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Operator Action Event Trees for the Zion 1 Pressurized Water Reactor

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Robert G. Brown
James L. VonHerrmann
James F. Quilliam

September 1982

Prepared for the
U.S. Nuclear Regulatory Commission
Under DOE Contract No. DE-AC07-76IDO1570

EG&G Idaho

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OPERATOR ACTION EVENT TREES FOR THE ZION 1 PRESSURIZED WATER REACTOR

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Published September 1982

Wood-Leaver and Associates, Inc.

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ABSTRACT

Operator Action Event Trees for transient and LOCA initiated accident sequences at the Zion 1 PWR have been developed and documented. These trees logically and systematically portray the role of the operator throughout the progression of the accident. The documentation includes a delineation of the required operator response and the key symptoms exhibited by the plant at each state of the tree. These operator action event trees were based on the best-estimate computer analyses performed by EG&G Idaho, Inc. and Los Alamos National Laboratory under the NRC Severe Accident Sequence Analysis (SASA) Program.

SUMMARY

The primary product of this work is a set of documented Operator Action Event Trees (OAETs) for transient, LOCA and steam generator tube rupture initiated accident sequences at the Zion 1 Pressurized Water Reactor. These OAETs logically depict the role of the operator throughout the progression of a wide variety of important multiple failure accident sequences. At each state in the OAETs, the required operator actions and key symptoms exhibited by the plant are delineated. These documented OAETs can provide the information foundation upon which a broad spectrum of analyses related to operator performance under accident conditions can be based.

The methods used for developing and documenting the OAETs are described in Section 2. These methods have been developed and refined as part of the NRC Plant Status Monitoring (PSM) Program.

The documented OAETs are presented in Section 3. These trees and the supporting information concerning plant response are based on the best-estimate thermal-hydraulic analyses available to date from the NRC Severe Accident Sequence Analysis (SASA) Program. The LOCA analyses and station blackout analyses were based on work performed by EG&G Idaho, Inc. utilizing the RELAP4/MOD7 code. Additional transient sequence analyses were based on work performed by Los Alamos National Laboratory utilizing the TRAC-PD2 code.

Section 4 summarizes some of the major recommendations for additional SASA computer runs. These additional analyses are required to allow unambiguous accident signatures and diagnostic algorithms to be generated from the OAETs.

ACKNOWLEDGEMENTS

The acquisition and interpretation of the Severe Accident Sequence Analysis program's transient and small break analysis was an important element in completing this work. The authors wish to express their appreciation to Don Fletcher (EG&G Idaho, Inc.), Walt Murfin (Sandia), and N. S. DeMuth (LANL) for their assistance in providing this information. We would also like to acknowledge the input and guidance provided by Milan Stewart (EG&G Idaho, Inc.) under whose direction this work was performed.

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LIST OF ACRONYMS

ADV	Atmospheric Dump Valve
AFW	Auxiliary Feedwater
ATWS	Anticipated Transient Without Scram
BIT	Boron Injection Tank
BWR	Boiling Water Reactor
CST	Condensate Storage Tank
CVCS	Chemical and Volume Control System
ECCS	Emergency Core Cooling System
ESF	Engineered Safety Feature
HPIS	High Pressure Injection System
HPRS	High Pressure Recirculation System
LANL	Los Alamos National Laboratory
LOCA	Loss of Coolant Accident
LOSP	Loss of Offsite Power
LPIS	Low Pressure Injection System
LPRS	Low Pressure Recirculation System
NPSH	Net Positive Suction Head
NRC	Nuclear Regulatory Commission
OAET	Operator Action Event Tree
PORV	Power Operated Relief Valve
PRT	Pressurizer Relief Tank
PSM	Plant Status Monitoring
PWR	Pressurized Water Reactor
RCP	Reactor Coolant Pump
RCS	Reactor Coolant System
RHRS	Residual Heat Removal System
RWP	Recirculating Water Pump
RWST	Refueling Water Storage Tank
SASA	Severe Accident Sequence Analysis (Program)
SB LOCA	Small Break Loss of Coolant Accident
SG	Steam Generator
SGTR	Steam Generator Tube Rupture
SI	Safety Injection
SSR	Secondary Steam Relief

Section 1
INTRODUCTION AND BACKGROUND

In the aftermath of Three Mile Island, considerable attention has been focused on the role of the reactor operator in ensuring plant safety. Numerous programs have since been initiated by diverse portions of the nuclear industry to investigate, analyze, and improve the operator's ability to efficiently respond to accident conditions. These efforts have involved a wide spectrum of activities ranging from the design of individual control room components or the formatting of emergency procedures based on "ergonomic principles" to initial efforts to produce a totally computerized disturbance analysis system.

In addition to these many and varied activities, the Nuclear Regulatory Commission (NRC) has undertaken two separate but related research programs -- the Plant Status Monitoring (PSM) Program and the Severe Accident Sequence Analysis (SASA) Program. These programs are based on the premise that any efficacious changes to present design and operation must be constructed as a firm foundation consisting of:

1) An explicit identification of potential accident sequences and the plant states comprising these sequences.

2) A careful delineation of the actions required of the operator at each plant state.

3) A thorough understanding of the plant physical response to postulated accident conditions.

The PSM Program has primarily addressed the first two elements of this foundation. As reported in Light Water Reactor Status Monitoring During Accident Conditions [1] (NUREG/CR-1440), the PSM Program has developed effective methods for systematically investigating the operator's role in preventing or mitigating the effects of accidents. The cornerstone of these methods is the Operator Action Event Tree (OAET) which logically displays the role of the operator throughout the progression of the accident and can thereby provide the framework for a wide variety of analyses related to the performance of operator actions. A detailed discussion of the methodology for constructing and documenting operator action event trees is presented in Section 2.

In NUREG/CR-1440, it was noted that the effective application of the OAET methodology required the availability of best-estimate thermal hydraulic analyses of multiple failure accident sequences. The primary goal of the SASA Program is to generate these best-estimate computer analyses of the response of both pressurized water reactors (PWRs) and boiling water reactors (BWRs) to risk significant accident sequences. Thus, the SASA Program will provide substantial information related to the third element of the foundation discussed above. Over the last year, the SASA Program has concentrated on PWR accident sequences and has generated considerable information concerning the response of the Westinghouse Zion 1 plant to a variety of transient-induced and loss-of-coolant accidents. This work has primarily been performed at EG&G Idaho, Inc. using the RELAP 4/MOD7 code, [2,3,4,5,6] the Los Alamos National Laboratory utilizing the TRAC-PD2 code. [7], and Sandia National Laboratories using the MARCH computer code [8].

It is the objective of the work reported here to combine the existing products of the PSM and SASA Programs -- the OAET methodology and the Zion best-estimate analyses -- into a set of documented OAETs for a wide selection of important PWR accident conditions. These documented trees can then be used as the foundation for a variety of analyses related to improving the operator's ability to respond to accidents at plants similar to Zion 1 or to evaluate and/or validate the results of such analyses which have already been completed.

In addition to the specific goal of producing a set of operator action event trees for a particular PWR, this work has the more general objective of demonstrating how detailed information concerning the realistic thermal hydraulic response of plants to risk significant accident sequences can be systematically presented in a form which can be readily integrated into human factors engineering analyses. In order to practically obtain the potentially significant benefits afforded by the various human factors disciplines, there must be a strong interacton between the human factors analysts and the plant thermal-hydraulic analysts. The role of the operator under accident conditions can be effectively investigated only if the plant physical response under these conditions is known, the information flowing to the operator via the plant instrumentation is identified, the effect of postulated operator responses to these conditions is determined, and the necessary diagnosis and response strategies are charted. The work reported here is a significant first step in providing this necessary link between the plant response analyst and the human factors analyst.

Section 2

METHODOLOGY FOR CONSTRUCTION OF OPERATOR ACTION EVENT TREES

The goal of the OAET construction process is to produce a clear logical representation of the operator's role throughout the accident sequence and to document this model by clearly defining the following information:

(1) The key states (with respect to operator response) to which the plant could evolve given a particular initiating event.

(2) The postulated events which can produce each state (e.g., steam generator tube rupture).

(3) The physical plant response to these events in terms of symptoms which the operator can use to diagnose the existence of each state.

(4) The appropriate operator actions at each state.

The starting point in the OAET construction process is a functional event tree which depicts the complete set of critical safety functions which must be performed in response to the selected initiating event and logically develops the potential success and failure states which can evolve from this initiator. A simple example of such a functional event tree is presented in Figure 2.1.

The plant safety systems designed to perform each of the critical safety functions are then identified and a system event tree is produced. These trees logically develop the success and failures pathways in terms of the success or failure of individual systems and are used to identify the risk significant multiple failure accident conditions with which the operator may be confronted. In many cases it is possible to utilize available system event trees which were developed as part of a probabilistic risk assessment (the OAETs presented in NUREG/CR-1440 were based on system event trees developed in the Reactor Safety Study [9]). An example of a system event tree is presented in Figure 2.2.

These system event trees are then transformed into operator action event trees. The events in each sequence which involve operator action are identified and in some cases broken down into additional events in order to separate out and highlight individual operator tasks. In addition, the sequences are expanded (by adding event headings in the tree) to include operator actions which could be performed in response to the postulated failure events. The result is a model which logically displays the role of the operator throughout the progression of the accident. Figure 2.3 presents a simple illustrative operator action event tree. Note that the key plant states (with respect to operator action) are individually enumerated in Figure 2.3.

Once a preliminary version of the OAET has been developed and the key states have been identified, the next group of tasks is concerned with providing a detailed evaluation and description of each state in the tree. The format that is used for this documentation process is presented in Figure 2.4.

As noted above and illustrated in Figure 2.4, the ultimate goal of the documentation is to clearly define for each state:

- The Postulated Event

  The failure events which produce each key state enumerated in the OAET are delineated and their implication to the maintenance of the critical safety functions is described.

- The Required Operator Response

  Emergency procedures, guidelines, and other relevant documents are used to describe the appropriate operator actions at each state.

- The Key Symptoms Exhibited By The Plant

  Best-estimate computer analyses supplemented by the FSAR and other available documents are used to describe the physical plant response at each state in terms of measurable plant parameters.

It is often the case that the fairly straightforward OAET construction documentation process described above cannot, in actual practice, be carried out in a simple step-by-step manner. This will usually be caused by a preliminary OAET structure which does not allow a precise definition of operator response or key symptoms for each key state. For example, an OAET heading labeled "LOCA" is obviously inadequate because the appropriate operator response and the symptoms exhibited by the plant will be clearly different depending upon the size and location of the break. Often the adequacy of the OAET structure will not be apparent until a detailed examination of operator actions and plant response is carried out as part of the OAET documentation process. For this reason, it is important that the OAET construction/documentation process be performed in an iterative manner with alterations made, as necessary, to the OAET structure as the documentation proceeds.

The documentation format presented in Figure 2.4 is designed to facilitate this iterative process. As the analyst endeavors to document each key state, he is directed to explicitly identify any aspects of the required operator actions or anticipated plant response which could affect the existing OAET structure. For example, in attempting to document a state described as "LOCA," the analyst would explicitly identify the different symptoms associated with breaks of different size or location. The set of OAETs can then be altered so that it is possible to clearly define the appropriate actions and symptoms for each state.

In addition, the analyst is called upon to delineate any major uncertainties in the documented information. This task is intended to not only provide a measure of the accuracy of the results but to guide the analyst in identifying key symptoms indicative of each state. If there is significant uncertainty concerning the behavior of a particular parameter due to lack of available information or due to particular aspects of the codes, the response of these parameters should not be relied upon as a key symptom. Additional analyses are required to define the symptom response that is representative of this state. This evaluation may determine that additional symptoms are required to adequately describe a particular state.

Thus, the OAET construction and documentation process, while straightforward in concept, must be carefully carried out to ensure that the basic goals described at the beginning of this section are achieved. It is crucial that the event headings and the tree logic allows a clear definition of the operator actions and plant physical response at each state. The iterative approach utilizing the documentation format described above and illustrated in Figure 2.4 should allow these goals to be achieved.

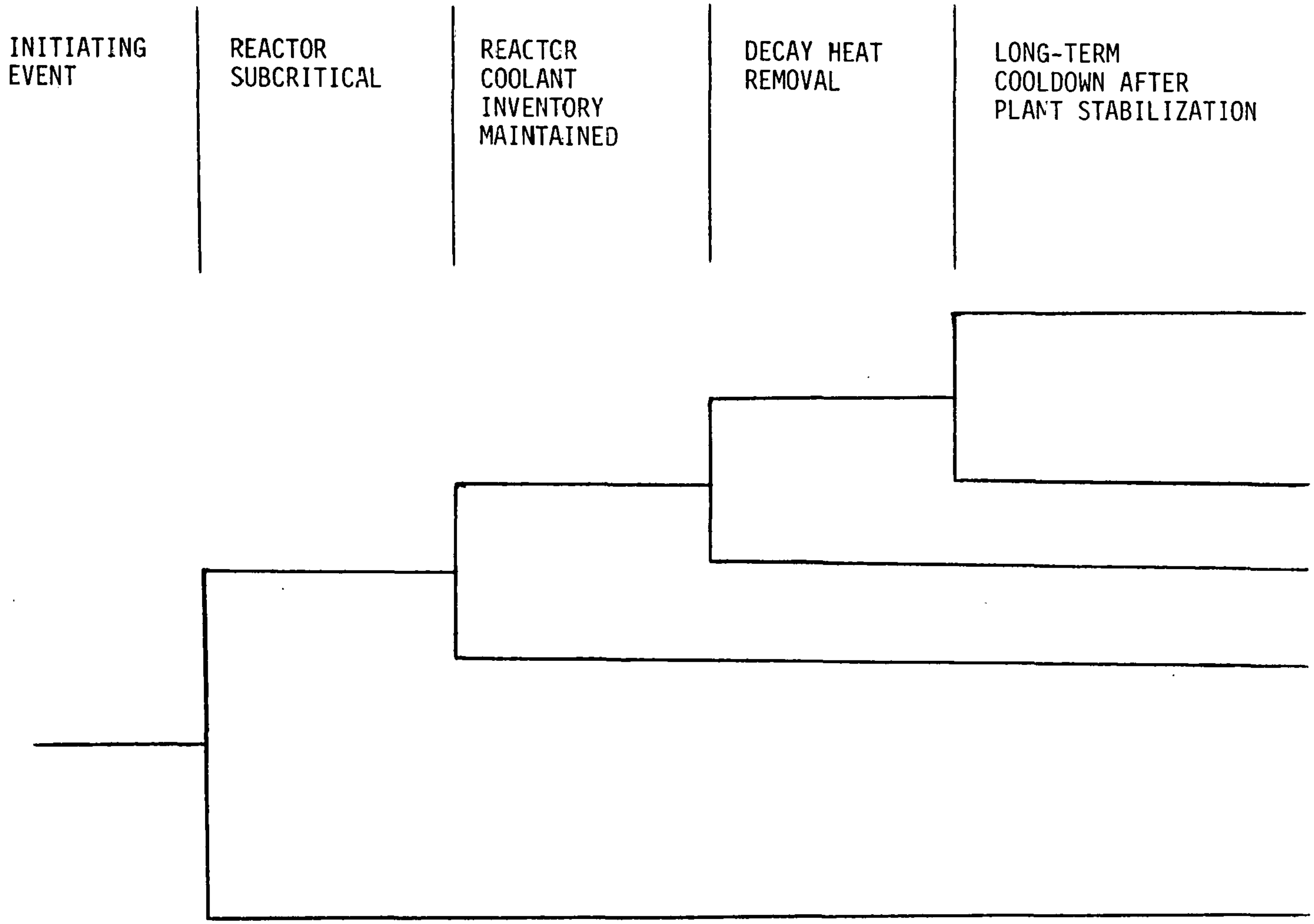
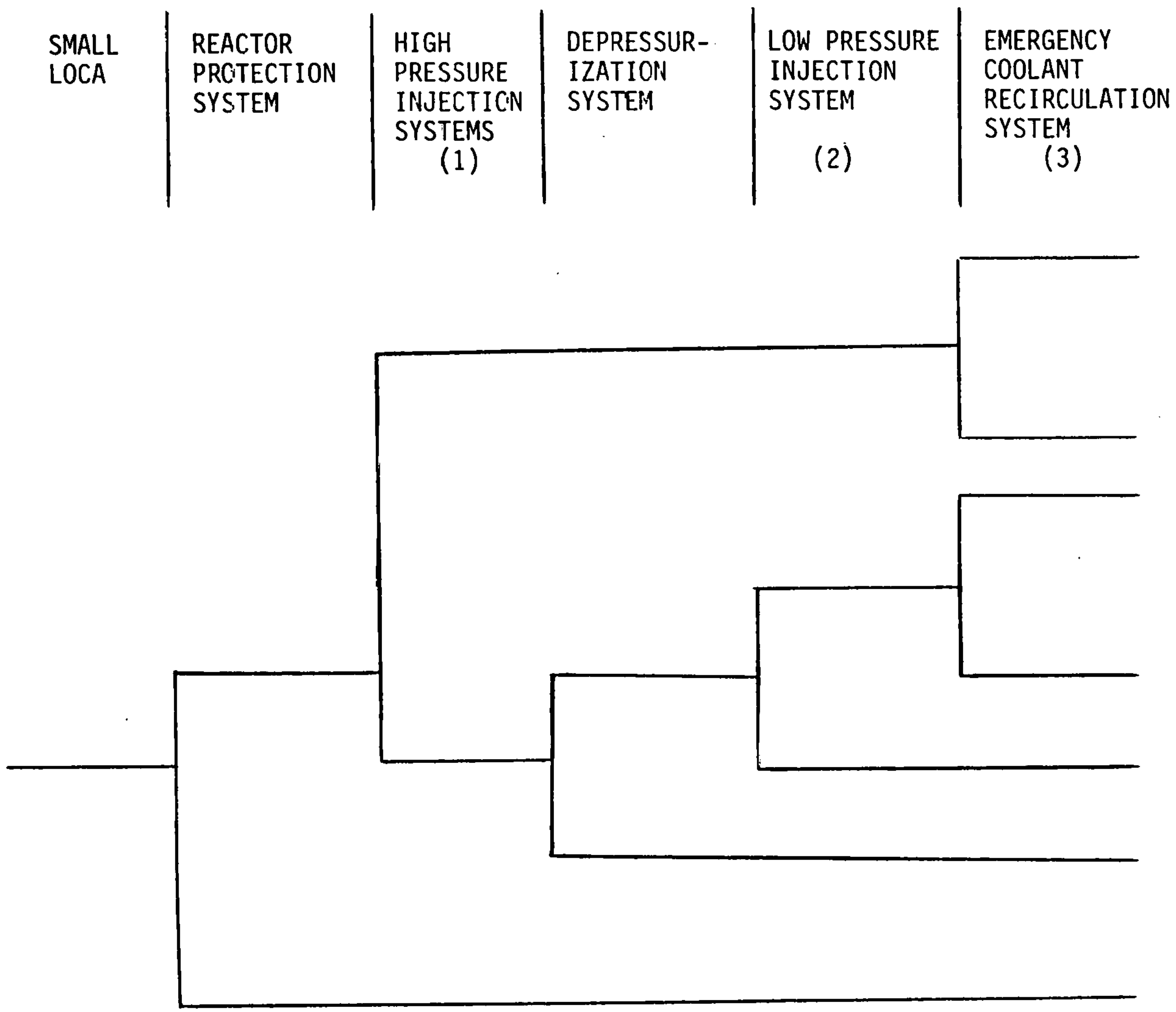


Figure 2.1 Example of Functional Event Tree



NOTES:

(1) Includes Reactor Core Isolation Cooling System, High Pressure Coolant Injection System, Feedwater System

(2) Includes Core Spray Injection System, Low Pressure Coolant Injection System, Condensate Pumps

(3) Includes Core Spray Recirculation System, Low Pressure Coolant Recirculaton System; Requires High Pressure Service Water System.

Figure 2.2 Example of System Event Tree (for small LOCA in a BWR)

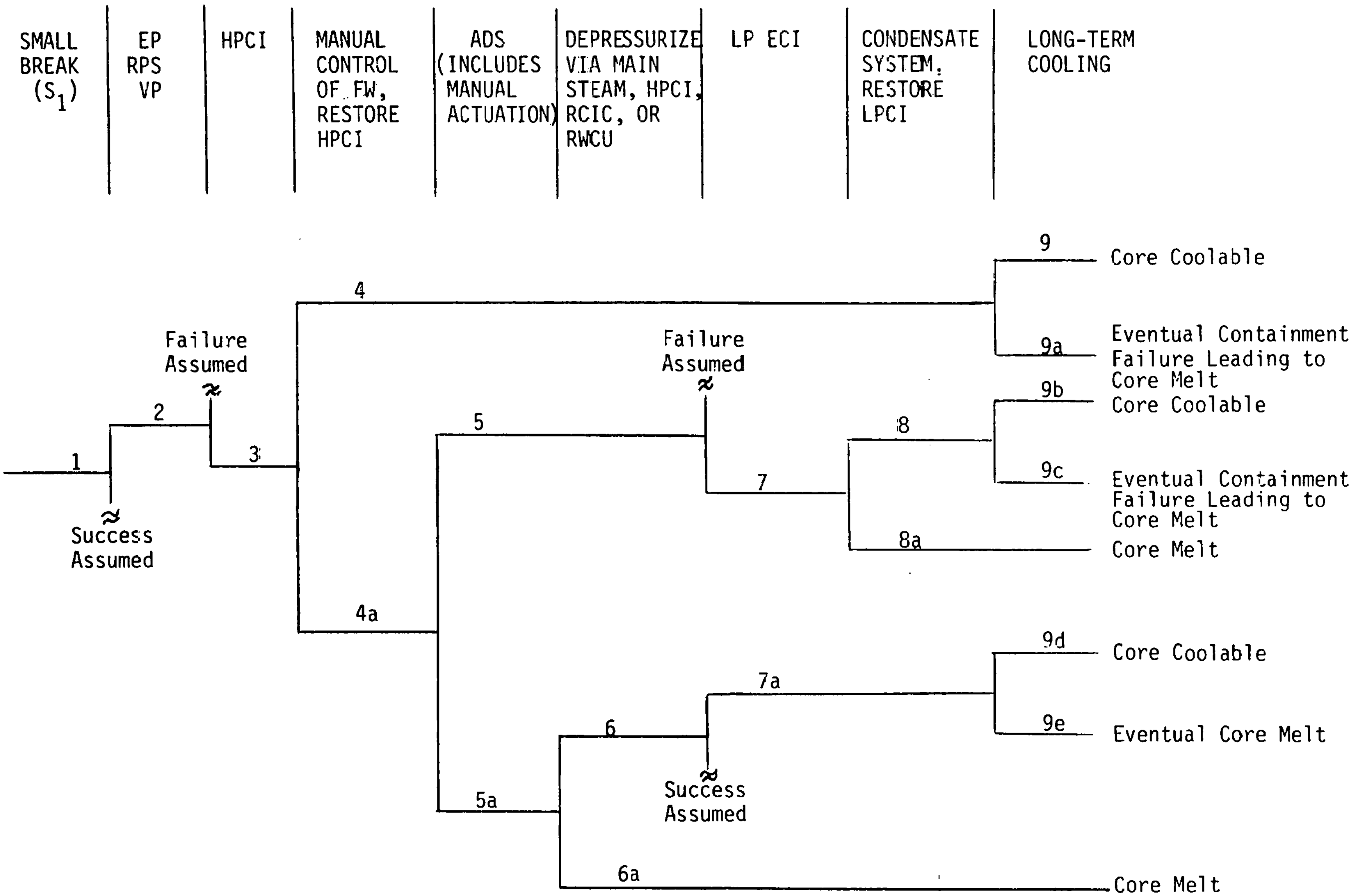


Figure 2.3 Example of Operator Action Event Tree (for small LOCA coupled with ECCS failure in a BWR)

- Postulated Sequence of Events

  Brief description of the failure events which produced this state and their implication to maintenance of critical safety functions.

- Required Operator Response

  Brief description of the appropriate operator response to this state. This includes verification, confirmation, diagnostic and action items. Differentiate between preplanned actions, required actions, delay action, "creative" actions, etc.

- Key Symptoms

  Identification and description of the major symptoms exhibited by the plant at this state. Track the parameters identified for precursor states and identify symptoms of new events associated with this state. List behavior of parameters associated with critical functions first.

- Uncertainties and Sensitivities

  Describe key aspects of Response and/or Symptoms which are uncertain or sensitive to variations in input assumptions. Describe potential impact of these uncertainties on OAET documentation.

- Potential Substates

  Identify any potential impact of knowledge gained in Response/Symptoms/Uncertainties on the structure of the original OAET.

- Additional Comments

  Mention anything that does not fit above categories, could affect accident signature development, or should be reiterated because of its importance.

Figure 2.4 Format For Documenting OAETs

Section 3
OPERATOR ACTION EVENT TREES

Presented in this section are the operator action event trees (OAETs) which have been developed for a selection of potential accident sequences at the Westinghouse Zion 1 PWR. These OAETs were developed in accordance with the methodology described in Section 2 and are based upon the best-estimate computer analyses performed and documented to date by EG&G Idaho, Inc. and Los Alamos National Laboratory (LANL) under the NRC Severe Accident Sequence Analysis (SASA) Program.

The OAETs presented in this report address the role of the operator in his attempt to prevent core damage and do not explicitly address his role subsequent to core damage. Thus, while the symptoms indicative of operator success or failure in preventing core damage are documented, the actions required after core damage has occurred are not addressed.

The accident conditions addressed by these OAETs can be grouped into two very general categories:

1) Those initiated by a break of the primary coolant system, and

2) Those initiated by faults or failure (other than coolant system breaks) which require reactor trip.

The first category of accidents, referred to as loss-of-coolant accidents (LOCAs) are addressed in Section 3.1. The second category, which is comprised of "transient" initiated events, is addressed in Section 3.2. It should be noted that this latter category also includes transient initiated sequences which subsequently result in breaches of the primary coolant boundary.

The OAETs presented in this section address a wide spectrum of potential accident conditions including transient and loss-of-coolant initiating events coupled with the subsequent failure of plant safety systems. Ideally, a package of OAETs should address a complete set of the risk significant accident sequences for a particular plant. Unfortunately, neither the plant specific risk assessment nor the required best-estimate analyses were available to support such a complete package. Nonetheless, the particular accident sequences which are encompassed by the OAETs presented here represent many of the important sequences for a large PWR like Zion 1 and these documented models can provide considerable information relative to the goals outlined in Section 1. In Section 4 a recommended strategy for producing a complete set of OAETs for the Zion plant is outlined.

3.1 LOSS OF COOLANT ACCIDENT CONDITIONS

The operator action event tree and supporting documentation presented in this section address the operator's role in responding to loss of coolant accidents (LOCAs). The SASA program has performed some analysis of small break LOCAs. These analyses were performed by EG&G using the RELAP4/MOD7 computer program. Due to the unavailability of a risk assessment for a Zion type plant at the time those runs were made, these analyses were performed for the risk significant sequences as determined by the Reactor Safety Study (WASH-1400). They are:

- Small break with a failure of high pressure injection
- Small break with a failure of recirculation

The Reactor Safety Study also determined that a small break followed by a failure of the containment spray injection system was a significant sequence for the Surry plant design. However analyses performed by Sandia [10] have shown that this combination of events is not a core damage sequence for Zion. The Zion containment design has five air fan coolers in addition to a containment spray system. The fan coolers, which would be actuated following a small LOCA, provide adequate heat removal to avoid the problems of elevated sump water temperature and pump cavitation which were postulated to cause failure of high pressure recirculation in the Surry plant.

RELAP analyses for the above two cases [4, 5] were performed for two sizes of small cold leg breaks: 1.5 and 4.0 inch diameter. However, the runs which assumed the failure of high pressure injection did assume operation of the charging pumps. Hence, these cases are not representative of a total failure of injection flow. Some additional analyses [6] were performed to investigate the feasibility of some proposed accident mitigation actions. These more recent runs assumed a failure of both charging and safety injection pump flow. However, because operator action was taken after 10 minutes in these runs, the system response for a total loss of injection flow is only available for this initial period. The mitigation actions which were analyzed involved depressurizing the primary system using either the atmospheric dump valves or the PORVs and using the low pressure injection system. For these investigations, cold leg breaks of 1.0 and 2.0 inches were considered. These RELAP small break analyses formed the information base upon which the small break LOCA operator action event tree was constructed. This model is described in detail in Section 3.1.1.

Section 3.1.2 addresses a steam generator tube rupture event. This special type of small break has several distinctly different symptoms and requires some unique operator actions. Hence this event has been considered separately. Because of an absence of SASA generated best-estimate calculations for the plant response to a steam generator tube rupture, this OAET was based in part on information describing actual steam generator tube rupture occurrences.[14,15] Therefore, the important operator actions and symptoms which allow the operator to diagnose that a steam generator tube rupture has occurred and respond to the event are more generic in nature than the SB LOCA discussion which deals with the Zion plant design.

Finally Section 3.1.3 discusses other types of LOCAs and related events. However, best-estimate calculations of the plant response to these events have not been performed in the SASA program. This unavailability of plant response information for these events precludes the development of detailed OAETs. Hence, their relationship to the small break OAET is summarized and the key operator actions in responding to these events are noted.

3.1.1 Small Break Loss of Coolant Accidents

A loss of coolant accident (LOCA) is defined as any event during which reactor coolant escapes due to loss of integrity of the primary coolant system. A LOCA can occur at any time (power operation, cooldown, heatup, cold shutdown) and can be either an initiating event or a result of another accident. Usually, LOCA's release reactor coolant to the containment environment. However, there are some LOCA's which can release reactor coolant to the secondary plant (steam generator tube leaks) or to the auxiliary building (such as interfacing LOCAs which produce breaks in the residual heat removal system).

LOCAs directly impact one of the critical safety functions which must be performed: that is, to provide adequate primary coolant inventory to remove heat from the reactor core. The loss of reactor coolant reduces the plant's ability to transport the core's heat to the steam generators. If the lost reactor coolant is not replaced, core cooling will be lost, and fuel damage may occur. To prevent such as accident from occurrring, PWRs are designed with several systems to replace coolant should a LOCA occur. These consist of a High Pressure Injection System (HPIS), a Low Pressure Injection System (LPIS), and Accumulators.

This section addresses the plant response to a small break LOCA and describes the operator actions required to bring the plant to a stable, safe shutdown condition. As treated in this analysis, a small break is defined to be a breach in the primary coolant system such that the resulting break flow exceeds the makeup capability of the Chemical and Volume Control System (CVCS), but does not rapidly depressurize the reactor to a level where the LPIS can be initiated. This assessment also considers the failure of various plant safety systems to perform their intended safety function and describes the appropriate operator responses to these conditions. The OAET for small breaks is presented in Figure 3.1. The key plant states are numbered and described in detail in the remainder of this section. Each state is addressed separately using the format presented in Figure 2.4.

STATE: S-1

This state represents the small break loss of coolant accident (SB LOCA) initiating event with successful operation of the safety injection system. For this evaluation a small break is defined to be a breach in the primary system such that the resulting break flow exceeds the makeup capabilities of the CVCS, but does not rapidly depressurize the system to a level where the low pressure injection system can be actuated. This latter limit defines the minimum break size for a large LOCA.

Among the automatic responses which would occur subsequent to a SB LOCA are a reactor trip, a reactor coolant pump trip,* actuation of the auxiliary feedwater system, containment isolation and actuation of the fan coolers, and initiation of high pressure safety injection (HPI). Some of these key automatic responses are noted in the second event tree heading (Figure 3.1). This state of the OAET assumes that each of these automatic responses is successful. Hence, the reactor power is reduced to decay heat generation and heat removal is available through the steam generators. Primary coolant is being discharged into containment and the HPIS is providing makeup to the reactor coolant system.

REQUIRED OPERATOR RESPONSE:

The operator's initial responses are to diagnose the transient as a small break inside containment and verify that the appropriate automatic responses have occurred. Depending on the break size and location, the operator may recognize that the LOCA has occurred before reactor trip. In other cases, the trip and the associated automatic actions may alert the operator to the existence of a problem. For these situations the operator would be diagnosing the accident during and after verification of the automatic safety system response. The key symptoms which would allow the operator to recognize and confirm the presence of a small break are addressed in the following section. The key immediate operator actions are summarized in the following list:

- Verify that an automatic reactor trip has occurred. If not, manually scram the reactor.

*The criteria for automatic RCP trip are HPIS actuation and an RCS pressure less than a plant-specific value. Because the break sizes analyzed in the SASA program all resulted in RCP trip, it was assumed that this occurred automatically in developing this OAET.

- Verify that the auxiliary feedwater system has actuated and that the water level in the steam generators is being restored or maintained at the proper level. Manually initiate and control auxiliary feedwater if necessary.

- Verify actuation of the HPIS and realignment of the charging pumps for safety injection when the reactor pressure drops to the safety injection setting. Ensure that the letdown line in the CVCS is isolated. If necessary manually initiate safety injection.

- Verify containment isolation, actuation of the fan coolers, and the containment spray systems when (and if) the containment environment reaches the set points for these actions. Manually perform these functions if necessary.

- Verify that the reactor coolant pumps have tripped automatically. Manually trip the pumps if necessary.

- Verify that there is electrical power supply to the emergency AC bus.

After these immediate actions, the operator's primary objective is to ensure adequate core cooling during the injection phase. The HPIS should perform this function automatically. However, the operator should monitor primary temperature and pressure to ensure an adequate subcooling margin. It may be necessary for the operator to control injection flow and auxiliary feedwater flow to reach stable conditions.

After the operator has ensured that the HPIS is functioning properly and the core is being cooled, the next key action is to determine if the break can be isolated. Although there are limited locations where a break could be isolated, this action is important as it could terminate the transient quickly, and avoid the possibility of a serious accident if equipment fails in responding to the LOCA. Two examples of breaks which might be isolated are a small break in the CVCS letdown line and a stuck-open PORV. This action is essentially an extension of the initial diagnosis in which the operator confirmed the presence of a small break LOCA. The operator should attempt to determine the location of the break and then isolate it if possible. For some breaks this may be relatively simple. An example is a PORV which fails to close when the reactor pressure drops below its closure setting. Like the small break inside containment, this initiator will decrease the reactor pressure. However, containment conditions will remain unchanged. The stuck-open valve will be evident from the PORV position indication, discharge line flow and temperature, and an increasing pressure and water level in the pressurizer relief tank (PRT). Pressurizer level instrumentation will also indicate a rising water level as water flashes to steam and coolant is drawn up into the pressurizer. The operator can isolate this break by closing the PORV or the block valve which is downstream of the PORV.

It may also be possible to isolate some breaks in the RCS piping. The Zion design is equipped with stop valves in the hot and cold legs of each coolant loop. These can be used to isolate part of each loop. If the operator is able to locate an RCS piping break, it may be possible to isolate it by closing the valves in the affected loop.

KEY SYMPTOMS:

Small break LOCAs can be difficult to identify. This section discusses the key symptoms associated with these accidents and describes how the operator can distinguish a small break inside containment from other events which require different operator response.

The immediate response to a SB LOCA is a decrease in primary system pressure as fluid is discharged through the break. There will be a concurrent increase in containment pressure, temperature, humidity, and radioactivity. The discharge of primary coolant will also eventually increase the water level in the containment sump. The rate at which these parameters change depends on the break size and location. Larger breaks will of course produce more rapid changes. Similarly, for a given break size, vapor space breaks will cause a more rapid initial depressurization than a liquid break. These effects as well as other factors which impact the system response are addressed in the following section on uncertainties and sensitivities.

To illustrate the response of the fundamental parameters, the results of an analysis of a small cold leg break for the Zion plant will be discussed. This analysis assumed no operator action in responding to this event. Figure 3.2 shows the reactor pressure response for a small cold leg break of 0.0381 m (1.5 inches) diameter. A reactor trip signal is generated at 90 seconds. Immediately after the scram, the primary pressure reduction accelerates due to the reduced heat generation in the reactor core. The safety injection signal is generated at 93 seconds and both the charging pumps and the HPI pumps are initiated at 98 seconds. As the primary system pressure decreases, the break flow is reduced while the HPI flow steadily increases. At 326 seconds, the injection flow exceeds the break flow and the reactor pressure begins to level off. This equilibrium level (∿ 7300 kPa or 1060 psi for the 1.5 inch break) is maintained for about 4 hours until the RWST is depleted.*

Even though this break is relatively small, the energy loss with the break flow is adequate to remove the core decay heat. As a result, the steam generator secondary side temperature exceeds the primary coolant temperature relatively soon (1050 seconds) and the steam generators begin acting as heat sources. From this point, the steam generator temperature (Figure 3.3) and pressure (Figure 3.2) decay slowly. This analysis assumed that the AFWS successfully maintains normal secondary water level in the steam generators.

The containment pressure response is given in Figure 3.4. Even for this relatively small break the containment pressure responds quickly. The containment pressure increases steadily until the fan coolers are actuated (at 290 seconds). These are more than adequate to remove the energy added to containment from the coolant. Hence the containment spray system is not required to mitigate the pressure transient.

In summary, the initial key symptoms of a SB LOCA inside containment are:

- Reactor pressure: Initially decreasing, stabilizing at a pressure where break flow equals safety injection flow after HPI initiation.
- Containment temperature and pressure: Initially increasing, then decreasing after fan cooler or fan cooler and containment spray actuation.
- Containment sump water level, humidity, and activity: Increasing.

* The analysis presented in Figure 3.2 is for a sequence in which recirculation is assumed to fail; hence, the reduction in pressure at 15000 seconds. This behavior will be discussed in State 9.

- HPIS Flow: After the pressure drops below the safety injection initiation set point, adequate flow is provided in the lines leading to the reactor cold legs. This symptom must be included to distinguish between states with inadequate SI flow or HPIS failure. (See State S-14).

The rate at which these changes occur and the time at which the safeguards systems are actuated depend on many parameters. These sensitivities are addressed in the following section.

Despite the fact that these are very distinct changes in key plant parameters, the operator may have difficulty in diagnosing a small break inside containment. This is because some other events have a similar set of symptoms. For example, steam generator tube ruptures, main steam line breaks, and stuck-open PORVs all result in a decrease of reactor pressure. Hence it is necessary for the reactor operator to confirm each of the above symptoms so that the most effective action can be taken to bring the plant to a safe condition. The remainder of this section addresses these similar events. The purpose of this discussion is to specify the key symptoms which distinguish these events from small LOCAs.

The key parameter which distinguishes a small break inside containment from other events is containment activity. The discharge of primary coolant into the containment enclosure should be detected by at least one of the area radiation monitors. How soon this alarm occurs will depend on the break size, the location of the break with respect to the detector location, and the primary coolant activity. This latter factor will depend on the system cleanliness and the number of fuel failures (which occurred during normal operation) in the core, as well as the normal coolant activity. Containment activity is a key symptom which distinguishes a primary system break from a main steam line break inside containment. Both accidents will elevate containment temperature, humidity, and pressure, and sump water level. Likewise both events will cause a reactor pressure reduction. However, because the steam line break releases secondary fluid, the radiation monitors should not respond. Steam line breaks can also be distinguished by a drop in turbine-generator output and steam generator side pressure and water level* reductions.

*Water level may recover if the automatic control system increases feed flow to compensate for the leakage.

Neither steam generator tube ruptures, interfacing system LOCAs outside containment, nor overcooling transients will affect conditions in containment. Hence, the presence of any of the containment symptoms rules out these events as potential initiators. Similarly, a stuck-open pressurizer relief valve will not initially affect containment, because the primary coolant is discharged into a relief tank. The absence of containment response coupled with PORV valve position, discharge line flow and temperature indication will confirm that the "break" is a stuck-open valve. If the operator is unsuccessful in isolating this break, then the capacity of the relief tank will be exceeded. The rupture disc would blow and coolant would then be released to containment. In this case the system response is identical to other small LOCAs.

UNCERTAINTIES AND SENSITIVITIES:

The plant response to small break loss of coolant accidents (SB LOCAs) and thus the symptoms the operator observes can vary significantly depending on several variables. The most important factors that affect system response are:

- break size and location
- response of high pressure injection and volume control systems
- heat removal through the steam generators

The numerous possible interactions and combinations of these variables result in a wide range of symptom behavior for key plant parameters. This section will address the impact of these parameters on the general response to small break LOCAs. Thus the sensitivity of the symptom responses described in the previous section to those key factors can be determined. This will also provide an estimate of the variability of the accident signature for small break LOCAs.

The size and location of the RCS breach determine the initial depressurization transient and the inventory depletion rate in the primary system. These factors also influence the response of the key containment parameters which the operator must use to diagnose the event. Breaks in the RCS can encompass a large range of inventory loss: from routine leakage to hypothetical double - ended guillotine ruptures of main coolant pipes. Several distinct groupings can be developed which classify this collection of breaks by the effect on reactor pressure and the response of plant emergency core cooling systems. The entire spectrum of RCS breaks can be broken down into the following general categories:

1) Slight RCS depressurization; adequate makeup provided by charging system. This condition represents the lower end of the spectrum. It includes normal RCS leakage and slightly larger flow rates. This does not constitute a break as considered in this analysis, as no reactor trip or safety injection signal is generated.

2) RCS repressurizes after safety injection. Actuation of both charging pumps and the HPI pumps provides inventory in excess of the break flow. Above the HPI pump shutoff head, the charging pump flow (both pumps at maximum capacity) still exceeds the break flow.

3) RCS pressure equilibrates above accumulator set points. The response is similar to that illustrated in Figure 3.2.

4) RCS depressurizes below the accumulator set points (600 psi) but above LPI pump shutoff heat (170 psi). For this small range of break sizes, accumulator injection supplements HPI.

5) RCS depressurizes below LPI pump shutoff head. For these breaks the LPIS provides makeup. These breaks constitute large LOCAs and are considered separately.

As noted above, classifications (1) and (5) are not small LOCAs. An example of the plant response for the third category is described in the previous key symptoms section. Hence this discussion will address the remaining two cases.

There is a small range of break sizes in which the leakage exceeds the capacity of a single charging pump, but is less than that of both charging pumps. During normal operation, only one charging pump is in service. Hence if a break of this type were to occur, the primary system would gradually depressurize - more slowly than in Figure 3.2. Eventually a reactor trip and safety injection signal would occur. This would realign the charging system to take suction from the boron injection tank, and actuate the standby charging pump as well as the two safety injection pumps. This immediate increase in coolant injection would more than offset the break flow. The primary system pressure transient would turn around and pressure would rise above the SI pump shutoff head. At this point, makeup is reduced, but is still more than adequate to offset the break flow as both charging pumps are operating. Eventually the pressure will equilibrate at some point above the SI shutoff head. It is possible that the system could repressurize to the PORV set point.* If this were to occur the operator would need to take action to control charging pump flow to avoid coolant release through the PORV. Additional discussion of this operator action is provided in the following section on potential substates.

The behavior trend of the symptoms for breaks which depressurize below the accumulator is similar to that described previously except the changes occur more rapidly. This will be illustrated by presenting results from a 0.10 m (4 inch) cold leg break for the Zion plant. This analysis used the same model and assumptions as the 1.5 inch break analysis. Hence,the effect of increased break size can be readily observed. Figure 3.5 illustrates the primary system pressure response for a 4 inch cold leg break. The scram occurs at 12.8 seconds and high pressure injection enters the core at 19.1 seconds. The pressure reaches the accumulator set point in 790 seconds. The rapid decrease in pressure accompanying accumulator injection shown in Figure 3.5 would not be expected. The RELAP4/MOD 7 code used to perform these analyses is an equilibrium code. Hence, when subcooled accumulator water enters the steam filled cold leg, the two phase mixture is assumed to be saturated. In forcing this calculation, steam condensation results in a sharp pressure reduction. Other analyses [13] indicate that accumulator injection will initially decrease pressure, but as the water enters the core, the system will repressurize to shutoff accumulator flow.

* Analyses of such breaks have not been performed for the Zion plant in the SASA program. However this response is predicted for similarly designed plants.[13]

Depending on the break size, accumulator injection may occur intermittantly as the pressure oscillates around the 600 psi set point. Hence, the pressure transient shown in Figure 3.5 is probably not representative beyond the accumulator injection set point.

As expected, the containment pressurizes much faster for a larger break. For a 4 inch break, the fan coolers are insufficient to remove the energy released through the break. The containment spray system is required to mitigate the containment pressure transient. As illustrated in Figure 3.6, containment spray is initiated at 520 seconds and immediately reduces pressure. After ~45 minutes, the rate at which energy is released into containment is significantly reduced. These analyses indicate that containment spray is no longer needed at this time. The fan coolers are now adequate to limit containment pressure. The termination of containment spray reduces the RWST depletion rate. This action could be important at a later time.

The hot leg fluid and steam generator secondary temperatures behave similarly to the 1.5 inch break (See Figure 3.7). The hot leg temperature declines rapidly at first while the secondary temperature rises after steam generator isolation. After the first minute, both temperatures decline slowly with the secondary temperature exceeding the primary at 390 seconds. Thus, the steam generators become heat sources for the remainder of the transient.

These previous results assume both HPI and AFW respond as designed. If their performance is degraded then the response of the key parameters would be altered. If the injection flow is reduced, the pressure at which the primary system stabilizes would be different. As an example, Figure 3.8 illustrates the primary system pressure transient for a 1.5 inch cold leg break. This analysis is identical to that illustrated in Figure 3.2 except that it is assumed that the SI pumps fail and that only the charging pumps are operating. In this case, the primary system pressure stabilizes at a higher level - ~ 1100 psia compared to ~ 890 psi. Furthermore, heat removal through the steam generators occurs for a longer period. It is 70 minutes before the secondaries begin to act as heat sources.

From the results available at this time, it is also obvious that the availability and effectiveness of heat removal through the steam generators can affect the accident signature. The impact is greater for the smaller breaks which remove less heat and depressurize more slowly. However, best estimate analyses of degraded AFWS performance have not been performed. Hence, it is not possible to provide specific examples of plant response for these conditions.

The important point of the various uncertainties and sensitivities addressed in this section is how these factors affect the accident signature. Do they produce such a wide range of responses that the operator may be unable to identify the plant state and take the appropriate actions? In general, the factors discussed in this section only affect the timing of the certain events and the rate at which various parameters change. In all small breaks, the primary pressure response is characterized by an initial decrease which accelerates after reactor trip and eventually stabilizes at some level where the injection flow equals the break flow. For larger breaks, the depressurization rate is greater and the equilibrium pressure lower, than for smaller breaks. In fact for breaks just in excess of the CVCS capacity the system may even repressurize and the equilibrium pressure could be above the HPI pump shutoff head. Similarly, the containment temperature, pressure, humidity, activity, and sump level will increase more rapidly for larger breaks. Thus, the larger breaks give the operator less time to diagnose and respond to the event. However, the symptoms are more pronounced, therefore diagnosis should be much easier.

The key differences in plant response which do not occur in all small breaks are summarized below:

- Accumulator injection: Occurs only if break is large enough to depressurize primary system to 600 psi.
- Containment spray actuation: Only actuated for larger breaks. Fan coolers adequate for smaller ones.
- Primary system repressurization above HPI pump shutoff head: Only for breaks at the lower end of the small break spectrum.

These occurrences do not affect the operator's capability to diagnose a small break and respond effectively to the event.

POTENTIAL SUBSTATES:

A potential substate mentioned in the previous section which could affect the operator response is the repressurization of the primary system after safety injection is initiated. As discussed in the previous section, this would only occur for a very small range of break sizes - those which just exceed the capacity of the CVCS. If the system repressurizes above the normal operating pressure, a PORV or safety valve* could open and fluid be released through this valve. This would not immediately impact core coolability, as the primary system is solid. However, a continuous release of fluid through the PORVs could possibly create some problems as the operator brings the plant to a cold shutdown condition. As an example, because the water leaking through the PORV enters a discharge tank, the volume of water in the sump will be reduced. This may complicate the transition to recirculation when the RWST is depleted. The operator can not take suction from the sump until there is sufficient head to avoid cavitation. It is uncertain if the volume of the discharge tank will prevent reaching adequate sump level before the RWST drains. For other, similar plant designs, the volume of the discharge tank should not preclude reaching adequate NPSH. However, the operator would have less time to complete the transition from injection to recirculation and still maintain a continuous supply of coolant to the core.

Since these breaks have not been analyzed for the Zion plant, it is uncertain if repressurization to the PORV setting will occur. However, analyses for similar plant designs have predicted this occurrence. Hence, this condition is noted as a possible substate.

The operator action for this condition is to throttle or terminate high pressure injection to avoid PORV actuation. This action avoids an

* Many plants have closed the block valves downstream of the PORVs because of leakage. If all PORVs were isolated, a safety valve would open.

unnecessary discharge of coolant from the primary system. Before altering the HPIS flow, the operator must ensure that adequate cooling is being provided to the core. This can be accomplished by ensuring adequate subcooling of the hot leg coolant, adequate inventory, and provisions for continued heat removal and makeup. The NRC has established a minimum of 50°F subcooling as an acceptable HPI termination criteria. Other vendors have proposed alternate means of assuring adequate core cooling. For example, the Westinghouse HPI termination criteria require all of the following:

- RCS pressure greater than 2000 psia and increasing (to ensure adequate subcooling)
- Pressurizer level greater than 50% (to ensure adequate inventory, given the above pressure condition)
- RCS subcooling greater than a plant specific value.
- Availability of steam generators as a heat sink.

If the operator terminates HPIS, conditions must be closely monitored to see if leakage out the break requires HPIS actuation. It is possible that intermittent HPI operation may be required.

STATE: S-2

At this state the operator has successfully isolated the break and the loss of reactor coolant has been terminated. High pressure coolant injection is restoring primary inventory. The auxiliary feedwater system is available and is now removing decay heat from the primary system.

REQUIRED OPERATOR RESPONSE:

Once the operator has ensured that the primary system inventory has been replenished and that there is adequate subcooling, the high pressure injection system should be terminated. This will avoid filling the system completely with water and repressurizing the system beyond the normal operating pressure. HPI termination is addressed in more detail under the Potential Substates section of state S-1.

The next objective is to bring the plant to a safe, cold shutdown condition. The operator should ensure that the AFWS is functioning correctly and that adequate level is being maintained in the steam generators. Since level has been restored in the pressurizer, the primary pressure can be stabilized using the pressurizer heaters and sprays. Although the reactor has been tripped, the operator should ensure adequate shutdown margin for cold shutdown and borate if necessary. The injection of water from the boron injection tank may have already satisfied this criterion.

The preferred method for plant cooldown would be to restart one or more reactor coolant pumps, and follow the normal plant shutdown procedures. When the pressure drops below 400 psi and the hot leg temperature is less than 350°F, the operator should transfer to the residual heat removal system (RHRS) for long-term cooling. If it is not possible to restart a reactor coolant pump, the system must be depressurized using natural circulation. In either mode, care must be taken to maintain an adequate subcooling margin. It is particularly important that the depressurization be gradual under natural circulation conditions. Even if adequate subcooling is indicated in the hot leg, there is the potential for local hot spots (e.g., upper head region). Voiding could occur at these locations if the system is depressurized too rapidly.

KEY SYMPTOMS:

After the break has been isolated, reactor pressure will begin to increase. Primary system inventory will be recovering and eventually level will be restored in the pressurizer. Prior to isolation, the steam generators may have been acting as heat sources to the primary coolant. However, during the cooldown process, the steam generators will be dumping steam to the condenser or to the atmosphere to remove decay heat. Hence, the secondary side temperature will decrease below the hot leg temperature. Secondary side water level will be maintained by auxiliary feedwater.

After the release of coolant into containment has been terminated, the containment temperature and pressure will be decreasing at an even faster rate as a result of continued operation of the air fan coolers and/or the containment spray.

Subsequent to HPIS termination, successful plant cooldown will be indicated by a gradual decline in primary and secondary temperatures and pressure.

UNCERTAINTIES AND SENSITIVITIES:

If the operator fails to terminate HPI before a PORV opens, then effectively a break has reoccurred. However, now the system is water solid and there is no immediate threat to core coolability. The operator should recognize this occurrence quickly. In this case, he should terminate HPIS and close the PORV (or its block valve). If this action is not performed, then the break has been "restored" and the system behavior is represented by state S-5.

The other uncertainty is the availability of the reactor coolant pumps. If these can not be restarted, then the system must be cooled down by natural circulation. This does not affect the structure of the OAET, or change the operator's objective to cooldown and depressurize the plant. Of course, the specific tasks which must be performed are different and the operator must exercise caution to maintain natural circulation and avoid voiding in the primary system.

POTENTIAL SUBSTATES:

Depending on the severity of the break, and the operator's understanding of the plant state after the break has been isolated, the operator may elect to return the plant to full power operation, rather than proceed to cold shutdown.

STATE: S-3

At this state, the operator has brought the plant to a stable, cold shutdown condition. The break has been isolated and HPI has successfully restored primary system inventory. The operator has cooled and depressurized the reactor and placed the RHRS in service. The RHRS is operating effectively to remove decay heat.

REQUIRED OPERATOR RESPONSE:

Monitor RHRS operation to ensure a continuation of long-term decay heat removal. Perform the necessary repairs and other activities so the plant can be returned to operation as soon as possible.

KEY SYMPTOMS:

The primary system is at cold shutdown conditions. (pressure <400 psi, coolant temperature ~140°F). Heat is being removed through the RHR heat exchangers by component cooling water. Hence, there is an increase in secondary side water temperature across the RHR heat exchangers.

STATE: S-4

This state represents the case where long-term cooling with the RHRS can not be established. The operator has successfully isolated the small break which initiated the transient and the reactor is shutdown. The primary system inventory has been restored and heat removal is being accomplished through the steam generators. Once the primary system depressurizes below 400 psi and the coolant temperature is less than 300°F, the RHRS should be actuated.

Although an unlikely occurrence, this state represents the case where the operator can not transfer to RHRS operation. This could result from component failures which disable the RHRS or unavailability attributable to the initiating event. (i.e., the LOCA affects use of RHRS).

REQUIRED OPERATOR RESPONSE:

The preferred course of action is to maintain the plant in a hot shutdown condition while repairing the failures that resulted in the RHRS unavailability. This requires that the AFWS be available for continued heat removal. If the operator is able to use the steam dump system, the AFWS can be operated essentially indefinitely. If steam is being discharged to the atmosphere, the condensate storage tank inventory will gradually become depleted. If AFWS operation is required for an extended period (more than ∿5 hours), the operator must make provisions to refill the tank. Demineralized water is preferred, as this would avoid introduction of impurities into the condensate system. However, the quantity of demineralized water is limited. Hence, the plant is designed so that the service water system can be used for this purpose. Operator action is required to align the service water system to refill the condensate tank.

KEY SYMPTOMS:

The plant is in a hot shutdown condition. The primary pressure and temperature are stable, and relatively close to the RHRS transition levels (400 psi and 350°F).* Steam generator water level is stable and secondary pressure is controlled to maintain the desired primary conditions. Water level in the condensate storage tank is decreasing, unless steam is being dumped to the condenser. In this case, the condensate storage tank level is relatively stable.

UNCERTAINTIES AND SENSITIVITIES:

The length of time before RHRS can be restored depends on the cause of its unavailability. Some repair actions may be performed rather quickly while others could take days. Consideration of specific failure modes and the necessary repair actions is beyond the scope of this investigation.

POTENTIAL SUBSTATES:

If the AFWS fails during this extended period, action would be required to provide RCS heat removal. Assuming the RHRS can not be repaired, the operator could restart a condensate pump and provide water from the condenser hotwell. If this can not be accomplished, the primary system pressure and temperature would gradually increase. Eventually the system would repressurize to the PORV setting. At this point, the operator would have to establish a feed-and-bleed mode of heat removal. This system state is addressed in detail in Section 3.2.

ADDITIONAL COMMENTS:

This path of the small break OAET represents the plant state when the normal long-term cooling mode can not be immediately established. Hence, the plant can not be brought to the stable end state of cold shutdown until after the RHRS is repaired. State S-4 is not necessarily a core damage state, even if conditions deteriorate to a feed-and-bleed condition. This state has been included to recognize the potential difficulties in the plant cooldown process.

* Effective heat transfer through the steam generators can not be maintained below approximately 350°F and 125 psi.

STATE: S-5

A small break in the primary coolant system has occurred. The reactor has scrammed and the HPIS has actuated to restore the fluid lost through the break. The operator has been unable to isolate the break and thus coolant continues to leak into containment. The primary pressure is relatively stable at at a level determined by the HPIS flow, break flow, and steam generator heat removal.

REQUIRED OPERATOR RESPONSE:

With successful ECCS injection, the operator's next objective is to depressurize and cooldown the plant. This action should only be taken after the plant is in a stable condition. Furthermore, the operator should ensure that there is adequate shutdown margin for cold conditions.* This action is accomplshed by decreasing the secondary side pressure. If the main condenser is available, the operator should dump steam through the turbine bypass line. Otherwise, steam can be vented directly to the atmosphere through the steam generator relief valves. This depressurization should be gradual to ensure that there is adequate subcooling margin in the primary system, and to avoid thermal stresses associated with excessive cooldown rates.

The operator must also monitor the RWST level and prepare to transfer to recirculation before the inventory is depleted. This action could be required in as little as a half an hour if the containment sprays are operating. Depending on the stability of the reactor system, transfer to recirculation may occur before or during the plant cooldown actions mentioned above. In the recirculation mode of operation, water is drawn from the containment sump by the RHRS pumps and delivered to a suction header for the high head SI and charging pumps. This header replaces the RWST as the water source for the HPIS. The SI and charging pumps continue to operate and deliver coolant to the cold legs of the RCS. Transfer to recirculation requires the following major actions:

* It is likely that the HPIS has injected enough water from the BIT to satisfy this criterion.

1) Provide component cooling water to the RHR heat exchangers (should occur automatically on low RWST level alarm)

2) Open sump recirculation valves (should occur automatically)

3) Isolate the low head RHR pumps from the RWST

4) Open valves which allow low head RHR pumps to supply the suction header for the high head SI and charging pumps

5) Close valves in suction lines from RWST to the high head SI and charging pumps, after assuring adequate coolant is being provided by the RHR pumps.

KEY SYMPTOMS:

This state is essentially a continuation of state S-1 up until the time when recirculation is required. The discussion for that state addresses the symptoms and their associated uncertainties and sensitivities in more detail. A brief summary is provided here.

The reactor pressure is relatively stable at a level deterimined by the break flow, HPIS injection, and secondary heat removal. The reactor coolant temperature and pressure are decreasing. The water level in the steam generators is being maintained by the AFW pumps. The secondary pressure is relatively stable. Steam is being dumped to the condenser or released through the relief valves to the atmosphere.

The containment temperature and pressure are decreasing as a result of air fan cooler and perhaps containment spray operation. The water level in the containment sump is increasing steadily. If the containment spray is actuated, the sump will fill quickly. Similarly, the RWST will drain much faster if containment spray pumps are drawing from this source. The RWST could be depleted in less than 45 minutes.

UNCERTAINTIES AND SENSITIVITIES:

The operator has a limited time to perform the transition from injection to recirculation of the sump water. This is especially true for the larger breaks where the containment spray pumps are running. In such cases, the time to complete the transition to recirculation before the RWST empties is on the order of a few minutes. Hence, relatively quick action may be required to ensure that coolant flow to the cold legs continues without interruption. One factor which must be considered in transferring to recirculation is the need for adequate NPSH for the low head RHRS pumps. This requires that the containment water level reach a certain elevation before the sump line suction valves open. Hence, the plant must be designed such that when the RWST low level alarm occurs, the minimum containment sump criterion appears to be satisfied for all LOCAs. However, in the case of the stuck-open relief valve, it is uncertain if there will be adequate sump water level at the RWST low level set point. (See discussion under Potential Substates S-1). This is because some of the primary coolant released through the stuck-open valve will be contained in the PORV discharge tank. This will delay the time required to fill the sump to an adequate height, and consequently reduce the time the operator has available to transfer from injection to recirculation operation.

STATE: S-6

At this state, the operator has successfully transferred from emergency coolant injection with the high head safety injection and charging pumps to recirculation of the sump water using these same pumps. This mode of operation is frequently designated as high pressure recirculation (HPR). The plant is in a quasi-steady state condition where the coolant leaking out the break is pumped through the RHR heat exchangers to remove the decay heat, and recycled back into the reactor.

REQUIRED OPERATOR RESPONSE:

The operator should continue to cooldown and depressurize the primary system, as described in the actions for State S-5. When the primary system pressure drops below 400 psi, recirculation can be accomplished using the RHRS pumps alone. This requires operator action to isolate the RHRS pumps from the high head pump suction header.

KEY SYMPTOMS:

At this state the reactor pressure and coolant temperature is stable or gradually decreasing, depending on whether or not the operator has initiated plant cooldown. During HPR operation, both the RHR and high head injection pumps are used to deliver sump water to the cold legs.

The water level in the containment sump is now stabilized by the transfer to recirculation. The RHR heat exchangers are removing heat from the sump water as reflected by a temperature rise in the component cooling water across the heat exchangers and a reduction in sump water temperature that is injected into the core.

The containment pressure is near that of normal operation and the temperature is not excessive. Humidity and radiation levels are high. The latter depends on the fuel burnup and number of fuel failures prior to, and as a consequence of the LOCA.

ADDITIONAL COMMENTS:

After a period of approximately one day, it is recommended that the operator transfer to hot leg recirculation to avoid boron precipitation and accumulation of residue in the reactor core. This requires the operator to change valve positions so that the sump water is injected into the primary hot legs rather than the cold legs. Failure to perform this action will not impact core coolability in the short term (i.e., first several days, if at all). Hence, this action has not been identified in the OAET.

STATE: S-7

This state represents a condition where a small break LOCA has occurred, all plant systems have responded as designed, and the operator has performed the necessary actions correctly. The HPIS was actuated and effectively provided short term makeup and stabilized primary conditions. When the RWST depleted, the operator successfully realigned the system for recirculation operation. A continuous flow of coolant has been provided to the reactor. The sump water is being cooled by the RHR heat exchangers. Throughout these early phases, the operator has successfully depressurized the primary system. Recirculation is now provided by the RHR pumps. The plant is at a stable, cold shutdown condition.

REQUIRED OPERATOR RESPONSE:

The operator must continue to monitor RHRS operation to ensure that long-term cooling is maintained. Since only one train is required for effective heat removal, the operator has a "backup train" available should a failure disable the operating components or maintenance be required. Post-accident investigation, clean-up, and repair activities can be initiated.

KEY SYMPTOMS:

The reactor pressure is stable and less than 400 psi. The primary system coolant temperature is stable at approximately 140°F. Heat removal through the steam generators has been terminated. The containment conditions are the same as described for state S-6.

STATE: S-8

The events leading to this state include a small break in the reactor coolant system followed by successful high pressure injection. The operator has successfully tranferred to recirculation when the RWST emptied. This state represents the case where the operator is unable to bring the plant to a cold shutdown condition. This could occur if the operator can not or does not cool-down and depressurize the primary system, and subsequently establish recirculation with the RHRS pumps. This plant condition does not necessarily produce a core damage condition as long as HPRS operation is maintained.

This plant state could also result from a failure of the HPRS after it has operated for some time. In this case, the operator actions and key symptom responses are similar to those described in State S-9.

REQUIRED OPERATOR RESPONSE:

The particular operator response at this state will depend on what failure mode has prevented or interrupted the cooldown process. In all cases, the general objective is the same; that is, to repair or restore the failed equipment and to subsequently cool down and depressurize the system. The inability to depressurize the primary system may be caused by a loss or severe degradation of heat removal capability through the steam generators and the inability to lower secondary pressure, thus reducing the primary pressure. In this case, the repair or restoration of the failed equipment associated with the steam generators would be required.

This state could also arise from a failure of the RHR heat exchangers to remove heat. Even though the steam generators are available, these components are required to bring the plant to a stable cold shutdown condition. Should the RHR heat exchangers fail to remove heat, perhaps due to a loss of component cooling water flow, the operator must diagnose this failure and restore this function. During this time, the operator must ensure that the HPRS continues to supply water to the core. This will maintain adequate primary inventory. Furthermore, continued recirculation of the sump water will provide some heat removal capability in the short term. This is due to the relatively large heat capacity of the cooler sump water and containment structure.

Finally, as noted above, this plant state could result from a failure of the HPRS after it has operated for some time. This occurrence would be similar to the system response described in State S-9. Operator actions for this condition are described in that state description.

KEY SYMPTOMS:

The reactor pressure and primary coolant temperatures are above the values where the low head pumps can operate alone (400 psi, 350°F). If all form of heat removal has been lost, these parameters will be slowly increasing. The sump water level will remain stable unless HPRS flow ceases. In this case, the water level will increase slowly as coolant continues to leak out the break. Sump water temperature will also gradually increase. The containment temperature and pressure are reduced from the values which were attained in the first several minutes after the break occurred, but may begin to rise slowly once core heat removal is lost. Air fan cooler operation or containment spray operation could counteract these trends.

STATE: S-9

This state represents the failure to establish emergency coolant recirculation after a small break LOCA. Up to this point in the OAET, all of the plant's automatic responses, including HPIS operation, have functioned successfully. Although the operator was unable to isolate the break, the system is in a relatively stable condition with the injection flow compensating for the fluid leaking out the break. As the inventory in the RWST becomes depleted, the operator must realign the SI system to recirculate water from the containment sump in order to maintain primary system inventory. This state assumes that recirculation is not established.

REQUIRED OPERATOR RESPONSE:

Without a continuous supply of makeup to the core, the primary system inventory will decrease leading to core uncovery and eventually fuel damage. The time between loss of HPRS and core damage depends on the reactor pressure, break size and location, and the coolant volume remaining when HPRS failed. This period could be as short as $\sim$10 minutes for breaks at the upper end of the small break spectrum. Hence, it is important that the operator recognize immediately that recirculation has failed. The symptoms that are characteristic of this condition which the operator can use to perform this diagnosis are described in the following section.

The potential operator actions to restore coolant flow to the core are limited and depend on when and how the HPRS failed. These options will be discussed briefly in this section.

One action which will restore coolant makeup and buy time to repair the faulted components is to return to the injection mode of operation.* This would require that the operator realign the valves to take suction from the

* Examples of some failure modes where this action might be employed are failure of the RHR pumps to deliver water to the high head pump suction headers, sump suction valve problems, or inadequate sump water level.

RWST and immediately take action to supply additional water to the RWST. If the RWST is not completely drained, the operator should terminate all other demands on this water source until makeup to the tank is established. As an example, the containment spray pumps may be operating. Temporarily interrupting containment spray* would provide a significant additional quantity of water for core injection while the operator is taking the actions necessary to provide water to the RWST. If the operator is successful in restoring injection, and supplying adequate water to the RWST, core damage can at least be temporarily avoided.

There is a limit as to how long this mode of operation can be maintained. Eventually the water level in containment will rise and may submerge (and fail) critical circuits or components, thus resulting in a loss of injection flow. In addition, rising water level may produce excessive loads on the containment structure leading to a loss of containment integrity and the release of radioactivity to the outside environment. Thus, injection can not be continued indefinitely. However, this action could buy substantial time in which to repair the failures which disabled or prevented recirculation.

If the failure of the HPRS results from problems with the SI and charging pumps, the operator can depressurize the primary system and utilize the RHR pumps in the low pressure recirculation mode (LPRS). The operator can reduce pressure by opening the atmospheric dump valves (as discussed in State S-18) or through the PORVs (see State S-22). With the pressure below 400 psi, the RHR pumps can take water from the sump and transport it through the heat exchangers directly to the cold legs. The high head pumps are no longer required to maintain primary system inventory.

Recirculation failure can also result from a failure to adequately cool the sump water before returning it to the core. If the RHR heat exchangers fail to cool the sump water, the water temperature will begin to increase and

* As shown in Figure 3.6, containment conditions are near-normal by this time. Hence, the containment spray pumps could be terminated for several minutes before a significant pressure rise would occur.

could reach saturation conditions. Cavitation could fail the RHR pumps as they attempt to transport the two phase mixture. This failure mode would occur after the ECCS has been realigned for recirculation and operated in this configuration for some period. Failure of the RHR heat exchangers would be indicated by increases in the sump water temperature, the temperature in the heat exchanger discharge lines, and the reactor coolant temperature in conjunction with verification of adequate flow to the cold legs. Once these trends are identified, the operator should attempt to restore heat removal through at least one of the RHR heat exchangers, before RHR pump failure terminates recirculation flow. This will likely involve repair of some fault in the component cooling water system or one of its supporting systems. If this can not be accomplished, the operator will have to re-establish the steam generator as the primary heat sink. This will require an adequate supply of water in the CST (see State S-4).

KEY SYMPTOMS:

The key symptoms associated with a failure of ECCS recirculation will depend to some extent on the failure mode. If recirculation was not established after a successful period of HPIS operation, the interruption of coolant flow would be reflected by decreasing primary system inventory - decreasing reactor vessel level and pressurizer level (if it had recovered). In addition the sump water level would continue to rise, rather than leveling off as would be expected after a transition to recirculation. Reactor pressure will decrease upon the loss of coolant flow and primary coolant temperature will begin to rise slowly. Figure 3.2 shows the primary pressure transient for a 1.5 inch break. In this analysis, HPIS flow was terminated when the RWST emptied at 15050 seconds. The pressure fell below the accumulator actuation setting.* Accumulator injection temporarily counteracted the inventory loss and temperature rise. However, after the accumulator inventory has been released, core temperatures begin to rise again. Secondary side pressure and temperature will also increase after recirculation flow has been terminated.

*The RELAP4 code does not predict all of the consequences of accumulator injection correctly. In particular the code overpredicts the depressurization associated with accumulator injection. Because it is an equilibrium code, any volume containing a two phase mixture is forced to saturation conditions. Hence, the injection of subcooled accumulator fluid into the partially steam-filled cold leg resulted in a condensation of the steam and the sharp pressure reduction shown in Figure 3.2.

If the heat removal through the RHR heat exchangers is lost, there may not be any immediate impact on primary system inventory (unless there are gross tube failures in the heat exchangers). Coolant will still be transported to the cold legs. However, the temperature of this water will rise steadily. This in turn, will cause the primary coolant temperatures to increase gradually. The sump water temperature will also increase due to the higher enthalpy of the break flow. However, because of the large volume of water in the sump, the temperature rise will lag behind the loss of heat removal. Because flow is still available, the primary system pressure will not drop. In fact it may increase slightly as warmer water is being introduced into the core. Other symptoms that would reflect a failure of the HPRS heat removal function could include, secondary side temperature changes across the RHR heat exchangers and a decrease in component cooling water flow to these components.

If the operator does not restore the heat removal function of the HPRS, then the RHR pumps could fail when the sump water reaches saturation. At this point makeup is lost and the vessel inventory and pressure would decrease as described previously for a failure of recirculation flow.

UNCERTAINTIES AND SENSITIVITIES:

Best estimate analyses for the case where the HPRS heat removal function fails have not been performed. Hence, the primary system pressure and temperature response are uncertain. Furthermore, the length of time available before pump cavitation is unknown.

The capability to provide makeup to the RWST is unknown. The demineralized water system probably has insufficient capability to keep with the ECCS pump demands. It is unknown whether or not there are other systems which the operator could use to refill the RWST within the time constraints of the accident.

STATE: S-10

A small break in the primary coolant system has occurred. The plant has been shutdown and safety injection successfully replenished RCS inventory. However, the transition to recirculation operation was unsuccessful, resulting in a loss of makeup (or a loss of heat removal through the RHR heat exchangers). At this state, it is assumed that the operator recognized the failure of HPRS and was successful in initiating or restoring recirculation cooling before core damage occurred.

REQUIRED OPERATOR RESPONSE:

The operator actions after recirculation has been restored are similar to those at State S-6. The system should be depressurized and the temperature reduced. When the pressure drops below 400 psi, recirculation should be established using only the RHR pumps. The operator would isolate these low head pumps from the high head pump suction headers and inject directly from the RHR pumps into the primary system.

KEY SYMPTOMS:

Restoration of recirculation flow and/or cooling has stabilized reactor pressure, temperature, and inventory. The values of these parameters will depend on the failure mode of the HPRS, the duration of the failure, and the operator actions to restore the system. They may be greater or less than those of State S-6. However, the general behavior as described in that state applies to this condition as well.

ADDITIONAL COMMENTS:

One of the potential operator actions in restoring recirculation is to depressurize the system and establish recirculation with the low head pumps. This action might be taken if some fault precluded use of the high head pumps. (See discussion of operator actions for State S-9). If this action is taken, then State S-10 is effectively bypassed and the plant is at State S-11.

STATE: S-11

This state is almost identical to State S-7. The plant has been depressurized and the coolant temperature is approaching that of a cold shutdown condition (~400°F). The RHR pumps are circulating sump water through the RHR heat exchangers and into the primary system. The transient has been terminated although coolant continues to leak out the break. The only difference in the sequence of events leading to this state and State S-7 is that the operator had to take action to repair or restore recirculation cooling after it failed prior to State S-11. This difference has no effect on the key symptoms once adequate long-term cooling is established and the system pressure and temperature are at cold shutdown conditions. It would only impact operator action if the fault that produced State S-9, could somehow affect his utilization of the RHR for continued heat removal. For example, a component failure may have disabled one train of the RHRS. In this case, the operator would not have a backup train available until repairs could be made.

REQUIRED OPERATOR RESPONSE:

See State S-7.

KEY SYMPTOMS:

See State S-7.

STATE: S-12

This state is essentially the same as State S-8. The key symptoms and operator actions presented in the documentation for State S-8 are applicable to this plant condition as well. It is worth noting that State S-9 in which HPRS failed is a precursor to this state. Hence, failures which resulted in this initial failure of HPRS may reoccur or somehow impact the events which produce the subsequent inability to establish or maintain long-term cooling which is represented by State S-12.

STATE: S-13

This state of the OAET represents a continuation of State S-9. A small LOCA has occurred and the automatic ESF systems responded as designed to accommodate the accident. This includes successful operation of the HPIS. The operator was unable to isolate the break, but the system is in a relatively stable condition with the injection flow restoring the coolant lost through the break. Before the RWST inventory becomes depleted, the operator attempts to establish recirculation cooling. State S-9 assumes that recirculation was not established or that this mode of operation failed after having been operating for some time. This state assumes that the operator was unsuccessful in repairing the faults that disabled recirculation cooling, or in providing an alternate means of restoring coolant to the primary system. Hence, there is a continuous loss of primary system inventory which results in core uncovery and eventual fuel damage.

REQUIRED OPERATOR RESPONSE:

The operator should continue attempts to restore cooling, even though core damage is occurring. If successful, this will minimize radionuclide release. The operator should also verify containment isolation and ensure operation of containment spray to mitigate the consequences of fuel damage. The administrative, emergency and evacuation procedures should be implemented as appropriate for a core damage event.

KEY SYMPTOMS:

The trends described in State S-9 continue. Reactor vessel water level is decreasing. Fuel temperatures increase after core uncovery. Fuel failures and melting release large quantities of fission products. These are transported through the break, thus elevating containment radiation levels far beyond those associated with the loss of coolant. Containment temperature and pressure are relatively stable as long as the containment sprays are operating.

STATE: S-14

This state represents the plant condition following a small break LOCA with a failure of HPIS. The other automatic plant responses are assumed to be successful. Hence, the reactor has tripped, auxiliary feedwater has been initiated, the containment has been isolated and the containment fan coolers are operating. However, the high head safety injection pumps and the charging pumps fail to provide sufficient flow to maintain primary system inventory.

REQUIRED OPERATOR RESPONSE:

The operator must immediately diagnose the occurrence of a small LOCA and verify that the appropriate automatic responses have occurred. As part of this verification, the operator must recognize that HPIS has failed. The key symptoms which the operator can use to determine that a small break has occurred and HPI flow is inadequate are discussed in the following section. The important immediate actions are summarized below:

- Verify that an automatic reactor trip has occurred. If not, manually scram the reactor.
- Verify that the auxiliary feedwater system has actuated and that the water level in the steam generators is being restored or maintained at the proper level. Manually initiate and control auxiliary feedwater if necessary.
- Verify containment isolation, actuation of the fan coolers, and the containment spray systems when (and if) the containment environment reaches the setpoints for these systems. Manually perform these functions if necessary.
- Verify that there is electrical power supply to the emergency AC bus.
- Verify that the reactor coolant pumps have tripped automatically. Manually trip the pumps if necessary.
- Verify actuation of the HPIS and realignment of the charging pumps for safety injection when the reactor pressure drops to the safety injection setting. Ensure that the let down line in the CVCS is isolated. If necessary manually initiate safety injection.

This plant state assumes that the operator is unable to actuate HPIS from the control room. Because core uncovery will occur in a relatively short time the operator may not have time to perform any repairs locally on components of the HPIS. Only if the fault is readily identified, should the operator attempt to restore HPI by performing local repairs or changing the positions of manual valves.

During the initial diagnosis of the event, the operator may discover that the break can be isolated. Although there are only a limited number of locations where a break could be isolated, this action has been included in the OAET because of its importance in responding to the event. Isolation effectively terminates the event quickly, and in this case, avoids the need to take unfamiliar backup measures to accommodate the loss of HPIS and prevent core damage. Examples of breaks that can be isolated include a stuck-open PORV and a rupture in the letdown line of the CVCS. Furthermore, the Zion design has loop isolation valves which could be used to isolate some RCS piping breaks if the operator is able to locate the rupture. If the operator does not isolate the break, actions to respond to the loss of injection flow are discussed in the description of State S-18.

KEY SYMPTOMS:

The symptoms which the operator can use to verify that a small LOCA has occurred have been discussed in detail in State S-1. However, in State S-1, the HPIS is assumed to operate and replenish the inventory which has been lost out the break. In this state, the HPIS is assumed to fail or supply insufficient coolant flow to prevent core damage. As will be evident from the following discussion, several key parameters exhibit similar behavior both with and without HPI flow. Hence, there is the potential for error in diagnosing whether or not there is adequate makeup to the core. This section describes the symptoms associated with a small break with a failure of HPIS and addresses how this state can be distinguished from State S-1.

The initial plant response to a small break is identical to that described in State S-1. The primary pressure decreases as fluid is lost through the break. At the same time, containment pressure, temperature, humidity, and radiation levels increase. The water level in the sump will begin to rise.

The rate at which these parameters vary depends on the break size and location. In this state it is assumed that both the charging pumps and the safety injection pumps fail to operate, once the pressure drops below the safety injection signal set point (1830 psia). Beyond this point the primary system pressure transient is strongly dependent on the break size. Figure 3.9 illustrates the pressure response for a 2" diameter cold leg break. In this case, the break size is not large enough to remove all of the decay heat. Some heat removal is performed by the steam generators early in the transient. Under the conditions present at this state, a pressurization of the secondaries to the relief valve set point occurs and reactor pressure stabilizes. This initial stabilization is very similar to the behavior when HPIS is assumed to operate. This can be seen by comparing Figure 3.2 (1.5 inch cold leg break with HPIS successful; primary pressure initially stabilizing at $\sim$ 890 psi) to Figure 3.9 (2 inch cold leg break with HPIS failure; primary pressure initially stablizing at 1100 psi).* However, for these particular examples, the steam generator pressure responses exhibit a different behavior. When HPIS fails, the secondaries repressurize, as the steam generators are removing some decay heat. If safety injection is successful, then the addition of cold water dominates, and the steam generator pressure slowly decays. It is uncertain if this difference is adequate to distinguish between HPIS success and failure for all small breaks. For example, this difference may not occur for breaks at the upper end of the small break spectrum. Beyond some point, the break size may be sufficient to remove the core decay heat. Thus the steam generators may not repressurize, even though HPI has failed. Hence, additional information is required to fully understand the secondary system responses for small breaks with failure of HPIS.

Primary system inventory is the fundamental parameter which should be used to determine whether or not HPIS is successful. Adequate makeup would best be indicated by reactor vessel water level. As long as the core remains submerged, then there is assurance of adequate inventory. However, analyses have shown that vessel level may fluctuate substantially, even with HPIS operation, depending on

* This comparison shows that for a given size break, the primary system depressurizes to a lower level if HPIS operates. However, this information is not of use to the operator in determining whether or not HPIS is effective.

break size and location. In the early part of the accident, it may not be possible to determine if HPIS is successful simply by monitoring vessel water level. Hence without an effective measure of primary system inventory, the operator must rely on monitoring the performance of the safety injection system. The most direct parameter which will indicate the success or failure of HPIS is the flow in the injection lines leading to the cold legs. Based on the best available small LOCA analyses, it appears that this information is required by the operator to unambiguously distinguish between a state where safety injection flow is adequate (S-1) and a state where it is not (S-14).

The response of the containment parameters is not significantly affected by the failure of the HPIS. Hence, the behavior described for the State S-1 is applicable to this state as well.

UNCERTAINTIES AND SENSITIVITIES:

The lack of documented analysis for this postulated condition - i.e., small break followed by a failure of all injection flow - restricts the ability to define adequate accident signatures. Analyses currently exist for only the first 10 minutes for a 1 in. and a 2 in. cold leg break. In the smaller break, the reactor pressure has not even begun to stabilize at 10 minutes.

Another area that is uncertain is the response of the secondary side pressure for breaks larger than 2". It needs to be determined if secondary repressurization will occur for all small breaks with insufficient injection flow.

STATES: S-15 THROUGH S-17

These three states are analogous to States S-2 through S-4. They represent the plant states after the operator has successfully isolated the break and thus the primary inventory loss has been stopped. The operator actions required to bring the plant to a safe cold shutdown condition are described in these sections. The only difference between State S-15 and S-2 is that the primary inventory in the former state may be less when the break is isolated. This is because of HPI failure prior to State S-15. Hence, there may be a need to provide more makeup to restore the primary coolant mass to its normal level. Furthermore, the fault which disabled HPIS may also affect the ability to use the charging pumps for makeup. However, with the system isolated, the operator has time to repair this condition. Furthermore, the Zion plant has a third positive displacement charging pump which is not used in the SI mode. This pump should be available to restore water level after break isolation.

These differences do not affect the particular operator actions or significantly alter the plant symptoms which the operator utilizes to diagnose the plant state and take the necessary actions. Hence, the discussions for States S-2 through S-4 are valid for States S-15 through S-17.

STATE: S-18

At this state, a small break has occurred and HPIS has failed to provide coolant to the core. The operator has been unable to isolate the break; hence, the primary coolant inventory is being depleted.

REQUIRED OPERATOR RESPONSE:

After the operator recognizes that HPIS has failed, he must quickly* find a way to provide coolant to the core to prevent core damage. The only systems which could perform this function are the accumulators and the low pressure injection system (LPIS). However to utilize either system the reactor pressure must be reduced. The accumulators inject water when the pressure drops below 600 psi and the LPIS requires that pressure be reduced below 200 psi to deliver adequate flow.

The operator can reduce pressure by opening the atmospheric dump valves (ADV's) associated with each steam generator secondary. This will dramatically increase the heat removal rate from the primary, thereby lowering the reactor pressure. Auxiliary feedwater must be maintained to the steam generators during this action to facilitate heat removal. The operator should ensure that the LPIS is properly aligned and that the pumps are operating, so that coolant will be readily available once the pressure is reduced. After the pressure has been reduced, adequate makeup to the core should be verified.

KEY SYMPTOMS:

This state is a continuation of State S-14. Thus, the symptoms described for this state are applicable to State S-18.

* The time available to perform the actions described in this section or the backup action described in State S-22 depends on the break size. For a 2 inch break, the core will begin to uncover in 30 minutes. However, for a 1 inch break the operator has 2 hours before the fuel becomes exposed.

ADDITIONAL COMMENTS:

It is important that the operator open the ADVs on all steam generators. Otherwise the primary system may not depressurize sufficiently to initiate LPIS. Steam generators with closed ADVs act as heat sources to the primary and thus counteract the reactor pressure loss. Even if LPIS is successfully actuated, there may be problems in maintaining coolant flow, as the system could repressurize above the LPI pump shutoff head. Hence it is necessary to depressurize through all four steam generators to ensure adequate system pressure reduction for continuous LPIS operation.

STATE: S-19

This state represents the plant condition during a small break LOCA followed by a failure of HPIS. The operator has recognized the failure of high pressure injection. To supply makeup to the core, he has successfully depressurized the reactor by opening the ADVs and actuated the LPIS. LPIS operation has restored vessel water level and prevented significant fuel damage.

REQUIRED OPERATOR RESPONSE:

The operator should monitor LPIS operation to ensure a continuation of effective heat removal. The water level in the RWST will decrease as the low pressure pumps draw on this source. Eventually the operator must switch to the recirculation mode to ensure continued flow of coolant to the core. The operator must realign the LPIS to take suction from the containment sump and deliver water through the RHR heat exchangers and into the cold legs. The operator must ensure that the component cooling water system is operating to remove heat through the RHR heat exchanger.

KEY SYMPTOMS:

The opening of the atmospheric dump valves causes a rapid depressurization in the steam generators and the primary system. This is illustrated in Figure 3.10 for a 1 inch cold leg break. The operator is assumed to have opened all ADVs 10 minutes after the break occurs in this analysis. When the pressure drops to 600 psi (345 seconds after the ADVs have opened in Figure 3.10) the accumulators begin to inject water into the core. The accumulator levels decrease steadily until their inventory is depleted. The primary and secondary coolant temperatures follow the pressure transient as illustrated in Figure 3.11.

Opening the ADV's will result in flashing of the secondary coolant in the steam generators. This will likely lead to swelling of the water level (as indicated by the level instrumentation) as the two phase mixture rises within the steam generator. Although water level may appear to increase, the actual inventory is being depleted by dumping of the steam. After the secondary side has blown down, auxiliary feedwater operation will restore inventory and steam generator water level will rise.

Containment temperature and pressure are being controlled by the fan coolers and/or the containment spray system. The water level in the sump is gradually increasing.

Until the LPIS actuates, the RWST level remains unchanged unless containment spray is operating. LPIS operation causes the RWST level to drop (or decrease at a faster rate if containment spray is running).

STATE: S-20

At this state, long-term cooling has been successfully established. Water is being recirculated from the containment sump back into the primary system. The RHR heat exchangers are removing the core decay heat. At this state the required operator response and key symptoms are identical to State S-7, although the sequence of events which produced State S-20 are different. These events are listed below:

- small break LOCA which is not isolated
- HPIS fails
- operator depressurizes through ADVs and provide makeup with LPIS
- recirculation is successfully established.

REQUIRED OPERATOR RESPONSE:

See State S-7.

KEY SYMPTOMS:

See State S-7.

STATE: S-21

The sequence of events leading to this state is initiated by a small break in the reactor coolant system. However, the HPIS fails to inject water to compensate for the fluid lost out the break. Hence, the operator has depressurized the reactor using the ADV's and successfully provided coolant with the LPIS. At this state it is assumed that the transition to recirculation was unsuccessful or that recirculation failed after having operated for some period.

REQUIRED OPERATOR RESPONSE:

The operator must attempt to repair the failures which caused the unavailability of recirculation cooling. The specific actions will depend upon the failures that disabled the LPRS. If the operator was unable to align the LPIS for recirculation, then there is a limited time available to perform repairs. The operator could attempt to buy time by continuing the injection mode of operation. This would require that the operator realign the LPIS to take suction from the RWST. The operator must also take immediate action to supply additional water to the RWST. If the RWST is not completely drained, the operator should terminate all demands on this source until makeup to the tank is established. If the operator is successful in restoring injection, and supplying adequate water to the RWST, core damage can at least be temporarily avoided.

There is a limit as to how long this mode of operation can be maintained. Eventually the water level in containment will rise and may submerge (and fail) critical circuits or components, thus resulting in a loss of injection flow. In addition, rising water level may produce excessive loads on the containment structure leading to a loss of containment integrity and the release of radioactivity to the outside environment. Thus, injection can not be continued indefinitely. However, this action should buy substantial time in which to repair the failures which disabled or prevented recirculation.

Recirculation failure can also result from a failure to adequately cool the sump water before returning it to the core. If the RHR heat exchangers fail to cool the sump water, the water temperature will begin to increase and could reach saturation conditions. Cavitation could fail the RHR pumps as they attempt to transport the two phase mixture. This failure mode would occur after the ECCS has been realigned for recirculation and operated in this configuration for some period. Failure of the RHR heat exchangers would be indicated by increases in the sump water temperature, the temperature in the heat exchanger discharge lines, and the reactor coolant temperature, in conjunction with verification of adequate flow to the cold legs. Once these trends are identified, the operator should attempt to restore heat removal through at least one of the RHR heat exchangers before RHR pump failure terminates recirculation flow. This will likely involve repair of some fault in the component cooling water system or one of its supporting systems. If this can not be accomplished, the operator will have to re-establish the steam generators as the primary heat sink. This will require the use of AFW. Hence, the operator must ensure adequate inventory in the CST (see State S-4).

KEY SYMPTOMS:

Opening of the ADV's has reduced the primary and secondary pressures to less than 200 psia. The primary and secondary coolant temperatures have decreased during the blowdown as well. During the depressurization, the accumulators have discharged their inventory into the primary. Hence these tanks are empty. Injection with the low head RHR pumps has restored vessel inventory and the RWST is close to empty. The containment conditions are as described in S-19. The sump water level should be sufficient for transition to recirculation.

Analyses have not been performed to address the case where recirculation fails subsequent to depressurization and successful LPIS injection. Hence, the immediate response is somewhat uncertain. The accident signature will depend somewhat on how recirculation fails. If flow is lost, the primary inventory would begin to decrease. This would be reflected by a decrease in pressurizer level, followed later by a draining of the reactor vessel. Other direct indications of a loss of recirculation flow would be a gradual increase in sump water level and an absence of coolant flow in the RHR system. Sump water level would be expected to stabilize after recirculation is established. Shortly after the loss of flow, reactor pressure and temperature would begin to rise slowly.

If a loss of heat removal occurs the response would be different. The immediate symptoms would be a lack of sump water temperature reduction across the RHR heat exchangers. Some symptoms would be present on the secondary side of these components, the most likely being an absence of component cooling water flow. Because the RHR pumps are still operating, the primary system inventory and sump water level would be stabilized. However, the water temperature of the recirculation flow would increase very slowly. This would gradually cause the reactor coolant temperature to increase. The increased break flow temperature would gradually affect the sump water temperature. Eventually if heat removal is not restored, the sump water could reach saturation and RHR pump cavitation could occur.

UNCERTAINTIES AND SENSITIVITIES:

There are several uncertainties with respect to the operator actions described by this state. These will be noted briefly in this section.

The capability to provide makeup to the RWST is unknown. The demineralized water system probably has insufficient capacity to keep up with the LPIS pump demands. It is unknown whether or not there are other systems which the operator could use to refill the RWST within the time constraints of the accident.

As noted earlier, best-estimate calculations have not been performed for this failure condition. Hence, the primary pressure and temperature response is uncertain. One area which is highly uncertain is the system response for a loss of the RHR heat removal capability. For example, could sufficient heat be removed through the steam generators to substantially delay or avoid pump cavitation as a result of saturation conditions in the sump?

STATE: S-22

At this state, a small break LOCA has occurred, but the HPIS has failed. The break has not been isolated so the primary system inventory continues to decrease. The only option available to prevent core damage is to depressurize the system and attempt to use the low pressure injection system. The operator either does not or can not depressurize the system by opening the atmospheric dump valves. Hence, the system pressure remains elevated and inventory continues to be discharged through the break.

REQUIRED OPERATOR RESPONSE:

If at all possible, the operator must attempt to correct the condition that precludes dumping steam through the ADV's. In order to buy time to perform any necessary repairs, the operator can prevent fuel overheating by re-establishing forced convection in the core. This requires starting the RCP's to increase the flow of water and steam through the core. This will prevent an increase in fuel temperatures which would follow core uncovery if forced coolant flow were not available.

If this action is not successful, the operator has one remaining option for depressurizing the primary system. The PORV's located on the pressurizer can be opened to directly reduce primary system pressure (as opposed to an accelerated cooldown through the steam generators). This action effectively increases the size of the break. Because the discharge through the PORV also increases the primary system coolant depletion rate, it is essential that the operator ensure that the LPIS is ready for operation when the system drops below $\sim$ 200 psi. Since the core may become partially uncovered during the blowdown, any significant delay in providing coolant could result in fuel damage.

If the operator successfully depressurizes through the PORVs, he must closely monitor the system pressure and LPIS performance. It is possible that the system could repressurize above the LPIS pump shutoff head and thus terminate injection flow.* In this case, the operator must continue to vent steam through

*The reason for this is that primary side voiding in the steam generators with the closed ADVs effectively decouples these loops from the core. However, once the accumulators and LPIS inject coolant into the system, these secondary loops will recouple and act as heat sources to the primary system.

the PORVs to attempt to reduce reactor pressure and thus restore injection flow. If possible, the secondary side pressure should be reduced (although this action is assumed to be unsuccessful at this state, the operator now has bought some additional time which might be utilized for repairs).

KEY SYMPTOMS:

This state is a continuation of the plant conditions which existed at States S-14 and S-18. The discussion provided for State S-14 is applicable to this state as well.

UNCERTAINTIES AND SENSITIVITIES:

The primary repressurization following LPIS injection which is discussed under "Required Operator Response" has not been analyzed. Some simplified calculations have been performed which indicate that once the system repressurizes, the operator may not be able to reduce pressure below the LPIS pump shutoff head before core damage occurs using only the PORVs. Nevertheless, this action is the only available option and must at least be attempted. Of course, the desired action would be to reduce secondary side pressure which would terminate the repressurization.

As noted under "Required Operator Resonse," the operator may be able to buy time to make repairs by restarting the RCP's. There are some uncertainties associated with this action. Some questions which need to be addressed include:

- How long can the pumps operate in this mode? Operation of the pumps will accelerate the loss of primary coolant.
- How effective is this action in reducing RCS pressure?
- Can the RCP's continue to operate when the coolant has a significant void fraction?

STATE: S-23

At this state, a small break LOCA has occurred, but HPIS has failed. The operator was not able to isolate the break, but was successful in lowering the primary system pressure and providing coolant to the core with the LPIS. The depressurization was achieved by opening the PORVs on the pressurizer. The system pressure is reduced and LPIS has restored primary system inventory.

REQUIRED OPERATOR RESPONSE:

The operator actions for this state are similar to those for State S-19. The operator should monitor LPIS operation to ensure a continuation of effective heat removal. As noted in State S-22, this may require continued venting through the PORVs or additional attempts to depressurize the steam generators. The water level in the RWST will decrease as the low pressure pumps draw on this source. Eventually the operator must switch to the recirculation mode to ensure continued flow of coolant to the core. The operator must realign the LPIS to take suction from the containment sump and deliver water through the RHR heat exchangers and into the cold legs. The operator must ensure that the component cooling water system is operating to remove heat through the RHR heat exchanger. The only difference between this state and State S-19 is that the time when the operator must transfer to recirculation operation may occur more quickly because the PORV opening has created a more rapid loss of primary system inventory.

KEY SYMPTOMS:

The opening of the pressurizer relief valves causes a rapid decrease in primary system pressure. However unlike State S-19, the steam generator secondary side pressure remains elevated, and the water level relatively constant (unless the operator is able to depressurize).

Initially the fluid released through the PORV's enters a discharge tank. However, this volume will fill and pressurize relatively quickly. The rupture disk will open releasing coolant to the containment. This water will collect in the sump along with the coolant released out the break.

Successful LPIS operation will be indicated by increasing vessel water level,* decreasing RWST level, and adequate flow in the injection lines.

The containment temperature and pressure are being maintained by the fan coolers and/or the containment spray. There may be a brief period of rising pressure and temperature after the rupture disk on the PORV discharge tank bursts. This transient should be turned around by the containment ESFs.

UNCERTAINTIES AND SENSITIVITIES:

Repressurization of the primary system may occur after the LPIS and accumulators begin to inject coolant (see discussion in State S-22). If this occurs, the LPIS pumps may cease to provide flow. This condition has not been analyzed; hence it is not possible to estimate the duration of repressurization, or its consequences. It is quite possible that the operator will be unable to keep the primary pressure below the LPIS shutoff head without depressurizing the secondaries. In any case, it appears that some pressure oscillations could be expected because of the large amount of stored energy in the steam generators. If this condition persisted, there may be complications in transferring to recirculation operation.

*Core uncovery is expected for this state.

STATES: S-24 AND S-25

These states are the same as States S-20 and S-21.

STATE: S-26

At this state, a small LOCA has occurred, HPIS has failed, and the operator has failed to provide any means of inventory replenishment. It is assumed that the operator either could not, or did not attempt to depressurize the reactor and use the LPIS. The core will uncover and fuel damage will occur.

REQUIRED OPERATOR RESPONSE:

The operator should verify that the containment is completely isolated and ensure the availability of the containment spray system to mitigate the consequences of fission product release following core damage. The administrative, emergency, and evacuation procedures should be implemented as appropriate for a core damage event.

KEY SYMPTOMS:

At this state, the reactor and secondary pressures are above the accumulator set point. The core is uncovered and fuel temperatures are increasing. Fuel failures and melting release large quantities of fission products. This results in a sharp increase in containment activity. Containment water level continues to rise as a result of the break flow and containment spray operation. Containment temperature and pressure are relatively stable as long as containment spray is operating.

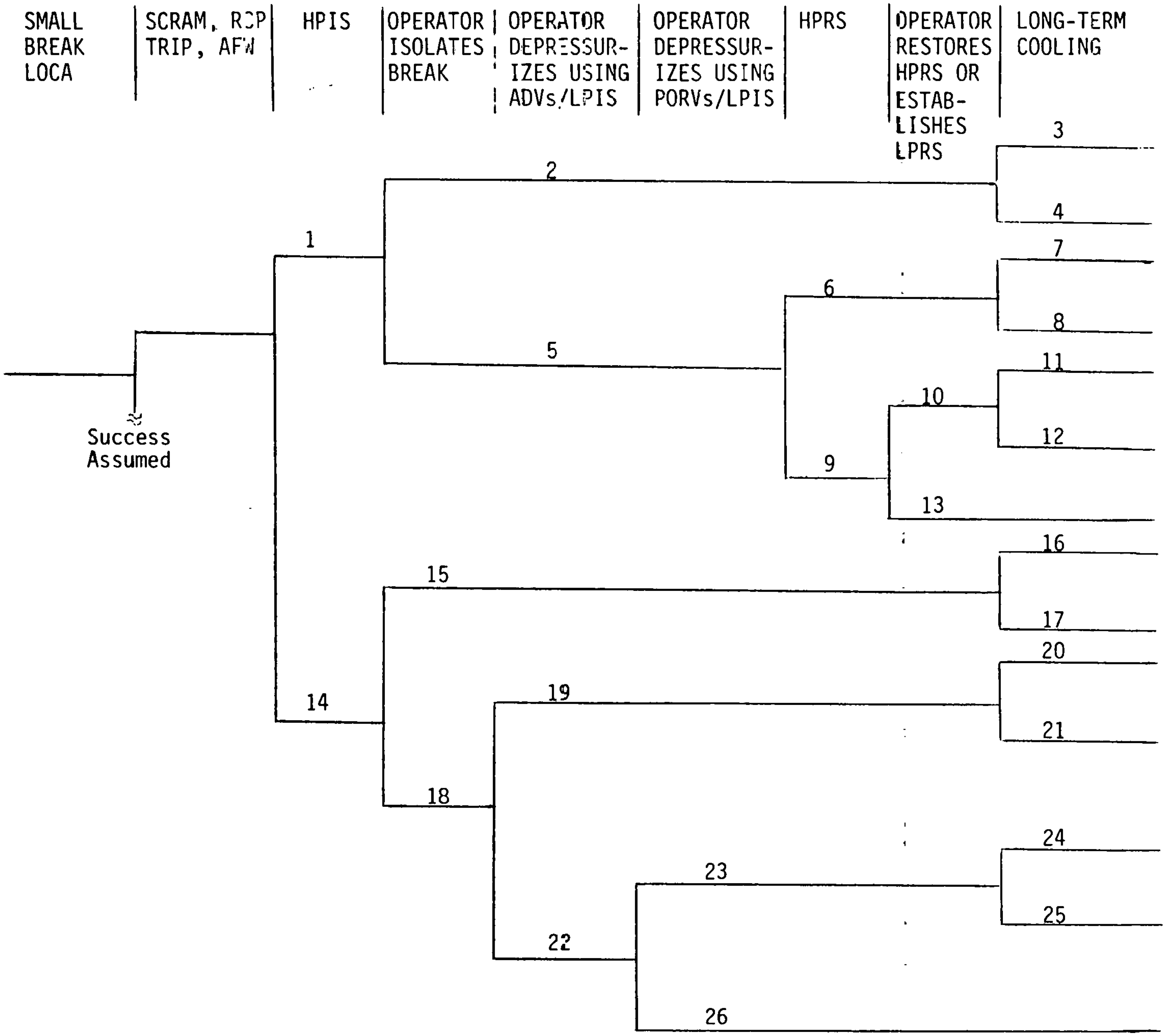


Figure 3.1 Operator Action Event Tree for Small Break LOCA Sequences

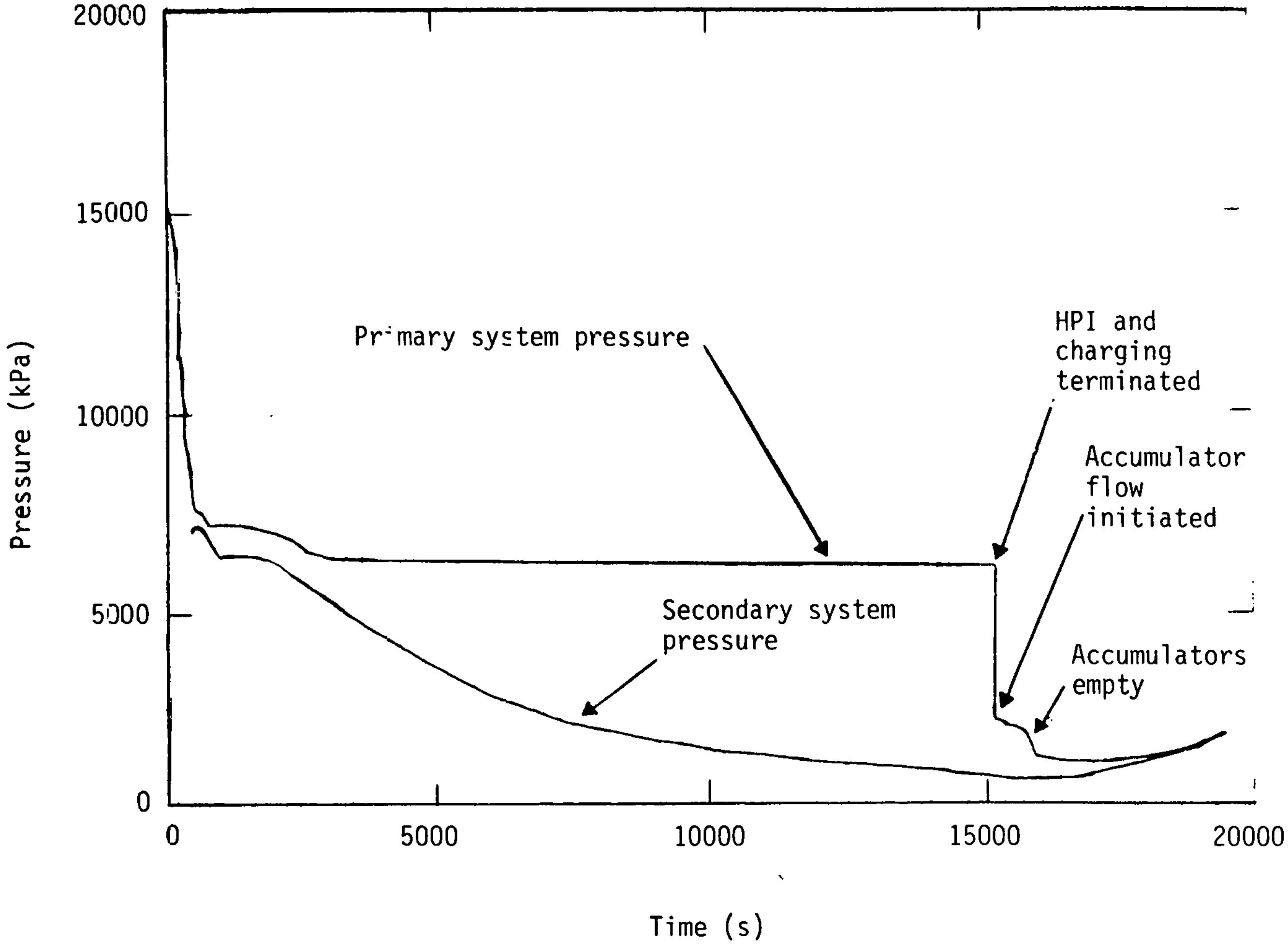


Figure 3.2 Primary and Secondary Pressure Response for a 1.5 Inch Cold Leg Break with Failure of HPRS.

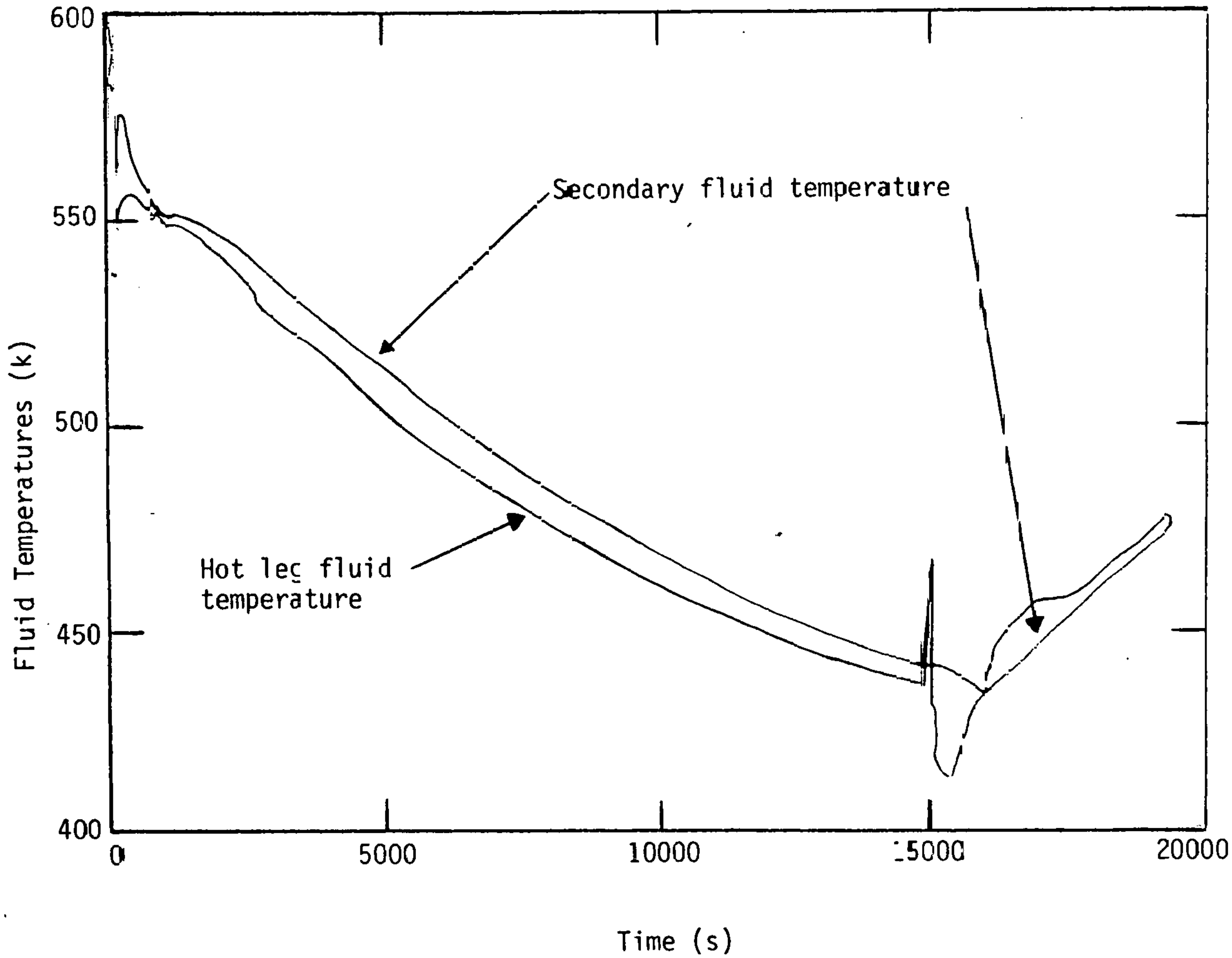


Figure 3.3 Primary Hot Leg and Secondary Coolant Temperature for a 1.5 Inch Cold Leg Break with Failure of HPRS.

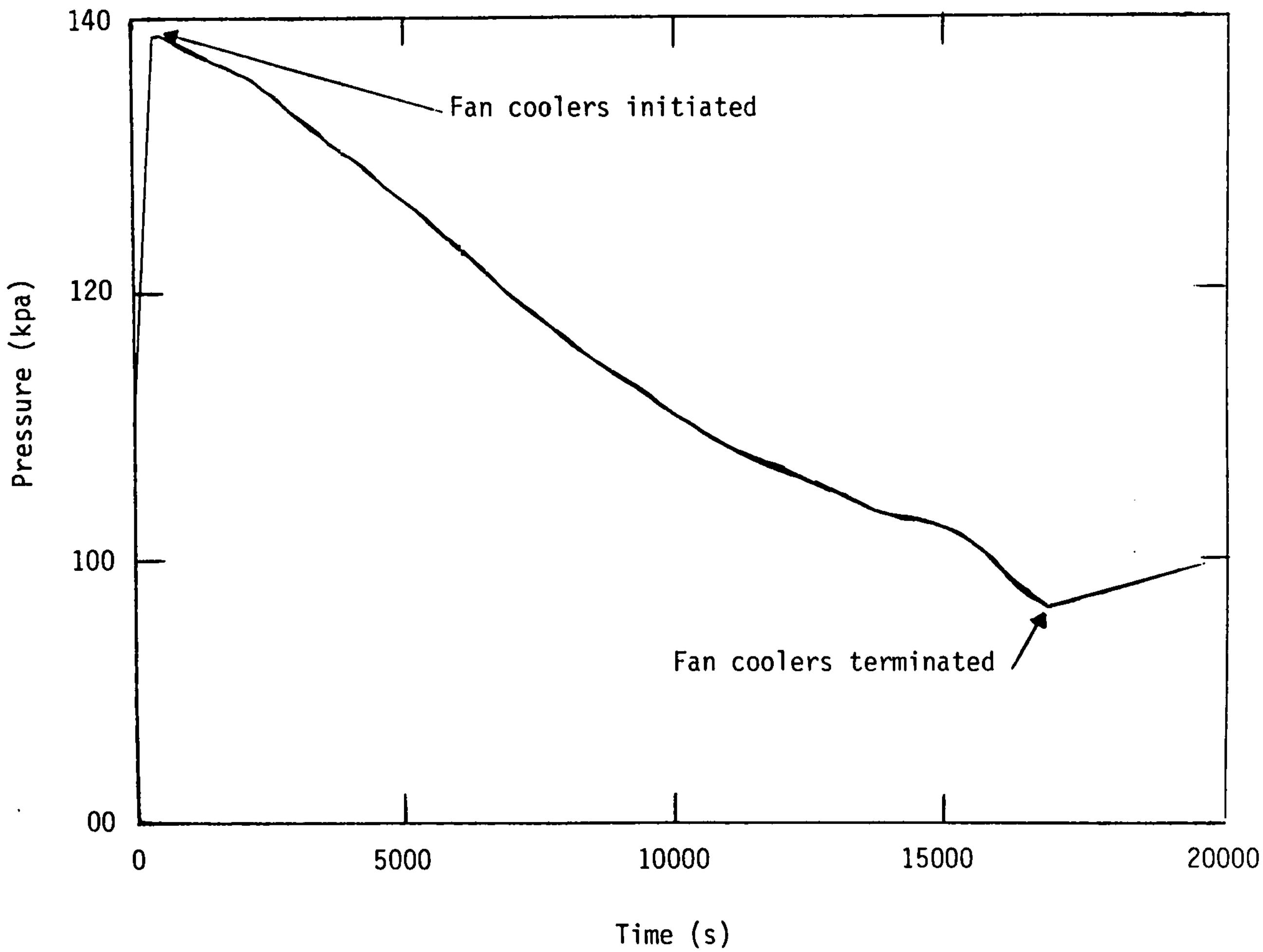


Figure 3.4 Containment Pressure for a 1.5 Inch Cold Leg Break with Failure of HPRS

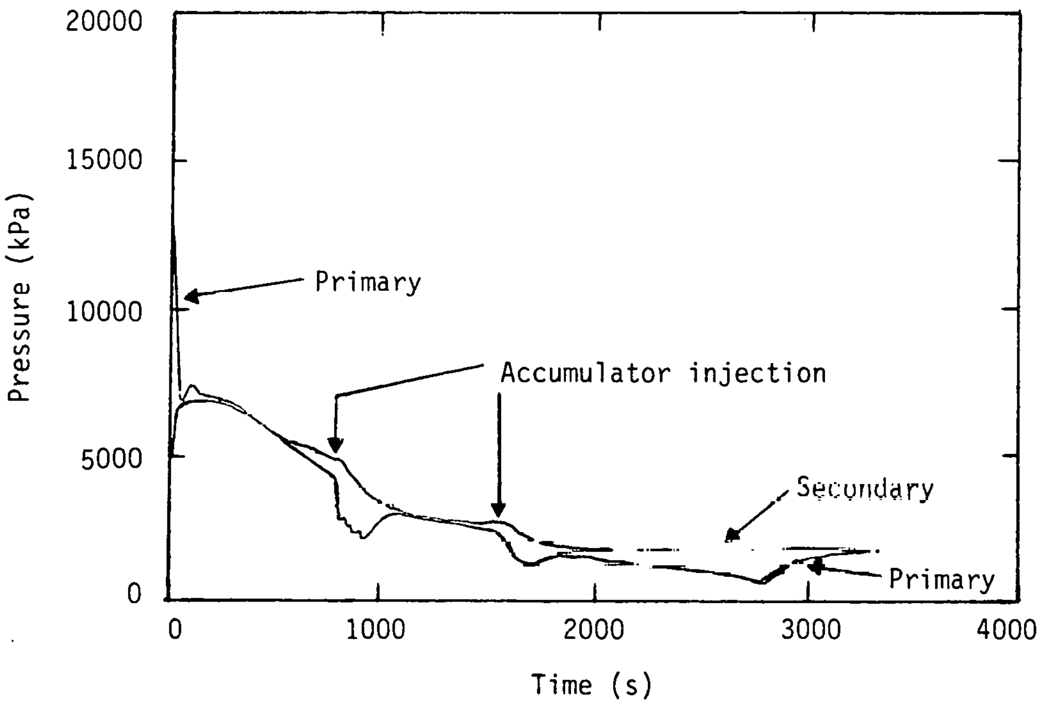


Figure 3.5 Primary and Secondary Pressure Response for a 4 Inch Cold Leg Break with Failure of HPRS

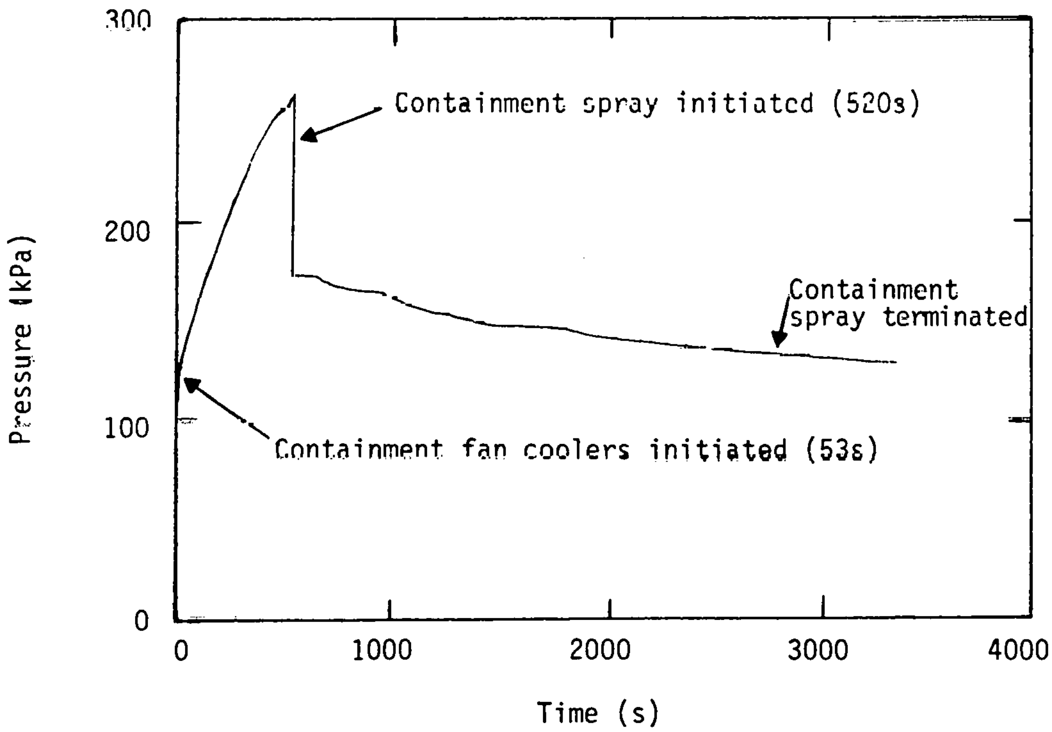


Figure 3.6 Containment Pressure Response for a 4.0 Inch Cold Leg Break with Failure of the HPRS

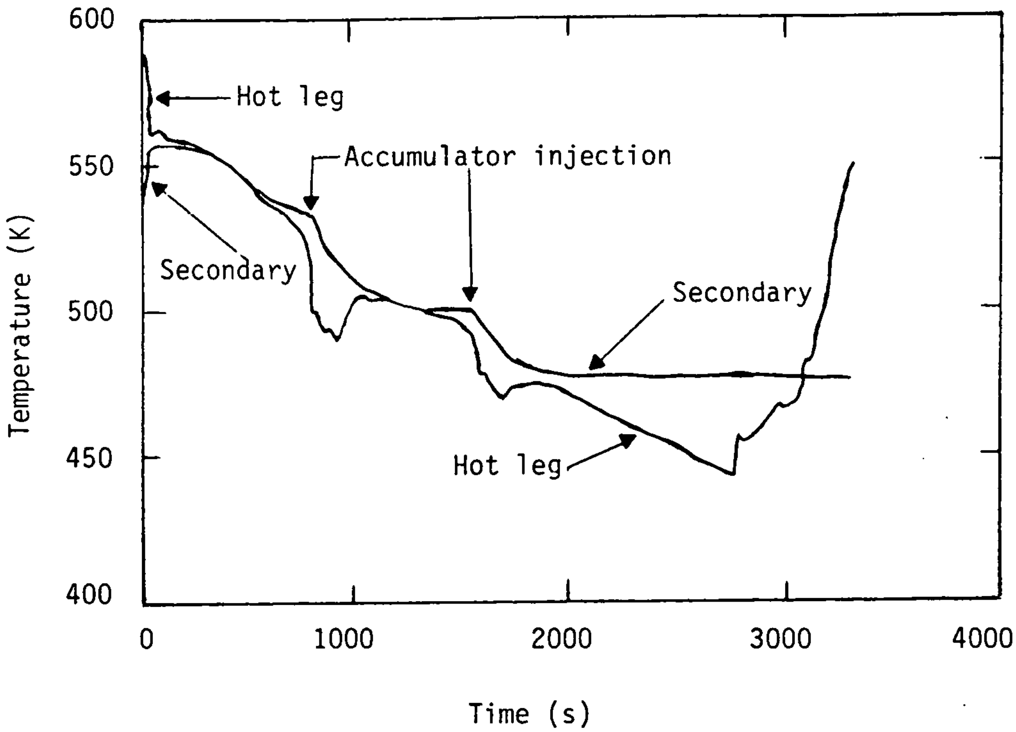


Figure 3.7 Primary Hot Leg and Secondary Coolant Temperatures for a 4.0 Inch Cold Leg Break with Failure of HPRS

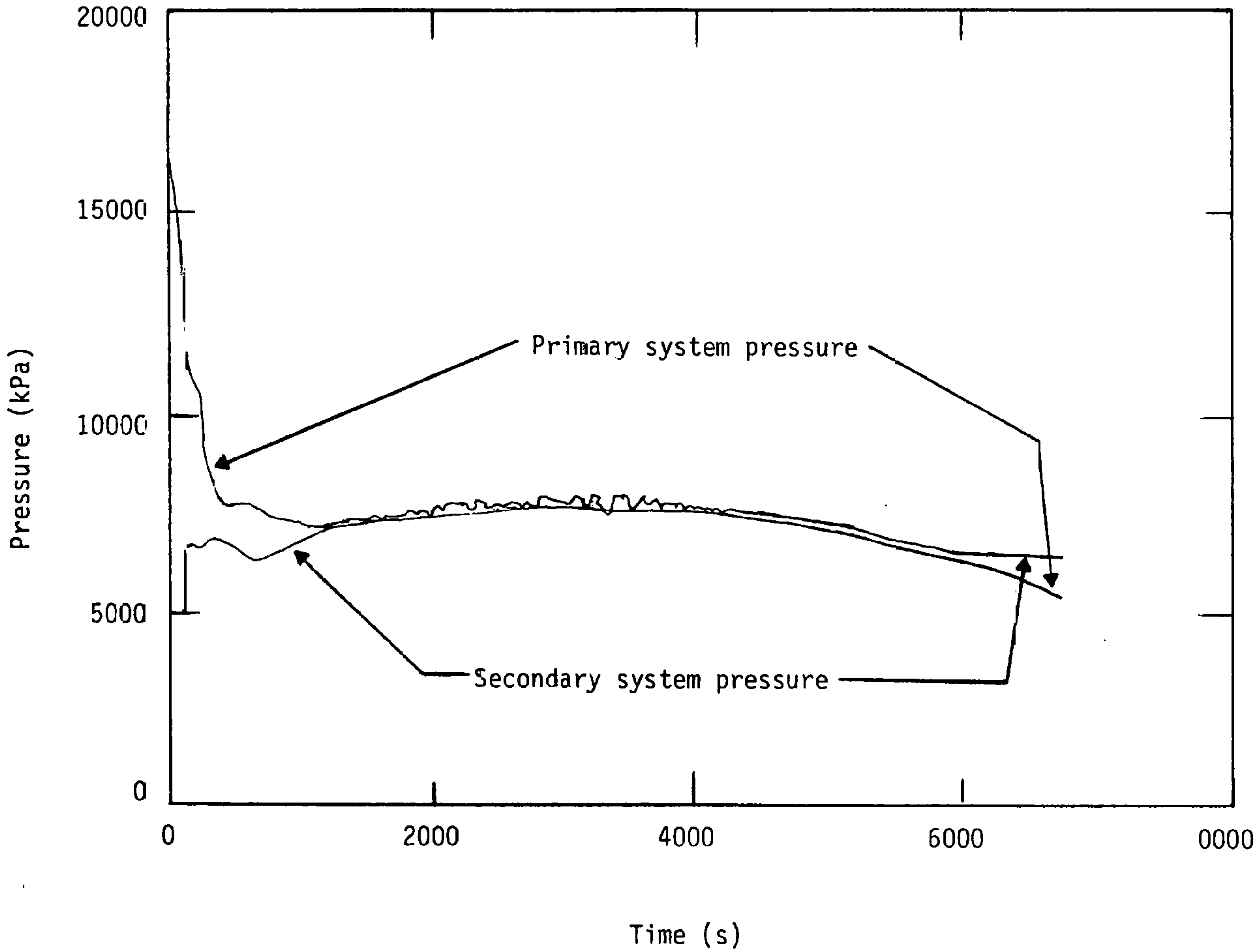


Figure 3.8 Primary and Secondary Pressure Response for a 1.5 Inch Cold Leg Break with Failure of S1 Pumps (Charging Pumps Operating)

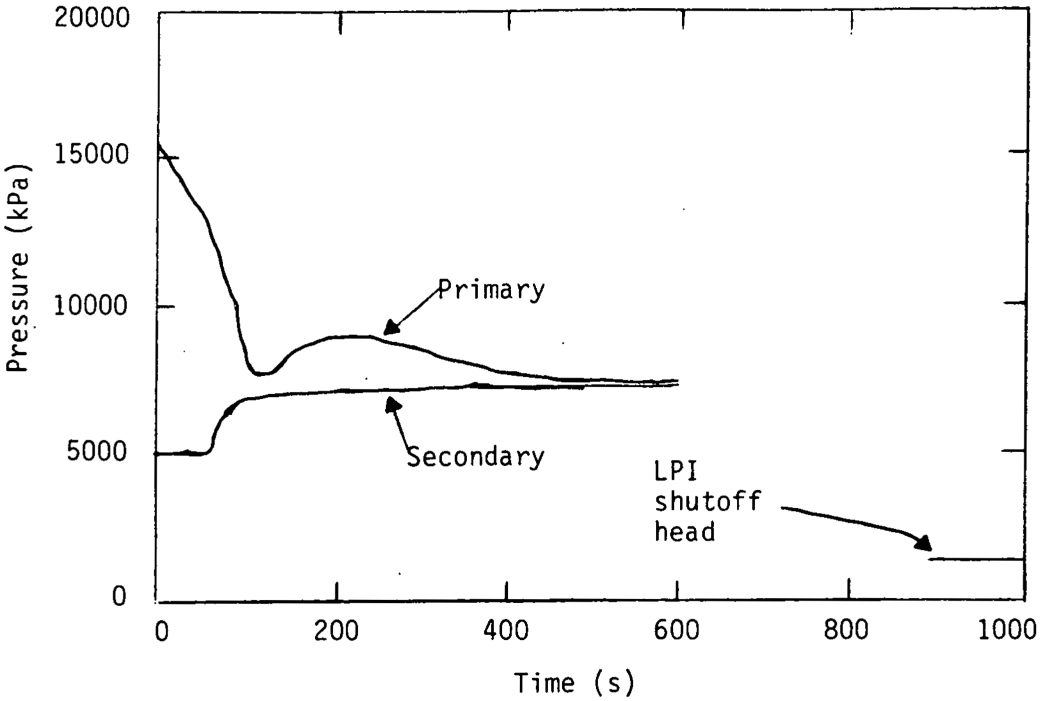


Figure 3.9 Primary and Secondary Pressure Response for a 2 Inch Cold Leg Break with Failure of All ECCS Injection.

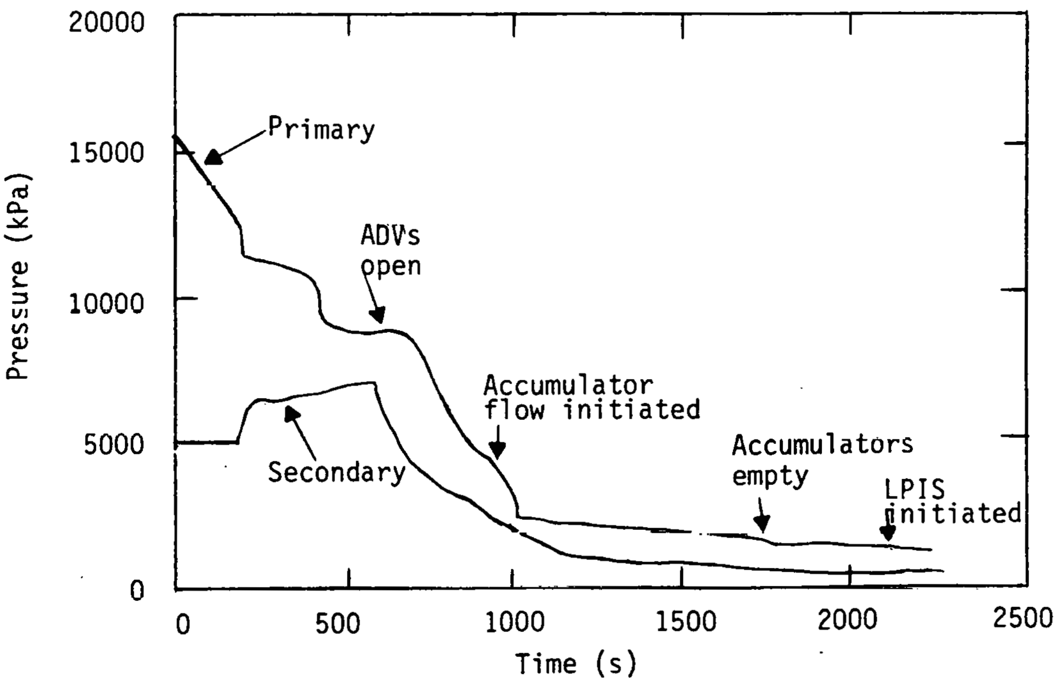


Figure 3.10 Primary and Secondary Pressure Response for a 1 Inch Cold Leg Break with Failure Of All ECCS Injection; Operator Opens All ADV's at 10 Minutes.

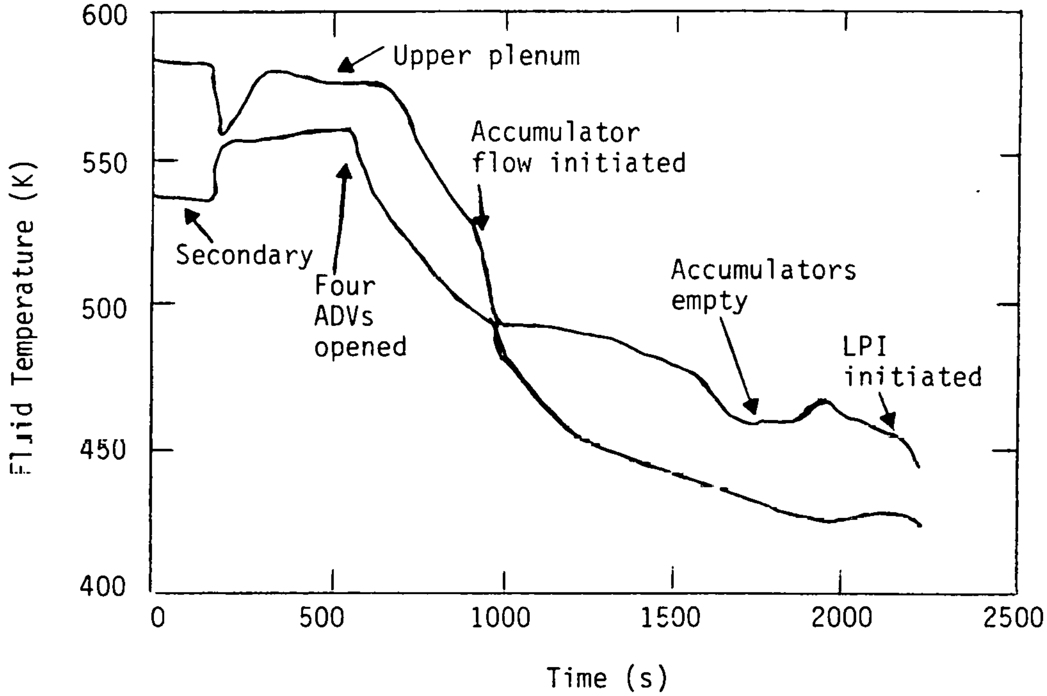


Figure 3.11 Upper Plenum and Secondary Coolant Temperature Response for a 1.0 Inch Cold Leg Break. Operator Opens All ADV's at 10 Minutes.

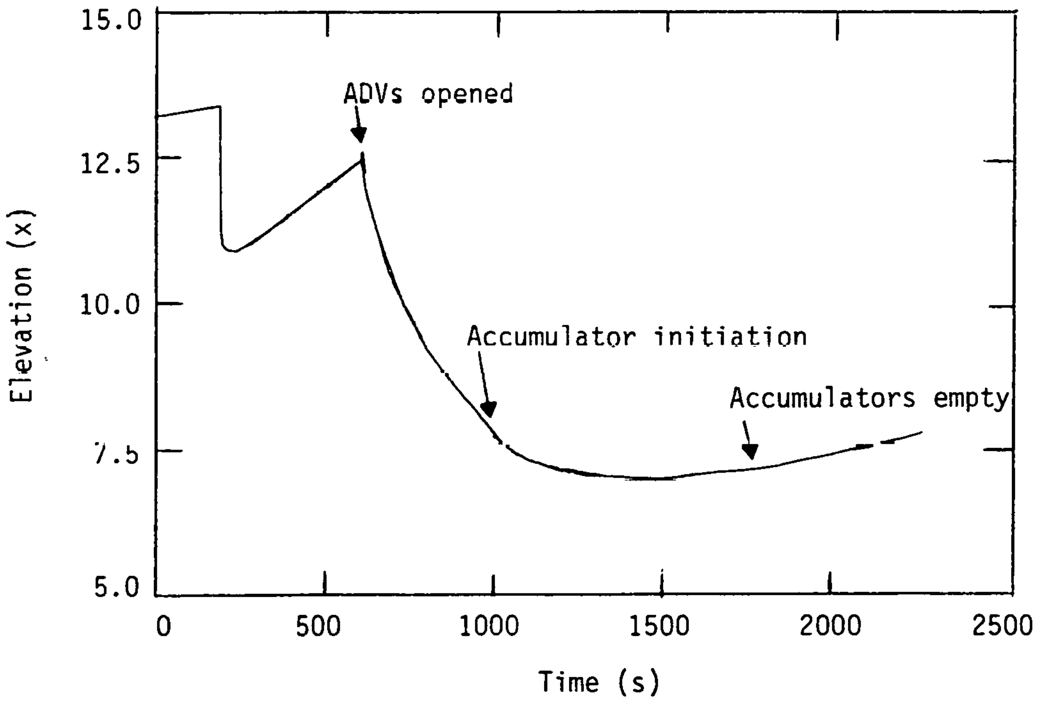


Figure 3.12 Steam Generator Secondary Water Level Response for a 1 Inch Cold Leg Break. Operator Opens All ADV's at 10 Minutes.

3.1.2. Steam Generator Tube Rupture

Several incidents have occurred in PWR's in which the integrity of the primary coolant system has been broken through ruptures or leaks in steam generator tubes. Under most circumstances the leaks are small and the inventory makeup can be easily handled by the CVCS. However, for larger ruptures, operation of the ECCS and operator action are required to prevent core damage and minimize radionuclide release to the atmosphere. A steam generator tube rupture results in some unique characteristics which differentiate the transient from other small breaks. One very important feature is the transfer of mass from the reactor coolant system to the steam generator. This results in a path for release of radioactivity to the environment and thus presents the operator with an important additional concern at the initiation of the event. Furthermore, experience has shown that the plant response during a steam generator tube rupture event may give the operator ambiguous information regarding the appropriate corrective actions that should be performed.

This section discusses the system response and key operator actions for steam generator tube ruptures. As considered in this section a rupture is defined to be a break such that the transfer of mass from the reactor coolant system to the steam generator secondary side is greater than the makeup capability of the CVCS. Because best-estimate analyses for these types of events are not available, it is not possible to illustrate the response of key plant parameters graphically as was performed for the small LOCA (Section 3.1.1.). However, some information is available describing incidents at Prairie Island Unit 1, Surry Unit 2, Point Beach Unit 1 [14] and Ginna [15], which has been factored into the development of the OAET for steam generator tube ruptures. The OAET is given in Figure 3.13 and the key plant states are described in the following sections. Because this OAET was based in part on experience with tube ruptures, the accompanying description is somewhat more generic in nature than the previous section on small breaks. The format is the same as utilized for the small break LOCA OAET in Section 3.1.1.

STATE: SGTR-1

State 1 represents the plant status immediately after the occurrence of a steam generator tube rupture (SGTR) and the initial automatic plant responses. For this evaluation, a SGTR is assumed to be a break in the primary boundary of the SG such that the resulting transfer of coolant from the primary to the secondary system exceeds the makeup capabilities of the CVCS. The size of the break and the charging pump response determine the rate of primary system depressurization, and therefore how rapidly the subsequent automatic responses occur. The important automatic responses subsequent to a SGTR are a reactor trip followed quickly by a safety injection actuation signal. A safety injection signal results in a containment isolation signal and the subsequent tripping of the main feedwater pumps. The auxiliary feedwater system is actuated automatically to maintain steam generator inventory. The diesel generators are also automatically started as a precaution against a loss of offsite electrical power. Some of these key automatic responses are noted in the second event tree heading (Figure 3.13). This state of the OAET assumes that each of these automatic plant responses is successful. Hence, at this state the reactor power is reduced to decay heat generation and heat removal is occurring through the steam generators. The HPIS has initiated operation to counteract the loss of primary coolant and the reactor depressurization.

REQUIRED OPERATOR RESPONSE:

The operator's initial responses are to verify that the appropriate automatic responses have occurred, and to diagnose the event as a SGTR. Subsequent to this set of actions, the operator should determine which steam generator contains the break and attempt to isolate it.

Depending on the size of the tube rupture, the operator may recognize that a SGTR has occurred before the reactor trips. In other situations, the trip and the associated automatic actions may alert the operator to the existence of an abnormal event. For such cases, the operators would be attempting to diagnose the event while verifying automatic safety system response. The key symptoms which the operator should observe to confirm the presence of a SGTR are addressed in the following section on "Key Symptoms". The important immediate operator actions are summarized in the following list:

- Verify that an automatic trip has occurred. If not, manually scram the reactor.

- Verify that the AFWS has actuated and that the water level in the steam generators is being restored or maintained at the proper level. Manually initiate and control auxiliary feedwater if necessary.

- Verify actuation of the HPIS and realignment of the charging pumps for safety injection when the reactor pressure drops to the safety injection setpoint. Ensure that the letdown line in the CVCS is isolated. [If the depressurization is slow, the operator may actuate the standby charging pump or manually initiate safety injection before the trip setting is achieved in an attempt to restore pressurizer level].

- Verify containment isolation, electrical power supply to the emergency AC bus, and operation of the service water and component cooling water pumps.

These verification actions are the appropriate responses to the initial symptoms for all sizes of SGTR's. They require no immediate diagnosis of the event. After the operator has ensured that the HPIS is functioning properly* and that primary system inventory is being replenished, the next key action is to diagnose the event as a SGTR and identify the steam generator with the tube failure(s) (i.e. the faulted SG).

Once a SGTR has been confirmed, the operator must immediately determine which SG contains the failure so that it can be isolated. This action is necessary to limit the release of radioactivity to the environment. Isolation is accomplished by closing the main steam isolation valve (MSIV) and the bypass valve associated with the ruptured SG, and terminating AFW to that SG. If the faulted SG is in a loop that supplies steam to the turbine driven AFW pump, the operator should isolate the steam supply valve in the line from the faulted SG to the turbine driven AFW pump. These actions prevent the SG from depressurizing through the steam dump system, and thus minimizes the inventory loss from the primary coolant system and the release of radioactivity outside containment.

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*For some very small SGTR's, the RCS may repressurize following HPIS actuation. For these cases, the operator may have to throttle or terminate safety injection to avoid opening a PORV (See discussion in the following "Key Symptoms and Potential Substates" sections).

KEY SYMPTOMS:

The immediate response to a SGTR event is a decrease in reactor pressure and pressurizer level as primary coolant is discharged into the secondary side of the faulted SG. The rate of pressure decay depends on the size of the tube failure and the response of the CVCS. Charging pump flow rate should increase as the automatic CVCS control system attempts to maintain pressurizer level. Following the reactor trip the pressure drops much faster due to the sudden decrease in heat generation.

Another key symptom which the operator must use to diagnose this event is a high level of radiation in the condenser air ejector. This information, coupled with the absence of any change in containment conditions (e.g. temperature, pressure, and humidity), will distinguish a SGTR from a LOCA inside containment.* Other radiation monitors in the secondary coolant system may also respond to a SGTR. Radiation monitors in the steam line** and the steam generator blowdown line associated with the faulted SG would also respond to a SGTR.

Another important initial symptom of a large SGTR event would be a steam flow-to-feed flow mismatch for the SG with the rupture. The feedwater control system sensing an increasing water level(due to in-leakage) will reduce feed flow to the faulted SG. This would likely produce an alarm prior to reactor trip.

The pressurizer water level will drop as the break flow exceeds the charging flow. After reactor trip, the reduction in level will continue as the primary coolant shrinks during cooldown. For the size of ruptures considered in this analysis, the pressurizer will likely drain before safety injection flow exceeds the break flow.

Safety injection may be initiated manually (if the depressurization transient is slow), or automatically when the low pressurizer pressure set point

*SGTR events will exhibit many characteristic responses that are similar to small LOCA's. State S-1 of Section 3.1.1 addresses how the operator can distinguish between the two events.

**This instrumentation is not available on all plants.

is reached shortly after trip. This results in actuation of the HPIS pumps and realignment of the charging pumps to take suction from the RWST. The symptoms which characterize safety injection operation are flow in the injection lines, increasing pump discharge pressures, and a decreasing RWST level*.

Operation of the HPIS will tend to counteract the RCS depressurization resulting from the loss of coolant through the SGTR. As the reactor pressure decreases, safety injection flow increases while the break flow decreases. Eventually an equilibrium pressure is reached where the break flow is approximately equal to the injection flow. This equilibrium pressure is determined primarily by the HPIS design (e.g. number of pumps and their head-flow characteristics), the response of the HPIS (e.g. all pumps may not operate at maximum capacity), and the break size. If the break is small, the primary system could even repressurize. This would occur when the break size results in a leak flow which exceeds the capacity of a single charging pump, but is less than the maximum capacity of both charging pumps (or the charging pumps and SI pumps for plants with high head SI pumps). After the safety injection signal, coolant injection more than offsets the break flow. The primary pressure transient would turn around and pressure would begin to rise. It is possible that the system pressure may not equilibrate below the pressurizer PORV set point. Hence, release through the PORV could occur, if the operator takes no action to reduce or terminate SI flow.

The secondary side pressure will increase rapidly following the reactor trip as closure of the turbine stop valve temporarily halts the flow of steam from the SG's. The dump valves will then open admitting steam to the condenser. The pressure will begin to decay gradually as the automatic control system functions to reduce system temperatures. Depending on the relative timing of events, the break size, and the variability in operating conditions, the SG relief valves may open briefly after reactor trip to limit the pressure rise in the SG's. Pressure in the faulted SG may be higher than that of the other SG's. However, this difference depends on the break size and the response of the AFWS.

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*Reactor pressure may not be a reliable indicator of adequate safety injection flow. See discussion in Key Symptoms section of State S-14 for small break LOCA.

After the main feedwater pumps are tripped, water level in the SG's begins to decrease until AFW flow is supplied. AFWS operation will eventually return the water level in the intact SG's to their normal operating range. Water level in the SG with the tube rupture may be somewhat higher than the other three SG's as a result of leakage from the primary system. This difference may not be immediately observable if the AFW flow to the SG's is not balanced and the break flow is relatively small. Hencc, it may not always be possible, to readily identify the faulted SG by comparing secondary side water levels. However, if the symptoms discussed below do not yield positive identification of the faulted SG, the operator can successively isolate each SG and monitor water level. The SG with the tube rupture will show a rising water level with steam and feed flow isolated.

The faulted SG can be identified by either high radiation in the steam line leaving the faulted unit or high radiation in the faulted SG blowdown line. These parameters would of course remain unchanged in the intact SG's, thus the failed SG can be distinguished. Since the SG blowdown lines are isolated by a SI signal, the operator will have to reopen the necessary valves for each SG sequentially until the faulted SG is discovered.

UNCERTAINTIES AND SENSITIVITIES:

The plant response can vary significantly depending on the size of the SGTR. The general considerations relative to the effect of break size discussed in state S-1 of the small LOCA OAET are applicable to a SGTR event as well.

POTENTIAL SUBSTATES:

One potential substate which could affect the operator response is the repressurization of the primary system after safety injection is initiated. As discussed previously, this would only occur for a very small range of tube rupture sizes - those which just exceed the capacity of the CVCS. If the system repressurizes above the normal operating pressure, a PORV or safety valve* could

*Many plants have closed the block valves downstream of the PORV's because of leakage. If all PORV's were isolated, a safety valve would open.

open and fluid would be released through this valve. Since these breaks have not been analyzed for the Zion plant, it is uncertain if repressurization to the PORV setting could occur. However, analyses for similar plant designs have predicted this occurrence. Hence, this condition is noted as a possible substate.

The operator action for this condition is to throttle or terminate high pressure injection to avoid PORV actuation. This action avoids an unnecessary discharge of coolant from the primary system. Before altering the HPIS flow, the operator must ensure that adequate cooling is being provided to the core. This can be accomplished be ensuring adequate subcooling of the hot leg coolant, adequate inventory, and provisions for continued heat removal and makeup. If the operator terminates HPIS, conditions must be closely monitored to see if continued leakage through the tube rupture requires the HPIS to be reactivated. The operator may want to reset SI, if pressurizer level and system pressure have been restored. It is possible that intermittent HPI operation may be required.

STATE: SGTR-2

At this time the operator has successfully diagnosed the event as a SGTR and identified the SG with the rupture. The faulted SG has been isolated by closing its MSIV and terminating its supply of AFW. The steam supply to the turbine driven AFWP from the faulted SG has been terminated, thus halting the release of radioactivity to the environment. The reactor has tripped and the HPIS is supplying makeup to the primary system. The automatic steam dump system should activate and begin a gradual cool-down of the plant by dumping steam from the intact SG's to the condenser. If for some reason the condenser is unavailable, steam will be released through the ADV's once the pressure reaches their actuation setting. Secondary pressure will then oscillate around this level as the valves automatically open and reclose.

REQUIRED OPERATOR RESPONSE:

The primary objective of the operator at this plant state is to terminate the discharge of primary coolant through the tube rupture by lowering the RCS pressure below the pressure in the faulted SG. Once the loss of coolant has been terminated, the operator can restore inventory and bring the plant to a safe cold shutdown condition.

Although the faulted SG has been isolated on the secondary side, primary fluid will continue to leak through the tube rupture as long as the RCS pressure is greater than the secondary side pressure. In addition to depleting RCS inventory, continued leakage could result in lifting of the SG ADV or safety valves, thus re-establishing a path for release of radioactivity to the environment. The operator can halt the break flow by lowering the RCS pressure below that of the faulted SG secondary side pressure, thus eliminating the driving force for coolant discharge. This depressurization must be performed carefully to avoid creating saturation conditions in the RCS, and risking extensive voiding and potential fuel damage in the reactor core. This can be accomplished by first cooling the RCS using the intact SG's, and then depressurizing the system.

The steam dump system is presumably operating automatically to reduce system pressures and temperatures in accordance with the normal procedure for a post-trip shutdown. Because this process is a slow one, the operator should manually control the discharge of steam to the condenser for a faster cooldown. The cooldown rate using this approach will be limited by the need to avoid excessive thermal stresses of the RCS structures and the need to maintain condenser vacuum. The operator should cool the RCS to a temperature such that subcooling is ensured when the pressure is reduced below that of the ruptured steam generator.

If for some reason the steam dump is unavailable, or the cooldown rate is not as rapid as desired, the operator can vent through the ADV's in the intact SG's. These valves may open automatically after turbine trip as secondary pressure rises after stop valve closure. If the steam dump system is not available, these valves will cycle about their setpoints to remove heat transferred from the RCS. To enhance the RCS cooldown, the operator must manually hold the ADV's open so they do not reclose when the SG pressure drops to the reclosure setpoint. The operator should ensure adequate water level is being provided by the AFWS*. Manual control for AFW flow and the steam release rate may be required to ensure a uniform cooldown through the intact loops and to maintain SG water level in the proper range. As noted previously, the operator should cool the RCS to a temperature such that subcooling is ensured when the primary is depressurized below the pressure in the faulted SG.

KEY SYMPTOMS:

Successful isolation of the faulted SG should be reflected by a gradual decrease in the radiation level in the condenser air ejector lines, and the blowdown line of the faulted SG. The pressure in the faulted SG will be increasing as leakage continues into the generator. The rate of increase of the pressure and water level in the faulted SG will depend on the break size and pressure difference between the RCS and faulted SG secondary.

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*Rapid dumping of steam from the SG's can cause flashing and swelling in the SG. This would create water level readings that are not a true representation of the SG liquid inventory. The operator must be careful not to terminate AFW flow on this misleading information.

If the steam dump system is available, the pressure and temperature in the intact SG's will gradually decrease as steam is released to the condenser. As the secondary side is depressurized, the primary coolant temperature will gradually decease, following the secondary temperature transient in the intact SG's.* If the condenser is not available as a heat sink, the pressure in the secondaries will oscillate around the ADV automatic set points.

Several factors interact to determine the primary pressure behavior and significantly different responses could be observed following a SGTR event. The primary pressure response will depend on the break size, the pressure in the secondaries, and the HPIS response. After the initial depressurization following the SGTR and reactor trip, the RCS pressure should tend to stabilize about a value where the SI flow equals the break flow. For small SGTR's this could mean that the RCS would repressurize following HPIS actuation (see State SGTR-1).

POTENTIAL SUBSTATES:

A potential substate at this plant condition, and until such times as the operator successfully reduces the RCS pressure to terminate the leak, is the possibility of opening an ADV or safety valve in the faulted SG. This could occur because the faulted SG has been isolated, yet primary coolant is still being discharged through the break. This would increase the pressure in the faulted SG, perhaps to the relief valve setpoints. Whether or not these pressures are reached depends on several factors including the break size, RCS pressure, the cooldown rate through the intact secondaries, and the conditions (e.g. temperature, pressure and water level) in the faulted SG prior to isolation. The only operator action to prevent relief valve opening in the faulted SG, or limit the release through these valves, is to accelerate the RCS cooldown and depressurization as described in states SGTR-2 and 3.

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*If the RCP's have tripped, the primary temperature transient will lag behind the secondary side. Furthermore, hot leg temperature in the loop with the faulted SG may remain higher than those in the other loops because natural circulation will not be significant.

If these relief valves do open, there is the possibility that they may fail to reseat once the SG secondary pressure drops below the valve closure setting. Should this occur, the faulted SG will be continuously releasing radioactivity to the environment. Furthermore, the faulted SG will begin to depressurize, thus making it much more difficult to stop the leak by primary system depressurization. The reduction in faulted SG pressure will also increase the likelihood of voiding in the RCS during the cooldown and depressurization phase.

A stuck open relief valve would be indicated by a falling pressure in the SG beyond the valve reclosure setting. Valve position indication could also inform the operator of a stuck-open valve*, as would observation of steam release from the plant yard and perhaps the site boundary radiation alarm. SG water level may not be a reliable indication of the stuck open valve as flashing could create swelling in the SG.

Once the presence of a stuck-open valve is confirmed, the operator should close the block valve associated with the ADV. (This is a manual valve, requiring an operator to go to the valve location.) If a safety valve is leaking there is no action the operator can take to terminate the discharge of coolant to the environment. Instead the operator should proceed with the primary depressurization as rapidly as possible (but not so rapidly as to cause fuel failure, and thus increase the radiation release).

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*Valve position is not always reliable. The limit switch could indicate valve closure when in fact the valve did not reseat properly or there was some seat damage.

STATE: SGTR-3

At this state the operator has successfully diagnosed the event as a SGTR and isolated the faulted SG. The primary coolant system temperature is being reduced by dumping steam to the condenser or through the ADV's of the intact SG's. The RCS temperature eventually reaches a value such that the primary coolant in the core and the coolant loops will remain subcooled when the system is depressurized below the pressure in the isolated, faulted SG. Primary system inventory is being restored by operation of the HPIS.

REQUIRED OPERATOR RESPONSE:

The operator should monitor the primary system cooldown. After adequate RCS subcooling has been ensured, the primary coolant system must be depressurized to a value less than the pressure in the faulted SG. There are two primary ways to accomplish this objective.* The preferred method is to use the pressurizer sprays. The coolant used for pressurizer spray is taken from the cold leg downstream of the RCP. Pump operation provides the driving force to deliver water to the pressurizer. Hence, RCP operation is required to utilize the PZR sprays. The availability of these pumps will depend on the initial depressurization following the SGTR. The criteria for automatic RCP trip are activation of HPIS and depressurization below a specific value (a design dependent value lower than the SI setpoint). In developing this OAET, it is assumed, that the SGTR is large enough to activate safety injection. However, the break may not depressurize the RCS sufficiently to trip the RCP's. HPIS operation may cause the pressure to stabilize above the RCP trip setting. In this case, the normal pressurizer spray could be used to lower primary pressure.

If the RCP's are unavailable to power the pressurizer sprays, the alternate method for depressurizing the primary system is to manually open a pressurizer PORV. The operator should manually hold one PORV open until the RCS

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*It may also be possible to depressurize the primary system sufficiently by dumping steam from the secondaries. See "Uncertainties and Sensitivities".

pressure is reduced below the pressure in the faulted SG. This will result in a loss of primary coolant inventory, with the associated risk of failure of the PORV to reseat. (See State SGTR-10).

If neither of the previous methods can be used, the operator can use the pressurizer auxiliary sprays. These draw water from the CVCS and do not require RCP operation. This method of depressurization is usually considered to be the least preferred because of the thermal shock associated with injecting cold fluid through the auxiliary spray lines. Isolation of the CVCS upon SI initiation precludes using the normal method of preheating this water with letdown line flow.

KEY SYMPTOMS:

This state is typified by a relatively high pressure in the faulted SG (which has been isolated) and significantly lower pressures in the other SG's. Depending on the leak rate and other factors, the relief valves in the faulted SG may be cycling. Water level in the faulted SG will depend on the leak rate and the SG inventory at the time of isolation. Water level may be above normal with water entering the steam line and possibly being released through the relief valves.

The HPIS is operating and restoring inventory. Hence, the RWST level is decreasing. Water level may be re-established in the pressurizer. If RCP's are operating ("success path" of the branch after SGTR-3), full primary flow in the loops, will cause the reactor hot and cold leg coolant temperatures to decrease steadily at a rate similar to the secondary temperature response in the intact SG's. Because heat removal through the SG containing the tube rupture is less effective than the heat transfer in the intact SG's, primary cold leg temperatures in the loop associated with the faulted SG may be slightly higher than the other loops. With the excellent mixing provided by the RCP's, any steam bubbles which may have formed after the initial RCS depressurization following the break should be dissipated in a relatively short time.

The RCS pressure is primarily dependent on the break size, the response of the HPIS, and the rate at which heat is being removed through the intact SG's.

A description of the effect of break size is given in the "Uncertainties and Sensitivities" section of State S-1 of the SB LOCA OAET (Section 3.1.1). This discussion is generally applicable to the SGTR event as well. However, the heat removal through the intact SG's and the influence of the isolated SG will alter the characteristic responses associated with the different break sizes. If the operator is rapidly dumping steam from the intact SG's there may not be a case where repressurization of the primary system occurs. The RCS pressure would more likely be relatively stable or decreasing slightly for breaks at the lower end of the break size spectrum. Larger size breaks (for a given secondary cool down rate) would probably have a somewhat more rapid pressure decay.

If the RCP's have tripped ("failure path" of the branch following state SGTR-3), the RCS heat removal is being accomplished by natural circulation in the loops associated with the intact SG's. Due to the lack of forced circulation, the RCS temperature will decrease much more slowly than if the RCP's were providing flow. The hot leg of the primary loop associated with the faulted SG would be at an elevated temperature relative to the other loops as near-stagnant flow conditions would exist. This presence of this "hot loop" will maintain a relatively stable RCS pressure during the secondary cooldown phase.

In contrast, the cold leg temperature in the loop associated with the faulted SG may be less than the cold leg temperatures in the other loops. This is due to the injection of cold SI water into relatively stagnant loop.

Temperature differences throughout the RCS will also be much greater without forced flow. In particular, the temperature difference between the hot and cold legs in the intact loops will be much greater than that for forced flow conditions. The operator will have to take this fact into account when cooling the RCS prior to depressurization. Natural circulation may create local hot spots where the temperature is significantly greater than at the location of the temperature sensor utilized to determine adequate RCS cooling. Hence, to prevent the formation of voids in the core and hot leg during the depressurization phase, the operator will have to reduce the temperature at the monitored location sufficiently to ensure subcooling at these hotter locations.

UNCERTAINTIES AND SENSITIVITIES:

The major uncertainty at this state is the RCS pressure behavior during the time when steam is being dumped to the condenser or released through the ADV's. For some cases it appears that the primary pressure may not be significantly reduced during secondary system cooldown and that depressurization of the RCS below that of the faulted SG will require the additional actions discussed for this state. This would be expected for smaller size breaks or cases where the RCP's are tripped.In other situations, it may be possible to depressurize the RCS by rapidly dumping steam from the secondaries. In this case further operator actions to depressurize the primary may not be necessary. Analyses for SGTR events where the ADV's are held open are not available. Hence, it is not possible to predict exactly what effect this action would have on the primary pressure for different SGTR sizes.

STATE: SGTR-3a

This state on the OAET represents the situation where the operator has successfully diagnosed the event as a SGTR, identified the SG with the failure, and isolated that SG on the secondary side. However, the operator either does not or can not use the intact SG's to cool the primary system. Hence, the system would be at a quasi-equilibrium condition. Heat removal from the RCS would be accomplished by periodic cycling of the SG relief valves. The RCS pressure would remain elevated at some value greater than the pressure in the ruptured steam generator. Hence, the flow through the break would continue. This would eventually fill the secondary side of the faulted SG and coolant would be discharged through its relief valves. The core would be in no immediate danger as the HPIS would be maintaining inventory. However, continued operation at this state is undesirable. First, the release of coolant through the relief valves in the faulted SG will increase the release of radioactivity to the environment. In addition, the RWST inventory will eventually deplete. The operator must replenish this water source to avoid uncovering the core and subsequent fuel damage. This state is probabilistically insignificant, but is included to illustrate the symptoms associated with failure to perform the actions described in state SGTR-2.

REQUIRED OPERATOR RESPONSE:

If this state occurs because the operator failed to perform the correct actions, the obvious operator response is to rediagnose the situation, consult the procedures, and then perform the actions discussed in state SGTR-2.

In the improbable case of a loss of condenser in conjunction with the loss of manual control capability for all ADV's on all of the intact SG's, the operator must attempt to repair one of these failures. This would entail restoring the main condenser as a heat sink, or repairing the ADV's control mechanism so that the operator can hold these valves open when the SG pressure drops below their reclosure set point. During the time these repairs are being performed, the operator must monitor core conditions and ensure that HPIS is maintaining adequate inventory. If the repairs require a significant time (periods approaching a day), then the operator will probably need to replenish the RWST inventory.

KEY SYMPTOMS:

The key parameter which would distinguish this state from state SGTR-3 is the secondary side pressure in the intact steam generators. The pressure would be oscillating about the relief valve set points as a result of the failure to depressurize the secondary side. Primary system pressure and temperatures would stabilize at some level determined by the break size and safety injection flow. HPIS is maintaining adequate inventory, although the pressurizer may not refill for some period (depends on the break size). As discussed in previous states, the RCS may repressurize for very small SGTR's. This could require the operator to terminate HPIS to avoid lifting the pressurizer PORV, and increasing the loss of primary coolant.

Water level in the faulted SG is increasing, and eventually coolant may be discharged through the relief valves. This would increase the release of radioactivity to the environment. Unlike state SGTR-3, there is little difference in secondary side pressure between the intact and the faulted SG's.

STATE: SGTR-4

At this state the operator has effectively terminated the loss of coolant through the tube rupture. The key actions which have been performed to accomplish this functions are:

- isolation of SG with tube rupture
- cooldown of RCS by dumping steam from intact SG's to the condenser, or venting steam through the ADV's.
- depressurization of RCS below faulted SG pressure using pressurizer sprays (RCP's available).

Decay heat is being removed through the SG's in the intact loops. RCS inventory is being restored by operation of the HPIS.

REQUIRED OPERATOR RESPONSE:

The operator's actions at this state are directed toward bringing the plant to a safe, cold shutdown condition and minimizing further releases through the tube rupture. After depressurization has been achieved, continued safety injection pump operation will begin to repressurize the RCS. Hence, the operator must terminate SI in order to avoid reestablishing flow through the break. The operator should only terminate SI when he has positive indication that RCS inventory has been restored and that there are no paths for coolant leakage other than through the tube rupture. The SI termination criteria are plant dependent but involve ensuring that:

1) RCS pressure is increasing: This verifies that inventory is increasing and that there are no other major leakage paths. This also insures that any voids formed during the depressurization phase are collapsed.

2) Pressurizer level has been re-established: In conjunction with increasing pressure, this confirms that RCS inventory is sufficient.

3) RCS is adequately subcooled: This minimizes the potential for vapor bubble formation.

After termination of the HPIS, the operator must establish charging and letdown flows to maintain pressurizer level. The RCS cooldown should be continued by continuing steam dump to the condenser. Before the RHRS can be activated, the faulted loop must be depressurized. Although this SG will gradually depressurize as the RCS pressure is reduced, further action may be necessary to reduce pressure to less than 400psi. This is accomplished by gradually releasing steam from the isolated SG to the condenser or through the atmospheric dump valve. Care must be maintained to ensure that the pressure in the faulted SG remains greater than the RCS pressure during this process. This will likely require use of the pressurizer sprays.

It may also be necessary to restore auxiliary feedwater flow to the faulted SG during this process to maintain control of the RCS and faulted SG pressures during cooldown. Water level in the faulted SG should be sufficient to cover the SG tubes. Otherwise steam condensation on the cold tubes could result in a sudden drop in SG pressure and a loss of pressurizer level.

The final key operator action is to activate the RHRS. This completes the transition to a cold, shutdown condition. The RHRS can be activated once the hot leg temperature is less than 350°F and the RCS pressure drops below 400 psi. In depressurizing the system to this level, the operator should isolate the accumulators from injecting when the pressure falls below their injection set points. In addition, the boron concentration should be monitored to ensure adequate shutdown margin at cold temperatures.

KEY SYMPTOMS:

After the operator terminates the RCS depressurization by ceasing spray flow, the reactor pressure will begin to increase as a result of continued operation of the safety injection pumps. The RCS pressure may increase above the pressure in the faulted SG and flow out the break may resume. This may cause an increase in the water level and pressure in the faulted SG. Continued operation of the HPIS will restore water level in the pressurizer if it was drained during the depressurization. Injection of cold SI water, increasing reactor pressure, and the mixing provided by RCP operation will collapse any remaining voids in the RCS. The AFW pumps are maintaining inventory in the intact SG's and the secondary pressure is being gradually reduced as the plant cooldown continues.

STATE: SGTR-5

At this state the operator has diagnosed the event as a SGTR, but has been unable to isolate the secondary side of the SG with the failure. Hence there is a pathway for continuous transport of radioactivity to the environment. Furthermore, it may not be possible to maintain RCS subcooling during subsequent actions to cooldown and depressurize the primary system if the faulted SG is not isolated from the other SG's.

The automatic plant responses to a SGTR are assumed to be successful at this state. The reactor has tripped and the HPIS is supplying makeup to the primary system. The automatic steam dump system should activate and begin a gradual cooldown of the plant by dumping steam from the intact SG's to the condenser. If for some reason the condenser is unavailable, steam will be released through the ADV's once the pressure reaches their actuation setting. Secondary pressure will then oscillate around this level as the valves automatically open and reclose.

REQUIRED OPERATOR ACTION:

If the secondary side of the faulted SG can not be isolated using the MSIV of its steam line, the operator should close the MSIV's and their bypass valves associated with the intact SG's. This will effectively isolate the unit with the tube rupture so that the primary can be depressurized with little or no voiding in the core or hot legs. This action precludes the use of the main condenser as a heat sink. The operator must cooldown the plant by releasing steam from the intact SG's through the ADVs in the intact SG's.

KEY SYMPTOMS:

Failure to isolate the faulted SG would result in continued release of radioactivity. Thus radiation monitor readings (e.g. condenser air ejector) would remain elevated. The pressure in the faulted SG would depend on the size of the tube rupture, and the pressure in the intact steam generators. This latter effect would be expected to dominate in most cases. Thus, if the intact SG's were gradually depressurizing as part of the plant cooldown, the pressure in the faulted loop would exhibit a similar behavior. This behavior is in contrast to state SGTR-2 where successful isolation results in increasing pressure in the faulted SG. The other symptoms associated with state SGTR-5 are the same as those for state SGTR-2.

STATE: SGTR-6

At this state the operator has successfully isolated the secondary side of the faulted SG by closing the MSIV's and bypass valves in the steam lines associated with the other, intact secondaries. This action was necessary because the operator was unable to isolate the faulted SG (state SGTR-5). The other plant automatic responses are assumed to be successful at this state. These include reactor trip and actuation of HPIS.

REQUIRED OPERATOR RESPONSE:

The operator's objective at this state is to cooldown and depressurize the primary system. Once the RCS pressure has been reduced below the pressure in the faulted SG, the loss of coolant will be terminated and releases to the environment minimized. This process must be done carefully to minimize the potential for voiding in the core and hot legs. Hence, the operator should first reduce RCS temperatures prior to depressurizing. Because the MSIV's and their bypass valves in the intact SG's were closed to isolate the faulted SG, it will not be possible to cooldown the plant using the main condenser. Instead the operator must manually open the ADV's on the intact SG's and release steam to the atmosphere. It will be necessary for the operator to manually hold these valves open when the pressure drops below their automatic reclosure set point. The operator must also ensure adequate water level is being provided by the AFWS. Manual control of AFW flow and steam release may be required to insure a uniform cooldown and to maintain SG water level in the proper range. This action will lower secondary side pressure and temperature in the intact SG's and remove heat from their associated primary coolant loops.

KEY SYMPTOMS:

The plant response at this state is the same as at state SGTR-2 except that the main condenser is unavailable. Hence, steam is being released through the ADV's in the intact SG's after isolation of the faulted SG has been completed. Thus, the secondary pressure in the intact SG's is oscillating about the ADV set point as these valves cycle to relieve pressure.

UNCERTAINTIES AND SENSITIVITES:

See State SGTR-2

POTENTIAL SUBSTATES:

See State SGTR-2

STATE: SGTR-6a

At this state the operator has diagnosed that a SGTR has occurred, but has been unable to isolate the SG with the rupture from the other intact SG's, either by closing the valves associated with the faulted unit or the MSIV's associated with the other SG's (see state SGTR-5). Hence, coolant leakage from the primary to the secondary is continuing and release to the environment has not been terminated. If the main condenser is available, the automatic control system has initiated a gradual cooldown by releasing steam to the condenser. If the main condenser is unavailable as a heat sink, the ADV's are cycling about their automatic set-points.

REQUIRED OPERATOR RESPONSE:

The operator should continue efforts to isolate the faulted SG from the intact SG's. If this can be accomplished the plant is returned to a condition represented by states SGTR-2 or SGTR-6. If this isolation can not be achieved, the operator should continue with a gradual plant cooldown taking care to minimize voiding in the primary system and the releases to the environment. Adequate HPIS flow must be maintained to prevent core uncovery.

KEY SYMPTOMS:

The symptoms exhibited at this state are the same as described for state SGTR-5. The failure to isolate the faulted SG has not altered the plant condition.

STATE: SGTR-7

The sequence of events leading up to this state are:

- SGTR
- Reactor trip followed by actuation of HPIS, containment isolation, and actuation of the AFWS.
- Operator diagnoses the event as a SGTR, but is unable to isolate the secondary side of the faulted SG by closing valves in its steam line.
- Operator successfully isolates the faulted SG by closing the MSIV's and bypass valves of the other, intact SG's.
- RCS cooldown is being accomplished by releasing steam through the ADV's on the intact secondaries.

State SGTR-7 and all states that could evolve from this condition are very similar to state SGTR-3 and its subsequent plant states. Hence, the logic structure in the OAET subsequent to state SGTR-7 has not been illustrated for reasons of simplicity.

REQUIRED OPERATOR RESPONSE:

The next operator action is to depressurize the RCS below the pressure in the faulted SG. The operator actions to accomplish this are described in State SGTR-3.

KEY SYMPTOMS:

The key symptoms of state SGTR-7 and all subsequent states are similar to state SGTR-3, and the conditions evolving from that plant state. The only difference is the unavailability of the main condenser at state SGTR-7.

STATE: SGTR-7a

This state represents the postulated condition where the operator is unable to cooldown the RCS by releasing steam through the ADV's on the intact SG's. It is analogous to state SGTR-3a and is considered to be probabilistically insignificant.

STATE: SGTR-8

At this state, the operator has diagnosed the event as a SGTR, identified the SG with tube failure, and isolated that unit. The RCS has been cooled below the saturation temperature corresponding to the pressure in the faulted SG by dumping steam from the intact secondaries to the atmosphere or to the condenser. The RCP's are still operating; however the operator either did not or could not depressurize the primary system using the pressurizer sprays.

REQUIRED OPERATOR RESPONSE:

The operator must depressurize the primary below the pressure in the ruptured SG to terminate the leak. This can be accomplished by opening a pressurizer PORV. This action releases steam to the pressurizer relief tank (PRT) and quickly lowers RCS pressure. If the RCS has been adequately subcooled prior to opening the PORV, there should be very little, if any, voiding in the core during the depressurization. If some voiding occurs, the mixing provided by RCP operation should dissipate and condense the vapor quickly.

KEY SYMPTOMS:

The symptoms at this state are the same as state SGTR-3 because the plant condition has not changed by the failure to use pressurizer sprays.

STATES: SGTR-8a and SGTR-12a

These states represent the case where the operator has successfully isolated the faulted SG and cooled down the RCS by releasing steam from the intact secondaries. However, the primary can not be depressurized using either the PORVs, the pressurizer sprays or the auxiliary sprays. These state are considered to be probabilistically insignificant and therefore subsequent states have not been further developed.

REQUIRED OPERATOR RESPONSE:

At this point the operator would continue the plant cooldown through the intact secondaries. This would gradually depressurize the RCS although it would require a considerable period of time (see "Uncertainties and Sensitivites", state SGTR-3). This would prolong the discharge of primary coolant through the rupture and therefore increase the release of radioactivity to the environment. The operator may need to supplement the RWST to maintain a source of water for the HPIS if the leak continues for a long period.

KEY SYMPTOMS

Since conditions have not changed, the key symptoms behavior at these states are the same as at state SGTR-3. The only difference between states SGTR 8a and 12a are due to the unavailability of the RCPs in the latter case. These differences are noted in the description for state SGTR-3.

STATE: SGTR-9

At this plant state, the operator has correctly diagnosed the event as a SGTR, identified the faulted SG, and isolated that unit. The RCS has been cooled below the saturation temperature corresponding to the pressure in the faulted SG by dumping steam from the intact secondaries to the atmosphere or to the condenser. The RCP's are operating; however, the operator did not or could not depressurize the RCS using the pressurizer sprays. Instead, a PORV was opened and RCS pressure was lowered below that of the faulted SG by releasing steam to the PRT. At state SGTR-9, it is assumed that the operator successfully closed the PORV at this time.

The HPIS is continuing to supply coolant to the primary system. At this time, the plant condition is similar to state SGTR-4. The main difference is that additional primary coolant has been lost as a result of discharge through the PORV. Hence, the additional SI flow will be required to restore inventory. Furthermore, release to the PRT may have exceeded its capacity resulting in a release of primary coolant to the containment.

REQUIRED OPERATOR ACTION:

The operator actions are the same as described for State SGTR-4. If the PRT rupture disk has burst, the operator may need to ensure that the containment fan coolers or perhaps the containment sprays are actuated.

KEY SYMPTOMS:

After the PORV is opened, the RCS pressure will drop rapidly. Actuation of the PORV will also be indicated by the discharge line temperature and flow as well as valve position. The pressure, temperature and water level in the PRT will also increase as primary coolant enters the PRT. Closure of the PORV can be immediately verified by a transition from rapidly decreasing to a stable or slowly increasing reactor pressure. Confirmation can also be obtained by checking the discharge line flow and valve position. Release of steam through the PORV may cause unreliable pressurizer level readings. It is possible that a two phase mixture could be forced up into the pressurizer when the

PORV is opened. This would certainly be observed if there was significant voiding in the upper head and/or steam generator tubes. This could result in an indication of rising pressurizer level. However, this would not be a reliable indicator of increasing RCS inventory as coolant is actually being discharged at this time. Closure of the PORV should result in an immediate decrease in pressurizer level, should such a false indication occur. Subsequent to PORV closure, HPIS operation will restore inventory and water will eventually re-enter the pressurizer, gradually increasing the pressurizer level.

Injection of cold SI water, increasing reactor pressure after PORV closure, and the mixing provided by RCP operation will collapse any remaining voids formed in the RCS during the depressurization. Hot and cold leg temperatures will be gradually declining as heat is removed through the intact SG's. The AFWS is maintaining level in the intact SG's and secondary pressure is gradually being reduced as the cooldown continues. Water level in the faulted SG should be stable or decreasing after RCS depressurization. Flow through the break will reverse direction when the primary pressure is brought below the faulted SG pressure. HPIS operation will repressurize the primary; hence this reverse flow and decreasing faulted SG level may not exist for a lengthy period.

UNCERTAINTIES AND SENSITIVITES:

The changes in PRT conditions accompanying opening of the PORV may be difficult to discern. This could occur because the PRT may be receiving fluid from other sources. Following containment isolation, leakage through the RCP seals can pressurize the isolated RCP seal return piping. Should this occur, coolant will be discharged to the PRT to avoid overpressurizing this line. Similarly, the PRT may receive RCS coolant from the CVCS letdown line if this system is overpressurized. Although letdown lines are isolated on a SI signal, they may automatically reopen during the event if pressurizer level is restored. It is uncertain if this condition would occur at this state.

STATE: SGTR-10

At this plant state, the operator has correctly diagnosed the event as a SGTR, identified the faulted SG, and isolated that unit. The RCS has been cooled below the saturation temperature corresponding to the pressure in the faulted SG by dumping steam from the intact secondaries to the atmosphere or to the condenser. The RCP's are operating; however, the operator did not or could not depressurize the RCS using the pressurizer sprays. Instead, a PORV was opened and RCS pressure was lowered below that of the faulted SG by releasing steam to the PRT. However, at this state, it is assumed that the PORV did not reclose when the operator actuated the switch in the control room. Hence, fluid is continuing to be released through the stuck-open valve resulting in a continued reduction in reactor pressure. Continued discharge of primary coolant to the PRT will cause its rupture disk to bust releasing water and steam into containment. The HPIS is operating providing makeup to compensate for the fluid being released through the PORV.

REQUIRED OPERATOR RESPONSE:

The operator must recognize that the PORV has not reclosed and then close the block valve to halt the discharge of coolant into the PRT. After the PRT rupture disk bursts, the operator must ensure that the containment fan coolers and/or containment sprays are actuated if containment pressurize increases.

KEY SYMPTOMS:

The most noticeable symptom accompanying the opening of the PORV will be a rapid decrease in reactor pressure. PORV actuation will also be indicated by discharge line flow and temperature, and valve position. The pressure, temperature, and water level in the PRT will all increase as primary coolant is released to this volume. Eventually, the capacity of the PRT will be exceeded and the rupture disk will burst, releasing steam and water to containment. This will cause an increase in containment temperature, pressure, humidity, and radiation. Water will also begin to accumulate in the containment sump. Failure of the PORV to reclose will be reflected by a continuation of these trends after the time when the operator attempted to close the valve. The reactor pressure will continue to decrease below the pressure in the ruptured SG.

Release of steam through the PORV may cause unreliable pressurizer level readings. It is possible that a two phase mixture could be forced up into the pressurizer when the PORV is opened. This could result in an indication of rising pressurizer level. However, this would not be a reliable indicator of increasing RCS inventory as coolant is actually being discharged at this time.

The AFWS is maintaining level in the intact SG's and secondary pressure is gradually being reduced as the cooldown continues. Water level in the faulted SG will be increasing during the time the RCS pressure exceeds the pressure in the SG. However, once the pressures are reversed, the flow through the tube rupture changes direction and the inventory in the faulted SG will decrease.

The continued depressurization caused by the stuck-open valve will result in a loss of the subcooling margin achieved during RCS cooldown (State SGTR-3). Voiding will occur in the hotter locations of the RCS after the primary pressure drops below the pressure in the faulted SG.

UNCERTAINTIES AND SENSITIVITES:

See state SGTR-9.

STATE: SGTR-11

This state is similar to state SGTR-9. The only difference is that during the time period between failure of the PORV to reclose and closure of the block valve, additional coolant was discharged from the primary system. Hence, it may take somewhat longer to restore inventory before HPIS can be terminated. The symptoms at this state are also similar to state SGTR-9. The major difference is in the extent of voiding in the RCS. As a result of the loss of coolant following failure of the PORV to reclose, the RCS will depressurize below the desired level. This would likely cause vapor formation in local hot spots in the core and reactor coolant loops as well as the as the reactor vessel upper head. The extent of voiding would depend on how long it takes the operator to recognize that the PORV has not reclosed and then subsequently close the block valve. These voids should collapse relatively quickly as the system repressurizes from HPIS operation and mixing from RCP operation dissipates the vapor to cooler portions of the RCS. Condensation of vapor formed in the upper head will be enhanced by flow through the head cooling spray nozzles. The operator actions at this point are the same as described in state SGTR-9.

STATE: SGTR-11a

In the sequence of events leading up to this state, the operator has successfully identified the SG with the tube rupture, isolated the faulted SG and reduced primary system temperature by removing heat through the intact SG's. RCS pressure has been reduced by opening a pressurizer PORV. However, at this state, the PORV has not reclosed and the operator has not been able to close the block valve in the discharge line of the stuck-open PORV. Hence, RCS inventory is continuing to deplete. The reactor operator now must deal with a small LOCA in addition to the SGTR.

REQUIRED OPERATOR RESPONSE:

The operator's primary goal is to ensure adequate make-up is being provided by the HPIS. Since the HPIS has been operating, this objective should be achieved. After the RCS depressurizes below the pressure in the faulted SG, flow through the tube rupture will reverse. Coolant from the SG will flow back into the RCS thus supplementing HPIS in restoring inventory. If this pressure differential is maintained for a significant period of time, the operator may have to restore AFW to the faulted SG to avoid uncovering the break and draining the faulted SG.

The operator actions at this state are similar to those at state S-5 of the SB LOCA OAET. After the reactor reaches a stable condition (reactor pressure relatively constant, inventory restored, and continued heat removal assured), the operator should depressurize and cooldown the system. The operator actions for state S-5 are applicable for this state as well. One factor might impact these actions. Transferring to the recirculation mode of safety injection (HPRS) requires an adequate inventory of water in the containment sump. For small breaks inside containment, the RWST is sized so that there will be adequate water in the sump before the RWST is depleted. However for a SGTR, the RCS coolant lost through the tube rupture during the initial stages of the accident is released outside containment. Hence, this quantity of water is not available for recirculation. Compounding this with the fact that some of the coolant discharged through the stuck-open PORV will remain in the PRT, there may not be enough water in the sump to supply adequate NPSH for recirculation operation. The operator can be forewarned of this condition by observing the sump and RWST water levels. If it appears that the sump will not fill before the RWST is depleted, it will be necessary to add water to the RWST. (See discussion under "Potential Substates" of state S-1 and "Uncertainties and Sensitivities" of State S-5 of the SB LOCA OAET).

KEY SYMPTOMS:

The key symptoms which distinguish this state from state SGTR-11 are continued flow in the PORV discharge line, and a continued reduction in reactor pressure. Pressure, temperature, and water level in the PRT will increase, and, after the rupture disk bursts, pressure, temperature, humidity, radiation, and sump water level will increase in containment. Block valve and PORV position indicators will also inform the operator that these have failed to close.

Since analyses have not been performed for this postulated sequence of events, the longer term behavior of the plant is uncertain. It is expected that the RCS pressure would stabilize at a level where flow into the RCS is approximately equal to the flow being lost. Depending on the pressure difference across the tube rupture, flow could be entering or leaving the RCS at this location.

On the secondary side, the AFW is maintaining level in the intact SG's and secondary pressure is gradually being reduced as the cooldown continues. Water level in the faulted SG will be increasing during the time the RCS pressure exceeds the pressure in the SG. However, once the pressures are reversed, the flow through the tube rupture changes direction and inventory in the faulted SG will decrease.

The continued depressurization caused by the stuck-open valve will result in a loss of the subcooling margin achieved during RCS cooldown (State SGTR-3). Voiding may occur in the hotter locations of the core and in the hot legs after the primary pressure drops below the pressure in the faulted SG. Because of the continued discharge of coolant through the stuck open valve, voids may be present for a significant period of time after RCS pressure stabilizes. The extent and duration of voiding depends on many factors including flow through the stuck-open valve, tube rupture size, HPIS flow, and heat removal through the intact SG's. Operation of the RCP's will help to dissipate these voids, particularly in the upper head.

STATE: SGTR-12

At this state the operator has effectively terminated the loss of coolant through the tube rupture. The key actions which have been performed to accomplish this function are:

- o isolation of the SG with the tube rupture
- o cooldown of the RCS by dumping steam from the intact SG's to the condenser, or venting steam through the ADV's
- o depressurization of the RCS below the faulted SG pressure using the pressurizer PORV's

Decay heat is being removed through the SG's in the intact loops. RCS inventory is being restored by operation of the HPIS. This state and subsequent success paths are the same as states SGTR-9 through 11a, except that for these states the RCP's are unavailable. The major impacts of RCP trip are the unavailability of the pressurizer sprays and the loss of forced coolant flow in the RCS. Heat removal in this case is accomplished by natural circulation. The following discussion highlights the differences which are important as a result of the unavailability of the RCP's. The states which could evolve from state SGTR-12 are not described in the OAET documentation because of their similarity to states SGTR-9 through 11a. The consequences of RCP trip discussed in this section are applicable to the states following SGTR-12.

REQUIRED OPERATOR RESPONSE:

The operator's objectives at this state are the same as those described for state SGTR-4. The operator must bring the plant to a safe, cold shutdown while minimizing the release of radioactivity to the environment. Only the major differences between this state and state SGTR-4 are discussed in this section.

First, the operator must ensure that the pressurizer PORV has reclosed once the RCS pressure reduction has been completed. If the PORV fails to close, the block valve must be closed to avoid creating a small break LOCA. (See state SGTR-10).

It is possible that some voiding in the core and hot legs may have occurred during the depessurization of the RCS. Without forced circulation cooling, void dissipation may not occur rapidly after the PORV has been closed. Hence it may be some time before HPIS can be terminated.

Following termination of safety injection (see State SGTR-4 for SI termination criteria), the operator should continue to cooldown and depressurize the system so that the RHRS can be activated. In order to accomplish this relatively quickly the operator should restart at least one RCP. This will provide the capability to transfer heat to the intact SG's at a more rapid rate. It will also allow the operator to use pressurizer sprays for pressure control. In the process of cooling and depressurizing the RCS, the operator must maintain the RCS pressure equal to or less than the pressure in the faulted SG. This is most easily accomplished using pressurizer sprays. If one RCP can not be restarted, the operator will have to maintain this pressure differential by dumping steam from the intact SG's or re-opening the pressurizer PORV.

KEY SYMPTOMS:

The symptoms are similar to those described for state SGTR-9. The major differences as a result of RCP trip are a significantly larger hot and cold leg temperature differences and the absence of forced flow in the reactor coolant piping. Because of the lack of mixing provided by forced flow and the absence of flow through the head cooling spray nozzles*, the upper head region has a greatly reduced capability to dissipate heat. Hence, it is very likely that a void will remain at this location for a significant period after the RCS depressurization.

UNCERTAINTIES AND SENSITIVITIES:

For large or multiple tube ruptures or SGTR's with reduced SI flow, the SI termination criteria discussed in state SGTR-4 may not be satisfied. The

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*RCP operation provides the driving force that supplies coolant from the upper portion of the downcomer to the head cooling spray nozzles.

pressurizer level may not be restored, or the RCS pressure may not increase following closure of the PORV. This could imply a large break where the equilibrium pressure is approximately equal to that of the faulted SG. It could also mean that there is some other source of coolant loss from the primary system (e.g., a stuck-open or leaking PORV). If confronted with this situation, the operator should check for additional sources of leakage and isolate them if they exist. If the pressurizer level is not recovering because the tube rupture area is large, the operator must further reduce RCS pressure so that increased SI flow and reverse flow through the break into the primary restores primary inventory. Once pressurizer level has been established and adequate subcooling is achieved, HPIS can be terminated.

Another area of uncertainty is the impact of restarting one or more RCP's. The sudden addition of a large quantity of cool water from the cold legs which would accompany RCP restart could create a sudden pressure reduction. This might result in void formation and perhaps a loss of pressurizer level control. The extent of pressure reduction from RCP restart is unknown. This was a point of concern to the operators during the Ginna incident, who kept one SI pump operational during RCP restart in order to prevent a possible loss of pressurizer level.

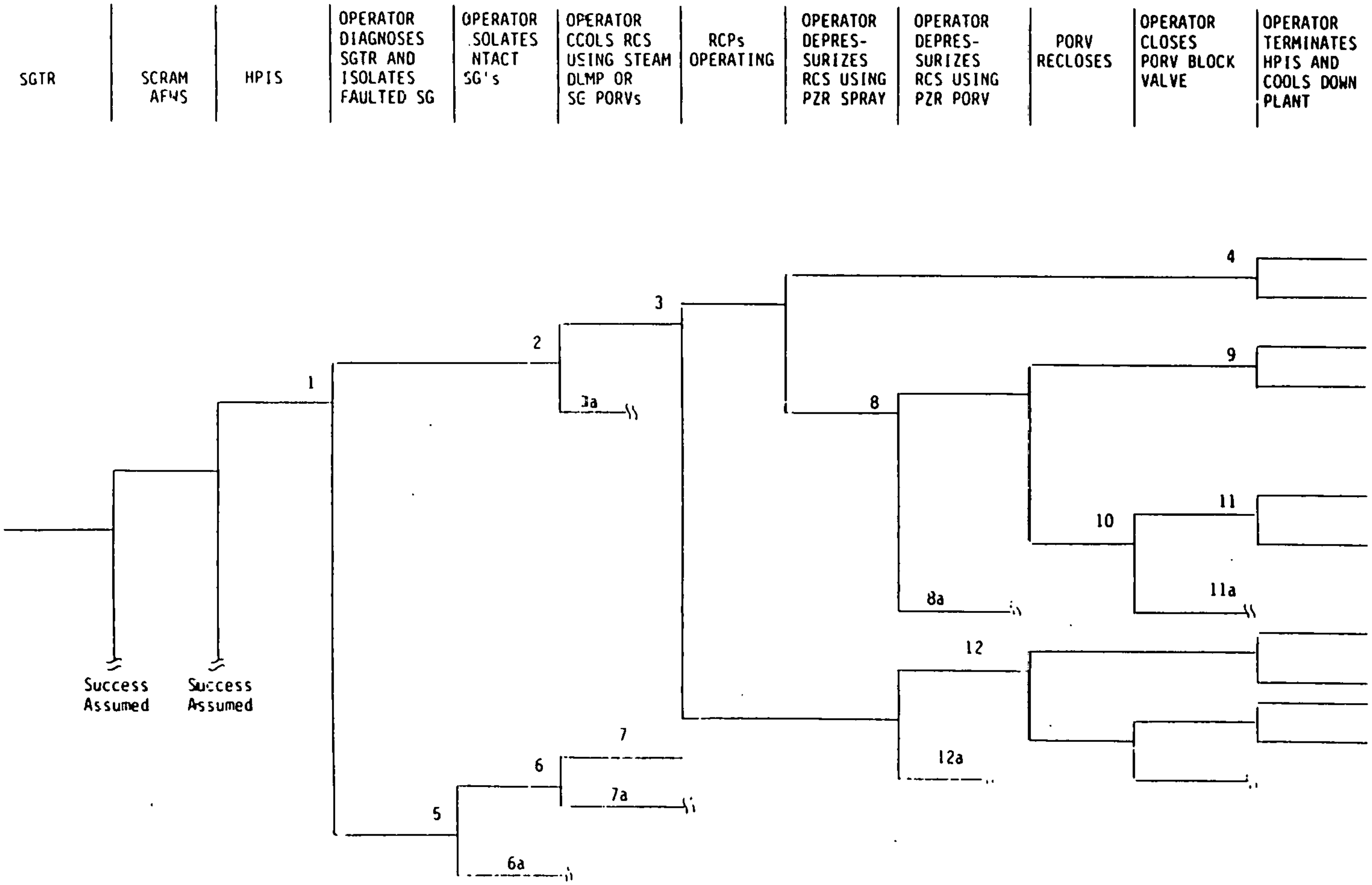

Figure 3.13. Operator Action Event Tree for Steam Generator Tube Rupture Sequences

3.1.3 Other LOCA and Related Sequences

Section 3.1.1 described the key operator actions and plant responses associated with accidents initiated by a small break in the reactor coolant system. The operator action event tree and associated documentation are based heavily on the information provided by the SASA program. Section 3.1.2 examined the special case of a steam generator tube rupture. Although best-estimate analyses are not available for this initiator, the key operator actions and a general description of the plant symptoms have been summarized for this important event. In addition to these initiators, there are several other events which should be considered to provide a complete assessment of possible loss-of-coolant accidents and related events. These include:

- stuck-open PORV
- interfacing system LOCA (outside containment)
- large LOCA
- overcooling transient
- steam line break.

Due to a lack of information on the realistic plant response to these accidents, OAETs have not been developed for these events. This section provides a discussion of these different events.

A stuck-open PORV is a special type of small break. The operator actions to respond to this event are fully addressed in Section 3.1.1. The key difference between this initiator and a small break in the primary system piping is that the operator can readily isolate the break by closing the block valve downstream of the PORV. This effectively terminates the accident. The key is for the operator to recognize that the PORV is stuck open. There are several distinct indications of this event which can be used to distinguish a stuck-open PORV from a small break. These include PORV position, discharge line flow and temperature, and discharge (quench) tank level and pressure, coupled with no change in containment conditions. If the operator does not or can not isolate the break, then the plant response and subsequent actions are the same as for an equivalent small break inside containment as discussed in Section 3.1.1.

An interfacing system LOCA, or the V sequence as designated in the WASH-1400 study, involves a break in a system which interfaces with the reactor coolant system resulting in a discharge of coolant outside containment. Although this accident was determined to be important for the PWR plant considered in the Reactor Safety Study, this is not the case for all PWR's. At the time this analysis was performed, an assessment of potential interfacing LOCAs had not been performed for plants such as Zion. Likewise, the plant response for an interfacing LOCA has not been analyzed in the SASA program. However the primary and secondary system response would be similar to that for other LOCAs. The major difference would be that coolant is not released into containment. Hence, the containment conditions would remain unchanged, while the location of the break (e.g., auxiliary building) would experience the symptoms associated with the release of primary coolant. Furthermore, if the interfacing system is part of the ECCS, the break could degrade or eliminate the ability to provide coolant injection to the core.

A detailed OAET for an interfacing system LOCA for the Surry plant is available in NUREG/CR-1440.[1] In summary, this evaluation determined that the most important operator action (after identifying the event) is to isolate the break. Thus, the operator must locate the break to determine if it can be isolated by closing valves upstream of the leak. If the break flow can not be stopped, the system response is similar to a small break with failure of recirculation cooling (see States 9 and 13 in Section 3.1.1). Because coolant is leaking outside containment, there is no water in the sump for recirculation. Hence, after injection depletes the RWST inventory, makeup to the core will be lost and core uncovery will occur. If the break has affected the ECCS, the operator must try to determine if any part of the system can be used, and if possible, realign the system and take other actions necessary to maximize the delivery of makeup to the core.

Large LOCAs are breaks which rapidly blow down the primary system to pressure such that the LPIS and accumulators can deliver flow to the core. Because of the large size of these breaks they are much less likely to occur than a smaller break. Nevertheless, these accidents have received considerable attention in the past as providing an enveloping case for all LOCAs. For this reason numerous analyses of the plant response to large LOCAs have been performed.

However, these have been performed with very conservative (and often unrealistic) assumptions to attempt to analyze a "worst case." Best-estimate calculations such as are required to develop OAETs and accident signatures have not been performed.

Because the blowdown itself results in core uncovery, there is very little time available to perform any immediate actions. The operator must verify that LPIS is operating and if not actuate it manually. If this can not be accomplished from the control room, core damage will likely occur before local repairs can be performed (although these should be attempted to minimize core damage). If LPIS is successful, but recirculation fails, the actions are similar to those addressed in State S-21 of the small break OAET for repair of LPRS.

In addition to breaks in the primary coolant system, there are also events which can occur in the secondary system which exhibit some similar responses to LOCAs. These include overcooling transients and main steam line breaks. Both of these can cause the primary system pressure and pressurizer level to decrease. In the case of a steam line break, fluid may be released into containment, thus appearing very similar to a LOCA. The key action would be to distinguish this event from a LOCA. For the steam line break, containment activity would remain unchanged and the primary pressure reduction would not be as severe as for a primary coolant system break. The pressurizer level should also recover as the charging pumps accommodate for primary system shrinkage. Abnormal steam generator behavior and steam/feed flow mismatch in the ruptured secondary loop are other symptoms which would be used for distinguishing a steam line from a LOCA. After identifying the event, the operator should attempt to isolate the loop with the steam line break and cooldown the plant using the intact loops as outlined in Section 3.1.2. The same symptoms (or lack of them) could be used to identify an overcooling transient. The specific operator response would then depend on the nature of the initiating event.

3.2 TRANSIENT INITIATED ACCIDENT CONDITIONS

The operator action event tree and supporting documentation presented in this section address the operator's role in responding to accident conditions initiated by transient events. The SASA Program has to date concentrated on transient sequences initiated by a loss of offsite power (LOSP). The analyses performed at EG&G were primarily concerned with station blackout sequences where LOSP is followed by failure of the diesel generators to provide onsite emergency AC power. The LANL analyses have investigated sequences where the diesel generators are available to supply emergency power subsequent to the LOSP initiator. While these SASA analyzed sequences represent only a few of the many possible transient sequences, they do represent some of the most risk significant sequences. Furthermore, the plant response to these SASA sequences is very similar to that of most other important transient initiated sequences (this will be discussed at greater length in Section 3.2.2).

The documented OAET for the SASA analyzed loss of offsite power initiated sequences is presented below in Section 3.2.1. This single OAET incorporates both EG&G and LANL analyses and addresses a variety of potential multiple failure sequences evolving from the LOSP initiater. In Section 3.2.2, the plant response and operator actions associated with other important transient sequences identified in the RSS are discussed and compared with the accident conditions encompassed by the LOSP OAET. In addition other possible transient initiating events are discussed and compared with the LOSP initiated sequences in Section 3.2.2.

3.2.1 Loss of Offsite Power Sequences

The initiating event for this group of sequences is a Loss of Offsite Power (LOSP) to the plant. The specific cause of the LOSP event is postulated to be such that no other plant failures are included in the initiating event definition (plant conditions associated with automatic plant response to a LOSP are addressed in subsequent events). The only events which could cause LOSP coincident with failures more serious than those addressed here are (1) very large external events such as earthquakes, tornadoes, etc., or (2) internal events which cause a turbine trip which, in turn, creates a grid disturbance large enough to upset the entire grid.

The first type, large external events, are beyond the scope of this analysis. Events of the second type are either probabilistically insignificant or involve failures which do not alter the results obtained here.

Presented in Figure 3.14 is the basic functional event tree which depicts the critical functions which must be performed by the plant systems (either automatically or through operator intervention) in response to the initiating event and the potential accident sequences which can evolve from the failure to perform these function.

As seen in Figure 3.14, the first concern is whether the reactor scrams. The LOSP event should result in an automatic turbine trip and reactor scram signal. Sequences which involve a failure to scram are addressed in another section of this report.

Following reactor trip, it is necessary to transport decay heat via the steam generators to the environment. These functions are associated with the event headings secondary steam relief (SSR) and feedwater delivery (FW) in Figure 3.14.

With decay heat removal successfully accomplished, another critical area of concern is the maintenance of adequate reactor coolant inventory.

Normally, this will be accomplished by high pressure makeup pumps. Additional failures which could substantially increase the need for makeup include a stuck open PORV or a steam generator tube rupture, or reactor coolant pump seal leakage.

For those sequences which involve releases of energy into the containment, the operation of the containment Engineered Safety Features (ESFs) will be required.

As would be expected following a LOSP initiating event, the availability of emergency AC power (supplied by the diesel generators) is critical throughout the sequence progression. Emergency AC power is required to run, for example, the motor-driven auxiliary feedwater pumps, the coolant makeup and injection pumps, component cooling water pumps, and the containment safety systems. Accordingly, the dominant risk sequences which can evolve from the LOSP involve the failure of the diesel generators.

Figure 3.15 represents an expended version of the functional event for LOSP (Figure 3.14) and delineates the basic states to which the plant could evolve which are relevant to the required operator response. This operator action event tree and the indicated states of the tree will form the basis for the following discussion.

STATE LOSP-1

State 1 represents the situation immediately following the initiating LOSP event, the subsequent automatic plant responses to the LOSP, and successful secondary steam relief. Since the time lapse between these events is only a matter of seconds, these states are considered as one with respect to operator response. The important automatic responses include reactor scram, turbine trip, reactor coolant pump trip, main feedwater pump trip, recirculating water pump trip and starting of the diesel generators. These automatic responses produce a plant state characterized by a decay heat power level and the inability to remove heat from the steam generators through the normal main feedwater/condenser cooling loop. The primary coolant flow is coasting down and primary pressure and temperature (following a brief rapid increase) are decreasing. The secondary steam flow is isolated and secondary pressure is approaching or has reached the dump valve set point.

REQUIRED OPERATOR RESPONSES:

The operator's role at this point is essentially one of diagnosis of the LOSP initiating event and verification of the automatic responses. The operator will then turn his attention to establishing heat removal through the steam generators and maintaining adequate core inventory. Action associated with maintenance of the heat removal and inventory maintenance functions are addressed in discussions of subsequent states. In the very unlikely event that automatic steam relief is not attained through the atmospheric dump valve or the steam generator safety valves, the operator must manually produce secondary steam relief by opening the atmospheric dump valves. Failure to attain secondary steam relief through auto or manual action is considered probabilistically insignificant.

KEY SYMPTOMS:

The key symptoms exhibited by the plant at State 1 are summarized in Figure 3.16 - 3.22 which illustrate the behavior of the important plant parameters associated with these key symptoms.

The LOSP initiator would be indicated by loss of offsite grid voltage indicated in the control room. The LOSP initiator can be differentiated from other transients which may result in similar effects (such as turbine trip or loss of main feedwater) by the bus voltage behavior of effects unique to LOSP such as trip of reactor coolant pumps.

Symptoms associated with the secondary side are produced by the automatic turbine trip and main feedwater pump trip. With the secondary steam flow isolated, steam outlet flow will rapidly decrease (Figure 3.16) and steam generator secondary pressure will rapidly increase to the atmospheric dump valve set point (Figure 3.17). The need for manual steam relief will be indicated by the secondary pressure continuing to rise past the safety valve set points. The loss of main feedwater flow will result in a rapid drop of the steam generator secondary level (Figure 3.18).

On the primary side, loop flow will gradually decrease as the coolant pumps coast down (Figure 3.19). The primary pressure initially increases rapidly but then decreases upon reactor scram. The primary pressure then begins to rise again as the reactor coolant pumps coast down (Figure 3.20). The hot leg temperature behavior is similar to that of the pressure; it undergoes an initial drop upon reactor scram followed by a fairly rapid rise as the pumps coast down (Figure 3.21). The pressurizer level behavior also mirrors that of the primary pressure; an initial rapid rise which is arrested by reactor scram followed by a more significant rise as the pumps coast down (Figure 3.22).

The reactor power will exhibit a rapid steep decline to decay heat levels following scram which will also be indicated by the illumination of the control rod bottom lights.

Additional symptoms of State 1 are associated with the performance indicators of components affected by the initiator (for example, rapid reduction in main feedwater or recirculating water flow or pump discharge pressure).

STATE LOSP-2

State 2 describes the plant situation following successful automatic delivery of auxiliary feedwater to the steam generators. At this point, the plant is continuing its successful automatic response to the LOSP initiating event. The major significance of State 2 is that an adequate heat sink has been provided for transport of primary decay heat loads. The basic function FW/SSR depicted in Figure 3.14 has been successfully initiated.

REQUIRED OPERATOR RESPONSE:

The operator's responsibilities at State 2 are to recognize successful automatic AFW operation and to maintain adequate AFW as long as required by throttling AFW flow and lining up service water as a source of feedwater should the condensate storage tank become depleted.

Upon receipt of the actuation signal, both motor-driven and the turbine-driven AFW pumps start and deliver rated flow to the steam generator within about one minute. The operator will be required to throttle the AFW before about one hour to avoid completely filling the secondary side of the steam generators. The condensate storage tank (CST) will be depleted in about 4-5 hours if the AFW is not throttled. At that time the operator would be required to line up service water to replace the CST as a source of auxiliary feedwater.

KEY SYMPTOMS:

The key symptoms of State 2 are associated with the indications and effects of feedwater delivery to the steam generators. On the secondary side, State 2 is indicated by the recovery of the secondary level as illustrated in Figure 3.23. Monitoring the steam generator secondary level will also allow the operator to effectively control AFW flow to maintain levels near normal shutdown values. The steam generator secondary pressure will continue to hover about the dump valve set point as shown in Figure 3.17.

On the primary side, the pressure, temperature, and pressurizer level will peak and begin decreasing once the steam generator heat removal rate exceeds the decay power. These symptoms are depicted in Figures 3.24, 3.25, and 3.26 respectively.

Additional symptoms can be based upon performance indications of specific AFW components such as pump discharge pressures, and CST level.

UNCERTAINTIES AND SENSITIVITIES:

Calculations indicate that the primary pressure increase will peak just below the pressurizer PORV set point. The inherent uncertainties in the model, as well as the sensitivity of the pressure response to the assumed initial conditions, suggest that the possibility of the PORV opening as a result of the pressure rise associated with pump coast down should be considered. The impacts of a PORV opening would be the need for makeup sooner in the sequence and the possibility of the PORV sticking open. These conditions are addressed in States 19, 21, 25, and 27.

STATE LOSP-3

This state depicts the plant situation following successful operation to maintain adequate feedwater flow to the steam generators after State 2 has been attained by controlling feedwater flow and lining up service water as a source of feedwater when and if appropriate. At this point heat removal from the primary system via the steam generators is under control.

REQUIRED OPERATOR RESPONSE:

The operator's responsibilities at State 3 are to verify stable feed-water delivery and to begin any actions required to maintain adequate reactor coolant inventory. The specific actions necessary to maintain coolant inventory will depend upon the state of the primary coolant boundary integrity and will be addressed in the discussions of subsequent states which delineate the important potential primary boundary conditions (See State 19 - 21).

KEY SYMPTOMS:

Many of the key symptoms exhibited by the plant at State 3 are identical to those identified for State 2. In addition, State 3 will be characterized by a stable steam generator secondary level near normal shutdown levels as depicted in Figure 3.23 (State 2 is characterized by the rising secondary level). Adequate service water flow and a stable CST level will also be indicated following the operator actions to line up service water.

STATE LOSP-4

This state describes the plant condition when successful achievement of State 1 is followed by failure to automatically supply auxiliary feedwater to the steam generators. The events leading to State 1 will produce an automatic AFW actuation signal. At State 4, the turbine driven pump and both the motor driven feedwater pump have failed to deliver adequate flow to the steam generators due to coincident failure of all pumps or due to valving failures in the feedwater lines. LANL calculations (7) indicate that if 15% of rated AFW flow is achieved, plant recovery using heat transfer through the steam generators could be achieved. Under this degraded flow condition, the water inventory in the steam generators would decrease steadily until about 6 hours, at which time the amount of heat that could be removed by boiling the AFW at the pressure corresponding to atmospheric relief valve setting equaled the decay heat produced in the core. At about 5 hours, the primary to secondary heat transfer would be degraded to the extent that primary pressure and temperature would begin to rise. This rise would be arrested, however, at 6 hours when the amount of heat generated equaled that removed by boiling the feedwater. LANL calculations also indicate that if full AFW were available to only one of the steam generators, the plant could be cooled by natural circulation in the cooled loop. It is important to note that the diesel generators have successfully started and are available at State 4.

REQUIRED OPERATOR RESPONSE:

The operator's primary duties at State 4 are to quickly recognize the AFW failure and to attempt to achieve adequate feedwater flow by starting one of the AFW pumps or by blowing down one or more steam generators and using low pressure backup feedwater to deliver flow to the steam generators. A key potential source of low pressure backup feedwater are the condensate pumps; however, offsite power must be restored before these pumps can be used.

Calculations indicate that core damage can be avoided if the operator is able to initiate turbine-driven auxiliary feedwater, a single motor-driven auxiliary feedwater pump, or low pressure backup feedwater within approximately 4500 seconds following the initiating LOSP event.

If the operator quickly ascertains that AFW flow will not be available, he should begin implementing alternative means for cooling the core. The primary alternative to long-term steam generator cooling is the injection of subcooled ECC water into the primary system. The ECC will be initiated automatically on high containment pressure (see below) and the operator can enhance the rate of ECC flow by reducing primary pressure. One method of depressurization prior to steam generator dryout is to blowdown the steam generators, thereby increasing primary to secondary heat transfer and lowering primary pressure. Another method, which will be discussed in State 7, is manually opening the pressurizer PORVs.

KEY SYMPTOMS:

The major parametric responses which indicate the existence of State 4 are depicted in Figures 3.27-3.31. One of the most important symptoms of State 4 is the continued decline of the steam generator secondary level. If not arrested, this would result in steam generator dryout in about 2900 seconds* as indicated in Figure 3.27. Note that in Figure 3.23, secondary level will quickly recover and regain normal level within 800 seconds for successful automatic AFW initiation. Figure 3.28 shows that the secondary pressure increases rapidly to the relief valve set points and remains there just as in the normal recovery mode.

In the primary system, the pressure will increase after steam generator dryout to the pressurizer PORV set point as shown in Figure 3.29. The pressure will then be cycling about relief valve set point and the rupture disks on the pressurizer relief tank will eventually blow. Containment pressure will then begin to rise and result in a ECC initiation signal. (Successful AFW delivery should result in pressure peak just below PORV set point followed by a steady

* LANL calculations indicate dryout will occur in about 3800 seconds.

decline as shown in Figure 3.24). Note that the primary pressure will be slowly decreasing prior to the steam generator dryout at about 2900 seconds. This decrease should be compared to Figure 3.24 where AFW is successful. In this case the pressure decreases much more quickly as a result of better heat removal through the steam generators. The hot leg temperature history is illustrated in Figure 3.30. Note that the temperature will (after a quick fall and rise associated with scram and pump coast down) slowly decline until steam generator dryout occurs. At this point (approximately 2900 seconds) a rapid rise will occur. The pressurizer level (Figure 3.31) will rise due to system expansion following steam generator dryout and ultimately reach the top of the pressurizer.

STATE LOSP-5

At this state, the operator has achieved delayed feedwater flow after initial failure to automatically provide AFW flow. This can be accomplished by either restoring the turbine driven AFW pump, either or both of the motor driven pumps, or low pressure backup feedwater flow. Restoration of offsite power and steam generator blowdown is required if the condensate pumps are used as the source of backup feedwater. With this accomplished, an adequate heat sink has been provided for primary heat removal and the plant has moved into a state equivalent to state 2.

REQUIRED OPERATOR RESPONSE:

The operator's responsibilities at state 5 are essentially identical to those at state 2. Successful achievement of adequate feedwater flow must be confirmed and the operator must ensure continued flow at a controlled rate. The operator may also be required to line up service water as a source of feedwater should the CST become depleted. If state 5 is attained by restoration of one motor driven pump, no throttling of FW flow by the operator will be necessary. However, if the turbine driven pump is brought on line, these throttling actions will be required once the secondaries have been filled to normal levels.

KEY SYMPTOMS:

The key symptoms for this state are associated with the change in primary and secondary response parameters which indicate the transition from inadequate feedwater to adequate feedwater flow. The state 5 symptoms can be described as a change in those parameters which describe state 4 failure of AFW to values representative of state 2 (success of AFW). The manner in which these parameters change is dependent, to some degree, on the specific actions performed by the operator to achieve adequate feedwater and the timing of those actions. Adequate flow could be attained by (1) restoring the turbine driven AFW pump, (2) restoring either or both of the motor driven AFW pumps, and (3) blowing down a steam generator and using low pressure backup feedwater from, for example, the condensate pump. If state 5 is attained through the starting of one of the AFW pumps, the most important symptom of state 5 is the recovery of the steam generator secondary level. Figure 3.32 shows that the secondary level will rapidly recover after FW delivery is initiated and regain normal level within about 8000 seconds after initiation of the turbine driven pump or within about 4500 seconds after initiation of the turbine driven pump. The steam generator secondary pressure will rapidly decrease from the relief valve set point as subcooled water is injected in to the secondaries; however, the timing and extent of this decrease is very sensitive to the timing of feedwater initiation.

The primary pressure, as depicted in Figure 3.33, will also rapidly decrease following feedwater initiation from one of the AFW pumps as the steam generators begin to remove heat from the primary at a significantly higher level than that afforded by the saturated steam in the secondaries prior to feedwater initiation.

If state 5 is attained by restoring offsite power, blowing down a steam generator, and using the condensate pumps as a low pressure source of backup feedwater, the key symptoms will be fairly similar to those just described for delayed AFW flow to all steam generators. The secondary pressure in the blown-down steam generator will obviously fall immediately to very low levels. Figure 3.34 illustrates the behavior of the secondary pressure in the intact steam generators. This secondary pressure decline which results from the coolant effect upon the primary fluid from the single steam generator is similar to that produced by delayed AFW to all steam generators. Figure 3.35 illustrates the primary pressure response when the amospheric dump valve on one steam generator was opened at 3270 seconds (about 300 seconds after all secondaries have dried out) and low pressure feedwater was immediately available to feed that generator. Note that the heat removal through only one steam generator is sufficient to remove more than the decay heat rate and the primary pressure drops. This pressure drop is comparable to that produced by the successful restoration of the AFW pumps.

Figure 3.36 depicts primary pressure response when the atmospheric dump valve is opened at 1200 seconds (when the secondary level was approximately 6 meters) but the low pressure feedwater was not initiated until 4400 seconds. The portions of the curve between 1200 and 4400 seconds reflect the sharp pressure drop upon opening of the valve and the subsequent increase when the secondary is dry. Note that when feedwater is initiated, the pressure reduction occurs much like in the other cases examined in this state.

STATE LOSP-6

State 6 represents the plant condition following successful operator action to achieve delayed feedwater flow (state 5) and to throttle (if necessary) and maintain this flow as long as necessary. At state 6, a stable long-term heat sink has been provided via the steam generator for removal of heat from the primary system. At this point, the plant will be in a condition essentially identical to that of state 3 and the description of that state should be referred to for more detailed discussion of the required operator action, key symptoms, etc.

REQUIRED OPERATOR RESPONSE:

Same as state 3.

KEY SYMPTOMS:

If state 5 is attained through use of AFW pumps, the key symptom of state 6 is a stable steam generator secondary level near normal shutdown levels. The attainment of state 6 by throttling turbine driven AFW flow will also be indicated by a sharp reversal of the steam generator secondary pressure and primary pressure declines associated with state 5. The secondary pressure will rise again to the relief valve set points following FW throttling (see Figure 3.37)

If state 5 is attained through the use of low pressure backup feedwater, the key symptom of state 6 (again like state 3) will be steadily declining primary pressure.

STATE LOSP-7

This state represents the plant condition following failure of the AFW system to automatically initiate (despite successful diesel generator start) and the inability of the operator to achieve delayed feedwater flow. At this point, the possibility of utilizing the steam generators as an adequate heat sink is lost.

REQUIRED OPERATOR RESPONSE:

At State 7, the operator must take the responsibility for both removing heat from the primary system and maintaining adequate coolant inventory. In order to achieve these goals, the operator should undertake a "feed and bleed" operation in which energy is released through the PORVs and the high pressure pumps are utilized to maintain coolant inventory.

With the primary pressure cycling about the PORV setpoint, only a small amount of fluid can be injected into the primary system. The high pressure ECC injection pumps have a shutoff head of approximately 1500 psi which is considerably less than the PORV setpoint. The high head charging pumps are capable of injecting approximately 200 gpm at the prevailing pressure.

LANL analyses indicate that with an injection flow rate of about 200 gpm, the clad temperature will peak at 625 K at 7300 seconds, and by 7800 seconds the decay power will have decreased sufficiently to drop primary fluid temperature below saturation. The system will then reach an equilibrium point at which clad temperature remains fairly constant and the core is not in danger of being damaged.

Despite the possibility that core damage might be avoided without the operator taking direct action, the operator should attempt to lower system pressure by manually controlling the pressurizer PORVs. With the system pressure reduced, a significantly greater flowrate of subcooled water can be injected into the system. This will produce a much more rapid cooling of the core and primary coolant. Manual depressurization ("bleed") combined with controlled high pressure coolant injection with the ECC pumps ("feed") will therefore ensure that the core is not damaged and that a cold shutdown can be achieved in a timely manner.

KEY SYMPTOMS:

State 7 can be represented as a continuation of State 4. The plant condition continues to degrade past State 4 as the AFW system remains incapable of delivering flow to the steam generators. As shown in Figure 3.27, in the absence of FW flow, the steam generator secondary level will decline until dryout occurs at about 2900 seconds. At State 7, the steam generators remain dry. The secondary pressure will rise to and remain around the relief/dump valve set point as illustrated in Figure 3.28. In the primary system, the pressure will be cycling about the relief valve as shown in Figure 3.29. The rupture disks on the pressurizer relief tank will have blown and the containment pressure will be elevated. The high pressure ECC pumps will be activated in high containment pressure.

STATE LOSP-8

At State 8, successful automatic AFW initiation has been followed by failure to maintain this flow. This failure could be caused by failure of pumps to continue running, or failure of the operator to throttle feedwater flow or align service water to replenish the Condensate Storate Tank. Also, this state assumes the inability to restore offsite power and use the condensate pumps to deliver feedwater. The ultimate result of this failure is the inability to use the steam generators as a long term heat sink.

REQUIRED OPERATOR RESPONSE:

The operator must take action to provide an alternate means of heat removal. The appropriate action at this point would be the feed and bleed operations discussed in State 7. In this response, the operator must manually maintain the pressurizer relief valves open while maintaining primary coolant inventory with high pressure injection. A more detailed discussion of this action is provided under State 7.

KEY SYMPTOMS:

State 8 is characterized by a degradation of plant parameters from the levels indicative of a successful State 2 to levels associated with the failure States 4 or 7. The most direct indication of State 8 is the decay of steam generator secondary level from the normal shutdown levels achieved at State 2. The primary pressure will also begin to rise again as AFW flow is decreased. Ultimately, it will reach the relief valve setpoint.

STATE LOSP-9

This state is very similar to State 8 in which successful AFW flow is not maintained. In State 9, the initial successful feedwater flow was achieved by operator intervention following failure of the AFW system to automatically actuate. At this point, there exists no stable long-term heat removal path through the steam generators and the operator must intervene to accomplish the heat removal and inventory maintenance functions.

REQUIRED OPERATOR RESPONSE:

The operator must initiate feed and bleed cooling as discussed in State 7.

KEY SYMPTOMS:

State 9 should exhibit the same basic symptoms as States 7 or 8. The key symptoms are decreasing or dry steam generator secondary level and primary pressure increasing to the relief valve setpoint.

STATE LOSP-10

At State 10, the diesel generators have failed to automatically start and take load following the LOSP initiating event. The major impact of this diesel generator failure is the unavailability of the motor-driven AFW pumps, the charging and injection pumps, and component cooling water to the RCP seals. Without the motor-driven AFW pumps, the availability of the steam generators as a viable heat sink is dependent upon successful operation of the turbine-driven AFW pump. Without the charging or injection pumps, there is no way to replenish any fluid lost from the primary system. Without component cooling water, there can be large leakage past the RCP pump seals. The subsequent plant states which could evolve from State 10 (States 11-18) are similar to those which evolve from State 1 (States 2-9) with the key exception of the assumed availability of diesel power for States 2-9.

REQUIRED OPERATOR RESPONSE:

The basic operator response at State 10 is to recognize the occurrence of the initiating LOSP event, the successful automatic responses to the initiating event (e.g., scram, RCP trip, MFW trip, RWP trip, and secondary steam relief), and the failure of the diesels to automatically start and take load. Once this recognition has taken place, the operator must turn his attention to ensuring decay heat removal and reactor coolant inventory maintenance under the conditions presented by the unavailability of all AC power. The operator's primary tasks at this point are to ensure start of the turbine driven AFW pump and to attempt to restore the diesel generators to service. At State 10, the station batteries are the only source of power. These batteries supply the DC buses and the AC vital instrumentation buses. All non-essential equipment and instrumentation should be removed from these buses. Since AC emergency power is not available to charge the station batteries, battery power supply must be conserved.

KEY SYMPTOMS:

Most of the key symptoms associated with State 10 are identical to those of State 1 and are illustrated in Figures 3.16-3.22. The significant differences between States 1 and 10 is the unavailability of the diesel generators. This will be indicated in the control room by the voltage readings and by monitoring motor-driven pump discharge pressure.

STATE LOSP-11

At State 11, the turbine-driven AFW pump has successfully started automatically following LOSP and failure of the diesels. This pump is delivering adequate flow to the steam generators and a heat sink for decay heat is therefore available. The condition of the plant at State 11 is similar to that at State 2 except for the unavailability of the diesel generators.

REQUIRED OPERATOR RESPONSE:

The operator should verify successful turbine-driven AFW pump flow and continue attempts to start the diesel generators (assuming off-site power is not restored). The operator will also have to throttle feedwater flow once the steam generator secondary level has attained normal shutdown levels. The operator should also determine if excessive RCP seal leakage is occurring. If so, he should decrease system pressure to diminish leak rate. He can do this by opening relief valves on the steam generators if they are air operated with DC control power. The operator may be able to reduce primary pressure sufficiently in this way to allow accumulator flow to the primary system to compensate for large seal leakages.

KEY SYMPTOMS:

The key symptoms of State 11 are very similar to those of State 2 and are illustrated in Figures 3.23-3.26. The most important indicators are a recovery of the secondary level up to normal values and, or the primary side, a peaking and subsequent decline of the pressure and temperature as the steam generator heat removal rate exceeds the decay power. If all other lines are isolated, pressurizer level will give a good indication of RCP seal leakage.

UNCERTAINTIES AND SENSITIVITIES:

Calculations indicate that primary pressure will peak just below the PORV set point.

STATE LOSP-12

At State 12, the operator has successfully throttled AFW flow, and a stable long-term heat sink has been established through the steam generators. Feedwater is being delivered by the turbine driven AFW pump. The diesel generators which failed to automatically start when called upon may or may not be available at this time. Successful attainment of State 12 does not require the diesels or restoration of off-site power but subsequent operator actions will be significantly affected by the availability of AC power (see States 22, 23, and 24).

REQUIRED OPERATOR RESPONSE:

The operator's responsibilities at State 12 are to verify stable heat removal through the steam generators and to begin to take the necessary actions to maintain adequate primary coolant inventory over the long term. The specific actions are delineated in States 22-24. The operator should continue his efforts to restore off-site power or to start the diesels.

KEY SYMPTOMS:

The key symptoms of State 12 are very similar to those exhibited at States 2, 3, or 11. The most important symptom is a stable steam generator secondary level near normal shutdown level which differentiates State 12 from the rising secondary level of States 2 or 11. If the diesel generators have been started, State 12 is virtually identical to State 3.

STATE LOSP-13

State 13 is analogous to State 4 except the diesel generators are not available. The key feature of State 13 is that an inadequate flow of AFW is being delivered to the steam generators after LOSP initiator and successful scram. The motor driven AFW pumps were not available due to the failure of the diesels to start and take load and the turbine driven AFW pumps has also failed to deliver adequate flow.

REQUIRED OPERATOR RESPONSE:

The operator response at State 13 is identical to that at State 4: recognize the failure of the AFW system to deliver adequate flow and attempt to initate flow by starting one of the motor-driven AFW pumps, or by restoring offsite power, blowing down a steam generator, and using the condensate pumps to provide a low pressure backup source of feedwater. The only difference between state 4 and State 13 is availability of AC power at State 4. At State 13 the operator can restore AFW flow by starting one diesel generator within about 4500 seconds. After this time, core uncovery is predicted to occur.

KEY SYMPTOMS:

The key symptoms indicative of State 13 are similar to those presented in Figures 3.27-3.31 for State 4. The most important symptom is the continued decline of the steam generator secondary level. If not arrested, this will result in steam generator dryout in about 2900 seconds as indicated in Figure 3.27. In the primary system, the chief indicator of State 13 is the continued increase of the primary pressure up to the relief valve set points as shown in Figure 3.29. The primary pressure will (after a quick fall and rise associated with scram and pump coast down) slowly decline until steam generator dryout occurs at 2900 seconds. At this point, the primary pressure and temperature will rapidly rise, as indicated in Figure 3.30. Figure 3.31 shows that the pressurizer level will rise and reach to top of the pressurizer.

STATE LOSP-14

At state 14, the operator has successfully achieved delayed feedwater flow by either starting the turbine driven AFW pump, starting one of the diesel generators (and, thereby, one of the motor driven AFW pumps), or restoring offsite power and using the condensate pumps to deliver feedwater to a blown-down steam generator. To achieve state 14 the operator is required to activate one of these pumps within about 4500 seconds after the initiating event. State 14 represents a recovery mode where the steam generators are beginning to remove decay heat loads after initial failure of the AFW system at state 13.

REQUIRED OPERATOR RESPONSE:

The required operator response at state 14 is identical to that at states 2,5, or 11. Successful achievement of delayed flow must be confirmed and flow may have to be throttled to attain a stable secondary level near normal shutdown levels. The operator should continue his attempts to restore offsite power or to start the diesels.

KEY SYMPTOMS:

The symptoms of state 14 are very similar to those of state 5. The major parametric changes are associated with the rather abrubt change from values indicative of AFW failure (state 13) to those representative of feedwater success (e.g. state 11). The only difference between state 5 and state 14 is the availability of the diesels for charging pump operation during the states leading to state 5.

If state 14 is achieved through delayed utilization of the AFW system, one of the most important symptoms of state 14 is the rapid recovery of the secondary level following initiation of AFW flow. Figure 3.32 shows that the secondary level will regain normal level within about 8000 seconds using one motor operated pump or within about 4000 seconds using the turbine driven pump.

The primary pressure will also rapidly decrease following feedwater initiation as the steam generators begin to remove heat from the primary system at rates significantly higher than those afforded by the saturated steam in the secondaries prior to feedwater intiation. The details of primary pressure response beyond the initial rapid decrease are sensitive to the particular restorative actions performed by the operator and the timing of those actions.

Figure 3.38 illustrates the behavior of the pressurizer level for the case where a single diesel is started by 3700 seconds. Note that the level drops rapidly but remains within the pressurizer. Figure 3.39 shows the pressurizer level behavior if the diesel genertor is started at 4300 seconds. Note that the pressurizer level shrinks to zero for a short period. This is due to the formation of more void space in the primary system during the extra 600 seconds of inadequate feedwater and charging flow. Figure 3.40 depicts the pressurizer level response if the turbine driven AFW is started within 3700 seconds or is started within 4300 seconds. As AFW is initiated and the primary system is cooled, the pressurizer level shrinks rapidly to zero. For the case where the turbine driven pump is started at 3700 seconds, the pressurizer level is reestablished at about 6250 seconds. However, if the turbine pump is not started until 4300 seconds, the pressurizer level will not be reestablished.

Figure 3.34, 3.35, 3.36 depict the secondary and primary pressure responses should State 14 be attained by the use of low pressure backup feedwater. The steadly decline of both secondary pressure (in the intact steam generators) and primary pressure are key symtpoms of the successful attainment of State 14 through means of backup low pressure feedwater.

UNCERTAINTIES AND SENSITIVITIES:

While the detailed behavior of all key plant parameters are sensitive to the timing as specifics of the operator's actions, the major features of the parametric response are fairly well understood. Care should be taken not to depend upon detailed response characteristics for unambiguous diagnosis.

STATE LOSP-15

At this state, the operator has achieved a stable long-term heat removal capability through the steam generators. Controlled feedwater flow is being delivered by either the turbine driven AFW, one of the motor driven pumps, or the condensate pumps. If the turbine driven pump is being used, the operator has throttled the flow to maintian the steam generator secondary level near normal shutdown levels. This state is very similar to states 3, 6, or 12.

REQUIRED OPERATOR RESPONSES:

The operator's responsibilities at state 15 are (like those at state 3,6, or 12) to confirm stable feedwater delivery and heat removal through the steam generators and to begin any actions necessary to ensure long-term primary coolant inventory maintenance. The operator should, if necessary, continue attempts to restore offsite power and/or start the diesel generators.

KEY SYMPTOMS:

The key symptoms of state 15 are virtually identical to those of states 3,6, or 12. The major symptoms are a stable steam generator level near normal shutdown level and/or a slowly decreasing primary pressure. Like state 12, and as opposed to states 3 or 6, the diesel generators might not be available at state 15.

STATE LOSP-16

At State 16, the operator has failed in his attempts to provide adequate feedwater to the steam generators following the LOSP initiator and failure of the diesel generators. At this point, which is similar to State 7, the decay heat load is not being removed from the primary system through the steam generators and alternate means of heat removal and coolant inventory maintenance must be found. At this state, the diesel generators may not be available Therefore, as opposed to State 7, there can be no high pressure injection into the primary system.

REQUIRED OPERATOR RESPONSE:

At State 16, the operator should attempt to establish a feed and bleed mode of cooling and inventory maintenance which is described in State 7. The required actions are made considerably more difficult by the possible unavailability of the diesel generators. If the diesels are not available (and off-site power has not been restored) the operator's first goal should be to restore a source of AC power. LANL calculations indicate that without any charging flow, the system will reach saturation by 6500 seconds and the core will be empty by 8600 seconds. If power is restored and ECCS initiated by 8000 seconds, these same analyses indicate that core damage can be prevented. LANL also states that recovery will not occur with half of ECC flow available even if initiated at the beginning of the transient without additional operator action.

KEY SYMPTOMS:

State 16 is essentially a continuation of State 13 and is very similar to States 4 or 7. As shown in Figure 3.27, the steam generator secondary level will decline until dryout occurs at about 2900 seconds. At State 16, the steam generators remain dry. The secondary pressure will rise to and remain around the relief/dump valve setpoint as illustrated in Figure 3.28. In the primary system, the pressure will cycle about the relief valve set point as shown in Figure 3.29.

STATE LOSP-17

At this state, the successful automatic feedwater delivery attained at State 11 is not maintained over the long-term. The plant condition will soon degrade to that similar to States 7 or 16 where the ability to remove heat through the steam generators is essentially lost.

REQUIRED OPERATOR RESPONSE:

The operator's responsibility at State 17 is identical to that at State 16: attempt to establish an alternate means of decay heat removal while maintaining adequate coolant inventory (See States 28, 29, and 30). The operator should continue to try to start the diesels or to ensure restoration of off-site power.

KEY SYMPTOMS:

State 17 is characterized by a degradation of plant parameters from levels indicative of the successful feedwater delivery at State 11 to those representative of the failure State 16. The key symptoms are a declining steam generator secondary level and an increasing primary pressure.

STATE LOSP-18

State 18 is very similar to state 17. Both states involve the failure to maintain feedwater delivery to the steam generators following successful delivery of such flow. In State 18, the initial success was due to operator intervention which resulted in the delayed start of one of the AFW pumps or delivery of low pressure backup feedwater.

REQUIRED OPERATOR RESPONSE:

The operator's responsibilities at State 18 are identical to those at States 16 or 17. The operator must attempt to establish an alternate means of removing decay heat from the primary system. The "feed and bleed" operation discussed for State 16 requires AC power and the operator's first concern, therefore, should be to restore off-site power or to start one of the diesel generators.

KEY SYMPTOMS:

The key symptoms of State 18 are identical to those of State 17. The most important symptoms are a declining secondary level and an increasing primary pressure.

STATE LOSP-19

State 19 represents the plant condition after the following sequence of events:

- LOSP Initiating Event
- Successful Automatic Start and Load of Diesel Generators
- Successful Maintenance of Stable Long-Term heat removal through the Steam Generators.

The PORV, if required to open prior to State 19, has successfully opened and reset following pressure reduction. The steam generator is intact with no tube ruptures.

REQUIRED OPERATOR RESPONSE:

At this point, the successful plant response to the LOSP initiating event has reduced the operator's duties to ensuring that adequate coolant inventory is maintained throughout the cooldown process.

At State 19, the only potentially significant loss of inventory could have been caused by cycling of the relief valves (if State 19 is reached through State 3, this cycling might not even take place). The operator's responsibility is to ensure charging flow to compensate for any mass loss out of the relief valves and for subsequent level reductions caused by cooling of the primary fluid.

KEY SYMPTOMS:

Because State 19 represents the successful reseating of the PORV and maintenance of steam generator tube integrity, the symptoms of State 19 are identical to those of States 3 or 6. The most important symptoms are a stable steam generator secondary level and a slowly declining primary pressure. The key symptom for the operator to monitor at State 19 is the pressurizer level. Successful maintenance of coolant inventory will be indicated by a stable pressurizer level.

STATE LOSP-20

State 20 represents the plant condition where the operator is able to maintain a stable long-term feedwater flow to the steam generators, but one of the steam generators (possibly due to the stresses associated with dryout and refill) has developed tube ruptures. Thus, while heat removal is not a problem at State 20, the primary system is losing inventory and slightly radioactive coolant is flowing into the secondary system and out of containment.

REQUIRED OPERATOR RESPONSE:

The operator has three main tasks to perform at State 20. The first is to identify and isolate the faulted steam generator, if possible. The second is to ensure adequate coolant injection into the primary system to compensate for flow out of the ruptured tube. The third task is to depressurize the primary system by blowing down the intact steam generators or using the pressurizer relief valves; the immediate purpose of this pressure reduction is to decrease the flow from the primary to the secondary through the rupture.

Once the primary pressure has been decreased to the point where leak flow is stopped (RCS pressure equals faulted steam generator secondary pressure). the operator can commence a normal cooldown and place the RHR in service to continue this cooldown to cold shutdown.

KEY SYMPTOMS:

The key symptoms of State 20 will be those associated with States 3 or 6 along with those indicative of the steam generator tube rupture. The rupture will be indicated by three major symptoms; (1) radiation in the steam lines of the faulty steam generator and in the condenser (2) slightly higher secondary level and pressure in the faulty steam generator, and (3) more rapid decline in pressurizer level and pressure than that of State 19. The radiation readings should provide the information necessary to diagnose the steam generator tube rupture for all rupture sizes. Larger rupture sizes will exhibit correspondingly larger effects on secondary and primary level and pressure and will, therefore, be easier to diagnose.

Successful isolation of the faulted steam generator will be indicated by rapid reduction in the level of that steam generator and a reduction of radiation level in the condenser.

The pressurizer level will recover and remain stable after actuation of sufficient charging or safety injection pumps.

The RCS pressure will decrease as the operator vents steam through the PORV. When the primary pressure is reduced to a level equal to that of the secondary pressure of the faulted steam generator, break flow should cease.

ADDITIONAL COMMENTS:

This state should be compared to small break states in which the steam generator rupture is considered.

STATE LOSP-21

At State 21, the steam generators are available as a long-term stable heat sink, but the PORV has stuck open. The situation at this point is similar to that of a small break sequence. Decay heat removal is being accomplished through the steam generators (assisted by energy flow out of the PORV) but primary coolant is being lost out of the PORV.

REQUIRED OPERATOR RESPONSE:

The operator has two main tasks to perform at State 21: (1) isolate the "break" by closing PORV block valve and thereby restore primary system integrity, and (2) ensure adequate coolant injection to the primary system to compensate for mass flow out of the stuck open valve.

KEY SYMPTOMS:

The key symptoms of State 21 are illustrated in Figures 3.41-3.43. These responses are based on the PORV sticking open at 200 seconds into the sequence (corresponding to the time where primary pressure could first reach PORV set point).

Figure 3.41 illustrates the rapid decline in primary pressure when the PORV initially opens, and the subsequent steady decline. Because so much energy is removed through the open PORV, the secondary pressure falls below the secondary relief valve set point. The secondary level will behave the same as in State 3 or 6 (stable level near normal shutdown level).

The pressurizer level behavior is depicted in Figure 3.42 with safety injection flow initiated at about 300 seconds, the pressurizer level will increase to the top of the pressurizer at about 600 seconds.

The hot leg fluid temperature, shown in Figure 3.43, will continuously decline and indicate the effectiveness of natural circulation cooling with the steam generators providing an adequate heat sink.

ADDITIONAL COMMENTS:

This state should be compared to comparable small break states and to other transient-induced small LOCA states to note the affects of RCP trip associated with LOSP. Compare with State 27.

STATES LOSP-22, 23, and 24

These three states are essentially identical to States 19, 20, and 21 except that the diesel generators have failed to automatically start and may not have been started at States 22-24. If neither the diesels or off-site power have been started, stable long-term AFW flow is being provided by the turbine driven AFW pump. If AC power has been restored, States 22, 23, 24 are identical to States 19, 20, and 21.

REQUIRED OPERATOR RESPONSE:

The operator's main responsibility at States 22, 23, and 24 is the same as that at States 19, 20, and 21: maintain adequate coolant inventory and achieve an orderly cooldown to cold shutdown. At State 22 (like State 19), the primary system is intact and makeup requirements are limited to those necessary to replenish mass lost while the PORV relief valve was open. At State 23 (like State 20), a steam generator has developed tube ruptures, and the operator must ensure sufficient coolant injection to compensate for flow through the tube rupture. The operator will also be called upon to isolate the faulty steam generator and depressurize the primary system at State 23. At State 24 (like State 21), the PORV has stuck open. This requires operator action to close the isolation valve and to ensure sufficient coolant injection to compensate for mass flow out of the stuck-open relief valve. In order to achieve steam generator isolation, opening of the PORV to depressurize the RCS, PORV block valve closure, or charging and safety injection flow, AC power is required. Therefore, the operator's primary goal at State 22, 23, or 24 is to start one or more of the diesel generators or to ensure restoration of off-site power.

KEY SYMPTOMS:

If the diesel generators are available at States 22, 23, and 24, the key symptoms of these states are identical to those of States 19, 20, and 21. If the diesels are not available, the key symptoms are identical to States 19, 20, and 21 except for the effects produced by an absence of charging flow.

These effects should be minimal except for State 24 where the PORV is stuck open. The availability of charging flow will then reduce the net inventory loss out of the stuck open valve.

STATE LOSP-25

At State 25, the steam generators are not available as a heat sink to remove decay heat. The resultant pressure rise in the primary system will cause the pressurizer relief valves to open and then cycle about their set points. With energy and mass being removed from the primary system via the cycling relief valves, the primary coolant inventory will begin to diminish.

REQUIRED OPERATOR RESPONSE:

The operator will be required to initiate a "feed-and-bleed" cooling mode at State 25. This will necessitate controlling the PORVs to slowly depressurize the primary system while providing sufficient coolant injection to compensate for coolant losses out the open relief valves.

KEY SYMPTOMS:

The key symptoms of State 25 are identical of those of states 7, 8, or 9. The steam generator secondary level is declining or has already reached dryout. Primary pressure is increasing to the PORV set point and pressurizer level is approaching or is at the top of the pressurizer.

Operator action in the feed-and-bleed mode can be monitored by observing primary pressure and pressurizer level. Successful action will be indicated by rapid pressure and temperature declines. The pressurizer level will stabilize after an initial drop from the top of the pressurizer when coolant injection ("feed") causes the voids to be collapsed.

LANL calculates that if the relief valves are allowed to cycle about their set points, ECC flowrate will be limited to about 200 gpm coming from the high head charging pumps. Under these calculations, the pressurizer level will begin to decrease about 1000s after ECC initiation and the system will reach saturation conditions about 400s later. Recovery will begin another 600s later when the decay power has fallen below the level commensurate with the heat removal rate of the ECC flow.

LANL further calculates that ECC can be turned on as late as 8200s into the sequence (about 4200s after PORV opening) and recovery can still be accomplished.

STATE LOSP-26

At this point, the unavailability of a stable long-term source of feedwater has rendered the steam generators incapable of providing a sufficient heat sink for decay heat removal. In addition, the stresses imposed upon the steam generators have produced tube ruptures in one of the steam generators.

REQUIRED OPERATOR RESPONSE:

The operator's basic responsibilities are to provide an alternate heat removal path for decay heat while maintaining adequate coolant inventory. For this particular state, this translates into the following specific tasks:

- manually depressurize the intact steam generators or manually control the PORV to depressurize the primary steam and to increase heat removal from the primary system
- identify and isolate the faulted steam generator
- ensure adequate safety injection flow to compensate for coolant flow out of the tube rupture and the open PORV.

KEY SYMPTOMS:

The effect of the steam generator tube rupture on the plant response will obviously be a function of the size of the rupture. The main effects of superimposing a steam generator tube rupture on States 7, 8, or 9 are:

- an increased pressure reduction in the primary system; the tube rupture will cause a lengthening of the PORV open/close cycle time and ultimately cause the cycling to cease as the pressure falls below and remains below the relief valve set point.
- radiation in the steam lines from the faulted steam generator and in the condenser.

UNCERTAINTIES AND SENSITIVITIES:

There are major uncertainties concerning the detailed effects of steam generator rupture on the primary system response, especially pressurizer level response. If state 26 is found to be difficult to diagnose after a comparative symptoms analysis is performed, these details should be investigated.

STATE LOSP-27

At State 27, the unavailability of feedwater flow to the steam generators has rendered the steam generators incapable of adequately removing reactor decay heat from the primary system. The steam generators have dried out by about 2900 sec. and the primary pressure has subsequently increased to the PORV setpoint. At this point, the PORVs successfully open but one has failed to reseat when the pressure diminished below the setpoint.

REQUIRED OPERATOR RESPONSE:

The operator has two main goals at State 27: (1) ensure that reactor decay heat is being removed from the primary system, and (2) ensure that adequate primary coolant inventory is maintained.

The loss of inventory out of the open PORV must be compensated for by charging and safety injection flow. The operator should manually initiate ECC flow as soon as possible. Approximately 1 minute after initial PORV opening, the pressurizer level will diminish (due to the stuck-open valve) to the low pressurizer pressure setpoint and a signal will be generated. However, the coincident low pressurizer level will not be present at this time and an automatic ECCS initation (which requires both coincident signals) may not occur.* The operator should manually initiate ECCS upon receipt of this low pressurizer pressure signal.

If ECC flow is not initiated upon low pressurizer pressure, flow will be initiated automatically upon high containment pressure. In this case, the primary pressure would drop to the point where the system is saturated. The ECC flowrate would be approximately 600 gpm through the vessel and out the PORV and would remove about 44 MW. Since decay power at this time is about 36 MW, the primary fluid will become subcooled and cooldown of the system will commence. Thus, operator action to initiate ECC prior to automatic trip upon high containment pressure is not absolutely necessary to prevent core damage, but will

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*Recent post-TMI changes to ECCS initiation have resulted in logic systems which would initiate ECCS on either low pressure or low level.

prevent the system from becoming saturated and will allow the recovery to be accomplished much sooner.

Of course, the operator should also attempt to isolate the "break" produced by the stuck open relief valve by manually closing the block valve downstream of the relief valve. If this is accomplished, the plant will be in a state similar to State 25. However, there will only be one relief valve through which mass and energy can flow from the primary system.

The operator should begin the "feed and bleed" operation discussed in State 25. By manually controlling the remaining PORV and using the charging and ECC pumps for injection, the operator can provide sufficient subcooled fluid to the primary system to produce an adequate cooldown.

KEY SYMPTOMS:

The key symptoms of State 27 are similar to those of State 25 but with the additional impact of the stuck-open PORV. The general features which indicate the need for operator intervention are those indicative of loss of all feedwater (e.g., steam generator secondary level rapidly falling to zero). The primary pressure will rise to the PORV setpoint. Shortly after this point, one of the PORVs fails to reseat. This will cause a reduction in pressurizer pressure below the PORV setpoints (very small effective "breaks" may cause an increase in cycle period for the remaining PORV until the pressure effectually drops below the setpoint). The stuck-open relief valve will also be indicated by elevated pressurizer relief tank pressure, temperature, or level, and eventually (after the rupture disks blow), an elevated containment pressure.

Successful isolation of the "break" will cause the pressure to rise again to the PORV setpoint. The success of the feed and bleed operation will be indicated by a controlled decline of primary pressure with a stable pressurizer level.

STATES LOSP-28, 29, and 30

These three states are analogous to States 25, 26, and 27. The difference is that AC power exists at States 25, 26, and 27 to operate PORVs and coolant injection systems. States 28, 29, 30 represent the situation where the failure of feedwater was caused (to a great extent) by loss of all AC power.

REQUIRED OPERATOR RESPONSE:

The actions of the operator at States 28, 29, and 30 are identical to those at States 25, 26, 27 with one major exception: the operator must ensure the restoration of off-site power or the starting of one of the diesel generators before any of the actions described for States 25, 26, or 27 can take place.

KEY SYMPTOMS:

The key symptoms of States 28, 29, and 30 are virtually identical to those of States 25, 26, and 27. The only difference between these sets of states is that charging flow of about 200 gpm is available at States 25, 26, and 27.

STATE LOSP-31

State 31 addresses a loss of off-site power with a ruptured steam generator secondary relief valve. Following the initiating event and the resultant trip of the main feedwater pumps, the secondary pressure increases and first reaches the secondary relief valve set point at about 40 seconds (see Figure 4). It is at this point that the rupture of the relief valve is assumed to occur. The availability of the diesels to supply emergency AC power is assumed.

REQUIRED OPERATOR RESPONSE:

The operator's main tasks at State 31 are to diagnose (1) the loss of off-site power initiator, (2) the associated automatic responses such as scram, reactor coolant pump trip, main feed pump trip, etc. and (3) the rupture of the steam generator relief valve. The diagnosis of the initiator and associated automatic responses is discussed in State 1. The diagnosis of the relief valve rupture is important because it affects the operator's ability to perform subsequent actions associated with ensuring a stable long-term flow of feedwater to the steam generators. The operator should observe the coincident low secondary level and low secondary pressure in the damaged steam generator and decrease feedwater flow to this unit. Later, the operator will be called upon to throttle the charging flow to prevent complete filling of the pressurizer.

KEY SYMPTOMS:

The key symptoms of State 31 are illustrated in Figures 3.44-3.47. The primary and secondary pressure responses are shown in Figure 3.44. The secondary pressure in the steam generator with the ruptured relief valve decreases rapidly. The secondary pressure in the other steam generators continues to increase to the relief valve set point. The primary pressure decreases more rapidly than normal (see Figure 3.24) due to the significantly greater cooling of the primary system by the ruptured secondary. At about 900 seconds, however, the ruptured secondary dries out (Figure 3.45) and the excellent heat sink is lost. The primary pressure will then increase because of this dryout and also due to the initiation of charging flow at about 850 seconds.

Figure 3.46 shows that the pressurizer level will decrease until charging flow is initiated. At 1400 seconds charging flow is terminated to prevent complete filling of the pressurizer. The pressurizer level will then drift upward as the hot leg fluid temperature increases (Figure 3.47). At approximately 3700 seconds, sufficient heat is being removed, mainly through the three intact steam generators, to remove core decay heat.

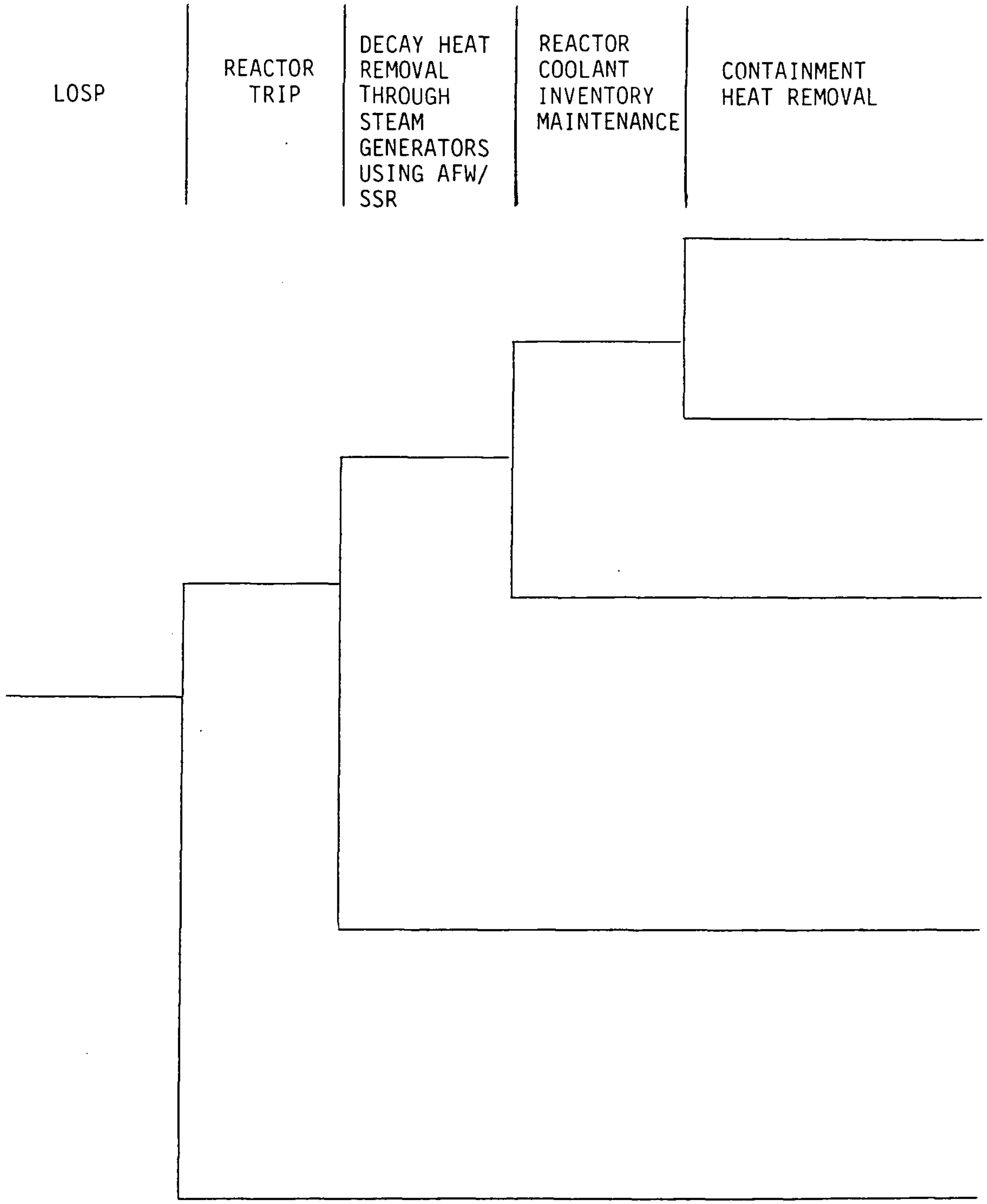

Figure 3.14 Functional Event Tree for LOSP Initiator

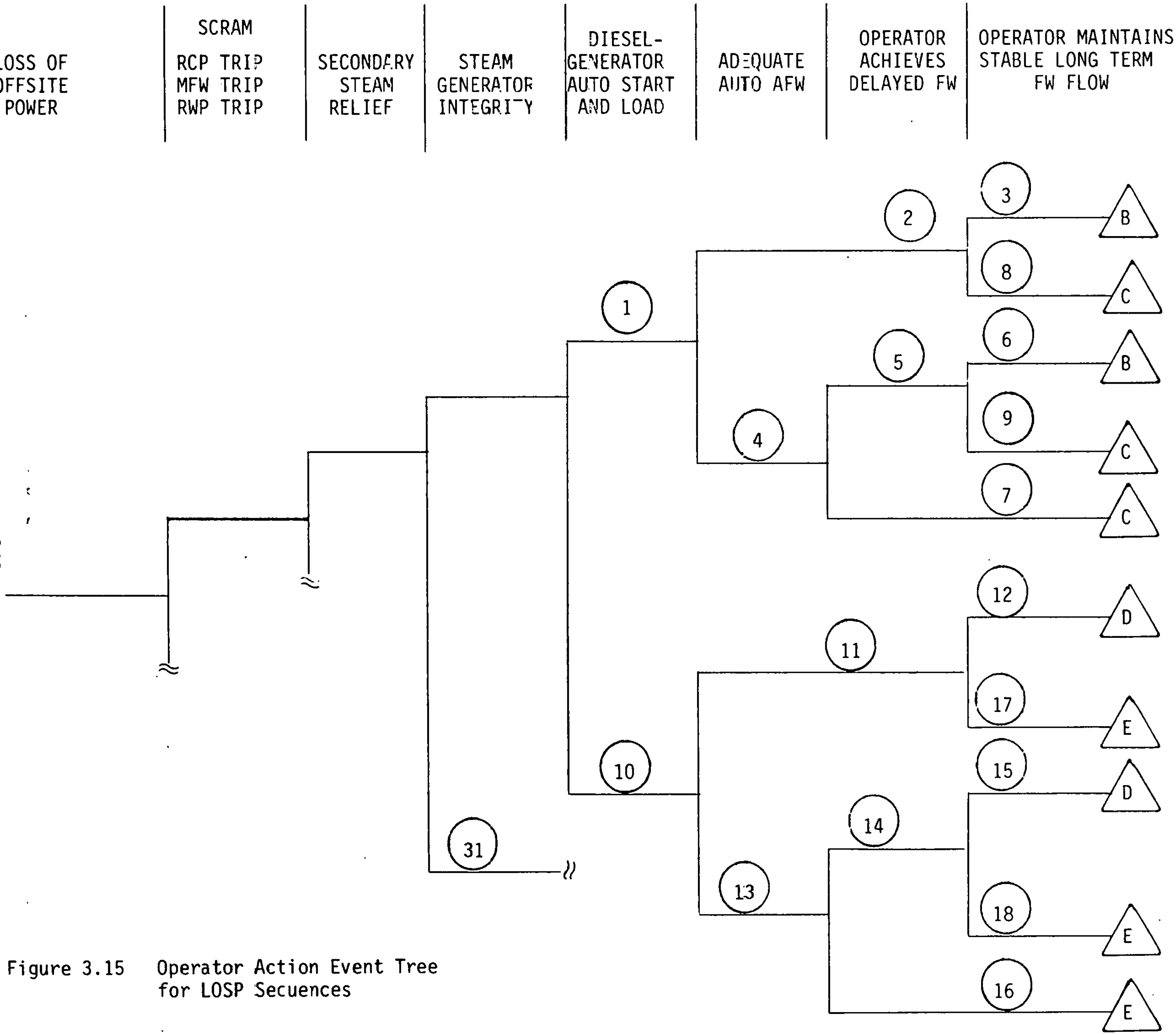

Figure 3.15 Operator Action Event Tree for LOSP Secuences

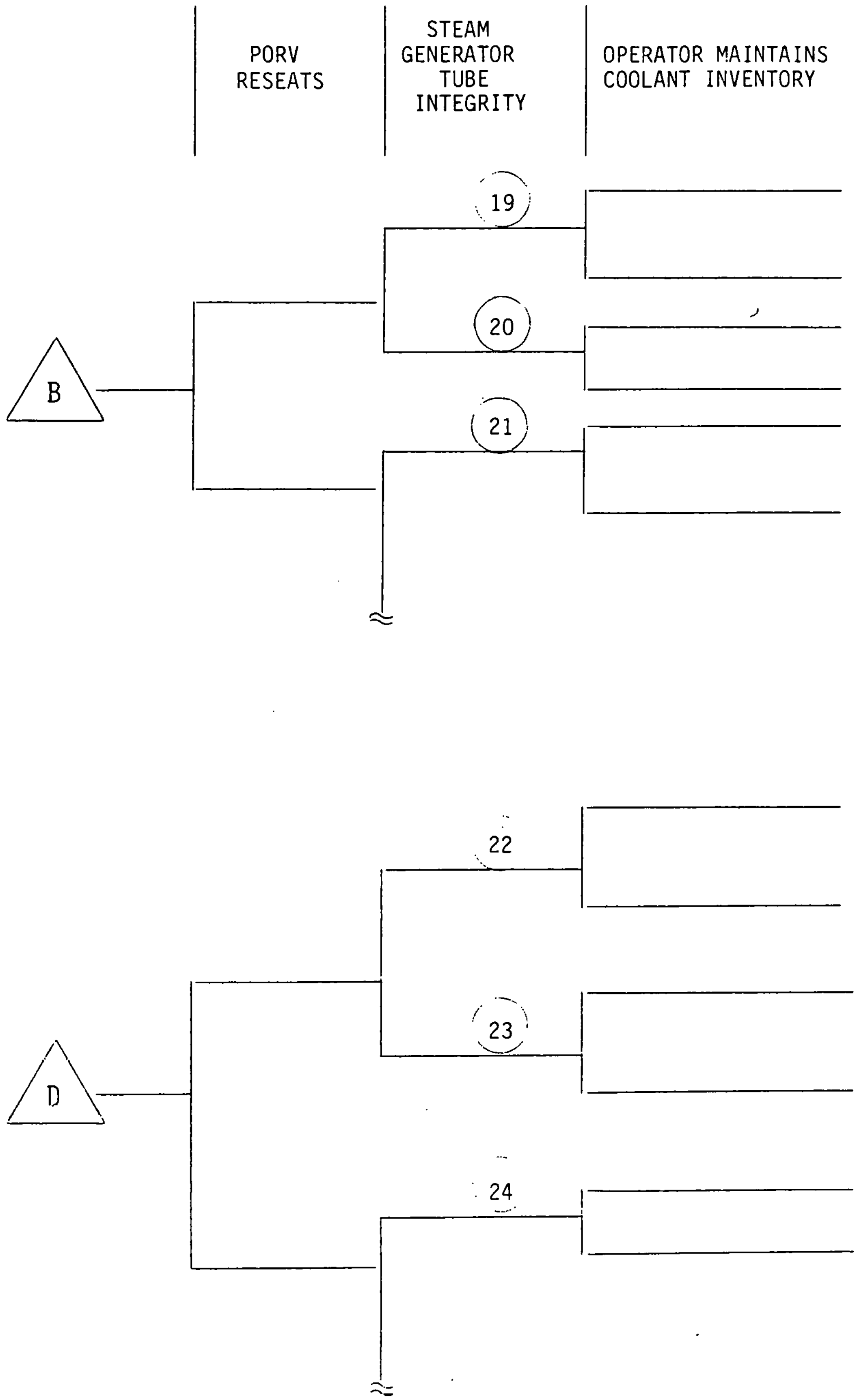

Figure 3.15 (Continued)

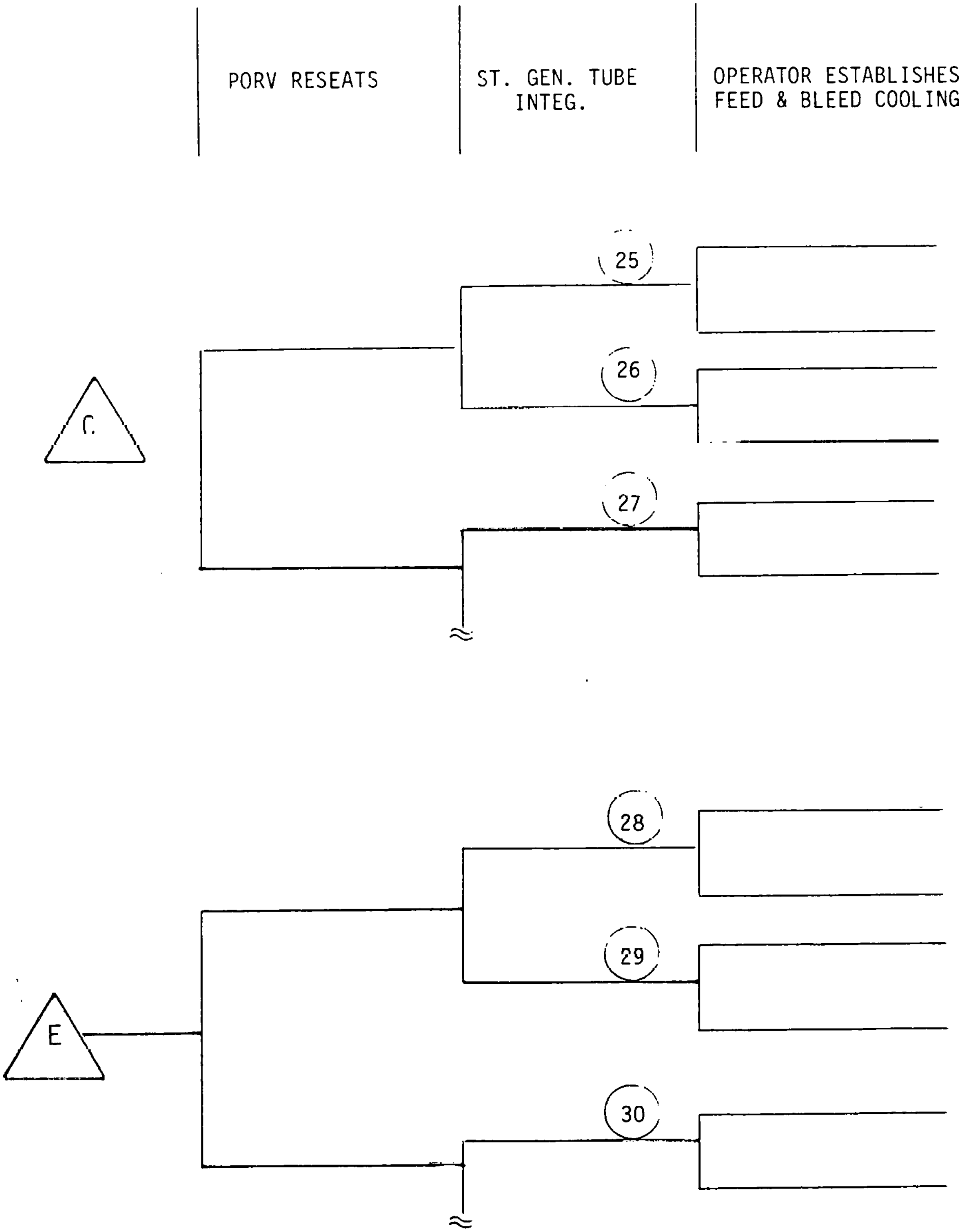

Figure 3.15 (Continued)

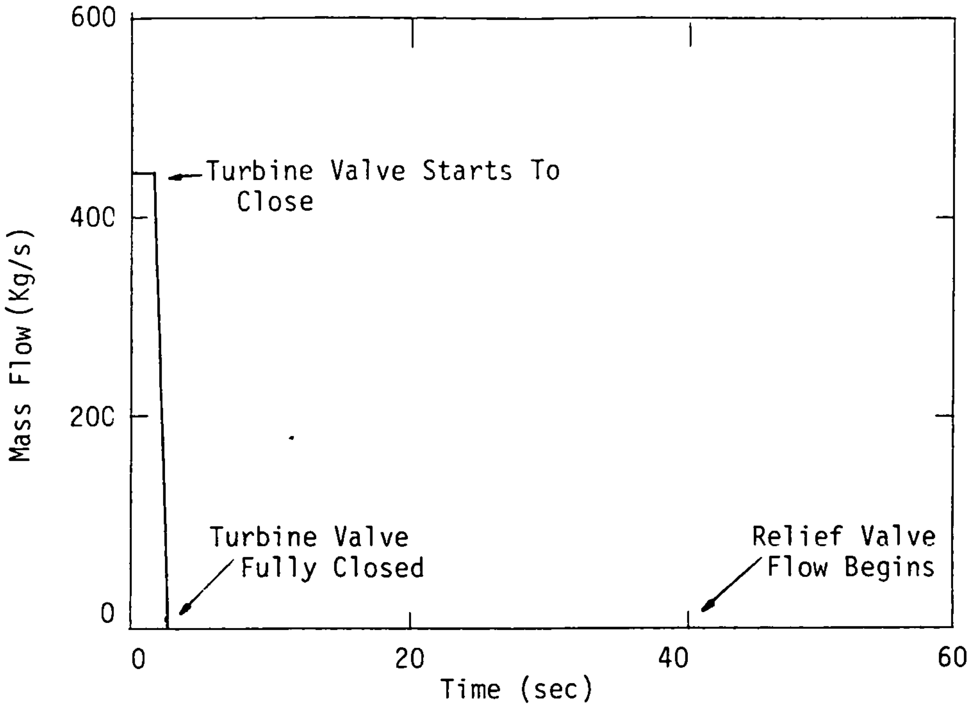

Figure 3.16 State LOSP-1 Steam Outlet Flow vs. Time

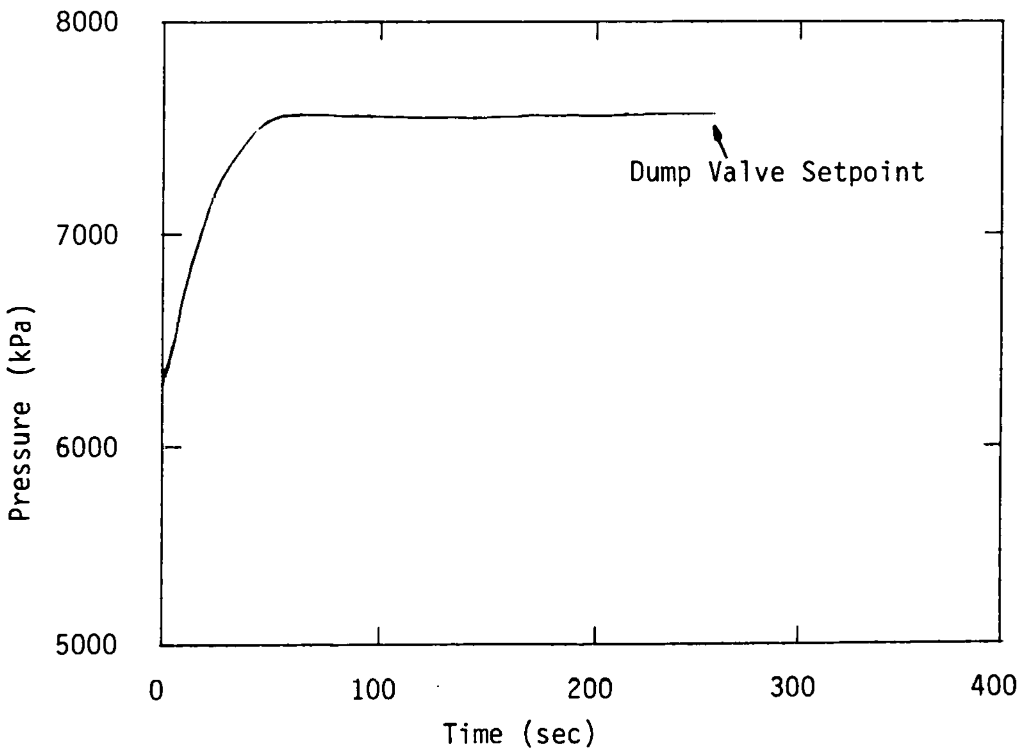

Figure 3.17 State LOSP-1 Steam Generator Secondary Pressure vs. Time

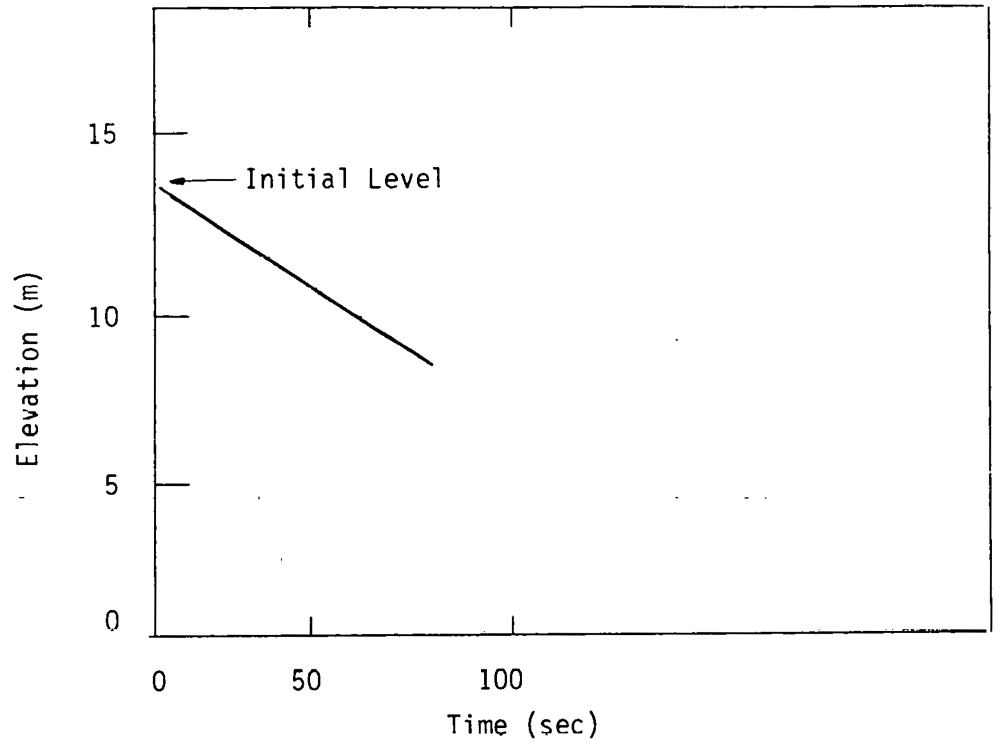

Figure 3.18 State LOSP-1 Steam Generator Secondary Level vs. Time

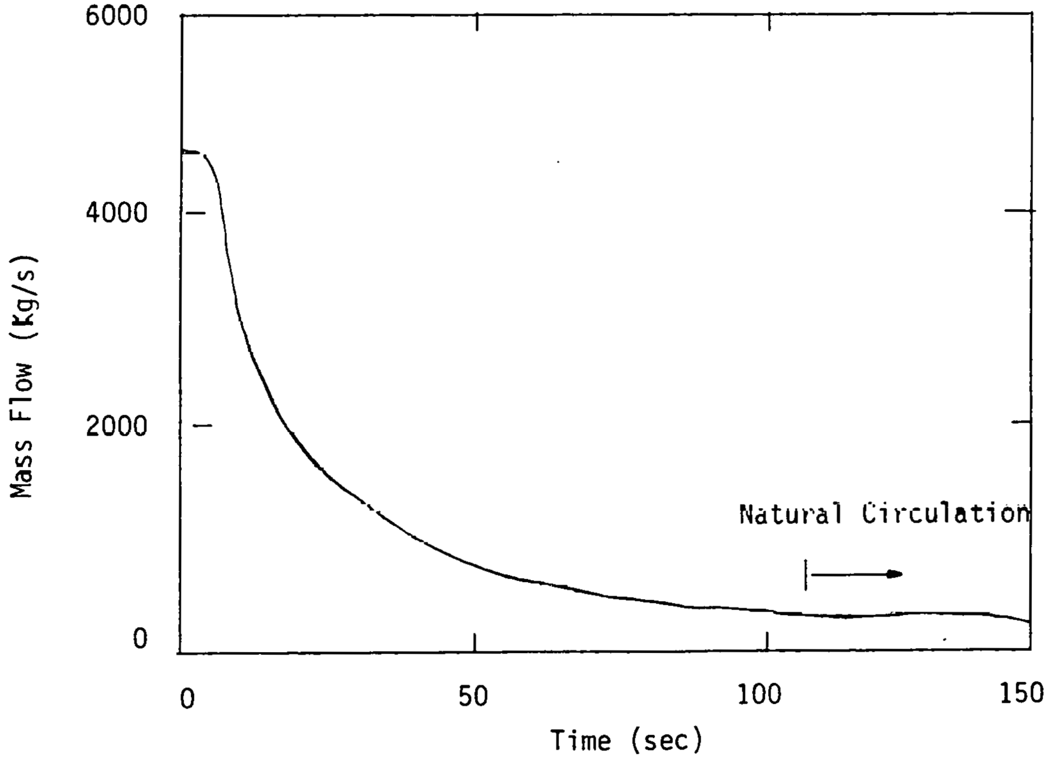

Figure 3.19 State LOSP-1 Loop Flow vs. Time

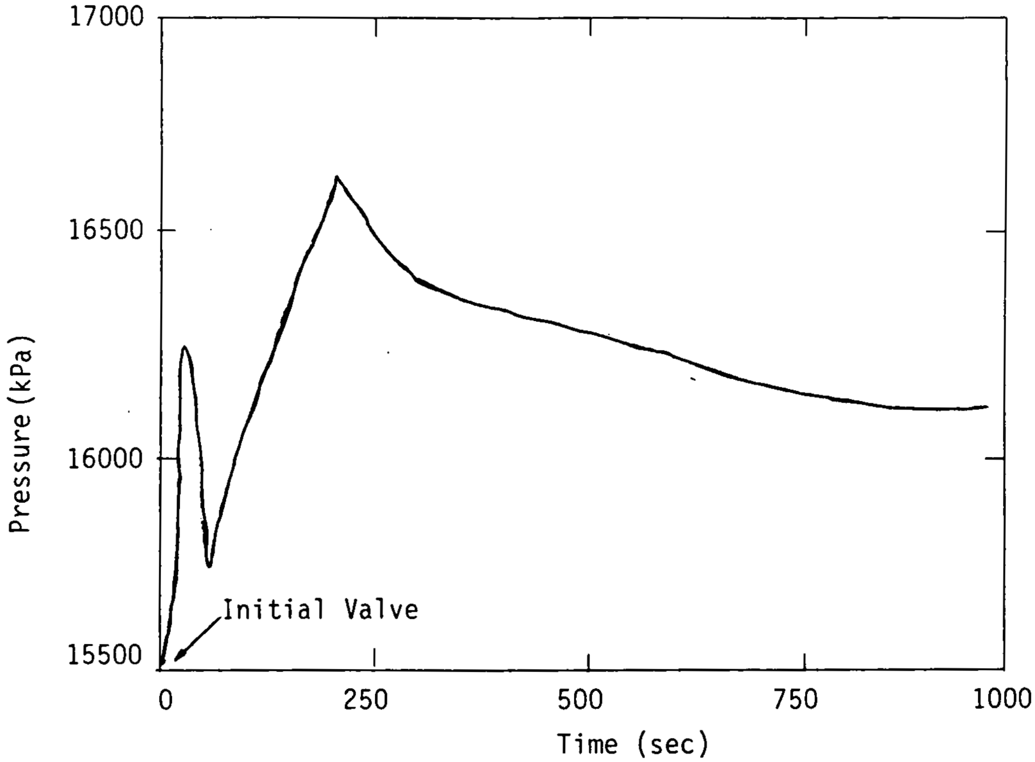

Figure 3.20 State LOSP-1 Primary Pressure vs. Time

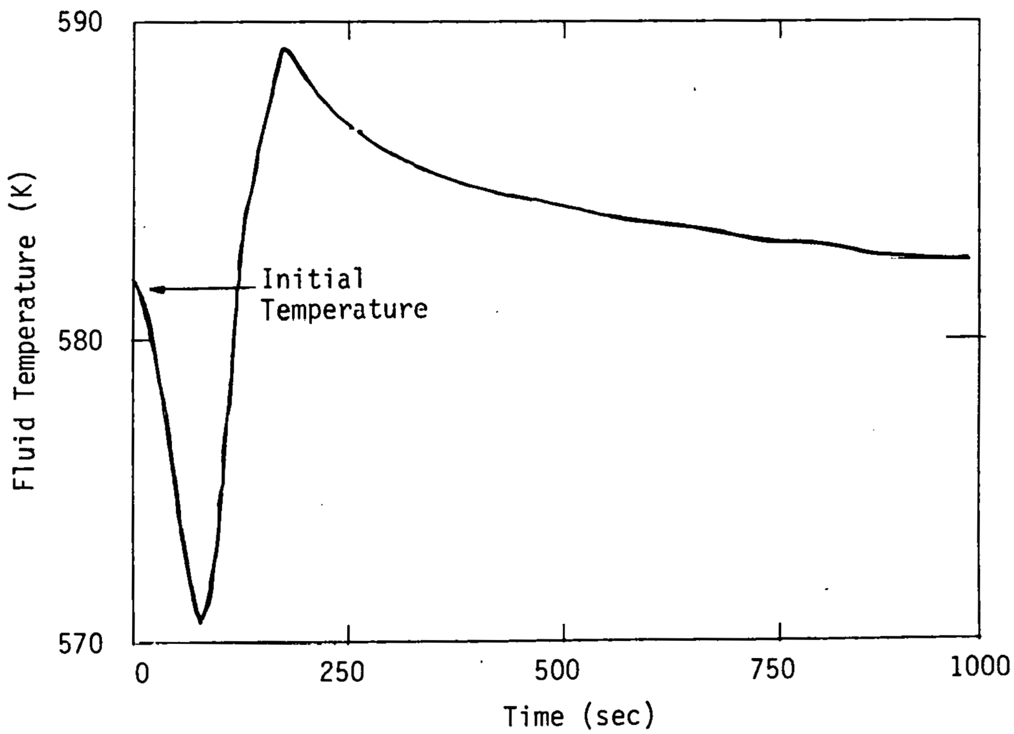

Figure 3.21 State LOSP-1 Hot Leg Temperature vs. Time

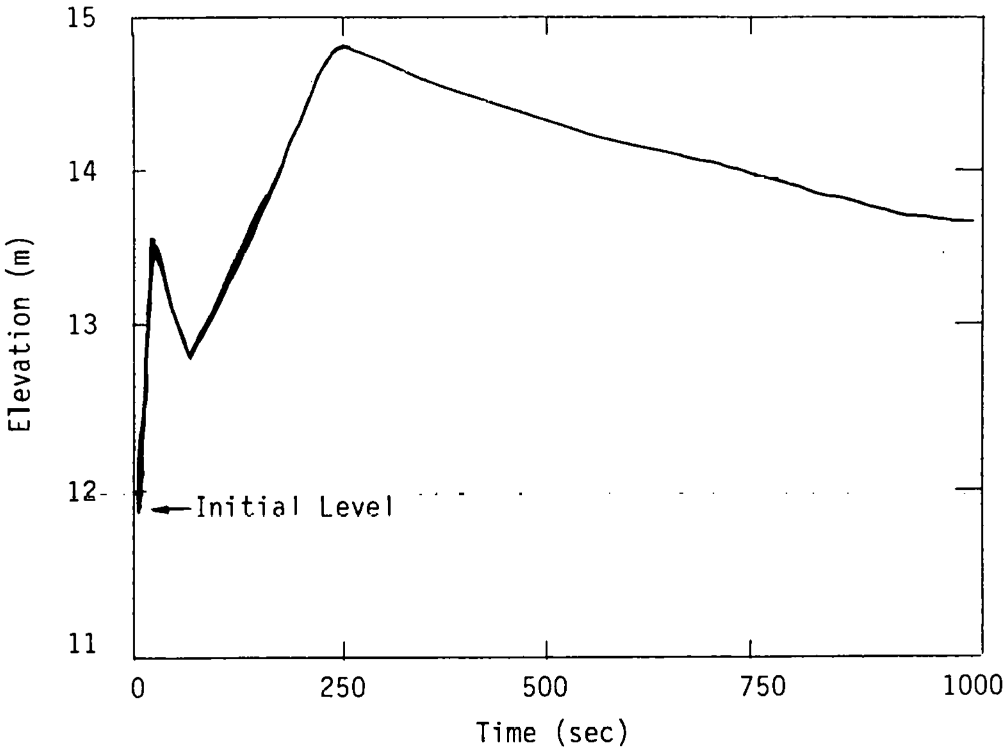

Figure 3.22 State LOSP-1 Pressurizer Level vs. Time

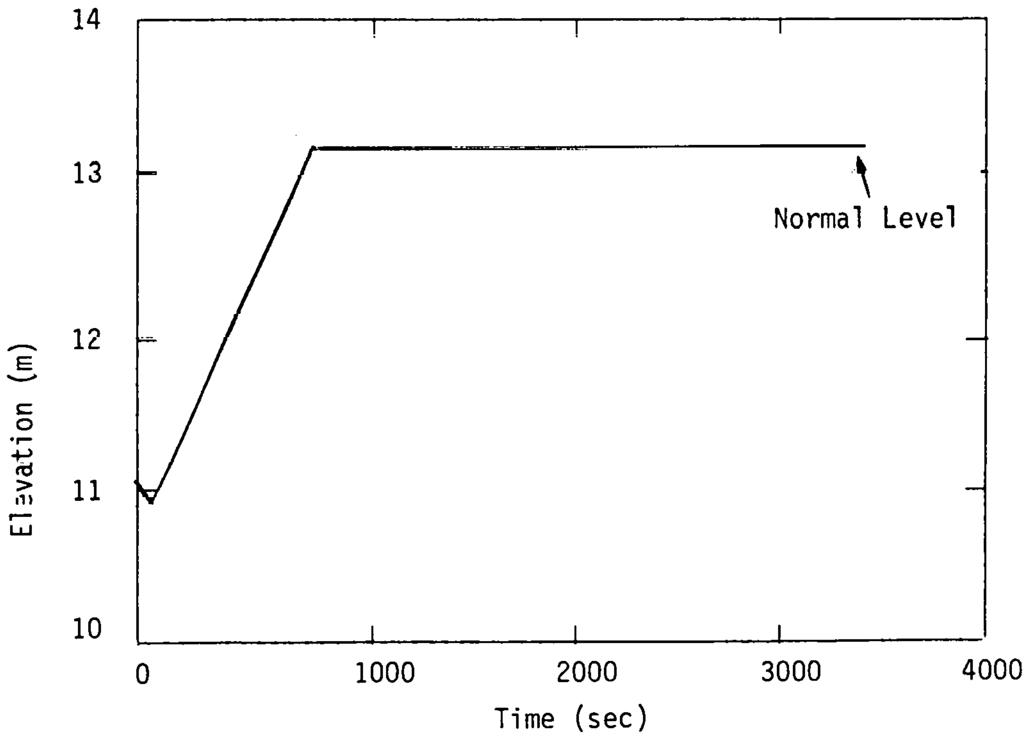

Figure 3.23 State LOSP-2 Steam Generator Secondary Level vs. Time

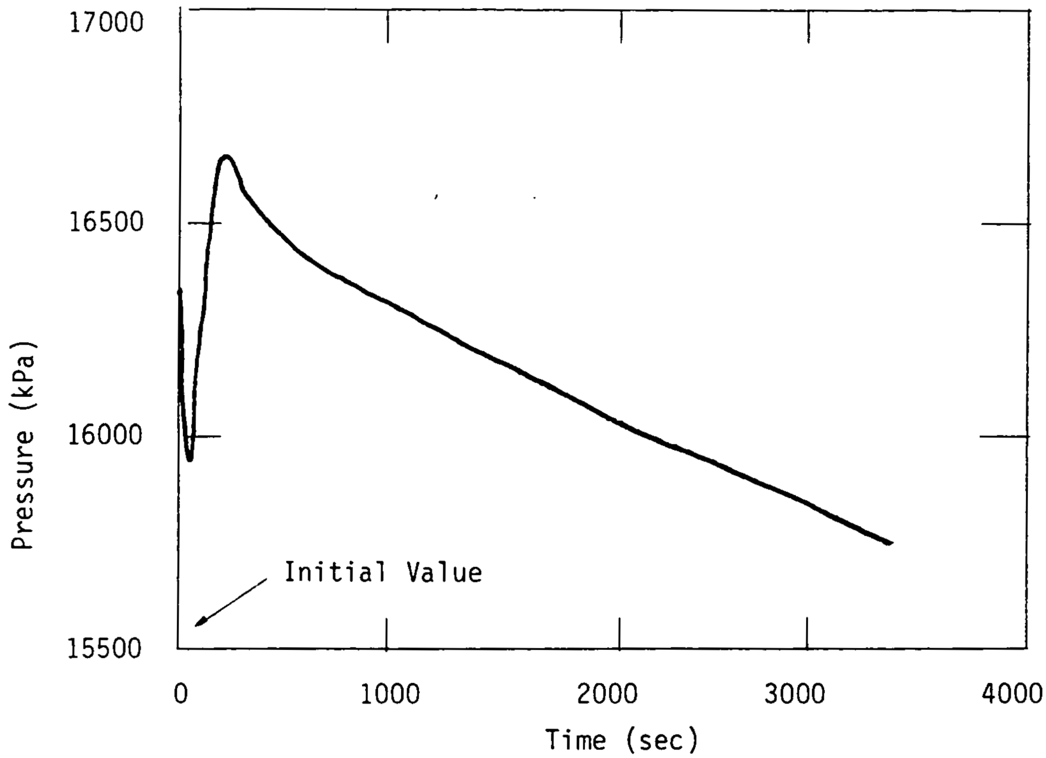

Figure 3.24 State LOSP-2, Primary Pressure vs. Time

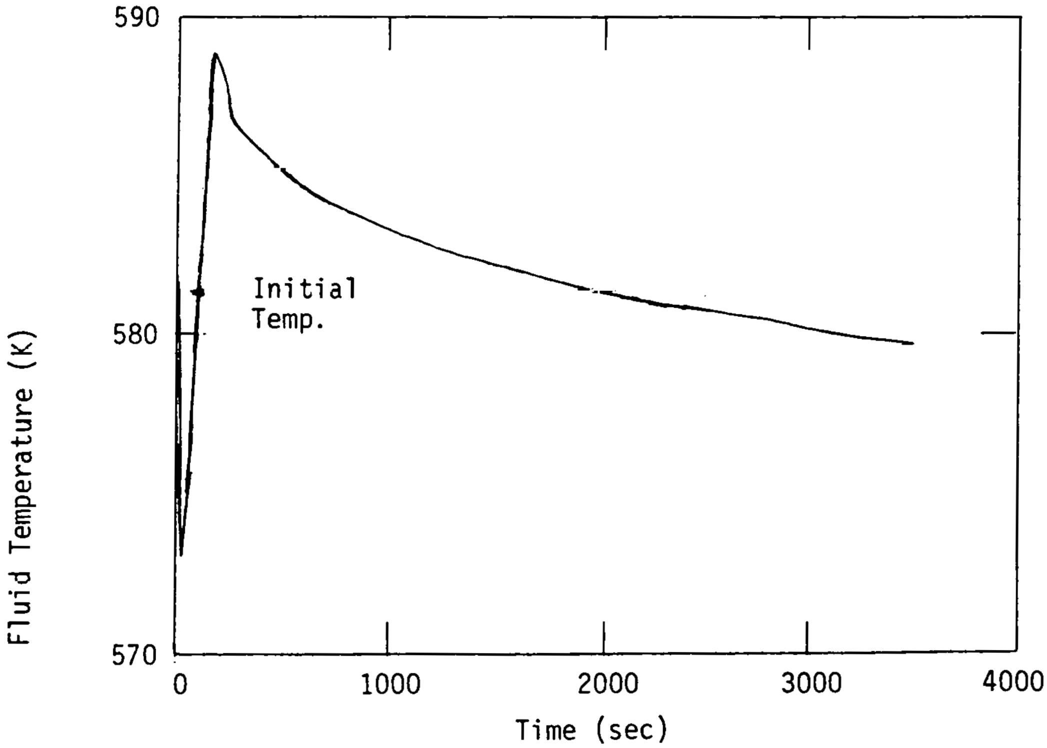

Figure 3.25 State LOSP-2, Hot Leg Temperature vs. Time

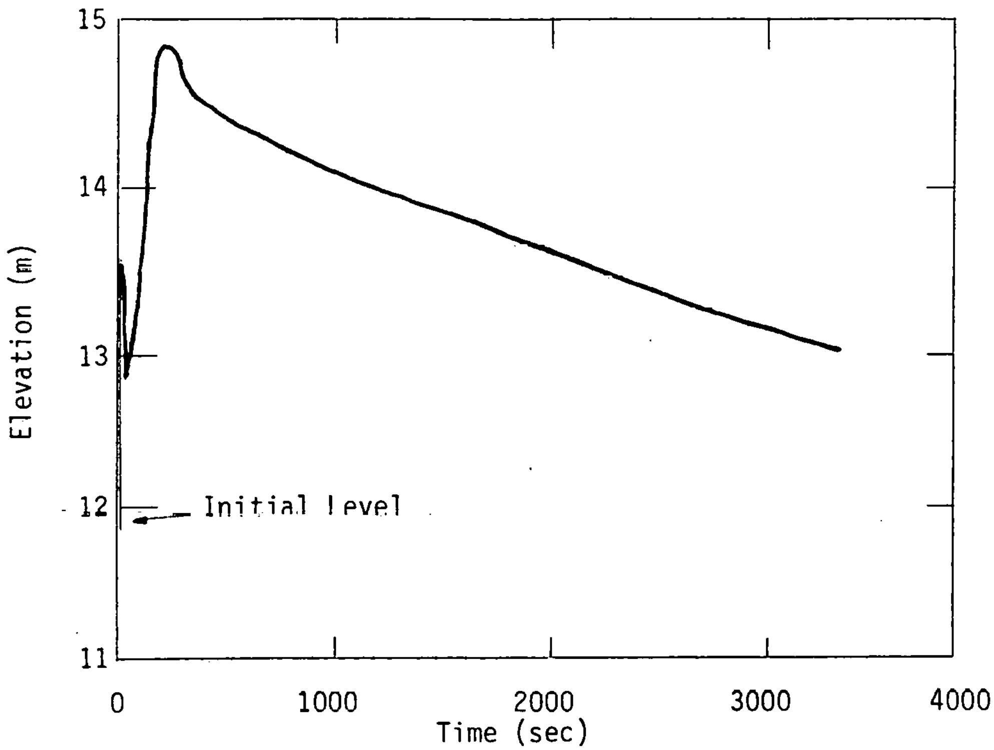

Figure 3.26 State LOSP-2, Pressurizer Level vs. Time

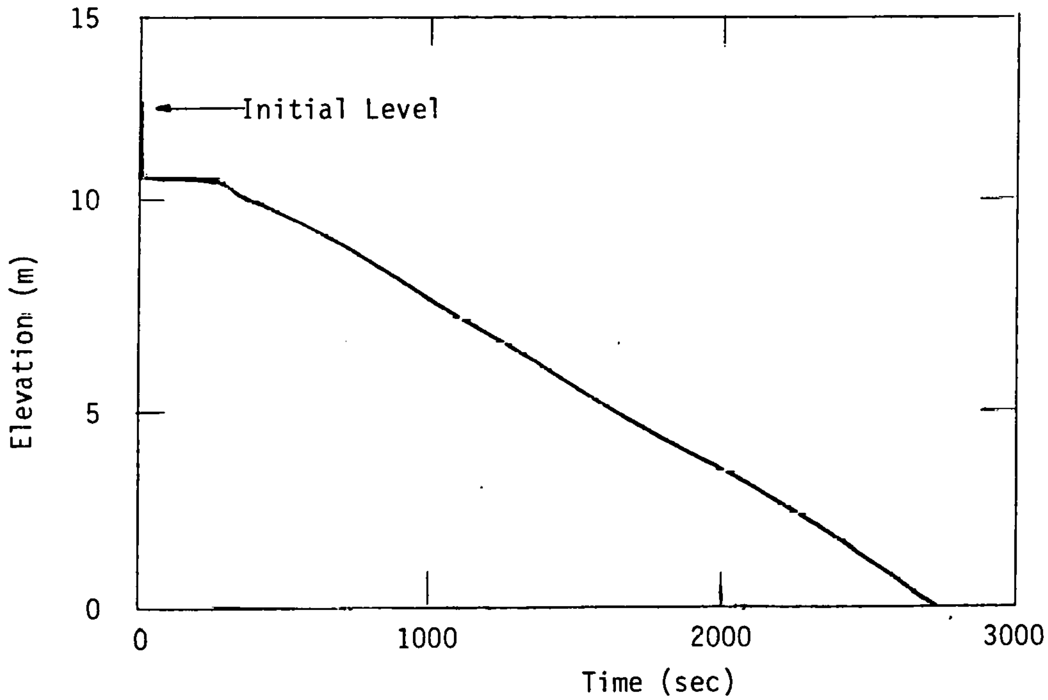

Figure 3.27 State LOSP-4, Steam Generator Secondary Level vs. Time

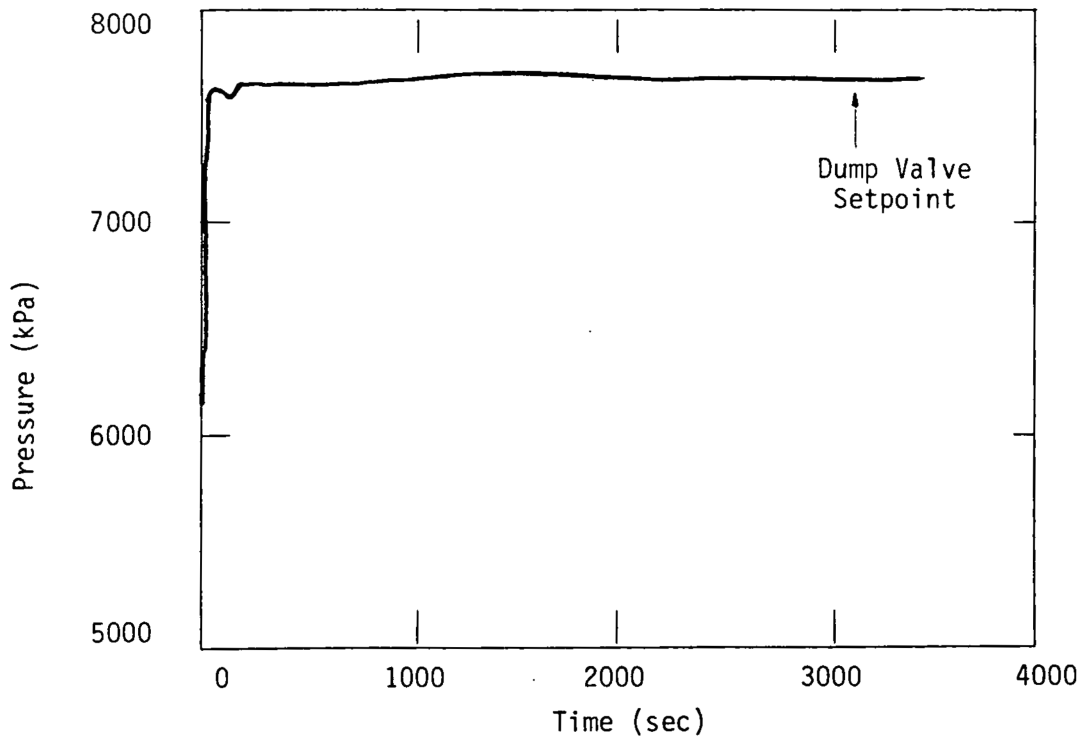

Figure 3.28 State LOSP-4, Steam Generator Secondary Pressure vs. Time

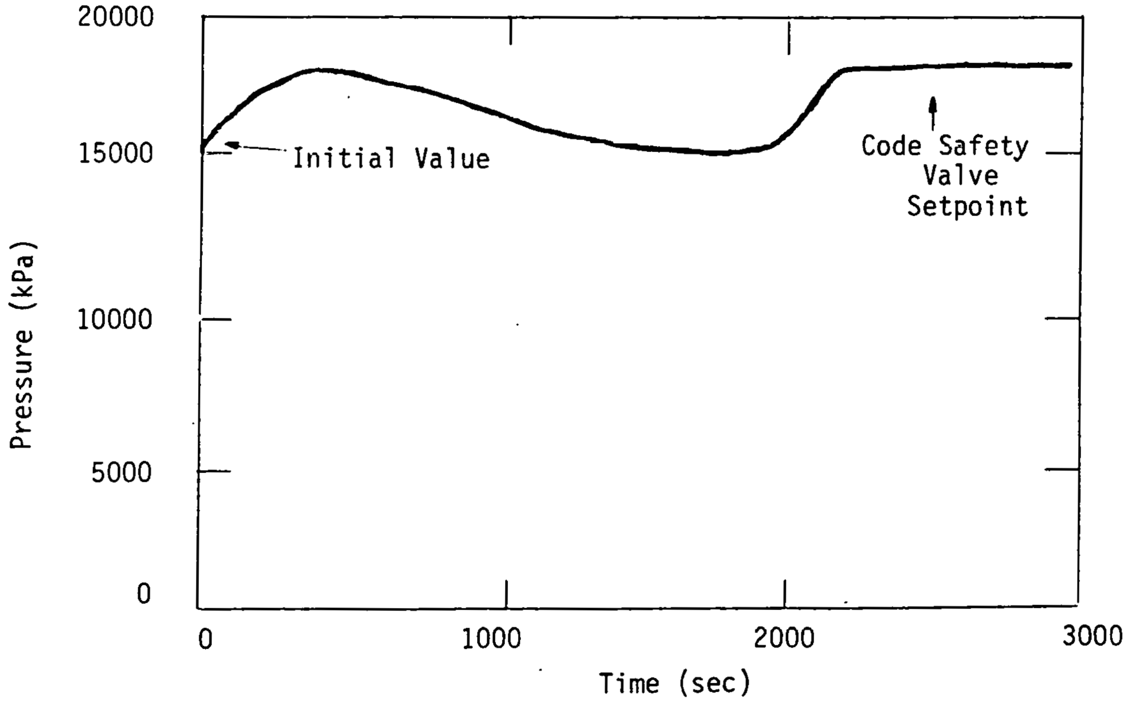

Figure 3.29 State LOSP-4, Primary Pressure vs. Time

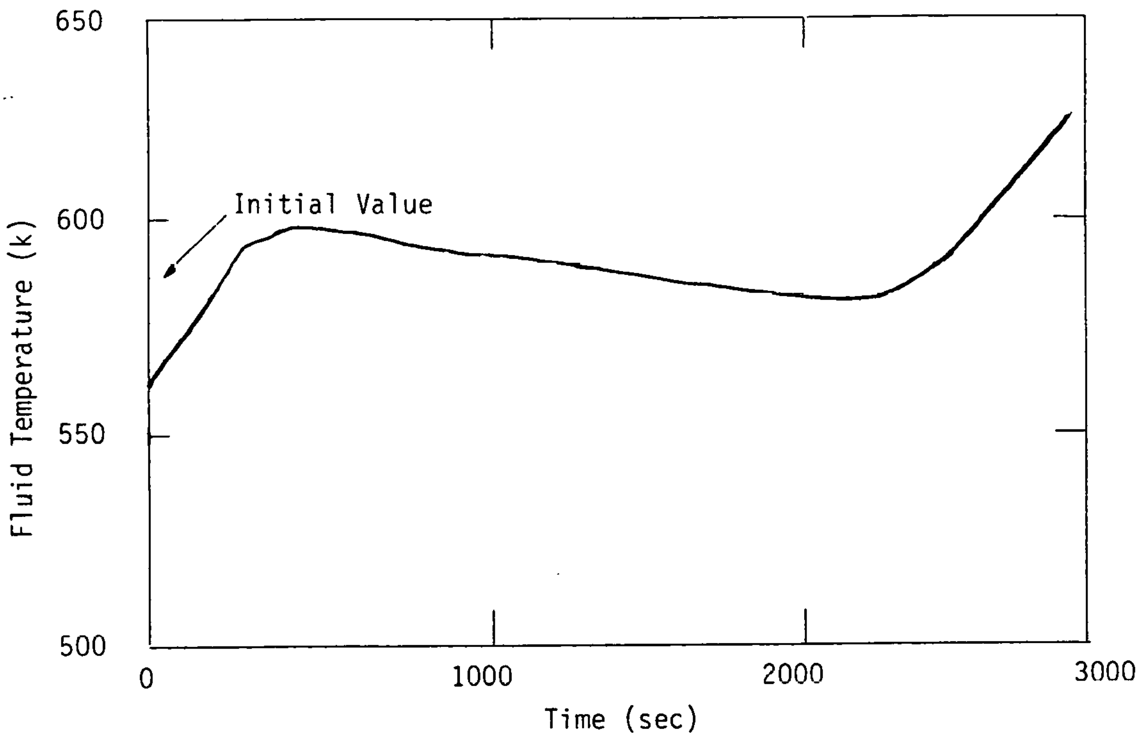

Figure 3.30 State LOSP-4, Hot leg Fluid Temperature vs. Time

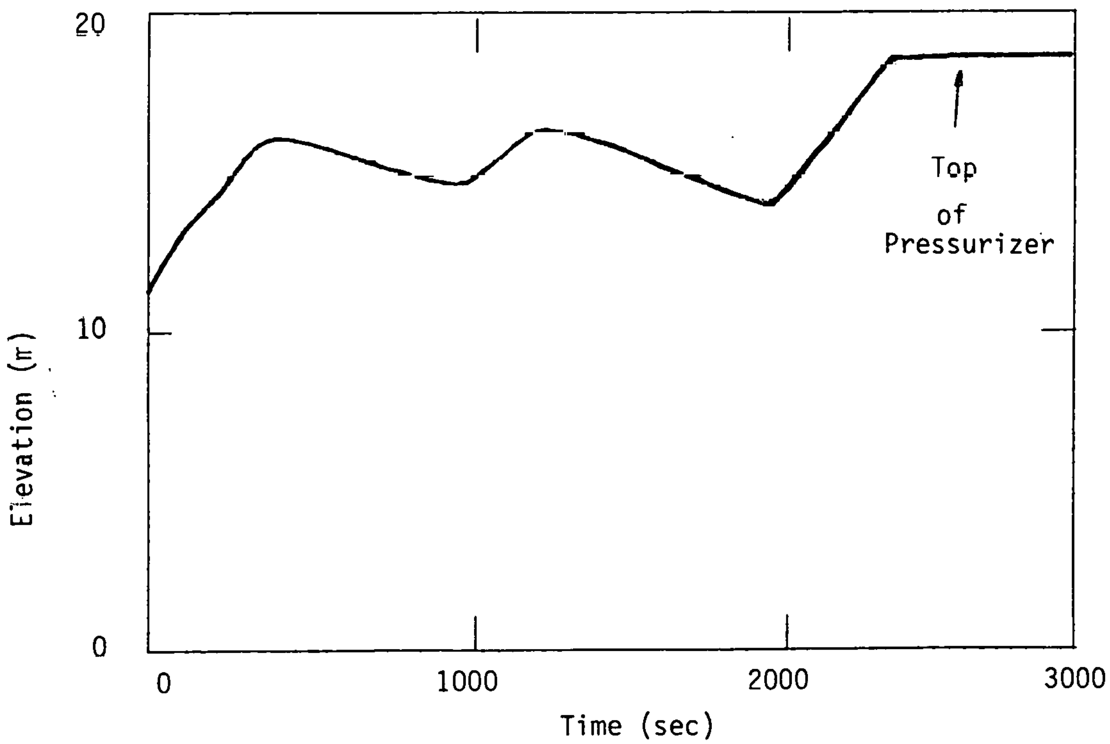

Figure 3.31 State LOSP-4, Pressurizer Level vs. Time

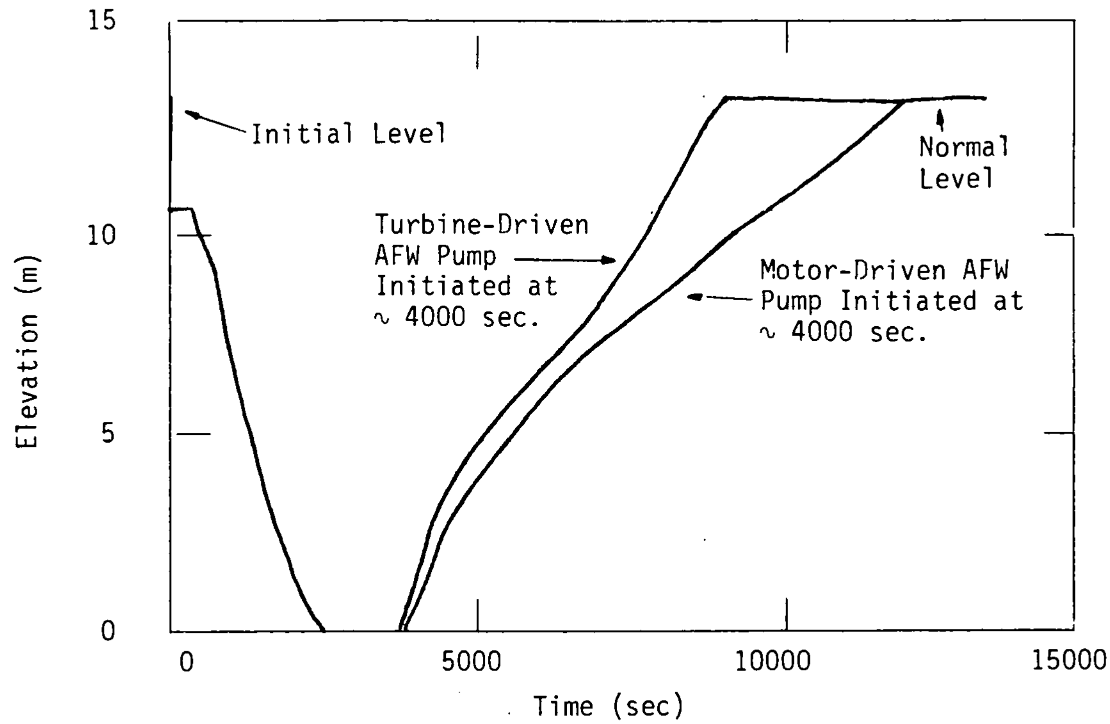

Figure 3.32 State LOSP-5, Steam Generator Secondary Level vs. Time

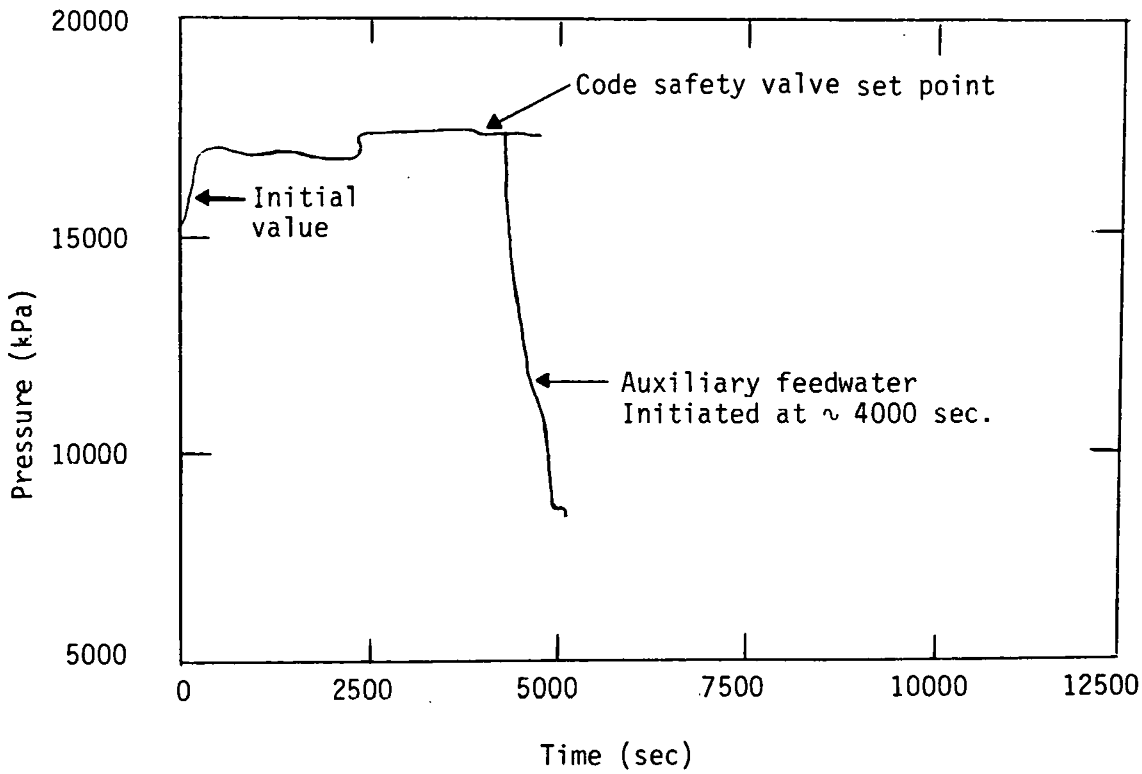

Figure 3.33 State LOSP-5, Primary Pressure vs. Time

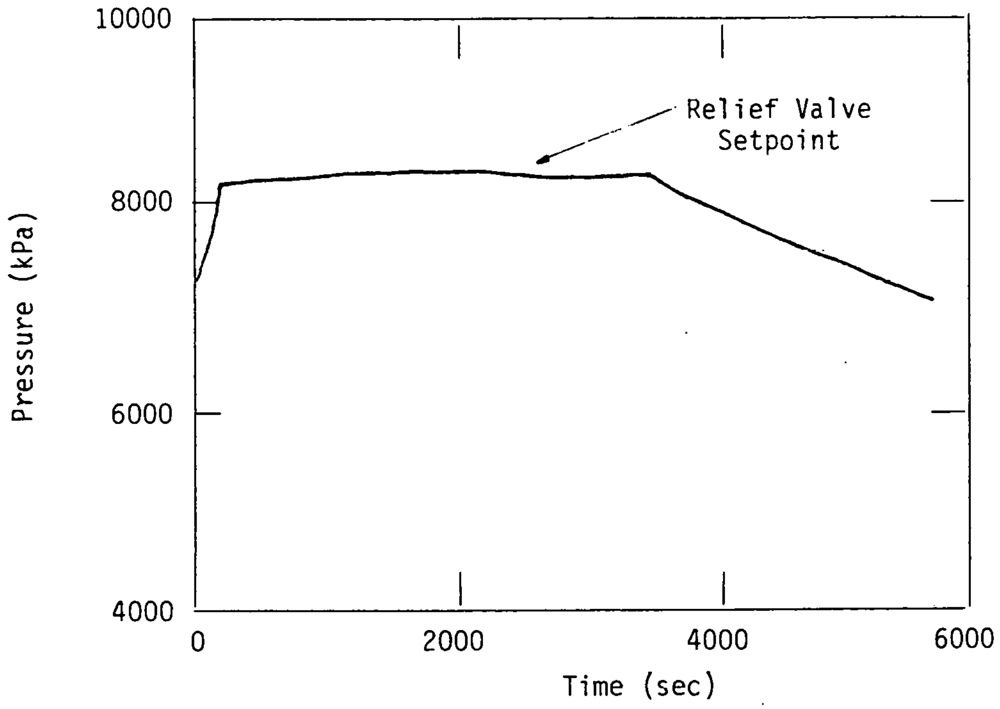

Figure 3.34 State LOSP-5, Intact Steam Generator Secondary Pressure vs. Time

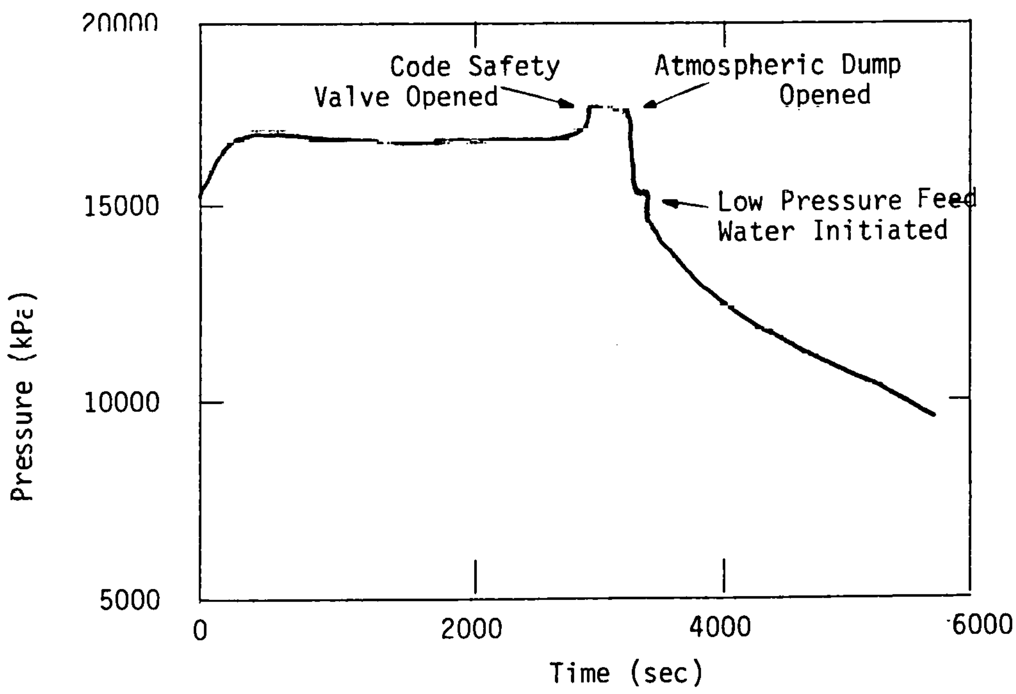

Figure 3.35 State LOSP-5, Primary Pressure vs. Time

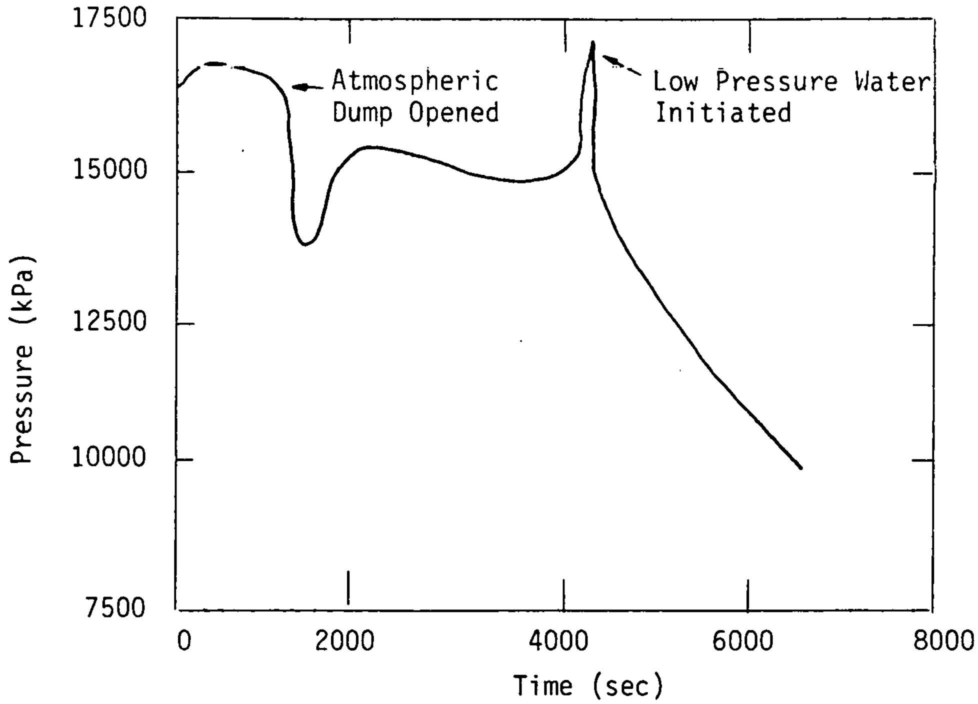

Figure 3.36 State LOSP-5, Primary Pressure vs. Time

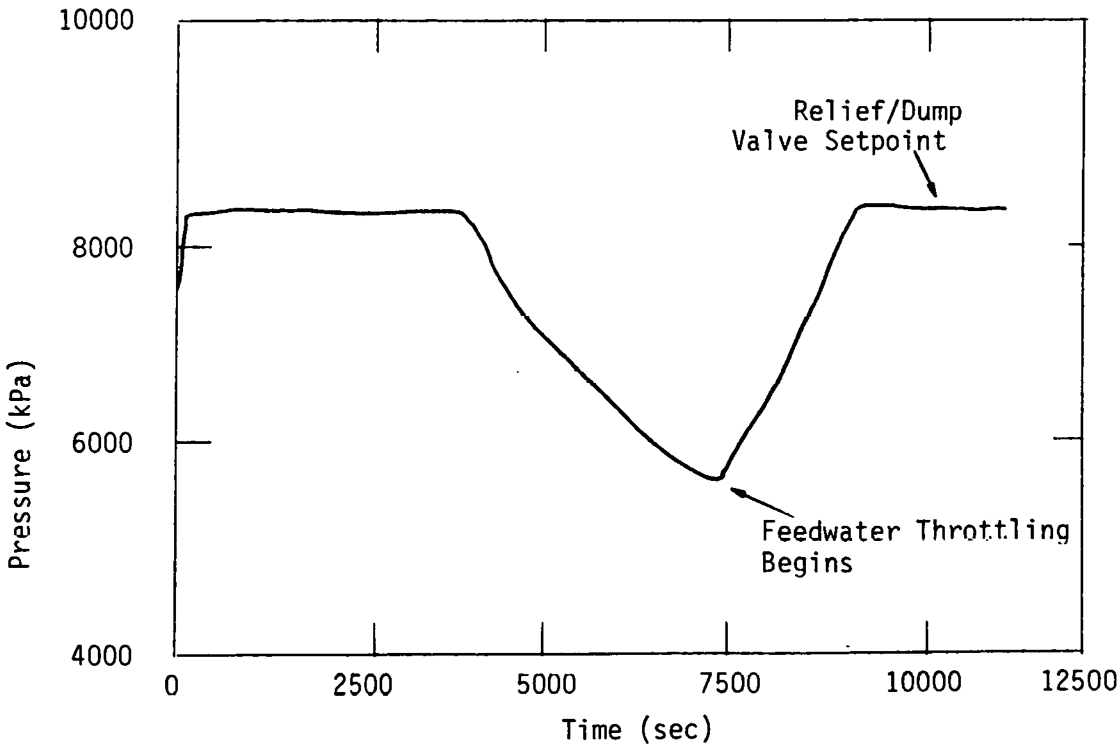

Figure 3.37 State LOSP-6, Steam Generator Secondary Pressure vs. Time

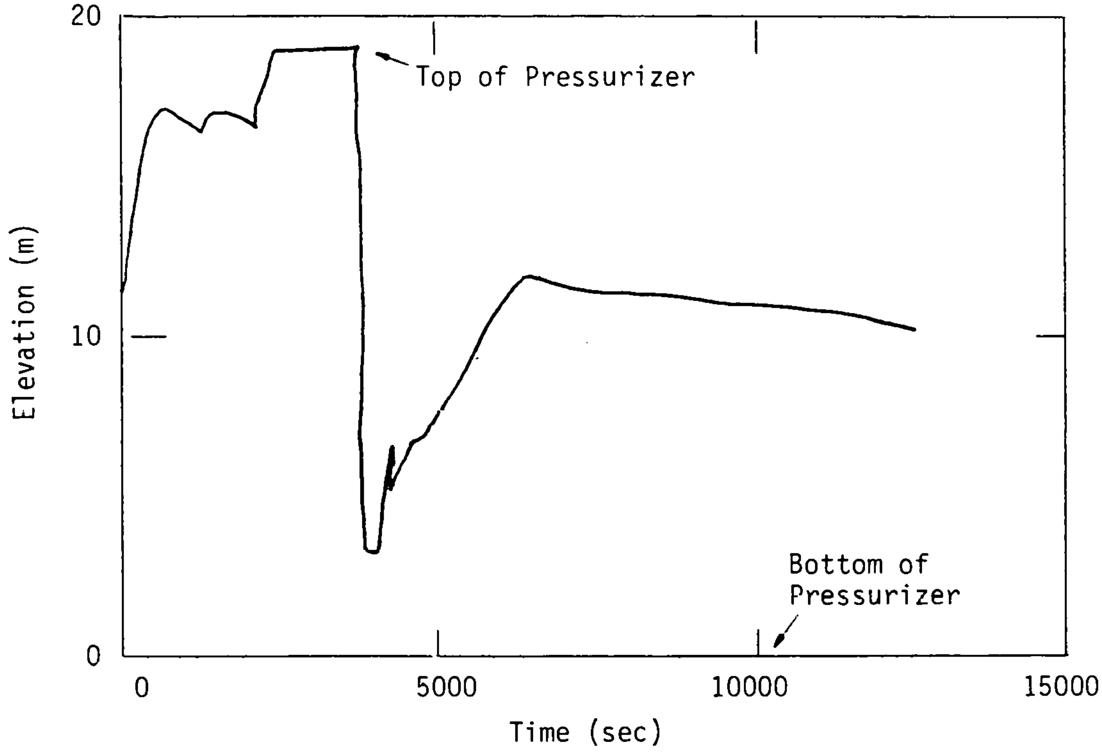

Figure 3.38 State LOSP-14, Pressurizer Level vs. Time: Diesel Generator Restored at 3700 sec.

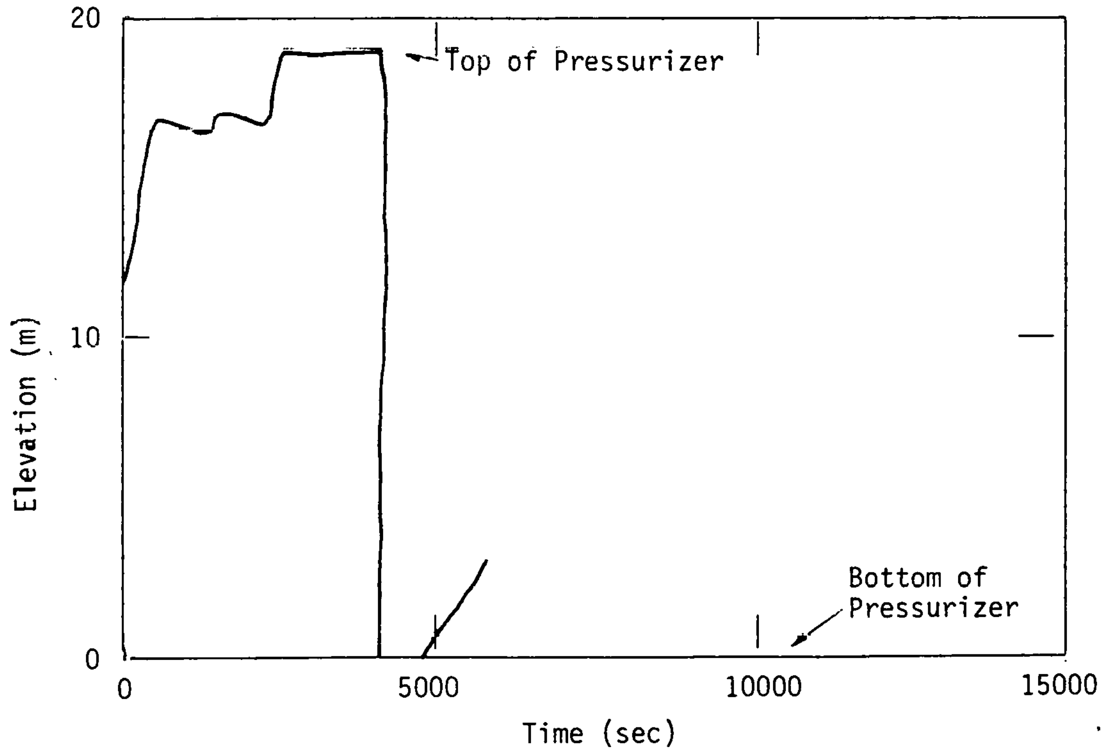

Figure 3.39 State LOSP-14, Pressurizer Level vs. Time: Diesel Generator Restored at 4300 sec.

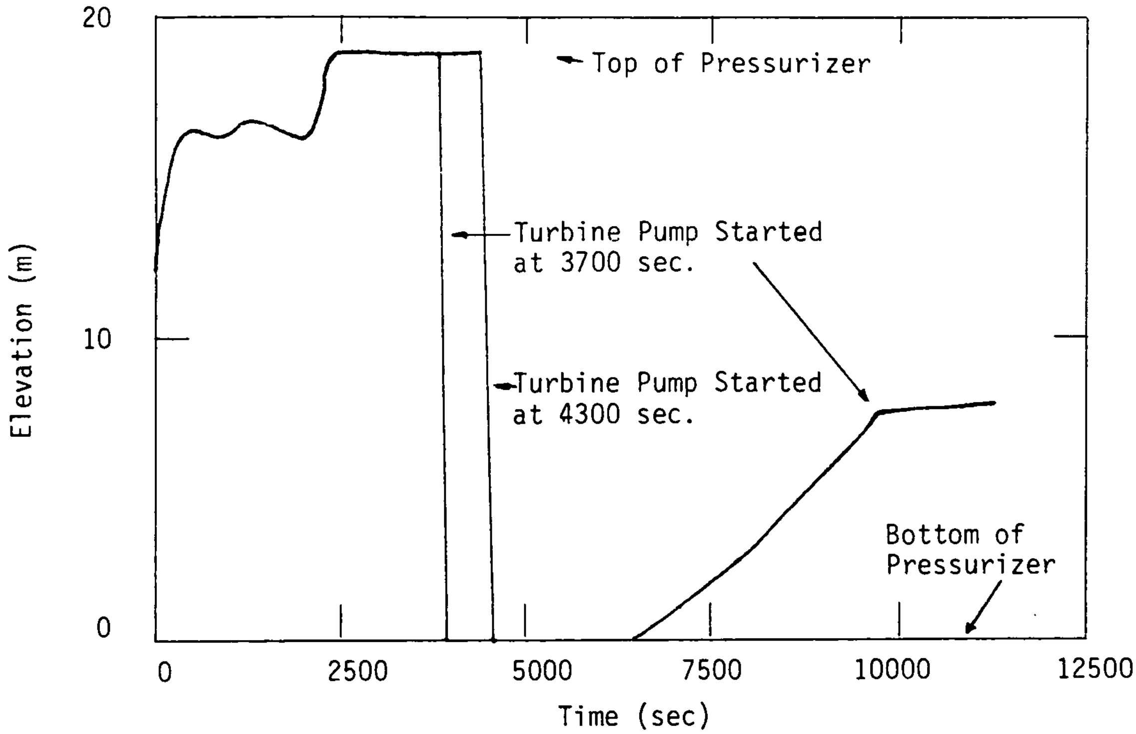

Figure 3.40 State LOSP-14, Pressurizer Level vs. Time

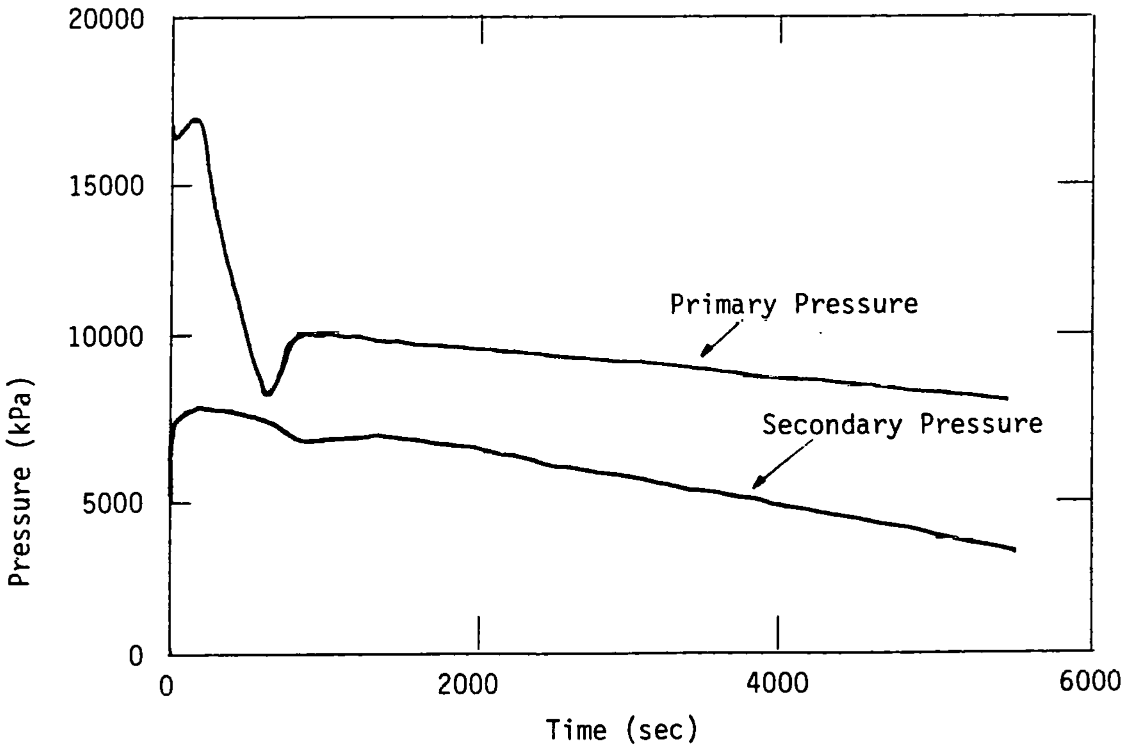

Figure 3.41 State LOSP-21, Stuck Open PORV, Primary and Secondary Pressure vs. Time

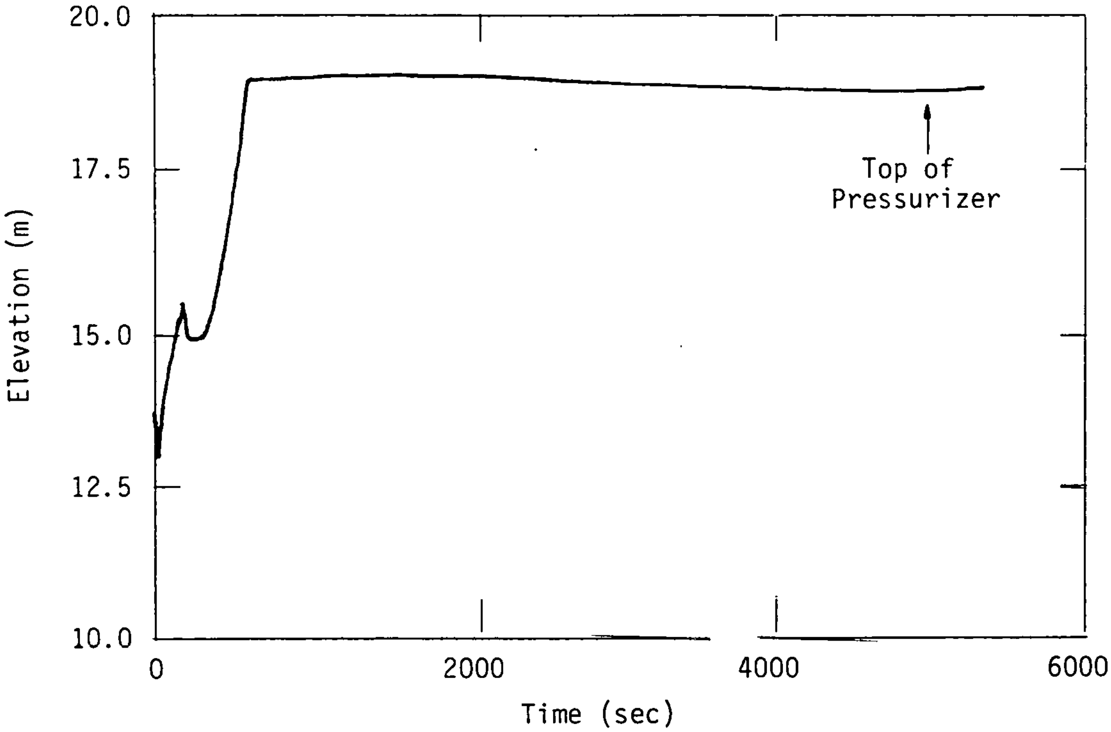

Figure 3.42 State LOSP-21, Stuck Open PORV, Pressurizer Level vs. Time

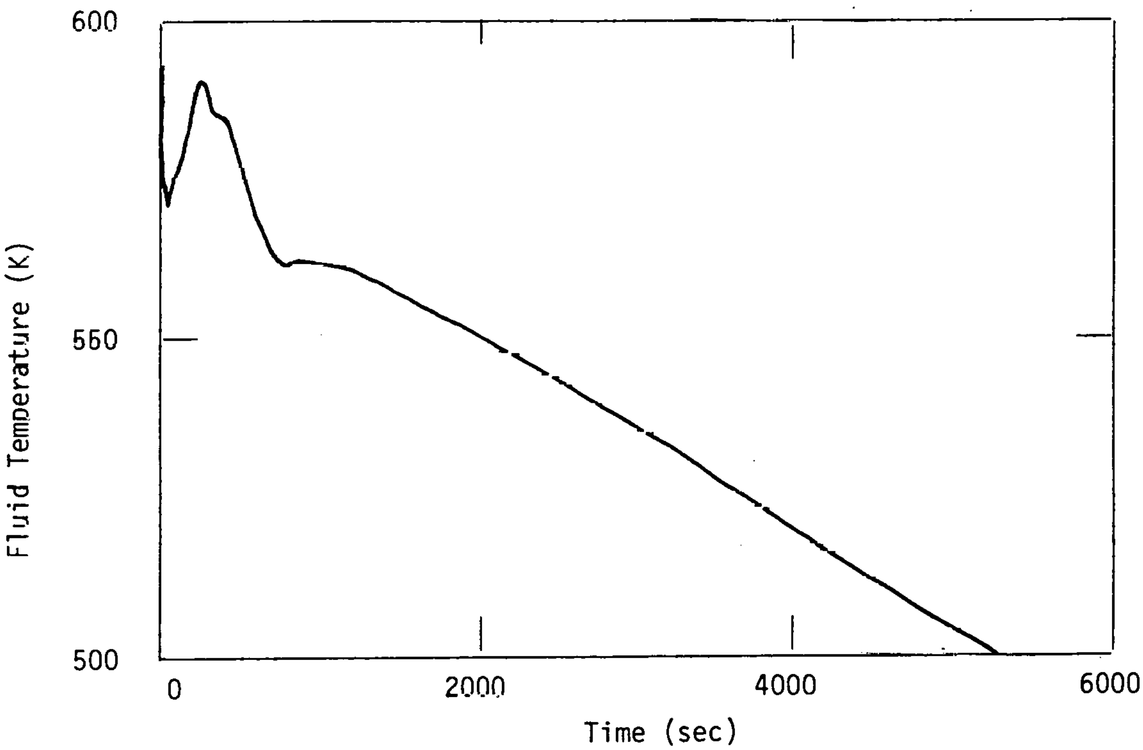

Figure 3.43 State LOSP-21, Stuck Open PORV, Hot Leg Fluid Temperature vs. Time

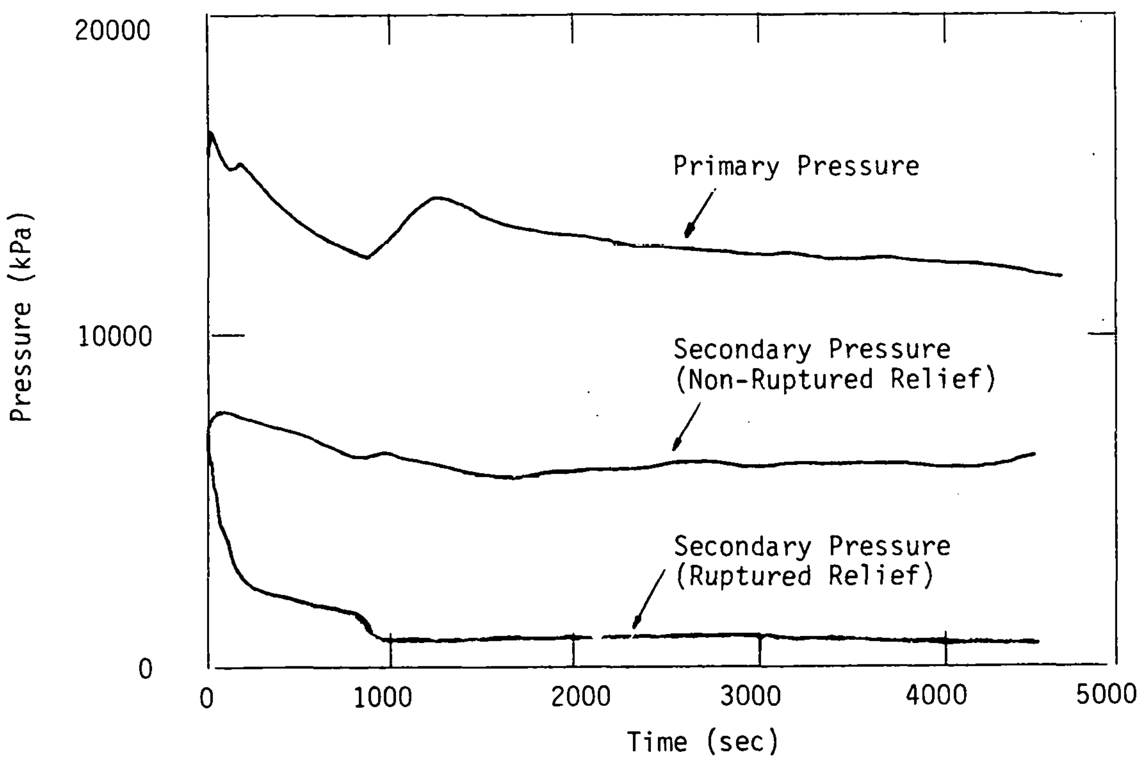

Figure 3.44 State LOSP-31, Ruptured S.G. Relief, Primary and Secondary Pressure vs. Time

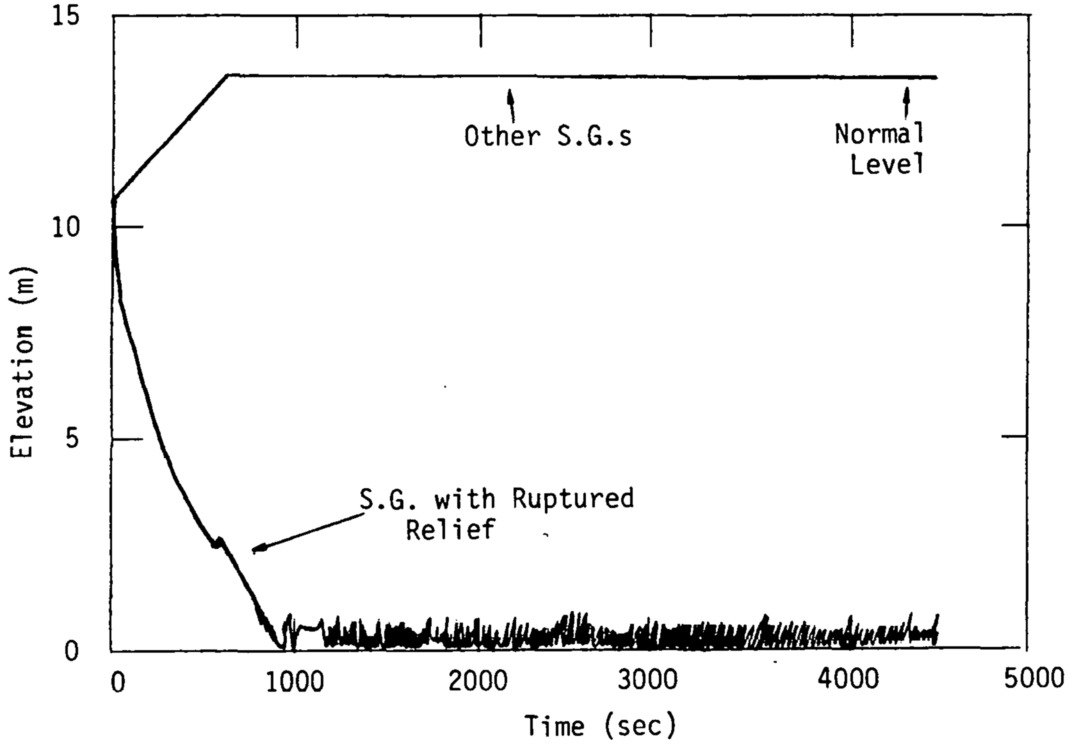

Figure 3.45 LOSP-31, Ruptured S.G. Relief, Steam Generator Secondary Mixture Levels vs. Time

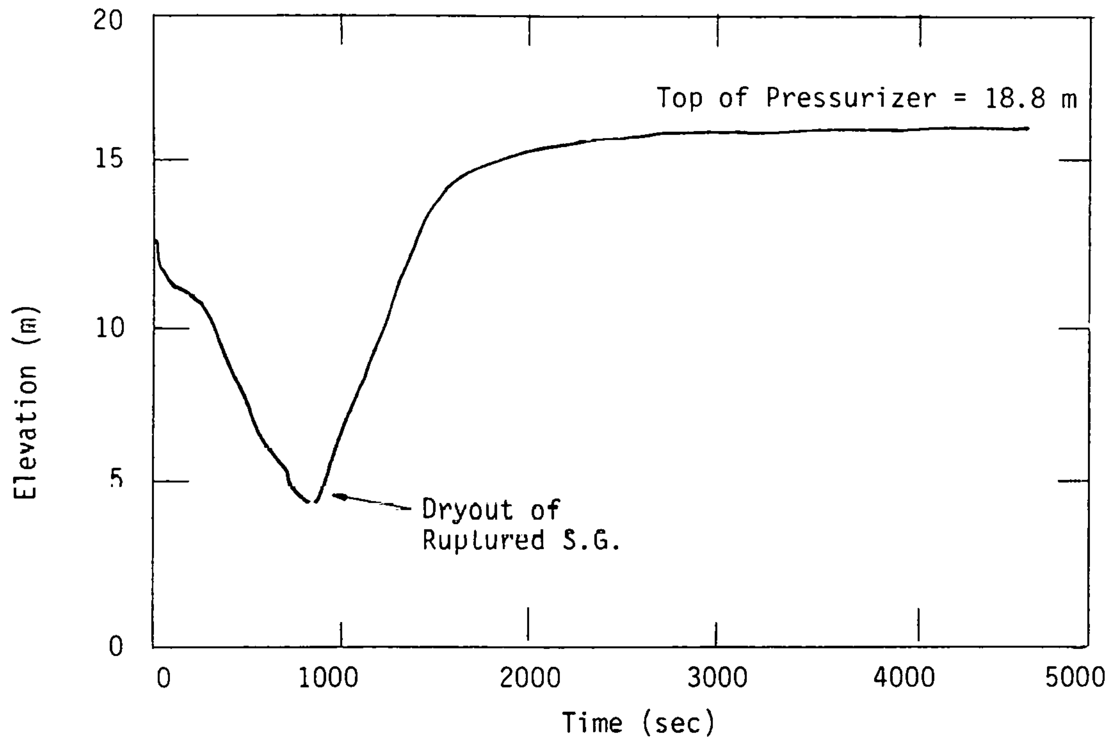

Figure 3.46 State LOSP-31, Ruptured S.G. Relief, Pressurizer Level vs. Time

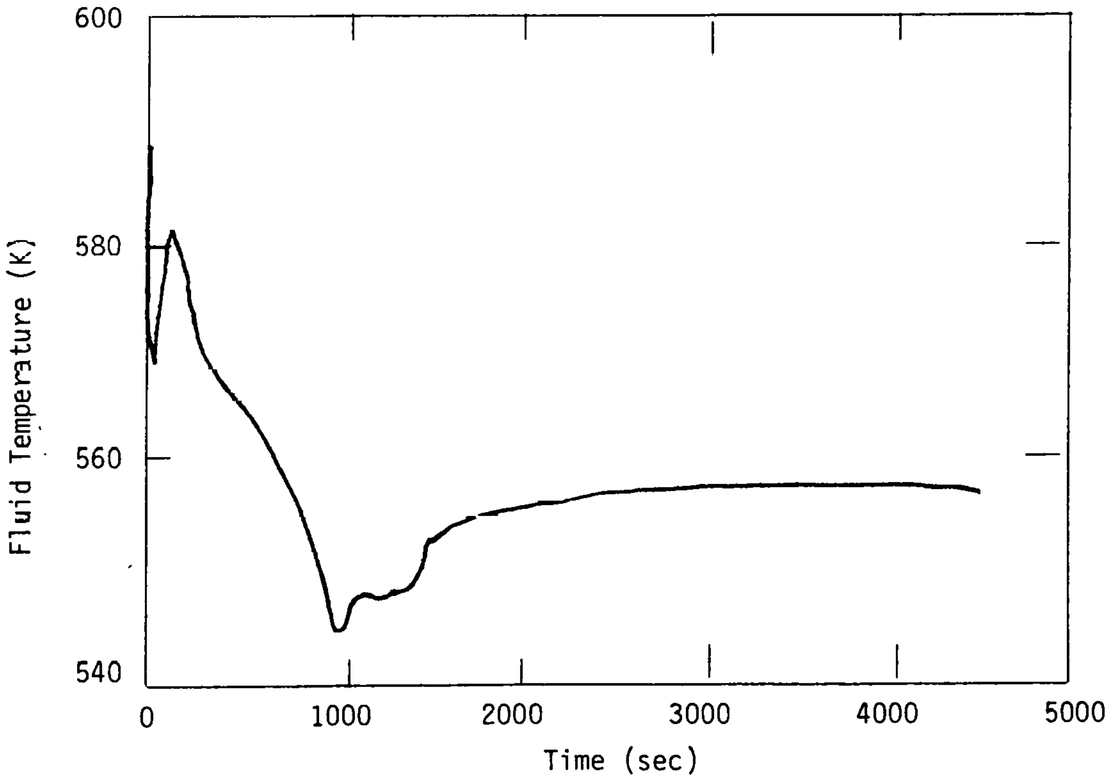

Figure 3.47 State LOSP-31, Ruptured S.G. Relief, Hot Leg Temperature vs. Time

3.2.2 Other Important Transient-Initiated Sequences

In the preceding section, the key plant symptoms and operator actions associated with a variety of LOSP initiated sequences were investigated and documented through the use of an operator action event tree developed for these sequences. These LOSP initiated sequences represent the documented PWR transient analyses available to date from the SASA Program. In this section, other important transient-initiated accident conditions will be discussed and the relevance of the information provided in the previous section to these additional sequences will be briefly examined.

There is obviously a very wide spectrum of possible transient-initiating events and potential accident sequences which can subsequently evolve from these events: The Electric Power Research Institute (EPRI) has catalogued forty-one (41) different types of transient initiating events [11]; the Reactor Safety Study identified four different types of important accident sequences which can evolve from a transient initiator.

The EPRI list of transient initiating events is reproduced in Table 3.1. As can be seen from this table, there is a wide diversity of possible transient initiators ranging from spurious trips with no accompanying plant faults or failures (#37) to a loss of offsite power resulting in a trip of reactor coolant and main feedwater pumps (#35). While many different specific transient initiating events exist, it is important to recognize that most of the initiating events listed in Table 3.1 will very quickly result in an identical plant condition and require identical operator response. Furthermore, this plant condition and required operator response are essentially the same as that described at state LOSP-1 in Section 3.2.1. Thus, there is a "basic PWR transient response" which is applicable to virtually all transient initiators. The key features of this basic response are the following.

- The reactor is scrammed and power is reduced to decay heat levels
- The turbine is tripped

- The reactor coolant pumps are tripped
- The main feedwater pumps are tripped
- Steam generator secondary level drops
- Auxiliary feedwater initiation signal is generated
- Secondary steam flow is isolated
- Steam generator secondary pressure rises to dump valve setpoint
- Atmospheric dump valves relieve steam from steam generators
- Primary pressure, temperature, and pressurizer level initially increase and then decrease upon reactor scram.

The ability to remove heat through the normal main feedwater/turbine/condenser loop is therefore lost and heat removal through the steam generators requires auxiliary feedwater and secondary steam relief. The operator's basic duties at this point are to ensure adequate auxiliary feedwater delivery and to monitor and maintain adequate reactor coolant makeup.

An examination of Table 3.1 will show that the vast majority of the listed transient initiating events will produce this basic response.

State LOSP-1 also corresponds to this basic transient response with only a few exceptions. The major difference is that the LOSP initiator will automatically trip the Reactor Coolant Pumps (RCP) while other transients do not. However,the availability of the RCPs will not have a significant impact on the behavior of the parameters described for state LOSP-1. The primary and secondary pressures, temperatures, and levels will respond in essentially the same manner as depicted in Figures 3.16 through 3.18 and 3.20 through 3.22 with or without the RCP running. Following the initial increase in reactor coolant temperature and pressure, the parameters would normally decrease following reactor scram and stabilize in a relatively short period of time. When the RCPs trip, the reactor coolant temperature and pressure initially follow these trends, but do not (as shown in Section 3.2.1) stabilize. Obviously, the primary flow rate will be much higher if the RCPs are running and the availability of the RCPs will also lead to a much more uniform heating of the primary fluid. The operator will also be called upon to manually trip the RCPs when the appropriate conditions (low primary system pressure, safety injection initiated) are present. Several alarms are provided to alert the operator that a complete loss of flow has occurred and he should not have any difficulty ascertaining what transient has occurred.

Thus, the operator action event tree presented in Section 3.2.1 is applicable, with minor modifications, to all transient initiating events which produce the basic transient response described above.

As noted above, the Reactor Safety Study identified four important types of PWR transient sequences:

- TMLB' - Loss of offsite power initiator coupled with the subsequent failure of both diesel generators
- TML - Loss of main feedwater initiating event coupled with coupled with failure of auxiliary feedwater system (with AC power available)
- TKQ - Transient initiator followed by failure to scram with one PORV stuck-open
- TMLQ - Loss of both main and auxiliary feedwater (TML) compounded by a stuck-open valve.

The first three sequences represent the largest contributors for the Westinghouse plant analyzed in the Reactor Safety Study. The fourth sequence is essentially the combination of events which occurred at Three Mile Island.

Sequence TMLB' is explicitly addressed in the OAET presented in Section 3.2.1. State LOSP-10 represents the plant condition where the LOSP initiator is followed by failure of the diesel generators to start and provide emergency AC power to the plant. The OAET states which evolve from state LOSP-10 directly address the TMLB' accident sequence (i.e., states 10-16, 22-24, and 28-30).

Sequence TML is also encompassed by the OAET with minor adjustments to account for the differences in the specific transient initiators. Sequence TML, as defined in the Reactor Safety Study, involves a loss of main feedwater initiator; the initiating event in the OAET is a loss of main feedwater caused by a loss of offsite power. Thus, except for the effects of automatically tripping the Reactor Coolant Pumps immediately after the LOSP initiator, sequence TML is directly addressed by the OAET in all states evolving from state LOSP-1 (i.e. states 1-9, 19-21, and 25-27). It is not expected that the availability of the RCPs will significantly alter the major parametric trends described for these states in the OAET.

Sequence TMLQ is the same as the TML sequence with the additional failure of a relief valve to re-seat. In as much as TML is encompassed by the OAET presented in Section 3.2.1 with minor modification, the TMLQ sequence can also be considered addressed by this OAET since the possibility of a stuck-open PORV is explicitly included in the OAET headings (see states LOSP-21 and LOSP-27).

Sequence TKQ is an Anticipated Transient Without Scram (ATWS) event coupled with a stuck-open relief valve. Although both EG&G [3] and LANL [12] have performed some ATWS calculations, this sequence is not addressed in the OAET in Section 3.2.1 due primarily to the relatively large uncertainties in the plant response under ATWS conditions. EG&G has stated that their superficial analysis was not adequate to accurately describe this transient and additional code development is required. The LANL report cautions that definitive conclusions based upon their ATWS calculations should be avoided until a more thorough analysis of the sensitivity of their results to reactivity feedback data is obtained.

However, the plant response under ATWS conditions is sufficiently distinctive to allow the operator to easily differentiate between ATWS events and other transient conditions involving successful scram. In addition to the obvious indications from the control rod position lights and power range monitors, many of the major parametric trends can be used to uniquely diagnose an ATWS event. The primary pressure increases rapidly to the safety valve setpoint and primary inventory is lost through the valve(s) within a few seconds after the initiating event occurs. The secondary pressure will rise rapidly to the relief valve setpoint and the steam generators will be voided within a few minutes. These physical responses can be compared to the much more gradual parametric changes associated with the successful scram conditions of state LOSP-1.

Table 3.1

PWR TRANSIENT CATEGORIES

1. Loss of RCS Flow (1 Loop)
2. Uncontrolled Rod Withdrawal
3. CRDM Problems and/or Rod Drop
4. Leakage from Control Rods
5. Leakage in Primary System
6. High or Low Pressurizer Pressure
7. Pressurizer Leakage
8. Pressurizer Relief or Safety Valve Opening
9. Inadvertant Safety Injection Signal
10. Containment Pressure Problem
11. CVCS Malfunction-Boron Dilution
12. Pressure, Temperature, Power Imbalance
13. Startup of Inactive Coolant Pump
14. Total Loss of RCS Flow
15. Loss of Reduction of Feed-water Flow (1 Loop)
16. Total Loss of Feedwater Flow (All Loops)
17. Full or Partial Closure of MSIV (1 Loop)
18. Closure of All MSIV
19. Increase in Feedwater Flow (1 Loop)
20. Increase in Feedwater Flow (All Loops)
21. Feedwater Flow Instability-Operator Error
22. Feedwater Flow Instability-Miscellaneous Mechanical Causes
23. Loss of Condensate Pumps (1 Loop)
24. Loss of Condensate Pumps (All Loops)
25. Loss of Condenser Vacuum
26. Steam Generator Leakage
27. Condenser Leakage
28. Miscellaneous Leakage in Secondary System
29. Sudden Opening of Steam Relief Valves
30. Loss of Circulating Water
31. Loss of Component Cooling
32. Loss of Service Water System
33. Turbine Trip, Throttle Valve Closure, EHC Problems
34. Generator Trip or Generator Caused Faults
35. Loss of Station Power
36. Loss of Power to Necessary Plant Systems
37. Spurious Auto Trip-No Transient Conditions
38. Auto/Manual Trip Due to Operator Error
39. Manual Trip Due to False Signals
40. Spurious Trips-Cause Unknown
41. Fire Within Plant

Section 4
RECOMMENDATIONS

The operator action event trees and supporting documentation presented in Section 3 are based on the best-estimate thermal-hydraulic analyses available to date from the SASA Program. These results will provide a valuable foundation for a variety of investigations concerning operator actions and key symptoms for risk significant accident sequences at the Zion 1 plant and for plants of similar design.

One of the most productive uses of operator action event trees is to provide a logical framework for a systematic comparison of the key symptoms exhibited by the plant under different accident conditions. By defining the minimum sets of symptoms by which the occurrence of a particular accident condition can be unambiguously diagnosed, it is possible to produce efficient diagnostic algorithms, improve emergency procedures, evaluate instrumentation requirements, etc. It is a major recommendation of this study that these "accident signatures" and diagnostic algorithms be systematically and fully developed.

These accident signatures and diagnostic algorithms must, however, be based upon a consistent best-estimate analysis of all important accident conditions. Therefore, additional SASA efforts should be devoted to analyzing the remaining important accident conditions for which no best-estimate information is presently available (e.g., steam generator tube rupture) and to address uncertainties or sensitivities in those sequences which have been addressed. In Section 3, a number of specific areas were noted where additional analysis would be useful to better define uncertain symptoms or to determine the sensitivity of the symptoms to minor changes in input assumptions.

The major areas where further analysis would be useful to support the development of accurate accident signatures and effective diagnostic algorithms include the following:

- Existing SASA analyses of small break LOCAs assume the successful operation of the AFWS. These results demonstrate that the availability and effectiveness of heat removal through the steam generators can affect the accident signature. Best-estimate analyses are needed to determine the sensitivity of the accident signature to AFWS performance. Of particular importance is the primary pressure response for smaller sized breaks both with and without HPIS. It is unknown if there are conditions where the primary system could repressurize after the initial blowdown to a pressure above the SI pump shutoff head or even to the PORV setpoint.

- Accident signature development for small breaks with a failure of all injection flow is hindered by the limited results which are available. Specific areas where additional analysis is needed are the response of smaller breaks (e.g., $\sim$ 1 in.) beyond the currently available 10 minutes, and breaks at the upper end of the small break spectrum (e.g., $\sim$ 4 in.).

- Best-estimate analyses for the steam generator tube rupture event and the other events discussed in Section 3.1.3 are necessary to develop a complete set of OAETs for the Zion plant. This information is needed before a comparative symptoms analysis can be performed to produce acceptable accident signatures for those events.

- Existing SASA analyses have only considered failure of HPRS flow for small breaks. The case where the heat removal function is lost, but flow is still available, has not been examined. This failure mode should be analyzed for use in developing a better understanding of the key symptom behavior and in determining the time constraints for corrective action.

- All of the SASA transient analyses performed to date have assumed the initiator to be a loss of offsite power. This particular event has some unique characteristics associated with it (e.g., automatic trip of RCPs). Other transient initiating events should be investigated to ascertain whether different initiators could produce significantly different general parametric trends than those associated with a loss of offsite power.

- While diagnosis of an ATWS event should not be too difficult for the operator, much more analysis of the progression of ATWS sequences is required before a credible OAET for such accident conditions can be produced.

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