SNUPPS

Standardized Nuclear Unit
Power Plant System

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Executive Director

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SLNRC 81-96 FILE: 0541
SUBJ: RSB Review

Mr. Harold R. Denton, Director
Office of Nuclear Reactor Regulation
U.S. Nuclear Regulatory Commission
Washington, D. C. 20555

Docket Nos. STN 50-482, STN 50-483, and STN 50-486

Dear Mr. Denton:

Technical review meetings were held with the NRC's Reactor Systems Branch on July 21 and August 12, 1981. As a result of the meetings, SNUPPS agreed to provide additional information. This letter contains some of the information requested.

1. Agenda Item #15-9 requested a discussion of the protection afforded in the SNUPPS design when certain ESF systems are bypassed or disabled during startup and shutdown. Enclosure A provides the requested information.

2. Agenda Item 440.104, .105 concerned low termperature over pressure protection. Enclosure B to this letter is a group of FSAR changes. The information required by item 440.104, .105 is included with these changes. Enclosure B will be incorporated in the next FSAR revision.

3. Agenda Item 440.106 concerned a DC bus failure. Information on this item is included in the Enclosure B FSAR changes.

4. The NRC requested clarification on TMI items II.K.2 and II.K.3. These clarifications are included in the Enclosure B FSAR changes.

5. During the meeting, revised feedwater line break and steam generator tube rupture accidents were discussed. These revised analyses are included in Enclosure B.

Very truly yours,

NAPetrick

Nicholas A. Petrick

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RLS/jdk
cc: See Attached

SLNRC 81-96

cc:	J. K. Bryan	UE
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LOCA

During the shutdown the following operator actions pertain to the isolation of ECCS equipment and would effect a LOCA during the time accumulator isolation valves are closed with power locked out. (Start-up is not addressed since shutdown is more limiting due to the higher core decay heat generation).

(i) At 1900 psig, the operator is instructed to manually block the automatic safety injection (SI) signal. This action disarms the SI signals from the pressurizer level and pressure transmitters along with the steam flow transmitters. All other SI signals, including containment high pressure and high steamline differential pressure, are armed and will actuate safety injection if their setpoints are exceeded. Manual SI actuation is also available.

(ii) At 1000 psig and 425°F, the operator closes and locks out the SI accumulator isolation valves. He also locks out and tags the two safety injection pumps and one high head charging pump. At this time, two Residual Heat Removal pumps (LH safety injection) would be available from either automatic or manual SI actuation.

(iii) At less than 400 psig and 350°F, the operator aligns the Residual Heat Removal (RHR) system suction to the Reactor Coolant System. The valves in the line from the Refueling Water Storage Tank (RWST) are closed.

The significance of these actions on the mitigation of a LOCA when power is locked out to the isolation valves is that:

(i) Between 1000 psig and 400 psig, a portion of the ECCS may be actuated automatically on containment high pressure or high steamline differential pressure signals or manually by the operator. The equipment that can be energized are two RHR and one high head charging pumps. Subsequently, the operator would reinstitute power at the motor control centers to the other high head charging pump, the two SI pumps, and the accumulator isolation valves.

(ii) Below 400 psig, the system is in the RHR cooling mode. The operator would realign the RHR system per plant emergency procedure, as the RHR and the high head charging pumps could still be initiated by an automatic high containment pressure signal, or by manual actuation. Subsequently the operator would reinstitute power at the motor control centers to the other high head charging pump, the two SI pumps, and the accumulator isolation valves.

Safety Significance During Shutdown

Comparing plant cooldown and heatup, the limiting case for a LOCA would be during a plant cooldown rather than a plant heat-up because the core decay heat generation would be higher. The ECCS analysis presented in the SNUPPS FSAR conforms to the Acceptance Criteria of 10CFR50.46 so that initiation of the LOCA is at 102% of full licensed power rating and corresponding RCS conditions. Some of the reasons why the analysis presented in the SNUPPS FSAR would be more limiting than LOCA during shutdown are:

(1) a LOCA initiated during shutdown would have reduced decay heat generation since the reactor, in general, would have been at zero power for an extended period of time,

(2) the core-stored energy during shutdown would be reduced due to the RCS uniform temperature condition at a reduced temperature, and;

(3) the energy content of the RCS would be lower.

Furthermore, the probability of the occurrence of a LOCA during this period along with the critical flaw size needed to rupture the RCS piping at reduced pressure clearly indicates that a LOCA is considered to be incredible. These arguments are provided in the following sections.

(i) Between 1000 psig and 400 psig: For the purpose of calculating the probability of a LOCA, a conservative time of 7 hours is assumed to cool the plant from 500°F to 350°F. The annual probabilities of small and large LOCA were estimated at 10^{-3} and 10^{-4} per year in WASH-1400.+ Assuming this same failure rate holds at reduced pressure (this assumption is not realistic since normal operation serves as a proof test for lower pressure operating modes as discussed later), the probability of a LOCA during heatup/cooldown periods (assuming two heatup/cooldown cycles per year) would be:

Small LOCA	3.2×10^{-6}/yr.
Large LOCA	3.2×10^{-7}/yr.

These can be compared to the total meltdown probabilities for small LOCA and large LOCA initiating events analyzed in WASH-1400:

Small LOCA	2×10^{-5}/yr.
Large LOCA	3×10^{-6}/yr.

Therefore, even if there were no pipe rupture protection for these heatup/cooldown periods, it is concluded that such events add only a small increase to the meltdown risk due to the short time periods involved.

\+ WASH-1400, "Reactor Safety Study", U.S. NRC, October, 1975.

(ii) Rupture of RCS piping at reduced pressure: Below 1000 psig, RCS piping rupture is considered incredible under these low pressure conditions since normal operation serves as a proof test against rupture. Calculations of critical flaw size for the reactor coolant piping show that at 1000 psi internal pressure:

1. Rupture cannot occur for a part through-wall flaw regardless of orientation.

2. For a circumferential through-wall flaw, a catastrophic rupture is not possible.

3. For a through-wall longitudinal flaw, the critical flaw size is in excess of 70 inches.

Therefore, postulated RCS piping flaws of critical size for internal pressure below 1000 psig cannot exist since they would have previously failed at the normal operating pressure (2235 psig).

(iii) Below 400 psig: After several hours into the cooldown procedure (a minimum time is approximately 4 hours) when the RCS pressure and temperature have decreased to 400 psig and 350°F, the RHR system is placed in operation. This system has a 600 psig design pressure and rupture of this system is also considered highly unlikely. However, the proof test argument given above for RCS piping does not apply to the piping in this system.

The provisions to isolate these lines and the ECCS capability for core cooling should a leak or rupture develop during this mode of operation are as follows. Any leakage of the RHR system piping would be expected to occur when the system is initially pressurized at 400 psig. The RCS is at this time under manual control by the reactor operator. The reactor operator is monitoring the pressurizer level and the RCS loop pressure so that any significant leakage from the RHR system would be immediately detected. When leakage is detected, then the operator would isolate the RHR system and identify the location and cause. Since the decay heat generation 4 hours after shutdown is about 1.2% of full power, the RCS fluid temperature is at about 350°F and the core stored energy is essentially removed, the operator would have ample time to isolate the RHR loop.

Therefore, in spite of the low probability of occurrence and the fact that certain failure modes for pipe rupture do not exist during cooldown at an RCS pressure of 1000 psig, the plant operation procedures are as follows:

1. At 1000 psig, the operator will maintain pressure and proceed to cool down the RCS to 425°F.

2. At 1000 psig and 425°F, the operator will close and lock out the accumulator isolation valves.

The above plant operating procedures will ensure that the accumulator isolation valves will not be locked out prior to about 2-1/2 hours after reactor shutdown for a cooldown rate of 50°F/hr.

A conservative analysis has determined that the peak clad temperature resulting from a large break LOCA would be significantly less than the 2200°F Acceptance Criteria limit using the ECCS equipment available 2-1/2 hours after reactor shutdown.

The following assumptions were used in the analysis:

1. The RCS fluid is isothermal at a temperature of 425°F and a pressure of 1000 psig.

2. The core and metal sensible heat above 425°F has been removed.

3. The hot spot occurs at the core midplane.

4. The peak fuel heat generation during full power operation of 12.88 Kw/Ft (102% of 12.63 Kw/Ft) will be used to calculate adiabatic heatup.

5. At 2-1/2 hours using decay heat in conformance with Appendix K of 10CFR50, the peak heat generation rate is 0.174 /Ft.

6. As previously noted in the original response, two low head SI pumps and one high head charging pump are available from either manual SI actuation or automatic actuation by the containment HI-1 signal. However, for this analysis the loss of one low head safety injection pump was assumed.

7. No liquid water is present in the reactor vessel at the end of blowdown.

8. A large cold leg break is considered.

For a postulated LOCA at the cooldown condition of 1000 psig, previous calculations show that the clad does not heat up above its initial temperature during blowdown. Proceeding from the end of blowdown and assuming adiabatic heatup of the fuel and clad at the hot spot, and increase of 737°F was calculated during the lower plenum refill transient of 147.0 seconds. During reflood, the core and downcomer water levels rise together until steam generation in the core becomes sufficient to inhibit the reflooding rate. At that time, heat transfer from the clad at the hot spot to the steam boiloff and entrained water will commence. This heat removal process will continue as the water level in the core rises while the downcomer is being filled with safety injection water. The reflood transient was evaluated by considering two bounding cases:

1. Downcomer and core levels rise at the same rate. No cooling due to steam boiloff is considered at the hot spot. Quenching of the hot spot occurs when the core water level reaches the core midplane.

2. Core reflooding is delayed until the SI pumps have completely filled the downcomer. No cooling due to steam boiloff is considered at the hot spot until the downcomer is filled. The full downcomer situation may then be compared with the results of the ECCS analysis for SNUPPS to obtain a bounding clad temperature rise thereafter.

For Case 1 described above, the water level reaches the core midplane 84.32 seconds after bottom of core recovery. The temperature rise during reflood at the hot spot from adiabatic heatup is 432, which results in a peak clad temperature of approximately 1584°F.

For Case 2 the delay due to downcomer filling is 67.8 sec. The corresponding temperature rise at the hot spot from adiabatic heatup is 340°F, which gives a hot spot clad temperature of 1466°F.

The clad temperature at the time when the downcomer has filled for the DECLG, C_D = 0.6 submitted to satisfy 10CFR50.46 requirements are 1906.2°F and 2088°F at the 6.0 and 7.5 foot elevations, respectively.

Core reflooding in the shutdown case under consideration will be more rapid from this point on due to less steam generation at the lower core power level in effect; decay heat input at any given elevation is less in the shutdown case. The combination of more rapid reflooding and lower power in the fuel ensures that the clad temperature rise during reflood will be less for the shutdown case than for the design basis case.

Another consideration which has been evaluated is the availability of alarms which would alert the operator to manually initiate safety injection. This situation would exist only for very small LOCA's that do not pressurize the containment to the containment Hi-1 set pressure which automatically initiates safety injection the evaluation is given below:

ALARMS:

Several alarms exist which could provide indication to the operator that a loss of Reactor Coolant System (RCS) inventory accident is underway. These alarms include the following:

1. Low-pressurizer level deviation:
   At 5% below programmed pressurizer level an alarm will sound. For SNUPPS this alarm must sound by 19.9% level. Since this is 5% below the no-load programmed operating level of 24.9%.

2. Low-pressurizer level heater cutoff at 17%.

ANALYSIS:

Based upon the Inadequate Core Cooling Study (WCAP 9753), it can be concluded that smaller breaks will exhibit longer transients than larger breaks; thus there will be more time for the operator to take action in a smaller break than in a larger break transient.

Calculations by Westinghouse show that a two inch diameter equivalent break with no SI, would result in no core uncovery in a four loop plant for approximately 42 minutes. Within the first 3 minutes of the transient, all of the previously described alarms would have sounded leaving the operator approximately 39 minutes to initiate SI manually.

Calculations also show that a two inch diameter equivalent break with no SI, would result in the high containment pressure SI trip in approximately 9 minutes for a three/four loop plant.

Thus, for breaks less than or equal to two inches in diameter, the operator would have at least 39 minutes to initiate SI manually, and for breaks greater than or equal to two inches in diameter, a high containment pressure SI trip would be reached in 9 minutes, and would provide SI automatically.

Steam Line Break

When RCS pressure is below the P-11 setpoint and SI is blocked on low pressurizer pressure or low steamline pressure, a steamline rupture would be less severe from a core integrity stand point than the steamline ruptures at hot zero power presented in the FSAR. Prior to blocking safety injection, the Technical Specifications require the shutdown margin to be increased by an amount necessary to make up for the shutdown margin that would be lost during the transition to cold shutdown. Thus the RCS would be heavily borated before SI is blocked and the return-to-power transient would be less than the cases presented in the FSAR.

The engineered safeguards functions desired during a steamline rupture are actuation of safety injection and steamline isolation. When the low pressurizer pressure signals and the low steamline pressure signals are blocked, safety injection and steamline isolation may be automatically initiated by the following signals.

1) HI Negative Steamline Pressure Rate Signal

   This signal is unblocked automatically when the low steamline pressure signal is blocked.

   (Actuates SI and Steamline Isolation)

2) HI 1 Containment Pressure Signal

   (Actuates SI)

3) HI 2 Containment Pressure Signal

   (Actuates Steamline Isolation)

Safety injection and steamline isolation may also be actuated manually by the operator, during a steamline break, steamline pressure, pressurizer pressure, pressurizer level, and steam generator inventory will tend to decrease and steam flow will increase. These parameters are all displayed in the control room. The operator's attention may be drawn to them by the following alarms:

1) Low pressurizer level deviation alarm

2) Low pressurizer level alarm

3) Steam flow/feedwater flow mismatch alarm

4) Low steam generator level deviation alarm

5) Low steam generator level alarm

Enclosure B to

SLNRC 81-

FSAR Changes

5.2.2.6 Applicable Codes and Classification

The requirements of ASME Boiler and Pressure Vessel Code, Section III, Paragraphs NB-7300 (Overpressure Protection Report) and NC-7300 (Overpressure Protection Analysis), are followed and complied with for pressurized water reactor systems.

Piping, valves, and associated equipment used for overpressure protection are classified in accordance with ANS-N18.2, "Nuclear Safety Criteria for the Design of Stationary Pressurized Water Reactor Plants." These safety class designations are delineated on Table 3.2-1 and shown on Figure 5.1-1.

For further information, refer to Section 3.9(N).

5.2.2.7 Material Specifications

Refer to Section 5.2.3 for a description of material specifications.

5.2.2.8 Process Instrumentation

Each pressurizer safety valve discharge line incorporates a control board temperature indicator and alarm to notify the operator of steam discharge due to either leakage or actual valve operation. Safety-related control room positive position indication is provided for the PORVs and safety valves. For a further discussion on process instrumentation associated with the system, refer to Chapter 7.0.

5.2.2.9 System Reliability

The reliability of the pressure relieving devices is discussed in Section 4 of Reference 3.

5.2.2.10 RCS Pressure Control During Low Temperature Operation

Administrative procedures are developed to aid the operator in controlling RCS pressure during low temperature operation. However, to provide a back-up to the operator and to minimize the frequency of RCS overpressurization, an automatic system is provided to maintain pressures within allowable limits.

→ INSERT A

5.2.2.10.1 System Operation

redundant

Two pressurizer power-operated relief valves are supplied with actuation logic to ensure that a ~~[illegible]~~ and independent RCS pressure control back-up feature is provided for the operator during low temperature operations. This system provides the capability for ~~[illegible]~~ RCS inventory letdown, thereby maintaining RCS pressure within allowable limits. Refer to Sections 5.4.7, 5.4.10, 5.4.13, 7.6.6, and 9.3.4 for additional information on RCS pressure and inventory control during other modes of operation.

INSERT A (to page 5.2-7)

Analyses have shown that one pressurizer power-operated relief valve is sufficient to prevent violation of these limits due to anticipated mass and heat input transients. However, redundant protection against an overpressurization event is provided through the use of two pressurizer power-operated relief valves to mitigate any potential pressure transients. The mitigation system is required only during low temperature water solid operation when it is manually armed and automatically actuated.

The basic function of the system logic is to continuously monitor RCS temperature and pressure conditions whenever plant operation is at a low temperature. An auctioneered system temperature will be continuously converted to an allowable pressure and then compared to the actual RCS pressure. ~~This comparison provides an actuation signal to the power-operated relief valves when required to prevent pressure temperature conditions from exceeding allowable limits.~~ INSERT B

5.2.2.10.2 Evaluation of Low Temperature Overpressure Transients

~~An evaluation of low temperature overpressure transients will be provided as soon as it becomes available. Results are expected by July, 1980.~~ INSERT C

5.2.2.10.~~3~~4 Administrative Procedures

Although the system described in Section 5.2.2.10.1 is installed to maintain RCS pressure within allowable limits, administrative procedures minimize the potential for any transient that could actuate the overpressure relief system. The following discussion highlights these procedural controls, listed in hierarchy of their function in mitigating RCS cold overpressurization transients.

Of primary importance is the basic method of operation of the plant. Normal plant operating procedures will maximize the use of a pressurizer cushion (steam/nitrogen bubble) during periods of low pressure, low temperature operation. This cushion will dampen the plants' response to potential transient generating inputs, providing easier pressure control with the slower response rates.
An adequate cushion substantially reduces the severity of potential pressure transients such as reactor coolant pump induced heat input and slows the rate of pressure rise for others. In conjunction with the alarms discussed in Section 7.6, this provides reasonable assurance that most potential transients can be terminated by operator action before the overpressure relief system actuates.

However, for those modes of operation when water solid operation may still be possible, procedures will further highlight precautions that minimize the potential for developing an overpressurization transient. The following precautions or measures are considered in developing the operating procedures:

a. The residual heat removal inlet lines from the reactor coolant loop are normally open when the

INSERT B (to page 5.2-8)

The system logic will first annunciate a main control board alarm whenever the measured pressure approaches within a pre-determined amount of the allowable pressure thereby indicating that a pressure transient is occurring. On a further increase in measured pressure, an actuation signal is transmitted to the pressurizer power-operated relief valves when required to mitigate the pressure transient.

INSERT C (to page 5.2-8)

→ INSERT "X"

The ASME Code (Section III, Appendix G) establishes guidelines and upper limits for RCS pressure primarily for low temperature conditions (<350 F). The mitigation system discussed in Section 5.2.2.10.1 satisfies these conditions as discussed in the following paragraphs.

Transient analyses have been performed to determine the maximum pressure for the postulated mass input and heat input events.

The mass input pressure transient which would occur most frequently during the course of normal plant operation would involve letdown isolation with charging pumps delivering an input less than or equal to 120 gpm. However, the mass input analysis has been performed assuming letdown isolation with two charging pumps operating in a configuration producing maximum delivery rates. This more unlikely and more severe configuration was chosen to provide additional system flexibility for pressure control.

The heat input transient has been performed over the entire RCS shutdown temperature range. This analysis assumes an inadvertent reactor coolant pump startup with a 50 F mismatch between the RCS and the temperature of the hotter secondary side of the steam generators.

INSERT "x"
(to page 1 of Insert C)

The following discussion represents the expected results of an evaluation of low temperature overpressure transients for the SNUPPS units. This evaluation is currently scheduled for completion by the end of 1981 and is expected to confirm the following material.

INSERT C (continued)

Both the heat input and mass input analyses take into account the single failure criteria and therefore, only one pressurizer power-operated relief valve was assumed to be available for pressure relief. The above events have been evaluated considering the allowable pressure/temperature limits established in the Technical Specifications. The evaluation of the transient results conclude that the allowable limits will not be exceeded and therefore will not constitute an impairment to vessel integrity or plant safety.

5.2.2.10.3 Operating Basis Earthquake Evaluation

A fluid systems evaluation has been performed considering the potential for overpressure transients following an operating basis earthquake.

The SNUPPS pressurizer power-operated relief valves have been designed in accordance with the ASME Code and seismically qualified under the Westinghouse valve operability program which is discussed in Section 3.9(N).3.2.

Therefore, the pressurizer power-operated relief valves will be available to provide pressure relief following an operating basis earthquake and maintain the primary system within the allowable pressure/temperature limits.

RCS pressure is less than 425 psi. This precaution assures that there is a relief path from the reactor coolant loop to the residual heat removal suction line relief valves when the RCS is at low pressure and is water solid.

b. Whenever the plant is water solid and the reactor coolant pressure is being maintained by the low pressure letdown control valve, letdown flow normally bypasses the normal letdown orifices. In addition, all three letdown orifices normally remain open.

INSERT D

d. ~~c~~. If all reactor coolant pumps are stopped and the RCS is being cooled down by the residual heat exchangers, a nonuniform temperature distribution may occur in the reactor coolant loops. Prior to restarting a reactor coolant pump, a steam bubble will be formed in the pressurizer or an acceptable temperature profile will be demonstrated.

e. ~~d~~. During plant cooldown, all steam generators will normally be connected to the steam header to assure a uniform cooldown of the reactor coolant loops.

f. ~~e~~. At least one reactor coolant pump will normally remain in service until the reactor coolant temperature is reduced to 160 F.

These special precautions back-up the normal operational mode of maximizing periods of steam bubble operation so that cold overpressure transient prevention is continued during periods of transitional operations.

The specific plant configurations of emergency core cooling system testing and alignment will also highlight procedural recommendations to prevent developing cold overpressurization transients. During these limited periods of plant operation, the following precautions/measures are considered in developing the operating procedures:

a. To preclude inadvertent emergency core cooling system actuation during heatup and cooldown, procedures require blocking the pressurizer pressure ~~high steam line differential pressure~~ and ~~high steam line flow coincident with~~ low steam line pressure ~~or lo-lo T_{avg}, safety injection~~ signal actuation logic at 1,900 psig.

INSERT D (to page 5.2-9)

c. If all reactor coolant pumps have stopped for more than 5 minutes during plant heatup and the reactor coolant temperature is greater than the charging and seal injection water temperature, a steam bubble will be formed in the pressurizer prior to restarting a reactor coolant pump. This precaution minimizes the pressure transient when the pump is started and the cold water previously injected by the charging pumps is circulated through the warmer reactor coolant components. The steam bubble will accommodate the resultant expansion as the cold water is rapidly warmed.

b. During further cooldown, closure and power lockout of the accumulator isolation valves and power lockout of the nonoperating charging pumps and safety injection pumps will be performed at 1,000 psig, approximately 425 F RCS conditions, providing additional back-up to step a above.

c. The recommended procedure for periodic emergency core cooling system pump performance testing will be to test the pumps during normal power operation or at hot shutdown conditions. This precludes any potential for developing a cold overpressurization transient.

   Should CSD testing of the pumps be desired, the test will be done when the vessel is open to atmosphere, again precluding overpressurization potential.

   If CSD testing with the vessel closed is necessary, the procedures require emergency core cooling system ~~[illegible]~~ pumps discharge valve closure and RHRS alignment to isolate potential emergency core cooling system pump input and to provide back-up benefit of the RHRS relief valves.

d. SIS circuitry testing, if done during CSD, requires RHRS alignment and nonoperating charging pump and safety injection pumps power lockout to preclude developing cold overpressurization transients.

The above procedural precautions covering normal operations with a steam bubble, transitional operations where potentially water solid, and specific testing operations provide in-depth cold overpressure preventions or reductions, augmenting the installed overpressure relief system.

5.2.2.11 Testing and Inspection

Testing and inspection of the overpressure protection components are discussed in Section 5.4.13.4 and Chapter 14.0.

5.2.3 MATERIALS SELECTION, FABRICATION, AND PROCESSING

5.2.3.1 Material Specifications

Material specifications used for the principal pressure retaining applications in components of the RCPB are listed in Table 5.2-2 for ASME Class 1 primary components and Table 5.2-3 for ASME Class 1 and 2 auxiliary components. Tables 5.2-2 and 5.2-3 also include the material specifications of

b. Sufficient liquid in the RCS is maintained so that the core remains inplace and geometrically intact with no loss of core cooling capability.

A major feedwater line rupture is classified as an ANS Condition IV event. See Section 15.0.1 for a discussion of Condition IV events.

The severity of the feedwater line rupture transient depends on a number of system parameters, including break size, initial reactor power, and credit taken for the functioning of various control and safety systems. Sensitivity studies presented in Reference 3 illustrate many of the limiting assumptions for the feedwater line rupture. In addition, the major assumptions pertinent to this analysis are defined below.

The main feedwater control system is assumed to fail due to an adverse environment. The water levels in all steam generators are assumed to decrease equally until the low-low steam generator level reactor trip setpoint is reached. After reactor trip, a double-ended rupture of the largest feedwater line is assumed. These assumptions conservatively bound the most limiting feedwater line rupture that can occur. Analyses have been performed at full power, with and without loss of offsite power, and with no credit taken for the pressurizer power-operated relief valves. For the case without offsite power available, the power is assumed to be lost at the time of reactor trip. This is more conservative than the case where power is lost at the initiation of the event. These cases are analyzed below.

The following provides the protection for a main feedwater line rupture:

a. A reactor trip on any of the following conditions:

   1. High pressurizer pressure
   2. Overtemperature ΔT
   3. Low-low steam generator water level in any steam generator
   4. Safety injection signals from any of the following: 1) two-out-of-three low steam line pressure in any one loop or 2) two-out-of-three high containment pressure (hi-1)

   Refer to Chapter 7.0 for a description of the actuation system.

b. The auxiliary feedwater system provides an assured source of feedwater to the steam generators for decay heat removal. Refer to Section 10.4.9 for a description of the auxiliary feedwater system.

15.2.8.2 Analysis of Effects and Consequences

Method of Analysis

A detailed analysis using the LOFTRAN code (Ref. 2) is performed in order to determine the plant transient following a feedwater line rupture. The code describes the plant thermal kinetics, RCS (including natural circulation), pressurizer, steam generators, and feedwater system, and computes pertinent variables, including the pressurizer pressure, pressurizer water level, and reactor coolant average temperature.

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Major assumptions used in the analysis are as follows:

a. The plant is initially operating at 102 percent of the engineered safety features design rating.

b. Initial reactor coolant average temperature is 6.5 F above the nominal value, and the initial pressurizer pressure is 30 psi above its nominal value.

c. No credit is taken for the pressurizer power-operated relief valves or pressurizer spray.

d. Initial pressurizer level is at the nominal programmed value plus 5 percent (error); initial steam generator water level is at the nominal value.

e. No credit is taken for the high pressurizer pressure reactor trip.

f. Main feedwater to all steam generators is assumed to stop at the time the break occurs (all main feedwater spills out through the break).

g. The worst possible break area is assumed. This maximizes the blowdown discharge rate following the time of trip, which maximizes the resultant heatup of the reactor coolant.

h. A bounding feedwater line break discharge quality is assumed.

i. Reactor trip is assumed to be initiated when the low-low steam generator level trip setpoint minus 15 percent of narrow range span in the ruptured steam generator is reached.

j. The auxiliary feedwater system is actuated by the low-low steam generator water level signal. The auxiliary feedwater system is assumed to supply a total of 563 gpm to three unaffected steam generators, including allowance for possible spillage through the main feedwater line break. A 60-second delay was assumed following the low-low level signal to allow time for startup of the standby diesel

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generators and the auxiliary feedwater pumps. An additional 372 seconds was assumed before the feedwater lines were purged and the relatively cold (120 F) auxiliary feedwater entered the unaffected steam generators.

k. No credit is taken for heat energy deposited in RCS metal during the RCS heatup.

l. No credit is taken for charging or letdown.

m. Steam generator heat transfer area is assumed to decrease as the shell side liquid inventory decreases.

n. Conservative core residual heat generation is assumed based upon long-term operation at the initial power level preceding the trip.

o. No credit is taken for the following potential protection logic signals to mitigate the consequences of the accident:

   1. High pressurizer pressure
   2. Overtemperature ΔT
   3. High pressurizer level
   4. High containment pressure

Receipt of a low-low steam generator water level signal in at least one steam generator starts the motor-driven auxiliary feedwater pumps, which in turn initiate auxiliary feedwater flow to the steam generators. The turbine-driven auxiliary feedwater pump is initiated if the low-low steam generator water level signal is reached in at least two steam generators. Similarly, receipt of a low steam line pressure signal in at least one steam line initiates a steam line isolation signal which closes all main steam line isolation valves. This signal also gives a safety injection signal which initiates flow of cold borated water into the RCS. The amount of safety injection flow is a function of RCS pressure.

Emergency operating procedures following a feedwater system pipe rupture require the following actions to be taken by the reactor operator:

a. Isolate feedwater flow spilling from the ruptured feedwater line and align the system so that the level in the intact steam generators is recovered.

b. High head safety injection should be terminated in accordance with the emergency operating procedures.

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Subsequent to terminating high head safety injection, plant operating procedures will be followed in cooling the plant to a safe shutdown condition.

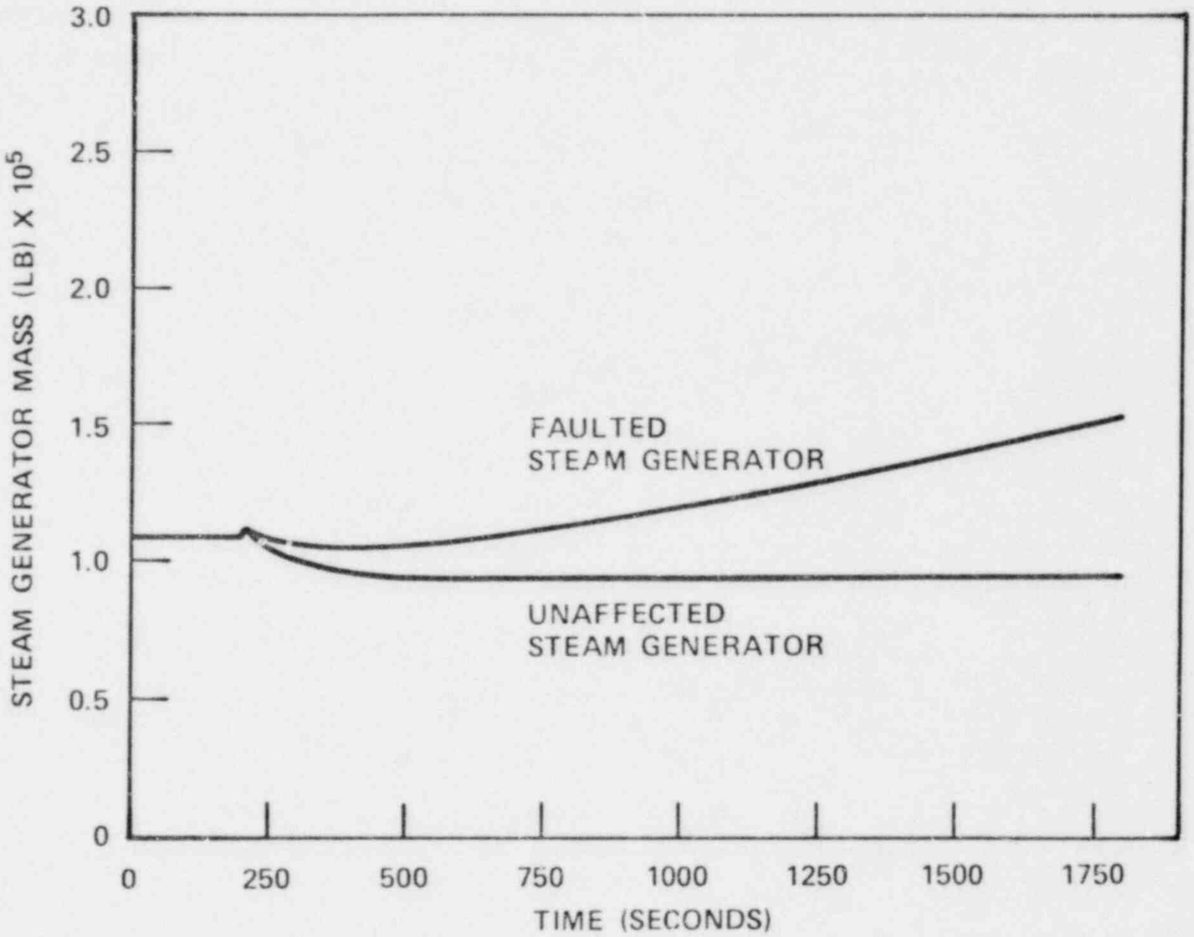
Plant characteristics and initial conditions are further discussed in Section 15.0.3.

No reactor control systems are assumed to function. The reactor protection system is required to function following a feedwater line rupture as analyzed here. No single active failure will prevent operation of this system.

The engineered safety systems assumed to function are the auxiliary feedwater system and the safety injection system. For the auxiliary feedwater system, the worst case configuration has been used, i.e., only three intact steam generators receive auxiliary feedwater following the break. A discharge flow control device, located on the auxiliary feedwater line to each steam generator, is assumed to regulate the flow from the motor-driven auxiliary feedwater pump feeding the break in loop 1. This ensures that a minimum flow of 250 gpm, from both the motor-driven and turbine-driven auxiliary feedwater pumps, is delivered to loop 2. The second motor-driven auxiliary feedwater pump has been assumed to fail. The turbine-driven auxiliary feedwater pump delivers 313 gpm equally split to the three intact steam generators. This assumption is conservative because it maximizes the purge time in the feedwater lines before auxiliary feedwater enters the unaffected steam generators. Thus, a total flow of 563 gpm is delivered to the intact steam generators.

For the case without offsite power, there will be a flow coastdown until flow in the loops reaches the natural circulation value. The natural circulation capability of the RCS has been shown (in Section 15.2.6) to be sufficient to remove core decay heat following reactor trip, for the loss of ac power transient. Pump coastdown characteristics are demonstrated in Sections 15.3.1 and 15.3.2 for single and multiple reactor coolant pump trips, respectively.

A detailed description and analysis of the safety injection system is provided in Section 6.3. The auxiliary feedwater system is described in Section 10.4.9.



SNUPPS

Figure 15.6-3J.

Steam Generator Mass Transient for Steam Generator Tube Rupture Event

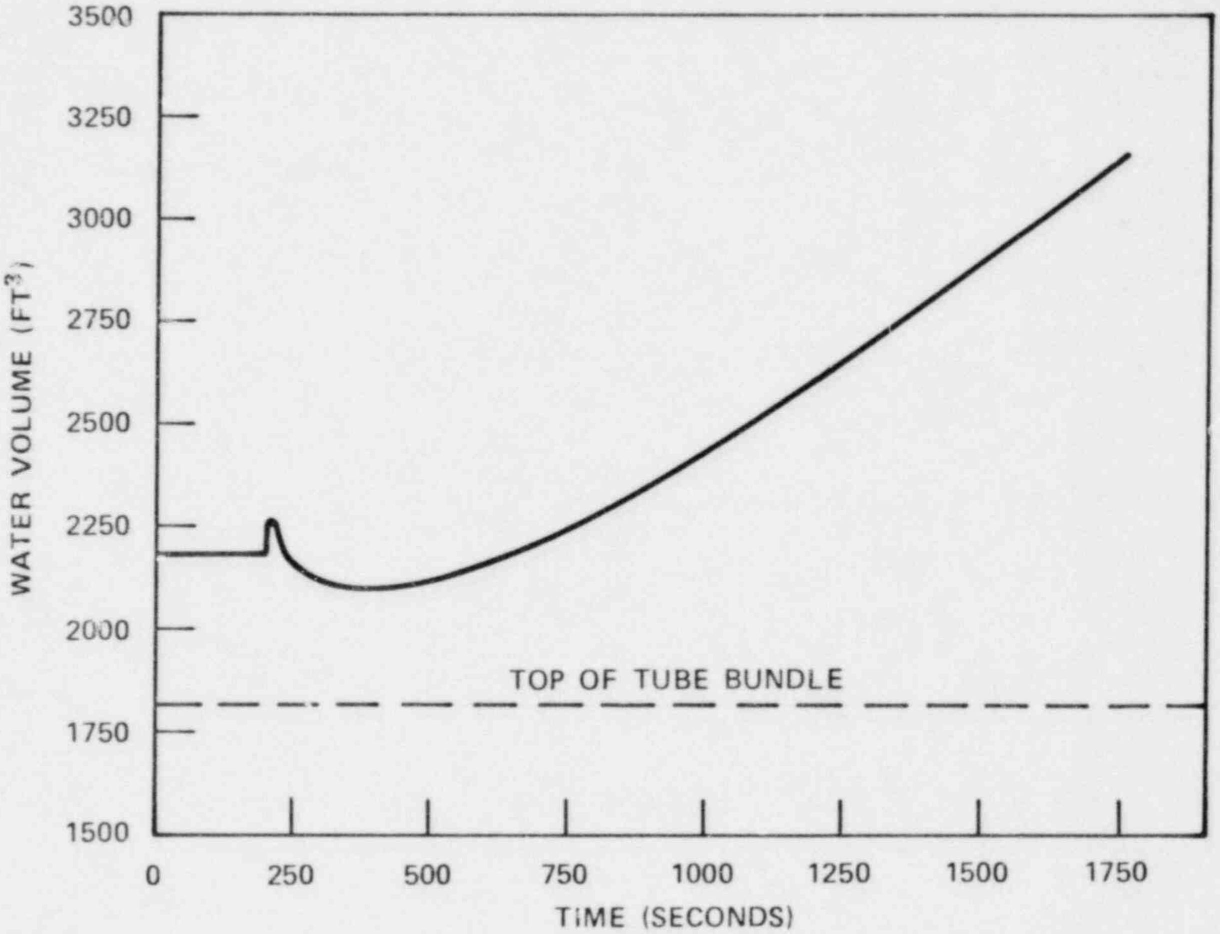


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Figure 15.6-3K.

Faulted Steam Generator Water Volume Transient for Steam Generator Tube Rupture Event ω̈

18.2.16 ORDERS ON FACILITIES WITH BABCOCK & WILCOX NUCLEAR STEAM SUPPLIER SYSTEMS (II.K.2)

18.2.16.1 Control of Auxiliary Feedwater Independent of the Integrated Control System (II.K.2.2)

Not applicable to Westinghouse pressurized water reactors.

18.2.16.2 Auxiliary Feedwater System Upgrading (II.K.2.8)

Not applicable to Westinghouse pressurized water reactors.

18.2.16.3 Failure Mode Effects Analysis on the Integrated Control System (II.K.2.9)

Not applicable to Westinghouse pressurized water reactors.

18.2.16.4 Safety-Grade Anticipatory Reactor Trip (II.K.2.10)

Not applicable to Westinghouse pressurized water reactors.

18.2.16.5 Thermal Mechanical Report--Effect of High-Pressure Injection on Vessel Integrity for Small-Break Loss-of-Coolant Accident with no Auxiliary Feedwater (II.K.2.13)

18.2.16.5.1 NRC Guidance Per NUREG-0737

Position

A detailed analysis shall be performed of the thermal-mechanical conditions in the reactor vessel during recovery from small breaks with an extended loss of all feedwater.

Clarification

The position deals with the potential for thermal shock of reactor vessels resulting from cold safety injection flow. One aspect that bears heavily on the effects of safety injection flow is the mixing of safety injection water with reactor coolant in the reactor vessel. B&W provided a report on July 30, 1980 that discussed the mixing question and the basis for a conservative analysis of the potential for thermal shock to the reactor vessel. Other PWR vendors are also required to address this issue with regard to recovery from small breaks with an extended loss of all feedwater. In particular, demonstration shall be provided that sufficient mixing would occur of the cold high-pressure injection (HPI) water with reactor coolant so that significant thermal shock effects to the vessel are precluded.

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18.2.16.5.2 SNUPPS Response

Westinghouse (in support of the Westinghouse Owners Group) is developing a method and will perform analyses for a spectrum of small loss-of-coolant accidents. The method will employ the NOTRUMP computer program to generate the thermal/hydraulic transients. The thermal transients on the reactor vessel beltline and the inlet nozzle will be analyzed based on the thermal/hydraulic data from the NOTRUMP code. The analyses are scheduled to be completed by the end of 1981; the Wolf Creek and Callaway dockets will reference appropriate documents submitted by the Westinghouse Owners Group to the NRC.

18.2.16.6 Effects of Slug Flow on Steam Generator Tubes (II.K.2.15)

Not applicable to Westinghouse pressurized water reactors.

18.2.16.7 Reactor Coolant Pump Seal Damage (II.K.2.16)

Not applicable to Westinghouse pressurized water reactors.

18.2.16.8 Potential for Voiding in the Reactor Coolant System During Transients (II.K.2.17)

18.2.16.8.1 NRC Guidance Per NUREG-0737

Position

Analyze the potential for voiding in the reactor coolant system (RCS) during anticipated transients.

Clarification

The background for this concern and a request for this analysis was originally sent to the Babcock and Wilcox (B&W) licensees in a letter from R. W. Reid, NRC, to all B&W operating plants, dated January 9, 1980.

18.2.16.8.2 SNUPPS Response

Westinghouse (in support of the Westinghouse Owners Group) has performed a study which addresses the potential for void formation in Westinghouse-designed nuclear steam supply systems during natural circulation cooldown/depressurization transients. This study has been submitted to the NRC by the Westinghouse Owners Group (Ref. 1) and is applicable to the Wolf Creek and Callaway units

In addition, the Westinghouse Owners Group is currently developing appropriate modifications to the Westinghouse Owners Group Reference Operating Instructions to take the results of the study into account so as to preclude void formation in the upper head region during natural circulation

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cooldown/depressurization transients, and to specify those conditions under which upper head voiding may occur. The SNUPPS utilities will consider the generic guidance developed by the Westinghouse Owners Group in the development of plant specific operating procedures.

18.2.16.9 Sequential Auxiliary Feedwater Flow Analysis (II.K.2.19)

Not applicable to Westinghouse pressurized water reactors.

18.2.16.10 Small-Break Loss-of-Coolant Accident Which Repressurizes the Reactor Coolant System to the Power-Operated Relief Valve Set Point (II.K.2.20)

Not applicable to Westinghouse pressurized water reactors.

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18.2.17 RECOMMENDATIONS FROM THE BULLETINS AND ORDERS TASK FORCE (II.K.3)

18.2.17.1 Installation and Testing of Automatic Power-Operated Relief Valve Isolation System (II.K.3.1)

18.2.17.1.1 NRC Guidance Per NUREG-0737

Position

All PWR licensees should provide a system that uses the PORV block valve to protect against a small-break loss-of-coolant accident. This system will automatically cause the block valve to close when the reactor coolant system pressure decays after the PORV has opened. Justification should be provided to ensure that failure of this system would not decrease overall safety by aggravating plant transients and accidents.

Each licensee shall perform a confirmatory test of the automatic block valve closure system following installation.

Clarification

Implementation of this action item was modified in the May 1980 version of NUREG-0660. The change delays implementation of this action item until after the studies specified in TMI Action Plan item II.K.3.2 have been completed, if such studies confirm that the subject system is necessary.

18.2.17.1.2 SNUPPS Response

Westinghouse, as a part of the response prepared for the Westinghouse Owners Group to address item II.K.3.2 (refer to Section 18.2.17.2), has evaluated the necessity of incorporating an automatic pressurizer power-operated relief valve isolation system. This evaluation is documented in Reference 2 and concluded that such a system should not be required. However, the SNUPPS design includes the capability to automatically isolate the power-operated relief valves.

18.2.17.2 Report on Overall Safety Effect of Power-Operated Relief Valve Isolation System (II.K.3.2)

18.2.17.2.1 NRC Guidance Per NUREG-0737

Position

(1) The licensee should submit a report for staff review documenting the various actions taken to decrease the probability of a small-break loss-of-coolant

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accident (LOCA) caused by a stuck-open, power-operated relief valve (PORV) and show how those actions constitute sufficient improvements in reactor safety.

(2) Safety-valve failure rates based on past history of the operating plants designed by the specific nuclear steam supply system (NSSS) vendor should be included in the report submitted in response to (1) above.

Clarification

Based on its review of feedwater transients and small LOCAs for operating plants, the Bulletins and Orders Task Force in the Office of Nuclear Reactor Regulation recommended that a report be prepared and submitted for staff review which documents the various actions that have been taken to reduce the probability of a small-break LOCA caused by a stuck-open PORV and show how these actions constitute sufficient improvements in reactor safety. Action Item II.K.3.2 of NUREG-0660, published in May 1980, changed the implementation of this recommendation as follows: In addition to modifications already implemented on PORVs, the report specified above should include safety examination of an automatic PORV isolation system identified in Task Action Plan item II.K.3.1.

Modifications to reduce the likelihood of a stuck-open PORV will be considered sufficient improvements in reactor safety if they reduce the probability of a small-break LOCA caused by a stuck-open PORV such that it is not a significant contributor to the probability of a small-break LOCA due to all causes. (According to WASH-1400, the median probability of a small-break LOCA S_2 with a break diameter between 0.5 inches and 2.0 inches is 10^{-3} per reactor-year with a variation ranging from 10^{-2} to 10^{-4} per reactor-year.)

The above-specified report should also include an analysis of safety-valve failures based on the operating experience of the pressurized-water-reactor (PWR) vendor designs. The licensee has the option of preparing and submitting either a plant-specific or a generic report. If a generic report is submitted, each licensee should document the applicability of the generic report to his own plant.

Based on the above guidance and clarification, each licensee should perform an analysis of the probability of a small-break LOCA caused by a stuck-open PORV or safety valve. This analysis should consider modifications which have been made since the TMI-2 accident to improve the probability. This analysis shall evaluate the effect of an automatic PORV isolation system specified in Task Action Plan, Item II.K.3.1.

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In evaluating the automatic PORV isolation system, the potential of causing a subsequent stuck-open safety valve and the overall effect on safety (e.g., effect on other accidents) should be examined.

Actual operational data may be used in this analysis, where appropriate. The bases for any assumptions used should be clearly stated and justified.

The results of the probability analysis should then be used to determine whether the modifications already implemented have reduced the probability of a small-break LOCA due to a stuck-open PORV or safety valve a sufficient amount to satisfy the criterion stated above, or whether the automatic PORV isolation system specified in Task Action item II.K.3.1 is necessary.

In addition to the analysis described above, the licensee should compile operational data regarding pressurizer safety valves for PWR vendor designs. These data should then be used to determine safety-valve failure rates.

The analyses should be documented in a report. If this requirement is implemented on a generic basis, each licensee should review the appropriate generic report and document its applicability to his own plant(s). The report and the documentation of applicability (where appropriate) should be submitted for NRC staff review by the specified date.

18.2.17.2.2 SNUPPS Response

As mentioned in item II.K.3.1 above (Section 18.2.17.1), the Westinghouse Owners Group has submitted a Westinghouse-prepared report (Ref. 2) which provides a probabilistic analysis to determine the probability of a PORV LOCA, estimates the effect of the post-TMI modifications, evaluates an automatic PORV isolation concept, and provides PORV and safety valve operational data for Westinghouse plants. Because of the sensitivity analyses included in the report, the report is generic and is applicable to the SNUPPS units. The report identifies a significant reduction in the PORV LOCA probability as a result of post-TMI modifications, and the calculations compare favorably with the operational data for Westinghouse plants (included as an appendix to the report).

18.2.17.3 Reporting Safety and Relief Valve Failures and Challenges (II.K.3.3)

18.2.17.3.1 NRC Guidance Per NUREG-0694

Assure that any failure of a PORV or safety valve to close will be reported to the NRC promptly. All challenges to the PORVs or safety valves should be documented in the annual report.

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18.2.17.3.2 SNUPPS Response

Failure of a PORV to close on demand and a failure of a primary system safety valve to close will be reported in accordance with the provisions of the Technical Specifications.

Challenges to the reactor coolant system PORV and safety valves will be reported in the annual report. A challenge will be defined for the safety valves as a reactor coolant system pressure greater than the valve set point. A challenge for the pressurizer PORV will be defined as an event which results in automatic actuation of a PORV.

18.2.17.4 Automatic Trip of Reactor Coolant Pumps During Loss-of-Coolant Accident (II.K.3.5)

18.2.17.4.1 NRC Guidance Per NUREG-0737

Position

Tripping of the reactor coolant pumps in case of a loss-of-coolant accident (LOCA) is not an ideal solution. Licensees should consider other solutions to the small-break LOCA problem (for example, an increase in the safety injection flow rate). In the meantime, until a better solution is found, the reactor coolant pumps should be tripped automatically in case of a small-break LOCA. The signals designated to initiate the pump trip are discussed in NUREG-0623.

Clarification

This action item has been revised in the May 1980 version of NUREG-0660 to provide for continued study of criteria for early reactor coolant pump trip. Implementation, if any is required, will be delayed accordingly. As part of the continued study, all holders of approved emergency core cooling (ECC) models have been required to analyze the forthcoming LOFT test (L3-6). The capability of the industry models to correctly predict the experimental behavior of this test will have a strong input on the staff's determination of when and how the reactor coolant pumps should be tripped.

18.2.17.4.2 SNUPPS Response

In response to IE Bulletin No. 79-06C, Westinghouse (in support of the Westinghouse Owners Group) performed an analysis of delayed reactor coolant pump (RCP) trip during small-break LOCAs. This analysis is documented in Reference 3 and is the basis for the Westinghouse and SNUPPS position on RCP trip (i.e., automatic RCP trip is not necessary since sufficient time is available for manual tripping of the RCPs).

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Westinghouse (again in support of the Westinghouse Owners Group) has performed test predictions of the LOFT Experiment L3-6. The results of these predictions are documented in References 4 and 5. The results constitute both a best estimate model prediction with the NOTRUMP computer program and an evaluation model prediction with the WFLASH computer program, using the supplied set of initial boundary assumptions.

The NRC has indicated that small-break tests at the Semiscale and LOFT facilities, as well as Owners Group test predictions, will aid in the final resolution of this issue. The results of the above-mentioned Westinghouse analyses and predictions are in good agreement and, therefore, design modifications are not considered to be necessary.

18.2.17.5 Evaluation of PORV Opening Probability During Overpressure Transient (II.K.3.7)

Not applicable to Westinghouse pressurized water reactors.

18.2.17.6 Proportional Integral Derivative Controller Modification (II.K.3.9)

18.2.17.6.1 NRC Guidance Per NUREG-0737

Position

The Westinghouse-recommended modification to the proportional integral derivative (PID) controller should be implemented by affected licensees.

Clarification

The Westinghouse-recommended modification is to raise the interlock bistable trip setting to preclude derivative action from opening the power-operated relief valve (PORV). Some plants have proposed changing the derivative action setting to zero, thereby eliminating it from consideration. Either modification is acceptable to the staff. This represents a newly available option.

18.2.17.6.2 SNUPPS Response

The SNUPPS design includes a pressure integral derivative (PID) controller in the power-operated relief valve control circuit (see Figures 7.7-4 and 7.2-1, Sheet 11). The time derivative constant in the PID controller for the pressurizer PORV will be turned to "OFF" at each of the SNUPPS plants. The appropriate plant procedure for calibrating the set points in this nonsafety grade system will reflect this decision.

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Setting the derivative time constant to "OFF," in effect, removes the derivative action from the controller. Removal of the derivative action will decrease the likelihood of opening the pressurizer PORV since the actuation signal for the valve is then no longer sensitive to the rate of change of pressurizer pressure.

18.2.17.7 Proposed Anticipatory Trip Modification (II.K.3.10)

18.2.17.7.1 NRC Guidance Per NUREG-0737

Position

The anticipatory trip modification proposed by some licensees to confine the range of use to high-power levels should not be made until it has been shown on a plant-by-plant basis that the probability of a small-break loss-of-coolant accident (LOCA) resulting from a stuck-open power-operated relief valve (PORV) is substantially unaffected by the modification.

Clarification

This evaluation is required for only those licensees/applicants who propose the modification.

18.2.17.7.2 SNUPPS Response

This anticipatory trip modification is included in the SNUPPS design.

The NRC has raised the question of whether the pressurizer power-operated relief valves would be actuated for a turbine trip without reactor trip below a power level of 50 percent (P-9 set point). An analysis has been performed using realistic yet conservative values for the core physics parameters (primarily reactivity feedback coefficients and control rod worths), and a conservatively high initial power, average reactor temperature (T_{AVG}), and pressurizer pressure level to account for instrument inaccuracies.

The transient was initiated from the set point for the P-9 interlock, namely 50 percent of the reactor full power level plus 2 percent for power measurement uncertainty. This is a conservative starting point, and would bracket all transients initiated from a lower power level. The core physics parameters used were the ones that would result in the most positive reactivity feedbacks (i.e., highest power levels). The steam dump valves were assumed to be actuated by the load rejection controller.

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Based upon the results from the analysis, the peak pressure reached in the pressurizer would be 2,302 psia. The set point for the actuation of the pressurizer power-operated relief valves is 2,350 psia. Even including the ±20 psi pressure measurement uncertainty, there is still a margin of 28 psi between the peak pressure reached and the minimum activation pressure for the pressurizer power-operated relief valves.

An additional analysis has been performed to determine the consequences (specifically the likelihood of the pressurizer power-operated relief valves opening) of having a turbine trip due to a loss of condenser vacuum.

The major difference between this analysis and the one presented above is that now the normal steam dump system is unavailable, and the steam relief must be carried out through the atmospheric relief valves. Since there is a longer delay time before the atmospheric reliefs reach their set point (in comparison to the normal steam dump system) and their capacity is about one-half of the steam dump system, there is an increased likelihood that the pressurizer PORVs will open.

Figure 18.2-3 shows the plant operating ranges for which the pressurizer PORVs will open for a turbine trip due to a loss of condenser signal. Above 50 percent power, a turbine trip will cause a reactor trip (due to P-9 set point), and the pressurizer PORV set point will not be reached. Below a power level of 35 to 40 percent (depending on fuel burnup), the pressurizer spray rate is adequate to maintain the pressurizer pressure below the set point. Therefore, only in the narrow band between about 35 and 50 percent power will the pressurizer PORVs open for a loss of condenser.

Based upon the operating history of current plants, the chances of getting a condenser unavailable signal (and hence a turbine trip) is about 156 out of 10^7 operating hours. Assuming 98 percent plant availability and a 40-year plant lifetime, this works out to about four condenser unavailable turbine trips occurring during the normal life of a plant. Assuming an equal chance of having the plant operate anywhere between 0 and 100 percent power (an unrealistic value, since they usually operate either at a full or no load level), the chances of having a condenser unavailable signal generate a transient which would result in the opening of the pressurizer PORVs is less than one per plant lifetime.

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18.2.17.8 Justification use of Certain PORVs (II.K.3.11)

18.2.17.8.1 NRC Guidance Per NUREG-0694

Position

Demonstrate that the PORV installed in the plant has a failure rate equivalent to or less than the valves for which there is an operating history.

18.2.17.8.2 SNUPPS Response

The PORVs to be used in the SNUPPS design are pilot-operated relief valves. These valves will be supplied by Airresearch.

18.2.17.9 Confirm Existence of Anticipatory Reactor Trip Upon Turbine Trip (II.K.3.12)

18.2.17.9.1 NRC Guidance Per NUREG-0737

Position

Licensees with Westinghouse-designed operating plants should confirm that their plants have an anticipatory reactor trip upon turbine trip. The licensee of any plant where this trip is not present should provide a conceptual design and evaluation for the installation of this trip.

18.2.17.9.2 SNUPPS Response

The SNUPPS design includes an anticipatory reactor trip upon turbine trip (refer to Figure 7.2-1).

18.2.17.10 Separation of High-Pressure Coolant Injection and Reactor Core Isolation Cooling System Initiation Levels--Analysis and Implementation (II.K.3.13)

Not applicable to Westinghouse pressurized water reactors.

18.2.17.11 Isolation of Isolation Condensers on High Radiation (II.K.3.14)

Not applicable to Westinghouse pressurized water reactors.

18.2.17.12 Modify Break-Detection Logic to Prevent Spurious Isolation of High-Pressure Coolant Injection and Reactor Core Isolation Cooling (II.K.3.15)

Not applicable to Westinghouse pressurized water reactors.

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18.2.17.13 Reduction of Challenges and Failures of Relief Valves--Feasibility Study and System Modification (II.K.3.16)

Not applicable to Westinghouse pressurized water reactors.

18.2.17.14 Report on Outages of Emergency Core-Cooling Systems Licensee Report and Proposed Technical Specification Changes (II.K.3.17)

18.2.17.14.1 NRC Guidance per NUREG-0737

Position

Several components of the emergency core-cooling (ECC) systems are permitted by technical specifications to have substantial outage times (e.g., 72 hours for one diesel-generator; 14 days for the HPCI system). In addition, there are no cumulative outage time limitations for ECC systems. Licensees should submit a report detailing outage dates and lengths of outages for all ECC systems for the last 5 years of operation. The report should also include the causes of the outages (i.e., controller failure, spurious isolation).

Clarification

The present technical specifications contain limits on allowable outage times for ECC systems and components. However, there are no cumulative outage time limitations on these same systems. It is possible that ECC equipment could meet present technical specification requirements but have a high unavailability because of frequent outages within the allowable technical specifications.

The licensees should submit a report detailing outage dates and length of outages for all ECC systems for the last 5 years of operation, including causes of the outages. This report will provide the staff with a quantification of historical unreliability due to test and maintenance outages, which will be used to determine if a need exists for cumulative outage requirements in the technical specifications.

Based on the above guidance and clarification, a detailed report should be submitted. The report should contain (1) outage dates and duration of outages; (2) cause of the outage; (3) ECC systems or components involved in the outage; and (4) corrective action taken. Test and maintenance outages should be included in the above listings which are to cover the last 5 years of operation. The licensee should propose changes to improve the availability of ECC equipment, if needed.

Applicant for an operating license shall establish a plan to meet these requirements.

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18.2.17.14.2 SNUPPS Response

The SNUPPS Utilities will provide safety system outage information that is proposed by "Standard Technical Specifications for Westinghouse Pressurized Water Reactors" (Rev. 3). Specifically, the following will be provided in 30-day written reports:

> Conditions leading to operation in a degraded mode permitted by a Limiting Condition for Operation or plant shutdown required by a Limiting Condition for Operation.

In addition, records will be retained of the maintenance, inspections, and surveillance tests of the principal items related to nuclear safety. These records can be reviewed by the NRC for additional specific data on component availability.

The SNUPPS facilities will report safety system outages as described above. This reporting is consistent with 10 CFR 50.36 and ensures that the data requested by Item II.K.3.17 of NUREG-0737 is available.

18.2.17.15 Modification of Automatic Depressurization System Logic--Feasibility for Increased Diversity for Some Event Sequences (II.K.3.18)

Not applicable to Westinghouse pressurized water reactors.

18.2.17.16 Interlock on Recirculation Pump Loops (II.K.3.19)

Not applicable to Westinghouse pressurized water reactors.

18.2.17.17 Restart of Core Spray and Low-Pressure Coolant-Injection Systems (II.K.3.21)

Not applicable to Westinghouse pressurized water reactors.

18.2.17.18 Automatic Switchover of Reactor Core Isolation Cooling System Suction--Verify Procedures and Modify Design (II.K.3.22)

Not applicable to Westinghouse pressurized water reactors.

18.2.17,19 Confirm Adequacy of Space Cooling for High-Pressure Coolant Injection and Reactor Core Isolation Cooling Systems (II.K.3.24)

Not applicable to Westinghouse pressurized water reactors.

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18.2.17.20 Effect of Loss of Alternating-Current Power on Pump Seals (II.K.3.25)

18.2.17.20.1 NRC Guidance Per NUREG-0737

Position

The licensees should determine, on a plant-specific basis, by analysis or experiment, the consequences of a loss of cooling water to the reactor recirculation pump seal coolers. The pump seals should be designed to withstand a complete loss of alternating-current (ac) power for at least 2 hours. Adequacy of the seal design should be demonstrated.

Clarification

The intent of this position is to prevent excessive loss of reactor coolant system (RCS) inventory following an anticipated operational occurrence. Loss of ac power for this case is construed to be loss of offsite power. If seal failure is the consequence of loss of cooling water to the reactor coolant pump (RCP) seal coolers for 2 hours, due to loss of offsite power, one acceptable solution would be to supply emergency power to the component cooling water pump. This topic is addressed for Babcock and Wilcox (B&W) reactors in Section II.K.2.16.

18.2.17.20.2 SNUPPS Response

During normal operation, seal injection flow from the chemical and volume control system is provided to cool the RCP seals, and the component cooling water system provides flow to the thermal barrier heat exchanger to limit the heat transfer from the reactor coolant to the RCP internals. In the event of a loss of offsite power, the RCP motor is deenergized and both of these cooling supplies are terminated; however, the diesel generators are automatically started and both seal injection flow and component cooling water to the thermal barrier heat exchanger are automatically restored within seconds. Either of these cooling supplies is adequate to provide seal cooling and prevent seal failure due to a loss of seal cooling during a loss of offsite power for at least 2 hours.

18.2.17.21 Provide Common Reference Level for Vessel Level Instrumentation (II.K.3.27)

Not applicable to Westinghouse pressurized water reactors.

18.2.17.22 Verify Qualification of Accumulators on Automatic Depressurization Sys m Valves (II.K.3.28)

Not applicable to Westinghouse pressurized water reactors.

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18.2.17.23 Study to Demonstrate Performance of Isolation Condensers with Noncondensibles (II.K.3.29)

Not applicable to Westinghouse pressurized water reactors.

18.2.17.24 Revised Small-Break Loss-of-Coolant Accident Methods to Show Compliance with 10 CFR Part 50, Appendix K (II.K.3.30)

18.2.17.24.1 NRC Guidance Per NUREG-0737

Position

The analysis methods used by nuclear steam supply system (NSSS) vendors and/or fuel suppliers for small-break loss-of-coolant accident (LOCA) analysis for compliance with Appendix K to 10 CFR Part 50 should be revised, documented, and submitted for NRC approval. The revisions should account for comparisons with experimental data, including data from the LOFT Test and Semiscale Test facilities.

Clarification

As a result of the accident at TMI-2, the Bulletins and Orders Task Force was formed within the Office of Nuclear Reactor Regulation. This task force was charged, in part, to review the analytical predictions of feedwater transients and small-break LOCAs for the purpose of assuring the continued safe operation of all operating reactors, including a determination of acceptability of emergency guidelines for operators.

As a result of the task force reviews, a number of concerns were identified regarding the adequacy of certain features of small-break LOCA models, particularly the need to confirm specific model features (e.g., condensation heat transfer rates) against applicable experimental data. These concerns, as they applied to each lightwater reactor (LWR) vendor's models, were documented in the task force reports for each LWR vendor. In addition to the modeling concerns identified, the task force also concluded that, in light of the TMI-2 accident, additional systems verification of the small-break LOCA model as required by II.4 of Appendix K to 10 CFR 50 was needed. This included providing predictions of Semiscale Test S-07-10B and LOFT Test (L3-1) and providing experimental verification of the various modes of single-phase and two-phase natural circulation predicted to occur in each vendor's reactor during small-break LOCAs.

Based on the cumulative staff requirements for additional small-break LOCA model verification, including both integral system and separate effects verification, the staff considered model revision as the appropriate method for reflecting any potential upgrading of the analysis methods.

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The purpose of the verification was to provide the necessary assurance that the small-break LOCA models were acceptable to calculate the behavior and consequences of small primary system breaks. The staff believes that this assurance can alternatively be provided, as appropriate, by additional justification of the acceptability of present small-break LOCA models with regard to specific staff concerns and recent test data. Such justification could supplement or supersede the need for model revision.

The specific staff concerns regarding small-break LOCA models are provided in the analysis sections of the B&O Task Force reports for each LWR vendor, (NUREG-0635, -0565, -0626, -0611, and -0623). These concerns should be reviewed in total by each holder of an approved emergency core cooling system (ECCS) model and addressed in the evaluation as appropriate.

The recent tests include the entire Semiscale small-break test series and LOFT Tests (L3-1) and (L3-2). The staff believes that the present small-break LOCA models can be both qualitatively and quantitatively assessed against these tests. Other separate effects tests (e.g., ORNL core uncovery tests) and future tests, as appropriate, should also be factored into this assessment.

Based on the preceding information, a detailed outline of the proposed program to address this issue should be submitted. In particular, this submittal should identify (1) which areas of the models, if any, the licensee intends to upgrade, (2) which areas the licensee intends to address by further justification of acceptability, (3) test data to be used as part of the overall verification/upgrade effort, and (4) the estimated schedule for performing the necessary work and submitting this information for staff review and approval.

18.2.17.24.2 SNUPPS Response

The present Westinghouse Small Break Evaluation Model used to analyze the SNUPPS units (refer to Section 15.6.5) is in conformance with 10 CFR Part 50, Appendix K. However (as documented in Ref. 6), Westinghouse has indicated that they will, nevertheless, address the specific NRC items contained in NUREG-0611 in a model change scheduled for completion by January 1, 1982.

W

18.2.17.25 Plant-Specific Calculations to Show Compliance With 10 CFR Part 50.46 (II.K.3.31)

18.2.17.25.1 NRC Guidance Per NUREG-0737

Position

Plant-specific calculations using NRC-approved models for small-break loss-of-coolant accidents (LOCAs), as described in item II.K.3.30 to show compliance with 10 CFR 50.46, should be submitted for NRC approval by all licensees.

18.2.17.25.2 SNUPPS Response

The present Westinghouse Small Break Evaluation Model and small break LOCA analyses for the SNUPPS units (refer to Section 15.6.5) are in conformance with 10 CFR Part 50, Appendix K and 10 CFR Part 50.46. As stated in the response to Item II.K.3.30 (refer to Section 18.2.17.24.2), Westinghouse plans to submit a new Small Break Evaluation Model to the NRC for review by January 1, 1982. If the results of this new Westinghouse model (and subsequent NRC review and approval) indicate that the present small break LOCA analyses for the SNUPPS units are not in conformance with 10 CFR Part 50.46, a new analysis utilizing the new and approved Westinghouse model will be submitted to the NRC in accordance with the NRC schedule.

18.2.17.26 Evaluation of Anticipated Transients with Single Failure to Verify No Fuel Failure (II.K.3.44)

Not applicable to Westinghouse pressurized water reactors.

18.2.17.27 Evaluation of Depressurization with Other than Automatic Depressurization System (II.K.3.45)

Not applicable to Westinghouse pressurized water reactors.

18.2.17.28 Identify Water Sources Prior to Actuation of Automatic Depressurization System (II K.3.57)

Not applicable to Westinghouse pressurized water reactors.

18.2.18 REFERENCES

1. Letter OG-57, dated April 20, 1981, Jurgensen, R. W. (Chairman, Westinghouse Owners Group) to Check, P. S. (NRC).

2. Wood, D. C. and Gottshall, C. L., "Probabilistic Analysis and Operational Data in Response to NUREG-0737 Item II.K.3.2 for Westinghouse NSSS Plants," WCAP-9804, February 1981.

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3. "Analysis of Delayed Reactor Coolant Pump Trip During Small Loss of Coolant Accidents for Westinghouse Nuclear Steam Supply Systems," WCAP-9584 (Proprietary) and WCAP-9585 (Non-Proprietary), August 1979.

4. Letter OG-49, dated March 3, 1981, Jurgensen, R. W. (Chairman, Westinghouse Owners Group) to Ross, D. F., Jr. (NRC).

5. Letter OG-50, dated March 23, 1981, Jurgensen, R. W. (Chairman, Westinghouse Owners Group) to Ross, D. F., Jr. (NRC).

6. Letter NS-TMA-2318, dated September 26, 1980, Anderson, T. M. (Westinghouse) to Eisenhut, D. G. (NRC).

 RSB

Q440.106 (5.2.2) In reviews of certain other Westinghouse-designed plants, a failure of a D.C. power bus was identified which could both initiate an overpressure event at low temperature (by isolating letdown) and fail closed one of the PORVs. A postulated single failure (closed) of the other PORV would fail mitigating systems for this event. Address this scenario for the SNUPPS design.

RESPONSE

The response to the above scenario will depend on whether the RHR system is isolated from the reactor coolant system; however, in any event, the SNUPPS design provides adequate protection against overpressure of the reactor coolant system.

In the case where the RCS is at low temperature and the RHR letdown isolation valves for either, or both RHR loops, are open, the RCS is protected from overpressurization by the RHR inlet relief valves. These valves are each sized to relieve the combined flow of all the charging pumps at a setpoint of 450 psig.

During normal startup and shutdown, a pressurizer bubble is maintained whenever the RHR system is isolated. The normal steam bubble volume in this condition would be approximately 1350 ft^3. Should normal letdown be isolated, the maximum makeup rate imbalance would be approximately 100 gpm, which is the capacity of the positive displacement charging pump that is normally in operation. This value would actually be much less as the transient progressed since the charging flow control system would throttle the flow to try to maintain pressurizer level. However, even if no credit is taken for the charging control system and also assuming that the pressurizer level is initially at the high level alarm setpoint (i.e. approximately 500 ft^3 steam bubble), the plant operator would have greater than 10 minutes to terminate the event.

CWBA

Results

Calculated plant parameters following a major feedwater line rupture are shown in Figures 15.2-15 through 15.2-24. Results for the case with offsite power available are presented in Figures 15.2-15 through 15.2-19. Results for the case where offsite power is lost are presented in Figures 15.2-20 through 15.2-24. The calculated sequence of events for both cases analyzed are listed in Table 15.2-1.

The system response following the feedwater line rupture is similar for both cases analyzed. Results presented in Figures 15.2-16 and 15.2-17 (with offsite power available) and Figures 15.2-21 and 15.2-22 (without offsite power) show that pressures in the RCS and main steam system remain below 110 percent of the respective design pressures. Pressurizer pressure decreases after reactor trip on low-low steam generator level (67.3 seconds). Pressurizer pressure decreases due to the loss of heat input, until the safety injection system is actuated on low steam line pressure in the ruptured loop. Coolant expansion occurs due to reduced heat transfer capability in the steam generators; the pressurizer safety valves open to maintain primary coolant system pressure at an acceptable value. Addition of the safety injection flow aids in cooling down the primary and helps to ensure that sufficient fluid exists to keep the core covered with water.

Figures 15.2-15 and 15.2-20 show that following reactor trip the plant remains subcritical.

RCS pressure will be maintained at the safety valve setpoint until safety injection flow is terminated as discussed above.

Figure 15.2-16 shows that the pressurizer does not empty throughout the transient to that the core remains covered at all times and that no boiling occurs in the reactor coolant loops.

The major difference between the two cases analyzed can be seen in the plots of hot and cold leg temperatures, Figure 15.2-18 (with offsite power available) and Figure 15.2-23 (without offsite power). It is apparent that for the initial transient (~150 seconds), the case without offsite power results in higher temperatures in the hot leg. For longer times, however, the case with offsite power results in a more severe rise in temperature until the auxiliary feedwater system is realigned. The pressurizer fills more rapidly for the case with power due to the increased coolant expansion resulting from the pump heat addition. As previously stated, the core remains covered with water for both cases.

FWBA

TABLE 15.2-1 (Sheet 4)

Accident	Event	Time (sec)
Feedwater system pipe break		
1. With offsite power available	Feedwater control system fails	0.0
	Low-low steam generator level reactor trip set-point reached in all steam generators	65.3
	Rods begin to drop and feedwater line rupture occurs	67.3
	Low steam line pressure setpoint reached in ruptured steam generator	118.1
	All main steam line isolation valves close	125.1
	Auxiliary feedwater to intact steam generators is initiated	125.3
	Pressurizer safety valve setpoint reached following feedwater line rupture	226.0
	Steam generator safety valve setpoint reached in intact steam generators	522.0
	Core decay heat decreases to auxiliary feedwater heat removal capacity	1,798

FWBA

TABLE 15.2-1 (Sheet 5)

Accident	Event	Time (sec)
2. Without offsite power	Feedwater control system fails	0.0
	Low-low steam generator level reactor trip setpoint reached in all steam generators	65.3
	Rods begin to drop; power lost to the reactor coolant pumps; and feedwater line rupture occurs	67.3
	Low steam line pressure setpoint reached in ruptured steam generator	113.4
	All main steam line isolation valves close	120.4
	Auxiliary feedwater to intact steam generators is initiated	125.3
	Steam generator safety valve setpoint reached in intact steam generators	219.0
	Pressurizer safety valve setpoint reached following feedwater line rupture	274.0
	Core decay heat decreases to auxiliary feedwater heat removal capacity	870

*DNBR does not decrease below its initial value.

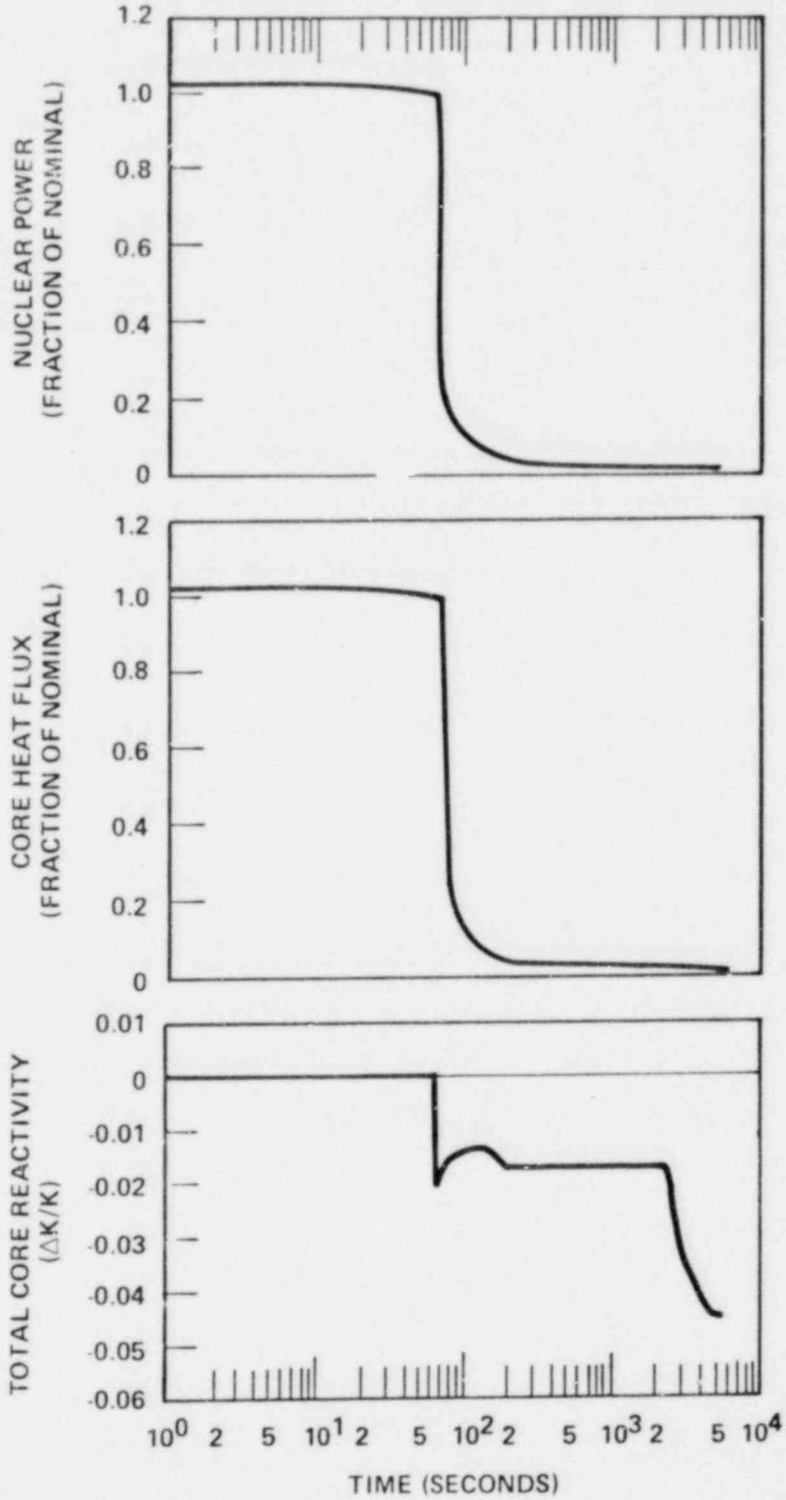

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FIGURE 15.2-15

NUCLEAR POWER, CORE HEAT FLUX AND TOTAL CORE REACTIVITY TRANSIENTS FOR MAIN FEEDWATER LINE RUPTURE WITH OFFSITE POWER AVAILABLE

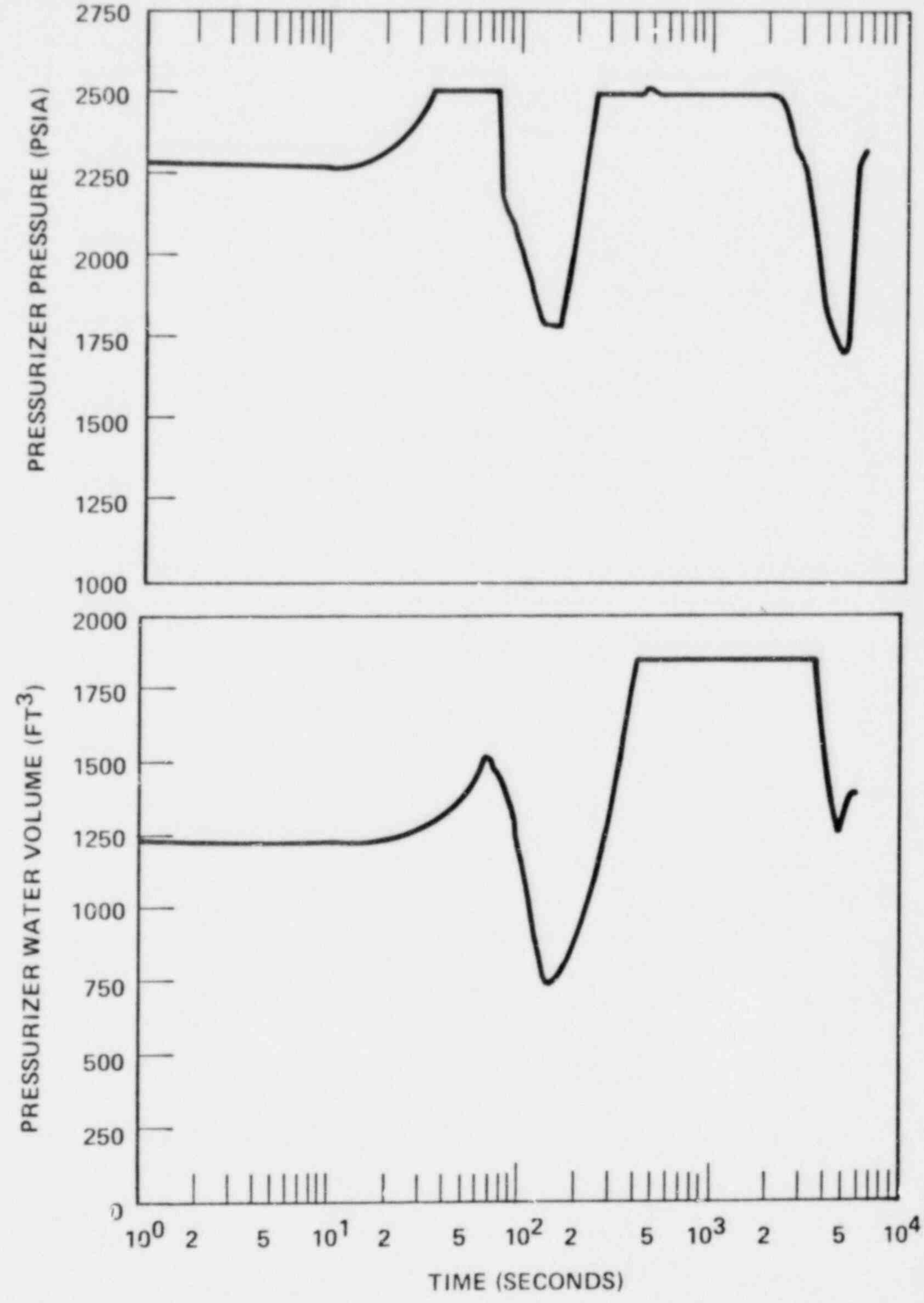

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FIGURE 15.2-16

PRESSURIZER PRESSURE AND WATER VOLUME TRANSIENTS FOR MAIN FEEDWATER LINE RUPTURE WITH OFFSITE POWER AVAILABLE

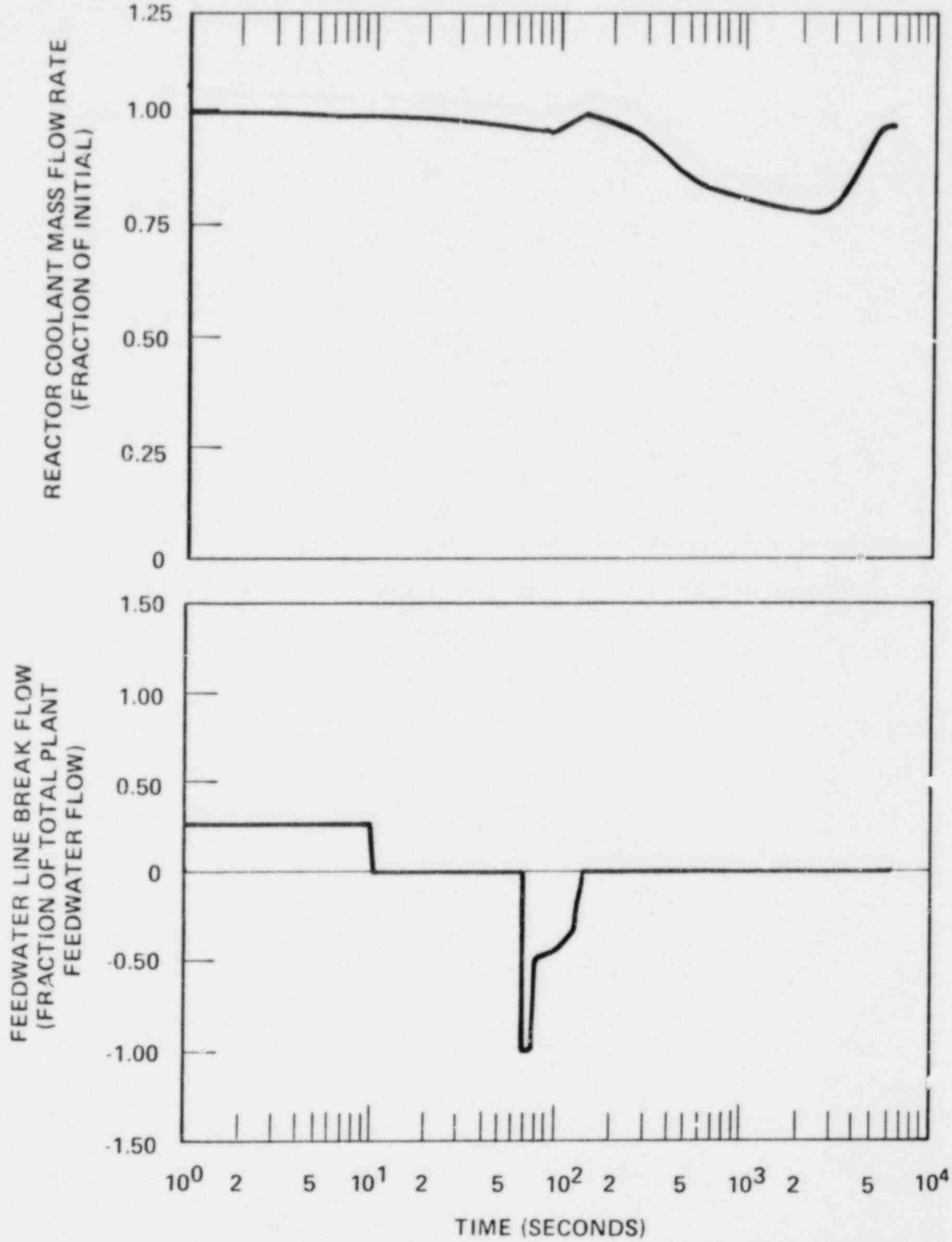

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FIGURE 15.2-17

REACTOR COOLANT MASS FLOW RATE AND FEEDWATER LINE BREAK FLOW TRANSIENTS FOR MAIN FEEDWATER LINE RUPTURE WITH OFFSITE POWER AVAILABLE

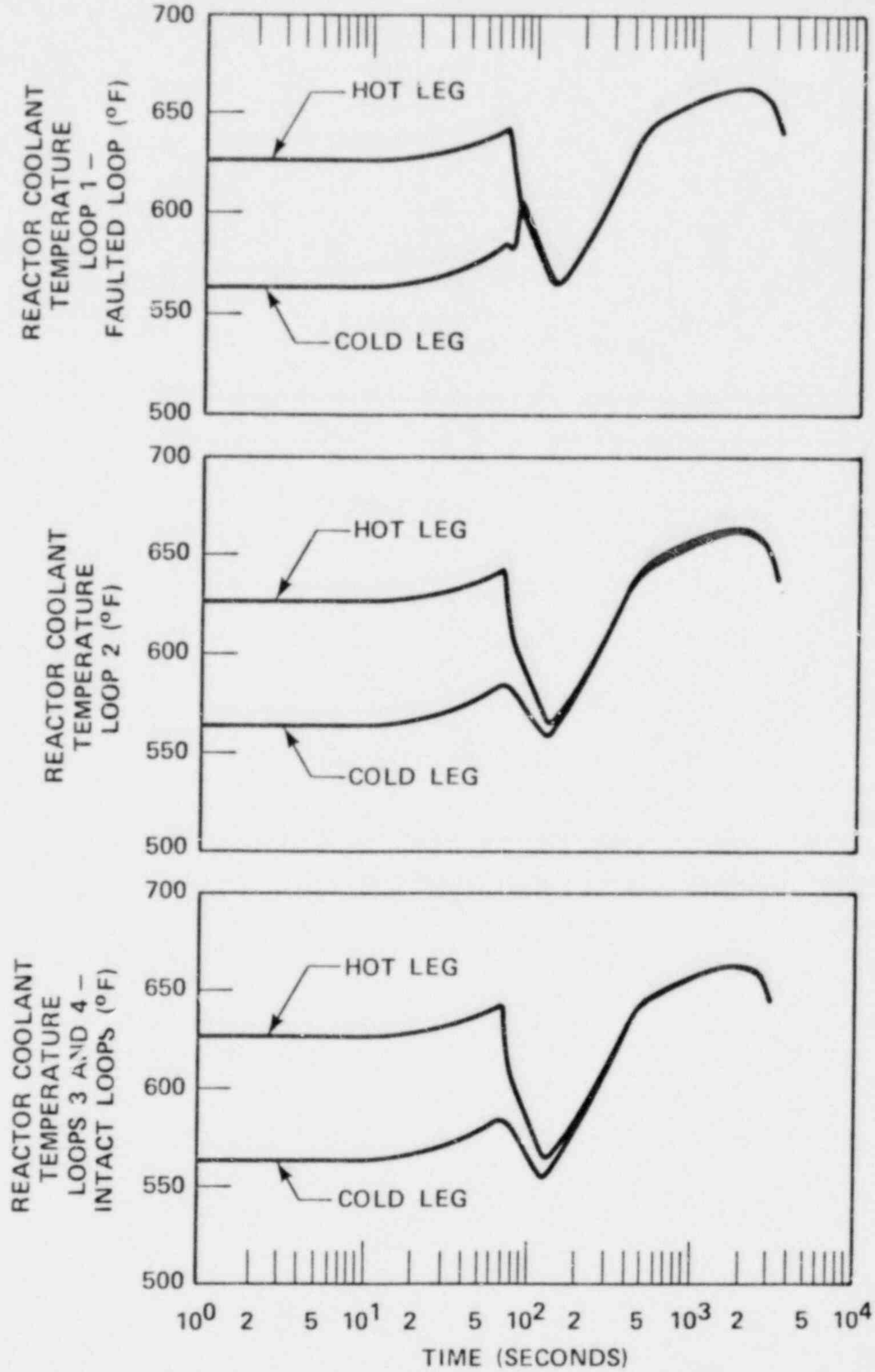

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FIGURE 15.2-18

REACTOR COOLANT TEMPERATURE TRANSIENT FOR MAIN FEEDWATER LINE RUPTURE WITH OFFSITE POWER AVAILABLE

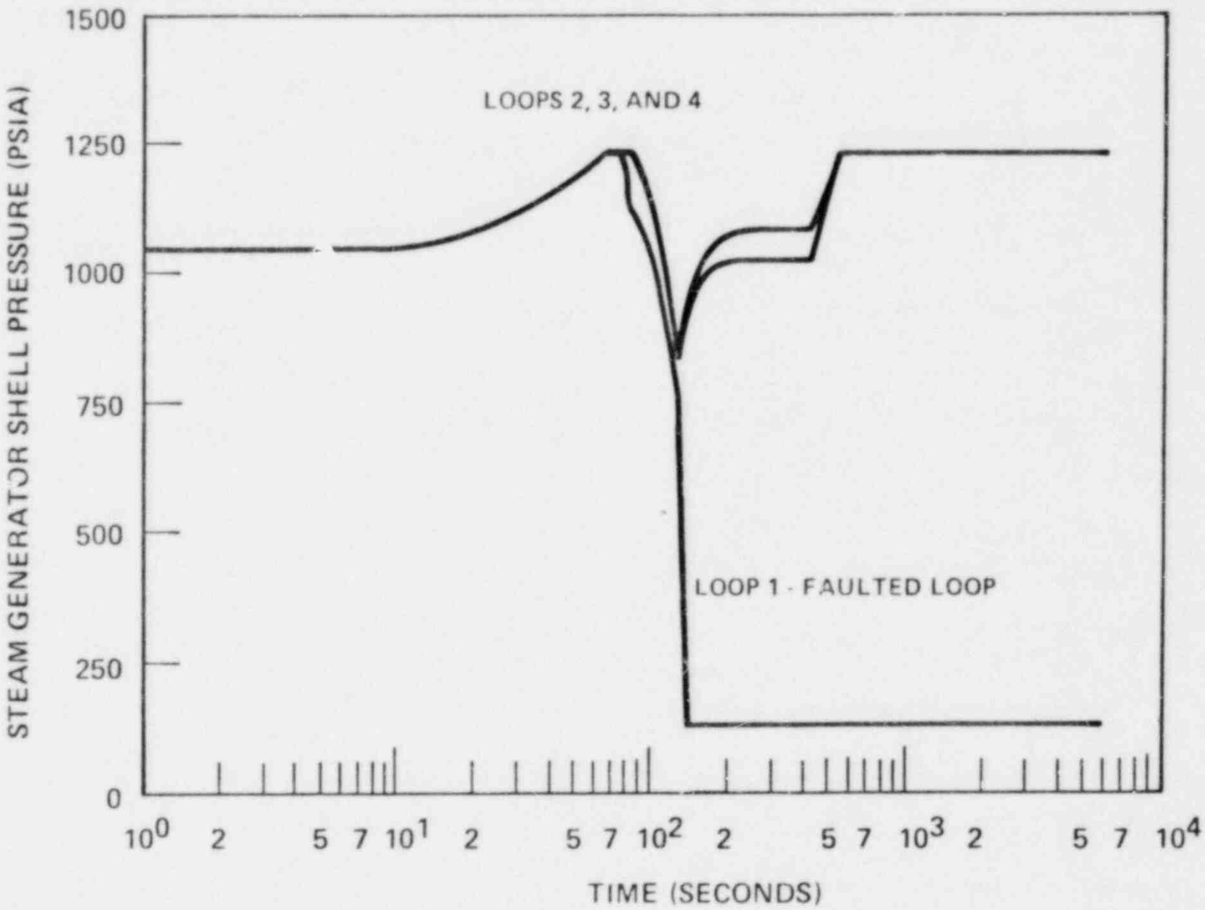

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FIGURE 15.2-19

STEAM GENERATOR SHELL PRESSURE TRANSIENT FOR MAIN FEEDWATER LINE RUPTURE WITH OFFSITE POWER AVAILABLE

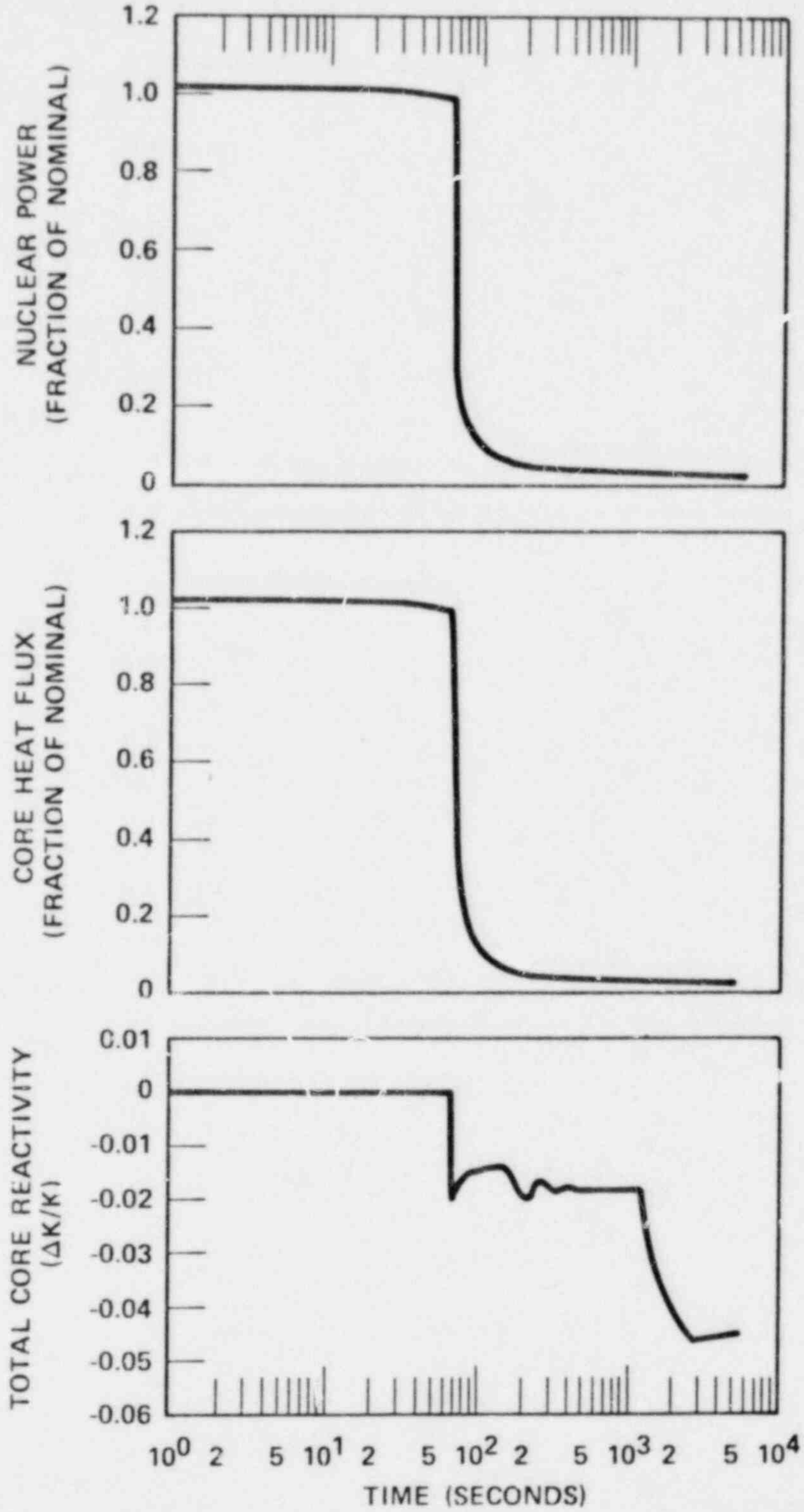

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FIGURE 15.2-20

NUCLEAR POWER, CORE HEAT FLUX AND TOTAL CORE REACTIVITY TRANSIENTS FOR MAIN FEEDWATER LINE RUPTURE WITHOUT OFFSITE POWER

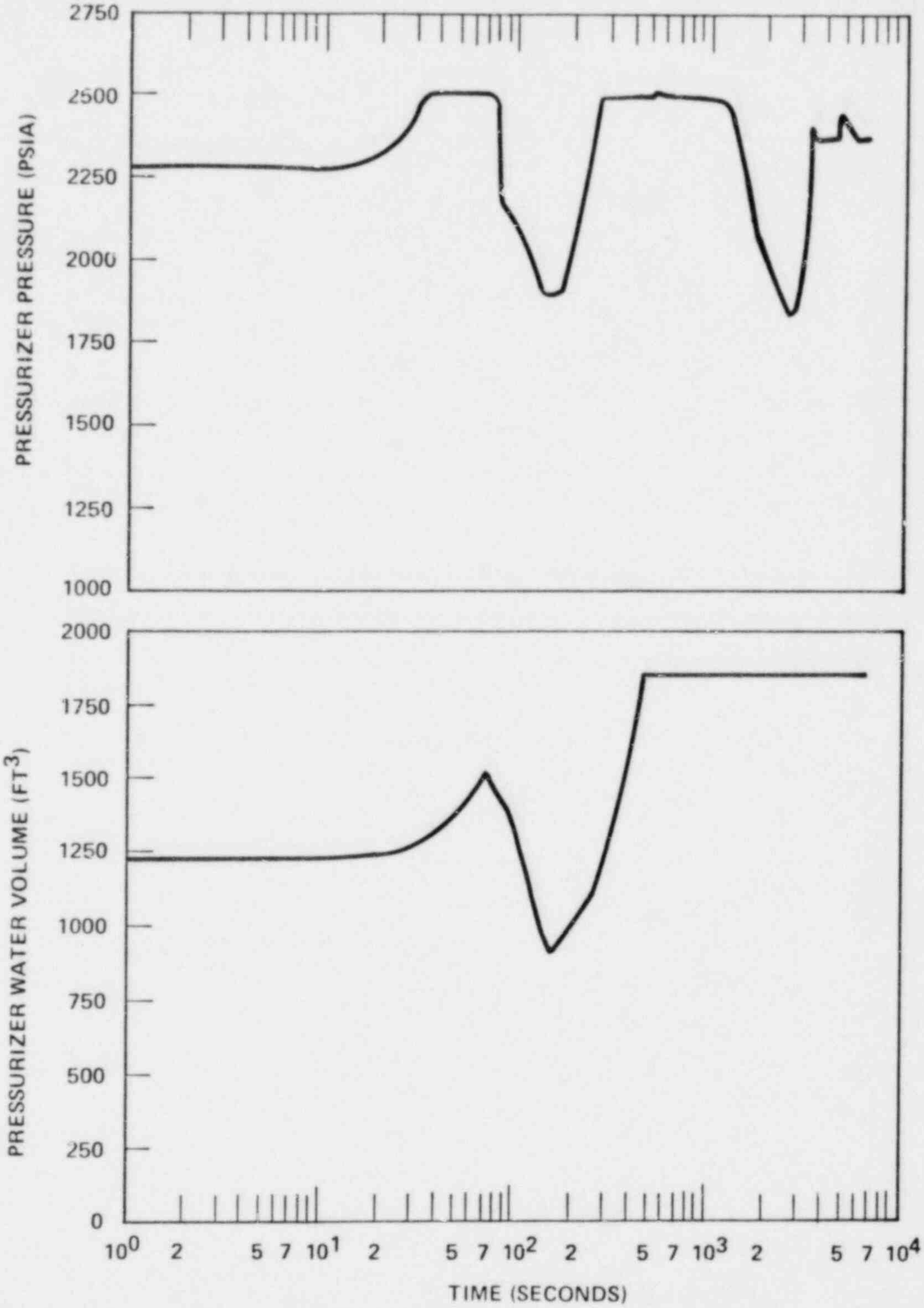

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FIGURE 15.2-21

PRESSURIZER PRESSURE AND WATER VOLUME TRANSIENTS FOR MAIN FEEDWATER LINE RUPTURE WITHOUT OFFSITE POWER

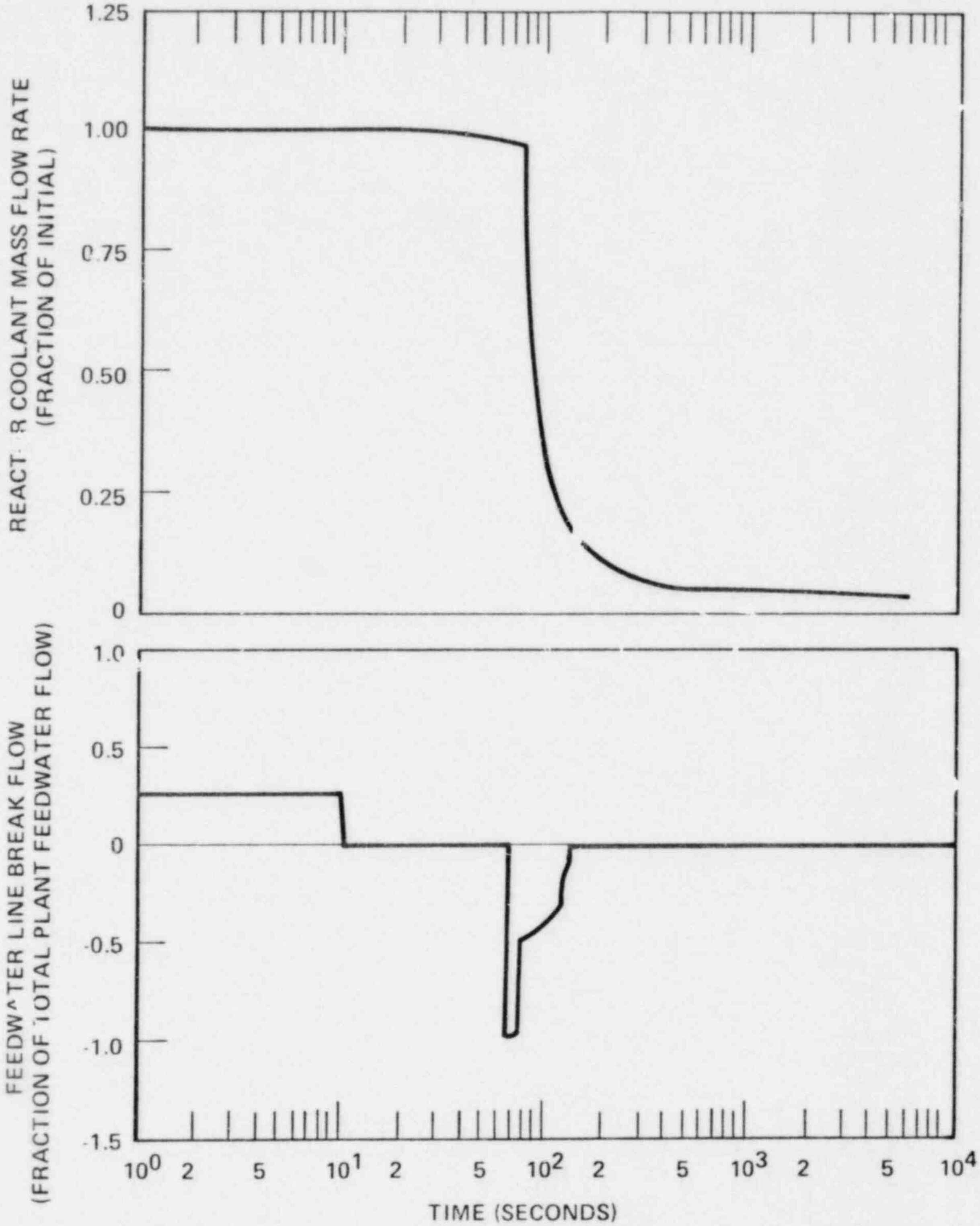

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FIGURE 15.2-22

REACTOR COOLANT MASS FLOW RATE AND FEEDWATER LINE BREAK FLOW TRANSIENTS FOR MAIN FEEDWATER LINE RUPTURE WITHOUT OFFSITE POWER

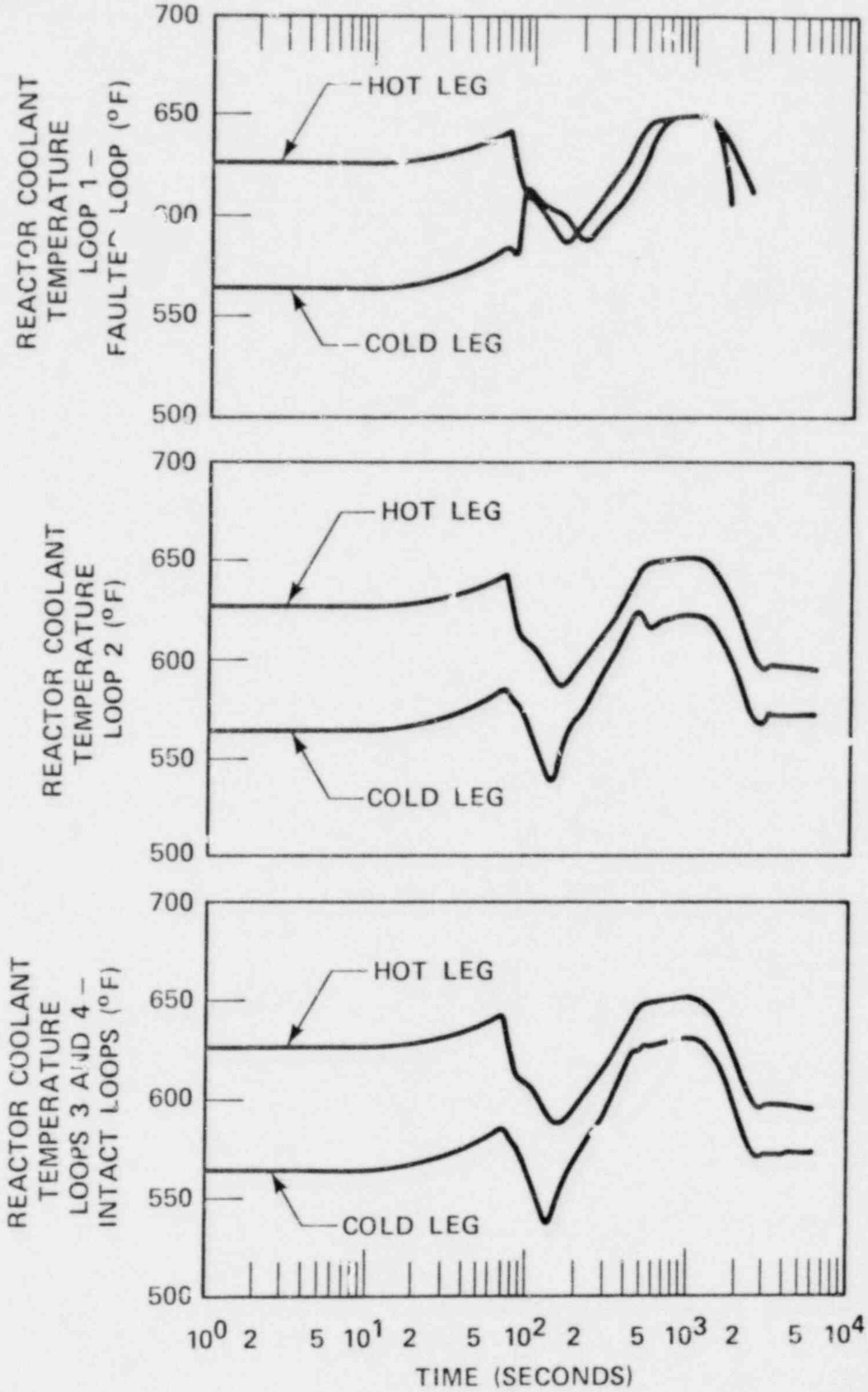

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FIGURE 15.2-23

REACTOR COOLANT TEMPERATURE TRANSIENT FOR MAIN FEEDWATER LINE RUPTURE WITHOUT OFFSITE POWER

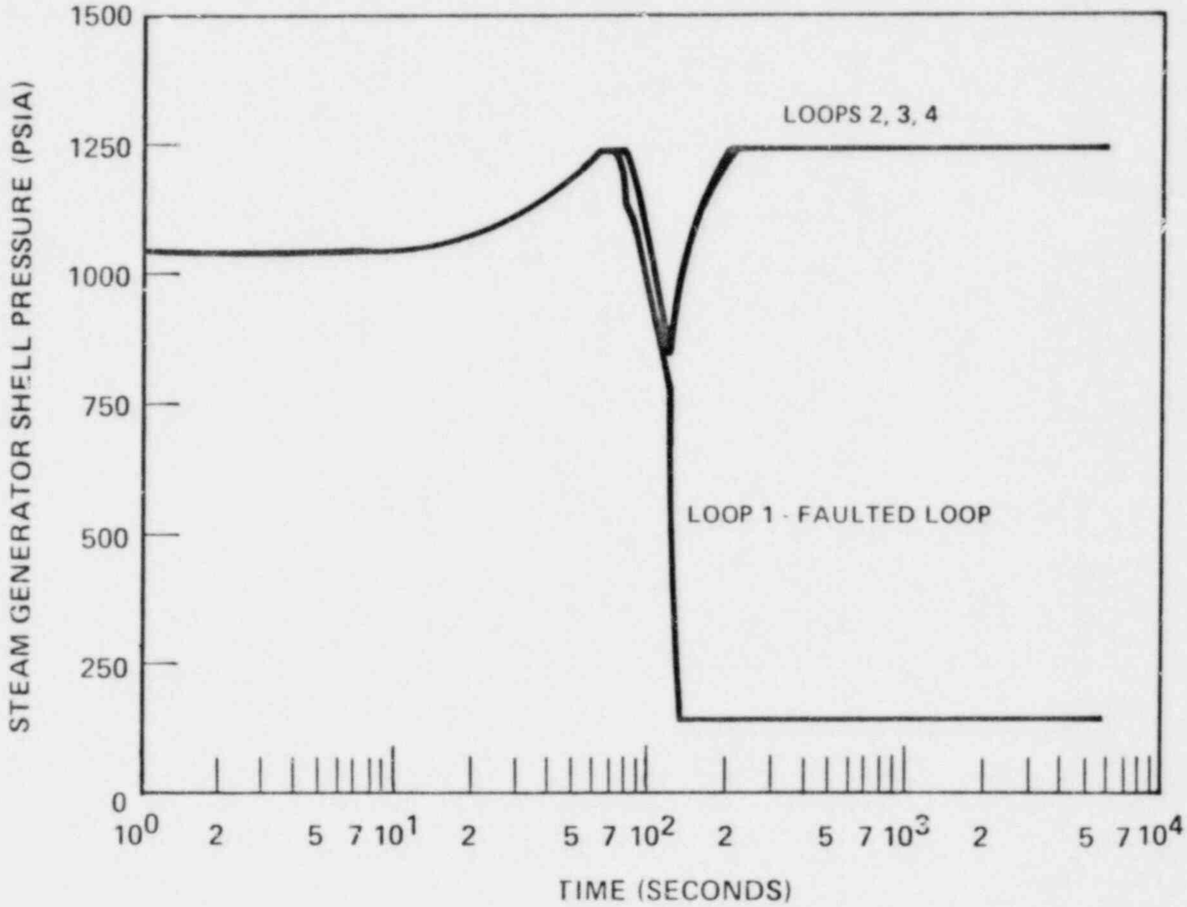

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FIGURE 15.2-24

STEAM GENERATOR SHELL PRESSURE TRANSIENT FOR MAIN FEEDWATER LINE RUPTURE WITHOUT OFFSITE POWER reactor trip. The safety injection signal automatically terminates normal feedwater supply and initiates auxiliary feedwater addition.

c. The steam generator blowdown liquid monitor and/or the condenser offgas radiation monitor will alarm, indicating a sharp increase in radioactivity in the secondary system, and will automatically terminate steam generator blowdown.

d. The reactor trip automatically trips the turbine, and if offsite power is available the steam dump valves open, permitting steam dump to the condenser. In the event of a coincident station blackout (loss of offsite power), as assumed in the transients presented in this section, the steam dump valves would automatically close to protect the condenser. The steam generator pressure (Figure 15.6-3c) would rapidly increase, resulting in steam discharge to the atmosphere through the steam generator safety/power-operated relief valves. In Figure 15.6-3f, the steam flow is presented as a function of time. The flow is constant initially until reactor trip, followed by turbine trip, which results in a large decrease in flow, but a rapid increase in steam pressure to the safety/relief valve setpoints.

e. Following reactor trip, the continued action of auxiliary feedwater supply and borated safety injection flow (supplied from the refueling water storage tank) provide a heat sink which absorbs the decay heat.

f. Safety injection flow results in increasing the pressurizer water level (Figure 15.6-3e); the rate of which depends upon the amount of operating auxiliary equipment.

15.6.3.2 Analysis of Effects and Consequences

Method of Analysis

Mass and energy balance calculations are performed using LOFTRAN (Ref. 1) to determine primary-to-secondary mass release and to determine the amount of steam vented from each of the steam generators during the initial 30-minute period following the tube rupture.

In estimating the mass transfer from the RCS through the broken tube, the following assumptions are made:

a. Reactor trip occurs automatically as a result of low pressurizer pressure or overtemperature ΔT. Loss of offsite power occurs at reactor trip.

SGTR

b. Following the initiation of the safety injection signal, two centrifugal charging pumps are actuated and are assumed in the analyses to continue to deliver flow for 30 minutes.

c. After reactor trip, the break flow reaches equilibrium when incoming safety injection flow is balanced by outgoing break flow, as shown in Figure 15.6-3. Break flow is assumed to persist for 30 minutes beyond initiation of the accident.

d. The steam generators are controlled at the power-operated relief valve setting.

e. During the initial 30-minute period following the accident, the operator is assumed to throttle the auxiliary feedwat r flow to match the steam flow, when possible, in all steam generators.

f. The operator identifies the accident type and terminates break flow to the affected steam generator within 30 minutes of accident initiation.

The above assumptions, suitably conservative for the design basis tube rupture, are made to maximize doses and do not explicitly model operator actions for recovery.

Prior to reactor trip, steam is dumped to the condenser from both the faulted and nonfaulted steam generators. After the condenser is lost, following assumed loss of offsite power at reactor trip, steam from all steam generators is released to the atmosphere.

Following isolation of the faulted steam generator, it is assumed that steam dump from the nonfaulted steam generators is used to reduce the RCS temperature to 50 F below no-load Tavg (557 F). From 2 to 8 hours, steam is assumed to be dumped from the nonfaulted steam generators to reduce the RCS temperature and pressure to RHRS conditions. The faulted steam generator is depressurized to the RHRS cut-in pressure via steam release from the faulted steam generator PORVs After 8 hours, further plant cooldown is carried out with the RHRS. The 0.5 to 2 hour and 2 to 8 h ur steam releases from and feedwater flows to the steam generator required to remove decay heat, metal heat, heat due to an operating reactor coolant pump, and stored fluid energy in the RCS and steam generators are determined based on these assumptions.

Key Recovery Sequence

The recovery sequence to be followed consists of the following major operator actions:

a. Identification of the faulted steam generator

SG-TR

b. Isolation of the faulted steam generator

c. Assuring subcooling of the RCS fluid to approximately 50 F below no load temperature

d. Controlled depressurization of the RCS to a value equal to the faulted steam generator pressure

e. Subsequent termination of safety injection flow

Results

In Table 15.6-1, the sequence of events are presented. These events are the normal plant response to the normal plant setpoints. Loss of offsite power is assumed to occur at reactor trip.

The previously discussed assumptions lead to an estimate of 107,980 pounds for the total amount of reactor coolant transferred to the secondary side of the faulted steam generator as a result of a tube rupture accident. The steam releases to the condenser and atmosphere from both the faulted and nonfaulted steam generators are given in Table 15.6-4. The total feedwater flows to all steam generators are also listed in Table 15.6-4.

The following is a list of figures of pertinent time dependent parameters:

Figure 15.6-3a - Core Pressure

SGTR

Figure 15.6-3b - Reactor Coolant System Temperature

Figure 15.6-3c - Steam Generator Pressure (Faulted Steam Generator)

Figure 15.6-3d - Steam Generator Temperature (Faulted Steam Generator)

Figure 15.6-3e - Pressurizer Water Volume

Figure 15.6-3f - Steam Generator Flow (Faulted Steam Generator)

Figure 15.6-3g - Feedwater Flow to Faulted Steam Generator

Figure 15.6-3h - Faulted Steam Generator Safety/Relief Valve Flow Rate

Figure 15.6-3i - Faulted Steam Generator Break Flow Rate

Figure 15.6-3j - Steam Generator Mass

Figure 15.6-3k - Faulted Steam Generator Water Volume

The DNB calculations performed with LOFTRAN (Ref. 1) indicate that DNB limits are met.

15.6.3.3 Radiological Consequences

15.6.3.3.1 Method of Analysis

15.6.3.3.1.1 Physical Model

The evaluation of the radiological consequences due to a postulated steam generator tube rupture (SGTR) assumes a complete severance of a single steam generator tube while the reactor is operating at full rated power and a coincident loss of offsite power. Occurrence of the accident leads to an increase in contamination of the secondary system due to reactor coolant leakage through the tube break. A reactor trip occurs automatically, as a result of low pressurizer pressure. The reactor trip will automatically trip the turbine.

SG-TR

TABLE 15.6-1

TIME SEQUENCE OF EVENTS FOR INCIDENT WHICH RESULTS IN A DECREASE IN REACTOR COOLANT INVENTORY

Accident	Event	Time (sec)
Inadvertent opening of a pressurizer safety valve	Safety valve opens fully	0.0
	Overtemperature ΔT reactor trip setpoint reached	13.8
	Minimum DNBR occurs	15.0
	Rods begin to drop	15.8
Steam generator tube rupture	Tube rupture occurs	0.0
	Reactor trip signal	198.9
	Rod motion	200.9
	Feedwater terminated	200.9
	Steam generator safety/ relief valves opened	204.0
	Safety injection signal	335.2
	Safety injection	360.2
	Auxiliary feedwater injection	396.0
	Operator takes actions to isolate and cooldown	1800.0

SGTR

TABLE 15.6-4

PARAMETER USED IN EVALUATING
THE RADIOLOGICAL CONSEQUENCES OF
A STEAM GENERATOR TUBE RUPTURE (SGTR)

I. Source Data	
a. Core power level, MWt	3,565
b. Steam generator tube leakage, gpm	1
c. Reactor coolant iodine activity:	
1. Case 1	Initial activity equal to dose equivalent of 1.0 μCi/gm of I-131 with an assumed iodine spike that increases the rate of iodine release into the reactor coolant by a factor of 500
2. Case 2	An assumed pre-accident iodine spike, which has resulted in the dose equivalent of 60 μCi/gm of I-131
d. Reactor coolant noble gas activity, both cases	Based on 1-percent failed fuel as provided in Table 11.1-5
e. Secondary system initial activity	Dose equivalent of 0.1 μCi/gm of I-131
f. Reactor coolant mass, lbs	5.3E+5
g. Steam generator mass (each), lbs	1.089E+5
h. Offsite power	Lost
i. Primary-to-secondary leakage duration	30 minutes
II. Atmospheric Dispersion Factors	See Table 15A-2
III. Activity Release Data	
a. Affected steam generator	
1. Reactor coolant discharged to steam generator, lbs	107,980

SGTR

TABLE 15.6-4 (Sheet 2)

2. Flashed reactor coolant, percent	17
3. Iodine partition factor for flashed fraction of reactor coolant	1.0
4. Total steam release, lbs	61,860
5. Iodine partition factor for the nonflashed fraction of reactor coolant that mixes with the initial iodine activity in the steam generator	0.01

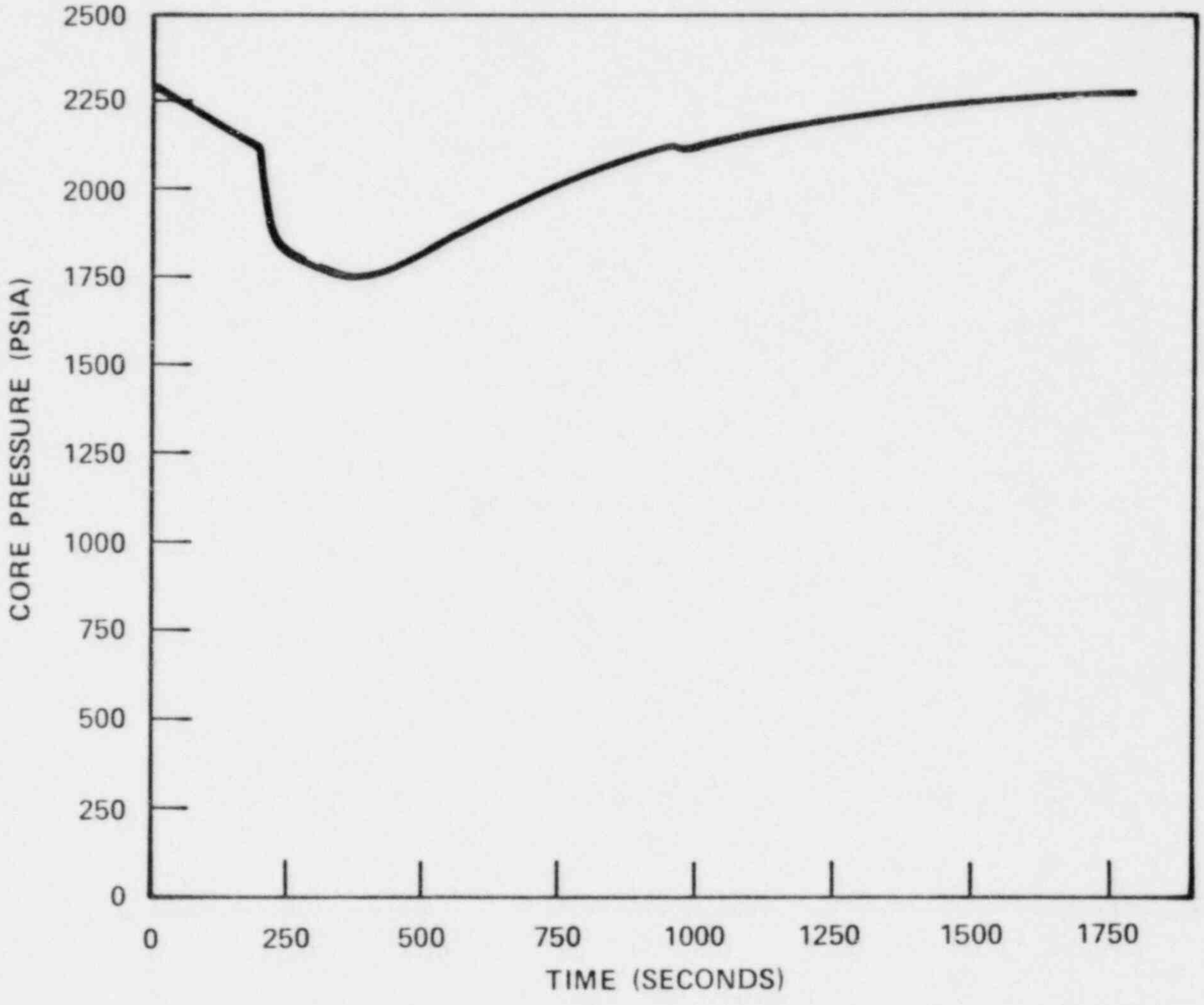
b. Unaffected steam generators

1. Primary-to-secondary leakage, lbs	250
2. Flashed reactor coolant, percent	0
3. Feedwater flow rate, lbs	
0-2 hours	1,350,000
2-8 hours	1,091,054
4. Total steam release, lbs	
0-2 hours	451,000
2-8 hours	1,020,434
5. Iodine partition factor	0.01
6. Isolation time, hrs	8

c. Activity released to the environment*

1. Case 1

Isotope	0-2 hr (Ci)	0-8 hr (Ci)
I-131	6.53E+1	6.58E+1
I-132	1.12E+2	1.12E+2
I-133	1.28E+2	1.29E+2
I-134	1.34E+2	1.34E+2
I-135	1.07E+2	1.07E+2
Xe-131m	8.10E+0	8.10E+0
Xe-133m	4.44E+1	4.44E+1
Xe-133	2.21E+3	2.21E+3
Xe-135m	2.70E+0	2.70E+0
Xe-135	1.34E+2	1.34E+2
Xe-138	8.20E+0	8.20E+0
Kr-83m	1.02E+1	1.02E+1
Kr-85m	4.78E+1	4.78E+1



SNUPPS

Figure 15.6-3A

Core Pressure Transient for Steam Generator Tube Rupture Event

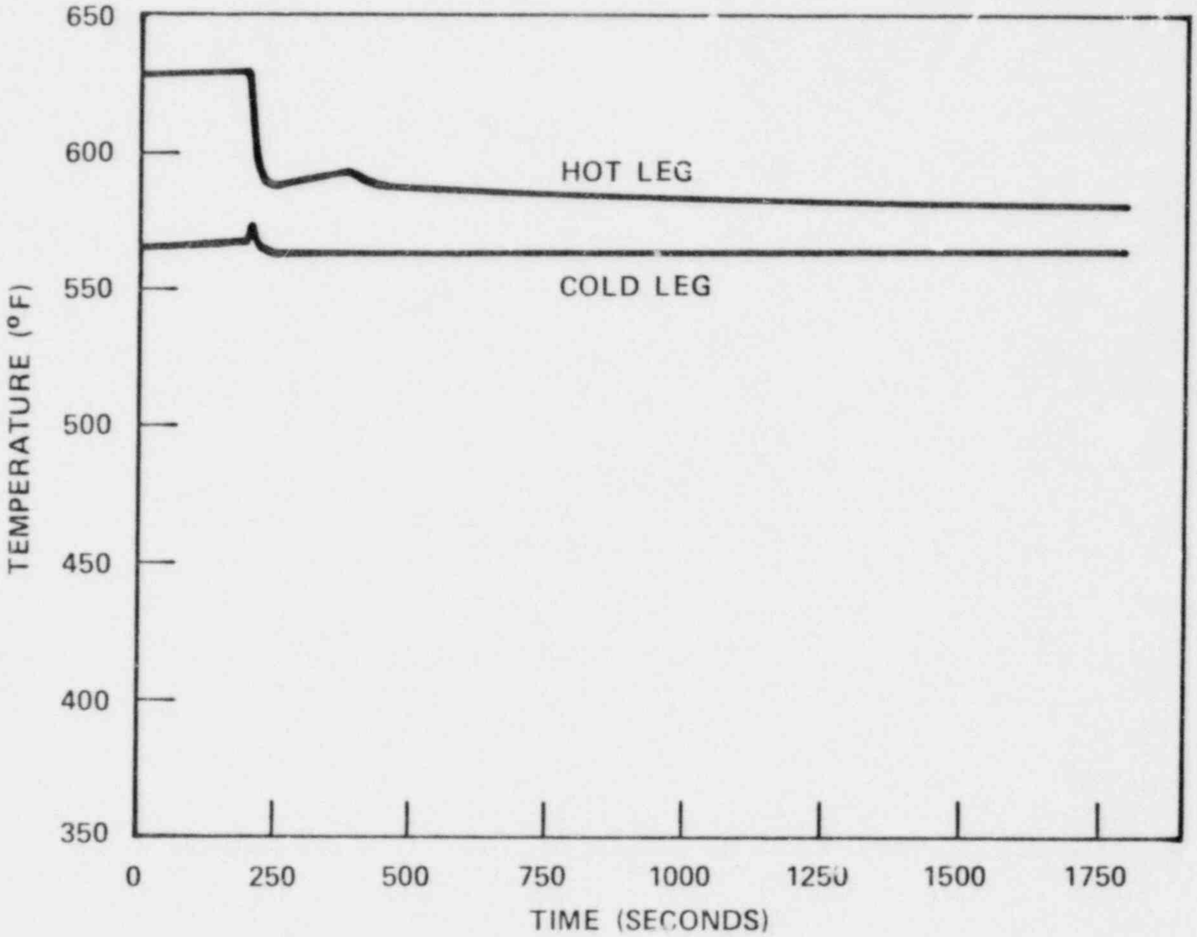


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Figure 15.6-3B.

Reactor Coolant System Temperature Transient for Steam Generator Tube Rupture Event

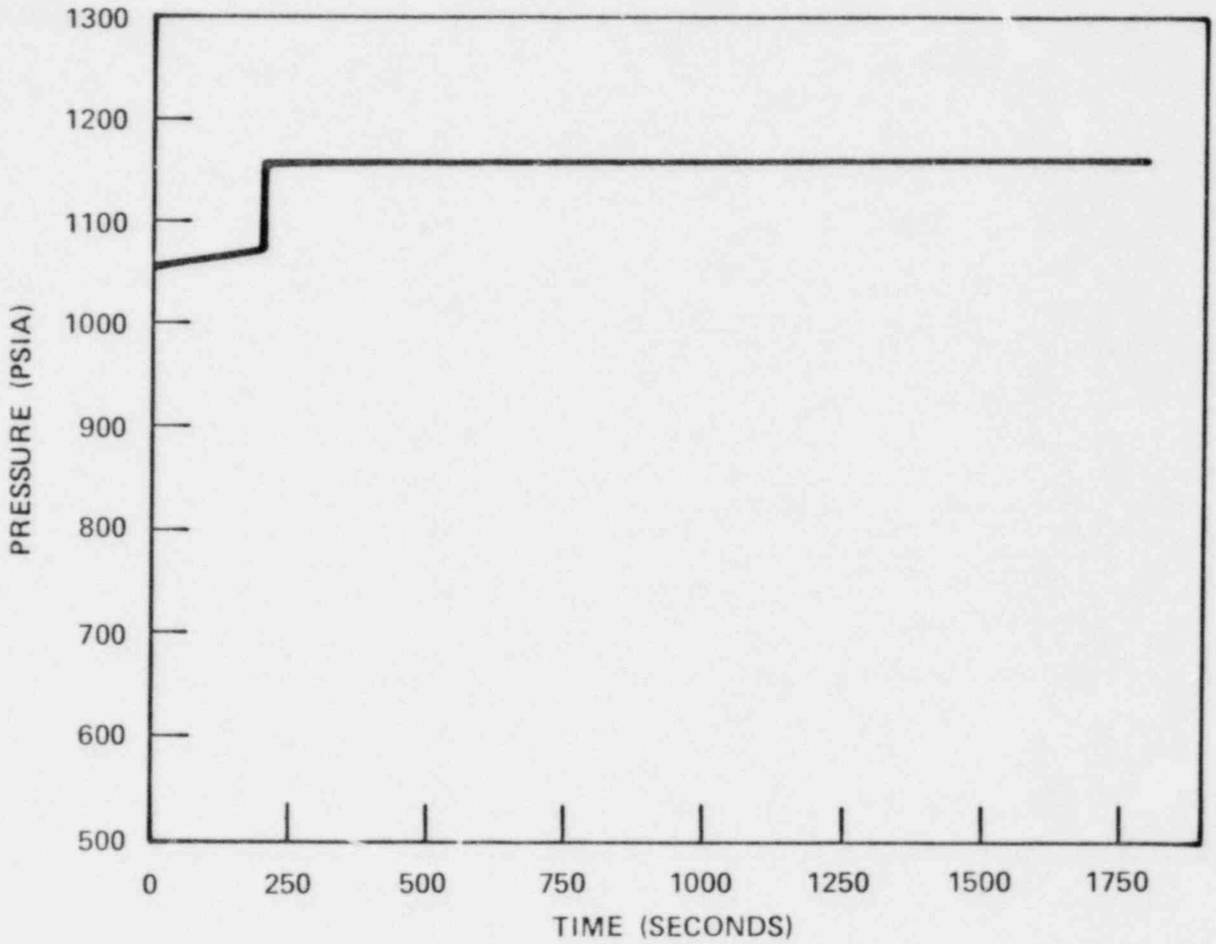

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Figure 15.6-3C.

Faulted Steam Generator Pressure Transient for Steam Generator Tube Rupture Event

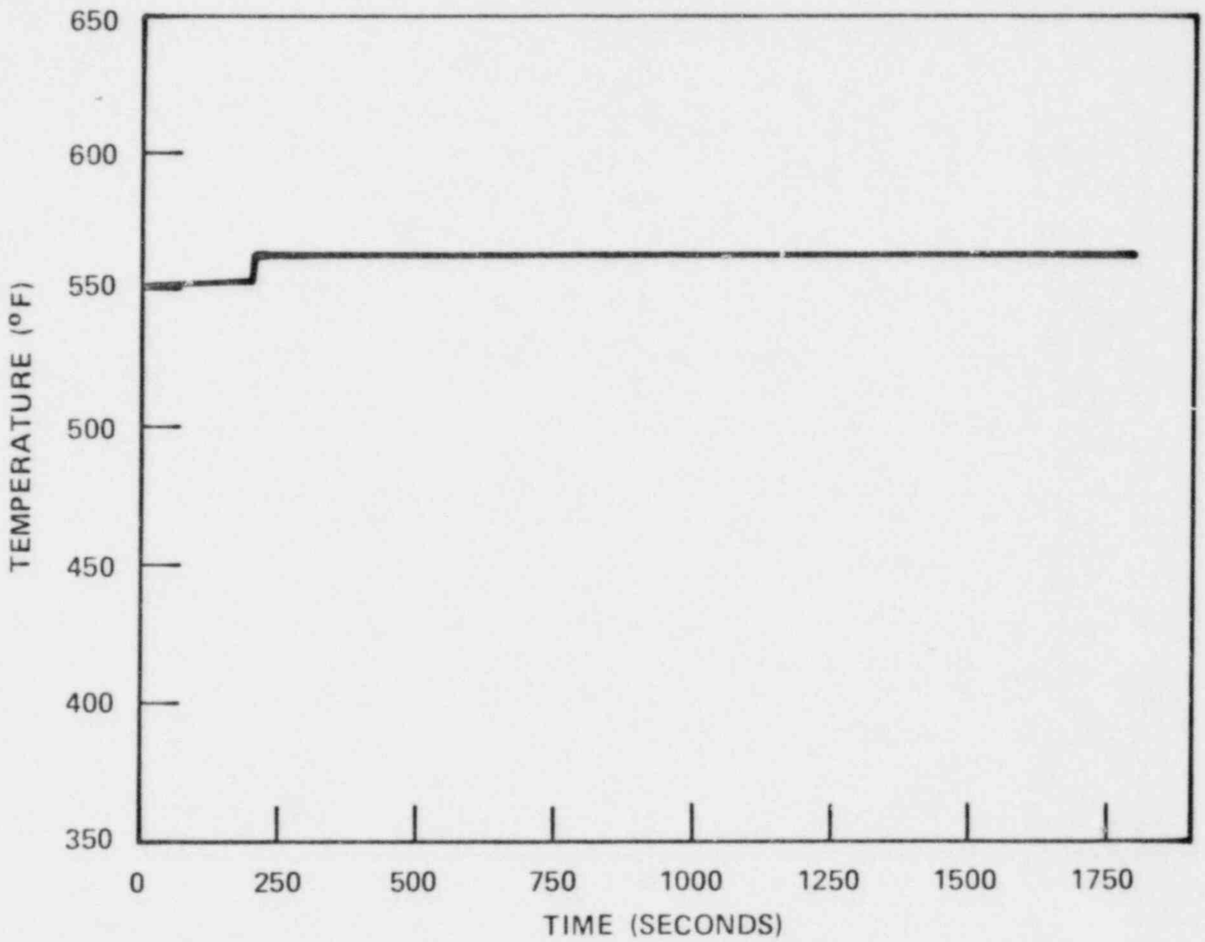

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Figure 15.6-3D.

Faulted Steam Generator Temperature Transient for Steam Generator Tube Rupture Event

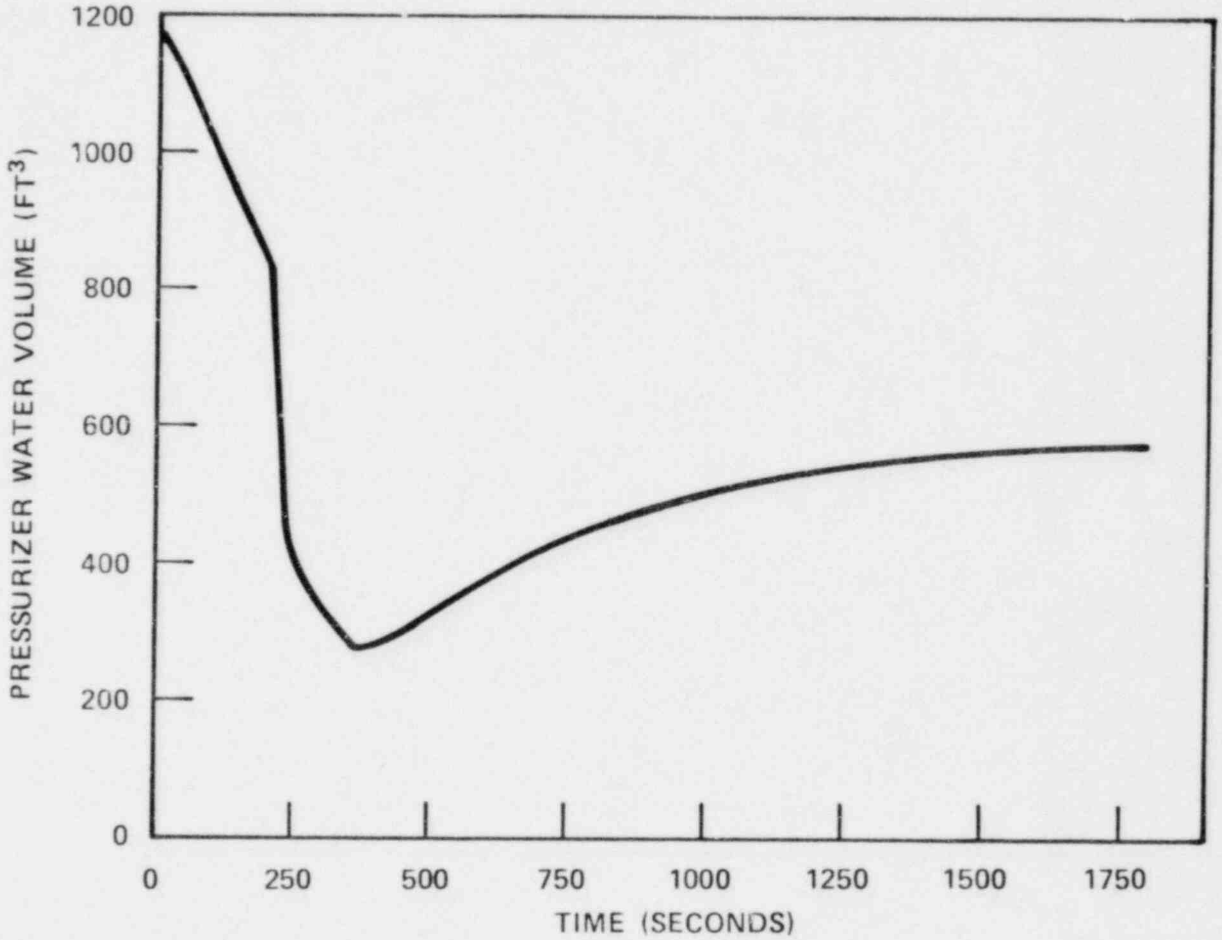

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Figure 1?.6-3E.

Pressurizer Water Volume Transient for Steam Generator Tube Rupture Event

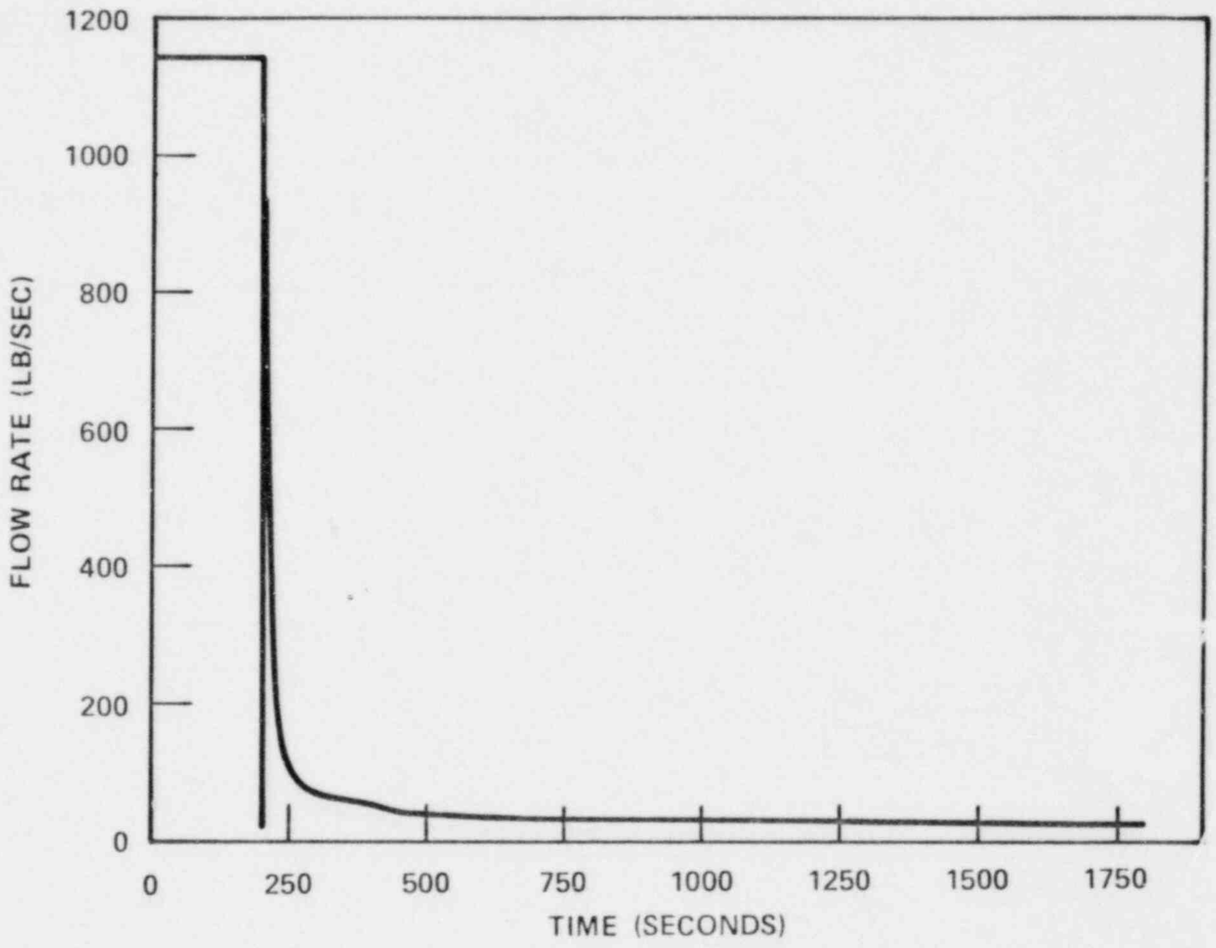

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Figure 15.6-3F.

Faulted Steam Generator Flow Rate Transient for Steam Generator Tube Rupture Event

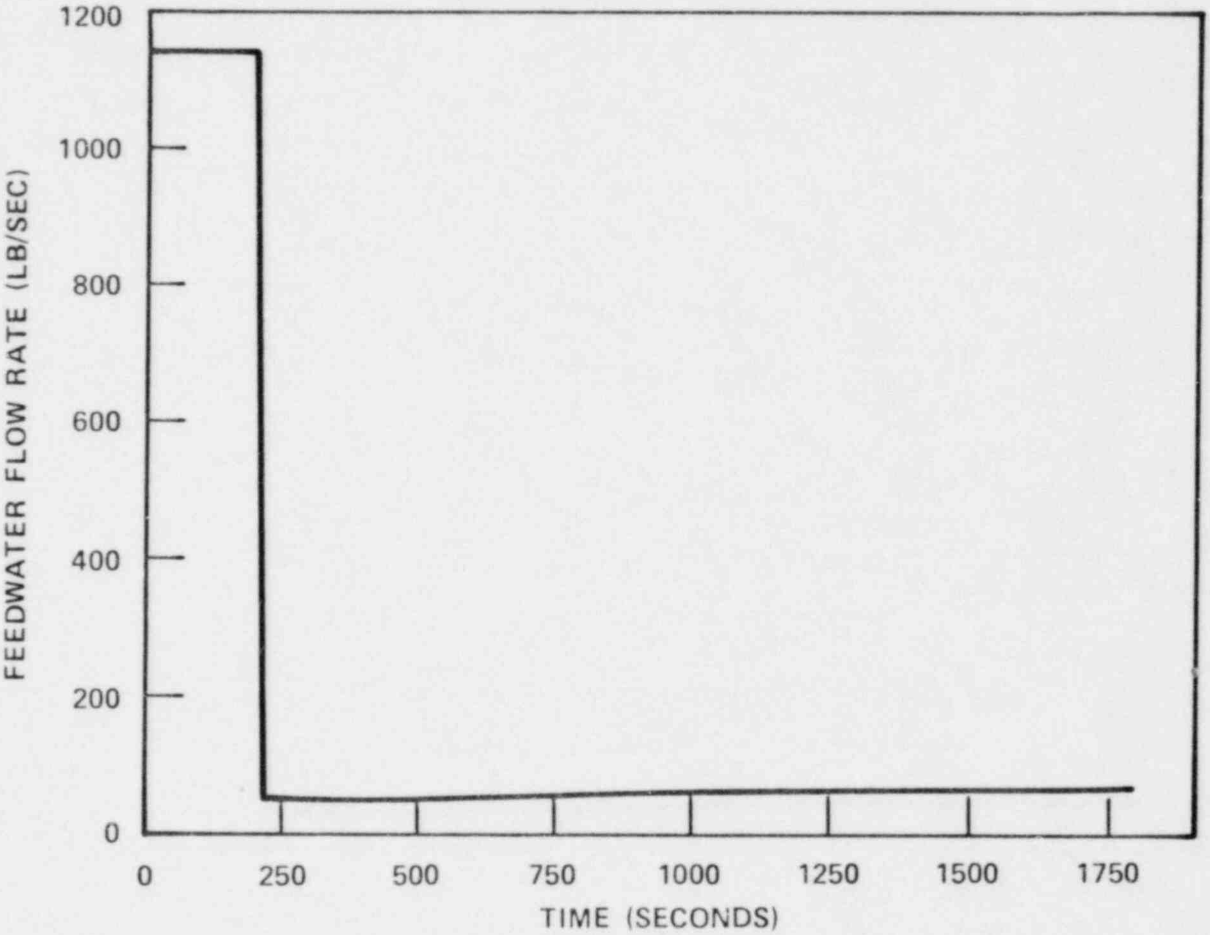

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Figure 15.6-3G.

Feedwater Flow to Faulted Steam Generator* Transient for Steam Generator Tube Rupture Event

*Includes Break Flow

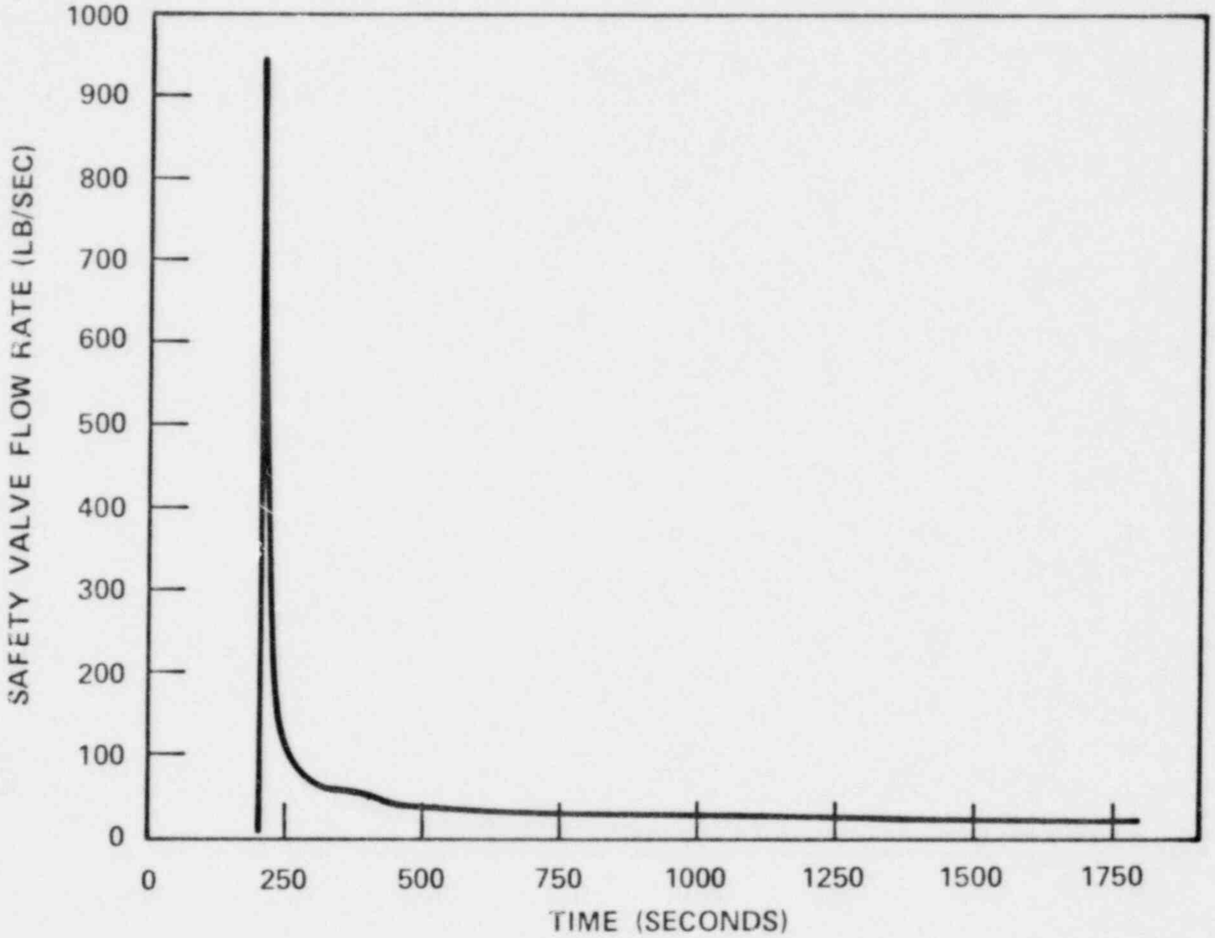

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Figure 15.6-3H.

Faulted Steam Generator Safety/ Relief Valve Flow Rate Transient for Steam Generator Tube Rupture Event

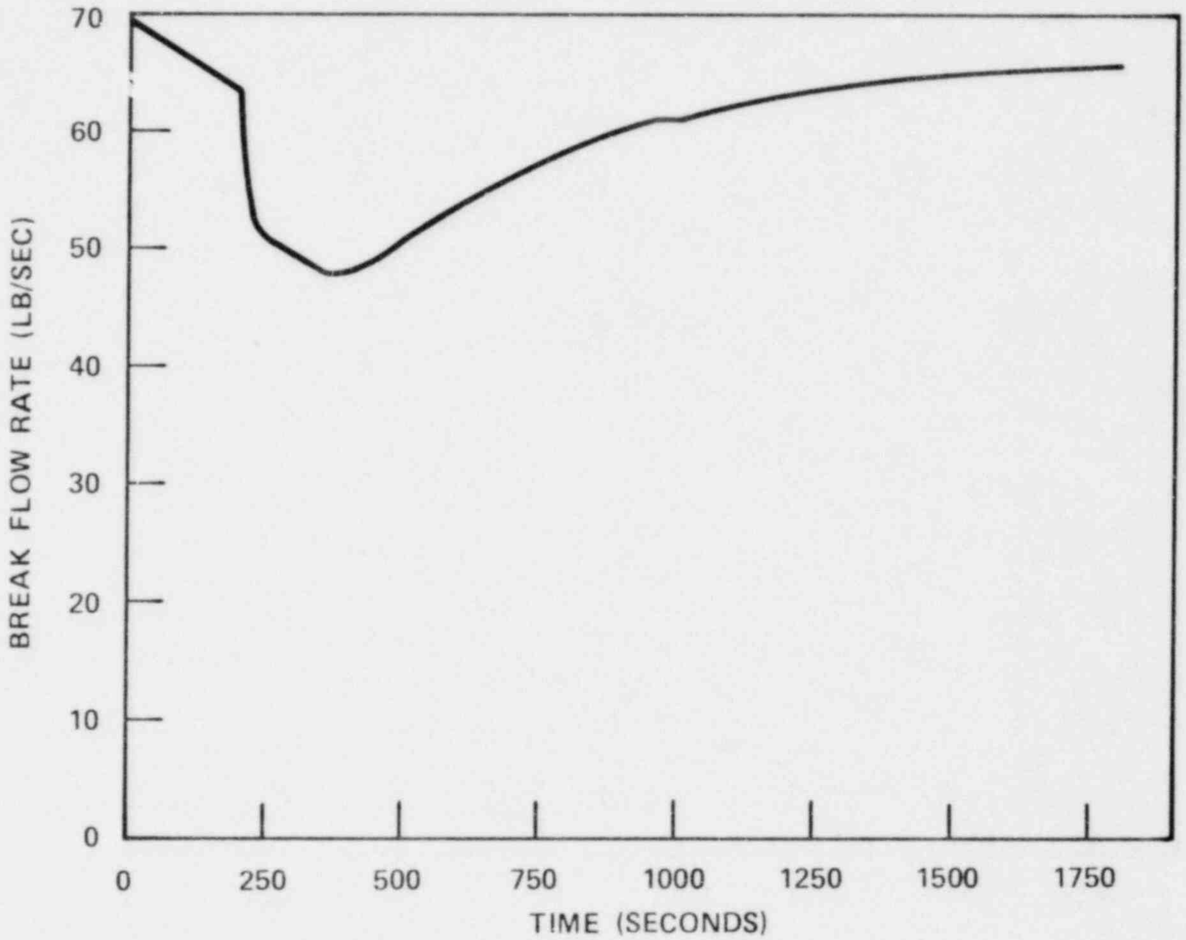

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Figure 15.6-31.

Faulted Steam Generator Break Flow Rate Transient for Steam Generator Tube Rupture Event