Westinghouse Nuclear Energy Systems

Westinghouse Class 3

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WESTINGHOUSE ANTICIPATED TRANSIENTS WITHOUT TRIP ANALYSIS

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ABSTRACT

The AEC Regulatory Staff licensing position on Anticipated Transients Without Trip (ATWT) is set forth in WASH-1270, "Technical Report on Anticipated Transients Without Scram for Water Cooled Power Reactors." Westinghouse has made extensive studies of reactor protection system reliability for many years.[1, 2, 3, 4]

As a result of these studies, Westinghouse has concluded that the high reliability and functional diversity of the Westinghouse Reactor Protection System make complete failure to trip on demand during an anticipated transient not credible. Thus, Westinghouse believes that ATWT should not be assumed to occur for design purposes.

Nevertheless, to satisfy the position set forth in WASH-1270, anticipated transients were analyzed for Westinghouse PWR's with the unrealistic assumption that a hypothetical, undefined common mode failure prevents reactor trip. These analyses were performed on a generic basis using appropriate parameters representative of operating characteristics of Westinghouse PWR's.

The results show that in all cases the DNB ratio is greater than 1.0, and the peak Reactor Coolant System pressure is below the allowable pressure listed in Appendix C. The radiological consequences calculated for these postulated events are well within the guileline values set forth in 10 CFR Part 100.

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SECTION 1
INTRODUCTION

The reliability of the Westinghouse Reactor Protection System (both relay and solid state type) has been exhaustively analyzed[1, 2, 3] for susceptibility to both random and common mode types of failure. Quantitative results of random failure analysis have shown the system response is controlled by the coincident failure of the two redundant trip circuit breakers to open on loss of voltage to their undervoltage coils. The probability of such a double failure has been estimated to be of the order of 10^{-7} per demand.

In addition, extensive analyses[4] have been performed assuming that multiple failures in redundant instrument channels hypothetically prevented a reactor trip. These studies show that, for all anticipated transients, at least two functionally-diverse reactor trip circuits would trip the reactor before any significant degradation of nuclear safety limits occurs.

This report, and the studies undertaken herein, are not to be understood as agreement by Westinghouse that failure of the reactor protection system is credible. The great care and depth in engineering and quality assurance given to the reactor protection system, coupled with its outstanding experience record, make the consideration of complete failure of this system an unreasonable design condition. The statistical manipulations contained in WASH-1270 show only that based on the existing volume of all types of operating data and a 95-percent confidence level, the unreliability of a reactor protection system tested on a monthly basis is 1×10^{-4} or less; Westinghouse believes that a complete failure of the Westinghouse reactor protection system is several orders of magnitude less probable.

However, in order to safisfy the positions set forth in WASH-1270, Appendix A, Part II.B, Anticipated Transients Without Trip (ATWT) have been analyzed for the Westinghouse PWR. This report sets forth the current methods for ATWT system transient analysis. Calculational results are presented for standard Westinghouse NSS Systems, including reference cases and pertinent sensitivity studies.

In consideration of the low probability of occurrence of ATWT events, the U.S. Atomic Energy Commission has specified [5] that in the analysis of ATWT events all system functions,

including control functions, except reactor trip operate as designed, and that assumed initial conditions and system parameters be considered to be those normally anticipated for the reactor state under consideration.

Accordingly, the analyses contained herein are based on normal operating initial conditions, on nominal plant parameters, and on the assumption that plant systems function normally. The event analyzed is an anticipated transient combined with a non-mechanistic common mode failure preventing control rods from dropping into the core as designed.

Anticipated transients are Condition II events, Faults of Moderate Frequency, as defined by ANSI-N18.2-1973, "Nuclear Safety Criteria for the Design of Stationary Pressurized Water Reactor Plants." For standard Westinghouse PWR's, these events are identified in RESAR, Westinghouse Reference Safety Analysis Report.

The ATWT events that are evaluated in this report include Uncontrolled Rod Cluster Control Assembly Withdrawal, Uncontrolled Boron Dilution, Partial Loss of Forced Reactor Coolant Flow, Startup of an Inactive Reactor Coolant Loop, Loss of External Load, Complete Loss of Normal Feedwater, Station Blackout, Excessive Load Increase, Accidental Depressurization of the Reactor Coolant System and Dropped Rod, all without reactor trip. A Small Line Break in the Reactor Coolant System and Steam Generator Tube Leaks are such minor transients that no protective action is required, and, in any event, are covered by the Accidental Depressurization. Detailed discussions of assumed plant parameters, initial conditions, and equipment operability are presented, and Appendix C, Stress Evaluation of the Reactor Coolant System Boundary, is included.

The results of these studies show that in all reference cases Reactor Coolant System peak pressure does not exceed the allowable pressure listed in Appendix C, the minimum DNB ratio is not less than 1.0, and containment peak pressure does not exceed design pressure. The stress evaluation of all Reactor Coolant System components demonstrates that no impairment of reactor coolant system integrity occurs for these ATWT events. Since the core thermal performance, the volume of Reactor Coolant and secondary fluid released, and the containment pressur transient are all less severe for these ATWT events than for design basis conditions, the radiological consequences of these postulated ATWT events are well within the guideline values set forth in 10CFR Part 100. The radiological consequences for the most limiting ATWT event are reported in Appendix E.

SECTION 2
BASIS FOR ANALYSIS

2-1. CURRENT ATWT ANALYSES METHODS

In recognition of the low likelihood of an anticipated transient occurring without reactor trip upon demand and the large measure of conservatism which accrues from assuming no trip, the analyses contained in this report have been performed based on plant conditions consistent with normal operation at power. The single exception to this normal operating basis is that no dropping or insertion of Rod Cluster Control Assemblies into the reactor is assumed at any time during the event.

All other components, equipment, and systems are assumed to operate normally during the ATWT event provided that:

- Failure of the equipment, component, or system is not the cause of the transient being analyzed;
- The function of the equipment, component, or system is not disabled as a consequence of the transient being analyzed; and
- The probability of failure of the component, equipment, or system is reasonably small during the interval of the transient being analyzed.

Where an operating control band is associated with a parameter, the least favorable value within the band was chosen for each analysis. Instrument or calibration errors were not included. The initial plant power chosen was the least favorable power in the range 0 percent to 100 percent consistent with the nature of the transient being analyzed.

Various control and safety features within the system limit the consequences of a postulated ATWT event. These features fall into two general categories, normal control systems and standby systems. The normal control systems are assumed to be operating at the initiation of the ATWT event. Experience shows that such systems continue to operate reliably during plant transients, and these systems are assumed to continue operating normally for the relatively short times associated with the postulated ATWT events.

The standby features available to mitigate the consequences of plant transients have been designed to operate reliably on demand, and are assumed to function as designed. Typical

reliability analyses for two such systems, the turbine trip, and pressurizer power-operated relief valves, are presented in paragraphs 2-31 and 2-32, respectively.

2-2. ASSUMED PLANT PARAMETERS

2-3. Plant Description

Table 2-1 provides a list of parameters for 2-, 3-, and 4-loop plants. It represents a composite of conservative parameters rather than a particular Westinghouse plant. Use of these typical parameters allows many plants to be bracketed by the reference case analyses. Since the course of the ATWT transients is not strongly affected by the majority of fluid system parameters, the more conservative parameters listed can be incorporated into the reference cases without unduly influencing the results. Where a parameter for an individual plant is not bracketed by these listed parameters, its effect is considered in a sensitivity study.

2-4. Reactor Coolant Flow

Reactor coolant flow is forced through the reactor core and loop piping by fixed speed centrifugal pumps. Flow is constant, depending only upon how many reactor coolant pumps are in operation. For calculational convenience in the ATWT analyses, the thermal-hydraulic design flow was assumed, i.e., 88,500 gpm per coolant loop. This is conservative since design margins in core and loop pressure drops and in pump head ensure that measured flow, including allowance for measurement error, is at least equal to the design flow. Typically, coolant flow is 5 percent, or more, above design.

During the transient, pump cavitation was assumed to occur when the cold leg temperature came within 6°F of saturation. Following cavitation, the flow was calculated using pump and pressure drop characteristics of the Reactor Coolant System. Cavitation of a single-stage centrifugal pump for high pressure fluid will cause a reduction in flow, but not complete flow stoppgae. However, in spite of the fact that this cavitation model is unrealistically conservative, additional refinements in the analytical technique are unwarranted since, in all cases, the most adverse core and reactor coolant system condtions occur prior to cavitation.

2-5. Liquid Relief Discharge Rates

During some postulated ATWT events, the pressurizer fills with liquid due to expansion of the reactor coolant. An analytical model is used to predict the liquid relief rate for the power-operated relief valves and safety valves during these intervals.

TABLE 2-1
PARAMETERS FOR 2-, 3-, AND 4-LOOP PLANTS

Parameters	2-Loop	3-Loop	4-Loop
Core:			
Core power (MWt)	1644	2776	3411
Core length (ft)	12	12	12
Number of assemblies	121	157	193
Reactor Coolant System:			
Total volume (ft^3) including pressurizer and surge line	6230	9600	12,600
Nominal[a] pressure (psia)	2250	2250	2250
Nominal[a] flow (gpm)	178,000	278,400	354,000
Nominal[a] average temperature (°F)	567.3	580.3	584.65
No-load temperature (°F)	547	557	557
Nominal[a] reactor vessel inlet temperature (°F)	535.5	546.6	552.3
Nominal[a] reactor vessel outlet temperature (°F)	599.1	614.0	617.0
Pressurizer:			
Total volume of pressurizer and surge line (ft^3)	1021.3	1436.8	1843.7
Nominal[a] water volume (ft^3)	600	840	1080
Heater capacity (kw)	1000	1400	1800
Maximum spray rate (lbs/sec)	42.6	75.0	87.4
Power-operated relief valve steam flow capacity (lbs/hr) (at 2350 psia)	2-210,000 (each)	2-210,000 (each)	2-210,000 (each)
Safety valve steam flow capacity (lbs/hr) (at 2500 psia)	2-325,000 (each)	3-345,000 (each)	3-420,000 (each)
Power-operated relief valve opening pressure (psia)	2350	2350	2350
Safety valve, start open → full open pressure (psia)	2515 → 2590	2515 → 2590	2515 → 2590
Secondary System:			
Steam generator (SG) type	51	51	51
SG design pressure (psia)	1100	1200	1200
Nominal[a] steam pressure (psia)	750	850	910
No-load steam pressure (psia)	1020	1106	1106
Nominal[a] steam temperature (°F)	510.8	525.2	533.3
Nominal[a] steam flow (lbs/sec)	998/SG	1145/SG	1048/SG
Nominal[a] SG secondary side fluid mass (lbs)	101,600/SG	101,600/SG	101,600/SG
Maximum steam moisture (%)	0.25	0.25	0.25

TABLE 2-1 (cont)
PARAMETERS FOR 2-, 3-, AND 4-LOOP PLANTS

Parameters	2-Loop	3-Loop	4-Loop
Secondary System (cont):			
Nominal[a] feed temperature (°F)	435.8	446.6	439.8
Nominal[a] feed enthalpy (Btu/lb)	414.8	426.6	419.2
Auxiliary feed flow capacity (gpm)	800	1400	1760
Auxiliary feed purge volume (ft^3)	261	500	500
Auxiliary feed water available (gal)	150,000	140,000	170,000
Auxiliary feed enthalpy (Btu/lb)	100	100	100

Note:

[a]Nominal refers to value at rated full power.

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2-6. Fauske Model — One analytical considers metastable flow through the safety valves and a choked flow condition downstream at the entrance to the pressurizer relief tank. The Fauske L/D = 40 approach[6] is used to model downstream choked flow and the Fauske L/D = 0 correlation[6] is used to deal with flow metastability through the safety valves. An iterative approach is used to converge upon a mass discharge rate that gives agreement between the upstream Fauske metastable flow and the downstream choked flow. This discharge rate is then the system water relief capability for a given pressurizer pressure. A graph of mass discharge rate as a function of upstream pressure is given in figure 2-1. These discharge rates represent values which are expected for high pressure liquid relief from the reactor coolant system.

2-7. Homogeneous Equilibrium Model — A homogeneous equilibrium critical flow model applied at the nozzle of the valves predicts mass discharge rates through the valves as a function of upstream fluid temperature and pressure. For the typical downstream piping configuration these homogeneous equilibrium valve discharge rates are independent of downstream choking phenomena.

For the range of pressurizer fluid conditions encountered in ATWT, the homogeneous equilibrium critical flow calculation represents a lower bound to the prediction of mass discharge rates. This position is indicated by a review of applicable experimental data and by consideration of flow phenomena.

2-8. Critical Flow Phenomena — The homogeneous equilibrium critical flow calculation considers an isentropic expansion from upstream reservoir conditions to fluid conditions corresponding to a throat or critical pressure. The fluid at the throat is assumed to have attained thermal equilibrium and no slip is considered between liquid and vapor phases. Critical flow investigations have indicated the occurrence of both slip and a non-equilibrium metastable flow condition. Metastability is particularly significant for the subcooled high pressure reservoir conditions that exist during water discharge for ATWT. This phenomenon is considered specifically by Henry and Fauske[7] for the part of their correlation that deals with subcooled or low quality critical flow. The occurrence of either phenomenon, phase slip or metastability, would increase critical flow rates above the homogeneous equilibrium prediction, and would result in lower peak pressure for transients involving water relief.

2-9. Experimental Data — The homogeneous equilibrium application for prediction of ATWT water discharge may be evaluated by comparison to applicable experimental data and the degree of underprediction of ATWT conditions quantified. In relating such a comparison to the ATWT calculation, both the upstream fluid condition and the discharge pipe geometry

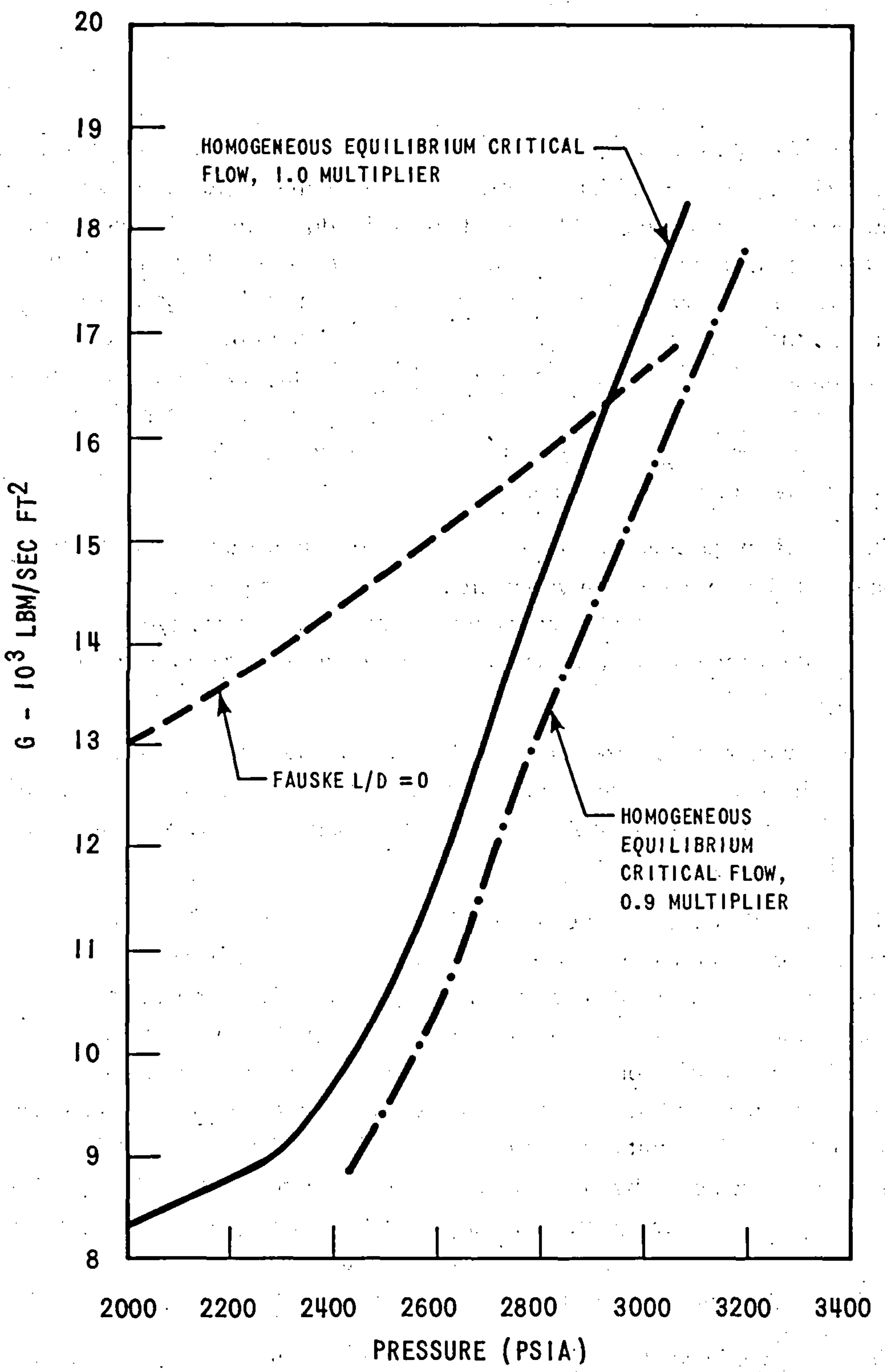

Figure 2-1 Comparison of Fauske L/D = 0 and Homogeneous Equilibrium Water Relief Models (for Fluid Temperature of 665°F)

must be considered. ATWT water discharge occurs for subcooled reservoir conditions with fluid pressure of about 2600 psia and a fluid temperature of about 655°F. The geometry of the valve restriction is that of a short (L/D < 5) pipe. Two significant subcooled critical flow investigations are applicable to the above conditions: that reported by Zaloudek[8] and that by Powell[9].

When the homogeneous equilibrium calculation is applied for Zaloudek's upstream reservoir conditions, a significant underprediction of measured critical flow rates results. A multiplier or discharge coefficient of from 1.25 to 1.4 must be applied to the homogeneous equilibrium predictions to match measured flow rates. The flow rates measured by Zaloudek are from a long pipe of L/D = 20. An even greater degree of flow metastability and higher discharge rates would be expected for an L/D < 5 geometry. Thus, a homogeneous equilibrium underprediction of from 25 to 40 percent is indicated by Zaloudek's data and an even greater margin is expected when flow metastability is considered.

When the critical flow data of Powell are considered, an underprediction of measured flow rates by the homogeneous equilibrium model is also observed. The recorded data indicate that a multiplier on the homogeneous equilibrium calculation greater than 1.0 is required at ATWT fluid conditions. Since Powell's data are taken for L/D < 5 nozzles, the degree of flow metastability existing in the experimental apparatus should be comparable to flow conditions expected in the safety valves.

2-10. Comparison of Homogeneous Equilibrium and Fauske L/D = 0 Models — The graphs in figure 2-1 present a comparison of Fauske L/D = 0 and the homogeneous equilibrium approaches for a fluid temperature of 655°F. Also plotted in figure 2-1 is the relief rate for the homogeneous equilibrium relief model with a 0.9 multiplier. Westinghouse believes that the Fauske L/D = 0 model yields relief rates expected for the reservoir conditions existing during postulated ATWT events. However the unrealistically low rates predicted by the homogeneous equilibrium model with a 0.9 multiplier have been used for the reference case analyses as dictated by the AEC Regulatory Staff. The effect of more representative relief rates is shown in a parametric study in section 4.

2-11. Moderator Temperature Coefficient

An occurrence of ATWT invariably results in an increase in the primary coolant temperature. Since the moderator temperature coefficient in the core is negative, this temperature increase results in an insertion of negative reactivity which terminates the transient. Because of this importance of the moderator temperature coefficient, detailed multi-dimensional calculations were performed.

Table 2-2 shows a comparison of measured and predicted moderator temperature coefficients for ten Westinghouse plants. The comparison was done during the startup physics tests at hot zero power with all rods out and no Xenon. The agreement is quite good as shown by the error analysis of the measured versus predicted values at the bottom of table 2-2. The average error is only -0.12 pcm/°F with a standard deviation of ± 0.226 pcm/°F.

Table 2-2 shows that the moderator temperature coefficient is calculated accurately but it does not show representative values of the moderator temperature coefficient at BOL operating conditions for the following reasons. First, at full power coolant temperatures, the temperature coefficient is more negative by 2 to 3 pcm/°F because the coefficient becomes more negative with increasing coolant temperature. Second, the build up of xenon makes the coefficient still more negative by 5 to 6 pcm/°F because of the decreasing boron concentration. Therefore, at BOL, hot full power, and equilibrium xenon, the temperature coefficient will typically be more negative than -8 pcm/°F. This is the best estimate of the temperature coefficient at BOL. The design basis for Westinghouse reactors is a temperature coefficient of 0 pcm/°F. However, for ATWT it is appropriate to use the best estimate value, since an ATWT event is assumed to occur from normal operating conditions. Later in this section it is shown that for more than 95 percent of the time that a reactor is critical, the temperature coefficient is more negative than -8 pcm/°F.

The moderator density coefficient is used in the neutron kinetics equation instead of the moderator temperature coefficient. The density coefficient is easily derived from the temperature coefficient by using known reactor coolant system parameters, i.e., temperature and pressure. Three-dimensional diffusion theory was used to calculate the density coefficient because of the accuracy needed to account for large enthalpy rises and bulk boiling that could occur in the ATWT transients. The moderator density coefficients are presented in figures 2-2 and 2-3 as a function of moderator density, power level, and boron concentration. These results are typical for a 4-loop, 17 x 17 core plant and demonstrate the methods used for all ATWT analyses.

Figure 2-2 shows the density coefficient as a function of moderator density with power level as a parameter. The coefficient varies with power because a change in the enthalpy rise in the core results in different axial power shapes.

Figure 2-3 shows the density coefficients as a function of moderator density with boron concentration as a parameter. The boron concentration is the major factor affecting the density coefficients. The reason for this is that the density coefficient is the effect on reactivity of changes in the moderator density. For example, as the density decreases, moderation of neutrons by the water becomes less and the reactivity of the core becomes less. But also as

TABLE 2-2

VERIFICATION OF TEMPERATURE COEFFICIENT MODEL USING STARTUP PHYSICS TESTS FROM CYCLE 1 AT HOT ZERO POWER, ALL RODS OUT, AND NO XENON

Plant[a]	Measured Value (pcm/°F)	Predicted Value (pcm/°F)	M-P (pcm/°F)	Conditions[b]
2L-1	-1.1	-1.1	0.0	D at 184
2L-2	-1.2	-0.9	-0.3	ARO
2L-3	-1.79	-1.99	0.2	D at 155
2L-4	-1.71	-1.91	0.2	D at 196
2L-5	-1.66	-1.56	-0.1	ARO
3L-1	-0.5	-0.25	-0.25	D at 160
3L-2	-0.3	-0.2	-0.1	D at 184
3L-3	-0.5	-0.2	-0.3	D at 182
3L-4	0	0	0	ARO
3L-5	-0.4	0.1	-0.5	D at 179

$\bar{x}$ = -0.12 pcm/°F

σ^2 = 0.05

σ = 0.226 pcm/°F

a Data for five 2-loop and five 3-loop plants presented

b D Bank position in steps withdrawn

the density of the water decreases, the amount of boron/cm^3 decreases which increases reactivity. The trade-off between these two opposing effects results in the magnitude of the coefficient.

Because the density coefficient is the change in reactivity as water density varies, changes within the fuel pin like xenon and burnup should have little effect on the coefficients. Test calculations show this to be true. They do have indirect effects in that they lead to adjustment of the boron concentration which strongly affects the density coefficient.

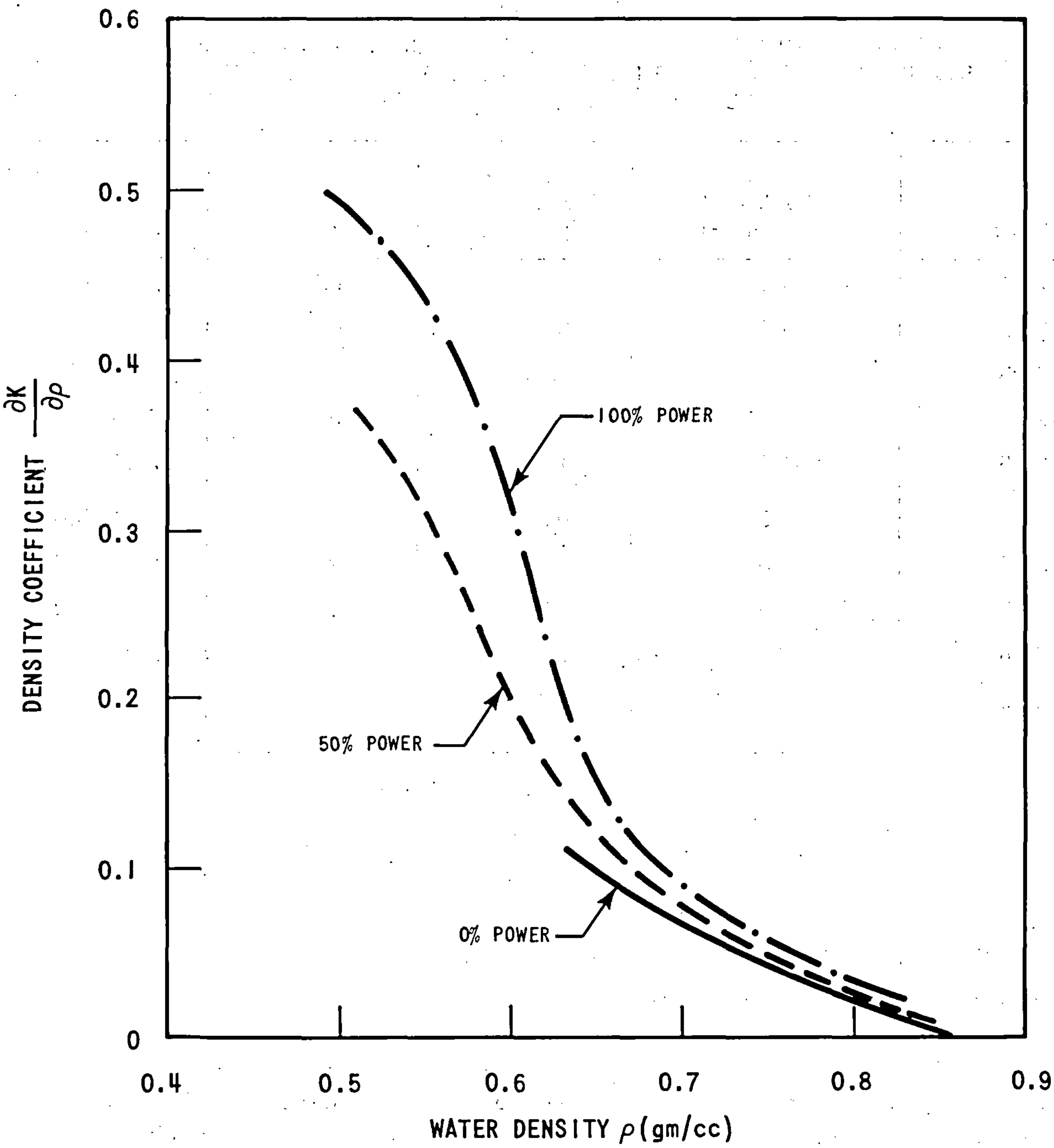

Figure 2-2 Density Coefficient as a Function of Water Density and Power (900 ppm Boron)

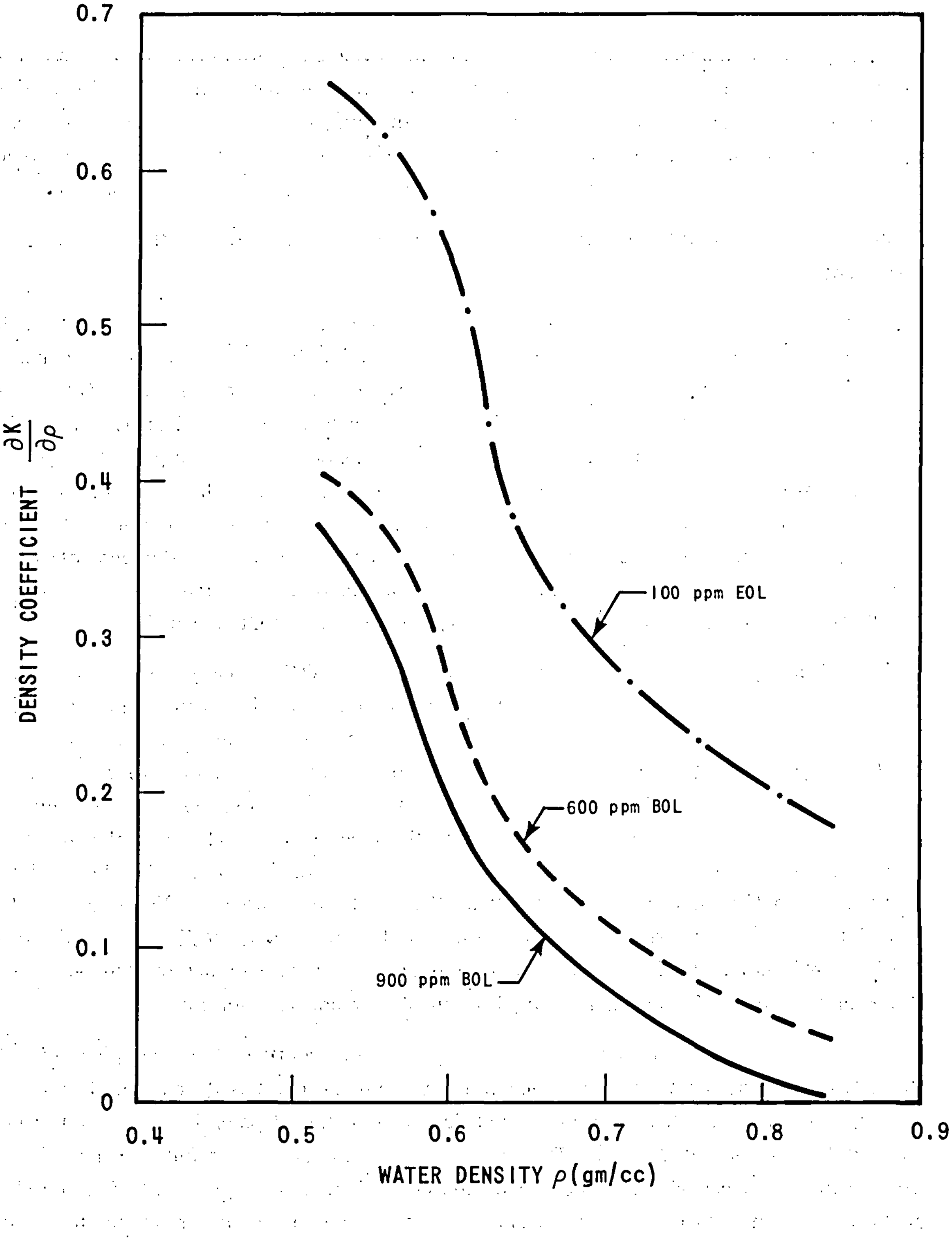

Figure 2-3 Density Coefficient as a Function of Water Density and Boron (50% Power)

The change in the density coefficient between full power equilibrium xenon and no xenon is due to the resulting adjustment of boron concentration. The change in the density coefficient between BOL and EOL as shown in figure 2-3 is due mainly to the boron concentration change. Large burnup accumulations (~10,000 MWD/MTU) do affect the density coefficient but this will increase the density coefficient which is beneficial to an ATWT ananlysis.

Changes in reactor coolant pressure are accounted for directly by use of the density coefficient.

One effect of an increase in pressure at normal hot full power operating conditions would be a decrease in the subcooled boiling void fraction which would result in a reactivity increase. This effect is implicitly accounted for in the density coefficient because the coefficient is plotted as a function of water density. The effect is small in any case, because the void fraction at hot full power is small (slightly less than 0.5 percent for a typical 17 x 17 design) and the density coefficient is small at BOL. The following example illustrates the magnitude of the pressure, void fraction effect. A 100 psi increase in the pressure at normal hot full power operation conditions reduces the average core void fraction from 0.5 percent to 0.43 percent. This change in the void fraction by itself would result in a reactivity insertion of 0.004%$\Delta\rho$. The effect is small since the density coefficient at BOL is small.

2-12. **Density Coefficient Applicability** — For generic ATWT analyses, it is appropriate to select nuclear parameters that are applicable as bounding values for normal operating states. Therefore, design parameters which bound all possible operating states are not used in the ATWT analysis. Instead, values which bound all probable operating states are used. The density coefficient for a 17 x 17 4-loop plant is an example of this philosophy. The following shows that for more than 95 percent of the time that the reactor is critical during the 40-year life of a plant, the density coefficient used is conservative. To do this, it will be shown that the temperature coefficient is more negative than -8 pcm/°F for more than 95 percent of the time that the reactor is critical. A temperature coefficient of -8 pcm/°F corresponds to a density coefficient of 0.065/gm/cm^3 for a plant with an average moderator temperature of 586°F and is typical for plants at BOL, hot full power and equilibrium xenon.

Figure 2-4 shows the as-calculated moderator temperature coefficient for a typical 17 x 17 plant. (Design basis temperature coefficient for this typical plant is 0 pcm/°F.) If the reactor were operated at hot-full power and equilibrium xenon, the -8 pcm/°F criteria would be satisfied 100 percent of the time. The dashed line represents the hot full power coefficient with no xenon. It can also be taken to be the coefficient at zero power because the change in the coefficient with power is small and the change due to moderator temperature change is already accounted for because the coefficient is a function of moderator density. Thus,

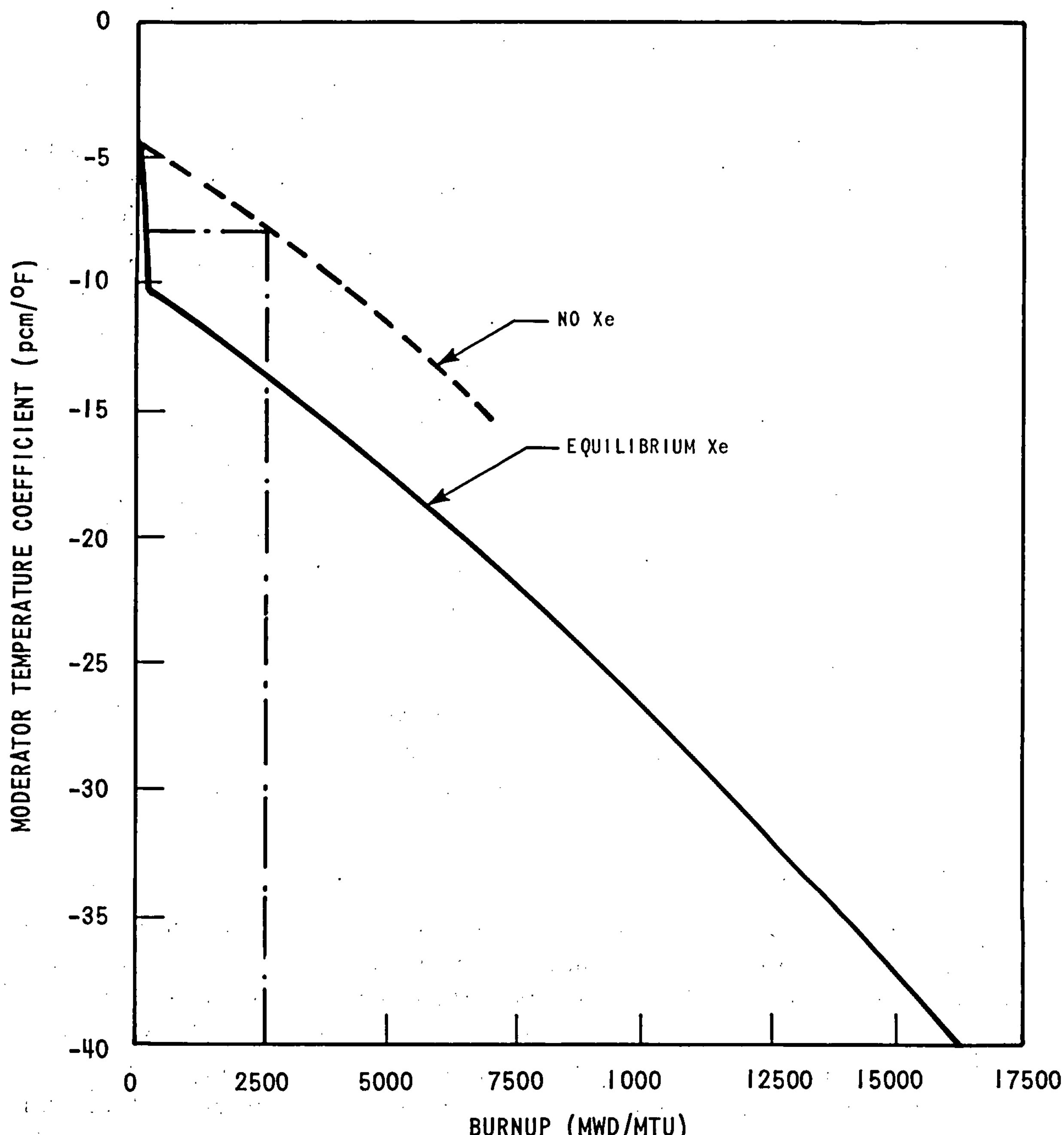

Figure 2-4 Hot Full Power Temperature Coefficient During Cycle I for Typical 17 x 17 4-Loop Plant at the Critical Boron Concentration

the temperature coefficient at some power level and burnup can be estimated by interpolating between the solid and dashed curves in figure 2-4.

Table 2-3 shows the fraction of rated power that various reactors were operating at during their first cycle of operation. Table 2-4 shows the same kind of data for reload cycles. The tables do not go beyond 2000 MWD/MTU because the -8 pcm/°F criterion is satisfied even at zero power beyond this burnup. Table 2-5 shows the average values of tables 2-3 and 2-4 along with the corresponding values of the moderator temperature coefficient which was determined from figure 2-4. Table 2-6 presents the calculation which shows that the -8 pcm/°F criterion is satisfied 97 percent of the time. This is done by calculating the percent of time that the criterion is not satisfied and subtracting from 100 percent. In these calculations the burnup intervals in which the -8 pcm/°F criterion is not satisfied have been divided by the average power in the interval in order to convert burnup into units of time.

This estimate is conservative for several reasons. First, no credit was taken for rod insertion. If power is reduced by rod insertion instead of boron insertion (rod insertion being a more typical operation), the temperature coefficient will not become less negative as postulated in figure 2-4. Second, no credit is taken for the fact that the temperature coefficient in reload cycles is typically lower than for the first cycle. Third, at times when the criterion is not satisfied, the reactor is at part power and the consequences of ATWT are less severe.

2-13. Doppler Effects

Figure 2-5 shows the Doppler defect as a function of power level at BOL. Figure 2-6 shows the Doppler temperature coefficient as a function of temperature at BOL. This is used to adjust the Doppler defect for changes in core temperature with power level. These two figures are typical for Westinghouse PWR plants.

2-14. Inserted Rod Worth

The inserted rod worth during constant axial offset operation (which is expected to be the standard operating mode for 17 x 17 plants) will typically be less than 0.3%$\Delta\rho$ plus the power defect at BOL. For inserted rod worth, operation with part length rods inserted is the limiting mode of operation. In this mode of operation, D bank is used to offset the power defect and the part length rod bank is used to control the axial offset. Thus, at a part power level, D bank will be inserted enough to compensate for the power defect plus some additional insertion to account for the part length rod position change and other effects which will typically not total more than 0.3%$\Delta\rho$.

2-15. Core Peaking Factors

The peaking factors used to determine the minimum DNBR for the ATWT analyses were the same as those used in FSAR analyses except that the uncertainty associated with $F^N_{\Delta H}$ was

TABLE 2-3
FRACTION OF RATED POWER AS A FUNCTION OF
BURNUP FOR CYCLE 1

Burnup MWD/MTU	Plant[a]								
	A1	B1	C1	D1	E1	F1	G1	H1	I1
100	0	0	0	0	0	0	0	0	0
200	0	0	0.2	0	0	0.4	0	0.4	1
300	0.5	0.7	0.2	0.5	0	0.4	0.2	0.4	0.5
400	0.5	0.8	0.2	0.5	0.6	0.4	0.6	0.4	0.5
500	0.5	0.8	0.2	0.5	0.5	0.4	0.6	0.4	0.5
600	0.7	0.8	0.2	0.5	0.5	0.7	0.7	0.4	0.5
700	0.7	0.8	0.2	0.7	0.7	0.7	0.7	0.4	0.5
800	0.5	0.8	0.2	0.5	0.7	0.7	0.7	0.7	0.8
900	0.7	0.9	0.2	0.5	0.7	0.7	0.7	0.7	0.8
1000	0.9	0.9	0.2	0.5	0.7	0.7	0.8	0.7	0.8
1100	0.9	0.9	0.2	0.5	0.7	0.7	0.8	0.7	0.8
1200	0.9	0.9	0.9	0.5	0.7	0.6	0.8	0.7	0.8
1300	0.9	0.8	0.9	0.5	0.7	0.6	0.8	0.7	0.8
1400	0.9	0.8	0.9	0.5	0.7	0.6	0.8	0.7	0.8
1500	0.9	0.8	0.9	0.5	0.7	0.8	0.8	0.7	0.6
1600	0.6	0.8	0.9	0.5	0.7	0.8	0.8	0.7	0.6
1700	0.8	0.8	0.9	0.5	0.7	0.8	0.8	0.7	0.6
1800	0.8	0.9	0.9	0.9	0.9	0.8	0.8	0.7	0.6
1900	0.8	0.9	0.9	0.9	0.9	0.8	0.8	0.7	0.6
2000	0.8	0.9	0.9	0.9	0.9	0.8	0.8	0.7	0.6

a Plant A1 refers to plant A for cycle 1,
plant B1 refers to plant B for cycle 1, etc.

TABLE 2-4
FRACTION OF RATED POWER AS A FUNCTION OF BURNUP FOR RELOADS

Burnup MWD/MTU	Plant[a]													
	A2	A3	A4	J2	K2	K3	K4	C2	D	D3	L2	M2	I2	I3
100	0	0	0	0	0.5	0.4	0.5	0.7	0.5	0.5	0.5	0	0.7	0.9
200	1	0.5	0.7	0.9	0.5	0.4	1	0.7	0.6	0.5	0.8	0.7	0.7	0.9
300	1	0.5	0.7	0.9	0.8	0.6	1	0.7	0.6	0.5	0.8	0.7	0.7	0.9
400	1	0.5	0.8	0.9	0.8	0.7	1	0.7	0.6	0.5	0.8	0.7	0.7	0.8
500	1	0.5	0.8	0.9	0.8	0.7	1	0.7	0.8	0.7	0.8	0.9	0.7	0.8
600	1	0.7	0.8	0.9	0.9	0.7	1	0.7	0.8	0.7	0.8	0.9	0.7	0.8
700	1	0.7	0.8	0.9	0.9	0.7	1	0.7	0.9	0.7	0.8	0.9	0.7	0.8
800	1	0.7	0.8	0.9	0.9	0.7	1	0.7	0.9	0.7	0.8	0.6	0.7	0.8
900	1	0.7	0.8	0.9	0.9	0.9	1	0.7	0.9	0.7	0.8	0.9	0.7	0.8
1000	1	0.9	0.8	0.9	0.9	0.9	1	0.7	0.9	0.7	0.8	0.9	0.7	0.9
1100	1	0.9	0.8	0.9	0.6	1	1	0.7	0.9	0.7	0.8	0.9	0.7	0.9
1200	1	0.9	0.8	0.9	0.9	1	1	0.7	0.9	0.7	0.8	0.9	0.7	0.9
1300	1	0.9	0.8	0.9	0.9	1	1	0.7	0.9	0.7	0.8	0.9	0.7	0.9
1400	1	0.9	0.8	0.9	0.9	1	1	0.7	0.9	0.7	0.8	0.9	0.7	0.9
1500	1	0.8	0.8	0.9	0.9	1	1	0.7	0.9	0.5	0.8	0.9	0.7	0.9
1600	1	0.8	0.8	0.9	0.9	1	1	0.7	0.9	0.5	0.8	0.9	0.7	0.9
1700	1	0.8	0.8	0.9	0.9	1	1	0.7	0.9	0.5	0.8	0.9	0.7	0.9
1800	1	0.8	0.8	0.9	0.9	0.9	0.7	0.7	0.9	0.5	0.8	1	0.7	0.8
1900	1	0.9	0.8	0.9	0.5	0.9	0.7	0.9	0.9	0.8	0.8	1	0.7	0.8
2000	1	0.9	0.8	0.9	0.5	0.9	0.7	0.9	0.9	0.8	0.8	1	0.7	0.8

a Plant A2 refers to plant A for cycle 2, plant A3 refers to plant A for cycle 3, etc.

TABLE 2-5

AVERAGE FRACTION OF RATED POWER AND MODERATOR TEMPERATURE COEFFICIENT AS A FUNCTION OF BURNUP FOR CYCLE 1 AND RELOAD CYCLES

Burnup MWD/MTU	Average Fraction of Rated Power Cycle 1	Moderator Temperature Coefficient (pcm/°F)	Average Fraction of Rated Power Reload Cycles	Moderator Temperature Coefficient (pcm/°F)
100	0	-5	0.3	-6
200	0.2	-5	0.7	-8
300	0.4	-6	0.7	-8
400	0.5	-7	0.7	-9
500	0.5	-7	0.8	-9
600	0.5	-7	0.8	-9
700	0.5	-8	0.8	-10
800	0.6	-8	0.8	-10
900	0.6	-8	0.8	-10
1000	0.7	-9	0.8	-10
1100	0.7	-9	0.8	-11
1200	0.7	-10	0.9	-11
1300	0.7	-10	0.9	-11
1400	0.7	-10	0.9	-11
1500	0.8	-10	0.8	-11
1600	0.7	-10	0.8	-11
1700	0.8	-10	0.8	-11
1800	0.8	-11	0.8	-11
1900	0.8	-11	0.8	-11
2000	0.8	-11	0.8	-11

TABLE 2-6

PERCENT OF TIME THAT THE MODERATOR TEMPERATURE COEFFICIENT IS LESS NEGATIVE THAN -8 pcm/°F

$$\text{Cycle 1: } \frac{(600/0.35)}{(14500/0.8)} \times 100 = 9.5\%$$

$$\text{Reload Cycles: } \frac{(100/0.3)}{(10500/0.9)} \times 100 = 2.8\%$$

$$\text{Total: } \frac{9.5 + 39 \times 2.8}{40} = 3.0\%$$

Therefore, percent of time more negative than -8 pcm/°F = 97%

not included. A value of 1.435 was used for $F^N_{\Delta H}$. Calculations indicate that 1.435 represents an upper bound to the radial hot channel power over the entire fuel cycle. A chopped cosine with a peak-to-average value of 1.55 was used as the axial power shape for DNB calculations. Transient peaking factors were determined from multidimensional nuclear calculations using system statepoints. These analyses verified the conservatism of the DNBR calculations.

2-16. Decay Heat

For many of the postulated ATWT events, decay heat determines the equilibrium core thermal output that is approached after the fission power output ceases. The decay heat model used for the ATWT analyses contained in this report is based on the ANS finite irradiation decay heat method described in ANS 5.1. This approach is conservative since the ANS finite irradiation decay heat method is based on a minimum irradiation time of 8000 hours (about one year) in the newest core region, while ATWT thermal transients analyzed assume beginning of core life conditions (in order to predict the most severe transient). Thus the decay heat prediction based on 8000 hours of operation overestimates the decay heat expected at beginning of life.

2-17. OPERABLE PLANT FEATURES

2-18. Operational Systems

The following systems were assumed operational in the ATWT analyses.

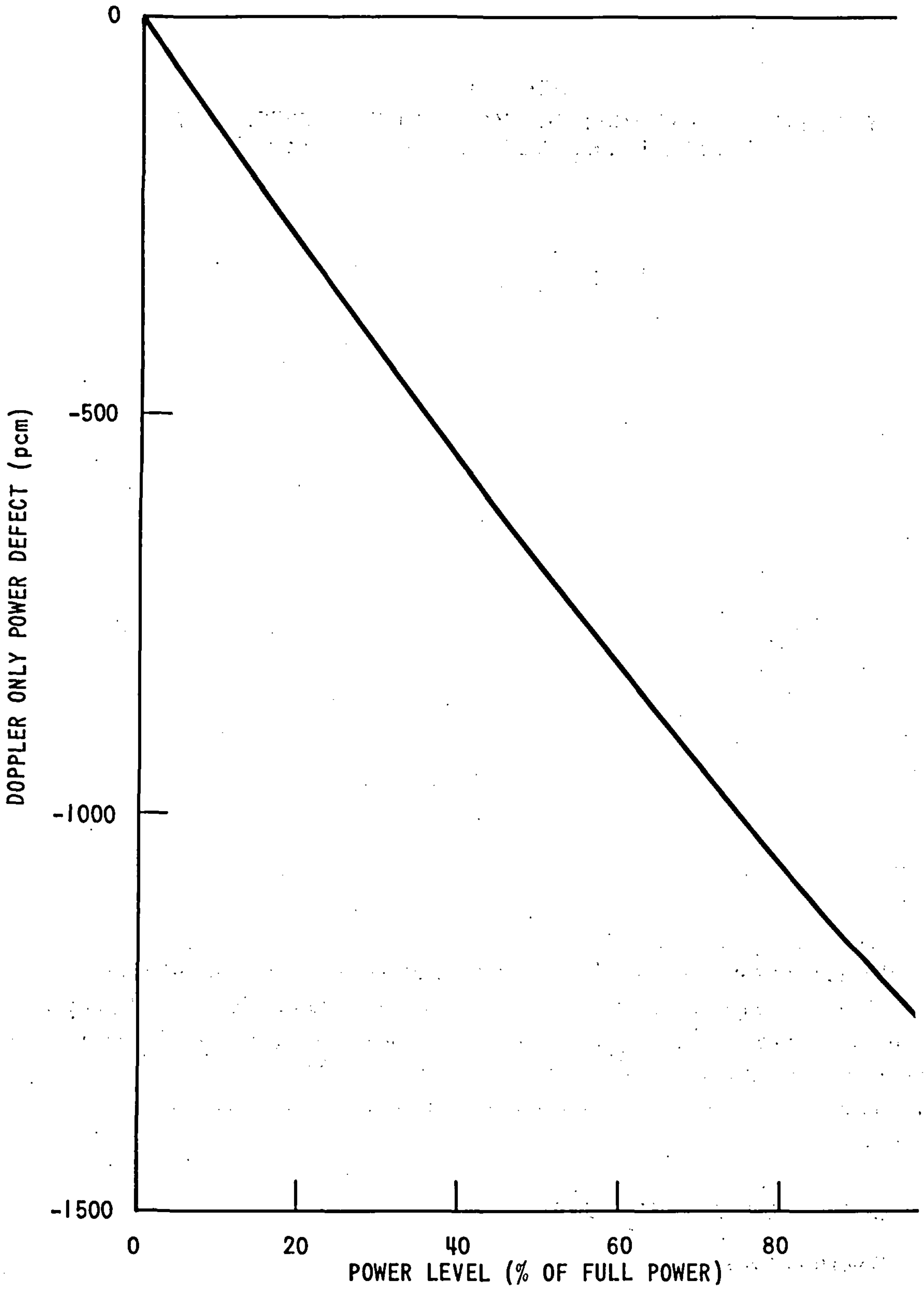

Figure 2-5 Doppler Only Power Defect BOL, Cycle 1 for Typical 4-Loop Plant

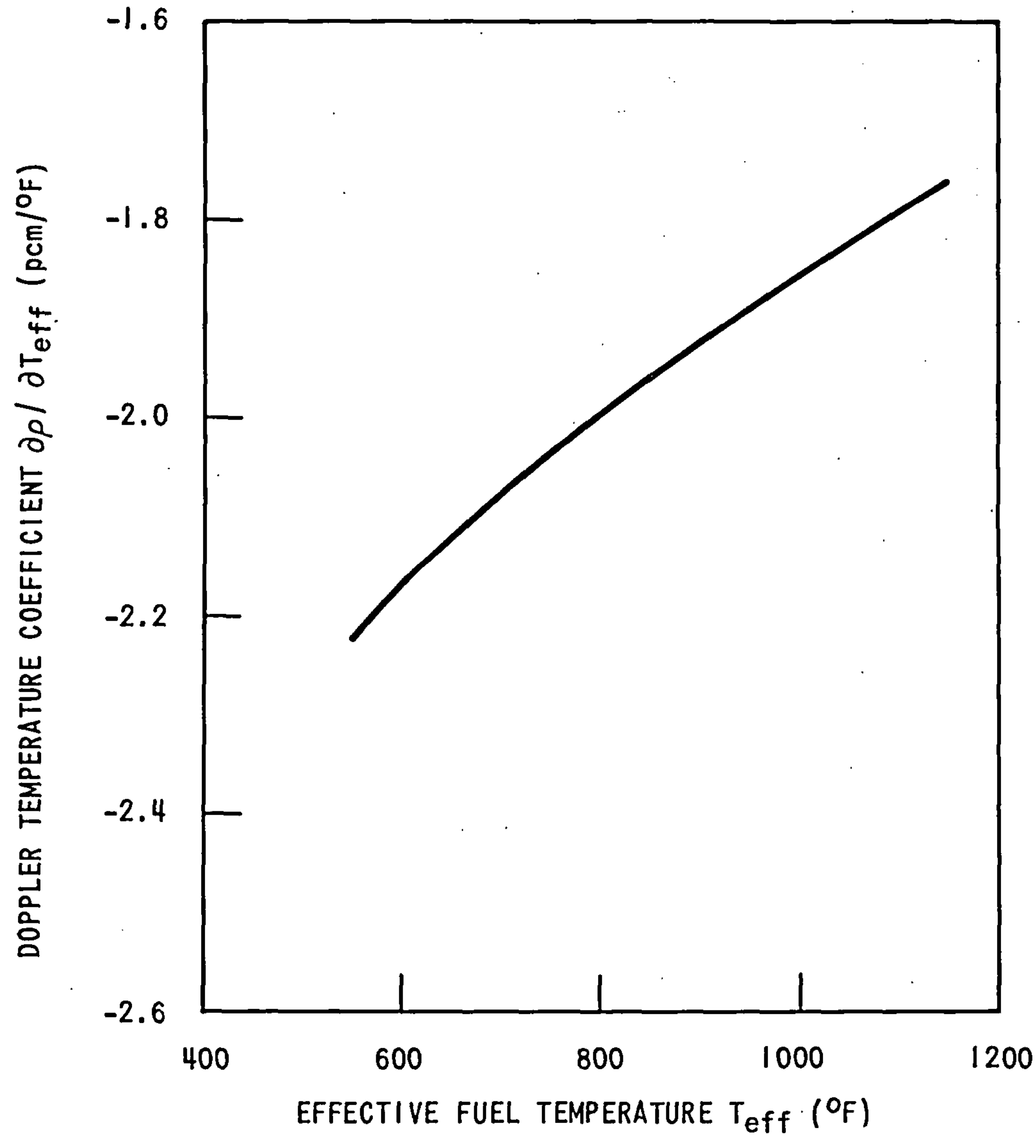

Figure 2-6 Doppler Temperature Coefficient at BOL Cycle 1 for Typical 17 x 17 4-Loop Plant

2-19. Pressurizer Pressure Control — The pressurizer control system is designed to maintain the pressurizer pressure at its design value, typically 2250 psia. If pressure increases, two separate, automatically controlled spray valves open to discharge water at cold leg temperatures into the steam space. The maximum design flows of the spray valves for the ATWT analyses are given in table 2-1. If pressurizer pressure decreases, constant output and proportional heaters are actuated. The total heater capacity is also given in table 2-1.

2-20. Pressurizer Level Control — Pressurizer level is also a controlled parameter. The water volume varies from 450 ft^3 at no load to 1080 ft^3 at full load for a 4-loop plant. Since pressurizer level control is relatively slow, its beneficial effect in maintaining level was neglected in the transient analyses.

2-21. Feedwater Control — During normal plant operation feedwater flow is automatically adjusted by a control valve that is controlled on the basis of feedwater flow, steam flow out of the steam generators, and steam generator water level.

2-22. Turbine Control — During normal plant operation the steam flow to the turbine is dependent on turbine demand and any changes in steam generator secondary side pressure are compensated for by automatic opening or closing of the turbine control valve. This valve is approximately 95 percent open at full power operation.

2-23. Automatic Rod Control and Reactor Coolant Average Temperature Control — Automatic rod control was not assumed operational during the ATWT events, since one of the guidelines for these analyses was no trip or rod insertion. However, prior to the initiation of the ATWT event, it is assumed that the rod control system is operating normally, controlling the average temperature (i.e., the average temperature of the primary side). The average temperature is programmed to be controlled as a linear function of reactor power between zero and 100 percent load; however, a control deadband of ± 1-1/2°F is associated with the average temperature. The initial value of the average temperature for the ATWT analyses was taken to be the least favorable value within the control deadband for the assumed initial power.

2-24. Standby Systems

During normal operation, the following systems are ready to operate if called upon. The effects of these systems were included in the ATWT analyses.

2-25. Turbine Trip — A turbine trip is initiated by any reactor trip signal listed in table 2-7, or directly by a high-high steam generator level. However, for the ATWT reference case analyses, turbine following a reactor trip was assumed only after several trip signals were generated in the Loss of Feed event. Turbine trip was part of the initiating sequence in the Loss of Load event, and resulted as a direct consequence of the Station Blackout event. Turbine trip was not assumed in any of the other transients.

TABLE 2-7
TRIP FUNCTIONS

Trip Function	Actuating Signals	Criteria	Degree of Protection
Trip reactor upon complete loss of reactor coolant flow	Undervoltage; RCP breaker position	ANS PWR ANS 4.1	No core damage
Trip reactor upon complete loss of flow in one or more reactor coolant loops	Flow sensor	ANS PWR ANS 4.1	No core damage
Trip reactor upon partial loss of reactor coolant flow	Frequency sensor	ANS PWR ANS 4.1	No core damage for frequency decreasing at rates below maximum credible rate (usually 4 Hz/sec)
Trip reactor upon RCS overpressurization	Pressure sensor	ANS PWR ANS 4.1	No core damage; no loss of function of any barrier to the escape of radioactive products
Trip reactor upon RCS depressurization	Pressure sensor	ANS PWR ANS 4.1	No core damage
Trip reactor upon approach to DNB (power operation)	Power Range High Neutron Flux; Over-temperature ΔT (temperature and pressure sensors, excore ion chambers)	ANS PWR ANS 4.1	No core damage
Trip reactor upon approach to kw/ft limit (power operation)	Power Range High Neutron Flux; Over-power ΔT (temperature sensors, excore ion chambers)	ANS PWR ANS 4.1	No core damage
Trip reactor upon turbine trip	Auto-stop oil pressure switches, turbine stop valve position sensors		No actuation of primary or secondary safety valves; limit severity of transient occurring with a relatively high frequency
Trip reactor upon pressurizer high water level	Level sensors; differential pressure sensors		Prevent water solid RCS at power; no water relief through pressurizer relief or safety valves
Trip reactor upon loss of heat sink	Steam generator level sensors (actually differential pressure sensors); feedwater flow and steam flow sensors	ANS PWR ANS 4.1	No core damage; no loss of function of any barrier to the escape of radioactive products; no water relief through pressurizer relief or safety valves; minimizes required auxiliary feed pump sizes; maximizes time for operator action following feed pipe break; minimizes steam generator thermal shock for loss of feed or feed pipe break
Trip reactor on operator judgment	Control board button or switch	ANS PWR ANS 4.1	Back-up trip
Trip reactor on SIS actuation	SI signal	ANS PWR ANS 4.1	No core damage

TABLE 2-7 (Cont)
TRIP FUNCTIONS

Trip Function	Actuating Signals	Criteria	Degree of Protection
Trip reactor upon rod ejection	Neutron Flux sensors	ANS PWR ANS 4.1	Minimize core damage
Trip reactor upon rod bank drop	Neutron Flux sensors	ANS PWR ANS 4.1	No core damage
Trip reactor on approach to DNB or kw/ft limit (startup operation)	Source and Intermediate range neutron flux sensors	ANS PWR ANS 4.1	No core damage

2-26. Pressure Relieving Devices — If pressure continues to increase faster than the reducing effect of pressurizer spray, the pressurizer power operated relief valves open. The setpoint of these valves is 2350 psia. The relieving capacities for these valves are given in table 2-1. Two or more relief valves are available to reduce pressure. If pressure continues to increase beyond 2350 psia, the pressurizer is equipped with three spring-loaded safety valves with a set pressure of 2500 psia. (For calculational simplicity, these valves were assumed to begin opening at 2515 psia and to be fully open at 2590 psia.)

The steam flows listed in table 2-1 were used in the ATWT analyses. For the transients which cause the pressurizer to fill and relieve water through the valves, the homogeneous equilibrium model with a 0.9 multiplier discussed in paragraph 2-6 was used to determine the water relief rate as a function of pressure.

2-27. Steam Dump Control — The steam dump is actuated following turbine trip to remove stored energy and core decay heat from the system without actuating the steam generator safety valves. A 40 percent steam dump capacity was used in the ATWT analyses.

2-28. Auxiliary Feedwater System — The auxiliary feedwater system is actuated on low-low water level in the steam generators, by loss of offsite power, by a safety injection signal, or by a manual start signal. The total auxiliary feedwater capacity for 2-, 3-, and 4-loop plants used in the ATWT analyses are given in table 2-1. In each case these flow rates represent a lower bound for the plants covered by the generic analyses, and therefore guarantee conservatism. After actuation of auxiliary feedwater, the 440°F water in the feedwater lines must be purged before the colder auxiliary feedwater enters the steam generator. The volume to be purged is dependent upon the plant and the number of loops. Purge volumes used in the ATWT analyses for 2-, 3-, and 4-loop plants are listed in table 2-1. The ATWT analyses assume that full auxiliary feedwater flow is reached 36 seconds after an actuation signal occurs. Plant data indicates this is a conservative value.

2-29. Safety Injection System — Safety injection is actuated by a manual signal from the operator, by a low pressurizer pressure signal (coincident with a low pressurizer level signal on some plants), or by a high containment pressure signal. If any of these signals are present, highly borated water (~20,000 ppm) is pumped into the Reactor Coolant System. The borated water increases the reactivity shutdown margin.

2-30. Chemical and Volume Control System — The chemical and volume control system provides for normal makeup for the reactor coolant system. However, it is also available to add borated water to the primary system by manual operator action. Credit was not taken for chemical and volume control system makeup during the first 600 seconds of the ATWT

transients. However, this system provides an additional shutdown mode available to the operator.

2-31. Reliability Analysis

The results of reliability analyses for two standby features, a typical power-operated relief valve system and a typical turbine trip function, are presented below to demonstrate the typically high reliability of nuclear plant components. The failure rates for components used in these analyses are taken from various government and industry sources. Where reference values included modes of failure which were not of concern for the application involved, a value was selected using engineering judgement and the closest item available in the literature.

2-32. Turbine Trip — Turbine trip is automatically initiated by any reactor trip, safety injection, high-high steam generator level, manual action, and other signals associated with the turbine or generator. When the trip signal is initiated by the appropriate switch or relay contacts, solenoids are energized providing parallel redundant dumping of control oil to shut the turbine stop valves and control valves.

There are several variations of turbine inlet valving. Figure 2-7 shows one type of turbine inlet valving scheme. Steam is supplied to the high pressure turbine by four lines, each containing a stop valve and a control valve.

Figure 2-8 is a simplified reliability block diagram for turbine trip. Table 2-8 summarizes the probabilities associated with failures which could result in at least one of the steam inlet lines to the turbine remaining open when a turbine trip has been called for. The conditional probability that any steam line remains open following receipt of the trip signal is $\sim 4.7 \times 10^{-8}$ per demand. With other valving arrangements, this value may vary by an order of magnitude, but with any combination the probability of failure is negligible.

2-33. Power-Operated Relief Valves — The typical 4-loop plant is equipped with two power relief valves set to open at 2350 psia. Figure 2-9 is a simplified reliability block diagram for this system. For valve operation to occur, both the control function and the interlock function of the system must be satisfied. The control function of the valve orders the valve open on a high pressure signal from the pressurizer pressure channel selected on the Channel Selector Switch.

The Proportional - Integral - Derivative Controller shown in the circuitry for power-operated relief valve #1 (PRV), figure 2-9, provides a feedback control system for modulated control of pressurizer heaters and spray, and on-off control for the backup heaters and PRV #1.

TABLE 2-8
TURBINE TRIP FAILURE PROBABILITIES

A. Failures Contributing to No-Control Oil Dump

Train A

Input Contact	2×10^{-6}
Power Supply	1×10^{-5}
Backup Turbine Autostop Trip Solenoid and Valve	2.4×10^{-5}
	3.6×10^{-5}

Train B

Input Contact	2×10^{-6}
Power Supply	1×10^{-5}
Turbine Autostop Trip Solenoid and Relay Valve	3.5×10^{-5}
	4.7×10^{-5}

P_1 = P (No Oil Dump) = $(3.6 \times 10^{-5})\ (4.7 \times 10^{-5}) = 1.7 \times 10^{-9}$

B. Failure of Governing Emergency Trip Valve and Any Stop Valve, Given That Control Oil Has Been Dumped

Trip Pilot Valve Mechanical Failure	7×10^{-6}
Stop Valve Mechanical Failure	2.7×10^{-5}
P_2 = P (Stop Valve Not Shut) =	3.4×10^{-5}

P_3 = P (One of Four Stop Valves Not Shut) = $4(3.4 \times 10^{-5}) = 1.4 \times 10^{-4}$

P_4 = P (Governing Emergency Trip Valve Mechanical Failure) = 1.1×10^{-4}

P (3 and 4) = $P_3 \times P_4 = 1.5 \times 10^{-8}$

C. Failure of One of Four Pairs, Control Valve and Stop Valve, Given That Control Oil Is Dumped, and Governing Emergency Trip Valve Functions Normally

P_5 = P (Control Valve Mechanical Failure) = 2.2×10^{-4}

P (2 and 5) = $P_2 \times P_5 = 7.5 \times 10^{-9}$

P_5 = P (One of Four Pairs Not Shut) = $4\ (P_2 \times P_4) = 3 \times 10^{-8}$

TABLE 2-8 (cont)
TURBINE TRIP FAILURE PROBABILITIES

Total: Combined Probability That One or More Steam Inlet Lines Remains Open

$$P\ (\text{No Trip}) = P_1 + (P_3 \times P_4) + 4\ (P_2 \times P_4)$$

$$= 1.7 \times 10^{-9} + 1.5 \times 10^{-8} + 3 \times 10^{-8}$$

$$P\ (\text{No Trip}) = 4.7 \times 10^{-8}$$

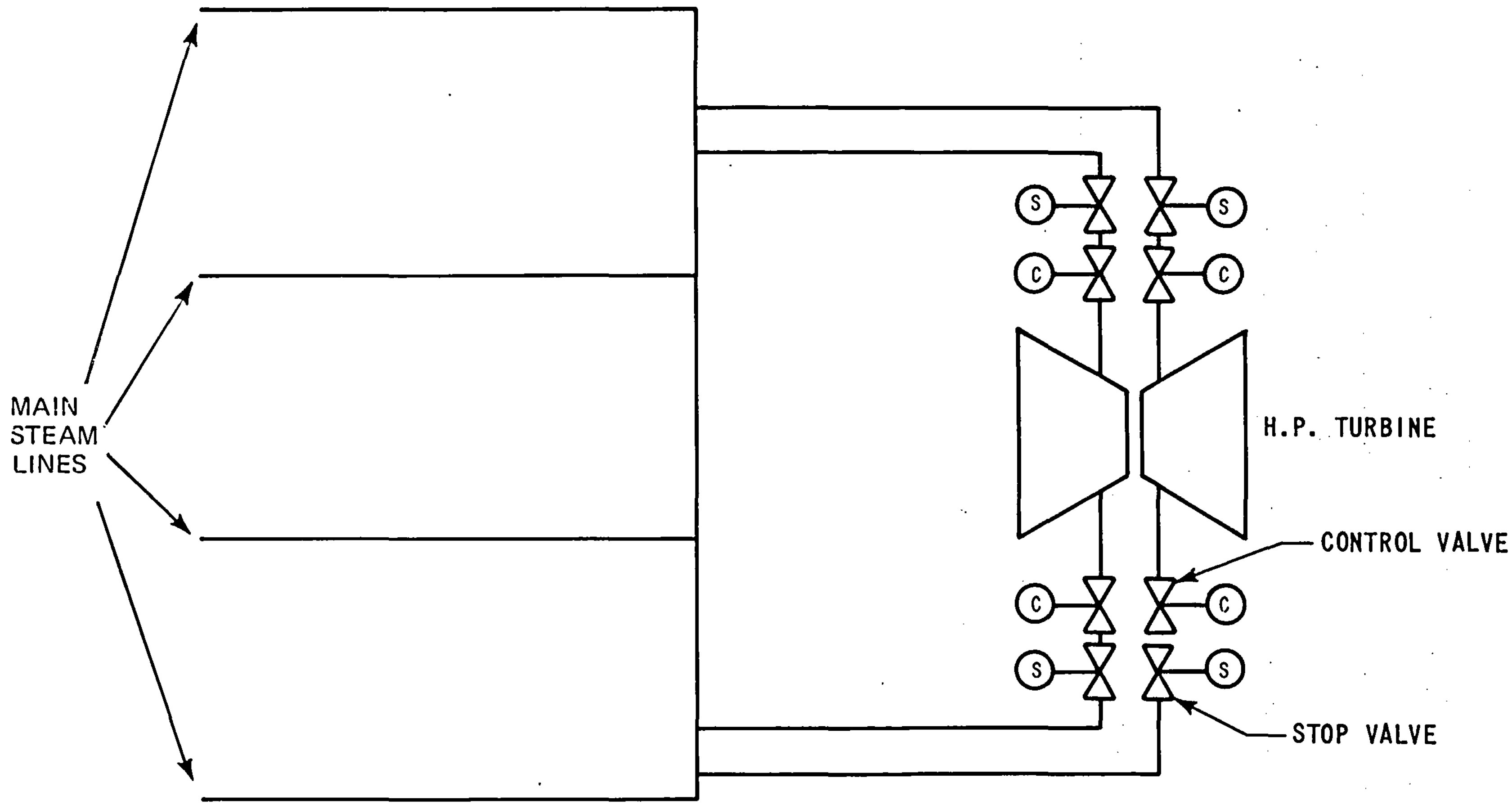

Figure 2-7 Typical Turbine Inlet Valving

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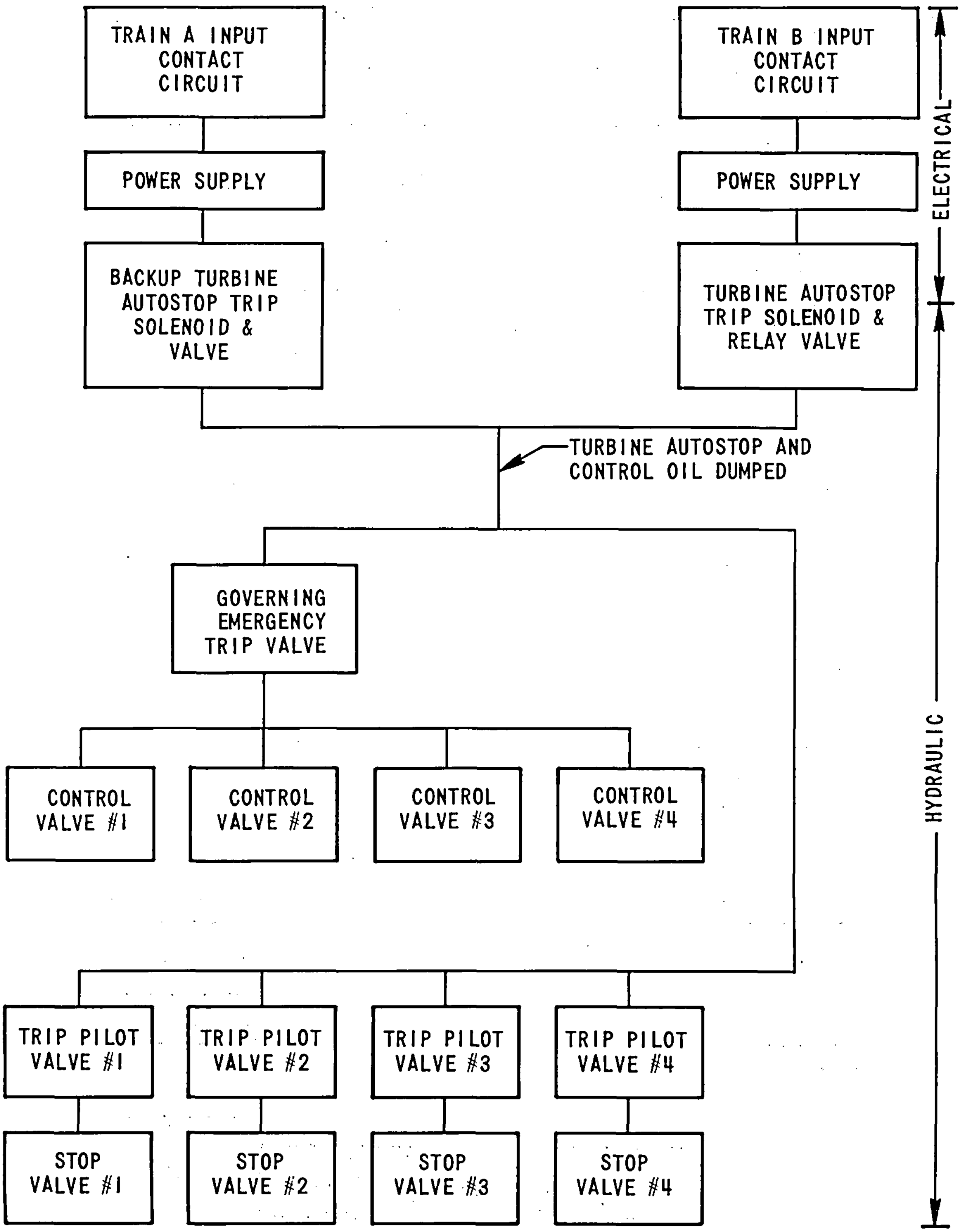

Figure 2-8 Reliability Block Diagram for Turbine Trip; Typical Westinghouse Turbine

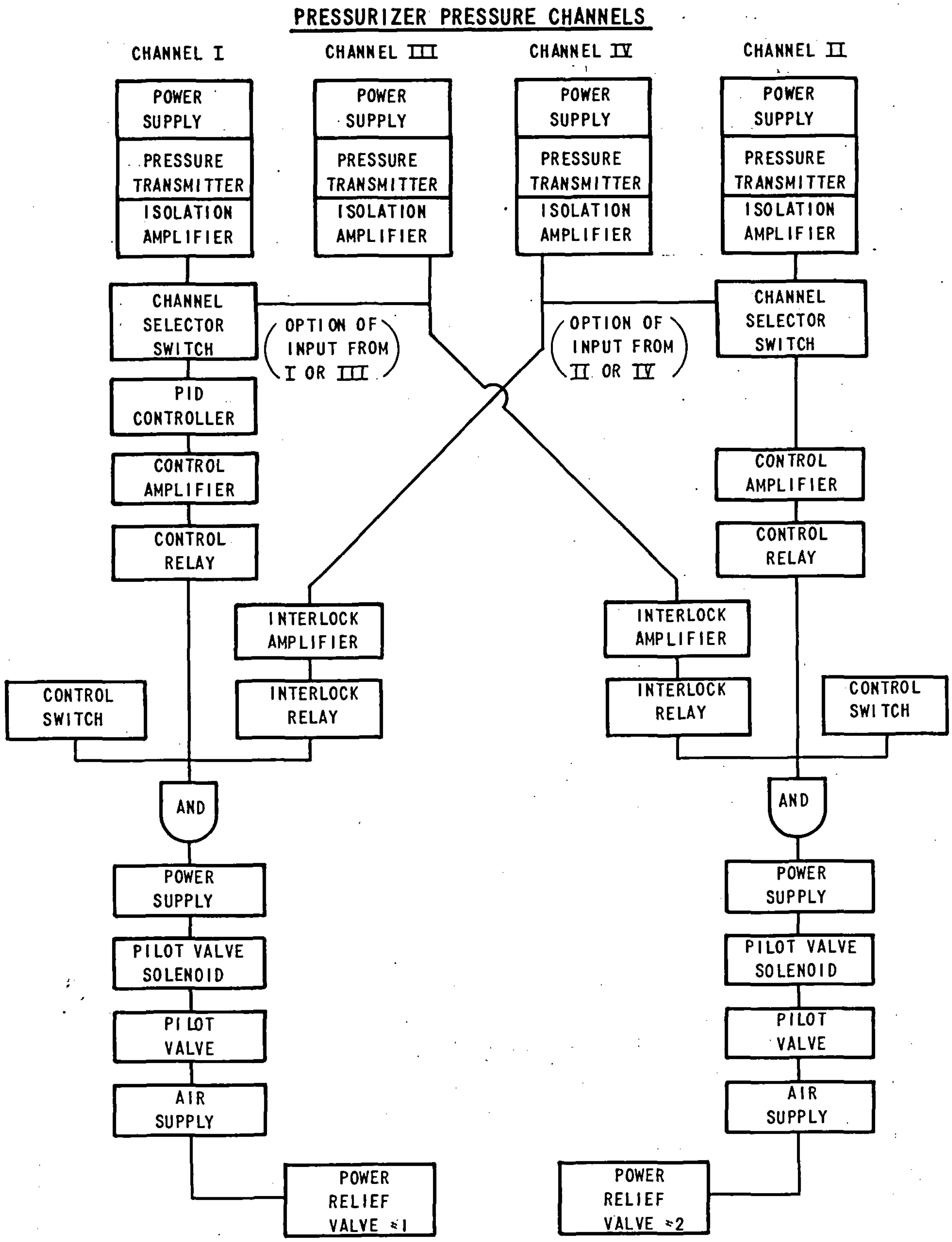

Figure 2-9 Typical Power Relief Valve Reliability Block Diagram, Two Valves (4-Loop Plant)

The interlock function prevents each valve from opening if the interlock pressurizer pressure channel is below the set pressure for the interlock amplifier. The interlock feature is provided to avoid an undesired opening of a power-operated relief valve, and a consequent depressurization transient.

Table 2-9 lists the failures which could prevent the operation of a power-operated relief valve, along with their associated probabilities. The sum of these individual probabilities shows that the probability of one of the valves failing to open on a given demand is $\sim 1.075 \times 10^{-2}$, and thus the probability that one of the two valves fails to open on a given demand is $\sim 2.15 \times 10^{-2}$.

These valves are assumed to open on demand for the ATWT transient analyses.

TABLE 2-9

FAILURES PREVENTING A POWER RELIEF VALVE FROM OPENING

Control Function	Power-Operated Relief Valve #1	Power-Operated Relief Valve #2
Degraded Output from Isolation Amplifier (Includes Power Supply, Pressure Transmitter, and Isolation Amplifier)	1.66×10^{-4}	1.66×10^{-4}
Open Channel Selector Switch	3×10^{-3}	3×10^{-3}
Failure of PID Controller	5×10^{-6}	N.A.
Failure of Control Amplifier	1.3×10^{-4}	1.3×10^{-4}
Failure of Control Relay	3.6×10^{-3}	3.6×10^{-3}
Open Control Switch	5×10^{-6}	5×10^{-6}
Interlock Function		
Degraded Output from Isolation Amplifier (Includes Power Supply, Pressure Transmitter, and Isolation Amplifier)	1.66×10^{-4}	1.66×10^{-4}
Failure of Interlock Amplifier	5×10^{-6}	5×10^{-6}
Failure of Interlock Relay	3.6×10^{-3}	3.6×10^{-3}
Valve Operation		
Failure of Pilot Valve Solenoid Power Supply	$1. \times 10^{-5}$	1×10^{-5}
Failure of Pilot Valve Solenoid	1.5×10^{-6}	1.5×10^{-6}
Mechanical Failure of Pilot Valve	6×10^{-6}	6×10^{-6}
Loss of Air Supply	1×10^{-5}	1×10^{-5}
Mechanical Failure of Power-Operated Relief Valve	1.7×10^{-5}	1.7×10^{-5}
Miscellaneous Open Fuse or Interconnect Wire	3×10^{-5}	3×10^{-5}
Probability That Power-Operated Relief Valve Fails to Open Total	$\sim 1.075 \times 10^{-2}$	$\sim 1.075 \times 10^{-2}$
Probability That 1 of 2 Power-Operated Relief Valves Fails to Open	$= 1.075 \times 10^{-2} + 1.075 \times 10^{-2}$ $= 2.15 \times 10^{-2}$	

SECTION 3
COMPUTER CODES USED FOR ATWT ANALYSIS

3-1. INTRODUCTION

Three computer codes were used in the ATWT analyses. These codes are LOFTRAN[10], FACTRAN[11], and THINC III[12]. The important input, output and model assumptions for each code are given in the following sections.

3-2. LOFTRAN

The systems code used in the ATWT analyses was LOFTRAN. The basic flow nodalization uses an explicit solution of the system equations. The core region and steam generator primary can be subdivided into many nodes to provide an accurate representation of heat transfer and flow in these regions. The core was represented by 15 nodes and the steam generator primary by 12 nodes in these analyses.

The calculated pressurizer pressure and calculated reactor coolant system pressure differ by the pressure drop in the surge line (up to 26 psi depending on surge rate). This effect is explicitly accounted for in LOFTRAN calculations. The effects of loop pressure drops and elevation head are not explicitly accounted for in the system pressure calculated by LOFTRAN. A correction is easily made to account for these effects adding 80 psi to the calculated pressure.

3-3. **Pressurizer Model** — An important consideration in the system modeling is the treatment of the pressurizer. LOFTRAN represents the pressurizer as two separate nodes, one to model the water region and one for the steam region. Mass transfer, but not heat transfer between the nodes, is modeled. It includes the effects of heaters, spray, steam condensation and valve relief.

3-4. **Core Hydraulic Model** — A solution of the momentum equation including frictional losses, fluid inertia and density changes is used for transients that involve a flow coastdown (e.g., station blackout). The core is modeled as a single average channel with 15 axial nodes. Heat transfer from the fuel, fuel and coolant temperatures, and coolant density and flow are calculated in each node.

3-5. **Steam Generator Model** — The LOFTRAN steam generator model used for the ATWT analyses divides the primary side into 12 nodes. The primary side film coefficient was

determined using the Dittus-Boelter correlation. The secondary side film coefficient is calculated as a function of heat transferred to the secondary and secondary side pressure, using the Jens-Lottes correlation.

The secondary side heat transfer coefficient is reduced as the water inventory in the secondary decreases below the volume needed to cover the tube bundle. This volume corresponds to the water inventory at which the quality of steam leaving the tube bundle is 90 percent. A calculation of this volume is given in appendix A.

3-6. **LOFTRAN Input** – The significant system parameters input to the LOFTRAN code are given in table 3-1. These parameters are the same for all the ATWT transient analyses. Those parameters which are input to model system response to a specific transient are listed in the discussion of that transient.

3-7. **LOFTRAN Output** – LOFTRAN outputs a variety of parameters at time intervals specified by the user. The key parameters for the ATWT analyses that are of direct interest or are needed as input for FACTRAN and/or THINC III are given below.

- Nuclear Power Vs. Time
- System Pressure Vs. Time
- Coolant Temperatures Vs. Time
- Coolant Flow Rate Vs. Time
- Pressurizer Water Volume Vs. Time
- Surge Rates Into the Pressurizer Vs. Time
- Flow Out of Pressurizer Relief & Safety Valves Vs. Time

3-8. **FACTRAN**

FACTRAN calculates the transient temperature distribution in a cross-section of a metal-clad UO_2 fuel rod and the heat flux at the surface of the rod, using as input the nuclear power and the local conditions of the coolant (pressure, flow, temperature). All those conditions may be functions of time.

The fuel rod is divided into a number of concentric rings. The number of rings required for the fuel itself is optional and specified in the input. In the ATWT analyses six fuel regions were used. Three more rings were added at the outside of the fuel: they represent, respectively, the gap, the clad, and the film. The transient heat conduction equations are written for each ring in finite difference form as a system of linear equations and are solved

TABLE 3-1
LOFTRAN INPUT FOR REPRESENTATIVE 4-LOOP PLANT

Input	Value
Nominal Full Power	3411 MWt
Nominal Full Reactor Vessel Flow	354,000 gpm
Nominal Pressurizer Pressure	2250 psia
Heat Transfer Coefficient, Fuel-to-Coolant UA	$4000 \frac{\text{BTU}}{\text{sec-}^\circ\text{F}}$
Fuel Clad Heat Capacity	3180 BTU/°F
Nominal Steam Generator Secondary Mass (4 Steam Generators)	406,400 lbs
Pressurizer Volume	1800 ft^3
Nominal Pressurizer Water Volume	1080 ft^3
Pressurizer Relief & Safety Valve Flows (Steam & Water)	Discussed in section 2
Pressurizer Spray	87.4 lbs/sec
Moderator Density Coefficient	Discussed in section 2
Doppler Power Coefficients	Discussed in section 2
Nominal Feedwater Enthalpy	419.2 Btu/lb
Coolant Average Temperature	584.65°F
Nominal Feedwater Flow	1045 lbs/sec
Nominal Steam Temperature	533°F
Nominal Steam Pressure	910 psia

simultaneously. The coefficients of the system are calculated from the temperatures in each ring at time t, and the unknowns are the temperature and heat flux in each ring at time $t + \Delta t$.

3-9. Film Heat Transfer Coefficient – The following is a discussion of film heat transfer before and after DNB.

Before DNB:

At each time step, the forced convection clad surface temperature (Dittus-Boelter correlation) and the local boiling surface temperature (Jens-Lottes correlation) are calculated, based on the heat flux at the previous time step. If the local boiling temperature is higher (forced convection regime), the film is considered as the last section in the system of concentric rings, and the outside boundary condition is the coolant temperature.

If the forced convection temperature is higher (local boiling regime) the clad is considered as the last section in the system, and the outside boundary condition is the local boiling temperature (clad surface temperature).

After DNB:

DNB starts when the time becomes greater than the input DNB time or the flux becomes greater than the input DNB flux. Once started, DNB is assumed to stay in effect until the end of the run no matter what the conditions are. The calculation method is the same as for the forced convection regime but, instead of being obtained from the Dittus-Boelter correlation, the film coefficient is calculated automatically by the Bishop-Sandberg-Tong[13] correlation.

3-10. Material Properties – The thermal and mechanical properties of UO_2 and Zircaloy are built into the code in the form of data tables as functions of temperature. At each time step, the properties of the materials constituting each ring of the model are calculated at the ring average temperature.

3-11. Gap Heat Transfer Coefficient – The gap heat transfer coefficient is calculated based on the thermal expansion of the pellet, that is, the sum of the radial (one-dimensional) expansions of the rings. Each ring is assumed to expand freely. The cladding diameter is calculated based on thermal expansion and internal and external pressures.

If the outside radius of the expanded pellet is smaller than the inside radius of the expanded clad, there is no fuel-clad contact and the gap conductance is calculated on the basis of the thermal conductivity of the gas contained in the gap. If the pellet outside radius so calculated is larger than the clad inside radius (negative gap), the pellet and the clad are pictured as exerting upon each other a pressure sufficiently large to reduce the gap to zero by elastic deformation of both. This contact pressure determines the gap heat transfer coefficient.

3-12. Zircaloy-Water Reaction – The heat generated by the Zircaloy-water reaction is assumed to be generated uniformly in the mass of the clad. The rate of the reaction is calculated by the Baker-Just correlation as a function of the temperature of the outside surface of the clad.

3-13. FACTRAN Input – The significant 17 x 17 fuel parameters needed for FACTRAN are given in table 3-2.

TABLE 3-2
FACTRAN INPUT FOR 17 x 17 FUEL

Input	Value
Clad Material	Zircaloy
Clad Outside Diameter	0.374
Clad Thickness	0.0225 in.
Fuel Pellet	0.3210 in.
Nominal Hot Spot Heat Flux	418,208 Btu/hr-ft^2
Nuclear Power Vs. Time	Output from LOFTRAN
System Pressure Vs. Time	Output from LOFTRAN
Coolant Temperature Vs. Time	Output from LOFTRAN
Coolant Mass Flow Vs. Time	Output from LOFTRAN
Time of DNB	Output from THINC III

3-14. FACTRAN Output – The FACTRAN output of interest consists of the following parameters:

- Heat Flux Vs. Time
- Fuel Temperatures Vs. Time
- Clad Temperatures Vs. Time
- Stored Energy in the Fuel Vs. Time

3-15. THINC-III

The THINC-III code is a detailed Thermal-Hydraulic simulation of the reactor core. In THINC-III, the region of the core being studied is considered to be made up of contiguous channels divided axially into increments of equal length. At time T = 0.0, equations representing the conservation of mass, energy, and momentum within a length increment are written for each channel. Considering the static pressure at a given elevation to be uniform, these equations are solved simultaneously to give the changes in density, velocity, and static pressure along the length increment for each channel. This procedure is continued stepwise up the core by using the values at the top of one length step as input quantities for the next axial step. A total of 37 axial steps was used for the ATWT analyses. The core was divided into 5 radial channels, in the following manner.

Channel 1 = hot channel
Channel 2 = surrounding 8 unit cells
Channel 3 = remainder of hot assembly
Channel 4 = surrounding 8 assemblies
Channel 5 = remainder of core

Therefore, the core was divided into 185 nodes (5 radial x 37 axial) for the calculation of minimum DNBR in the ATWT analyses.

Basic assumptions in THINC-III are given below.

- The static pressure at any elevation is considered to be uniform throughout the channel array.
- Local boiling voids are taken as those computed by the modified Thom correlation.
- The flow is considered to be homogeneous. Correction factors for subcooled and bulk boiling are applied to the friction and momentum pressure drop terms in the force balance equation to account for vapor voids effects.

3-16. THINC-III Input — Typical input parameters for 17 x 17 fuel used by THINC-III to calculate the DNB ratio in the hot channel for these ATWT analyses are listed in table 3-3.

TABLE 3-3
THINC III INPUT FOR 17 x 17 FUEL

Input	Value
Peaking Factors	$F_{\Delta H} = 1.435$ $F_Z = 1.55$
Average Heat Flux Vs. Time	Output from FACTRAN
Core Inlet Enthalpy Vs. Time	Output from LOFTRAN
Core Inlet Flow Vs. Time	Output from LOFTRAN
Core Pressure Vs. Time	Output from LOFTRAN

3-17. **THINC-III Output** – The THINC-III output of primary concern for the ATWT analyses is DNB ratio as a function of time.

3-18. Data Transfer Between Computer Codes

The output information that is transferred from LOFTRAN to FACTRAN and THINC-III was discussed in paragraphs 3.7, 3.13, 3.14, 3.16, and 3.17. Figure 3-1 shows this data transfer in block diagram format.

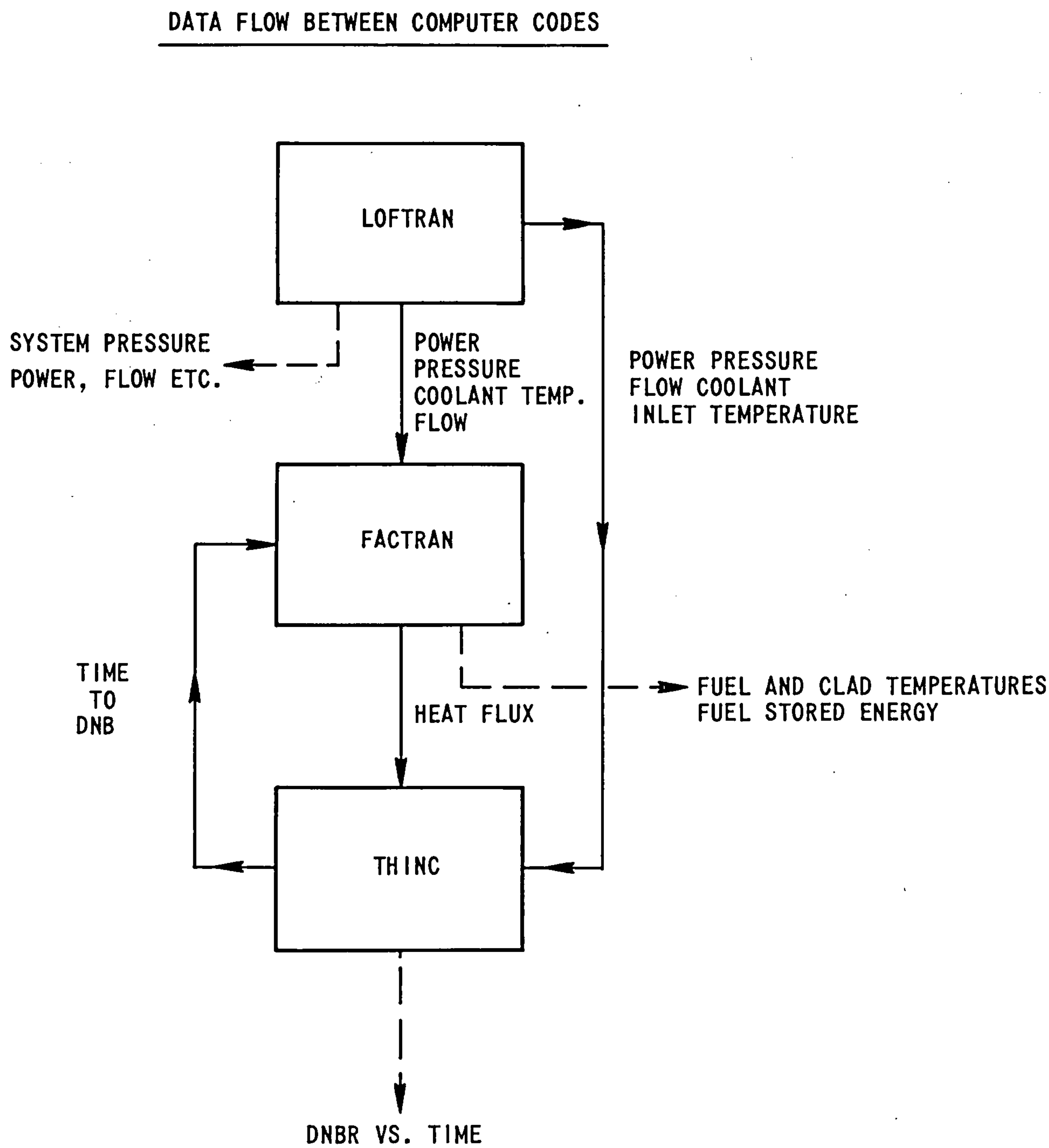

Figure 3-1 Data Flow Between Computer Codes

SECTION 4
ATWT TRANSIENT ANALYSES

4-1. INTRODUCTION

ANSI N.18.2 Condition II transients (those which are in the "anticipated" category) have been evaluated with the assumption that no trip occurred. Detailed digital simulations were performed for the limiting events. Steam generator tube leakage and Condition II loss of coolant are similar to, but less severe than the accidental depressurization transient analyzed in paragraph 4-73, and are therefore bounded by the limiting cases explicitly treated in this report.

The analyses were performed using composite plant parameters to bound as many Westinghouse plants as possible, rather than using parameters for any specific plant. Sensitivity studies were performed where appropriate to demonstrate that the conclusions are valid for all plants covered by the generic approach. These analyses consider 2-, 3-, and 4-loop plant configurations with either 51 Series or Model D steam generators.

The transient analyses were performed to evaluate both departure from nucleate boiling (DNB) ratio and Reactor Coolant System pressure associated with ATWT events. In the loss of feedwater and loss of load cases, DNB ratio increases with time; therefore peak Reactor Coolant System pressure is the parameter of concern. The peak pressure is sensitive to fuel type only to the extent that reactivity coefficients vary with different fuel rod configurations. In paragraph 2-12 it was pointed out that the 100-percent power, 900 ppm boron curve for the moderator density coefficient is conservative for all times that the plant is at full power with significant xenon buildup. However, the more conservative 50-percent power, 900 ppm boron curve was used for all the analyses in this report.

Since the reactivity coefficients used in the LOFTRAN calculations in this report are conservative with respect to all fuel configurations, the peak pressures reported for loss of feedwater, loss of load, and the other transients studied are conservative for all fuel arrays. The calculated Reactor Coolant System pressures do not include elevation head or pressure drops around the loop. These effects result in an additional 80 psi.

4-2. ROD WITHDRAWAL FROM SUBCRITICAL CONDITIONS WITHOUT A REACTOR TRIP – IDENTIFICATION OF CAUSES AND TRANSIENT DESCRIPTION

A rod withdrawal accident from a subcritical condition could result from a Reactor Control System malfunction which would cause the rod control mechanisms to request a rod withdrawal in the absence of an operator initiated control signal. Several reactor trip functions and control system blocks would terminate any such event well before any DNB could occur.

The results of an uncontrolled rod withdrawal while the reactor is subcritical are strongly dependent on the initial plant conditions. For instance, if the plant is at hot shutdown and all shutdown banks are inserted, the shutdown margin is typically of the order of -5 to -10 percent. To return critical from this condition would require that both the shutdown banks and the control rod banks withdraw. The time required to return critical, assuming the rods move at the maximum rate, is in excess of 10 minutes and allows sufficient time for the operator to detect the withdrawal and take action to terminate the event.

When the plant is being shutdown for maintenance shortly after going subcritical, the reactor core is highly borated. Withdrawal of all the rods at this time would not result in criticality.

If the plant is at a hot shutdown condition, only the control banks would be inserted (banks D, C, B and A). The core would be shutdown by 5% $\Delta k/k$, or more, depending on the boron concentration of the Reactor Coolant System. If a rod withdrawal event were to happen at this time the core might become critical. If the core does go critical, the time required to return critical, assuming that the banks withdraw at their maximum rate, would be 4 to 10 minutes.

The probability of this occurring is extremely low because only during a very small portion of any core cycle is a plant at hot shutdown condition with the shutdown rod banks out of the core. Generally, the time of hot shutdown is only an interim period in the process of bringing the plant to cold shutdown or bringing it to a power generating condition.

In the event that the rod withdrawal went undetected, there are several features of the automatic Reactor Protection System which would normally act to prevent core damage.

- One source range nuclear flux protection channel in excess of the high neutron flux setpoint actuates a reactor trip.
- One intermediate range nuclear flux instrumentation channel in excess of the high nuclear flux setpoint actuates a reactor trip.
- Two power range nuclear flux instrumentation channels in excess of the power range high neutron flux (low setpoint) actuate a reactor trip.

In addition to these reactor trip functions, the following Reactor Control System rod blocks terminate the rod withdrawal demand signal:

- One intermediate range nuclear flux control channel in excess of the high neutron flux setpoint blocks withdrawal of the control rods.
- One power range nuclear flux control channel in excess of the high neutron flux setpoint blocks withdrawal of the control rods.

If an uncontrolled rod withdrawal were to continue beyond these protection and control setpoints, the following Reactor Protection System features would normally also act to alleviate the consequences of the nuclear and thermal excursions:

- Two pressurizer level protection channels in excess of the high level setpoint actuate a reactor trip.
- Two pressurizer pressure protection channels in excess of the high pressure setpoint actuate a reactor trip.
- Overtemperature ΔT reactor trip
- Overpower ΔT reactor trip

However, for the ATWT analyses, no rod insertion was assumed to take place as a result of the control and protection features.

To illustrate the effects of rod withdrawal from a subcritical condition, a bank worth of 1.0% Δk/k is withdrawn from a core that is initially critical at zero nuclear power.

4-3. Analysis of Effects and Consequences

The rod withdrawal from the subcritical event was analyzed using the LOFTRAN code with the following assumptions:

- Initial plant conditions representative of a hot zero power operating condition with nominal reactor coolant flow
- Reactivity coefficients characteristic of early core life
- A total reactivity insertion of 1% Δk/k at a rate characteristic of the control rod integral worth curve.
- Continuous rod withdrawal at maximum rod speed
- Auxiliary feed is available to remove decay heat.

- No credit for automatic reactor trip
- No credit for automatic rod blocks
- The reactor coolant pumps cavitate when the cold leg temperature comes within six degrees of saturation.

The analyses were done for all existing combinations of 2-, 3-, and 4-loop plants and model 51 and model D steam generators.

4-4. Results

The most severe results for a rod withdrawal from subcritical occur in a 4-loop plant with a model 51 steam generator. This is due to the smaller volume in the pressurizer relative to the total Reactor Coolant System volume. Table 4-1 and figures 4-1 through 4-9 show the sequence of events and transient response of important system parameters for this case. Because of the low core power and nominal core flow, the DNB ratio is very high throughout the transient. For comparison, the same transient for 2- and 3-loop plants is shown in figures 4-10 through 4-17.

As the figures show, there is an initial rapid rise in nuclear and thermal power which is attenuated slightly by the opening of the steam generator safety valves at approximately 100 seconds. The power rise terminates at about 180 seconds when the rod bank is completely out of the core and secondary and primary plant conditions are closely matched. At this time

TABLE 4-1
SEQUENCE OF EVENTS FOR A ROD WITHDRAWAL FROM SUBCRITICAL WITHOUT A REACTOR TRIP
(2-, 3-, AND 4-LOOP PLANT/MODEL 51 STEAM GENERATOR)

Event	Time (Seconds)		
	2-Loop	3-Loop	4-Loop
Rod Withdrawal Begins	0.0	0.0	0.0
High Nuclear Flux Reactor Trip Low Setpoint Reached	85.2	87.2	86.6
Pressurizer Power-Operated Relief Valves Open	90.9	88.6	88.6
Steam Generator Safety Valves Open	105.0	104.0	105.0
Pressurizer High Level Reactor Trip Setpoint Reached	369.9	350.4	363.8
Pressurizer Fills	410.0	383.0	392.0
Pressurizer High Pressure Reactor Trip Setpoint Reached		389.8	393.5
Reactor Coolant Low Flow Reactor Trip Setpoint Reached			551.6

the pressure drops due to the effects of the pressurizer pressure control. At approximately 280 seconds the steam generator tubes begin to uncover forcing the core average temperature up and eventually causing the pressurizer to fill at approximately 390 seconds. The decreased effectiveness of the pressurizer relief valves in water relief produces a Reactor Coolant System pressure surge up to a peak of 2530 psia. The reactor coolant pumps cavitate at 550 seconds.

4-5. Sensitivity Studies

Several sensitivity studies were made to determine the effects of varying key system parameters such as reactor coolant flow, amount of inserted reactivity, steam generator mass, and reactivity insertion rates. A summary of the results of these studies is presented in table 4-2. The following paragraphs discuss the sensitivity studies performed.

4-6. **Reactor Coolant Flow** — Cases were studied with one, two, and three reactor coolant pumps running to determine if reduced core coolant would result in DNB. Results are shown in figures 4-18 through 4-29.

Because of the reduced core flow, the primary temperatures increased more rapidly resulting in a greater moderator density feedback early in the transient. Thus, the peak power was lower than that for the base case. The ratio of power to flow in the core remained relatively small and the DNB ratio remained well above 1.0. In all three cases, the peak pressure for the first 600 seconds was 2540 psia which results when three of four pumps are operating.

4-7. **Amount of Inserted Reactivity** — Because a larger amount of inserted reactivity would result in a higher core power and possibly higher pressures when the pressurizer fills, a case was run assuming a 1.6-percent reactivity insertion. Again, the rate was determined by the shape of the control rod integral worth curve and rod withdrawal at the maximum rate. A reactivity worth of 1.6 percent was representative of the maximum control bank D worth at any time in core life.

Figures 4-30 through 4-35 show that the net effect of the higher reactivity was higher peak core power and consequently, higher primary temperatures. The steam generator dried out earlier, and because of the greater insurge into the pressure at this time, the peak pressure reached 2583 psia. However, the DNB ratio remained high.

4-8. **Steam Generator Mass** — Two cases were run to determine the effects of the dry-out time on peak system pressures. Since the peak pressure occurred when the steam generator dried out, the dry-out time was changed by varying steam generator mass by ± 10 percent.

Figures 4-36 through 4-41 show that the dry-out time had essentially no effect on peak system pressures since it occurred late in the transient when the total plant system was in a steady-state condition.

TABLE 4-2

SUMMARY OF RESULTS FOR A ROD WITHDRAWAL FORM SUBCRITICAL WITHOUT A REACTOR TRIP

Case	Peak Reactor Coolant System Pressure
Reference Case[a]	2532
3-Loop Plant	2446
2-Loop Plant	2361
Model D Steam Generator	2357
Steam Generator Mass + 10 Percent	2533
Steam Generator Mass - 10 Percent	2533
Twice Reference Reactivity Insertion Rate	2531
Half Reference Reactivity Insertion Rate	2533
3 of 4 Reactor Coolant Pumps Operating	2540
2 of 4 Reactor Coolant Pumps Operating	2357
1 of 4 Reactor Coolant Pumps Operating	2355
1.6% $\frac{\Delta k}{k}$ Inserted Reactivity	2583

[a]Reference case: Hot zero power initial conditions, 1.0% $\frac{\Delta k}{k}$ inserted reactivity 4-loop plant, Model 51 steam generator

4-9. Reactivity Insertion Rate — Finally, to determine if the rate of the reactivity insertion by the rods affects the peak pressures during the transient, two cases were examined, one at half the base case insertion rate and one at twice the base case insertion rate. Figures 4-42 through 4-47 show that the only effect of this change was to accelerate or delay the course of the transient. The system was always in a quasi-equilibrium state and still effectively in steady-state when the pressurizer filled. Thus, the results were not sensitive to the shape of the integral rod worth curve as shown in figure 4-48.

4-10. Conclusions

Based upon the calculated DNB ratios, no significant clad damage is expected. No impairment of Reactor Coolant System mechanical integrity occurs because peak pressures are below allowable pressures in an uncontrolled rod withdrawal from subcritical condition even when failure to terminate the withdrawal and failure to trip the reactor is postulated.

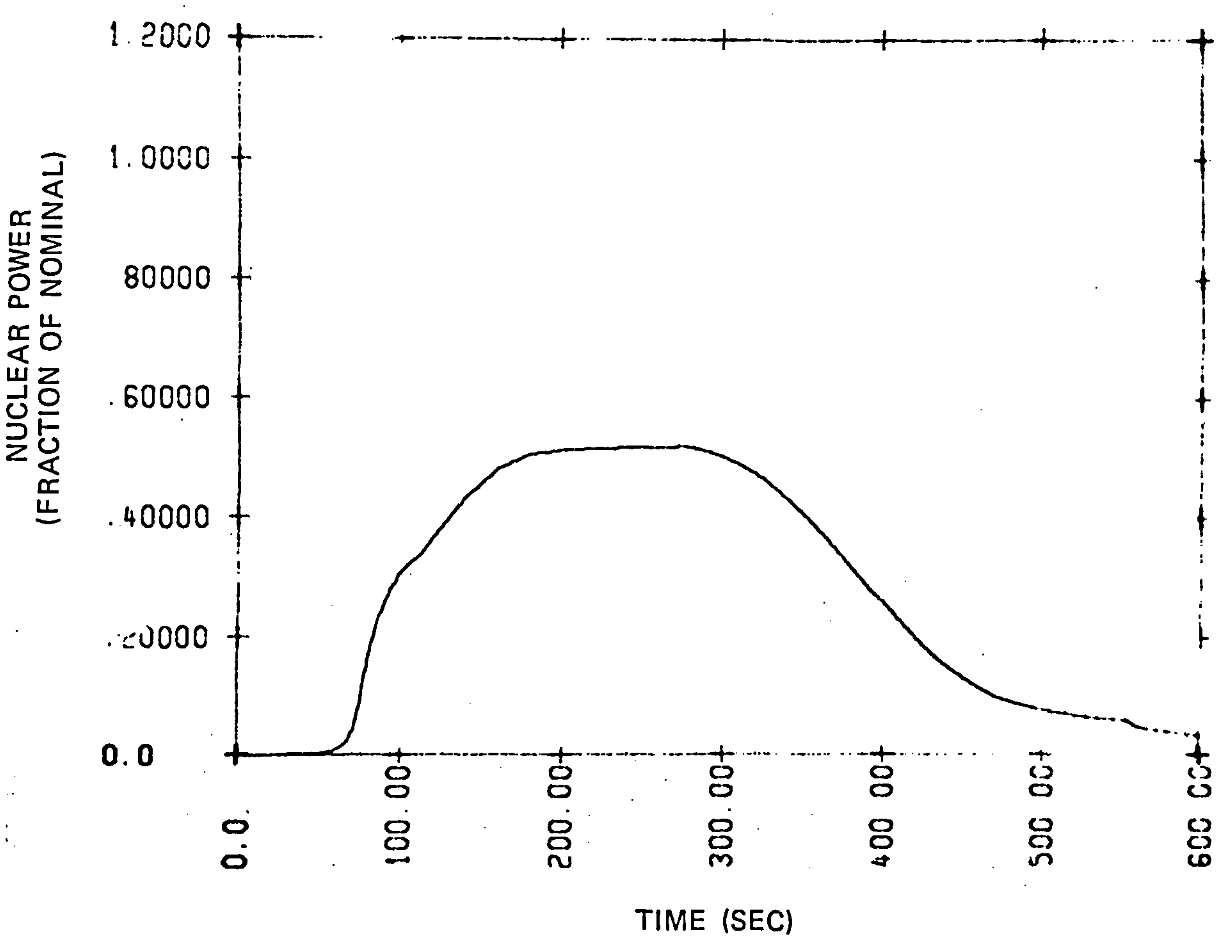

Figure 4-1. Rod Withdrawal from Subcritical – Reference Case
(Nuclear Power Vs. Time)

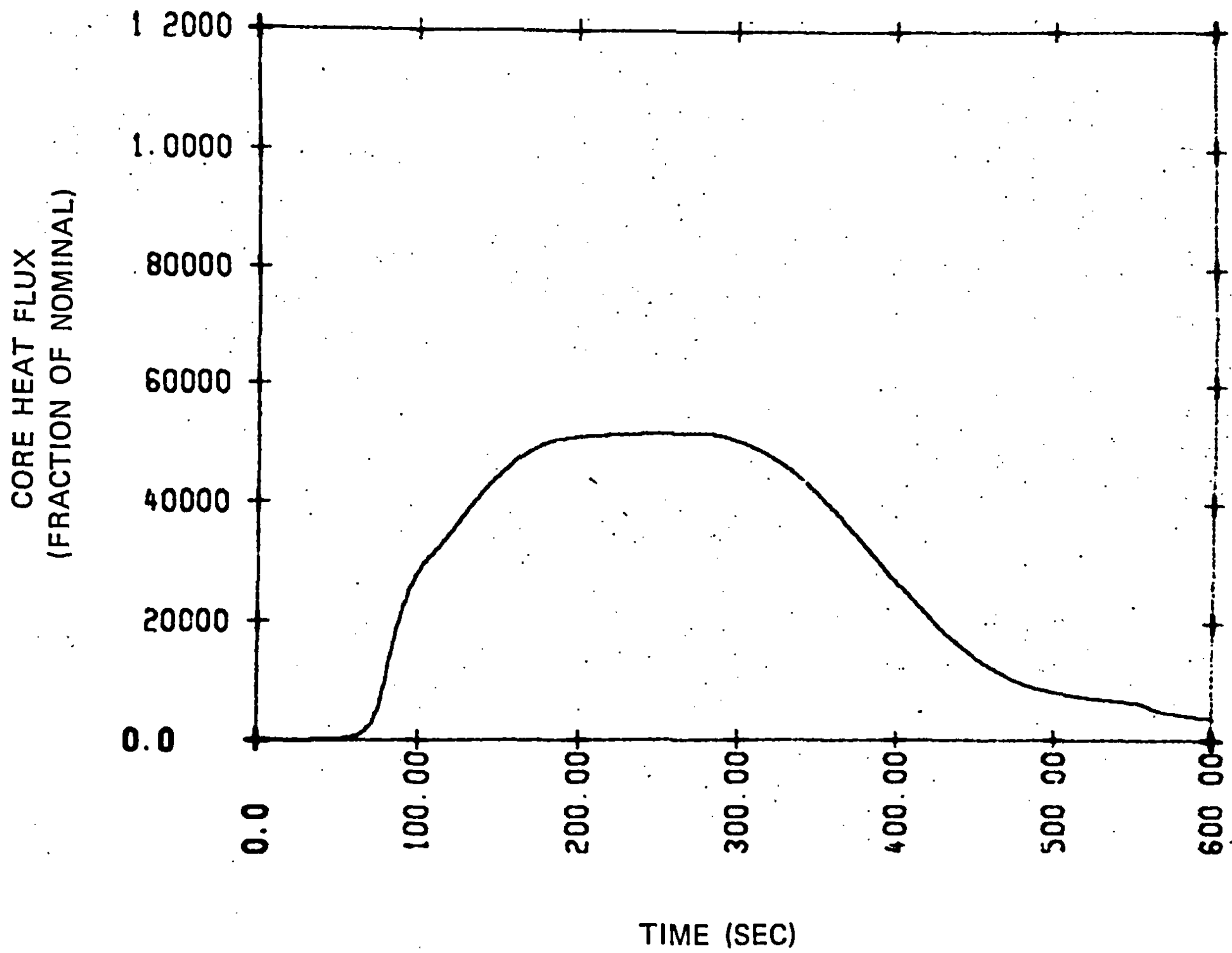

Figure 4-2. Rod Withdrawal from Subcritical – Reference Case
(Core Heat Flux Vs. Time)

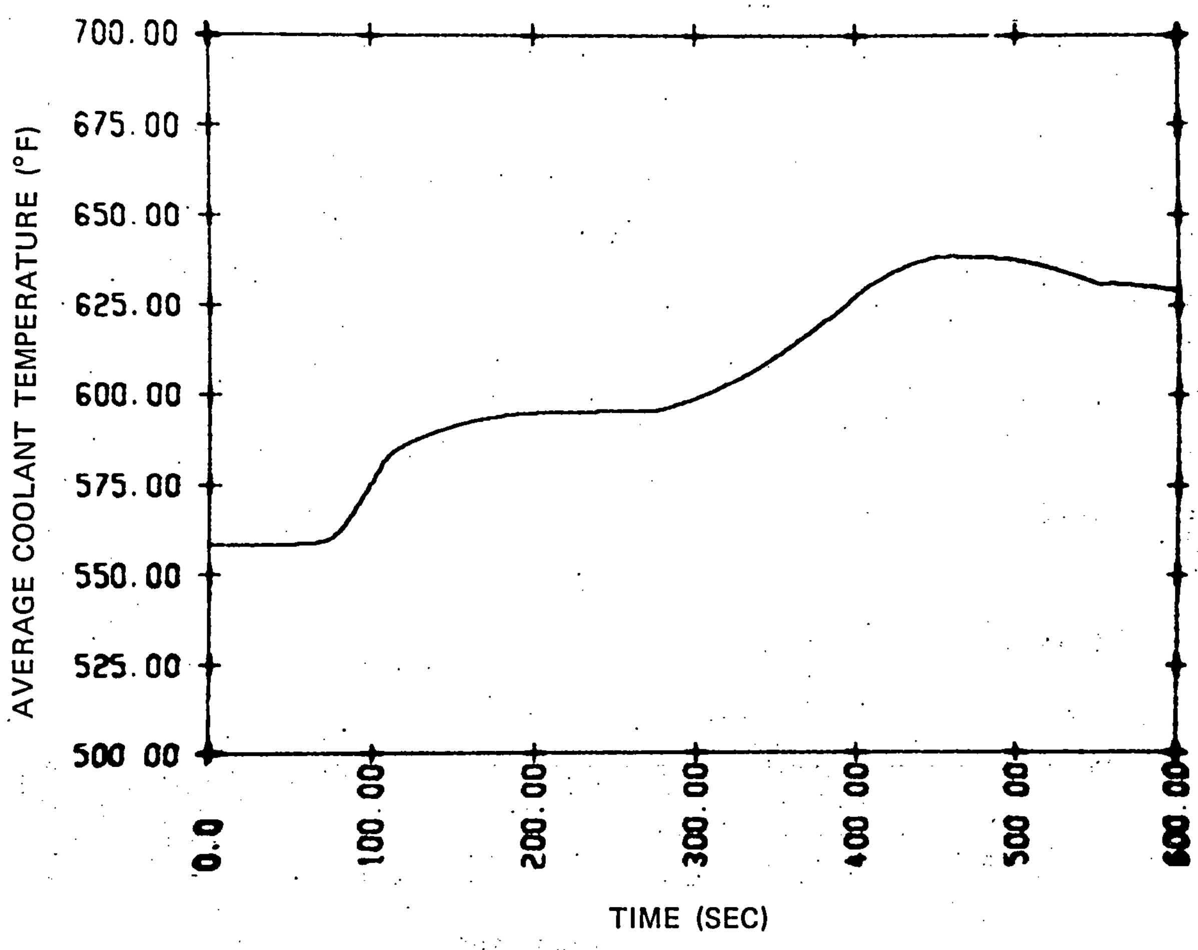

Figure 4-3. Rod Withdrawal from Subcritical — Reference Case (Average Coolant Temperature Vs. Time)

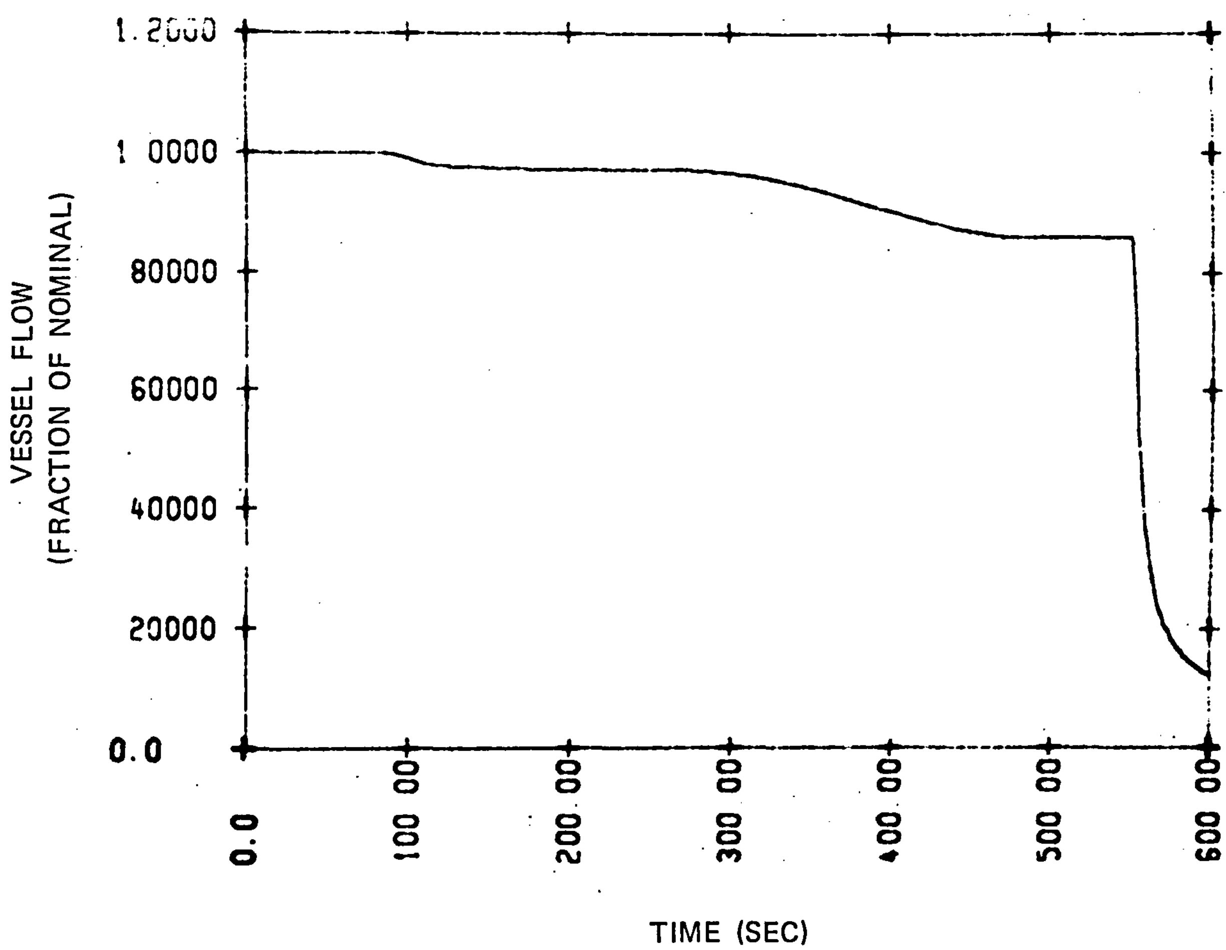

Figure 4-4. Rod Withdrawal from Subcritical — Reference Case
(Vessel Flow Vs. Time)

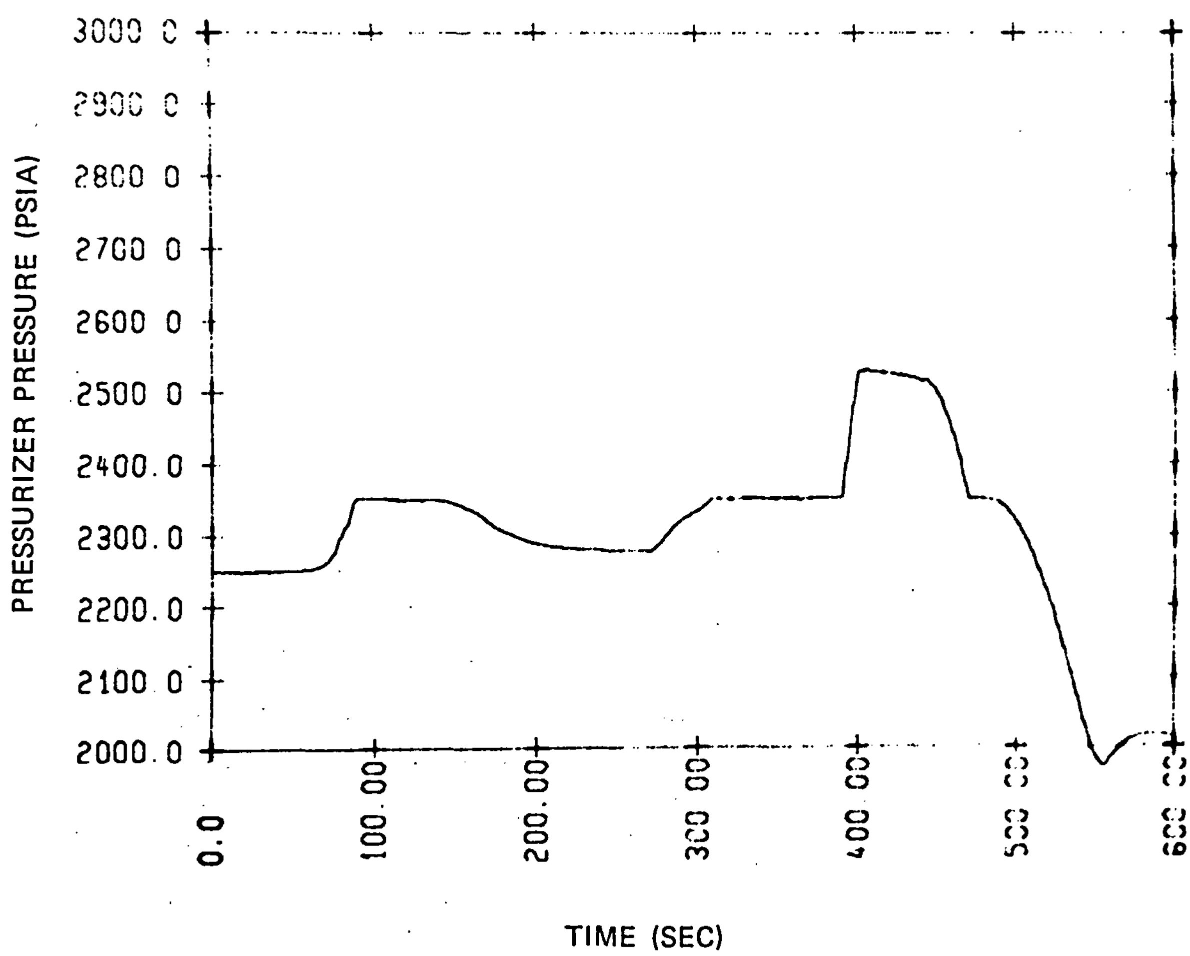

Figure 4-5. Rod Withdrawal from Subcritical — Reference Case (Pressurizer Pressure Vs. Time)

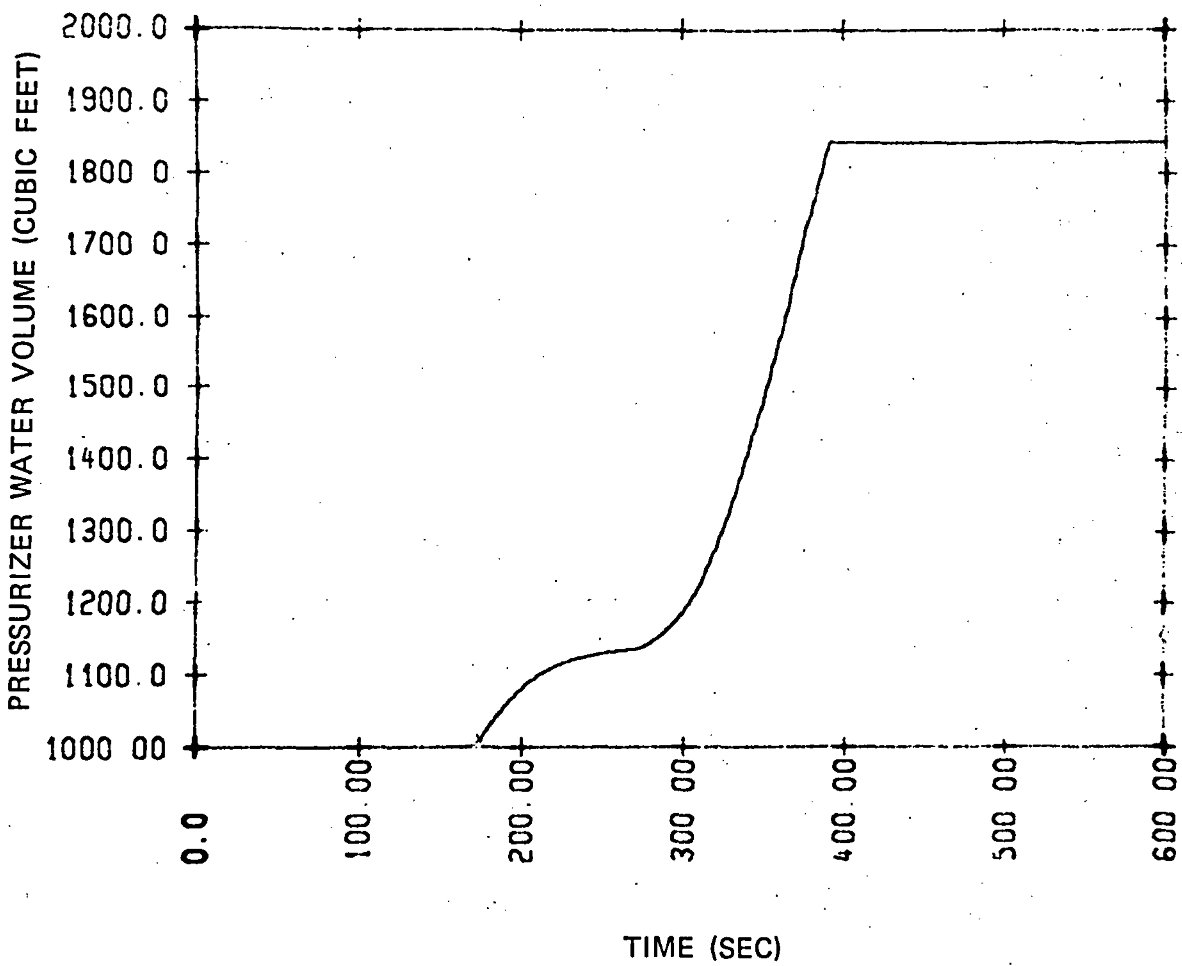

Figure 4-6. Rod Withdrawal from Subcritical — Reference Case (Pressurizer Water Volume Vs. Time)

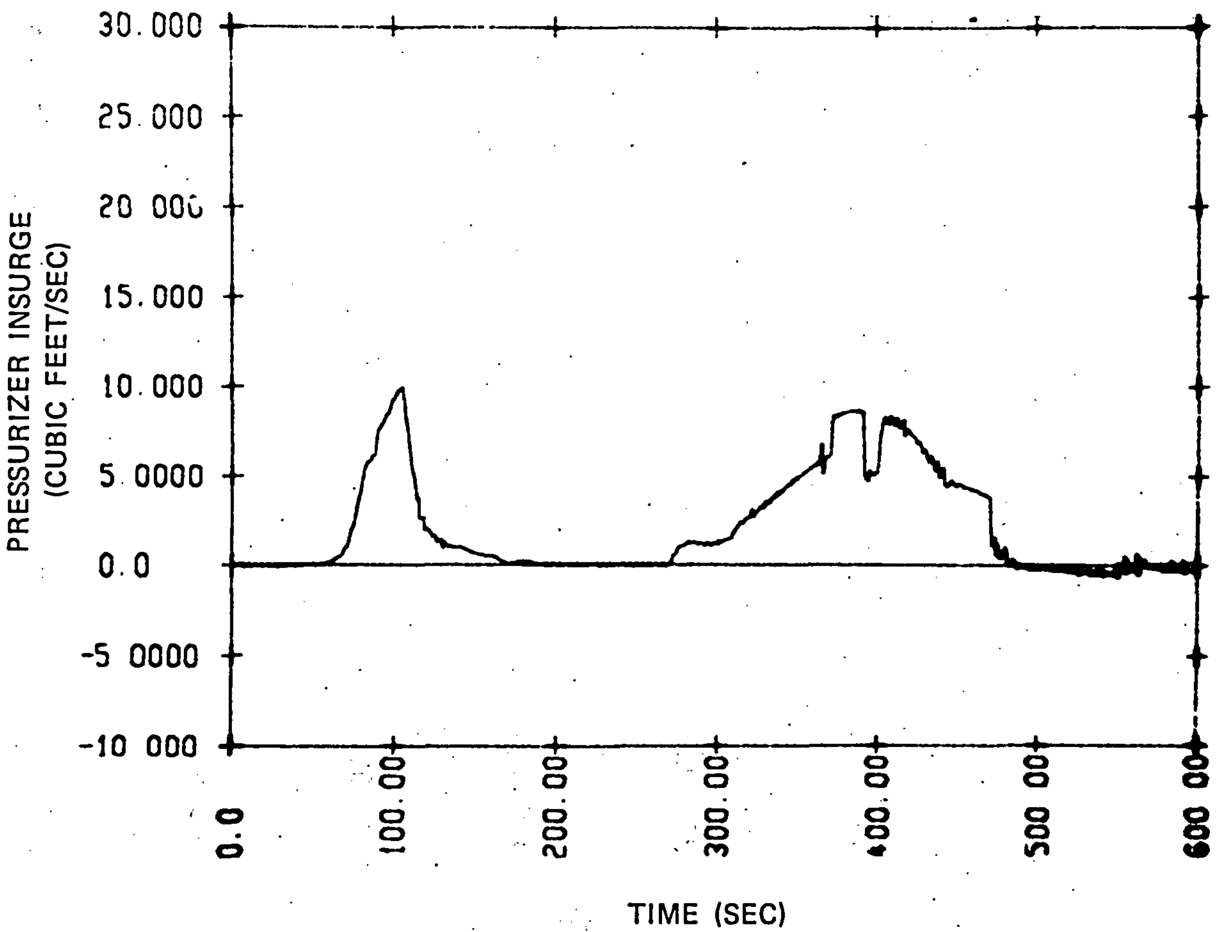

Figure 4-7. Rod Withdrawal from Subcritical — Reference Case (Pressurizer Insurge Vs. Time)

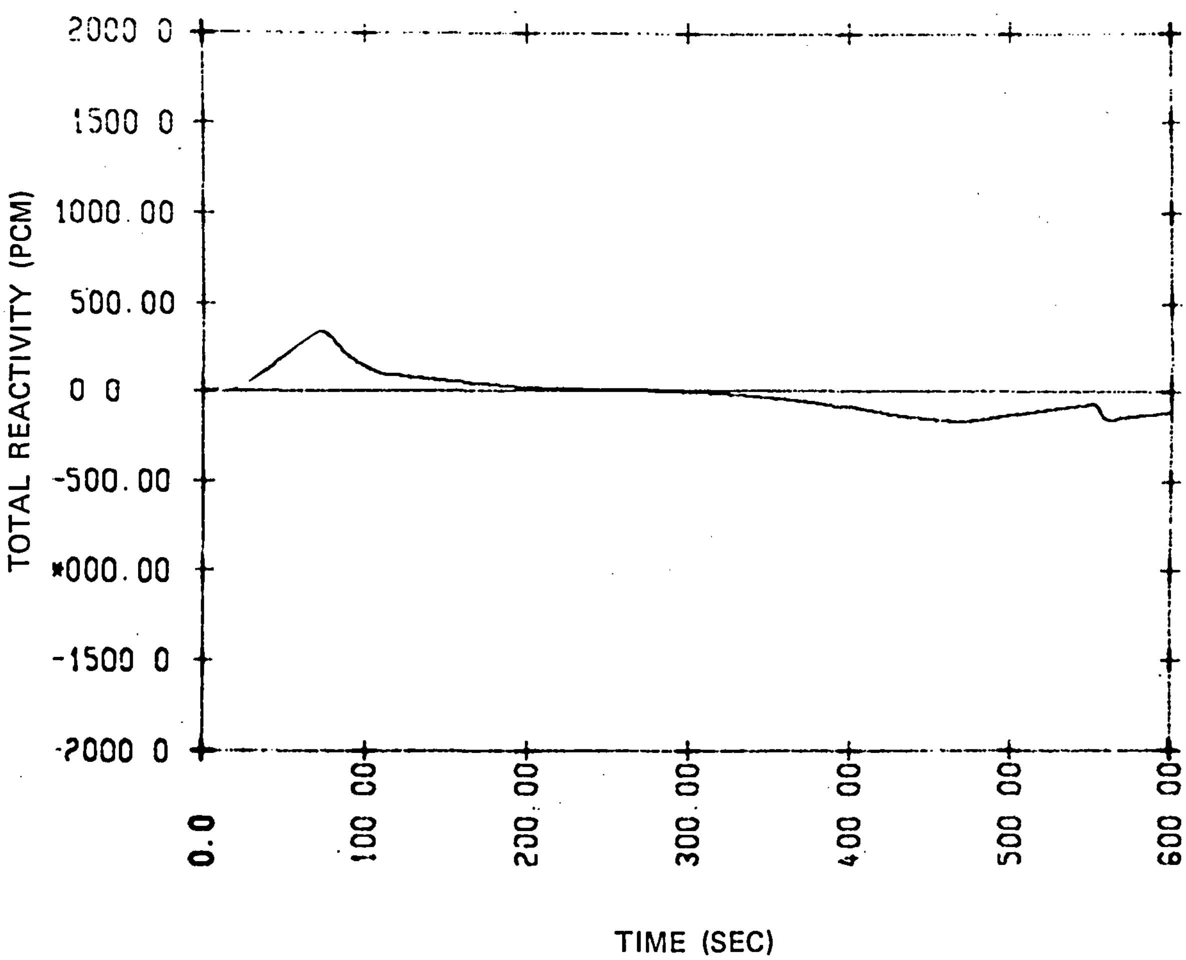

Figure 4-8. Rod Withdrawal from Subcritical — Reference Case
(Total Reactivity Vs. Time)

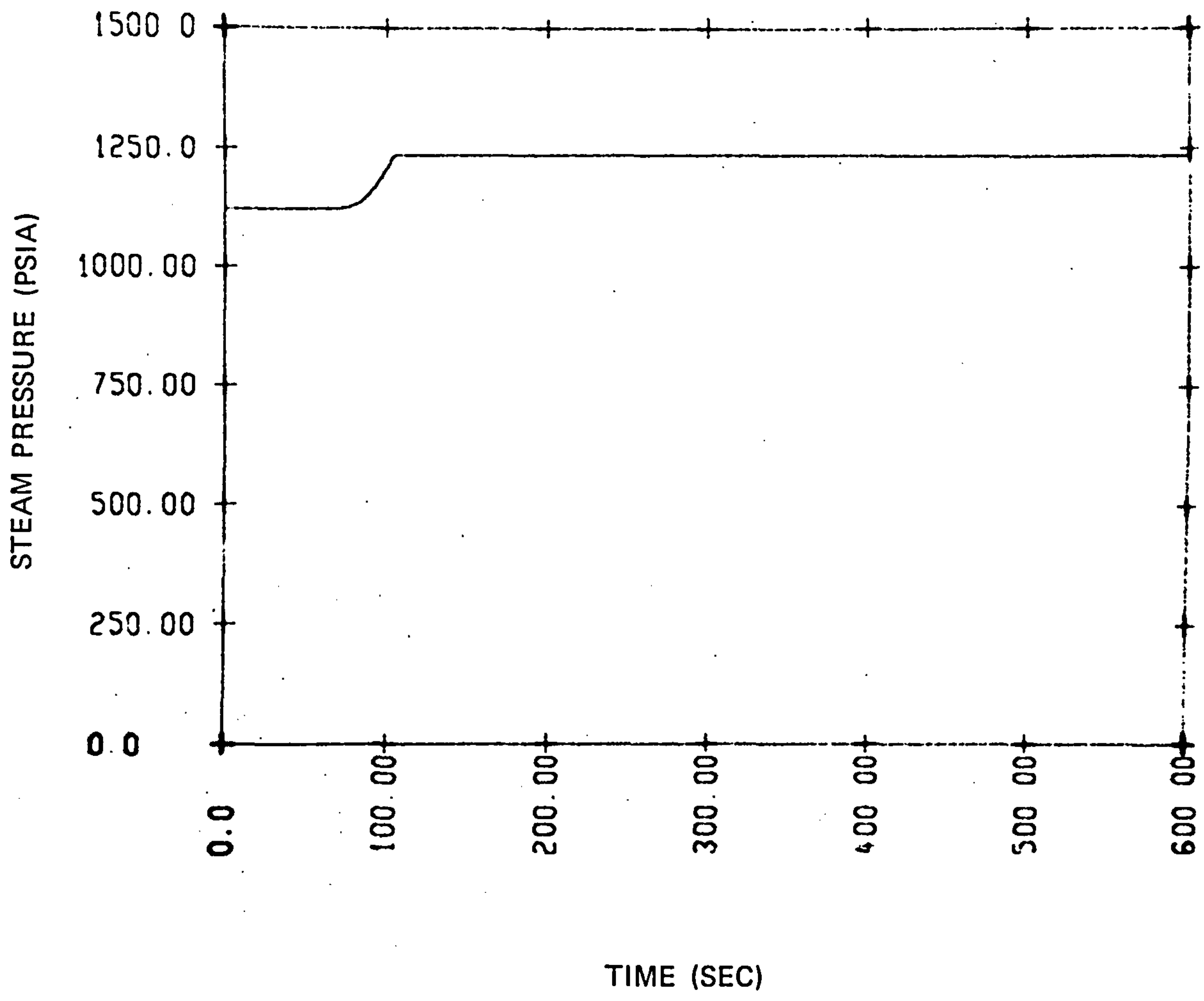

Figure 4-9. Rod Withdrawal from Subcritical — Reference Case (Steam Pressure Vs. Time)

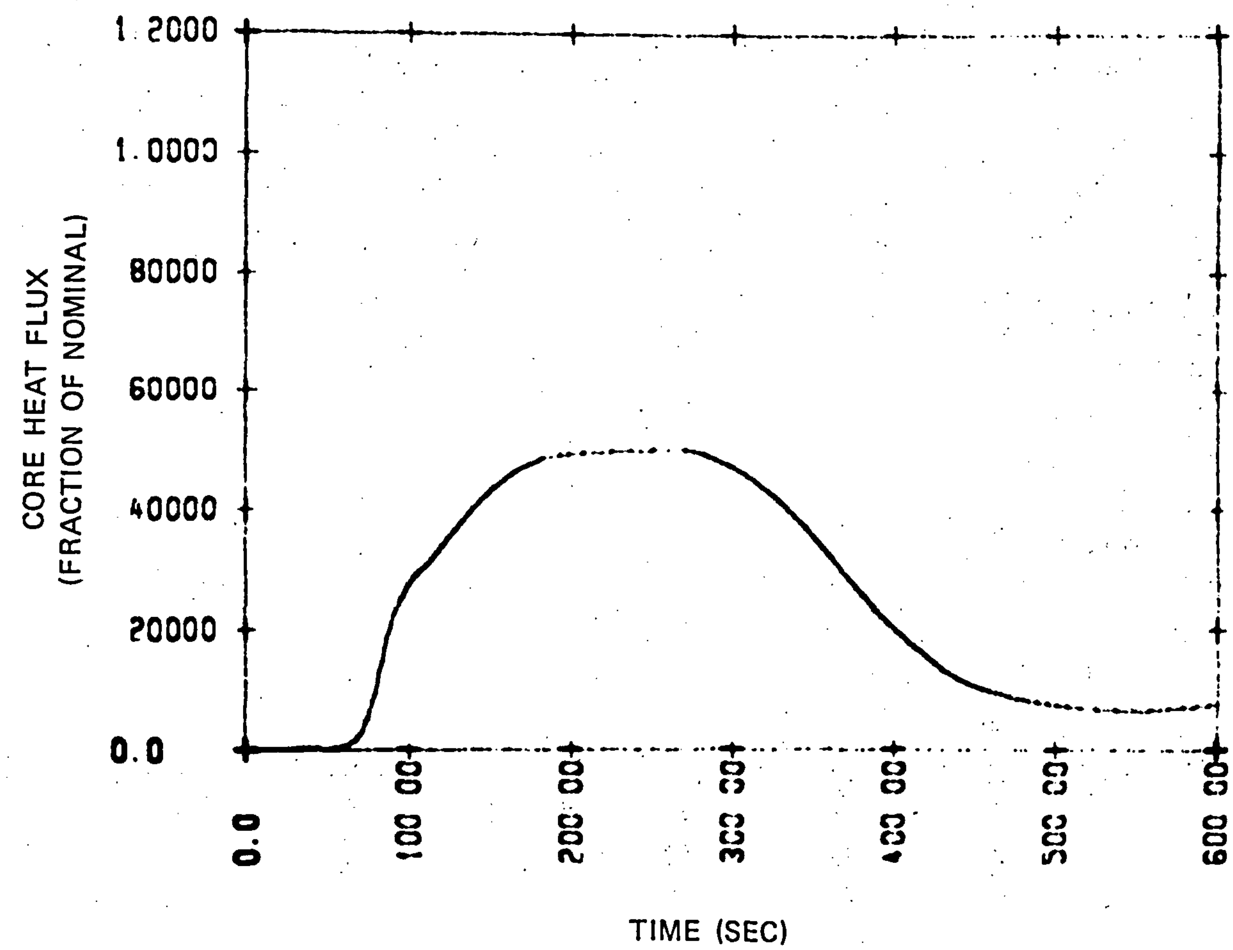

Figure 4-10. Rod Withdrawal from Subcritical – 3-Loop Plant
(Core Heat Flux Vs. Time)

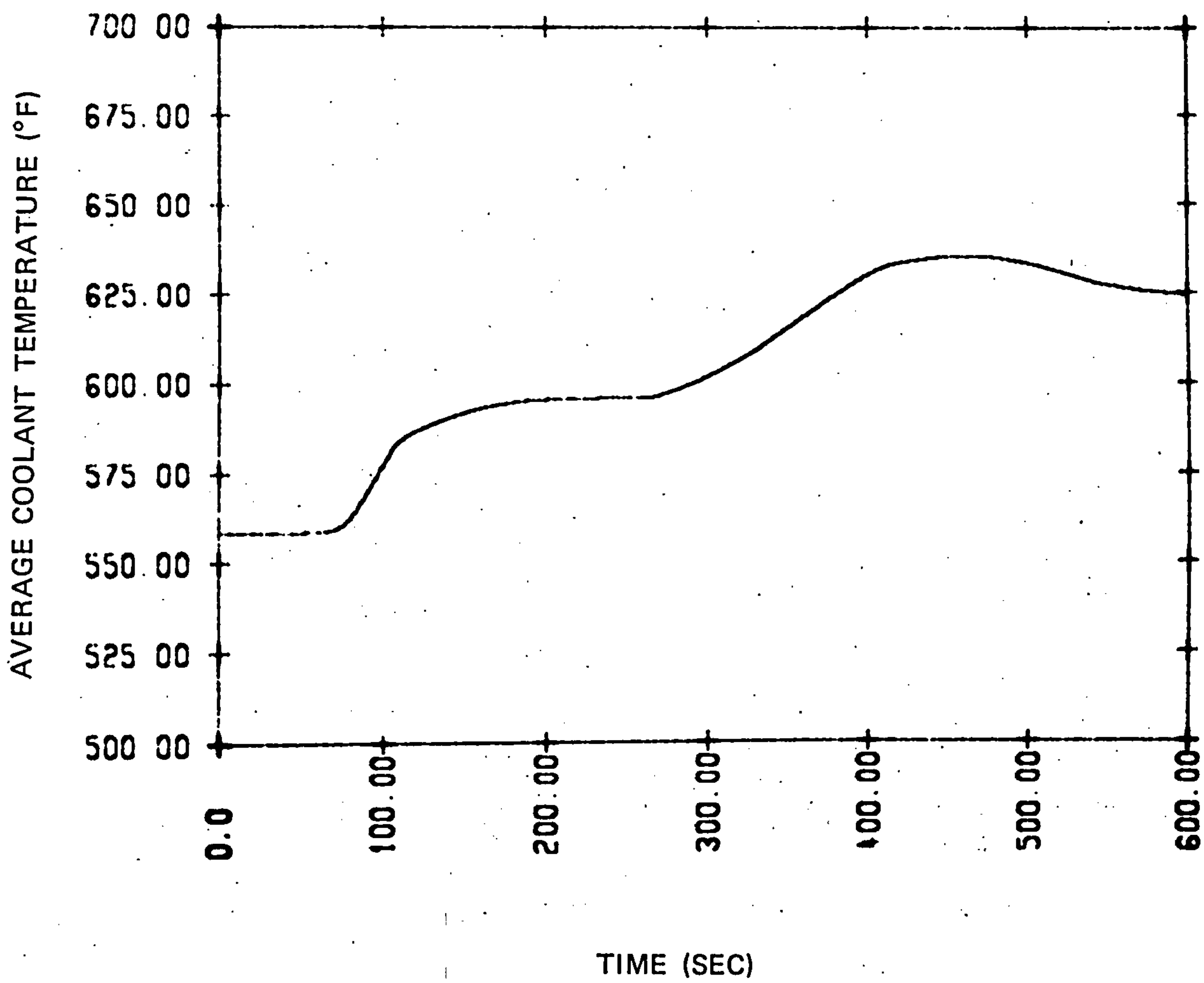

Figure 4-11. Rod Withdrawal from Subcritical – 3-Loop Plant (Average Coolant Temperature Vs. Time)

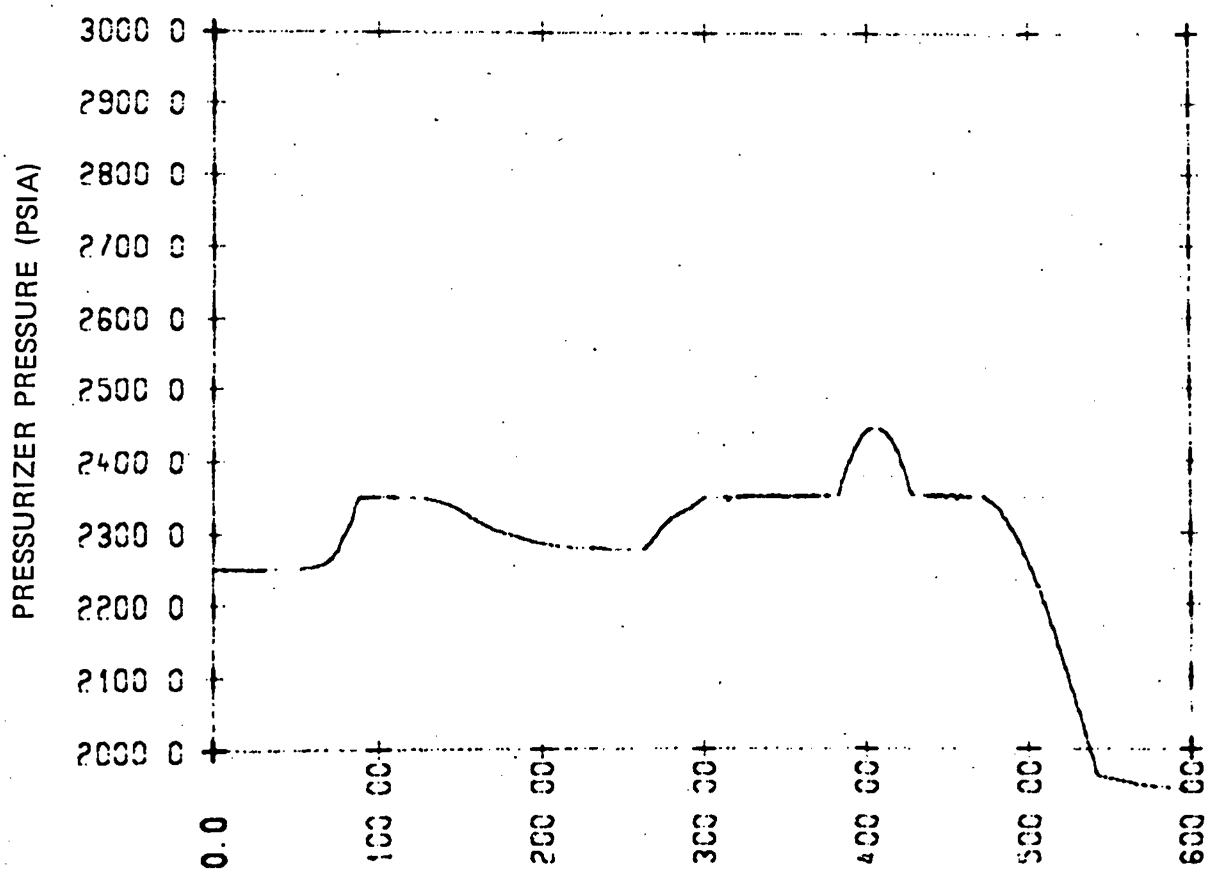

Figure 4-12. Rod Withdrawal from Subcritical — 3-Loop Plant (Pressurizer Pressure Vs. Time)

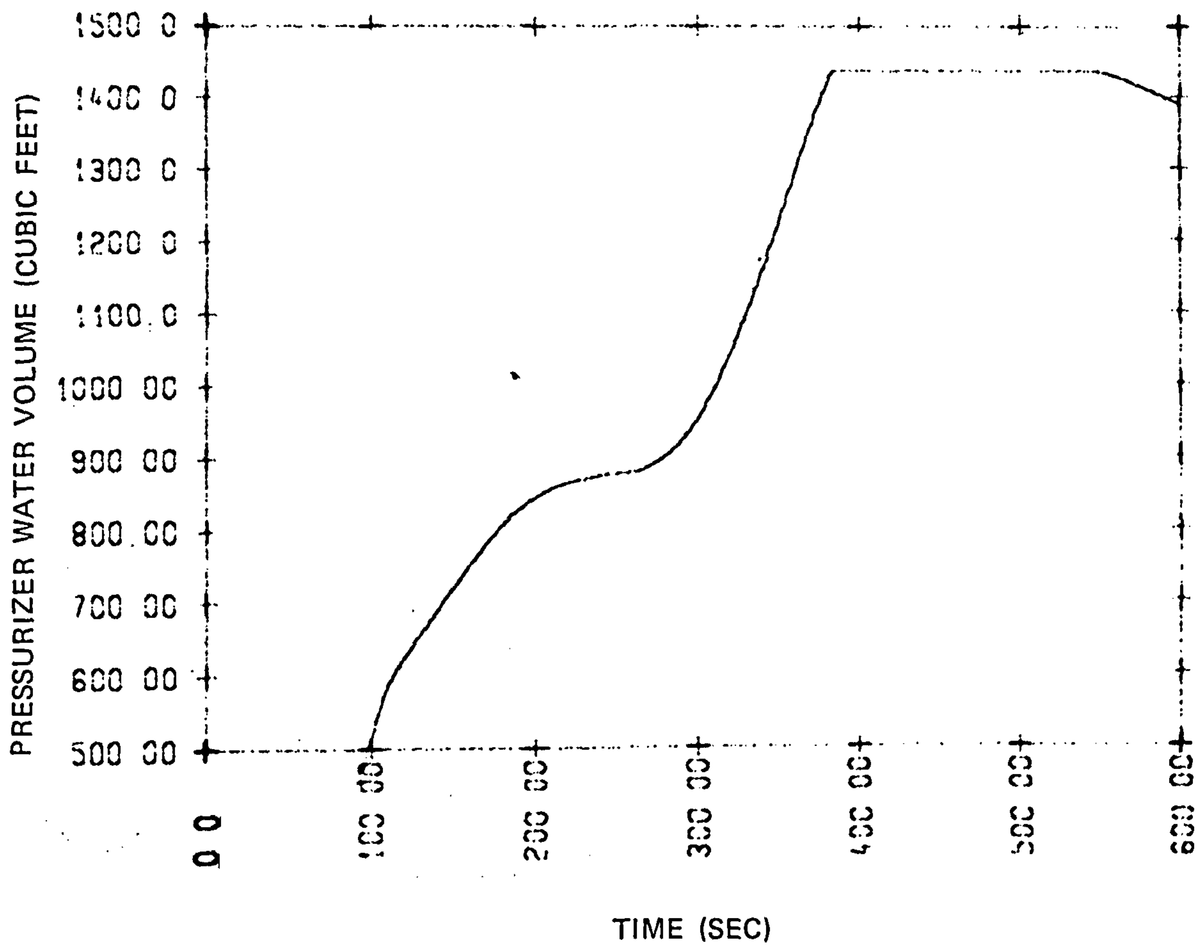

Figure 4-13. Rod Withdrawal from Subcritical – 3-Loop Plant
(Pressurizer Water Volume Vs. Time)

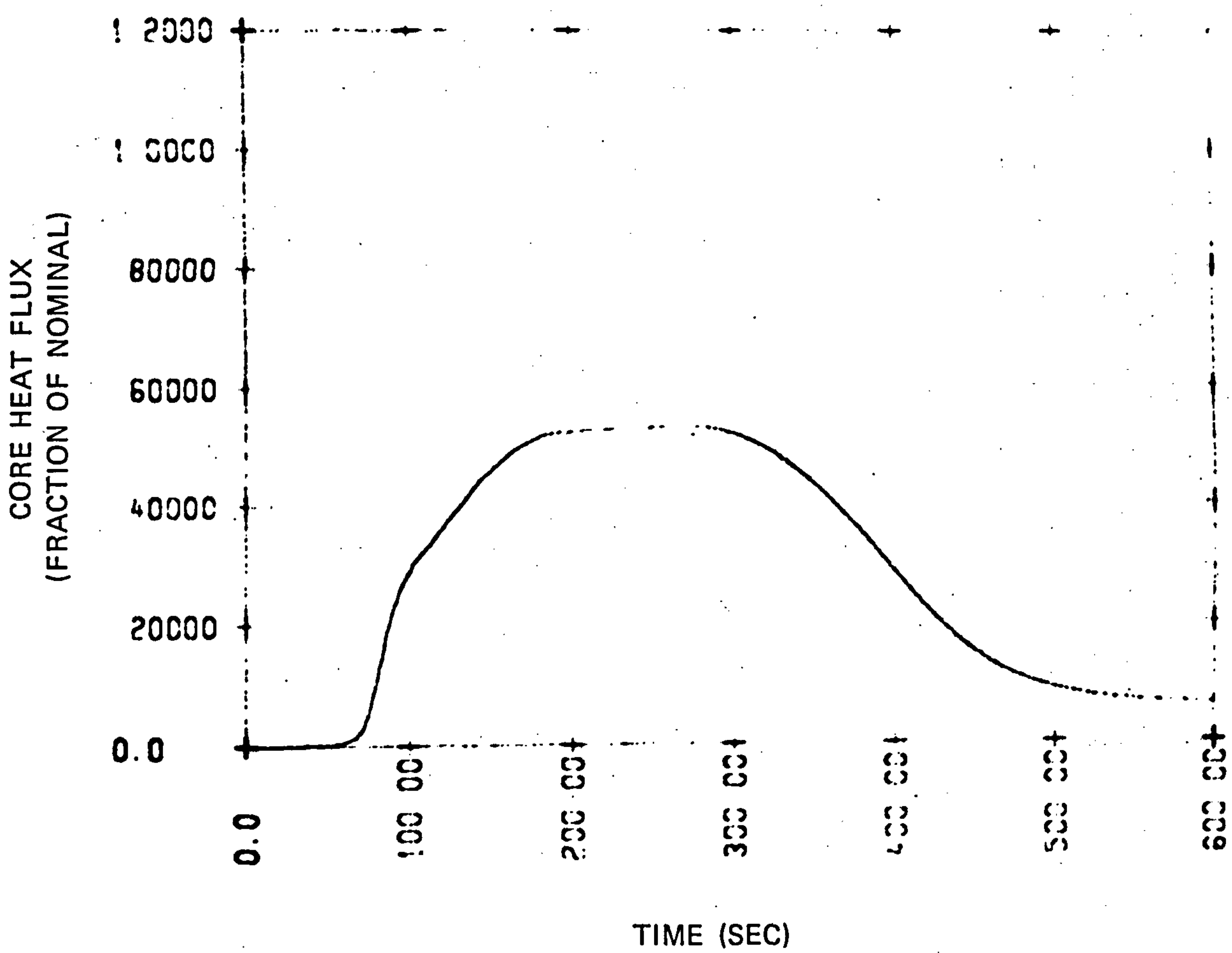

Figure 4-14. Rod Withdrawal from Subcritical – 2-Loop Plant
(Core Heat Flux Vs. Time)

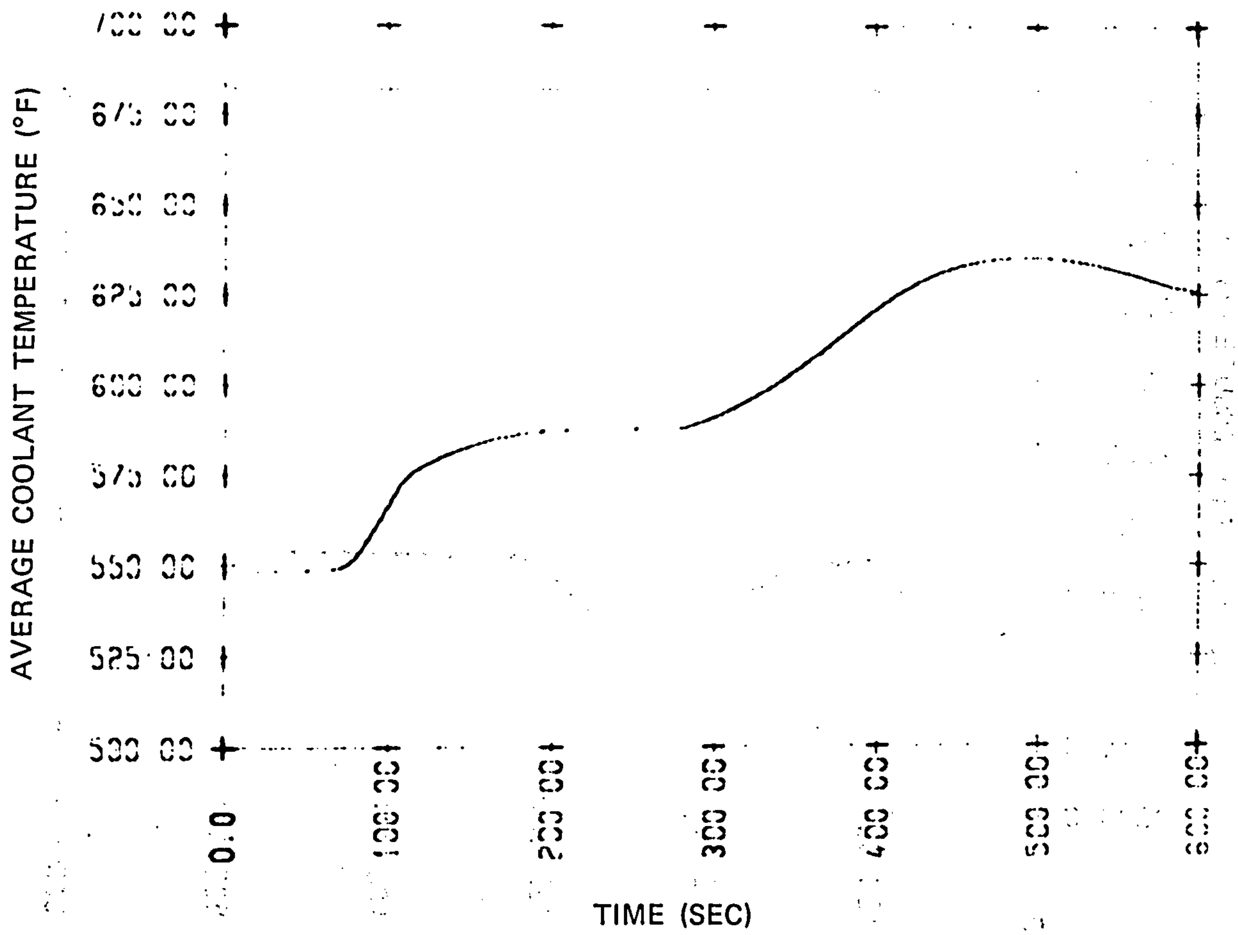

Figure 4-15. Rod Withdrawal from Subcritical — 2-Loop Plant (Average Coolant Temperature Vs. Time)

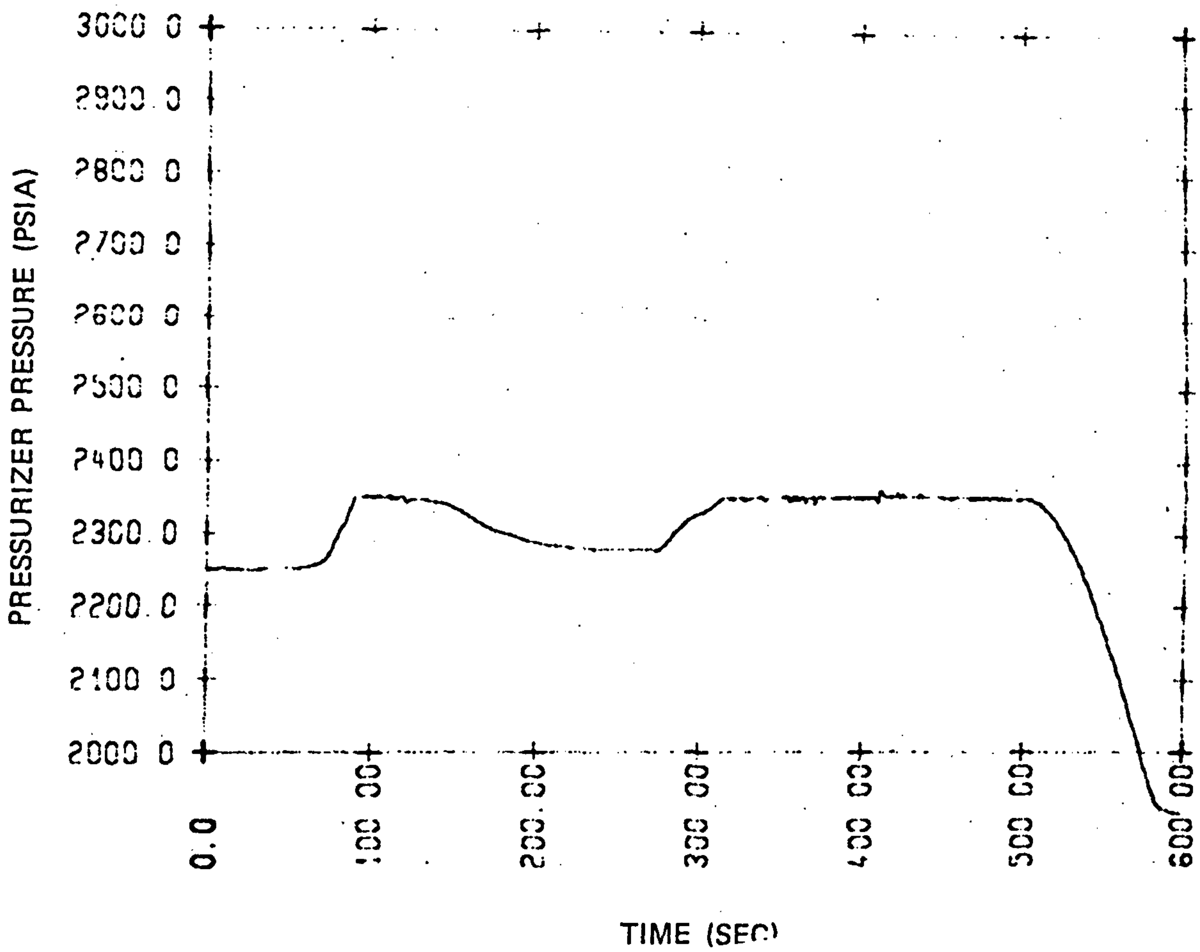

Figure 4-16. Rod Withdrawal from Subcritical – 2-Loop Plant (Pressurizer Pressure Vs. Time)

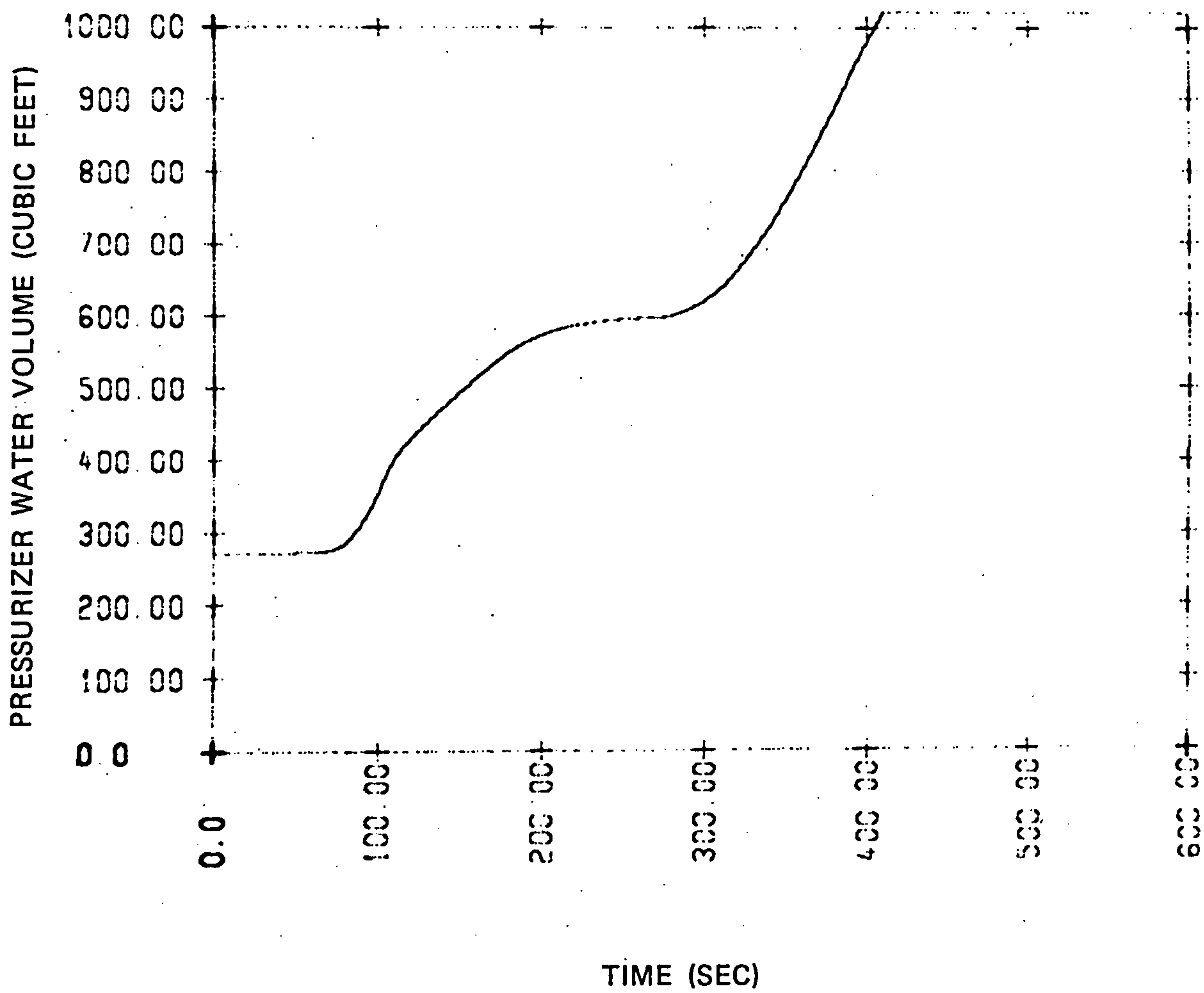

Figure 4-17. Rod Withdrawal from Subcritical – 2-Loop Plant (Pressurizer Water Volume Vs. Time)

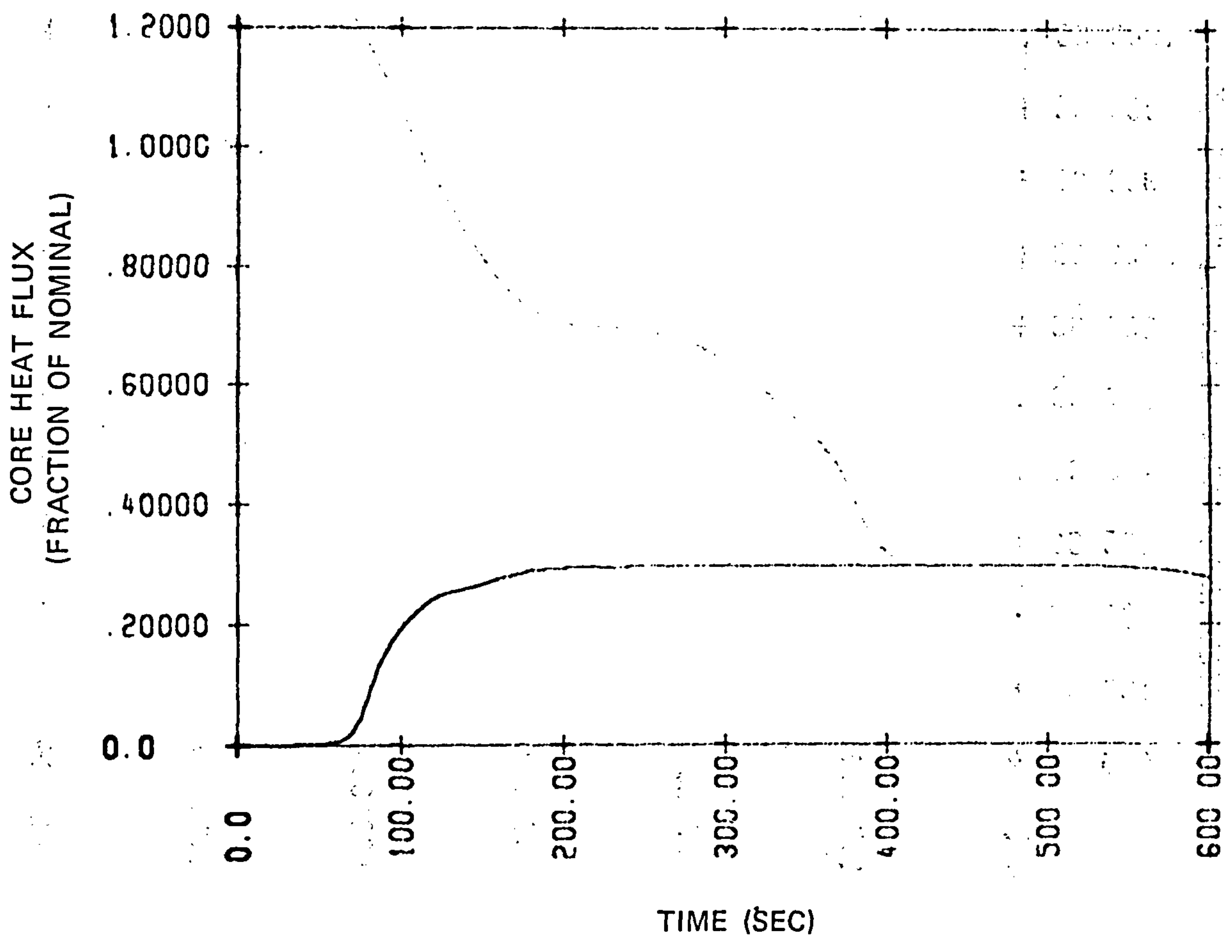

Figure 4-18. Rod Withdrawal from Subcritical — 1 of 4 RCP's Running
(Core Heat Flux Vs. Time)

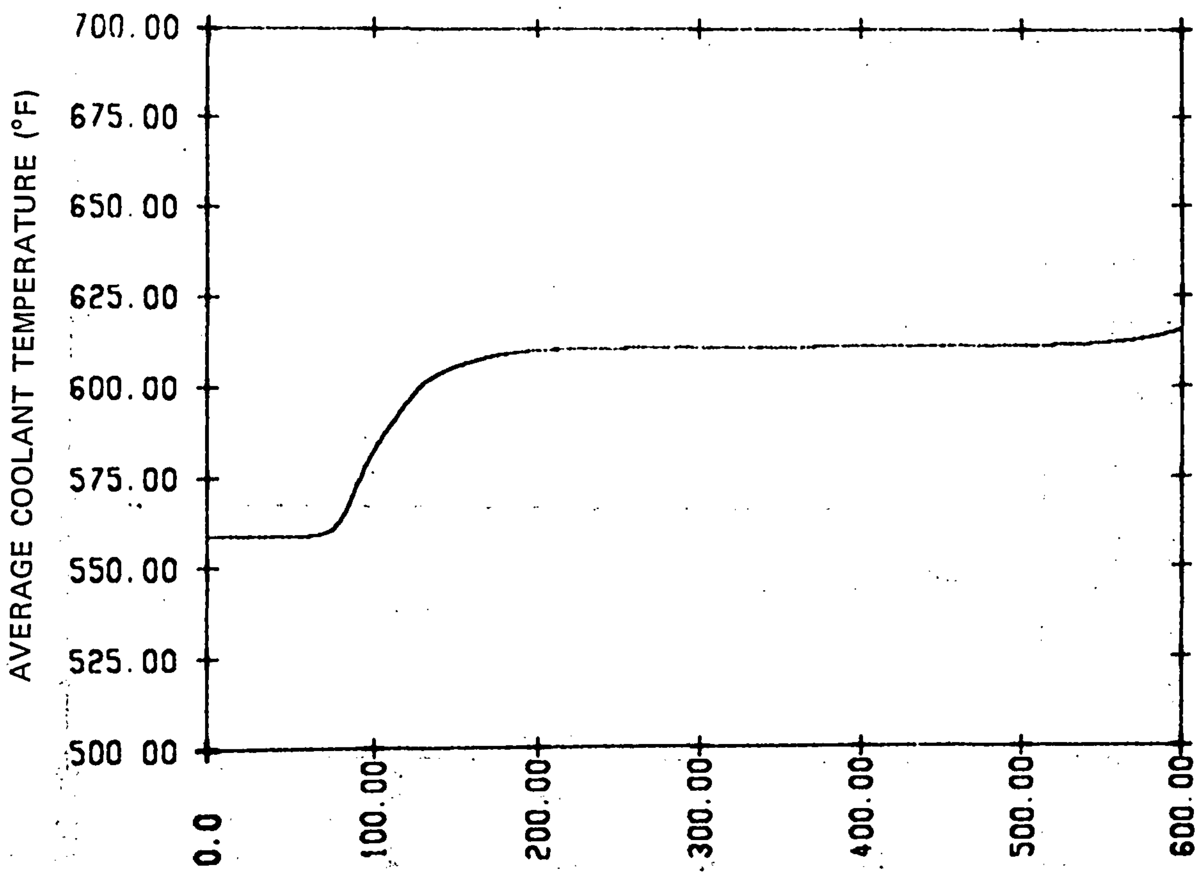

Figure 4-19. Rod Withdrawal from Subcritical — 1 of 4 RCP's Running (Average Coolant Temperature Vs. Time)

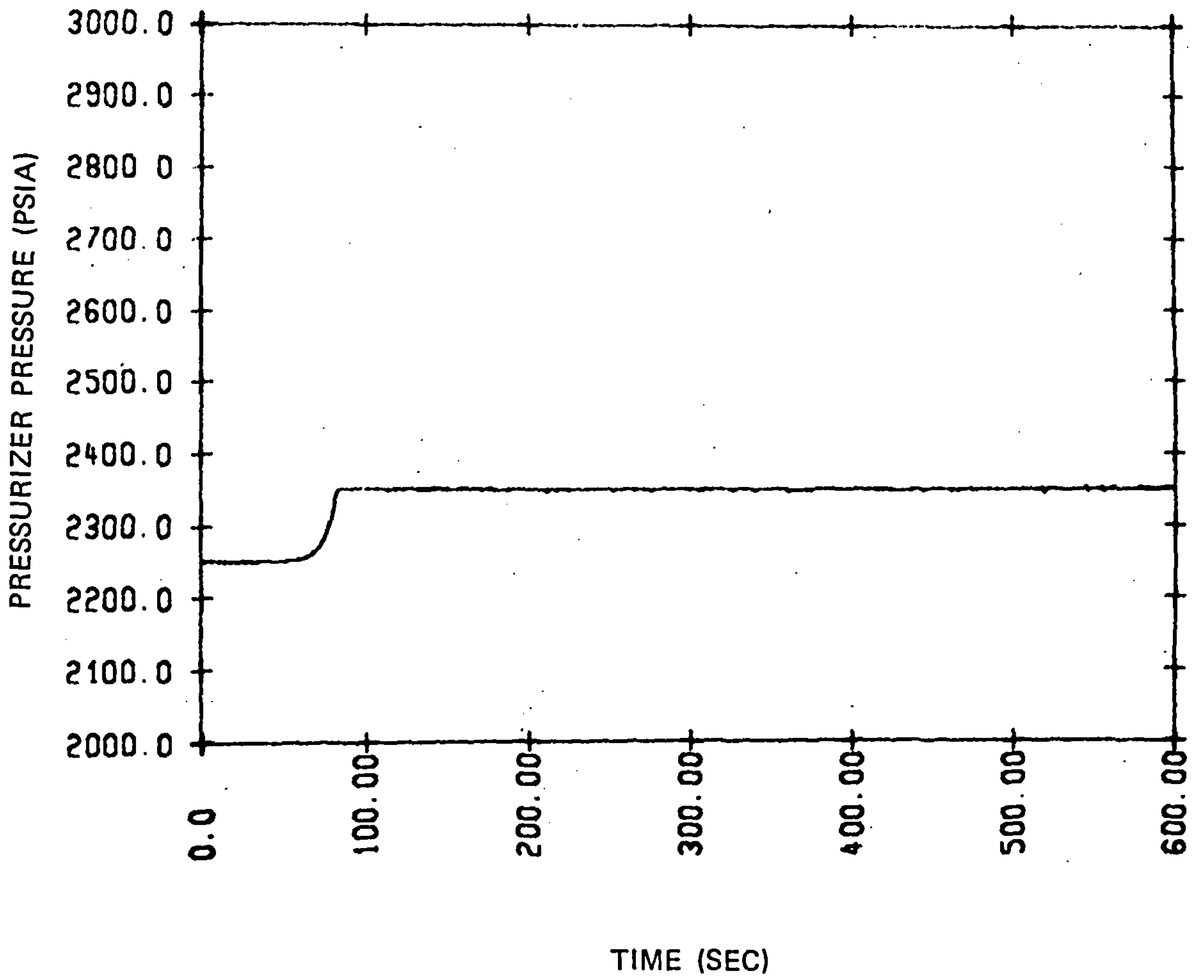

Figure 4-20. Rod Withdrawal from Subcritical – 1 of 4 RCP's Running (Pressurizer Pressure Vs. Time)

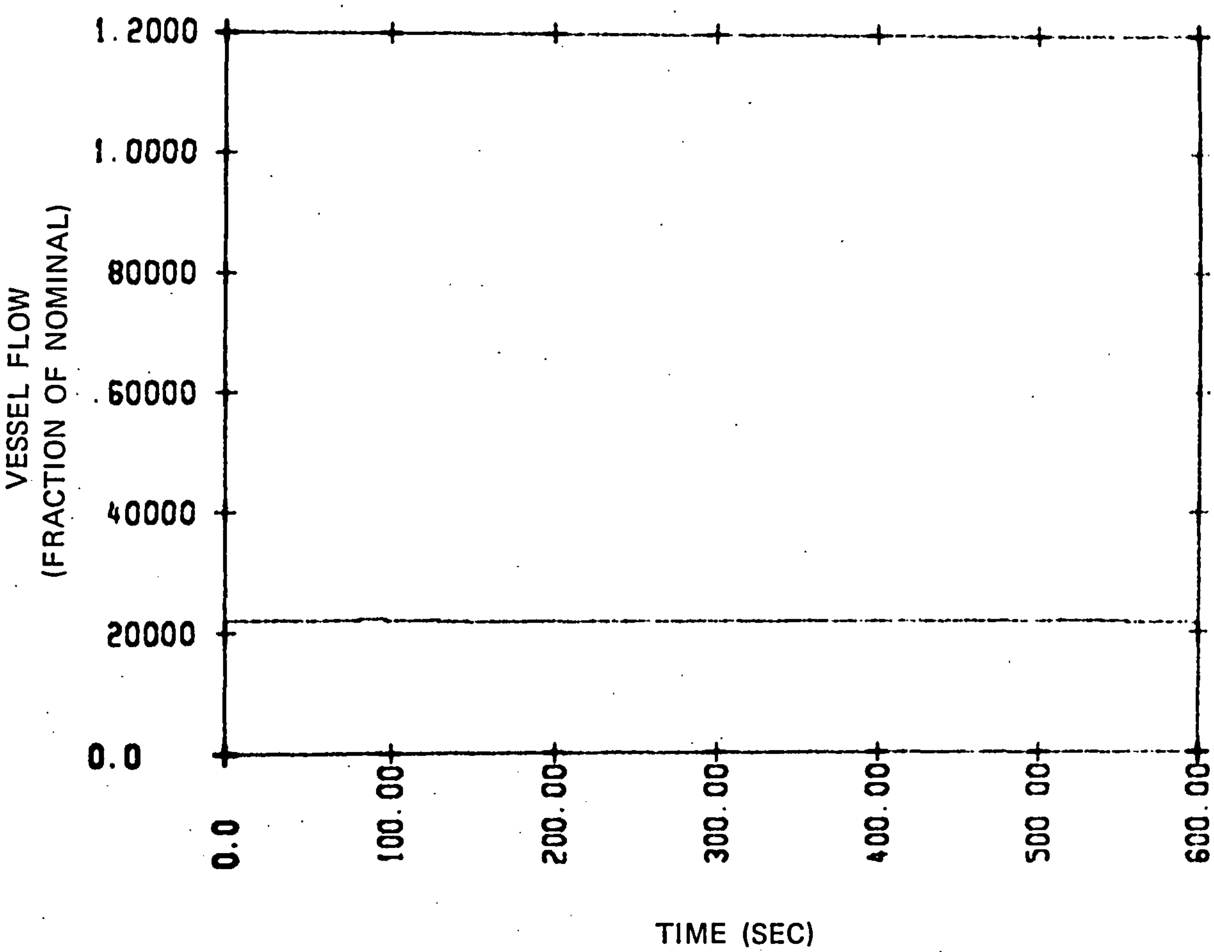

Figure 4-21. Rod Withdrawal from Subcritical – 1 of 4 RCP's Running (Vessel Flow Vs. Time)

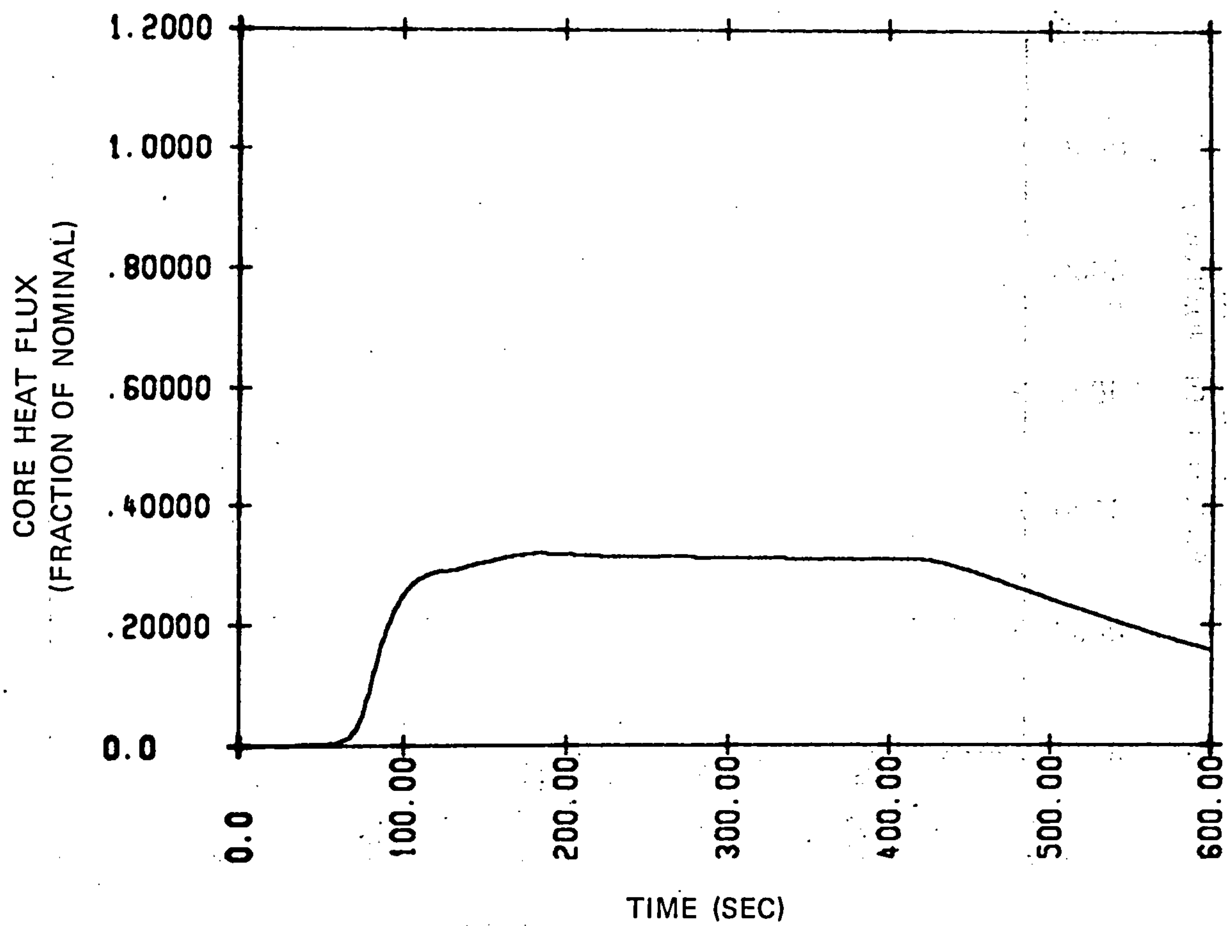

Figure 4-22. Rod Withdrawal from Subcritical — 2 of 4 RCP's Running
(Core Heat Flux Vs. Time)

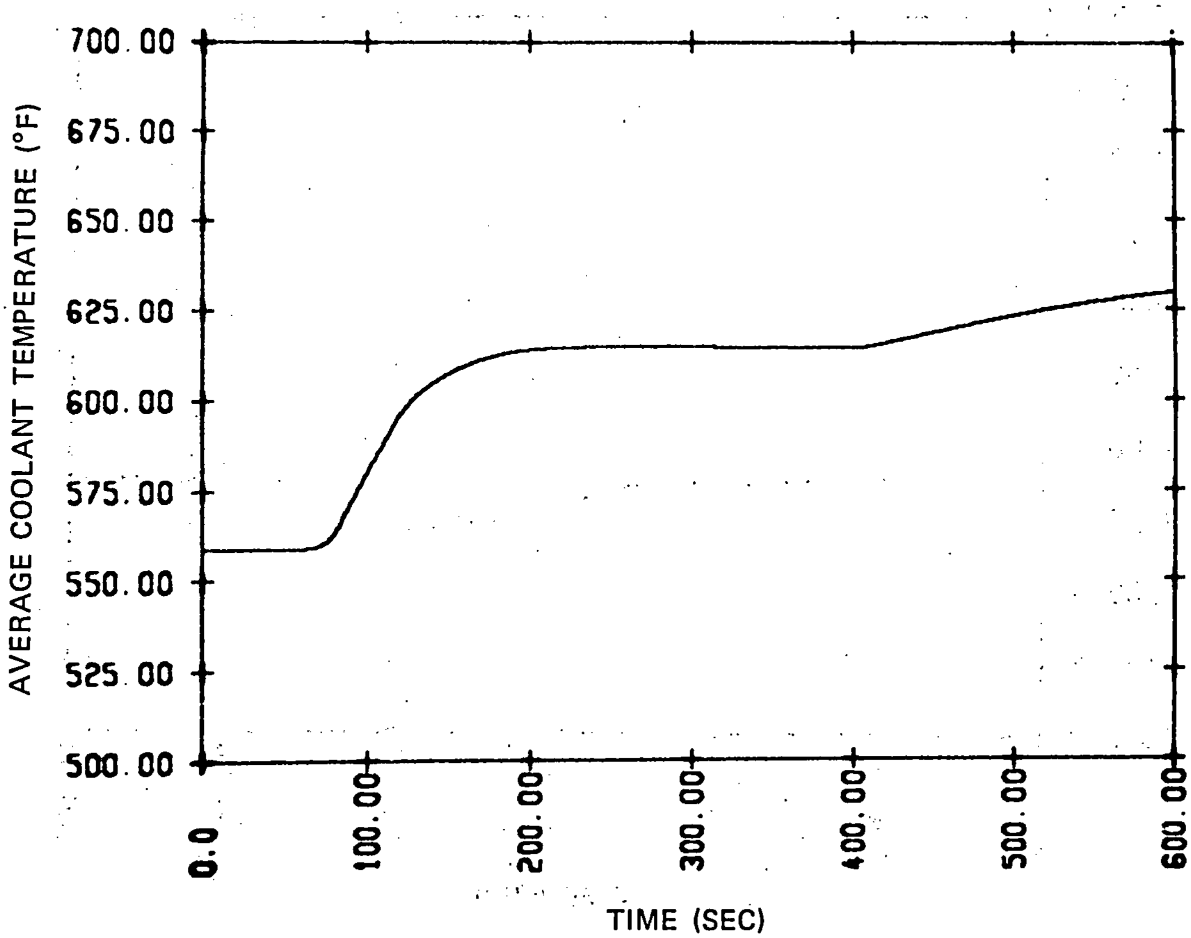

Figure 4-23. Rod Withdrawal from Subcritical – 2 of 4 RCP's Running (Average Coolant Temperature Vs. Time)

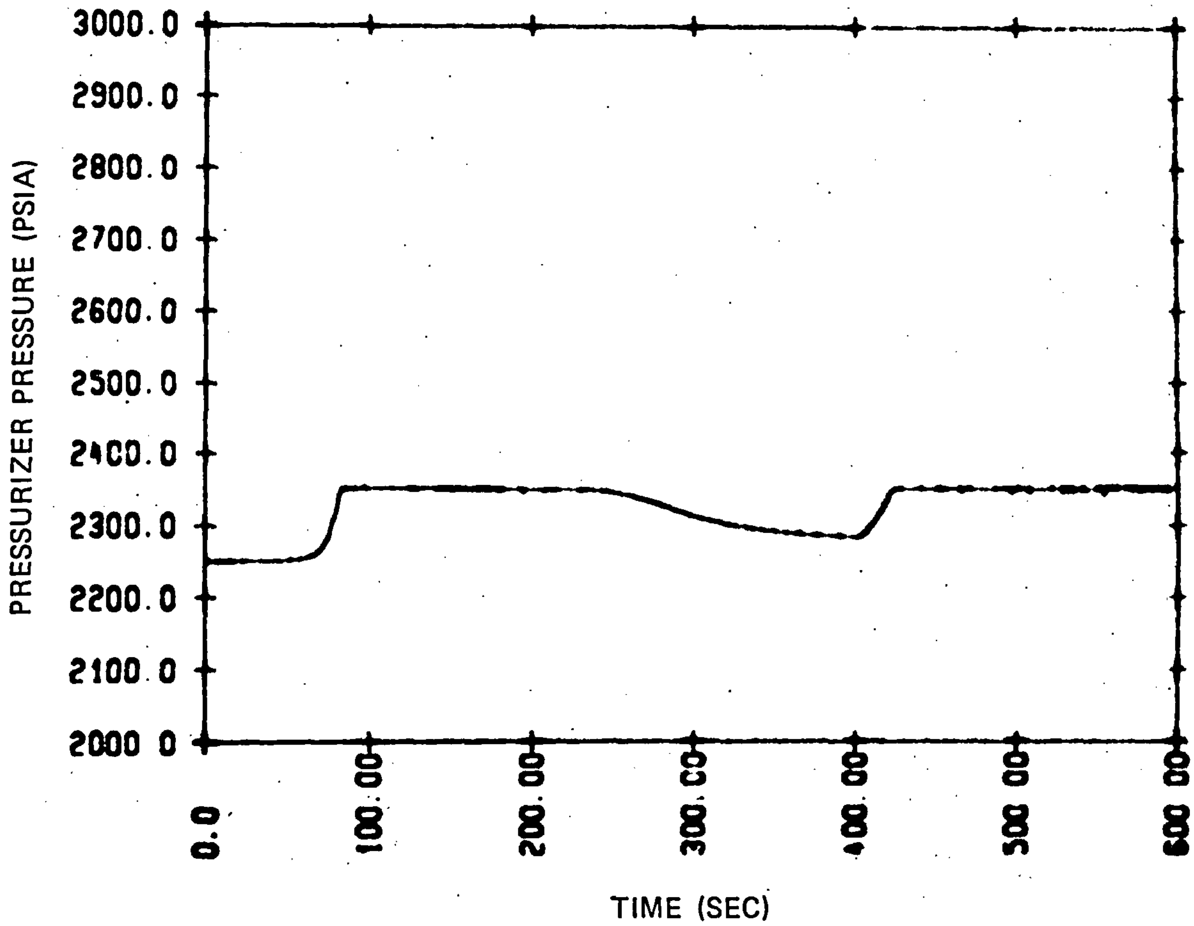

Figure 4-24. Rod Withdrawal from Subcritical – 2 of 4 RCP's Running (Pressurizer Pressure Vs. Time)

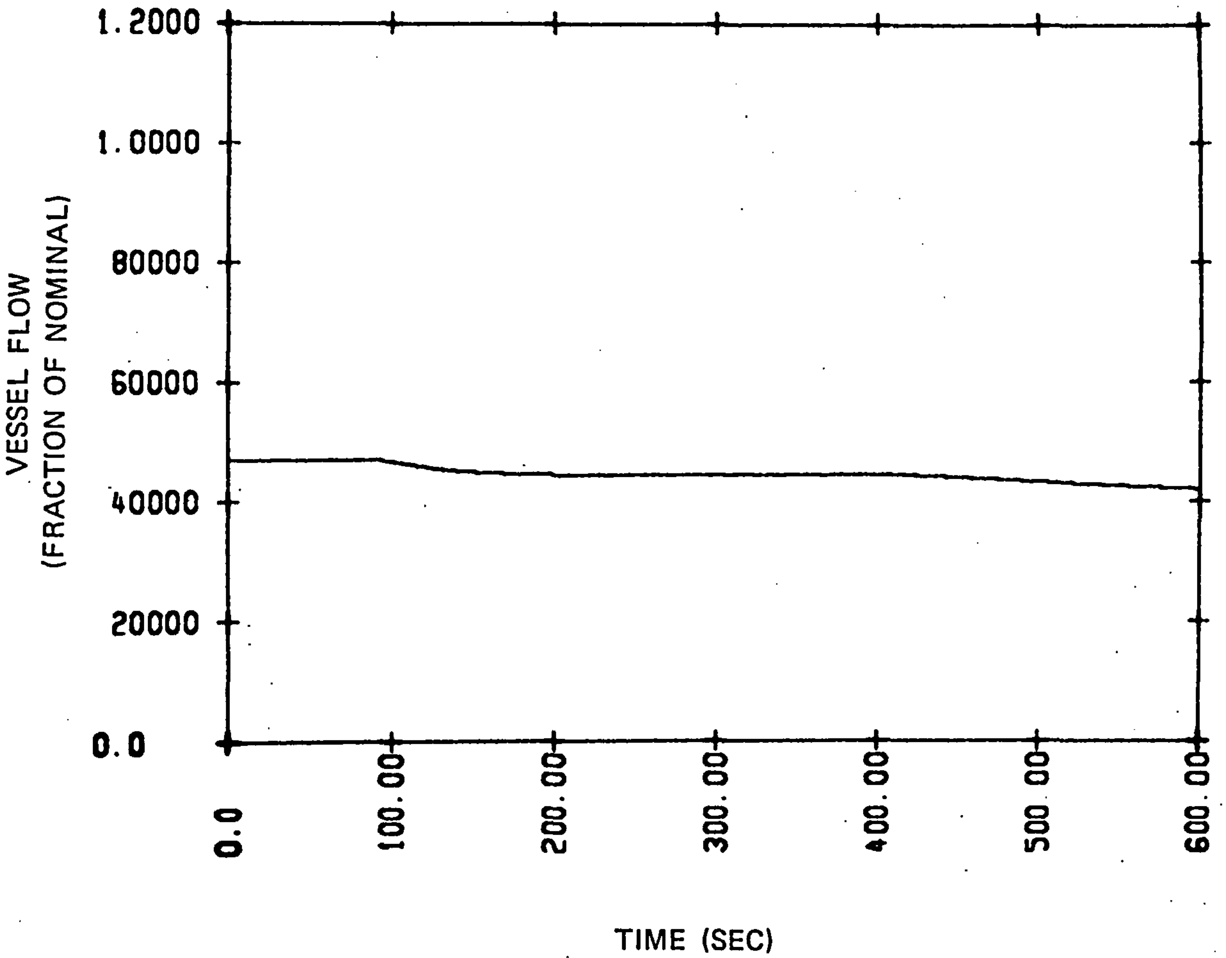

Figure 4-25. Rod Withdrawal from Subcritical – 2 of 4 RCP's Running (Vessel Flow Vs. Time)

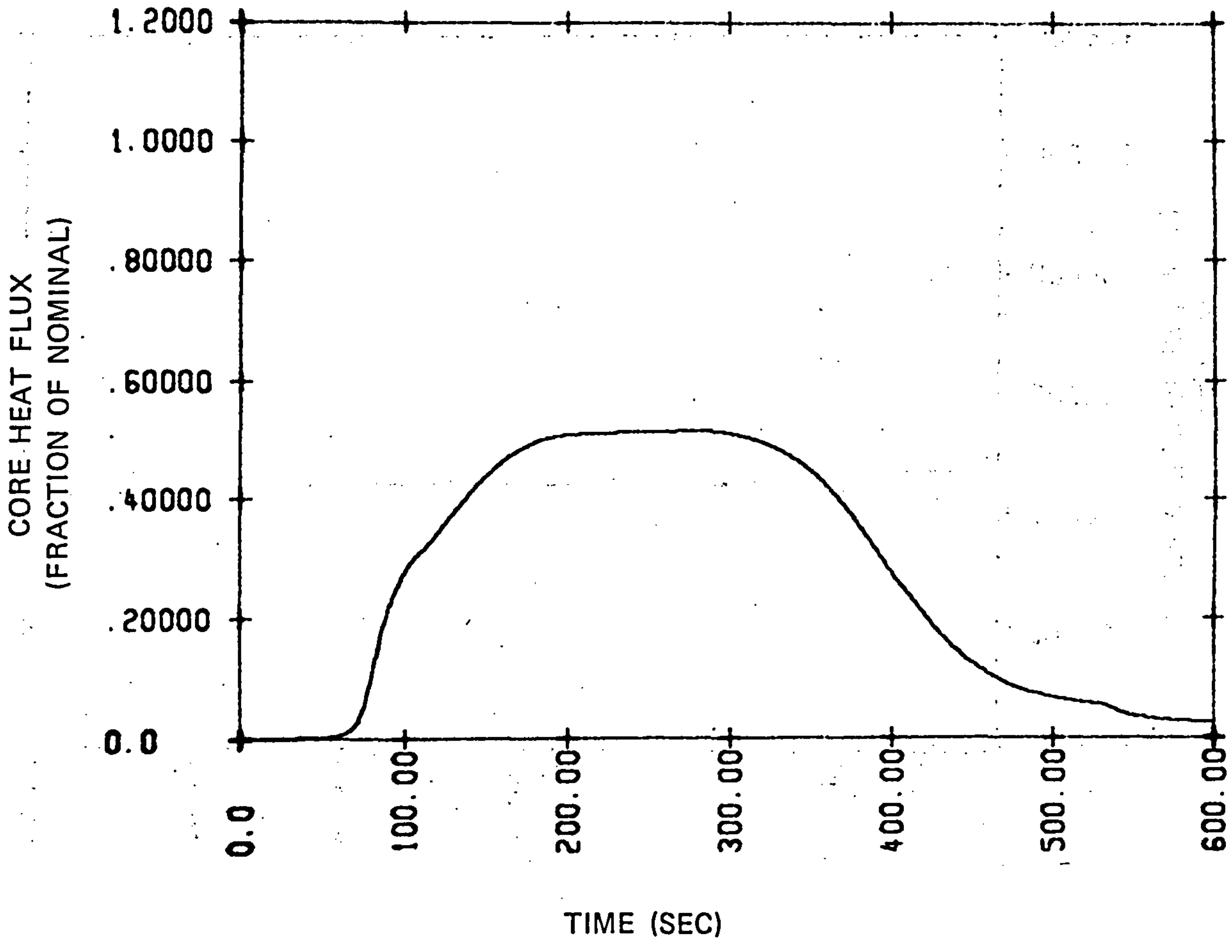

Figure 4-26. Rod Withdrawal from Subcritical — 3 of 4 RCP's Running (Core Heat Flux Vs. Time)

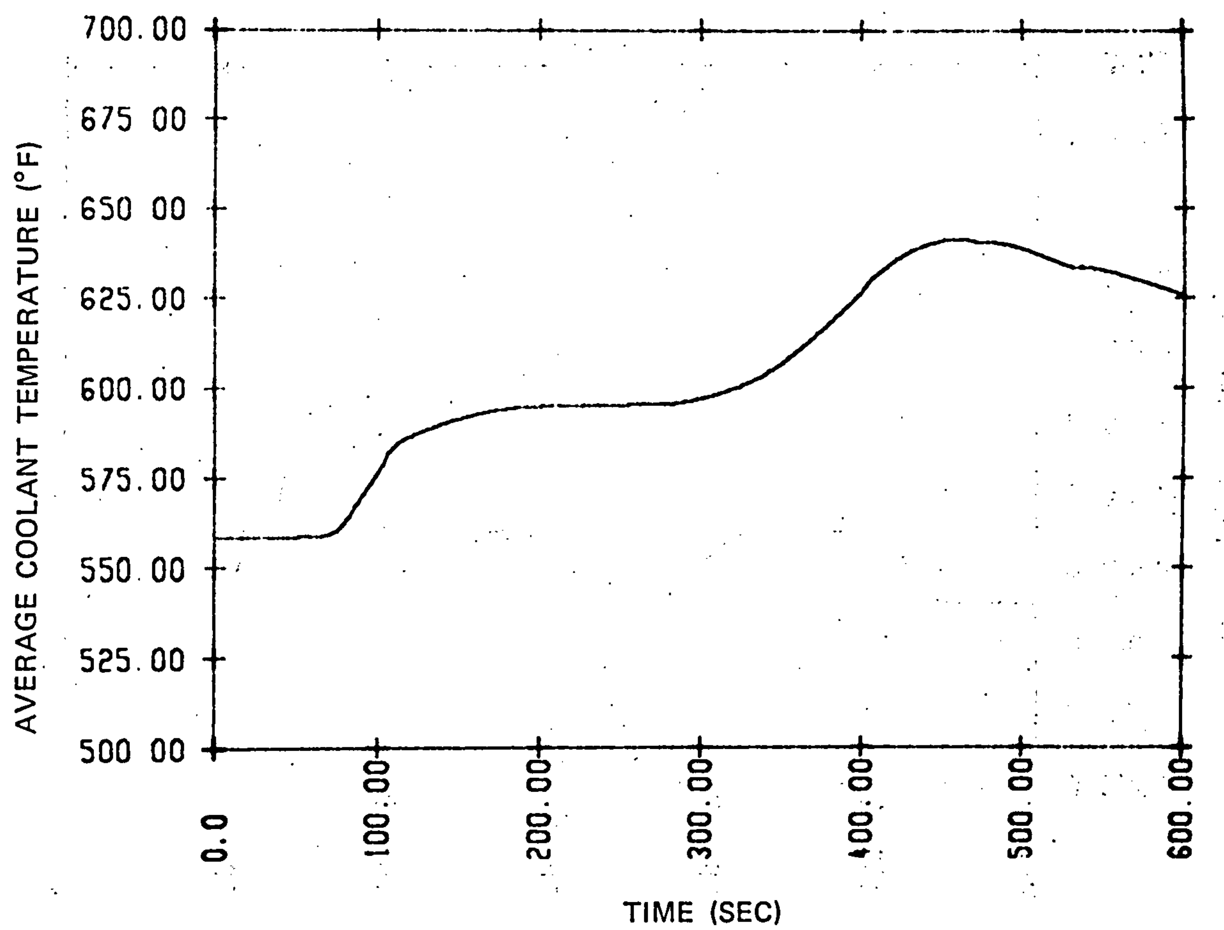

Figure 4-27. Rod Withdrawal from Subcritical — 3 of 4 RCP's Running (Average Coolant Temperature Vs. Time)

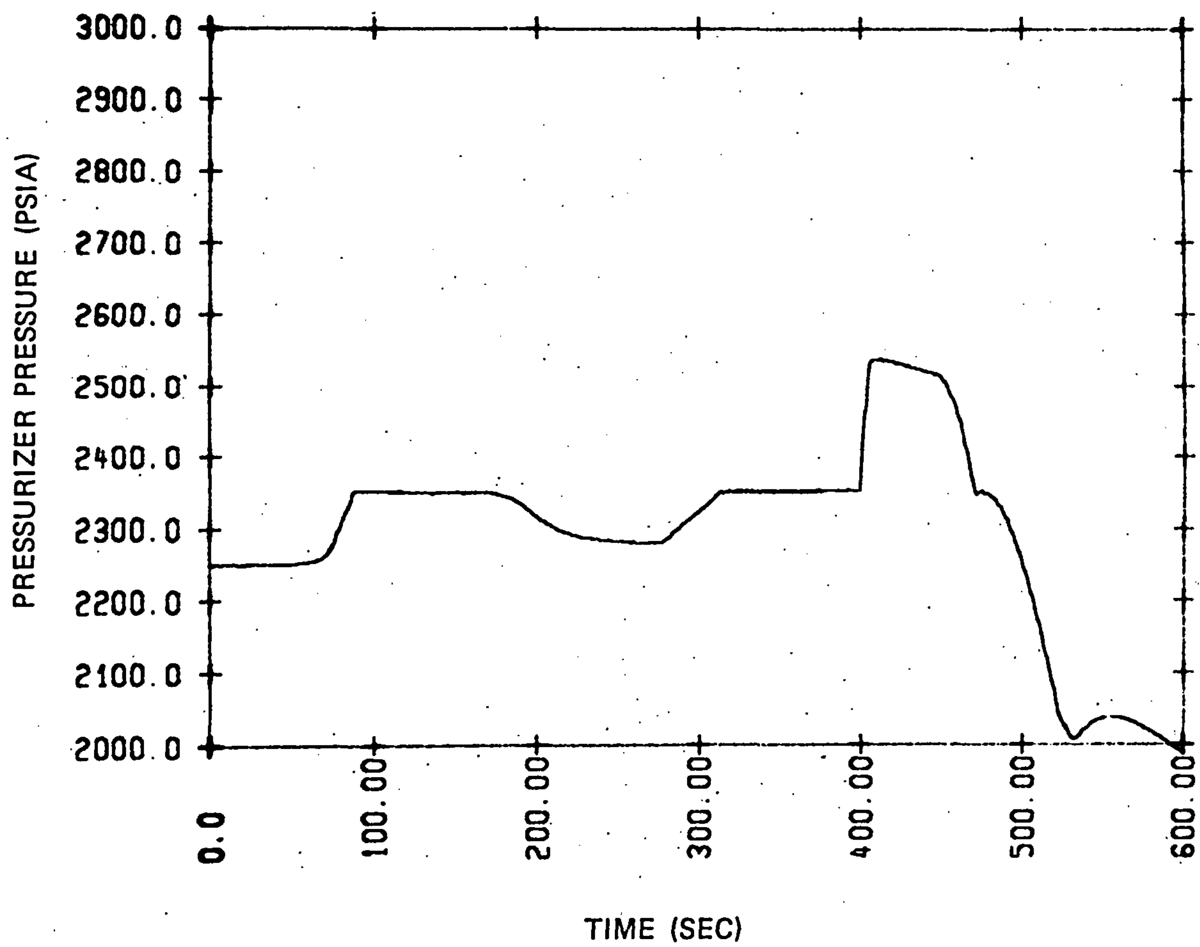

Figure 4-28. Rod Withdrawal from Subcritical – 3 of 4 RCP's Running (Pressurizer Pressure Vs. Time)

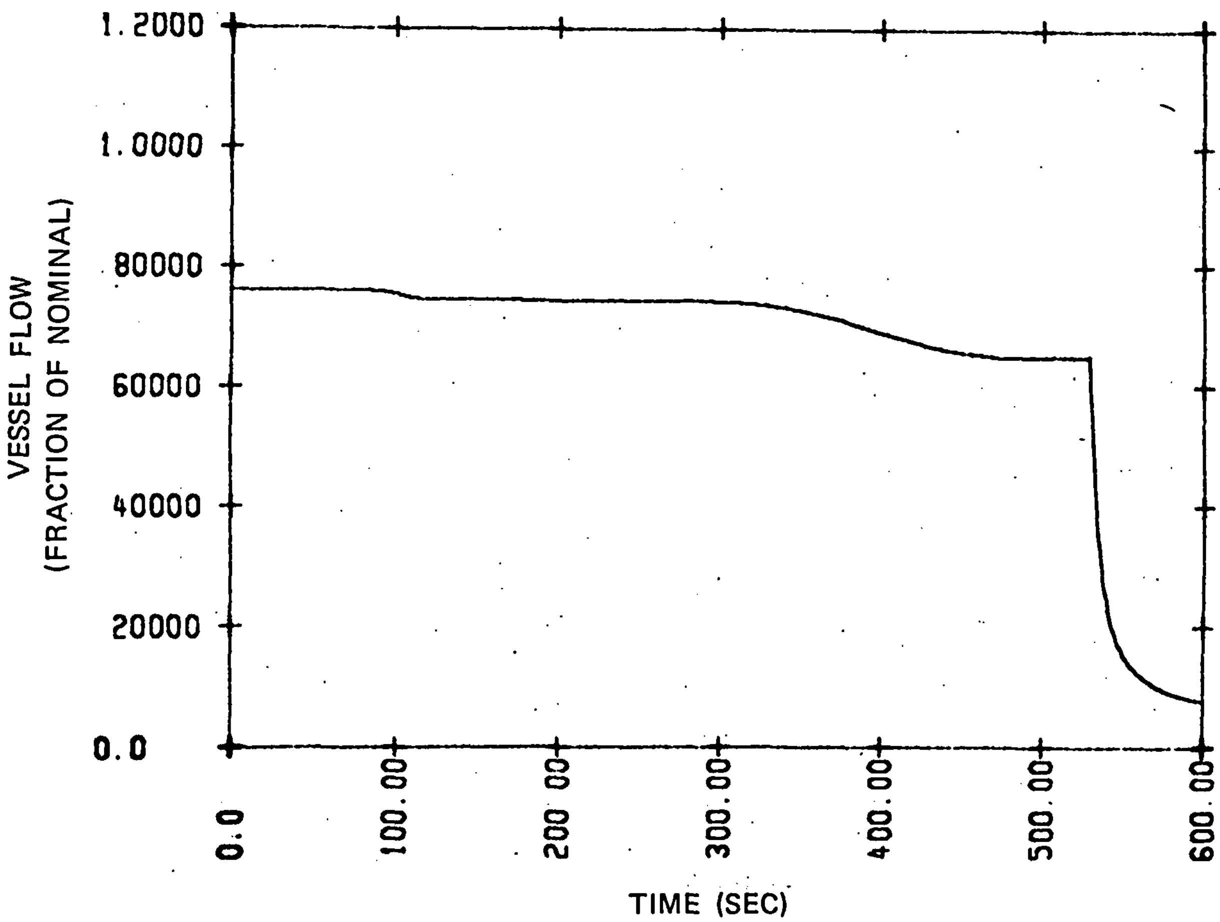

Figure 4-29. Rod Withdrawal from Subcritical — 3 of 4 RCP's Running (Vessel Flow Vs. Time)

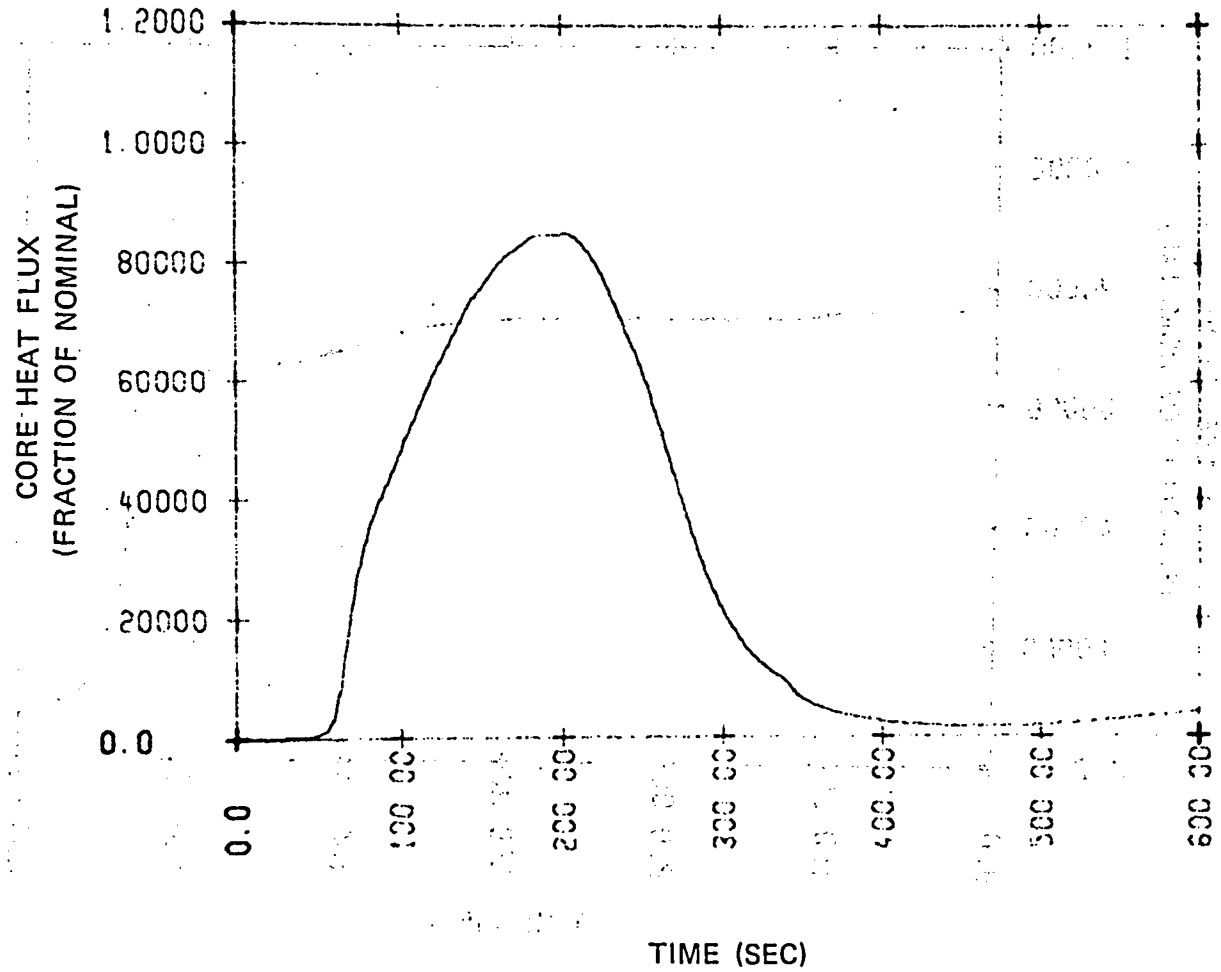

Figure 4-30. Rod Withdrawal from Subcritical — 1.6 Percent Inserted Reactivity (Core Heat Flux Vs. Time)

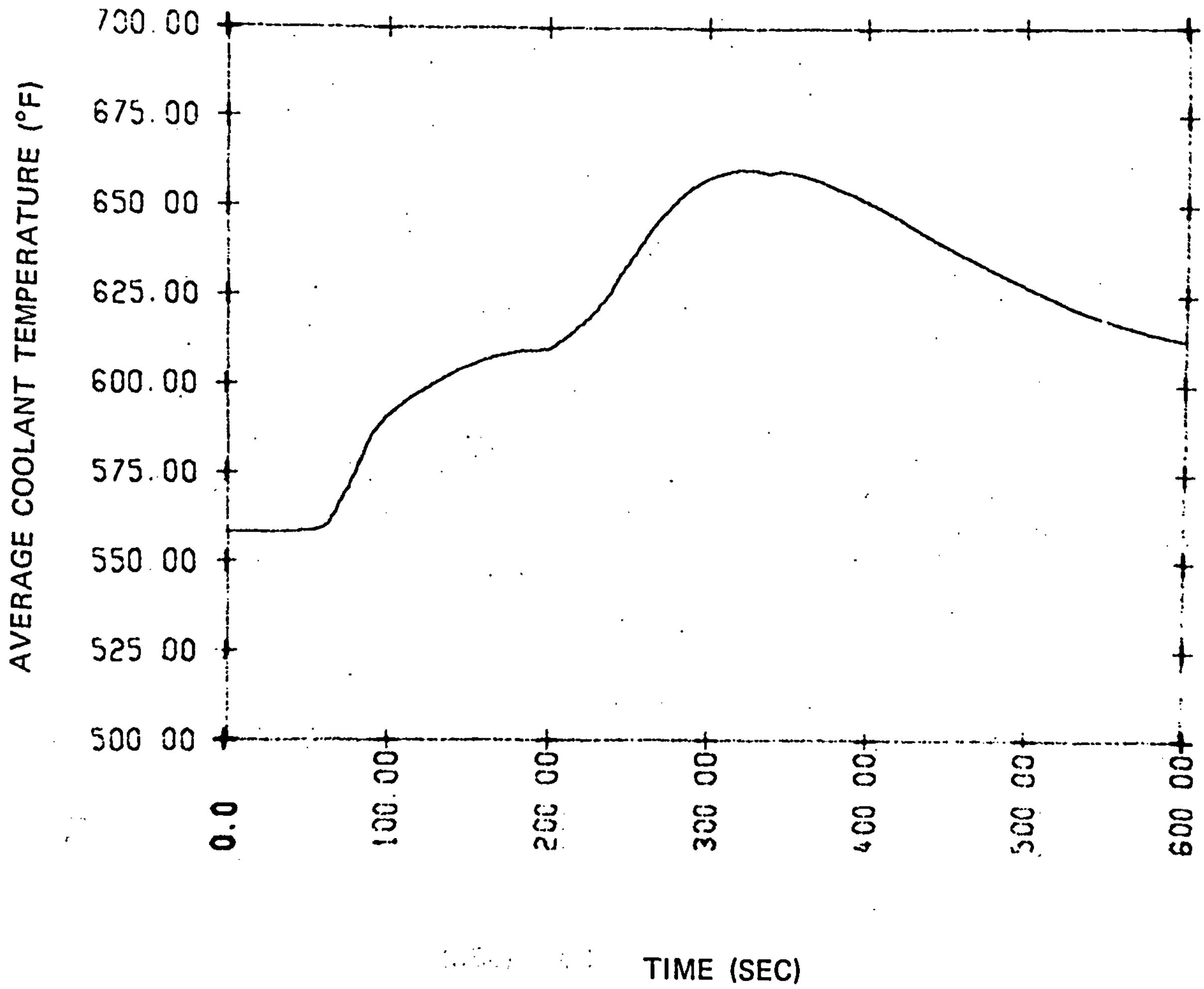

Figure 4-31. Rod Withdrawal from Subcritical — 1.6 Percent Inserted Reactivity (Average Coolant Temperature Vs. Time)

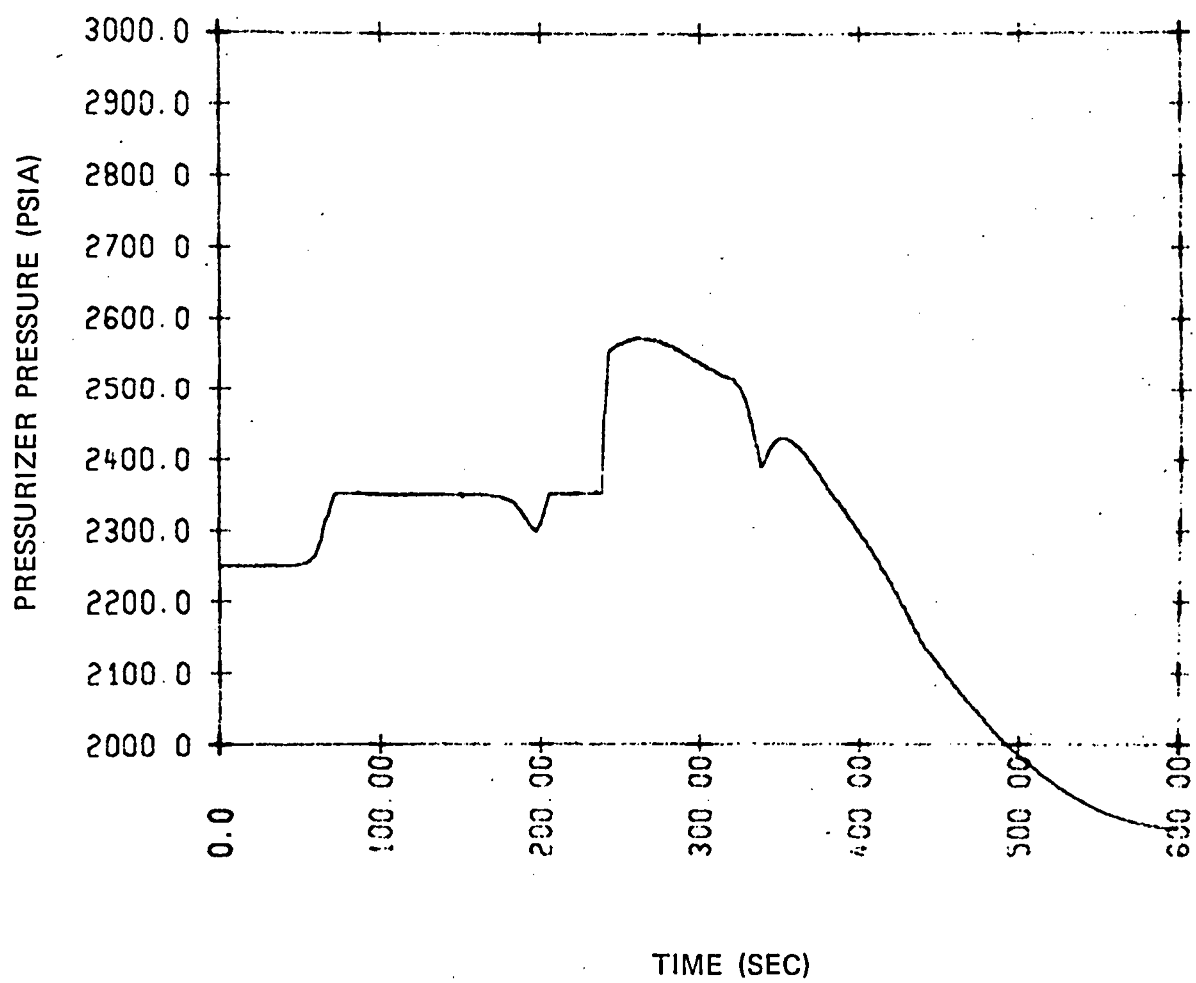

Figure 4-32. Rod Withdrawal from Subcritical — 1.6 Percent Inserted Reactivity (Pressurizer Pressure Vs. Time)

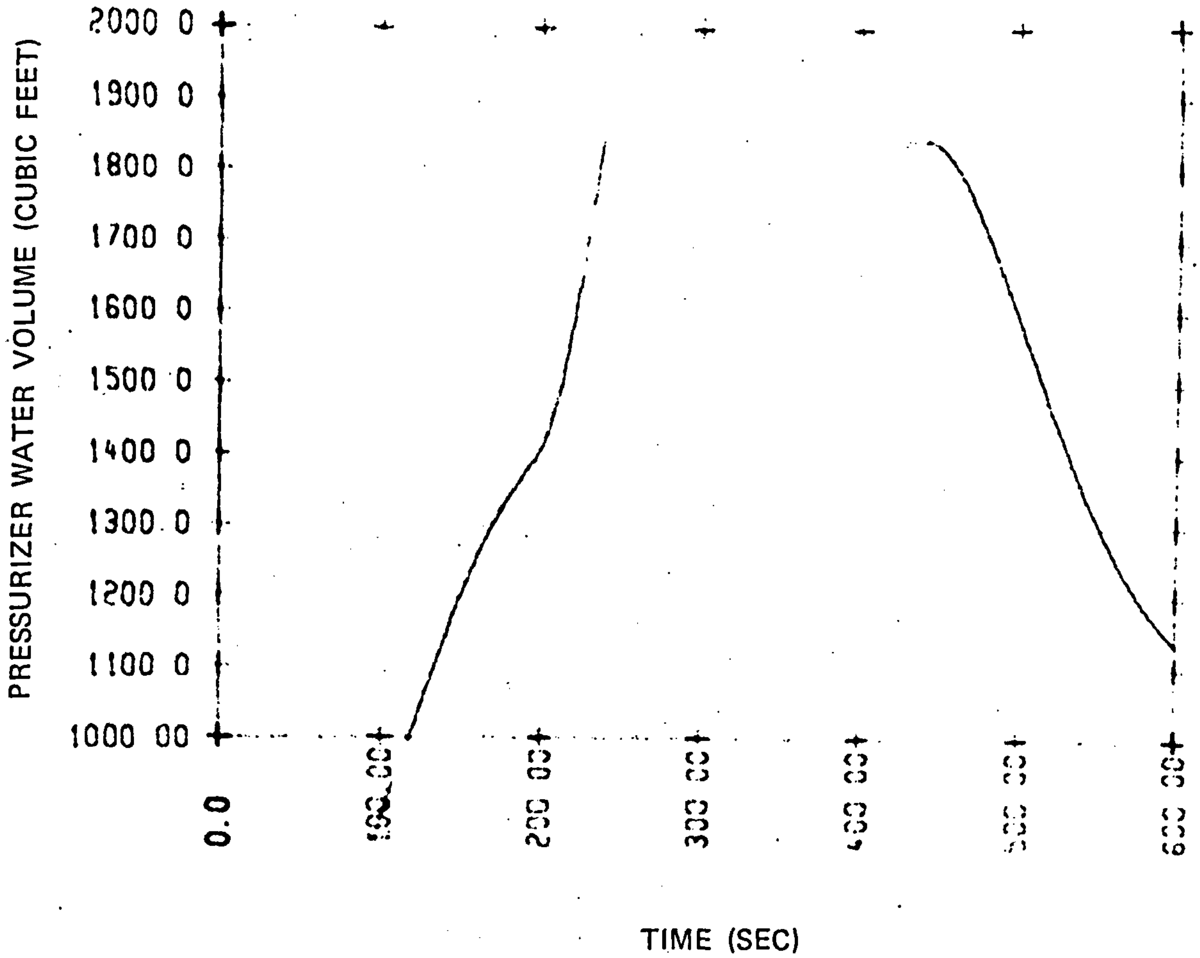

Figure 4-33. Rod Withdrawal from Subcritical — 1.6 Percent Inserted Reactivity (Pressurizer Water Volume Vs. Time)

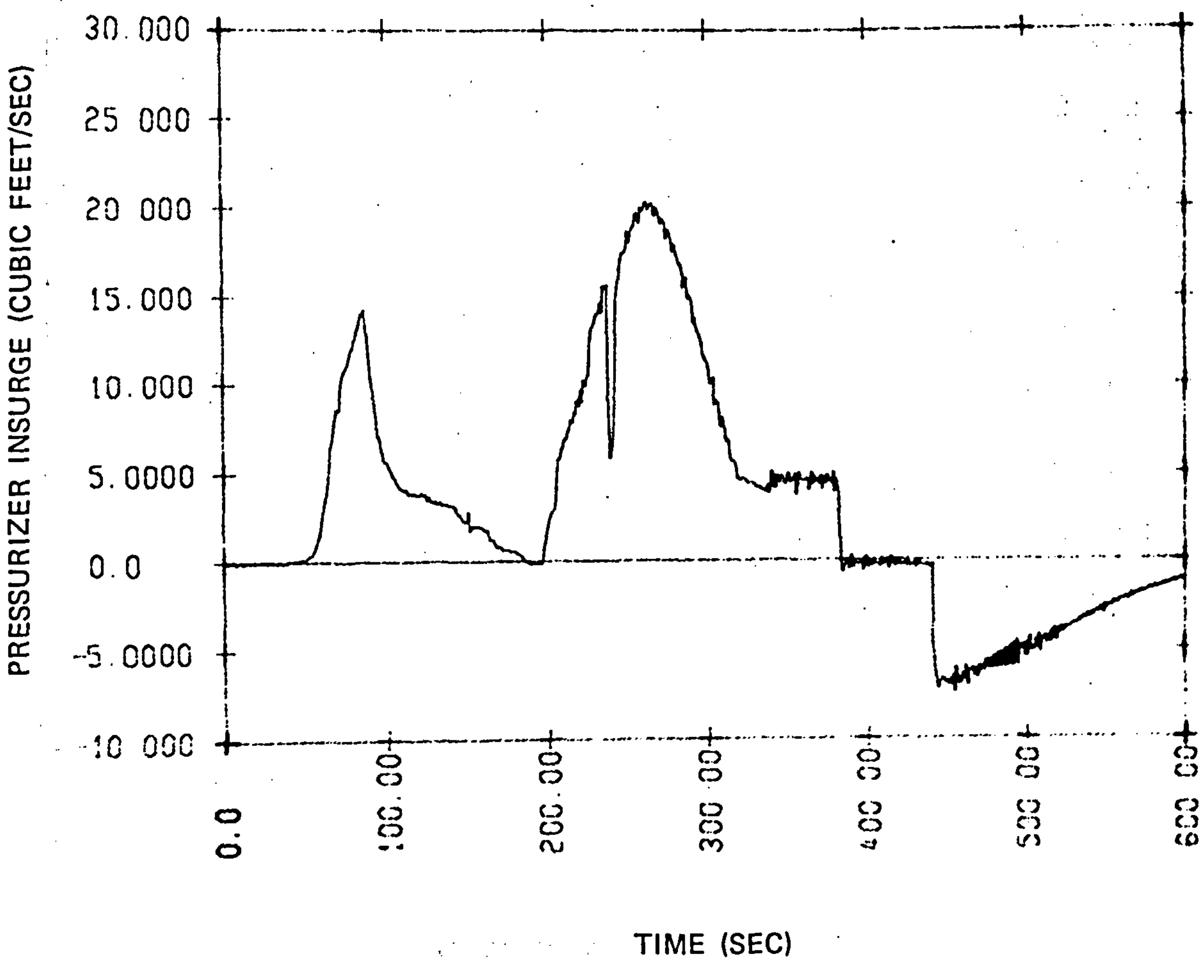

Figure 4-34. Rod Withdrawal from Subcritical — 1.6 Percent Inserted Reactivity (Pressurizer Insurge Vs. Time)

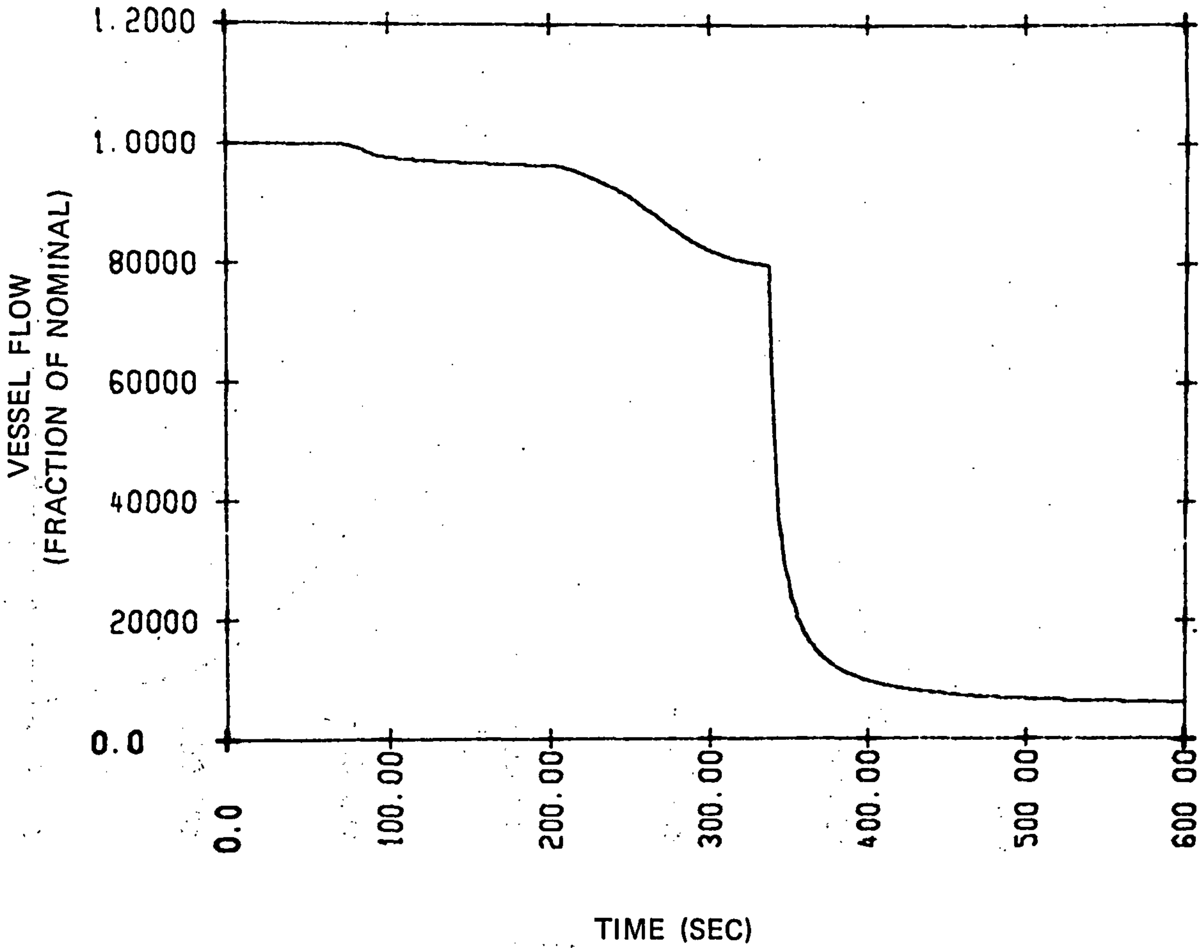

Figure 4-35. Rod Withdrawal from Subcritical — 1.6 Percent Inserted Reactivity (Vessel Flow Vs. Time)

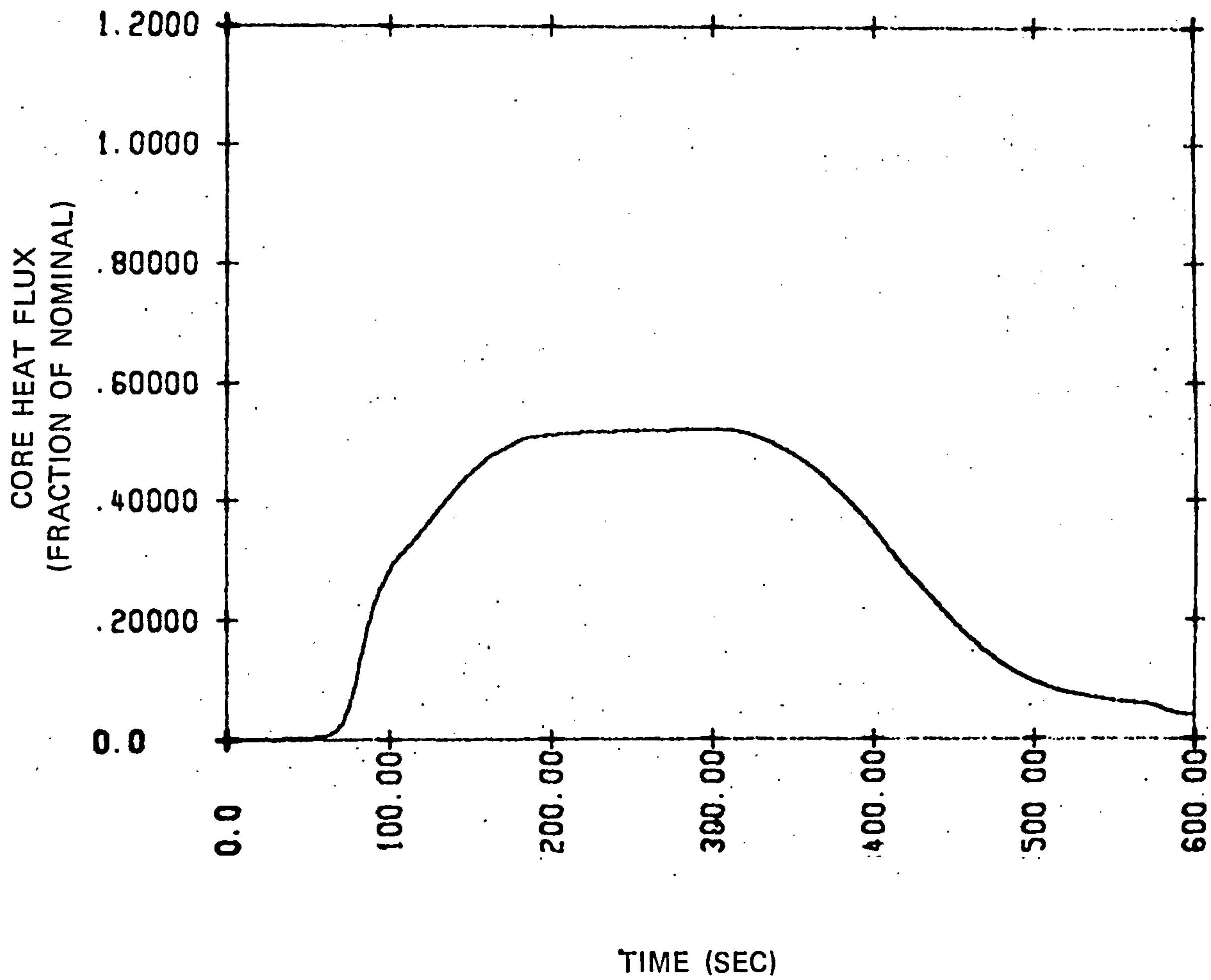

Figure 4-36. Rod Withdrawal from Subcritical – Steam Generator Mass + 10 Percent (Core Heat Flux Vs. Time)

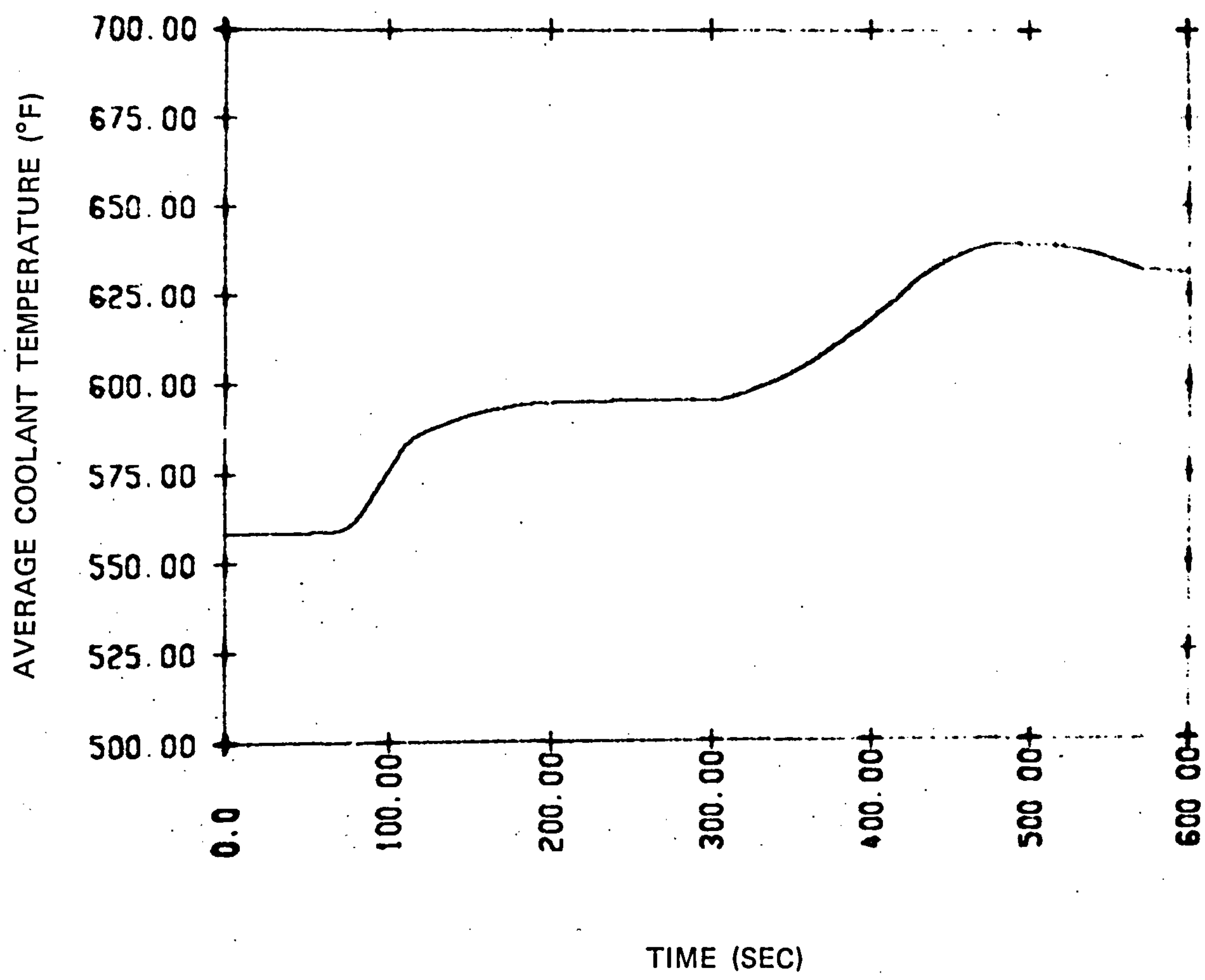

Figure 4-37. Rod Withdrawal from Subcritical – Steam Generator Mass + 10 Percent (Average Coolant Temperature Vs. Time)

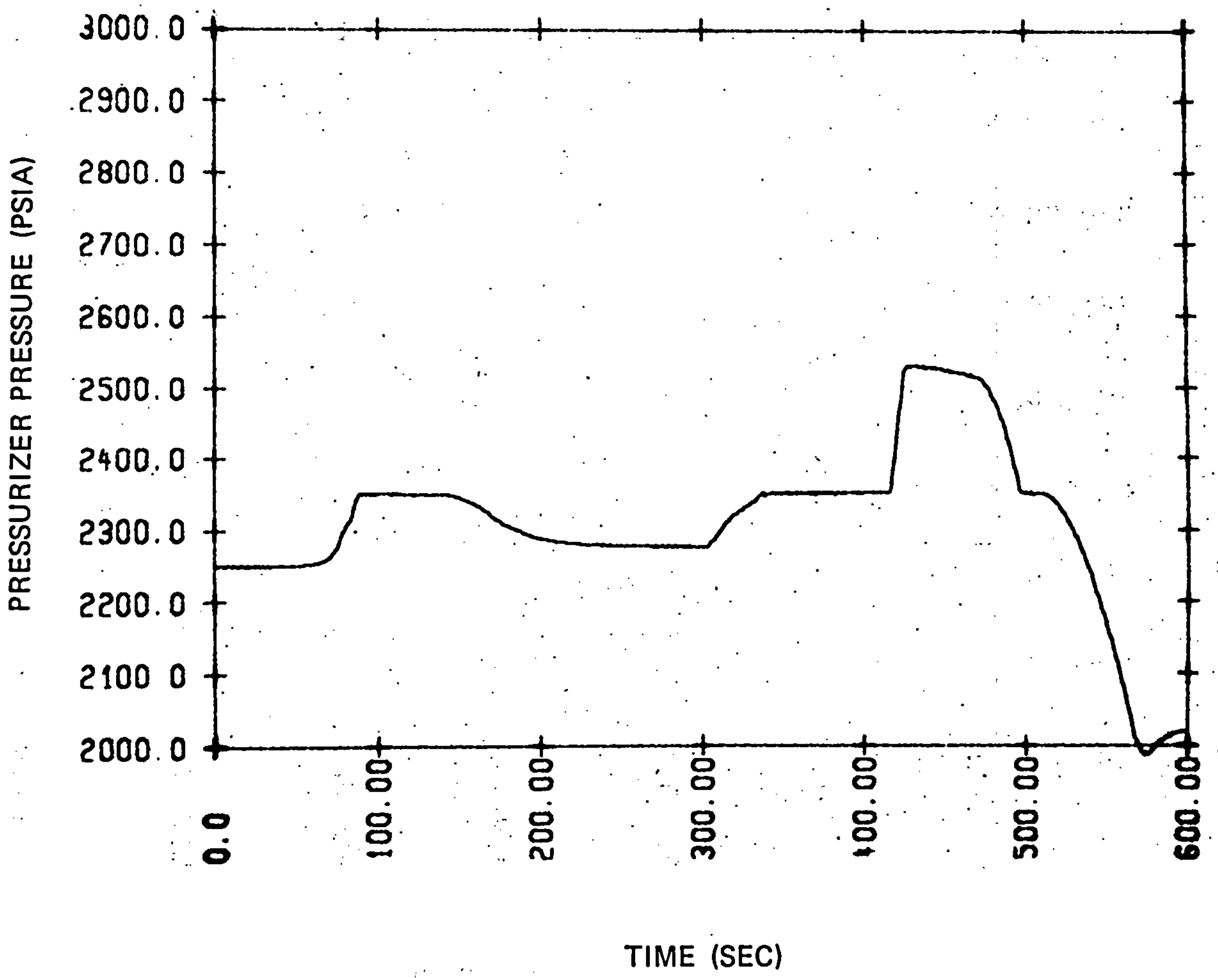

Figure 4-38. Rod Withdrawal from Subcritical — Steam Generator Mass + 10 Percent (Pressurizer Pressure Vs. Time)

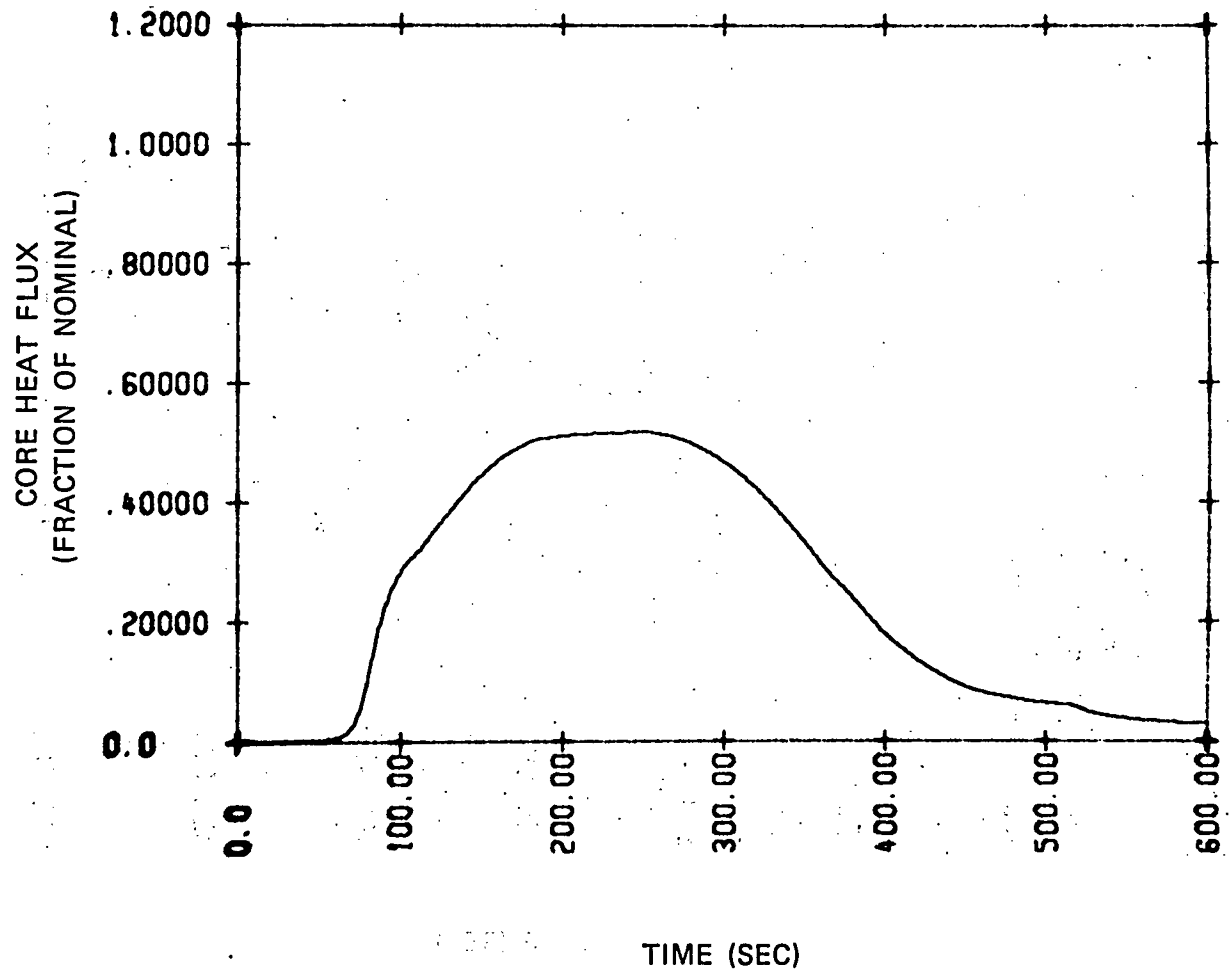

Figure 4-39. Rod Withdrawal from Subcritical — Steam Generator Mass - 10 Percent (Core Heat Flux Vs. Time)

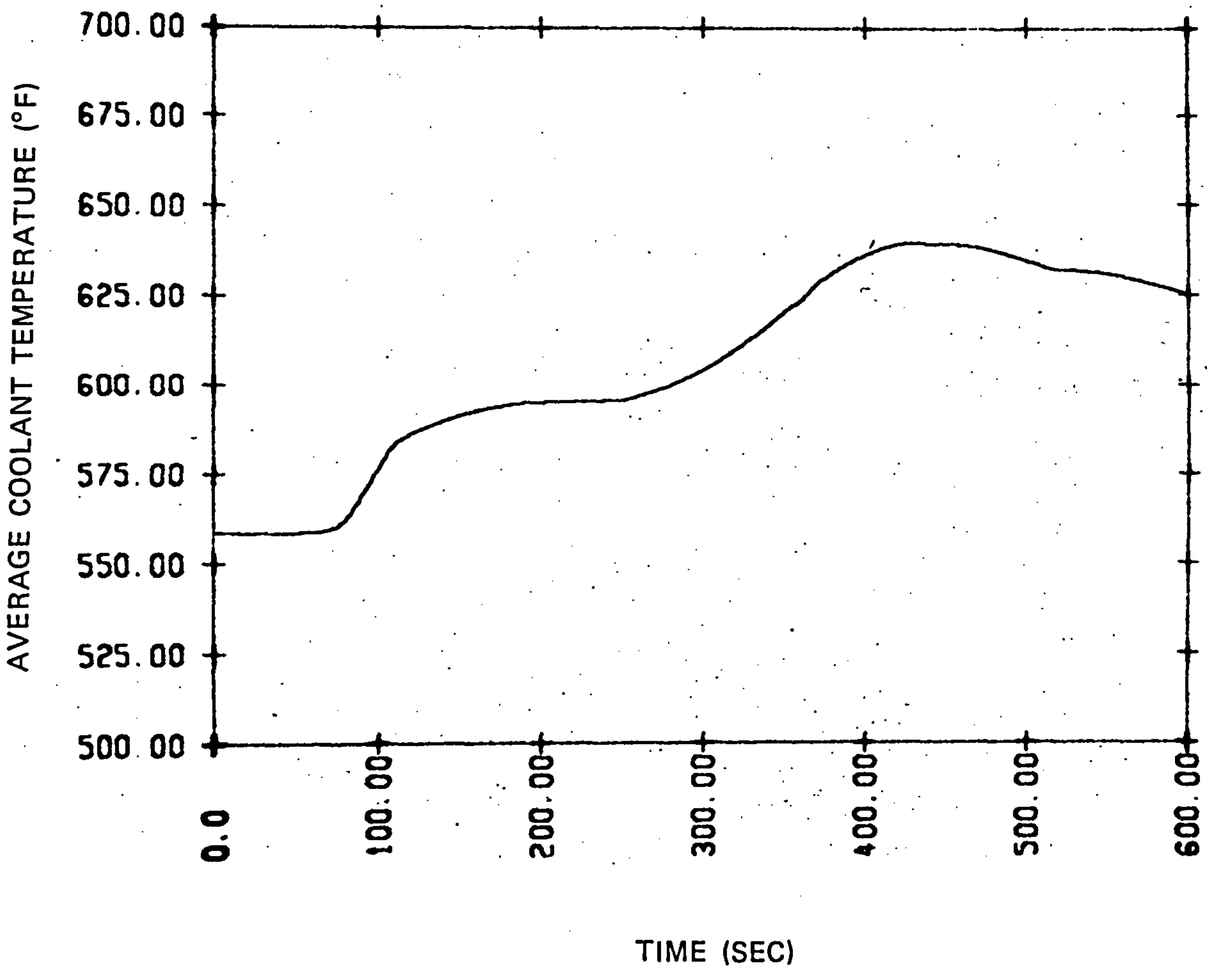

Figure 4-40. Rod Withdrawal from Subcritical — Steam Generator Mass - 10 Percent (Average Coolant Temperature Vs. Time)

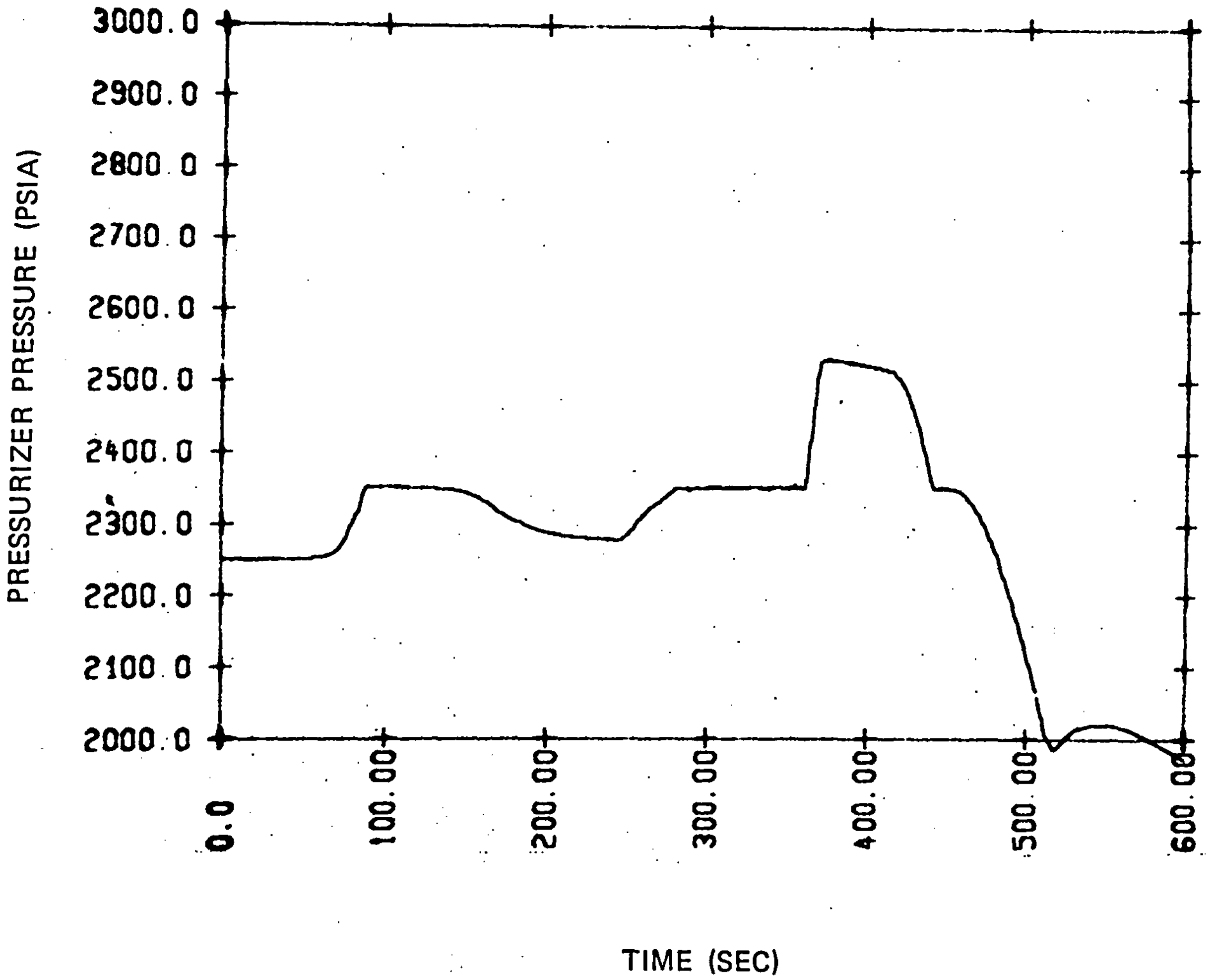

Figure 4-41. Rod Withdrawal from Subcritical — Steam Generator Mass - 10 Percent (Pressurizer Pressure Vs. Time)

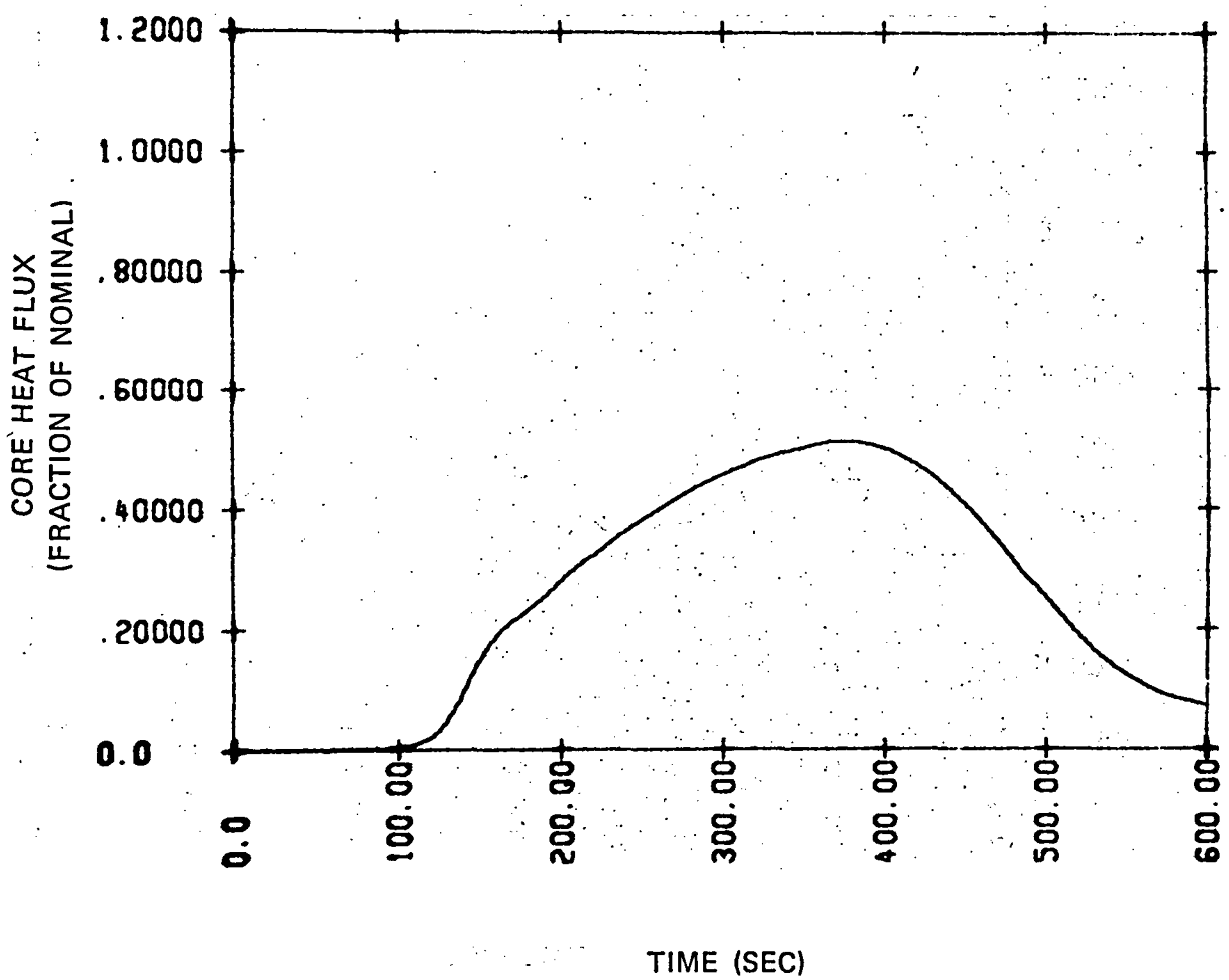

Figure 4-42. Rod Withdrawal from Subcritical – Halved Reactivity Insertion Rate (Core Heat Flux Vs. Time)

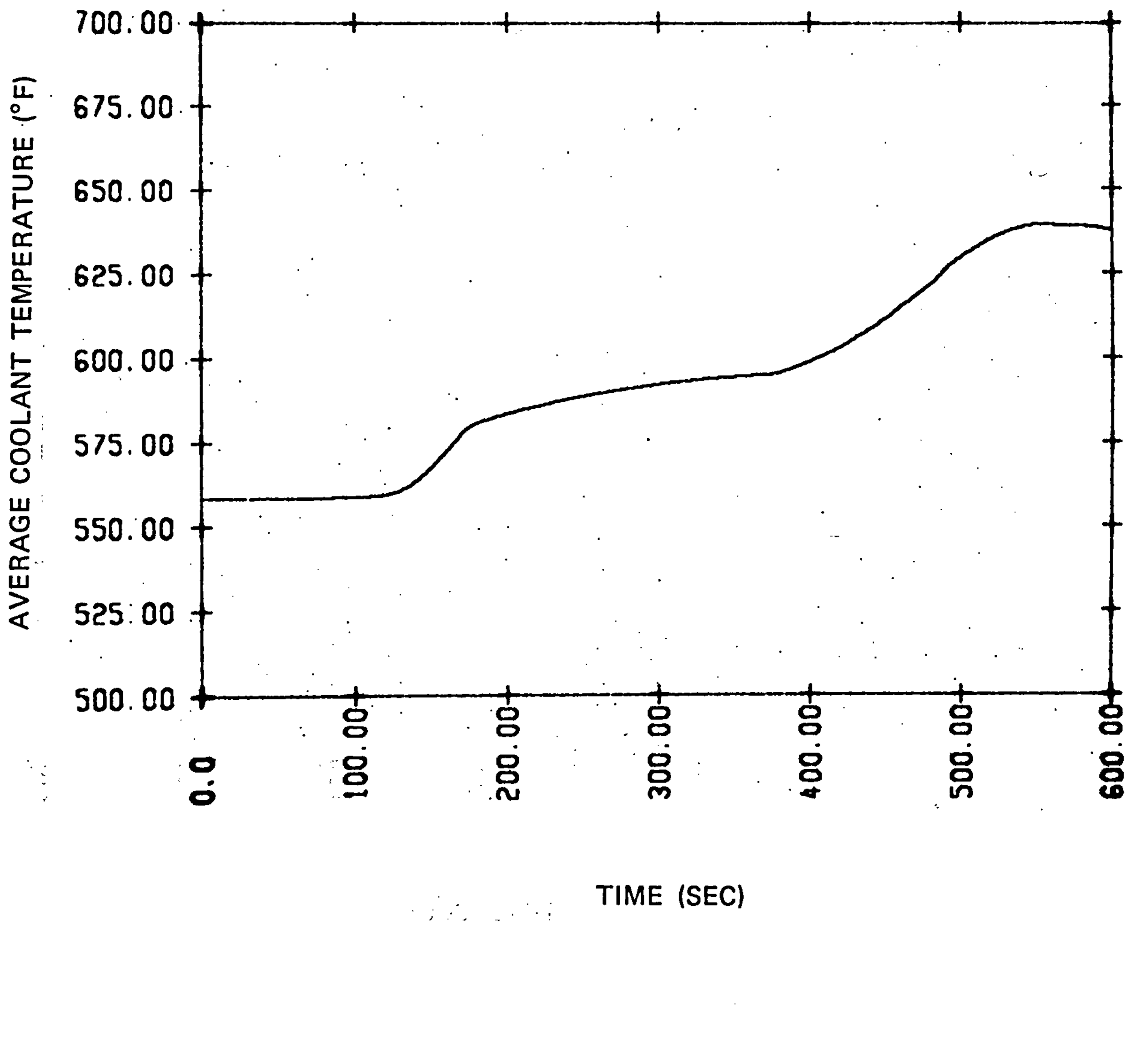

Figure 4-43. Rod Withdrawal from Subcritical — Halved Reactivity Insertion Rate (Average Coolant Temperature Vs. Time)

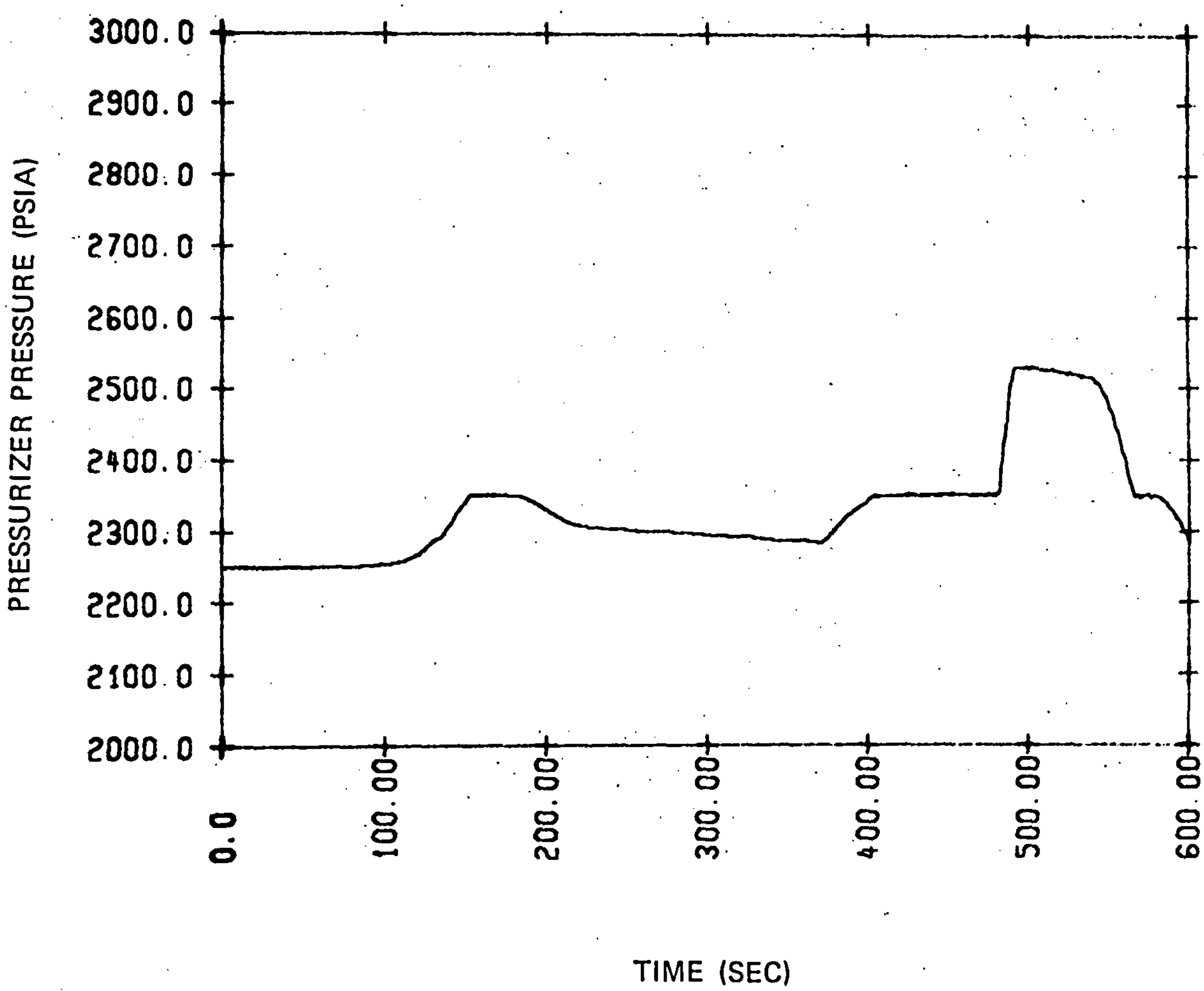

Figure 4-44. Rod Withdrawal from Subcritical – Halved Reactivity Insertion Rate (Pressurizer Pressure Vs. Time)

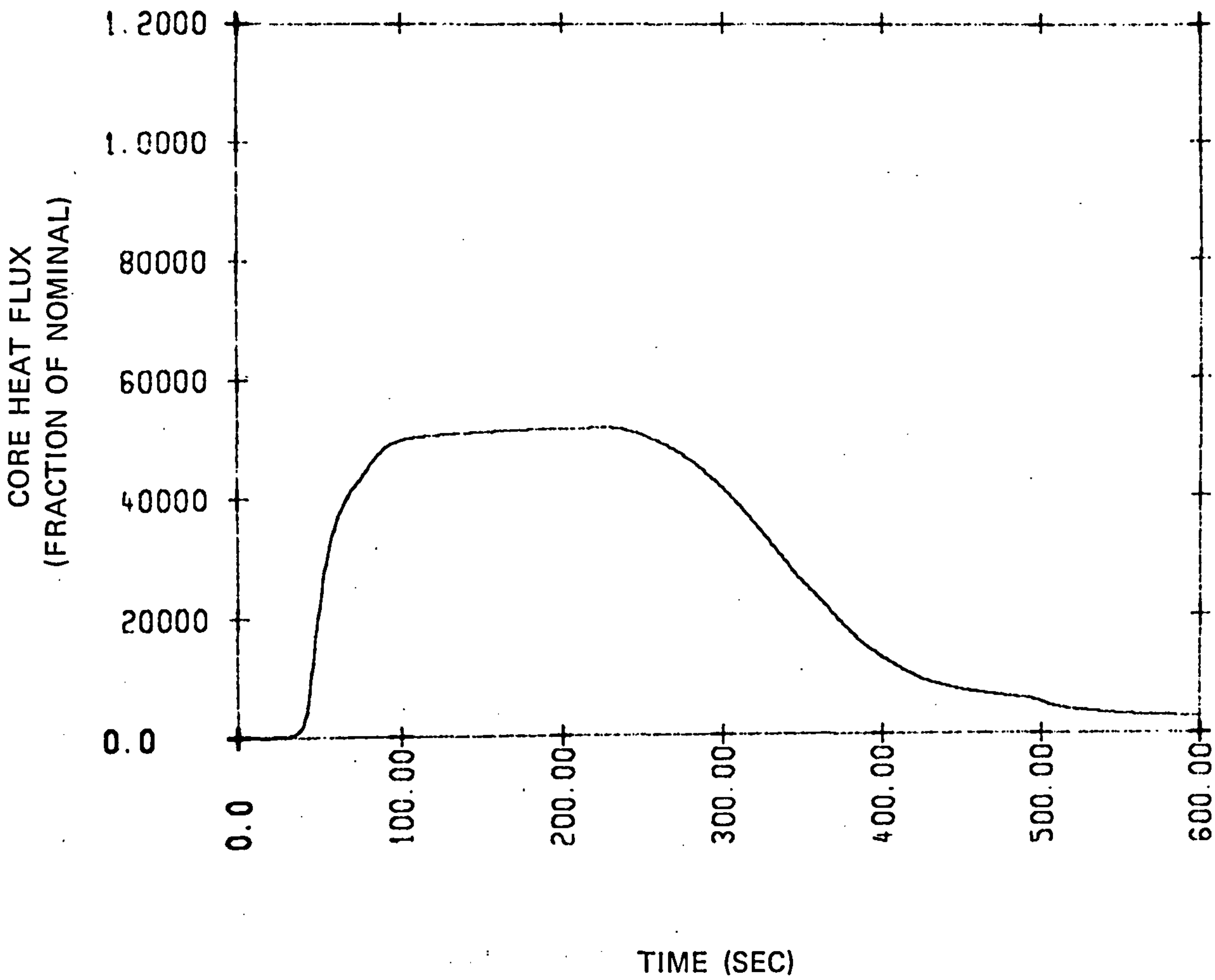

Figure 4-45. Rod Withdrawal from Subcritical — Doubled Reactivity Insertion Rate (Core Heat Flux Vs. Time)

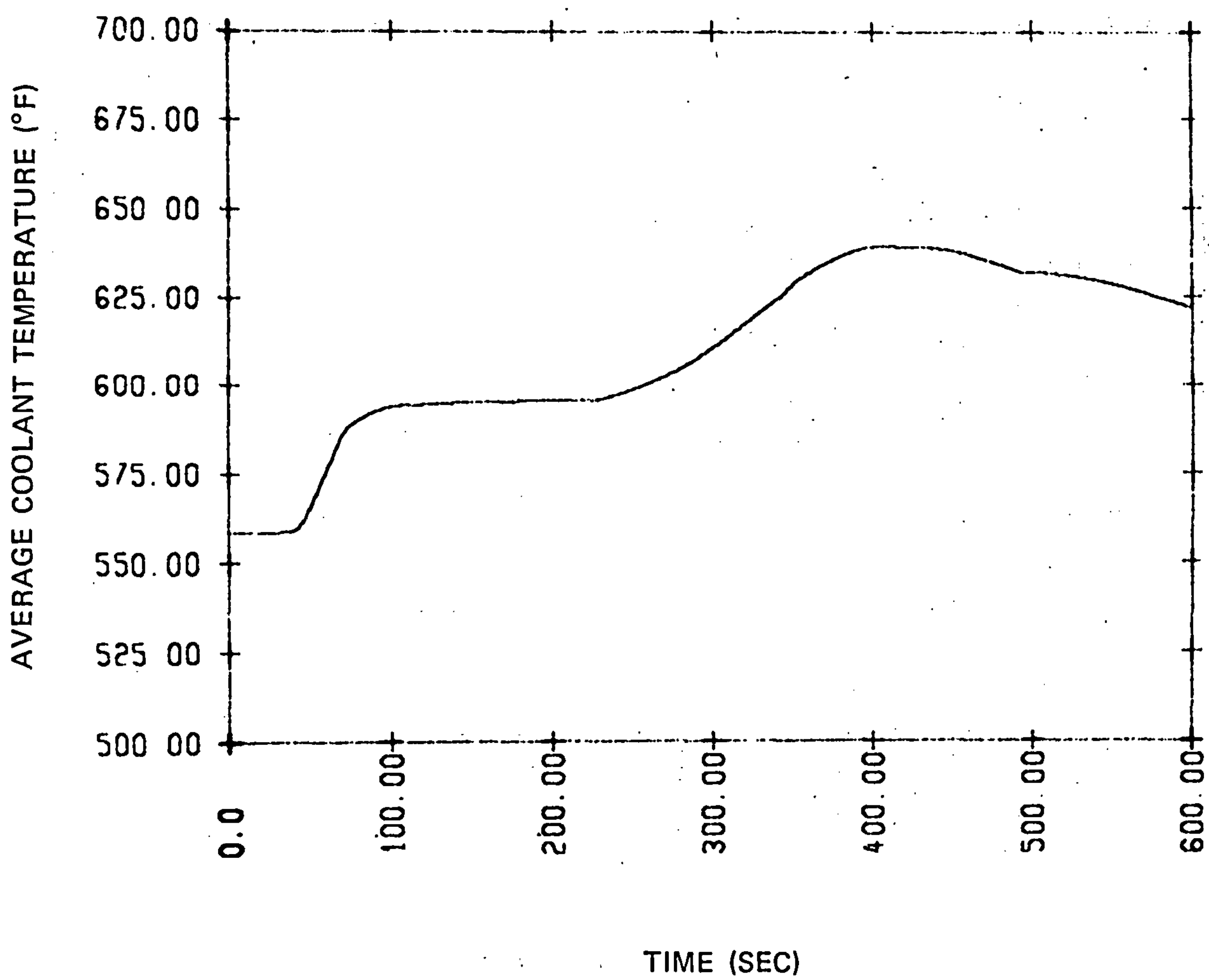

Figure 4-46. Rod Withdrawal from Subcritical – Doubled Reactivity Insertion Rate (Average Coolant Temperature Vs. Time)

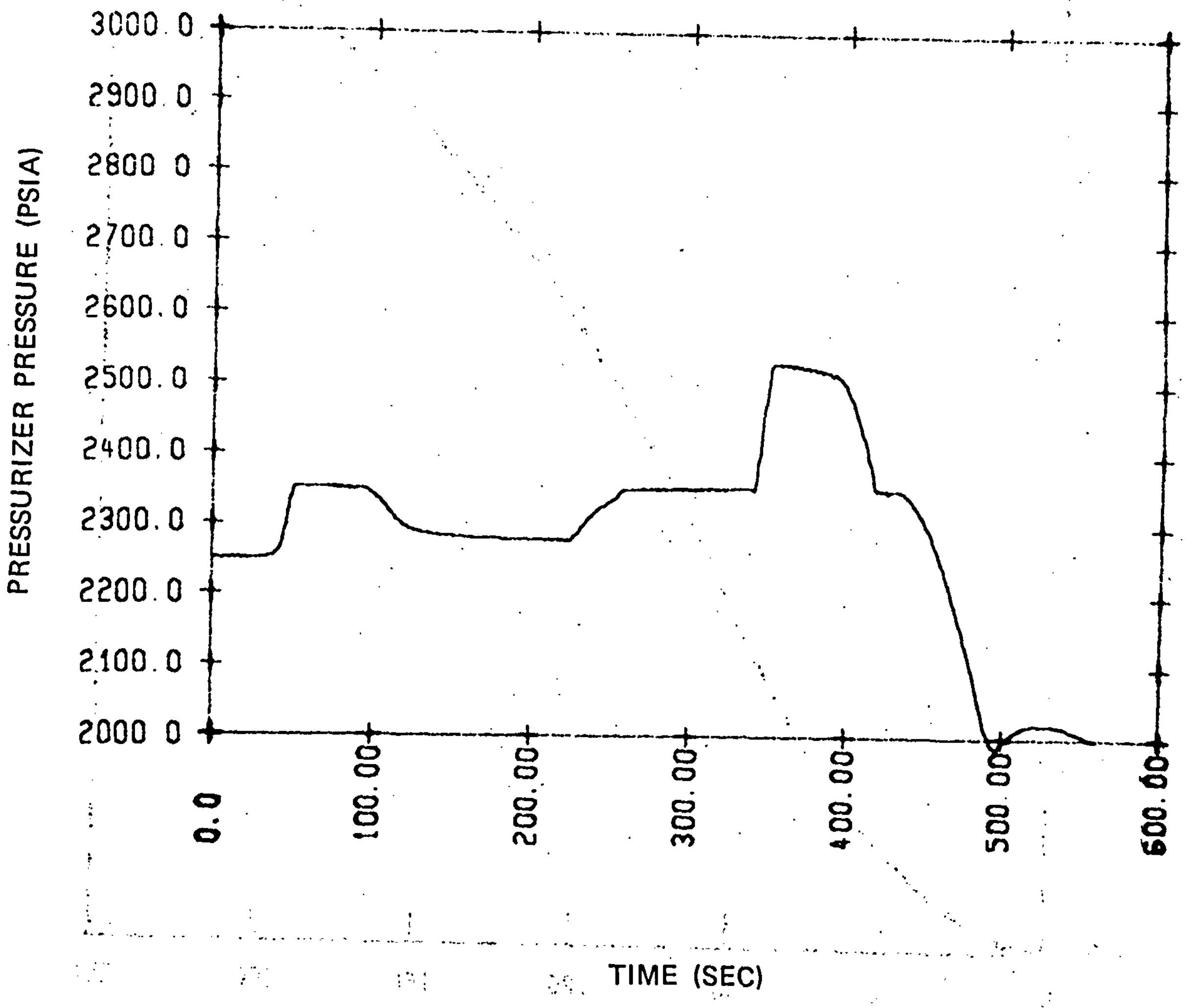

Figure 4-47. Rod Withdrawal from Subcritical – Doubled Reactivity Insertion Rate (Pressurizer Pressure Vs. Time)

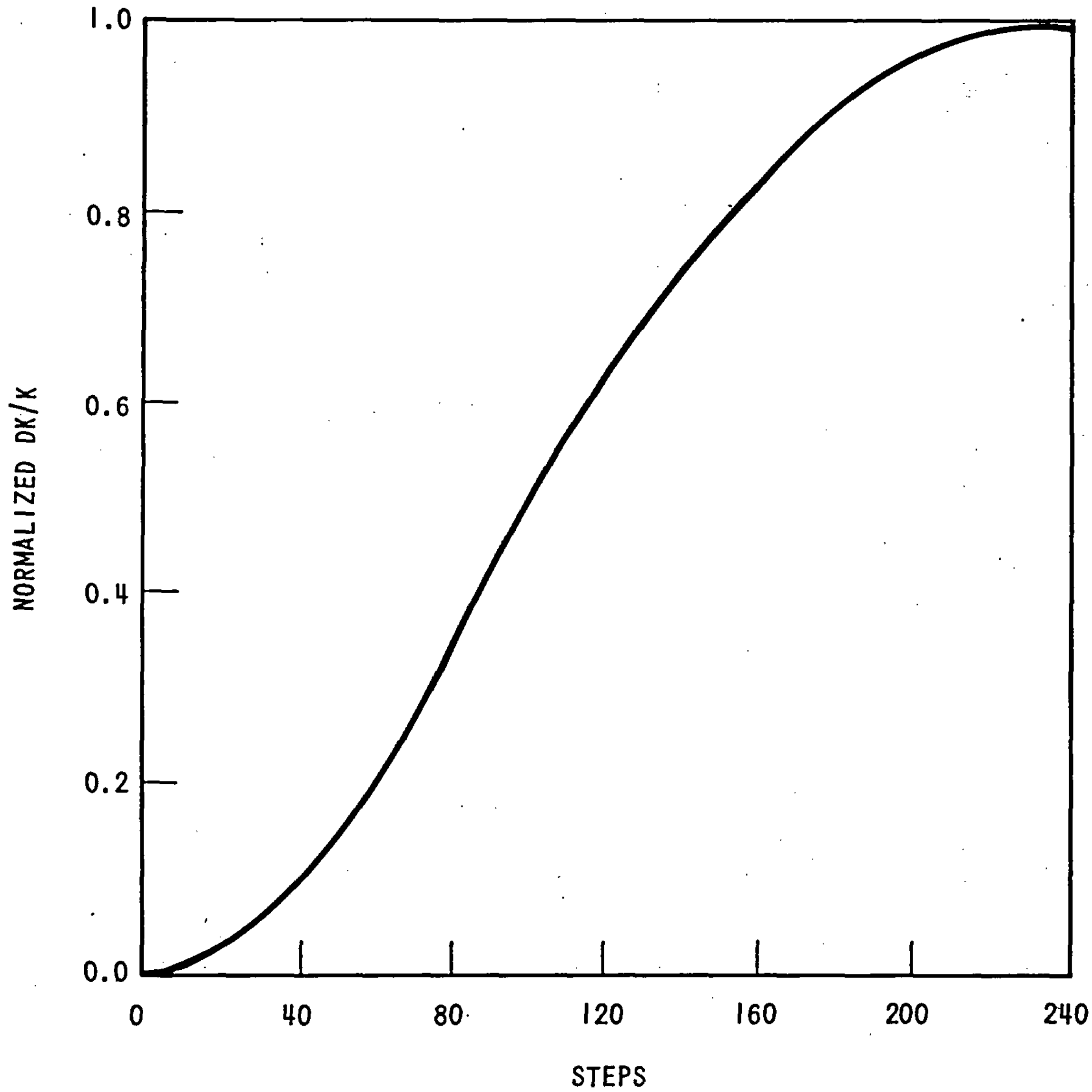

Figure 4-48. Normalized Integral Rod Worth

4-11. UNCONTROLLED ROD CLUSTER CONTROL ASSEMBLY BANK WITHDRAWAL AT POWER WITHOUT REACTOR TRIP

4-12. Identification of Causes and Transient Description

A rod withdrawal accident could result from a Reactor Control System malfunction which would cause the rod speed programmer to request control rod withdrawal in the absence of either a temperature deviation or a power mismatch signal. In the event of such an occurence, a reactor trip signal from any one of the several protection systems would terminate the rod withdrawal.

The result of an uncontrolled rod withdrawal would be the addition of reactivity to the reactor core resulting in an increase in core nuclear power and thermal flux. Because the heat extraction from the steam generator lags the increasing core power generation, the reactor coolant temperature rises, and, if no action terminates the process, DNB may occur in the core resulting in possible fuel and cladding damage. Because of the nature of the transient, the magnitude of the nuclear and thermal excursions and the margin to DNB in the core are primarily a function of the total excess reactivity inserted by the rods and is only slightly affected by the rates of reactivity insertion.

There are several features of the automatic Reactor Protection System which normally would act to prevent core damage in the event of this accident. These include the following:

- Two power range nuclear flux instrumentation channels in excess of the nuclear overpower setpoint actuate a reactor trip.
- Two ΔT channels exceeding the overtemperature ΔT setpoint actuate a reactor trip. The setpoint is automatically varied with axial power distribution, reactor coolant temperature, and reactor coolant pressure to protect against DNB.
- Two ΔT channels exceeding the overpower ΔT setpoint actuate a reactor trip. This setpoint is also automatically varied with axial power distribution to ensure that the allowable transient heat generator rate is not exceeded.
- Two pressurizer level channels exceeding a fixed high pressurizer water level setpoint actuate a reactor trip.
- Two pressurizer pressure channels exceeding a fixed high pressure setpoint actuate a reactor trip.

In addition to the above reactor trip functions, the following Rod Cluster Control Assembly withdrawal blocking setpoints would be reached in the event of an uncontrolled rod withdrawal transient:

- One power range nuclear flux channel exceeding a high nuclear flux setpoint
- Two ΔT channels exceeding a overtemperature ΔT setpoint
- Two ΔT channels exceeding a overpower ΔT setpoint

4-13. Analysis of Effects and Consequences

Three digital computer codes are used to analyze a rod withdrawal accident without reactor trip. The total response during the transient is determined using a full digital plant simulation in the LOFTRAN code. Transient values of core heat flux, reactor coolant core inlet temperatures, reactor coolant pressures, and reactor coolant flows from LOFTRAN are then used in a detailed thermal/hydraulic code, THINC-III, to determine the DNB ratio in the reactor core. If DNB occurs, the FACTRAN code is used to calculate fuel and cladding temperatures based on the nuclear power and reactor coolant temperatures and pressure from LOFTRAN.

The following assumptions were made in the analysis:

- Initial normal full power operation early in core life. Since the negative moderator temperature coefficient of reactivity limits the overtemperature-overpower transient, and the moderator coefficient becomes more negative during core life, rod withdrawal later in core life would be less severe than the case studied.
- Normal operation of the following control systems:
  1) Automatic regulation of feedwater flow to maintain steam generator water level
  2) Pressurizer pressure control, including heaters, spray, and both the power-operated and the spring-loaded relief valves
  3) Turbine governor valves in impulse pressure control
- No credit for automatic reactor trip
- No credit for automatic rod stops
- Continuous rod withdrawal at maximum rod speed of 45 in./minute (72 steps/minute) until control rods are fully withdrawn

The analyses were done for all existing combinations of 2-, 3-, and 4-loop plants and model 51 and model D steam generators, and appropriate fuel arrays. The worst case with respect to DNB was then evaluated for both 17x17 and 15x15 fuel assemblies. For calculational convenience, the inlet temperature listed in table 2-1 was used for the 15x15 DNB analysis. The actual inlet temperature for the 15x15 core is approximately 10°F lower. Thus, the DNB ratios reported for 15x15 fuel are conservative.

4-14. Results

The minimum DNB ratio for a rod withdrawal at power occurred in 4-loop plants equipped with model 51 steam generators.

Figures 4-49 through 4-56 show the transient response of this type plant to an 0.3% $\Delta k/k$ rod withdrawal from 100-percent power. An inserted rod worth of 0.3% $\Delta k/k$ is typical of the available control rod reactivity at 100-percent power, as discussed in section 2. Tables 4-3, 4-4, and 4-5 list the sequence of events and the time of their occurrence during the transient. Included in tables 4-3, 4-4, and 4-5 are the times at which various Reactor Protection System trip points are reached. The minimum DNB ratio during the transient was 1.49. For comparison, the transient response of 2- and 3-loop plants to the same rod withdrawal are shown in figures 4-57 through 4-64.

As the rods were withdrawn, core power increased forcing core temperatures up because of the mismatch between core power and secondary plant power. The high nuclear flux trip was reached approximately 12.3 seconds after the rods began to be withdrawn. Core power increased to about 112 percent and core average temperature to about 612°. The nuclear power increase was stopped by Doppler and moderator feedback. The rapid insurge into the pressurizer resulted in opening of the power-operated relief valves and a peak system pressure of 2350 psia.

After the initial surge in power, the core power and secondary power extraction stabilized at about 100 percent of the nominal power level. After this point, the inserted reactivity was balanced by moderator feedback due to increasing core average temperature until the rod withdrawal ceased at 62 seconds.

TABLE 4-3

SEQUENCE OF EVENTS FOR A ROD WITHDRAWAL AT POWER WITHOUT A REACTOR TRIP (4-LOOP PLANT/MODEL 51 STEAM GENERATOR)

Event	Time (sec)
Rod Withdrawal Begins	0.0
High Nuclear Flux Reactor Trip Setpoint Reached	12.3
Overtemperature ΔT Reactor Trip Setpoint Reached	16.3
Overpower ΔT Reactor Trip Setpoint Reached	19.0
Pressurizer Power-Operated Relief Valves Open	21.8
Pressurizer High Level Reactor Trip Setpoint Reached	88.8

TABLE 4-4

SEQUENCE OF EVENTS FOR A ROD WITHDRAWAL AT POWER WITHOUT A REACTOR TRIP (3-LOOP PLANT/MODEL 51 STEAM GENERATOR)

Event	Time (sec)
Rod Withdrawal Begins	0.0
High Nuclear Flux Reactor Trip Setpoint Reached	10.3
Overpower ΔT Reactor Trip Setpoint Reached	19.0
Pressurizer Power-Operated Relief Valves open	23.5
Overtemperature ΔT Reactor Trip Setpoint Reached	28.7
Pressurizer High Level Reactor Trip Setpoint Reached	82.8

TABLE 4-5

SEQUENCE OF EVENTS FOR A ROD WITHDRAWAL AT POWER WITHOUT A REACTOR TRIP (2-LOOP PLANT/MODEL 51 STEAM GENERATOR)

Event	Time (sec)
Rod Withdrawal Begins	0.0
High Nuclear Flux Reactor Trip Setpoint Reached	9.2
Overpower ΔT Reactor Trip Setpoint Reached	18.9
Overtemperature ΔT Reactor Trip Setpoint Reached	22.2
Pressurizer Power-Operated Relief Valves Open	27.2
Pressurizer High Level Reactor Trip Setpoint Reached	82.4

4-15. Sensitivity Studies

Several sensitivity studies were made to determine the effects of total inserted reactivity, rate of inserted reactivity, initial plant power level, turbine trip, steam generator mass, and core average temperature on DNB ratio during a rod withdrawal transient. The results of these studies are discussed below and are shown in figures 4-65 through 4-99 and summarized in table 4-6.

4-16. Effects of Amount of Inserted Reactivity — A case was examined assuming a total reactivity insertion of 0.5 percent in approximately 80 seconds from the rod withdrawal. A reactivity worth of 0.5 percent is the typical maximum control rod worth at 100-percent power for any time in core life.

Figures 4-65 through 4-69 show the transient response. The minimum DNB ratio was 1.27; therefore, no DNB was expected.

4-17. Effects of Initial Reactor Power — A case was studied assuming an initial power level below 100-percent rated power to determine the effects of Doppler defect and lower initial system temperatures on a rod withdrawal transient. The power levels chosen were 50 percent and 25 percent of nominal rated core power.

For these cases, the assumptions made were identical to the reference case with the exception of the inserted reactivity and consequential changes. Because of the lower power level, the initial core average temperature, pressurizer water volume and feedwater temperatures were also at lower values. The initial steam generator fluid inventory was also greater at the lower powers.

Consistent with the procedures described for the full-power case, a total inserted reactivity of 1.01 and 1.40 percent, respectively, were assumed. This represents the reactivity required to overcome moderator and Doppler reactivity in going from the initial power level to 100-percent power plus the additional 0.3-percent reactivity assumed available in the rods when the plant is at full power. The times required for withdrawal were approximately 97 and 200 seconds, respectively.

The results of these transients are shown in figures 4-70 through 4-77. The peak power was less than 100 percent of nominal because of the rapid rise in the core average temperature and the associated moderator feedback. The rapid rise in the average temperature was due to a large imbalance between the core power and the steam generator heat extraction. The minimum DNB ratios during the transient were 1.65 and 1.62, respectively.

TABLE 4-6

SUMMARY OF RESULTS FOR A ROD WITHDRAWAL AT POWER WITHOUT A REACTOR TRIP

Case		Minimum DNB Ratio	
	Peak Pressure	17x17	15x15
Reference Case[a]	2352	1.49	1.41
3-Loop Plant	2352	1.56	1.46
2-Loop Plant	2353	b	b
Model D Steam Generator	2353	1.50	1.40
Turbine Trip	2585	1.65	1.53
Average Temperature + 8°	2352	1.41	1.31
Average Temperature - 20°	2352	1.70	1.62
Steam Generator Mass + 10 Percent	2356	1.49	1.40
Steam Generator Mass - 10 Percent	2352	1.49	1.40
0.5% $\frac{\Delta k}{k}$ Rod Worth	2355	1.27	1.17
Twice Reference Insertion Rate	2352	1.46	1.38
Half Reference Insertion Rate	2352	1.51	1.41
Initial Power = 50 Percent Nominal	2364	1.65	1.49
Initial Power = 25 Percent Nominal	2353	1.62	1.46

[a]Reference case: Initial power = 100 percent
Inserted reactivity = 0.3% $\frac{\Delta k}{k}$
No turbine trip
4-Loop plant
Model 51 steam generator

[b]2-Loop: 1.73 applicable to 14x14 array.

4-18. Effects of Turbine Trip — The reference case was examined assuming a turbine trip at the time of the first reactor trip signal plus appropriate delays. All other assumptions were the same. The peak power was slightly lower than the reference case because the increase in core average temperature was more rapid and larger in magnitude. This was due to the mismatch in core power and secondary power during the period between tripping the turbine and the opening of the steam safety valves. The plant eventually stabilized at approximately 93-percent power at an increased average temperature. Minimum DNB ratio was 1.65. Peak system pressure was 2585 psia. Results are shown in figures 4-78 through 4-81.

4-19. Effects of Reactivity Insertion Rate — The results of inserting 0.3% $\frac{\Delta k}{k}$ at twice and one-half the base case insertion rates are given in figures 4-82 through 4-87. The peak core power for the fast insertion rate was higher than that for the slower insertion rate because the moderator feedback lagged further behind core nuclear power and heat flux due to the rapidity of the transient. The minimum DNB ratio was 1.46 for the doubled reactivity insertion rate, and 1.51 for the halved reactivity insertion rate.

4-20. Effects of Initial Core Average Temperature — Figures 4-88 through 4-93 show that varying the initial core average temperature had very little effect on the total plant response to a rod withdrawal event. The two cases presented of nominal T_{avg} + 8° and nominal T_{avg} - 20° bound operating temperatures for all existing plants. Changing the average temperature did, however, change the margin to DNB as the minimum DNB ratio's were 1.41 and 1.70, respectively.

4-21. Effects of Steam Generator Mass — Varying steam generator mass had no effect on the rod withdrawal at power incident because of the automatic Feedwater Control System. Figures 4-94 through 4-99 show results for nominal steam generator mass ± 10 percent. The minimum DNB ratio in both cases was the same as the base case, i.e., 1.49.

4-22. Conclusions

Based upon the calculated DNB ratios, no significant clad damage is expected and because Reactor Coolant System pressures are below limiting values, no damage to the Reactor Coolant System is expected from an uncontrolled rod withdrawal at power without trip.

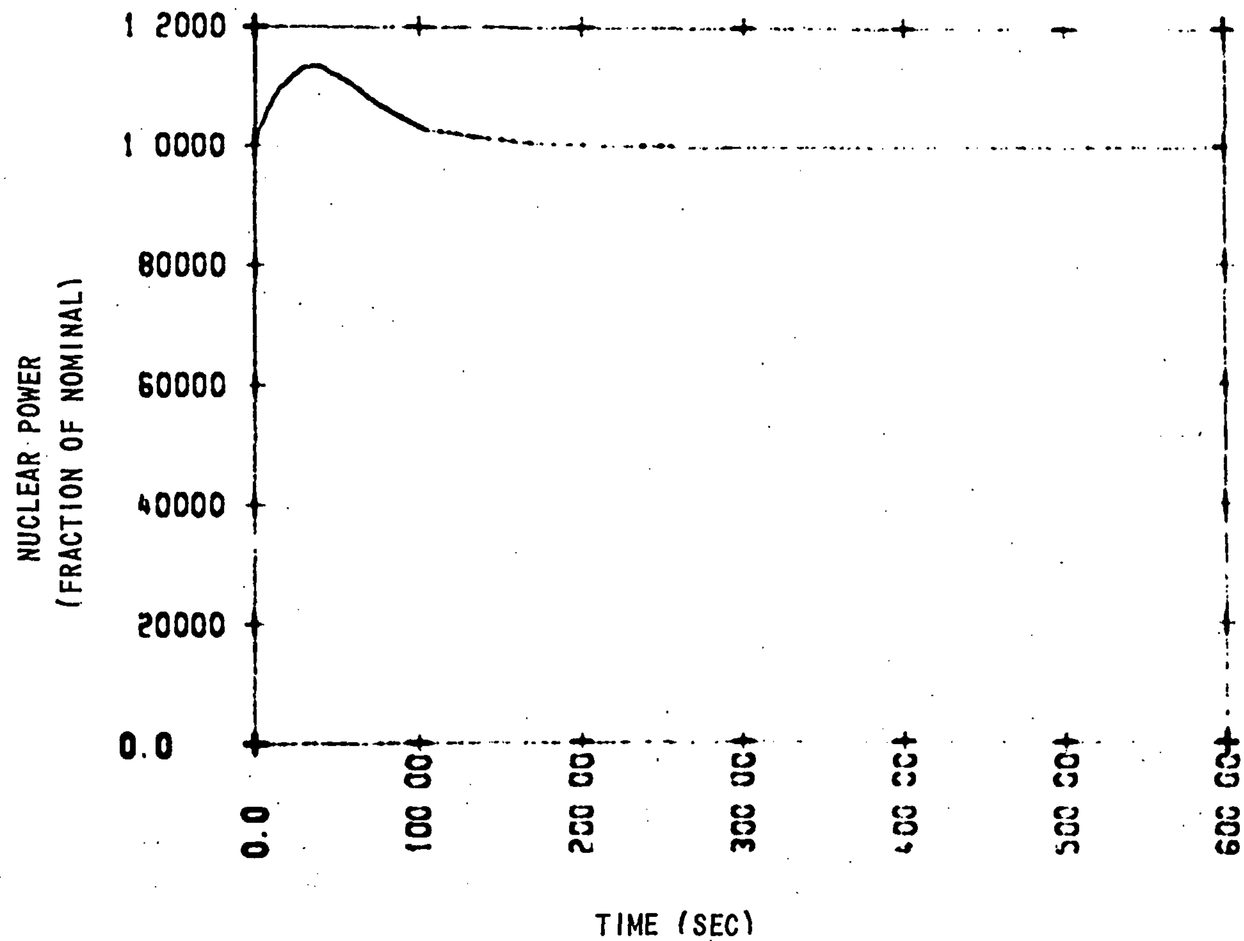

Figure 4-49. Rod Withdrawal at Power — Reference Case (Nuclear Power Vs. Time)

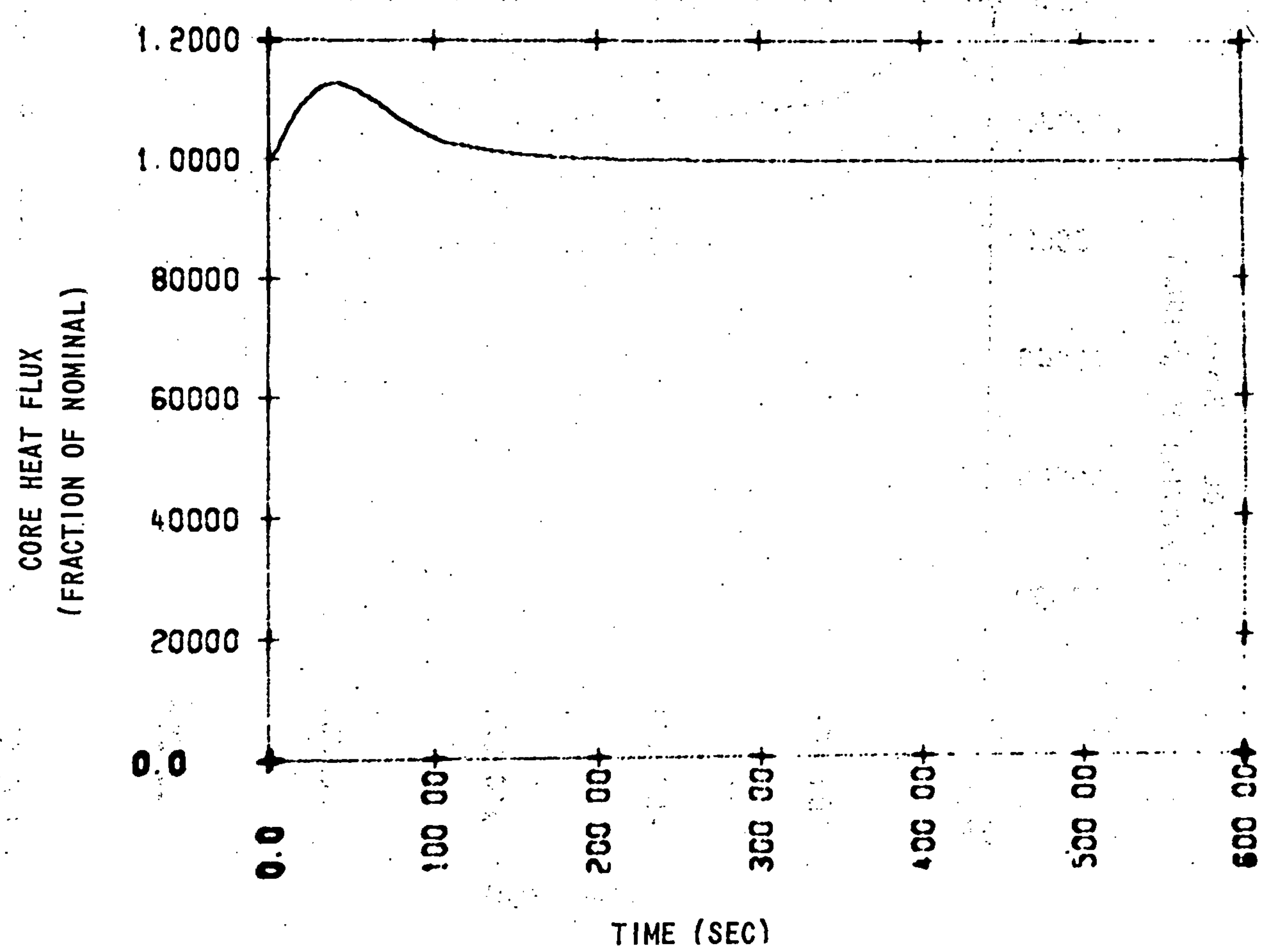

Figure 4-50. Rod Withdrawal at Power — Reference Case (Core Heat Flux Vs. Time)

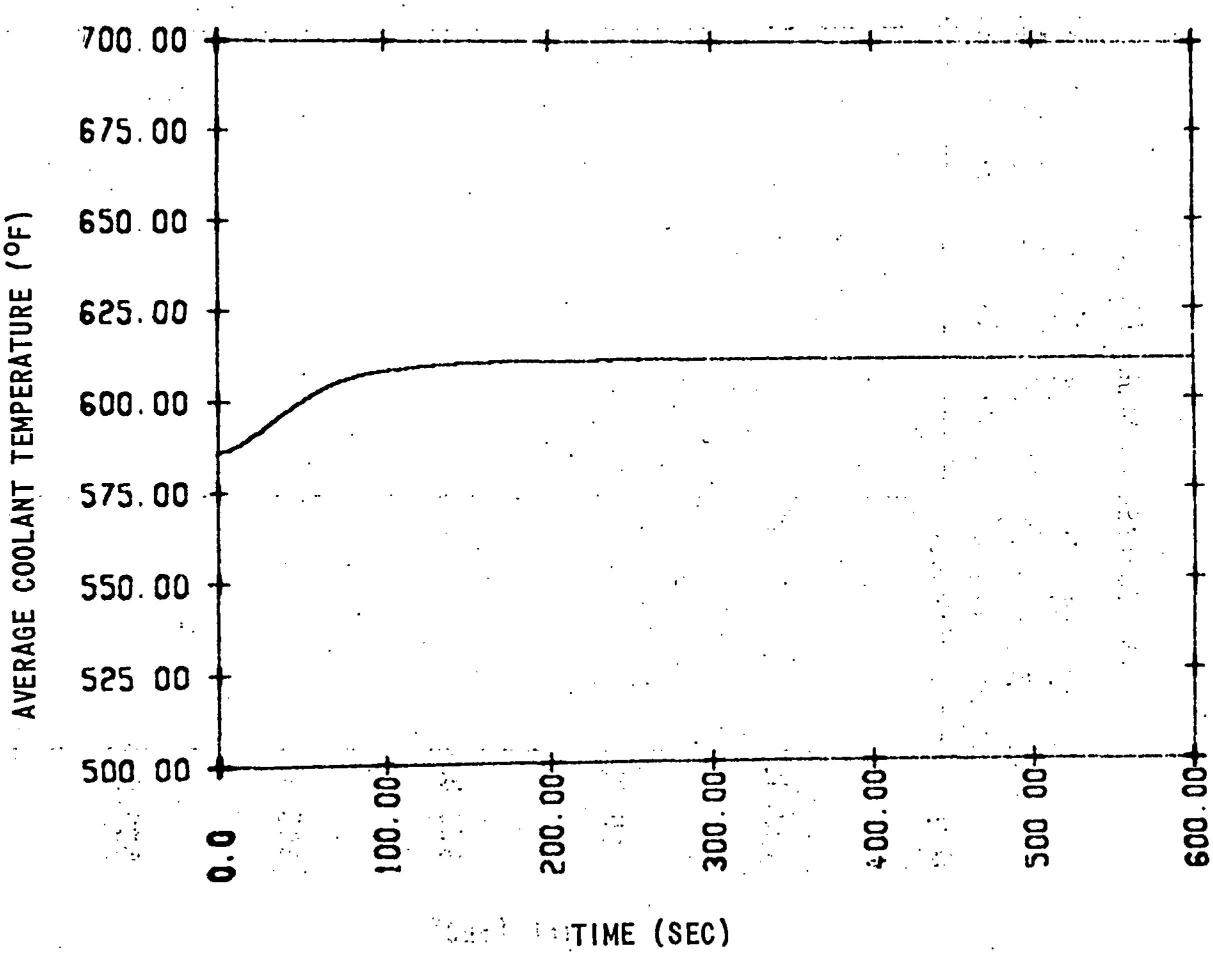

Figure 4-51. Rod Withdrawal at Power — Reference Case (Average Coolant Temperature Vs. Time)

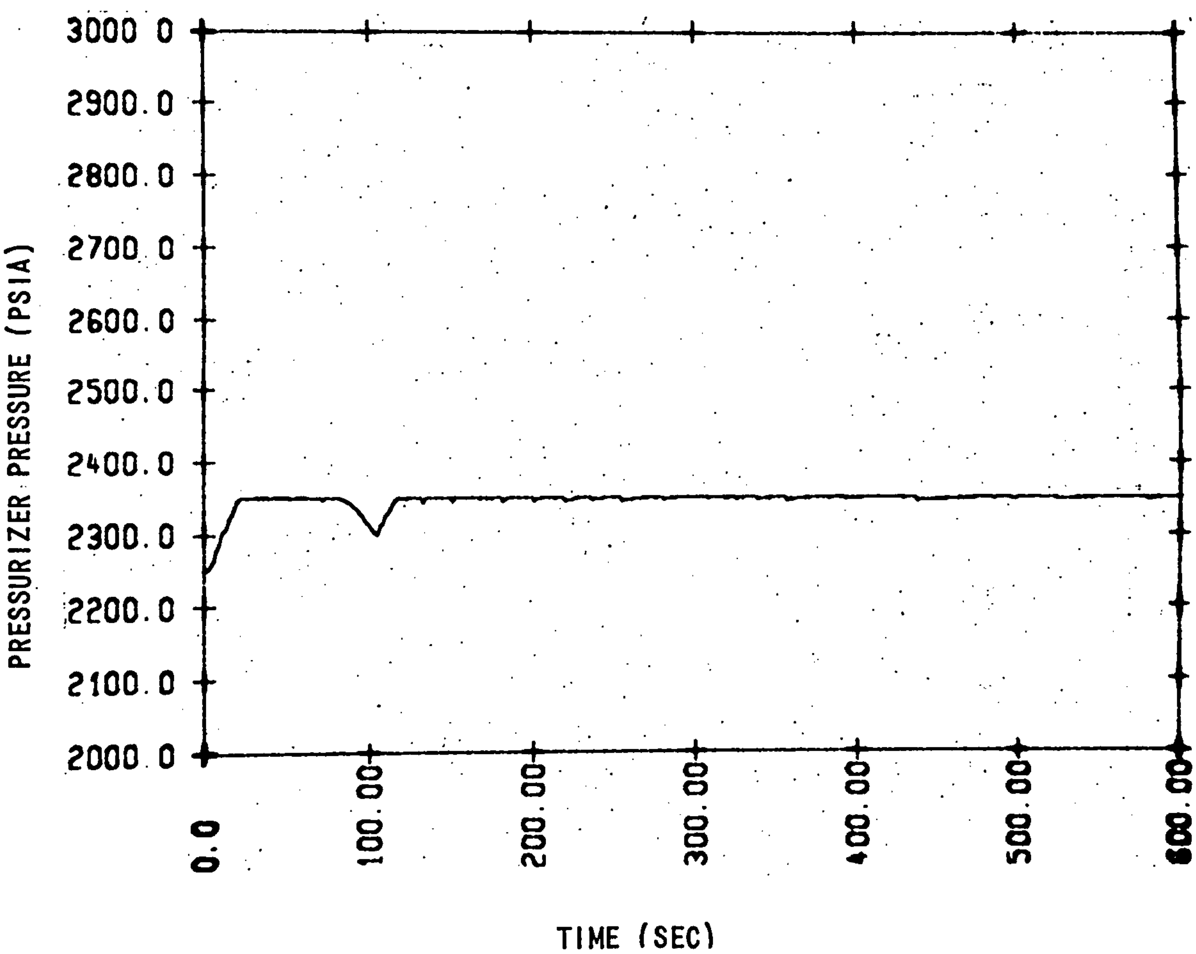

Figure 4-52. Rod Withdrawal at Power – Reference Case (Pressurizer Pressure Vs. Time)

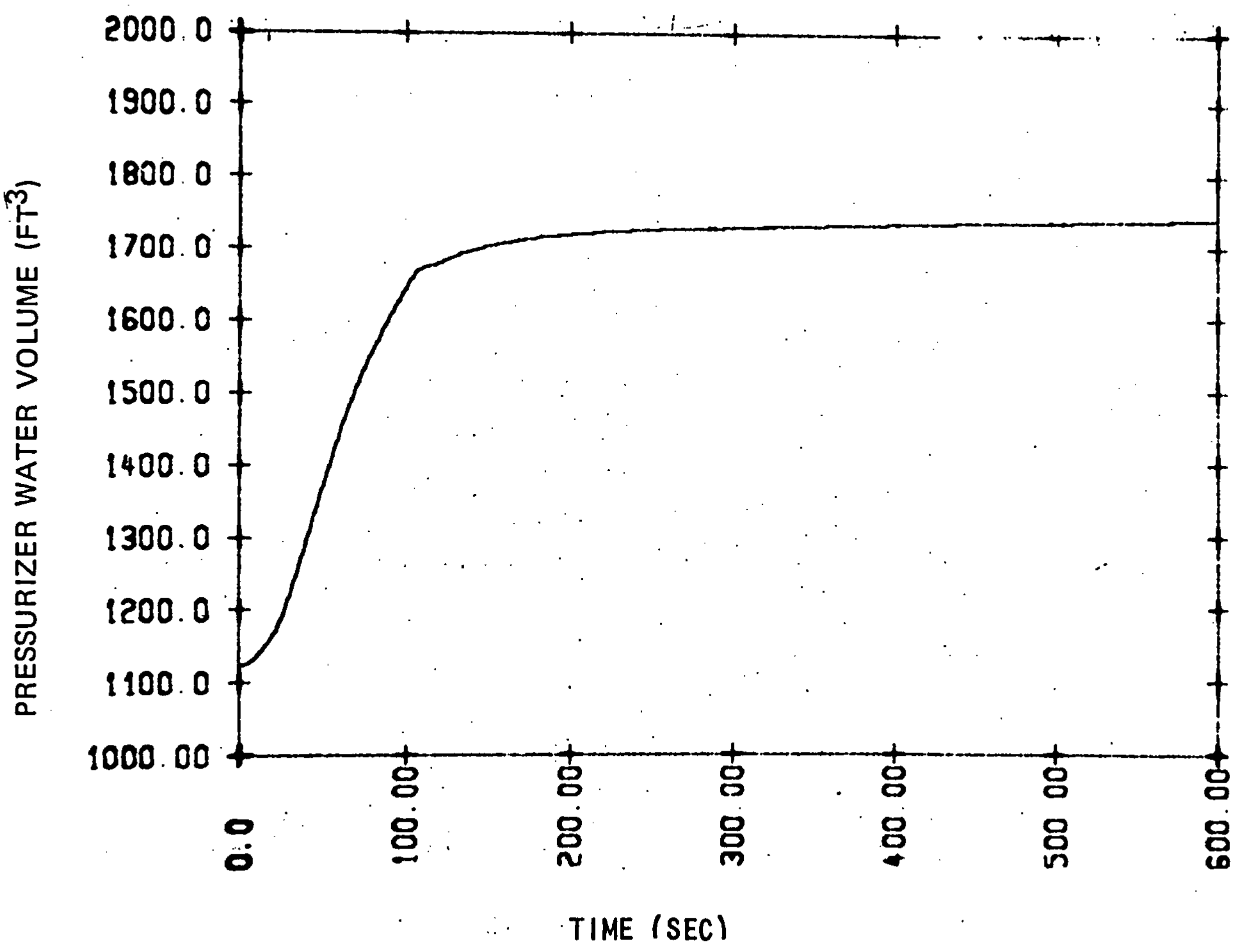

Figure 4-53. Rod Withdrawal at Power — Reference Case (Pressurizer Water Volume Vs. Time)

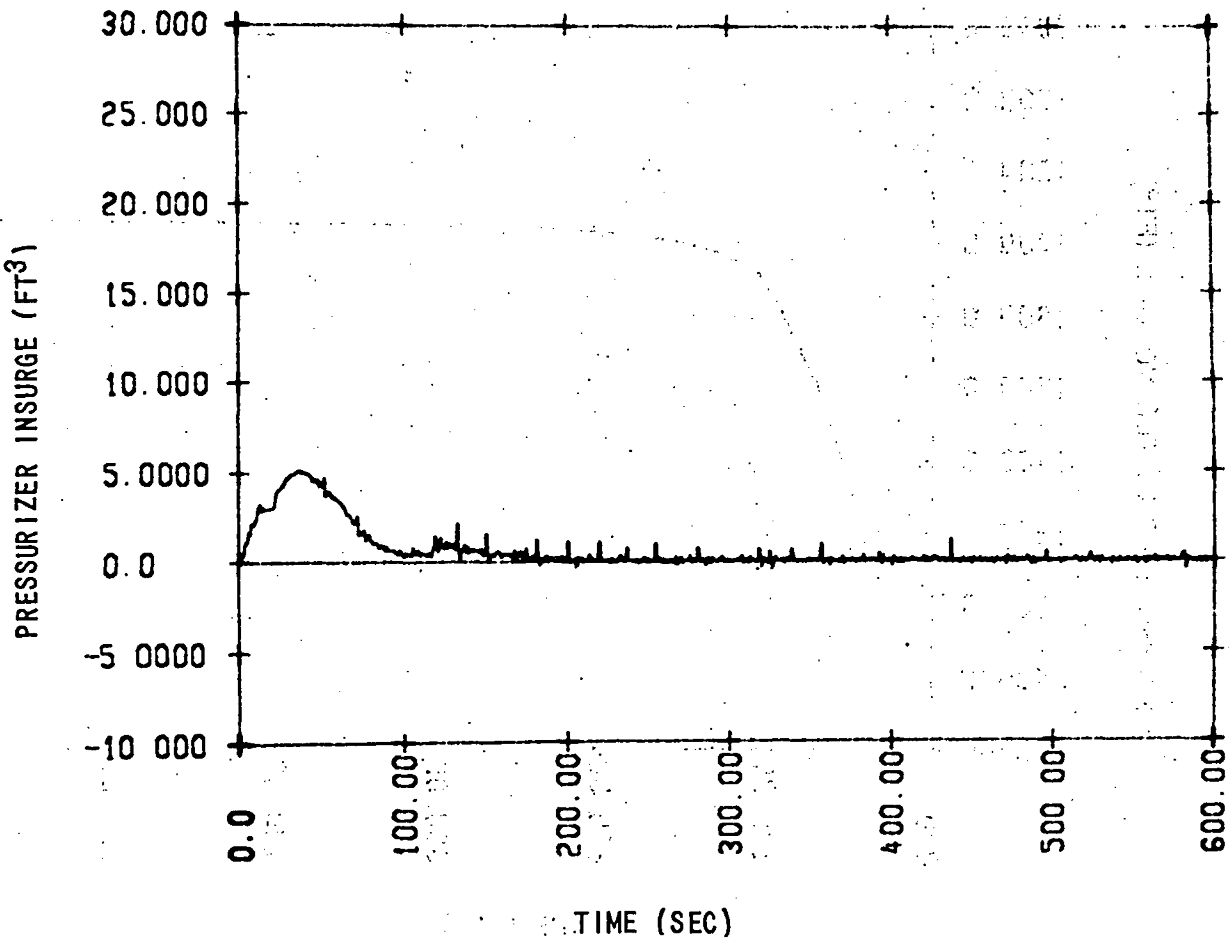

Figure 4-54. Rod Withdrawal at Power — Reference Case (Pressurizer Insurge Vs. Time)

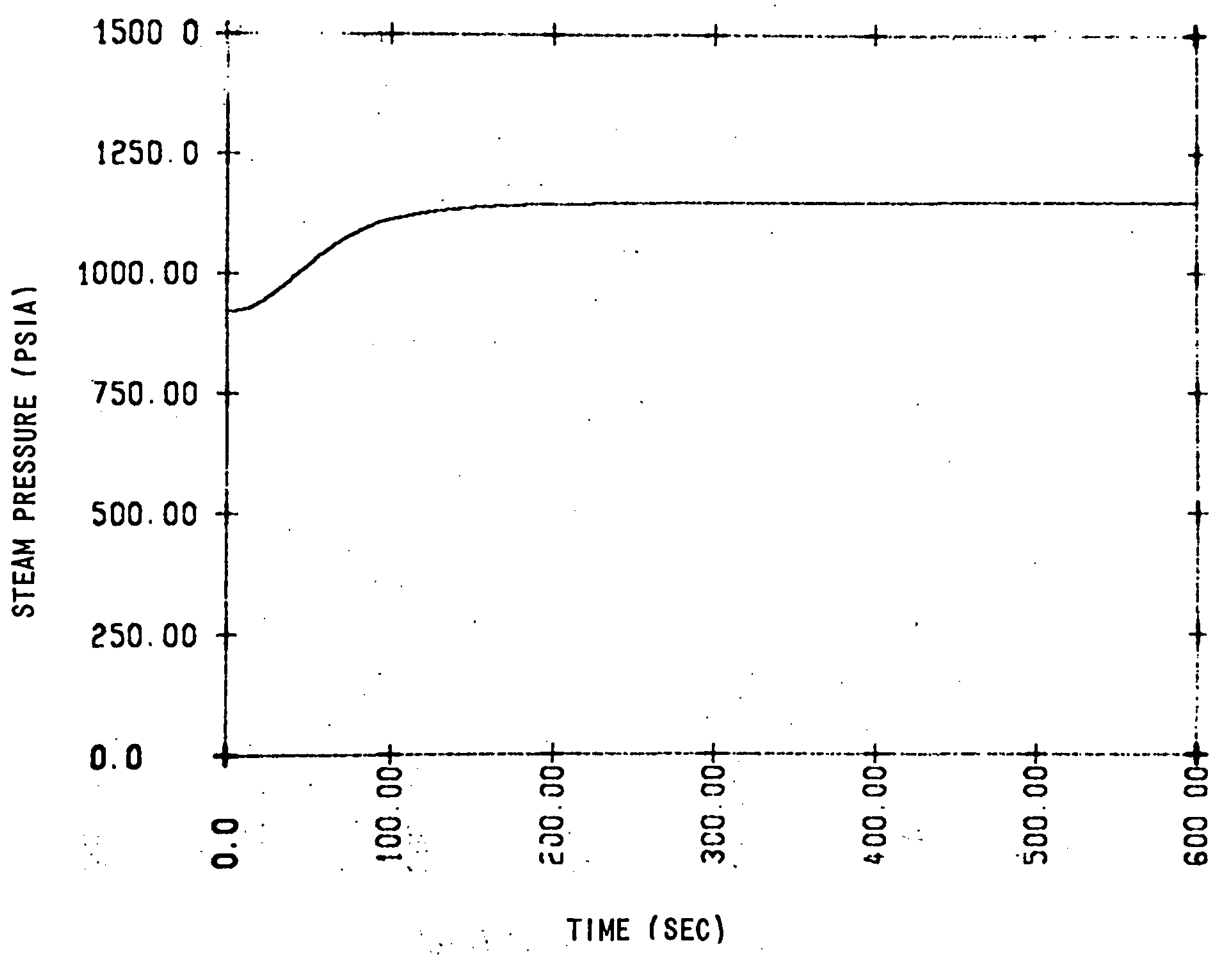

Figure 4-55. Rod Withdrawal at Power — Reference Case (Steam Pressure Vs. Time)

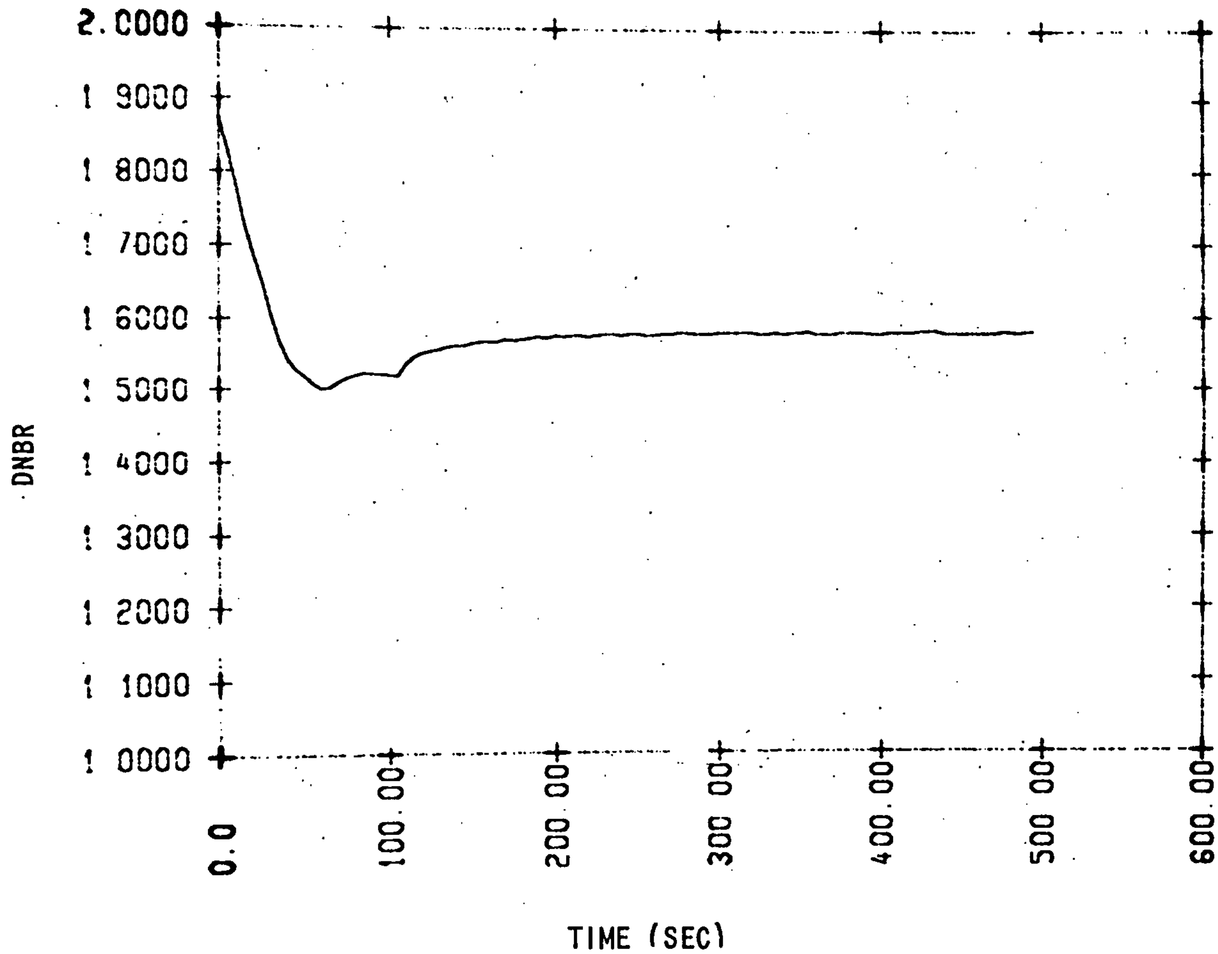

Figure 4-56. Rod Withdrawal at Power — Reference Case (DNBR Vs. Time)

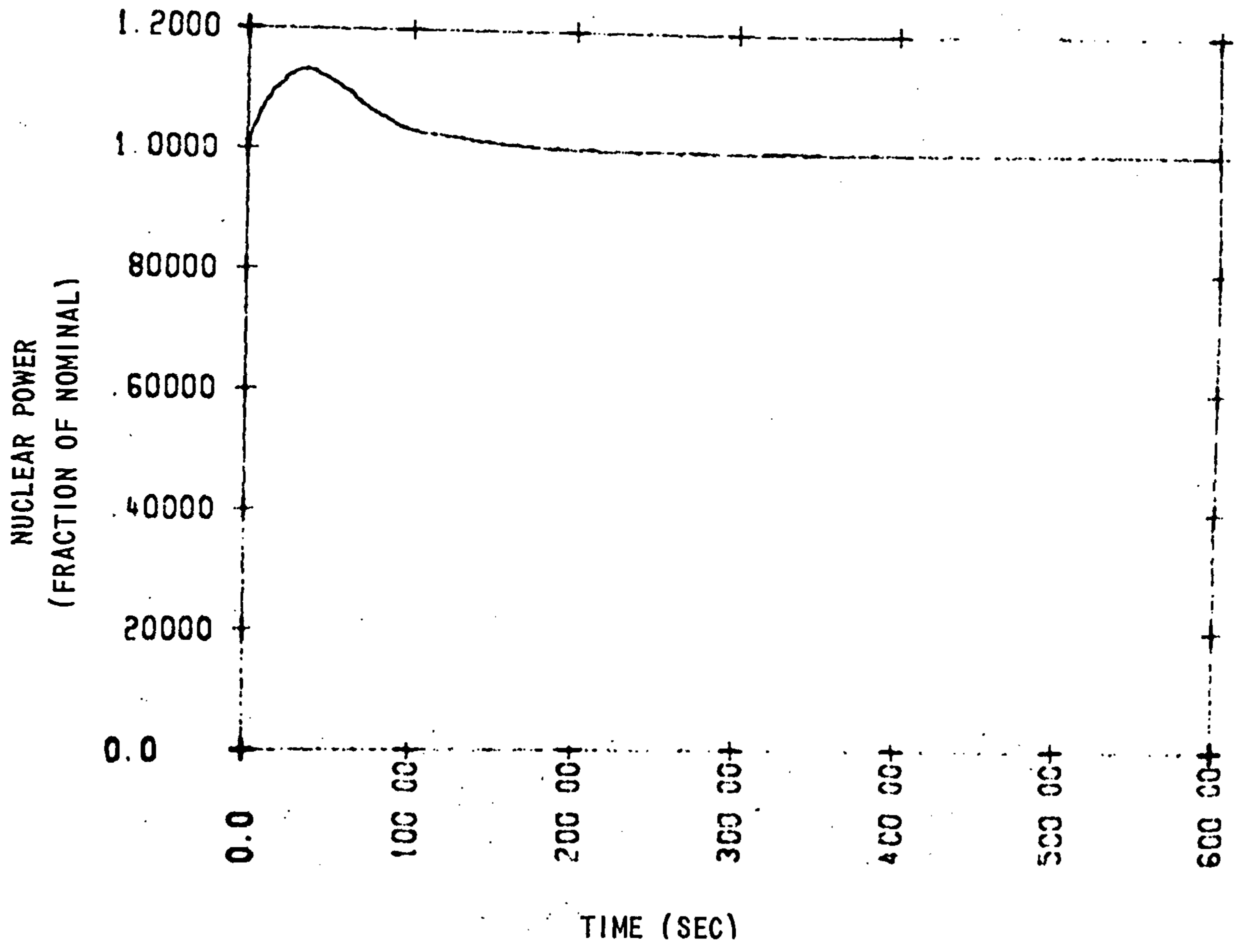

Figure 4-57. Rod Withdrawal at Power - 3-Loop Plant (Nuclear Power Vs. Time)

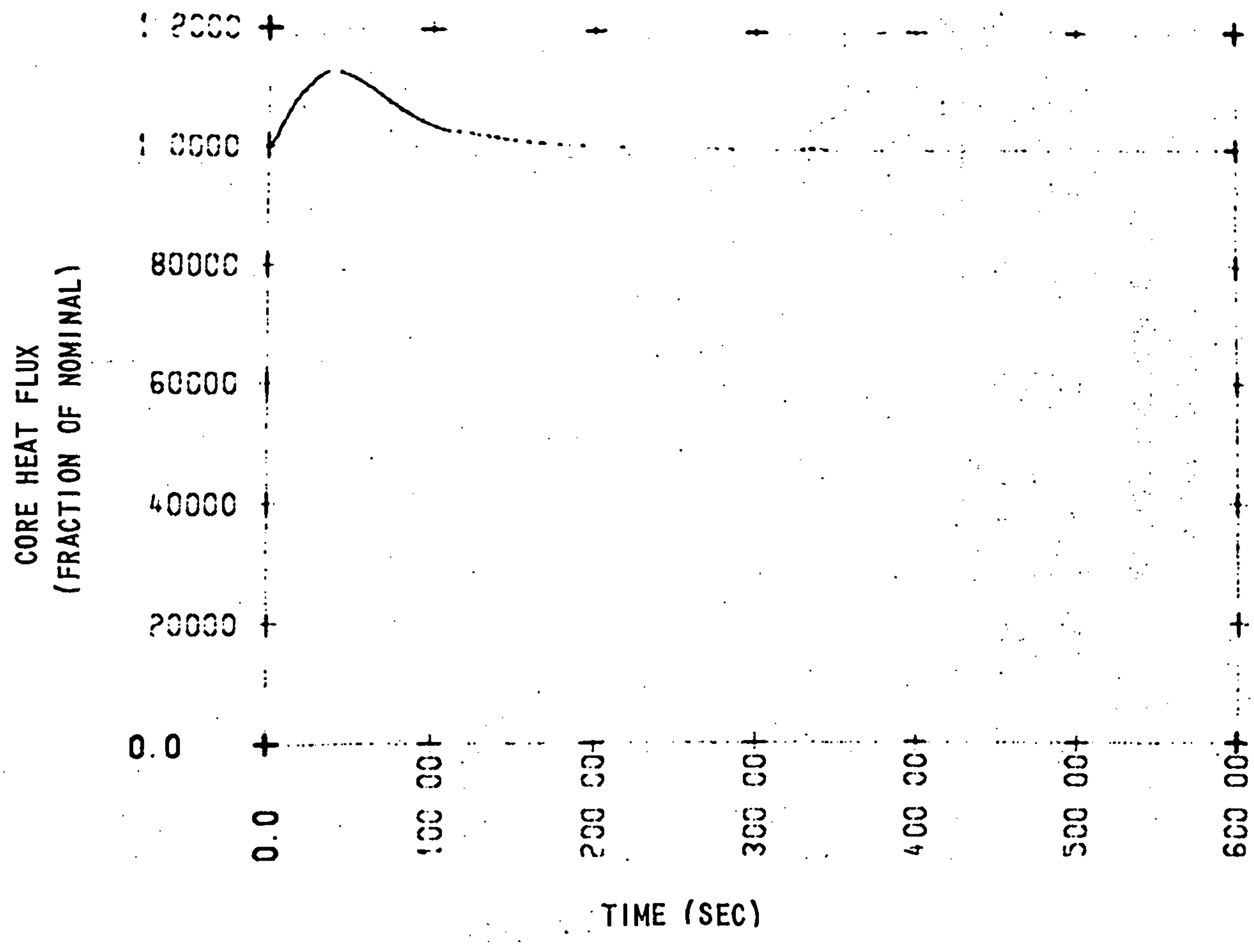

Figure 4-58. Rod Withdrawal at Power - 3-Loop Plant (Core Heat Flux Vs. Time)

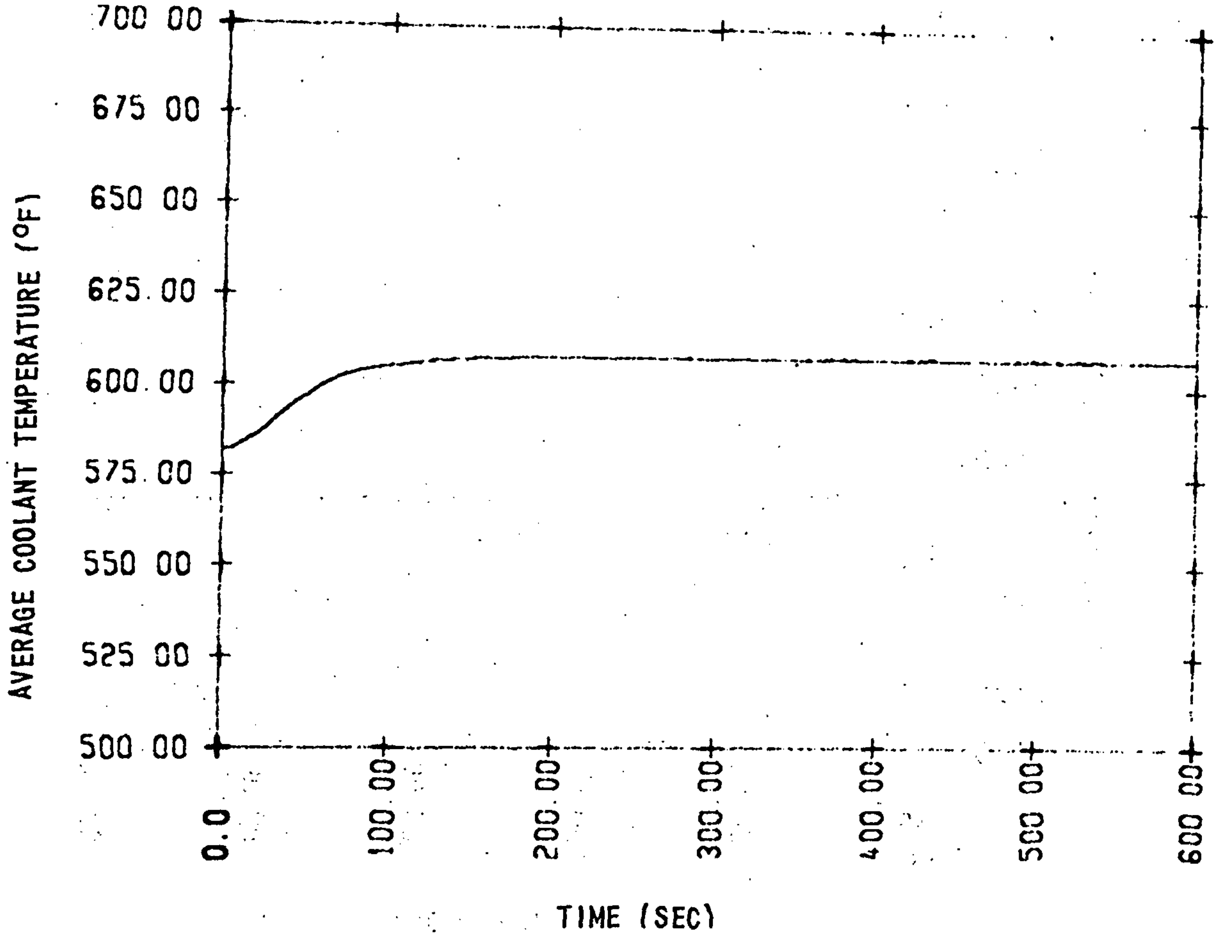

Figure 4-59. Rod Withdrawal at Power – 3-Loop Plant (Average Coolant Temperature Vs. Time)

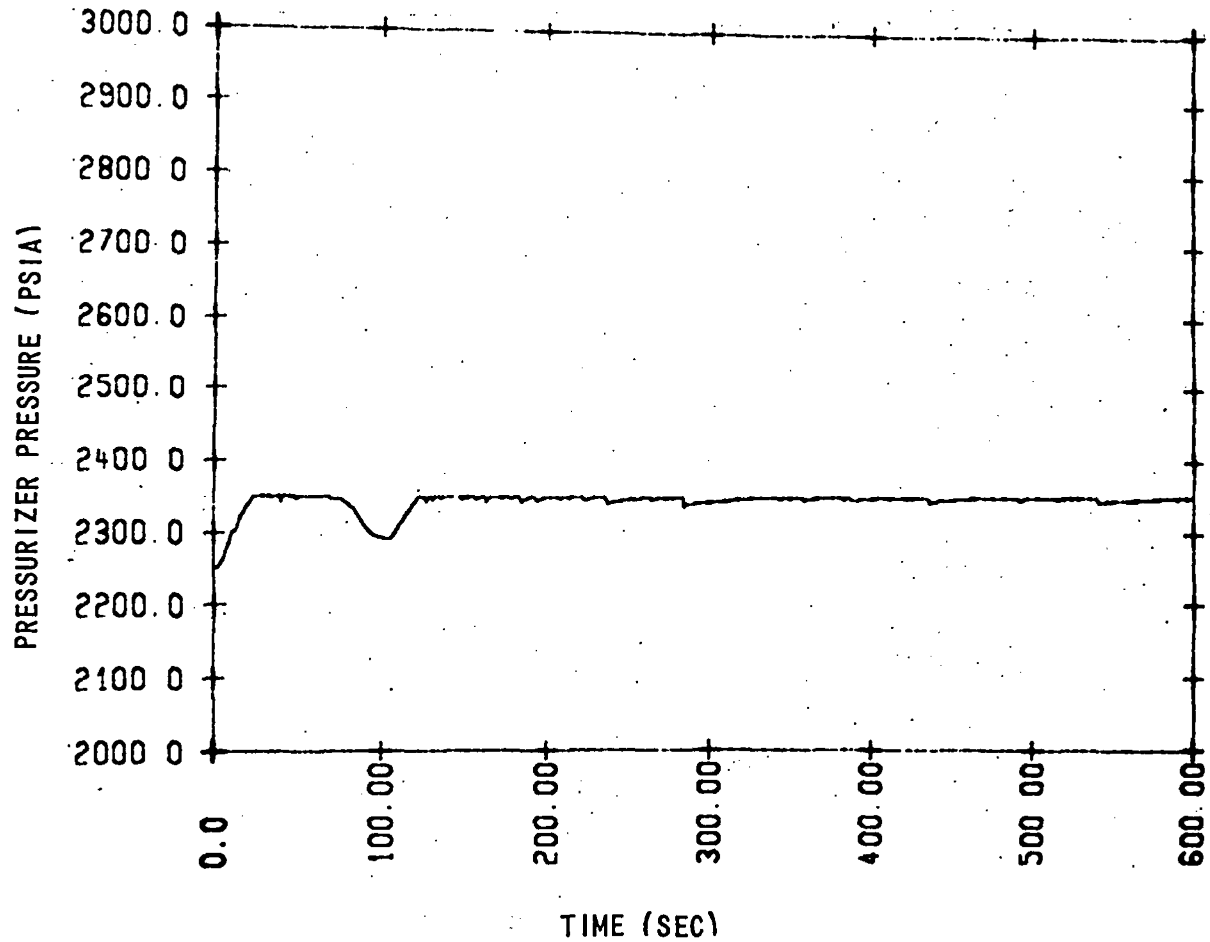

Figure 4-60. Rod Withdrawal at Power — 3-Loop Plant (Pressurizer Pressure Vs. Time)

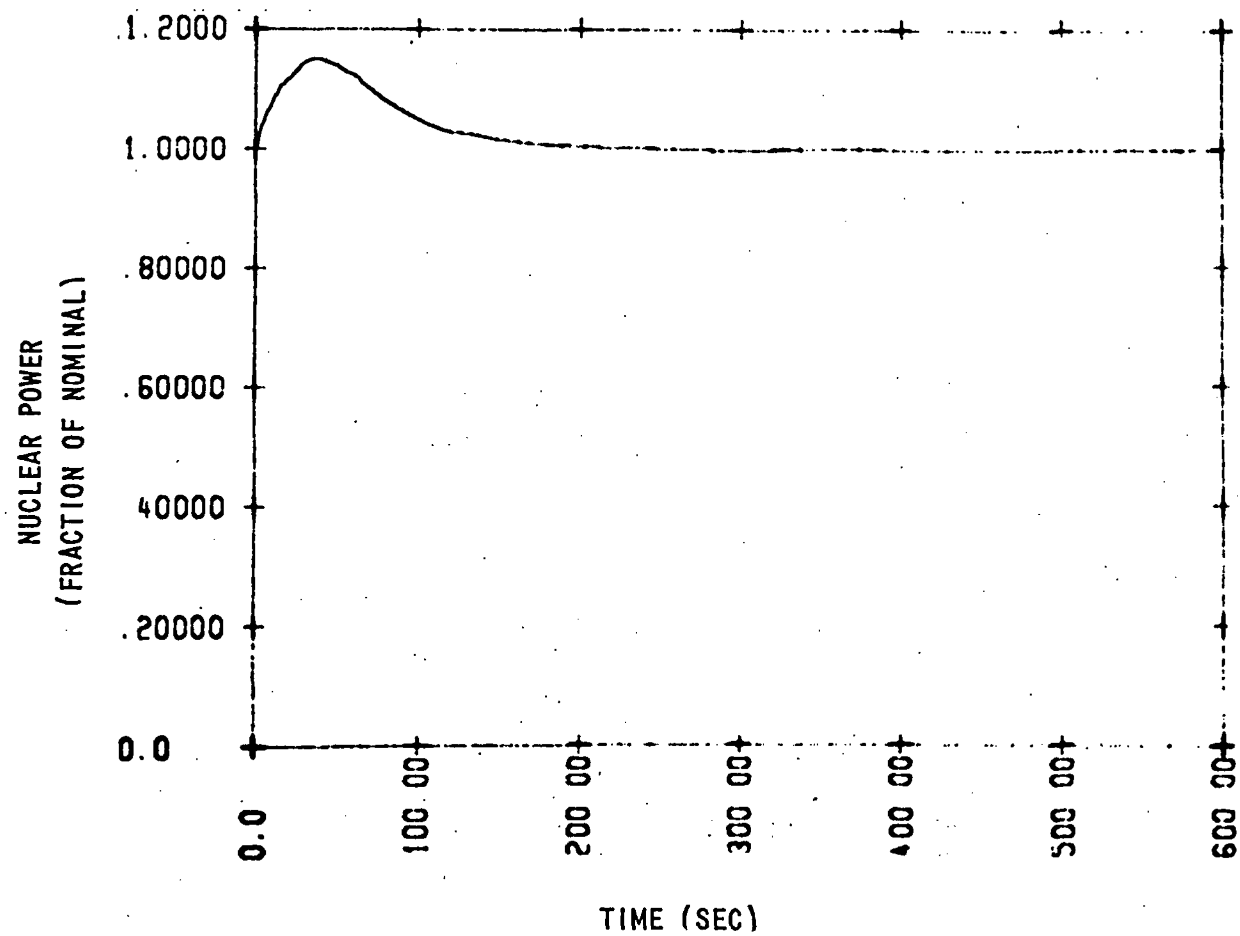

Figure 4-61. Rod Withdrawal at Power — 2-Loop Plant (Nuclear Power Vs. Time)

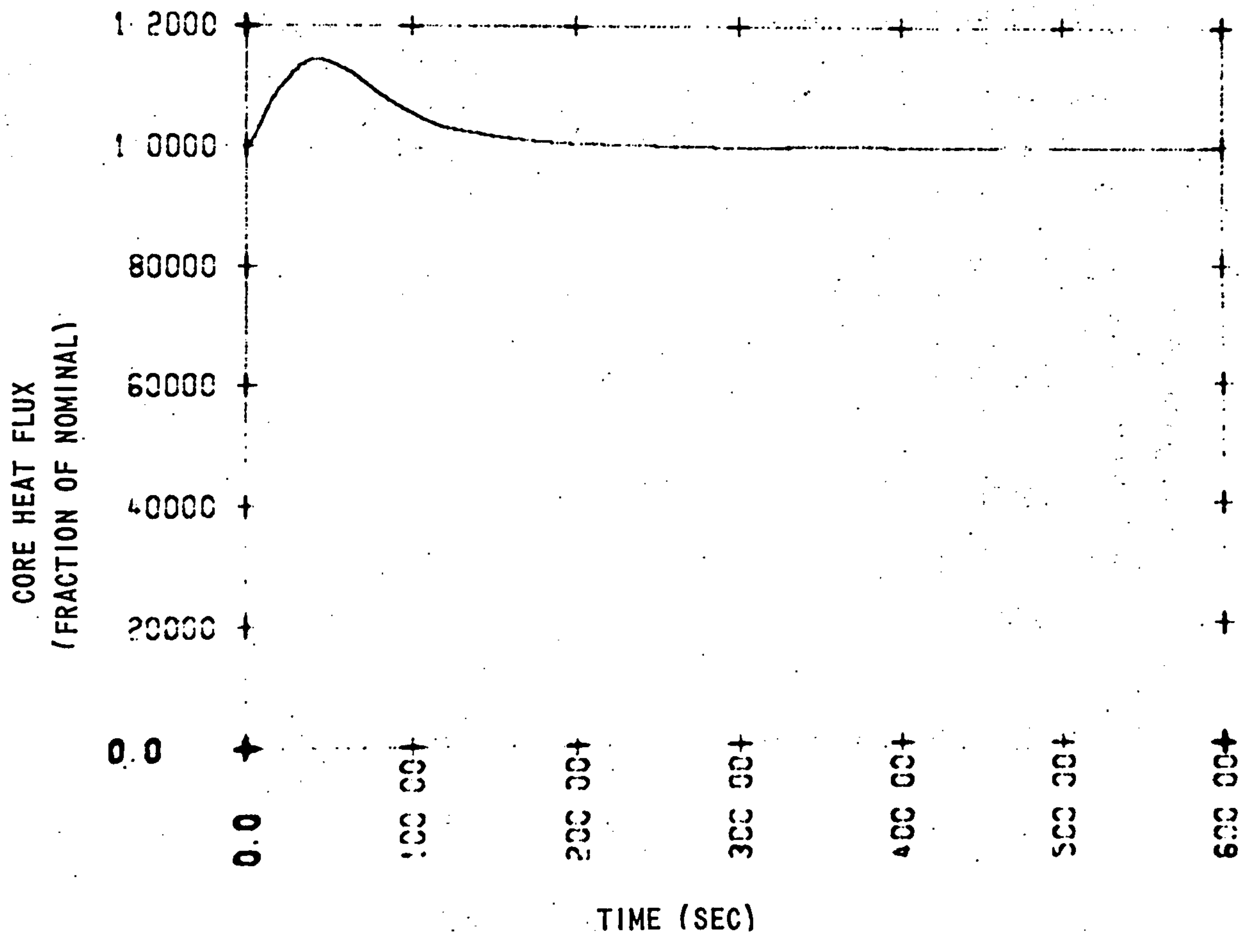

Figure 4-62. Rod Withdrawal at Power — 2-Loop Plant (Core Heat Flux Vs. Time)

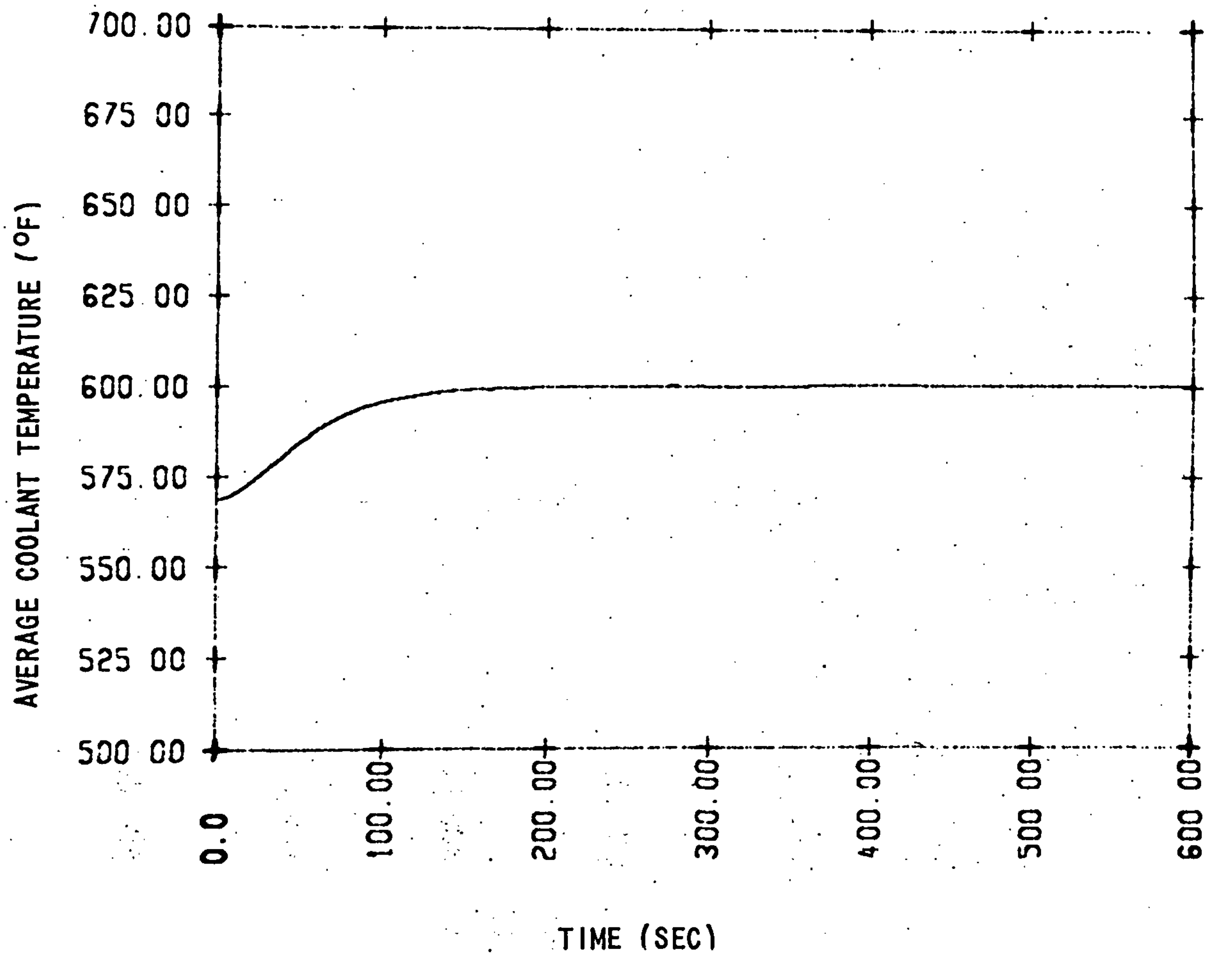

Figure 4-63. Rod Withdrawal at Power — 2-Loop Plant (Average Coolant Temperature Vs. Time)

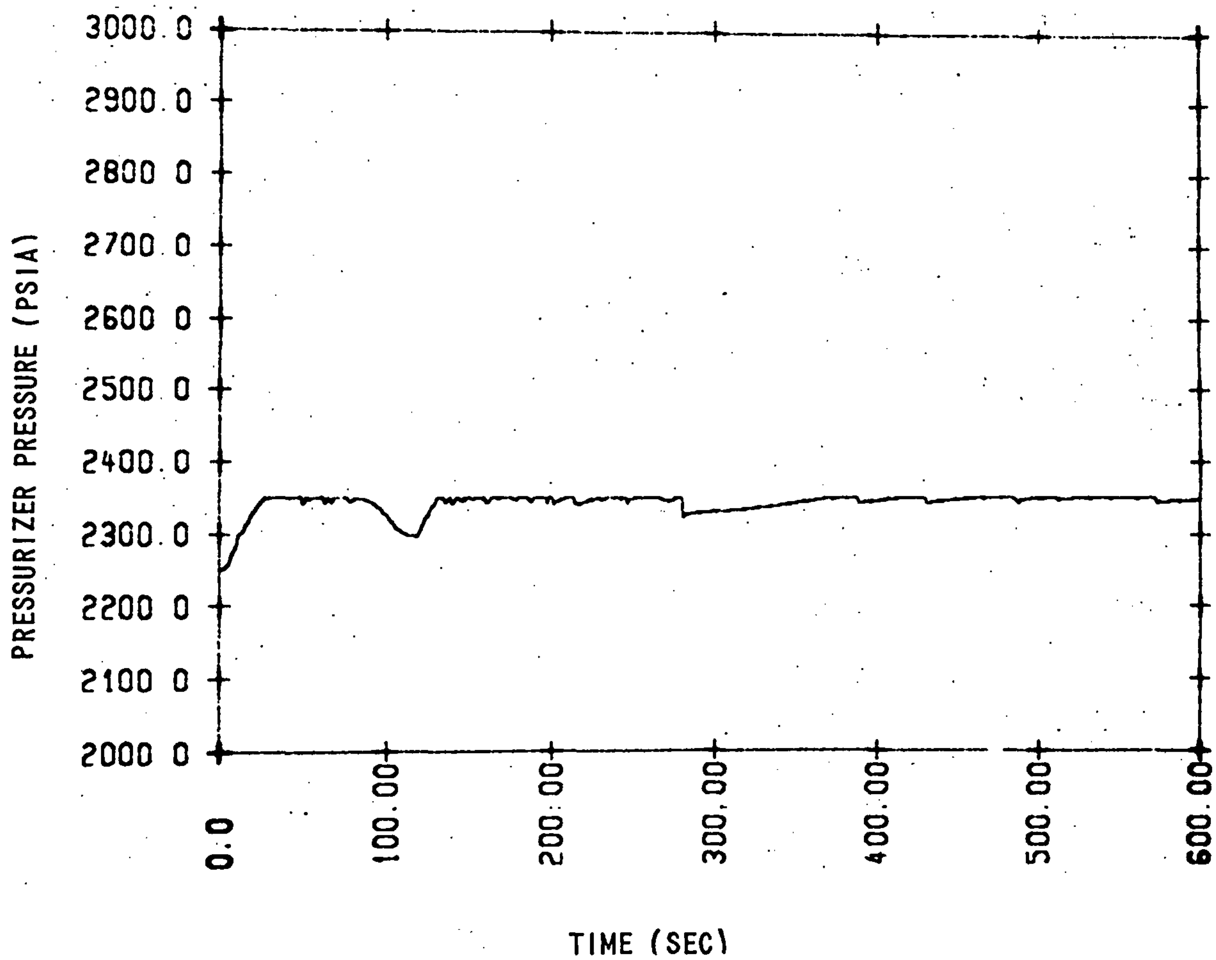

Figure 4-64. Rod Withdrawal at Power – 2-Loop Plant (Pressurizer Pressure Vs. Time)

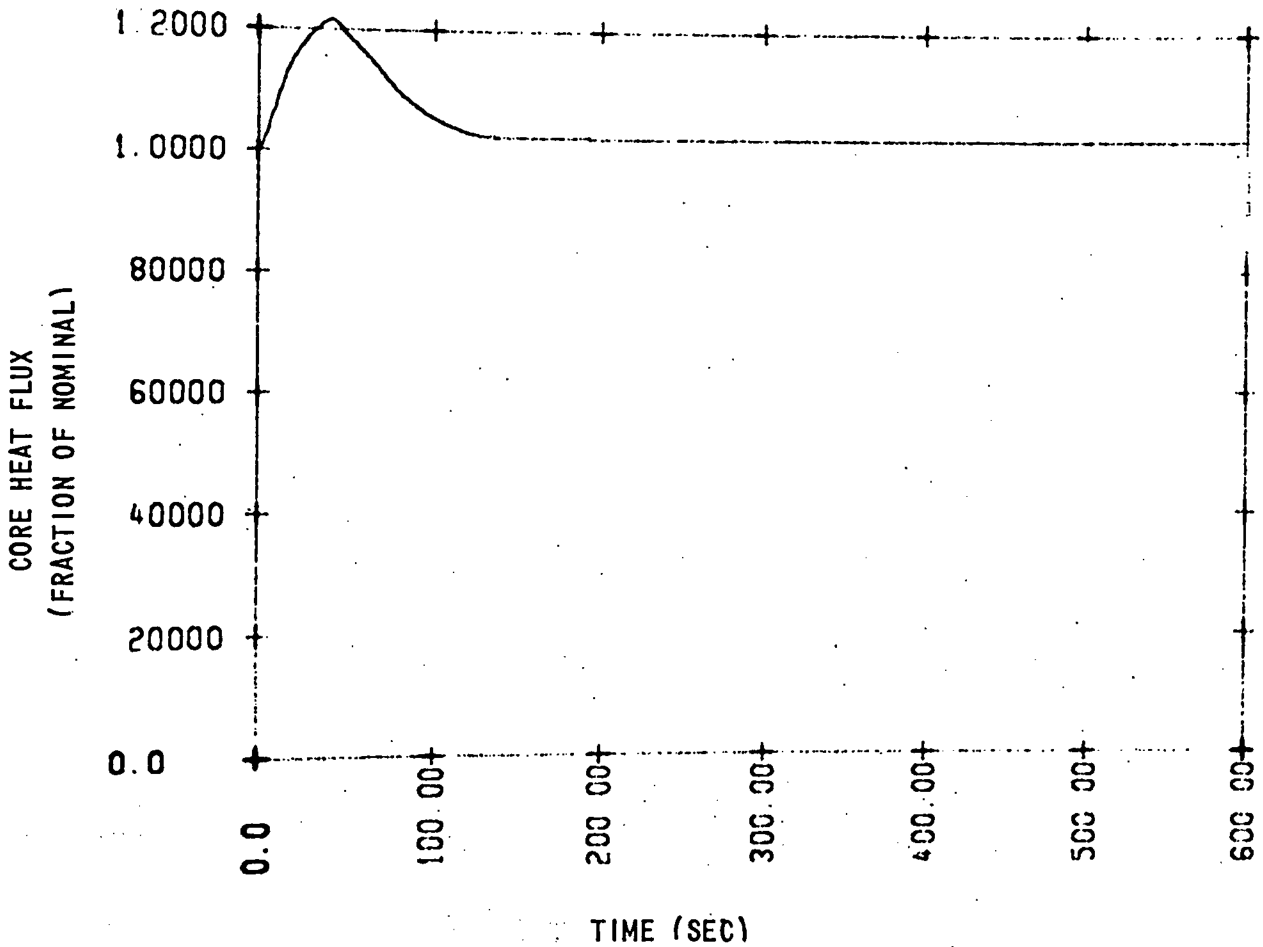

Figure 4-65. Rod Withdrawal at Power — 0.5 Percent Inserted Reactivity (Core Heat Flux Vs. Time)

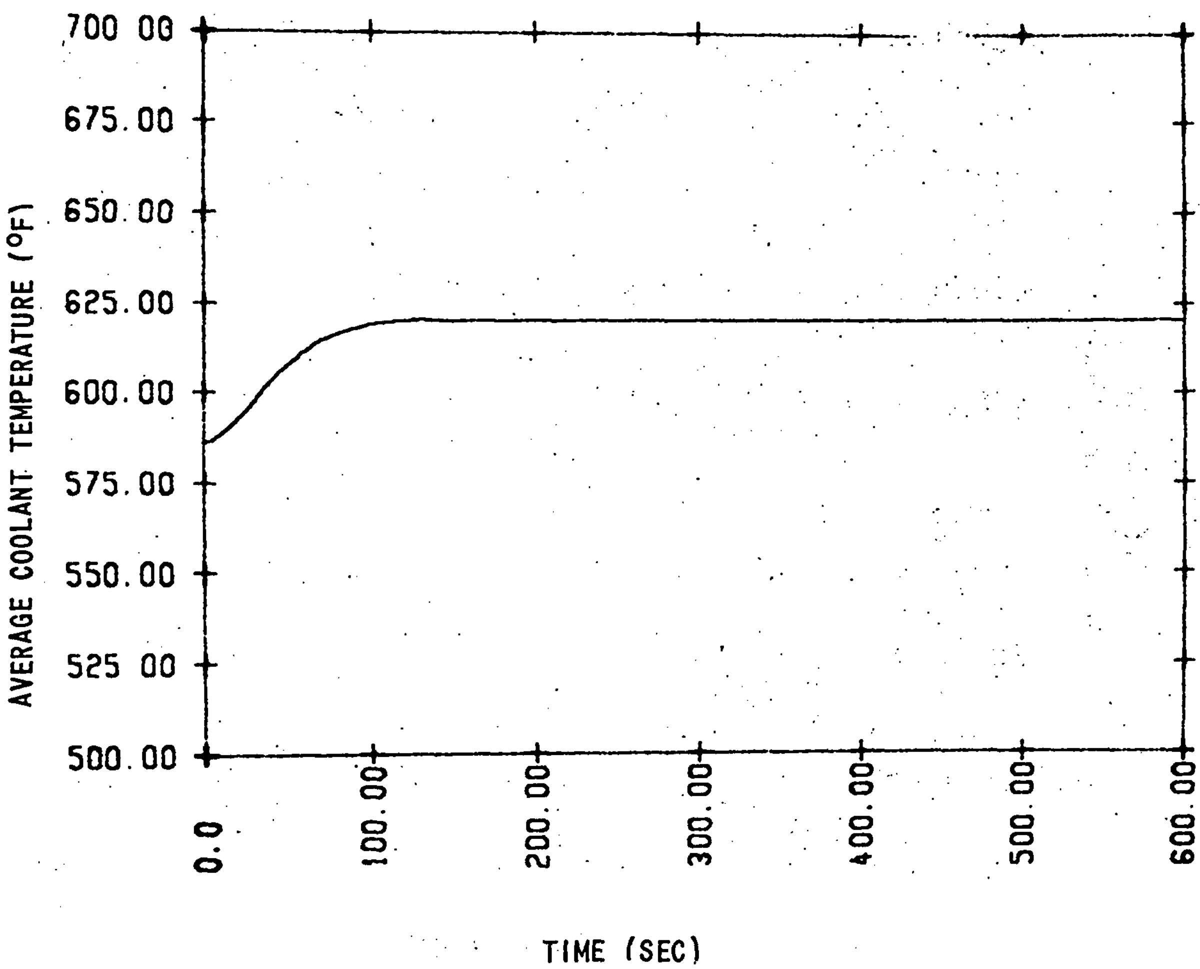

Figure 4-66. Rod Withdrawal at Power — 0.5 Percent Inserted Reactivity (Average Coolant Temperature Vs. Time)

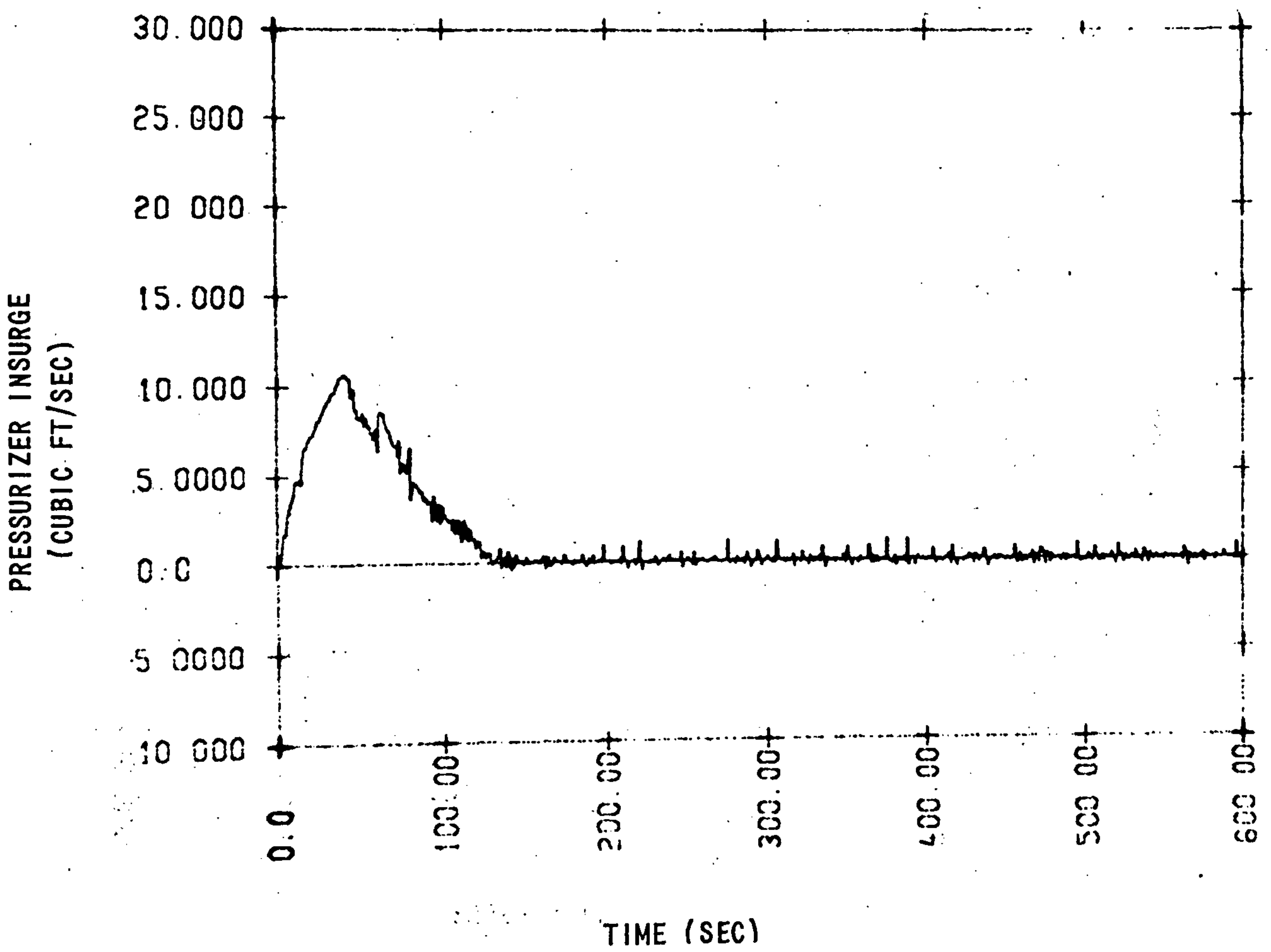

Figure 4-67. Rod Withdrawal at Power – 0.5 Percent Inserted Reactivity (Pressurizer Insurge Vs. Time)

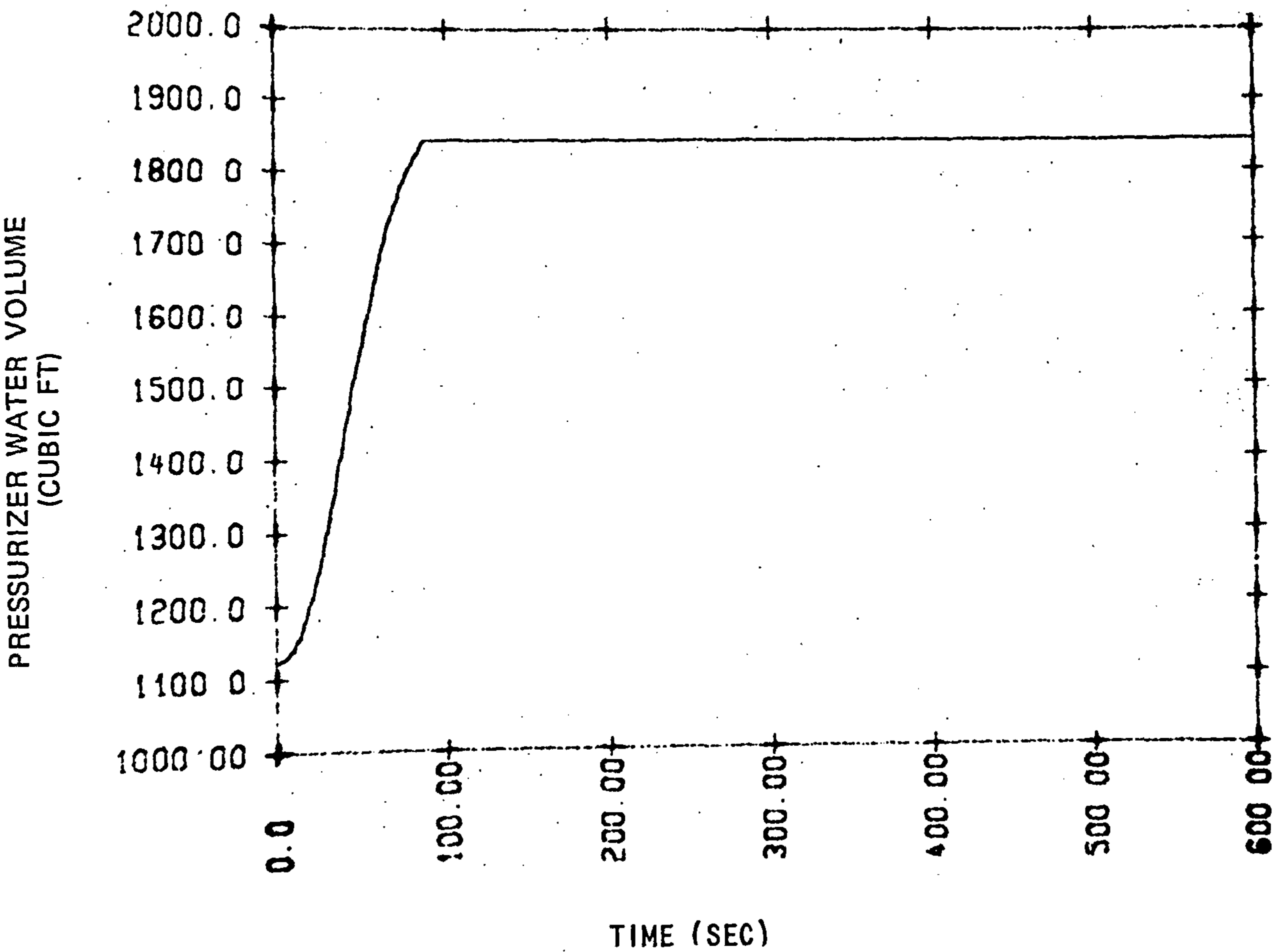

Figure 4-68. Rod Withdrawal at Power — 0.5 Percent Inserted Reactivity (Pressurizer Water Volume Vs. Time)

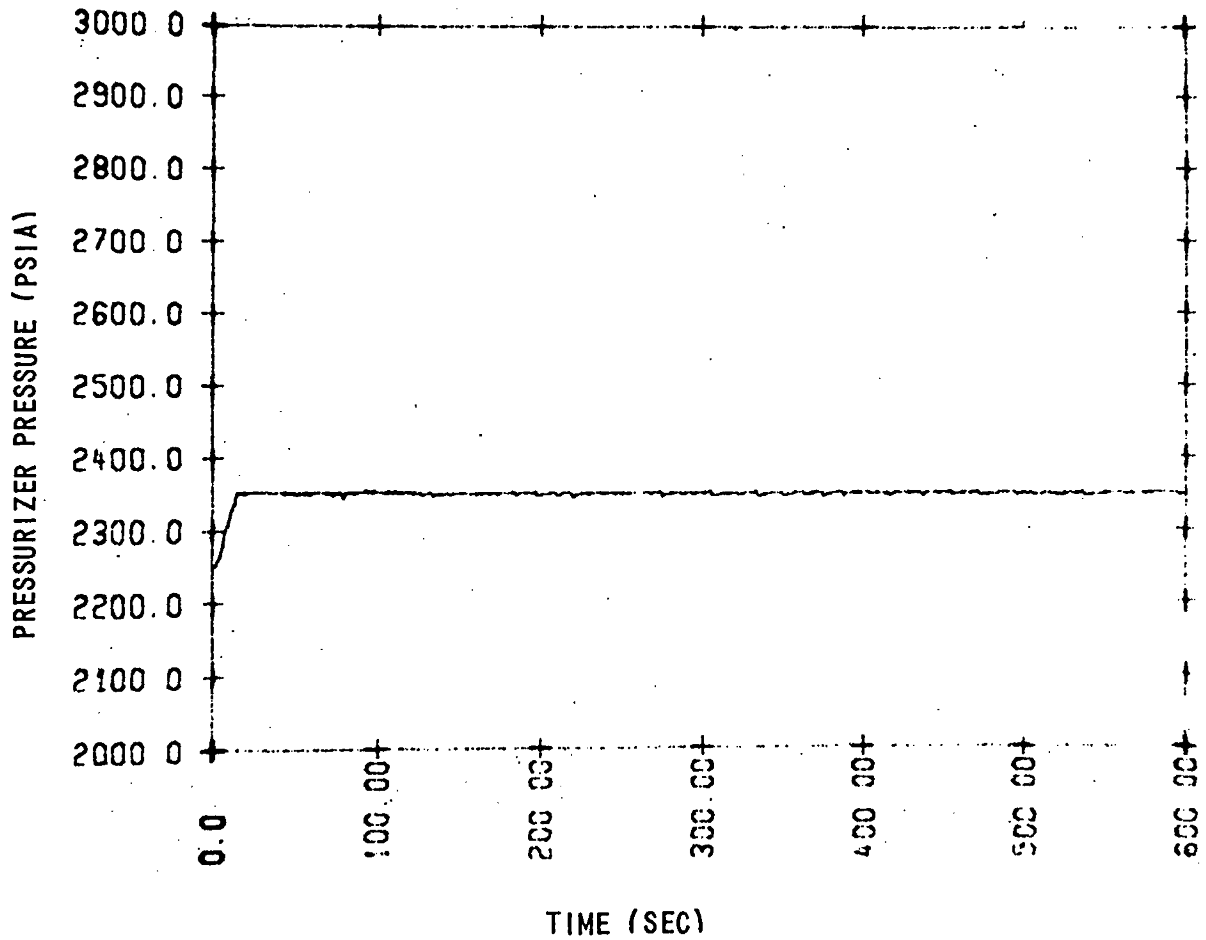

Figure 4-69. Rod Withdrawal at Power — 0.5 Percent Inserted Reactivity (Pressurizer Pressure Vs. Time)

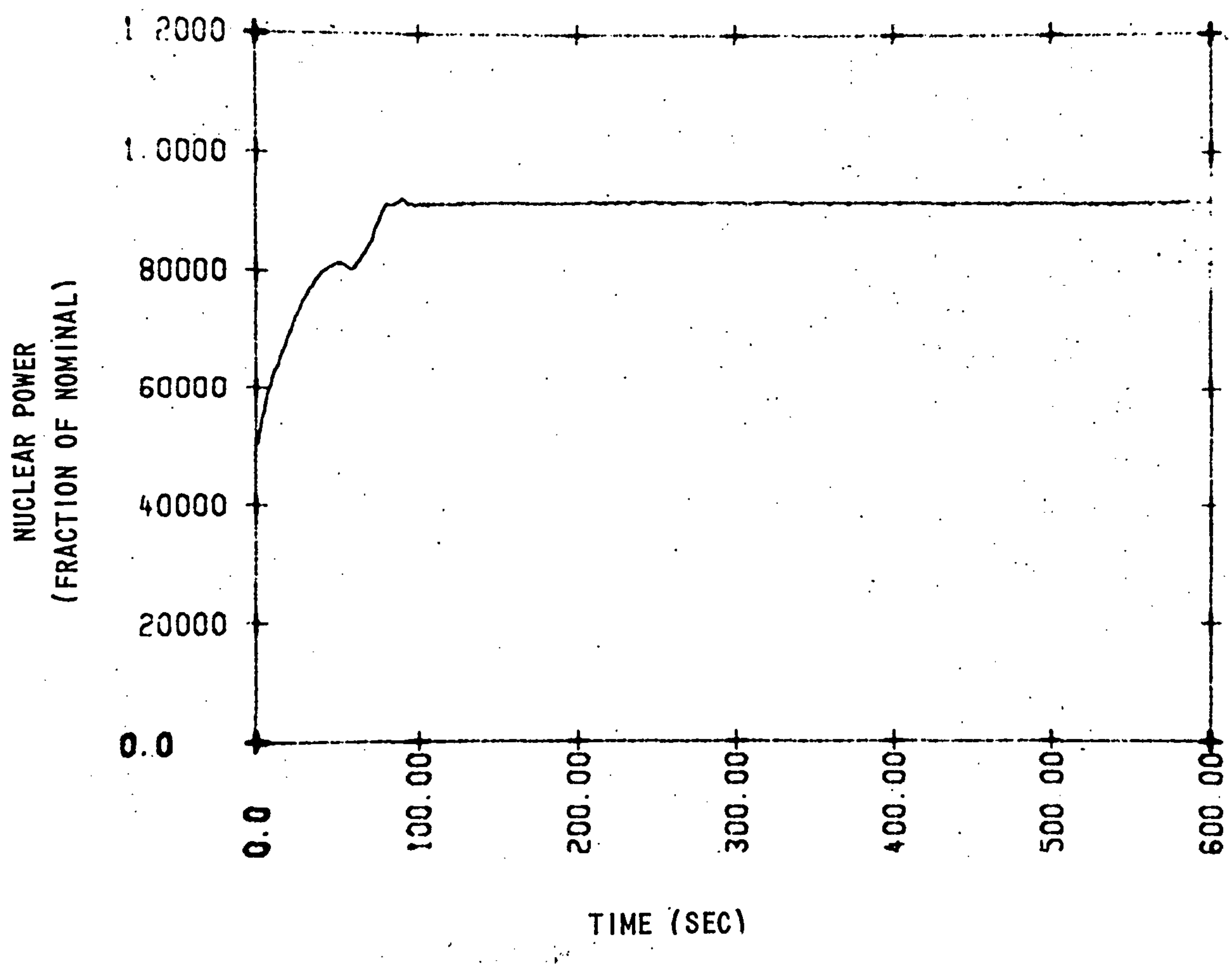

Figure 4-70. Rod Withdrawal at Power — 50 Percent Power (Nuclear Power Vs. Time)

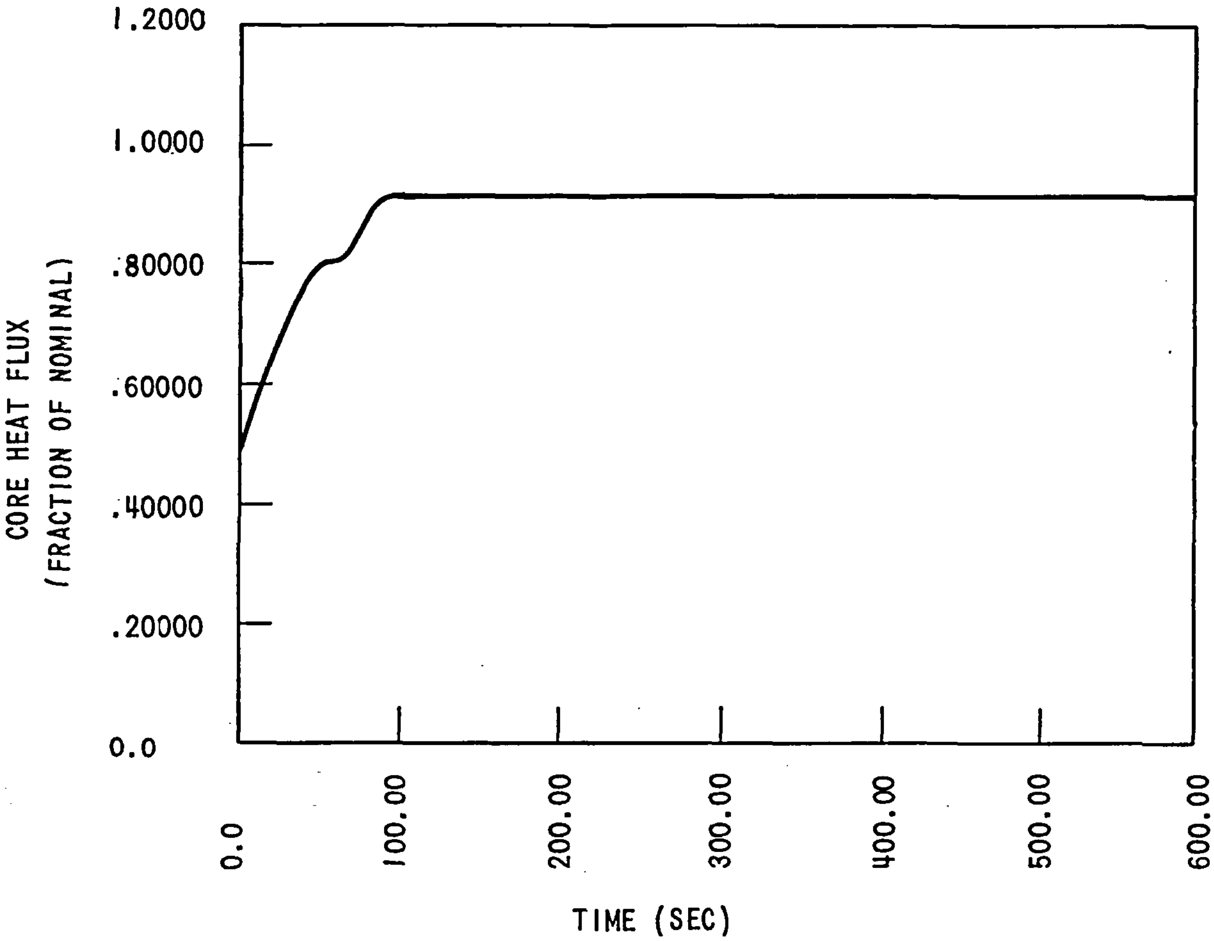

Figure 4-71. Rod Withdrawal at Power – 50 Percent Power (Core Heat Flux Vs. Time)

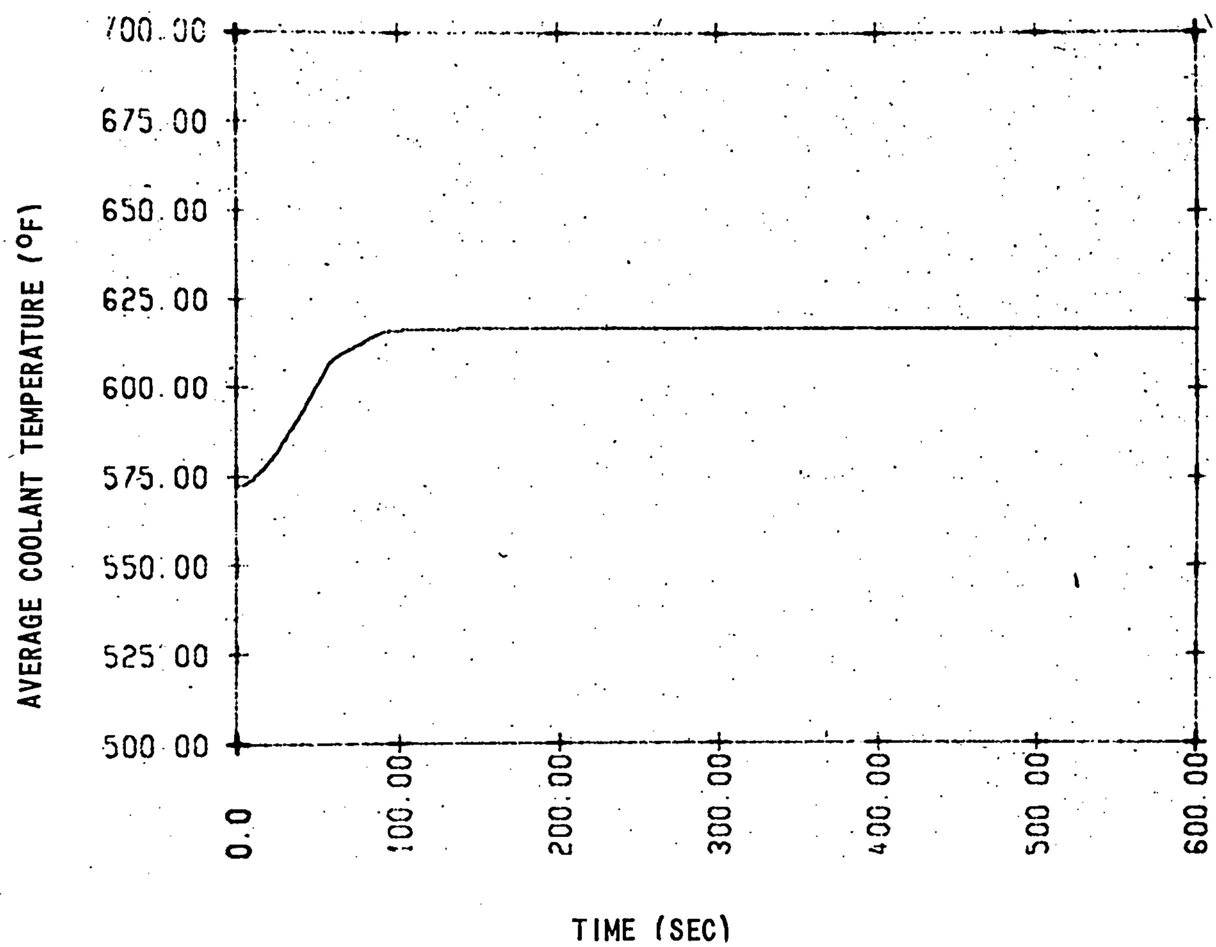

Figure 4-72. Rod Withdrawal at Power — 50 Percent Power (Average Coolant Temperature Vs. Time)

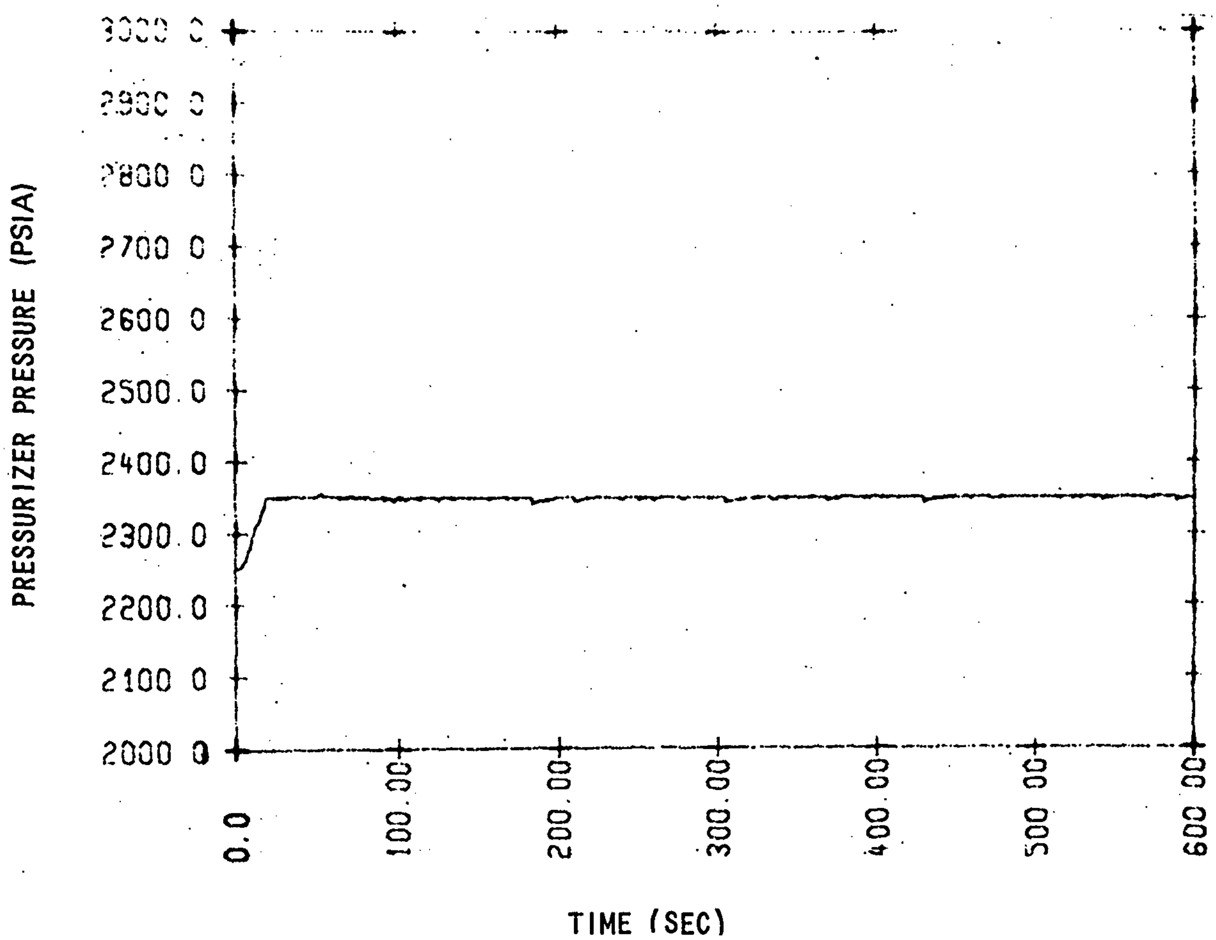

Figure 4-73. Rod Withdrawal at Power — 50 Percent Power (Pressurizer Pressure Vs. Time)

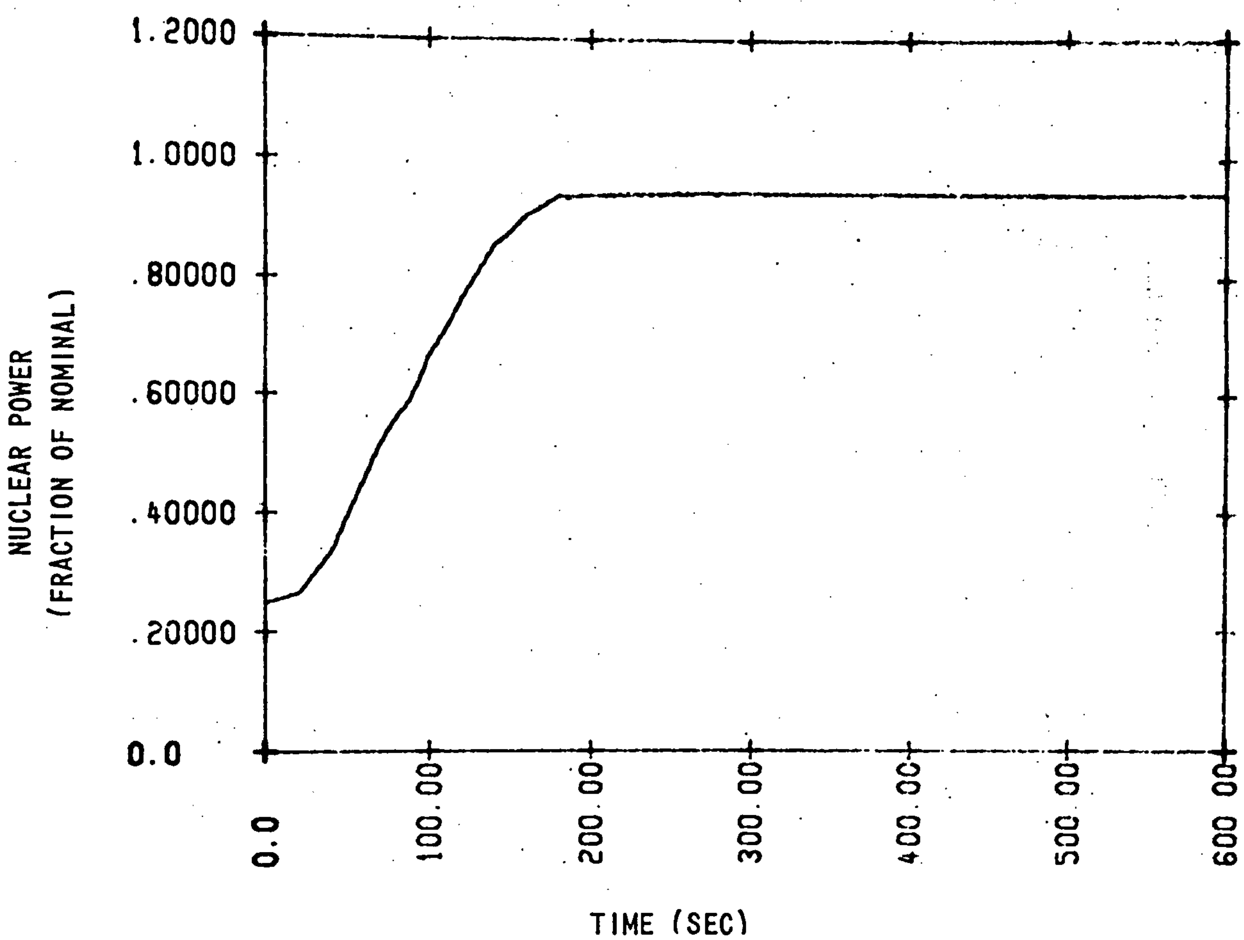

Figure 4-74. Rod Withdrawal at Power — 25 Percent Power (Nuclear Power Vs. Time)

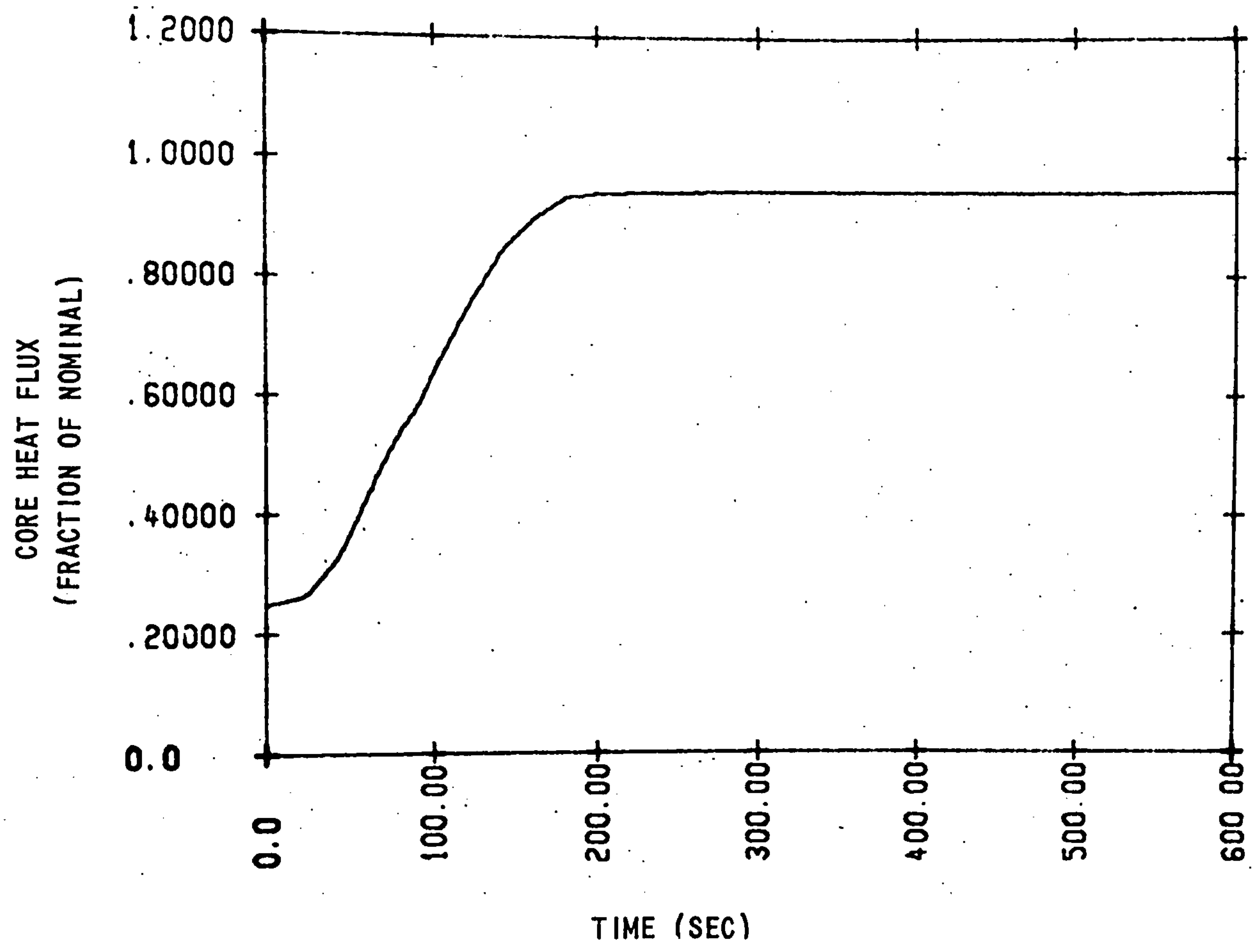

Figure 4-75. Rod Withdrawal at Power — 25 Percent Power (Core Heat Flux Vs. Time)

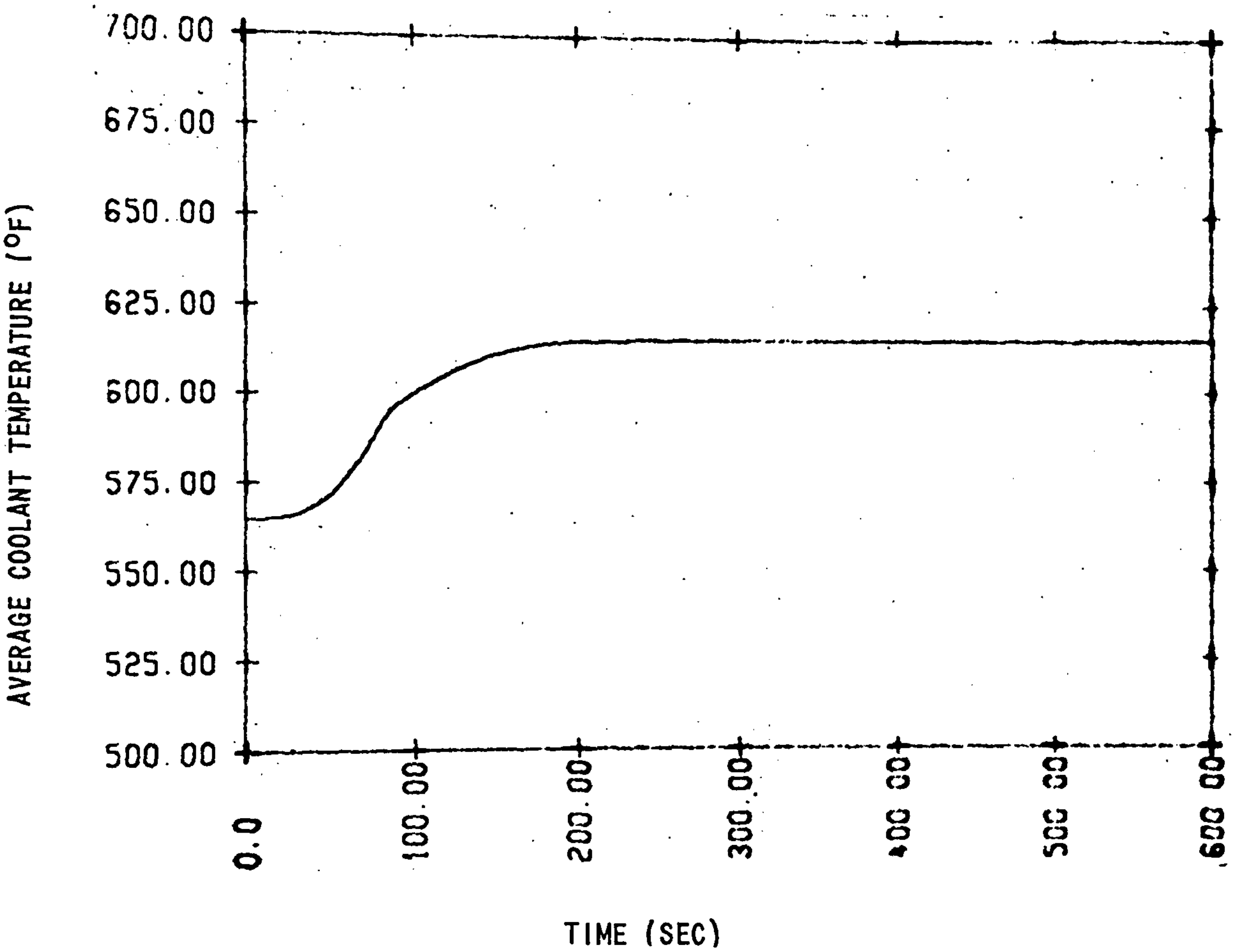

Figure 4-76. Rod Withdrawal Power — 25 Percent Power (Average Coolant Temperature Vs. Time)

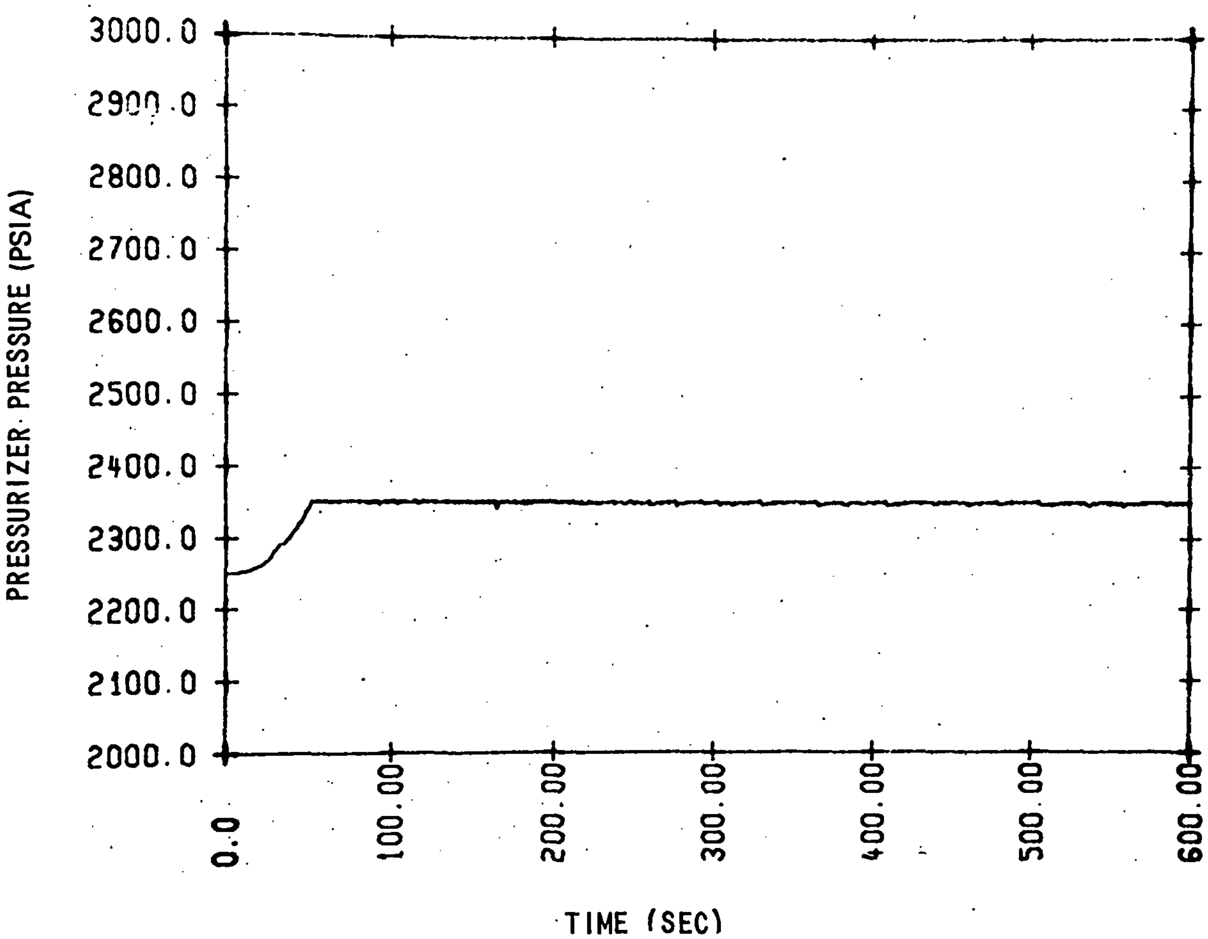

Figure 4-77. Rod Withdrawal at Power — 25 Percent Power (Pressurizer Pressure Vs. Time)

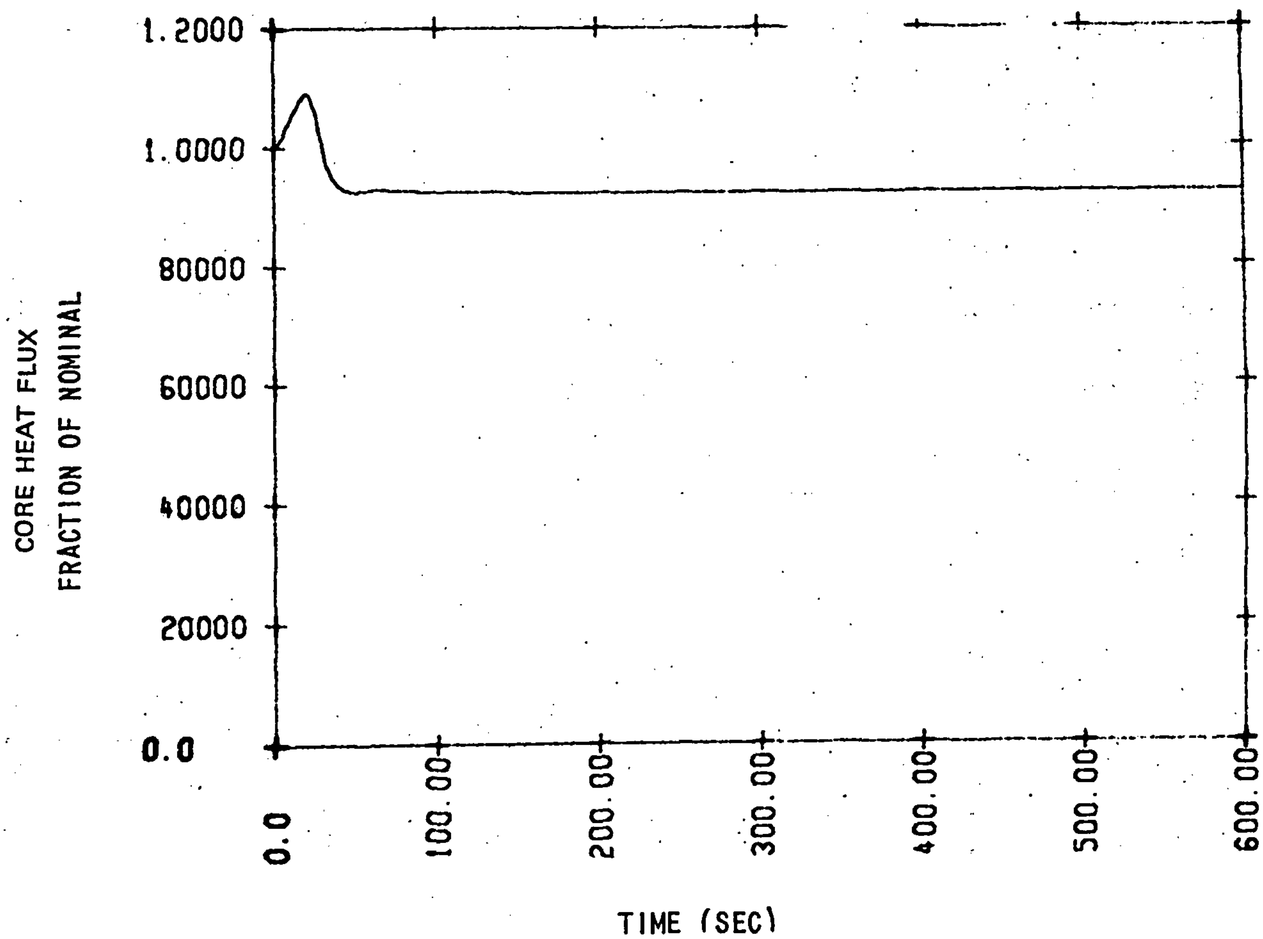

Figure 4-78. Rod Withdrawal at Power-with Turbine Trip (Core Heat Flux Vs. Time)

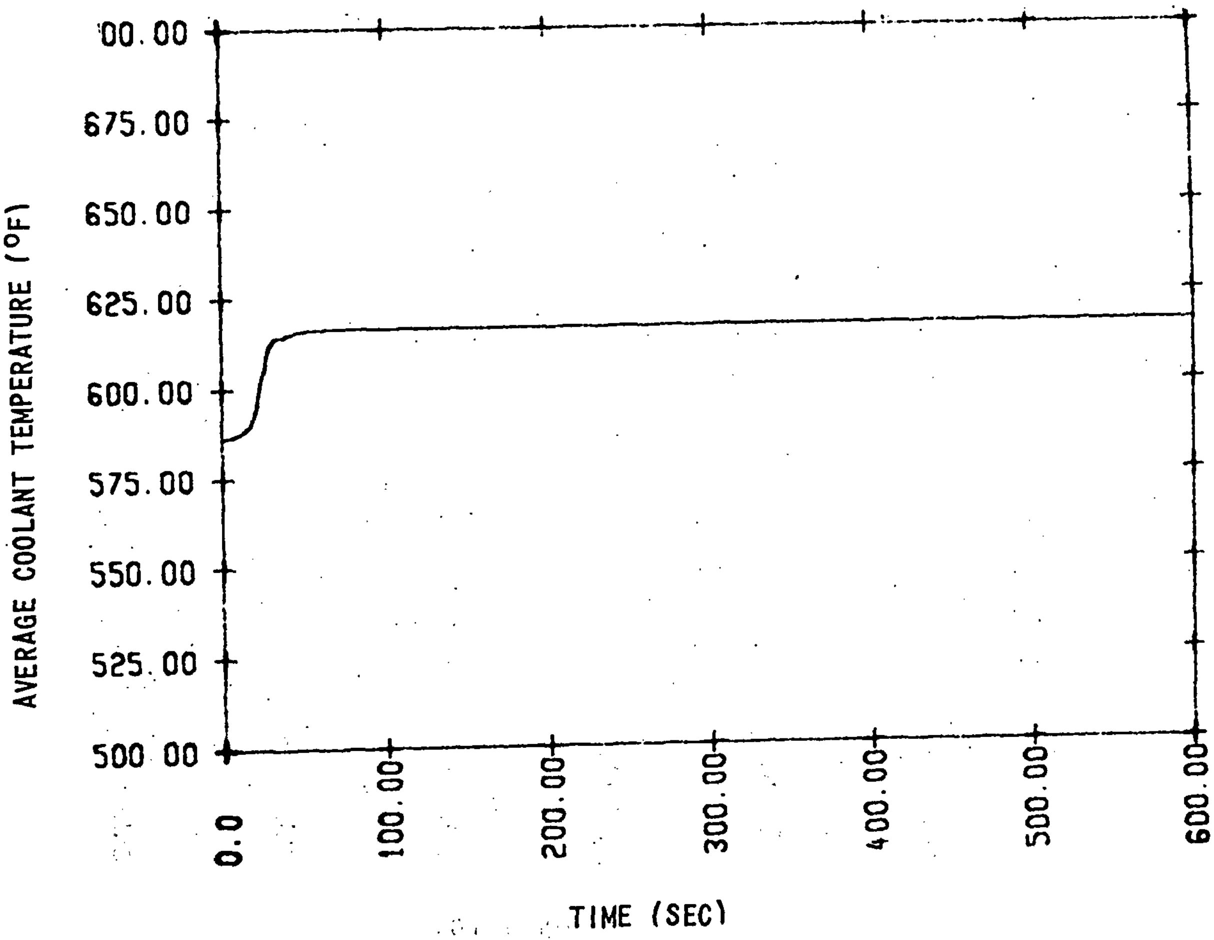

Figure 4-79. Rod Withdrawal at Power-with Turbine Trip (Average Coolant Temperature Vs. Time)

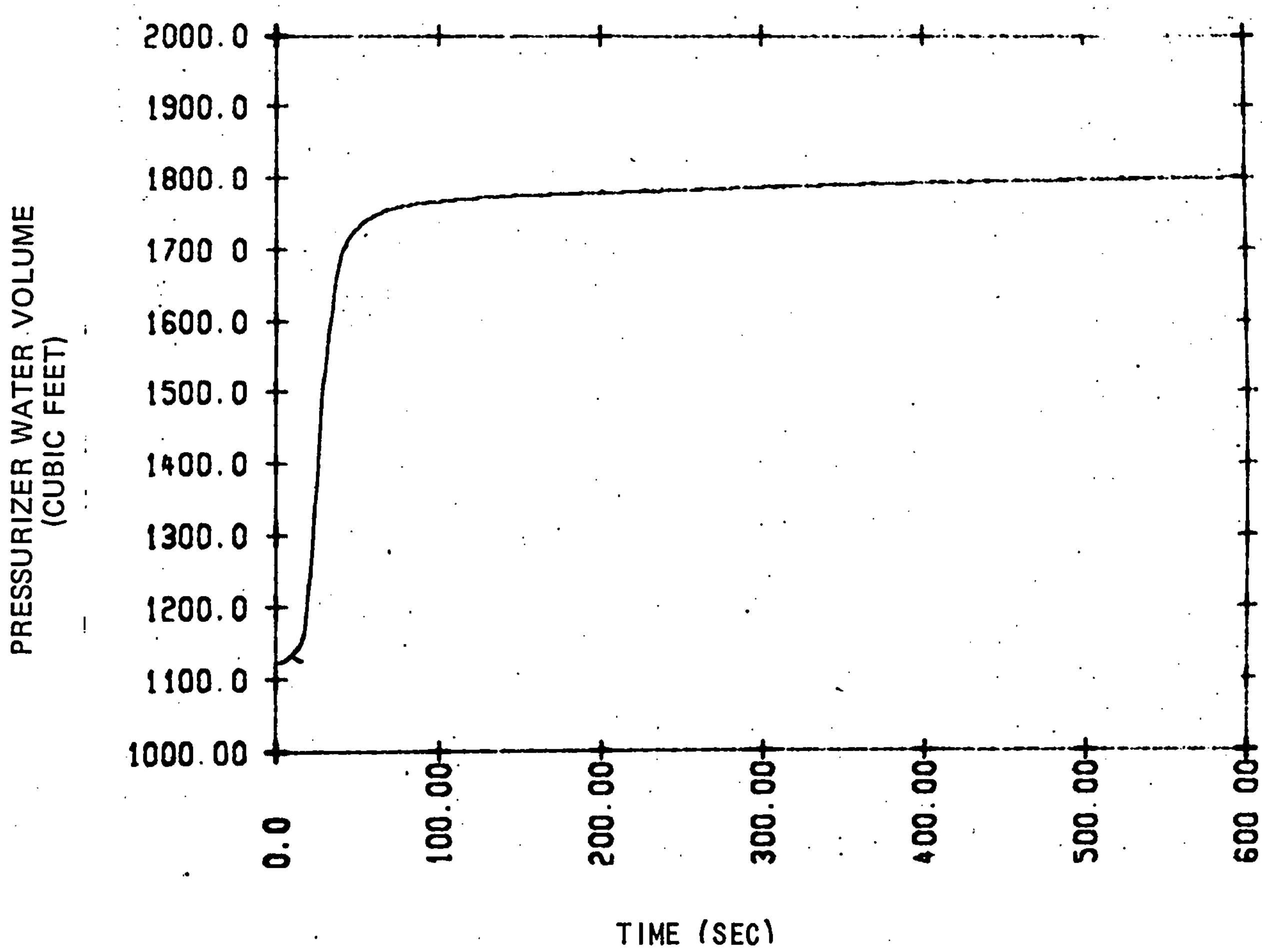

Figure 4-80. Rod Withdrawal at Power-with Turbine Trip (Pressurizer Water Volume Vs. Time)

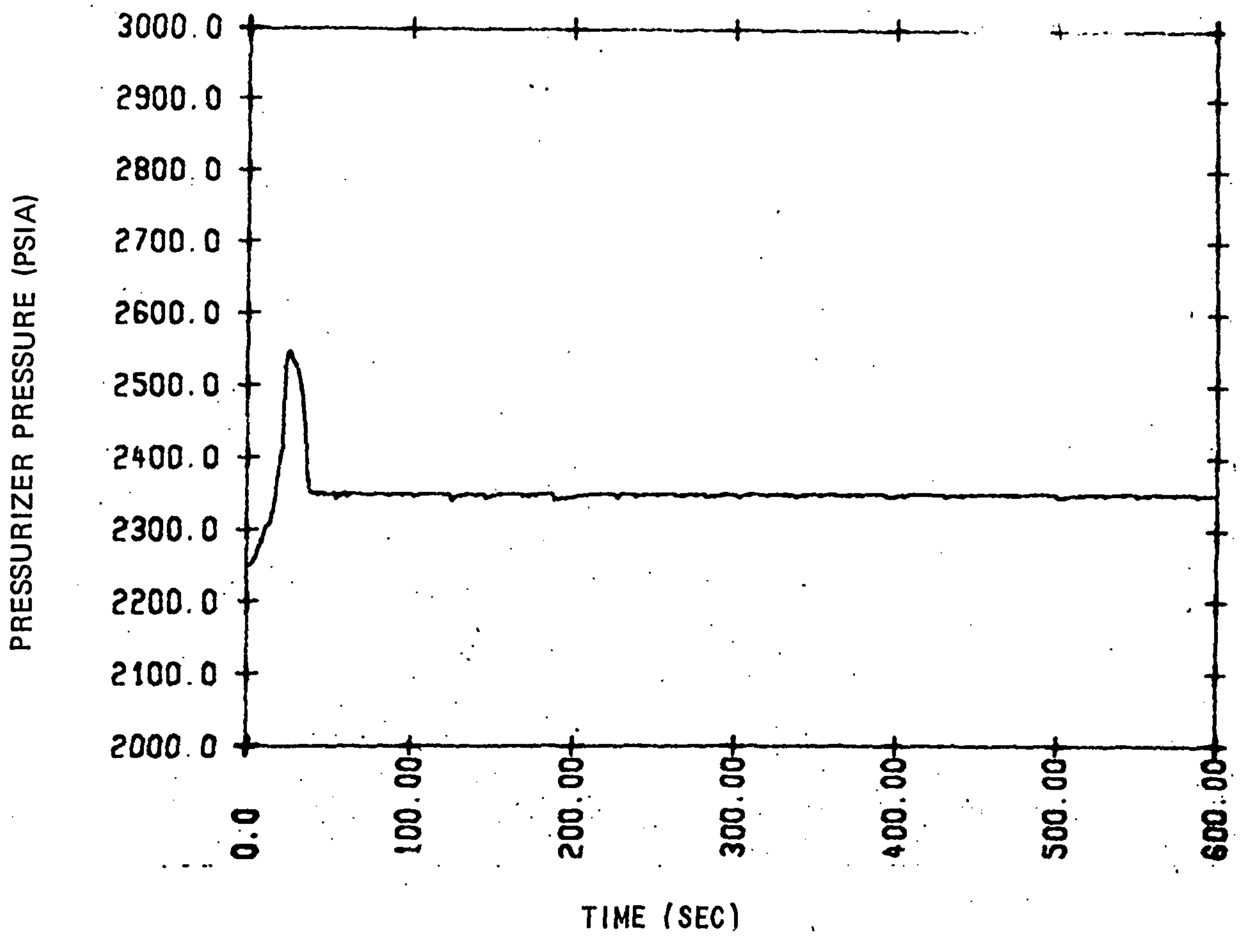

Figure 4-81. Rod Withdrawal at Power-with Turbine Trip (Pressurizer Pressure Vs. Time)

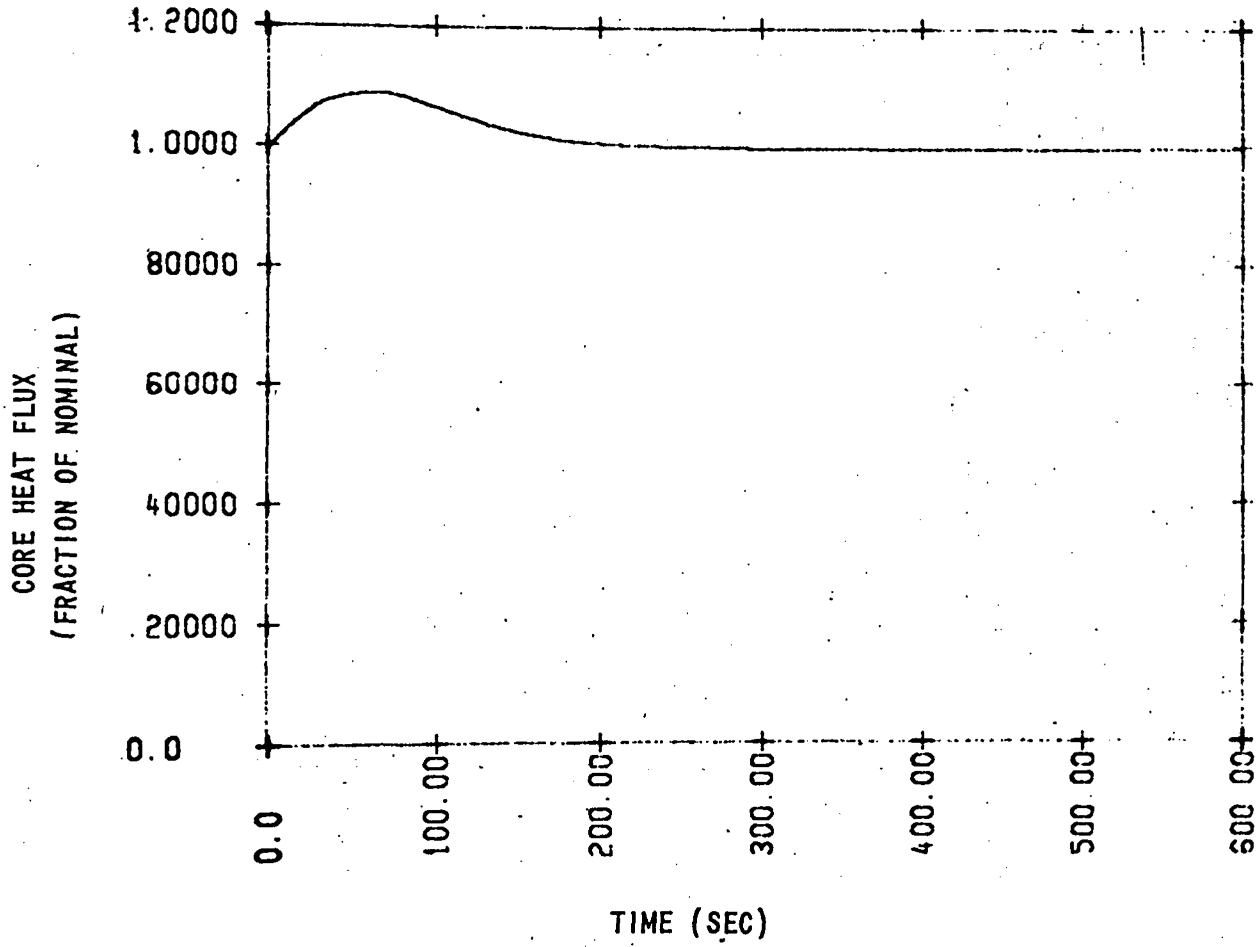

Figure 4-82. Rod Withdrawal at Power-Halved Reactivity Insertion Rate (Core Heat Flux Vs. Time)

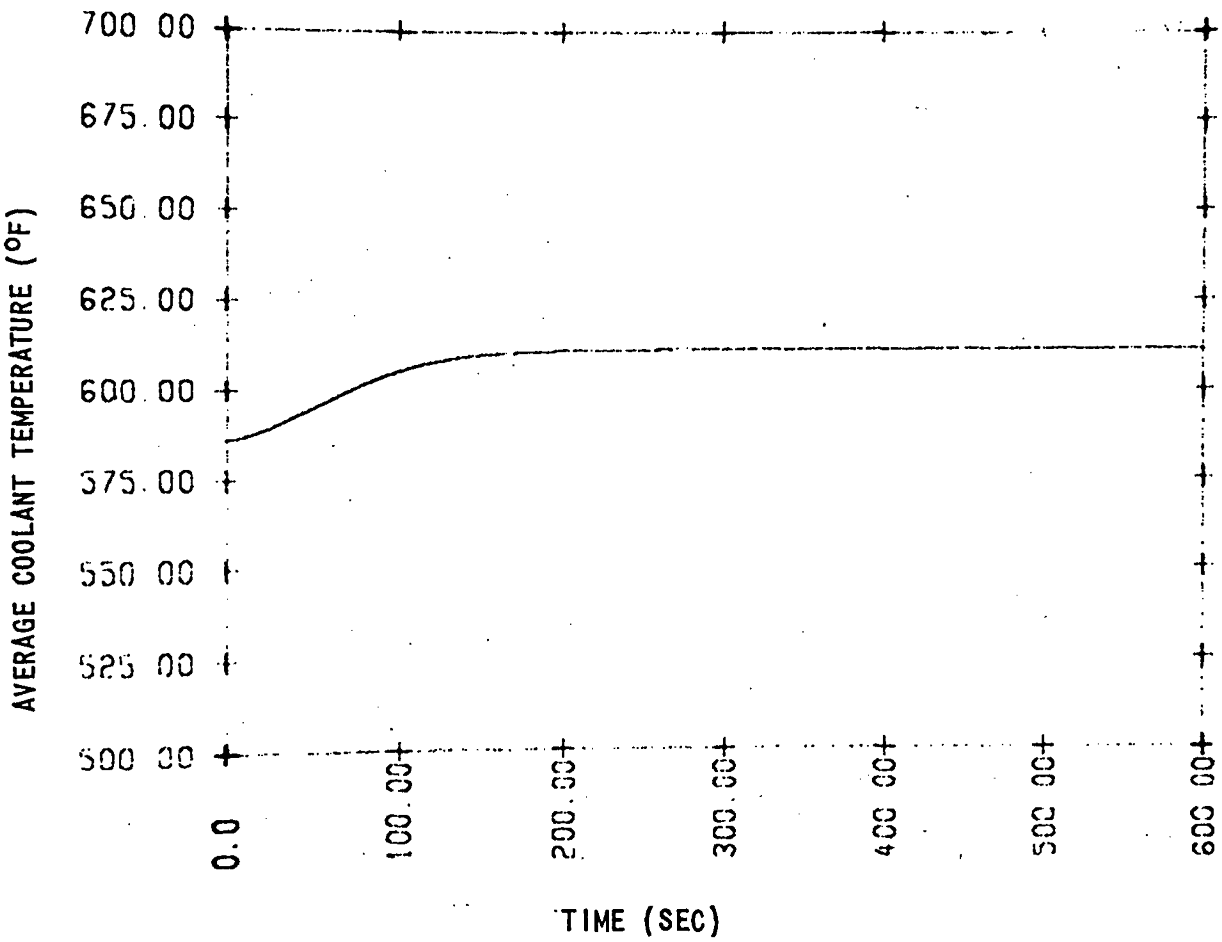

Figure 4-83. Rod Withdrawal at Power-Halved Reactivity Insertion Rate (Average Coolant Temperature Vs. Time)

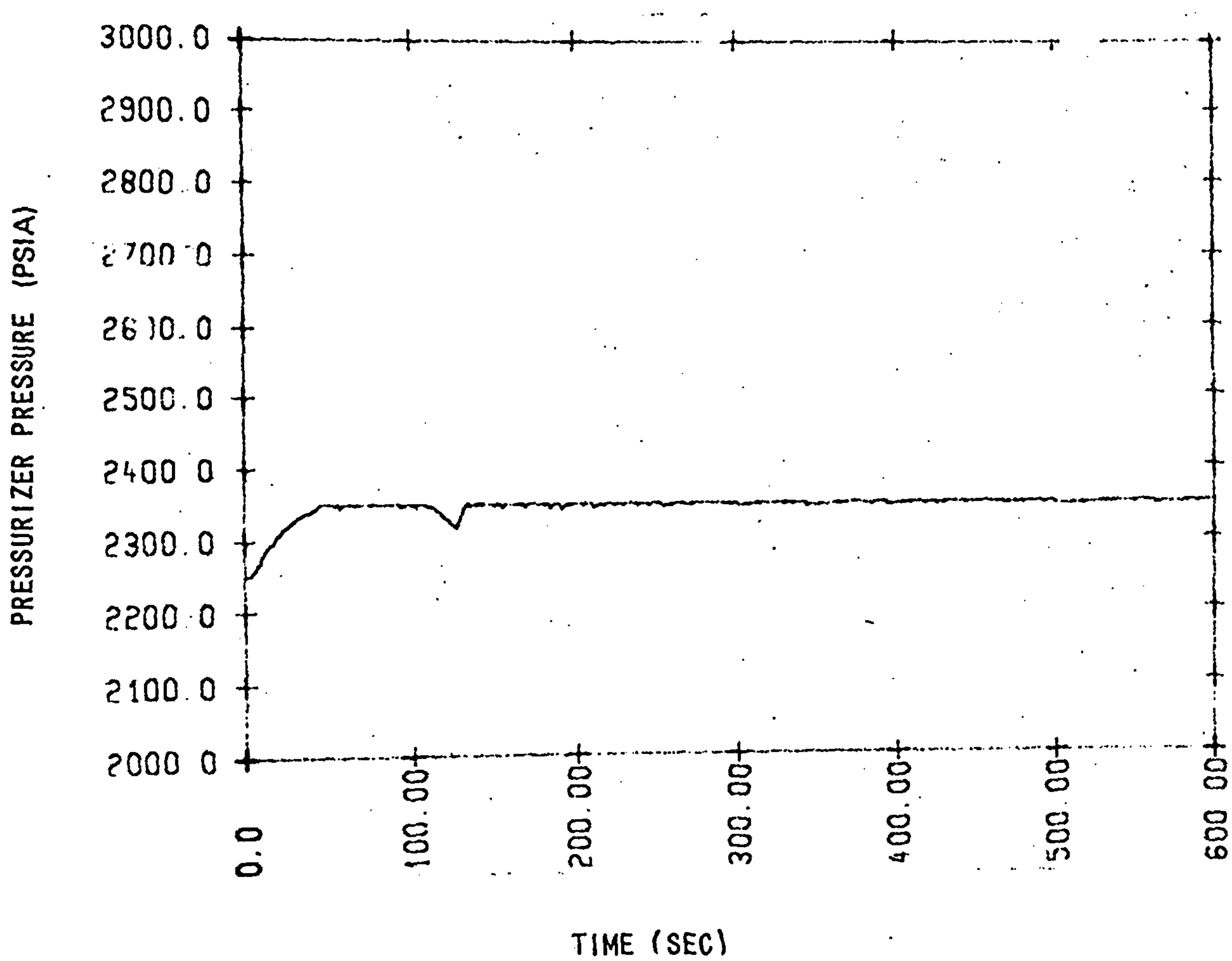

Figure 4-84. Rod Withdrawal at Power–Halved Reactivity Insertion Rate (Pressurizer Pressure Vs. Time)

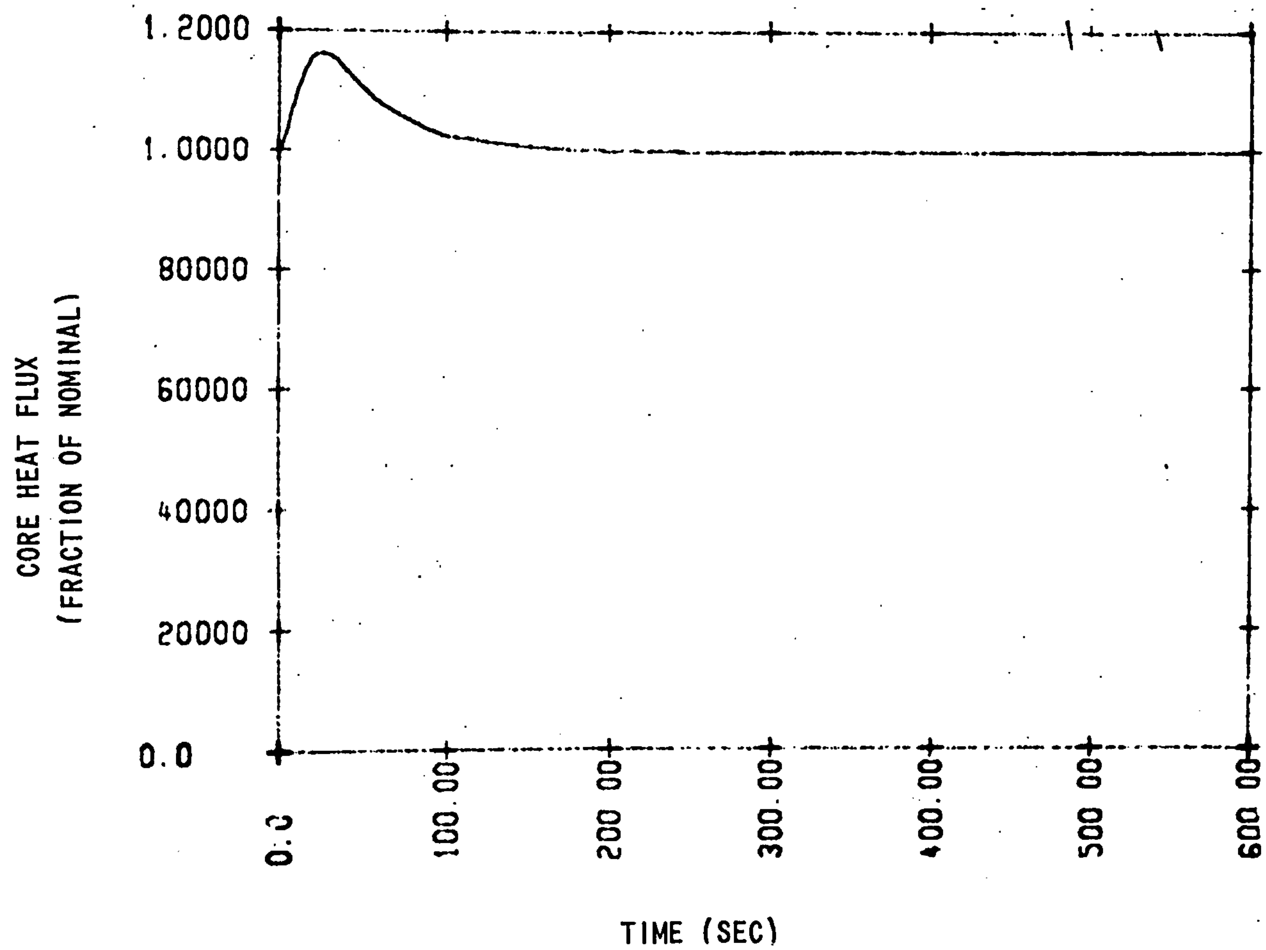

Figure 4-85. Rod Withdrawal at Power-Doubled Reactivity Insertion Rate (Core Heat Flux Vs. Time)

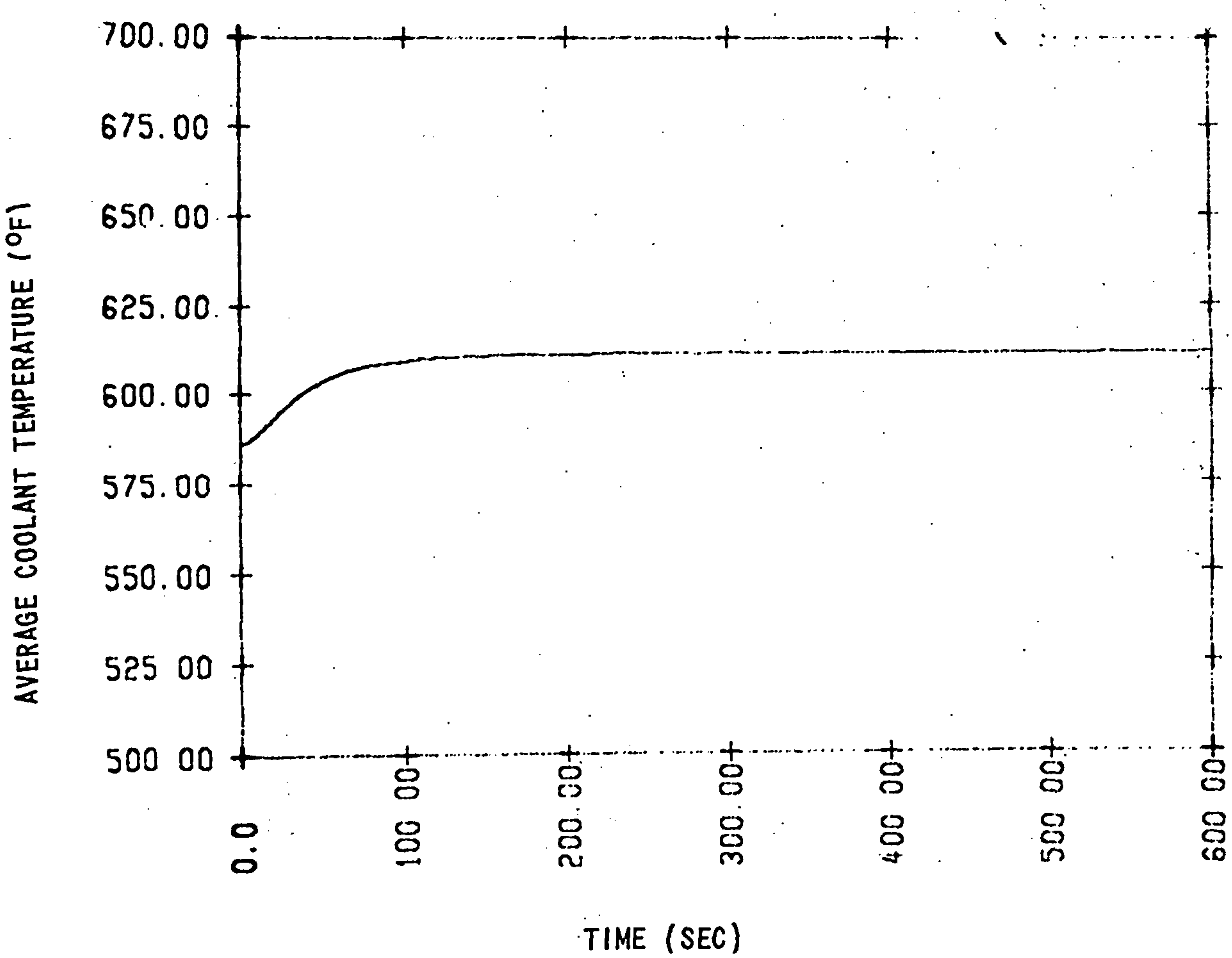

Figure 4-86. Rod Withdrawal at Power-Doubled Reactivity Insertion Rate (Average Coolant Temperature Vs. Time)

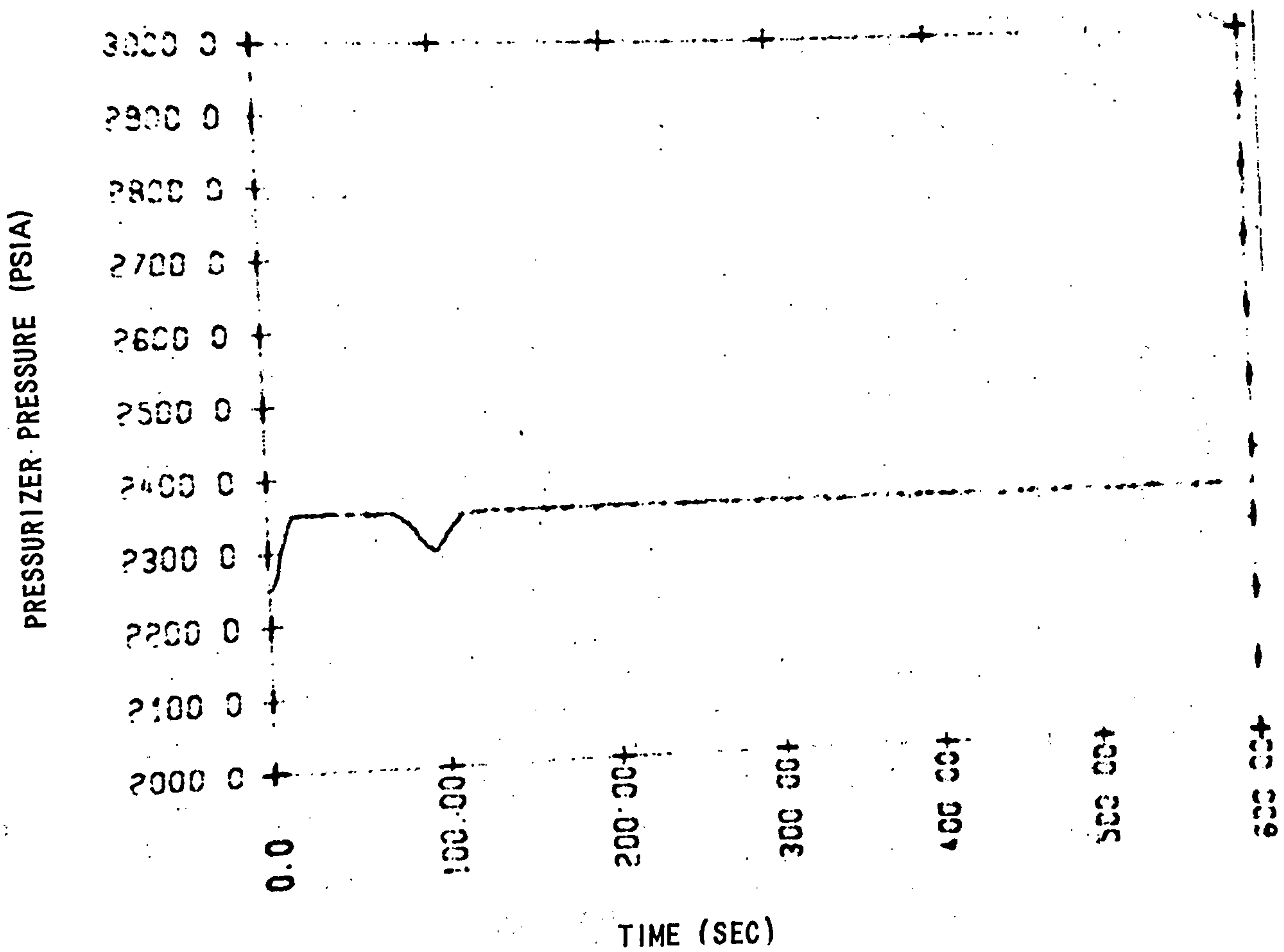

Figure 4-87. Rod Withdrawal at Power-Doubled Reactivity Insertion Rate (Pressurizer Pressure Vs. Time)

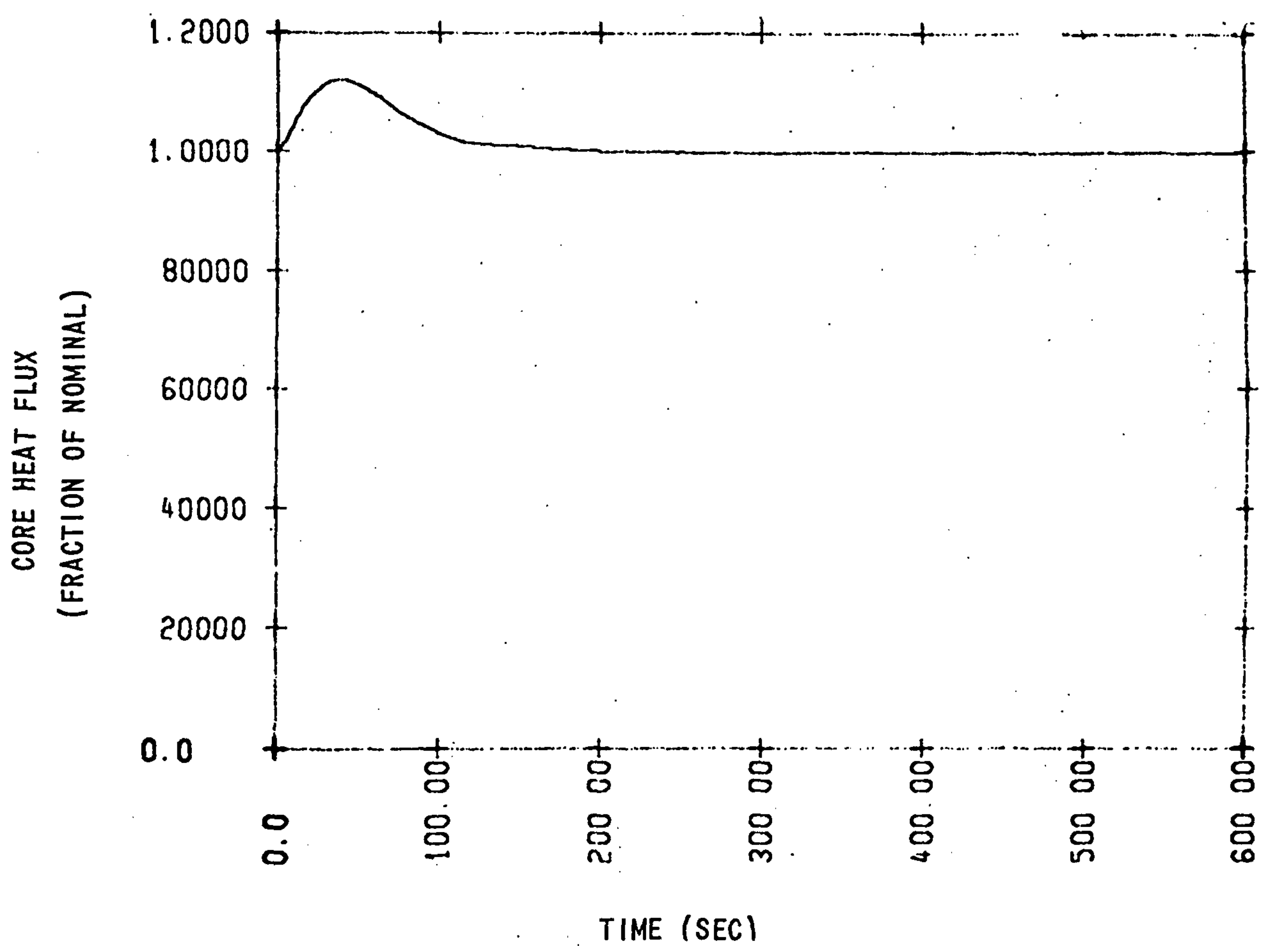

Figure 4-88. Rod Withdrawal at Power-T_{AVG} + 8°F (Core Heat Flux Vs. Time)

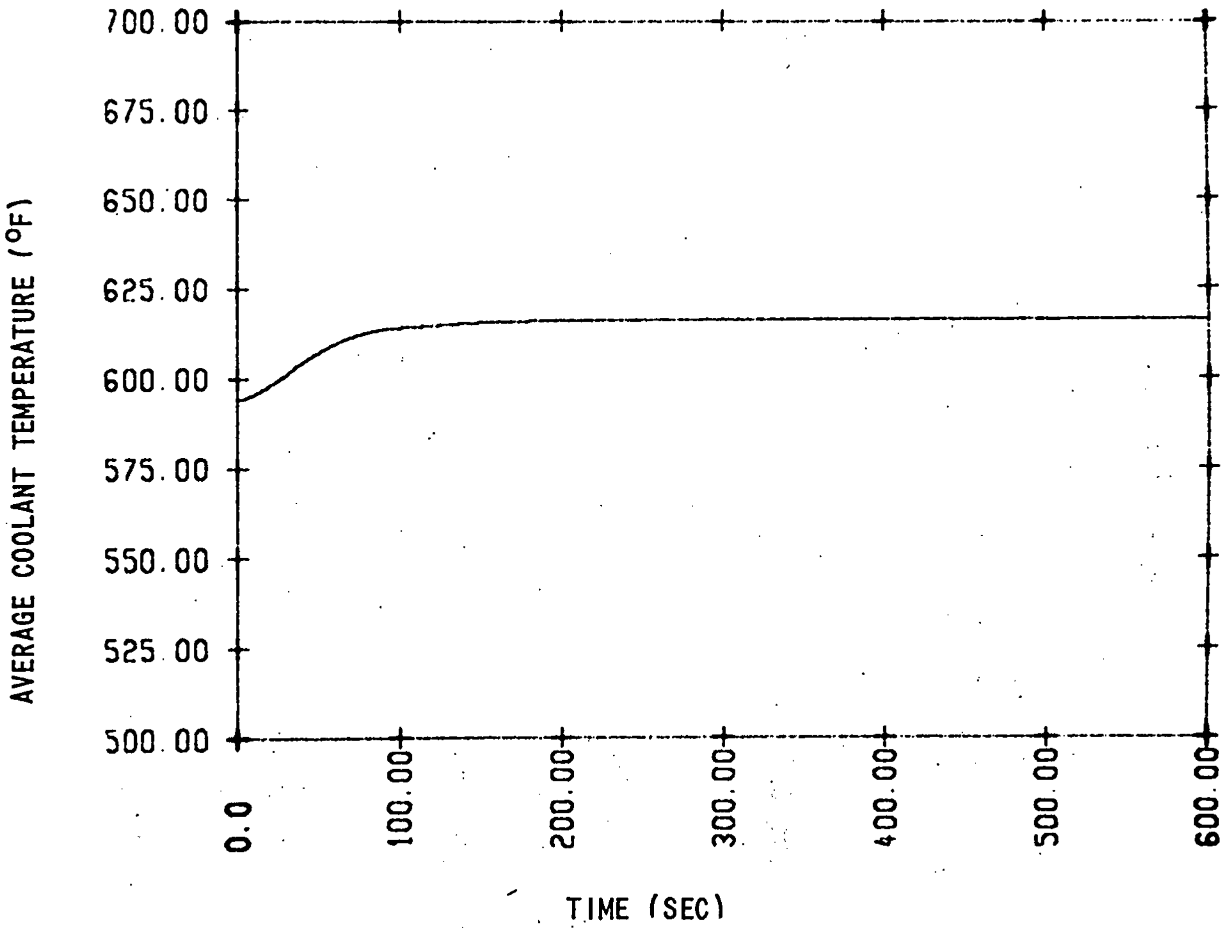

Figure 4-89. Rod Withdrawal at Power-T_{AVG} + 8°F (Average Coolant Temperature Vs. Time)

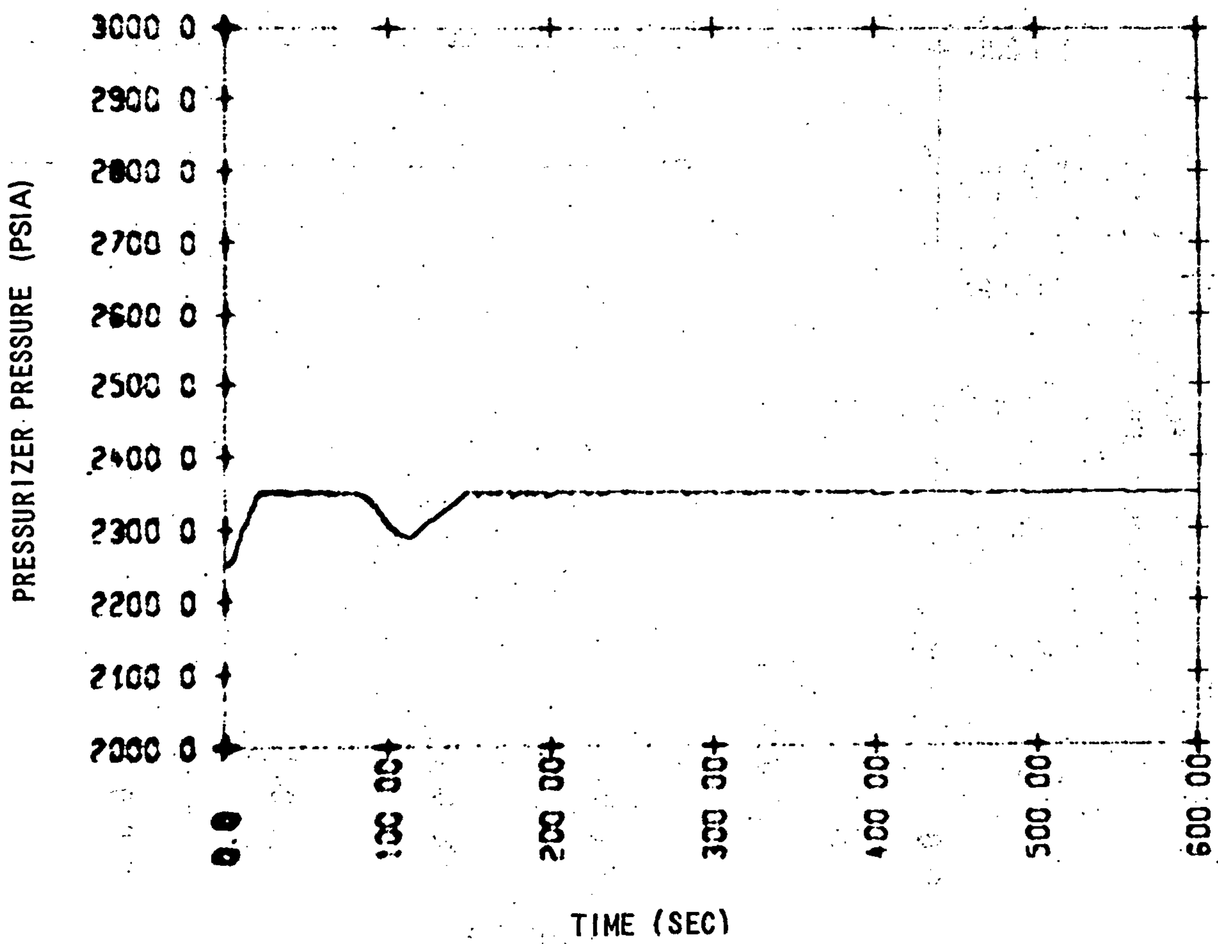

Figure 4-90. Rod Withdrawal at Power-T_{AVG} + 8°F (Pressurizer Pressure Vs. Time)

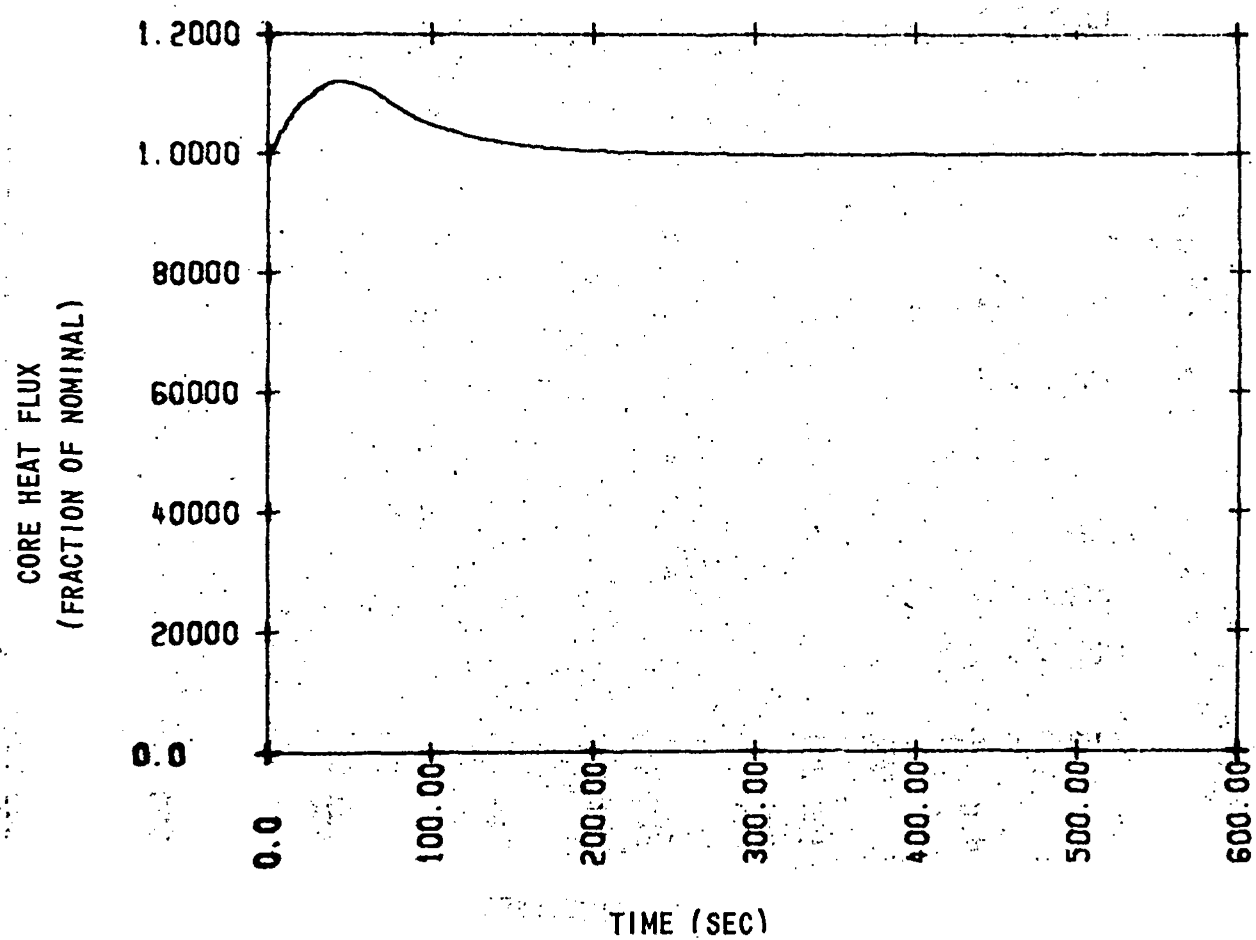

Figure 4-91. Rod Withdrawal at Power–T_{AVG} – 20°F (Core Heat Flux Vs. Time)

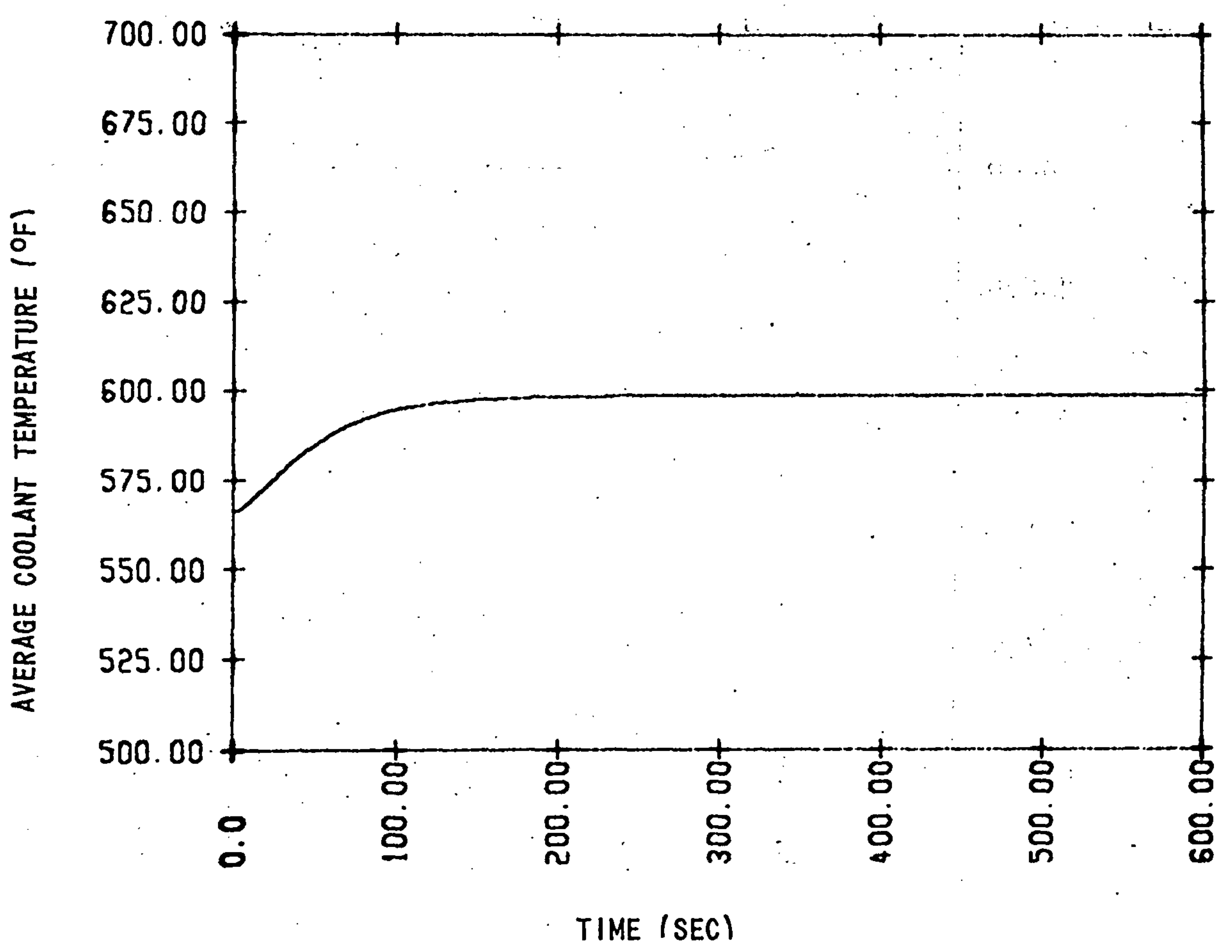

Figure 4-92. Rod Withdrawal at Power–T_{AVG} - 20°F (Average Coolant Temperature Vs. Time)

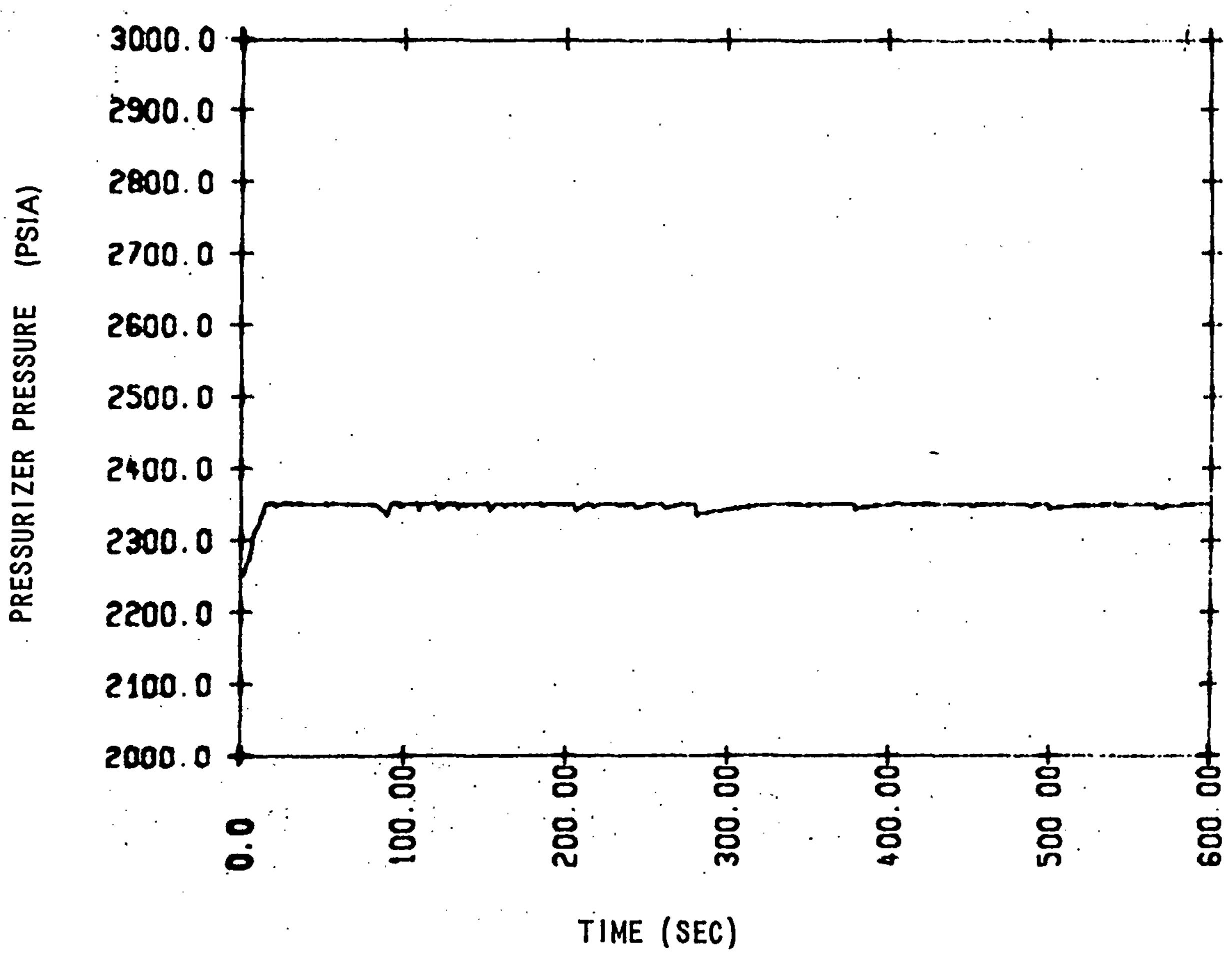

Figure 4-93. Rod Withdrawal at Power–T_{AVG} - $20^{o}F$ (Pressurizer Pressure Vs. Time)

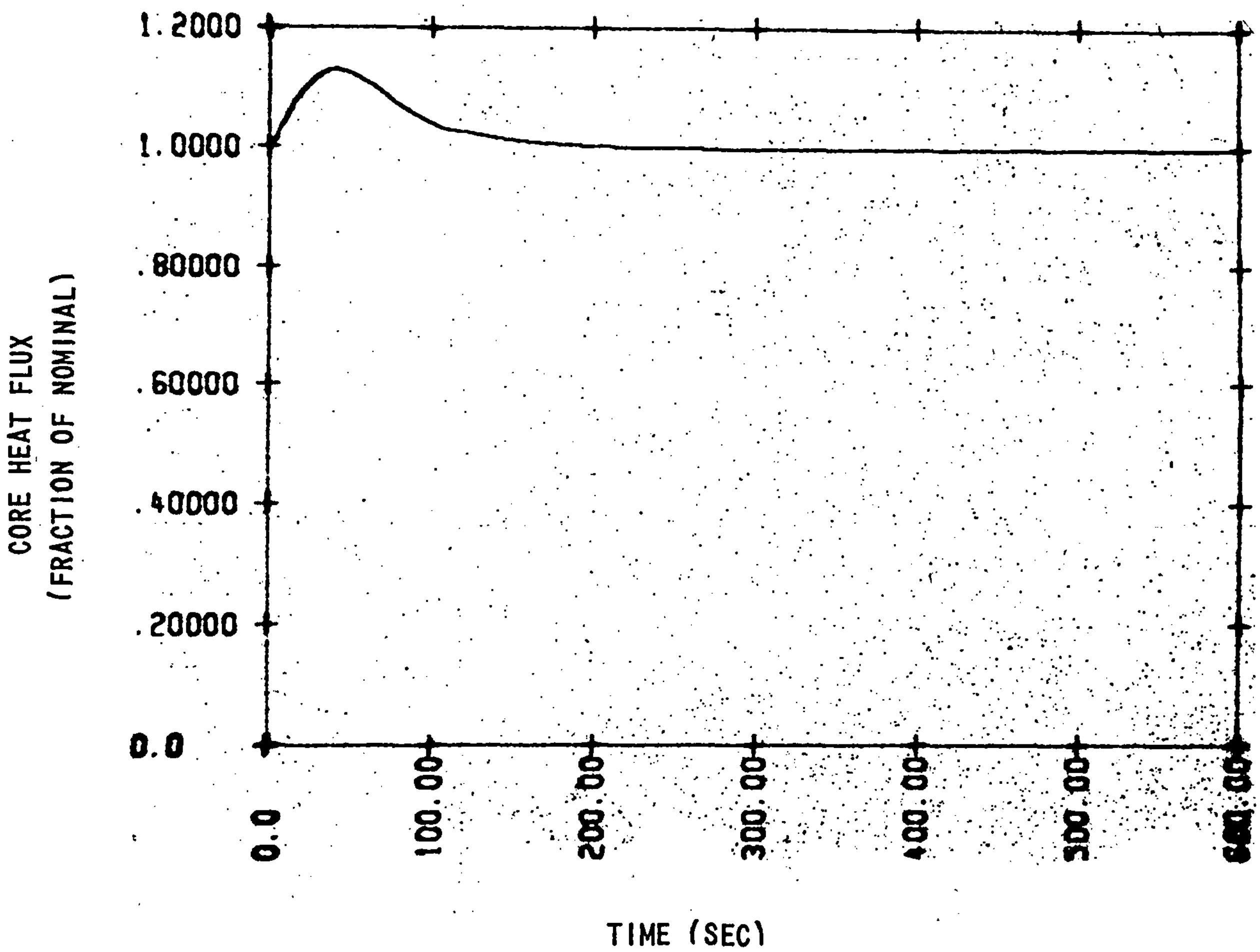

Figure 4-94. Rod Withdrawal at Power-SG Mass + 10 Percent (Core Heat Flux Vs. Time)

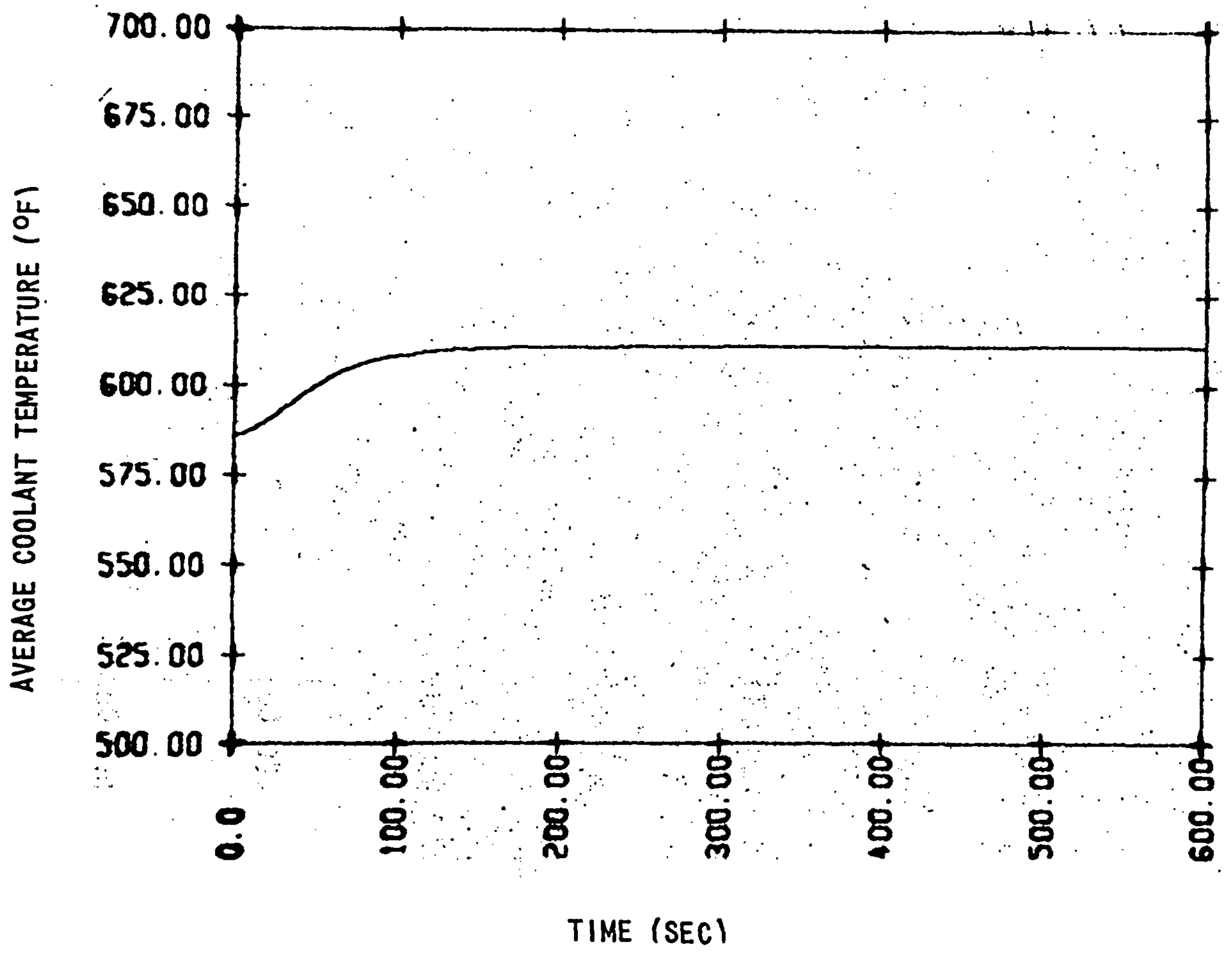

Figure 4-95. Rod Withdrawal at Power-SG Mass + 10 Percent (Average Coolant Temperature Vs. Time)

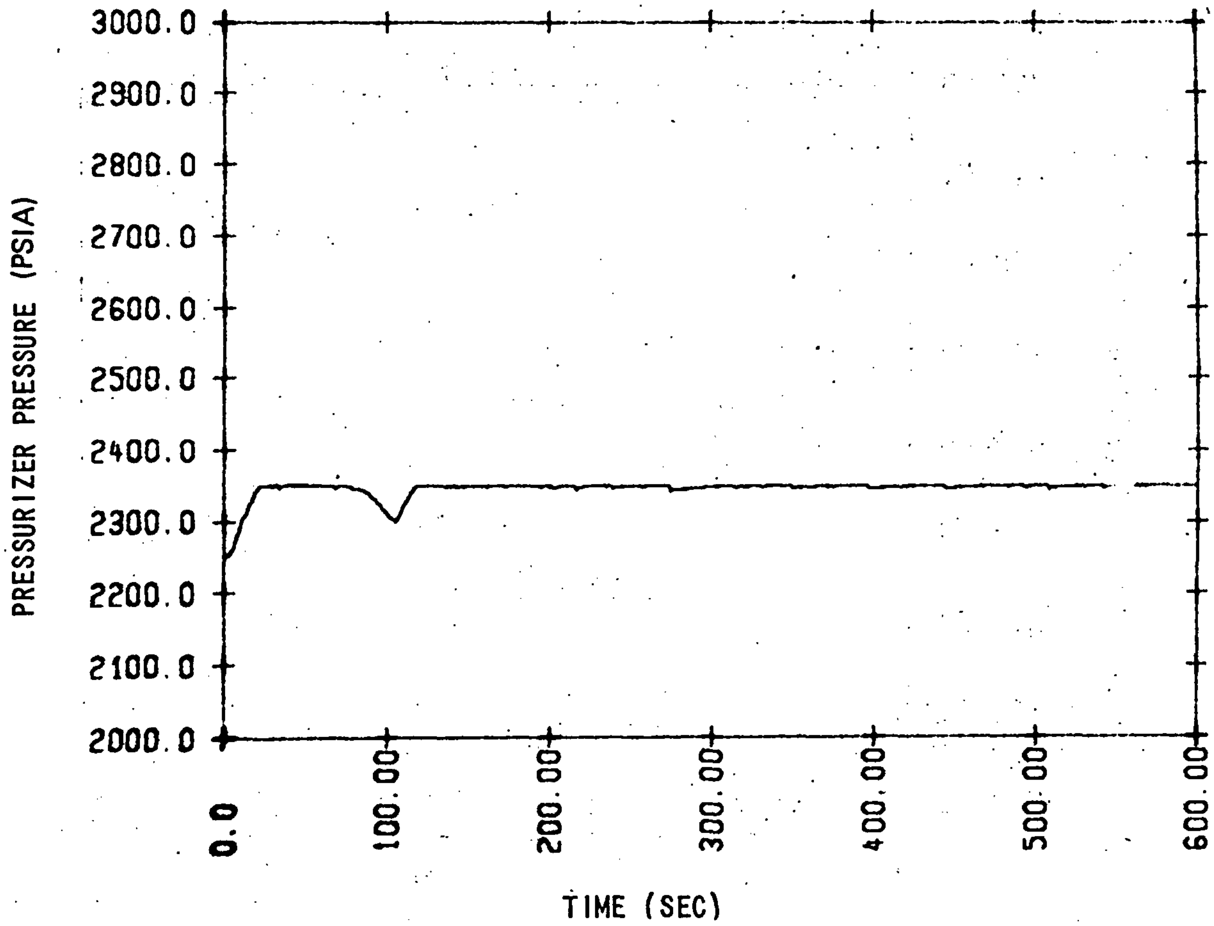

Figure 4-96. Rod Withdrawal at Power-SG Mass + 10 Percent (Pressurizer Pressure Vs. Time)

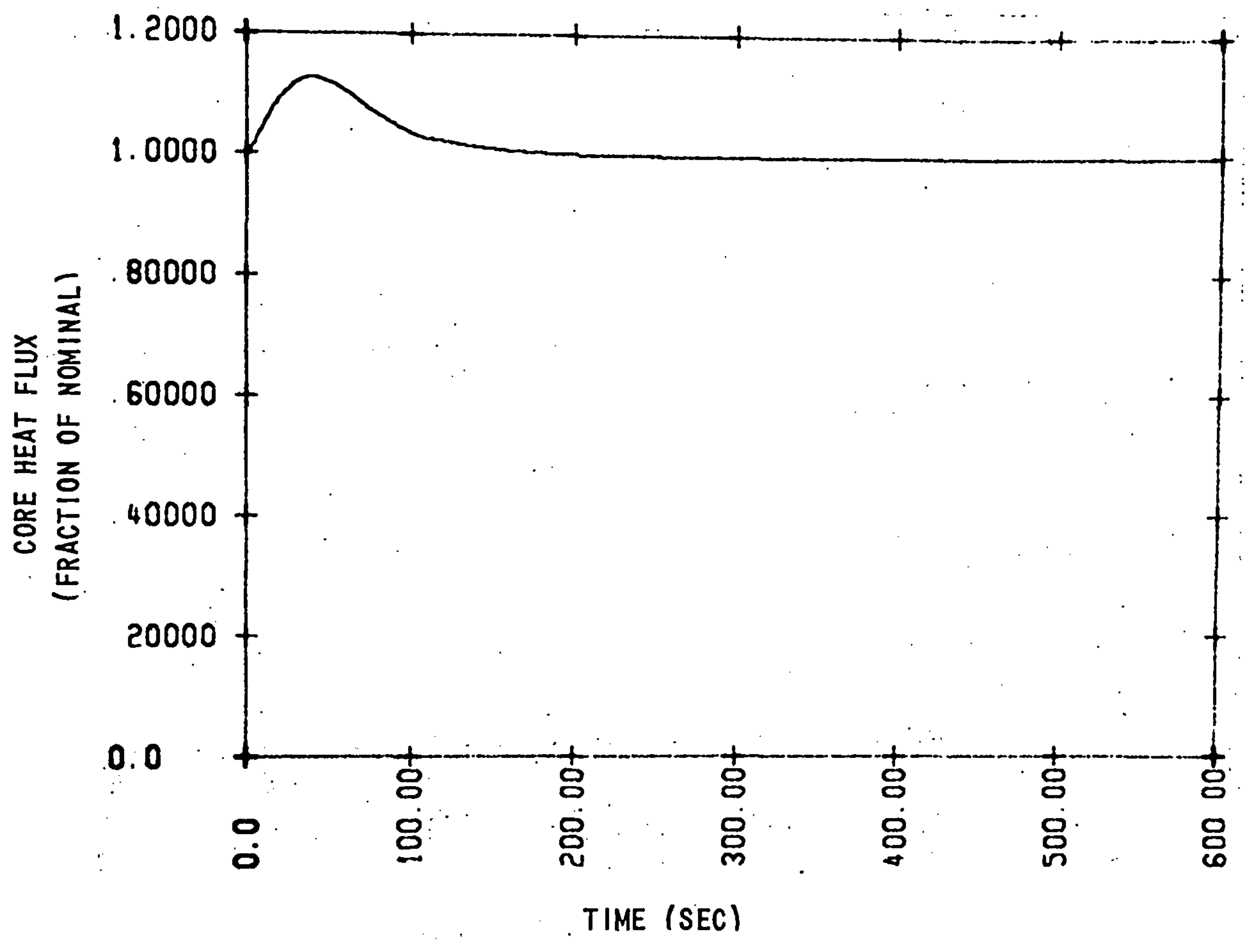

Figure 4-97. Rod Withdrawal at Power — SG Mass - 10 Percent (Core Heat Flux Vs. Time)

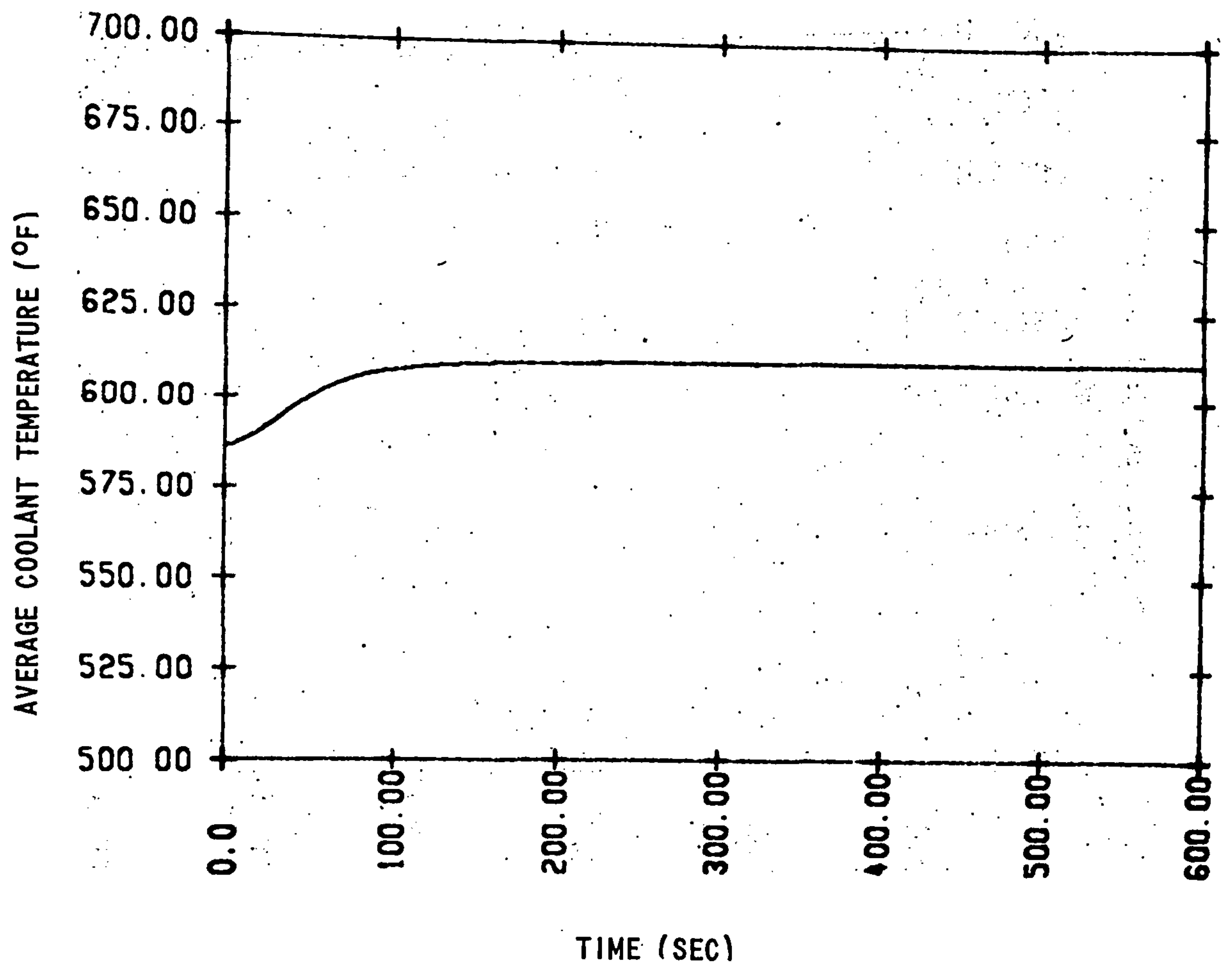

Figure 4-98. Rod Withdrawal at Power — SG Mass - 10 Percent (Average Coolant Temperature Vs. Time)

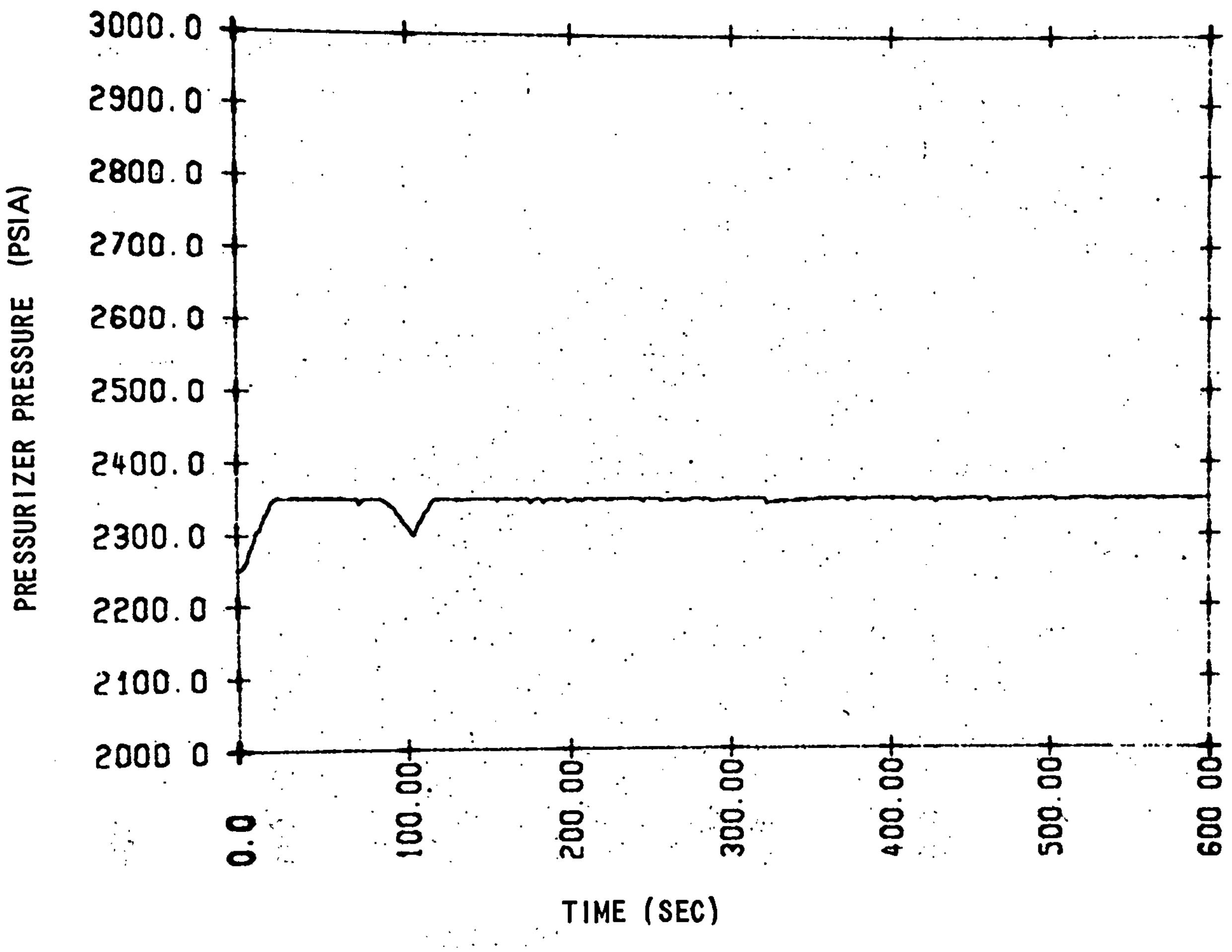

Figure 4-99. Rod Withdrawal at Power — SG Mass - 10 Percent (Pressurizer Pressure Vs. Time)

4-23. BORON DILUTION INCIDENT WITHOUT REACTOR TRIP

4-24. Identification of Causes and Transient Description

A boron dilution accident could result from any malfunction which results in the addition of unborated water into the reactor coolant system by way of makeup portions of the Chemical and Volume Control System. All boron dilution procedures are operator-initiated actions and are strictly controlled by specified administrative procedures. There are many alarms which would be activated by a dilution process which would, because of the slow nature of the transient, give an operator sufficient time to take corrective action.

Because it is a manual operation, two actions are required to initiate dilution of the reactor coolant system water:

- The operator must switch from automatic makeup mode to dilute mode.
- The dilution Start button must be depressed.

At all times information is displayed on the main control board about the status of the Chemical and Volume Control System, the reactor coolant makeup, and the operating condition of Chemical Volume and Control System pumps. Alarms also warn of deviations of either boric acid or demineralized water flow rates from pre-set valves. Therefore, any condition resulting in an uncontrolled boron dilution would require not only two or more random system failures, but also operator error.

The result of an uncontrolled boron dilution would be the addition of positive reactivity to the reactor core causing an increase in core power. Because the secondary power extraction remains unchanged, the primary system temperatures would increase such that the increased moderator feedback compensates the effects of the dilution.

If no action were taken to terminate the dilution, DNB could eventually occur causing possible fuel and cladding damage.

Several features of the automatic Reactor Protection System would normally act to prevent core damage from a dilution accident. Also several alarms of the Chemical Volume and Control System would warn of the malfunction.

- Protection System Trips

  1) Two of four ΔT channels exceeding the overtemperature ΔT setpoint actuate a reactor trip. The setpoint is automatically varied with axial power tilt, reactor coolant temperature and reactor coolant pressure to protect against DNB.

  2) Two of four power range nuclear flux instrumentation channels in excess of the nuclear overpower setpoint actuate a reactor trip.

- Control System Alarms

    1) High primary water flow deviation alarm
    2) Rod insertion indication (if in auto rod control)
    3) Low control rod insertion limit alarm (if in auto rod control)
    4) Low-low control rod insertion limit alarm (if in auto rod control)
    5) Volume control tank level deviation alarm (possible)
    6) Overtemperature ΔT turbine runback signal

4-25. Analysis of Effects and Consequences

Analysis of an uncontrolled boron dilution was done using the following assumptions:

- One centrifugal charging pump running
- Normal charging/letdown flow rate of 75 gpm
- Initial Reactor Coolant System boron concentration of 900 ppm
- Boron worth of -10.5 pcm/ppm
- Complete volumetric mixing of charging water with primary water
- Plant operating at nominal full power conditions
- Doppler and moderator coefficients characteristic of core conditions after physical testing with equilibrium xenon conditions

4-26. Results

With the above assumptions, the maximum reactivity insertion due to dilution over a ten-minute period is less than 0.10% dk. Therefore, the reactivity added to the core is less than that considered in the rod withdrawal.

4-27. Conclusions

Comparing a boron dilution accident with the results of the uncontrolled rod withdrawal transient, no significant clad damage is expected from a boron dilution accident.

4-28. PARTIAL LOSS OF FORCED REACTOR COOLANT FLOW

4-29. Identification of Causes and Accident Description

A partial loss of coolant flow accident could result from a failure in a reactor coolant pump, or from a fault in the power supply to the pump. If the reactor is at power at the time of

the accident, the immediate effect of loss of coolant flow is an increase in the coolant temperature. This increase results in a reduced margin to DNB.

The necessary protection against a partial loss of coolant flow accident is provided by the low reactor coolant flow reactor trip. A reactor trip signal from the pump breaker position is provided as an anticipating signal which serves as a backup to the low flow signal.

4-30. Analysis of Effects and Consequences

The discussion assumes that half of the loops are coasting down. This approach is appropriate for a 2-loop plant and conservative for 3- and 4-loop plants since only one loop in flow-coastdown is considered as an "anticipated event."

A partial loss of flow would result in an increased coolant average temperature, that would decrease the nuclear power by the negative feedback from the lower moderator density. The increase in coolant average temperature would cause a coolant surge into the pressurizer increasing the Reactor Coolant System pressure.

The reduced flow and higher coolant temperature conditions result in a reduced margin to DNB, but the following discussion shows that a partial loss of coolant flow accident is considerably less severe than a station blackout.

Early in the transient the reduction in heat transfer across the steam generators in the coasting-down loops due to the reduction in primary flow would cause void collapse on the secondary side of the steam generators. This has been verified by plant operating experience. The resulting drop in steam generator water level is sufficient to generate a low-low steam generator level reactor trip signal. Following a turbine trip on reactor trip, the coolant average temperature would increase at a faster rate resulting in a lower nuclear power. The steam generator level can be assumed to drop at the time the flow reverses direction in the coasting-down loops.

Following a turbine trip, the steam dump system would become active and constitute the only secondary load on the plant. Hence, the system would settle out to a steady-state condition consistent with the plant steam dump capacity and the near steady-state primary flow of about 50 percent.

The power-to-flow ratio for a two out of four pump coastdown was calculated using the flows in the active and coasting-down loops given in figure 4-100. The turbine demand was assumed to remain approximately constant at the initial 100 percent power until the turbine was tripped.

After this point core volumetric flow was approximately 45 percent and remained constant with time. The core power for these conditions can be determined using the reactivity

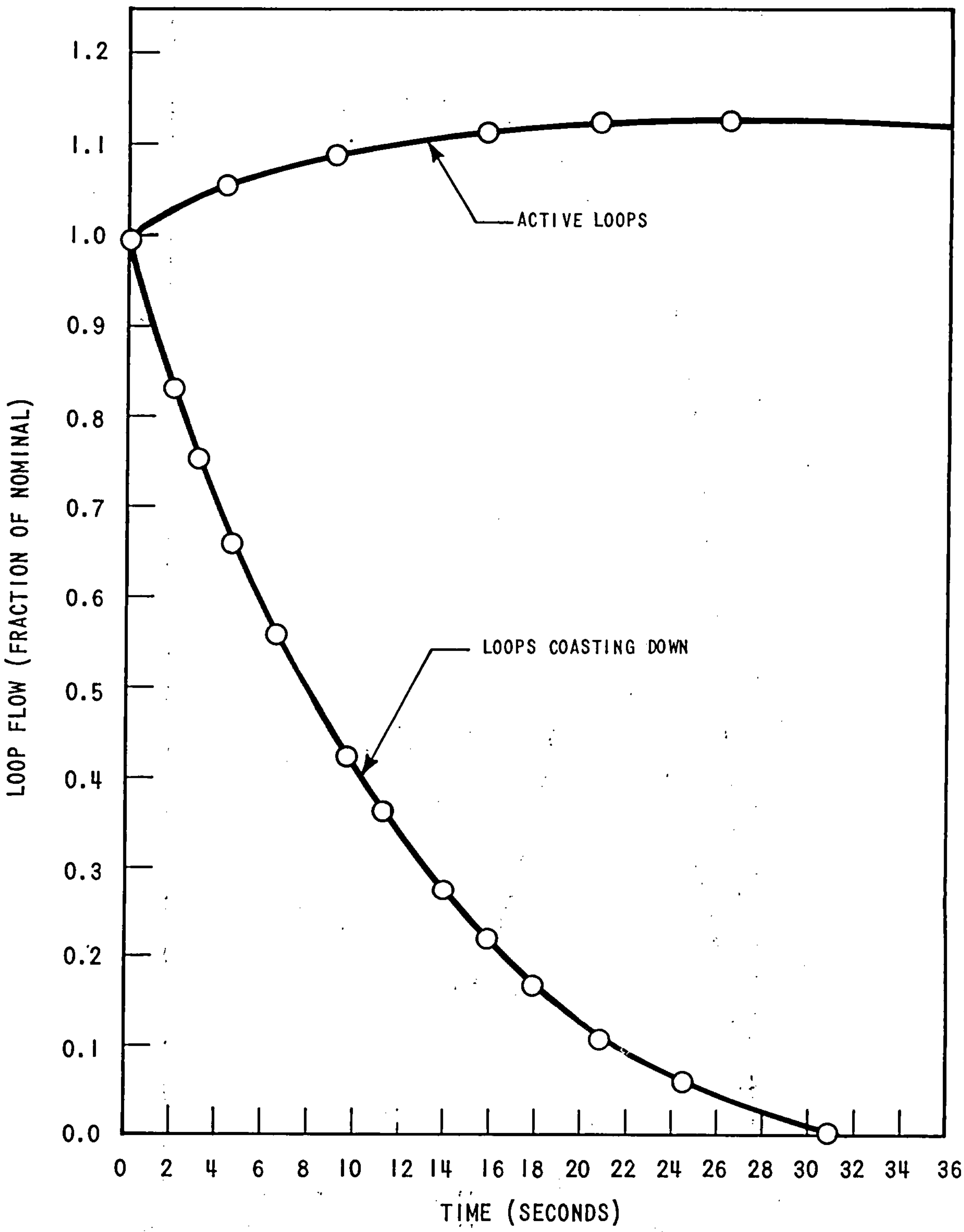

Figure 4-100. Loop Flow versus Time for Active and Inactive Loops

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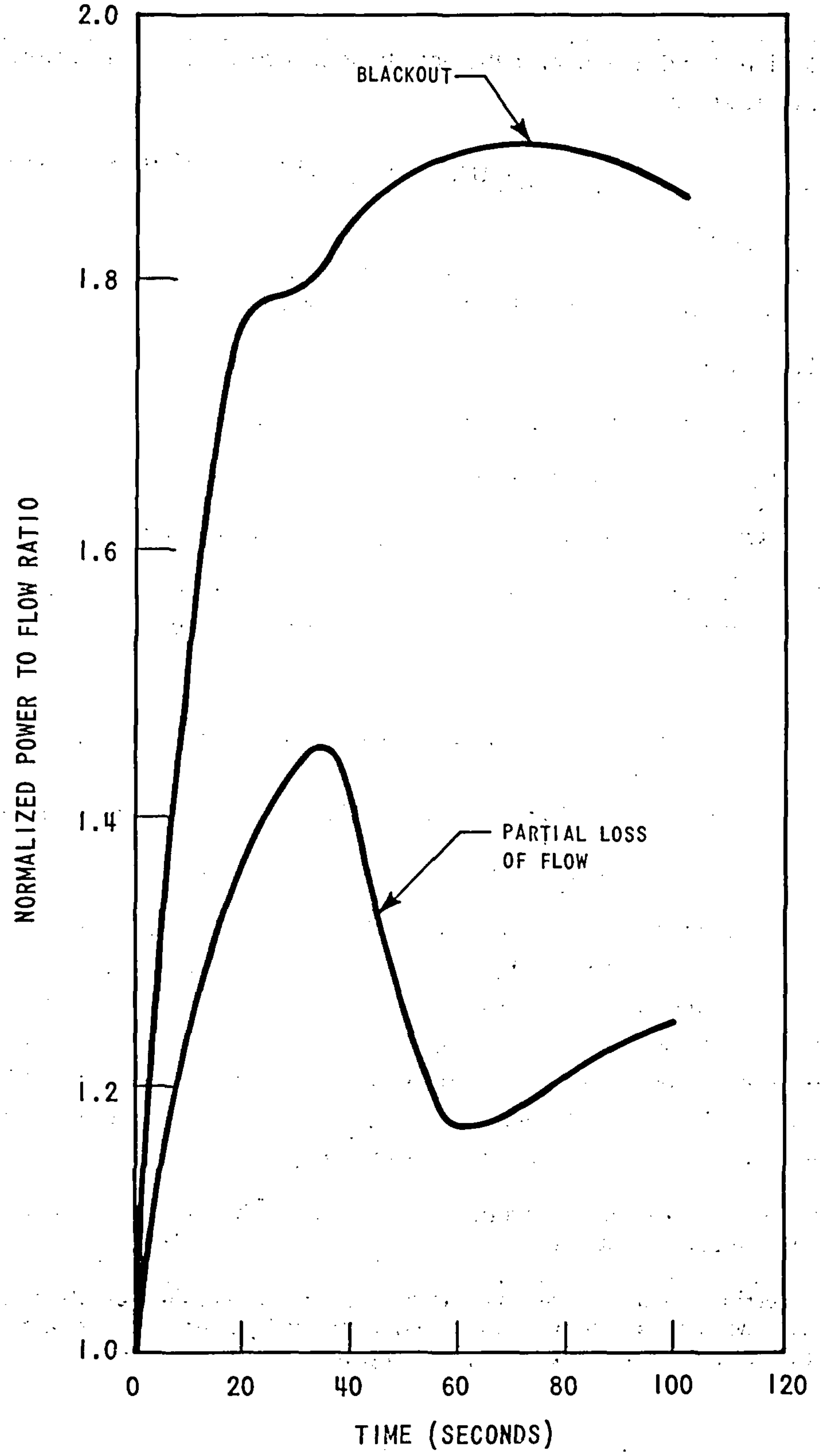

Figure 4-101. Normalized Power to Flow Ratio for Partial Loss of Flow and Blackout

coefficients in Section 2 and determining the heat transfer across the steam generator using the following relation:

$$Q = UA\,(\bar{T} - T_S)$$

where

Q = Total heat transferred into the steam generator secondary

UA = Steam generator heat transfer coefficient

$\bar{T}$ = Average coolant temperature in the steam generator

T_s = Saturation temperature of secondary side water

The power-to-flow ratio for a two out of four pump coastdown is shown in figure 4-101.

Figure 4-101 shows that the power-to-flow ratio for the partial loss of flow transient remains well below the value for station blackout even for the conservative assumptions made.

4-31. Conclusion

The partial loss of flow ATWT is considerably less severe than a station blackout ATWT.

4-32. STARTUP OF AN INACTIVE REACTOR LOOP WITHOUT A REACTOR TRIP

4-33. Identification of Causes and Transient Description

If a reactor coolant pump is out of service, (referred to as N-1-loop operation) the average temperature of the water in that coolant loop is lower than the coolant temperature in the remaining loops. If the inactive pump is started inadvertently, cooler water is introduced into the reactor core causing an increase in core power due to effects of moderator density feedback. As explained below, this power increase is insufficient to cause core DNB. Several features of the Reactor Protection System would normally act to cause reactor trip even though they are not required to prevent reactor core damage. These are:

- Power range nuclear flux protection channels exceeding the nuclear overpower setpoint actuate a reactor trip.
- ΔT protection channels exceeding the overpower ΔT setpoint actuate a reactor trip. The setpoint is automatically varied with axial power distribution to ensure that the allowable transient heat generation rate is not exceeded.

- ΔT protection channels exceeding the overtemperature ΔT setpoint actuate a reactor trip. The setpoint is automatically varied with axial power distribution, reactor coolant temperature, and reactor coolant pressure to ensure protection against DNB.

- Power range nuclear flux protection channels exceeding an interlock setpoint in conjunction with low flow in any reactor coolant loop actuate a reactor trip.

In addition to these protective functions, numerous administrative procedures prevent the inadvertent startup of an inactive pump before that loop's temperature is matched to the active coolant temperature. The following lists these administrative functions:

- Plants without loop stop valves must be brought below 25-percent power before starting an inactive reactor coolant pump.

- Plants with loop stop valves may not be operated at power with the stop valves open in an inactive loop.

- Administrative procedures and redundant plant interlocks prevent the opening of stop valves in an inactive loop unless the proper procedures have been followed to bring the inactive loop temperatures and boron concentrations into close agreement.

4-34. Analysis of Effects and Consequences

Two-loop plants are not permitted to operate at power with a loop out of service; therefore, the inactive loop startup accident is most severe for 3-loop plants. The water inventory in the idle loop is a larger fraction of the total reactor coolant water and this produces a greater cooldown than occurs in 4-loop plants. Also, automatic rod control, if operable, would alleviate the severity of the transient because the increasing power produces a control signal demanding rod insertion. (Automatic rod control is not required for the consequences of this event to be acceptable.)

The startup of an inactive reactor coolant loop was analyzed using the following assumptions:

- Initial power at the nominal maximum power level allowable for N-1-loop operation, i.e., 60 percent of rated N-loop operation.

- Reverse flow in the inactive coolant loop.

- End-of-core life reactivity coefficients. (Since the moderator cooldown causes a power increase, this transient is more severe at end of core life.) Plant loop flows change linearly from their initial values to nominal loop flow for N-loop operation in ten seconds.

- No credit for automatic control rod insertion.

4-35. Results

Using the assumptions listed above, the increase in density for a 3-loop plant based on an initial 22° temperature drop in the inactive loop steam generator and 25 percent mixing in the core inlet plenum is 0.0127 gm/cm^3 which results in ± 0.32 percent $\frac{\Delta K}{K}$ reactivity. However, to return to full power from the initial power level requires 0.29 percent $\frac{\Delta K}{K}$ reactivity to overcome the Doppler power defect. Therefore, the net reactivity available to produce an overpower condition is 0.03 percent $\frac{\Delta K}{K}$, which is less than the reactivity addition at full power considered in the rod withdrawal at power transient.

Since turbine load and feedwater temperature was constant during this transient, reactor core power settled out at its initial value of 60 percent. The excess power generated during the flow transient merely heats the cooler water in the inactive loop up to the average temperature in the active loops. Core coolant average temperature also settled out at its initial value to satisfy the reactivity balance. Therefore, following the flow-induced transient, the reactor core operated at substantially less than design power; less than design coolant temperatures, design flow, and consequently, much more than design DNB safety margins.

4-36. Conclusions

The startup of an inactive coolant loop is less severe than the rod withdrawal at power transient for the following reasons:

- The total reactivity insertion once the core has returned to 100 percent power was approximately 10 percent of that considered in rod withdrawal at power.
- The colder core inlet temperature provided more margin to DNB.

4-37. LOSS OF EXTERNAL ELECTRICAL LOAD AND/OR TURBINE-GENERATOR TRIP WITHOUT REACTOR TRIP

4-38. Identification of Causes and Transient Description

A major load loss could result either from a loss of external electrical load or from a turbine/generator trip. In either case, unless a loss of ac power to the station auxiliaries also occurs, off-site power would be available for the combined operation of plant components, such as the reactor coolant pumps. In this section, the loss of load accident is analyzed assuming that the control rods fail to drop into the core following a turbine trip from full power, which would produce the maximum possible load loss. The analysis of loss of ac power to the station auxiliaries (station blackout) without reactor trip is presented in paragraph 4-56.

For turbine trips, the reactor normally trips directly (unless below approximately 10-percent power) from a signal derived from the turbine auto-stop oil pressure (Westinghouse Turbine) or from closure of both turbine stop valves. The automatic steam dump system opens valves to pass off the excess generated steam, and therefore, reactor coolant temperatures and pressure do not significantly increase. If the turbine condenser were not available to receive steam through the steam dump system, the excess steam would be dumped into the atmosphere through the steam generator relief and safety valves. In addition, main feedwater flow might be lost if the turbine condenser were not available to run the turbine driven pumps but some feedwater flow would be supplied by the auxiliary feedwater system at a rate sufficient to remove the sensible heat of the fuel and coolant plus the residual heat produced in the reactor.

For a complete loss of external electrical load without subsequent turbine trip, no direct reactor trip signal would be generated. Plants designed with full load rejection capability would continue operation without a reactor trip, since the mismatch between core power and turbine load would be accommodated by sufficient steam dump capacity and primary pressure relief. The Reactor Control System would bring the reactor to a turbine/generator electric load of approximately five percent after a complete loss of external electrical load to match the power requirements of the plant auxiliaries. Plants designed with less than full load rejection capability (40-percent steam dump) that undergo a full load rejection might possibly have the reactor trip from the first four reactor protection system signals listed in the following paragraph. Plant startup tests, however, have demonstrated that Westinghouse plants with 40-percent steam dump capacity can generally ride through a complete loss of electric load even under the most adverse operating conditions[14].

If the steam dump valves fail to open following a large loss of load, or if the plant does not have full load rejection capability, the steam generator safety valves may lift since steam generator shell side pressure increases rapidly. If reactor core or primary system safety limits are approached, a reactor trip signal would be generated by the reactor trip signals which are listed below:

- Direct reactor trip on turbine trip
- High pressurizer pressure reactor trip
- High pressurizer water level reactor trip
- Overtemperature ΔT reactor trip
- Low feedwater flow reactor trip
- Low-low steam generator water level reactor trip

The most severe plant conditions that could result from a loss of load occur following a turbine trip from full power when the turbine trip is caused by a loss of condenser vacuum. Since the main feedwater pumps may be turbine driven with steam exhaust to the main condenser, loss of feedwater may also result from a loss of condenser vacuum. For this reason, the low feedwater flow reactor trip and the low-low steam generator water level trip are included in the above listing.

The pressurizer safety valves and steam generator safety valves are sized to protect the Reactor Coolant System and steam generator against overpressure for all load losses without assuming the operation of the steam dump system, pressurizer spray, pressurizer power-operated relief valves, steam generator power-operated relief valves, automatic rod control, or direct reactor trip on turbine trip. That is, the steam relief capacity of the pressurizer safety valves is selected to match the maximum pressurizer insurge following a turbine trip without credit for the items mentioned above. The steam generator safety valve relief capacity is sized to remove the steam flow at the Engineered Safeguards Design rating (~ 105 percent of the steam flow at rated power) from the steam generator without exceeding 110 percent of the steam system design pressure. The pressurizer safety valve capacity is sized for a complete loss of heat sink with the plant initially operating at the maximum calculated turbine load and with operation of the steam generator safety valves. The pressurizer safety valves are then able to maintain the Reactor Coolant System pressure to within 110 percent of the Reactor Coolant System design pressure without direct or immediate reactor trip action.

4-39. Analysis of Effects and Consequences

Plant behavior was evaluated for a turbine trip and loss of main feedwater occurring from full power with the assumption that the control rods failed to drop into the core following generation of a reactor trip signal. The evaluation showed the effectiveness of Reactor Coolant System pressure-relief devices and the extent of approach to core safety limits.

The loss of load transient was analyzed using the LOFTRAN digital computer code that was described in paragraph 3-2. The program computes pertinent plant variables including temperatures, pressures and power level.

The following assumptions were made in the analysis:

- Initial normal full power operation early in core life. Since the negative temperature coefficient of reactivity reduces core power as the coolant temperature rises, and the temperature coefficient becomes more negative with core life, the ATWT loss of load is less severe later in core life.

- Normal operation of the following control systems:

  1) Pressurizer pressure control, including heaters, spray, and both the power-operated and the spring-loaded relief valves

  2) Turbine governor valves in impulse pressure control prior to trip, and valve closure on turbine trip

- Loss of condenser vacuum at t = 0
- No credit for automatic reactor trip
- No credit for automatic control rod insertion as reactor coolant temperature rises
- Main feedwater flow falls to zero in the first four seconds of the transient, with no main feed after that time.
- Auxiliary feedwater flow begins at 60 seconds, at a rate of 1760 gpm.
- Auxiliary feedwater is injected into the feedwater pipe at a temperature of 130°F, 500 ft^3 upstream of the steam generator, such that the cooler water enters the steam generator after this volume is purged.
- Primary to secondary heat transfer area is reduced as the steam generator shell-side water inventory drops below the value necessary to wet the tubes.

4-40. Results

Figures 4-102 through 4-127 show the plant transient response for a loss of load without reactor trip. Sequence of events for this transient are shown in table 4-7. The first peak in pressurizer pressure occurred when the steam generator safety valves lifted, and the second, higher peak (maximum system pressure of 2641 psia) occurred after the pressurizer was filled with water due to a coolant volume surge resulting from a rapid reduction of steam generator heat transfer. Nuclear power decreased to a value of 77 percent due to negative reactivity feedback caused by moderator (coolant) heating. Further coolant heatup caused by loss of steam generator heat transfer area decreased nuclear power further, starting at about 65 seconds.

The DNB ratio did not decrease below its initial value of 1.7 during the transient.

At ten minutes into the transient, conditions stabilized, with auxiliary feedwater providing heat removal capability and with an intact Reactor Coolant System and core. Thus, the operator could begin shutdown operations through rod insertion, actuation of the safety injection system, or through the BORATE or EMERGENCY BORATE modes of the Chemical and Volume Control System.

TABLE 4-7

SEQUENCE OF EVENTS FOR LOSS OF LOAD WITHOUT A REACTOR TRIP

Event	Time (seconds)
Turbine trips	
Auxiliary feedwater pump start signal generated on loss of main feed	
Reactor trip signal generated on turbine trip	0
Pressurizer relief valves lift	4
Overtemperature ΔT reactor trip setpoint reached	7.3
High pressurizer pressure reactor trip setpoint reached	7.4
Steam generator safety valves lift	10
High pressurizer water level reactor trip setpoint reached	34.7
Auxiliary feed pumps begin delivering flow	60
Pressurizer safety valves lift and pressurizer fills with water	92
Maximum reactor coolant pressure (2641 psia) reached	124
Reactor coolant pump cavitates causing reactor coolant flow coastdown	174
Low reactor coolant flow reactor trip signal generated	176
Bulk saturation conditions reached at core outlet	185
Pressurizer safety valves close	219
Pressurizer relief valves close and pressurizer steam space is recovered	275

4-41. Conclusions

During a loss of load with failure of rod insertion after a reactor trip signal generation, core safety limits are not exceeded since DNB ratio does not go below its initial valve and the peak reactor coolant pressure is limited to 2641 psia. Further, plant conditions are stabilized at 10 minutes such that the operator can begin shutdown operations.

Comparison of the results with those for the base case loss of feedwater indicates the severity of the loss of external electrical load is less and therefore sensitivity studies for loss of feed will be limiting.

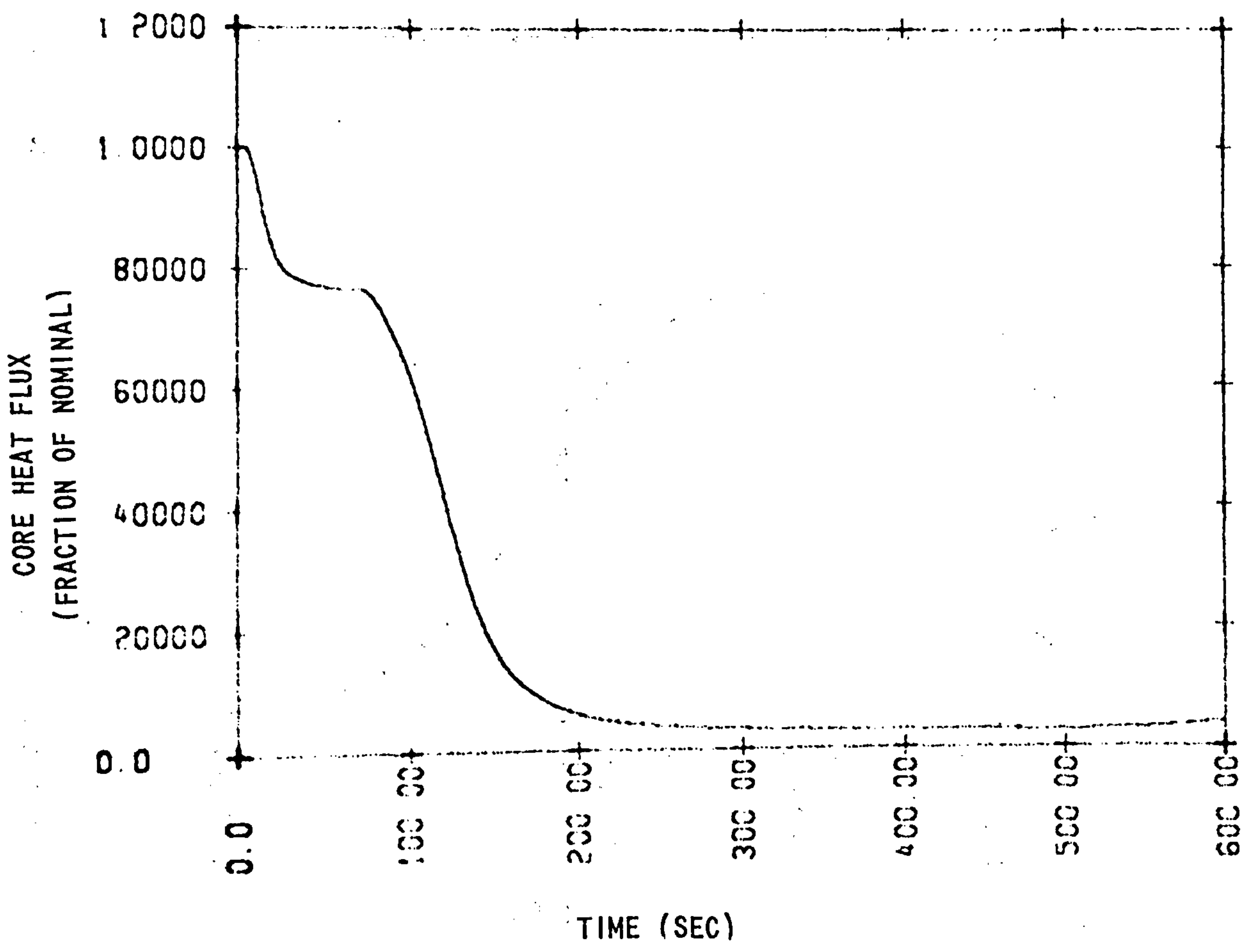

Figure 4-102. Loss of Load
(Core Heat Flux vs. Time)

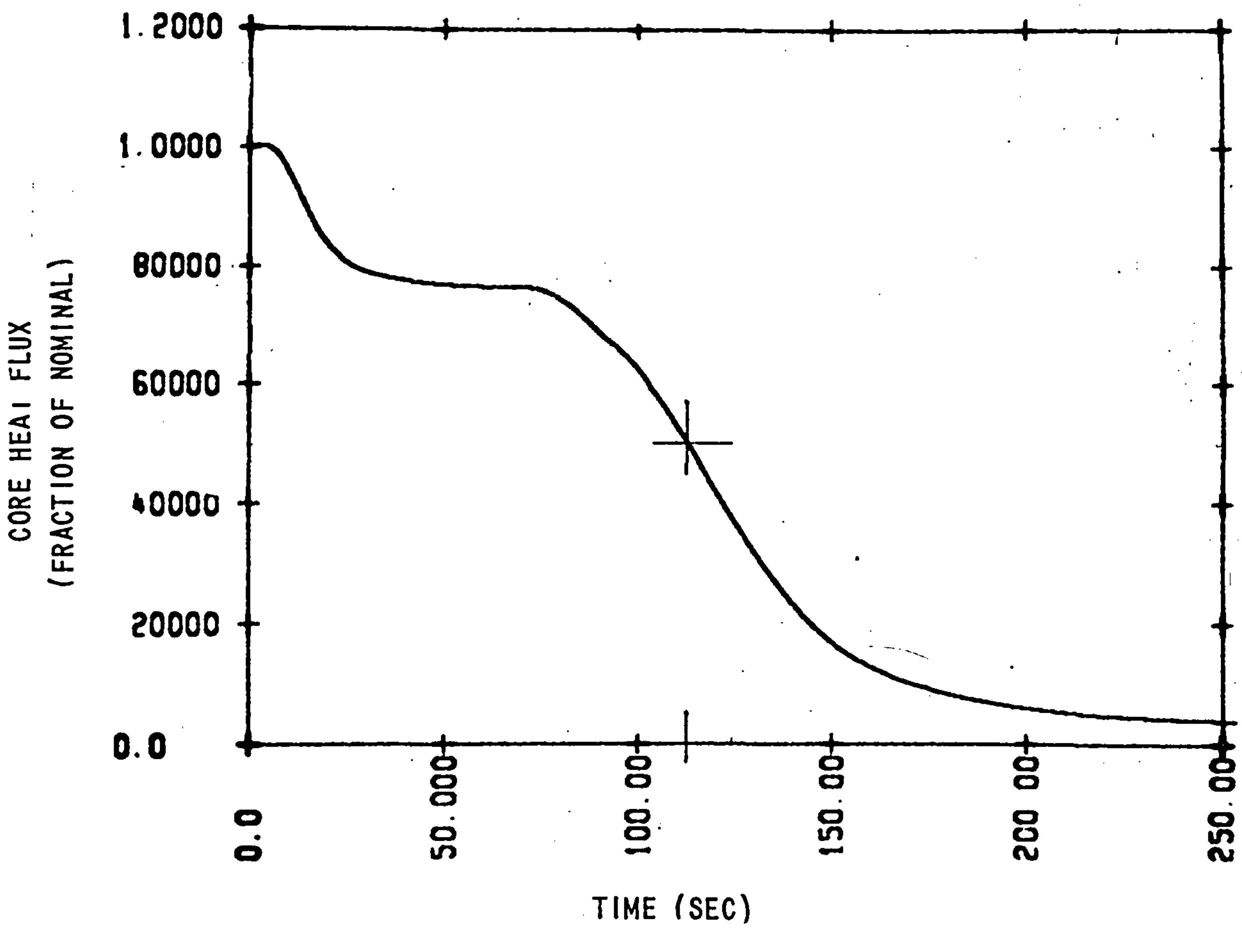

Figure 4-103. Loss of Load
(Core Heat Flux vs. Time)

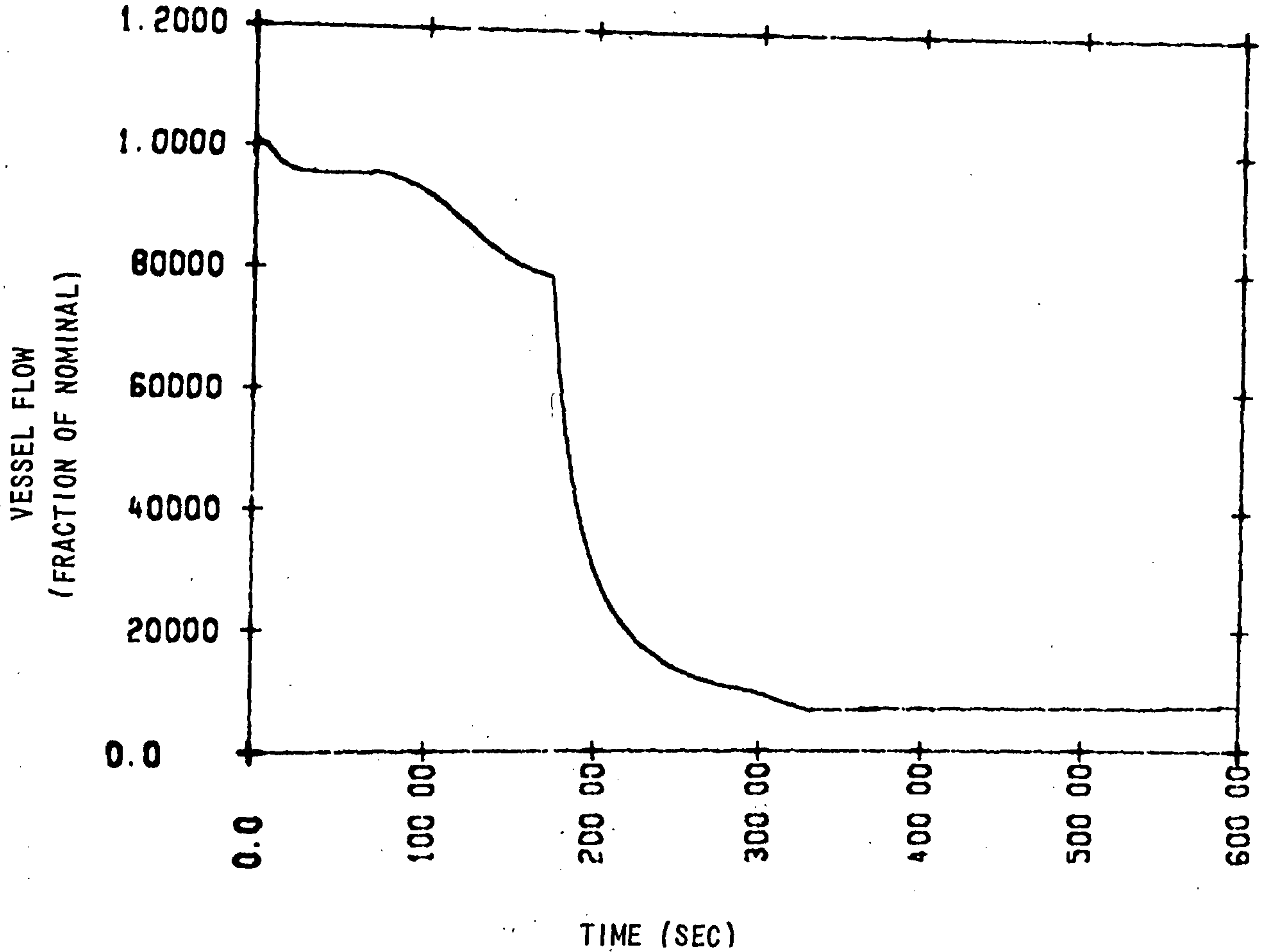

Figure 4-104. Loss of Load
(Vessel Flow vs. Time)

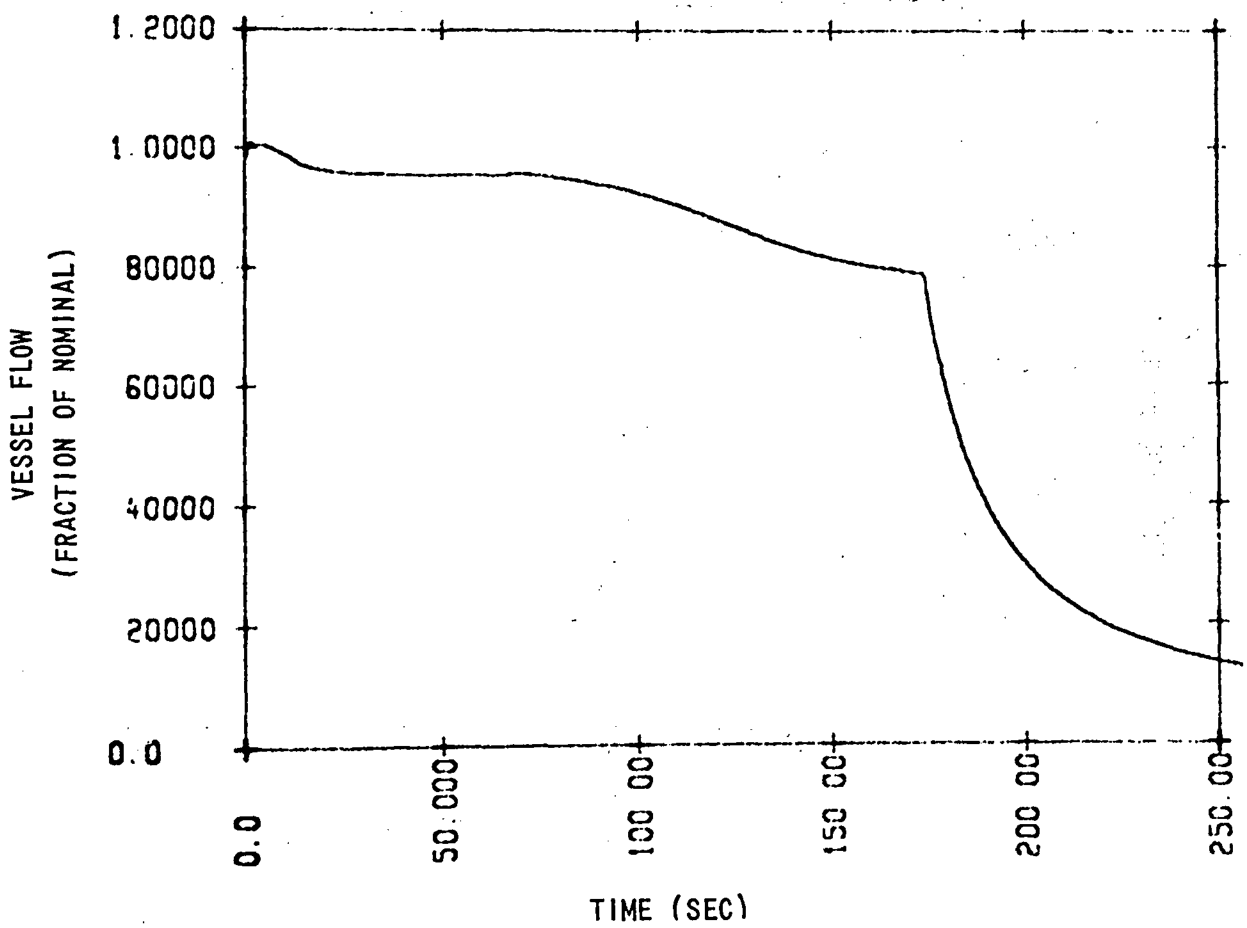

Figure 4-105. Loss of Load
(Vessel Flow vs. Time)

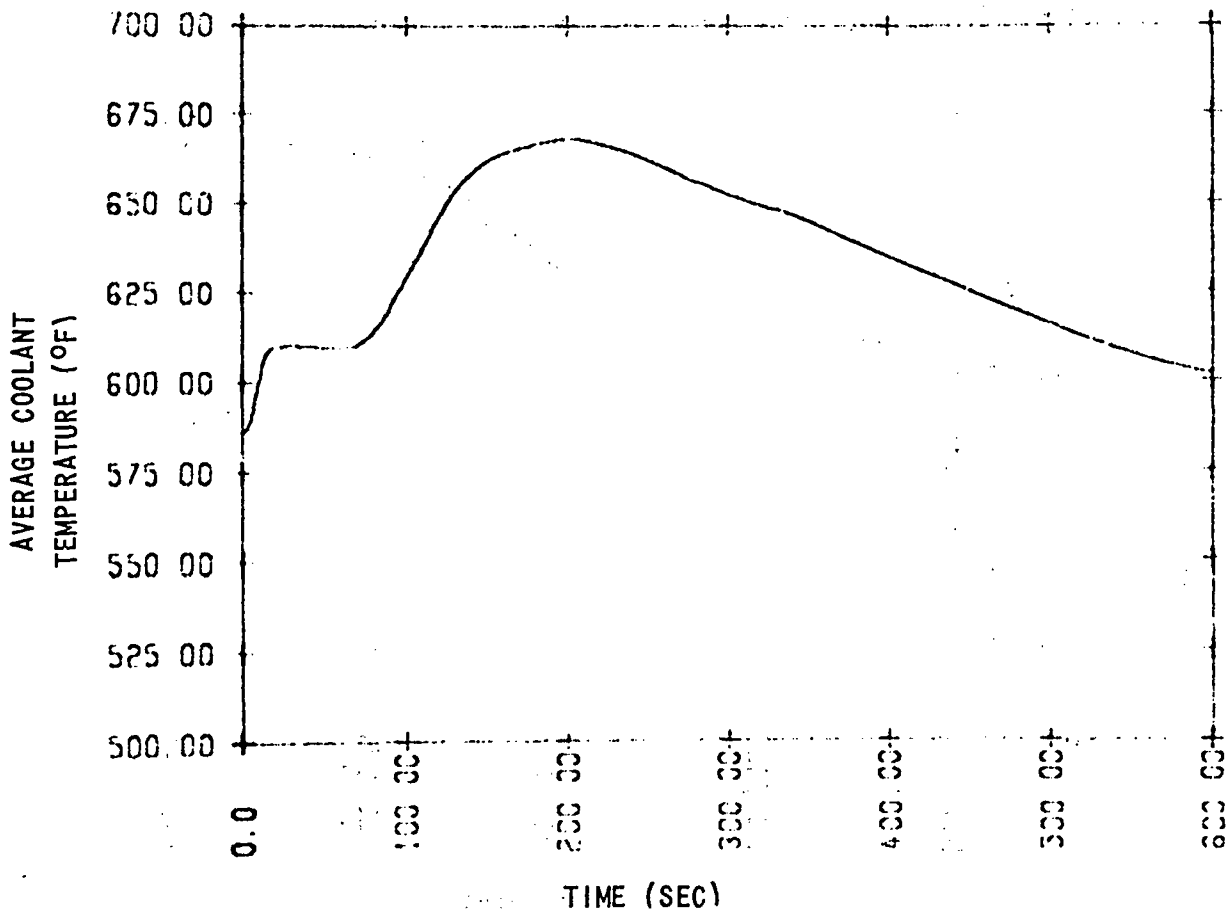

Figure 4-106. Loss of Load
(Average Coolant Temperature vs. Time)

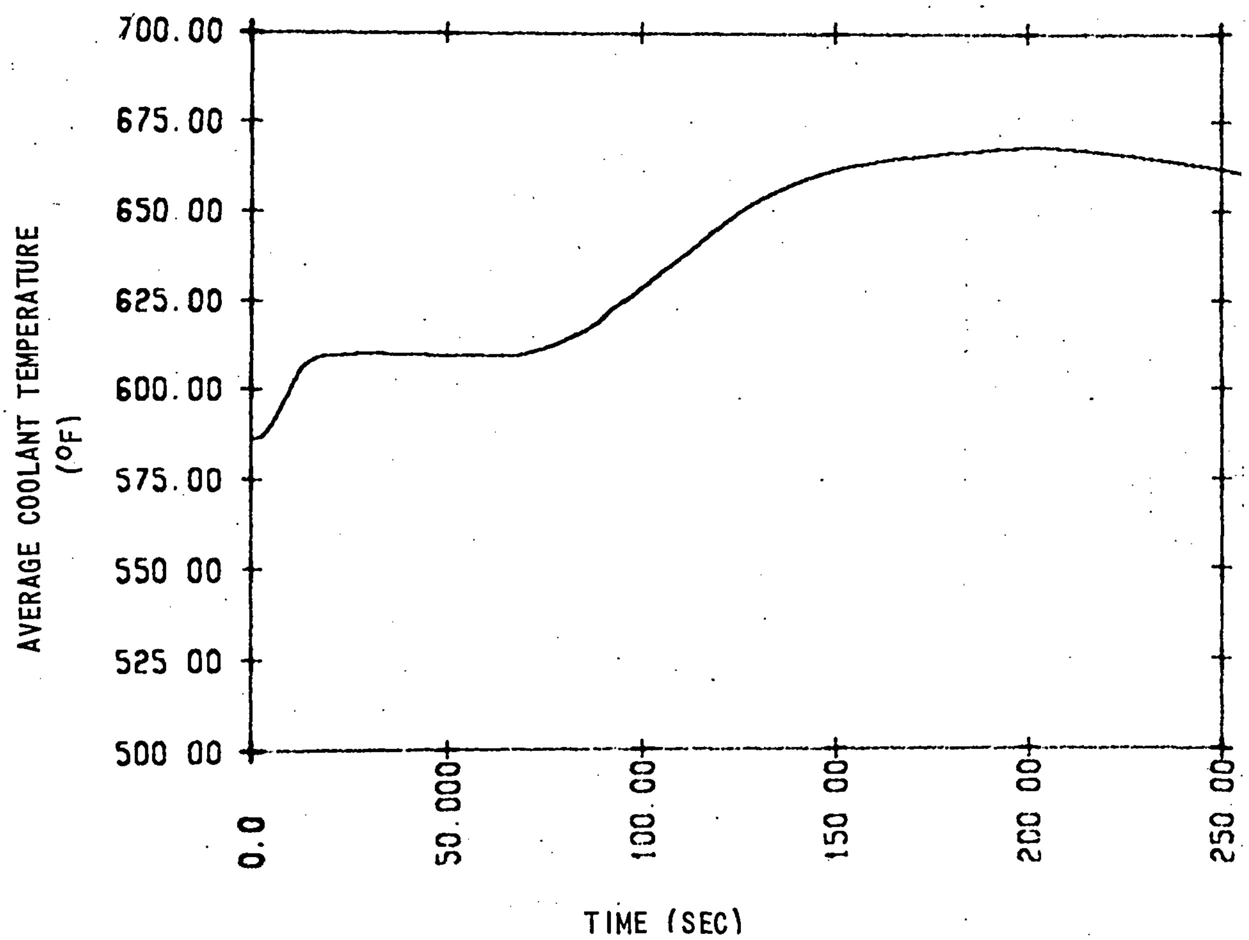

Figure 4-107. Loss of Load
(Average Coolant Temperature vs. Time)

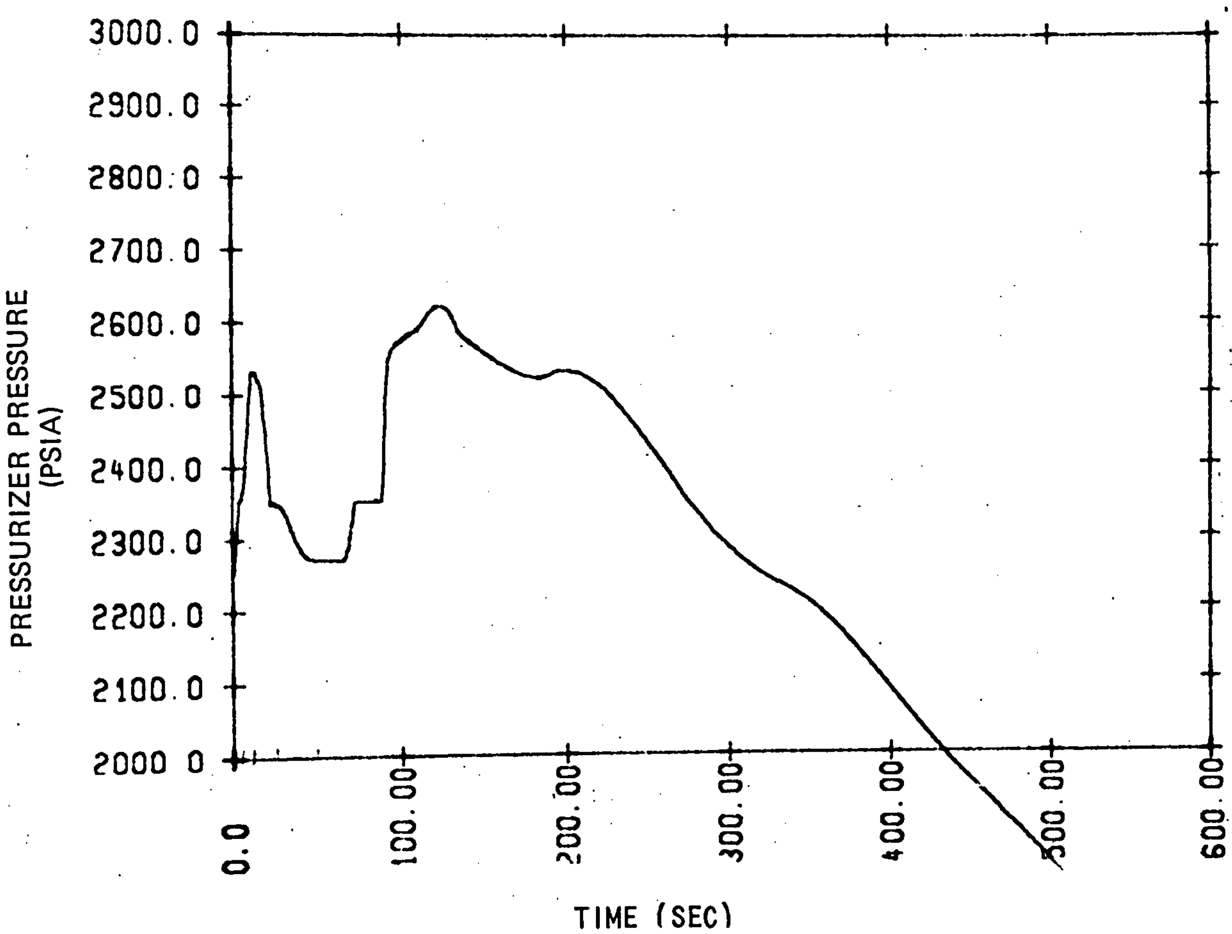

Figure 4-108. Loss of Load
(Pressurizer Pressure vs. Time)

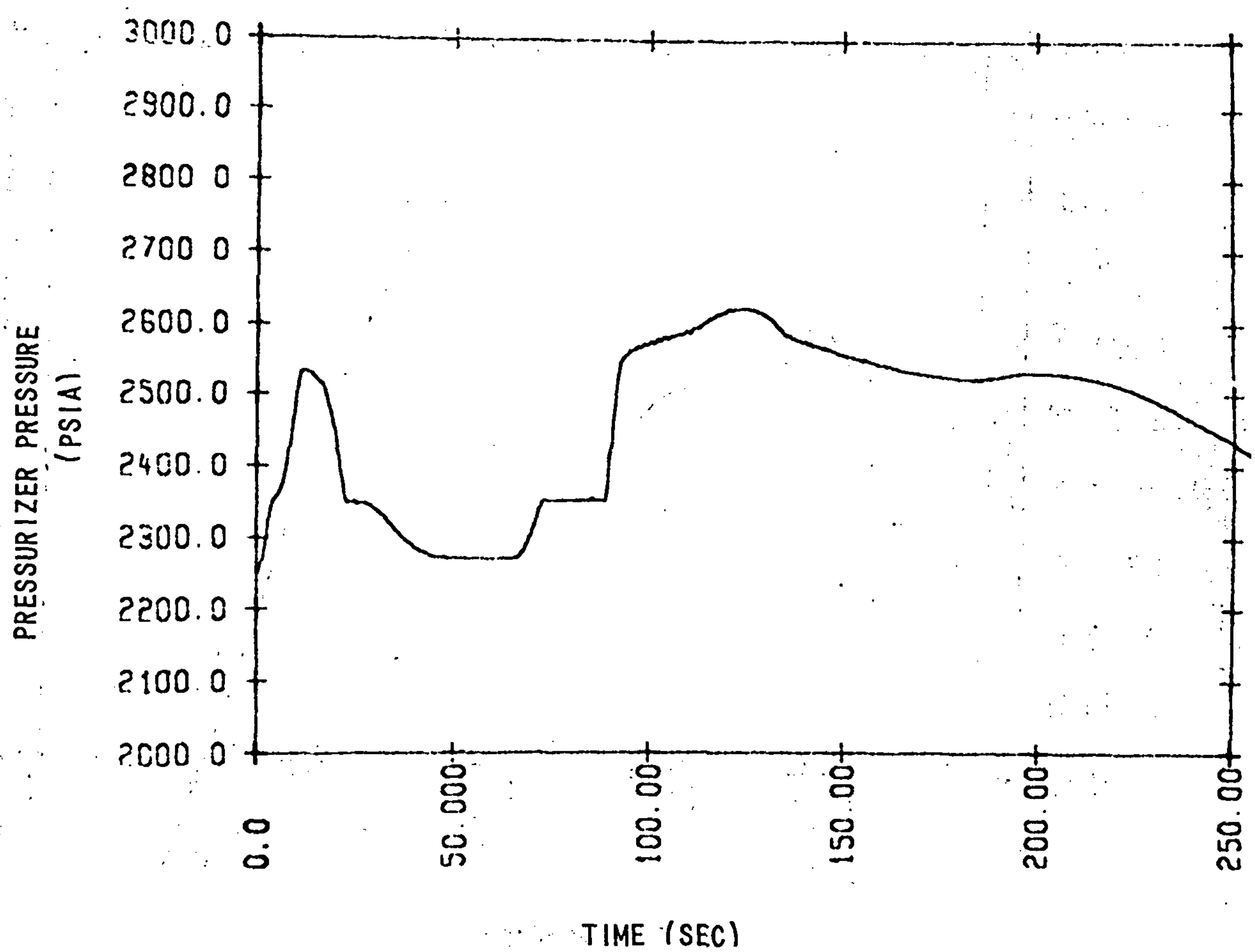

Figure 4-109. Loss of Load
(Pressurizer Pressure vs. Time)

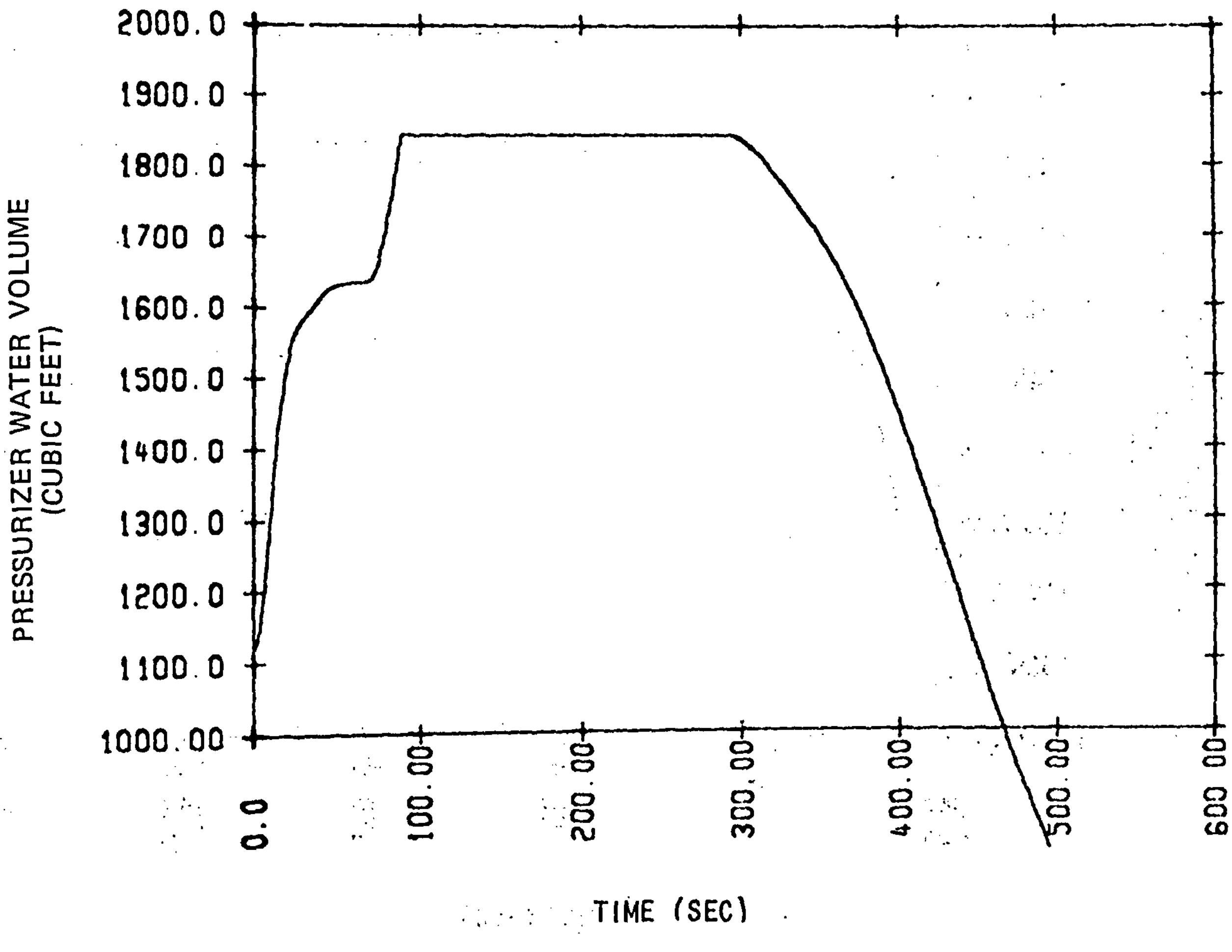

Figure 4-110. Loss of Load
(Pressurizer Water Volume vs. Time)

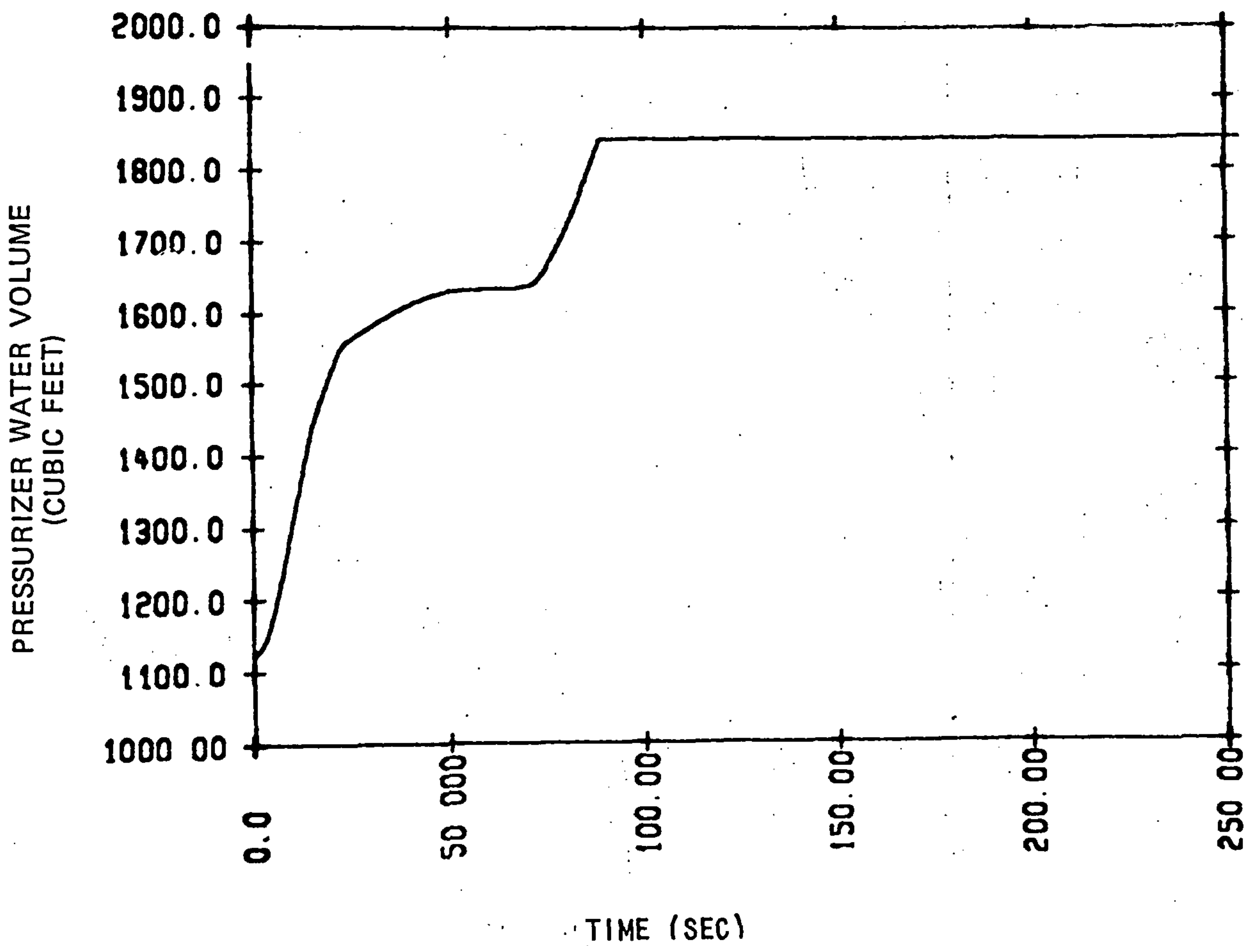

Figure 4-111. Loss of Load
(Pressurizer Water Volume vs. Time)

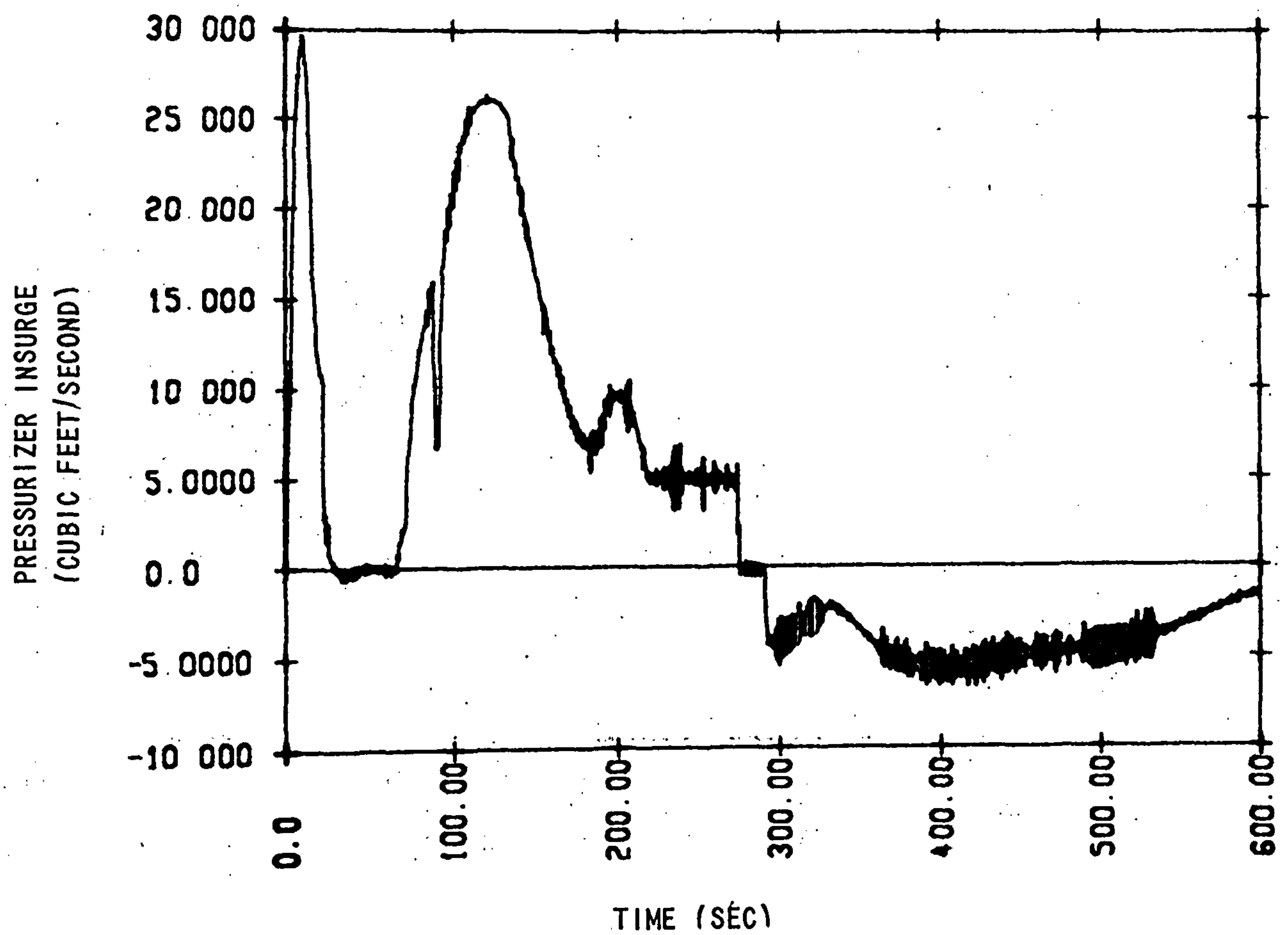

Figure 4-112. Loss of Load
(Pressurizer Insurge vs. Time)

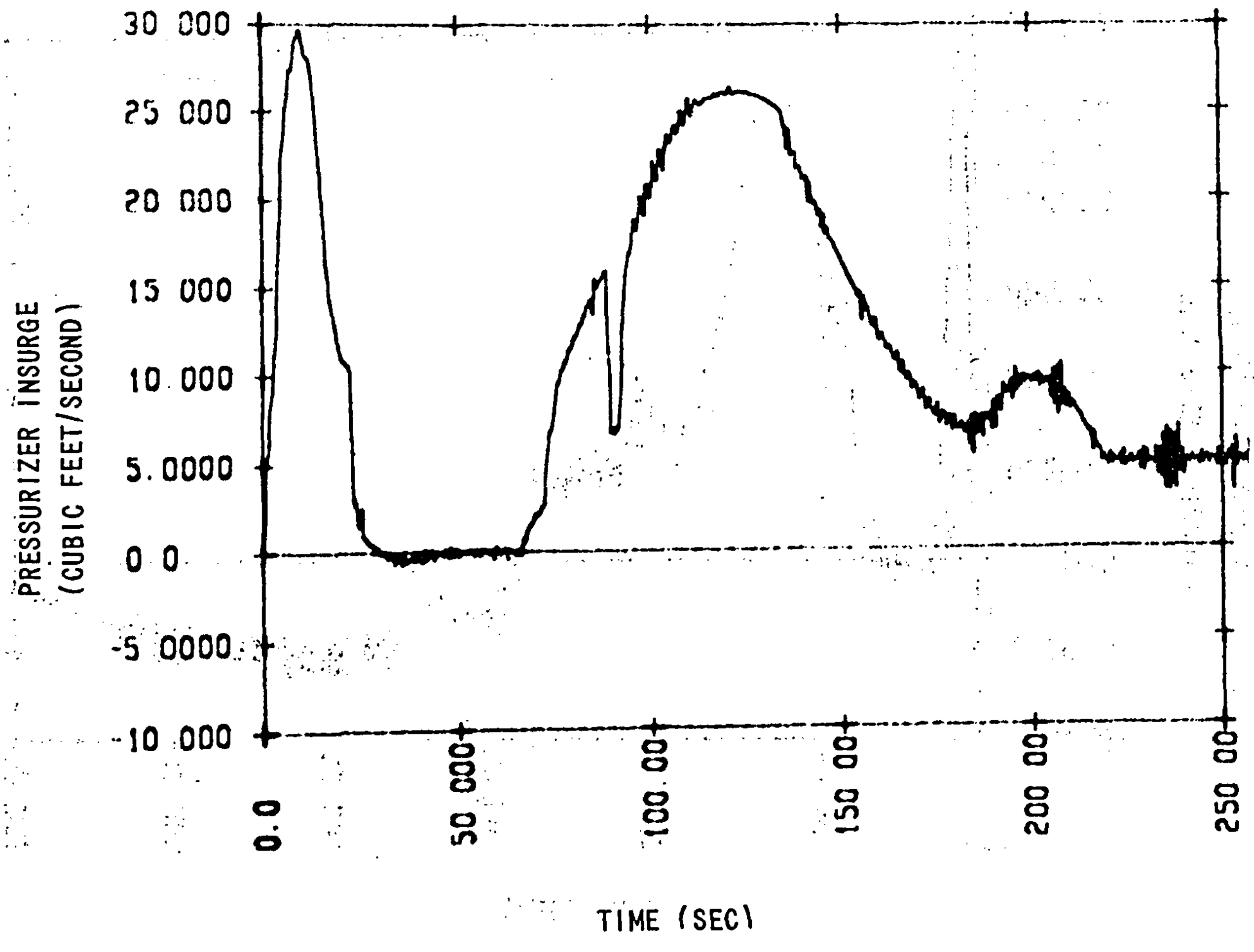

Figure 4-113. Loss of Load
(Pressurizer Insurge vs. Time)

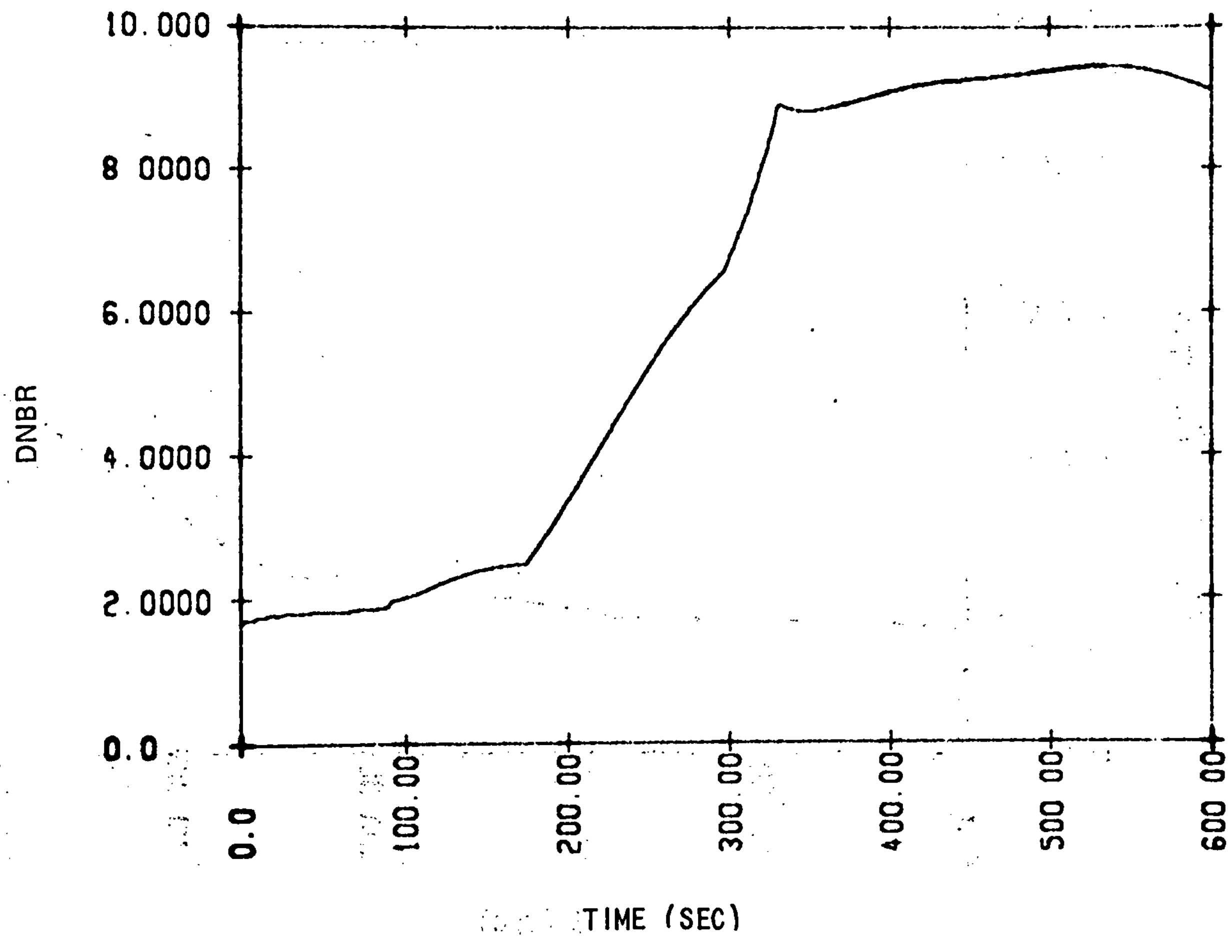

Figure 4-114. Loss of Load
(DNBR vs. Time)

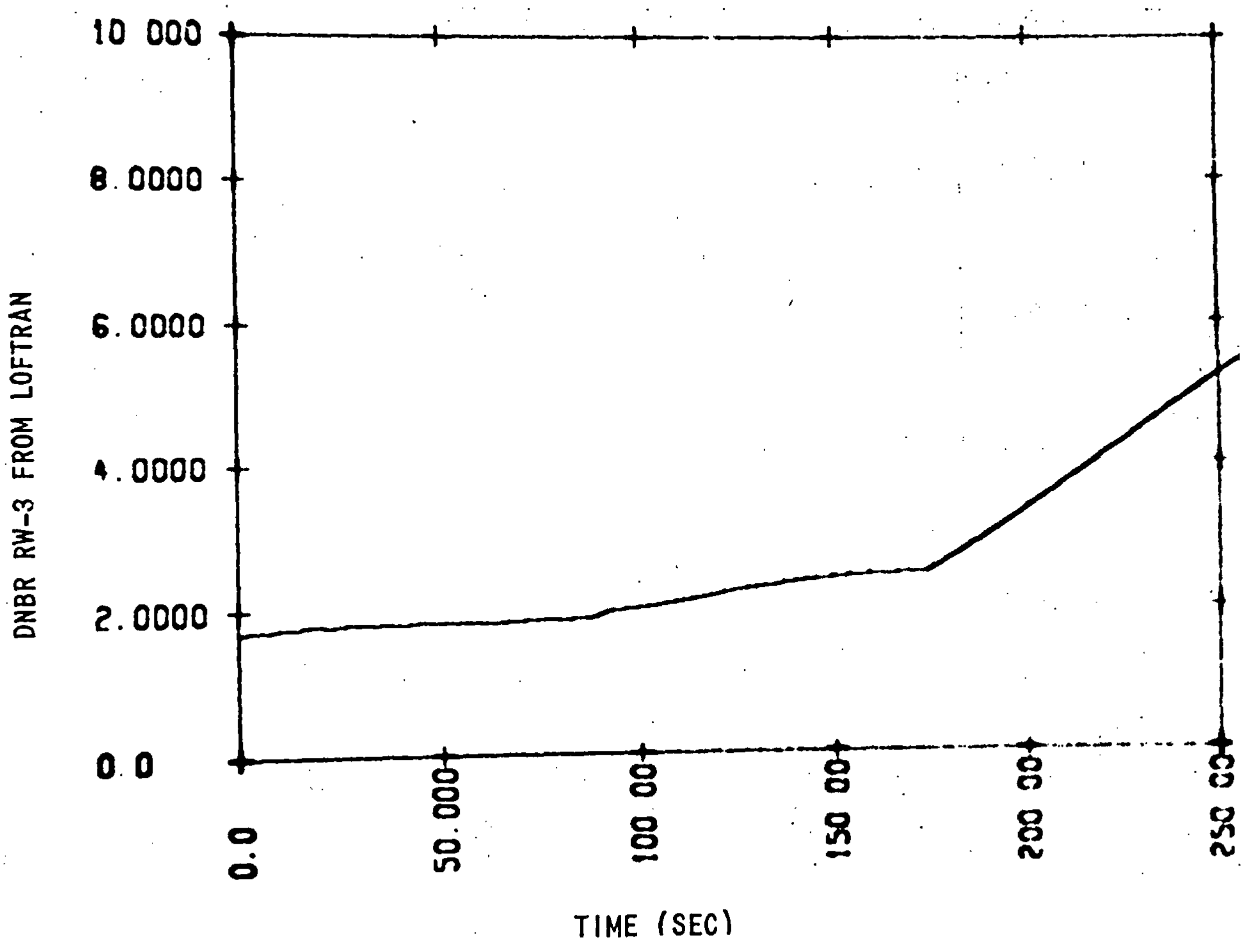

Figure 4-115. Loss of Load
(DNBR vs. Time)

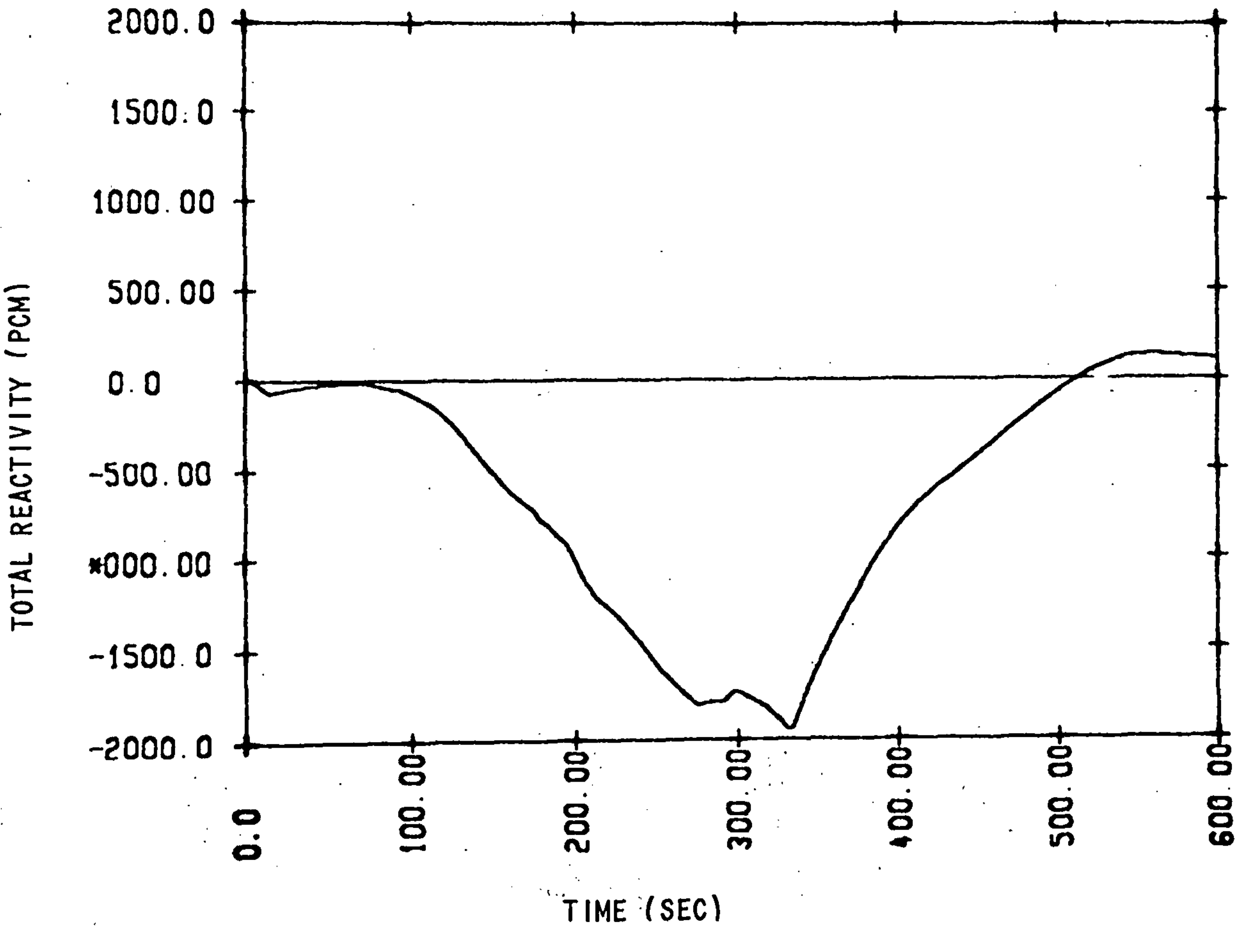

Figure 4-116. Loss of Load
(Total Reactivity vs. Time)

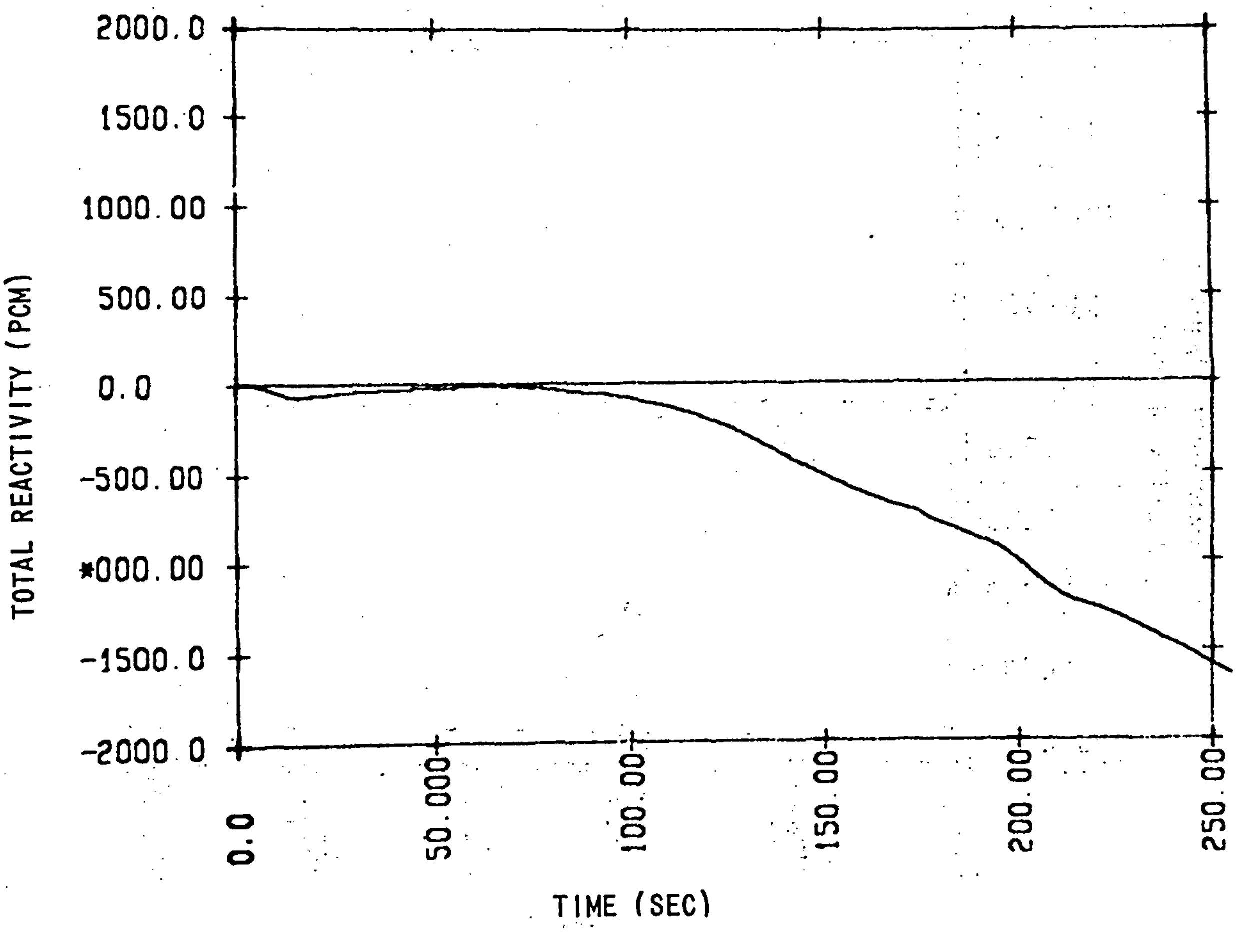

Figure 4-117. Loss of Load
(Total Reactivity vs. Time)

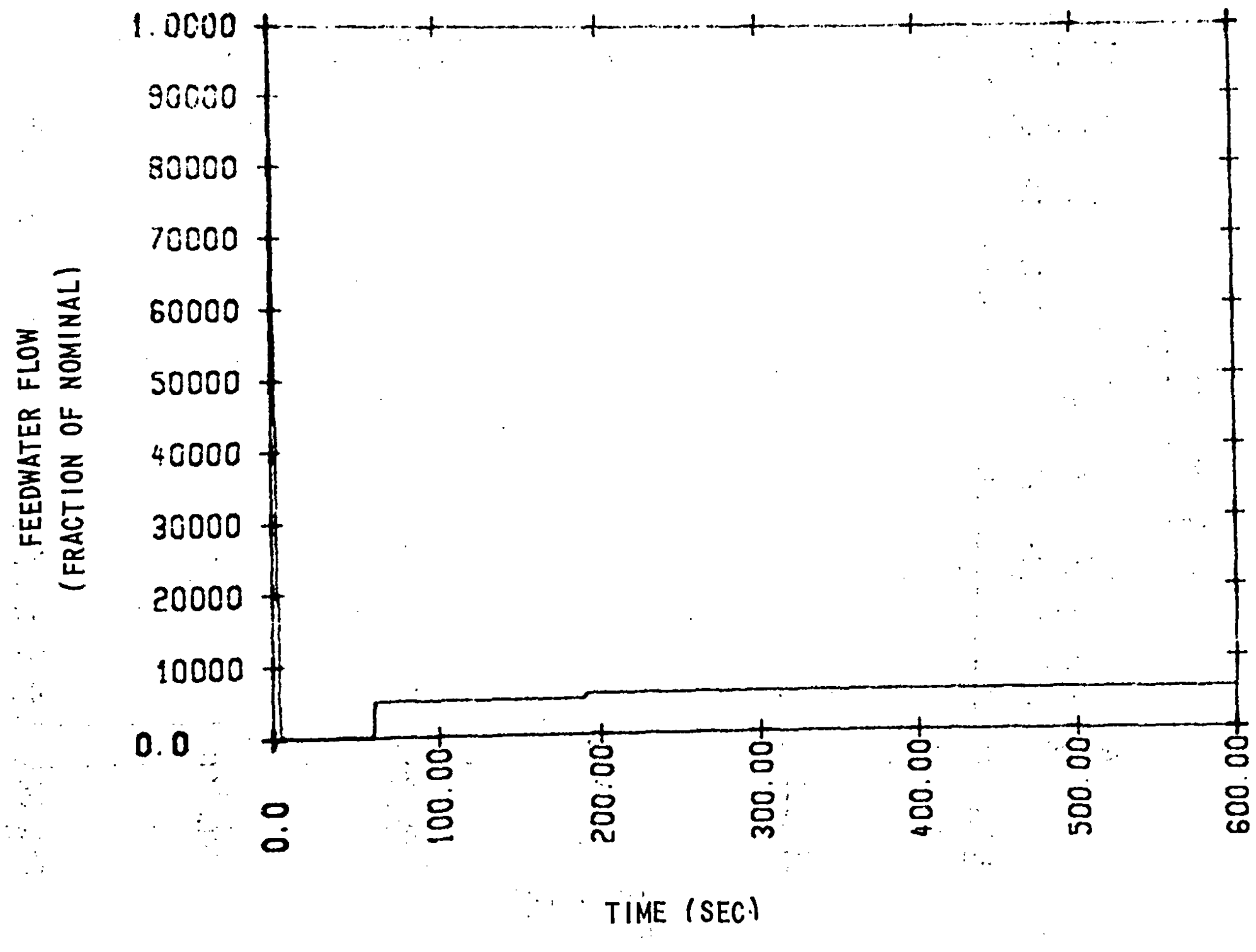

Figure 4-118. Loss of Load
(Feedwater Flow vs. Time)

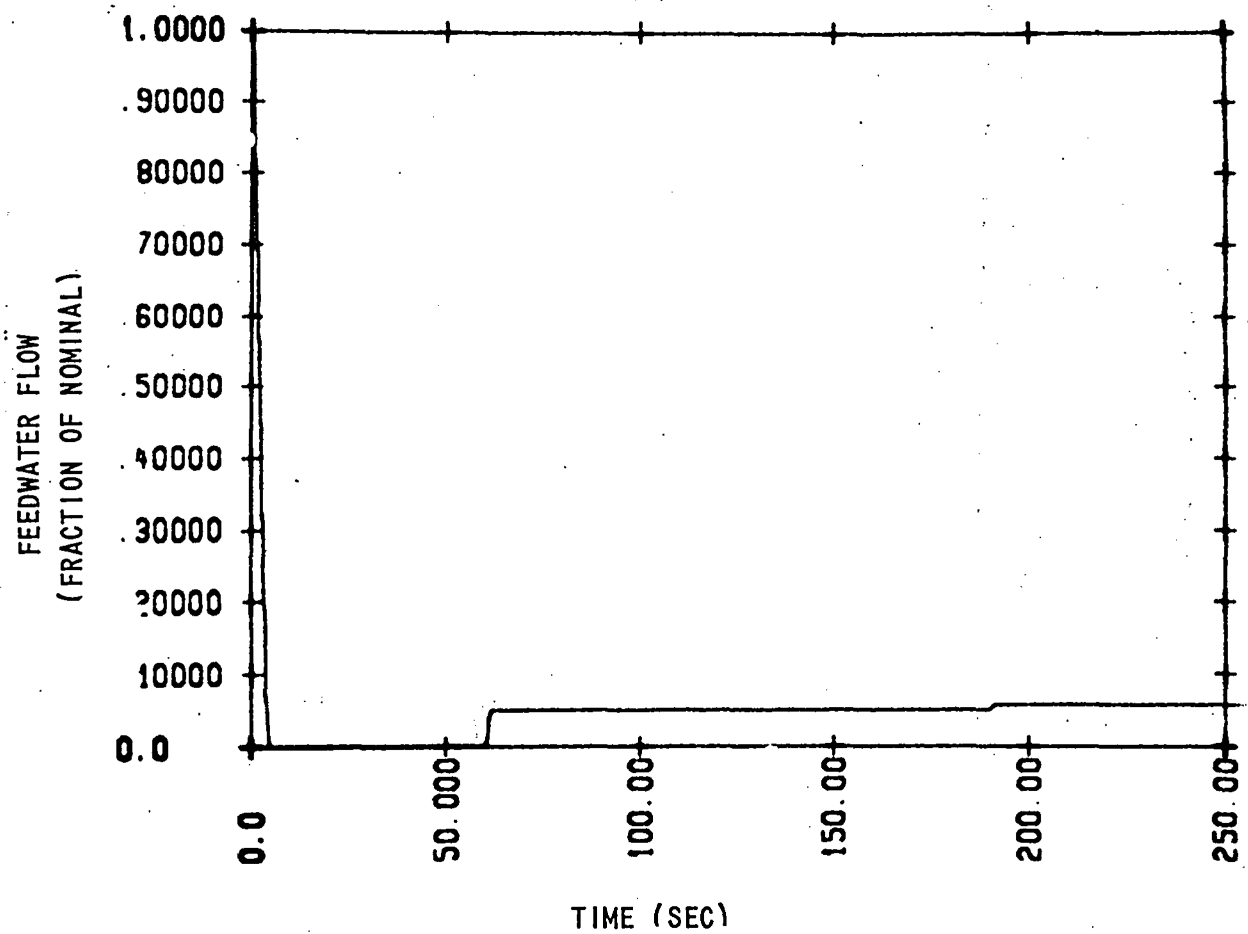

Figure 4-119. Loss of Load
(Feedwater Flow vs. Time)

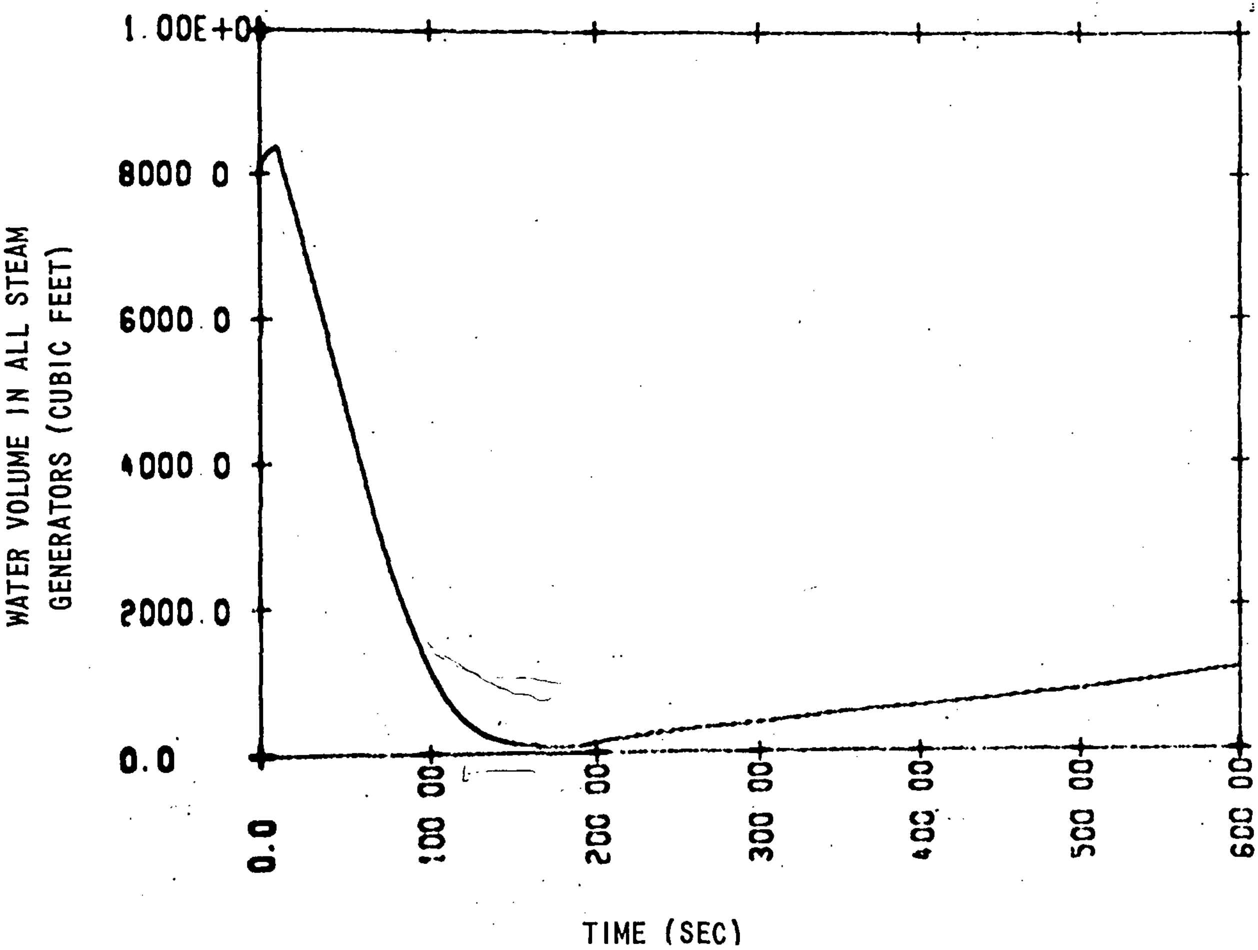

Figure 4-120. Loss of Load
(Water Volume in All Steam Generators vs. Time)

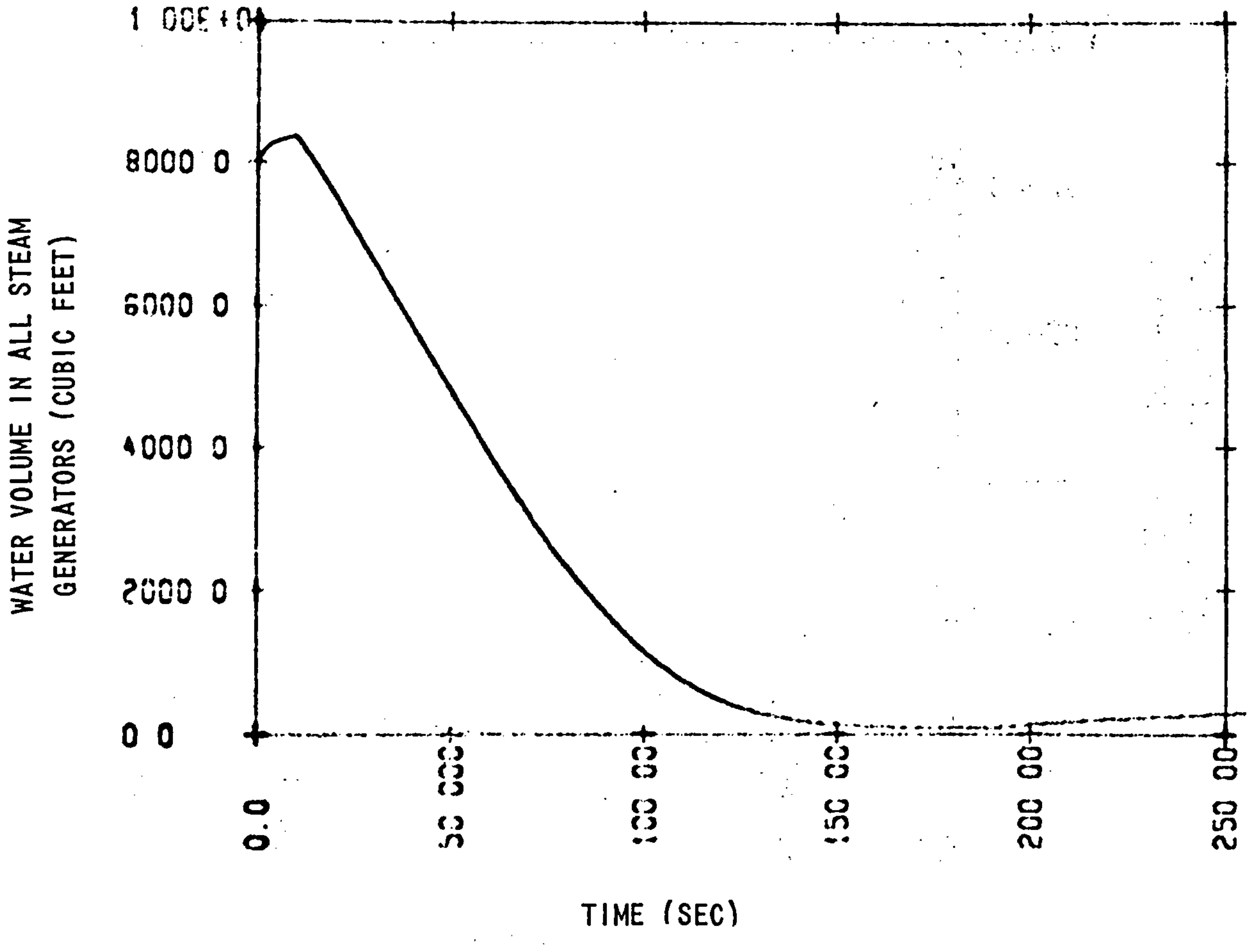

Figure 4-121. Loss of Load
(Water Volume in All Steam Generators vs. Time)

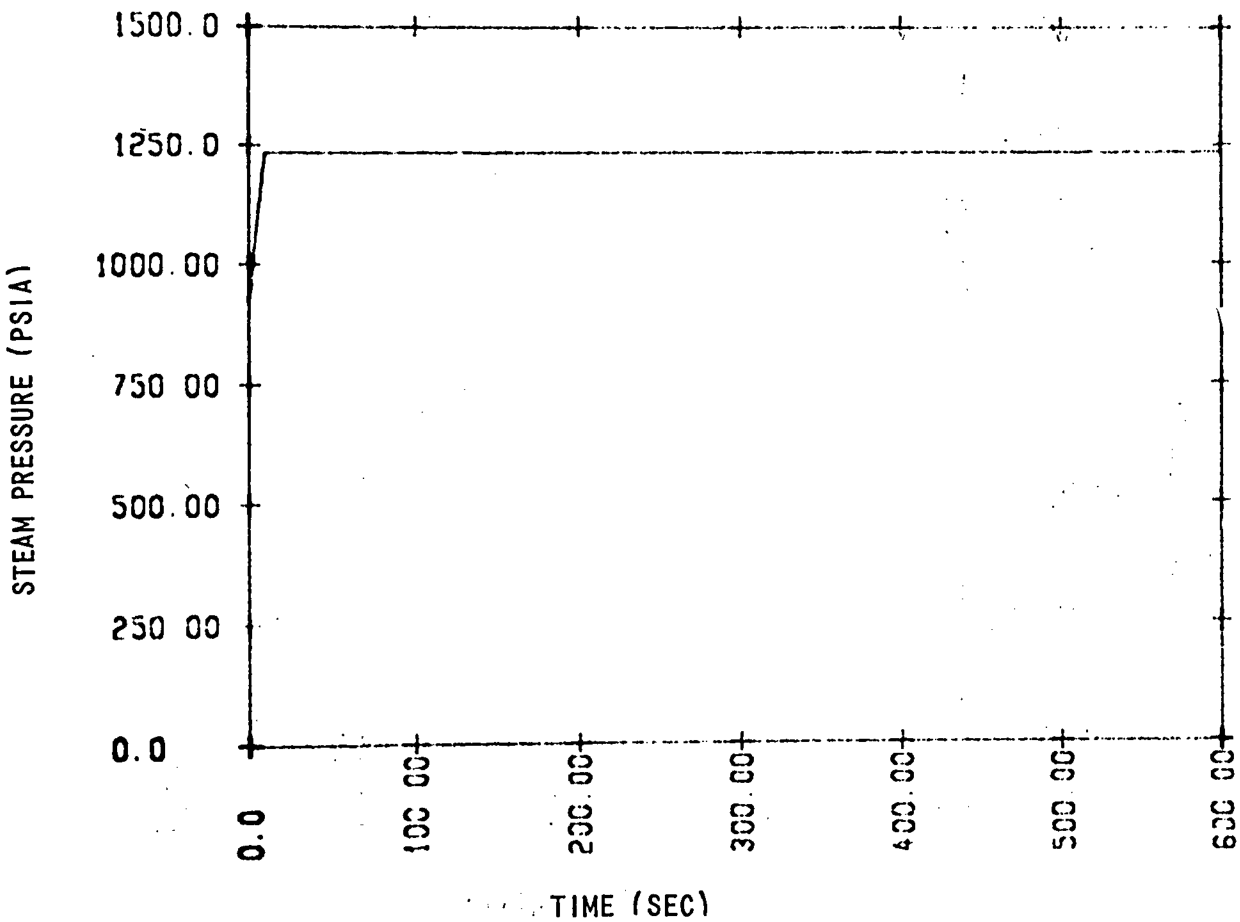

Figure 4-122. Loss of Load
(Steam Pressure vs. Time)

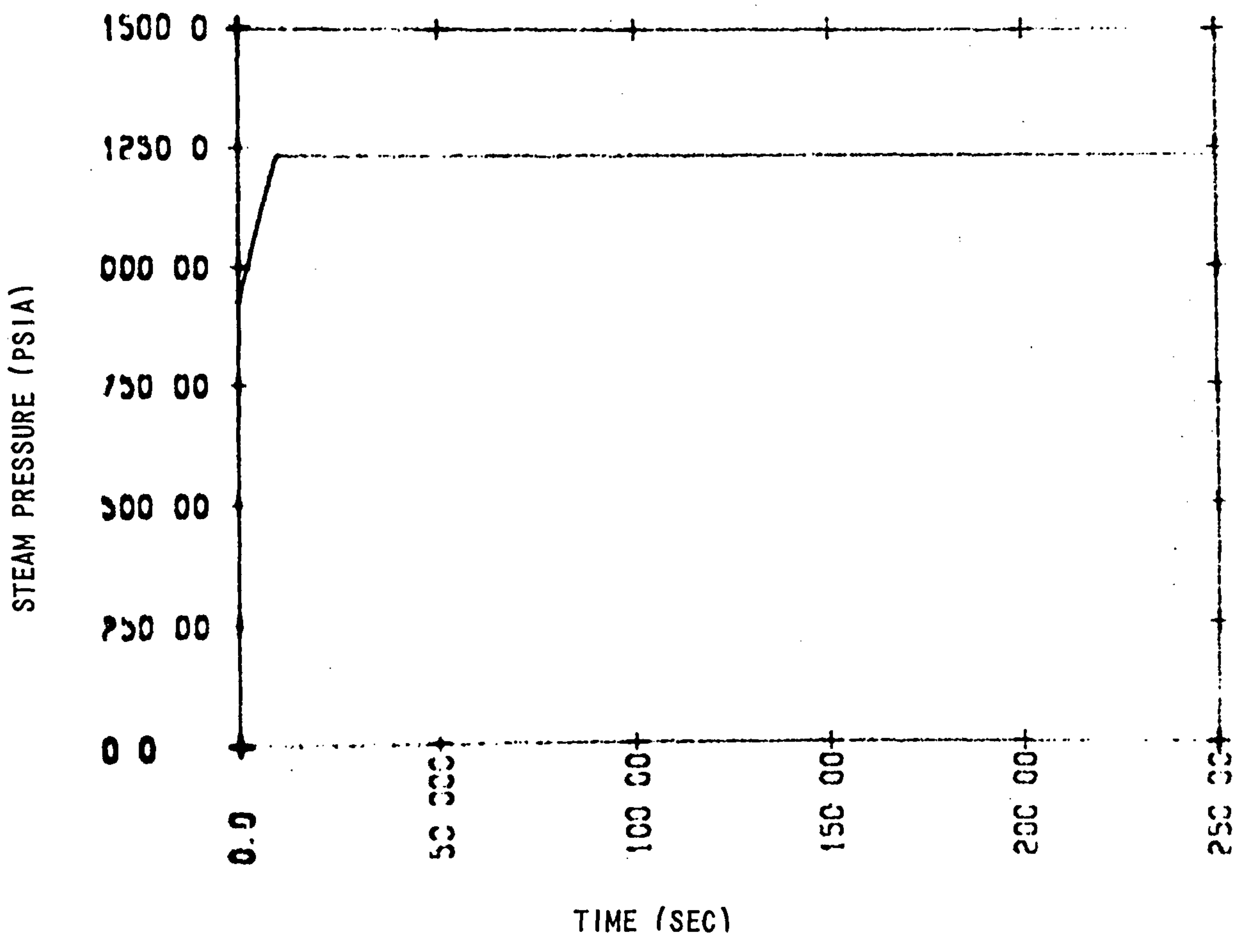

Figure 4-123. Loss of Load
(Steam Pressure vs. Time)

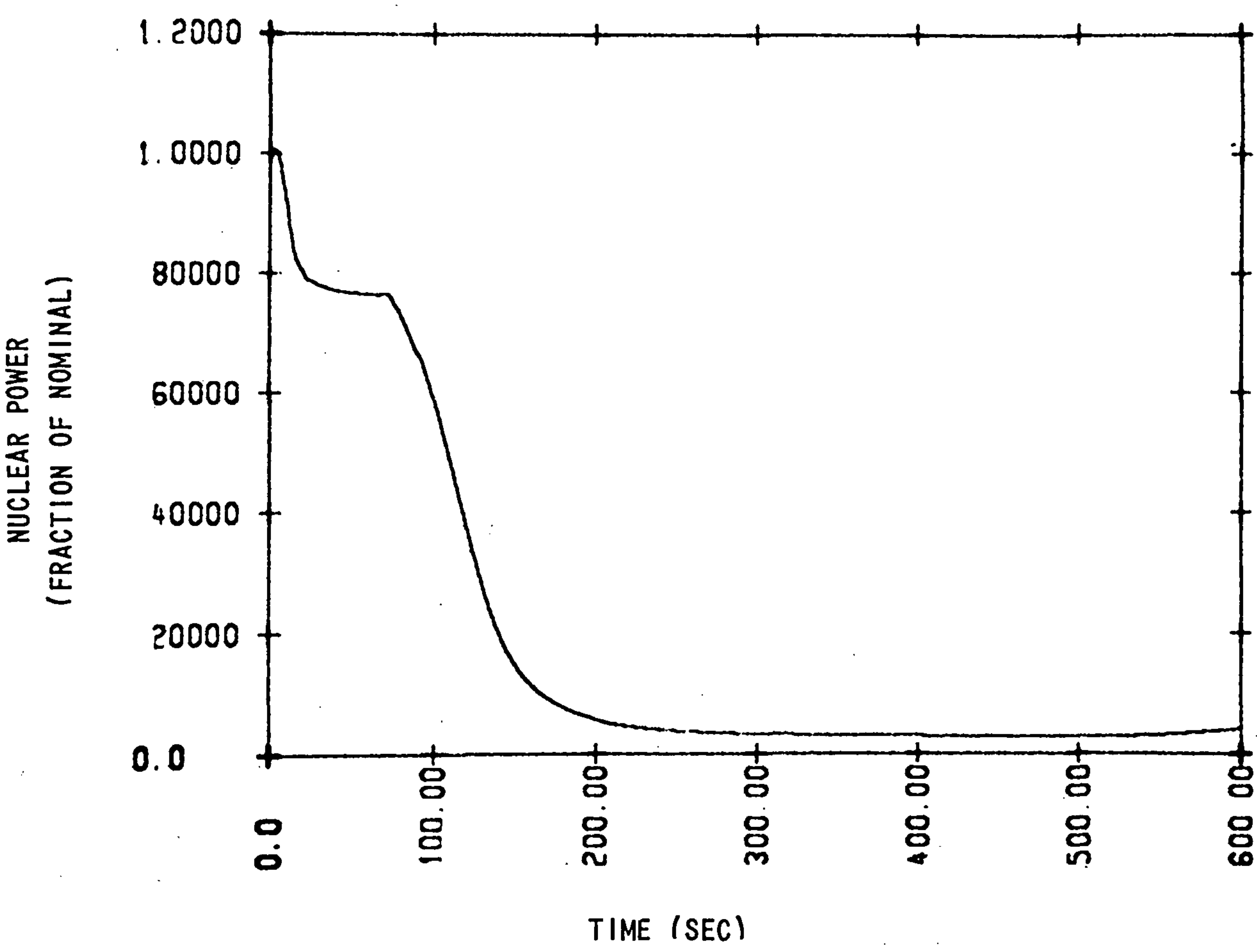

Figure 4-124. Loss of Load
(Nuclear Power vs. Time)

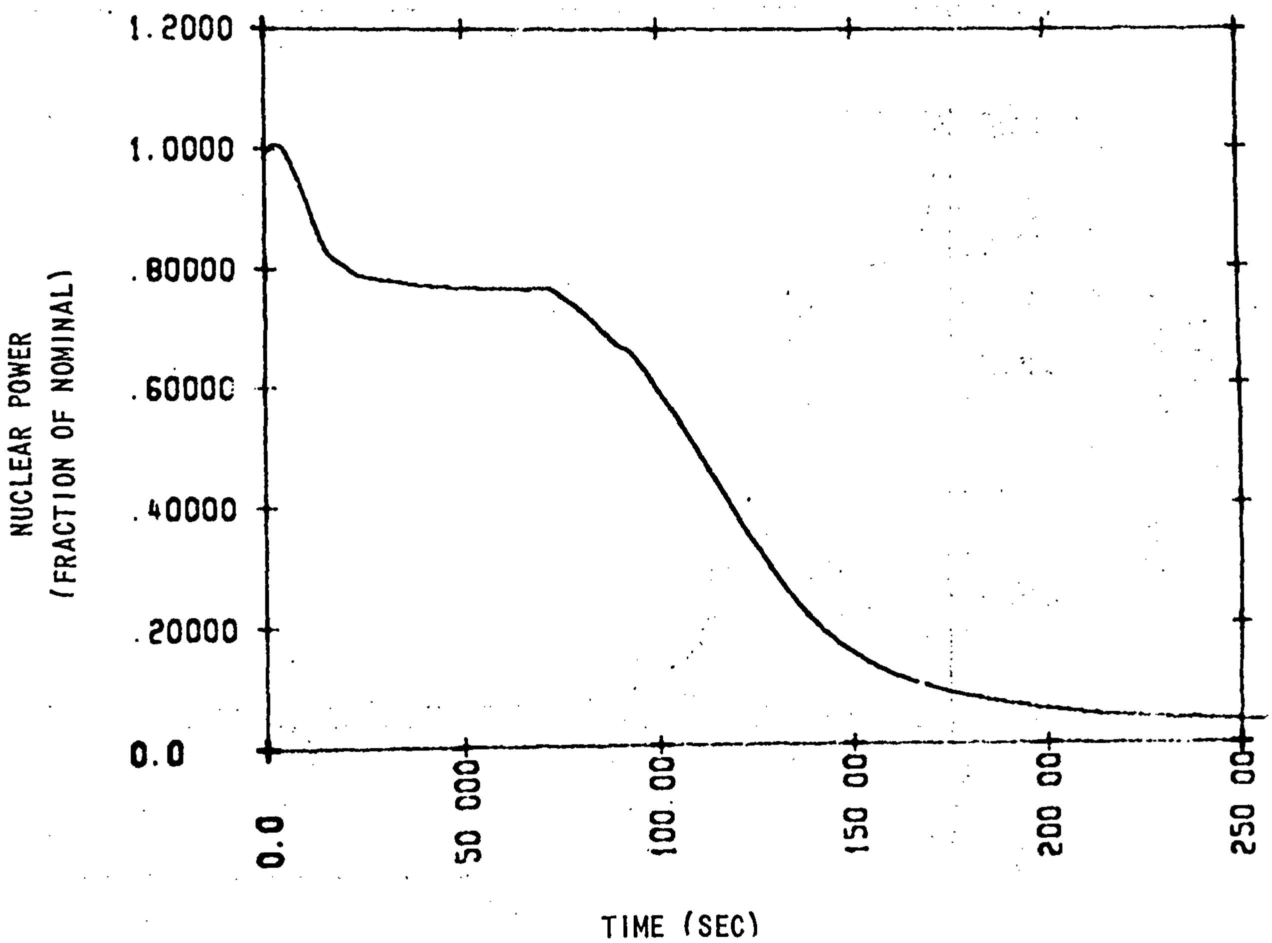

Figure 4-125. Loss of Load
(Nuclear Power vs. Time)

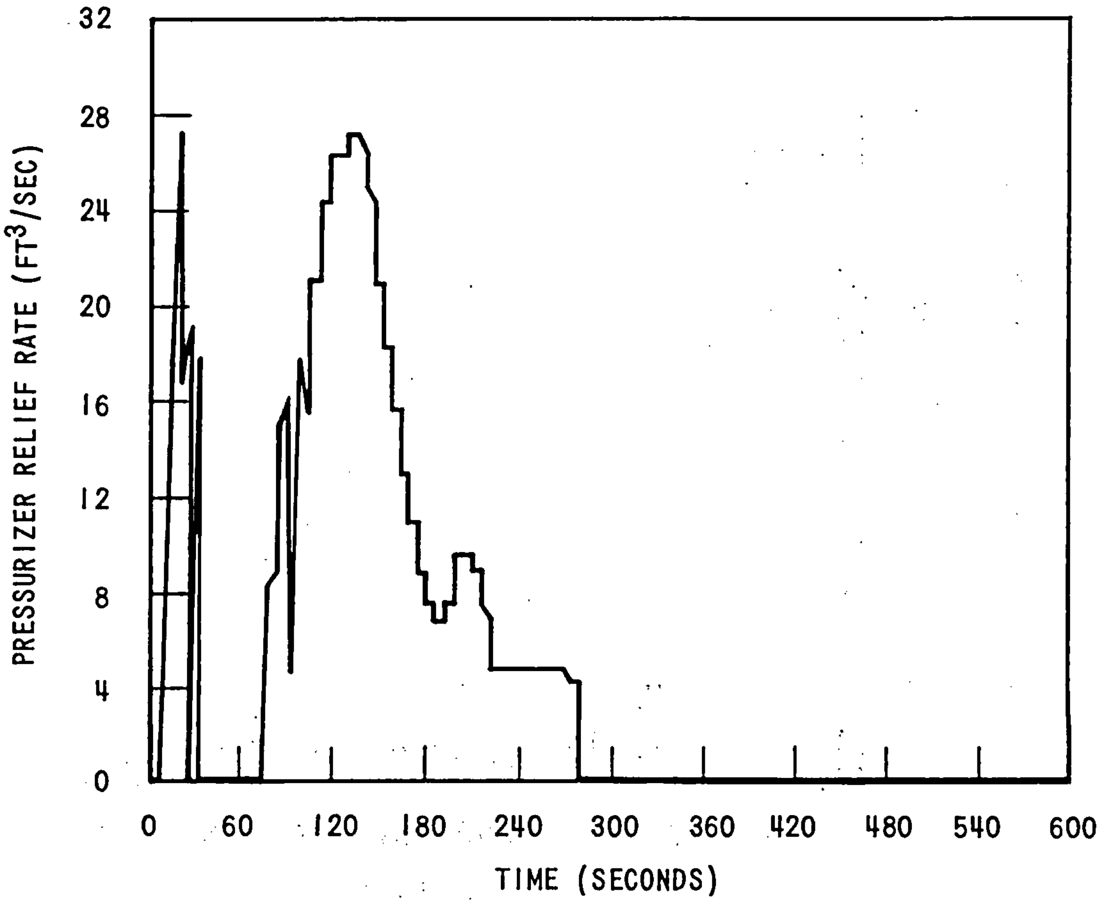

Figure 4-126 Loss of Load
(Pressurizer Relief Rate Vs Time)

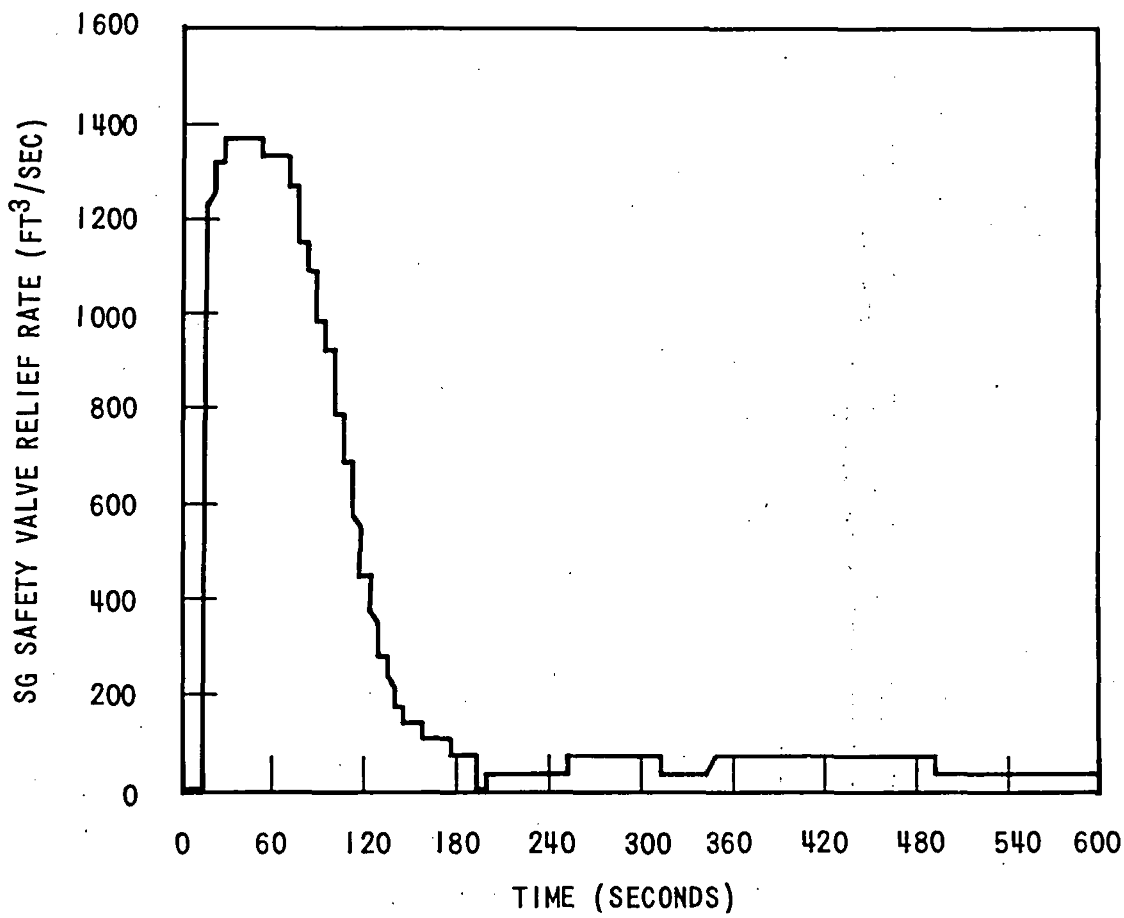

Figure 4-127 Loss of Load
(SG Safety Valve Relief Rate Vs Time)

4-42. COMPLETE LOSS OF NORMAL FEEDWATER WITHOUT REACTOR TRIP

4-43. Identification of Causes and Transient Description

Loss of normal feedwater could result from a malfunction in the feedwater condensate system or its control system from such causes as simultaneous trip of both condensate pumps, simultaneous trip of both main feedwater pumps (or closure of their discharge valves), or simultaneous closure of all feedwater control valves. The vast majority of these cases would cause only a partial loss of feedwater flow. The most likely cause of a complete loss of feedwater would be loss of station power (station blackout) which is independently evaluated in a separate section. Not withstanding the low probability of occurrence, a complete loss of normal feedwater is evaluated with the additional assumption that a non-mechanistic, common mode failure prevents rods from dropping into the core.

The loss of main feedwater produces a large imbalance in the heat source/sink relationship. When feedwater flow to the steam generators is terminated, the secondary system can no longer remove all of the heat that is generated in the reactor core. This heat buildup in the primary system is indicated by rising Reactor Coolant System temperature and pressure, and by increasing pressurizer water level, which is due to the insurge of expanding reactor coolant. Water level in the steam generators drops as the remaining water in the secondary system, unreplenished by main feedwater flow, is boiled off. When the steam generator water level falls to the point where the steam generator tubes are exposed and primary-to-secondary system heat transfer is reduced, the reactor coolant temperature and pressure begin to increase at a greater rate. This greater rate of primary system temperature and pressure increase is maintained as the pressurizer fills and releases water through the safety and relief valves. (The safety and relief valves have a smaller volumetric relief capacity for water than for steam.) Reactivity feedback, due to the high primary system temperature, reduces core power. The system pressure begins to decrease and a steam space is again formed in the pressurizer.

The ATWT for 2-, 3-, and 4-loop plants involves a heat source/sink mismatch; therefore, the peak pressure attained in the primary system depends upon the ability of the pressurizer safety and relief valves to release the reactor coolant volumetric insurge to the pressurizer. The volumetric relief capacities of these valves are reduced when the pressurizer fills and water is passed instead of steam. During a loss of feedwater or loss of load ATWT, the heat source/sink mismatch causes the reactor coolant temperature and coolant expansion rate to increase and the core reactivity and power to drop. Reduction of the pressurizer safety and relief valve volumetric relief capacity (due to filling the pressurizer and relieving water) early in the transient when core power is still relatively high, will result in a higher peak Reactor Coolant System pressure than the peak pressure that would result from reduction of pressurizer relief and safety valve capacity later in the transient, when core power is lower.

Important parameters to consider when determining the relative peak pressures that will be reached in the various Westinghouse plants are:

- The time at which the pressurizer fills
- The volumetric relief capacities of the valves
- The total pressurizer volume in comparison to the Reactor Coolant System volume
- The rate of reactor coolant insurge to the pressurizer

Table 4-8 lists the relevant parameters for representative 2-, 3-, and 4-loop plants, and their plant configurations to the relative peak pressures that are expected to result from a heat source/sink mismatch.

Table 4-9 shows that a 4-loop plant will attain a higher peak primary system pressure than the others. Analyses of 2-, 3-loop loss of feedwater transients without trip (figures 4-128 through 4-131) confirm this estimate when compared to the corresponding 4-loop transient (figure 4-141). Therefore, the 4-loop plant configuration has been selected as the basis for the loss of feedwater and loss of external load ATWTs and for all of their associated parametric variations. Calculations showed equal peak pressure for the model D and Series 51 steam generator; this result was expected since the two types have approximately the same secondary mass inventory.

TABLE 4-8
PRESSURIZER PARAMETERS FOR 2-, 3-, AND 4-LOOP PLANTS

Parameters	Peak Pressures		
	2-Loop	3-Loop	4-Loop
Pressurizer Volume including surge line (ft^3)	1021.3	1436.8	1843.7
Pressurizer Volume to Reactor Coolant System Ratio	0.196	0.175	0.171
Asymptatic Suge Rate (ft^3/sec)	19.7	37.7	48.0
Time to Fill Pressurizer at Asymptotic Surge Rate (sec)	51.84	38.11	38.41
Pressurizer Relief Rate (ft^3/sec) (Steam at 2590 psia)	37.36	50.80	58.655
Relief Rate to Asymptotic Surge Rate Ratio	1.90	1.35	1.22

For protection for loss of feedwater, the reactor would be tripped when any of the following conditions are reached:

- Steam/feedwater flow mismatch (low feedwater flow) and low steam generator water level (40-percent mismatch and 25 percent of narrow span, respectively)
- Overtemperature ΔT reactor trip
- High pressurizer pressure (2400 psia)
- High pressurizer level (92 percent of span)
- Steam generator low-low water level (10 percent of narrow span)
- Low reactor coolant flow (90 percent of nominal)

4-44. Analysis of Effects and Consequences

The following assumptions were made in the analysis:

- Initial normal full power operation early in core life. Since the negative temperature coefficient of reactivity reduces core power as the coolant temperature rises, and the temperature coefficient becomes more negative with core life, the ATWT loss of feed is less severe later in core life.
- Normal operation of the following control systems:
  1) Pressurizer pressure control, including heaters, spray, and both the power-operated and the spring-loaded relief valves
  2) Turbine governor valves in impulse pressure control prior to trip, and valve closure on turbine trip
  3) Steam dump to condenser at 40 percent of rated turbine flow following turbine trip
- Turbine trip 30 seconds after loss of feed. (This is after generation of a reactor and turbine trip signal on low steam generator water level in coincidence with steam/feed flow mismatch.)
- No credit for automatic reactor trip
- No credit for automatic control rod insertion as reactor coolant temperature rises
- Main feedwater flow falls to zero in the first four seconds of the transient, with no main feed after that time.
- Auxiliary feedwater flow begins at 60 seconds, at a rate of 1760 gpm.

- Auxiliary feedwater is injected into the feedwater pipe at a temperature of 130°, 500 ft^3 upstream of the steam generator, such that the cooler water enters the steam generator after this volume is purged.

- Primary-to-secondary heat transfer area is reduced as the steam generator shell-side water inventory drops below the value necessary to wet the tubes.

4-45. Results

The peak pressure in the Reactor Coolant System for the base case was 2688 psia and occurred approximately 113 seconds after the termination of feedwater supply to the steam generators. The pressurizer reached a peak pressure of 2666 psia at the same time, while relieving 27.40 ft^3 of water/sec.

The chronology of events for this case is shown in table 4-9 and plots are presented in figures 4-132 through 4-157.

Figures 4-136 and 4-137 depict the primary system mass flow rate as a fraction of nominal. The gradual drop in flow rate, before jump cavitation occurs, is due to coolant expansion (drop in density). The volumetric flow rate, however, is relatively constant before the pump is assumed to cavitate.

In addition to the automatic reactor trips, the operator may shut down the reactor with emergency boration or safety injection.

4-46. Sensitivity Studies

The loss of feedwater transient discribed above was also subjected to sensitivity studies which were analyzed for changes in significant assumptions and parameters to determine their effect on Reactor Coolant System overpressure. The results of these studies are discussed below and are shown in figures 4-158 through 4-190. Also, see table 4-9.

4-47. Effect of not Tripping the Turbine During a Loss of Feedwater ATWT — Failure to trip the turbine permitted higher steam release from the steam generators. In addition, more heat was removed from the primary system early in the transient, the core power level stayed relatively high and the primary pressure attained a higher maximum value than for the case in which the turbine was tripped. The Reactor Coolant System pressure reached a peak of 3647 psia, the pressurizer pressure went to a maximum of 3565 psia, and the pressurizer valves relieved water at a maximum rate of 53.04 ft^3/sec. The pressurizer pressure response to a loss of feedwater ATWT without a turbine trip is shown in figures 4-158 through 4-160.

TABLE 4-9

SEQUENCE OF EVENTS FOR LOSS OF FEEDWATER WITHOUT A REACTOR TRIP

Event	Time (sec)
Main Feedwater Supply to All Steam Generators Is Terminated	0-4
Steam generator water level begins to fall Steam temperature and pressure begin to rise Reactor Coolant System temperature and pressure begin to increase Expanding reactor coolant surges into the pressurizer, causing level to rise Core power begins to drop	
Reactor/Turbine Trip Signal: Low Steam Generator Water Level and Steam/Feed Flow Mismatch	5.9
Reactor/Turbine Trip Signal: Low-Low Steam Generator Water Level	10.4
Turbine is Assumed to Trip	30
40 percent steam dump to condensers Reactor coolant temperature rises more steeply Core power declines more rapidly	
Power-Operated Relief Valves on the Pressurizer Open and Release Steam	31.5
Pressurizer pressure > 2350 psia and rises very rapidly	
Reactor/Turbine Trip Signal: Overtemperature ΔT	35.6
Reactor/Turbine Trip Signal: High Pressurizer Pressure	42.1
Steam Generator Safety Valves Open and Hold Steam Pressure Constant	43
Total steam flow rises rapidly above the 40 percent being dumped to the condenser Core power decline begins to slow, as more heat is removed by increased steam flow	
Pressurizer Pressure Reaches a Peak of 2412 psia	43.5
Peak relief valve release is 16.61 ft^3/sec	
Pressurizer Relief Valves Close	53
Reactor/Turbine Trip Signal: High Pressurizer Water Volume	58

TABLE 4-9 (cont)

SEQUENCE OF EVENTS FOR LOSS OF FEEDWATER WITHOUT A REACTOR TRIP

Event	Time (sec)
Total Steam Flow From the Steam Generators Reaches a Peak of 91.45 Percent of Nominal Flow	59.5
Reactor Coolant System and pressurizer pressure drops Core power decreases very slowly	
All Auxiliary Feedwater Pumps Are Assumed to Start	60
Purging of the main feedwater lines begins; main feedwater remaining in the lines is pushed into the steam generators by the auxiliary feedwater (5 percent of nominal feedwater flow) Steam flow slowly decreases Core power slowly decreases Primary system pressure drops	
Steam Generator Tubes Are Effectively Uncovered and UA Begins to Decrease	67
Primary system pressure rises rapidly Steam flow and core power drops more rapidly	
Pressurizer Relief Valves Open	72.5
Pressurizer pressure levels off at 2350 psia, as relief valves release steam	
Reactor/Turbine Trip Signal: Overtemperature ΔT	74
Rapid Rise in Pressurizer Pressure — Relief Valves Cannot Release Steam Fast Enough to Hold Pressure at 2350	81
Pressurizer Fills With Water	85
No steam space remains in the pressurizer Relief valves release water Pressurizer pressure continues to rise rapidly	
Reactor/Turbine Trip Signal: High Pressurizer Pressure	85.5
Pressurizer Safety Valves Open to Relieve Water	87
Steam Generator Safety Valves Close	91.5
Total steam flow consists of steam dump to condenser	

TABLE 4-9 (cont)

SEQUENCE OF EVENTS FOR LOSS OF FEEDWATER WITHOUT A REACTOR TRIP

Event	Time (sec)
Peak Reactor Coolant System Pressure Is Reached (2688 psia)	113
Peak Pressurizer Pressure Is Reached (2666 psia)	113.5
Peak Pressurizer Relief and Safety Valve Relief Rate Is Attained (27.40 ft^3/sec of water)	
Core power decreases Primary pressure decreases Reactor coolant temperature still increases	
Pump is Assumed to Cavitate (Cold Leg Temperature is $\leqslant$ 6°F Below Saturation Temperature)	164
Reactor/Turbine Trip Signal: Low Reactor Coolant Flow	
Purging of the Main Feedwater Lines by Auxiliary Feedwater Is Completed – Colder (Auxiliary Feedwater) Water 100 BTU/lb Enters the Steam Generators and Heat Transfer in the Steam Generator Increases Slightly	166 191
Steam Space Forms in Pressurizer, as Water Level Begins to Drop	
All pressurizer valves are closed	260-270
Primary System Pressure Falls to About 1690 Psia	
Water level in pressurizer falls to about 1/3 of normal Cold leg temperature falls below 580°F	270-517
Reactor/Turbine Trip Signal: Fixed Low Pressure	
Core Becomes Critical	411
Core power increases very, very slowly from 3.2 percent of nominal	418
Reactor/Turbine Trip Signal: Overtemperature ΔT	
Reactor/Turbine Trip Signal: Variable Low Pressure	518
	549

TABLE 4-9 (cont)

SEQUENCE OF EVENTS FOR LOSS OF FEEDWATER WITHOUT A REACTOR TRIP

Event	Time (sec)
Primary Pressure Begins to Rise Slowly from about 1670 psia Pressurizer water level rises from about 1/3 normal. Core power at 10 percent of nominal Primary System pressure is 1762 psia Pressurizer level is ~ 40 percent of nominal level	600

4-48. Effect of Not Opening the Power-Operated Relief Valves — Simulation of the loss of feedwater ATWT with only the three pressurizer safety valves available for steam and water relief from the pressurizer showed that the primary system pressure would increase by about 9 percent. The maximum pressure attained in the pressurizer was 2903 psia, while the safety valves released a maximum of 27.70 ft^3 water/sec. The Reactor Coolant System peak pressure was 2925 psia. These transients are presented in figures 4-161 and 4-162.

4-49. Effect of Not Using the Pressurizer Spray — The loss of feed ATWT system transient response without pressurized spray is shown in figures 4-163 through 4-165, and table 4-8. Addition of spray water into the pressurizer steam space reduced early in the transient. Once the pressurizer was full and water relief began, the pressure rose rapidly to its maximum value of 2666 psia. Thus, the use of no pressurizer spray did not significantly affect the peak pressure reached during the transient.

4-50. Effect of Rod Control During the Loss of Feedwater ATWT — The automatic insertion of control rods to compensate for rising average coolant temperature during the loss of feedwater ATWT reduced the coolant expansion rate to the point that the pressurizer safety valves easily relieved the coolant insurge without even reaching the fully open position (at 2590 psia). Also, the temperature and pressure transients were controlled to the extent that the reactor coolant pumps did not cavitate and the power relief valves were able to limit the pressurizer pressure to about 2350 psia. When the pressurizer filled and water was

released through the valves, the primary pressure rose rapidly. The maximum reactor coolant and pressurizer pressures reached were 2539 and 2538 psia, respectively. The maximum pressurizer water relief rate was 16.89 ft^3/sec. Figure 4-166 through 4-170 describe this case.

4.51 Effect of Variation in Initial Average Coolant Temperature – For the purpose of determining the effect of initial average temperature on the loss of feedwater ATWT transient, and in order to encompass the average coolant temperatures of a variety of Westinghouse plants, analyses were done assuming + 8°F and -20°F variation in initial average temperature. The steam generator heat transfer coefficient was assumed to be unchanged from its design value for these cases, such that the initial steam temperature was correspondingly higher (or lower). All other initial plant conditions remained unchanged. The results are shown in table 4-10.

TABLE 4-10
EFFECT OF VARIATION OF INITIAL AVERAGE TEMPERATURE ON LOSS OF FEEDWATER WITHOUT REACTOR TRIP

Deviation from Normal Value	Maximum Reactor Coolant System Pressure (psia)	Maximum Pressurizer Pressure (psia)	Maximum Water Relief Rate (ft^3/sec)
-20°F	2600	2586	23.66
0°F	2688	2666	27.40
+8°F	2796	2770	30.43

The pressurizer pressure transients for loss of feedwater ATWT occurring when the average coolant temperature was changed by -20°F and +8°F are presented in figures 4-171 through 4-176.

4-52. Effect of Variation in Initial Pressurizer Water Level – Variation of ±10 percent in initial pressurizer water level was considered. The effect of this variation of initial pressurizer water level is shown in figures 4-177 through 4-182. The maximum pressurizer pressure attained during a loss of feedwater ATWT, which commenced when the pressurizer water level was 10 percent higher than the nominal level, was 2671 psia (see figure 4-177). Another transient which was based on a lower pressurizer water level (10 percent below nominal level) produced a maximum pressurizer pressure of only 2662 psia (see figure 4-180). The higher

initial water level meant that the pressurizer filled to capacity earlier in the transient when the core power was still relatively high. A lower than normal water level delayed the filling of the pressurizer and provided more steam for volumetric relief through the relief valves and resulted in a lower pressurizer pressure.

4-53. Effect of Lower Initial Power Levels — If a loss of feedwater ATWT occurred when the plant was operating at 80 or 90 percent of full power, then the resulting heat source/sink mismatch, coolant expansion rate, and peak primary pressure would be lower than for loss of feedwater ATWT at full power. The system transients for the 80- and 90-percent power cases are shown in figures 4-183 through 4-188.

4-54. Effect of Different Flow Model for Water Relief — If the Fauske L/D = 0 correlation is used to calculate the water relief rates from the pressurizer, higher flow rates (in the pressure range of interest) through the valves and a lower peak pressure result. The peak pressurizer pressure was only 2570 psia and the maximum volumetric relief rate was 28.18 ft^3/sec. Figures 4-189 and 4-190 show the pressurizer pressure and coolant insurge behavior during the transient.

4-55. Conclusions

Table 4-11 summarizes the results for the loss of feed water ATWT reference case and sensitivity studies. These results demonstrated that the sensitivity to variation of most of the parameters is slight.

Increasing initial core average temperature, increasing initial pressurizer water level, and increasing initial reactor power each results in a slight increase in peak pressurizer pressure. Pressurizer spray has little effect on peak pressurizer pressure. A slightly higher peak pressurizer pressure results when the power relief valves are neglected. Use of the Fauske water relief model or assuming automatic rod control results in lower peak pressurizer pressure. The assumption of no turbine trip causes a higher peak pressurizer pressure, since turbine trip causes faster heatup of the reactor coolant resulting in more rapid decrease in power and also maintains steam generator inventory and heat transfer capability for a longer time after the loss of main feedwater occurs.

The DNB ratio for the hot channel increases above its initial value during the transient as pressure increases. The peak Reactor Coolant System pressure (including allowances for elevation and pump head as described in section 3) is about 2760 psia. Thus, no core damage or impairment of Reactor Coolant System integrity would occur for the loss of feedwater ATWT.

TABLE 4-11
SUMMARY OF RESULTS FOR LOSS OF FEEDWATER
WITHOUT A REACTOR TRIP

Case	Maximum Pressurizer Pressure (psia)	Maximum Reactor Coolant System Pressure (psia)	Maximum Pressurizer Relief Rate (ft^3/sec)
2-Loop Plant	2568	2577	12.64
3-Loop Plant	2649	2671	23.29
4-Loop Plant Parametric Variation on the 4-Loop Plant	2666	2688	27.40
No Turbine Trip	3565	3647	53.04
No Pressurizer Relief Valves	2903	2925	27.70
No Pressurizer Spray	2666	2687	27.37
Automatic Rod Control Operates	2538	2539	16.89
Average Temperature +8°F	2770	2796	30.43
Average Temperature -20°F	2586	2600	23.66
Pressurizer Water Level +10 Percent	2671	2693	27.52
Pressurizer Water Level -10 Percent	2662	2683	27.26
Plant Operation at 80 Percent of Full Power	2576	2588	21.30
Plant Operation at 90 Percent of Full Power	2586	2600	23.73
Fauske Flow through Pressurizer Valves	2570	2591	28.18

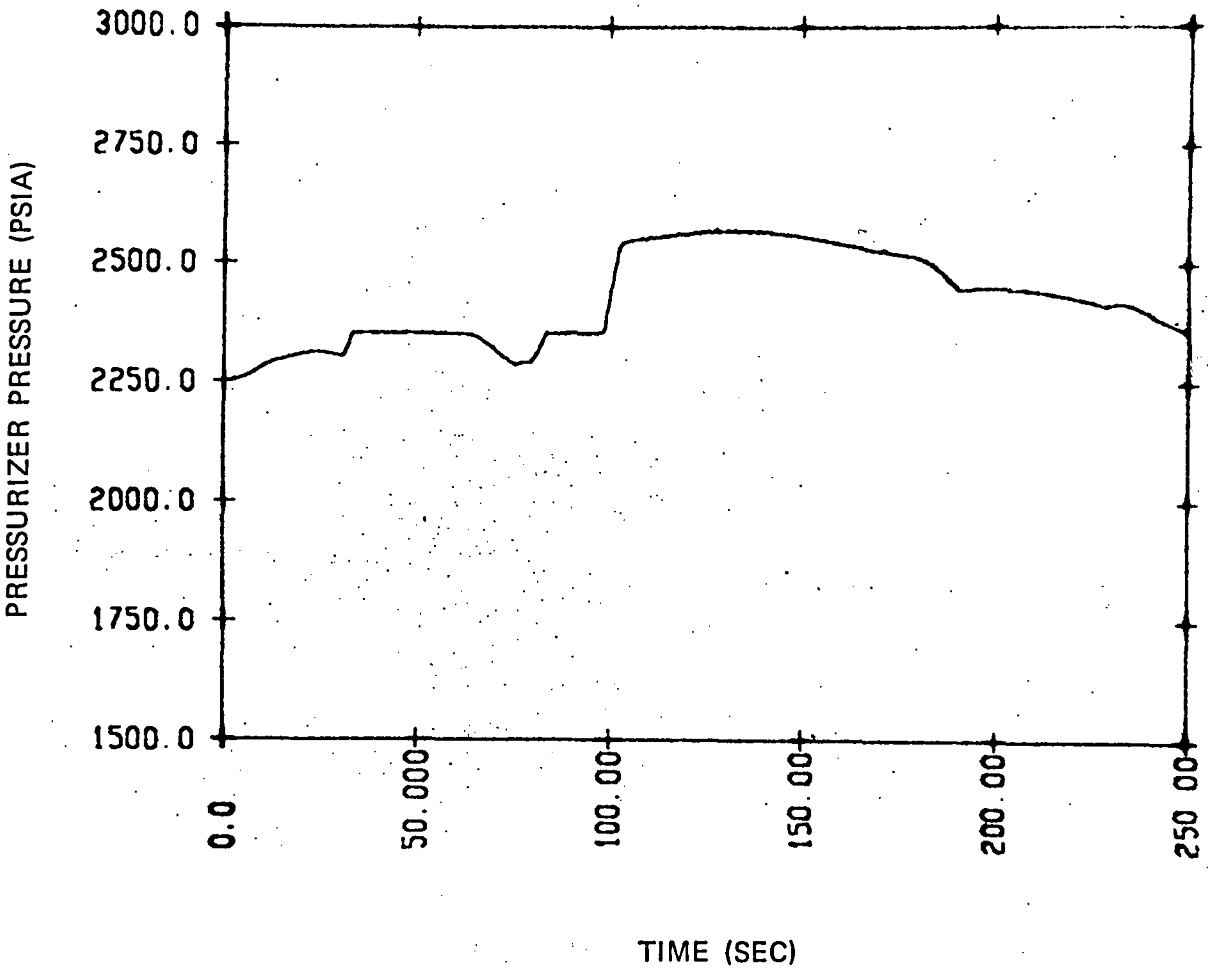

Figure 4-128. Loss of Feedwater – 2-Loop Plant
(Pressurizer Pressure vs. Time)

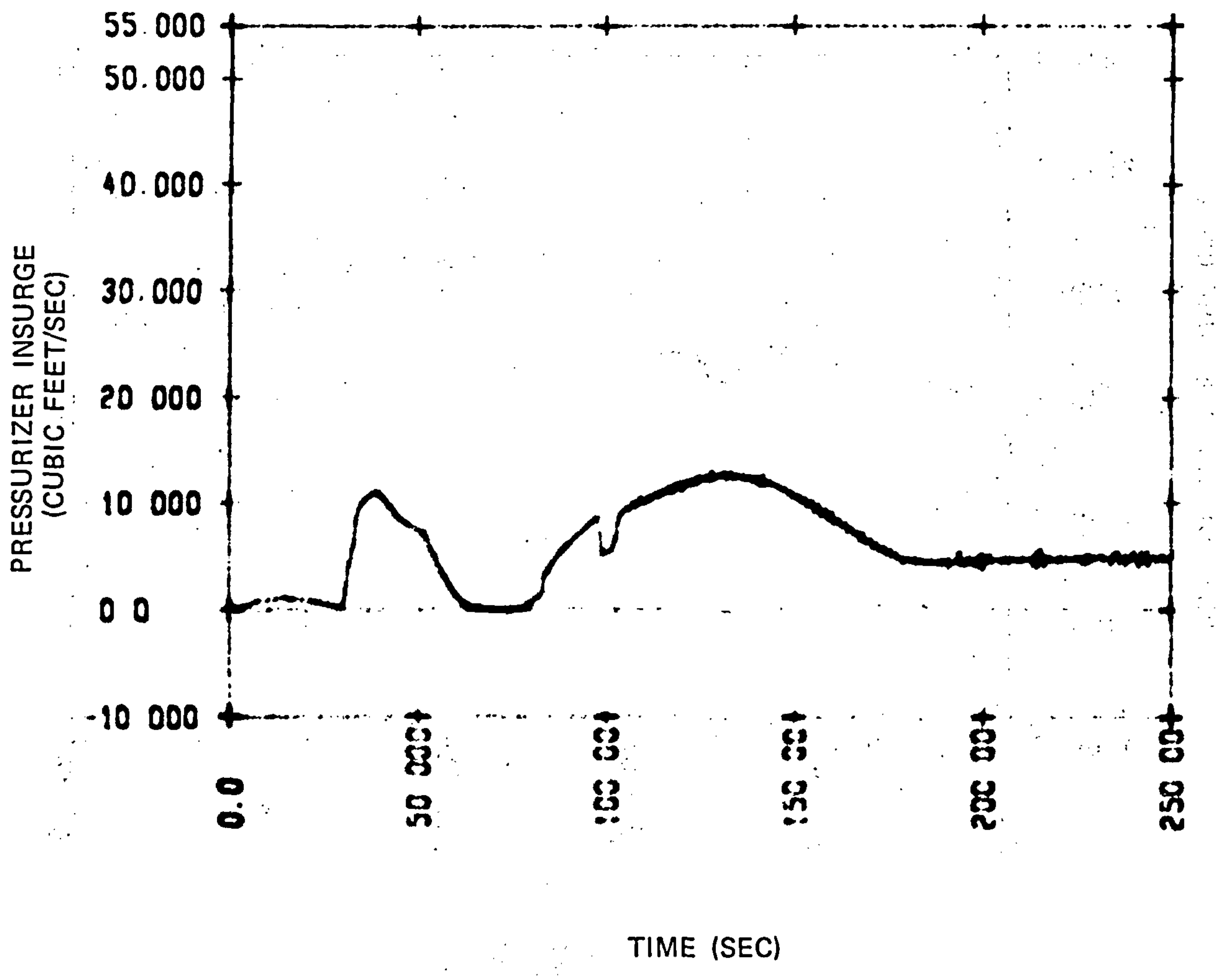

Figure 4-129. Loss of Feedwater — 2-Loop Plant
(Pressurizer Insurge vs. Time)

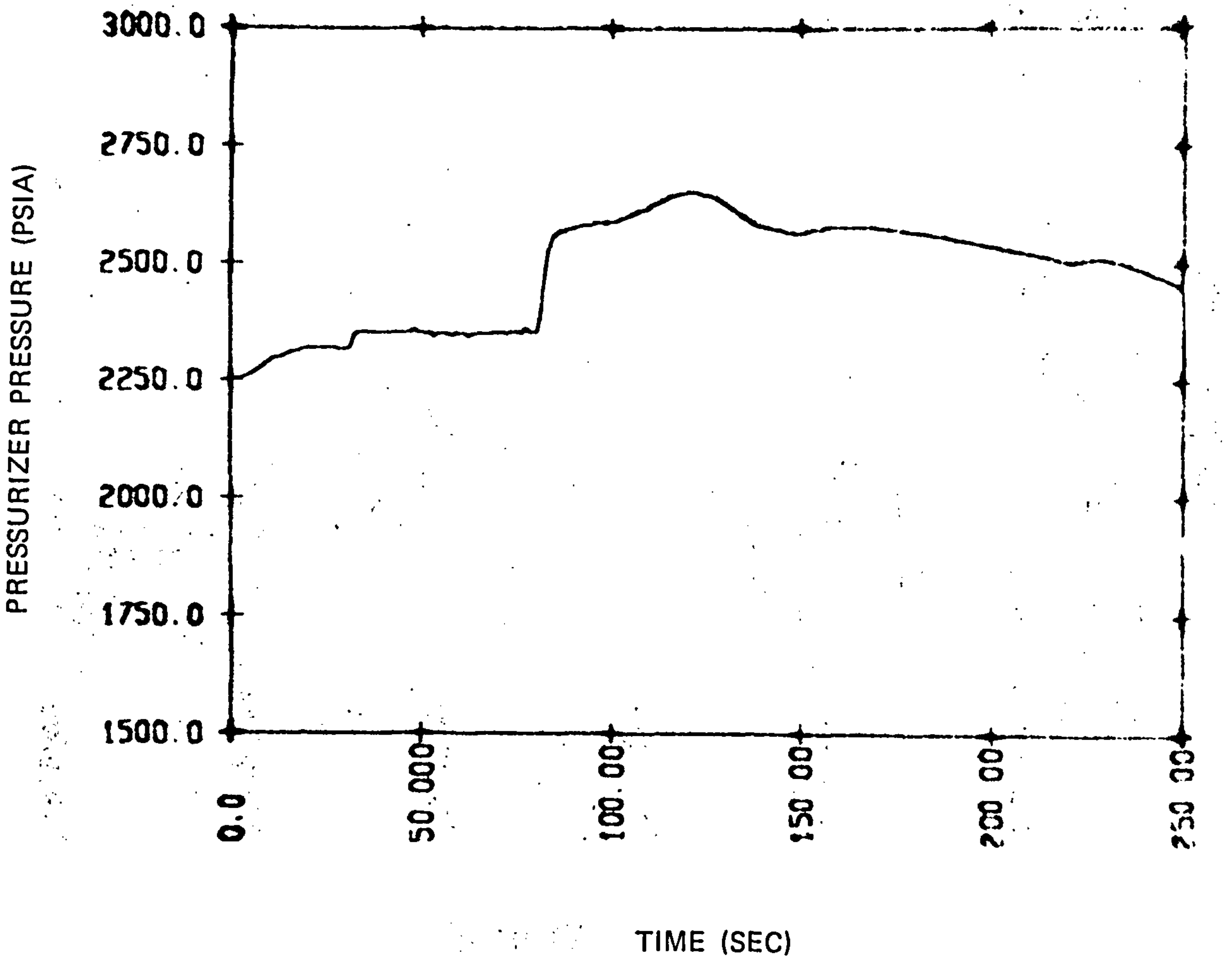

Figure 4-130. Loss of Feedwater – 3-Loop Plant (Pressurizer Pressure vs. Time)

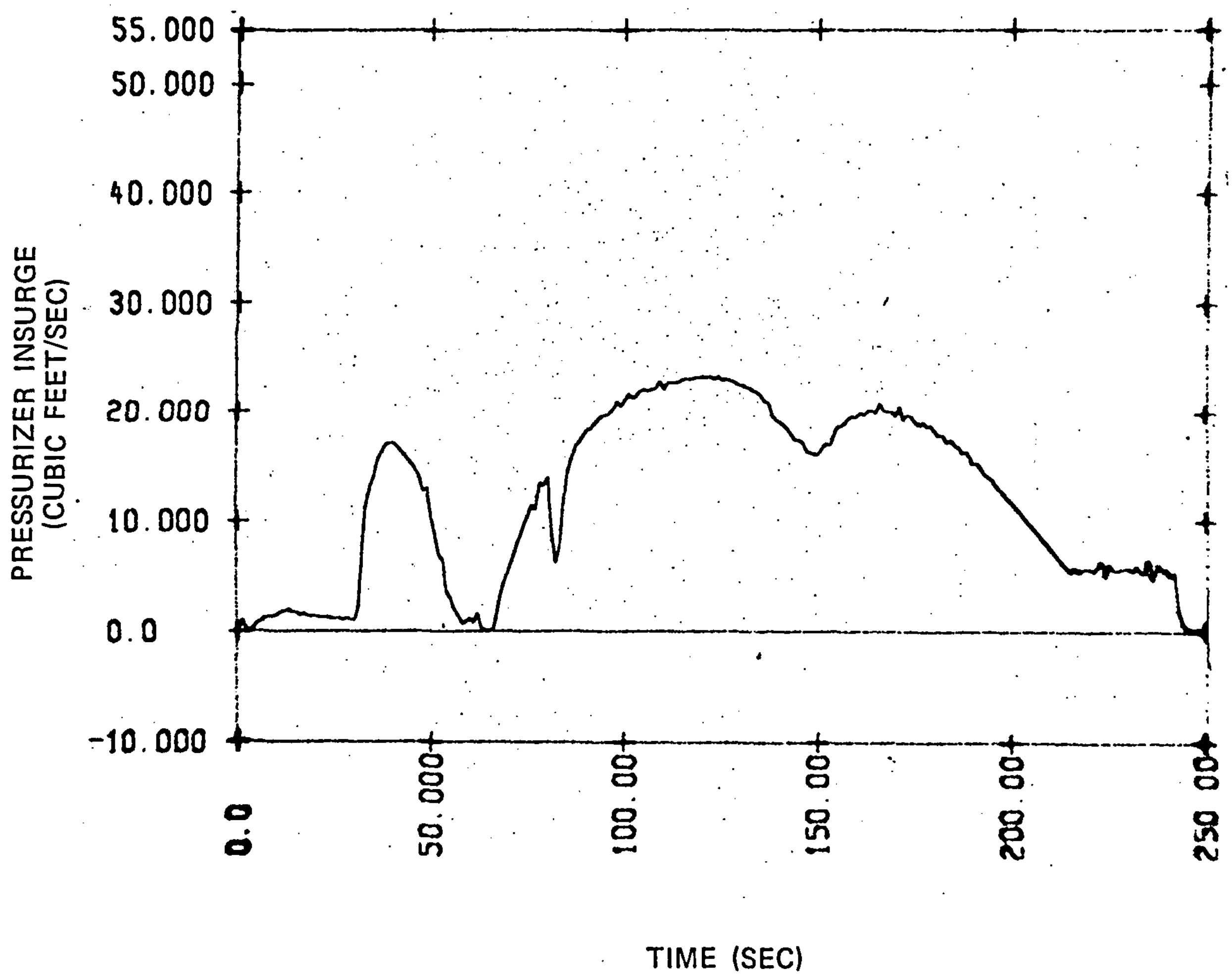

Figure 4-131. Loss of Feedwater – 3-Loop Plant
(Pressurizer Insurge vs. Time)

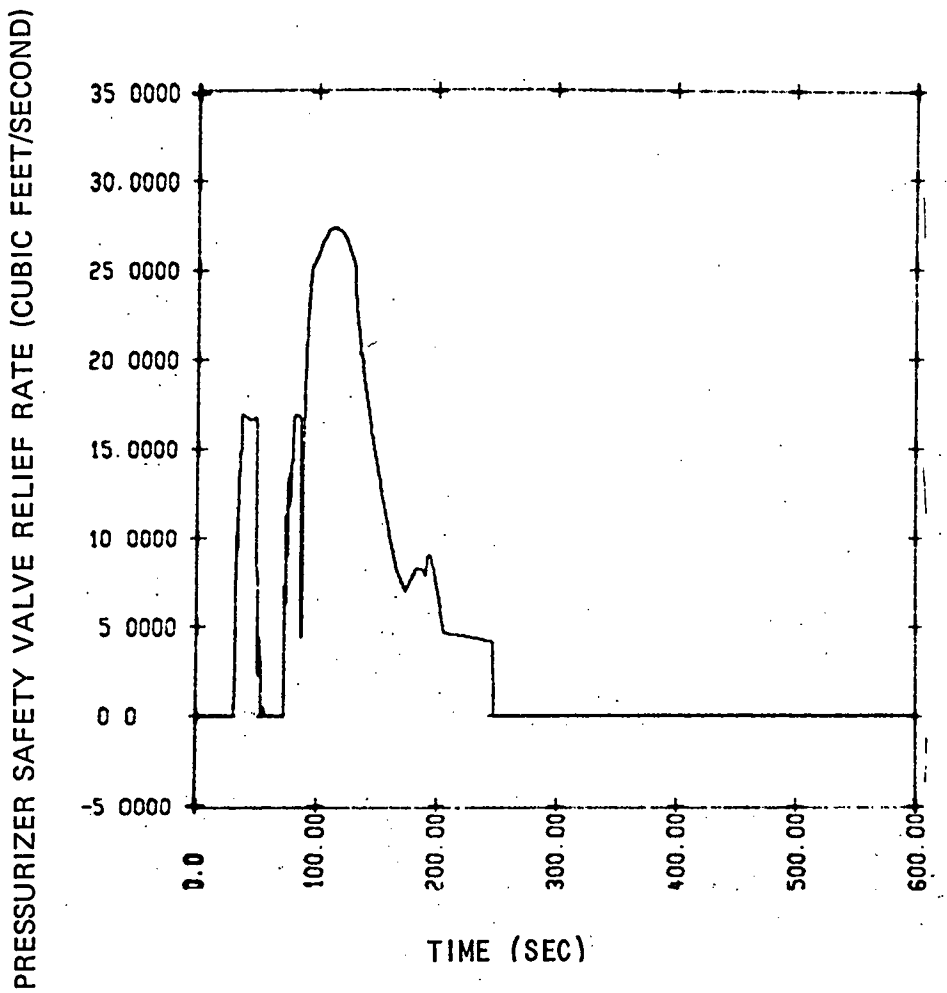

Figure 4-132. Loss of Feedwater — Reference Case
(Pressurizer Valve Relief Rate vs. Time)

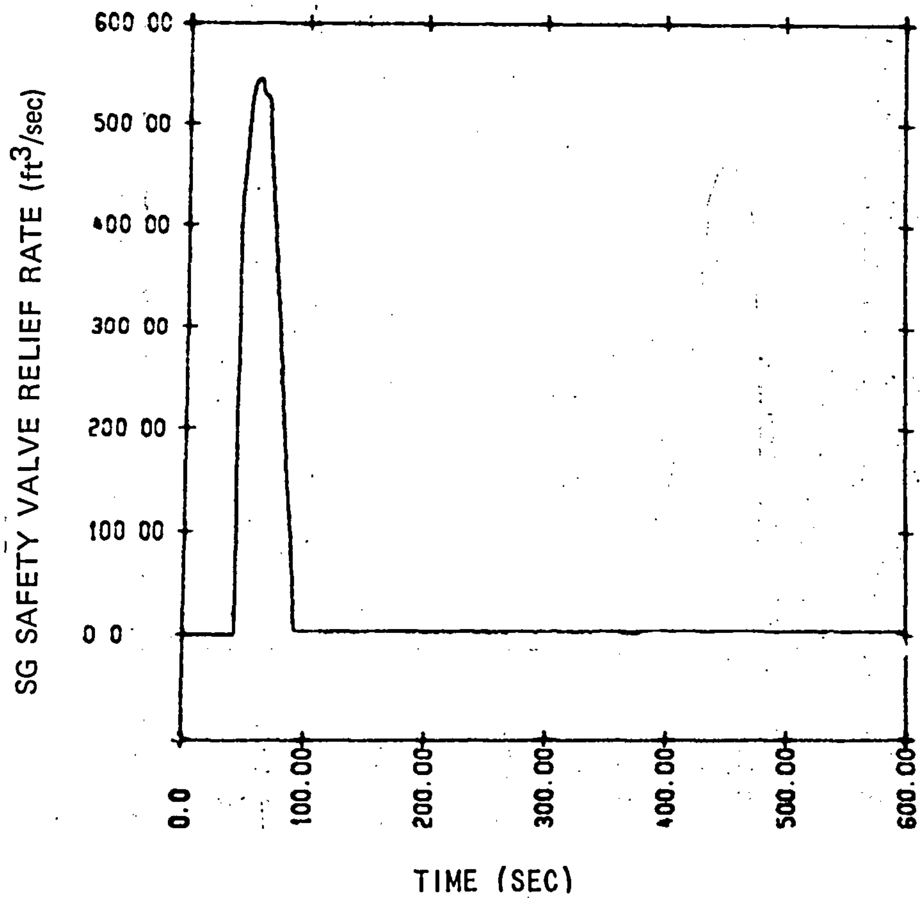

Figure 4-133. Loss of Feedwater - Reference Case (SG Safety Valve Relief Rate vs. Time)

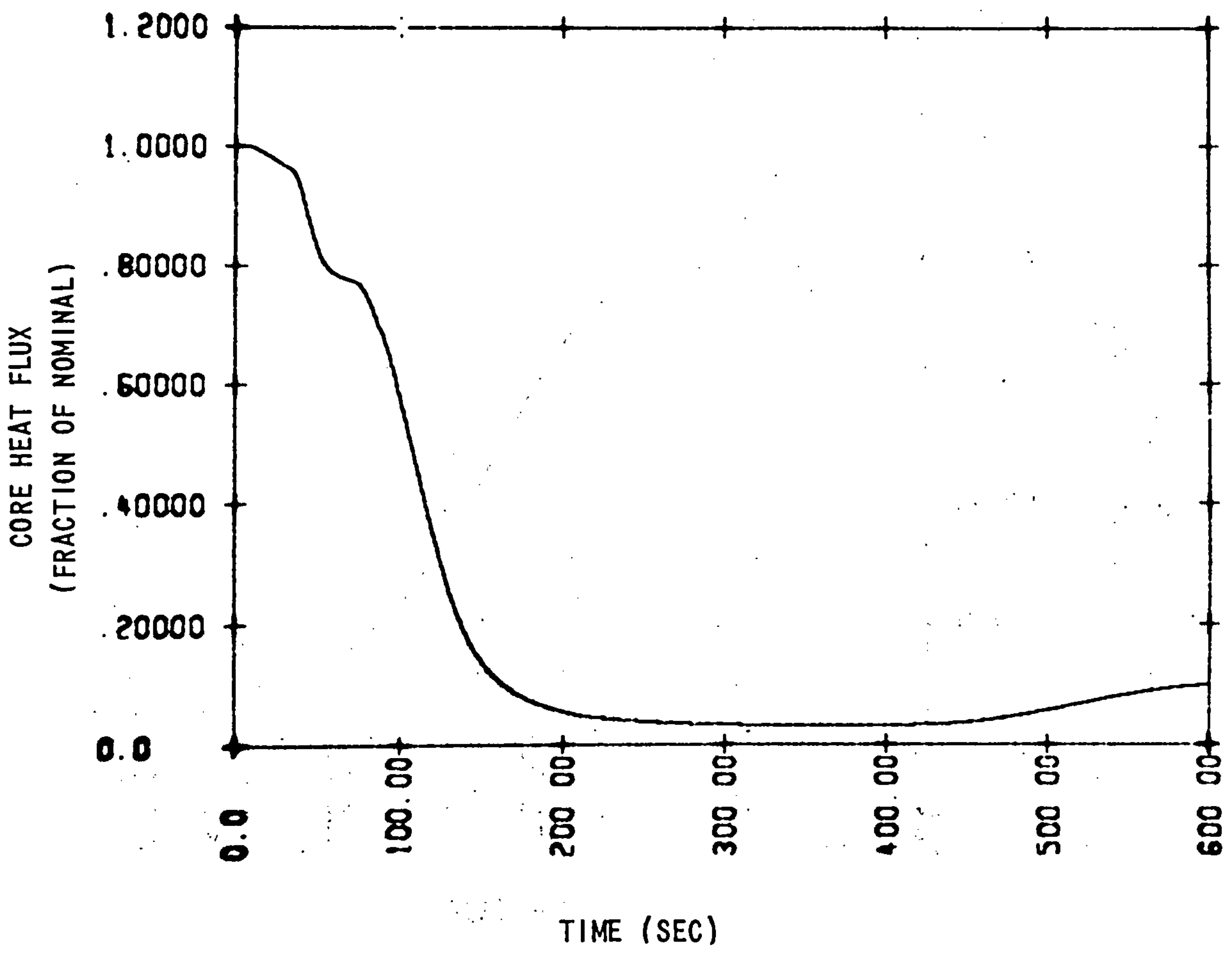

Figure 4-134. Loss of Feedwater - Reference Case (Core Heat Flux vs. Time)

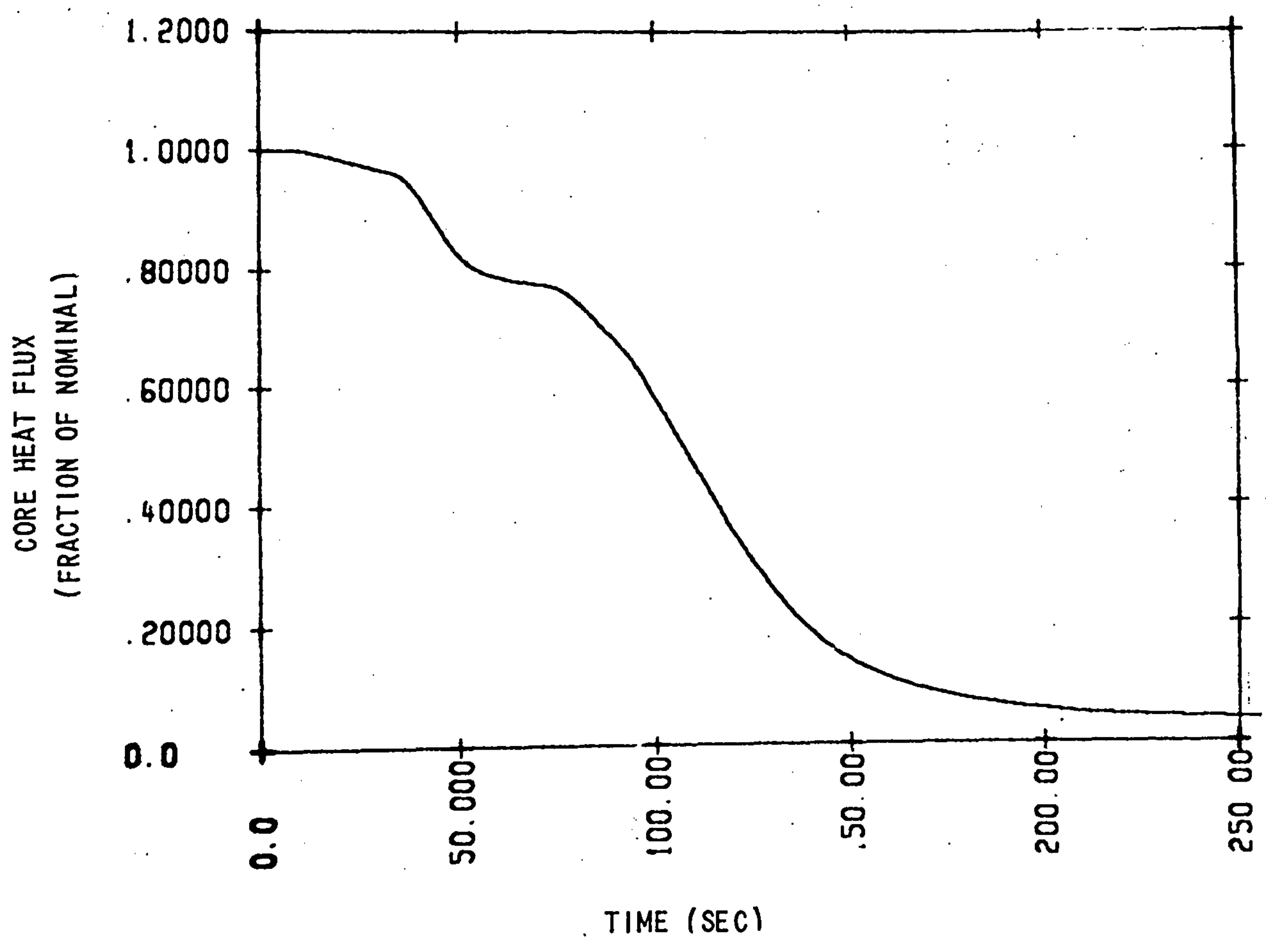

Figure 4-135. Loss of Feedwater - Reference Case
(Core Heat Flux vs. Time)

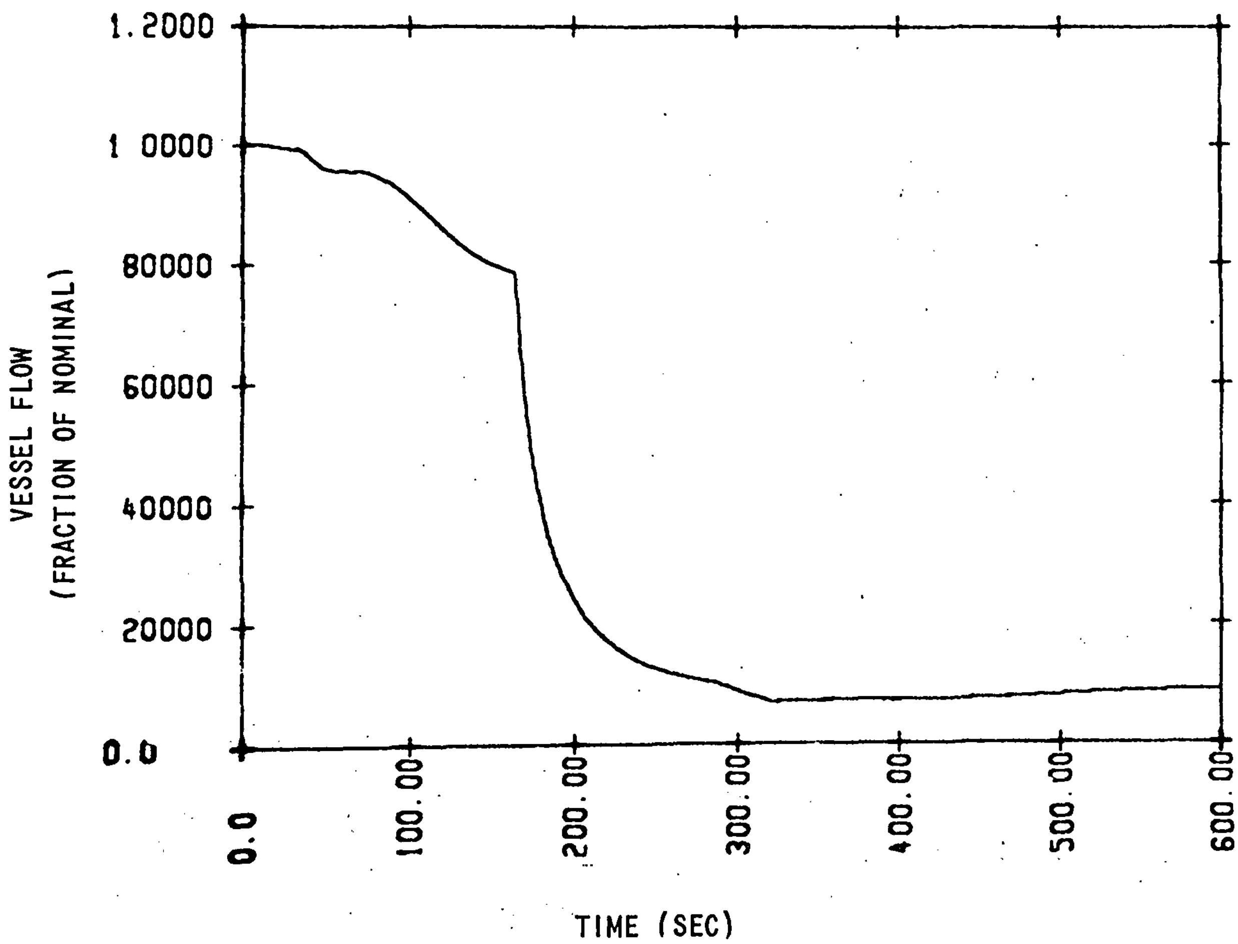

Figure 4-136. Loss of Feedwater - Reference Case
(Vessel Flow vs. Time)

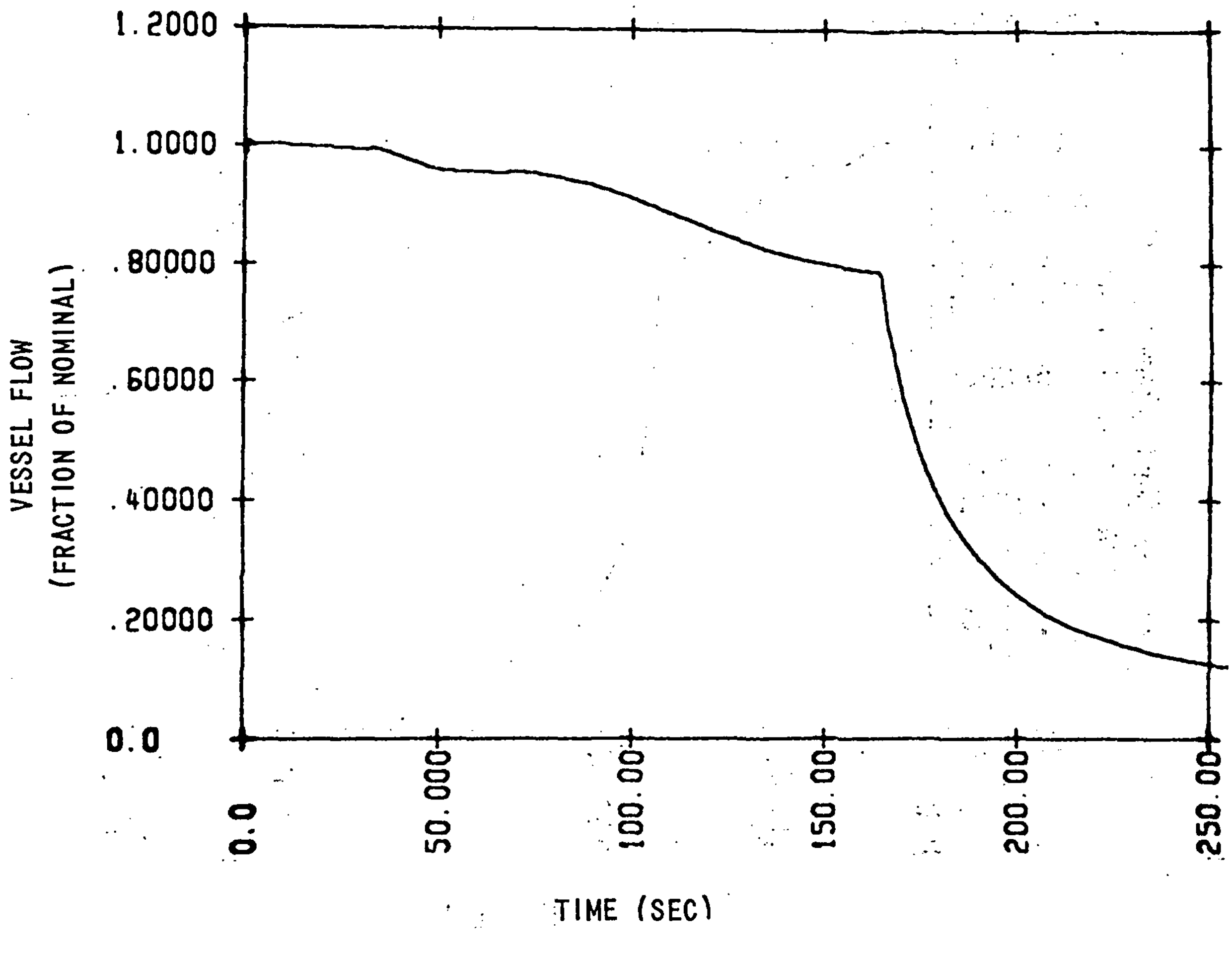

Figure 4-137. Loss of Feedwater - Reference Case
(Vessel Flow vs. Time)

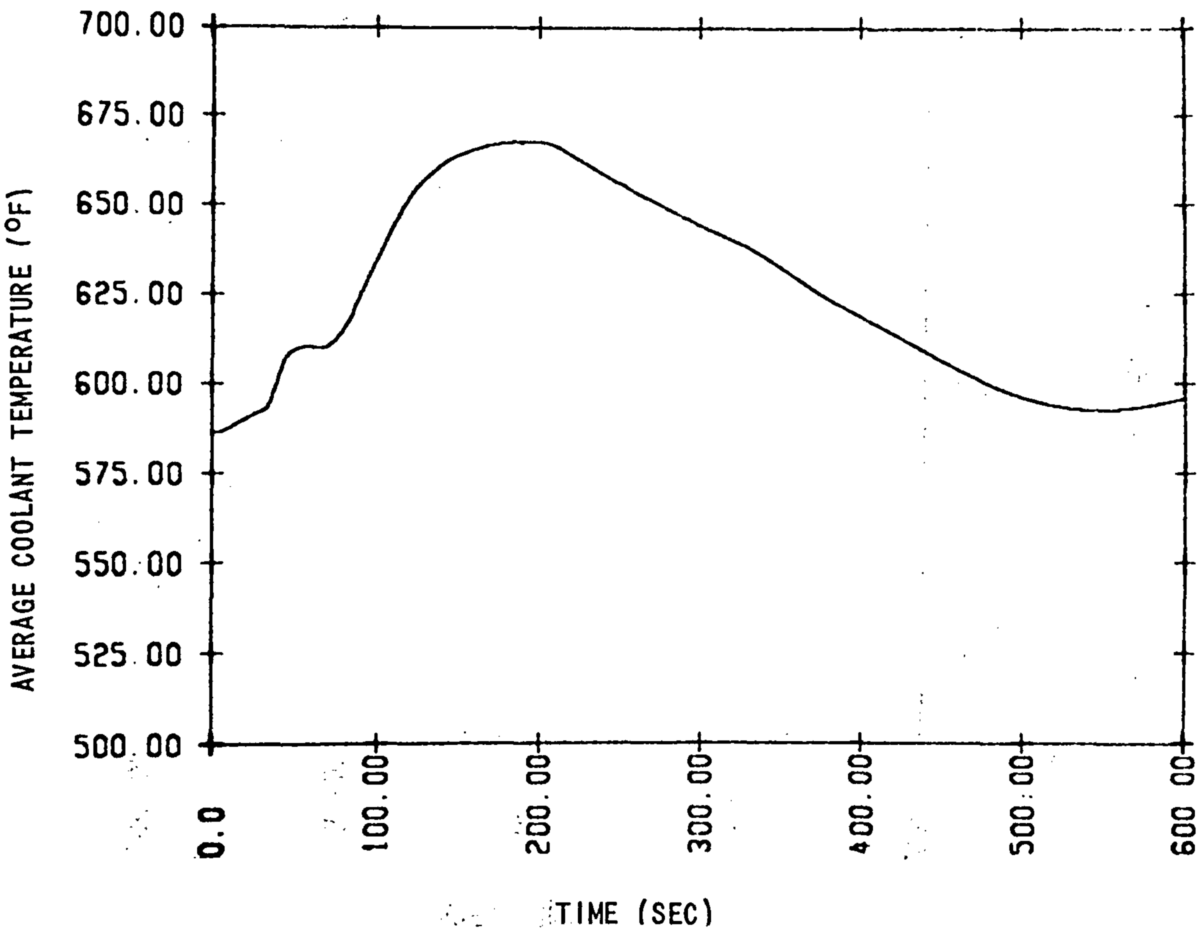

Figure 4-138. Loss of Feedwater - Reference Case (Average Coolant Temperature vs. Time)

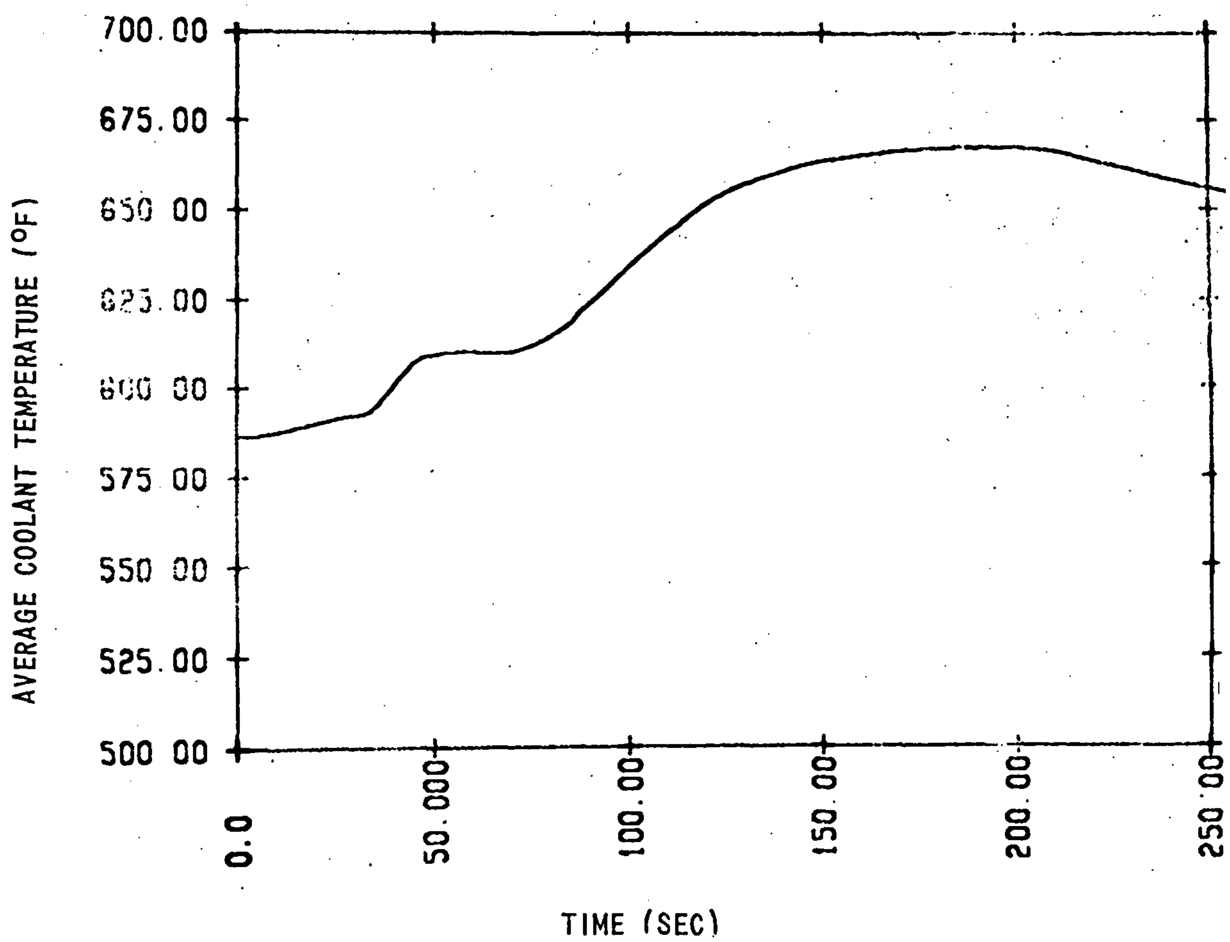

Figure 4-139. Loss of Feedwater - Reference Case
(Average Coolant Temperature vs. Time)

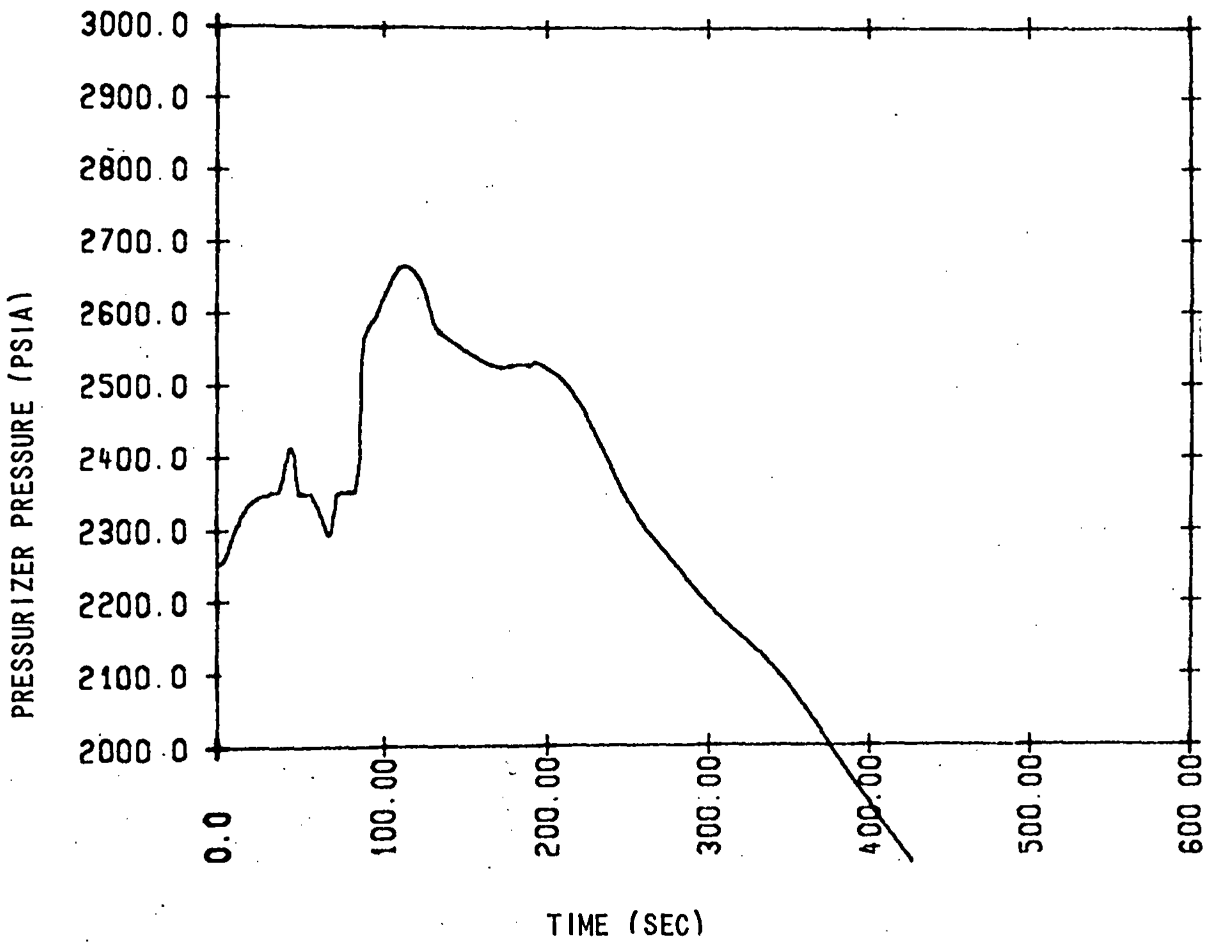

Figure 4-140. Loss of Feedwater - Reference Case
(Pressurizer Pressure vs. Time)

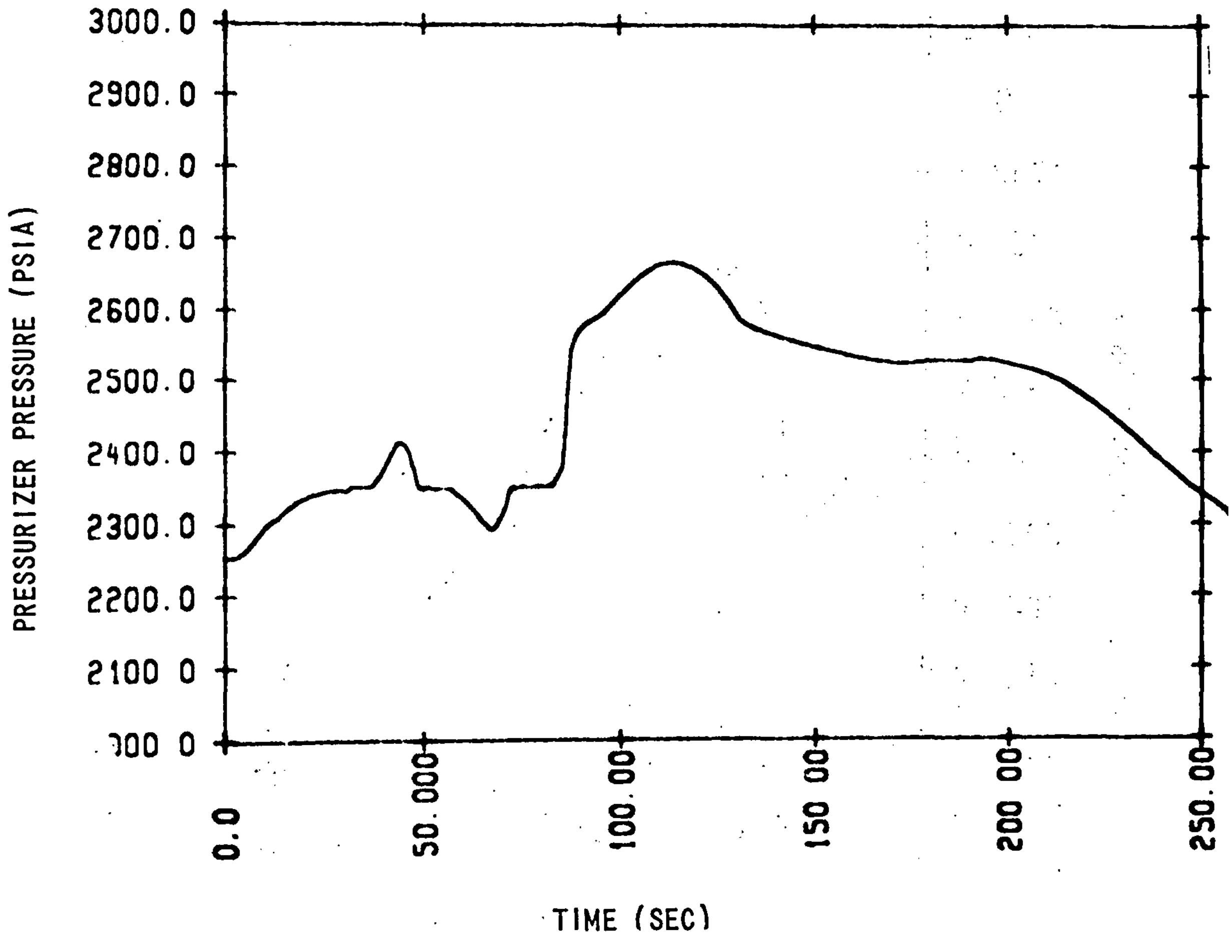

Figure 4-141. Loss of Feedwater - Reference Case
(Pressurizer Pressure vs. Time)

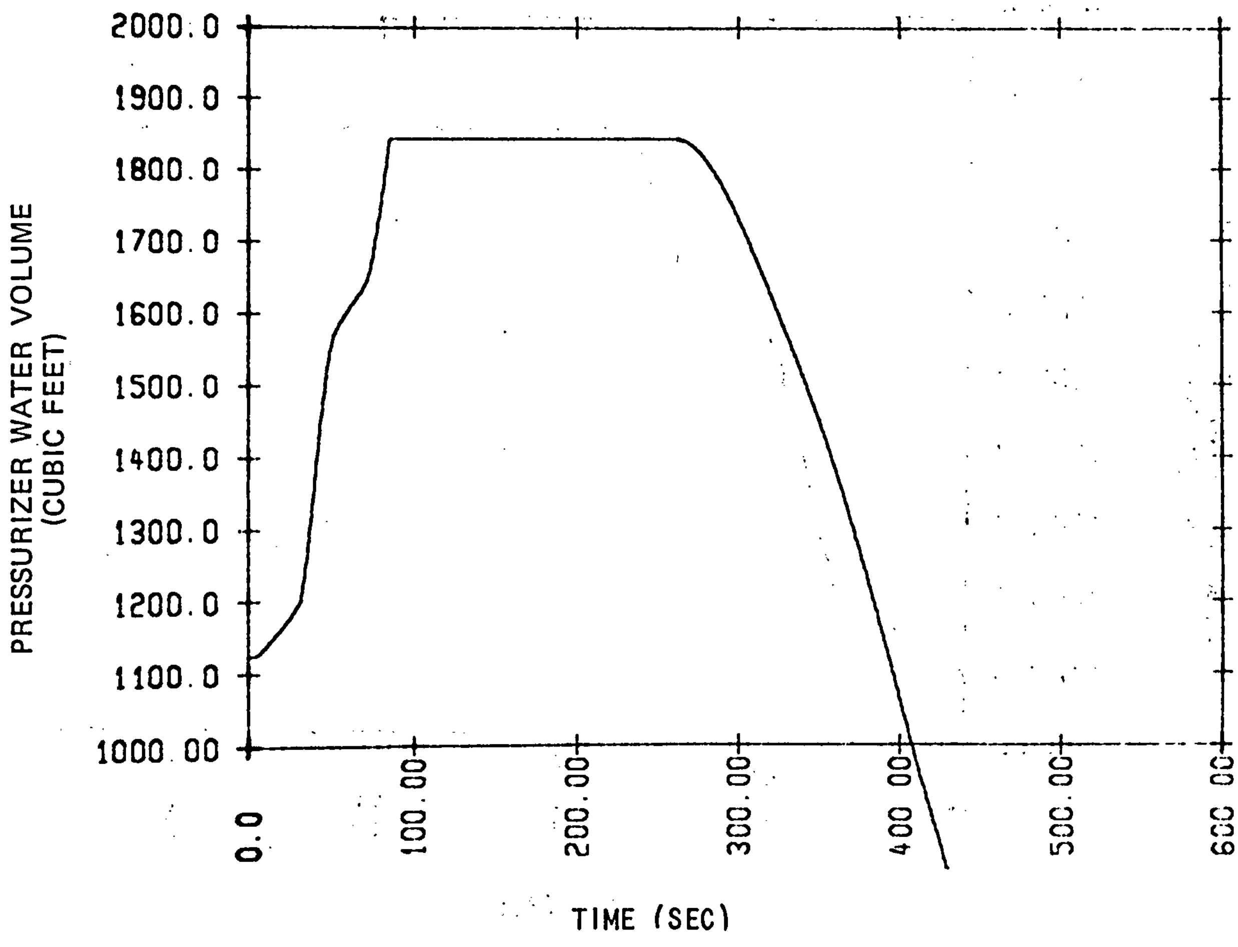

Figure 4-142. Loss of Feedwater — Reference Case
(Pressurizer Water Volume vs. Time)

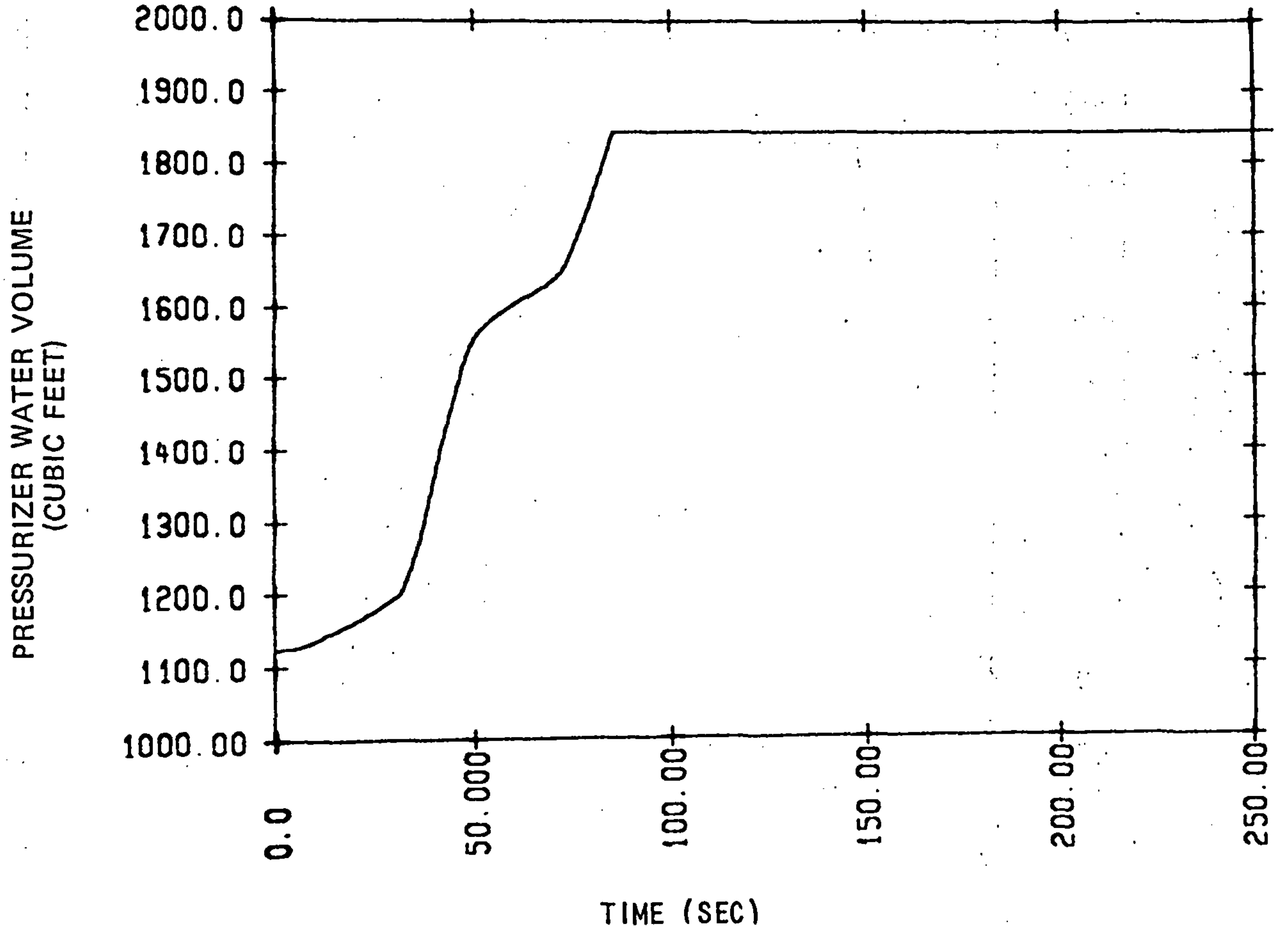

Figure 4-143. Loss of Feedwater – Reference Case
(Pressurizer Water Volume vs. Time)

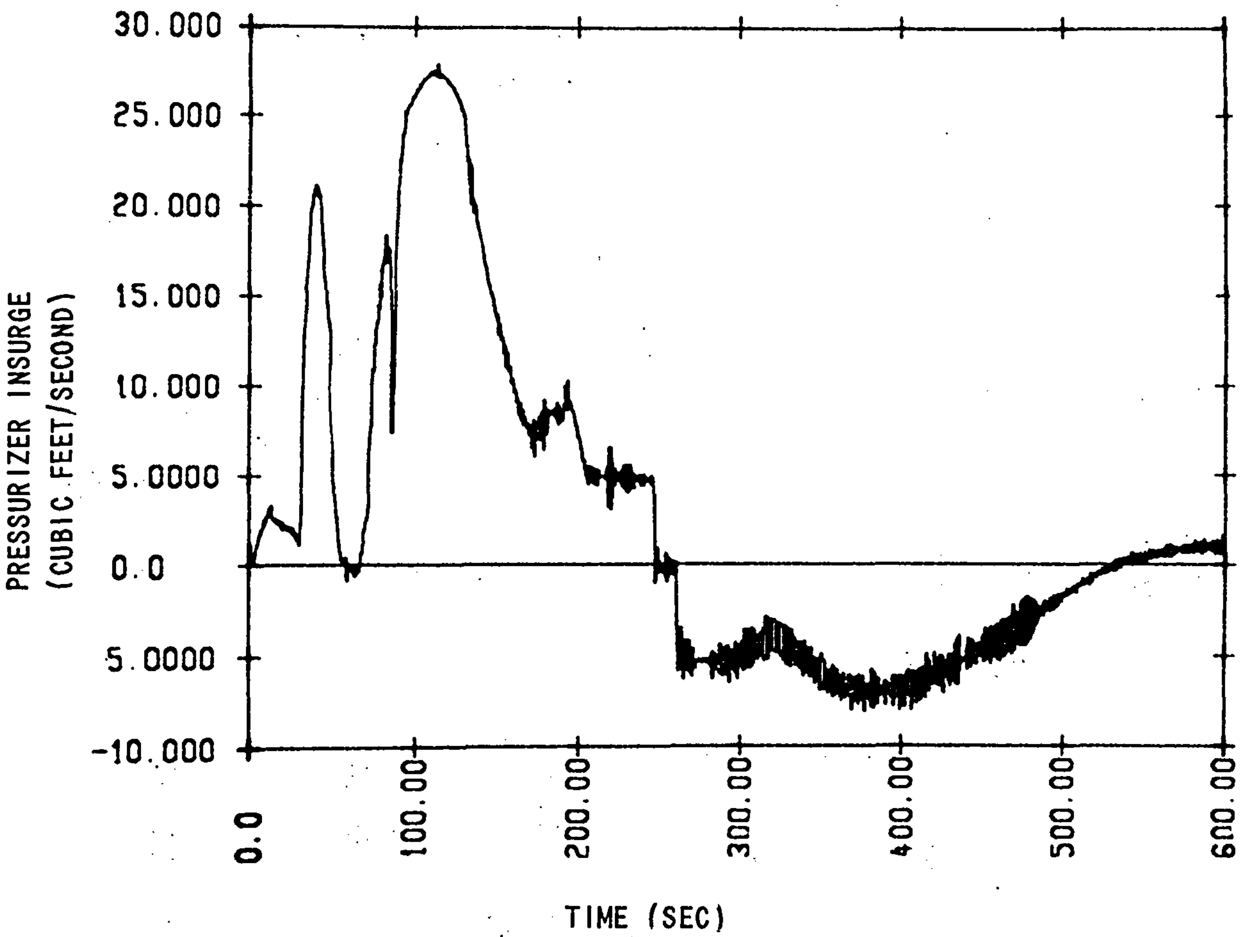

Figure 4-144. Loss of Feedwater - Reference Case
(Pressurizer Insurge vs. Time)

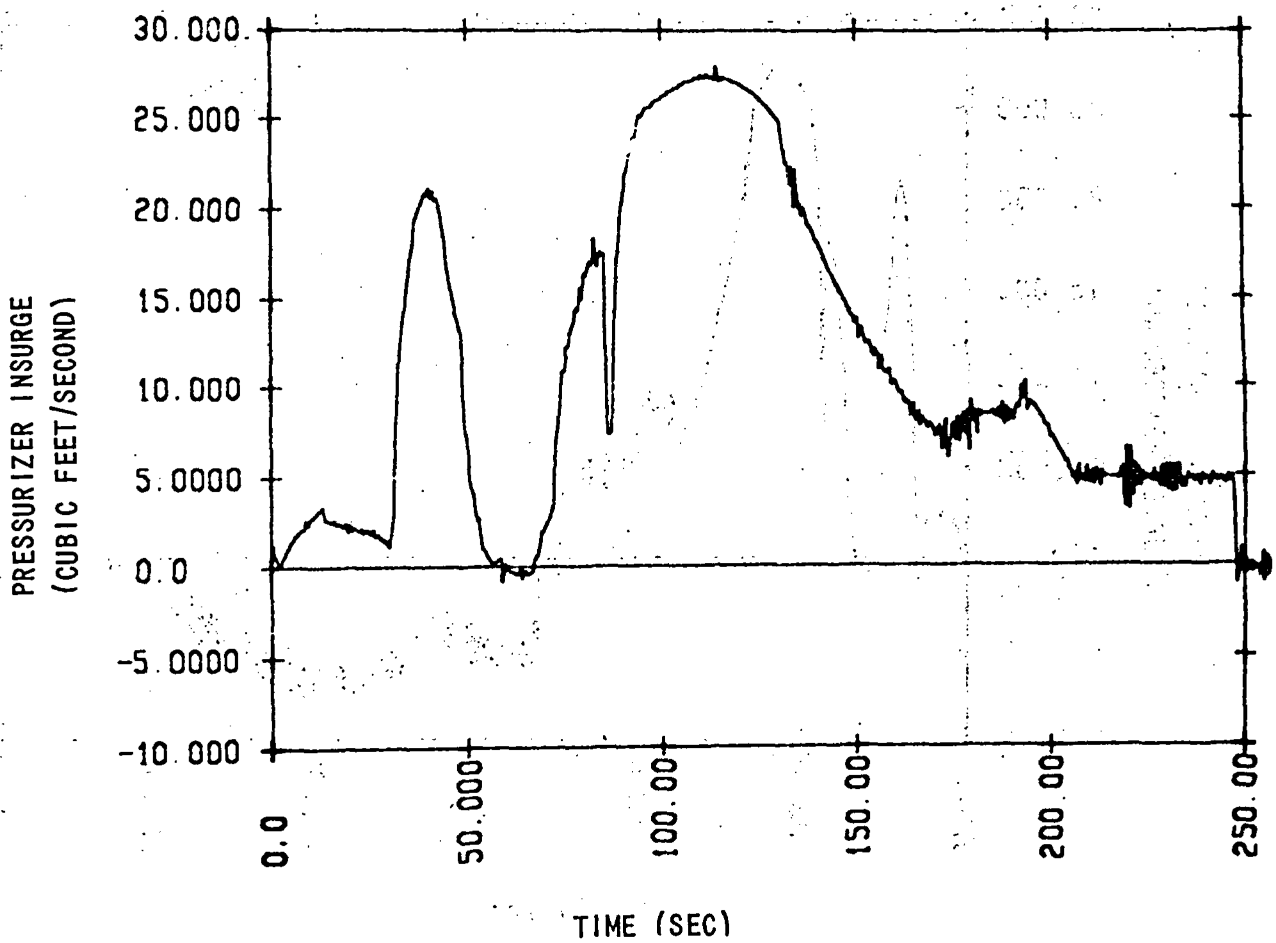

Figure 4-145. Loss of Feedwater – Reference Case
(Pressurizer Insurge vs. Time)

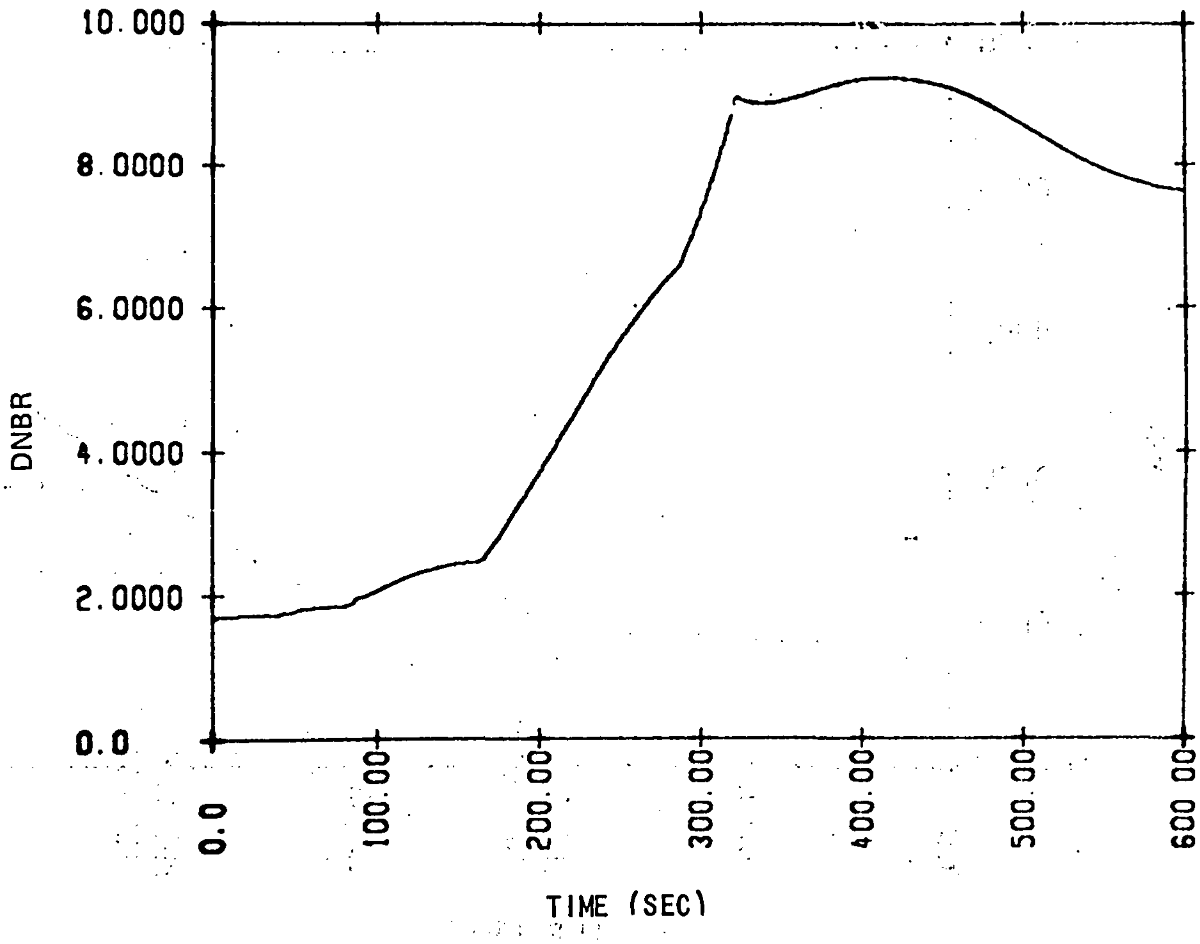

Figure 4-146. Loss of Feedwater - Reference Case
(DNBR vs. Time)

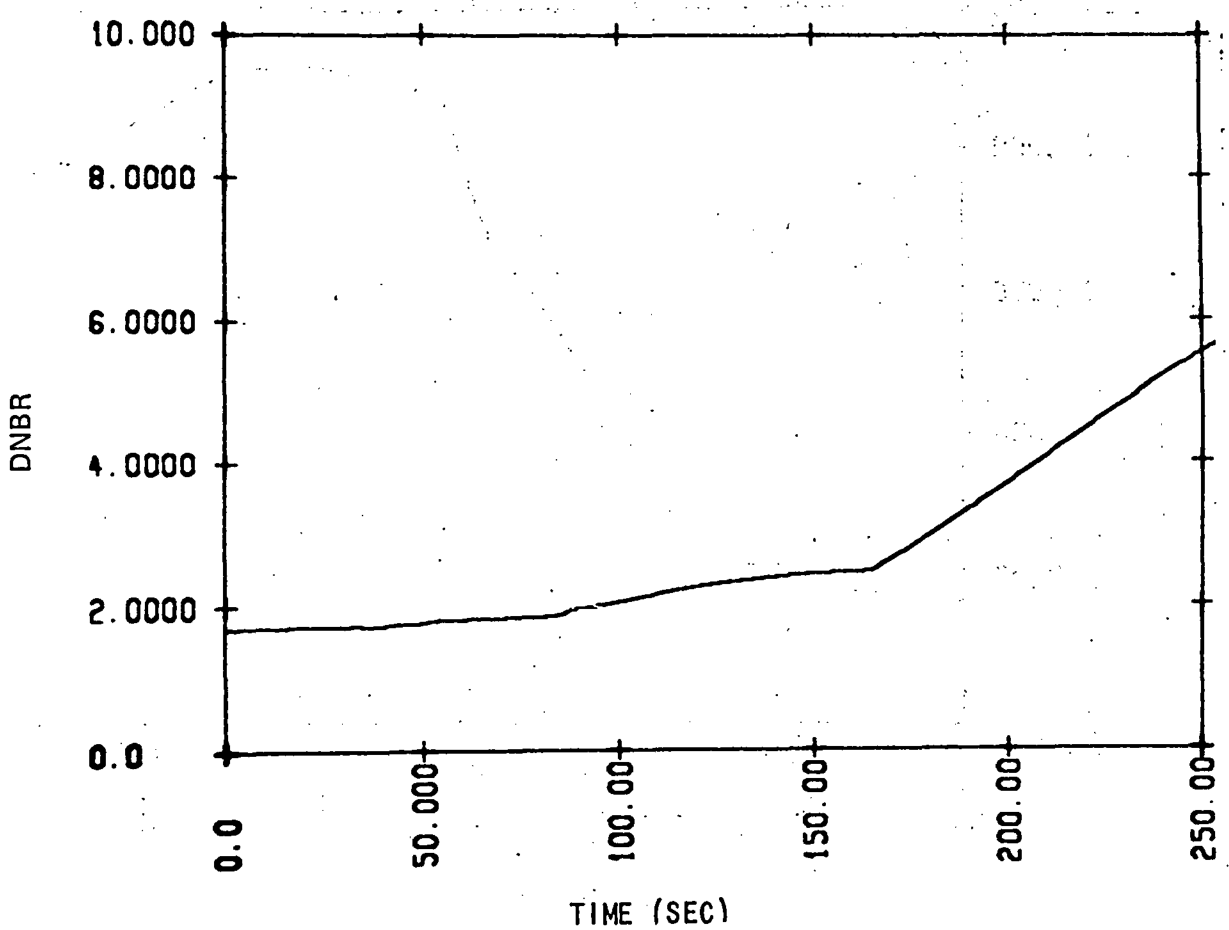

Figure 4-147. Loss of Feedwater - Reference Case
(DNBR vs. Time)

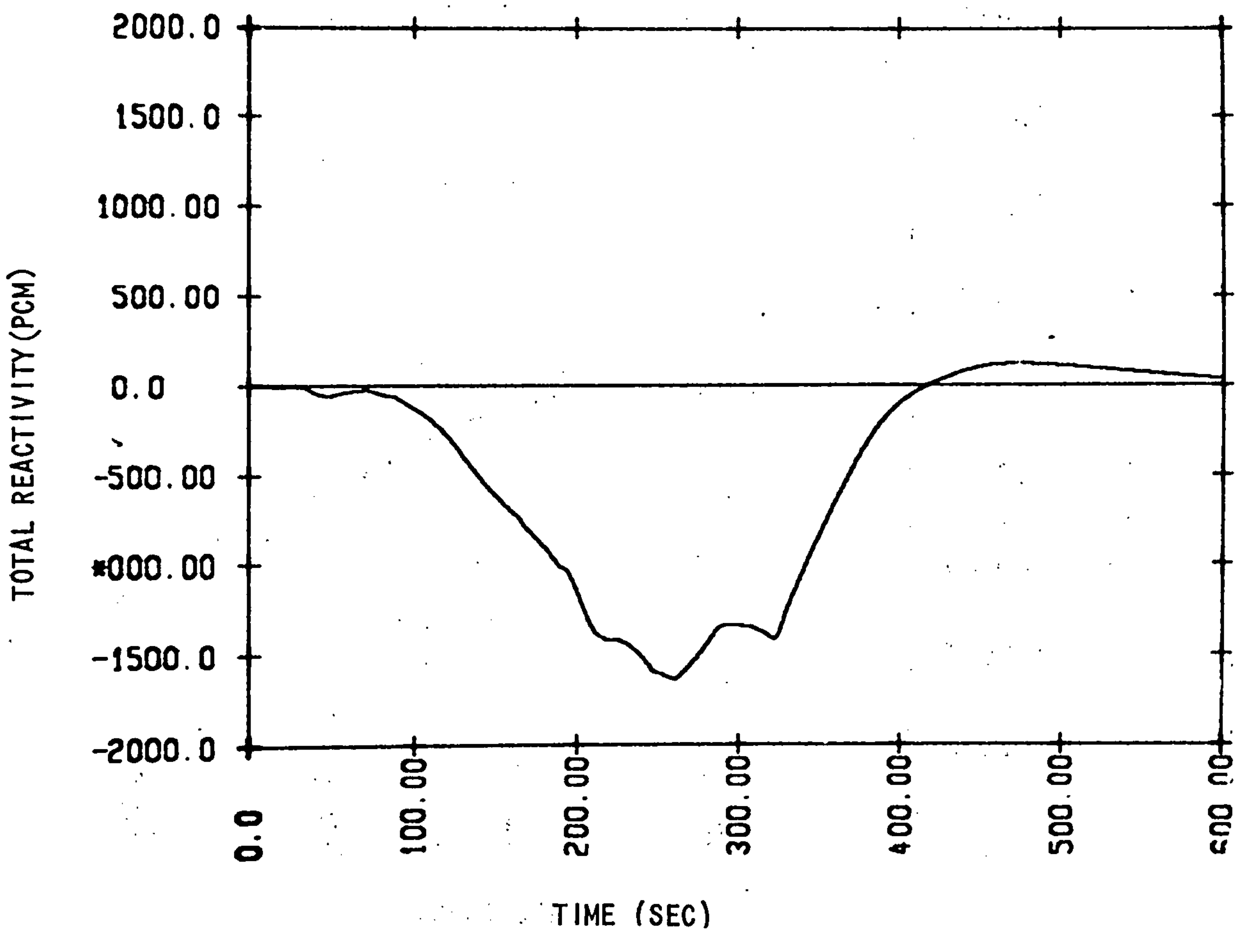

Figure 4-148. Loss of Feedwater - Reference Case
(Total Reactivity vs. Time)

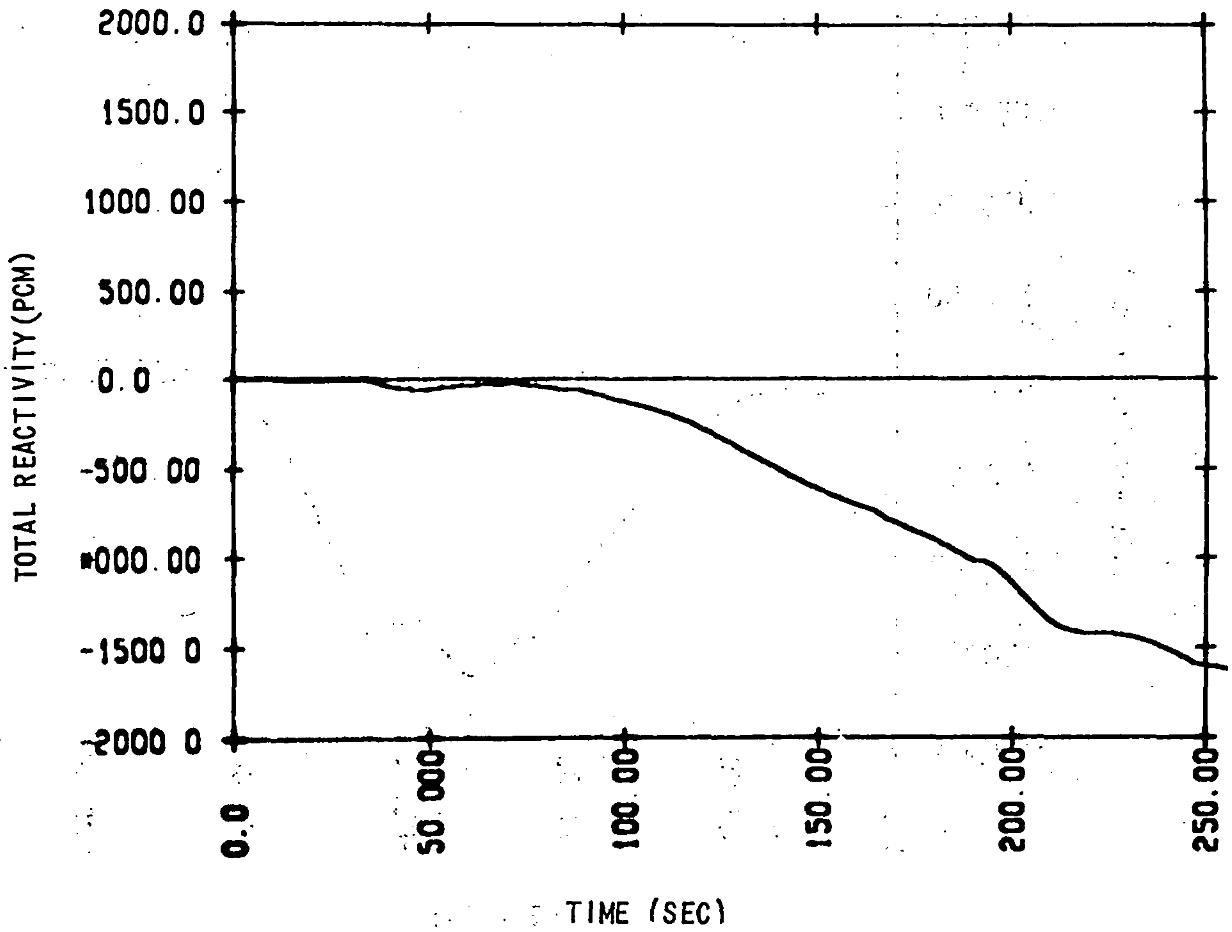

Figure 4-149. Loss of Feedwater - Reference Case (Total Reactivity vs. Time)

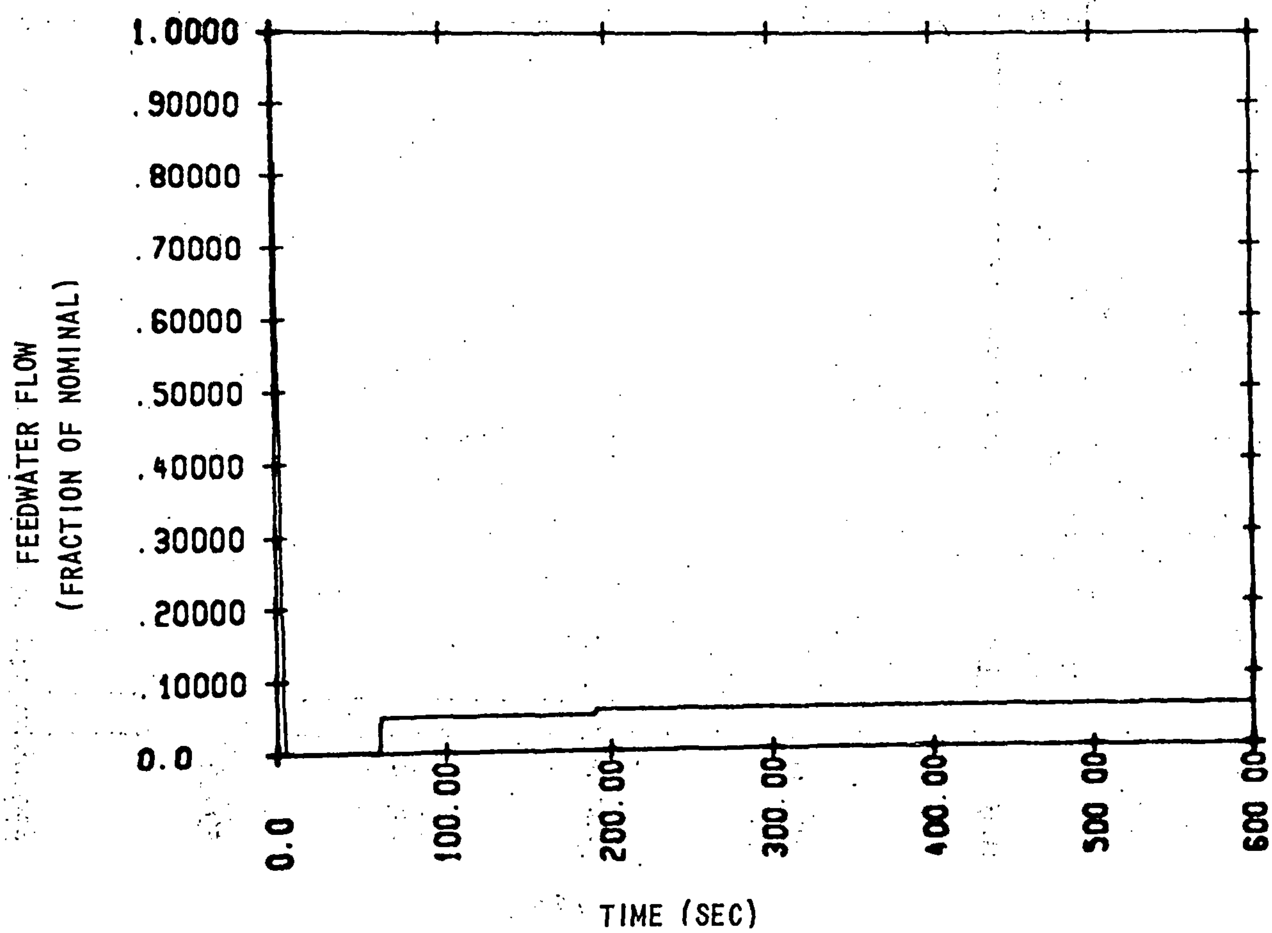

Figure 4-150. Loss of Feedwater - Reference Case
(Feedwater Flow vs. Time)

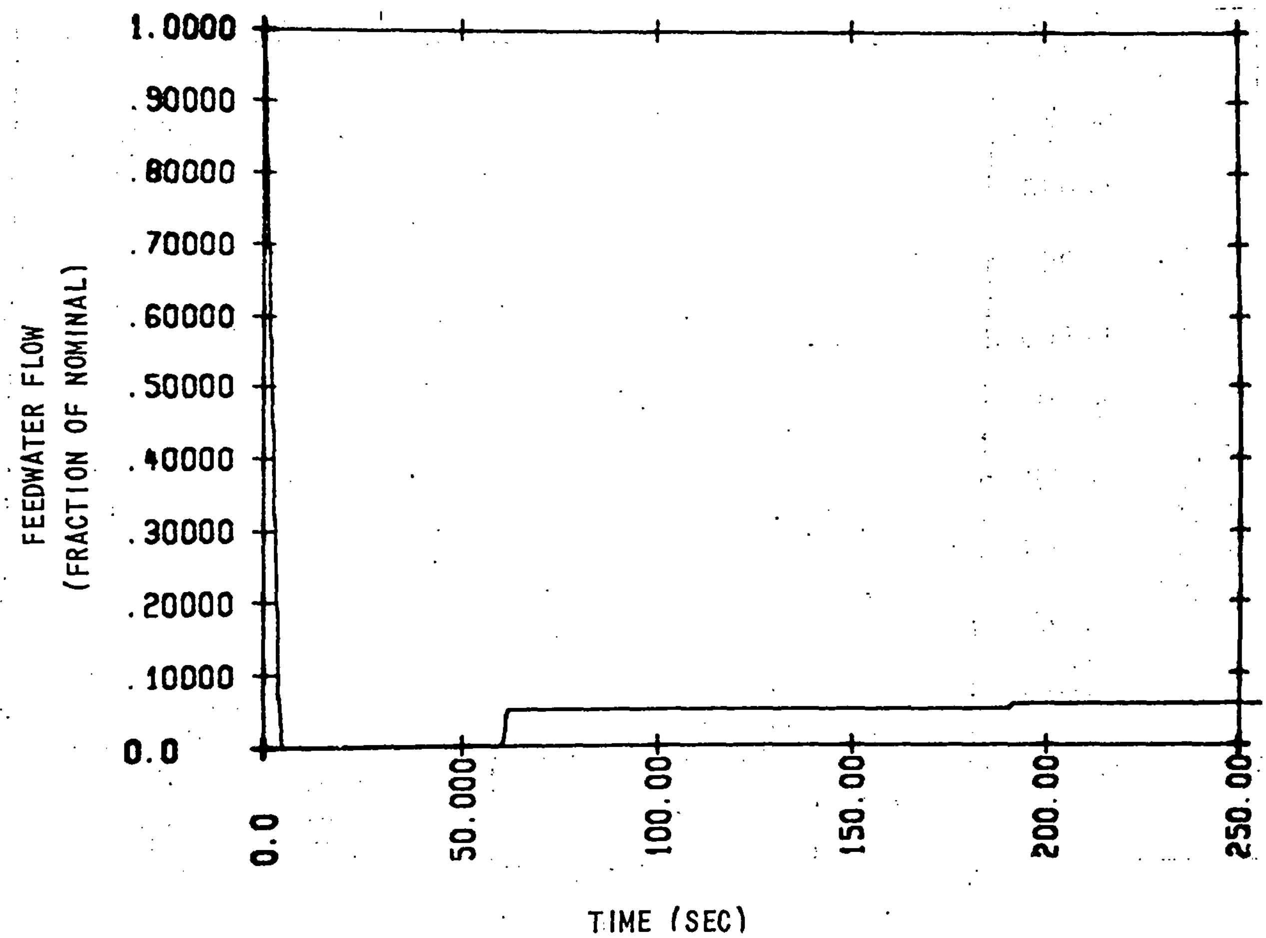

Figure 4-151. Loss of Feedwater - Reference Case
(Feedwater Flow vs. Time)

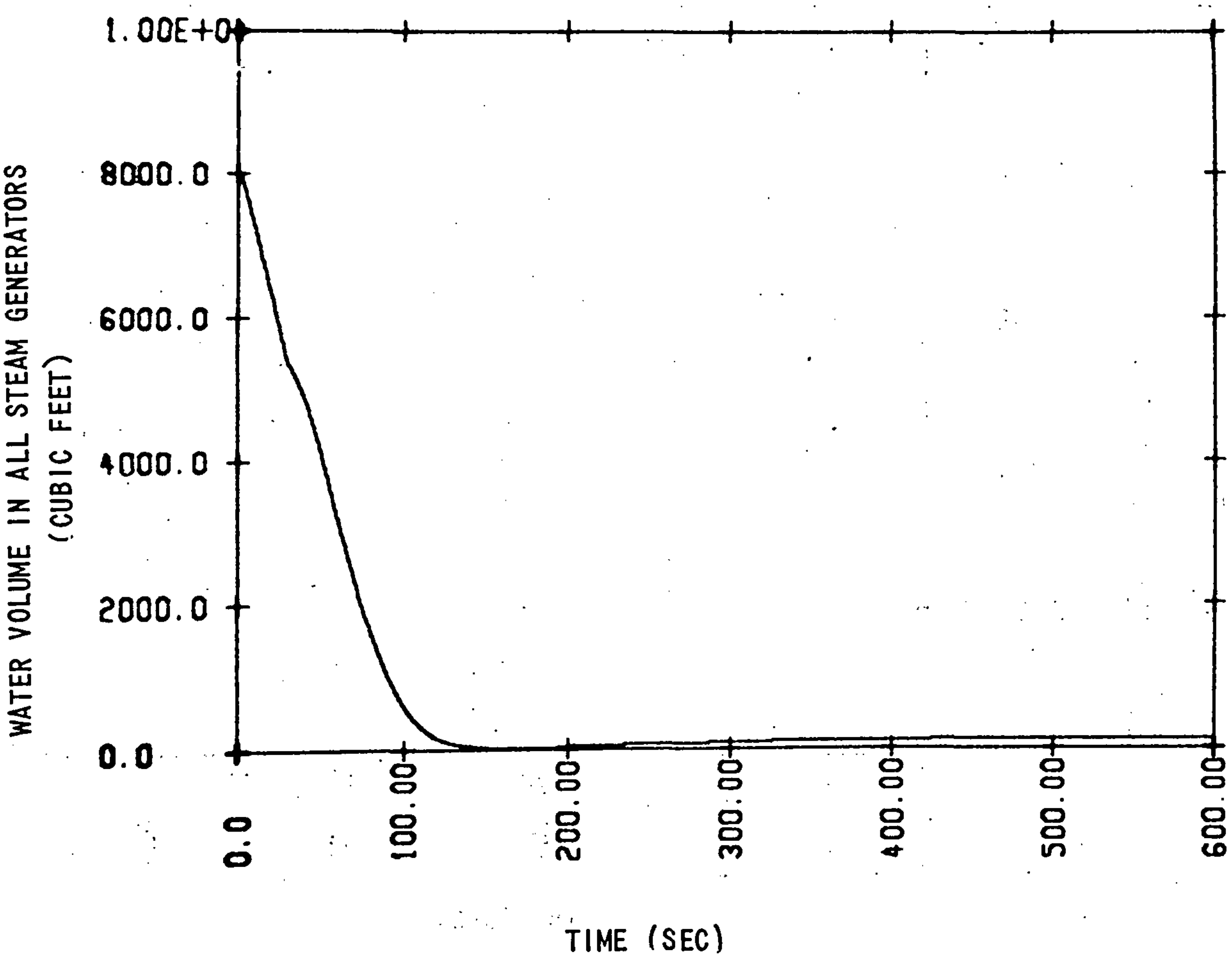

Figure 4-152. Loss of Feedwater – Reference Case
(Water Volume in All Steam Generators vs. Time)

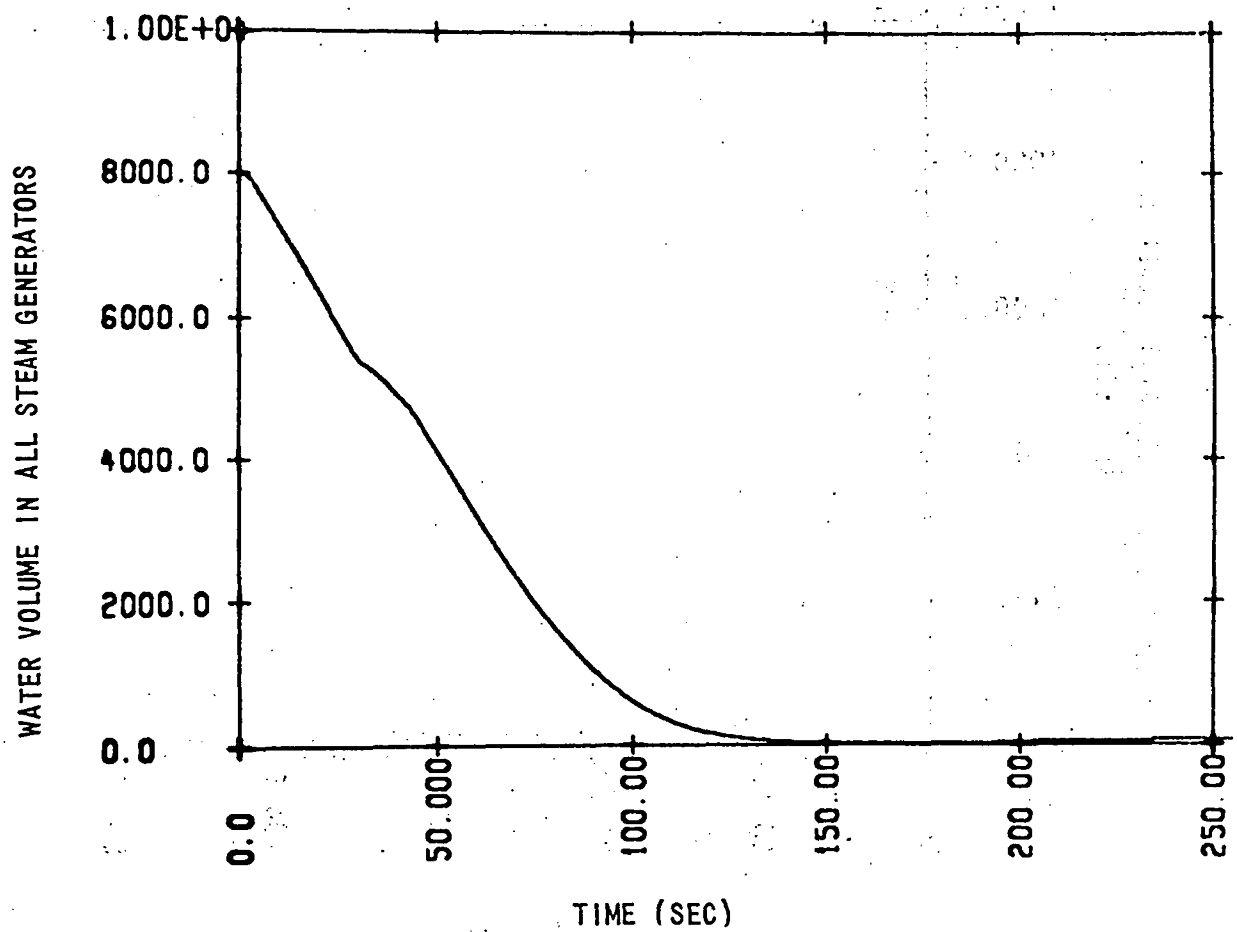

Figure 4-153. Loss of Feedwater – Reference Case
(Water Volume in All Steam Generators vs. Time)

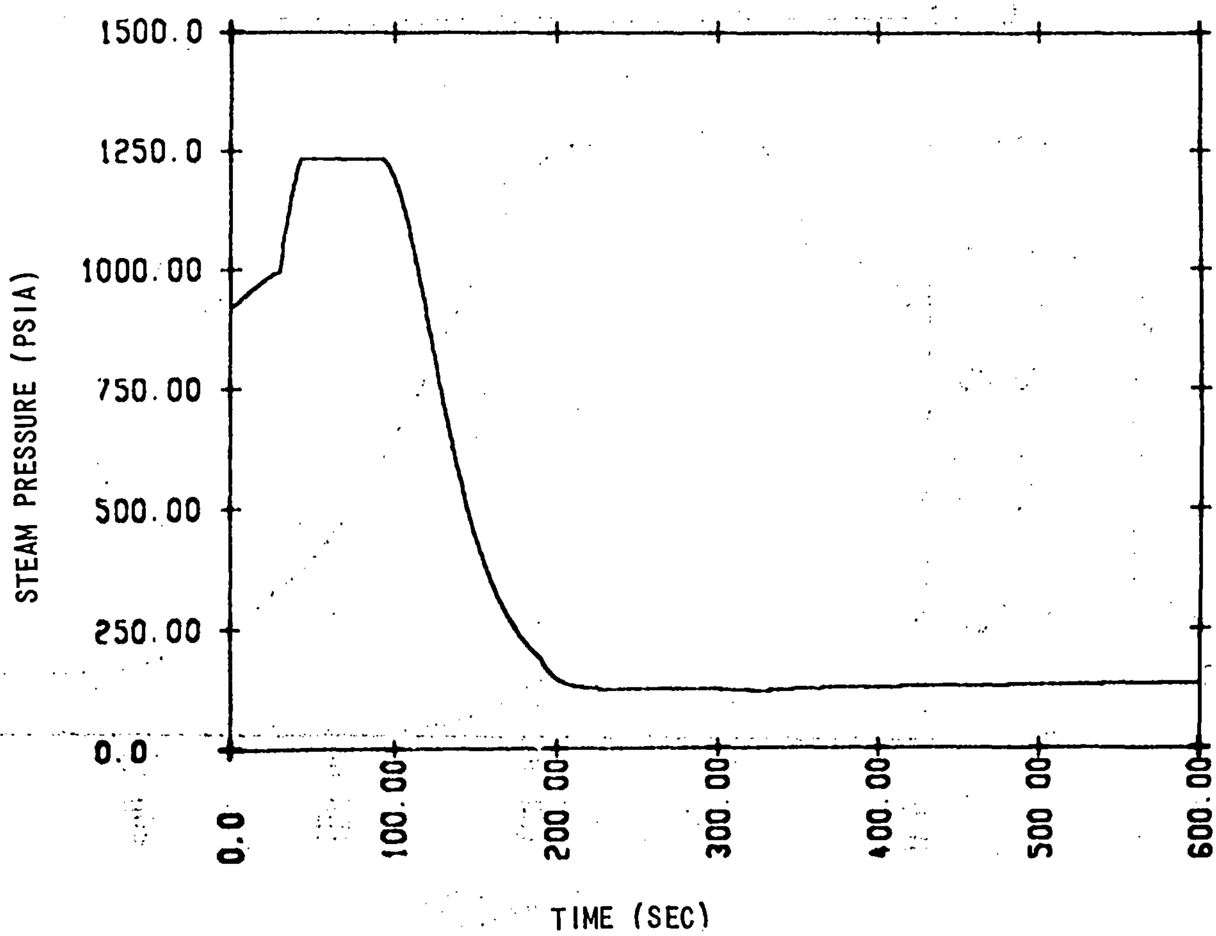

Figure 4-154. Loss of Feedwater – Reference Case
(Steam Pressure vs. Time)

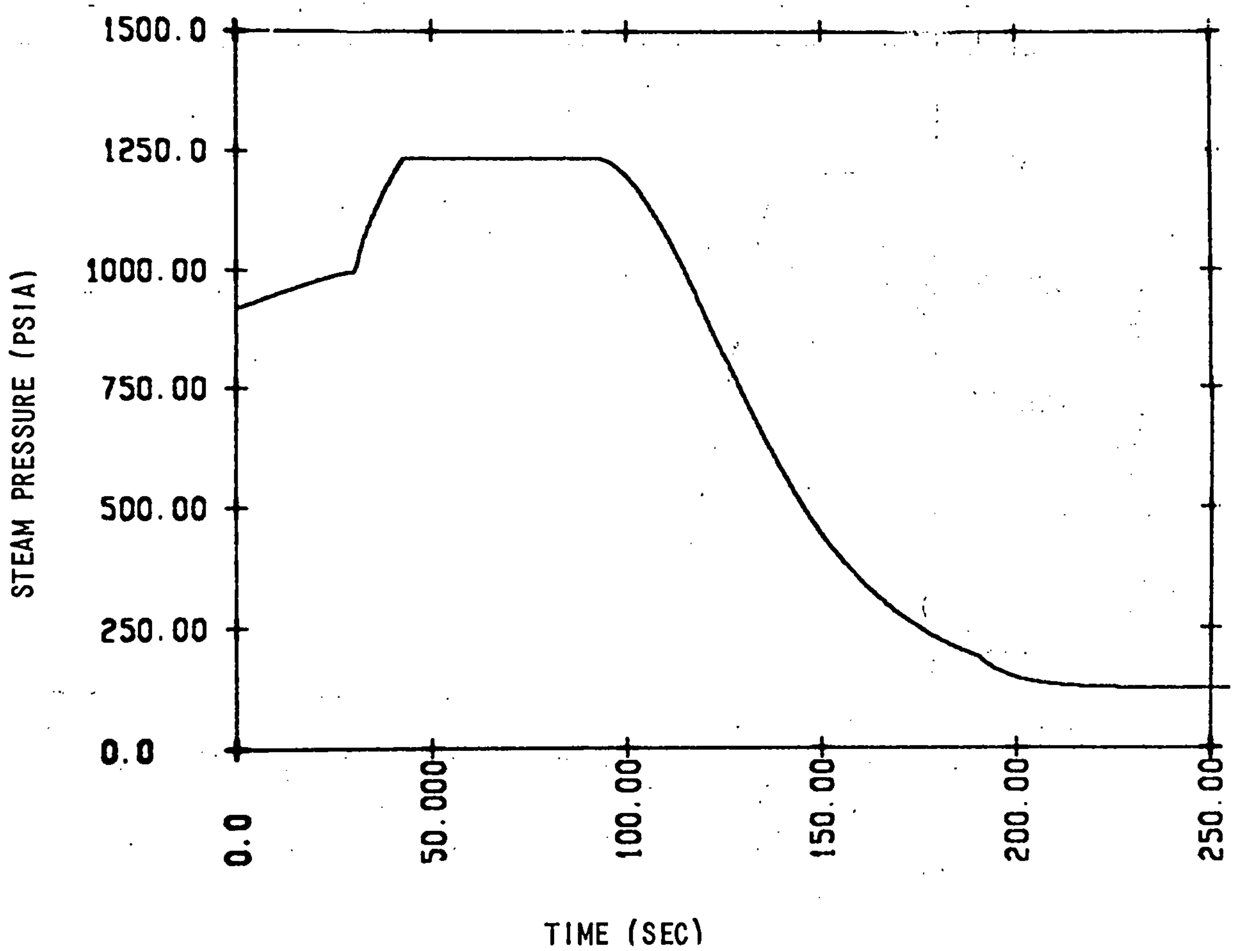

Figure 4-155. Loss of Feedwater - Reference Case
(Steam Pressure vs. Time)

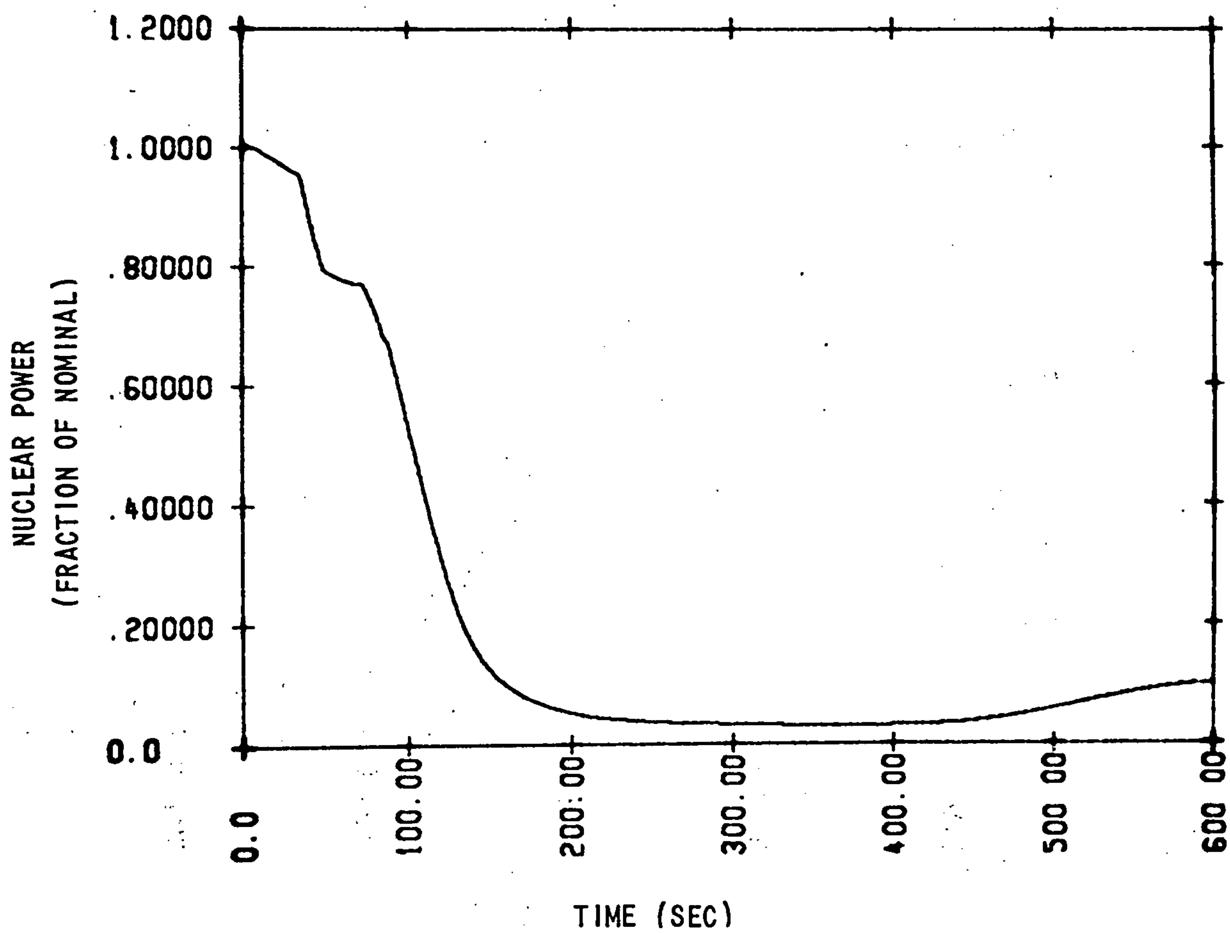

Figure 4-156. Loss of Feedwater - Reference Case
(Nuclear Power vs. Time)

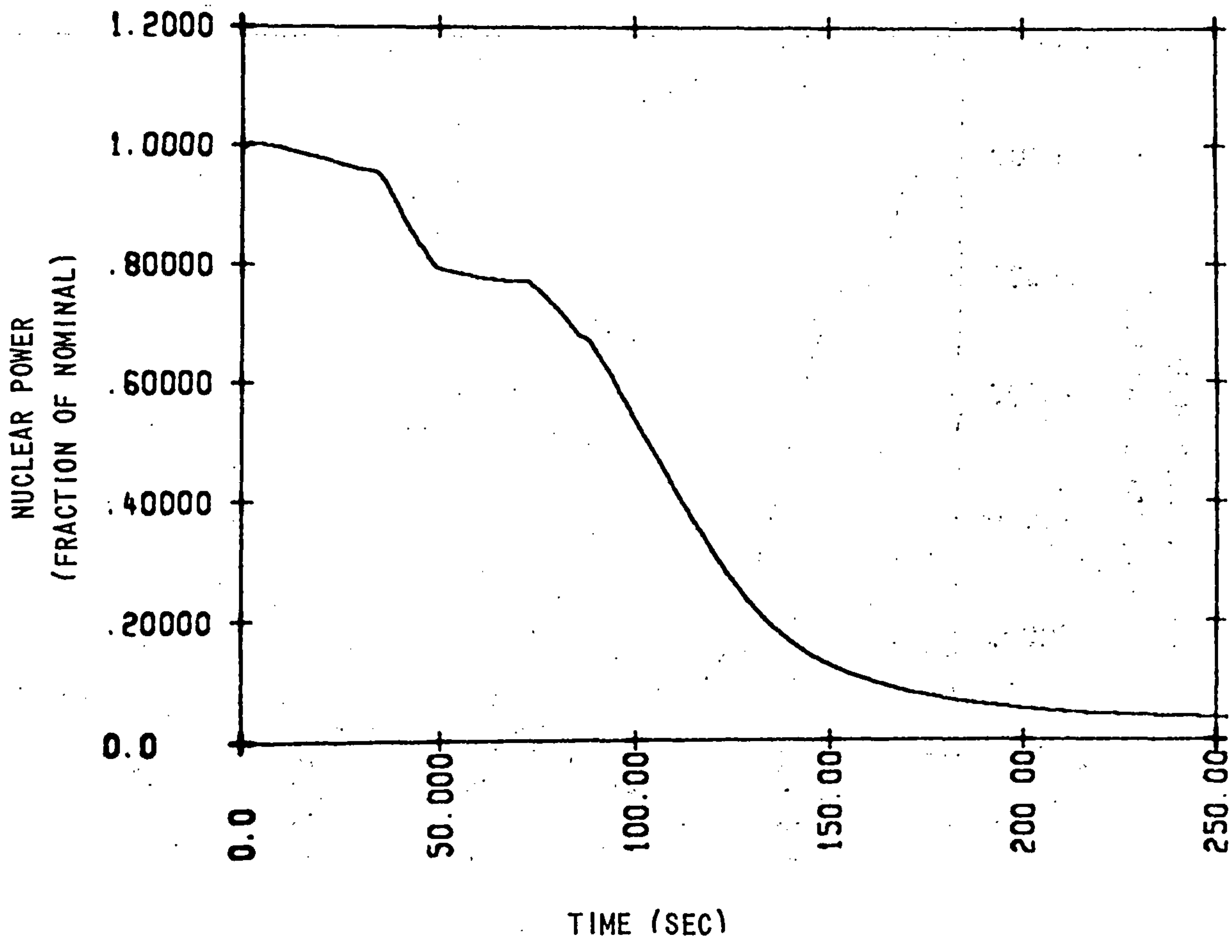

Figure 4-157. Loss of Feedwater - Reference Case
(Nuclear Power vs. Time)

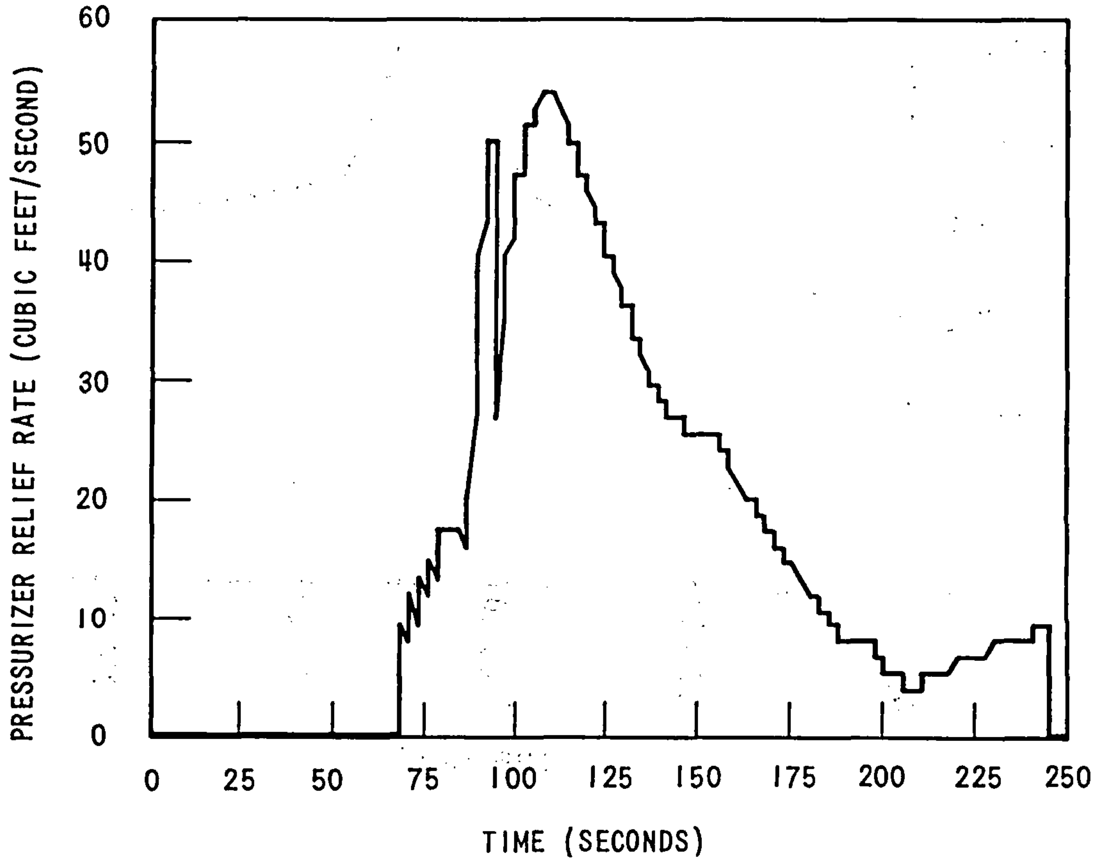

Figure 4-158 Loss of Feedwater - No Turbine Trip
(Pressurizer Relief Rate Vs Time)

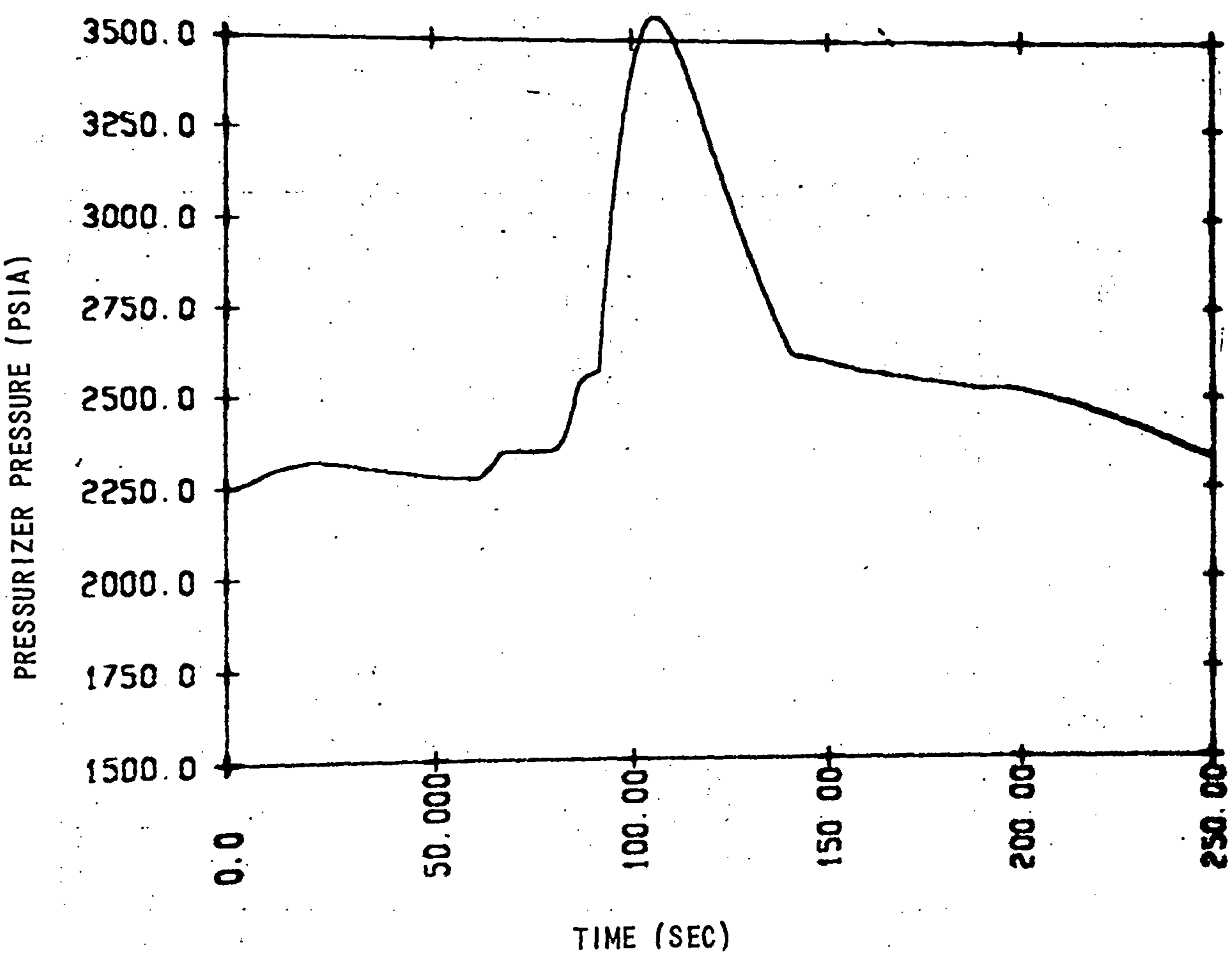

Figure 4-159. Loss of Feedwater - No Turbine Trip
(Pressurizer Pressure vs. Time)

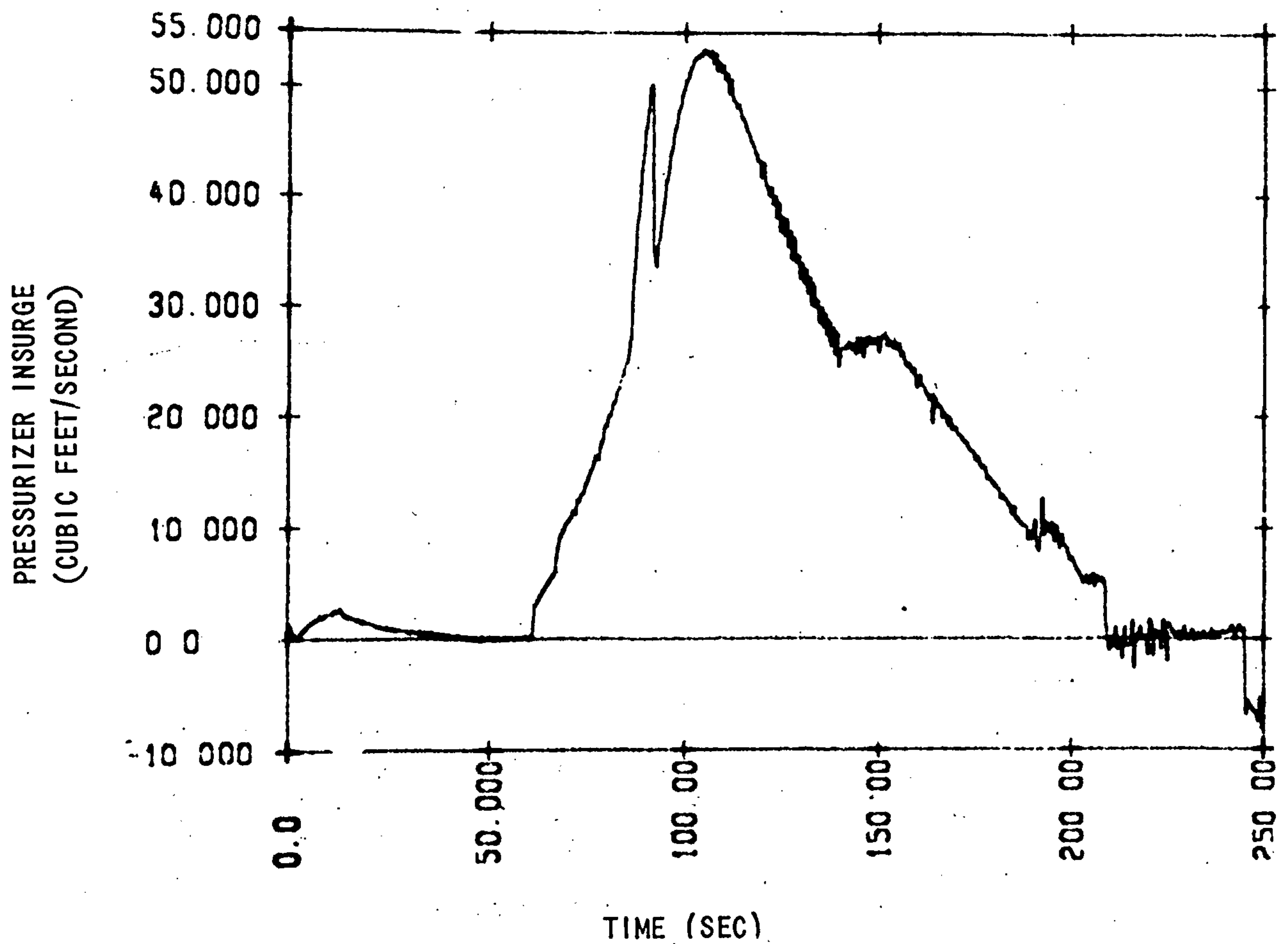

Figure 4-160. Loss of Feedwater - No Turbine Trip
(Pressurizer Insurge vs. Time)

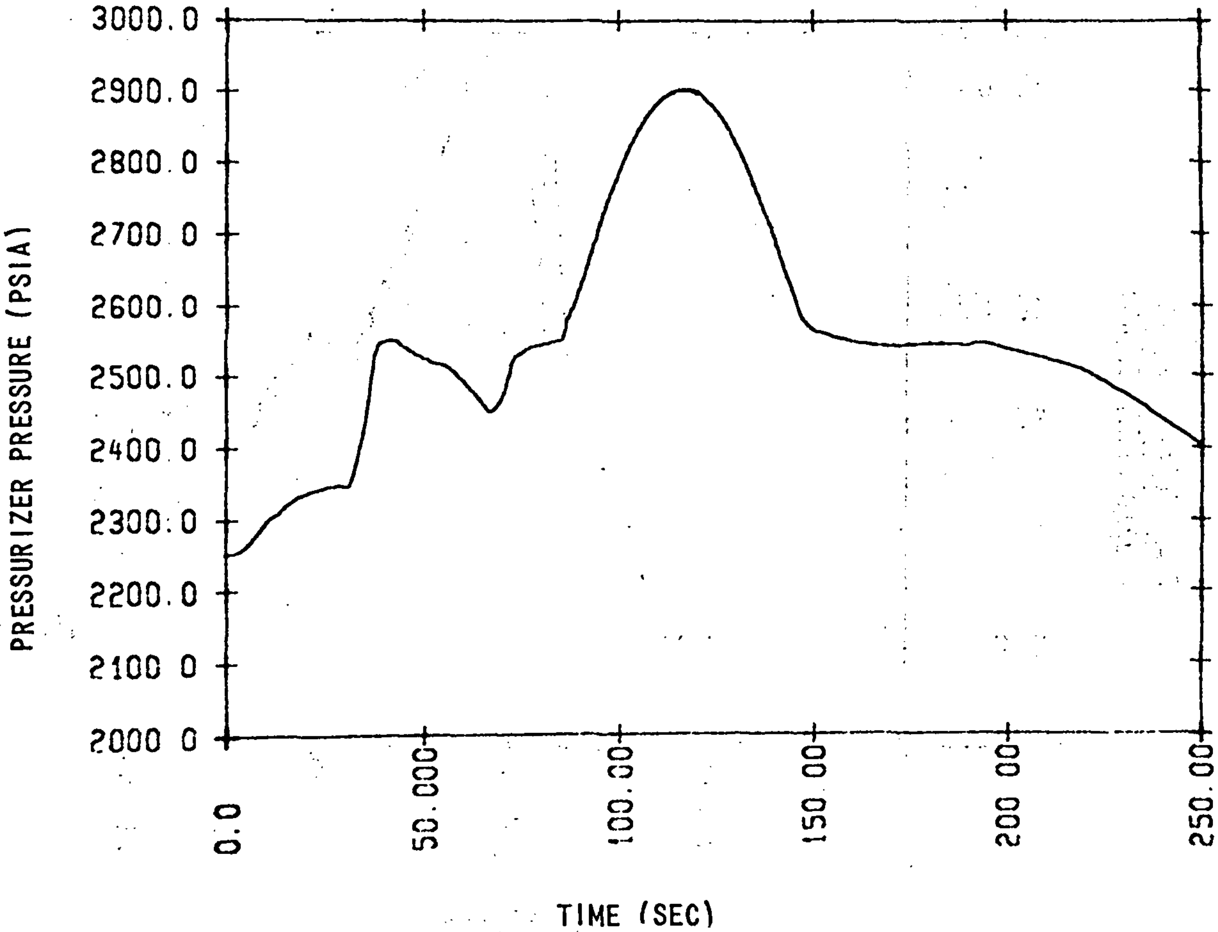

Figure 4-161. Loss of Feedwater – No Power-Operated Relief Valves (Pressurizer Pressure vs. Time)

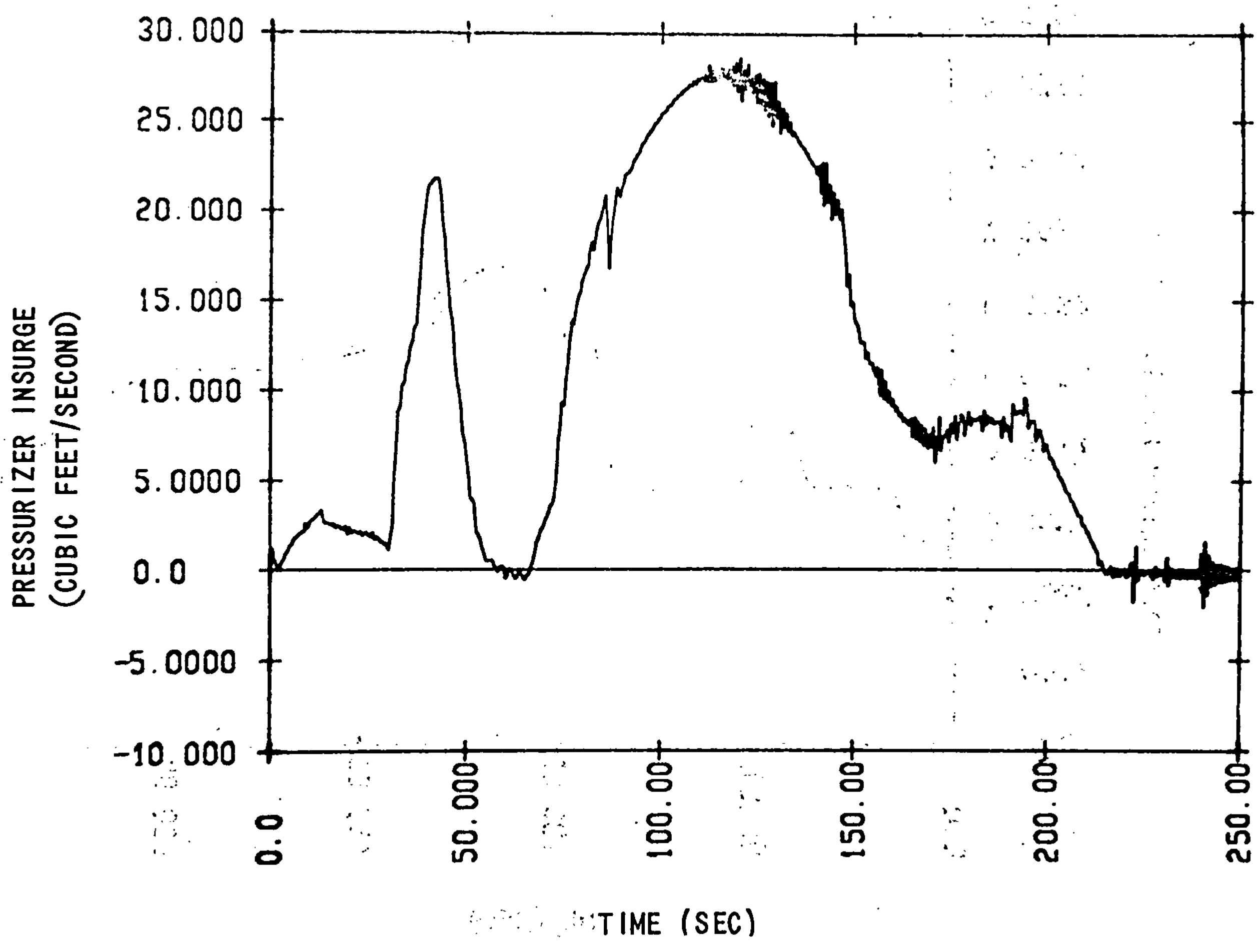

Figure 4-162. Loss of Feedwater – No Power-Operated Relief Valves (Pressurizer Insurge vs. Time)

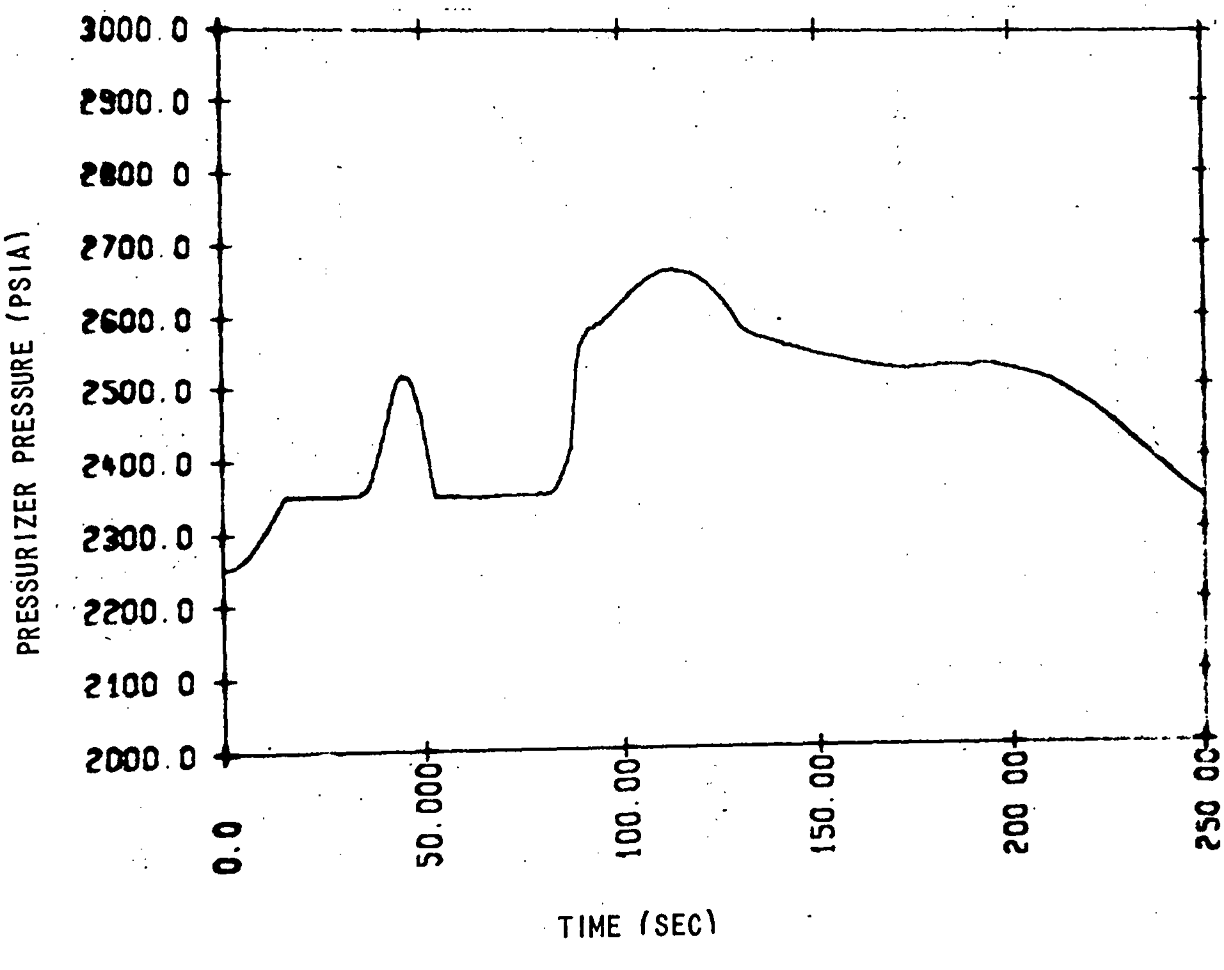

Figure 4-163. Loss of Feedwater - No Pressurizer Spray
(Pressurizer Pressure vs. Time)

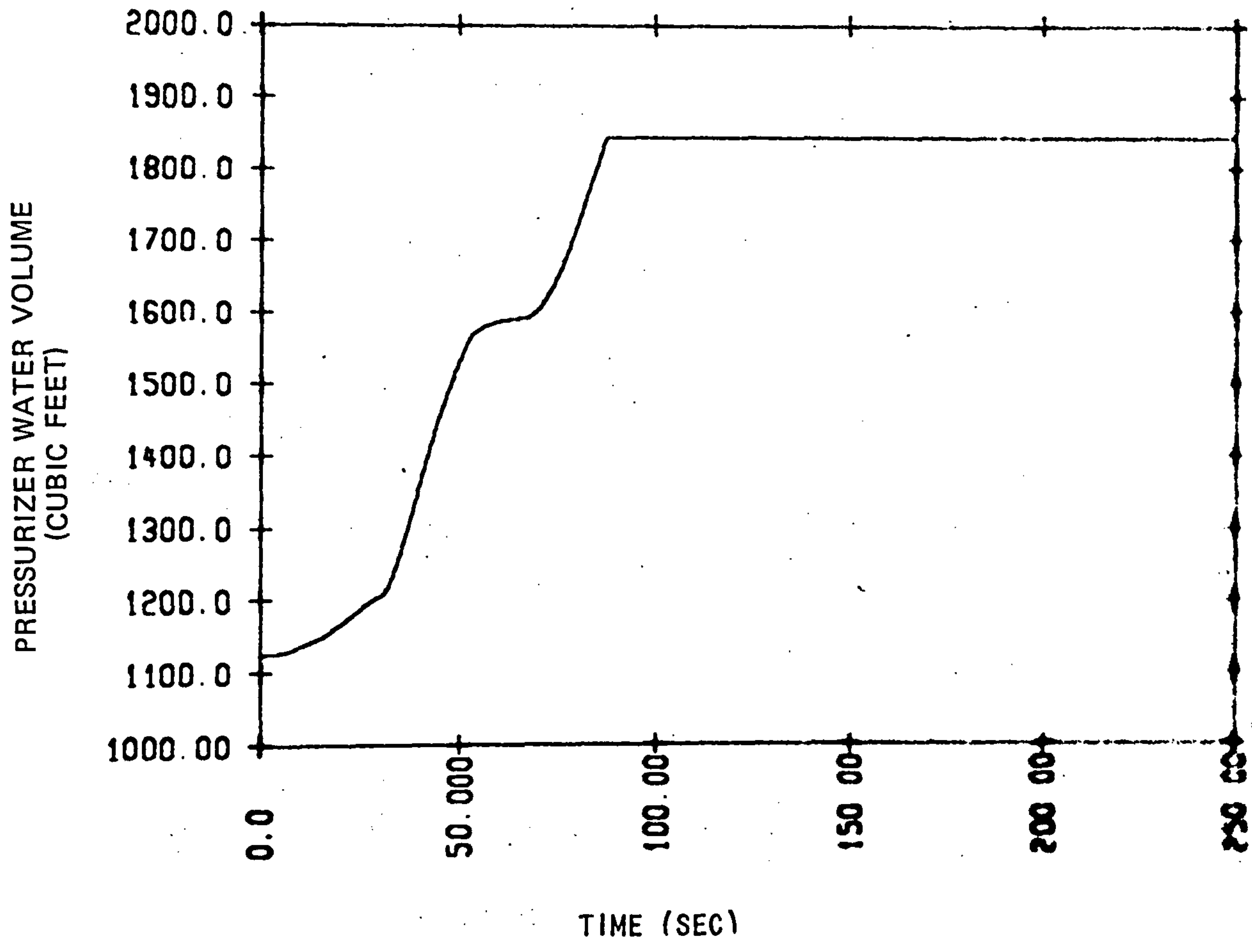

Figure 4-164. Loss of Feedwater — No Pressurizer Spray
(Pressurizer Water Volume vs. Time)

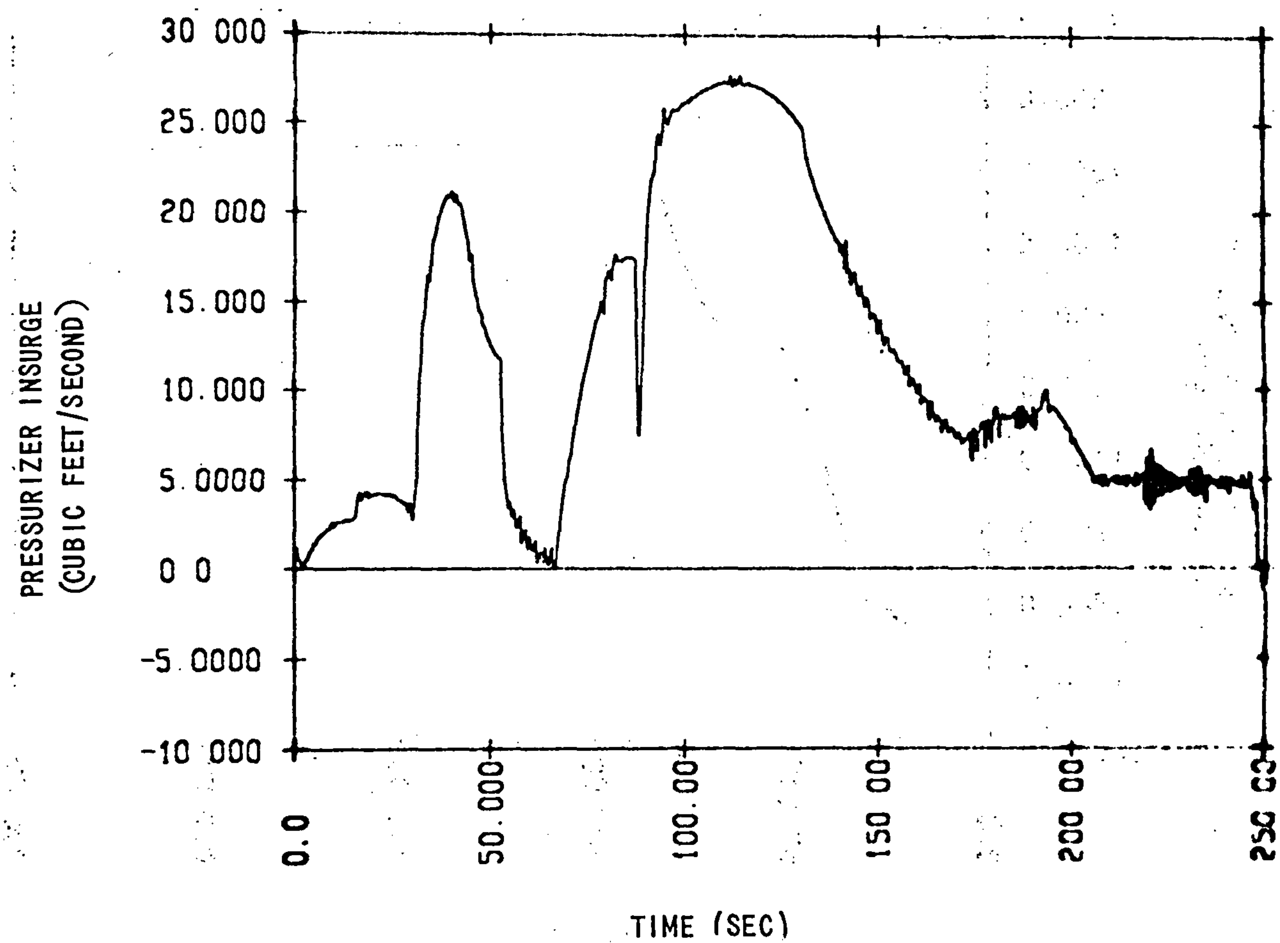

Figure 4-165. Loss of Feedwater – No Pressurizer Spray
(Pressurizer Insurge vs. Time)

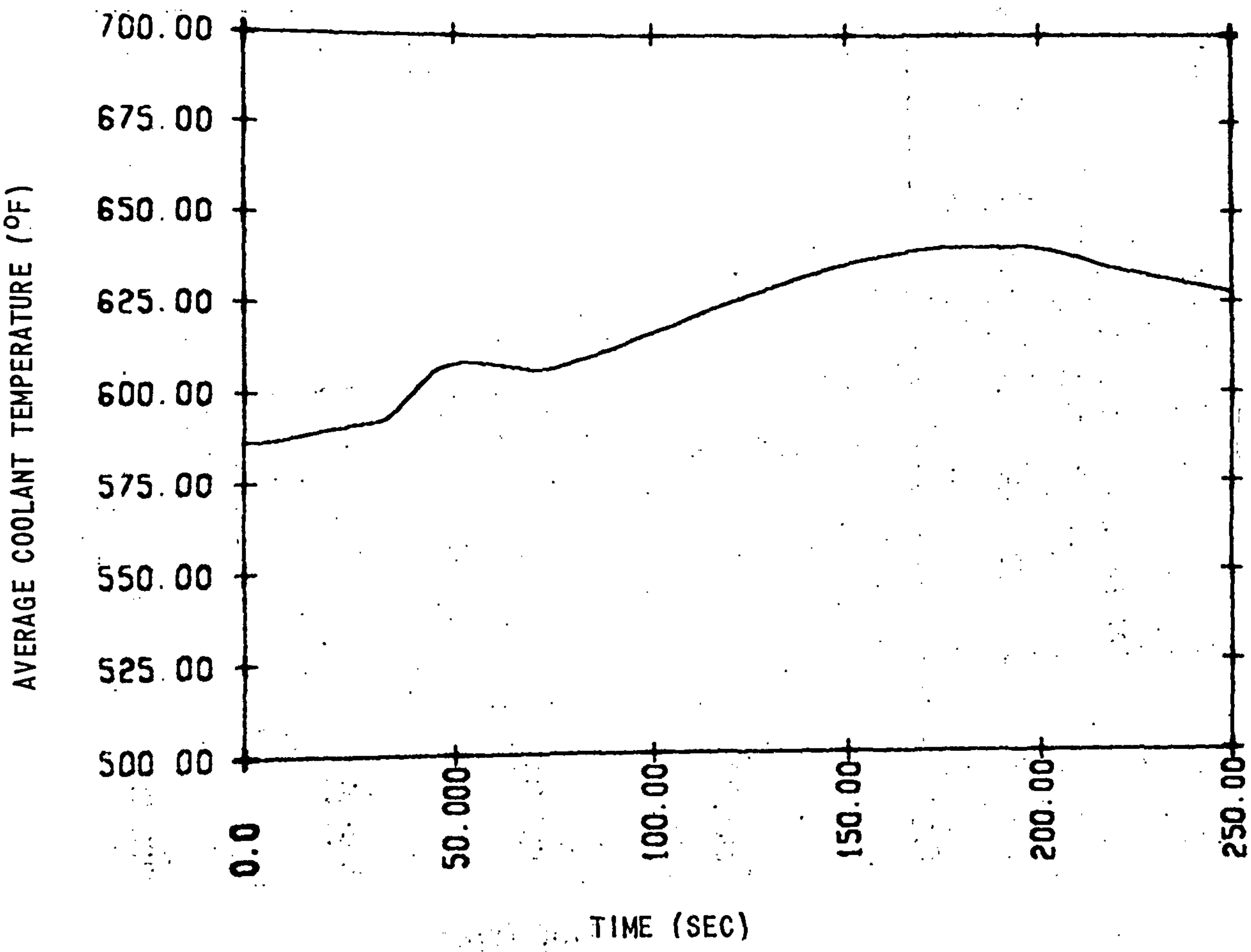

Figure 4-166. Loss of Feedwater - Automatic Rod Control
(Average Coolant Temperature vs. Time)

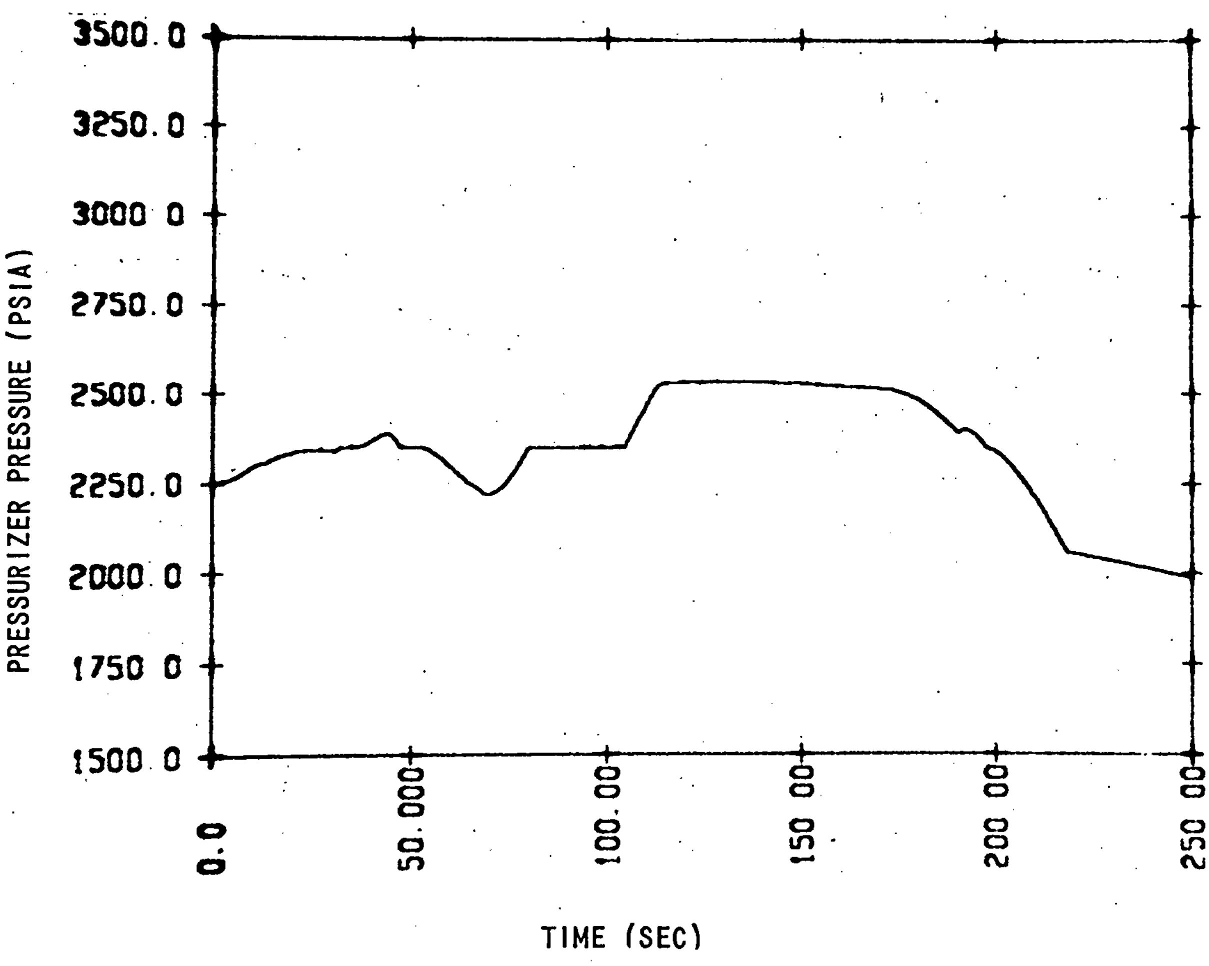

Figure 4-167. Loss of Feedwater - Automatic Rod Control
(Pressurizer Pressure vs. Time)

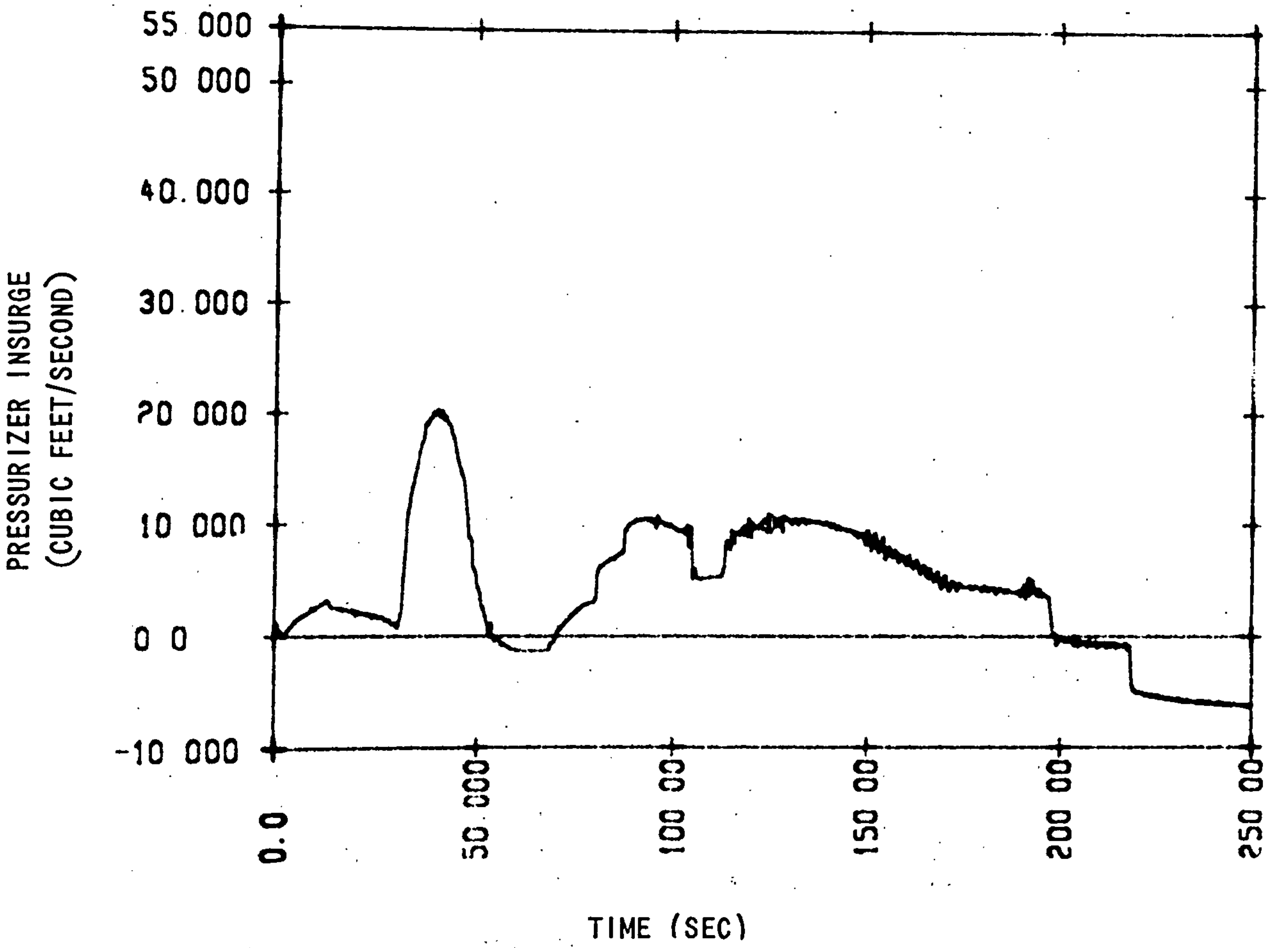

Figure 4-168. Loss of Feedwater - Automatic Rod Control
(Pressurizer Insurge vs. Time)

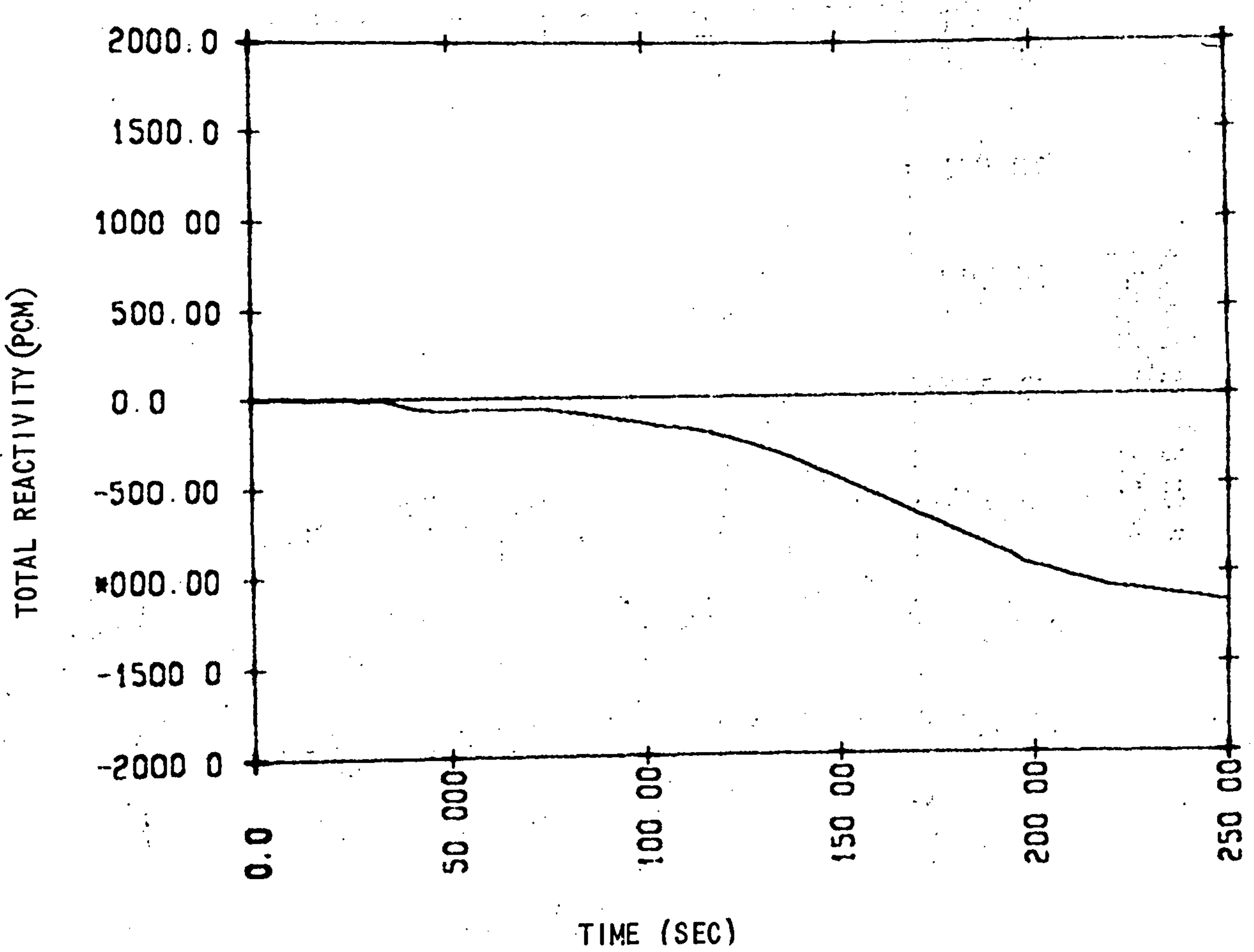

Figure 4-169. Loss of Feedwater – Automatic Rod Control
(Total Reactivity vs. Time)

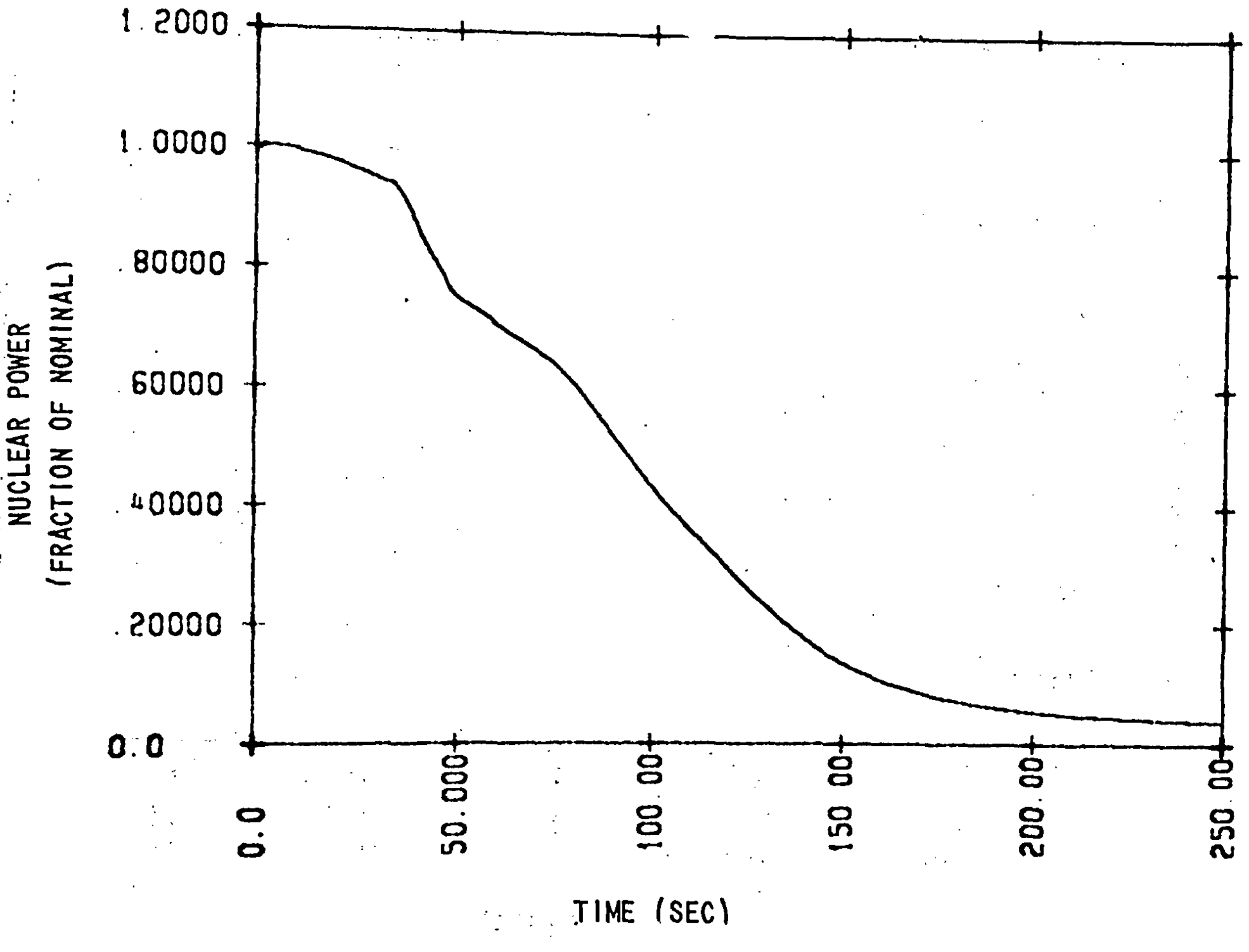

Figure 4-170. Loss of Feedwater – Automatic Rod Control
(Nuclear Power vs. Time)

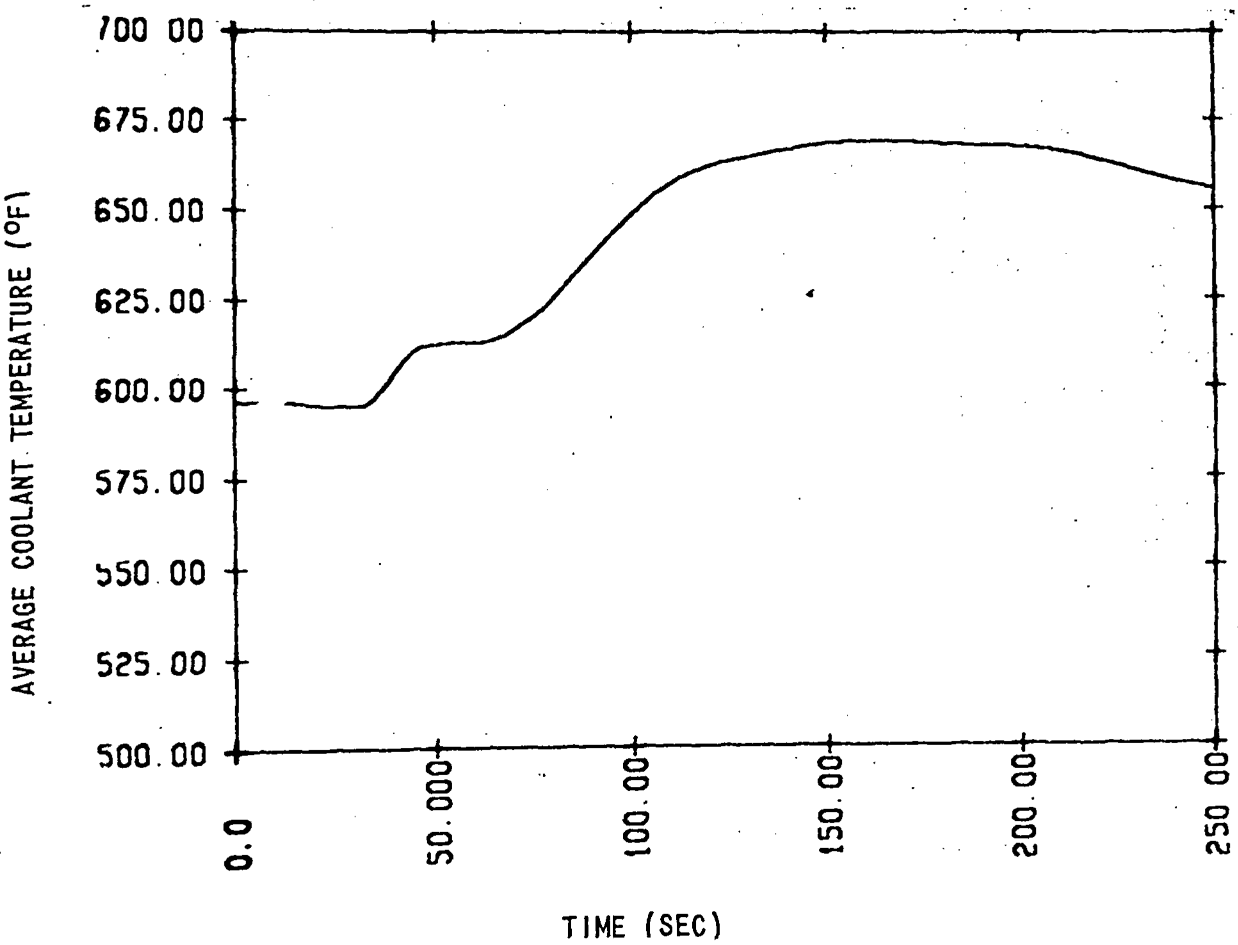

Figure 4-171. Loss of Feedwater - Tavg +8°F
(Average Coolant Temperature vs. Time)

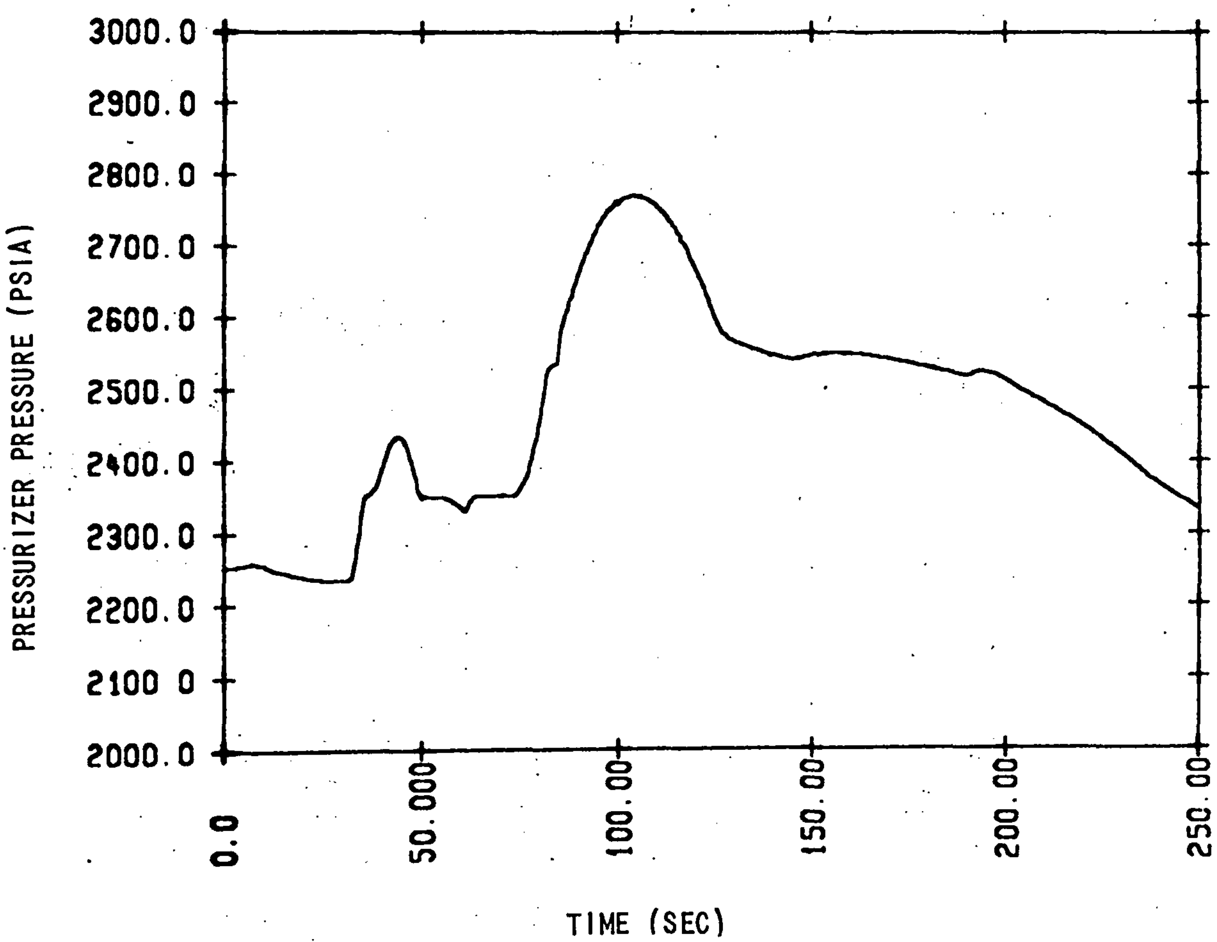

Figure 4-172. Loss of Feedwater - Tavg +8°F
(Pressurizer Pressure vs. Time)

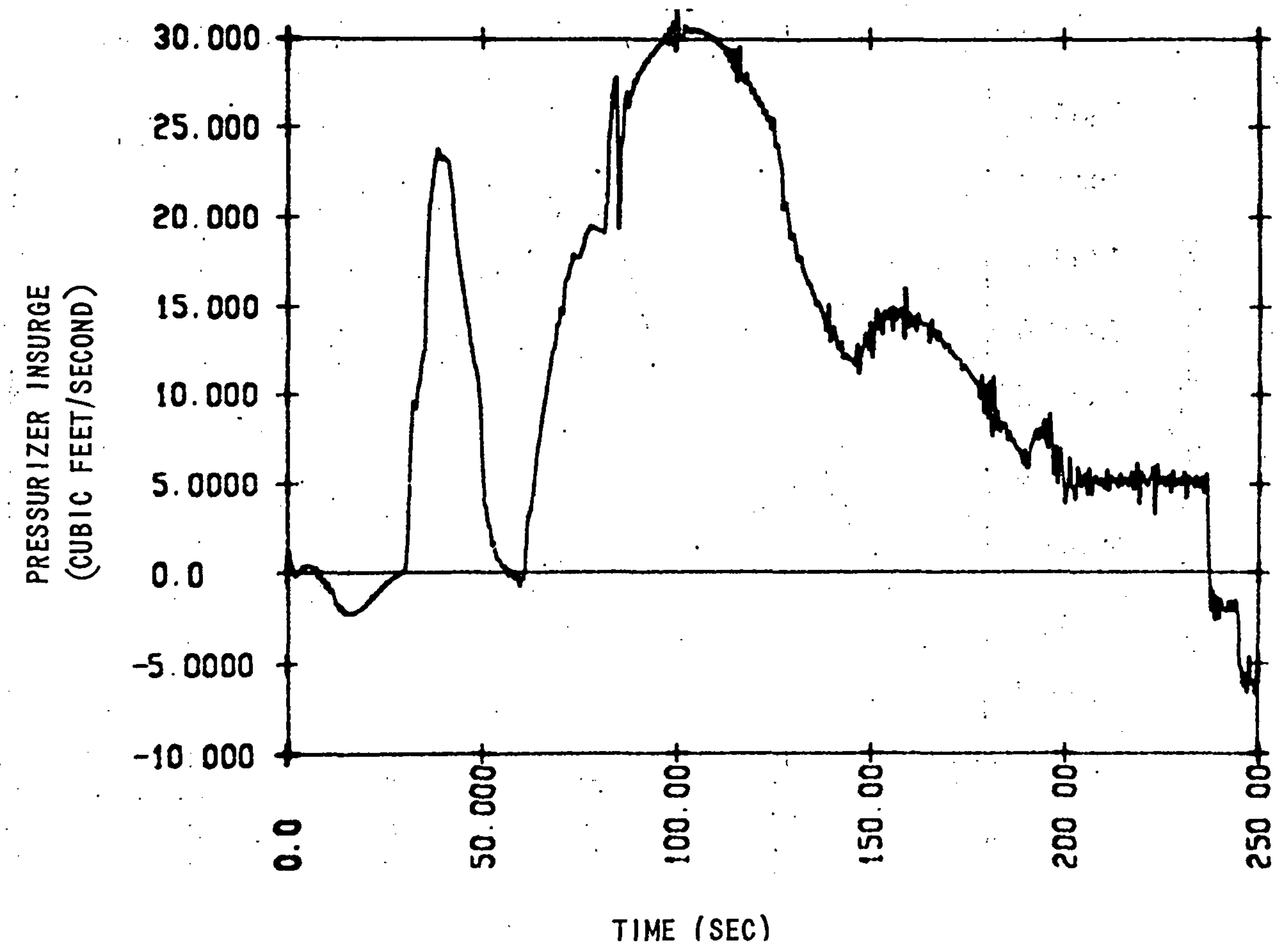

Figure 4-173. Loss of Feedwater - Tavg +8°F
(Pressurizer Insurge vs. Time)

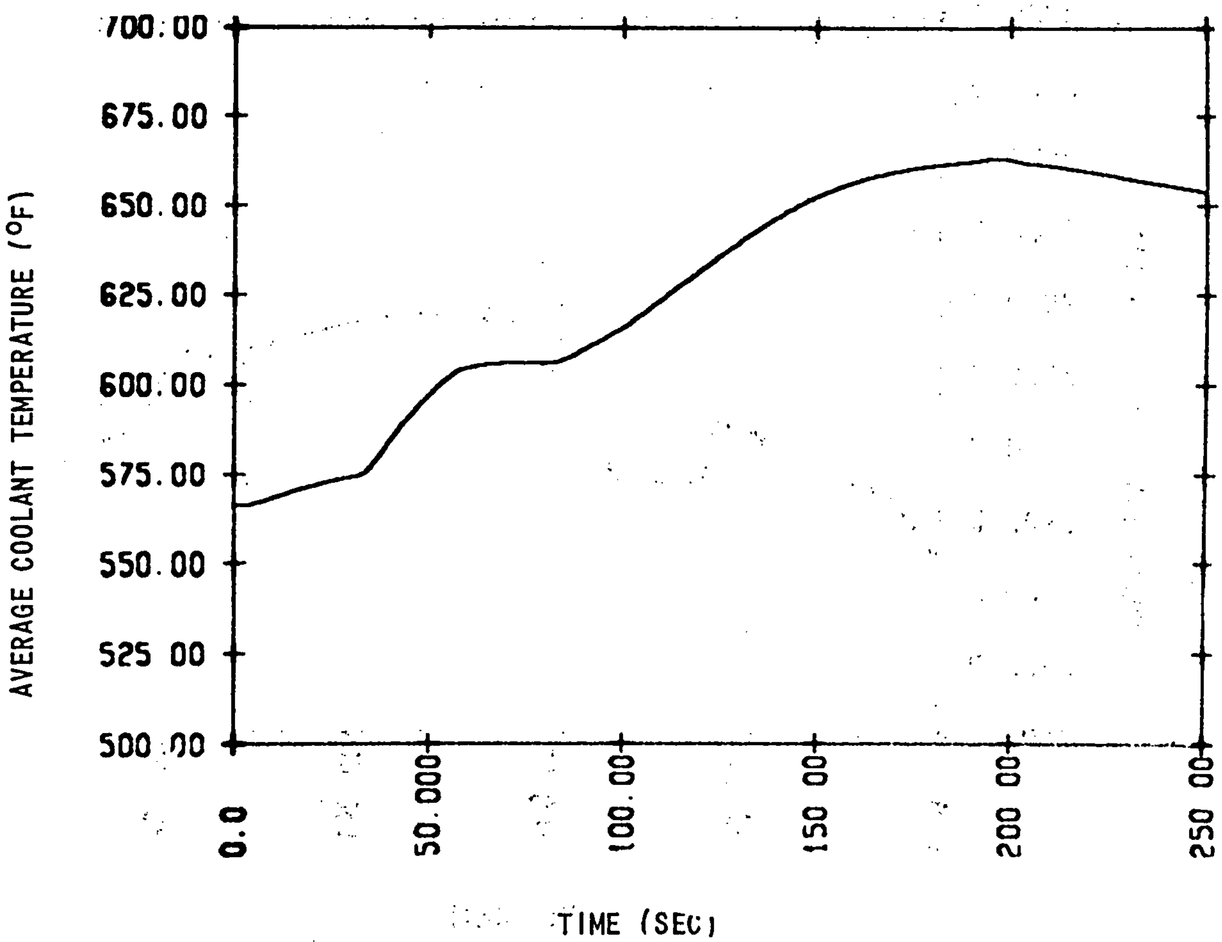

Figure 4-174. Loss of Feedwater - Tavg - 20°F
(Average Coolant Temperature vs. Time)

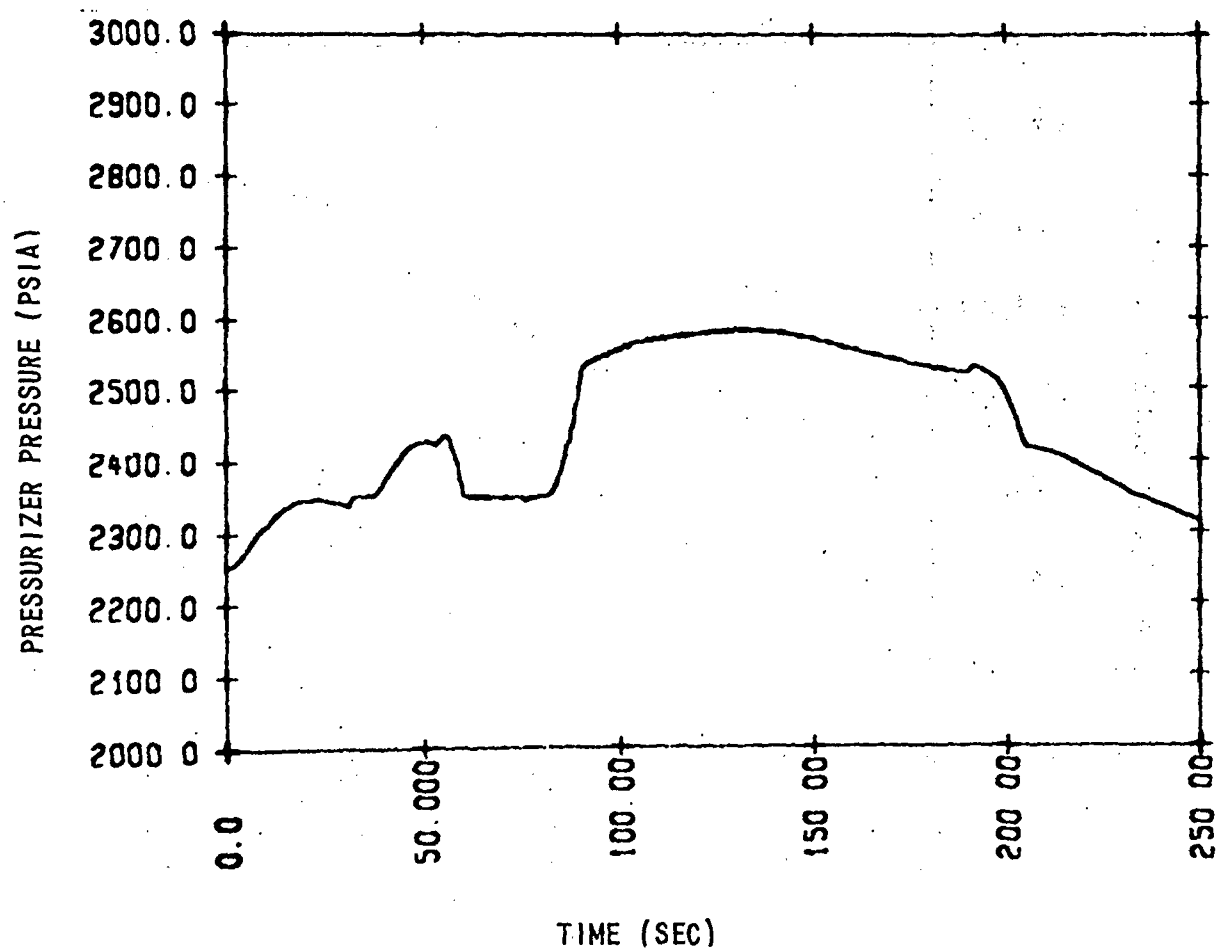

Figure 4-175. Loss of Feedwater - Tavg - 20°F
(Pressurizer Pressure vs. Time)

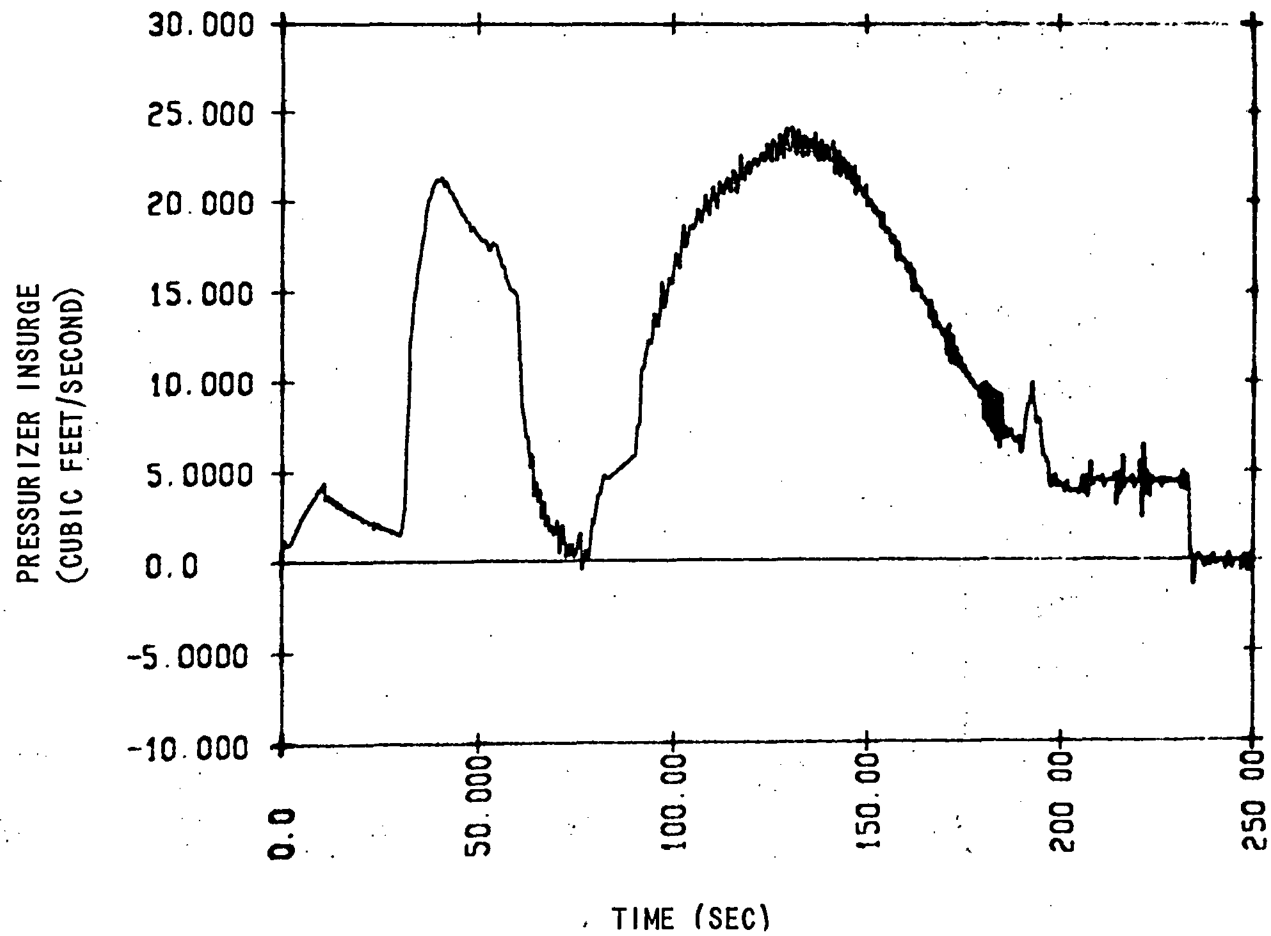

Figure 4-176. Loss of Feedwater - Tavg - 20°F
(Pressurizer Insurge vs. Time)

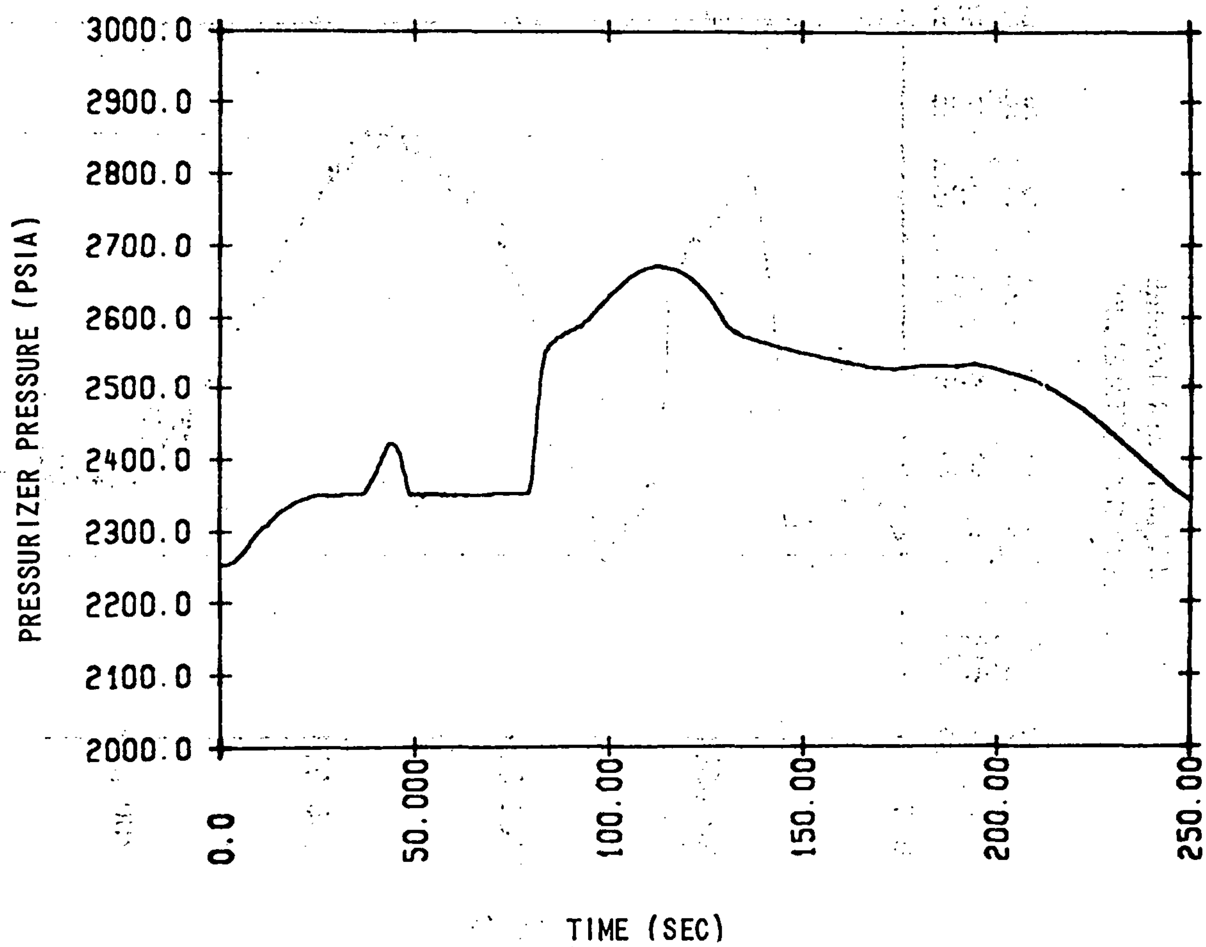

Figure 4-177. Loss of Feedwater - Initial Pressurizer Level +10 Percent
(Pressurizer Pressure vs. Time)

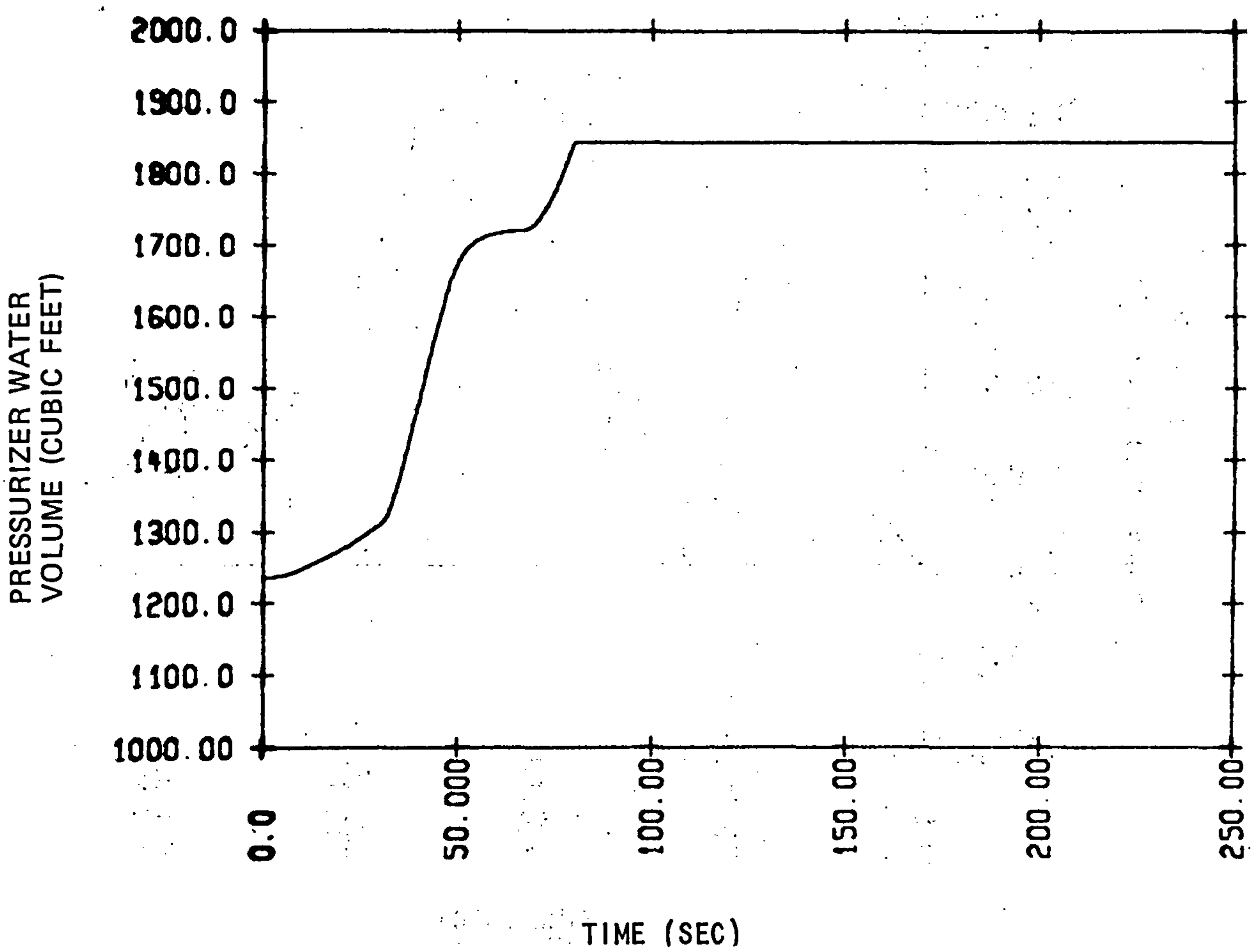

Figure 4-178. Loss of Feedwater – Initial Pressurizer Level +10 Percent (Pressurizer Water Volume vs. Time)

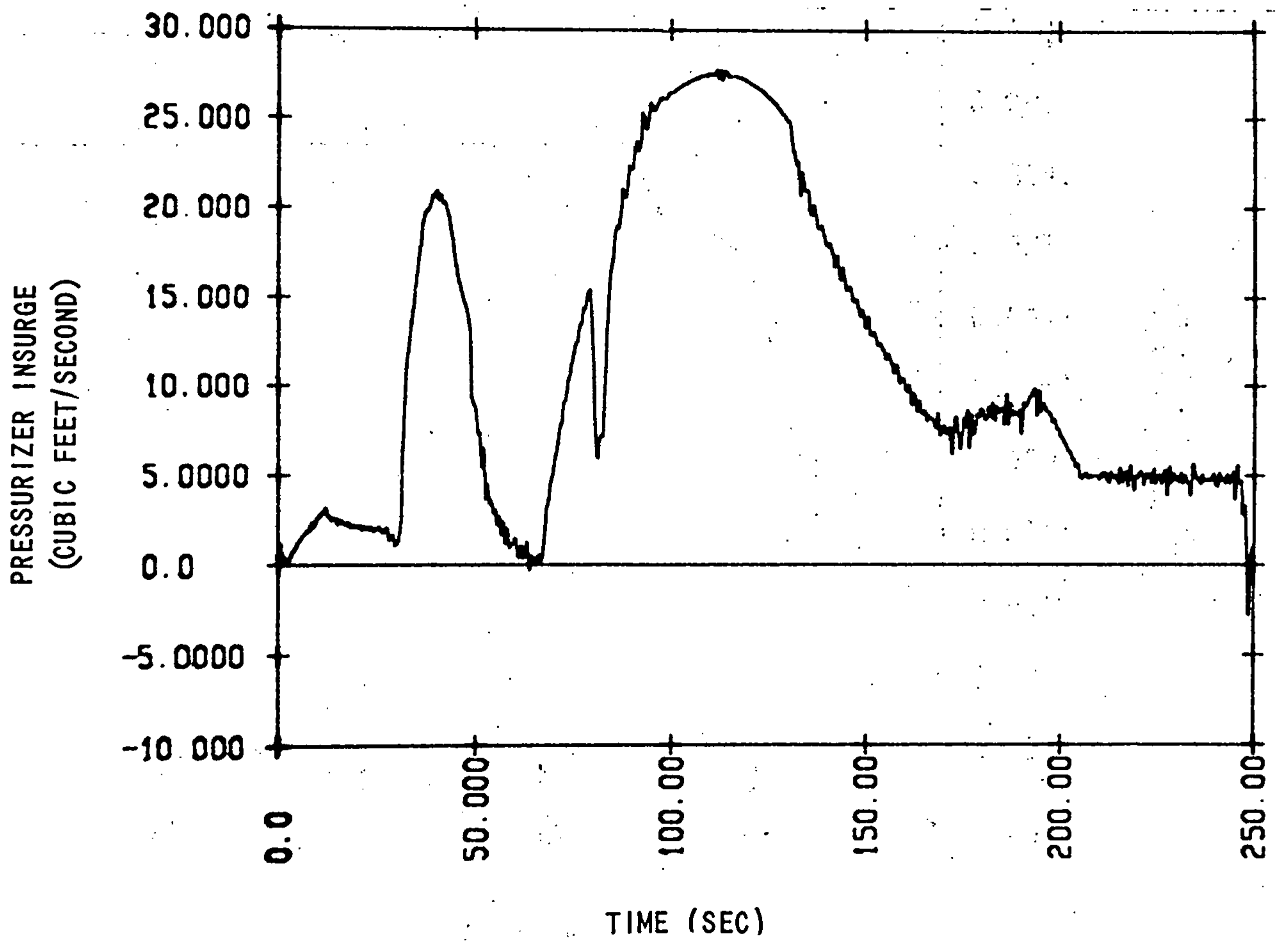

Figure 4-179. Loss of Feedwater - Initial Pressurizer Level +10 Percent (Pressurizer Insurge vs. Time)

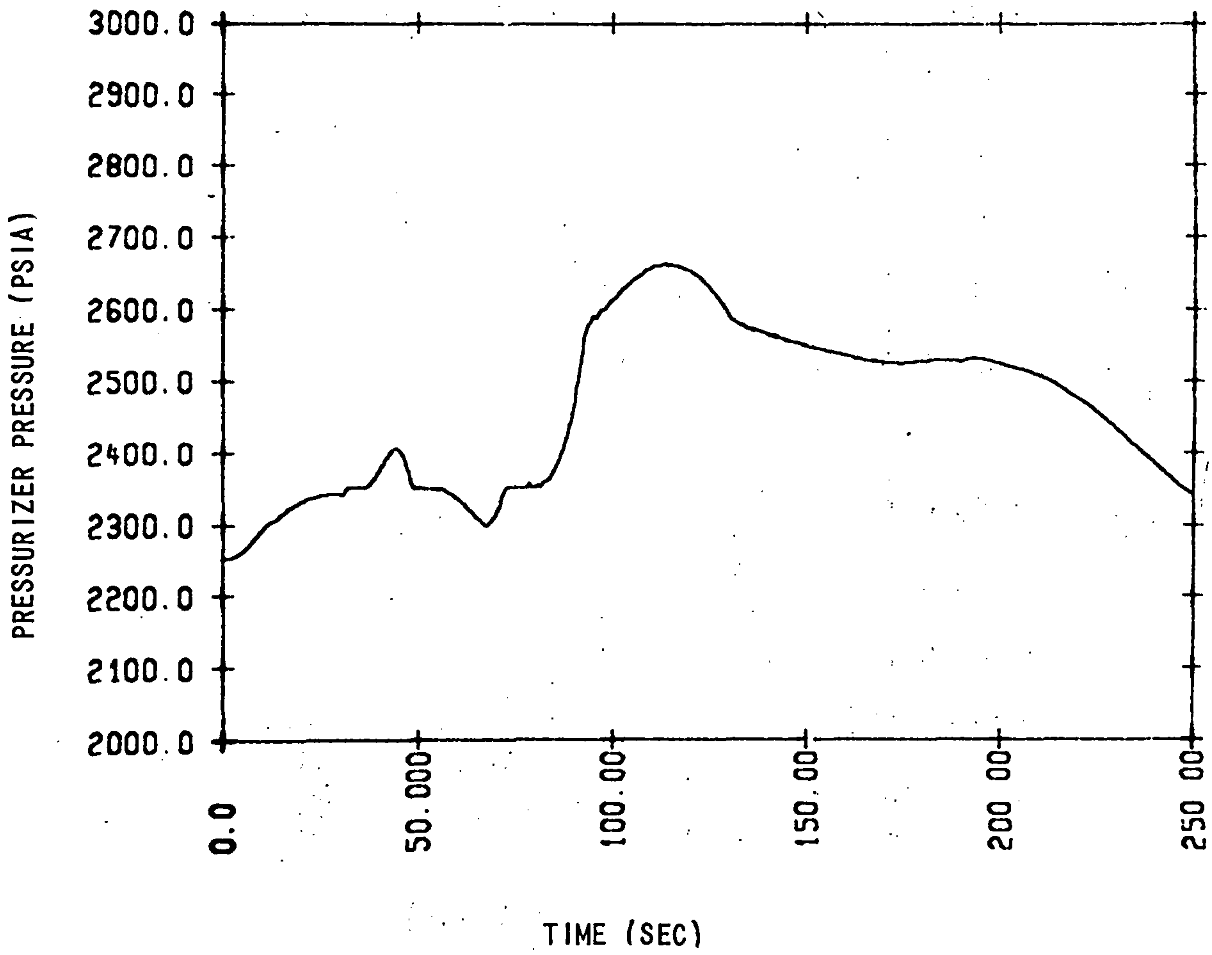

Figure 4-180. Loss of Feedwater - Initial Pressurizer Level - 10 Percent
(Pressurizer Pressure vs. Time)

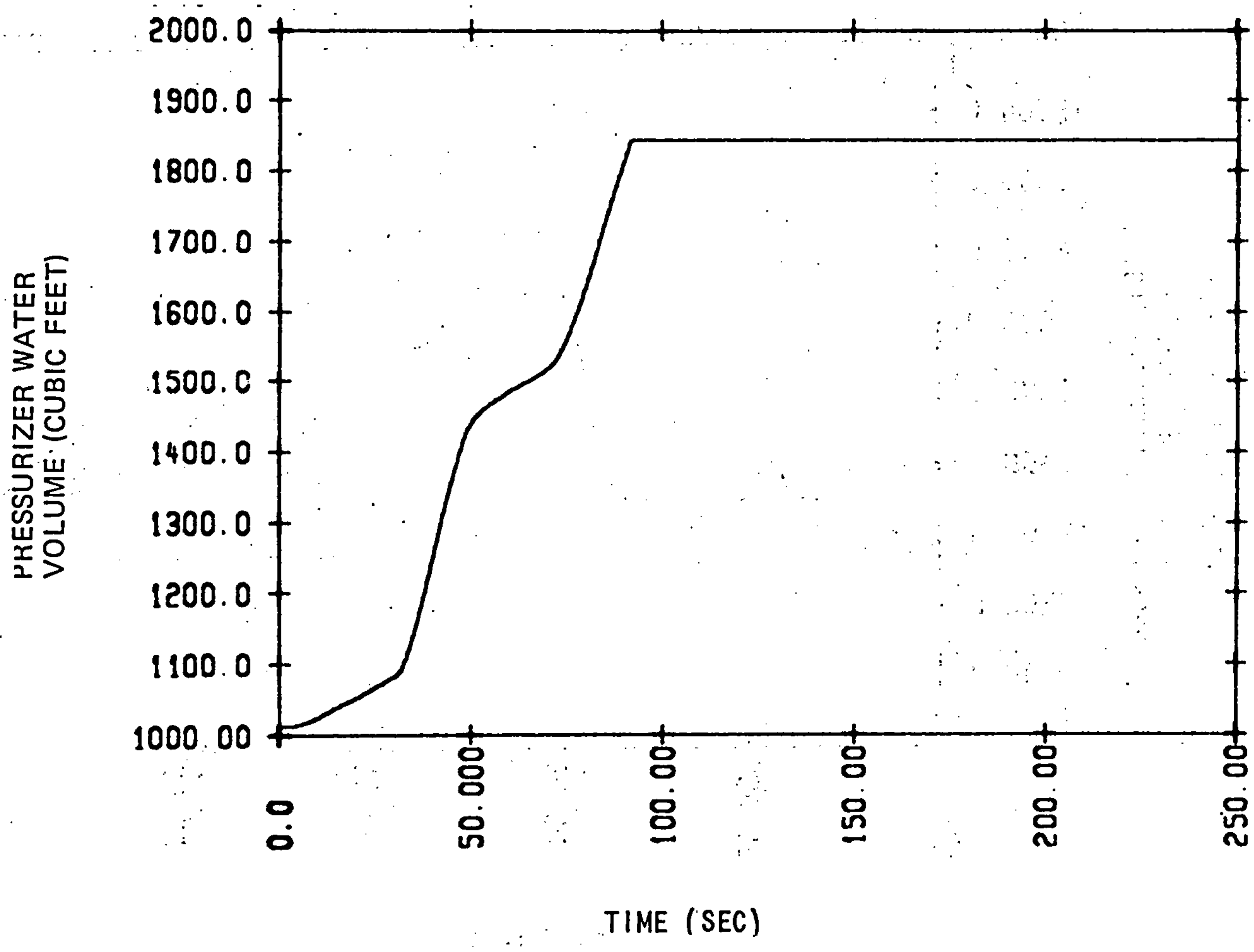

Figure 4-181. Loss of Feedwater — Initial Pressurizer Level — 10 Percent (Pressurizer Water Volume vs. Time)

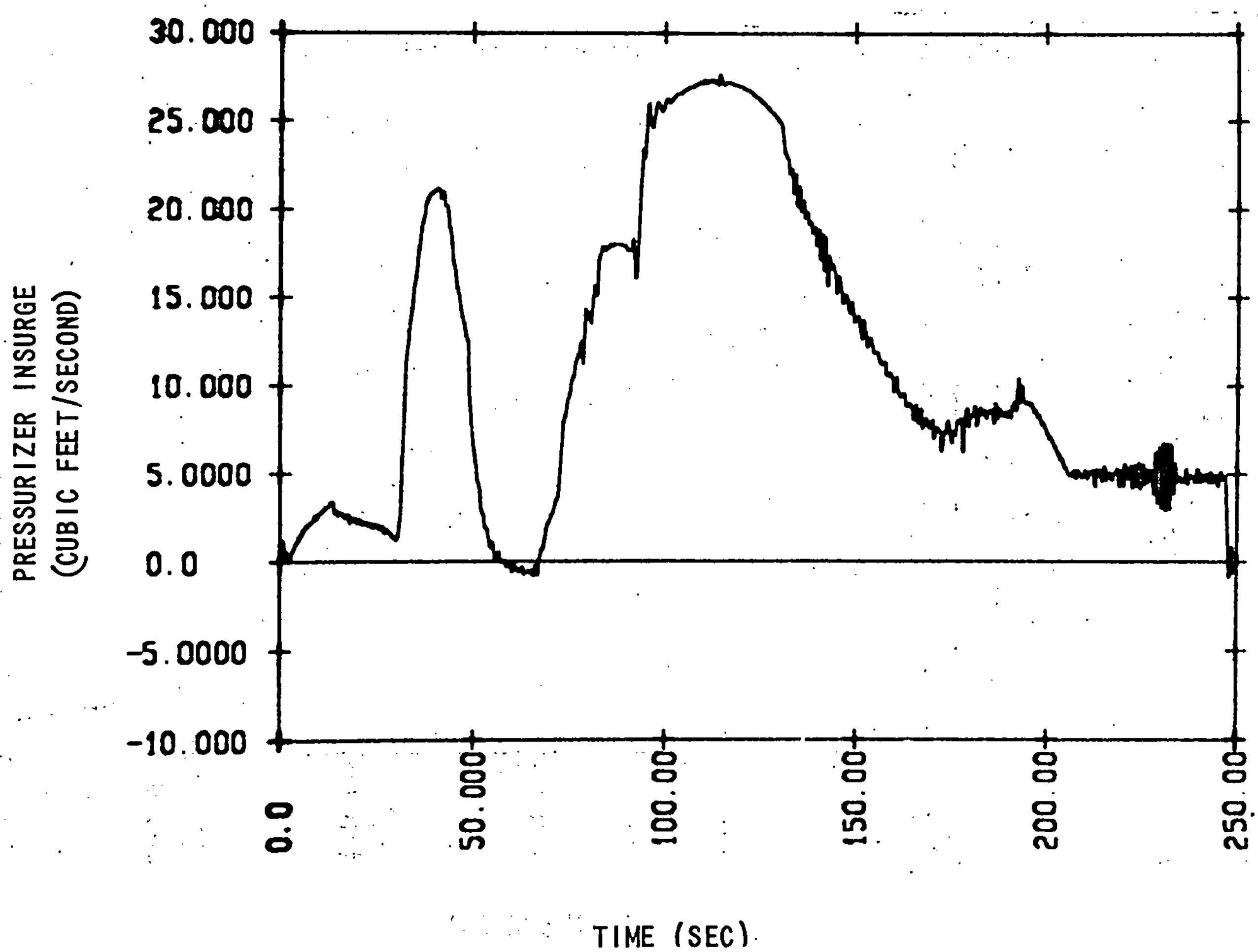

Figure 4-182. Loss of Feedwater - Initial Pressurizer Level - 10 Percent
(Pressurizer Insurge vs. Time)

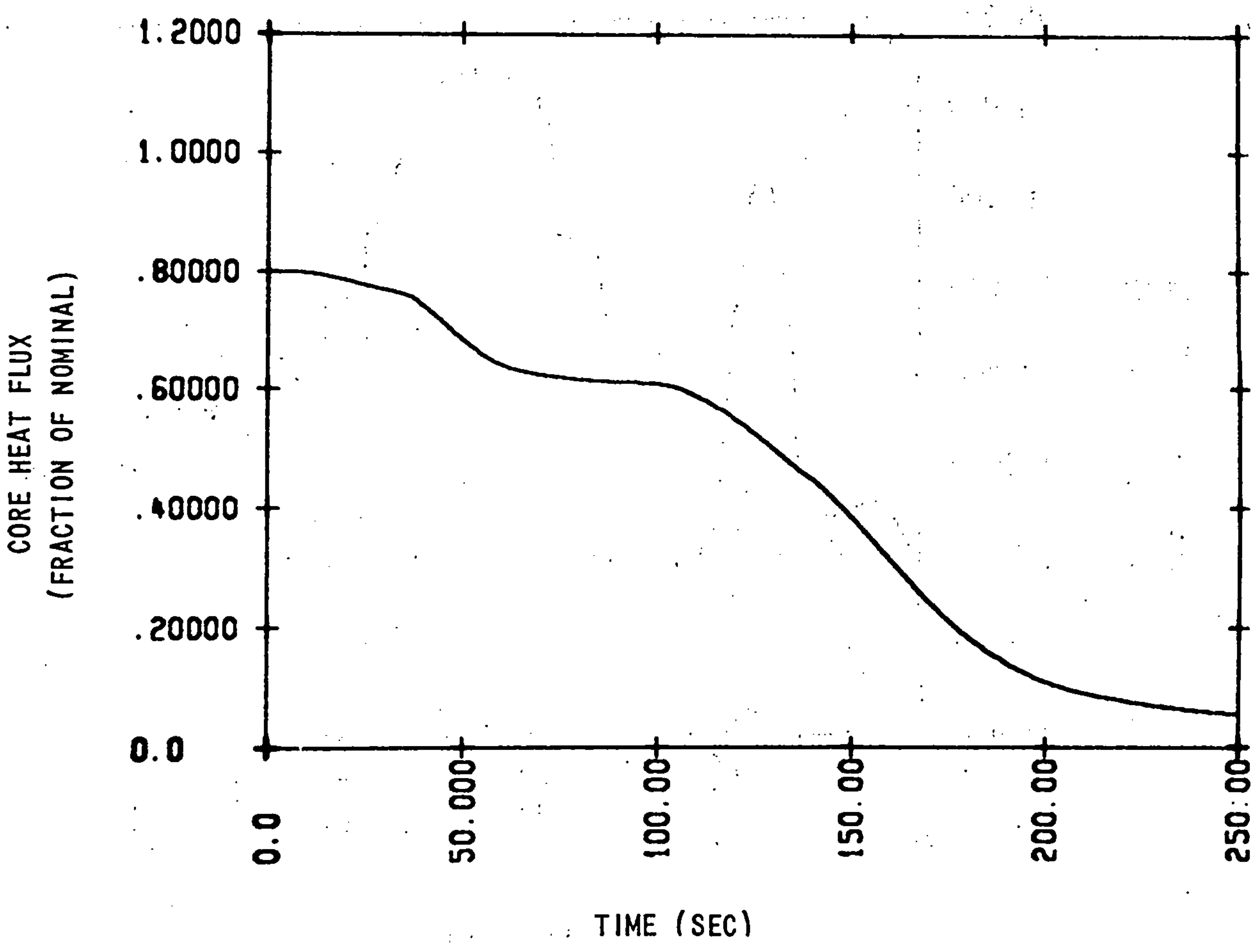

Figure 4-183. Loss of Feedwater - 80 Percent Initial Power
(Core Heat Flux vs. Time)

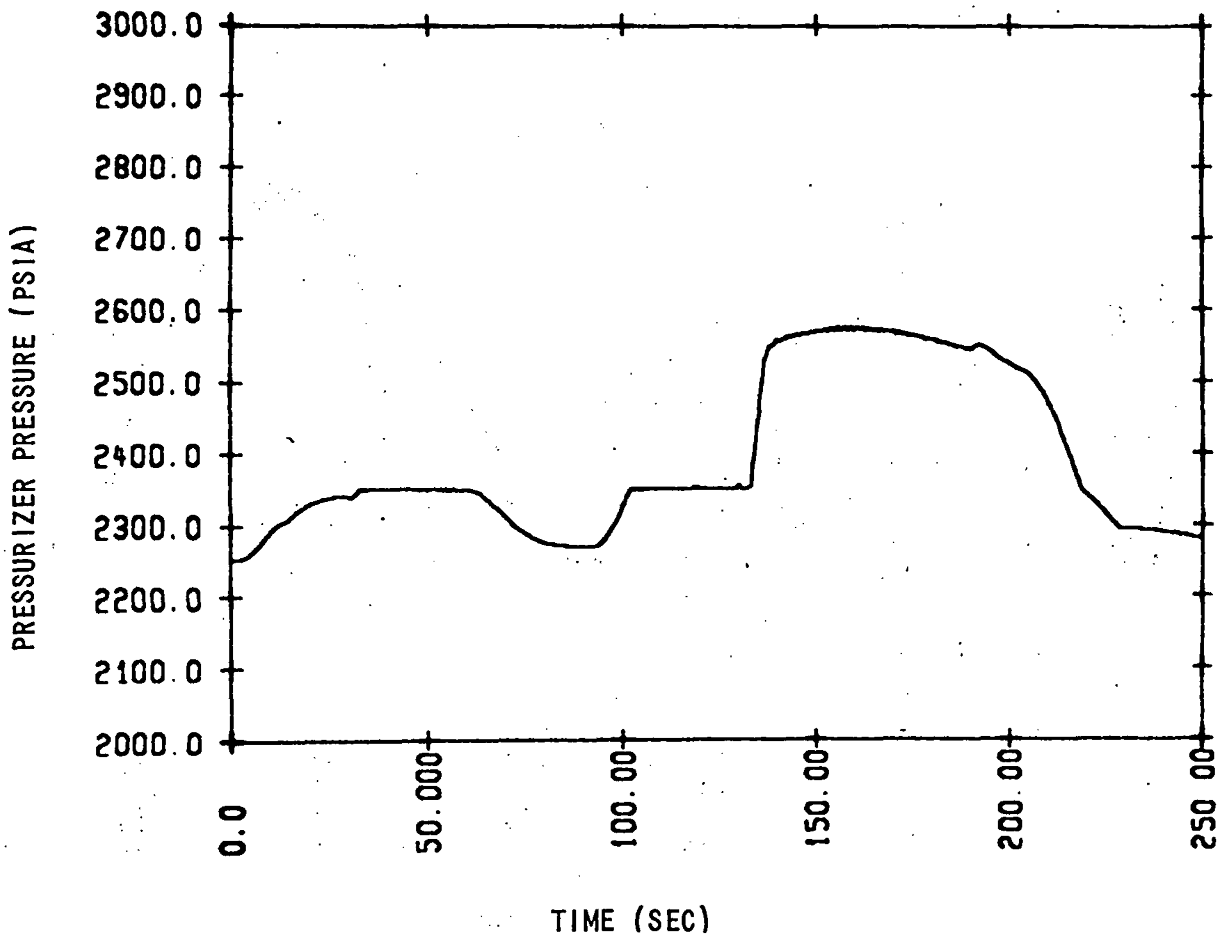

Figure 4-184. Loss of Feedwater - 80 Percent Initial Power
(Pressurizer Pressure vs. Time)

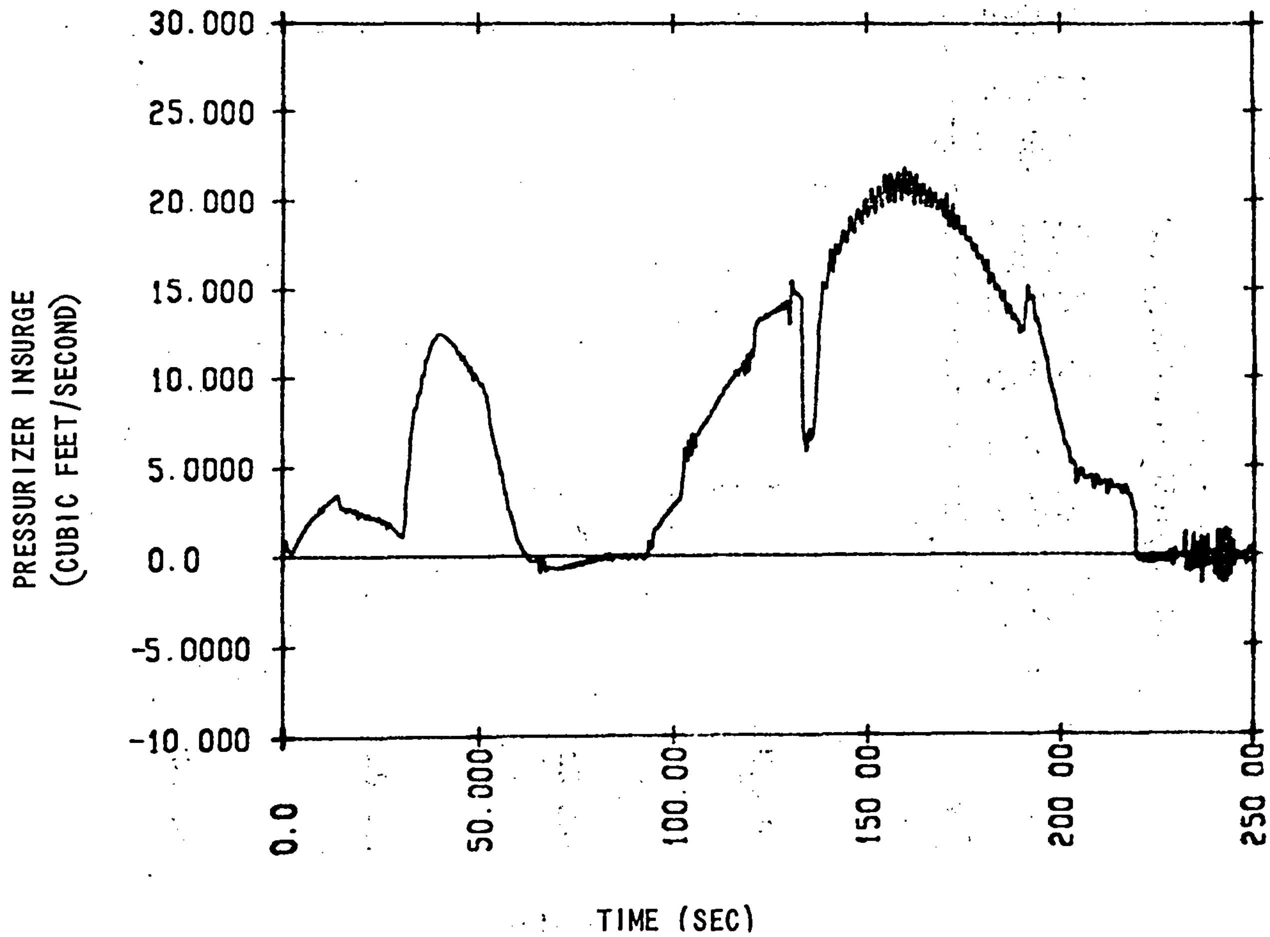

Figure 4-185. Loss of Feedwater – 80 Percent Initial Power
(Pressurizer Insurge vs. Time)

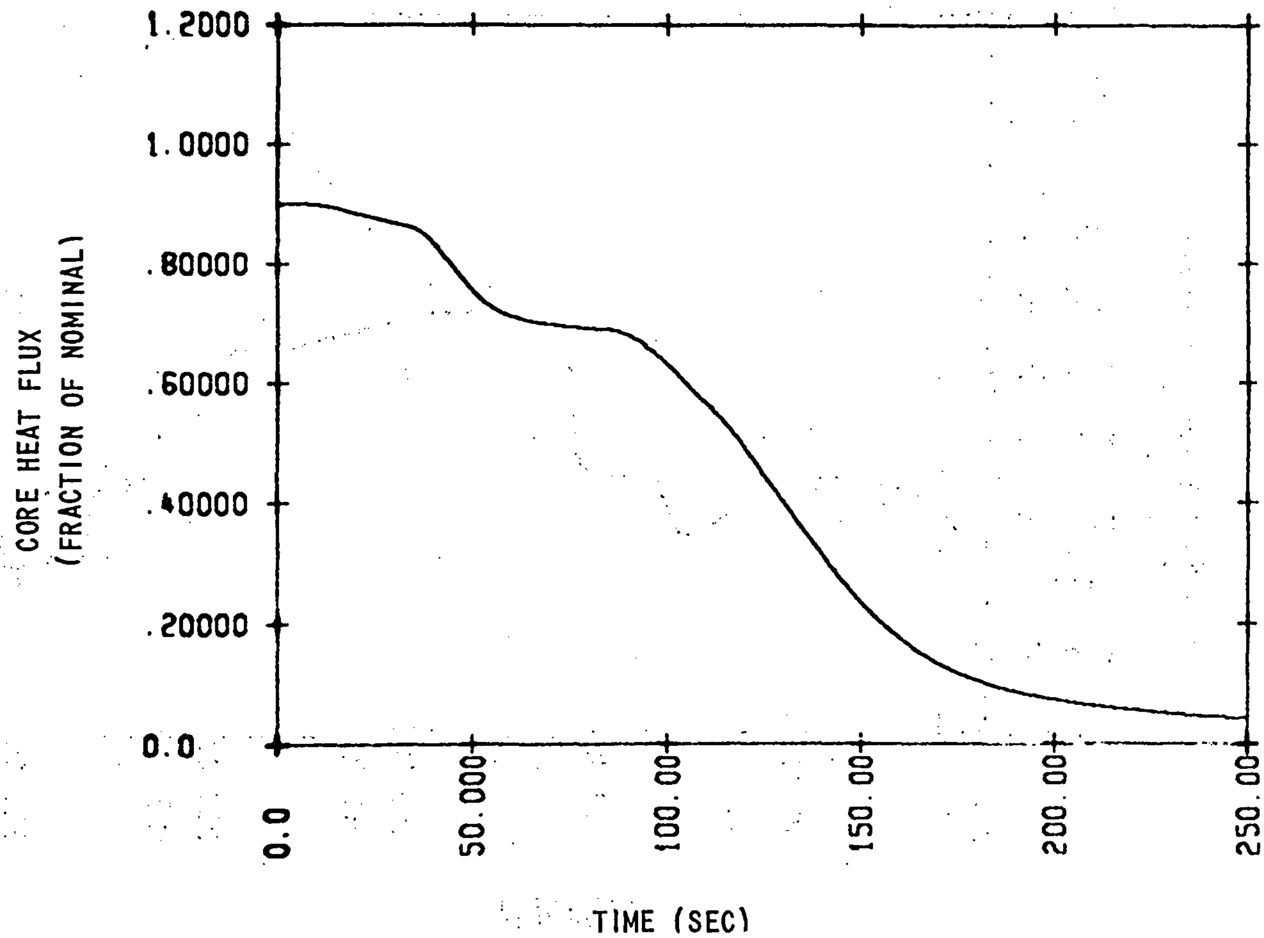

Figure 4-186. Loss of Feedwater - 90 Percent Initial Power
(Core Heat Flux vs. Time)

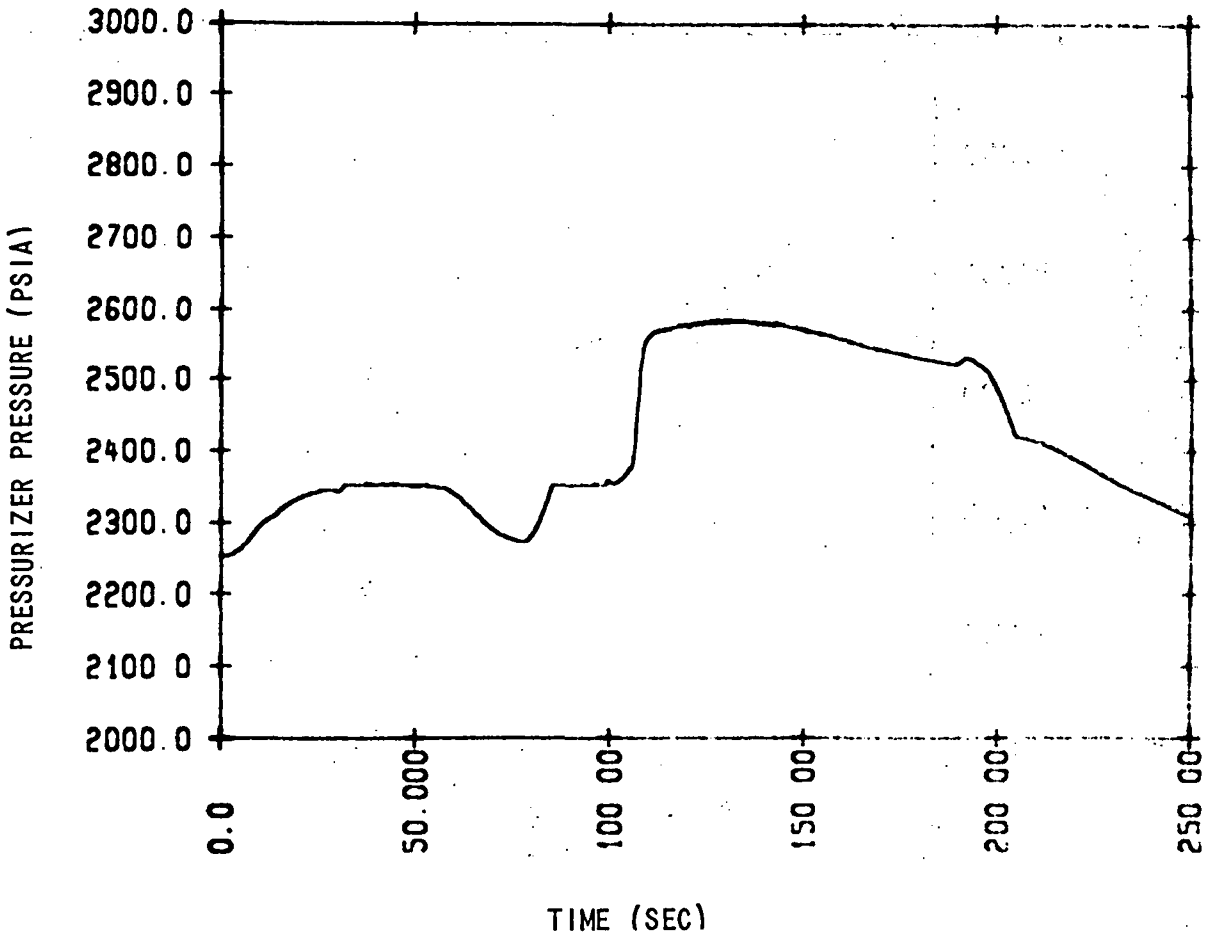

Figure 4-187 Loss of Feedwater - 90 Percent Initial Power (Pressurizer Pressure vs. Time)

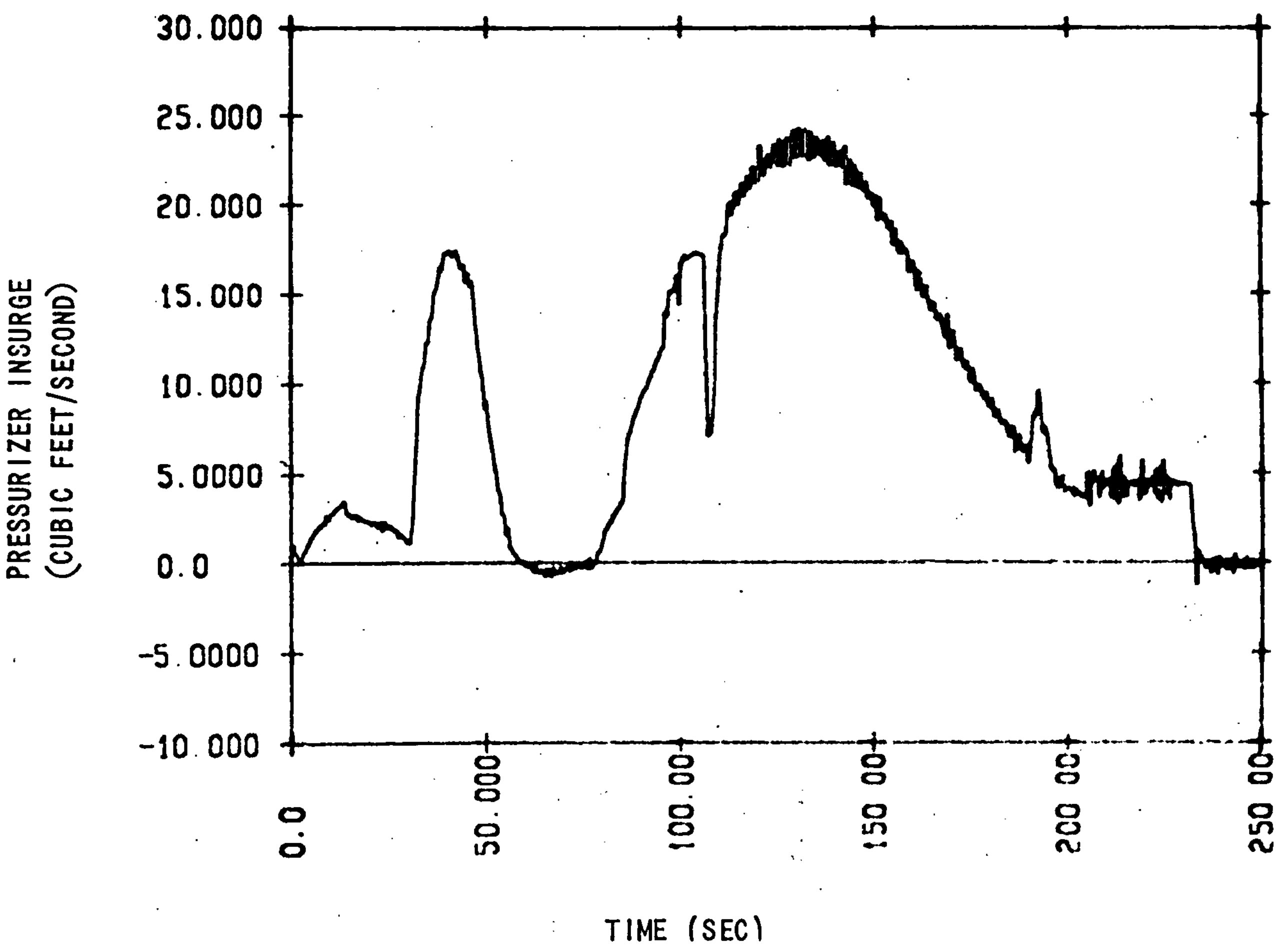

Figure 4-188. Loss of Feedwater – 90 Percent Initial Power
(Pressurizer Insurge vs. Time)

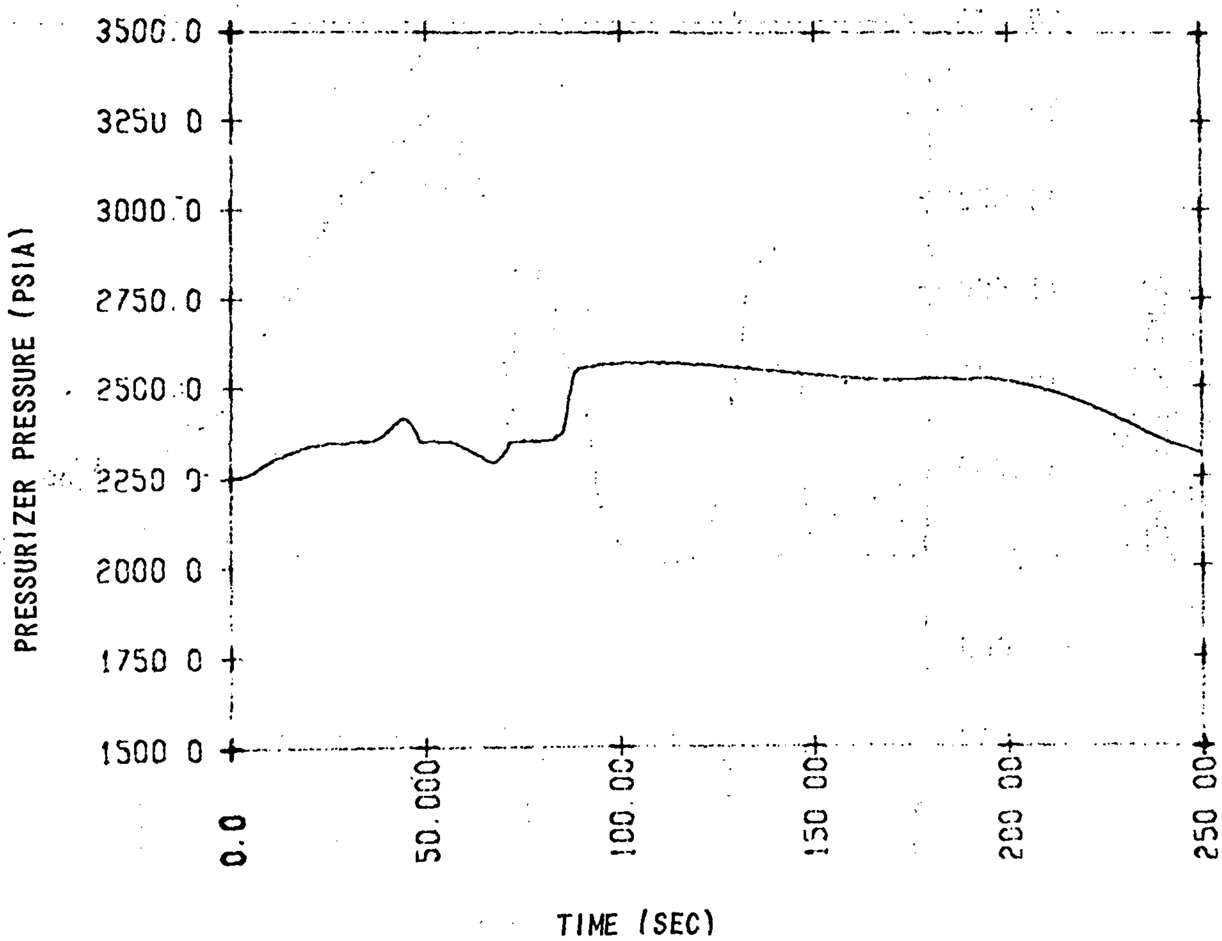

Figure 4-189 Loss of Feedwater - Fauske Water Relief Model
(Pressurizer Pressure vs. Time)

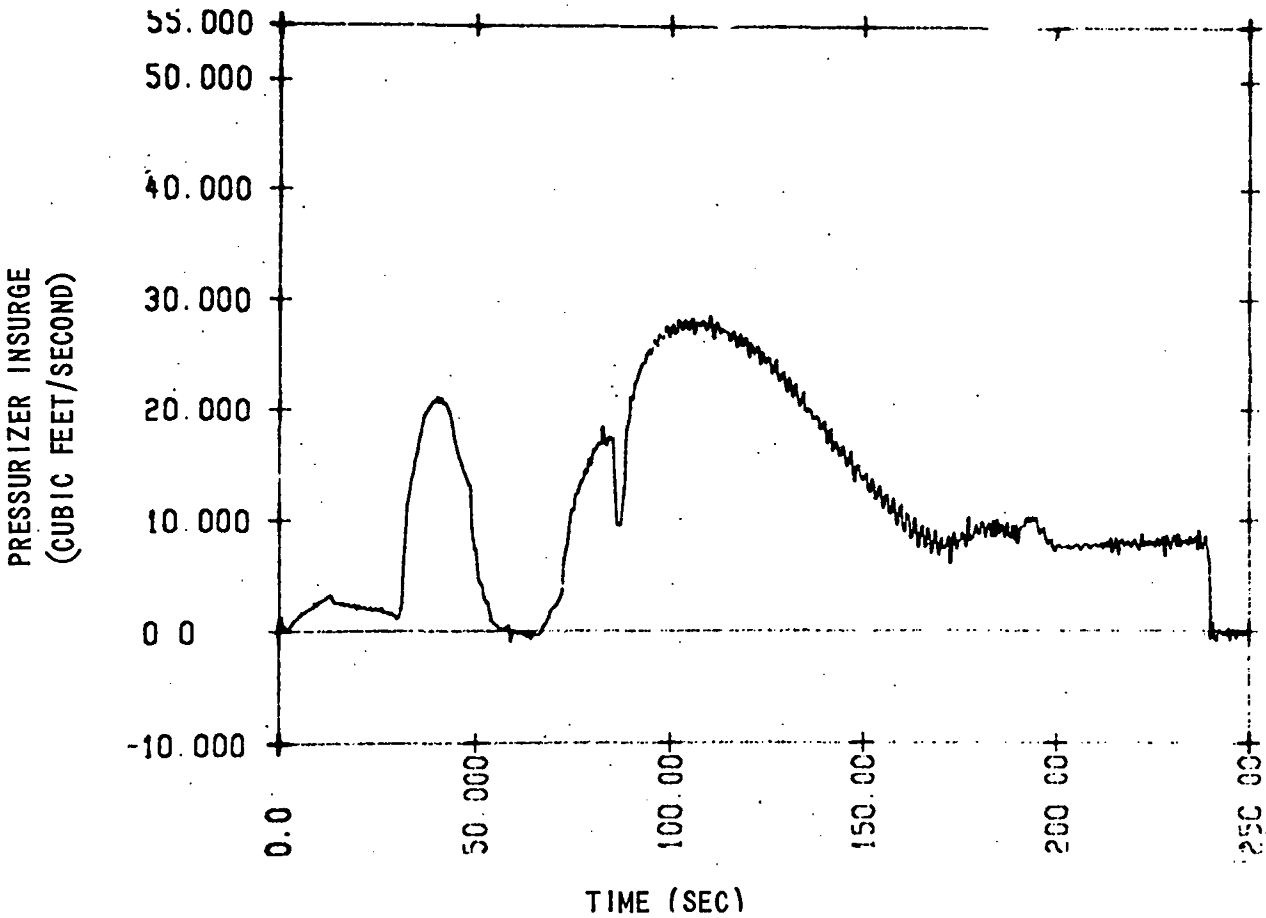

Figure 4-190. Loss of Feedwater - Fauske Water Relief Model
(Pressurizer Insurge vs. Time)

4-56. LOSS OF AC POWER TO THE STATION AUXILIARIES (STATION BLACKOUT) WITHOUT REACTOR TRIP

4-57. Identification of Causes and Transient Description

A complete loss of normal ac power to the station auxiliaries would result from a loss of off-site power combined with a trip of the turbine/generator.

If site and off-site power were lost, plant components requiring ac power would lose their normal power source. These components include reactor coolant pumps, condensate pumps, circulating water pumps, and main feedwater pumps (if main feedwater pumps are motor-driven). The emergency diesel generators are started on an undervoltage signal on the plant emergency busses and begin to supply vital plant loads. Emergency power is also provided by the station batteries.

Loss of power to the control rod motor/generator sets results in a loss of power to the rod drive mechanism gripper coils. This releases the rods to fall into the core independently of any protection system action to open the reactor trip circuit breakers. This method of rod release into the core is not part of the plant protection system, but is nevertheless a consequence of a loss of station power. Over eleven million control rod hours actual experience in operating reactors confirms the very low likelihood of failure of the rods to drop when power is removed.

As a result of the power loss to the reactor coolant pumps, forced reactor coolant flow is lost as the pumps coast down. Reactor coolant flow decreases with pump speed to the point where natural circulation flow is established. If the reactor is at power at the time of the accident, the immediate effect of loss of coolant flow is an increase in the coolant temperature. The decrease in flow and increase in coolant temperature causes reduced margin to DNB resulting in prompt protection system action to generate a reactor trip. There are about 25 trip inputs to the Reactor Protection System (varies slightly among plants), all of which operate on the deenergize-to-trip principle. In addition to rod mechanisms being deenergized by loss of power, the following trip demands would occur to the motor/generator sets:

- Undervoltage or underfrequency on the reactor coolant pump power supply busses — This reactor trip is generated following a low voltage (or low frequency) signal when the reactor is operating at high power.

- Low reactor coolant loop flow — This reactor trip is generated if a low-flow condition in any loop is detected while the reactor is operating at high power.

- Open reactor coolant pump circuit breakers — During operation at or near rated power, opening of any pump circuit breaker will cause a reactor trip. The standard electrical system design provides for tripping all circuit breakers when the bus to which they are connected is deenergized.

- Overtemperature ΔT — This reactor trip is actuated when the primary loop overtemperature ΔT setpoint is exceeded. This setpoint is continuously calculated from primary average temperature, primary pressure, and core axial power distribution.

- Overpower ΔT — This reactor trip is actuated when the primary loop overpower ΔT setpoint is exceeded. This setpoint is continuously calculated from primary average temperature and core axial power distribution.

- High pressurizer pressure reactor trip

- High pressurizer water level reactor trip

The auxiliary feedwater system will be actuated on trip of the main feedwater pumps and/or a loss of site power signal during a station blackout. The steam-driven auxiliary feed pump uses steam from the secondary system and exhausts to the atmosphere. The motor-driven auxiliary feed pump is supplied with power from the emergency diesel-generators. The pumps take suction directly from a condensate storage tank for delivery to the steam generators.

4-58. Analysis of Effects and Consequences

During a station blackout where normally expected protection system action occurs, the reactor is promptly tripped by reactor coolant pump bus undervoltage with no DNB or fuel damage even with extremely conservative initial conditions being assumed. However, ATWT analyses assumed that loss of power to the rod power supply motor/generator sets was disregarded. In addition, all of the reactor trip signals were postulated not to result in a reactor trip.

The analysis was done using the LOFTRAN, FACTRAN, and THINC-III codes which were discussed in section 3. The following assumptions were made:

- Initial normal full power operation early in core life

- Loss of off-site ac power and on-site ac power occurs, causing:

  1) Reactor coolant pump coastdown to natural circulation in the coolant loops

  2) Loss of all main feedwater pumps

  3) Turbine trip

  4) Actuation of auxiliary feedwater pumps following start of emergency generators, 60 seconds from the start of the transient.

- Pressurizer relief valves are operable.
- Remaining plant control systems are not operable as a consequence of the loss of ac power
- No credit for automatic reactor trip.

4-59. Results

The station blackout was analyzed for 2-, 3-, and 4-loop plants with 51 Series and Model D steam generators and appropriate fuel arrays. The limiting plant configuration for the blackout transient was found to be a 4-loop plant with 17x17 fuel with a 51 Series steam generator. Therefore, this was used for the base case. (See table 4-12). The results of this case are shown in figures 4-191 through 4-202 and its sequence of events listed in table 4-13. The figures show that the rapid decrease in core flow, due to loss of the reactor pumps, caused loss of secondary heat transfer with an associated rise in core inlet temperature, core average temperature, and pressurizer pressure. The minimum DNB ratio for this case was 1.52 at 12 seconds.

TABLE 4-12
RESULTS OF BLACKOUT FOR 2-, 3-, AND 4-LOOP PLANTS

Case			
No. of Loops	SG Type	Minimum DNB Ratio	Peak RCS Pressure (psia)
4[a]	51	1.52	2605
3	51	1.53	2592
2[b]	51	1.60	2530
4	D	1.53	2556
3	D	1.57	2583

[a] Reference Case

[b] 14x14 fuel array

TABLE 4-13

SEQUENCE OF EVENTS FOR A STATION BLACKOUT WITHOUT REACTOR TRIP – REFERENCE CASE

Event	Time (seconds)
Loss of Site ac Power and Off-Site ac Power	0
Reactor Coolant Pumps Begin to Coast Down	
Main Feedwater Lost	
Power to Rod Drive Mechanisms Lost	
Signal Generated to Start Auxiliary Feedwater Pumps (Loss of Site ac Power and/or Loss of Main Feed Pumps)	
Undervoltage Reactor Trip Setpoint Reached and Underfrequency Reactor Trip Setpoint Reached	0
Low Reactor Coolant Flow Reactor Trip Setpoint Reached	1.6
Pressurizer Power-Operated Relief Valves Open	4.0
Overtemperature ΔT Reactor Trip Setpoint Reached	4.6
Overpower ΔT Reactor Trip Setpoint Reached	5.1
High Pressurizer Pressure Reactor Trip Setpoint Reached	5.2
Pressurizer Safety Valves Open	7.0
Steam Generator Safety Valves Open	13
High Pressurizer Water Level Reactor Trip Setpoint Reached	18
Pressurizer Fills with Water	33
Bulk Saturation Reached at Core Outlet	40
Auxiliary Feedwater Pumps Start Delivering Flow	60
Steam Space Regained in Pressurizer	440

The lifting of the secondary safety valves limited the reactor coolant temperature and pressure increase. The peak Reactor Coolant System pressure was 2606 psia. A later increase in pressure occurred when the pressurizer filled with water. Core nuclear power decreased, due to the effect of negative reactivity feedback from a reduction in moderator density as the core average temperature increased, and came to an equilibrium value of about 18 percent of nominal at 140 seconds. Core flow due to natural circulation equilibrated at about 10 percent of its nominal value. Primary coolant temperature increased during the transient causing a slight nuclear power decrease due to the moderator heating. The steam space was recovered in the pressurizer at 440 seconds into the transient and the primary pressure began to drop below the power-operated relief-valve setpoint shortly thereafter. At 600 seconds, the operator was able to begin recovery and shutdown operations.

4-60. Sensitivity Studies

Additional cases were evaluated for a station blackout without a reactor trip to determine the effect of various initial conditions and assumptions on the consequences of the transient. These additional cases were analyzed in the same manner as the preceding reference case. The results of these sensitivity studies are summarized in table 4-14.

4-61. **80 Percent Initial Power Case** — This case was analyzed because of the initially less-negative moderator temperature coefficient at the reduced power (a result of a lower initial average coolant temperature). At 80 percent power (2738 MWt), the corresponding initial average temperature was 580.6°F. In spite of the reduced moderator feedback, the lower initial power inherently made this case less severe than the reference case as shown by the minimum DNB ratio of 2.22.

4-62. **Initial Steam Generator Mass Inventories** — The initial steam generator secondary fluid mass in the reference case was changed by ± 10 percent (447040 and 369455 lbs., respectively) to show the insensitvity of the minimum DNB ratio to this parameter. The results showed the minimum DNB ratio to be 1.52 for the +10-percent case, and 1.52 for the -10 percent case.

4-63. **Core Average Coolant Temperature** — Core average coolant temperature was both increased 8°F and decreased 20°F (594.2 and 564.65, respectively) to encompass the variation for 2-, 3-, and 4-loop plants. Initial steam generator steam pressure, pressurizer water volume, and feedwater enthalpy were adjusted for new average core temperature. See figures 4-203 and 4-204. This sensitivity study showed a minimum DNB ratio of 1.47 for the +8°F case and 1.62 for the -20°F case.

4-64. **Primary Coolant Flow Coastdown Rate** — To show the insensitivity of the results to the primary coolant flow coastdown rate, the pump inertia was changed by ± 30 percent

TABLE 4-14
SUMMARY OF RESULTS FOR BLACKOUT WITHOUT A REACTOR TRIP

Case Description	Minimum DNB Ratio	Peak RCS Pressure (psia)
4 Loop/51 Series SG	1.52	2605
80 Percent Initial Power	2.22	2570
Initial SG Mass + 10 Percent	1.52	2602
Initial SG Mass - 10 Percent	1.52	2610
Initial Coolant Avg. Temp. + 8°F	1.47	2595
Initial Coolant Avg. Temp. --20°F	1.62	2602
Time to Half Flow of 14 sec.	1.53	2604
Time to Half Flow of 11.6 sec.	1.51	2608
Press'r Relief Valves Inoperable	1.50	2634
Purge Volume Doubled	1.52	2606
Automatic Rod Control	1.64	2588
15x15 Core	1.25	2606

causing the times to half flow to change to 14.0 and 11.6 seconds, respectively (the reference case value is approximately 13 seconds). The results for this case showed a minimum DNB ratio of 1.53 for the +30-percent case, and 1.51 for the -30-percent case.

4-65 **Power Relief Valves** – For this case, no credit was taken for the pressurizer power relief valves. The results of this case (figures 4-205 and 4-206) showed a minimum DNB ratio of 1.50.

4-66. **Feedwater System Purge Volume** – This case was analyzed to show the insensitivity of the results to the volume of hot feedwater that must be purged before the cold water (from the condensate storage tank) is pumped into the steam generator by the auxiliary feedwater system. A minimum DNB ratio of 1.52 resulted from this case in which the purge volume was increased from 500 ft^3 for the reference case to 1000 ft^3.

4-67. **Automatic Rod Control** – Automatic rod control was used to show the effect of stabilizing the average coolant temperature before the time when the reactor trip renders the rods immovable (rod worth – 8 pcm/step). The results showed a minimum DNB ratio of 1.64.

4-68. **15x15 Fuel Assembly** – The 15x15 fuel assembly was analyzed to demonstrate the effect of fuel array on DNB ratio. The results of this case (figures 4-207 and 4-208) showed a minimum DNB ratio of 1.25. For calculational convenience, the inlet temperature listed in table 2-1 was used. The actual inlet temperature for the 15x15 core is approximately 10°F lower. Thus the reported DNB ratio of 1.25 is conservative.

4-69. **Shutdown** – In all of the cases analyzed, the primary system reached an essentially stable condition at 10 minutes. With level in the steam generators beginning to rise and secondary heat removal sufficient capability was available to remove energy generated in the core by use of the auxiliary feedwater system.

4-70. Conclusions

For the station blackout without reactor trip the transient results show that based upon the calculated DNB ratio no significant clad damage is expected and a peak Reactor Coolant System pressure which will not cause impairment of Reactor Coolant System mechanical integrity.

The transient equilibrates to a condition from which the operator can commence shutdown procedures by boration, with decay heat removal, and cooldown can be accomplished with the auxiliary feedwater system.

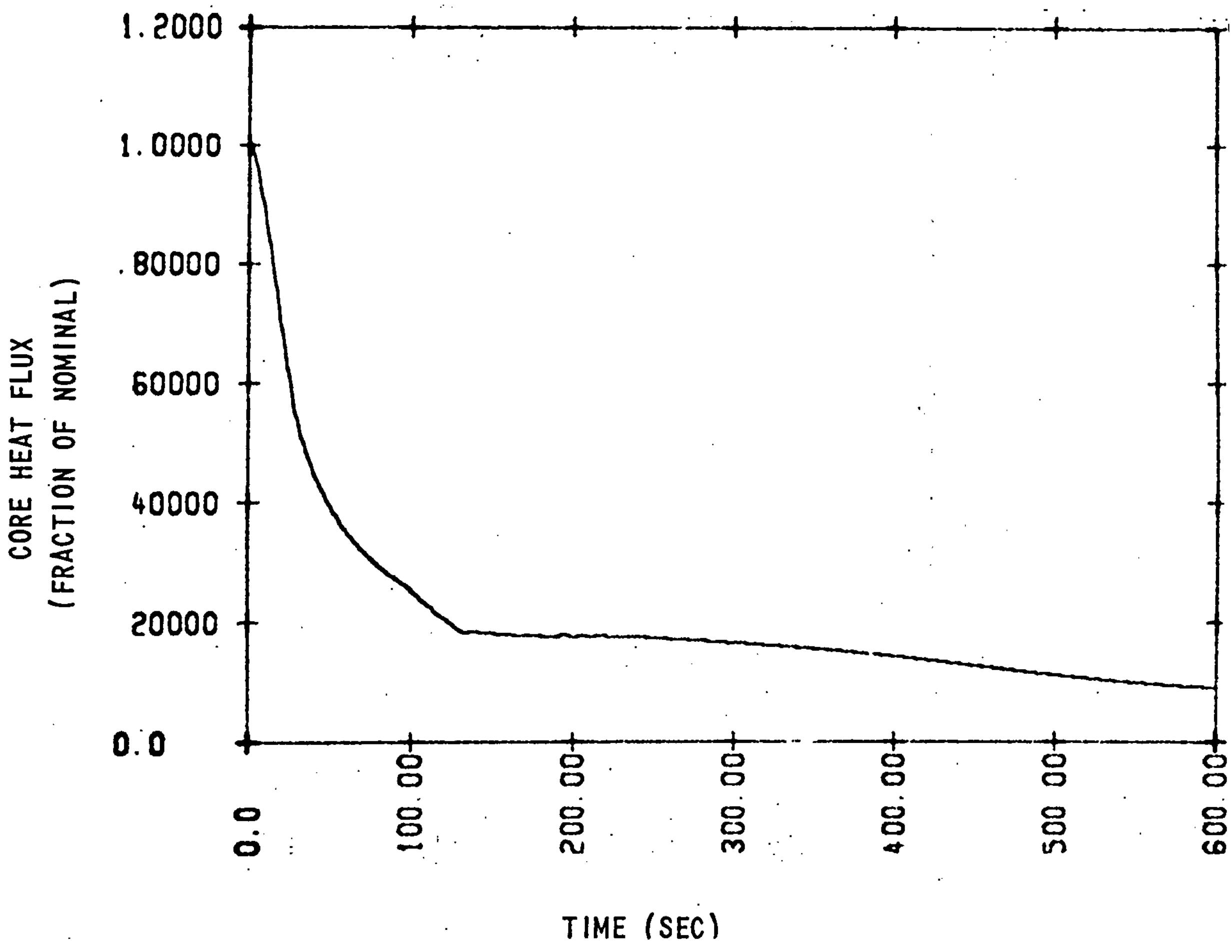

Figure 4-191. Station Blackout - Reference Case
(Core Heat Flux vs. Time)

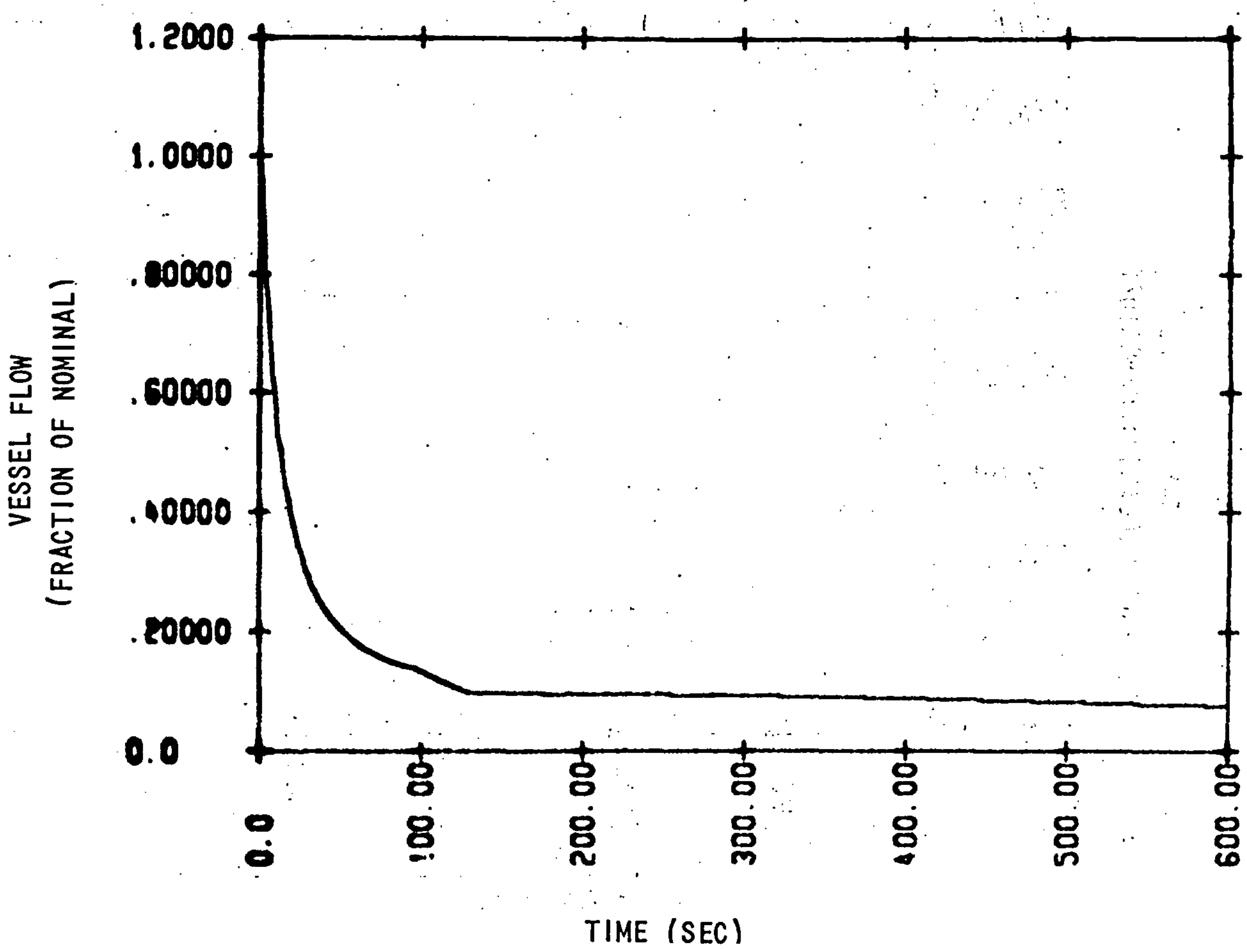

Figure 4-192. Station Blackout - Reference Case
(Vessel Flow vs. Time)

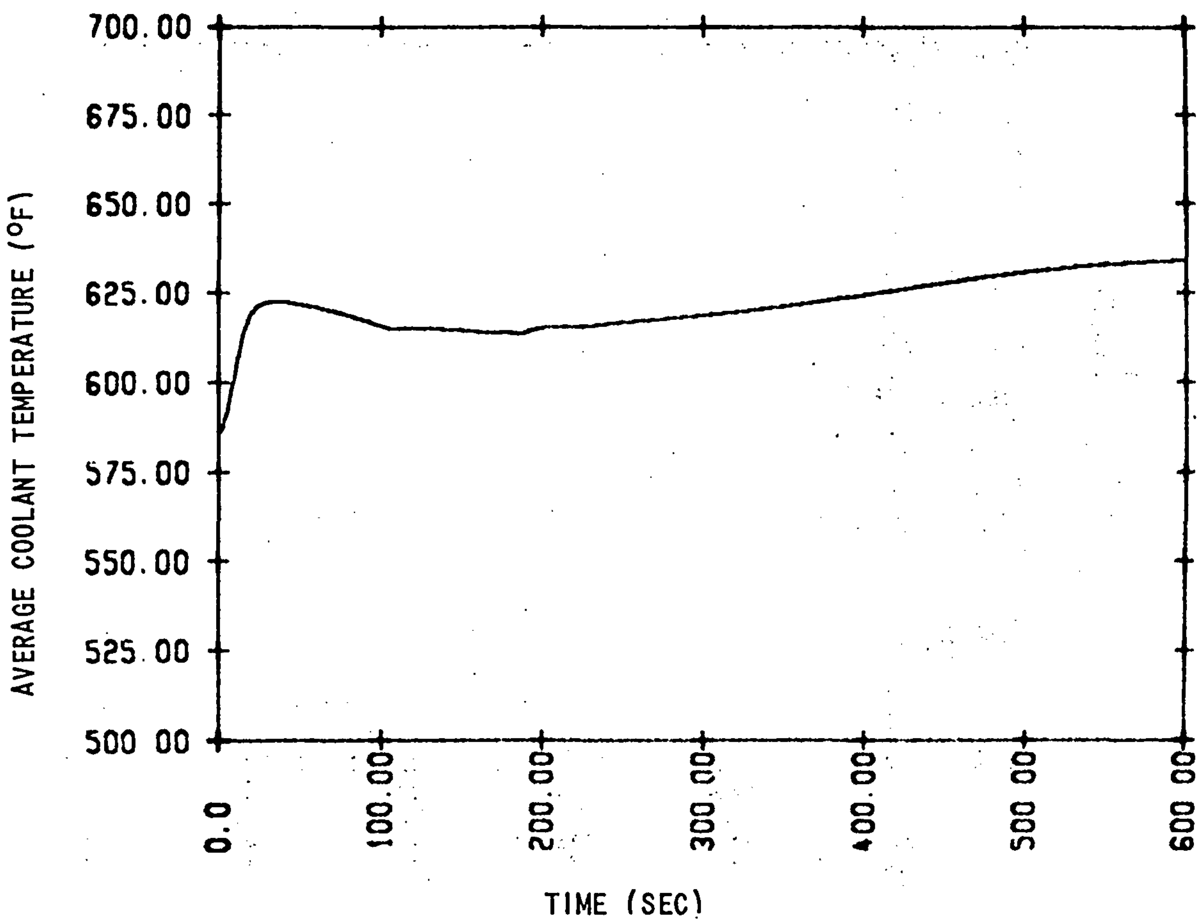

Figure 4-193. Station Blackout - Reference Case
(Average Coolant Temperature vs. Time)

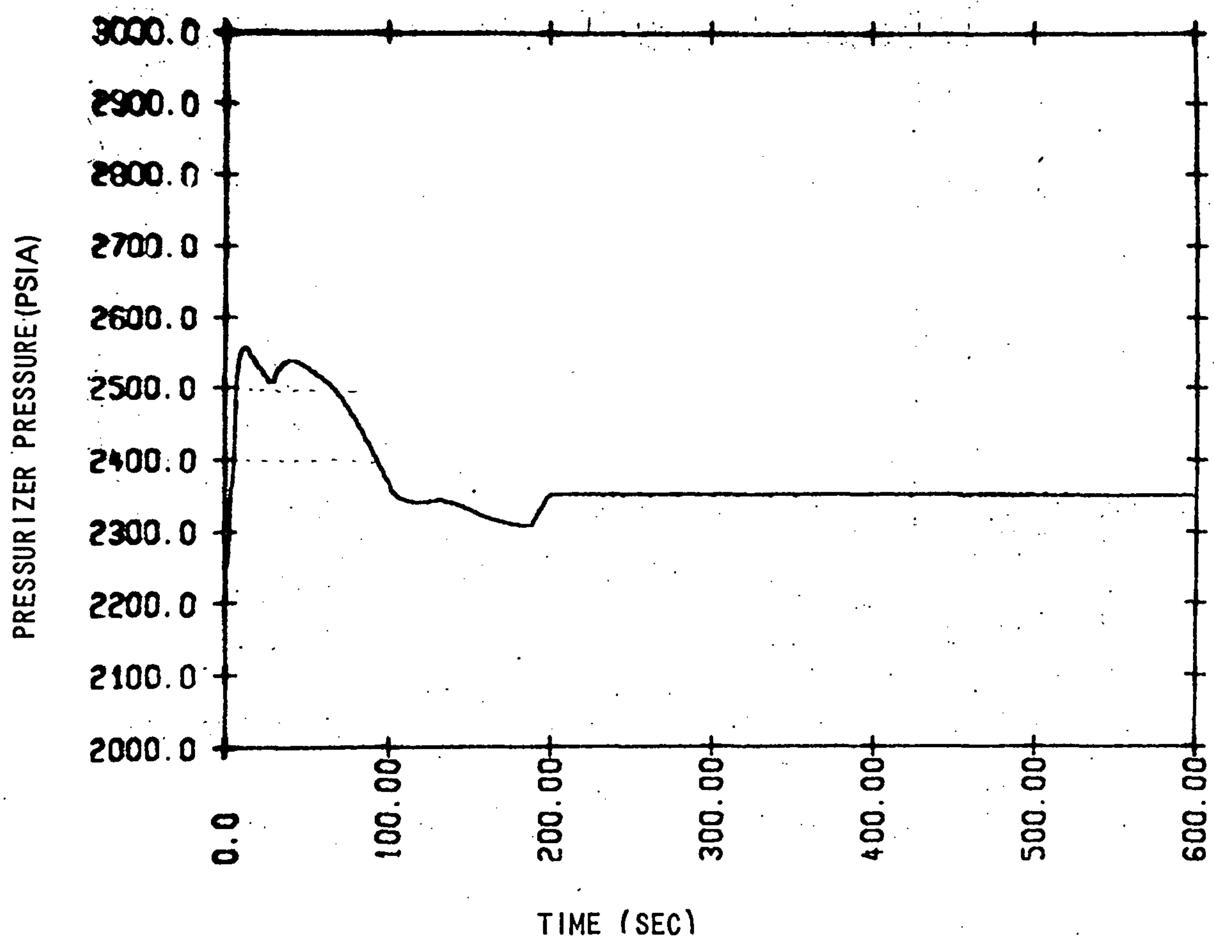

Figure 4-194. Station Blackout - Reference Case
(Pressurizer Pressure vs. Time)

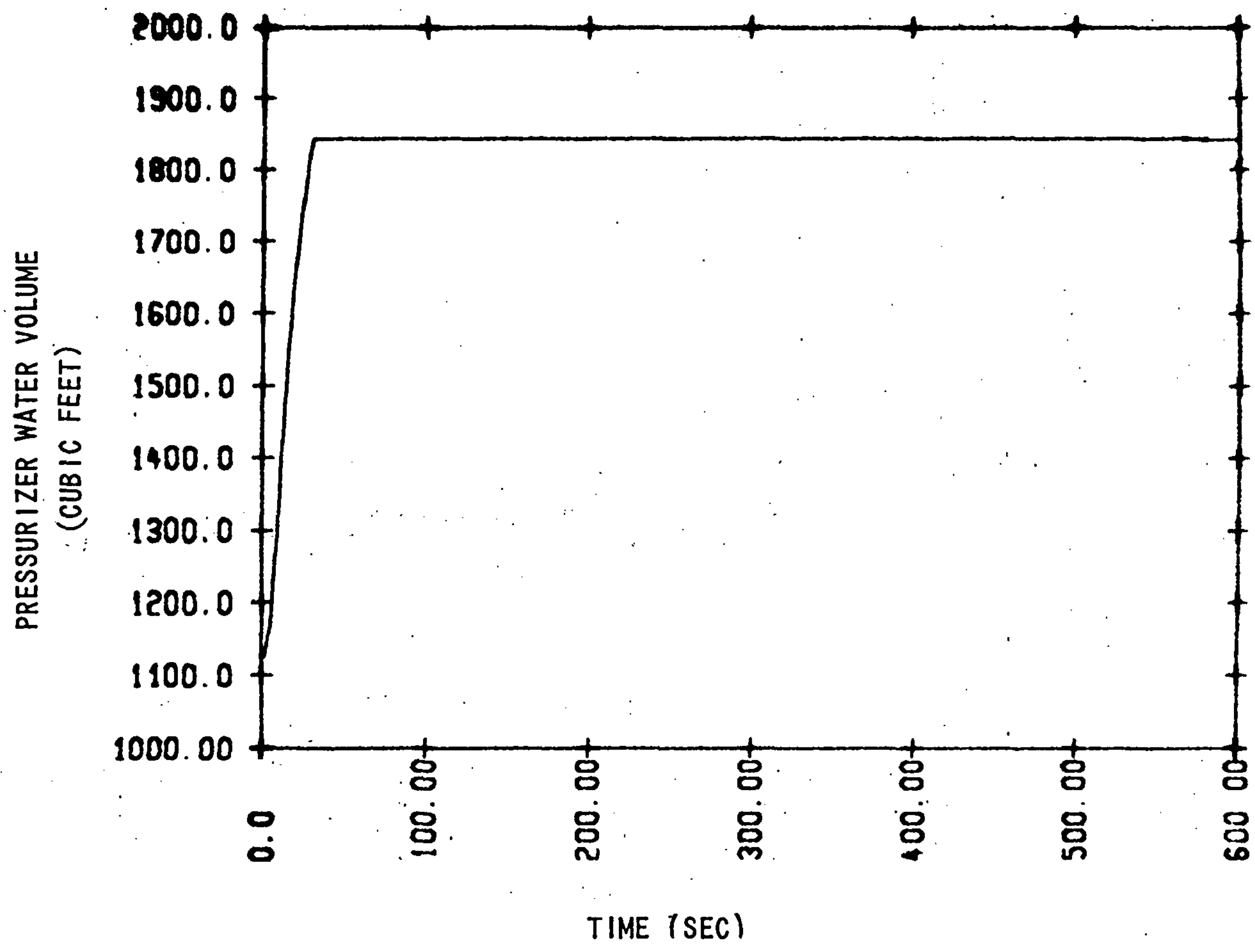

Figure 4-195. Station Blackout - Reference Case (Pressurizer Water Volume vs. Time)

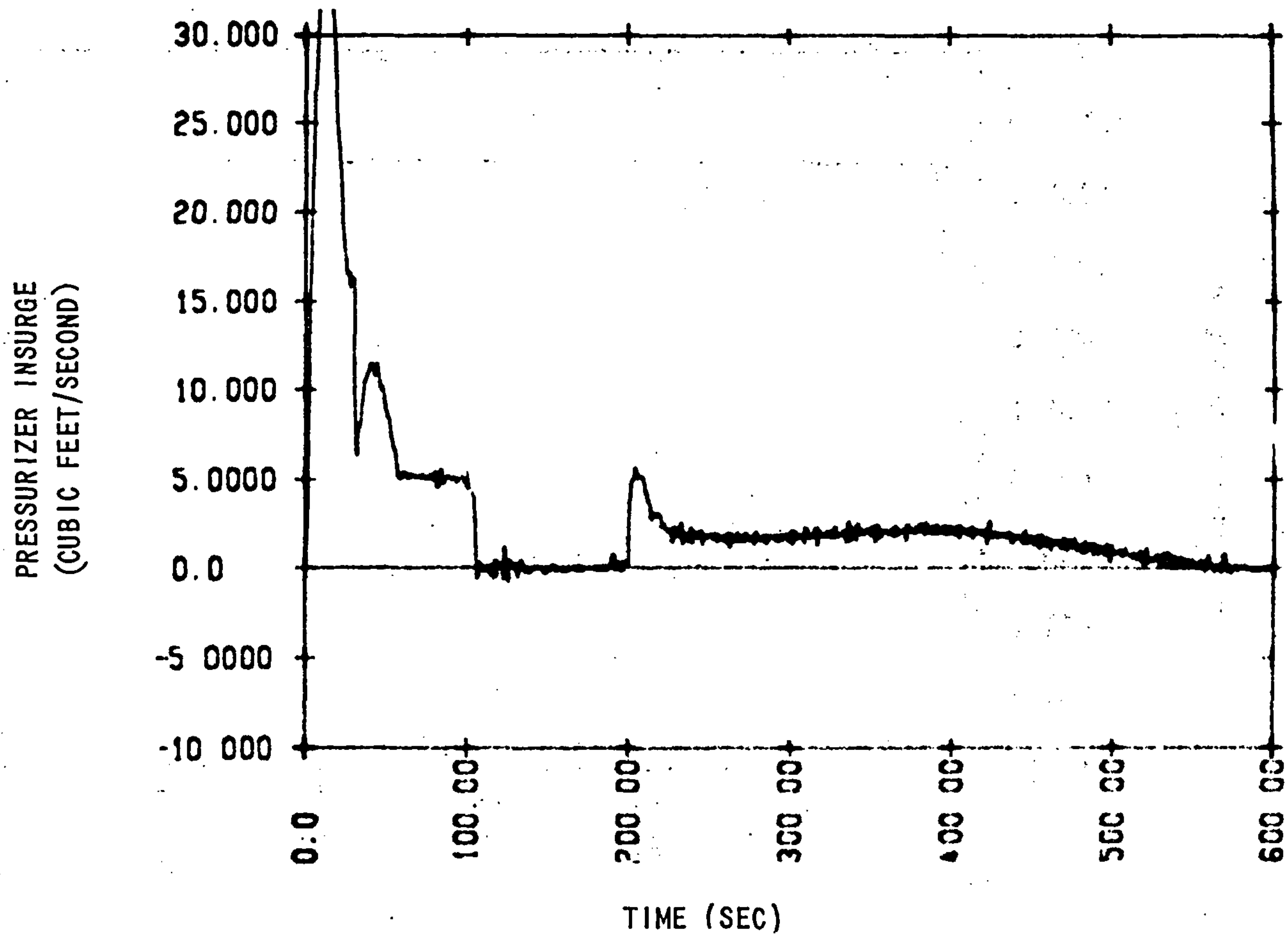

Figure 4-196. Station Blackout - Reference Case
(Pressurizer Insurge vs. Time)

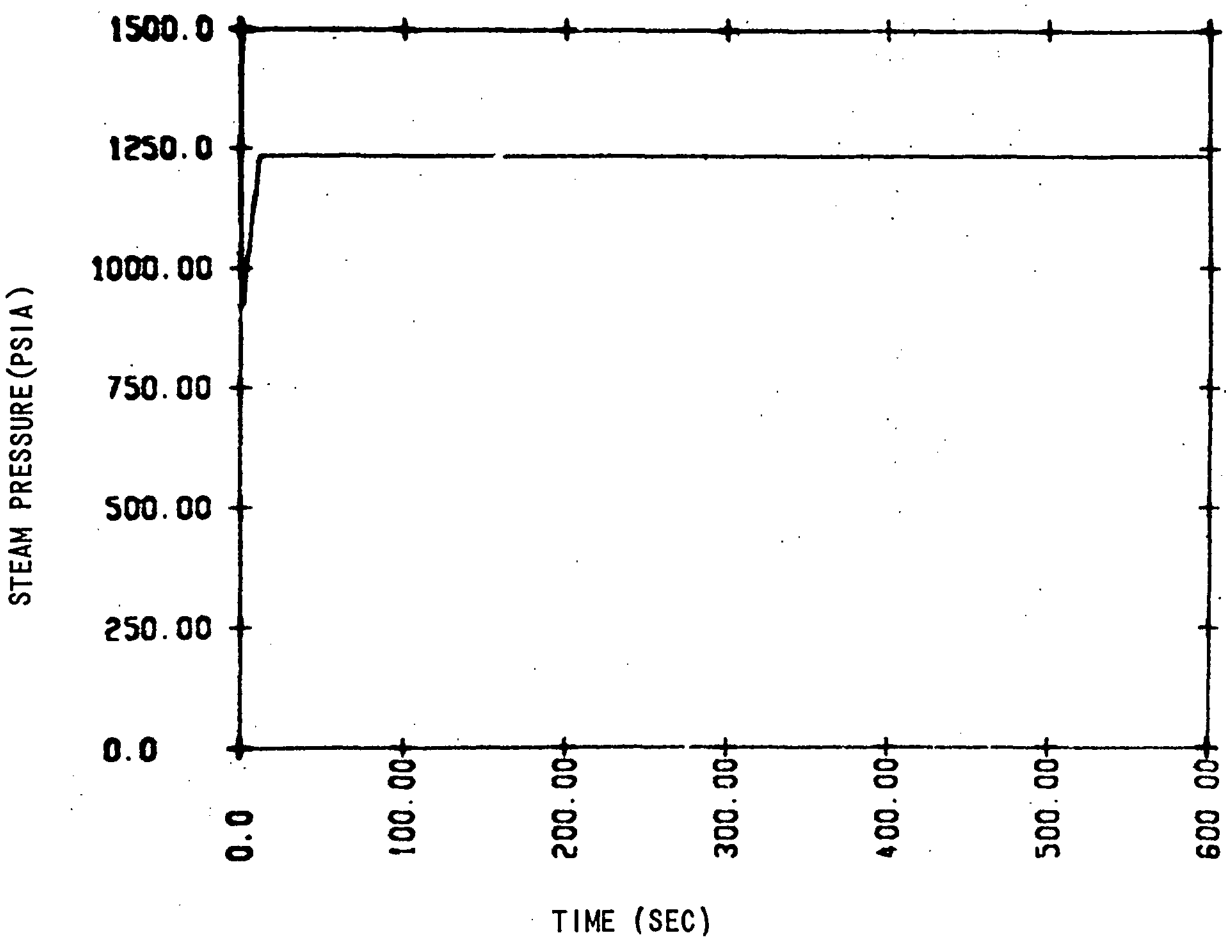

Figure 4-197. Station Blackout - Reference Case
(Steam Pressure vs. Time)

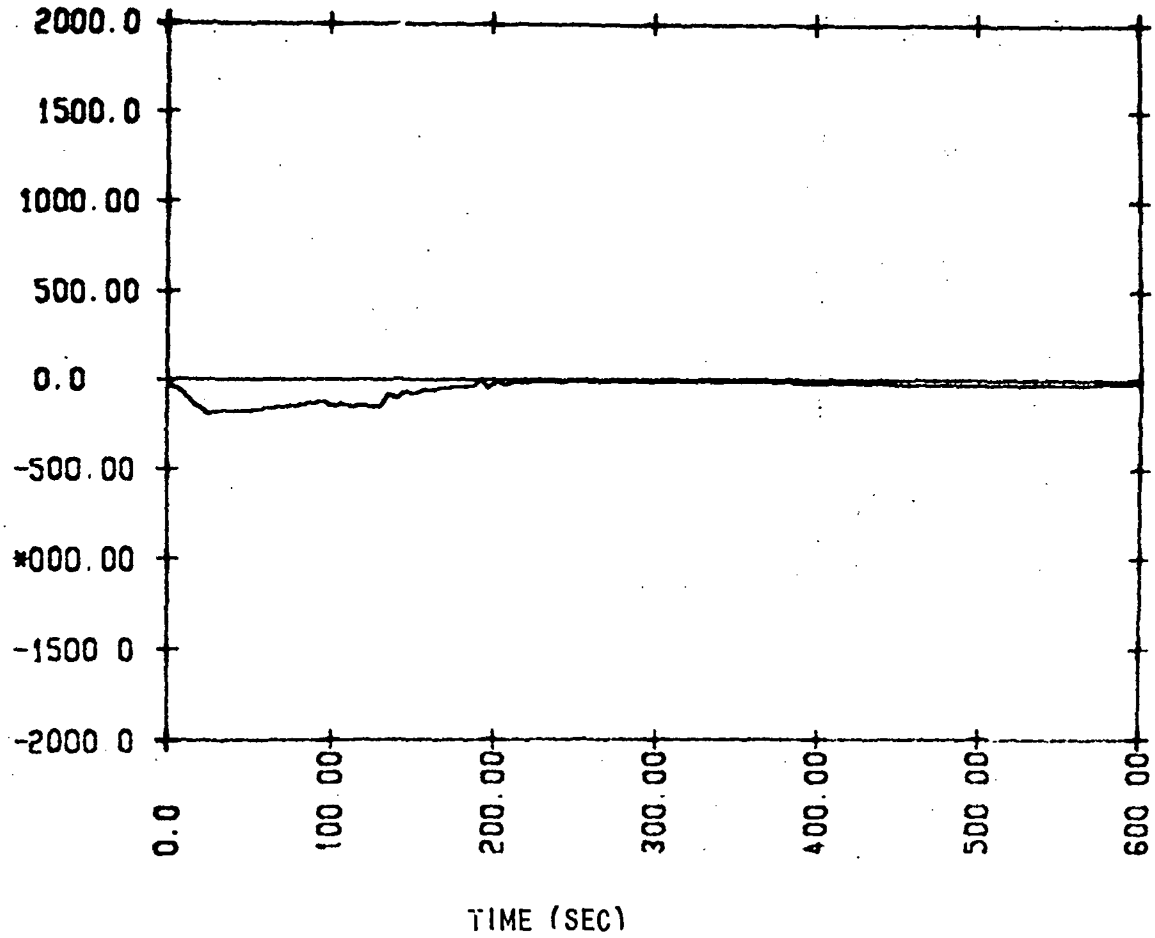

Figure 4-198. Station Blackout - Reference Case
(Total Reactivity vs. Time)

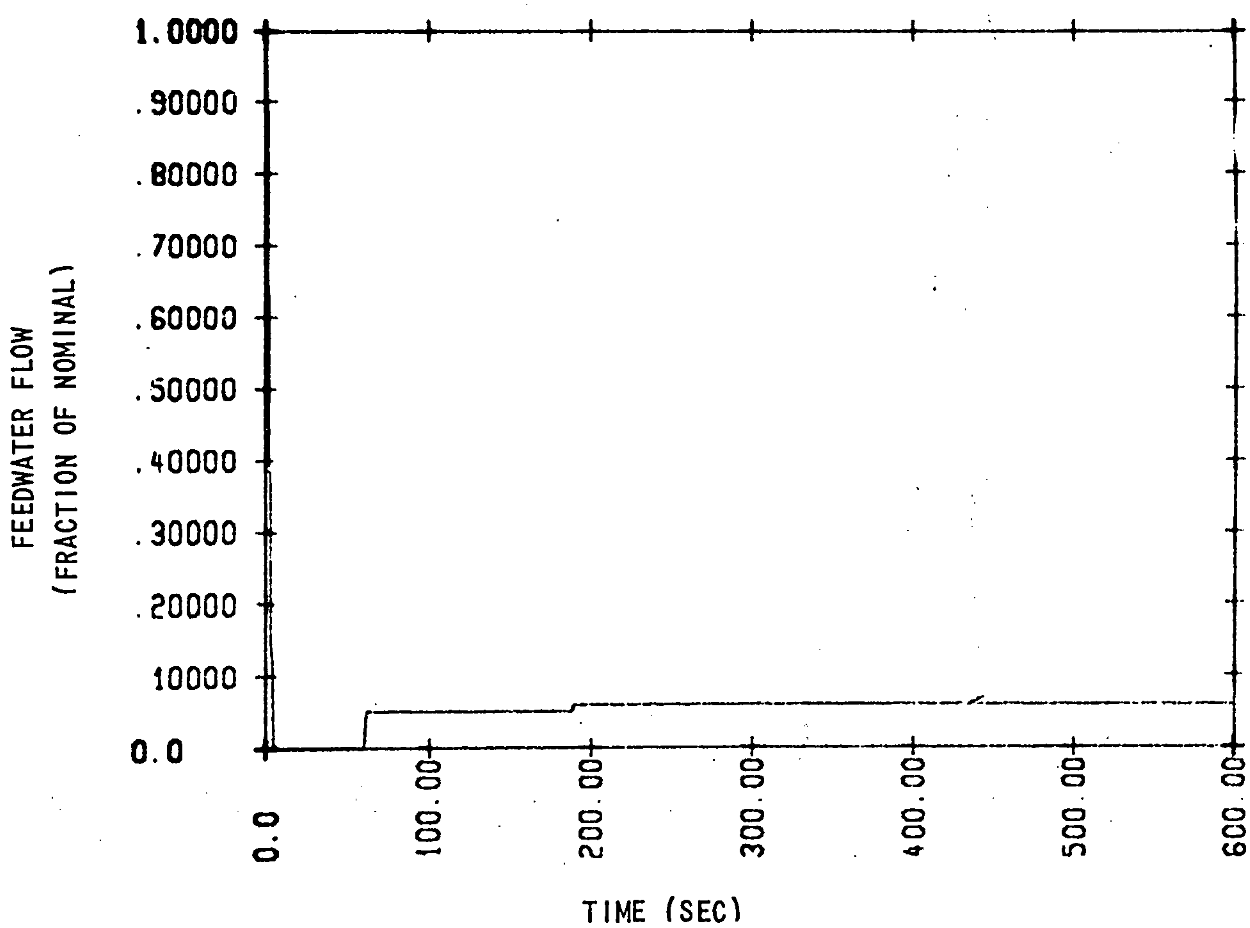

Figure 4-199. Station Blackout – Reference Case
(Feedwater Flow vs. Time)

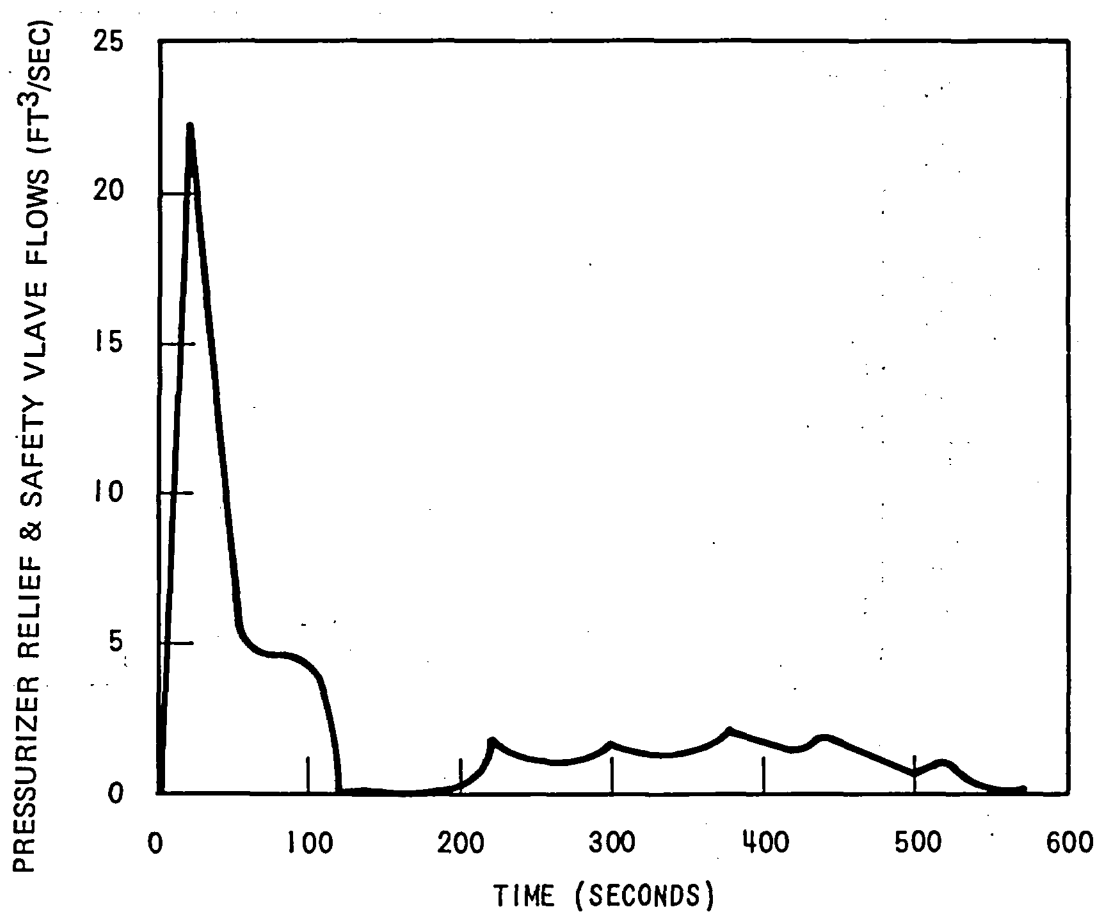

Figure 4-200. Station Blackout — Reference Case
(Pressurizer Relief & Safety Valve Flows vs. Time)

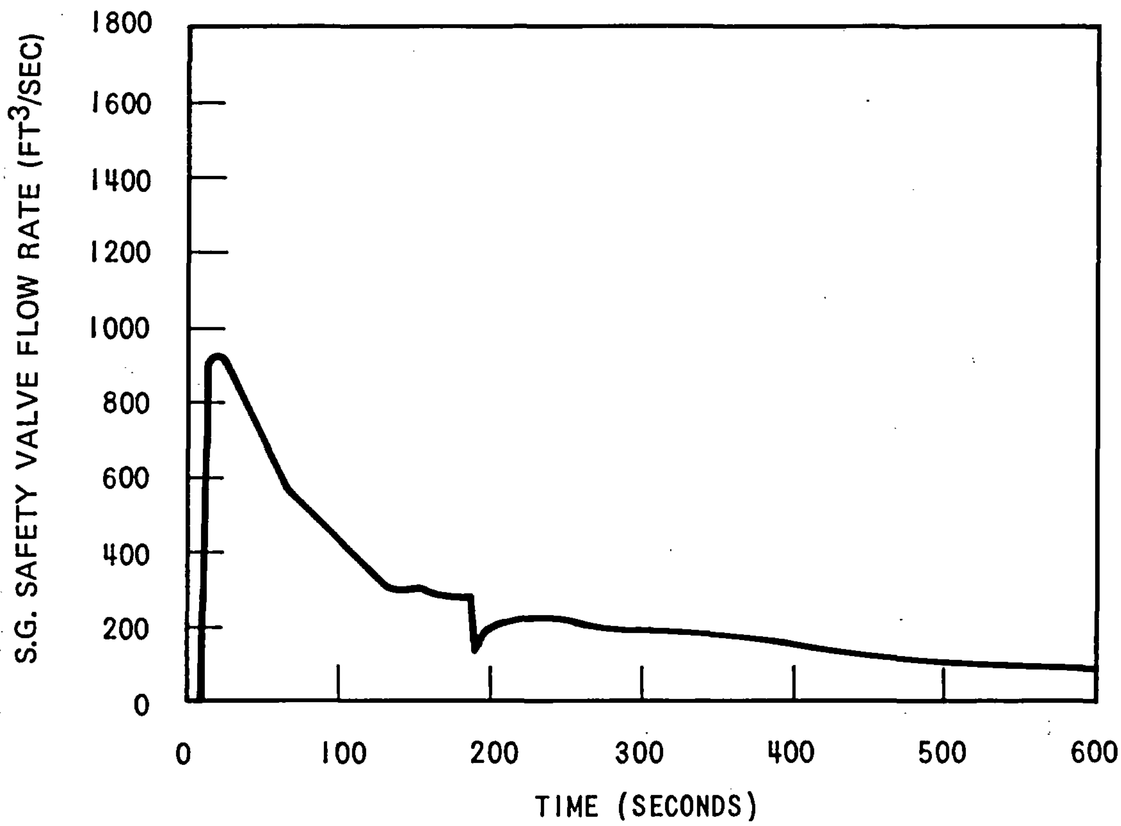

Figure 4-201. Station Blackout — Reference Case
(S.G. Safety Valve Flow Rate vs. Time)

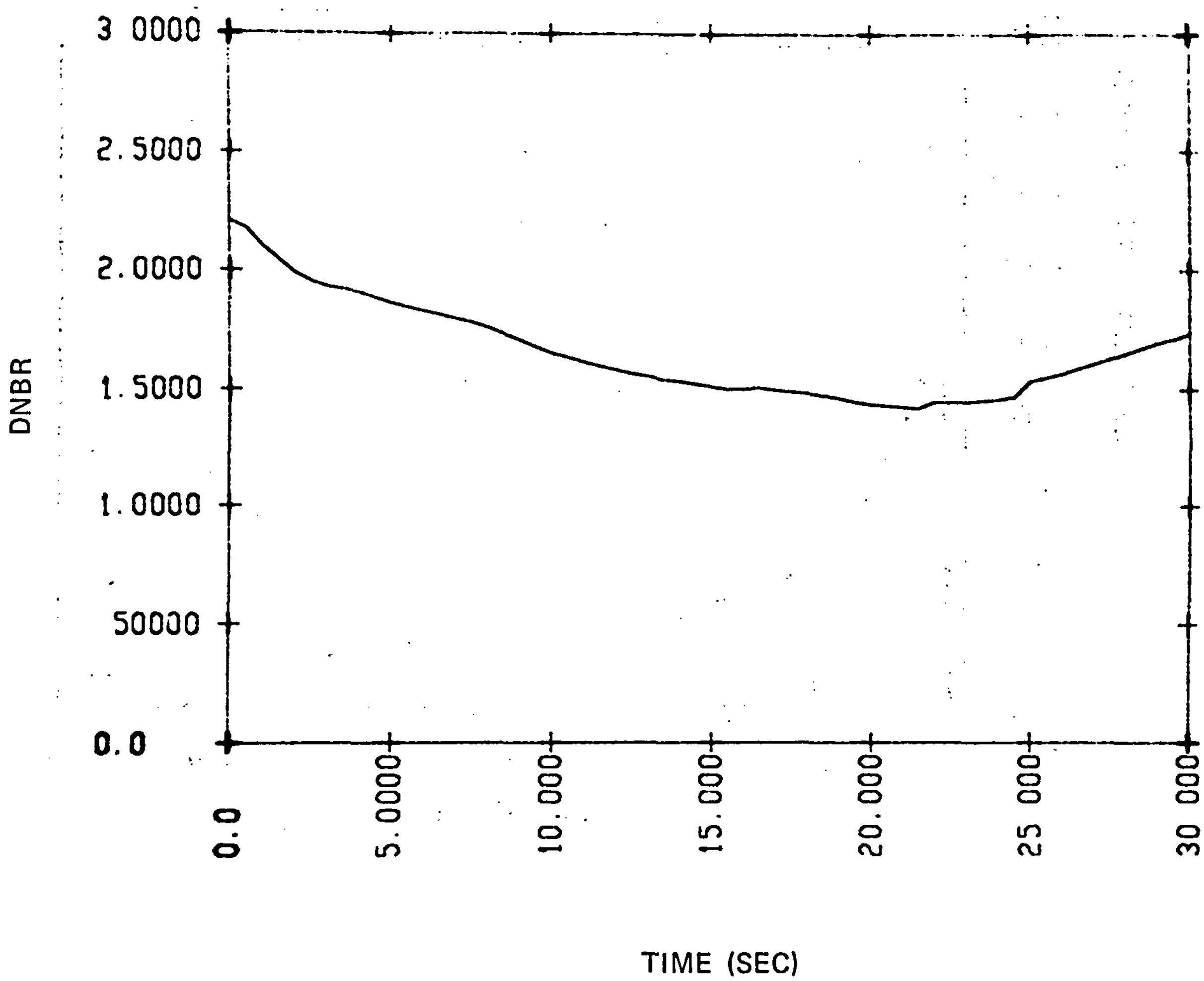

Figure 4-202. Station Blackout — Reference Case
(DNBR vs. Time)

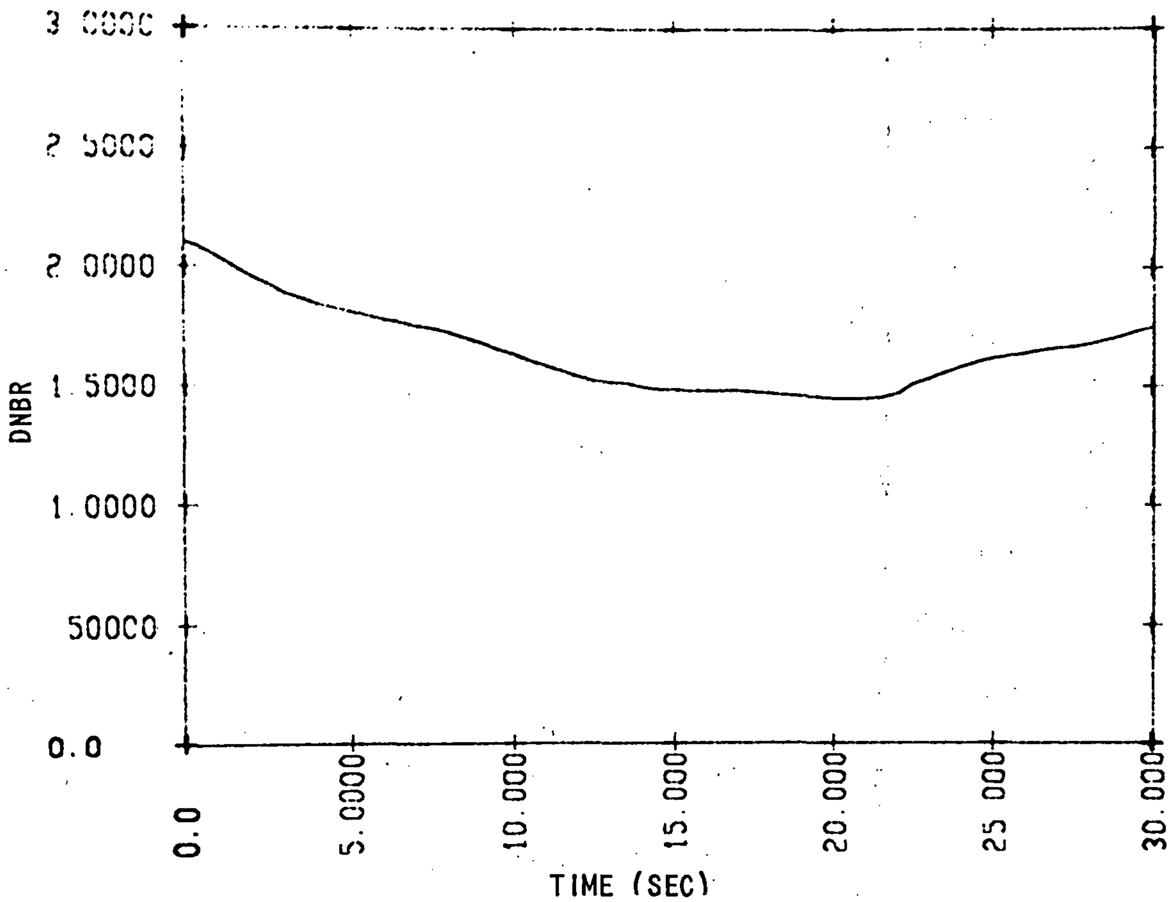

Figure 4-203. Station Blackout - Tavg +8°F
(DNBR vs. Time)

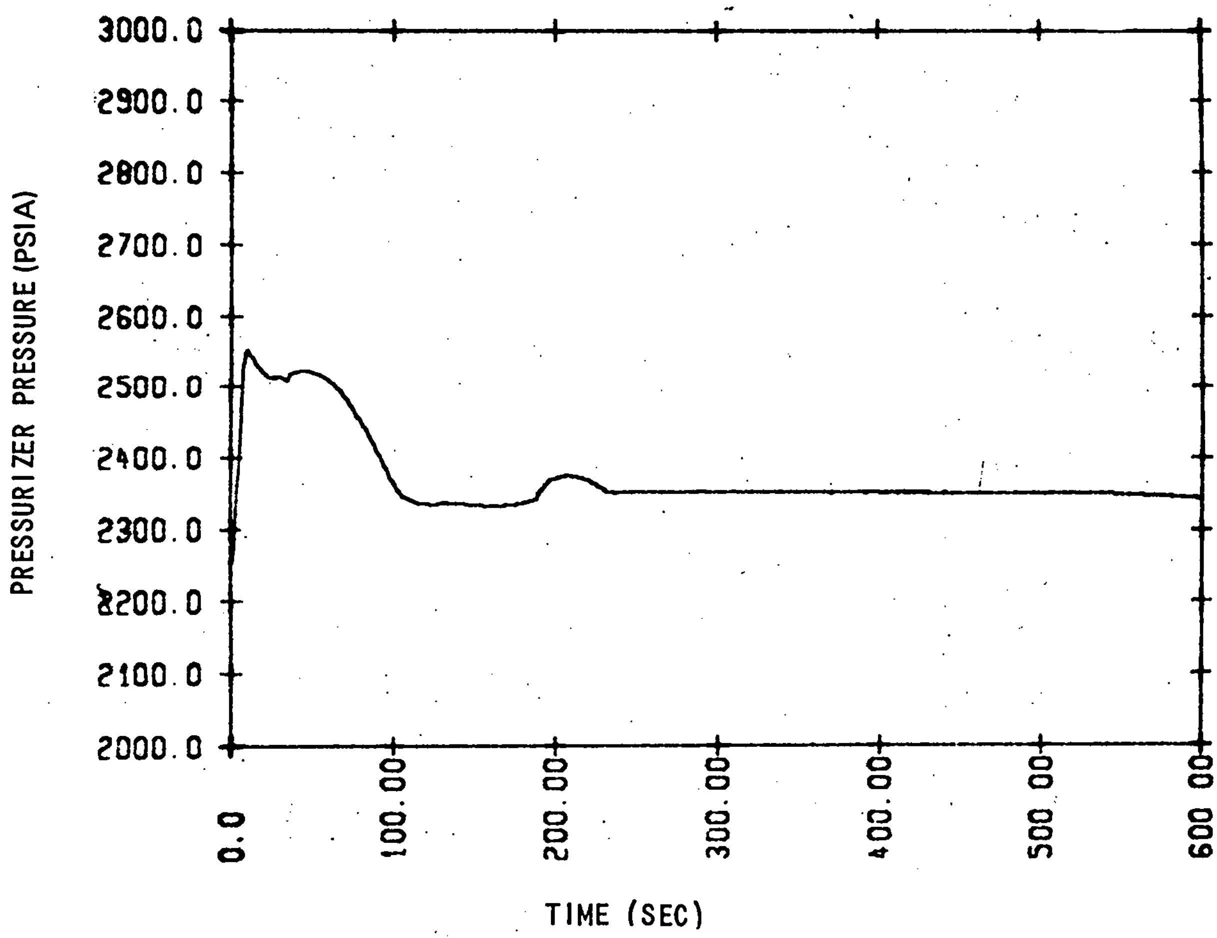

Figure 4-204. Station Blackout - Tavg +8°F
(Pressurizer Pressure vs. Time)

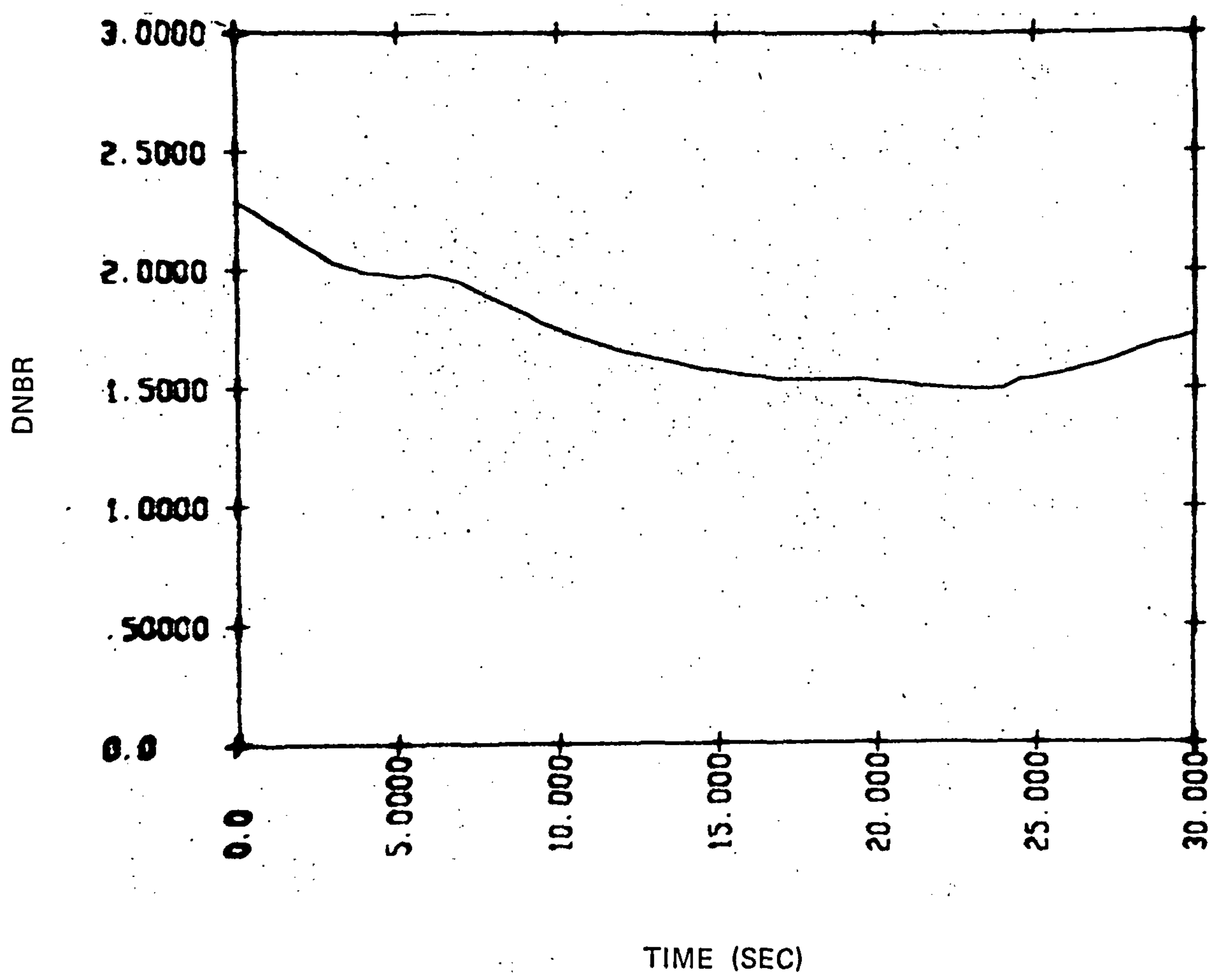

Figure 4-205. Station Blackout — No Power Relief Valves
(DNBR vs. Time)

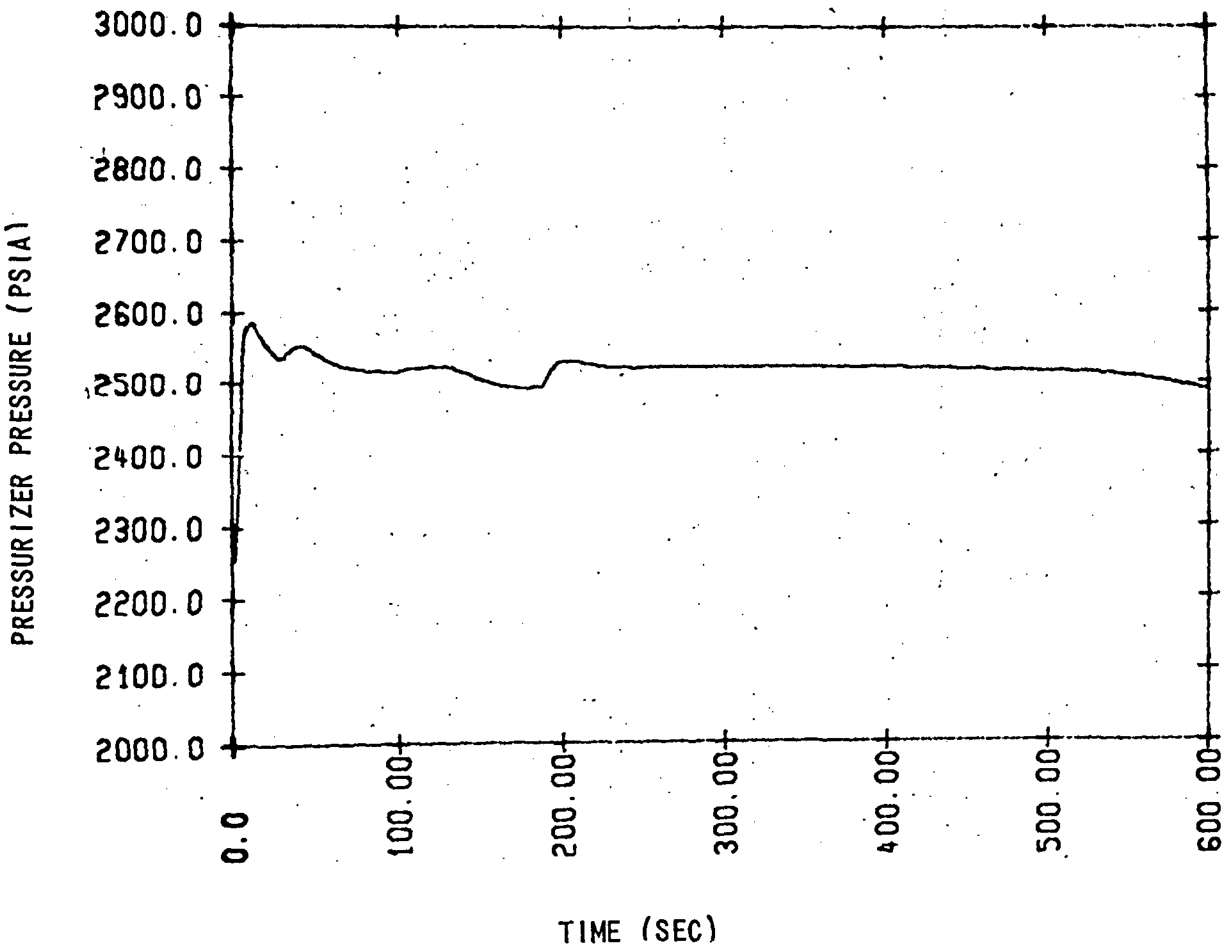

Figure 4-206. Station Blackout - No Power Relief Valves
(Pressurizer Pressure vs. Time)

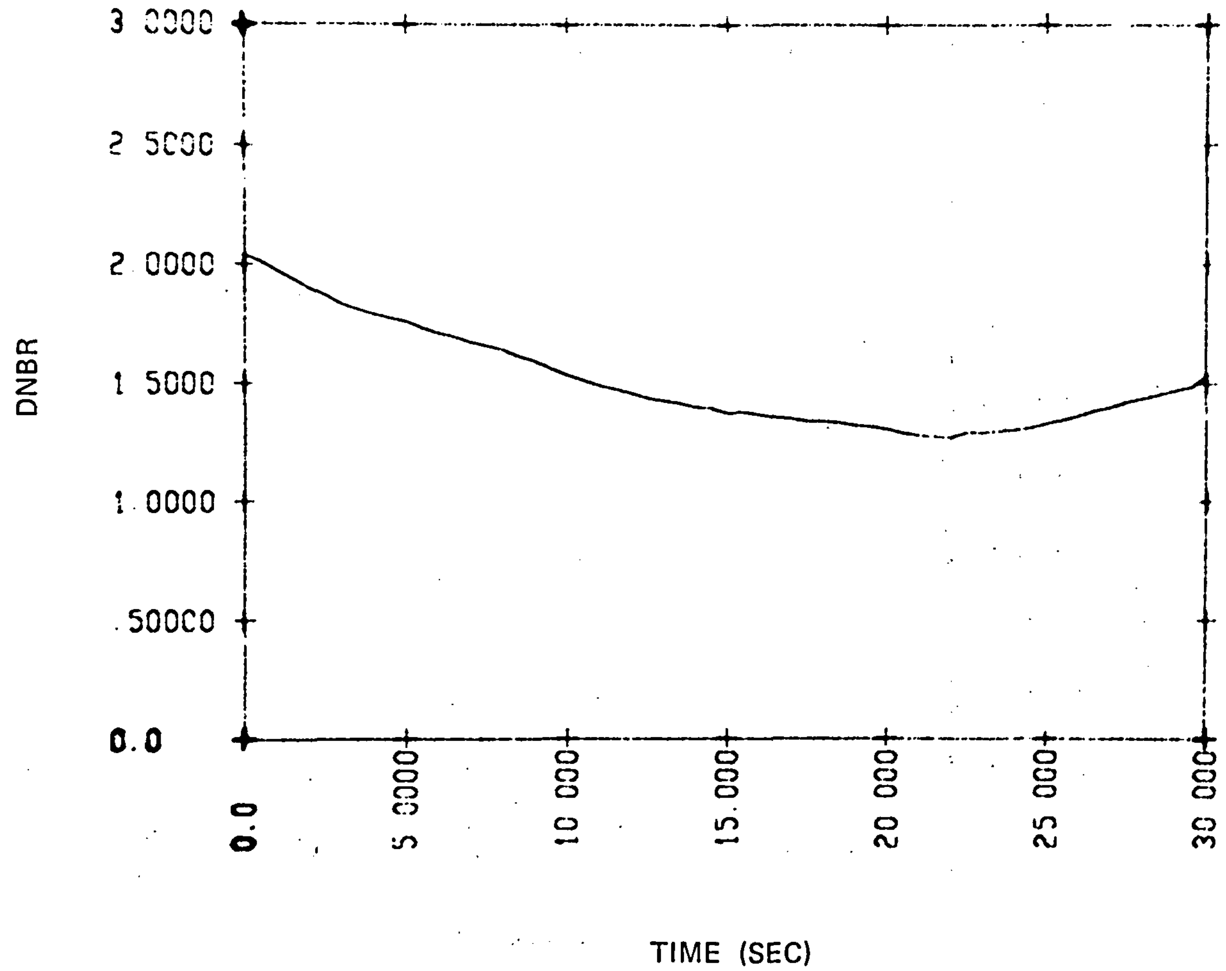

Figure 4-207. Station Blackout — 15 x 15 Fuel
(DNBR vs. Time)

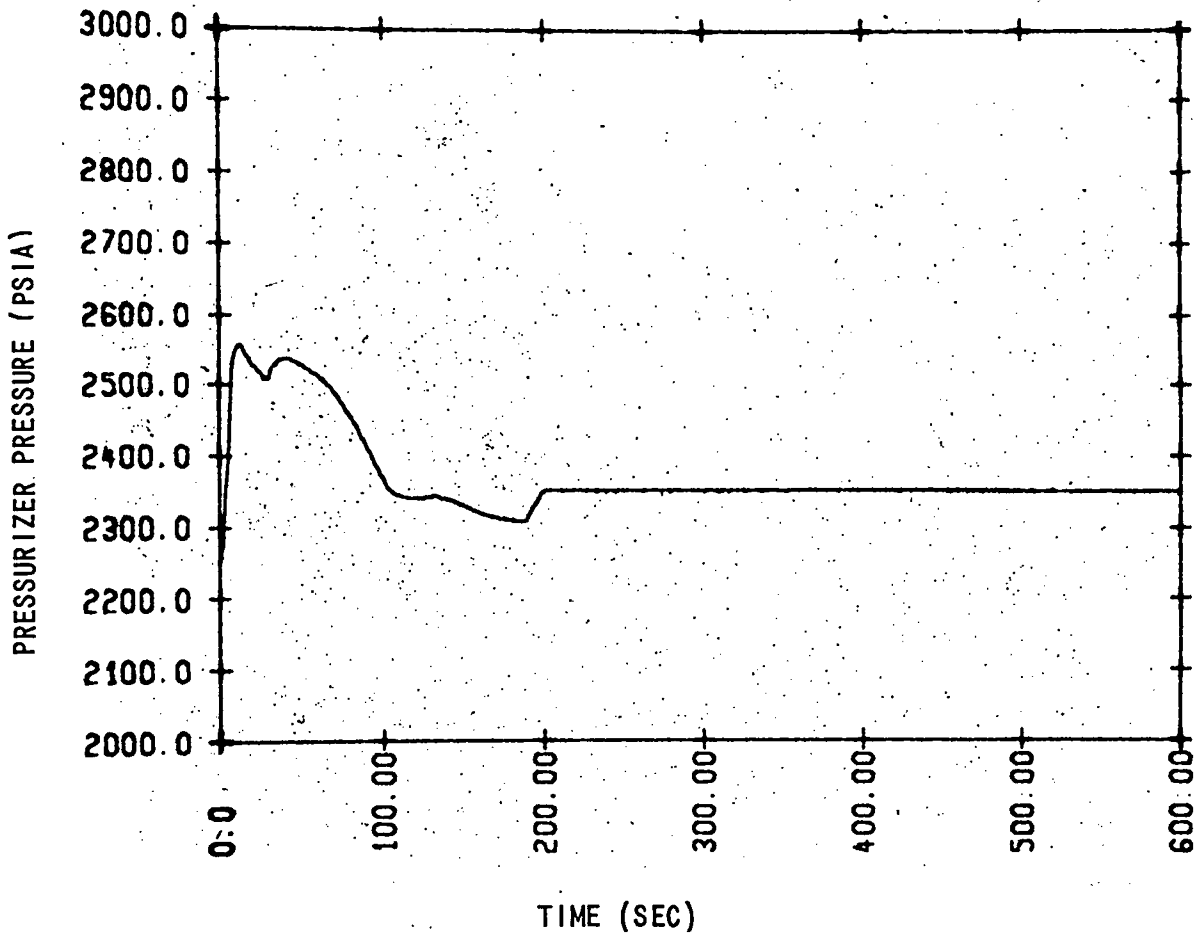

Figure 4-208. Station Blackout - 15 x 15 Fuel (Pressurizer Pressure vs. Time)

4-71. EXCESSIVE LOAD INCREASE INCIDENT

4-72. Identification of Causes and Transient Description

An excessive load increase incident is defined as a rapid increase in the steam flow that causes a power mismatch between the reactor core power and the steam generator load demand. The Reactor Control System is designed to accommodate a 10-percent step load increase or a 5-percent per minute ramp load increase in the range of 15 to 100 percent of full power.

Excessive load increase could result from either an administrative violation such as excessive loading by the operator, or an equipment malfunction in the steam dump control or turbine speed control.

During power operation, steam dump to the condenser is controlled by reactor coolant condition signals; e.g., high reactor coolant temperature indicates a need for steam dump. A single controller malfunction does not cause steam dump; an interlock is provided which blocks the opening of the valves unless a large turbine load decrease or a turbine trip has occurred.

The largest postulated Condition II steam demand increase is a 10-percent step load increase from 100 percent power due to a hypothetical turbine governor malfunction. The Westinghouse Reactor Control System is designed to accommodate a 10-percent step load increase without reactor trip.

If a 10-percent step load increase from 100 percent power is postulated, feed flow will increase to match steam flow and maintain steam generator level. If automatic rod control is available, core power will be increased to match the 110-percent steam demand, and reactor coolant average temperature will remain at its initial value. Reactor Coolant System pressure will remain essentially constant. If automatic rod control is not available, the coolant temperature will decrease adding positive reactivity and increasing core power to match the 110-percent steam demand until reactivity is once again balanced. Reactor coolant pressure will decrease slightly and be restored to the nominal value. In either case, no reactor trip would be demanded.

More than 10 percent power margin in DNB is available in all Westinghouse plants. This margin is evident in the core limit curves presented in the SAR for each plant. This excess margin can also be seen in the overtemperature ΔT setpoint equation. In the case where automatic rod control is not assumed, extra DNB margin is also provided during the excessive load increase transient by the reduced coolant inlet temperature.

Detailed analysis of the 10-percent step load increase is described in RESAR.

4-73. ATWT ACCIDENTAL DEPRESSURIZATION OF THE REACTOR COOLANT SYSTEM

4-74. Identification of Causes and Transient Description

Depressurization of the Reactor Coolant System could result from accidental opening of a pressurizer relief valve, or from a leak in a sample line or instrument line connected to the Reactor Coolant System.

Two types of pressure relieving devices are provided — power-operated relief valves and spring-loaded safety valves. Continuous blowdown from either type is not considered credible for the following reasons:

- The power-operated relief valves are pneumatic, air-to-open, with air pressure to the valve operator controlled by a deenergize-to-vent electric solenoid. The solenoids for the two relief valves are actuated by independent pressure control channels. A single failure in the actuation system could cause a single relief valve to open when not needed. However, as described in paragraph 2-32, an electric interlock is provided to independently close the valve on low pressure. This interlock is actuated by an independent pressure signal, and deenergizes the solenoid when pressurizer pressure drops significantly below normal operating pressure. Therefore, two independent simultaneous failures must be assumed to cause continuous relief from a power-operated pressurizer relief value.
- The spring-loaded safety valves are self-actuated by system pressure such that no external failure could cause an undesired opening. Only a massive mechanical failure, such as failure of the spring, could cause the valve to remain open when the system pressure is below the set pressure. This type of mechanical failure is generally considered as an ANSI-18.2 Condition III or IV event, i.e., the probability of occurrence is too low to consider as a Condition II event, "anticipated" transients.

Notwithstanding the above, a 3.6 in.^{2} vent area at the top of the pressurizer was selected for evaluation purposes to bound all credible depressurization incidents. This size is equal to the throat area of a spring-load safety valve, and twice the throat area of a power-operated relief valve. The area is larger than that which could result from any credible leak in a sample line or instrument sensor line. Further, the location is such that automatic actuation of the safety injection system on low pressurizer level and pressure would not occur prior to bulk boiling in the Reactor Coolant System. Finally, an arbitrary assumption was made that a hypothetical, non-mechanistic common mode failure prevents reactor trip.

Initially, the postulated blowdown results in rapidly decreasing the reactor system pressure until saturation occurs in the upper part of the core which slows down the pressure decrease. The effect of the pressure decrease is to decrease nuclear power by the lower

moderator density. The coolant average temperature decreases slowly but the pressurizer water volume increases. Thus, the reactor core is protected from damage by the following trips:

- Overtemperature ΔT trip.
- Pressurizer low pressure trip.
- High pressurizer water level trip.

4-75. Analysis of Effects and Consequences

The system transients during an accidental depressurization of the Reactor Coolant System are generated using the LOFTRAN code. THINC-III was used to calculate the DNB ratio as a function of time.

Representative 2-, 3-, and 4-loop plants were analyzed for an accidental depressurization event. Two-loop plants have a larger safety valve throat area for the relative size of the pressurizer as compared to 3-, and 4-loop plants.

Therefore, 2-loop plants depressurize more rapidly than 3-, and 4-loop plants. The pressurizer and safety valve sizes for the representative 2-, 3-, and 4-loop plants are listed in table 4-15. However, the rate of depressurization has a less significant effect on DNB ratio than other variations in plant parameters. Comparison of the 2-, and 3-loop plant results with the 4-loop case shows that the 4-loop plant has the lowest minimum DNB ratio. Therefore, the system transients for the representative 4-loop plant are reported as the reference case and all sensitivity studies were done on the 4-loop plant. Two- and 3-loop plant results are also shown in the sensitivity studies.

TABLE 4-15

PRESSURIZER AND SAFETY VALVE THROAT SIZE
FOR 2-, 3-, AND 4-LOOP PLANTS

Plant	Pressurizer Size (ft^3)	Safety Valve Throat Area (ft^2)
2-Loop	1000	0.0193
3-Loop	1400	0.0205
4-Loop	1800	0.025

The following assumptions were made in the analyses:

- Initial normal full power operation early in core life
- Normal operation of the following control systems:
  1) Automatic regulation of feedwater flow to maintain steam generator water level
  2) Pressurizer pressure control (heater actuation)
  3) Turbine governor valves in impulse pressure control prior to trip, and valve closure on turbine trip
- The blowdown rate is assumed to be 110 percent of rated steam flow for a single safety valve at a given pressure for steam relief, and homogeneous equilibrium saturated flow for a single safety valve at a given pressure for water relief with 0.9 multiplier.
- Reactor Control System is assumed inoperative
- Feed enthalpy remains constant

4.76. Results

The system transients are shown in figures 4-209 through 4-214. Figure 4-209 shows the pressurizer pressure response. Table 4-16 shows the sequence of events for the base case. Initially, the pressure decreased rapidly at a rate of about 10.6 psi/sec until the system pressure reached a value corresponding to the hot leg saturation pressure. At that time the pressure decrease slowed considerably. Nuclear power (figure 4-210) decreased slowly as the density decreased with reduced pressure. Following saturation in the hot leg and the upper part of the core, the lower moderator density in the core caused the nuclear power to decrease at a faster rate. This continued until the pressurizer filled with water; the lower relief rate then retarded the rate of pressure decrease. Figure 4-211 shows the average coolant temperature. The rapidly decreasing nuclear power together with the relatively small change in the rate of energy removal across the steam generator following hot leg saturation, caused the average temperature to decrease rapidly. The pressurizer filled with water at about 130 seconds as shown in figure 4-212 and remained in that condition for the remainder of the transient. The steam pressure is shown in figure 4-213. The time sequence of events is shown in table 4-16. On plants with safety injection on low pressurizer pressure signal, safety injection will be actuated at 50 seconds. Safety injection will further decrease nuclear power and provide makeup for coolant lost by blowdown. However, automatic safety injection was not assumed in the analysis.

TABLE 4-16

SEQUENCE OF EVENTS FOR ACCIDENTAL DEPRESSURIZATION OF THE REACTOR COOLANT SYSTEM WITHOUT REACTOR TRIP

Event	Time (sec)
Safety Valve Opens	0
Overtemperature ΔT Reactor Trip Setpoint Reached	17
Low Pressurizer Pressure Reactor Trip Setpoint Reached	37
Minimum DNB Ratio	55
Hot Leg Saturation Pressure Reached	60
High Pressurizer Water Volume Reactor Trip Setpoint Reached	90
Pressurizer Fills	135

DNB ratios for the system conditions shown in figures 4-209 through 4-213 were calculated for the 15 x 15 and 17 x 17 fuel assemblies. The 15 x 15 fuel gives a lower minimum DNB ratio as shown in figure 4-214. The minimum DNB ratio for the 17 x 17 fuel was 1.57. The minimum DNB ratio for 15 x 15 fuel was 1.45.

4-77. Conclusions

Based upon the calculated DNB ratio, no significant clad damage is expected during a Reactor Coolant System depressurization without reactor trip.

At the end of ten minutes the core is at 40 percent power with the system pressure and temperature at 525 psia and 464°F, respectively. At this stage the total relief through the 3.6 in.^{2} opening is 42 lbs/sec. This water being relieved from the system is easily made up by the safety injection system which will also serve to borate the core and reduce power. Auxiliary feed is also available to cool the plant down.

4-78. Sensitivity Studies

The sensitivity of the minimum DNB ratio during the accidental depressurization to various plant conditions and assumptions was studied. The results are presented in table 4-17.

A description of the parameters varied and its effect on the system transients follows.

4-79. **Initial Reactor Power** – The accidental depressurization was analyzed assuming the reactor be initially at 90 percent power and 80 percent of rated power. In both cases the system pressure and temperature transients are similar to those shown in figures 4-209 and 4-211. The lower powers, however, resulted in higher DNB ratios of 1.62 and 1.79, respectively.

4-80. **Relief Rates** – The relief rate was varied by ± 50 percent from that described in the assumptions; i.e., a) 150 percent, and b) 50 percent of the reference case.

In the 150-percent case, pressure decreased a little more rapidly than shown in figure 4-209. A minimum DNB ratio of 1.45 occurred at an earlier time than the reference case. In the 50-percent case, pressure decreased at a slower rate than in the reference case shown in figure 4-209. In this case, the minimum DNB ratio was 1.44 and occurred later into the transient than the reference case.

4-81. **Automatic Rod Control** – When automatic rod control was assumed, the rods initially moved out slowly to maintain constant power. After the control rods were fully withdrawn, the moderator density feedback acted to decrease the power. Thereafter, the system transients were similar to the base case but the higher nuclear power during the initial part of the transient resulted in a lower DNB ratio for this case. The minimum DNB ratio was 1.32. A total of 300 pcm of reactivity was inserted by control rods at a uniform rate of 6 pcm/step.

4-82. **3-Loop Plant** – The pressure, power, and coolant temperature transients for the representative 3-loop plant are shown in figures 4-215 through 4-217. These transients are similar to the 4-loop case described earlier. A minimum DNB ratio of 1.47 was reached for the 15 x 15 fuel assembly. The 17 x 17 fuel was less severe.

4-83. **2-Loop Plant** – The system transients were similar to the 4-loop case and are shown in figures 4-218 through 4-220. The 2-loop plant with 14 x 14 fuel array gave a minimum DNB ratio of 1.65.

4-84. **Model D Steam Generators**

The representative 3- and 4-loop plants were studied for the effects of a Model D steam generator on the minimum DNB ratio. The effect was negligible because the water inventories were approximately equal for the Series 51 and Model D. The minimum DNB ratio was the same same as the value reported for the Series 51 steam generator.

4-85. **Turbine Trip** — The effect of turbine trip on the minimum DNB ratio for the base case with 15 x 15 fuel was also evaluated. The analyses showed that the DNB ratio would not go below 1.53. The relevant system transients are shown in figures 4-221 through 4-223.

TABLE 4-17

SUMMARY OF RESULTS FOR ACCIDENTAL DEPRESSURIZATION OF THE REACTOR COOLANT SYSTEM WITHOUT A REACTOR TRIP

Description of Case[a]	Minimum DNB Ratio
Reference Case:	1.45
4-Loop Plant	
100 Percent Power	
No Rod Control	
1.1 Rated Steam Relief	
0.9 of Homogeneous Equilibrium Saturated Flow for Water Relief	
Series 51 Steam Generator	
15 x 15 Fuel	
Reference Case with 17 x 17 Fuel	1.57
3-Loop Plant with 15 x 15 Fuel	1.47
2-Loop Plant with 14 x 14 Fuel	1.65
90 Percent Power	1.62
80 Percent Power	1.79
150 Percent Relief (150 Percent of Reference Case)	1.45
50 Percent Relief	1.44
Automatic Rod Control	1.32
Turbine Trip	1.53

[a] Only deviation from reference case indicated.

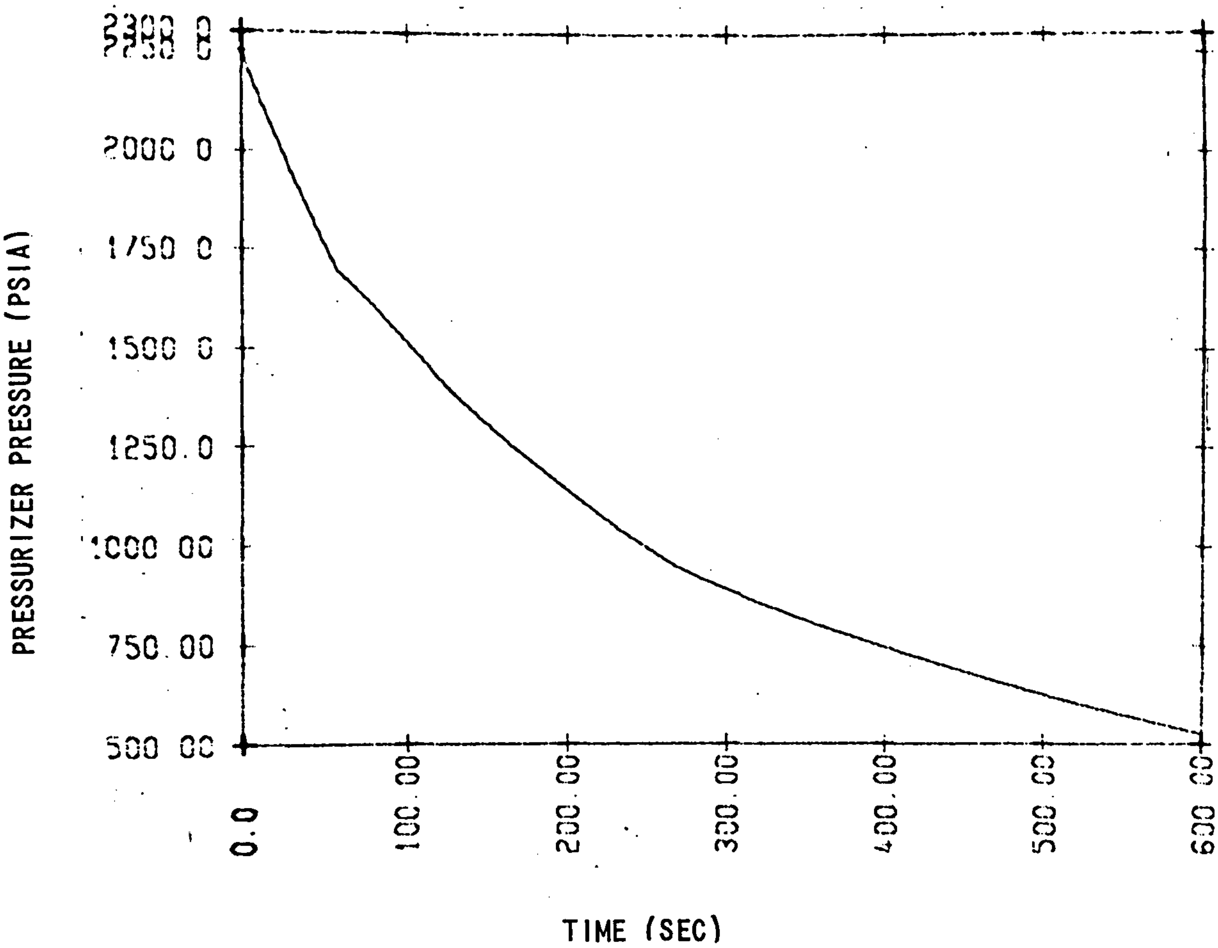

Figure 4-209. Depressurization - Reference Case
(Pressurizer Pressure vs. Time)

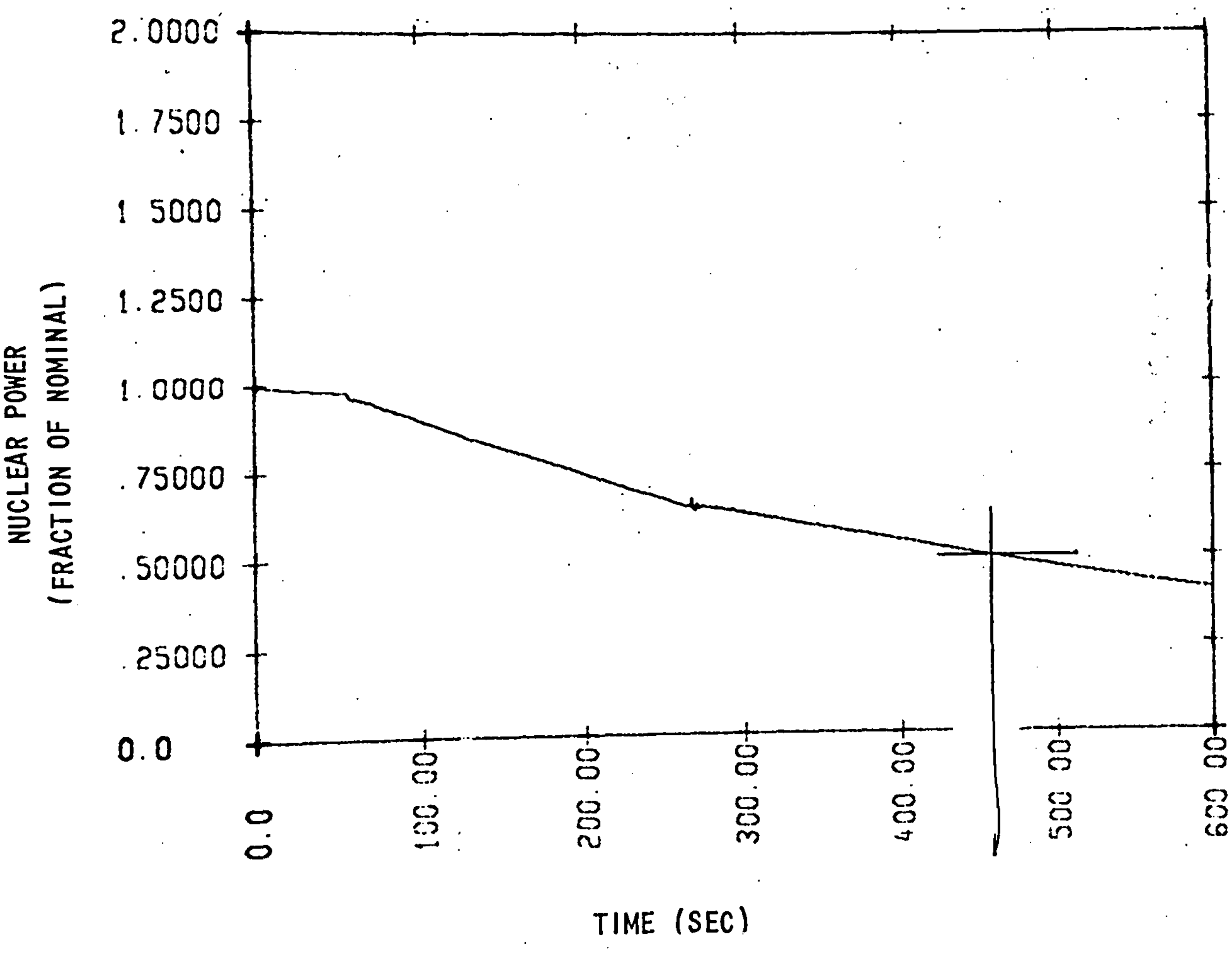

Figure 4-210. Depressurization - Reference Case (Nuclear Power vs. Time)

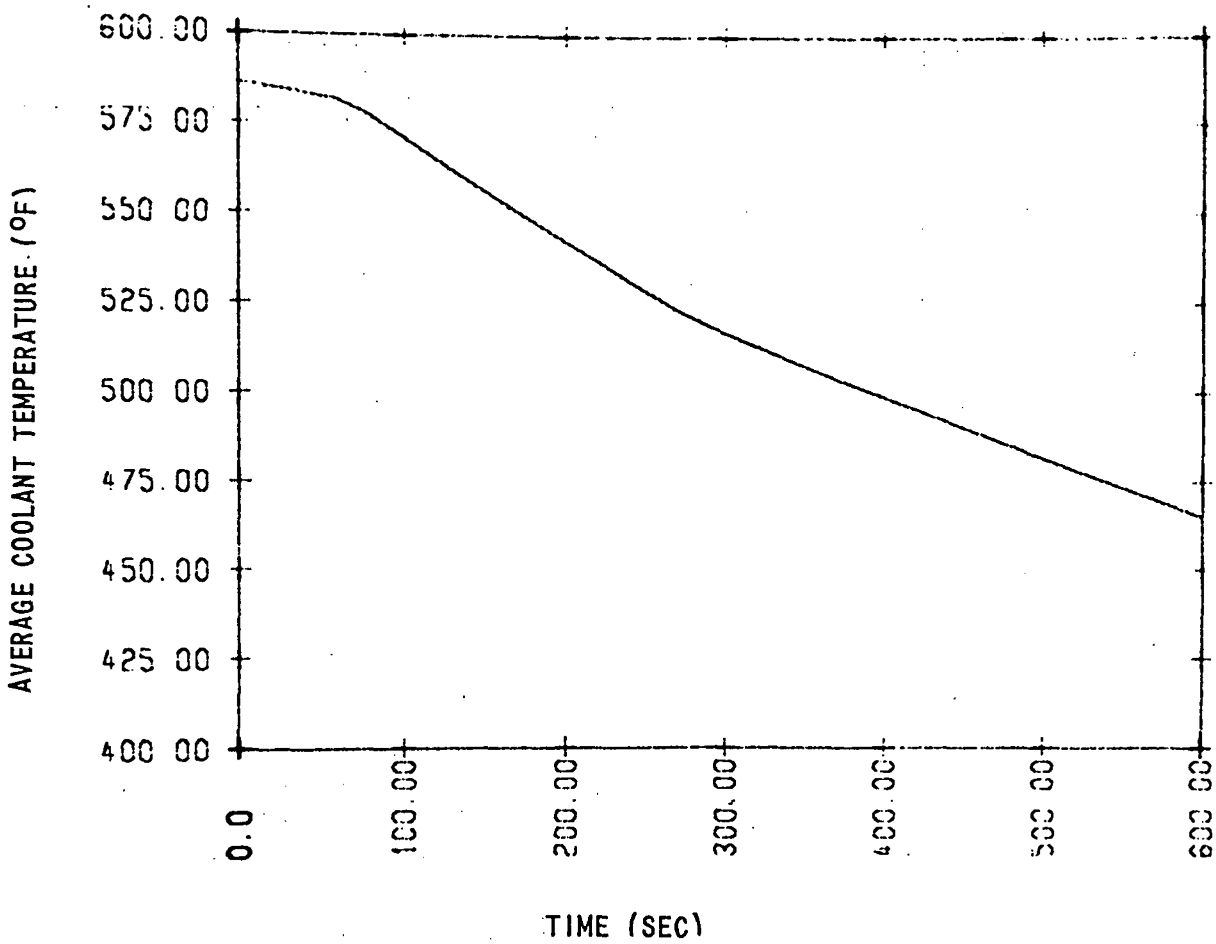

Figure 4-211. Depressurization - Reference Case
(Average Coolant Temperature vs. Time)

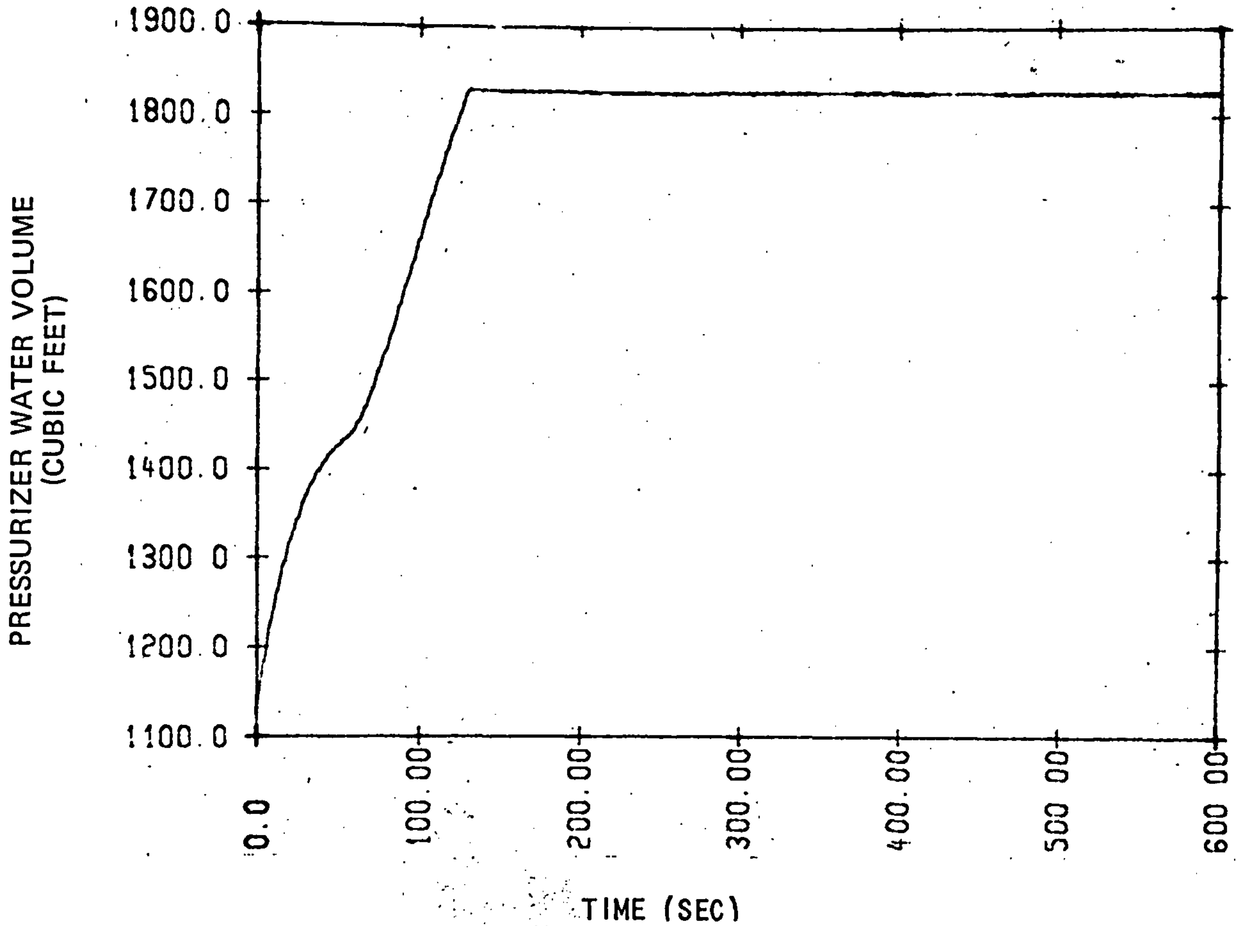

Figure 4-212. Depressurization – Reference Case
(Pressurizer Water Volume vs. Time)

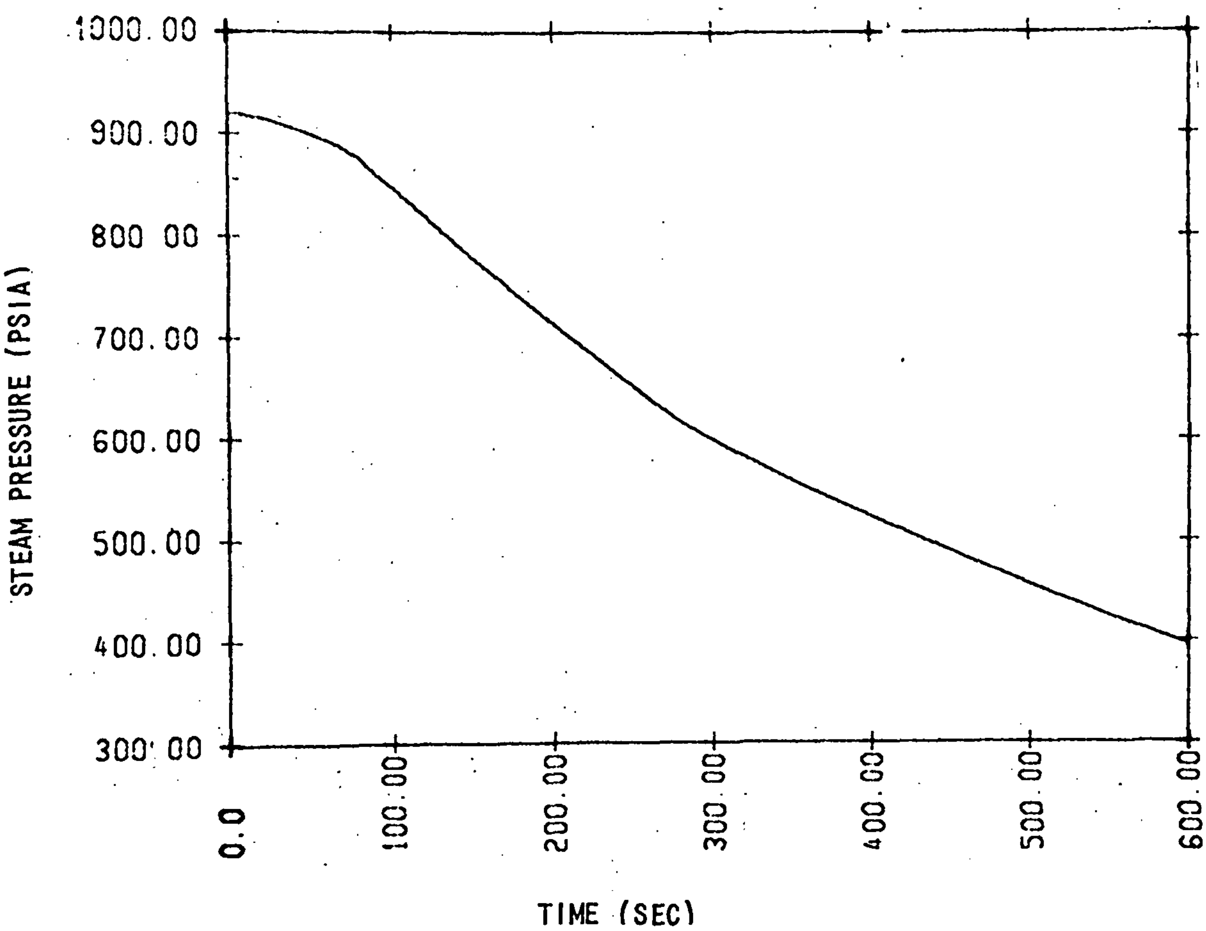

Figure 4-213. Depressurization - Reference Case
(Steam Pressure vs. Time)

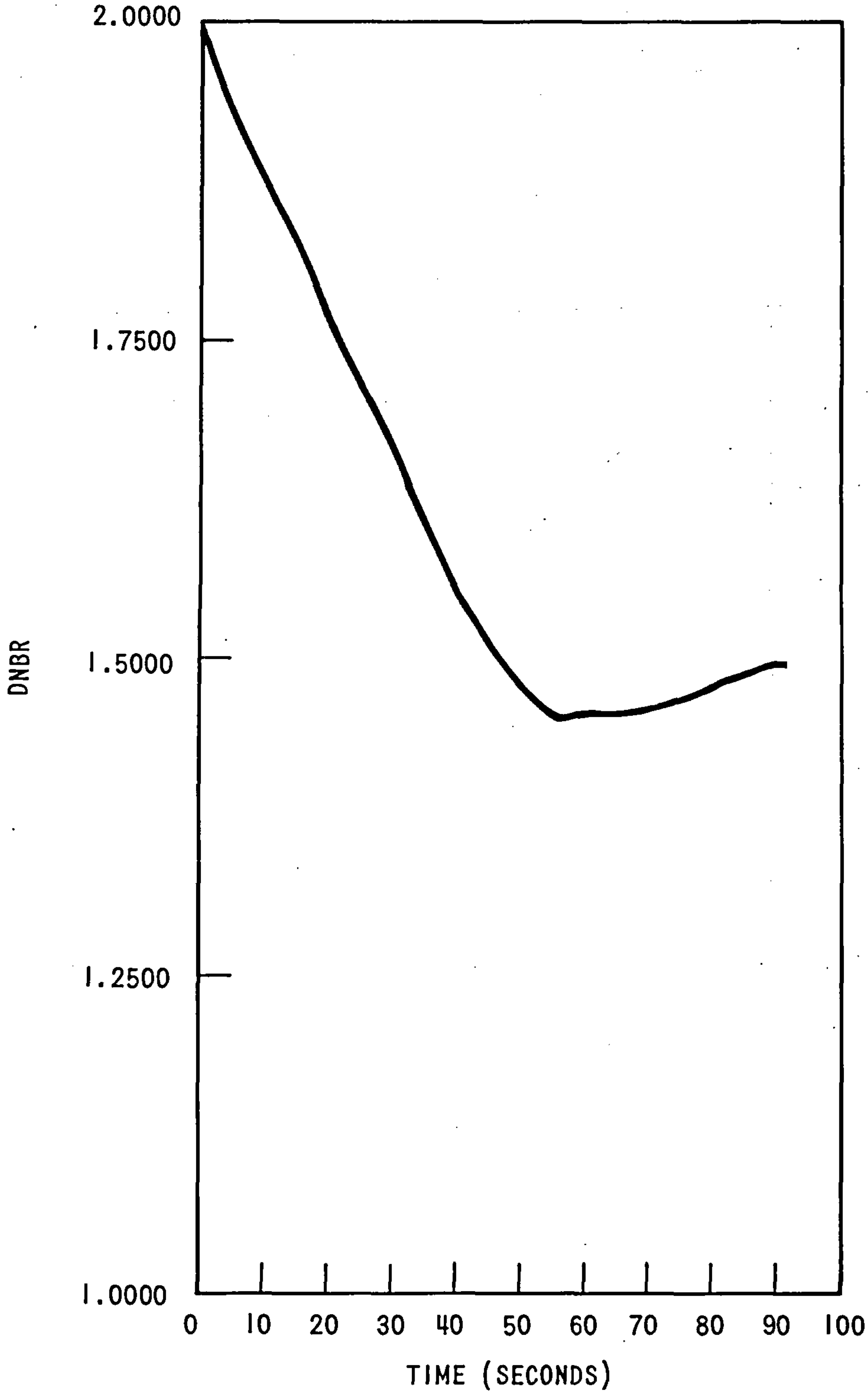

Figure 4-214. Depressurization - Reference Case (DNBR versus Time)

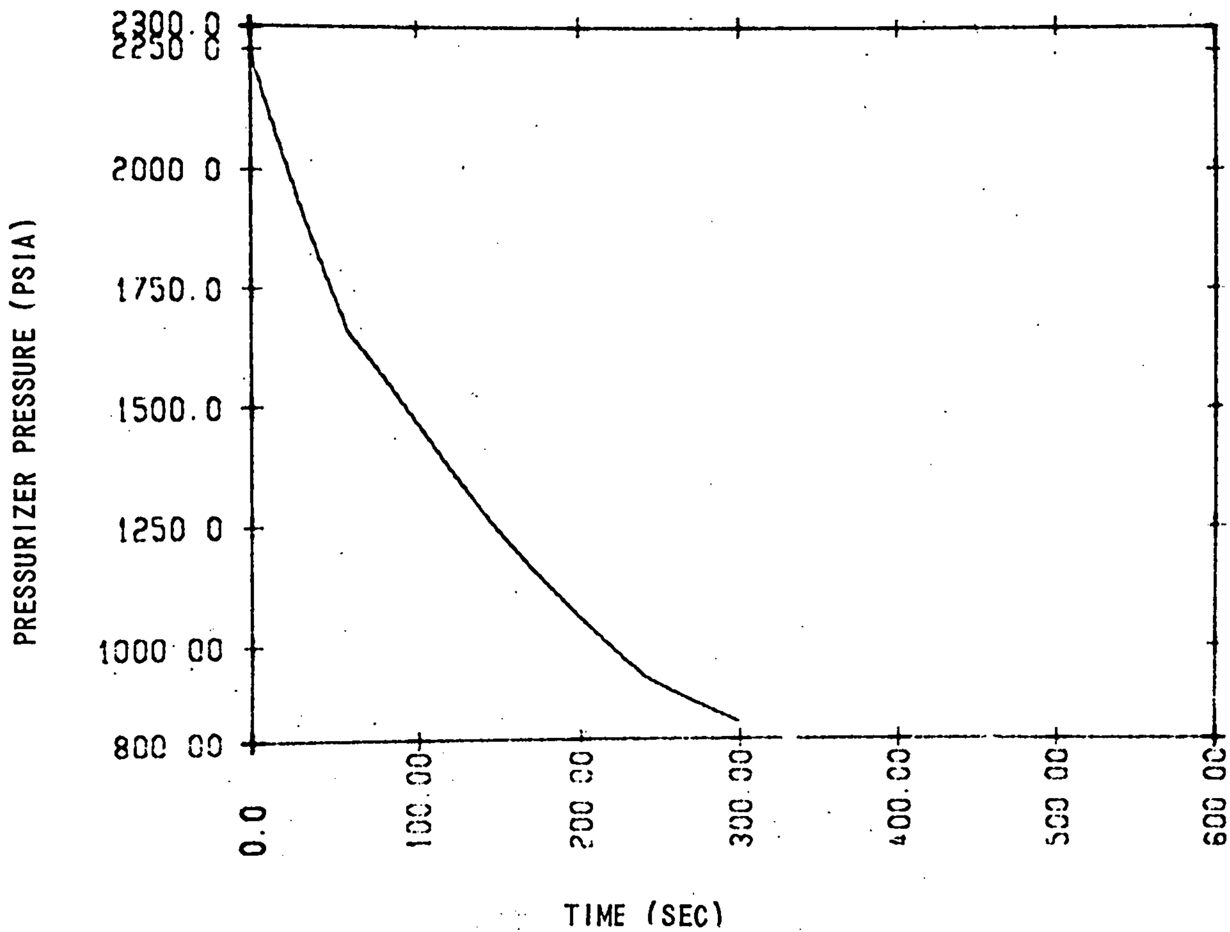

Figure 4-215. Depressurization - 3-Loop Plant
(Pressurizer Pressure vs. Time)

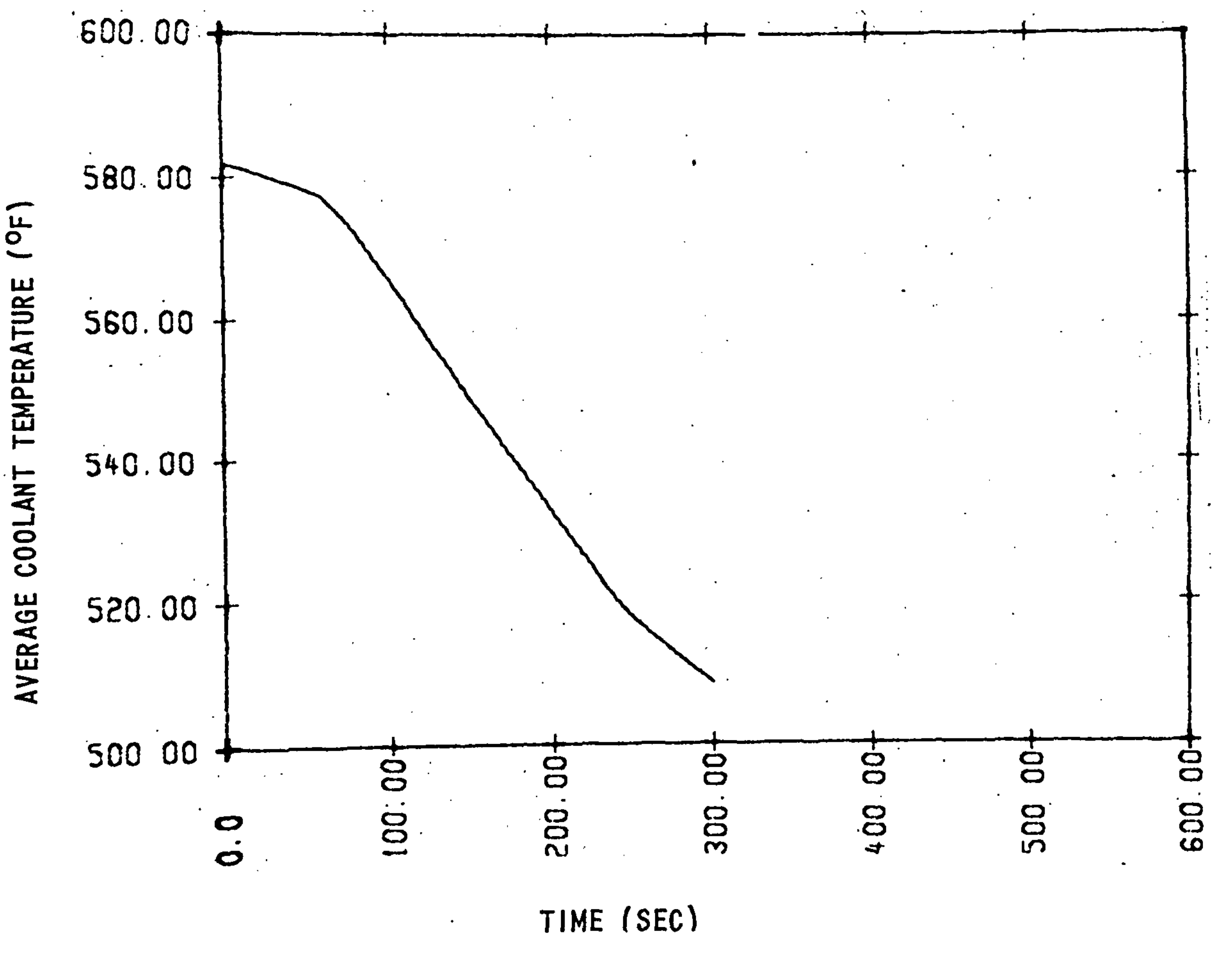

Figure 4-216. Depressurization - 3-Loop Plant
(Average Coolant Temperature vs. Time)

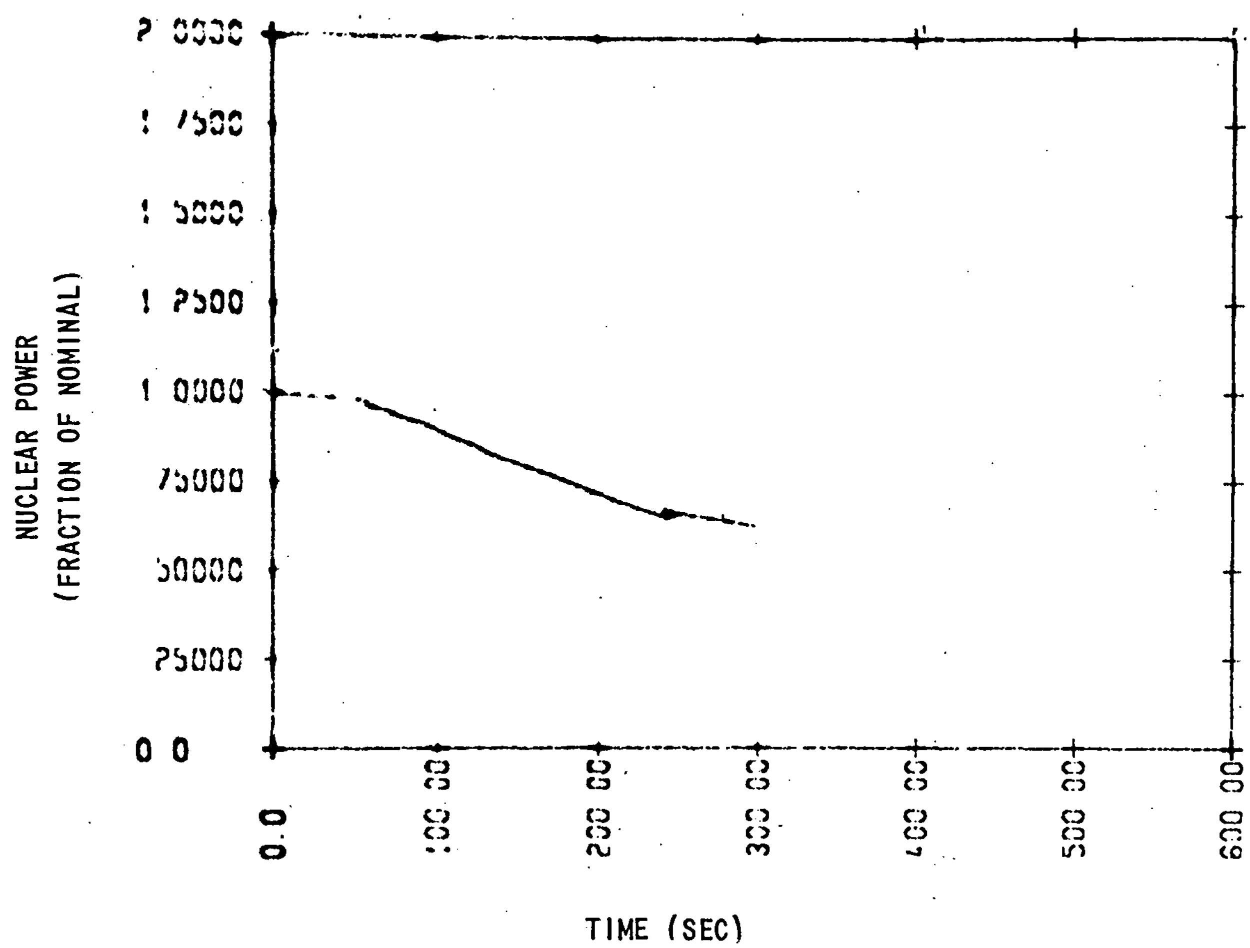

Figure 4-217. Depressurization - 3 Loop Plant
(Nuclear Power vs. Time)

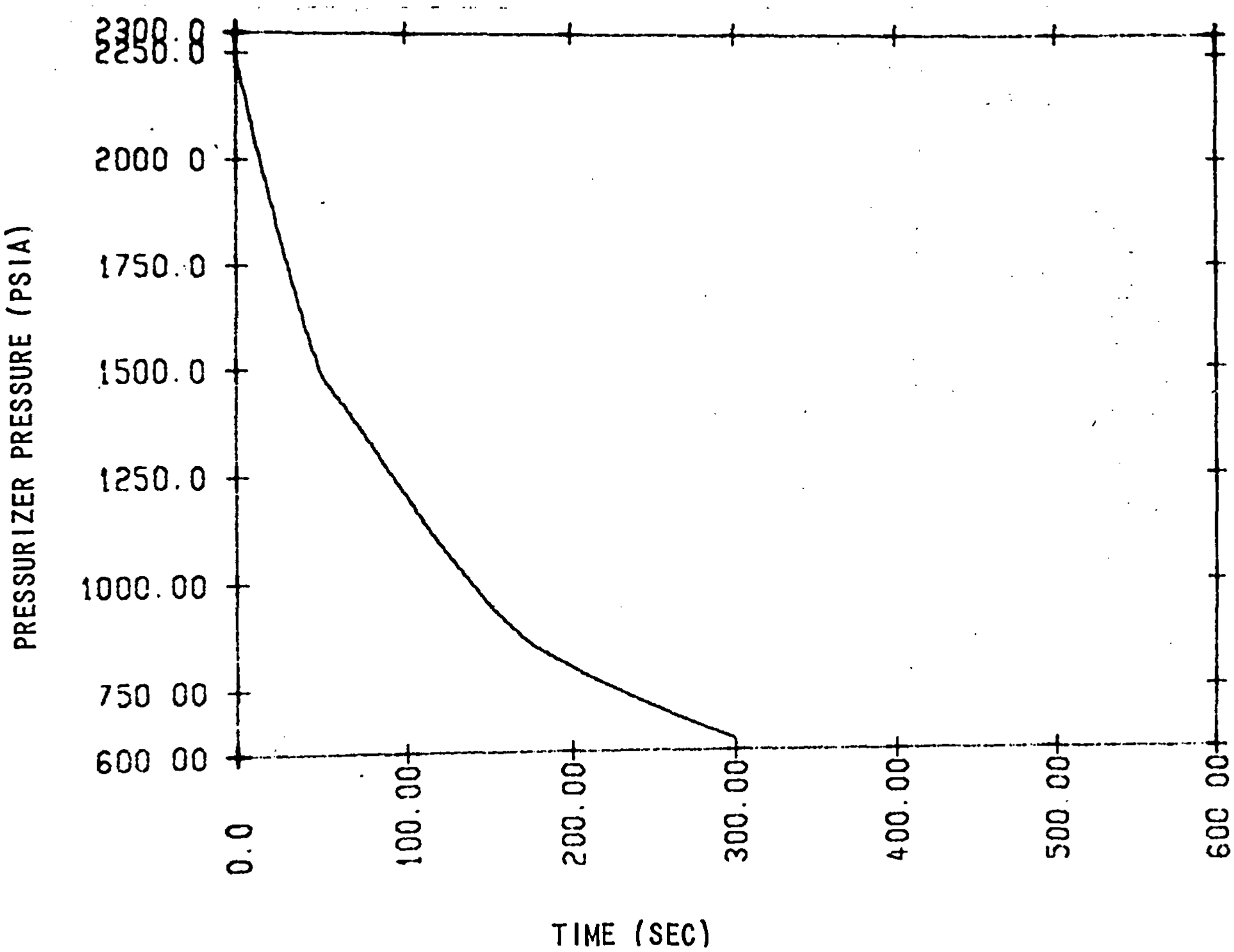

Figure 4-218. Depressurization - 2-Loop Plant
(Pressurizer Pressure vs. Time)

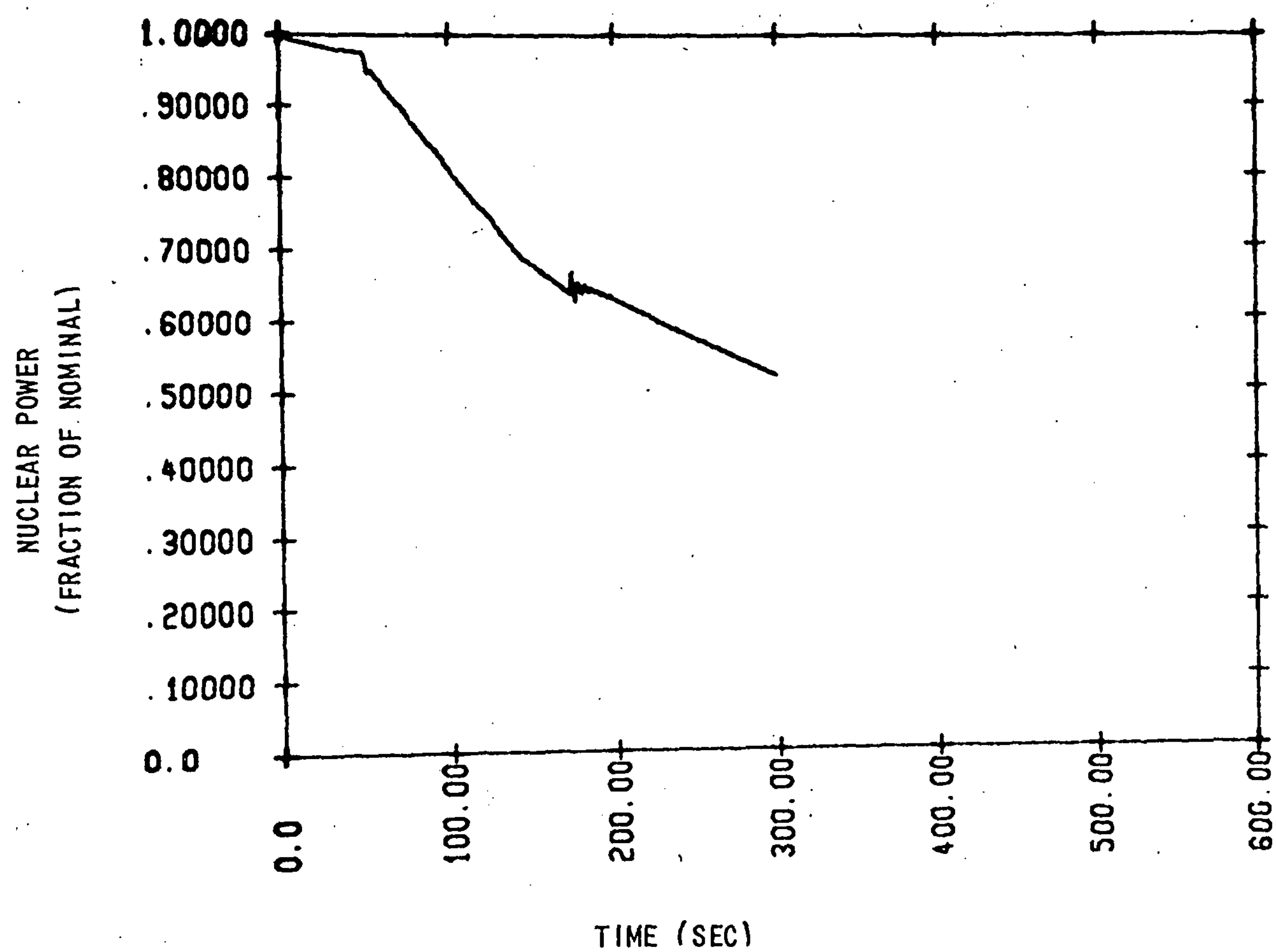

Figure 4-219. Depressurization - 2-Loop Plant
(Nuclear Power vs. Time)

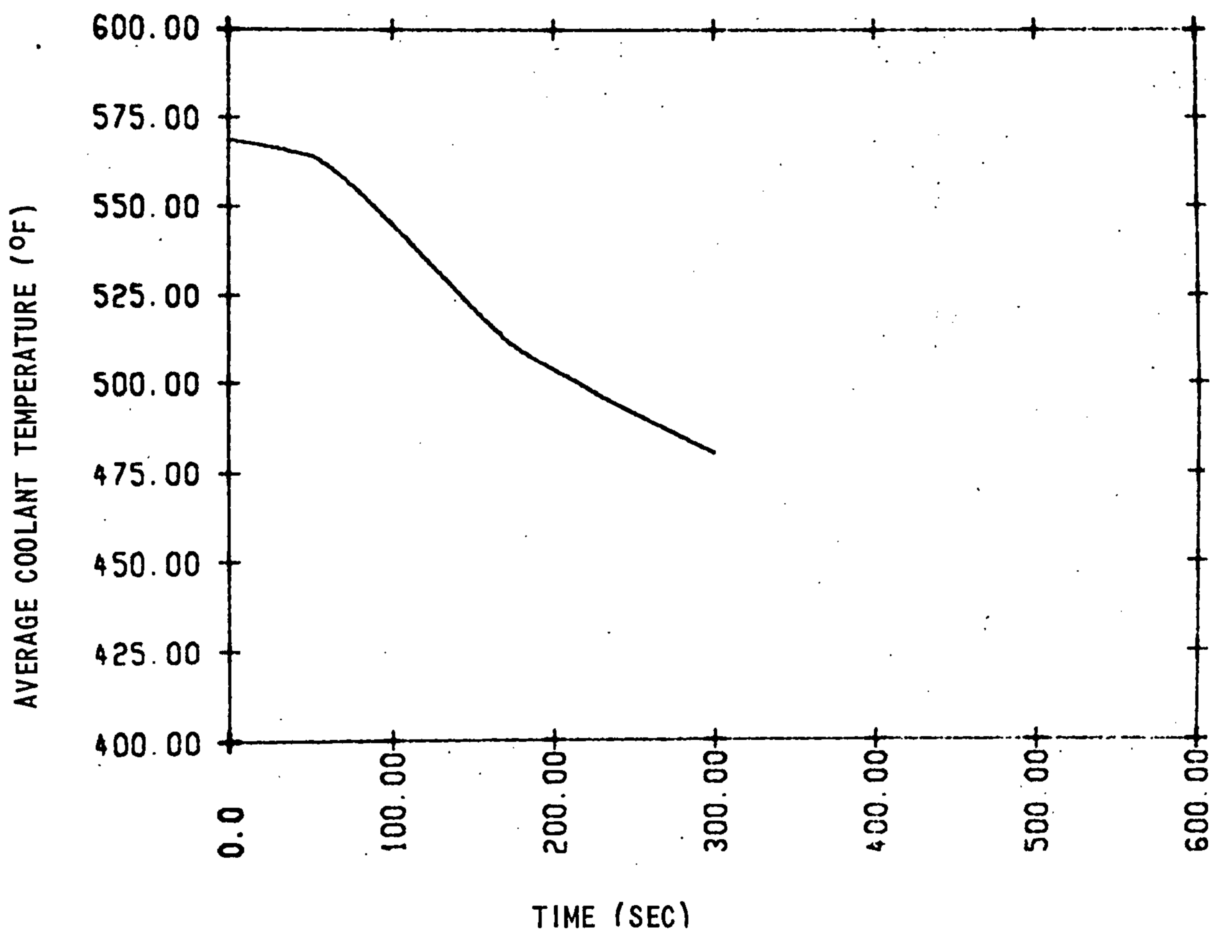

Figure 4-220. Depressurization - 2-Loop Plant
(Average Coolant Temperature vs. Time)

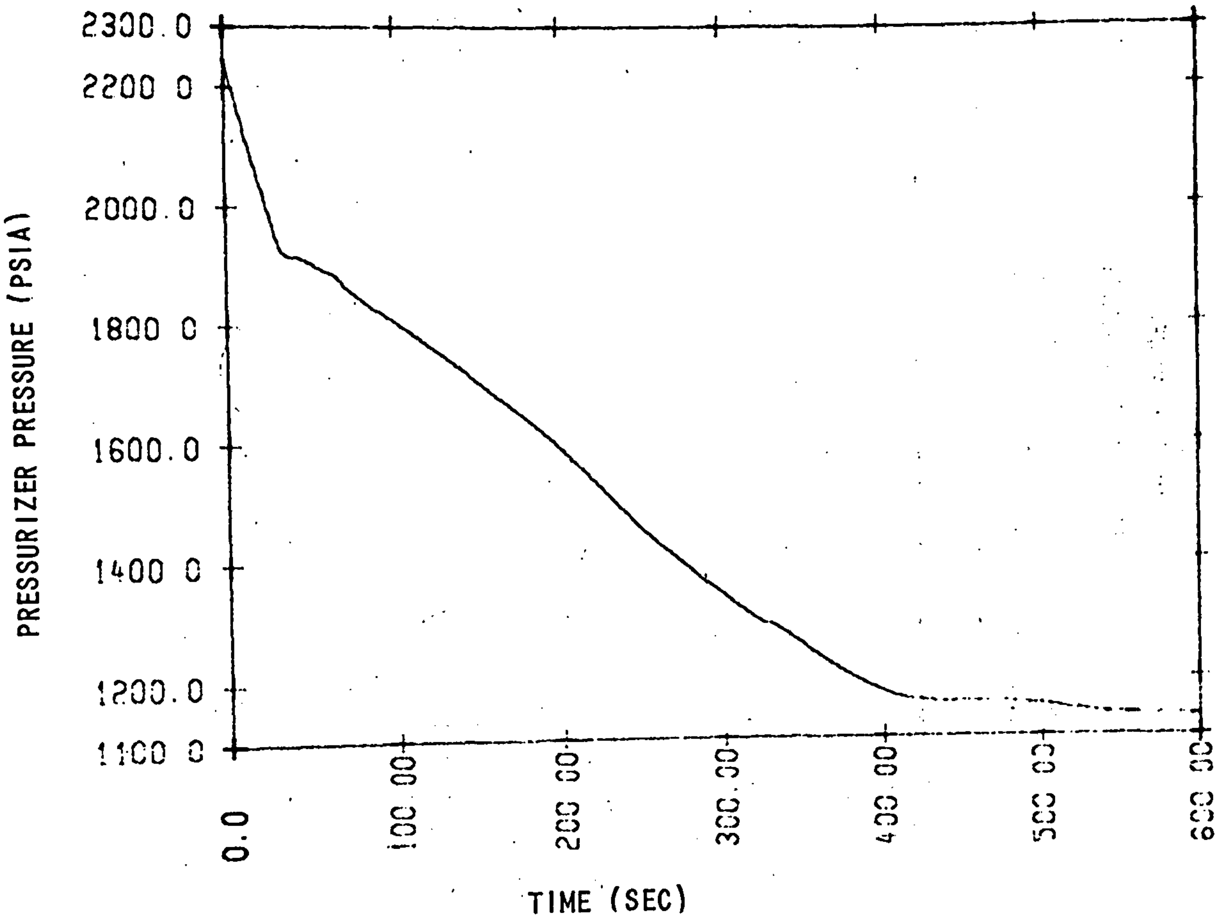

Figure 4-221. Depressurization - With Turbine Trip
(Pressurizer Pressure vs. Time)

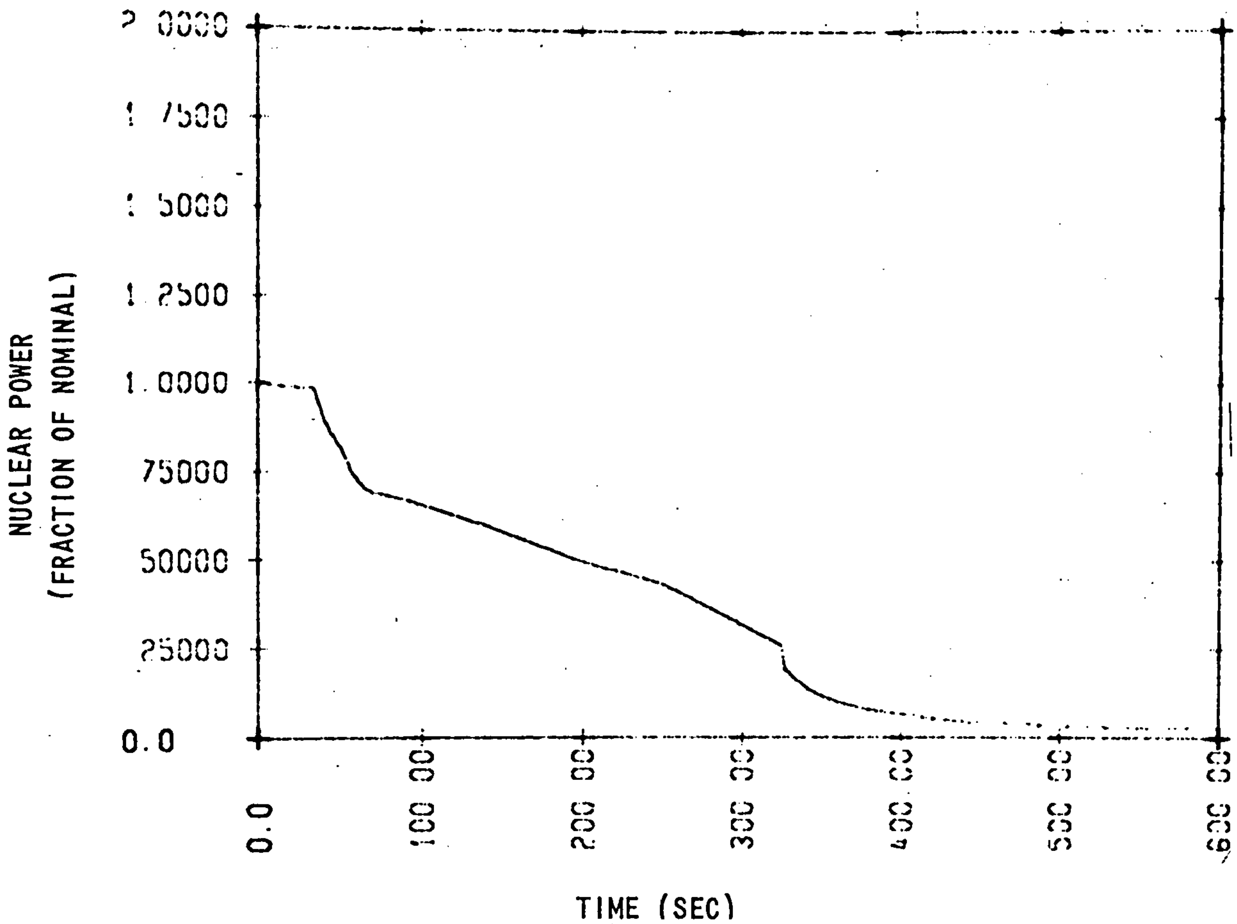

Figure 4-222. Depressurization - With Turbine Trip
(Nuclear Power vs. Time)

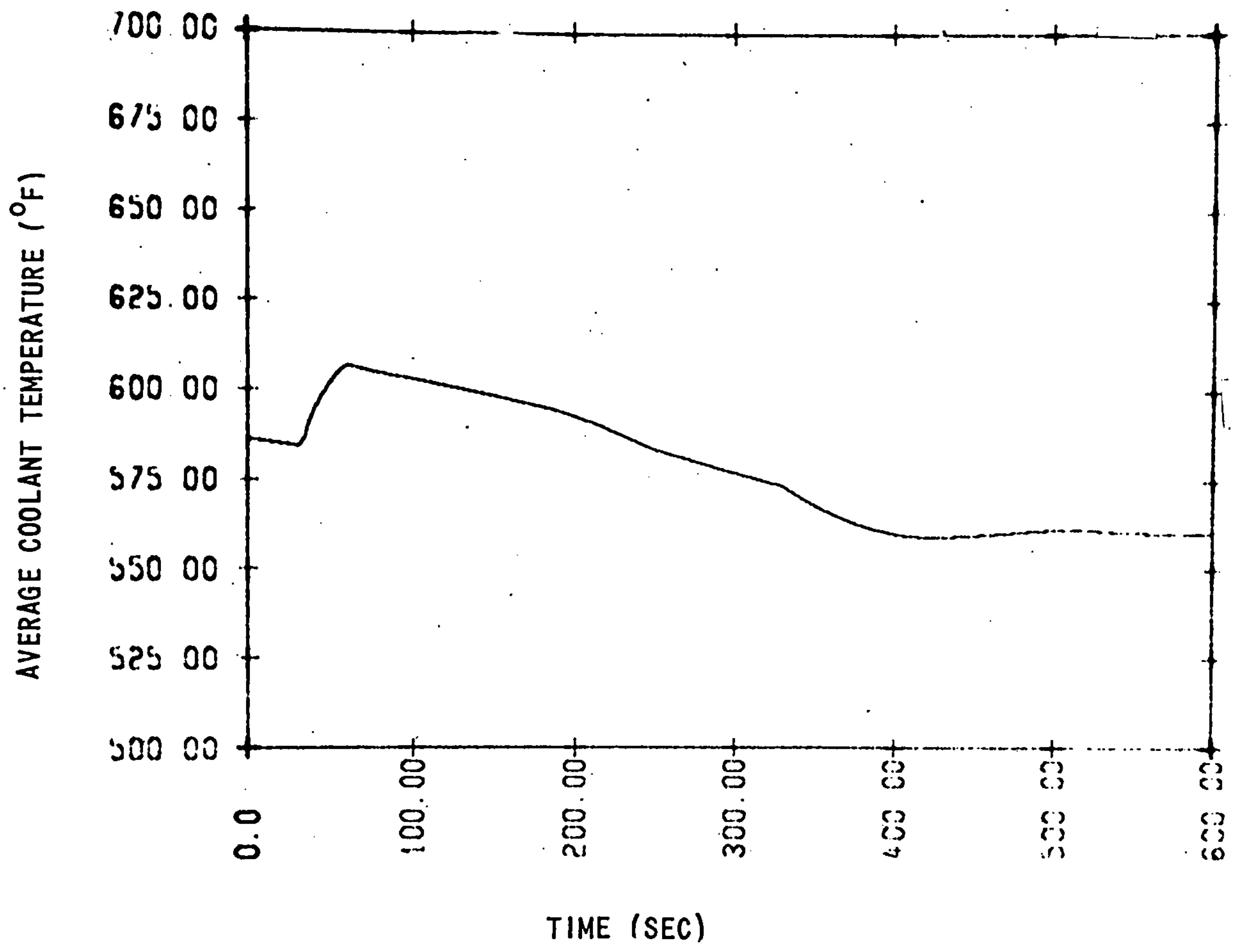

Figure 4-223. Depressurization - With Turbine Trip
(Average Coolant Temperature vs. Time)

4-86. ROD DROP WITHOUT REACTOR TRIP

4-87. Identification of Causes and Accident Description

A rod drop may be caused by an electrical or mechanical failure. The negative reactivity inserted by the dropped rod will cause an immediate decrease in nuclear power. If automatic rod control is operable, the control bank will be withdrawn to compensate for the dropped rod reactivity and the core will return to full power. If automatic rod control is not operable, full power may be restored via the moderator feedback. In either case, the radial peaking factor could increase, resulting in a decrease in the margin to DNB.

The Westinghouse PWR core design can accommodate this event throughout plant life. In fact, a dropped rod is an acceptable operating condition as defined in the plant Technical Specifications.

A reactor trip is neither called for nor required in the event of a dropped rod since a large margin to DNB is retained in this event.

SECTION 5
SUMMARY AND CONCLUSIONS

In Section 1, studies were referenced which demonstrate that the present Westinghouse Reactor Protection System is extremely reliable. This reliability has been achieved by paying attention to detail in developing, over a period of 15 years, the present system used in standardized Westinghouse PWRs. In addition, analyses have been documented which show that any given reactor trip function could be ignored with no serious degradation in safety.

Notwithstanding the vanishingly low probability of occurrence, analyses have been completed assuming that a hypothetical, undefined, non-mechanistic common mode failure somehow prevents any automatic reactor trip.

The results of the analyses, presented in Section 4, demonstrate that a Westinghouse PWR is inherently self-limiting within well defined safety limits. Because of the inherent characteristics of a PWR in combination with conservative design margins, a Westinghouse PWR has very little need of automatic action from the Reactor Protection System.

The analyses were performed using conservative assumptions. "Best-estimate", or "most-probable" results would be substantially less severe than those presented. The conservatisms include:

- Excluding the design margin and measurement uncertainty from $F_{\Delta H}^{N}$, core power distribution was assumed at its Technical Specification limit. No credit was taken for less-than-design peaking factors which exist over the vast majority of core life. Further, no credit was taken for power distribution flattening which could occur as the core approached its safety limits.
- The thermal-hydraulic conservatisms used in SAR analyses were also used in the ATWT analyses.
- Conditions appropriate to very-early-in-core-life were assumed. Later in core life, the moderator reactivity coefficient is more negative and conditions would be less severe than those presented.
- Design reactor coolant flow, rather than expected, was assumed.

- No credit was taken for heat absorption in structural metal in the Reactor Coolant System. This metal (several million pounds) represents a substantial heat sink (or source).

- In many of the analyses, the initiating event was selected to be more severe than could be justified for an ANSI-18.2 Condition II event.

- A conservative model, rather than "best-estimate" was selected for liquid relief capacity through the pressurizer safety valves. Further, as dictated by the AEC Regulatory Staff, an arbitrary 0.9 multiplier was applied to the already conservative model.

Even with the above conservatisms, the results of section 4 show the following:

- Because of the admittedly low probability of occurrence, DNB would be acceptable for an ATWT event. However, based on the calculated minimum DNB ratios no significant clad damage is expected. This result stems from the nuclear-thermal-hydraulic design margin in current Westinghouse reactors.

- In no case does the Reactor Coolant System pressure exceed the maximum allowable pressure determined in Appendix C, let alone approach the ultimate failure limits of the Reactor Coolant System. This result stems from Westinghouse's conservative approach to overpressure protection; safety valves, and power-operated relief valves are sized without consideration for direct reactor trip or inherent shutdown characteristics of a PWR, although credit for these considerations is allowable by the ASME Code, Section III. (In fact, studies have shown that no safety valves whatsoever are necessary on Westinghouse PWRs to meet code requirements for upset conditions; the high pressure reactor trip itself is adequate. This result is borne out by operating experience on Westinghouse PWRs. In only a very few cases has a high pressure reactor trip occurred; lifting of the pressurizer safety valves during power operation has never been reported.)

- The containment pressure transients yield peak pressures below design (and it could be legitimately argued that design pressure is not an appropriate limit for events of such low probability). These containment pressure transients are negligible compared to the containment design basis transient, e.g., loss-of-coolant accident.

- The core thermal performance, the volume of reactor coolant and secondary fluid released, and the containment pressure transient are all considerably less severe for these ATWT events than for the design basis accidents. The evaluation contained in Appendix E demonstrates that the dose consequences for ATWT are well within the guideline values set forth in 10 CFR 100.

SECTION 6
REFERENCES

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APPENDIX A

STEAM GENERATOR UA CALCULATION

Reduction of heat transfer in the steam generator occurs as water level drops and the tube bundle begins to uncover. Detailed steam generator models indicate this occurs when the quality of the steam in the riser is approximately 90 percent. The following conditions exist at that time.

riser exit quality (X)	= 0.9
riser void fraction (α_R)	= 0.97*
tube bundle void fraction (α_B)	= 0.79*
circulation ratio (CR)	= 1/X = 1.111

The total secondary water volume at which the above conditions are satisfied and primary-to-secondary heat transfer begins to decrease is (VSTUBE) X (No. of steam generators), where VSTUBE is given by:

$$VSTUBE = WVPR + WVDC + WVBL + WVR$$

and

WVPR = volume of water in preheat section = (WLPR) (cross sectional area at preheat level)

WVDC = volume of water in downcomer - fn [WLDC]

WVBL = volume of water in boiling region = (1-F) (1-α_B) (bundle volume)

WVR = volume of water in riser - (1-α_R) (riser volume)

These volumes are calculated as described in figure A-1 using the information listed below.

WS = steam flow (lbs/sec)

WRW = recirculation water flow (lbs/sec) = (0.111) (WS/X)

* These values are determined using the Armand void correlation and assuming a linear enthalpy rise with elevation in the tube bundle.

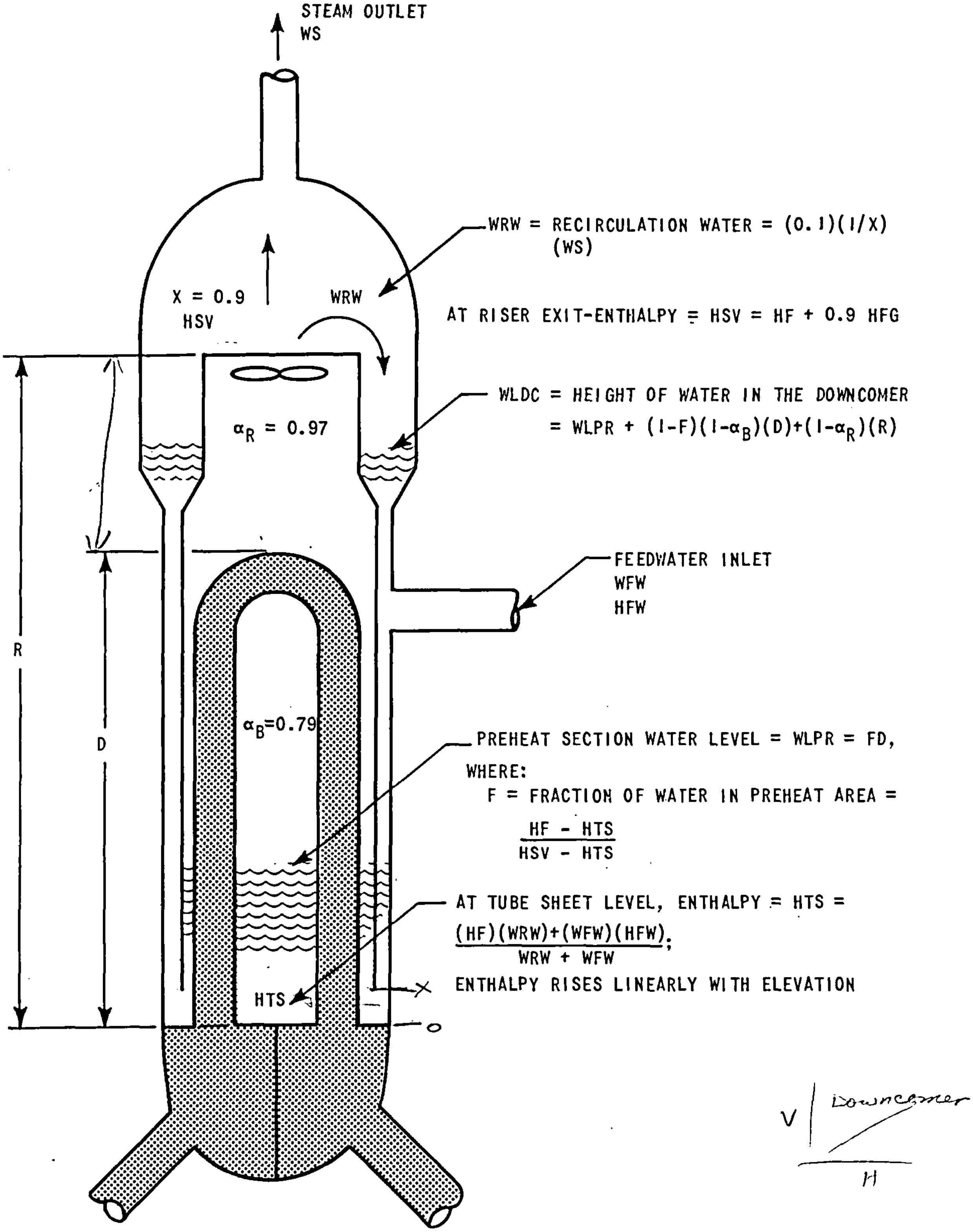


Figure A-1. Use of Steam Generator Parameters in UA Calculation

HSV = steam enthalpy at riser exit = HF + X·HFG
where HF = saturated water enthalpy
HG = saturated steam enthalpy

HTS = enthalpy of water at tube sheet level

= [(HF) (WRW) + (WFW) (HFW)]/(WRW + WFW)

where WFW = feedwater flow (lbs/sec)
HFW = feedwater enthalpy

F = fraction of tube height covered by preheated water = (HF-HTS)/(HSV-HTS)

WLPR = height of water in preheat section = (F) (distance of top tube from tube sheet)

WLDC = height of water in the downcomer = WLPR + (1-F)(1-α_B) (distance to top of tube) + (1-α_R) (riser height)

R = height of riser region above tube sheet

D = elevation of highest tube from tube sheet

Assuming the geometry of a 51 Series steam generator and the following conditions:

- 70 percent power and corresponding steam flow
- steam generator is at the safety valve set pressure (approximately 1200 psia)
- total feedwater inflow is from the auxiliary feedwater pumps which are purging the main feedwater from the feedwater lines (1760 gpm at 440°F)

then the water volume at which the steam generator tubes are exposed and UA begins to decrease is approximately 600 ft^3 in each steam generator.

APPENDIX B
SHUTDOWN FOLLOWING A POSTULATED ATWT EVENT

There are several mechanisms by which a plant may be shutdown following an ATWT event. These include initiation of a safety injection process, an emergency boration process, a normal boration process, or a manual reactor trip.

A manual reactor trip signal is processed both directly to the trip breakers and through the protection logic. If this action should fail to deenergize the control rod drive mechanisms, the operator can trip the control rod power supply motor-generator set supply breakers to trip the reactor. If the control rods are tripped, the shutdown banks drop into the core in approximately 2 seconds, inserting more than -4% $\frac{\Delta k}{k}$ negative reactivity.

If safety injection is used, borated water is supplied from the boron injection tank through two centrifugal charging pumps. Boron concentration in the boron injection tank is 20,000 ppm. At nominal Reactor Coolant System pressure the safety injection flow is approximately 60 lb/sec.

If emergency boration is used, borated water is supplied from the boric acid tank through the boric acid pumps into the normal charging system. Boron concentration in the boric acid tank is approximately 4 percent boric acid by weight. The charging flow is generally in the range of the normal charging flows. Parameters assumed for emergency boration shutdown are given in table B-1.

If a standard boration is used, borated water is supplied through the Chemical Volume and Control System, through the boric acid blender. The source of the borated water is the boric acid tank. Total flow is controlled by the batch integrators in the Chemical Volume and Control System.

The most severe ATWT event in terms of shutdown requirements is the rod withdrawal accident. Conditions after 10 minutes in the reference rod withdrawal event are the following:

Power = 99.4 percent nominal

Average Temperature = 611.2°F

P_{RCS} = 2350 psia

C_{Boron} = 900 ppm

TABLE B-1
ASSUMPTIONS FOR SHUTDOWN

Manual Reactor Trip
$-4\% \frac{\Delta k}{k}$ Reactivity Worth in the Shutdown Rods
Rod Drop Time of 2.4 Seconds
Turbine Trip when Reactor Trip Breakers Open.
Safety Injection
Safety Injection Flow Increases with Decreasing Pressure
Boron Concentration of SI Flow = 20,000 ppm.
Boron Worth is Constant at -10.5 pcm/ppm
Initial Core Boron Concentration = 900 ppm
Available Borated Water = 900 gpm
Borated Water Enthalpy = 40 Btu/lbm
Turbine Trip on Safety Injection Signal
Emergency Boration
Make Up Flow Rate of Borated Water = 75 gpm
Boron Concentration of Make Up Water = 6000 ppm
Boron Worth is Constant at -10.5 pcm/ppm
Initial Core Boron Concentration = 900 ppm
Available Borated Water (@ 6000 ppm) = 48,000 gal
Operator Trips the Turbine at 10 Minutes

To obtain subcriticality at hot zero-power from these conditions requires the insertion of approximately 2 percent reactivity.

The plant response to a reactor trip, safety injection, and emergency boration shutdown is shown in figures B-1 through B-12. The assumptions made to evaluate the three shutdown methods are listed in table B-1. For a manual trip, safety injection signal, or emergency boration signal, the times after operator action required to reach a point where only decay heat is being removed from the core are approximately 40 seconds, 3 minutes and 45 minutes, respectively. At this time the operator would be able to proceed with normal plant procedures for cooling the Reactor Coolant System to conditions that permit the use of the Residual Heat Removal System. Sufficient feedwater is available for plant cooldown using either the main feedwater system, the auxiliary feedwater system, or both for all Westinghouse plants.

A review of plant data shows that Westinghouse plants have enough capacity to continue auxiliary feed flow at the maximum rate for about one or two hours without a change in the auxiliary feedwater system lineup. Thereafter, an essentially indefinite supply is provided by one or more of condensate storage, service water, fire main, well, or city water.

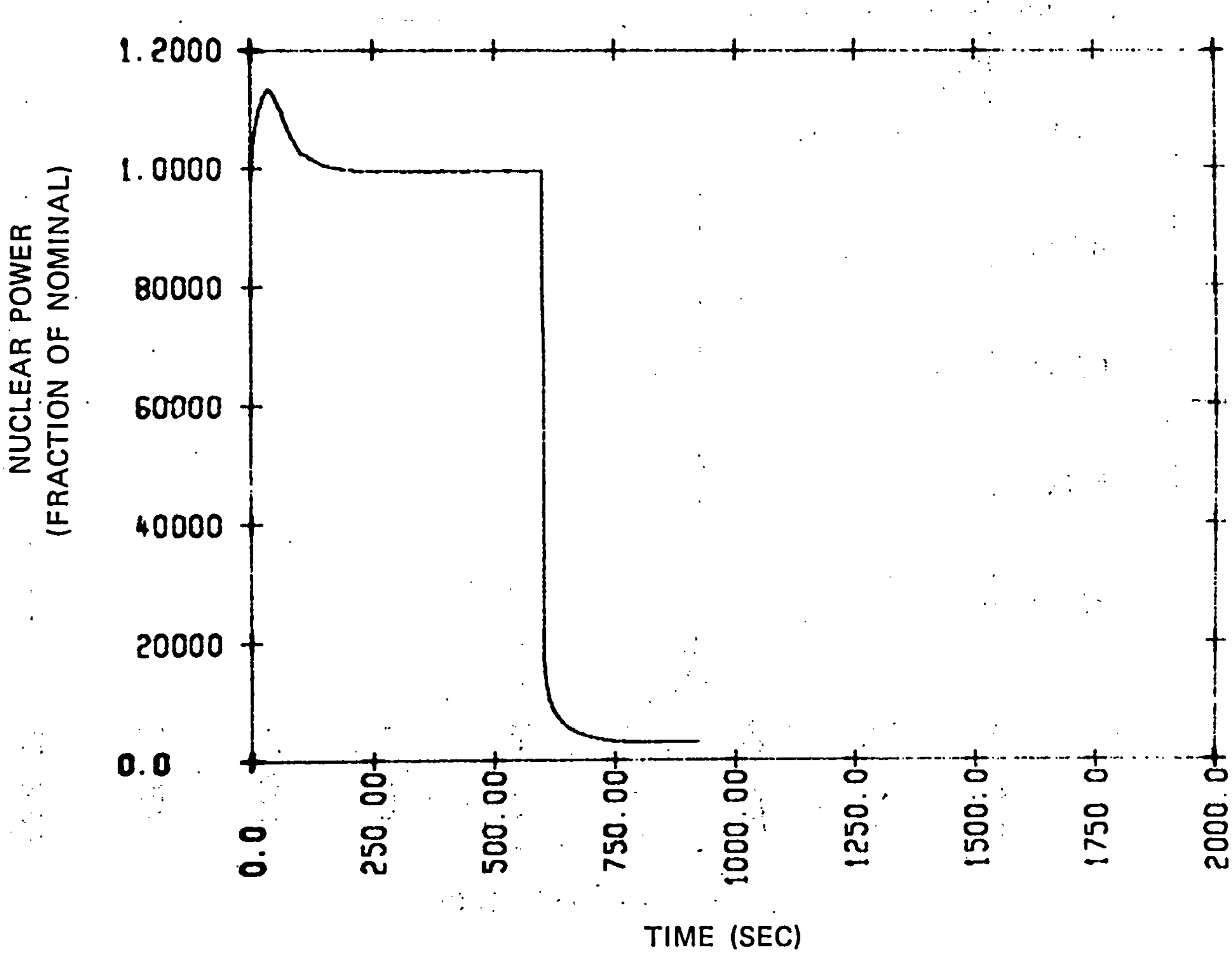


Figure B-1. Rod Withdrawal at Power; Shutdown by Manual Rod Trip (Nuclear Power Vs. Time)

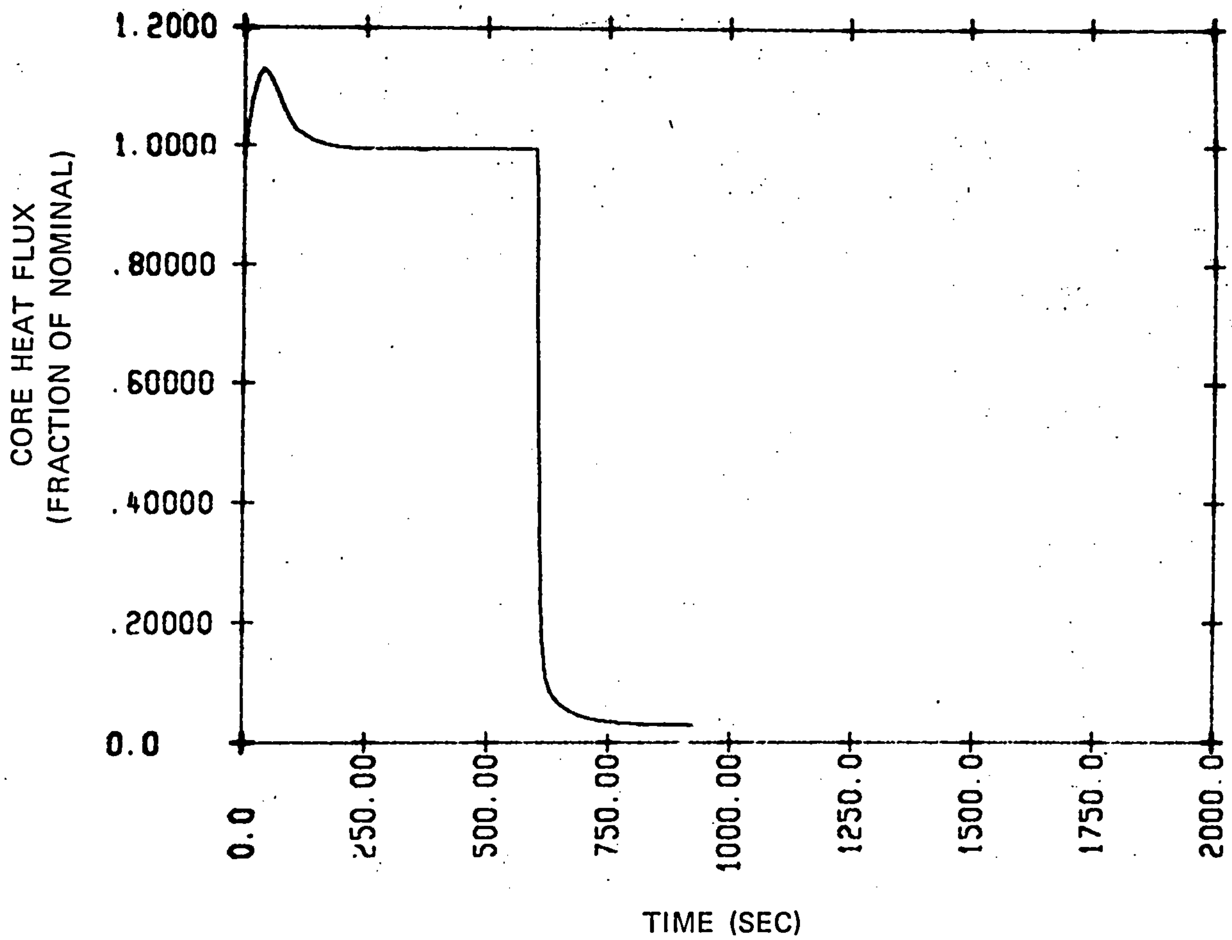


Figure B-2. Rod Withdrawal at Power; Shutdown by Manual Rod Trip (Core Heat Flux Vs. Time)

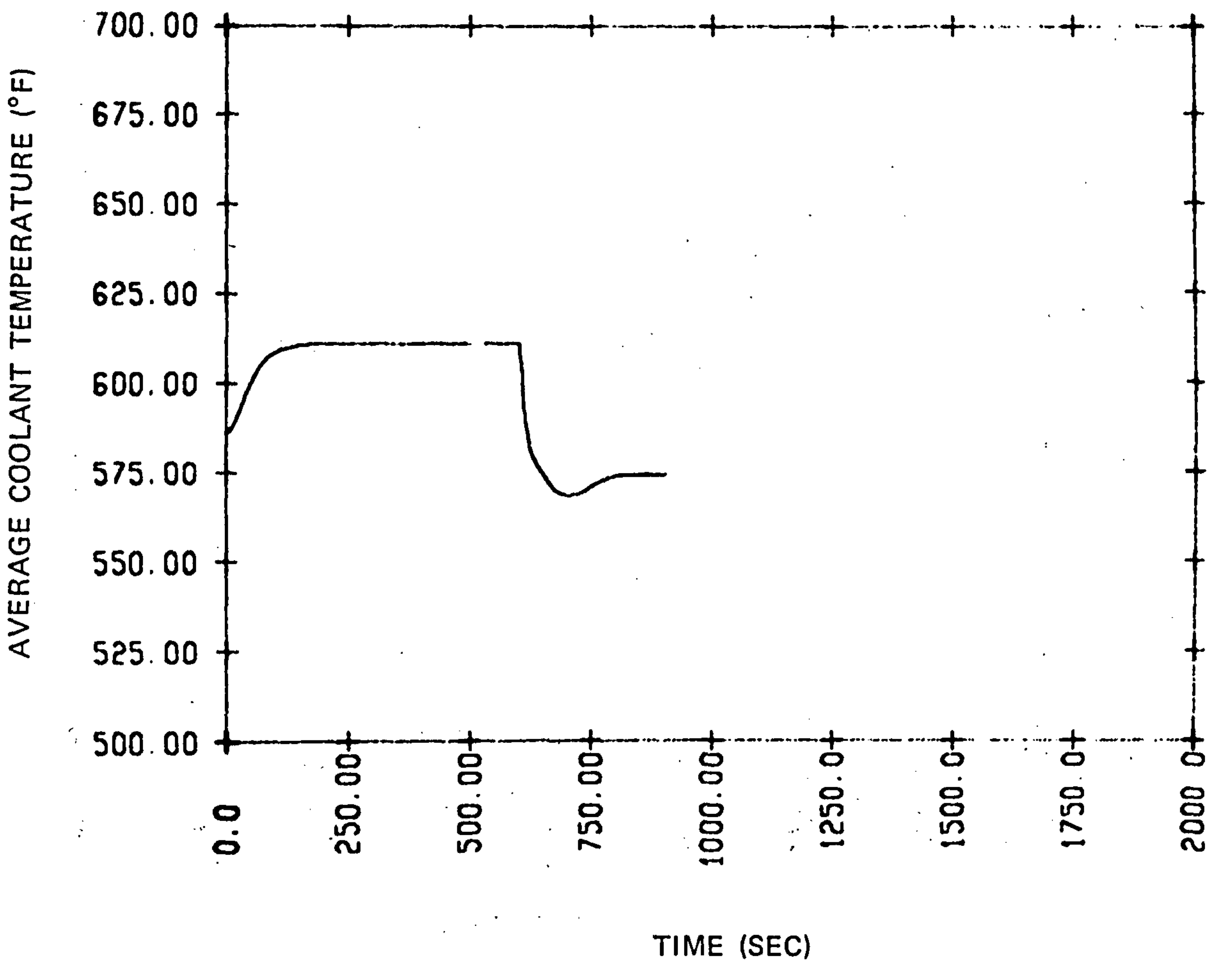


Figure B-3. Rod Withdrawal at Power; Shutdown by Manual Rod Trip (Average Coolant Temperature Vs. Time)

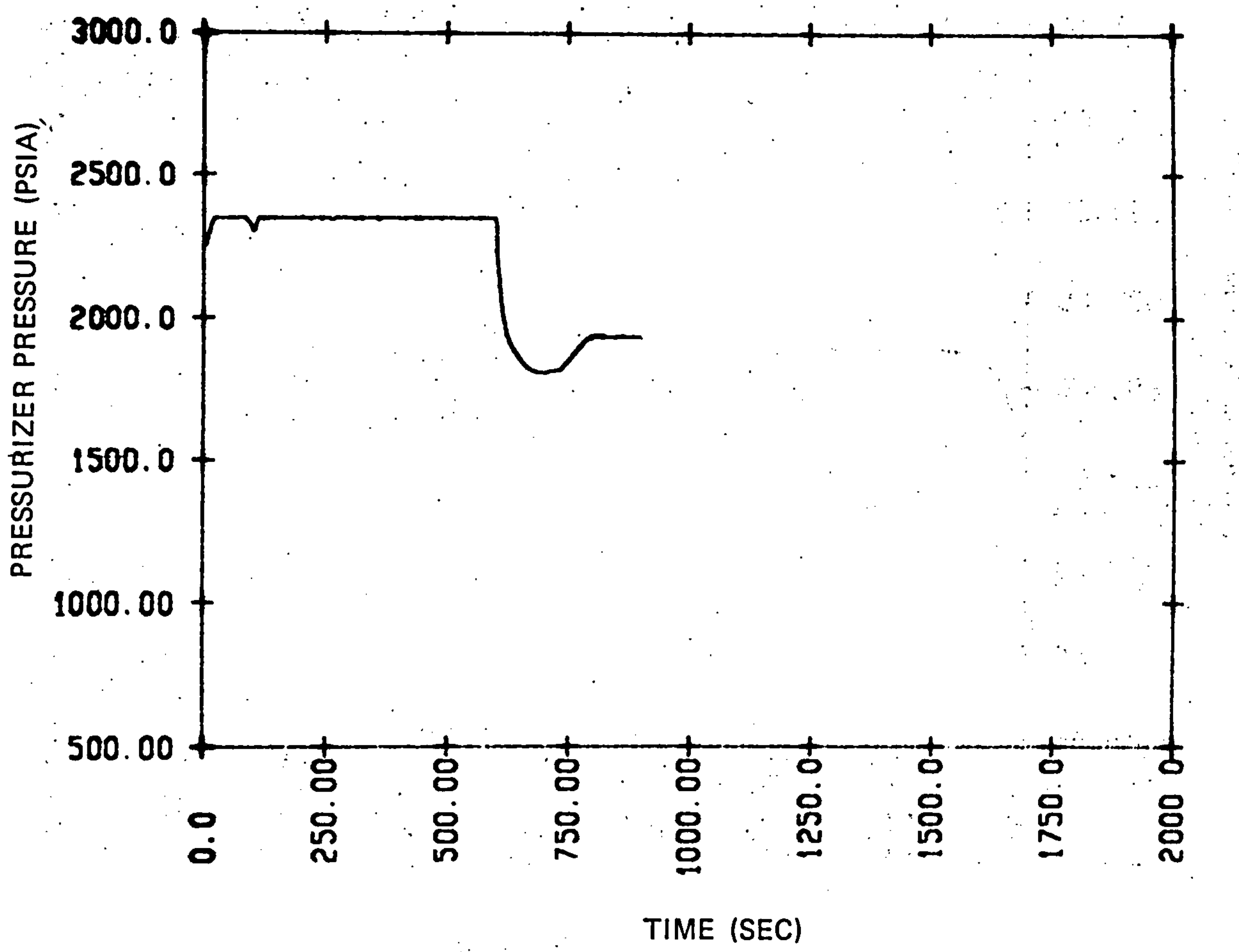


Figure B-4. Rod Withdrawal at Power; Shutdown by Manual Rod Trip (Pressurizer Pressure Vs. Time)

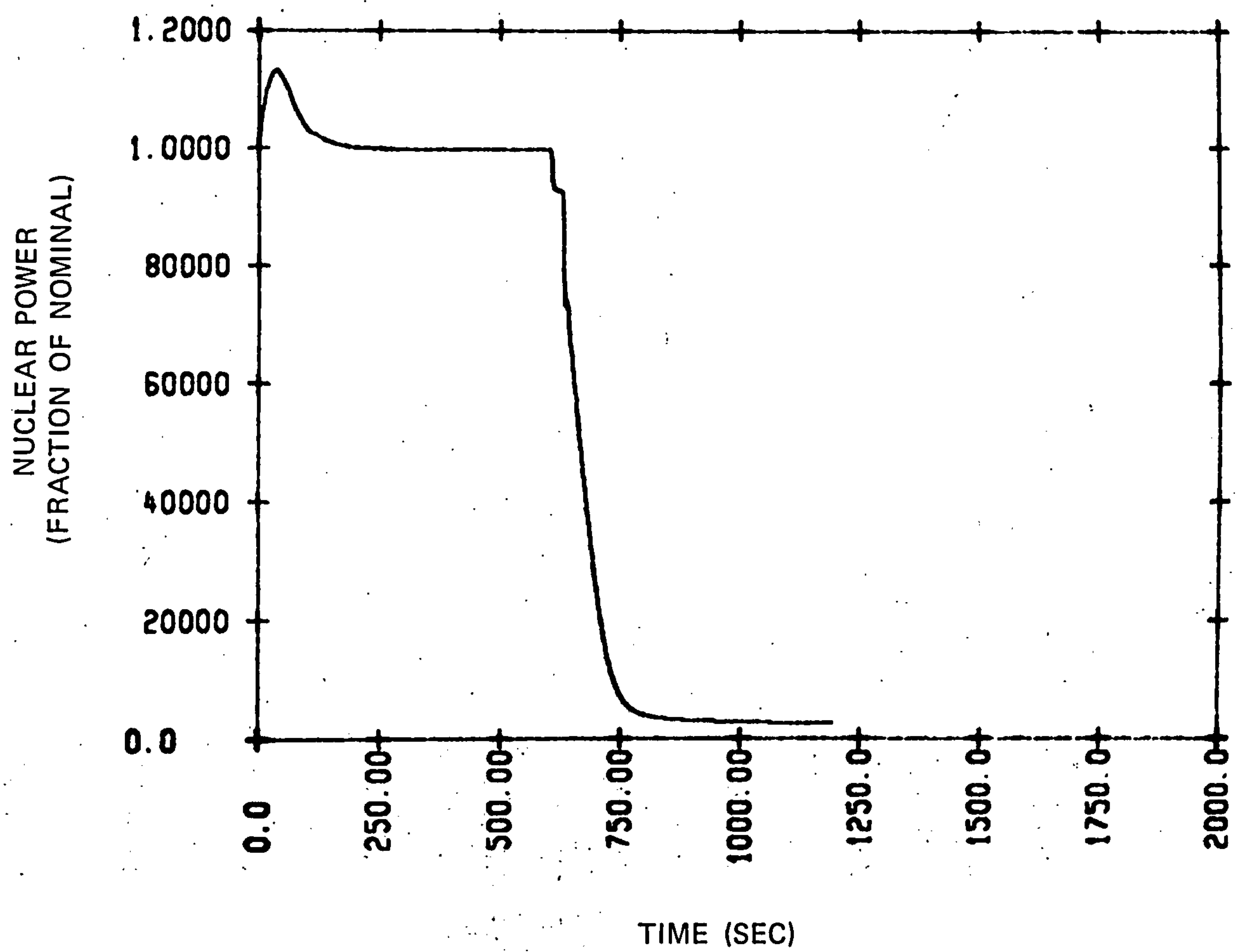


Figure B-5. Rod Withdrawal at Power; Shutdown by Safety Injection (Nuclear Power Vs. Time)

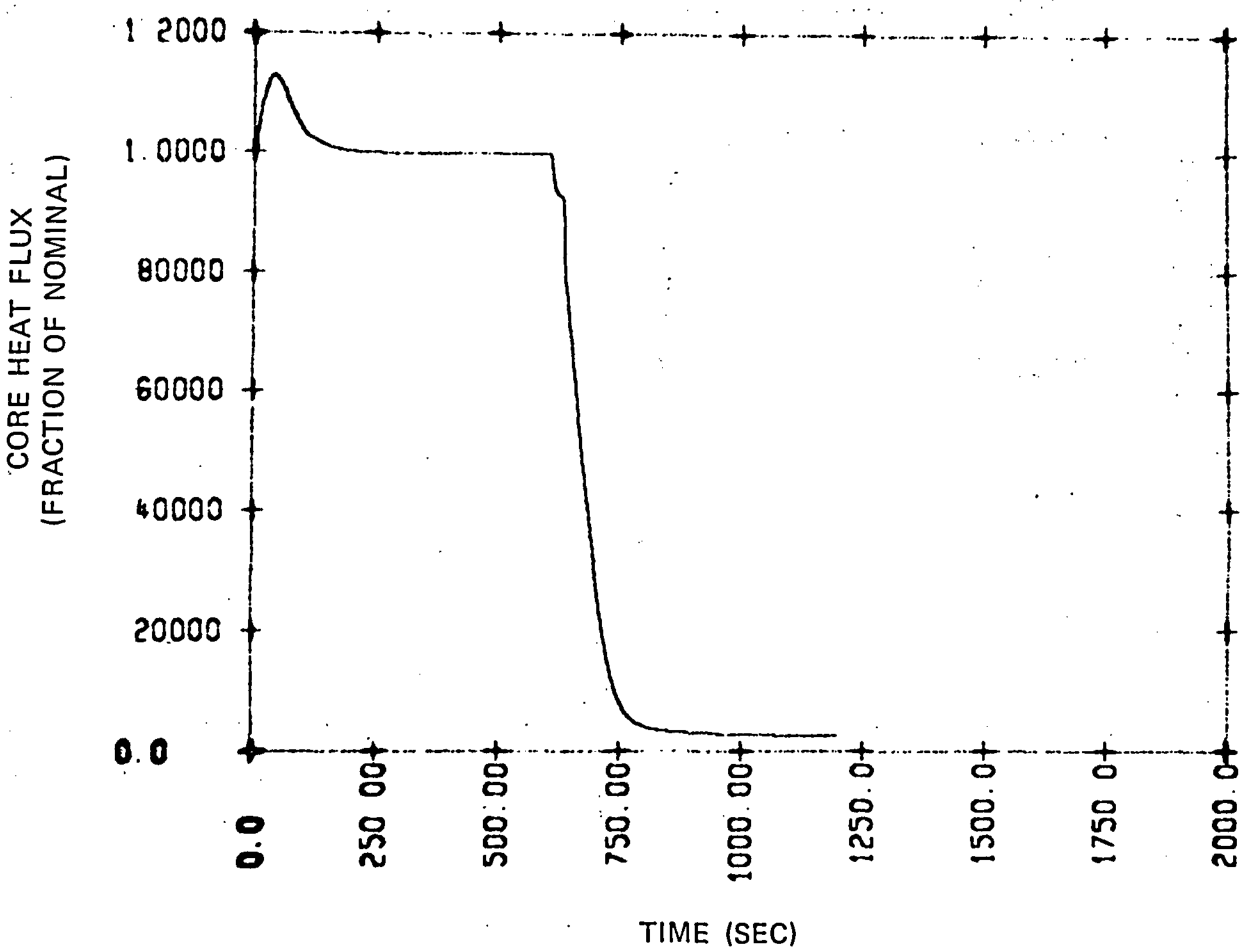


Figure B-6. Rod Withdrawal at Power; Shutdown by Safety Injection (Core Heat Flux Vs. Time)

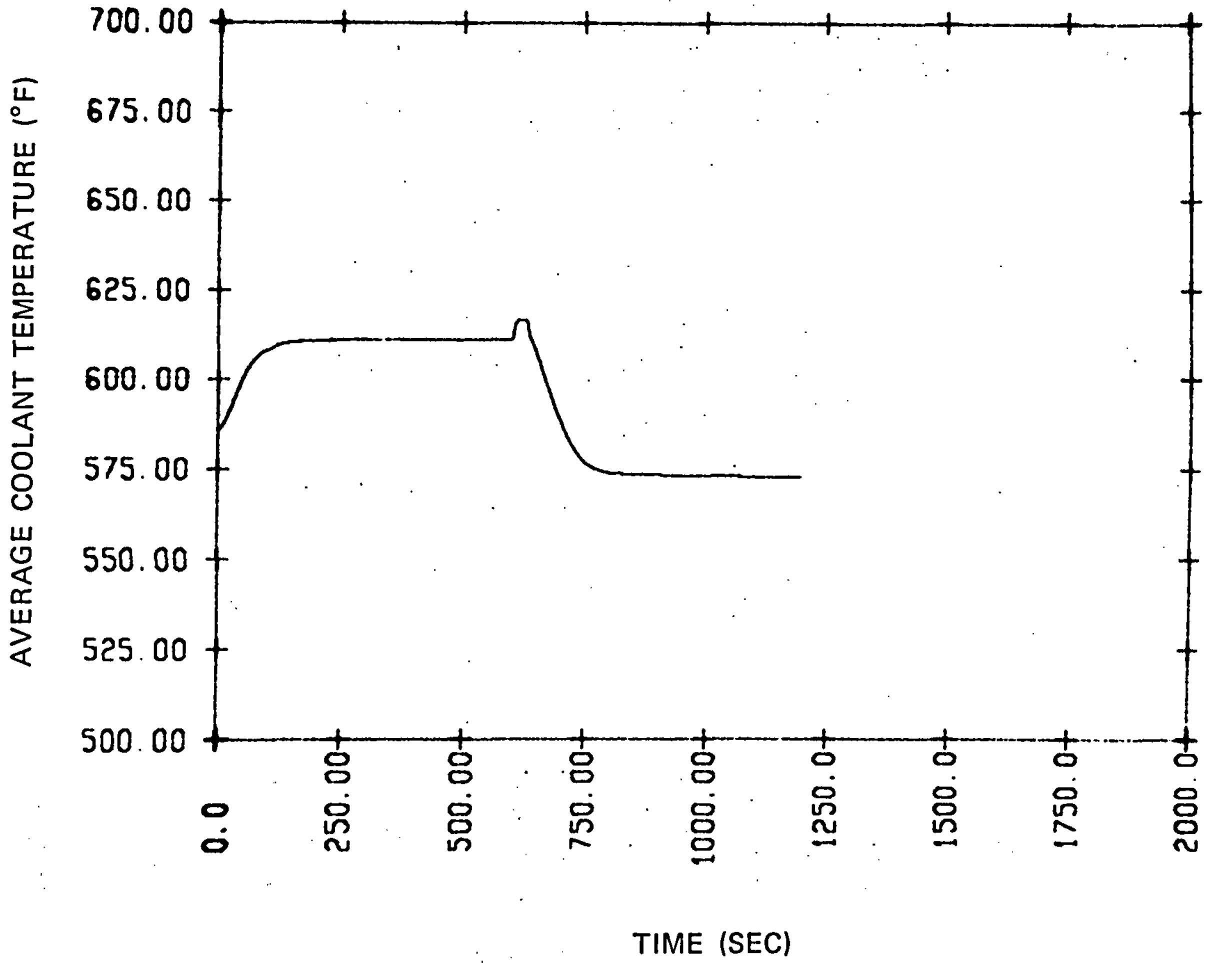


Figure B-7. Rod Withdrawal at Power; Shutdown by Safety Injection (Average Coolant Temperature Vs. Time)

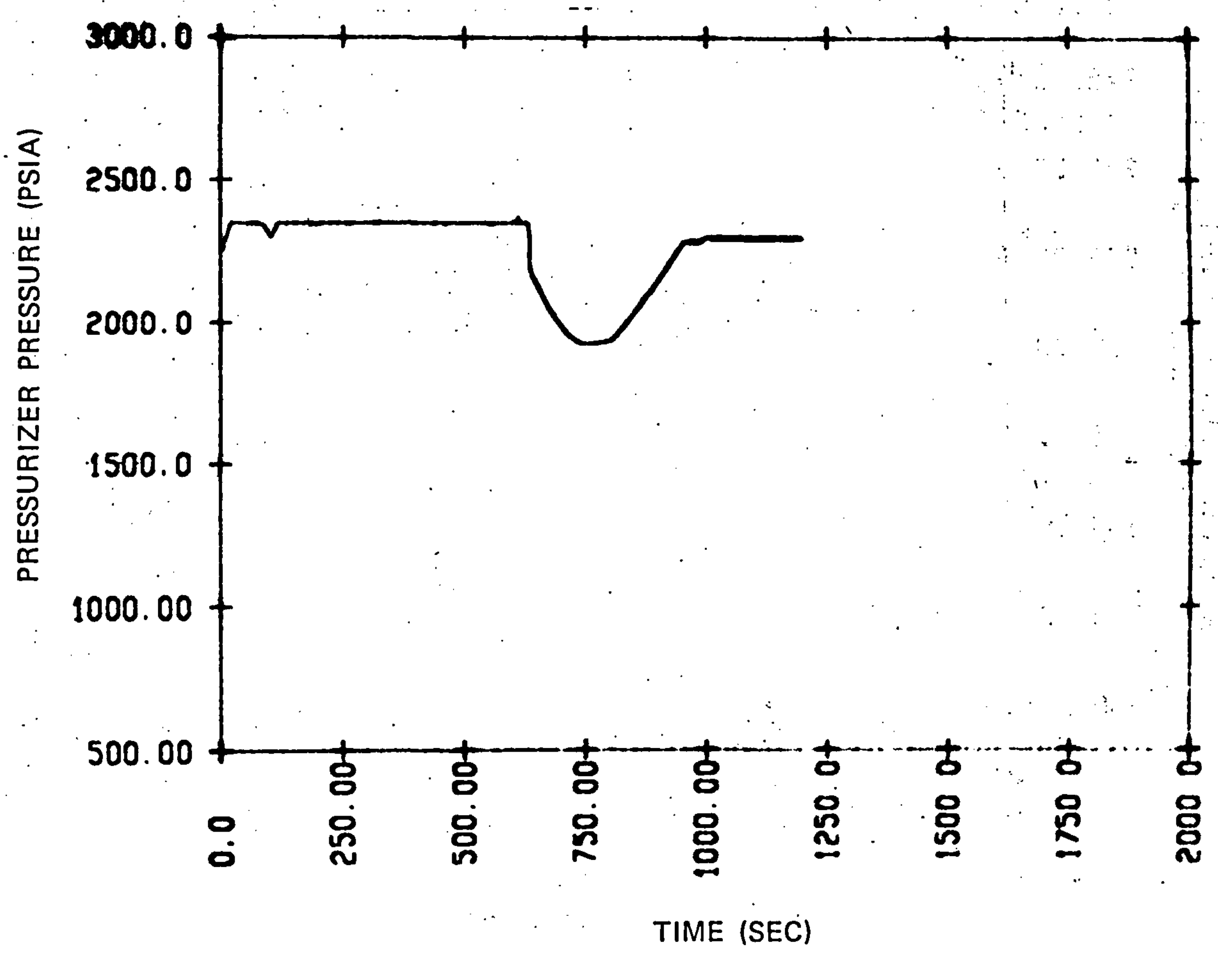


Figure B-8. Rod Withdrawal at Power; Shutdown by Safety Injection (Pressurizer Pressure Vs. Time)

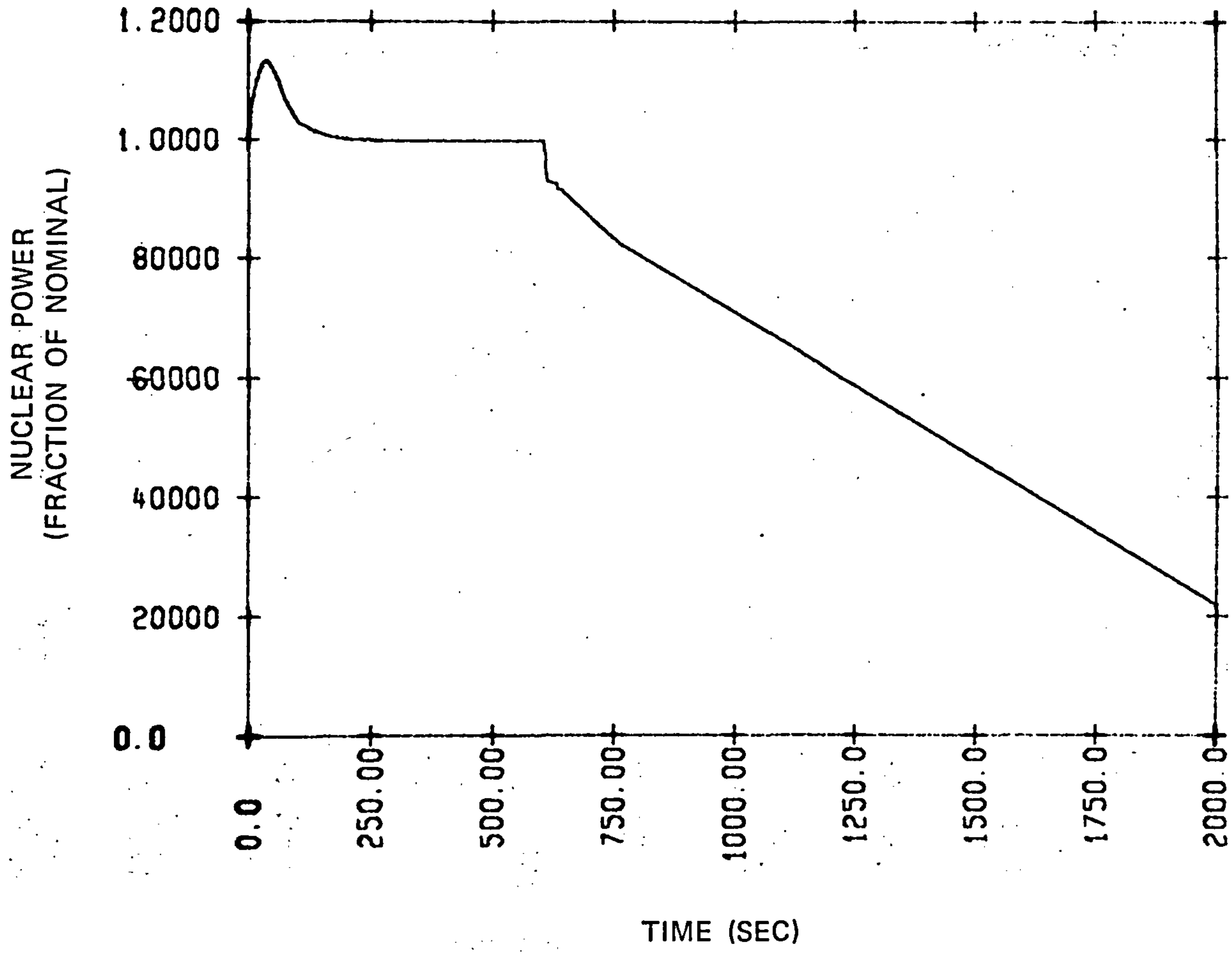


Figure B-9. Rod Withdrawal at Power Shutdown by Emergency Boration (Nuclear Power Vs. Time)

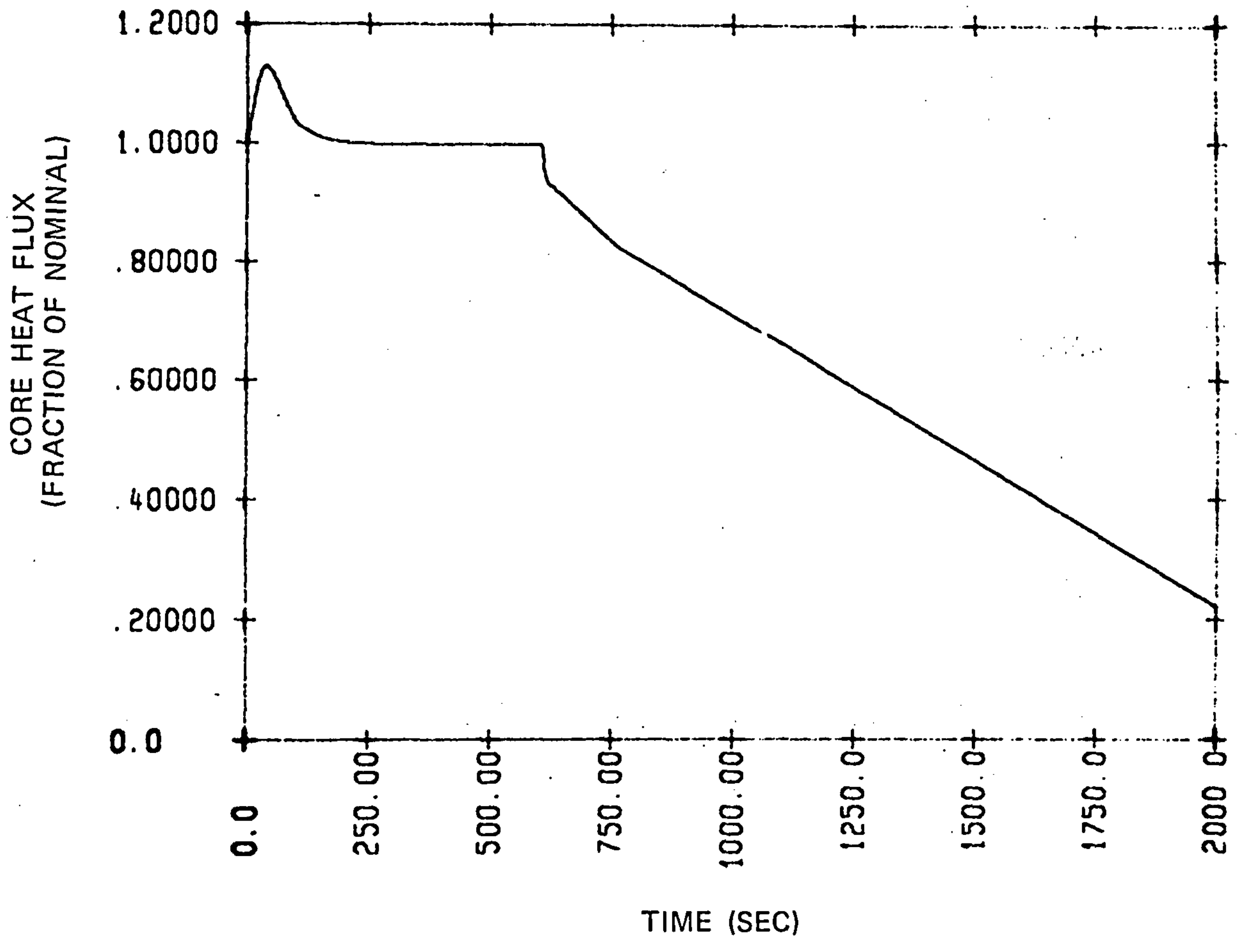


Figure B-10. Rod Withdrawal at Power Shutdown by Emergency Boration (Core Heat Flux Vs. Time)

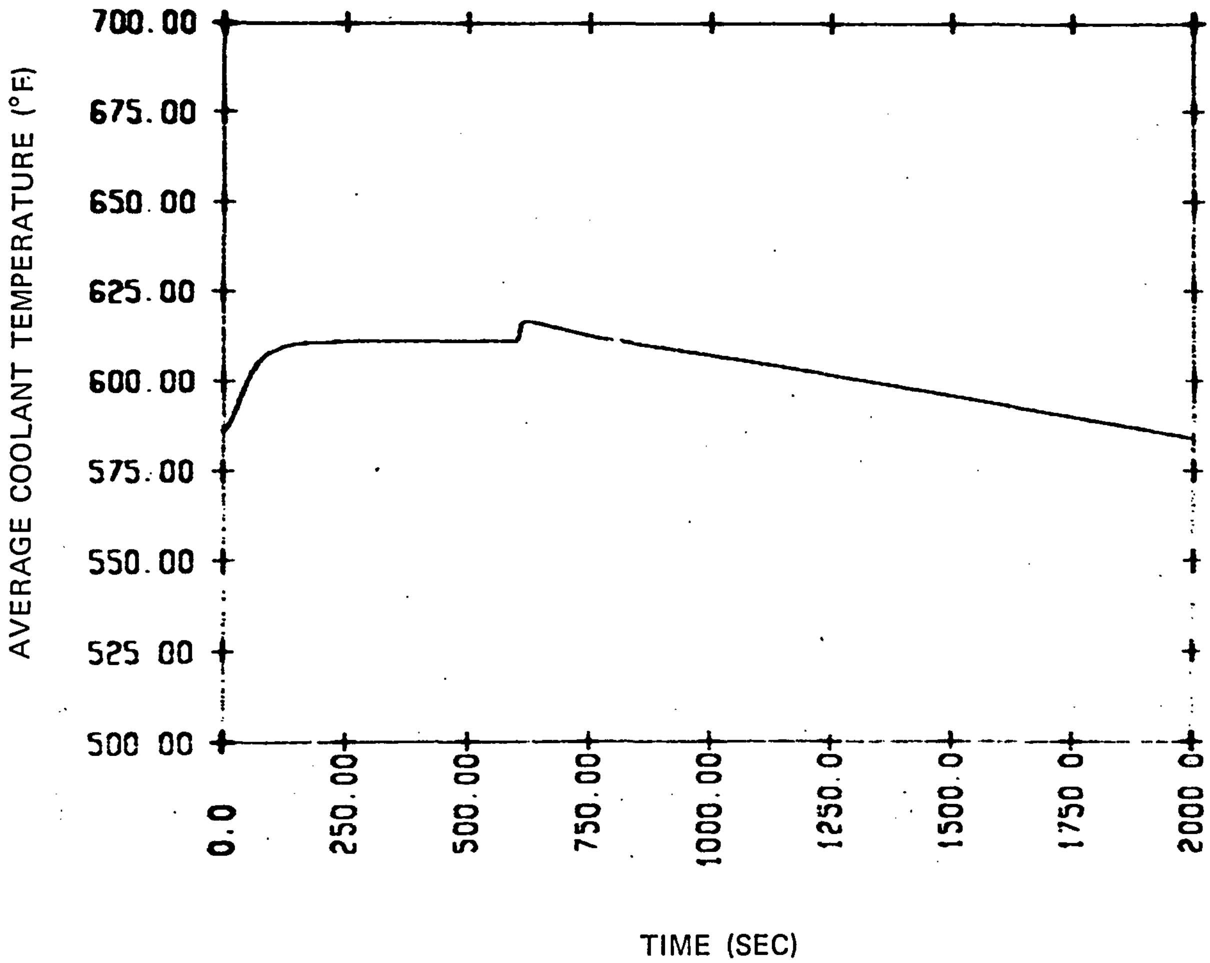


Figure B-11. Rod Withdrawal at Power Shutdown by Emergency Boration (Average Coolant Temperature Vs. Time)

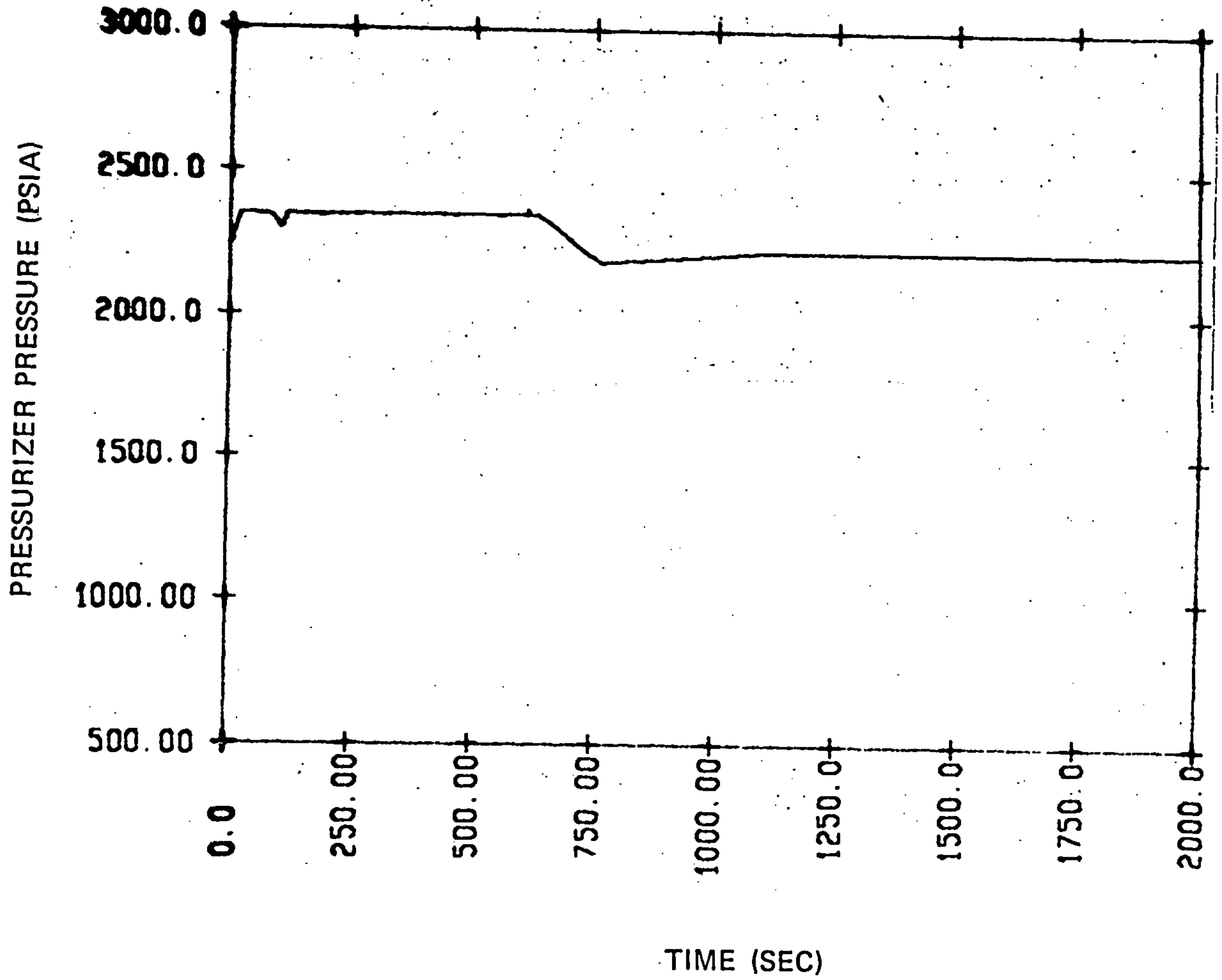


Figure B-12. Rod Withdrawal at Power Shutdown by Emergency Boration (Pressurizer Pressure Vs. Time)

APPENDIX C

STRESS EVALUATION OF REACTOR COOLANT SYSTEM BOUNDARY COMPONENTS FOR ATWT EVENTS

C-1. INTRODUCTION

Appendix A to WASH-1270 states that in evaluating the reactor coolant system boundary for ATWT events, "the calculated reactor coolant system transient pressure should be limited such that the maximum primary stress anywhere in the system boundary is less than that of the "emergency conditions" as defined in the ASME Nuclear Power Plant Components Code, Section III".

To demonstrate that the components of the reactor coolant system boundary satisfy the above recommendation limits, analyses were performed to establish the pressure at which emergency condition stress intensity limits were reached. (If peak pressure is less than 110 percent of design pressure, this objective is met since the ASME Code, Section III, Subsection NB-7000 recognizes this as allowable for anticipated transients.) The specific limits that were applied to the various components are given in the following ASME Section III Code paragraphs:

Component	Paragraph
Vessels, Pumps, and Valves	NB-3224
Piping	NB-3655
Bolts	NB-3234

Results of the analyses are summarized below and are tabulated in tables C-1 and C-2 where the material, material temperature, emergency condition stress intensity limits, and maximum pressure for the locations of high stress in each component are listed. The allowable pressures shown in table C-2 are conservative, since the actual average temperature of the components will remain considerably lower than the peak fluid temperatures due to the relatively short duration of the transients.

C-2. COMPONENT SUMMARY

C-3. **Reactor Pressure Vessel** — Based on a review of reactor vessels for 2-, 3-, and 4-loop plants, the maximum allowable pressure for the reactor vessel is 3200 psig. At this pressure, and a temperature of 700°F, the general membrane stress intensity for the nozzle safe ends

TABLE C-1

MAXIMUM PRESSURES FOR COMPONENTS

Component	Location and Material	Material Temperature (°F)	Emergency Condition Stress Intensity Limits Pm (psi)	$P_L + P_B$ (psi)	Maximum Pressure (psig)
	Shell & Head SA533-B C1.1	700	1.0Sy 33,100.	1.5Sy = 49,650.	3820
	Flanges SA508 C1.2	700	1.0Sy = 33,100.	1.5Sy = 49,650	4490
	CRDM Housing Flanges A182 Type 304	700	1.2Sm = 20,040.	1.8Sm = 30,060.	6690
Reactor Pressure Vessel	CRDM Housing & Inst. Tubes SB-167	700	1.2Sm = 27,960.	1.8Sm = 41,940.	3670. - CRDM 3510. - Inst. Tubes
	Nozzles SA336 Gr. FI	700	1.0Sy = 33,100.	1.5Sy = 49,650.	3870.
	Nozzle Safe Ends SA182-F316	700	1.2Sm = 20,040.	1.8Sm = 30,060.	3200
	Studs SA540B-24C1.3	700	2.0Sm = 67,400.	3.0Sm = 101,100	3210
	Motor Tube AISI Type 403	700	1.0Sy = 74,000	1.5Sy = 111,000.	5520
Part Length Control Rod Drive Mechanism	Adapter Section SA182-F304	700	1.2Sm = 18,120.	1.8Sm = 27,180	2940
	Bolts SA453 Type 660	700	2.0Sm = 53,600	3.0Sm = 80,400	2970
Full Length Control Rod Drive Mechanism	Rod Travel Housing SA336 Gr. F8	700	1.2Sm = 18,120	1.8Sm = 27,180.	2940
	Bolts SA453 Type 660	700	2.0Sm = 53,600	3.0Sm = 80,400	2970

TABLE C-1 (cont)

MAXIMUM PRESSURES FOR COMPONENTS

Component	Location and Material	Material Temperature (°F)	Emergency Condition Stress Intensity Limits		Maximum Pressure (psig)
			Pm (psi)	$P_L + P_B$ (psi)	
	Shell SA-533-C1.1	700	1.0Sy = 40,600.	1.5Sy = 60,900.	3800
	Heads SA-216-WCC	700	1.0Sy = 32,400.	1.5Sy = 48,600.	4550
Pressurizer with Cast Heads	Relief Nozzle SA-216 WCC	700	1.0Sy = 32,400.	1.5Sy = 48,600.	4200
	Surge Nozzle SA-216 WCC	700	1.0Sy = 32,400.	1.5Sy = 48,600.	4900
	Manway Cover SA-302-Gr. B	700	1.0Sy = 40,600.	1.5Sy = 60,900.	4300
	Manway Bolts SA-193 B7	700	2.0Sm = 53,600.	3.0Sm = 80,400.	6600
Pressurizer with Fabricated Heads	Shell & Heads SA-533 Gr. A C1.2	700	1.0Sy = 60,000.	1.5Sy = 90,000.	4970
	Relief Nozzle SA-508 C1.2	700	1.0Sy = 40,600.	1.5Sy = 60,900.	3780
	Surge Nozzle SA-508 C1.2	700	1.0Sy = 40,600.	1.5Sy = 60,900.	4450
	Manway Cover SA-302-Gr. B	700	1.0Sy = 40,600.	1.5Sy = 60,900.	4300
	Manway Bolts SA-193-B7	700	2.0Sm = 53,600.	3.0Sm = 80,400.	6600
Steam Generator	Tubesheet SA-508-C1.2	700	1.0Sy = 40,600.	1.5Sy = 60,900.	2980[a]
	Tube SB-163	700	1.2Sm = 27,960.	1.8Sm = 41,940.	2980[a]

TABLE C-1 (cont)

MAXIMUM PRESSURES FOR COMPONENTS

Component	Location and Material	Material Temperature (°F)	Emergency Condition Stress Intensity Limits Pm (psi)	$P_L + P_B$ (psi)	Maximum Pressure (psig)
Steam Generator	Primary Head SA-216 Gr. WCC	700	1.0Sy = 32,400.	1.5Sy = 48,600.	4150
	Primary Nozzle SA-216 Gr. WCC	700	1.0Sy = 32,400.	1.5Sy = 48,600.	4150
	Manway Cover SA-533 Gr. A C1.1	700	1.0Sy = 40,600.	1.5Sy = 60,900.	4300
	Manway Bolts SA-193-B7	700	2.0Sm = 53,600.	3.0Sm = 80,400.	6600
Reactor Coolant Pump	Casing SA-351 Gr. CF8	700	1.2Sm = 18,120.	1.8Sm = 27,180.	2890
	Bolts SA-540-Cl.4 Gr. B24	700	2.0Sm = 62,200.	3.0Sm = 98,300.	2890
RHR Gate Valve	Body SA-182 Gr. F304	550	1.2Sm = 16,300.		4400
	Disc SA-182 Gr. 347	550		1.0Sy = 21,000.	3000[a]
	Studs A 193 B7 (ASME-I, '65)	550	2.0Sm = 40,000.	3.0Sm = 60,000.	3000
Loop Isolation Valves	Body SA-351 Gr. CF8M	700	1.2Sm = 22,080		3770
	Studs SA-540 Cl.4 Gr. B24	700	2.0Sm = 62,200	3.0Sm = 93,300	2820

[a] Maximum differential pressure (psi).

TABLE C-2

MAXIMUM PRESSURES FOR PIPING

Component	Material	Material Temperature (°F)	Emergency Condition Stress Limit (psi)	Emergency Condition Pressure Limit (psig)	Maximum Pressure (psig)
Piping	SA-376 Type 304	700	2.25Sm = 35,775	1.5P = 3727	3727
	SA-351 Gr. CF8M	700	2.25Sm = 41,400	1.5P = 3727	3727
	SA-403 Gr. WP304	700	2.25Sm = 36,000	1.5P = 3727	3727

of 4-loop plants equals the emergency condition stress intensity limit of $1.2S_m$ and the local membrane-plus-bending stress intensity for the studs of 4-loop plants equals 0.997 times the emergency condition stress intensity limit of $3.0S_m$.

C-4. Control Rod Drive Mechanisms — The general membrane stress intensity equals the emergency condition stress intensity limit of $1.2S_m$ at 2940 psig and 700°F.

C-5. Pressurizer — A review of the pressurizers resulted in a maximum allowable pressure for the pressurizer of 3780 psig. At this pressure and a temperature of 700°F, the general membrane stress intensity for the relief nozzle in the fabricated head pressurizer equals the emergency condition stress intensity limit of $1.0S_y$.

C-6. Steam Generator — The steam generators were able to be subjected to a maximum allowable primary to secondary differential pressure of 2980 psig at 700°F. For these conditions, the general membrane stress intensity for the tubes of the steam generator equals the emergency condition stress intensity limit of $1.2S_m$ and the local membrane plus bending stress intensity for the tubesheet equals the emergency condition stress intensity limit of $1.5S_y$.

C-7. Reactor Coolant Pump — A review of the reactor coolant pumps produced a maximum allowable pressure of 2890 psig. At this pressure, and a temperature of 700°F, the stress intensities for the pump casing and bolts equaled emergency condition limits.

C-8. Piping — The maximum pressure that the reactor coolant piping can be subjected to and still remain within the ASME Section III emergency condition limits is 3727 psig. At this pressure, and a temperature of 700°F, the pressure limit of 1.5P is reached.

C-9. Valves - (Line Valves) — The limiting line valves are the Residual Heat Removal System pump suction isolation valves. These valves would not be subjected to an ATWT thermal transient since the valves are located on long non-flow lines. The maximum metal temperature is thus less than or equal to the normal Reactor Coolant System operating temperature of about 550°F. At this temperature, the general membrane stress intensity in the valve body crotch will equal the emergency condition stress intensity limit of $1.2S_m$ at an internal pressure of 4400 psig.

The valve discs, however, must not be distorted such that functional operation is impaired since these valves are closed and may be required to open for plant cooldown. To ensure functional operation, a limit of $1.0\ S_y$ is placed on the local membrane-plus-bending stress intensity in the disc. This limit is not exceeded for differential pressures less than 3000 psi.

C-10. Loop Isolation Valves — The maximum allowable pressure for loop isolation valves is 2820 psig. At this pressure, and a temperature of 700°F, the general membrane stress intensity of the studs equals the emergency condition stress intensity limit of $2.0S_m$.

C-11. **Safety Valves** – The ASME-III Code allows an overpressure of 110 percent of design pressure for upset conditions. Since the ATWT pressurizer pressure transients do not exceed the 110 percent of design pressure that is allowed under upset conditions, the pressurizer safety valves are adequate for this service condition.

APPENDIX D
CONTAINMENT PRESSURE STUDIES

The containment pressure transients were evaluated for the ATWT events with the largest integrated mass and energy releases, loss of feed and accidental depressurization. The results for these transients are shown in figure D-1. The mass and energy releases for a design basis LOCA event are also provided for comparison. Figure D-1 demonstrates that the rates of mass and energy release for ATWT transients are significantly lower than for a LOCA event. Hence, the containment pressure transient resulting from postulated ATWT events is much less severe than the containment pressure transient resulting from the design basis LOCA; thus, the peak containment pressure resulting from postulated ATWT events is much less than the containment design pressure. The containment pressure transient for the depressurization, ATWT event with the largest integrated mass and energy release, is shown in figure D-2.

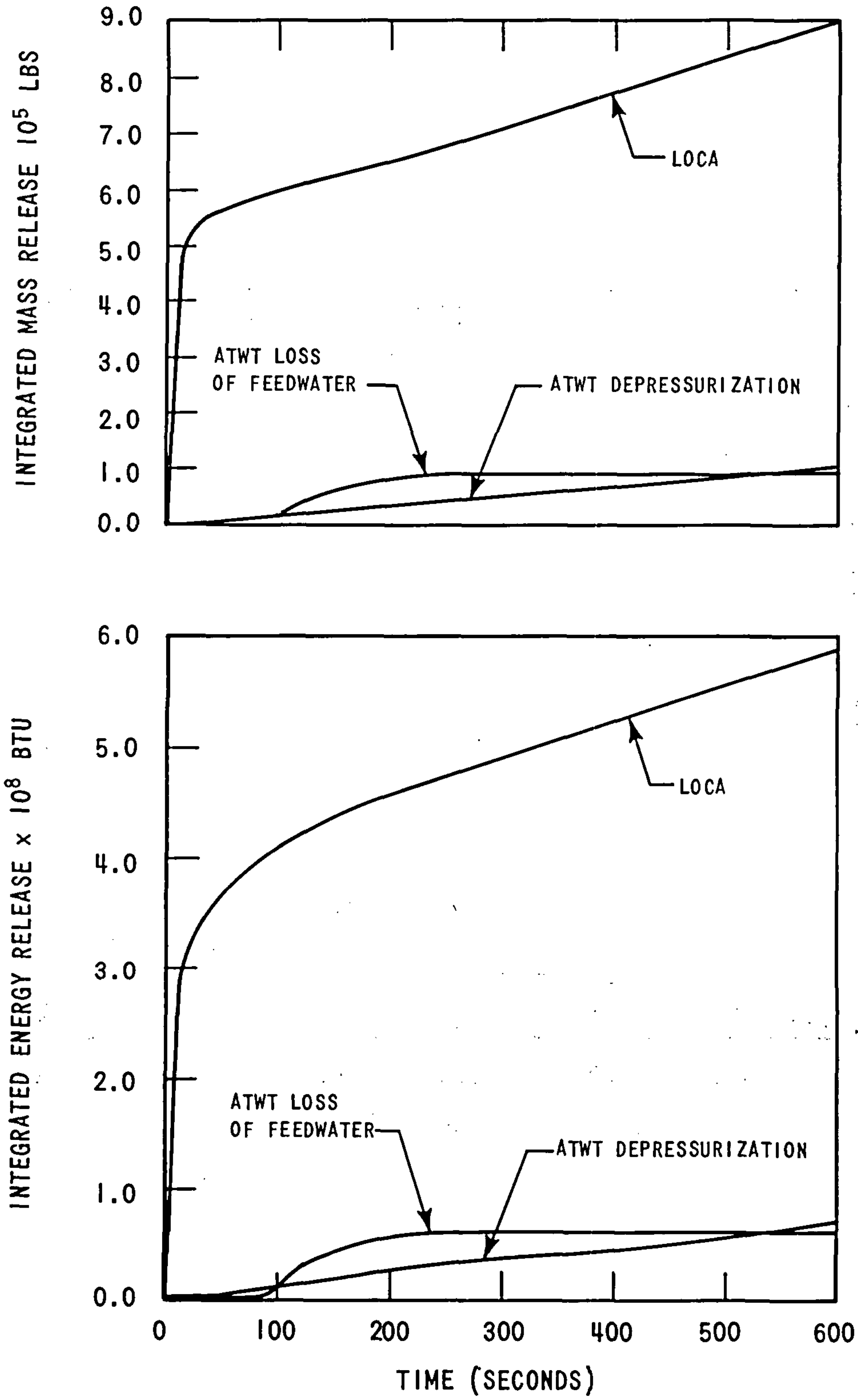
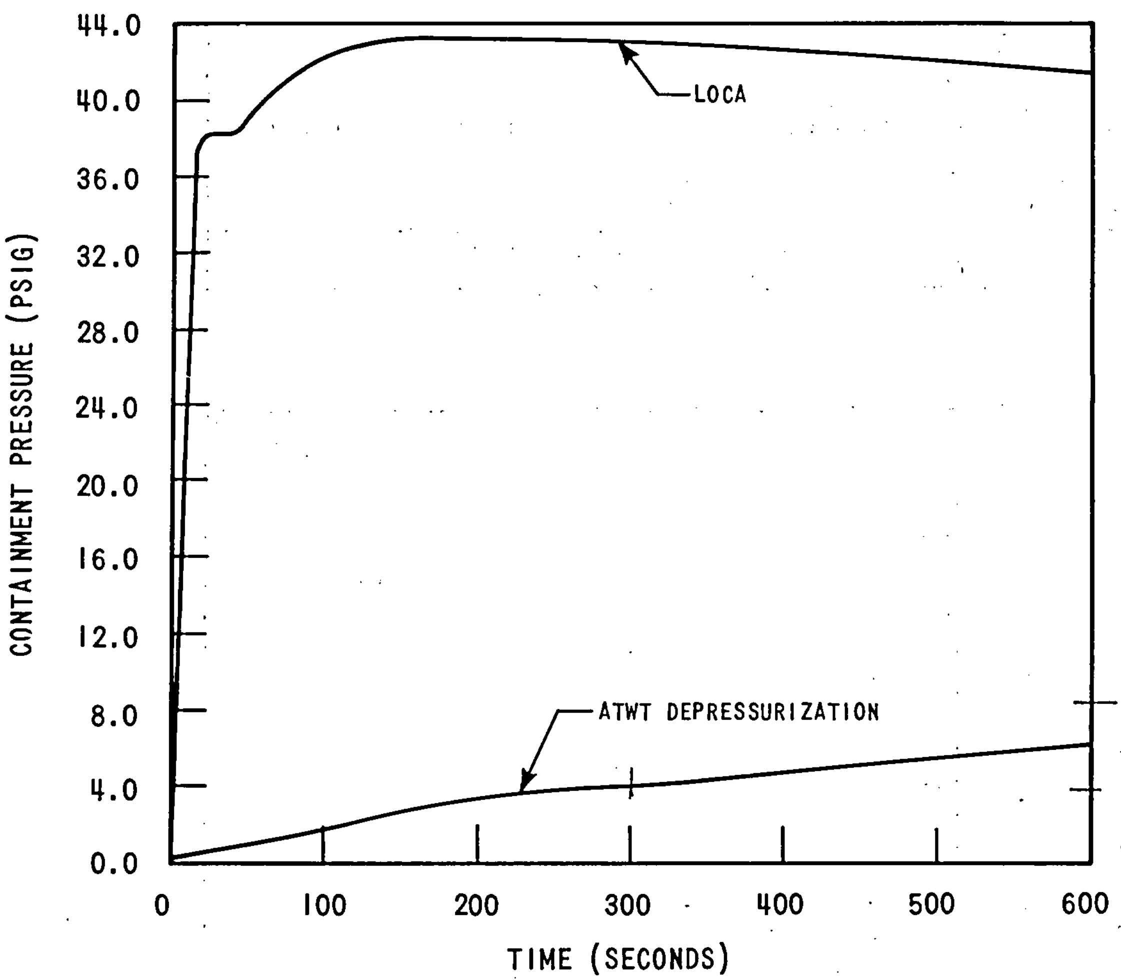


Figure D-1. Containment Mass and Energy Release for LOCA, ATWT Depressurization, and ATWT Loss of Feed



$\frac{2\ psi}{300\ sec} = \frac{2\ psi}{5\ min} = .4 \frac{psi}{min}$

Figure D-2. Containment Pressure Transient for LOCA and ATWT Depressurization

APPENDIX E
ATWT RADIOLOGICAL CONSEQUENCES

The ATWT events studied in section 4 have been evaluated for dose consequences. The sources considered in the evaluation were the reactor coolant released to the primary containment and then leaking to atmosphere, and the secondary system water relieved directly to atmosphere.

The loss of load transient caused by loss of condenser vacuum was chosen for dose evaluation since it gives the highest secondary mass release. A steam generator primary to secondary leak rate of 0.1 gpm was assumed, and all secondary steam dump and relief were assumed released directly to atmosphere. The site boundary and the low population zone distances were conservatively assumed to be 500 meters and 1,100 meters, respectively. A $\frac{\chi}{Q}$ of 3.3×10^{-3} sec/m^3 was assumed, based on the worst weather conditions for a Westinghouse designed PWR.

Since it is expected that the pressurizer relief tank rupture disks would rupture during prolonged relief, the mass of reactor coolant expelled from the pressurizer safety and relief valves was assumed to be relieved directly to containment. The activity content of this coolant was assumed to leak from containment to atmosphere at the rate of 0.05 percent per day (a conservative leak rate considering the relatively low containment pressure).

The 2-hour site boundary thyroid, beta, and gamma doses for the loss of load ATWT event were calculated to be 4.6×10^{-2} Rem, 5.4×10^{-4} Rem, and 3.8×10^{-4} Rem, respectively. The 30 day low population zone thyroid, beta, and gamma doses are 5.2×10^{-2} Rem, 5.6×10^{-4} Rem and 3.2×10^{-4} Rem, respectively. For each of these doses, the contribution from primary to containment to atmosphere was found to be only about two percent of the total, far overshadowed by the contribution from secondary relief to atmosphere.

Thus, the dose consequences of ATWT events are far below the 10 CFR Part 100 guideline values.