ULNRC-3069

ATTACHMENT ONE

TECHNICAL SPECIFICATION CHANGES
(MARKED-UP)

TABLE 2.2-1

REACTOR TRIP SYSTEM INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT	TOTAL ALLOWANCE (TA)	Z	SENSOR ERROR (S)	TRIP SETPOINT	ALLOWABLE VALUE
1. Manual Reactor Trip	N.A.	N.A.	N.A.	N.A.	N.A.
2. Power Range, Neutron Flux					
a. High Setpoint	7.5	4.56	0	$\leq$109% of RTP*	$\leq$112.3% of RTP*
b. Low Setpoint	8.3	4.56	0	$\leq$25% of RTP*	$\leq$28.3% of RTP*
3. Power Range, Neutron Flux, High Positive Rate	2.4	0.5	0	$\leq$4% of RTP* with a time constant $\geq$2 seconds	$\leq$6.3% of RTP* with a time constant $\geq$2 seconds
4. Deleted					
5. Intermediate Range, Neutron Flux	17.0	8.41	0	$\leq$25% of RTP*	$\leq$35.3% of RTP*
6. Source Range, Neutron Flux	17.0	10.01	0	$\leq 10^5$ cps	$\leq 1.6 \times 10^5$ cps
7. Overtemperature ΔT	9.3	6.47	1.83 +1.24***	See Note 1	See Note 2
8. Overpower ΔT	5.7	1.90	1.65	See Note 3	See Note 4
9. Pressurizer Pressure-Low	5.0	2.21	2.0	$\geq$1885 psig	$\geq$1874 psig
10. Pressurizer Pressure-High	~~7.5~~ 3.125	~~4.96~~ 0.71	~~1.0~~ 2.0	$\leq$2385 psig	~~$\leq$2400 psig~~ $\leq$ 2393
11. Pressurizer Water Level-High	8.0	2.18	2.0	$\leq$92% of instrument span	$\leq$93.8% of instrument span
12. Reactor Coolant Flow-Low	2.5	1.38	0.6	$\geq$90% of loop minimum measured flow**	$\geq$88.8% of loop minimum measured flow**

*RTP = RATED THERMAL POWER

**Minimum Measured Flow = 95,660 gpm

***Two Allowances (temperature and pressure, respectively)

TABLE 3.3-2

REACTOR TRIP SYSTEM INSTRUMENTATION RESPONSE TIMES

FUNCTIONAL UNIT	RESPONSE TIME
1. Manual Reactor Trip	N.A.
2. Power Range, Neutron Flux	$\leq$ 0.5 second*
3. Power Range, Neutron Flux, High Positive Rate	N.A.
4. Deleted	
5. Intermediate Range, Neutron Flux	N.A.
6. Source Range, Neutron Flux	N.A.
7. Overtemperature ΔT	$\leq$ 6.0 seconds*
8. Overpower ΔT	$\leq$ 6.0 seconds*
9. Pressurizer Pressure-Low	$\leq$ 2.0 seconds
10. Pressurizer Pressure-High	$\leq$ ~~2.0~~ 1.0 second~~s~~
11. Pressurizer Water Level-High	N.A.

*Neutron detectors are exempt from response time testing. Response time of the neutron flux signal portion of the channel shall be measured from detector output or input to first electronic component in channel.

TSi 2

TABLE 3.7-1

MAXIMUM ALLOWABLE POWER RANGE NEUTRON FLUX HIGH SETPOINT WITH INOPERABLE STEAM LINE SAFETY VALVES DURING FOUR LOOP OPERATION

MAXIMUM NUMBER OF INOPERABLE SAFETY VALVES ON ANY OPERATING STEAM GENERATOR	MAXIMUM ALLOWABLE POWER RANGE NEUTRON FLUX HIGH SETPOINT (PERCENT OF RATED THERMAL POWER)
1	~~87~~ 56 (71)*
2	~~65~~ 39
3	~~44~~ 22

* With only one (1) of the 20 MSSVs inoperable, the maximum allowable power range neutron flux high setpoint may be 71 percent of rated thermal power. The 56 percent setpoint is required if a maximum of one (1) MSSV is inoperable on more than one steam generator.

REVISION 1

TABLE 3.7-2

STEAM LINE SAFETY VALVES PER LOOP

VALVE NUMBER				LIFT SETTING* ~~(±1%)~~	ORIFICE SIZE
Loop 1	Loop 2	Loop 3	Loop 4		
V055	V065	V075	V045	1185 psig	16.0 sq. in.
V056	V066	V076	V046	1197 psig	16.0 sq. in.
V057	V067	V077	V047	1210 psig	16.0 sq. in.
V058	V068	V078	V048	1222 psig	16.0 sq. in.
V059	V069	V079	V049	1234 psig	16.0 sq. in.

*The lift setting pressure shall correspond to ambient conditions of the valve at nominal operating temperature and pressure.

The as-found lift setting tolerance is +3/-1 % of the nominal setpoint. The as-left lift setting tolerance is ± 1% of the nominal setpoint.

REVISION 1

3/4.7 PLANT SYSTEMS

BASES

3/4.7.1 TURBINE CYCLE

3/4.7.1.1 SAFETY VALVES

The OPERABILITY of the main steam line Code safety valves ensures that the Secondary Coolant System pressure will be limited to within 110% (1320 psia) of its design pressure of 1200 psia during the most severe anticipated system operational transient. The maximum relieving capacity is associated with a Turbine trip from 102% RATED THERMAL POWER coincident with an assumed loss of condenser heat sink (i.e., no steam bypass to the condenser).

The specified valve lift settings and relieving capacities are in accordance with the requirements of Section III of the ASME Boiler and Pressure Code, (1971 Edition). The total relieving capacity for all valves on all of the steam lines is (~~18.28~~ 18.035 x 10^6) lbs/h which is ~~115%~~ 113% of the total secondary steam flow of ~~15.05~~ 15.96 x 10^6 lbs/h~~ at 102% RATED THERMAL POWER~~. A minimum of two OPERABLE safety valves per steam generator ensures that sufficient relieving capacity is available for the allowable THERMAL POWER restriction in Table 3.7-1.

STARTUP and/or POWER OPERATION is allowable with safety valves inoperable within the limitations of the ACTION requirements on the basis of the reduction in Secondary Coolant System steam flow and THERMAL POWER required by the reduced Reactor Trip Settings of the Power Range Neutron Flux channels. The Reactor Trip Setpoint reductions are derived on the following bases:

~~For four loop operation:~~

$$\cancel{SP = \frac{(X) - (Y)(V)}{X} \times (109)}$$

~~Where:~~

~~SP = Reduced Reactor Trip Setpoint in percent of RATED THERMAL POWER,~~

~~V = Maximum number of inoperable safety valves per steam line,~~

INSERT A

INSERT A

To insure overpressurization of secondary system does not occur, the maximum allowed power for operation would be conservatively set equal to the heat removing capability of the operable MSSVs. Thus, the power range neutron flux high setpoint (SP), in percent of rated thermal power, is given by

$$SP = (100 / Q) [W_s \times h_{fg} \times N] / K$$

where Q = the rated NSSS power, which is equal to 3579 MWt for Callaway Plant,

W_s = minimum total steam flow rate capability of the operable MSSVs on any one steam generator at the highest MSSV opening pressure including tolerance and accumulation, as appropriate, in Btu/sec,

h_{fg} = heat of vaporization for steam at the highest MSSV opening pressure including tolerance and accumulation in Btu/lbm.,

N = Number of loops, and

K = Conversion factor, 947.82 (Btu/sec)/Mw_t.

For reactor protection, the setpoint calculated is adjusted lower, accounting for the instrument and channel uncertainty.

SAFETY VALVES (Continued)

~~109 = Power Range Neutron Flux-High Trip Setpoint for four loop operation,~~

~~X = Total relieving capacity of all safety valves per steam line in lbs/hour, and~~

~~Y = Maximum relieving capacity of any one safety valve in lbs/hour.~~

3/4.7.1.2 AUXILIARY FEEDWATER SYSTEM

The OPERABILITY of the Auxiliary Feedwater System ensures that the Reactor Coolant System can be cooled down to less than 350°F from normal operating conditions in the event of a total loss-of-offsite power.

Testing of each electric motor-driven auxiliary feedwater pump on a fixed orifice recirculation flow and ensuring a discharge pressure of greater than or equal to 1535 psig verifies the capability of each pump to deliver a total feedwater flow of 575 gpm at a pressure of 1221 psig to the entrance of the steam generators. The steam-driven auxiliary feedwater pump is capable of delivering a total feedwater flow of 1145 gpm at a pressure of 1221 psig to the entrance of the steam generators. This capacity is sufficient to ensure that adequate feedwater flow is available to remove decay heat and reduce the Reactor Coolant System temperature to less than 350°F when the RHR System may be placed into operation.

3/4.7.1.3 CONDENSATE STORAGE TANK

The OPERABILITY of the condensate storage tank with the minimum water volume ensures that sufficient water is available to maintain the RCS at HOT STANDBY conditions for 4 hours with steam discharge to the atmosphere concurrent with total loss-of-offsite power and then a cooldown to 350°F at 50°F per hour. The contained water volume limit includes an allowance for water not usable because of tank discharge line location or other physical characteristics.

3/4.7.1.4 SPECIFIC ACTIVITY

The limitations on Secondary Coolant System specific activity ensure that the resultant offsite radiation dose will be limited to a small fraction of 10 CFR Part 100 dose guideline values in the event of a steam line rupture. This dose also includes the effects of a coincident 1 gpm reactor to secondary tube leak in the steam generator of the affected steam line. These values are consistent with the assumptions used in the safety analyses.

ATTACHMENT TWO

TECHNICAL SPECIFICATION CHANGES
(RE-TYPED)

TABLE 2.2-1

REACTOR TRIP SYSTEM INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT	TOTAL ALLOWANCE (TA)	SENSOR ERROR Z	SENSOR ERROR S	TRIP SETPOINT	ALLOWABLE VALUE
1. Manual Reactor Trip	N.A.	N.A.	N.A.	N.A.	N.A.
2. Power Range, Neutron Flux					
a. High Setpoint	7.5	4.56	0	≤ 109% of RTP*	≤112.3% of RTP*
b. Low Setpoint	8.3	4.56	0	≤25% of RTP*	≤28.3% of RTP*
3. Power Range, Neutron Flux, High Positive Rate	2.4	0.5	0	≤4% of RTP* with a time constant ≥ 2 seconds	≤6.3% of RTP* with a time constant ≥2 seconds
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8. Overpower ΔT	$\leq$ 6.0 seconds*
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* The lift setting pressure shall correspond to ambient conditions of the valve at nominal operating temperature and pressure. The as-found lift setting tolerance is +3/-1% of the nominal setpoint. The as-left lift setting tolerance is ± 1% of the nominal setpoint.

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where Q = the rated NSSS power, which is equal to 3579 MWt for Callaway Plant,

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3/4.7.1.4 SPECIFIC ACTIVITY

The limitations on Secondary Coolant System specific activity ensure that the resultant offsite radiation dose will be limited to a small fraction of 10 CFR Part 100 dose guideline values in the event of a steam line rupture. This dose also includes the effects of a coincident 1 gpm reactor to secondary tube leak in the steam generator of the affected steam line. These values are consistent with the assumptions used in the safety analyses.

ATTACHMENT THREE

SAFETY EVALUATION

SAFETY EVALUATION

This amendment application requests a revision to Technical specification (TS) 3.7.1.1 (Tables 3.7-1 and 3.7-2), 2.2 (Table 2.2-1), 3/4.3 (Table 3.3-2), and Bases 3/4.7. These specifications are revised to increase the lift setting tolerance for the main steam safety valves from $\pm 1\%$ to $+3/-1\%$, lower the maximum allowable power levels with inoperable main steam safety valves, and to incorporate the revised methodology for calculating maximum power levels with inoperable main steam safety valves into the Bases.

Background

The function of the main steam line safety valves is to provide overpressure protection, ensuring that the secondary system pressure will be limited to within 110% (1320 psia) of its design pressure (1200 psia) during the most severe anticipated system operational transient. The total relieving capacity for all valves on all steam lines is 113% of the total secondary steam flow.

Revision of the lift setting tolerance to $+3/-1\%$ as-found and $\pm 1\%$ as-left will have no effect on the relieving capacity of the safety valves. The change in lift setting tolerance will provide reasonable acceptance criteria taking into account the component service conditions and conservative criteria for the as-left condition of the safety valves. The test equipment tolerance ($+2/-1\%$) will not be accounted for in the TS tolerance because this equipment tolerance is specifically addressed by the ASME Code. Therefore, as long as the testing equipment and methodology meet the $+2/-1\%$ tolerance requirements of OM-1, there is no need to account for testing tolerances in the TS or the safety analyses. (This position is also applicable for the primary safety valves.)

Previous safety analyses conservatively included accumulation in the modelling. Accumulation is no longer modeled for spring loaded MSSVs. This approach is acceptable because the valve setpoint is determined by stem motion and setting the valves on steam. This procedure insures the valves will "pop open" at the TS setpoint. Earlier analyses used accumulation to account for valve chatter prior to opening. This conservatism is no longer required with present testing methods.

The existing tolerance of $\pm 1\%$ specified in Technical Specification 3/4.7.1 for steam line safety valve lift settings is based on the design requirements for safety valves specified in ASME Section III, Subsection NC-7614.2. The $\pm 1\%$ tolerance is appropriate for design criteria, but is not appropriate for testing acceptance criteria for the following reasons: a) The $\pm 1\%$ lift setting tolerance currently specified does not take into consideration the service conditions of the safety valves. For safety valves subjected to a constant load for extended periods of time without being cycled, it is common for the valve springs to take a set resulting in a slight increase in the spring rate, until broken loose during the initial test stroke of the valve. ASME Section XI

test criteria requires the performance of 2 successive lifts with no adjustments to the valve lift setting. Due to the valve spring taking a set as described above, the first test lift is commonly found to be slightly out of tolerance and the second and third lifts within tolerance. b) ASME Section XI, Subsection IWV requires safety valves to be tested using OM-1. (Union Electric will adopt the 1989 version of the ASME Code for the next 10 year IST interval, which will begin December 20, 1994. This version of the Code indirectly imposes the 1987 version of OM-1.)

The ASME Section XI schedule used previously for testing additional valves will continue to be used, except that the criteria for testing additional valves will be +3/-1% of the setpoint instead of ±1%. However, all valves that are tested and found outside the ±1% band will be reset to within ±1%.

Industry operating experience has also demonstrated that a setpoint tolerance for the main steam safety valves of only ±1% results in safety valves frequently failing surveillance tests. Information Notice 86-56, "Reliability of Main Steam Safety Valves," tabulated a number of problems with setpoint drift as reported in various LERs. This information notice discussed the various safety concerns that may be encountered with setpoint drift. Union Electric has considered these concerns in the proposed relaxed tolerance limits. Other plants, such as Trojan, Palisades, Yankee Rowe, Calvert Cliffs, LaSalle, Diablo Canyon, and Wolf Creek have been granted setpoint tolerance relaxations.

As shown below, the proposed tolerance relaxation meets overpressure protection requirements and all ASME code requirements. In addition, evaluation of the FSAR accident analyses affected by the change has demonstrated that the conclusions for these analyses as stated in the FSAR remain valid, and results in no additional operational concerns.

All safety analyses done to support the MSSV tolerance change were performed using WCAP-12910 Rev. 1-A, "Primary Safety Valve Surge Line Loop Clearance Models." Specifically, primary safety valves utilize a TS setpoint of 2500 psia, a ±1% tolerance and +1% setpoint shift. Union Electric calculated a loop seal purge time of 1.15 seconds (using the methodology of WCAP-12910) which was implemented in the analysis as a time delay.

A sensitivity study was performed, to assess the effect on DNBR, in which the pressurizer safety valves were modeled as opening at 2475 psia (-1% tolerance) and the loop seal clearing time was neglected. This modeling confirmation results in minimum pressurizer pressure, which is conservative for DNBR evaluations. The Westinghouse DNBR evaluation of this sensitivity shows negligible impact on DNBR.

Non-LOCA Accident Evaluation

Many of the non-LOCA accidents are not affected by the assumption of maximum tolerance on the main steam line safety valves. This is because the pressures reached in the transient never approach the values for the lift setpoints. The pressure in a given transient would have to reach 1236 psia on the secondary side for the transient to begin to be affected by the increased tolerance, where the 1236 psia secondary setpoint reflects the Westinghouse transient methodology of modeling all main steam line safety valves as lifting at the same setpoint. All FSAR Chapter 15 non-LOCA transients have been evaluated and most are not significantly affected by the main steam line safety valve increased setpoint tolerance. The following accidents could possibly be impacted either because of Departure from Nucleate Boiling Ratio (DNBR) concerns or other licensing-basis acceptance criteria:

- Loss of External Load/Turbine Trip

RETRAN was used to reanalyze the loss of external load/turbine trip for DNBR. See Appendix A for a description of the RETRAN computer code and the Callaway model. This is the same model used by Union Electric to analyze the tube rupture accident presented in the Callaway FSAR. To assure the adequacy of this model for analyzing the turbine trip event, Union Electric benchmarked the RETRAN model to the existing Callaway FSAR turbine trip analysis which was done using LOFTRAN. The results of this benchmark are contained in Appendix B.

The benchmarked RETRAN model was used to reanalyze the turbine trip accident to assure the DNB design limits were not exceeded. In addition to modeling +3/-1% MSSV tolerances, changes were made to the benchmarked RETRAN model to account for the presence of a pressurizer loop seal and to expressly model five MSSVs per steam generator. The results of this revised DNBR analysis are contained in Appendix C. This analysis shows that the DNB design limits are not exceeded.

Westinghouse used LOFTRAN to reanalyze the loss of external load/turbine trip to assure design pressure was not exceeded (see Appendix D). This analysis shows that the design pressure was not exceeded with an expanded main steam line safety valve setpoint tolerance band, provided that the high pressurizer pressure safety analysis trip setpoint was reduced to 2425 psia and the trip response time for that trip function was reduced to 1 second.

- Rod Withdrawal at Power

The Westinghouse review of the rod withdrawal at power transients shows that the minimum reported DNBR occurs before MSSV actuation for most analyzed cases. Note that this transient is not very sensitive to secondary side changes, and the FSAR analyses conclusions remain valid.

- RCP Locked Rotor/Shaft Break

Westinghouse reviewed the locked rotor/shaft break accident and it was found that the MSSV tolerance increase to +3/-1% has little impact on the transient. However, as shown in WCAP-12910, the peak primary pressure will not remain below the 110% design limit when the primary safety valve loop seal is modeled. WCAP-12910 states that a Service Level C limit is more appropriate for this transient. RCS peak pressure will remain below the Service Level C values.

- Loss of Normal Feedwater/Station Blackout
  Feedwater Line Break
  Partial Loss of Forced Reactor Coolant Flow
  Complete Loss of Forced Reactor Coolant Flow

Westinghouse determined that the impacted non-LOCA accidents would have slightly higher DNBR values if the main steam safety valves lift at higher initial pressures. The DNBR transient is not changed significantly for the relaxation in setpoint tolerance and the conclusions reached for the DNBR accidents in the FSAR analyses remain valid.

- Inadvertent ECCS Actuation at Power

Westinghouse determined that the inadvertent ECCS actuation at power event would be impacted by an increased MSSV tolerance. However, the current analysis conservatively models a +3% tolerance.

<u>Non-DNB Transients</u>

Westinghouse determined that the locked rotor and rod ejection events will not be affected by the setpoint tolerance as it relates to the peak heat flux calculation. These analyses assume a conservative pressure which is less than the steady state RCS pressure. This pressure is maintained at a constant value throughout the transient so as to maximize the peak heat flux. Therefore, the FSAR analyses conclusions remain valid.

Westinghouse and Union Electric reviewed the quantity of steam mass released from the main steam line safety valves and determined that doses will not be significantly affected by the revised tolerance values. The primary effect of the increase in the safety valve tolerance on the impacted accidents is to alter the time at which the valves would open during the pressure increase transient. Even though the initial steam flow through the safety valves will increase due to a higher back pressure, the integrated mass release relieved from the secondary side is not expected to be significantly increased.

Westinghouse reviewed the effect of the setpoint tolerance change on long-term heat removal for both the loss of normal feedwater and station blackout events. The competing effects of increased/decreased heat removal capability on the secondary side and higher/lower average coolant temperatures on the primary side result in no significant impact on the heat removal capability of the secondary system. There is significant margin in these events to filling the pressurizer and the conclusions presented in the FSAR analyses remain valid.

Union Electric reviewed the applicable AFW calculations and it has been determined that the potentially higher discharge pressure against which the AFW must flow due to the increase in the MSSV tolerance will have no appreciable affect on Auxiliary Feedwater flow.

Union Electric determined that the ANSI/ASME piping system analysis equations have elements pertaining to internal pressure. This pressure stress is typically small with respect to the moments generated due to occasional and sustained loads. The additional 36 psi related to the +2% increase in MSSV set pressure will have no appreciable affect on secondary side pipe stresses.

LOCA Accident Evaluation

A safety evaluation for a safety valve setpoint tolerance relaxation to +3/-1 percent on the Chapter 15 FSAR LOCA accidents was performed in order to justify relaxation of the current ± 1 percent tolerance on the main steam line safety valves.

The current large break LOCA analysis forming the licensing basis for Callaway Plant (break size greater than or equal to 1.0 sq. ft.) results in a very rapid (approximately 30 seconds) depressurization of the RCS from the operating pressure to a pressure slightly above that of the containment. Because of the rapid primary depressurization, the secondary side of the steam generators quickly becomes a heat source rather than a heat sink such that the main steam safety valves are not challenged. The pressurizer safety valves are also not challenged because of the RCS depressurization. Therefore, the proposed safety valve tolerance relaxation will have no effect on the large break LOCA analysis.

The current small break LOCA analysis forming the licensing basis for Callaway Plant causes the system to depressurize to a pressure slightly above that of the steam generator secondary side pressure relief. The main steam safety valves provide a significant path for RCS energy release until steam venting through the break occurs. The primary pressure and the duration of time that the RCS primary remains above the secondary side pressure is governed by the rate of decay energy removal through the break and the amount of heat transferred to the steam generator secondary side. A slight increase in RCS pressure is computed to occur during this portion of the transient due to the higher secondary pressure as a result of the relaxed tolerances. Analysis has shown that increasing the secondary pressure, and as a result, the RCS pressure, results

in higher peak cladding temperatures (PCT). The PCT increase is 120°F, which when added to existing penalties, results in a PCT of 1985°F. The current Callaway small break analysis assumes nominal main steam line safety valve setpoints. An evaluation of the relaxed tolerance on PCT shows there is still a significant margin to the 2200°F regulatory limit. Further, since the small break LOCA is a depressurization transient, the pressurizer safety valves are not challenged. Therefore, the relaxed main steam line safety valve tolerance is acceptable with respect to the small break LOCA analysis. The increase in PCT for small break LOCA will be reported consistent with the requirements of 10 CFR 50.46.

Post-LOCA hot leg recirculation switchover time is determined for inclusion in emergency procedures to ensure long term core cooling by precluding boron precipitation in the reactor vessel following boiling in the core. This time is dependent on power level as well as the RCS, refueling water storage tank, and accumulator water masses and boron concentrations. Changes in the steam generator secondary pressure influence the RCS pressure and masses assumed in the switchover analysis. The effect of the proposed main steam line safety valve tolerance relaxation has been evaluated and is insignificant. Further, operation of the pressurizer safety valves will not affect the analysis since calculations are based on total mass inventories.

The LOCA hydraulic forcing functions acting upon the vessel, internals, and loop are a function of the primary system geometry and primary operating conditions. The peak forces are generated within the first seconds after break initiation. For this reason, the forces model does not consider the effects of the secondary side. As such, the relaxation in main steam line safety valve lift set tolerances to +3 percent will have no effect on the magnitude or frequency of the LOCA hydraulic forcing functions provided in the Callaway FSAR.

Post-LOCA long-term core cooling will not be affected by an increase in main steam line safety valves setpoint tolerances because no change in the sump boron concentration would occur. Sump boron concentration is determined by the accumulation of all potential water sources in the containment, based on each respective source boron concentration. A scenario has not been envisioned whereby changes in safety valve operation would result in spilling additional non-borated water, reduce the inventory of borated water, or limit component boron concentration as used in the mass average calculation used in the evaluation. It is concluded that there would be no change to the long-term cooling capability of the emergency core cooling system as a result of increased valve tolerances.

<u>Steam Generator Tube Rupture Accident Evaluation</u>

The FSAR Steam Generator Tube Rupture (SGTR) analysis is performed to evaluate the radiological consequences of an SGTR accident. The major factors that affect the resultant offsite doses are the amount of radioactivity in the reactor coolant, the total

amount of primary coolant transferred to the secondary side of the ruptured steam generator through the ruptured tube, and the steam released from the ruptured steam generator to the atmosphere. The amount of radioactivity in the reactor coolant assumed in the FSAR SGTR analysis is not affected by the changes in the main steam line safety valve setpoint tolerances. An increase in the setpoint tolerance in the positive direction will reduce the calculated break flow and offsite doses.

Conclusion

The non-LOCA safety evaluation supports the conclusion that the proposed tolerance of +3 percent for the main steam line safety valves is acceptable. This conclusion is reached based on the assessment that the non-LOCA acceptance criteria are met for this increase in opening setpoints for all the non-LOCA accidents. It is concluded that the tolerances on the main steam line safety valves as given in the Technical Specifications for Callaway Plant may be changed to specify +3/-1 percent.

The LOCA safety evaluation supports the conclusion that the effects of increasing main steam line safety valve tolerances to +3 percent at Callaway Plant do not result in exceeding any design or regulatory limit. Therefore, it is concluded that the proposed technical specification valve tolerance relaxation is acceptable.

The increase in safety valve setpoint tolerance from $\pm$1 percent to +3/-1 percent has been evaluated with respect to both LOCA and non-LOCA events for impact on the radiological consequences of accidents. There is no impact on the radiological consequences of any accident.

Table 3.3-2 is changed to revise the pressurizer pressure-high response time from 2 seconds to 1 second. This provides margin to expand the main steam safety valve setpoint tolerance to +3/-1%.

The revisions to Table 2.2-1 are made to assess the impact of reducing the high pressurizer pressure safety analysis limit (SAL) from the current value of 2445 psig to 2410 psig. This SAL reduction is needed to ensure acceptable accident analysis results are obtained to accommodate a relaxation of the main steam safety valve setpoint tolerance to $\pm$3/-1%. These changes recognize that older generation Barton transmitters, subject to excessive negative drift, are no longer used in this application. This negative drift accounted for 4.25% of the 4.96% of span Z term. Deletion of this drift term requires that the S term be increased by 1% of span to account for a typical drift allowance. Thus, Z and S are revised to 0.71% span and 2.0% span, respectively. The reduced SAL directly results in a reduced total allowance (TA), i.e. since it reflects the difference between the SAL and the nominal trip setpoint

$$\left(\frac{2410 - 2385 \text{ psig}}{800 \text{ psig} / 100\% \text{ span}} = 3.125\% \text{ span}\right)$$

The decreased TA in conjunction with the increased S term results in a reduced allowable value of 2393 psig.

The revision to Table 3.7-1 (and Bases 3/4.7), utilized the methodology as described in Westinghouse Nuclear Service Advisory Letter 94-001 and Information Notice 94-60, "Potential Overpressurization of Main Steam System." These documents notified utilities of a calculational error in determining the maximum power level for inoperable main steam safety valves. Using the new methodology results in lower allowed power levels with inoperable MSSVs. As such, these changes are conservative and do not impact any accident analysis or involve an unreviewed safety question.

The revision to Bases 3/4.7 reflects changes necessitated by the use of V5 fuel and the plant uprating. These changes supersede the changes submitted in ULNRC-2450 (dated July 30, 1991). This Bases section is also revised to incorporate a change in the methodology used to determine the maximum power level for inoperable main steam safety valves. These changes are conservative in nature and therefore do not impact any accident analysis or involve an unreviewed safety question.

Evaluation

The proposed change to Technical Specifications does not involve an unreviewed safety question because operation of the Callaway Plant with this change would not:

1. Increase the probability of occurrence or the consequences of an accident or malfunction of equipment important to safety previously evaluated in the safety analysis report. There is no increase in the probability of occurrence or the consequences of an accident. The main steam line safety valves are designed to mitigate transients by preventing overpressurization of the main steam system. The proposed change does not alter this design basis. The revised analysis shows that the probability or consequences of all previously analyzed accidents are not changed by increasing the setpoint tolerance of the safety valves. Therefore, there is no increase in the probability of occurrence or the consequences of any accident.

2. Create a possibility for an accident or malfunction of a different type than any previously evaluated in the safety analysis report. There is no new type of accident or malfunction created and the method and manner of plant operation will not change nor is there a change in the method in which any safety related system performs its function. Any main steam safety valve lifting at the extremes of the proposed tolerance will not result in a low lift setpoint that is less than the normal no load system pressure or a high lif tpoint that allows main steam system overpressurization.

3. Reduce the margin of safety as defined in the basis for any technical specification. This is based on the fact that no plant design changes are involved and the method

and manner of plant operation remains the same. With the exception of locked rotor, all safety analysis which model the MSSV increased setpoint tolerances demonstrate that the main steam safety valves will still prevent pressure from exceeding 110 percent of design pressure in accordance with the ASME code. For locked rotor, the impact of changing the tolerance to +3/-1% has little impact on peak pressure and the Service Level C acceptance limit is satisfied. All FSAR accident analysis conclusions remain valid and unaffected by this change.

Given the above discussions as well as those presented in the Significant Hazards Evaluation, the proposed change does not adversely affect or endanger the health or safety of the general public or involve a significant safety hazard.

SAFETY EVALUATION

Appendix A:

Description of RETRAN MODEL

Appendix A

1.0 RETRAN COMPUTER CODE

The RETRAN-02 (Mod 5.1) code is a one-dimensional, best-estimate, thermal-hydraulic, transient analysis computer code developed from RELAP-4/003 (Reference A-1). The NRC issued a Safety Evaluation Report (References A-2, A-3) which concluded that RETRAN-02 is an "acceptable computer program for use in licensing applications for calculating the transients described in Chapter 15 of NUREG-0800, and other transients and events as appropriate and necessary for nuclear power plant operation."

RETRAN-02 is a variable nodalization code and, therefore, requires a user to input a control volume/flow path network/heat slab model of both primary and secondary system elements similar in type to those utilized in the RELAP series of codes. The control volume/flow path equilibrium thermal hydraulics have three slip options: homogeneous, drift flux, and a four equation set. Point kinetics or one-dimensional space-time kinetics can be used for the neutronics.

Polynomial fits are used for the thermodynamic properties of water. Air is approximated by an ideal gas. There is an extensive list of forced and natural convection heat transfer correlations covering the entire boiling curve plus a number of condensing heat transfer correlations. A modified Bennett flow regime map can be used to select friction factors. Critical flow options available use the Moody, isoenthalpic and the extended Henry-Fauske models. Special purpose models include a subcooled void fit, bubble rise, trips and a wide ranging control system which gives the user flexibility to program user-specific modifications, transport delay, auxiliary DNBR, enthalpy transport, and local condition heat transfer. Component models include a two region nonequilibrium pressurizer, centrifugal and jet pumps, valves, non-conducting heat exchangers, steam separators, and turbine. An automatic steady state initialization procedure is also available.

2.0 GENERAL DESCRIPTION

The Callaway turbine trip noding diagram employed in the RETRAN analysis is shown schematically in Figure A-1. The RETRAN model utilizes two loops; one represents a single loop of the plant while the second loop combines the remaining three plant loops into one. Noding of this manner allows analysis of asymmetric transients such as a turbine trip.

The pressurizer is positioned on the lumped loop. This placement is typical of that for other RETRAN models for similar plants.

The reactor vessel is modeled with eight control volumes as shown in Figure A-1; one volume for the downcomer region, one volume for the core bypass region, three volumes for the active core region, one volume each for the upper plenum and the lower plenum and the upper head.

The primary coolant piping and steam generators are modeled in some detail so that area changes and elevation differences would be included in the model. The hot leg, pump suction leg, pump, and cold leg were represented by one volume each. Six volumes are used to model each steam generator; one each for the inlet and outlet plenums and four in the U-tube region. The pressurizer, pressurizer surge line, and pressurizer spray line are each represented by a single volume.

Heat conductors are modeled only for the steam generator tubes and the active length of the reactor core. The active length of steam generator tubes has four heat conductors (one for each fluid volume) and the reactor core has three axial core conductors (one for each fluid volume) to describe the active core.

The turbine trip model consists of 37 fluid volumes, 64 junctions and 11 heat conductors. The nodalization was selected so as to identify important hydraulic features of the system and provide sufficient detail to attain accuracy in solution. A summary of the volume description is given in Table A-1.

3.0 COMPONENT DESCRIPTIONS

Steam Generators

Nodalization

The primary portion of the steam generator is divided into four nodes. These four nodes represent the 5626 U-tubes associated with the Model F. According to Figure A-1, the single loop nodes are identified by Volumes 402, 412 through 462 and 492 and the lumped loop nodes are identified by Volumes 401, 411 through 461 and 491.

The secondary side of the steam generators is represented as a single saturated volume. This noding is a significant simplification for the actual plant geometry but is consistent with the modeling technique employed for the turbine trip transient in the FSAR.

Initialization

Since the secondary side is modeled by a single volume and does not account for recirculation flow in the tube bundle region, the flow area in the tube bundle has been reduced by the recirculation ratio to obtain a realistic value of velocity for the heat transfer calculations.

In addition to initializing with the proper heat transfer characteristics, steam and liquid mass inventories must be initially correct. The initial steam generator liquid mass depends on the input initial conditions and was adjusted by varying the initial mixture quality while maintaining a fixed mixture level height.

Heat Conductors

The steam generator tubes are divided into four equal conductors, one conductor for each SG tube volume, in order to provide one to one correspondence for heat transfer. Thus, the inside and outside surface areas and volume of metal for each conductor are one-fourth of the value of these parameters calculated for all the SG tubes. The eight heat conductors for the two steam generators are shown in Figure A-1.

Feedwater

Main Feedwater

The main feedwater is represented as a fill junction and is identified as junction 701 for the lumped loop and Junction 702 for the single loop.

Auxiliary Feedwater

The auxiliary feedwater is also represented as a fill junction and is identified as Junction 711 for the lumped loop and Junction 712 for the single loop. Although Figure A-1 shows the auxiliary feedwater junction elevation above that of the main feedwater junction, the model input has the auxiliary feedwater junction correctly positioned as in the plant.

Main Steam Line

The main steam line from the steam generator outlet nozzle inclusive to the main steam isolation valve is modeled as a single volume. According to Figure A-1, the single loop steam line is identified as Volume 602 whereas the lumped loop is identified as Volume 601.

Safety and Relief Valves

In the event of steam generator secondary over-pressurization, five safety valves and one atmospheric relief valve can open to relieve pressure. The actuation of the valves is controlled by trip functions that monitor pressure of the secondary side.

Pressurizer

The pressurizer, Volume 310 on Figure A-1, is modeled as a single non-equilibrium fluid volume with phase separation. This option uses the equations for mass and energy balances in RETRAN to permit the pressurizer volume to have different temperatures in the liquid and vapor regions of the pressurizer during a transient.

Safety, Relief and Spray Valves

The model includes the pressurizer relief and safety valves, pressurizer spray, but does not include pressurizer heaters. The pressurizer relief and safety valves are activated by trip functions which are set to open and reset on pressurizer pressure. The pressurizer spray is controlled by a control system acting upon a pressurizer pressure error signal. The relief and safety valves discharge to the pressurizer relief tank, Volume 330.

Reactor Vessel

Lower Plenum

The lower plenum, Volume 100, includes the lower head and the volume inside the lower internals assembly below the core.

Upper Plenum

The region above the core consists of an upper plenum (Volume 120) and upper head volumes (Volume 130) as illustrated in Figure A-1. The flow paths in this region represent both the main flow path from the core to the hot leg piping and the downcomer to upper head leakage of approximately 1.5% of total flow.

Downcomer

The downcomer, Volume 140, is the annular volume between the reactor vessel and the outer surface of the lower barrel assembly. The volume extends from the upper flange of the lower barrel assembly to the bottom of the lower barrel assembly.

Core

The core is divided into three axial nodes. The length of each of these fluid volumes is one-third the average active length of a fuel assembly. The total flow area in the core is composed of the difference between the area within the core baffle and the total cross section area of the fuel rods, instrumentation tubes and RCCA thimbles.

RETRAN determines the core power generation by employing the kinetics model with one prompt neutron group, six delayed neutron groups, and eleven delayed gamma emitters plus U-239 and Np-239.

Core Heat Conductors

There are three core heat conductors numbered 1 through 3. These provide a one for one correspondence with each core fluid volume numbered 1 through 3. All volume heat conductors have a length equal to their corresponding fluid volumes. The conductivity of the gas in the gap between the fuel and the clad gives an average fuel temperature corresponding to full power.

Core Bypass

The core bypass, Volume 110, consists of the space between the core barrel and the core baffle, the incore instrument tube assembly, and the RCCA thimbles.

Reactor coolant Pumps

The reactor coolant pumps are represented by the design Westinghouse model 93A pump homologous performance characteristic curves. For the model, the thermal energy generated by the pumps is added to the reactor coolant system in the pump control volumes, Volumes 221 and 222 as shown in Figure A-1.

Reactor Coolant Piping

The remaining volumes represent the reactor coolant piping. These nodes are identified as Volumes 201, 211, 231, 202, 212 and 232 on Figure A-1.

Safety Injection

Safety injection to the cold legs of the reactor coolant piping is modeled as fill junctions. Upon reaching the low pressurizer pressure setpoint, the fill junction trips on and emergency core cooling is provided. Safety Injection is not employed in analyzing the Turbine Trip transient.

Charging and Letdown

The Chemical and Volume Control System functions of normal charging and letdown are not included in this model.

4.0 MODELING TECHNIQUES

Reactor Trips

Overtemperature and Overpower Delta T

Both the OTΔT and OPΔT equations are programmed into RETRAN via linear control systems which trip the reactor if either setpoint is reached.

Pressurizer pressure

Both extremes of pressurizer pressure are monitored for reactor trip purposes. In addition to reactor trip, safety injection occurs when the low pressurizer pressure setpoint is reached.

5.0 MODELING OPTIONS

Enthalpy Transport

The standard enthalpy transport option is used on all the heated or heat exchanging conductors. This involves the three core conductors and the four steam generator conductors in each loop. This option provides a value for junction enthalpy based on known enthalpy at the center of the associated volume.

Pressurizer Model

The non-equilibrium model is used to determine the pressurizer response. This model is a necessity for operational transients because the surge into the pressurizer causes a significant non-equilibrium effect which is not accounted for by the standard equilibrium state solution. This model keeps track of the mass and energy in both liquid and vapor regions allowing different thermodynamic states in each region. The model includes a "flashing" model for movement of vapor from the liquid region to the vapor region and a rainout model for movement of liquid from the vapor region to the liquid region.

The limitations of the non-equilibrium pressurizer model as identified in the SER are recognized and it is noted that at no point in the turbine trip transient analyses does the pressurizer completely empty or become water solid.

Temperature Transport Delay

The temperature transport delay model is employed to model the movement of temperature fronts through the piping volumes. As identified in the SER, the transport delay option is only used in piping exhibiting a dominant flow direction.

Momentum Equation

Of the options available to calculate momentum effects, the complete compressible momentum equation is employed for all junctions in the model. At junctions like the surge line entrance from the hot leg piping it is assumed that there is no momentum flux exchanged since this is a "T" junction with a much smaller line entering the reactor coolant piping and the angle is biased 90° to remove the momentum flux.

Homogeneous Equilibrium Model

All volumes employed in the model with the exception of the pressurizer and the steam generator secondary are homogeneous equilibrium model volumes.

Bubble Rise Model

The steam generator secondary side employs the standard equilibrium mixture bubble rise model in order to account for separation of phases.

6.0 REFERENCES

A-1 McFadden, J.H., et al, RETRAN-02 - A Program for Transient Thermal-Hydraulic Analysis of Complex Fluid Flow Systems, EPRI NP-1850-CCM-A, Rev. 5, 1992

A-2 Safety Evaluation Report on RETRAN-01 MOD 003 and RETRAN-02 MOD 002, September 4, 1984, Page 3.

A-3 Letter from A. C. Thadoni (NRC) to W. J. Boatwright (TU), November 1, 1991, Subject: "Acceptance for Use of RETRAN02 MOD 005.0."

TABLE A-1. CONTROL VOLUME DESCRIPTIONS

Control Volume No.	Description
201 (202)	Hot leg pipe - includes RV outlet nozzle and steam generator inlet nozzle
401 (402)	Steam generator primary inlet volume and tubesheet volume
411, 412 (412, 422)	Steam generator tubes vertical upflow section
431 (432)	Steam generator tubes upflow includes half of U bend
441 (442)	Steam generator tubes downflow includes half of U bend
451, 461, (452, 462)	Steam generator tubes vertical downflow section
491 (492)	Steam generator primary outlet tubesheet and outlet plenum
211 (212)	Crossover pipe - steam generator outlet nozzle to RC pump
221 (222)	RC pump
231 (232)	Cold leg pipe - RC pump to RV inlet nozzle
310	Pressurizer
300	Pressurizer surge line
320	Pressurizer spray line
140	Reactor vessel downcomer annulus
100	Reactor vessel lower plenum
1	Lower third of core active length
2	Middle third of core active length
3	Upper third of core active length

Control Volume No.	Description
120	Core outlet plenum
130	Reactor vessel upper head
110	Core bypass
501 (502)	Steam generator secondary
330	Pressurizer Relief Tank (Time Dependent Volume)
999	Atmosphere (Infinitely Large Volume)
601 (602)	Main steam line inclusive to the MSIVs

* Control volume numbers in parenthesis are associated with loop representing the single steam generator and the other control volume numbers are for the lumped loop.

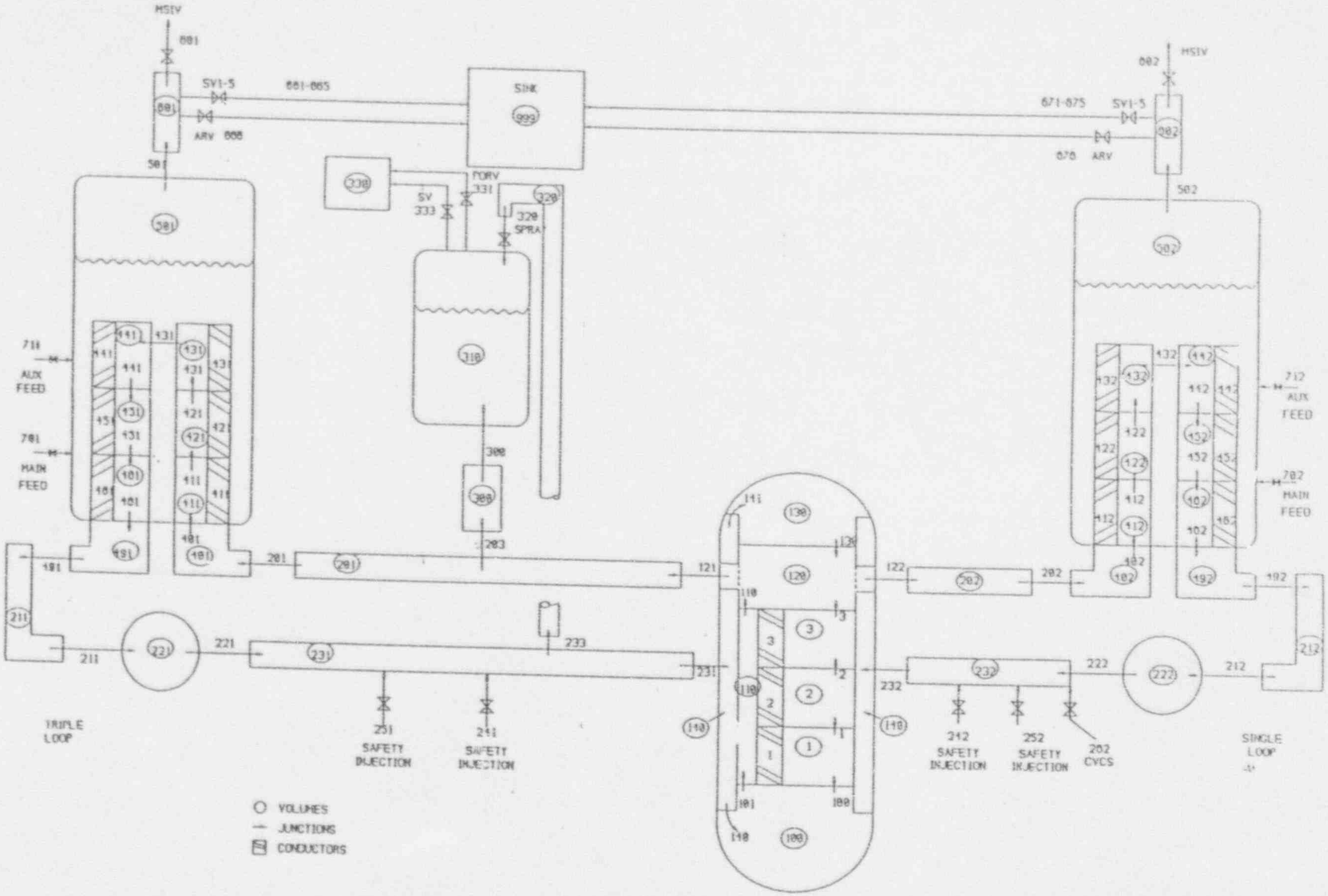


Figure A-1. Callaway Base Deck Nodalization Diagram

SAFETY EVALUATION

Appendix B:

Benchmark of the Callaway Plant
RETRAN-02 Base Deck to the
LOFTRAN Results Presented
in FSAR Section 15.2.3

Appendix B

1.0 INTRODUCTION

The purpose of this report is to document a turbine trip event analysis performed with RETRAN-02 MOD005.1 and compare that analysis to similar analyses presented in the Callaway FSAR. There are four turbine trip analyses presented in the FSAR and those analyses are duplicated and presented here in this report.

These analyses were performed to demonstrate that the RETRAN-02 input model of the Callaway Plant could adequately replicate the FSAR results when using similar assumptions, initial conditions and values of key parameters. The results of the RETRAN-02 analyses are compared to the FSAR analyses in Section 5.0, where it is shown that the results agree very well. This benchmark serves as a demonstration that the Callaway input model and the RETRAN-02 computer code can be used to evaluate turbine trip events.

This report documents the assumptions and key parameters in Section 2.0, the initial conditions in Section 3.0, the modifications to the base deck in Section 4.0 and the RETRAN-02 analysis results are compared to the FSAR analysis results in Section 5.0.

2.0 Assumptions and Key Parameters

The RETRAN-02 analysis was performed to duplicate the LOFTRAN turbine trip analysis presented in the FSAR. Where possible, the same values of initial conditions, key parameters, and assumptions were used in the RETRAN-02 analysis as in the LOFTRAN analysis. However, there are some basic differences between the computer code models that cannot be addressed through input; or they may require the key parameters to be supplied in a different form.

Assumptions

The major assumptions used for this analysis are:

(1) No credit is taken for the direct reactor trip upon turbine trip. The reactor trip occurs on the first reactor protection trip setpoint reached after the turbine trip.

(2) The reactor is in manual control (no credit is taken for automatic response to the event).

(3) No credit is taken for steam release through the steam dump system or the steam generator power-operated relief valves. Consequently, the steam generator pressure is limited only by the steam generator safety valves.

(4) Main feedwater flow is assumed to be lost at the time of reactor trip and no credit is taken for the auxiliary feedwater system.

(5) Two sets of reactivity assumptions were used. One assumes minimum reactivity feedback and the other assumes maximum reactivity feedback as follows:

(a) Minimum Reactivity Feedback

A least negative moderator temperature coefficient and a least negative Doppler temperature coefficient were assumed (BOL conditions). In addition, it is conservatively assumed that a 5 pcm/°F PMTC exists at 100% power.

(b) Maximum Reactivity Feedback

A conservatively large negative moderator temperature coefficient and a most negative Doppler temperature coefficient were assumed (EOL conditions).

(6) Two cases were analyzed for each set of reactivity assumptions. These cases were analyzed with full credit for RCS pressure control, and without credit for RCS pressure control. These cases are described as follows:

(a) With Pressure control

Full credit was taken for the effect of pressurizer spray and pressurizer power-operated relief valves (PORVs) in reducing or limiting the primary pressure. Pressurizer safety valves were also assumed operable.

(b) Without Pressure Control

No credit was taken for the effect of pressurizer spray and pressurizer PORVs in reducing or limiting the coolant pressure. The pressurizer safety valves were assumed operable.

(7) The limiting single failure assumed is the loss of one protection train.

Four turbine trip transient analyses were performed with the RETRAN-02 MOD005.1 code and compared to the FSAR analyses. These cases are:

(1) Maximum Reactivity assumptions with no credit taken for the pressurizer PORVs or spray,

(2) Maximum Reactivity assumptions with credit taken for the pressurizer PORVs and spray,

(3) Minimum Reactivity assumptions with no credit taken for the pressurizer PORVs or spray, and

(4) Minimum Reactivity assumptions with credit taken for the pressurizer PORVs and spray.

3.0 Initial Conditions

The initial conditions of the RETRAN-02 analyses were selected to match the FSAR analysis as closely as possible and are compared in Table 3-1. All four transients analyzed were initiated from these initial conditions.

The RCS flow used in the RETRAN-02 analyses is slightly less than that used in the FSAR analysis. The FSAR analyses used minimum measured flow (141.9E6 lbm/hr). However, when this flow rate was used to initialize the RETRAN-02 cases it produced a vessel ΔT of 60.95°F instead of the desired value of 62.16°F. Therefore,, the RCS flow was adjusted down until the desired vessel ΔT was obtained.

4.0 Modifications to the Base Model

The base model for the Callaway Plant was modified for these transient analyses. The modifications are designed to be placed at the end of the base deck so as to replace the original data cards. A nodalization diagram for the RETRAN-02 Callaway model is shown in Figure 4-1. The modifications were made to represent the transient scenario and assumptions, to represent initial conditions, and to emulate the analysis methods used by the LOFTRAN code. Generally, these modifications included:

a) changes to the pressurizer safety valve and steam generator safety valve models,

b) transient initiation by closing the MSIVs and terminating main feedwater (where MSIV closure approximates closure of the turbine stop valves),

c) keeping the reactor coolant pumps running throughout the transient,

d) deactivating the SG relief valves,

e) deactivating the pressurizer heaters,

f) and, preventing the auxiliary feedwater system from actuating.

Other modifications were made on a case by case basis to model the transient conditions of pressure control and reactivity feedback.

5.0 Turbine Trip Transient Analysis Results

The turbine trip transient is characterized by degraded primary-to-secondary heat transfer due to an increase in secondary pressure from the turbine trip. Because of the degraded SG heat transfer, the primary fluid temperature increases thereby causing the fluid to expand into the pressurizer and increase the RCS pressure. After the turbine trip, the secondary pressure continues to rise until the SG SVs open. The primary fluid also continues to expand until the reactor is tripped. The peak RCS pressure reached depends on the power response, the degraded SG heat transfer, and the actions of the primary pressure control systems.

Four turbine trip transient analyses were performed with the RETRAN-02 MOD005.1 code. These cases are:

(1) Maximum Reactivity with no credit taken for the pressurizer PORVs or spray,

(2) Maximum Reactivity with credit taken for the pressurizer PORVs and spray,

(3) Minimum Reactivity with no credit taken for the pressurizer PORVs or spray, and

(4) Minimum Reactivity with credit taken for the pressurizer PORVs and spray.

These four transient analyses are compared with the same analyses from the FSAR. The initial conditions and assumptions used for these analyses are the same as those used in the FSAR. However, because the RETRAN-02 code uses different solution methods and different mathematical models for plant systems and physical phenomena than the LOFTRAN code, the FSAR analysis results cannot be matched exactly. If code model differences are believed to cause differing results for certain parameters, they are discussed in the subsections presenting the specific analyses.

The results of these RETRAN-02 analyses match the FSAR results well in all four cases. In the next subsections, the results of the four RETRAN-02 analyses are compared to the FSAR results and include graphical comparisons and timing of key events.

5.1 Maximum Reactivity with No Primary Pressure Control

This case uses the most negative Doppler and moderator temperature reactivity functions and assumes the pressurizer spray and PORV are inoperable. Comparison with the FSAR data for this case are shown in Figures 5-1 through 5-5. The sequence of events are compared in Table 5-1.

The primary system pressure shown in Figure 5-1 increases immediately in response to the turbine trip and resulting degraded SG heat transfer. The pressure increase is slowed by opening of the pressurizer safety valves at 5.8 seconds and then reversed by the reactor trip at 6.8 seconds. After the reactor trip, the pressure decreases sharply and in the longer term gradually decreases in parallel with the RCS temperatures.

The normalized system power is shown in Figure 5-2. The power increases slightly prior to reactor trip which occurs on high system pressure at 6.8 seconds. This power increase is caused by the increased moderator density as a result of the primary pressurization. Even though the moderator temperature increases, the primary pressurization causes a net increase in core density. It should be noted that this is a short-lived effect; that is, the pressurization is induced by heat transfer degradation in the steam generators, and the relatively hot fluid that consequently exits the steam generators must traverse the cold legs prior to being "seen" as a reactivity effect in the core. This in turn results in an initial positive reactivity addition and a minor power increase prior to the reactor trip. After the reactor trip, the power decreases rapidly to decay heat levels.

The core average temperature and the core inlet temperature are shown in Figures 5-3 and 5-4, respectively. Both of these parameters respond to the degraded SG heat transfer and increased core power by an immediate increase until the reactor trip. After the reactor trip, the primary temperatures drop rapidly, then gradually decrease as the decay heat decreases.

The pressurizer liquid volume is shown in Figure 5-5. The pressurizer liquid volume matches the FSAR result well through the first 20 seconds of the transient. After that time the two analyses show differences. The change in liquid volume of the pressurizer is directly related to the primary fluid temperature. As the primary temperature increases, the increased coolant volume is displaced into the pressurizer. As can be seen in Figures 5-3 and 5-4, the primary temperature response for the two analyses match very well. In addition, the pressurizer pressure also matches well (Figure 5-1). Therefore, the discrepancy in the pressurizer liquid volume response can only be attributed to a difference in the pressurizer modeling methods in the two codes. In all four analyses, the pressurizer liquid volume comparison between the two analyses display differences.

5.2 Maximum Reactivity with Primary Pressure Control

This case uses the most negative Doppler and moderator temperature reactivity functions and assumes the pressurizer spray and PORV are operable. Comparison with the FSAR data for this case are shown in Figures 5-6 through 5-10. The sequence of events are compared in Table 5-2.

The primary system pressure shown in Figure 5-6 begins to immediately increase in response to the turbine trip and resulting degraded SG heat transfer. The expansion of the primary fluid into the pressurizer is rapid enough that the pressurizer spray and PORVs are unable to stop the pressure from increasing. The pressure increase is slowed by opening of the pressurizer PORVs at 3.8 seconds and then reversed by a decrease in power resulting from the increased

temperature (decreased density) of the primary coolant. At 13.4 seconds the PORVs close, stopping (at least temporarily) the decline in RCS pressure. The small changes in RCS pressure that immediately follow reflect the minor fluctuations in SG pressure shortly after the SG SVs open. The reactor trips at 14.6 seconds as a result of the OTΔT protection logic. After the reactor trip, the pressure decreases sharply and then gradually decreases in parallel with the RCS temperatures.

The normalized system power is shown in Figure 5-7. The power increases slightly for the first 4 seconds, predominantly caused by the increased moderator density as a result of the primary pressurization. However, the moderator temperature increase from the degraded SG heat transfer eventually causes a net expansion of the moderator in the core and consequent decrease in power. The power continues to decrease until it reaches a momentary plateau at 12 seconds. The power begins to level out at this time because the SG secondary has reached an equilibrium pressure (see Figure 5-16) causing the primary system to reach a quasi-equilibrium state. However, shortly after that, at 14.6 seconds the reactor is tripped on an OTΔT reactor trip and the power decreases to a decay heat level.

The core average temperature and the core inlet temperature are shown in Figures 5-8 and 5-9, respectively. Both core inlet temperature and core average temperature respond to the degraded SG heat transfer and changes in core power by an immediate increase after the turbine trip. At approximately 12 seconds the temperature rise is slowed after the steam generator pressure reaches the SV setpoint. After the reactor trip at 14.6 seconds, the primary temperatures drop rapidly, then gradually decrease as the decay heat decreases.

The pressurizer liquid volume is shown in Figure 5-10. The pressurizer liquid volume matches the FSAR result well until the pressurizer PORV opens at 3.8 seconds. After that time, the two analyses begin to show differences. The change in liquid volume of the pressurizer is directly related to the primary fluid temperature. As the primary temperature increases, the increased coolant volume is displaced into the pressurizer. As can be seen in Figures 5-8 and 5-9, the primary temperature response for the two analyses match very well, which is also true of the pressurizer pressure. Consequently, the difference in the pressurizer liquid volume response can only be attributed to a difference in the pressurizer modeling methods in the two codes. In all four analyses, the pressurizer liquid volume comparison between the two analyses display differences.

5.3 Minimum Reactivity With No Primary Pressure Control

This case uses the least negative Doppler and moderator temperature reactivity functions and assumes the pressurizer spray and PORV are inoperable. Comparison with the FSAR data are shown in Figures 5-11 through 5-15. The sequence of events are compared in Table 5-3.

The primary system pressure shown in Figure 5-11 begins to immediately increase in response to the turbine trip and resulting degraded SG heat transfer. The pressure increase is slowed by opening of the pressurizer safety valves at 6.0 seconds and then reversed by the reactor trip at

6.9 seconds. The primary pressure reaches a slightly higher peak than the maximum reactivity case described in Section 5.1 because of the higher power obtained prior to the reactor trip (consistent with the least negative reactivity feedback). After the reactor trip, the pressure decreases sharply and gradually decreases in parallel with the RCS temperatures.

The normalized system power is shown in Figure 5-12. The power increases prior to the reactor trip which occurs on high system pressure at 6.9 seconds. This power increase is caused by the positive moderator temperature coefficient and the increasing temperature prior to reactor trip. In the first two cases that use maximum reactivity input, the power increased early due to the increase in moderator density from primary pressurization prior to the time the changes in fluid temperature was transported to the core. In this case, there is no apparent change in power during that similar early period. This is due to the fact that the moderator reactivity feedback is supplied in terms of a temperature coefficient rather than a density coefficient, therefore, the initial change in core fluid density is not accounted for. This method of inputting the moderator feedback coefficients is consistent with the way the values are documented in the FSAR. In addition, it appears to be consistent with the method of input used in the LOFTRAN code since the turbine trip results in the FSAR displayed the same behavior (a slight initial power increase for the cases with maximum reactivity and a lack of any initial power change in the cases with minimum reactivity). Also note that had the reactivity effects from the initial density increase been modeled for the minimum reactivity cases, the power would have decreased initially which would be less conservative.

After the reactor trip, the power decreases rapidly to decay heat levels. As can be seen from the figure, the power increases more prior to the reactor trip in the RETRAN-02 analysis. As best as can be determined, the assumptions regarding the reactivity functions are similar in the two analyses. However, the method that the RETRAN-02 and LOFTRAN codes use to model the Doppler reactivity feedback are significantly different. In the LOFTRAN code, the Doppler reactivity feedback is predominantly a function of system power while in the RETRAN-02 code the Doppler feedback is a direct function of average fuel temperature. It is possible that the differences in the Doppler feedback models are responsible for differences in power prior to the reactor trip.

The core average temperature and the core inlet temperature are shown in Figures 5-13 and 5-14, respectively. Both parameters respond to the degraded SG heat transfer and increased core power by an immediate increase until the reactor trip. After the reactor trip, the primary temperatures drop rapidly, then gradually decrease as the decay heat decreases. The peak temperatures reached in both figures are slightly higher in the RETRAN-02 analyses because of the higher power prior to the reactor trip.

The pressurizer liquid volume is shown in Figure 5-15. The pressurizer liquid volume matches the FSAR result well through the first 10 seconds of the transient. After that time the two analyses show significant differences. The change in liquid volume of the pressurizer is directly related to the primary fluid temperature. As the primary temperature increases, the increased coolant volume is displaced into the pressurizer. As can be seen in Figures 5-11, 5-13 and 5-14 the primary pressure and the primary temperature response for the two analyses

match very well. Consequently, the difference in the pressurizer liquid volume response can only be attributed to a difference in the pressurizer modeling methods in the two codes.

5.4 Minimum Reactivity with Primary Pressure Control

This case uses the least negative Doppler and moderator temperature reactivity functions and assumes the pressurizer spray and PORV are operable. Comparison with the FSAR data is shown in Figures 5-16 through 5-20. The sequence of events are compared in Table 5-4.

The primary system pressure shown in Figure 5-16 begins to immediately increase in response to the turbine trip and resulting degraded SG heat transfer. The pressure increase is slowed by opening of the pressurizer PORVs at 3.9 seconds, then reversed by the pressurizer SVs opening at 8.9 seconds followed shortly by a reactor trip at 9.5 seconds. After the reactor trip, the pressure decreases sharply and then gradually decreases in parallel with the RCS temperatures.

The normalized system power is shown in Figure 5-17. The power increases prior to the reactor trip which occurs on high system pressure at 9.5 seconds. This power increase is caused by the positive moderator temperature coefficient and the increasing temperature prior to reactor trip. In the first two cases that use maximum reactivity input, the power increased early due to the increase in moderator density from primary pressurization prior to the time the changes in fluid temperature was transported to the core. In this case, there is no apparent change in power during that similar early period. This is due to the fact that the moderator reactivity feedback is supplied in terms of a temperature coefficient rather than a density coefficient, therefore, the initial change in core fluid density is not accounted for. This method of inputting the moderator feedback coefficients is consistent with the way the values are documented in the FSAR. In addition, it appears to be consistent with the method of input used in the LOFTRAN code since the turbine trip results in the FSAR displaying the same behavior (a slight initial power increase for the cases with maximum reactivity and a lack of any initial power change in the cases with minimum reactivity). Also note that had the reactivity effects from the initial density increase been modeled for the minimum reactivity cases, the power would have decreased initially which would be less conservative.

After the reactor trip, the power decreases rapidly to decay heat levels. As can be seen from the figure, the power increases more prior to the reactor trip in the RETRAN-02 analysis. As best as can be determined, the assumptions regarding the reactivity functions are similar in the two analyses. However, the method that the RETRAN-02 and LOFTRAN codes use to model the Doppler reactivity functions are significantly different. In the LOFTRAN code, the Doppler reactivity feedback is predominantly a function of system power while in the RETRAN-02 code the Doppler feedback is a direct function of fuel temperature. It is possible that the differences in the Doppler feedback models are responsible for the differences in power prior to the reactor trip.

The core average temperature and the core inlet temperature are shown in Figures 5-18 and 5-19, respectively. Both parameters respond to the degraded SG heat transfer and increased core

power by an immediate increase until the reactor trip. After the reactor trip, the primary temperatures drop rapidly, then gradually decrease as the decay heat decreases. The peak temperatures reached in both figures are slightly higher in the RETRAN-02 analyses because of the higher power prior to the reactor trip.

The pressurizer liquid volume is shown in Figure 5-20. The pressurizer liquid volume matches the FSAR result well through the first 20 seconds of the transient. After that time the two analyses show significant differences. The change in liquid volume of the pressurizer is directly related to the primary fluid temperature. As the primary temperature increases, the increased coolant volume is displaced into the pressurizer. As can be seen in Figures 5-18 and 5-19 the primary temperature response for the two analyses match very well, as do the pressures. Consequently, the difference in the pressurizer liquid volume response can only be attributed to a difference in the pressurizer modeling methods in the two codes.

TABLE 3-1

SUMMARY OF INITIAL CONDITIONS

PARAMETER	FSAR	RETRAN-02
Power (MWth)		
Total	3579.0	3579.0
Pump	20.0	20.0
Core	3559.0	3559.0
Pressurizer Pressure (psia)	2250.0	2250.0
Vessel ΔT (°F)	62.16	62.16
Vessel Tavg (°F)	590.9	590.9
Cold Leg Temperature (°F)	559.9	559.9
Hot Leg Temperature (°F)	622.0	622.0
Feedwater Temperature (°F)	446.0	449.0
Total Core Flow (lbm/hr)	141.9×10^6	138.9×10^6
Average Core Density (lbm/ft^3)	43.59	43.53
Average Fuel Temperature (°F)	1345.0	1345.0
Steam Generator Pressure (psia)	960.2	960.2
Steam Generator Mass (lbm)	93360	93369

TABLE 5-1

SEQUENCE OF EVENTS FOR MAXIMUM REACTIVITY
WITHOUT PRESSURE CONTROL

Event	FSAR (seconds)	RETRAN-02 (seconds)
Turbine Trip, Loss of Main Feedwater Flow	0.0	0.001
High Pressurizer Pressure Reactor Trip Setpoint Reached	4.7	4.8
Pressurizer SVs Open	---	5.8
Rods Begin to Drop	6.7	6.8
SG SVs Open	8.0	7.7
Peak Pressurizer Pressure	8.0	8.0
Pressurizer SVs Close	---	12.6

TABLE 5-2

SEQUENCE OF EVENTS FOR MAXIMUM REACTIVITY
WITH PRESSURE CONTROL

Event	FSAR (seconds)	RETRAN-02 (seconds)
Turbine Trip, Loss of Main Feedwater Flow	0.0	0.001
Pressurizer PORVs Open	---	3.8
SG SVs Open	8.0	7.7
Peak Pressurizer Pressure	9.0	9.2
OTΔT Reactor Trip Setpoint Reached	12.6	12.6
Pressurizer PORVs Close	---	13.4
Rods Begin to Drop	14.6	14.6

TABLE 5-3

SEQUENCE OF EVENTS FOR MINIMUM REACTIVITY
WITHOUT PRESSURE CONTROL

Event	FSAR (seconds)	RETRAN-02 (seconds)
Turbine Trip, Loss of Main Feedwater Flow	0.0	0.001
High Pressurizer Pressure Reactor Trip Setpoint Reached	4.8	4.9
Pressurizer SVs Open	---	6.0
Rods Begin to Drop	6.8	6.9
SG SVs Open	8.0	7.7
Peak Pressurizer Pressure	8.5	8.6
Pressurizer SVs Close	---	12.8

TABLE 5-4

SEQUENCE OF EVENTS FOR MINIMUM REACTIVITY
WITH PRESSURE CONTROL

Event	FSAR (seconds)	RETRAN-02 (seconds)
Turbine Trip, Loss of Main Feedwater Flow	0.0	0.001
Pressurizer PORVs Open	---	3.9
High Pressurizer Pressure Reactor Trip Setpoint Reached	7.4	7.5
SG SVs Open	8.0	7.7
Pressurizer SVs Open	---	8.9
Rods Begin to Drop	9.4	9.5
Peak Pressurizer Pressure	10.5	11.0
Pressurizer SVs Close	---	13.8
Pressurizer PORVs Close	---	13.9

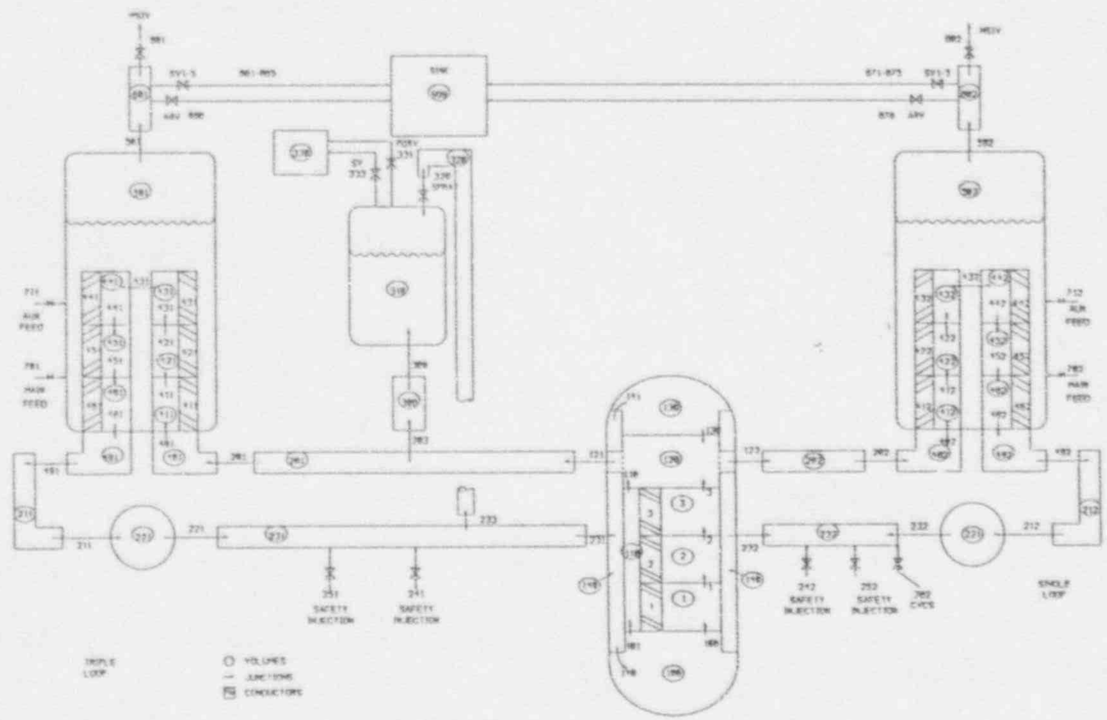


Figure 4-1. Callaway Base Deck Nodalization Diagram

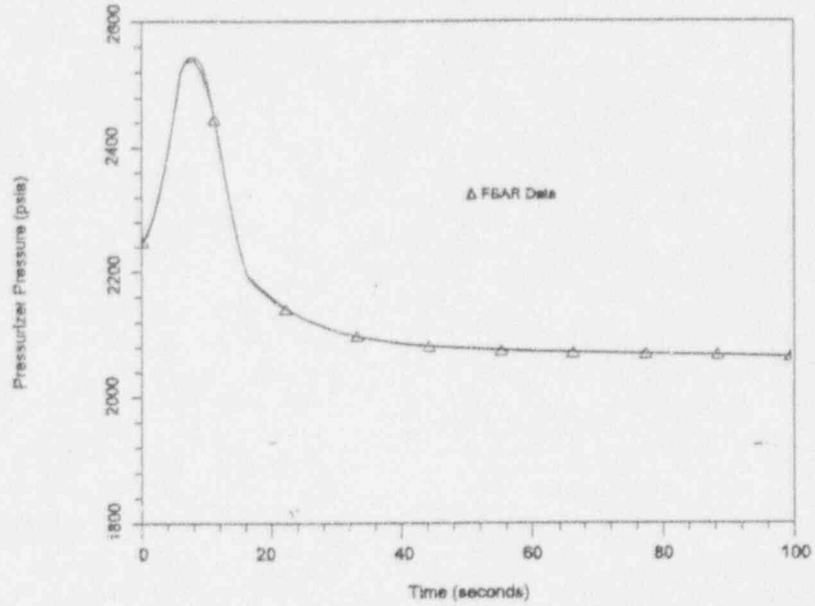


Figure 5-1. Pressurizer Pressure for the Turbine Trip Transient with Maximum Reactivity and No Pressure Control.

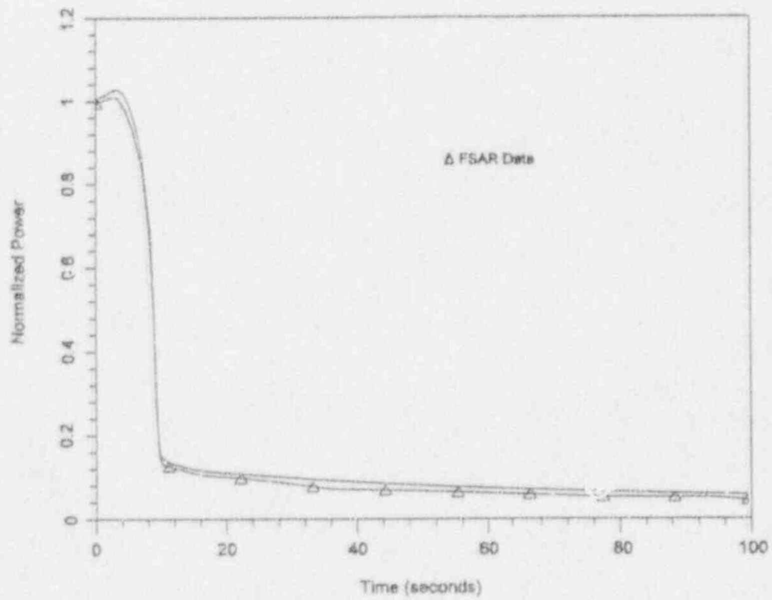


Figure 5-2. Normalized Power for the Turbine Trip Transient with Maximum Reactivity and No Pressure Control.

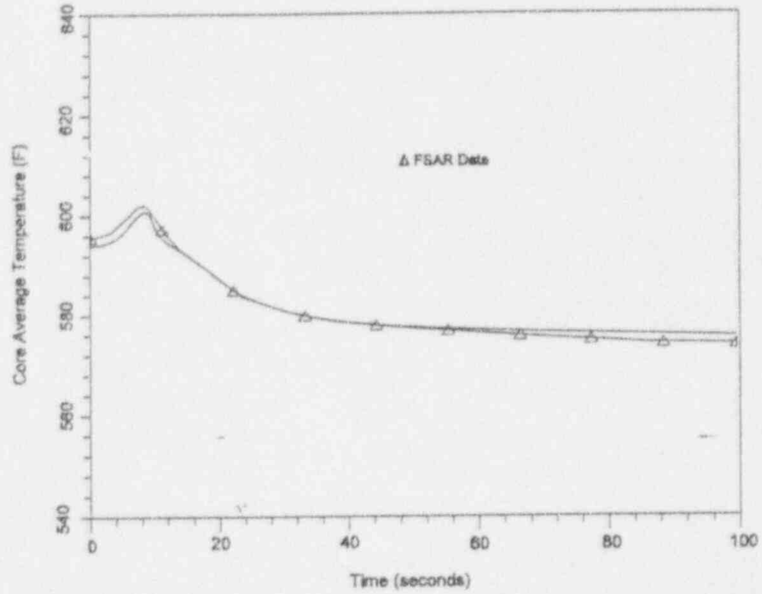


Figure 5-3. Average Core Temperature for the Turbine Trip Transient with Maximum Reactivity and No Pressure Control.

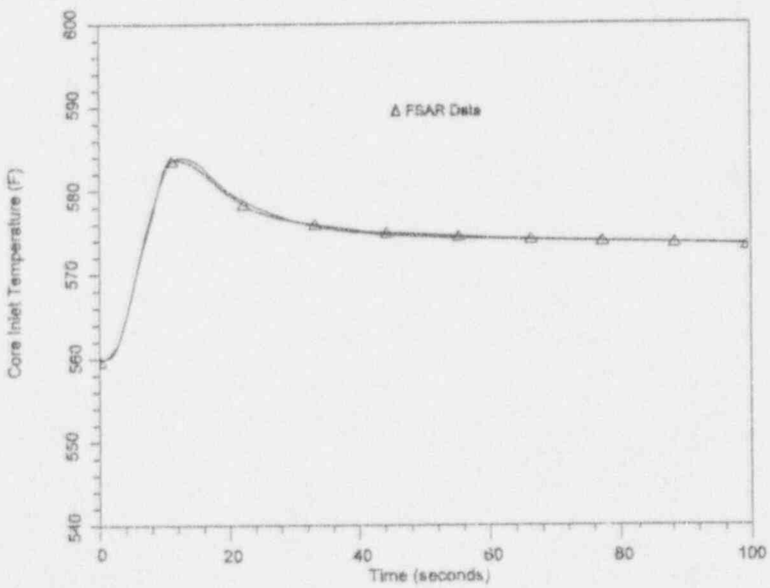


Figure 5-4. Core Inlet Temperature for the Turbine Trip Transient with Maximum Reactivity and No Pressure Control.

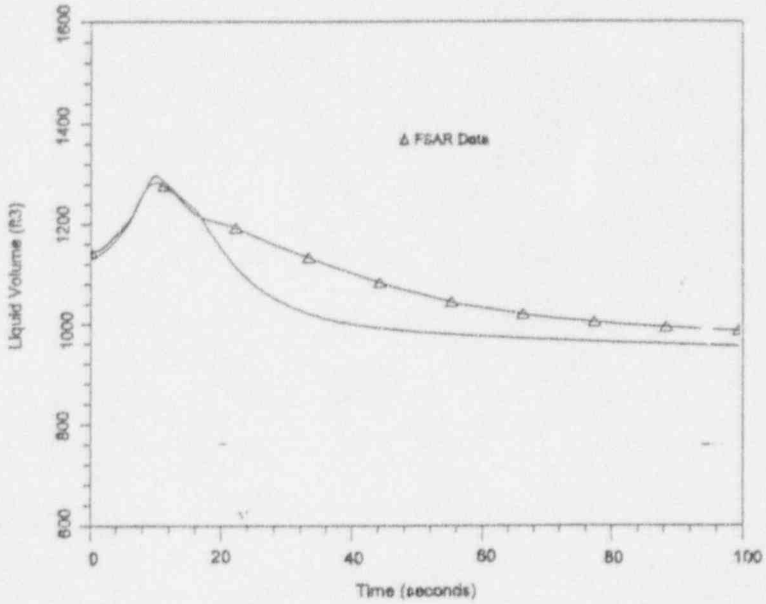


Figure 5-5. Pressurizer Liquid Volume for the Turbine Trip Transient with Maximum Reactivity and No Pressure Control.

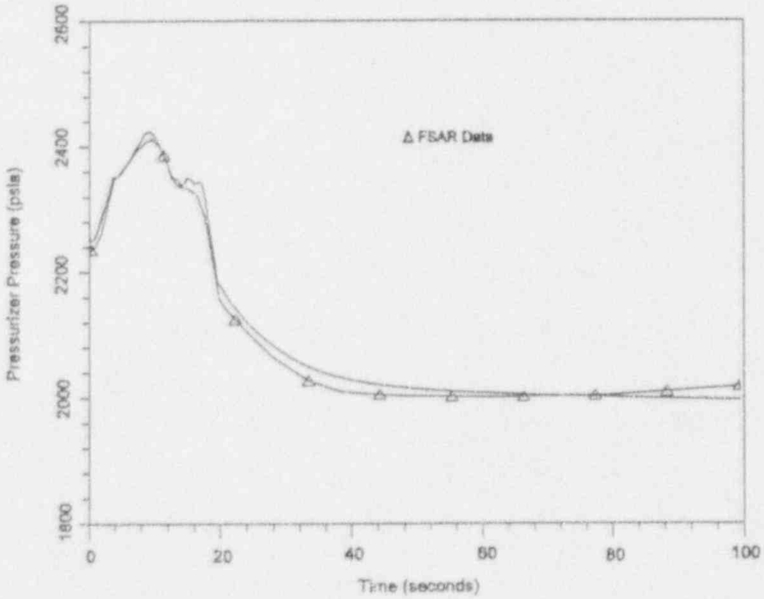


Figure 5-6. Pressurizer Pressure for the Turbine Trip Transient with Maximum Reactivity and Pressure Control.

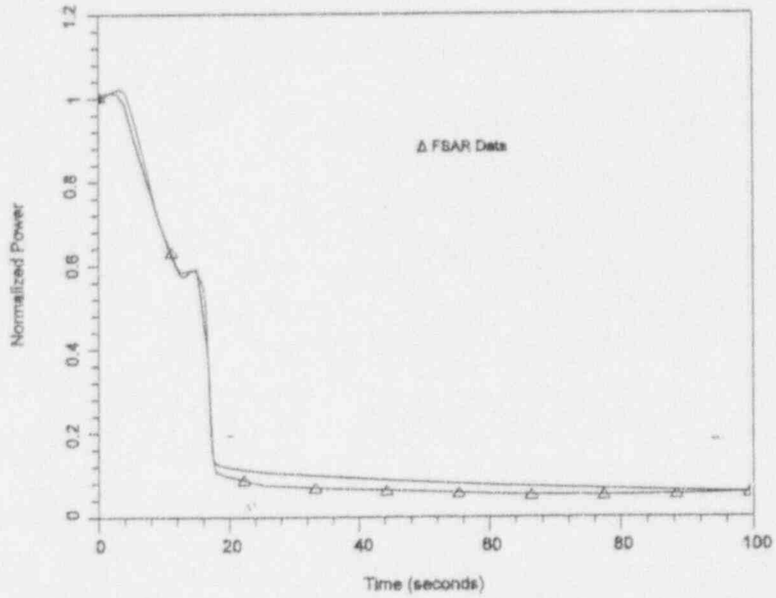


Figure 5-7. Normalized Power for the Turbine Trip Transient with Maximum Reactivity and Pressure Ccontrol.

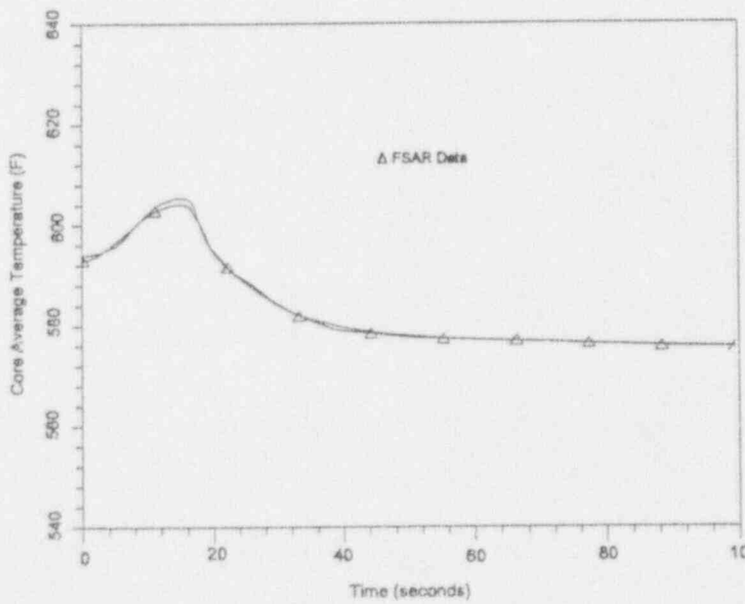


Figure 5-8. Average Core Temperature for the Turbine Trip Transient with Maximum Reactivity and Pressure Control.

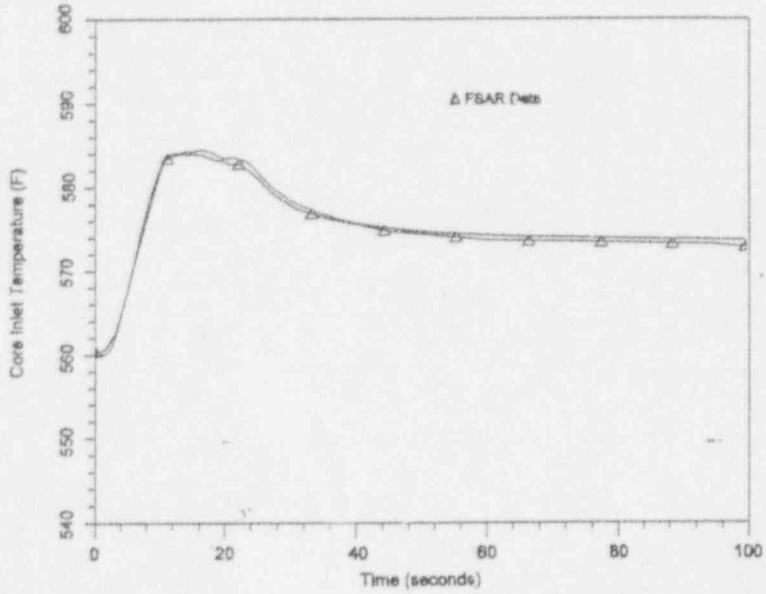


Figure 5-9. Core Inlet Temperature for the Turbine Trip Transient with Maximum Reactivity and Pressure Control.

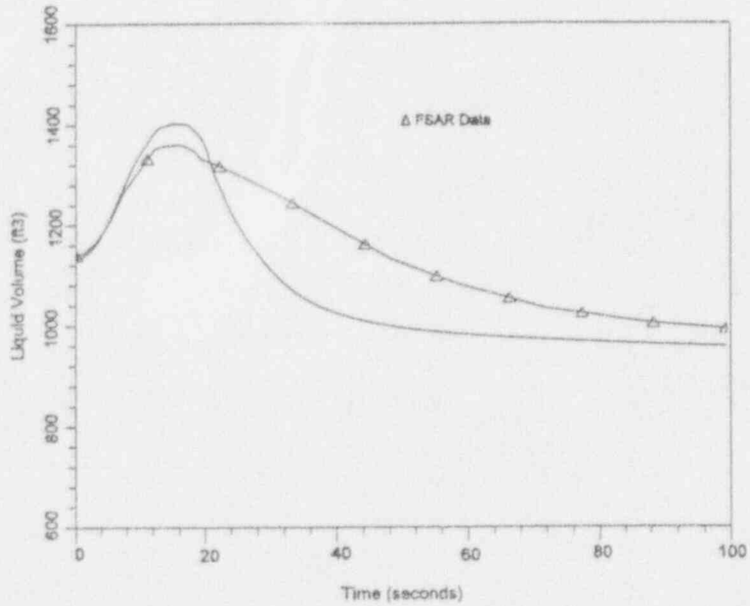


Figure 5-10. Pressurizer Liquid Volume for the Turbine Trip Transient with Maximum Reactivity and Pressure Control.

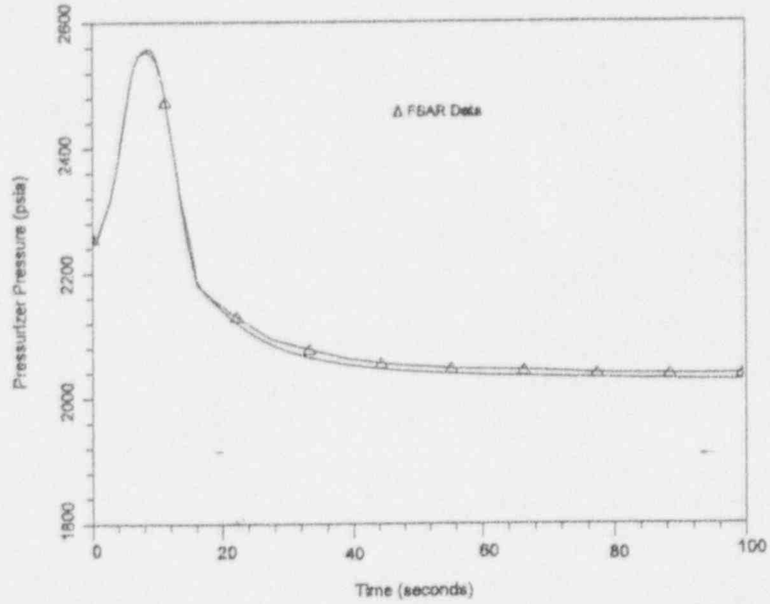


Figure 5-11. Pressurizer Pressure for the Turbine Trip Transient with Minimum Reactivity and No Pressure Control.

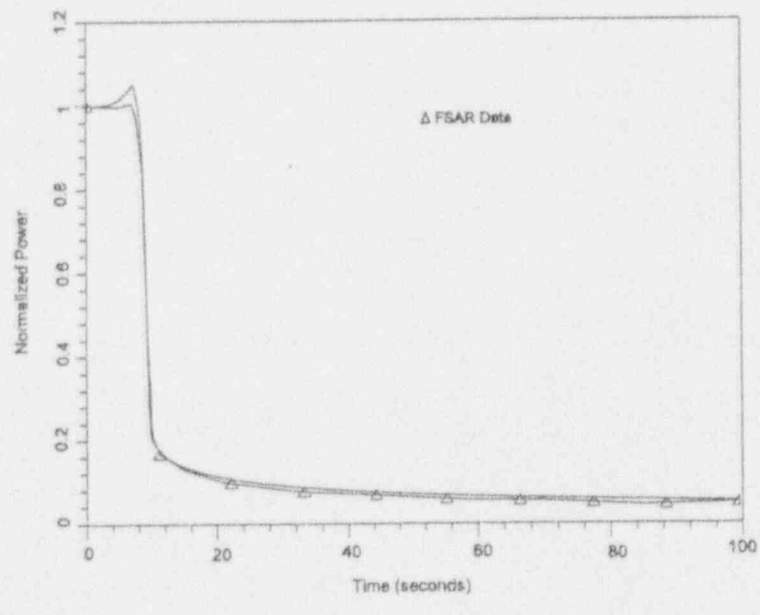


Figure 5-12 Normalized Power for the Turbine Trip Transient with Minimum Reactivity and No Pressure Control.

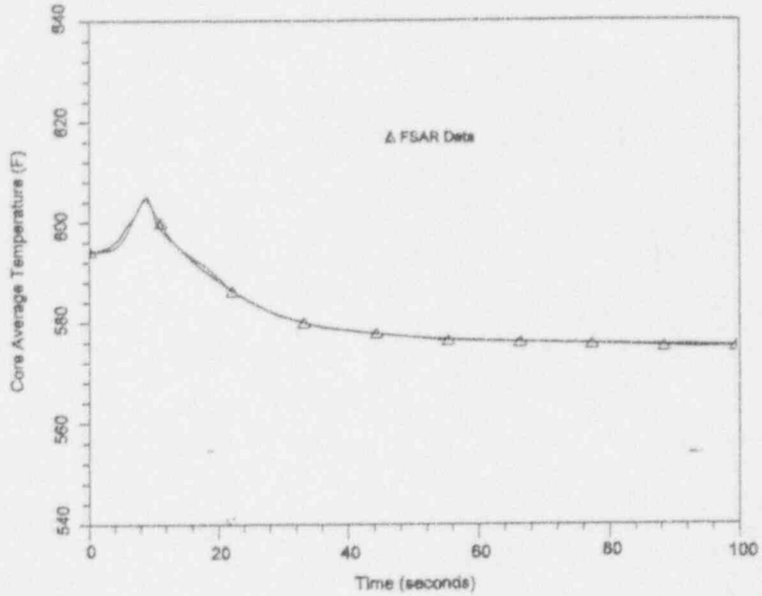


Figure 5-13. Average Core Temperature for the Turbine Trip Transient with Minimum Reactivity and No Pressure Control.

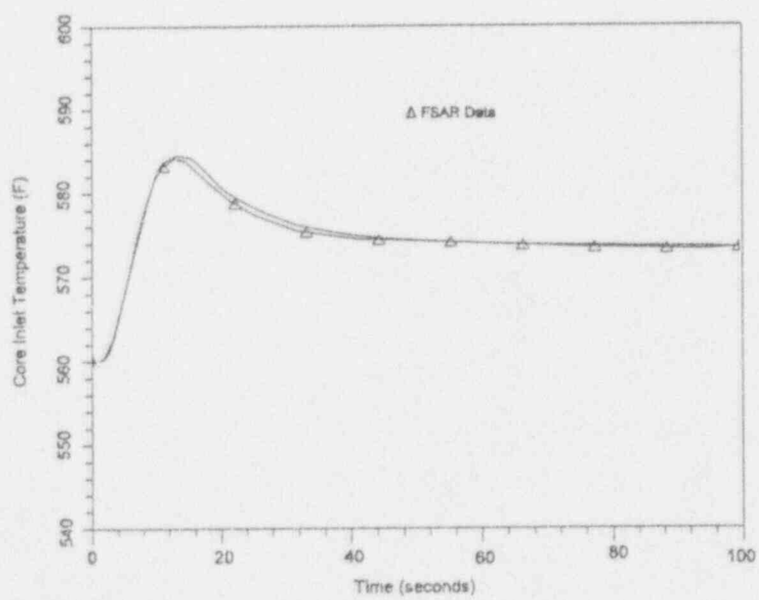


Figure 5-14. Core Inlet Temperature for the Turbine Trip Transient with Minimum Reactivity and No Pressure Control.

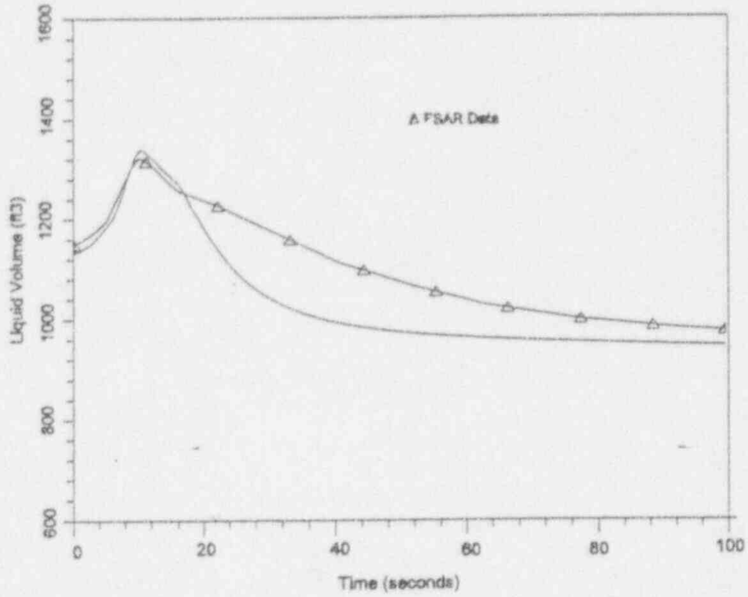


Figure 5- 15. Pressurizer Liquid Volume for the Turbine Trip Transient with Minimum Reactivity and No Pressure Control.

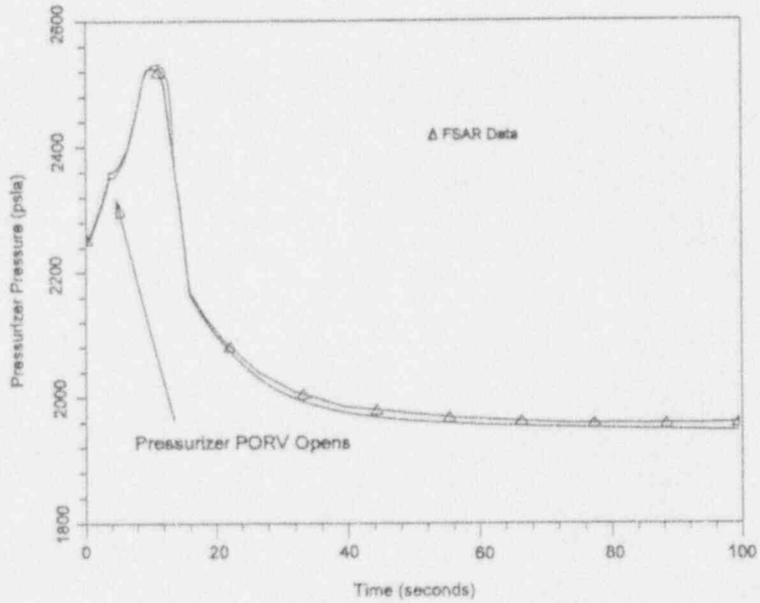


Figure 5- 16. Pressuizer Pressure for the Turbine Trip Transient with Minimum Reactivity and Pressure Control.

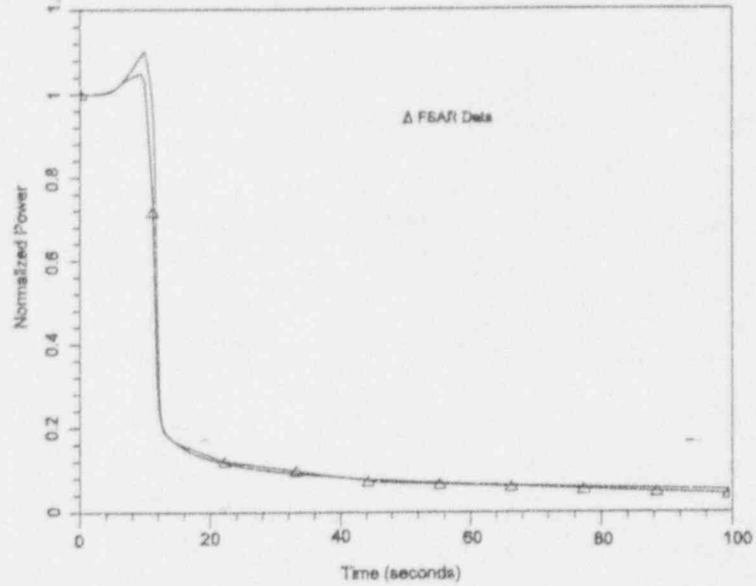


Figure 5-17. Normalized Power for the Turbine Trip Transient with Minimum Reactivity and Pressure Control.

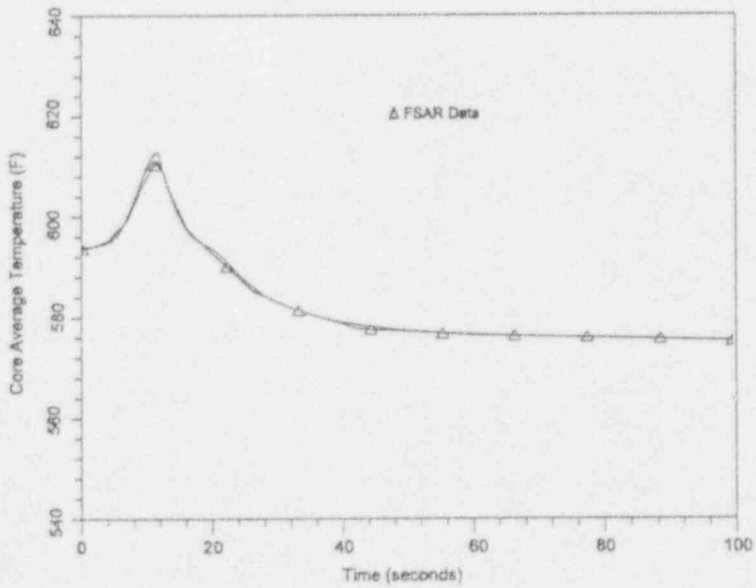


Figure 5-18. Average Core Temperature for the Turbine Trip Transient with Minimum Reactivity and Pressure Control.

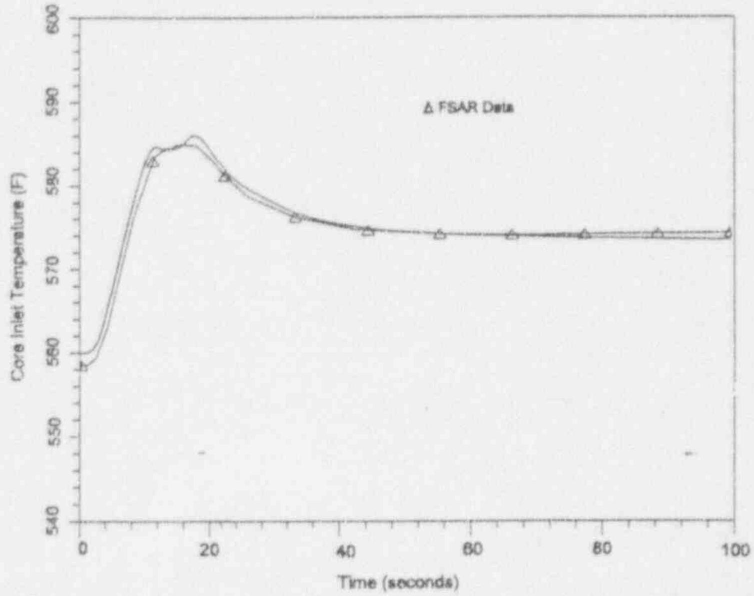


Figure 5-19. Core Inlet Temperature for the Turbine Trip Transient with Minimum Reactivity and Pressure Control.

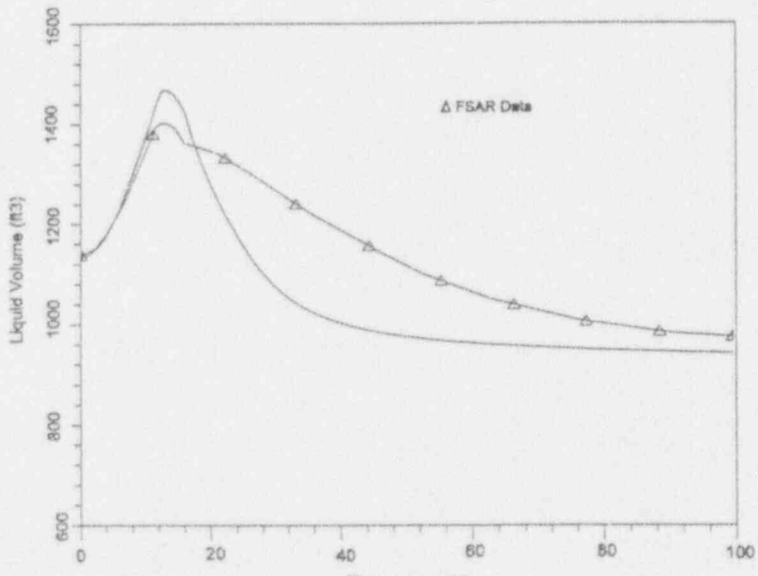


Figure 5-20. Pressurizer Liquid Volume for the Turbine Trip Transient with Minimum Reactivity and Pressure Control.

SAFETY EVALUATION

Appendix C:

Turbine Trip DNBR Analysis

Appendix C

1.0 IDENTIFICATION OF CAUSES AND ACCIDENT DESCRIPTION

For a turbine trip event, the reactor would be tripped directly (unless below approximately 50-percent power) from a signal derived from the turbine emergency trip fluid pressure transmitters and turbine stop valve limit switches. The turbine stop valves close rapidly (typically 0.19 second) on loss of trip fluid pressure actuated by one of a number of possible turbine trip signals. Turbine trip initiation signals include:

a. Generator trip

b. Low condenser vacuum

c. Loss of lubricating oil

d. Turbine thrust bearing failure

e. Turbine overspeed

f. Manual trip

Upon initiation of stop valve closure, steam flow to the turbine stops abruptly. Limit switches on the stop valves detect the turbine trip and initiate steam dump, and, if above 50-percent power, a reactor trip. The loss of steam flow results in an almost immediate rise in secondary system temperature and pressure. As a result, the heat transfer rate in the steam generator is reduced, causing the reactor coolant temperature to rise, which in turn causes coolant expansion, pressurizer insurge, and RCS pressure rise. Reactor coolant temperatures and pressure do no significantly increase if the steam dump system and pressurizer pressure control system are functioning properly. The more rapid loss of steam flow caused by the more rapid valve closure makes turbine trip a more severe transient than a loss of external electrical load.

If the condenser were not available, the excess steam would be relieved to the atmosphere. Additionally, main feedwater flow would be lost if the condenser were not available. For this situation, feedwater flow would be maintained by the auxiliary feedwater system.

The automatic steam dump system would normally accommodate the excess steam generation. Reactor coolant temperatures and pressure do not significantly increase if the steam dump system and pressurizer pressure control system are functioning properly. If the turbine condenser was not available, the excess steam generation would be dumped to the atmosphere and main feedwater flow would be lost. For this situation, feedwater flow would be maintained by the auxiliary feedwater system to ensure adequate residual and decay heat removal capability. Should the steam dump system fail to operate, the steam generator safety valves may lift to provide pressure control.

In the event that a safety limit is approached, protection would be provided by the high pressurizer pressure, high pressurizer water level, and overtemperature ΔT trips. Voltage and frequency relays associated with the reactor coolant pump provide no additional safety function for this event. In the event that the steam dump valves and steam generator/PORVs fail to open following a large loss of load, the steam generator safety valves may lift, and the reactor may be tripped by the high pressurizer pressure signal, the high pressurizer water level signal, or the overtemperature ΔT. A turbine trip is classified as an ANS Condition II event, fault of moderate frequency.

A turbine trip event is more limiting than loss of external load, loss of condenser vacuum, and other turbine trip related events. As such, this event has been analyzed for DNBR in detail.

2.0 ANALYSIS OF EFFECTS AND CONSEQUENCES

A. Method of Analysis

In this analysis, the behavior of the plant is evaluated for a complete loss of steam load from full power without direct reactor trip. This is done to show the adequacy of the pressure relieving devices, and also to demonstrate core protection margins. The reactor is not tripped until conditions in the RCS result in a trip. The turbine is assumed to trip without actuating all the turbine stop valve limit switches. The assumption delays reactor trip until conditions in the RCS result in a trip due to other signals. Thus, the analysis assumes a worst-case transient. In addition, no credit is taken for steam dump. Main feedwater flow is terminated at the time of turbine trip, with no credit taken for auxiliary feedwater (except for long-term recovery) to mitigate the consequences of the transient.

The turbine trip transients are analyzed by employing the detailed digital computer code RETRAN. RETRAN simulates the neutron kinetics, RCS, pressurizer, pressurizer relief and safety valves, pressurizer spray, steam generators, and steam generator safety valves. It also computes pertinent plant variables, including temperatures, pressures, and power level. Westinghouse performed the actual DNB evaluation using the WRB-2 correlation and the RETRAN results.

This accident is analyzed with the ITDP. Plant characteristics and initial conditions are discussed in Table 1. Uncertainties in initial conditions are included in the limit DNBR as described in WCAP 8567, "Improved Thermal Design Procedure," July 1975.

Major assumptions are summarized below:

a. Moderator and Doppler Coefficients of Reactivity

The turbine trip is analyzed with both maximum and minimum reactivity feedback. The maximum feedback cases assume a large negative moderator temperature coefficient and the most negative Doppler power coefficient. The minimum feedback cases assume a minimum moderator temperature coefficient and the least negative Doppler coefficient.

b. Reactor control

From the standpoint of the maximum pressures attained, it is conservative to assume that the reactor is in manual control. If the reactor were in automatic control, the control rod banks would move prior to trip and reduce the severity of the transient.

c. Steam release

No credit is taken for the operation of the steam dump system or steam generator power-operated relief valves. The steam generator pressure rises to the point where steam release through safety valves occurs thus limiting the secondary steam pressure increase. Because these valves are set on steam in a manner that accounts for accumulation, no accumulation is modeled. Each steam generator has five valves. The setpoint for each valve is set at the technical specification setpoint plus 3 percent for setpoint tolerance.

d. Pressurizer spray and power-operated relief valves

Two cases for both the minimum and maximum reactivity feedback cases are analyzed:

1. Full credit is taken for the effect of pressurizer spray and power-operated relief valves in reducing or limiting the coolant pressure. The pressurizer safety valves are also available.

2. No credit is taken for the effect of pressurizer spray and power-operated relief valves in reducing or limiting the coolant pressure. The pressurizer safety valves are operable.

e. Feedwater flow

Main feedwater flow to the steam generators is assumed to be lost at the time of turbine trip. No credit is taken for auxiliary feedwater flow since a stabilized plant condition will be reached before auxiliary feedwater initiation is normally assumed to occur; however, the auxiliary feedwater pumps would be expected to start on a trip of the main feedwater pumps. The auxiliary feedwater flow would remove core decay heat following plant stabilization.

f. Reactor trip is actuated by the first reactor protection system trip setpoint reached, with no credit taken for the direct reactor trip on the turbine trip. Trip signals are expected due to high pressurizer pressure, overtemperature ΔT, high pressurizer water level, and low-low steam generator water level.

g. The pressurizer safety valves explicitly model the impact of loop seal purge delay. The setpoint for the safety valve is modeled to lift at the technical specification setpoint (2500 psia) plus 2% (1% tolerance and 1% setpoint shift). Opening of the safety valves is then delayed by the loop seal purge delay time (1.15 seconds).

Except as discussed above, normal reactor control systems and engineered safety features are not required to function. Cases are presented in which pressurizer spray and power-operated relief valves are assumed, but the more limiting cases where those functions are not assumed are also presented. Pressurizer safety valves and/or steam generator safety valves may be required to open to maintain system pressures below allowable limits. No single active failure will prevent operation of any system required to function.

B. Results

The transient responses for a turbine trip from full power operation are shown for four cases: two cases for minimum reactivity feedback and two cases for maximum reactivity feedback (Figures 1 through 20). The calculated sequence of events for the accident is shown in Table 2.

Figures 1 through 5 show the transient responses for the total loss of steam load with minimum reactivity feedback, assuming full credit for the pressurizer spray and pressurizer power-operated relief valves. No credit is taken for the steam dump. The reactor is tripped by high pressurizer pressure trip channels. Westinghouse found that the minimum DNBR remains well above the safety analysis limit values. The pressurizer safety valves are not actuated for this case and, therefore, maintain system pressure below 110 percent of the design value. The steam generator safety valves open and limit the secondary steam pressure increase.

Figures 6 through 10 show the response for the total loss of steam load with maximum reactivity feedback. All other plant parameters are the same as the above. The reactor is tripped on the overtemperature ΔT signal. The DNBR increases throughout the transient and never drops below its initial value. Pressurizer relief valves and steam generator safety valves prevent overpressurization in primary and secondary systems, respectively. The pressurizer safety valves are not actuated for this case.

The turbine trip accident was also studied assuming the plant to be initially operating at full power with no credit taken for the pressurizer spray, pressurizer power-operated relief valves, or steam dump. The reactor is tripped on the high pressurizer pressure

signal. Figures 11 through 15 show the transients with minimum reactivity feedback. The neutron flux remains essentially constant at full power, until the reactor is tripped. The DNBR never goes below the initial value throughout the transient. In this case, the pressurizer safety valves are actuated, and maintain system pressure below 110 percent of the design value.

Figures 16 through 20 show the transients with maximum reactivity feedback, with the other assumptions being the same as in the preceding case. Again, the DNBR increases throughout the transient and the pressurizer safety valves are actuated to limit primary pressure.

CONCLUSIONS

Results of the analyses show that the plant design is such that a turbine trip without a direct or immediate reactor trip presents no hazard. The integrity of the core is maintained by operation of the reactor protection system, i.e., the DNBR will be maintained above the safety analysis limit values.

TABLE 1: SUMMARY OF INITIAL CONDITIONS

	Loss of Electrical Load Turbine Trip			
	Maximum Reactivity w/o Control Systems	Minimum Reactivity w/o Control Systems	Maximum Reactivity with Control Systems	Minimum Reactivity with Control Systems
PORVs	No	No	Yes	Yes
Spray	No	No	Yes	Yes
Moderator Density Coefficient ($\Delta K/K/gm/cc$)(1)	0.43	Note 2	0.43	Note 2
Doppler(1)	Lower Curve of Figure 15.0-2	Upper Curve of Figure 15.0-2	Lower Curve of Figure 15.0-2	Upper Curve of Figure 15.0-2
Fuel Temperature(1)	EOL	BOL	EOL	BOL
DNB Correlation	WRB-2	WRB-2	WRB-2	WRB-2
ITDP	Yes	Yes	Yes	Yes
Initial Core Thermal Power (MWt)	3565	3565	3565	3565
Reactor Coolant Pump Heat (MWt)	14	14	14	14
Reactor Vessel Coolant Flow (gpm)	382,630	382,630	382,630	382,630

TABLE 1: SUMMARY OF INITIAL CONDITIONS
(cont'd.)

Loss of Electrical Load Turbine Trip

	Maximum Reactivity w/o Control Systems	Minimum Reactivity w/o Control Systems	Maximum Reactivity with Control Systems	Minimum Reactivity with Control Systems
Vessel T-Avg (°F)	590.9	590.9	590.9	590.9
Pressurizer Pressure (psia)	2250	2250	2250	2250
Pressurizer Water Volumn (Ft^3) Note 3	1080	1080	1080	1080
Feedwater Temperature °F	446	446	446	446
S/G Tube Plugging Level	15%	15%	15%	15%

Notes: (1) Reactivity Coefficients

(2) A density coefficient corresponding to +5 pcm/°F is added to 0.0 ΔK/K/gm/cc.

(3) Does not include surge line volume of 57.4 ft^3

TABLE 2

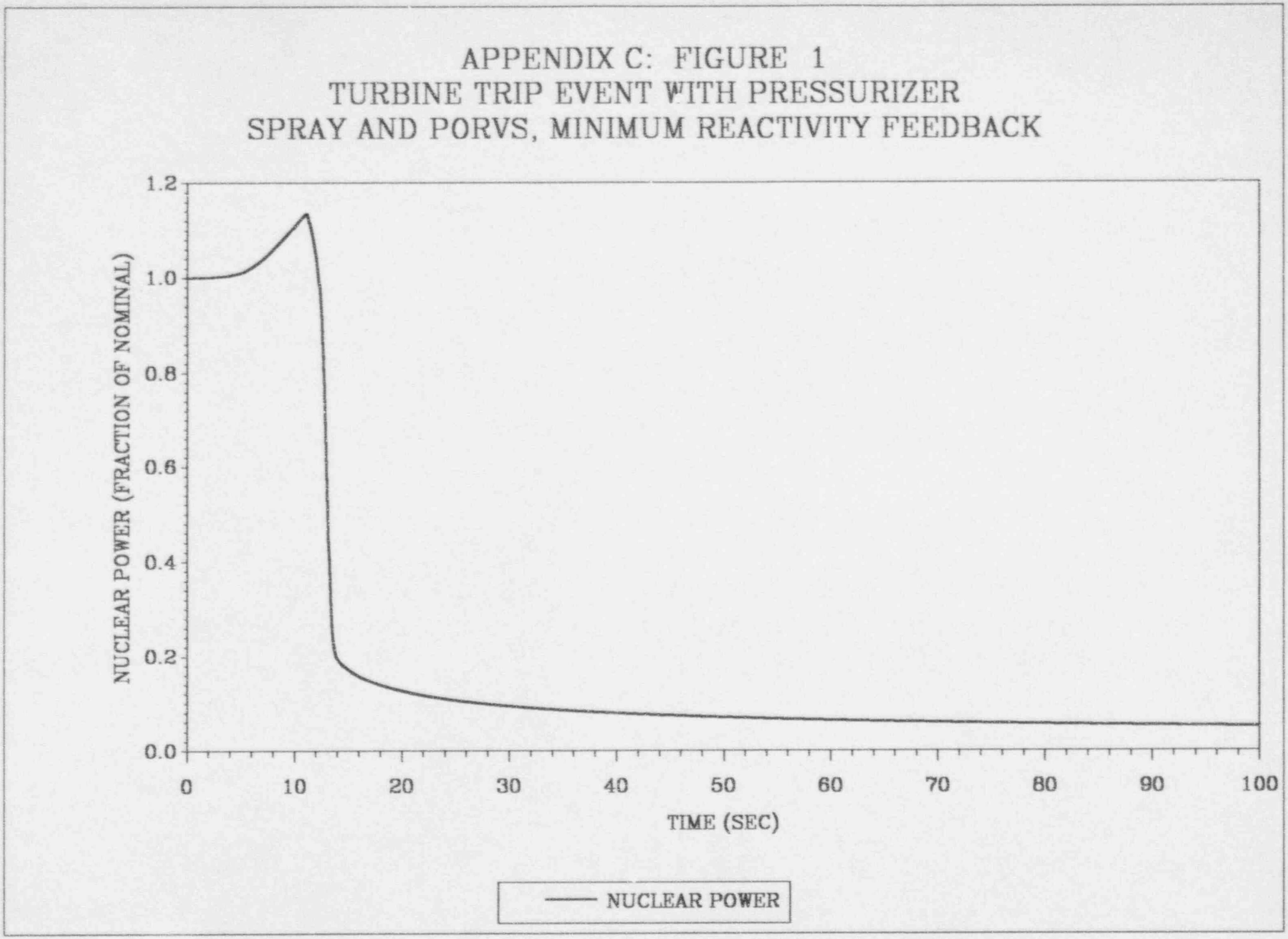
TIME SEQUENCE OF EVENTS FOR INCIDENTS WHICH RESULT IN A DECREASE IN HEAT REMOVAL BY THE SECONDARY SYSTEM

Accident	Event	Time (sec)
Turbine Trip		
1. With pressurizer control (minimum reactivity feedback)	Turbine trip; loss of main feedwater flow	0.0
	High pressurizer pressure reactor trip setpoint reached	8.6
	Initiation of steam release from steam generator safety valves	8.7
	Rods begin to drop	10.6
	Peak pressurizer pressure occurs	11.2
	Minimum DNBR occurs	*
2. With pressurizer control (maximum reactivity feedback)	Turbine trip; loss of main feedwater flow	0.0
	Initiation of steam release from steam generator safety valves	8.7
	Peak pressurizer pressure occurs	10.0
	Overtemperature ΔT reactor trip setpoint reached	12.8
	Rods begin to drop	14.8
	Minimum DNBR occurs	*

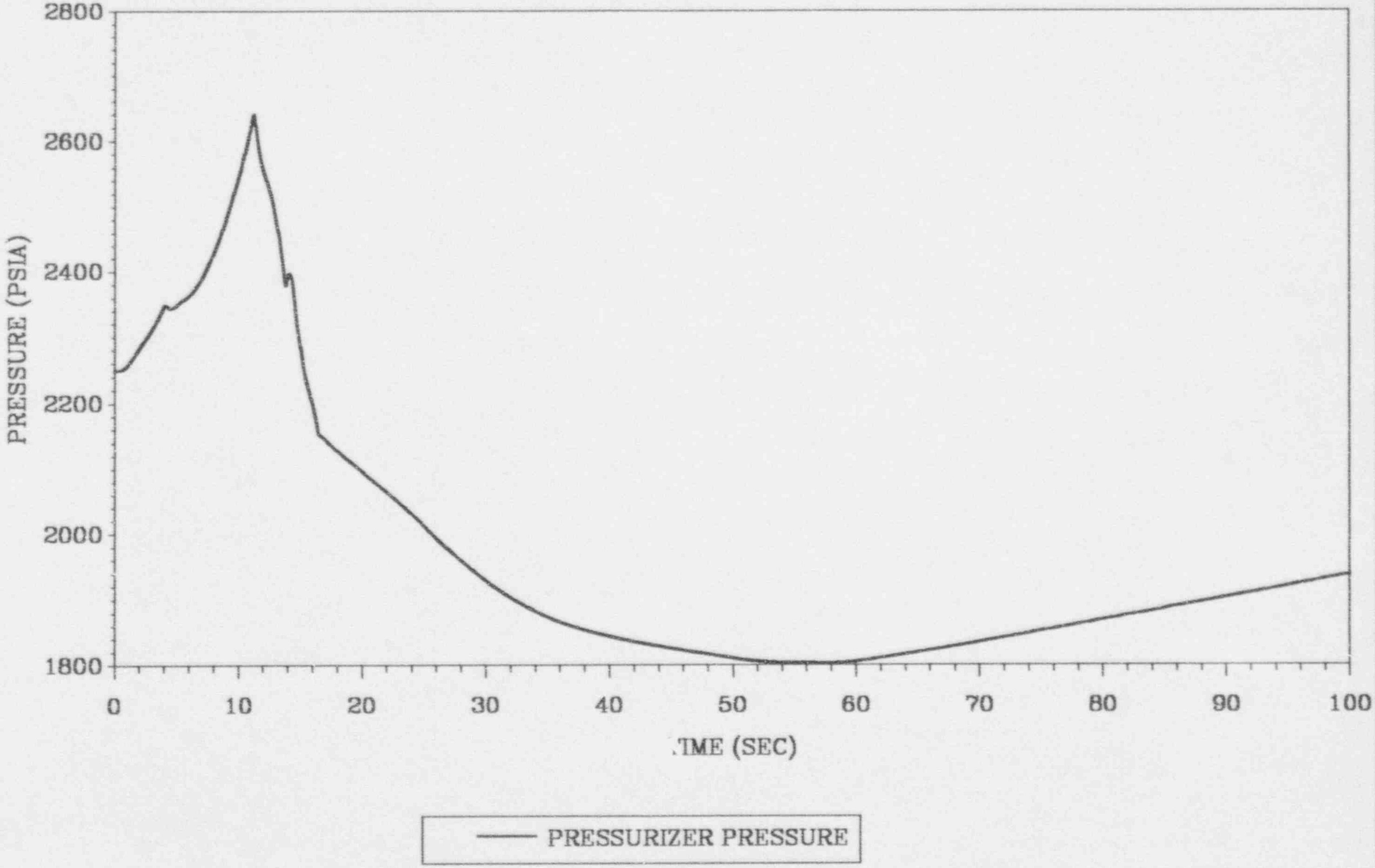
TABLE 2 (continued)

Accident	Event	Time (sec)
3. Without pressurizer control (minimum reactivity feedback)	Turbine trip; loss of main feedwater flow	0.0
	High pressurizer pressure reactor trip setpoint reached	5.1
	Rods begin to drop	6.1
	Peak pressurizer pressure occurs	7.9
	Initiation of steam release from steam generator safety valves	8.6
	Minimum DNBR occurs	*
4. Without pressurizer control (maximum reactivity feedback)	Turbine trip; loss of main feedwater flow	0.0
	High pressurizer pressure reactor trip setpoint reached.	5.5
	Rods begin to drop	7.5
	Peak pressurizer pressure occurs	7.9
	Initiation of steam release from steam generator safety valves	8.6
	Minimum DNBR occurs	*

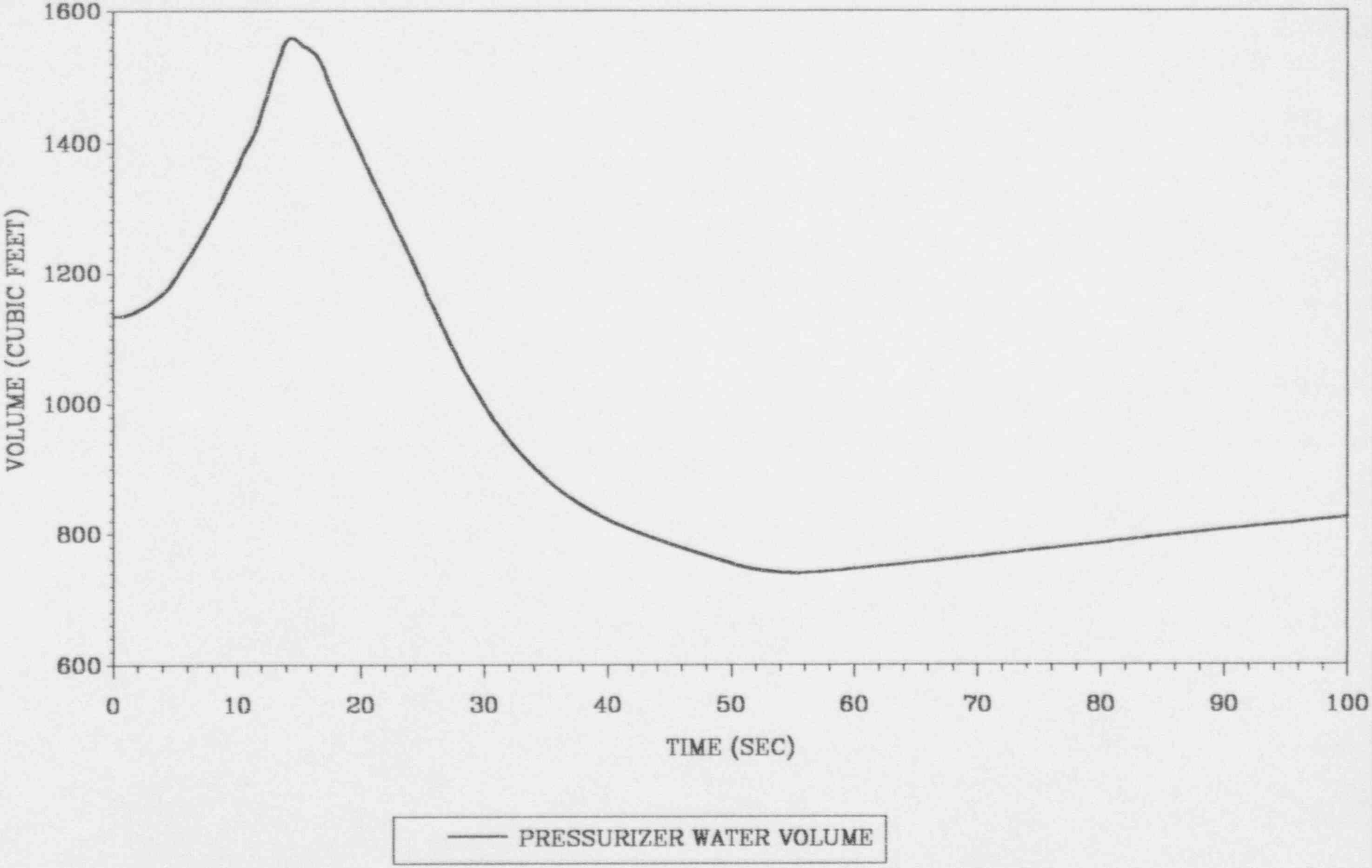
* Previously reported DNBR results are unaffected by increased MSSV tolerance.


APPENDIX C: FIGURE 1
TURBINE TRIP EVENT WITH PRESSURIZER
SPRAY AND PORVS, MINIMUM REACTIVITY FEEDBACK
NUCLEAR POWER (FRACTION OF NOMINAL)
1.2
1.0
0.8
0.6
0.4
0.2
0.0
0
10
20
30
40
50
60
70
80
90
100
TIME (SEC)
NUCLEAR POWER

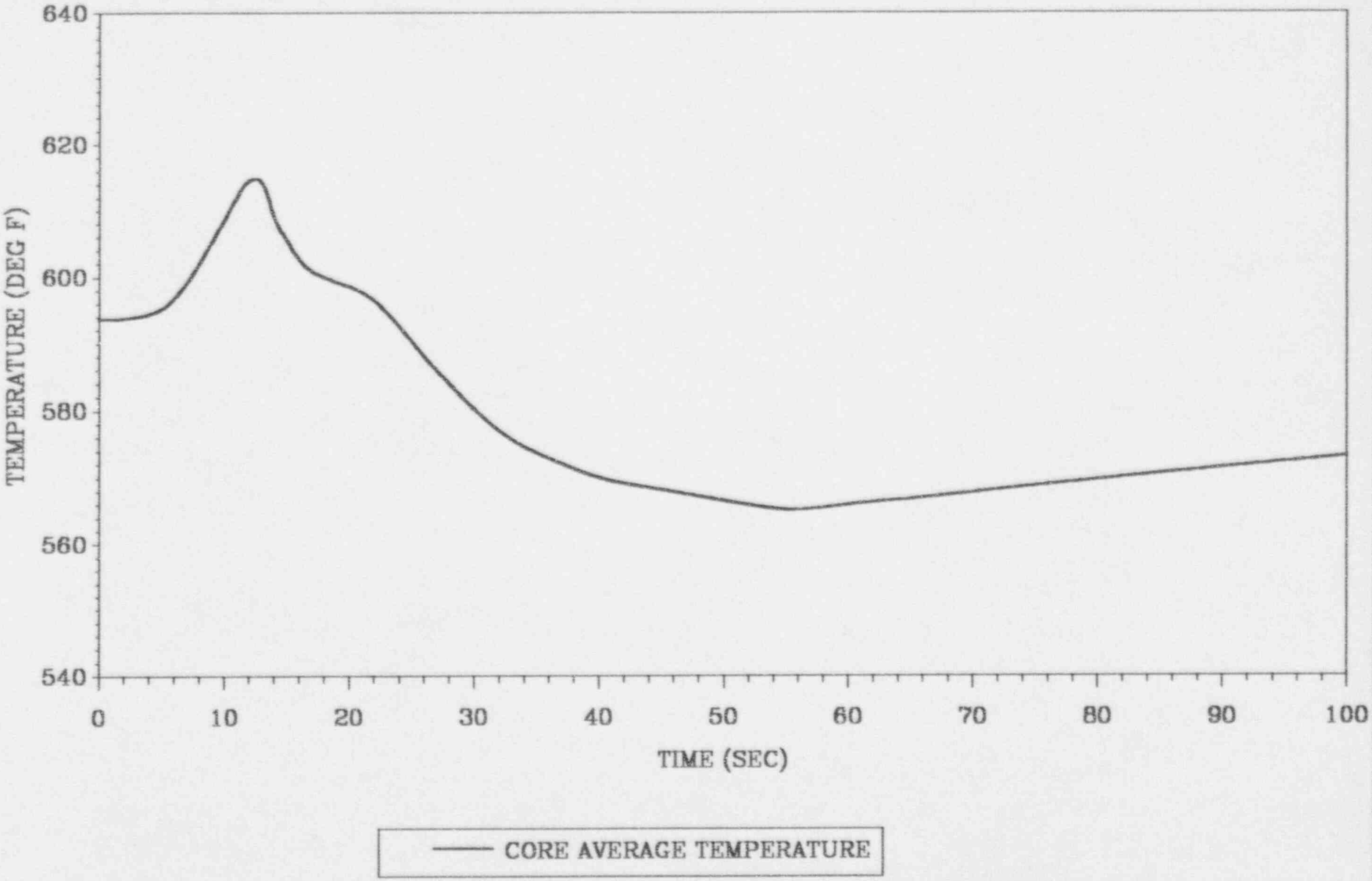
APPENDIX C: FIGURE 2
TURBINE TRIP EVENT WITH PRESSURIZER
SPRAY AND PORVS, MINIMUM REACTIVITY FEEDBACK



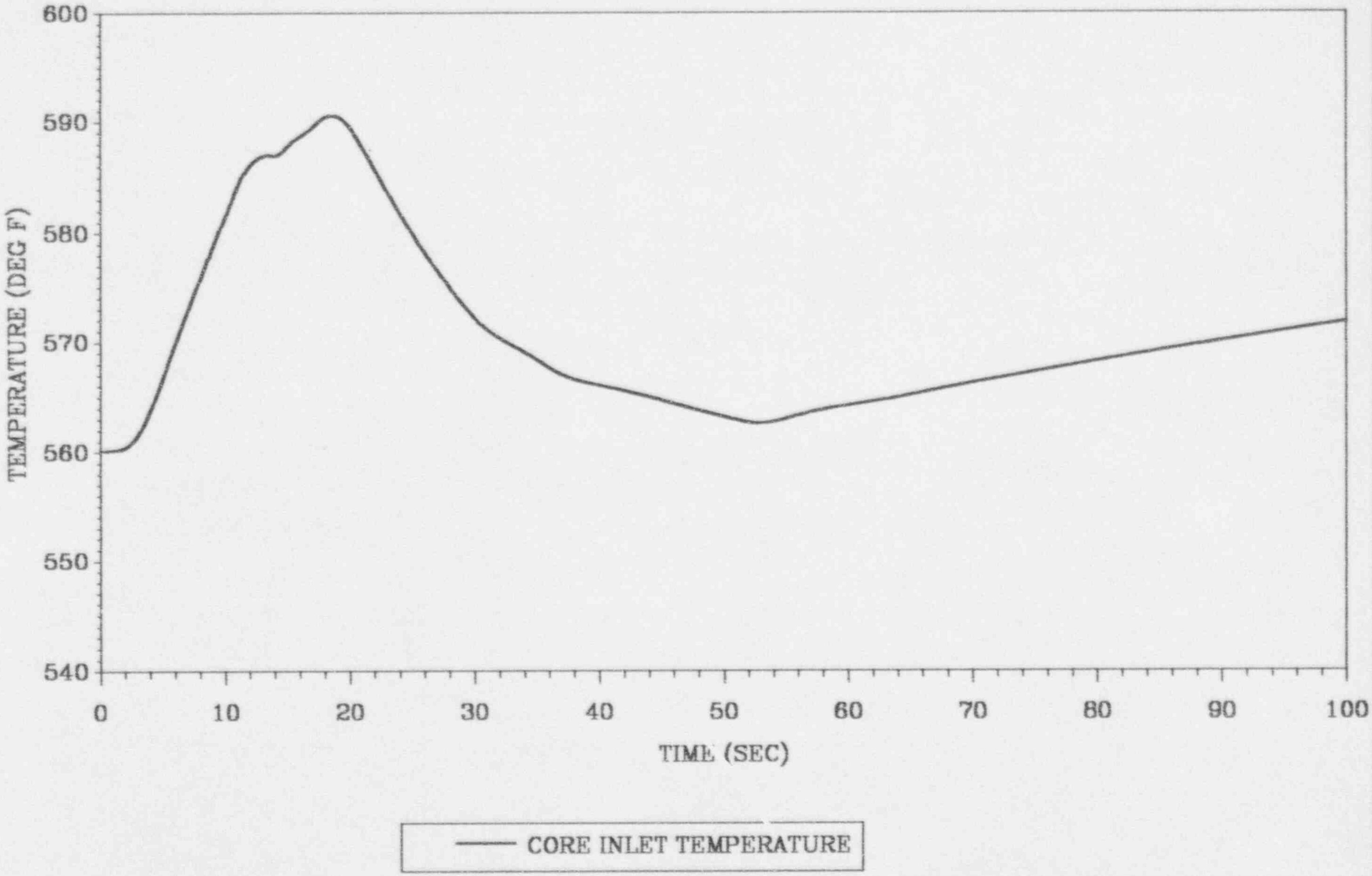
APPENDIX C: FIGURE 3
TURBINE TRIP EVENT WITH PRESSURIZER
SPRAY AND PORVS, MINIMUM REACTIVITY FEEDBACK



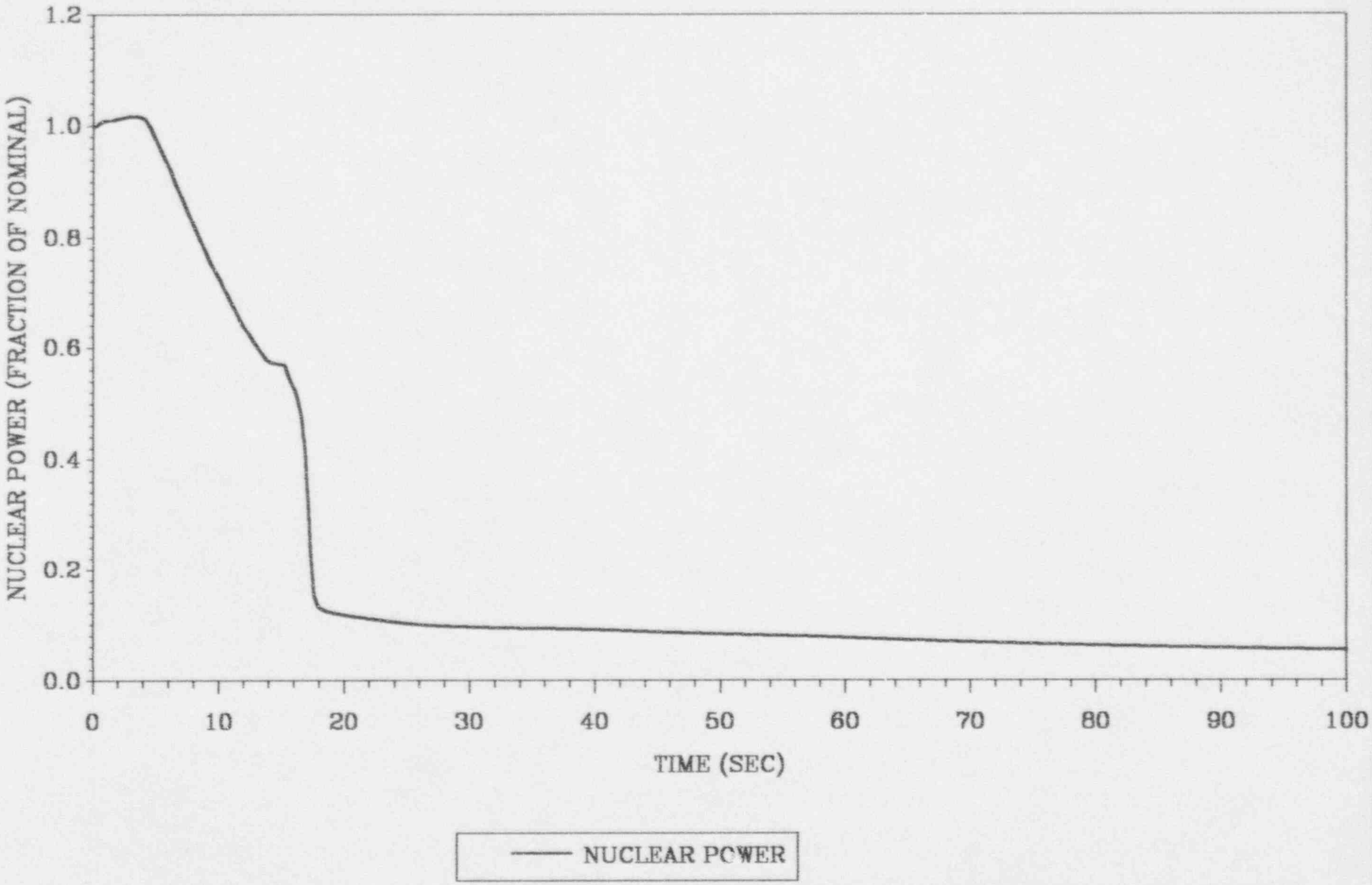
APPENDIX C: FIGURE 4
TURBINE TRIP EVENT WITH PRESSURIZER
SPRAY AND PORVS, MINIMUM REACTIVITY FEEDBACK



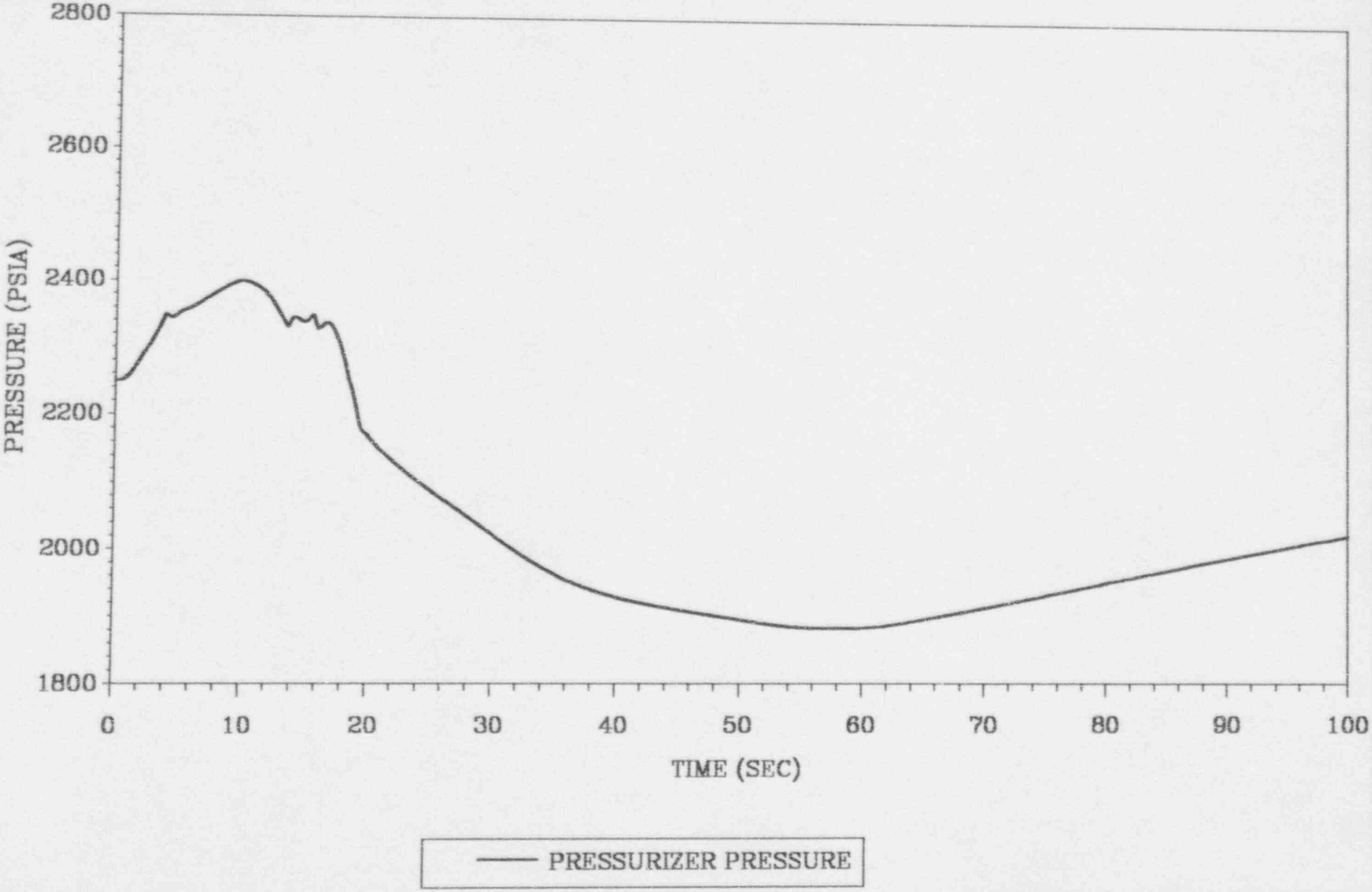
APPENDIX C: FIGURE 5
TURBINE TRIP EVENT WITH PRESSURIZER
SPRAY AND PORVS, MINIMUM REACTIVITY FEEDBACK



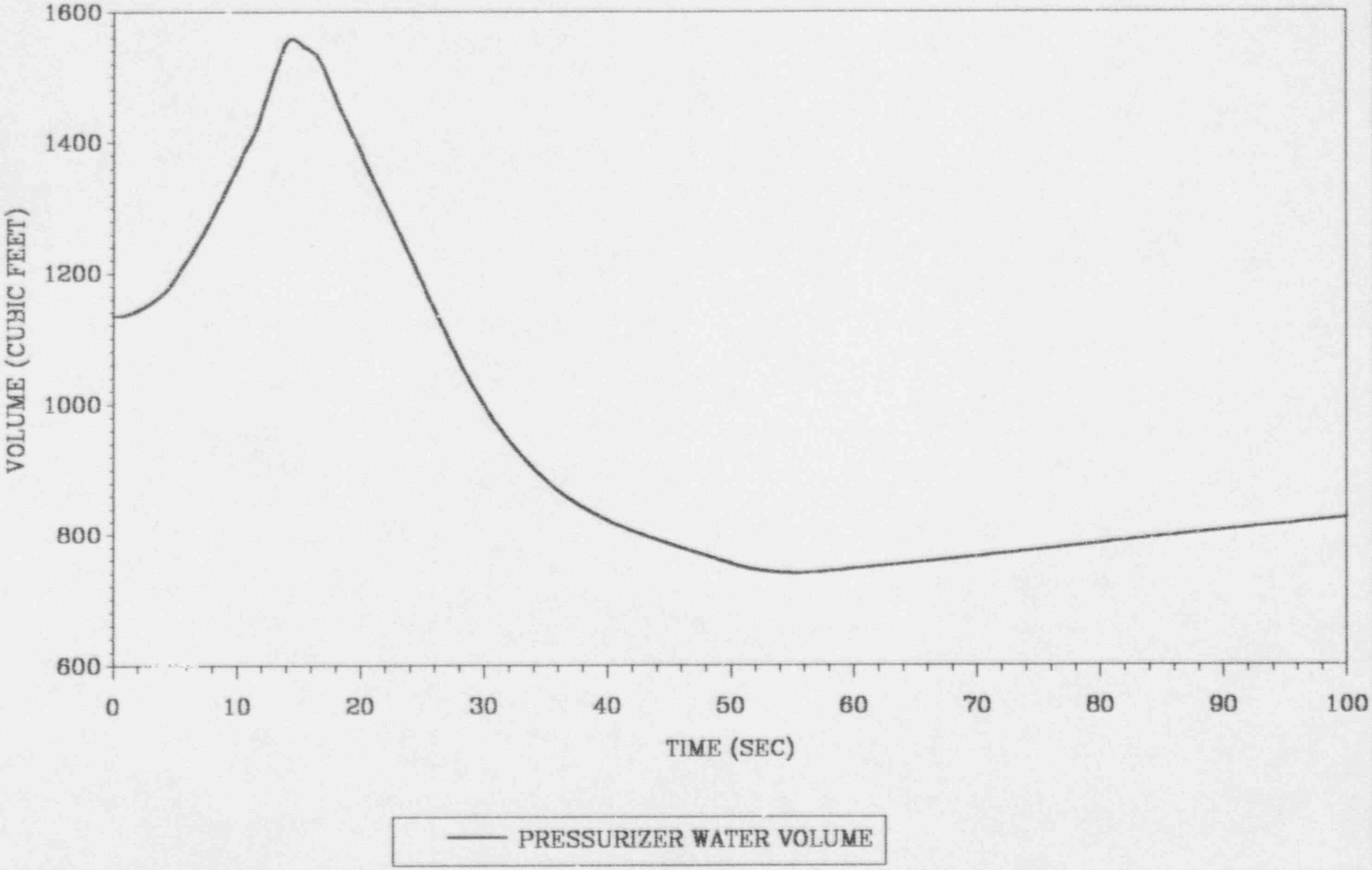
APPENDIX C: FIGURE 6
TURBINE TRIP EVENT WITH PRESSURIZER
SPRAY AND PORVS, MAXIMUM REACTIVITY FEEDBACK



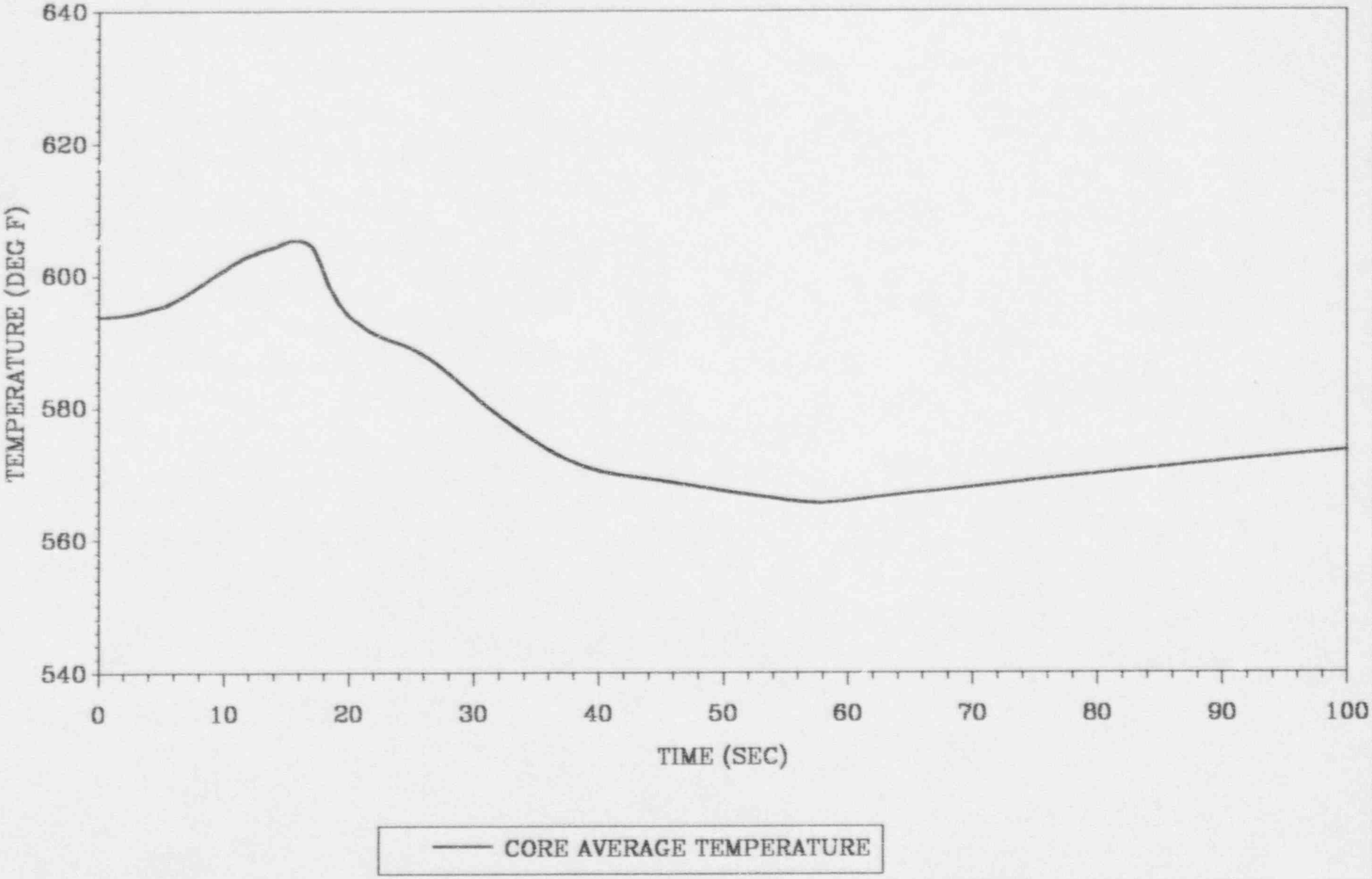
APPENDIX C: FIGURE 7
TURBINE TRIP EVENT WITH PRESSURIZER
SPRAY AND PORVS, MAXIMUM REACTIVITY FEEDBACK



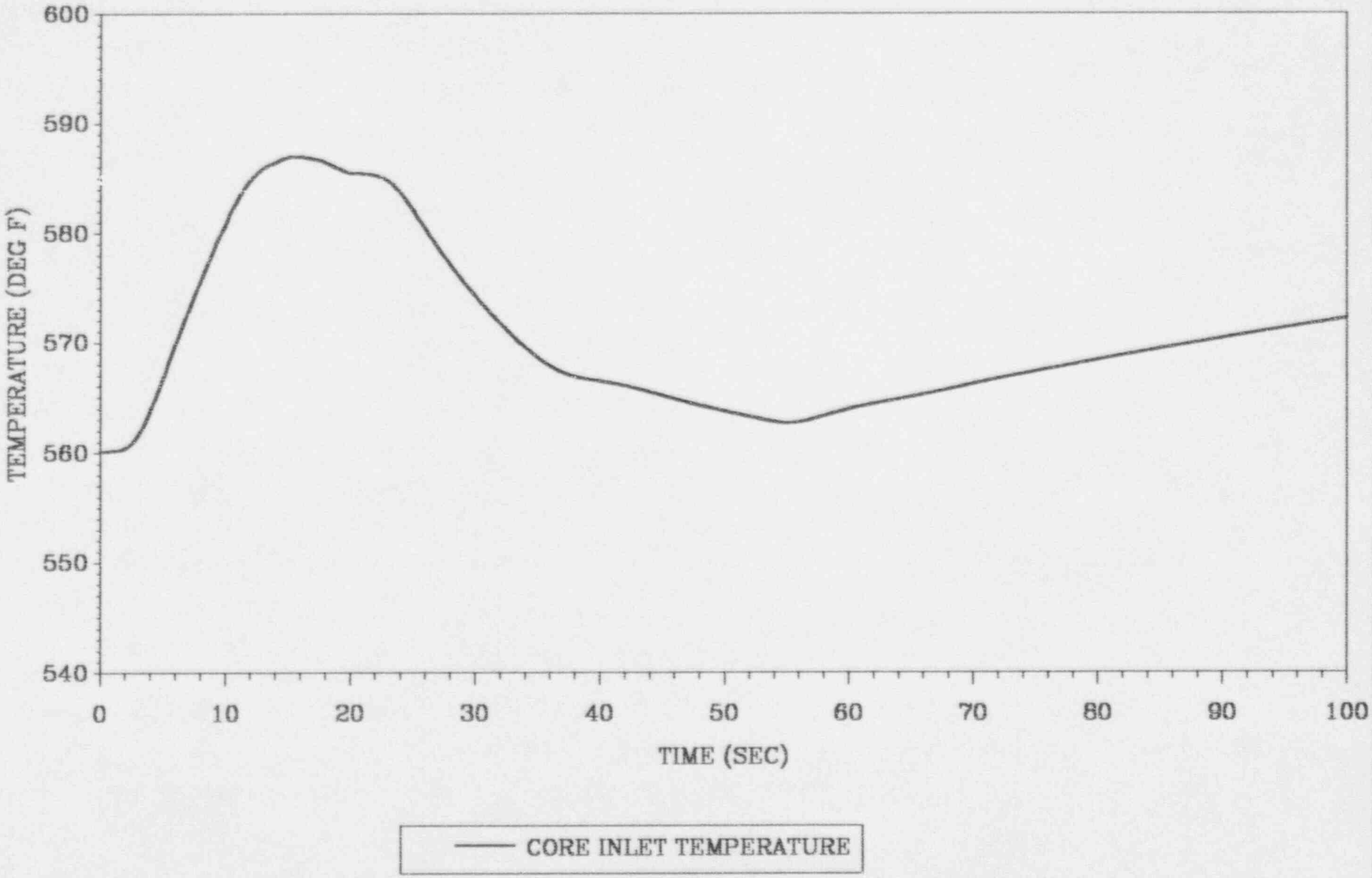
APPENDIX C: FIGURE 8
TURBINE TRIP EVENT WITH PRESSURIZER
SPRAY AND PORVS, MAXIMUM REACTIVITY FEEDBACK



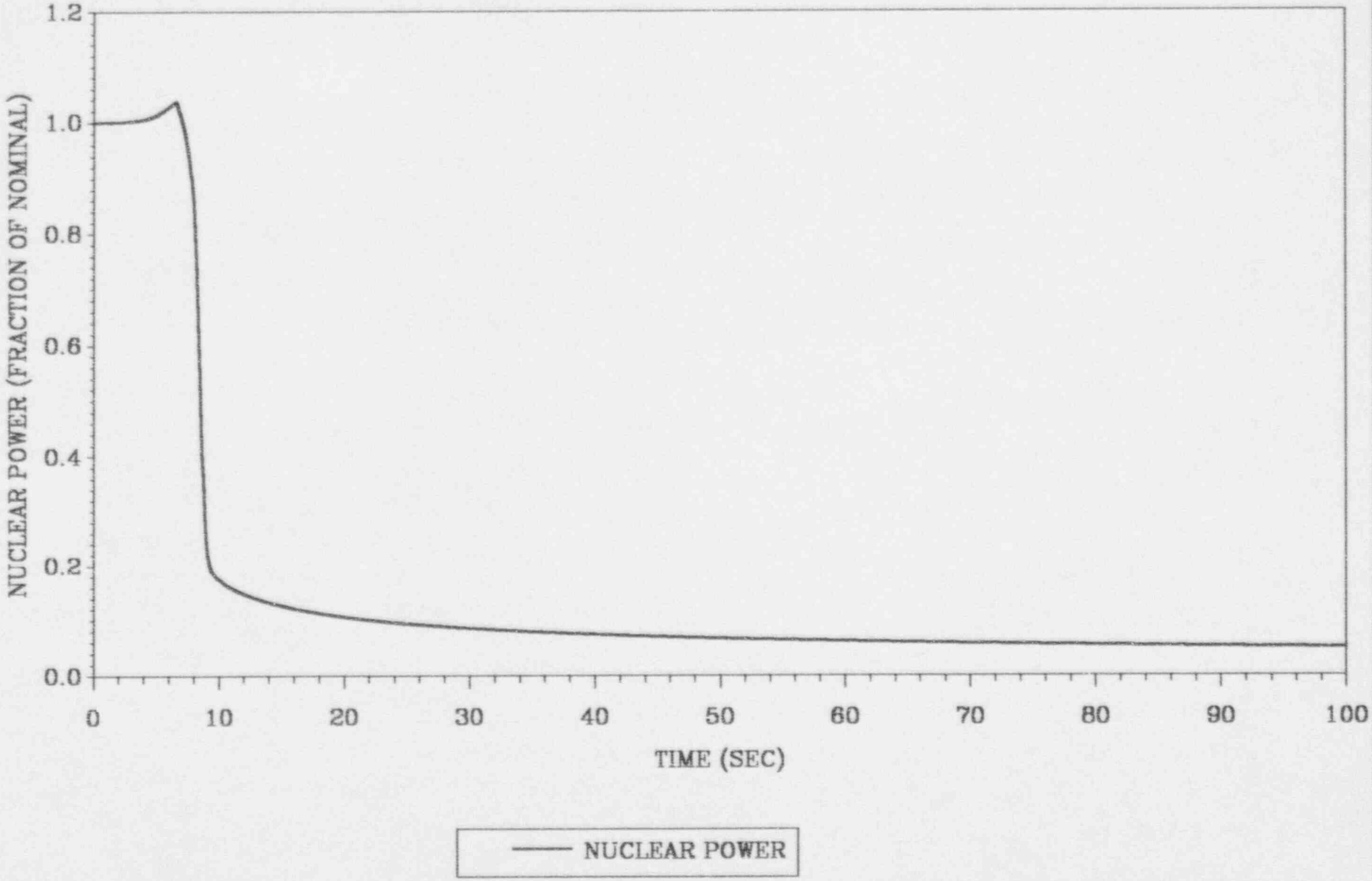
APPENDIX C: FIGURE 9
TURBINE TRIP EVENT WITH PRESSURIZER
SPRAY AND PORVS, MAXIMUM REACTIVITY FEEDBACK

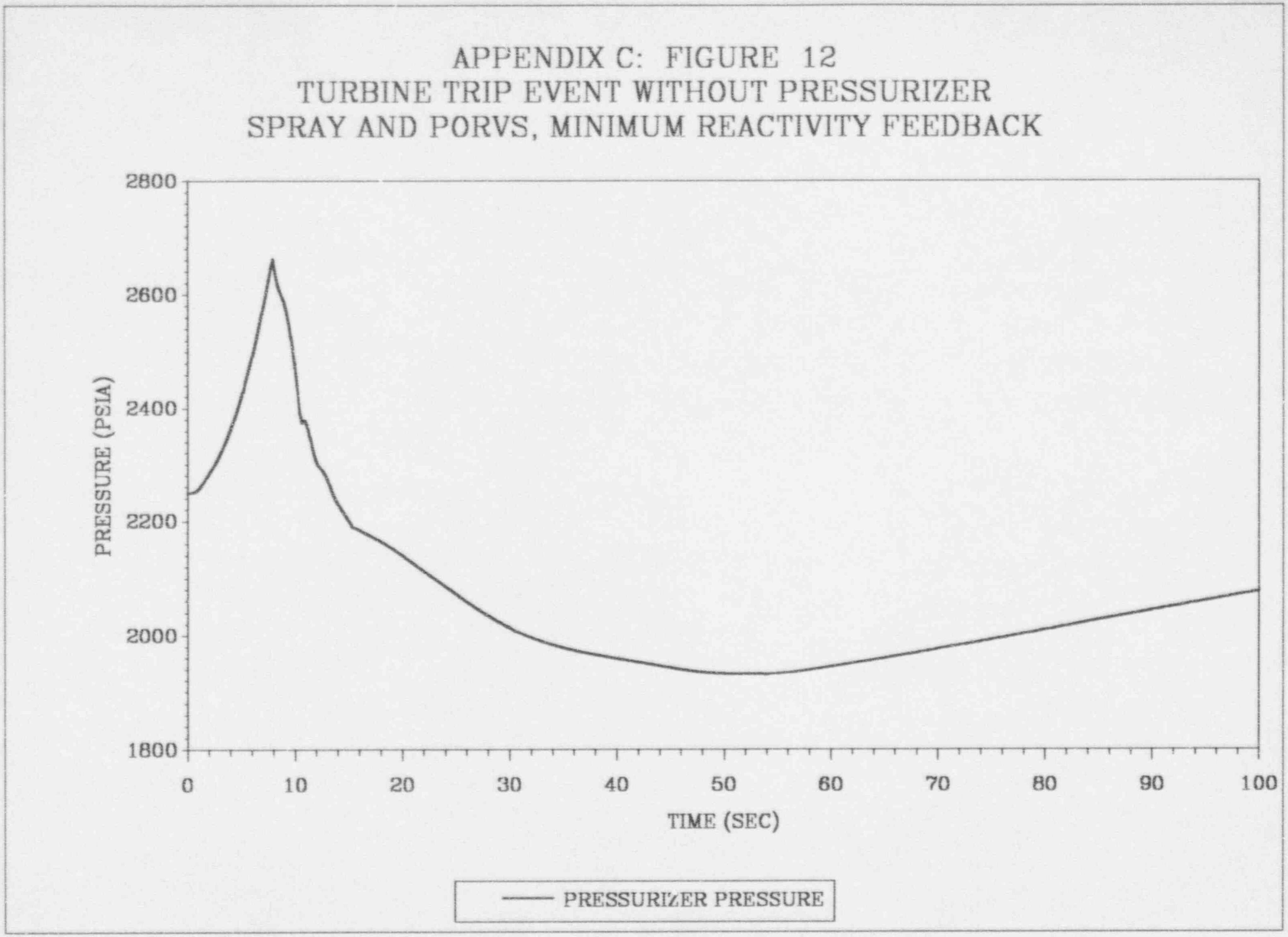


APPENDIX C: FIGURE 10
TURBINE TRIP EVENT WITH PRESSURIZER
SPRAY AND PORVS, MAXIMUM REACTIVITY FEEDBACK

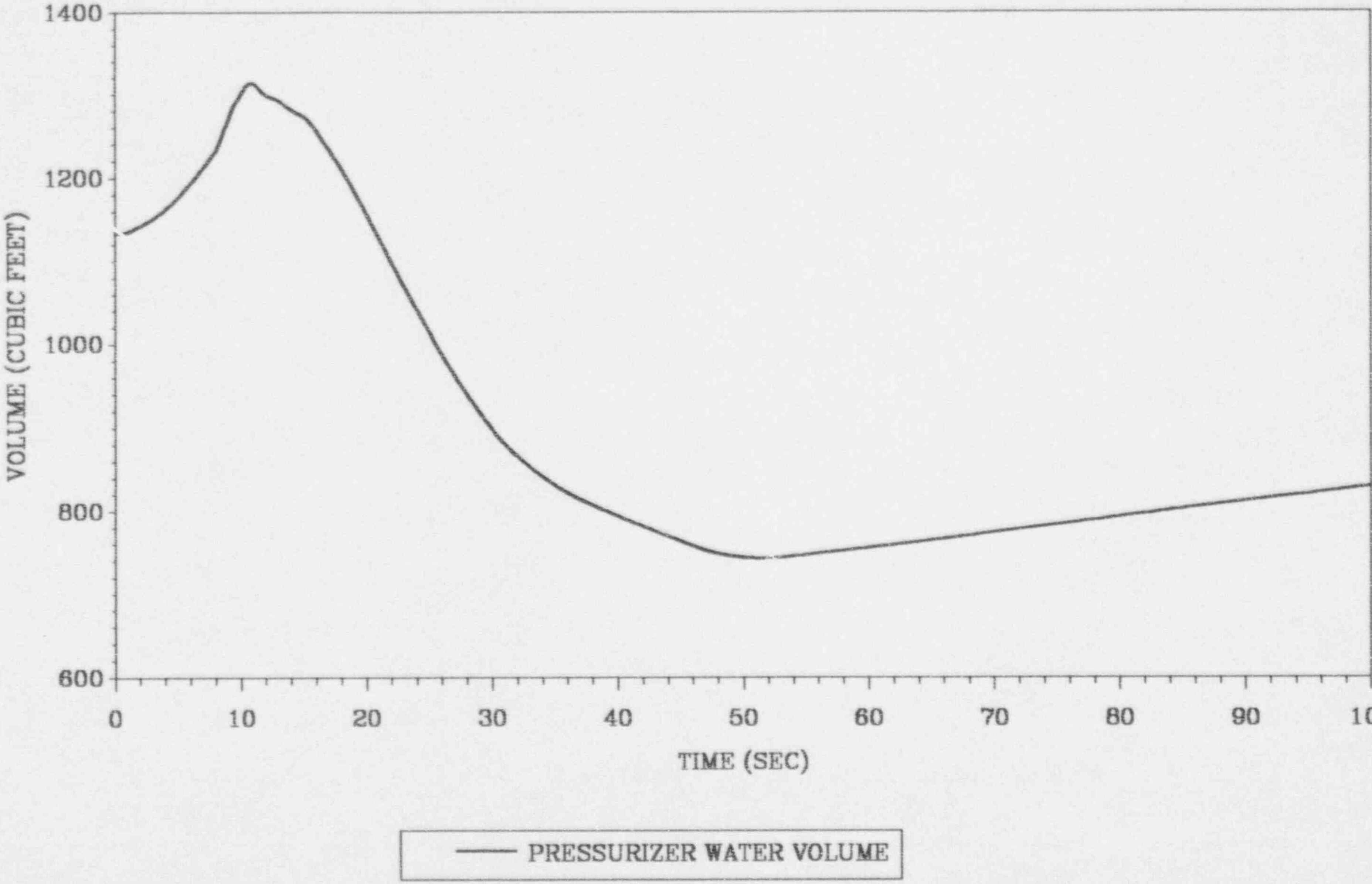


APPENDIX C: FIGURE 11
TURBINE TRIP EVENT WITHOUT PRESSURIZER
SPRAY AND PORVS, MINIMUM REACTIVITY FEEDBACK

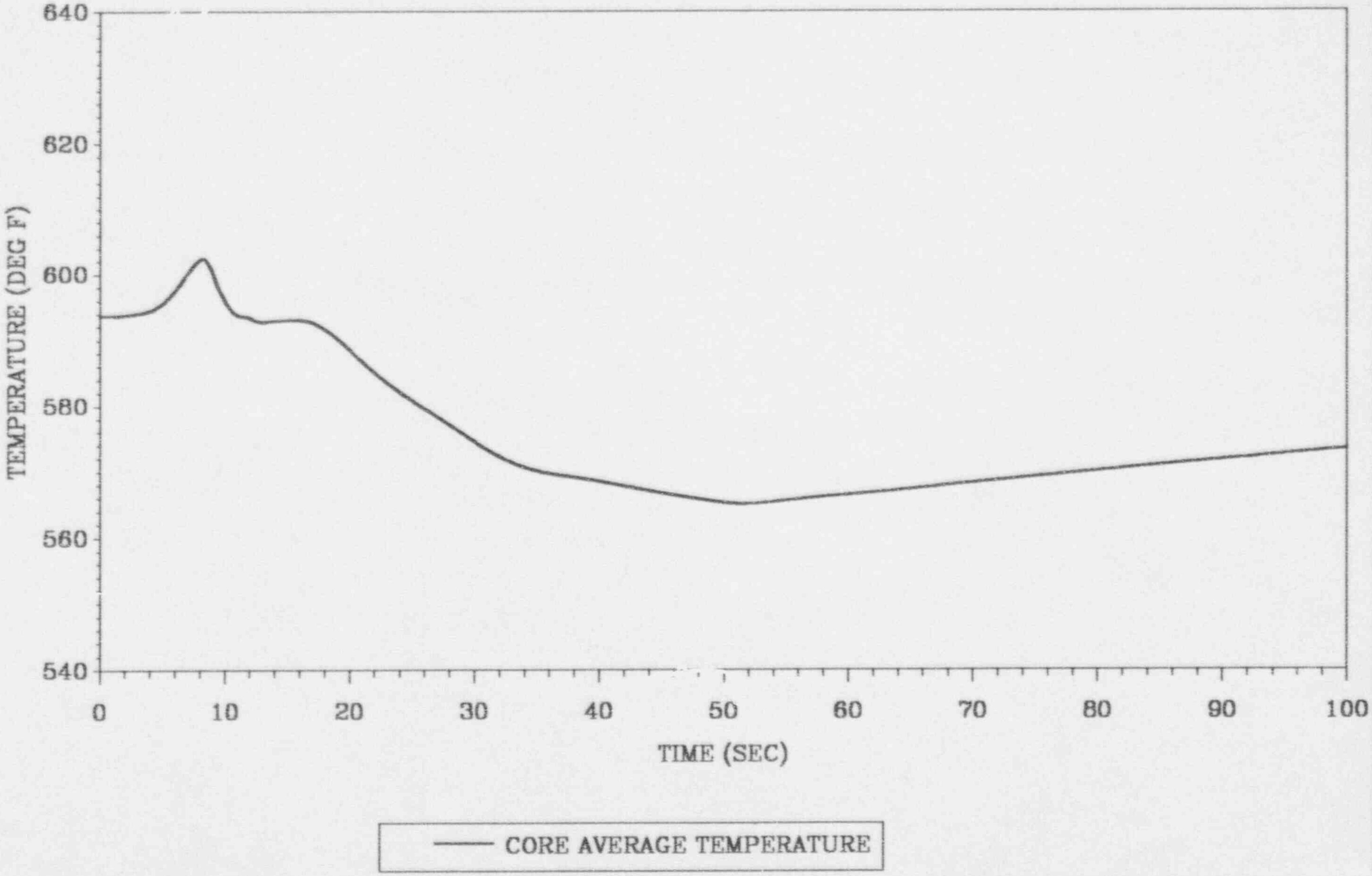



APPENDIX C: FIGURE 12
TURBINE TRIP EVENT WITHOUT PRESSURIZER
SPRAY AND PORVS, MINIMUM REACTIVITY FEEDBACK
PRESSURE (PSIA)
2800
2600
2400
2200
2000
1800
0
10
20
30
40
50
60
70
80
90
100
TIME (SEC)
PRESSURIZER PRESSURE

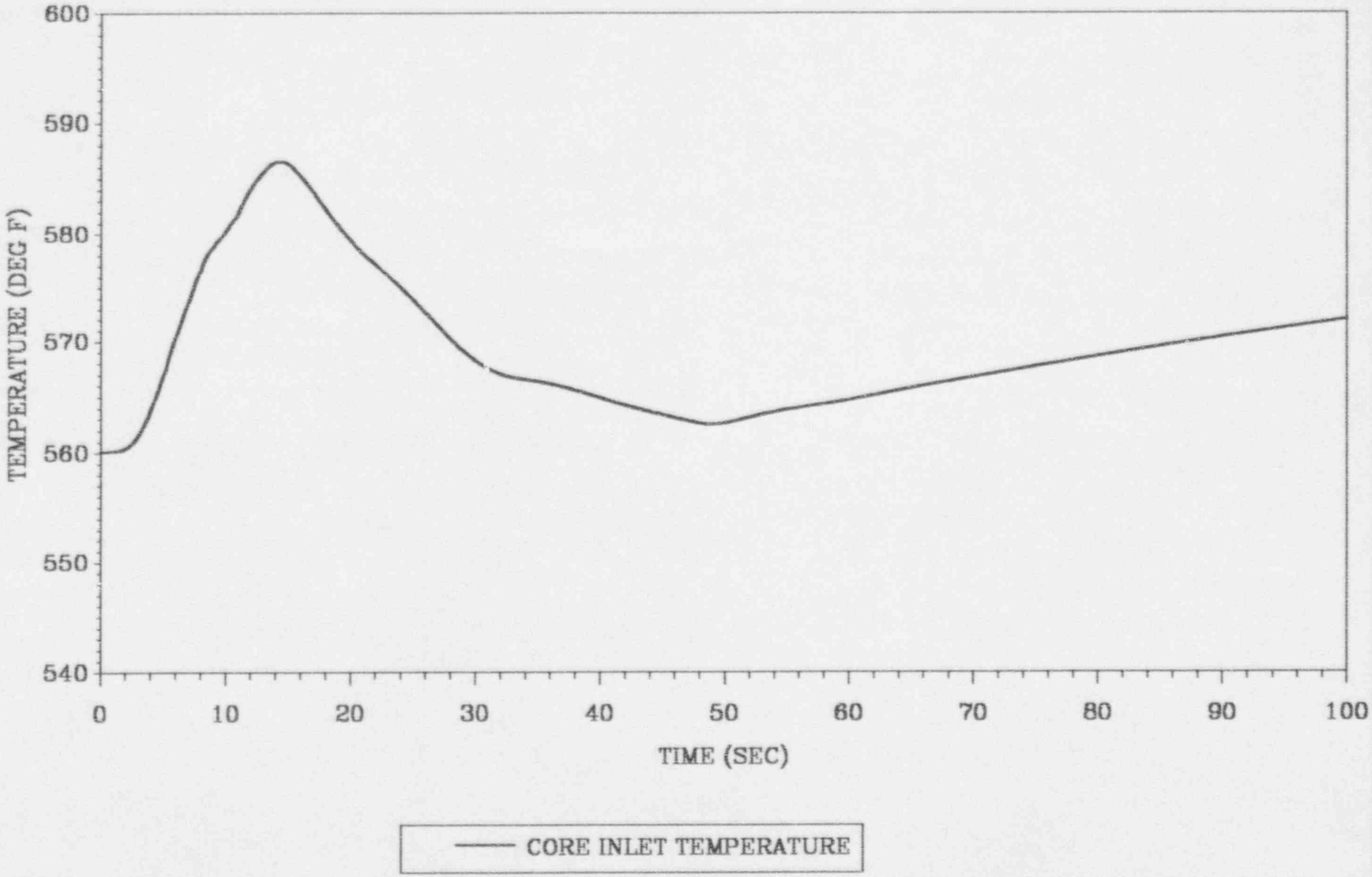
APPENDIX C: FIGURE 13
TURBINE TRIP EVENT WITHOUT PRESSURIZER
SPRAY AND PORVS, MINIMUM REACTIVITY FEEDBACK



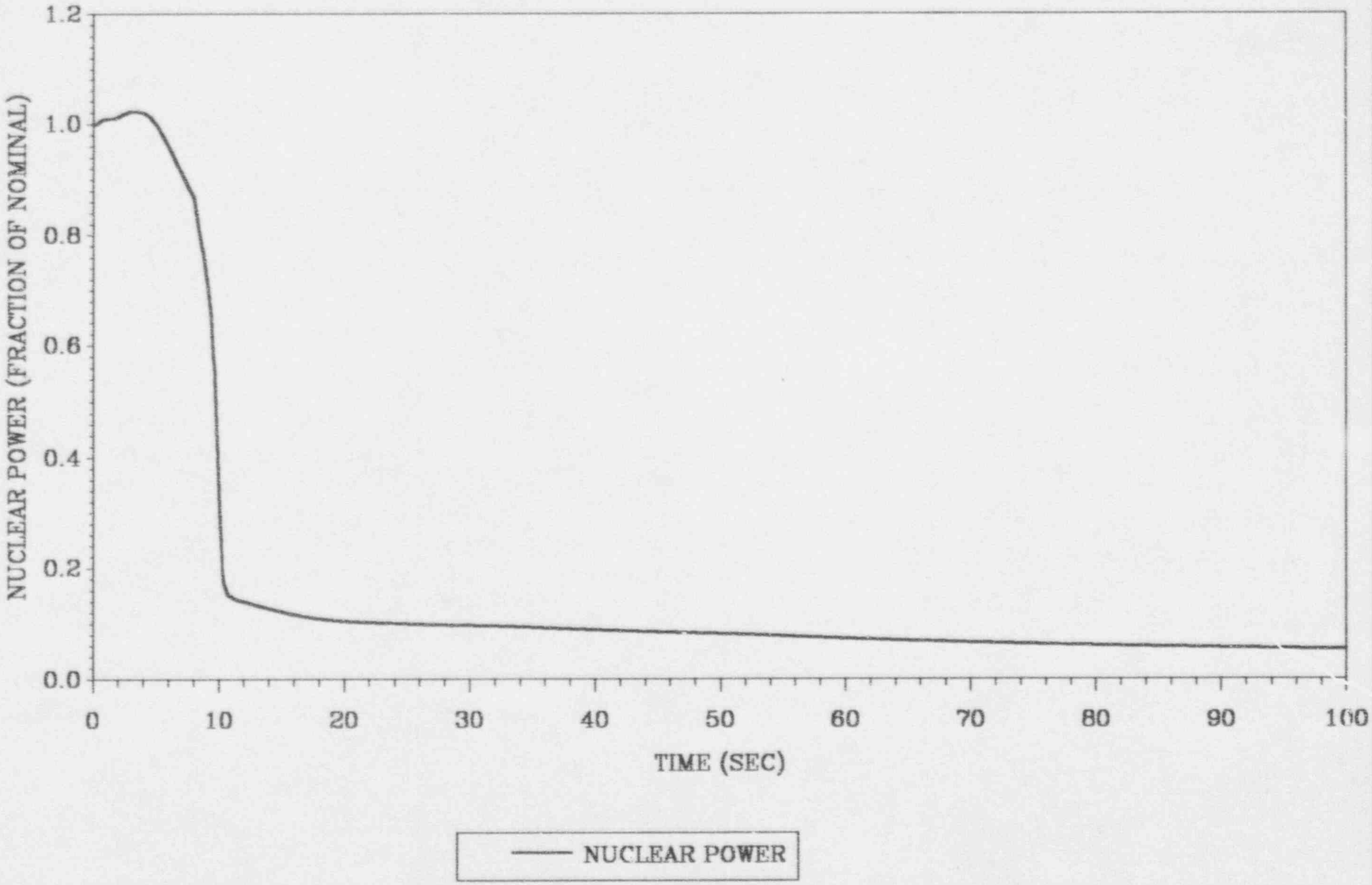
APPENDIX C: FIGURE 14
TURBINE TRIP EVENT WITHOUT PRESSURIZER SPRAY AND PORVS, MINIMUM REACTIVITY FEEDBACK

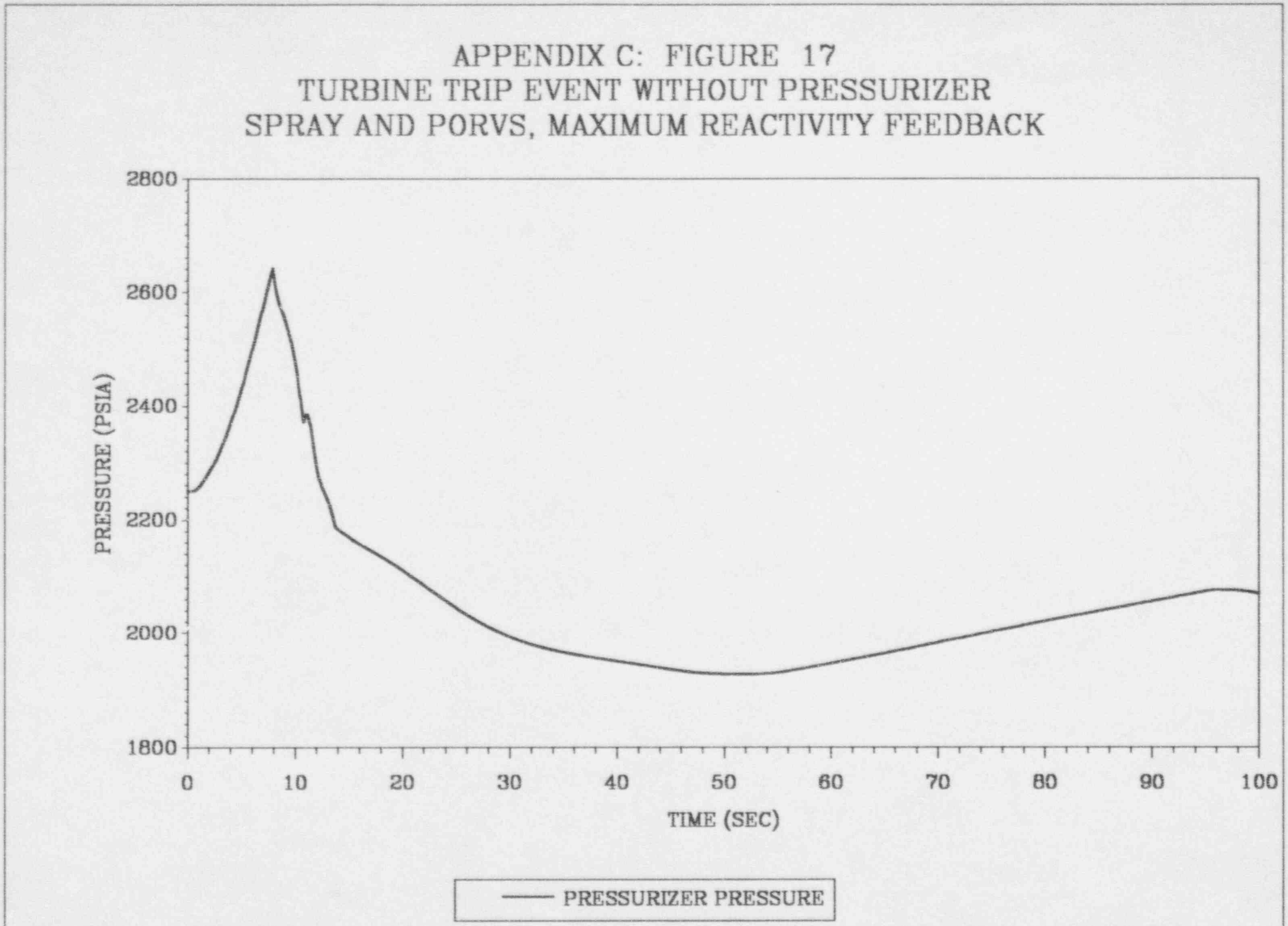


APPENDIX C: FIGURE 15
TURBINE TRIP EVENT WITHOUT PRESSURIZER
SPRAY AND PORVS, MINIMUM REACTIVITY FEEDBACK

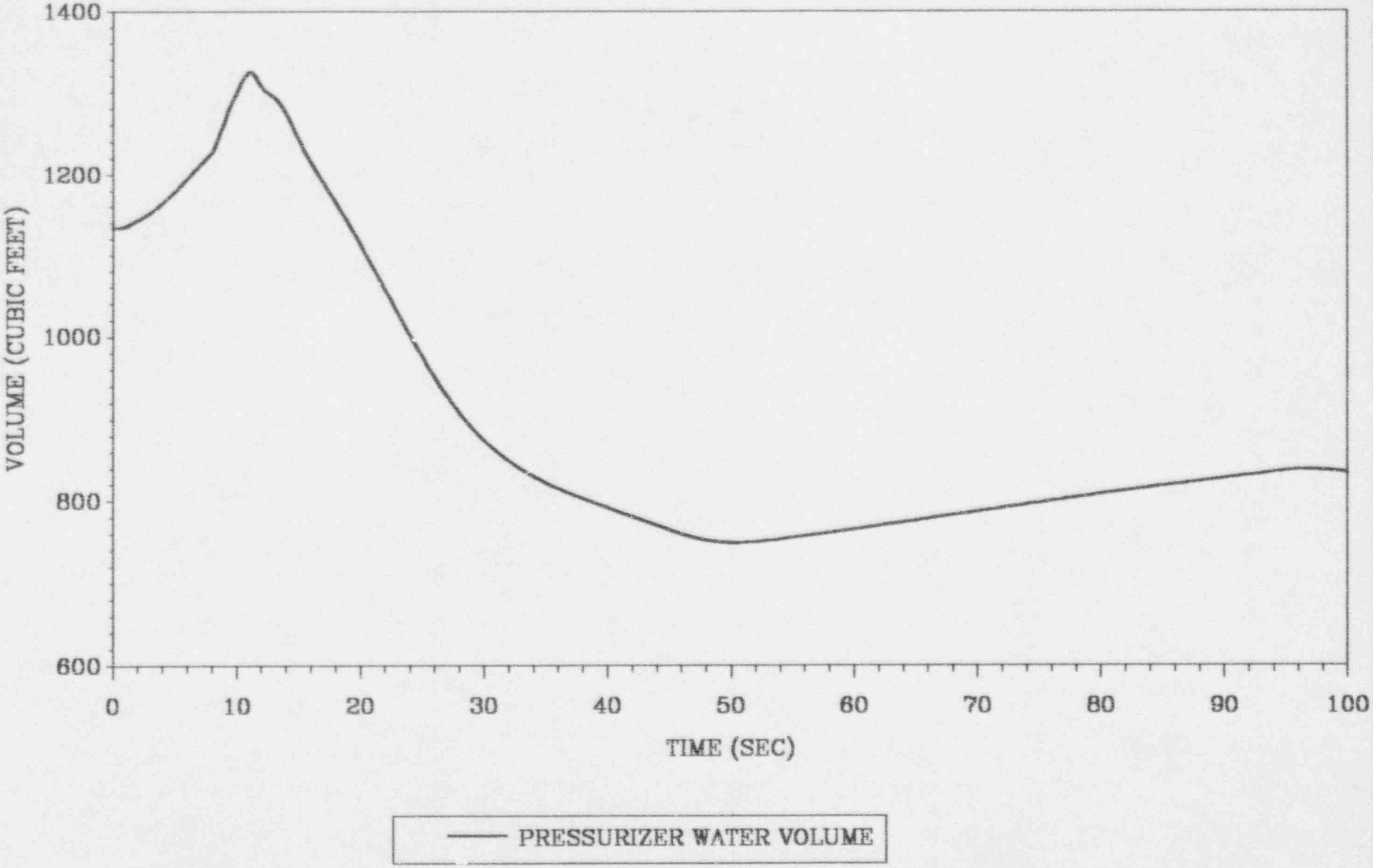


APPENDIX C: FIGURE 16
TURBINE TRIP EVENT WITHOUT PRESSURIZER
SPRAY AND PORVS, MAXIMUM REACTIVITY FEEDBACK

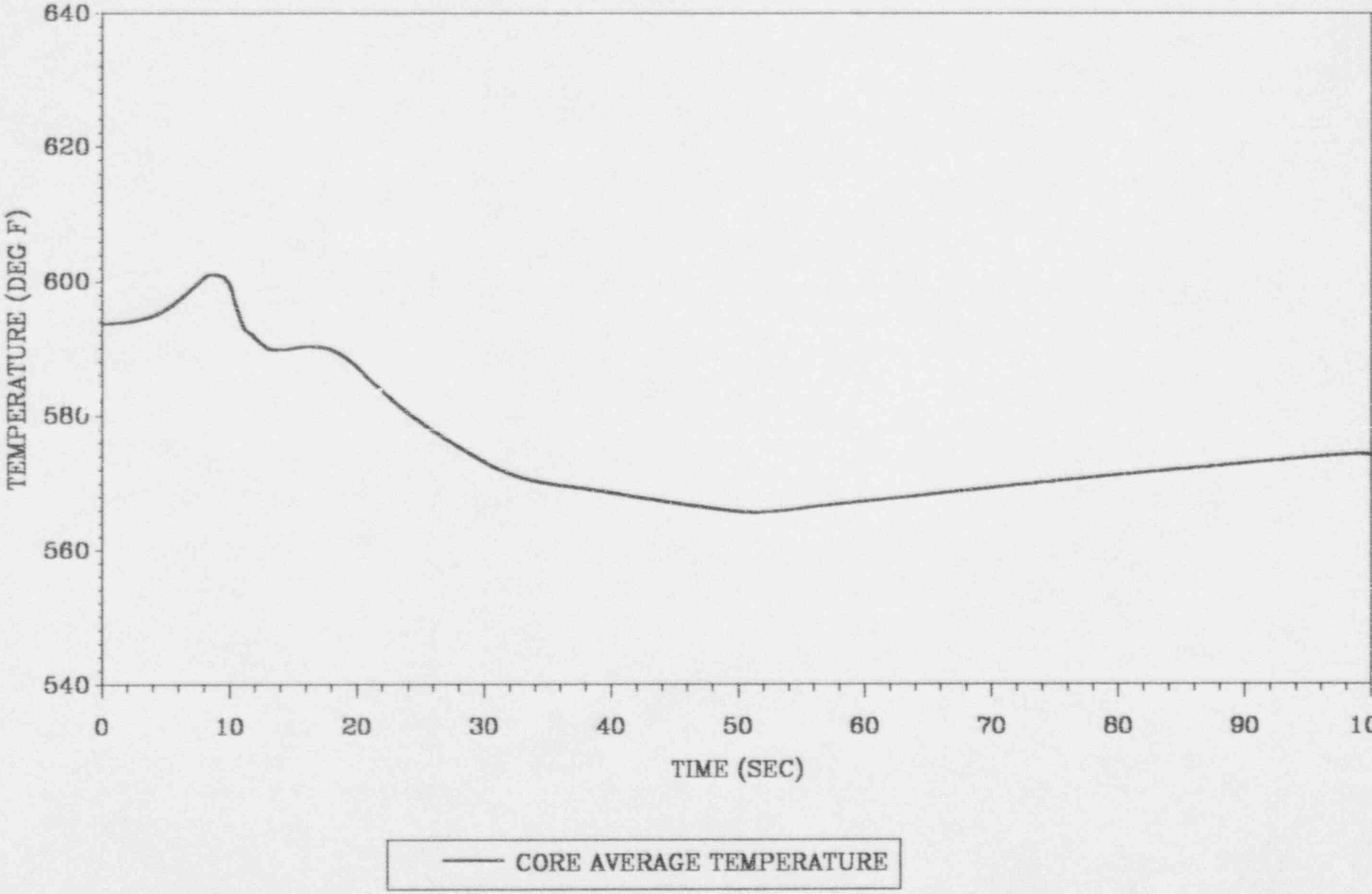



APPENDIX C: FIGURE 17
TURBINE TRIP EVENT WITHOUT PRESSURIZER
SPRAY AND PORVS, MAXIMUM REACTIVITY FEEDBACK
2800
2600
2400
2200
2000
1800
PRESSURE (PSIA)
0
10
20
30
40
50
60
70
80
90
100
TIME (SEC)
PRESSURIZER PRESSURE

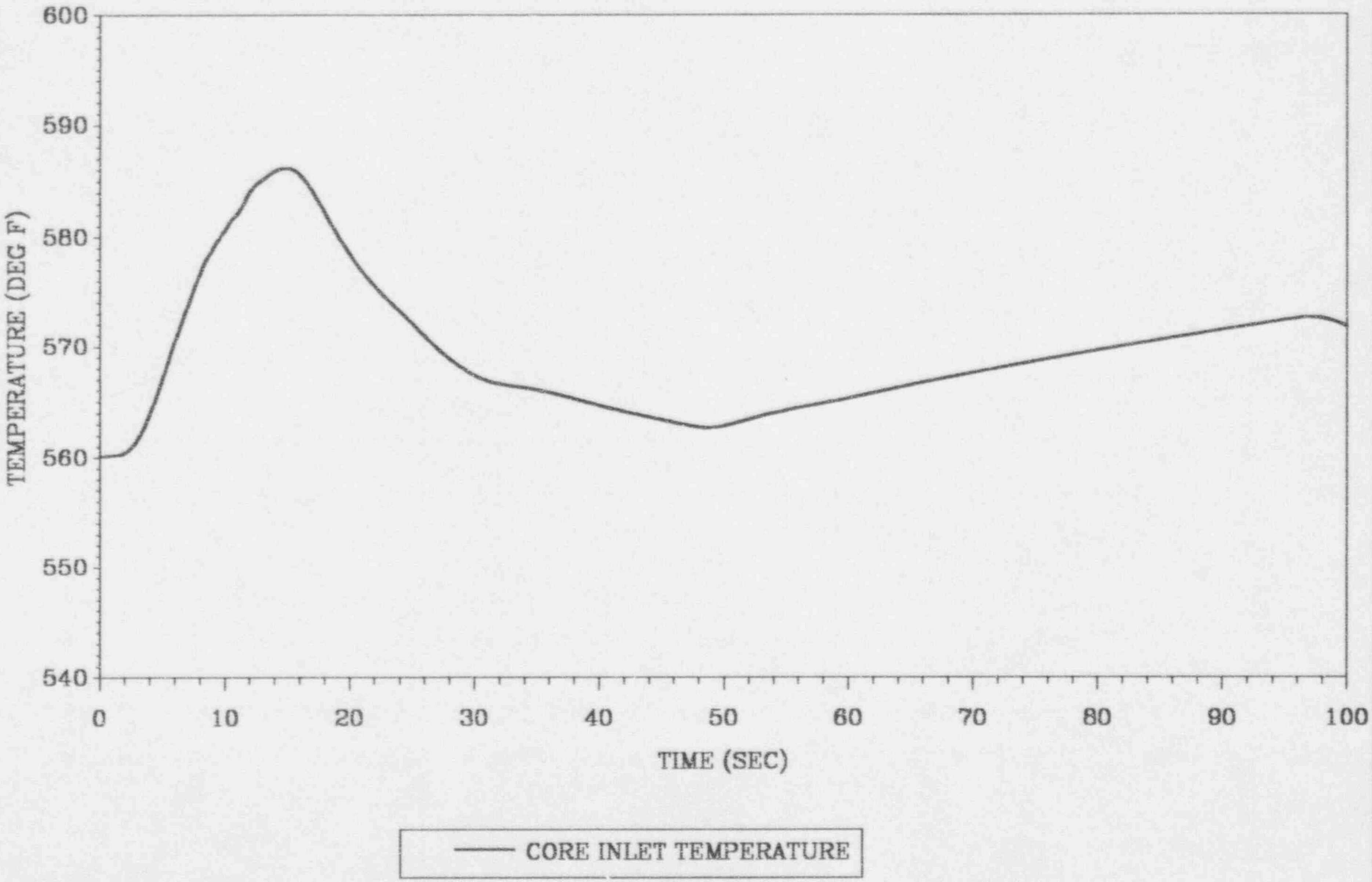
APPENDIX C: FIGURE 18
TURBINE TRIP EVENT WITHOUT PRESSURIZER
SPRAY AND PORVS, MAXIMUM REACTIVITY FEEDBACK



APPENDIX C: FIGURE 19
TURBINE TRIP EVENT WITHOUT PRESSURIZER
SPRAY AND PORVS, MAXIMUM REACTIVITY FEEDBACK



APPENDIX C: FIGURE 20
TURBINE TRIP EVENT WITHOUT PRESSURIZER
SPRAY AND PORVS, MAXIMUM REACTIVITY FEEDBACK



SAFETY EVALUATION

Appendix D:

Overpressure Protection Report

Appendix D

1.0 Purpose of Report

This report documents the overpressure protection provided for the Reactor Coolant System (RCS) in accordance with the ASME Boiler and Pressure Vessel Code, Section III, Articles NB-7000 and NC-7000. This report documents the overpressure protection provided in the Westinghouse NSSS scope.

2.0 Description of Overpressure Protection

2.1 Overpressure protection is provided for the RCS and its components to prevent a rise in pressure of more than 10% above the system design pressure of 2485 psig, in accordance with NB-7411. This protection is afforded for the following events which envelope those credible events which could lead to overpressure of the RCS if adequate overpressure protection was not provided.

1. Loss of External Electrical Load and/or Turbine Trip
2. Uncontrolled Rod Cluster Control Assembly Bank Withdrawal at Power
3. Loss of Forced Reactor Coolant Flow
4. Loss of Normal Feedwater Flow
5. Loss of Offsite Power to the Station Auxiliaries

2.2 The extent of the RCS is as defined in 10 CFR, Part 50, and includes:

1. the reactor vessel including control rod drive mechanism housings;
2. the reactor coolant side of the steam generators;
3. reactor coolant pumps;
4. a pressurizer attached to one of the reactor coolant loops;
5. safety and relief valves;
6. the interconnecting piping, valves and fittings between the principal components listed above; and
7. the piping, fittings and valves leading to connecting auxiliary or support systems up to and including the second isolation valve (from the high pressure side) on each line.

2.3 The pressurizer provides volume surge capacity and is designed to mitigate pressure increases (as well as decreases) caused by load transients. A pressurizer spray system condenses steam at a rate sufficient to prevent the pressurizer pressure from reaching the setpoint of the power-operated relief valves during a step reduction in power level equivalent to ten percent of full rated load.

The spray nozzle is located in the top head of the pressurizer. Spray is initiated when the pressure-controlled spray demand signal is above a given setpoint. The spray rate increases proportionally with increasing compensated error signal until it reaches a maximum value. The compensated error signal is the output of a proportional plus integral controller, the input to which is an error signal based on the difference between actual pressure and a reference pressure.

The pressurizer is equipped with 2 power-operated relief valves which limit system pressure for a large power mismatch to avoid actuation of the fixed high pressure reactor trip. The relief valves are operated automatically or by remote manual control. The operation of these valves also limits the frequency of opening of the spring-loaded safety valves. Remotely operated stop valves are provided to isolate the power-operated relief valve if excessive leakage occurs. The relief valves are designed to limit the pressurizer pressure to a value below the high pressure trip setpoint for all design transients up to and including the design percentage step load decrease with steam dump but without reactor trip.

Isolated output signals from the pressurizer pressure protection channels are used for pressure control. These are used to control pressurizer spray and power-operated relief valves in the event of increase in RCS pressure.

In the event of unavailability of the pressurizer spray or power-operated relief valves, and a complete loss of steam flow to the turbine, protection of the RCS against overpressurization is afforded by the pressurizer safety valves in conjunction with the steam generator safety valves and a reactor trip initiated by the Reactor Protection System.

There are 3 safety valves with a minimum required capacity of 420,000 lb/hr for each valve at 2575 psia. The pressurizer safety valves are totally enclosed pop-type, spring-loaded, self-activated valves with backpressure compensation. The set pressure of the safety valves will be no greater than system design pressure of 2485 psig in accordance with Section NB-7511. The pressurizer safety valves and power-operated relief valves discharge to the pressurizer relief tank (PRT). Rupture disks are installed on the pressurizer relief tank to prevent PRT overpressurization. The safety valve flow rates quoted are based on a developed backpressure of 500 psi which is equivalent to 20% of the safety valve design setpoint.

Figure 1 shows a schematic arrangement of the primary system pressure-relieving devices.

2.4 Overpressure protection for the main steam system is provided by the steam generator safety valves to prevent a rise in pressure of more than 10% above the steam generator

shell-side design pressure in accordance with NC-7411. The main steam system safety valve capacity is based on providing enough relief to remove 105% of the Engineered Safeguards Design steam flow. This protection is afforded for the same events as listed in Section 2.1 which envelope those credible events which could lead to system overpressurization if adequate overpressure protection were not provided.

The set pressure of the lowest set main steam safety valve is selected to be the steam generator shell design pressure of 1185 psig. The set pressure of the highest set main steam safety valve is selected to be 1234 psig which ensures that all five main steam safety valves in each steam line are fully open below the maximum pressure limit of 1303.5 psig which is 10% above the design pressure. The three intermediate main steam safety valves are set to open at different, staggered pressures between the minimum and maximum set pressures on each steam line.

3.0 Sizing of Pressurizer Safety Valves

3.1 The sizing of the pressurizer safety valves is based on analysis of a complete loss of steam flow to the turbine with the reactor operating at 102% of Engineered Safeguards Design Power. In this analysis, feedwater flow is isolated at the start of the transient and no credit is taken for operation of pressurizer power-operated relief valves, pressurizer level control system, pressurizer spray system, rod control system, steam dump system or steam line power-operated relief valves. The reactor is maintained at full power (no credit for reactor trip), and steam relief through the steam generator safety valves is considered. The total pressurizer safety valve capacity is required to be at least as large as the maximum surge rate into the pressurizer during this transient.

This sizing procedure results in a safety valve capacity well in excess of the capacity required to prevent exceeding 110% of system design pressure for the events listed in Section 2.1. An analysis demonstrating the conservative nature of this sizing procedure is presented in the following section.

3.2 Each of the overpressure transients listed in Section 2.1 has been analyzed and reported in the Callaway Plant Final Safety Analysis Report. The analysis methods, computer codes, plant initial conditions and relevant assumptions are also discussed in the FSAR for each transient.

Review of these transients shows that the loss of load/turbine trip event results in the maximum system pressure and the maximum safety valve relief requirements. In order to support an increase in setpoint tolerance on the main steam safety valves (MSSVs), this pressure-limiting transient was reanalyzed to ensure that all applicable acceptance criteria continue to be met. This transient is presented in detail below.

For a loss of load/turbine trip event, the reactor would be tripped directly (unless below approximately 50 percent power) from a signal derived from the turbine stop emergency trip fluid pressure and turbine stop valves. The turbine stop valves close rapidly (typically 0.19 second) on loss of trip fluid pressure actuated by one of a number of possible turbine trip signals. This will cause a sudden reduction in steam flow, resulting in an increase in pressure and temperature in the steam generator shell.

As a result, the heat transfer rate in the steam generators is reduced, causing the reactor coolant temperature to rise, which in turn causes coolant expansion, pressurizer insurge, and RCS pressure rise.

The automatic steam dump system would normally accommodate the excess steam generation. Reactor coolant temperature and pressure do no significantly increase if the steam dump system and pressurizer pressure control system are functioning properly. If the turbine condenser was not available, the excess steam generation would be dumped to the atmosphere and main feedwater flow would be lost. For this situation, feedwater flow would be maintained by the Auxiliary Feedwater System to ensure adequate residual and decay heat removal capability. Should the steam dump system fail to operate, the steam generator safety valves may lift to provide pressure control.

In this analysis, the behavior of the unit is evaluated for a complete loss of steam load from the nominal full power level plus a two percent calorimetric error without direct reactor trip; that is, the turbine is assumed to trip without actuating all the sensors for reactor trip on the turbine stop valves. This assumption delays reactor trip until conditions in the RCS result in a trip due to other signals. Thus, the analysis assumes a worst transient. In addition, no credit is taken for steam dump. Main feedwater flow is terminated at the time of the turbine trip, with no credit taken for auxiliary feedwater to mitigate the consequences of the transient.

The loss of load/turbine trip transient is analyzed by employing the detailed digital computer program LOFTRAN. The program simulates the neutron kinetics, RCS, pressurizer, pressurizer relief and safety valves, pressurizer spray, steam generators, and steam generator safety valves. The program computes pertinent plant variables including temperatures, pressures, and power level.

Major assumptions are summarized below.

a. Initial operating conditions

   The initial reactor power is assumed to be at nominal full power plus a calorimetric error; the initial pressure is assumed to be nominal minus an appropriate pressure uncertainty to allow for errors in the pressurizer pressure measurement and control channels. The average RCS temperature is assumed to be at the nominal full power value. This results in the maximum possible increase in coolant pressure for the loss of load/turbine trip event.

b. Moderator and Doppler coefficients of reactivity

   The analysis assumes a zero moderator temperature coefficient and a least negative Doppler power defect. Part-power cases analyzed assuming a positive moderator temperature coefficient, consistent with BOL conditions, were shown to be less limiting with respect to peak RCS pressure.

c. Reactor control

From the standpoint of the maximum pressures attained, it is conservative to assume that the reactor is in manual control. If the reactor were in automatic control, the control rod banks would move prior to trip and reduce the severity of the transient.

d. Steam release

No credit is taken for the operation of the steam dump system or steam generator power-operated relief valves.

A staggered main steam safety valve model is used such the each valve can be properly modeled to lift and be fully open at 3% above its setpoint. The 3% setpoint uncertainty accounts for safety valve setpoint tolerance. Using this model, the steam generator pressure rises until four of the five main steam safety valve setpoints are reached. Steam release through four of the five main steam safety valves on each steam line limits secondary steam pressure to levels well below the 110% of shell design pressure.

e. Pressurizer spray and power-operated relief valves

No credit is taken for the effect of pressurizer spray and power-operated relief valves in reducing or limiting the coolant pressure. Safety valves are operable.

The modeling of the three pressurizer safety valves uses approved methodology (Reference 10) to account for the effects of the pressurizer safety valve loop seals. A pressurizer safety valve setpoint uncertainty of +2% and 1.15-second loop seal purge time are assumed in the analysis. The 2% setpoint uncertainty includes a 1% set pressure shift and 1% set pressure tolerance. No steam flow is assumed until the valve loop seals are purged.

f. Feedwater flow

Main feedwater flow to the steam generators is assumed to be lost at the time of turbine trip. No credit is taken for auxiliary feedwater flow since a stabilized plant condition will be reached before auxiliary feedwater initiation is normally assumed to occur; however, the auxiliary feedwater pumps would be expected to start on a trip of the main feedwater pumps. The auxiliary feedwater flow would remove core decay heat following plant stabilization.

g. Reactor trip

Reactor trip is actuated by the first Reactor Protection System trip setpoint reached with no credit taken for the direct reactor trip on the turbine trip. Trip signals are expected due to high pressurizer pressure, overtemperature ΔT, high pressurizer water level, and low-low steam generator water level.

The results of the loss of load/turbine trip transient are shown on Figures 2, 3 and 4. The reactor is tripped on a high pressurizer pressure signal. Figure 2 shows the nuclear power and the reactor coolant loop hot leg and cold leg temperatures for this transient. Figure 3 shows pressurizer pressure and reactor coolant pump discharge pressure, which is the point of highest pressure in the RCS. It also shows the pressurizer safety valve relief rate which remains below the minimum required capability assumed in the analysis: 350 lbm/sec. Figure 4 shows the steam generator shell side pressure and main steam safety valve relief rate per steam generator. This last figure indicates that four of the five valves on each steam line are actuated during the loss of load/turbine trip accident.

The results of these analyses show that the overpressure protection provided is sufficient to maintain peak RCS pressure and the main steam system pressure below the code limit of 110% of the respective system design pressures. The plot of pressurizer safety valve relief rate shows that adequate overpressure protection for this limiting event could be provided by about 88% of the installed safety valve capacity.

4.0 References

1. ASME Boiler and Pressure Vessel Code, Section III, Articles NB-7000, 1971 and 1974 Editions

2. "Topical Report - Overpressure Protection for Westinghouse Pressurized Water Reactors," WCAP-7769, Rev. 1, June 1972

3. "LOFTRAN Code Description," WCAP-7907-P-A (Proprietary), WCAP-7907-A (Nonproprietary), April 1984

4. Callaway Certified Safety Valve Capacity, purchase order number 250052, quality release number 40915 (valve serial number N60446-00-0006) and quality release number 40937 (valve serial numbers N60446-00-0004 and N60446-00-0005)

5. Callaway OPPR Loss of Load/Turbine Trip Analysis for Increased MSSV Tolerance, Calculation No. CN-TA-94-126, August 1994 (Proprietary)

6. Callaway Rod Withdrawal at Power Analysis, Calculation No. CN-TA-87-002, January 1987 (Proprietary)

7. Callaway Loss of Reactor Coolant Flow Analysis, Calculation No. CN-TA-86-223, February 1987 (Proprietary)

8. Callaway Loss of Normal Feedwater/Station Blackout Analysis, Calculation No. CN-TA-86-251, January 1987 (Proprietary)

9. SNUPPS Deletion of Reactor Trip on Turbine Trip Below 50% Power Analysis, Calculation No. CN-RPA-79-12, January 1979 (Proprietary)

10. "Pressurizer Safety Valve Set Pressure Shift," WCAP-12910 Rev. 1-A (Proprietary), May 1993

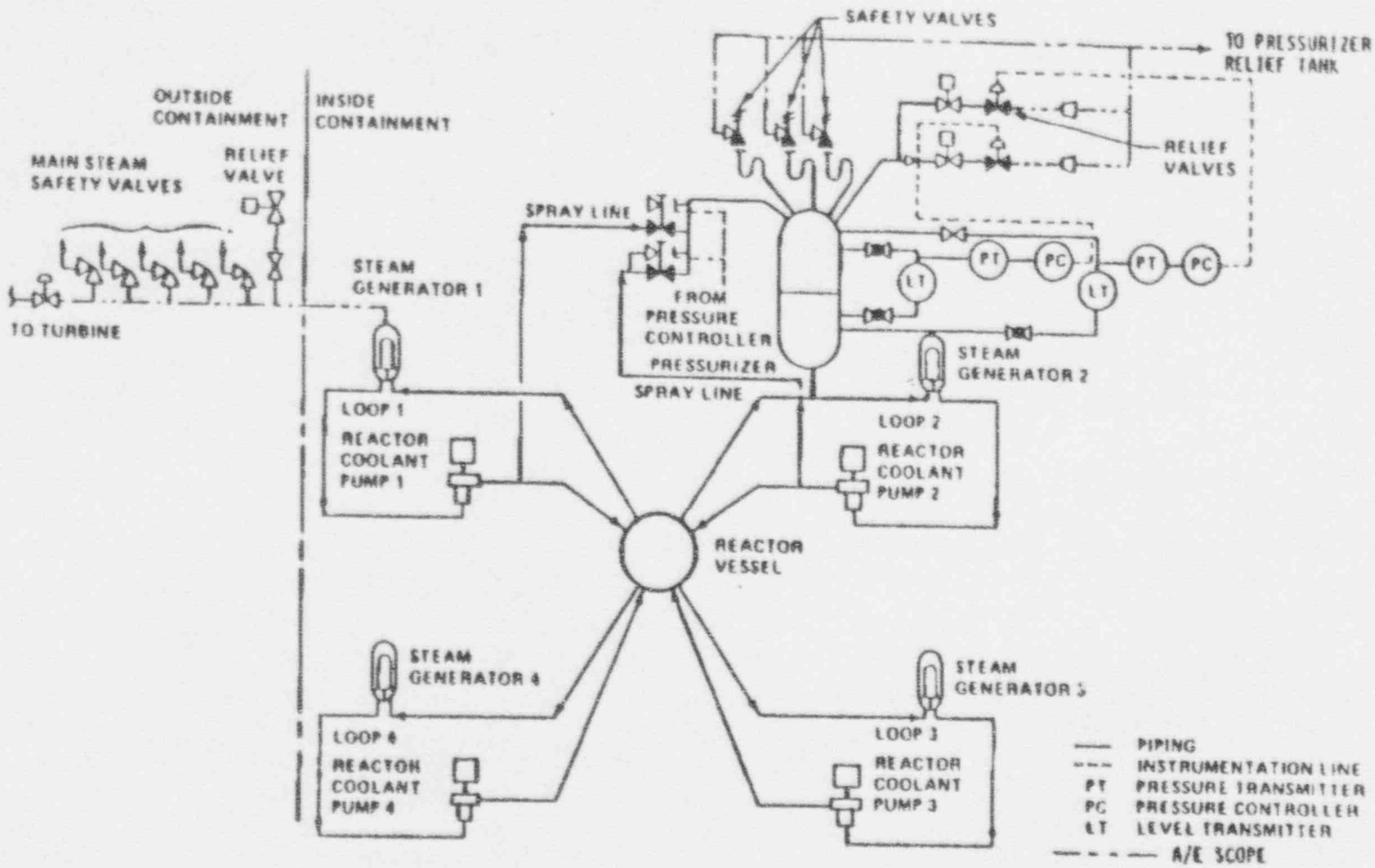
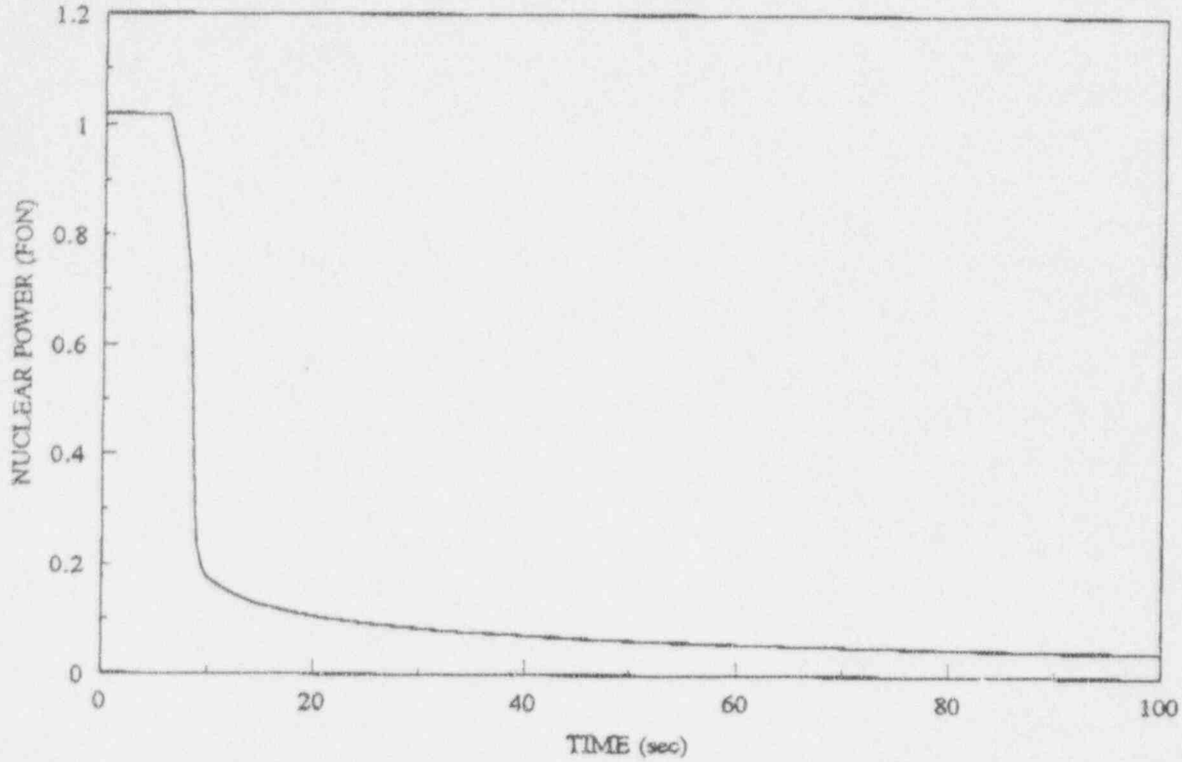


Figure 1 Schematic Arrangement of Pressure Relieving Devices


1.2
1
0.8
0.6
0.4
0.2
0
NUCLEAR POWER (FON)
0
20
40
60
80
100
TIME (sec)

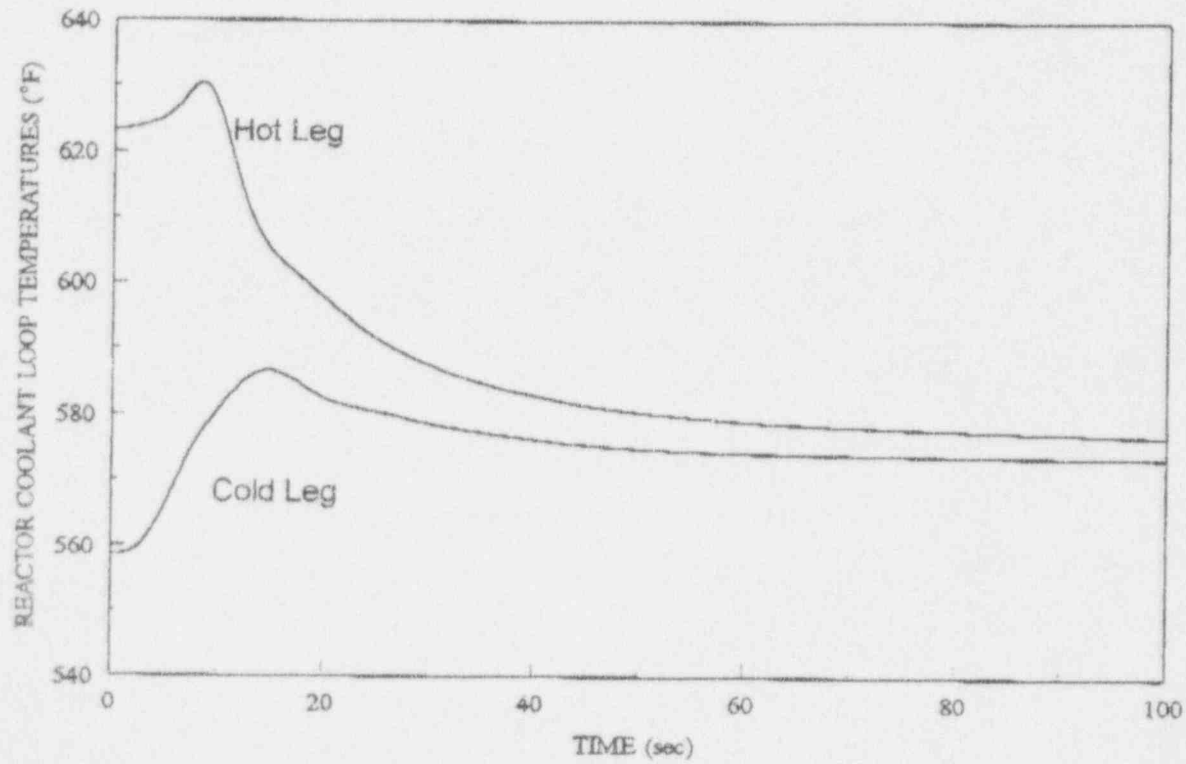
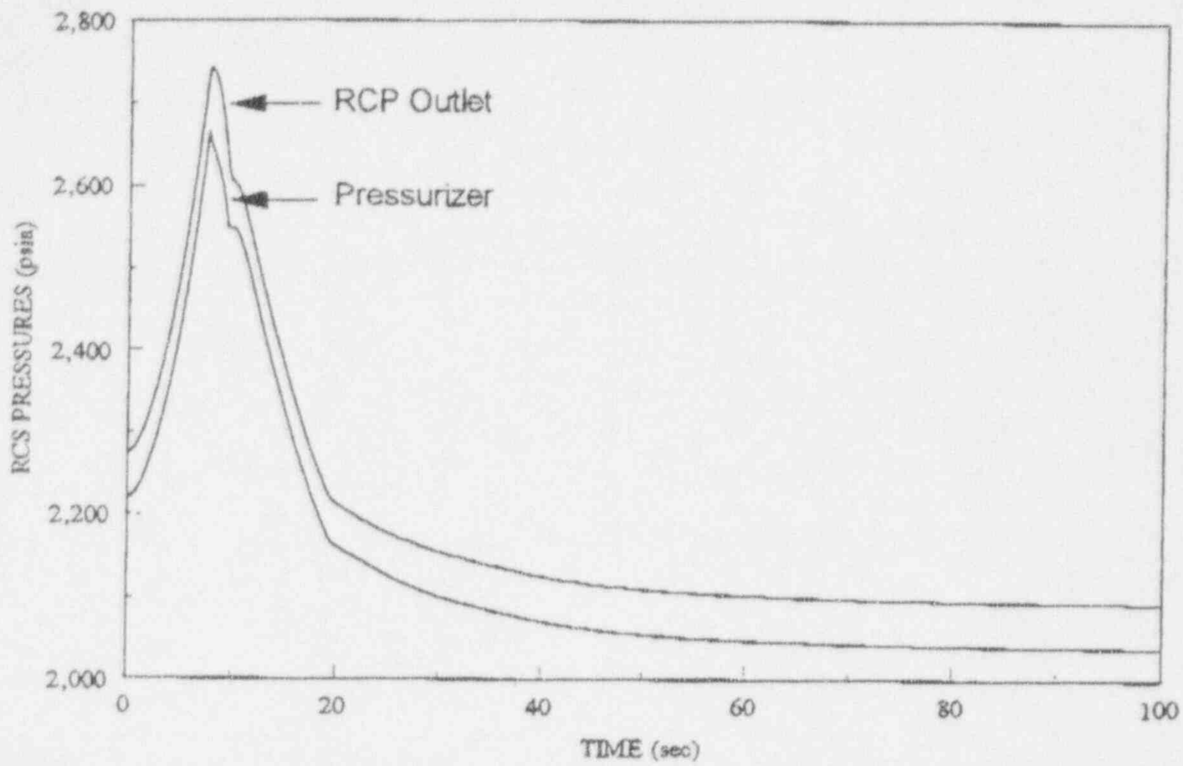

640
620
600
580
560
540
REACTOR COOLANT LOOP TEMPERATURES (°F)
Hot Leg
Cold Leg
0
20
40
60
80
100
TIME (sec)

Figure 2


2,800
2,600
2,400
2,200
2,000
RCS PRESSURES (psia)
RCP Outlet
Pressurizer
0
20
40
60
80
100
TIME (sec)

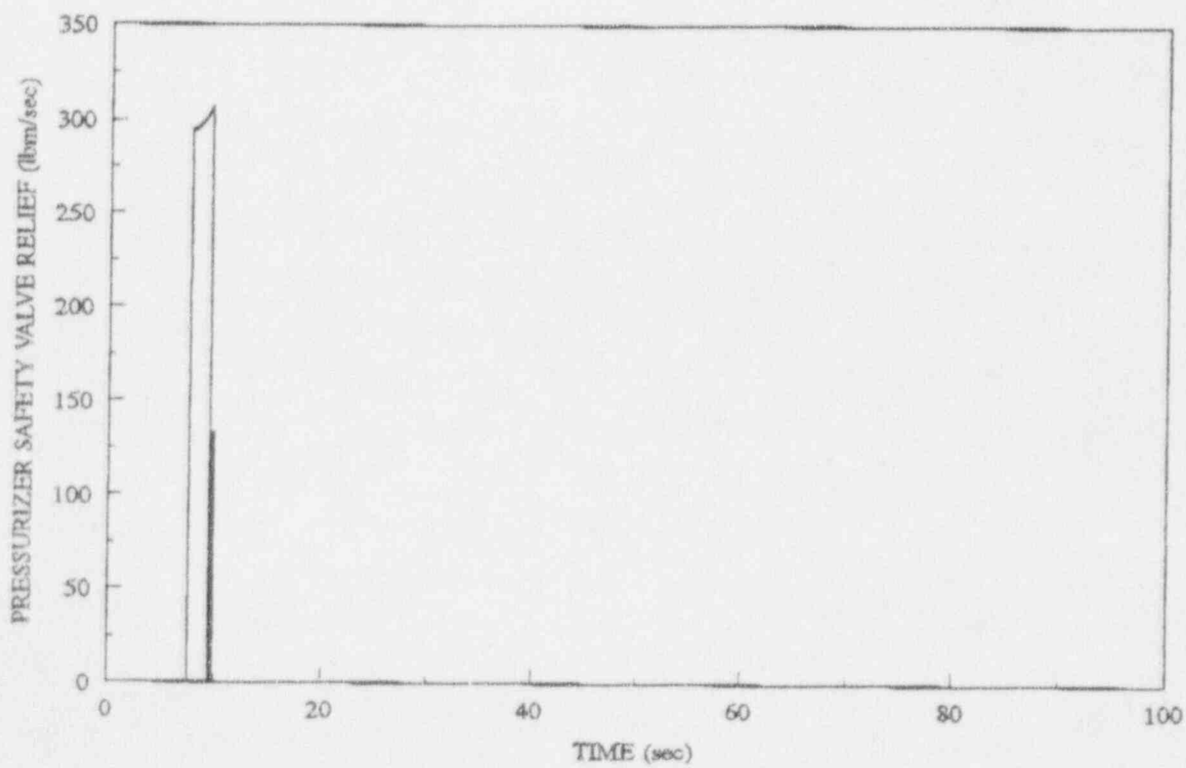
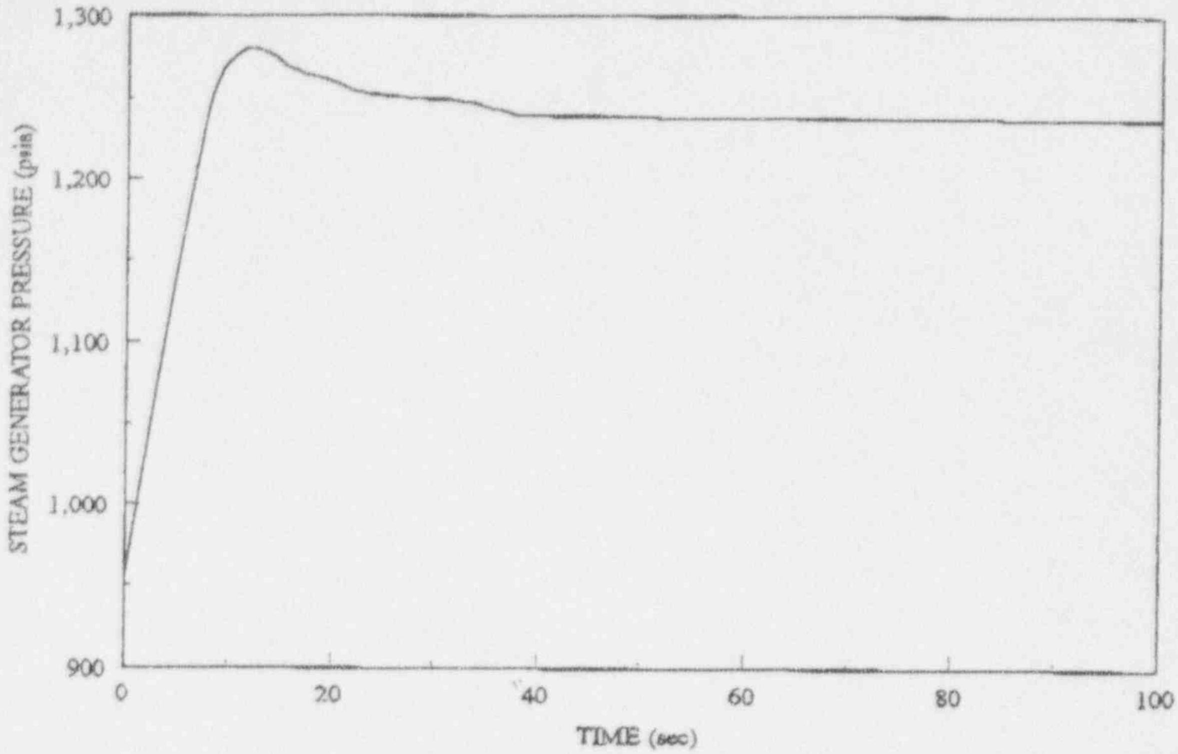

350
300
250
200
150
100
50
0
PRESSURIZER SAFETY VALVE RELIEF (lbm/sec)
0
20
40
60
80
100
TIME (sec)

Figure 3


1,300
1,200
1,100
1,000
900
STEAM GENERATOR PRESSURE (psia)
0
20
40
60
80
100
TIME (sec)

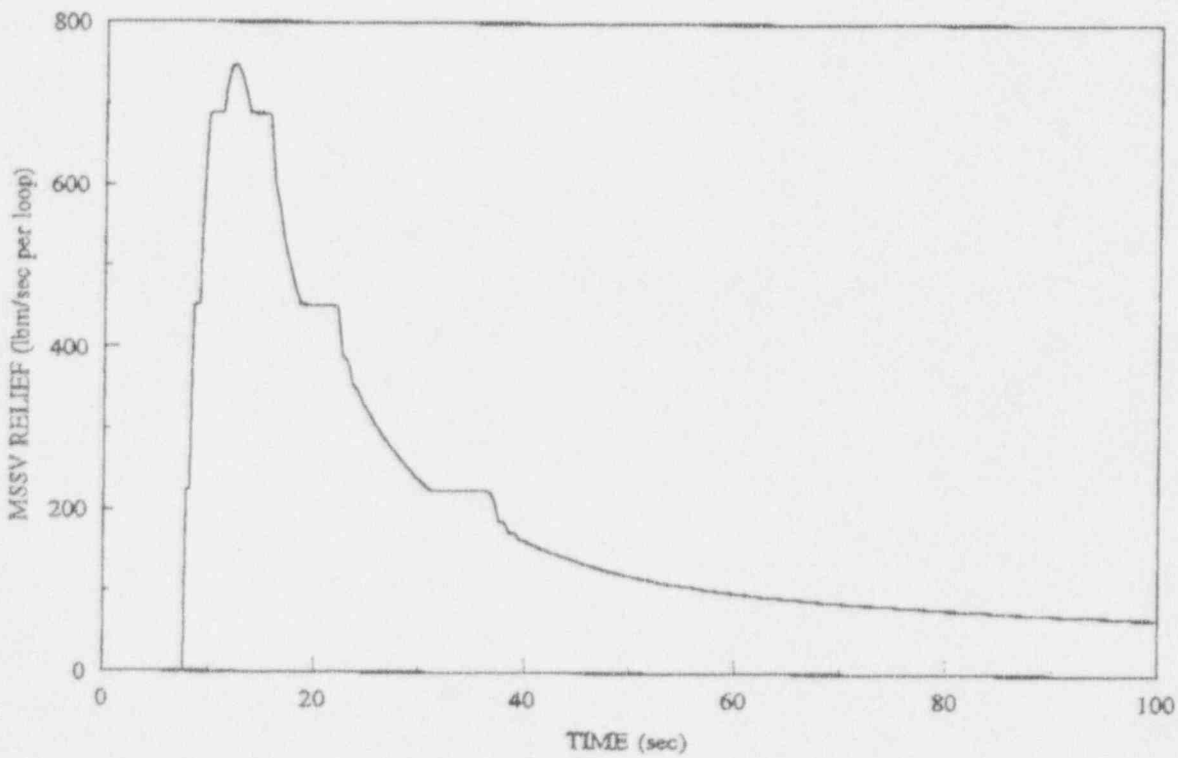

800
600
400
200
0
MSSV RELIEF (lbm/sec per loop)
0
20
40
60
80
100
TIME (sec)

Figure 4

SIGNIFICANT HAZARDS EVAULATION

This amendment application requests a revision to Technical specification (TS) 3.7.1.1 (Tables 3.7-1 and 3.7-2), 2.2 (Table 2.2-1), 3/4.3 (Table 3.3-2), and Bases 3/4.7. These specifications are revised to increase the lift setting tolerance for the main steam safety valves from ±1% to +3/-1%, lower the maximum allowable power levels with inoperable main steam safety valves, and to incorporate the revised methodology for calculating maximum power levels with inoperable main steam safety valves into the Bases.

Background

The function of the main steam line safety valves is to provide overpressure protection, ensuring that the secondary system pressure will be limited to within 110% (1320 psia) of its design pressure (1200 psia) during the most severe anticipated system operational transient. The total relieving capacity for all valves on all steam lines is 113% of the total secondary steam flow.

Revision of the lift setting tolerance to +3/-1% as-found and ±1% as-left will have no effect on the relieving capacity of the safety valves. The change in lift setting tolerance will provide reasonable acceptance criteria taking into account the component service conditions and conservative criteria for the as-left condition of the safety valves. It is Union Electric's position that the test equipment tolerance (+2/-1%) will not be accounted for in the TS tolerance because this equipment tolerance is specifically addressed by the ASME Code. Therefore, as long as the testing equipment and methodology meet the +2/-1% tolerance requirements of OM-1, there is no need to account for testing tolerances in the TS or the safety analyses.

Previous safety analyses conservatively included accumulation in the modelling. Accumulation is no longer modeled for spring loaded MSSVs. This approach is acceptable because the valve setpoint is determined by stem motion and setting the valves on steam. This procedure insures the valves will "pop open" at the TS setpoint. Earlier analyses used accumulation to account for valve chatter prior to opening. This conservatism is no longer required with present testing methods.

The existing tolerance of ±1% specified in Technical Specification 3/4.7.1 for steam line safety valve lift settings is based on the design requirements for safety valves specified in ASME Section III, Subsection NC-7614.2. The ±1% tolerance is appropriate for design criteria, but is not appropriate for testing acceptance criteria for the following reasons: a) The ±1% lift setting tolerance currently specified does not take into consideration the service conditions of the safety valves. For safety valves subjected to a constant load for extended periods of time without being cycled, it is common for the valve springs to take a set resulting in a slight increase in the spring rate, until broken loose during the initial test stroke of the valve. ASME Section XI test criteria requires the performance of 2 successive lifts with no adjustments to the

valve lift setting. Due to the valve spring taking a set as described above, the first test lift is commonly found to be slightly out of tolerance and the second and third lifts within tolerance. b) ASME Section XI, Subsection IWV requires safety valves to be tested using OM-1. (Union Electric will adopt the 1989 version of the ASME Code for the next 10 year IST interval, which will begin December 20, 1994. This version of the Code indirectly imposes the 1987 version of OM-1.) OM-1 requires that the testing methodology utilized to test safety valves be accurate to +2/-1%. The +3/-1% tolerance specified by this TS change does not include the testing accuracy.

The ASME Section XI schedule used previously for testing additional valves will continue to be used, except that the criteria for testing additional valves will be +3/-1% of the setpoint instead of ±1%. However, all valves that are tested and found outside the ±1% band will be reset to within ±1%.

Industry operating experience has also demonstrated that a setpoint tolerance for the main steam safety valves of only ±1% results in safety valves frequently failing surveillance tests. Information Notice 86-56, "Reliability of Main Steam Safety Valves," tabulated a number of problems with setpoint drift as reported in various LERs. This information notice discussed the various safety concerns that may be encountered with setpoint drift. Union Electric has considered these concerns in the proposed relaxed tolerance limits. Other plants, such as Trojan, Palisades, Yankee Rowe, Calvert Cliffs, LaSalle, Diablo Canyon, and Wolf Creek have been granted setpoint tolerance relaxations.

As shown below, the proposed tolerance relaxation meets overpressure protection requirements and all ASME code requirements. In addition, evaluation of the FSAR accident analyses affected by the change has demonstrated that the conclusions for these analyses as stated in the FSAR remain valid, and results in no additional operational concerns.

All safety analyses done to support the MSSV tolerance change were performed using WCAP-12910 Rev. 1-A, "Primary Safety Valve Surge Line Loop Clearance Models." Specifically, primary safety valves utilize a TS setpoint of 2500 psia, a ±1% tolerance and +1% setpoint shift. Union Electric calculated a loop seal purge time of 1.15 seconds (using the methodology of WCAP-12910) which was implemented in the analysis as a time delay. It is Union Electric's position that the test equipment tolerance (+2/-1%) will not be accounted for in the TS tolerance because this equipment tolerance is specifically addressed by the ASME Code. Therefore, as long as the testing equipment and methodology meet the +2/-1% tolerance requirements of OM-1, there is no need to account for testing tolerances in the TS or the safety analysis.

with inoperable MSSVs. As such, these changes are conservative and do not impact any accident analysis or involve an unreviewed safety question.

The revision to Bases 3/4.7 reflects changes necessitated by the use of V5 fuel and the plant uprating. These changes supersede the changes submitted in ULNRC-2450 (dated July 30, 1991). This Bases section is also revised to incorporate a change in the methodology used to determine the maximum power level for inoperable main steam safety valves. These changes are conservative in nature and therefore do not impact any accident analysis or involve an unreviewed safety question.

Evaluation

The proposed change to Technical Specifications does not involve a significant hazards consideration because operation of the Callaway Plant with this change would not:

1. Involve a significant increase in the probability of occurrence or the consequences of an accident or malfunction of equipment important to safety previously evaluated in the safety analysis report. The main steam line safety valves are designed to mitigate transients by preventing overpressurization of the main steam system. The proposed change does not alter this design basis. The revised analysis shows that the probability or consequences of all previously analyzed accidents are not changed by increasing the setpoint tolerance of the safety valves. Therefore, there is no increase in the probability of occurrence or the consequences of any accident.

2. Create the possibility of a new or different kind of accident from any previously evaluated in the safety analysis report. There is no new type of accident or malfunction created, the method and manner of plant operation will not change nor is there a change in the method in which any safety related system performs its function. Any main steam safety valve lifting at the extremes of the proposed tolerance will not result in a low lift setpoint that is less than the normal no load system pressure or a high lift setpoint that allows main steam system overpressurization.

3. Involve a significant reduction in a margin of safety. This is based on the fact that no plant design changes are involved and the method and manner of plant operation remains the same. With the increased setpoint tolerance, the main steam safety valves will still prevent pressure from exceeding 110 percent of design pressure in accordance with the ASME code. All FSAR accident analysis conclusions remain valid and unaffected by this change.

Given the above discussions as well as those presented in the Safety Evaluation, the proposed change does not adversely affect or endanger the health or safety of the general public or involve a significant safety hazard.

ATTACHMENT FOUR

SIGNIFICANT HAZARDS EVALUATION

SIGNIFICANT HAZARDS EVAULATION

This amendment application requests a revision to Technical specification (TS) 3.7.1.1 (Tables 3.7-1 and 3.7-2), 2.2 (Table 2.2-1), 3/4.3 (Table 3.3-2), and Bases 3/4.7. These specifications are revised to increase the lift setting tolerance for the main steam safety valves from ±1% to +3/-1%, lower the maximum allowable power levels with inoperable main steam safety valves, and to incorporate the revised methodology for calculating maximum power levels with inoperable main steam safety valves into the Bases.

Background

The function of the main steam line safety valves is to provide overpressure protection, ensuring that the secondary system pressure will be limited to within 110% (1320 psia) of its design pressure (1200 psia) during the most severe anticipated system operational transient. The total relieving capacity for all valves on all steam lines is 113% of the total secondary steam flow.

Revision of the lift setting tolerance to +3/-1% as-found and ±1% as-left will have no effect on the relieving capacity of the safety valves. The change in lift setting tolerance will provide reasonable acceptance criteria taking into account the component service conditions and conservative criteria for the as-left condition of the safety valves. The test equipment tolerance (+2/-1%) will not be accounted for in the TS tolerance because this equipment tolerance is specifically addressed by the ASME Code. Therefore, as long as the testing equipment and methodology meet the +2/-1% tolerance requirements of OM-1, there is no need to account for testing tolerances in the TS or the safety analyses. (This position is also applicable for the primary safety valves.)

Previous safety analyses conservatively included accumulation in the modelling. Accumulation is no longer modeled for spring loaded MSSVs. This approach is acceptable because the valve setpoint is determined by stem motion and setting the valves on steam. This procedure insures the valves will "pop open" at the TS setpoint. Earlier analyses used accumulation to account for valve chatter prior to opening. This conservatism is no longer required with present testing methods.

The existing tolerance of ±1% specified in Technical Specification 3/4.7.1 for steam line safety valve lift settings is based on the design requirements for safety valves specified in ASME Section III, Subseciion NC-7614.2. The ±1% tolerance is appropriate for design criteria, but is not appropriate for testing acceptance criteria for the following reasons: a) The ±1% lift setting tolerance currently specified does not take into consideration the service conditions of the safety valves. For safety valves subjected to a constant load for extended periods of time without being cycled, it is common for the valve springs to take a set resulting in a slight increase in the spring rate, until broken loose during the initial test stroke of the valve. ASME Section XI

test criteria requires the performance of 2 successive lifts with no adjustments to the valve lift setting. Due to the valve spring taking a set as described above, the first test lift is commonly found to be slightly out of tolerance and the second and third lifts within tolerance. b) ASME Section XI, Subsection IWV requires safety valves to be tested using OM-1. (Union Electric will adopt the 1989 version of the ASME Code for the next 10 year IST interval, which will begin December 20, 1994. This version of the Code indirectly imposes the 1987 version of OM-1.)

The ASME Section XI schedule used previously for testing additional valves will continue to be used, except that the criteria for testing additional valves will be +3/-1% of the setpoint instead of ±1%. However, all valves that are tested and found outside the ±1% band will be reset to within ±1%.

Industry operating experience has also demonstrated that a setpoint tolerance for the main steam safety valves of only ±1% results in safety valves frequently failing surveillance tests. Information Notice 86-56, "Reliability of Main Steam Safety Valves," tabulated a number of problems with setpoint drift as reported in various LERs. This information notice discussed the various safety concerns that may be encountered with setpoint drift. Union Electric has considered these concerns in the proposed relaxed tolerance limits. Other plants, such as Trojan, Palisades, Yankee Rowe, Calvert Cliffs, LaSalle, Diablo Canyon, and Wolf Creek have been granted setpoint tolerance relaxations.

As shown below, the proposed tolerance relaxation meets overpressure protection requirements and all ASME code requirements. In addition, evaluation of the FSAR accident analyses affected by the change has demonstrated that the conclusions for these analyses as stated in the FSAR remain valid, and results in no additional operational concerns.

All safety analyses done to support the MSSV tolerance change were performed using WCAP-12910 Rev. 1-A, "Primary Safety Valve Surge Line Loop Clearance Models." Specifically, primary safety valves utilize a TS setpoint of 2500 psia, a ±1% tolerance and +1% setpoint shift. Union Electric calculated a loop seal purge time of 1.15 seconds (using the methodology of WCAP-12910) which was implemented in the analysis as a time delay.

As discussed in the Safety Evaluation, the non-LOCA safety evaluation supports the conclusion that the proposed tolerance of +3 percent for the main steam line safety valves is acceptable. This conclusion is reached based on the assessment that the non-LOCA acceptance criteria are met for this increase in opening setpoints for all the non-LOCA accidents. It is concluded that the tolerances on the main steam line safety valves as given in the Technical Specifications for Callaway Plant may be changed to specify +3/-1 percent.

The LOCA safety evaluation supports the conclusion that the effects of increasing main steam line safety valve tolerances to +3 percent at Callaway Plant do not result in exceeding any design or regulatory limit. Therefore, it is concluded that the proposed technical specification valve tolerance relaxation is acceptable.

The increase in safety valve setpoint tolerance from ± 1 percent to +3/-1 percent has been evaluated with respect to both LOCA and non-LOCA events for impact on the radiological consequences of accidents. There is no impact on the radiological consequences of any accident.

Table 3.3-2 is changed to revise the pressurizer pressure-high response time from 2 seconds to 1 second. This provides margin to expand the main steam safety valve setpoint tolerance to +3/-1%.

The revisions to Table 2.2-1 are made to assess the impact of reducing the high pressurizer pressure safety analysis limit (SAL) from the current value of 2445 psig to 2410 psig. This SAL reduction is needed to ensure acceptable accident analysis results are obtained to accommodate a relaxation of the main steam safety valve setpoint tolerance to $\pm$3/-1%. These changes recognize that older generation Barton transmitters, subject to excessive negative drift, are no longer used in this application. This negative drift accounted for 4.25% of the 4.96% of span Z term. Deletion of this drift term requires that the S term be increased by 1% of span to account for a typical drift allowance. Thus, Z and S are revised to 0.71% span and 2.0% span, respectively. The reduced SAL directly results in a reduced total allowance (TA), i.e. since it reflects the difference between the SAL and the nominal trip setpoint

$$\left(\frac{2410-2385\text{ psig}}{800\text{ psig}/100\%\text{ span}}=3.125\%\text{ span}\right)$$

The decreased TA in conjunction with the increased S term results in a reduced allowable value of 2393 psig.

The revision to Table 3.7-1 (and Bases 3/4.7), utilized the methodology as described in Westinghouse Nuclear Service Advisory Letter 94-001 and Information Notice 94-60, "Potential Overpressurization of Main Steam System." These documents notified utilities of a calculational error in determining the maximum power level for inoperable main steam safety valves. Using the new methodology results in lower allowed power levels with inoperable MSSVs. As such, these changes are conservative and do not impact any accident analysis or involve an unreviewed safety question.

The revision to Bases 3/4.7 reflects changes necessitated by the use of V5 fuel and the plant uprating. These changes supersede the changes submitted in ULNRC-2450 (dated July 30, 1991). This Bases section is also revised to incorporate a change in the methodology used to determine the maximum power level for inoperable main steam

safety valves. These changes are conservative in nature and therefore do not impact any accident analysis or involve an unreviewed safety question.

Evaluation

The proposed change to Technical Specifications does not involve a significant hazards consideration because operation of the Callaway Plant with this change would not:

1. Involve a significant increase in the probability of occurrence or the consequences of an accident or malfunction of equipment important to safety previously evaluated in the safety analysis report. The main steam line safety valves are designed to mitigate transients by preventing overpressurization of the main steam system. The proposed change does not alter this design basis. The revised analysis shows that the probability or consequences of all previously analyzed accidents are not changed by increasing the setpoint tolerance of the safety valves. Therefore, there is no increase in the probability of occurrence or the consequences of any accident.

2. Create the possibility of a new or different kind of accident from any previously evaluated in the safety analysis report. There is no new type of accident or malfunction created, the method and manner of plant operation will not change nor is there a change in the method in which any safety related system performs its function. Any main steam safety valve lifting at the extremes of the proposed tolerance will not result in a low lift setpoint that is less than the normal no load system pressure or a high lift setpoint that allows main steam system overpressurization.

3. Involve a significant reduction in a margin of safety. This is based on the fact that no plant design changes are involved and the method and manner of plant operation remains the same. With the increased setpoint tolerance, the main steam safety valves will still prevent pressure from exceeding 110 percent of design pressure in accordance with the ASME code. All FSAR accident analysis conclusions remain valid and unaffected by this change.

Given the above discussions as well as those presented in the Safety Evaluation, the proposed change does not adversely affect or endanger the health or safety of the general public or involve a significant safety hazard.

ATTACHMENT FIVE

ENVIRONMENTAL CONSIDERATION

ENVIRONMENTAL CONSIDERATION

This amendment application requests a revision to Technical Specification (TS) 3.7.1.1 (Tables 3.7-1 and 3.7-2) 2.2 (Table 2.2-1), 3/4.3 (Table 3.3-2), and Bases 3/4.7. These specifications are revised to increase the lift setting tolerance for the main steam safety valves, lower the maximum allowable power levels with inoperable main steam safety valves, and to incorporate the methodology of calculating maximum power levels with inoperable main steam safety valves into the Bases.

The proposed amendment involves changes with respect to the use of facility components located within the restricted area as defined in 10 CFR Part 20, and changes a surveillance requirement. Union Electric has determined that the proposed amendment does not involve.

1. A significant hazard consideration, as discussed in the Significant Hazards Evaluation of this amendment application;

2. A significant change in the types or significant increase in the amounts of any effluents that may be released offsite;

3. A significant increase in individual or cumulative occupational radiation exposure.

Accordingly, the proposed amendment meets the eligibility criteria for categorical exclusion set forth in 10 CFR 51.22(c)(9). Pursuant to 10 CFR 51.22(b) no environmental impact statement or environmental assessment need be prepared in connection with the issuance of this amendment.