CE-NPSD-154

NATURAL CIRCULATION COOLDOWN

TASK 430 FINAL REPORT

Prepared for the C-E OWNERS GROUP

NUCLEAR POWER SYSTEMS DIVISION
OCTOBER, 1981

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ABSTRACT

This report has been prepared in response to a C-E Owners Group request for an evaluation of natural circulation plant cooldowns. This report consists of system dynamic analysis and evaluation of reactor vessel head voiding on the reactor vessel shell and internals. Based on this information, operator safety functions needed during a natural circulation cooldown process were developed for use in preparation of plant specific procedures and operator training.

PREFACE RELATIVE TO PRESSURIZED THERMAL SHOCK

A natural circulation cooldown may be required following an initiating event which depressurizes the reactor coolant system (RCS) sufficiently to require that the reactor coolant pumps be tripped. The NRC currently requires that reactor coolant pumps be tripped following a Safety Injection Actuation Signal. If the initial cooldown rate exceeds Tech. Spec. limits, there may be a potential for pressurized thermal shock of the reactor vessel. (The term pressurized thermal shock refers to damage caused by a rapid RCS cooldown with concurrent high pressure or subsequent repressurization.) Pressurized thermal shock may occur unless RCS pressure/temperature combinations are maintained within appropriate limits. These limits are currently being developed. Until these limits are available for use, RCS pressure should be maintained at normal operating pressure during natural circulation cooldown only if the cooldown rate during the initiating event and subsequent plant cooldown does not violate Tech. Spec. limits. If the Tech. Spec. limits are violated, then the RCS pressure during natural circulation cooldown should be maintained as low as possible while avoiding flashing in the reactor vessel head.

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LIST OF ABBREVIATIONS

CEA	-	Control Element Assembly
CEDM	-	Control Element Drive Mechanism
CSB	-	Core Cupport Barrel
C_p	-	Specific Heat
E	-	Young's Modulus
HPSI	-	High Pressure Safety Injection
ICI	-	In Core Instrumentation
K	-	Thermal Conductivity
Ksi	-	1000 psi
LOCA	-	Loss of Coolant Accident
LTOP	-	Low Temperature Overpressure Protection
MWt	-	Megawatts (thermal)
NC	-	Natural Circulation
NSSS	-	Nuclear Steam Supply System
psi	-	Pounds per square inch
RCP	-	Reactor Coolant Pump
RCS	-	Reactor Coolant System
RTD	-	Resistance Temperature Detector
RV	-	Reactor Vessel
Tc	-	Cold Leg Temperature
T_h	-	Hot Leg Temperature
Tech. Spec.	-	Technical Specifications
UGS	-	Upper Guide Support
α	-	Thermal Expansion Coefficient
ρ	-	Density
ν	-	Poisson's Ratio

1.0 INTRODUCTION

1.1 Purpose

This report describes the results of activities performed for the C-E Owners Group. Activities included the evaluation of the natural circulation cooldown process and the development of natural circulation cooldown safety functions. A plant cooldown via natural circulation is necessary to achieve cold shutdown whenever forced circulation by reactor coolant pumps is not available. The analysis and operational information described in this report can be used by each utility during their preparation of plant specific natural circulation cooldown procedures and operator training.

1.2 Scope

Several analytical activities on the natural circulation cooldown process are summarized in this report. System dynamic analysis on asymmetrical natural circulation cooldowns and on natural circulation cooldown head voiding is provided in Section 2.0. A description of a structural evaluation of the effects of reactor vessel head voiding on the reactor vessel shell is provided in Section 3.0. Section 4.0 contains a description of a structural evaluation of the effects of reactor vessel head voiding on the reactor vessel internals.

Section 5.0 provides operational guidance on natural circulation cooldown safety functions and the important concepts involved with the operator actions. The operational guidance in Section 5.0 was developed in part based on the conclusions drawn fron the Sections 2.0 - 4.0 analyses since they provided new information concerning NSSS asymmetrical cooldowns and reactor vessel head voiding.

1.3 Background

In April, 1980, C-E provided the C-E Owners Group with the report CEN-128 which was developed in response to the TMI Lessons Learned requirements. CEN-128 included interim emergency guidelines that provided operator guidance to accommodate emergency transients and to place the NSSS into a stable state following the transient. Limited event specific guidance was provided regarding follow-up operation. Guidance for NSSS boration, cooldown, and depressurization following abnormal events was not included in the CEN-128 scope.

In June, 1981, C-E provided the C-E Owners Group with the report CEN-152. This report contains an improved set of emergency guidelines which addresses multiple failures. Although a guideline was provided for a natural circulation cooldown in CEN-152, the natural circulation cooldown guideline only listed the minimum guideline actions required. The natural circulation analysis and recommendations provided herein were developed to supply additional detailed information that could be used by the C-E Owners Group during their preparation of plant specific procedures and for operator training regarding natural circulation cooldown evolutions.

1.4 Report Summary

A natural circulation plant cooldown could be required when forced RCS flow is not available. Maximizing the RCS cooldown rate and maintaining a high RCS pressure will maximize the reactor vessel upper head heat loss while preventing void formation. Following a hold period to allow for adequate reactor vessel upper head heat transfer, depressurization of the RCS to the shutdown cooling entry pressure can occur without drawing a bubble in the reactor vessel dome. If a void were to occur during RCS depressurization, no structural damage would occur to the reactor vessel shell or internals. A method of cooling the reactor vessel upper head by expanding and collapsing a reactor

vessel dome bubble has been evaluated. The analysis shows that the upper reactor vessel head cooldown rate can be accelerated by the RV head fill and drain process without any thermal, hydraulic or fatigue damage to reactor vessel components.

Natural circulation flow in an isolated steam generator can be stagnated or slightly reversed during a one steam generator natural circulation plant cooldown. Natural circulation flow through the unisolated steam generator and core will not be affected by stagnated or reversed flow conditions in the isolated steam generator and its loop. However the hot isolated steam generator must be cooled before the RCS can be depressurized to the shutdown cooling entry pressure.

Information is provided on operator safety functions that need to be addressed during natural circulation plant cooldowns. The four safety functions include reactivity control, RCS pressure control, RCS inventory control, and RCS heat removal. Operator actions and their important concepts are provided for natural circulation cooldown, asymmetric natural circulation cooldown, reactor vessel head voiding, cooldown following various system failures and solid RCS cooldowns.

2.0 SYSTEM DYNAMIC ANALYSIS

2.1 Introduction

The system dynamic analysis activities were divided into three categories. The first activity involved generating worst case thermal data during voiding in the reactor vessel (RV) dome and generating upper plenum temperature stratification predictions for input to the RV shell and RV internals structural evaluations. The thermal data used for the RV voiding component stress calculations are described in Sections 3.3 and 4.3.

The second activity involved analyzing asymmetric natural circulation (NC) plant cooldowns such as might result following a steam generator tube rupture or other events which might require isolation of one of the two steam generators.

The third activity investigated the cooldown of the RV dome region due to conduction cooling and local natural circulation flow in the dome region. A plant cooldown strategy was developed to minimize the hold time required to avoid drawing a bubble in the RV dome during a natural circulation cooldown.

2.2 Asymmetric Natural Circulation Cooldown

2.2.1 Objectives

The activities summarized in this Section describe the thermal behavior of an isolated steam generator when the entire NSSS is being cooled via natural circulation through the other (unisolated) steam generator. Specifically the following points are addressed:

1. Will natural circulation flow through the core ever stagnate or reverse due to to a hot isolated steam generator?

2. Will the flow in the isolated loop stagnate even though normal natural circulation flow is occuring in the unisolated loop?

3. If the flow through the isolated loop is not stagnant, then what is the thermal response of the isolated steam generator as the unisolated steam generator is cooled?

4. Is there an optimum set of conditions to maximize the cooldown of an isolated steam generator?

5. What is the maximum cooldown rate of an isolated steam generator via natural circulation reverse heat transfer under the optimum set of conditions?

2.2.2 Generic Asymmetric Analysis

Both a steady state and dynamic simulation approach were used to evaluate asymmetric natural circulation plant cooldown. The steady state natural circulation governing equations were investigated in a generalized and rigorous manner. The steady state equations address momentum through both loops and the reactor vessel, and the conservation of mass at junction points with a constant system pressure. A rigorous temperature distribution within the steam generator tubes was used while considering an arbitrary secondary two-phase height to allow for degraded heat transfer conditions. RCS metal to coolant heat transfer was not modeled.

The steady state equations were numerically solved using geometrical and hydraulic data for a typical two loop C-E plant. Given the component elevations and resistance, results are determined as a function of time (decay heat) and the secondary temperatures of both steam generators ($T_{sec.\ 1}$ & $T_{sec.\ 2}$). The heat transfer rate (q_2) from the isolated unit, defined as steam generator #2, is plotted as functions of $T_{sec\ 1}$ and $T_{sec\ 2}$ in Figures 2-1 through 2-4. All cases investigated exhibit the same basic trends.

Several significant conclusions can be drawn. Positive q_2 represents heat transfer from primary to secondary. The region of interest is that of negative q_2 or reverse heat transfer. Note that these results are for forward flows in both loops and therefore negative q_2 means that T_{hot} is less that $T_{sec\ 2}$. All the curves show a point of <u>minimum</u> q_2, representing the point of <u>maximum</u> cooling of the isolated steam generator. The reverse heat transfer in unit #2 will increase as T_{hot} is decreased for a given value of $T_{sec\ 2}$. However, the density driving term associated with the unit also decreases which decreases the flow through that loop. Therefore the reverse heat transfer process in the isolated unit is subject to the competition of two factors:

1. Decreasing T_{hot} tends to increase the reverse heat transfer.

2. Increasing the reverse heat transfer decreases the NC flow through the isolated unit as the density driving term becomes increasingly negative until stagnant conditions are reached; thereby terminating the reverse heat transfer process.

The point of maximum reverse heat transfer corresponds to a set fraction of decay heat. The ability to cool the hot isolated steam generator decreases with time. The temperature difference (between $T_{sec\ 1}$ and $T_{sec\ 2}$) required to attain the optimum point is a function of the decay heat, and hence is a function of time. It is also a weak function of the temperatures themselves; this effect is caused by the nonlinearity of the density vs. temperature of subcooled water. Approximate values of this optimum temperature difference are listed below:

Time After Trip From Full Power, sec	Optimum ΔT, °F ($T_{sec\ 2} - T_{sec\ 1}$)	Decay Heat Fraction
100	120 ± 10	0.035
1000	90 ± 10	0.022
10000	60 ± 7.5	0.011
100000	40 ± 5	0.0059

The optimum ΔT between the two secondary temperatures decreases with time which has some serious implications for successful natural circulation cooldown of the isolated unit. In particular it implies that if the unisolated unit is "overcooled", the system would have to be "reheated" to establish the correct temperature distribution in the RCS to facilitate natural circulation flow in the isolated unit. Maintaining optimum conditions for reverse heat transfer would result in RCS cooldown rates of approximately 10°F/hr and 5°F/hr at 10^4 seconds (2.8 hours) and 10^5 seconds (27.8 hours) after trip.

The time dependent response of the NSSS during an asymmetrical natural circulation cooldown was calculated with the LTC computer code which was used to develop the transient response curves (compiled in CEN-128) for the preparation of the Emergency Procedure Guidelines.

All cases were run as a reactor/turbine/RCP trip from full power at time zero. Cooldown was started at 900 seconds (15 minutes), after both primary and secondary side conditions stabilized. Also at 900 seconds, one unit was isolated. A tabulation of secondary temperatures versus heat transfer rate and the transient parameter plots for the four cases are contained in Appendix A.

Case 1 is a 75°F/hr cooldown of the unisolated unit until steam flow limited. For a relatively brief period of time (3000 to 4000 seconds), reverse heat transfer occurred. After this time the flow in the isolated unit was stagnant (LTC results show a small $\sim$ 10 #/sec reverse flow). Except for the 3000 to 4000 second time period, no cooling of the isolated unit occurred.

Case 2 is a cooldown of the unisolated unit with the temperature of the unisolated unit dictated from the steady state analysis for the optimum secondary temperature differential value. A marked improvement was obtained in cooling the isolated unit. However cooling of the isolated unit is a slow process even with optimum conditions.

Case 3 is a cooldown of the unisolated unit with the temperature of the unisolated unit held at the optimum secondary temperature differential value plus 20°F. Essentially no cooling of the hot unit occurred since $T_{sec\ 1}$ was not low enough to cause reverse heat transfer from the isolated unit.

Case 4 is a cooldown of the unisolated unit with the temperature of the unisolated unit held at the optimum secondary temperature differential value minus 20°F. These results show the effect of $T_{sec\ 1}$ being too high at first, then passing through the optimal reverse heat transfer conditions, and ending with the natural circulation flow choked off in the isolated loop.

2.2.3 Asymmetric Natural Circulation Cooldown Conclusions

1. A hot isolated steam generator and RCS loop by itself will not interrupt natural circulation flow through the core with normal natural circulation conditions established in the operating steam generator.

2. Natural circulation flow can be forward, stagnant, or slightly reversed through an isolated RCS loop with normal natural circulation flow occurring in the unisolated RCS loop.

3. Cooldown of an isolated steam generator by natural circulation reverse heat transfer can only be accomplished with optimal thermal conditions.

4. The error band on the optimal conditions is typically less than 20°F and decreases with time.

5. A full cooldown of the isolated unit, even under optimal conditions, will take about a day.

6. It will take an hour or two to achieve optimal conditions from most initial conditions.

7. The optimal cooldown rate of the unisolated unit decreases with time.

Based on the analysis as outlined in Section 2.2.2 and the conclusions stated herein, asymmetric natural circulation cooldown may be considered too intricate for an operator to implement and maintain especially in light of the available system instrumentation. Refer to Section 5.3.5 for further details on asymmetric cooldown.

2.3 Reactor Vessel Dome Voiding

2.3.1 Objectives

The activities summarized in this section describe the thermal behavior of the reactor vessel (RV) upper head region during a typical two-loop natural circulation plant cooldown. Specifically the following points are addressed:

1. What operator actions can alter the cooling rate of the reactor vessel upper head region during a natural circulation cooldown?

2. What plant cooldown procedure or strategy will minimize the possibility of forming a void in the reactor vessel dome?

3. What are the time requirements before depressurizing the RCS down to the shutdown cooling system entry pressure condition to ensure no reactor vessel dome void formation?

2.3.2 Voiding Analysis

During a plant cooldown without any reactor coolant pumps running, the RCS flow loop is cooled by discharging secondary steam while maintaining the RCS natural circulation flowrate. However, the primary coolant in the upper head region of the reactor vessel will lag the loop coolant because the flowrate through this

region can be very small or negligible without forced flow in the RCS. Thus the RV upper head can contain a relatively stagnant region of hot coolant and metal. During primary depressurization, a condensable void can be created in the RV dome by flashing coolant as system pressure is reduced below the saturation pressure in the dome.

There are two processes through which heat can be transferred out of the RV upper head region during natural circulation flow conditions in the RCS. The first involves heat transfer through the RV head into the containment environment, which occurs at a very low and relatively fixed rate. The second involves heat transfer down through the coolant and metal mass to the hot leg elevation region which is being cooled by natural circulation flow. Consequently heat conduction plays a significant role in the RV head cooling process under natural circulation conditions.

Increasing the temperature differential between the stagnant upper head region and the flowing coolant region will increase the heat transfer rate out of the hot upper head region. Conducting a cooldown at the maximum allowed cooldown rate will increase the temperature gradient to the maximum possible value and facilitate upper head cooling. Maintaining a low RCS cooldown rate actually hinders the upper head cooldown since the temperature gradient is maintained at lower values. Moreover the RCS cooldown rate should not be stopped when the loop temperatures have been decreased to just below the maximum allowed shutdown cooling entry temperature. RCS cooldown should be continued to as low a temperature as practical to maximize the temperature differential between the RV upper head region and the coolant flow path region.

A simulation of the RV upper head cooling process was conducted for natural circulation conditons. The cooling processes included heat conduction, localized natural circulation induced flow into the upper head, and shrinkage induced flow into the upper head. The simulation assumed a reactor trip from full power at time

zero followed by the onset of natural circulation in the RCS. After two hours of hot standy, a 75°F/hr cooldown was initiated. Three final RCS temperatures were used to evaluate the cooling effect on the RV upper head.

Figure 2-5 shows the results for a 3410 MWt class C-E plant. Assuming that the maximum shutdown cooling system entry pressure of 361 psig, then the RCS can not be depressurized down to shutdown cooling entry conditions without drawing a RV dome void until the RV upper head temperature decreases below the corresponding saturation temperature of 438°F. For the case where the RCS hot leg temperature is decreased to 330°F, final system depressurization could not occur until 17.5 hours following the reactor trip. Figure 2-5 also shows that shorter hold times are required for RV upper head cooling if lower RCS temperatures can be established. Whether such elapsed times are permitted is dependent upon adequate condensate storage supply.

Figure 2-6 shows the results for System 80 plants. Slower head cooling in System 80 plants is due to less flow in the upper head region and a larger amount of water which must be cooled.

Pre-System 80 plants are generally similiar regarding the hydraulic design features of the RV upper head region. The most notable exception is in the Palisades plant which has a much more open mechanical configuration. Therefore the results shown in Figure 2-5 are indicative of what to expect for Pre-System 80 plants. Plant specific differences in RV internal structure and RV insulation could influence the cooldown hold time by several hours with the expected response of Palisades being much shorter.

Plant specific shutdown cooling entry pressure and corresponding saturation temperature should be used in place of the 361 psig example shown in Figure 2-5.

2.3.3 Reactor Vessel Dome Voiding Conclusions

1. Increasing the RCS cooldown rate will increase the RV upper

head heat conduction temperature gradient and facilitate RV upper head cooling.

2. A rapid RCS cooldown while maintaining as high as possible system pressure will maximize the RV upper head cooling while avoiding RV dome void formation.

3. Continuing the RCS cooldown below the shutdown cooling system entry temperature will enhance the RV upper head cooling.

4. A minimum time limit is recommended between the start of the plant cooldown and plant depressurization to avoid forming a RV dome void.

Figure 2-1

STEADY STATE HEAT TRANSFER FROM ISOLATED SG vs SECONDARY TEMPERATURE OF NON-ISOLATED SG

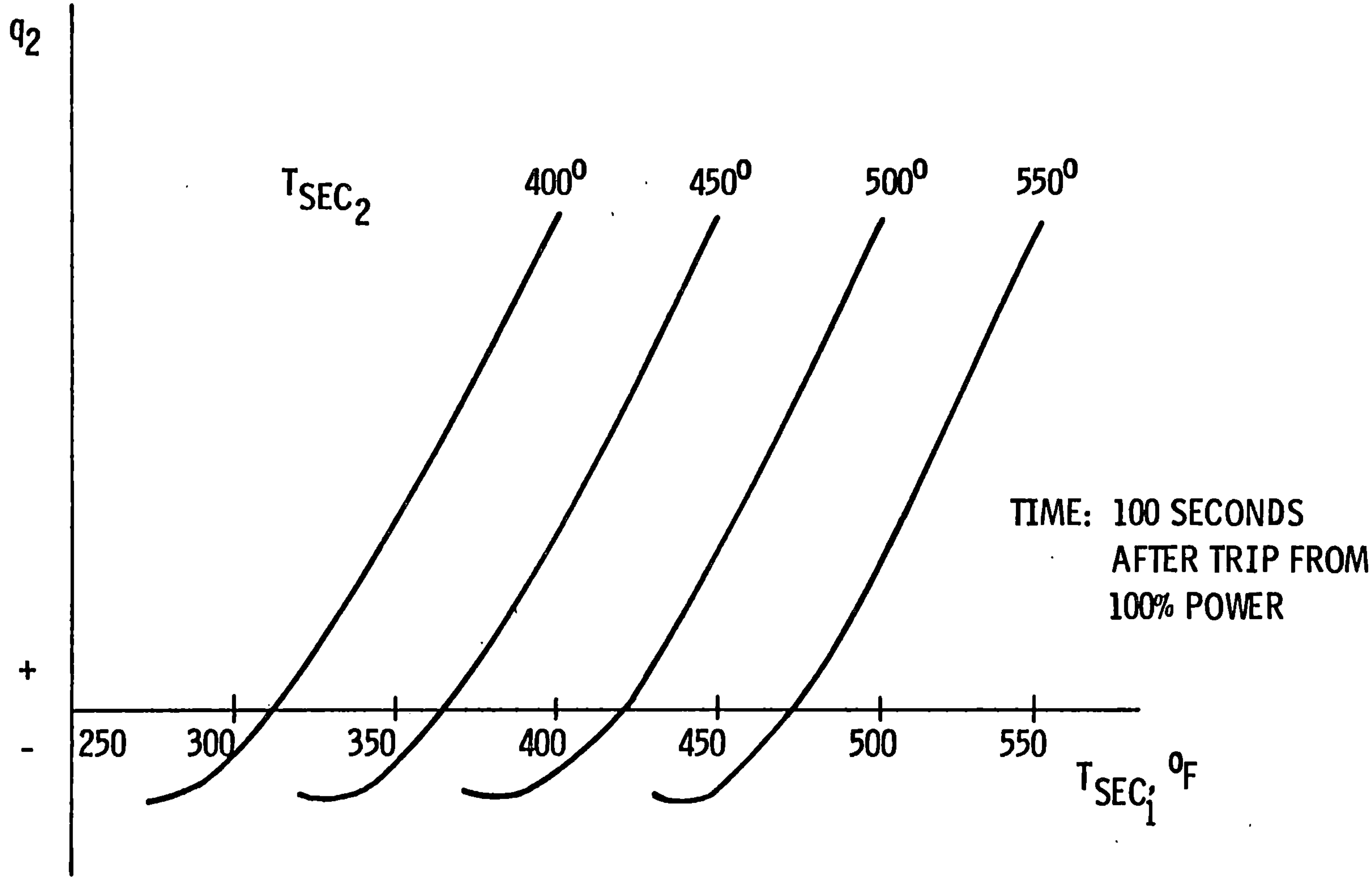


Figure 2-2

STEADY STATE HEAT TRANSFER FROM ISOLATED SG vs SECONDARY TEMPERATURE OF NON-ISOLATED SG

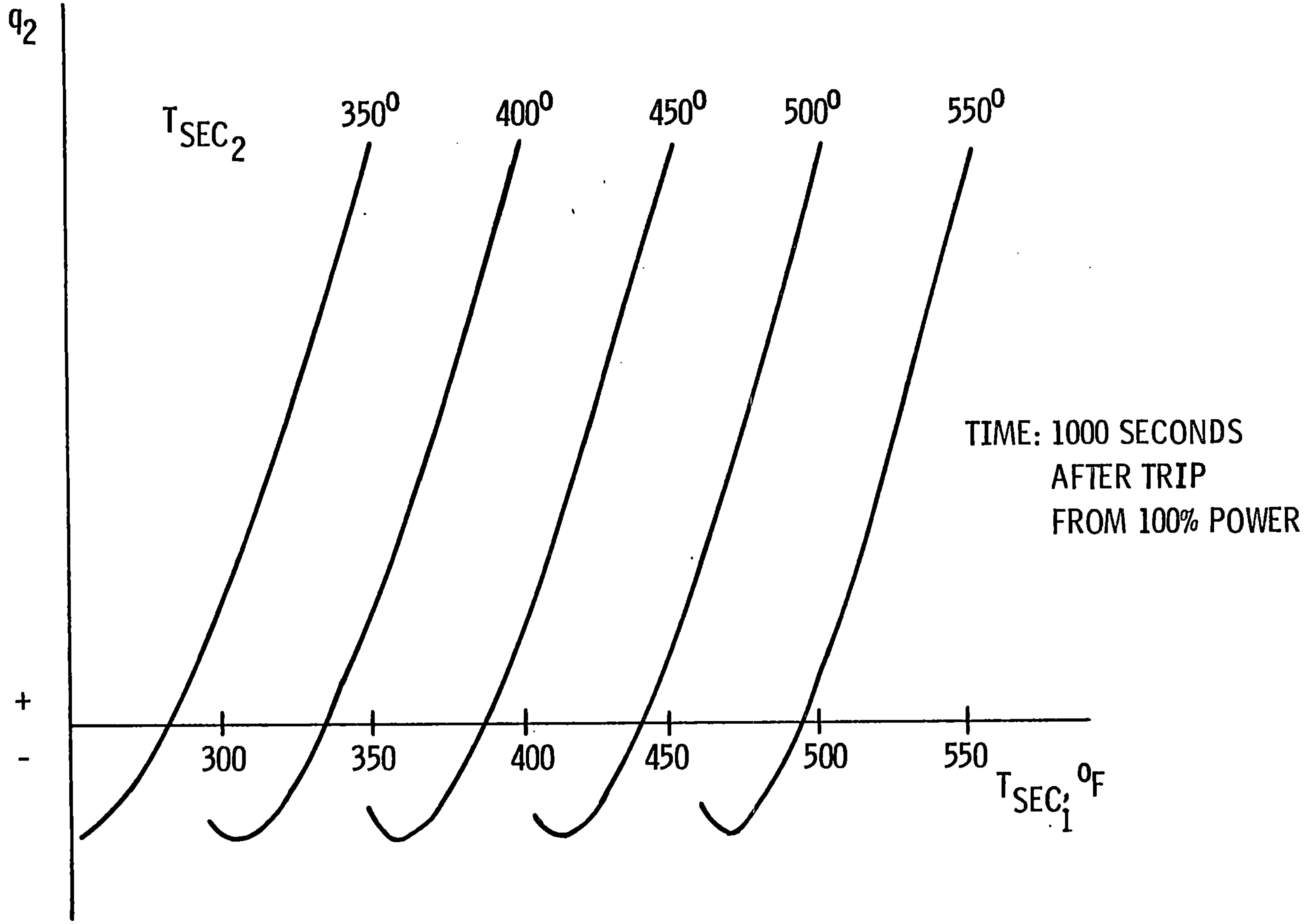


Figure 2-3

STEADY STATE HEAT TRANSFER FROM ISOLATED SG vs SECONDARY TEMPERATURE OF NOT-ISOLATED SG

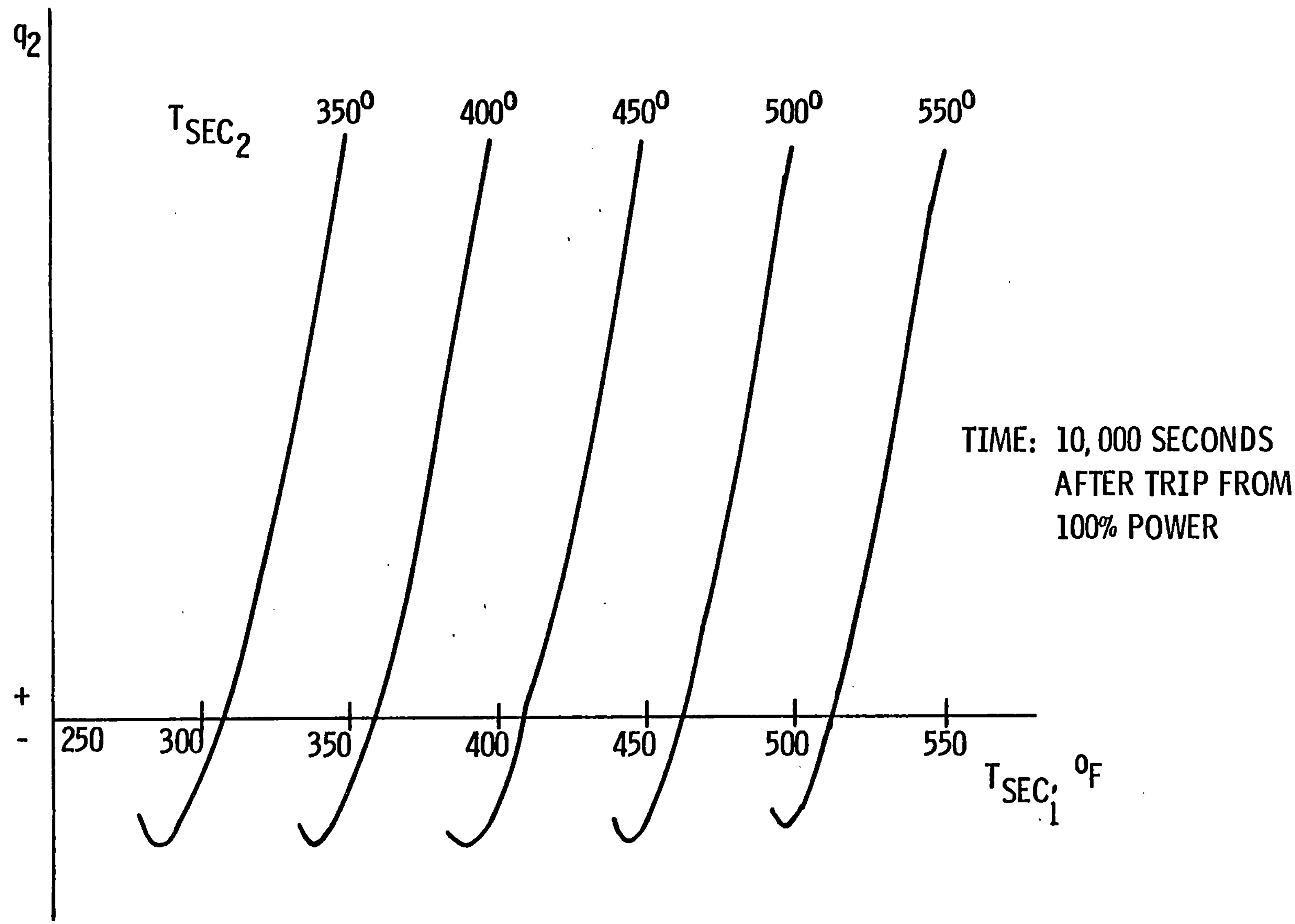
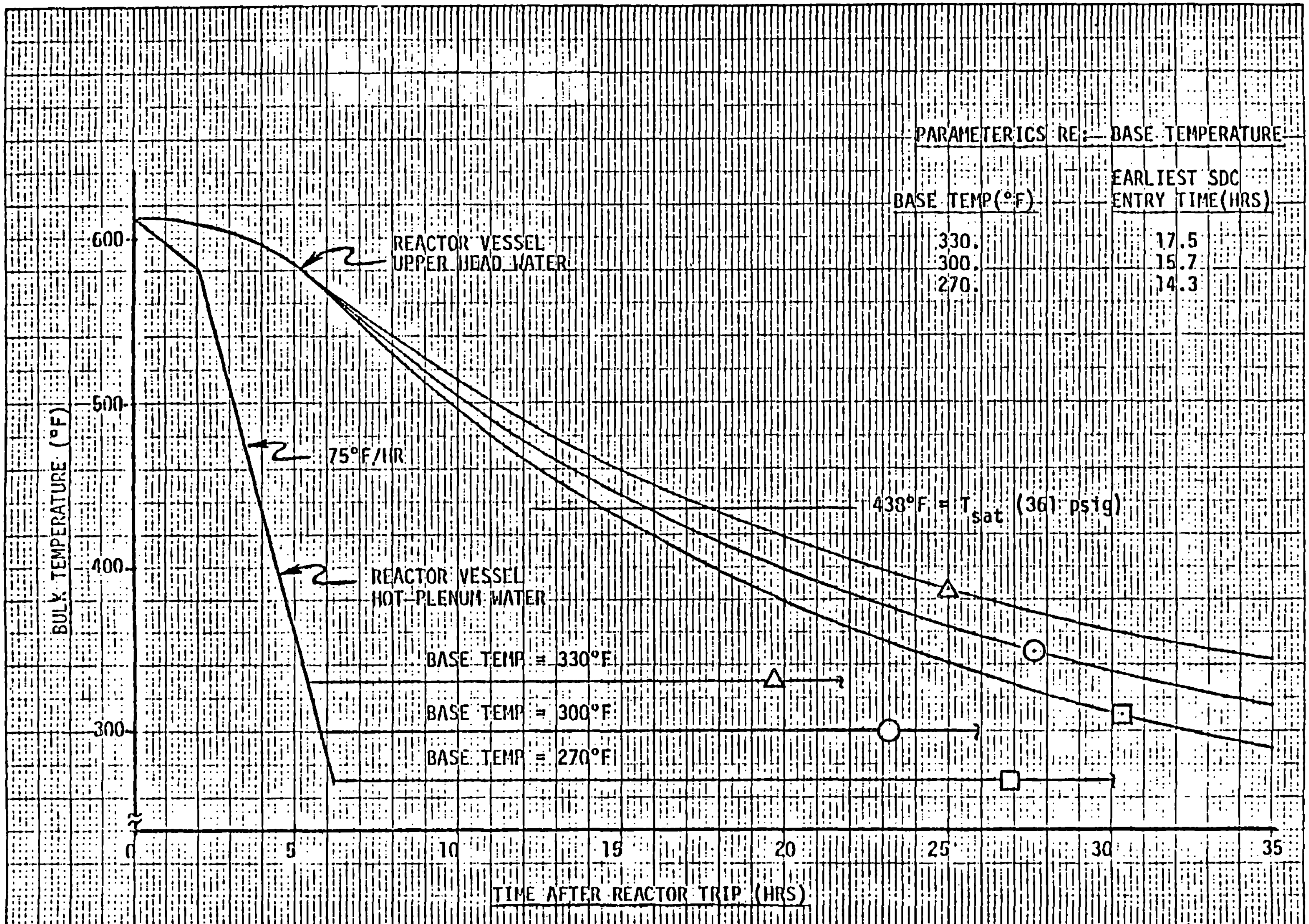


FIGURE 2-5

REACTOR VESSEL UPPER HEAD COOLING VIA NATURAL CIRCULATION



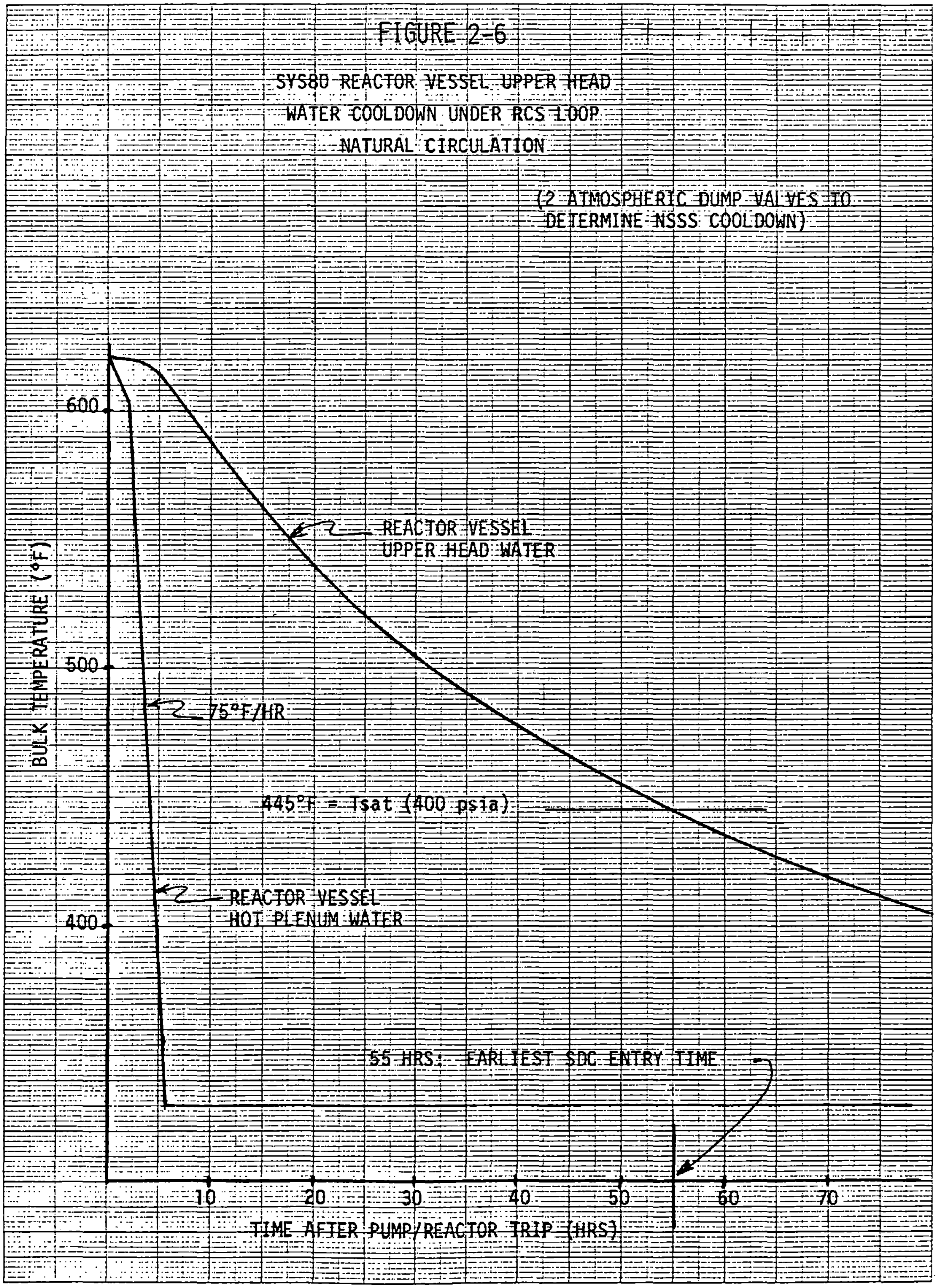


FIGURE 2-6
SYS80 REACTOR VESSEL UPPER HEAD
WATER COOLDOWN UNDER RCS LOOP
NATURAL CIRCULATION
(2 ATMOSPHERIC DUMP VALVES TO
DETERMINE NSSS COOLDOWN)
600
500
400
BULK TEMPERATURE (°F)
REACTOR VESSEL
UPPER HEAD WATER
75°F/HR
445°F = Tsat (400 psia)
REACTOR VESSEL
HOT PLENUM WATER
55 HRS: EARLIEST SDC ENTRY TIME
10
20
30
40
50
60
70
TIME AFTER PUMP/REACTOR TRIP (HRS)

3.0 EVALUATION OF THE EFFECTS OF REACTOR VESSEL HEAD VOIDING ON THE REACTOR VESSEL SHELL

3.1 Description of Design Basis Event

During a natural circulation plant cooldown, stagnant coolant in the dome of the Reactor Vessel (RV) will be hotter than the circulating loop coolant. The hot coolant in the RV dome can flash to steam during RCS depressurization. In the event that a condensable void is formed in the reactor vessel during a natural circulation plant cooldown, a drain and fill process may be employed to remove heat from the RV upper head region (See Section 5.3.4.7.D for RV head drain and fill procedures). The drain and fill process cools the RV upper head region by alternately allowing the RV dome void to expand and then be collapsed. During the void expansion, the hot stagnant water is forced down into the RCS natural circulation flow path and carried away. Subsequently the void is compressed, drawing cooler loop coolant back into the RV upper head region.

The following assumptions were used for the RV dome coolant level and the fluid and metal temperatures in the design basis model.

1. The upper head is allowed to drain down to the Upper Guide Structure plate in 20 minutes with initial upper head steam, fluid, and metal temperatures at 600°F (Figure 3-1).

2. The water level is held at this height for 40 minutes with a fluid temperature of 350°F from the RCS flowpath. Upper head steam and metal temperatures remain at 600°F.

3. The head is refilled over a short period of time (between 1 min. and 20 minutes) with 350°F water.

4. The upper head remains filled with water which remains at 350°F for a period of time (unspecified).

5. During the "drain-and-fill" procedure the system pressure remains at approximately 1600 psi.

6. The heat transfer coefficient for water is very large ($H \approx 1000$ Btu/ft^2-hr-°F).

7. The heat transfer coefficient for steam is very small ($H \approx 0.$ Btu/ft^2-hr-°F).

8. The thermal properties of the materials are constant, and these are evaluated at the average temperatures.

The above assumptions were established in a conservative manner in order to evaluate the highest thermal stress case expected by one RV upper head drain and fill cycle.

3.2 Objectives

The activities summarized in this section describe the structural analysis on the reactor vessel due to voiding in the reactor vessel dome. Specifically the following points are addressed:

1. Does a drain and fill process of cooling the RV upper head region adversely affect the RV shell?

2. Does a rapid expansion or compression of the RV dome void adversely affect the RV shell?

3. Will structural fatigue limit the number of drain and fill cooling cycles?

3.3 Reactor Vessel Shell Voiding Analysis

A generic thermal/stress analysis was performed to determine the range of stresses produced in the 2570 MWt and 3800 MWt class reactor vessel heads due to voiding in the reactor vessel dome. The thermal response of the reactor vessel and head during this transient was analyzed using the MARC-CDC Program (Reference 3.7.1). MARC is a general purpose finite element program which includes heat transfer capabilities. Transient heat conduction is performed by direct integration of the heat conduction equations.

The reactor vessel was modelled as a 2-D mesh of axisymmetric quadrilateral elements, as shown in Figure 3-2. All of the dimensions were obtained from Reference 3.7.2 for the 2570 MWt class plant and from Reference 3.7.3 for the 3800 MWt class plant. A reduction in thickness was used for the elements representing the bolts to better account for the thermal conductivity in this region.

The physical properties of the reactor vessel materials were assumed to be constant for the range of temperatures in this analysis. The corresponding material properties for the carbon steel wall and the stainless steel cladding are as follows:

Carbon Steel	Stainless Steel
$K = 3.653 \times 10^{-2}$ Btu/min-in-°F	$K = 1.3056 \times 10^{-2}$ Btu/min-in-°F
$\rho = .2836$ lb/in^3	$\rho = .2865$ lb/in^3
$C_p = .120$ Btu/lb-°F	$C_p = .127$ Btu/lb-°F

The analysis was performed using the forcing function shown in Figure 3-1. Also, a second analysis was performed using a similar forcing function with a much shorter (1 minute) rise time. The temperature distributions were calculated for the entire structure at 1 minute intervals to be used as input to the stress analysis.

An axisymmetric stress analysis model of the reactor vessel and head region was used to determine the peak stress levels during the transient. The calculated temperature distributions were applied to the model along with the bolt-up loads and pressure loads. A conservative pressure load of 1600 psi was used during the transient. Stresses were calculated at all locations in the head, flange, bolts, and RV wall in order to determine the highest stressed region. All behavior was assumed to be elastic with material properties as follows:

Carbon Steel	Stainless Steel
$E = 28.0 \times 10^6$ psi	$E = 27.0 \times 10^6$ psi
$\nu = .285$	$\nu = .30$
$\alpha = 7.54 \times 10^{-6}$ in/in/°F	$\alpha = 9.96 \times 10^{-6}$ in/in/°F

Stresses in the structure were calculated for various times during the transient, and the maximum stress range was determined for the highest stressed region using the Tresca stress intensity, which is defined as: $\sigma_T = \sigma_1 - \sigma_3$

Where σ_1 = maximum principal stress
σ_3 = minimum principal stress

3.4 Reactor Vessel Shell Voiding Results

The displacements caused by thermal straining during the drain and fill procedure for both the 2570 MWt and 3800 MWt plants are shown in the displacement plot of the finite element model in Figure 3.3. The combination of bolt-up loads, pressure loads, and nonuniform thermal loads produce the bending effects which are apparent in this figure. A blow-up of the displacements in the head and flange, as shown in Figure 3.4, indicates the region with the highest stresses is the "Knuckle" region of the head near the inside radius. The Tresca stress intensity values were calculated for various times during the thermal transient for the 2570 MWt class plant and for the 3800 MWt class plant. The values of σ_T vs. time are plotted in Figures 3-5 and 3-6 for a 20 minute refill of the head. The peak stress intensity value of 36.9 ksi (2570 MWt) and 39.8 (3800 MWt) was calculated to occur during refill of the head. A maximum stress range of 26.9 Ksi (2570 MWt) and 23.7 Ksi (3800 MWt) was calculated for this transient condition at the inside radius of the "Knuckle" region.

The effect of a more rapid refill on the stress intensity in the "Knuckle" region is shown in Figures 3-7 and 3-8. The temperatures

resulting from the thermal transient with a 1 minute refill time were applied to the stress analysis mode, and the stress intensity was again calculated as a function of time. The maximum stress range for this case was calculated to be 27.4 Ksi (2570 MWt) and 22.0 Ksi (3800 MWt). These values indicate that the more rapid refill of the head is no more severe in terms of thermally-induced stresses than a slower refill time of 20 minutes.

To determine the severity of the thermal transient with RV head voiding compared to a normal cooldown, an analysis of a typical cooldown was performed. The combination of thermal and pressure loading was considered with a decrease in system pressure vs. time as given in Figure 3-9. The Tresca stress intensity vs. time during the typical cooldown was calculated from the finite element model. The results are given in Figures 3-10 and 3-11 for both the inside and outside radii in the "Knuckle" region of the head. From these results it is evident for the 2570 MWt class plant that a maximum stress range of 18.8 Ksi occurs near the outside radius of the "knuckle" region, as compared to the maximum stress range of 26.9 Ksi as the result of the "drain-and-fill" cooldown procedure. Similiarity 21.0 Ksi and 23.7 Ksi were calculated respectively for the 3800 MWt class plant.

A fatigue evaluation is performed according to NB3222.4 of the ASME Code (Reference 3.7.4). The procedure for calculating usage factors is outlined as follows:

1. Determine the principal stresses σ_1, σ_2, σ_3 considering both the gross and local structural discontinuities and the thermal effects which vary during the cycle.

2. Determine the stress differences $S_{12} = \sigma_1 - \sigma_2$, $S_{23} = \sigma_2 - \sigma_3$, $S_{31} = \sigma_3 - \sigma_1$, versus time for the complete cycle.

3. The alternating stress intensity is then calculated as:

$$S_{alt} = \frac{\sigma\, max - \sigma\, min}{2}$$

From the stress results for the drain and fill procedure with a 20 minute refill time, S_{alt} is determined to be:

$$S_{alt} = \frac{36.6 - 9.7}{2} = 13.45 \text{ Ksi} \quad (2570 \text{ MWt})$$

$$S_{alt} = \frac{39.8 - 16.1}{2} = 11.85 \text{ Ksi} \quad (3800 \text{ MWt})$$

4. The corresponding cyclic life, N, is determined from the appropriate design fatigue curve shown in Figure 3-12 (Reference 3.7.5). The cyclic life N for the stress range is determined to be 500,000 cycles (2570 MWt) and 600,000 cycles (3800 MWt).

5. The usage factor is determined from $U = \frac{n}{N}$ where n is actual number of occurrences.

For example, for 100 "drain-and-fill" cycles, the usage factor would be

$$U = \frac{100}{500,000} = 2.0 \times 10^{-4} \quad (2570 \text{ MWt})$$

$$= \frac{100}{600,000} = 1.6 \times 10^{-4} \quad (3800 \text{ MWt})$$

For comparison with the effects of 100 cycles of a normal cooldown:

S_{alt} = 9.4 Ksi (2570 MWt)
= 10.5 Ksi (3800 MWt) $\quad N > 1,000,000$

$$\text{Thus, } U \approx \frac{100}{1,000,000} = 1 \times 10^{-4}$$

It should be noted that $U << 1.0$ for both cases. The drain-and-fill usage factor is slightly larger than that due to a normal cooldown. Since U is much less than 1.0, the amount of fatigue damage is negligible for both cases.

3.5 Generic Voiding Conclusions

The following conclusions apply for the 2570 MWt and 3800 MWt class of C-E plants:

1. The results of this analysis indicate that the highest stresses occur in the knuckle region of the RV head near the inside radius during a drain and fill cooling of the RV head.

2. A rapid refill of the head is determined to be no more severe than a slow refill of the head. This is because the conduction of heat through the reactor vessel wall (rather than away from the surface) is the dominant heat transfer mechanism.

3. The fatigue usage factor due to a drain and fill cooling transient is much less than 1.0. This indicates that the cumulative fatige damage for a drain-and-fill transient is negligible.

3.6 Additional Plant Voiding Conclusions

The effects of RV dome voiding during a drain and fill cooldown procedure was examined for the upper RV head region of the 2570 MWt and 3800 MWt class of C-E reactors. Based on the similiarities with the 3410 MWt class of C-E reactors and on the fact that the two completed analysis essentially envelope the behavior for the 3410 MWt class vessel, the results of the stress analysis for the generic analysis can be extended to the 3410 MWt class as well. Thus the effects of a drain and fill cooldown process is also considered to be negligible for the 3410 MWt class reactor.

Similiarly C-E expects that no significant adverse effects would be found for Palisades, Fort Calhoun, or Maine Yankee if a detailed analysis were conducted for those plants. Although the calculated vessel stresses could vary slightly from the values determined in the 2570 MWt and 3800 MWt detailed analysis, it is expected that the effect on the usage factor would be similiar.

3.7 References

3.7.1 MARC - CDC, Non-Linear Finite Element Analysis Program, Control Data Corp, Minneapolis, Minn., 1976.

3.7.2 Analytical Report for Florida Power & Light Co., Reactor Vessel, Unit No. 1, C-E Report No. CENC 1168, DEC., 1971.

3.7.3 Analytical Report for Arizona Public Service Reactor Vessel, Unit 1, C-E Report No. CENC-1330, June, 1978.

3.7.4 ASME Boiler and Pressure Vessel Code, Section III, Subsection NB, Class 1 Components, July, 1980.

3.7.5 ASME Boiler and Pressure Vessel Code, Section III, Subsection NA, Figure I.9-1, July, 1980.

FIGURE 3-1

FORCING FUNCTION USED FOR THERMAL TRANSIENT

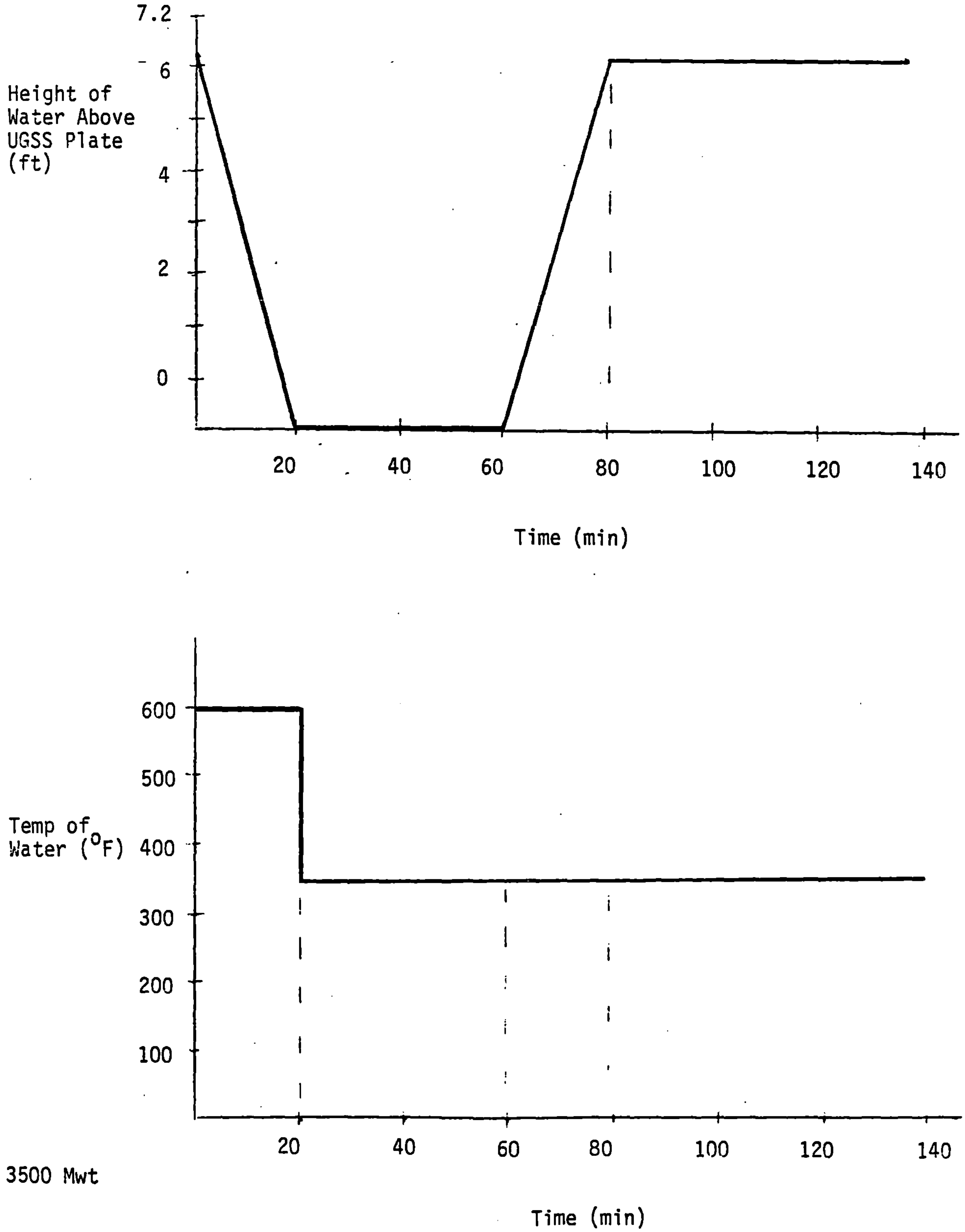


FIGURE 3-2

FINITE ELEMENT MODEL

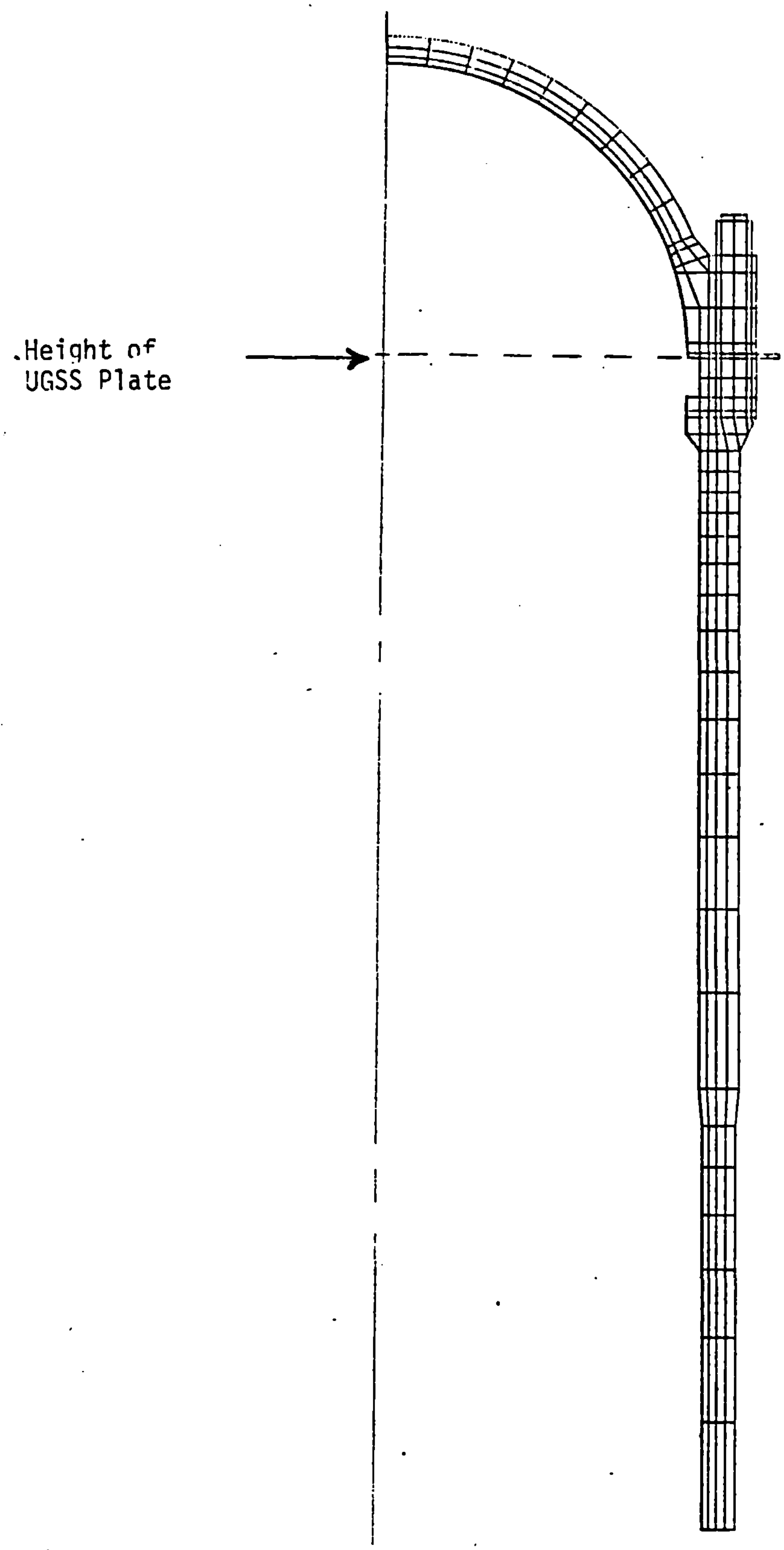


FIGURE 3-3

DISPLACEMENTS DUE TO THERMAL STRAINS DURING DRAIN-AND-FILL COOLDOWN PROCEDURE

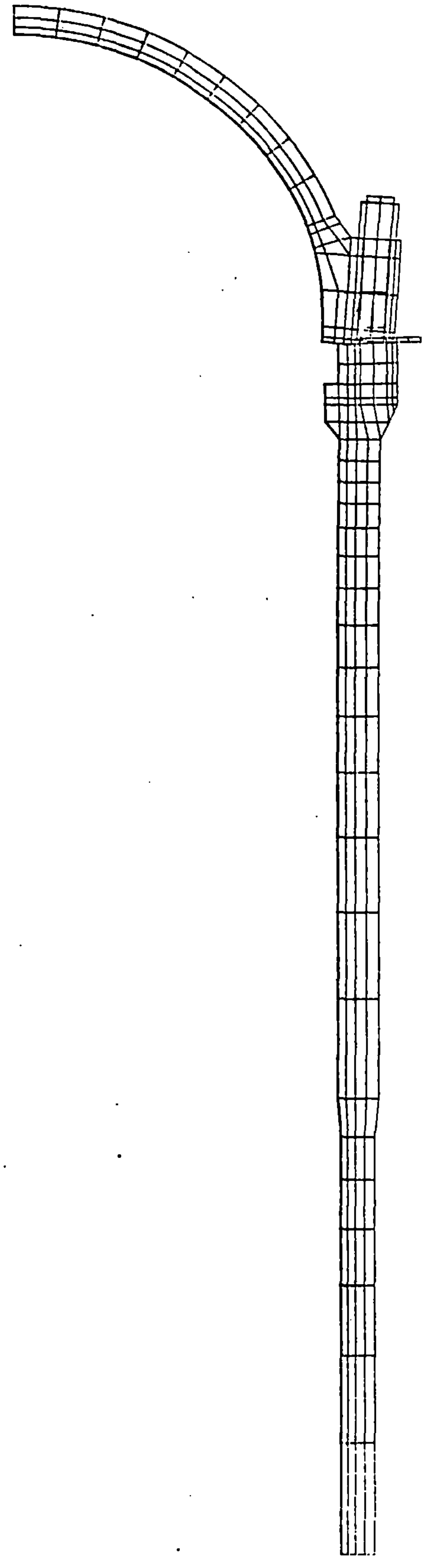


FIGURE 3-4

DISPLACEMENTS IN HEAD AND FLANGE REGION

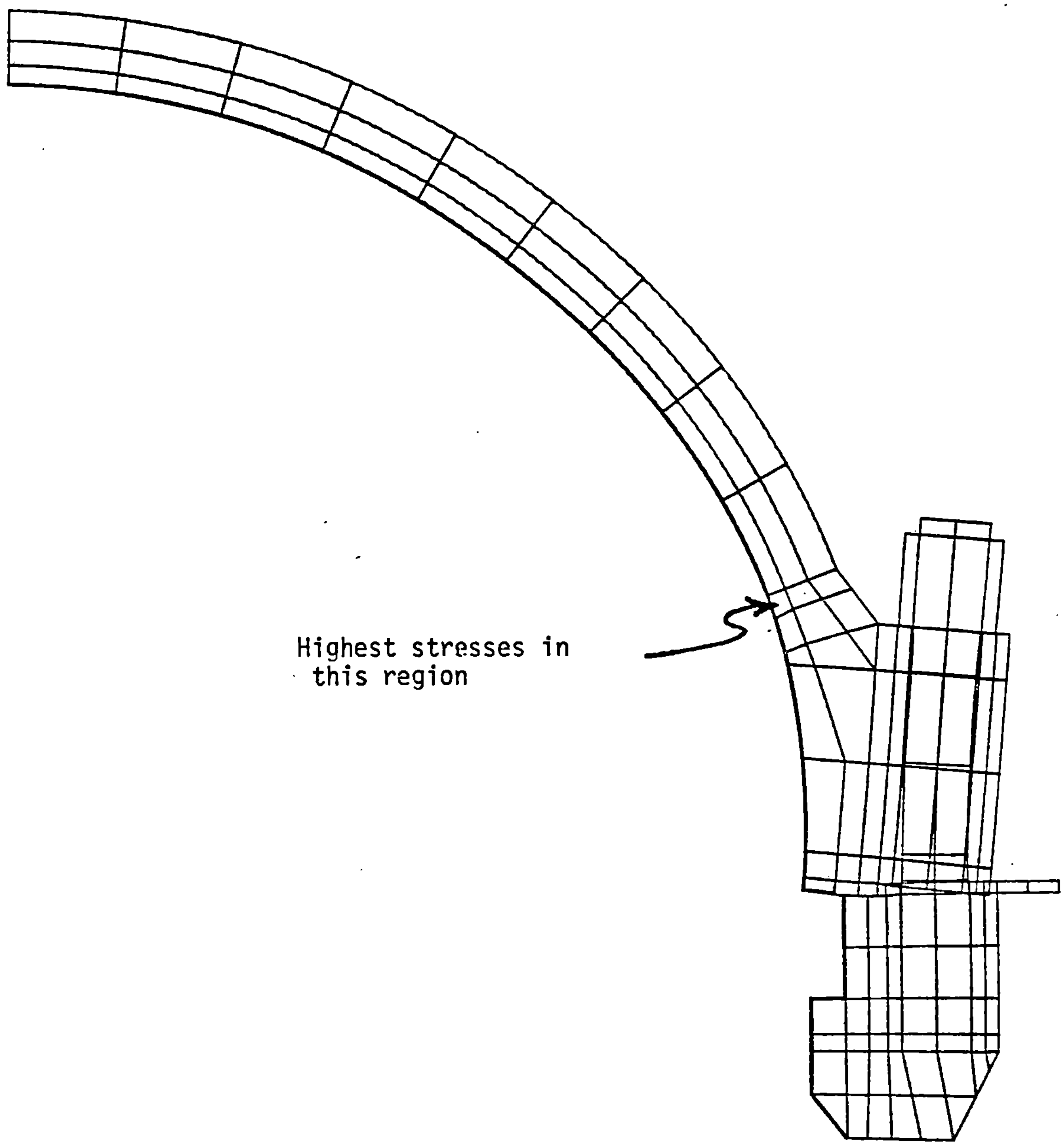
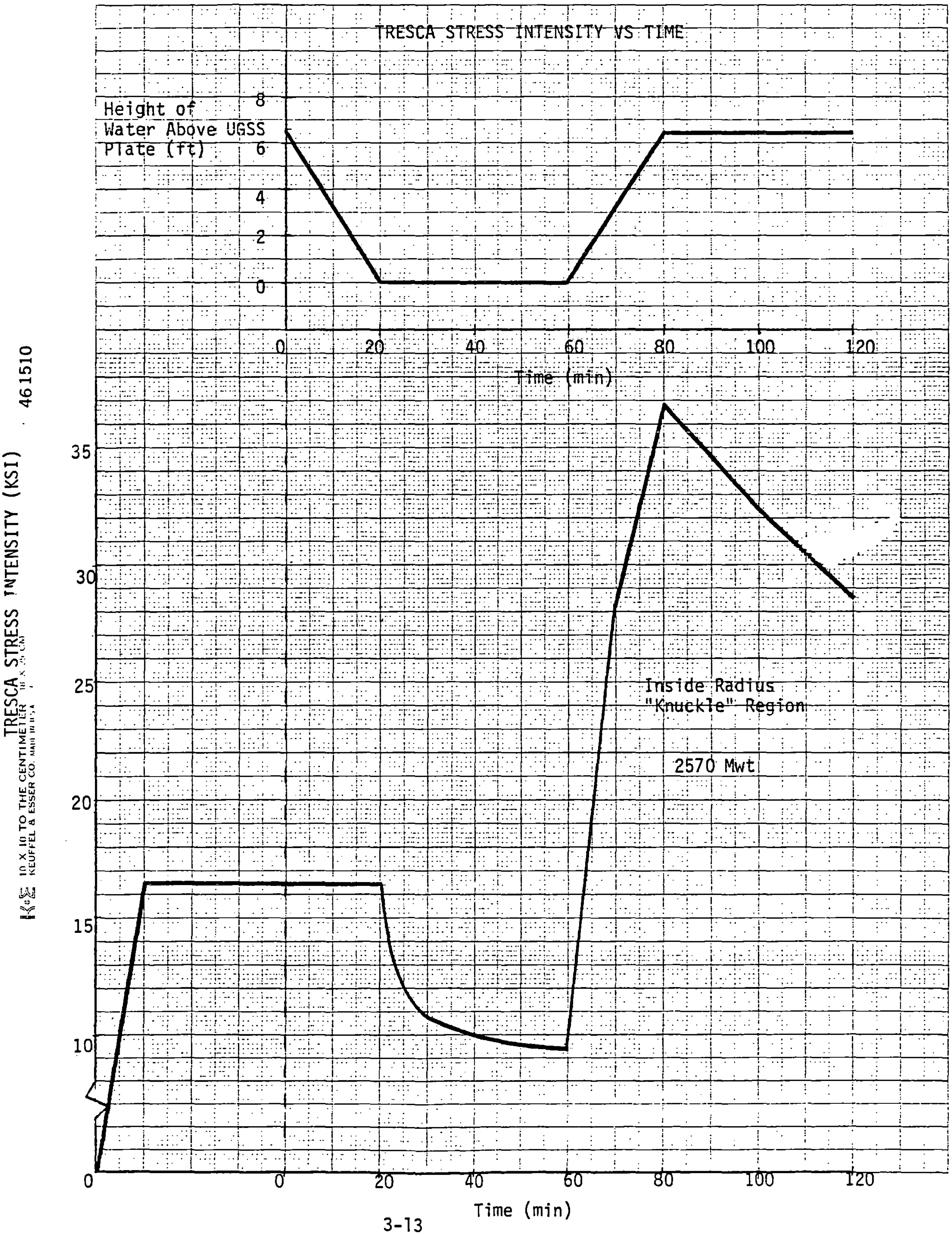


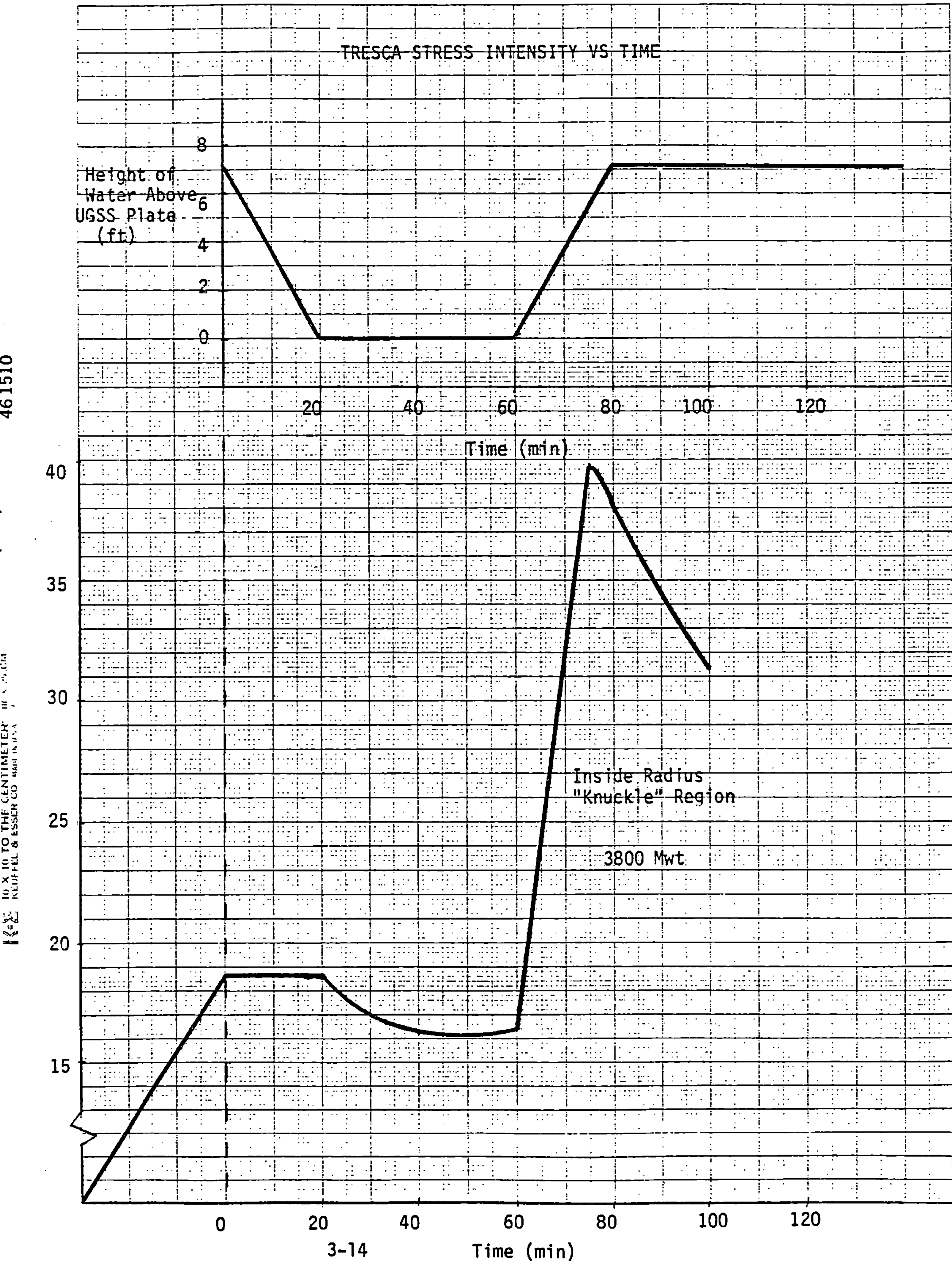
FIGURE 3-5



461510

K&E 10 X 10 TO THE CENTIMETER KEUFFEL & ESSER CO.

FIGURE 3-6



461510

10 X 10 TO THE CENTIMETER
KEUFFEL & ESSER CO. MADE IN U.S.A.

FIGURE 3-7

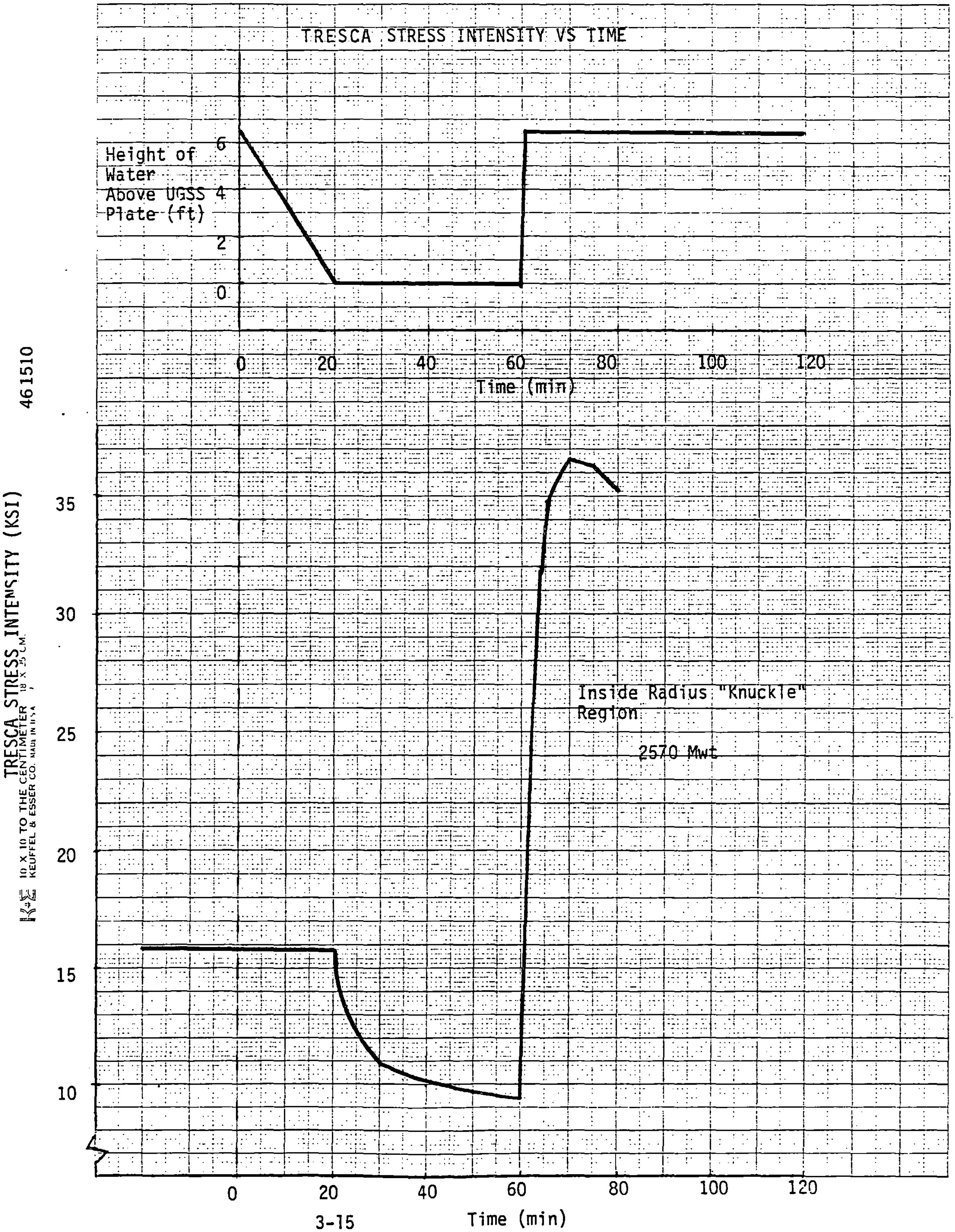


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FIGURE 3-8

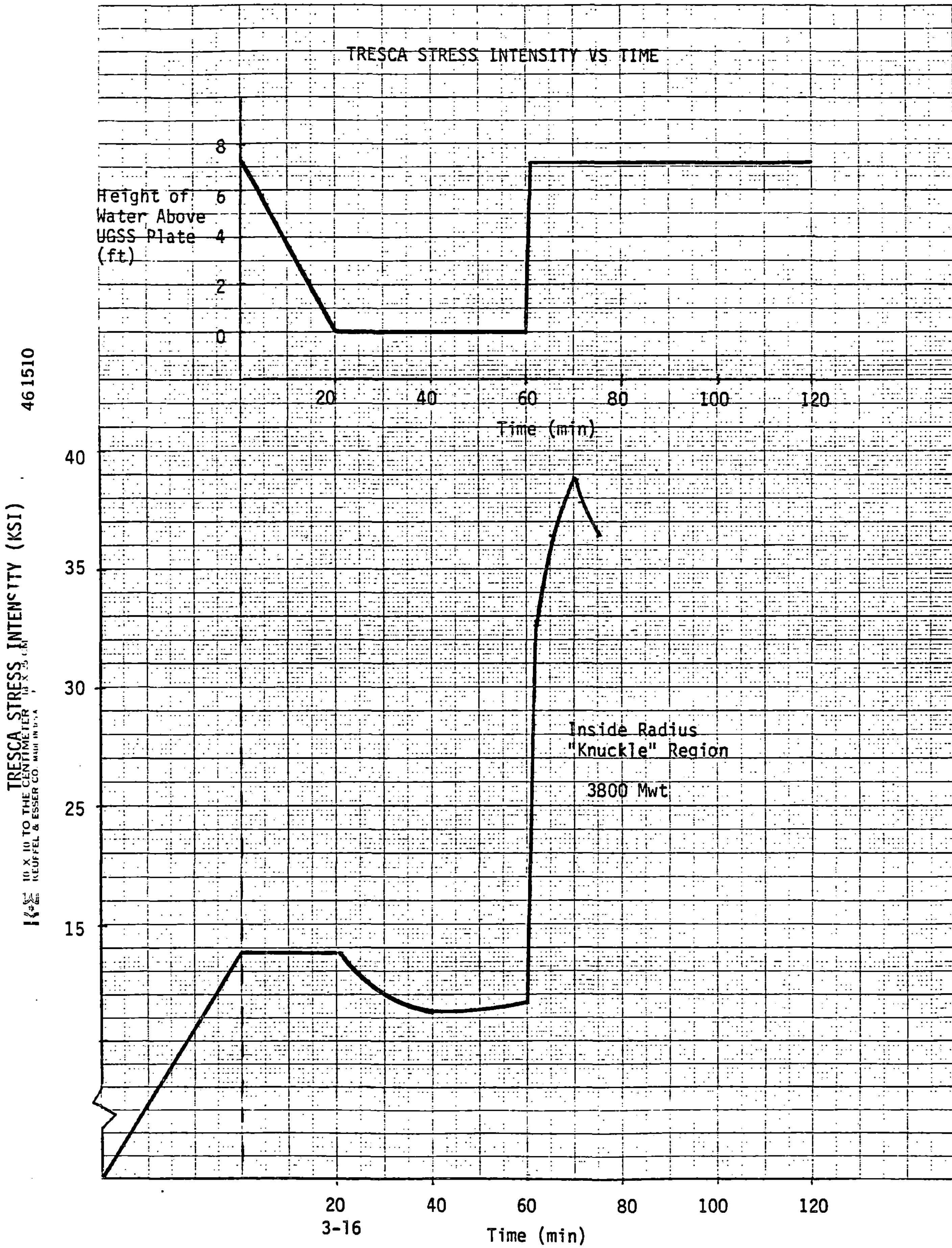

TRESCA STRESS INTENSITY VS TIME
Height of Water Above UGSS Plate (ft)
8
6
4
2
0
20
40
60
80
100
120
Time (min)
TRESCA STRESS INTENSITY (KSI)
40
35
30
25
15
Inside Radius "Knuckle" Region
3800 Mwt
Time (min)
10 X 10 TO THE CENTIMETER
KEUFFEL & ESSER CO. MADE IN U.S.A.
461510

FIGURE 3-9

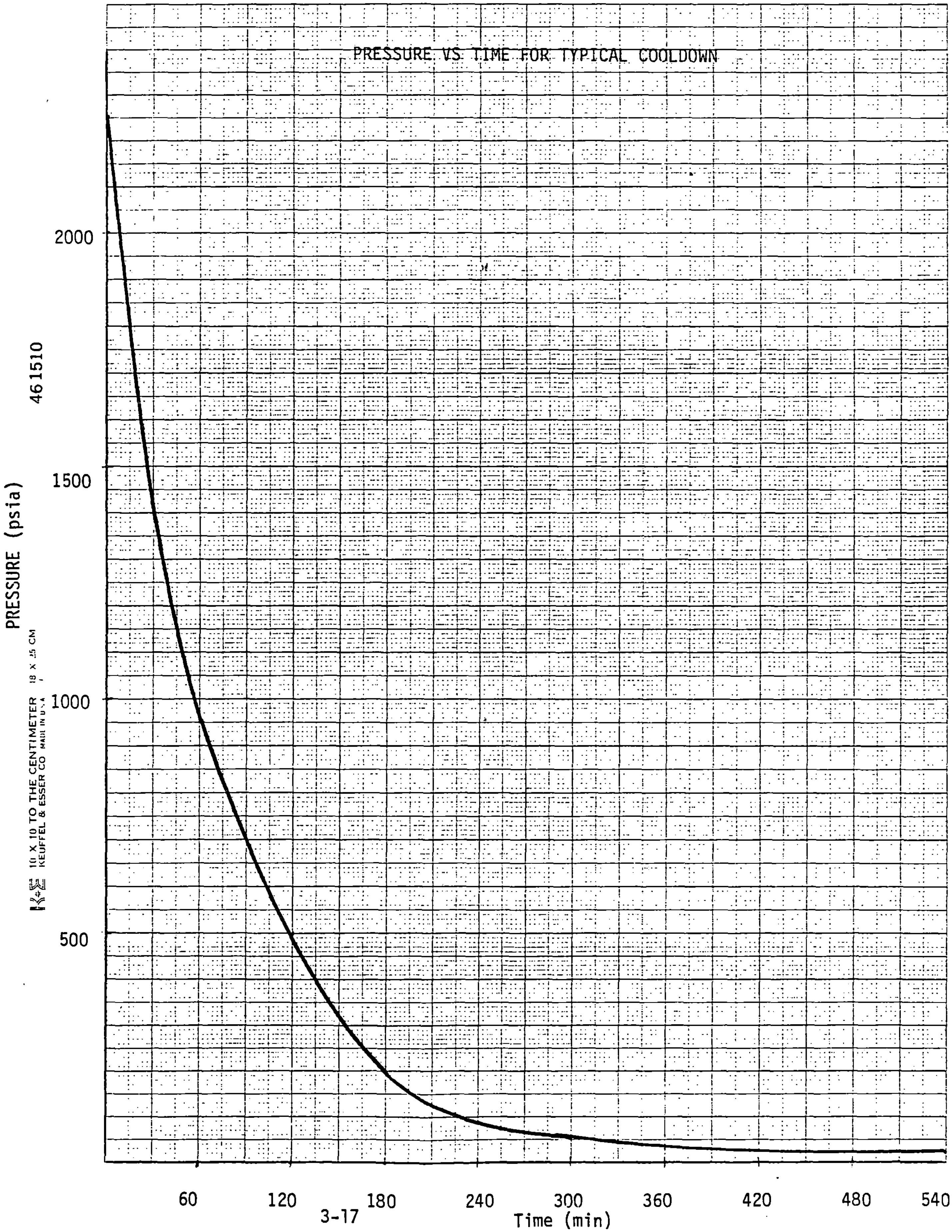
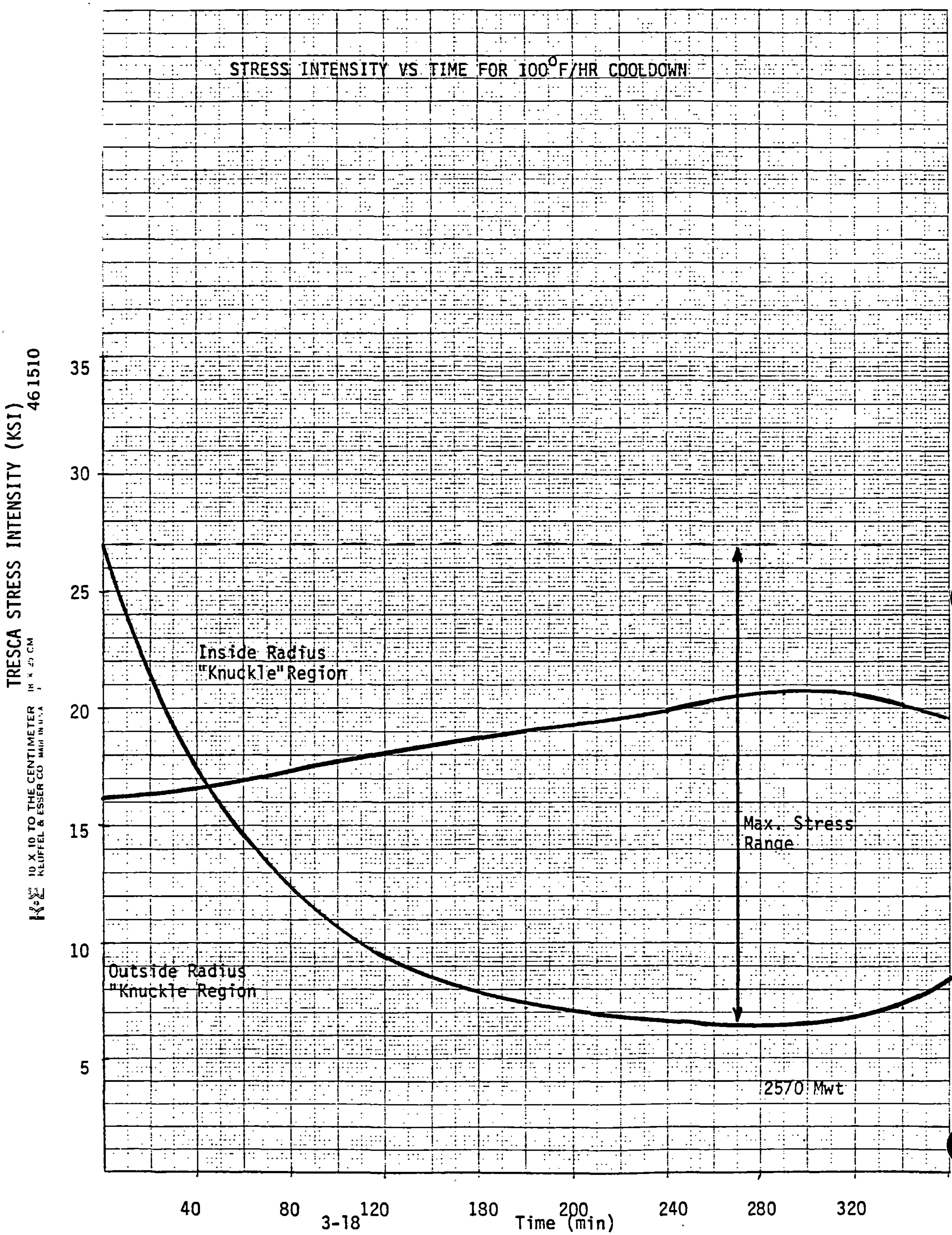
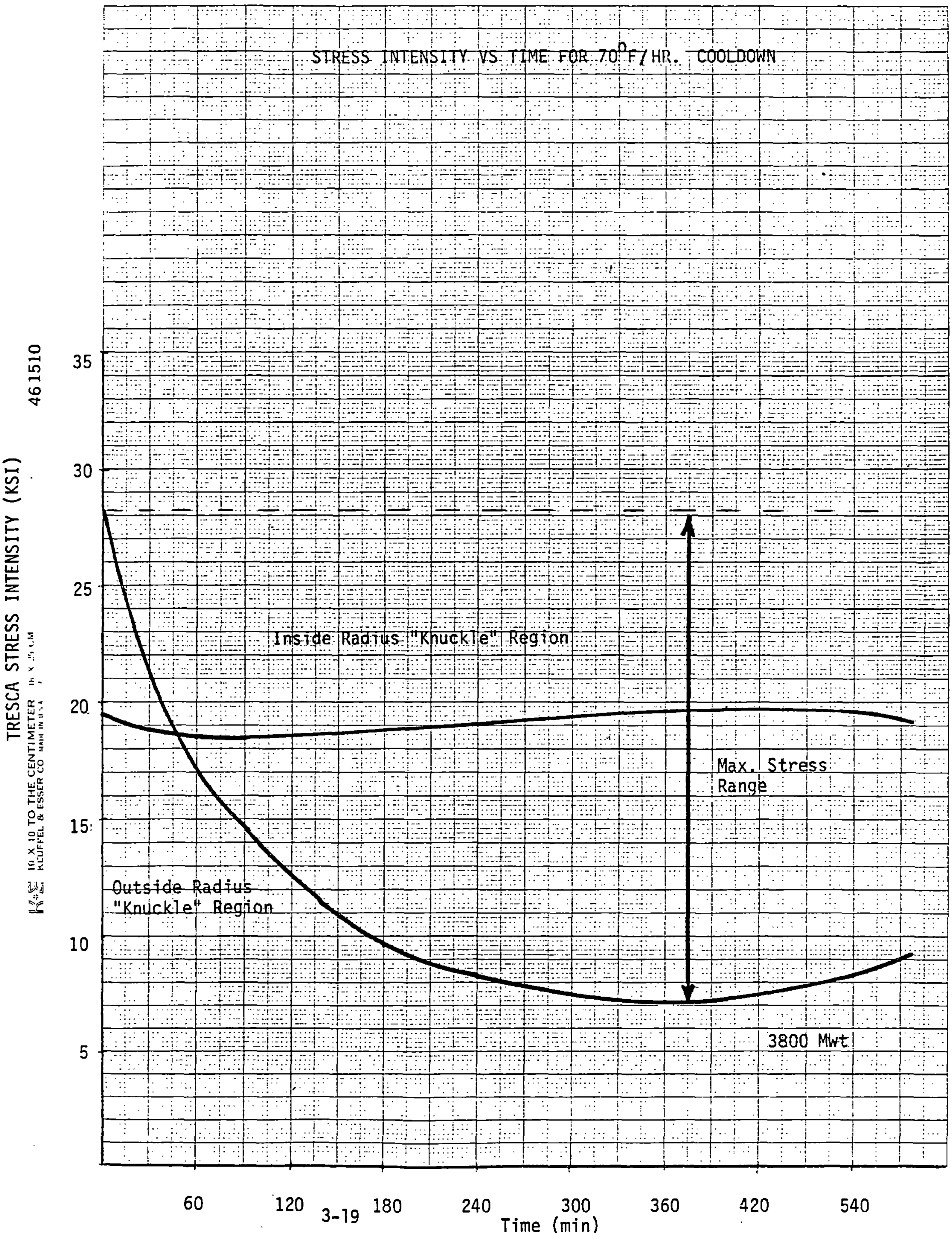

PRESSURE VS TIME FOR TYPICAL COOLDOWN
PRESSURE (psia)
2000
1500
1000
500
60
120
180
240
300
360
420
480
540
Time (min)
461510
10 X 10 TO THE CENTIMETER 18 X 25 CM
KEUFFEL & ESSER CO MADE IN U.S.A.

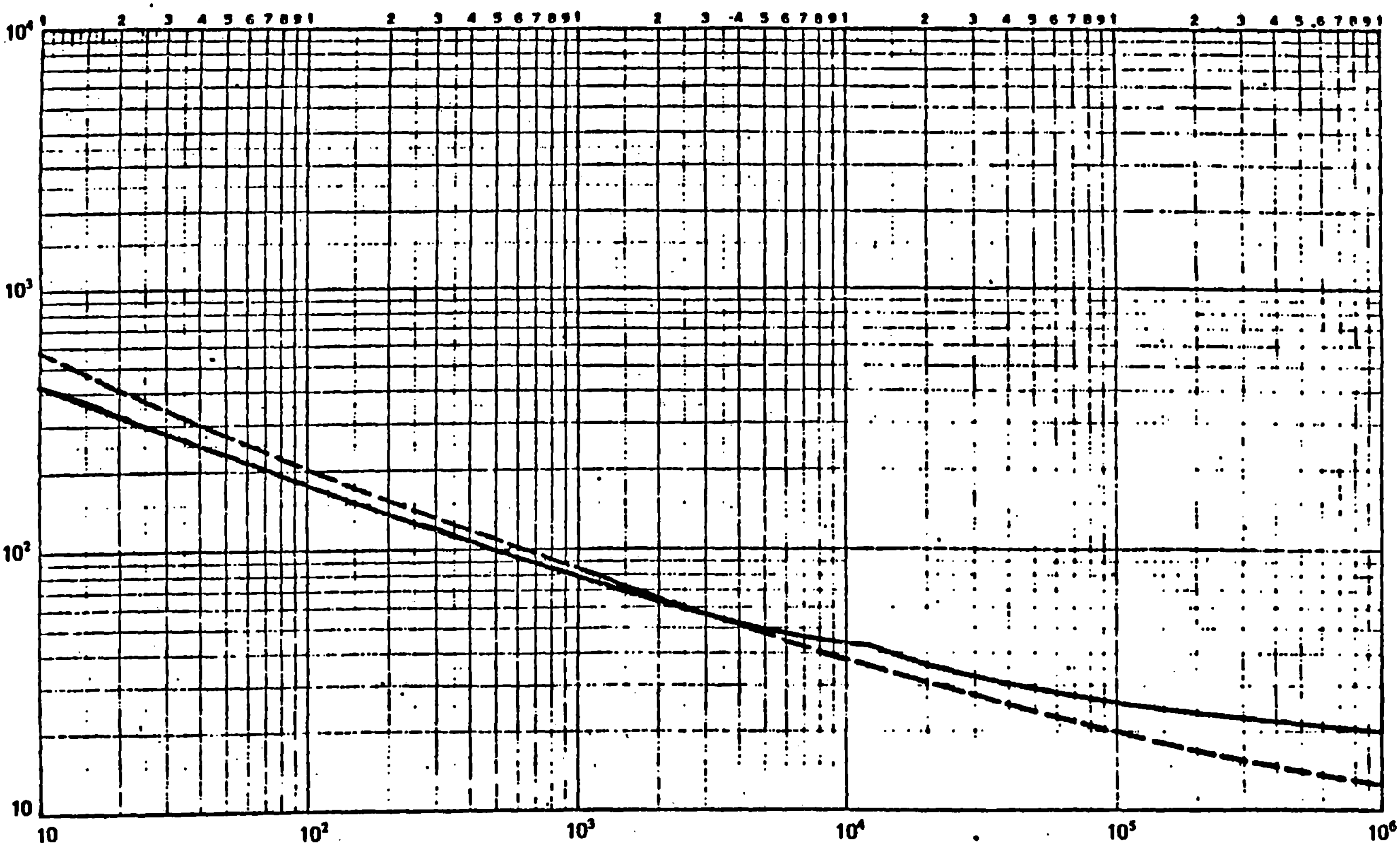
FIGURE 3-10



STRESS INTENSITY VS TIME FOR 100°F/HR COOLDOWN
TRESCA STRESS INTENSITY (KSI)
35
30
25
20
15
10
5
Inside Radius
"Knuckle" Region
Outside Radius
"Knuckle Region
Max. Stress
Range
2570 Mwt
40
80
120
180
200
240
280
320
Time (min)
10 X 10 TO THE CENTIMETER
KEUFFEL & ESSER CO. MADE IN U.S.A.
461510

FIGURE 3-11


STRESS INTENSITY VS TIME FOR 70°F/HR. COOLDOWN
TRESCA STRESS INTENSITY (KSI)
35
30
25
20
15
10
5
Inside Radius "Knuckle" Region
Outside Radius
"Knuckle" Region
Max. Stress
Range
3800 MWt
60
120
180
240
300
360
420
540
Time (min)
461510
10 X 10 TO THE CENTIMETER
KEUFFEL & ESSER CO.



NOTE: $E = 30 \times 10^6$ ksi
---- UTS < 80.0 ksi
—— UTS 115.0–130.0 ksi
Interpolate for UTS 80.0–115.0 ksi

FIG. I-9.1 DESIGN FATIGUE CURVES FOR CARBON, LOW ALLOY, AND HIGH TENSILE STEELS
(For Metal Temperatures Not Exceeding 700 F)

4.0 EVALUATION OF THE EFFECTS OF REACTOR VESSEL HEAD VOIDING ON THE REACTOR VESSEL INTERNALS

4.1 Description of Design Basis Event

During a natural circulation plant cooldown, stagnant coolant in the dome of the Reactor Vessel (RV) will be hotter than the circulating loop coolant. The hot coolant in the RV dome can flash to steam during RCS depressurization. In the event that a condensable void is formed in the reactor vessel during a natural circulation plant cooldown, a drain and fill process may be employed to remove heat from the RV upper head region (See Section 5.3.4.7.D for RV head drain and fill procedures). The drain and fill process cools the RV upper head region by alternately allowing the RV dome void to expand and then be collapsed. During the void expansion, the hot stagnant water is forced down into the RCS natural circulation flow path and caried away. Subsequently the void is compressed, drawing cooler loop coolant back into the RV upper head region.

The following assumptions were used for the RV dome coolant level and the fluid and metal temperatures in the design basis model.

1. The steam/water interface level in the RV dome is first expanded to just above the hot leg outlet nozzle region.

2. Initial steam, water and metal temperatures are assumed to be 600°F.

3. The steam void is then compressed with uniform 300°F water refilling the upper RV head region.

4. A 300°F temperature difference between the steam and water was considered to be the highest differential that the RV would ever experience on a drain and fill transient.

4.2 Objectives

The activities summarized in this section describe the structural analysis on the reactor vessel internals due to voiding in the reactor vessel dome. Specifically the following points are addressed:

1. Is the structural integrity of the reactor vessel internal components adversely affected during a drain and fill process of cooling the RV upper head?

2. Is the Control Element Assembly (CEA) motion and insertibility adversely affected during a drain and fill process?

3. Does a rapid expansion or compression of the RV dome void adversely affect the RV internals?

4. Will structural fatigue limit the number of drain and fill cooling cycles?

4.3 Reactor Vessel Internals Voiding Analysis

The following descriptions identify the key reactor internal components considered in this analysis.

ICI Plate Assembly:
The in-core instruments (See Figure 4-1) are located in the in-core instrumentation assembly. The in-core instrumentated thimble support frame and guide tubes are supported by the Upper Guide Structure Assembly. The tubes are conduits which protect the in-core instruments and guide them during removal and insertion operations. The thimble support frame supports the in-core thimble assemblies and acts as an elevator to lift the thimbles from the core into the upper guide structure during the refueling operation.

Core Support Barrel:

The Core Support Barrel (See Figure 4-2) is a right circular cylinder with a nominal inside diameter of 148 inches and a length of 27 feet, with a heavy ring flange at the top end and an internal ring flange at the lower end. The Core Barrel is supported from a ledge on the reactor vessel. The Core Support Barrel, in turn, supports the lower support structure upon which the fuel assemblies rest. The CSB (for Millstone and St. Lucie I) also has a thermal shield affixed to its outer surface and located at its mid section. Press fitted into the flange of the Core Support Barrel are four alignment keys located 90 degress apart. The reactor vessel, closure head, holddown ring, and Upper Guide Structure Assembly flange are slotted in locations corresponding to the alignment key locations to provide alignment between these components in the reactor vessel flange region. The upper section of the barrel contains two outlet nozzles contoured to minimize coolant by-pass leakage.

Upper Guide Structure Assembly:

The upper guide structure assembly (See Figure 4-3) consists of the upper support structure, 69 (65 for Calvert Cliffs Units 1 & 2) control element assembly shrouds, fuel assembly alignment plant and a holddown ring. The Upper Guide Structure Assembly aligns and laterally supports the upper end of the fuel assemblies, maintains the Control Element Assembly (CEA) spacing, holds down the fuel assemblies during operation, prevents fuel assemblies from being lifted out of position during a severe accident condition, protects CEA's from the effect of coolant cross flow in the upper plenum, and supports the ICI Plate Assembly.

The upper end of the assembly is a structure consisting of a support plate welded to a grid array of 24 inch deep beams and a 24 inch deep cylinder, which encloses and is welded to the ends of the beams. The periphery of the plate contains four accurately machined equally spaced alignment keyways, which engage the core barrel alignment keys. This system of keys and slots provides an accurate means of aligning the core with the closure head and with the Control Element Drive Mechanism (CEDM).

The CEA shrouds extend from the fuel assembly alignment plate to above the upper guide structure support plate. The single CEA shrouds consist of cylinderical upper sections welded to integral bottom sections, which are shaped to provide flow passages for the coolant through the alignment plate while shrouding the CEA's from cross flow. Duel CEA shrouds accommodate two adjacent and interconnected CEA's. These shrouds have an oval shaped upper section welded to a flow diverting base section. The shrouds are bolted and lockwelded to the fuel assembly alignment plate. At the upper guide structure support plate, the single shrouds are connected to the plate by spanner nuts. The dual shrouds are attached to the upper plate by welding.

A detailed analysis was completed which evaluated the effects of RV dome voiding on a 2570 MWt class reactor internals. The stress analysis of the reactor internals was conducted using the ANSYS computer code on a scaled finite element model of the Upper Guide Structure (UGS) Grid Beam Assembly, as shown in Figures 4-4 and 4-5. The model is a 3-dimensional representation of the grid beams, cylinder, upper plate and flange. It was analyzed using the Elastic Flat Rectangular Shell Element (ANSYS Element STIF 43) and the Elastic Flat Triangular Shell Element (ANSYS Element STIF 13). One-quarter symmetry of the UGS grid beam upper plate cylinder and flange was used in this analysis. Appropriate boundary conditions were applied along all interface planes for this scaled moded (See Figure 4-5) to represent the entire assembly.

A preliminary stress evaluation using a reduced finite element model of a single grid beam was conducted to establish the effects of various types of thermal gradients through the Upper Guide Structure Assembly. A 300°F linear thermal gradient (Figure 4-6) was applied at different vertical beam locations. Results of this analysis showed that a 300°F linear thermal gradient through the grid beam mid-height produced the most critical displacements and stresses. This information was incorporated into the scaled finite element model of the UGS Assembly.

4.4 Reactor Vessel Internals Voiding Results

The radial and vertical displacements of the grid beam computer model were considered to evaluate reactor internals vessel potential interference. The closest fit between the Reactor Internals and Reactor Vessel exists at the core support barrel upper flange outer diameter. Evaluation of this interface, assuming a 300°F linear thermal gradient shows no possibility of interference.

The alignment keys (Figure 4-2) are attached to the CSB at the upper flange. The alignment keys have been designed to provide alignment of the internals and support against lateral motion of the reactor internals while allowing unrestricted radial growth of the internals. Therefore, although they provide the closest fit between the reactor vessel and reactor internals, the radial differential thermal expansion associated with the RV upper head drain and fill cooling event does not effect the alignment keys.

Potential interference of the CEA guide path interface with the UGS Assembly due to reactor internals/head relative displacement was considered. The maximum radial growth of the CEA shroud occurred at the shroud location with the greatest radial distance from the center of the UGS plate, Location A (See Figure 4-4). Worse case tolerances, including Extension Shaft Guide/Reactor Vessel Head relative thermal displacements showed that no interference existed along the guide path with either the reactor internals or reactor vessel head. CEA insertibility is therefore assured.

A stress analysis of the UGS Assembly was conducted to determine potential fatigue damage due to this transient event. The Grid Beam model, when subjected to the 300°F thermal gradient, behaved similar to a simply supported beam. The maximum stress intensity of 11,000 psi was found at a grid beam mid-span. The stress occurs at the weld which joins the UGS support plate to the Grid Beam structure. The allowable stress intensity for these welds

is 33,800 psi, based on the requirements of the ASME Boiler & Pressure Vessel Code Subsection NG, 1974 Edition. Since this value is greater than the calculated stress, the Grid Beam Assembly will not suffer any structural damage.

The fatigue usage factor associated with this stress intensity, considering 10^6 transient events (cycles) is essentially 0. Therefore, no fatigue damage will occur as a result of RV dome voiding during the RV upper head drain and fill cooling event.

The relative movement of the ICI Plate with respect to the internals was considered to evaluate potential CEA guide path interference. It was found that the maximum hydraulic uplift load on the plate was less than the weight of the ICI Assembly. Therefore, the ICI Plate will remain in place during the refill cycle and not interfere with the CEA guide path.

The resultant stresses from the overall CEDM component and nozzle were evaluated and found to be within the $3S_M$ limit of ASME Section III, paragraph XIII-1150. The resultant stresses were also enveloped within the fatigue limits of ASME III, Subsection NB-3222.4. The maximum operating cycle is limited to 480 cycles, based on the maximum reactor trip restriction dictated by fatigue analysis for all CEDMs.

4.5 Generic Voiding Conclusions

The analysis has shown no deleterious effects to the Reactor Internals as a result of a maximum 300°F linear thermal gradient associated with a RV head drain and fill cooldown event. The following conclusions have been reached for specific components, based on a detailed analysis of the applicable Reactor Internals using results from the finite element model of the Upper Guide Structure Assembly (UGS).

1. Thermal growth of the Reactor Internals was considered to verify CEA guide path integrity by evaluating potential interference with the internals and/or vessel head. A detailed tolerance study, including relative thermal displacements between the extension shaft guide and reactor vessel head showed that no interference occurred along the guide path. CEA insertibility is therefore assured.

2. Evaluation of the relative thermal growths between the reactor vessel and the reactor vessel internals showed sufficient clearance between the components to preclude an interference condition.

3. The Upper Guide Structure Grid Beam Assembly displayed behavior similar to a simply supported beam, pinned at the upper flange/holddown ring interface. The maximum stress intensity of 11,000 psi at a grid beam mid-span is well below the allowable value of 33,800 psi. The fatigue usage factor associated with this stress intensity, considering 10^6 cycles is essentially 0. No fatigue damage will occur.

4. A final item considered in this analysis was the possible vertical uplift of the ICI plate. The maximum hydraulic uplift load was shown to be well below the weight of the ICI Assembly. Therefore, the ICI plate will remain in place during this transient event and not interfere with the CEA guide path.

4.6 Plant Specific Voiding Conclusions

Using the results from 2570 MWt grid beam analysis, an evaluation was conducted to assess similar impact on Omaha, Palisades, Arkansas Unit 2, 3410 MWt class plants and System 80 plants. A comparison of the upper guide structure parameters of the different C-E plants are shown in Table 4-1.

Omaha's upper guide structure assembly is similar to the 2570 MWt grid beam assembly (See Table 4-1). Therefore, the detailed finite element model is applicable to Omaha. An assessment of grid beam stresses has shown no damaging effects to the Omaha internals as a result of a RV head drain and fill event. In addition, an evaluation of upper guide structure deflections has shown no reactor vessel/internals interference. CEA insertibility is assured.

Both Arkansas Unit 2 and the 3410 MW reactors have upper guide structures which are similar in design to the 2570 MWt assembly analyzed. Structurally, these grid beam assemblies will meet all ASME code stress and fatigue allowables. An evaluation of upper guide structure deflections has shown no reactor vessel/internals interference. However, a potential CEA guide path/internals interference exists during the natural cooldown event. Unless a further analysis is conducted, it is recommended that all CEA's are verified to be fully inserted before depressurizing the RCS during a natural circulation cooldown.

Maine Yankee is included with the reference 2570 MWt analysis (St. Lucie 1 and 2, Millstone 2, Calvert Cliffs 1 and 2). The only significant difference is that Main Yankee does not have an ICI plate.

An evaluation of the hydraulic uplift loads on ICI plate for the Omaha, Arkansas and 3410 MW reactors from a RV head drain and fill event shows that these loads are significantly less than the weights. Therefore, the ICI plates will not be displaced and no interference will occur with the CEA guide path.

The upper guide structure assembly for Palisades is significantly different from the assembly considered in the detailed analysis (See Table 4-1). Because of these differences, CEA insertibility and grid beam structural integrity cannot be evaluated from the 2570 MWt model analysis. Although no detailed analysis has been done for Palisades, no significant differences from the 2570 MWt

model analysis is expected if an analysis were conducted. A comparison of internals/reactor vessel relative thermal growth was conducted and radial clearance is assured.

A scoping evaluation of the effects on the System 80 upper guide structure assembly from a RV head drain and fill event was conducted. The structural integrity of the assembly and the insertibility of the CEA's are assured provided that the steam bubble is not "drawn" below the top surface of the UGS support plate, which is 6.375 inches above the top of the hot leg. Further analysis would be needed to evaluate the effects on the internals if the steam bubble is "drawn" below this level. Reactor Vessel/internals interference will not occur.

TABLE 4-1

COMPARISON OF UPPER GUIDE STRUCTURE PARAMETERS

	OMAHA	PALISADES	ARKANSAS	2570 MW	3410 MW	SYSTEM 80
UGS LOAD CARRYING STRUCTURE	WELDED GRID STRUCTURE	BOLTED GRID STRUCTURE	WELDED GRID STRUCTURE	WELDED GRID STRUCTURE	WELDED GRID STRUCTURE	TUBE SHEET
DEPTH OF GRID BEAMS	24 in.	18 in. (full length) 9 1/2 in. (cross beam)	24 in.	24 in.	24 in.	N/A
LENGTH OF LONGEST GRID BEAM	116 in.	144 in.	128.5 in.	142.8 in.	141.5 in.	N/A
THICKNESS OF GRID BEAMS	1 1/2 in.	1 1/2 in.	1 1/2 in.	1 1/2 in.	1 1/2 in.	N/A
LENGTH OF CEA SHROUDS	124 13/16 in.	125 in.	110 7/8 in.	124 1/2 in.	103 7/8 in.	50 in.
END SUPPORT OF GRID BEAMS	WELDED TO A CYLINDER	WELDED TO A CYLINDER	WELDED TO A CYLINDER	WELDED TO A CYLINDER	WELDED TO A CYLINDER	N/A
UGS SUPPORT PLATE THICKNESS	3 1/4 in.	N/A	3 1/2 in.	4 in.	3 1/2 in.	4 in.
LOCATION OF BOTTOM SURFACE OF UGS SUPPORT PLATE RELATIVE TO TOP OF HOT LEG	57.75	N/A	30.25	31.640 in.	29.25 in.	2.375 in.

FIGURE 4-1
REACTOR VERTICAL ARRANGEMENT

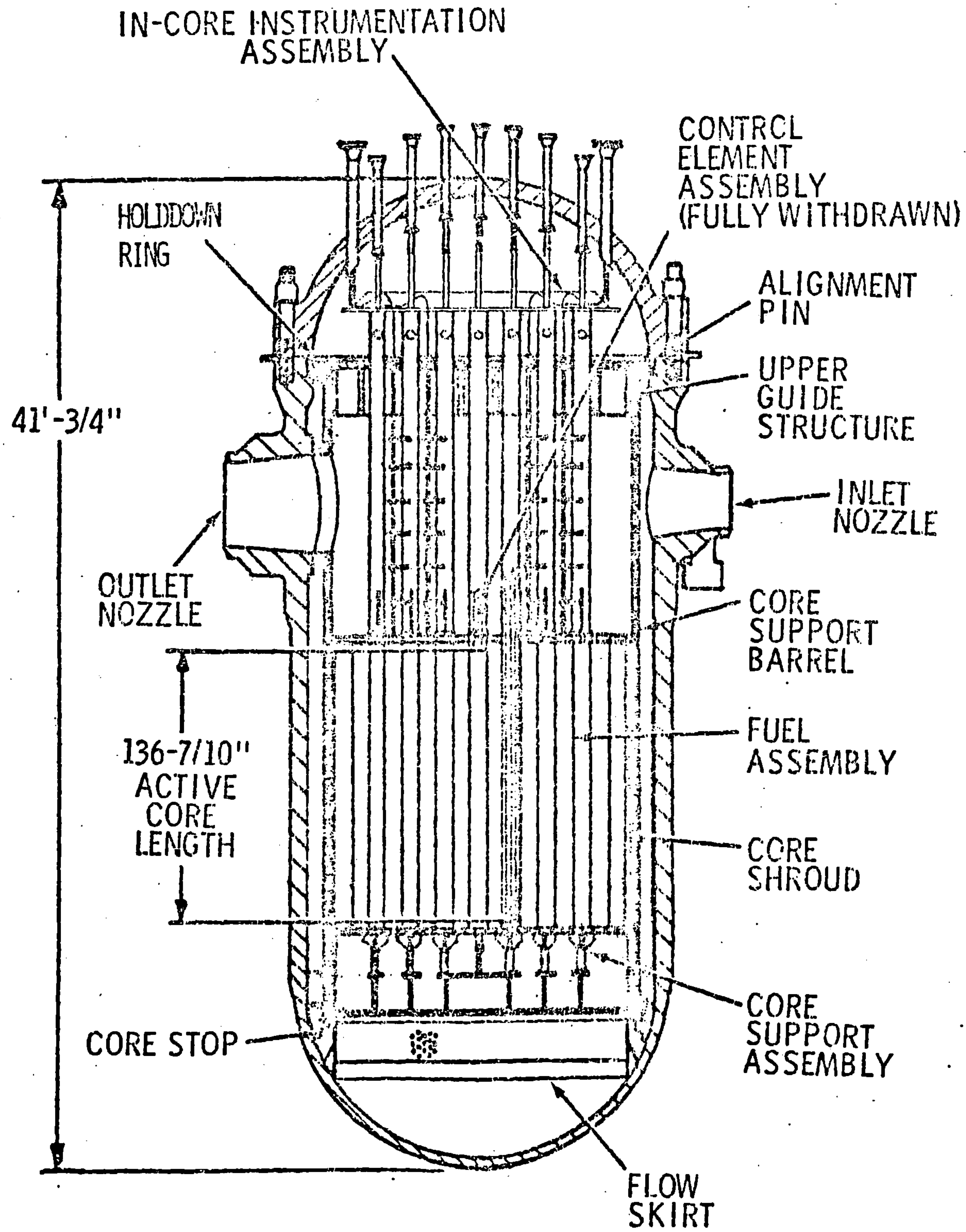


FIGURE 4-2
REACTOR INTERNALS ASSEMBLY

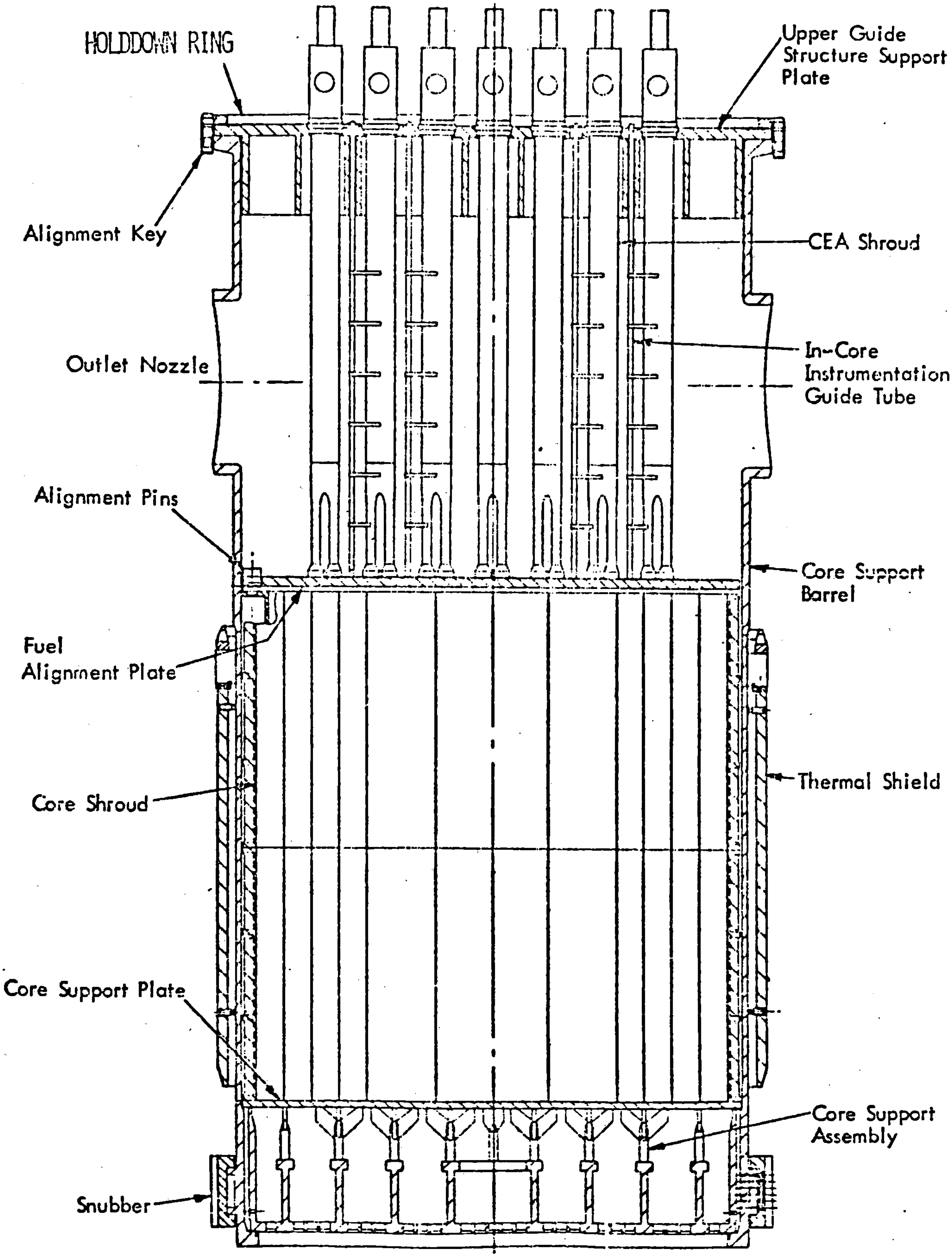


FIGURE 4-3
UPPER GUIDE STRUCTURE ASSEMBLY

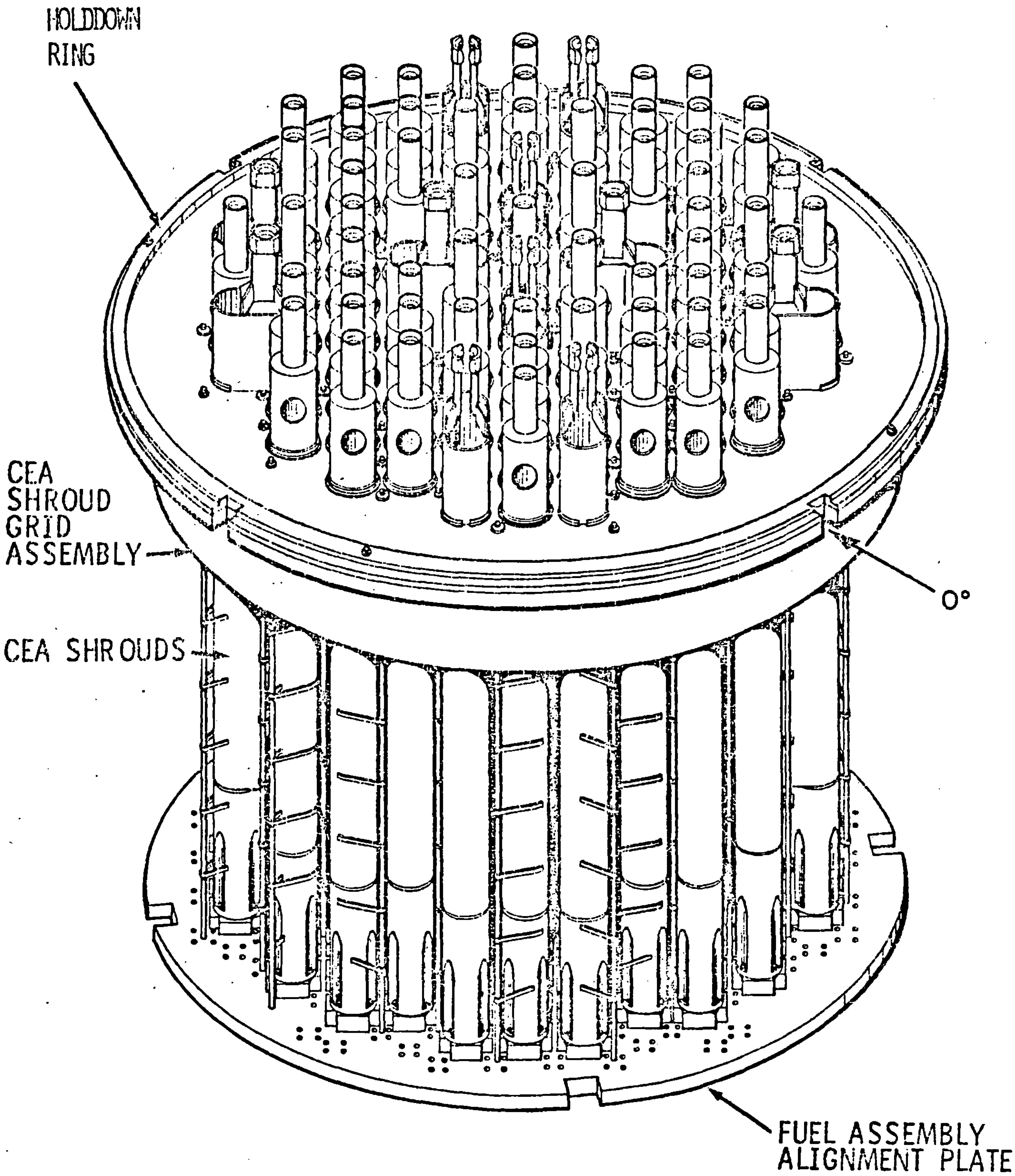
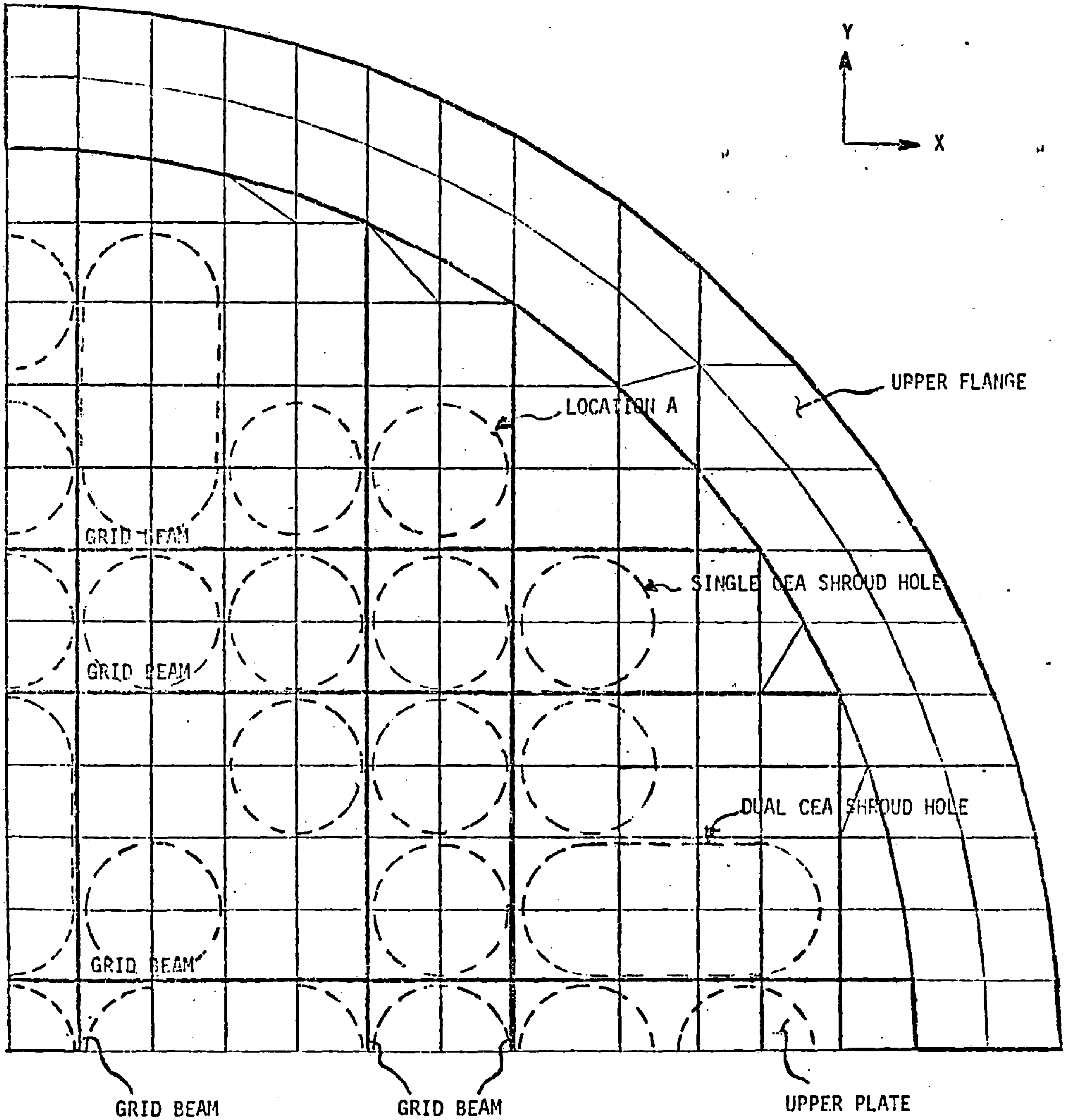


FIGURE 4-4
FINITE ELEMENT MODEL OF UGS GRID BEAM ASSEMBLY (PLAN VIEW)



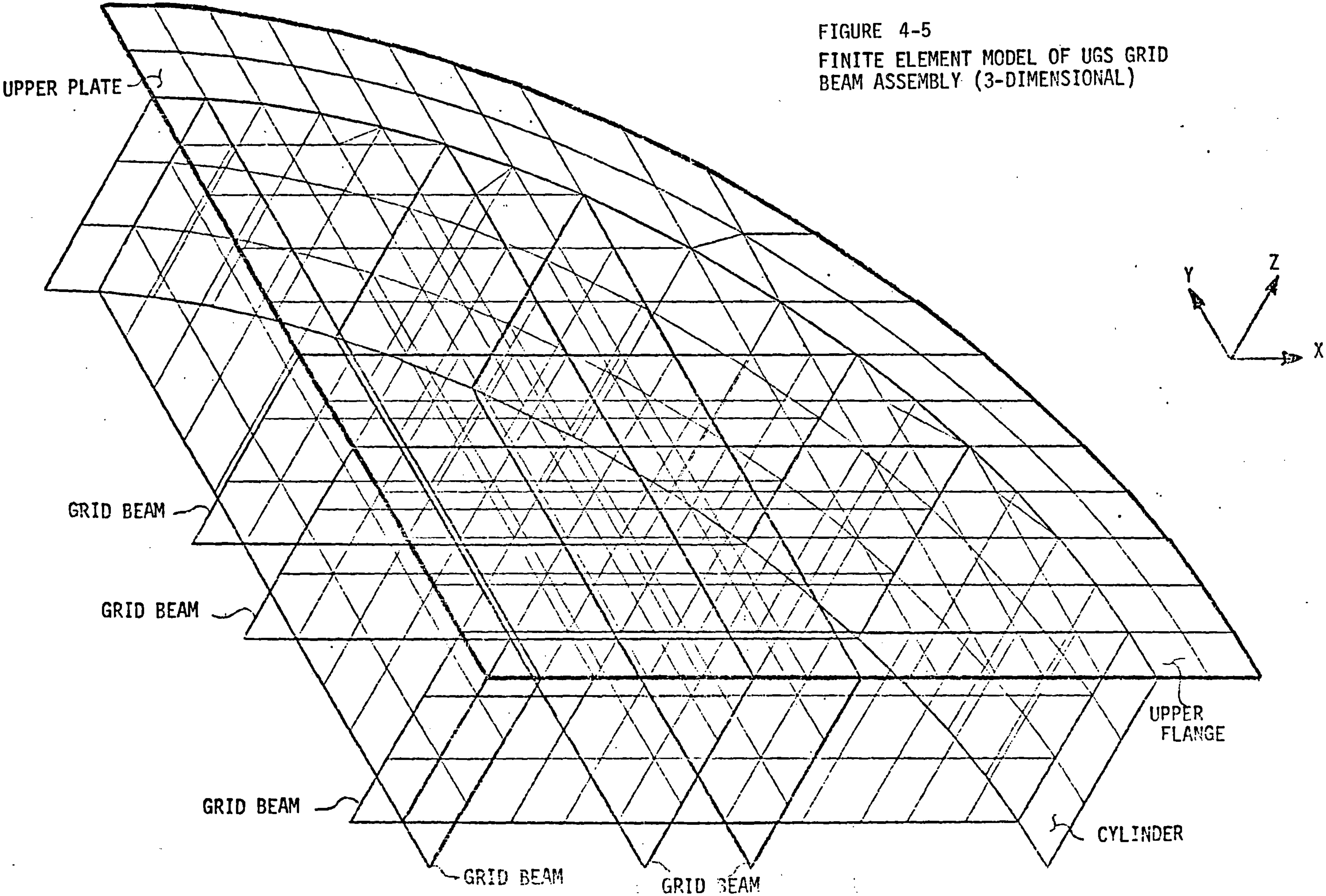
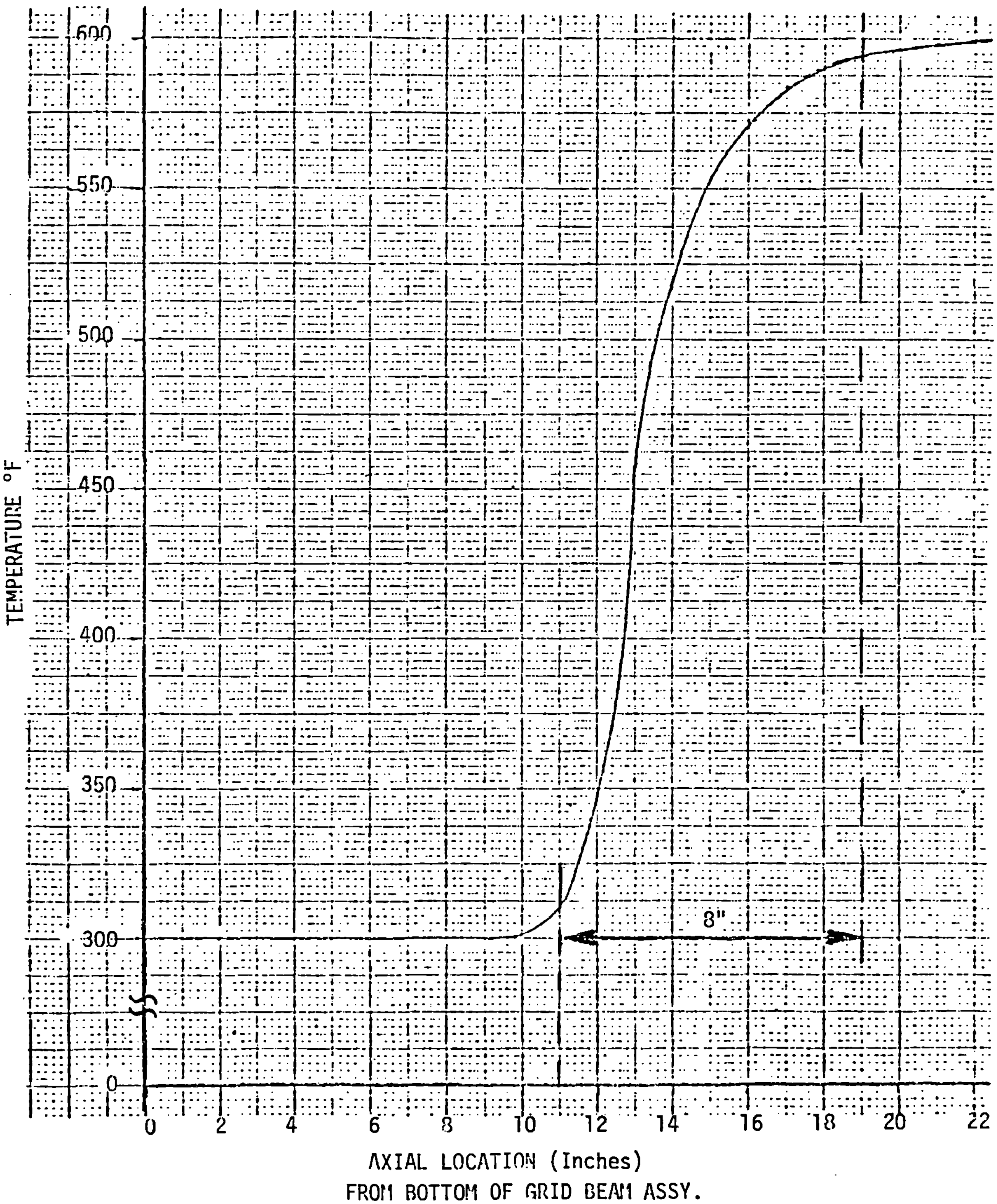


FIGURE 4-5
FINITE ELEMENT MODEL OF UGS GRID BEAM ASSEMBLY (3-DIMENSIONAL)

FIGURE 4-6

THERMAL GRADIENTS THRU
GRID BEAM HEIGHT



5.0 NATURAL CIRCULATION COOLDOWN SAFETY FUNCTIONS AND IMPORTANT CONCEPTS

5.1 Purpose

This section describes recommended methods and processes to deal with the multitude of potential problems that may arise during an abnormal plant cooldown. Specific recommendations for performing optional techniques to accomplish a natural circulation (NC) plant cooldown evolution on a generic C-E plant are provided. Each method listed is not intended to be used on every C-E plant. CEN-152 provides the minimum guideline actions needed during a natural circulation plant cooldown. The information provided in this section is intended to provide expanded information to the utility procedure writer on the important concepts needed to develop a plant specific procedure dealing with the phenomenon of natural circulation and natural circulation plant cooldown.

5.2 Background

Reactor coolant pump forced circulation and heat transfer to the steam generators is the preferred method of residual and sensible heat removal whenever plant temperatures and pressures are above the shutdown cooling system entry conditions. The inherent natural circulation capability of all C-E plants provides a back-up means for core cooling and plant cooldown if the reactor coolant pumps (RCPs) are unavailable.

Four main functional areas of operator control must be addressed throughout a plant cooldown using natural circulation (NC) flow in the RCS. The functional areas are:

1. Reactivity Control.
2. RCS Inventory Control.
3. RCS Pressure Control.
4. RCS Heat Removal.

Incomplete response in any of these four safety functions could lead to interruption of NC core cooling. This report provides instruction in these four safety functions to ensure operator control throughout the plant boration, NC cooldown and depressurization to cold shutdown conditions.

The rate of natural circulation flow is governed by decay heat, component elevations, primary to secondary heat transfer, loop flow resistance, and the presence of voids. Component elevations on C-E plants are such that satisfactory natural circulation decay heat and system sensible heat removal can be obtained by density differences between the bottom of the core and the top of the steam generator tube sheet. Successful natural circulation plant cooldown and subsequent depressurization to shutdown cooling system entry conditions has been demonstrated successfully in the field.

It is important to note that some limited operations of RCPs following a reactor trip can be very beneficial. The reactor vessel (RV) upper head region temperature is controlled by the hot leg temperature during forced flow conditions in the RCS. Operating RCPs after a reactor trip will reduce the RV upper head temperature from the full-power hot leg temperature down towards the lower post-trip hot leg temperature. The amount of upper head temperature reduction will be dependent upon the length of RCP operation possible after the reactor trip and the post-trip decrease in hot leg temperature. Operating the RCPs even for just a minute or more beyond the reactor trip can be effective reducing the probability of subsequently drawing a RV dome bubble during a natural circulation cooldown.

5.3 Natural Circulation Cooldown Safety Functions

5.3.1 Prerequisites

1. The reactor and turbine are shut down.

2. The Nuclear Steam Supply System (NSSS) is in a stabilized condition with the operator in control of reactor coolant system (RCS) parameters following an abnormal event.

3. Feedwater is capable of being supplied to the steam generator(s) by either the main feedwater system or the auxiliary feedwater system.

4. Secondary pressure is being controlled by discharging steam through the turbine bypass valves or atmospheric dump valves.

5. RCS inventory control is being maintained through the use of the chemical and volume control system (CVCS) and/or the safety injection system (SIS).

6. No reactor coolant pumps (RCPs) are available for operation or a condition exists in which running a RCP may be detrimental. Natural circulation flow in the RCS has been verified.

7. The RCS is not being cooled by the shutdown cooling system.

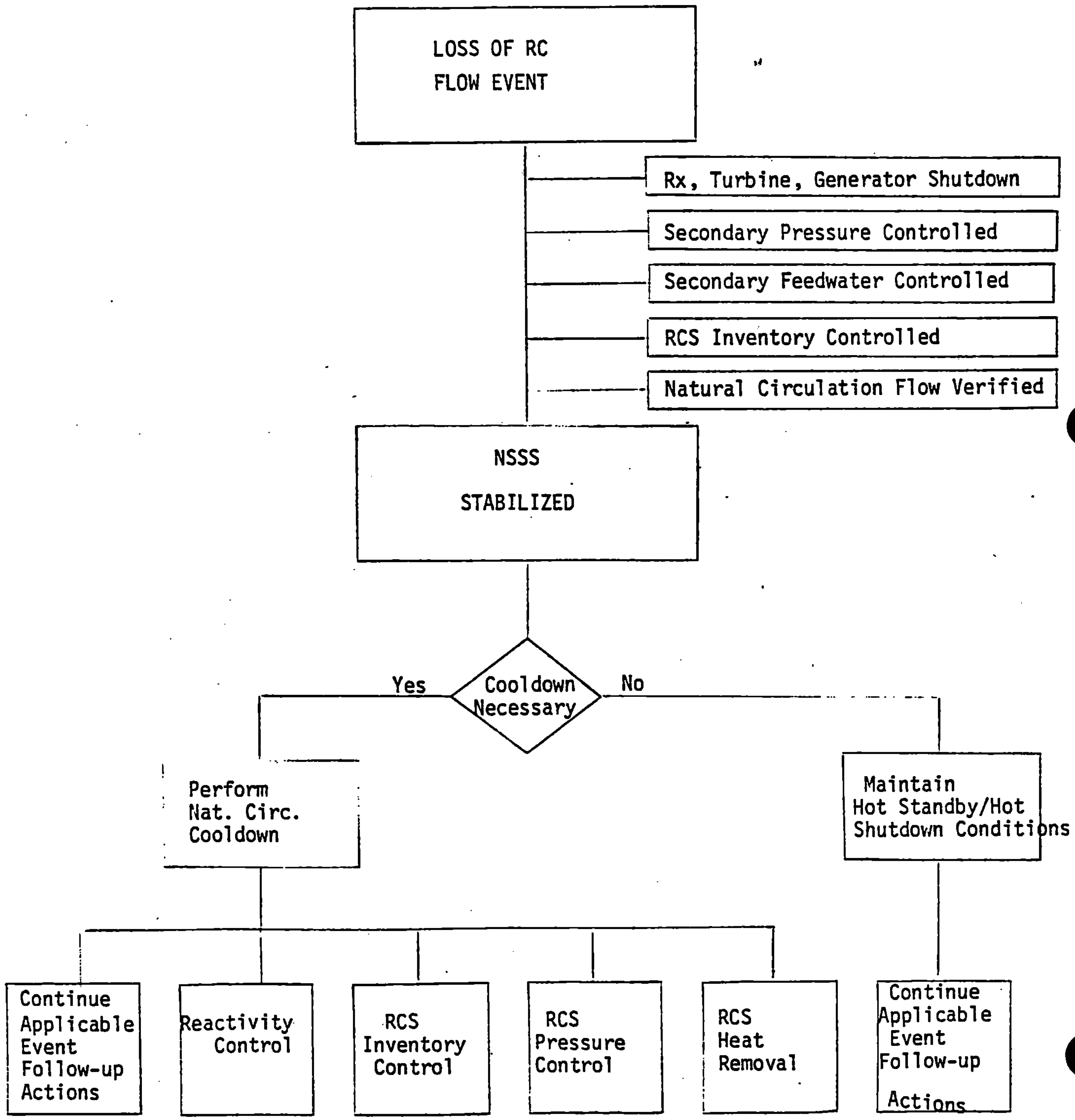
General: Any applicable follow-up actions that are required by the initiating emergency or abnormal event procedure(s) shall continue to be performed in parallel with plant cooldown procedures. Applicable emergency procedure requirements may supercede parts of the criteria suggested in the following sections.

The prerequisites for a natural circulation cooldown are summarized in Figure 5-1.

FIGURE 5-1

NATURAL CIRCULATION COOLDOWN

SAFETY FUNCTIONS



5.3.2 Reactivity Control

Actions:

1. Borate the RCS in accordance with Technical Specification requirements.

Precautions:

1. Do not start or continue any plant cooldown until the minimum required reactor shutdown margin for the present operating mode is attained and can be maintained in accordance with the Tech. Specs.

2. After a cold shutdown boron concentration is attained in the RCS, makeup water added to the RCS during the cooldown should be at least the same boron concentration as in the RCS to prevent any dilution of RCS boron concentration.

3. Throughout the NC plant cooldown and following any operation of RCPs, monitor the RCS boron concentration to ensure that any possible dilution from regions with poor circulation, such as the RV upper head, does not reduce the boron concentration below the minimum required.

4. Pressurizer auxiliary spray should be used as necessary to equalize the pressurizer and RCS loop water boron concentration as a change is made to the RCS boron concentration. If pressurizer spray is not available, RCS boron concentration should be increased to avoid being diluted below minimum requirements later by a possible pressurizer outsurge.

Important Concepts: (Paragraphs are numbered with their corresponding Action section paragraph number)

1. The RCS should be borated to the cold shutdown boron concentration level before starting a plant cooldown if no safety related criteria dictate an immediate cooldown initiation.

However, as a minimum, the required reactor shutdown margin must be achieved in accordance with the Tech. Specs. before cooling down to another operating mode (e.g., the reactor shutdown margin for hot shutdown operating mode must be attained before leaving the hot standby operating mode). If the letdown system is not operable, normal boration procedures will not be available to change RCS boron concentration. Pressurizer level will have to be raised as a result of charging highly borated makeup water to raise the RCS boron concentration before commencing a plant cooldown.

Natural circulation flow rate in C-E plants is normally approximately 2-3% of full forced flow. This flow rate produces turbulent flow within the RCS flow path which promotes adequate boron mixing throughout the RCS. The time lag between when boron is injected into the cold leg and when that boron reaches the core is approximately 1 minute for NC flow (versus approximately 1 second under full forced flow conditions). This longer time lag for boron to reach the core during NC flow should not alter the RCS cooldown process.

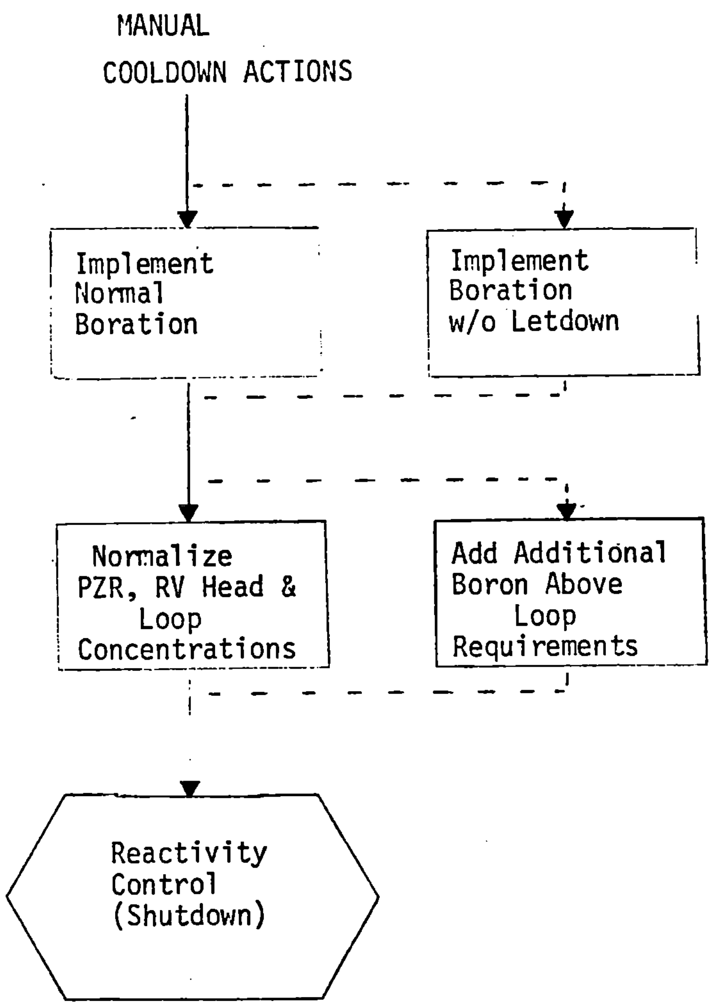
If the pressurizer water level is maintained relatively constant throughout the plant cooldown and little spray flow is used, the pressurizer's water boron concentration will be significantly less than the RCS loop's water boron concentration. As the RCS boron concentration is changed, the auxiliary spray should be used to normalize the pressurizer and RCS boron concentration. This may require auxiliary spray flow beyond what is needed for depressurization. Pressurizer heaters should be used to offset the depressurization caused by intermittent auxiliary spray. An alternative to using spray flow for pressurizer boron control is to increase the RCS boron concentration higher than the required RCS cold shutdown concentration to account for a potential dulution from the pressurizer water. Thus, if a

pressurizer outsurge occurs, mixing of the water from the pressurizer with the RCS loop water will not dilute the boron concentration below the cold shutdown concentration requirement.

Another region of reactor coolant which may contain less boron than the RCS loop water as cold shutdown boration progresses is the reactor vessel upper head areas. This potentially low borated water will be slowly flushed out thorughout the NC plant cooldown, quickly flushed out following operation of any RCP, or forced out during formation of any RV upper head void.

The reactivity control safety functions are summarized in Figure 5-2. The solid line path shows the preferred methods to accomplish adequate reactivity control until cold shutdown is attained. Alternative methods and processes are shown as dotted line paths. The priority of the suggested alternatives decrease as the dotted lines proceed to the right.

FIGURE 5-2
REACTIVITY CONTROL
SAFETY FUNCTIONS



5.3.3 RCS Inventory Control

Actions:

1. Maintain the pressurizer level at or near (*) % with the charging and letdown system throughout the plant cooldown if possible. Whenever possible, continue to maintain a bubble in the pressurizer.

2. If the charging system becomes unavailable during the plant cooldown:

   A. Isolate the letdown system
   B. Initiate the high pressure safety injection pumps as necessary for coolant contraction.
   C. Isolate any known leakage if possible.
   D. If the RCS pressure is above the HPSI pump shutoff head pressure, depressurize by continuing the RCS cooldown.

3. If the letdown system is not available, operate the charging pumps as needed to maintain a low pressurizer water level and a large pressurizer steam bubble after the RCS cooldown is commenced.

* Plant specific (normal shutdown reference level).

Precautions:

1. Once the pressurizer cooldown is begun, pressurizer level indication decalibration will occur and the pressurizer level indication will begin to deviate from the true pressurizer level. The operator should use plant cooldown correction curves to find the true pressurizer water level. A cold calibrated pressurizer level indication is also available for lower pressurizer temperatures.

2. Do not operate pressurizer heaters if pressurizer water level falls below the top of the heaters.

Important Concepts: (Paragraphs are numbered with their corresponding Action Section paragraph number)

1. Pressurizer level should be maintained at the normal shutdown reference level throughout the plant cooldown. The normal shutdown reference level (plant specific) may or may not be the same as the hot zero-power pressurizer reference level. If the hot zero-power level for a plant is the shutdown reference level, the pressurizer level control system may be left in automatic. Even though decreasing pressurizer temperature will decalibrate the pressurizer level instrument on the controlling channel, the error developed at the hot zero-power level is low (in the absence of reference leg heating).

   Once the pressurizer water temperature varies from the normal hot standby pressure, the instrument indication on the normal pressurizer level channel will begin to deviate from the true pressurizer level and the operator should use plant cooldown correction curves to find the true pressurizer water level. A cold calibrated pressurizer instrument channel is provided. This channel can be used as a quick reference during the plant cooldown. The actual pressurizer water level during pressurizer cooldown will be between the level indicated on the cold calibrated channel (which reads low) and the level indicated on the hot calibrated channel (which reads high).

   If the normal shutdown reference level is not maintained, a pressurizer level above 10% and below 90% should be maintained to avoid losing pressure control with the saturated bubble in the pressurizer. If the pressurizer level drops below the top of the pressurizer heaters, pressurizer heater

operation will be interlocked off for overheating protection. A plant cooldown can be initiated without a pressurizer level within the above preferred level indications as long as adequate primary pressure control is being maintained. However pressurizer level should be brought back to normal as soon as possible.

All pressurizer level indication and plant cooldown pressurizer level correction curves are based on normal ambient reference leg water temperature. If the containment environment temperature is raised above nominal conditions, reference leg heating will occur and level indication decalibration will result. Reference leg temperature can be approximated by the containment temperature. Reference leg heating produces an indicated level erroneously higher than actual level. The pressurizer level indication should be lowered by the following amount to account for the effect of reference leg heating:

Reference Leg Temperature (°F°)	Correction to Indicated Level (% of Span to be Lowered)
120°	0
200°	5
250°	9
300°	14
350°	19
400°	25
450°	32

Basis: Level Calibration Pressure 2250 psia
Ref. Leg Calibration Temperature 120°F
No Reference Leg Flashing

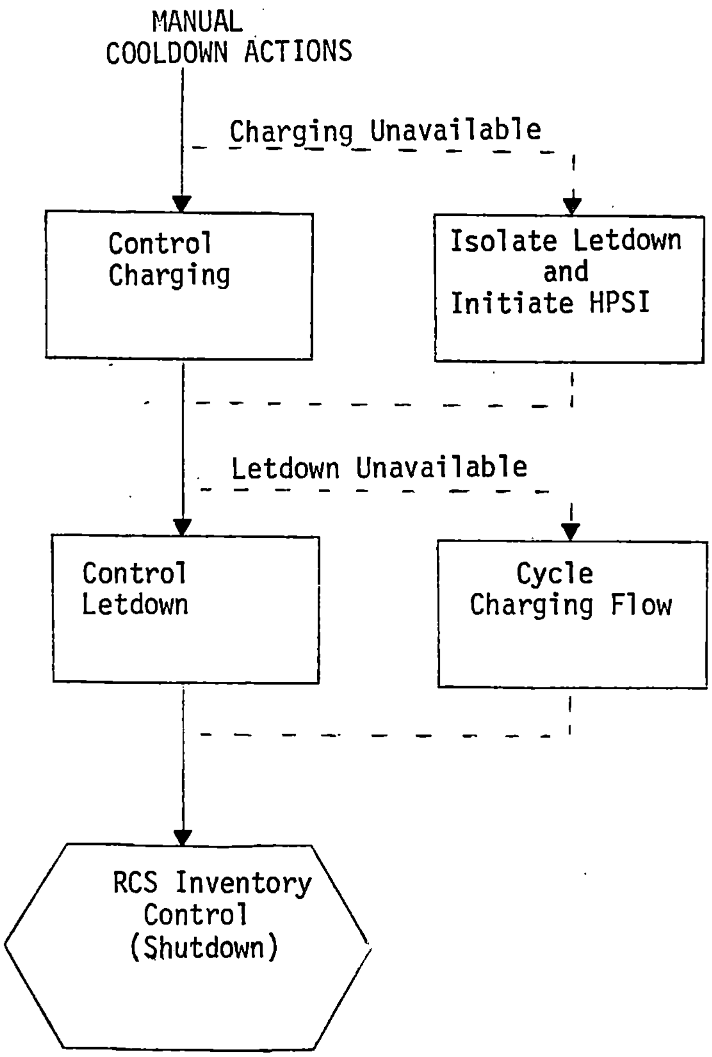
2. If the charging system becomes unavailable, then the high pressure safety injection system must be used to provide makeup to the RCS. System pressure must be reduced down to

the HPSI pump shutoff head before any makeup can be added to the RCS. Thus available RCS coolant should be conserved until the pressure is reduced and the HPSI pumps are able to provide makeup flow to the RCS. If at any time during the plant cooldown RCS leakage exceeds the rated charging system capacity, a LOCA is considered to have occurred and the LOCA procedure should be carried out.

3. If the letdown system is not available, normal inventory control procedures may not be used. After the initial pressurizer fill to accomplish boration before cooldown, a large steam volume should be maintained in the pressurizer. A large pressurizer void ensures that an adequate volume will be available after the RCS cooldown is completed to accept subsequent auxiliary spray flow to depressurize the RCS. A low water volume will also provide less mass in the pressurizer to cool, enhancing the depressurization capability of the available auxiliary spray flow. For example ≈5000 gallons of auxiliary spray flow would be needed to cool the pressurizer down to shutdown cooling initiation if the initial pressurizer water volume was ≈800 ft^3. This amount of auxiliary spray without coolant loss would just about fill the pressurizer solid. A pressurizer with a larger initial volume may not be able to be quickly cooled using auxiliary spray because it would result in filling the pressurizer solid before adequate depressurization takes place. Once the RCS cooldown is completed, no further coolant contraction will take place and the amount of auxiliary spray flow (and amount of depressurization due to the auxiliary spray) is limited to the existing pressurizer steam space before filling the pressurizer.

The RCS inventory contron safety functions are summarized in Figure 5-3. The solid line path shows the preferred methods to accomplish adequate inventory control until cold shutdown is attained. Alternative methods and processes are shown as dotted line paths. The priority of the suggested alternatives decrease as the dotted lines proceed to the right.

FIGURE 5-3
RCS INVENTORY CONTROL
SAFETY FUNCTIONS



5.3.4 RCS Pressure Control

Actions:

1. Maintain pressurizer pressure at normal operating pressure or as high as practical without exceeding Tech. Spec. pressure/temperature requirements during the RCS cooldown by utilizing the pressurizer heaters and auxiliary spray.

2. After (15*) hours following the start of the RCS cooldown, commence the pressurizer cooldown and RCS depressurization by manually operating the auxiliary spray.
   A. Maintain pressurizer cooldown rate within Technical Specification requirements.
   B. Maintain at least 20°F + (inaccuracies*) subcooled margin in the RCS.

3. If pressurizer heaters are inoperative or insufficient capacity is available to maintain pressurizer pressure as required, follow the guidance provided below for pressure control throughout the plant cooldown:

   A. Maintain the pressurizer bubble as long as possible. The following criteria will help slow the loss of RCS subcooled margin:
      (1) Minimize use of pressurizer auxiliary spray.
      (2) Stop all pressurizer sampling if not needed.
      (3) Minimize pressurizer level fluctuations.
      (4) Stop any isolable leakage from the pressurizer.
      (5) Until RCS temperatures are cooled down to the shutdown cooling system maximum allowed entrance temperature, maintain an RCS cooldown rate greater than or equal to the pressurizer cooldown rate caused by the pressurizer ambient heat loss.

* Plant Specific

B. If the RCS hot leg subcooled margin becomes less than 20°F +(inaccuracies*), initiate the HPSI system. Terminate HPSI pump operation only when RCS subcooled margin is greater than 20°F +(inaccuracies*) and pressurizer level is indicated and can be maintained.

C. If the RCS hot leg subcooled margin remains less that 20°F +(inaccuracies*), initiate charging (which may result in eventually filling the pressurizer solid). When the hot leg subcooled margin exceeds 20°F +(inaccuracies*), stop all charging pumps except one and regulate the letdown flow to control the RCS pressure/subcooled margin or stop all charging pumps and cycle a charging pump on and off as needed to control the RCS pressure/subcooled margin.

D. Reform a bubble (if possible) in the pressurizer whenever the RCS hot leg subcooled margin can be maintained above (20°F + inaccuracies*).

E. If the RCS is solid, throttle or cycle makeup flow as needed when depressurizing the RCS to enter shutdown cooling.

4. If the auxiliary spray system is inoperative, implement one or more of the following alternatives (listed in order of decreasing preference) to cool and depressurize the pressurizer. Ensure pressurizer heaters are deenergized when not needed.

   A. Determine when a plant cooldown must be initiated based on existing plant conditions and requirements. If plant conditions permit, stay at hot standby conditons until main or auxiliary spray flow can be restored.
   B. Use the pressurizer fill and drain method of cooling the pressurizer by putting cooler RCS loop water into the pressurizer in order to cool the pressurizer.
   C. Allow the pressurizer to cool due to ambient heat loss.
   D. Operate the pressurizer vent (if available remotely) to reduce pressurizer pressure as needed.

* Plant Specific

E. Operate a power operated relief valve (PORV) to reduce pressurizer pressure as needed. Monitor quench tank parameters since any sustained operation of the PORVs will rupture the tank's rupture disc.

5. Reset or bypass Engineered Safeguards Features* and reduce safety injection tank pressures* as required due to the decreasing primary and secondary pressures.

6. During the RCS depressurization, monitor for condensable void formation. Symptoms of void formation are:

   A. Pressurizer level increases significantly greater than expected while operating auxiliary spray.
   B. Pressurizer level decreases while operating charging or HPSI pumps.
   C. Letdown flow unexpectedly greater then charging flow if the pressurizer level control system is in automatic.
   D. Void level formation as indicated by the reactor vessel level monitor (if available).

7. If condensable void formation in the RCS is indicated, perform the following:

   A. Isolate letdown flow.
   B. Stop normal charging flow and/or auxiliary spray flow.
   C. Stop the RCS cooldown (if any) and maintain the existing RCS temperature relatively constant. [If reactor vessel level monitoring instrumentation is available, the RCS cooldown may continue with charging and letdown operating whenever a void in the RV head does not expand below a level of 3 feet above the top of the hot leg nozzle].
   D. Determine whether available secondary condensate supplies or some other plant safety concern prevents delaying the plant depressurization and the initiation of the shutdown cooling system.

* Plant Specific

(1) If plant conditions will permit a prolonged plant depressurization:

(a) Eliminate the condensable RV bubble by repressurizing the RCS:

- Energize all pressurizer heaters.
- If pressurizer level drops below the heater cutout level, commence charging until the pressurizer level returns to above the heater cutout level.

(b) When the RV bubble is eliminated as indicated by the lack of void symptoms:

- Stop any repressurization and maintain existing pressurizer pressure.
- Unisolate letdown and reestablish proper pressurizer level.

(c) If indication of a relatively constant void persists at the same system pressure, consider the void to contain noncondensible gases and follow the procedure for removing noncondensible gases.

(d) Resume the RCS cooldown and depressurization (4)* hours after the condensible void is eliminated.

(e) If indications of condensible voiding reappear during subsequent RCS depressurization, repeat this complete action step from the beginning.

(2) If plant conditions will not permit a prolonged plant depressurization:

(a) Continue the RCS depressurization allowing the RV head void to grow.

(b) Stop the depressurization when (I) the pressurizer level has increased to 90% indicated level or no longer continues a steady increase or (II) the RCS subcooled margin reaches a minimum value of 20°F + (inaccuracies*).

(c) Repressurize the RCS by energizing all pressurizer heaters and commencing charging flow to the RCS loop.

* Plant Specific

(d) Stop the charging flow and deenergize the pressurizer heaters when (I) the pressurizer level stops decreasing and begins a normal steady increase due to charging or when the pressurizer level decreases down to the top of the pressurizer heaters or (II) the RCS subcooled margin is sufficiently raised to permit another depressurization cycle.

(e) Repeat the above four steps again for several drain and fill cooling cycles of the RV head dome.

(f) When the RV upper head has cooled as indicated by a lack of void symptoms, letdown can be unisolated and proper pressurizer level reestablished. If indication of a relatively constant void persists at the same system pressure, consider the void to contain noncondensible gases and follow the procedure for removing noncondensible gases.

(g) Resume the RCS cooldown and depressurization.

(h) If indications of condensible voiding reappear during subsequent RCS depressurizaton, repeat this complete action step from the beginning.

8. If void indication cannot be eliminated by implementing actions for condensable gas, consider the gases to be partially or completely noncondensable gases.

   A. Increase pressurizer pressure above the pressure where void symptoms were originally noticed.

   B. Operate the RV head vent* as needed to eliminate the noncondensable gases.

Precautions:

1. Minimize the use of pressurizer auxiliary spray whenever the temperature differential between the spray water and the pressurizer is greater than 200°F to minimize the increase

in the spray nozzle thermal stress accumulation factor. Every cycle must be recorded in accordance with the Technical Specifications.

2. Letdown flow unexpectedly greater than charging flow with the pressurizer level control system is in automatic or a rapid increase in pressurizer level while operating auxiliary spray (possibly followed by a decrease in pressurizer level when charging is realigned to the RCS loop) is indicative of a void in the RV head dome.

3. If the RCS becomes solid, closely monitor any makeup or draining and any heatup or cooldown to avoid unfavorable rapid pressure excursions.

4. Continued venting from the reactor vessel head vent system may depressurize the RCS and form a condensable bubble in the reactor vessel head region.

Important Concepts: (Paragraphs are numbered with their corresponding Action Section paragraph number)

1. Pressurizer pressure should be maintained as high as possible within operating restrictions until the time criteria of Action #2 have been satisfied. This cooldown strategy will minimize the possibility of flashing a condensable void in the stagnant RV head dome during a NC plant cooldown. A RV void will not form until the RCS pressure is decreased below the RV head saturation pressure, regardless of the RCS cooldown rate used. Thus maintaining high pressurizer pressure until time requirements are met, coupled with a rapid RCS cooldown rate to as low a temperature as possible, should ensure that a condensable RV void will not be formed during the NC plant cooldown process.

   The pressurizer pressure control system may be left in automatic to control pressurizer pressure with the pressurizer heaters until the pressurizer cooldown in initiated. However

this is not recommended since automatic main spray capability is not available with the RCPs not operating. Pressure control with manual auxiliary spray and automatically controlled heaters may be awkward.

The operator should maintain at least 20°F (+ inaccuracies*) subcooled margin as a minimum whenever possible within plant and operating restrictions. Although NC flow could continue well into saturated conditions, operation with voids in the RCS should be avoided since there is no direct method to monitor multiple void locations, sizes and impact on NC flow. The preferred method of primary pressure control is with a bubble in the pressurizer throughout the plant cooldown with no voids in the RCS.

The subcooled margin value of 20°F is based on a minimum tolerance margin below saturation that C-E believes should be maintained to preclude the possibility of inadvertently reaching saturation conditions in the reactor coolant flow path. Technically only 1°F margin is needed to provide subcooled coolant in the RCS.

Plant specific and event specific instrumentation and elevation inaccuracies should be added to the base value of 20°F to establish the minimum required subcooled margin value which should be used in a procedure. The instrumentation accuracy that should be added to the base value for any situation will vary dependent upon the existing containment environmental conditions, the instruments being used to determine the subcooled margin, and the elevation inaccuracy based upon the pressure drop developed by the difference in elevation and event-specific fluid density between the pressurizer pressure sensor and the reactor coolant flow path. Normal ambient containment conditions provide the lowest inaccuracy for the minimum subcooled margin.

The method of developing the subcooled margin values to be used in the plant procedures is determined by the individual utility procedure writer. An all encompassing value with

its overly restrictive disadvantage during normal conditions can be used or a value which will vary with the event and containment conditions can be instituted.

2. The pressurizer pressure control system should be placed in manual and the auxiliary spray operated as needed when the pressurizer cooldown is commenced.

When the RCS cooldown begins, the operator is required to maintain the RCS pressure/temperature within the Technical Specification requirements. However, the Tech, Spec. criteria provides some flexibility as to when the pressurizer cooldown must begin. The RCS temperature should be reduced until the temperature/pressure limit is approached and then initiate a partial pressurizer cooldown and depressurization. The pressurizer pressure should continue to be maintained as high as possible within Tech Spec requirements until [15]* hours following the start of the RCS cooldown. Initially the RCS is rapidly cooled down via NC flow to increase the conductive heat transfer rate out of the RV head region. The pressure is maintained high to avoid drawing a bubble in the RV dome.

RCS depressurization to shutdown cooling initiation pressure is initiated after sufficient time has elapsed to permit some cooling of the RV head region. The temperature of the RV head region will initially be at the temperature of the hot leg at the time RCPs were stopped. Although the initial temperature of the RV head and the conductive heat transfer capability in this region is event and plant specific, the recommended process of a fast RCS cooldown with final RCS depressurization initiated after a holdup period will greatly reduce the possibility of drawing a condensible void in the RV dome. A shorter holdup period which could be coordinated with other plant shutdown activities such as warmup of the shutdown cooling system is mandatory to limit the extent of RV dome voiding.

* Plant Specific

If the minimum subcooled margin can not be maintained within operating restrictions while establishing shutdown cooling initiation conditions, the highest possible subcooled margin should be maintained. Natural circulation may well continue with saturated conditions in some parts of the RCS flow path.

The RV head fluid temperature should be monitored if available. However subcooled margin requirements should be based on loop and core temperature and not on the RV head temperature. RV head dome temperature should be used only for dome void generation/collapse indication and decisions. Condensable voids in the RV dome will not affect RCS natural circulation flowrate whenever loop subcooled margin criteria is established.

The difference between the pressurizer temperature and the auxiliary spray water temperature should be monitored. The differential temperature should be maintained below 200°F if possible. Auxiliary spray water temperature may be increased by increasing letdown flow or reducing charging low which will increase the regenerative heat exhanger outlet temperature. Other plant specific methods to increase auxiliary spray water temperature may include raising boric acid makeup tank temperature or raising heat tracing line temperatures. If auxiliary spray is used when a 200°F or more difference exists; then such a cycle must be recorded as per the Tech. Specs. The number of such cycles should be minimized.

3. Even though pressurizer heaters may not be available the preferred method of primary pressure control is still with a bubble in the pressurizer. Normally pressurizer heaters are needed to offset pressurizer ambient heat loss. Without adequate pressurizer heaters to makeup for the heat loss, the pressurizer will slowly cool and depressurize. For this event, the operator is instructed to minimize any pressurizer heat loss evolutions (e.g., pressurizer level fluctuations) whenever there is no need for an increase in the pressurizer cooldown rate beyond ambient losses. Any decrease in pres-

surizer level will decrease pressurizer pressure. An increase in pressurizer level may initially increase pressure due to the compression of the steam bubble. Maintaining a steady increase in pressurizer level can be used as a short term process for raising (or maintaining) pressurizer pressure. However, once the pressurizer level increase is stopped, pressurizer pressure should return to or decrease below the initial starting pressure (before the start of the continuous level increase) due to the injection of cold water into the pressurizer.

If the RCS hot leg subcooled margin drops below 20°F (+ inaccuracies*) the HPSI pumps should be started.** RCS pressure should then stabilize at the HPSI pump shutoff head if there is no LOCA. When the plant has been cooled down below the required shutdown cooling initiation temperature, the required minimum subcooled margin may not be attainable within plant specific operating limitations (e.g., shutdown cooling entry conditions, Tech. Spec. criteria, etc.) when depressurizing down to the shutdown cooling initiation pressure limit. In this event, HPSI pumps need not be operated solely to maintain the subcooled margin. If the subcooled margin cannot be maintained, then the subcooled margin should be kept as high as possible within operating restrictions and closely monitored for verification of NC flow.

Operating the HPSI pumps will result in filling the pressurizer only if the pressurizer pressure remains below the HPSI pump shutoff head. If the RCS hot leg subcooled margin remains below 20°F +(inaccuracies*) with the RCS pressure at the HPSI shutoff head, the charging pumps should be started to fill the pressurizer and pressurize the RCS. If the RCS fills to a solid condition, any additional makeup flow will very rapidly raise system pressure. An approximation which can be used to roughly estimate the pressure increase due to

* Plant Specific

** At very low plant temperatures, HPSI pumps may be racked out due to LTOP considerations and may not be available. Charging pump operation should be substituted.

the pressure increase due to makeup flow into a solid RCS is approximately 1 psi increase for every 1 gallon added (and vice versa for draining from a solid system). Similarly any coolant heat-up will rapidly raise system pressure during solid operation. An approximation which can be used to roughly estimate the pressure increase due to coolant heatup in a solid RCS is approximately 150 psi increase for every 1°F rise (and vice versa for coolant cooling in a solid system). Adequate RCS subcooled margin and pressure can be maintained while in a solid condition by cycling a charging or HPSI pump on and off as needed.

4. If the auxiliary spray system is inoperative, alternative processes must be considered to cool and depressurize the pressurizer. However, if no requirements for an immediate plant cooldown exist (such as limited secondary condensate, Tech Spec. requirement, etc.), then hot standby conditions should be maintained while spray flow capability is being restored.

   The first alternative process to reduce pressurizer pressure is the fill and drain process. The pressurizer fill and drain process involves raising the pressurizer water level to the plant specific maximum allowed level by operating all charging pumps and minimizing letdown flow. Then the pressurizer water level is decreased to just above the top of the pressurizer heaters by decreasing charging and increasing letdown.

   During the filling portion of the cycle, cooler RCS loop water is forced into the pressurizer and mixed with the pressurizer water thereby lowering the pressurizer temperature. Due to the compressing of the pressurizer steam space possibly with a small hot stratified layer of water at the top of the water volume, pressurizer pressure may increase as the water level is raised. However, during the draining portion of the cycle, some pressurizer heat is

carried away with the draining fluid. As a result, the average pressurizer temperature (and presssure) should be decreased after every complete fill and drain cycle. The amount of cooling obtained is dependent of the temperature differential between the cool incoming water and the hot pressurizer water. If the temperature differential is small, little net temperature reduction may occur.

The fill and drain process can be used even if the letdown system is not operable. The draining portion of the cycle would be accomplished by the coolant contraction from the RCS cooldown. Because the number of drain cycles that can be accomplished without letdown is limited to the amount of coolant contraction, only one* charging pump should be operated during the draining cycle and the RCS cooldown should be stopped during the filling cycle to obtain as many complete fill and drain cycles as possible.

The second alternative process to cool down the pressurizer is to allow normal conductive and convective cooling of the pressurizer to the containment atmosphere. If plant conditions will permit sufficient time (greater than 24 hours), the pressurizer saturation conditions will slowly drop due to ambient heat loss, resulting in a slowly decreasing primary pressure. Maintaining a low pressurizer level will help the ambient cooldown rate since less water would be in the pressurizer to store heat. The RCS cooldown and the pressurizer cooldown/pressure reduction should be coordinated to stay within Tech. Spec. operating limits. Availability of secondary condensate will strongly affect the use of this alternative. If this method is used, plant specific methods to lower the containment ambient temperature may be pursued to increase the ambient heat loss rate from the pressurizer. This could include operating all reactor building fans at high speed and maximum cooling water flow to the coolers.

* If charging flow is not needed for reactor coolant pump seal injection and letdown is isolated, all charging pumps should be turned off to decrease the time between subsequent pressurizer fills and hence increase the overall depressurization rate.

Use of a pressurizer vent (plant specific) or steam space sample line to vent pressurizer steam will improve the slow ambient heat loss rate. The third alternative process available to depressurize the pressurizer is to open a PORV. This method is least desirable because any sustained operation may rupture the rupture disc on the quench tank dispersing radioactive primary coolant into containment. Pressure/temperature operating limits should be monitored since PORV operation will quickly reduce pressurizer pressure.

5. As the primary pressure is decreased, the Safety Injection Actuation Signal (SIAS) and Containment Isolation Actuation Signal (CIAS) should be manually bypassed or reset to 400 psi below the existing pressurizer pressure to avoid inadvertent automatic system actuation. As the secondary pressure is decreased, the Main Steam Isolation Signal (MSIS) should also be manually bypassed or reset to 200 psi below the existing steam generator pressure. Safety injection tanks should be depressurized and isolated as required when decreasing primary pressure.

6. During a normal plant cooldown with reactor coolant pumps running, a small percentage of the forced flow is circulated in the RV upper head dome region which cools that area during the RCS cooldown. During natural circulation flow conditions in the RCS, the amount of flow through the RV upper head may be negligible. Thus the RV upper head can become a stagnated region with the only cooling being the heat loss to ambient and the head conducted down through the reactor vessel and internal structures.

   The initial RV head temperature starts at the temperature of the hot leg at the moment all forced flow is stopped. Even though the RCS can be cooled down to low temperatures by natural circulation flow with a large subcooled margin, the RV head region may remain relatively hot if insufficient time is allowed for ambient heat losses from the RV head areas.

Thus as the RCS is depressurized in preparation for entering shutdown cooling, a steam bubble may form by flashing primary coolant in the RV head dome. When natural circulation flow is maintained in both loops of the RCS, the indicated hot and cold leg temperatures should be representative of the temperatures in all the RCS loop components except possible for the RV upper head. The temperature in the RV upper head region should be monitored if available. Thus no condensable steam void should form anywhere in the RCS other than possible in the RV head region if the RCS subcooled margin is being properly maintained and the RCS dissolved gas concentration is not abnormally high. Another potential source of voiding is the hot stagnant fluid which may exist on the primary side of an isolated steam generator.

If a bubble does form in the RV dome during depressurization it is most likely due to a steam void. If a Reactor Vessel Level Monitor is available, the operator has a direct means of monitoring water level in the RV dome region and the RCS cooldown may continue as long as the void is maintained above the hot leg nozzle. The operator may drain and fill the RV upper head several times for RV head cooling by controlling system pressure if the RCS needs to be quickly depressurized in order to enter shutdown cooling operation. However, if no reactor vessel level monitor is available, the operator must monitor a RV head void by indirect methods.

Pressurizer level change can be used to monitor the growth or collapse of the RV void. Letdown is isolated, charging and spray is stopped (except if some charging flow is needed for reactor coolant pump seal injection), and the RCS cooldown halted to stop any major variations in pressurizer level. Pressurizer level may still be decreasing due to any RCS leakage. However, with all major pressurizer level variations stopped, any change in the RV head void size will now result in essentially a similar size change in the opposite direction in the pressurizer level. A decision must now be made as to

whether the plant cooldown process should be interrupted to allow time for ambient cooling of the RV head or if plant conditions require a prompt depressurization in order to enter shutdown cooling. The first alternative involves waiting several hours while maintaining pressurizer level. Whenever a RV head void is present, normal charging flow is expected to decrease or to produce minor changes to pressurizer level due to the RV void shrink and collapse.

Normal increasing pressurizer level (approximately 1/2 to 1 percent increase per minute without letdown) will occur when the RV head void has been eliminated. Auxiliary spray flow is expected to increase pressurizer level rapidly whenever a RV head void is present due to the RV void expansion from decreasing pressurizer pressure. A normal slow pressurizer level increase (approximately 1/2% increase per minute without letdown) will occur when the RV head void has been eliminated.

The second alternative involves draining and filling the RV upper head several times by raising and lowering system pressure causing the bubble to expand and to shrink. As cool water is forced into the region, the upper head is cooled. A large drain and fill volume of water flushed through the RV upper head region will result in more cooling per complete drain and fill cycle than a small flush volume. The pressurizer should not be taken solid or drained below 10% indicated level to avoid losing pressure control with a saturated bubble in the pressurizer and to ensure that the void size can continue to be adequately monitored. Several drain and fill cycles will result in lower system pressure. System pressure should not be allowed to go below the minimum required pressure to maintain RCS subcooled margin. The number of drain and fill cycles can be slowed and the volume exchanged reduced in order to maintain RCS subcooled margin if pressurizer heaters are not adequate.

When the overall plant cooldown and depressurization is resumed after either alternative, plant indications should be monitored for further signs of voiding when depressurizing. If found subsequently, the same procedure is used. A reactor coolant pump should not be started or jogged while a condensable void is known to be present in the RV head region. Sudden forced flow of cool reactor coolant into this region may result in a very quick collapse of the condensable void with resultant water hammer effects. Avoiding RCP operation with a bubble in the RV head will preclude this concern.

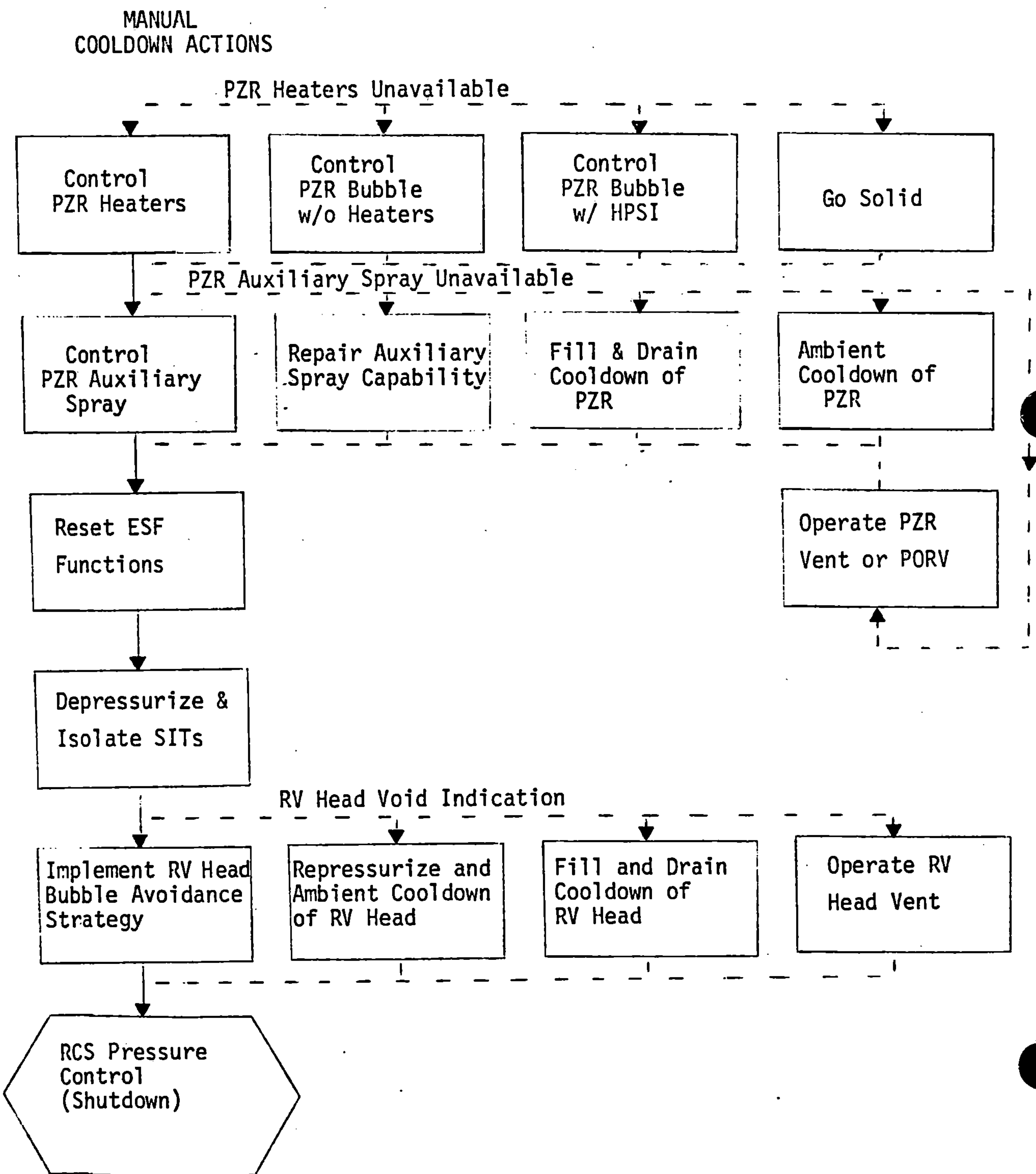
8. If a void persists despite efforts to cool and to condense it or if the RCS dissolved gas concentration is high, the void may be partially or completely comprised of noncondensable gases. Primary pressure should first be raised to eliminate any condensable gases that may be present. Then the plant specific procedure for operating the RV head vent should be followed to purge the noncondensable gases. It should be noted that continued operation of the RV head vent may depressurize the RCS and create a condensable void in the RV head. The RV head vent (plant specific) may be used to transfer a void to the pressurizer.

The RCS pressure control safety functions are summarized in Figure 5-4. The solid line path shows the preferred methods to accomplish adequate pressure control until cold shutdown is attained. Alternative methods and processes are shown as dotted line paths. The priority of the suggested alternatives decrease as the dotted lines proceed to the right.

FIGURE 5-4

RCS PRESSURE CONTROL

SAFETY FUNCTIONS



5.3.5 RCS Heat Removal

Actions:

1. Maintain normal steam generator water level throughout the plant cooldown. Initiate the auxiliary feedwater system if the main feedwater system is not able to operate adequately.

2. Survey all available condensate inventory and replacement capability. Ensure that initiation of plant cooldown is commenced within sufficient time such that adequate condensate will be available to cool down and depressurize the NSSS to within shutdown cooling system entrance conditions.* If available condensate appears to be marginally adequate, immediately initiate plant cooldown.

3. Maintain RCS temperature by operating the turbine bypass valves (or atmospheric dump valves) until ready to begin the RCS cooldown. Maintain the RCS hot leg subcooled margin of at least 20°F +(inaccuracies*).

4. Commence the RCS cooldown by manually controlling the turbine bypass valves (or atmospheric dump valves) flow rate to establish the maximum possible cooldown rate in accordance with Technical Specification requirements. Continue the RCS cooldown to as low a temperature as can be obtained by dumping secondary steam.

5. If a steam generator must be isolated continuously as a heat sink to the RCS during the cooldown, the following criteria should be used throughout the natural circulation plant cooldown:

   A. When a steam generator is initially isolated, ensure that the hot leg temperature is below the saturation temperature/ pressure that corresponds to the lowest secondary safety valve set pressure to prevent the secondary safety valves from opening on the isolated steam generator.

* Plant Specific

B. Cooldown an isolated steam generator by one or more of the following methods (listed in order of decreasing preference) while maintaining normal natural circulation core cooling with the unisolated steam generator and its loop:

(1) If possible, restart one RCP in each loop to establish cooling of the isolated steam generator. If not available, consider maintaining present condition until RCPs are available.

(2) Cool the intact steam generator below the isolated steam generator's temperature by dumping secondary steam. Subsequently cool the isolated steam generator by draining part of the isolated steam generator secondary water volume to a storage tank and refilling the isolated steam generator with cold feedwater. Regulate the feedwater refill rate so as not to cause an excessive RCS cooldown rate in the isolated loop components.

(3) Allow the isolated steam generator and its loop to cool due to ambient heat loss through its insulation.

(4) If needed, cool the isolated steam generator by reinitiating steam and feed flow as a last resort.

6. Implement Low Temperature Overpressure Protection (LTOP) features* as required due to the decreasing primary temperatures.

7. Monitor available condensate inventory and replenish from alternate sources as required throughout the cooldown.

8. Continuously verify that natural circulation flow is established in the RCS by observing the following indications.

A. Loop ΔT (T_h - T_c) less than normal full power ΔT (with both steam generators operating).

B. Cold leg temperatures constant or decreasing.

C. Cold leg temperatures approximately equal to steam generator secondary temperature.

D. Hot leg temperature constant or decreasing.

E. Hot leg temperatures decrease as steam generator secondary temperature and pressure is decreased.

F. No abnormal differences between T_h RTDs and core exit thermocouples.

9. If the RCS hot leg subcooled margin approaches or becomes less than 20°F +(inaccuracies*) and/or natural circulation degradation is suspected, try to enhance natural circulation flow by:

   A. Increasing turbine bypass or atmospheric steam dump flow to reduce RCS temperatures.

   B. Increasing RCS pressure with pressurizer heaters or by operating safety injection or charging pumps.

   C. Verifying adequate secondary water level.

   D. Verifying adequate primary water inventory without any voids.

   E. Verifying adequate subcooled margin.

10. One reactor coolant pump in each loop should be restarted whenever:

   A. At least one steam generator is removing heat from the RCS.

   B. Pressurizer level and pressure are responding normally to the pressurizer level and pressure control systems.

   C. Proper RCS pressure-temperature conditions are established.

   D. RCP support system services have been restored.

   E. There is no condensible RCS void indications.

   F. Other plant specific requirements.

11. Place the shutdown cooling system into operation when the pressurizer pressure and hot leg temperature have decreased below the maximum allowed entrance conditions*. Continue the plant cooldown using the shutdown cooling system and its procedures*. Stop all secondary steam flow only after the shutdown cooling system is verified to be operating satisfactorily.

* Plant Specific

Precautions:

1. When cooling down by natural circulation with an isolated steam generator:

   A. Shutdown cooling can not be initiated until the isolated steam generator secondary temperature is reduced below the saturation pressure corresponding to the maximum allowed shutdown cooling entry pressure.
   B. An inverted ΔT (i.e. T_c higher then T_h) may be observed in the idle loop and will not affect the natural circulation flow in the intact steam generator.
   C. Automatic auxiliary feedwater actuation* to the operating steam generator may become unavailable if 100 psi differential pressure develops between the operating steam generator and the hot isolated steam generator.
   D. Do not depressurize the RCS to the saturation condition associated with the isolated steam generator primary fluid temperature.

2. Do not start any RCP while a condensable void is established in the RV head dome.

3. Verification of plant responses to a plant change cannot be accomplished until approximately 5 to 10 minutes following the action due to increased loop cycle times.

4. Do not completely isolate or otherwise intentionally yield both steam generators unavailable as a heat sink to the RCS until after the shutdown cooling system is fully aligned and shown to be operating normally.

5. All available indications should be used to aid in diagnosing the event since the event may cause irregularities in a particular instrument indication. Critical parameters must be verified when one or more confirmatory indications are available.

* Plant Specific

Important Concepts: (Paragraphs are numbered with their corresponding Action Section paragraph number).

1. The operator must ensure that the secondary water inventory is being maintained by feedwater flow to the steam generator(s). Natural circulation is assured even if the U-tubes are partially uncovered on the steam generator secondary side. The steam generator heat transfer area is sized for full power operation. Therefore only a portion of the tubes (approximately 1/3 of the tube height which corresponds to approximately 35-40% on the wide range steam generator level instrument) must remain covered to ensure normal NC flow. The top of the U-tubes is at approximately 24-30% indicated level on the narrow range steam generator level instrument. Increasing the steam generator water level above the minimum required level will have a minimal impact on the NC flow rate. However, by increasing the secondary water inventory, the operator provides an extra margin above the limit required to establish and maintain normal NC flow. The target that an operator should eventually strive to reach is the normal steam generator water level throughout the plant cooldown. Feedwater flow throughout the cooldown should be throttled to maintain continuous feedwater addition to minimize thermal shock to the feedwater nozzle.

   If adequate RCS cooling is not being achieved due to insufficient secondary water, cold leg temperature (T_c) increase will be the first indication, causing an abnormal and misleading decrease in Loop ΔT. This will persist for some time due to the slow loop transport times. Eventually hot leg temperature (T_h) will also increase. During natural circulation with an adequate secondary water inventory, T_c and secondary temperature are approximately equal. T_c increasing (followed later by hot leg temperature (T_h) increasing) without a corresponding change in steam generator secondary pressure/temperature signals a lack of sufficient secondary water.

All steam generator level indications are based on normal ambient reference leg water temperature. If the ambient containment temperature is raised beyond nominal conditions, reference leg heating will occur and level indication decalibration will result. Reference leg heating produces an erroneously higher than actual level indication. The steam generator level indication as shown by the level instrumentation should be lowered by the following amount to account for the effect of reference leg heating.

Reference Leg Temperature (°F)	Correction To Indicated Level (% of Span)
120°	0
200°	4
250°	7
300°	10
350°	14
400°	18
450°	23

Level Calibration Pressure 900 psia (hot zero power)
Ref. Leg Calibration Temperature 120°F
No Reference Leg Flashing

2. The required secondary condensate volume and methods of condensate replenishment are plant specific. The operator must initially evaluate the availability of the condensate and condensate supply systems and determine the total time available before shutdown cooling system must be initiated. If the condensate appears to be marginally adequate, the plant cooldown should be immediately started in order to avoid running out of existing condensate before the shutdown cooling system can be place into operation. Otherwise the cooldown is not required to be initiated before completion of cold shutdown boration.

Although the amount of condensate needed to complete a plant cooldown down to shutdown cooling initiation is plant specific, an approximation can be used to estimate the magnitude of condensate required in order to provide the operator with a method of determining if condensate supplies are low or marginal. The method of estimating condensate required to reach shutdown cooling follows:

250 gallons per 1°F cooldown needed and
4.5 gal/hr-MWt (1-8 hrs after trip) for decay heat removal
3.0 gal/hr-MWt (8-24 hrs after trip) for decay heat removal
2.5 gal/hr-MWt (>24 hrs after trip) for decay heat removal

3. RCS temperature should be controlled such that the hot leg subcooled margin is maintained while waiting to start a plant cooldown. Subcooled margin can be increased by increasing pressurizer pressure or reducing the RCS temperature.

4. After the preparatory actions are completed, the RCS cooldown can be initiated and controlled by regulating the steam flow through the turbine bypass valves or atmospheric dump valves. A rapid cooldown is recommended to enhance the conductive cooling capability of the RV upper head region. A large temperature difference between the RV head and the RCS coolant will provide a large thermal gradient and a greater heat transfer rate. The RCS should be cooled down as far as possible with the steam generators to provide the largest thermal gradient possible. There is no need to stop the RCS cooldown once the shutdown cooling initiation temperature is reached since shutdown cooling can not be initiated until the system pressure is also reduced. A lower RCS temperature will enhance RV dome cooling.

   The operator should maintain the maximum possible RCS cooldown rate without exceeding the Tech. Spec. limit. The Tech. Spec. operating pressure/temperature curve is based on the cold leg temperature and not on the hot leg temperature during natural circulation flow conditions.

The operator should be aware of other processes which could affect the RCS cooldown rate other than the secondary steam flow. These processes include the flow of the feedwater system and the charging and letdown systems flow rates.

5. An event such as a steam generator tube rupture may require that one steam generator be isolated continuously from the RCS as a heat sink (i.e. all feedwater and steam flow in and out of that steam generator stopped). During normal forced flow conditions in the RCS when one steam generator must be isolated as a heat sink, sufficient reverse heat transfer occurs to maintain the isolated steam generator at the same relative temperature as the operating RCS loop during a plant cooldown. However with no RCPs operating, conditions can be easily generated which will stop natural circulation flow through the isolated steam generator and RCS loop, leaving those components in a hot stagnant condition.

   This condition by itself will not necessarily affect core cooling via natural circulation in the unisolated steam generator and RCS loop. As long as reactivity control, RCS pressure control, RCS inventory control, and RCS heat removal are properly maintained in the operating loop, sufficient NC flow will be maintained through the core and operating loop.

   A steam generator will not immediately lose either natural circulation flow or cooling capacity when isolated by stopping steam and feed flow. Hot leg coolant will continue to transfer heat into the isolated steam generator causing that steam generator's secondary temperature and pressure to increase. As the isolated steam generator's temperature rises toward the hot leg temperature, the isolated steam generator accepts heat from the hot leg coolant at a smaller and smaller rate. The steam flow from the unisolated steam generator must now be slowly increased to pick up the share of the decay heat removal not being removed by the isolated

steam generator. Because more heat removal is slowly being transferred to the operating steam generator, the hot-to-cold leg ΔT in the operating loop increases while the hot-to-cold leg ΔT in the isolated loop decreases. NC flow can still be maintained through the isolated RCS loop in the forward direction even at the point when no heat transfer occurs in the isolated steam generator. Since an isolated steam generator will heat up to the hot leg temperature, the hot leg temperature should be maintained below the saturation temperature/pressure corresponding to the secondary safety valve setpressure by dumping sufficient steam from the operating steam generator to avoid opening the secondary safety valves. Automatic dump valve actuation logic on the isolated steam generator should also be bypassed to ensure no inadvertent steam discharge occurs.

When a plant cooldown is commenced using the operating steam generator, the hot leg temperature will drop below the isolated steam generator secondary temperature. The amount of reverse heat transfer cooling in an isolated steam generator depends upon both the magnitude of the secondary side temperature difference between the isolated and unisolated steam generators, and the amount of forward NC flow occurring through the isolated RCS loop. The larger the temperature differential between the two steam generators, the better potential there is for heat transfer. However, as this same steam generator temperature differential increases, the more the NC flowrate will decrease through the isolated steam generator. A large enough secondary side temperature differential (which will vary based on the existing decay heat) will effectively stop all NC flow in the isolated steam generator, leaving it in a hot stagnant condition unable to be cooled by the operating RCS loop. A hot stagnant isolated steam generator presents a situation similiar to the RV dome region when trying to depressurize the RCS to initiate shutdown cooling. Depressurization of the RCS to the isolated steam generator's saturation temperature/pressure will quickly void large

portions of the isolated RCS loop which could lead to interruption of the natural circulation cooling established in the operating RCS loop. The isolated steam generator would act like a pressurizer and prevent further depressurization to the shutdown cooling initiation pressure. Thus an isolated steam generator must be cooled down before shutdown cooling can be aligned.

The preferred method to cool an isolated steam generator is to start a reactor coolant pump, if possible. A reactor coolant pump should be first started in the unisolated loop to minimize the effect of mixing coolant from the hot isolated steam generator. If a reactor coolant pump can not be started, it is preferable to maintain hot shutdown conditions until forced flow can be restored.

If a plant cooldown must be established, one process to cool an isolated steam generator is to drain (not completely dry) and refill the isolated steam generator secondary water volume. Control of the cooldown in the isolated loop should be regulated by the refill rate of the cool feedwater.

Some cooling can be obtained by the reverse heat transfer cooling (i.e. secondary to primary) process with natural circulation flow in the isolated steam generator. Slow controlled cooling of the plant and a large quantity of secondary condensate would be required for this process. Very close regulation of the plant cooldown rate is needed to maintain adequate NC flow and reverse heat transfer in the isolated loop. If the secondary side temperature difference between the two steam generators is not optimal, inadequate cooldown will occur in the isolated loop. This method may be considered too complex for an operator to implement with the existing instrumentation. See Section 2.2 of this report for more information on this process.

Normal ambient heat losses will cool the isolated steam generator but this will take the longest period of time and require the largest amount of secondary condensate. The ambient cooling rate of a steam generator is highly dependent upon the amount of secondary water contained in the steam generator. A large secondary water volume could extend cooldown times through ambient heat loss to beyond 36 hours.

A last alternative includes restoring steam and feedwater flow to cool the isolated steam generator. If a radiological release concern is present, steam should be dumped to the condenser rather than to the atmosphere.

Whenever charging flow is being injected into an isolated RCS cold leg, that cold leg temperature indication may drop due to the introduction of the cold charging water near the temperature sensor and possibly produce a misleading hot leg-to-cold leg ΔT. Normal RCS loop ΔT is a function of the RCS loop flow rate and heat transfer rate. The operator should monitor all hot and cold leg temperature indications in an isolated RCS loop for a true indication of RCS loop ΔT and NC flow conditions.

6. As the primary temperature is decreased, the Low Temperature Overpressure Protection (LTOP) requirements should be implemented. Although LTOP requirements are plant specific, the procedures involve aligning either low setpressure safety valves (e.g. shutdown cooling safety valves) or changing the PORV setpoint to a lower setpressure whenever the cold leg temperature decreases below the value when a sudden pressurization to the pressurizer safety valve setpoint would violate Technical Specification brittle fracture requirements. Note that RCS pressure must be sufficiently low (plant specific) before LTOP alignment can take place.

7. As the plant cooldown progresses, there is a continual need for condensate to be supplied to the feedwater pumps as long as the steam generators are being used for heat removal.

Thus the operator should ensure that adequate condensate is continuously available and that the conditions assessed as part of Action #2 continue to remain acceptable.

8. NC flow should continuously be verified to be adequate. Cold leg temperatures should be verified to be decreasing or constant dependent upon whether the RCS cooldown is continuing or being held up. Cold leg temperatures should also not increase significantly above steam generator secondary saturation temperature. Similarly hot leg temperatures should be stable or decreasing based on the RCS cooldown status. Hot leg temperature should trend downward throughout the plant cooldown as the secondary pressure and temperature is decreased. Another means available to the operator of verifying adequate NC flow is to verify that no abnormal differences exist between the hot leg RTDs and core exit thermocouples. These symptoms will be the most direct indication that NC flow is normal.

Some possible causes for degradation of NC flow:

	Cause	First probable symptom
A.	Not enough secondary water inventory	Low steam generator water level and T_c increasing above secondary temperature.
B.	Inadequate secondary steam flow	T_c and secondary pressure increasing.
C.	Noncondensable voids collecting in the RCS flowpath	Loop ΔT increasing
D.	Condensable voids collecting in the RCS flowpath	Loop ΔT increasing, abnormal pressurizer level control systems response

E.	Small break or large break LOCA	Primary pressure decreasing
F.	Inadequate primary inventory	Low pressurizer level and loop RTD/core exit thermocouple mismatch
G.	Physical blockage of the NC flowpath	Loop ΔT increasing and/or loop RTD/core exit thermcouple mismatch.

If NC flow has been lost or degraded, efforts should be concentrated towards regaining adequate RCS heat removal, RCS pressure control, RCS inventory control, and reactivity control in the RCS flowpath. Any plant response as a result of a change will be slow (5-10 minutes) as compared to normal forced flow system response time (6-12 seconds) since the coolant loop cycle time has significantly increased. A minimum of 10 minutes should be given to allow adequate time for the system to respond as a result of an operator-induced plant change to correct a NC flow condition.

9. Subcooled margin should be maintained whenever possible. However, if the subcooled margin becomes completely degraded and saturation condition becomes established in the hot legs, NC flow may still be established and maintained. In this event, re-establish subcooled conditions as soon as possible and continue to verify NC flow is being maintained by the indications in Action #8. If these parameters do not indicate that NC flow is lost, alternative emergency methods of core cooling should not be implemented solely because subcooled margin is lost.

10. Forced circulation is the preferred method of core cooling whenever possible. At least one steam generator must be removing heat from the RCS before starting a RCP. There would be no need for forced circulation and its resultant heat input to the RCS if secondary steaming was not being used as a means of RCS heat removal. Pressurizer level and pressure must be responding normally. This implies that no significant LOCA has occurred and pressurizer level and

pressure respond normally to operator induced actions with the pressurizer level and pressure control systems. A large break LOCA, for example, would not produce a normal pressurizer level or a normal level response as a result of charging and letdown charges. Similiarly normal pressurizer level and pressure response implies no condensable voids are present in the RV head dome. RCP operation is precluded when a condensable void is present in the RV head dome to avoid a potential water hammer and its potential effects on the upper RV head region. Other RCP start criteria (plant specific) such as pressure/temperature criteria for NPSH and support system services such as RCP oil lift flow should be verified before restarting a RCP. RCP operation may intentionally not be used if their operation is suspected to possible lead to other serious plant consequences (such as the need to inspect RCP seals before further operation). This last concern for RCP operation may need to be waived if serious conditions within the NSSS warrant otherwise.

11. The final step is to place the shutdown cooling system into operation. Once this system is verified to be operating adequately, only then should the steam generator cooling capability be disabled (e.g. putting the steam generators into wet layup, opening the primary pressure boundary, etc.).

    Shutdown cooling system maximum heat removal capability is plant specific. However a typical C-E shutdown cooling system when placed into operation near its maximum allowed RCS initiation temperature should be able to remove approximately 1.5 to 2% of full rated power (dependent upon the cooling water temperature supplied to the shutdown cooling heat exhanger). Thus the shutdown cooling system could remove the decay heat anytime beyond approximately one hour after a reactor trip from full power operation and be able to remove the complete decay heat load. For all plant cooldown events, shutdown cooling will be initiated well beyond one hour after a reactor trip with its resultant lower decay heat level.

Entering shutdown cooling need not be a required stop in the plant cooldown process. If adequate condensate is available and other operating criteria can be met, continuing to remove decay heat with the steam generators can be an acceptable alternative to using the shutdown cooling system for removing reactor decay heat. This would be the preferred path if significant radioactivity were present in the RCS fluid.

The RCS heat removal safety functions are summarized in Figures 5-5 and 5-6. The solid line path shows the preferred methods to accomplish RCS heat removal until cold shutdown is attained. Alternative methods and processes are shown as dotted line paths. The priority of the suggested alternatives decrease as the dotted lines proceed to the right.

FIGURE 5-5

RCS HEAT REMOVAL
SAFETY FUNCTIONS

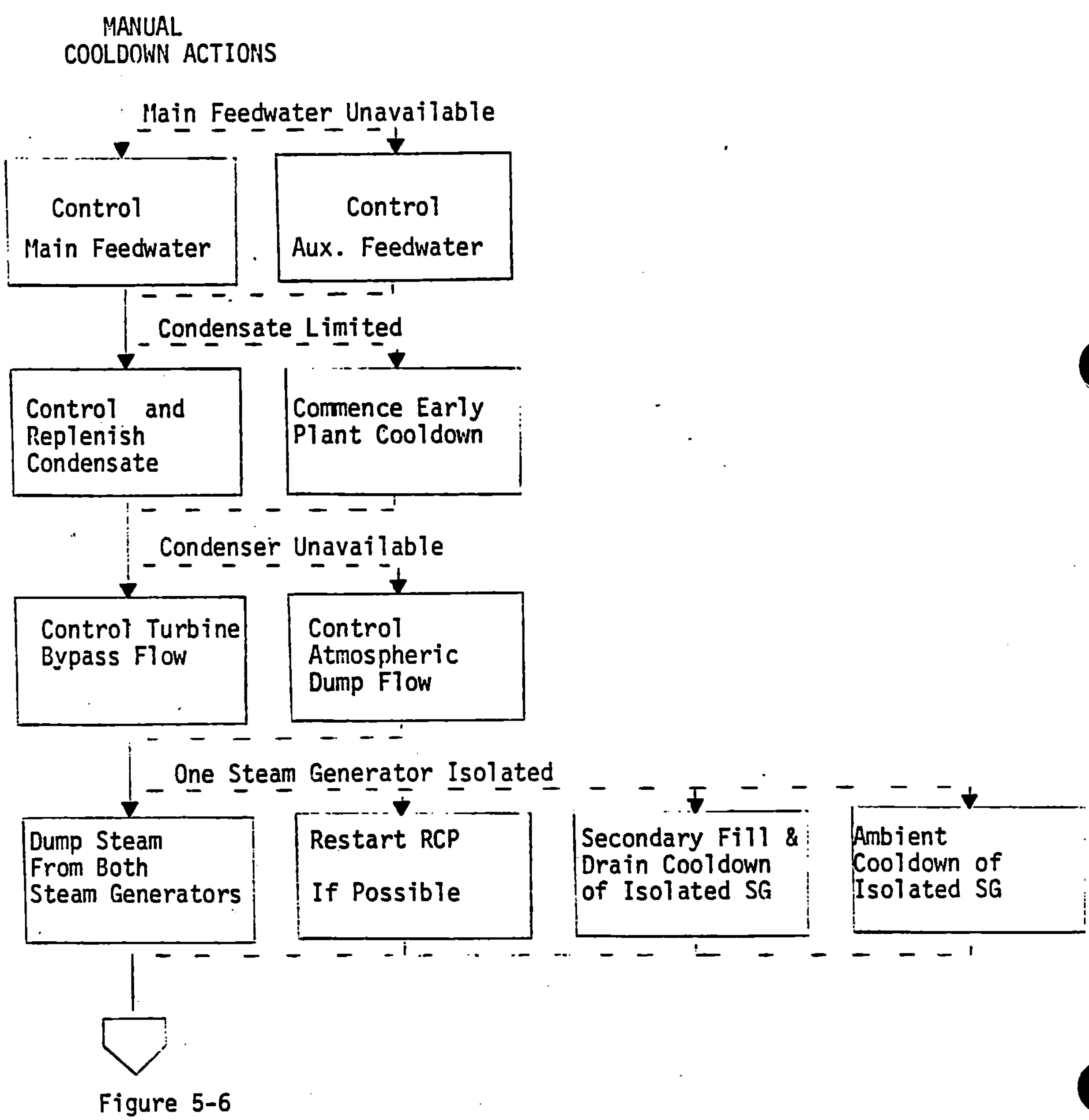
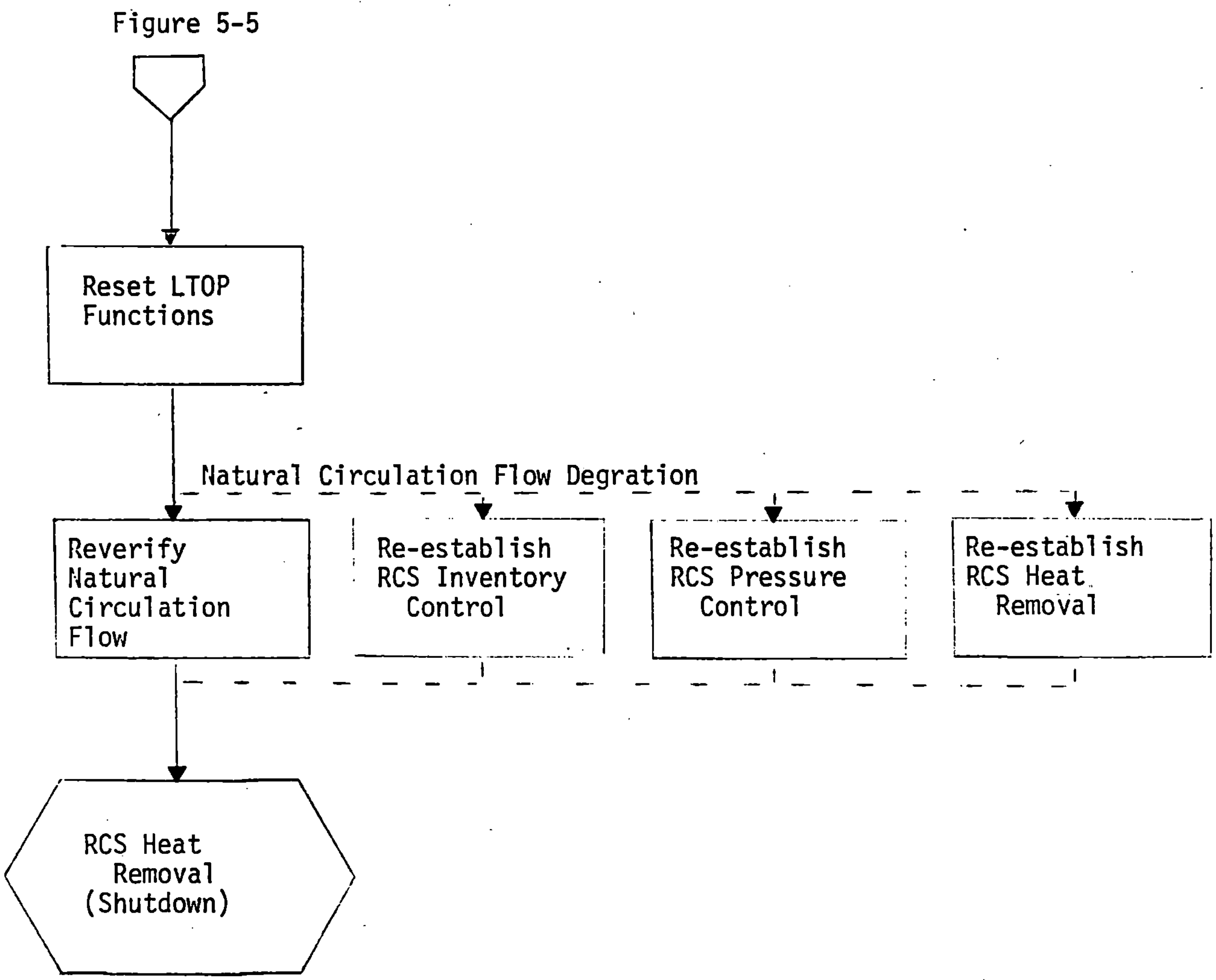


FIGURE 5-6

RCS HEAT REMOVAL
SAFETY FUNCTIONS



APPENDIX A

ASYMMETRIC NATURAL CIRCULATION COOLDOWN LTC ANALYSIS

APPENDIX A

List of Figures

Appendix A - List of Figures (Cont'd)

Appendix A - List of Figures (Cont'd)

Appendix A - List of Figures (Cont'd)

CASE 1

75°F/hr Cooldown of Unisolated Steam Generator
Until Steam Flow Limited

t, sec	$T_{SG\ 1}$, °F	$T_{SG\ 2}$, °F	q_2, Btu/sec
900	525	525	27400
1000	521	529	17900
1500	507	543	7082
2000	492	544	3616
2500	484	544	770
3000	473	542	-804
3500	468	540	-1245
4000	455	539	-165
4500	445	539	25
5000	433	539	4
6000	412	539	5
9800	351	538	-7
12000	341	538	0

Cooling of the hot unit (#2) occurred only at or near the optimum conditions predicted in the steady state analysis. The following figures are LTC transient parameter plots for Case 1.

FIGURE A-1

SL1 - INT. S.G. COOLDOWN, NAT CIR, NO RCP

PZR NARROW RANGE PRESSURE

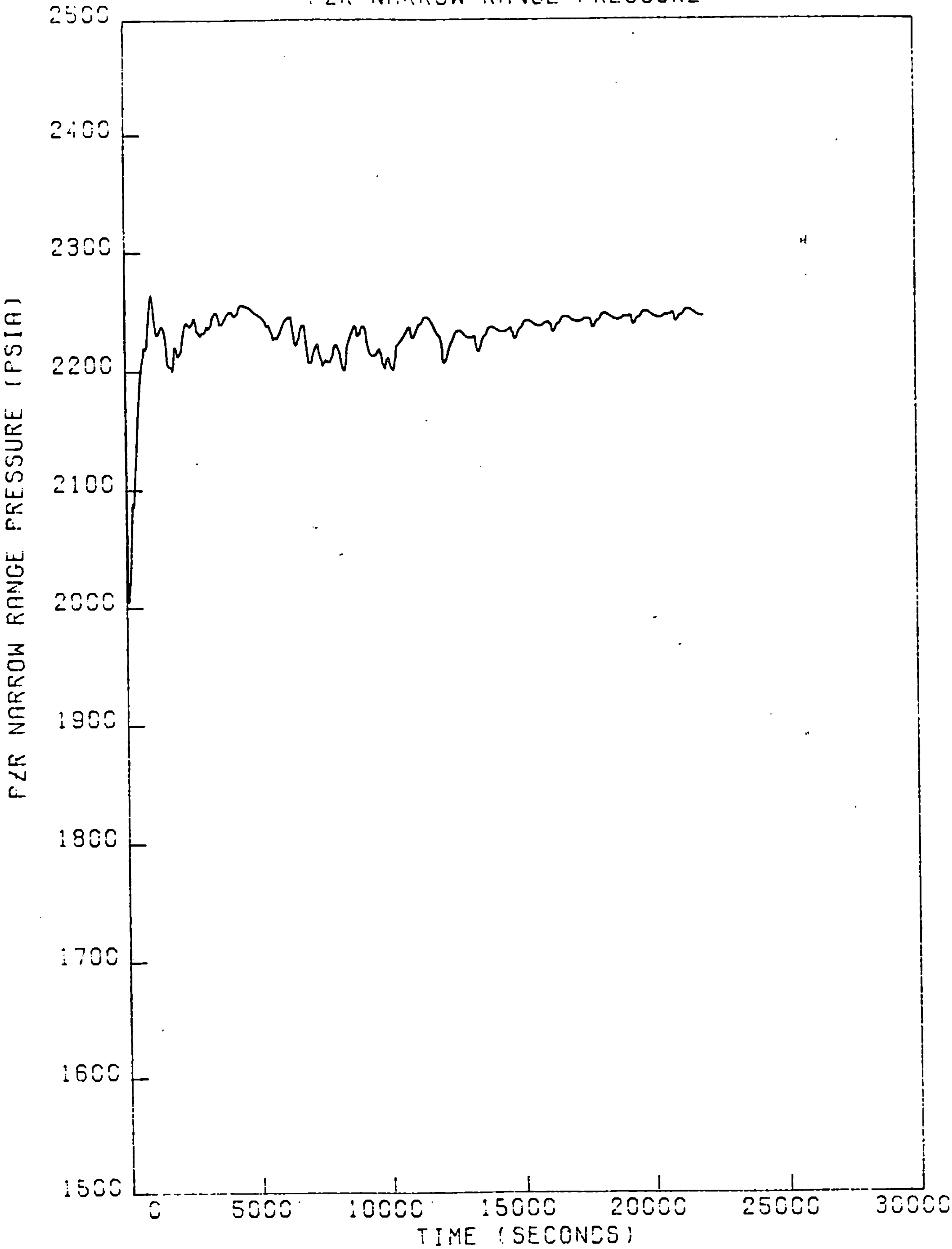


FIGURE A-2

SL1 - INT. S.G. COOLDOWN, NAT CIR, NO RCP
PZR NARROW RANGE TEMPERATURE

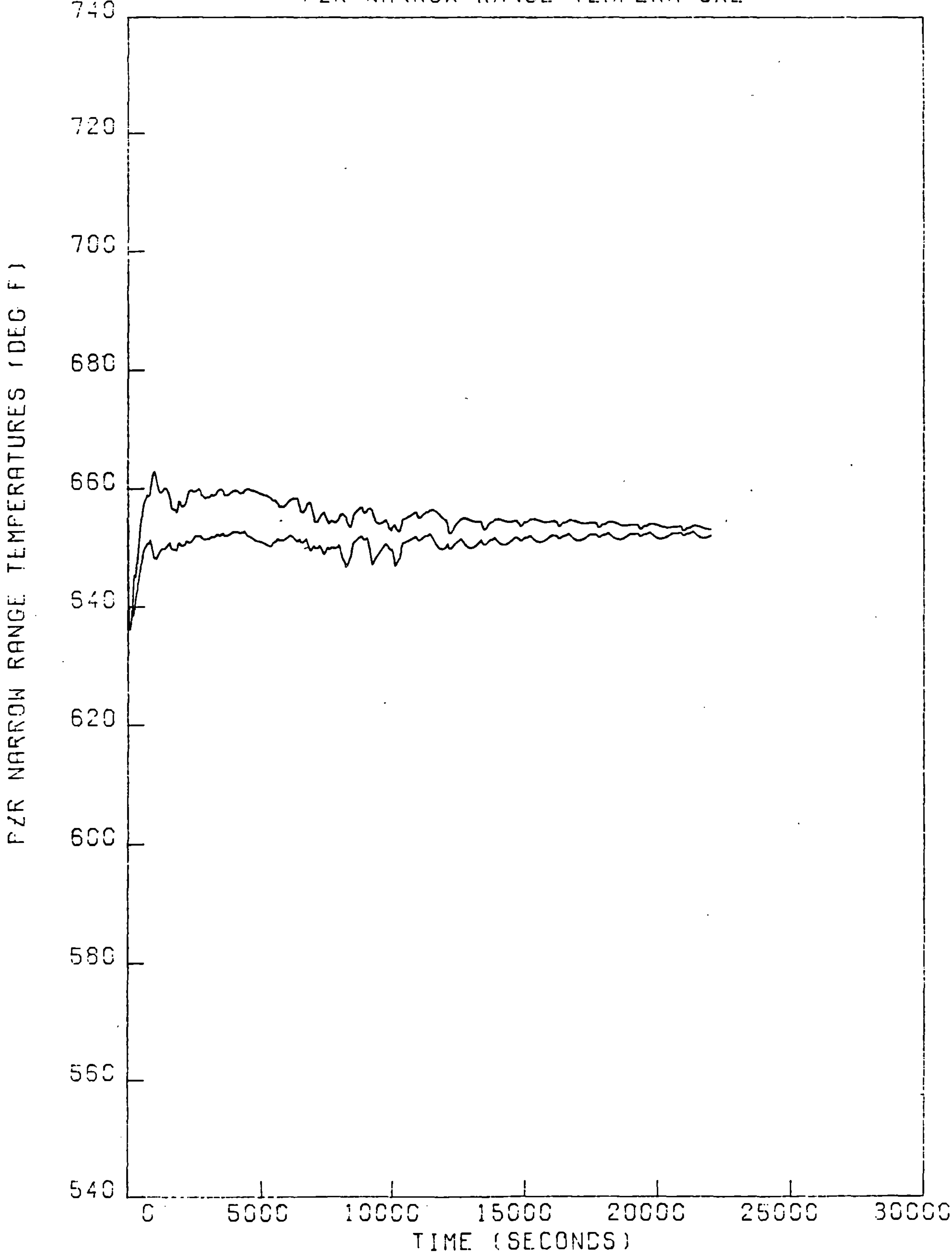


FIGURE A-3

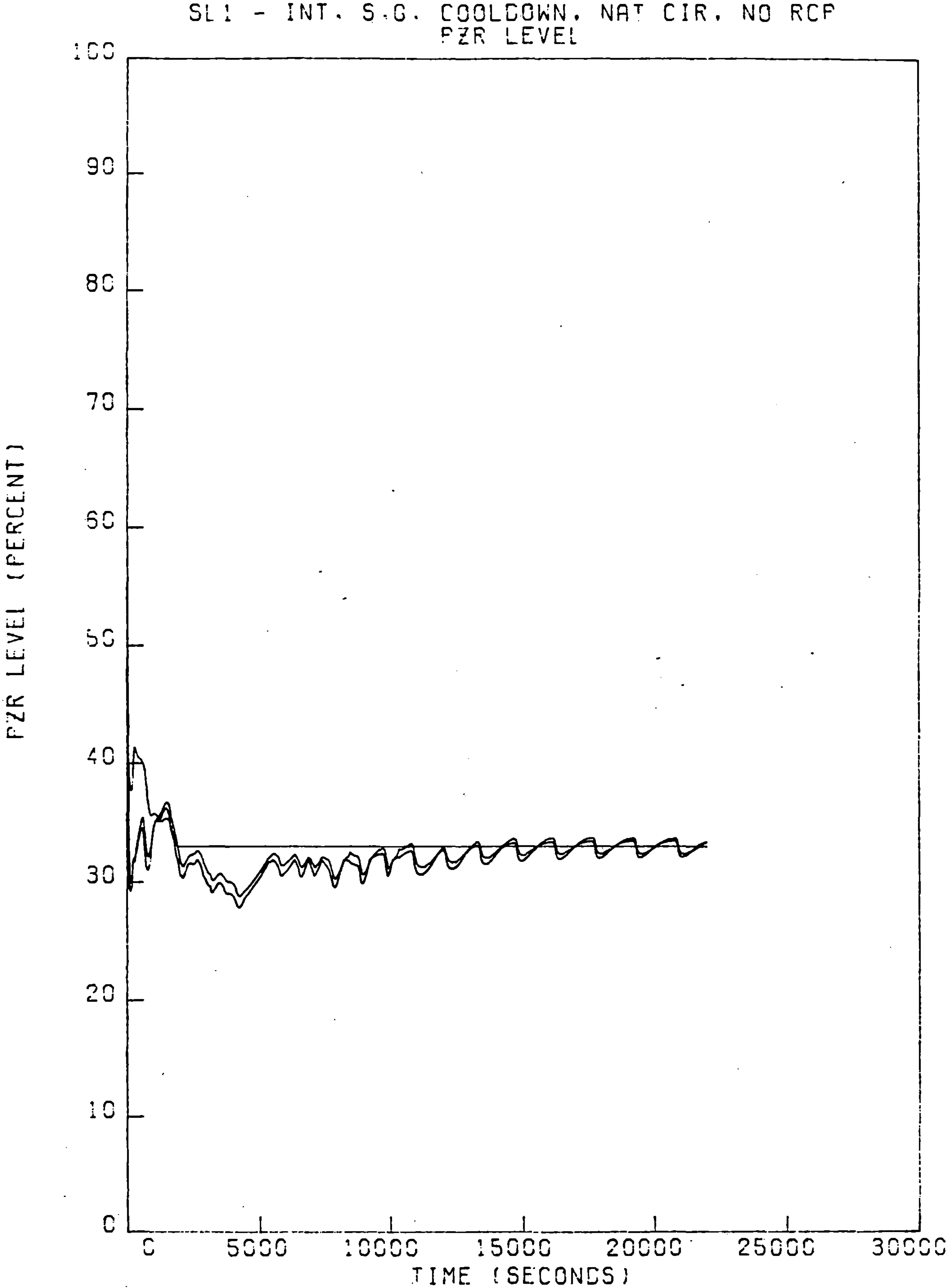

SL1 - INT. S.G. COOLDOWN, NAT CIR, NO RCP
PZR LEVEL
100
90
80
70
60
50
40
30
20
10
0
PZR LEVEL (PERCENT)
0
5000
10000
15000
20000
25000
30000
TIME (SECONDS)

FIGURE A-4

SL1 - INT. S.G. COOLDOWN, NAT CIR, NO RCP

PZR HEATER RATE

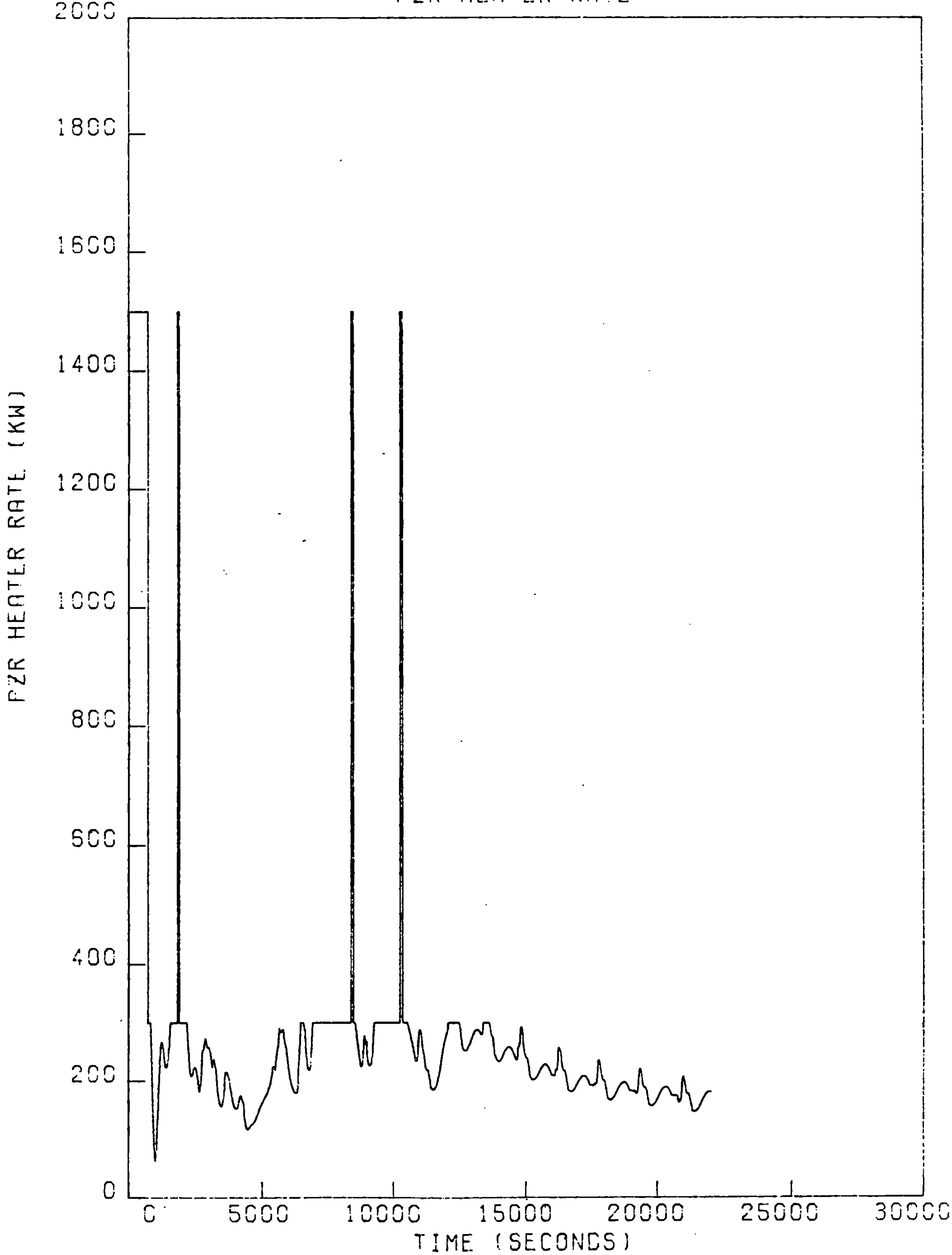


FIGURE A-5

SL1 - INT. S.G. COOLDOWN, NAT CIR, NO RCP
CHARGING - LETDOWN FLOWS

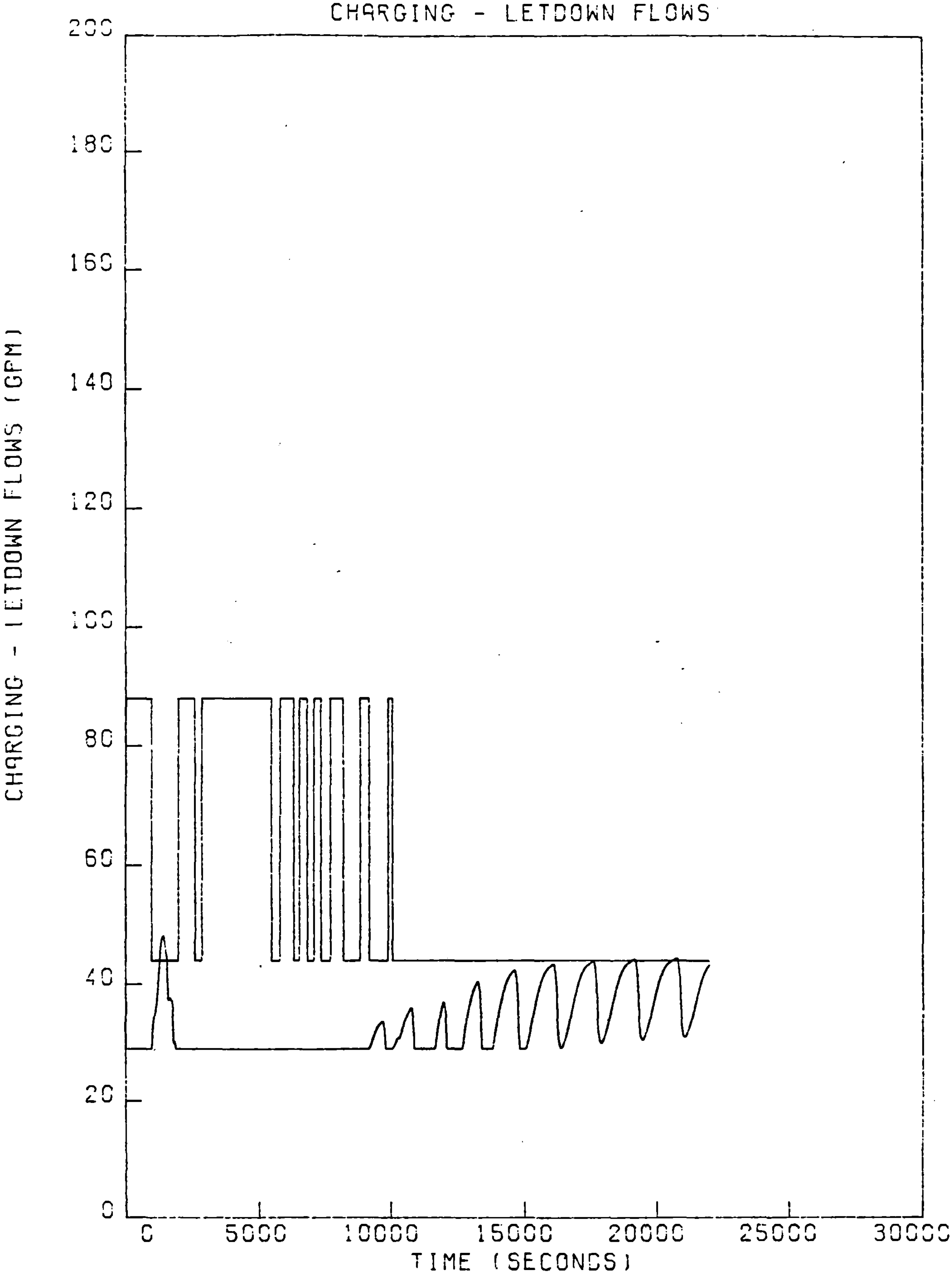


FIGURE A-6

SL1 - INT. S.G. COOLDOWN, NAT CIR, NO RCP

VCT LEVEL

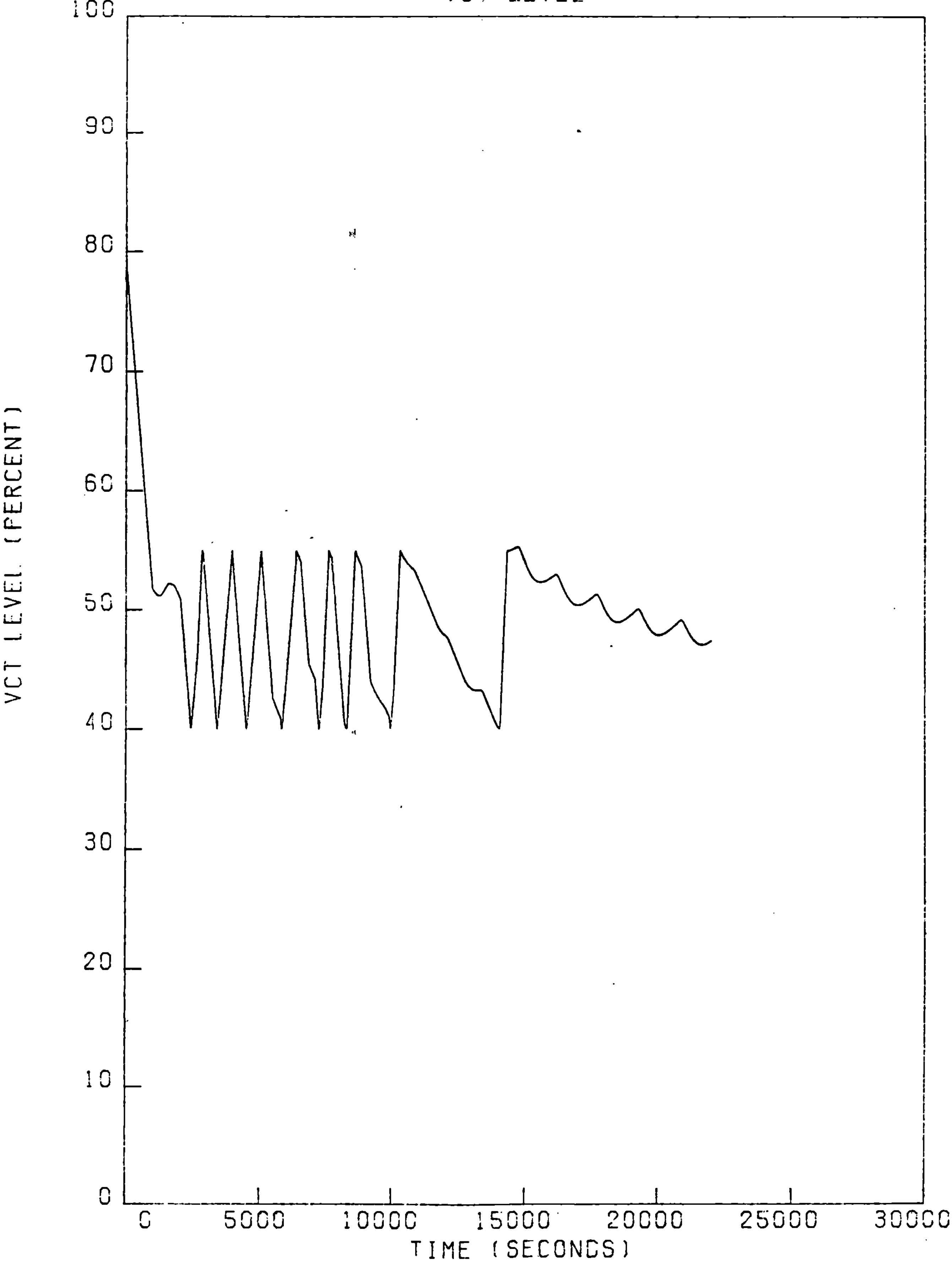


FIGURE A-7
SL1 - INT. S.G. COOLDOWN, NAT CIR, NO RCP
LOOP A RCS MASS FLOWS

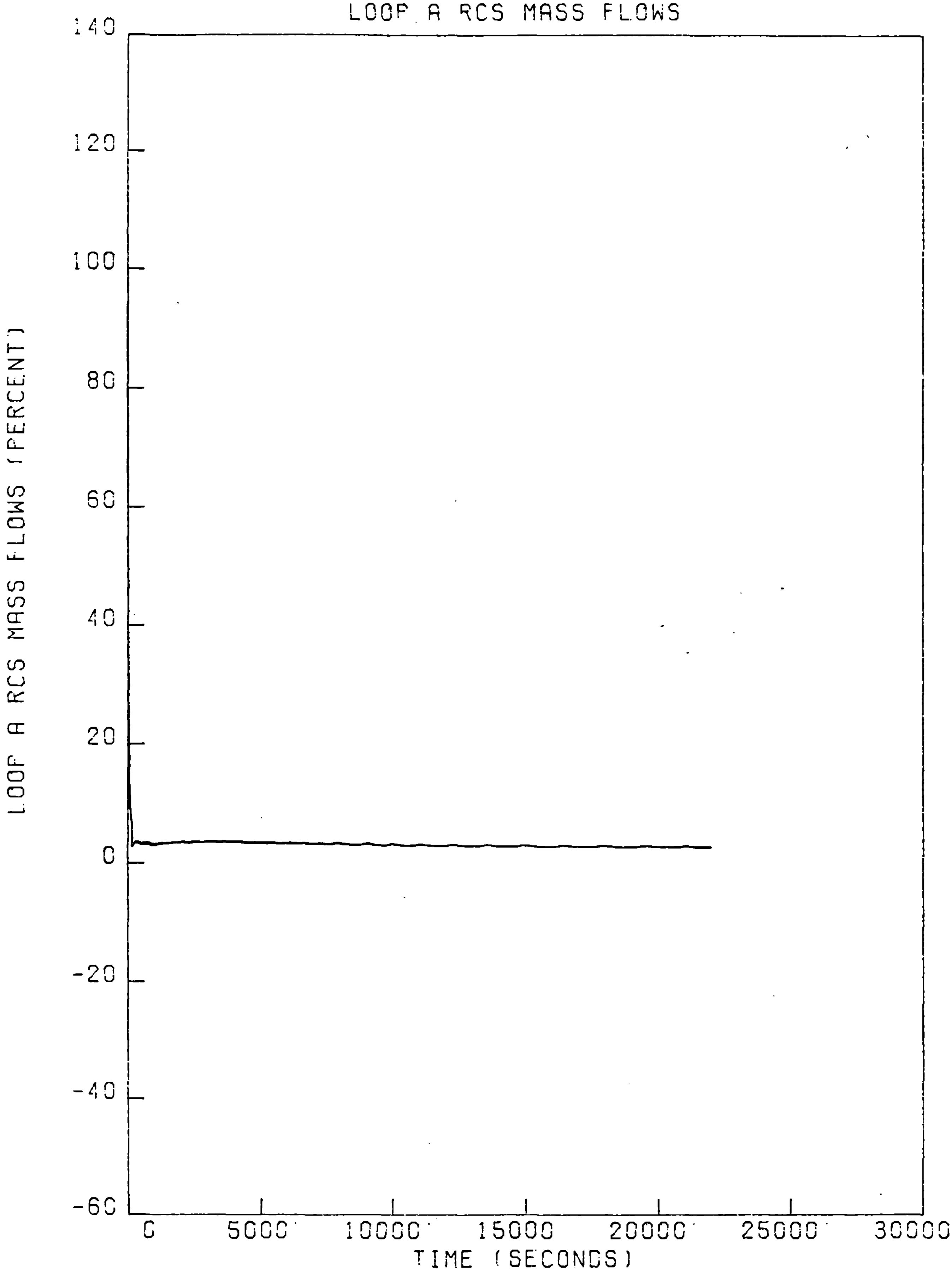


FIGURE A-8

SL1 - INT. S.G. COOLDOWN, NAT CIR, NO RCP
LOOP B RCS MASS FLOWS

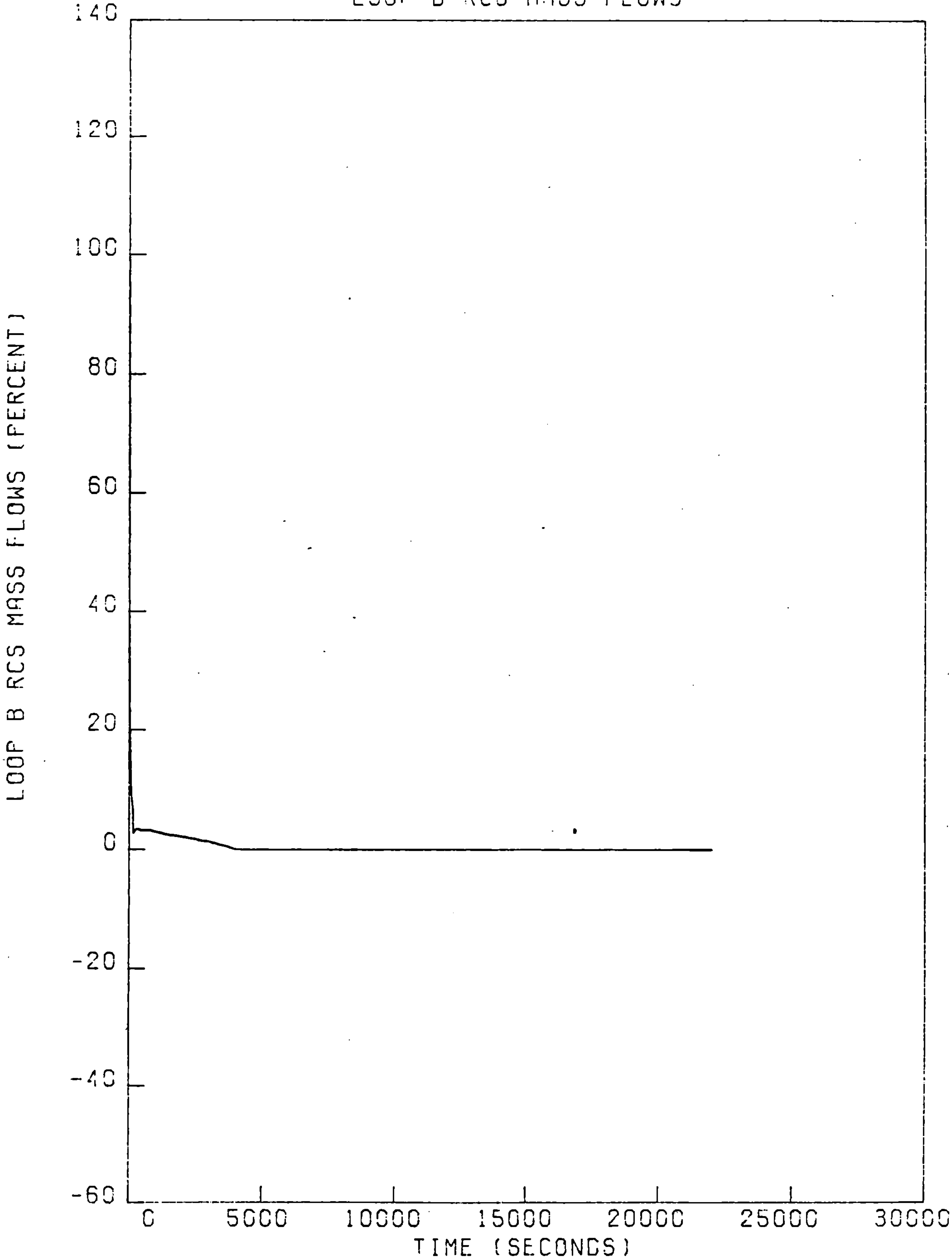


FIGURE A-9

SL1 - INT. S.G. COOLDOWN, NAT CIR, NO RCP
LOOP A RCS NARROW RANGE TEMPERATURES

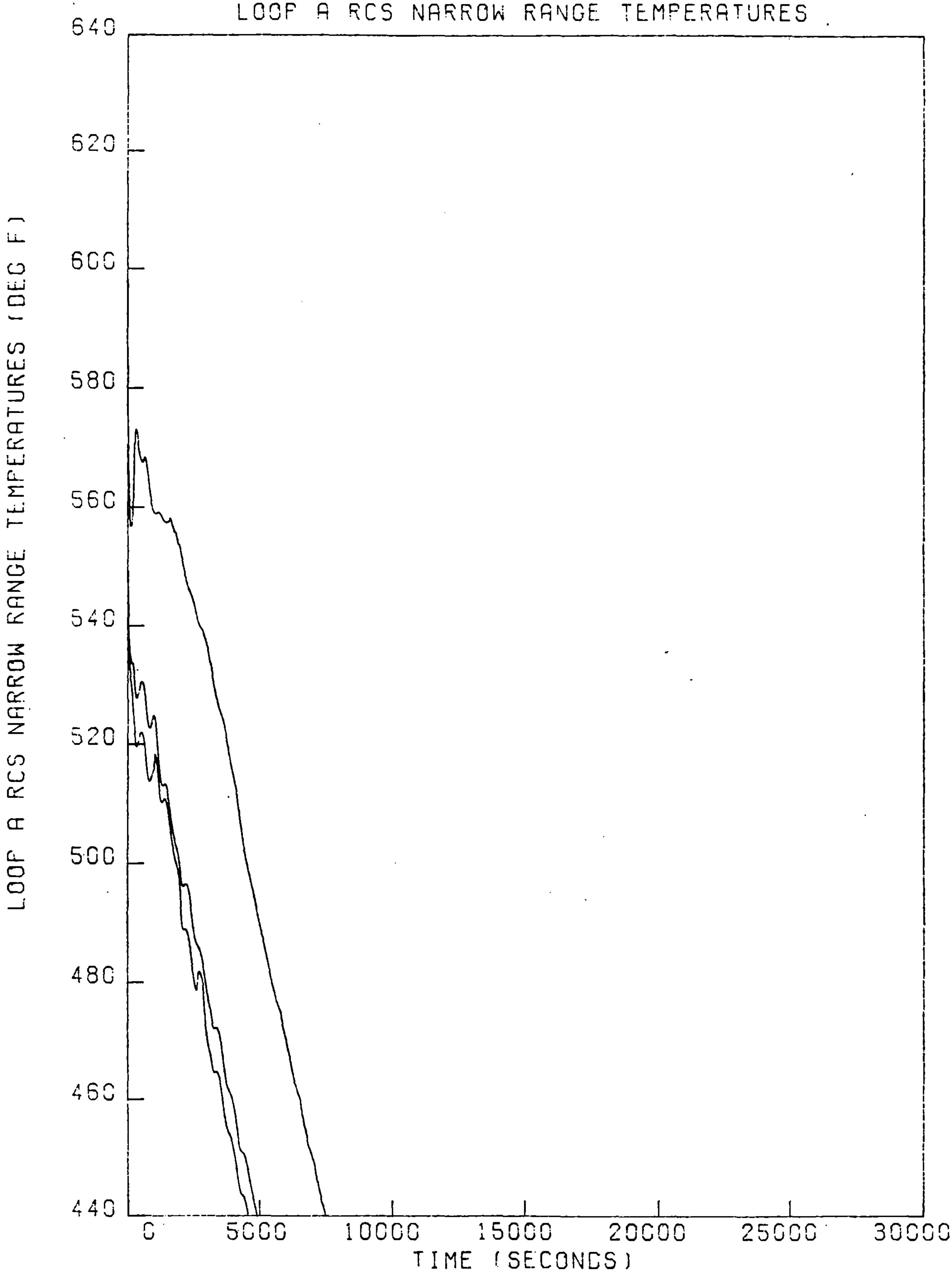


FIGURE A-10

SL1 - INT. S.G. COOLDOWN, NAT CIR, NO RCP
LOOP B RCS NARROW RANGE TEMPERATURES

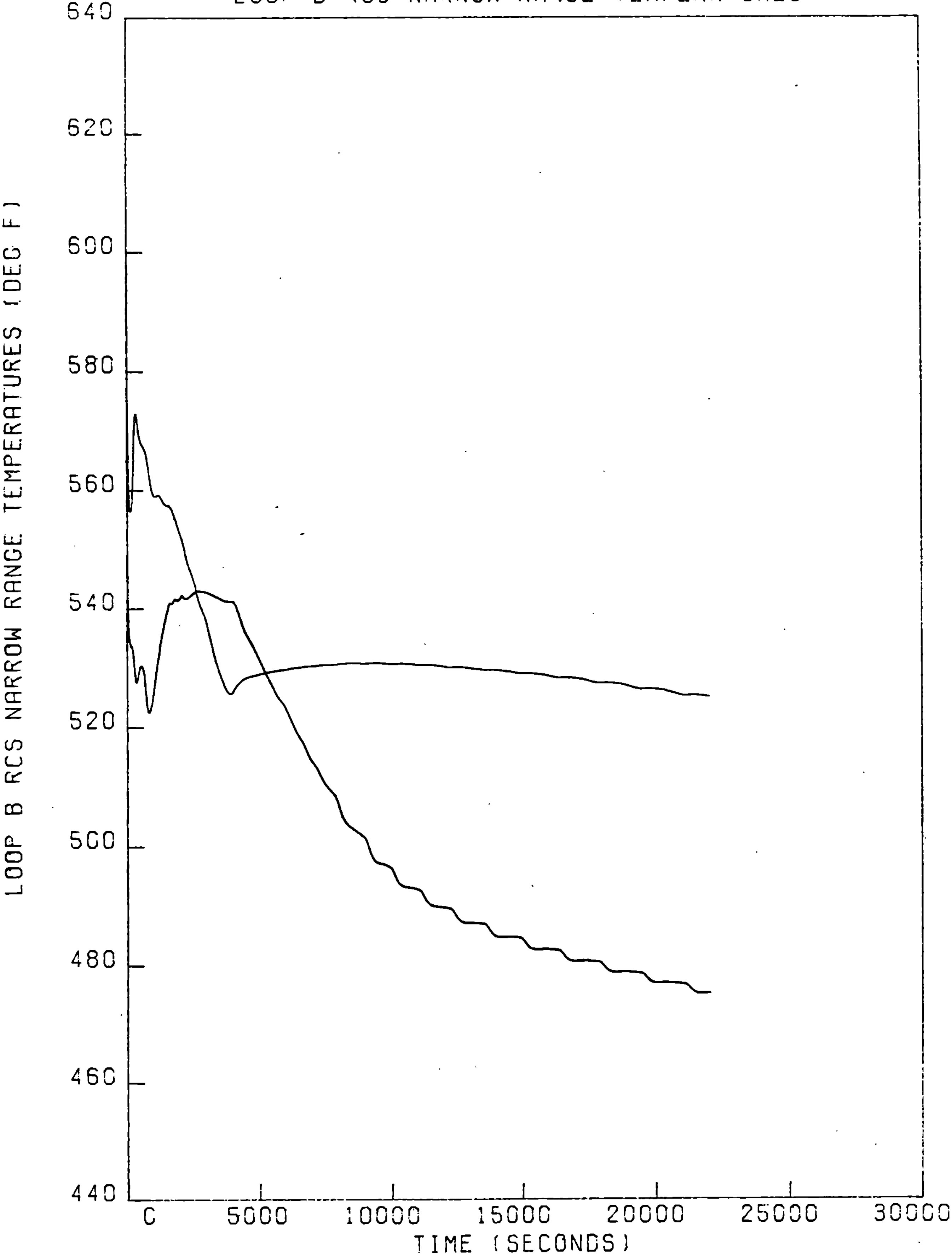
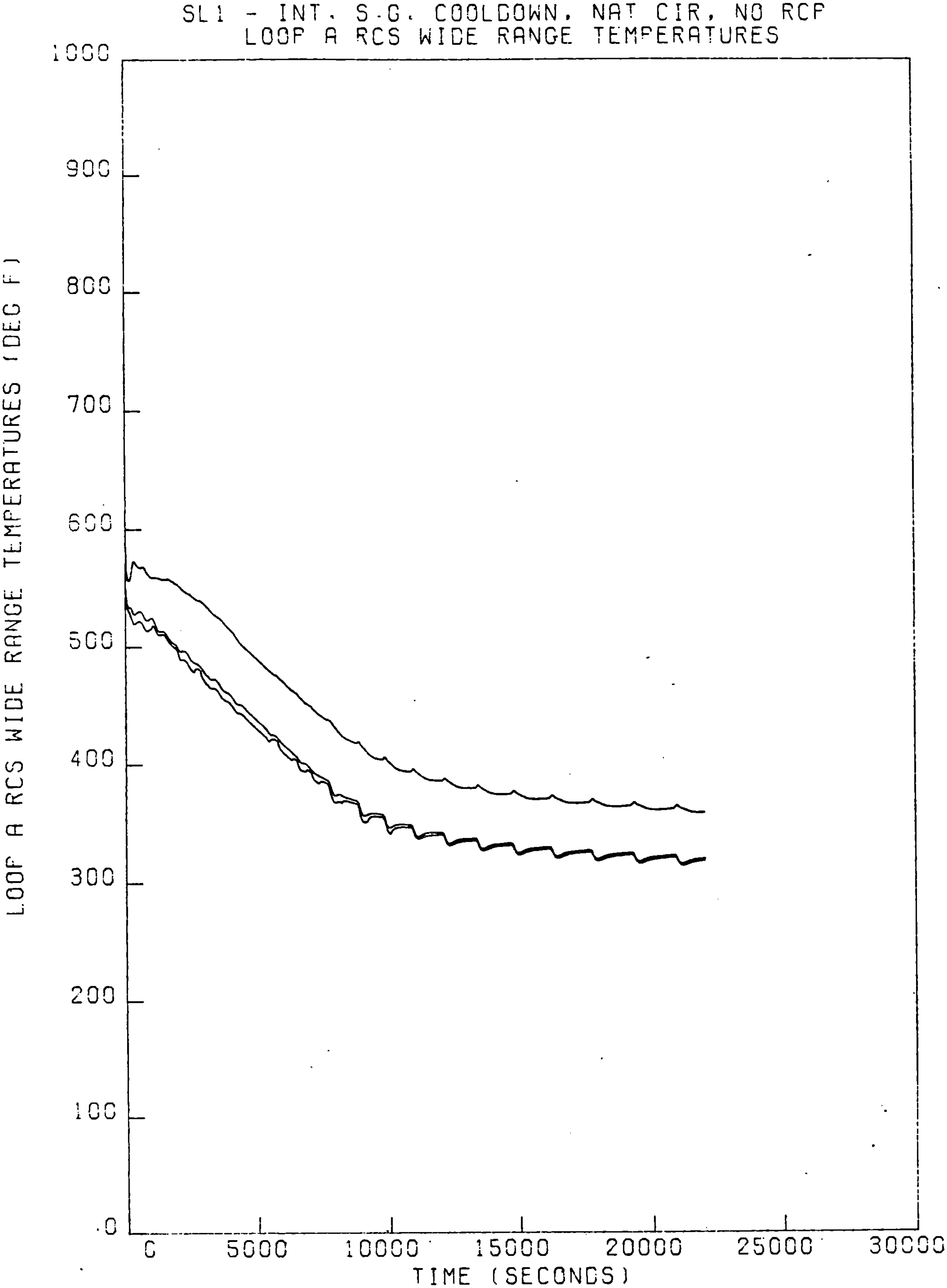


FIGURE A-11



SL1 - INT. S.G. COOLDOWN, NAT CIR, NO RCP
LOOP A RCS WIDE RANGE TEMPERATURES
LOOP A RCS WIDE RANGE TEMPERATURES (DEG F)
1000
900
800
700
600
500
400
300
200
100
.0
0
5000
10000
15000
20000
25000
30000
TIME (SECONDS)

FIGURE A-12
SL1 - INT. S.G. COOLDOWN, NAT CIR. NO RCP
LOOP B RCS WIDE RANGE TEMPERATURES

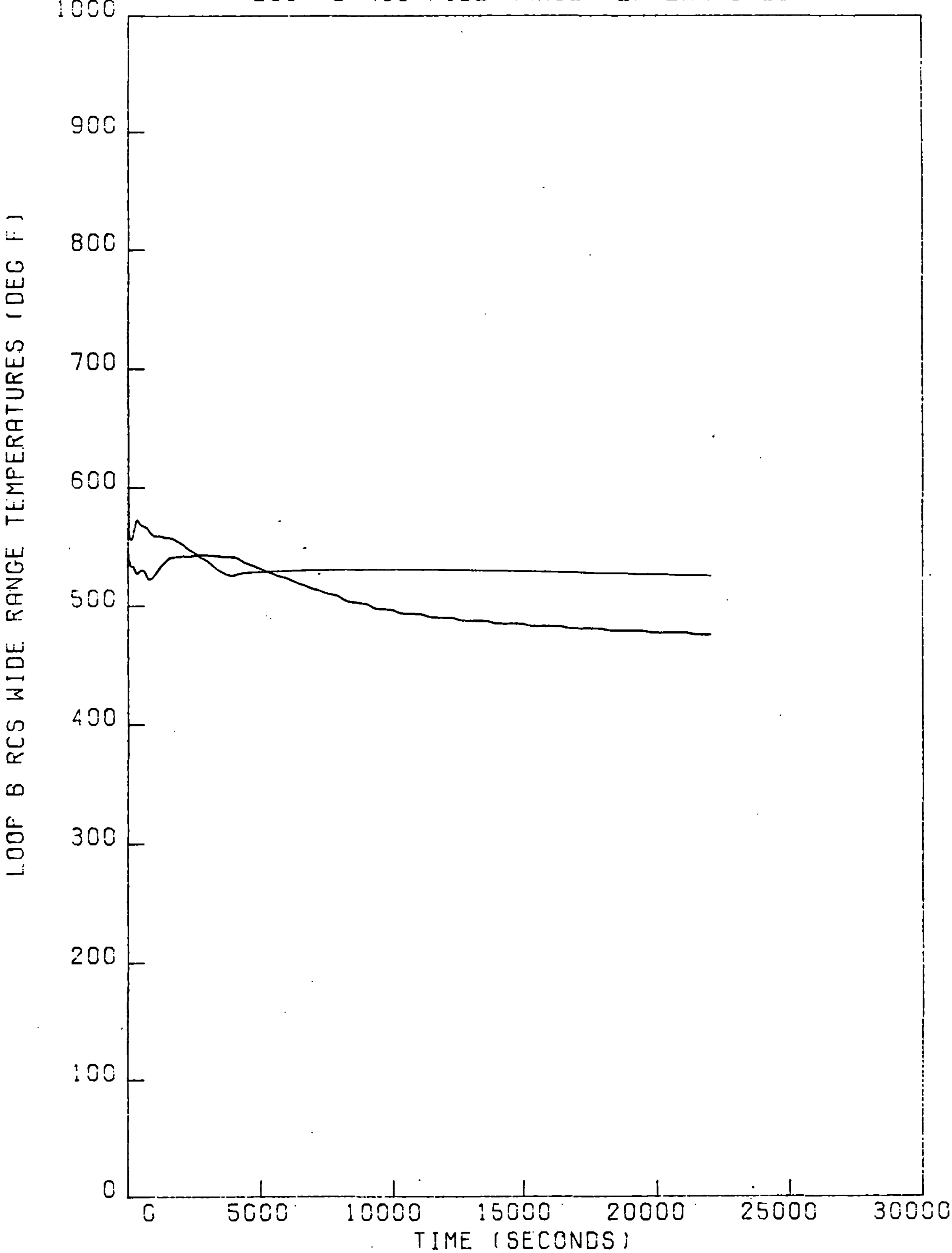


FIGURE A-13

SL1 - INT. S.G. COOLDOWN, NAT CIR, NO RCP

DELTA T SUBCOOLING

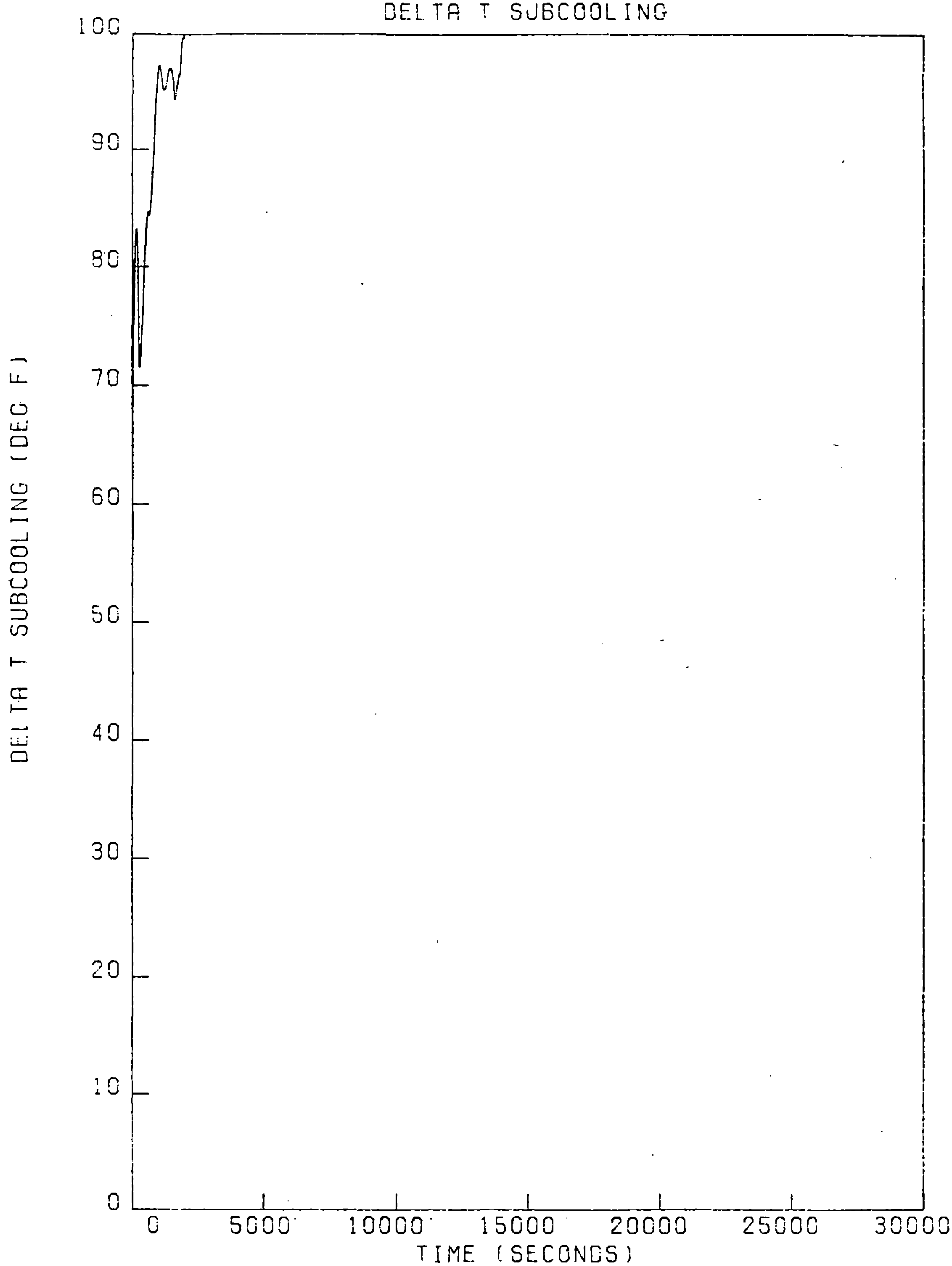


FIGURE A-14

SL1 - INT. S.G. COOLDOWN, NAT CIR, NO RCP

STM GEN A PRESSURE

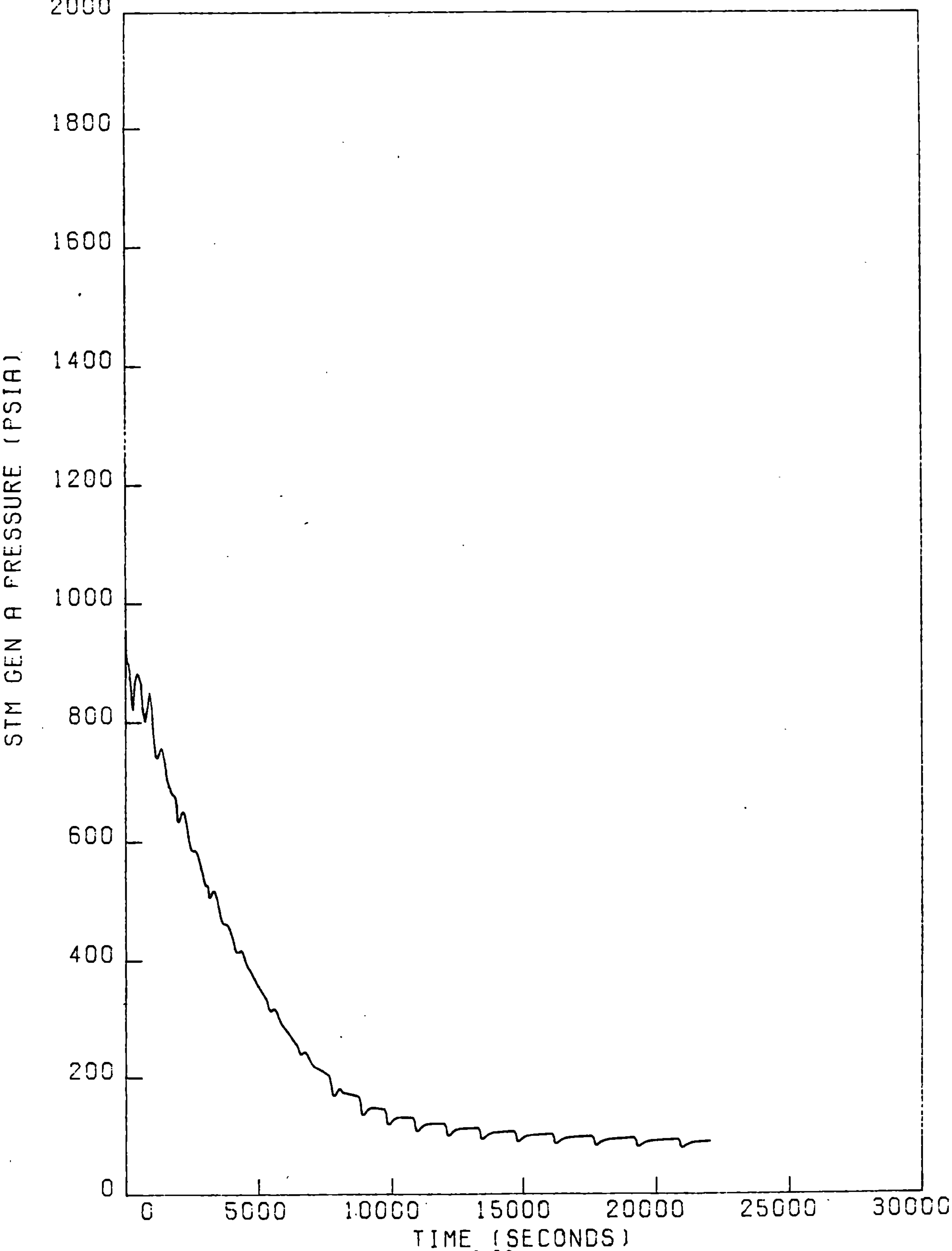


FIGURE A-15

SL1 - INT. S.G. COOLDOWN, NAT CIR, NO RCP

STM GEN B PRESSURE

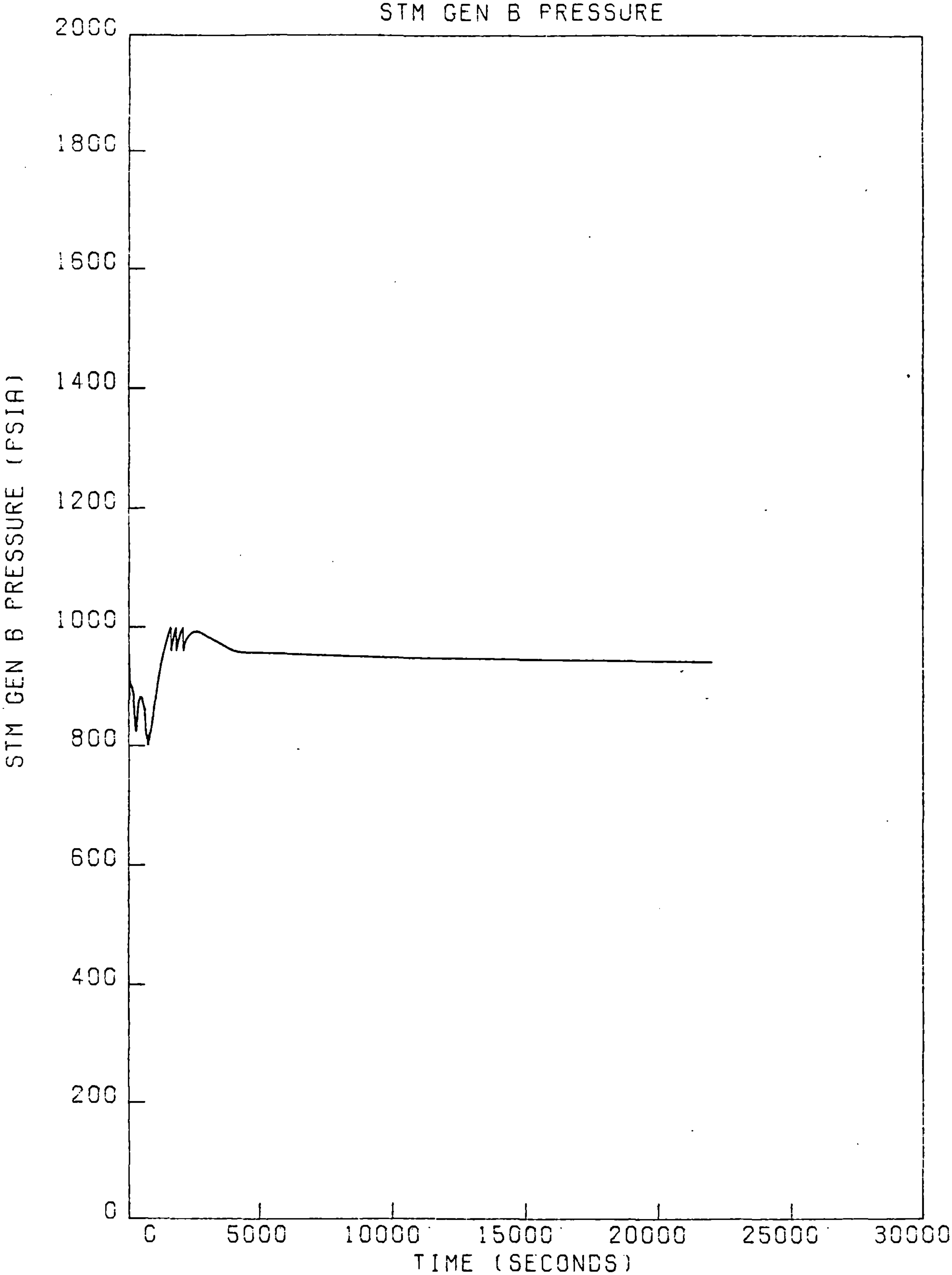


FIGURE A-16
SL1 - INT. S.G. COOLDOWN, NAT CIR, NO RCP
STM GEN A NARROW RANGE LEVEL

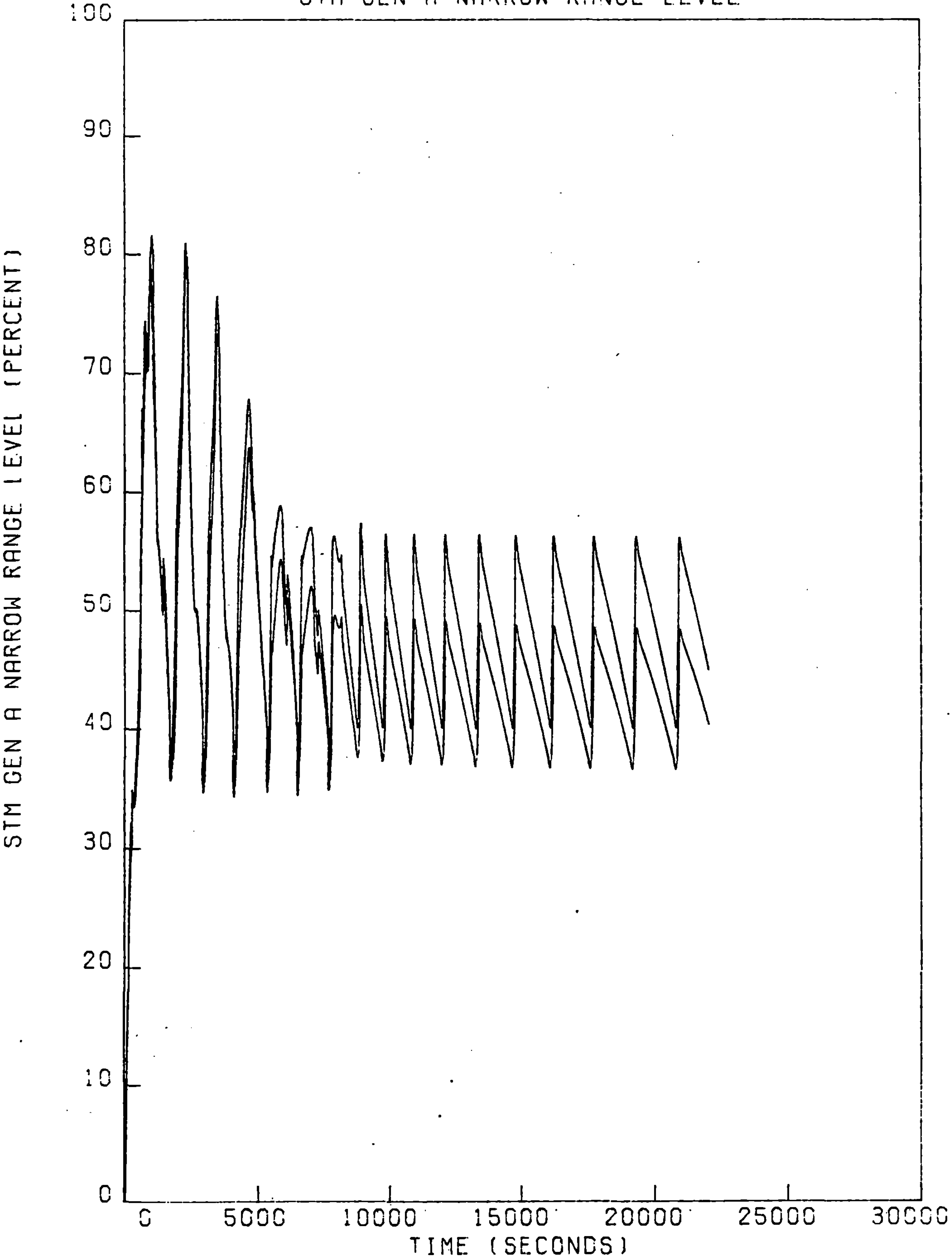


FIGURE A-17

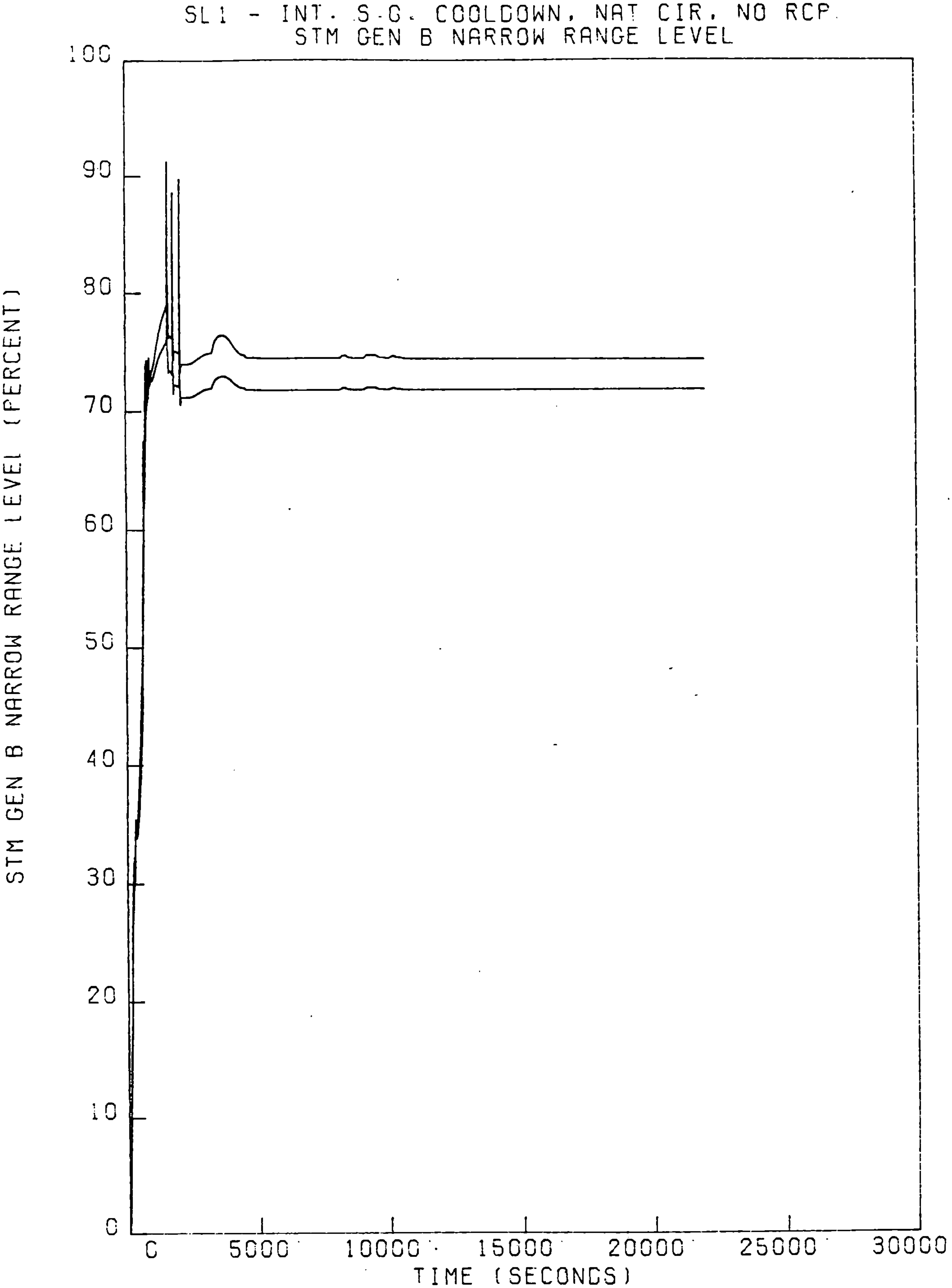

SL1 - INT. S.G. COOLDOWN, NAT CIR, NO RCP
STM GEN B NARROW RANGE LEVEL
100
90
80
70
60
50
40
30
20
10
0
STM GEN B NARROW RANGE LEVEL (PERCENT)
0
5000
10000
15000
20000
25000
30000
TIME (SECONDS)

FIGURE A-18

SL1 - INT. S.G. COOLDOWN, NAT CIR, NO RCP
STM GEN A STEAM FLOW

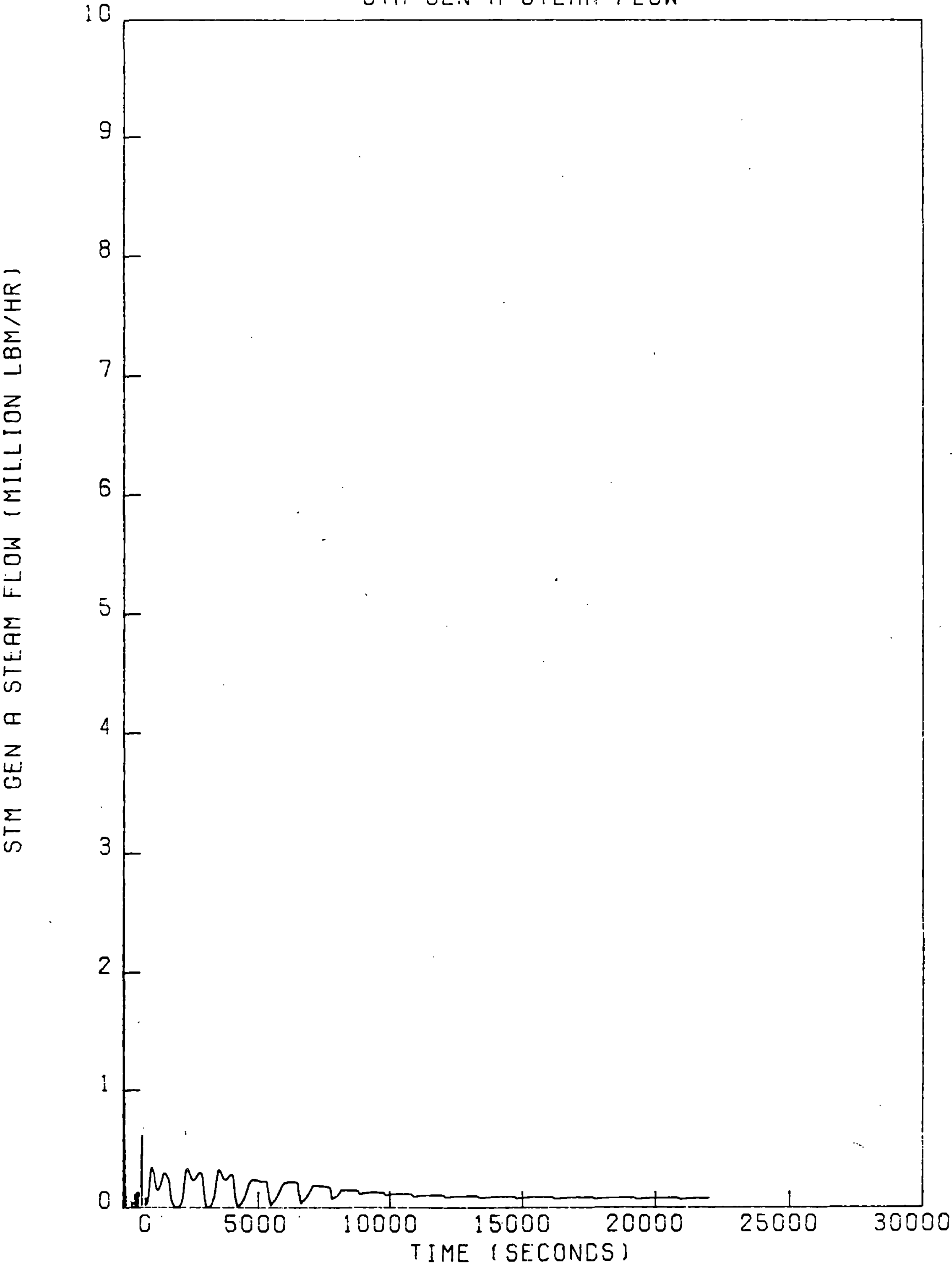


FIGURE A-19

SL1 - INT. S.G. COOLDOWN, NAT CIR, NO RCP

STM GEN B STEAM FLOW

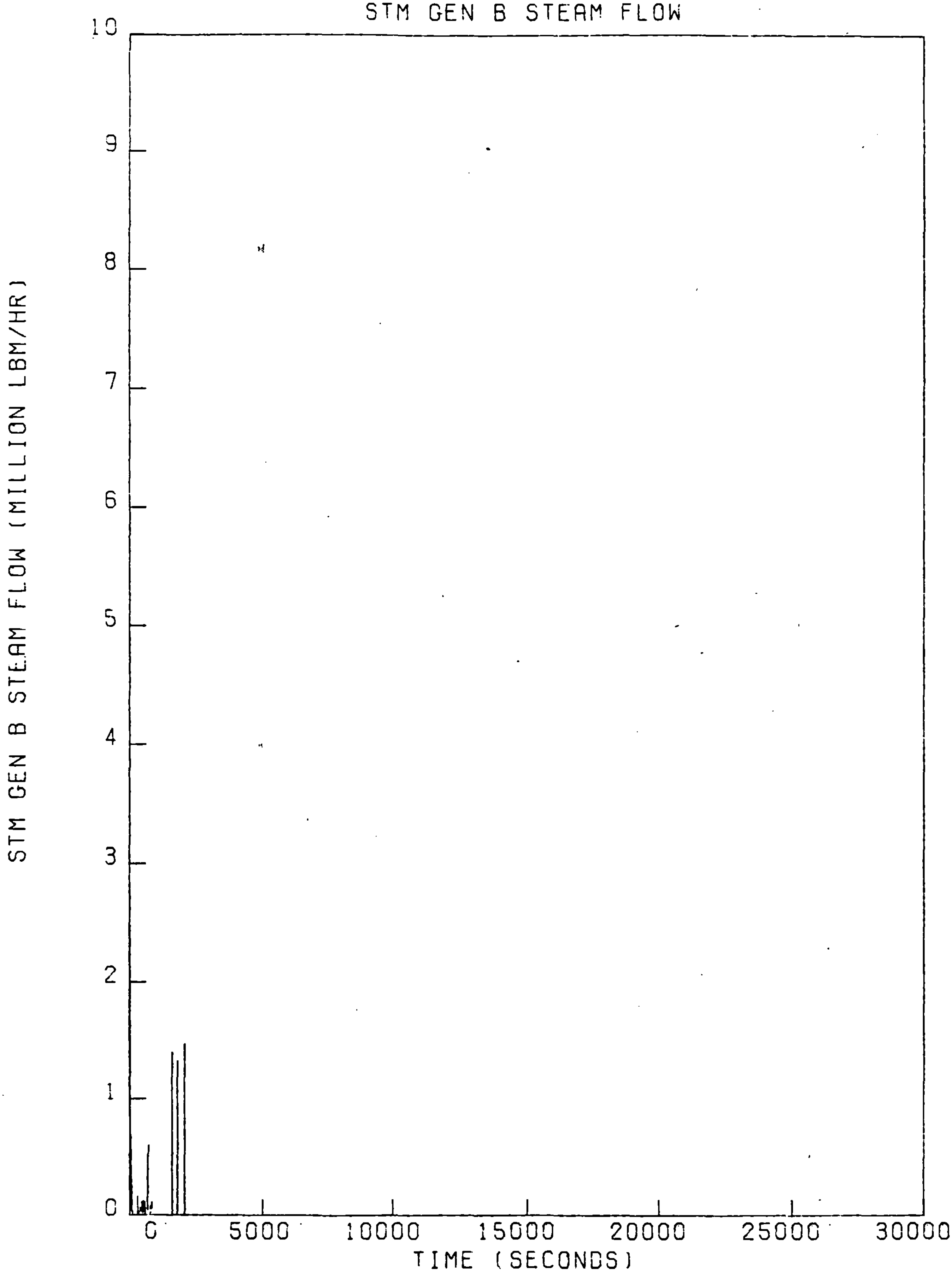


FIGURE A-20

SL1 - INT. S.G. COOLDOWN, NAT CIR, NO RCP

STM GEN A MAIN FEEDWATER FLOW

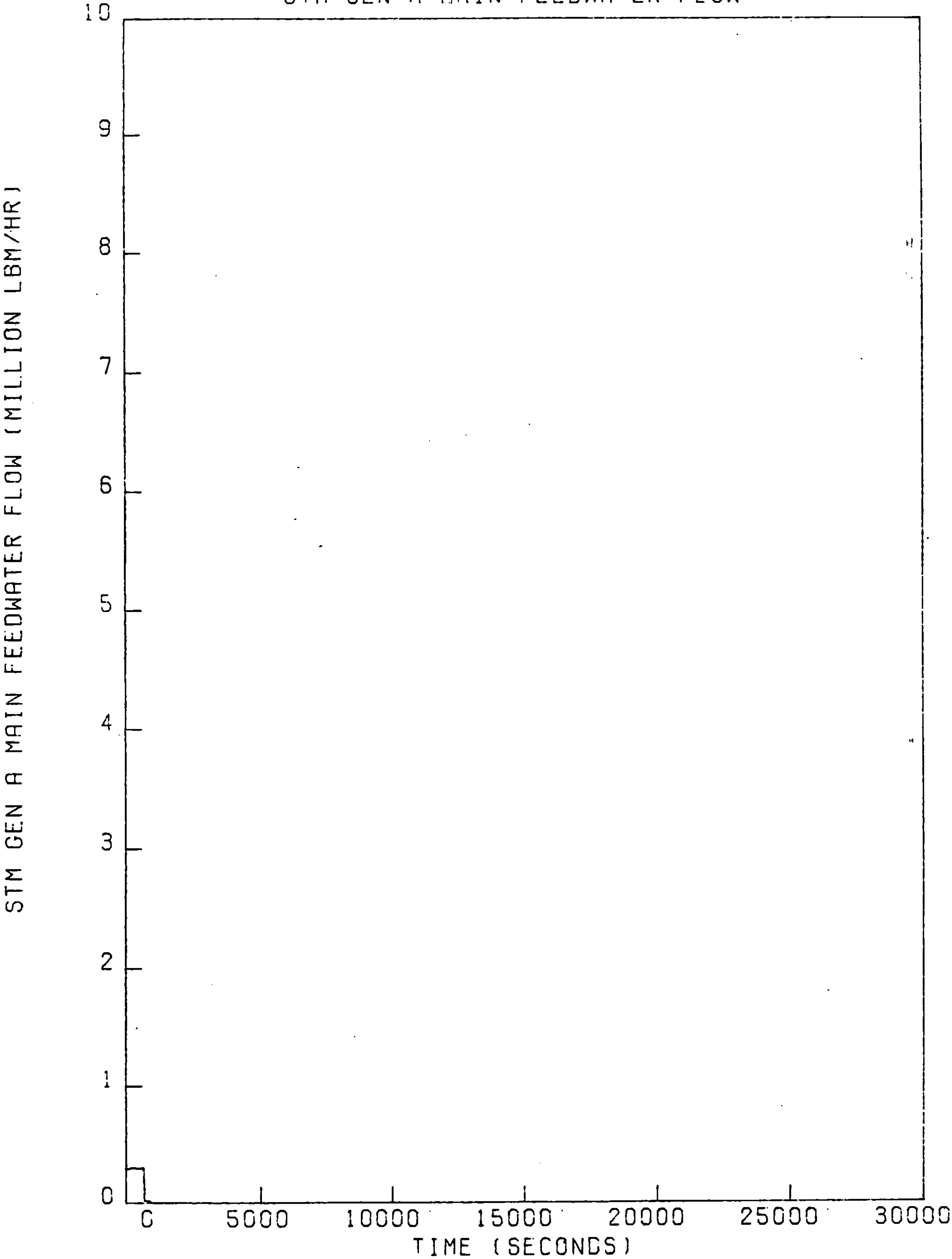


FIGURE A-21

SL1 - INT. S.G. COOLDOWN, NAT CIR, NO RCP
STM GEN B MAIN FEEDWATER FLOW

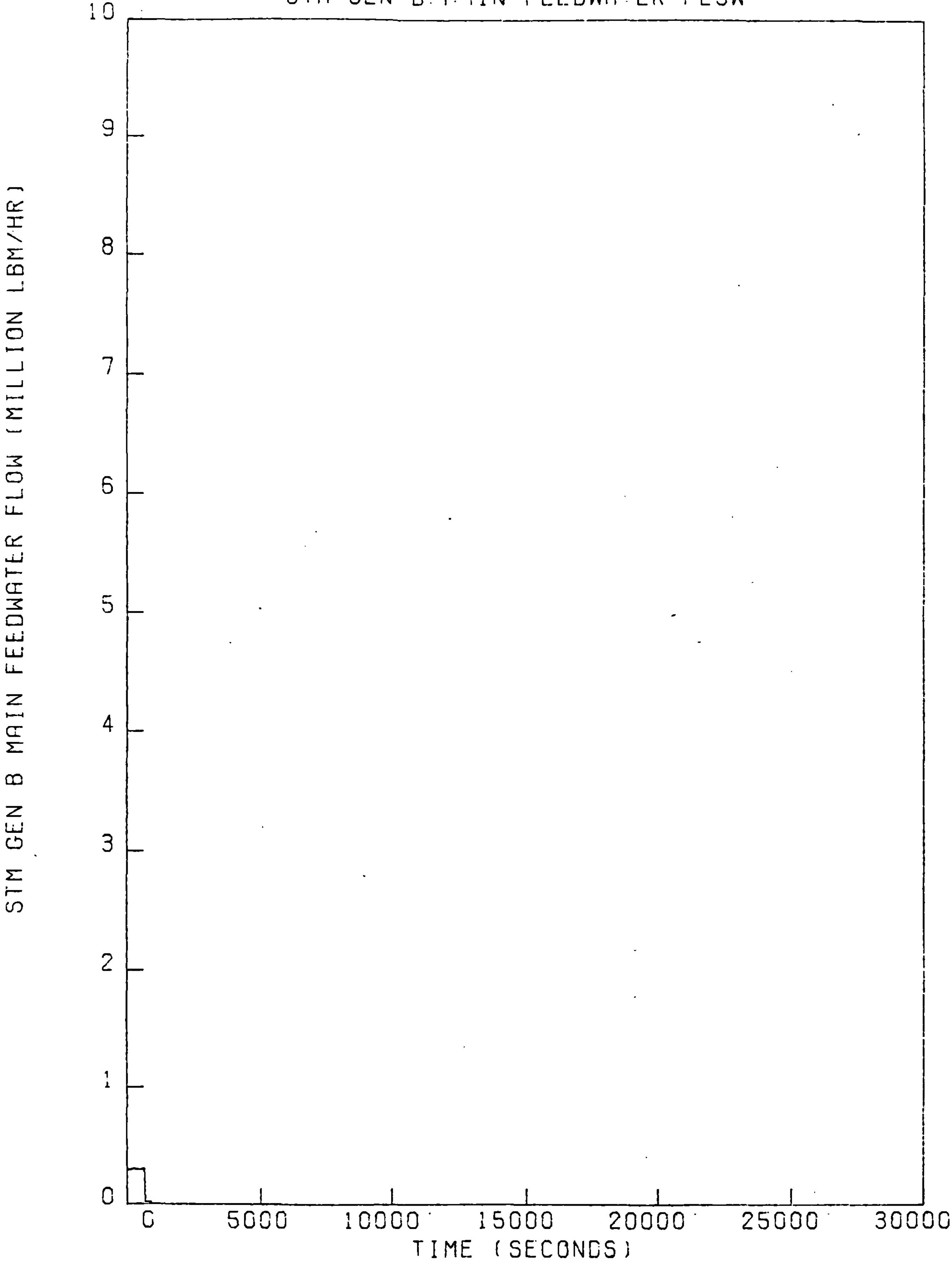


FIGURE A-22
SL1 - INT. S.G. COOLDOWN, NAT CIR, NO RCP
STM GEN A AUXILIARY FEEDWATER FLOW

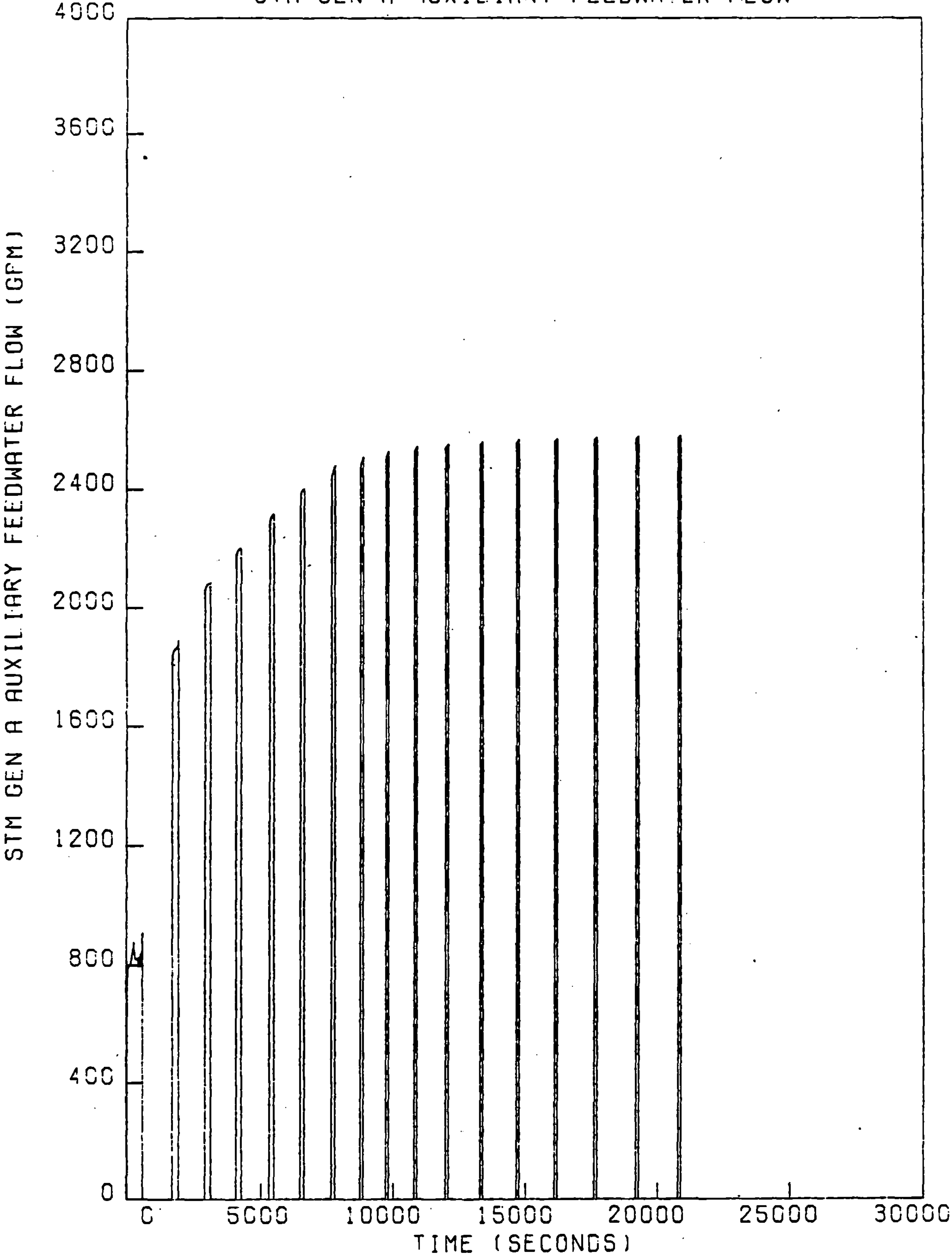


FIGURE A-23

SL1 - INT. S.G. COOLDOWN, NAT CIR, NO RCP
STM GEN B AUXILIARY FEEDWATER FLOW

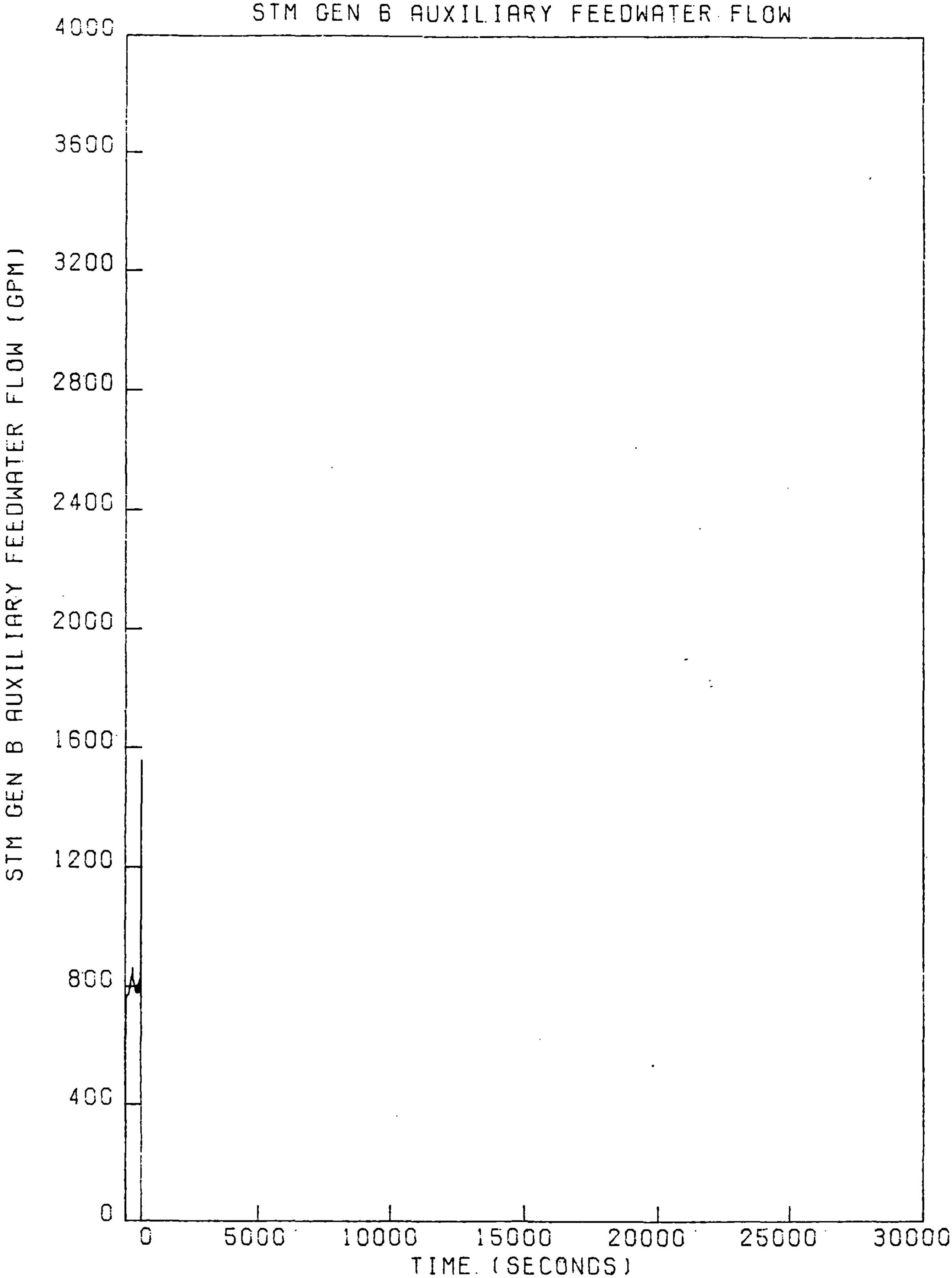
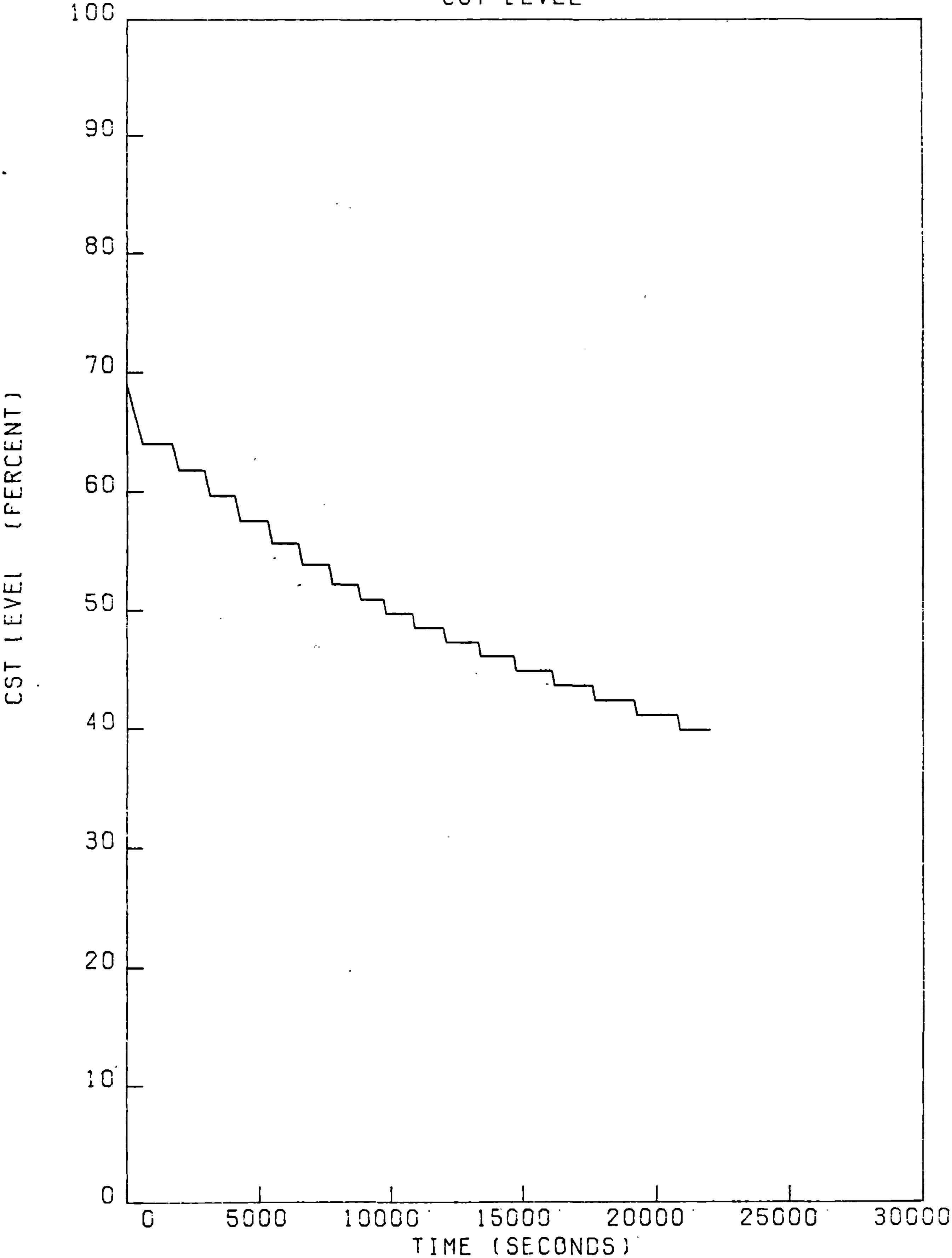


FIGURE A-24

SL1 - INT. S.G. COOLDOWN, NAT CIR, NO RCP

CST LEVEL



CASE 2

Cooldown of Unisolated Steam Generator
Based on Optimum Steady State Analysis Secondary Temperature

t, sec	$T_{SG\ 1}$, °F	$T_{SG\ 2}$, °F	q_2, Btu/sec	Notes
900	525	525	27400	Cooling SG 1 to T_{opt}
1000	522	529	17900	
1500	511	544	7930	
2000	500	542	5339	
2500	490	544	1289	
3000	479	544	-420	$T \sim T_{opt}$; SG 2 now cooling
3500	478	541	-1211	
4000	477	539	-1363	
4500	476	537	-1336	
5100	475	535	-1249	
6100	473	531	-1262	
10100	466	518	-1084	
15100	458	504	-840*	
20100	451	493	-607*	
28700	445	482	-302*	

* Estimate of T_{opt} less accurate for $t > 10^4$ seconds

These results show that continued cooling of the isolated unit (#2) can be achieved if $T_{SG\ 1}$ is kept at an optimum value as a function of time (T_{opt}). The following figures are LTC transient parameter plots for Case 2.

FIGURE A-25
LCG (DELTA S.G. TEMP.) CONTROLLER
PZR NARROW RANGE PRESSURE

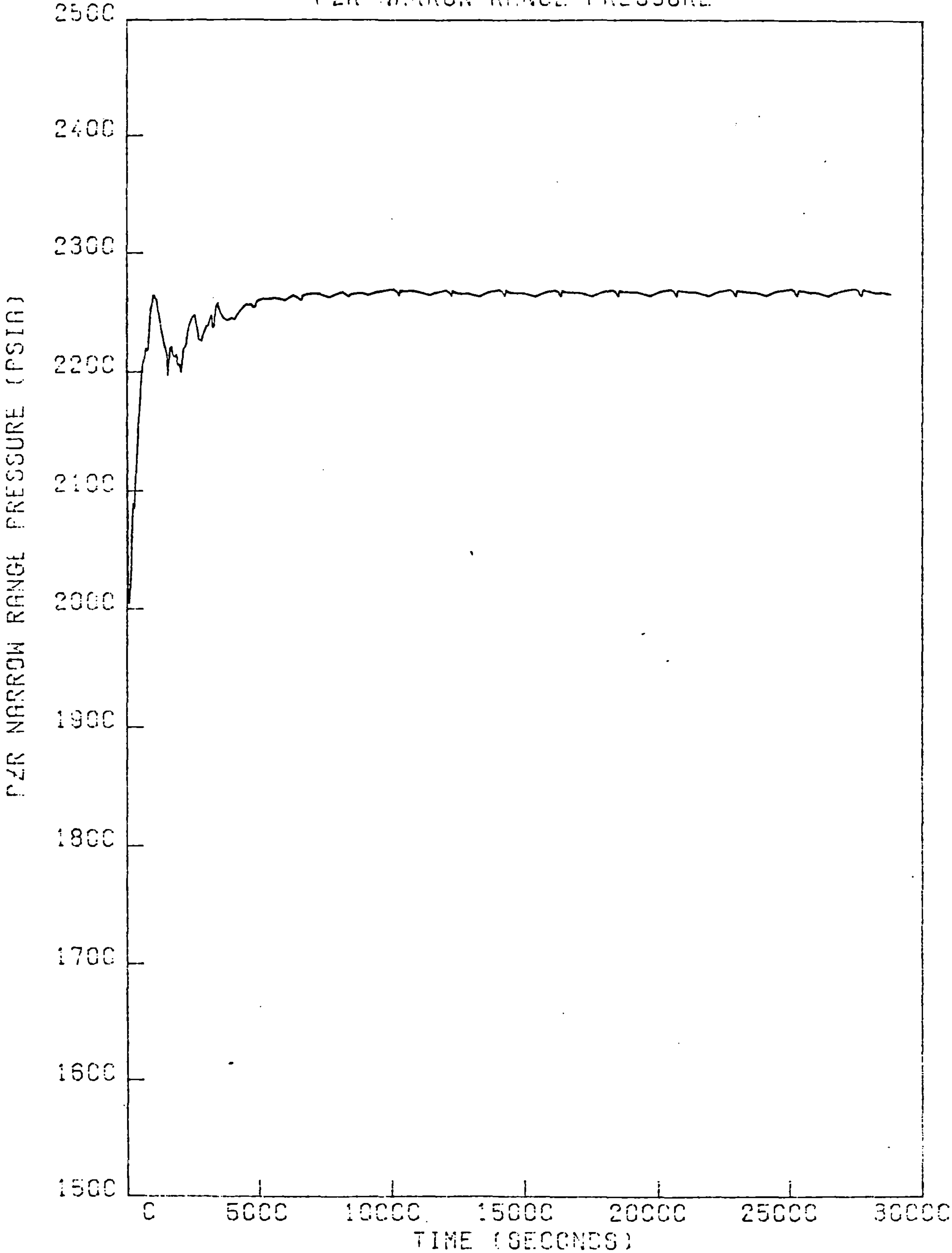


FIGURE A-26
LCG (DELTA S.G. TEMP.) CONTROLLER
PZR NARROW RANGE TEMPERATURE

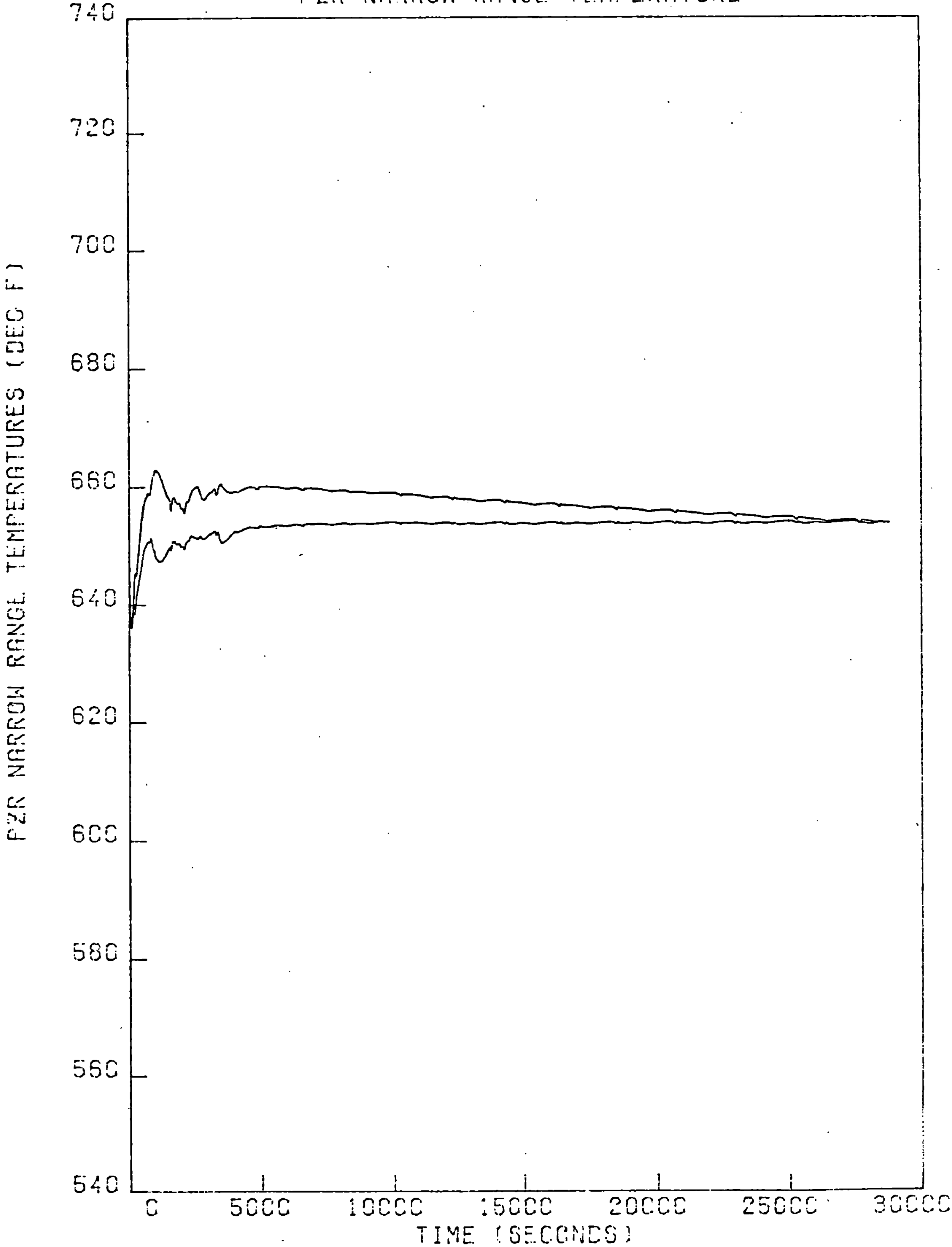


FIGURE A-27
LCG (DELTA S.G. TEMP.) CONTROLLER
PZR LEVEL

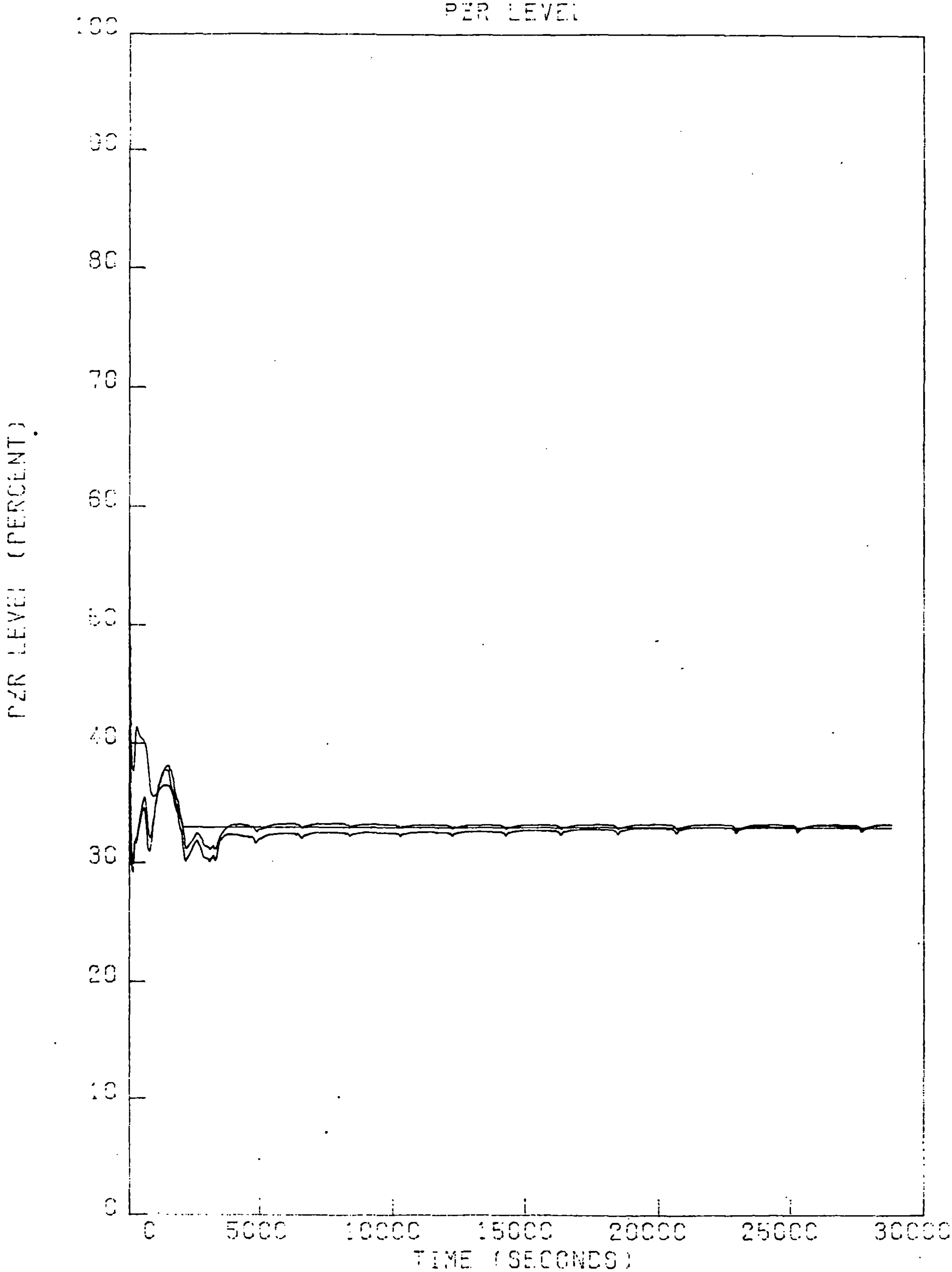


FIGURE A-28

LOG (DELTA S.G. TEMP.) CONTROLLER
PZR HEATER RATE

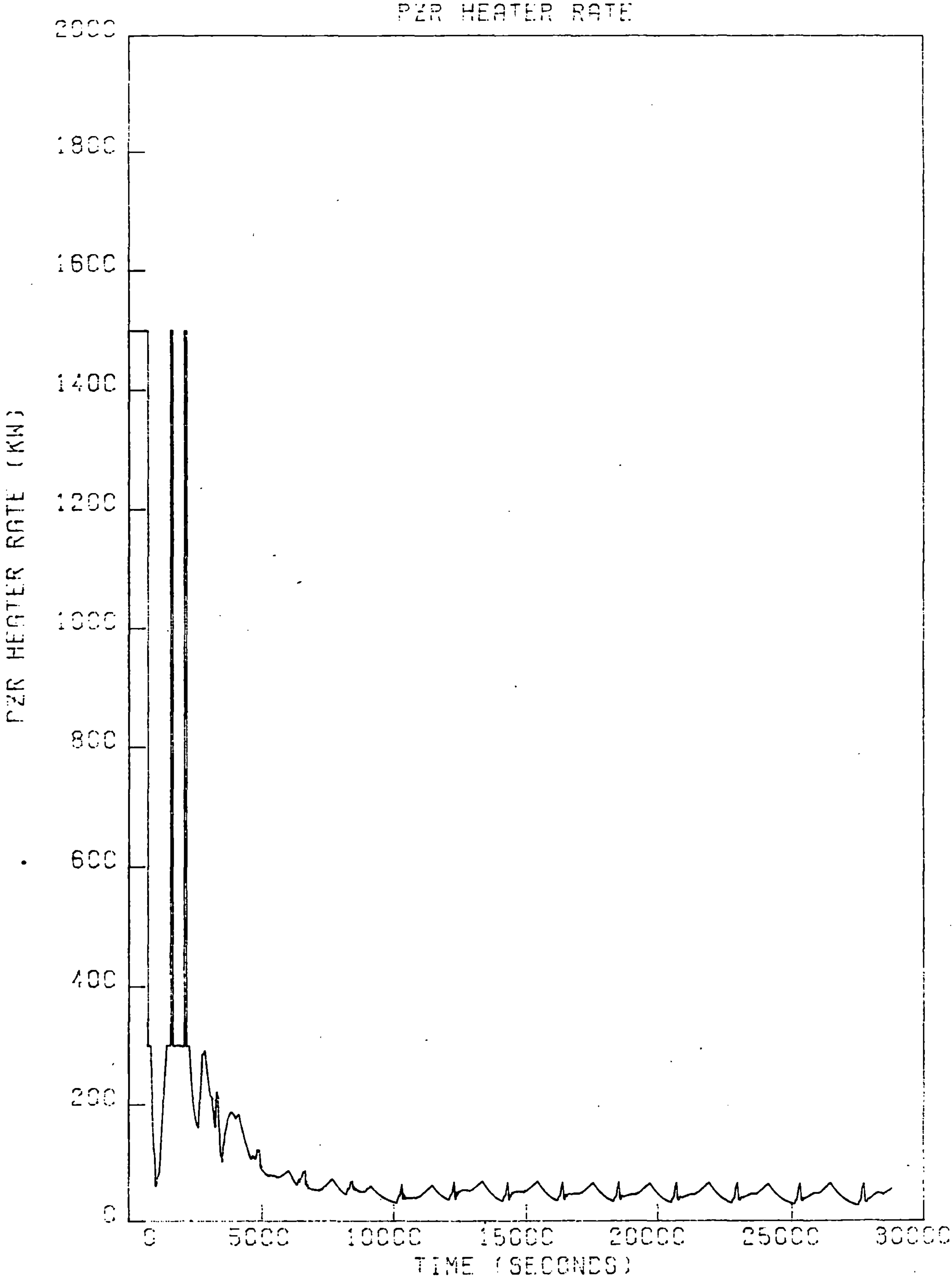


FIGURE A-29

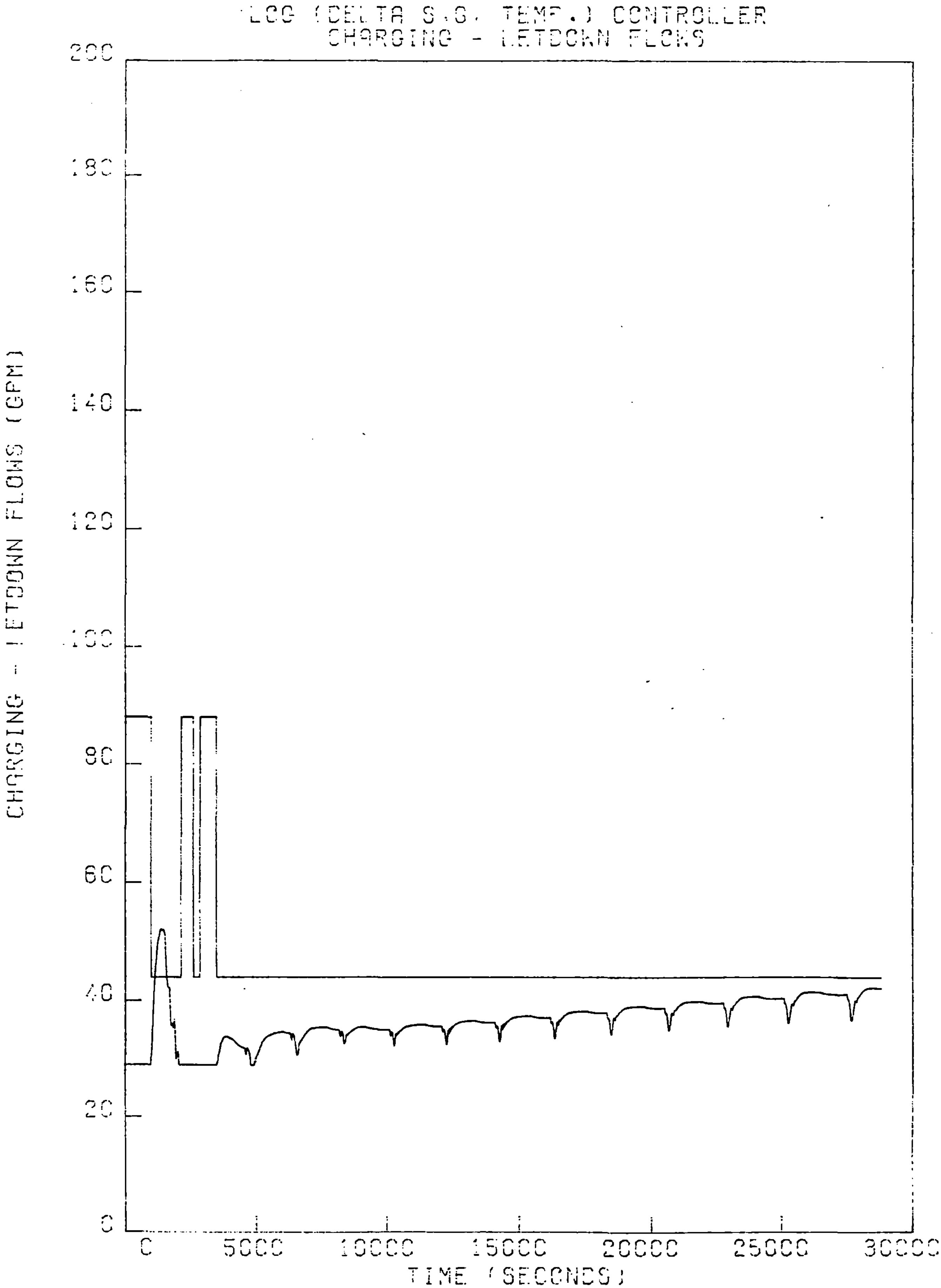

LCG (DELTA S.G. TEMP.) CONTROLLER
CHARGING - LETDOWN FLOWS
CHARGING - LETDOWN FLOWS (GPM)
200
180
160
140
120
100
80
60
40
20
0
0
5000
10000
15000
20000
25000
30000
TIME (SECONDS)

FIGURE A-30

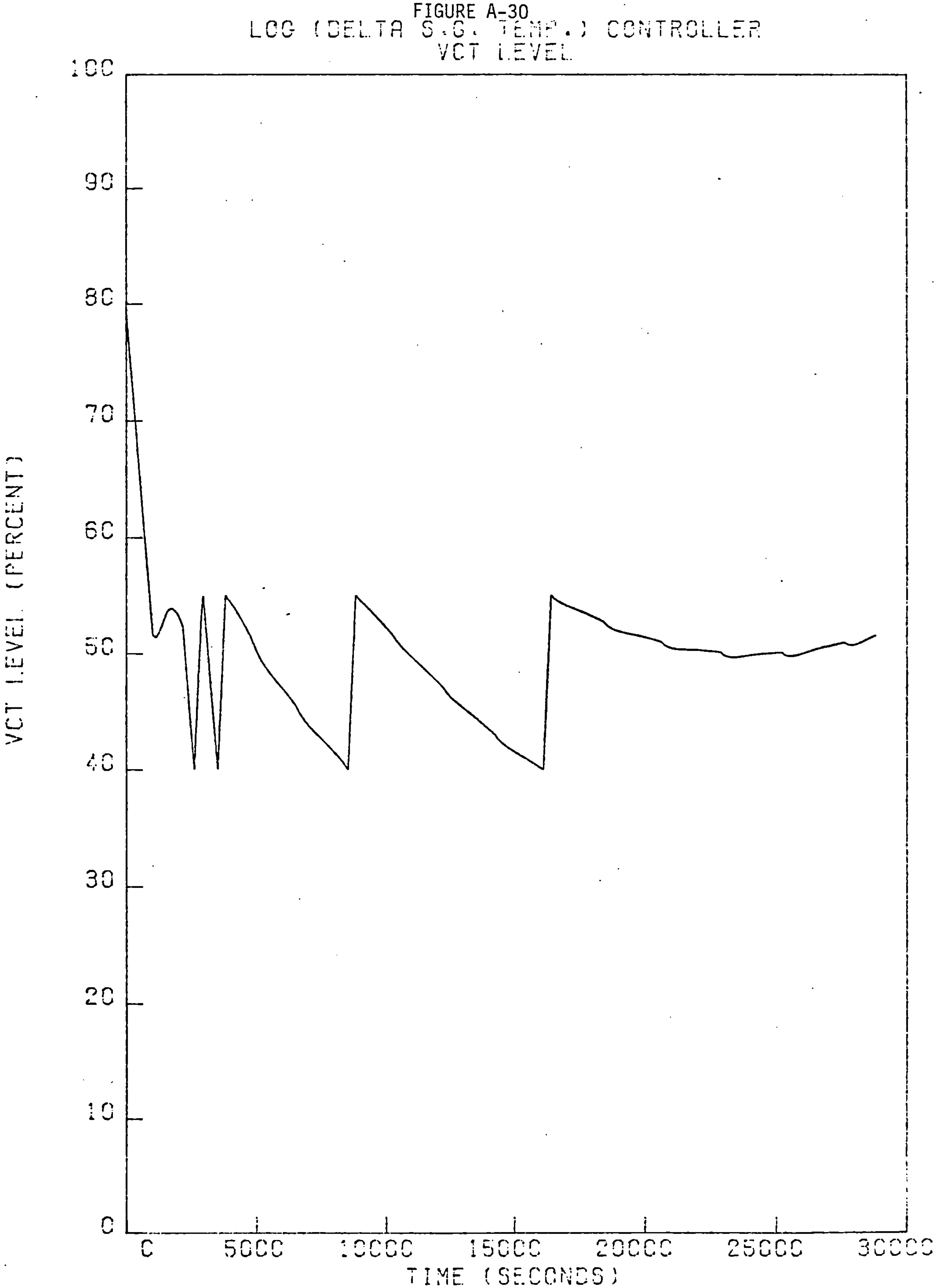

LOG (DELTA S.G. TEMP.) CONTROLLER
VCT LEVEL
VCT LEVEL (PERCENT)
100
90
80
70
60
50
40
30
20
10
0
0
5000
10000
15000
20000
25000
30000
TIME (SECONDS)

FIGURE A-31

LCO (DELTA S.G. TEMP.) CONTROLLER
LOOP A RCS MASS FLOWS

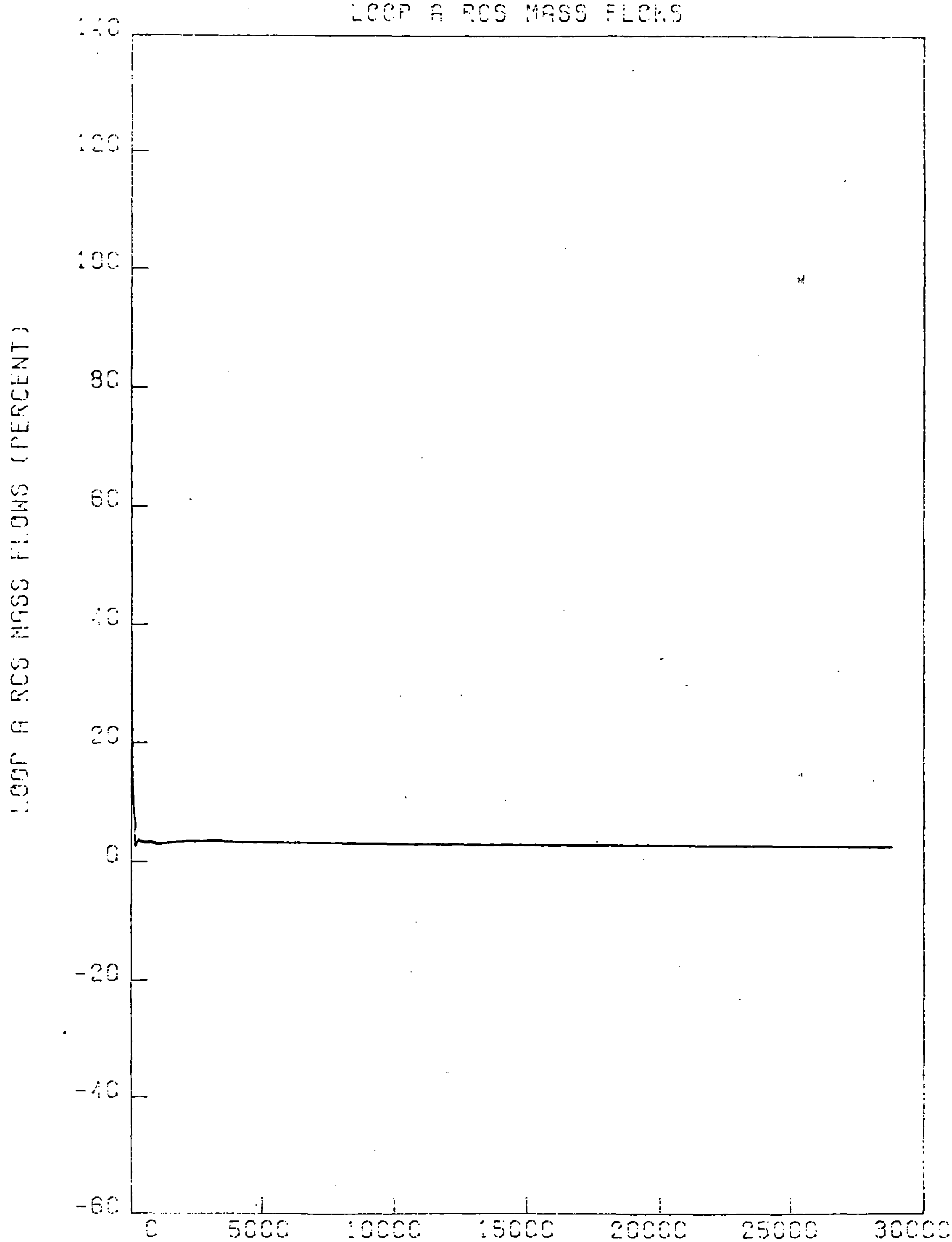


FIGURE A-32
LOG (DELTA S.G. TEMP.) CONTROLLER
LOOP B RCS MASS FLOWS

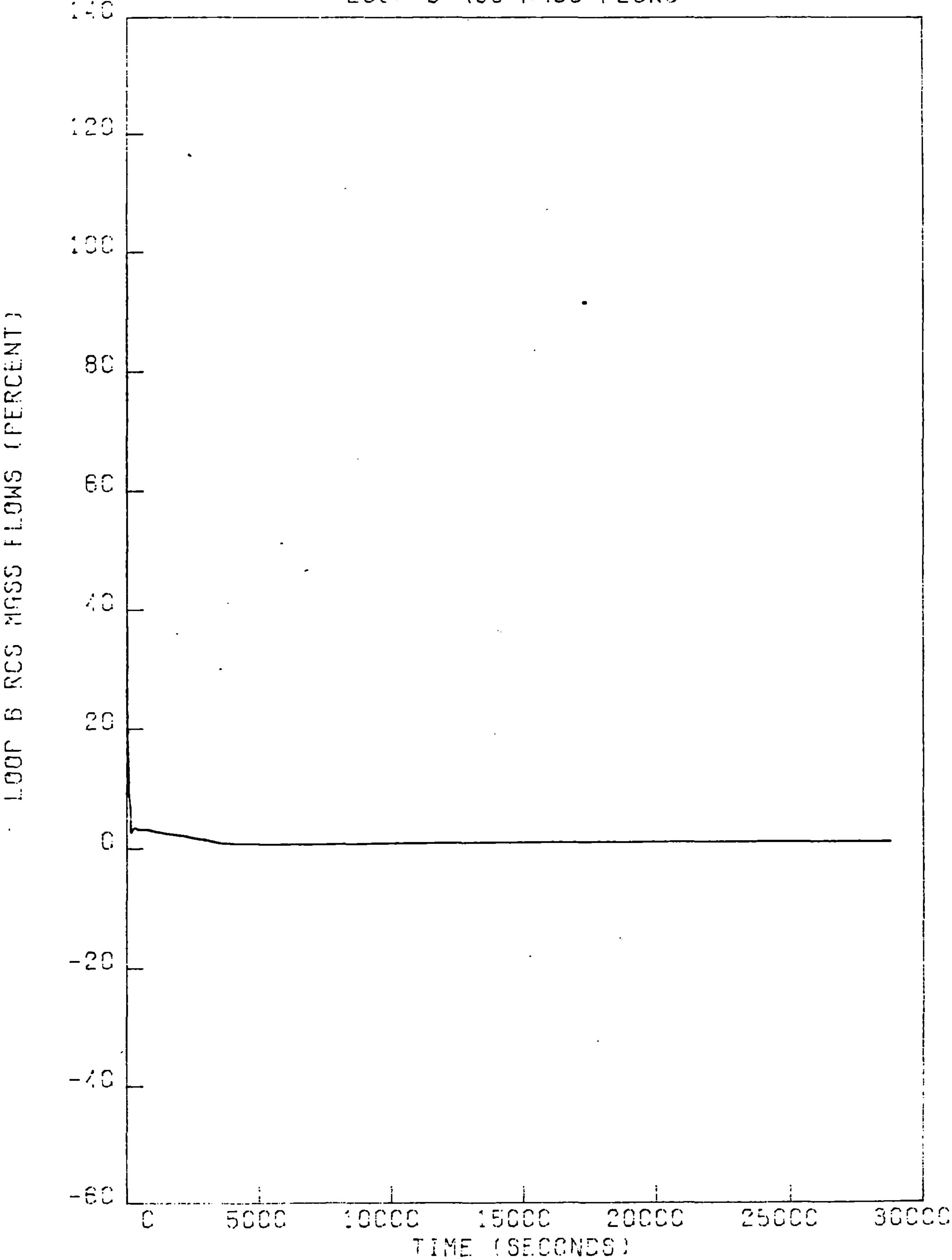


FIGURE A-33

LCG (DELTA S.G. TEMP.) CONTROLLER
LOOP A RCS NARROW RANGE TEMPERATURES

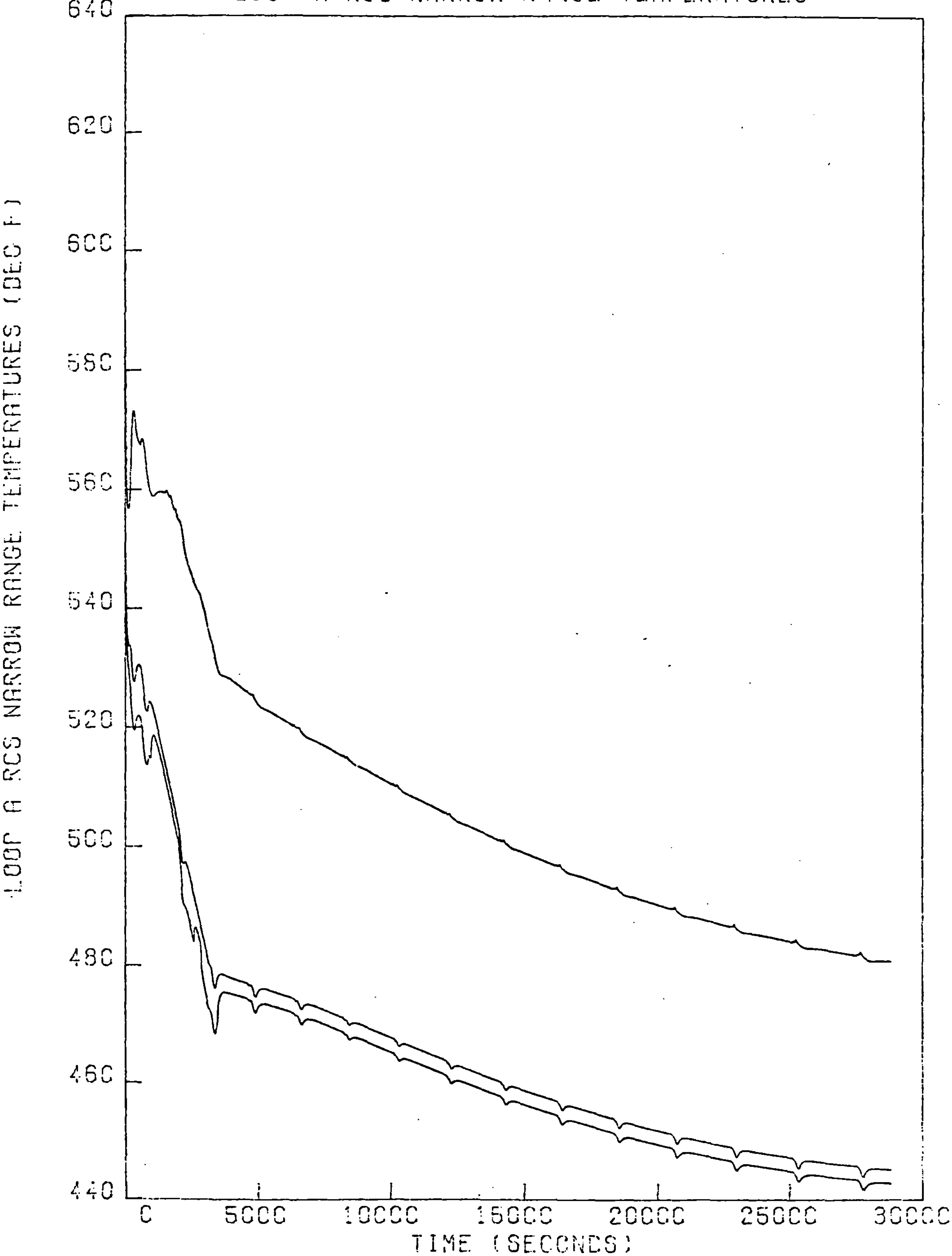


FIGURE A-34

LOG (DELTA S.G. TEMP.) CONTROLLER
LOOP B RCS NARROW RANGE TEMPERATURES

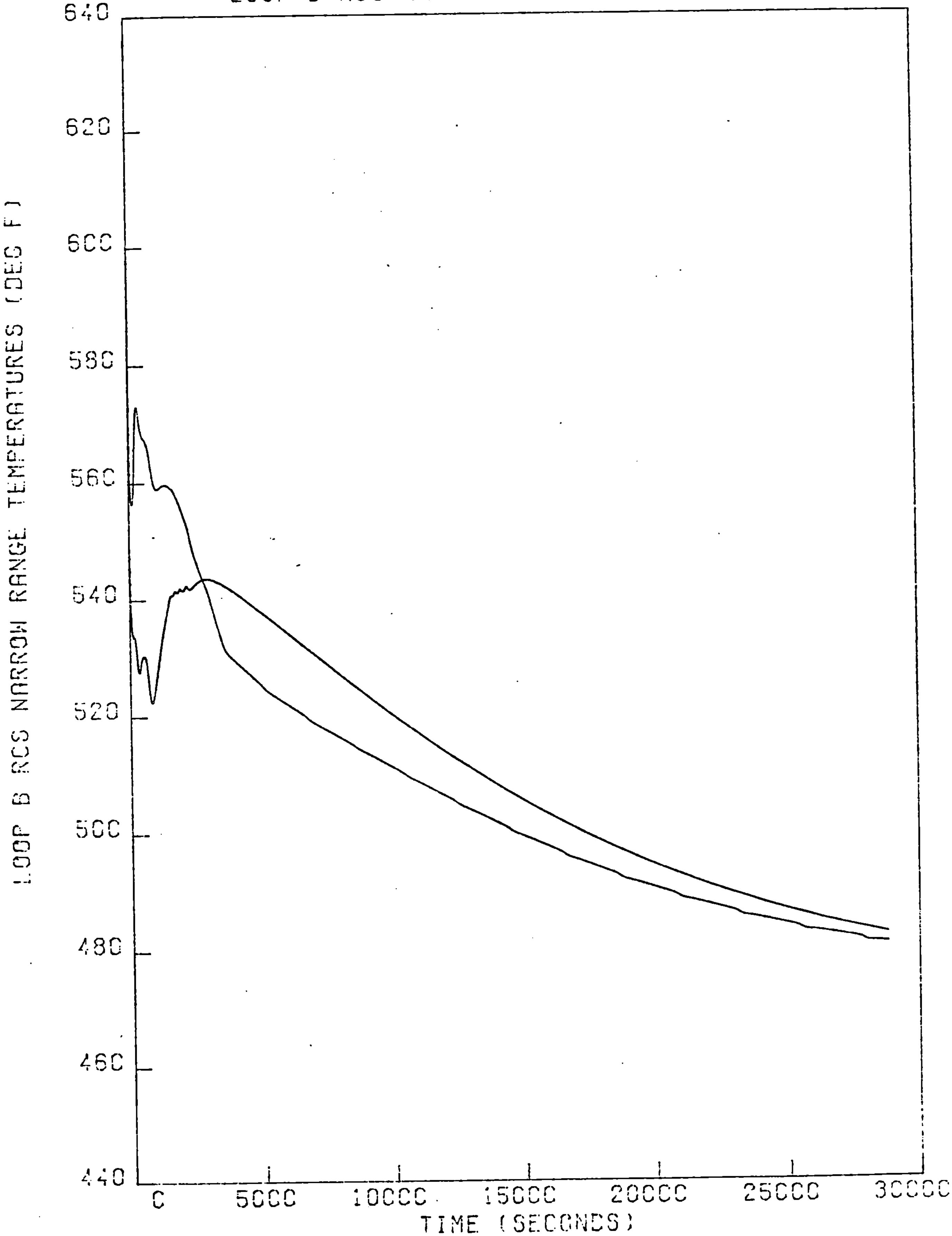


FIGURE A-35

LOG (DELTA S.G. TEMP.) CONTROLLER
LOOP A RCS WIDE RANGE TEMPERATURES

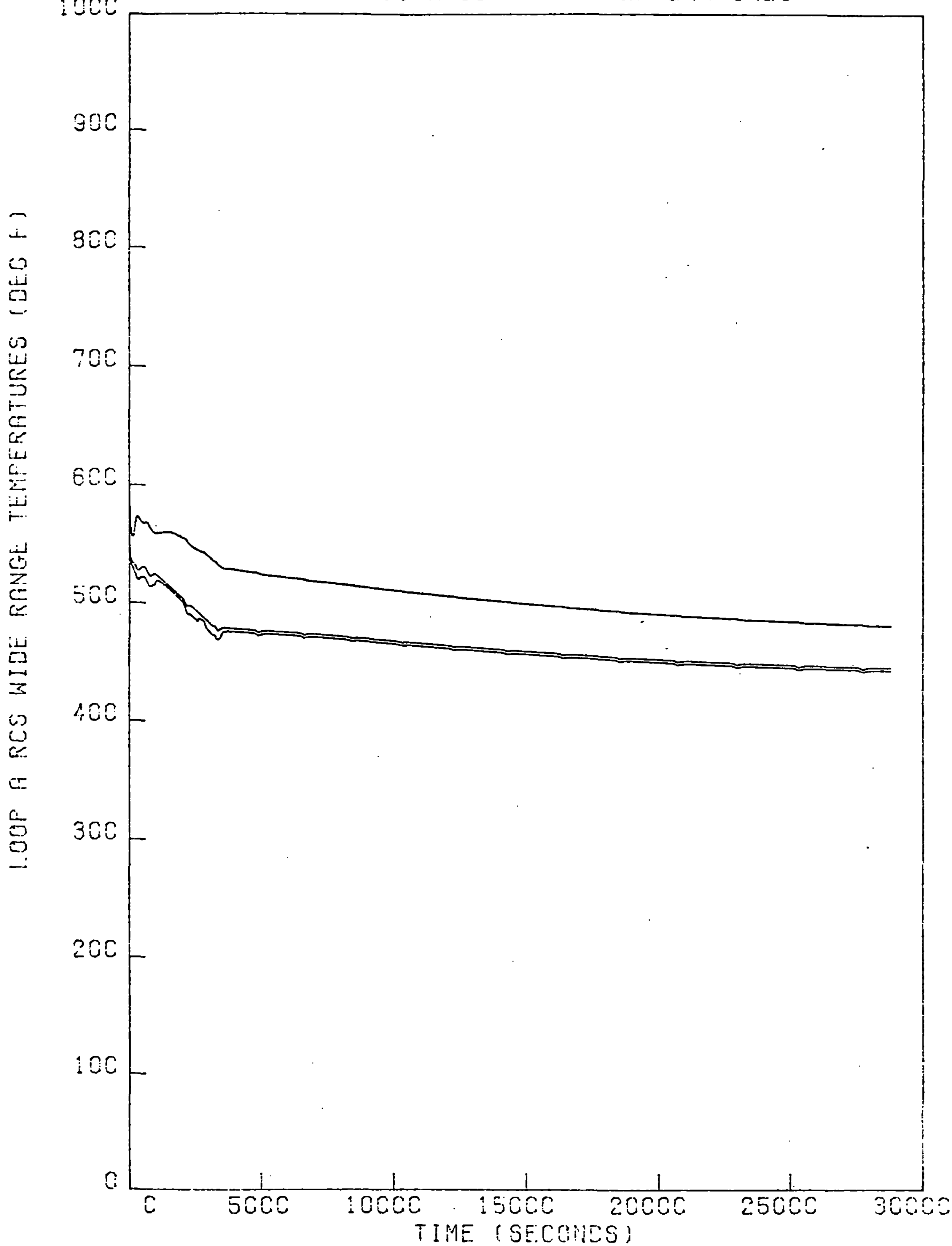


FIGURE A-36

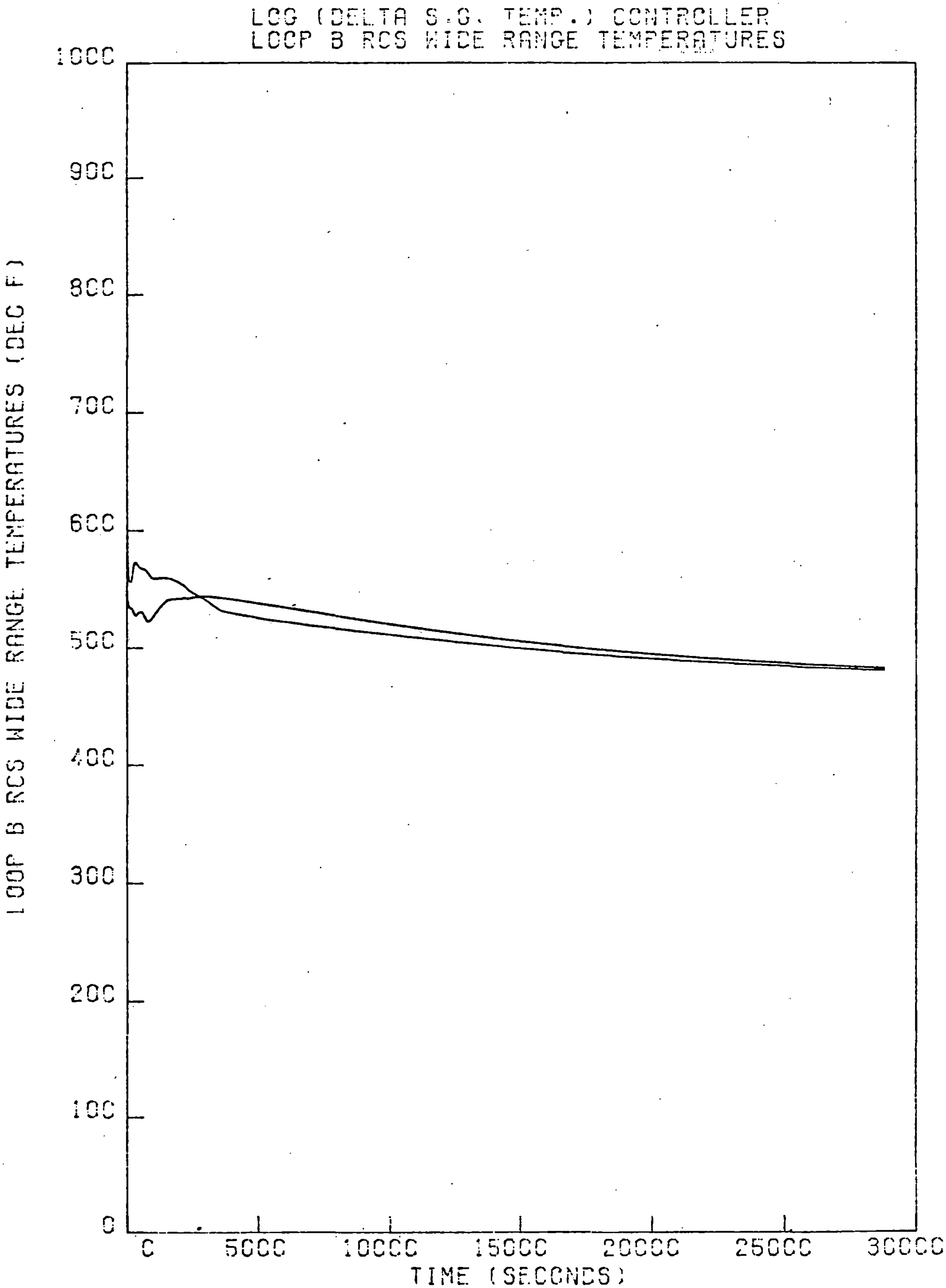

LOG (DELTA S.G. TEMP.) CONTROLLER
LOOP B RCS WIDE RANGE TEMPERATURES
LOOP B RCS WIDE RANGE TEMPERATURES (DEG F)
1000
900
800
700
600
500
400
300
200
100
0
0
5000
10000
15000
20000
25000
30000
TIME (SECONDS)

FIGURE A-37

LCG (DELTA S.G. TEMP.) CONTROLLER
(DELTA T SUBCOOLING

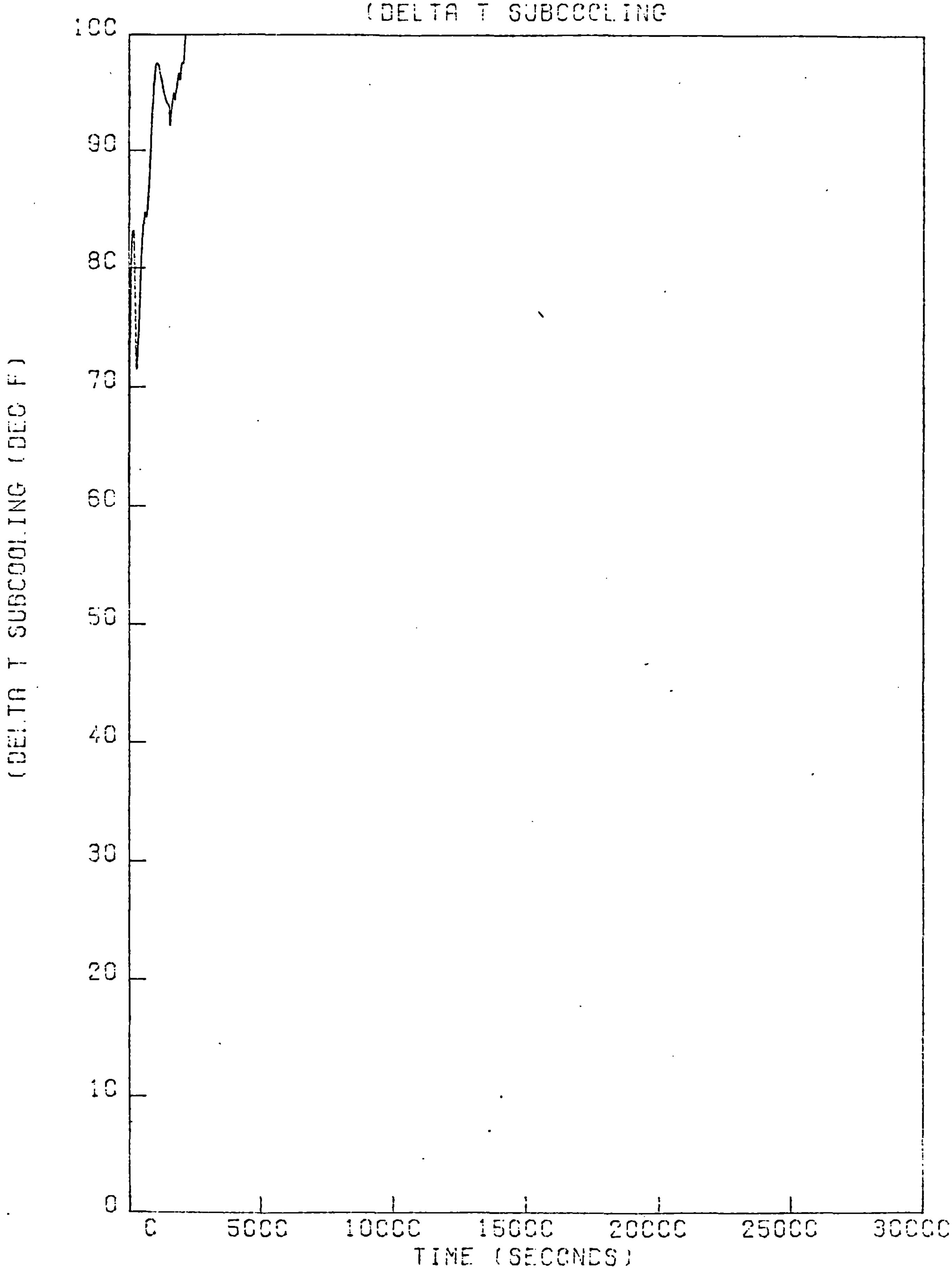


FIGURE A-38

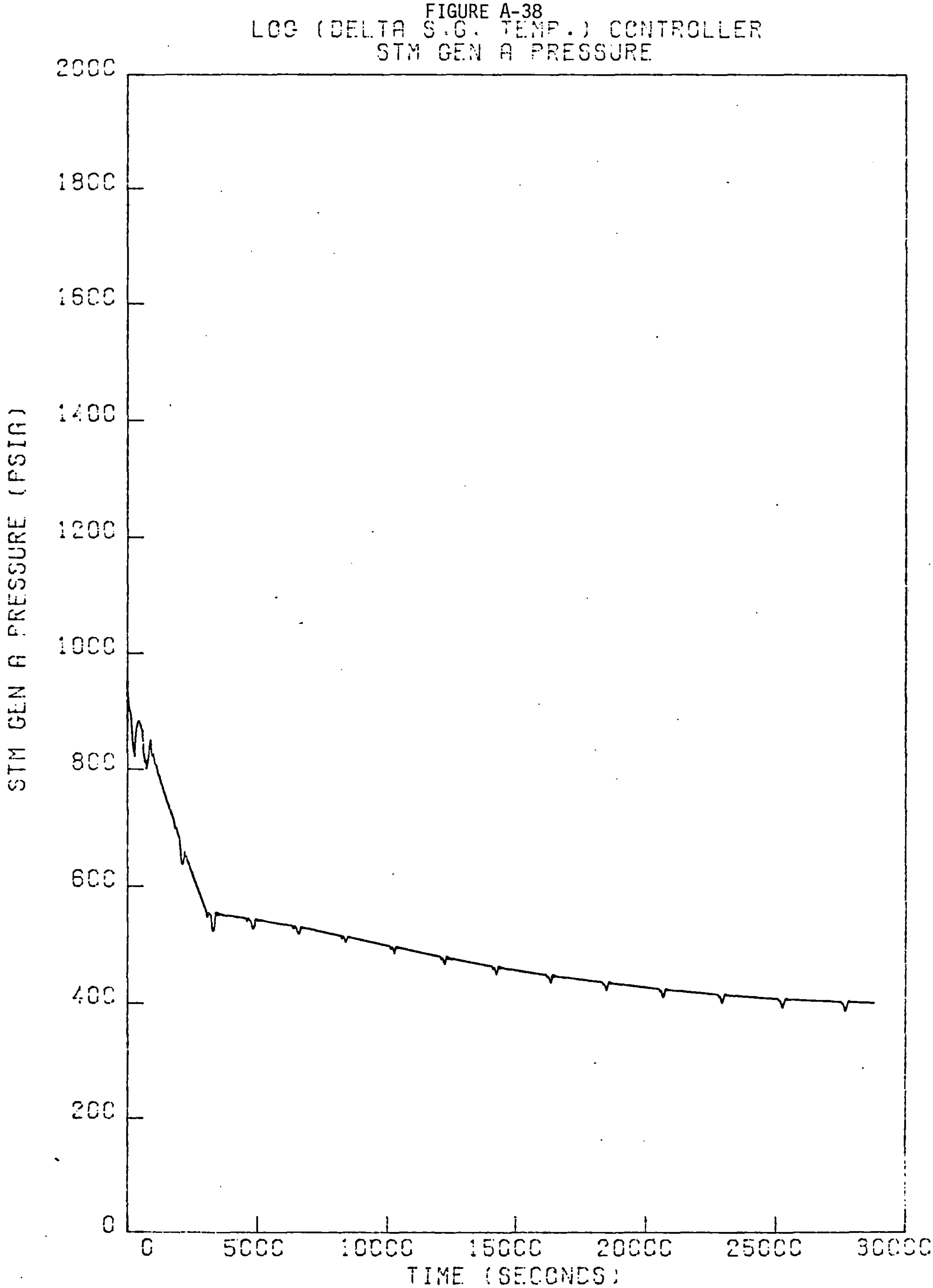
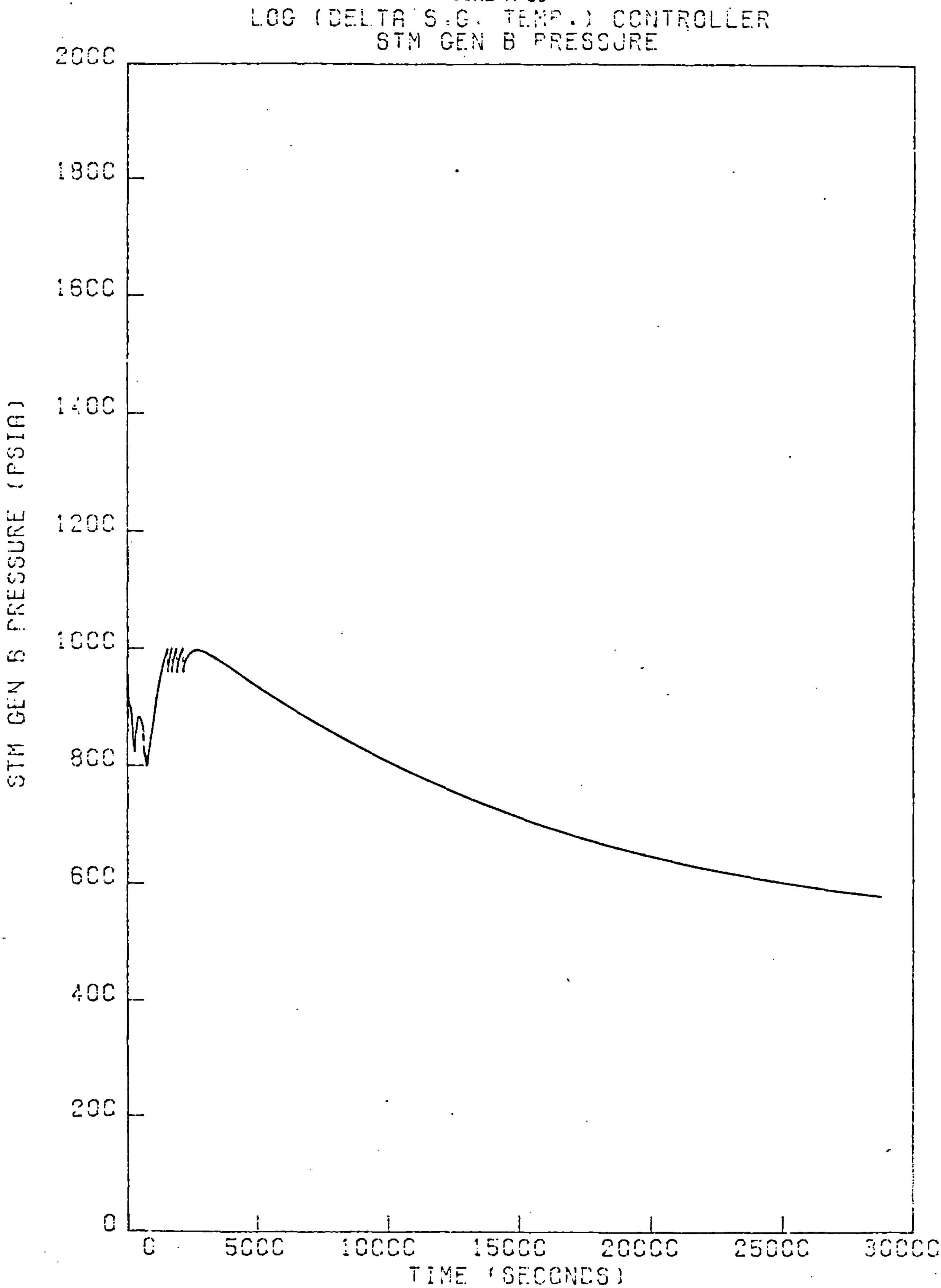

LOG (DELTA S.G. TEMP.) CONTROLLER
STM GEN A PRESSURE
2000
1800
1600
1400
1200
1000
800
600
400
200
0
STM GEN A PRESSURE (PSIA)
0
5000
10000
15000
20000
25000
30000
TIME (SECONDS)

FIGURE A-39



LOG (DELTA S.G. TEMP.) CONTROLLER
STM GEN B PRESSURE
2000
1800
1600
1400
1200
1000
800
600
400
200
0
STM GEN B PRESSURE (PSIA)
0
5000
10000
15000
20000
25000
30000
TIME (SECONDS)

FIGURE A-40

LCG (DELTA S.G. TEMP.) CONTROLLER
STM GEN A NARROW RANGE LEVEL

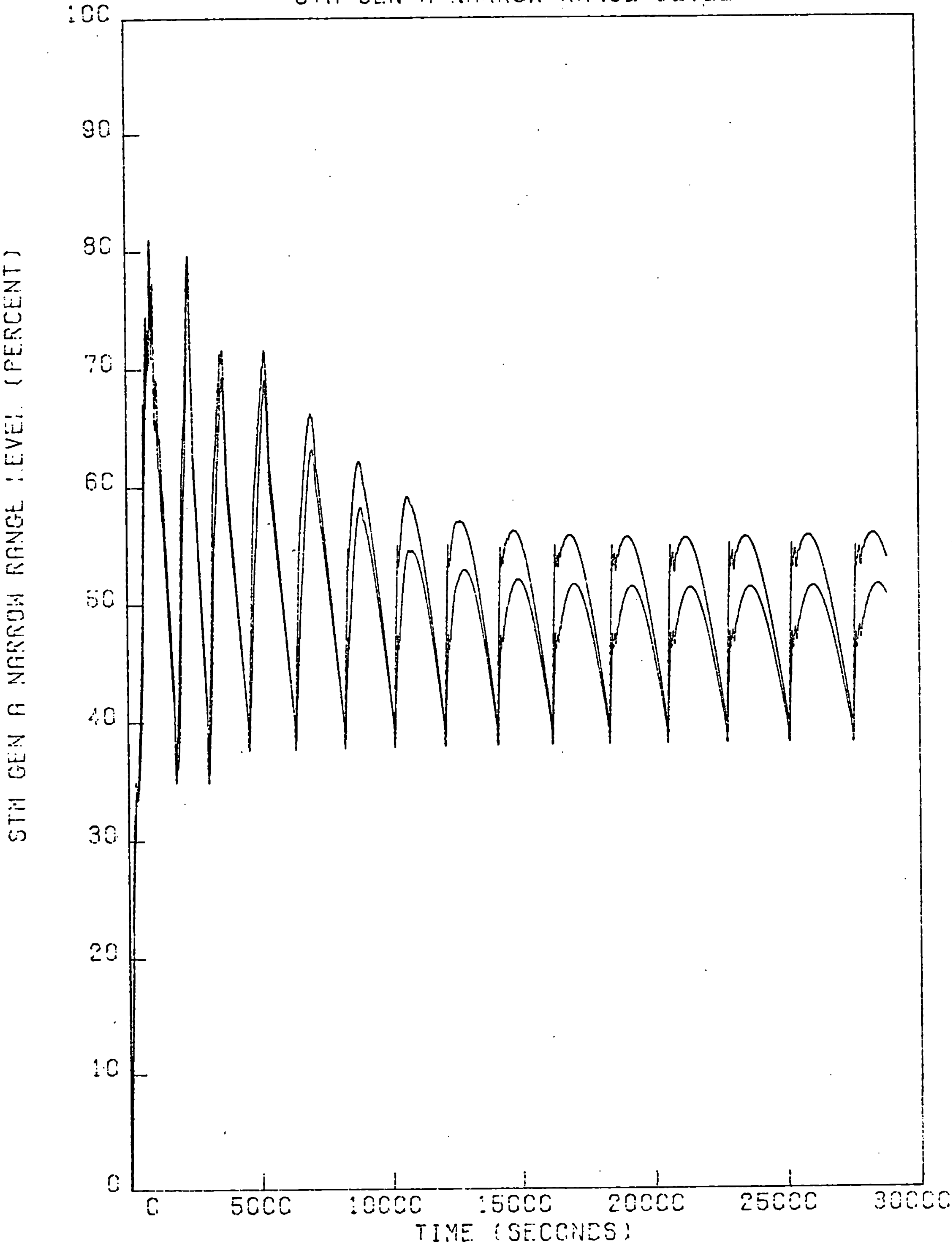


FIGURE A-41
LCC (DELTA S.G. TEMP.) CONTROLLER
STM GEN B NARROW RANGE LEVEL

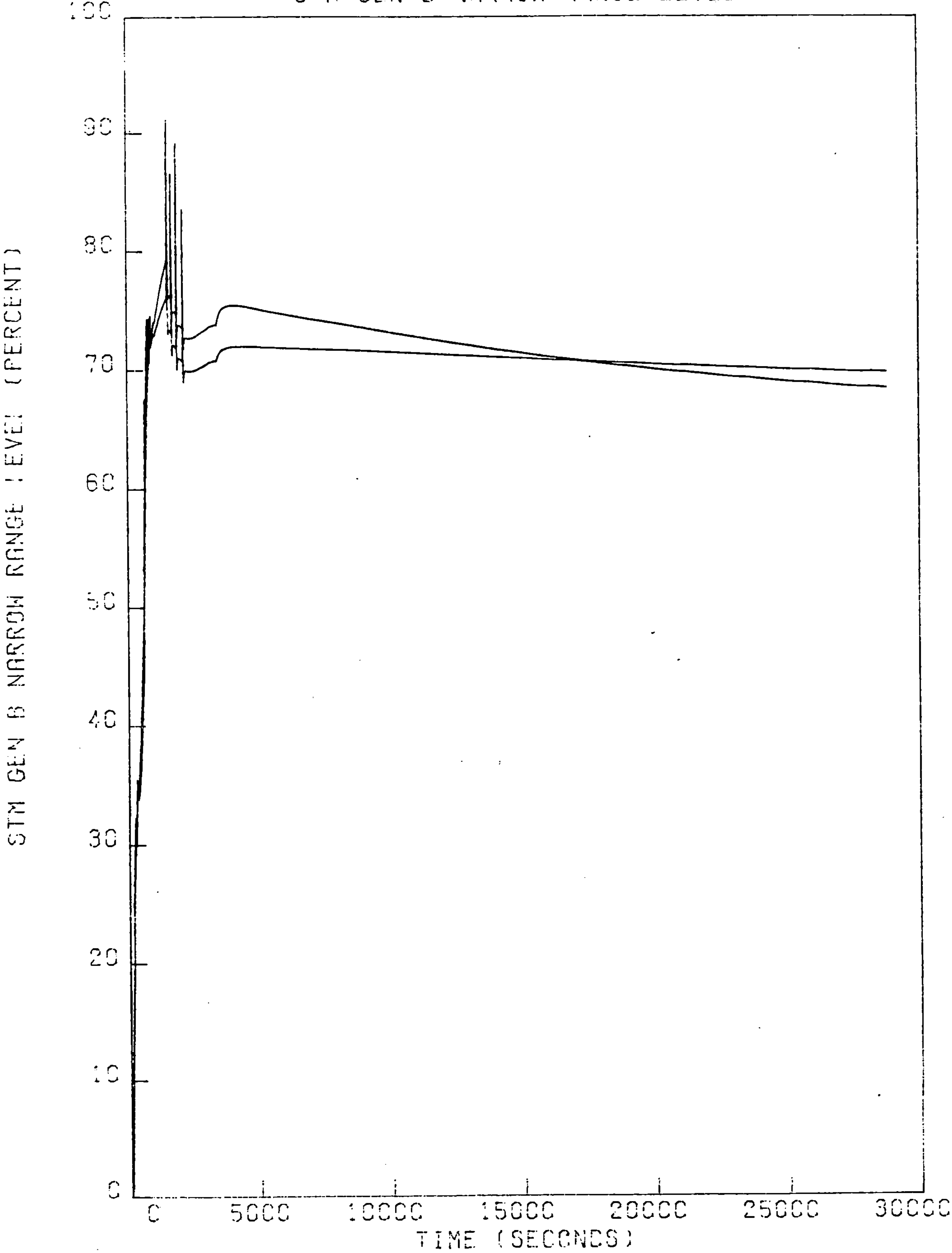


FIGURE A-42

LOG (DELTA S.G. TEMP.) CONTROLLER
STM GEN A STEAM FLOW

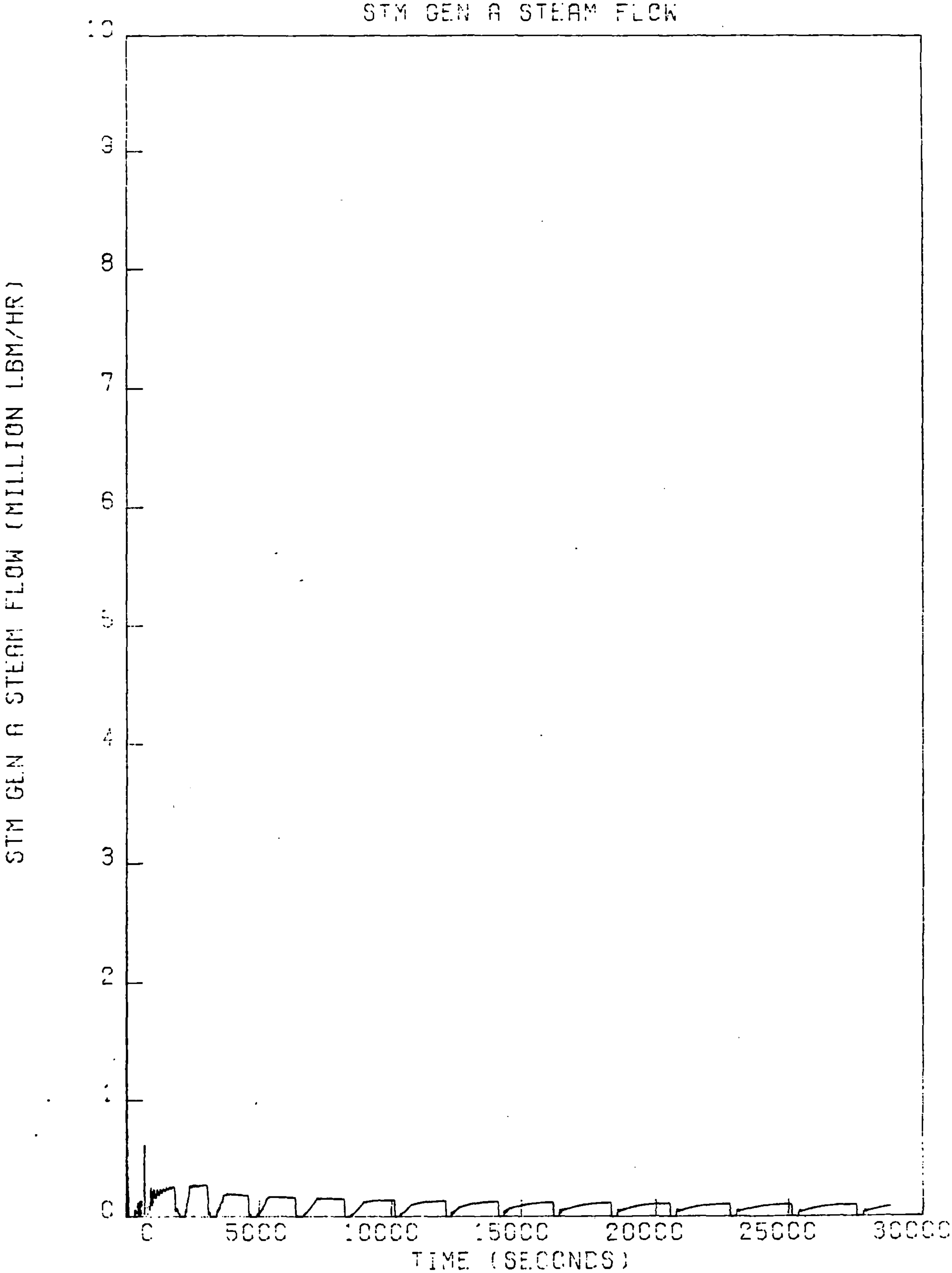


FIGURE A-43

LCG (DELTA S.G. TEMP.) CONTROLLER
STM GEN B STEAM FLOW

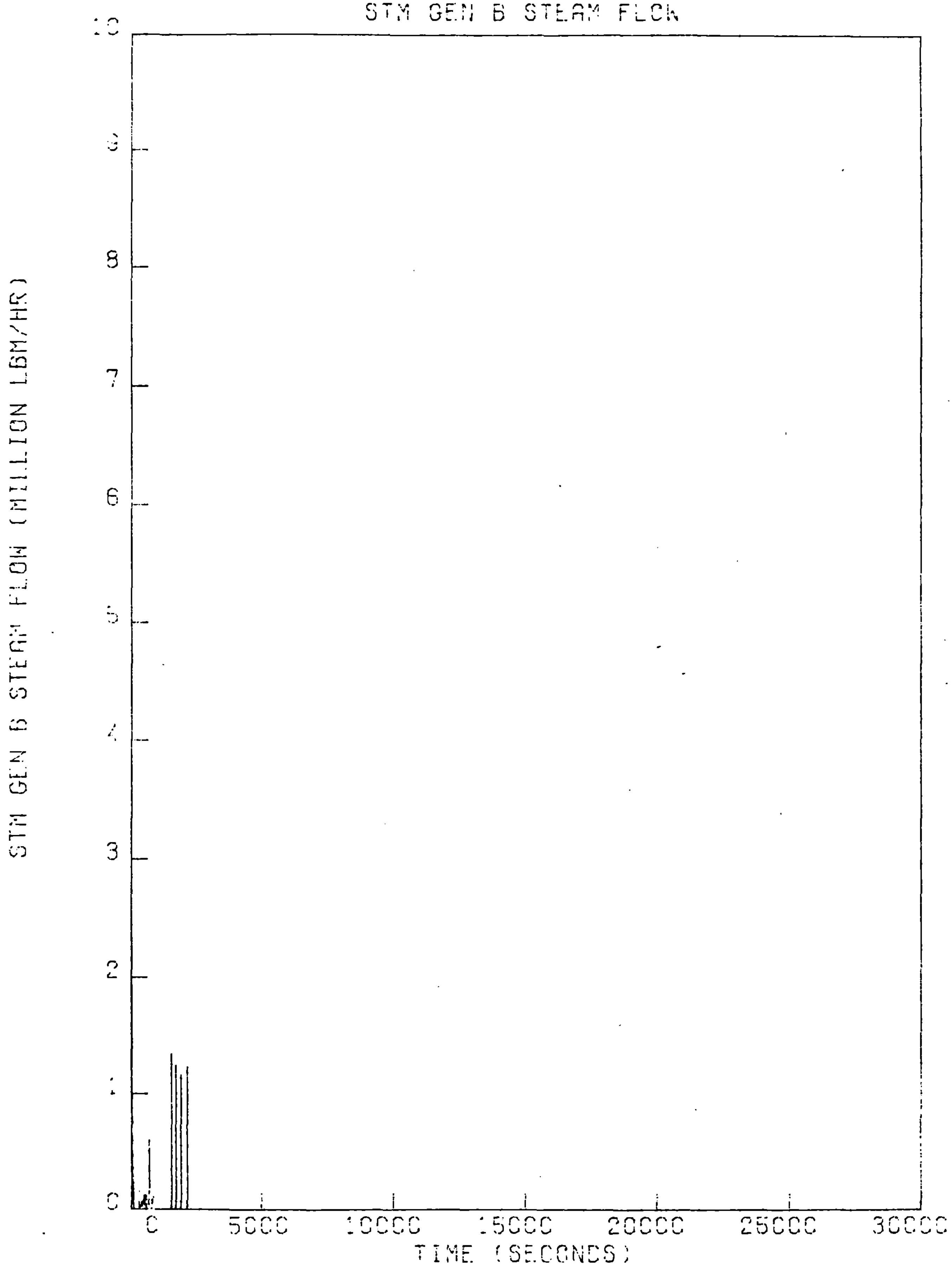


FIGURE A-44

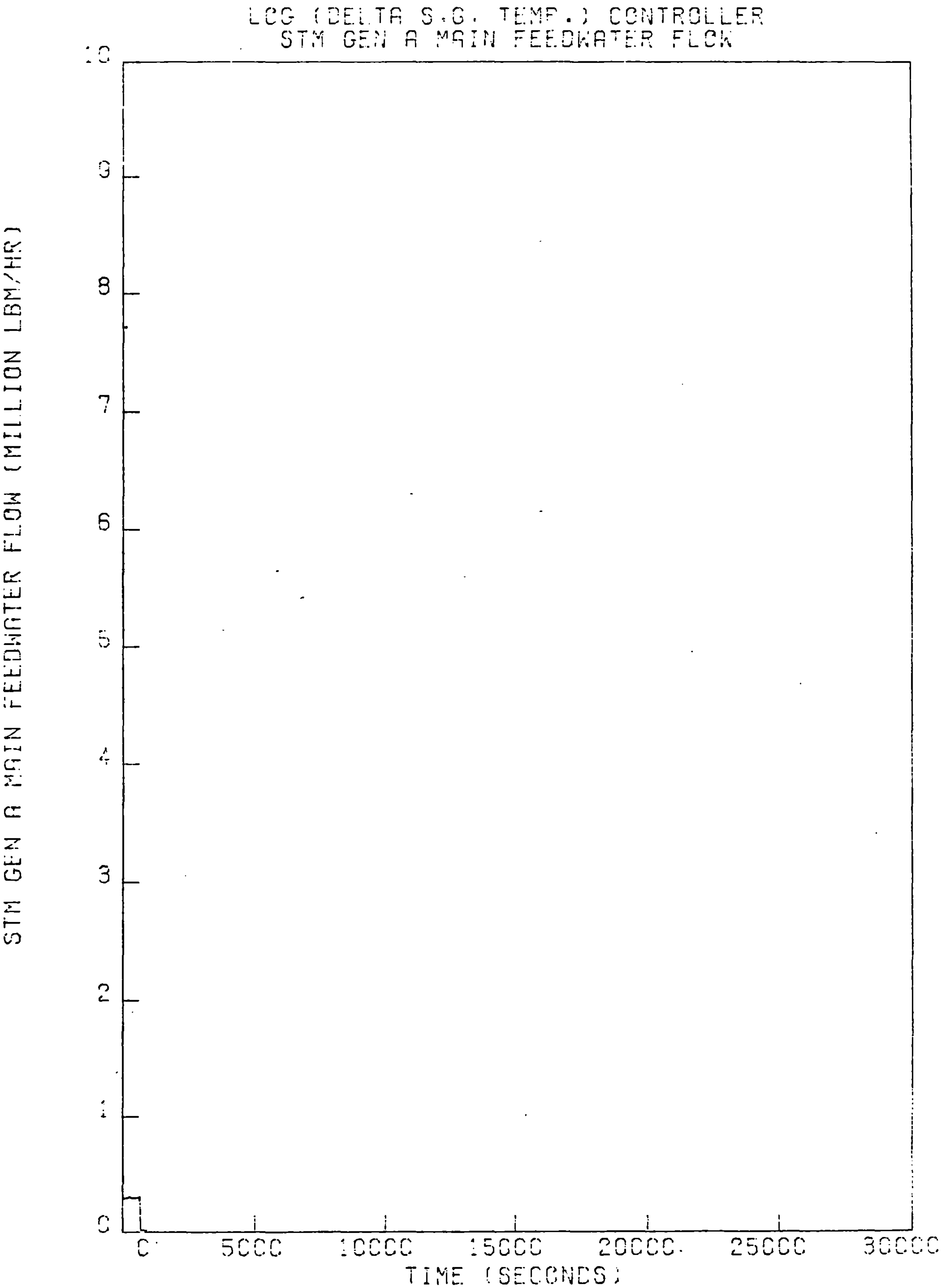
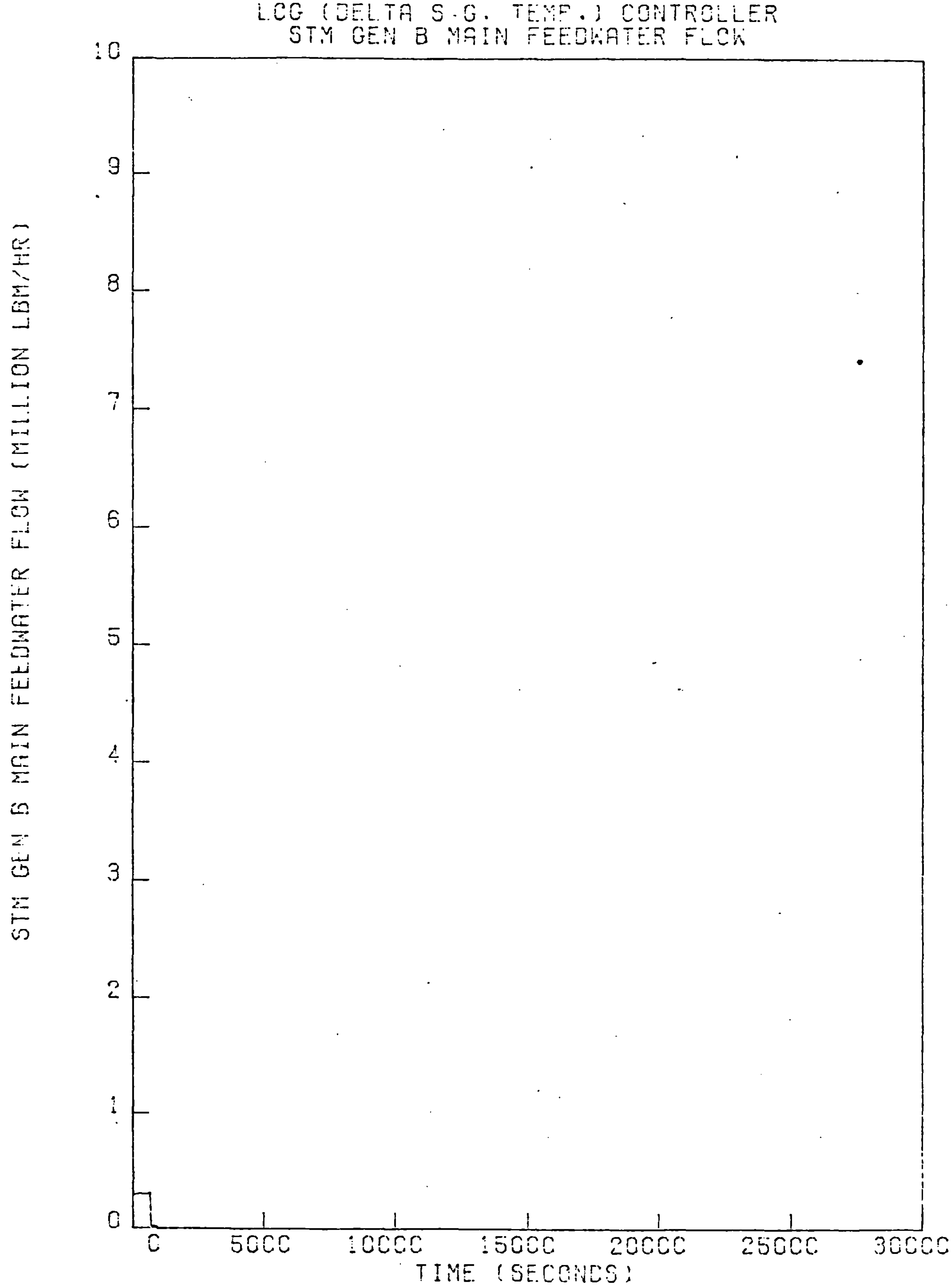

LCG (DELTA S.G. TEMP.) CONTROLLER
STM GEN A MAIN FEEDWATER FLOW
STM GEN A MAIN FEEDWATER FLOW (MILLION LBM/HR)
0
1
2
3
4
5
6
7
8
9
10
0
5000
10000
15000
20000
25000
30000
TIME (SECONDS)

FIGURE A-45



LOG (DELTA S.G. TEMP.) CONTROLLER
STM GEN B MAIN FEEDWATER FLOW
STM GEN B MAIN FEEDWATER FLOW (MILLION LBM/HR)
10
9
8
7
6
5
4
3
2
1
0
0
5000
10000
15000
20000
25000
30000
TIME (SECONDS)

FIGURE A-46

LOG (DELTA S.G. TEMP.) CONTROLLER
STM GEN A AUXILIARY FEEDWATER FLOW

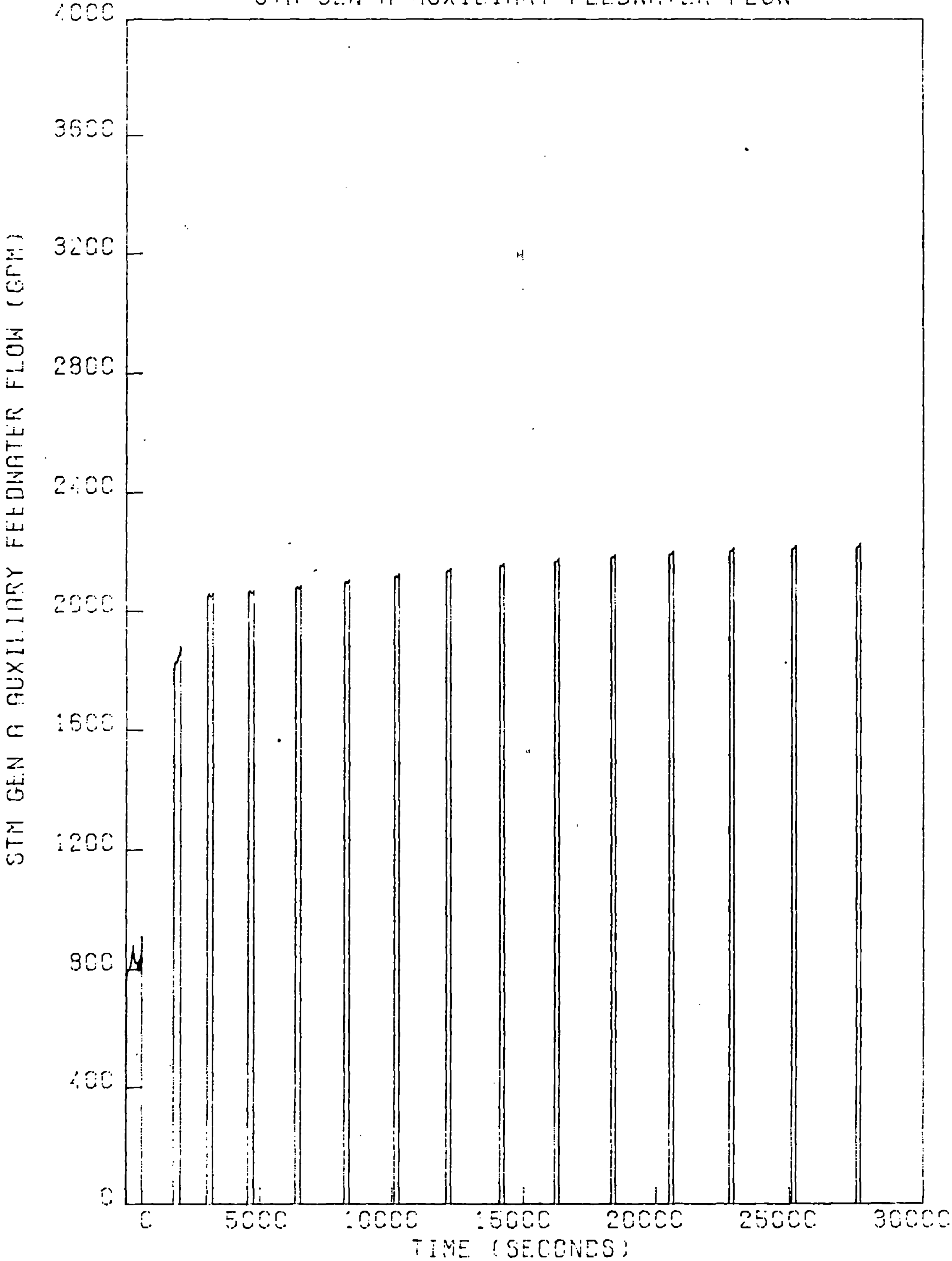


FIGURE A-47

LCG (DELTA S.G. TEMP.) CONTROLLER
STM GEN B AUXILIARY FEEDWATER FLOW

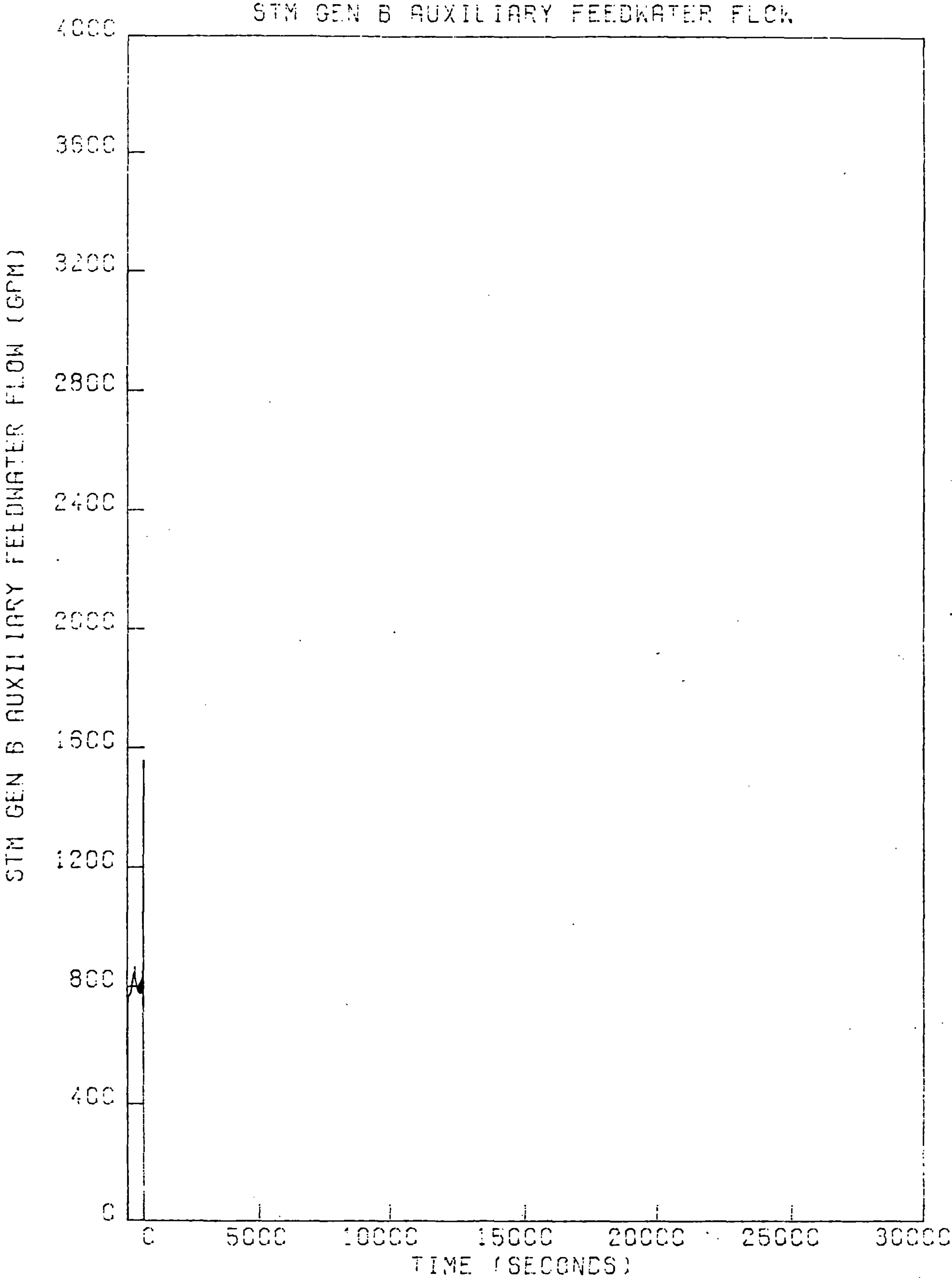
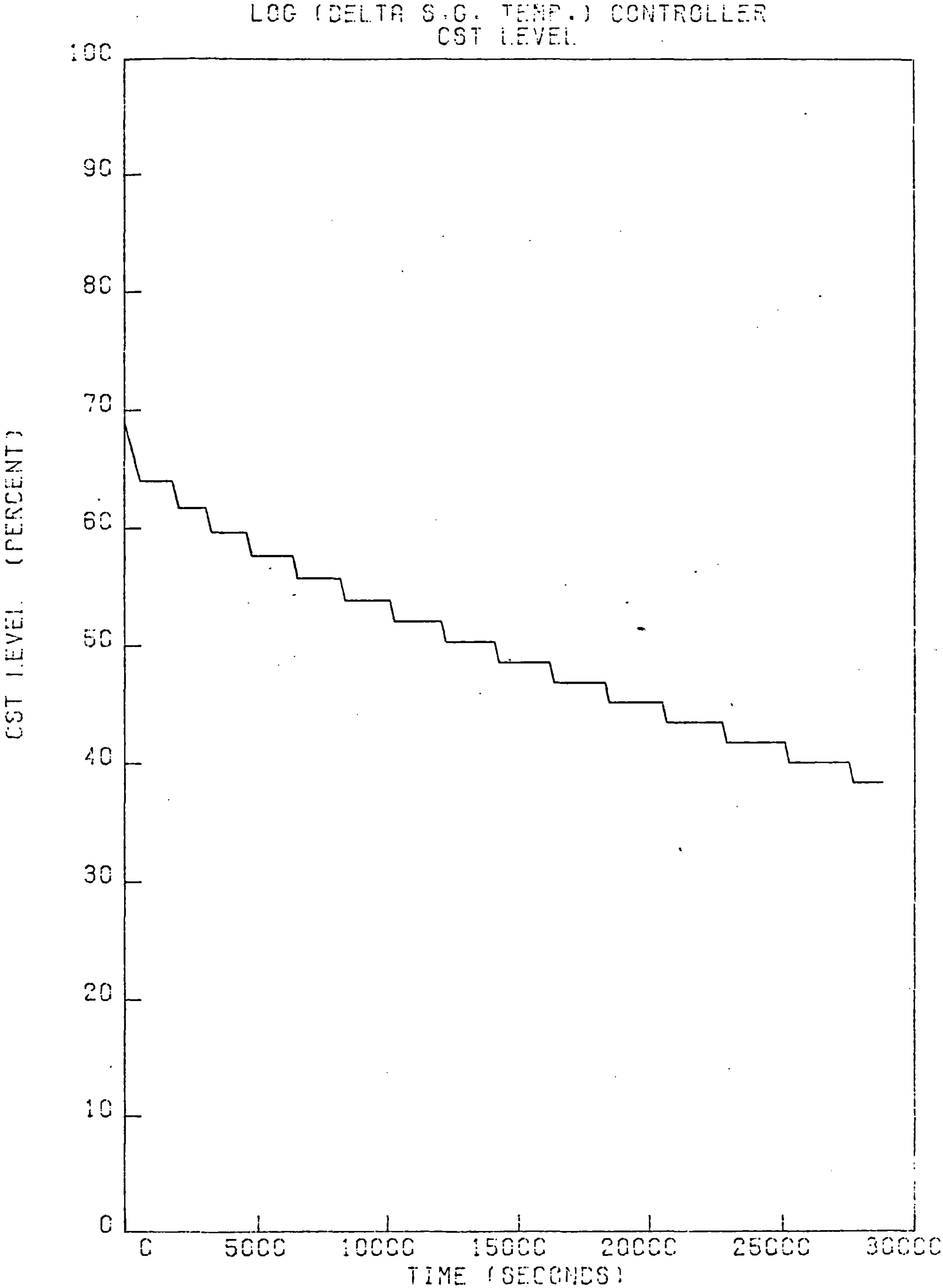


FIGURE A-48


LOG (DELTA S.G. TEMP.) CONTROLLER
CST LEVEL
CST LEVEL (PERCENT)
100
90
80
70
60
50
40
30
20
10
0
0
5000
10000
15000
20000
25000
30000
TIME (SECONDS)

CASE 3

Cooldown of Unisolated Steam Generator Based on Optimum Steady State Analysis Secondary Temperature Plus 20°F

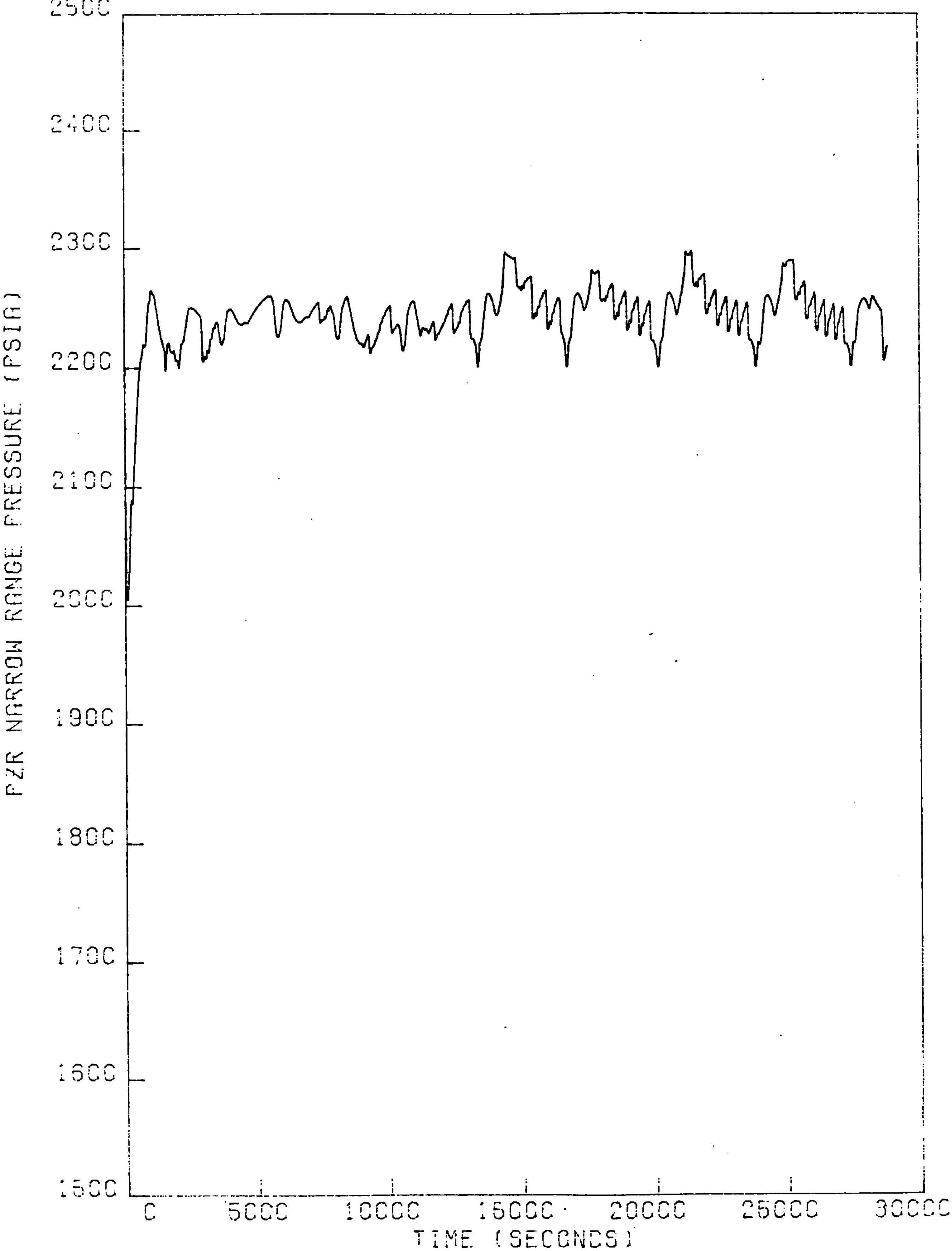
t, sec	$T_{SG\ 1}$, °F	$T_{SG\ 2}$, °F	q_2, Btu/sec	Notes
900	525	525	27400	Cooling SG 1
1000	522	529	17900	
1500	511	544	7900	
2000	500	542	5300	
2500	495	544	1300	
3000	495	540	3100	
3500	497	542	649	Low forward heat transfer
4000	500	542	-143	$T_{hot} \approx T_{sec\ 2}$
4500	502	543	437	
5100	504	544	611	
6100	505	542	370	Higher forward heat transfer
10100	514	543	1127	T_{opt} inaccurate for $t>10^4$ sec
15100	518	543	1898	
28700	523	542	2548	

These results show that essentially no cooling of the hot unit occurred since $T_{sec\ 1}$ was not low enough to cause reverse heat transfer from the isolated unit. The following figures are LTC transient parameter plots for Case 3.

FIGURE A-49

LOG (DELTA S.G. TEMP. + 20 DEGF) CONTROLLER

PZR NARROW RANGE PRESSURE



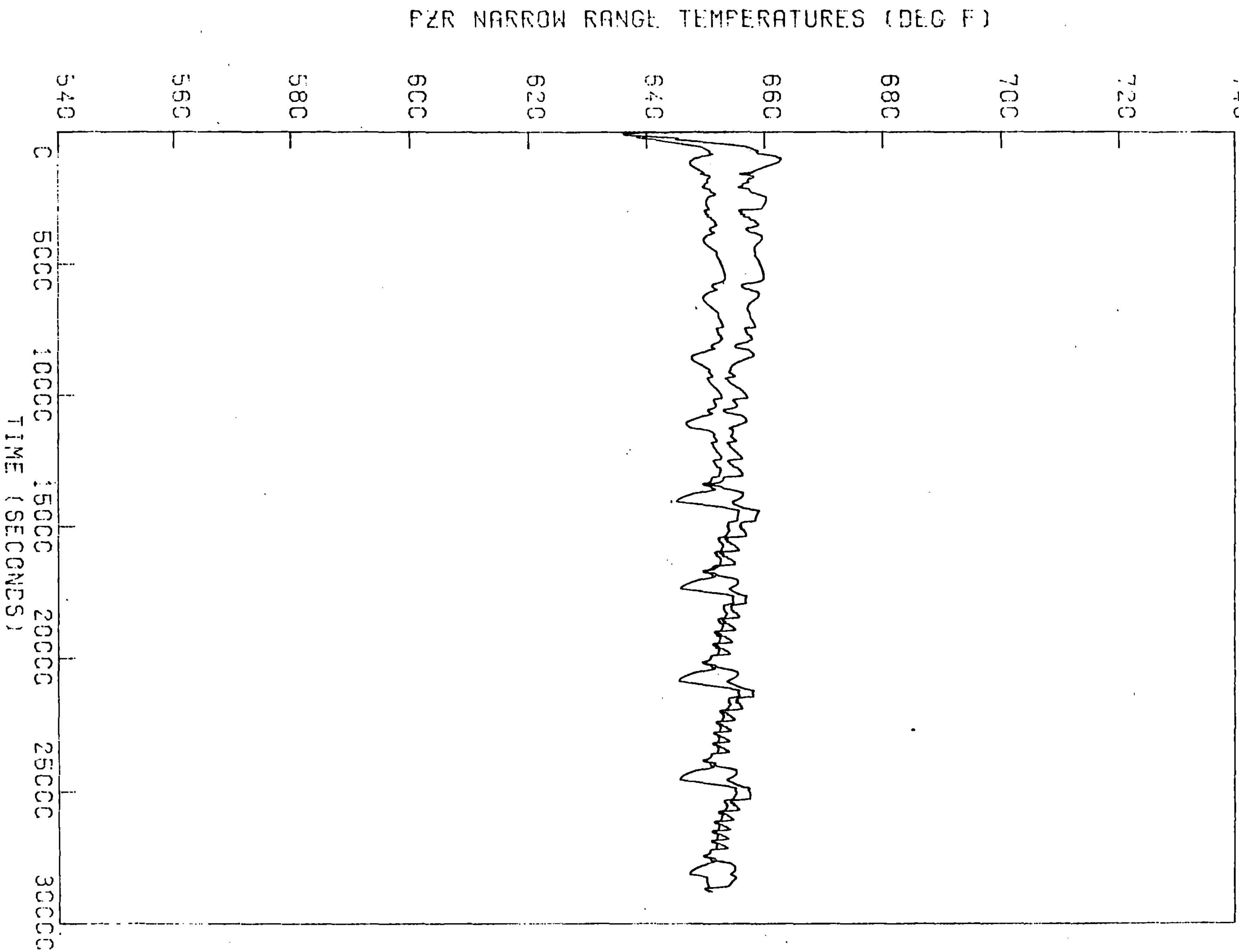


FIGURE A-50
LOG (DELTA S.G. TEMP. + 20 DEGF) CONTROLLER
PZR NARROW RANGE TEMPERATURE

FIGURE A-51

LCG (DELTA S.G. TEMP. + 20 DEGF) CONTROLLER

PZR LEVEL

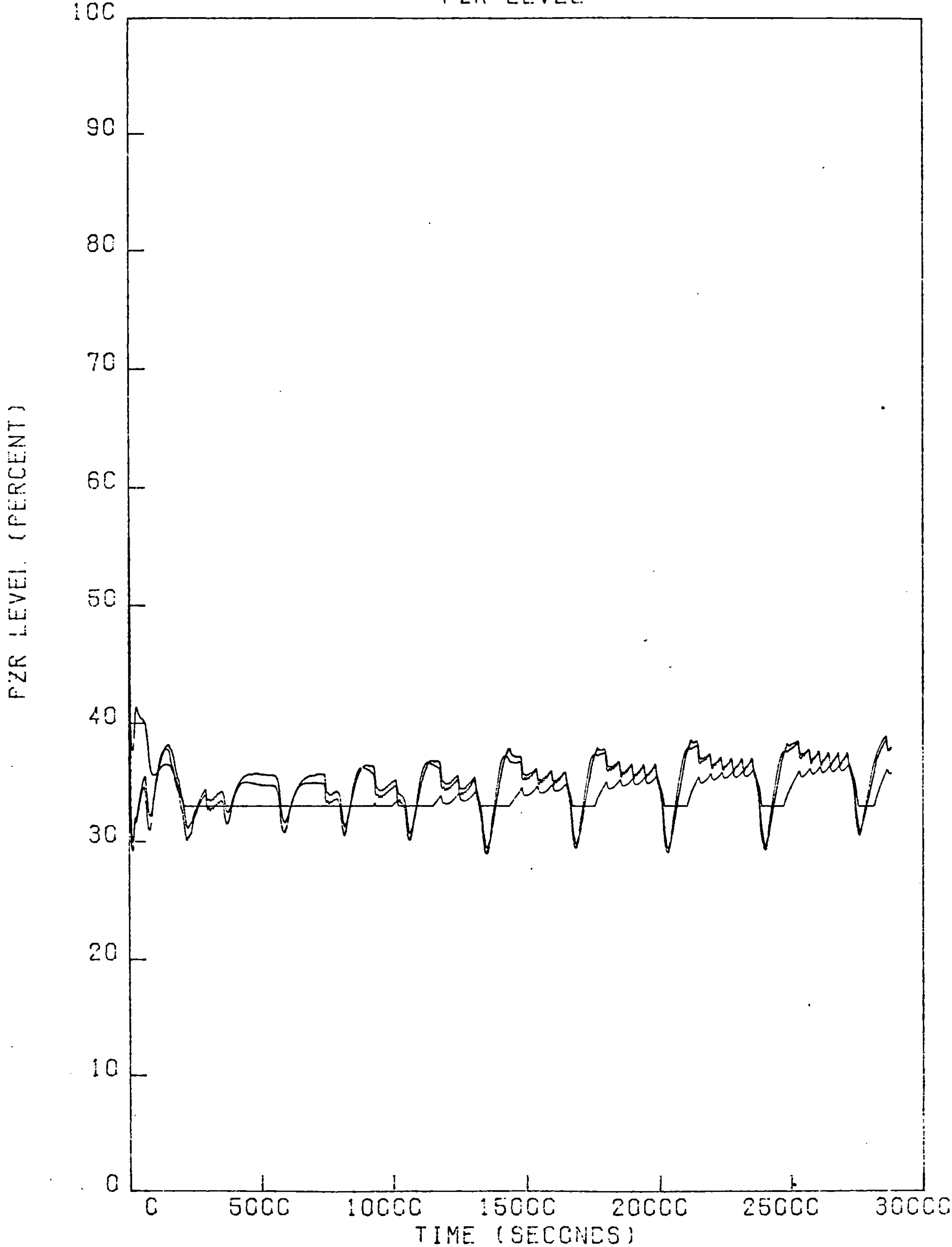


FIGURE A-52

LCG (DELTA S.G. TEMP. + 20 DEGF) CONTROLLER
PZR HEATER RATE

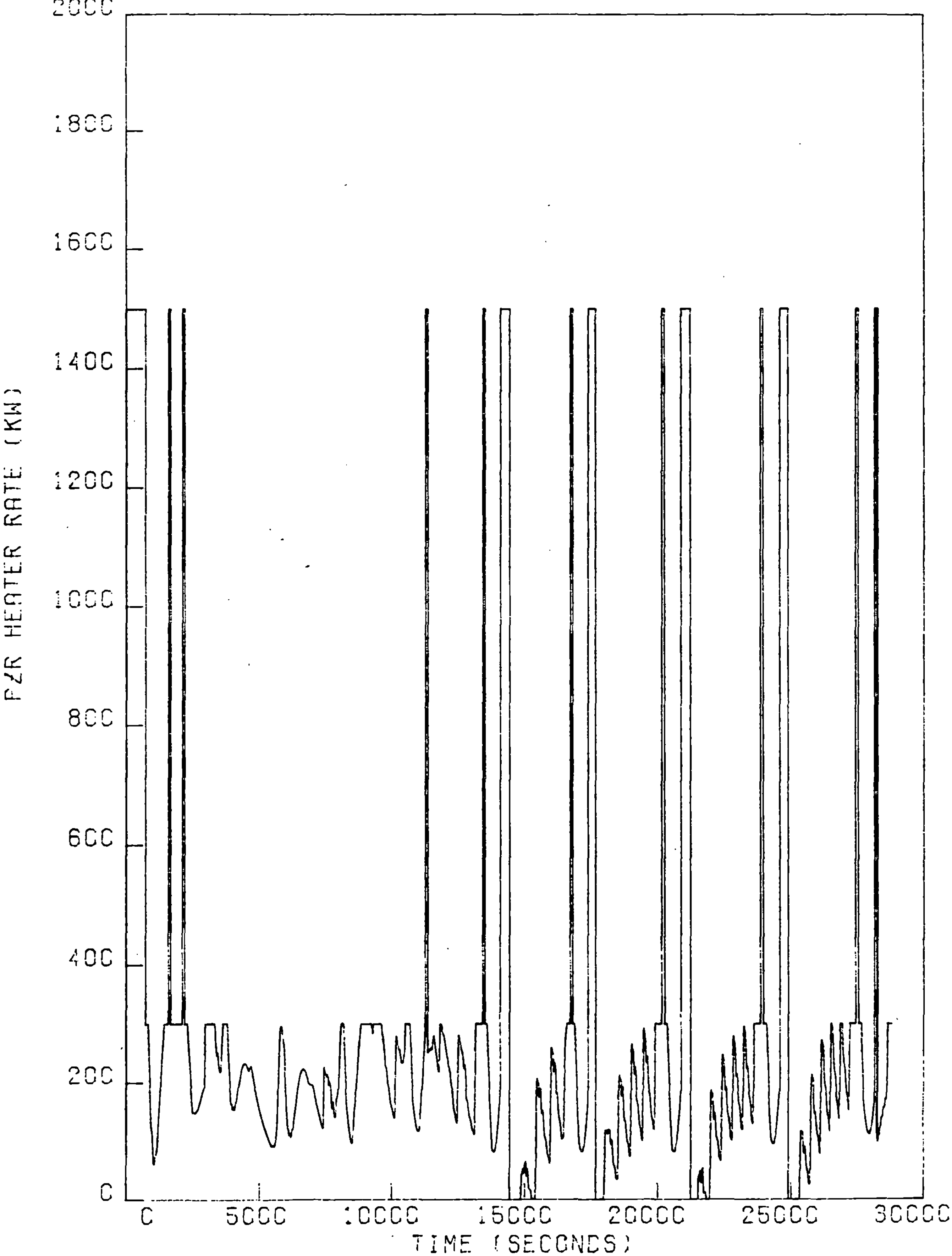


FIGURE A-53

LCG (DELTA S.G. TEMP. + 20 DEGF) CONTROLLER

CHARGING - LETDOWN FLOWS

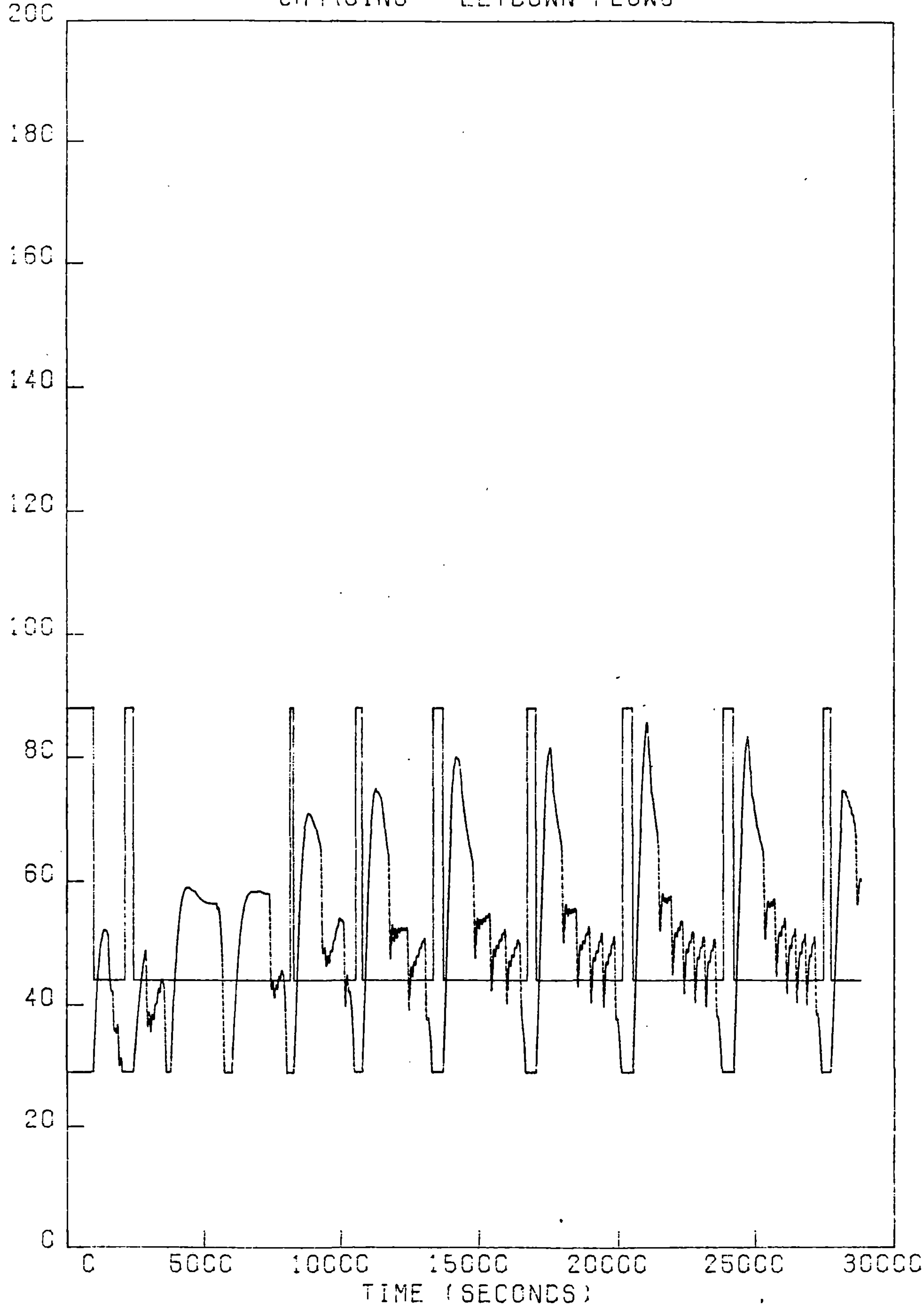


FIGURE A-54

LOG (DELTA S.G. TEMP. + 20 DEGF) CONTROLLER
VCT LEVEL

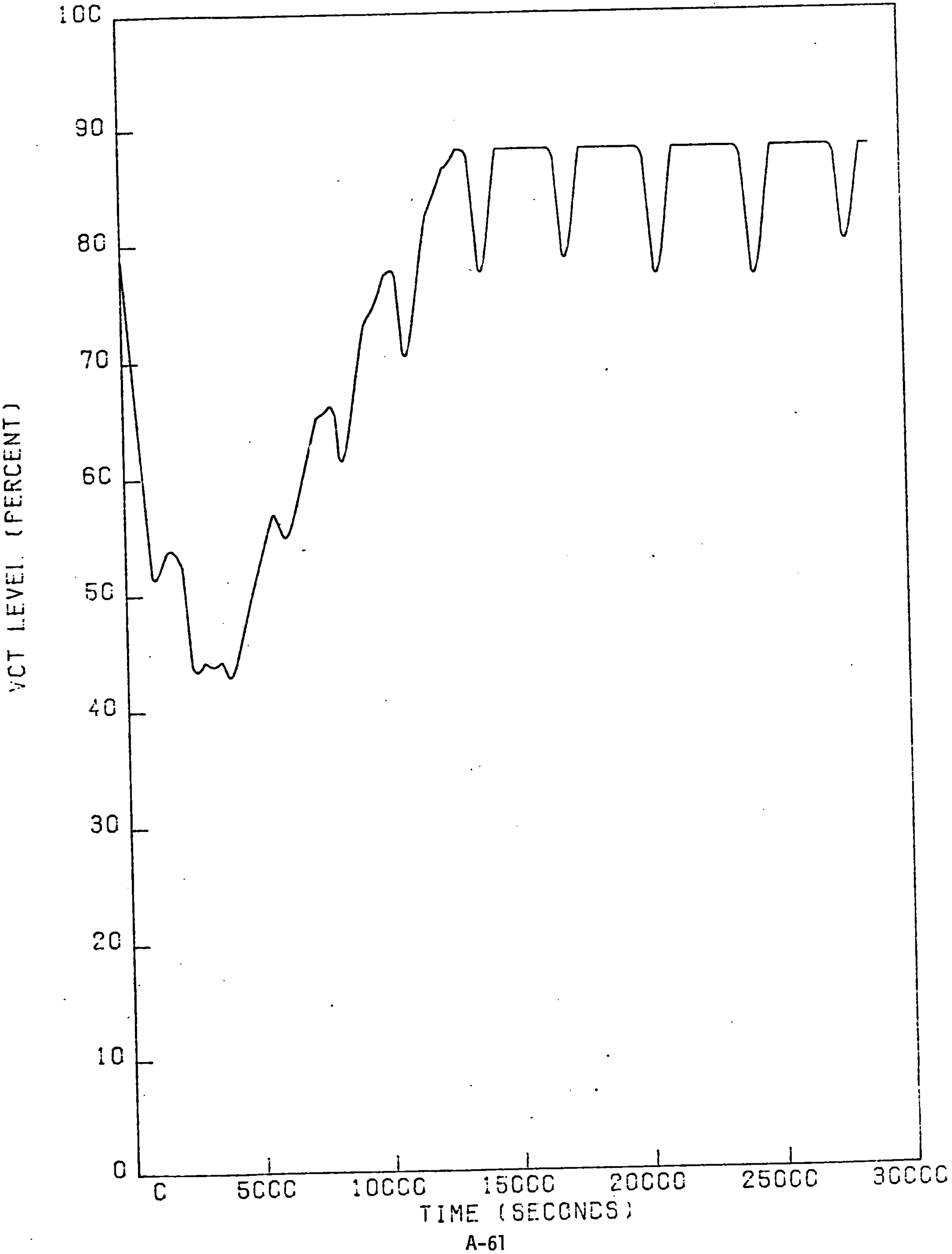


FIGURE A-55

LOG (DELTA S.G. TEMP. + 20 DEGF) CONTROLLER
LOOP A RCS MASS FLOWS

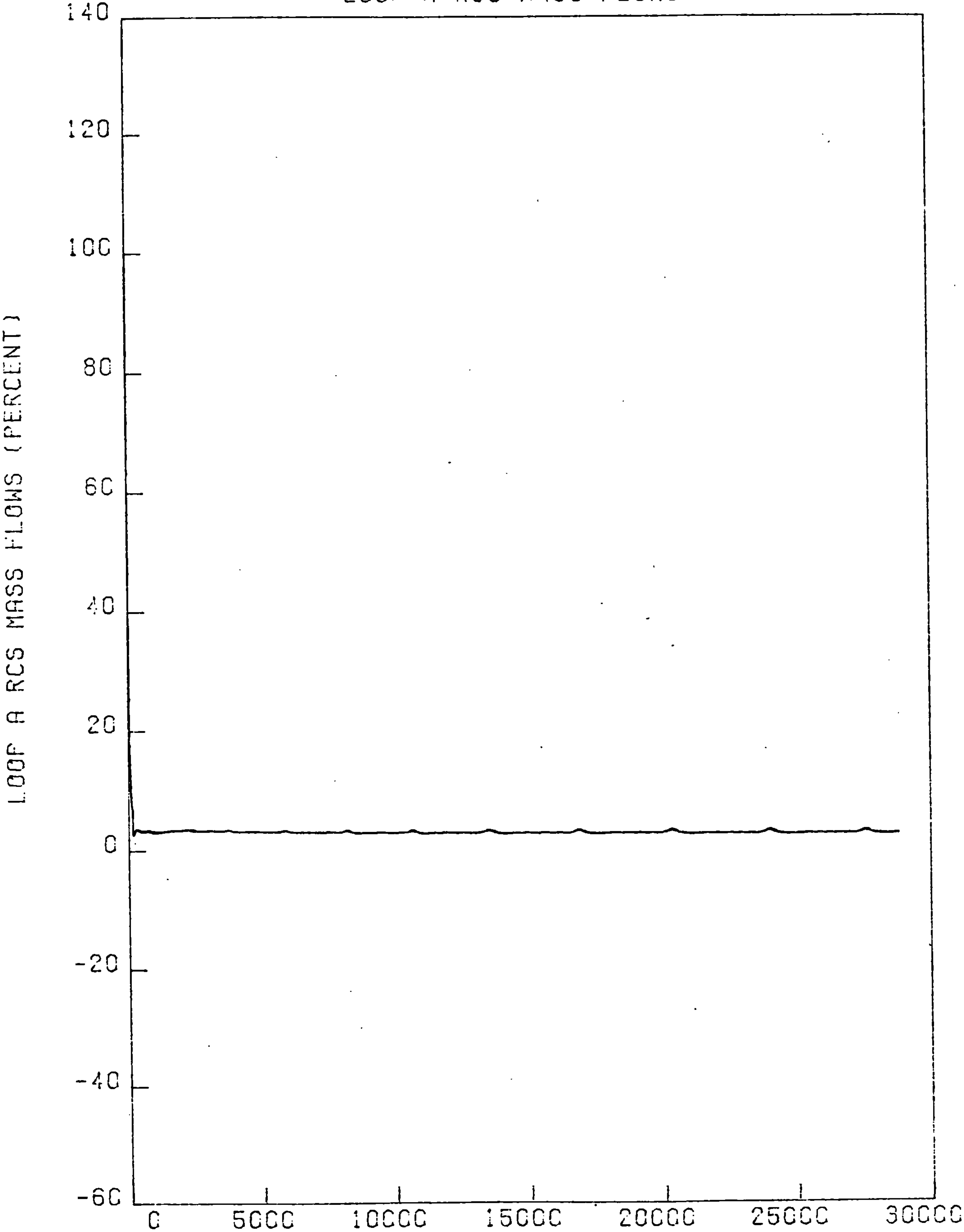


FIGURE A-56

LOG (DELTA S.G. TEMP. + 20 DEGF) CONTROLLER

LOOP B RCS MASS FLOWS

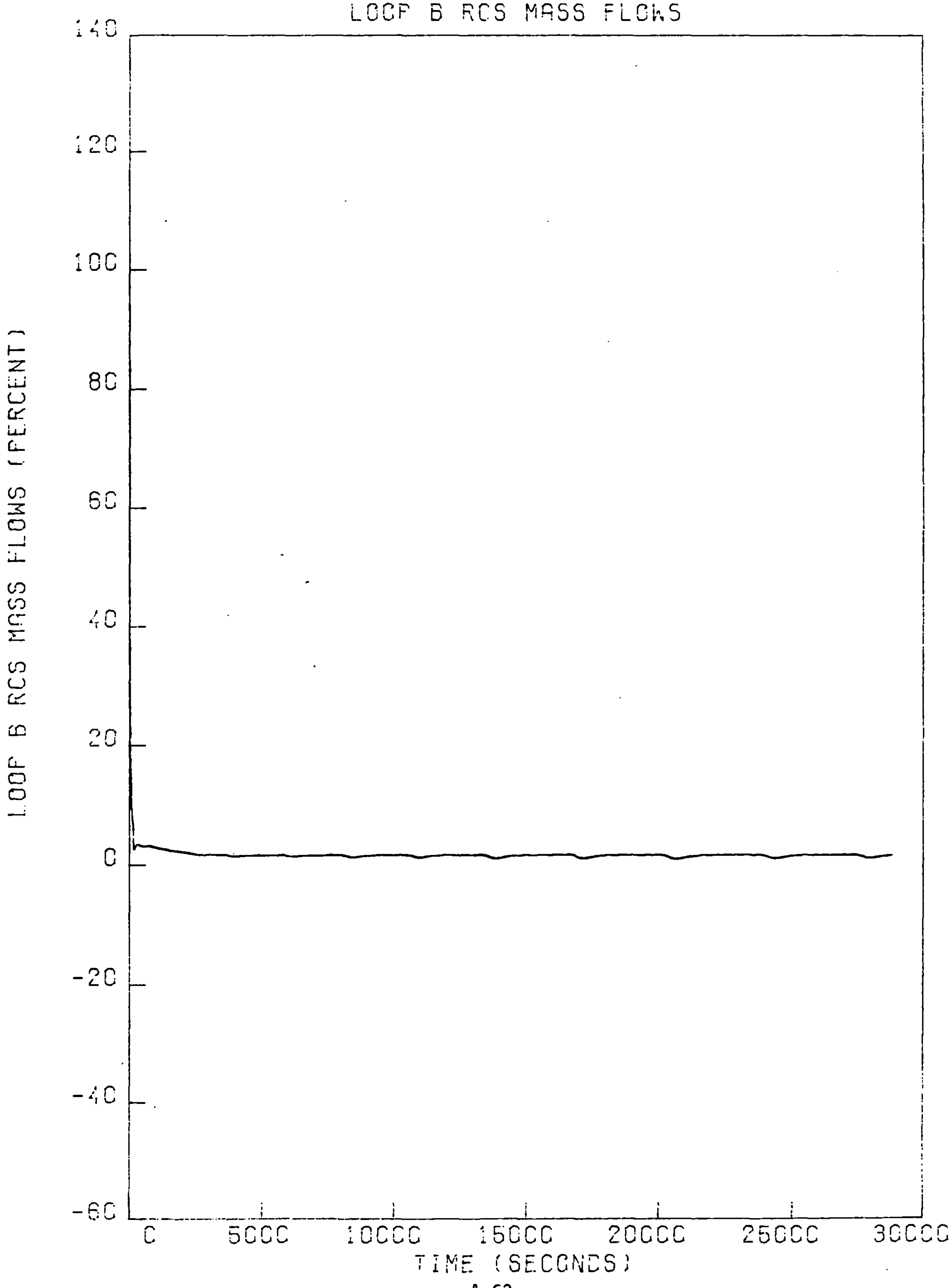


FIGURE A-57

LCG (DELTA S.G. TEMP. ± 20 DEGF) CONTROLLER
LOOP A RCS NARROW RANGE TEMPERATURES

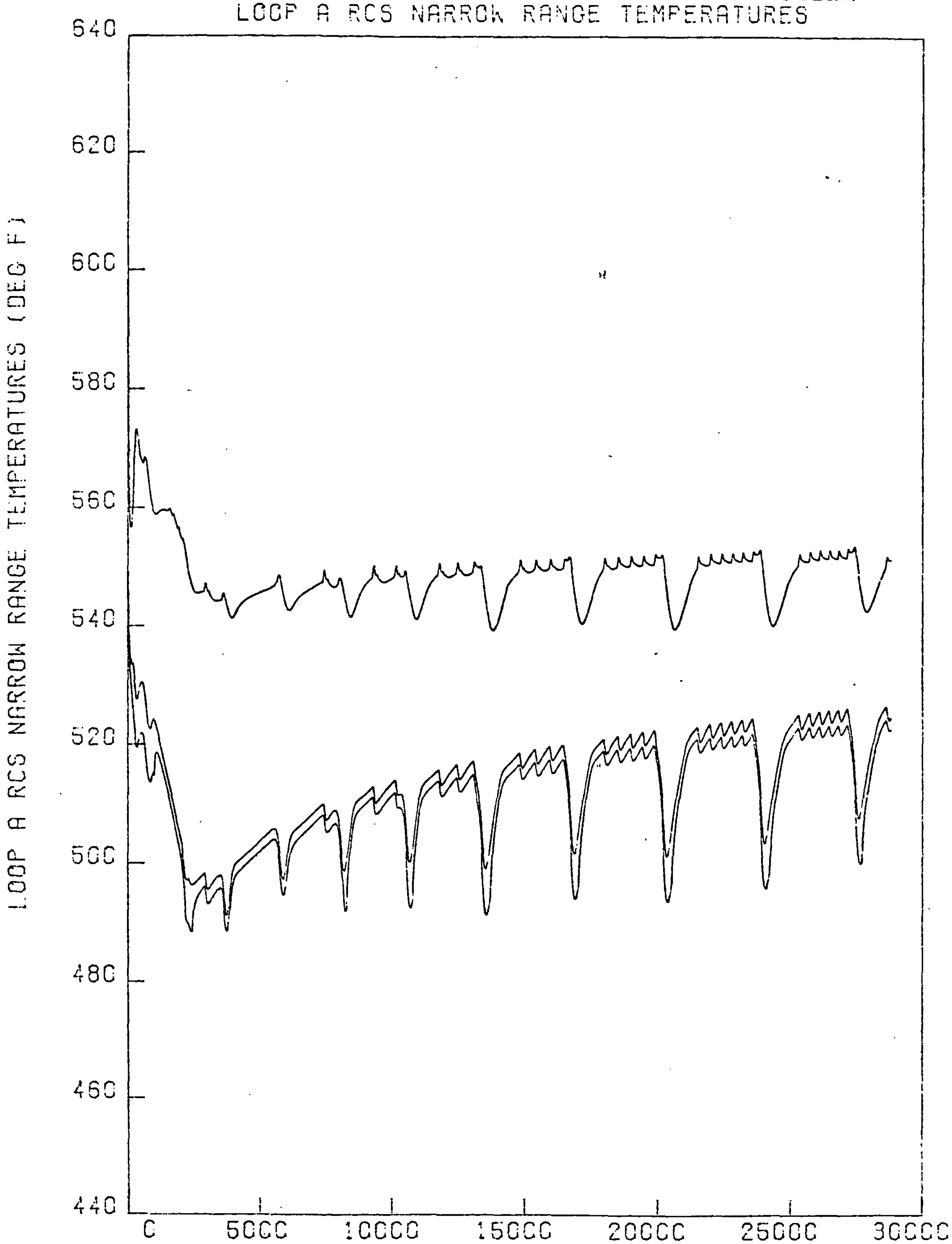


FIGURE A-58

LOG (DELTA S.G. TEMP. + 20 DEGF) CONTROLLER
LOOP B RCS NARROW RANGE TEMPERATURES

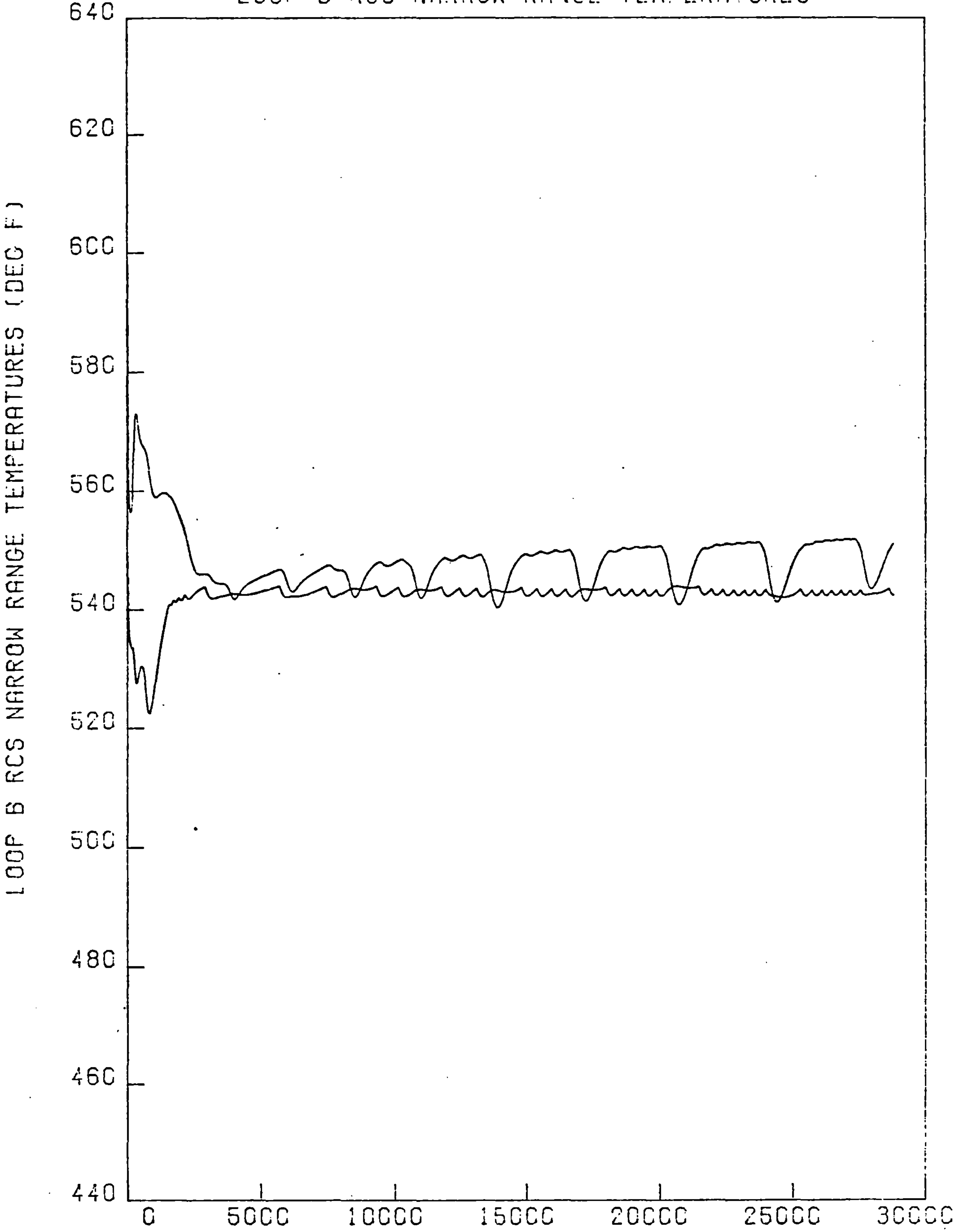


FIGURE A-59

LOG (DELTA S.G. TEMP. + 20 DEGF) CONTROLLER

LOOP A RCS WIDE RANGE TEMPERATURES

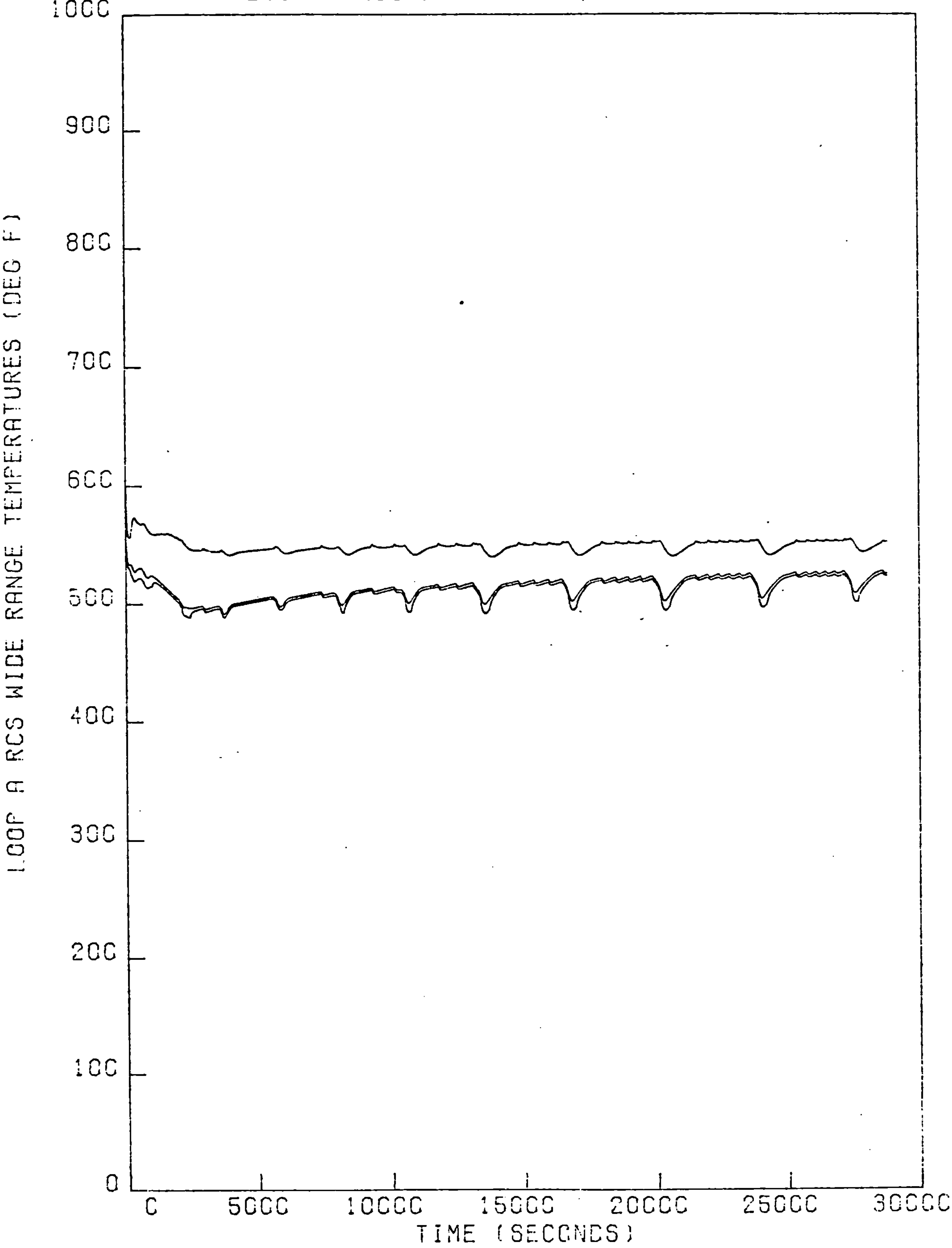


FIGURE A-60

LOG (DELTA S.G. TEMP. + 20 DEGF) CONTROLLER
LOOP B RCS WIDE RANGE TEMPERATURES

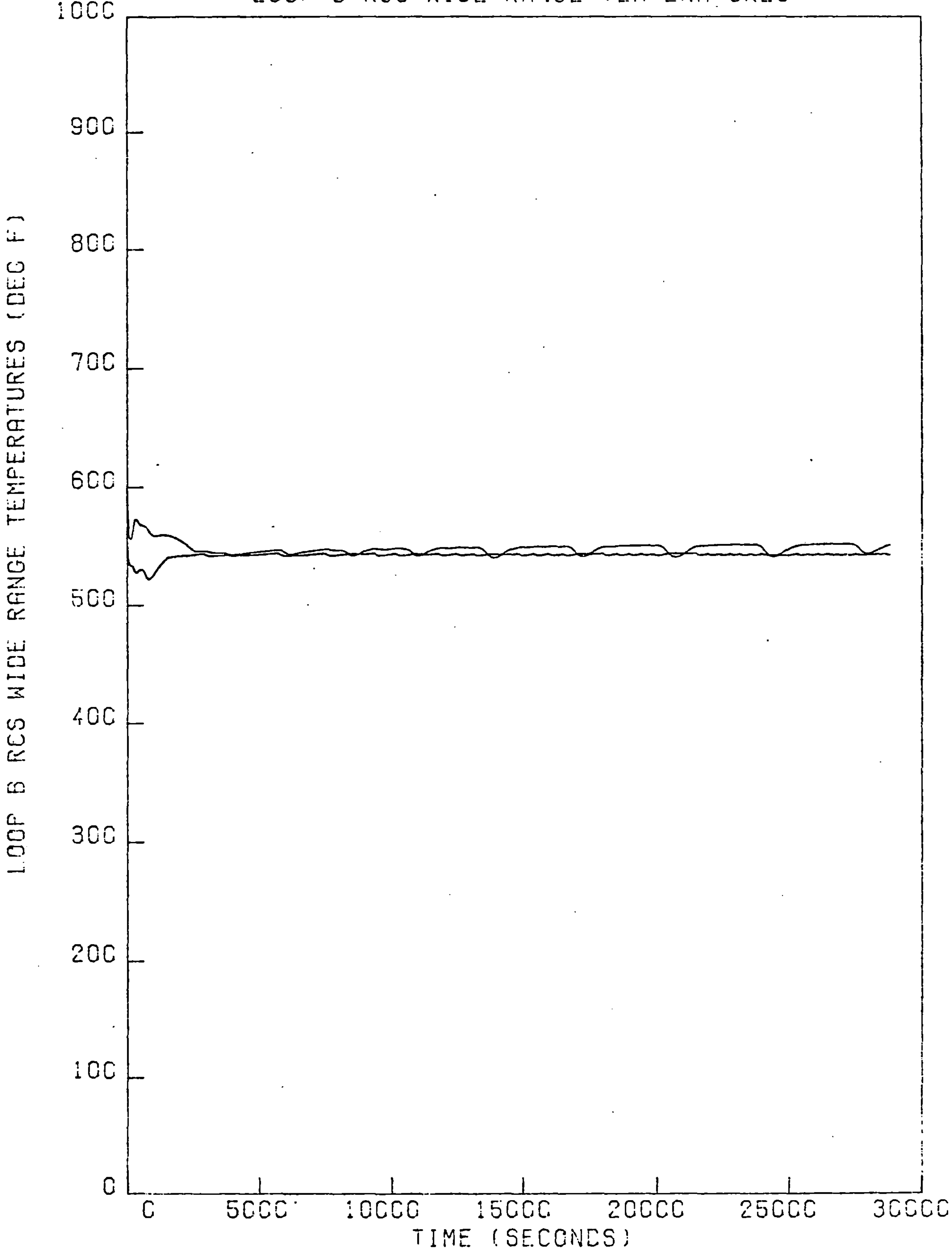


FIGURE A-61

LOG (DELTA S.G. TEMP. + 20 DEGF) CONTROLLER
(DELTA T SUBCOOLING

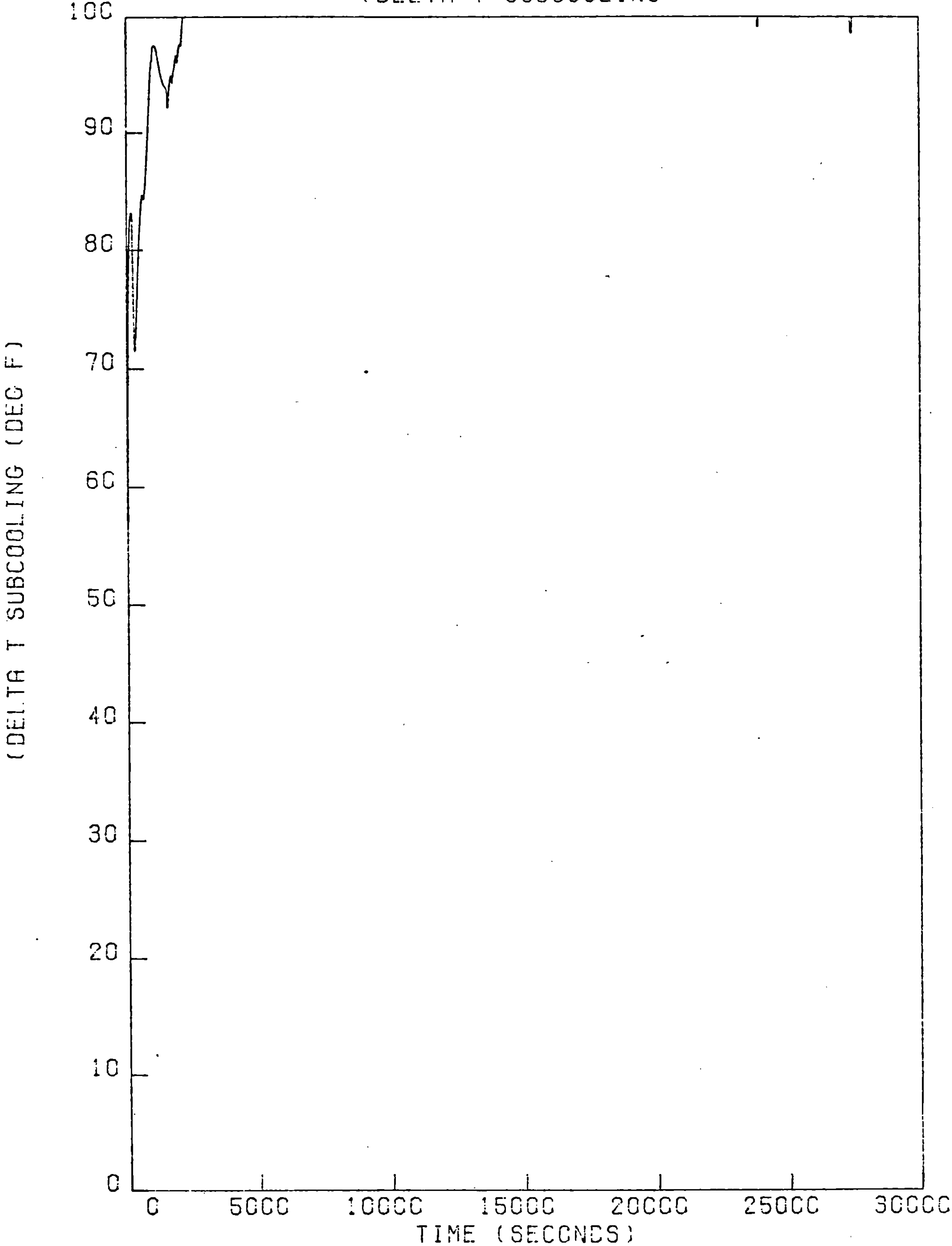


FIGURE A-62

LCG (DELTA S.G. TEMP. + 20 DEGF) CONTROLLER

STM GEN A PRESSURE

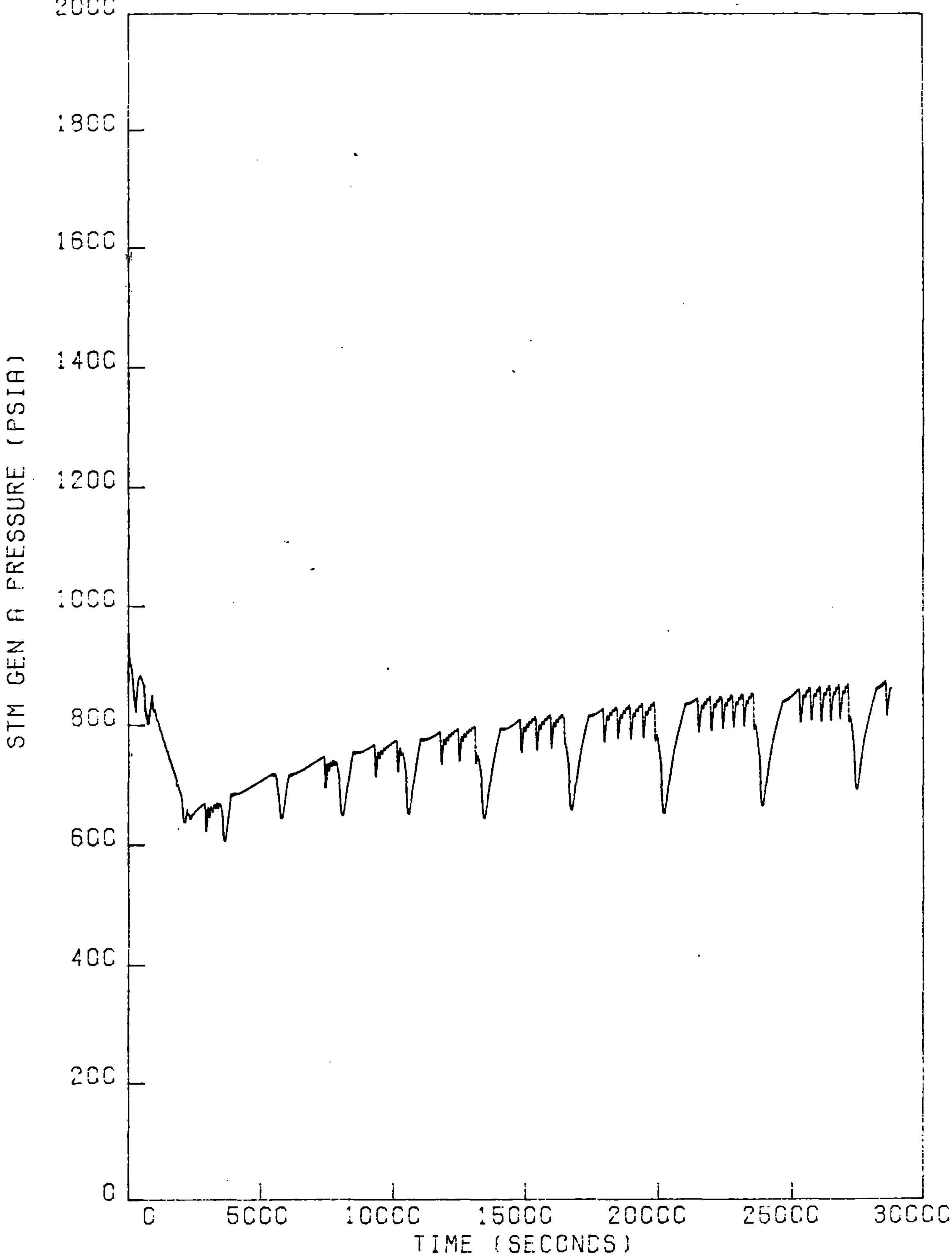


FIGURE A-63

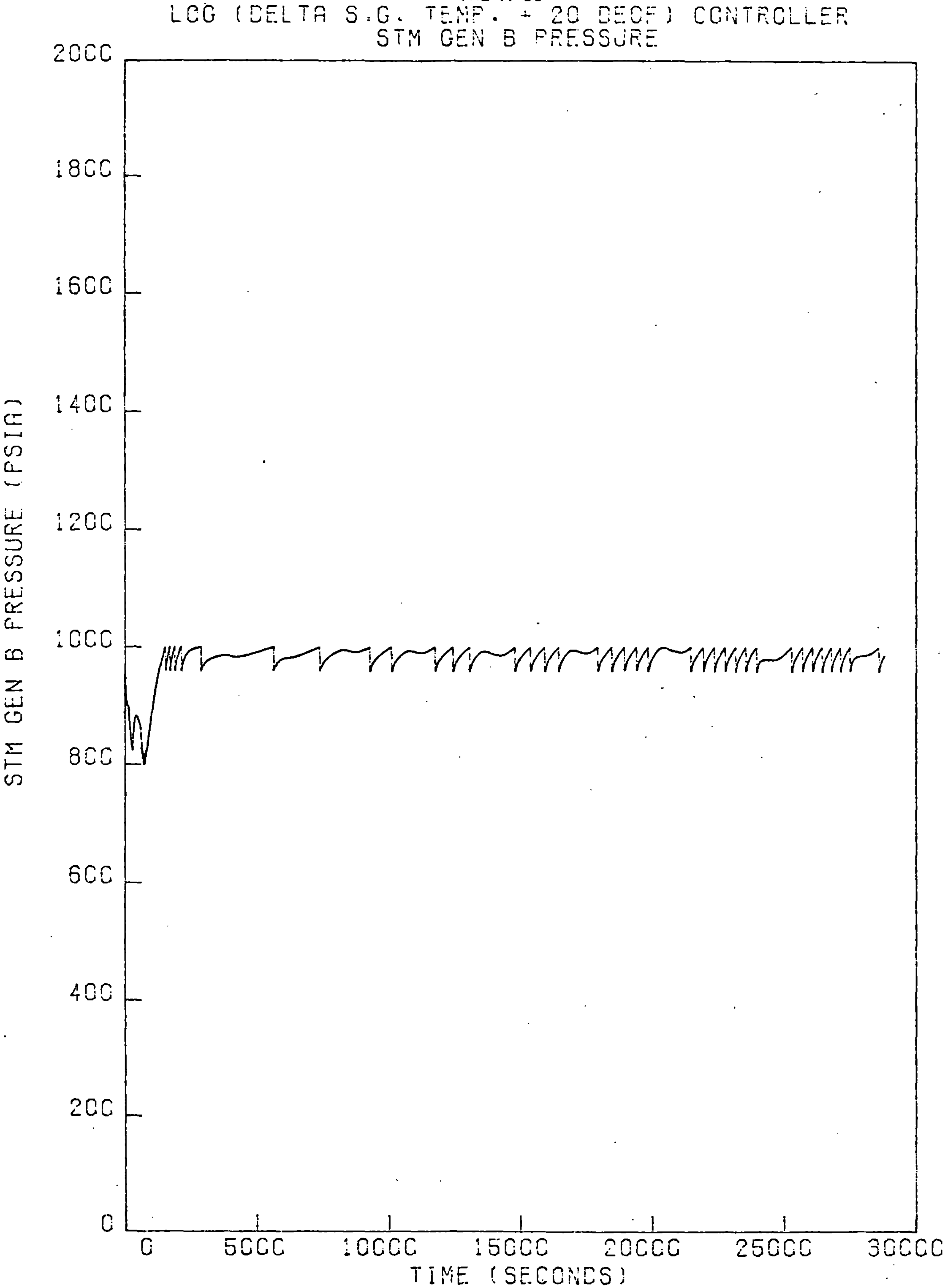

LCG (DELTA S.G. TEMP. + 20 DEGF) CONTROLLER
STM GEN B PRESSURE
2000
1800
1600
1400
1200
1000
800
600
400
200
0
STM GEN B PRESSURE (PSIA)
0
5000
10000
15000
20000
25000
30000
TIME (SECONDS)

FIGURE A-64

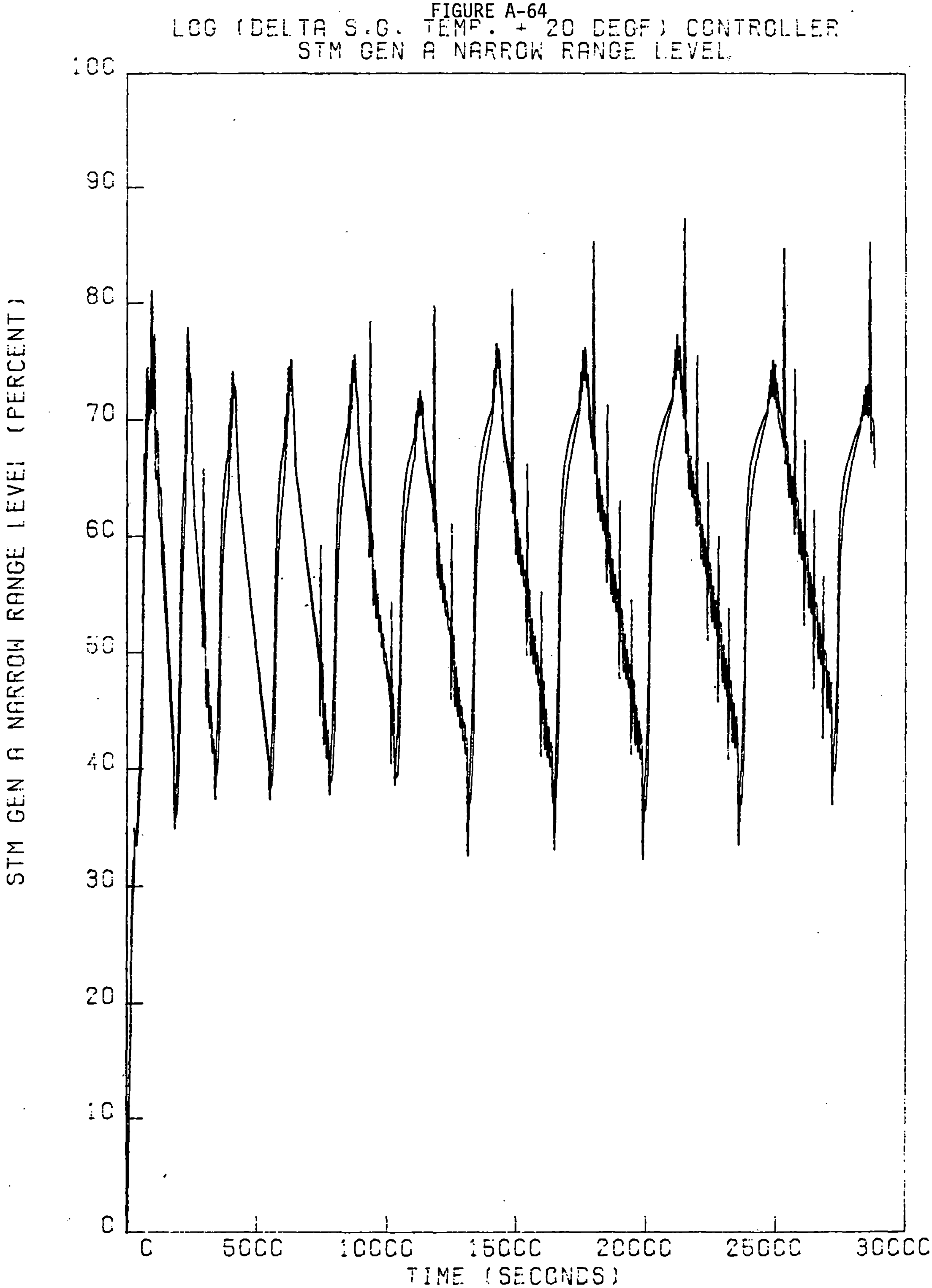

LOG (DELTA S.G. TEMP. + 20 DEGF) CONTROLLER
STM GEN A NARROW RANGE LEVEL
STM GEN A NARROW RANGE LEVEL (PERCENT)
100
90
80
70
60
50
40
30
20
10
0
0
5000
10000
15000
20000
25000
30000
TIME (SECONDS)

FIGURE A-65

LOG (DELTA S.G. TEMP. + 20 DEGF) CONTROLLER
STM GEN B NARROW RANGE LEVEL

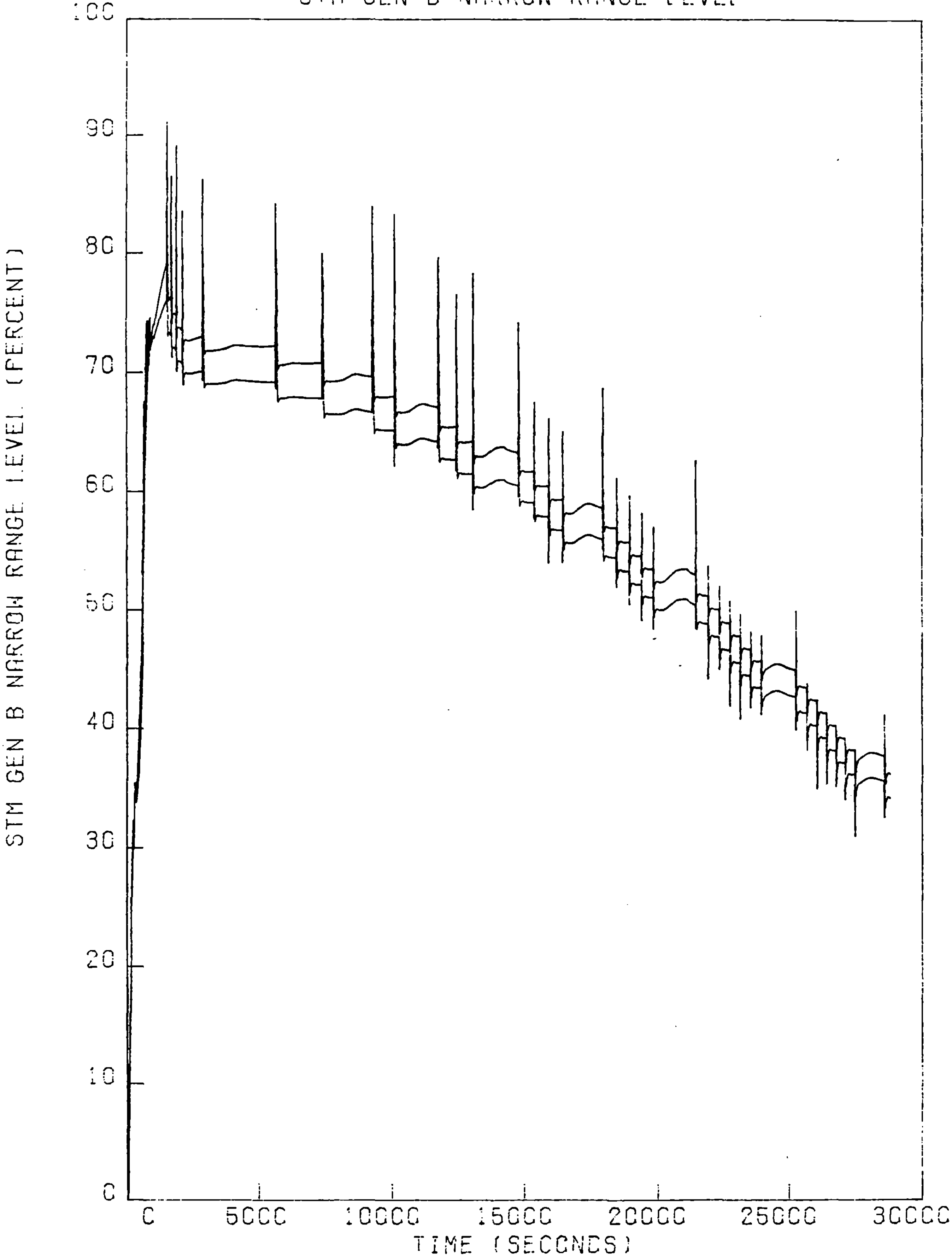


FIGURE A-66

LOG (DELTA S.G. TEMP. + 20 DEGF) CONTROLLER
STM GEN A STEAM FLOW

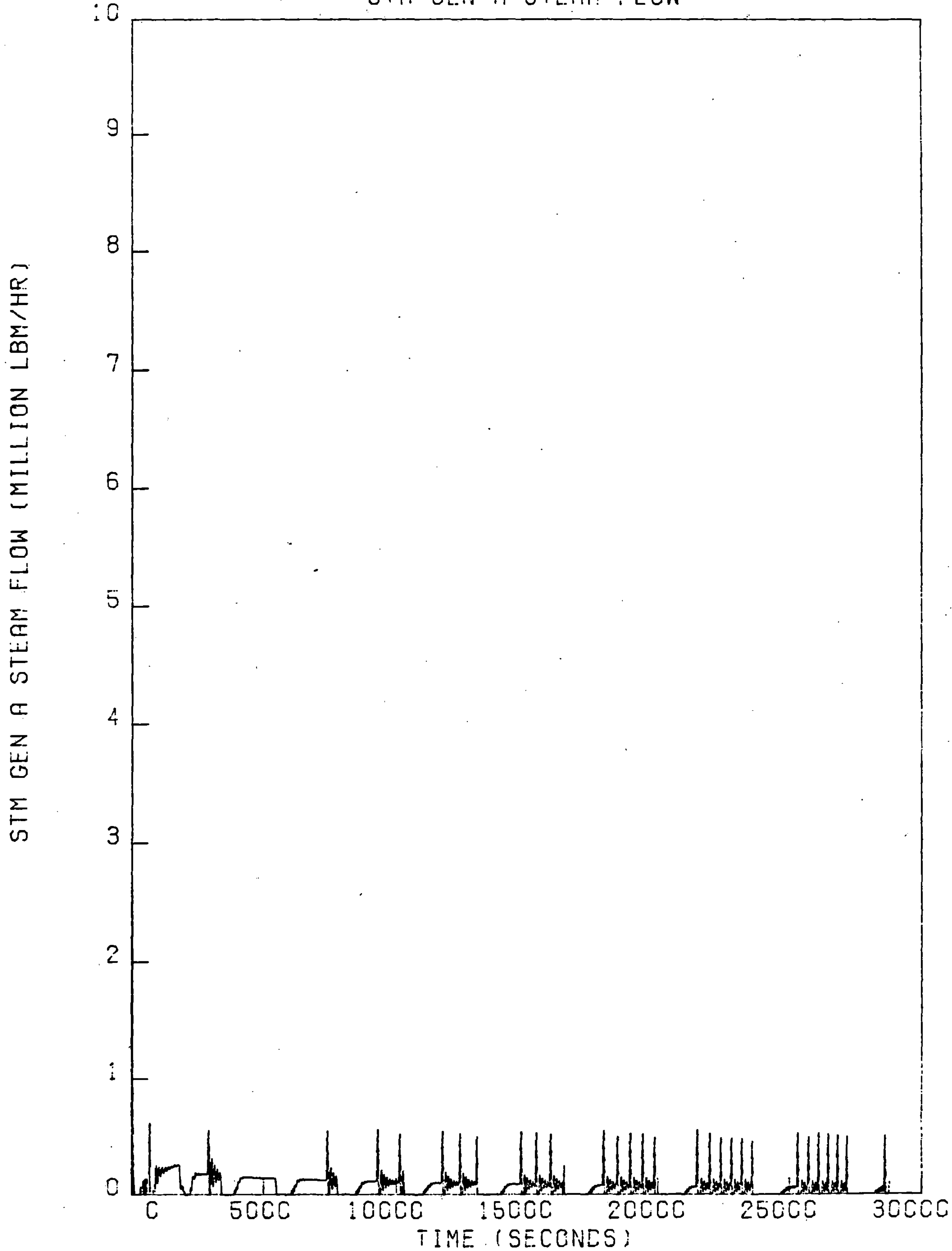


FIGURE A-67

LOG (DELTA S.G. TEMP. ± 20 DEGF) CONTROLLER
STM GEN B STEAM FLOW

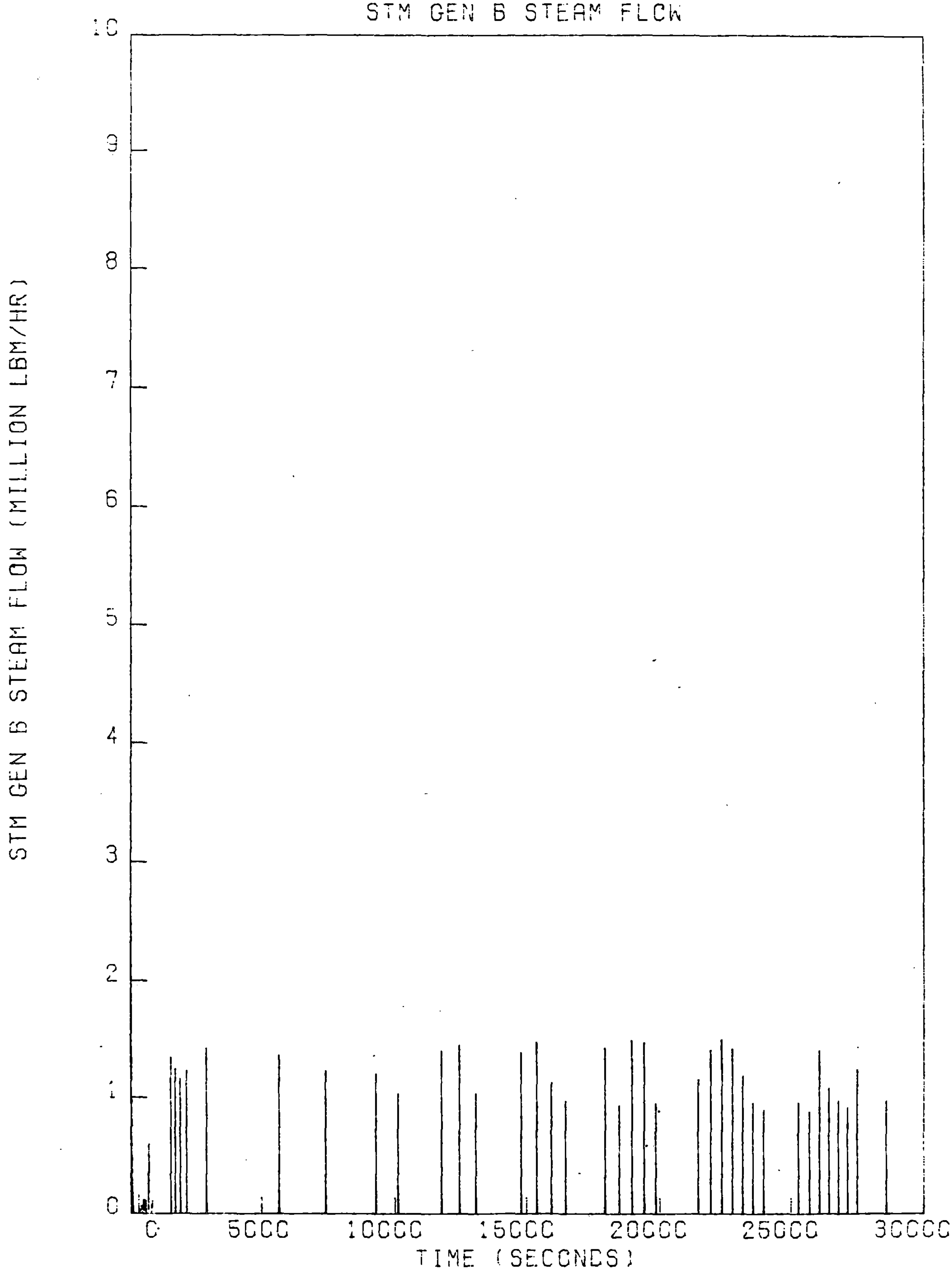


FIGURE A-68

LOG (DELTA S.G. TEMP. + 20 DEGF) CONTROLLER
STM GEN A MAIN FEEDWATER FLOW

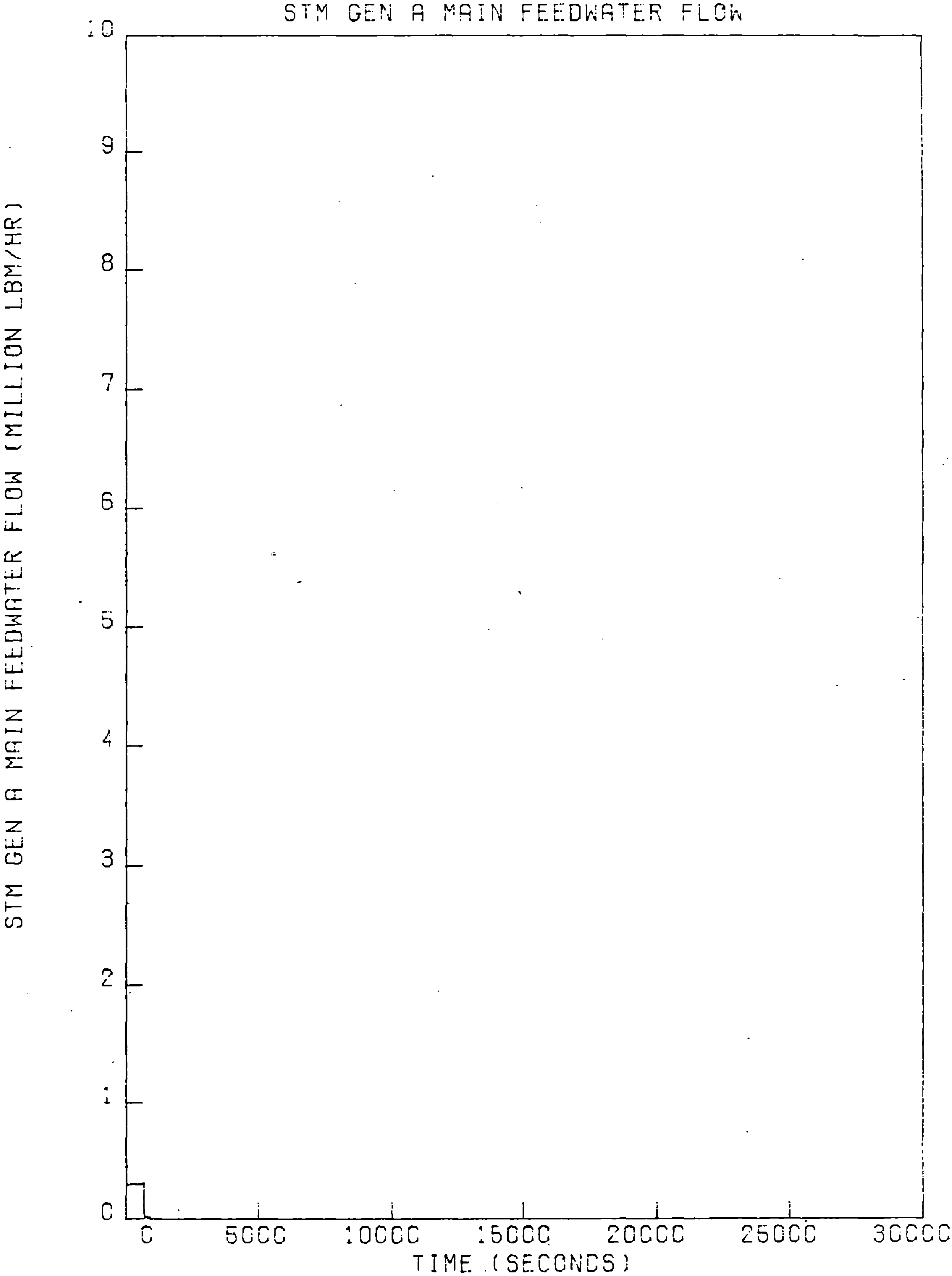


FIGURE A-69

LOG (DELTA S.G. TEMP. + 20 DEGF) CONTROLLER
STM GEN B MAIN FEEDWATER FLOW

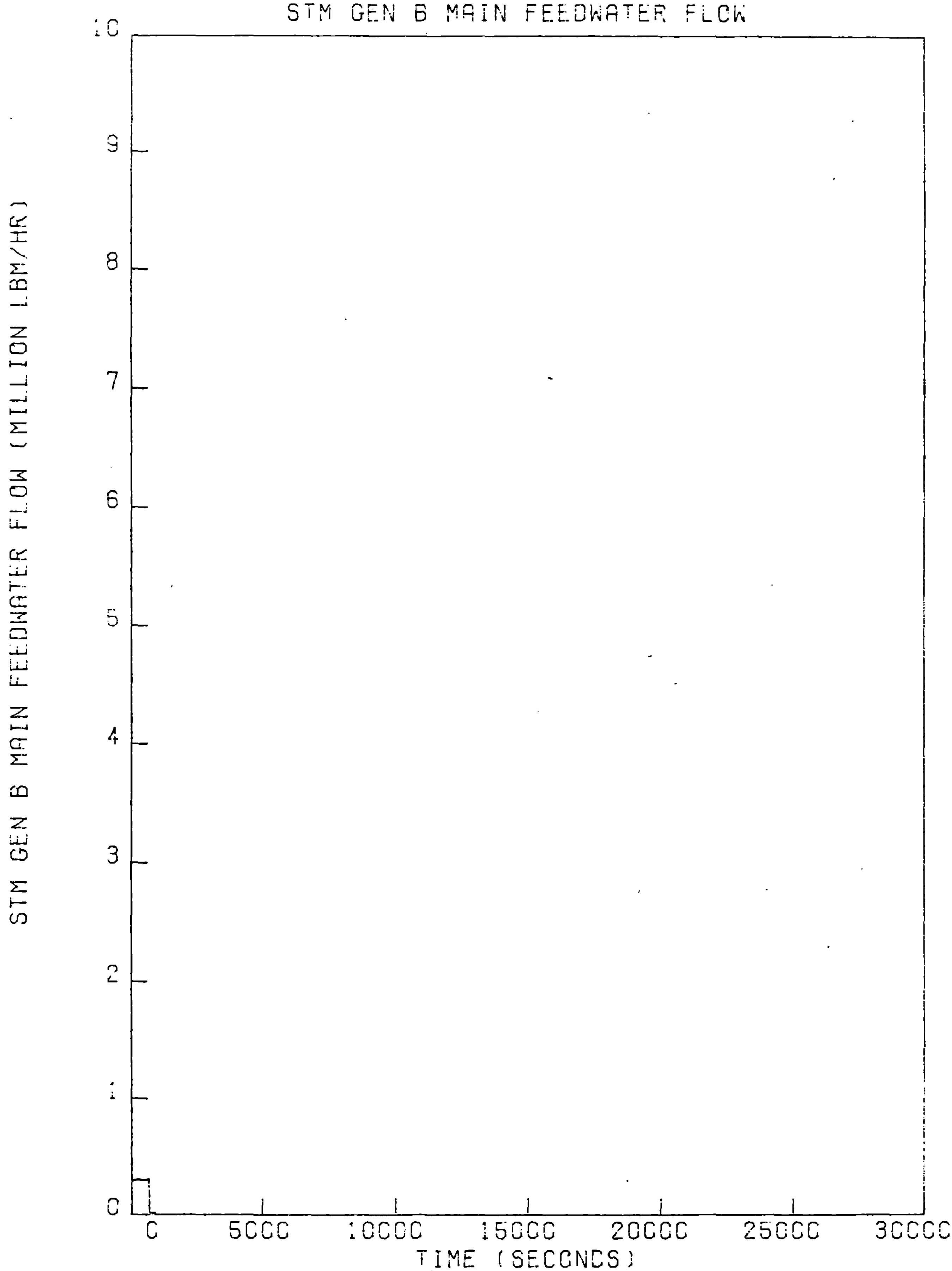


FIGURE A-70

LCG (DELTA S.G. TEMP. + 20 DEGF) CONTROLLER

STM GEN A AUXILIARY FEEDWATER FLOW

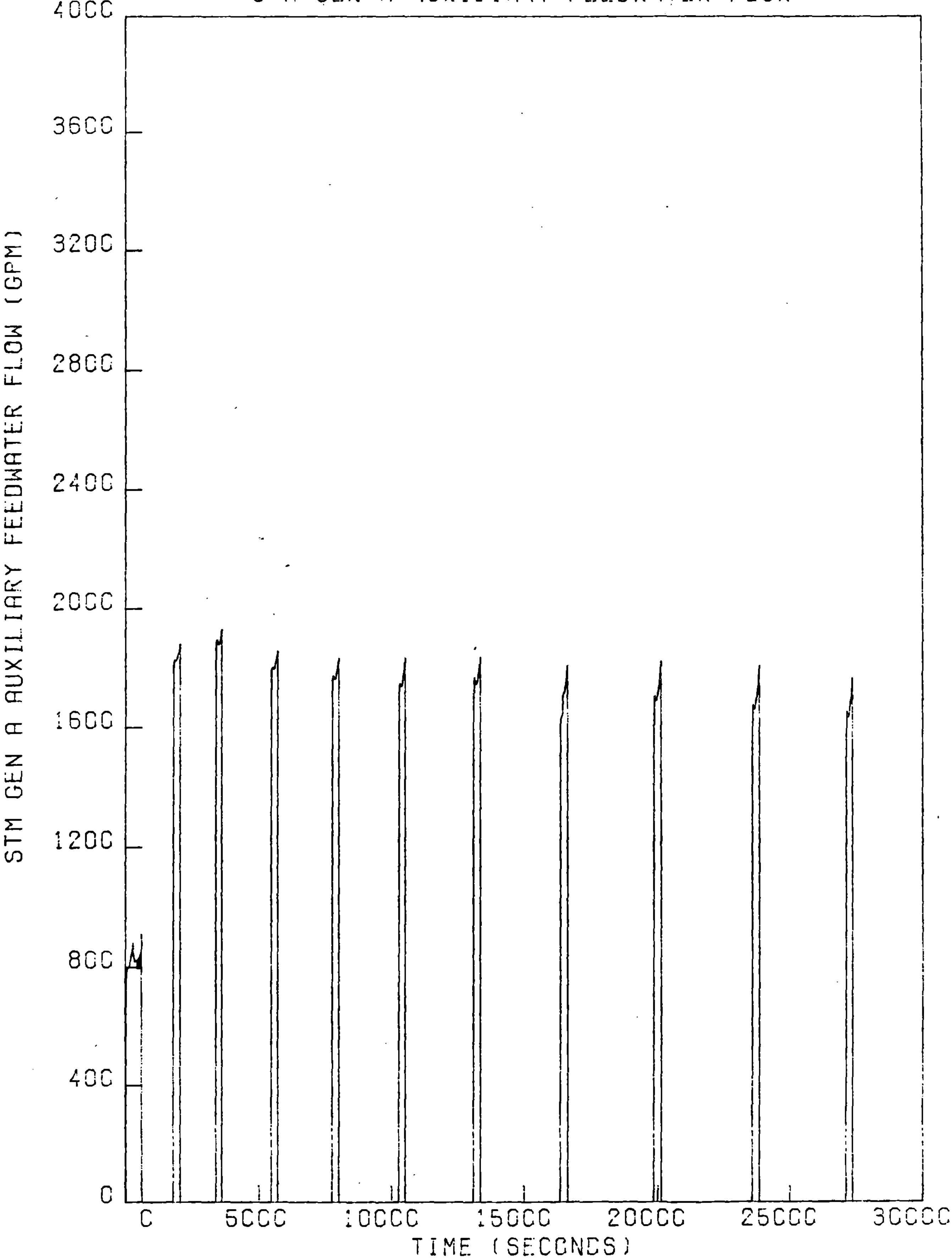


FIGURE A-71

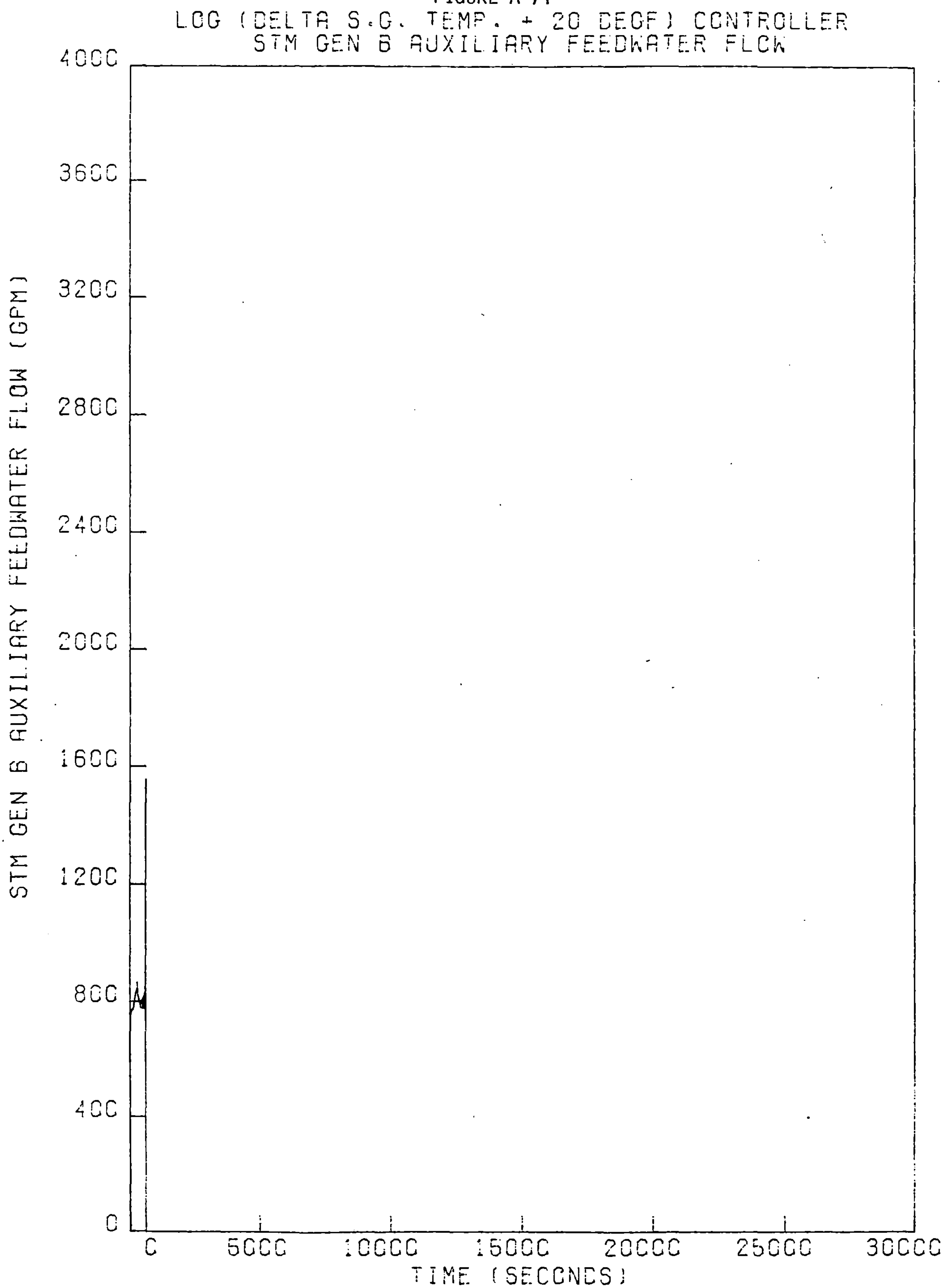
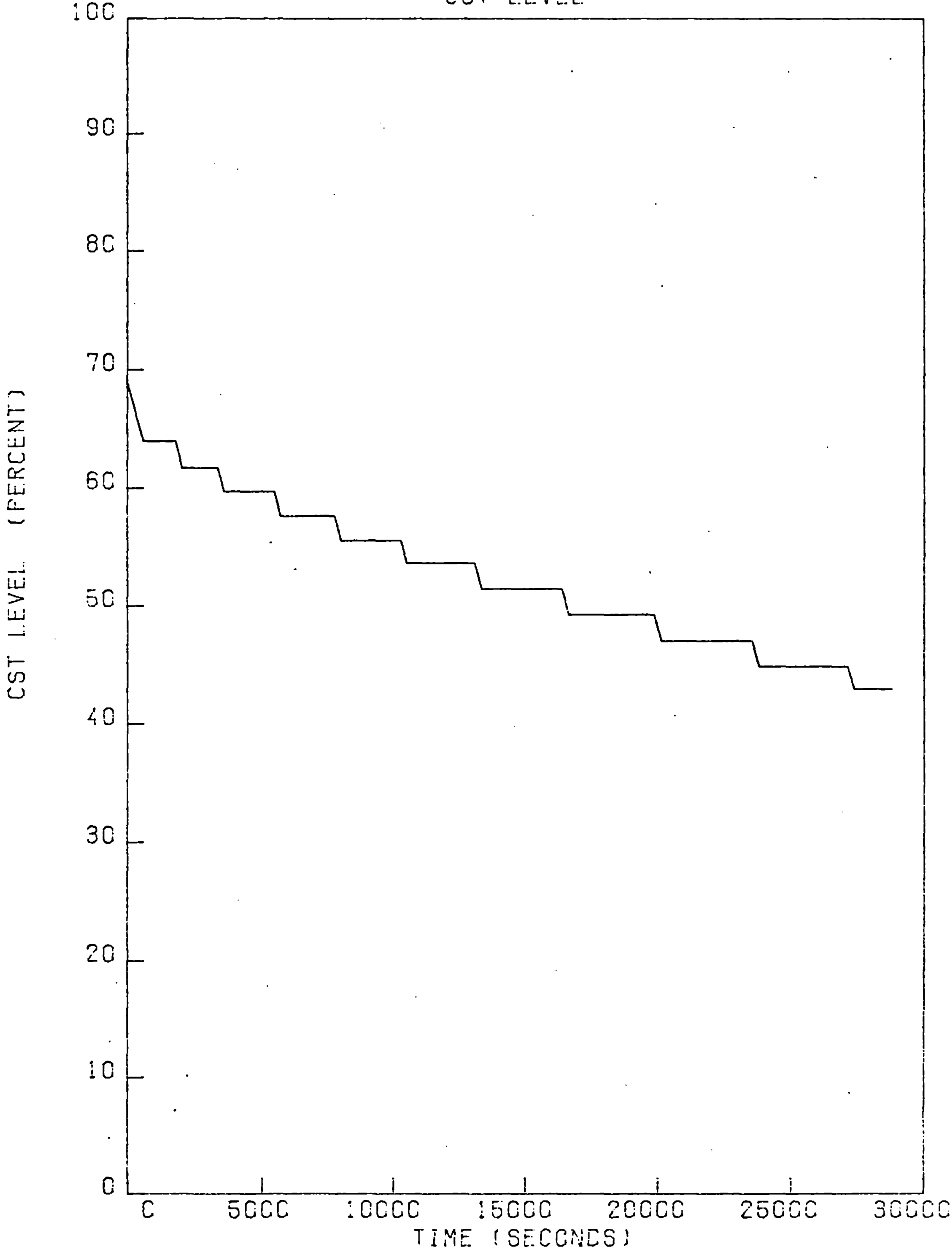

LOG (DELTA S.G. TEMP. + 20 DEGF) CONTROLLER
STM GEN B AUXILIARY FEEDWATER FLOW
STM GEN B AUXILIARY FEEDWATER FLOW (GPM)
4000
3600
3200
2800
2400
2000
1600
1200
800
400
0
0
5000
10000
15000
20000
25000
30000
TIME (SECONDS)

FIGURE A-72

LOG (DELTA S.G. TEMP. + 20 DEGF) CONTROLLER

CST LEVEL



CASE 4

Cooldown of Unisolated Steam Generator Based on
Optimum Steady State Analysis Secondary Temperature Minus 20°F

t, sec	$T_{SG\ 1}$, °F	$T_{SG\ 2}$, °F	q_2, Btu/sec	Notes
900	525	525	27400	Cooling SG 1
1000	522	529	17900	
1500	511	544	7930	
2000	500	542	5339	
2500	490	544	1289	
3000	479	543	-420	$T_{sec\ 1} \approx T_{opt}$
3500	469	542	-1243	
4000	458	539	-610	
4500	458	539	0	
5100	460	539	0	
6100	461	539	0	
10100	469	539	0	
15100	473	539	0	
20100	477	538	-39	
28700	479	535	-228	

These results show the effect of $T_{sec\ 1}$ being too high at first, then passing through the optimal conditions into a region where the flow was choked off. An unexpected feature of this case was the long term result when the inaccuracy of the T_{opt} estimate (which yields values of T_{opt} which are too high for $t > 10^4$ seconds) began to cancel the -20°F bias. The following figures are LTC transient parameter plots for Case 4.

FIGURE A-73

LCS (DELTA S.G. TEMP. - 20 DEGF) CONTROLLER

PZR NARROW RANGE PRESSURE

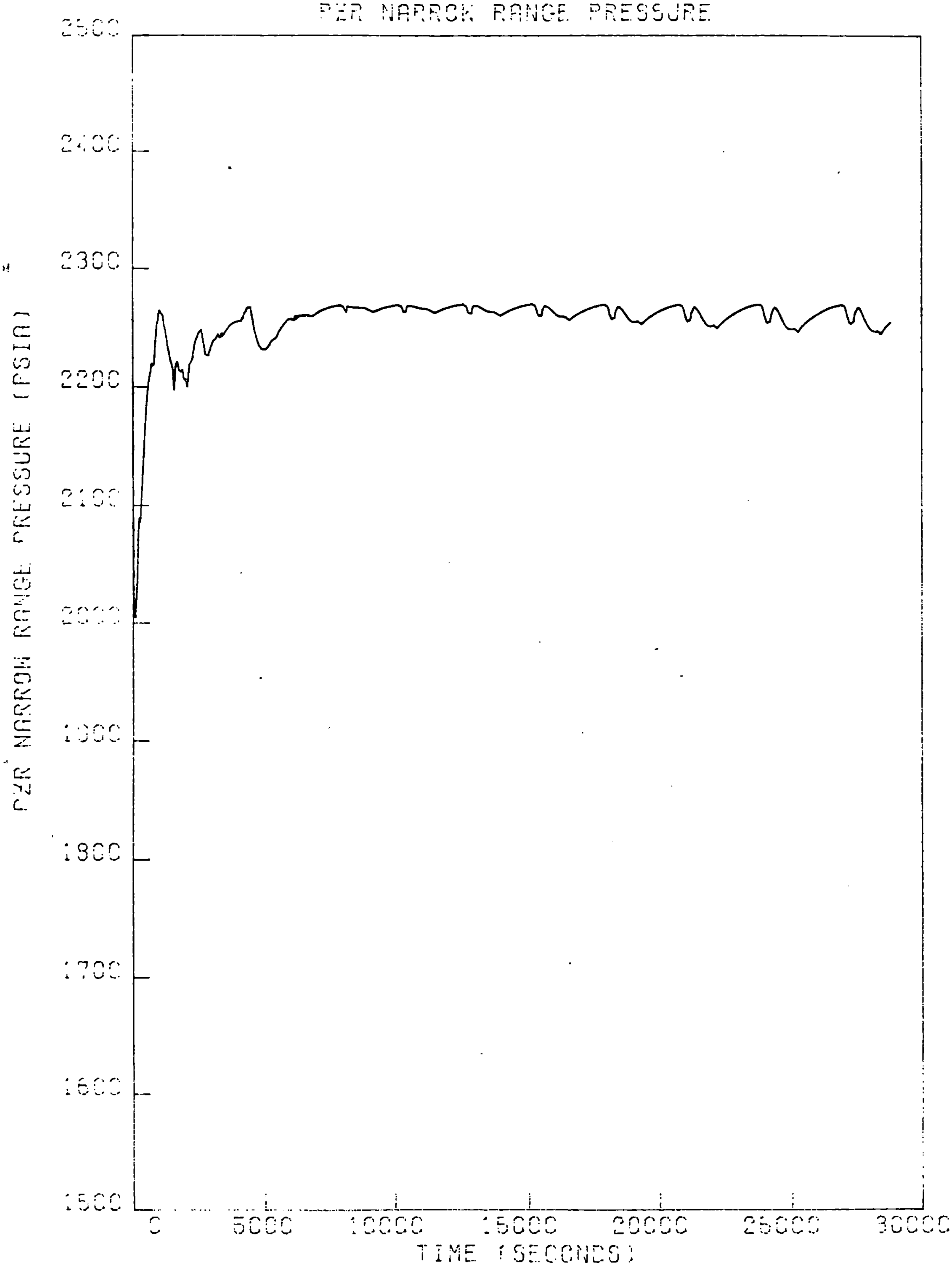


FIGURE A-74

LCG (DELTA S.G. TEMP. - 20 DEGF) CONTROLLER

PZR NARROW RANGE TEMPERATURE

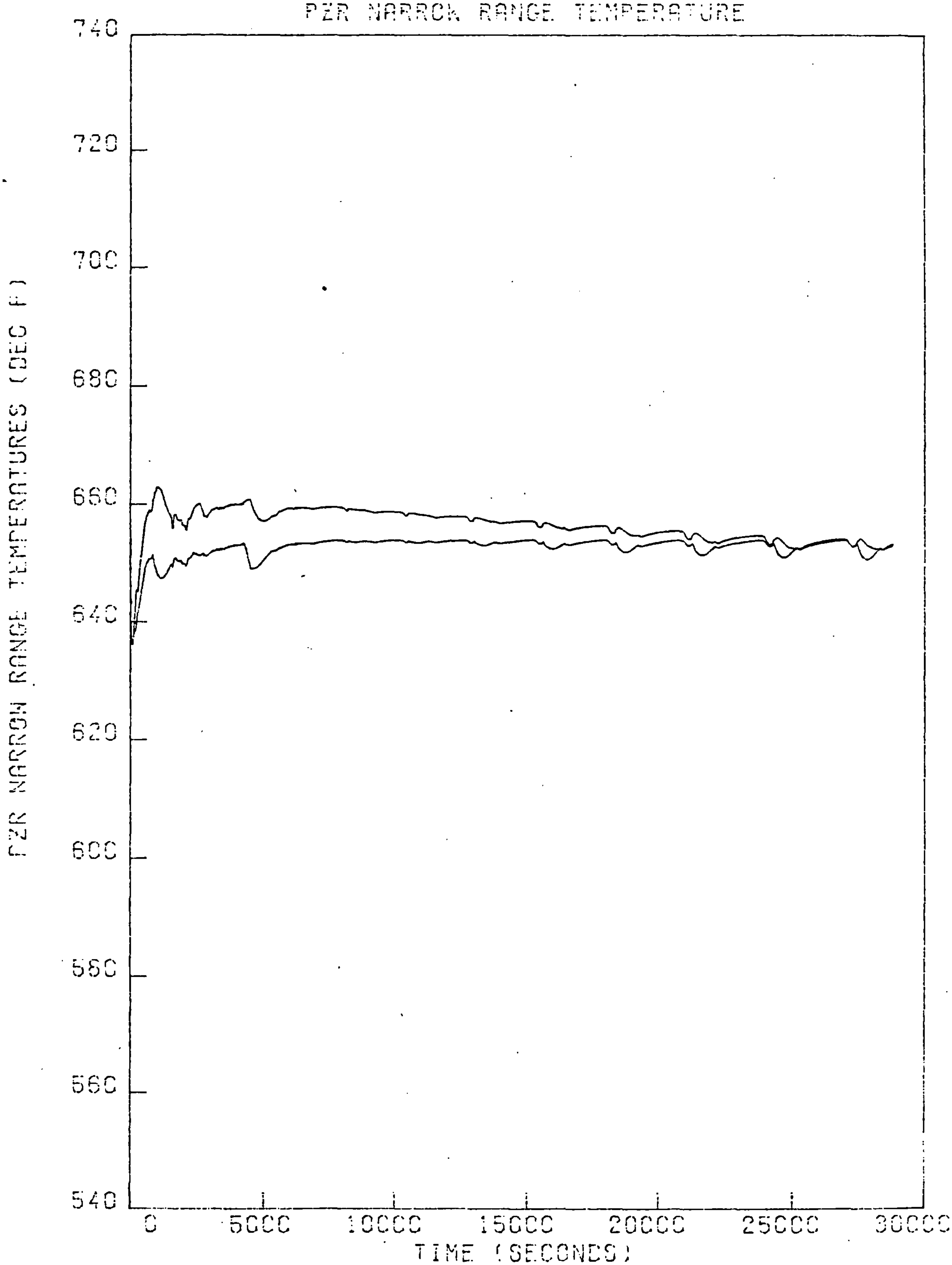


FIGURE A-75
LCC (DELTA S.G. TEMP. - 20 DEGF) CONTROLLER
PZR LEVEL

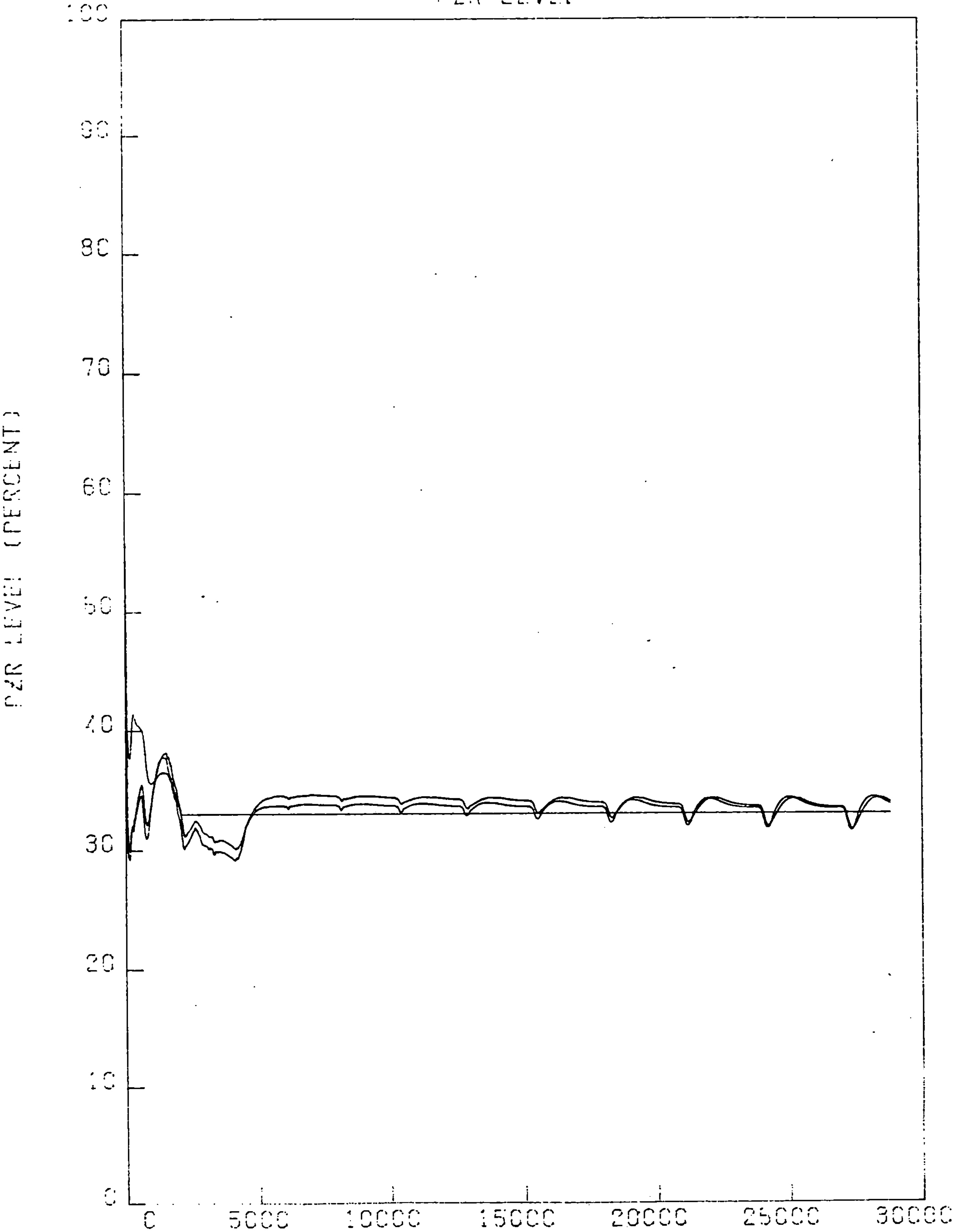


FIGURE A-76

LCS (DELTA S.G. TEMP. - 20 DEGF) CONTROLLER

PZR HEATER RATE

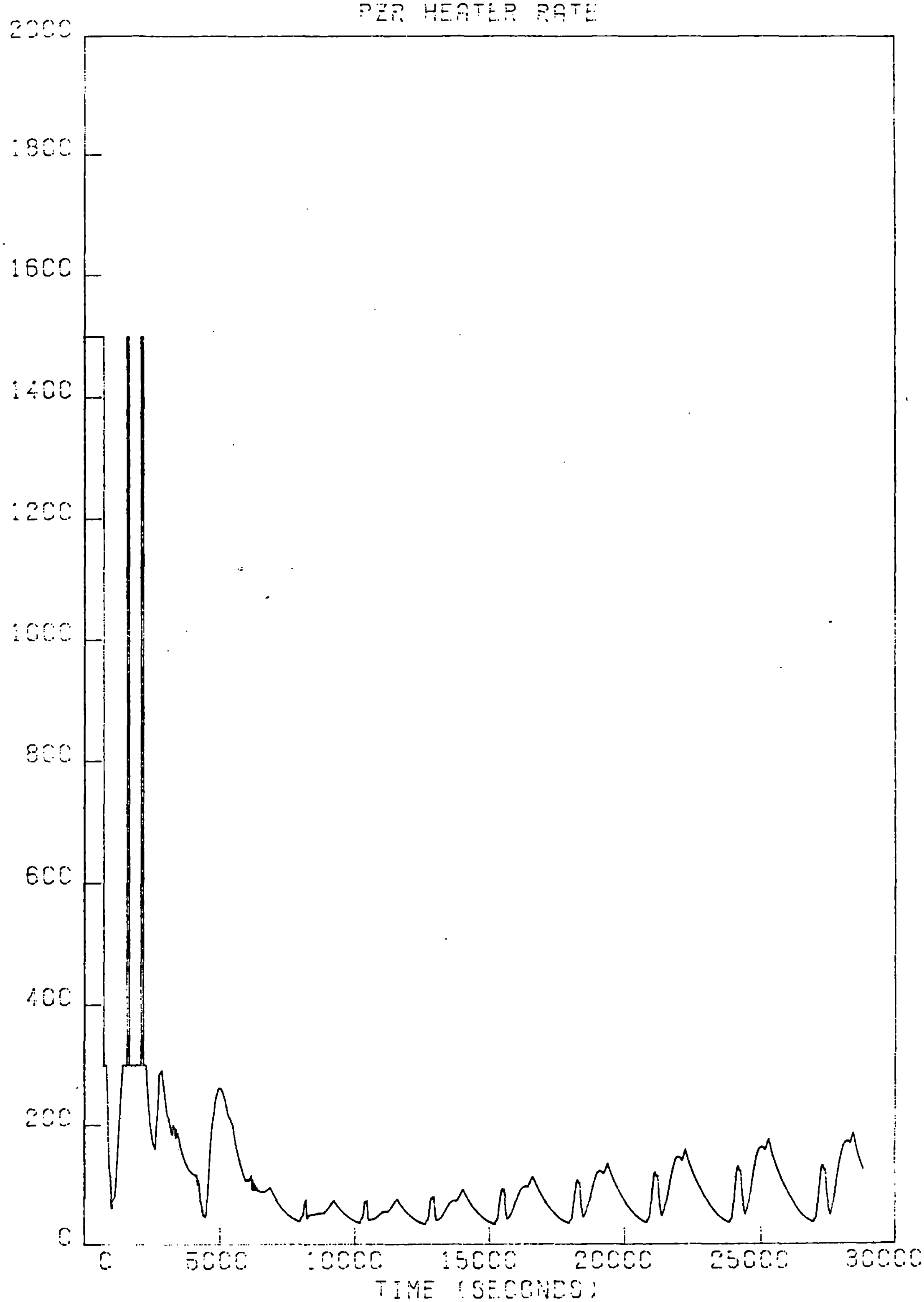


FIGURE A-79

LCG (DELTA S.G. TEMP. - 20 DEGF) CONTROLLER
CHARGING - LETDOWN FLOWS

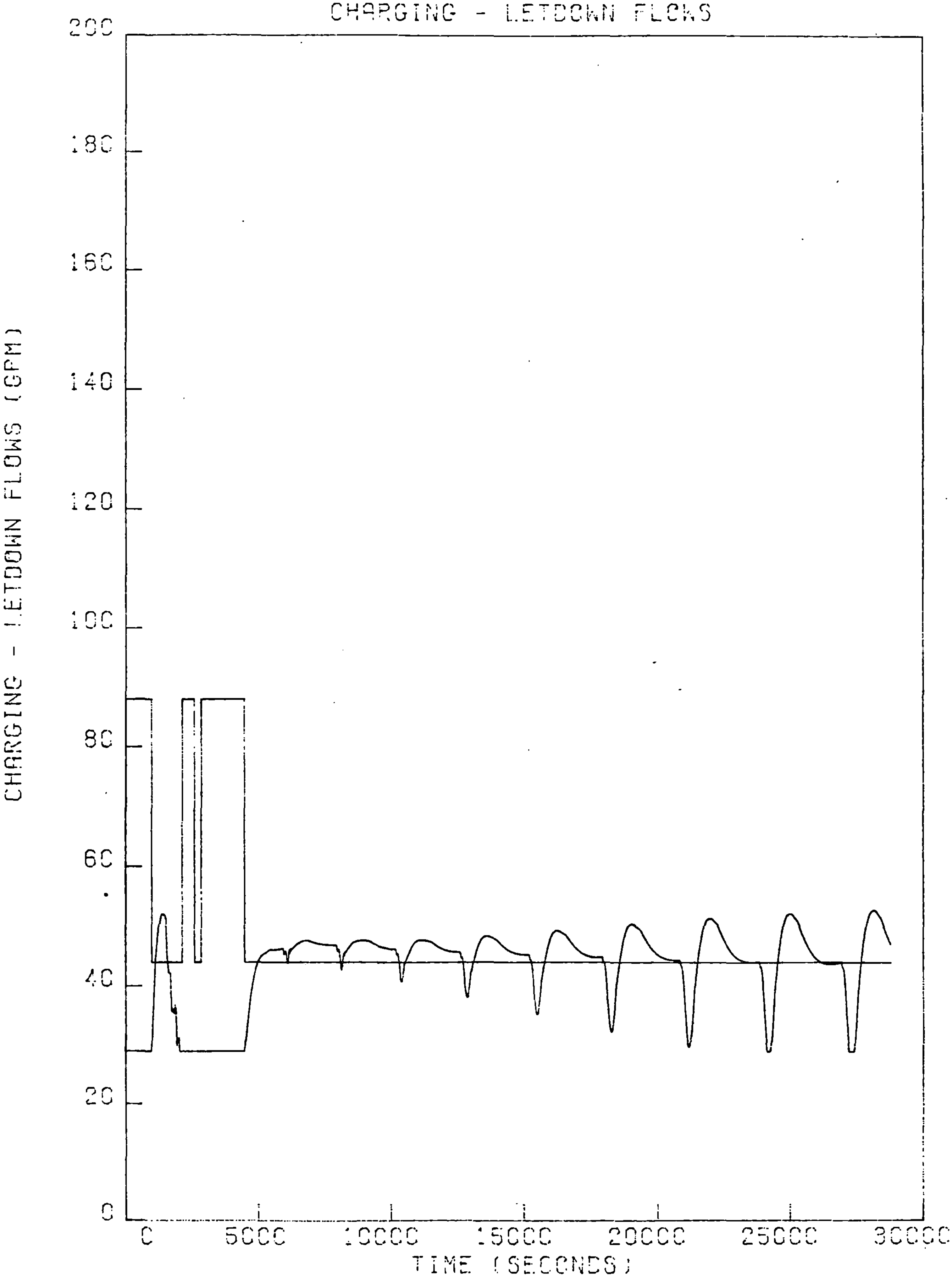


FIGURE A-78

LOG (DELTA S.G. TEMP. - 20 DEGF) CONTROLLER

VCT LEVEL

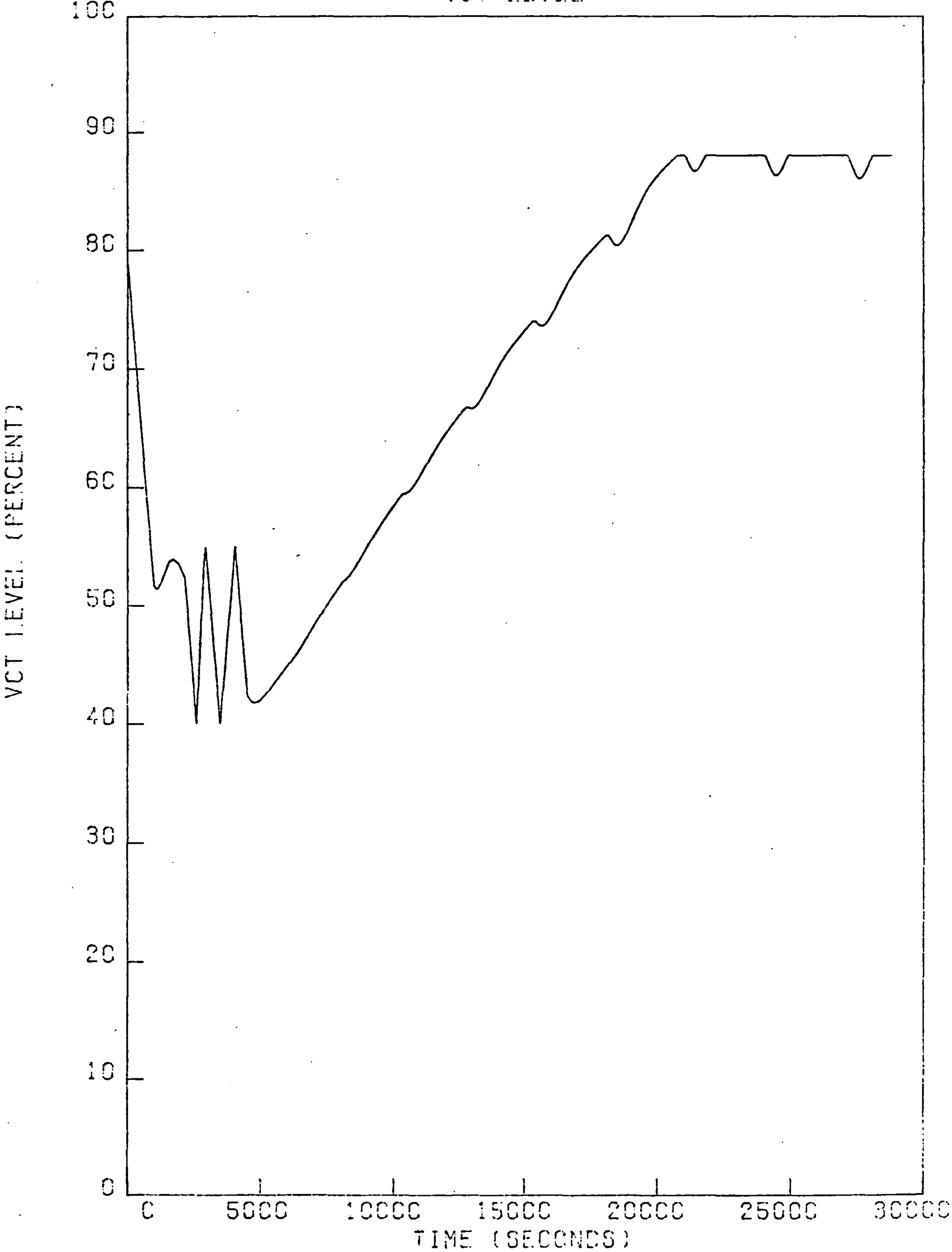


FIGURE A-79
LOG (DELTA S.C. TEMP. - 20 DEGF) CONTROLLER
LOOP A RCS MASS FLOWS

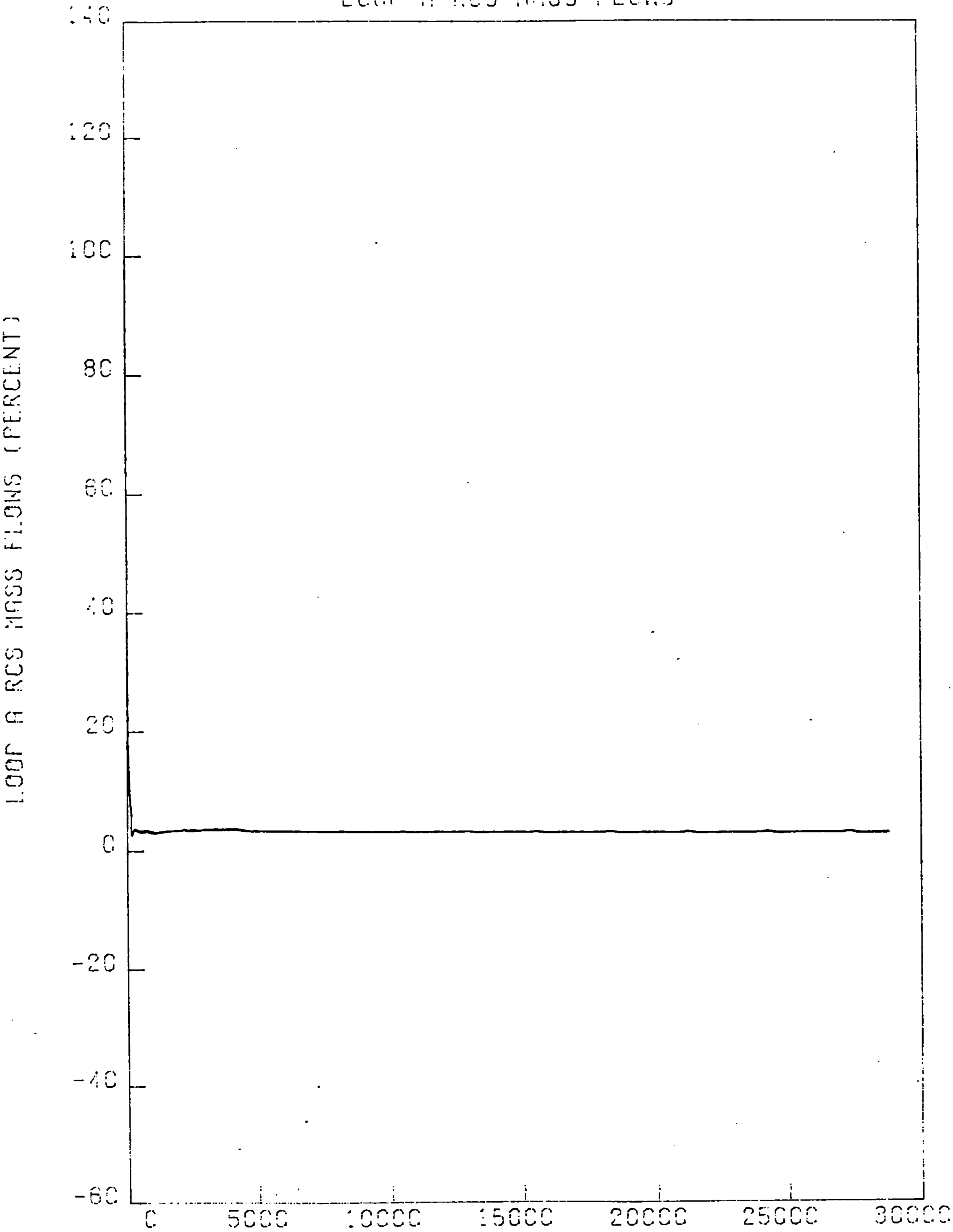
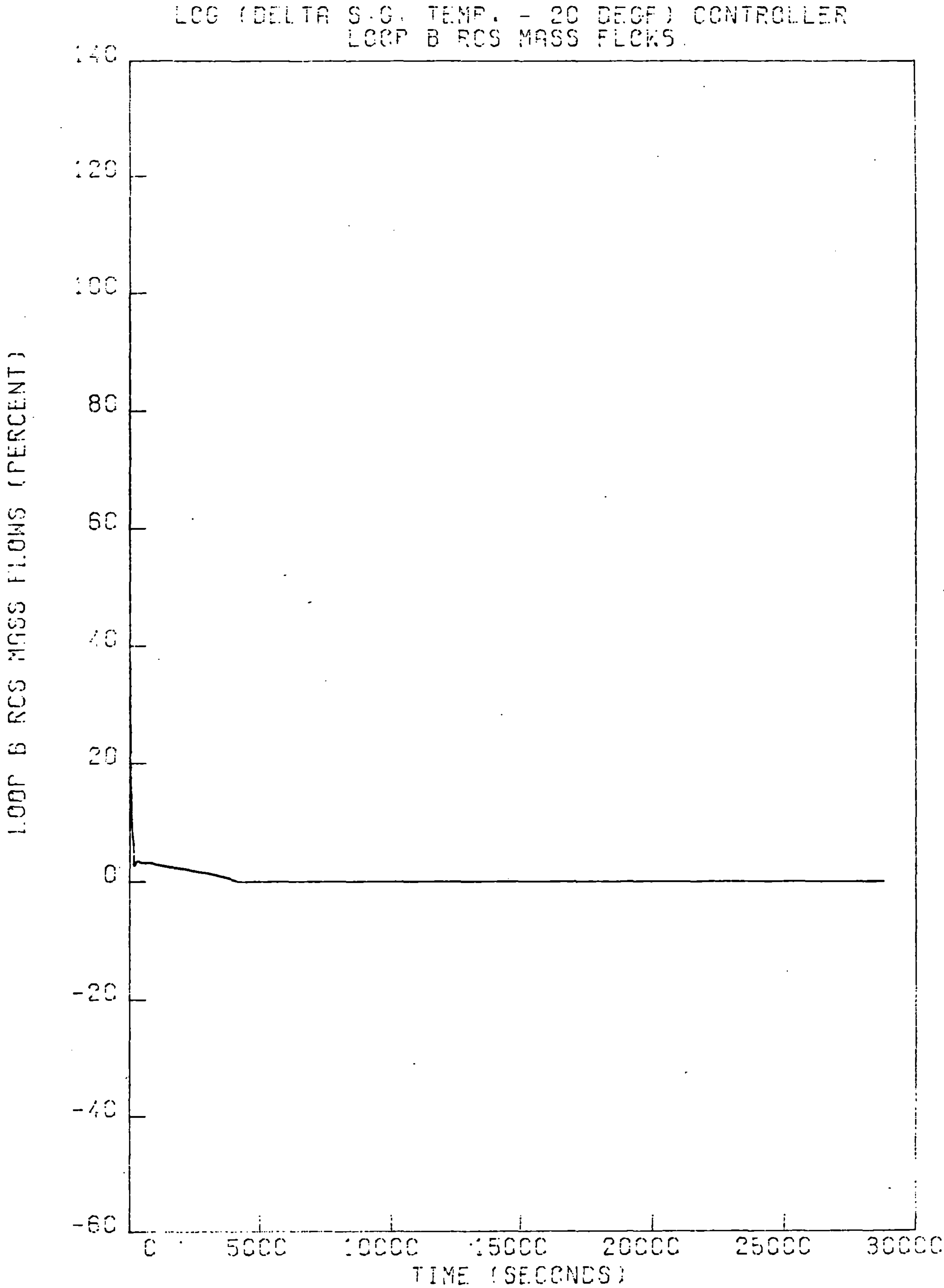


FIGURE A-80



LOG (DELTA S.G. TEMP. - 20 DEGF) CONTROLLER
LOOP B RCS MASS FLOWS
LOOP B RCS MASS FLOWS (PERCENT)
140
120
100
80
60
40
20
0
-20
-40
-60
0
5000
10000
15000
20000
25000
30000
TIME (SECONDS)

FIGURE A-81

LOOP (DELTA S.G. TEMP. - 20 DEGF) CONTROLLER
LOOP A RCS NARROW RANGE TEMPERATURES

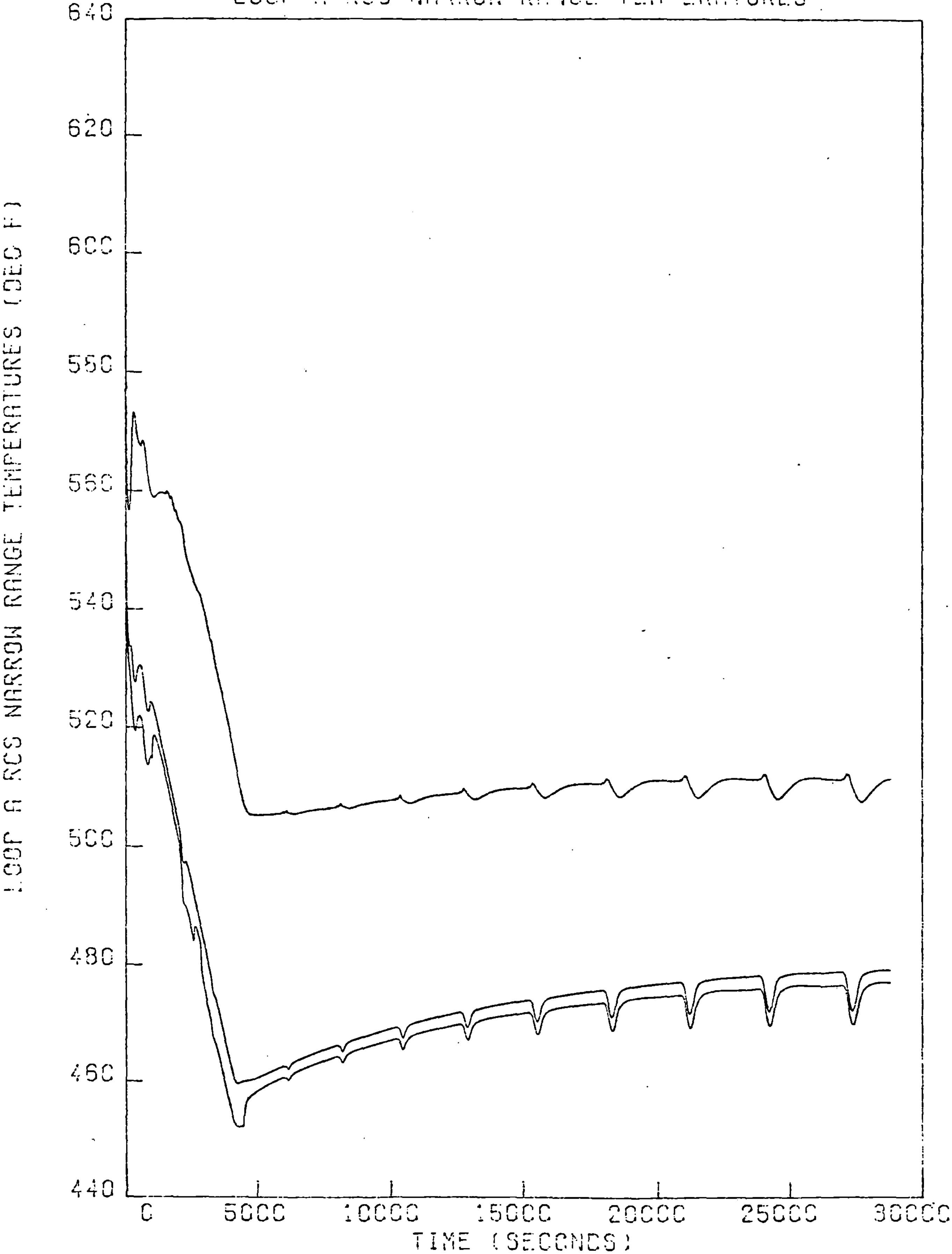


FIGURE A-82

LOG (DELTA S.G. TEMP. - 20 DEGF) CONTROLLER

LOOP B RCS NARROW RANGE TEMPERATURES

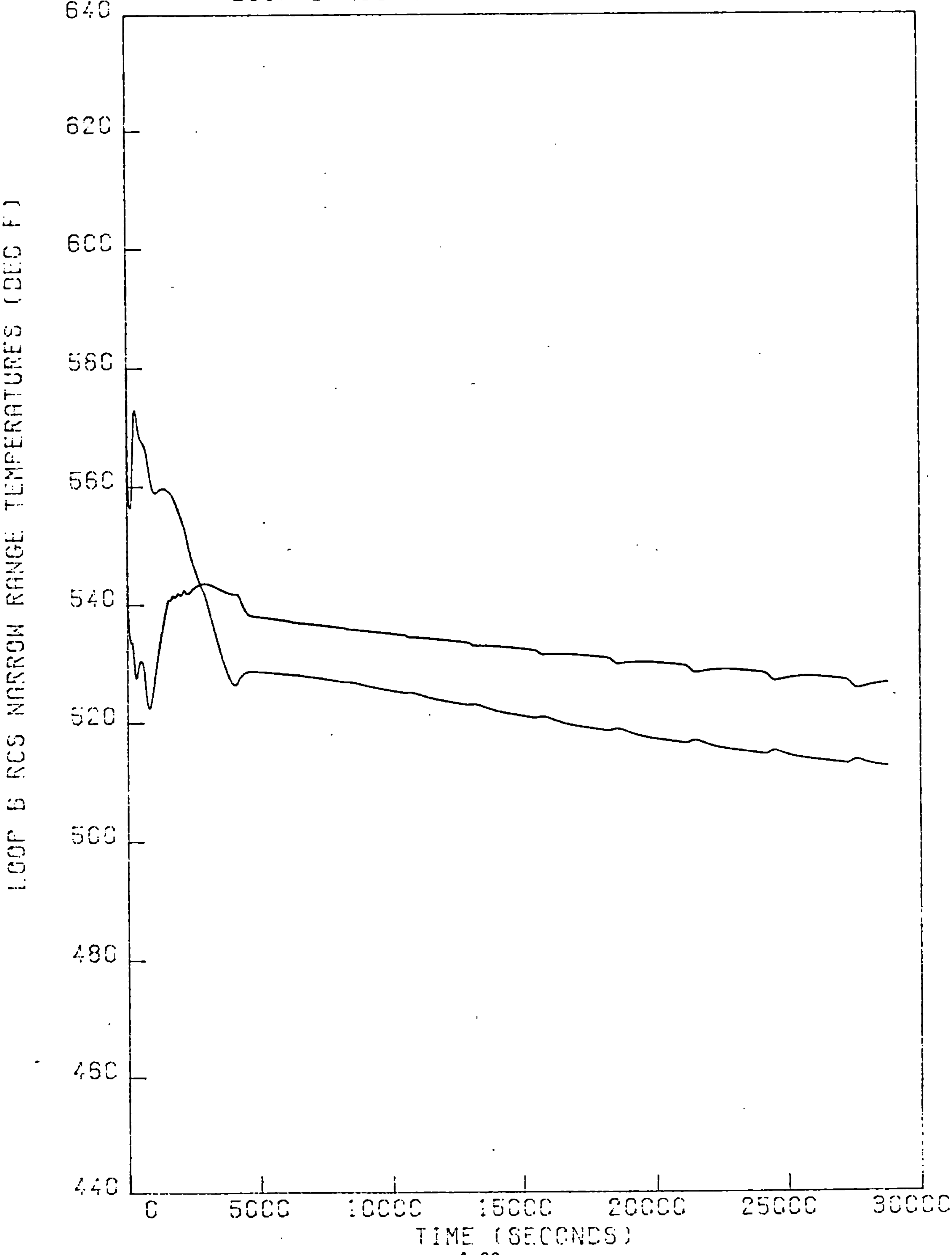


FIGURE A-83
LOG (DELTA S.G. TEMP. - 20 DEGF) CONTROLLER
LOOP A RCS WIDE RANGE TEMPERATURES

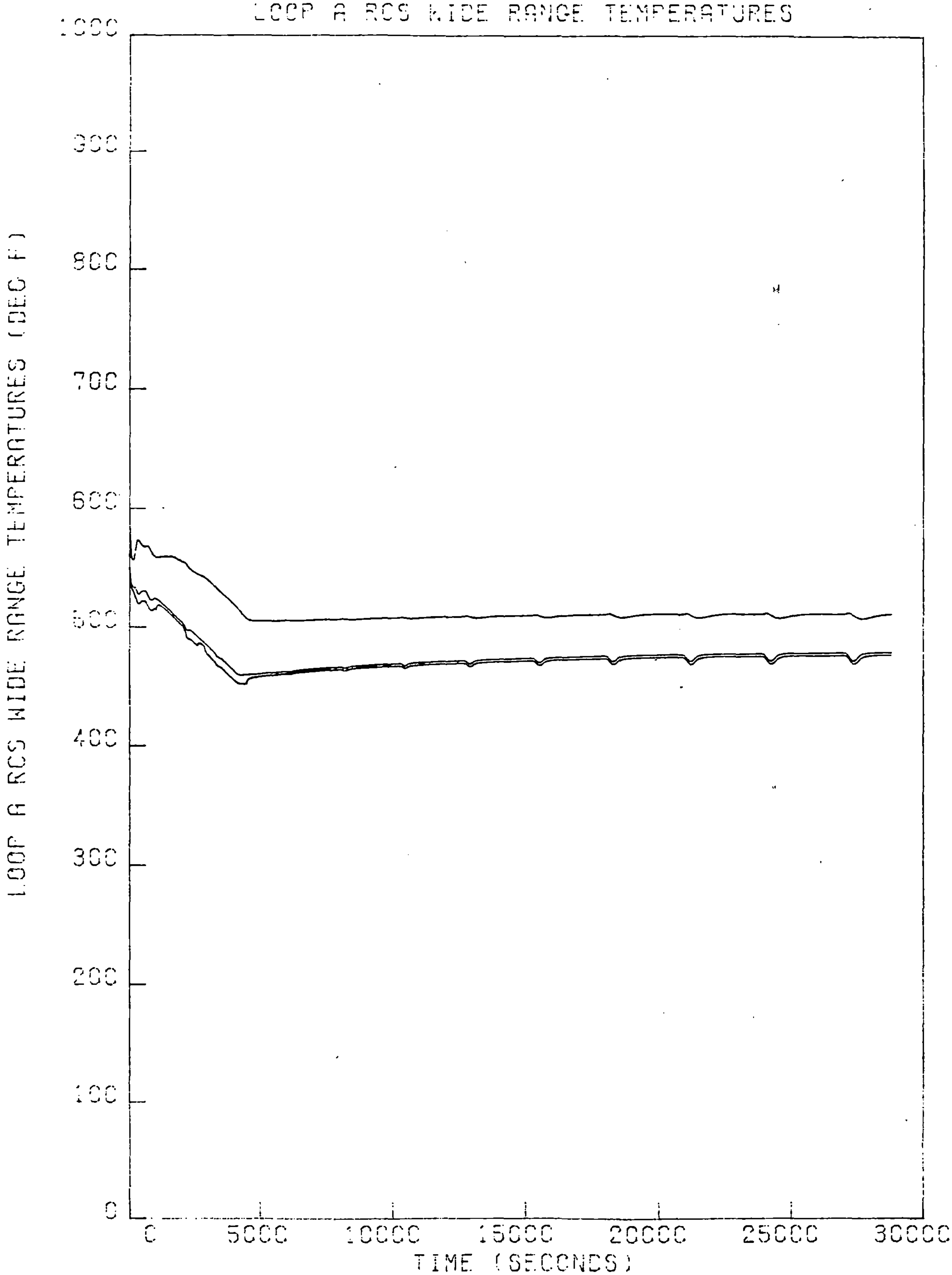


FIGURE A-84

LCG (DELTA S.G. TEMP. - 20 DEGF) CONTROLLER
LOOP B RCS WIDE RANGE TEMPERATURES

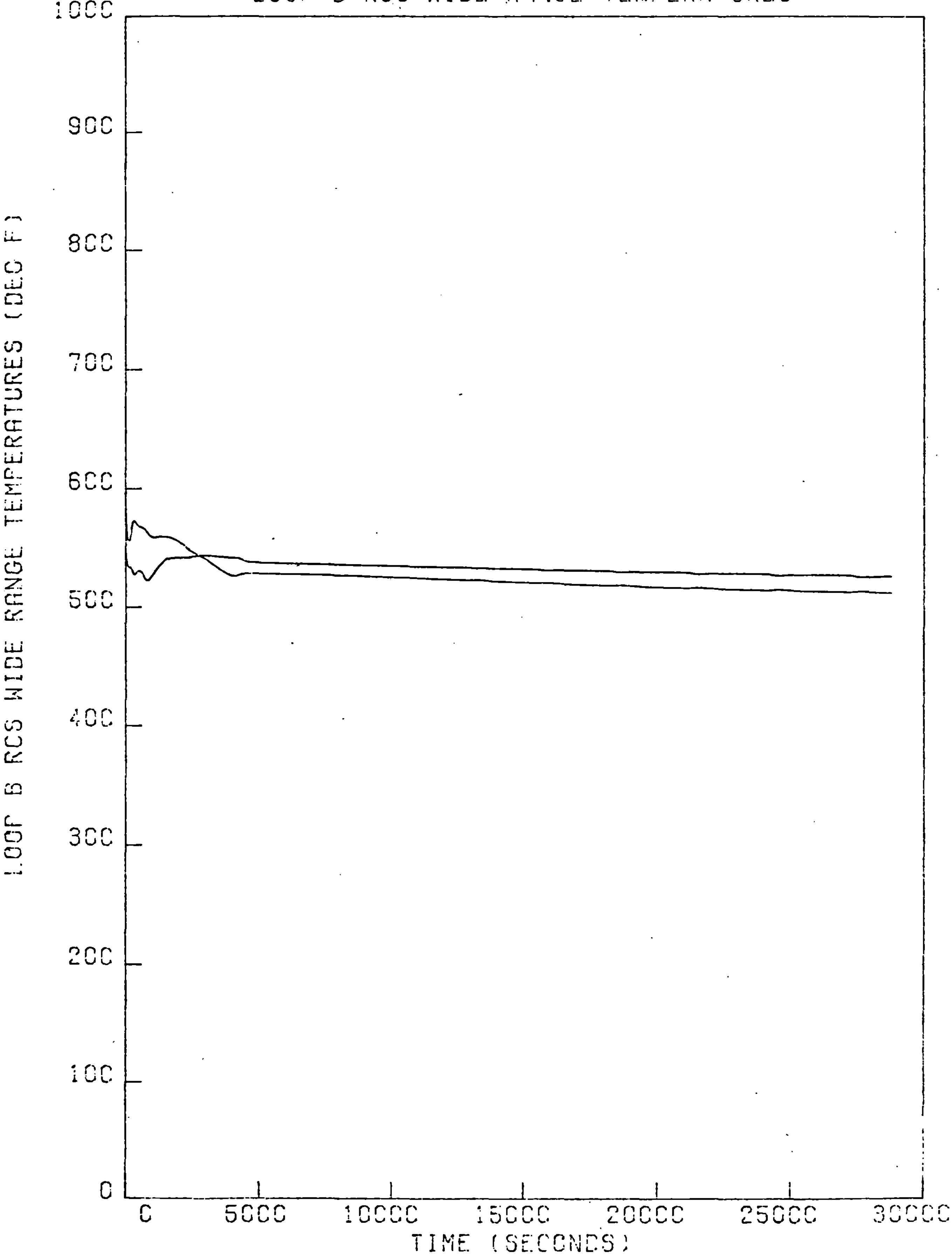


FIGURE A-85

LOG (DELTA S.G. TEMP. - 20 DEGF) CONTROLLER
(DELTA T SUBCOOLING

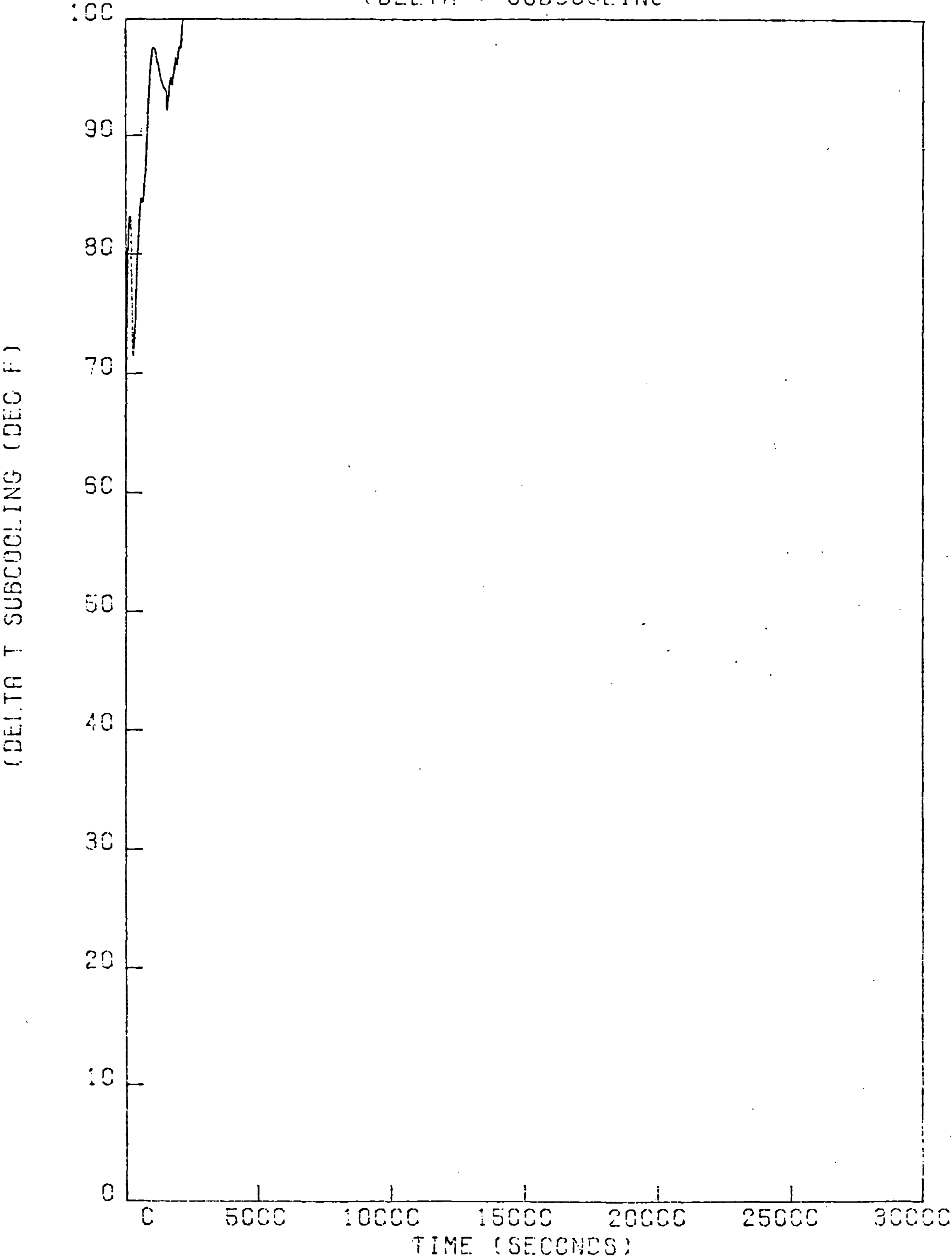


FIGURE A-86

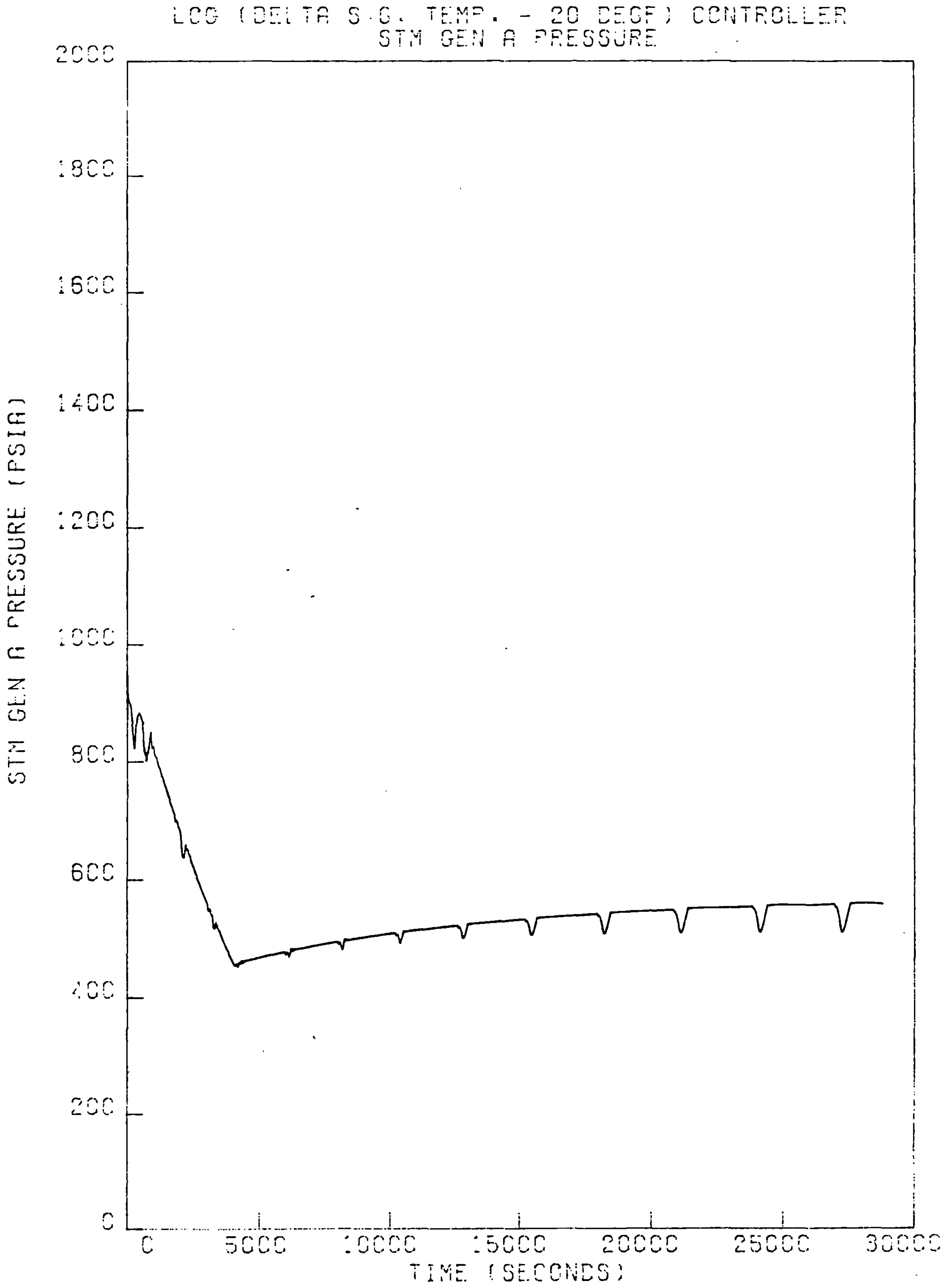

LCO (DELTA S.G. TEMP. - 20 DEGF) CONTROLLER
STM GEN A PRESSURE
STM GEN A PRESSURE (PSIA)
2000
1800
1600
1400
1200
1000
800
600
400
200
0
0
5000
10000
15000
20000
25000
30000
TIME (SECONDS)

FIGURE A-87

LOG (DELTA S.G. TEMP. - 20 DEGF) CONTROLLER
STM GEN B PRESSURE

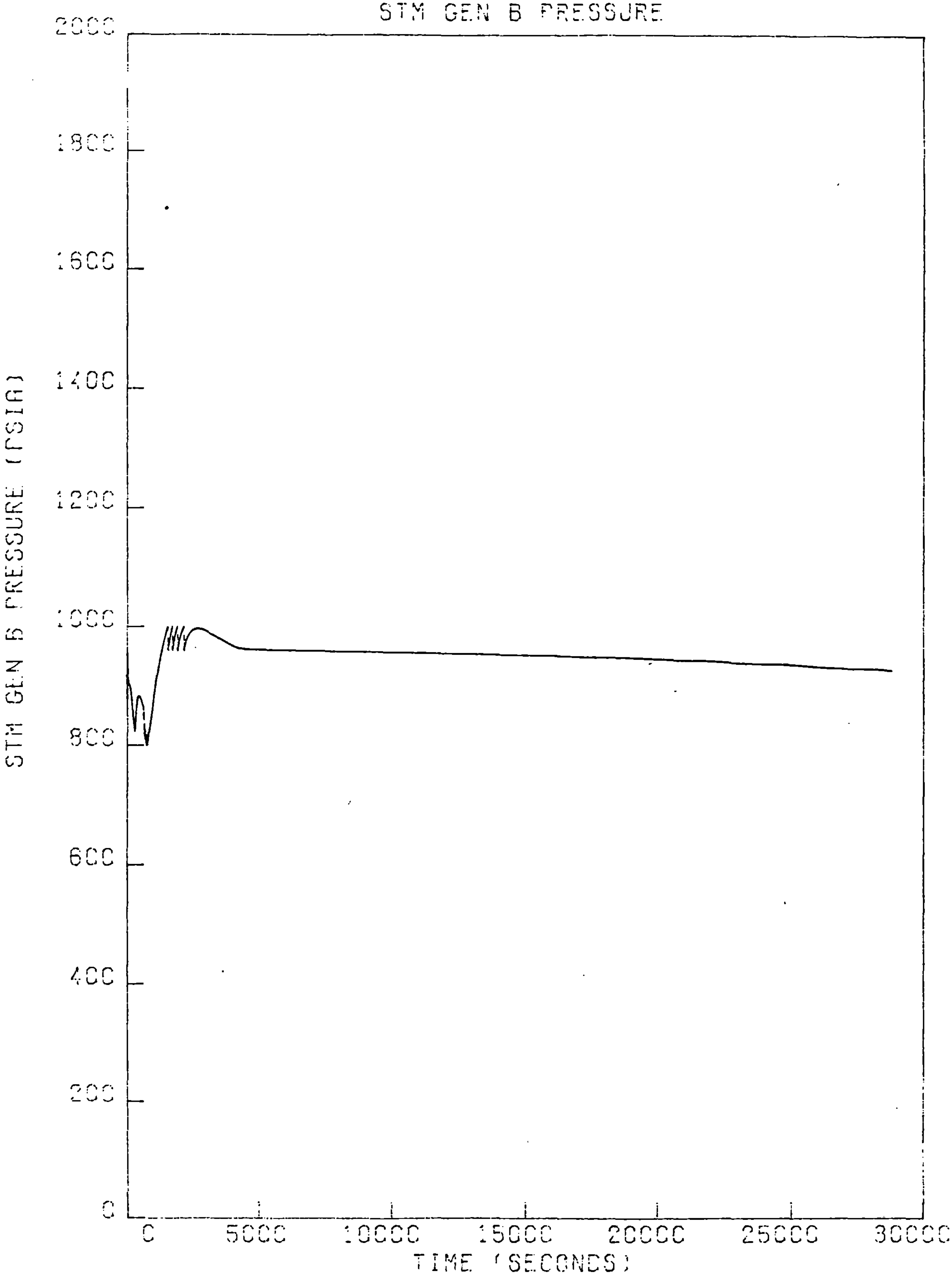


FIGURE A-88

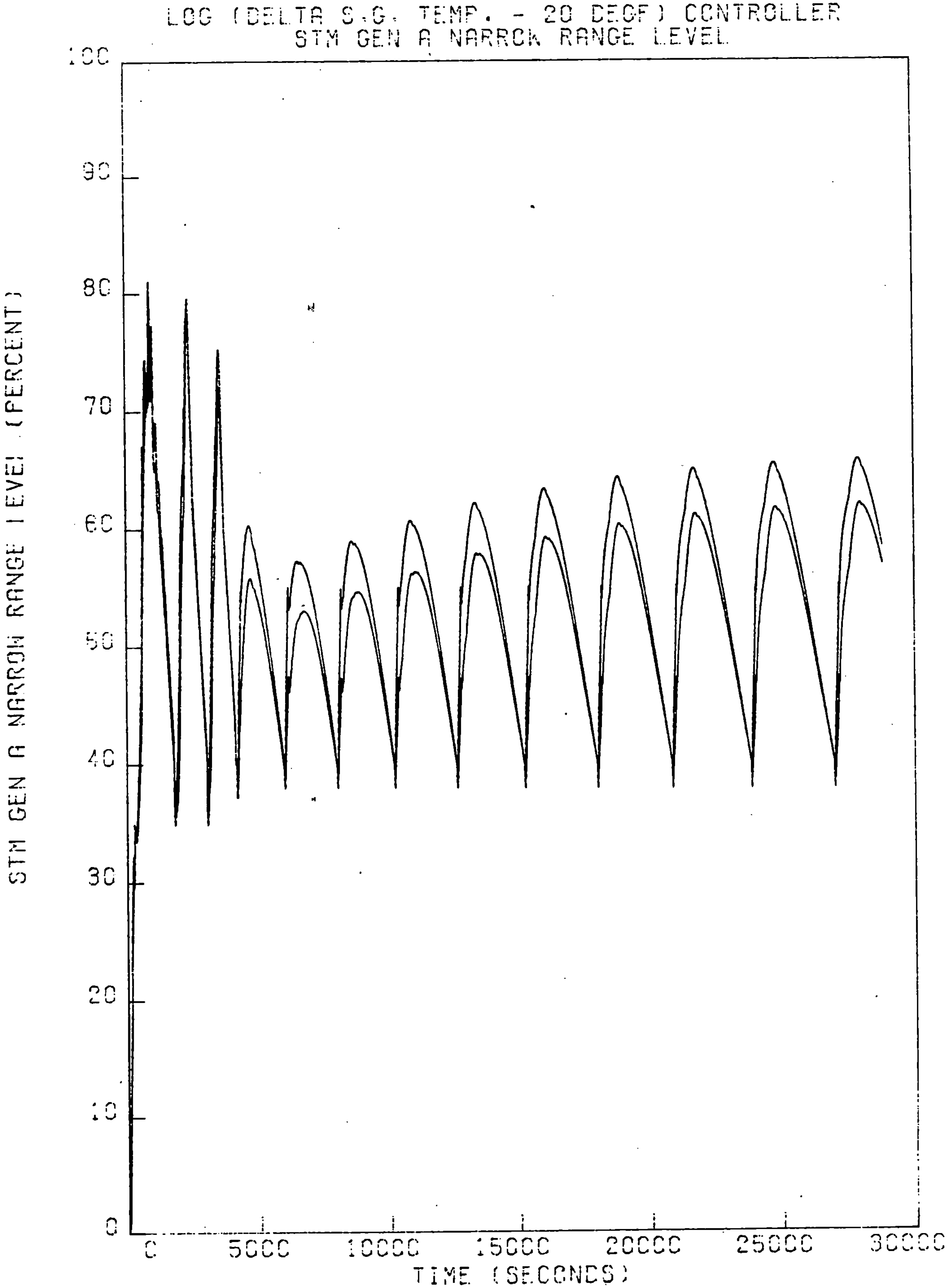

LOG (DELTA S.G. TEMP. - 20 DEGF) CONTROLLER
STM GEN A NARROW RANGE LEVEL
STM GEN A NARROW RANGE LEVEL (PERCENT)
100
90
80
70
60
50
40
30
20
10
0
0
5000
10000
15000
20000
25000
30000
TIME (SECONDS)

FIGURE A-89

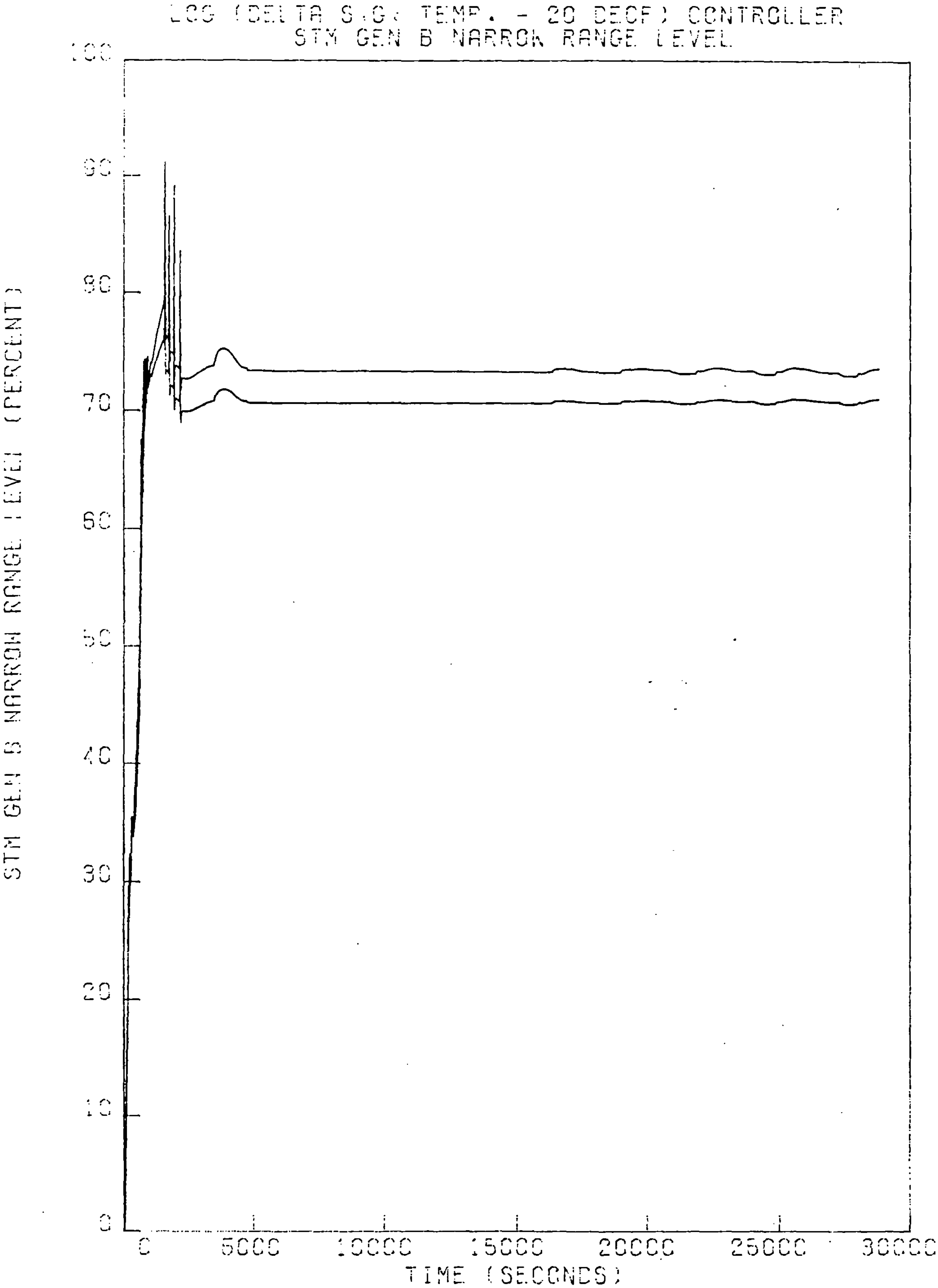

LOG (DELTA S.G. TEMP. - 20 DEGF) CONTROLLER
STM GEN B NARROW RANGE LEVEL
STM GEN B NARROW RANGE LEVEL (PERCENT)
100
90
80
70
60
50
40
30
20
10
0
0
5000
10000
15000
20000
25000
30000
TIME (SECONDS)

FIGURE A-90

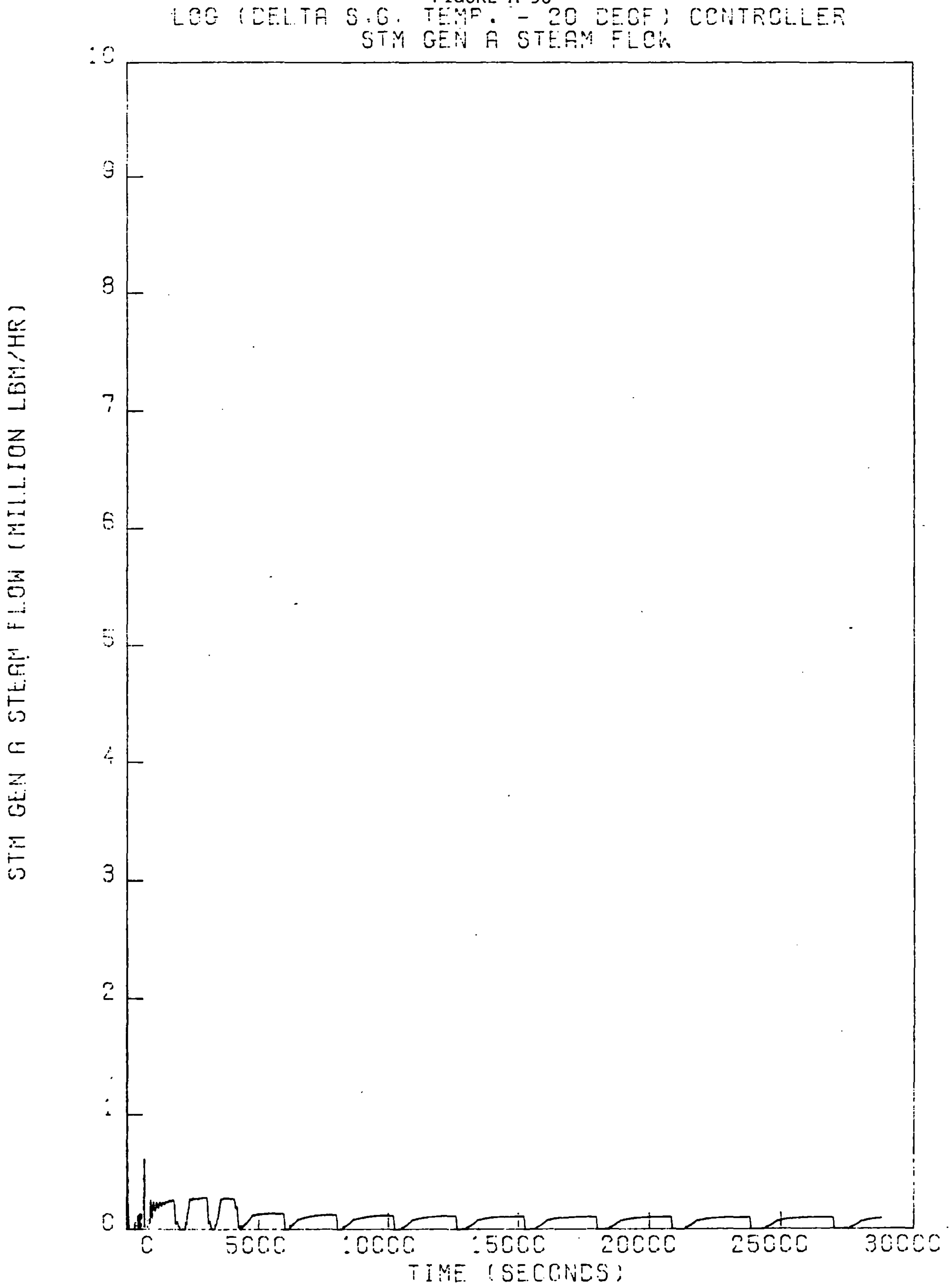

LOG (DELTA S.G. TEMP. - 20 DEGF) CONTROLLER
STM GEN A STEAM FLOW
STM GEN A STEAM FLOW (MILLION LBM/HR)
10
9
8
7
6
5
4
3
2
1
0
0
5000
10000
15000
20000
25000
30000
TIME (SECONDS)

FIGURE A-91

LCG (DELTA S.G. TEMP. - 20 DEGF) CONTROLLER
STM GEN B STEAM FLOW

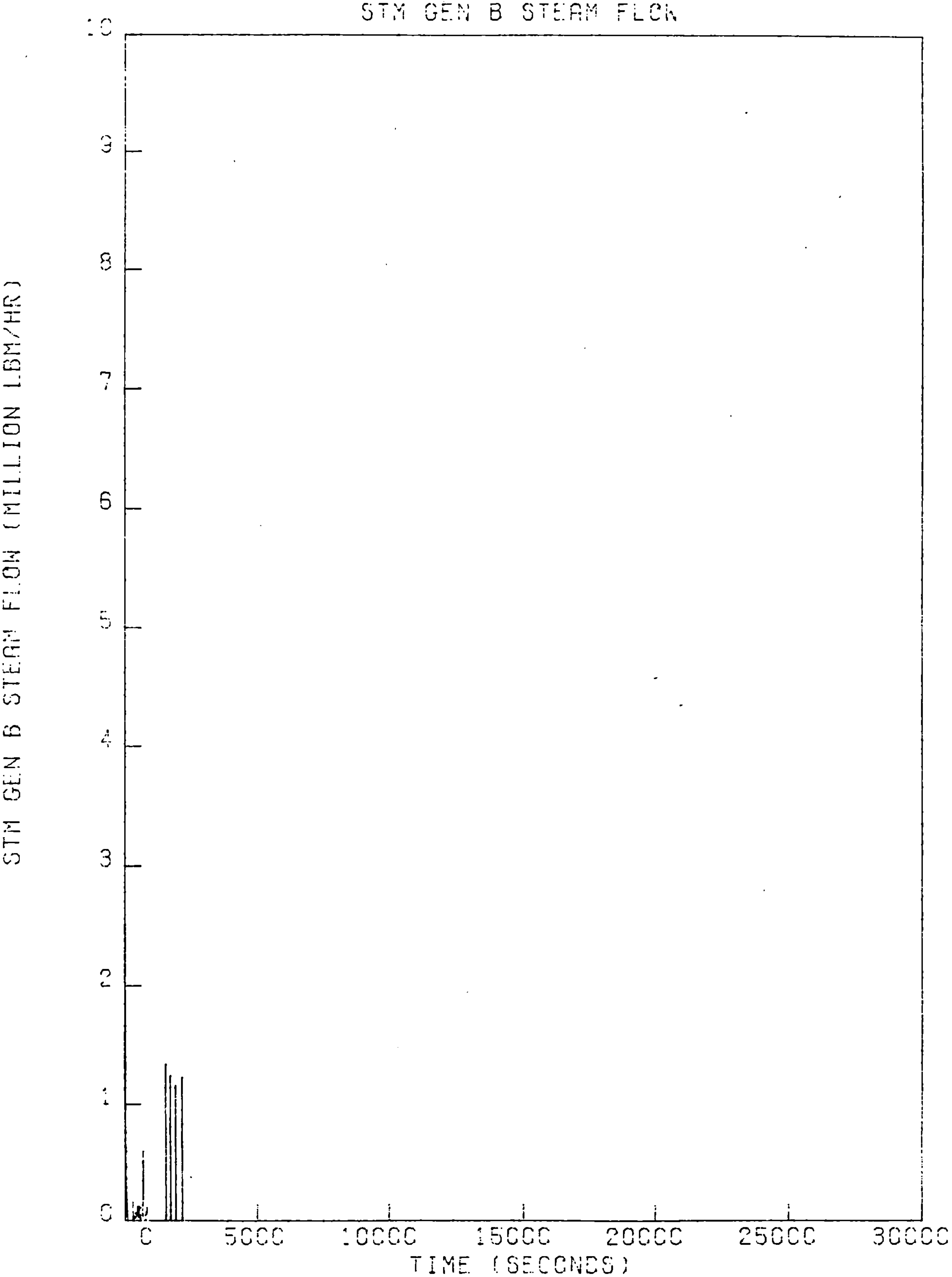
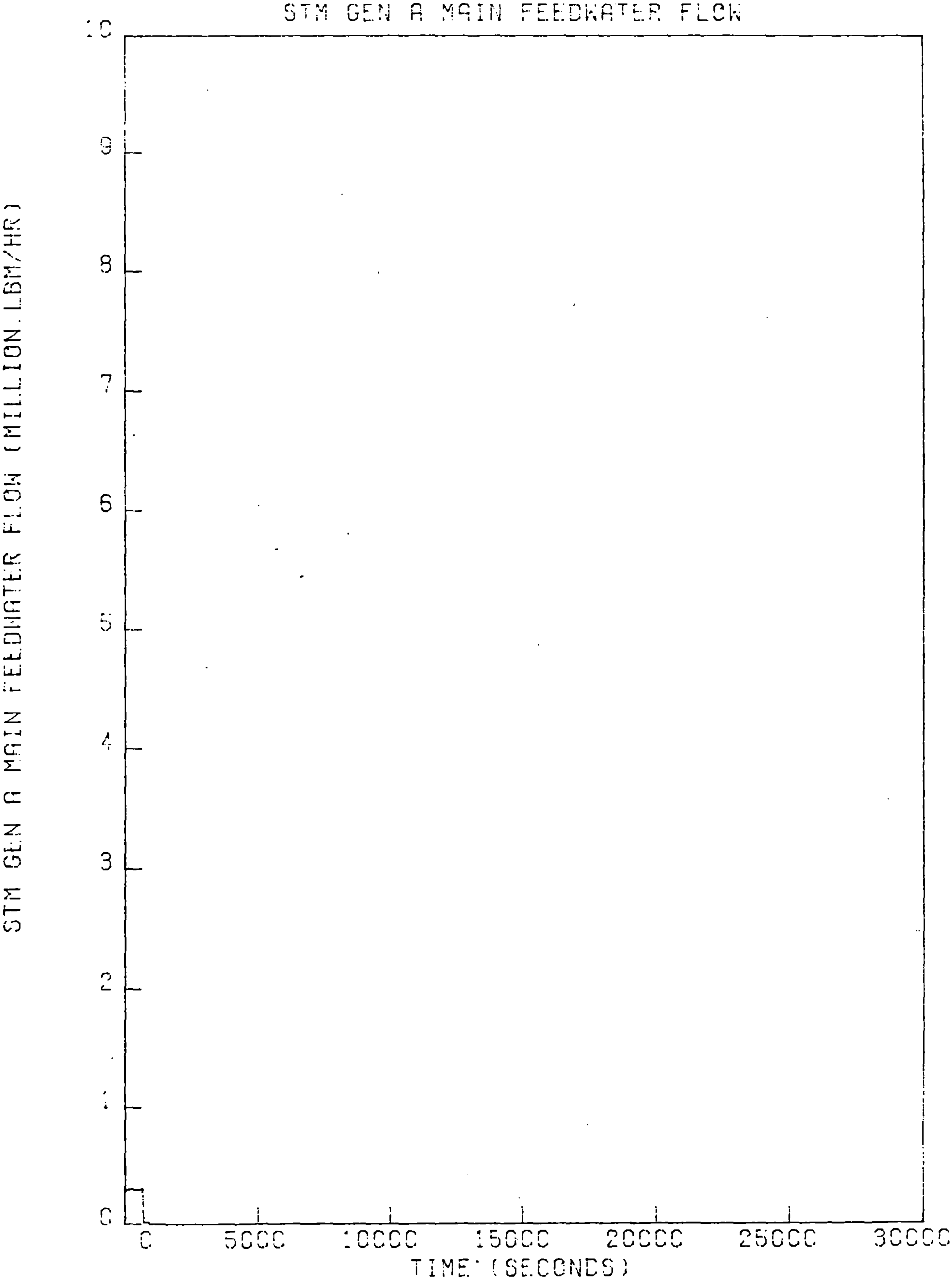


FIGURE A-92

LCG (DELTA S.G. TEMP. - 20 DEGF) CONTROLLER
STM GEN A MAIN FEEDWATER FLOW



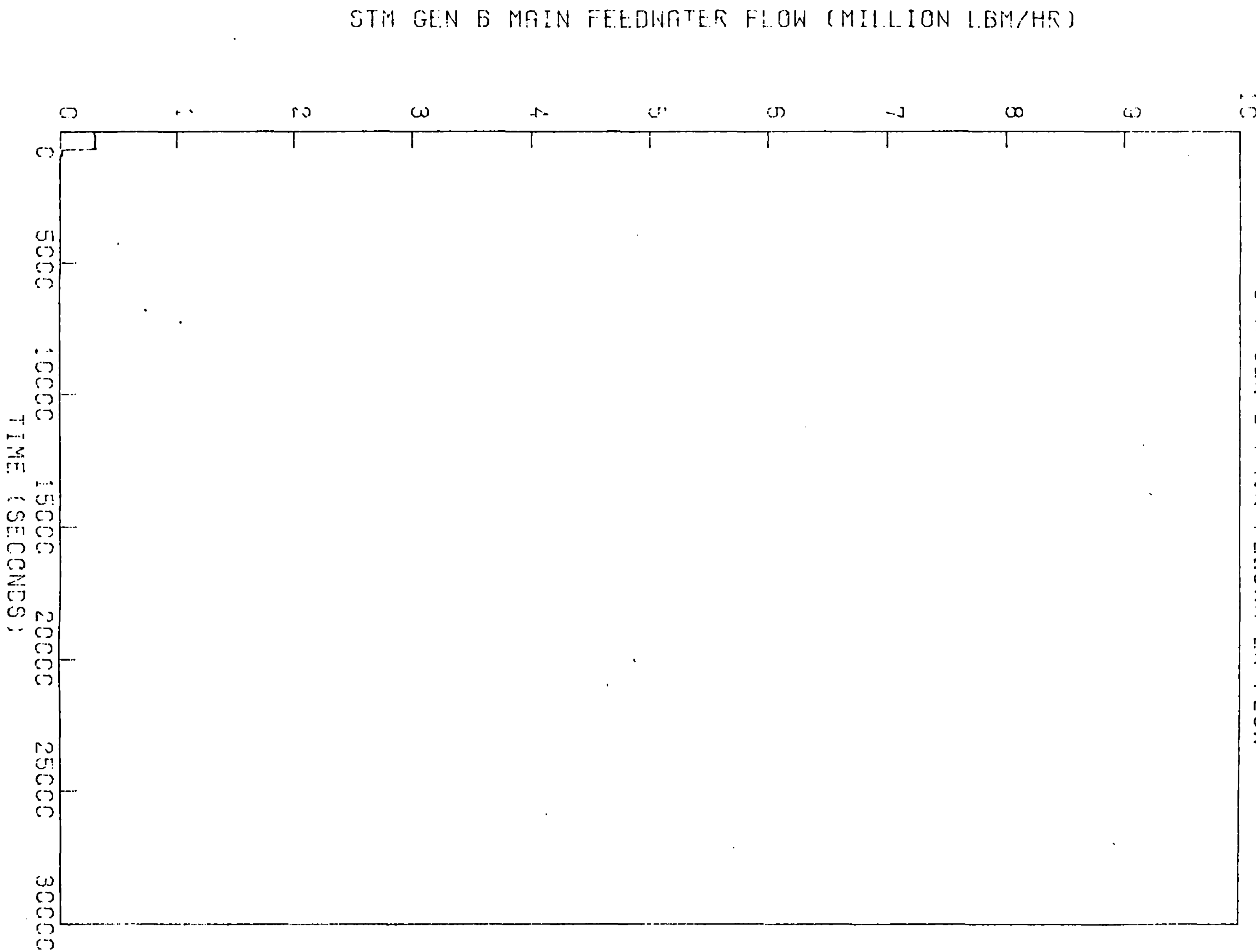


FIGURE A-93
LCO (DELTA S.G. TEMP. - 20 DEGF) CONTROLLER
STM GEN B MAIN FEEDWATER FLOW

FIGURE A-94

LCG (DELTA S.G. TEMP. - 20 DEGF) CONTROLLER
STM GEN A AUXILIARY FEEDWATER FLOW

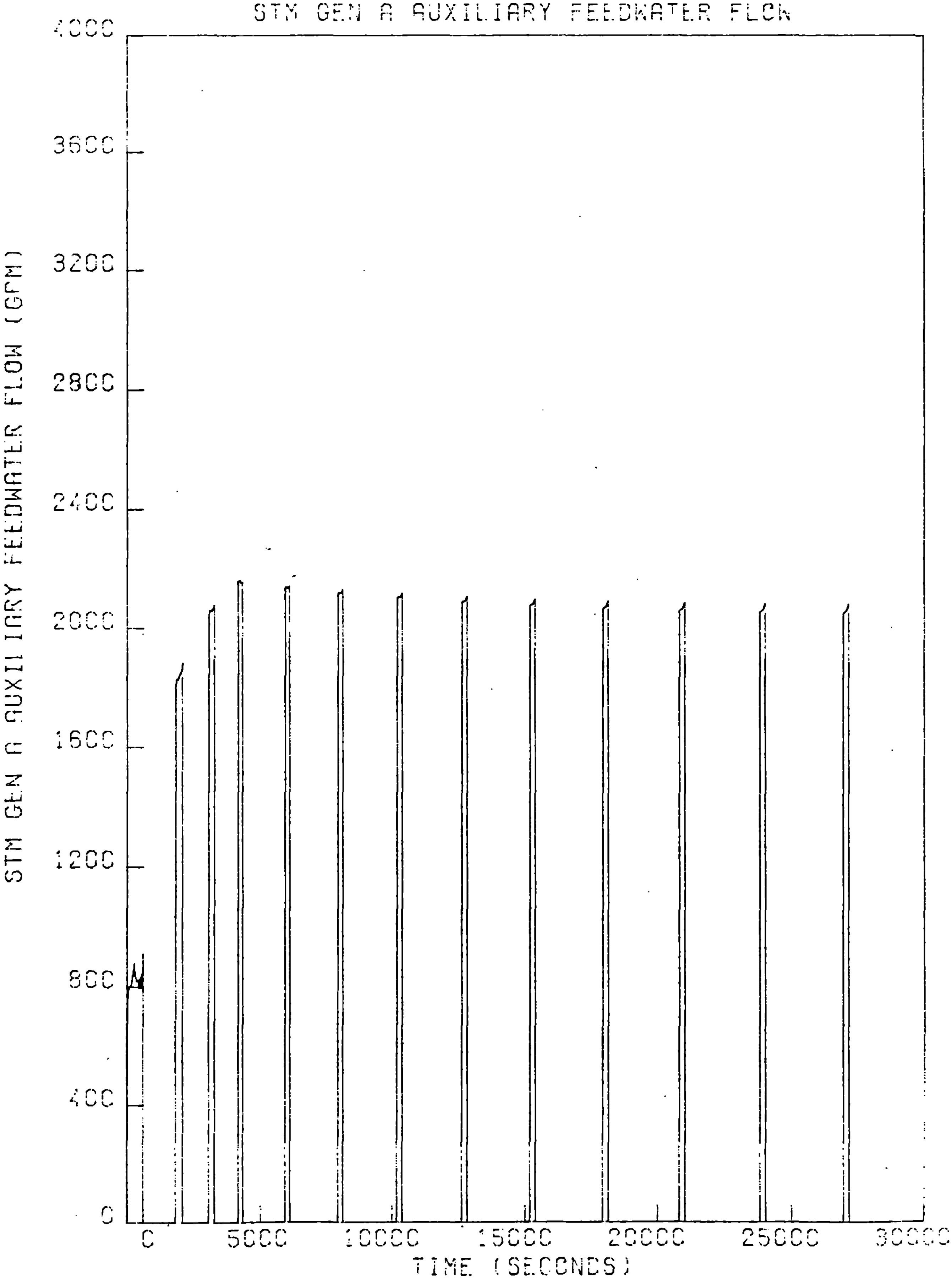


FIGURE A-95

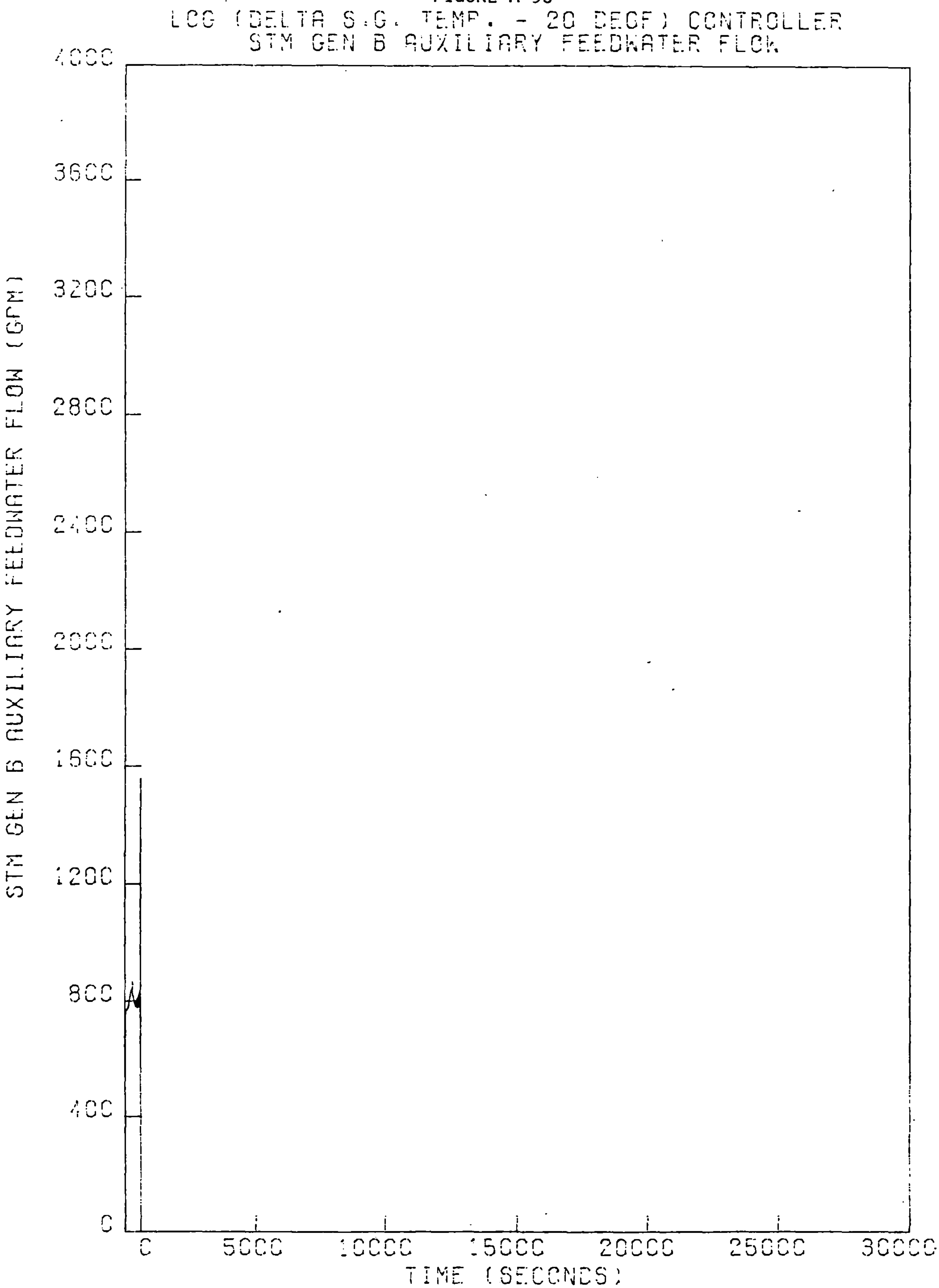
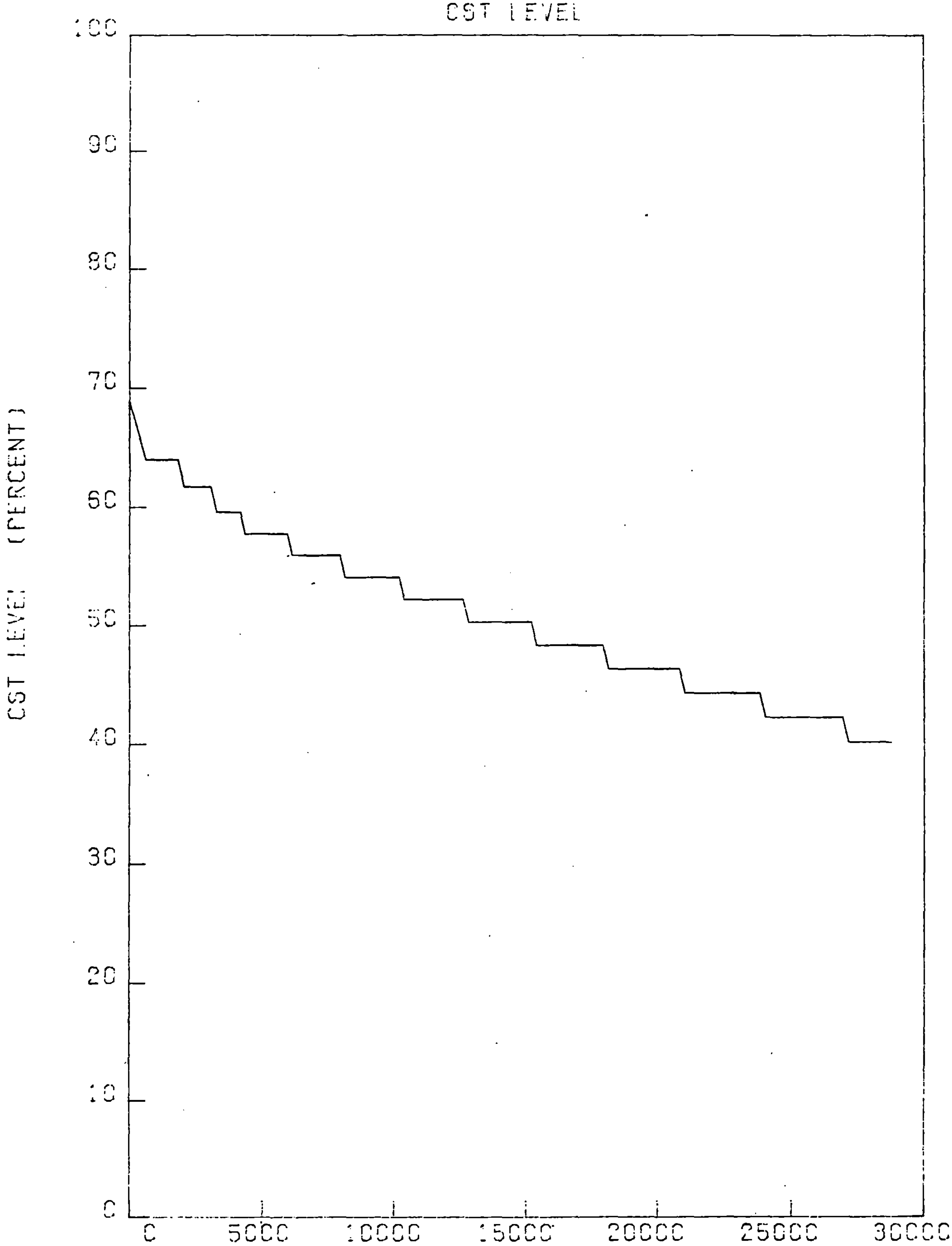

LOG (DELTA S.G. TEMP. - 20 DEGF) CONTROLLER
STM GEN B AUXILIARY FEEDWATER FLOW
STM GEN B AUXILIARY FEEDWATER FLOW (GPM)
4000
3600
3200
2800
2400
2000
1600
1200
800
400
0
0
5000
10000
15000
20000
25000
30000
TIME (SECONDS)

FIGURE A-96

LCG (DELTA S.G. TEMP. - 20 DEGF) CONTROLLER

CST LEVEL



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