September 24, 1996

MEMORANDUM TO: Noel Dudley
Senior Staff Engineer
Advisory Committee on Reactor Safeguards

FROM: Robert C. Jones, Chief
Reactor Systems Branch
Division of Systems Safety and Analysis

SUBJECT: FORWARDING EPRI RESPONSE TO SEVERE ACCIDENT QUESTIONS

During the ACRS Subcommittee meeting on June 4, 1996, Dr. Catton requested material which had been made available to the staff by NEI in response to questions regarding the EPRI draft report, "Risks from Severe Accidents Involving Steam Generator Tube Leaks or Ruptures" (TR-106194, January 1996).

A previous memo to you (August 22, 1996) transmitted the informal NEI response. Attached is the complete NEI response including the information on steam generator inlet mixing that Dr. Catton requested. The hand calculation referred to during the meeting is part of the Question 2 response.

Attachment: As stated

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NUCLEAR ENERGY INSTITUTE

R. Clive Callaway
SR PROJECT MANAGER
ENGINEERING

September 17, 1996

Mr. Timothy Reed
Project Manager
Materials and Chemical Engineering Branch
Division of Engineering
Office of Nuclear Reactor Regulation
U.S. Nuclear Regulatory Commission
Washington, DC 20555

SUBJECT: EPRI Responses to NRC Questions on EPRI TR-106194, "Risk from Severe Accidents Involving Steam Generator Tube Leaks or Ruptures."

Dear Mr. Reed:

Enclosure 1 contains answers to questions that were discussed during a recent conference call with NEI, EPRI, and the NRC regarding the subject report.

If you have any questions regarding this material, please call me at (202) 739-8114.

Sincerely,

R. Clive Callaway

R. Clive Callaway
Enclosure

c: NEI Task Force on Steam Generator Rulemaking (w/enclosure)
Joe Donoghue, NRC (w/o enclosure)
Steve Long, NRC (w/o enclosure)

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In evaluating the answers presented below to the questions posed, it should be realized that the draft report (EPRI TR-106194) was prepared as a study of risk impact, recognizing the uncertainties associated with severe accident analyses. Because of these uncertainties evaluation of primary system loop behavior and its structural behavior is difficult. Hence, the report develops base-case results and presents sensitivity studies over what are judged to be reasonable ranges of uncertainties. A review of this report reveals these uncertainty ranges are quite broad. Nevertheless, the computed variations in risk associated with steam generator tube ruptures during station blackout (SBO) events were not sufficient to call the overall plant risk into question. Work done since to better assess the potential for safety valve failure during these events has resulted in predictions of lower risk impact than appear in the subject draft report.

Specific answers to the submitted questions are as follows.

1. As the author of the question correctly notes, Figure 4-7 shows that oxidation of the zircaloy cladding begins in earnest at about 12,800 seconds. In addition, Figure 4-3 shows that the natural circulation flow rates drop quickly as the zirconium oxidation transient proceeds over the time frame from about 12,800 to 13,000 secs. This is due to the drop in gas (i.e., the steam and hydrogen mixture) density, which occurs as gas temperature and the volume fractions of hydrogen in the upper plenum, hot legs, and steam generators increase. The flow rates begin to recover after 13,000 secs, when the hydrogen production has largely finished, then are reduced to zero when the hot leg ruptures soon thereafter.

   Figure 1 (attached) shows the increase in specific volume (drop in gas density) calculated for the same sequence in a Westinghouse 4 loop plant around the time of the zirconium oxidation transient. Natural circulation flow rates are approximately proportional to the average density which exists on each of the flow loops. Figure 2 illustrates the natural circulation flow rates when hot leg rupture is suppressed; as shown, the flow rates respond in the expected manner to the changes in gas density.

   It is worth noting that MAAP predicts a very high rate of hydrogen production compared to a comparable case run with SCDAP/RELAP5 (Figure C.15 in NUREG/CR-6075, Supplement 1). Natural circulation flow rates were not shown in the NUREG, but it is likely that the magnitude of the temporary drop in natural circulation flow rates will be larger in MAAP for the reasons cited above. Since the steam generator tubes respond more quickly to the temperature rise in the upper plenum than do the hot legs, a rapid oxidation rate is conservative.

2. The MAAP hot leg/steam generator natural circulation model calculates the flow rates in the hot legs and steam generators given a user-input value for the fraction of tubes carrying "out" flow (from the inlet plenum to the outlet plenum) and the various temperatures, gas densities, etc. calculated by the rest of the code. When applied to the Westinghouse experiments, this model does a good job reproducing the data when the appropriate value for the tube fraction is input.

   As shown in Table A-3 of EPRI TR-102815, the various experiments exhibit ratios of steam generator to hot leg flow of about 1.7 to 2.3. Both steady-state and transient experiments were run by Westinghouse. In the former, cooling water was supplied to the apparatus to keep temperatures and flow rates constant; in this sense the steady-state results are not directly applicable to the reactor case, in which temperatures steadily increase with time. The steady-state tests shown in the table exhibit flow ratio values in the range from 1.7 to 2.2 while the transient experiments show values from 1.9 to 2.3. Compared to the transient tests, the steady-state tests generally have a larger mismatch in the fraction of tubes carrying flow from the hot leg to the cold leg rather than the reverse direction. Stated another way, the optimal ratio (that which would produce maximum flow) of the number of tubes carrying "out" flow to "back" flow is a little larger than 50 percent, because the density in the out tubes is lower and the velocity therefore higher (for equal flow areas) compared to the "back" tubes. The transient tests come much closer to that ideal (area ratios from 55 to 61 percent) than do the steady-state tests (29 to 35 percent), and this at least partly explains the lower flow ratio seen in the steady-state tests. We regard the transient tests as being more representative for the subject accident scenarios, and for this reason generally run MAAP calculations using a 50-50 split.

   Other factors contribute to the differences seen between the various transient experiments and between the experimental results and the MAAP calculations for the reactor cases. A hand calculation, Attachment 1, was performed to explain the trends seen in the experimental data and in the MAAP calculations. Because of the approximations that had to be made, this calculation was not expected to reproduce the precise values of the flow ratio; indeed the calculated values are off by about 15 percent, but it was found that the trends in the data and calculations could be explained fairly well. For example, test T-1 had the lowest reported steam generator to hot leg flow ratio for the transient tests (1.9). Compared to the other transient tests, this experiment was run with the lowest pressure and lowest core heating. For these reasons, fully turbulent flow was not achieved in the steam generators

(the calculated Reynolds number is about 2600). Fully turbulent flow is predicted in the accident scenarios and was assumed in the scaling analysis of the apparatus (see page 2-3 of the EPRI report). We conclude that the lower range of the observed transient test data (i.e. those seen to develop flow rates near 2.0) are not representative of expected conditions in the accident case.

Explaining the differences between the fully-turbulent transient tests and the MAAP calculations (flow ratio of about 2.3 in the former versus 3.0 in the latter) requires careful analysis. Based on the results shown in the attachment, other factors that contribute to differences between the experiments and the calculations is the non-ideal nature of both sulfur hexafluoride and steam at the pressures and temperatures of interest, and differences in geometry.

For all these reasons, we believe that it is necessary to use a model which calculates the flow rates, and the flow rate ratio cannot be assumed to be that obtained in any particular experiment.

3. We did not attempt in EPRI TR-106194 to establish the manner in which the pressurizer safety valves would fail, but have recently carried out a failure modes and effects analysis (FMEA) and developed a cumulative damage failure model that appear in a draft report entitled Safety Valve Reliability Considerations During High Pressure Station Blackout Severe Accidents.[1] Although we believe that we now have a much better understanding of how the valves would fail than before, we have found no data to establish that they will fail fully-open. A number of tests carried out by EPRI, during which sub-cooled water was challenging pressurizer safety valves, had to be terminated by pulling up the valve lifting lever with a rope, thus lifting the valve stem to stop the excessive chattering. Thus, there were no tests carried through to complete valve failure.

   This does not mean, however, that the RCS would remain at a pressure sufficiently high to challenge flawed tubes if the valve remained partially stuck-open. Indeed, it is likely that the RCS pressure would indeed decrease. Sensitivity calculations were performed with MAAP to understand the effect of partially-stuck-open valves. These results indicate that surge line failure will occur prior to hot leg failure (and well before steam generator tube failure) if the valve is stuck open in such a way as to have half its rated flow area or more, and temperatures will therefore be substantially mitigated compared to cases where the valve re-seats after lifting. If the safety valve flow area is only one quarter of that corresponding to a fully stuck-open

[1] Presently, this report is under industry review.

valve, then steam generator tube temperatures in the MAAP calculations are not substantially different than for cases with no stuck-open valve and hot leg rupture occurs approximately coincident with surge line rupture (and still well before steam generator tube failure). However, with only one quarter of a stuck valve (or less), additional valve lifts would occur in the still-intact safety valves, making it likely that they will also stick open when challenged by sub-cooled liquid.

4. The question cites SCDAP/RELAP5 calculations which show periods of RCS re-pressurization to 1400 psi, caused by accumulator injection into a damaged core. These pressure spikes give rise to high steam generator tube temperatures, presumably by displacing high temperature gas to the steam generators.

   MAAP calculations indicate that the discharge of the accumulator to the reactor coolant system will occur in a quasi-steady fashion. No substantial pressurization is observed since small increases in core water level cause small increases in pressure which temporarily arrest the accumulator discharge. Typical results are shown in Figures 3 and 4; it should be noted that hot leg rupture was predicted to occur at 11,900 seconds, but was suppressed for illustrative purposes.

   Because of the unavailability to industry of the SCDAP/RELAP5 calculations referred to by the author of Question 4, we reviewed Appendix C of NUREG/CR-6075, Supplement 1, which may contain similar calculational results. Figure C.26 of this report indicates that for Case 3 (480 gpm per RCP seal LOCAs) the onset of accumulator injection, at a pressure of approximately 4 MPa (600 psi), leads to a short period of accelerated RCS depressurization. Consequently, a rapid discharge of water occurs to the RCS which then leads to rapid steaming and pressurization to about 9 MPa (1300 psi).

   Case 2 in NUREG/CR-6075, Supplement 1 (Figure C.17) has smaller seal LOCAs (250 gpm per pump) and therefore exhibits accumulator discharge after hydrogen production is nearly complete. In this case there appear to be two short periods of accelerated accumulator discharge, although the magnitudes of each are much smaller than in Case 3. The pressure spike occurs nearly 1000 secs after the first of these, when water re-enters the core region. The resulting pressure spike is significantly smaller, reaching about 6 MPa (900 psi).

One explanation for the much greater rate of depressurization in Case 3 compared to Case 2 is that rapid condensation of steam occurs in the former as the cold accumulator water is injected. In Case 2, the presence of substantial quantities of hydrogen would tend to suppress such condensation. If this interpretation is correct, then Case 3 represents the worst possible case: at the time of reflood the core temperatures are high enough to potentially threaten the tubes, but the timing of core uncovering and complete dry-out is such that hydrogen has not yet been produced.

Even in sequences such as Case 3 where there is little or no hydrogen present in the system, we would expect that the introduction of water into the overheated core would immediately create enough steam to overwhelm the condensation and (momentarily) stop further accumulator discharge. This reasoning suggests that it would not be likely that enough accumulator water could be added to reach the core mid-plane (as indicated in Figure C.27 of the NUREG) nor could accumulator injection cause a subsequent large pressure spike.

We have not performed an extensive review of the literature, but we note that NUREG/CR-4393 (pages 56-58) indicates that the decline in primary system pressure caused by condensation on accumulator water in Semiscale was very modest for the large end of the small break regime (10 percent equivalent breaks). For smaller breaks, more applicable to pump seal LOCAs, the NUREG states that the "accumulators appeared to *float* on the system pressure" (italics in the original). The latter is typical of the behavior seen in MAAP calculations.

A different mechanism for introducing large amounts of accumulator water before high steaming rates occur is to assume that substantial flow blockages exist at the bottom of the core. In this case water would collect in the downcomer until sufficient static head accumulates to overcome the resistance to flow. The existence of such blockages would not explain the difference in depressurization between Cases 2 and 3. In fact, the greater amount of core damage in the former would presumably lead to a larger effect. Furthermore, hand calculations indicate that quasi-steady RCS depressurization (such as would develop in the absence of rapid condensation, given the presence of hydrogen after significant core damage) limits the rate of accumulator water discharge. Accordingly, storage of water in the downcomer would be minimal for flow areas that would realistically be expected to exist around a damaged core.

To resolve this issue, it would be useful to confirm in the SCDAP/RELAP5 calculation that the condensation rates on the injected accumulator water are

reasonable, and that steaming from the core has a reasonable magnitude and is not somehow delayed as the water level is recovered.

5. As requested, additional plots for the cited sequence are attached (Figures 5 to 7). The run was terminated at the calculated time of hot leg rupture. The peak tube temperature at the time of hot leg rupture is inferred from Figure 6 to be about 1035 K. As in the other MAAP calculations, the tube damage index is calculated assuming 50 percent thinning.

   It should be noted that an increase in the probability of NORUPT-3 from 0.5 (assumed in draft EPRI TR-106194) to 1.0 would have little impact on the overall results, since the affected end-state R7 has such a low frequency. Specifically, the likelihood of the largest source term bin (composed of end-states R3, R5, R7, and R11) would increase by only 20 percent, and this bin would still only comprise 2 percent of all the sequences considered.

6. No calculations were performed during the severe accident study in order to arrive at the 100 gpm value for assumed primary-to-secondary leak rate, given depressurization following failure of a MSSV to re-seat after lifting. This value was initially established, although not documented, during EPRI's Steam generator Degradation Specific Management (SGDSM) Program, as an estimate of the leakage that could result during non-severe accident conditions such as would result from a main steam line break that induced leakage through degraded tubes. It was assumed to be the maximum allowed leakage at EOC following such an accident, for purposes of carrying out an operational assessment. This value is dictated by radiation dose allowables for design basis accidents. Updated dose analysis specifies a maximum allowable value of 200 gpm, as explained below. Note that the actual expected leakage, given relatively severe tube damage conditions, is far less than 100 gpm (see, for example, Chapter 2 of Probabilistic Safety Analysis Support for Steam Generator Degradation Specific Management, where an example is shown that leads to a value of 13.8 gpm).

   After completion of the above-noted calculations, the Draft Industry Guideline for Implementing Steam Generator Tube Integrity Rule was prepared. It proposes a higher upper-bound value, namely, 200 gpm, in conjunction with meeting 10 CFR 100 dose requirements. This value represents leakage corresponding to roughly one-third of that from a ruptured tube; such leakage would not significantly affect thermal-hydraulic behavior, relative to a 100 gpm leak, since the RCS pressure would remain at about the pressurizer safety valve set point in either case. The risk impacts of

using the higher allowable leak rate are not expected to change appreciably, since hot leg rupture and its attendant effects on fission product release are still very likely.

7. The differences between the "Zion-like" non-proprietary model used in the EPRI study and a more accurate model for a Westinghouse 4-loop plant are identified in the attached memorandum which was previously sent to INEL at the Staff's request.

8. The event tree shown on Figure 5-1 of EPRI TR-106194 encompasses high-pressure station blackout scenarios, all of which involve loss of all feedwater. As the author of the question correctly observes, early core damage cases characterized under Plant Damage State Group 3 (Fast SBO) in NUREG/CR-4550, Volume 3, Revision 1, Part 1 for Surry fall into this category. Their core damage frequency (CDF) was determined to be 5.4E-6 per reactor year. In addition, some of the sequences making up Plant Damage State Group 1 (long-term station blackout) are included as well. These long-term SBO sequences include (see NUREG/CR-4550, Vol. 3, etc., pp. 5-29 to 5-32):

Sequence	CDF
T_{1SU1} - NR7	6.8E-6
T_{1SU1} - QS-NR7	2.4E-6
Total	9.2E-6

For these two sequences, batteries are depleted after four hours, at which time instrumentation needed to measure steam generator level is no longer available, and the turbine-driven auxiliary feedwater (AFW) pump is conservatively assumed to fail immediately. Both the reactor coolant system and steam generators had been depressurized prior to this time. With closure of the atmospheric dump valves, the RCS and the steam generators repressurize, the core uncovers, and core damage ensues.

Referring to the response to Question 9, it is evident that the AFW would continue to operate after battery depletion, and in fact may well operate until the condensate storage tank (CST) is depleted. The likelihood of recovery of AC power during this period is high. Thus, the CDFs listed above would be considerably lower if credit were given for continued AFW operation and either recovery of AC power before CST depletion or refill of the CST.

In addition to the long-term SBO sequences listed above, four other long-term SBO sequences involving pump seal LOCAs, also contribute to Plant Damage

State 1 in NUREG/CR-4550. It is assessed in NUREG-1150 that seal LOCAs do not occur until 1.5hours after loss of seal cooling, and that 1/3 of these lead to very small leaks (21 gpm per pump), such that the RCS remains at high pressure. The four sequences involved, and their CDFs, are:

T_{1SU1} - W_2 - NRSL	3.5E-6
T_{1SU2} - NRSL	2.4E-6
T_{1SU1} - QS - W_2 - NRSL	1.5E-6
T_{1SU2} - QS - W_2 - NRSL	8.8E-7
Total	8.3E-6

Since one-third of the time the Seal LOCA flow rate is very small, the contribution to the event tree is

8.3E-6/3 = 2.8E-6

Thus, applying the event tree to NUREG/CR-4550 for Surry would require an entry core damage frequency computed as follows:

Fast SBO:	5.4E-6
Long-term SBO/loss of feedwater:	9.2E-6
Long-term SBO/small seal LOCA:	2.8E-6
Total	1.7E-5

Note that the value 1.0E-5 listed on the event tree is for illustrative purposes only and the individual end-state frequencies for any assumed entry frequency can be obtained by taking ratios. In fact, the risk impact analysis shown in Chapter 7 of EPRI TR-106194 used 1.4E-5. This value was derived from a discussion on page C-66 of NUREG-1150, where it is stated that

> "In the Surry analysis, approximately 71 percent of these accident progressions result in a failure of the seals in at least one reactor coolant pump. Of these, roughly one-third are estimated to result in a large enough leak rate to depressurize the reactor vessel to 200 psia prior to reactor vessel breach; another third result in leak rates small enough to preclude any significant depressurization. In the remaining one-third of the cases, the reactor vessel is at an intermediate pressure (200-600 psia) at the time of vessel breach."

There would be no leakage through the pump seals for the remaining 29% of the accident sequences.

As stated on page 5 of EPRI TR-106194, the probability of a high-pressure SBO was calculated as

$$(0.71/3 + 0.29) \times 2.7E\text{-}5 = 1.4E\text{-}5 \text{ per reactor-year}$$

Thus, the value obtained by consideration of the assumptions and details in NUREG/CR-4550 is about 15% higher than that used in EPRI TR-106194 Draft, Revision 0.

The SBO event tree is used only for sequences involving total loss of feedwater. Other sequences, such as ATWS, need to be considered separately. Just as the consequences of MSLB-induced core damage scenarios can be encompassed under those of the spontaneous SGTR, so could those of ATWS events leading to core damage. After the initial tube ruptures from RCS overpressure, the accident would progress in a manner similar to the spontaneous SGTR. That is, the same types of operator actions would be taken and the same time frames would be involved. The environmental releases would be similar. Since the core damage frequency of such an event is significantly lower than that of a spontaneous SGTR, it is appropriate to bin it with the SGTR instead of with the SBO.

9. It has recently become apparent that a further assessment of depressurization mechanisms, safety valve failure mechanisms, and probabilities of safety valve failure is necessary in order to better quantify the event tree. The tree was originally envisioned to represent station blackout (SBO)-like accident sequences for which the reactor coolant system (RCS) remained at high pressure. We did, however, consider the possibility of operator-initiated depressurization of the secondary side (see pp.31-32 of the report).

   For high-pressure scenarios, it was realized during event tree construction that both pressurizer safety valves (PSVs) and main steam safety valves (MSSVs) would be challenged, and that the probabilities of failure to re-seat after lifting needed to be accounted for in the model. It seemed reasonable to select valve failure probabilities from NUREG/CR-4551, Vol. 3, Rev. 1, Part 1 for this purpose, but to do sensitivity studies that reflected the degree of uncertainty associated with these values.

   Subsequent to preparation of EPRI TR-106194, it was discovered that the valve failure probabilities chosen were not always consistent with tests that have been carried out on Dresser and Crosby safety valves, performed by the valve manufacturers and under the auspices of EPRI. For example, failure of MSSVs to re-seat after lifting has not occurred after more than 1500 tests.

Because of this discovery, it was decided to do a more thorough assessment of both pressurizer safety valve (PSV) and MSSV failure probabilities and, if appropriate, re-quantify the event tree. This new assessment considers both safety valve tests and actual operating experience, and is reported in EPRI draft final report, Safety Valve Reliability Considerations During High Pressure Station Blackout Severe Accidents.[2] Both test data and operational experience are considered in order to develop a failure model based on cumulative damage to the valves, New values of valve failure to re-seat on demand are determined, and new probabilities of valve failure probabilities are determined, as functions of the numbers of lifts. It is concluded that a more representative value for failure of MSSVs to re-seat after lifting is less than half of the value previously chosen (the calculated value being a function of the percent blowdown assumed; this is a plant- and valve design-specific value that in turn defines the number of valve lifts during the accident).

The SBO accident sequences, and their core damage frequencies, for which the secondary side may be depressurized are listed in the response to question 8, where the entry frequency is now assessed to be about 15% higher than previously stated (if the conservative assumption is still made that AFW fails when batteries are depleted in a long-term SBO). The relevant sequences include fast SBOs, long-term SBOs with loss of feedwater after battery depletion, and long-term SBOs with small seal LOCAs. During this reassessment, a review of NUREG/CR-4550, Vol. 3, Rev. 1, Part 1 revealed that a correct association of safety valve lifts to the SBO accident sequences in which they would occur would also affect re-quantification of the event tree. This is the case for both fast and long-term SBOs. Each case will now be discussed in turn.

In NUREG/CR-4550 for Surry, Plant Damage State 3 (Short Term Blackout) is assumed to result from SBO followed by failure of the turbine-driven auxiliary feed water to start. The mean core damage frequency (CDF) was found to be 5.4E-6 per reactor-year. It was also determined that, in 88% of the sequences, a steam generator MSSV would fail to re-seat after lifting. Details of this assessment could not be found in the report. It can only be assumed that the generic Accident Sequence Evaluation Program (ASEP) value of 0.03 per demand was used. If this is indeed the case, then roughly 23 demands per loop must have been assumed; this value is obtained by: $P_{fail} = 1 - P_{success} = 1 - (1 - 0.03)^d$, where d is the number of demands for all three loops. For a failure probability of 0.88, the number of demands is about 69 or 70. Thus, roughly 23 demands per loop must have been made. It is also assumed that the valves with the lowest set points in each loop were the ones challenged.

[2] Presently, this report is under industry review.

The industry does not consider the 0.03 per demand value to be valid, since neither valve test data nor operational experience support it.

In an accident, the number of challenges to the valve is a function of the percent blowdown relative to the set point pressure before the valve re-seats. That is, the lower the pressure at valve closing, the more fluid is lost during each valve cycle. The mean value of expected blowdown is a function of valve design. For example, EPRI sponsored tests on two Crosby valve designs that involved more than 230 valve lifts. Those with "R" orifices had average blowdowns of 7.2% (varying from 0.3% to 18.1%), while those with "Q" orifices had average blowdowns of 14.7% (varying from 8.7% to 23.3%). More than 1200 tests of Dresser valves led to average blowdowns in the 6-7% range. The actual average value is clearly plant-specific.

In order to reasonably bracket the expected range, MAAP 4.0.2 was used to compute the number of lifts per loop for 5% and 15% blowdowns. The results were, respectively, 84 and 28 lifts per loop, shown as "B S/G" on Figures 8 and 9. These values were subsequently confirmed by hand calculations. For a three-loop plant, then, the total number of lifts would range from 256 to 84, given that the average blowdown fell within the 5-15% range. For a four-loop plant, the total number of lifts would range from 336 to 112. MAAP analyses, then, predict many more challenges than inferred from the NUREG/CR-4550 assessment. If the 0.03 per demand failure probability were assigned, then MSSV failure to re-seat after lifting would be a virtual certainty. However, using the cumulative damage model developed in the above-referenced draft report with the MAAP 4.0.2 results, the new MSSV failure probabilities are considerably lower than before.

A discussion of the role of operator-initiated depressurization during the long-term SBOs follows below; as will be shown, these sequences can still be represented by the event tree, because the secondary side repressurizes after battery depletion.

While reviewing NUREG/CR-4550 for Surry, it was discovered that the choice of 0.27 for failure probability for the MSSVs in NUREG/CR-4551 for Surry was, in fact, based on implementing an emergency operating procedure that would be followed following a loss of AC power, but with DC power available. Specifically, the review revealed that the value was derived from an assessment of failure of MSSVs to re-seat after lifting during the first hour of a long-term station blackout. The procedure includes actions to manually line up valves in the steam system, in order to depressurize the secondary sideby venting through the condenser (ADVs are not available at Surry following total loss of AC power). The purpose of such actions is to cool

down the reactor coolant system (and lower its pressure correspondingly). The assumption was made that, while carrying out the procedure, each MSSV would lift every 20 minutes over a one-hour period. Since Surry has three loops, there would be 9 demands altogether. The probability of failure to re-seat per demand was taken to be 0.03 from a generic ASEP data base. The value 0.27 was simply taken to be the product of 9 and 0.03. It should be noted that, based on the valve test programs, the generic ASEP value of 0.03 per demand is grossly conservative.

Unlike Surry, at most plants the EOPs would instruct the operators to depressurize the RCS by depressurizing the steam generators through the atmospheric dump valves (ADVs). During this period the turbine-driven auxiliary feedwater pumps work, and the flow through the dump valves is controlled in order to maintain steam generator pressure at roughly 260 psig; this value is chosen so that the accumulators do not dump water into the RCS. Thus, the core remains covered while the operators seek to restore AC power.

Once the batteries have been depleted, the ADVs fail closed and the steam generators repressurize. The RCS repressurizes as well (see Figures 10 and 11). The turbine-driven AFW pumps would continue to supply water to the steam generators at the same rate as before the batteries were depleted. The MSSVs would begin cycling open and closed once their setpoint pressures were reached.

If the operators are not successful in restoring AC power from this time onward, then the condensate storage tank could either become depleted or (less likely) a steam generator could refill. In either event, the AFW flow would be lost and the steam generators would dry out (see Figure 12). This situation is similar to that resulting during the fast SBO sequence. Thus, the effect of operator depressurization is to delay challenges to the MSSVs.

Regarding the effects of leakage through MSIVs, the experience with BWRs is that, rarely, flows up to 100 scfh are observed through leaky valves. Such flow rates would lead to negligible rates of depressurization of steam generators.

10. The comment states that 0.05 should be interpreted as the probability per steam generator of a tube rupture, given that maximum differential pressure is imposed on the tubes. The comment goes on to state that the probability of rupture in sequences in which <u>all</u> steam generators are challenged by high

differential pressure should be increased to reflect the number of steam generators in the plant.

We agree with this comment and have performed a calculation to assess the impact on the results provided in EPRI TR-106194. Let b denote the probability that a single steam generator is depressurized. If n is the number of loops, the probability that one or more steam generators is depressurized is most easily calculated by taking one minus the probability that no steam generator is depressurized:

$$P_{depress} = 1 - (1 - b)^n$$

If $n = 4$ and $P_{depress} = 0.27$ (as in the report), then $b = 0.076$. The probability that at least one steam generator undergoes a pressure-induced tube rupture is similarly calculated by determining the probability that no such rupture occurs. If r is the probability that a steam generator ruptures given that it is depressurized:

$$P_{rup} = 1 - (1-br)^n$$

Inserting $r = 0.05$, we obtain

$$P_{rup} = 0.015$$

In the report, the same quantity was calculated on the event tree using

$$P_{rup} = P_{depress}\, r$$

$$= .0135$$

Thus, the refinement in the interpretation of the 0.05 factor has little effect on the results. This is true because in the majority of cases only one steam generator is depressurized.

Question 11. "A better basis is needed for the presumed reduction in spontaneous tube rupture frequency. The evidence to date indicates that the basis for our current frequency estimate, tube ruptures actually experienced, have not been prevented by bobbin coil inspections. Improved inspections usually occur only after an incident forces the licensee to use better inspection techniques, and these are usually limited to specific areas of the generators that have a known occurrence of a particular degradation mechanism. Therefore, it is not clear that improved detection methods have had a significant impact on spontaneous tube failure frequency."

Answer 11. Industry disagrees with the question's discussion, particularly the statement "Improved inspections usually occur only after an incident forces the licensee to use better inspection techniques,...." The implication of the question is that only a steam generator tube rupture (SGTR) "incident" results in improved ISI and that only the affected licensee improves their ISI capability subsequent to the incident. This is an inaccurate evaluation of industry practice, both in this country and overseas, as explained below.

Steam generator reliability, as measured by annual industry-wide capacity-factor-loss and tube-leak-forced-outage-rate values, has increased in large part from improved ISI/NDE capability and techniques, and measures to insure improved sampling and detection techniques are applied to any steam generator that may be susceptible to emerging damage forms (reference 1).

The above noted industry improvements have resulted in a situation where the "standard bobbin coil examination" is now seldom the only examination to which a steam generator is exposed; therefore, assuming future SGTR frequencies using historical data associated with bobbin coil technology is not valid.

Though difficult to quantify, industry does believe that improved ISI/NDE techniques, as currently being used, as well as the trend and desire of the industry to continue to improve this capability for reliability reasons will lead to a continuing improvement/reduction in SGTR frequencies.

That is, improved detection methods do have a significant impact on reducing the frequency of steam generator tube rupture events. Industry considers "inspection methods" to include NDE hardware, inspection sampling plans, and system qualification. This frequency reduction is enhanced further by other steam generator degradation specific management program elements (see reference 3), such as quality control procedures to reduce the occurrence of loose parts, and limiting steam generator operational leakage.

NRC's current Standard Technical Specification (NUREG-0103, NUREG-0212, and NUREG-0452) specify that inservice inspection of the steam generator tubes be performed at periodic intervals. The minimum required inspection sample is 3% of all steam generator tubes per plant. This requirement allows the sample to be allocated among fewer than the total number of steam generators. The results of this inspection are categorized, which may result in further and more extensive inspection of the steam generators. As noted in NUREG-0844 there is no theoretical basis for the initial 3% sample size.

Reference 1 specifies industry's steam generator ISI sampling programs and requirements. These guidelines require in part:

1. preservice inspection of steam generators shall be conducted in 100% of the tubing (tube inspection is defined as inspection over the entire length of the tube) using general purpose eddy-current probes capable of volumetric examination,

2. 100% examination after initial startup or steam generator replacement shall be performed after the initial cycle of operation, a duration not less than 6 effective full power months (EFPM) and not more than 24 EFPM.

3. all steam generators to be examined at each refueling outage if active damage mechanisms have been identified,

4. 100% of the tubing to be inspected within a rolling 60 EFPM time frame. If 60 EFPM occurs during an operating cycle, completion of that cycle is acceptable and is within the stated requirements, and

5. the percentage of the installed tube population to be examined full length during each refueling outage in which steam generators are inspected shall be at least 20%.

If the steam generators are free from active damage mechanisms, some latitude is provided in terms of number of steam generators to be inspected and/or frequency of inspection. For these steam generators, twice the number of tubes in half the number of steam generators may be inspected in a given ISI, or 40% of the tubes in all steam generators may be inspected every other ISI. However, no steam generator shall operate more than two cycles without inspection.

The above requirements are a departure from present day technical specifications. The primary benefit comes from increasing the initial sample size from 3% to 20%.

The technical specifications are interpreted (see reference 2) in light of the sampling plan with the assumption of perfect detection capability. It is found

that at a 90% confidence level, the minimum required 3% sample size is adequate for finding on the order of 75 degraded tubes present in a given steam generator. Increasing the sample size from 3% to 20% results in an approximate six-fold increase in detection sensitivity i.e., the minimum number of degraded tubes required in the total tube population for observation of one degraded tube, is reduced from approximately seventy-five to about twelve. If realistic values of probability of detection (POD) are used in the analysis, the number of degraded tubes increases to approximately twenty.

Therefore, the change in the sample plan alone suggests that earlier detection of steam generator tube degradation will occur and reduce the likelihood of SGTRs over time. Additional requirements noted above, dealing with frequency of inspection, will further enhance early detection of steam generator degradation, thus further reducing the frequency of SGTRs.

Once an active form of degradation is identified in a generator additional tube inspection is required. Expansion requirements are categorized (i.e., categories 1, 2, and3) depending on the number of defects and seriousness of the degradation detected. In summary, for the first category, no further testing is required. If categories 2 or 3 are observed, expanded testing is required by either of the following two paths:

1. A category 2 result, based on identification of a crack-type defect in any sample requires that all of the active tubes, plugs or sleeves be examined in the affected locations. A category 3 result for both crack and non-crack flaw types requires that 100% of the active tubes, plugs or sleeves in that steam generator be examined, and that 20% samples of all unscheduled steam generators also be examined, and

2. Examination and verification of 100% of the tube sections in a critical area.

The expansion requirements summarized above are detailed with further discussion in reference 1.

In addition to the general inspection requirements noted above, specific inspection requirements are imposed when a plant is implementing an alternate repair strategy discussed in reference 3 for a particular tube degradation mechanism. As noted in Section 3.2.2.5 of reference 3, the inspection requirements for degradation specific repair are provided in the utility steam generator program associated with each repair criterion.

Specifically, when degradation specific repair limits are implemented, NDE guidelines are recommended to specify the inspection probes, scope, data acquisition and data analysis required for implementation of the repair criteria. For example, if a utility implements the requirements of NRC Generic Letter 95-05 for ODSCC type degradation at tube support plate intersection, bobbin coil

inspection includes 100 percent of the hot-leg tube support plate intersections and cold-leg intersections down to the lowest cold-leg tube support plate with known ODSCC. This is an increase in inspection coverage from what has been historically implemented within the industry. It is suggested that such practice will lower the probability of an ODSCC induced SGTR. Additionally, it is not unreasonable to expect that such inspection practices for a given degradation mechanism may identify other forms of degradation in the area of interest; further lowering the probability of SGTR events.

Justification for the reasonableness of the above arguments can be found by reviewing the ten SGTR events documented in reference 4. Although industry does not accept the definition of a SGTR* provided by this reference, it is instructive to review these events as they relate to the effectiveness of in-service inspection of steam generator tubes. This review follows below.

The Point Beach Unit 1 event of 1975 occurred at a tube location that had not been inspected prior to the event. It is noted that subsequent inspection of both A and B steam generators after the event identified 127 tubes with apparent reductions in wall thickness greater than 60%, a volumetric defect signal that is easily detectable by a bobbin coil. It is suggested that the 3% sample size requirement for inspection was inadequate, leading to the missed tube degradation.

The Surry Unit 2 rupture event of 1976 occurred from a PWSCC axial crack(s) in a the U-bend region of a small radius tube. Bobbin coil technology being used at this time probably could not detect the cracks. Using a higher gain setting with the bobbin coil can detect large cracks of this nature, which was done subsequent to this event. Eventually in the 1980's, the industry began using rotating pancake coils so that a higher probability of detection would be achieved for crack like defects. This event shows that NDE technology can be used to reduce future occurrences of tube rupture events if the chosen NDE probe is appropriately matched to the degradation mechanism to be detected.

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* Industry believes the proper definition of a SGTR is that it is a rapidly propagating failure or gross ruture, with rupture defined as significant crack plastic deformation and tearing of the crack's ends. This definition is consistent with GDC 14. Tube leakage that does not meet this criteria, but is greater than the normal makeup capacity of the plant (i.e., the definition in reference 4) should not necessarily be considered a SGTR. It should be considered as abnormal leakage. GDC 14 requires the reactor coolant pressure boundary to be designed to have an extremely low probability of abnormal leakage. Abnormal leakage should therefore be defined in a probabilistic sense and not be arbitrarily defined as a value greater than normal makeup capacity of the plant.

Appropriate matching of NDE technology and the type of degradation to be detected is documented in reference 1. Additionally, stress relief was applied to the inner row tubes to mitigate future PWSCC cracking which further reduced the probability of a SGTR from this mechanism.

The Doel Unit 2 tube rupture on June 25, 1979 is similar to the Surry Unit 2 event and is not discussed further.

The Prairie Island Unit 1 event in 1979 was due to a loose part (i.e., a spring wedged against a tube and a flow blocking device on the tubesheet) that remained in the steam generator after sludge lancing and wore against a tube during plant operation. The steam generator was not inspected by NDE after sludge lancing and in any event, it is not known whether NDE inspection would have identified the existence of the loose part. This event shows the need to institute effective quality control procedures when performing work in the steam generator. Implementation of such procedures will be a requirement to satisfy the NRC's steam generator rule (see reference 3). Again, it is apparent that SGTR's should be expected to decrease in the future because of rule implementation for reasons other than enhanced NDE inspection.

The cause of the Ginna Unit 1 SGTR event in 1982 can ultimately be traced to the existence of a loose part, in this case a carbon steel plate laying on the tubesheet in the downcomer region of the steam generator. What makes this event different from the Prairie Island Unit 1 case is that there were NDE indications of apparent tube damage on the tube bundle's outer peripheral region. These NDE indications resulted in the affected tubes being plugged. These plugged tubes continued to suffer loose parts wear until one of them severed at the top of the tubesheet and impacted a non-plugged tube resulting in it's wear and subsequent tube rupture. In this case, NDE inspection indicated existence of a problem and if thoroughly investigated as to cause, would have resulted in the prevention of the SGTR. It is suggested that requirements specified under steam generator degradation specific management (reference 3) in support of the steam generator rule would mitigate this type of situation developing in the future, thus lowing the frequency of SGTR's.

The SGTR event at Fort Calhoun in 1984 was caused by ODSCC in the U-bend region. The ruptured tube had been inspected by NDE in the prior refueling outage. Re-evaluation of the NDE data tape from that inspection indicated a 99% throughwall defect 6 mm along the tube. As noted in reference 2 this indication was missed during the initial analysis of the data due to human error. Subsequent multi-frequency eddy-current testing of all accessible tubes in both steam generators identified three additional tubes with eddy current indications exhibiting depths greater than 40% per cent throughwall. It is assumed these tubes were repaired or plugged. This case shows the need for well defined NDE procedures, qualified NDE analysts and equipment. These

needs are now requirements as part of steam generator degradation specific management (reference 3) in support of the steam generator rule. It is suggested that these requirements will help mitigate similar occurrences of missed indications in the future, thus lowering the frequency of SGTRs.

The North Anna Unit 1 tube rupture event in 1988 and the Mihama Unit 2 tube rupture event in 1991 are similar in nature. Both events occurred due to fatigue cracking caused by excessive tube vibration, due in part to a steam generator manufacturing deficiency. The affected steam generators had as-built conditions for anti-vibration bar placement which did not conform to steam generator design specifications. In these cases it is not apparent that NDE technology would have identified the initial phases of fatigue cracking, if it existed at the time of the refueling outage prior to the tube rupture. Fatigue cracking is inherently difficult if not impossible to identify by NDE in its very early stages, assuming such a stage exists at the time of the inspection. Prevention of this type of tube failure mechanism is based on adequate steam generator mechanical design and a tube material not highly susceptible to corrosion fatigue. NDE technology and inspection requirements play no role in preventing SGTRs due to this failure mechanism. It is possible that sufficiently robust primary-to-secordary leakage guidelines can help prevent fatigue cracking from reaching the rupture stage. Such guidelines are part of steam generator degradation specific management (reference 3) in support of the steam generator rule.

The McGuire Unit 1 rupture event in 1989 was due to a long axial crack initiated on the tube OD and passed through a tube/tube support intersection on the cold side of the unit. A definitive reason for the existence of this crack was not established, although it has been theorized to be associated with a groove created during tube insertion and it's associated high residual stresses. This tube was not inspected in the refueling outage prior to the event. It is suggested that implementation of the requirements of steam generator degradation specific management (reference 3) would have significantly enhanced the probability that this defect would be found in the prior refueling outage. The tube sampling plan used at the plant after startup was consistent with it's technical specifications and the plant consistently implemented evolving industry recommendations during this period of time. In 1988 the plant formally referenced the requirements of the Inservice Inspection(ISI) Guidelines published by EPRI at that time. It is suggested that implementing the sample plan, and using the qualified NDE technology and procedures required by these ISI Guidelines from the start of plant operation would have increased the likelihood that this crack would have been identified before it ruptured.

The Palo Verde Unit 2 event in 1993 was also due to a long axial crack in the upper free span of the steam generator. The key contributing factors for the formation of the crack were: free span crevice formation, localized high void

regions, adverse chemistry, susceptible material microstructure and, possibly, residual stresses from scratches. The location on the tube where the crack occurred was not previously analyzed by NDE. It is not apparent NDE technology and procedures advocated by the steam generator degradation specific management program in support of the rule would if followed have allowed this crack to be identified before it's rupture. NDE procedures put in place after the event helped in part identify localized regions in the steam generator where this type of cracking could occur and appropriate actions were taken to prevent future SGTRs occurring from this mechanism.

Upon review of the above information, one concludes that historically the majority of SGTRs have occured because of unforseen circumstances, human error, use of non-qualified inspection technology, or an inadequate inspection sampling strategy. The latter three problems are effectively being dealt with by industry's steam generator degradation specific management program in support of the steam generator rule.

Finally, it should be noted that EDF in France has been operating within guidelines similar in intent to those that are being proposed by industry's steam generator specific management program (reference 3) in support of the upcoming steam generator rule. Specifically, French regulatory authorities have allowed EDF to leave in service tubes with ODSCC degradation at tube support plate intersections that exhibit voltage levels up to 12 volts (US). In contrast, NRC's Generic Letter 95-05 for ODSCC at tube support intersections allow a repair limit of 2 volts for 7/8 inch OD tubing and 1 volt for 3/4 inch OD tubing.

It must be noted in light of this significant regulatory relief for EDF that occurred in the early 1980's, that during operation up to 1993 of the existing 900MW, PWR plants, comprising 102 steam generators with an average operating time of 70,000 hours, and the existing 1300 MW plants comprising 76 steam generators with an average operating time of 28,000 hours, there has been no occurrence of a steam generator tube rupture (reference 5). Additionally, there has not been a SGTR in France between 1993 and the present. This situation provides hard evidence of how steam generator degradation specific management practices can significantly reduce SGTR events over time.

When serious damage has been identified by NDE inspection within the EDF steam generators, it was the result of causes unknown at the time and therefore difficult, if not impossible to predict. Once identified, this newly found degradation is taken into account with an aggressive inspection program and structural integrity assessment. This sequence of events is similar to US experience noted above. A rational response to new degradation found within a steam generator is defined in the steam generator degradation specific management program prescribed in reference 3. Such response is typical of industry action in the last few years prior to the development of this document.

For example, some plants have found free span axial cracking in the sludge pile and have initiated 100% inpections of the affected region with RPC eddy current technology. Such an extensive inspection with better eddy current technology is not required by past NRC regulations. This type of proactive response clearly reduces the probability of SGTR events associated with this type of degradation.

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1. EPRI Final Report, PWR Steam Generator Examination Guidelines: Revision 4, Volume 1: Guidelines, June 1996

2. EPRI Final Report, PWR Steam Generator Examination Guidelines:Revision 3, November 1992

3. NEI Report, Industry Guideline Implementing Steam Generator Tube Integrity Rule, Draft 0 (January 1996)

4. NRC Contractor Report, Steam Generator Tube Failures, NUREG/CR-6365/INEL-95/0383, April 1996

5. EDF Report, EDF Steam Generator Tube Guidelines Policy and Surveillance Programs 1993 Update, Revision 0, D.567/93-7109NT

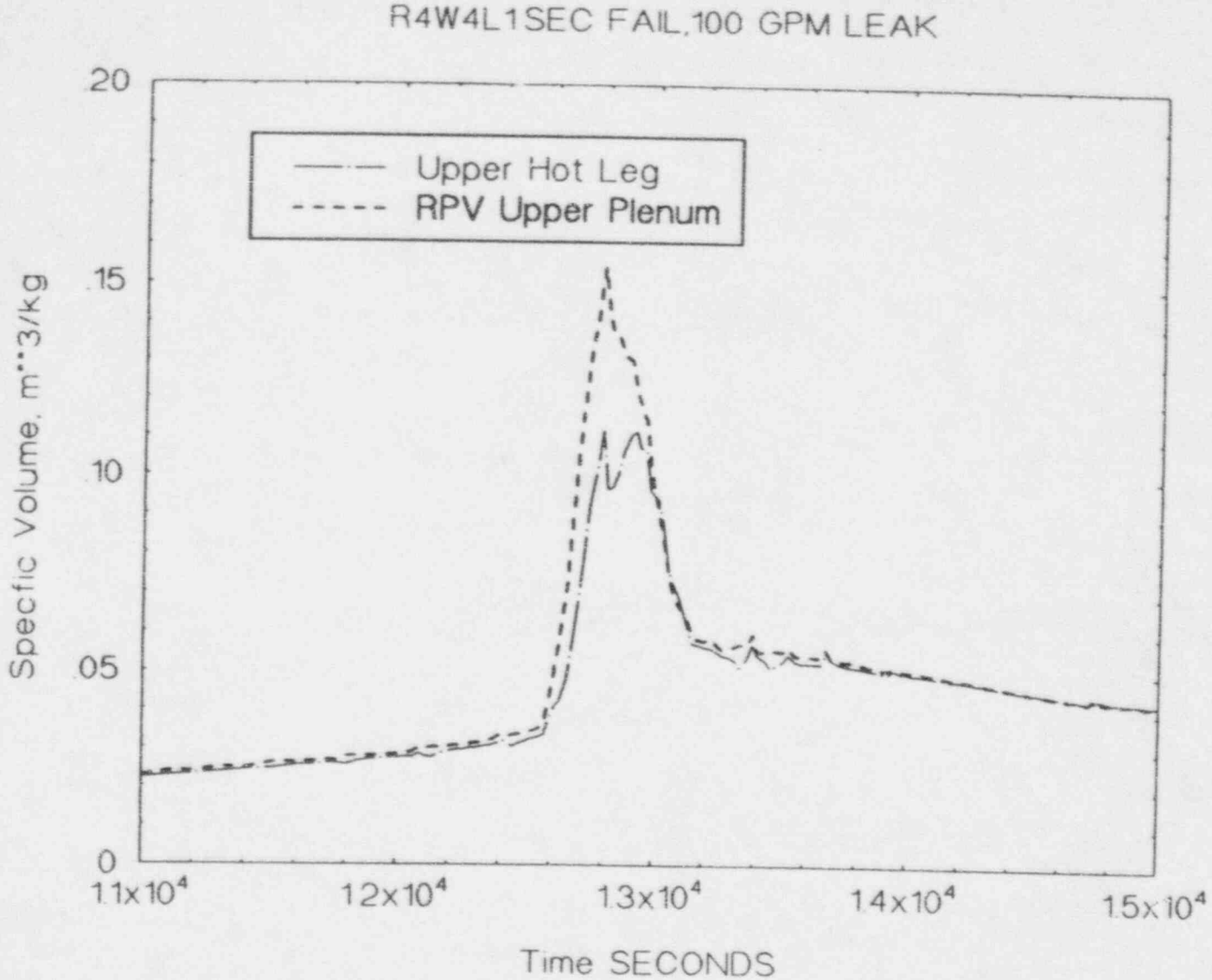

Figure 1

Reduction in Gas Density During Zirconium Oxidation Transient

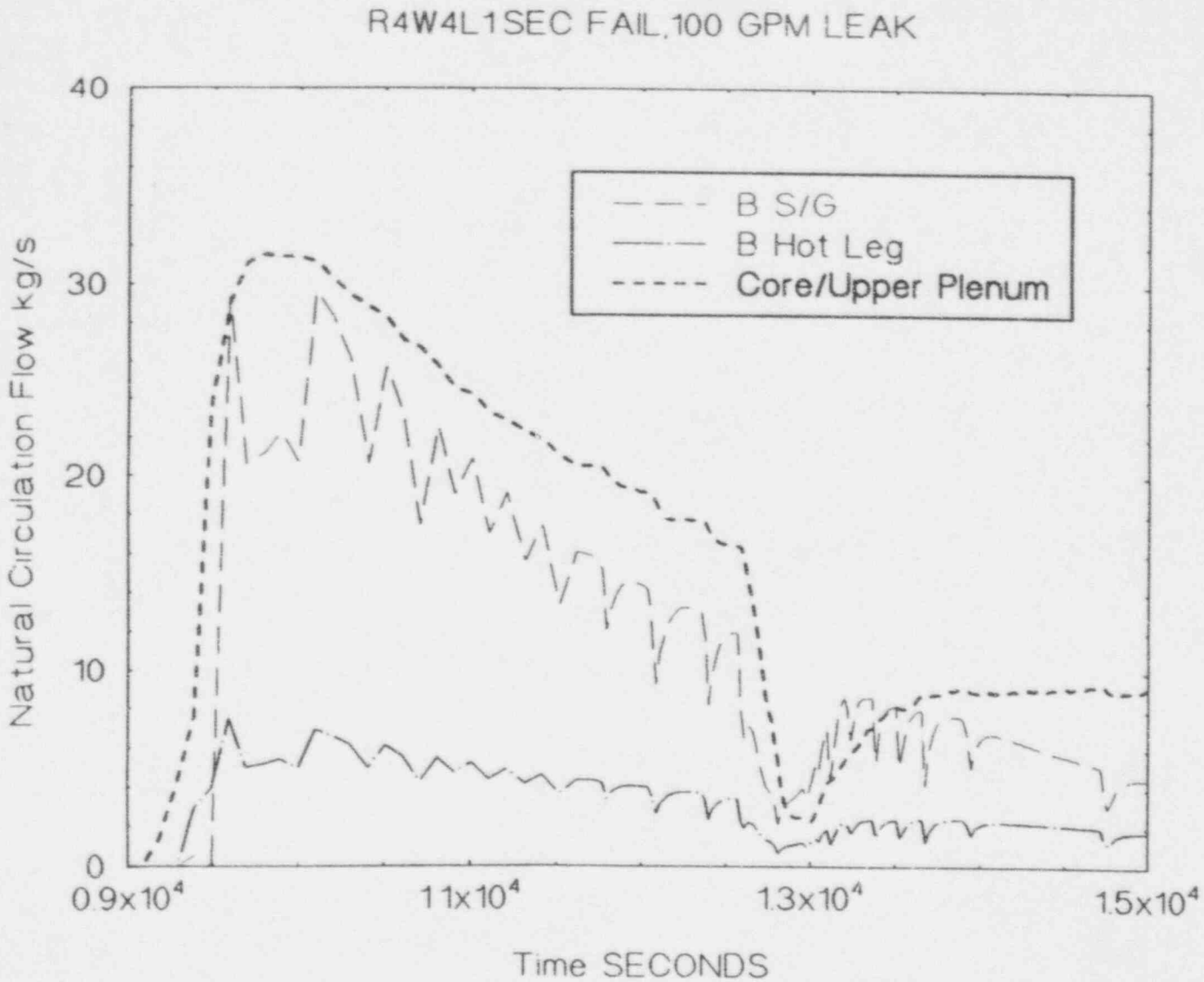

Figure 2

Natural Convection Flow Rates in Core and B-loop

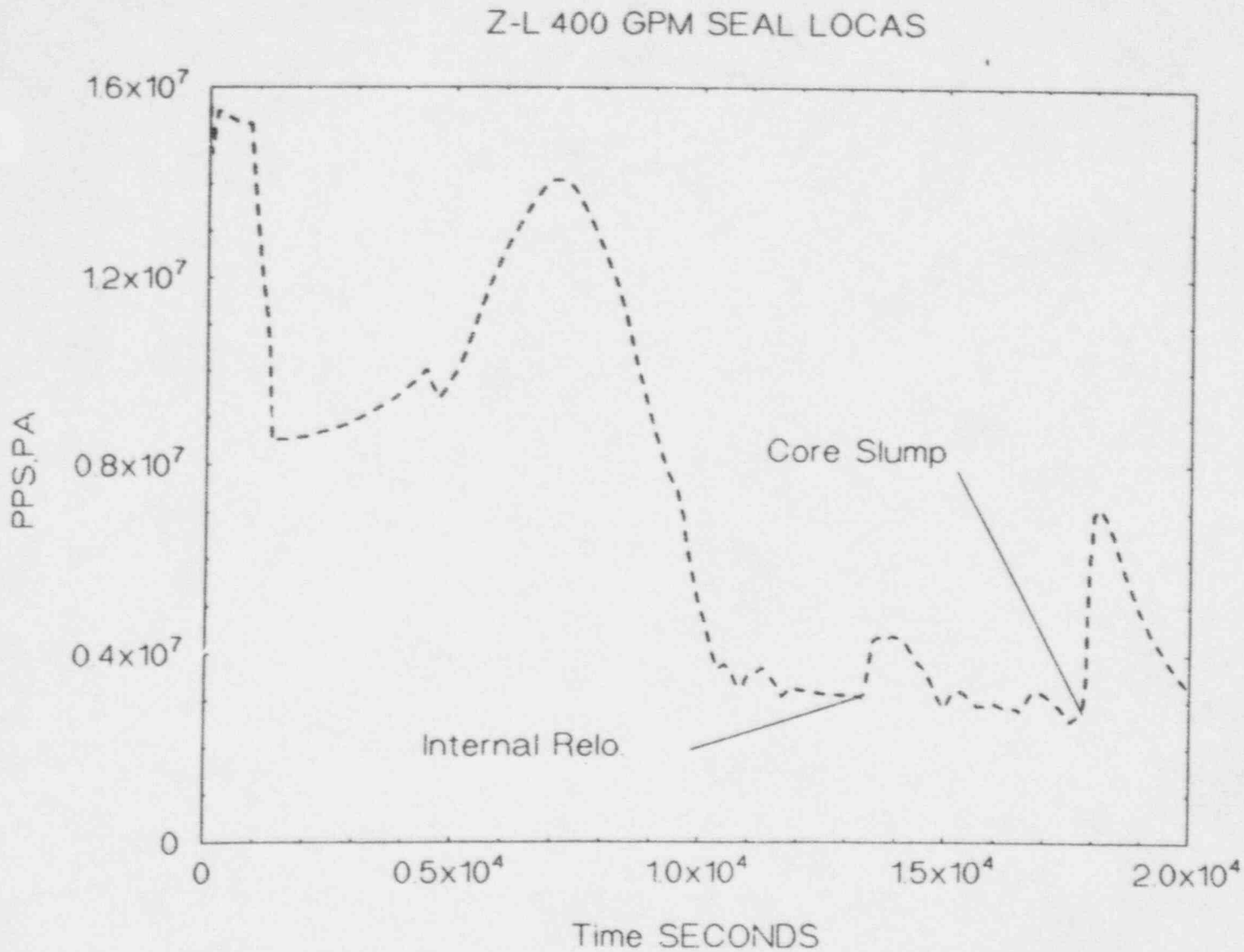

Figure 3

Effect of Accumulator Discharge on RCS Pressure

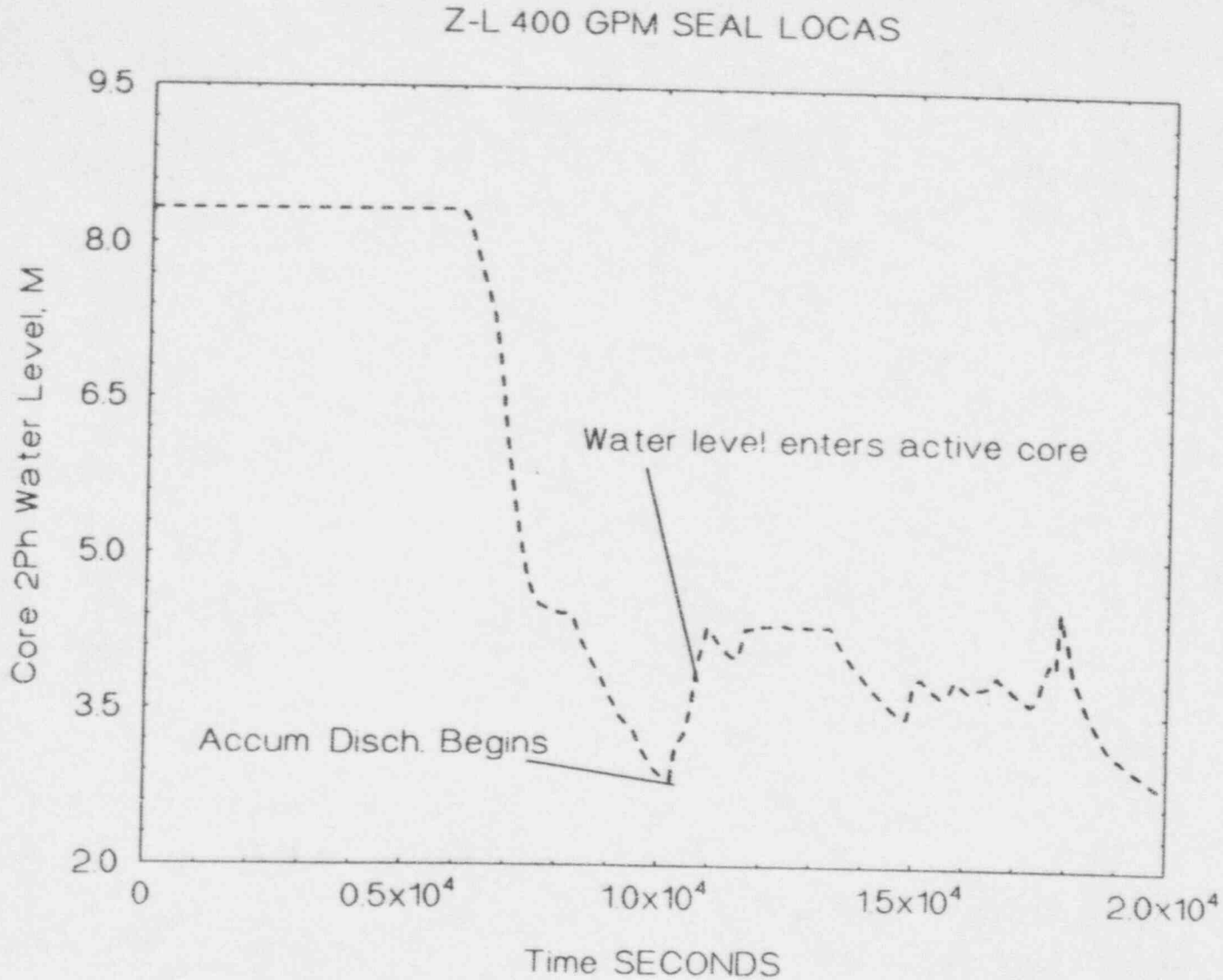

Figure 4

Effect ρf Accumulator Discharge on Core Water Level

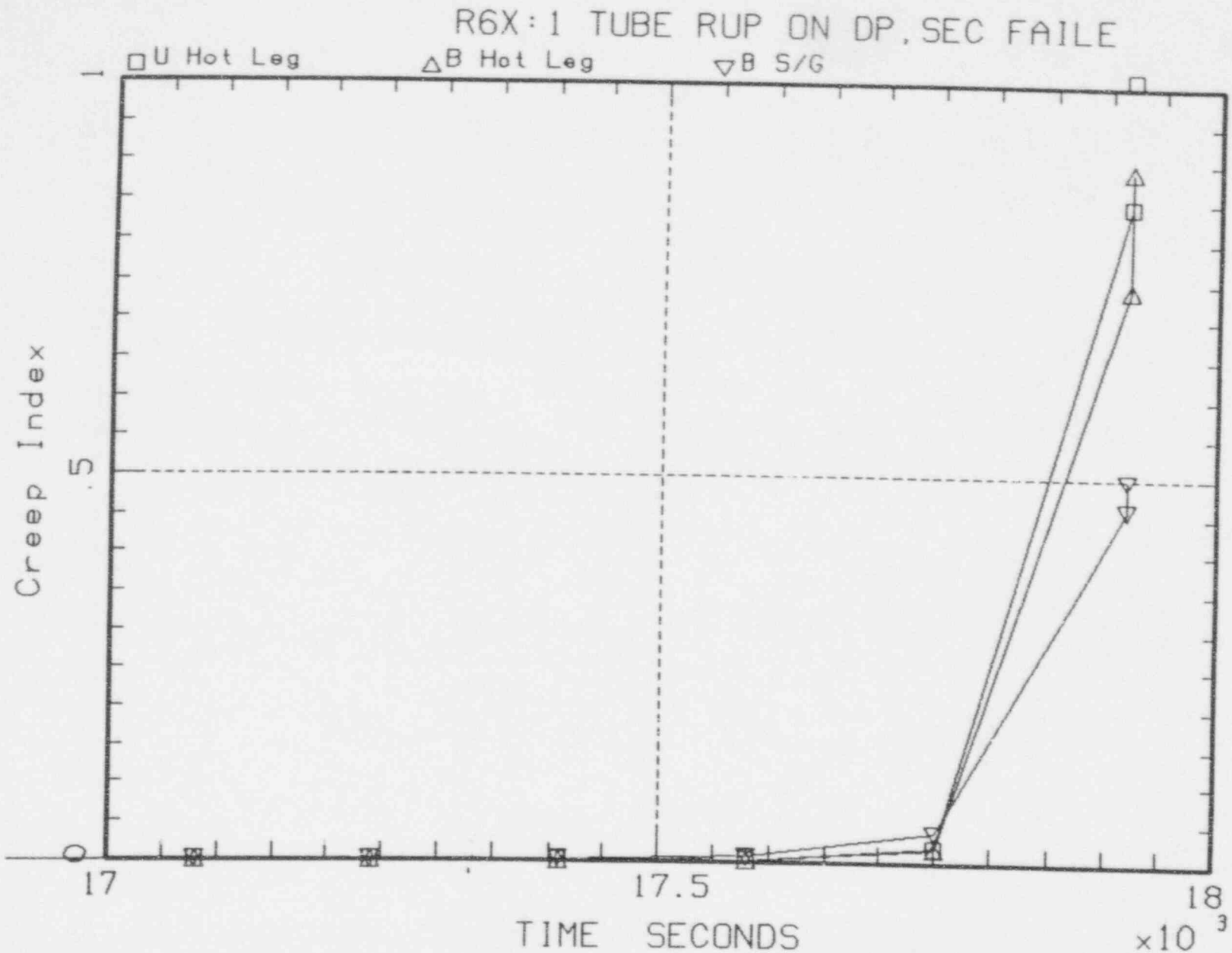

Figure 5

End State 6 - Pressure Induced Rupture of 1 Tube

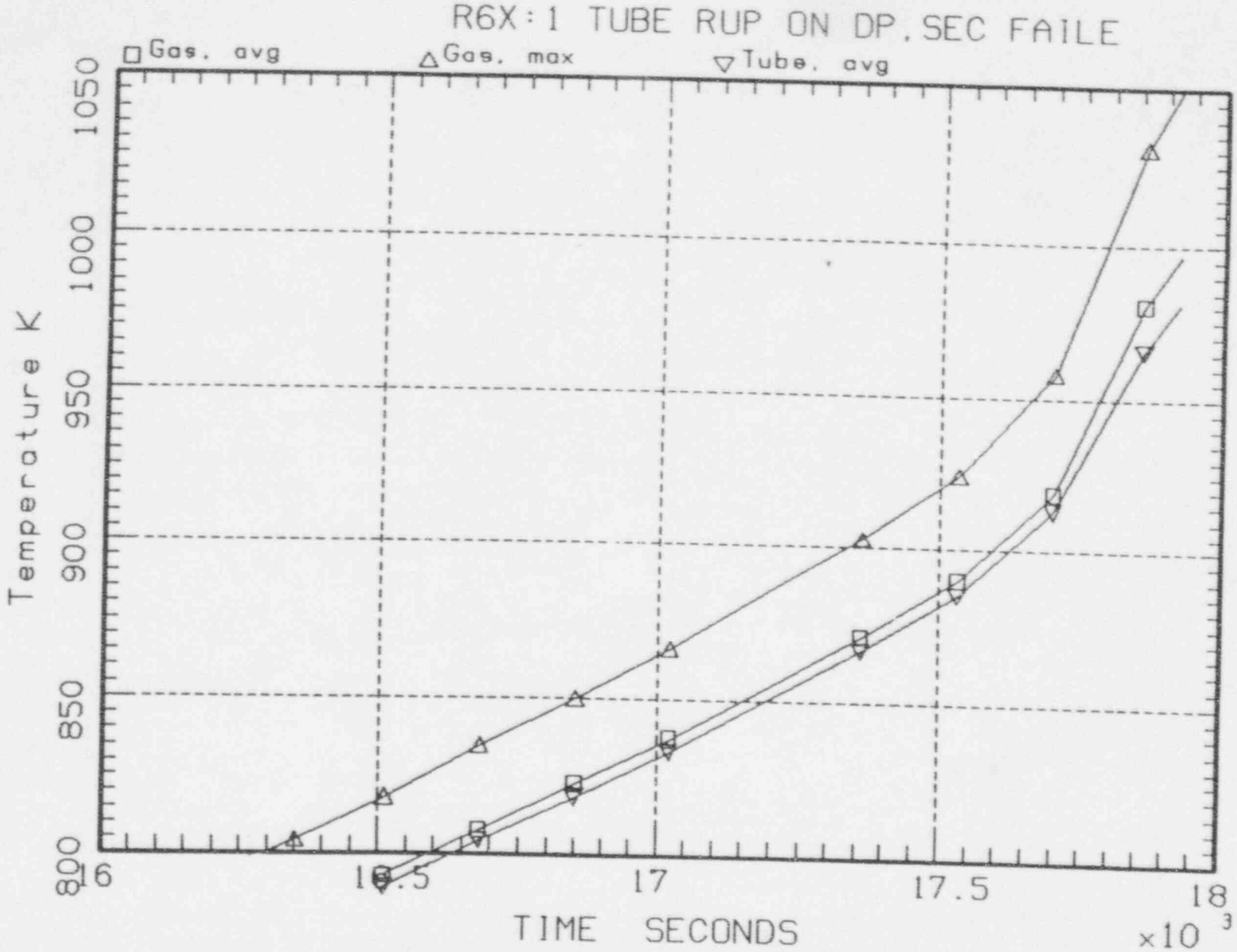

Figure 6

End State 6 - Pressure Induced Rupture of 1 Tube

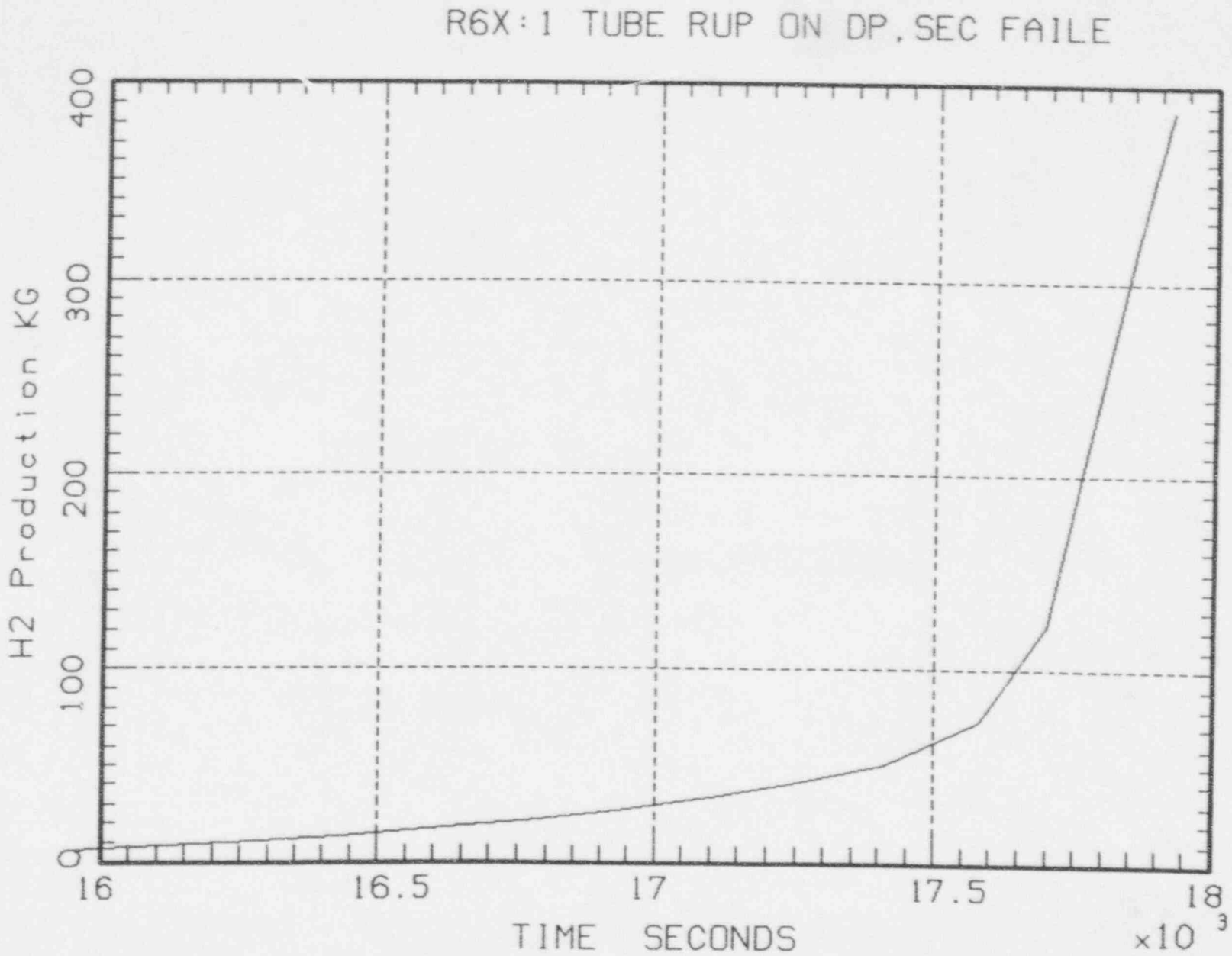

Figure 7

Endstate 6 - Pressure Induced Ruptur : of 1 Tube

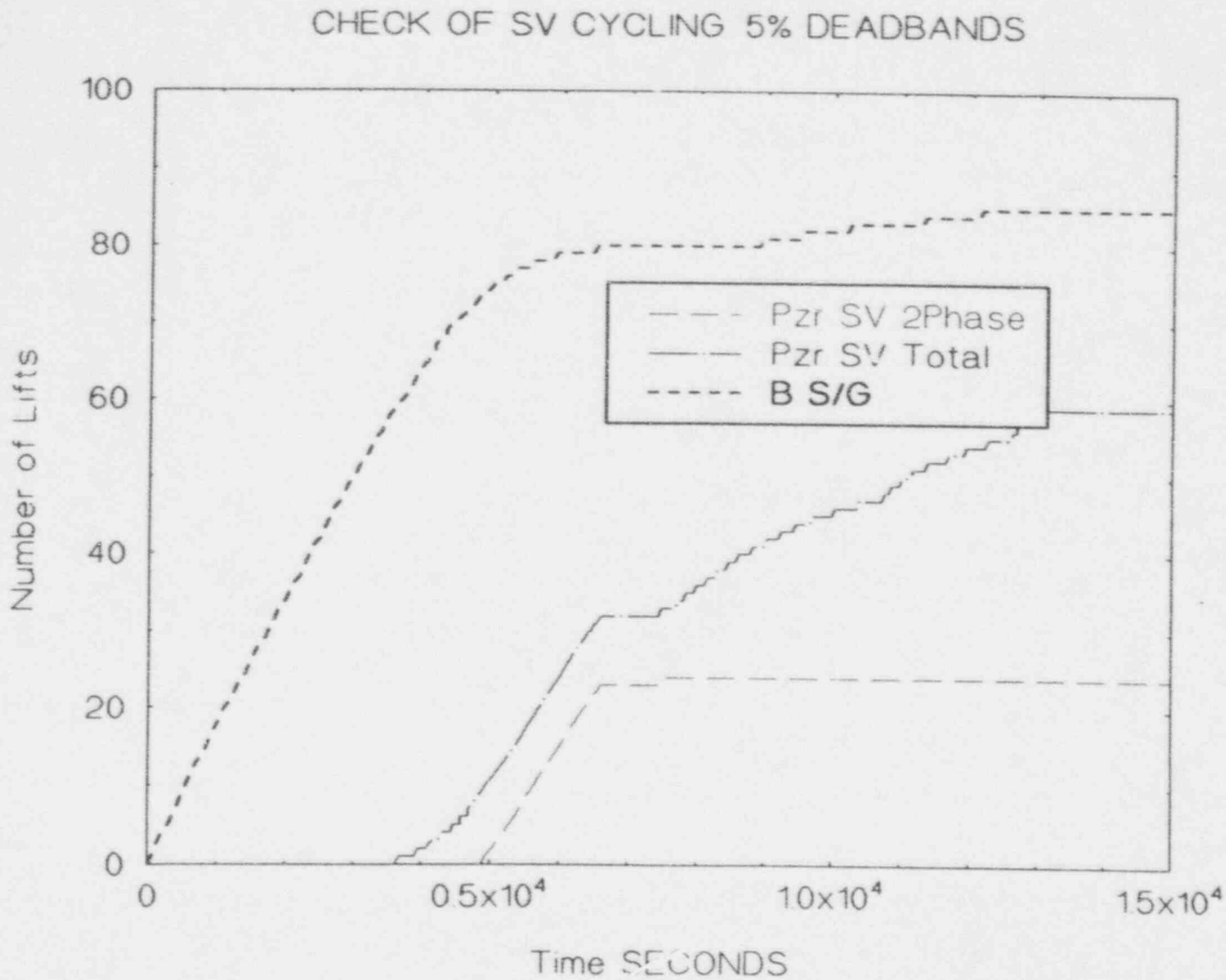

Figure 8
Safety Valve Lifts in Short Term Station Blackout (5% Blowdown)

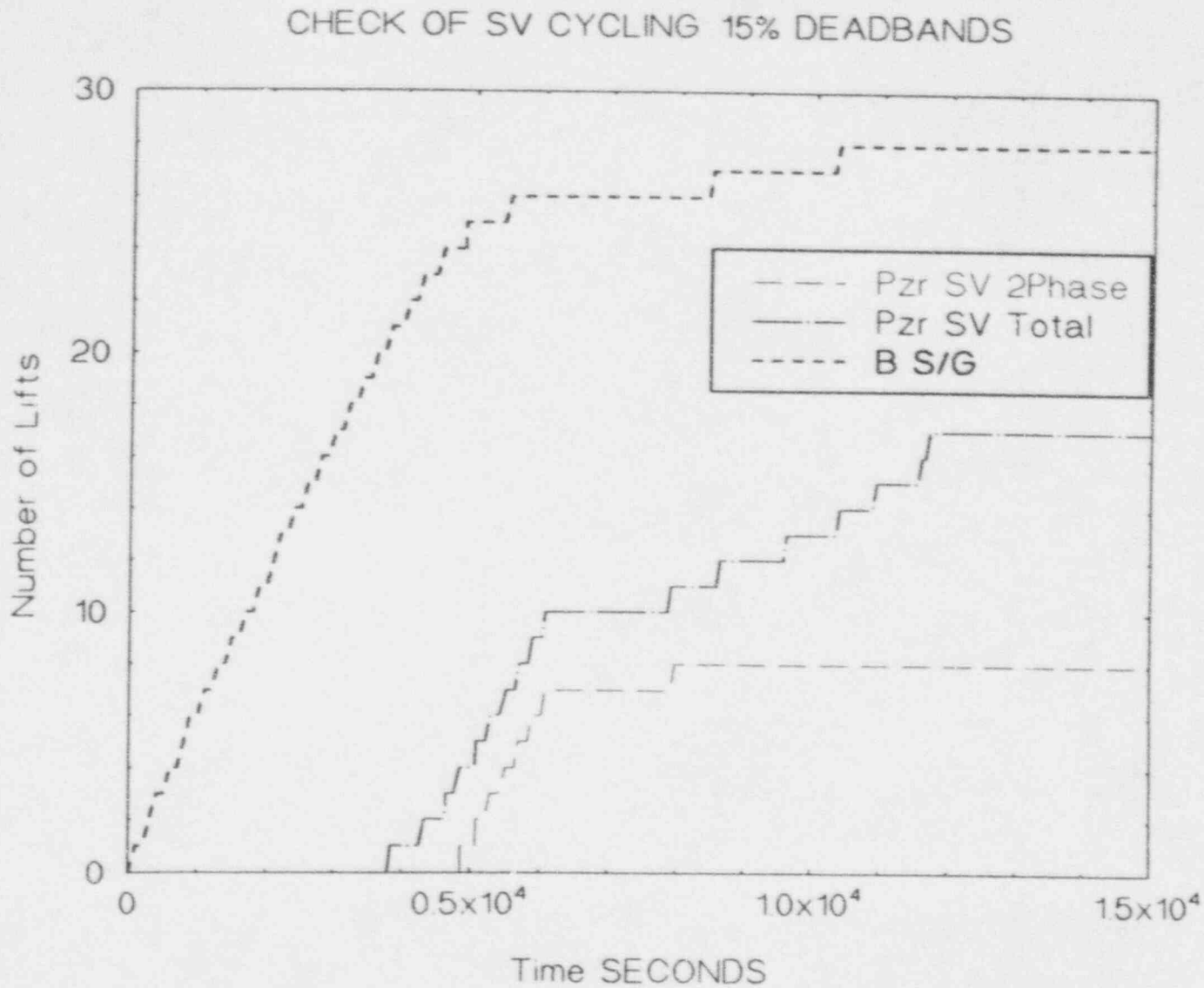

Figure 9

Safety Valve Lifts in Short Term Station Blackout (15% Blowdown)

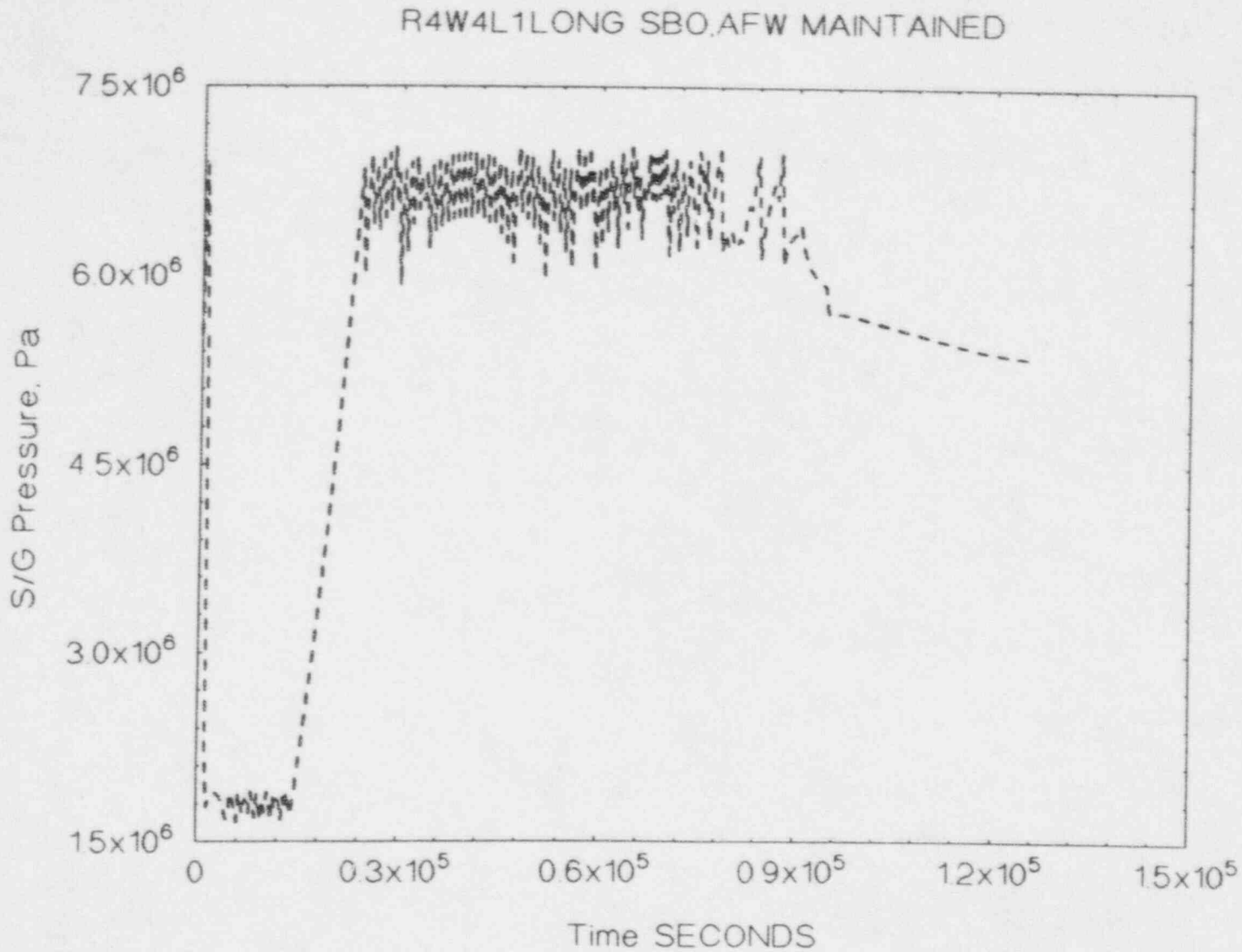

Figure 10

Steam Generator Pressure During Long-Term Station Blackout

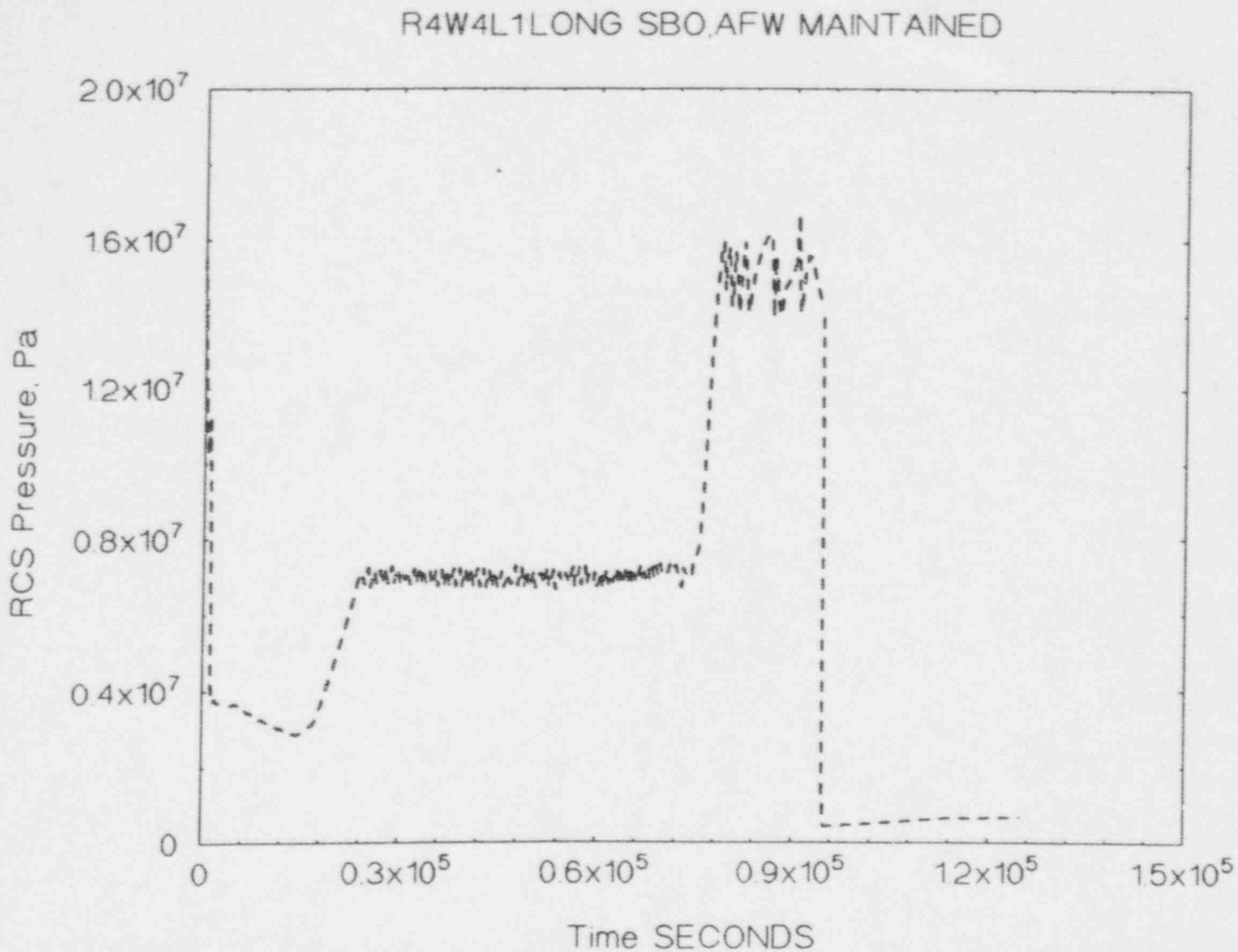

Figure 11

RCS Pressure During Long-Term Station Blackout

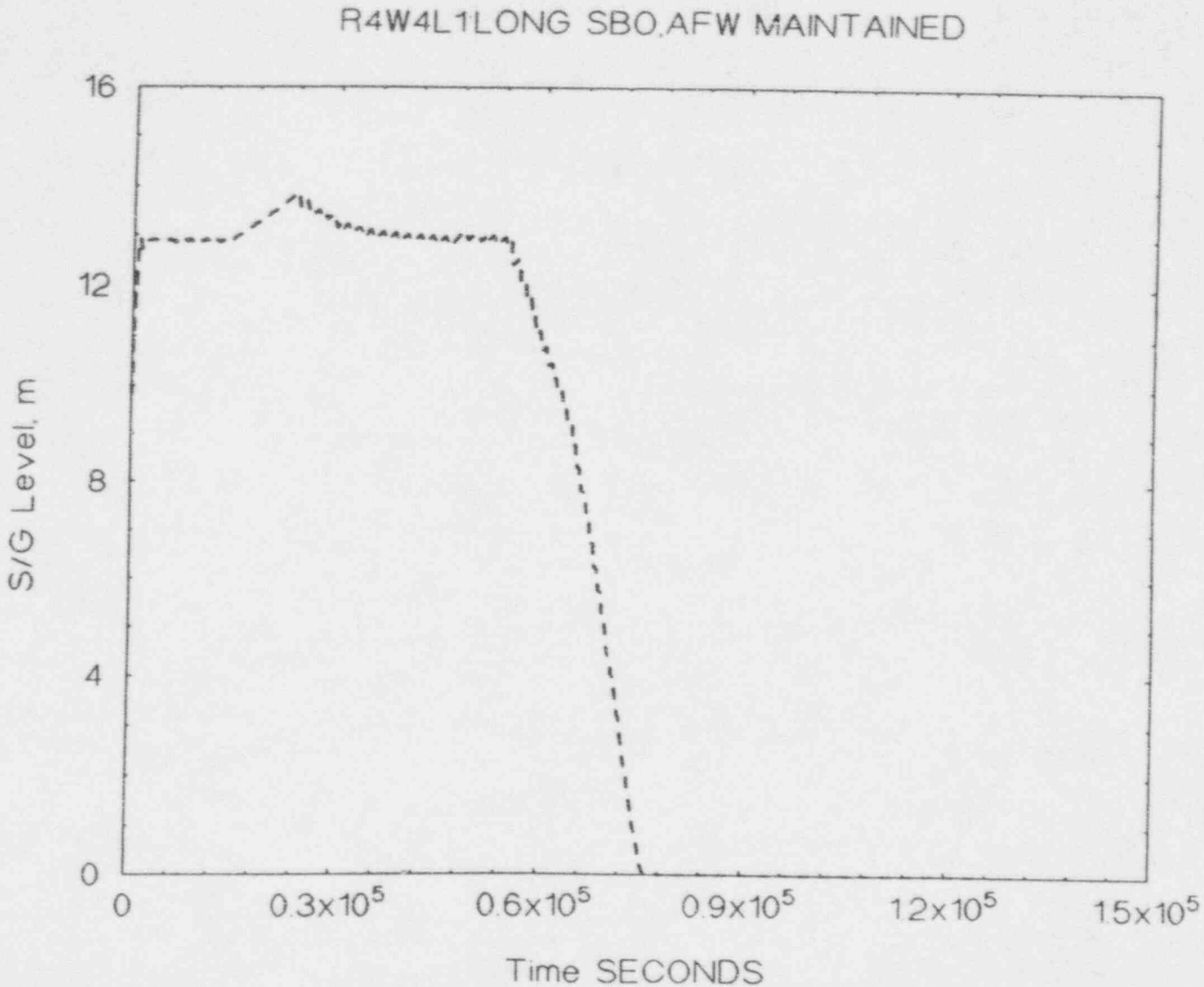

Figure 12

Steam Generator Level During Long-Term Station Blackout

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TO: File

FROM: Marc Kenton MK

DATE: February 5, 1996

SUBJECT: Hand Calculation of Recirculatory Flow in a Steam Generator with a Depressurized Secondary

1. Introduction

Until recently, most attention has been focused on SBO cases in which the steam generator secondary sides are pressurized. In such cases, calculation of substantial cooling of the tubes by circulating steam on the secondary side naturally leads to the assumption that an exponential temperature decay will occur in the primary side vapor, i.e. as if the fluid is being cooled by tubes that are relatively isothermal.

Cases with a depressurized steam generator can be considered effectively adiabatic with regards to heat transfer on the secondary side. Such cases are amenable to hand-calculation, as we shall demonstrate below.

2. Assumptions

We assume that there is negligible heat transfer to the steam on the secondary side. MAAP and COMMIX calculations predict about 2MW of energy Q is deposited in the steam generator tubes. If the primary side flow rate W_{SG} is, say, 10 kg/sec, the ΔT between the vapor entering and exiting the tubes is approximately

$$\Delta T = \frac{Q}{W_{SG} C_p}$$

$$= 66\ K$$

MAAP typically predicts even higher flow rates, so ΔT will be smaller still.

Note that the steam generator tubes are initially at about 600 K and heat to about 900 K in the time frame of interest. In view of this increase in temperature by 300 K, and the ΔT at any time of about 20 percent of this value, we assume that the rate of change of tube temperature T is approximately constant for all portions of the tube.

3. Calculation of Steam Generator Flow Rate

An energy balance on the gas flowing through the fraction of tubes F carrying "out" flow (from the inlet plenum to the outlet plenum) yields:

$$Wc_p \frac{dT}{dz} = Fn_T \rho_T \delta_T \pi D_T c_{p_T} \dot{T}_T$$

where the subscript "T" denotes quantities associated with the tubes:

ρ_T = tube density

c_{p_T} = specific heat of tube material

$\dot{T}_T$ = (constant) rate of change of tube temperature

δ_T = tube thickness

D_T = tube diameter

n_T = number of tubes

The solution of this equation for the gas temperature in the out tubes is trivial

$$T = T_{HT} - F\Delta T \frac{z}{z_T}$$

$$0 < z < z_T$$

where

ΔT = total temperature change across the steam generator

T_{HT} = gas temperature at inlet of "out" tubes

z_T = (average) length of a single tube

Similarly, for the "back" tubes we have

$$T = (T_{HT} - F\Delta T) - (1 - F)\Delta T\frac{(z - z_T)}{2z_t}$$

$$z_T < z < 2z_T$$

Note that as used in these expressions, the gas traverses a distance from 0 to z_T in the out tubes and from z_T to $2z_T$ in returning to the inlet plenum through the back tubes.

The hydrostatic head imbalance which develops across the out tubes is obtained by first expressing

$$\rho = \rho_{HT} + \frac{d\rho_{SG}}{dT}(T - T_{HT})$$

and then:

$$\Delta P_o = \int_0^{z_T/2} - F\Delta T\frac{z}{z_T}\frac{d\rho_{SG}}{dT}g\,dz$$

$$- \int_{z_T/2}^{z_T} - F\Delta T\frac{z}{z_T}\frac{d\rho_{SG}}{dT}g\,dz$$

$$= F\Delta T\frac{z_T}{4}\frac{d\rho_{SG}}{dT}g$$

where $\frac{d\rho_{SG}}{dT}$ is the derivative of the vapor density with respect to temperature and g is the acceleration of gravity. In performing this calculation, we have implicitly assumed that the tubes are straight, i.e. the effect of the U-bend region is not considered. The impact of this simplification is assessed later.

For the back tubes, we obtain, in a similar way:

$$\Delta P_b = (1 - F)\Delta T\frac{z_T}{4}\frac{d\rho_{SG}}{dT}g$$

To calculate the flow, we equate the sum of these terms to the frictional and inertial pressure drops created by a flowrate W:

$$\Delta P_{TOTAL} = \frac{d\rho_{SG}}{dT} g \; \Delta T \frac{z_T}{4}$$

$$= \frac{-W^2}{2\bar{\rho} A_{SG}^2} \left[\frac{f_o z_T + K_o D_T}{D_T F^2} + \frac{f_B z_T + K_B D_T}{D_T (1 - F)^2} \right]$$

where

f_o, f_B = friction coefficients for out and back flow, respectively

$\bar{\rho}_{SG}$ = average gas density in steam generator

K_o, K_B = inertial pressure drop coefficients associated with flow entering and leaving out and back tubes, respectively, and negotiating the U-bends (this term is typically relatively small compared to the frictional terms, but is included for completeness)

A_{SG} = total flow area through tubes

Thus:

$$W_{SG}^2 = \frac{- D_T \bar{\rho}_{SG} A_{SG}^2 \frac{d\rho_{SG}}{dT} g \; \Delta T}{2 \left(\frac{f_o + K_o \frac{D_T}{z_T}}{F^2} + \frac{f_B + K_B \frac{D_T}{z_T}}{(1 - F)^2} \right)}$$

4. <u>Calculation of Temperatures</u>

Westinghouse defines

$$f = 1 - \left(\frac{W_{SG}}{W_{HL}} \right) \frac{T_{HT} - T_m}{T_H - T_m}$$

where

f = "mixing fraction" in inlet plenum

W_{HL} = hot leg flow rate

T_H = inlet temperature from hot leg

T_m = mixture temperature in inlet plenum

The inlet plenum mixture temperature is simply the weighted average of T_H and T_{CT}:

$$T_m = \frac{1}{1 + \frac{W_{SG}}{W_{HL}}} \left[T_H + \frac{W_{SG}}{W_{HL}} T_{CT} \right]$$

where

T_{CT} = gas temperature exiting back tubes

If we neglect the normally small heat transfer which occurs to inlet plenum structures, the temperature of the gas T_c returning to the hot leg is given in the Westinghouse formulation by:

$$T_c = (1 - f) \frac{W_{SG}}{W_{HL}} (T_{CT} - T_m) + T_m$$

After manipulating these three expressions, one obtains the temperature differences across the steam generator and hot leg:

$$\Delta T \equiv T_{hc} - T_{CT} = (2 - f) \frac{W_{HL}}{W_{SG}} (T_h - T_m)$$

$$\Delta T_{HL} \equiv T_h - T_c = (2 - f) (T_h - T_m)$$

Note that

$$W_{HL} \Delta T_{HL} = W_{SG} \Delta T,$$

as required by energy conservation, if we assume (as did Westinghouse) that the specific heats are equal.

5. Calculation of Hot Leg Flow

Based on the Westinghouse experiments as well as other data, the hot leg flow can be correlated by

$$W_{HL}^2 = C_{HL}^2 \left(g\bar{\rho}_{HL} \left(- \frac{d\rho_{HL}}{dT} \right) (T_{up} - T_c) D_{HL}^5 \right)$$

where

C_{HL} = correlation coefficient (~0.1)

T_{up} = upper plenum temperature

$\bar{\rho}_{HL}$ = average hot leg density

D_{HL} = hot leg diameter

We can normally neglect the small amount of cooling of the flow traversing the hot leg from the upper plenum to the inlet plenum of the steam generator. This leads to

$$T_{up} \sim T_H$$

so that

$$T_{up} - T_c = (2 - f)(T_H - T_m)$$

Thus:

$$W_{HL}^2 = C_{HL}^2 \left(g\ \bar{\rho}_{HL} \left(- \frac{d\rho_{HL}}{dT} \right) (2 - f)(T_H - T_m)\ D_{HL}^5 \right)$$

6. Ratio of Steam Generator Flow to Hot Leg Flow

Dividing the two expressions obtained above, and using $A_{SG} = n_T \frac{\pi D_T^2}{4}$

we obtain

$$\left(\frac{W_{SG}}{W_{HL}}\right)^3 = \frac{1}{2}\left(\frac{D_T}{D_{HL}}\right)^5\left(\frac{\pi n_T}{4C_{HL}}\right)^2 \times \left[\frac{\bar{\rho}_{SG}\,\frac{d\rho_{SG}}{dT}}{\bar{\rho}_{HL}\,\frac{d\rho_{HL}}{dT}}\right]\frac{1}{\left[\frac{f_o + K_o\frac{D_T}{z_T}}{F^2} + \frac{f_B + K_B\frac{D_T}{z_T}}{(1-F)^2}\right]}$$

Note that the only important assumptions that have been made are

(1) Equality of tube temperature rates of change

(2) Negligible cooling in the hot leg and inlet plenum

7. Application of Formula to Westinghouse Experiment T-4

The following values are taken from Ref. [1] at 3362 secs:

a. $C_{HL} \sim .1$

b. $N_T = 216$

c. $D_{HL} = 10.22$ cm

d. $D_T = 0.775$ cm

e. $F = 0.5$

f. $Z_T = 250$ cm

To avoid iterating, the Re for the steam generator tubes can be estimated using the measured flow rate of 0.136 kg/sec and the viscosity reported in Ref [1]:

$$Re = \frac{(0.136\ kg/sec)\ (.00775m)}{(5.1 \times 10^{-3}\ m^2)\left(2.1 \times 10^{-5}\ \frac{kg}{m\ sec}\right)} = 10{,}000$$

From a Moody chart:

$$f \sim .031$$

Using property and temperature data in reference (1) we estimate that the

compressibility factor z for SF_6 in the range of interest is approximately

$$z = 0.628 + 6.48 \times 10^{-4}\ T(K)$$

For the hot leg:

$$\bar{T} = 193\ C = 466\ K$$

$$z = .93$$

$$\rho = \frac{(27.6 \times 10^5\ Pa)\ 146\ \frac{kg}{mole}}{8314\ \frac{J}{K\text{-}mole}\ 466\ K\ 0.93} = 112\ kg/m^3$$

$$\frac{d\rho}{dT} = \frac{-\rho}{T} - \frac{\rho}{z}\frac{dz}{dT} = -.32\ \frac{kg}{m^3\ K}$$

For the steam generator tubes, in a similar way we get

$$\bar{T} = 140\ C = 414\ K$$

$$z = 0.896$$

$$\rho = 130.7$$

$$\frac{d\rho}{dT} = -.41\ \frac{kg}{m^3\ K}$$

Substituting all these quantities, we obtain:

$$\frac{W_{SG}}{W_{HL}} = 2.7$$

The measured value is ~2.3. Considering the assumptions made in the derivation of the flow ratio, part of this discrepancy is presumably caused by the fact that the tube temperature rate of change is not really constant. Indeed, data shown in Figures 4-100 and 4-101 of Ref [1] indicates that the temperature drop across the "out" tubes in test SG-T4 is about twice that which occurs across the "back" tubes.

Another part of the discrepancy can be traced to the second assumption, i.e. negligible cooling in the hot leg and inlet plenum. Based on MAAP results, this is reasonable for the reactor scale, but in the experiment Westinghouse reports a loss of energy in the inlet plenum of 510 W.

Because of this and other losses, the total energy convected to the hot leg is

$$Q_{HL} = \left(0.06\ \frac{kg}{\sec}\right)\left(879\ \frac{J}{kgK}\right)(240.5 - 146\ C) = 4980\ W$$

whereas the energy convected to the tubes and tubesheet is

$$Q_{SG} = \left(.136\ \frac{kg}{\sec}\right)\left(859\ \frac{J}{kgK}\right)(159.2 - 120.9\ C) = 4470\ W$$

Note that the difference is very close to the 500 W value reported.

The formula for the flow ratio goes like

$$\left(\frac{W_{SG}}{W_{HL}}\right)^2 \sim \frac{\Delta T_{SG}}{\Delta T_{HL}}$$

If we replace the term on the right hand side by

$$\frac{\dfrac{Q_{SG}}{W_{SG}c_{PSG}}}{\dfrac{Q_{HL}}{W_{HL}c_{PHL}}}$$

we have

$$\left(\frac{W_{SG}}{W_{HL}}\right)^3 = [same\ as\ before]\left[\frac{\dfrac{Q_{SG}}{c_{PSG}}}{\dfrac{Q_{HL}}{c_{PHL}}}\right]$$

The factor in the right most bracket has the value 0.92 which reduces the predicted

flow ratio from 2.7 to about 2.6.

Another small error was incurred by assuming that the height of the tubes is equal to half their length, i.e. neglecting the effects of the U-bend. This can be shown to be about a two percent effect, i.e. it reduces the calculated flow ratio from 2.6 to about 2.55.

In any event, the simple formula agrees with the results of the experiment within about ten percent.

The formula was also applied to tests T-3 and T-1. The former gives results virtually identical to those shown above for T-4. Test T-1 is particularly interesting, since of the four transient tests whose results are provided in Table A-3 of ref[1], it has the smallest ratio of steam generator to hot leg flow (~1.9). This may perhaps be due to the fact that the calculated Reynolds number in the tubes is about 2600, i.e. squarely in the transition from laminar to turbulent flow. Based on other data, we expect the flow to oscillate between these two regimes, and an accurate prediction of flow rate would be problematical. If we proceed nonetheless by using the friction factors reported for these Reynolds numbers in pipe flow provided in ref[2], we obtain a flow ratio of 2.3. This result is also too high, but does show the correct trend relative to the other two experiments.

8. Application to MAAP Calculation

For a MAAP calculation

a. $C_{HL} \sim .1$

b. $N_{SG} = 3388$

c. $D_{HL} = .738$ m

d. $D_{SG} = .0197$ m

e. $F = .5$

At a particular point (12000 secs) near the time of hot leg rupture:

$T_{HT} \sim 841$ K $\qquad \rho_{HT} \sim 48.7$ kg/m^3

$T_{CT} \sim 776$ K $\qquad \rho_{CT} \sim 55.3$ kg/m^3

$T_{up} \sim 1067$ K $\qquad \rho_{up} \sim 35.7$ kg/m^3

$T_c \sim 802$ K $\qquad \rho_c = 52.5$ kg/m^3

$\bar{\rho}_{HL} = 44.1\ kg/m^3$

$\bar{\rho}_{SG} = 52\ kg/m^3$

$$\frac{d\rho_{HL}}{dT} \equiv -.063\ \frac{kg}{m^3\ K}$$

$$\frac{d\rho_{SG}}{dT} \equiv -.10\ \frac{kg}{m^3\ K}$$

$$Re_{SG} \sim = \frac{(14.3\ kg/sec)\ (.0197)}{(.52\ m^2)\left(3.1 \times 10^{-5}\ \frac{kg}{m\text{-}sec}\right)} = 17{,}000$$

$f_o = f_B = .027$

$$\frac{W_{SG}}{W_{HL}} = 3.4$$

which is nearly the same ratio (3.56) as is calculated by the code.

9. <u>Application to a MAAP Calculation at an earlier time</u>

At 11,000 secs in the same calculation, the only quantities that differ are:

$T_{HT} \sim 744$ K $\qquad \rho_{HT} \sim 60.69$ kg/m^3

$T_{CT} \sim 701$ K $\qquad \rho_{CT} \sim 69.47$ kg/m^3

$T_{up} \sim 906$ K $\qquad \rho_{up} \sim 44.27$ kg/m^3

$T_c \sim 715$ K $\qquad \rho_c \sim 66.1$ kg/m^3

$\bar{\rho}_{HL} = 55.2\ kg/m^3$

$$\bar{\rho}_{SG} = 65.1\ kg/m^3$$

$$\frac{d\rho_{HL}}{dT} = -.114\ kg/m^3\ K$$

$$\frac{d\rho_{SG}}{dT} = -.204\ kg/m^3\ K$$

$$Re_{SG} = \frac{(18)\ (.0197)}{(.52)\ (2.9 \times 10^{-6})} = 23{,}500$$

$$f_o = f_B = .025$$

The calculated ratio is 3.7, but the ratio predicted by the code is nearly 3.9. Comparing this to the previous result, we see that the formula predicts the trend correctly: a decrease in flow ratio with time caused by changes in steam properties and friction factor. The predicted magnitude of the decrease is also approximately correct.

10. Conclusions

As shown in Table 1, the simple formula does a rather good job predicting the relative flow rates in the cases investigated. The unexplained errors in flow ratio are around 10-15 percent, and the appropriate trends seem to be predicted. In view of the simplifying assumptions made, particularly those involving the rate of energy loss as the gas traverses the steam generator, this degree of success is no doubt a benefit of the relatively weak dependence of the flow rate on non-geometrical parameters.

References

1. W. A. Stewart et al., Natural Circulation Experiments for PWR High-Pressure Accidents, EPRI TR-102815, August 1993.

2. I.E. Idel'chik, Handbook of Hydraulic Resistance, AEC-TR-6630, 1960.

MAK/dr

cc: E. Fuller, Polestar
R. Henry, FAI
D. Steininger, EPRI

Case	*Hand-calculation*	*Data/Code Calculation*
T-1 (6768 secs)	2.3	1.9
T-3 (3582 secs)	2.6	2.3
T-4 (3362 secs)	2.55-2.6	2.3
MAAP (11000 secs)	3.7	3.9
MAAP (12000 secs)	3.4	3.6

Table 1: Summary of comparisons of hand calculation to data from Westinghouse experiments and MAAP results

DAMES & MOORE

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TO: Darrel Knudson

FROM: Marc Kenton MK

DATE: April 26, 1996

SUBJECT: Parameters in "Zion-like" MAAP4 Model

To facilitate comparisons between our respective calculations, I have compared our non-proprietary "Zion-like" parameter file to a more accurate 4-loop Westinghouse model for an actual plant. While there are a large number of differences between the two models, those differences which are judged to be the most important for the calculation of tube temperatures in the sequences of interest are summarized in the attached table.

Based on MAAP calculations, some of these parameter differences increase temperatures over those seen with the actual plant model and some cause them to drop. When the code is run with all the attached parameter changes made to the actual plant model, the results are fairly close to those observed with the "Zion-like" model (within 10K at the time of hot leg rupture).

It would be useful to know if making these changes in your model causes tube temperatures to vary significantly. Please contact me if you have questions.

MAK/dr
Attachment

cc: E. Fuller
D. Steininger

Zion-like Parameters

Hot leg diameter	0.8 m
Hot leg length	6.76 m
Hot leg mass	6300 kg
Mass of S/G head	17,000 kg
Mass of upper plenum internals	75,000 kg
Mass of plate separating upper plenum from the upper head	15,000 kg
Hydraulic diameter in upper plenum	0.2 m
Heat transfer area to upper plenum internals	100 m^2
Number of fuel pins	39,372
Number of control rods	3,028
Core flow area (active fuel)	4.28 m2
Core bypass area	0.5 m2
Downcomer flow area	3.51 m2
Core nodalization	see attached

Zion-like core nodalization

1. Axial peaking factors (13 row representation, 10 contain fuel, shown from bottom to top):

FPA(1)	0.
FPA(2)	0.
FPA(3)	.565
FPA(4)	1.0845
FPA(5)	1.2775
FPA(6)	1.286
FPA(7)	1.235
FPA(8)	1.1505
FPA(9)	1.077
FPA(10)	.9765
FPA(11)	.777
FPA(12)	.571
FPA(13)	0.

2. Radial peaking factors (7 ring representation, from inside to outside)

FPR(1)	1.181
FPR(2)	1.173
FPR(3)	1.227
FPR(4)	1.13
FPR(5)	.973
FPR(6)	.820
FPR(7)	.711

3. Fraction of fuel pins in each radial ring, inside to outside

FA(1)	.081
FA(2)	.102
FA(3)	.143
FA(4)	.16
FA(5)	.169
FA(6)	.170
FA(7)	.175

4. Bottom and top of active fuel, measured from bottom of RPV

ZCRL	3.57
ZCRU	7.23