after feedwater flow is decreased to that required to maintain the higher level, most of the added inventory becomes saturated water and, all other factors being constant, the total heat transfer rate returns to that existing before the level was increased.

The most significant means of affecting primary to secondary ΔT is on the secondary side by varying steam pressure. When steam pressure is decreased (e.g., by opening turbine bypass valves), saturation temperature also decreases, which increases the ΔT across the tube wall. The higher ΔT causes heat transfer (Q_{sg}) to increase, thus cooling the primary side. Of these two factors (surface area and ΔT), ΔT is the major factor. Effects due to surface area are only significant while the surface area is changing. Once a constant water level is maintained, changes in heat transfer are primarily due to changes in ΔT.

Heat transfer can be increased significantly by injecting auxiliary feedwater which enters the SG through the upper nozzles. The increase in heat transfer is due to several factors. First, the spray of feedwater into the steam space reduces steam pressure similar to the action of pressurizer spray. This reduces the saturation temperature which increases heat transfer as described previously. Second, where water contacts the tube surfaces in the steam space the heat transfer coefficient is increased, essentially replacing steam area with water area as in the case of raising steam generator level. Third, AFW will have a greater cooling effect than main feedwater due to its cooler temperature.

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

In summary, the operator can control primary to secondary heat transfer after reactor trip by controlling two major parameters on the secondary side (assuming the capability of the reactor coolant to transport core heat to the steam generators remains intact). The

operator can increase heat transfer by reducing steam pressure or by raising steam generator level (increasing feedwater flow rate). He can decrease heat transfer by allowing the steam generator pressure to increase.

Control of Heat Transfer

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

The five fundamental functions of heat transfer control are:

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

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

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

4. Steam Generator Inventory Control - The water-steam inventory is the heat transfer fluid which removes the heat from the reactor coolant. In order for it to remove heat at the correct rate the amount of fluid and its flow rate through the steam generator must be controlled.
5. Steam Generator Pressure Control - The water temperature of the reactor coolant is best controlled by controlling the pressure of the steam generator. In combination with reactor coolant pressure control, steam generator pressure control will maintain the reactor coolant in a subcooled liquid state.

Each one of these control functions are discussed individually as they relate to heat transfer.

Steam Generator Pressure Control

Heat transfer from the reactor coolant to the steam generators goes to both the steam and water in the generator. After reactor trip, the steam and feedwater in the generator are saturated and changes of steam pressure will cause a direct change in the saturation

temperature of the steam and water. A review of the saturated water and steam properties will show how much the steam and water temperature will be changed by increasing and decreasing steam pressure. There are situations where the operator controls the steam pressure manually using the condenser dump valves or the atmospheric dump valves. When the steam pressure is lowered, the heat transfer from the reactor coolant to the steam generator increases because the steam and water in the steam generator become a colder heat sink causing more heat to flow away from the reactor coolant. Two reasons combine to create the colder heat sink: first, the saturation temperature of the steam and water is reduced by lowering the steam pressure, which causes the rate of boiloff to increase. The increased boiloff takes away more heat. Second, the increased boiloff requires more feedwater flow to be added to maintain level. The feedwater inlet temperature is colder than the water already in the steam generator, thus its addition contributes to the colder heat sink. Because a colder secondary heat sink exists, the primary side temperature will decrease as heat is transferred. (05)

Steam pressure can be lowered in two ways:

- By opening the steam line and releasing steam (condenser dump valves, steam line break, ADV etc.).
- By spraying cold AFW into the steam space and condensing it. This is similiar to the way pressurizer pressure is reduced by the presurizer spray.

Steam pressure can also increase; but normally it will only increase from the operating condition to the reactor trip condition where it will be limited by the the ADVs and CDVs, so the effect on reactor coolant temperature is small. But if steam pressure is initially low because of a failure, for example a steam line break, the subsequent increase in reactor coolant temperature could be much larger when the steam break is isolated. After isolation, the reactor coolant adds heat to the generator and causes the steam pressure to increase. Without operator action, steam pressure would increase to the CDV, ADV, MADV, or MSSV setpoint. The operator can limit the increase in reactor coolant temperature under these conditions by manual control of the turbine bypass valves or MADVs to limit the increase in steam pressure.

Steam Generator Inventory Control

Heat transfer from the reactor coolant goes to both the steam and the feedwater in the secondary side of the steam generators. When changes of feedwater flow or steam pressure occur, the volumes occupied by the steam or water will change and the heat transfer will change. For example, when the volume of water increases, it occupies space formerly occupied by steam, so the volume of steam has to decrease. This changes the relative amounts of tube surface area covered by water and steam. Water has a greater heat capacity than steam does, thus it is a better heat sink for the reactor coolant

than steam. Simply stated, there are more pounds of water in a cubic foot to absorb heat than there are of steam. If the water inventory increases, then the generator will become a better heat sink for the reactor coolant; but if the water inventory decreases or is lost, the generator will lose some or all of its ability to absorb heat from the reactor coolant.

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

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

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

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

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

b) T_{inlet} feedwater is colder for AFW than for MFW, (05)

c) it has a steam pressure reduction effect that main feedwater does not have because it is injected into the steam space at the top of the tube bundle.

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

For example, if <u>all</u> feedwater is lost, the water in the generator will boil away and only steam will remain to remove heat. But because the steam does not have enough heat capacity, the reactor coolant must retain the core heat and the reactor coolant temperatures will increase. When all feedwater is lost, the reactor

coolant pressure will increase to the PORV setpoint and the reactor coolant will eventually become saturated as the core continues to add heat. The SG pressure will drop. The rate of pressure drop can be quick if a steam valve is open or will be slow if the pressure drop is due only to steam condensation. Loss of the steam eliminates the heat sink of the steam generators altogether.

Finally, another part of steam generator inventory control is feedwater temperature. The heat sink of the generators will be affected by an abnormally low feedwater temperature. A reduction of feedwater heating steam or loss of a feedwater heater will cause reactor coolant temperature to decrease. Usually ICS operation will stabilize the plant, but the decreased feed temperature will cause a change in the heat sink and an increase of heat transfer from the reactor coolant.

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

Reactor Coolant Inventory Control

Reactor coolant heat transfer can be affected by changes in the RC inventory (the mass of fluid in the reactor coolant system) or by changes in the pressure and temperature of the reactor coolant. (05)

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

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

1) A loss of mass can affect the ability of the reactor coolant to transport heat from the core to the steam generators. If the RC pumps are not running, steam can collect in the hot legs and block natural circulation. When circulation and heat transport stops, then the steam generator temperature will not "set" the temperature of the reactor coolant; T_{cold} will not change due to changes in the SG T_{sat}. However, the T_{cold} indication may go down due to RC pump seal injection or HPI flow. (05)

If the mass of the reactor coolant system continues to decrease and the core becomes partially or completely covered by steam, then (05) the mass of coolant remaining will not provide a sufficient heat sink and the core will retain the heat and heatup. Fuel failures can result if this situation is not corrected.

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

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

The operator has indications to determine if the inventory is sufficient for core cooling. Pressurizer level is an accurate measure of the inventory when the rest of the reactor coolant is subcooled (except for a rare possibility when free hydrogen gas may exist in the loops; this condition will likely exist only after fuel failures caused by uncovering of the core). The other measure is the incore thermocouples; if these read subcooled or saturation temperature, then enough mass exists in the reactor vessel to cover

and cool the core. But the incore thermocouples will not show if the loops are full. In addition to these indications, hot leg level measurements can be used when no reactor coolant pumps are runnning and the high point vents are closed. Reactor vessel head level measurement is also available for checking inventory in the RV head.

Reactor Coolant Pressure Control

Reactor coolant pressure control is required to keep the reactor coolant subcooled so that the coolant is in the best state to transfer heat from the core to the steam generators. Usually, RCS pressure control is provided by the pressurizer. (Reactor coolant pressure control is different for LOCAs and LOFW than for other plant conditions. LOCA control is discussed in detail in Appendix D. Control following LOFW is discussed in detail in Chapter D, "Backup Cooling Methods"). Use of pressurizer heaters and spray is the usual way of increasing and decreasing RCS pressure when a steam and water interface exists in the pressurizer. The purpose of the heaters is to maintain the reactor coolant in a subcooled condition by maintaining RCS pressure > saturation pressure; the spray retards pressure increases to limit operation of the pressurizer relief and safety valves. Neither the heaters nor spray have enough capacity to prevent large abrupt pressure changes, but they can moderate

small changes. As a backup, auxiliary spray from HPI or LPI can be used. The PORV can also be used to reduce pressure but it is not as desirable to use as the spray because it relieves to the RC drain tank and because of the possibility of PORV failure. Frequent use of the PORV can result in failure of the drain tank rupture disk. (05)

RCS pressure control by the pressurizer can be lost in four ways: (05)

1) The steam-water interface in the pressurizer can be lost either by draining the pressurizer or if the pressurizer fills solid with water
2) The heaters and spray can fail.
3) Noncondensible gases can accumulate in the pressurizer.
4) Large voids can develop elsewhere in the RCS.

The first two of these are discussed below, the last two are discussed in Appendix D. (05)

Draining the Pressurizer:

If the pressurizer level drops sufficiently to uncover the heaters, the heaters cannot provide pressure control because no water is available to be boiled by the heaters to create steam. If the pressurizer drains completely, RCS pressure will then be controlled by the highest fluid temperature at saturation in the system.

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

Filling the Pressurizer:

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

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

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

Failure of Spray and/or Heaters:

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

Reactivity Control

Reactivity control is usually taken care of automatically by ICS rod control or by reactor trip. Reactor trip lowers the core heat output

to the decay heat level. The operator must verify rod insertion and decreasing reactor power to ensure the reactivity control systems function properly. After the trip no more heat transfer control can be achieved by use of the rods, unless the rods did not insert. If after manual trip, reactor power is not decreasing (total failure to trip) the operator should begin boron addition by HPI and manual rod insertion, while performing local breaker trips. If one rod remains stuck out, the operator should begin emergency boration and a reactivity balance calculation should be performed to ensure a shutdown margin in excess of 1% $\Delta k/k$ is achieved.

Summary

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

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

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

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

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

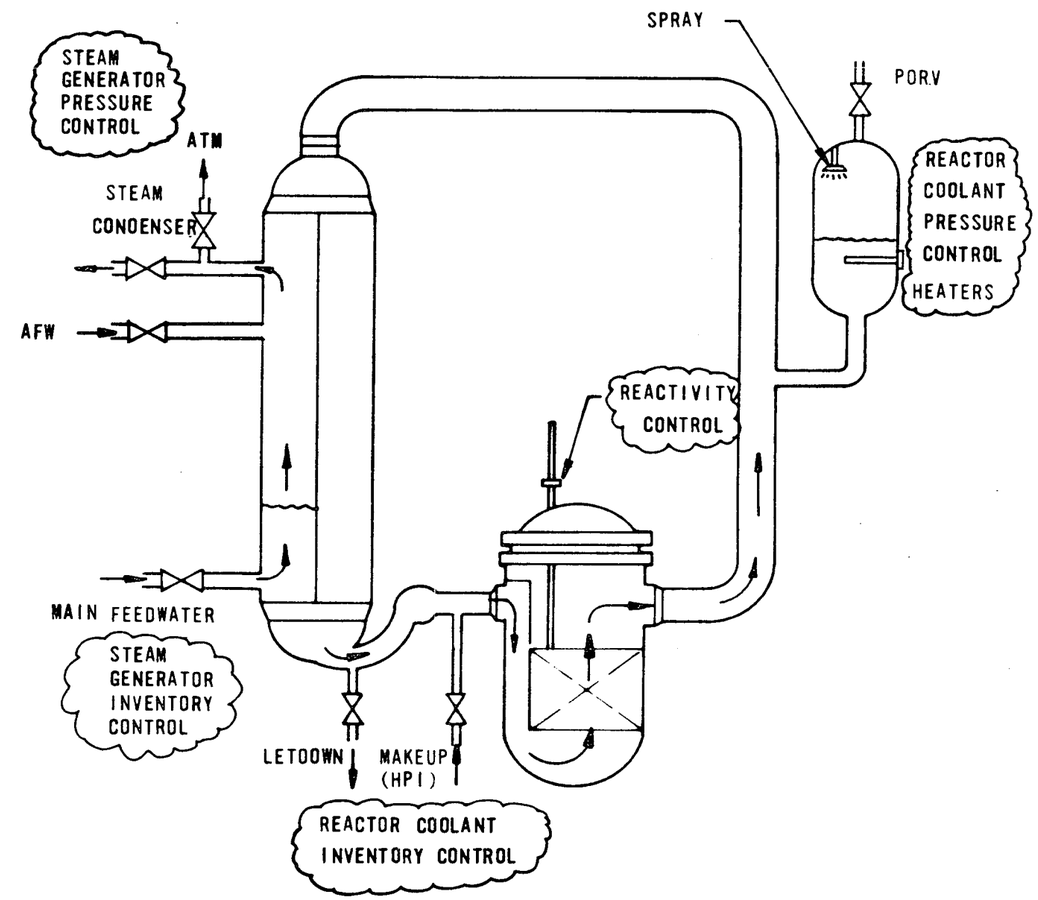
1. He can treat the symptoms by manipulating equipment to regain heat transfer control without knowing exactly which equipment has failed. Consequently, proper heat transfer can be restored quicker and more accurately than if the operator had to hunt for the equipment failure. In some instances, treating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

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

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

The next section builds on the information about heat transfer and extends those principles into a disciplined approach to transient diagnosis and recovery.

Figure 1 FUNDAMENTAL METHODS OF HEAT TRANSFER CONTROL



ADDENDUM A

(SUBCOOLED, SATURATED, SUPERHEATED WATER)

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

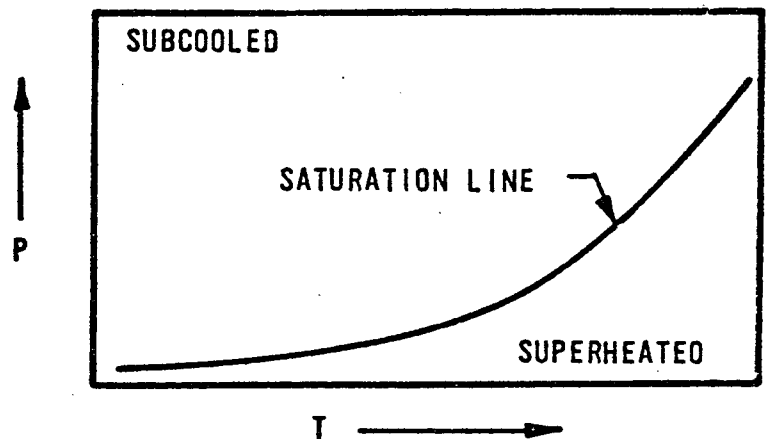
Subcooled: Water can exist only in the liquid state.

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

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

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

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



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

Subcooling

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

1. The primary loops are solid water and water is present within the pressurizer (it may have a level with a steam bubble or be solid).
2. The pressurizer water level is a true measurement of RCS inventory (with no breaks in PZR steam space e.g. open PORV). The inventory can be controlled by regulation of pressurizer level by the MU and/or HPI system and letdown. (NOTE: A very special case can exist when the reactor coolant is subcooled and a water level is in the pressurizer but the loops are not full. In that case pressurizer level is not a true measurement of inventory. That condition is when there is a large amount of free gases in the loop. The gases will be mostly H_2 that have been created after a large amount of fuel failure. Since this would be an uncommon event, reliance on pressurizer level is usually acceptable when the reactor coolant is subcooled.)
3. The reactor coolant is liquid and is ideal for heat removal from the core and heat transport to the steam generator by either forced or natural circulation.
4. RC pressure can be maintained by the pressurizer and can be regulated by using normal procedures and equipment (spray and heaters) unless the pressurizer is solid.
5. RC temperature can be controlled by the secondary system (with feedwater available) and can be regulated by adjusting feedwater flow and steam pressure.

Subcooling should be checked in all parts of the loop, especially when natural circulation is removing heat. The operator should check T_{hot} and T_{cold} in both loops and the core exit thermocouples. Anytime the reactor coolant gets too close to saturated conditions, the HPI system should be turned on full. The reactor coolant is too close to saturated conditions if subcooling decreases below a subcooling margin limit which is approximately 20-30F subcooled. Subcooling margin is explained in more detail in Chapter B.

> HPI Subcooling Rule:
>
> WHENEVER the reactor coolant subcooling margin does not exist
>
> THEN two HPI pumps must be run at full capacity.

Saturation

A loss of subcooling can occur when the pressurizer drains or when filled solid (if the pressurizer is solid because of HPI and adequate core cooling is provided by the steam generators or HPI flow, then the reactor coolant may stay subcooled). A loss of subcooling can be caused by an overheating or overcooling transient or a loss of reactor coolant. Saturated conditions can exist in isolated pockets of the RCS (e.g., within one or both hot leg pipes or the reactor vessel head but not in the

cold leg pipes) or within the system as a whole, as would be the case during a major LOCA. Therefore, temperatures should be checked in the hot legs of both loops. When the RCS has saturated conditions:

1. The reactor coolant temperature and pressure will not show whether the saturated fluid is liquid or gas (steam).
2. Voids (steam bubbles or pockets) can exist within the primary system, even if the temperature indications show subcooled conditions. These steam bubbles will exist until they can be moved to a point of heat removal or vented.
3. The pressurizer water level indication is not a true measurement of reactor coolant inventory.
4. With the RC pumps off, a loss of natural circulation may occur, because steam voids can form at the top of the hot legs and block water flow.
5. Normal pressure control by the pressurizer has been lost. The RCS hot leg loops and/or reactor vessel (RV) head, which have a steam bubble at the top, now work as a pressurizer. RC pressure will be controlled by the highest fluid temperature in the system. The amount of steam can change because of steam condensation by the steam generators, by addition of cold HPI water to compress the steam, or by loss of steam generator heat removal.

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

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

Superheating

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

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

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

See "Backup Cooling Methods" section for a discussion of Inadequate Core Cooling.

ADDENDUM B

NATURAL CIRCULATION

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

Thermal Center Definition

1. Core thermal center: That elevation in the core which the reactor coolant may be considered to go from T_{cold} to T_{hot}.

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

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

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

- The friction (resistance to flow) of the piping and components around the primary loops: this is determined when the plant is designed and built; the operator has no control over it.
- The strength of the heat source: this depends on the existing decay heat, which is a function of past power history and time since the reactor trip. It will, of course, decrease with time after trip. The operator has no control of this after trip except to make sure the reactor is shut down so that the only heat input is decay heat.
- The strength of the heat sink: the colder the heat sink, the more it will be able to cool the primary coolant passing through the steam generator. This will make the water more dense and the natural circulation flowrate will increase. The operator can make the heat sink colder by lowering secondary steam pressure (opening

the condenser dump or atmospheric dump valves); this will lower secondary saturation temperature, which will increase heat transfer across the tubes.

- Difference in height between the core thermal center and the steam generator thermal center: As the difference in height (SG thermal center higher) becomes larger, the natural circulation flow will increase. The core thermal center is fixed, but the operator can control the steam generator thermal center. Most of the heat transfer occurs in the nucleate boiling region just below the established secondary side water level. Therefore, the operator can raise the thermal center by raising the steam generator water level.

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

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

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

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

ρ_c = density of cold water at steam generator thermal center

ρ_H = density of hot water at core thermal center

This is shown graphically in Figure 2.

Natural Circulation (All Other Conditions Normal)

When the reactor coolant pumps are tripped, the operator should check two things to make sure natural circulation is being initiated properly. First, he should make sure the reactor coolant remains subcooled. If it does not, he should make every effort to restore subcooling (the methods for doing this are discussed in Chapter C "Abnormal Transient Diagnosis and Mitigation"). Second, he should make sure the thermal center is being raised in both steam generators. Normally, automatic equipment will increase level at a controlled rate to the Mode B level setpoint in each steam generator when the RC pumps trip. The operator should monitor this process to ensure proper automatic operation.

Figure 3a shows how RCS temperature and pressure, and steam generator temperature and pressure will vary during the transition to natural circulation. Approximate times for the transient are also included. The times are approximate because they depend on the amount of decay heat available. When steady state is reached, the cold leg temperatures (T_{cold}) will be just about equal to the saturation temperature in the steam generators. The hot leg and incore thermocouple temperatures will increase as necessary to develop the driving head required for flow (by developing a density change between T_h and T_c). The best measures to use to see if natural circulation has started are the coupling between T_c and the steam generator temperature, the relationship of T_h and the incore thermocouples, and the temperature difference between T_h and T_c. When the incore thermocouples, T_h, and T_c are subcooled, they should follow steam generator T_{sat} when it changes; the temperature difference between T_h and T_c should be ∿50-60F (maximum decay heat with both SG levels at the natural circulation SG level setpoint) and an average of the five highest incore thermocouples should track T_h within approximately 10F. If T_c only is subcooled, and T_h and the incores are saturated, natural circulation characteristics should be the same as if they are all subcooled. The incores will not provide verification of flow since both T_h and the incores are saturated; however, the incores are the best and most direct means of assessing the adequacy of core cooling.

Once natural circulation is established and the higher steam generator levels are reached, the operator must ensure feedwater remains available to replace the steam generator water being boiled off removing decay heat and to maintain the RCS subcooled.

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

Natural Circulation Cooldown

Natural circulation is usually the result of loss of power to the RCP motors and/or loss of services (cooling water and seal injection) to the RCP's. Experience has shown that the existence of either of these causes for an extended period of time is a very unlikely occurrence. Therefore, if a forced shutdown is not required it is preferable to maintain hot standby while on natural circulation and delay cooldown until forced circulation can be restored.

However, if a natural circulation cooldown is desired or required, the operator must be aware that the reactor vessel (RV) upper head will not cooldown at the same rate as the RCS loops. The hot, stagnant fluid in the RV upper head can flash to steam as depressurization occurs, even though the loops are subcooled. Thus, the RCS loop minimum subcooling margin alone is not a good indication of RV upper head conditions during a natural circulation cooldown. (The next chapter, "Use of the P-T Diagram," provides a description of the minimum subcooling margin). Steam

bubble formation in the RV upper head is not in itself a safety problem, but it could restrict further depressurization. Therefore, actions should be taken to avoid steam bubble formation in the RV upper head during natural circulation cooldowns.

Forced circulation flow with RCP operation provides sufficient mixing flow in the RV upper head to cause to it cooldown along with T_{hot}. Without forced circulation flow, the upper head region becomes virtually stagnant, with a very low heat loss rate to the cooler surroundings. The natural circulation cooldown and depressurization rate can be limited to the rate of heat loss from the upper head, thus preventing void formation. However, this is not an adequate cooldown method for cases that require rapid depressurization and cooldown, such as a small break LOCA.

The preferred method, if a natural circulation cooldown is required, involves bleeding of the hotter subcooled coolant from the upper head out the RV high point vent. This bleeding prevents flashing under the RV head which results in a faster cooldown rate in the upper head and, consequently, a faster allowable rate of depressurization. The RV upper head can be cooled by bleeding at least 3000 gallons of coolant from the RV head vent for each 50F of RCS loop cooldown.

If a 50 gpm average bleed flow rate is maintained during cooldown, the RV upper head cooldown will not limit the RCS loop design cooldown rate of 50 F/hr. Therefore, a natural circulation cooldown with an average 50 gpm

bleed rate will require no additional feedwater beyond that required for a forced RCS circulation cooldown. The head vent design maximum flow rate is 200 gpm, thus full bleed for 15 minutes of every hour will provide the 50 gpm average.

As previsouly stated, the normal subcooling margin line is not adequate for monitoring RV head saturation conditions during a natural circulation cooldown. Therefore, a lower temperature limit for T_{hot} is required. This is shown on Figure 3b.

Figure 3b depicts a natural circulation cooldown using the larger subcooling margin and periodic venting from the RV head. In this case, a 15 minute vent at 200 gpm is shown in order to achieve the required 3000 gallon bleed for every 50F cooldown. Basically, the natural circulation cooldown depicted by Figure 3b is performed as follows:

1. The RCS is cooled at $\leq$ 50 F/hr and depressurized (using auxiliary spray and/or the PORV) until T_{hot} approaches the natural circulation temperature limit.
2. The RC pressure is held constant with makeup and pressurizer heaters and the cooldown is continued until T_{hot} is 30 to 50F colder than the natural circulation temperature limit. Simultaneously, the RV head vents are opened (in this case for 200 gpm bleed rate) as required to achieve 15 minutes of venting for every 50F of cooldown ($\sim$ 3000 gallons of bleed for each 50F of cooldown). (05)
3. The RCS is again depressurized while continuing the cooldown.

It should be noted, however, that a 200 gpm bleed rate will probably overpressurize the RC drain tank. Therefore, if possible (e.g. the condenser is available so that condensate storage is not limiting), the bleed time should be somewhat shorter than the 15 minutes, with a corresponding slower cooldown rate, to prevent failure of the drain tank rupture disk. The drain tank cooling should also be maximized.

Following this basic natural circulation cooldown procedure should prevent void formation in the RV upper head. However, should a head bubble develop, it can be mitigated by stopping the cooldown and again using the RV head vents. Some symptoms that indicate possible void formation in the RV head are:

- Pressurizer level increasing unexpectedly while operating auxiliary spray.
- Letdown flow unexpectedly greater than makeup flow while pressurizer level control is in automatic.
- Void level formation as indicated by the RV level monitor when the RV head vent is not in use.

Pressurizer level decreasing while operating makeup pumps can indicate the existence of a RV head void.

Natural Circulation - Abnormal Operation

The discussion so far concerned expected or normal natural circulation conditions. That is, the RCS is subcooled, the level in both steam generators is at the natural circulation setpoint, and both steam

generators are being steamed. This section will discuss the following off normal conditions:

1) natural circulation with only one SG operating, 2) natural circulation with a saturated RCS, and 3) recognition of loss of natural circulation.

Natural Circulation Cooldown With Only One Operating SG

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

Only T_{hot} in the operating loop will indicate core outlet temperature. T_{cold} on the operating generator will be equal to T_{sat} in the operating steam generator; T_{cold} in the isolated generator will not be equal to T_{sat} in the isolated generator, it will probably be much colder being influenced by seal injection water temperature coming into the idle pumps. (T_h-T_c) on the operating steam generator may be 10F higher than the 50-60F ΔT expected with two operating SGs and the level in the operating steam generator may have to be raised above the natural circulation setpoint to maintain adequate natural circulation flow. Steady state operation under these conditions is stable and safe. Plant cooldown, however, is complicated because the cooldown of the loop with the isolated steam generator will lag behind the steaming steam generator. The reactor coolant in the idle loop may flash to steam. If this happens, that hot

leg will act as a pressurizer and slow down the depressurization during cooldown. This will also slow down the cooldown rate. The operator must carefully watch subcooling in both loops under these conditions and make sure adequate subcooling margin is maintained by regulating the rate of cooldown with steam pressure control of the operating steam generator.

Natural Circulation with a Saturated RCS

A subcooled reactor coolant system is the desired state, however, natural circulation can still remove core heat when the RCS is saturated. As long as the four requirements for natural circulation are met, heat will be removed from the core and transferred to the steam generator. The problem with saturated natural circulation is that the operator doesn't know how much of the reactor coolant is steam and how much is water (see discussion of saturation in Addendum A). If the RCS is losing inventory, steam will form in the hot legs and eventually stop natural circulation flow (this is a violation for the requirement that a flow path exists connecting the hot water and the cold water*). A steam void of sufficient magnitude to stop natural circulation flow should be evident on the hot leg level measurement instrumentation.

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

Another form of natural circulation could still exist under these conditions called boiler-condenser cooling (boiling in the core and condensing in the steam generator) but it requires a higher steam generator level (80% on full range). This method is discussed in detail in the Backup Cooling Methods chapter of these guidelines.

Recognition of Loss of Natural Circulation

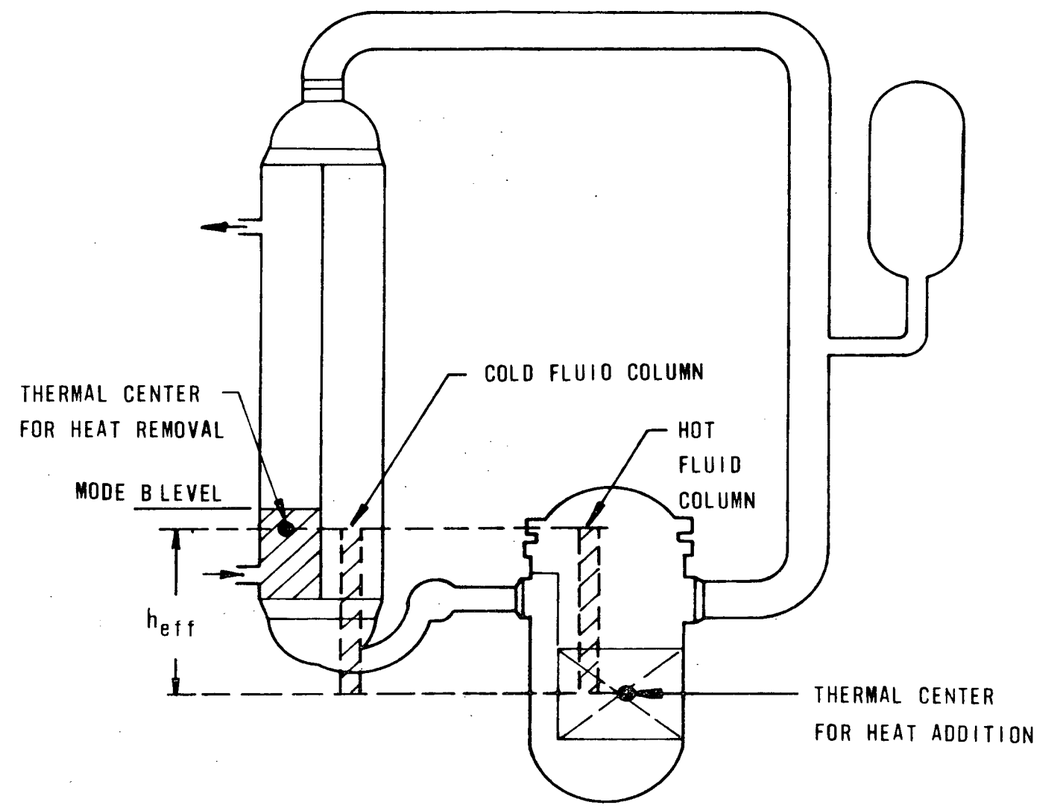
A loss of natural circulation can occur for various reasons and several indications may be available. If the RCS is subcooled, a loss of natural circulation flow is more than likely a result of inadequate heat removal by the steam generators. The thermal center in the steam generators may be too low. At low decay heat levels or during single loop cooldown, the SG levels may have to be raised above the natural circulation setpoint to induce or maintain natural circulation flow. When natural circulation flow exists, T_{hot} and the incore thermocouples will track together within ∿10F (although there will be some time lag due to long loop transport times). In addition, T_{cold} and T_{sat} of the SG should track together.

The best single indication of a loss of natural circulation flow when the RCS is subcooled is a divergence developing between the incore thermocouples and T_{hot}. When the flow is lost, the incore thermocouples will begin a continual increase toward saturation. The rate will depend on the decay heat level. T_{hot} indications may also increase but can actually decrease and begin to converge with T_{cold}. In any case, T_{hot} will not

increase as rapidly as the incore thermocouples and the two indications will diverge. Another indication of loss of natural circulation is a "decoupling" between T_{sat} in the SG and T_{cold}. If T_{cold} ceases to follow T_{sat} in the SG, natural circulation flow is lost. However, this is not as positive an indication as the divergence between the incore thermocouples and T_{hot}.

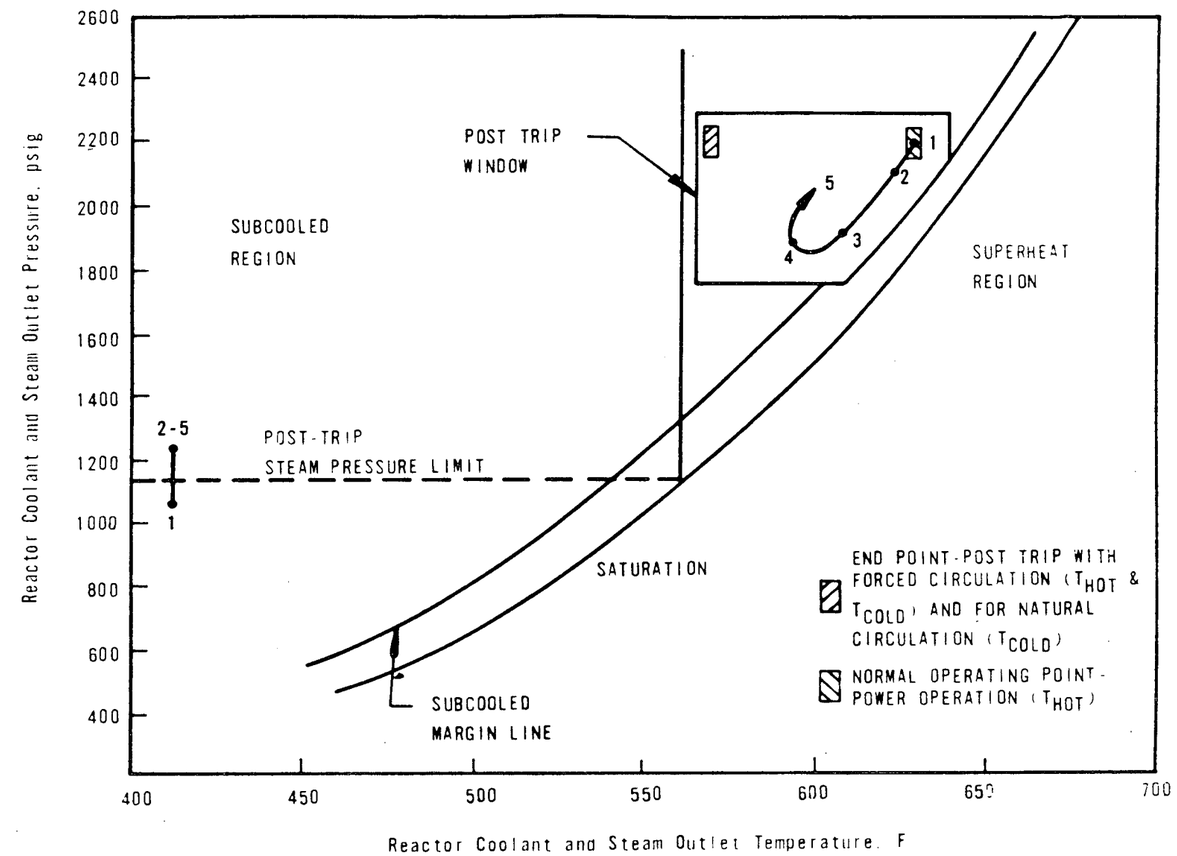
When the RCS is saturated and natural circulation flow is lost, this divergence may not develop significantly. The best indication of a loss of natural circulation flow when the RCS is saturated is a trend of incore thermocouple temperature vs. RCS pressure increasing along the saturation curve. Flow can be lost due to low thermal centers in the SG's or blockage due to voids in the RCS. When the RC is saturated, the SG levels should be maintained at 40 ft. (80% on the full range), and full HPI flow should exist. If voids exist in the RCS, it is possible that boiler-condenser cooling is in progress. As the RCS refills, cooling in this manner is expected to be lost when the RCS liquid level increases above the AFW nozzles. However, in this case cooling should be restored by continued refill and by following the actions specified in Section III B of Part I (RCP bumps, reducing SG pressure, etc.). This is also discussed in Appendix D. (05)

Figure 2 ILLUSTRATION OF PARAMETERS CONTRIBUTING TO NATURAL CIRCULATION DRIVING HEAD



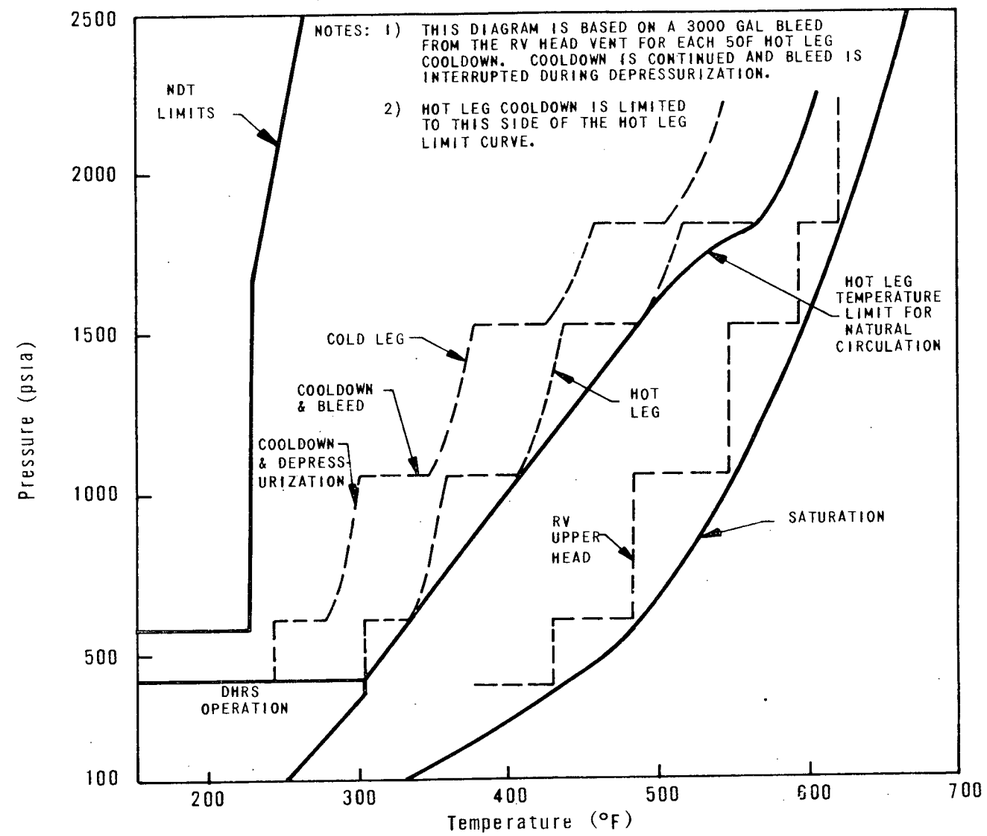
$$\Delta P_{driving\ head} = h_{eff}\,(\rho_c - \rho_h)$$

Figure 3a TRANSITION TO NATURAL CIRCULATION



Reference Point	Time (Seconds)	Remarks
1	0-2	Loss of all AC power to the station auxiliaries feedwater, RCP's, reactor and turbine trip. Diesel generators start. MADV's and MSSV's relieving steam pressure.
2	5-10	Turbine-driven AFW pump reaches full speed and begins raising SG levels.
3	11-27	DG's begin loading. MU/HPI pumps and motor-driven AFW pumps loaded.
4	50-150	Natural circulation flow developing; Thot increases as driving head is developed. SG levels being raised to mode B setpoint.
5	>150	RCS reheats and repressurizes to stable post conditions.

Figure 3b TYPICAL NATURAL CIRCULATION COOLDOWN - PRESSURE-TEMPERATURE DIAGRAM



CHAPTER B

USE OF THE P-T DIAGRAM

Introduction

The foundation for abnormal transient diagnosis and operator action is the reactor coolant pressure-temperature diagram (P-T) which is used to show how changes of heat transfer affect plant operation. This chapter introduces the P-T diagram concept and shows the typical expected plant response to a normal reactor trip. The next chapter, "Abnormal Transient Diagnosis and Mitigation", shows how the P-T diagram can be used to identify and correct abnormal transients.

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

Description of the P-T Diagram

Figure 4 shows the P-T diagram with information pertinent to normal power operation. The features of plant power operation that this diagram shows include the saturation line which applies to both primary and secondary water and steam conditions. Above and to the left of the saturation line is the subcooled water region; below and to the right is the superheated steam region.

The reactor coolant information displayed also shows the RPS trip envelope. A small window shows the expected normal reactor power operation point. This point is based on $T_{hot\ leg}$; if $T_{cold\ leg}$ were shown on the figure, it would be to the left. The size of the window is based on an expected approximate instrument error and also an allowance from the desired setting due to ICS control of minor plant variations. Actual "normal" power operation could be anywhere within this window and be acceptable. This window is a "moving" window because T_{hot} will change as plant power goes up and down.

Steam generator outlet pressure is shown as a line crossing the saturation line, and steam generator outlet temperature is also shown. The point where these two lines cross in the superheat region is the "normal" steam outlet operating point at power. The amount of superheat is shown as the difference between the saturation temperature (where the steam pressure line meets the saturation curve) and the steam operating temperature. The amount of superheat will change when the power level changes. (Note: In an actual P-T display, superheat will be shown only if steam temperature is measured. If steam temperature is calculated from steam pressure, the P-T display will always show saturation temperature even at power.)

Figure 5 shows a P-T diagram for post trip conditions. Most of the features of Figure 4 are also shown on Figure 5. The important difference

between Figures 4 and 5 is a line that shows the subcooling margin from the saturation curve. This subcooling margin line is only to be used to gauge the condition of the reactor coolant and not the steam generator fluid. Because the reactor coolant conditions around the loop can be different, and because the conditions can be different from one loop to the other, this line must be compared to reactor coolant pressures and temperatures in the hot and cold legs of both loops. The amount of subcooling margin was chosen based on the ability to accurately measure the reactor coolant temperatures and pressures (instrument errors) and includes an extra 5F to allow for temperature variations from the point of measurement in the system. Below an RC pressure of 1700 psig the margin also considers the instrument errors during degraded reactor building environmental conditions caused by overcooling and depressurizing events (LOCA or steam line break). This gives assurance that when the reactor coolant is above the margin line, it is truly subcooled and has the ability to move the heat from the core to the generator. Since the subcooling margin is also used for tripping the RC pumps it also considers RCP NPSH requirements.

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

HPI Subcooling Rule

WHENEVER the reactor coolant subcooling margin does not exist,

THEN two HPI pumps should be run at full capacity.

The P-T diagram can also be used to monitor and control HPI and RC pump operation. When HPI is initiated, it can be throttled only when the subcooling margin is regained. In general, if the RC pumps have been tripped, they can be restarted when the subcooling margin is regained and SG level exists (i.e., heat sink available). Exact details of HPI and RC pump control are given in Chapter E, entitled "Best Methods for Equipment Operation".

Figure 5 also shows a "post trip" operating window. This window has been drawn to show where the reactor coolant pressure and temperature should end up after a reactor trip. The size of the window is based on operating experience from several actual reactor trips on 177FA plants (plus computer simulations) with and without equipment failures; its size is not exact and it is possible for a trip (with minor failures) to end slightly outside the window and still have a stable plant. Some judgement will have to be applied. However, this window gives a good first basis for determining if the plant is responding correctly after a trip. If the reactor coolant system pressure and temperature move outside the window after trip and do not return in a fairly short time (about 2 to 3

minutes), then an abnormal transient is in progress and operator corrective actions are needed. A review of other plant indications may be required to find out the exact cause. After the corrective actions have been taken, the plant will be stabilized. The stable point can be inside or outside of the window (criteria for plant stability are given in Chapter F, entitled "Post Transient Stability Determination".)

An abnormal transient could also be indicated by the steam pressure and steam saturation temperature lines. Generally, if steam pressure falls below about 1140 psig after trip (the post-trip steam pressure limit line on Figure 5), some failure has occurred and the operator should begin a diagnosis of the plant. A saturation temperature of 562F corresponds to 1140 psig, therefore, if steam temperature is lower than 562F after a trip, an abnormal condition is indicated. A loss of reactor coolant to steam generator heat transfer may also be noted when T_c does not follow T_{sat} in the steam generator.

The "post trip window" shows two operating points. One shows the expected normal post trip conditions with forced circulation. When the reactor coolant pumps are running, T_{hot} will be slightly higher than T_{cold} (6-10F) and T_{cold} will be almost the same temperature as steam temperature. For normal post trip conditions with natural circulation, T_{cold} should again fall in or near this point, but T_{hot} will be somewhat higher, depending on decay heat level. Nearly every trip will end at either the forced or the natural circulation point if <u>all</u> equipment operates correctly and no

equipment failures have happened. If some minor equipment failures have occurred (a leaky steam safety valve for example), the end point will be somewhere else inside the window. The other operating point shown is the normal operating point for T_{hot} at 100% power. This point is shown as a starting point for most normal reactor trips and abnormal transients.

The post trip window is a good gauge for determining if systems are operating correctly after a trip. If the path of reactor coolant temperature and pressure stay inside this window, or if the transient path goes outside this window slightly but returns, then the transient is going as expected and the core cooling with steam generator heat transfer is correct. However, severe excessive feedwater transients should be discovered before the transient path goes outside this window. This will be discussed in more detail later. If the reactor coolant pressure and temperature are moving away from this window and do not return, then an abnormal transient is in progress and corrective actions for abnormal transients should be implemented. These corrective actions are directed toward restoring control of reactor-steam generator heat transfer, which is the preferred method for core cooling.

Successful transient mitigation can end with reactor coolant temperature and pressure inside the window, or the plant can be stabilized outside the window. In some cases, where stability is reached outside this window, staying outside the window is desirable. For example, after an overcooling transient, maintaining the low temperature may be desirable to prevent heatup and swell of the RC.

Figure 5 also shows steam pressure. After trip, steam pressure will normally be approximately 1200 psia. A "lower limit" line is shown at 1140 psig. Steam temperature is also shown. After trip the steam temperature should decrease to the steam generator saturation temperature (approximately 567F) which is set by the steam generator pressure of 1200 psia. (Note: In an actual P-T display, steam temperatures will always be shown at saturation temperature if they are calculated from steam pressures rather than measured.)

Steam pressure and temperature are very important parameters to review to determine if the plant is responding correctly after trip. These two parameters, in combination with reactor coolant pressure and temperature, will show if: 1) the reactor coolant is transporting the core heat to the steam generators, and 2) the steam generators are removing the right amount of heat. It is important to note that other parameters, that are not displayed on the P-T diagram, must also be checked to ensure proper primary to secondary heat transfer. For example, excessive main feedwater (e.g., failure to run back after trip) will not initially cause noticeable steam generator pressure or temperature reduction and will be masked somewhat by the normal post trip cooldown. By the time excessive feedwater causes the transient path to leave the post trip window, the overcooling of the reactor coolant may cause the pressurizer to be in a nearly-drained condition and the affected SG nearly full. Automatic isolation of the MFWIVs on high SG level is provided to protect against severe overfilling by main feedwater. The operator should verify this automatic action. Therefore,

main feedwater flow rates and SG levels must be checked very early following a reactor trip.

P-T Transient - Normal Trip

Figure 6 shows the typical response of primary and secondary plant parameters following a reactor trip. Individual important parameters are shown as well as the P-T diagram. The shape of the reactor coolant P-T characteristic path from power operation (above 15%) to hot zero power is always similar to the one shown unless an abnormal transient is in progress. The dip of the curve is due to cooldown of the RCS to near T_{sat} of the steam generators for the turbine bypass system (TBS) setpoint. The cooldown results in coolant shrinkage, which causes a pressurizer outsurge and pressure reduction. After the RCS reaches a temperature slightly above T_{sat} of the SG's, the reactor coolant will repressurize (due to pressurizer (05)
heaters and refill) and stabilize. Depending on prior power operating conditions, the low point of the dip will have different values, but the characteristic shape will always exist. When the plant trips, the steam pressure will rise until stopped by the increasing capacity of the sequentially opening valves of the turbine bypass system. Fifteen seconds after trip the TBS setpoints will change from the turbine trip to the higher reactor trip setpoints; therefore, steam pressure will again rise and settle out at the reactor trip setpoints. The required steam flow will quickly drop so that only the first bank (lowest setpoint) of valves of the turbine bypass system is needed. Their reactor trip setpoint is

temperature will fall from the superheated condition to saturation temperature (if displayed steam temperature is measured; if derived from steam pressure, saturation temperature will always be shown).

A similar P-T characteristic shape can also be seen for some abnormal transients, especially those that are caused by secondary side overcooling. On the other hand, small LOCAs which depressurize the RCS slowly will not show the characteristic repressurization upturn (unless they are very small leaks or they are isolated). Figure 6 also includes individual parameters versus time to show the approximate time for stabilization. Since stabilization takes a certain amount of time, the overcooling characteristic can mask failures that would not show up while the normal post trip cooling trend exists. Since overcooling can be caused by too much feedwater or low steam pressure, one of the immediate post trip operator actions includes a review of the steam pressure, MFW flow, and steam generator level to assure that the trip is normal and not combined with an overcooling transient.

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

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

Figure 5 POST-TRIP P-T DIAGRAM

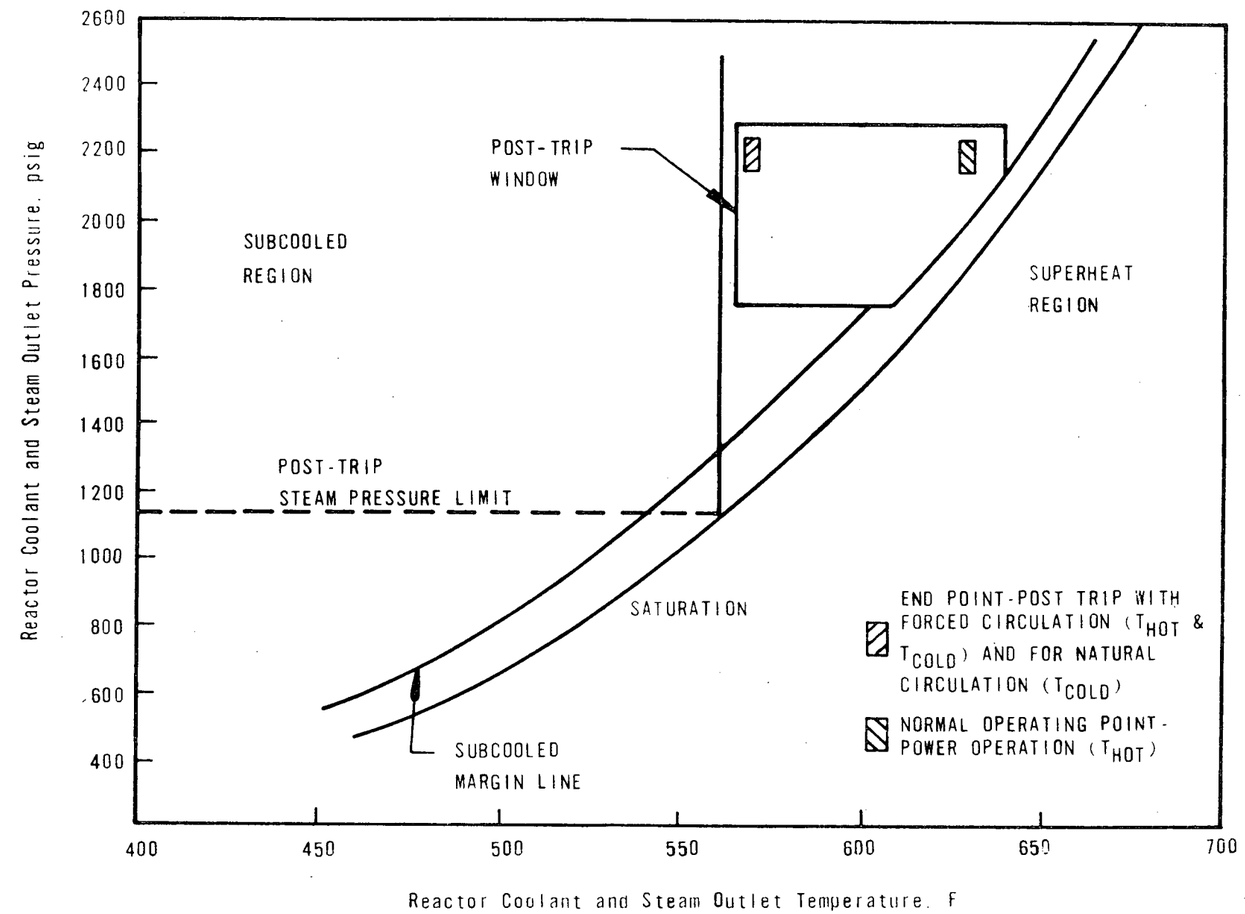
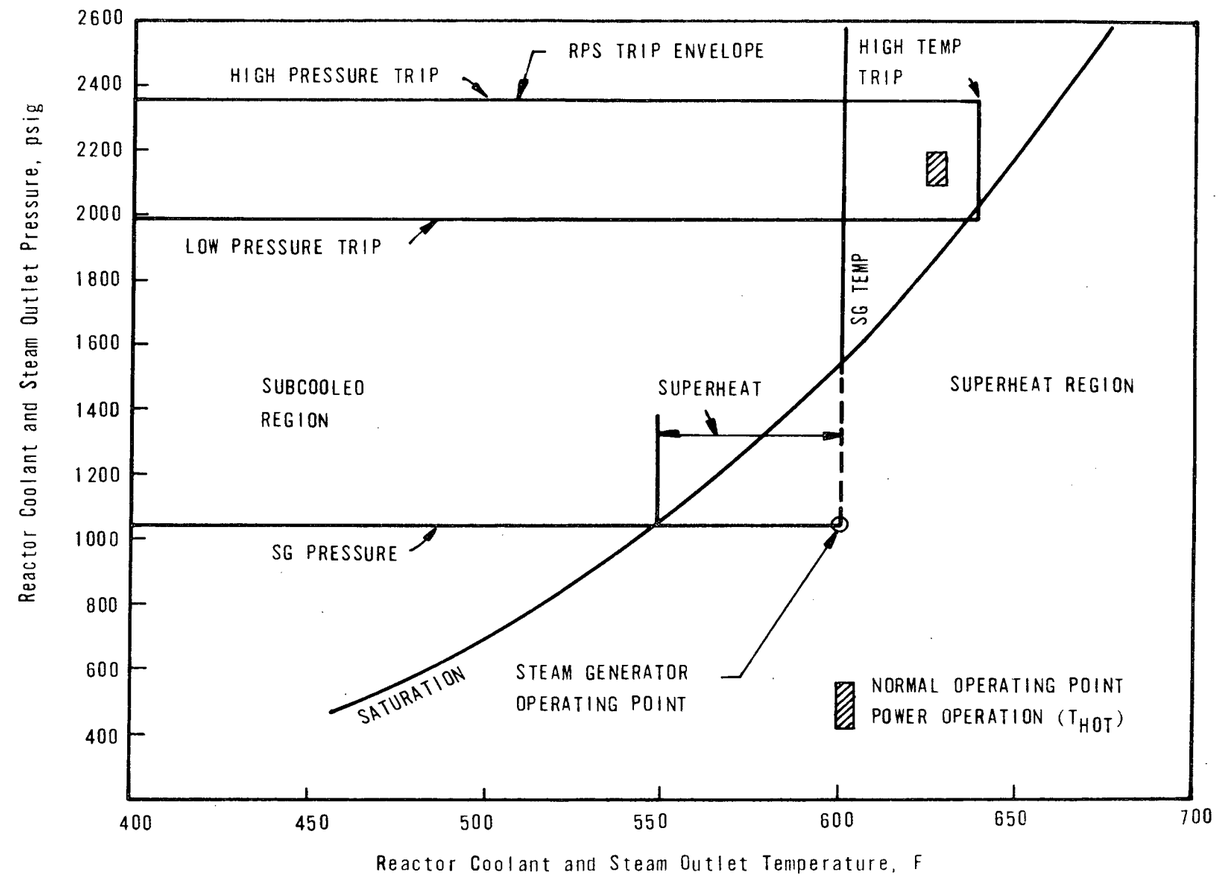
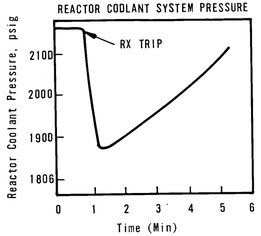
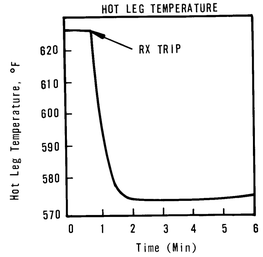
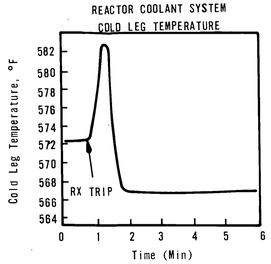


Figure 4 POWER OPERATION P-T DIAGRAM









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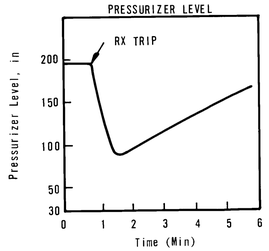

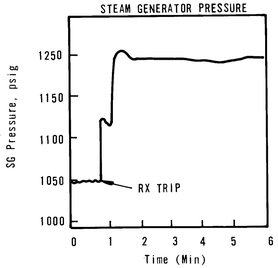

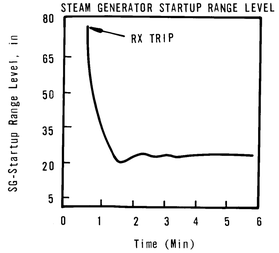

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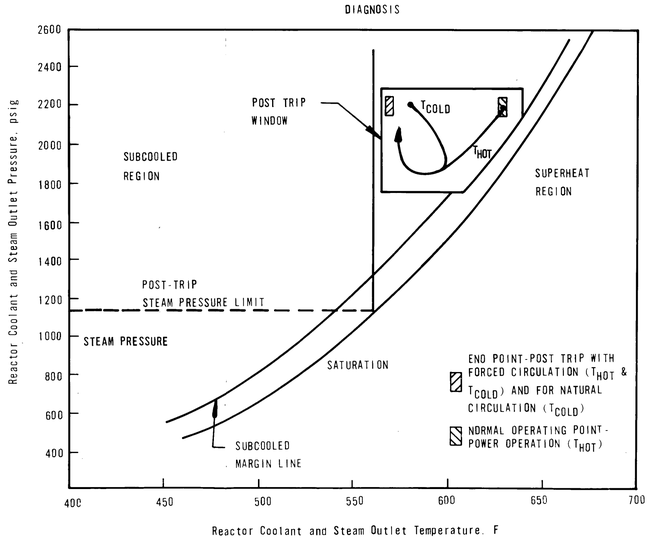
Figure 6 TYPICAL RESPONSE OF MAJOR PLANT PARAMETERS FOLLOWING A REACTOR TRIP

Figure 6. TYPICAL RESPONSE OF MAJOR PLANT PARAMETERS FOLLOWING A REACTOR TRIP



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CHAPTER C

ABNORMAL TRANSIENT DIAGNOSIS AND MITIGATION

Introduction

This chapter shows how an abnormal transient can be diagnosed and mitigated using the information provided by the P-T diagram and the concepts on heat transfer discussed in the previous chapters. A simplified flow chart of the approach to be used to diagnose and mitigate an abnormal transient is provided in Figure 7, "General Approach to Diagnosis and Mitigation of Abnormal Transients". The Abnormal Transient Operating Guidelines are implemented whenever an automatic or manual reactor trip occurs or a forced shutdown is necessary.

The guidelines are provided in Part I. They list the appropriate operator actions necessary to mitigate an abnormal transient. They follow the approach outlined in Figure 7 and incorporate the following features.

1. Use of the P-T diagram, which provides a constant feedback to the operator on his success or failure after taking each step in Part I, and therefore should be checked frequently to make sure things are progressing as expected. It will give the operator early indications of subsequent failures that are delayed after the initial event, or multiple failures that were masked by the predominant event and thus did not appear until that one was corrected.

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

3. The operator is given frequent plant status notations throughout the procedure to help him maintain proper orientation.

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

This chapter provides a general discussion of transient diagnosis and mitigation. A detailed discussion on the use of the guidelines in Part I is provided in Chapter H of this volume.

Entry Conditions/Immediate Actions

The first block in Figure 7 correlates to Section I of the guidelines in Part I and contains the immediate actions for the existing entry condition. If a reactor trip has occurred, the operator should manually trip the reactor and turbine, then proceed to the next post trip section of the guidelines, entitled "Vital Systems Status Verification". However, if

plant conditions warrant a forced shutdown, the operator should initiate the appropriate shutdown procedure. If the forced shutdown is due to a steam generator tube rupture (SGTR), the operator should proceed directly to Section III. D of the guidelines. If a reactor trip should occur during the forced shutdown operations, the post trip ATOG procedures should be implemented.

Vital Systems Status Verification

The next major block on Figure 7 correlates to Section II of the guidelines in Part I covering Vital Systems Status Verifications. This section requires reviewing specific plant status items, including the P-T diagram, to determine if they are behaving as they should for a normal reactor trip. If the specific plant status items cannot be verified as performing as expected, the operator should perform the specified remedial actions. The procedures provide specific remedial actions for each plant status item which cannot be verified. The plant status items which are checked first are the normal automatic post trip functions which control core reactivity, primary and secondary inventory, and primary and secondary pressure.

The actions to be taken are given in Table 1.

Excessive main feedwater (failure to run back flow to the SG after trip) (05)
requires the operator to quickly verify automatic MFW isolation to prevent water spilling into the steam line. If the MFW overfill protection system fails to stop the excessive MFW flow, the operator should trip the MFW pumps.

Next, the operator needs to check the P-T diagram for indications of loss of subcooling margin, lack of heat transfer, or excessive heat transfer. The P-T diagram is the foundation for transient diagnosis and for the actions to correct abnormal transients.

Finally, if the P-T diagram indicates heat transfer is satisfactory, the operator checks for a steam generator tube leak.

Abnormal Transient Diagnosis and Mitigation

Although the type of transient may have become evident during the first 2 or 3 minutes after trip, plant monitoring is required to make sure that the transient is going as expected. Generally, after 2 or 3 minutes the plant will begin to stabilize within the "Post Trip Window". The systems which should be operating have been checked to make sure that they are working correctly. Further plant monitoring should begin. At this stage, the effort should now be to make sure that the plant stabilizes as it should. To do this the P-T diagram is kept under surveillance. If reactor coolant pressure and temperature stabilize within the P-T post trip window, and steam pressure is above the low steam pressure limit, the transient is probably not abnormal and a quick check of the following should be made to ensure system and equipment parameters are within expected values:

Heat Transfer Balance Indicators

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

Equipment Status and Operation (depending on what was started)

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

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

But, if the first review of the P-T diagram indicates that the reactor coolant pressure and temperature are not going to remain within the post trip window (or return to it), or that steam pressure is below the steam pressure limit, then something is wrong with heat transfer and corrective actions are required to bring the heat transfer into balance.

Diagnosis and Mitigation

The next major block of Figure 7 correlates to Section III of Part I. Section III of the guidelines provides the followup actions for the treatment of the three types of abnormal heat transfer transients and for one special case transient.

The three general types of abnormal heat transfer transients that can become evident following a reactor trip are:

- Loss of Subcooling Margin.
- Lack of Primary to Secondary Heat Transfer - "overheating".
- Excessive Primary to Secondary Heat Transfer - "overcooling".

Section III of the guidelines in Part I also covers the special case of a steam generator tube rupture. This particular event is covered in considerable detail in Appendix C of Volume 2, therefore this chapter concentrates on the three general transient types listed above.

The basic approaches for the diagnosis and mitigation of loss of subcooling margin, lack of heat transfer, and excessive heat transfer are shown in Figures 8, 9, and 10, respectively. The left side of each figure, entitled "Diagnosis," shows the transient characteristics on the P-T diagram and lists the key identifying symptoms. The right side, entitled "Mitigation," provides a block diagram flow chart of the corrective actions as prescribed by Section III of Part I.

Loss of Subcooling Margin

The P-T diagram on Figure 8 shows a loss of subcooling margin caused directly by a loss of RC inventory (i.e., small LOCA). A loss of subcooling margin can also be combined with, or caused by, an overheating or overcooling transient. Since those causes of loss of subcooling are covered by the discussions of those transients, this discussion centers on a direct loss of subcooling margin due to loss of RC inventory. This is also covered in more detail in Appendix D. (05

The key distinguishing difference for a direct loss of subcooling is the loss of RC pressure with no significant change (increase or decrease) in RC temperatures other than the normal temperature response following a reactor trip. This is shown on the P-T diagram in Figure 8, which also shows near normal steam pressures. If the loss of RC inventory is large enough to create steam voids in the RC hot legs, heat removal by the steam generators may be lost, in which case steam pressures would begin to decrease slowly. Table 3 lists the characteristics to distinguish LOCA's from other transients, and Table 4 lists symptoms and appropriate isolation components for LOCA's that can be isolated. (05

The operator's primary objectives are to restore subcooling margin and to maintain or restore primary to secondary heat transfer. Most of the necessary actions are performed automatically. The operator should verify the completion of these actions and perform them manually, if necesssary. These actions are:

- Verify RCP trip; initiate manually if necessary.
- Verify HPI initiated (low RC pressure or high RB pressure (ESFAS)); initiate manually, if necessary.
- AFW initiated and controlling to obtain 40 ft. setpoint (80% full range).
- The PORV should be closed, but if it has failed open the block valve should have been isolated automatically on RC pressure @2170 psig (ESFAS).

These actions are directed at regaining RCS inventory control and ensuring the steam generators remain available as heat sinks. Further actions will be determined by the plant's response to the actions already taken, as shown on Figure 8 (i.e., whether or not subcooling margin and/or heat transfer are restored).

Lack of Heat Transfer

Figure 9 shows the corrective actions to take when the reactor coolant cannot transfer heat to the steam generators. In general there are four causes of insufficient heat transfer: (05)

- There is insufficient inventory in the steam generators to receive the heat (loss of all feedwater).
- The reactor coolant cannot transport the heat to the steam generators because there is insufficient RC inventory (LOCA)
- Circulation has stopped (forced and natural).
- SG T_{sat} is equal to or greater than RCS T_{hot}. (05)

Natural circulation can be temporarily interrupted because of reactor coolant contraction after a severe overcooling transient. A long interruption would not be expected since HPI will refill the system and natural circulation will normally restart. Loss of natural circulation would be expected for most LOCAs, or for an extended loss of feedwater. Therefore, to restore natural circulation for either of these, the failure must be corrected (e.g., feedwater restored) and subcooling should be restored (to ensure the best natural circulation). The most probable of the overheating conditions, a total loss of feedwater, is shown on the P-T diagram in Figure 9.

Overheating when all feedwater is lost can take different paths depending on the decay heat level, when feedwater was lost, and whether HPI was operating before FW was lost. The P-T diagram illustrated shows (05)
a total loss of all feedwater immediately after reactor trip from full power. The loss of all feedwater from power operation will exhibit two clear characteristics on the P-T diagram:

- After the normal post trip cooldown, the RCS will begin to reheat and repressurize beyond the normal post trip "window" as the SGs boil dry.
- Steam pressure and steam temperature will decrease because there is (05)
no feedwater and no heat transfer.

The corrective actions for this transient are: (05)

1) Attempt to restore MFW or AFW. if this fails, (05)

2) Initiate HPI cooling when heat transfer is lost. When initiating HPI cooling, two HPI pumps should be started and run at full capacity and the PORV should be manually opened when RCS pressure increases to the PORV lift setpoint. When opened, the RCS pressure will rapidly decrease to saturation pressure. The automatic PORV block valve closure signal must be bypassed to keep the PORV block valve open. Without these operator actions, this transient would result in losing primary inventory out of the PORV (or pressurizer safety valves) for about 30 or 40 minutes before subcooling margin is lost at which time the loss of subcooling rule would be followed. This could increase the chances of core uncovering. Therefore, the operator should initiate HPI cooling when primary to secondary heat transfer is lost to assure core protection, rather than wait until loss of subcooling margin.

When HPI cooling (with the PORV open) is started under these circumstances, all but one RC pump should be tripped. This will reduce the heat input to the RC. One RC pump should continue to run as long as possible to maintain forced core cooling. When the subcooling margin is lost, all the RC pumps must be tripped. HPI cooling is discussed in more detail in Chapter D, "Backup Cooling Methods." and in Appendix D. (05)

Continued operation without feedwater, but with HPI cooling, will provide adequate core cooling, but the operator should continue efforts to restore feedwater and primary to secondary heat transfer. While on HPI cooling, after the subcooling margin is restored, the HPI flow should be throttled. A reactor coolant pump should also be restarted at this time. Control of HPI flow to keep the minimum subcooling margin is important to prevent overpressurizing the RCS. Forced reactor coolant flow will also provide better loop temperature indications and facilitate restoration of primary to secondary heat transfer.

Excessive Heat Transfer

The characteristics and general corrective actions for an "overcooling" transient are shown on Figure 10. The P-T diagram shows T_{hot} decreasing significantly below normal post trip values (T_{cold} is not plotted, but would also decrease with T_{hot}). RC pressure will initially decrease due to the RC contraction. If makeup (HPI) can compensate for the contraction rate, RC pressure will recover even with continued cooling (dashed arrow on Figure 10). If makeup (HPI) cannot compensate for the contraction rate (severe overcooling), RC pressure will continue to decrease with temperature (solid arrow).

Overcooling is always caused by failures on the secondary side. The usual sources of failure are low steam pressure or excessive main or auxiliary feedwater, or by combinations of high feedwater flowrates

and low steam pressure. The general trend shown by the P-T diagram is characteristic of overcooling due to either a steam leak or excessive feedwater. Some LOCAs can also cause a loss of steam pressure because the RCS will depressurize, cool, and draw heat away from the steam generators; this will be temporary for small breaks.

Once this overcooling trend is exhibited, checks should be made on steam pressures, steam generator levels, loop T_{cold} temperatures, and main or auxiliary feedwater flow. If the cause (or affected SG) is obvious, then direct actions to isolate the cause (or generator) should be taken.

If the subcooling margin is lost during an overcooling transient, the subcooling rule must be followed: two HPI pumps must be turned on and run at full capacity until the subcooling margin is restored. When the subcooling margin is lost, the RC pumps should be tripped and not restarted until subcooling is restored.

Overcooling transients caused by feedwater control failures on only one SG may be obvious when the T_{cold} temperatures, SG levels, and FW flowrates are compared. If the magnitude of the overcooling is significant, T_{cold} in the affected loop will always lead T_{cold} in the loop with the good SG (i.e., T_{cold} in the affected loop will be lower). In addition, the affected SG level and/or FW flowrate should be significantly higher for large mismatches.

Overcooling transients induced by low steam pressure (steam leaks) will also cause higher than normal feedwater flowrates, but SG levels should be near normal. Identification of the affected SG will be difficult while the MSIV's are open since both SG's will effectively "see" the leakage path through the cross-connected main steam line.

If neither the cause of the overcooling nor the affected SG is obvious, the operator should isolate both SGs by closing the MSIVs, MADVs, and isolating both MFW and AFW. The intent is to determine the overcooling SG by monitoring SG levels and pressures, and most importantly, to terminate the overcooling transient. FW is then restored to the good SG before its inventory is boiled away. This will restore primary to secondary heat transfer.

If the overcooling has been terminated and both SG's stabilize in both level and pressure, then the overcooling was due to either a) steam leak downstream of the MSIVs, b) excessive feedwater to both SG's, or c) inadvertently open MADV on one or both SGs. The operator can then restore controlled feedwater flow to both SGs and control steam pressure with the MADVs. He should not reopen the MSIVs unless he is sure no downstream leak exists or such a leak has been repaired or locally isolated.

If one SG stabilizes and the other SG continues to lose pressure and level, an unisolable upstream steam leak exists. The operator can restore controlled cooling with the intact SG and allow the leaking SG to boil dry.

It is highly unlikely, but possible, that both SGs have unisolable steam leaks. If this situation occurs, the operator should try to cool with the SGs before using HPI-PORV open cooling to prevent blowing RC to the RB and to provide better heat removal. The operator should proceed as follows:

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

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

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

4. Continue attempts to repair or isolate the leak path on at least one SG. When the steam leak is repaired (isolated) on one SG, then use the repaired SG to restore primary to secondary heat transfer and recover from HPI cooling.

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

During the course of performing the followup actions in Section III of Part I, and after stabilizing the plant after correcting an abnormal transient, the operator should continue monitoring the P-T diagram and key plant parameters. This continuing surveillance will provide feedback on the success of actions taken and allow early recognition of other failures/transients should they occur (indicated by dashed arrow on Figure 7).

Cooldown Procedures

The basic concept in abnormal transient mitigation consists of identifying the type of transient, performing the appropriate corrective actions to restore plant stability, and then continuing with more or less normal plant operation (e.g., cooldown). The possible plant conditions existing after stabilization from a transient may not coincide with normal plant cooldown procedures. Therefore, Part I of ATOG provides several cooldown procedures, as shown on Figure 7, to make the transition to normal plant procedures.

Most of the end conditions in Section III of Part I refer the operator to the appropriate cooldown procedure. However, it is also possible that recovery from an abnormal transient results in normal plant conditions (i.e., subcooled, controlled primary to secondary heat transfer, bubble in the pressurizer, etc.) with no failures. In these cases, plant cooldown may not be necessary or desired and plant management will decide on further course of action.

This chapter has provided a general overview of how the P-T diagram and the guidelines are used to identify and correct abnormal transients. Further information on concepts and use of the guidelines is provided in Chapter H, "Use of the Guidelines."

Figure 7 GENERAL APPROACH TO DIAGNOSIS AND MITIGATION OF ABNORMAL TRANSIENTS

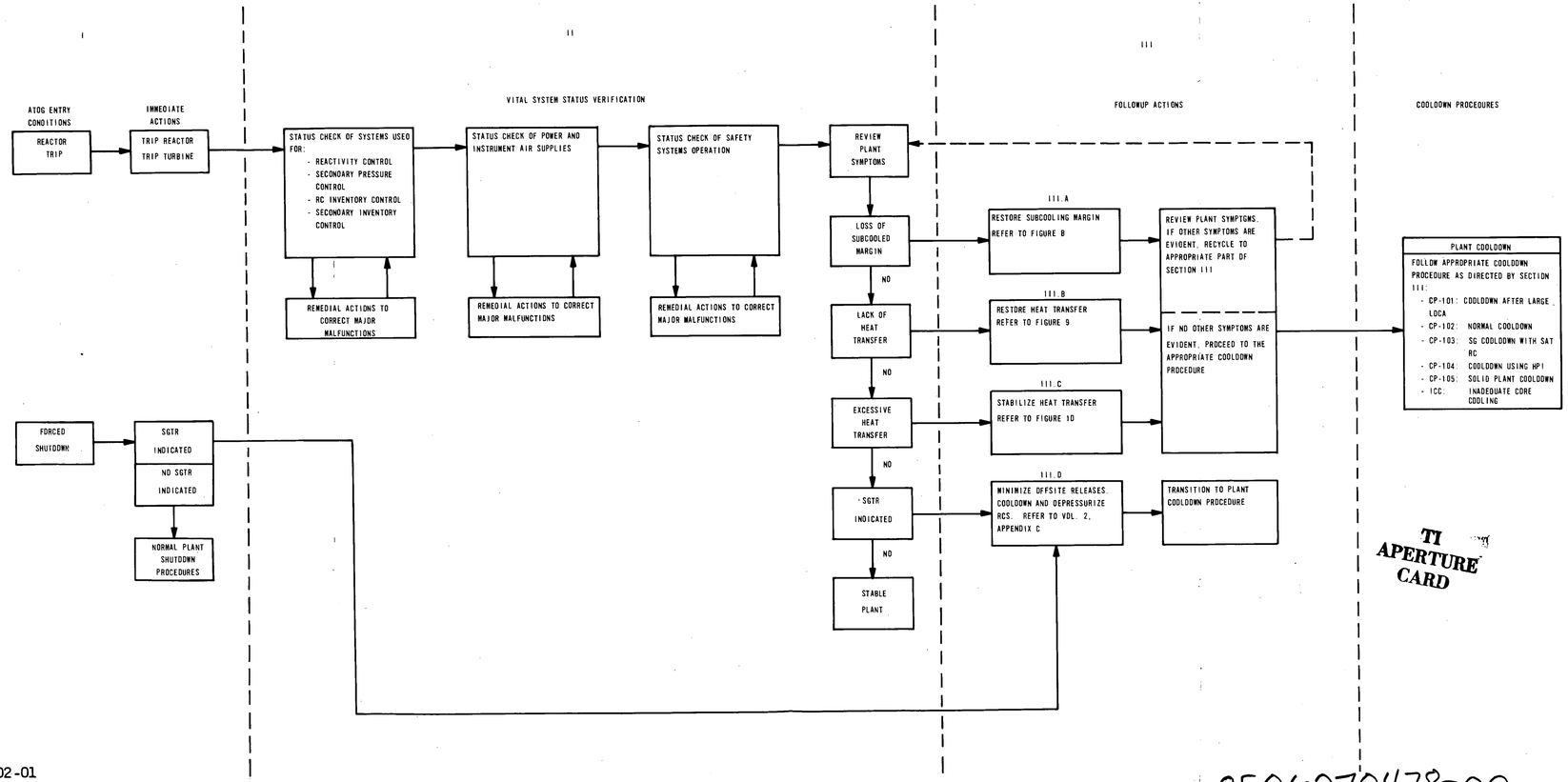

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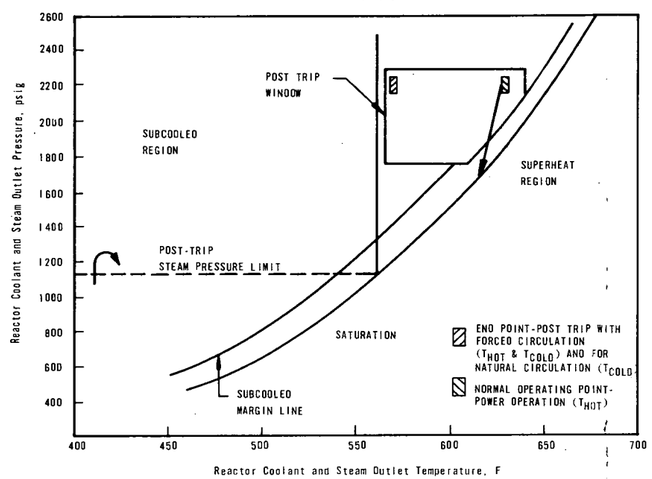
Figure 8 DIAGNOSIS AND MITIGATION FOR LOSS OF SUBCOOLING MARGIN

DIAGNOSIS



KEY SYMPTOMS

- DECREASING RCS PRESSURE AND LOSS OF SUBCOOLING MARGIN WITHOUT SIGNIFICANT RCS TEMPERATURE CHANGE (OTHER THAN NORMAL RCS TEMPERATURE RESPONSE AFTER REACTOR TRIP)
- NEAR NORMAL POST-TRIP STEAM PRESSURES; MAY DECAY IF PRIMARY TO SECONDARY HEAT TRANSFER LOST DUE TO VOIDS IN RCS
- POSSIBLE INCREASE IN REACTOR BUILDING PRESSURE, SUMP LEVEL, AND RADIATION LEVEL

MITIGATION

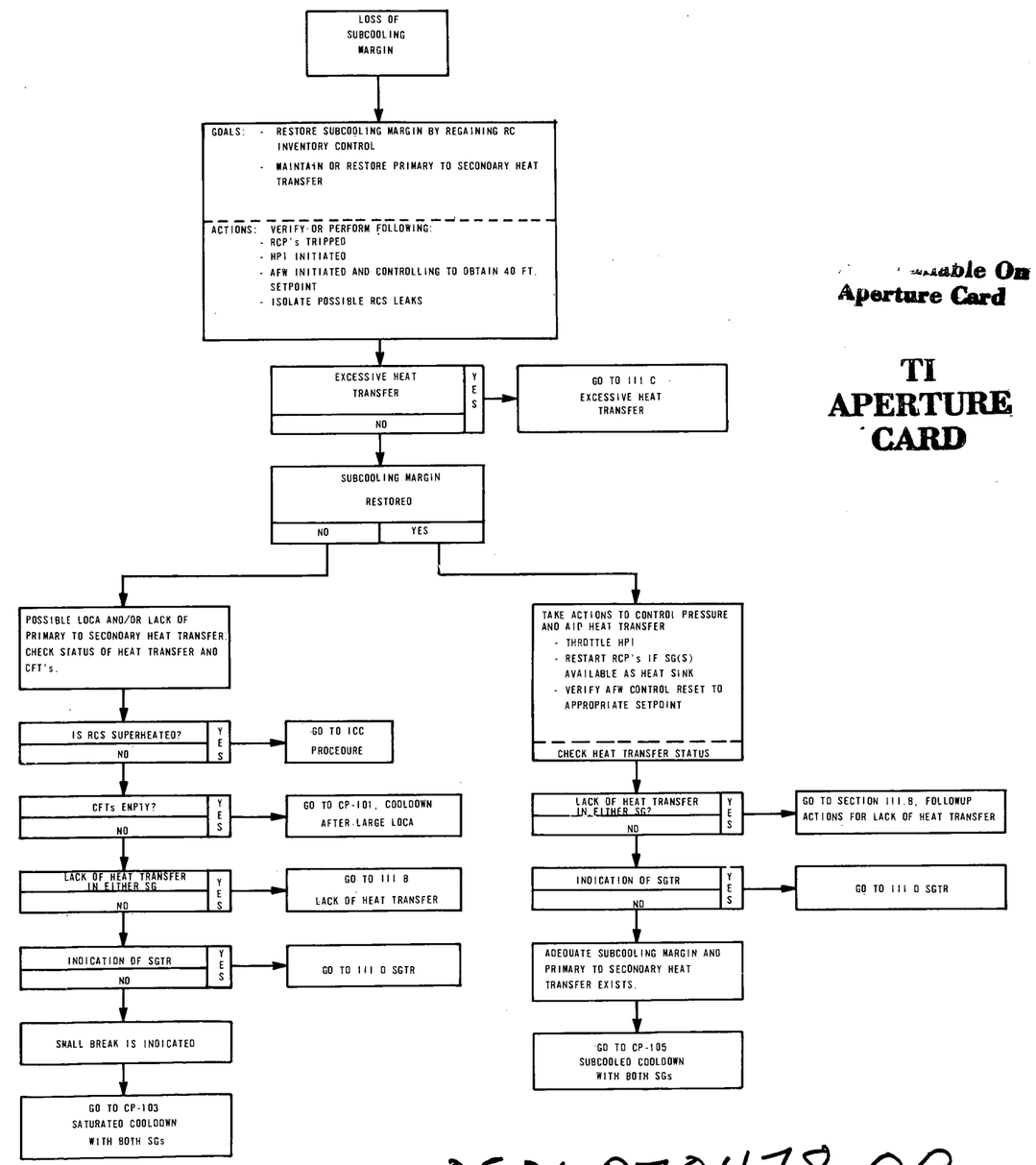


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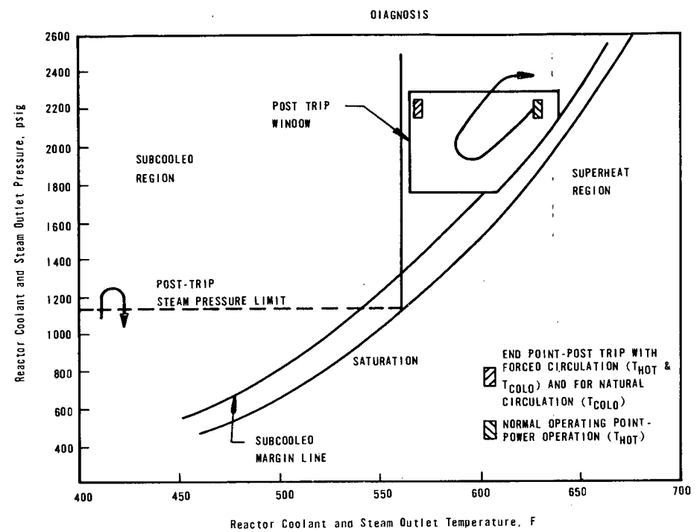
Figure 9 DIAGNOSIS AND MITIGATION FOR LACK OF HEAT TRANSFER



KEY SYMPTOMS

- WITH SUBCOOLED MARGIN (AS SHOWN ABOVE), SYMPTOMS INDICATIVE OF TOTAL LOSS OF FEEDWATER:
  - RCS REHEATING AND REPRESSURIZING AFTER NORMAL POST-TRIP COOLDOWN
  - LOW OR NON-EXISTENT SG LEVELS AND FEEDWATER FLOWRATES; SG PRESSURES WILL DECREASE AFTER DRYOUT/LOSS OF HEAT TRANSFER
- WITHOUT SUBCOOLED MARGIN, SYMPTOMS COULD BE AS ABOVE AND/OR LOCA SYMPTOMS (REFER TO APPENDIX D IN PART II, VOLUME 2)

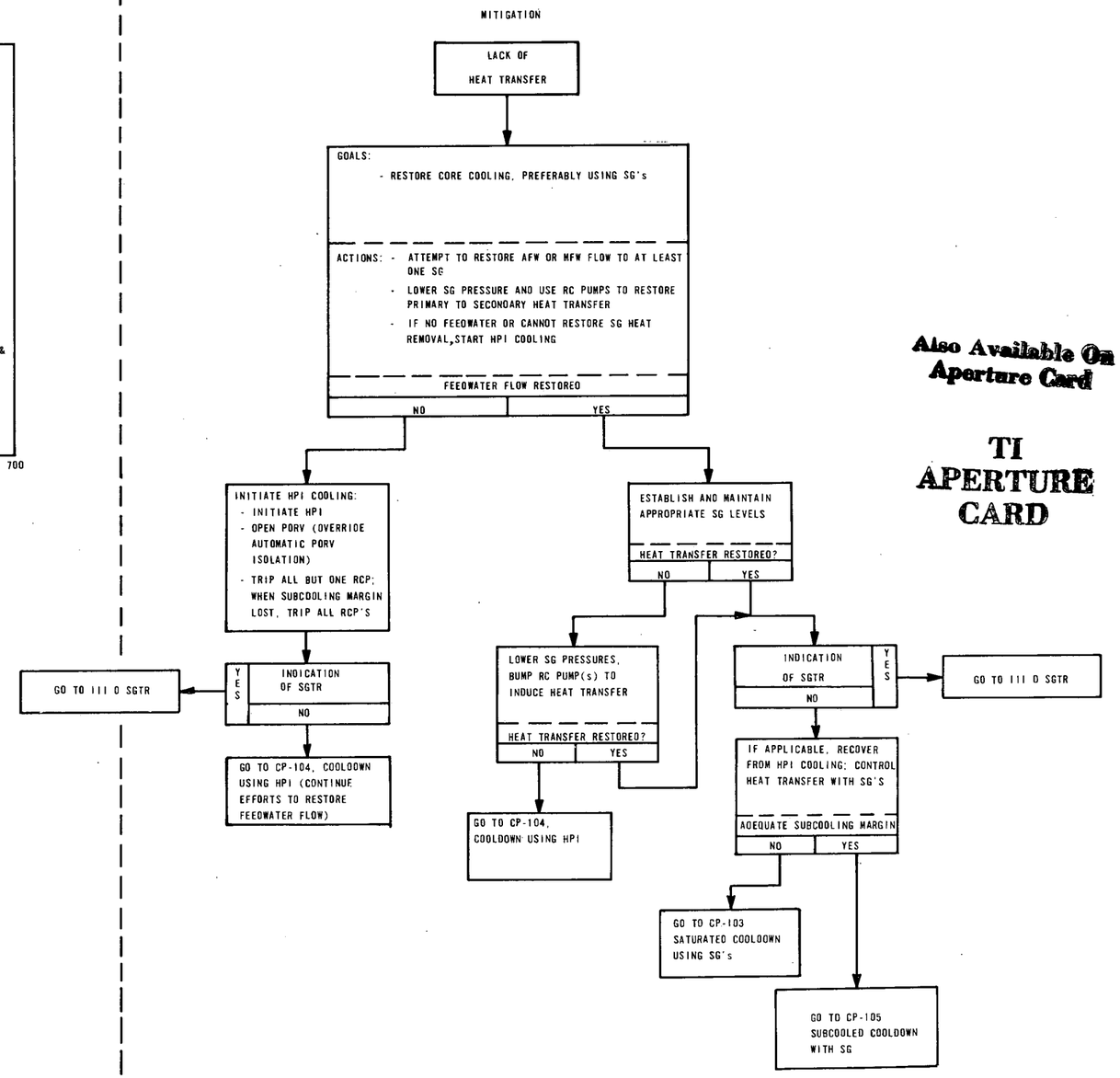


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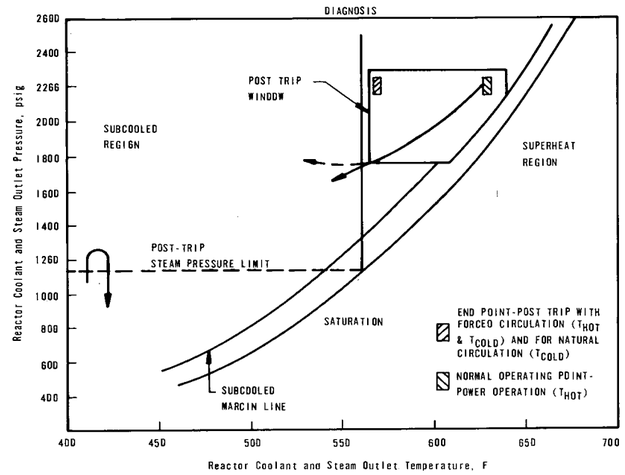
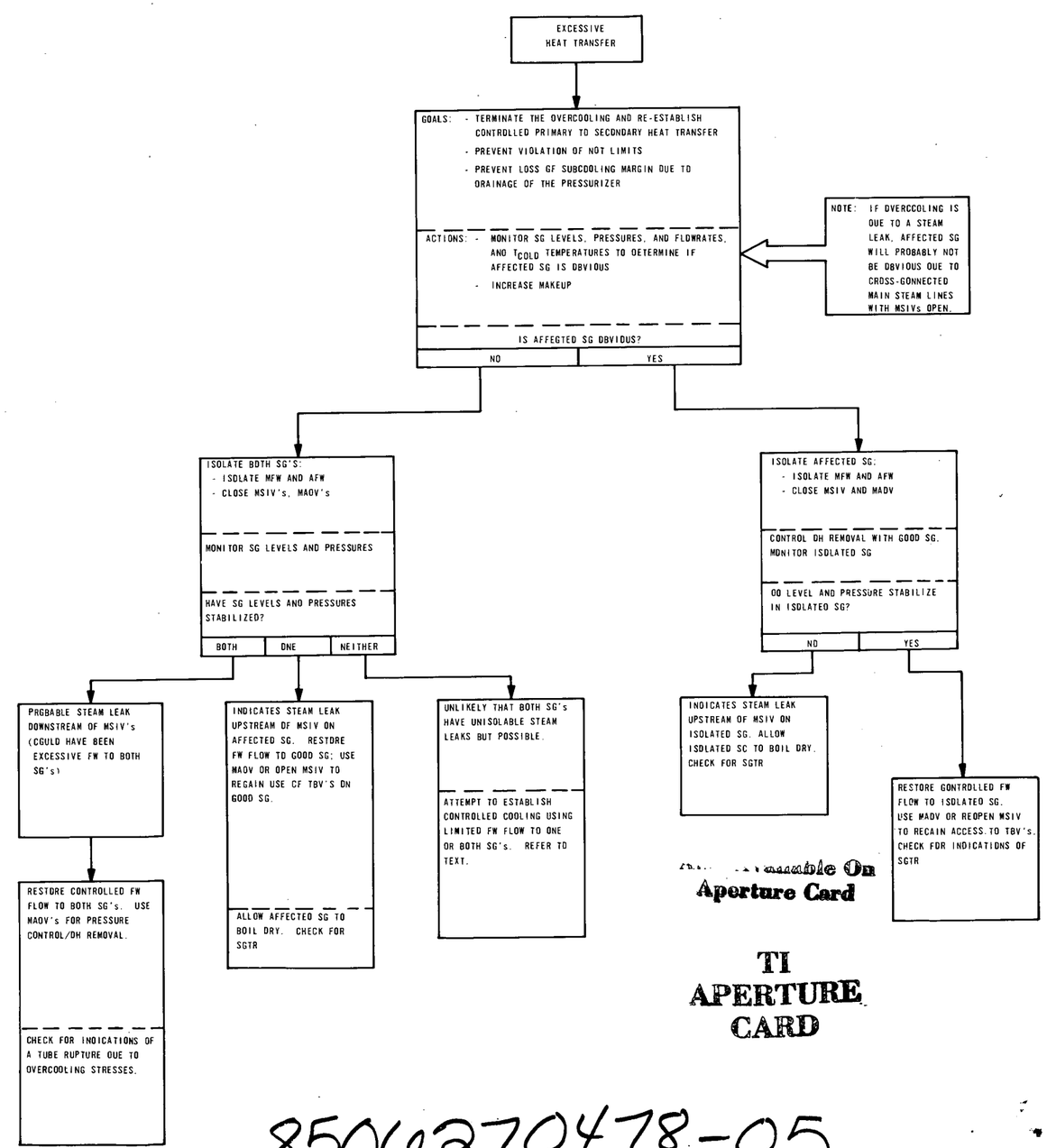
Figure 10 DIAGNOSIS AND MITIGATION FOR EXCESSIVE HEAT TRANSFER



KEY SYMPTOMS

- DECREASING RCS TEMPERATURES AND SG PRESSURES SIGNIFICANTLY BELOW NORMAL POST-TRIP COOLDOWN
- POSSIBLY HIGH SG LEVEL(S) AND FEEDWATER FLOWRATE(S)
- LOW RCS PRESSURE/PRESSURIZER LEVEL AND/OR HIGH MAKEUP/HPI FLOWRATE (DEPENDING ON MAGNITUDE OF OVERCOOLING, DECAY HEAT LEVEL, ETC., RCS MAY CONTINUE TO LOSE PRESSURE AND PRESSURIZER LEVEL OR BEGIN TO REPRESSURIZE WITH CONTINUED COOLING, AS SHOWN ABOVE)

MITIGATION



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Plant status indicators	Operator action required	Symptoms	Basis for action
1. Reactor Trip	Immediately following reactor trip verify feedwater has runback. ● If MFW has not run back, verify automatic closure of MFIV on overfed SG(s) ● If MFIV(s) fail to close, then trip MFW pumps e.g. SG level is "high" and MFW flow is still on Allow SG level to decrease to appropriate setpoint; then resume FW addition by - Manual control of MFW or - AFW addition if MFW has been isolated. ● Ensure AFW starts if MFWP's are tripped and is throttled properly to prevent overcooling.	High SG level High FW flow	Excessive MFW is the addition of water to the SG at a rate faster than it can be boiled off. It can result in overcooling of the RCS. Water spillage into the steam lines must be avoided. Overfill of the SG can occur very rapidly because of the large flow capacity of the MFW system; this is especially true following a reactor trip.

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TABLE 2 ACTIONS TO CORRECT FAST TRANSIENTS

Plant Status Verification	Operation Action Required	Basis for Action
1. Reactivity controlled -Reactor power decreasing -All rods at in limit (except APSRs)	● Start HPI from BWST ● Emergency borate ● Manual rod insertion ● Perform local breaker trips of CRD ● Maintain proper primary to secondary heat transfer	After reactor or turbine trip, the operator manually trips the reactor and turbine and should verify that the fission process is shutdown by ensuring the rods are fully inserted and that power is decreasing. If power is not decreasing, a total failure to trip has occurred. In this case the operator should immediately begin HPI flow from the BWST to add boron and manual rod insertion. Local breaker trips should then be performed to achieve a reactor trip. Compensation for a stuck rod will have to be by boration to maintain a subcritical margin when the plant is stablized or plant cooldown is required.
2. Secondary pressure controlled -All turbine steam stop valves shut	● Manually trip turbine ● Close turbine control valves	If steam pressure is allowed to drop below turbine bypass setpoint, the RC will over cool which could lead to emptying pressurizer.
3. RC inventory controlled. -Letdown flow through block orifice only.	● Close block orifice bypass valves	When a reactor trip occurs, T_{ave} will decrease due to the loss of core fission power, and an outsurge from the pressurizer will be caused by the contraction of the reactor coolant. The MU control valve will open to increase MU in response to a decrease in pressurizer level. To minimize the potential for a loss of pressurizer level and/or indication, the operator should manually isolate the letdown bypass valve.
4. SG inventory controlled -Feedwater flow not excessive	● Verify MFIV close	Feedwater should be added to maintain steam generator heat removal. Too much feedwater will lead to overcooling of the RCS and water in the steam lines.
5. Instrumentation and control available -Vital DC and AC power, emergency standby busses and instrument air	● Make use of what is available while trying to reestablish power and air supplies.	Instrumentation is needed to determine what the plant's condition is to determine of corrective measures are needed and if the corrective actions are effective. Plant controls are needed to be able to correct any adverse plant conditions.
6. Station auxiliaries powered	● Verify that at least one emergency diesel generator starts and automatic and manual load sequencing is completed. If only one has started manually, start the other. ● Verify AFW actuation - verify that at least one AFW pump is on and flow is delivered when SG level is below the appropriate setpoint. ● Verify MU pump actuation and seal injection reinstated. ● Verify ERCW and air compressor starts	Upon loss of normal power sources, the two engineered safeguard busses are energized, each powered by its respective diesel generator. Bus load shedding, transfer to the diesel generators, and pick-up of critical loads is automatic with ESFAS. When a loss of power occurs, the operator should ensure that at least one diesel generator starts. He should try to start the other. The operator should confirm that the above actions are complete by examination of valve position indicators and AFW status and flow.
7. No ESFAS alarm -Low RC pressure or high RB pressure -High high RB pressure	● Confirm that the HPI and LPI are started. ● Verify, by review of ECCS flow indication, that proper flow exists in the injection lines. ● Confirm reactor building isolation. ● Confirm reactor building cooling systems start. ● Confirm RC pumps on loss of subcooling margin. ● Verify that appropriate MSIVs, MADVs and MFIVs are closed. ● Verify RB spray system on.	When an ESFAS actuation occurs, the operator should assure that at least one train is operative (one pump on) and that proper flow is present. At this point, HPI/LPI flow balancing is not required, but can be done later. Function is to prevent overcooling RCS and release to RB due to steam line break.
8. P-T diagram check Lack of subcooling margin Overheating Overcooling	● Replenish RG inventory ● Regain SG heat removal ● Reduce SG heat removal	Provide stable core cooling. Provide stable core cooling. Provide stable core cooling.
9. Condenser vacuum pump rediation alarm due to SG tube leak.	● Start immediate cooldown and depressurization of RCS.	Reactor coolant has flow path to outside environment via secondary system. Should depressurize RCS to stop tube leak.

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Table 3 HOW TO DIFFERENTIATE A LOCA FROM OTHER TRANSIENTS

Unique Characteristics of LOCA's

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

  NOTE: A steam or feed line leak inside containment will cause high pressure, temperature, and humidity, but will not cause high radiation.
- Steam pressure, feed flow, and steam generator level do not indicate overcooling (this helps to differentiate LOCA's from overcooling transients)
- High steam line radiation alarms (tube leaks only).
- Low letdown storage tank level (in the absence of all of the above, this indicates a leak outside the containment).

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

THIS TABLE WILL AID IN LOCATING SOME BREAKS; ALL BREAKS CANNOT BE LOCATED. SOME BREAKS WHICH CAN BE LOCATED CAN ALSO BE ISOLATED AND THE LOCA CAN BE STOPPED. IT MAY BE DIFFICULT TO DISTINGUISH SMALL STEAM LINE LEAKS INSIDE CONTAINMENT FROM LOCA'S; BUILDING ENVIRONMENT WILL CHANGE FOR BOTH AND THE STEAM PRESSURE WILL NOT ALWAYS BE LOW. HOWEVER, A LOCA WILL CHANGE BUILDING RADIATION LEVELS.

SYMPTOMS FOR LOCA'S THAT CAN BE ISOLATED

(Symptoms or alarms most likely to show location are underlined)

Failure	Locating Symptoms	Isolating Hardware
Makeup and purification system outside containment and letdown coolers	- Low makeup tank level - High component cooling water (CCS) surge tank level (for breaks in letdown cooler) - Local sump levels, radiation alarms - High CCS discharge temperature from letdown coolers	Letdown valve **1) upstream of coolers
Seal return line and seal return cooler outside containment	- Low makeup tank level - High CCS radiation - High CCS surge tank level (for breaks in seal return cooler) - Local sump levels, radiation alarms (auxiliary building vent monitor) - High seal return flow - High CCS seal return cooler discharge temperature (local)	Seal return **1) isolation valve
Pressurizer PORV	- Flow Monitor Alarm - High RC drain tank level - High RC drain tank temperature and pressure (These will only be good when the RC drain tank rupture disk is good)	PORV isolation valve
Makeup-letdown imbalance (this is not a break, but is a loss of coolant)	- High makeup tank level - Bleed holdup tank level - Makeup flow combined with seal injection flow is less than letdown flow	Letdown control **1) valve
Decay Heat removal line break outside containment (decay heat removal system in operation-plant is cooled down)	- High or low decay heat removal flow - Low pump suction press. - Local sump and local radiation alarms	Decay heat letdown drop line valve
Decay heat cooler tube leak (decay heat removal sys. in operation-plant is cooled down)	- High CCS temperature at DH cooler outlet - High CCS radiation - High CCS surge tank level	Cooler isolation valves

SYMPTOMS FOR LOCA'S THAT CANNOT BE ISOLATED

(Symptoms or alarms most likely to show location are underlined)

Failure	Locating Symptoms
Steam Generator Tube(s)	- High steam line radiation - High steam generator level - High condenser vacuum pump radiation
Pressurizer Safety Valves	- Flow Monitor Alarm - High RC drain tank level - High RC drain tank temperature and pressure (These will only be good while the RC drain tank rupture disk is good)
HPI Line Break **2)	- Flow imbalance between injection lines
RC Pump Seal Failure	- High seal return temperature combined with: Low stage and upper stage pressures are equal and high
RCS Instrumentation Lines	
- Pressurizer Level	- False low level reading
- Pressures	- False low pressure
- RC Flow	- False high or low flow compared with known pump operation

**Footnotes: 1) Do not allow makeup tank to drain or operating makeup pump will lose suction and fail.

2) Depending on break location, leak may or may not be isolable. If downstream of last check valve, loss of reactor coolant cannot be prevented, but loss of HPI can be stopped by isolating both the leaking injection line and the cross-connected injection line.

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CHAPTER D

BACKUP COOLING METHODS

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

1. HPI Cooling
2. Boiler-Condenser Cooling

HPI cooling exists when the core is cooled by reactor coolant, including HPI, which is then released to the containment through a break or open PORV. This method is used when the steam generators are not available as heat sinks (e.g., total loss of feedwater).

Boiler-condenser cooling exists when reactor coolant is boiled in the core region forming steam (removing core heat) which flows through the hot leg pipe(s) to the steam generator(s) where it is

condensed in the tube region. The condensed water returns to the core via the cold leg pipe(s). The method is used when the steam generator is available, but insufficient RC inventory exists to sustain natural circulation (e.g., small LOCA). Boiler-condenser cooling can occur in one loop or both loops simultaneously.

In addition, this chapter also discusses methods to restore natural circulation heat removal.

HPI Cooling (for Loss of All Feedwater)

A complete loss of feedwater is not a likely event, but it can occur because of multiple equipment failures or operator error. If primary to secondary heat removal is lost because of the loss of feedwater, core cooling should be provided by initiating HPI and opening the PORV. The core energy is removed by the reactor coolant and released to the reactor building, which serves as the heat sink instead of the steam generator. The core is kept covered and cooled by HPI.

A total loss of all feedwater, without actions to initiate backup cooling by HPI, is illustrated in Figure 11 and is discussed below:

1. With the plant at power, a loss of main feedwater would result in a reactor trip (anticipatory trip on loss of MFW or RPS actuation on high RCS pressure). A loss of MFW could also occur during hot shutdown or plant heatup/cooldown.

2. If auxiliary feedwater also fails, the secondary side of the steam generators will boil dry and the RCS will then heat up due to decay heat.

3. Due to the heatup of the RC fluid, subsequent fluid expansion and resulting insurge into the pressurizer, the pressurizer steam space is compressed and the RCS pressure increases. Steam/water relief through the PORV or the pressurizer safety valves will also occur.

4. Subcooling will decrease as temperature continues to increase while pressure remains at the PORV or safety valve setpoint.

   NOTE: The rate at which the above occurs will depend upon the initial inventory in the steam generators and the core decay heat level. For example, the RCS heatup rate may

be as high as 4F/min with high decay heat or as low as 1F/min with low decay heat following boil off of the SG inventory.

5. The reactor coolant will eventually saturate and boiling will occur throughout the core.

6. Without corrective action, the reactor coolant will slowly be vaporized to steam and relieved to the containment building and core damage will result.

To avoid these consequences, the operator should make every attempt to regain feedwater to at least one steam generator. This includes main feedwater, auxiliary feedwater, condensate and booster pumps (if steam generator pressure is low enough). If feedwater cannot be regained before the RC pressure reaches the PORV open setpoint, he should manually start two HPI pumps and open and leave open the PORV (requires override of automatic PORV isolation). HPI flow should be balanced to give the maximum flow possible.

This event can be recognized by observation of steam generator level and equipment status checks or through use of the P-T diagram. Figure 12 illustrates the P-T response of the RCS after a loss of main feedwater from 100% power with no AFW, but with appropriate operator action. Figure 12 and the following transient description should be considered as typical. Actual times and sequence will

depend on actual HPI flowrate, DH level, etc. (e.g., subcooling could be regained before the RCS begins to cool).

After HPI is started, the RCS will eventually go to a water solid condition (subcooled) with RC pressure controlled by a combination of the HPI pump head rise and the relief capability of the PORV. The number of running reactor coolant pumps should be reduced to one to reduce the heat input to the RC. The time to become water solid depends on the core decay heat level and the number of operating HPI pumps. If core decay heat is high, the reactor coolant will saturate and its pressure will rise along the saturation curve (points 5-6 and Figure 12). The running RCP should be tripped when subcooling margin is lost. Note: The RC pumps will automatically trip on (05)
coincident ESFAS signal and loss of subcooling margin. Core cooling is provided by heat transfer to the reactor coolant. The RCS is cooled by releasing mass and energy through the PORV and by replacing the lost coolant with colder HPI. The water inventory in the RCS will decrease because of core boiling and relief out the PORV, (05)
until the amount of water added by HPI can compensate. When the energy released through the PORV and the cooling provided by HPI exceeds the decay heat, the RCS will begin to cool. When HPI capacity begins to exceed core boiling and losses through the PORV, RCS inventory will start to increase, steam will be condensed and the system will slowly go to a water-solid (subcooled) state (points 6-7 on Figure 12). If the core decay heat level is low at the time feedwater is lost, the RCS may begin to cool and repressurize (water solid) without losing the subcooling margin.

When all feedwater is lost, it is very important that two HPI pumps be run until subcooling exists. One HPI pump is adequate for core heat removal, but the time required for 100% decay heat to decrease to the cooling capacity of one HPI pump is much longer than with two pumps. The time for 100% decay heat to decrease to the capacity of one HPI pump is approximately 70 minutes and approximately 8 minutes with two HPI pumps. These approximate times will vary depending on RCS pressure which determines available HPI flowrate.

When the subcooling margin is restored (based primarily on incore thermocouples) the operator should throttle HPI flow to maintain the reactor coolant subcooled but within the RC pressure/temperature limits as shown in Figure 13.

In summary, HPI cooling should be initiated if secondary heat removal is lost. It is not a normal operating mode for many reasons; three reasons are:

1. The PORV will pass a large amount of solid and two-phase flow. Since the PORV was designed for steam flow, it may fail to close when HPI cooling is terminated (e.g., on restoration of primary to secondary heat transfer). This could necessitate closing the PORV isolation valve.

2. Long-term solid water operation is sensitive to fluctuations in temperature and flowrates, and must be closely monitored to prevent exceeding equipment design limits (Figure 13).

3. The degraded containment environment may cause failures or erroneous readings of instrumentation.

Consequently, feedwater should be restored as quickly as possible so that normal primary to secondary heat transfer can be resumed.

Boiler-Condenser Cooling

Although primary to secondary heat transfer with subcooled reactor coolant is the desired core cooling condition, controlled core heat removal can occur when the RC is saturated. Natural circulation with saturated reactor coolant is discussed in Addendum B to Chapter A. However, the primary system will probably not stay both saturated and in natural circulation for an extended period of operation. Instead, the plant will probably evolve into one of two conditions:

a. Either the continued heat transfer coupled with HPI flow will restore subcooled conditions (as in the case of saturation due to overcooling or small break well within the capacity of the HPI system)

   or

b. Steam voids will collect in the upper hot leg piping ("candy cane") sufficiently to block natural circulation flow. This would be the expected case if the RCS continued to lose inventory. Figure 14 illustrates the loss of circulation due to the buildup of steam.

Under the latter conditions of flow blockage due to steam voids, another form of controlled core heat removal could still exist called boiler-condenser cooling. In this mode of cooling, reactor coolant is boiled in the core. The resulting steam rises through the hot leg piping and collects in the "candy cane." Reactor coolant steam is then condensed in the relatively cool steam generator tubes. The

condensed water flows back to the reactor core through the cold leg piping to complete the process. In order for boiler-condenser cooling to exist, several conditions must be present:

a. The steam void in the candy cane must be large enough to include the upper tube region of the steam generator so that RC steam can be condensed. This condition will naturally evolve if the RCS continues to lose inventory.

b. The steam generators will condense the RC steam, and adequately remove core heat, if the cooler feedwater is on the outside of the voided tubes. This requires a feedwater elevation in the steam generators sufficiently higher than the RC water level in the tube bundle to provide the necessary condensing surface area. Achieving the small break LOCA level setpoint of 40 ft. (∿ 80% on full range indication) will provide sufficient SG level for boiler-condenser cooling. This condition will be satisfied either automatically by AFW control or manually by the operator. However, while AFW is spraying into the SG, the effective condensing surface of the SG tubes is higher than the 80% on the full range because the AFW spray will be also cooling the tube surface between the AFW injection elevation and the SG water level.

c. The elevation of the RC water level in the steam generator tubes must be above the elevation of the RC pump discharge piping. This will allow the water in the cold leg piping to flow up and over the RC pump discharge into the core. This

condition should be satisfied by the condensation of RC steam in the upper tube region and the continued full HPI flow.

As previously stated, primary to secondary heat transfer with subcooled reactor coolant is the desired condition. Therefore, although the core can be cooled by boiler-condenser cooling it is not desirable and the operator should continually try to restore subcooling.

Figure 15 illustrates the boiler-condenser method of cooling. The indications on the P-T diagram will be similar to those for saturated natural circulation; however, the operator may be able to distinguish between the two methods using the hot leg level indication.

During the transition from saturated natural circulation to boiler-condenser cooling, there will be a period of time where primary to secondary heat transfer will essentially be lost. This will occur when the hot leg steam void becomes large enough to block natural circulation flow, but is not yet large enough to provide for steam condensation in the tube region. The indications will be the same as those shown in Figure 16. Figure 16 is primarily intended to show system refill by HPI, but the same basic conditions will exist during this transitional period. In addition, the operator can monitor the growth of the hot leg "bubble" with the hot leg level indication.

If natural circulation has been lost and steam cannot be condensed in the steam generators (that is, the steam bubble is in the top of the candy cane but not low enough to be in the steam generator tube region), the RCS will repressurize. This mode of operation will be indicated (see Figure 16) by saturated hot leg conditions with reactor coolant pressure above the steam generator pressure (SG pressure may be decreasing due to lack of primary to secondary heat transfer). As indicated in Figure 16, the same actions identified for boiler-condenser cooling apply to this operating mode. This condition can also develop after boiler-condenser cooling operation when HPI begins to refill the RCS. As the RC water level in the tube region rises, boiler-condenser cooling will decrease and eventually stop. In this mode, the HPI is refilling the RCS. During refill, steam in the upper region of the hot leg piping will be compressed and/or condensed as the water level in the loops and steam generator rises. With low decay heat and both HPI pumps on, subcooling and natural circulation can occur with minor increases in RC pressure. The hot leg vents can be used to aid the refill process. Figure 16 shows the actions to take to restart natural circulation if the steam generator can be used as a heat sink and the RC pumps are available for restart (see the RC pump restart guidelines in Chapter E, "Best Methods for Equipment Operation"). If the RC pumps are available, pump bumps (short run times of (05)

approximately 10 seconds duration) are allowed. This momentary use of (05)
forced circulation tries to force reactor coolant steam condensation by mixing it with liquid reactor coolant and by moving the steam into the generator tubes where it can condense. Use of the PORV to limit RCS pressure rise and to increase HPI flow is also allowed (separate or in conjunction with RCP operation). To be effective, the steam generator must be available as a heat sink; the steam generator saturation temperature selected (50F less than incore temperature) is somewhat arbitrary; it was chosen to ensure a strong temperature gradient for condensation. When the pumps are bumped and steam is condensed the RCS pressure may drop as much as several hundred psi. HPI flow will increase to help refill of the voids. If natural circulation starts the RC pressure will stay low; if natural circulation does not start the RCS will again begin to repressurize and another bump can be used about 15 minutes later.

Another situation can develop that can hinder or stop boiler-condenser cooling, even though the required conditions for boiler-condenser cooling are apparently present. This can occur if significant amounts of noncondensible gases accumulate in the RCS steam void in the upper tube region. As the gases collect in the tube region, the RC steam will have to diffuse through the gases in order to reach the tubes and condense. Thus, the accumulated gases effectively insulate the tubes and reduce heat transfer.

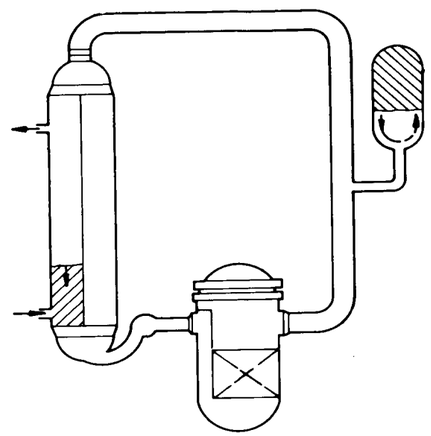
This condition can be recognized two ways. First, if all the conditions necessary for boiler-condenser cooling (listed previously) exist, but little or no heat transfer is occurring, then it can be assumed that a significant quantity of noncondensible gases exist. A second method of detection is to compare measured RCS pressure with saturation pressure for the measured RCS temperature. The partial pressure of the noncondensibles will tend to increase RCS pressure above saturation pressure. It has been calculated that the partial pressures at the expected noncondensible concentrations could add between 25 and 35 psi to the RC steam pressure. As an example of the potential impact, if the measured temperature is 577F (saturation temperature for 1300 psia), and the gases added 50 psi to the steam pressure in the RCS, the measured pressure (assuming no instrument error) would be 1350 psia. These indications might erroneously lead to the conclusion that the RCS is 5F subcooled since saturation temperature for 1350 psi is 582F. When the hot leg is known to contain a steam volume using the hot leg level measurements, these seemingly contradictory pressure and temperature readings could indicate the presence of a large quantity of noncondensible gases. Of course, instrument errors could also result in these indications or mask the presence of noncondensibles.

If indications of decreased heat transfer due to the presence of noncondensibles occur, the operator should first ensure that all of

the necessary conditions for boiler-condenser cooling are present. If all the conditions exist, he should then use the hot leg vents to vent off noncondensibles. The vents should be open for short durations (few minutes at a time) since hot leg level measurement is invalid while the vents are open. Between venting periods, he should verify the appropriate boiler-condenser conditions and check for restoration of heat transfer.

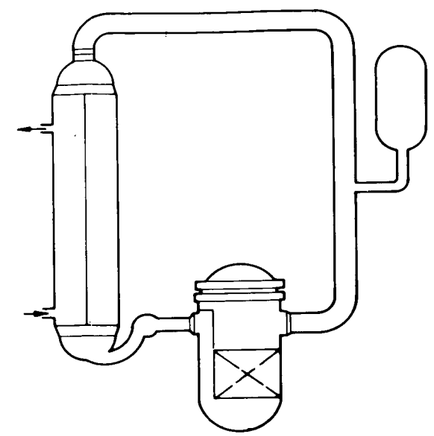
Finally, a LOCA of a certain size could depressurize the RCS below the steam generator pressure before it settles to an equilibrium with HPI (HPI will automatically start because this size LOCA will depressurize the RCS below the ESFAS setpoint). If this happens, the (05)
operator should lower the steam generator pressure (using the MADV's) until the saturation temperature on the secondary side is 50F below the incore thermocouple temperature. If desired, the operator may use the TBS after opening the MSIV bypass valves and the MSIV's. This will ensure the steam generators are available as heat sinks. Other actions are the same as discussed above for boiler-condenser cooling (Figure 15).

Figure 11 LOSS OF ALL FEEDWATER (NO OPERATOR ACTION)



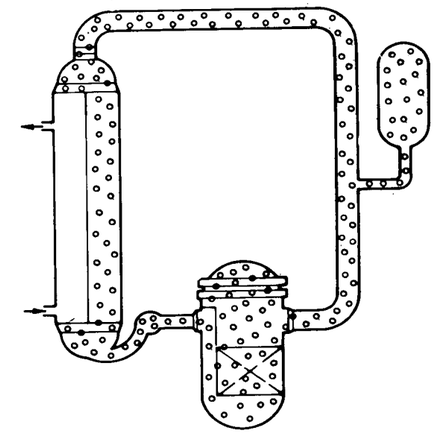
TIME I

1. LOSS OF FEEDWATER.
2. REACTOR TRIP ON HIGH RCS PRESSURE (OR ANTICIPATORY TRIP).
3. PRESSURIZER LEVEL DECREASES (NORMAL RESPONSE FOLLOWING A REACTOR TRIP) THEN INCREASES BECAUSE OF MU ADDITION AND REHEAT OF REACTOR COOLANT.
4. SECONDARY SIDE BOILS DRY.
5. AFW DOES NOT START.
6. RC PRESSURE SHOWS NORMAL POST TRIP RESPONSE THEN INCREASES AS PRESSURIZER LEVEL IS RESTORED.



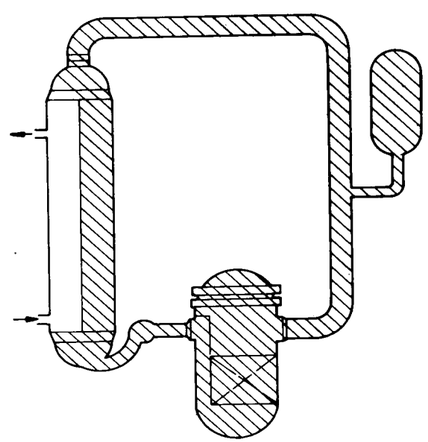
TIME II

1. RC HEATS UP DUE TO LOSS OF SECONDARY HEAT SINK AND EXPANDS INTO PRESSURIZER.
2. RC PRESSURE INCREASES TO PORV SETPOINT. PRESSURIZER STEAM IS EJECTED OUT OF PORV.
3. PRIMARY SYSTEM GOES WATER SOLID (STILL SUBCOOLED) AT ~2500 PSIG. CONTINUED HEATUP OF REACTOR COOLANT CAUSES WATER RELIEF OUT OF PORV OR SAFETY VALVES.
4. RC TEMPERATURE IS SLOWLY APPROACHING SATURATED CONDITIONS ≈ 2500 PSIG.



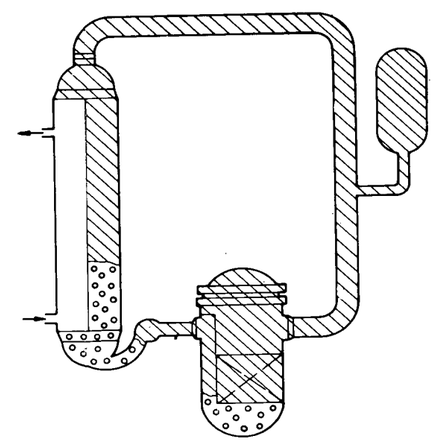
TIME III

1. RCS GOES SATURATED AT ~ 2500 PSIG.
2. STEAM IS CREATED IN CORE BECAUSE OF BOILING THROUGHOUT THE CORE.
   - IF RC PUMPS ARE RUNNING, STEAM WILL BE DISTRIBUTED AROUND THE LOOP (SEE ABOVE).
   - IF RC PUMPS ARE OFF, THE STEAM WILL SEPARATE FROM THE REACTOR COOLANT AND COLLECT IN THE UPPER REGION AT RV AND HOT LEG.



TIME IV (RC PUMPS ON)

END CONDITION FOR TOTAL LOSS OF FW WITHOUT MU/HPI ACTUATION. SYSTEM WOULD COMPLETELY VOID (STEAM ONLY IN RCS). CORE TEMPERATURE WILL INCREASE AND CAUSE SUPERHEATED STEAM TO FORM. INADEQUATE CORE COOLING CONDITIONS EXIST.



TIME IV (RC PUMPS OFF)

END CONDITION FOR TOTAL LOSS OF FW WITHOUT MU/HPI ACTUATION. WITH RC PUMPS OFF EARLY IN THE EVENT, REACTOR COOLANT CAN BE TRAPPED IN LOWER REGIONS OF LOOP AND REACTOR VESSEL. CORE WILL HEATUP WHEN MIXTURE LEVEL DROPS BELOW TOP OF FUEL. INADEQUATE CORE COOLING WILL EXIST.

LEGEND

PRIMARY SIDE
- WATER
- TWO PHASE LIQUID
- STEAM

SECONDARY SIDE
- WATER
- STEAM

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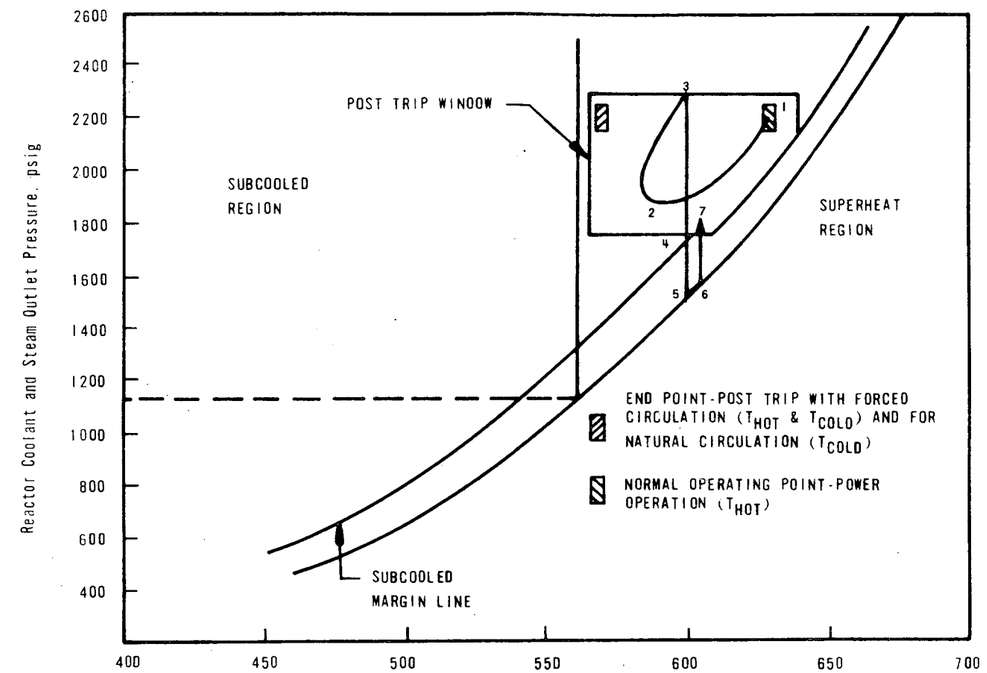
Figure 12 BACKUP COOLING BY HPI FOR LOSS OF ALL FEEDWATER (WITH OPERATOR ACTION)



Reference Points	Time (Minutes)	Remarks
1-2	0-1	Reactor tripped on anticipatory loss of feedwater. Normal post-trip cooldown and depressurization in progress. AFW does not initiate.
2	1-2	Steam generators dry. RCS begins to reheat and re-pressurize due to loss of secondary cooling. SG pressure starts decreasing.
3	3-4	Operator diagnoses loss of heat transfer, opens PORV, starts two HPI pumps and balances HPI flow. PORV release rate exceeds HPI capacity initially and RCS begins to depressurize. Operator trips all but one RCS pump to reduce heat input.
4	5-6	Subcooling margin is lost. Remaining RC pump trips.
5	6-7	RCS reaches saturation.
6	7-8	Pressurizer in solid or near solid condition. HPI flow "matches" decay heat and begins to repressurize RCS to subcooled conditions.
7	8-10	RCS subcooling margin restored and RCS is beginning to cool due to HPI flow and PORV release. Operator throttles HPI flow to maintain subcooled conditions at a pressure lower than the safety valve setpoint.

Figure 13 RC PRESSURE/TEMPERATURE LIMITS

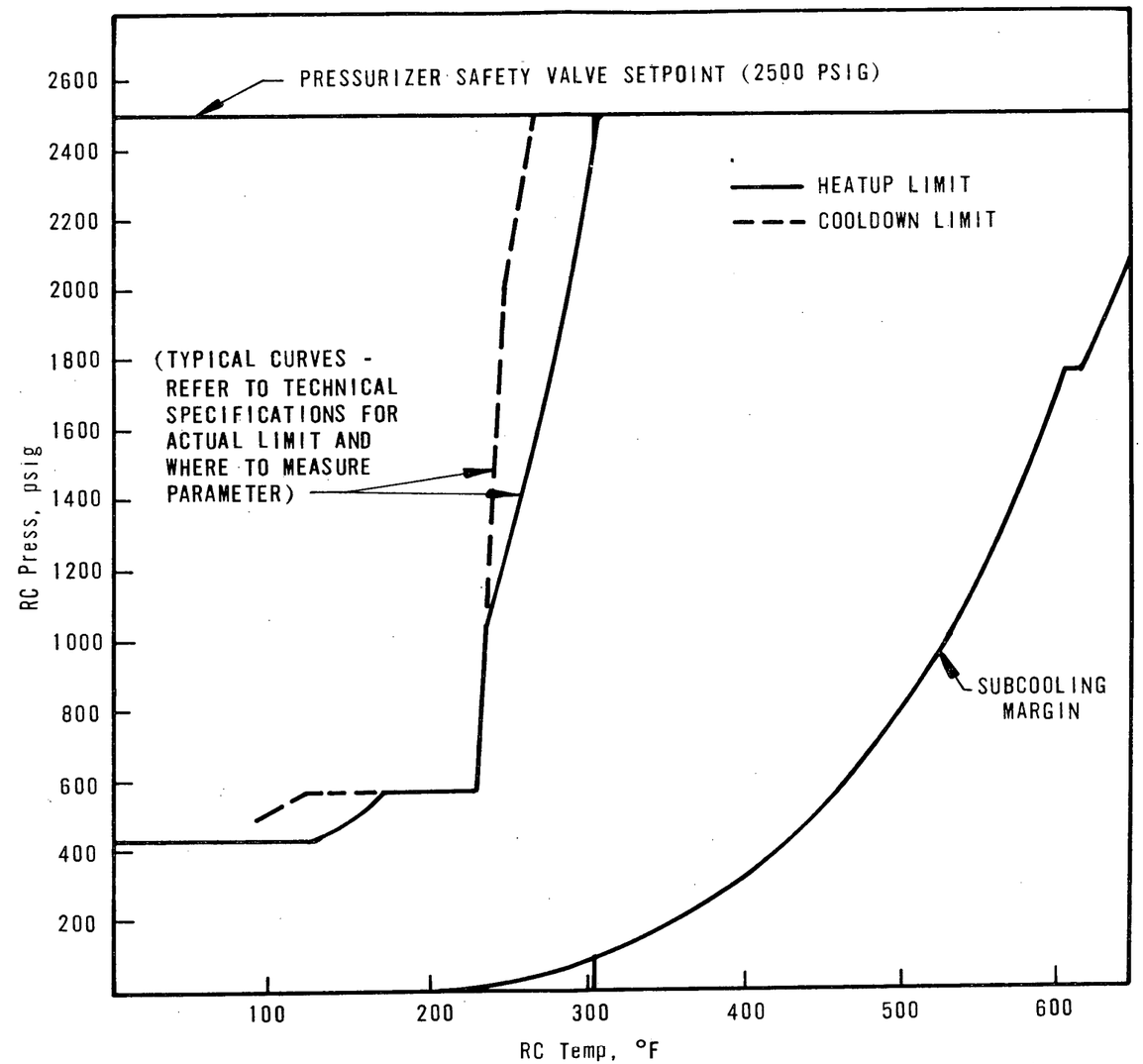
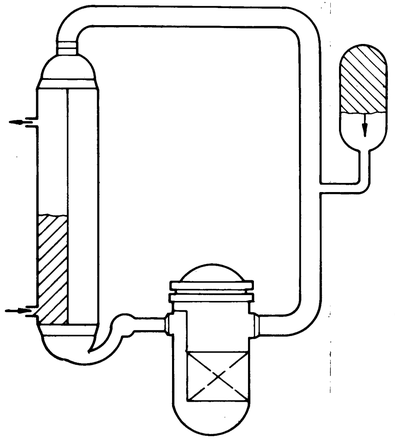
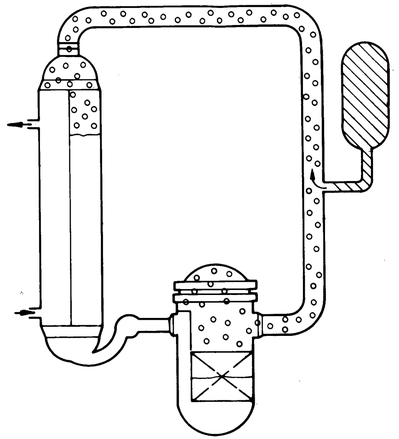


Figure 14 ILLUSTRATION OF LOSS OF NATURAL CIRCULATION DUE TO BUILDUP OF STEAM IN THE REACTOR COOLANT SYSTEM



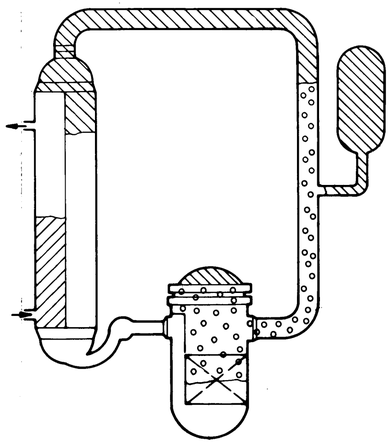
TIME I

1. DECREASING PRESSURIZER LEVEL BECAUSE OF LOSS OF REACTOR COOLANT (LOCA) OR CONTRACTION OF REACTOR COOLANT (OVERCOOLING).
2. REACTOR TRIP ON LOW REACTOR COOLANT PRESSURE.
3. ESFAS ACTUATION ON LOW REACTOR COOLANT PRESSURE.
   - HPI ACTUATION
   - AFW ACTUATION



TIME II

1. PRESSURIZER LIQUID VOLUME IS LOST; STEAM FROM PRESSURIZER CAN ENTER RCS LOOPS WHEN THE RCS DEPRESSURIZES. OPERATOR TRIPS RC PUMPS WHEN SUBCOOLING MARGIN IS LOST.
2. REACTOR COOLANT PRESSURE DROPS TO A VALUE ABOUT EQUAL TO STEAM GENERATOR PRESSURE.
3. STEAM FORMS IN HOT LEG BECAUSE OF ACCUMULATION OF PRESSURIZER STEAM AND BECAUSE OF FLASHING OF REACTOR COOLANT. STEAM IS IN THE FORM OF BUBBLES WITHIN RCS.
4. 2-PHASE NATURAL CIRCULATION WILL OCCUR - BOILING MAY OCCUR IN CORE.
5. IF SUFFICIENT STEAM IS CREATED, IT WILL START TO COLLECT IN UPPER REGION OF LOOP BECAUSE STEAM CAN RISE AT A FASTER VELOCITY THAN WATER.



TIME III

1. STEAM SEPARATES IN UPPER REGIONS OF LOOP.
2. 2-PHASE NATURAL CIRCULATION STOPS.
3. SIZE OF THE STEAM BUBBLE DEPENDS ON SEVERITY OF ACCIDENT, HPI FLOWRATE, AND HPI STARTUP TIME.

LEGEND

PRIMARY SIDE	SECONDARY SIDE
WATER	WATER
TWO PHASE LIQUID	STEAM
STEAM	

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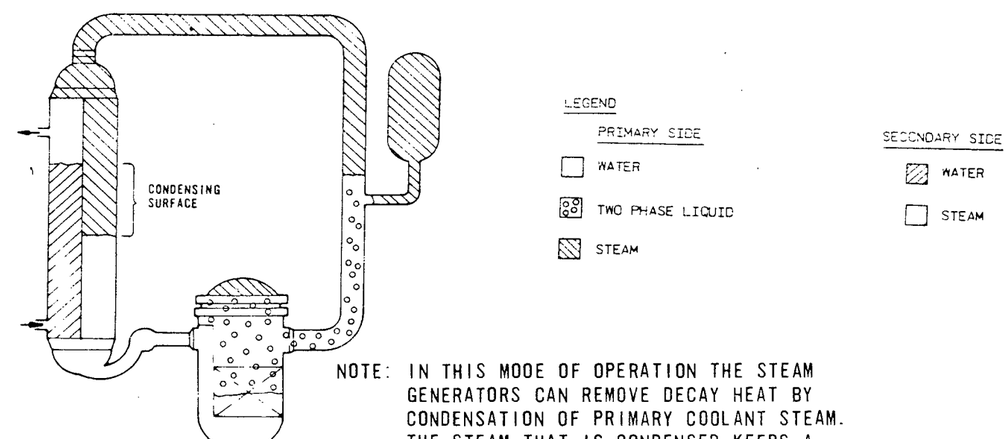
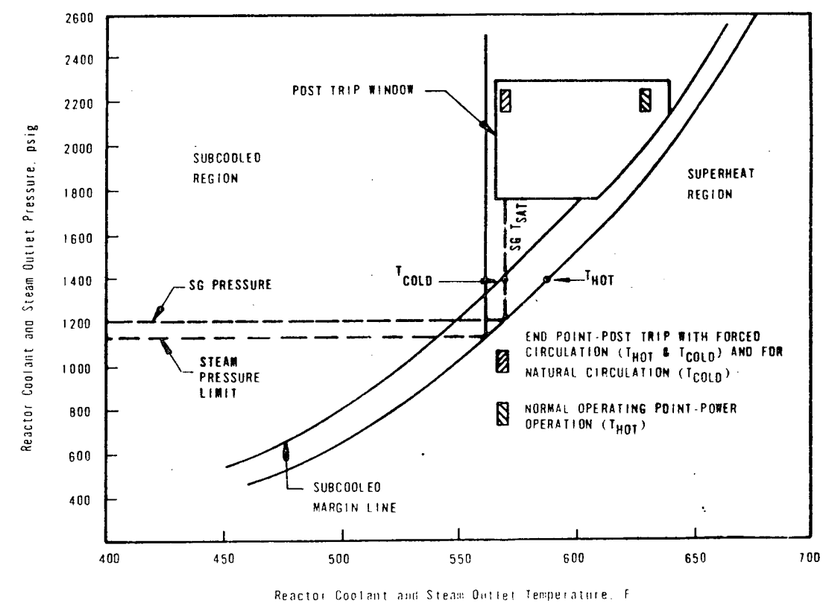
Figure 15 BOILER-CONDENSER COOLING



NOTE: IN THIS MODE OF OPERATION THE STEAM GENERATORS CAN REMOVE DECAY HEAT BY CONDENSATION OF PRIMARY COOLANT STEAM. THE STEAM THAT IS CONDENSED KEEPS A WATER LEVEL IN THE STEAM GENERATOR TUBES TO FORCE FLOW UP THE COLD LEG AND INTO THE REACTOR VESSEL.



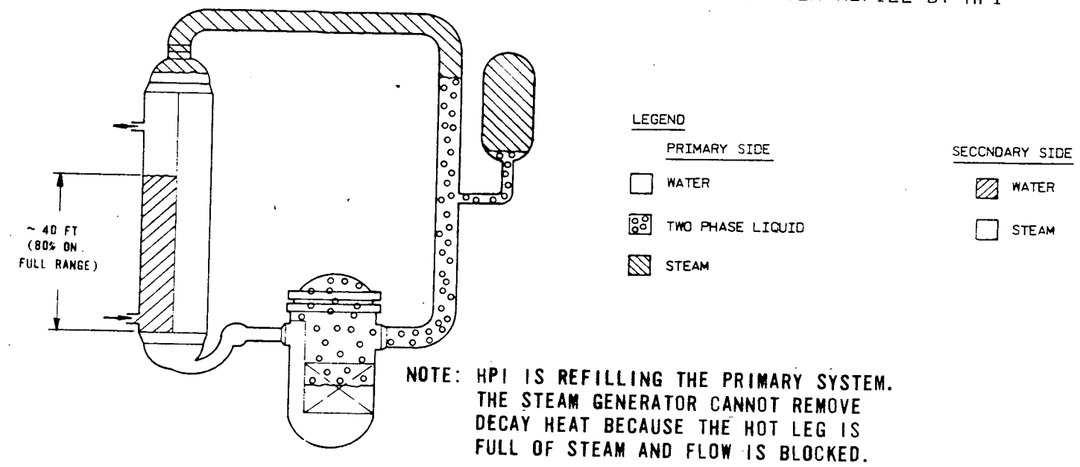
NOTES ON P-T DIAGRAM

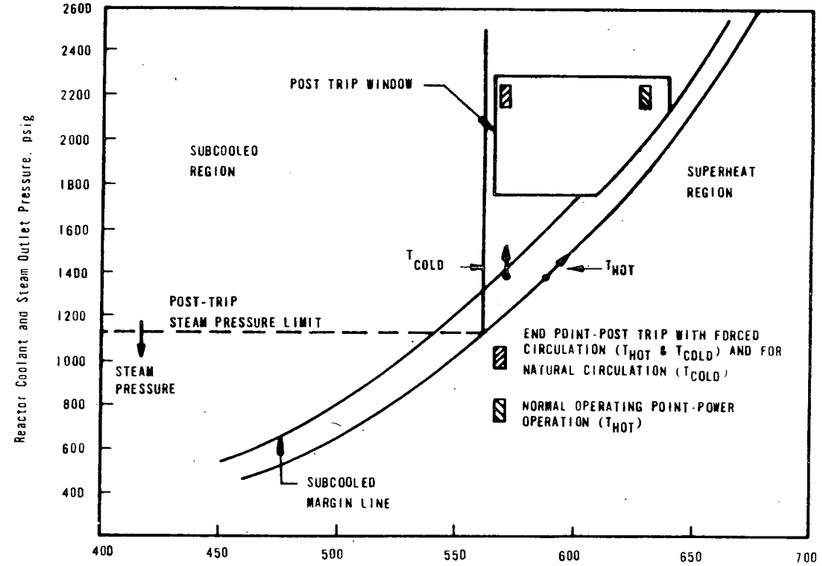
1. RC PRESSURE IS SLIGHTLY HIGHER THAN STEAM GENERATOR PRESSURE.
2. T_{HOT} IS EQUAL TO T_{SAT} FOR EXISTING RC PRESSURE.
3. T_{COLD} IS EQUAL TO T_{SAT} FOR EXISTING STEAM PRESSURE.

OPERATOR ACTION REQUIRED

1. TURN HPI ON AT HIGHEST FLOW RATE.
2. VERIFY AFW FLOWING AND RAISING STEAM GENERATOR LEVELS TO 80% ON FULL RANGE INDICATION.
3. START PLANT COOLDOWN AT 50F/HR.
4. MONITOR PLANT CONDITIONS FOR A LOSS OF CORE BOILING/SG CONDENSING OR A RETURN TO NORMAL NATURAL CIRCULATION (SUBCOOLING).

Figure 16 LOSS OF NATURAL CIRCULATION - SYSTEM REFILL BY HPI





NOTES ON P-T DIAGRAM

1. T_{HOT} IS EQUAL TO T_{SAT} FOR EXISTING RC PRESSURE.
2. RC PRESSURE WILL INCREASE ABOVE STEAM GENERATOR PRESSURE AND CAN GO AS HIGH AS THE PRESSURIZER SAFETY VALVE SETPOINT (2500 PSIG).
3. STEAM PRESSURE MAY DROP BECAUSE HEAT TRANSFER FROM REACTOR COOLANT IS LOW.
4. T_{COLD} MAY DROP DUE TO HPI OR RC PUMP SEAL INJECTION, BUT WILL GO UP WHEN RC PUMP IS BUMPED.

OPERATOR ACTION REQUIRED

1. SAME AS BOILER-CONDENSER COOLING.
2. ESTABLISH THE STEAM GENERATORS AS A HEAT SINK (SG T_{SAT} SHOULD BE ABOUT 50F LESS THAN THE INCORE THERMOCOUPLE TEMPERATURE).
   - OPEN PORV
   - BUMP ONE RC PUMP

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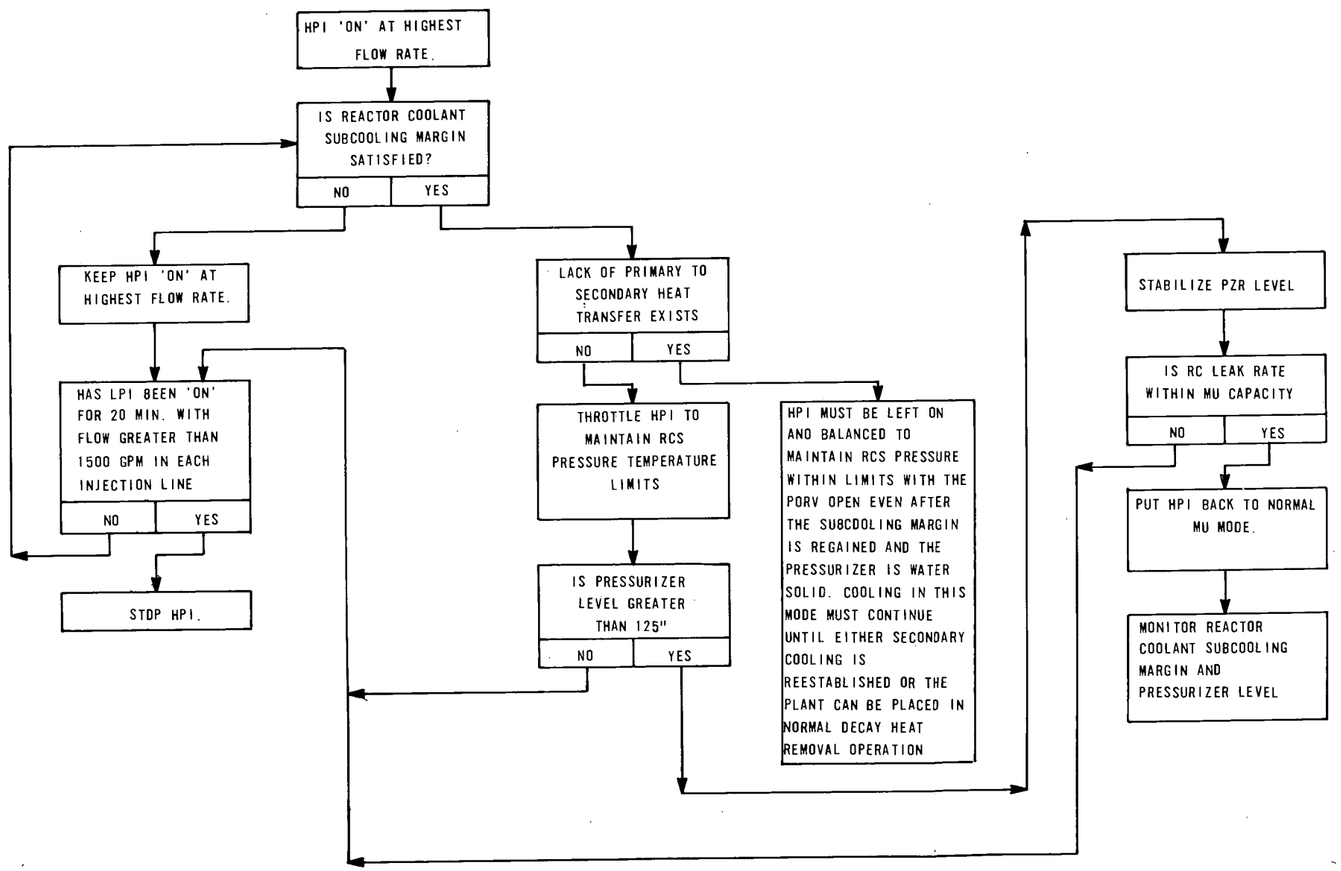

Figure 18 HPI CONTROL LOGIC

NOTES: 1) PREVENT PUMP RUNOUT AND CAVITATION DAMAGE BY LIMITING THE TOTAL FLOW FROM ONE PUMP TO 800 GPM.

2) PREVENT PUMP DAMAGE AT LOW FLOW CONDITIONS BY LIMITING THE MINIMUM TOTAL PUMP FLOW TO MORE THAN 100 GPM.

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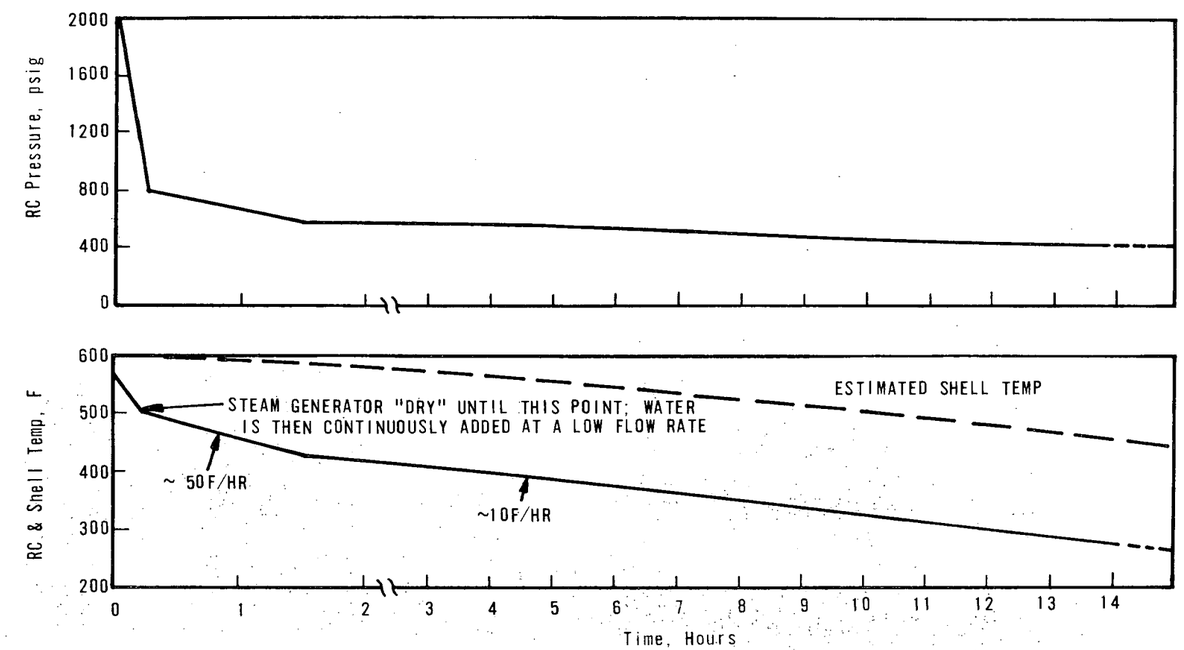
Figure 19 COOLDOWN ON ONE STEAM GENERATOR



CONDITIONS:

- RC PUMPS ON OR OFF
- STEAM LEAK IN ONE GENERATOR; STEAM PRESSURE IS AMBIENT
- SLOW FEEDING OF GENERATOR BEGINS AT ~ 500F - IT IS DOUBTFUL THAT LEVEL WILL BUILD FOR SEVERAL HOURS: LOWER SHELL WILL NOT BE COVERED FOR SOME TIME; SHELL COOLING IS BY STEAM CONVECTION.

Table 5 RULES FOR RC PUMP TRIPS

RULE	REASON
1. The RC pumps shall be tripped immediately whenever subcooling margin is lost.	Precludes the potential for uncovering the core (ICC) during a small loss of coolant accident due to a late pump trip when the amount of water in the RCS is low.
2. *If component cooling water to the RC pump motor is lost and the pumps are running, the RC pumps must be tripped if cooling water is not restored within six minutes or guide bearing temp. reaches 212°F, or thrust bearing temp. reaches 221°F, or stator temp. reaches 302°F.	Pump trip precludes motor failure and minimizes the chance of a fire inside containment due to lack of cooling water to the RC pump motors.
3. *If both seal injection and component cooling water are lost to a RC pump the affected RCPs must be tripped and seal return isolated within 90 seconds. The seal return should automatically isolate.	Pump trip reduces damage to the pump seals and the chance of a LOCA. If CCW can be restored prior to reaching a high temp. alarm condition, the controlled bleed-off valve should be opened within 60 seconds. This should be followed by a restart of the RCP within 30 seconds and a re-establishment of seal injection flow if available.

* These rules do not apply if the pumps were not tripped immediately after the subcooling margin was lost. The operator should try to restore cooling water.

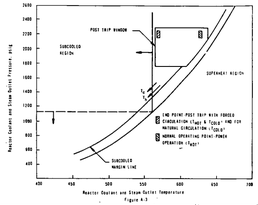


Figure A-3

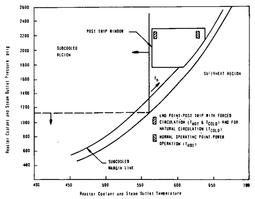


Figure A-3

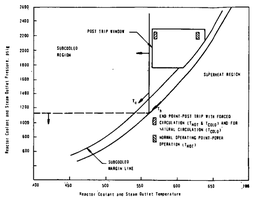


Figure A-3

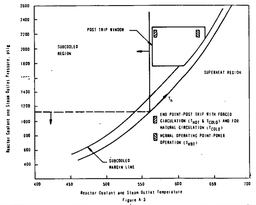


Figure A-3

REACTOR COOLANT CONDITION	SUBCOOLED WITH NATURAL CIRCULATION EXISTING	SUBCOOLED WITH NO NATURAL CIRCULATION	SATURATED WITH NATURAL CIRCULATION EXISTING (HPI ON)	SATURATED WITH NO NATURAL CIRCULATION (HPI ON)	SUPERHEATED WITH CLAD TEMPERATURE GREATER THAN 1400F (CURVE 1 OF FIGURE 17)	SUPERHEATED WITH CLAD TEMPERATURE GREATER THAN 1800F (CURVE 2 OF FIG. 17)
RESTART ACTIONS	▪ CONFIRM THAT NO PUMP DAMAGE WILL OCCUR ▪ START AND RUN ONE RC PUMP IN EACH LOOP (REFER TO TABLE BELOW FOR PUMP COMBINATIONS TO ACHIEVE ADEQUATE SPRAY FLOW)	▪ CONFIRM THAT NO RC PUMP DAMAGE WILL OCCUR ▪ ESTABLISH AT LEAST ONE STEAM GENERATOR AS A HEAT SINK (T_{SAT} OF STEAM GENERATOR IS AT LEAST 50F COLDER THAN INCORE THERMOCOUPLES; FEEDWATER AVAILABLE) ▪ START AND RUN AN RC PUMP IN THE LOOP(S) WITH A STEAM GENERATOR AVAILABLE AS A HEAT SINK ▪ SPECIAL CASE WHEN THE PLANT IS SUBCOOLED WITH NO NATURAL CIRCULATION AND THE HPI IS ON, ONE RC PUMP MAY BE STARTED TO CAUSE FLUID MIXING. SG COOLING IS NOT REQUIRED.	▪ DO NOT RESTART ▪ PROCEED WITH RCS COOLDOWN BY GRADUALLY LOWERING STEAM PRESSURE AND LOWERING RCS PRESSURE WITH THE AUXILIARY SPRAY OR PORV	▪ CONFIRM THAT NO RC PUMP DAMAGE WILL OCCUR ▪ ESTABLISH AT LEAST ONE STEAM GENERATOR AS A HEAT SINK (T_{SAT} OF STEAM GENERATOR IS AT LEAST 50F COLDER THAN INCORE THERMOCOUPLES) ▪ DUMP PUMP ONCE TO SEE IF NATURAL CIRCULATION STARTS. IF IT DOES, PROCEED WITH RCS COOLDOWN BY GRADUALLY LOWERING STEAM PRESSURE AND LOWERING RCS PRESSURE WITH THE AUXILIARY SPRAY OR PORV. IF NATURAL CIRCULATION DOES NOT START, BUMP ALTERNATE PUMPS (ONE EVERY 15 MINUTES) UNTIL ALL FOUR HAVE BEEN BUMPED. IF NATURAL CIRCULATION HAS STARTED, PROCEED WITH COOLDOWN. IF NOT, LOWER STEAM PRESSURE UNTIL THE STEAM TEMPERATURE IS 100F COLDER THAN THE INCORE THERMOCOUPLE TEMPERATURE. RUN THE RC PUMP AND CONTINUE COOLDOWN AND DEPRESSURIZATION.	IF RC PUMP PROTECTIVE INTERLOCKS PERMITS START AND RUN ONE PUMP IN EACH LOOP EVEN IF STEAM GENERATORS ARE NOT AVAILABLE	START AND RUN ALL RC PUMPS EVEN IF PUMP DAMAGE CAN OCCUR AND EVEN IF STEAM GENERATORS ARE NOT AVAILABLE

SPECIAL PRECAUTION: IF SUBCOOLING MARGIN IS LOST AFTER PUMP RESTART, THE RC PUMPS MUST BE TRIPPED AND NOT RESTARTED UNTIL THE SUBCOOLING MARGIN IS REGAINED

CALCULATED SPRAY FLOW RATES (% OF MAXIMUM) FOR VARIOUS RC PUMP COMBINATIONS

	UNIT 1	UNIT 2															
OPER RC PUMP	A2	A1	X	X	X	X	X		X	X			X				
	A1	A2	X	X	X	X		X			X	X		X			
	D1	D1	X	X			X	X	X		X				X		X
	B2	B2	X		X		X	X		X		X				X	X
SPRAY FLOW	% OF MAX		100	84	84	69	42	0	14	14	0	0	0	0	0	0	0

NOTE: SPRAY LINE OFF PUMP A1 DISCHARGE ON UNIT 1
SPRAY LINE OFF PUMP A2 DISCHARGE ON UNIT 2

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CHAPTER F

POST TRANSIENT STABILITY DETERMINATION

To determine if the transient has been brought under control five general areas must be checked.

1. Reactivity Control - The reactor must have a subcritical margin of at least 1% $\Delta k/k$.
2. Core Heat Removal Control - The core must be covered and cooled; the heat removal rate is equal to or slightly greater than the core heat generation rate.
3. Radiation Release Control - Release to offsite is terminated.
4. Plant Equipment is Operating Correctly - Equipment to maintain the plant safe and stable is operating within design conditions; equipment failures have been bypassed, isolated or repaired.
5. Reactor Building Control - refer to the reactor building chapter.

Several things around the plant must be checked to make sure these five general areas are being controlled. The following basic check list defines the more important items. The list is divided into two cases. Case I applies to LOCA's which can be stopped by complete isolation of the leak and to all other transients. Case II applies to LOCAs which cannot be isolated. The difference between the two cases is that a reactor leak that cannot be stopped is a transient that cannot be positively terminated in the short-term. However, a leak can be reduced to the smallest amount

possible and become stable for "long-term cooling". Steam generator heat removal can be used for some small leaks, but HPI must be kept running to keep the reactor coolant subcooled. Subcooling can be regained for some very small break sizes at a time when the decay heat decreases and HPI is able to refill the RCS loops and add water to the pressurizer.

Case I - All Transients (including LOCA's which can be isolated)

1. Reactor coolant pressure and temperature are preferably within the "post trip window" of the P-T diagram; however, pressure and temperature may be anywhere on the P-T diagram within a region bounded by: a) reactor vessel pressure temperature limits, b) the subcooling margin, c) an RC pressure upper limit equal to the PORV setpoint, d) fuel pin compression limits and e) RCP NPSH requirements, if applicable. Subcooling will exist in the hot and cold legs of both loops.
2. The "long term" trend of reactor coolant pressure and temperature is constant or slowly decreasing with time. "Short-term" fluctuations of temperature and pressure are small and can be attributed to periodic operations of other equipment (pressurizer heaters, spray, or feedwater).
3. Pressurizer level is within the indicated range above the heater cut-off setpoint.
4. If forced circulation exists (RC pumps on), then reactor coolant T_{av} is slightly above the saturation temperature of the water in the steam generator (or generators) that is removing the heat.

5. If natural circulation exists, $T_{cold\ leg}$ will be about equal to the saturation temperature of the water in the steam generator (or generators) that is removing the heat. The difference between incore thermocouples and T_{hot} in the operating loop (or loops) will track within ∿10F. If only one generator is removing heat, the other reactor coolant loop will be subcooled.
6. Steam generator (or generators) level will be at the correct setpoint (either natural or forced circulation setpoint) and will be steady.
7. Steam generator pressure is steady and is below the safety valve opening setpoint.
8. The core is at least 1% $\Delta k/k$ subcritical on rods and boron. If more than one rod did not fully insert, the core must be at least 1% $\Delta k/k$ subcritical on boron alone (assuming all rods out).
9. If the transient caused water to enter the containment (reactor coolant or steam generator water) and the containment environment had been degraded, it will now be returned to near normal levels. Pressure will be close to atmospheric pressure; average containment temperature will be near prior operating temperature; relative humidity will be about 100%.
10. If radioactive water leaks occurred in auxiliary buildings, those areas will be sealed and the spillage either trapped or drained to storage tanks.

11. The component failure (or failures) which caused the transient is known. It has been bypassed, isolated, repaired, or otherwise handled so that it no longer compromises plant safety.
12. Components which support plant safety are operating near their normal operating point (examples: pumps are operating away from the minimum shutoff flow and have adequate NPSH, throttle valves are near the proper opening, electric motors are in the normal service range, electronic equipment is environmentally protected). If a component is operating at or beyond design limits and future failure is possible, then redundant or alternate equipment is on standby and ready to replace the equipment which might fail.
13. Stored water (condensate tank, BWST) is adequate for long term use or backup supplies are readily available.
14. Instrumentation to monitor plant performance is operating correctly. Potential failures of critical instrumentation have been identified and alternate instrumentation is available.

Case II - LOCA's which cannot be isolated

Many of the criteria of Case I apply to Case II except that the reactor coolant will not always regain the subcooling margin and operating conditions that depend on subcooling will not apply. The very smallest reactor coolant leaks may allow the reactor coolant system to repressurize (because of continued High Pressure Injection) and some amount of subcooling may be regained, but it is not likely that enough margin will occur until at least several hours after the break occurs. Consequently, the

criteria for LOCA stability does not include the subcooling margin. Also, because subcooling may not exist, the hot legs may have steam binding and natural circulation may not exist; therefore, the criteria do not include natural circulation requirements (however, it can exist for very small breaks and should be checked). A reactor-steam generator heat transfer balance cannot usually be accomplished because of saturated (or near saturated) conditions which may not permit the reactor coolant to move the heat from the core to the steam generator, but some heat transfer to the steam generator is possible for small breaks. The steam generator level should be at 80% on the full range for small breaks to permit condensation of primary side steam.

The most important criterion for LOCA is to keep the core covered and cooled. This condition is confirmed by readings of the incore thermocouples and the hot leg RTD's; both should show that the reactor coolant is saturated (or even subcooled) but not superheated.

The continued loss of coolant from a LOCA will not permit the transient to be truly terminated, but the leak rate can be minimized. Lowering RCS pressure is the best way to lower the leak rate. This can be done by losses through the leak, by opening the PORV, or by lowering secondary side pressure. Long term loss of coolant, when the RCS is depressurized, occurs in two ways: 1) steaming out of the leak because of continued boiling, and 2) water loss because the head of water is above the break. The leak rate will depend on the system pressure, the decay heat level

(which causes boiling), and the elevation of the leak (a leak high in the system will have a lower flow rate than a leak low in the system). The leak rate will also depend on the hole size.

The criteria for stability is that the leak rate is as low as possible, and that the flow into the core keeps it covered. It may take a very long time to recover from some LOCA's, and during that time there will be two general stages when the leak rate diminishes. The first stage is when the reactor coolant system is depressurized to atmospheric pressure (big breaks will depressurize rapidly, smaller breaks will take longer); the second stage is when the core heat drops so that it cannot boil the water in the reactor vessel. Steaming will stop at that time (which may be as long as several months after the transient). Until the water in the vessel becomes subcooled (incore thermocouples read less than 212F), the plant must be operated by injecting containment sump water in the recirculation mode or by continuing to inject fresh borated water from other sources. When the vessel water becomes subcooled, the operator has the option to transfer one train of LPI to the decay heat removal mode and keep the other train on sump recirculation. The reason one train is left on recirculation is that it will keep water above the elevation of the hot leg suction nozzle for decay heat removal. Decay heat removal has the advantage of rapid RCS cooldown, but it must be carefully monitored to make sure the decay heat pump does not lose suction (or it will fail), and to make sure the decay heat pump does not run at shut-off head.

Because the leak may continue a long time before the decay heat system is engaged, an arbitrary definition of stability is given. The following criteria define post-LOCA long term stability:

1. The core is covered. Incore thermocouple readings show saturated or subcooled reactor coolant.
2. ECCS injection is in the "long term cooling" mode. Long term cooling exists when the ECCS is operating with recirculation from the containment emergency sump.
3. The reactor coolant system is depressurized to near atmospheric pressure so that the leak rate is as low as possible. The LPI system is used to cool the core. (NOTE: If the break size did not permit depressurization before the BWST was empty, so that HPI "piggyback" recirculation had to be used while further depressurization took place, then the plant is not considered to be stable until the pressure and leak rate are as low as possible).
4. Steam generator level is at 80% on the full range and is steady.
5. Reactor coolant pumps are off (operation of RC pumps could move water past the break and increase the leak rate).
6. The following criteria from the previous part also apply: Numbers 7, 8, 9, 10, 11, 12, 13, 14.

7. For the special case of steam generator tube leaks:

   a) Feedwater (main and auxiliary) has been stopped to the generator with the tube leak.

   b) Either the tube leakage is contained within the isolated generator, or the steam created by boiling the RCS leakage is directed to the condenser (if it is operating), or the RCS leakage is draining to the RB sump.

   c) The plant is on decay heat removal or standby backup borated water sources are available to replenish BWST inventory.

CHAPTER H

USE OF THE GUIDELINES

Philosophy of Part I Organization

Part I is designed for use following any reactor trip or forced shutdown. Its primary purpose is to maintain core cooling and ensure plant stability. A reactor trip, depending on the cause and initial plant conditions, can result in demands on various systems and components (MSSV's, CDV's, AFW, etc.). These demands, coupled with the cause of the trip or forced shutdown, are occurrences that have a higher probability for abnormal conditions to develop.

When equipment or system failures occur resulting in an abnormal plant response following a trip, it is not so important to immediately identify the cause as it is to restore stable, controlled conditions. Once the plant has been stabilized, then time exists for failure identification and the decision for future operations (i.e., return to power, remain at existing conditions, or begin controlled cooldown). The main thrust of ATOG, and certainly the most important aspect of dealing with any transient or accident, is to maintain adequate core cooling. The most expeditious and positive approach to accomplish this objective is to recognize abnormal conditions when they develop and take appropriate actions to restore stability.

Part I of ATOG contains four basic sections that flow in a logical sequence based on this philosophy. The four sections, in order, are:

a. Section I: Immediate Actions

b. Section II: Vital System Status Verification

c. Section III (A-D): Follow-up Actions for Key Symptoms

d. Cooldown Procedures (including Inadequate Core Cooling)

A two level format is used in Section III and in the cooldown procedures (including inadequate core cooling). The main steps or headings are designed to provide sufficient information for the supervisor and the experienced operator. The sub-steps under each heading provide additional detailed information for the operator actually performing the actions as well as a step by step procedure for the less experienced operator. This approach is designed to allow the more experienced operator to follow the procedure more quickly by not requiring him to read detailed information he is already familiar with. The flow charts for Section III are provided as a visual aid to supplement the text. They do not replace the text, since the detailed information of the sub-steps is not included on the flow charts.

The immediate actions to be taken in Section I are dependent upon the entry condition. If a reactor trip has occurred, or if a trip parameter has been reached, the operator should immediately perform a manual trip of both the reactor and the turbine and then proceed directly to Section II. He should perform these manual trips regardless of whether the reactor and turbine automatically tripped and should do so as soon as a trip condition is reached without waiting to verify an automatic trip. If a forced

shutdown is required by technical specifications or other operating documents, and a trip condition has not been reached, then the operator should proceed to the appropriate forced shutdown procedure and not trip the reactor or turbine. If there is indication of a tube rupture, he should proceed directly to Section III.D, which provides guidance on plant shutdown and cooldown with a tube rupture. In this case, a reactor trip is to be avoided, if possible, to preclude lifting of the MSSVs on the affected SG.

Once the operator has performed the immediate actions for a reactor trip condition, the next priority is to verify that the reactor is shutdown and that key systems and equipment are available and functioning properly (e.g., NNI/ICS power, turbine stop valves shut, etc.). These items are included in Section II. The first check in Section II (Step 1.0) is verification that reactor power is decreasing on the intermediate range. If not, the control rod assemblies (CRA's) have failed to insert producing a serious event. Core reactivity is not being controlled and the specified remedial actions are directed at regaining control of core reactivity as soon as possible. The operator accomplishes this by initiating full HPI flow with two HPI pumps drawing suction from the BWST to achieve a maximum rate of boron addition and manually inserting the control rods to obtain as high a rate of negative reactivity addition as possible. Concurrently, an operator should be dispatched to the cable spread room to manually trip the CRD AC breakers. If this action still fails to trip the reactor, then the 480 volt AC supply breakers off the

XA2 and XB2 busses should be locally tripped. The sequencing of the local, manual breaker trips is based on rapid accessibility. In the interim, the operator in the control room should continue to monitor rod insertion and boration by HPI and that the secondary plant, if not tripped, is ramping down tracking the reactor shutdown.

The response of the RCS to these actions will vary depending on the status of the secondary plant. If the turbine did not trip, the ICS will run back the secondary plant tracking the manual rod insertion. The operator should monitor this process to ensure the secondary steam demand and MFW flow follow reactor power thus maintaining proper primary/secondary heat transfer. RC temperatures should not change significantly, however, the addition of HPI will cause pressurizer level and pressure to increase and could result in lifting the PORV and/or safety valves. If the turbine did trip, secondary heat removal will still exist through the turbine bypass valves and steam safety valves. Since this results in a higher steam pressure and temperature, RC temperature will also increase. The accompanying RC pressure increase will make lifting of the PORV and safety valves occur sooner. In either case, it is important that the operator monitor secondary plant performance to ensure adequate main feedwater flow and steam demand exist to maintain proper primary/secondary heat transfer. The goal is to limit the RCS heatup and pressurization to the extent practical while preventing unnecessary cooling of the RCS while the reactor is at power. Cooling of the RCS will insert additional positive reactivity due to the moderator temperature coefficient.

If a failure to trip should occur, the operator's top priority is achieving reactor shutdown. Therefore, he should not proceed with other portions of ATOG until the rods are inserted or the reactor is at least 1% $\Delta K/K$ subcritical on rods and/or boron. In addition, it is important to limit the effects during reactor shutdown by maintaining a primary/secondary heat balance. Operation of main feedwater and the reactor coolant pumps is important, since auxiliary feedwater and natural circulation do not provide the desired heat removal capacity while at power. It is expected that taking the remedial actions specified will result in a reactor trip. Careful control of the manual reactor shutdown will limit the perturbation of the RCS until the trip occurs. Step 2.0 of Section II is verification that a stuck rod situation does not exist. This situation is not as serious as a total failure to trip, but boration should begin immediately to ensure a shutdown margin of 1% $\Delta K/K$.

Another abnormal condition that can require prompt recognition and response by the operator is excessive MFW flow after trip. Therefore, one of the first checks in Section II is the verification that MFW flow has run back after the reactor has tripped. The important items to check quickly are reactor/turbine trip and MFW flow status. No particular importance should be placed on the sequencing of the other verification steps as long as all of them are performed.

Section II also includes obtaining a status of the four main symptoms of abnormal transients (the three basic heat transfer symptoms and the special case for SG tube rupture). However, operator training should emphasize continuous surveillance for indications of off-normal conditions. Four main symptoms are:

1. Lack of adequate subcooling margin
2. Lack of primary to secondary heat transfer (overheating)
3. Excessive primary to secondary heat transfer (overcooling)
4. Indications of steam generator tube rupture

Recognition of these symptoms is covered in more detail in the "P-T Diagram" and "Abnormal Transient Diagnosis and Mitigation" chapters of this volume. Should any of these symptoms occur, Section II references the operator to the appropriate follow-up action in Section III of Part I.

Philosophy on the Use of Section III

The order that the symptoms are listed in Section II corresponds with the order of the respective follow-up actions in Section III and is based on the relative priorities of the corrective actions. Lack of adequate subcooling margin is, of course, top priority because core cooling cannot be assured until certain actions are performed. If a lack of adequate subcooling margin occurs, tripping (automatic or manual) the RC pumps and initiating full HPI flow must be performed quickly. While ICC is the most severe condition of the RCS, it follows after a lack of adequate subcooling margin and the operator would be directed to the ICC section if it

should occur. However, if the actions in the lack of adequate subcooling margin can be performed, ICC will not occur. Lack of heat transfer and excessive heat transfer are both second priority symptoms. These two symptoms are equal in priority because they are mutually exclusive conditions. The SG Tube Rupture is the last priority symptom. The order of the priority for these symptoms can be understood by focusing on the objectives for treating any abnormal transient, which is to maintain adequate core cooling and minimize radiation release. For example, even though a SGTR occurs which can release large amounts of radiation if it is not quickly treated, the lack of adequate subcooling margin and the lack of heat transfer take precedence. This is true because, if adequate core cooling is not maintained, the radiation release would be much greater.

Again, even though it is important to diagnose and treat a steam generator tube rupture as soon as possible, termination of a concurrent overcooling transient takes precedence. This is true because:

1. The overcooling could be the result of a steam leak to atmosphere on the steam generator with the tube rupture, resulting in higher offsite releases.
2. The overcooling increases the tensile stresses on the steam generator tubes which could result in a larger leak size.
3. The contraction of the RCS liquid volume due to the overcooling, especially when compounded by the inventory loss through the tube leak, could result in draining the pressurizer and saturation of the RC loops. Subsequent voiding in the loops can

significantly delay the cooldown and thus lead to increased offsite releases.

This discussion of priorities is given to show the logic behind the development of Part I. The important point to remember is that the operator should always be alert for the presence of these symptoms and should always proceed directly to the appropriate section for follow-up actions for a symptom without necessarily waiting to see if a "higher priority" symptom develops. This constant operator surveillance should continue during and after the stabilization of a transient. Some symptoms can mask the presence of others. For example, an overcooling transient can mask the presence of a small LOCA. However, once the overcooling transient is terminated, the small LOCA should quickly become evident. Abnormal transients can occur at any time and will not always oblige by beginning immediately after a reactor trip. Therefore, continuous surveillance is warranted.

One symptom, lack of adequate subcooling margin, always requires immediate attention. The operator must trip reactor coolant pumps (if not done automatically) and initiate HPI flow (if not done automatically) immediately whenever the subcooling margin is lost, regardless of which part of Section III he is currently following. For this reason, the other parts of Section III will reference the operator to Section III.A.

It can be seen that these symptoms can occur in various combinations and virtually at any time during a transient or subsequent cooldown. Thus it would be very difficult to write a comprehensvive procedure that will lead the operator through any possible sequence of events. Where it is known that multiple symptoms are more likely to occur, the guidelines will specifically address the possibility. However, to ensure maximum coverage, this approach is supplemented by a combination of operator training and procedural guidelines. Recognition of the four basic symptoms and following the appropriate actions of Section III will provide plant stabilization for all single events regardless of cause. Operator training is the key in the recognition and understanding of the four basic symptoms. When events become more complex, either due to additional failures or due to an event progressing to the point of inducing other symptoms (e.g., loss of subcooling margin), operator training is again the key in successful mitigation. The procedural guidelines contain all the necessary information, but the operator must know when to implement the appropriate sections. He does this by careful surveillance of the plant conditions during and following a transient, recognizing the symptoms whenever they occur, and going to the appropriate section. In this respect ATOG is somewhat similar to event-oriented procedures in that the operator must recognize a condition and react to it. The difference is that the symptom will <u>always</u> be evident when the failure occurs. The cause (event) will not always be evident. Also, there are just four symptoms to recognize as opposed to numerous events.

In addition to recognizing a symptom and implementing the appropriate part of Section III, the operator must also know when to transfer between parts of Section III (for multiple symptoms or incorrect diagnosis) and when to terminate his actions if the problem is corrected. Some basic instructions for the use of Part I can be summarized as follows:

1. Priorities between the parts of Section III:
   a. Loss of subcooling margin always requires immediate attention regardless of which part of Section III is being followed.
   b. Lack of heat transfer or excessive heat transfer must be corrected before, or at least concurrently, with actions for SGTR.
2. Follow the appropriate part of Section III for the dominant symptom, unless a "higher priority" symptom (in item 1 above) appears, in which case recycle to the part of Section III for the higher priority symptom.
3. If a reactor trip occurs during a forced shutdown, recycle to Section I.
4. If a major change in equipment status occurs during the performance of a part of Section III or subsequent cooldown, carry out the appropriate actions of Section II (i.e., loss of NNI/ICS power, loss of offsite power, safeguards actuation, etc.).
5. If it is discovered that an incorrect diagnosis has been made and:

a. no other symptom exists (e.g., inadvertent entry into Section III because an overshoot after trip misinterpreted as overcooling), then stabilize plant (e.g., restore heat transfer; don't exit III.C immediately after isolating both SG's) and recycle to Section II; or

b. a different symptom exists, then recycle to the appropriate part of Section III.

6. If, during the performance of follow-up actions in Section III, the cause of the transient becomes evident and is corrected, then hold at that point and allow the plant to stabilize while checking for other symptoms/problems (e.g., if in the process of isolating both SG's for excessive heat transfer and closing of the MADV on one SG stops the transient, there is no need to continue isolation of steam and feedwater on both SG's). Similarly, if the intent of a group of actions is satisfied, then continuation of those actions may not be necesary (e.g., HPI flow can be throttled and SG levels do not need to be raised to the high level if subcooling margin is restored).

7. All normal limits and precautions are applicable during the performance of Part I unless specifically superceded by the ATOG procedure (e.g., the use of pump bumps, regardless of NPSH requirements, when saturated with SG level). Whenever a step appears in Part I that supersedes a normal limit or precaution, it has been carefully considered and deemed acceptable for plant conditions existing at the point in the procedure (e.g., violation of fuel pin compression limits during a large SGTR). One

should not infer, however, that since it is acceptable at one point in the procedure then it is always acceptable to violate the limit or precaution.

As an example on the use of Part I, assume an overcooling transient occurs following a reactor trip that leads to drainage of the pressurizer and a loss of the subcooling margin. When the subcooling margin is lost the operator must quickly perform the actions of III.A which include tripping the reactor coolant pumps and initiating full HPI flow (1.a above). The operator is also required to raise SG levels. These actions are required in the event of a small break LOCA. In this case the LOCA could be masked by the overcooling or induced by the overcooling transient. The overcooling was caused by either excessive feedwater flow or loss of steam pressure in one or both steam generators, and will be compounded by the rapid fill of both SGs to 80%. However, if the cause was excessive feedwater, the affected SG will reach the required setpoint sooner and control of feedwater at the setpoint will terminate the overcooling. If the cause was loss of steam pressure, it may become evident during or after SG filling, at which time the operator can isolate it, if possible. If the loss of subcooling margin was due to <u>just</u> an overcooling event (i.e., no LOCA), then termination of the transient would restore the subcooling margin. Similarly, if the subcooling margin is regained while the operator is filling the SGs, he need not continue to the high level required for small breaks (6 above). The intent of the actions (restore

subcooling margin and ensure SGs available for heat removal) has been satisfied. The operator should throttle HPI flow and adjust SG levels to the appropriate setpoint for natural circulation, or forced circulation if he has restarted RC pumps. These variations on the use of the guidelines are examples of situations that, if Part I attempted to cover them all, would result in a procedure of such bulk and complexity as to render it useless. However, by training the operator so that he understands what the symptoms mean in terms of heat transfer and what is really occurring in the plant, and so that he understands what the guidelines are intended to accomplish, then his educated use of the guidelines will ensure transient termination and plant stability for any event or combination of events.

Another example of proper operator judgement can be shown by again assuming an overcooling transient. The guidelines may tell the operator to completely isolate both SGs (steam and feedwater). This is because Part I is designed to restore plant stability assuming worst case transients, which, in the case of overcooling, would be an unisolable steam line break. If the operator does not know the cause of the overcooling, or even which SG is causing the overcooling, then the proper response <u>is</u> to isolate both SGs to stop the transient. With the transient terminated he should then be able to monitor secondary conditions and isolate the problem to one SG so that controlled decay heat removal can be restored using the unaffected SG. However, if he should discover the cause of the transient while he is isolating the SGs (e.g., stuck open MADV), and

isolation of this cause does indeed stop the overcooling, then there is no reason for him to complete the isolation of both SGs. If he understands the purpose of the steps he is taking in following the guidelines, then he will understand when that intent is satisfied and may be able to exit the procedure at that point rather than arbitrarily following it through to completion. Of course, should he fail to realize that isolation of the MADV terminated the transient, continuing through the guidelines, including isolation of both SGs for this example, will not cause any significant problem; it is merely unnecessary. Continuing through the procedure will lead to restoration of core cooling using the unaffected SG(s).

Objectives of Section III

In order to promote understanding of the procedural guidelines, this section will address each subsection of Part I, Section III in terms of what the plant conditions are, what are the possible causes, and why the operator is directed to take the specified actions (i.e., what the actions are intended to accomplish). The referenced section of Part I should be followed while reading this section.

Section III.A, Follow-up Actions for Treatment of Lack of Adequate Subcooling Margin

Whenever plant conditions reach or exceed the subcooling margin curve the assumption is that the RCS is saturated. The RCS can become saturated as a result of three basic causes:

i. Loss of coolant inventory (LOCA)

ii. Overcooling that results in sufficient coolant contraction to drain the pressurizer, or

iii. Prolonged loss of heat transfer that allows the RCS to overheat to saturation at high pressure (this cause would be recognized as lack of heat transfer before loss of subcooling and handled in accordance with Section III.B).

The primary objectives of this section are to 1) restore subcooling margin and 2) maintain or restore core cooling. To accomplish these objectives, HPI must be initiated and either secondary heat transfer or HPI cooling must be established.

Three actions are <u>always</u> required whenever the subcooling margin is lost:

1. Trip all reactor coolant pumps,
2. Initiate full, balanced HPI flow, and
3. Initiate rapid fill of the SG's to 80% on full range (at $\geq$ 600 gpm/SG).

These actions are necessary in the event the loss of subcooling margin is due to a small break LOCA. Tripping the RC pumps must be done immediately following the loss of subcooling margin to minimize inventory loss if a small break exists. In addition, if the loss of subcooling margin was the result of an overcooling transient, HPI will compensate for the coolant

contraction and restore subcooling. Re-establishing controlled secondary heat removal should then be possible. If the loss of subcooling margin was due to a total loss of feedwater (main and auxiliary), then full HPI will be needed to establish HPI cooling (in Section III.B). In this case subcooling should also be restored, but it may take some additional time until the cooling capacity of the HPI flow exceeds the core heat generation rate.

Raising SG levels must also be done in the event of a small break LOCA. High SG levels will allow condensation of steam voids in the RCS side of the upper tube region to establish boiler-condenser cooling. The rapid fill rate will cool and depressurize the RCS to allow more HPI flow. If the transient was initiated by total loss of feedwater, then the operator may not be able to restore feedwater and raise SG levels; but after he has established HPI cooling he should continue efforts to restore feedwater. Actions are also included to isolate possible causes for the loss of primary pressure.

At this point the operator has full HPI flow, the RC pumps are off, he is raising SG levels, and he has isolated possible causes of the loss of subcooling. Further actions will be determined by the plant response to the actions already taken. The subcooling margin may be restored by HPI, or the plant may remain at saturation. In either case, primary to secondary heat transfer may or may not exist.

Subcooling Margin Restored

If the subcooling margin is restored, the operator may restart reactor coolant pumps if a SG is available as a heat sink. This will aid in establishing primary to secondary heat removal if it does not already exist. He will also throttle HPI flow to prevent excessive RCS pressure that could lead to RV pressure temperature limit violation and/or unnecessary lifting of the pressurizer safety valves.

If primary to secondary heat transfer does not exist, even after the subcooling margin is restored, it is probably due to a lack of feedwater or a blockage of RC flow due to steam voids in the hot legs. The operator will proceed to Section III.B which will provide for restoration of feedwater and primary to secondary heat transfer or establishment of HPI cooling.

If excessive heat transfer exists, the operator will proceed to Section III.C. The operator should also be alert for indications of a small break (refer to Appendix D in Volume 2) as a small break could exist that is within the capacity of the HPI system.

If controlled primary to secondary heat transfer exists, then the operator should regulate feedwater flow to establish SG levels at the appropriate setpoint (dependent upon whether RC pumps were restarted). The operator should also control steam pressure to prevent RCS reheating and swell. If the RCS were allowed to reheat, the added inventory from HPI could result in a large pressure increase and possibly a full pressurizer.

Subcooling Margin not Restored

If full HPI flow does not restore the subcooling margin even with heat transfer to the SGs, it is a LOCA. If heat transfer does not exist or exists in only one SG, the operator will proceed to Section III.B to attempt restoration of heat transfer to both SG's. The prolonged period at saturation may be due to a total loss of feedwater or a small break. In either case, restoration of feedwater flow in III.B will aid primary cooling. If, however, the CFTs empty, a large break exists and primary to secondary heat transfer cannot be regained. In this case the operator will go to CP-101 for long term cooling following a major LOCA.

NOTE: Whenever adequate subcooling margin does not exist, the operator should be alert to indications of superheat in the RCS incore thermocouples read higher than saturation temperature for the existing RCS pressure). If indications of superheat occur, the operator should proceed to the Inadequate Core Cooling (ICC) guidelines.

Summary

The bases for Section III.A can be summarized as follows:

Symptom: RCS pressure-temperature to the right and/or below the subcooling margin curve.

Problems:
a) Possible LOCA
b) Void formation in RCS at saturation can interrupt core cooling

Objectives:
a) Restore subcooling margin
b) Maintain or restore core cooling:
   i. Preferably with SGs
   ii. With HPI cooling (after transfer to Section III.B) if SG cooling unavailable

Key Points:
a) Be alert for indications of ICC
b) Lack of subcooling margin can severely hamper primary to secondary heat transfer
c) HPI cooling, while adequate for core cooling, is not a stable long-term cooling mode. Cooling with one or both SGs must be restored as soon as possible. (HPI cooling is discussed in more detail in the "Backup Cooling Methods" chapter).

Section III.B: Follow-up Actions for Treatment of Lack of Primary to Secondary Heat Transfer in Either OTSG

If adequate subcooling margin exists, the most likely cause for lack of primary to secondary heat transfer is no heat sink (loss of feedwater). The operator will take steps to restore feedwater. If he cannot restore feedwater he will establish HPI cooling, and he should reduce the number of running RC pumps to one to minimize heat input to the RCS. This will provide adequate core cooling while he continues efforts to restore feedwater to at least one SG.

Lack of Adequate Subcooling Margin

If, however, adequate subcooling margin does not exist, then the lack of heat transfer could be due to no heat sink (loss of feedwater) and/or no reactor coolant flow (hot leg voiding). The primary objective is to restore core cooling. The preferred method of core cooling is with primary to secondary heat transfer.

If the operator has feedwater flow and a level in at least one SG, then the lack of heat transfer is due to lack of RC flow. If the CFTs are empty, a major LOCA has occurred and there is no benefit in restoring primary to secondary heat transfer. In this case the operator will proceed to the procedure for long term cooling following a major LOCA. If a major LOCA has not occurred, he will attempt to induce natural circulation flow by raising SG level(s) and lowering SG pressure. If

this fails, and RCPs are operable, he will attempt to induce natural circulation flow by bumping an RC pump. With the SG available as a heat sink, bumping an RC pump will force steam voids in the RCS into the SG tubes where they can be collapsed. Fifteen minutes should be allotted between successive pump bumps to allow natural circulation flow to build. If natural circulation flow is still not established after all operable RCPs have been bumped and one hour has passed since the reactor trip, a pump should be started and run, if possible, in a loop with the SG available as a heat sink.

If the RCPs are not operable, he must cool the core with HPI and he will go to CP-104 for HPI cooling. If he is successful in establishing primary to secondary heat transfer, then he will go to the appropriate cooldown procedure depending on the degree of subcooling. If the subcooling margin is not restored, then a small break probably exists.

Summary

The bases for Section III.B can be summarized as follows:

Symptoms: a) With subcooling margin, symptoms are those indicative of loss of feedwater:

i. RCS reheating and repressurizing after normal post-trip cooldown.

ii. Low or non-existent SG levels and feedwater flowrates.

b) With lack of adequate subcooling margin, symptoms could be as above for an extended loss of feedwater and/or small break symptoms (see Appendix D in Volume 2).

Problems:

a) Lack of core cooling

b) Extended loss of feedwater will lead to saturation and loop voiding; necessitates HPI cooling.

c) Possible LOCA.

Objectives:

a) Maintain or restore subcooling margin.

b) Restore core cooling, preferably using the SGs.

Key Points:

a) Lack of heat transfer with adequate subcooling is more than likely due to total loss of feedwater or insufficient feedwater to induce natural circulation.

b) Every effort must be made to restore primary to secondary heat transfer (unless a major LOCA occurred). HPI cooling will be adequate for core cooling, but is not a stable long-term cooling mode (see HPI cooling section in "Backup Cooling Methods" chapter).

Section III.C: Followup Actions for Treatment of Too Much Primary to Secondary Heat Transfer

Excessive heat transfer is always caused by a failure in the control of secondary side parameters, resulting in a loss of steam pressure or excessive feedwater flow or a combination of both. The overcooling places large thermal stresses on the RCS piping and components and on the steam generators. It can also lead to saturation of the primary system if multiple failures occur resulting in draining of the pressurizer. The primary objective of this section is to terminate the overcooling transient and then to restore controlled decay heat removal.

Makeup is increased if pressurizer level is low and RCS pressure is decreasing in an effort to prevent drainage of the pressurizer and loss of subcooling margin. The operator will then check to see if the SG causing the overcooling can be identified. The best method to identify the affected SG is to compare T_{cold} temperatures. The loop with a significantly lower T_{cold} is the loop with the affected SG. However, T_{cold} temperatures can be fairly close together even when only one SG is causing the overcooling (refer to the discussion on overcooling transients in the "Diagnosis and Mitigation" chapter). Since the primary objective is to first terminate the transient, both steam generators should be isolated if there is any doubt which SG is affected.

In either case (one or both SGs isolated), the affected SG(s) will

either:

a) Stabilize in level and pressure if the overcooling was due to excessive feedwater or isolable steam leak, or

b) One SG will continue to lose pressure and level due to an unisolable steam leak, or

c) Both SG's will continue to lose pressure and level due to unisolable steam leaks on both (unlikely).

If a), then controlled decay heat removal can be restored using both SG's (being careful not to unisolate a steam leak). If b), then the SG with the steam leak should be allowed to boil dry while decay heat removal is established with the intact SG. If c), then the operator should attempt to achieve controlled cooling by limiting feedwater flow to one or both SG's. If controlled cooling in this manner is not possible, then the operator should initiate HPI cooling and allow both SG's to boil dry.

Once controlled decay heat removal is established, the operator should check for indications of a tube rupture (since the tubes have been stressed by the overcooling).

Whenever an overcooling transient has been terminated, the operator should hold RCS temperatures at the existing values. If the RCS were allowed to reheat, the added inventory from HPI could result in a large pressure increase and possibly a full pressurizer.

Summary

The bases for Section III.C can be summarized as follows:

Symptoms:
a) Decreasing T_{colds} and/or SG pressures significantly below the normal post-trip cooldown.
b) Possibly high SG level(s) and feedwater flowrate(s).
c) Low RCS pressure and pressurizer level.

Problems:
a) Thermal stresses on RCS components and SGs (tubes).
b) Possible RCS saturation due to pressurizer drainage.
c) Excessive feedwater flow could result in water carryover into the main steam lines.

Objectives:
a) Prevent loss of subcooling margin due to RCS contraction and drainage of the pressurizer.
b) Terminate the overcooling.
c) Reestablish controlled primary to secondary heat transfer.

Key Points:
a) Comparison of loop T_{cold} temperatures is best method for identifying affected SG before SG isolation.
b) Comparison of SG levels and pressures is best method for identifying affected SG after both SGs are isolated.
c) Severe overcooling can induce tube leaks.
d) The RCS should not be allowed to reheat in an uncontrolled manner after the transient is terminated.

e) Unisolable steam leaks require boiling the affected SG dry to stop the overcooling. If both SG's have unisolable steam leaks, controlled primary to secondary heat transfer may not be possible; HPI cooling may be required.

Section III.D: Followup Actions for SG Tube Rupture

Several concerns exist whenever indications of a steam generator tube rupture become evident. In addition to being a LOCA, the primary inventory lost through the tube leak may not be recovered for sump recirculation as it would for other LOCAs. (Steam generator drains may be used to send leakage to the RB sump.) Thus, it is important to cooldown and stop the tube leak before makeup capacity (BWST) is lost. However, it is also important to minimize offsite releases. Therefore, if at all possible, it is desirable to perform a controlled power runback so that the reactor can be tripped at a power level less than the capacity of the CDVs rather than trip the reactor at high power. This prevents lifting of the safety valves and atmospheric dump valves on the SG with the tube leak, which helps reduce overall releases to the atmosphere. Thus, the primary objectives in mitigating a tube rupture are to minimize offsite releases and total tube leakage by performing an orderly but expedient shutdown and cooldown.

Reactor Trip

If a reactor trip should occur, or be required because the tube leakage exceeds HPI capacity, then it is important to ensure proper plant response, particularly with respect to steam and feedwater control. If a loss of subcooling margin occurs, the RC pumps must be tripped and full HPI initiated. These actions are required for the same reason as in any small break but, in addition, it is very important with a tube rupture to prevent void formation in the hot legs which could block coolant flow and

severely hamper the cooldown. It is also very important to terminate excessive heat transfer should it occur. Uncontrolled cooldown could also result in void formation in the hot legs and could overstress the SG tubes resulting in larger leak rates. Thus, if excessive heat transfer is indicated, the operator is directed to Section III.C to correct the condition before continuing in Section III.D.

During the period that the operator is performing the runback and/or shutdown observe the main steam line radiation monitors to verify which SG has the tube rupture. It is desirable to isolate the affected SG as soon as possible after primary temperature is low enough to preclude lifting of the main steam safety valves.

Cooldown Methods

Two basic cooldown methods are provided for tube ruptures, designated here as "normal" and "emergency". The method to be used is determined by the tube leak rate and the existing plant status. The differences between the methods are as follows:

	Normal	Emergency
1) Cooldown rate	50F/hr	268F/hr to 500F; 50F/hr < 500F
2) Tube/shell ΔT limit	160F	160F
3) Fuel pin compression limit	Applies	May be violated, if necessary

The factors determining use of the "normal" cooldown method are:

1) Small tube leak - tube leak rate within capacity of makeup system (i.e., pressurizer level maintained > 125" with one makeup pump operating at full capacity through the normal makeup line and the letdown isolated; this indicates an acceptable rate of BWST depletion). (04)

2) Condenser available

3) RC pumps available

4) Steam pressure controlled on both SG's (e.g., no unisolable steam leaks) (04)

All four conditions must exist to use the normal cooldown. If any one condition is not met, the emergency cooldown method must be used. If, during the performance of the emergency cooldown all four conditions are satisfied, then the normal cooldown can be used. Conversely, if during the performance of the normal cooldown any one of the conditions is no longer satisfied, then the cooldown must be switched to the emergency method. In general, the (04) affected SG (or most affected when both SGs have leaks) should be isolated as soon as it is identified and the proper RCS conditions exist to prevent lifting the steam safeties on the SG with the tube leak.

Loss of Offsite Power/RC Pumps Not Running

A loss of offsite power can significantly impact the mitigation of a tube rupture, and therefore power should be restored as quickly as possible.

While power is unavailable, a natural circulation cooldown will be required before the SG can be isolated. Since the condenser is not available with a loss of offsite power, the affected (or most affected) SG, along with the unaffected (or least affected) SG, will have to be steamed to the atmosphere during the cooldown. However, as soon as isolation conditions are reached the appropriate SG should be isolated.

In addition, while RC pumps are not available, RCS pressure reduction must be accomplished using the auxiliary spray. If auxiliary spray is not available, then the PORV must be used. This is a less desirable method since it repeatedly uses the relief valve, results in additional inventory loss, and may degrade the reactor building environment. The best course to follow when natural circulation is required is as follows:

- Perform rapid cooldown and depressuriation to 560F (or 540F) at $\leq$ 268F/hr using both SG's to atmosphere.
- Isolate the SG with the tube rupture and maintain level below 80% FR with drains.
- Continue cooldown with intact SG at $\leq$ 268 F/hr to 500F.
- Continue cooldown with intact SG at $\leq$ 50 F/hr while maintaining SG tube to shell temperature limit.
- Steam isolated SG only as necessary to control SG tube-to-shell ΔT and RC loop cooling (do not steam an isolated TRSG to the atmosphere just to limit level).

Following this procedure may result in void formation in the RV head (refer to natural circulation discussion in Addendum B). However, the void may be vented while holding the RCS at 500F/1100 psig. This method should result in minimizing the offsite releases.

RC Pumps Running

With RC pumps available, steaming of an affected SG can be reduced to the minimum necessary to cool the RCS to less than 560F or 540F, as appropriate. This is required to prevent lifting of the steam safeties (additional release to atmosphere). Once SG isolation has been effected, the RCS must be cooled cooled and depressurized. Forced circulation will prevent the formation of steam voids in the idle (non-steaming) loop. (04) (04)

Normal pressurizer spray should be used as necessary to maintain the RCS pressure as close as possible to the minimum subcooling margin to minimize the leak rate.

Continued Cooldown and Isolation of the Affected SG

The plant is not stable after a tube rupture until the tube leakage has been stopped. If an affected SG can be isolated and allowed to fill solid, the leak can be stopped before the cooldown is completed. If, however, the affected SG is steamed or drained, stopping the tube leak will require cooldown and depressurization to DHRS operation at which point the affected SG is alowed to fill solid. Therefore, the cooldown should progress as expediently as possible. (04)

For very small tube leaks, an affected SG may have to be fed to achieve a level sufficient to maintain the tube/shell ΔT within the limits. Excessive tube/shell ΔT could result in a higher leak rate due to the increased tensile stress on the failed tube.

After a SG is isolated:

- If the condenser is available, the affected SG should be steamed to the condenser as needed to maintain SG level below 80% FR or promote natural circulation.

- If the condenser is not available, the affected (or most affected if both have leaks) SG should be drained to RB as needed to maintain SG level below 80% FR.

- If neither the condenser or drains are available the affected (or most affected) SG should be allowed to fill solid.

Summary

Symptoms:
a) High radiation in steam lines and/or condenser
b) LOCA symptoms (decreasing pressure, unaccountable RCS inventory loss, etc.)

Problems:
a) SG tube rupture/LOCA
b) Unrecoverable RCS inventory loss (i.e., not available for sump recirculation)
c) Offsite releases

Objectives:
a) Minimize offsite releases
b) Terminate leakage before BWST depletion
c) Maintain core cooling/expedient cooldown and depressurization

Key Points:
a) Transient (leakage) not terminated until affected SG(s) fills solid or RCS cooled, depressurized, and drained below tube leak elevation (04)
b) LOOP/natural circulation cooldown will probably result in higher offsite releases due to greater need to steam affected SG initially (before isolation).
c) Natural circulation cooldown may necessitate use of RV head vent after initial cooldown and depressurization.
d) If each SG has tube leaks, usually the most affected SG is isolated and cooldown performed on the other SG. (04)

Cooldown Procedures/Inadequate Core Cooling

The main objective of these guidelines is to maintain adequate core cooling by terminating transients and stabilizing the plants with controlled decay heat removal. Once stable conditions are achieved, further plant

cooldown can be accomplished by existing plant procedures. However, the end conditions at stabilization following the execution of the guidelines will not necessarily coincide with the entry conditions for plant cooldown procedures. Therefore, procedures are provided in Part I to accomplish the transition from the guidelines to the plant procedures. Five cooldown procedures are provided to cover the five possible end conditions of the guidelines:

1) Cooldown following a large LOCA
2) Normal cooldown
3) Saturated cooldown with primary to secondary heat transfer
4) HPI cooling
5) Solid plant cooldown/recovery from solid plant.

A sixth procedure is provided for the special case of Inadequate Core Cooling (ICC). The philosophy and the objectives of the actions for ICC are discussed in detail in the "Backup Cooling Methods" chapter in Volume 1 of Part II.

Also in Part I (immediately after the cooldown procedures) are specific rules and guidelines. These are provided in a separate section to avoid repetition throughout Section III of the guidelines. These rules apply wherever they are referenced in Section III. Five specific rules are provided to cover:

1) Initiation of HPI
2) HPI flow control
3) Feedwater throttling methods

4) SG level setpoint

5) SGTR cooldown methods.

In addition, three figures are provided at the back of Part I for easy reference during the use of the guidelines. These figures provide:

1) Unthrottled HPI flow vs. RCS pressure

2) Reactor vessel pressure-temperature limits

3) Natural circulation cooldown - Hot leg temperature limit

P-T Display

In addition to the guidelines in Part I and the training material in Part II, the P-T display developed by the ATOG program can provide significant assistance to the operator during the mitigation of abnormal transients.

The information required to identify and track the symptoms discussed previously is already available in the control room. However, it consists of discrete displays for reactor coolant system hot and cold leg temperatures, reactor coolant system pressure and steam generator pressure. This format requires mental integration on the part of the operator to quickly assess plant cooling status using individual displays and the steam tables. Thus, the problem is how these variables could best be displayed in real time to give the operator a simple and logical method of monitoring the symptoms of interest. The solution developed in ATOG was the use of a P-T display on a cathode ray tube (CRT). The display continuously shows the primary subcooling margin and the dynamic relationship of the primary to secondary heat transfer. The particulars of the display

format and identification of the symptoms is discussed in detail in the "P-T Diagram" and "Diagnosis and Mitigation" chapters. This section will discuss the various functions the display can perform to aid the operator.

Symptom Identification

The primary purpose for developing the P-T display is to provide the means for the operator to monitor the plant response following a reactor trip or during a forced shutdown to verify normal response and to quickly identify abnormal response should it occur. The "P-T Diagram" chapter describes the normal post trip cooldown of the RCS and the "Diagnosis and Mitigation" chapter describes the various trends that can develop when the response is abnormal. With the P-T display, the operator can quickly recognize the loss of subcooled margin, lack of heat transfer, or excessive heat transfer and proceed directly to the appropriate section of Part I to restore plant stability and core cooling.

Response Verification

The P-T display also provides positive feedback to the operator on the response of the plant to his actions. For example, after the loss of subcooling margin, the operator can easily determine the effectiveness of full HPI flow by monitoring the P-T display, and determine when to throttle HPI flow if the subcooling margin is restored.

Controlling Within Limits

Certain operations require that the operator control the primary system within specified P-T regions that can readily be displayed on the P-T diagram. For example, the guidelines for a natural circulation cooldown require maintaining greater RCS subcooling to prevent void formation in the RV head. If the operator has the capability to select a T_{hot} limit curve for display on the CRT then he has a simple, convenient format for monitoring the cooldown. Many other examples exist, including uses during normal plant cooldowns and heatups (e.g., fuel pin compression limits, NDT limits, etc.).

Power Operation

The CRT format is readily adaptable for displaying plant status information during normal power operation. Some examples for such usage are the reactor protection system pressure-temperature trip envelope (shown in the "P-T Diagram" chapter) and power imbalance envelope. However, if the ATOG CRT is used for these displays, they should be of a secondary nature with the CRT automatically reverting to the ATOG P-T display on reactor trip.

Backup for the CRT

It can readily be seen that the availability of a P-T display improves the flow of information to the operator and enhances the use of Part I. Effort should be made in the implementation of CRT displays to provide high reliability.

However, control room personnel should allow for the possibility that the CRT displays are unavailable when needed. Provisions should be made to facilitate hand plotting of the parameters on a P-T diagram similar to the diagrams depicted herein. Hand plotting is quick enough to provide data which can be used for plant control. The format of the diagram for hand plotting (with the saturation and subcooling margin lines pre-drawn) would allow for trend diagnosis and still be a significant improvement over mental assimilation of discrete data displays.

CHAPTER E

BEST METHODS FOR EQUIPMENT OPERATION

During an abnormal transient the operator has to perform several actions to control different systems. This chapter will show the best ways to do the following things:

- Start and Stop RC Pumps
- Throttle or Stop HPI
- Throttle or Stop Auxiliary Feedwater
- Stop Main Feedwater
- Use the Incore Thermocouples
- Cooldown with One Generator out of Service
- Use the High Point Vents
- Recover from Loss of LPI Recirculation Capability

RC Pumps

During the course of an abnormal transient, the RC pumps may need to be stopped and, at a later time, may be restarted depending on the kind of transient and the conditions of the reactor coolant system.

In general, the reasons for stopping the pumps are:

- To prevent possible core damage if a small break LOCA occurs
- To prevent pump damage (e.g., loss of NPSH or motor cooling)
- To decrease heat input into the RCS

In general, the reasons a pump should be restarted are:

- To start natural circulation if it has stopped
- To allow a faster rate of cooldown and RCS depressurization
- To increase core cooling if the core has become uncovered (inadequate core cooling)

This section will show the rules and guidelines for stopping and restarting RC pumps.

RC Pump Trip

RC pumps must be tripped during certain size small break LOCAs to prevent core damage. This is discussed in detail in Section 5.0 of Appendix D. For these LOCAs, if the pumps are kept running, they will force steam and water by the break; because the water is forced by the break more reactor coolant mass will be lost out the break than if the pumps were not running. As long as the pumps continue to run the core will be cooled by the steam and water mixture circulating through the core. But if the pumps are tripped at a later time in the transient, when very little liquid remains in the RCS, the steam and water remaining in the vessel and loops will separate. Steam will collect in the high points and water will collect in the low points. If enough water does not collect in the vessel, the core will be uncovered and will not be adequately cooled. Core (05

damage can result. Analyses show that a later pump trip may lead to core damage, but an early pump trip is safe.

The RC pumps must be tripped for these certain size LOCAs. These LOCAs will cause an RC pressure decrease below the low RC pressure ESFAS actuation setpoint of 1700 psig and a loss of subcooling margin. Other transients, such as overcooling or loss of all feedwater usually will not cause both a loss of subcooling margin and a low RC pressure of 1700 psig. The RC pumps are automatically tripped on the loss of subcooling margin with a coincident low RC pressure of 1700 psig (or high RB pressure). However, the operator should be prepared to manually trip the RCPs if the automatic trip fails. (05)

When the RC pressure is above 1700 psig, the RC pumps should still be tripped on loss of subcooling margin. However, this must be done manually.

Consequently, to protect the core and the RC pumps the following rule is given.

RC PUMP TRIP RULE

The RC pumps shall be tripped immediately whenever the subcooling margin is lost.

NOTE: IT IS ABSOLUTELY MANDATORY TO TRIP THE RC PUMPS IMMEDIATELY BUT IF THE PUMPS ARE NOT TRIPPED IMMEDIATELY (I.E., WITHIN THREE MINUTES) WHEN THE SUBCOOLING MARGIN IS LOST IT IS MANDATORY THAT THEY SHOULD NOT BE TRIPPED AT A LATER TIME. THE OPERATOR MUST MAKE SURE THAT COOLING WATER AND SEAL INJECTION ARE MAINTAINED TO PREVENT PUMP DAMAGE. THESE SERVICES MUST BE MAINTAINED FOR SEVERAL HOURS. IF MECHANICAL DAMAGE TO THE PUMPS IS LIKELY, THEN TWO PUMPS (ONE IN EACH LOOP) SHOULD BE STOPPED. THE TWO REMAINING PUMPS MUST BE KEPT RUNNING. IF THEY FAIL, THE TWO PUMPS WHICH WERE STOPPED SHOULD BE STARTED EVEN IF MECHANICAL DAMAGE IS LIKELY. THE OPERATOR MUST ALSO TRY TO GET AS MUCH HPI FLOW INTO THE RCS AS POSSIBLE. WITH THE LPI/DHRS IN SERVICE AND RCS SUBCOOLING MARGIN RESTORED, THE OPERATING RCP'S CAN THEN BE TRIPPED.

The RC pumps can be tripped to prevent mechanical damage in all cases except the one noted above and during severe ICC conditions. Mechanical damage is not expected to cause safety problems unless total seal failure occurs.

It is desirable to trip the pumps to prevent mechanical damage in case they must be restarted at a later time. Preserving the pumps for long-term cooling or cooldown is desirable, and it is recommended that they be shut down if high vibration or loss of cooling services occurs. Limits on continued pump operation are given in the "Plant Limits and Precautions".

Table 5, "Rules for RC Pump Trips," summarizes these requirements. Included in this table are the limits on pump operation because of failures of cooling water and seal injection. These limits are shown because containment isolation can affect cooling water.

When the RC pumps are tripped to prevent mechanical damage, auxiliary feedwater will be automatically initiated and the steam generator level setpoint will be changed to the natural circulation setpoint. The operator should make sure that natural circulation starts. If only component cooling water to the RC pumps is lost, approximately five minutes exist to raise the water level or restore CCW before the pumps are tripped. If, however, both CCW and seal injection are lost, the operator must restore CCW or seal injection immediately or trip the RC pumps. If the pumps are tripped on loss of subcooling margin, natural circulation may or may not start, depending on the amount of steam in the RCS. Nevertheless, a check on natural circulation is desired. Actions to establish natural circulation when the pumps are tripped because of subcooling margin are given in the pump restart guidelines which follow.

During HPI-PORV open cooling all RCPs but one should be tripped to reduce heat input to the RC. However, if the subcooling margin is lost during HPI cooling, all RC pumps must be tripped.

Further guidance on RC pump trip is given in Part II Volume 2, Appendix D Section 5.0.

RC Pump Restart

Core cooling and plant control are best if the RC pumps are running. Pumps can be restarted after trip if the reactor coolant conditions are right. Therefore, to complement the RC Pump Trip requirements given previously, conditions when the pumps can be restarted are given. These conditions cover both LOCA and non-LOCA events and have been carefully chosen so that a pump restart followed shortly afterwards by an inadvertent trip will not cause fuel damage during small breaks.

Restart of the RC pumps is desirable for several reasons:

- If natural circulation was lost, the pumps can be used to restart circulation.
- If the plant must be cooled down and depressurized, the RC pumps will permit use of the normal pressurizer spray.
- During a LOCA, cooldown will be faster with forced circulation and the decay heat removal system can be placed in operation before the BWST is depleted.
- If severe Inadequate Core Cooling (ICC) conditions exist, the RC pumps must be restarted.
- To limit excessive cooling of the Reactor Vessel during HPI cooling.

The major reason for restarting the RC pumps is to increase the rate of heat transfer from the core to the steam generators; or if natural circulation has stopped and there is no heat transfer from the core to the steam generators, then a pump bump will help to restart natural circulation. Because the purpose of restarting the pumps is to increase core-to-steam generator heat transfer, it is necessary that the steam generator

be available for heat removal. The steam generator will remove heat if: 1) the steam generator saturation temperature is lower than the RCS incore thermocouple temperature - a 50F temperature difference is a good rule of thumb to use, and 2) the steam generator is fed with main or auxiliary feedwater. It is preferable to start a pump in the loop with the operating steam generator if only one is in service, and it is best to start the pumps that will provide sufficient pressurizer spray flow if possible. Calculated spray flow rates for various pump combinations are provided on Table 6. Except in an advanced ICC situation, a pump restart (05)
is not advised if mechanical damage can result.

One RC pump should be restarted and run to minimize the concern for exceeding the NDT limits of the reactor vessel when the reactor coolant is subcooled and the core is being cooled by HPI cooling. For this unusual situation, which can be caused by a prolonged loss of all feedwater, one RC pump may be run even though there is no steam generator cooling. However, it should not be run if mechanical damage can occur. If subcooling margin is lost the RC pump should be tripped.

Inadequate Core Cooling is a condition where the reactor coolant is superheated. This is a condition when core damage could occur. For this condition, exceptions are taken: 1) RC pumps can be restarted if the steam generators are <u>not</u> available, and 2) If severe ICC conditions exist, RC pumps <u>must</u> be restarted even if mechanical damage can occur. For all other cases of pump restart, mechanical damage should be avoided.

When the RC pumps are restarted, the operator should expect to see pressure changes in the RCS as follows:

- If the reactor coolant is subcooled and the pressurizer is filled solid, an abrupt rise in pressure could occur.
- If the reactor coolant is subcooled with a near normal pressurizer level, almost no change in pressure should occur.
- If the reactor coolant is two-phase and saturated, a pressure drop could occur when the heat removal rate of the steam generator increases. In addition, starting a pump may collapse steam voids in the RCS which will result in a corresponding drop in pressurizer level and RC pressure.

Table 6, "RC Pump Restart Guidelines", shows the conditions when the pumps can be restarted. The table is divided into three parts: subcooled, saturated, and superheated. Guidelines for restart of the pumps in the subcooled and saturated conditions are dependent on the existence of liquid or two-phase natural circulation. Generally, if natural circulation does not exist the RC pumps are "bumped" to try to start natural circulation; if natural circulation does start, then that is a good indication that a large amount of water is in the RCS. "Bump" means to start a pump and then turn it off when the motor current drops to the run current.

When an RC pump is "bumped", it will cause hot reactor coolant in the vessel and hot leg to move into the steam generator and cold water in the

steam generator to move into the reactor vessel. This will establish flow between the thermal centers and initiate natural circulation (if enough water is in the RCS). When the RCS is saturated, the "bump" may or may not start natural circulation, but it will help to depressurize the RCS by condensing reactor coolant steam in the generators and allow more HPI to flow into the system.

The "bumps" are used only every 15 minutes because: 1) that will limit the liquid flow out of the break and 2) it will take some time for natural circulation to develop and stabilize. Between "bumps" the development of natural circulation can be checked.

Table 6 shows two columns when the RCS is saturated - one with natural circulation and one without. Both show that HPI is on.

When natural circulation exists, the steam generator T_{sat} will control the incore thermocouple temperature; if T_{sat} is changed, the incore thermocouple temperature will follow. If the incore thermocouple temperature does not change when T_{sat} changes, the steam generators are not coupled to the reactor coolant system. Extended saturation <u>with</u> the steam generators available as a heat sink can exist only because of a LOCA.

For the condition with no natural circulation, the operator is directed to perform several "bumps". If after four bumps natural circulation does not start, and one hour has elapsed since the reactor trip, then one RC pump

should be run for cooldown as long as at least one SG is available as a heat sink. Natural circulation will not start when there is not enough water in the RCS. The reasons for allowing RC pump operation in this case, which goes against other requirements that do not permit RC pump operation when the subcooled margin is lost, are that the RCS should be depressurized and placed on the decay heat removal system before reaching the low level BWST transfer setpoint to avoid HPI recirculation from the sump.

Starting the RCS pump is acceptable as explained in Appendix D Section 6.0 of Part II Volume 2.

HPI Control

The HPI system is used for emergency injection of borated water to make up for lost inventory from a small break. It may also be actuated for other reasons. The operator will have to control the flow rate in different ways depending on the cause of its actuation. The general control actions are:

Maximizing HPI Flow

1. Maximize the HPI flow small break
2. Verifying proper HPI flow through each injection line.

Throttling HPI Flow

1. Stop the HPI system when the LPI system has been operating at $\geq$ 1500 gpm in each line for 20 minutes.
2. Throttle or stop the flow to prevent filling the pressurizer solid when the RCS is subcooled (except during HPI cooling as described in "Backup Cooling Methods").
3. Throttle the flow to prevent runout and cavitation of the HPI pumps at low pressure
4. Do not throttle below the minimum required HPI pump flow with the HPI recirculation valves shut.
5. Throttle the HPI to prevent exceeding reactor vessel pressure/temperature limits.

Each one of these topics will be addressed and the best ways for handling HPI will be shown.

NOTE: Manual actuation of HPI should be accomplished on a component level as opposed to a system level actuation by the ESFAS. System level actuation will also result in other actions (i.e. RB isolation) that

may not be desired. Therefore, the operator should manually actuate HPI by opening the BWST suction valves, starting two HPI pumps and opening the injection line isolation valves.

Maximizing HPI Flow

> HPI SUBCOOLING RULE:
>
> WHENEVER the Reactor Coolant Subcooling margin does not exist, THEN two HPI pumps must be run at full capacity.

When the HPI system is started, its purpose is to remove decay heat either by HPI cooling or by allowing the reactor coolant to transfer heat to the steam generator. In order to be most effective, the HPI flow to the core must be the greatest amount possible. One HPI pump will satisfy core cooling requirements, but two HPI pumps are preferred. The injection valves should be pre-throttled during initial system tests to achieve a balanced, adequate flowrate. However, whenever the system is actuated, the operator should check the flow indicators on all four injection lines. If an injection line reads low flow, the associated injection line isolation valve should be verified open. If an injection line reads abnormally high flow (indicating a HPI line break), the associated isolation valve should be closed and adequate flow through the remaining lines verified. Depending on break location, the HPI line which is cross connected may also read high flow. It is necessary to isolate only one of the lines in this case to ensure adequate HPI flow enters the core. However, both of the affected lines may be isolated as long as both HPI pumps continue to operate through the two remaining injection lines.

HPI Throttling

After it is started, HPI must be run at full capacity until the reactor coolant system conditions allow it to be terminated or throttled. Guidelines for throttling or terminating HPI flow are provided for the five general conditions stated previously.

Guideline 1 for HPI termination or throttling:

HPI operation may be terminated if the LPI system has been flowing at a rate in excess of 1500 gpm in each injection line for 20 minutes.

This condition is applicable to a large LOCA when the RCS depressurizes enough to allow the LPI to flow into the reactor vessel. Since LPI will provide sufficient emergency injection flow, HPI can be stopped. The 20-minute delay is used to make sure that the primary system will not repressurize and result in a loss of LPI flow. The minimum flow requirement of 1500 gpm is based on full HPI flow below 600 psig of $\geq$ 1500 gpm, and is used to make sure that the injection flow can remove decay heat with no loss of reactor vessel water inventory after HPI is stopped. 1500 gpm flow to each LPI injection line is required to make sure at least 1500 gpm gets into the RCS. A possible break in one of the two LPI/CFT lines would allow LPI water to be lost out the break and not reach the reactor vessel.

Guideline 2 for HPI termination or throttling:

- HPI may be throttled any time the reactor coolant subcooling margin is restored.
- HPI may be stopped any time the reactor coolant subcooled margin is restored and pressurizer level is on scale ($\geq$ 125") and leak rate is within the normal MU capacity. Normal makeup should be restarted. The one exception to this guideline is the case where core cooling is provided solely by HPI. In this case, HPI can be throttled when the subcooling margin is restored, but should not be stopped until secondary heat removal is established, even though the pressurizer will be solid.

These guidelines apply to both LOCA and non-LOCA transients and are intended to limit the amount of water going into the RCS so that the pressurizer will not fill solid and let water discharge through the pressurizer valves.

An overcooling transient causes the reactor coolant to shrink. If HPI is started, additional water is added to the RCS. When the overcooling is stopped, the core heat will cause the reactor coolant and the added water to swell. It can expand enough to fill the pressurizer. In order to limit the amount of filling, HPI flow can be throttled when the reactor coolant subcooling margin is restored. HPI flow can be stopped when the subcooling margin is restored and an adequate pressurizer level indication is shown. The 125 inch pressurizer level indication was chosen because it is above the pressurizer heater cut-off level at 105".

If the overcooling was severe, throttling HPI flow alone may not be enough to prevent the pressurizer filling. Therefore, the reheat of reactor coolant must also be limited. This can be done by lowering steam pressure to approximately the pressure corresponding to saturation for the existing cold leg temperature. The operator can monitor the effects of steam pressure by monitoring T_{cold} and pressurizer level and control steam pressure as necessary. Throttling or termination of HPI and lowering steam pressure will keep the RC pressure and temperature from returning to the "post trip window". This is an acceptable end point if the system is stable.

For many events that use the HPI system, subcooled reactor coolant conditions will be restored in the first several minutes. When the reactor coolant subcooling margin is established, the following general procedure to control RCS inventory should be followed:

HPI Control After RC Subcooling is Regained

1. Avoid too much subcooling (high RCS pressure). There is a tendency to think that if "adequate" subcooling margin is good, then 200F subcooling must be better. The easiest way to get this excess subcooling is to allow HPI to run unthrottled and raise RCS pressure. This may lead to unnecessary lifting of the PORV and/or primary safety valves (the time between 2200 psig and the 2295 psig PORV setpoint, with two HPI pumps running unthrottled, is about 30 seconds) or, in some cases, violation of reactor vessel pressure-temperature limits. Also, there

are transients, such as as a steam generator tube rupture, where the higher RCS pressure makes the transient worse (larger leak rates). Therefore, the operator should throttle HPI, and begin to stabilize RCS pressure, as soon as subcooling margin is regained.

2. If pressurizer level is still off-scale low, maintain HPI but reduce the amount of flow that is being added to the RCS.
   - Throttle HPI injection valves. If an HPI line break is suspected, throttle the valves feeding the suspected broken line first.
   - If flow is throttled to within capacity of one HPI pump then stop the other HPI pump. (05)

   NOTE: Do not decrease HPI flow below low flow limits (< 100 gpm/pump) with the recirculation valves shut.

3. If pressurizer level is on scale but below 125 inches, throttle HPI using HPI injection valves and attempt to stabilize pressurizer level.
   - Maintain HPI at the reduced flow rate if pressurizer level and subcooled margin stabilizes (i.e., HPI is matching a leak).
   - If pressurizer level continues to increase above 125 inches, control HPI per Item 4 below (except during HPI cooling as described in "Backup Cooling Methods").

4. If pressurizer level is increasing and greater than 125 inches (indicated) and the RCS leak rate is less than MU capacity, then realign the HPI system into the normal makeup and letdown mode.
   - Monitor reactor coolant subcooling; restart HPI if subcooling margin lost.

- Reset ESFAS after HPI has been stopped (if RCS pressure is high enough).

5. If the pressurizer level is increasing rapidly, it may also be necessary to open the MADV's or the turbine bypass valves to decrease steam pressure to prevent the RCS from going water solid.
6. If leak is in top of pressurizer and unisolable, pressurizer will fill whether above actions are taken or not. (C

Guideline 3 for HPI termination or throttling

- HPI should be throttled to prevent pump runout and cavitation damage. The maximum allowable flow per pump is 800 gpm.

This guideline is implemented for pump protection so that core cooling will continue. Even when the reactor coolant system is at atmospheric pressure, the pre-throttled injection line isolation valves should limit HPI flow to <800 gpm per pump. However, the operator should monitor the individual injection line flowrates to ensure that total pump flow is not greater than the 800 gpm limit.

Guideline 4 for HPI termination or throttling

- The minimum allowable MU pump flow is 100 gpm per pump. The pump flow should not be throttled below this limit.

Pump overheating and damage can occur at very low flows. The pump flow is a combination of the recirculation flow and the injected flow; however the recirculation flow paths are isolated on HPI actuation.

The operator must override ESFAS and reopen the recirculation valves before taking manual control of the HPI pumps.

Guideline 5 for HPI termination or throttling:

- If forced RC flow exists the HPI should be throttled to prevent exceeding the reactor vessel pressure-temperature limit.
- If forced RC flow does not exist the HPI should be throttled to keep as close as possible to the subcooling margin limit to reduce the amount of reactor vessel cooling by the HPI flow and extend the time until the BWST is depleted. (05)

The RCS pressure/temperature combination must be kept within RV NDT limits. The method and indications for controlling depends on the RC flow status as follows:

Forced Flow

The RCS pressure and temperature must be kept within the normal technical specification reactor vessel pressure temperature limits (Figure 13).

With at least one RCP running, any cold leg RTD can be used to determine the temperature for comparison to the limit.

No Forced Flow

If the RC pumps are NOT running, the same RC pressure/temperature limits of Figure 13 apply; however, the operator has no indication of the RV

temperature. The incore T/C's will be used to measure RC temperature. However, the reactor vessel downcomer temperature will be colder than the core exit temperature measured by the T/C's. These colder temperatures occur because the HPI flow entering the RCS has not been heated by the core and does not completely mix with the reactor coolant as would happen if the RC pump were operating. The HPI water, which can be as low as 40F per technical specifications, will enter the cold leg pipe then flow into the RV downcomer and cool the reactor vessel walls. These RV temperatures cannot be determined without forced flow. During little or no circulation, the incore thermocouples are the only valid temperature measurements. Since thermocouple temperatures will be higher than the RV downcomer temperature, the T/C temperature should be kept as close to the subcooling margin as possible to maintain the largest margin between the RV temperature and the NDT limits.

It is desirable during HPI cooling to restart an RCP as soon as conditions permit. The forced flow from the RCP will provide some thermal mixing which decreases the amount of RV cooling and will allow the cold leg temperature measurements to be used as a measurement of the RV temperature.

If the NDT limit is exceeded, the RCS pressure should be reduced to regain the allowable operating region as quickly as possible.

HPI VALVE CONTROL

The HPI valves will be used to reduce HPI flow until the RC system pressure becomes low enough to initiate the LPI or DHR system or HPI cooling is no longer needed. If a small break exists, the RC pressure will have to be reduced to the LPI operating pressure. If only a loss of feedwater exists, then the RC pressure need only be reduced to the DHRS operating pressure (unless secondary cooling is reestablished) and then the pressurizer power operated relief valve should be closed.

Without feedwater, the time to depressurize will depend on the size of the break. The HPI flow will be performing two functions. It will be maintaining system pressure, which will be a function of the HPI pump head and the choked flow out the PORV (or break). It will also be removing decay heat from the core. The amount of decay heat will determine the amount of HPI flow needed, and the HPI flow will establish the RC pressure. Consequently, as the decay heat level decreases the HPI flow can be throttled back, which will cause the RC pressure to decrease.

With feedwater and either forced or natural circulation, the HPI flow to the core is needed only to control pressure. The steam generator will remove heat. Consequently, the RCS can be depressurized much quicker. The steam generator can cool the core as quickly as possible up to the 50F/hr. limit. Simultaneously, the HPI flow will be throttled to maintain the RC pressure within the acceptable P-T limits.

The HPI flow rate should be balanced among all injection nozzles to distribute the HPI flow around the reactor vessel downcomer as much as possible. This will ensure adequate HPI flow reaches the core.

During plant cooldown, a situation may occur where the RC pressure cannot be reduced by throttling HPI flow. This can be caused by hot water flashing to steam in the RV head, in either of the RC hot leg 180 degree elbows (due to no flow in one or both loops) or in the pressurizer (PORV closed) or under the RV head.

The operator should attempt to remove the RC loop steam and hot water by bumping a RC pump in the loop with natural circulation flow. If no natural circulation flow exists, any RC pump can be bumped. In addition, the high point vents can be used to vent steam and allow refill. The RV head vent can be used vent steam from under the RV head.

With a small enough break, HPI can cool the core sufficiently to provide subcooling with choked flow out the break. Then the RCS pressure can be reduced by throttling back on HPI flow. However, if the break is not in the pressurizer, the pressurizer steam bubble will also need to be controlled in order to reduce RCS pressure. This can be accomplished either by opening the PORV or by using pressurizer auxiliary spray.

Guidelines for controlling HPI are summarized in Figure 18.

Feedwater Control

Abnormal transient operation with main or auxiliary feedwater requires special attention to feedwater control. Failures can cause too much water to be added. Excessive main feedwater addition can cause undesirable overcooling, especially if feedwater heating is lost and cold water is added to the steam generator. If safety systems fail, it could even result in filling the steam lines with water and causing the SG(s) to be unavailable for heat removal by steaming. Excessive auxiliary feedwater can have the same general effects, but it will cause a more severe cooldown (for the same flowrate) because of the greater steam pressure reduction effect due to the lower temperature and high injection point for AFW. Both excessive main and auxiliary feedwater may require that quick actions be taken to stop it. In order to limit overcooling, auxiliary feedwater is designed to be automatically throttled and in order to prevent main feedwater overfill the MFIVs are automatically closed on high SG level. This section will recommend the best methods for manual control. (05)

Main Feedwater Overfill

After fifteen seconds following a reactor trip, if any SG level is at or subsequently reaches a high level of 60% on the full range indication, the MFW overfill protection system will close the MFW isolation valve on the high level SG(s). The operator should act to verify termination of

excessive main feedwater. If the MFW overfill protection system fails to stop the excessive main feedwater flow the operator should trip the main feedwater pumps. This is the quickest and surest method of stopping the overfill. This will stop all feedwater to both generators (it will be a loss of feedwater, but since the generators have a large inventory, the heatup effects will be delayed). This action can be taken if one or both generators have excessive feedwater.

Flow should be monitored in all cases; it will show the effects of corrective action faster than level. The MFW pumps must be tripped within 2-3 minutes to prevent steam generator overfill (water level at the top of the shroud) with large excessive MFW flow rates should the overfill protection system fail.

If all main feedwater has been stopped, the operator should make sure auxiliary feedwater starts. Resumed feeding can begin when the generator water level boils down to the automatic control setpoint.

Auxiliary Feedwater Overfill

To stop auxiliary feedwater from filling one steam generator:

- Isolate the failed control valve to high level/high flow steam generator. Verify the redundant control valve (in line from other AFW pump) provides proper flow control.

- If both control valves have failed, isolate the feed line from the turbine-driven AFW pump and attempt manual control with the remaining flow control valve.

It is highly unlikely that AFW flow control to each SG cannot be achieved with either parallel flow path. However, should both flow control valves for a SG fail to respond, the operator should proceed as follows:

- Isolate the flow control valve in the feed line from the turbine-driven pump. Leave the parallel AFW feed path open. When steam generator level is high, stop the associated motor-driven pump, allow the steam generator level to boiloff, and restart the pump. Continue using that one pump to "batch" feed the generator by starting and stopping the pump.

  Infrequent starts and stops of the pump are expected because it will take about 5 to 10 minutes to boil the added inventory off to a low level.

- If no control of AFW to either SG can be obtained, the pumps can be stopped and HPI cooling can be used. This method is not desirable, but it will keep the core cool. Every attempt should be made to maintain AFW to at least one generator, even if the operation is not steady.

AFW Throttling

The AFW control system is designed to automatically throttle AFW flow to prevent overcooling while achieving the correct level whenever AFW is automatically actuated. However, there are times when manual flow control may be required (e.g., failures). Therefore, guidelines to prevent overcooling the RCS during manual control of AFW flow are provided.

Steam generator level must be raised to the Mode B level setpoint to establish natural circulation flow. Steam generator level must also be increased to 80% on the full range if the subcooling margin is lost. The 80% level is required in case a small break LOCA has occurred. Anytime the subcooling margin is lost the level should be raised to 80%; if the subcooling margin is regained while the level is increasing, then the level increase does not need to be continued to the 80% level, but must be raised to the Mode B level setpoint if the RC pumps are not running.

Steam Generator Level Rule

Anytime the subcooling margin is lost, levels in the operable steam generators must be raised to 80% on the full range with AFW flow $\geq$ 600 gpm to each steam generator.

Overcooling can result if the AFW flow is unthrottled because, as the level increases, the inventory accumulation is a colder heat sink than is needed to balance decay heat. Thus, significant amounts of stored RCS heat could be removed resulting in overcooling. However, cooling and depressurization of the RCS is desired for small break LOCA's, therefore large AFW flowrates are required on loss of subcooling margin.

Addition of AFW at the maximum rate is not needed to achieve stable natural circulation. AFW can be throttled to control the level and limit the overcooling when the Mode B level setpoint is in effect. Full flow of AFW is not needed, but continuous flow is. It is not mandatory to limit the rate of AFW addition to prevent overcooling, but throttling is preferred to control the plant better.

The amount that AFW can be throttled depends on the decay heat load, which will vary depending on the prior operating power history. To increase level, the flow must be greater than that required to remove the decay heat.

Because the decay heat can be different, the amount of flow needed to remove decay heat and increase level is different; therefore, no fixed flow rate can be established. However, the maximum flow rate can be gauged by its effects. Generally, the flow rate should not drop steam pressure by more than about 60 psi below the pressure setpoint. For example, after a trip the turbine bypass set pressure is 1200 psia so the AFW flow should not cause steam pressure to drop below around 1140 psia.

If the operator has adjusted steam pressure to a different setting the steam pressure drop should stay within 60 psi of that setting. The 60 psi change in steam pressure is a rule of thumb for limiting the cooling of the RC system.

The effects of AFW throttling can also be seen in pressurizer level (if the reactor coolant is subcooled and is circulating). Pressurizer level indication should be visible and not be allowed to drop out of range because of AFW.

An important objective is to maintain natural circulation. If natural circulation has been previously established and the AFW flow rate is enough to maintain natural circulation, then it is the right flow (if pressurizer level and steam pressure are about right). Generally, AFW should only be throttled to prevent overcooling while achieving the natural circulation setpoint.

As previously stated, AFW flow will normally be controlled automatically and the operator need only monitor its performance. When circumstances require manual AFW control, the following guidelines should be used.

Guidelines for AFW Throttling:

- AFW should only be throttled when the natural circulation setpoint is in effect, and then only as necessary to limit overcooling (steam pressure within 60 psi of steam pressure control setpoint).
- Steam generator level must be gradually raised to the applicable setpoint; the steam generator level must never be allowed to decrease if level is still below the applicable setpoint (see setpoints below).
- Flow into the steam generators must be continuous at all times until the setpoint is reached.

Steam Generator Level Setpoints:

- Mode A - 36" on the startup range when one or more RC pumps are operating.
- Mode B - 23% on the full range with two steam generators (it may be necessary to raise the level higher than 23% if only one steam generator is working) when no RC pumps are operating.
- Mode C - 80% on the full range when the subcooling margin is lost.

Use of the Incore Thermocouples

The incore thermocouples can be used for a variety of reasons. Information about the incores is given in different chapters. The following summarizes that information:

1. They are used to detect core uncovering. They are the most valid indication of adequate core cooling. If the incore thermocouples clearly indicate superheated conditions, then the actions to counter Inadequate Core Cooling should be taken.
2. They provide indication of natural circulation. T_{hot} should read within ∿10F of the incore thermocouples when the plant is subcooled and solid water natural circulation is occurring. When the reactor coolant is saturated, the incore thermocouples do not provide as good an indication of natural circulation.

   They should follow steam generator T_{sat} when it changes.

3. They are the only valid indication of core outlet conditions when no circulation exists.

Cooldown with One Steam Generator Out of Service

Attempting to cool the plant down using one steam generator can cause excessive thermal stresses in the other steam generator if it is dry and the cooldown rate is large. Although one steam generator can remove the decay heat and the stored heat needed to cooldown, the dry steam generator is not properly cooled because the shell stays hot.

During normal cooldown, the shell of each generator is cooled by liquid in the lower part and by steam in the upper part. When the shell is not cooled and the tubes are cooled by reactor coolant, the tubes can get much colder than the shell causing them to contract relative to the shell. Because the tubesheets hold the tubes in a fixed position and the shell does not shrink, the tubes go into tension. If they get cold enough, the tension stresses will be greater than the yield stress and they will permanently stretch. If the tubes are cracked, flawed, or thinned they may fail. Consequently, limits are placed on the tube-to-shell ΔT. For cooldown this limit has been set at 160F. Any transient which results in exceeding the design ΔT limit of 160F requires specific stress evaluation after the plant is shutdown to determine SG tube integrity.

Cooldown with one generator at the highest rate of cooldown should not be done unless it is absolutely necessary. The choices to be made prior to cooldown are:

- Stay at stable hot conditions until the generator is repaired and returned to service, if possible.
- Cooldown at a slow rate so that the tube-to-shell temperature limit does not exceed the ΔT limit of 160F.

The need to cooldown can be established only after a review of the plant status. There are a limited number of reasons why cooldown may be required; these include:

- LOCA - small or intermediate break LOCA's will require cooldown so that the primary system can be depressurized. Depressurization will slow down or stop the leak rate. Tube leaks or ruptures require at least partial depressurization to prevent lifting of the steam generator safety valves.

- BWST Draining - in conjunction with LOCA, it is desirable to have the plant completely cooled down to avoid recirculation from the sump using the HPI system. For leaks which do not return sufficient water to the sump, it is absolutely required to have the plant depressurized or the leak stopped before the BWST drains.

- Condensate tank draining - It is desirable to have the plant on the decay heat removal system before the condensate storage tank is drained.

- Transients other than LOCA - most transients will not require cool-down for mitigation, so the plant can be placed in hot shutdown while the "bad" steam generator is repaired. However, some situations, such as fires, may have left the plant so badly damaged that a decision to cool down is necessary to avoid unknown side effects.

In order to cool the plant down as rapidly as possible with one generator out of service, it will be necessary to add water to the "bad" generator so the shell can be cooled. If the generator is completely dry, the shell will cool only by heat loss through the insulation to the reactor building; the average shell cooldown rate will be low (around 3-5F per hour). Water addition to the generator will allow the shell to cool faster. Water may accumulate and cover the lower part of the shell, but the area of the shell contacted by water is very small relative to the area covered by steam. Therefore, the shell is mostly cooled by steam, and the average rate of shell cooldown will be around 10 F/hr. Since the rate of shell cooldown is greatest when water is in contact with it, the preferred way to add water is with the main feedwater

system. However, the feedwater flow rate must be carefully controlled so the tubes do not "overcool". The cooldown rate of the plant will be limited by the cooldown rate of the shell and the cooldown limit is based on the tube-to-shell ΔT limit. The tube-to-shell limit can be calculated by using the shell thermocouples to determine the average shell temperature and subtracting the reactor coolant average temperature. However, in some rare cases T_{av} might not represent the average tube temperature; these cases can occur if the hot leg is steam bound and no circulation is occurring. If T_{hot} is increasing but T_{cold} is fixed, then T_{cold} should be used rather than T_{hot}.

To illustrate a plant cooldown, the following example is given. The example shows a tube leak with a generator that cannot hold pressure (a failed steam safety valve could do this). In this case, the plant must be cooled down as quickly as possible since the tube leakage will be steamed to the atmosphere. The example is illustrated in Figure 19.

The example follows the recommended procedure for tube leaks. That is, the plant is runback, depressurized and cooled rapidly from 567F (T_{av}) to 500F (T_{av}) at a rate of $\leq$ 268F/hr. After that, the RCS is cooled down and depressurized at $\leq$ 50F/hr until the tube-to-shell limit of 160F is reached. At that time, the cooldown is slowed and follows the cooldown rate of the shell and the tube-to-shell ΔT is the controlling limit. When the plant first reaches the tube-to-shell temperature limit of 160F the RCS pressure will be around 400 to 450 psig and the tube leak rate will be lower.

The RCS should be cooled down at $\leq$ 50F/hr while slowly adding main feedwater (if possible) or auxiliary feedwater until the tube-to-shell temperature limit is reached. When that limit is reached, the cooldown rate should be slowed so as not to exceed the tube-to-shell temperature limit. The rate of feedwater flow should initially be around 100 gpm, but actual flow rate will be dictated by the circumstances (e.g., a significant tube leak may require no additional feedwater). A continuous low flow rate is desired rather than an interrupted "batch" feeding rate.

If the reactor coolant pumps are not operating, or have been shut off sometime during the cooldown sequence, natural circulation will not occur in the loop with the generator out of service. If the reactor coolant in that loop is at a high temperature when the RCS depressurization begins, it may flash to steam. The steam will collect in the candy cane and system pressure will "hang up" at that pressure, preventing further depressurization. In some cases, not much can be done to prevent this except slowing the rate of cooldown. If possible, one or more RC pumps should be run, at least periodically, to preclude steam voids collecting in the idle loop. If steam does form, and any reactor coolant pump can be "bumped", it will help to mix the fluid so cooldown can continue. If a reactor coolant pump cannot be started, then the associated hot leg vent can be used to aid refill of the loop. In any case, the cooldown rate will have to be slowed. These actions should be performed only for situations where

it is necessary to continue the cooldown. If continued cooldown isn't required, the plant should be held stable with continued natural circulation in the one loop to remove decay heat until the voids in the idle loop are collapsed due to heat losses to ambient and/or refill by venting (05) and HPI or until the idle steam generator is returned to service (i.e., the problem requiring single steam generator cooldown is corrected).

Also see Part II, Volume 1, Addendum B for discussion of natural circulation cooldown with one OTSG.

Use of High Point Vents

The high point vents on the hot legs and reactor vessel head are used for various reasons. These uses are discussed separately in other chapters of Volume 1 and can be summarized as follows:

1. Natural circulation: Whenever the RC pumps are unavailable, it is desirable, if possible, to maintain decay heat removal with natural circulation but postpone cooldown until such time that forced circulation can be regained. However, there may be situations where it is preferable to cooldown on natural circulation, at least partially (as in the case of a tube rupture). Natural circulation cooldowns may require the use of the high point vents as follows:
   a. The RV head vent may be used periodically to prevent head bubble formation or to mitigate a head bubble once formed.
   b. The hot leg vents may be used to purge an idle loop during single loop natural circulation cooldowns to prevent void formation in the "candy cane" or to mitigate a void once formed.
2. Boiler-condenser cooling: The hot leg vents may be used to vent non-condensible gases that otherwise could hinder or interrupt boiler-condenser cooling.
3. System refill: The high point vents can be used to aid system refill after core boiling has ceased, as in the case of recovery from boiler-condenser cooling. The hot leg vents are used first to refill the loops and allow restoration of natural circulation. Once the loops are filled, the RV head vent is used to complete RCS refill and allow RC pump restart.

4. Inadequate core cooling: the high point vents are used to recover from inadequate core cooling by venting non-condensibles and aiding RCS pressure reduction.

The operator should be aware that hot leg level measurements will be invalid while the associated hot leg vent is open due to the common tap. The level indication should become operable again shortly after the vent is closed.

Refer to Part II Volume 2, Appendix D Section 7.0 for more information in venting.

Loss of LPI Recirculation Ability

The ability to recirculate water from the reactor building emergency sump can be lost during recirculation or when trying to start recirculation. If this ability is lost, the cause should be determined and flow started as soon as possible. There are two general causes: 1) loss of sump water and 2) loss of both flow paths from the sump. Loss of sump water can occur because of:

A. A steam generator tube rupture - A steam generator tube rupture is a LOCA; however, the water which leaks from the RCS does not accumulate in the reactor building sump. Instead, it leaks out of the reactor building via the secondary system while the SG is steamed and accumulates in the SG after it is isolated. If the BWST is depleted and time has come to transfer to the RB sump,

there will be no sump water. This situation should not occur if the SG with the tube rupture is allowed to fill and the tube leak flow is terminated. However, if the SG must be steamed, or otherwise the leak flow is not terminated, BWST depletion may occur. Backup sources of borated water must be made available.

B. Diluted sump water - Diluted sump water caused by a leak from a non-borated water source, such as the CCW system or the feedwater system, will make the sump water unusable if the boron concentration becomes too low. The diluted water should not be added to the reactor core because it could allow the reactor to go critical. This would make the core cooling problem worse. This problem must be corrected by adding borated water to the recirculation flow and by stopping the dilution process, e.g., if a feedwater line is adding water to the reactor building, the flow to the broken line should be stopped.

C. Leak in DHRS. (05)

Both sump flow paths can be lost if both the RB emergency sump inlets become clogged or if valves in both lines fail to open. If the motor operated valves fail to operate remotely, then local manual operation of the valves should be attempted to open at least one of the valves. However, the problem may not be electrical, e.g., the valve stem or disk may be binding, and manual operation of the hand wheel may not work, but some kind of mechanical leverage may be able to open the valves. Local attempts to open these valves may not be possible because of high radiation levels.

If the cause of a loss of sump water or flow path cannot be corrected, the operator should attempt to cool the reactor core with the DHRS. This method of cooling will be successful if the cooling water can flow through the RCS without leaking to the reactor building. To accomplish this, the RCS water must be 1) subcooled to prevent steaming out the break, 2) below the break elevation to stop RCS water from continually leaking to the reactor building, and 3) high enough to prevent a vortex formation as water is drawn into the DHRS suction pipe (this would be the same elevation as required for normal DHRS operation when draining the RCS). The RCS water is brought subcooled by increasing the LPI cooling as much as possible. When the RCS pressure drops below the DHRS design pressure, DHRS operation can be initiated and the RCS water level will drop to the break location. If the the break location is high enough, vortex formation in the DHRS drop line will not occur.

However, if the break elevation is too low, then a vortex will form in the DHRS letdown line and LPI cooling will need to be continued. Vortex formation can be detected by noting LPI pump cavitation (e.g., by locally visually checking for LPI pump vibration or by annunciation alarm on low NPSH for the LPI pump).

Because of the possibility of vortex formation, the transition from LPI to DHRS cooling should be made cautiously by switching one LPI train at a time from LPI to DHRS mode of operation.

During LPI cooling, water will continually be lost out the break until the water level in the reactor building increases to the elevation equal to the water level required in the RCS for DHRS operation. This will require more water than that contained in the BWST. Therefore, sources of borated water in addition to the BWST water will need to be used for core cooling. These additional sources will need to be pumped to the reactor vessel for core cooling until either a) the sump recirculation can be established or b) the RB is flooded to the RCS level needed for DHRS operation so that the DHRS can be put into operation. If the RB needs to be flooded, the operator should prepare for equipment and instrument failures due to water submergence. For example, the DHRS suction line valves should be opened before they are submerged because, after they are submerged, they may not operate.

If available, the hot leg level measurements should be used as an aid to assure an adequate water level exists above the DHRS suction nozzle.

During DHRS operation the RCS water temperature should be held constant to prevent volumetric water changes which cause the RCS water level to fluctuate. In addition, the RCS water temperature should be held below the boiling point to prevent water loss by steam flowing out the break.

CHAPTER G

FUNDAMENTALS OF REACTOR BUILDING CONTROL

1.0 INTRODUCTION

The Three Mile Island Accident of 3-28-79 provided some significant insight to reactor building performance. Two separate conditions existed during the TMI-2 accident that lead to a conclusion that a more comprehensive approach should be used for reactor building control to limit radiation releases during abnormal transients.

First, the reactor building pressure remained low for a significant time before reaching 4 psig where automatic reactor building isolation of penetrations could occur. During this time period the core was uncovered and high concentrations of radioactive material were released to the reactor building. The reactor building penetrations that were open did not permit a direct release of reactor building gases to the site. The sump line was open, however, and radioactive liquid was pumped to the auxiliary building.

This scenario above illustrates the need for operator action to control radiation releases by controlling the reactor building boundary at all times. Operator action prior to automatic system actuation may be appropriate; operator action may also be needed for conditions when systems used for automatic reactor building isolation control fail, and the automatic isolation requirement exists.

Another condition that existed at TMI was an accumulation of hydrogen in the reactor coolant system. Since hydrogen is flammable, the presence of a high H_2 concentration in the RB may necessitate control of its concentration to preserve the integrity of the reactor building and its operating equipment. H_2 concentrations may not have to be controlled if resulting temperature and pressure effects are shown to be tolerable.

Operator action is required to control the reactor building environment (radiation, pressure and temperature, H_2, and other physical phenomena) so that:

- Radiation release from the reactor building to the site surroundings is limited to as low as reasonably achievable.
- Radiation release to the auxiliary building atmosphere or fluid systems is limited to as low as reasonably achievable.
- Systems or components inside the reactor building that are used for reactor bulding control or for core cooling are protected.

The main purpose of the reactor buiding is to prevent unacceptable releases to the environment of radioactive material leaking from the reactor coolant system. Although the reactor building serves this purpose during normal operation and abnormal transients, this discussion will be limited to abnormal transients. Proper reactor building control during abnormal transients, especially during a Loss of Coolant Accident, will limit the amount of radioactive

material leaking to the environment. The operator must be prepared to take manual control of any automatic control function in the event of a malfunction or to manually actuate a non-automatic control.

2.0 DIAGNOSIS AND CONTROL

The two basic types of reactor building control are: reactor building isolation control and reactor building environment control. This section discussses how these two types of reactor building controls are used during the diagnosis and control of the reactor building required during abnormal transients.

This chapter will first discuss the general approach (Section 2.1) to diagnosis and control of the reactor building. The following sections (2.2, isolation control and 2.3, environment control), will be more specific in describing what parameters to monitor, when to take action, and what the action should be. Tables 7 and 8 are a summary of these control actions.

2.1 General Approach for Diagnosis and Control

Figure 32 illustrates the general approach to be used for additional building control following an abnormal transient.

The first block on Figure 32 refers to the abnormal transients which require additional operator actions for reactor building control. Additional reactor building control is required for abnormal transients; especially for reactor building conditions following a LOCA or steam/feedline break. Of these events the LOCA imposes the most difficult problems. A LOCA can result in release of radioactive material, H_2, acidic water (boric acid) and a caustic substance

(NaOH), but a steam or feedline break releases only steam, water, and acidic water (if RB spray is initiated), unless the steamline break is concurrent with an SG tube leak. A steamline break will also result in the addition of NaOH through the RB spray system. The rate of hydrogen release and accumulation during the LOCA will be gradual unless a severe Zr-water reaction occurs. However, large amounts of radiation will be released to the reactor building even if adequate core cooling is maintained. Either of the above events can cause equipment damage and require repair prior to placing the plant back into service. This section will emphasize the LOCA, but additional discussion of the steam line break and inadequate core cooling (ICC) is included in Section 3.0. (05)

Following the ATOG instructions, the operator maintains adequate core cooling and then ensures RB control. Adequately cooling the core will limit the H_2 and radiation levels in the reactor building. Inadequate core cooling (ICC) will aggravate the ability to control the reactor building and can require more drastic actions than would otherwise be required. In fact, if ICC occurs the emphasis on reactor building control will become greater because of the greater potential for hydrogen and radiation release.

First Line of Defense - Limit Radiation Release.

The first line of defense is against radiation release. Attention should be primarily on isolation of pentrations of non-safety fluid systems used in power operation.

Some examples are:

- Those that should be normally closed, but may not be, such as the pressurizer sample line and the RB purge valves.
- Those that could be isolated by automatic actions but can be closed by the operator if the setpoints are not reached such as the normal letdown line.
- Paths that can transfer liquid reactor coolant to the auxiliary building such as the RB normal sump drain.
- Filling steam generator(s) and portions of the steam line(s) for long term post LOCA operation allows a water seal to limit possible radioactive leakage from tubes.

Conversely, paths that should remain open or must be reopened are those needed for core cooling or reactor building control; for example, cooling water should be available for operating reactor coolant pumps.

Confirmation that isolation is effective is provided by valve operator lights, flow indicators, level indicators, temperature indicators as well as other indirect indications.

Second Line of Defense - Preserve RB Integrity.

The next line of defense is preservation of the reactor building integrity. This requires a careful balance of RB isolation

requirements and RB environmental requirements. (Note to TVA: Containment structural integrity may not be challenged at the design pressure; in fact studies indicate that large volume dry containments can be structurally sound at about 2x design pressure. Selection of design pressure as a limit may be over cautious in the sense that unusual operator actions to prevent exceeding the design pressure may not be warranted. For example, were we to prescribe containment venting (which may or may not be effective) a secondary hazard of radiation release may be brought to the forefront. Alternative choices include actions based on "steep" pressure trends vs. "mild" trends or using some pressure higher than design for special actions. Conversely high temperatures may endanger operating (01
equipment and special actions to reduce temperature may be desirable.) Pressure and/or temperature can be high within the reactor building for two reasons:

- the mass and energy from high energy line breaks.
- hydrogen burning or detonation.

Containment air coolers and sprays are used to reduce excessive pressure and temperature caused by mass and energy release. Hydrogen concentration is limited by hydrogen recombiners or by controlled purging, provided that the purge will not permit significant radiation release.

Third Line of Defense - Eliminate or Reduce the Cause for the Change in the RB Internal Environment.

The next line of defense is to eliminate or reduce the cause of the change in the reactor building environment to:

- minimize the continued radiation release to the reactor building.
- minimize the continued mass and energy release.
- minimize hydrogen release to the reactor building atmosphere.

Maintaining adequate core cooling, in conjunction with RB control, results in the major elimination or reduction of the cause of the adverse RB environment. A proper balance must be struck between the need to maintain adequate core cooling and the need to control the environment. Generally, a priority should be given to maintaining adequate core cooling because that is the most effective way to limit radiation and hydrogen release. However, the selection of equipment should be such that the actions taken to cool the core do not threaten the containment insofar as possible.

For example, following a steam line break inside the RB, the feeding and steaming of the affected SG to assist in RCS cooling would be discontinued unless this steaming was essential for adequate core cooling or necessary to maintain SG tube-to-shell temperature differential limits.

As another example, following recovery from ICC, H_2 venting from the RCS to the RB would be limited to prevent the RB H_2 concentration from exceeding 4.0 vol.%.

Fourth Line of Defense - Return the RB Internal Environment to Normal.

The fourth line of defense is the followup required to restore the RB internal environment to a normal or acceptable set of conditions. This fourth line of defense will limit radiation release by protecting the reactor building control equipment, protecting the RCS heat removal equipment, continued reduction in RB pressure and removal of radiation and hydrogen from the RB atmosphere.

This includes the following:

- Control of reactor building water level to prevent flooding of vital equipment (such as decay heat drop line valves, instrumentation connections, RC pumps, ventilation ducts).
- Control of reactor building water level to ensure adequate emergency sump level so that sump recirculation can occur. (01
- Control of normal and emergency sump water chemistry (boron concentration and pH) to limit corrosive effects, (especially stress corrosion) and enhance removal and retention of radioactivity from the RB atmosphere. (01
- Control of RB spray to reduce RB pressure, temperature and airborne radioactive material. (01

- Control of RB air coolers to lower RB pressure and temperature.
- Control of RB hydrogen recombiners and purging to limit the H_2 concentration.
- Control of the secondary containment systems to permit radiation leakage control and processing.

2.2 Reactor Building Isolation Control.

Reactor building isolation control is one of the two basic types of RB control as discussed in Section 2.1.

Reactor building isolation control involves reducing and controlling leakage through the reactor building penetrations following a diagnosis of an abnormal condition. The control actions consist of:

1. Isolating reactor building nonsafety fluid systems by automatic action ESFAS actuation on a RB pressure of 4 psig (increasing) or a RCS pressure of 1700 psig (decreasing). Steam and feedwater lines, as well as some other normal lines such as letdown, are isolated on these two parameters and on a steam generator pressure of 600 psig (decreasing).
2. Selectively operating penetration isolation valves as needed for abnormal transient operations.
3. Operating the Secondary Containment equipment to monitor and control leakage from the reactor building.

2.2.1 Diagnosis

Specific parameters are monitored that will indicate the need for reactor building isolation. These parameters, as listed in Table 7 are:

- High reactor building radiation.
- High reactor building pressure.
- Low RCS pressure.

Each of the three conditions listed above relate to a potential release of radioactive material as follows:

1. High radiation - If the radiation level in the reactor building is above the limit, then a normal amount of RB leakage can release excessive radioactive material. The gaseous radiation dome monitor is the fastest method of detecting an abnormal radiation level in the reactor building atmosphere. For an RCS leak rate of 1 gpm, the following gaseous radiation monitor alarm response times are typical:

Coolant Activity	Response Time
1% defective fuel in core	approximately 1 minute
0.1% defective fuel in core	approximately 5 minutes

A leak rate such as the 1 gpm above is usually not an abnormal transient. Any RCS leak rate above normal, however, may be an indication of an incipient LOCA or it may mask other abnormal events.

2. High reactor building pressure - As the reactor building pressure increases, the leak rate of radioactive materials will tend to increase. Some small amount of leakage is expected, based on the results of the RB leak rate test; however, the secondary containment will collect any leakage and limit release to the site. The leak rate test can be used to estimate expected radiation releases.

3. Low reactor coolant pressure - Low reactor coolant pressure indicates a possible LOCA. The LOCA can cause both a high reactor building radiation condition and may increase reactor building pressure. A combination of high radiation and high pressure increases the potential for an excessive radiation release if there is any RB leakage.

If the high RB radiation, high RB pressure or low RCS pressure exceed the values specified in Table 7, the potential for too much radiation release exists and isolation control actions should be taken as specified.

In addition to the above parameters, the failure of systems circulating reactor coolant outside the reactor building will contribute to the radiation release. Liquid leakage can be monitored by the changes in sump levels in the auxiliary building and by local radiation detectors if the release is gaseous or water vapor. Some leakage of these systems is anticipated. The maximum allowed leak rates for normal operation are specified in the technical specifications and the actual leak rates should be known by the shift supervisor so an assessment of abnormal leakage can be made.

The essential services or component cooling water systems may pose a path for radiation release from the reactor building space. However, they do not normally carry radioactive fluid and they operate at a pressure which is usually higher than the pressure of the reactor building. In the event of a cooler tube leak and a high RB pressure, these systems can be isolated.

2.2.2 Isolate Penetrations of Non-Safety Fluid Systems Used in Power Operation.

The only non-safety penetrations not isolated or sealed before power operation are those for fluid systems used in power operation (e.g. feed lines, or reactor coolant letdown). Most of these non-safety penetrations are isolated automatically if the ESFAS is

tripped on either a RCS pressure of 1700 psig (decreasing) or a RB pressure of 4 psig (increasing). A low steam generator pressure of 600 psig will also isolate steam and feed lines; however, the isolation signal is primarily for prevention of overcooling accidents rather than for radiation release prevention.

Another automatic isolation parameter is also used: the containment purge and RB sump drain valves are isolated by separate high radiation signals. An air monitor signals the purge isolation valves to close while the RB sump isolation valve signal originates from an area monitor.

The operator must be alert to the fact that many abnormal conditions may release radioactive material from the RB before automatic isolation occurs or an isolation valve may fail to close when a signal is received. If there is any evidence of an abnormal amount of radioactive material in the Reactor Building, then there are certain penetrations which should be manually isolated immediately to ensure that releases are not transported directly to the site or to the auxiliary buildings. These penetrations include the RB normal purge valves and the RB normal sump drain. Special actions may also be required to prevent direct reactor coolant release if a leaking steam generator tube occurs.

All non-safety penetrations, however, may require manual isolation under certain circumstances such as a small break LOCA.

Additional isolation to limit possible tube leakage during the long term is afforded by filling the steam generators and portions of the steam lines. This action can only be taken after the steam generator(s) are no longer needed for heat removal.

A small break LOCA is the most likely abnormal condition which requires action to prevent abnormal radioactive releases to the RB. This transient is characterized by a leak rate to the RB which may or may not reduce the RCS pressure to 1700 psig and may or may not raise RB pressure significantly or may gradually cause RB pressure to increase over an extended period of time, particularly if the normal RB coolers are all in operation.

The RB radiation monitors normally initiate automatic actions to isolate the RB atmosphere under these conditions.

2.2.3 Control With Equipment Failure.

If an automatic isolation valve does not close on the close signal, the operator should check its redundant isolation valve to see if it has automatically closed. If at least one valve has closed for each reactor building penetration, then no other immediate action is required. If both valves on a penetration fail to close then the operator should try individual remote operation of one or both

of the redundant isolation valves. If neither valve will close, attempts should be made to locally close the isolation valve outside the reactor building. This may not be possible if radiation levels are too high. If the failed isolation valve can be locally reached and still cannot be closed, a determination should be made of what caused the valve inside the reactor building to fail open. Then attempt to correct the problem and close the valve.

If neither of the redundant isolation valves can be closed, then follow the system out from the penetration to the next set of valves and close them.

2.2.4 Selectively Operate Penetration Isolation Valves.

During abnormal transients, the operator may need to use some of the non-safety fluid system penetrations to help maintain core cooling and to control the reactor building environment. Some of the safety fluid system penetrations may require isolation upon a failure. Consequently, the operator will have to selectively operate the reactor building isolation valves as he chooses between the need for reactor building isolation and fluid system operations. The decision to open the valves should be accompanied by a judgement of consequences (e.g. the penetration path cannot be reclosed).

The penetrations the operator needs to manipulate can be divided into two groups as follows:

a. The penetrations of non-safety fluid systems used during power operation. The most prominent non-safety systems that may need operator control include CCW to the RC pumps and letdown coolers and normal feedwater to the steam generators. Most of these penetrations close automatically on ESFAS actuation. The operator has administrative control over others.

b. The pentrations of safety fluid systems. Most of these penetrations open automatically or remain open upon ESFAS actuation. The operator has administrative contol of others such as the DHRS suction line. (01)

The RB penetrations are listed in Table 6.2.4 of the FSAR.

When the penetrations for non-safety fluid systems are isolated, the operator needs to be aware of what is affected so that he can make appropriate compensation. For example: following a steamline (01) break inside the reactor building, the RC pumps will be automatically tripped if a loss of subcooling margin occurs coincident with either a high RB pressure or low RC pressure ESFAS signal. The (01) normal seal water return path from the RC pumps will be isolated on RB isolation, however the return remains operable via a three way valve that diverts flow to the RB emergency sump. When the subcooling margin is returned in the RCS, RC pumps may be restarted. (01)

However, they should not be restarted until seal water return is reestablished. The cooling water to the RC drain tank should also be reestablished if PORV or pressurizer safety valve release causes the tank temperature to significantly increase.

If the safety function is required immediately following an abnormal transient, the isolation valves will be automatically opened if ESFAS is actuated. If the safety function is not required immediately following an abnormal transient, the isolation valve will not automatically open. (e.g. reactor building emergency sump valves).

The RCP seal injection penetrations remain open when the RB is isolated and should be left open by the operator. Some isolation valves remain open during power operation, but they still have the automatic valve opening feature just in case the valve happens to be closed.

The essential raw cooling water penetration valves supply cooling water to the reactor building emergency coolers and they remain open following a transient requiring reactor building isolation. Reactor building emergency cooler isolation valves are available but require operator action to close. Separate isolation valves are provided for each cooler. These valves are used to isolate cooling water to a cooler should the cooler develop a leak. The

essential raw cooling water is not borated, thus any leakage from the cooler would dilute any borated water collected in the sump after a LOCA. If the cooler containing the leak can be identified (01) (utilizing an increased flowrate as measured on the flowmeter) then it should be isolated to prevent boron dilution in the sump. If the leakage is so small that the flowmeters cannot be utilized to identify the leaking cooler, then boron dilution should not be a problem. Dilution would be a slow process and sufficient time should be available for the operator to periodically adjust, as necessary, the sump boron level.

2.2.4 Secondary Containment Control Systems

Note to TVA: Considerable information is required. Information includes:

A. Features used for accident conditions when the accident proceeds as expected -

1. Radiation and negative pressure monitoring
2. Purge/filter operation
3. Operator actions to start/stop equipment operation.

B. Action to take when secondary containment equipment fails.

C. Special actions when the accident proceeds beyond the design basis for which the equipment is designed. For example: a) stop purge/filter when secondary containment radiation is

excessive; b) alter the negative pressure to reduce leakage into the secondary containment.

D. In addition, can failures of equipment, such as pipe breaks, which occur in the secondary containment, require special accident mitigation analogous to primary containment accidents?

E. Can secondary containment equipment be used in unusual ways to backup or supplement other accident equipment for accidents that go beyond the design basis (e.g. loss of containment integrity, high H_2, high radiation)?

2.3 Reactor Building Internal Environment Control

As discussed in Section 1.0 reactor building internal environment control is one of the two basic types of reactor building control.

After an abnormal transient, the environment inside the reactor building can become harsh enough to cause failures of equipment and structures. Other effects include degradation of equipment performance, especially instrumentation.

The reactor building environment needs to be controlled to reduce or eliminate failures of equipment and structures required to control the harsh environment itself and required to control core

heat removal. Reactor building control requires controlling the following to bring them within acceptable limits.

a. Reactor building pressure and temperature.

b. Reactor building hydrogen concentration.

c. Reactor building sump chemistry.

d. Reactor building radiation.

e. Reactor building water/sump level.

Actions to control these parameters are summarized in Table 8. Control of each of these will now be discussed in more detail.

2.3.1 Reactor Building Pressure and Temperature

Temperature and pressure are coupled together for a LOCA so that if the temperature is reduced the pressure will also be reduced and vice versa. Figure 33 illustrates the pressure-temperature relationship for a 2.14 ft^2 LOCA with minimum ECCS, RB spray and RB coolers.

As the LOCA releases steam and water, this mixture heats up the RB atmosphere. The decreasing mixture temperature and increasing air temperature will come to equilibrium at a common atmospheric temperature. This temperature will determine the reactor building pressure. The pressure will be the sum of the partial pressures of air and steam. The partial pressure due to the initial air in the (01) RB is only about 5 psig at the peak temperature, therefore the RB

atmospheric temperature and pressure approximate the saturation values for steam. For comparison, Figure 34 shows the pressure and temperature for a 8.55 ft^2 LOCA with minimum ECCS, RB spray and RB coolers.

Hydrogen burning or detonation can also cause containment pressure and temperature excursions as discussed later in this section. One other high energy line break, the steam line break, is discussed in Section 3.2.

2.3.1.1 Pressure and Temperature Control

The reactor building pressure and temperature must be reduced to:

a. Prevent exceeding the failure pressure and design temperature of the reactor building.

b. Reduce the driving force (ΔP) for reactor building leakage.

c. Prevent equipment damage.

The following combinations of RB safety cooling equipment are the minimum design requirements for pressure and temperature control under LOCA conditions:

- 2 reactor building spray (RBS) trains or,
- 2 reactor building coolers or,
- 1 RBS train and 1 reactor building cooler.

If the high reactor buiding pressure limit (4 psig) is reached or RCS pressure drops to 1700 psig, the ESFAS system will automatically:

a. Place the RB coolers in the emergency mode.

b. Isolate the RB.

At 10 psig, the containment sprays will be automatically started.

No automatic actions are taken based on a high temperature signal.

The number of emergency coolers and sprays does not significantly affect the peak RB pressure for large LOCA's in which the peak pressure is reached soon after this equipment is actuated. On the other hand the peak pressure for a small LOCA is very dependent upon the amount of cooling equipment in operation.

Large increases in reactor building temperature and pressure may not occur for small LOCAs such as a stuck open PORV. However, radiation will be released to the reactor building. Also, the RCS pressure may not drop to the ESFAS setpoint for some time.

Normal operation of some systems may delay or prevent these parameters from reaching setpoints which actuate safety equipment. The RB coolers may provide sufficient cooling (in the normal mode)

during the SBLOCA such that only a small RB pressure or temperature transient will occur and the operator must be alert to verify the RB atmosphere is isolated on a radiation signal. The operator should try to reduce the amount of energy being released to the reactor building by:

1. Maintaining core cooling to keep the core covered.
2. Limit feedwater added to a steam generator which has a break inside the reactor building.
3. Increase the heat removal by the LPI cooler (if in operation).
4. Increase the heat removal by the steam generators (if in operation).
5. Isolate any break in the RCS or steam generators if possible.

Containment temperature can affect the operation of some equipment; consequently if a high RB temperature (120F) is reached, then the operators should start RB coolers as required to bring the temperature back within limits. Temperature monitoring in the instrument room should be started; if high temperature (120F) occurs the operator should begin reviewing instrument readouts for possible spurious indications and be aware that misleading readings can occur.

2.3.1.2 Pressure and Temperature Control With Equipment Failures

The primary method of reducing the reactor building pressure and temperature under abnormal conditions is with the reactor building coolers in the emergency mode. If this equipment fails to keep the (01
reactor building pressure below 10 psig, backup cooling with the reactor building spray system is automatically started by the ESFAS on a high building pressure of 10 psig. However, manual initiation should be made if the ESFAS does not automatically (01
actuate the reactor building spray systems.

Reactor building spray for RB pressure reduction following a LOCA may be stopped after the RB pressure is reduced to 4 psig and is decreasing. RB emergency cooler operation for pressure reduction may be restored to the normal mode when the RB pressure is reduced to that for normal operation.

Reactor Building Pressure Rule

Whenever RB pressure $\geq$ 4 psig:

a. Isolate all non-safety RB isolation valves.
(Reopen those required for RCP operation if closed),

b. Start all RB coolers in the emergency mode.

Whenever RB pressure $\geq$ 10 psig:

a. Start both RB spray trains.

Reactor Building Temperature Rule

Whenever the average RB Temperature $\geq$ 120F.

a. Start RB coolers as required to maintain temperature below 120F.

Failure of both containment fan coolers and sprays is not likely; however, were this to occur the effects on RB pressure and temperature depend on the ability to remove heat through the steam generators for a LOCA and for a steam line break the effects would depend on the ability to stop feedwater to the broken generator. Containment pressure could increase beyond design pressure; however, the containment design is capable of up to about 2 x the rating before structural failure will occur, but operating equipment may be damaged. Pressure reduction using backup equipment such as firewater systems is required. The operator should not attempt to reduce reactor building pressure by opening the reactor building normal containment purge system (CPS) valves. The valves may fail open which could release large quantities of radioactive material. Restart of sprays or coolers is required along with monitoring the secondary containment and site monitors for increased leakage. Containment integrity will be threatened and actions for loss of integrity must be undertaken (see Section 2.4).

2.3.2 Reactor Building Hydrogen Concentration

The sources of hydrogen following a LOCA will result in a time dependent build-up in the containment until control measures are taken. The sources are: a) radiolytic releases from the core and the RB sump, b) release from galvanized metals in the RB, c) release from zinc primer paint in RB, d) release from corrosion of aluminum, e) release from H_2 dissolved in RCS, and f) release from the zirconium-water reaction. Figure 35 shows the time dependent buildup for an assumed 5% zirconium-water reaction.

The extent of the Zr-water reaction is controlled by the ECCS performance. Consequently, if the operator keeps the core adequately covered and cooled, the Zr-water reaction will be an insignificant source of hydrogen.

Figure 35 is an illustration of the quantities and rates of generation for the LOCA with a 5% Zr-water reaction. Other conditions can occur that result in greater or lesser amounts of hydrogen release; and the rates can be greater or lower. Furthermore, these curves assume that the released H_2 is evenly dispersed; possibilities exist for high local concentration or stratification. Flammability is dependent on the concentration and the concentration depends on how well the reactor building atmosphere is mixed.

The flammability limits of hydrogen-air-steam mixtures are shown in Figure 36. The lower flammability limit for H_2 is 4.1 vol. % in dry air. At this concentration, the flame would only propagate upward. Therefore, there would not be any widespread H_2 burning at this concentration. At 9.0 vol. %, in dry air the flame can propagate rapidly in all directions and, at 19.0 vol. %, the H_2 can detonate. A hydrogen and steam mixture of $\geq$ 57 vol. % steam is completely inerted.

If H_2 is released from the reactor coolant system too rapidly, then local concentrations much higher than those above may occur. Thus H_2 burning or detonation may occur with low H_2 releases if the RB atmosphere is not mixed well. H_2 burning will increase RB temperature and pressure. The most apparent feature of H_2 burning is a sudden RB pressure spike with a return to a pressure only nominally higher than before the burn. The SG and RCS pressure indications will dip by about the same amount as the RB increases during the H_2 burn since the low pressure side of these transmitters are vented to the containment. H_2 detonation causes a more pronounced presssure spike. Figure 38 is a diagram of the processes affecting the primary containment hydrogen concentration.

2.3.2.1 Hydrogen Control

The post LOCA hydrogen concentration is controlled to either prevent burning or to limit hydrogen burn or detonation in order to prevent:

a. Equipment damage within the reactor building.

b. Structural damage to the reactor building or penetrations.

The reactor building hydrogen concentration must be periodically analyzed following a LOCA or ICC to determine the rate of hydrogen build up in the reactor building. Note that an adequate sample that is representative of the entire containment requires good mixing and up to 2 to 3 hours may be required to completely mix the entire containment volume. High local concentrations can build up in a short time if ICC occurs or the high point vents are opened. If the fans are not running stratification can occur. Consequently, sampling adequacy and interpretation of the results must consider the plant conditions. Special actions must be taken if bad samples are expected or if high local concentrations can exist.

Hydrogen is controlled to keep the concentration below the value at which it burns (4.1 vol. %). The primary means of hydrogen control is maintenance of adequate core cooling which limits the amount of H_2 produced. While hydrogen is in the RCS, it will not present an explosive hazard if little (<5 vol %) oxygen is

present. Since H_2 can interfere with natural circulation cooling, ICC procedures require it to be vented from the RCS and in the case of most LOCAs, any H_2 is released to the RB along with the steam and water.

The first method of H_2 control in the RB is by mixing the RB atmosphere with hydrogen mixing fans, which are at a higher elevation than the RB coolers and are effective at preventing stratification at high RB elevations. The RBS system also mixes the RB atmosphere when actuated. Even though mixing can take considerable time, the fans will help disperse any local concentration of hydrogen and create a more homogeneous mixture for sampling and purging the hydrogen in the reactor bulding.

The second method of hydrogen control is reduction of hydrogen thru use of the H_2 recombiners. Startup of the recombiners should begin at the first indication of an abnormal H_2 buildup to prevent the concentration from exceeding 3.5%. The recombiners are sized so that one can remove the amount of hydrogen that is expected for LOCAs that do not result in extended periods of uncovered core operation. The recombiner capacity is not large enough to remove quantities of H_2 significantly larger than that for the design basis LOCA (5% Zr-water reaction).

Purging through the vacuum relief system to the secondary containment air cleanup system (SCACS) can be used to backup the recombiners. The hydrogen should not be purged to the site atmosphere if the reactor building radiation level is above the high limit (see Table 8) because this will cause an excessive radiation release from the reactor building. Since the air is purged through the station vent, automatic isolation on high vent radiation will stop the purge. (01)

Figure 37 shows the effect of starting either one H_2 recombiner at 3.5% or a 60 SCFM purge at 3.75 vol. % following a design LOCA.

2.3.2.2 Hydrogen Control With Equipment Failures

Several different conditions can exist that affect the ability to control H_2. Special actions must be taken if the H_2 generation rate is greater than can be accommodated by the equipment design (recombiners or purge) or if equipment fails. Special actions must also be taken to prevent combustion if local concentrations can exist. Finally, special actions must be taken if combustion or detonation occurs to limit damage.

Methods for H_2 control under "other than expected" post LOCA conditions depend on the amount of H_2 to be removed. Usually, if ICC has not occurred, the quantities of H_2 that are released to

the containment will not build to a combustible concentration for a reasonable time provided good mixing prevents local concentrations from developing. Therefore, the biggest problem to contend with is to ensure good mixing. If good mixing is provided then the second problem becomes one of H_2 removal.

Loss of atmospheric mixing may permit stratification and may affect the ability to obtain a representative sample with the hydrogen analyzers. To obtain as much mixing as possible, the fans of the containment air recirculation system (CARS) should be started. The H_2 recirculation fans should be used to circulate air through the recombiners and the H_2 analyzers should also be started. These fans may not provide adequate circulation at the lower containment elevations, especially in the reactor and steam generator compartments. Ventilation in the reactor head region can be by the control rod drive cooling fans.

Loss of H_2 analyses systems will not permit reasonable decisions for startup of H_2 control equipment. H_2 analyses failure can occur from unexpected equipment failure or might possibly be caused by the adverse pressure, temperature, or radiation conditions. The failure may be a complete loss of reading or spurious readings. In either circumstance, the action to take is to start the recombiner systems immediately.

Loss of both H_2 recombiners is unlikely. They are sized so that either one may remove the amount of H_2 developed by LOCA's that do not result in ICC conditions. Information from TVA is required (01) to indicate loss of recombiners. The information should be specific as to evidence of loss such as loss of power as well as indications for degraded performance). If one recombiner is disabled, the remaining recombiner should be maintained in service and frequent samples should be taken. If both recombiners are out of service, the Vacuum Relief System should be engaged in the H_2 removal mode provided that radiation levels permit.

A backup method for hydrogen control that may be used for unusual conditions (loss of other control equipment, excessive hydrogen generation, or high local concentrations) is the reactor building sprays. The sprays will create turbulence to help disperse local concentrations and may aid in suppression of flammability. If H_2 ignites, the sprays will help reduce the RB peak pressure. The RBS should be started if all other efforts to keep the containment concentration below 4 vol. % have failed or it is expected that the containment concentration will exceed 4 vol. %.

Hydrogen control during inadequate core cooling conditions (ICC) is discussed in more detail in Section 3.1.

2.3.2.3 RCS Control to Limit Hydrogen from Entering the Containment

Free hydrogen inside the RCS does not pose a significant combustion hazard, (as noted earlier), if only a limited amount of free oxygen is present for combustion. If the free hydrogen accumulation does not interfere with plant control or core cooling, controlled venting to the RC drain tank (if available) and then to the waste disposal gas processing system should be started. Pressurizer venting to permit H_2 removal and restoration of pressurizer spray control should usually be performed through the RC drain tank. There are two reasons for removing H_2 in a controlled fashion. One reason is that the H_2 molecule is very small and the possibility of it seeping through tight fitting gaskets (such as the CRDM closures) to the containment is high. Therefore, H_2 removal from the RCS, to limit accumulation in the containment, is important. The other reason is that were H_2 to continue to accumulate in the RCS, core cooling might be affected. When free H_2 accumulates and prevents adequate core cooling it may be vented to the RC drain tank or the containment. Venting to the containment will remove the H_2 faster than to the RC drain tank and is preferred. Although venting to the containment increases the risk of ignition, for most conditions core cooling takes precedence. (Information for RCS venting to improve core cooling is provided in Part I, Section ICC of the ATOG guidelines).

Detection of H_2 within the RCS and distinguishing H_2 from steam voids is difficult and can only be inferred. The most likely condition is for the void to be composed of steam or a mixture of steam and H_2. A void entirely composed of H_2 is unlikely. The hot leg and head level measurements will indicate the existence of voids but will not show the proportions of steam or non-condensible gases. If adequate core cooling is restricted by voids, it is not necessary to distinguish; venting is required. For other conditions the presence of free H_2 can be inferred by one (01)
or more of the following observations:

- Voids are indicated by hot leg or head level measurements while in natural circulation and the reactor coolant is subcooled. Bumping RC pumps will not remove the void(s); they will reappear gradually after the pumps are stopped although the void(s) may be redistributed between the head and hot legs.
- If ICC has not occurred, a reactor coolant liquid sample will indicate a lower dissolved H_2 concentration than normally expected (assuming no degassing operation has taken place).
- Pressurizer spray will not be as effective for reducing pressure if free H_2 is in the steam space. The affect will be to show almost no pressure reduction for a high H_2 concentration.

- ICC has occurred (see Section 3.0).

2.3.2.4 Actions in Response to Containment H_2 Fires

For most H_2 burn situations, an abrupt pressure spike is expected. If the containment integrity has been retained, (omitting the possibility of small leaks) the containment pressure will be approximately the same after the burn as before. The temperature spike will usually not be seen due to the relatively slow response times for the containment temperature detectors. The abrupt pressure spike is a significant indication of H_2 ignition, however the size of the spike will depend on the volume of H_2 consumed and the original concentration. Furthermore, if the spike results from the ignition of one local concentration and is followed by ignition of H_2 at another location, multiple spikes can show up. Although an abrupt spike is the most likely characteristic, wide spread constant burning can result in abnormal continued pressure and temperature increases that are more gradual.

To confirm that H_2 ignition has occurred, other indications can be used for supplemental information. The effects on steam generator and RCS pressure indications were discussed earlier. The H_2-O_2 analyses should show a decrease of O_2 since oxygen will have been consumed as well as a decrease of H_2. Evidence that a

burn has occurred should be confirmed by a review of all symptoms, however, actions should be taken largely based on containment pressure, confirmed quickly by RCS and SG pressures, without waiting for H_2-O_2 samples or temperature. (01)

Effects of a hydrogen burn or detonation can be:

1. Damage to equipment caused by the high flame temperature or radiant heating of components near the flame front.
2. Start of additional fires of combustible material (such as leaking reactor coolant pump oil).
3. Damage to equipment or structures caused by missiles created by a detonation.
4. Local damage to equipment by high pressure if detonation occurs in a confined space (such as ducts or the pressurizer compartment).
5. Damage to penetrations if H_2 combustion or detonation occurs near or within penetrations. For example, if the Vacuum Relief System is in operation, a burn within the ductwork may cause failure of the penetration leading to loss of containment systems such as the Secondary Containment Air Cleanup Systems may also occur. (01)

6. Loss of containment structural integrity caused by high pressure resulting from detonation. This is an unlikely condition. The large Bellefonte containment volume has a relatively low sensitivity to energy addition; and maintenance of containment integrity is expected at pressure considerably above design pressure.

Actions to take after detection of H_2 burn or detonation:

- Start reactor building sprays if the pressure spike did not cause initiation.
- Check RCS performance to determine if damage has affected core cooling. Take ATOG actions to enhance core cooling as required.
- Check containment isolation (the pressure increase may have caused isolation of needed equipment). Realign containment isolation to restore fluid systems services to RCS and containment as required.
- If containment purge or vacuum relief system was in operation, check for containment integrity and secondary containment effects.
- Close all isolation valves that connect the containment atmosphere to the secondary containment or to the site.
- Monitor containment temperature and pressure.

- Sample H_2 and O_2 concentration; if O_2 is low it will be less likely to support combustion, therefore do not reopen makeup air paths unless H_2 concentration is much lower than 4.0%.
- Evaluate the performance of containment coolers, recombiners, and other containment environmental control equipment.
- Evaluate instrumentation for failures or spurious operation.
- Evaluate containment integrity (see Section 2.4.)

2.3.3 Reactor Building Emergency Sump Chemistry

The reactor building emergency sump water boron concentration following a LOCA should not be diluted. This is to assure the recirculation water has sufficient boron to maintain the core subcritical. Boron dilution can be caused if a fluid system leaks nonborated water to the reactor building sump such as a feedwater leak or a leak in the service water. If this occurs the source of nonborated water should be isolated. Boron precipitation in the reactor vessel can also lower boron concentration in the RB sump. The operator should take appropriate actions to prevent boron precipitation in the reactor vessel as discussed in Appendix D. (05)

A RB emergency sump pH limit from > 7.0 to < 11.0 is required to limit acid and caustic stress corrosion, respectively. However, a limit of 8.5 or above maximizes the iodine removal and retention capability (from the RB atmosphere) of the RB spray system. (01)

2.3.3.1 RB Emergency Sump Chemistry Control

pH

The sodium hydroxide (NaOH) tank is designed to automatically drain down simultaneously with the BWST and provide initial pH control of the RB sump.

Sump pH is controlled to between 8.5 and 11.0 after recirculation starts. The limits are intended to minimize stress (caustic and chloride) corrosion of the RCS and maximize Iodine in solution in the RB sump water and minimize it getting back into the containment atmosphere.

For a small break LOCA in which the RB spray is not actuated, the NaOH tank will not discharge until the LPI system starts to deliver flow and the manual NaOH valves are opened to the DH pump suction. These valves are motor operated and are opened automatically by ESFAS at 10 psig RB pressure. (01)

The pH of the RB sump may decrease gradually as recirculation continues. If not automatically aligned, the NaOH tank can be manually aligned and used to adjust pH in the RB sump via the DHR pump suction. However, since the addition of NaOH can have detrimental effects, an evaluation of the potential impact and need should be made before manual initiation. (05) (05)

Boron

Some causes of a low RB sump boron concentration are boron precipitation in the RCS or nonborated fluid systems leaking into the RB, e.g:

- Main or emergency feedwater leak.
- Steam line leak.
- Service water leak.

If the low boron concentration limit is reached, boron from the concentrated boric acid storage tank must be added to bring the sump boron concentration back above the low concentration limit. (01)

When caustic (NaOH) has been added to the reactor coolant, modified laboratory procedures are required to determine the boron concentration.

2.3.3.2 RB Emergency Sump Chemistry Control With Equipment Failure.

pH - The NaOH tank is designed to drain down prior to BWST depletion regardless of whether one or two RBS trains are in operation. (01)

Boron - The concentrated boric acid storage tank is available to supply additional boric acid to the RB sump via the makeup system in the event of sump dilution.

2.3.4 Reactor Building Radiation

The amount of radioactivity in the reactor building atmosphere or sump following an abnormal transient is dependent upon many factors such as the per cent of defective fuel pins, the power history, time in core life, amount of reactor coolant leaked to the containment and whether the leak was direct (LOCA) or to the SG (tube leak) and then to the RB due to a steam leak. In addition, the equipment which has operated since the transient determines, to some extent, the radioactivity present.

A reduction in the amount of radioactive material released to the reactor building atmosphere helps to limit the amount of radioactive material that can be released offsite. Figure 39 includes a schematic of processes affecting the site dose.

It is very important to know what radiation levels are in the reactor coolant and reactor building as soon as possible after an abnormal transient. For the LOCA, the NRC has recommended (NUREG-0578) that the reactor coolant and reactor building air be sampled within 1 hour after an accident (LOCA) and that a sample for possible core damage be made in less than 2 hours.

The primary radionuclides of concern are the noble gas nuclides - primarily Kr-85, Kr-88, Xe-132m, Xe-133m and Xe-133 and the iodine nuclides - primarily I-132, I-133, and I-135. The means

of detecting radiation (uCi/cc and Ci/cc) in the RB atmosphere is with the continuous Air Monitoring System. Before discussing how to control these above nuclides to limit personnel and equipment exposure, some discussion is first included on their behavior in the RB.

2.3.4.1 Behavior of Noble Gases and Iodine Nuclides in the Reactor Building.

The noble gas nuclides will always follow the steam and/or coolant flow and will accumulate wherever there is a gas phase, i.e., in the pressurizer steam space, in the makeup tank cover gas, or in the reactor building atmosphere. A significant fraction of all noble gas nuclides will be soluble in the reactor coolant while the system is at a high pressure, but the gas will rapidly leave the liquid upon depressurization. After 10 to 20 minutes at atmospheric pressure, less than a few percent will remain in solution. All noble gases are chemically inert.

The behavior of iodine nuclides is complicated by the fact that the iodine can exists in several different chemical forms, each of which has somewhat different behavior characteristics.

Elmental iodine is one of these chemical forms and it constitutes about 85% of the total iodines.

Elemental iodine (I_2) is very volatile, but it will react with water and form Iodide (I) which is very soluble in water in the following manner:

a) $I_2 + H_2O \rightarrow H^+ + I^- + HOI$

The HOI (hypoidous acid) is also somehwat volatile, but it will also react quickly with O_2, if present, in the following manner:

b) $HOI + O_2 \rightarrow IO_3 + H^+$

The IO_3 is also very soluble in water.

2.3.4.2 Reactor Building Radiation Control

All noble gases are chemically inert, so there is no effective way to remove them following a reactor accident other than to attempt to contain them and wait for decay, which should take 60 to 70 days. After this period, the remaining noble gas activity is so small that it is only a small fraction of the original activity.

The solubility of I^- and IO_3 in water, especially in water of higher pH, is used to remove elemental iodine from the RB primary containment atmosphere. The RBS system, by virtue of the large surface area provided by the liquid droplets, provides an excellent means of absorbing soluble components such as I_2 from the gas phase of the primary containment atmosphere. If the I^- and IO_3 can be kept in the RB sump liquid then leakage to the environment can be much better controlled.

Organic and particulate iodine constitute the other 15% of the total iodines. Particulate iodine is also removed from the RB atmosphere readily by the RBS. Organic iodine (which is mostly methyl iodide - CH_3I) is not removed well by the RBS. However, should any iodine leak into the secondary containment, it will be absorbed by the Secondary Containment Air Cleanup System (SCACS). The charcoal filters in the SCACS adsorb all forms of iodine, but the RBS, if actuated, will remove the elemental and particulate iodine from the RB primary containment atmosphere.

If an abnormally high radiation level is detected on the containment noble gas detectors, then the operator should:

a) Ensure adequate core cooling.

b) Stop all normal RB purging.

c) Close the normal purge valves and the RB sump drain valve.

d) Use all available RB fans to mix the RB atmosphere and take samples of the RB atmosphere.

e) Sample the RCS.

f) Check for RCS leakage.

g) Check RB pressure and temperature.

If a high RB radiation alarm is received on the continuous Air Monitor System, then the operator should as a general guideline: (01)

a) Isolate all non-safety RB isolation valves on lines which are open to the RB atmosphere.

b) Start all RB coolers.

c) Start the Secondary Containment Air Cleanup System.

2.3.4.3 Reactor Building Radiation Control With Equipment Failure.

In the event of radioactivity in the RB atmosphere and an excessive RB leak rate, all available RB coolers should be operated to reduce the pressure and thus reduce the radiation leakage. The RBS can also be used to reduce pressure and remove iodine from the RB atmosphere prior to a RB pressure of 10 psig in the event of a loss of RB integrity. The RBS is capable of primary containment atmospheric cleanup with either train in service. The primary containment may also be cleaned up by purging via either train of the SCACS. In the event of primary containment leakage to the auxiliary building (Zones A&B), the Auxiliary Building ESF Zone Environmental Control System Air Cleanup Units can be used.

2.3.5 Reactor Building Water/Emergency Sump Level

The best method of detecting an improper RB water or emergency sump level is by level instrumentaion. Another indication of low sump level is loss of suction and cavitation of a pump taking suction from the emergency sump. Valve lineup, suction fluid temperature, flow rates, etc., should be checked since these symptoms may be a result of a variety of causes. The level of the BWST after ECC injection is also an indication of sump level.

Detection of a high RB water level by other than level instrumentation is more difficult and may not be confirmed until submerged equipment is damaged. The volume of borated water in the BWST is designed to provide the correct RB water level for recirculation cooling when the BWST is drained to the low level for ECC pump switch over to the RB emergency sump.

Therefore, high RB water level should not be a problem unless additional water has been added to the reactor building. If this additional water was nonborated, then there will be indication of boron dilution in the RB sump.

2.3.5.1 RB Water/Emergency Sump Level Control

The water level should be maintained high enough for LPI or reactor building spray recirculation flow (NPSH), but not so high that it submerges equipment important to core heat removal or reactor building control. If the water level is at the low level limit, more borated water should be added. The operator should also check for a steam generator tube rupture or some other possible source of water loss such as inadvertent pumping or draining from the sump or break in LPI or spray recirculation line.

If water level becomes too high, consideration of lowering it should be made depending on the core cooling method being used (sump recirculation or DHR). The amount of radiation in the sump

must also be considered before attempting to remove any of the sump water.

The reactor building water/emergency sump level should be kept between the values shown in Table 8 when recirculating from the emergency sump.

2.3.5.2 RB Water/Emergency Sump Level Control With Equipment Failure

Each DHR pump can only take suction from its respective sump. In the event of a clogged sump screen following a LOCA or failure of one of the RB emergency sump valves to open, the remaining decay heat removal train provides a redundant flow path for recirculation of sump fluid.

2.4 Reactor Building Integrity

Reactor building integrity exists when the RB functions as a barrier against radiation release as required by the design basis.

A loss of RB integrity may be caused by a loss of either primary or secondary containment integrity or both. Some causes include structural failure, equipment failure and/or personnel error.

The effects of a loss of RB integrity may include an immediate and excessive release of radiation or it may create other conditions such as inadequate core cooling which can then result in excessive radiation release.

The basic objectives of RB control are directed towards maintenance of RB integrity. The first step in mitigating a loss of RB integrity is the detection of it. Once a loss of integrity is detected, the operator should attempt to determine and correct the exact cause if possible and at the same time treat the symptoms. In the event the cause is not corrected, the symptoms can continue to be treated.

2.4.1 Detection of Loss of Integrity

Five types of leakage paths have been identified which could result from a loss of primary or secondary containment integrity:

Type A - Type A leakage is from the Auxiliary Building into the annulus. This includes the following:

1) Equipment hatch secondary containment sleeve,
2) Annulus access door,
3) Containment purge supply and exhaust isolation valves outside of secondary containment. The possible leakage is through the valves (and leakoffs) into the annulus,
4) Secondary containment penetration seal leakage.

Type B - Type B leakage paths are from the Primary Containment to the annulus. Type B leakage includes the following:

1) Equipment hatch double O-ring, and
2) Containment purge supply and exhaust inboard and outboard containment isolation valves. The leakage will pass through the leakoffs and into the annulus.

Type C - Type C leakage is leakage from uncontrolled environments into the annulus. Type C leakage includes leakage from the main steam and feedwater lines annulus seals.

Type D - Type D leakage paths cover the through-line leakage from the Primary Containment to the Auxiliary Building. Included in this type of leakage are the lines associated with the safety systems required for post-LOCA operation, such as Containment Spray, DHR, High Pressure Injection Systems, and RB sump drains. Steam generator tube leaks which leak through the secondary side to atmosphere are included in Type D.

Type E - Type E leakage paths are paths from the containment that bypass the annulus and leak directly past a cleanup system. The personnel lock is a possible source of bypass leakage.

Types A, B, and C leakage would produce a higher flow rate from the Secondary Containment Air Cleanup System (SCACS) to the

station vent and, depending on leak rate, might reduce the vacuum in the annulus. The pressure and radiation level in the primary containment and the auxiliary building as well as the radiation level in the annulus can provide clues to the leak source.

Type D leakage would likely produce higher temperatures and/or radiation levels in the auxiliary building. Other symptoms would be loss of RB sump level, SGTR, and increased auxiliary building sump levels.

Type E leakage would result in increased area radiation levels.

2.4.2 RB Control With Loss of Integrity

The response to a loss of integrity is dependent upon the type of leakage:

Types A and C - The immediate concern should be maintaining a 1 inch H_2O vacuum in the annulus. The annulus purge supply system should be throttled if necessary. The annulus should be sampled to help determine the leakage source and the source should be isolated if possible.

Types B, D, and E - All RB coolers should be operated to maintain RB pressure near atmospheric. (01)

For SGTR events, the first course of action should be an attempt to cooldown the affected SG by steaming via the condenser (if available), and relieving fluid as necessary via the drains to the RB sumps to maintain a level in the SG. If this method cannot be utilized, then the affected SG should be isolated, and the secondary side filled to stop the leak. Other leaks should be isolated as conditions permit. If the radiation monitoring system continues to indicate an excessive radiation release rate from the RB, then the reactor building spray system should be operated, (see Table 7).

3.0 DISCUSSION OF SOME ABNORMAL TRANSIENTS

The preceding discussion has emphasized the LOCA. This section will first add some additional discussion on RB control with inadequate core cooling (ICC) or a steam line break (SLB).

Finally, some aspects of RB control as it relates to the 3-28-79 accident at the TMI-2 plant and the 2-26-80 transient at the CR-3 plant will be discussed.

3.1 Inadequate Core Cooling

The symptom of inadequate core cooling (superheat in the core) is an expected result of a large (> .5 ft^2) LOCA. Under these conditions, however, the ECCS should automatically mitigate the ICC and recover the core with very little Zr-water reaction. ICC is not an expected part of any other abnormal transient and its occurrence means that the equipment has not operated according to the design basis, either as a result of personnel error or of multiple equipment failure.

Discussion of ICC is usually associated with recovery from a small LOCA, however ICC conditions can be postulated to result with no RCS boundary break. An example is a total loss of feedwater coupled with no operator action. Mitigation of ICC includes opening the PORV and high point vents and releasing steam, water, radioactivity and H_2 to the RC drain tank and the RB. During the

the most severe stages of ICC (See Part I, Figure 3, Regions 3 and 4), a large amount of hydrogen may be generated by the zirconium-water reaction in the core. This hydrogen will be vented to the RB through the high point vents. This generation of hydrogen may very well exceed the cladding reaction assumed for the design LOCA. This can occur within hours in contrast to the weeks required for the radiolytic component of hydrogen to peak. Thus hydrogen control becomes a very important part of reactor building control following an ICC event. The hydrogen recombiners should be started as soon as there is any indication of ICC.

For some ICC conditions the H_2 recombiners may not be sufficient. Since ICC can be accompanied by high radiation, the backup hydrogen control by purging may not be feasible.

It is very important to sample the RB H_2 concentration soon after an ICC condition is detected and to continue to closely monitor H_2. However, if ICC occurs, H_2 release to the RB can be very rapid, and it should be assumed that mixing cannot occur regardless of the equipment that is available. High, combustible concentrations can develop within hours.

The RBS should be started at a clad temperature equivalent to 1800F. These actions should take place even if the H_2 analyzer

samples do not indicate high concentration. The reason is that H_2 can be released too rapidly to allow homogeneous mixing and representative sampling.

Following recovery from ICC, the venting of H_2 from the RCS to the RB should be controlled to prevent exceeding 3.5 vol. % of H_2 in the RB unless this venting is essential to maintain adequate core cooling.

A severe case of ICC (Region 4) may also result in a large radiation release to the RCS, the RB atmosphere and RB sump. Recirculation into the auxiliary buildings should be minimized under these conditions. If RCS inventory is under control, then an alternative to sump recirculation or DHR system operation is steam generator cooling until the sump radiation levels are allowed to decay.

3.2 Steam Line Break (In RB)

Following a double-ended main steam line rupture inside primary containment, both steam generators will blow down causing a reactor coolant system (RCS) cooldown and depressurization. High primary containment pressure caused by the steam line rupture initiates ESFAS closure of the main feedwater (MFIV) and the main steam isolation valves (MSIV), unless single failure is assumed. With closure of the main steam isolation valves, the unaffected

steam generator will repressurize. Auxiliary feedwater will be fed to both steam generators unless ESFAS determines that a steam generator has depressurized and remains below 600 psig while the other steam generator has repressurized to above 600 psia. If both SG's are below 600 psig, a FOGG signal will allow feeding of only the SG with the higher pressure, if the pressure differential between the two SG's exceeds 150 psid. Auxiliary feedwater will then be isolated from the one depressurized steam generator. If the ΔP between the two SG's is less than 150 psid and both SG's are less than 600 psig then both SG's should be fed. Heat removal from the reactor system then continues with auxiliary feedwater flow and steam relief through the main steam safety valves.

A steamline break inside the RB will release superheated steam into the RB atmosphere. Consequently, when the reactor building air is heated up and the steam is cooled, the two will equalize at a temperature high enough to maintain superheated vapor in the reactor building atmosphere. It will not approximate the steam saturation curve as does the LOCA. If the RBS is actuated, the RB pressure and temperature will later tend to approximate the steam saturation curve.

If there is a tube rupture in the SG with the leaking steam line, then RB control is very similiar to that with a SB LOCA. RB atmospheric cooling is accomplished with the RB emergency coolers

except for the larger steam line breaks. The larger steam line breaks may result in RBS actuation with a high water level in the RB. The DH drop line valves will be required to open prior to going on DHR system cooling. If these valves are submerged, then they may not open. This situation is somewhat different than that for a LOCA, since for a LOCA, RB sump recirculation is used until the RCS is depressurized, except for the smaller SB LOCAs. A high RB water level is not expected for these smaller SB LOCA. The RBS should be shut off after a SLB prior to submerging the DH drop line valves.

Figure 40a is predicted containment pressure and Figure 40b is predicted containment vapor temperature for a 32 inch double ended SLB (Figures 40a and 40b supplied by TVA). (04)

3.3 TMI-2 Accident of 3-28-79

3.3.1 RB Pressure and Temperature

Figure 41 is a diagram of the RB pressure and temperature during the first 20 hours after the accident. The PORV was stuck at least partially open during much of the accident. The PORV block valve was closed at approximately 2 hours after turbine trip and the RB temperature dropped off rapidly. The PORV block valve was later reopened and reclosed several times which caused most of the RB temperature cycles between 120 and 180F. RB isolation was

actuated at ~4 hours. The H_2 burn produced a 28 psig spike which actuated the RBS. The RBS stayed on several minutes and reduced RB temperature from ~170F to ~140F.

3.3.2 Hydrogen

The amount of hydrogen that was estimated to be in the TMI-2 reactor coolant system is shown in Figure 42. It can be seen that 173,000 SCF was generated in the period between 2 and 4 hours after the accident. At least 63,000 SCF was released into the containment and burned approximately 9 hours 50 minutes after the accident causing the 28 psig pressure pulse inside the reactor building. The remaining hydrogen was slowly removed from the RCS over the next several days by a combination of either venting the pressurizer into the containment, degassing the letdown flow in the makeup tank or by a small leak in the area of the control rod drives. The hydrogen concentration in the reactor building subsequently reached a maximum concentration of 2.3 volume percent on April 3rd (6 days after the accident). A 95 CFM recombiner operated frequently during the period of April 2nd to May 1st and slowly reduced the hydrogen concentration to about 0.8 percent. Estimates of the total Zr-water reaction range from about 35 to 50% of the fuel cladding. (This is in contrast to the 5% assumed for the maximum hypothetical accident (MHA) at Bellefonte.)

It can be seen that even if all of the plant's waste gas storage tanks were empty, they could only accommodate a small fraction of the hydrogen generated. The hydrogen, while in the reactor coolant system, did not present an explosive hazard. While the RCS pressure was high, the hydrogen occupied a relatively small volume (e.g., 173,000 SCF = 2125 cu. ft. @ 220 psig and 450F).

3.3.3 Equipment Failure in RB

One of the TMI-2 area radiation monitors inside the reactor building, the personnel hatch monitor, was removed during one of the first post-accident reactor building entries for analysis. The results of the analysis showed that a rubber boot on the instrument's cable connect was not on securely; therefore, when the reactor building sprays were on, a drop of water caused a short between two high voltage connections.

The TMI-2 dome monitor also failed. Failures that leave the indicator needle on scale are particuarly confusing because they often indicate believable values (e.g., TMI-2 dome monitor indicated a constant 40 R/h after about 2 months of decay, see Figure 43).

A similar problem arose during a different open PORV incident at CR-3 caused by the loss of power to the non-nuclear instrumentation. Since the power supply was a -10 V to +10 V system, the

loss of power produced 0 V, which corresponded to a mid-scale reading. The mid-scale reading is usually very close to the normal reading for that process variable, so the operators have difficulty identifying which instruments are functioning properly and which have failed.

3.3.4 Reactor Building Radiation

Figure 43 shows the dome monitor readings following the TMI-2 accident. Several interesting features are shown in this figure.

1. The large dose rate reduction produced by the reactor building sprays.
2. The large increase in dose rate between March 29 and April 2 when the RCS was degassed by venting steam to the reactor building.
3. The increase in dose rate on April 6, when the waste gas tanks were vented into the reactor building.
4. The series of linear decreases in dose rate indicating exponential removal rates, which surprisingly did not relate to radioactive decay but rather to other removal processes (e.g., the large decrease on or about May 1 seemed to relate to operation of the reactor building coolers).
5. The constant dose rate, about 40 R/h, after May 15, is indicative of instrument failure.

The vast majority of the dome monitor reading initially was from Xe-133. A containment gas sample (corrected to 0700, March 31, 1979) contained 755 Ci/ml of which 751 Ci/ml was from XE-133g and X-133m. By April 3, 1979, the containment sample had decayed to 29 Ci/ml. Experience has shown (including TMI-2) that the amount of idoine release from the RCS during an accident is orders of magnitude lower than that assumed in the safety analysis provided the release pathway is not dry. The indications are that the solubility of iodine compounds in water (or steam) is much greater than assumed. Measurements showed that only about 2000 Ci of I^{131} were released to the TMI-2 RB atmosphere. This represents only 0.003% of the core inventory. In contrast, about 20% of the core I^{131} inventory was released to the RB sump.

3.4 CR-3 Transient

Figure 44 shows the response of the reactor building dome monitor following a February 26, 1980, transient at the CR-3 plant site. The detector is unshielded and thus showed the correct dose rate response relative to the other detectors in the reactor building. There are several important observations that can be made based on Figure 44.

1. The fuel handling bridge monitor was reading about a factor of 500 lower than the reactor building dome monitor. Apparently, the hot steam and air carried the activity to the top of the

reactor building, thus, even though the bridge monitor and dome monitor were both exposed to large gas volumes in the reactor building, there was not enough mixing to prevent radiation dose rates being several orders of magnitude different.

2. The reactor building incore instrument area monitor responded to the decay of the N-16 activity immediately after reactor trip, then eventually climbed to correspond to the dome monitor reading. The decrease in both the dome monitor reading and the reactor building incore instrument area monitor reading corresponds to the mixing rate provided by the reactor building fan-coolers.

3. The core was properly cooled so that no core damage occurred. However, a large amount of radioactive material was released which caused a significant change in the reactor building radiation monitor readings.

4. The reactor buildings at both TMI-2 and CR-3 had significant radiation concentration gradients for several hours and therefore the assumption of a well mixed building atmosphere cannot be justified on the basis of the fan-cooler operation until several hours after a LOCA.

TABLE 7

SUMMARY OF REACTOR BUILDING ISOLATION CONTROL ACTIONS

PARAMETER	LIMIT	CONTROL ACTION
High RB Pressure or Low RCS Pressure	$\geq$ 4 psig $\leq$ 1700 psig	- Verify penetration of non-safety fluid systems are isolated.
High RB Radiation	(By TVA)	- Verify penetrations to the RB atmosphere are isolated.
High RB Pressure	$\geq$ 4 psig	- Verify that CCW penetrations are closed. (01)
Loss of Primary Containment Integrity	Radiation Release Rate $\geq$ c/sec (By TVA)	- Maintain 1 inch H_2O vacuum in the containment - Operate the RB coolers to maintain minimum pressure. - For SGTR, fill the SG secondary. - Sample to determine the leakage source and isolate if possible.

TABLE 8

SUMMARY OF REACTOR BUILDING INTERNAL ENVIRONMENT CONTROL ACTIONS

PARAMETER	LIMIT	CONTROL ACTION
High RB Pressure	> 4 psig	Verify 3 RB coolers start in the emergency mode.
High High RB Pressure	> 10 psig	- Verify 2 RB spray systems start. - When RB pressure returns to 4 psig, and is decreasing, stop spray.
High RB Temperature	> 120F	- Start RB coolers as required to maintain RB temperature below 120F.
High RB Temperature	> (By TVA)	- Operate the RB Spray system as required to maintain RB temperature below this limit.
High RB Hydrogen	> (By TVA)	- Start the hydrogen mixing fans and the RB fans to mix the RB atmosphere. Start the H_2 recombiners.
High RB Hydrogen	> 3.75 vol%	- Run all RB fans continuously. Start continuous RB purge if RB radiation level is < (By TVA).

TABLE 8 (Cont'd.)

SUMMARY OF REACTOR BUILDING INTERNAL ENVIRONMENT CONTROL ACTIONS

PARAMETER	LIMIT	CONTROL ACTION
		- Maintain the RB pressure as low as possible with the RB coolers. Do not vent H_2 from the RCS unless it is necessary to establish or maintain adequate core cooling.
High RB Hydrogen	$\geq$ 4.0 vol%	Start one train of the RB Spray System.
H_2 Burn in RB	(By TVA)	- Start RBS System. (0 - Stop containment purge if in operation. - Isolate containment atmosphere. - Sample H_2 and O_2 in containment. - Start all RB coolers.
RB Sump pH	8.5 to 11.0	- Add NaOH to RB sump to raise pH.
RB Sump Boron	(by TVA - ppm vs burnup)	- Add boron. - Check for nonborated fluid system leaks into RB. - Take actions to prevent boron precipitation in RCS. ((

TABLE 8 (Cont'd.)

SUMMARY OF REACTOR BUILDING INTERNAL ENVIRONMENT CONTROL ACTIONS

PARAMETER	LIMIT	CONTROL ACTION
High RB Radiation	(By TVA)	- Ensure adequate core cooling. - Stop hydrogen purge if in progress. - Operate RB coolers to maintain minimum RB pressure. - Sample the RCS. - Operate RB fans to keep the RB atmosphere mixed. - Close the RB sump drain valves - Operate the SCACS.
High RB Radiation Release Rate	μc/sec (By TVA)	- Atempt to stop the leakage as specificed in Table 7 - Operate RB Spray as required t stay below release rate limit. - Operate the SCACS.
High Level RB Sump	by TVA (elevation of equipment not to be sub-merged)	- Lower sump level if core cooli is assured and radiation level of sump water are less than (b TVA). - Check for other fluid systems leaking into RB.
Low Level RB Sump (When on sump recirculation)	By TVA	- Raise level to between low and high RB sump level limits with borated water.

TABLE 8 (Cont'd.)

SUMMARY OF REACTOR BUILDING INTERNAL ENVIRONMENT CONTROL ACTIONS

PARAMETER	LIMIT	CONTROL ACTION
		- Check for steam generator tube rupture.
High RCS Temperature (ICC)	> 1400F	- Start H_2 recombiners and all RB coolers.
High RCS Temperature (ICC)	> 1800F	- Start RB spray system.

Figure 32 GENERAL APPROACH FOR CONTROL OF THE REACTOR BUILDING

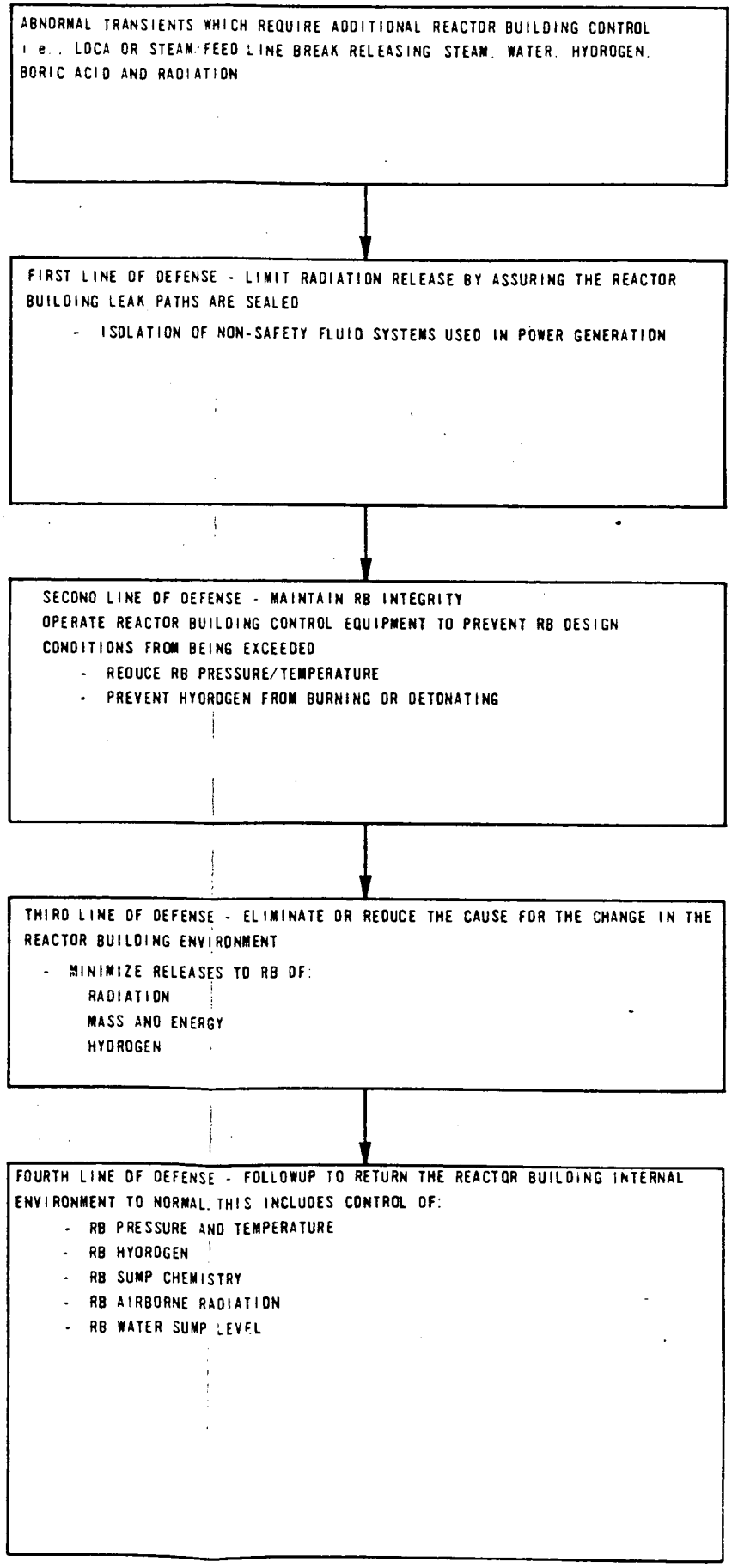

Figure 33 REACTOR BUILDING TEMPERATURE AND PRESSURE VS. TIME FOR 2.14 FT^2 DOUBLE-ENDED PUMP DISCHARGE BREAK WITH MIN. ECCS

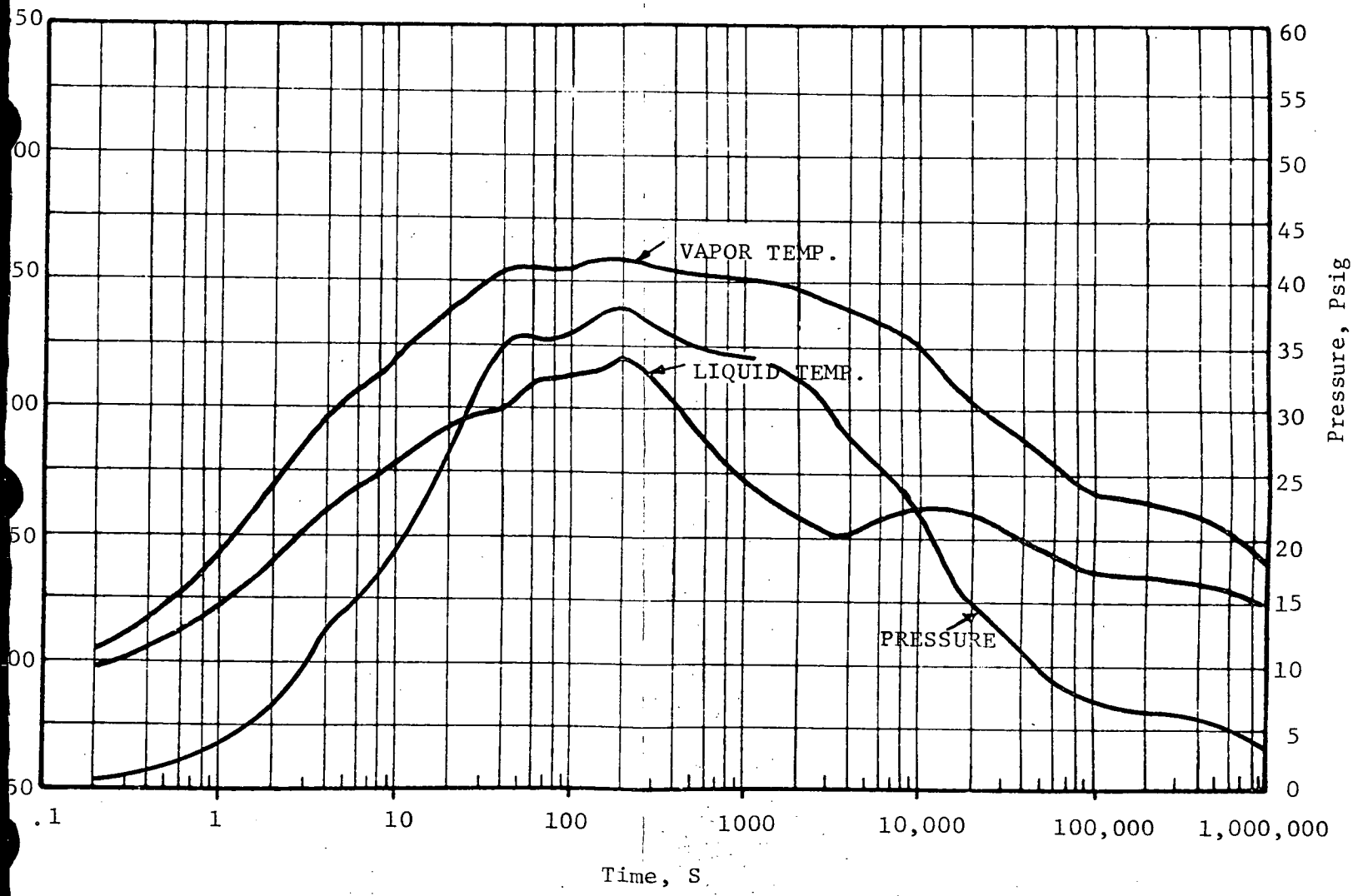

Figure 34 REACTOR BUILDING TEMPERATURE AND PRESSURE VS. TIME FOR 8.55 FT^2 DOUBLE-ENDED PUMP DISCHARGE BREAK WITH MIN. ECCS.

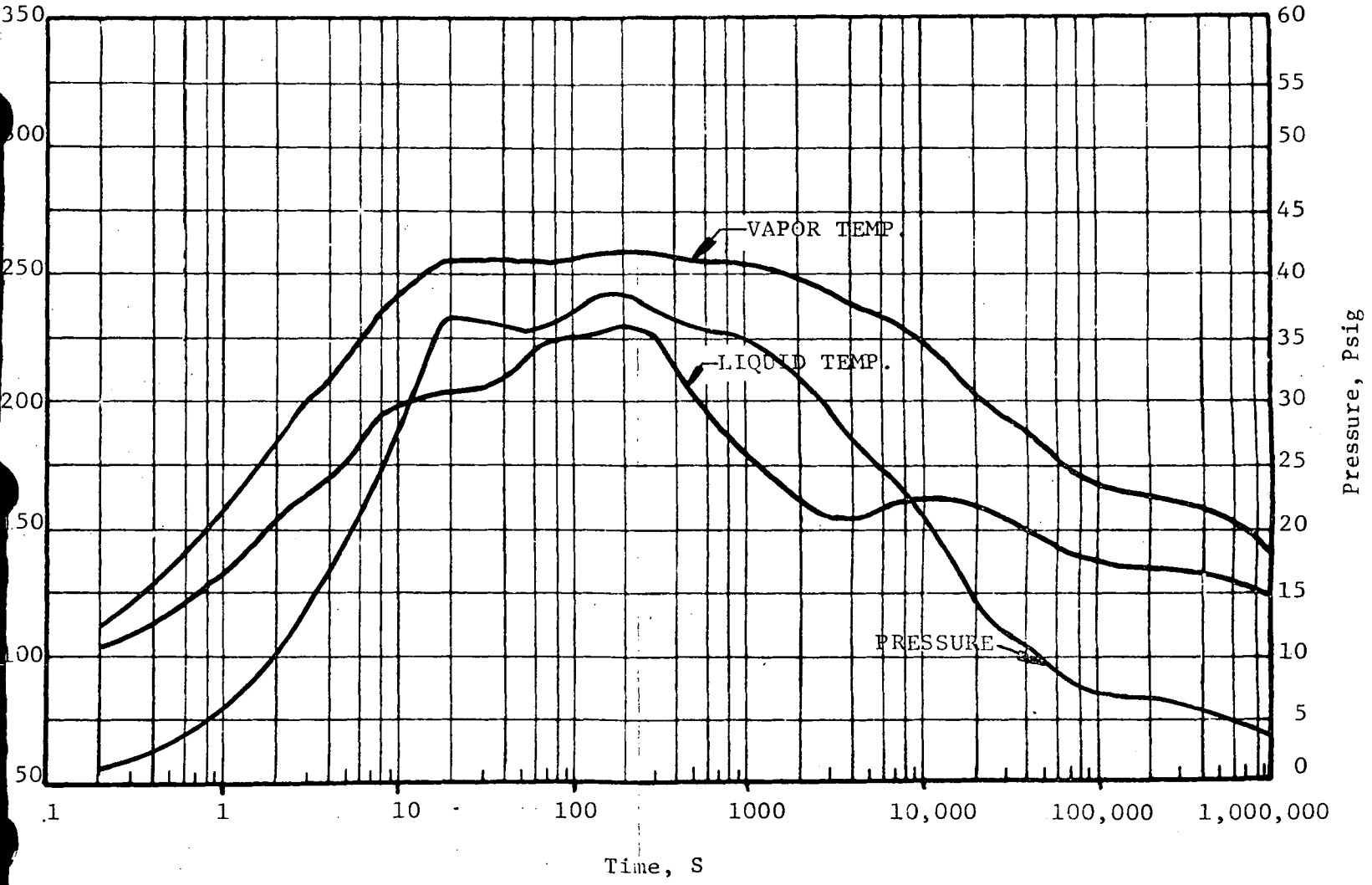

Figure 35 CONTAINMENT HYDROGEN BUILDUP AFTER LOCA

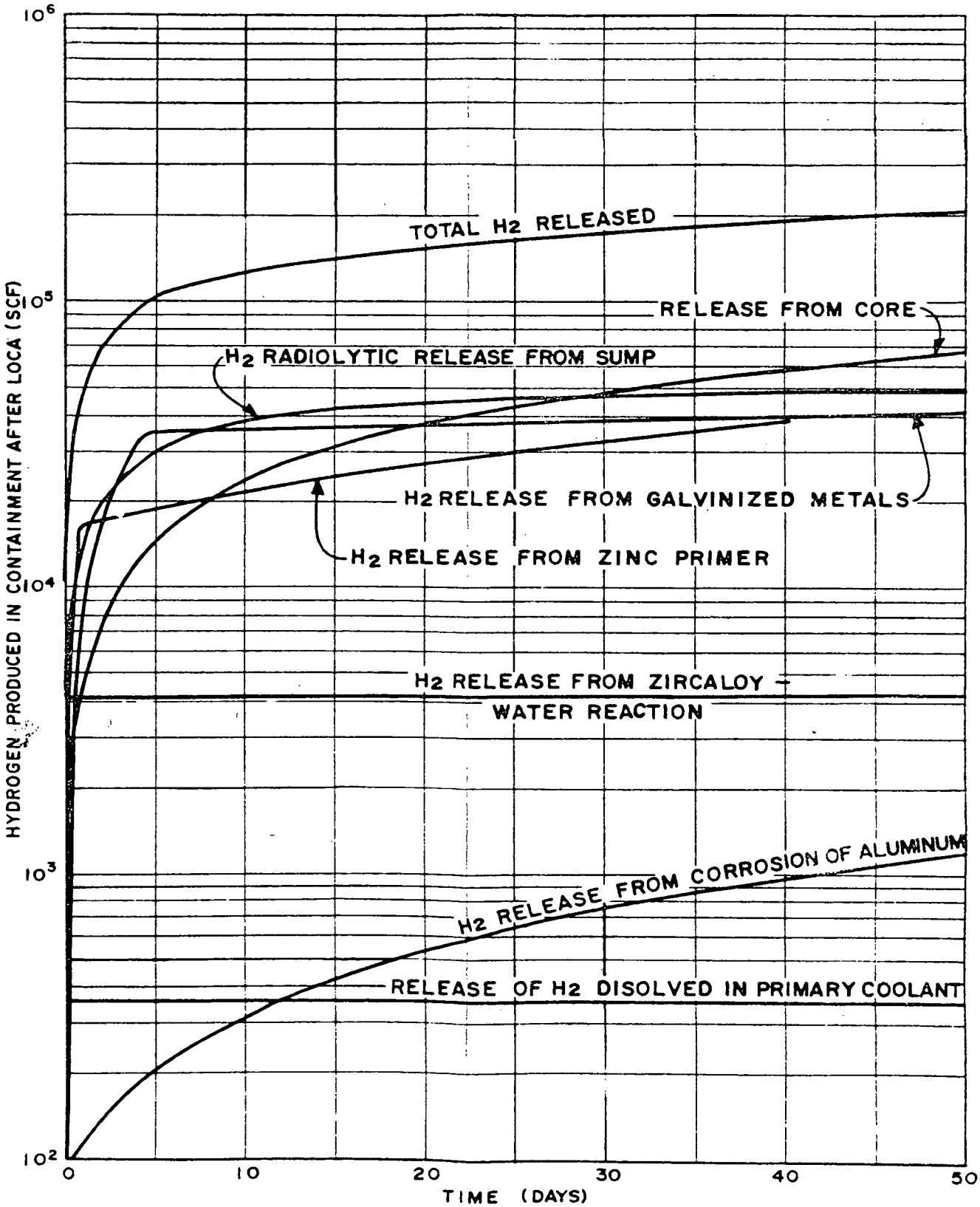

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Figure 36 FLAMMABILITY LIMITS OF HYDROGEN-AIR STEAM MIXTURES

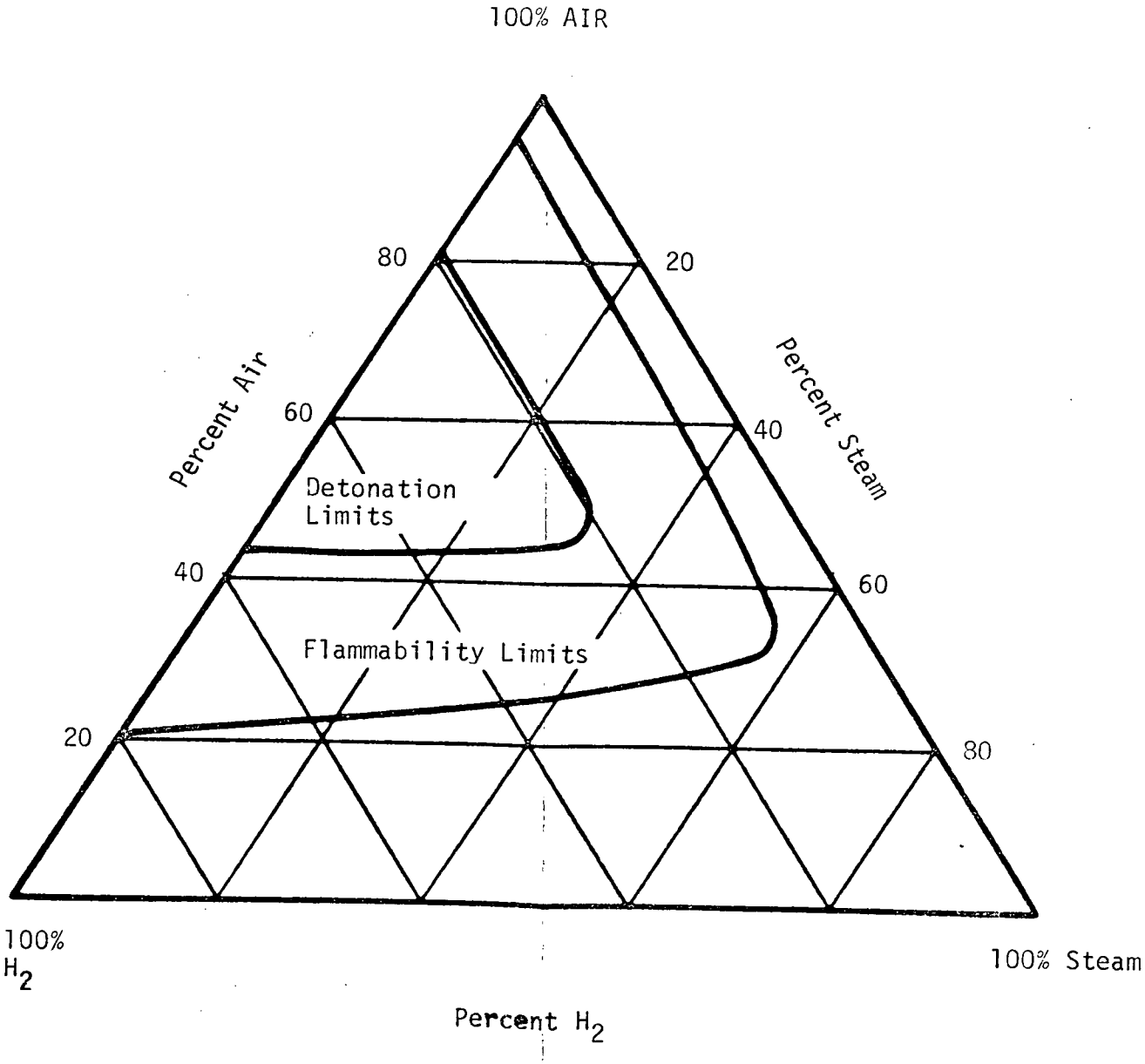

Figure 37 PRIMARY CONTAINMENT HYDROGEN CONCENTRATION AFTER LOCA

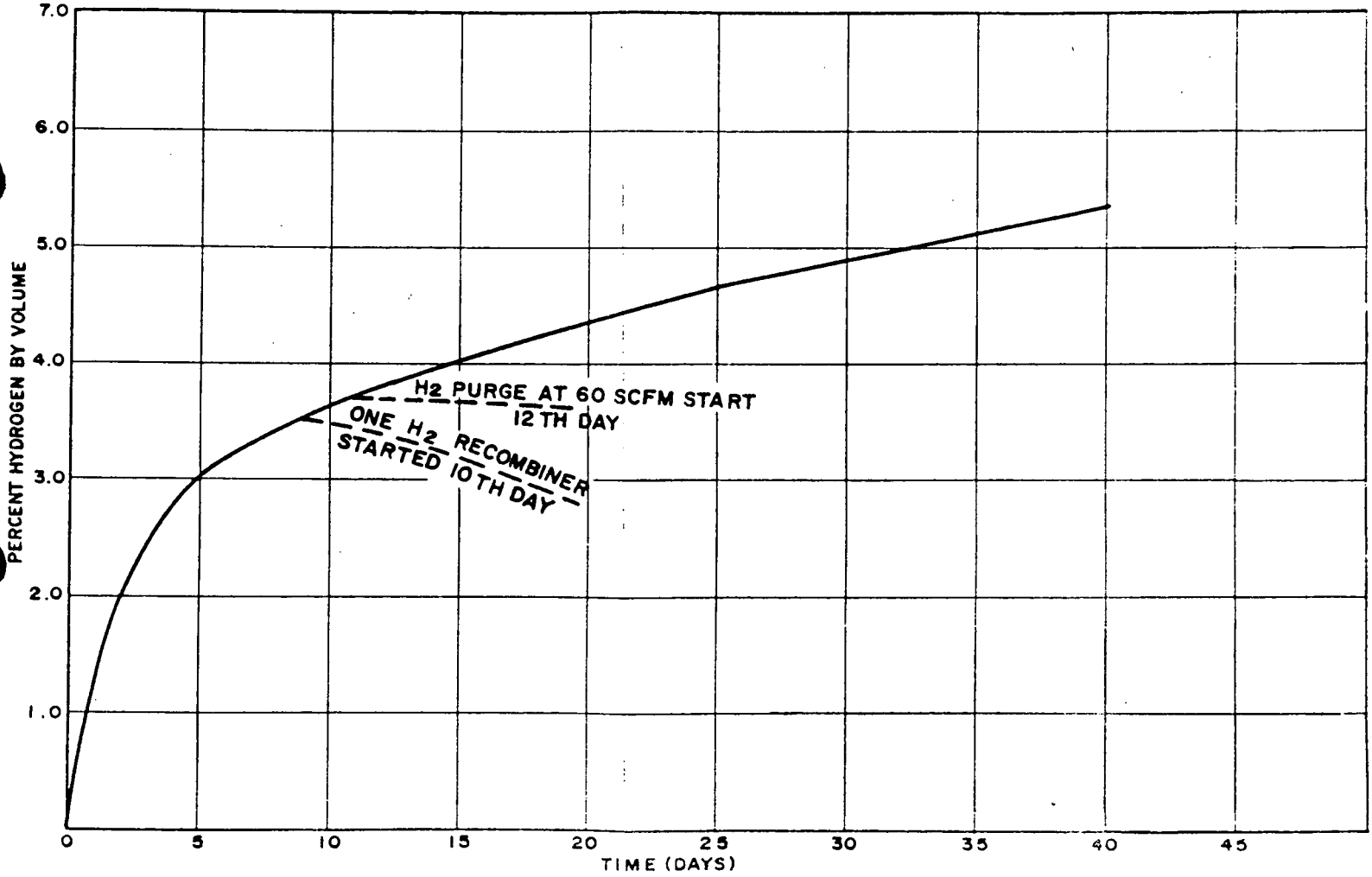

Figure 38 PRINCIPAL PROCESSESS AFFECTING PRIMARY CONTAINMENT HYDROGEN CONCENTRATION

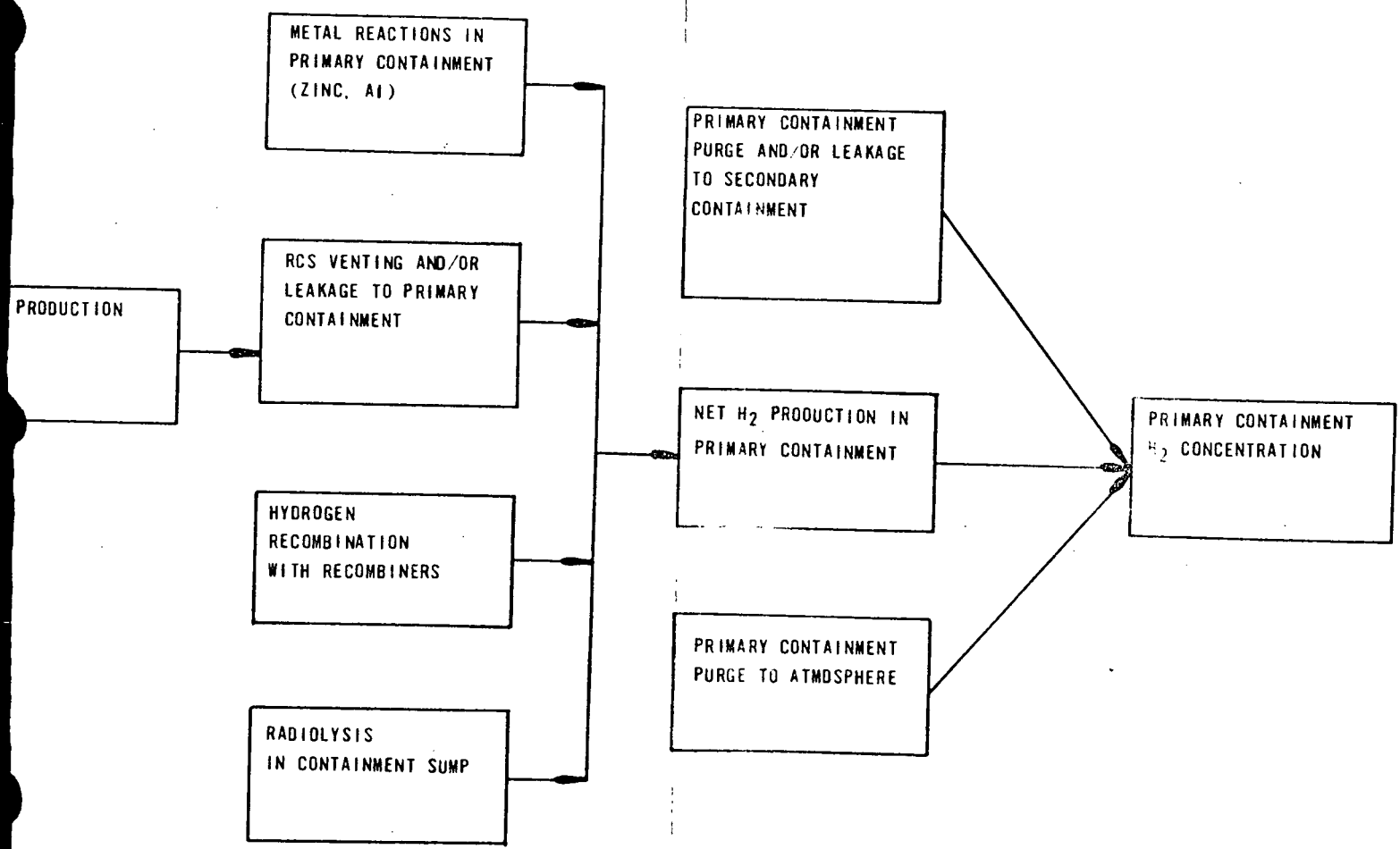

Figure 39 PRINCIPAL PROCESSES AFFECTING SITE DOSE

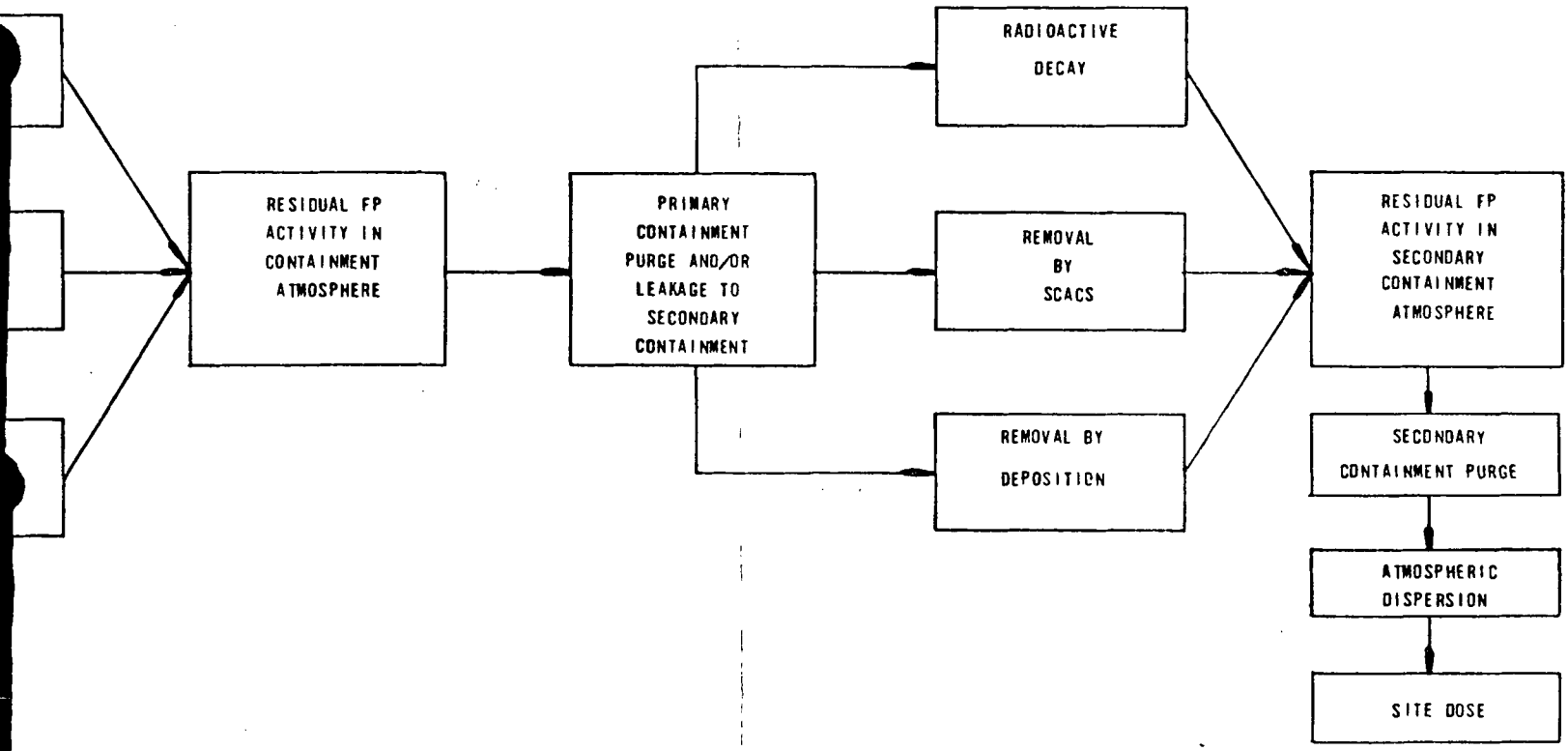

Figure 40A. PREDICTED CONTAINMENT PRESSURE RESPONSE FOR 32-INCH DOUBLE-ENDED SLB

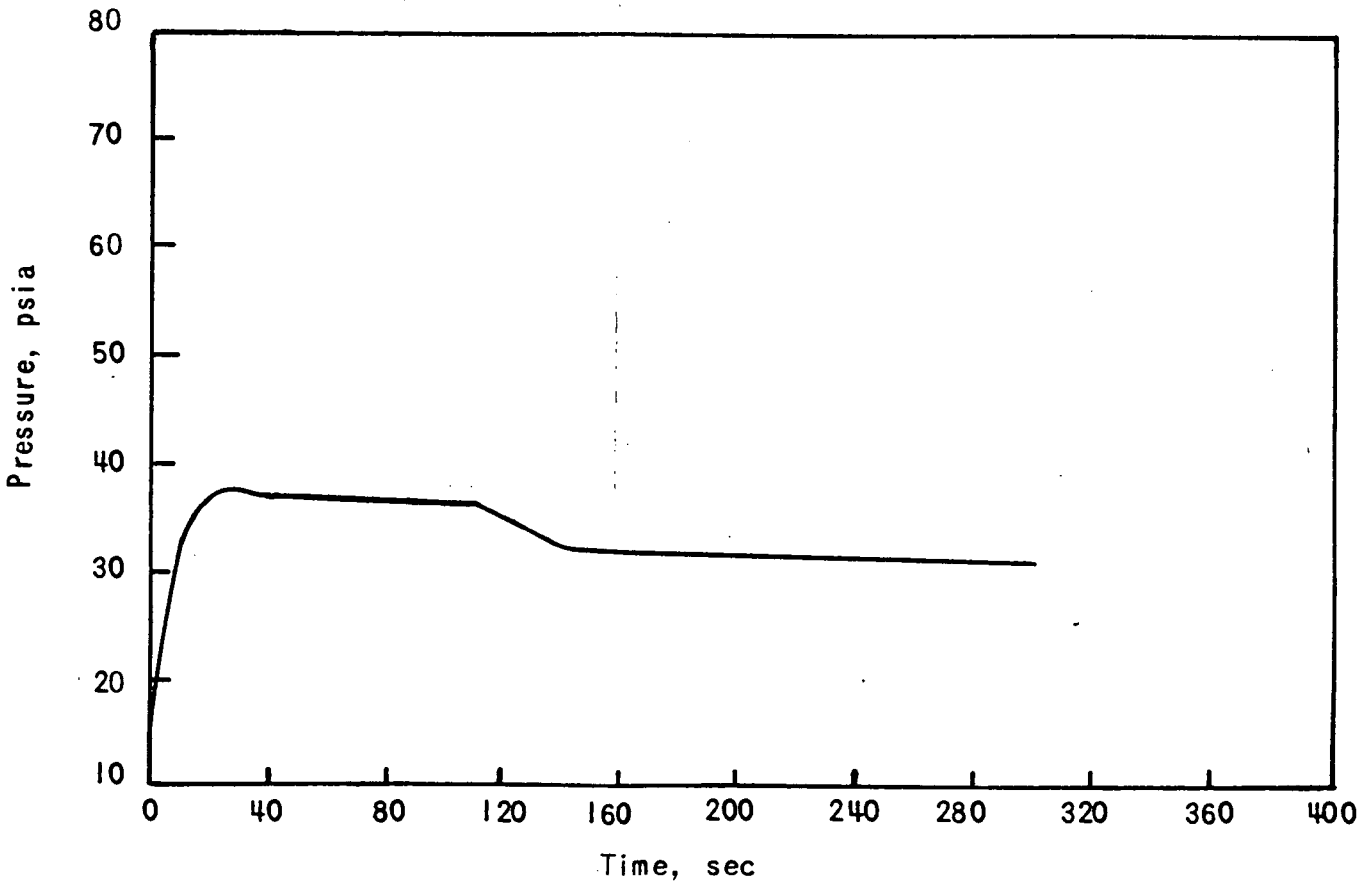

Figure 40B. PREDICTED CONTAINMENT TEMPERATURE RESPONSE FOR 32-INCH DOUBLE-ENDED SLB

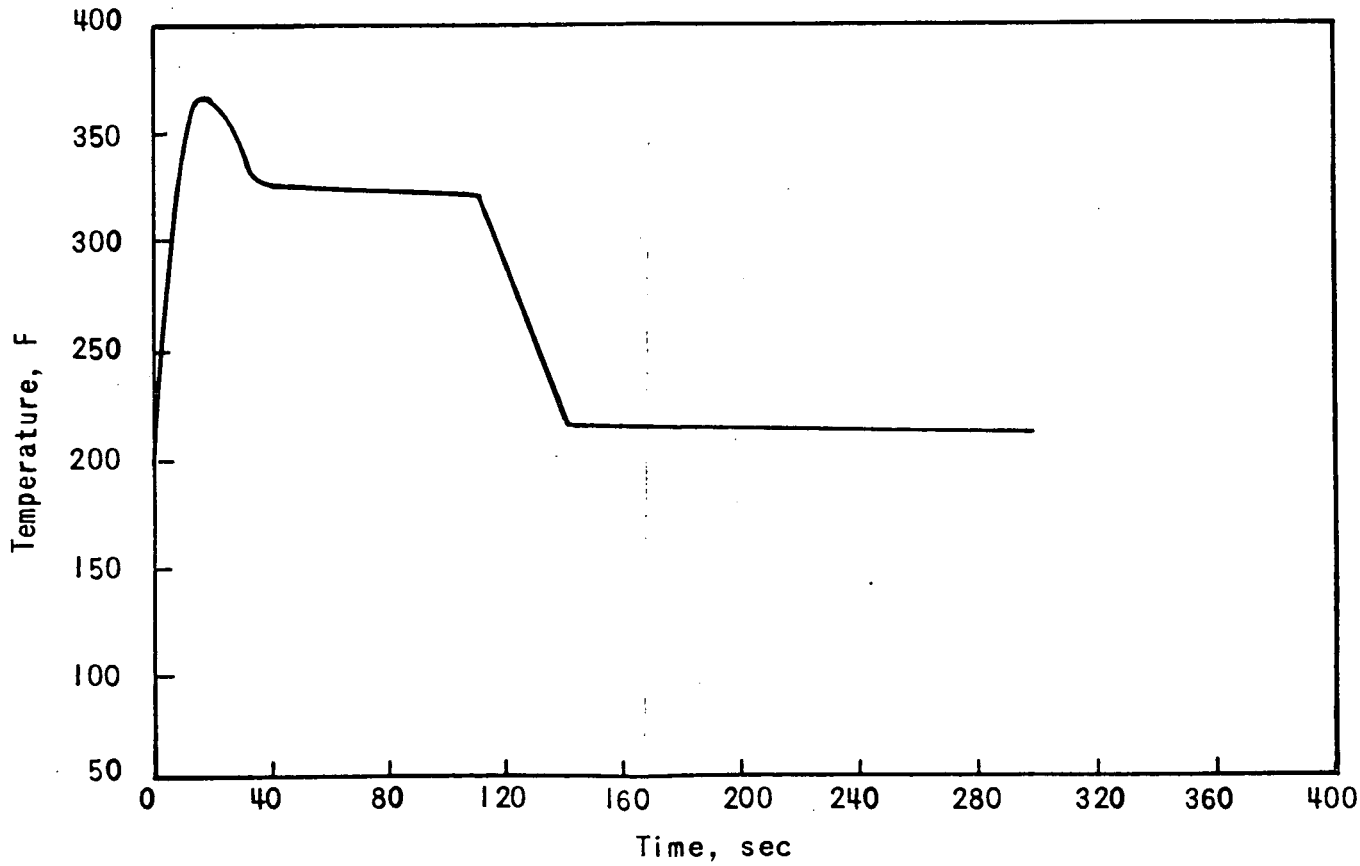

Figure 41 TMI-2 LOSS OF COOLANT ACCIDENT
3/28/79 REACTOR BUILDING TEMPERATURE
AND PRESSURE

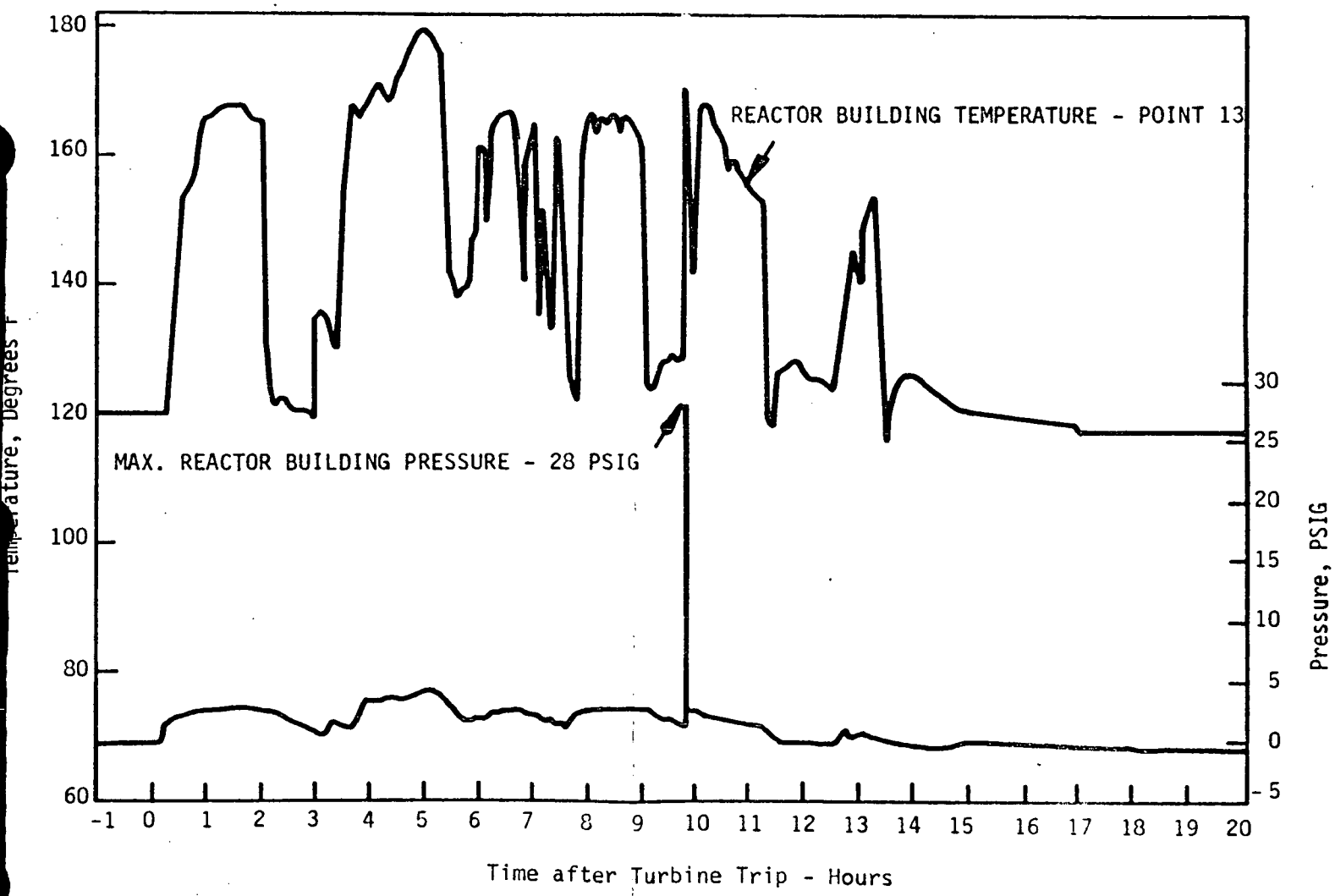

Figure 42 ESTIMATE OF TOTAL HYDROGEN VOLUME IN RCS OF TMI-2

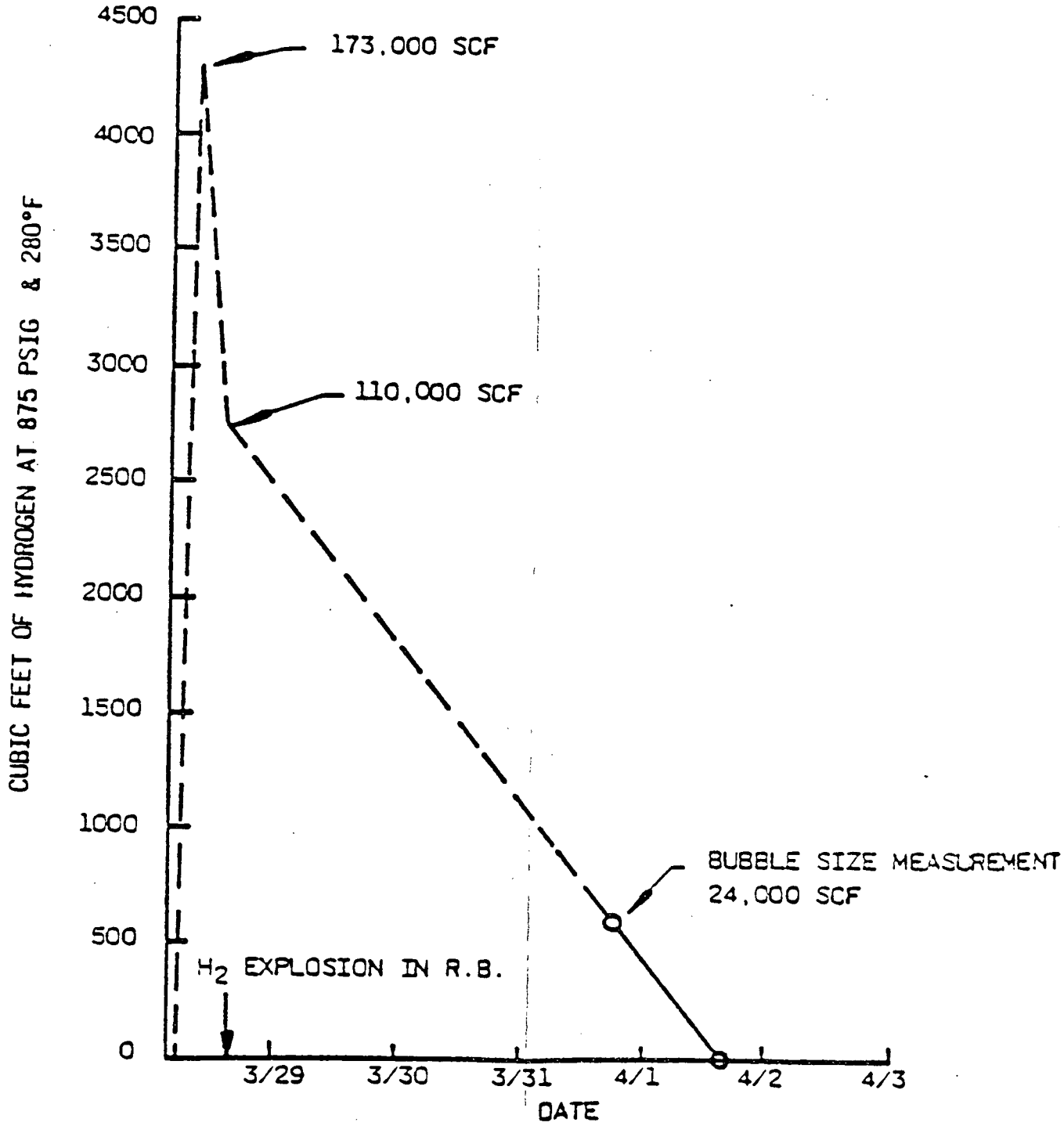

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Figure 43 TMI-2 DOME MONITOR READINGS

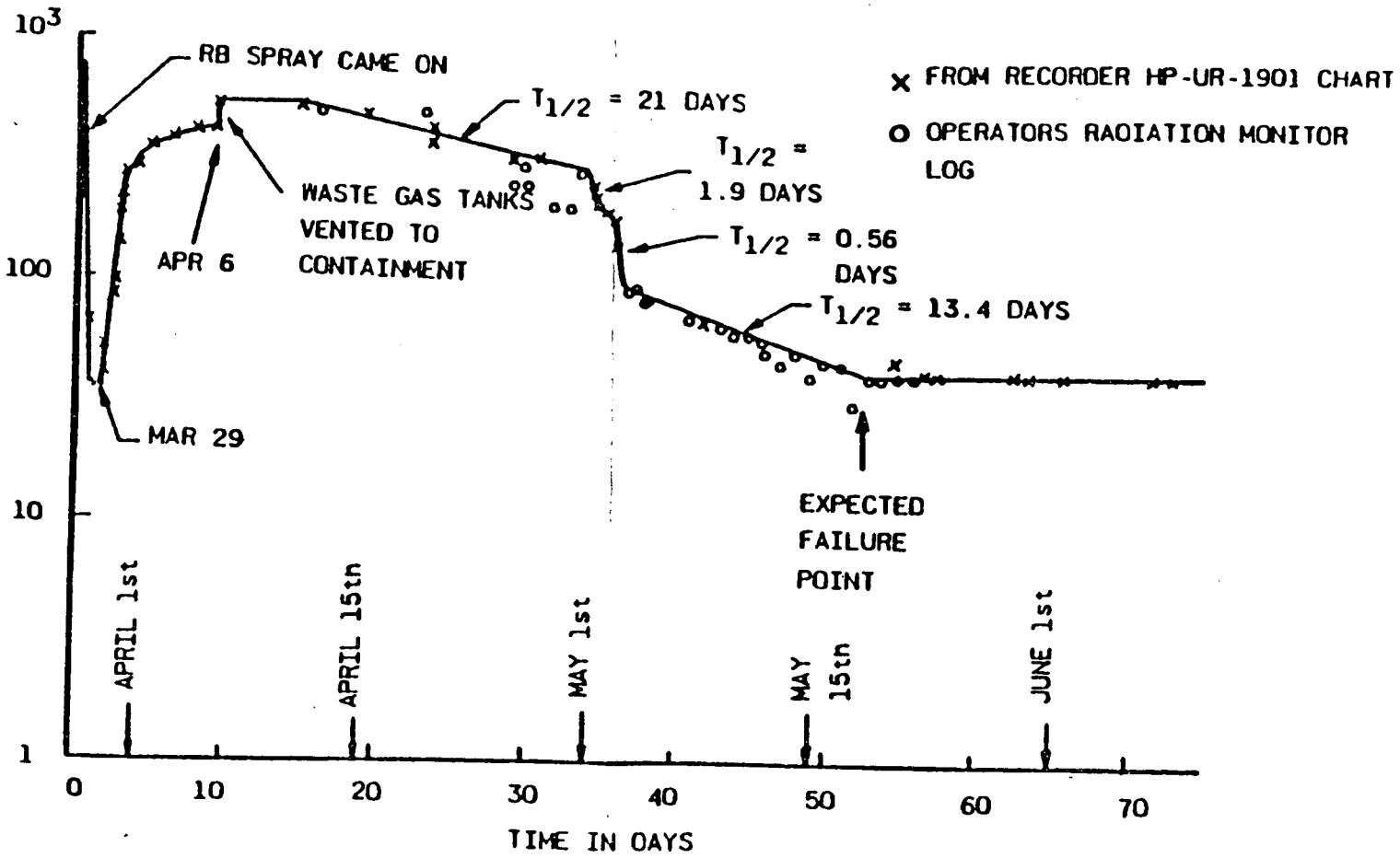

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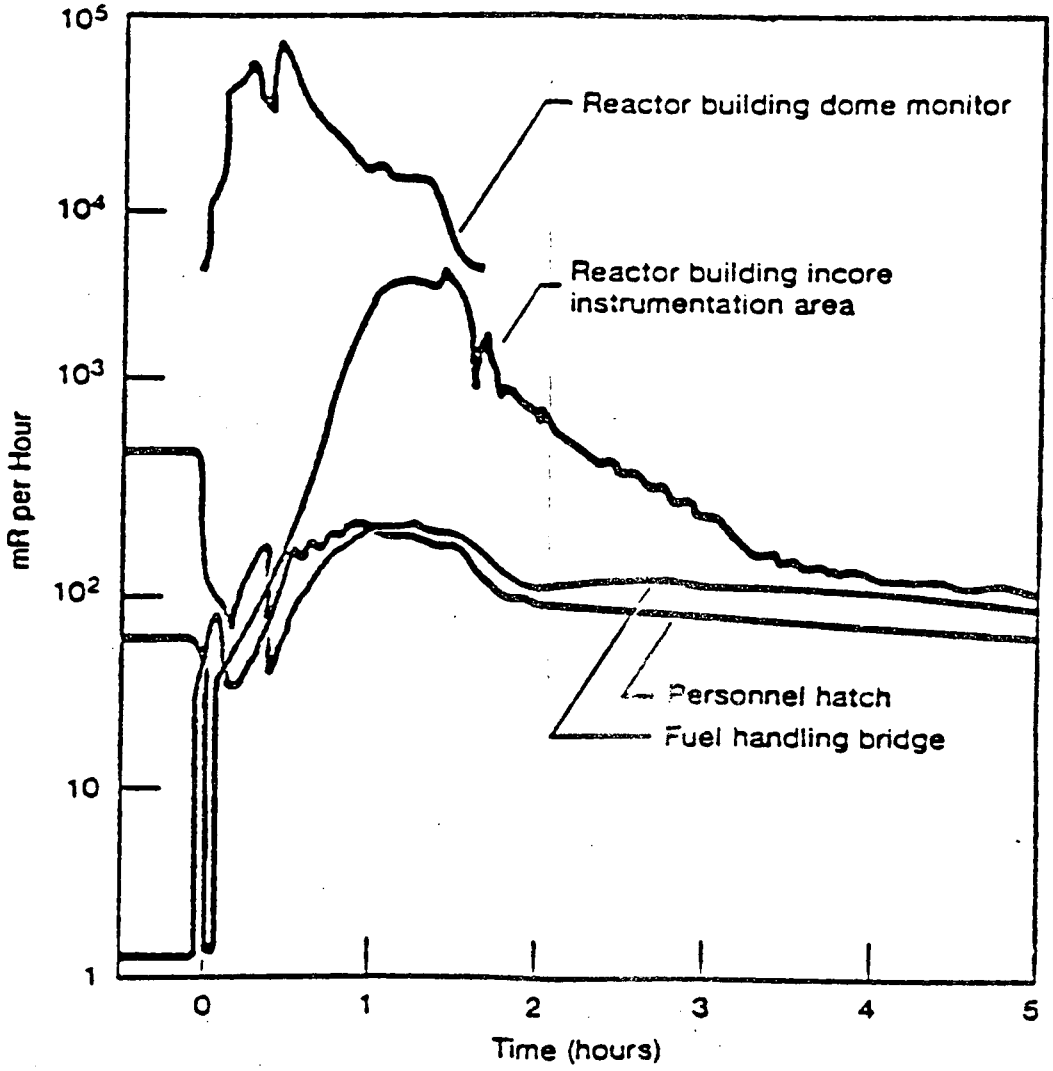
Figure 44 REACTOR BUILDING RADIATION MONITOR RESPONSE FOLLOWING THE CR-3 LOSS OF NON-NUCLEAR INSTRUMENTATION WITH HPI COOLING EVENT, 2/26/80



CHAPTER I (02)

INADEQUATE CORE COOLING

INTRODUCTION

Inadequate core cooling (ICC) occurs when the reactor coolant at the core outlet becomes superheated. When superheated, the fuel rods lack sufficient heat removal causing them to heat up and eventually undergo fuel damage. This will cause large amounts of radioactive gases to be released. Consequently, the plant should be controlled to prevent inadequate core cooling (ICC). However, should it occur, the operator should immediately take appropriate actions to restore adequate core cooling.

This chapter will discuss:

a) How to determine if the RCS is approaching ICC conditions,

b) Identifying and evaluating ICC conditions, (03)

c) The operator actions to re-establish adequate core cooling and

d) Post ICC cooldown.

Approach to ICC

Due to the redundancy of the reactor safety systems, multiple failures must occur before ICC becomes a possibility. Some scenarios which could cause ICC to develop are:

1. Small break LOCA with a total loss of the HPI system.
2. Total loss of feedwater (LOFW) (both main and auxiliary FW) with inadequate HPI to maintain core cooling.

In general, the strategy for getting out of an ICC condition is to identify and correct enough failures to provide adequate core cooling. In the meantime the operator will be doing whatever he can to increase core heat removal.

Inadequate core cooling (ICC) conditions occur when the core outlet temperature becomes superheated. To reach superheated conditions the RCS pressure-temperature conditions must first pass from a normal subcooled condition through the loss of subcooling margin region (Region 1 of Figure 20) to a saturated state. Next, with the RC pumps tripped (Automatic reactor coolant (03)
pump trip occurs on a coincident signal of loss of subcooling margin combined with either low RC pressure or high reactor building pressure. However, the operator is required to manually trip the RC pumps whenever the subcooling margin is lost.) and the RC saturated, sufficent RC inventory must be lost to start uncovering the core. RC inventory can be lost by a LOCA through a break in the RCS (LOCA) or out the pressurizer relief valves due to overheat- (03)
ing the reactor coolant. When the RCS water level goes below the top of the core, the fuel rods will not be adequately cooled. With insufficient heat removal, they will heat up and cause the core outlet temperature to reach superheat (or ICC) conditions. If the RC pumps fail to trip, the entire RCS will become saturated steam before the core outlet temperature becomes super- (03)
heated. A RCS level will not exist.

The various methods for identifying the approach to ICC are discussed below. Although the information provided by these methods is not a basis for

operator actions, it is available to provide the operator with advance warning that ICC is approaching. Once aware of the approach to ICC, the operator is able to prepare both himself and the plant for ICC, should it occur.

1. P-T Diagram

The best method to identify the approach to ICC is by plotting the RC pressure-temperature conditions on a pressure-temperature (P-T) diagram. (03) [This can be done on a CRT or on graph paper.] If the RCS condition is changing to ICC, the P-T diagram will show the transition from subcooling to superheat as described above.

The pressure coordinate of the P-T diagram should be obtained from the RCS hot leg pressure which is indicative of core outlet pressure. The core outlet temperature should be obtained from the incore thermocouples (T/Cs) because they provide a direct measurement of the core outlet temperature. Also they are the only valid measurement of core outlet temperature if there is no reactor coolant flow around the loop. Most likely, if ICC is about to occur there is no RC flow around the loop. The RC pumps would have been tripped on loss of subcooling margin and there is not enough RC inventory for natural circulation to develop.

2. Hot Leg Level Measurement System (HLLMS)
(Both wide range and narrow range)

The HLLMS provides the operator with a means of checking the RCS

inventory level in the hot leg. A level which decreases continously may indicate that ICC is approaching. The wide-range LMS and the narrow range LMS can be checked aginst each other for redundancy, provided the level is within the range of both. The HLLMS is not valid if:

a. Reactor Coolant Pumps are on. — If forced circulation exists, the HLLMS will measure a flow-induced pressure in addition to the elevation head, and the level indication will be inaccurate.

b. High point vent is open in the respective loop. — The reference leg sensor for the HLLMS is attached to the piping of the high point vent. If the vent is open, the reference leg will not provide a correct measurement of water head.

c. Dump to sump valve is open. — The lower sensor connection for the wide range LMS in one loop is connected to the dump to sump piping.

d. DHRS is in operation. — The lower sensor connection for the wide range LMS in the loop with the DHRS dropline is connected to the DHRS dropline. (03)

3. Reactor Vessel Level Measurement System (RVLMS)

The RVLMS provides the operator with information on the RC level in the reactor vessel upper head. The reference leg for the RVLMS attaches to the top of the reactor vessel head, and the lowermost sensor connection is approximately three feet above the top of the core. The RVLMS is not valid if:

a. RCPs are on.

b. The reactor head vent is open. -- The reference leg for the RVLMS is connected to the reactor vessel vent piping. (03)

4. Hot Leg RTDs

The hot leg RTDs, located just below the U-bend of each hot leg, detect hot leg temperature and may provide an indication of temperature trends in the core region. However, use of the RTDs during an ICC transient is limited to the following situation:

a. Incore T/Cs do not indicate superheat, and

b. One or more RCPs are on (or with RC pumps off, loop flow must exist from the core outlet to the RTD being used), and

c. a rapid RCS depressurization is not occurring.

Conditions (a) and (b) must be satisfied to ensure that circulation is occurring around the hot leg loops. Condition (c) is to avoid an erroneous indication of superheat. (03) The pressure indication will decrease as rapidly as the RC pressure does. However, the RTD indication will not decrease as rapidly as the RC temperature because of the slower instrumentation response time. Consequently, an indication of superheat can occur. However, during most SBLOCAs the RCS conditions change slow enough so that the RTD response time is insignificant relative to the rate of RCS depressurization.

In summation, the incore T/Cs in conjunction with RC pressure detectors are the primary indicator of approach to ICC because they provide direct measurement of temperature in the core region. The HLLMS, RVLMS, and hot leg RTDs can be used as a secondary source of information, to alert the operator that ICC may be occurring, or that the RCS is trending toward ICC.

However, just because the RCS is approaching ICC does not mean it will occur. The RC conditions may approach ICC conditions, then stop and even reverse without reaching ICC conditions. This behavior can be detected with the methods used to detect approach to ICC. The most important objective to prevent ICC is to keep the core covered. The core will be adequately cooled as long as the core remains covered with water. When the core is covered with water, the core outlet temperature will be either subcooled or saturated.

Inadequate Core Cooling

ICC is indicated when the reactor coolant pressure (RC hot leg pressure) and (03)
temperature (incore thermocouples) enter the superheat region. This condition should only occur without forced circulation because the RC pumps should have been automatically tripped (see Chapter E). When the RC pumps are off,
core cooling can be is accomplished by keeping the core covered with a steam- (03)
water mixture. If not enough cooling water is supplied to make up for losses, the core will become uncovered and the core exit fluid temperature will become superheated. If the RC pumps are operating, superheated

conditions imply that the reactor coolant is nearly all steam. That is, the liquid in the RCS has been lost, due to a leak in the primary system, and/or boiled off out the pressurizer relief valves by decay heat, and the steam mass left within the system is not enough to remove core heat even though it is circulated by the RC pumps.

If the RC pumps stop under these conditions, the RC inventory will settle out at a level far below the top of the core. This would cause severe ICC conditions.

Analyses have been performed which show the relationship between core exit steam temperature and fuel cladding temperature for various RC pressures (see Figure 20) when ICC conditions are present. (03)

The results of these analyses provide a series of curves on a P-T diagram of superheated core outlet temperature versus core outlet pressure. These curves divide the superheat region into three subregions. These are labeled as Regions 2, 3 and 4 on the P-T diagram of Figure 20. Region 1 is the sub- (03)
cooled region and the loss of subcooling margin region which includes the saturation curve. ICC occurs when Region 2 is entered (superheat conditions exist).

These regions can be used to indicate how serious the ICC situation is as described below.

Region 2 (Figure 20)

When the RCS pressure and temperature conditions are superheated but in Region 2 on Figure 20, an IGC condition exists but it is not severe enough to cause core damage.

Region 3 (Figure 20)

If the RCS pressure and temperature conditions reach Region 3 on Figure 20, the cladding temperature may be 1400F or higher.

In Region 3, the following can be expected to occur:

1. An increasing rate of fuel pin cladding swelling brought on by increasing internal gas pressures and weakening cladding structure as the cladding temperature increases. (03)
2. An increasing rate of reaction of the zircaloy cladding with steam (metal-water reaction) at cladding temperatures above approximately 750F°. This will add heat to the fuel rods increasing the chances of fuel failure. (03)
3. An increased build-up of non-condensibles in the RV head and hot leg U-bends, and possibly the RV, resulting from increased rates of cladding rupture and metal-water reaction. The non-condensible gases can:
   a. Affect RCS circulation by blocking hot leg U-bends.
   b. Result in the danger of hydrogen ignition within the reactor building. (03)

RCS conditions during Region 3 are serious. However, extensive core damage is avoidable if these conditions are not sustained. (03)

Region 4 (Figure 20)

If RCS presure and temperature conditions reach Region 4 of Figure 20, the cladding temperature may be 1800F or higher. This is a very serious condition.

During Region 4, some or all of the following may occur:

1. An increased rate of hydrogen production as a result of significant metal-water reaction taking place.
2. An increased level of radioactive releases from the fuel to the surrounding fluid as the fuel cladding fails.
3. Possible cladding embrittlement, at approximately 2200F.

When the RCS is in Region 4, extensive core damage may be unavoidable. Extreme measures are warranted to prevent major core damage.

Operating Guidelines

The ICC guidelines provide actions which the operator can take to try and increase core heat removal to reverse the ICC situation and to establish a safe situation. The two main approaches are to cover the core and to increase primary to secondary heat transfer. The operator attempts to achieve control of four elements in order to accomplish this: (03) (03)

1. RCS inventory control (via ECCS).
2. RCS pressure control.
3. SG inventory control.
4. SG pressure control.

Actions which can be taken to achieve control of the four elements present varying degrees of risk that the action will cause equipment damage. The risk of each action is then considered relative to the extent of probable core degradation at that time. The end result is different operator actions depending on which ICC region (of Figure 20) the RCS is in. As the RC pressure and temperature conditions pass from one ICC region to a more severe ICC region, the permitted operator actions become more of a risk to causing equipment damage. An action with increased risk is taken only when the increased risk resulting from that action is judged to be outweighed by the resultant potential for core degradation should the action be omitted.

Thus, actions necessary to achieve control of the four elements, but which pose an insignificant increased risk, are taken when the RCS is in Region 2 of the P-T diagram. When the RCS is in Region 3 of the P-T diagram, actions which are taken present a minor risk; however, the increased probability that a degraded core will occur warrants that these actions be taken. During Region 4, actions which are taken present a more significant risk. These actions are necessary to reverse the trend toward increasing core damage, and to compensate for multiple failures.

The following principles apply to actions in all regions:

1. In checking each system (e.g., HPI, LPI, AFW) the operator confirms that the system is operating correctly and at maximum capacity. He attempts to correct any malfunctions in the system, if practical and possible. (03)
2. If while taking actions in one region, the RCS conditions enter a more severe ICC region, the operator should transfer to guidelines for the more severe ICC region.
3. If at any time the RCS conditions enter a less severe ICC region, the operator should not revert to the actions for the less severe ICC region. The reason being that the action which caused the conditions to improve may be cancelled causing the ICC conditions to worsen again.
   For example, when region 3 is entered, the operator is reqired to start two RC pumps. This action may cause conditions to improve with a return to region 2. The operator should not make any further region 3 actions but should continue with the actions already made until the RC becomes subcooled or saturated. If the RC pumps are tripped when the conditions return to region 2, the conditions could go back to region 3. To make the situation worse, this time the RC pumps may not start. (03) (03)
   If the intent of a group of actions for a given ICC region has been satisfied then further actions may not be necessary. The operator should watch the system response to each action being made so that he can judge whether not the intent has been satisfied; e.g., the incore thermal couple temperature is returning to saturated conditions.

The following actions are taken by the operator according to the region of the P-T diagram (Figure 20) that the RCS is in. (03)

Region 2 actions are similar to those in ATOG Section III.A, "Loss of Subcooling Margin." (03) The similarity of the regions is intentional. The instrumentation error or response time may cause the incore T/Cs to indicate a superheated condition in the core when only loss of a subcooling margin exists. Or, RCS pressure and temperature may hover near the saturation line, and the operator may be uncertain as to which actions are applicable. If he takes Region 2 actions, the operator initiates the mitigation of possible ICC without placing undue risk on plant equipment. High-risk actions are reserved for Regions 3 and 4, when ICC is definite.

The following actions are taken in Region 2:

1. Continually monitor the RCS condition using the P-T diagram.
   a. If the RCS conditions enter Region 3 or 4 - transfer to the appropriate region actions.
   b. If the RCS conditions remain in Region 2 - continue Region 2 actions.
   c. If the RCS conditions become saturated or subcooled - refer to appropriate cooldown procedure.
2. If the RCS pressure increases to 2295 psig, open the PORV and leave it open until the RCS pressure drops to either 100 psi above secondary system (03) pressure or the ICC limit line between region 2 and region 3. The operator will need to assure that the automatic PORV isolation function is bypassed to prevent isolation when the RC pressure goes below 2170 psig.

a. The PORV will automatically open at its setpoint to prevent continued RCS repressurization and subsequent opening of pressurizer code relief valves. However, leaving the valve open will limit cycling of the PORV.

b. This action lowers RCS pressure to increase ECCS flow.

c. The pressure difference between the RCS and secondary system should not be allowed to go much below 100 psid to assure a primary to secondary temperature difference exists for heat transfer. (03)

d. The depressurization should be stopped before causing the RC conditions to go from region 2 to region 3, since region 3 exhibits worse core conditions. (03)

3. Verfiy or initiate maximum HPI flow. (03)

4. Confirm that CFT isolation valves are open. (03)

   a. This is to assure that core flood tank water will enter the RCS if the RCS pressure goes below the CFT pressure.

5. If the RCS depressurizes below the LPI pump shutoff head, confirm that LP injection starts. (03)

   a. Activation of LPI may result in a return to saturated or subcooled RCS conditions. (03)

6. Confirm that SG level has increased to 40 feet in the operable SGs. The AFW system is designed to automatically control SG level at 40 feet. The operator should verify or set the 40 foot SG level setpoint to provide for this automatic feature. If an unisolable steam leak exists, then bypass FOGG and trickle feed AFW to the dry SG. (03)

a. Initiate MFW if AFW is not working. AFW. Level must be controlled (03)
manually if MFW is used.

b. The steam generators will remove some of the superheat contained in (03)
the primary system, tending to lower RCS pressure and temperature if
primary to secondary heat transfer exists.

c. Auxiliary steam may be needed for AFW turbine.

d. A SG with an unisolable steam leak will not be able to maintain a
level if the leak is significant, and AFW would have been isolated by
FOGG allowing the SG to boil dry. Therefore, bypass FOGG to reestab- (03)
lish AFW flow.

7. Begin SG depressurization.

a. Start decreasing SG generator pressure to establish a secondary T_{sat} (03)
100F lower than T_{sat} for existing RC pressure, then maintain 100F ΔT
until primary to secondary heat transfer is established.

(1) The 100F ΔT is for stimulating primary to secondary heat trans- (03)
fer.

This step uses "T_{sat} for the existing RC pressure" rather than (03)
"RC temperature" for the following reasons:

a. If this action was based on RC temperature, the RC tempera-
ture may already be at least 100F hotter than the SG since
the RC can be superheated. Consequently, if the step
directed to the operator to reduce the SG to 100F lower than
the RC temperature, the operator may not be required to do
anything because the ΔT is already greater than 100F. This

defeats the intent of this step, which is to stimulate primary to secondary heat transfer by decreasing the SG temperature below what already exists.

b. If the secondary temperature is kept below the primary saturation temperature, the steam in the primary system will be able to condense in the steam generators. Condensing RC steam is perferred over just reducing the RC steam temperature because of the ability to remove more RC energy. If the 100F primary to secondary temperature difference is keyed on core outlet temperature, conditions can exist where the steam generator temperature is above the saturation temperature of the RC. Consequently, RC steam condensation will not occur.

(2) If reasonable, the operator uses the normal cooldown limit and the SG tube-to-shell ΔT limit as guidelines during SG depressurization. The operator may not be able to adhere to these limits.

a. Normal cooldown limit - RCS should not cool faster than 50 F/hr. The SG T_{sat} should be cooled at 50 F/hr. (03)

b. SG tube to shell ΔT limit - SG tube-to-shell ΔT should not exceed 160 F.

The following actions are taken in Region 3:

1. Continually monitor the RCS condition using the P-T diagram.

   a. If the RCS enters Region 4 - transfer to Region 4 actions.

   b. If the RCS remains in Region 2 or 3 - continue Region 3 actions.

c. RCS becomes saturated or subcooled - refer to appropriate cooldown procedure.

2. Do Region 2 actions 2, 3, 4, 5, and 6.

3. Establish and maintain operation of one RCP per loop.

a. Do not override RCP starting interlocks. (03)

b. Bypass the automatic RC pump trip function which actuates on loss of subcooling margin combined with either low RC pressure or high RB pressure ESFAS. (03)

c. Operating RCPs may move some water from the loops to the core and raise the level in the core region. This action may also provide forced steam circulation heat removal. (03)

d. Operation of the RCPs may result in the loss of additional inventory, since some of the fluid entering the core region may vaporize upon contact with superheated core temperatures. However, operation of the RCPs at this time is advantageous, since it may provide additional core cooling and additional time to restore emergency injection. (03)

4. Depressurize the operable SGs as quickly as possible to achieve a 100F temperature difference between the secondary T_{sat} and the RC T_{sat} corresponding to the RC pressure by manipulating valves on the secondary side. Continue SG depressurization to ensure that a 100F ΔT between secondary T_{sat} and T_{sat} for existing RC pressure is maintained. Do not reduce the steam pressure below the pressure necessary to operate the steam driven AFW pump unless steam is available from another source or both motor driven AFW pumps are operating. (03) (03)

a. This action may result in primary to secondary heat transfer. If it already exists, the heat transfer rate should increase.

5. Open high point vents and reactor head vent.

a. This will release any non-condensible gases which will be generated as a result of fuel pin rupture and the zirconium water reaction.

b. Venting of the gases may reduce RCS pressure to increase ECCS flow and may help establish boiler-condenser primary to secondary heat transfer. (03)

As a consequence of Region 3 actions, the RCS condition may improve to Region 2. However, the operator should maintain the Region 3 actions already made.

If the actions are discontinued, the RC conditions could return to Region 3. (03) There are some risks involved in continuing Region 3 actions (i.e., in operating RCPs with a steam/water mixture present), but the risks will diminish as conditions improve. By continuing Region 3 actions until saturation or subcooling is achieved, the operator increases the probability of recovering from ICC. Likewise, if the RCS enters Region 4, the operator starts and maintains Region 4 actions until saturation or subcooling is achieved.

The following actions are taken in Region 4:

1. Continually monitor the RCS condition using the P-T diagram.

a. RCS remains in Region 4, 3, or 2 - Continue Region 4 actions.

b. RCS becomes saturated or returns to Region 1 - refer to appropriate cooldown procedure.

2. Do Region 2 actions 2, 3, 4, 5 and 6.

3. Start all RCPs.

a. Bypass all RCP interlocks except the overload trip interlock. (03)

b. RCPs may move water remaining in the SG to the RV and raise the liquid level in the core.

4. Initiate SG blowdown by opening the MADVS, CSSVS, MSIVS, CDVS, AND ADVS and depressurize the SGs as quickly and as low as possible, but do not re- (03) duce the steam pressure below the pressure necessary to operate the steam driven AFW pump unless steam is available from another source or both motor driven AFW pumps are operating.

a. Rapid SG depressurization will challenge SG design limits.

b. Rapid SG depressurization will allow for maximum primary to secondary heat transfer, tending to decrease RCS pressure.

c. Need to provide steam to steam driven auxiliary FW pump if two motor (03) driven auxiliary FW pumps are not available.

5. Open or confirm that the following vents are open for removing noncondensible gases. (03)

- Hot leg high point vents.
- Reactor head vent.

6. Quickly depressurize the RCS until adequate ECCS cooling is obtained. (03)

- Open PORV, PORV block valve and pressurizer vent. Bypass automatic PORV isolation function.
- Open the dump to sump valves.

a. By opening all valves on the primary side, the operator allows for maximum primary system depressurization, and therefore maximizes HPI and makes CF and LPI possible.

b. The operator should attempt to depressurize by first using the PORV, PORV block valve and the pressurizer vent. If they do not cause sufficient depressurization then open the dump to sump valve. The dump to sump valves are designed to operate with a lower pressure across the valves. Also, being at a low elevation, refill of the RCS would be difficult if the dump to sump valves failed to close. (03)

Some degree of core damage is considered inevitable if the RCS enters Region 4. The objective of Region 4 actions is to end the transient as quickly as is practical, and thus limit the extent of core damage. It is unlikely that the RCS will enter Region 4 when ECCS injection exists and steam generator inventory and pressure are properly controlled. Instead, the cause will probably be a complete failure of one or more of these systems. The actions which the operator takes to compensate for the failure(s) present an increased risk. However, these operator actions are justified because of the possibility that the core is or could become degraded.

Post ICC Cooldown

After RCS saturated or subcooled conditions are reestablished, the operator should cooldown the plant using the appropriate cooldown procedure depending on RCS conditions (i.e., saturated, or subcooled with or without SG heat

transfer). Some of the actions which were taken during the ICC transient (especially in Region 4) may have to be reversed before long-term cooling can (03) be established. However, reverting to pre-ICC status may result in a return to ICC. Therefore, the operator should proceed with caution while reverting to pre-ICC status. While taking an action to revert to pre-ICC status, the operator must continually monitor the effect of any action on the RCS. If the action has a negative effect (e.g., continued RCS repressurization, HLLMS off-scale low and/or incore T/Cs indicate superheat), the operator must re- (03) verse the action immediately and not take that action again until he is assured that no negative effects will result.

If the action results in a return to ICC, the operator must return to the ICC guidelines. If completion of an action has no negative effect upon the RCS, the operator proceeds with caution to the next action. When each action necessary to revert to pre-ICC status has been completed, and if the RCS remains saturated or subcooled, the operator transfers to the appropriate cooldown procedure.

The HLLMS, RVLMS and hot leg RTDs may be useful as an indication of refill, or progression towards regaining the subcooling margin. All limitations associated with using this instrumentation as described earlier are still applicable.

The following operator actions must be reversed when establishing long-term cooling following an ICC transient:

a. Re-establish normal RC pump interlocks.

b. Close the dump to sump valves, reactor vessel head vent and pressurizer vent. (03)

c. If four RC pumps are operating reduce the number of operating RC pumps according to what is specified in the appropriate cooldown procedure.

d. Close the RC loop vents when the RCS reaches adequate subcooling margin. (03) If the RCS is saturated, they should be closed when the RC pressure drops below 150 psig to accommodate LPI operation.

e. Secondary system configuration (i.e., MADVS, CSSVS, MSIVS, ADVS, and CDVS opened or closed) is such that operator can control SG steaming.

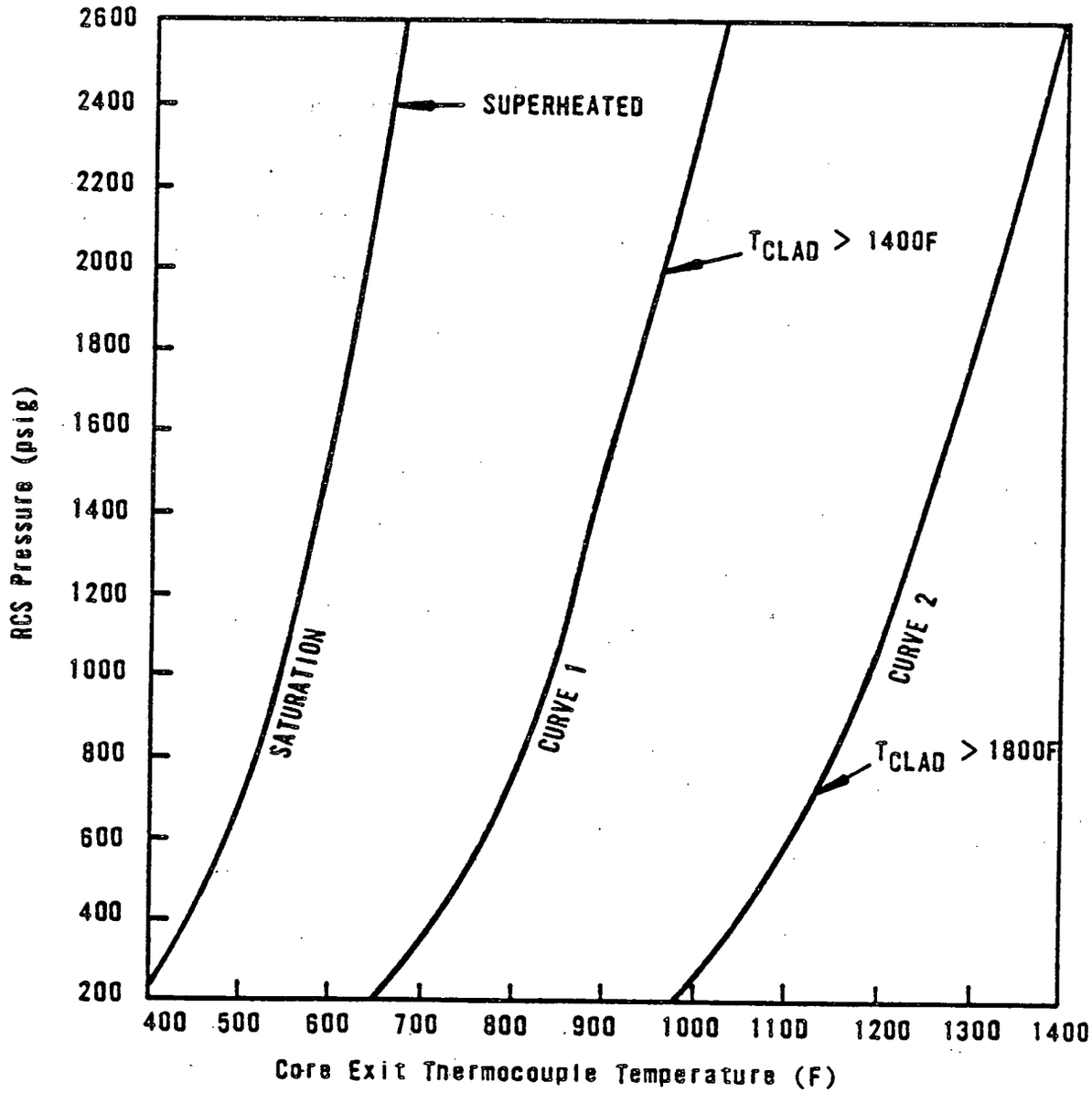



Figure 20 - CORE EXIT FLUID TEMPERATURE FOR INADEQUATE CORE COOLING