SNUPPS

Standardized Nuclear Unit Power Plant System

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Nicholas A. Petrick
Executive Director

December 3, 1984

SLNRC 84- 0129 FILE: 0278
SUBJ: Steam Generator Tube Rupture Event

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

Docket No.: STN 50-482 and STN 50-483

Reference:
1. NRC letter (B. Youngblood) to Union Electric Company, and Kansas Gas and Electric Company, dated June 12, 1984: Request for Additional Information - Steam Generator Tube Rupture Event
2. SLNRC 84-0113, dated 9/7/84, Steam Generator Tube Rupture Event
3. SLNRC 84-0044, dated 3/16/84, Steam Generator Tube Rupture Event

Dear Mr. Denton:

Reference 1 requested that additional information be provided by September 13, 1984 to support the NRC staff review of the Steam Generator Tube Rupture (SGTR) event for the SNUPPS plants - Callaway Plant Unit No. 1 and Wolf Creek Generating Station Unit No. 1. Reference 2 stated that a formal submittal would be provided to Reference 1 by November 30, 1984 to facilitate the coordination of SNUPPS activities with other industry SGTR event evaluation efforts.

The enclosure presents the SNUPPS response to Reference 1 and supplements the information provided to the NRC in Reference 3. As a result of the meeting held with the NRC on November 27, 1984, SNUPPS believes that the enclosure addresses the NRC questions transmitted by Reference 1. The results presented in the enclosure have not been independently reviewed and verified and are considered preliminary. As stated in the November 27, 1984 meeting with the NRC, SNUPPS plans to submit to the NRC a confirmatory RETRAN analysis of the worst SGTR case by December 31, 1985.

Very truly yours,

JD Cermak for

Nicholas A. Petrick

JOC/nld15a27
Enclosure
cc: See Page 2

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1/1

cc:	G. L. Koester	KGE
	J. M. Evans	KCPL
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ENCLOSURE

1. Q. Submit SGTR analyses for both the "offsite power available" and "loss of offsite power" (LOOP) cases. Your submittal should contain sufficient backup information to justify the results (e.g. plots or tabulations of pressurizer pressure and level, ruptured steam generator inventory, break flow rate, etc. versus time). List all operator actions credited to mitigate this accident, and justify the operator action times assumed.

A. Two complementary methods of analysis have been utilized to calculate the response of a SNUPPS plant to a postulated steam generator tube rupture (SGTR). The first method utilizes the RETRAN code. It is intended that the RETRAN code be used for reference calculations to be reported in the FSAR. To date the RETRAN model has been used to develop reference data for the primary system during postulated SGTR events. The second method utilizes a special-purpose BASIC program, capable of being run on a personal computer. This method has been normalized to the results of RETRAN analyses and to the FSAR analyses and has been used to calculate the secondary side responses and amounts of radioactive iodine released for a wide range of assumed operator response times and postulated single failures. This method is capable of showing the sensitivities of offsite doses to operator response times and postulated single failures and of identifying the most limiting single failure. Reference calculations for the limiting single failure will ultimately be done using the RETRAN model.

The loss of offsite power (LOOP) case results in more iodine released to the atmosphere and higher offsite doses than the case of offsite power available and, therefore, is the case that has been analyzed more extensively. If offsite power is available, the condenser and steam dump to the condenser are operable and iodine is released to the atmosphere through the condenser air removal filtration system. The overall iodine partitioning factor for this case is at least 100. If offsite power is lost, steam and iodine are released to the atmosphere through the atmospheric relief valve (ARV) and/or steam line safety valves. In this case the iodine partitioning factor is assumed to be unity for the fraction of the break flow that flashes to steam in the steam generator (SG). In addition, in the LOOP case, overfilling of the faulted SG and its steam line may result in the release of water through the ARV and/or safety valves. In this case the iodine partitioning factor is also assumed to be unity.

Results as calculated by RETRAN are used to compare with those given in the SNUPPS FSAR. The analysis utilizes a break flow model determined from the RCS pressure versus break flow as shown in Figure 15.6-3 of the FSAR. The assumptions used in

the analysis are generally identical to that used in the FSAR and briefly described as follows:

1) Reactor trip is set at a time identical to that in the FSAR analysis and loss-of-offsite-power is assumed to occur at the reactor trip.

2) The steam generator pressure is controlled by the set-points associated with the atmospheric relief valve.

3) The safety injection signal is initiated at a low pressurizer pressure setpoint of 1755 psia.

4) Upon receipt of the safety injection signal, the auxiliary feedwater is initiated and its flow is regulated to match the steam flow for all steam generators.

5) Single failure assumption consistent with FSAR (no auxiliary feedwater to faulted steam generator).

Table 1-1.1 of Attachment 1-1* provides a time sequence of events for RETRAN and FSAR analyses.

A noding diagram used by RETRAN to represent various components in the primary and secondary systems is shown in Figure 1-1.1. Plots of parameters as calculated by RETRAN and LOFTRAN for the primary system, faulted and intact steam generators are shown in Figures 1-1.2 through 1-1.7. The water inventories (Figures 1-1.6 and 1-1.7) as calculated by RETRAN in the faulted and intact steam generators agree with those given in the FSAR.

As mentioned above, the break flow is derived from the knowledge of RCS pressure. Therefore, break flows obtained from RETRAN and FSAR analyses are expected to be in close agreement if the corresponding RCS pressures agree. The plots given in Figure 1-1.2 and 1-1.5, however, do not indicate such correspondence. This is primarily due to the break flow model, as mentioned earlier, being merely an approximation.

Figure 1-1.2 indicates that under the RETRAN analysis the initiation of safety injection flow does not repressurize the primary system in as short a period of time as the FSAR analysis does. The average RCS temperature (Figure 1-1.4), as predicted by LOFTRAN, reaches a stabilized value prior to safety injection. Therefore, the primary system is repressurized upon the initiation of safety injection. However, the flow coastdown predicted by RETRAN is faster and this causes safety injection to compensate for the shrinkage of RCS

* Results contained in Attachments 1-1, 1-4, and 1-5 have not been independently reviewed and verified and are considered preliminary.

volume associated with the decreasing average temperature. The pressure of the primary system starts to turn around as the decrease in RCS average temperature stabilizes to natural circulation conditions.

Additional RETRAN analyses utilize a more accurate break flow model represented by the modified Zaloudek correlation. The latter includes pressure drops from the steam generator inlet and outlet plena to the break location. A design basis tube rupture, which is a double-ended guillotine break, is assumed to occur above the tube sheet. The assumptions discussed earlier are used except the reactor trip is controlled by a setpoint associated with the over-temperature ΔT trip. Also, the safety injection signal is initiated by the low pressurizer pressure setpoint at 1860 psia given in the Technical Specifications. Listed in Table 1-1.2 is a comparison of time sequence of events for the tube breaking at the hot leg and the cold leg sides of the steam generator. Results of the parameters in connection with the primary and secondary systems are plotted in Figures 1-1.8 through 1-1.13. Comments on these plots are given as follows:

1) The break flow calculated by the modified Zaloudek correlation is directly proportional to two parameters, namely, the fluid density at the break location and the difference of the RCS pressure and the saturated pressure at the break location. Therefore, the break flow through the tube rupture at the cold leg side is higher than that at the hot leg side (Figure 1-1.11).

2) At the reactor trip, there is a sharp increase in break flow for the hot leg break due to a decrease in temperature at the break location (Figures 1-1.10 and 1-1.11).

3) Upon the repressurization of the primary system, the pressurizer power-operated-relief-valve (PORV) is actuated (open/closed) in response to the pressure changes (Figure 1-1.8).

The RETRAN results have been extended beyond 1800 sec and to other postulated single failures and operator action times by three versions of the BASIC program, designated SGTRHL, SGTRCL, and SGTRAR. An outline of the calculational method is given in attachment 1-2 to this response. SGTRHL deals with tube ruptures postulated to occur at the tubesheet in the hot leg. This maximizes the amount of the break flow that is flashed and, in the absence of SG overfill, the amount of radioactive iodine that is released to the atmosphere. The second version deals with tube ruptures postulated to occur at the tubesheet in the cold leg. This maximizes the break flow and the tendency to overfill the SG. The third version deals

with the postulated failure in the open position of the ARV on the faulted SG, which may result in the highest iodine releases and offsite doses under certain assumed operator action times.

Operator actions have been assumed to follow SNUPPS plant specific procedures that are based on the generic emergency response guidelines (ERGs) for Westinghouse plants. The procedures for the Callaway plant are based on the basic version of the ERGs and the procedures for the Wolf Creek plant are based on Rev 1 of the ERGs. Both versions of the SGTR emergency procedure have been considered. The timings of operator actions have been estimated using three sources: (1) actual SGTR events at the Prairie Island and Ginna plants; (2) simulator data; and (3) draft standard ANS 58.8, Rev. 2. This process and the results are described in attachment 1-3.

Plots of secondary system parameters, as calculated by SGTRHL and SGTRCL, are given in attachment 1-4. Results are provided for a nominal case, with the break in the hot leg at the tubesheet and with no postulated single failure. Results are also provided for what has been determined to be the most severe single failure with respect to SG overfill, i.e., a failure in the wide open position of the AFW control valve to the faulted SG. Results are given for two cases: a hot leg break and a cold leg break.

The calculated 0-2 hr site boundary doses for Callaway (which are slightly higher than for Wolf Creek) are given in attachment 1-5. In all cases, the doses are less than the values given in the SNUPPS FSAR. One reason is that the SNUPPS FSAR conservatively assumes that 17% of the break flow flashes to steam and is released with a partitioning factor of unity. The actual fraction of break flow that flashes is less than 7%. A second reason is that the current analyses have a more accurate break flow model (modified Zaloudek including pressure drops from the SG inlet and outlet plena to the break location) that results in break flows about half those of the FSAR analysis. The results also show that operator action times can be extended significantly beyond the times given in SLNRC 84-0044 without exceeding the acceptance criteria of Standard Review Plan 15.6.3. In all instances, the case 1 iodine spiking model (as defined by SRP 15.6.3) results in doses that are a higher fraction of the acceptance criterion than the case 2 iodine spiking model.

Plots of secondary side parameters, as calculated by SGTRAR for the case of a stuck-open atmospheric relief valve (ARV), are also given in attachment 1-4. Offsite doses for this postulated single failure are given in attachment 1-5. It has been conservatively assumed, in calculating these doses,

that manual closure of the ARV block valve can be accomplished within 30 minutes. In a recent "Unusual Event" at the Callaway plant the block valve was closed in 11 minutes, which substantiates that the assumed time of 30 min to close the block valve is conservative. The offsite doses for the postulated case of a stuck-open ARV are below the doses given in the FSAR and well below the acceptance criteria of SRP 15.6.3.

2.a. Q. Your preliminary submittal of March 16, 1984, indicates that the first operator action, i.e., isolation of the auxiliary feedwater to the faulted SG, is performed 16 minutes after the event. Your submittal also indicates that based on simulator data and because control of SG water level is "a common operation," the availability of high and low SG level alarms, the operator action time is adequate, and consistent with the guidance of ANS Draft Standard 58.8 (ANSI N660) for a condition III event. However, the staff notes that the SGTR is a condition IV event, for which ANSI N660 prescribes a minimum time margin for operator action of 20 minutes. Also, we question that SG level control following SGTR is a common operation. Therefore we require further justification for the assumed operator action time.

A. Control of SG water level is considered "a common operation" because the operators are trained to monitor SG level and, in particular, to look for an abnormally high level and decreasing feedwater flow to the same SG as a means of identifying a faulted SG.

In the case of the actual SGTR event at the Ginna Station in 1982, auxiliary feedwater (AFW) to the faulted SG was isolated in 13 min.

Simulator data from routine training operations of Callaway and Wolf Creek operators on the in-plant simulators show times of 12 to 16 min after a simulated SGTR to isolate AFW to the faulted SG.

Other simulator data, from operator training (1) on the SNUPPS simulator at the Westinghouse Training Center in Zion, Illinois, and from the emergency response guideline (ERG) verification and validation programs at the (2) Callaway and (3) Seabrook simulators have shown times of 9, 19, and 10 minutes, respectively, to isolate AFW to the faulted SG.

These data are believed to support the assumed operator action time of 16 min. to isolate AFW to the faulted SG. However, analyses have also been performed for longer operator action times (up to 28 min.) and the resulting offsite doses were within the acceptance criteria of Standard Review Plan 15.6.3 (see attachment 1-5).

See attachment 1-3 for a more extensive discussion of operator action times.

2.b. Q. Justify that primary/secondary pressure equalization can occur only 8 minutes after initiation of RCS cooldown, as indicated in your March 16, 1984, submittal.

A. Primary/secondary pressure equalization requires that (1) the RCS be cooled by relieving steam from the intact SGs, until their pressure is reduced approximately 600 psi (from about 1155 to about 590 psia) and (2) the RCS be depressurized (in the absence of offsite power by opening a pressurizer power operated relief valve (PORV)).

The emergency procedures limit the rate of intact SG depressurization to 100 psi per 50 sec. At this rate, the minimum time for the pressure to be reduced 600 psi is 300 sec, or 5 min. This rate of depressurization can be achieved when the atmospheric relief valves (ARVs) on at least two of the intact SGs are operable. Thus a failure of an ARV on one intact SG to open is not a limiting single failure.

The time for the operators to terminate SG depressurization, verify RCS subcooling and open a pressurizer PORV is estimated to be no more than 2 minutes. The time required to reduce RCS pressure to the pressure of the faulted SG (1150 to 1200 psia) is estimated to be 1 minute. The sum of these times is 8 minutes.

Simulator data from emergency response guideline (ERG) verification and validation programs at the Callaway and Seabrook simulators have shown times of 6 and 10 min, respectively, to complete primary/secondary pressure equalization, after initiating RCS cooldown. Timing of the Callaway and Wolf Creek emergency procedures using the criteria of Draft Standard ANS 58.8, Rev. 2, yields times for the basic version and for Rev. 1 of 10 and 7 min, respectively (see attachment 1-3).

Analyses have been performed for times of both 8 and 10 minutes from initiation of RCS cooldown to primary/secondary pressure equalization. The results are within the acceptance criteria of SRP 15.6.3 in each case (see attachment 1-5).

3. Q. Demonstrate that failure of an auxiliary feedwater (AFW) valve in the open position is the most limiting failure with regard to steam generator overfill, as indicated in your March 16, 1984 submittal. Also specify what indications are available and the operator actions required to terminate AFW flow. Justify that the time available, i.e. 10 minutes after actuation of S.G. high level alarm, is adequate to perform the proper actions.

A. A schematic diagram of the main feedwater, auxiliary feedwater and main steam systems is provided in attachment 3-1. The systems are similar to those of other Westinghouse-supplied PWRs. Specific features of the SNUPPS design that are pertinent to SGTR events are as follows.

(1) The SG relief valves (atmospheric relief valves or ARVs) are Class IE, fully qualified to safety requirements, and actuated from the control room. The control power is DC. The block valves are locally, manually actuated.

(2) There are 5 safety valves on each steam line, located between the ARV and the main steam isolation valve (MSIV).

(3) The MSIVs are Class IE, fully qualified to safety requirements, and actuated from the control room. All valves can be closed by a single switch in the control room.

(4) The main feedwater pumps are steam driven. They stop on SG high-high level, closure of MSIVs, or manual closure of the steam-supply stop valve.

(5) The feedwater isolation valves (FWIVs) are Class IE, fully qualified to safety requirements, and actuated from the control room. They close automatically on low-low SG level (23.5% narrow range) or high-high SG level (78% narrow range).

(6) Each motor driven AFW pump delivers a design flow of 500 gpm to two SGs. The turbine driven AFW pump delivers a design flow of 1000 gpm to four SGs. Flow balancing orifices are provided in the pump discharge lines.

(7) The control valves on the discharge of the motor driven pumps are automatically positioned to limit the total AFW flow to any SG to a nominal value of 320 gpm. The tolerance on this control is $\pm$ 70 gpm.

(8) Steam is supplied to the turbine driven AFW pump from the steam lines of SGs B and C.

(9) The PORVs on the pressurizer and the PORV block valves are Class IE and fully qualified to safety requirements. The valves are electrically powered and actuated from the control room.

There are three sources of water to a faulted steam generator: (1) main feedwater flow, (2) auxiliary feedwater flow, and (3) leakage from the primary system.

Main feedwater flow is not the most limiting source of overfill of the faulted steam generator, for the following reasons:

- The SNUPPS plants have a single-failure proof, Class IE system, with 2-out-of-4 logic that trips the main feedwater pumps on high-high SG level. The setpoint for this function is 78% of narrow range level. Consequently, main feedwater flow will always be terminated before the SG water level exceeds 78%, with the plant operating in the power range (i.e., with steam voids in the SG).

- Since the SG level control system maintains SG level at 50 $\pm$ 5% of narrow range level, a failure of the feedwater controller would be required before trip of the main feedwater pumps on high SG level could occur.

- If there is no single failure in the AFW system, maximum AFW flow is 390 gpm (320 nominal plus control tolerance). This case is less limiting with respect to SG overfill than the large AFW flow rates that could result from a postulated single failure in the AFW system.

Failure in the wide open position of the control valve on the discharge of the MD pump feeding the faulted SG has the potential for supplying 750 gpm to the faulted SG. This would occur under the following circumstances. The control valve for one intact SG, the one supplied by the same MD AFW pump as the faulted SG, is assumed to limit AFW flow to the low side of its control band (250 gpm). The AFW flow to the faulted SG is then 750 gpm (250 gpm from the TD pump and 500 gpm from the MD pump). This results in a rapid rate of filling of the faulted SG, as shown in the plots of SG level vs. time contained in attachment 1-4.

Extended leakage from the primary system, resulting from a single failure, is not the limiting case with regard to steam generator overfill, for the following reasons.

- Termination of primary to secondary leakage requires that: (1) RCS temperature be reduced; (2) RCS pressure be reduced; and (3) safety injection be terminated.

- The first function, reduction of RCS temperature, can be accomplished with the atmospheric relief valve (ARV) on only one intact SG. Therefore, a failure of an ARV cannot prevent this function from being performed.

- The second function, reduction of RCS pressure, can be accomplished with only one of the two pressurizer power operated relief valves (PORVs). Therefore, failure of a PORV or its block valve cannot prevent this function from being performed.

- The third function, termination of SI, can be accomplished by putting the SI pumps into pull-to-lock with handswitches in the control room. The pull-to-lock function overrides a potential failure in the SI reset circuitry, so that a single failure of SI reset would not prevent SI flow from being terminated. The procedural guidance with respect to termination of SI has been clarified since the SGTR event at the Ginna station in 1982, during which the operators allowed SI to continue and repressurize the RCS. Therefore, failure to terminate SI is not considered the most limiting failure with respect to SG overfill.

- It is also pertinent that the water addition rate, with the postulated failure of the AFW control valve, is 750 gpm or about 100 lb/sec, as opposed to a maximum primary to secondary leakage flow of about 50 lb/sec for a single double-ended tube rupture.

The indications of excessive AFW flow that are available in the control room are: SG narrow range level, AFW flow to each SG, and the operating status of AFW pumps and valves. Operator actions to terminate AFW flow to the faulted SG are:

- Attempt to close the remote manual valves in the turbine and motor-driven AFW pump discharge lines.

- Stop AFW pump(s) still feeding AFW to the faulted SG.

- As time permits, send an operator to close the local manual isolation valve(s) in the pump discharge line(s) to the faulted SG. Then restart AFW pump(s) to maintain water levels in the intact SGs.

For the limiting postulated single failure and for the worst break location (cold leg at tube sheet), the time at which AFW flow to the faulted SG must be terminated to avoid overfill is 12-1/2 minutes after occurrence of the SGTR and 2-1/2 minutes after actuation of the SG high level alarm, provided that primary/secondary pressure equalization is accomplished 40

min. after the SGTR. As discussed in the response to question #1, should the operators take longer to isolate AFW flow, the consequences would still be within the acceptance criteria of Standard Review Plan 15.6.3.

4. Q. Discuss whether the steam generator safety valves would function properly if their actuation pressures are reached with the steam lines filled with liquid, and whether they would reseat at the proper pressure.

A. Limited experimental data indicates that the safety valves would open and reseat properly.

One source of data is the SGTR event at the Ginna plant in January 1982. In the course of that event, the operators closed the block valve ahead of the relief valve on the faulted steam generator. The safety valve is thought to have opened and closed three times with the steam line filled with water. Available data indicate that the safety valve opened and reseated at the normal actuation pressures.

A second source of data is the test program conducted by EPRI of pressurizer relief and safety valves. The safety valves were tested with combined steam and water, as well as steam, and in these tests the valves opened and reseated at essentially the proper pressure.

5. Q. Justify your conclusion that in the event of SG overfill the possibility of damaging water hammer is extremely remote. You state that liquid would enter the steam line slowly, that the steam and water in the steam line would be at nearly the same temperature, and therefore condensation shocks would not occur. Provide analyses to justify these conclusions.

A. The most common cause of water hammer is for subcooled water to come in contact with steam, with a large interface area at which condensation can occur. If the temperature difference is large, rapid condensation of the steam creates a low pressure that causes water to flow rapidly to the condensation site. The water hammer occurs as the steam volume collapses. Another cause of water hammer is rapid closure of a valve in a pipe in which water is flowing at high velocity.

Neither of these situations will exist in the steam line at the time that overfill may occur. The steam line will be filled with steam, essentially in thermal equilibrium with water in the upper region of the steam generator. The piping and other metallic components in contact with the steam will be hot, by virtue of having been in contact with flowing steam prior to reactor trip, being insulated, and being in contact with steam after the SGTR event. Density gradients within the SG will tend to keep the hottest water at the top of the SG, where the nozzle to the steam line is located. Thus there will be no significant temperature differential between the steam and water, and no possibility of rapid condensation.

At the time that overfill is calculated to occur, sufficient time will have elapsed for the operators to terminate auxiliary feedwater flow to the faulted SG and the addition of water to the SG will be solely from the break flow. The break flow for a double-ended tube rupture is approximately 50 lb/sec or about 1 ft^3/sec. As the minimum area in the steam line is 1.4 ft^2, the velocity at which water will enter the steam line will be at most 0.7 ft/sec. This is well below the flow velocities at which high pressures result from sudden stoppage of the flow.

As there are no circumstances that could lead to water hammer in the steam lines, numerical analyses are considered unnecessary.

6. Q. As stated in your March 16, 1984 letter, the steam generator atmospheric relief valves are needed for SGTR mitigation, and are properly qualified. Therefore, you should develop and propose suitable Technical Specifications to ensure the operability of these valves consistent with the analyses. What is the minimum number of ADVs necessary for SGTR mitigation?

A. The NRC has asked the Westinghouse Owners Group (WOG) Technical Specification Subcommittee to address a number of generic technical specification issues, one of which is the need for a specification for secondary power operated relief valves (PORV's). The SNUPPS utilities are participants in this WOG subcommittee and will be directly involved in developing a generic specification. The SNUPPS utilities will propose an appropriate specification based on the WOG effort and consistent with our analysis, on a schedule which will provide sufficient time for NRC review and approval prior to restart following the first refueling.

PRELIMINARY

Table 1-1.2 TIME SEQUENCE OF EVENTS FOR THE FSAR AND RETRAN MODELS

Event	Time (sec.) FSAR	RETRAN
Tube rupture occurs	0.0	0.025
Reactor trip signal	198.9	198.9
Rod motion	200.9	200.9
Feedwater terminated	200.9	200.9
Steam generator safety/ relief valves opened	204.0	209.4
Safety injection signal	335.2	391.6
Safety injection	360.2	416.6
Auxiliary feedwater injection	396.0	452.6
Operator takes actions to isolate and cooldown	1800.0	1800.0

Table 1-1.2 Time Sequence of Significant Events as Predicted by RETRAN Utilizing the Modified Zaloudek Correlation PRELIMINARY

Event	Time (sec.) Cold Leg Break	Time (sec.) Hot Leg Break
Tube rupture occurs	0.0	0.0
Reactor trip	93.5	139.4
Feedwater terminated	93.5	139.4
Steam generator PORV's opened	96.3	142.2
Safety injection signal	402.0	532.0
Safety injection	427.0	557.0
Auxiliary feedwater injection	463.0	593.0
Pressurizer PORV opened	1177.4	1183.5
Pressurizer PORV closed	1183.8	1190.0
Pressurizer PORV opened	1386.4	1350.7
Pressurizer PORV closed	1391.8	1356.0
Pressurizer PORV opened	1581.5	1508.2
Pressurizer PORV closed	1586.1	1513.2
Pressurizer PORV opened	1761.9	1663.5
Pressurizer PORV closed	1766.3	1667.9

Attachment 1-1

PRELIMINARY

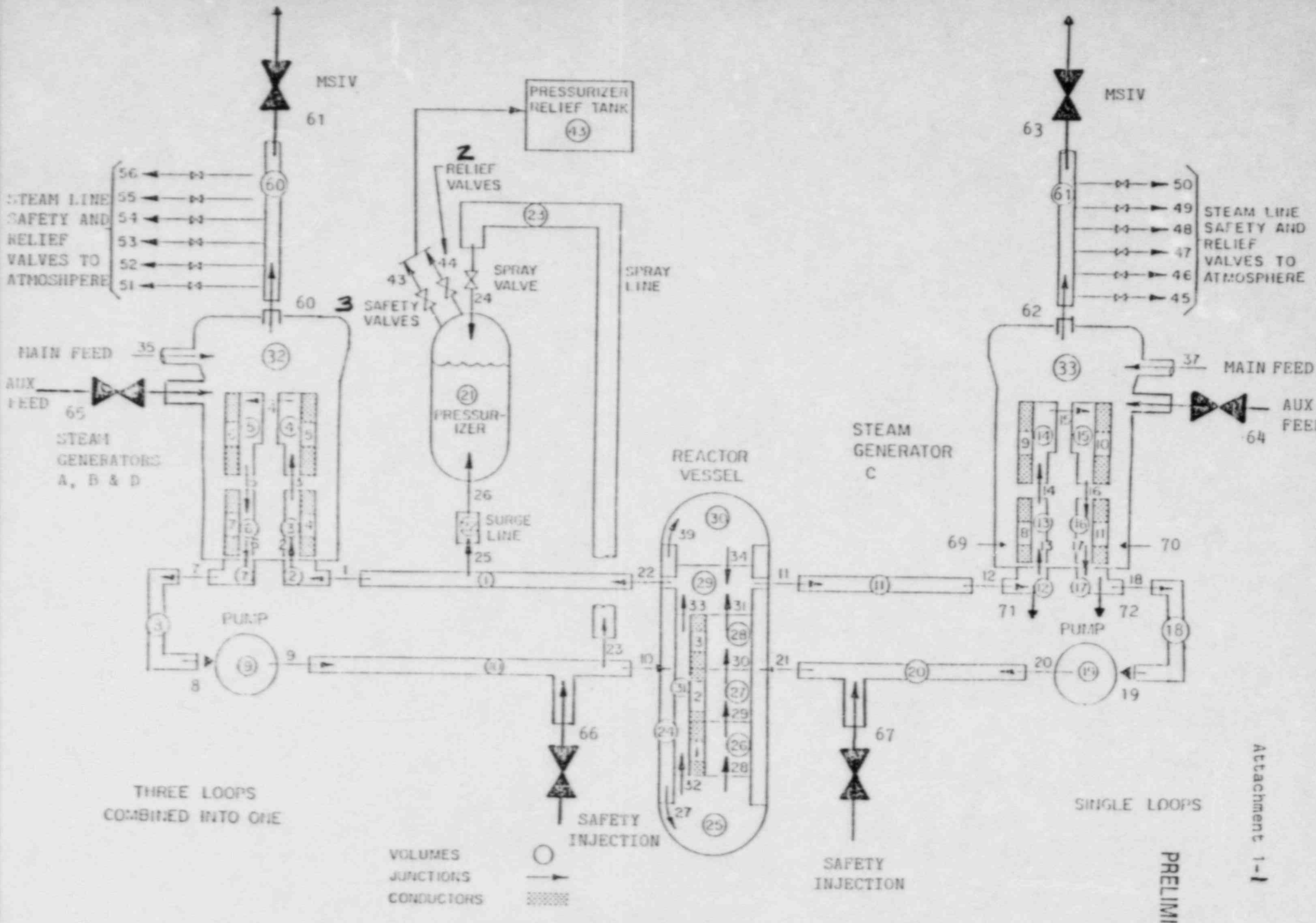


Figure 1-1.1 Noding Diagram used in RETRAN Analyses

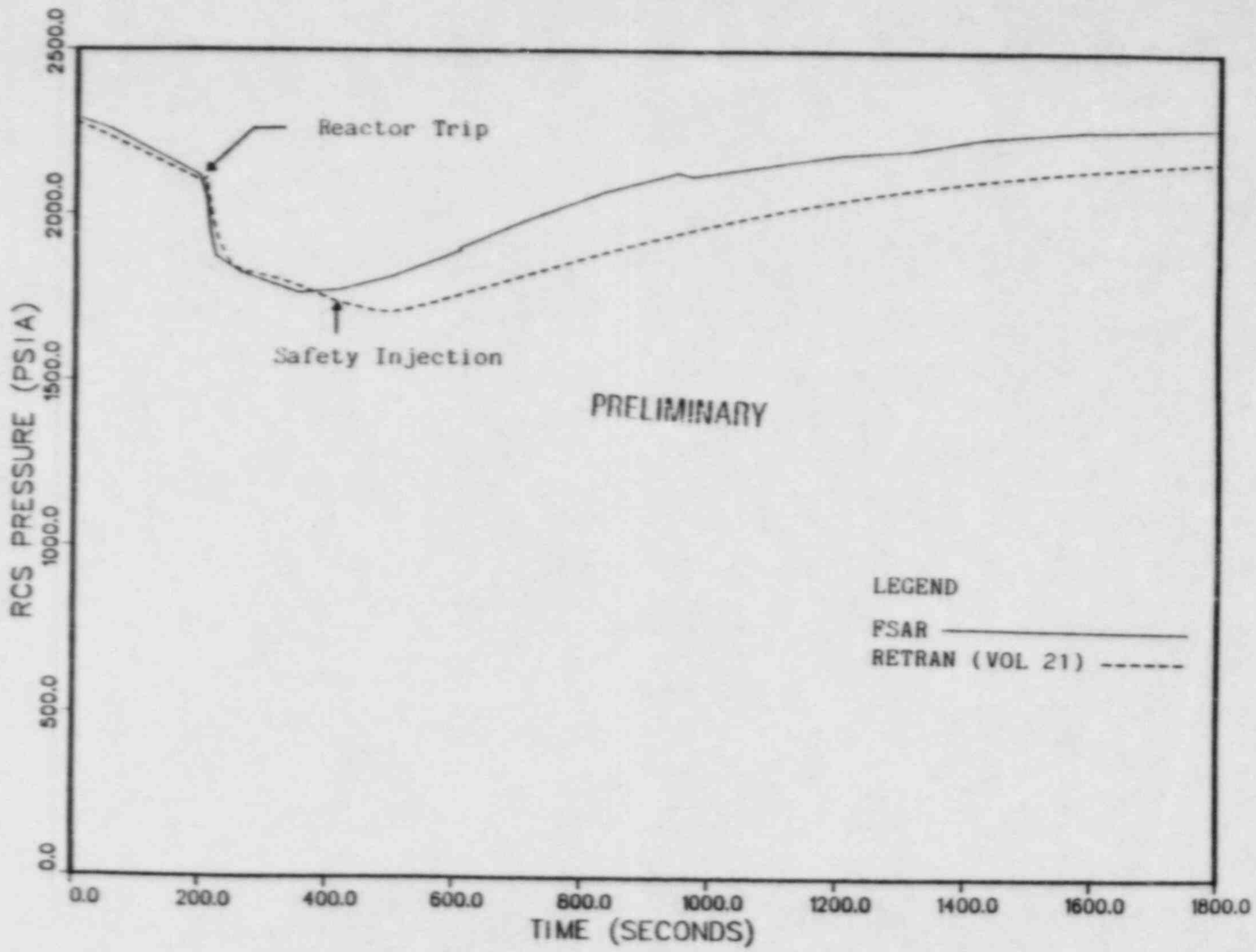


Figure 1-1.2 Reactor Coolant System Pressure

Attachment 1-1

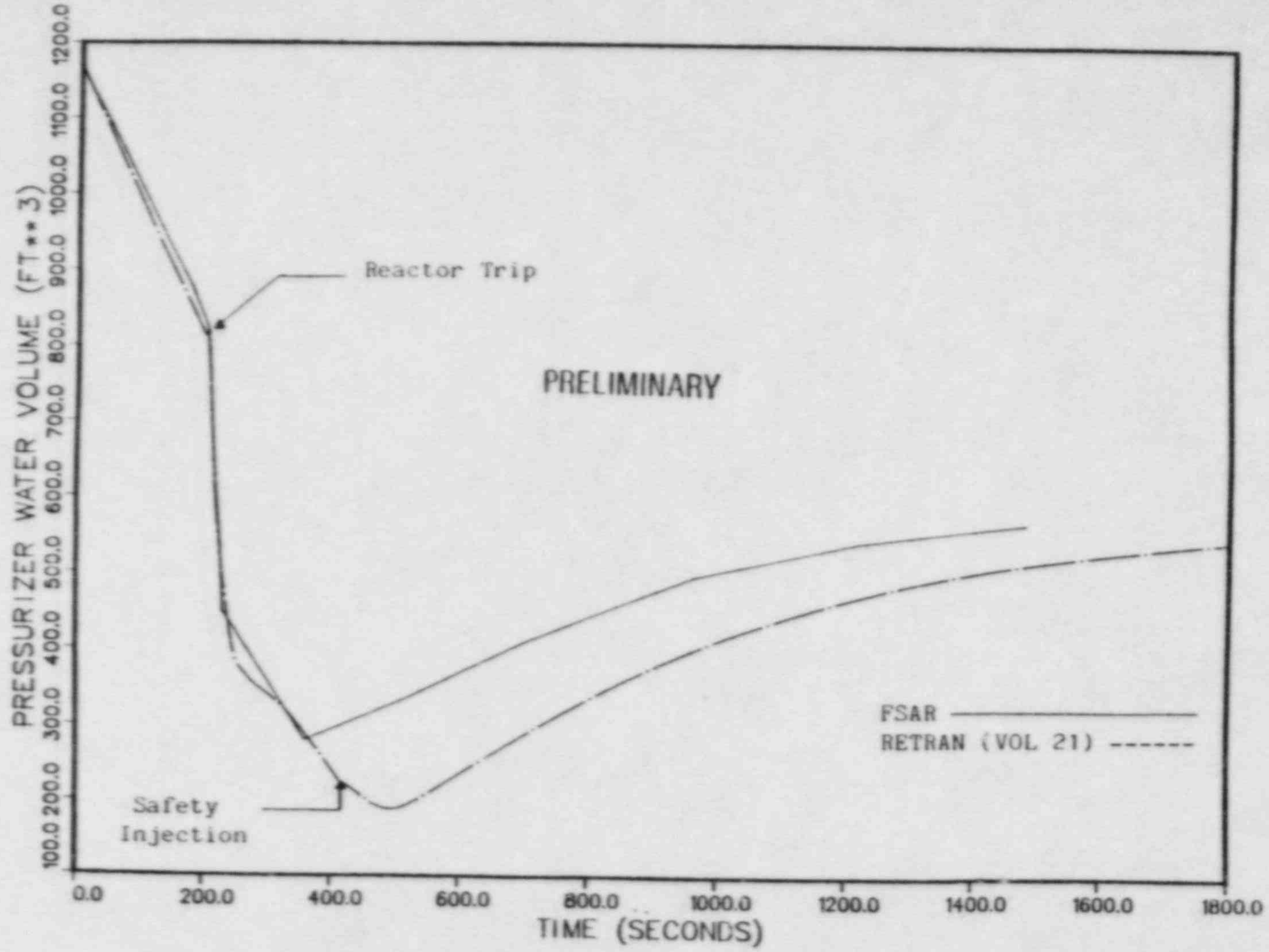


Figure 1-1.3 Pressurizer Water Volume

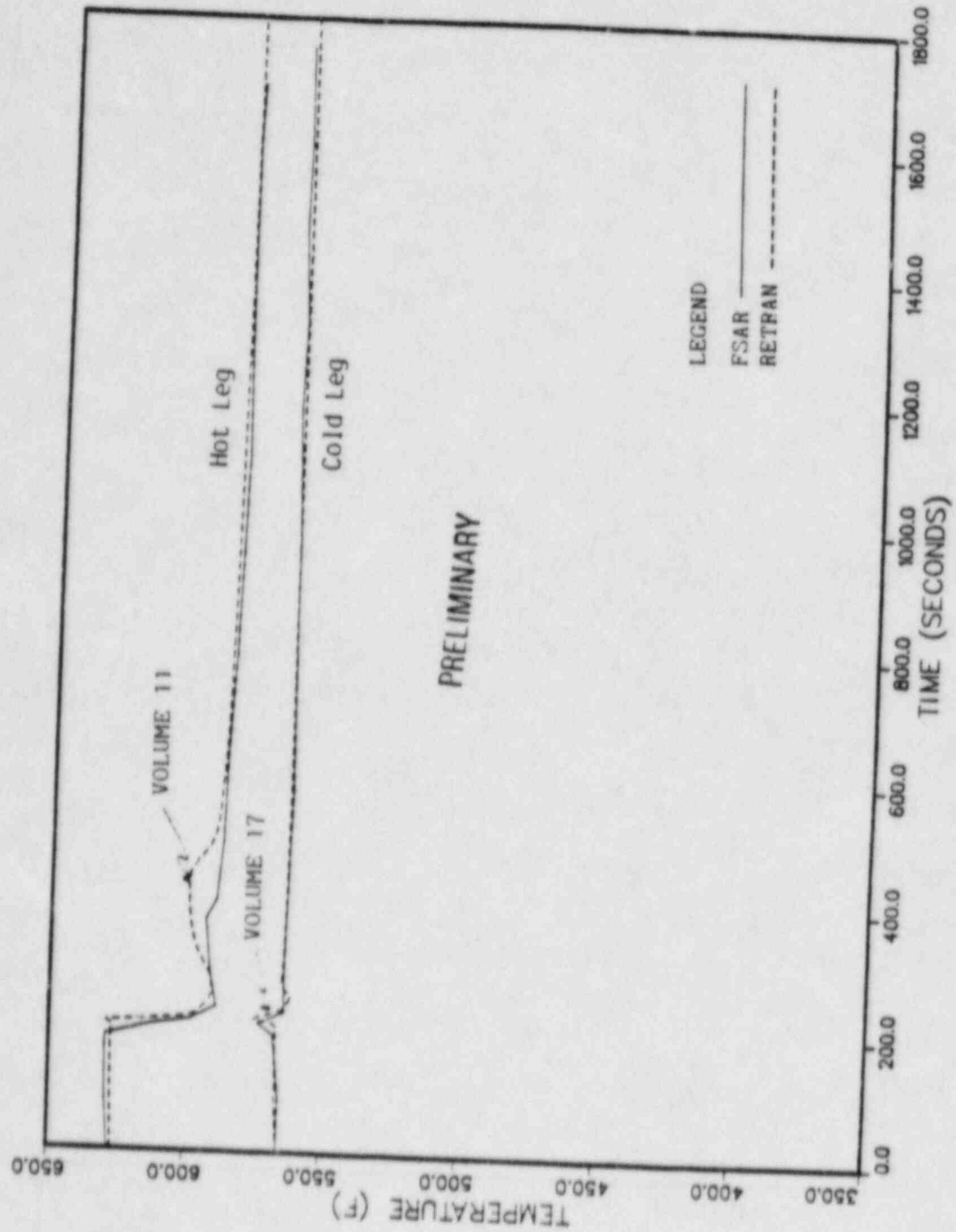


Figure 1-1.4 Reactor Coolant System Temperature

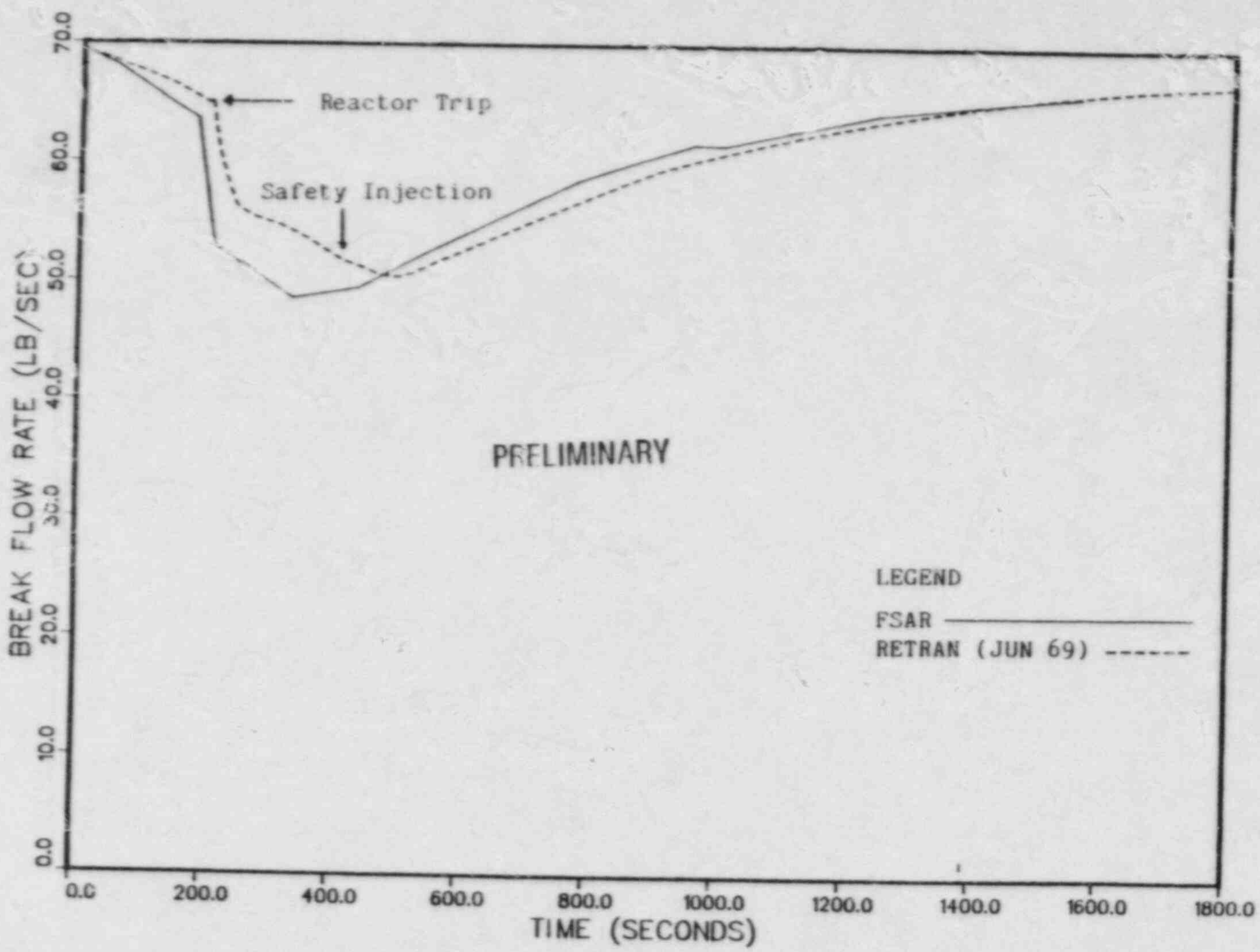


Figure 1-[illegible].5 Faulted Steam Generator Break Flow (lb/sec)

Attachment 1-[illegible]

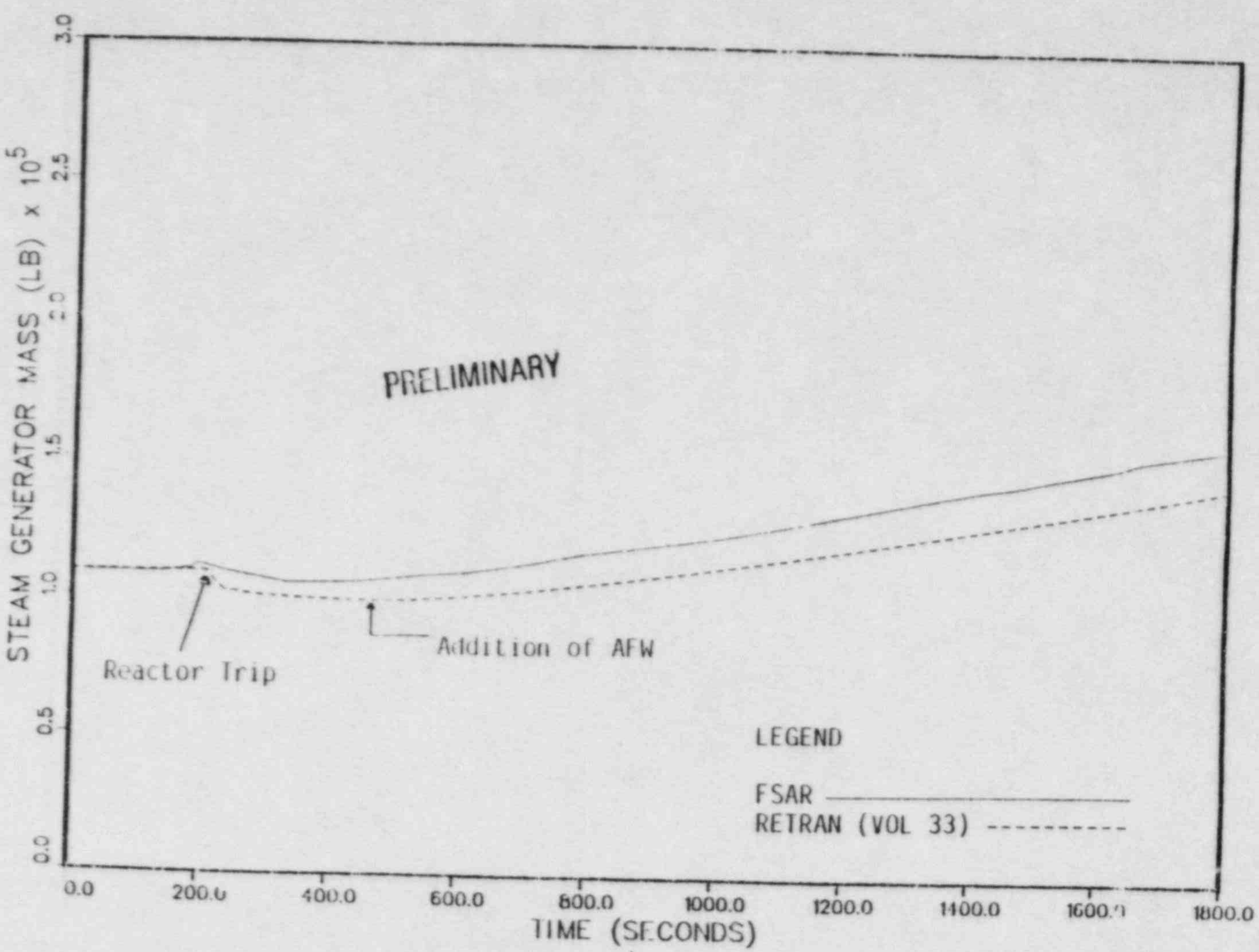


Figure 1-1.6 Faulted Steam Generator Liquid Mass

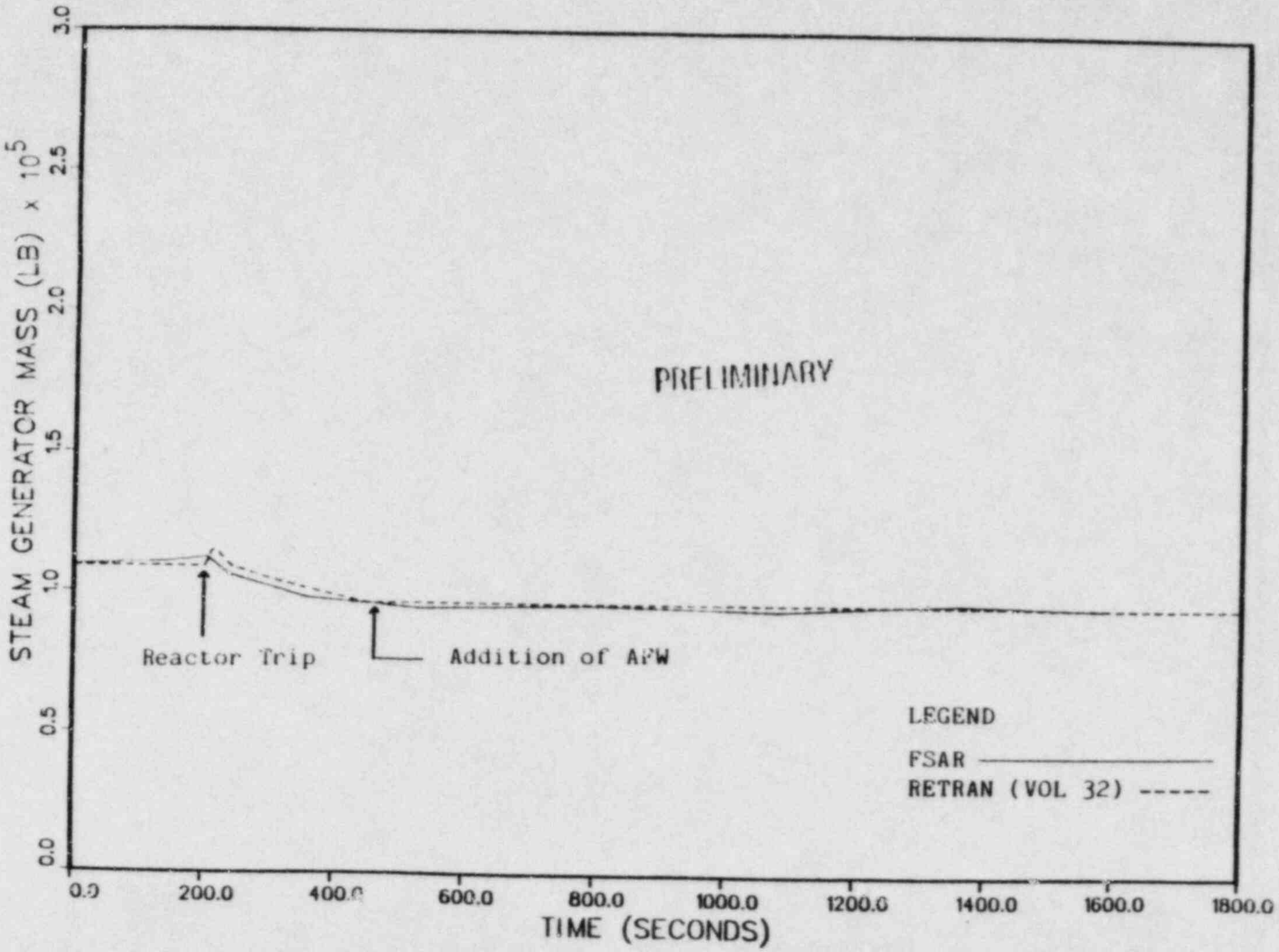


Figure 1-1.7 Intact Steam Generator Liquid Mass

Attachment 1-1

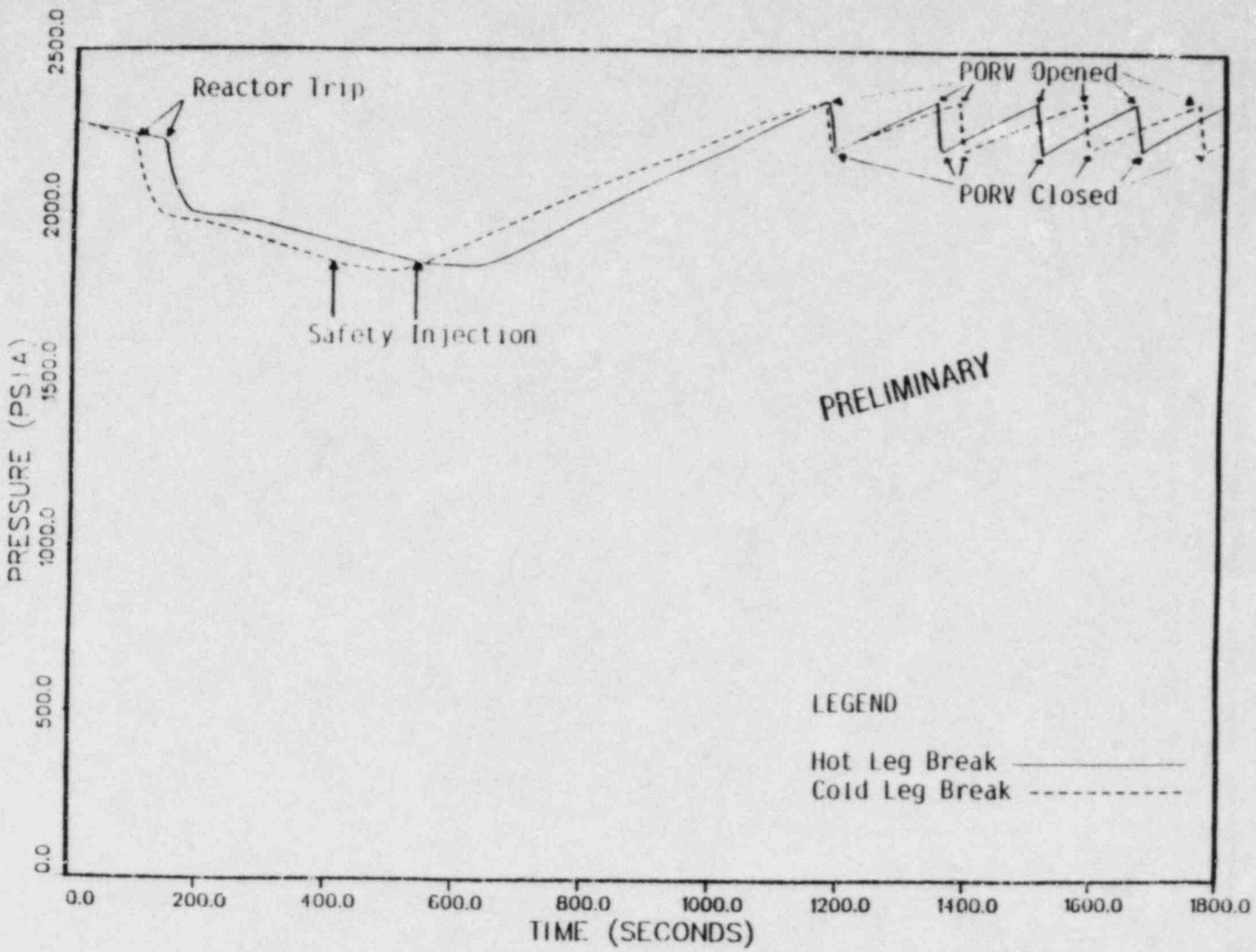
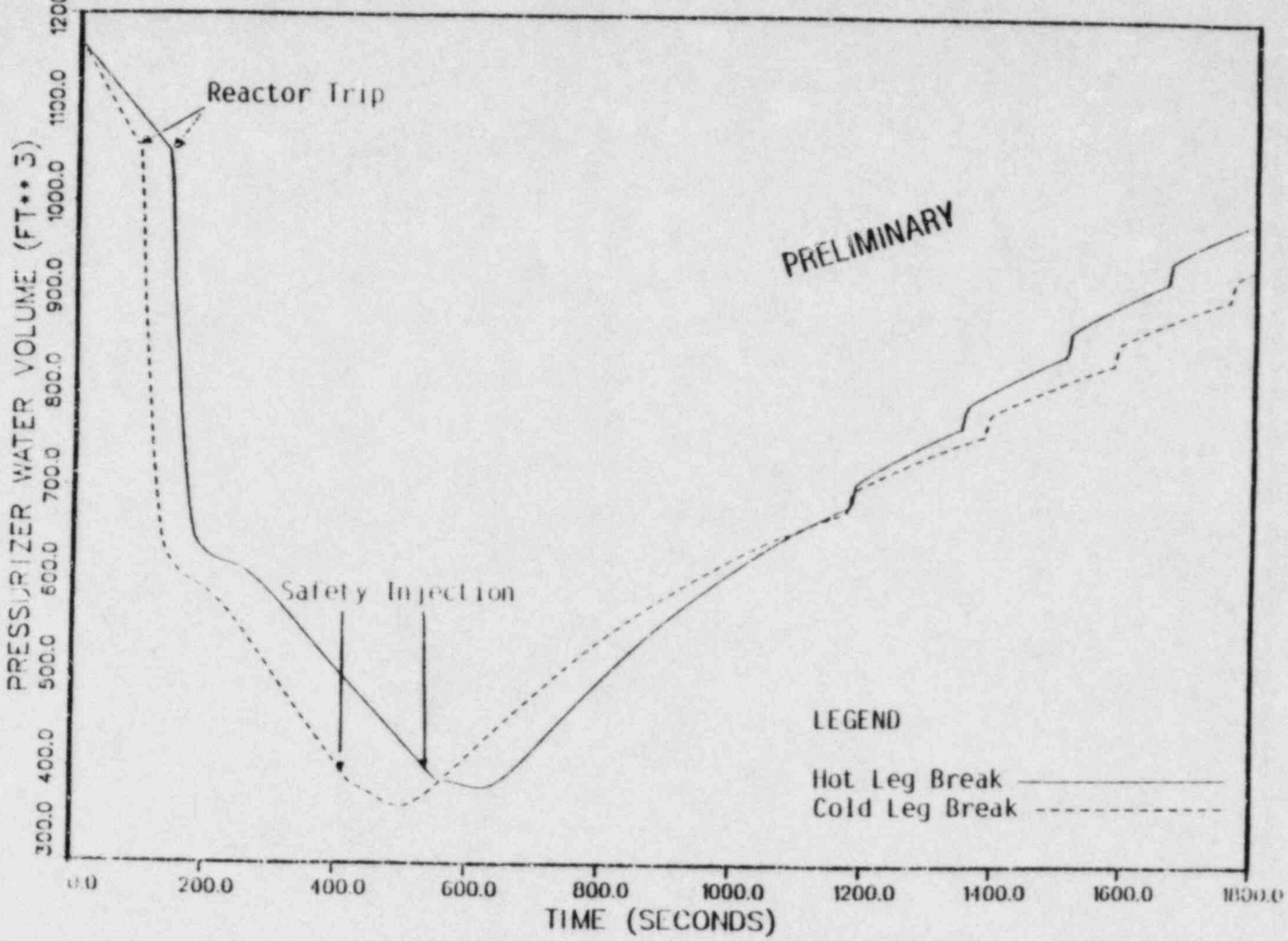


Figure 1-1.8 Reactor Coolant System Pressure (Vol 21)

Attachment 1-f



Attachment 1-I

Figure 1-1.9 Pressurizer Water Volume (Vol 21)

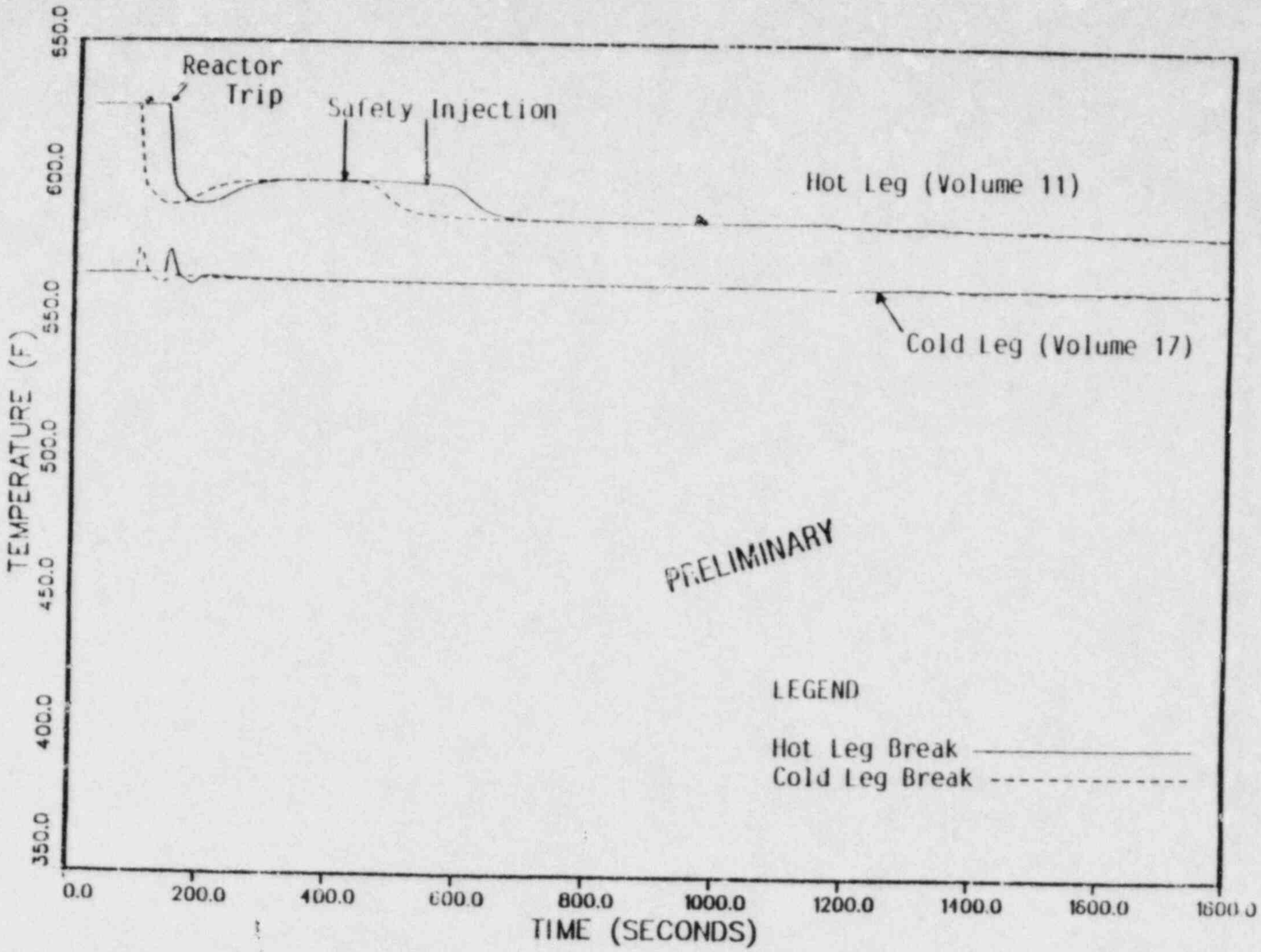


Figure 1-1.10 Reactor Coolant System Temperatures

Attachment 1-1

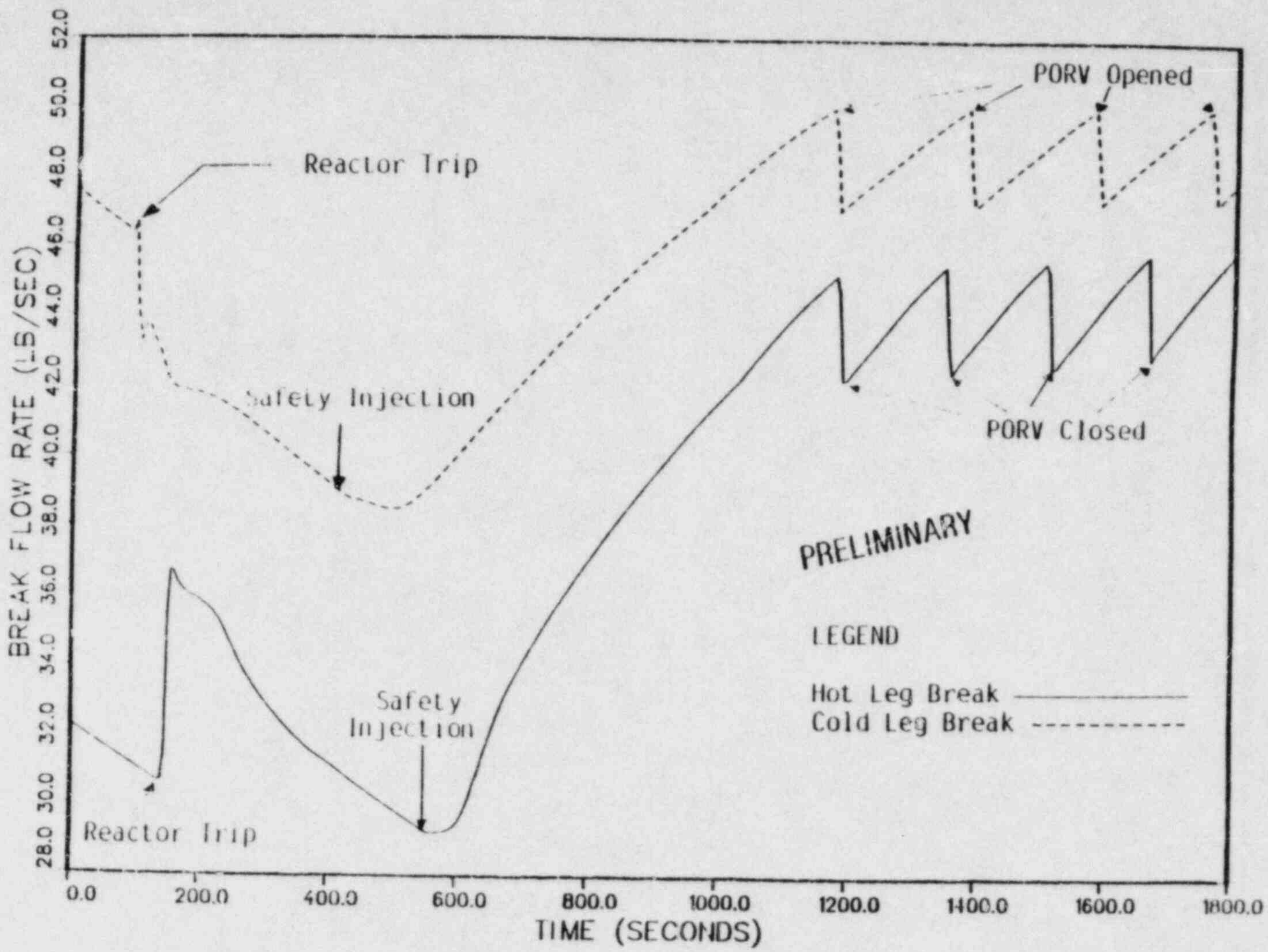


Figure 1-1.11 Faulted Steam Generator Break Flow (Junctions 69 & 70)

Attachment 1-1

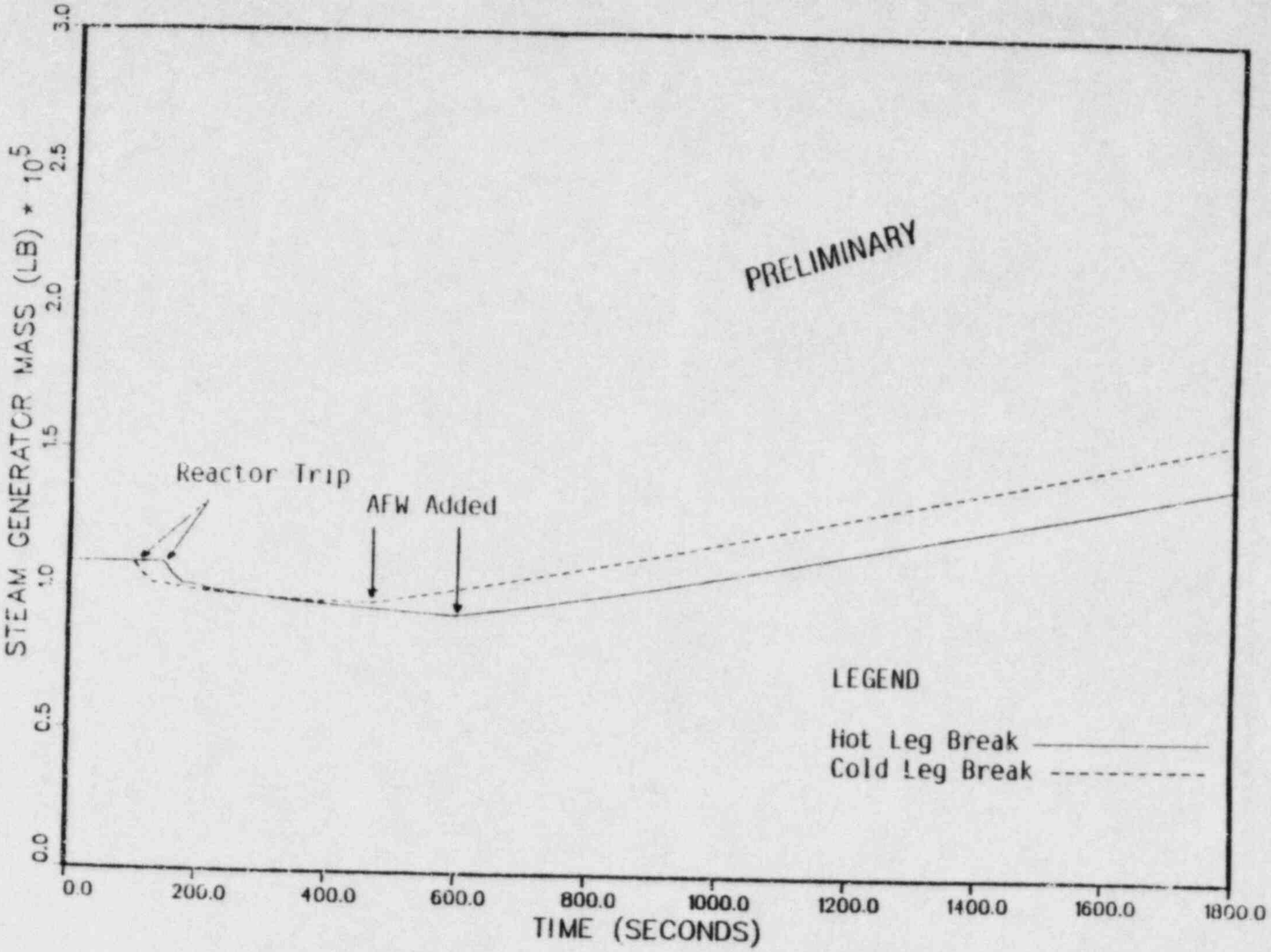


Figure 1-I.12 Faulted Steam Generator Liquid Mass (Vol 33)

Attachment 1-I

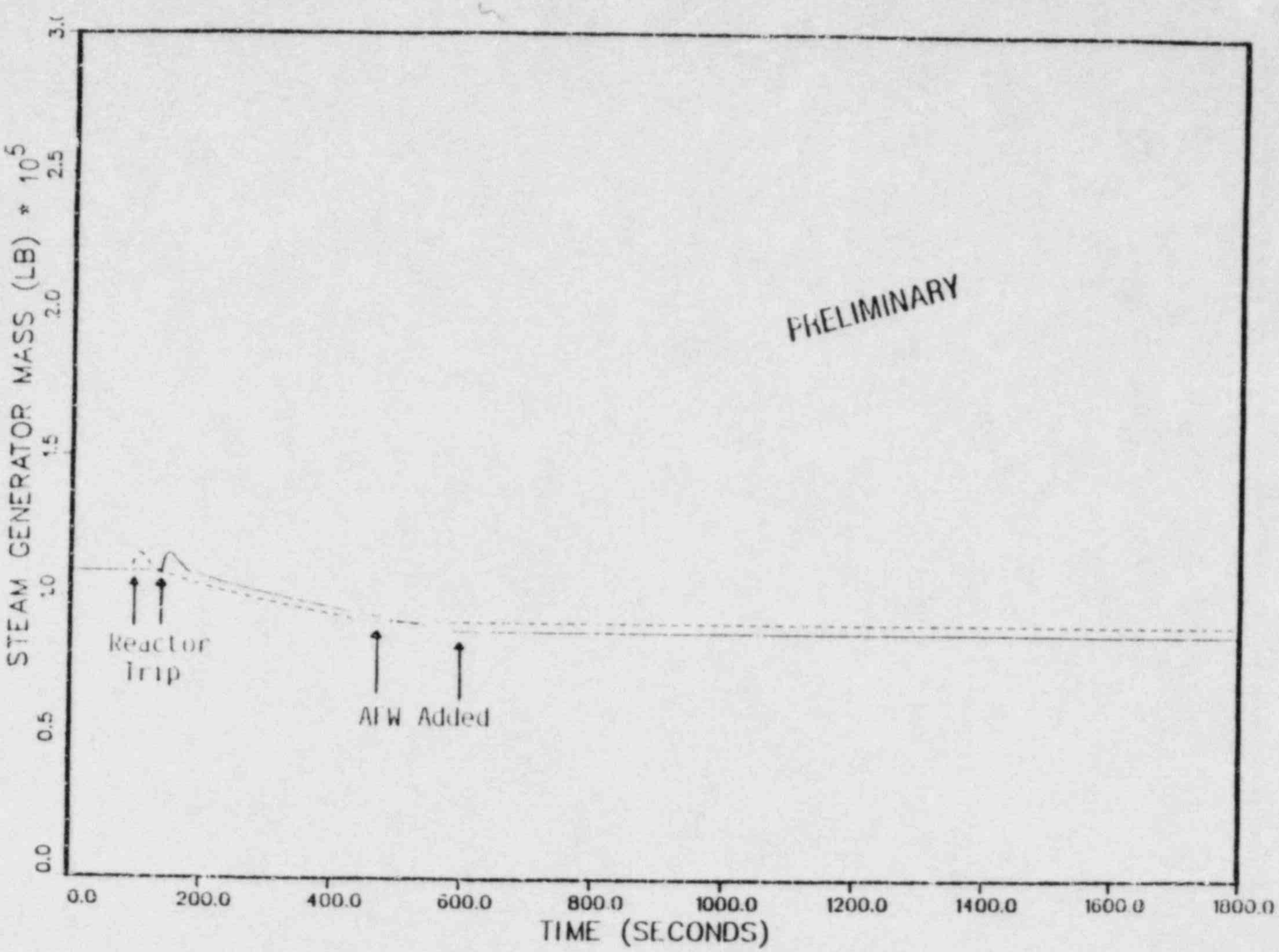


Figure 1-1.13 Intact Steam Generator Liquid Mass (Vol 32)

Outline of Calculation - BASIC Program

INPUT

Conditions representing plant state (single failure, etc.).
Operator action times.
Initialize to steady state operation prior to SGTR.

TIME INTERVAL

Advance time interval counter (N = N+1).

PRIMARY SIDE CALCULATIONS

Decay heat (per ANS).
T_C based on secondary pressure.
T_H based on decay heat and natural circulation flow correlation.
Change of latent heat of reactor coolant.
Latent heat of SI.

BREAK FLOW AND FLASHED FRACTION

Modified Zaloudek correlation with consideration of pressure drop from SG plena to break location.
Hot and cold leg contributions to break flow .
Fraction of break flow that flashes.

NEXT TIME INTERVAL

MASS AND ENERGY BALANCE IN FAULTED AND INTACT SGs

Mass addition from break.
Mass addition from AFW (initially assume no throttling of AFW by operators).
Apportion total energy transferred from primary among SGs.
Latent heat of AFW.
Change of latent heat of steam and water in SG.

STEAM PRODUCED

If net energy addition is positive.
Can have subcooled water and non-thermal-equilibrium between steam and water if net energy addition is negative. In this case steam produced is zero.

WATER INVENTORY IN SG

Water present at start of time interval.
Water added by break flow and AFW.
Water lost by steam produced.
Water present at end of interval.

WATER LEVEL

Compute void fraction.
Correct water volume for voids.
Check water level vs. max. level to be controlled by operators. If too high, iterate on AFW addition.
Compare water volume vs. volume available (SG plus steam line). If water volume exceeds available volume, excess water is released to atmosphere.

NEXT TIME INTERVAL

ITERATION ON AFW ADDITION

REPEAT FOR OTHER SGS

STEAM INVENTORY IN SG

Avalable volume is SG plus steam line volume minus water volume.
Compare with steam inventory at start of interval plus net steam produced.
Excess steam is released to atmosphere.

NEXT TIME INTERVAL

REPEAT FOR OTHER SGs

IODINE CONCENTRATIONS IN RCS AND SG WATER

Case 1 or case 2 iodine spiking model.
Concentration in RCS based on release from fuel, loss through break, and dilution by SI.
Concentration in SG based on addition from break and leakage, loss to atmosphere, and dilution by AFW.

IODINE RELEASED

Via steam and water released. Partitioning factor (PF) is 1 for flashed fraction of break flow and water released. PF is 100 for steam released.

PRINT INTERMEDIATE DATA

Optional printout at end of each time interval.

PRINT SUMMARY DATA

Summations for 0-2 hours.

OPERATOR RESPONSE TIMES

A. Actual SGTR Events

Westinghouse has summarized operator response times for the SGTR events that occurred at Prairie Island in 1979 and at Ginna in 1982 as follows:

	Time after Occurrence of SGTR (min.)	
Action	Prairie Island	Ginna
Isolate faulted SG	30	13
Initiate RCS cooldown	43	15
Complete RCS depressurization	51	45
Terminate SI	55	72

The Prairie Island event consisted of a tube leak of less than a full double-ended rupture and consequently the accident progressed more slowly than analyzed in an FSAR. As a result, operator action times are probably longer than they would be for a larger SGTR. This observation is supported by the fact that operator action times in the early stages of the Ginna event were shorter than at Prairie Island.

The Ginna event was complicated by several factors that are not expected in a SGTR in a SNUPPS plant. These were a stuck-open pressurizer PORV, that resulted in lower than intended RCS pressures, and occurrence and persistence of a steam bubble in the head of the reactor vessel. The steam bubble occurred, in part, because the Ginna plant has hot leg temperature in the vessel upper head. The SNUPPS plants are designed to have cold leg temperature in the vessel head. The procedures in effect at Ginna were not explicit about the criteria

for terminating SI with a steam bubble present in the reactor vessel. The operators, taking a conservative approach to maintaining core cooling, allowed SI to run and thus repressurized the RCS. This is a dominant reason for the long time required to terminate leakage to the ruptured SG. With the experience of the Ginna event and improved procedures and operator training, it is expected that primary to secondary leakage would be terminated sooner if a SGTR were to occur in a SNUPPS plant.

B. Simulator Data

Operator action times are available from four sources: (1) the verification and validation of the Westinghouse generic ERGs, Rev. 0 at the Callaway simulator in 1982, (2) composite verification and validation data including Rev. 1 of the generic ERGs at the Seabrook simulator in 1984, (3) training of operators from several utilities at the Westinghouse Training Center in Zion, Illinois, and (4) operator training on the SNUPPS in-plant simulators. These data may be summarized as follows:

	Time after Occurrence of SGTR (min)			
Action	V&V	Comp. V&V	Zion	SNUPPS
Isolate faulted SG	19	10	9	12-16
Initiate RCS cooldown	24	23	16	24
Complete RCS depressurization	30	33	32	41
Terminate SI	40	41	37	44

C. ANS Draft Standard 58.8, Rev. 2

This draft standard specifies criteria for calculating operator

response times. The timing consists of an initial time to assess the state of the plant and decide how to respond. The specified time is 10 minutes for a Condition III event and 20 minutes for a Condition IV event. The standard then specifies an additional time of one minute for each manipulation performed by the operator.

The SGTR event, as analyzed in the FSAR with a pre-existent iodine spike and loss of offsite power(LOOP), is a Condition IV event. However, since the operators normally throttle auxiliary feedwater (AFW) manually whenever it is initiated and are trained to maintain SG water level, it is judged conservative to assume a 10 minute initial delay for isolation of AFW. This delay is conservatively assumed to come after the reactor trips, which occurs approximately 2 minutes after a reference (double-ended tube break) SGTR. Actions after AFW isolation are assumed to follow after an additional 10 minute delay (for a total of 20 minutes). The operator response times are developed in Tables 1 and 2 and may be summarized as follows:

	Time after Occurrence of SGTR (min)	
Action	Callaway procedure	Wolf Creek procedure
Terminate AFW to faulted SG	14	18
Initiate RCS cooldown	35	39
Complete RCS depressurization	45	46
Terminate SI	49	49

D. SGTR Analyses

Comparison of the response times in Sections A-C indicates that the response times based on ANS 58.8 are conservative upper bounds and are longer than can reasonably be expected to occur. For the

analyses of SGTR events in a SNUPPS plant, the followng operator response times are judged to be conservative.

Action	Time after Occurrence of SGTR (min)
Terminate AFW to faulted SG	16
Initiate RCS cooldown	32
Complete RCS depressurization	40
Terminate SI	45

Table 1

OPERATOR RESPONSE TIME ESTIMATES (BASED ON ANS 58.8, REV. 2)

Callaway Emergency Procedure E-3 (Based on ERGs, Rev. 0)

Step	Action	No. of Manipulations	Elapsed Time
1.	Identify affected SG	0	12(1)
	- Narrow range level rising/decreasing feedwater flow to same SG		
	- High radiation in steam line		
	- High radiation in SG blowdown line		
	- High radiation in SG sample		
2.	Isolate affected SG		
	- Stop aux. feedwater to SG	2	14
	- Close MSIV (Bypass valve normally closed)	1	15
	- Verify atm relief vlv (ARV) closed	0	
	- Close steam supply to AFW turbine-driven pump	2(2)	17
3.	Pressurizer PORV block valves		
	- Check power avail & valves open	0	
4.	Pressurizer PORVs		
	- Verify closed	0	
5.	Reactor coolant pumps		
	- Verify centr chg or SI pumps running	0	
	- RCS pressure <=1405 psig	0	

- Stop RCPs (occurs on LOOP)	0	
6. <u>RHR pumps</u>		
- Check RCS pressure	0	27 (3)
- Reset SI	2	29
- Stop RHR pumps	2	31
7. <u>Check elec power & air supply to essential equip</u>	0	
8. <u>Check secondary system integrity</u>	0	
- Check RCS T_H		
- Check all SG pressures		
9. <u>Check SG levels</u>		
- Narrow range > 6%		
- Throttle AFW to bring & maintain narrow range level = 56%	3 (4)	34
10. <u>Cooldown non-ruptured SGs</u>		
- Determine final pressure	0	
- Start cooldown by dumping steam	3	35 (5)
via ARVs (limit rate to -100 psi/50 sec)		42 (6)
- Close relief valves	3	43 (6)
11. <u>Check RCS pressure</u>	0	
12,13. Not applicable with LOOP		
14. <u>Depressurize RCS</u>		
- Open one PORV	1	44
15. <u>Stop depressurization</u>		
- Compare RCS & ruptured SG pressures	0	
or pzr. level & high level rx. trip	1	45
setpoint (92%)	0	
- Close PORV		
- Check pzr level & RCS pressure		

16,17. Terminate SI

- Check RCS press, subcoolg, pzr lvl	0	
- Stop 2 SI pumps	2	47
- Stop 1 centrifugal chg pump	1	48

Notes:

(1) 10 minutes delay assumed after reactor trip (per ANS 58.8 for Condition III event). Trip occurs at approximately 2 minutes (per RETRAN calculation).

(2) Required only when ruptured SG is in loop B or C. Includes reset of AFAS prior to closing valves.

(3) Additional 10 minute delay assumed (per ANS 58.8 for Condition IV event).

(4) Normally requires manipulation of throttle valves from only 1 AFW pump per SG, or shutdown of turbine-driven pump.

(5) Opening of one ARV starts RCS cooldown.

(6) Requires 5 minutes to depressurize each SG. Assuming 1 min. per manipulation, the intact SGs depressurize on a staggered basis and each relief valve is closed 6 min. after it is opened.

Table 2

OPERATOR RESPONSE TIME ESTIMATES (BASED ON ANS 58.8, REV. 2)

Wolf Creek Emergency Procedure E-3 (Based on ERGs, Rev. 1)

Step	Action	No. of Manipulations	Elapsed Time
1.	Check if RCPs should be stopped	0	12(1)
2.	Identify ruptured SG	0	
	- Narrow range level rising/decreasing feedwater flow to same SG		
	- High radiation in steam line		
	- High radiation in SG blowdown line		
	- High radiation in SG sample		
3.	Isolate flow from ruptured SG		
	- Adjust relief valve setpt upwards	1	13
	- Close MSIV (bypass vlvs norm clsd)	1	14
	- Check SG ARV closed	0	
	- Close steam supply to AFW TD pump	2(2)	16
	- Verify blwdwn isol vlv clsd	0	
4.	Check water level in ruptured SG		
	- Narrow range >5% (norm contmt)	0	
	- Control feed to maintain level in range of 5 to 50%	2	18(3)
5.	Przr PORVs & block valves		
	- Power available to block valves	0	
	- PORVs closed	0	
	- At least 1 block valve operable	0	
6.	Check if other SGs are ruptured		
	- Check pressures	0	

7. Check intact SG levels		
- Narrow range level > 5%	0	28[4]
- Control feed flow to maintain narrow range level between 5 & 50%	3[5]	31
8. Reset SI		
-SIS and RWST switchover	2	33
9. Reset) CIS-A and CIS-B	2	35
10. Establish instr. air to containment	1	36
11. Verify AC busses energized by offsite power		
- Not applicable if LOOP	0	
12. RHR pumps		
- Check RCS pressure	0	
- Stop pumps	2	38
13. Check ruptured SG pressure	0	
14. Initiate RCS cooldown		
- Determine reqd core exit temperature	0	
- Dump steam at maximum rate		
Open one ARV	1	39
Open remaining ARVs	2	41
- Check core exit TCs	0	
- Stop RCS cooldown	3	44
15. Check ruptured SG pressure	0	
16. Check RCS subcooling	0	
17. Not applicable if LOOP		
18. Depressurize RCS		
- Open 1 przr PORV	1	45
- Check RCS pressure, przr level, subc	0	
- Close PORV	1	46

19.	Check RCS pressure	0	
20.	Check if SI should be terminated		
	- Check RCS subcooling	0	
	- Check secondary heat sink avail	0	
	- Check RCS pressure and przr level	0	
21.	Stop SI and CC pumps	3	49
22.	Establish 60 gpm charging flow	6	55

Notes:

(1) 10 minutes delay assumed after reactor trip (per ANS 58.8 for Condition III event). Trip occurs at approximately 2 minutes (per RETRAN calculation).

(2) Required only when ruptured SG is in loop B or C. Includes reset of AFAS prior to closing valves.

(3) Two operations required to isolate flow to SG (close 2 pump discharge valves or stop 2 AFW pumps).

(4) Additional 10 minute delay assumed (per ANS 58.8 for Condition IV event).

(5) Normally requires manipulation of throttle valves from one AFW pump per SG, or shutdown of turbine-driven pump.

ATTACHMENT 1-4

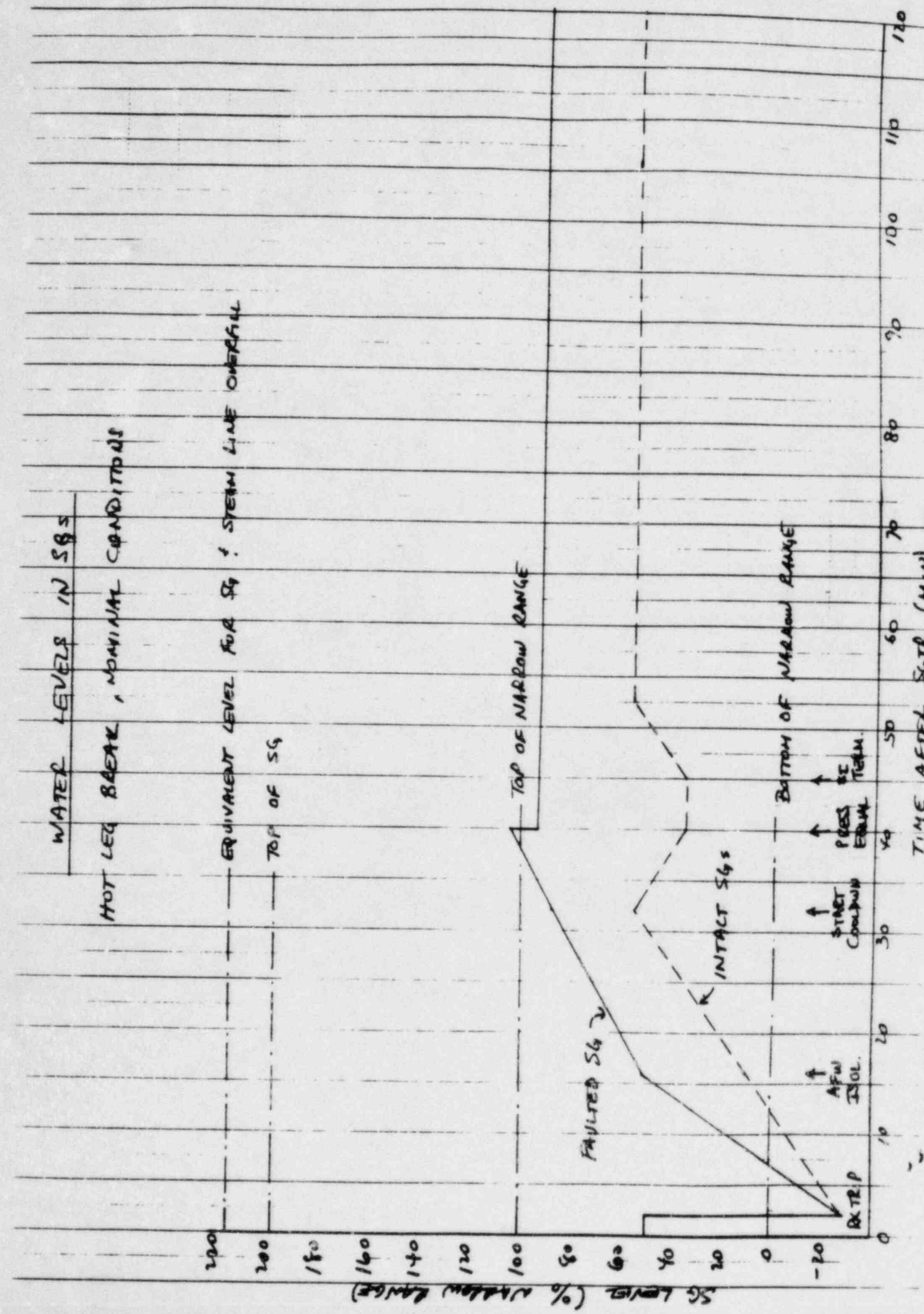


FIGURE 1-4.1

Attachment 1-4

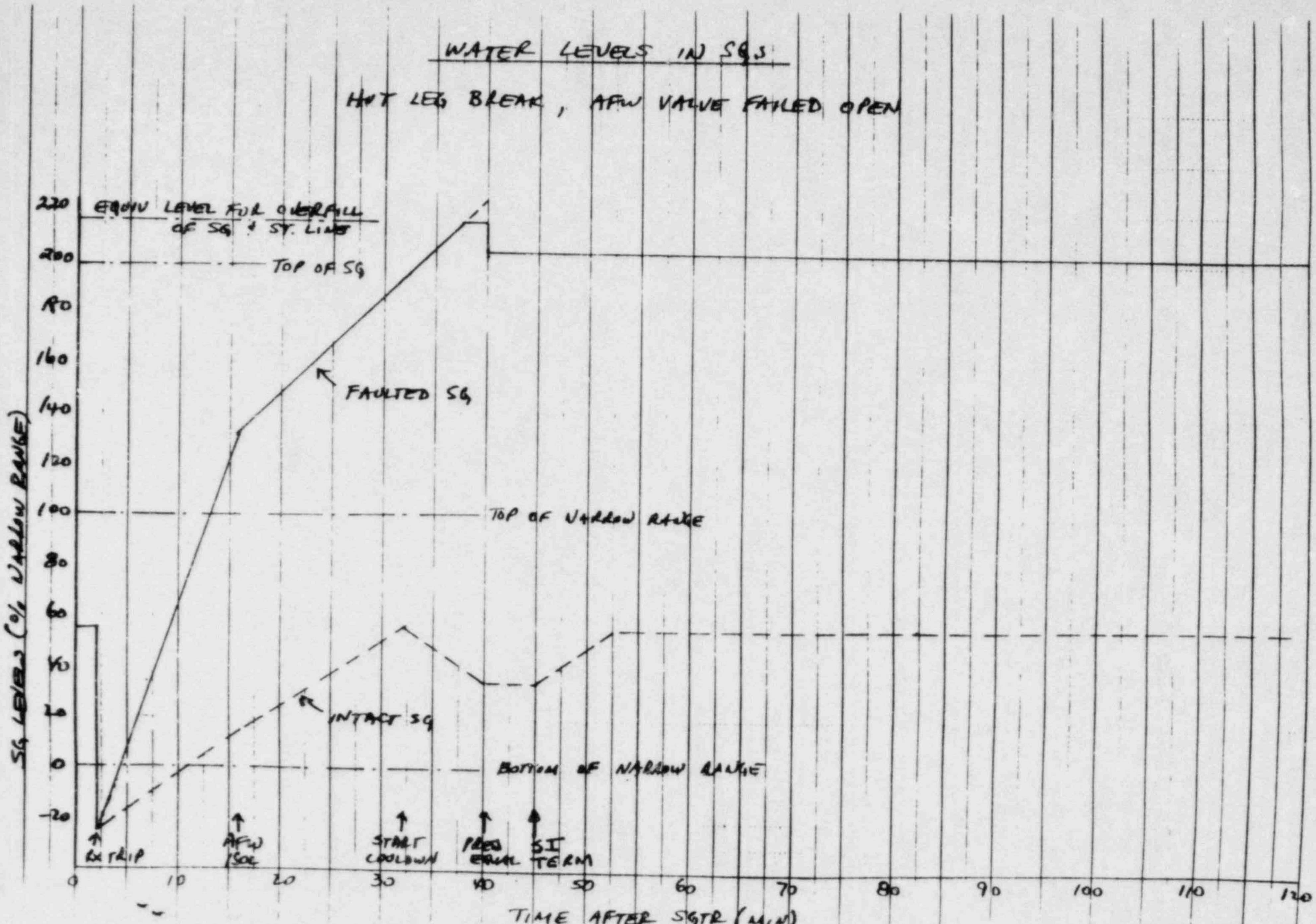


FIGURE 1-4.2

ATTACHMENT 1-4

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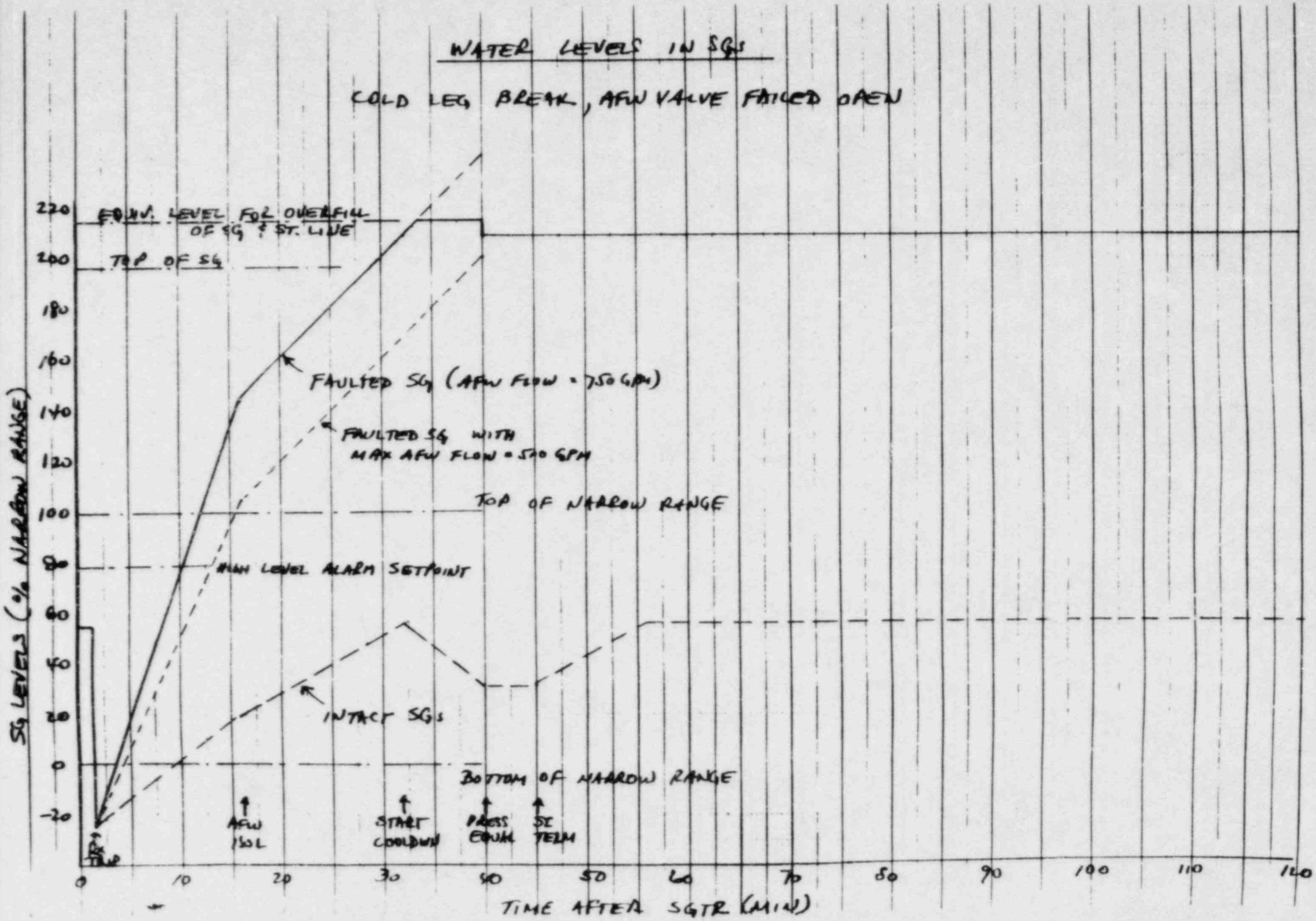


FIGURE 1-4.3

Attachment 1-5

TABLE 1-5.1

SUMMARY OF RESULTS

NOMINAL CASE

320 gpm AFW to each SG
Initial water level in SGs = 50% narrow range (NR)
Hot leg break at tube sheet

Operator action times:	
Isolate AFW	16 min.
Start cooldown of RCS	32 min.
Complete press. equaliz.	40 min.
Terminate SI	45 min.
Equiv. I-131 release	11 Ci (case 1 iodine spiking)
0-2 hr site boundary (SB) thyroid dose (Callaway)	1.4 rem

FAILURE OF TURBINE-DRIVEN AFW PUMP

250 gpm AFW to each SG
Initial water level in SGs = 45% NR
Hot leg break at tube sheet

Operator action times:		
Isolate AFW	16	10 min.
Start cooldown of RCS	32	40 min.
Complete press. equaliz.	40	50 min.
Terminate SI	45	60 min.
Case 1 iodine spiking:		
Equiv. I-131 release	11	17 Ci
0-2 hr SB thyr. dose (Call)	1.5	2.2 rem
Case 2 iodine spiking:		
Equiv. I-131 release		97 Ci
0-2 hr SB thyr. dose (Call)		13 rem

TABLE 1-5.1 (Contd.)

AFW CONTROL VALVE FAILED OPEN

750 gpm AFW to faulted SG
320 gpm AFW to each of 2 intact SGs
250 gpm AFW to 3rd intact SG
Initial water level in SGs = 55% NR
Hot or cold leg break at tube sheet

Operator action times (min.):				
Isolate AFW	16	20	24	28
Start RCS cooldwn	32	40	40	40
Compl. pr. equal.	40	50	50	50
Terminate SI	45	60	60	60
HL break; Case 1 iodine spiking:				
Eqv I-131 rel (Ci)	21	114	136	144
0-2 hr SB thyr. dose (Call) (rem)	2.7	14.8	17.7	18.7
HL Break; Case 2 iodine spiking:				
Eqv I-131 rel (Ci)	138			953
0-2 hr SB thyr. dose (Call) (rem)	18			124
CL Break; Case 1 iodine spiking:				
Eqv I-131 rel (Ci)	33	131	144	154
0-2 hr SB thyr. dose (Call) (rem)	4.3	17.0	18.7	20.0
CL Break; Case 2 iodine spiking:				
Eqv I-131 rel (Ci)	215			1077
0-2 hr SB thyr. dose (Call) (rem)	28			140

TABLE 1-5.1 (Contd.)

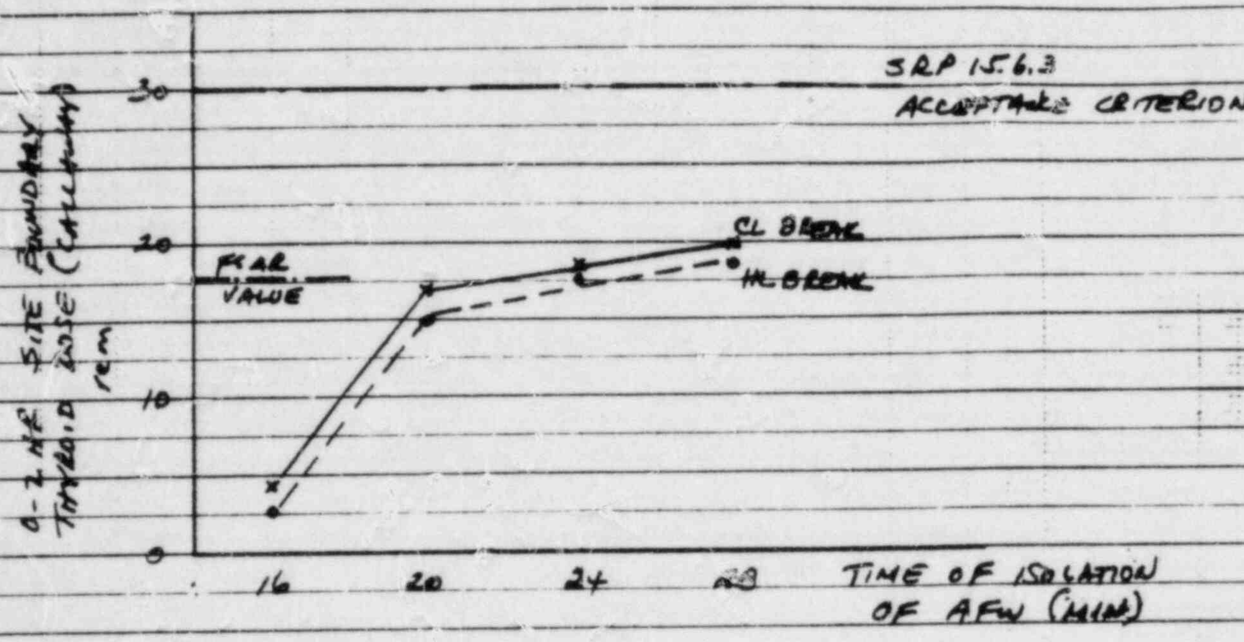
ARV STUCK OPEN

	Block Valve Isolation Time 20 Min.	30 Min.
At Reactor Trip		
Case I with AFW	14 Ci/1.8 Rem	31 Ci/4 Rem
Case I without AFW	14 Ci/1.9 Rem	35 Ci/4.5 Rem
Case II without AFW	175 Ci/23 Rem	280 Ci/36 Rem
At 20 Min.		
Case I with AFW		
Terminated at 10 Min.	40 Ci/5.1 Rem	66 Ci/8.5 Rem
At 30 Min		
Case I with AFW		
Terminated at 10 Min.	70 Ci/9.2 Rem	102 Ci/13 Rem

DOSE SUMMARY

SGTR WITH AFW CONTROL VALVE FAILED OPEN

CASE 1 IODINE SPIKING:



CASE 2 IODINE SPIKING

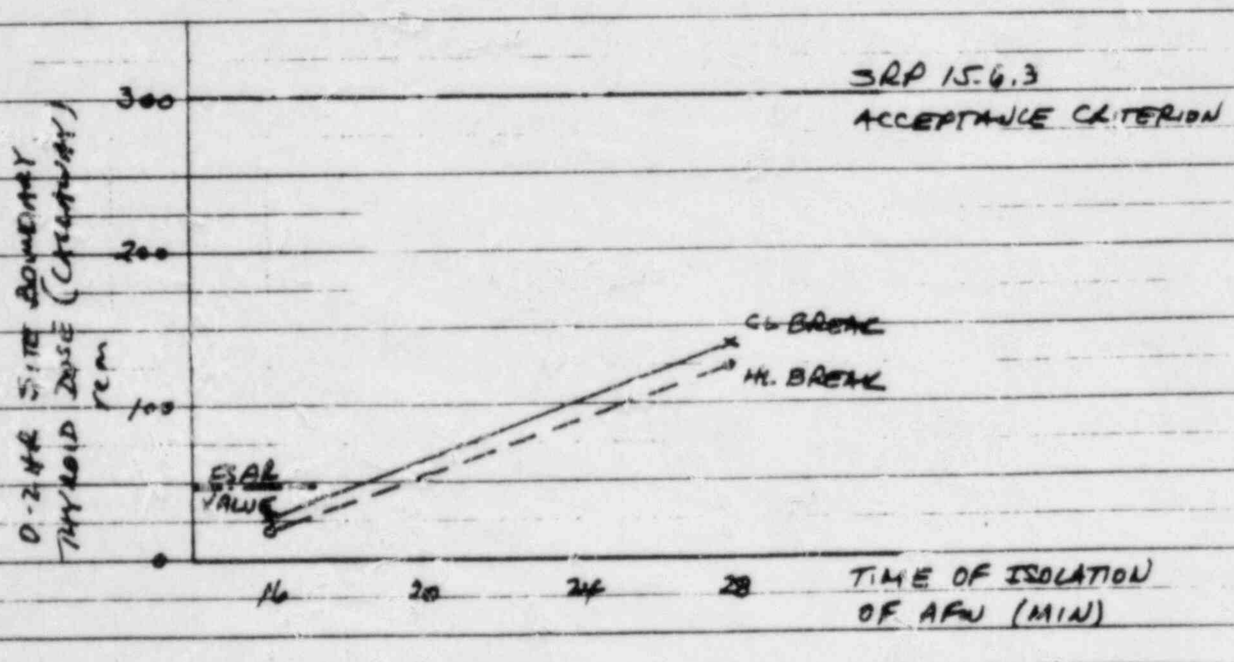


FIGURE 1-5.1

DOSE SUMMARY

SGTR WITH FAILED OPEN RELIEF VALVE (ARV) ON FAULTED SG

Case 1 Iodine Spiking Model

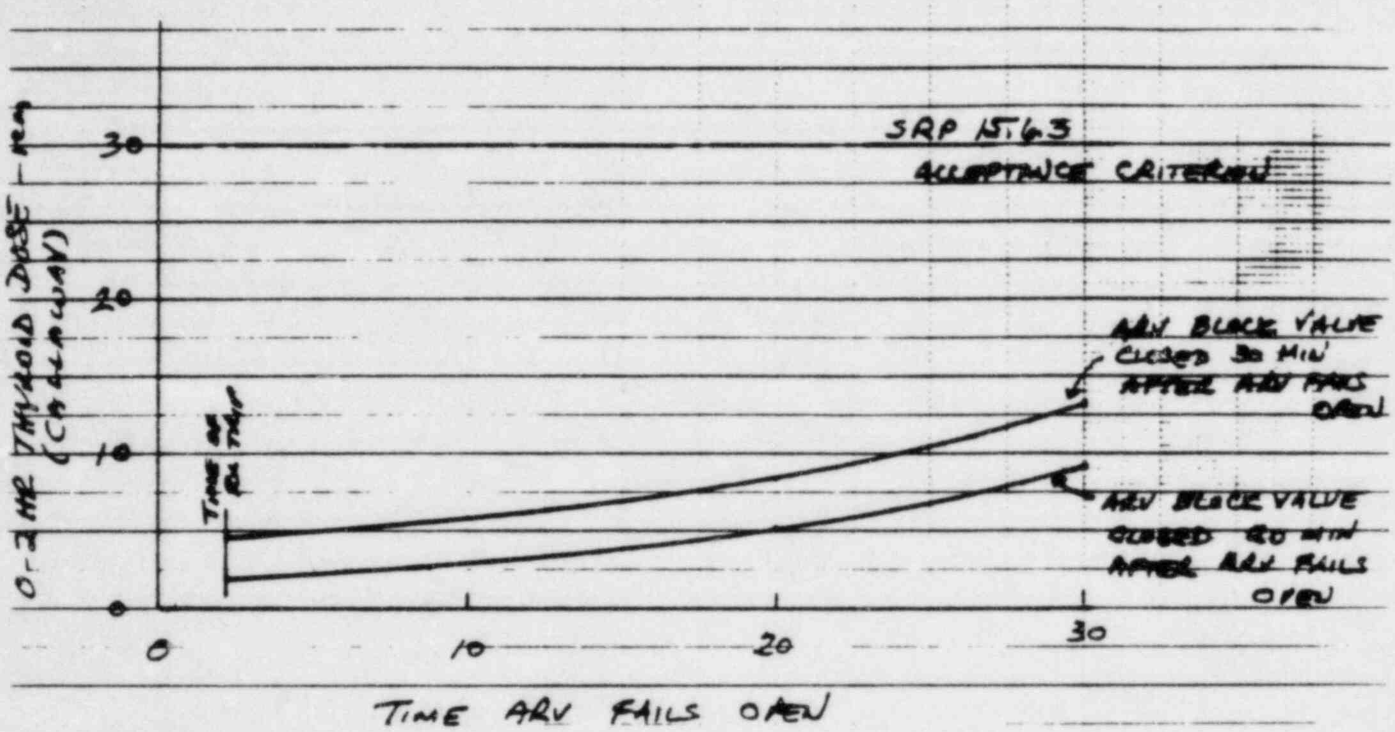
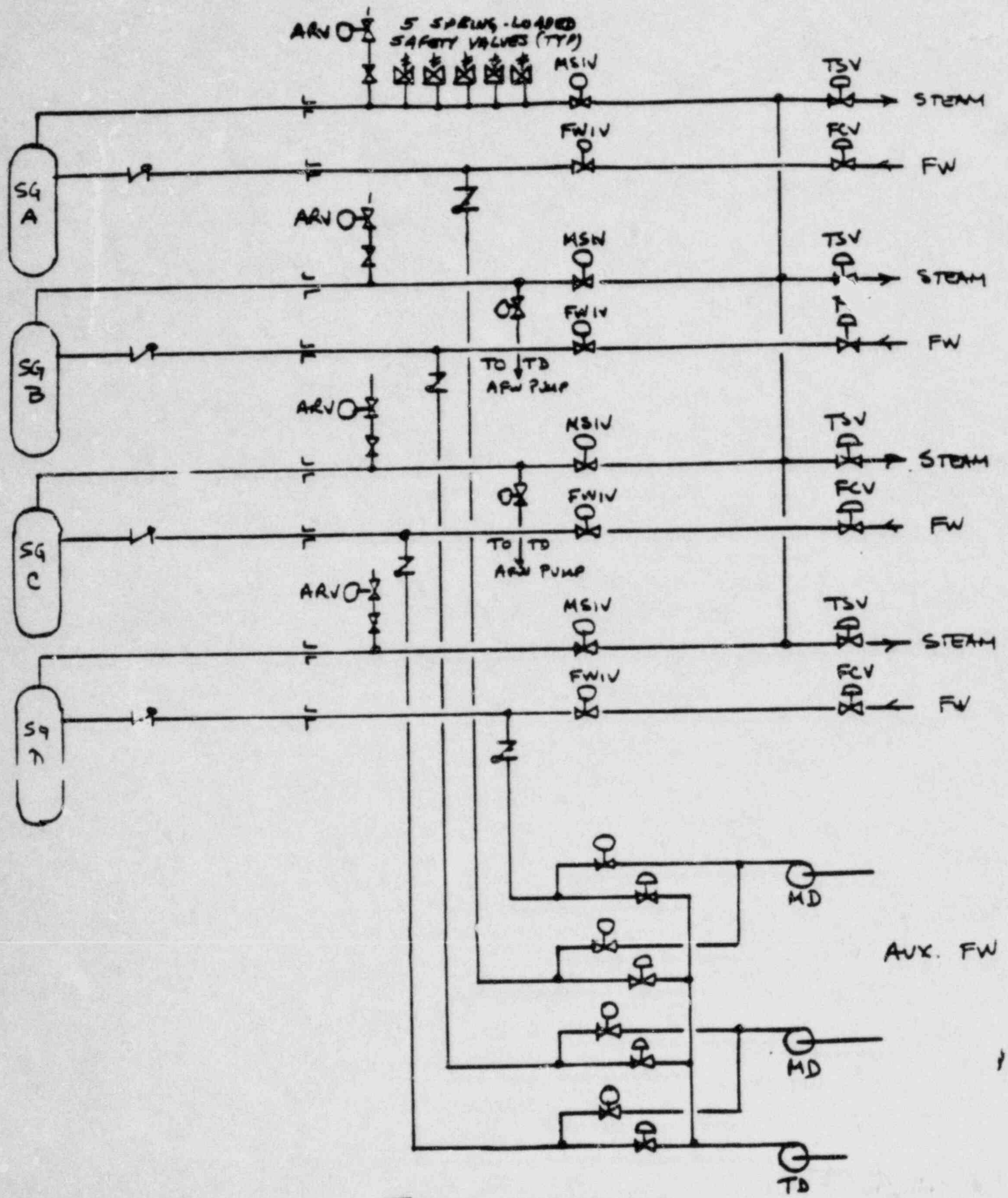


FIGURE 1-5.2

Schematic Diagram of SNUPPS Secondary Systems



F 3-1.1