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MARGIN TO OVERFILL ANALYSIS FOR A STEAM GENERATOR TUBE RUPTURE FOR MILLSTONE NUCLEAR POWER STATION UNIT 3 FOUR-LOOP OPERATION

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I. INTRODUCTION

An Analysis for a design basis steam generator tube rupture (SGTR) event has been performed for the Millstone Nuclear Power Station Unit 3 to demonstrate margin to steam generator overfill. Millstone Unit 3 employs a Westinghouse pressurized water reactor (PWR) unit rated at 3411 MWt. The reactor coolant system has four reactor coolant loops with Model F steam generators. The SGTR analysis was performed for four-loop operation and is applicable for an uniform steam generator tube plugging level of up to 10 percent*. The SGTR analysis is bounding for operation with a Westinghouse standard fuel core, a Vantage-5H fuel core, or a standard fuel/Vantage-5H fuel transition core installed with a positive moderator temperature coefficient.

The steam generator tube rupture analysis was performed for Millstone Unit 3 using the methodology developed in WCAP-10698 (Reference 1). This analysis methodology was developed by the SGTR Subgroup of the Westinghouse Owners Group and was approved by the NRC in a Safety Evaluation Report dated March 30, 1987. The LOFTTR2 program, an updated version of the LOFTTR1 program, was used to perform the SGTR analysis for Millstone Unit 3. The LOFTTR1 program was developed as part of the revised SGTR analysis methodology and was used for the SGTR evaluations in Reference 1. However, the LOFTTR1 program was subsequently modified to accommodate steam generator overfill and the revised program, designated as LOFTTR2, was used for the evaluation of the consequences of overfill in WCAP-11002 (Reference 2). The LOFTTR2 program is identical to the LOFTTR1 program, with the exception that the LOFTTR2 program has the additional capability to represent the transition from two regions (steam and water) on the secondary side to a single water region if overfill occurs, and the transition back to two regions again depending upon the calculated secondary conditions. Since the LOFTTR2 program has been validated against the LOFTTR1 program, the LOFTTR2 program is also appropriate for performing licensing basis SGTR analyses.

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* Assumes 10% of steam generator tubes in each generator are plugged and corresponds to the worst plugging level of any steam generator.

Plant response to the SGTR event was modeled using the LOFTTR2 computer code with conservative assumptions of break size and location, condenser availability and initial secondary water mass in the ruptured steam generator. The analysis methodology includes the simulation of the operator actions for recovery from a steam generator tube rupture based on the Millstone Unit 3 Emergency Operating Procedures (EOPs), which were developed from the Westinghouse Owners Group Emergency Response Guidelines (ERGs). The operator action times used for the analysis are based on the results of simulator studies of the SGTR recovery operations which were performed by the Millstone Unit 3 operations personnel using the plant training simulator. Thus, the SGTR analysis is based on the application of the actual plant procedures and operator training.

An SGTR results in the leakage of contaminated reactor coolant into the secondary system and subsequent release of a portion of the activity to the atmosphere, and an analysis is typically performed to assure that the offsite radiation doses resulting from an SGTR are within the allowable guidelines. However, one of the major concerns for an SGTR is the possibility of steam generator overfill since this could potentially result in a significant increase in the offsite radiation doses. Therefore, to ensure that steam generator overfill will not occur for a design basis SGTR for Millstone Unit 3, an analysis was performed to demonstrate margin to steam generator overfill assuming the limiting single failure relative to overfill.

The limiting single failure was assumed to be the [

]a,c

consistent with the methodology in Reference 1. The LOFTTR2 analysis to determine the margin to overfill was performed for the time period from the tube rupture until the primary and secondary pressures are equalized and the break flow is terminated. The water volume in the secondary side of the ruptured steam generator was calculated as a function of time to demonstrate that overfill does not occur. The results of this analysis demonstrate that there is margin to steam generator overfill for a design basis SGTR for Millstone Unit 3.

ANALYSIS

An analysis was performed to determine the margin to steam generator overfill for a design basis SGTR event for four-loop operation for Millstone Unit 3. The analysis was performed using the LOFTTR2 program and the methodology developed in Reference 1. This section includes a discussion of the methods and assumptions used to analyze the SGTR event, as well as the sequence of events for the recovery and the calculated results.

A. <u>Design Basis Accident</u>

The accident modeled is a double-ended break of one steam generator tube located at the top of the tube sheet [ ]^{a,c} The location of the break [ ]^{a,c} It was also assumed that loss of offsite power occurs at the time of reactor trip, and the highest worth control assembly was assumed to be stuck in its fully withdrawn position at reactor trip.

For the three-loop reference plant in WCAP-10698, the most limiting single failure with respect to steam generator overfill was determined to be [ ]^{a,c} The Millstone Unit 3 plant has one main steam pressure relieving valve (MSPRV) and one main steam pressure relieving bypass valve (MSPRBV) for each steam generator. The MSPRVs provide automatic pressure relief capability, but the manual operation of the valves is not seismically qualified. The MSPRBVs do not have automatic pressure relief capability, but provide a safety-grade means for manual steam relief, and were assumed to be used for the plant cooldown. Thus, the equivalent single failure for Millstone Unit 3 would be [ ]^{a,c} However, based on previous sensitivity studies for four-loop plants, the limiting single failure may be [

] a,c

The Millstone Unit 3 AFW system consists of two motor-driven pumps, and one turbine-driven pump with a capacity equal to the combined capacity of the two motor-driven pumps. Each motor-driven pump normally feeds two steam generators and the turbine-driven pump feeds all four steam generators. There are two AFW flow control valves for each steam generator, one in the flow path from the motor-driven pump and one in the flow path from the turbine-driven pump. There is also an isolation valve in series with the control valve in each AFW flow path. The AFW flow control and isolation valves would be normally open and the flow control valves are used to terminate feedwater flow to the ruptured steam generator and control inventory in the intact steam generators. However, when isolating the AFW flow to the ruptured steam generator, the operator would first close the flow control valve in each of the flow paths to the ruptured steam generator, and then if the flow does not decrease, the operator would immediately close the corresponding isolation valve. Thus, a single failure of a ruptured steam generator flow control valve to close would not require significant additional time to terminate AFW flow to the ruptured steam generator. Since a single failure of an AFW flow control valve is not limiting, the single failure was assumed to be [

] a,c

This failure increases the time required to perform the RCS cooldown, which results in additional primary to secondary leakage and decreases the margin to steam generator overfill.

B. Conservative Assumptions

Sensitivity studies were performed previously to identify the initial plant conditions and analysis assumptions which are conservative relative to steam generator overfill, and the results of these studies were reported in Reference 1. The conservative conditions and assumptions which were used in Reference 1 were also used in the LOFTTR2 analysis to determine the margin to steam generator overfill for Millstone Unit 3 with the exception of the following differences.

1. <u>Reactor Trip and Turbine Runback</u>

A turbine runback can either be initiated automatically or the operator can manually reduce the turbine load following an SGTR to attempt to prevent a reactor trip. For the reference plant analysis in WCAP-10698, reactor trip was calculated to occur at approximately [ ]^{a,c} and turbine runback to [ ]^{a,c} was simulated based on a runback rate of [ ]^{a,c} The effect of turbine runback was conservatively simulated by [ ]^{a,c} However, if reactor trip occurs prior to [ ]^{a,c} turbine runback to [ ]^{a,c} would not be possible. It is noted that earlier reactor trip will result in earlier initiation of primary to secondary break flow accumulation in the ruptured steam generator and earlier initiation of AFW flow. These effects will result in an increased secondary mass in the ruptured steam generator at the time of isolation since the isolation is assumed to occur at a fixed time after the SGTR occurs rather than at a fixed time after reactor trip. It would be overly conservative to include the simulation of turbine runback to [ ]^{a,c} in addition to the penalty in secondary mass due to earlier reactor trip. Thus, for this analysis, the time of reactor trip was determined by modeling the Millstone Unit 3 reactor protection system, and turbine runback was simulated [ ]^{a,c}

2. <u>Steam Generator Secondary Mass</u>

A [ ]a,c initial secondary water mass in the ruptured steam generator was determined by Reference 1 to be conservative for overfill. As noted above, turbine runback was assumed to be initiated and was simulated by [ ]a,c The initial steam generator total fluid mass was conservatively assumed to be [ ]a,c

3. <u>AFW System Operation</u>

For the reference plant analysis in WCAP-10698, reactor trip occurred on [ ]a,c after the SGTR, and SI was initiated on low pressurizer pressure at [ ]a,c after reactor trip. The reactor and turbine trip and the assumed concurrent loss of offsite power will result in the termination of main feedw flow and actuation of the AFW system. The SI signal will also result in automatic isolation of the main feedwater system and actuation of the AFW system. The flow from the turbine-driven AFW pump will be available within approximately 10 seconds following the actuation signal, but the flow from the motor-driven AFW pumps will not be available until approximately 60 seconds due to the startup and load sequencing for the emergency diesel generators. For the reference plant analysis, it was assumed that AFW flow from both the turbine and motor-driven pumps is initiated [ ]a,c The total AFW flow from all of the AFW pumps was assumed to be distributed uniformly to each of the steam generators until operator actions are simulated to throttle AFW flow to control steam generator water level in accordance with the emergency procedures.

It is noted that if reactor trip occurs on [ ]a,c the pressure at the time of reactor trip may be significantly higher than the SI initiation setpoint. In this event, there may be a significant time delay between reactor trip and SI initiation, and it would not be conservative to model the [ ]a,c. Thus, for this analysis, the time of reactor trip was determined by modeling the Millstone Unit 3 reactor protection system, and the actuation of the AFW system was based on the [ ]a,c It was assumed that flow from both the turbine and motor-driven AFW pumps is initiated at [ ]a,c A conservatively high AFW flow rate of 300 gpm per steam generator was assumed for the analysis since cavitating venturi flow elements are provided in the AFW supply lines to each steam generator which limit the flow to less than this value.

4. Instrument Uncertainties

Instrument uncertainties have been included as a part of the analysis assumptions where they produce conservative results. Analysis results should be reviewed if the uncertainties for the instruments used in the steam generator tube rupture analysis increases.

C. Operator Action Times

In the event of an SGTR, the operator is required to take actions to stabilize the plant and terminate the primary to secondary leakage. The operator actions for SGTR recovery are provided in Millstone Unit 3 EOP 35E-3 which is based on the Westinghouse Owners Group ERG E-3, and these actions were explicitly modeled in this analysis. The operator actions modeled include identification and isolation of the ruptured steam generator, cooldown and depressurization of the RCS to restore inventory, and termination of SI to stop primary to secondary leakage. These operator actions are described below.

1. Identify the ruptured steam generator.

   High secondary side activity, as indicated by the main steamline radiation monitors, condenser air ejector radiation monitor, or steam generator blowdown radiation monitors typically will provide the first indication of an SGTR event. The ruptured steam generator can be identified by an unexpected increase in steam generator level, or a high radiation indication from a steam generator sample, a main steamline, or steam generator blowdown line. For an SGTR that results in a reactor trip at high power as assumed in this analysis, the steam generator water level as indicated on the water level instrumentation will decrease significantly for all of the steam generators. The AFW flow will begin to refill the steam generators, distributing approximately equal flow to each of the steam generators. Since primary to secondary leakage adds additional liquid inventory to the ruptured steam generator, the water level in that steam generator will increase more rapidly. This response, as indicated by the steam generator water level instrumentation, provides confirmation of an SGTR event and also identifies the ruptured steam generator.

2. Isolate the ruptured steam generator from the intact steam generators and isolate feedwater to the ruptured steam generator.

   Once a tube rupture has been identified, recovery actions begin by isolating steam flow from and stopping feedwater flow to the ruptured steam generator. In addition to minimizing radiological releases, this also reduces the possibility of overfilling the ruptured steam generator with water by 1) minimizing the accumulation of feedwater flow and 2) enabling the operator to establish a pressure differential between the ruptured and intact steam generators as a necessary step toward terminating primary to secondary leakage. In the Millstone Unit 3 EOP for steam generator tube rupture recovery, the operator is directed to isolate feed flow to the ruptured steam generator when the wide range level is greater than 58%. For the Millstone Unit 3 SGTR analysis, it was assumed that the ruptured steam generator will be isolated when the steam generator wide range level reaches 58% or at the time determined from simulator studies, whichever is longer.

3. Cool down the Reactor Coolant System (RCS) using the intact steam generators.

   After isolation of the ruptured steam generator, the RCS is cooled as rapidly as possible to less than the saturation temperature corresponding to the ruptured steam generator pressure by dumping steam from only the intact steam generators. This ensures adequate subcooling in the RCS after depressurization to the ruptured steam generator pressure in subsequent actions. If offsite power is available, the normal steam dump system to the condenser can be used to perform this cooldown. However, if offsite power is lost, the RCS is cooled using the MSPRBVs on the intact steam generators. Since offsite power is assumed to be lost at reactor trip for this analysis, the cooldown was performed by dumping steam via the MSPRBVs on the intact steam generators.

4. Depressurize the RCS to restore reactor coolant inventory.

   When the cooldown is completed, SI flow will increase RCS pressure until break flow matches SI flow. Consequently, SI flow must be terminated to stop primary to secondary leakage. However, adequate reactor coolant inventory must first be assured. This includes both sufficient reactor coolant subcooling and pressurizer inventory to maintain a reliable pressurizer level indication after SI flow is stopped. Since leakage from the primary side will continue after SI flow is stopped until RCS and ruptured steam generator pressures equalize, an "excess" amount of inventory is needed to ensure pressurizer level remains on span. The "excess" amount required depends on RCS pressure and reduces to zero when RCS pressure equals the pressure in the ruptured steam generator.

The RCS depressurization is performed using normal pressurizer spray if the reactor coolant pumps (RCPs) are running. However, since offsite power is assumed to be lost at the time of reactor trip, the RCPs are not running and thus normal pressurizer spray is not available. In this event, RCS depressurization can be performed using the pressurizer PORVs or auxiliary pressurizer spray. Because the pressurizer PORVs are the preferred alternative, it was assumed that a pressurizer PORV is used for the RCS depressurization for this analysis.

5. Terminate SI to stop primary to secondary leakage.

   The previous actions will have established adequate RCS subcooling, a secondary side heat sink, and sufficient reactor coolant inventory to ensure that SI flow is no longer needed. When these actions have been completed, SI flow must be stopped to terminate primary to secondary leakage. Primary to secondary leakage will continue after SI flow is stopped until the RCS and ruptured steam generator pressures equalize. Charging flow, letdown, and pressurizer heaters will then be controlled to prevent repressurization of the RCS and reinitiation of leakage into the ruptured steam generator.

Since these major recovery actions are modeled in the SGTR analysis, it is necessary to establish the times required to perform these actions. Although the intermediate steps between the major actions are not explicitly modeled, it is also necessary to account for the time required to perform the steps. It is noted that the total time required to complete the recovery operations consists of both operator action time and system, or plant, response time. For instance, the time for each of the major recovery operations (i.e., RCS cooldown) is primarily due to the time required for the system response, whereas the operator action time is reflected by the time required for the operator to perform the intermediate action steps.

The operator action times to identify and isolate the ruptured steam generator, to initiate RCS cooldown, to initiate RCS depressurization, and to perform safety injection termination were developed in Reference 1 for the design basis analysis. Northeast Utilities has performed simulator studies to determine the corresponding operator action times to perform these operations for Millstone Unit 3. The operator actions and the corresponding operator action times used for the Millstone Unit 3 analysis are listed in Table 1. These operator action times represent bounding times for a typical operations crew.

D. Transient Description

The LOFTTR2 analysis results for the margin to overfill analysis are described below. The sequence of events for this transient is presented in Table 2.

Following the tube rupture, reactor coolant flows from the primary into the secondary side of the ruptured steam generator since the primary pressure is greater than the steam generator pressure. In response to this loss of reactor coolant, pressurizer level decreases as shown in Figure 1. The RCS pressure also decreases as shown in Figure 2 as the steam bubble in the pressurizer expands. As the RCS pressure decreases due to the continued primary to secondary leakage, automatic reactor trip occurs at approximately 110 seconds on an overtemperature delta-T trip signal.

After reactor trip, core power rapidly decreases to decay heat levels. The turbine stop valves close and steam flow to the turbine is terminated. The steam dump system is designed to actuate following reactor trip to limit the increase in secondary pressure, but the steam dump valves remain closed due to the loss of condenser vacuum resulting from the assumed loss of offsite power at the time of reactor trip. Thus, the energy transfer from the primary system causes the secondary side pressure to increase rapidly after reactor trip until the steam generator MSPRVs (and safety valves if their setpoints are reached) lift to dissipate the energy, as shown in Figure 3. The main feedwater flow will be terminated and AFW flow will be automatically initiated following reactor trip and the loss of offsite power.

The RCS pressure and pressurizer level continue to decrease after reactor trip as energy transfer to the secondary shrinks the reactor coolant and the tube rupture break flow continues to deplete primary inventory. The decrease in RCS inventory results in a low pressurizer pressure SI signal at approximately 338 seconds. After SI actuation, the SI flow rate initially exceeds the tube rupture break flow rate, and the RCS pressure and pressurizer level begin to increase and trend toward the equilibrium values where the SI flow rate equals the break flow rate.

Since offsite power is assumed lost at reactor trip, the RCPs trip and a gradual transition to natural circulation flow occurs. Immediately following reactor trip the temperature differential across the core decreases as core power decays (see Figure 4); however, the temperature differential subsequently increases as the reactor coolant pumps coast down and natural circulation flow develops. The increase in the temperature differential slows the rate of the pressurizer level and pressure decrease as shown in Figures 1 and 2, respectively. The cold leg temperatures initially trend toward the steam generator temperature as the fluid residence time in the tube region increases. The RCS hot and cold leg temperatures then slowly decrease due to the continued addition of the auxiliary feedwater to the steam generators until operator actions are initiated to control the auxiliary feedwater flow.

Major Operator Actions

1. Identify and Isolate the Ruptured Steam Generator

   Once a tube rupture has been identified, recovery actions begin by isolating steam flow from the ruptured steam generator and isolating the auxiliary feedwater flow to the ruptured steam generator. As indicated previously, it is assumed that the ruptured steam generator will be identified and isolated when the wide range level reaches 58% on the ruptured steam generator or at 16.5 minutes after initiation of the SGTR, whichever is longer. For the Millstone Unit 3 analysis, the time to reach a wide range level of 58% is less than 16.5 minutes, and thus it was assumed that the actions to isolate the ruptured steam generator are performed at 16.5 minutes. The actual time used in the analysis is 2 seconds longer because of the computer program numerical requirements for simulating the operator actions.

2. Cool Down the RCS to Establish Subcooling Margin

   After isolation of the ruptured steam generator is completed at 992 seconds, an 8 minute operator action time is imposed prior to initiating the cooldown. After this time, actions are taken to cool the RCS as rapidly as possible by dumping steam from the intact steam generators. Since offsite power is lost, the RCS is cooled by dumping steam to the atmosphere using the MSPRBVs on the intact steam generators. As noted previously, the limiting single failure was assumed to [

   ]a,c Thus, it was assumed that [

   ]a,c are opened for the RCS cooldown. [

]a,c was assumed to be opened at 1474 seconds and [ ]a,c was assumed to be opened at 1476 seconds. The cooldown is continued until RCS subcooling at the ruptured steam generator pressure is 20°F plus an allowance of 30°F for subcooling uncertainty. When these conditions are satisfied at 2300 seconds, it is assumed that the operator closes the intact steam generator MSPRBVs to terminate the cooldown. This cooldown ensures that there will be adequate subcooling in the RCS after the subsequent depressurization of the RCS to the ruptured steam generator pressure. The reduction in the intact steam generator pressures required to accomplish the cooldown is shown in Figure 3, and the effect of the cooldown on the RCS temperature is shown in Figure 4. As shown in Figure 2, the RCS pressure also decreases during this cooldown process due to shrinkage of the reactor coolant, and then begins to increase due to the increased SI flow after the cooldown is terminated.

3. Depressurize RCS to Restore Inventory

After the RCS cooldown, a 3 minute operator action time is included prior to the RCS depressurization. The actual delay time used in the Analysis is 3 minutes and 4 seconds because of the computer program limitations for simulating operator actions. The RCS depressurization is performed to assure adequate coolant inventory prior to terminating SI flow. With the RCPs stopped, normal pressurizer spray is not available and thus the RCS is depressurized by using a pressurizer PORV. The RCS depressurization is initiated at 2484 seconds and continued until any of the following conditions are satisfied: RCS pressure is less than the ruptured steam generator pressure and pressurizer level is greater than the allowance of 13% for pressurizer level uncertainty, or pressurizer level is greater than 73%, or RCS subcooling is less than the 30°F allowance for subcooling uncertainty. For this case, the RCS depressurization is terminated because the RCS pressure is reduced to less than the ruptured steam generator pressure and the pressurizer level is greater than 13%. The RCS depressurization reduces the break flow as shown in Figure 5, and increases SI flow to refill the pressurizer as shown in Figure 1.

4. Terminate SI to Stop Primary to Secondary Leakage

The previous actions have established adequate RCS subcooling, verified a secondary side heat sink, and restored the reactor coolant inventory to ensure that SI flow is no longer needed. When these actions have been completed, the SI flow must be stopped to prevent repressurization of the RCS and to terminate primary to secondary leakage. The SI flow is terminated at this time if RCS subcooling is greater than the 30°F allowance for subcooling uncertainty, minimum AFW flow is available or at least one intact steam generator level is in the narrow range, the RCS pressure is increasing, and the pressurizer level is greater than the 13% allowance for uncertainty.

After depressurization is completed, an operator action time of 3 minutes was assumed prior to SI termination. Since the above requirements are satisfied, SI termination was performed at this time. An additional 2 second delay was also assumed due to the computer program limitations in simulating the operator actions. After SI termination at 2794 seconds, the RCS pressure begins to decrease as shown in Figure 2. The RCS temperatures also begin to increase and the intact steam generator MSPRBVs are opened to dump steam to maintain the prescribed RCS temperature to ensure that subcooling is maintained. When the MSPRBVs are opened, the increased energy transfer from primary to secondary also aids in the depressurization of the RCS to the ruptured steam generator pressure. The primary to secondary leakage continues after the SI flow is terminated until the RCS and ruptured steam generator pressures equalize.

The primary to secondary break flow rate throughout the recovery operations is presented in Figure 5. The water volume in the ruptured steam generator is presented as a function of time in Figure 6. It is noted that the water volume in the ruptured steam generator when the break flow is terminated is approximately 5496 ft^3, which is significantly less than the total steam generator volume of 5850 ft^3. Therefore, it is concluded that overfill of the ruptured steam generator will not occur for a design basis SGTR for Millstone Unit 3.

III. CONCLUSION

An analysis has been performed for a design basis SGTR event for four-loop operation for Millstone Unit 3 to demonstrate margin to steam generator overfill assuming the limiting single failure relative to overfill. The limiting single failure is the failure of [ ][a,c] The results of this analysis indicate that the recovery actions can be completed to terminate the primary to secondary break flow before overfill of the ruptured steam generator would occur.

Thus, it is concluded that margin to steam generator overfill exists for a design basis steam generator tube rupture for four-loop operation at Millstone Unit 3.

IV. REFERENCES

1. Lewis, Huang, Behnke, Fittante, Gelman, "SGTR Analysis Methodology to Determine the Margin to Steam Generator Overfill," WCAP-10698-P-A [PROPRIETARY]/WCAP-10750-A [NON-PROPRIETARY], August 1987.

2. Lewis, Huang, Rubin, Murray, Roidt, Hopkins, "Evaluation of Steam Generator Overfill Due to a Steam Generator Tube Rupture Accident," WCAP-11002 [PROPRIETARY]/WCAP-11003 [NON-PROPRIETARY], February 1986.

Millstone Unit 3 Four-Loop Operation
Steam Generator Tube Rupture
Margin to Overfill Analysis

TABLE 1
OPERATOR ACTION TIMES FOR DESIGN BASIS ANALYSIS

Action	Time
Identify and isolate ruptured SG	16.5 min or LOFTTR2 calculated time to reach 58% wide range level in the ruptured SG, whichever is longer
Operator action time to initiate cooldown	8 min from isolation
Cooldown	Calculated by LOFTTR2
Operator action time to initiate depressurization	3 min from end of c ldown
Depressurization	Calculated by LOFTTR2
Operator action time to initiate SI termination	3 min from end of depressurization
SI termination and pressure equalization	Calculated time after SI termination for equalization of RCS and ruptured SG pressures

Millstone Unit 3 Four-Loop Operation
Steam Generator Tube Rupture
Margin to Overfill Analysis

TABLE 2

SEQUENCE OF EVENTS

EVENT	Time (sec)
SG Tube Rupture	0
Reactor Trip	110
SI Actuation	338
Ruptured SG Isolated	992
RCS Cooldown Initiated	1476
RCS Cooldown Terminated	2300
RCS Depressurization Initiated	2484
RCS Depressurization Terminated	2612
SI Terminated	2794
Steam Relief to Maintain RCS Subcooling	3420
Break Flow Terminated	4040

Millstone Unit 3 Four-Loop Operation
Steam Generator Tube Rupture
Margin to Overfill Analysis

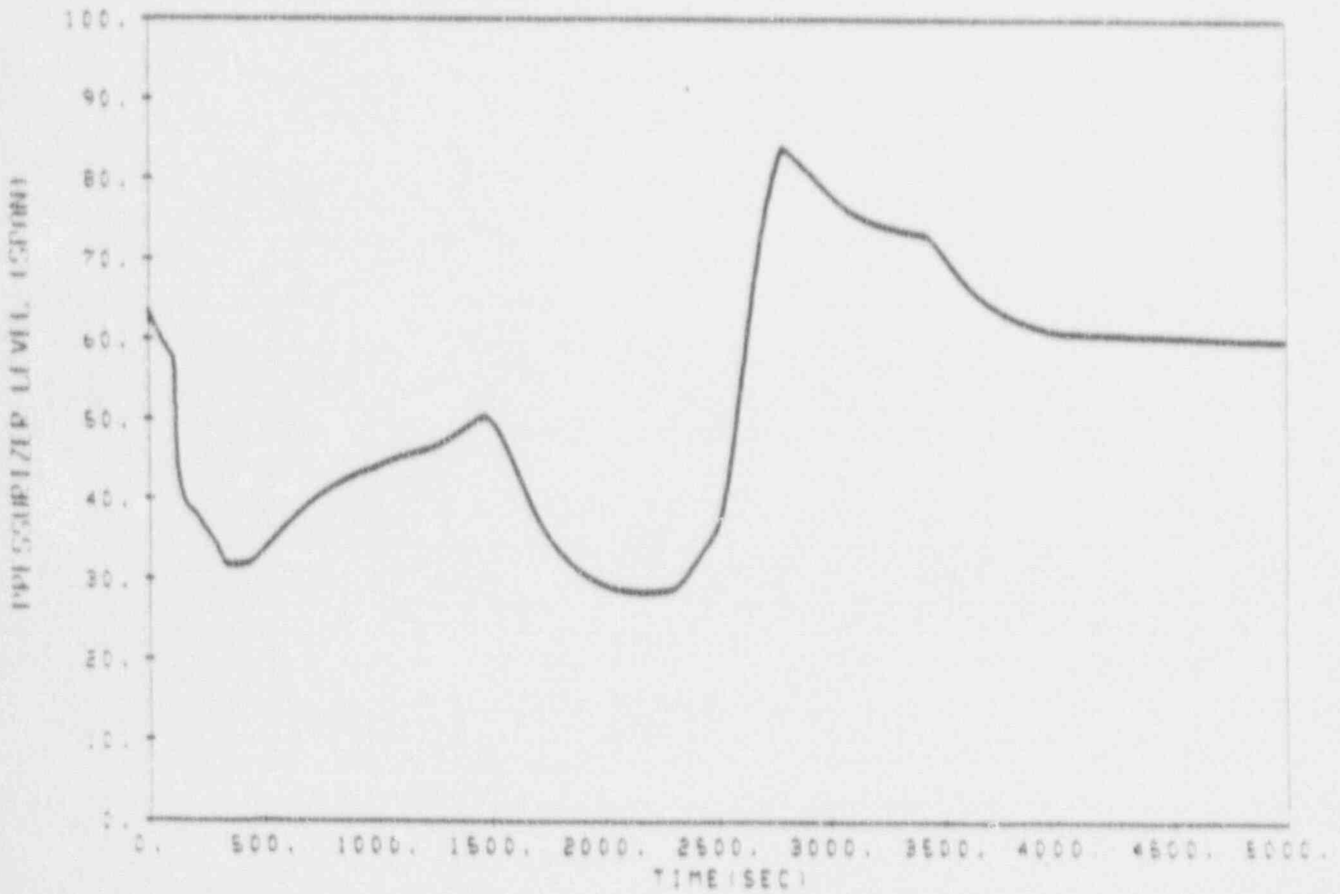

Figure 1 Pressurizer Level

Millstone Unit 3 Four-Loop Operation
Steam Generator Tube Rupture
Margin to Overfill Analysis

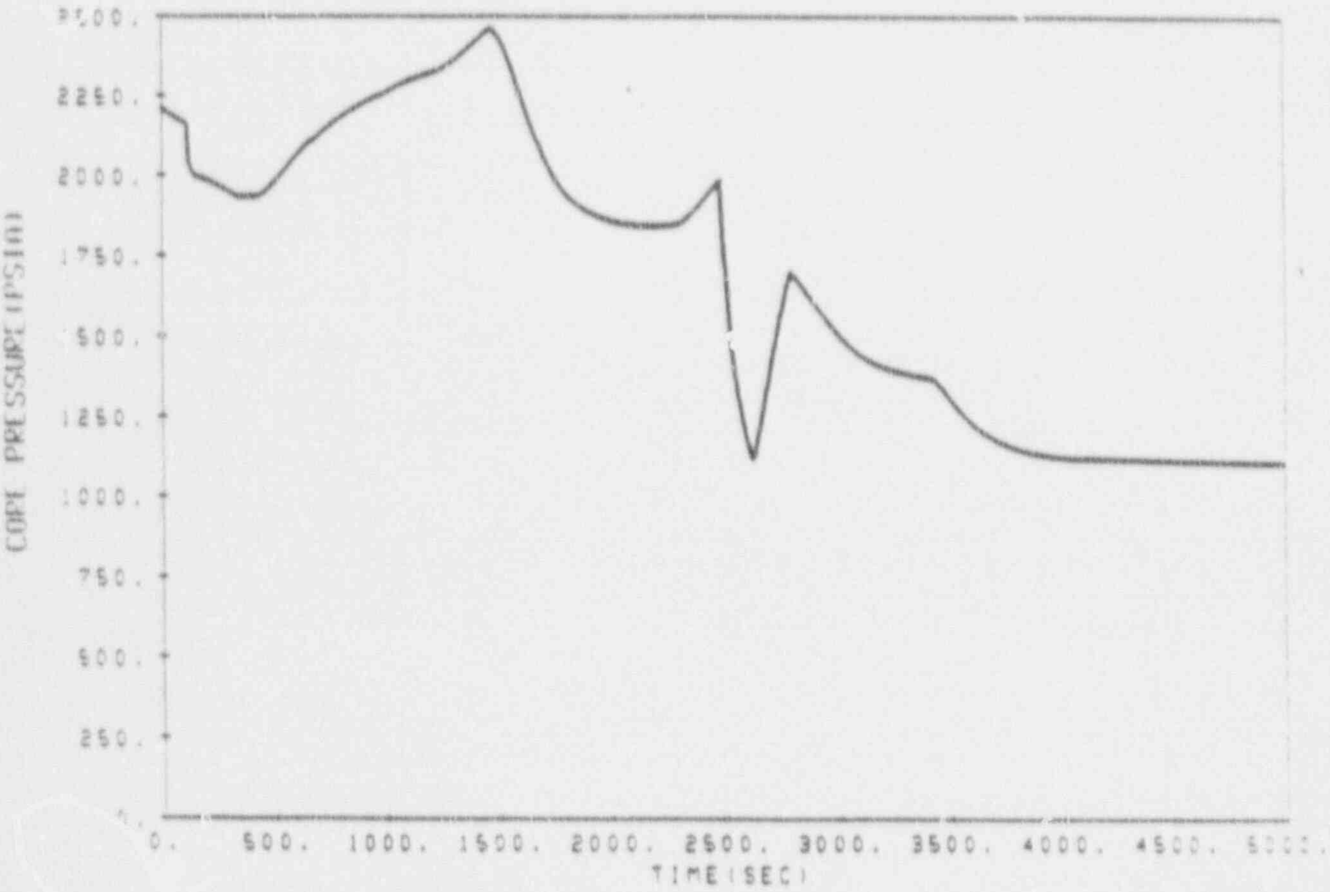

Figure 2 RCS Pressure

Millstone Unit 3 Four-Loop Operation
Steam Generator Tube Rupture
Margin to Overfill Analysis

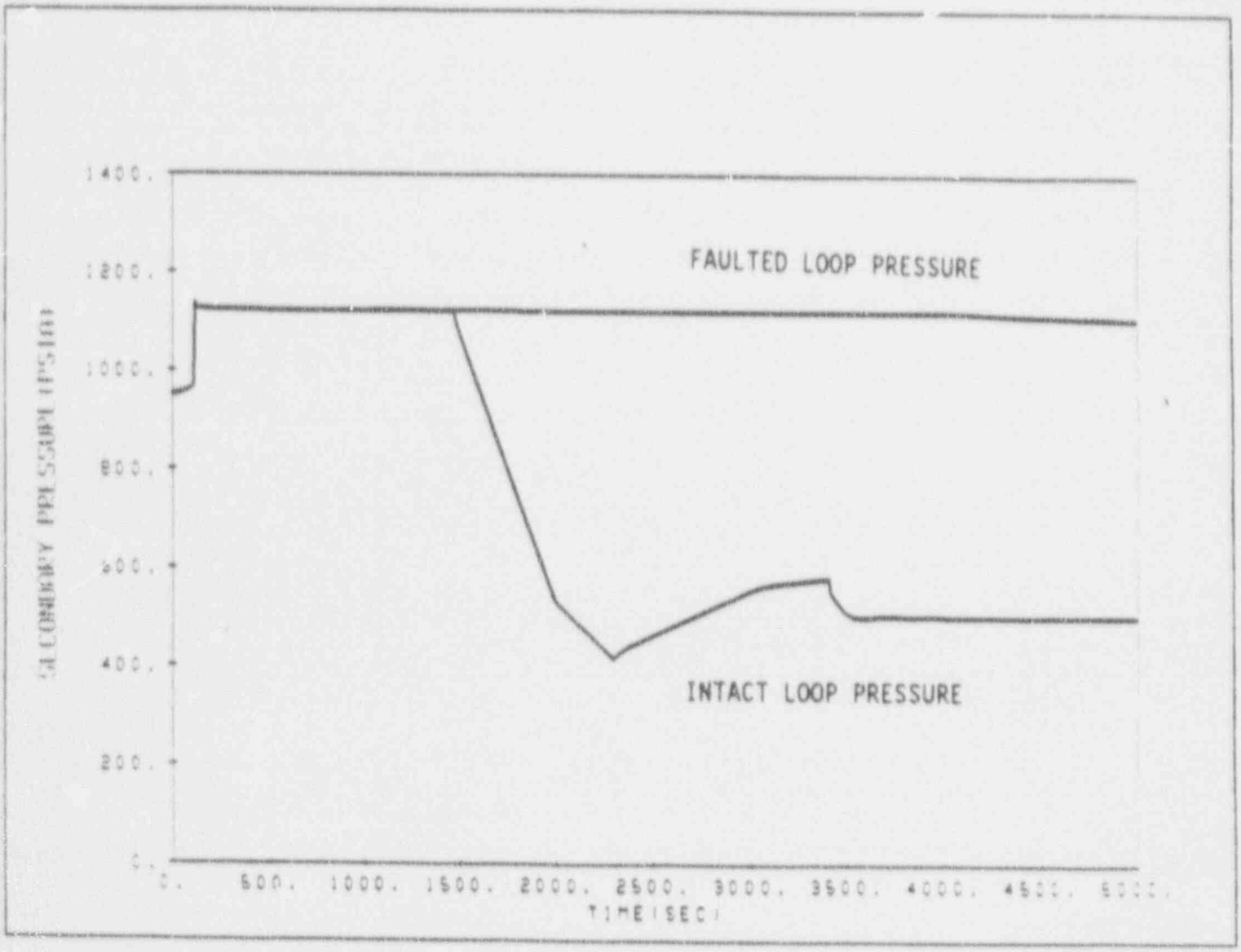

Figure 3 Secondary Pressure

Millstone Unit 3 Four-Loop Operation
Steam Generator Tube Rupture
Margin to Overfill Analysis

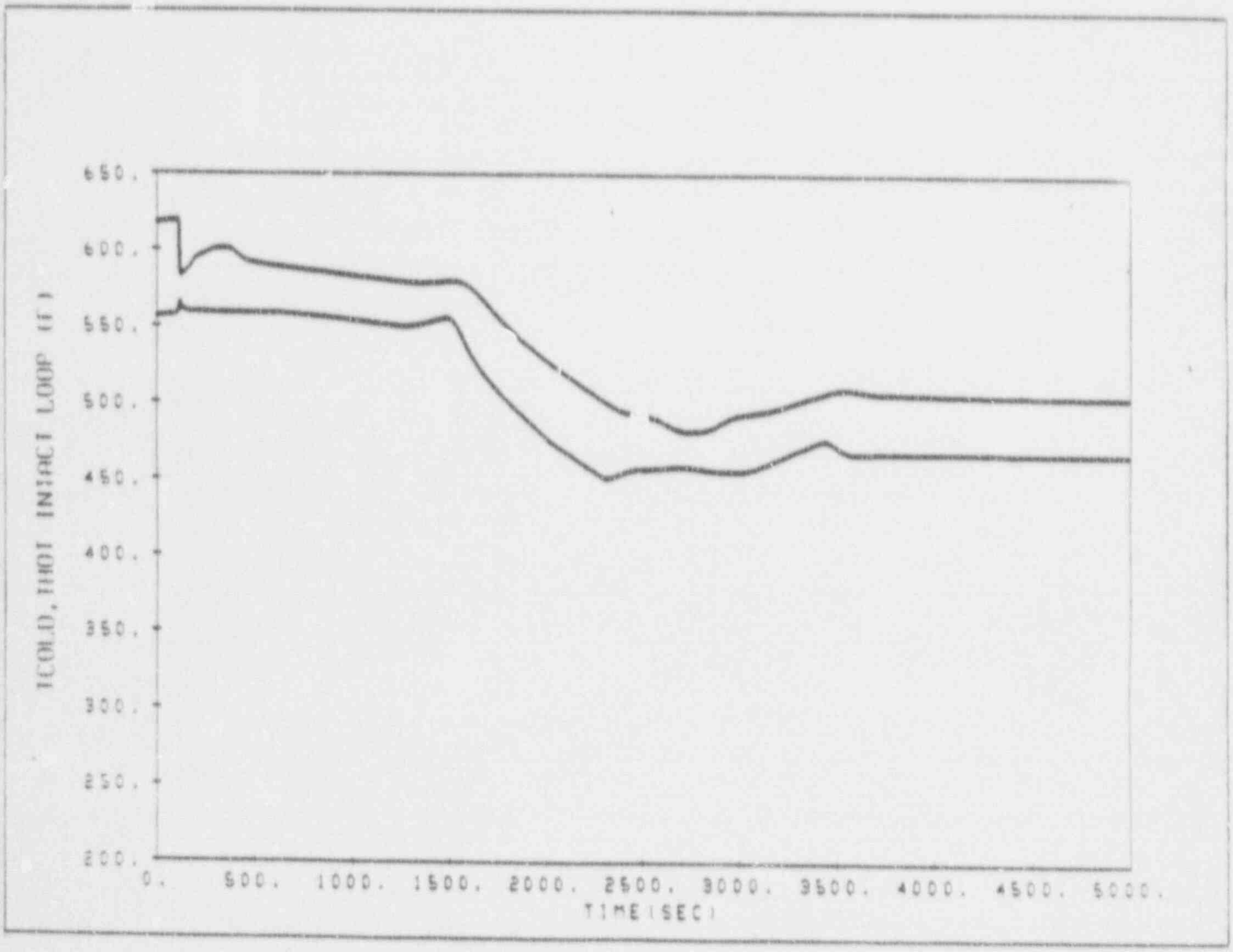

Figure 4 Intact Loop Hot and Cold Leg RCS Temperatures

Millstone Unit 3 Four-Loop Operation
Steam Generator Tube Rupt.
Margin to Overfill Analysis

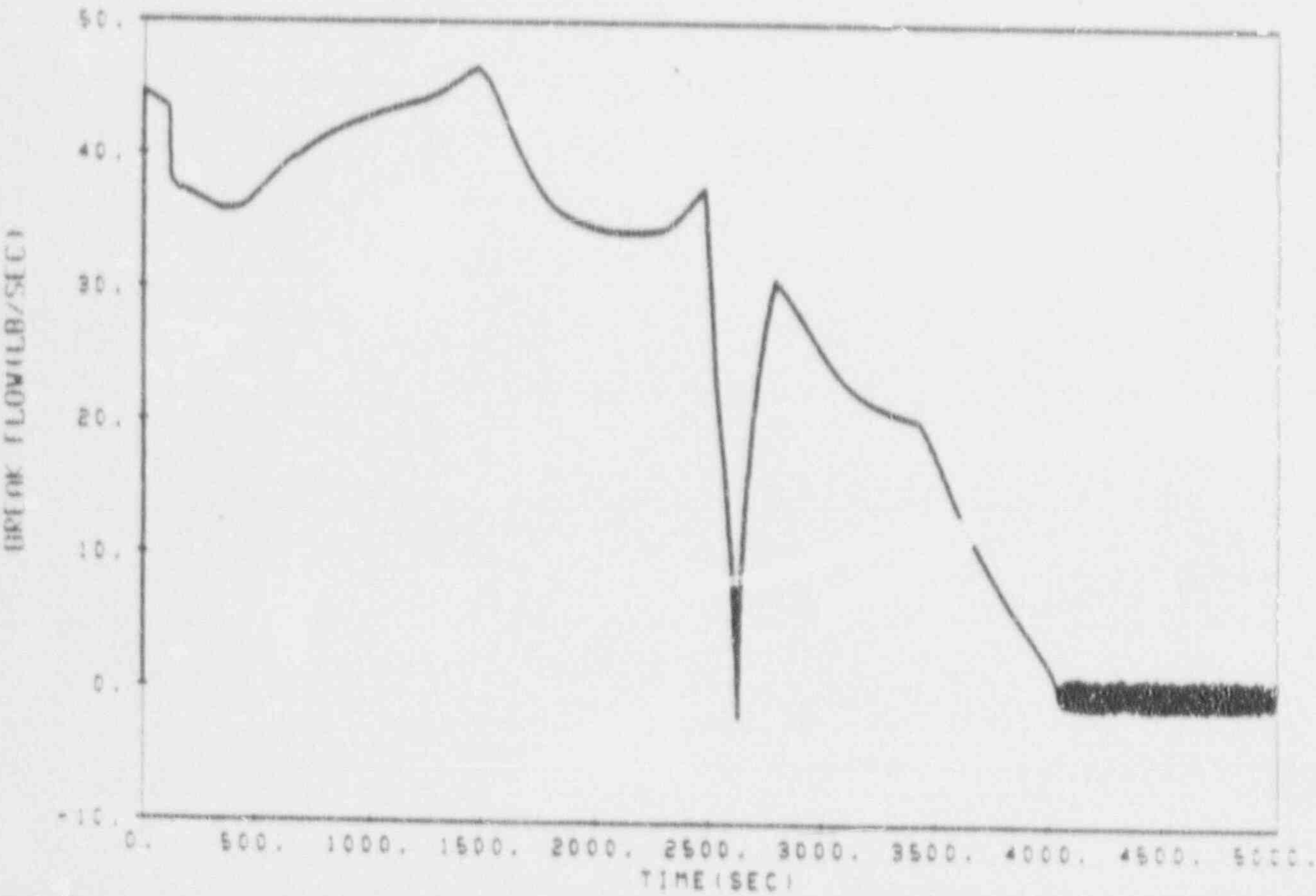

Figure 5 Primary to Secondary Break Flow Rate

Millstone Unit 3 Four-Loop Operation

Steam Generator Tube Rupture

Margin to Overfill Analysis

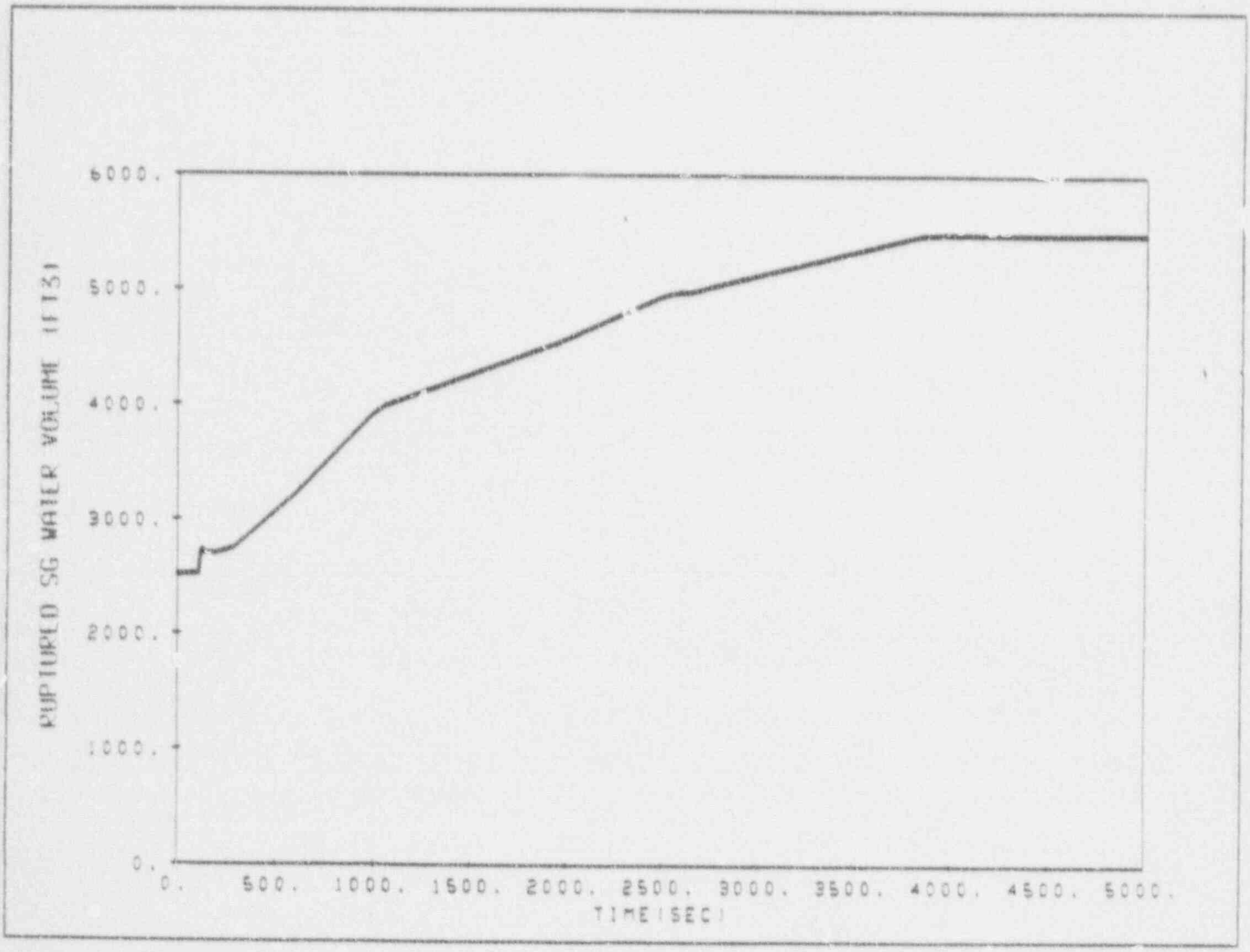

Figure 6 Ruptured SG Water Volume