REGU[illegible]Y INFOR[illegible]IBUT[illegible]YSTEM (RIDS)

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FACIL:50-438 Bellefonte Nuclear Plant, Unit 1, Tennessee Valley Au 05000438
50-439 Bellefonte Nuclear Plant, Unit 2, Tennessee Valley Au 05000439

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DENTON,H.R. Office of Nuclear Reactor Regulation

SUBJECT: Responds to NRC 791025 ltr re design adequacy of B&W nuclear steam supply sys utilizing once-through steam generators. Based on review of overcooling event consequences,concludes continued const justified.CPs should not be changed.

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	22 AD SITE TECH	1	0	26 ACCDNT ANLYS	1	1
	27 EFFL TRT SYS	1	1	28 RAD ASMT BR	1	1
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	AD SITE ANLYSIS	1	0	DIRECTOR NRR	1	0
	HYDRO-METEOR BR	2	2	MPA	1	0
	OELD	1	0			
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TENNESSEE VALLEY AUTHORITY

CHATTANOOGA, TENNESSEE 37401
400 Chestnut Street Tower II

December 3, 1979

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

Dear Mr. Denton:

In the Matter of the Application of	)	Docket Nos. 50-438
Tennessee Valley Authority	)	50-439

In response to your October 25, 1979, letter to H. G. Parris regarding the design adequacy of Babcock & Wilcox (B&W) Nuclear Steam Supply Systems utilizing Once Through Steam Generators, we are enclosing the detailed responses to the six requests for information identified as items a) through f). The detailed reply to this request is enclosed, similarly identified.

From the reference letter and our meeting with the staff on November 6, 1979, we understand the NRC's main concern as being one of the sensitivity of the reactor coolant temperature and volume to perturbations in the secondary system. We have studied this concern with B&W to the extent possible in the available time and are committed to further evaluations of the effects on the total plant to deal with the concern for sensitivity. In addition, our Nuclear Safety Review Staff will perform an independent review of these concerns. We will implement any changes that are proven by these studies to be appropriate.

The areas of study are included in Enclosure F. It should be noted that these studies involve the areas of control, instrumentation, and valves. This, in conjunction with the advanced stage of design, fabrication, and construction of the various systems as discussed in Enclosure C, leads us to conclude that installation of the affected systems can and should continue and that any necessary modifications will not be made significantly more difficult by this continued construction.

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Mr. Harold R. Denton, Director December 3, 1979

Based on the conclusions of the enclosed report, continued construction of all portions of the Bellefonte Nuclear Plant is justified, and the construction permits for Bellefonte units 1 and 2 should not be modified suspended, or revoked. If our additional assessments indicate otherwise, we will notify you immediately.

Very truly yours,

TENNESSEE VALLEY AUTHORITY

L. M. Mills, Manager
Nuclear Regulation and Safety

Sworn to and subscribed before
me this 3 day of Dec. 1979

Kim Bradbury
Notary Public

My Commission Expires 10/4/81

Enclosure
cc: Mr. James McFarland
Senior Project Manager
Babcock & Wilcox Company
P.O. Box 1260
Lynchburg, Virginia 24505

ENCLOSURE A

Item a). Identify the most severe overcooling events (considering both anticipated transients and accidents) which could occur at your facility. These should be the events which causes the greatest inventory shrinkage. Under the guidelines that no operator action occurs before 10 minutes, and only safety systems can be used to mitigate the event, each licensee should show that the core remains adequately cooled.

Response

Attached is B&W's analysis of the most severe overcooling events entitled "Overcooling Event Consequence Review." Time constraints have not allowed a detailed review of this report by TVA. If our review indicates the need for any major revisions, you will be promptly informed.

ATTACHMENT

OVERCOOLING EVENT CONSEQUENCE REVIEW

OVERCOOLING EVENT CONSEQUENCE REVIEW

1.0 INTRODUCTION AND CONCLUSIONS

1.1 Background

On October 25, 1979, the NRC issued a letter to utilities holding Construction Permits for B&W NSSS's; the utilities were requested to assess overcooling events on their plants, accounting for balance-of-plant features. Two specific requests of the NRC letter were:

a) "Identify the most severe overcooling events (considering both anticipated transients and accidents) which could occur at your facility. These should be the events which causes the greatest inventory shrinkage. Under the guidelines that no operator action occurs before 10 minutes, and only safety systems can be used to mitigate the event, each licensee should show that the core remains adequately cooled."

b) "Identify whether action of the ECCS or RPS (or operator action) is necessary to protect the core following the most severe overcooling transient identified. If these systems are required, you should show that its design criterion for the number of actuation cycles is adequate, considering arrival rates for excessive cooling transients."

1.2 Scope

This report responds to the specific NRC requests identified above. More than one transient type is analyzed to address different frequency of occurrence classifications and to assure the most severe cases are indeed included in the evaluation. A qualitative assessment of possible non-mitigative operator actions in the 0 to 10 minute time frame is also provided. This assessment provides indication of what operator action is anticipated during the initial phases of an overcooling transient.

The analyses identify the frequency of the RPS, ESFAS, and operator action for mitigation of the transient.

A summary of the results is given in Section 2.0. Section 3.0 provides the details of the initial conditions, computer codes, and basic assumptions used in the analysis. The transient response data is given in Section 4.0. Section 5.0 demonstrates the adequacy of the design criteria for each system.

1.3 Conclusions

Based on the analyses performed in this report, the following conclusions can be drawn:

a) The overcooling accident (Main Steam Line Break) and the overcooling transient (Main Feedwater Overfill) analyzed herein, retain adequate core cooling even when analyzed with no operator action before 10 minutes and with only safety systems used to mitigate the event.

b) RPS and ECCS actuation are required to mitigate the most severe overcooling transient; however, operating data imply the arrival rate of transients requiring RPS or ECCS actuation is within the design basis.

It should be noted that this report could not exhaustively determine the most severe overcooling transient in the allotted time; the reasons for selecting Main Feedwater Overfill are discussed in Section 4.1.1.

1.4 Applicability of Results

The results presented in this report are applicable specifically to this NSS with the parameters tabulated in Section 3. Specific attention has been paid to the balance-of-plant equipment in the mitigative functions performed.

2.0 SUMMARY

This section provides a detailed summary including: (a) identification of the concern and basis for selection of the transients to resolve the concern, and (b) principal results of the analysis. By reviewing this section, supported by the details given in Section 3.0, 4.0, and 5.0, a concise overview can be obtained of the completed resolution of this concern.

Section 2.1 addresses the selection of anticipated transient and accident conditions causing greatest core shrinkage, and Section 2.2 discusses the phenomena of void formation under inventory shrinkage conditions. Section 2.3 summarizes the analyses. Section 2.4 summarizes Section 5.0 in demonstrating that the design criteria for the number of actuation cycles of the RPS and ESFAS is adequate.

2.1 Limiting Overcooling Event Confirmation

Maximum RCS coolant inventory shrinkage results from a decrease in the pressure and temperature of the coolant at a maximum rate, without a compensating coolant makeup addition. The double-ended steam line break (SLB) provides maximum cooldown rates and is analyzed in Section 4.2 as the limiting accident. Several sensitivities and differing conditions were analyzed to provide greater insight into the steam void formation and collapse which would occur and its subsequent effect on core cooling. These additional studies were performed on the SLB since this accident was expected to result in RCS voiding, whereas, it will be shown the limiting moderate frequency event analyzed does not produce voiding as a result of RCS coolant inventory shrinkage.

In selecting the limiting anticipated transient, SAR and operating plant overcooling events were reviewed. The most severe moderate frequency event in the SAR is the steam pressure regulator malfunctions. In review of plant transient data (see Section 4.1.1), the overfeed by main feedwater after reactor trip has produced the most severe overcooling transients. Hence, based on arrival rates for operating plants and the cooldown rate associated with this transient, the main feedwater overfeed following a reactor trip/turbine trip is considered the limiting anticipated transient and is analyzed in Section 4.1

2.2 Shrinkage Effects

Shrinkage of the RCS coolant liquid volume occurs as temperature decreases during an overcooling event. The pressurizer volume of 2250 ft^3 contains 1050 ft^3 of mostly saturated water during normal operation. This liquid volume flows out of the pressurizer into the system as the system inventory volume decreases. If the RCS coolant inventory volume decrease is greater than 1050ft^3, and continues to decrease, then the pressurizer steam space can be transferred into the RCS. This type of steam voiding is limited by the inventory volume difference between hot, full power and the final pressure/temperature achieved during the transient. Its effect is further mitigated by actuation of emergency core cooling system (ECCS) such as high pressure injection (HPI), low pressure injection (LPI), or core flood tank (CFT) systems.

The other mechanism which produces steam voids in the RCS is flashing of RCS water. As the pressure rapidly decreases in the RCS, the liquid in the hotter portions of the system can become saturated and steam can form. This effect can be aggravated by the hot metal in this area, flashing additional water to steam. This process, in a non-LOCA situation, however, is self-regulating. As the steam separates, or additional flashing occurs, the pressure decrease in the system lessens as the overcooling continues. The steam void formation is then reduced and the steam void will tend to collapse as a subcooled state is again established.

Examination of the SLB analysis indicates a small amount of steam formation occurs in the upper hot leg region prior to the pressurizer emptying, occurring almost exclusively on the side with the affected steam generator. If the affected steam generator is on the loop with the pressurizer, emptying the pressurizer contributes to the steam void formation. If the affected steam generator is on the opposite loop from the pressurizer, emptying the pressurizer has little effect on the steam voids on that side and they are quickly quenched. Therefore, the limiting accident, in terms of void volume formation, occurs for the SLB in the same loop that has the pressurizer.

2.3 Adequacy of Core Cooling

In this section, a summary of the results presented in Section 4.0 is given and analyzed for determination of adequate core cooling. The anticipated transient analyzed is the overfeed of the steam generators by the main feedwater (Section 4.1). This overcooling transient, with no mitigative operator action for 10 minutes, resulted in the pressurizer emptying briefly. However, the HPI actuation and flow rate is sufficient to prevent any steam voiding in the RCS.

The design basis steamline break (SLB) accident (Section 4.2) produces steam voiding in the upper hot leg regions of the RCS. Several sensitivity studies were performed to assess impact on steam void formation and subsequent core cooling flow. The sensitivity studies included: a) varying the time of loss-of-offsite power (LOOP) from time of trip to time of ESFAS, b) with and without core decay heat, c) single failure assumptions of stuck open relief valve on unaffected steam generator or loss of one HPI pump, and d) moving the break from the steam generator with the pressurizer in its loop to the side without the pressurizer. In all analyzed cases, core flow continued, or if interrupted, resumed immediately upon collapse of the void in the unaffected steam generator side of the RCS. The core region remained subcooled throughout the transient for all cases analyzed. The results of SLB cases are presented in Section 4.2.

Mitigative operator action was not assumed in the analysis in the first 10 minutes. From a review of potential operator actions during this time it is concluded that only two actions are of major importance. Operator control of the steam generator level would have reduced the extent of RCS inventory shrinkage for both MFW overfeed and SLB transients. A non-mitigative operator action would result from the premature cut-off of the HPI flow. Indication to the operator during steam voiding situations such as occurred during the SLB accident analyzed are to maintain HPI flow since pressurizer level and subcooled margin both indicate the necessity of HPI. Adequate core cooling would necessitate that HPI makeup to the RCS be available at some point during the course of the overcooling transients.

2.4 Adequacy of Core Protective Measures

Section 5.0 provides the details of the design basis for operating transient cycles. Operating plant data has shown the 40 cycles of actuation of HPI to be sufficient design basis to cover automatic initiation arrival rate for this system. The analysis presented in Section 4.0 confirms that the most severe overcooling events require ECCS actuation. The operating plant data shows that ESFAS automatic actuations occur <1/year and, therefore, 40 cycles/lifetime is an adequate design for transients not expected to occur <40/lifetime of the plant

3.0 ANALYTICAL TECHNIQUES

3.1 Computer Codes

The B&W certified computer code TRAP2 (Reference 1) has been used in the analyses presented in the following sections. This computer code is a nodal type, digital simulation (similar to CRAFT2, Reference 2) capable of handling rapid overcooling transients that may result in two-phase fluid conditions in the reactor coolant system.

The noding flow path networks used in the TRAP2 analysis of the plant are given in Figures 3-1 and 3-2. A description of each node and the important flow paths are given in Tables 3-1 and 3-2. The more detailed noding shown in Figure 3-1 (description in Table 3-1) is referred to as maxi-TRAP, the less detailed model in Figure 3-2 (description in Table 3-2) is referred to as mini-TRAP. The more detailed maxi-TRAP model is used during the initial phase of the transient while the primary and secondary variables are rapidly changing. In the interest of computer calculational time saving, the mini-TRAP model is used in the long-term solution where system variables are more slowly varying and the additional noding is not required.

3.2 Transient Selection

The types of overcooling events considered include (a) those which constitute the initiating event, (b) those which result from single failures following any initiating event, and (c) those which are made more severe from single failures following the initiating overcooling event. The specific systems whose malfunction or failure are considered either as initiating events or single failures which enhance overcooling, are:

A. Feedwater heater failure which causes a decrease in feedwater temperature,

B. Feedwater flow control malfunction that causes an increase in feedwater flow,

C. Steam pressure regulator malfunction which causes increased steam flow,

D. Inadvertent opening or stuck open steam relief valve which causes increased steam flow and/or depressurization of a steam generator, and

E. Steam system piping failure which causes excessive steam flow and depressurization of a steam generator.

The SAR analyses are referred to in order to narrow the most severe type overcooling events for consideration. More specifically:

a) Events which constitute initiating event: A through D are moderate frequency of which steam regulator malfunction is most limiting according to the SAR analyses. E is a design basis event for which the double-ended rupture (DER) MSLB is limiting.

b) Events which result from single failure following any initiating event: This infrequent occurrence is a combination of a moderate frequency event plus one of A through D occurring as a single failure. The event chosen to be analyzed in this category is an immediate reactor trip on turbine trip signal (decrease the heat source), combined with a feedwater flow control malfunction that allows continued main feedwater flow (increase the heat sink).

c) Events which are more severe from single failures following the initiating overcooling event:
The limiting design basis overcooling transient to be a double-ended SLB. The single failure chosen to maximize continued long-term cooling is a stuck open relief valve on the unaffected steam generator.

The limiting or potentially limiting overcooling cases to be analyzed as discussed above are summarized in Table 3-3.

3.3 Basic Assumptions

Key input parameters used in the plant analysis are given in Table 3-4. These values represent as-built information, realistic setpoints, actuation times, flow rates, and valve closures. Other system parameters not listed are those applicable to the plant design. The assumption of stuck rod was removed from the shutdown rod worth, thereby being more realistic in a conservative direction for the overcooling type events concerned with maximum RCS coolant shrinkage.

Single failures of active components assumed in the analysis are given in Table 3-3. Some parameterization of the single failure assumption is done for the limiting overcooling case. Since only safety grade equipment is assumed to function, the single failures of mitigative equipment is limited. Table 3-5 lists the equipment assumed to function for each transient analyzed.

No mitigative operator action is assumed for 10 minutes in the analysis.

4.0 RESULTS OF CORE COOLING STUDIES

4.1 Anticipated Transients

4.1.1 Scope of Evaluation

The anticipated transients analyzed in the SAR's were reviewed for cooldown rates and consequences in order to select the most limiting case for shrinkage. Operating plant data was also reviewed. From this review, the transient with highest frequency of occurrence and the potential for greatest overcooling was due to malfunctions resulting in overfeed of the steam generators by main feedwater.

Operating plant data shows that overcooling of the RCS has occurred from primarily two types of events: 1) Failure of a relief valve to reseat at the proper pressure, which limits the overcooling to the saturation temperature of the pressure at which the valve does reseat. 2) Overfeed of the steam generators following a reactor trip, which has caused the greatest primary cooldown observed. Steam pressure regulator malfunctions that allow increased steam flow would represent overcooling by depressurizing the secondary system. Its effect is very similar to a small SLB analysis. The arrival rate for this transient has been zero at operating B&W plants; therefore, in the limited time frame for the preparation of this report, the MFW overfeed transient is presented. The MFW overfeed represents the maximum cooling that can be achieved by feeding the OTSG's first with uncontrolled main feedwater and then, after ESFAS, with colder auxiliary feedwater.

4.1.2 Main Feedwater Overfeed Analysis

The initiating event is a turbine trip with simultaneous reactor trip and a control failure such that main feedwater continues to feed both steam generators at full capacity.

The sequence of events for this transient are given in Table 4-1. The analysis was performed using the models and assumptions given in Section 3.0. Time constraints dictated that this analysis be completed entirely with maxi-TRAP. Neither credit for ICS nor operator action was assumed.

Figures 4-1 through 4-8 present the system parameters. The pressurizer does not empty during the 10 minute period and no voiding occurs. The cooldown rate was slow enough that HPI flow adequately compensated for system shrinkage.

Without additional means to control OTSG levels, the steam generators will overfill with main feedwater. Subsequently, the steam lines will become filled with water. This was found to occur prior to ESFAS isolation of the main feedwater. It was assumed for the analysis that no immediate operator action was taken and water relief out of the safety valves was permitted. After ESFAS isolated main feedwater, auxiliary feedwater flow was then continued to the steam generators to maximize the cooling rate.

From the system response observed, two probable operator actions during the course of the transient are suggested. First, operator action would be needed to terminate the OTSG overfill by main feedwater early in the transient, which would stop the overcooling of the RCS. Also, since sufficient subcooled margin exists throughout most of the transient, the operator would regulate HPI flow to maintain pressurizer inventory. However, this particular action is not required for the first 10 minutes of the transient.

4.1.3 Conclusions

The RCS coolant inventory remains subcooled throughout the transient, thus assuring core cooling. HPI actuation and flow rate was sufficient to prevent the pressurizer from emptying throughout the 10 minute transient time. Only additional failures, such as bypass relief valves stuck open, could increase the cooldown rate experienced during the transient. ESFAS terminates the excessive feedwater flow. With the fill rates of main feedwater assumed, the steam generators will overfill in about 90 seconds.

The RC pumps running case presented represents the maximum cooling rate. Therefore, no voiding for this case assures that the RC pump trip case also would not produce voids in the RC system.

4.2 Accidents

4.2.1 Scope of Evaluation

Maximum overcooling of the RCS results from an uncontrolled blowdown of the secondary plant, i.e., steam line break accident (SLB). The double-ended rupture from full power has been demonstrated in the SAR to result in maximum overcooling. Selection of the worst coolant inventory shrinkage case for this event has been studied by analyzing a spectrum of different conditions. Table 4-3 shows the various conditions and identifies these different analyses by case number for further reference in the discussion of results provided in following sections.

4.2.2 SLB Analysis

A double-ended guillotine break is assumed to occur in the 28-inch ID steam line. The location of the break is outside of the reactor building. Other system parameters, models and assumptions are as presented in Section 3.0.

The sequence of events is given in Tables 4-4 through 4-11 for each case analyzed. The figures for each case are listed on the table for that case. The figures for Case 1 RC Pumps Running also include a comparison of maxi-TRAP and mini-TRAP results, showing reasonably good agreement between the two models. Subsequent SLB analyses were performed using the mini-TRAP model.

The SLB accident was analyzed for 10 minutes assuming no mitigative operator action and only safety grade equipment for transient mitigation. The overcooling rate as would be anticipated is much higher for the SLB cases than that obtained for the MFW overfeed cases presented in the previous section.

The case resulting in the most severe consequences of RCS shrinkage occurs with LOOP at time of ESFAS actuation. The assumption of no decay heat aggravates this shrinkage effect. A bubble rise velocity of 5 ft/sec was used in the hot leg piping nodes. It is important to note that the void formation data presented includes entrained, as well as separated bubble mass. Therefore, with RC pumps running and during the start of flow coastdown, the bubble mass will be almost totally entrained. Comparing the single failure assumption of a stuck-open relief valve on the unaffected steam generator versus failure of one HPI pump, the stuck-open relief valve (Case 4) results in the maximum steady steam void formation. However, for the one HPI failure (Case 6), the steam void remains in the RCS longer. The maximum steam void occurs in the hot leg attached to the pressurizer and is about 500 ft^3 for the cases analyzed.

The first steam void formation that appears during the SLB accident is due to flashing, i.e., reaching saturation, in both hot legs. This occurs prior to the pressurizer emptying. One the loop side opposite the pressurizer and analyzed with the unaffected steam generator, this effect is small and returns to a solid, subcooled state about the time the pressurizer empties. On the loop with the pressurizer and the affected steam generator, this steam void continues to increase as the pressurizer empties. ESFAS initiation also occurs at about this time and HPI injection, as well as isolation of the affected stream generator main steam and feedwater, tend to limit the size of the steam void formed. HPI flow is sufficient to overcome the shrinkage that is still occurring from the heat removal through auxiliary feedwater to the unaffected steam generator. As refill and repressurization of the RCS continues by the HPI, the steam void is quenched and collapsed. Core flow is maintained throughout the transient. During LOOP cases, natural circulation is maintained by the cooling from the unaffected steam generator side of the RCS.

Without additional means of steam generator level control, the auxiliary feedwater fills the unaffected steam generator in 6 to 7 minutes. The pressurizer is filling, but has not completely filled in the first 10 minutes of the accident. Thus, adequate time is available for operator action to prevent pressurizer overfill. Level control on the unaffected steam generator would allow earlier repressurization of the RCS; thereby leading to earlier collapse of the void. It was assumed for the analysis that no immediate operator action was taken and water relief out of the safety valves was permitted.

The most probable operator action during a steam line break would be to control auxiliary feedwater to the intact steam generator to maintain level and secondary pressure.

4.2.3 Conclusions

Steam void formation in the upper hot leg regions was found to occur during the steam line break accident. The magnitude and duration of the steam void formation varied with conditions under which the analysis was performed. In all cases, core flow was maintained or, if interrupted, resumed upon collapse of the void in the unaffected steam generator side of the RCS. In all cases, the core remained subcooled.

Some of the specific phenomena noted for the various cases analyzed are:

1. The LOOP assumption at ESFAS produces slightly worse consequences than at an earlier time. This is because the pumps running maximizes the overcooling, such that the later the LOOP (up to ESFAS) the more shrinkage that has occurred. LOOP after ESFAS should not continue to increase the severity, since isolation of the affected steam generator main feedwater supply occurs at ESFAS and greatly reduces the overcooling rate.

2. The assumption of no decay heat aggravates the steam voiding situation. However, as decay heat level decreases, the need for additional core flow decreases. In the extreme, no decay heat implies no core cooling is necessary.

3. Single failure of a relief valve on the unaffected steam generator to maximize cooling rate and a single failure of 1 HPI pump to maximize the refill-repressurization effects were examined. The larger magnitude of steam void occurred for the stuck-open relief valve case; whereas the steam void formation was of longer duration for the HPI failure case.

4. The void formation in a given loop was large enough to create temporary flow blockage in that loop. However, the net core flow remains positive through most of the analysis, and is never interrupted to the point that saturation occurs in the core region.

No mitigative operator action was assumed for 10 minutes in the analysis. With the fill rates of auxiliary feedwater assumed, the unaffected steam generator will overfill in 6 to 7 minutes. Core cooling appears adequate for all cases analyzed, since subcooled conditions are maintained in the core region.

5.0 DESIGN BASIS FOR CORE PROTECTION

Required ECCS and RPS actions necessary to protect the core has been summarized in Table 3-5 and discussed in more detail for each transient in Section 4.0. No operator action has been assumed within 10 minutes for mitigation in the analysis. The purpose of this section is to demonstrate that the design criteria for the number of actuation cycles is adequate.

Twenty-five different types of transient cycles (several are SAR analyses) are used in evaluating the acceptable number of design cycles. These operating transients are listed in Table 5-1 along with the number of design cycles for each transient type. This data is the basis on which the stress evaluation is performed for the plant and will be contained in Section 5.7 of the Standard Technical Specifications for the plant (per NUREG 0103, Rev. 3). The number of cycles for transient types listed in Table 5-1 is not meant to be an absolute limit but were chosen on the basis of expected frequency (plus margin) and shown to be acceptable in the stress evaluation. Special transient analyses can be performed based on any actual transient data, thereby allowing categorization of the special case into one of the allowable transient design cycles.

The adequacy of the number of design cycles can be inferred from operating plant data. Table 5-2 compares the actual arrival rate for RPS and ESFAS actuation to date on plants of B&W design to the rates allowed by the design basis (Table 5-1). The operating data is less than the allowable actuation rate for both systems, thereby supporting the adequacy of design.

6.0 REFERENCES

1. J. J. Cudlin, P. W. Dagett, "TRAP2-FORTRAN Program for Digital Simulation of the Transient Behavior of the Once-Through Steam Generator and Associated Reactor Coolant System", BAW-10128, Babcock and Wilcox, Lynchburg, Virginia, August 1976.

2. R. A. Hedrick, J. J. Cudlin, and R. C. Foltz, "CRAFT2-FORTRAN Program for Digital Simulation of a Multinode Reactor Plant During Loss of Coolant," BAW-10092, Revision 2, Babcock and Wilcox, Lynchburg, Virginia, April 1975.

TABLE 3-1: MAXI-TRAP NODE AND PATH DESCRIPTIONS

NODE NUMBER	DESCRIPTION
1	RV lower plenum up thru the bottom of the core support sheets.
2	Reactor core, core bypass, upper plenum, and outlet nozzles.
3	Hot leg A, includes SG A upper plenum and upper tube support sheets.
4-13	SG A tube region between tube support sheets.
14	A cold legs, including lower tubesheet, SG A lower plenum, and RCS pumps A1&A2.
15	RV annulus, includes inlet nozzles.
16	Hot leg B, includes SG B upper plenum and tube support sheets (upper).
17-26	SG B tube regions (primary) between the tube support sheets.
27	B cold legs, including lower tubesheet, SG B lower plenum, and RCS pumps B1&B2.
28-30	Pressurizer.
31-40	SG A secondary side heat transfer region.
41-50	SG B secondary side heat transfer region.
51	SG A steam riser.
52	SG B steam riser.
53	Main Steam Line 1 to the MSIV (SG A).
54,57	Main Steam Line #2 to the MSIV (SG A) - Split to model a DESLB.
55,58	Main Steam Line #3 to the MSIV (SG B) - Split to model a DESLB.
56	Main Steam Line #4 to the MSIV (SG B)
59	MSL #1&3 from the MSIV's to the cross pairing (denoted here as "X").
60	MSL #2&4 from the MSIV's to the cross pairing (denoted as "Y").
61	From cross pairing X to the turbine stop valves on X - includes ½ cross connection.
62	From cross pairing Y to the turbine stop valves on Y - includes ½ cross connection.
63	Turbine.
64	From the MFW pumps to HTR bank #6
65	FW Htr banks #6&7, and associated piping.

TABLE 3-1: MAXI-TRAP NODE AND PATH DESCRIPTIONS CONT'D

NODE NUMBER	DESCRIPTION
66	From FW Htr bank #7 to the FW fork (does not include any fork piping).
67	From the FWL fork to MFIV "B".
68	From the FWL fork to MFIV "A".
69	From MFIV B to SG B inlet.
70	From MFIV A to SG A inlet.
71	SG B downcomer.
72	SG A downcomer.

TABLE 3-1 (cont'd.)

PATH DESCRIPTIONS

PATH NUMBER	DESCRIPTION
1	Core path
2	Core bypass
3,17	Paths from the reactor to the hotlegs
4,18	Paths from the hotlegs to the steam generators
5-13, 19-27	Steam generator primary paths
14, 28	Paths from the steam generators to the cold legs, including the RCS pumps
15, 29	Paths from the cold legs to the RV downcomer
16	Path from the downcomer to the RV lower plenum
30	Pressurizer surge lines
51-54	Pressurizer flow paths
31-39, 41-49	Steam generator secondary flow paths
40,50	Paths from the SG heat transfer regions to the risers
55-58	Paths from the SG risers to main steam lines (MSL) #1-#4
60,61	MSL #2 & #3
59, 62-64	MSLV #1-#4
65,66	Paths from the junction of MSL #1,3 and 2,4 to the turbine stop valves (TSV's)
67-70	TSV #1-#4
71	Cross connection
72,73	MFW pumps
74	Path from the MFW pumps to MFW HTR banks #6 & #7
75	Path from MFW banks #6 & #7 to the MFW branch
76,77	Path from the MFW brach to the MSLV's
78,79	MFIV "A" & "B"
80,81	Paths from the MFIV's to the SG downcomer
82,83	Paths from the SG downcomer to the SG heat transfer region
84,85	AFW flow paths
86	HPI
87	LPI
88,89	SLB paths

TABLE 3-2: MINI-TRAP NODE AND PATH DESCRIPTIONS

NODE NUMBER	DESCRIPTION
1	RV lower plenum to bottom of support plates.
2	Core, core bypass, upper plenum, outlet nozzles.
3	Hot Leg.
4	Candy Cane
5,6,7	Steam Generator primary tube region
8	Hot Leg
9	Candy Cane
10,11,12	Steam Generator primary tube region.
13	Cold Leg
14	Cold Leg
15	Reactor vessel downcomer
16	Pressurizer
17,18,19	Steam Generator secondary tube region.
20,21,22	Steam Generator secondary tube region.
23	Feedwater piping
24	Feedwater piping
25	Steam riser
26	Steam riser
27	Steam piping
28	Steam piping
29	Turbine
30	Atmosphere

TABLE 3-2 (cont'd.)
PATH DESCRIPTIONS

PATH NUMBER	DESCRIPTION
1	Core
2	Core bypass
3,11	Hot leg
4,12,38,39	Hot leg candy cane
5,13	Hot leg piping (candy cane to SG upper plenum)
6,7,14,15	Steam generator primary tubes
8,16	RC pumps
9,17	Cold leg piping
10	Downcomer, reactor vessel
18	Pressurizer surge line
19	Steam piping crossover
20,27	Main feedwater pumps
21,28	Feedwater piping
22,23,29,30	Secondary heat transfer region steam generator
24,31	Steam riser, SG
25,26,32,33	Main steam piping
34,35	HPI pumps
36,37,43,44	Auxiliary feedwater paths
40,41	Breaks
42	LPI
45	Stuck-open relief

TABLE 3-3: SUMMARY OF EVENTS ANALYZED

INITIATING EVENT	SINGLE FAILURE	SENSITIVITY STUDIES
A. Anticipated Event Made More Severe By Single Failure		
Reactor Trip/Turbine Trip	Main Feedwater Overfeed	
B. Design Basis Overcooling		
Double Ended Steam Line Break	Main Steam Relief Valve Stuck Open	o LOOP at Reactor Trip o LOOP at Low RC Pressure ESFAS Trip o Decay Heat o HPI Single Failure o Steam Generator Level Control o Break on Different OTSGs

Parameter	205 FA
Power Level	102%
T_{ave}, °F	597.5
RCS Operating Pressure (at Pressurizer tap), psig	2195
Pressurizer Level (indicated), in.	185
RPS Trip Signals	
High Flux, % FP	105.5
Low Pressure (core outlet), psig	1950
ESFAS Trip Setpoints	
Low RC Press., psig	1585
Low SG Press., psig	585
ESFAS Trip Delay, sec.	2.5
MSIV Closure Time, sec.	5
MSIV Closure Time (linear ramped area), sec.	6
Auxiliary Feedwater	
Design Capacity	
Turbine, gpm	1620
Motor, gpm	810 (one per generator)
Temperature, °F	40
Initiation Time After ESFAS, sec.	—
With Offsite Power	7.4
With Loss of Offsite Power	40
Main Feedwater Temperature, °F	465
HPI System	
Design Capacity per Pump, gpm	2 pumps @ 700 each
Temperature, °F	40
Boron Concentration, ppm	2270
Initiation Time After ESFAS, sec.	
With Offsite Power	20
With Loss of Offsite Power	25
OTSG Outlet Pressure, psig	1050

TABLE 3-5: EQUIPMENT AND RELATED SYSTEMS ASSUMED TO FUNCTION

EVENT	RPS/CRDCS	ESFAS MSLIS FOGG	AFW	HPI	LPI	CFT	MSIV FWIV	RC PUMPS	TURBINE BYPASS	TURBINE TRIP
Reactor Trip/Turbine Trip with MFW Overfeed	X	X	X	X	–	–	X	X	X	X
Steam Line Break (Double-Ended Rupture)	X	X	X	X	–	X	X	(a)	–	–

X Denotes system used when needed in the analysis

– Denotes system not used in the analysis

(a) Loss of offsite power cases assume 4 pump coastdown

TABLE 4-1

MAIN FEEDWATER OVERFEED

SEQUENCE OF EVENTS

EVENT	TIME (SEC.)
Turbine Trip	0
Reactor Trip Signal	0
Rods Begin to Drop	.4
ESFAS Signal on Low Primary Side Pressure	18.4
Main Feedwater Isolation Valves Begin to Close	20.9
Auxiliary Feedwater Begins to Flow to Both Generators	25.8
MSIV Closes	25.9
Main Feedwater Isolation Valves Close	26.9
HPI Flow Begins	38.4
Steam Generator B Tube Region Full of Liquid	200
Steam Generator A Tube Region Full of Liquid	220

(Refer Figs. 4-1 to 4-8)

TABLE 4-2

This table was intentionally left blank.

Table 4-3. SLB Sensitivity Studies

Steam line break	RC pumps running	LOOP at reactor trip	LOOP at ESFAS	LOOP at ESFAS, with no decay heat
With stuck open relief valve on unaffected generator, 2 HPI pumps available	Case 1[a]	Case 2	Case 3	Case 4 Case 8 (d)
With failure of one HPI pump, no stuck open relief valve	--	--	Case 5	Case 6 (b) Case 7 (c)

(a) Maxi-/Mini-TRAP comparison presented for this case.

(b) The SLB occurs in the LOOP with the pressurizer.

(c) The SLB occurs in the opposite LOOP from the pressurizer.

(d) The Case 4 was re-analyzed with failure of FØGG to maintain the affected steam generator isolated.

TABLE 4-4

DOUBLE ENDED STEAM LINE BREAK

CASE 1 - NO LOOP

SEQUENCE OF EVENTS

EVENT	TIME, s
Double Ended Rupture of 28" Steam Line Between SG and MSIV	0.
Closure of Turbine Stop Valves.	0.
High Flux Trip Setpoint Reached	2.9
Rods Begin to Drop	3.3
ESFAS Signal on Low Primary System Pressure	9.3
Main Feedwater Isolation Valves Begin to Close	11.8
Pressurizer Empties	12.0
Auxiliary Feedwater Begins to Flow to Intact SG	16.7
MSIV Closes	16.8
Main Feedwater Isolation Valves Close	17.8
HPI Flow Begins	29.3
Unisolated SG Drys Out	50.0
Pressurizer Starts to Refill	270.

(Refer Figs 4-9 to 4-20)

TABLE 4-5

DOUBLE ENDED STEAM LINE BREAK

CASE 2 - LOOP AT TRIP

SEQUENCE OF EVENTS

EVENT	TIME, s
Double Ended Rupture of 28" Steam Line Between SG and MSIV	0.
Closure of Turbine Stop Valves	0.
High Flux Trip Setpoint Reached	2.9
Loss of Offsite Power; Main Coolant Pumps Begin to Coastdown	2.9
Rods Begin to Drop	3.3
ESFAS Signal on Low Secondary System Pressure	8.1
Main Feedwater Isolation Valves Begin to Close	10.6
Pressurizer Empties	15.
MSIV Closes	15.6
Main Feedwater Isolation Valves Close	16.6
Pressurizer Empties	18.
HPI Flow Begins	33.1
Auxiliary Feedwater Begins to Flow to Intact SG	48.1
Unisolated SG Drys Out	46.
Pressurizer Begins to Fill	270.

(Refer Figs. 4-21 to Figs 4-29)

TABLE 4-6

DOUBLE ENDED STEAM LINE BREAK

CASE 3 - LOOP AT ESFAS

SEQUENCE OF EVENTS

EVENT	TIME, s
Double Ended Rupture of 28" Steam Line Between SG and MSIV	0.
Closure of Turbine Stop Valves	0.
High Flux Trip Setpoint Reached	2.9
Rods Begin to Drop	3.3
ESFAS Signal on Low Primary System Pressure	9.3
LOOP and Main Coolant Pump Coastdown Begins	9.3
Main Feedwater Isolation Valves Begin to Close	11.8
Pressurizer Empties	14.0
MSIV Closes	16.8
Main Feedwater Isolation Valves Close	17.8
HPI Begins to Flow	34.3
Auxiliary Feedwater Begins to Flow to Intact SG	49.3
Unisolated SG Drys Out	47.
Pressurizer Begins to Refill	270.

(Refer Figs. 4-30 to 4-38)

TABLE 4-7

DOUBLE ENDED STEAM LINE BREAK

CASE 4 - LOOP AT ESFAS NO DECAY HEAT

SEQUENCE OF EVENTS

EVENT	TIME, s
Double Ended Rupture of 28" Steam Line Between SG and MSIV	0.
Closure of Turbine Stop Valves	0.
High Flux Trip Setpoint Reached	2.9
Rods Begin to Drop	3.3
ESFAS Signal on Low Primary System Pressure	9.3
LOOP and Main Coolant Pump Coastdown Begins	9.3
Main Feedwater Isolation Valves Begin to Close	11.8
Pressurizer Empties	14.
MSIV Closes	16.8
Main Feedwater Isolation Valves Close	17.8
HPI Flow Begins	34.3
Auxiliary Feedwater Begins to Flow to Intact SG	49.3
Unisolated SG Drys Out	48.
Pressurizer Begins to Fill	355.

(Refer Figs. 4-39 to 4-47)

TABLE 4-8

DOUBLE ENDED STEAM LINE BREAK

CASE 5 - LOOP AT ESFAS HPI FAILURE

SEQUENCE OF EVENTS

EVENT	TIME, s
Double Ended Rupture of 28" Steam Line Between SG and MSIV	0.
High Flux Trip Setpoint Reached	2.9
Rods Begin to Drop	3.3
ESFAS Signal on Low Primary System Pressure	9.3
LOOP and Main Coolant Pump Coastdown Begins	9.3
Main Feedwater Isolation Valves Begin to Close	11.8
Pressurizer Empties	14.0
MSIV Closes	16.8
Main Feedwater Isolation Valves Close	17.8
HPI Flow Begins	34.3
Unisolated SG Drys Out	48.
Auxiliary Feedwater Begins to Flow to Intact SG	49.3
Pressurizer Begins to Fill	490.

(Refer Figs. 4-48 to 4-56)

TABLE 4-9

DOUBLE ENDED STEAM LINE BREAK

CASE 6 - LOOP AT ESFAS

HPI FAILURE

NO DECAY HEAT

SEQUENCE OF EVENTS

EVENT	TIME, s
Double Ended Rupture of 28" Steam Line Between SG and MSIV	0.
High Flux Trip Setpoint Reached	2.9
Rods Begin to Drop	3.3
ESFAS Signal on Low Primary System Pressure	9.3
Main Feedwater Isolation Valves Begin to Close	11.8
Pressurizer Empties	14.0
MSIV Closes	16.8
Main Feedwater Isolation Valves Close	17.8
HPI Flow Begins	34.3
Unisolated SG Drys Out	48.
Auxiliary Feedwater Begins to Flow to Intact SG	49.3
Pressurizer Begins to Fill	>600.

(Refer Figs. 4-57 to 4-65)

TABLE 4-10

DOUBLE ENDED STEAM LINE BREAK

CASE 7 - LOOP AT ESFAS
NO DECAY HEAT
HPI FAILURE
NO STUCK SAFETY VALVE

SEQUENCE OF EVENTS

EVENT	TIME, s
Double Ended Rupture of 28" Steam Line Between SG and MSIV	0.
High Flux Trip Setpoint Reached	2.9
Rods Begin to Drop	3.3
ESFAS Signal on Low Primary System Pressure	9.3
Main Feedwater Isolation Valves Begin to Close	11.8
Pressurizer Empties	14.0
MSIV Closes	16.8
Main Feedwater Isolation Valves Close	17.8
HPI Flow Begins	34.3
Unisolated SG Drys Out	48.
Auxiliary Feedwater Begins to Flow to Intact SG	49.3
Pressurizer Begins to Fill	>600.

(Refer Figs. 4-66 to 4-74)

TABLE 4-11

DOUBLE ENDED STEAM LINE BREAK

CASE 8 - LOOP AT ESFAS

NO DECAY HEAT

SV STUCK OPEN

SEQUENCE OF EVENTS

EVENT	TIME, s
Double Ended Rupture of 28" Steam Line Between SG and MSIV and Closure of Turbine Stop Valves	0.
High Flux Trip Setpoint Reached	2.9
Rods Begin to Drop	3.3
ESFAS Signal on Low Primary System Pressure	9.3
LOOP and Main Coolant Pump Coastdown Begins	9.3
Main Feedwater Isolation Valves Begin to Close	11.8
Pressurizer Empties	14.
MSIV Closes	16.8
Main Feedwater Isolation Valves Close	17.8
HPI Flow Begins	34.3
Unisolated Steam Generator Drys Out	48.0
Auxiliary Feedwater Flow Begins to Intact Steam Generator	49.3
Isolated Steam Generator Pressure Drops Below 600 psia	58.
Auxiliary Feedwater Flow Begins to Unisolated Steam Generator	58.
Pressurizer Fills Up	450.

(Refer Figs. 4-75 to 4-83)

TABLE 5-1: Operating Transient Cycles

Transient Number	Transient Description		Design Cycles
1	Heatup and Cooldown (Normal Condition)		
	50°F/hr heatup and cooldown with no decay heat		10
	50°F/hr heatup and cooldown with decay heat		230
	Total		240
2	Power change 0 to 15% (Normal Condition)		730
	and 15 to 0%		240
3	Power Loading 8% to 100% power (Normal Condition)		3000
	Power Loading 15% to 100% power (Normal Condition)		15000
4	Power Unloading 100% to 8% power (Normal Condition)		3000
	Power Unloading 100% to 15% power (Normal Condition)		15000
5	10% Step Load Increase (Normal Condition)		40000
6	10% Step Load Decrease (Normal Condition)		40000
7	Step Load Reduction from 100% to 8% power (Upset Condition)		
	Resulting from turbine trip	150	
	Resulting from electrical load rejection	150	
	Total		300
8	Reactor Trip (Upset Condition)		
	Type A	120	
	Type B	140	
	Type C	120	
	Trips included in transient numbers 11, 15, 16, 17, & 21	112	
	Total		492
9	Rapid Depressurization (Upset Condition)		40
10	Change of Flow (Upset Condition)		30
11	Rod Withdrawal Accident (Upset Condition)		40
12	Hydrotests (Test Condition)		20
13	Steady-State Power Variations (Normal Condition)		∞
14	Control Rod Drop (Upset Condition)		40

-2-

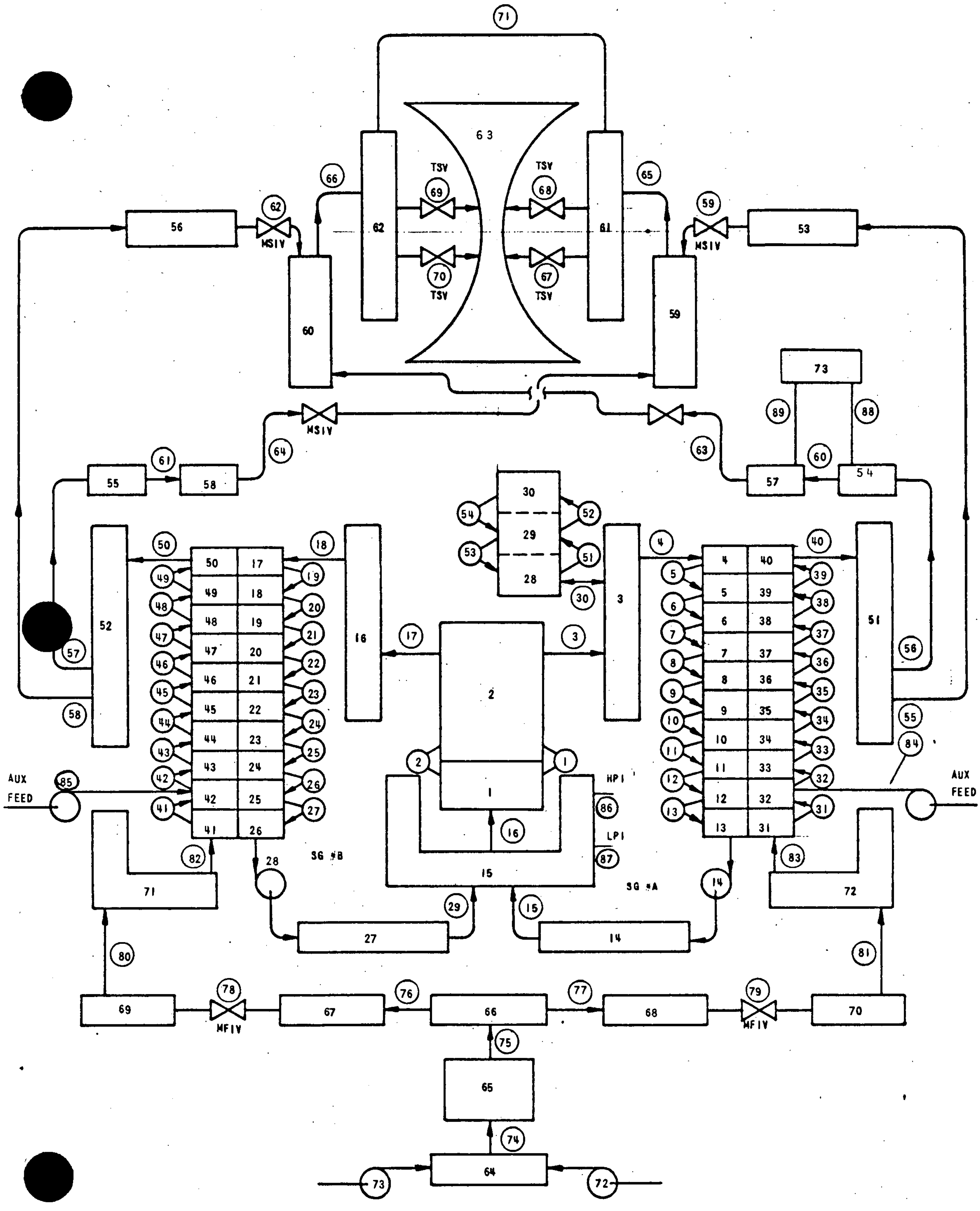
TABLE 5-1 (Cont'd)

Transient Number	Transient Description	Design Cycles
15	Loss of Station Power (Upset Condition)	40
16	Steam Line Failure (Faulted Condition)	1
17A	Loss of Feedwater to One Steam Generator (Upset Condition)	20
17B	Stuck Open Atmospheric Dump Valve (Emergency Condition)	10
18	Loss of Feedwater Heat (Upset Condition)	40
19	Feed and Bleed Operations (Normal Condition)	18000
20	Miscellaneous A (Normal Condition)	30000
	Miscellaneous B	4×10^6
	Miscellaneous C	20000
21	Loss of Coolant (Faulted Condition)	1
22	Test Transient - High Pressure Injection System (Normal Condition)	40
	Test Transients - Core Flooding System (Normal Condition)	240
23	Steam Generator Fill, Draining, Flushing and Cleaning (Normal Condition)	
	Steam Generator secondary side filling	240
	Steam Generator Primary side filling	240
	Flushing	40
	Chemical Cleaning	20
		540
24	Hot Functional Testing (Normal Condition)	5
25	Leak Testing (Test Condition)	100

TABLE 5-2

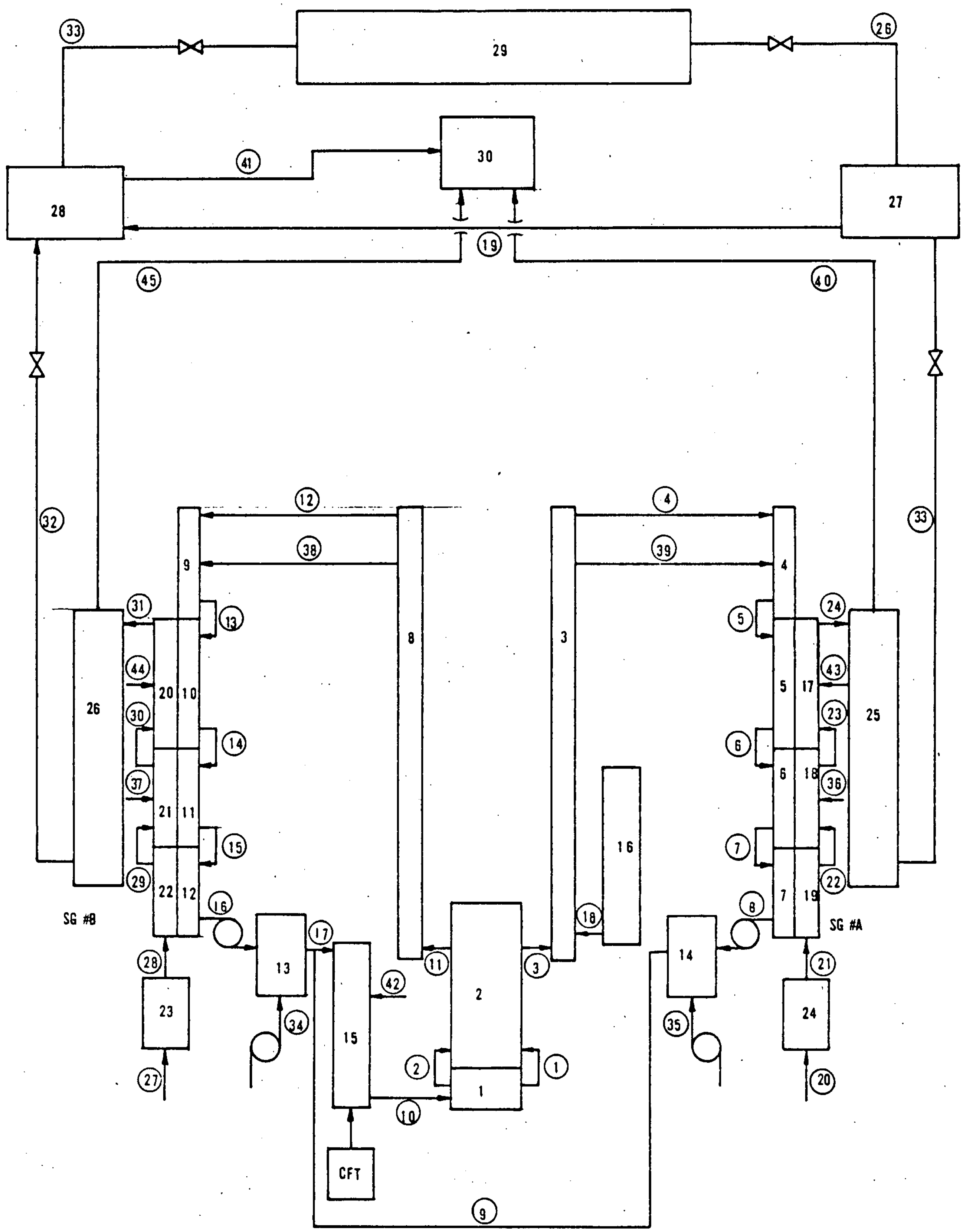
RPS/ESFAS FREQUENCY

	Actual Data		Allowed
	Number	Frequency	Frequency
No. of Reactor Trips (RPS)	228	6.95/yr	10/yr
No. of Automatic ESFAS Actuations	27	.816/yr	1.0/yr
No. of Plants Included	9	32.8 Reactor-Years	



MAXI-TRAP NODING SCHEME, 205 FA

Figure 3-1



MINI-TRAP NODING SCHEME, 205 FA

Figure 3-2

FIGURE 4-1. MFW OVERFEED, 205 FA

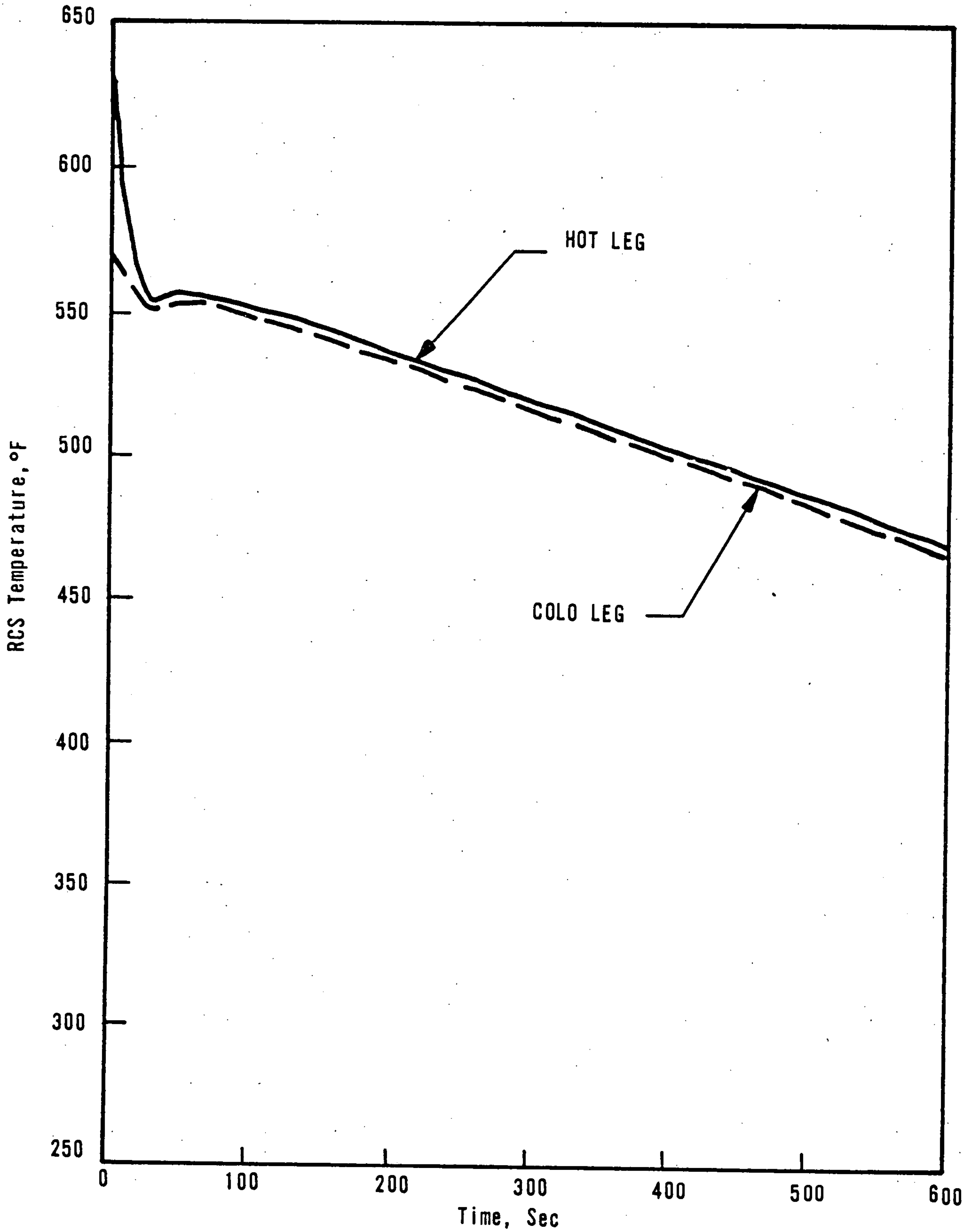


FIGURE 4-2. MFW OVERFEED, 205 FA

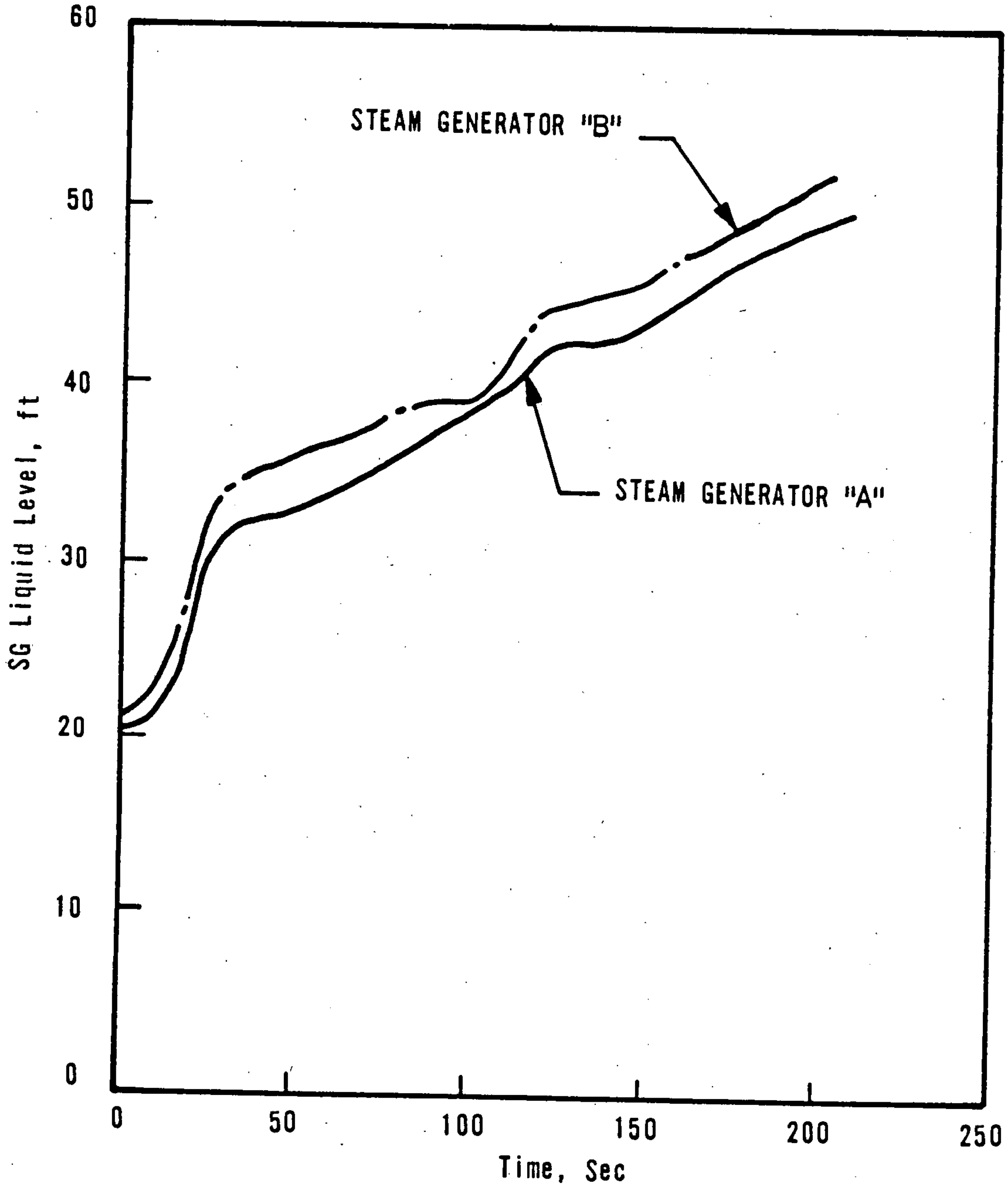


FIGURE 4-3. MFW OVERFEEO, 205 FA

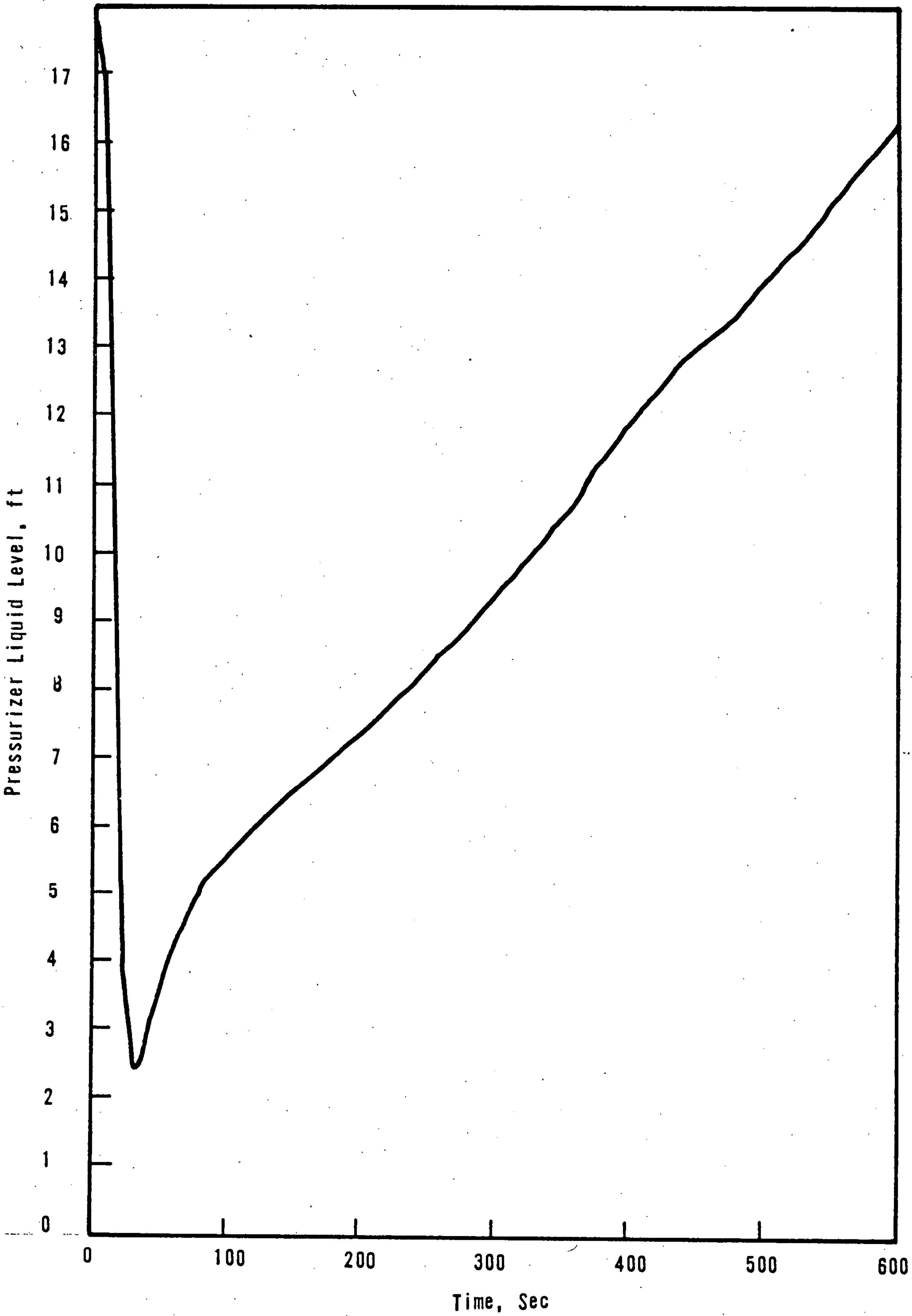


FIGURE 4-4. STEAM GENERATOR A - MFW OVERFEED, 205 FA

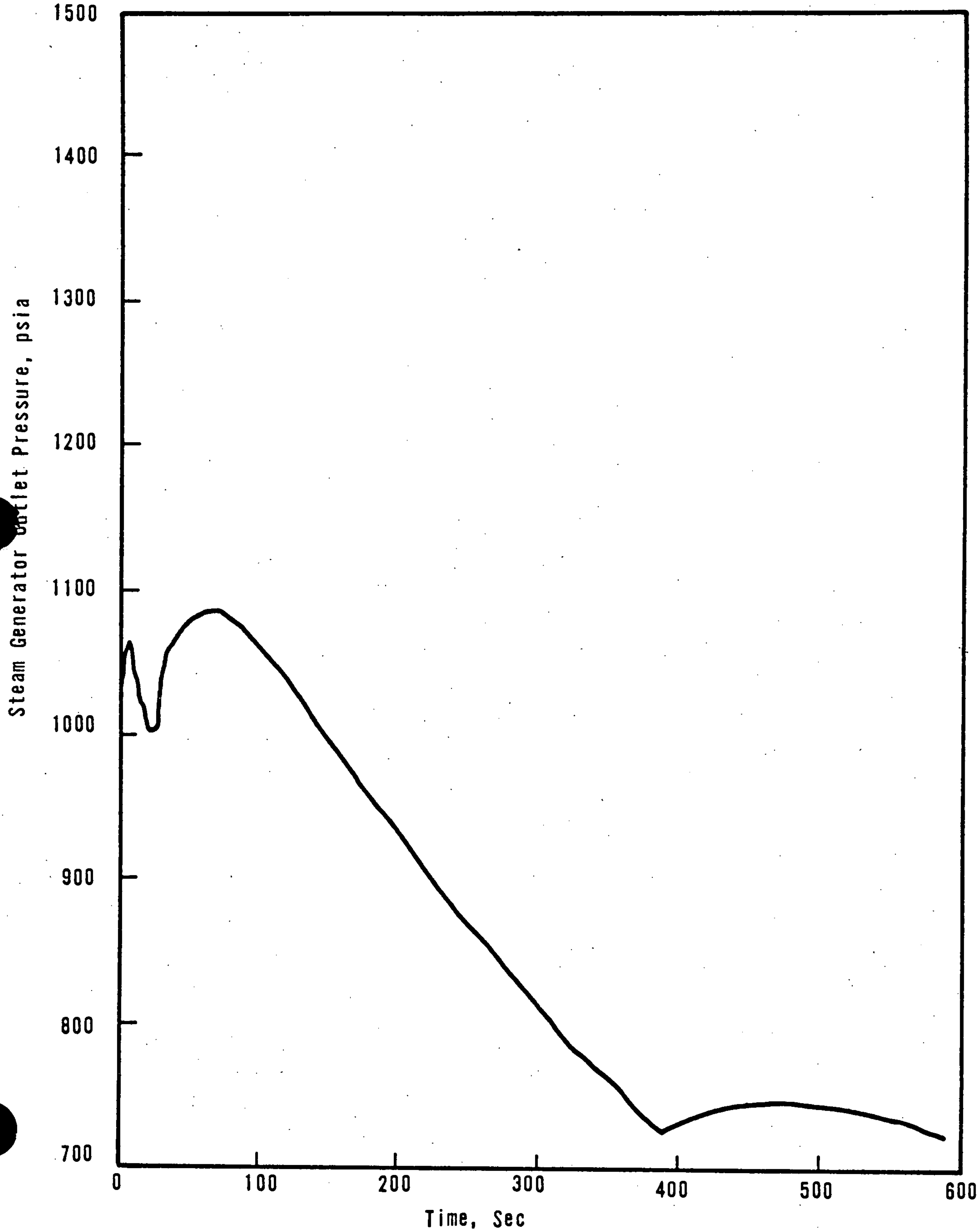


FIGURE 4-5. STEAM GENERATOR B - MFW OVERFEEO, 205 FA

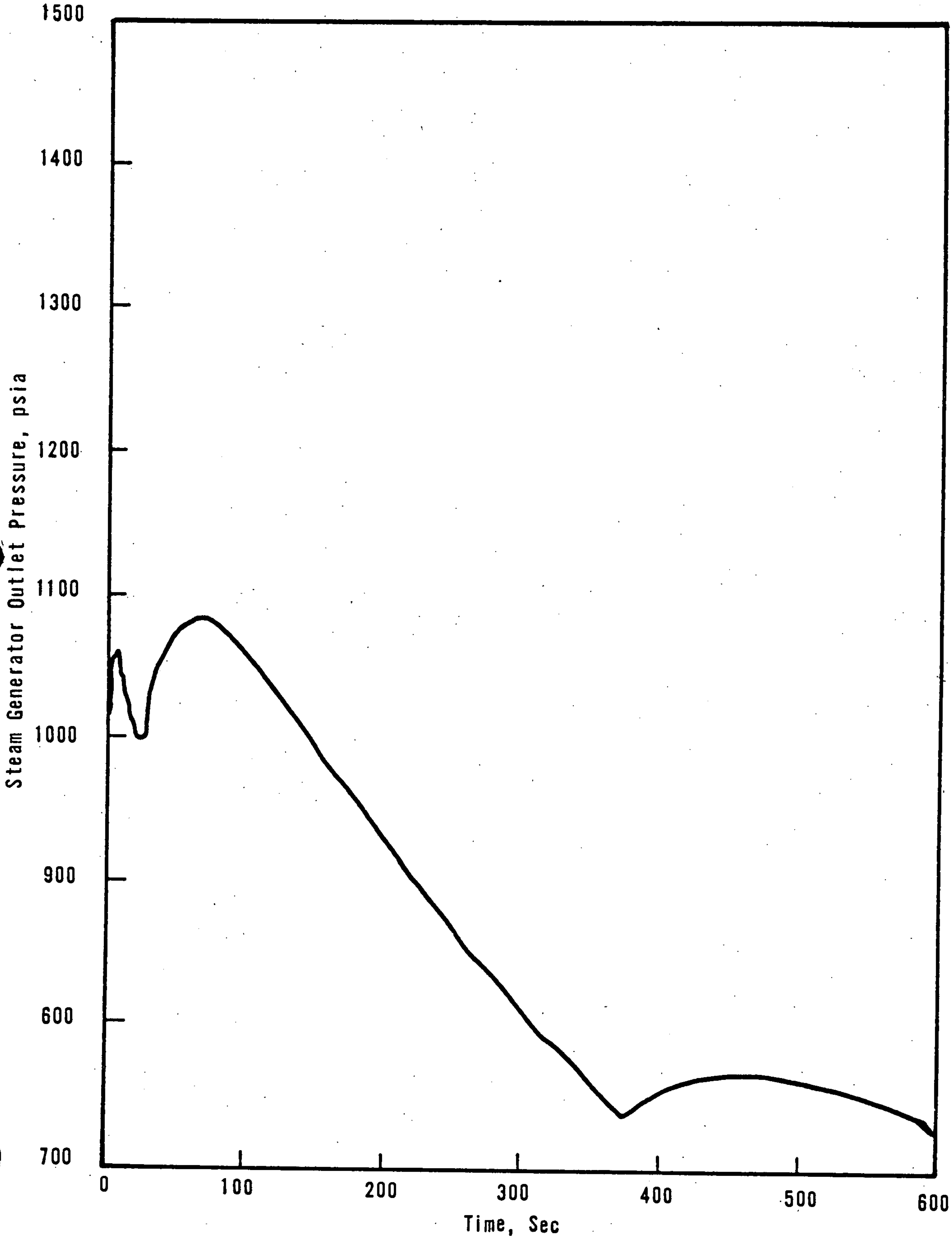


FIGURE 4-6. MFW OVERFEED, 205 FA

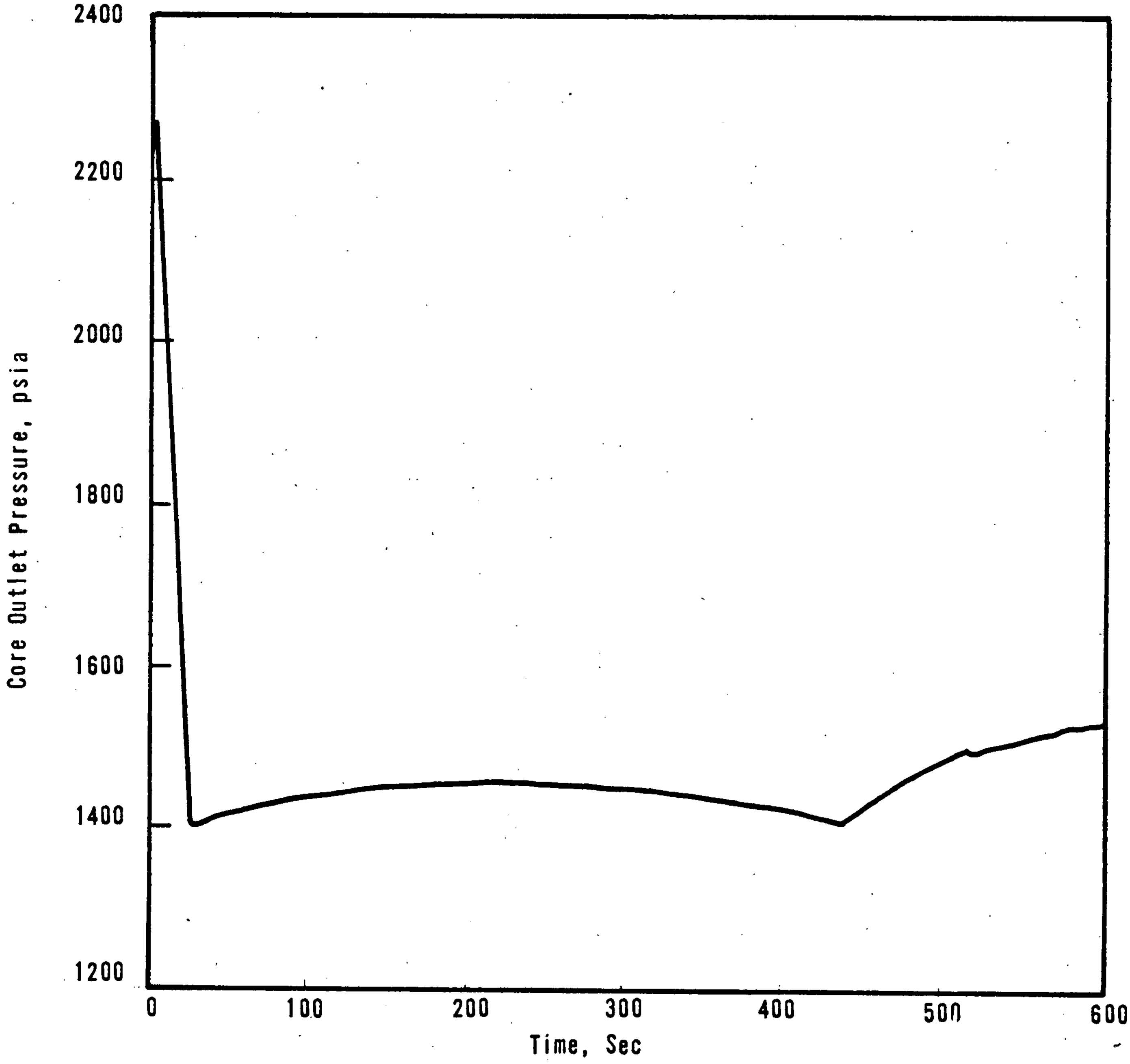


FIGURE 4-7. MFW OVERFEED, 205 FA

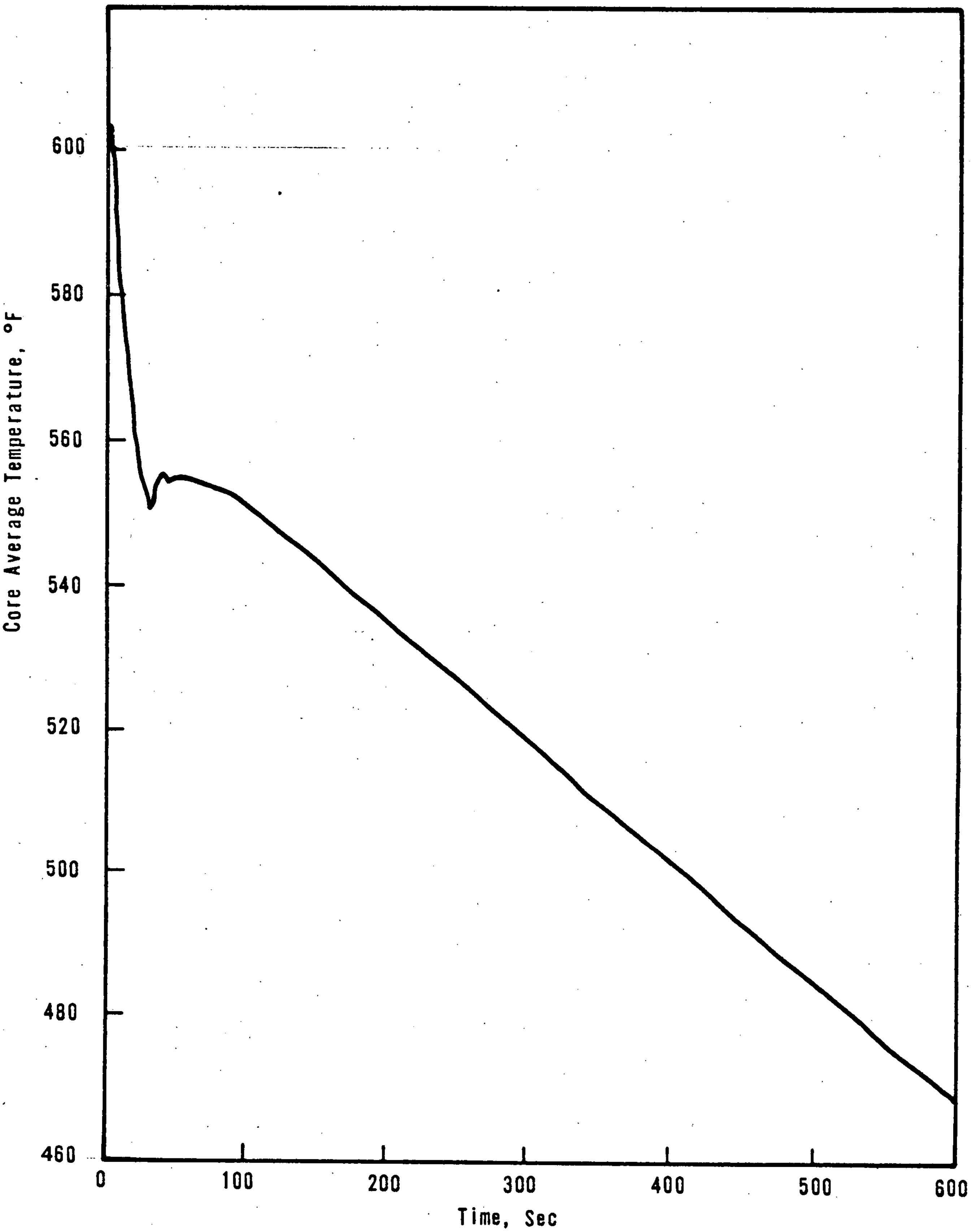


FIGURE 4-8. MFW OVERFEED, 205 FA

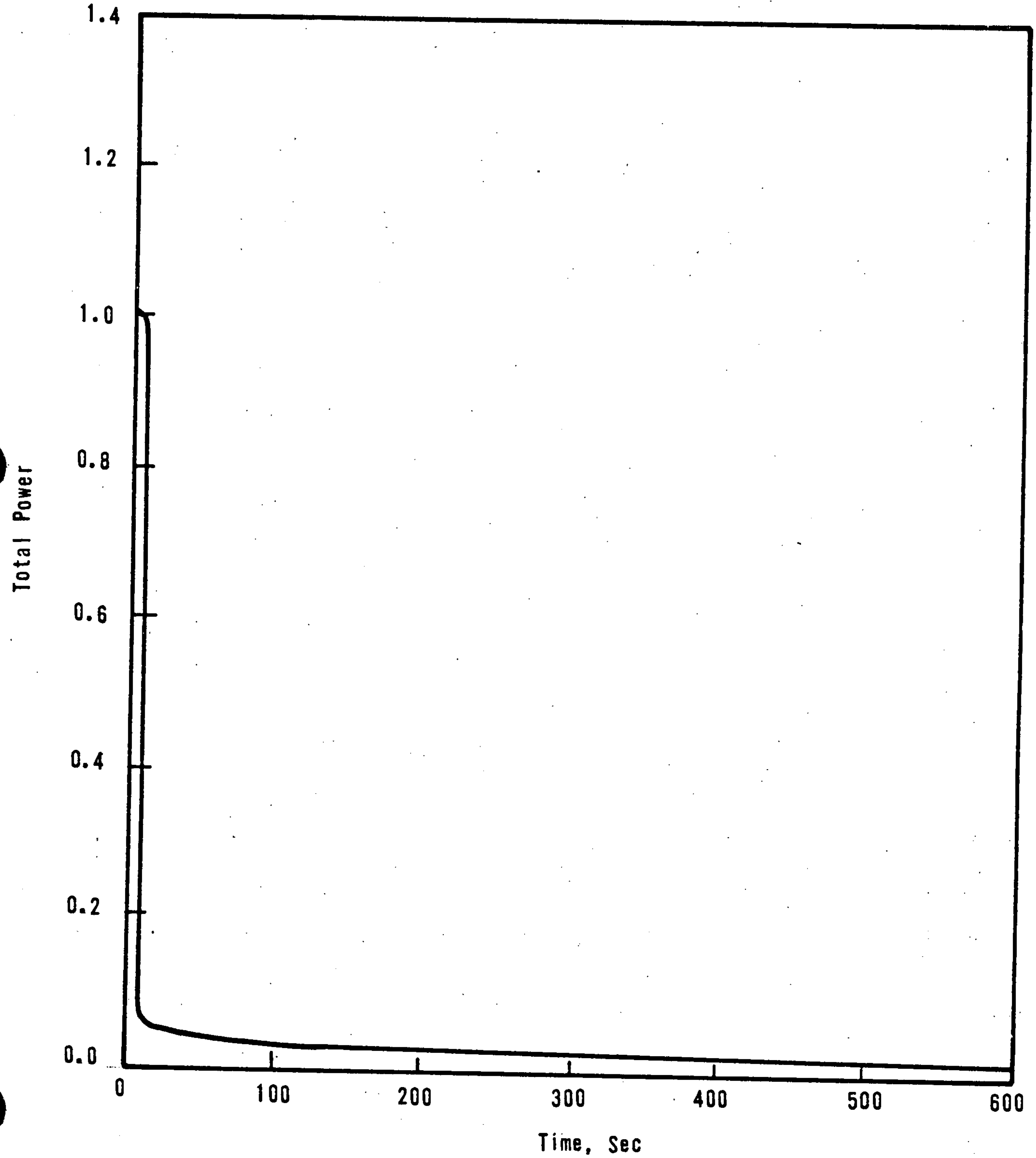


FIGURE 4-9. SLB MAXI-MINI TRAP COMPARISON, 205 FA

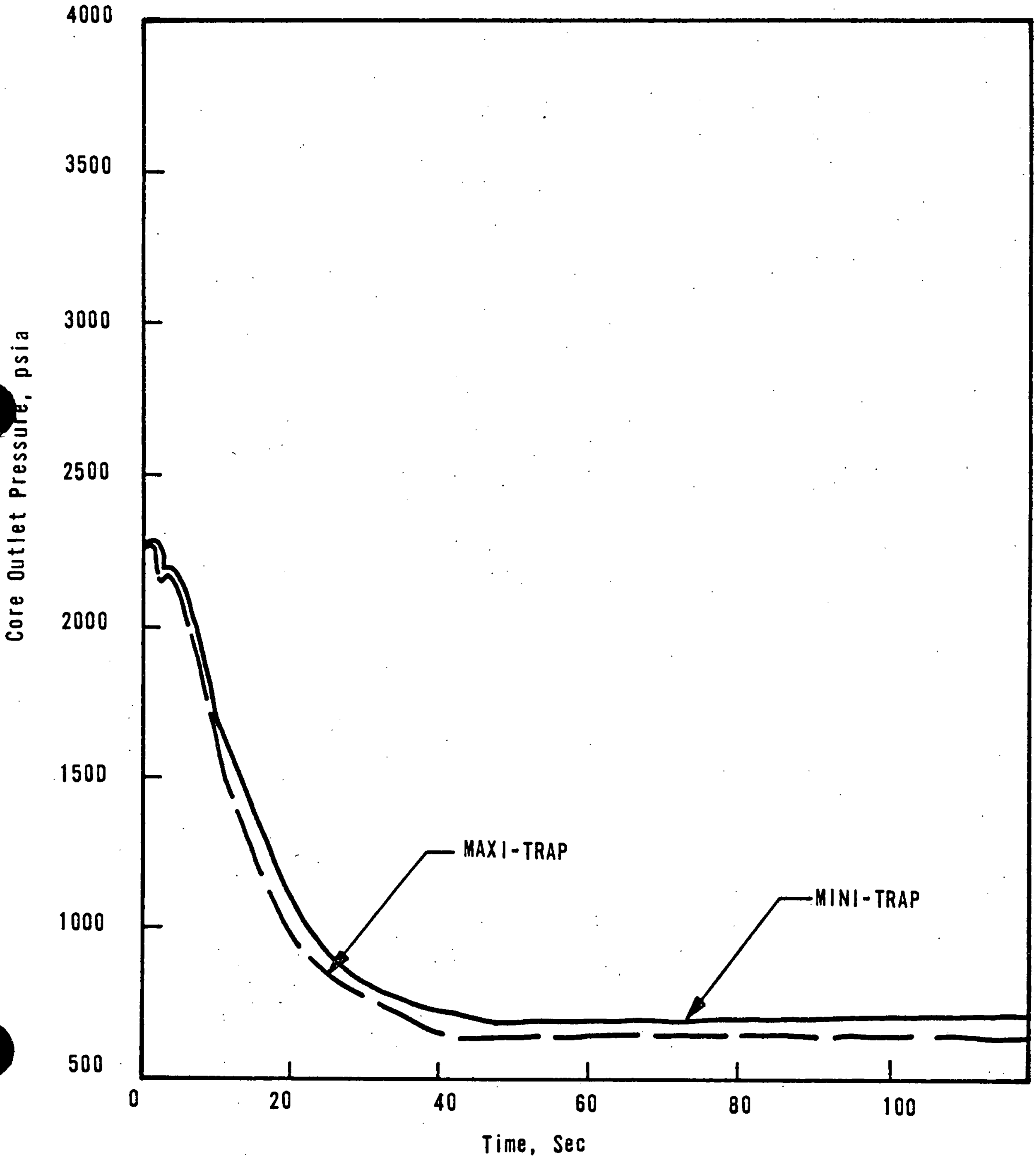


FIGURE 4-10. SL8 MAXI-MINI TRAP COMPARSION, 205 FA

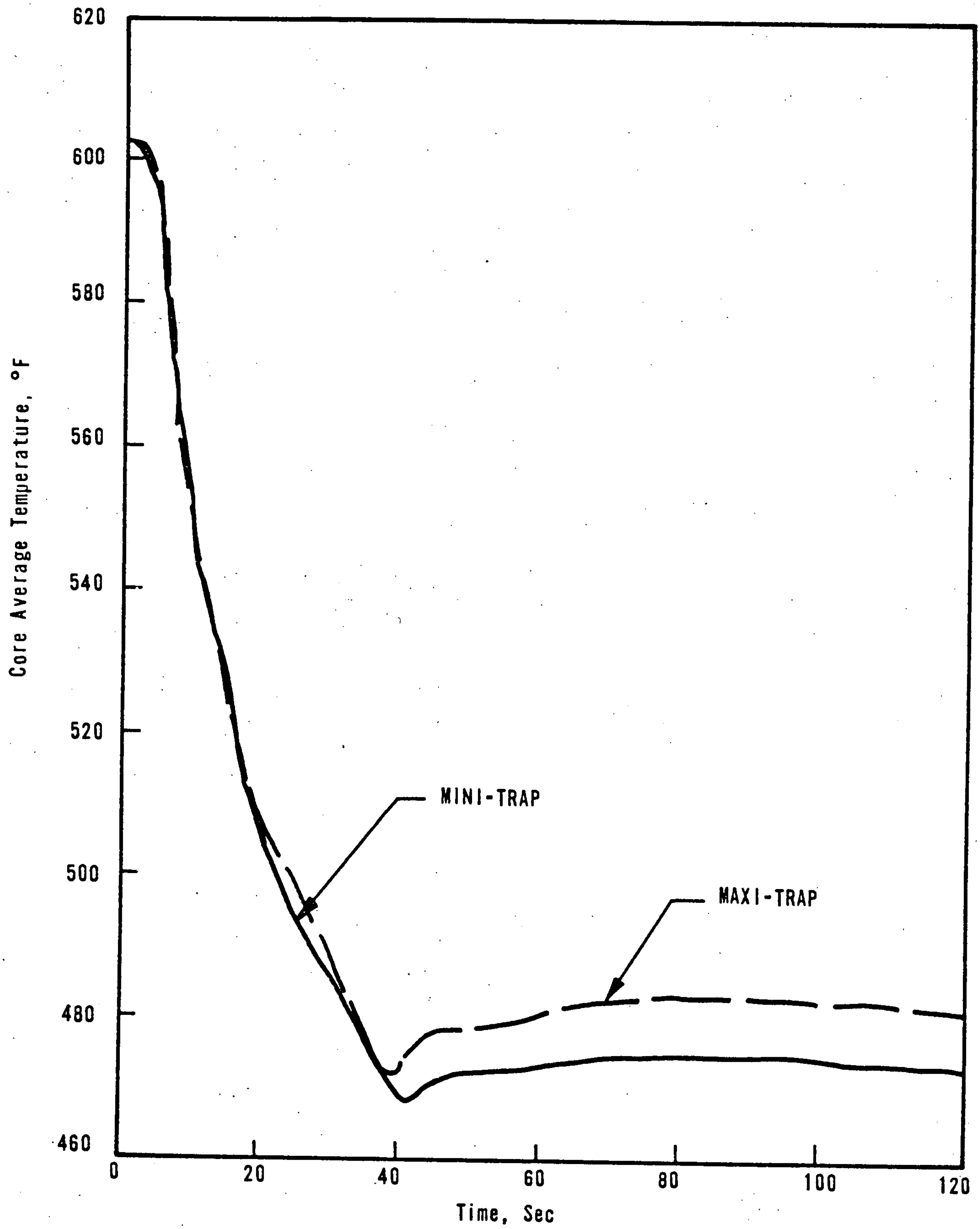


FIGURE 4-11. SLB MAXI-MINI TRAP COMPARISON, 205 FA

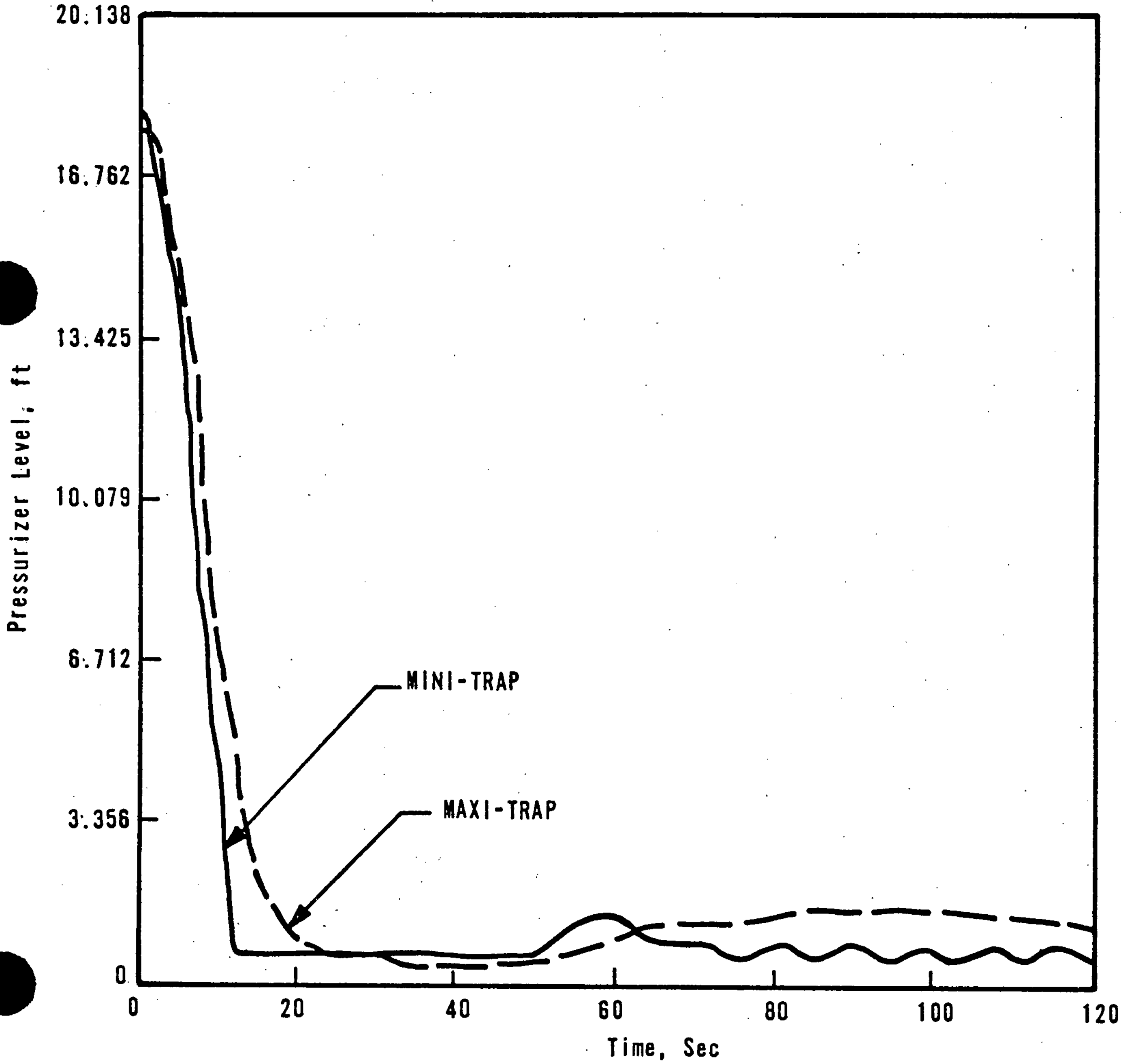


FIGURE 4-12. STEAM LINE BREAK CASE 1, 205 FA

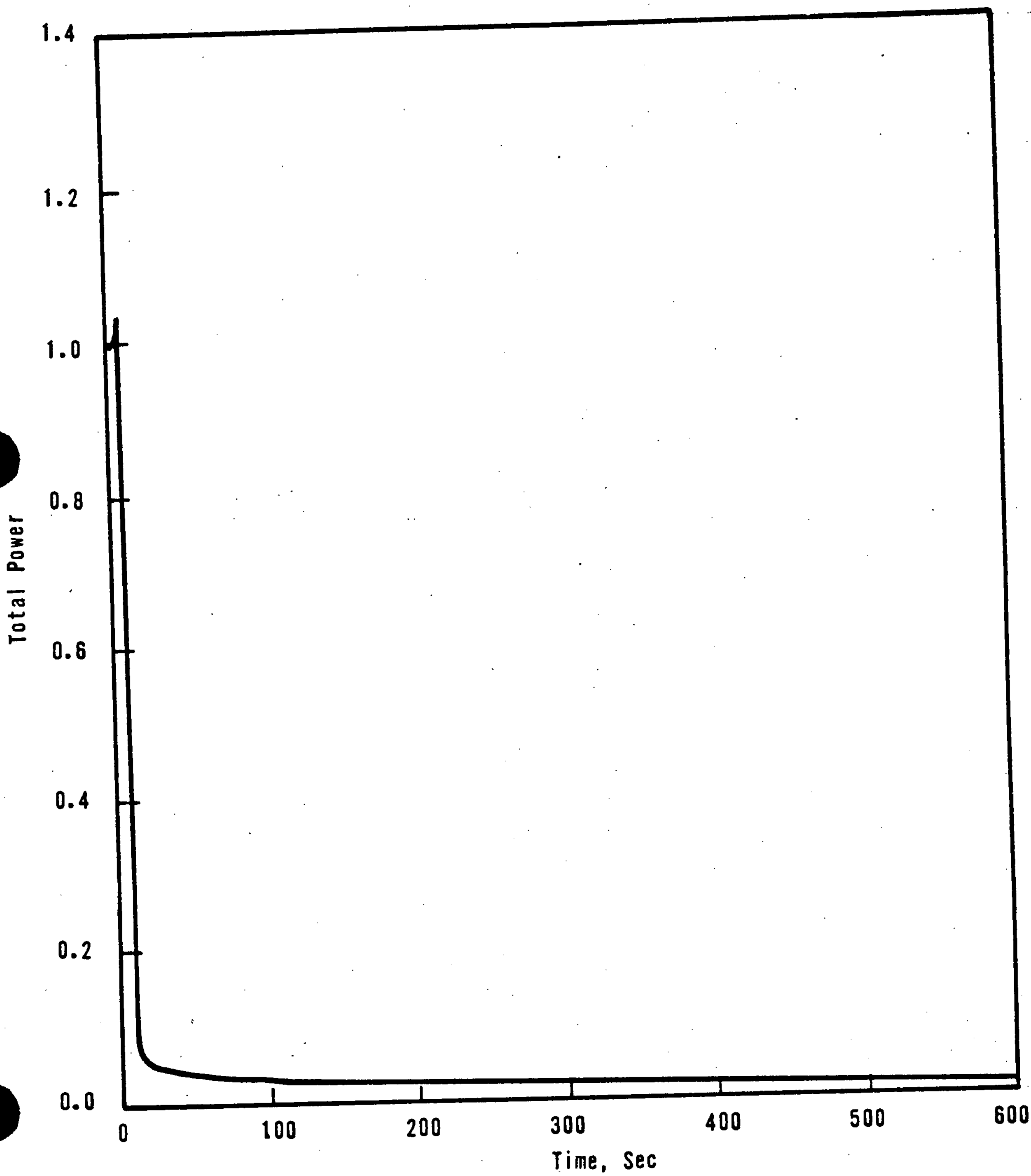


FIGURE 4-13. STEAM LINE BREAK CASE 1, 205 FA

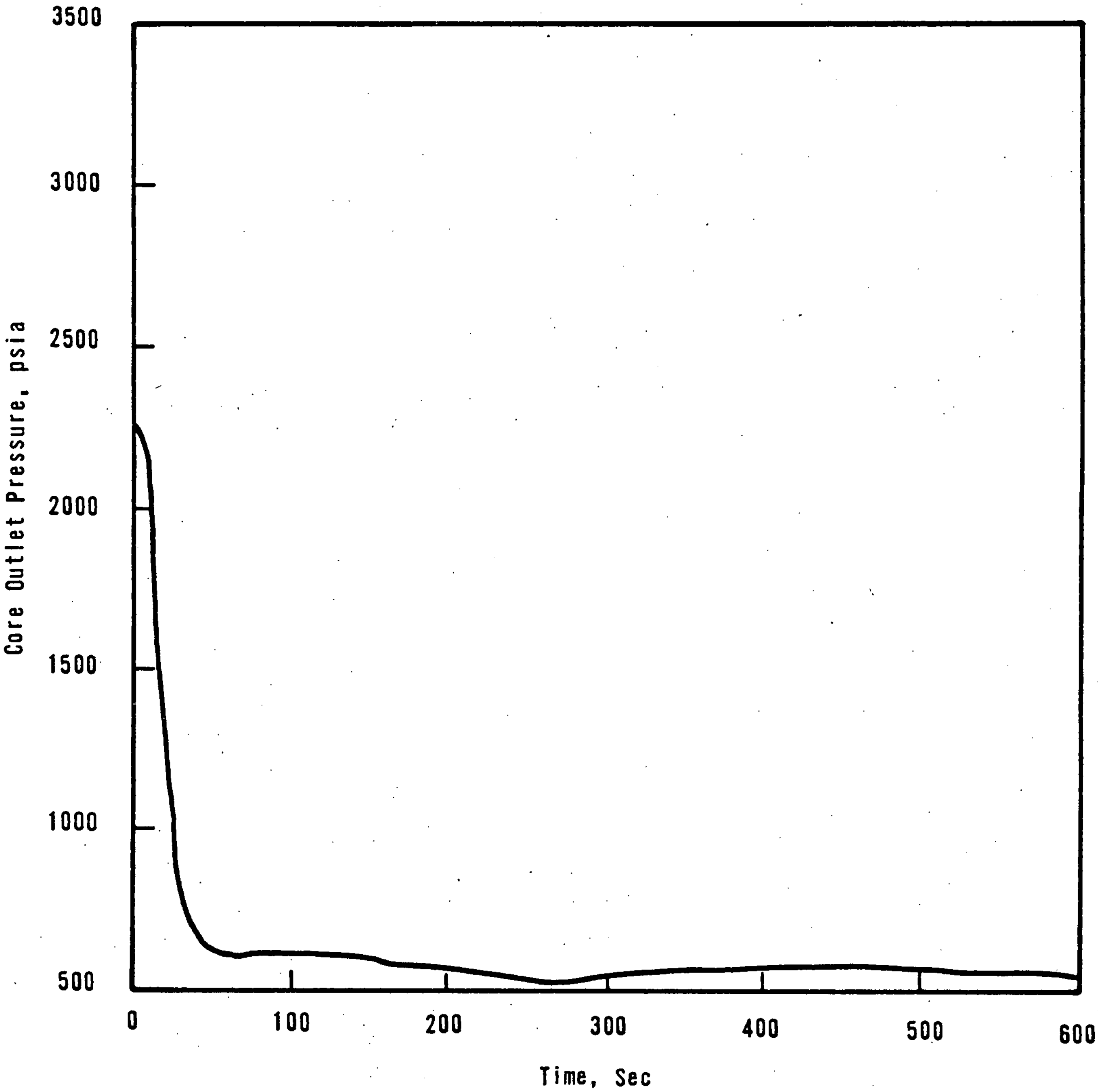


FIGURE 4-14. STEAM LINE BREAK CASE 1, 205 FA

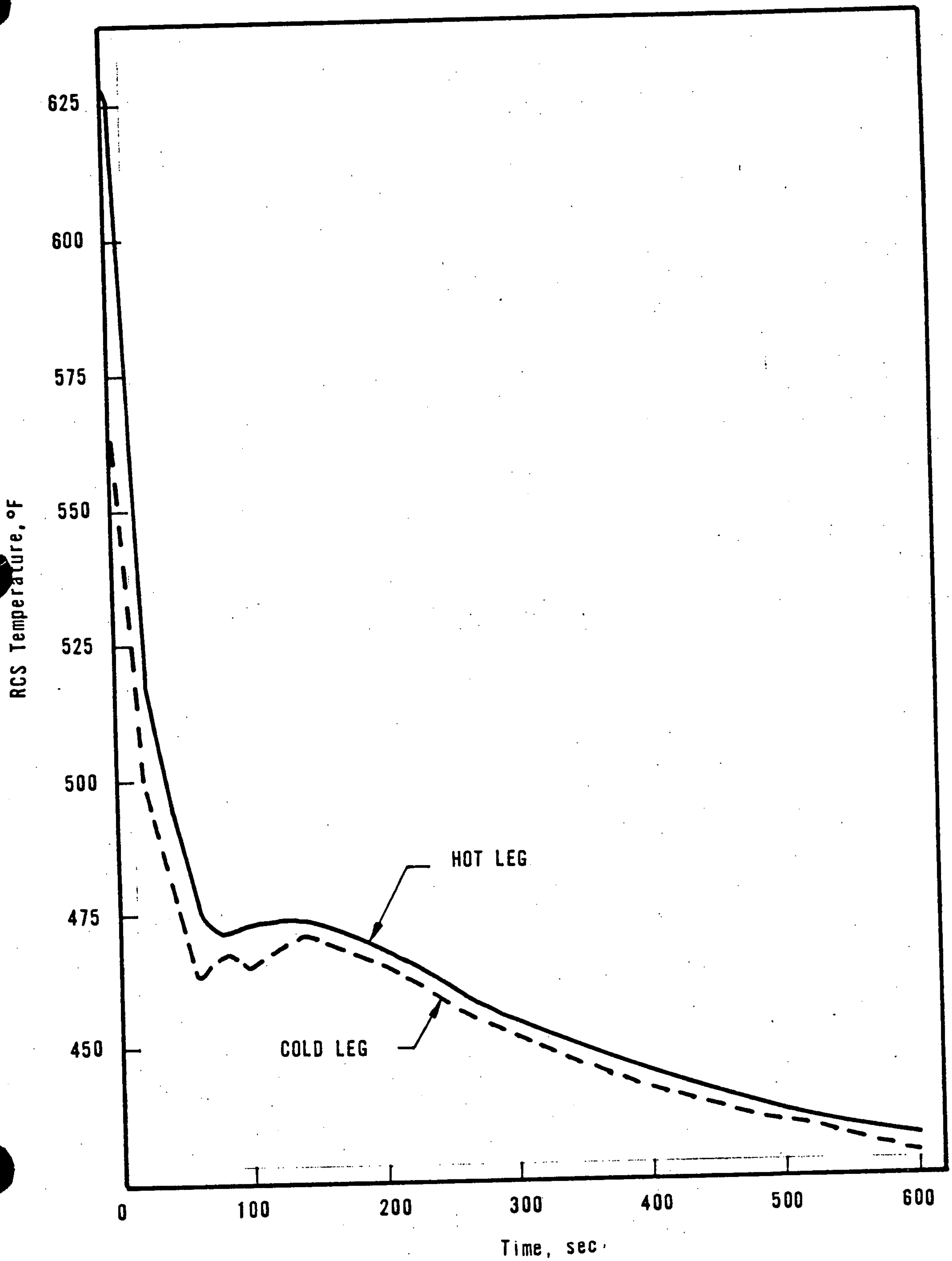


FIGURE 4-15. STEAM LINE BREAK CASE 1, 205 FA

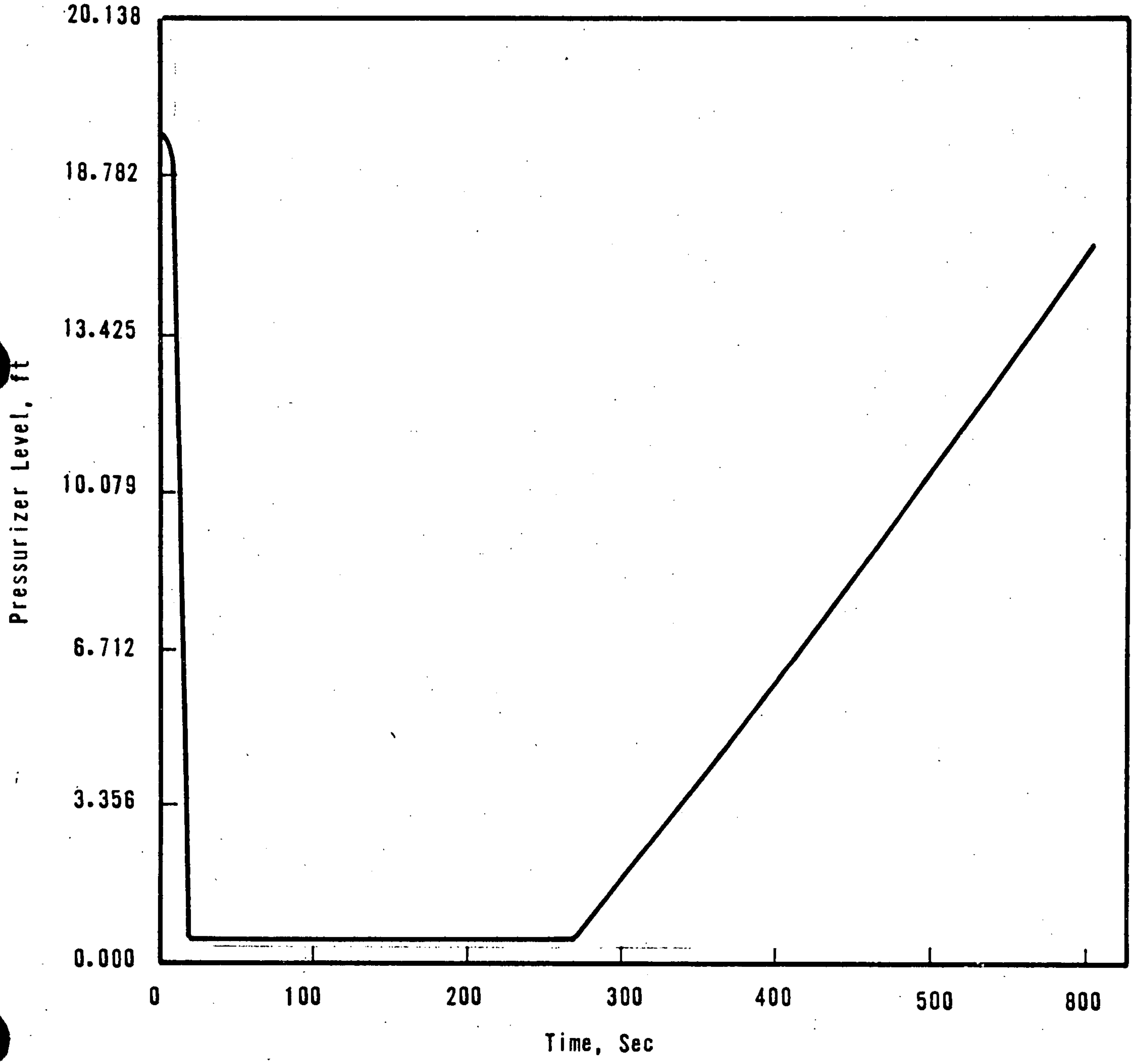


FIGURE 4-16. STEAM LINE BREAK CASE 1, 205 FA

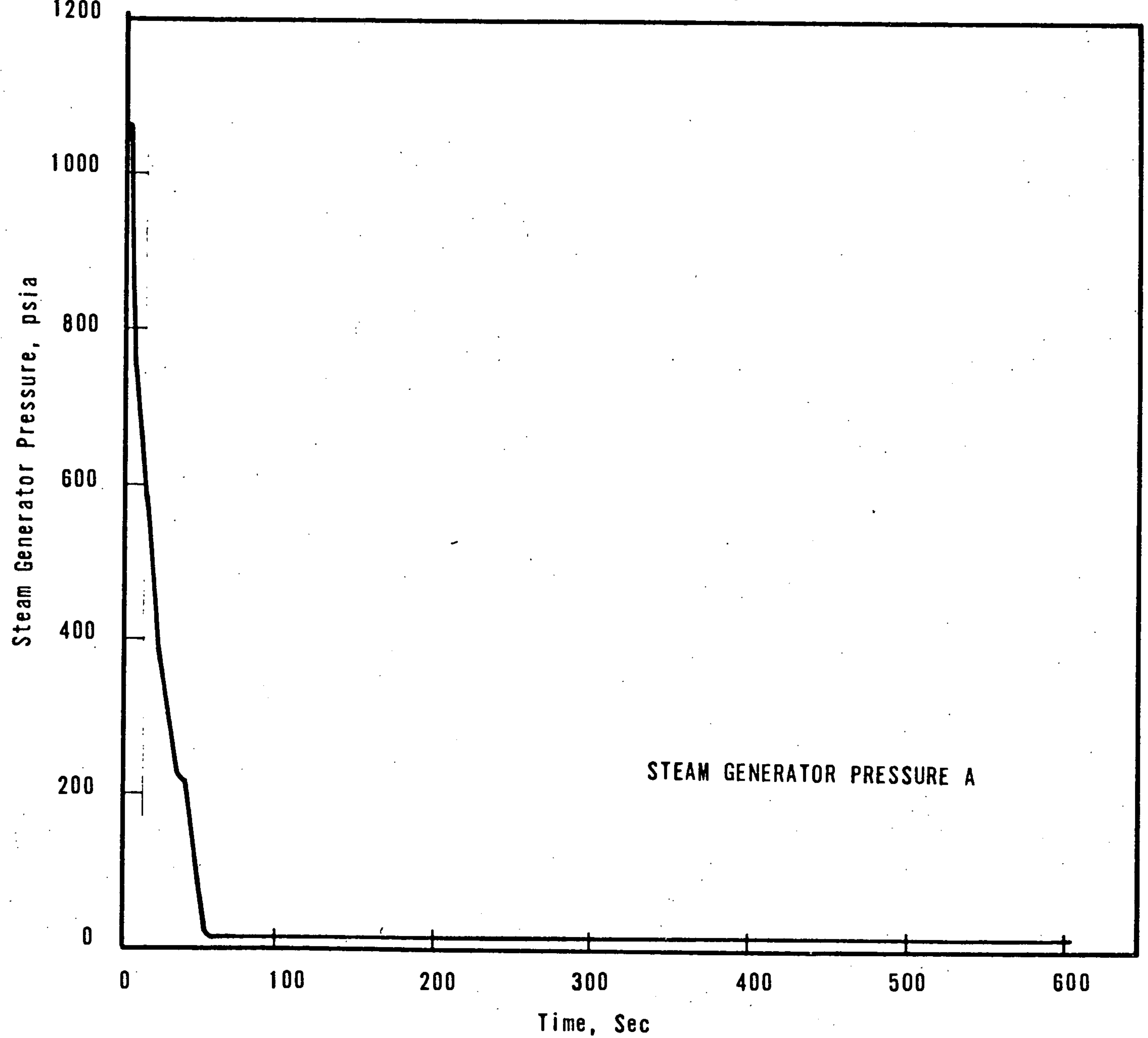


FIGURE 4-17. STEAM LINE BREAK CASE 1, 205 FA

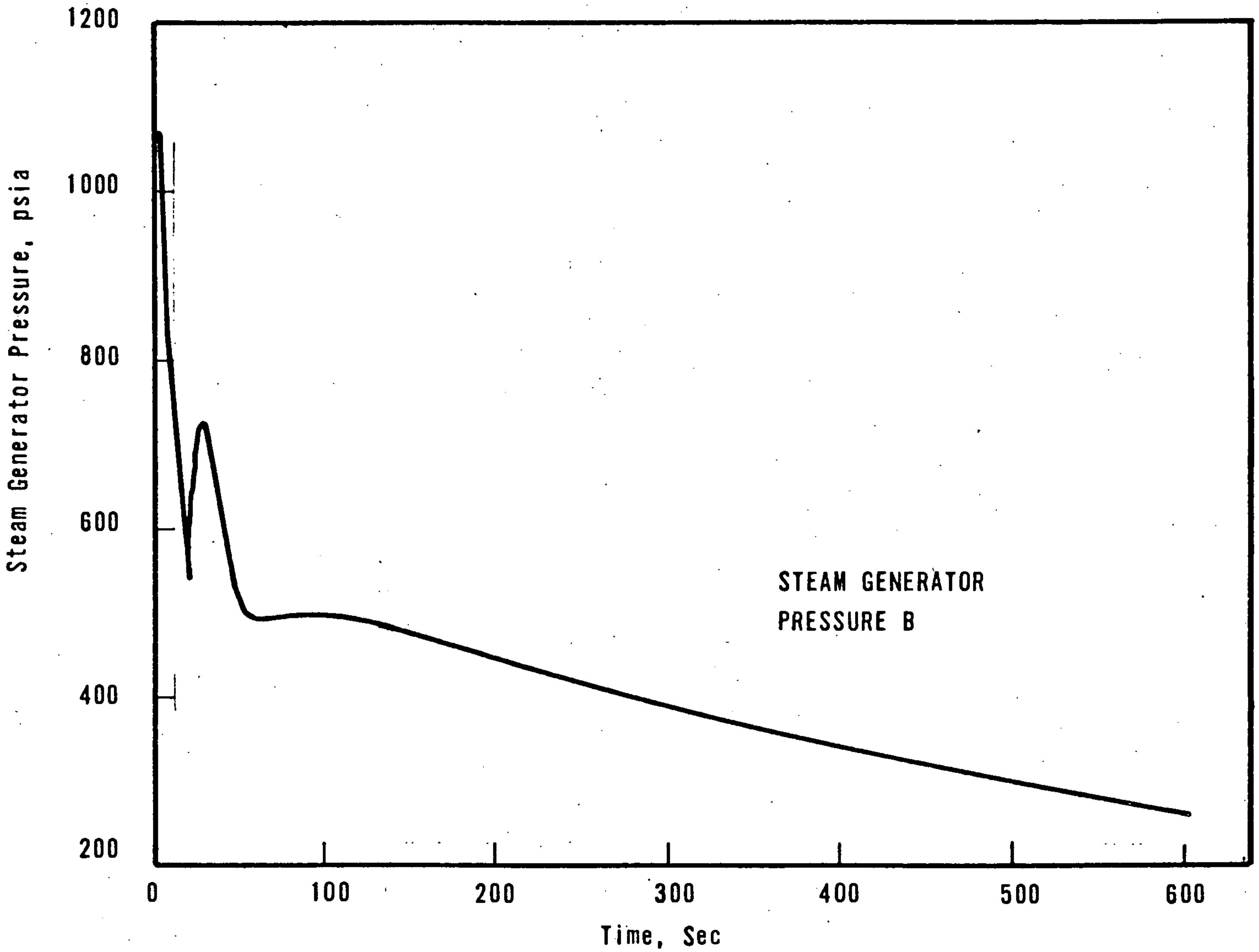


FIGURE 4-18 STEAM LINE BREAK CASE 1, 205 FA

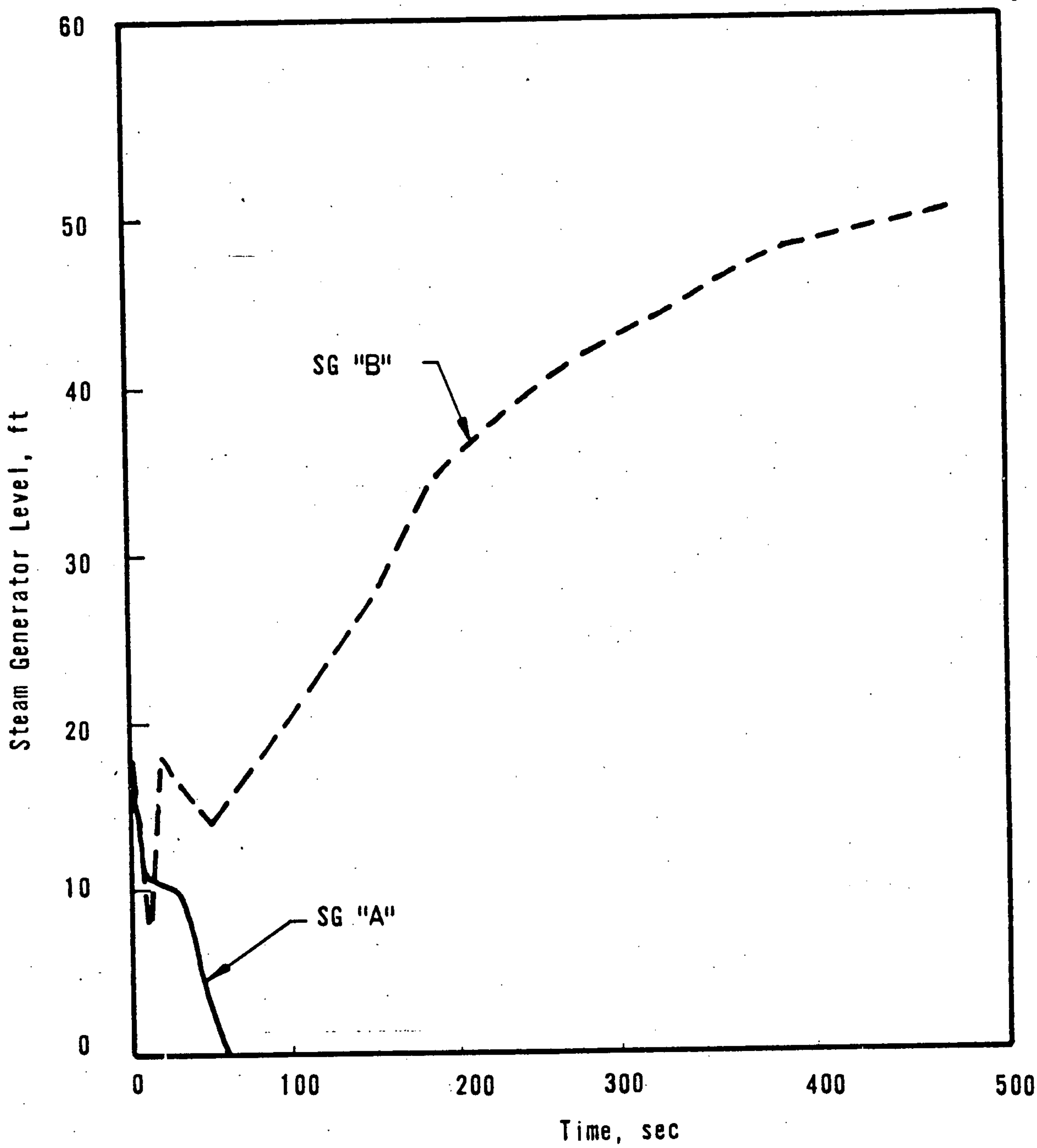


FIGURE 4-19. STEAM LINE BREAK CASE 1, 205 FA

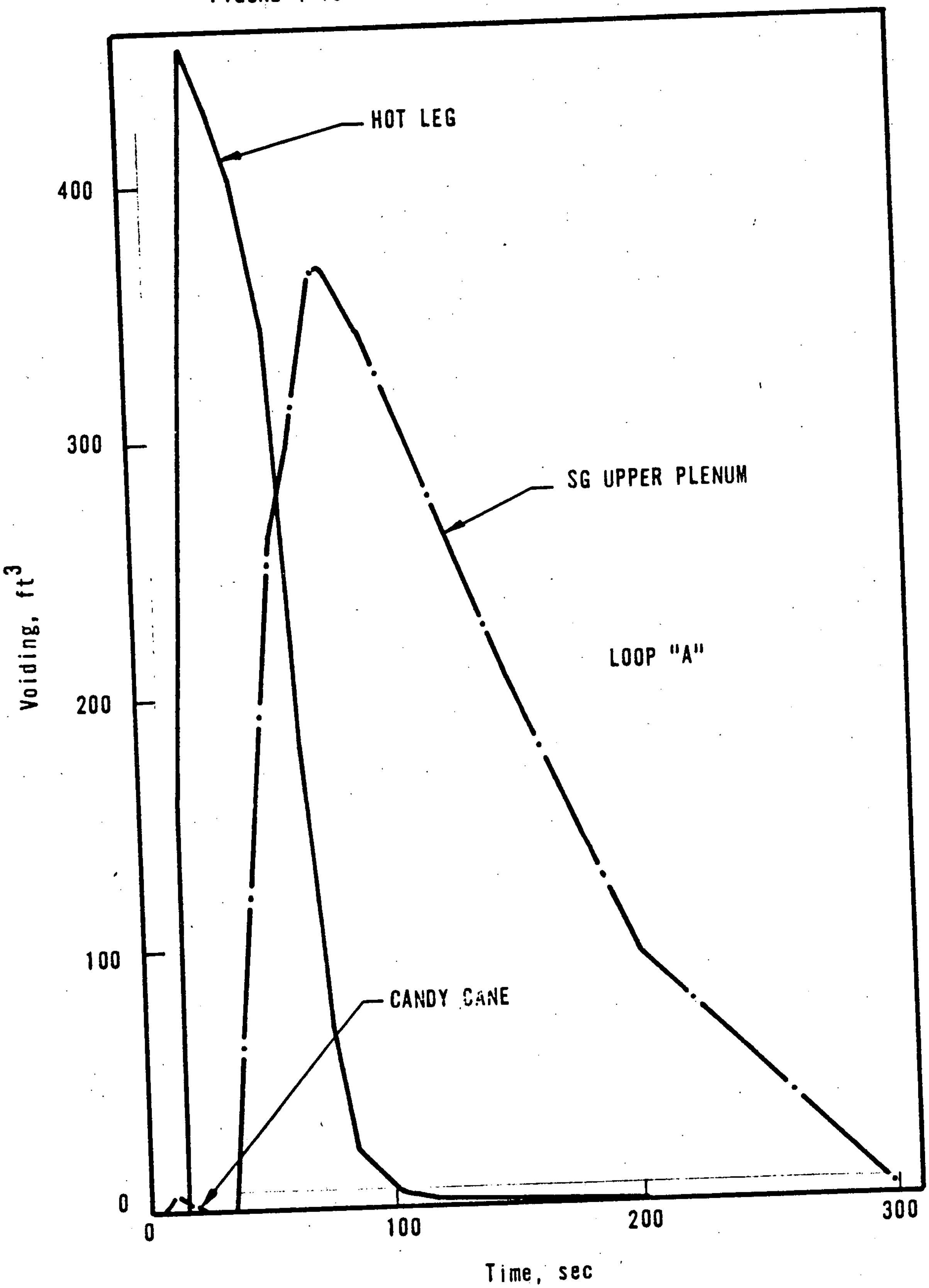


FIGURE 4-20. STEAM LINE BREAK CASE 1, 205 FA

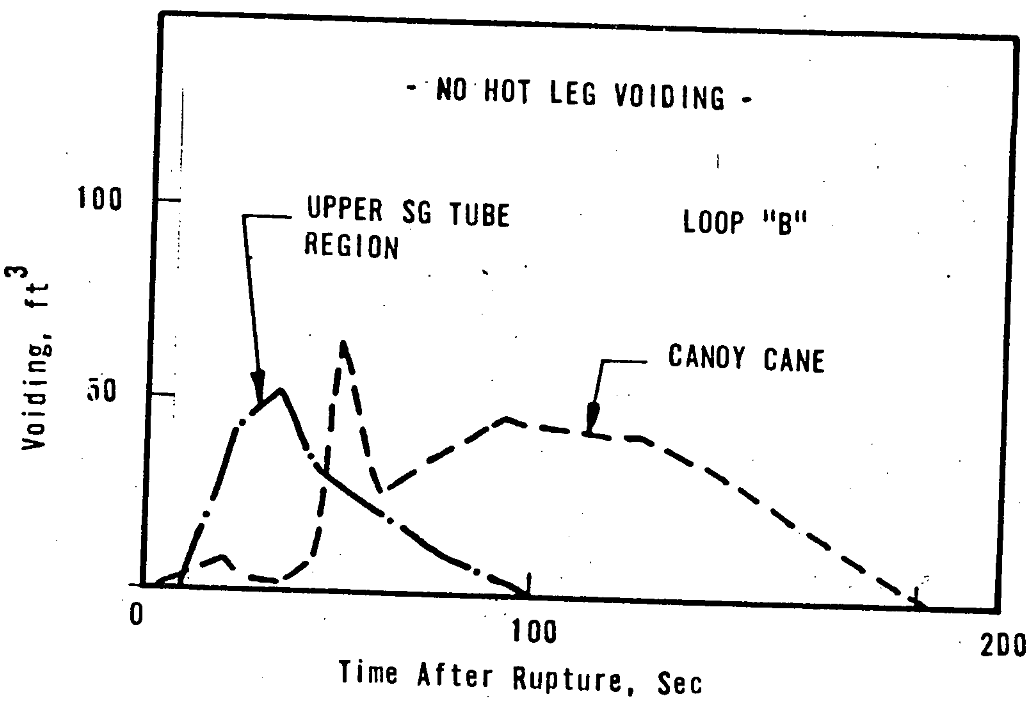


FIGURE 4-21. STEAM LINE BREAK CASE 2, 205 FA

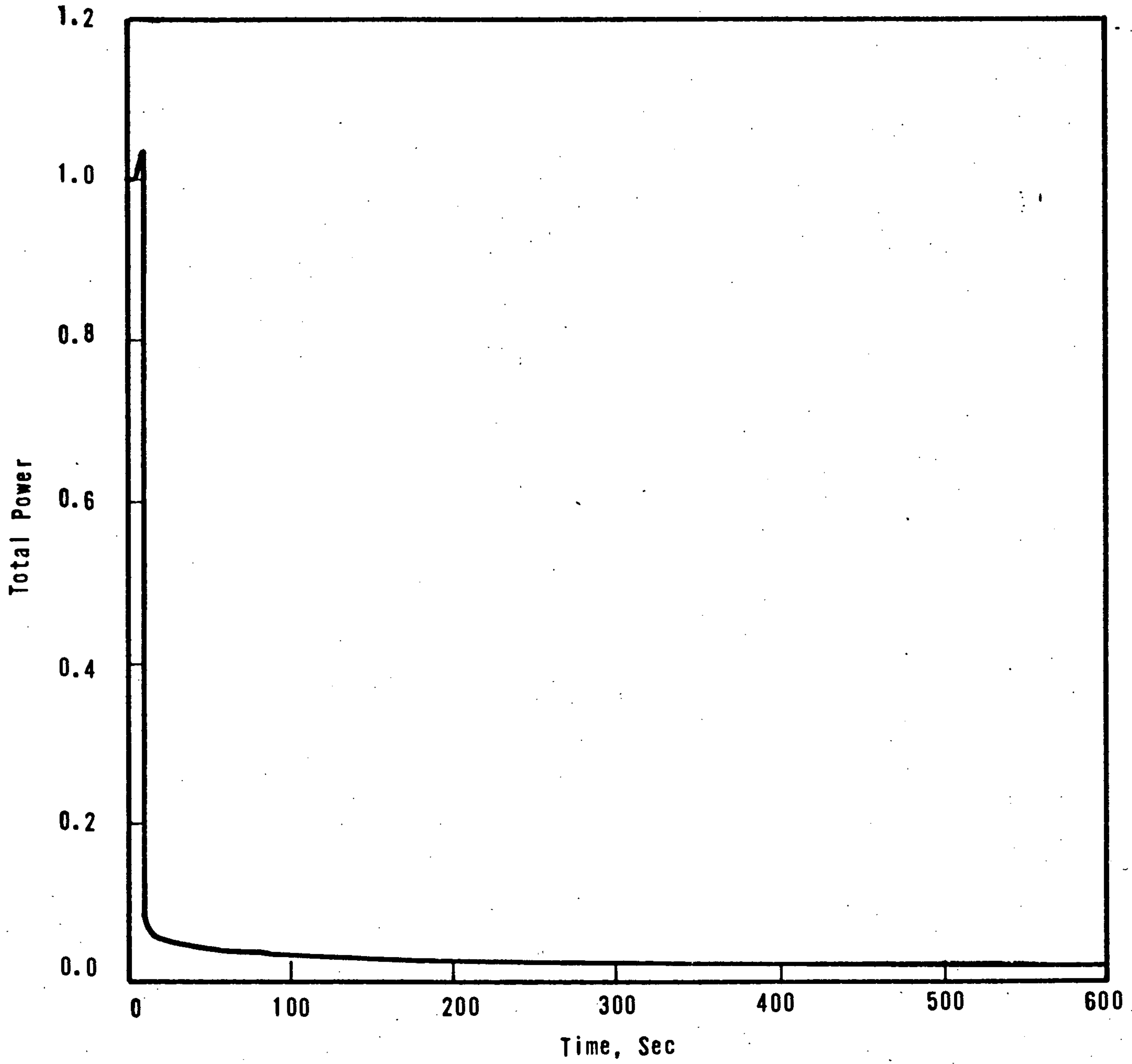


FIGURE 4-22. STEAM LINE BREAK CASE 2, 205 FA

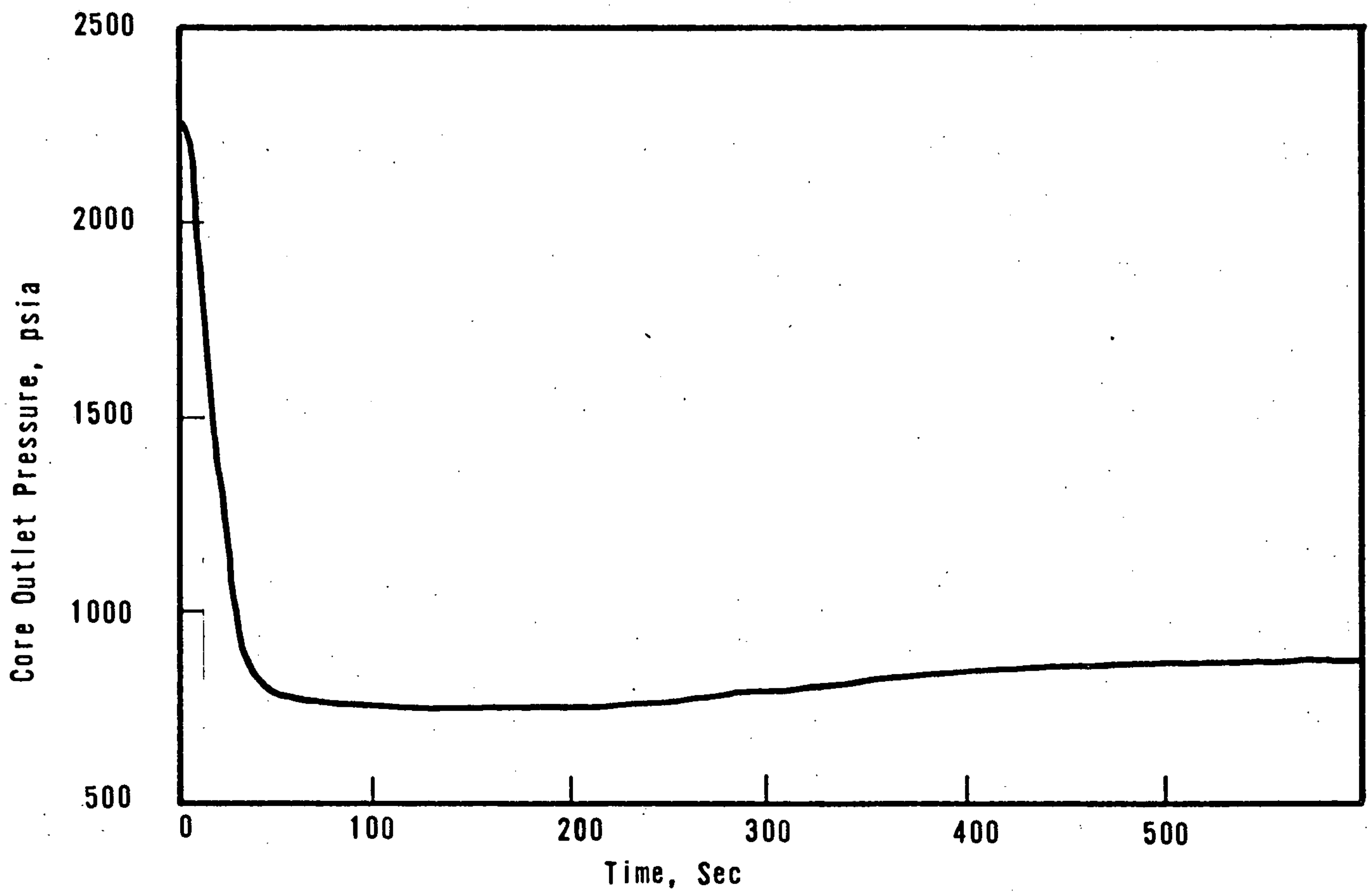


FIGURE 4-23. STEAM LINE BREAK CASE 2, 205 FA

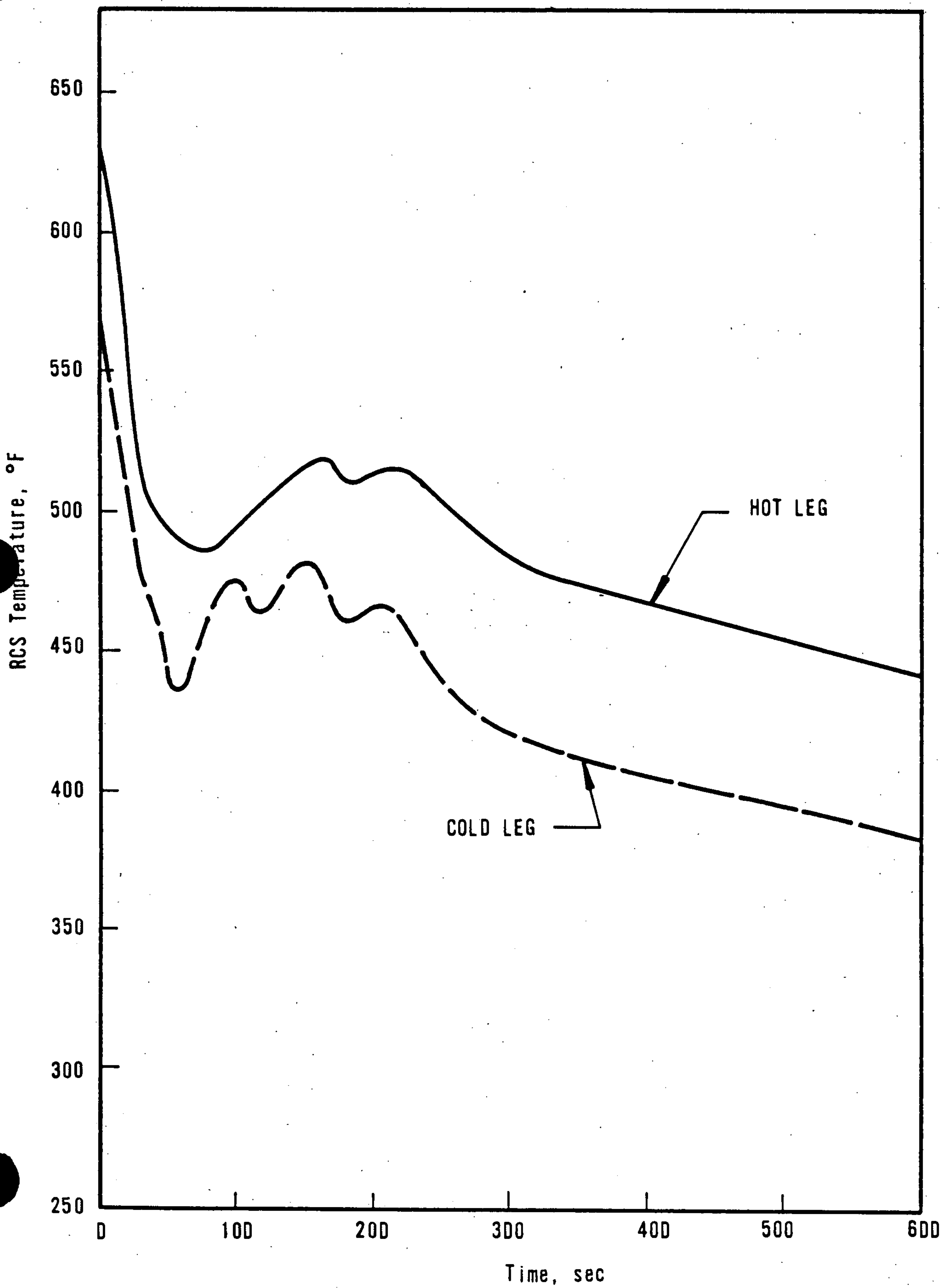


FIGURE 4-24. STEAM LINE BREAK CASE 2, 205 FA

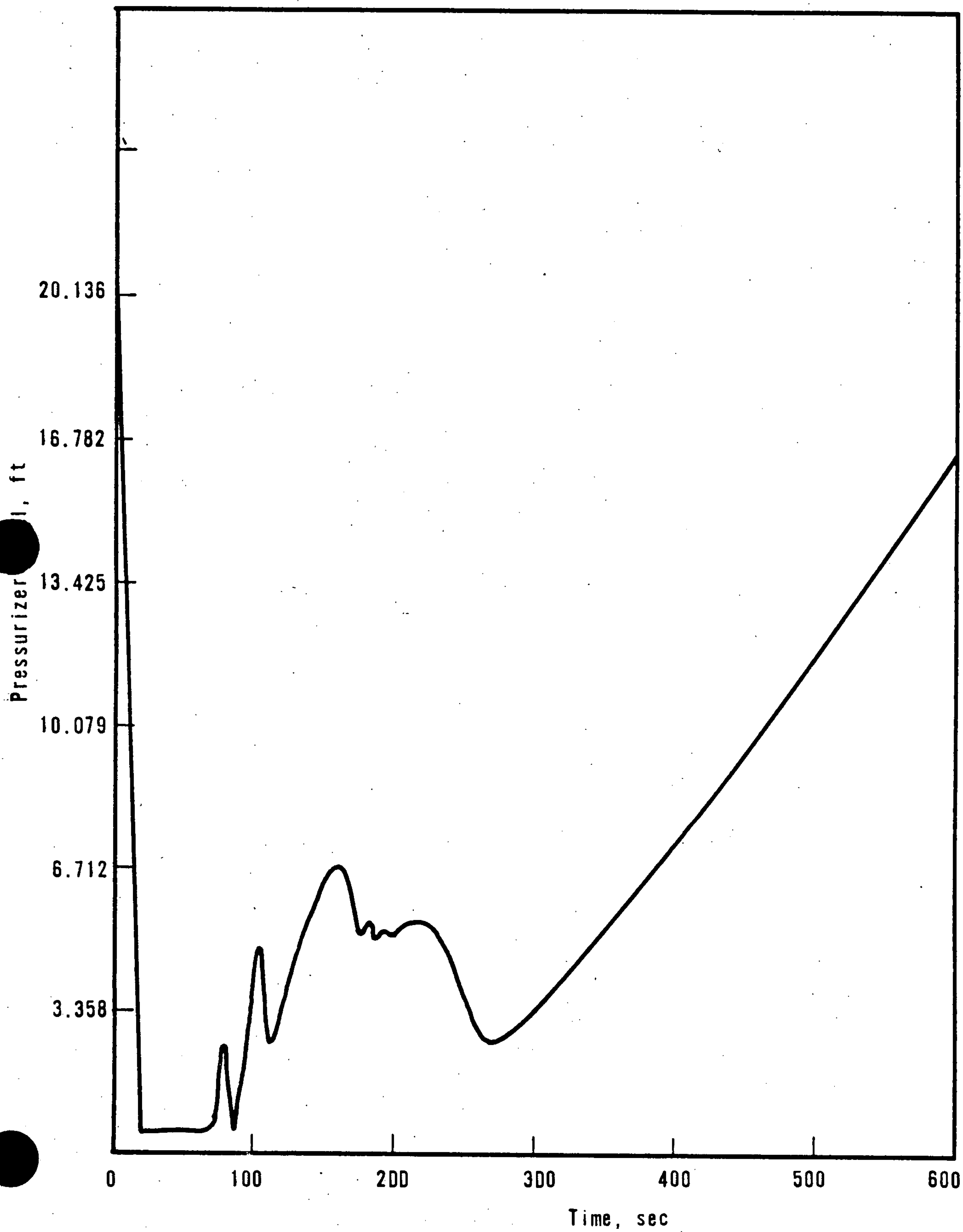


FIGURE 4-25. STEAM LINE BREAK CASE 2, 2D5 FA
STEAM GENERATOR A PRESSURE

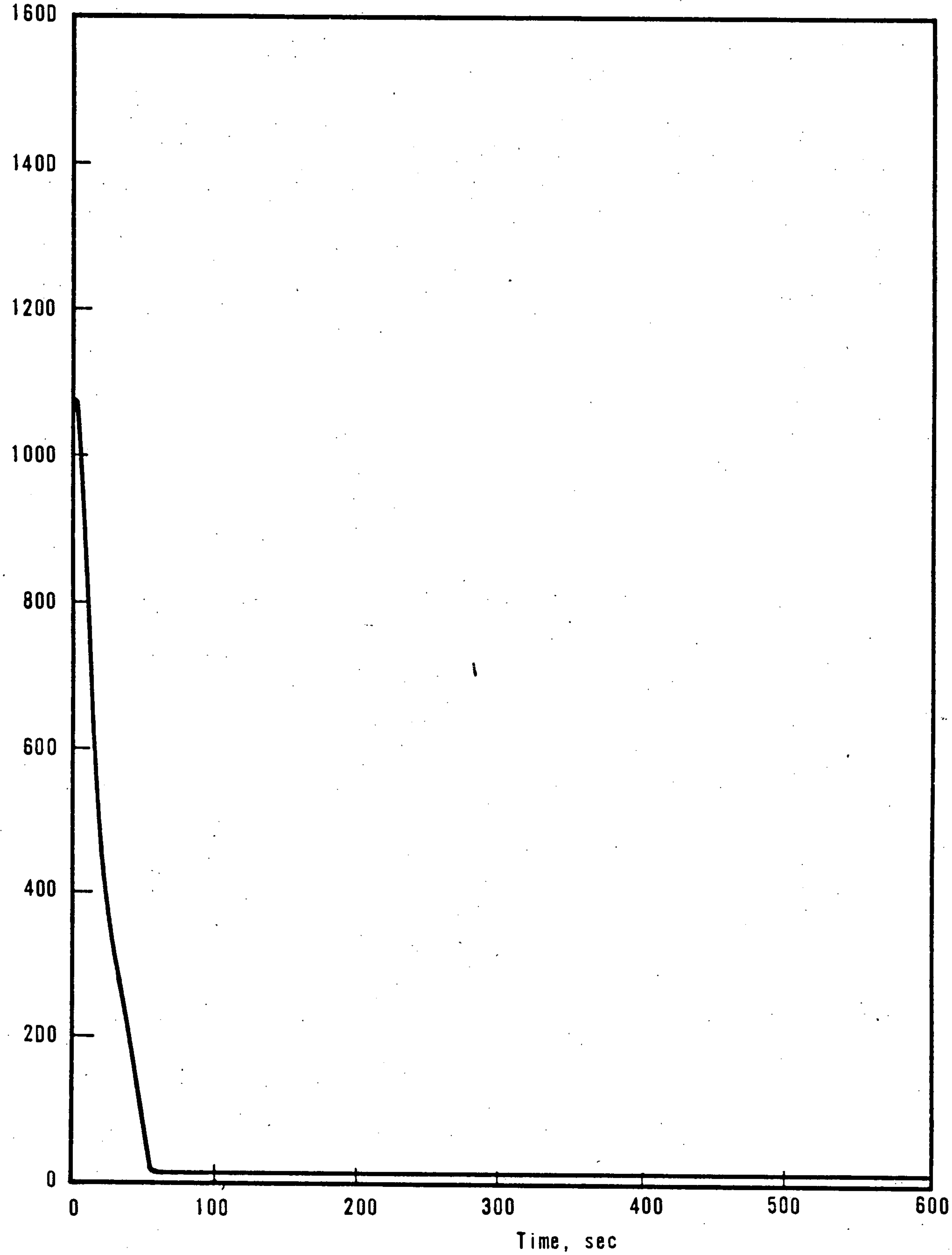


FIGURE 4-26. STEAM LINE BREAK CASE 2,205 FA
STEAM GENERATOR B PRESSURE

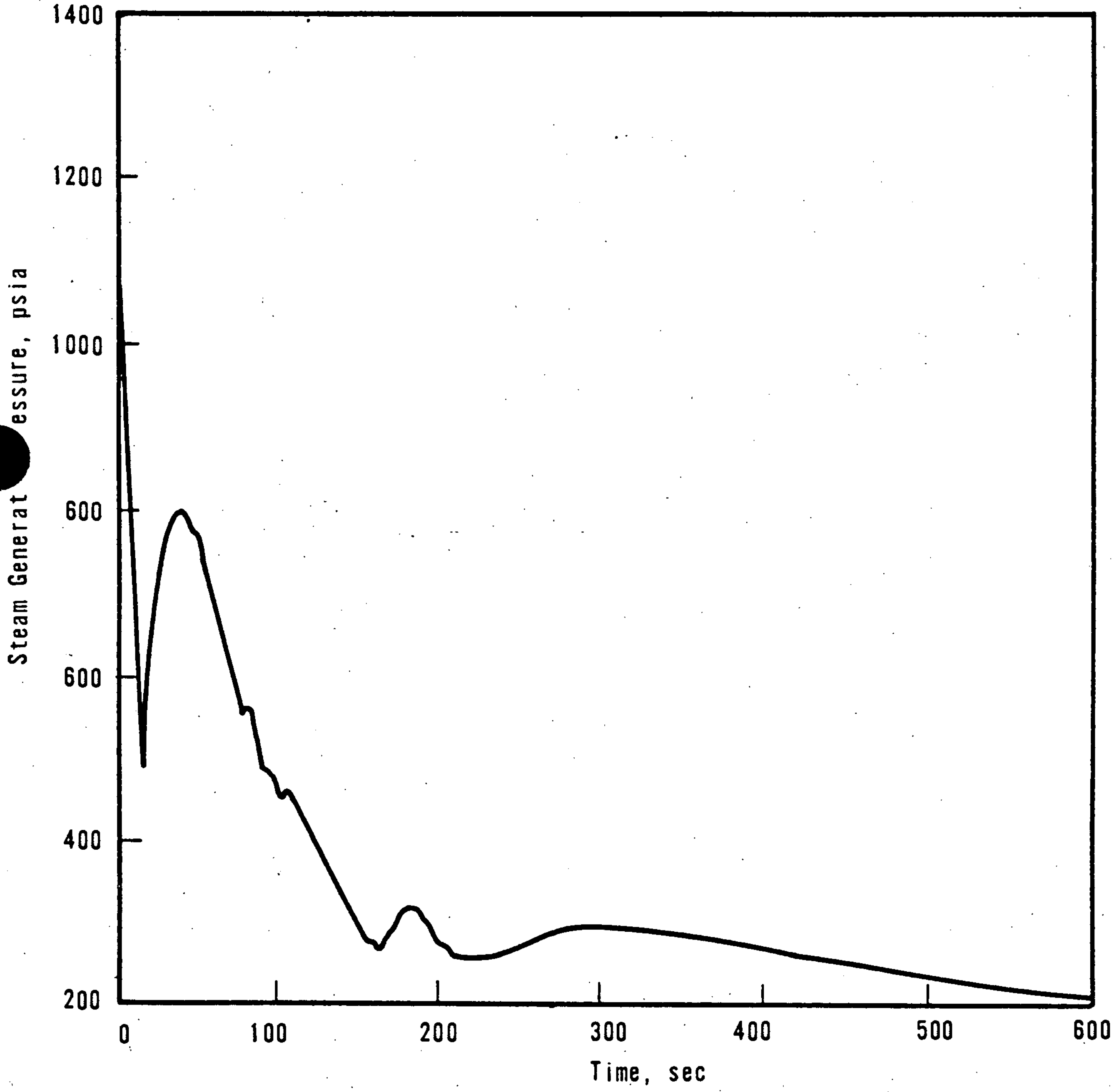


FIGURE 4-27. STEAM LINE BREAK CASE 2, 205 FA

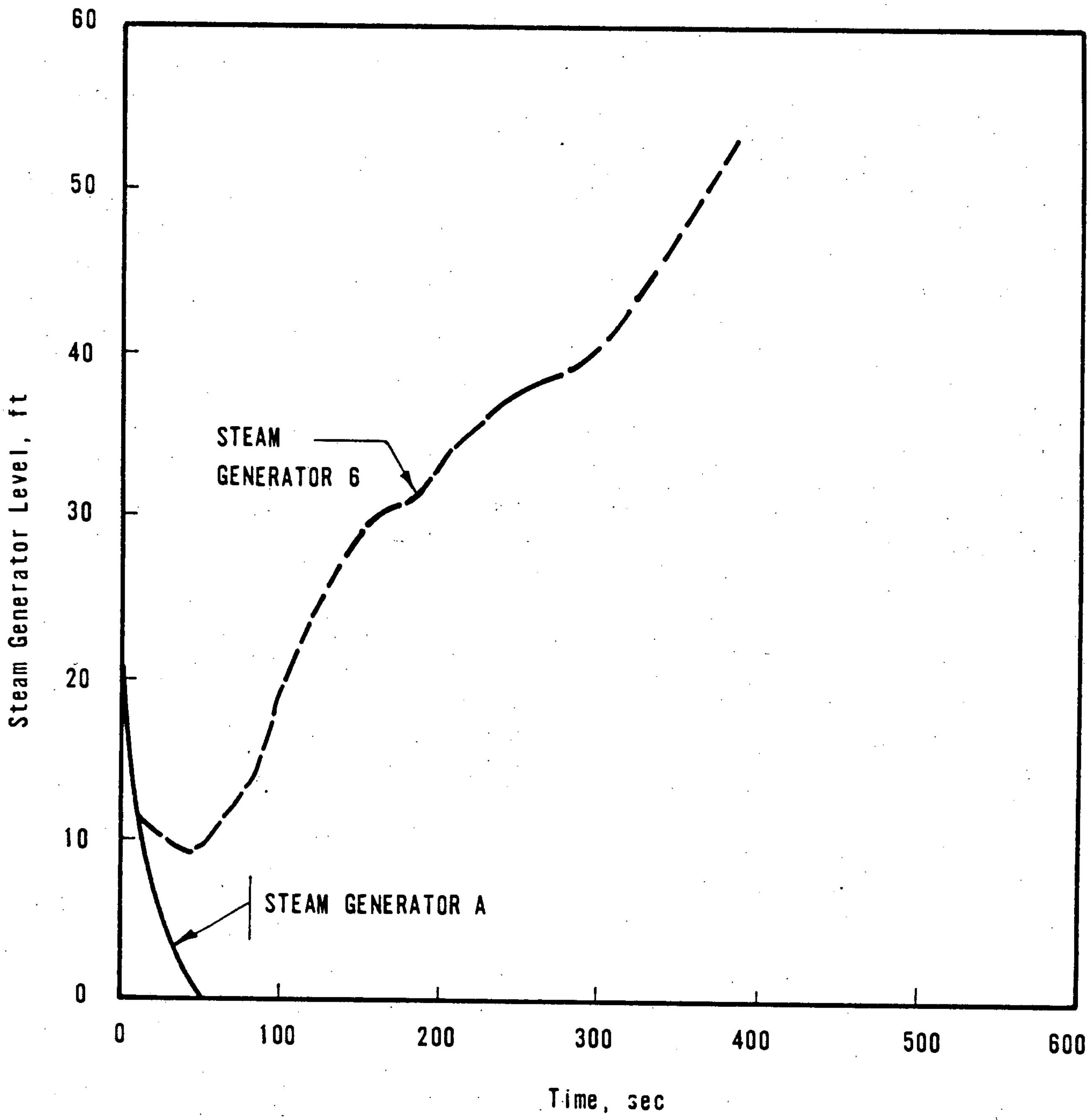


FIGURE 4-28. STEAM LINE BREAK CASE 2, 205 FA

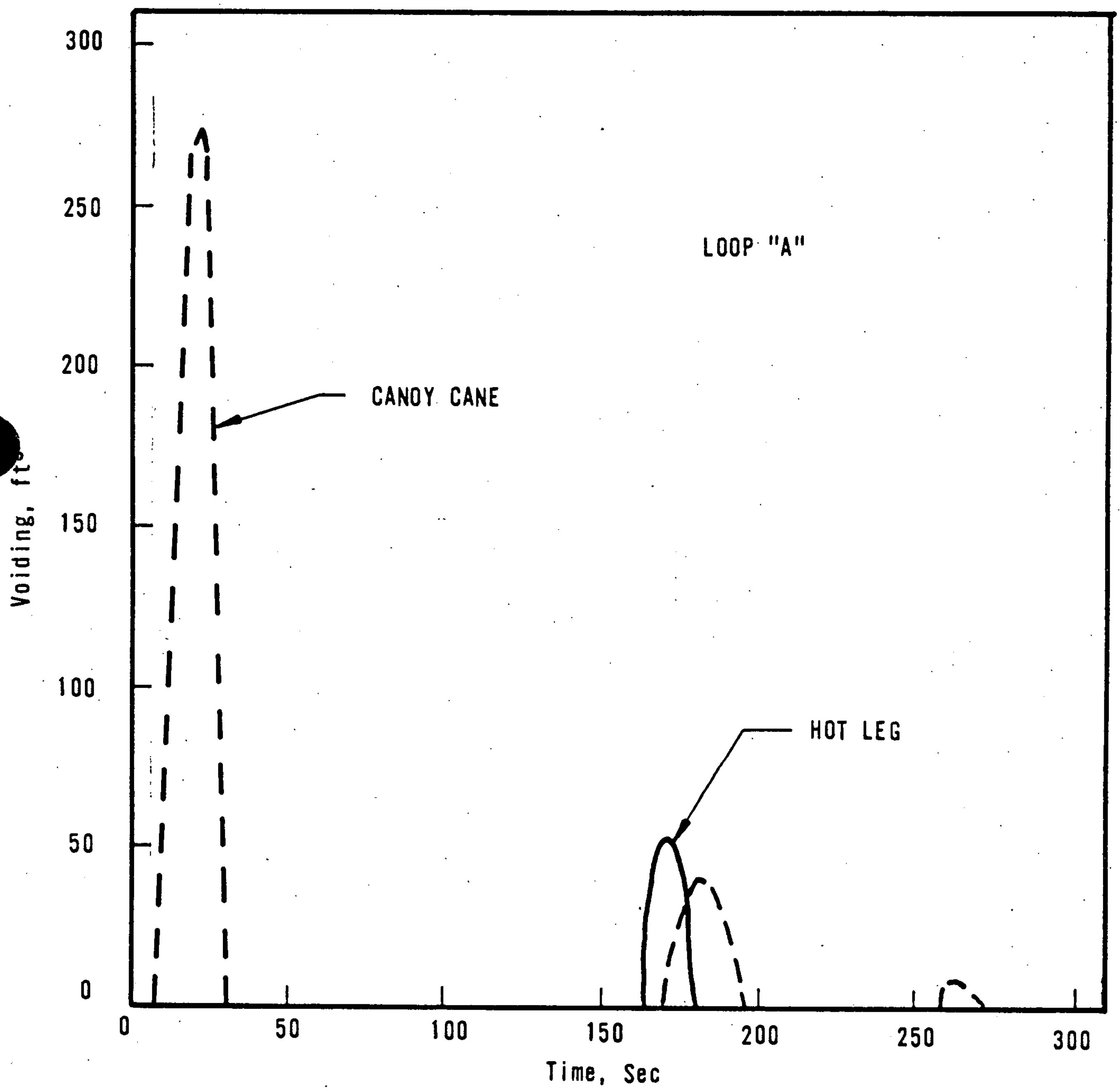


FIGURE 4-29. STEAM LINE BREAK CASE 2, 205 FA

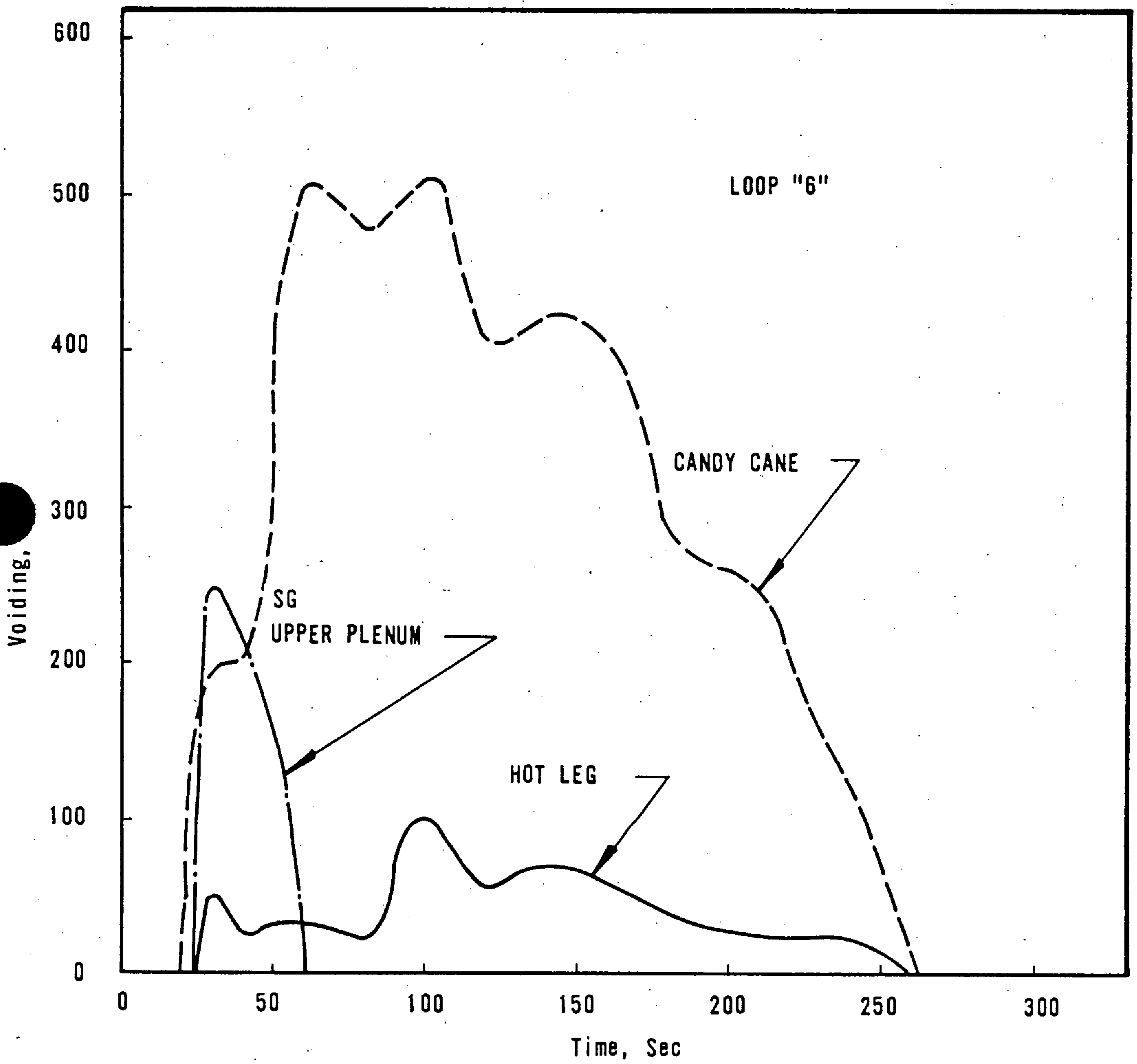


FIGURE 4-30. STEAM LINE BREAK CASE 3, 205 FA

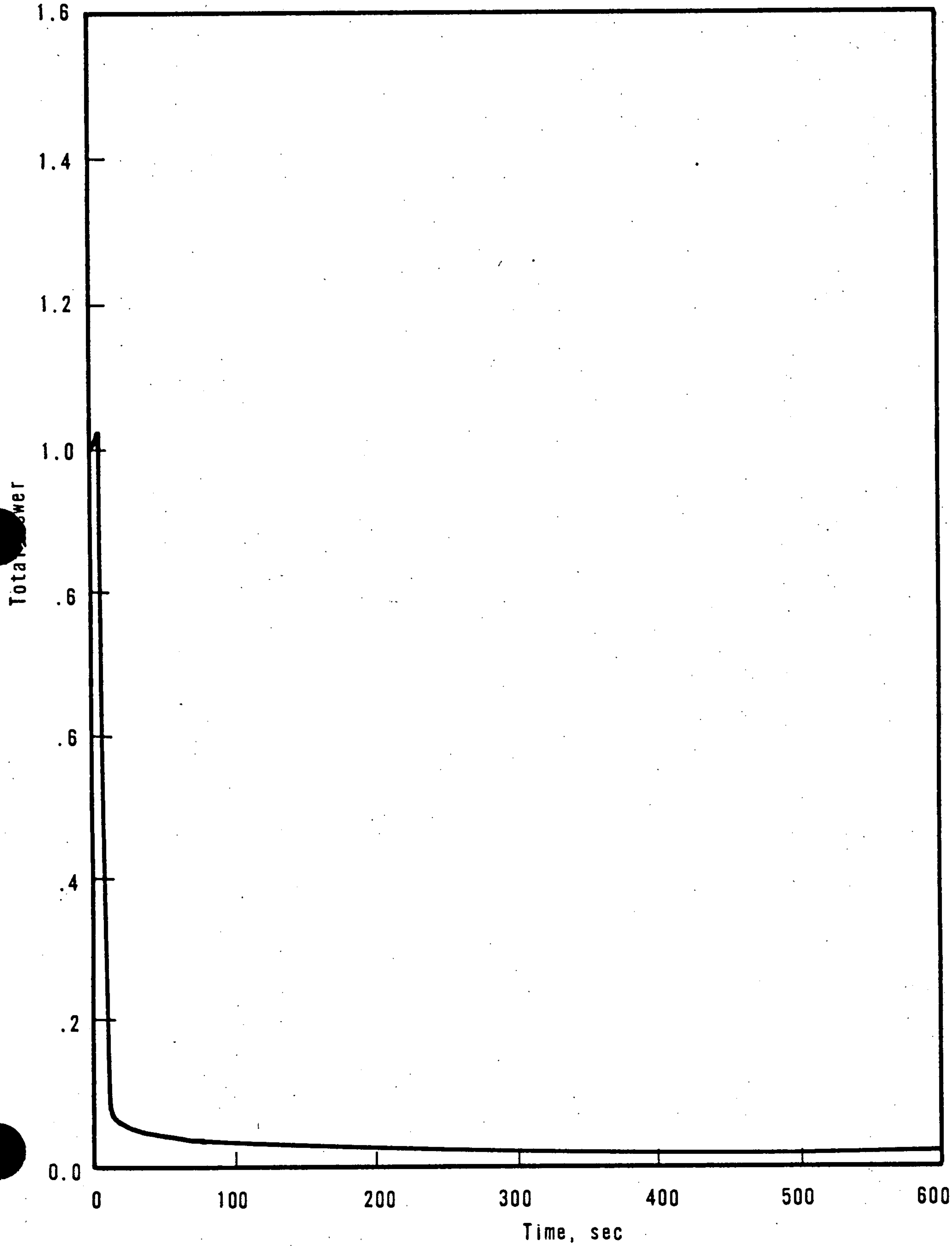


FIGURE 4-31. STEAM LINE BREAK CASE 3, 205 FA

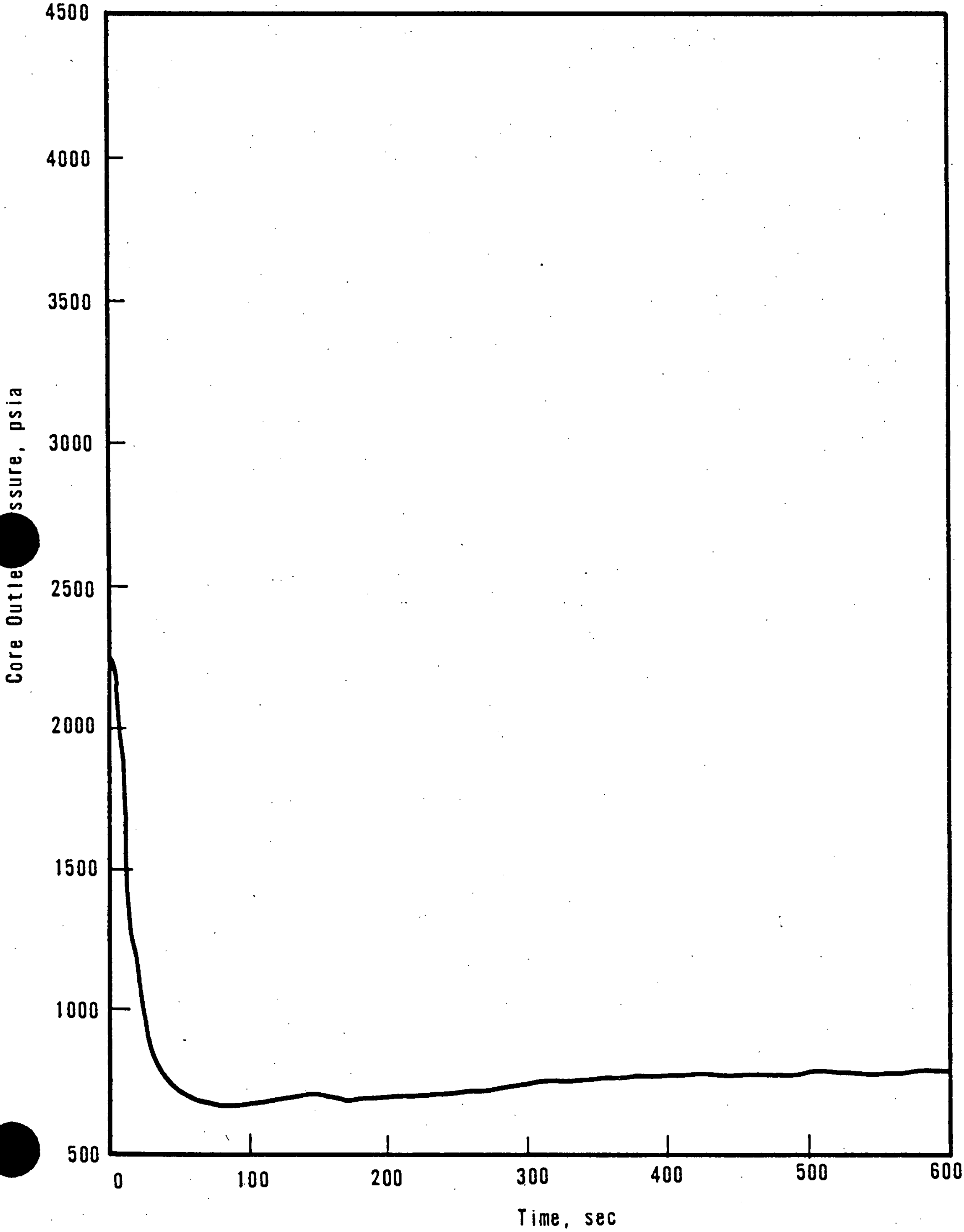


FIGURE 4-32. STEAM LINE BREAK CASE 3, 205 FA

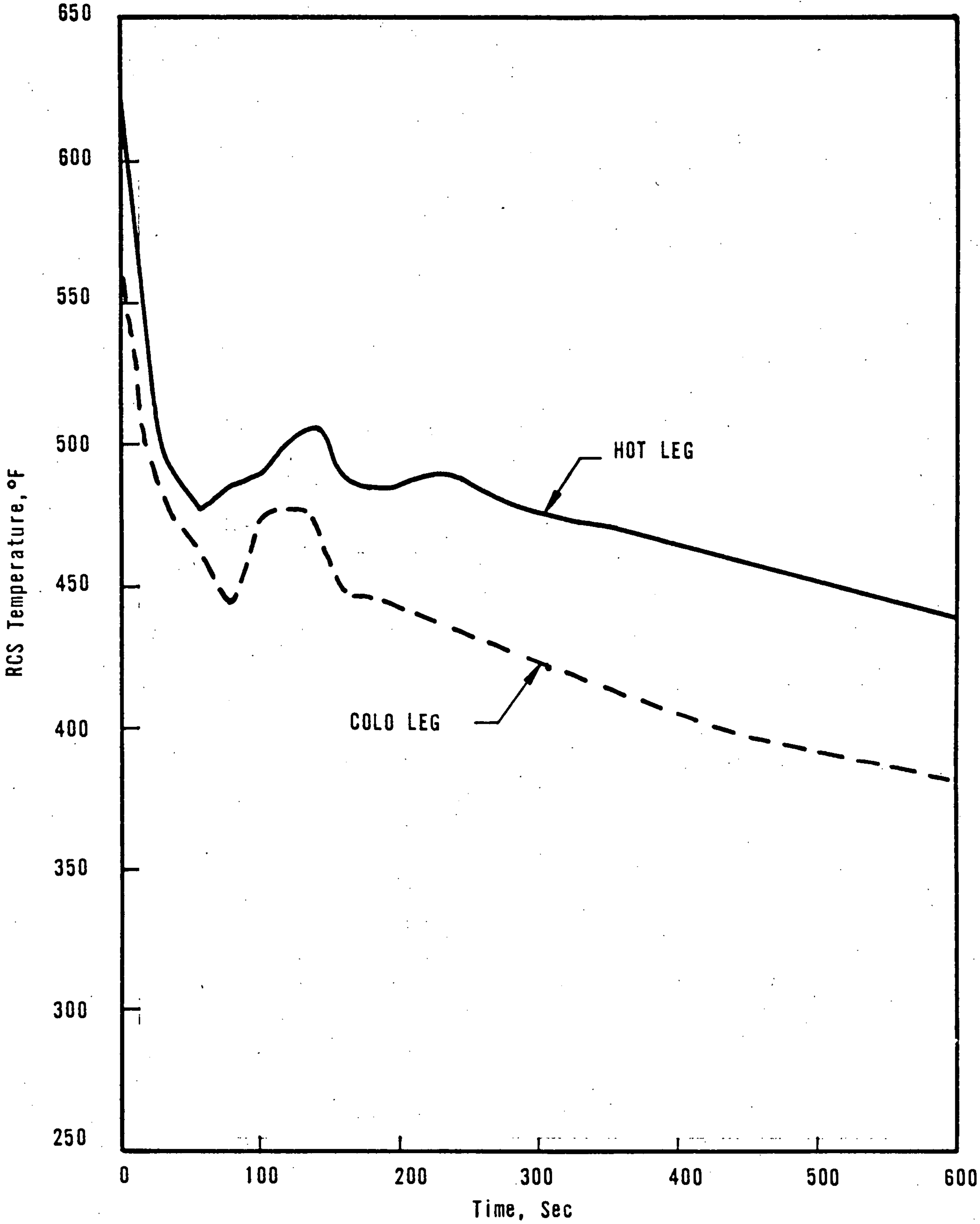


FIGURE 4-33. STEAM LINE BREAK CASE 3, 205 FA

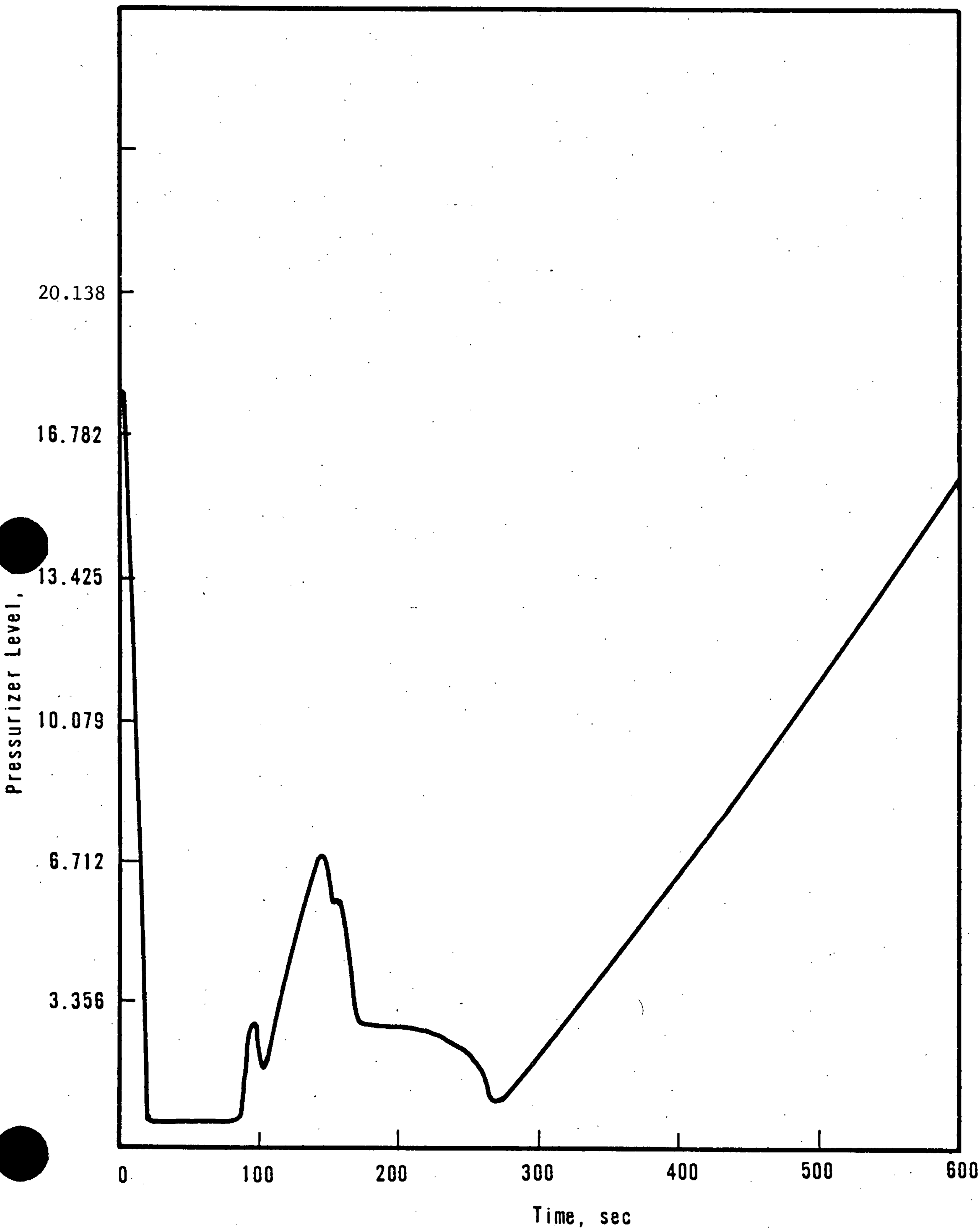


FIGURE 4-34. STEAM LINE BREAK CASE 3, 205 FA
STEAM GENERATOR A PRESSURE

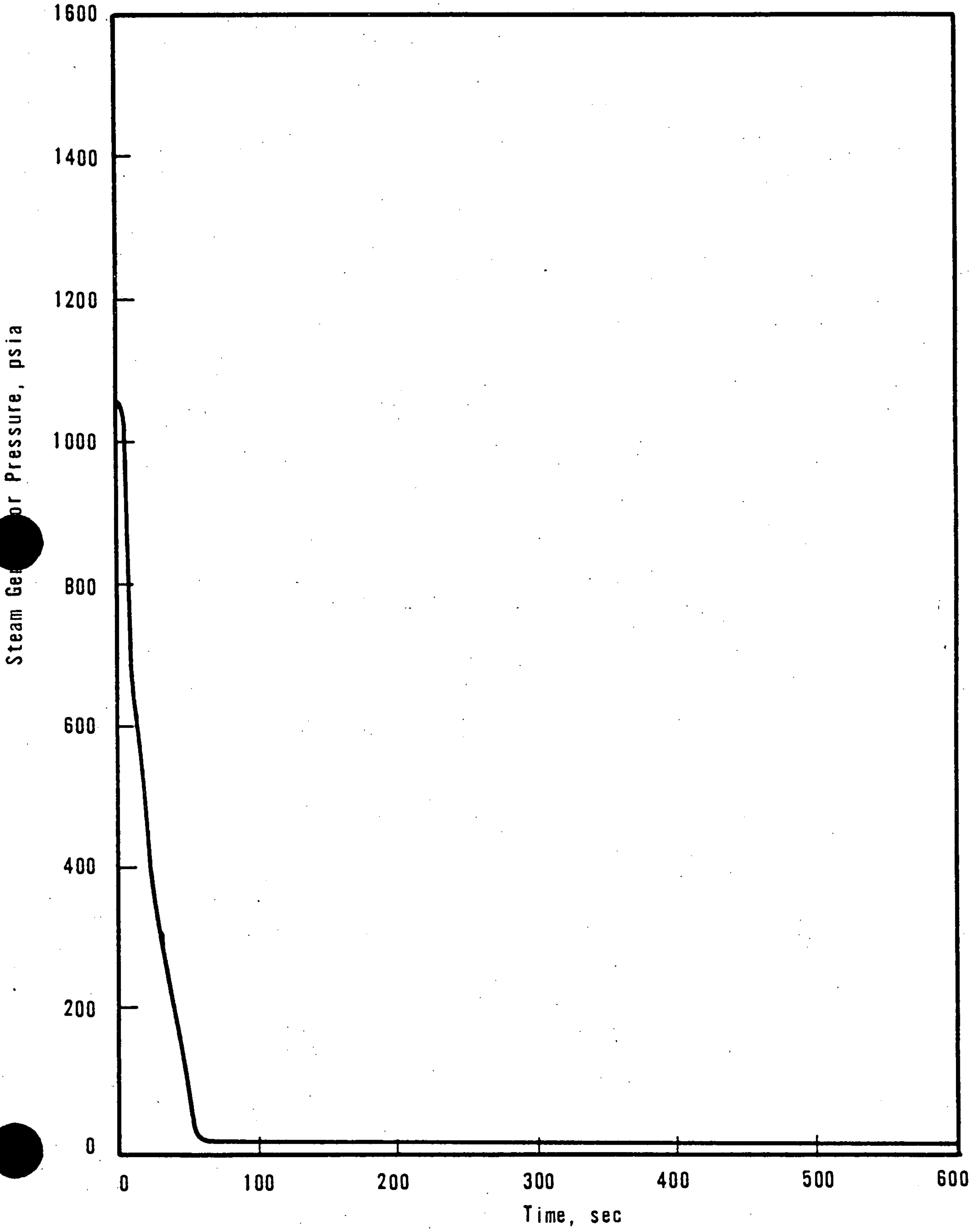


FIGURE 4-35. STEAM LINE BREAK CASE 3, 205 FA
STEAM GENERATOR B PRESSURE

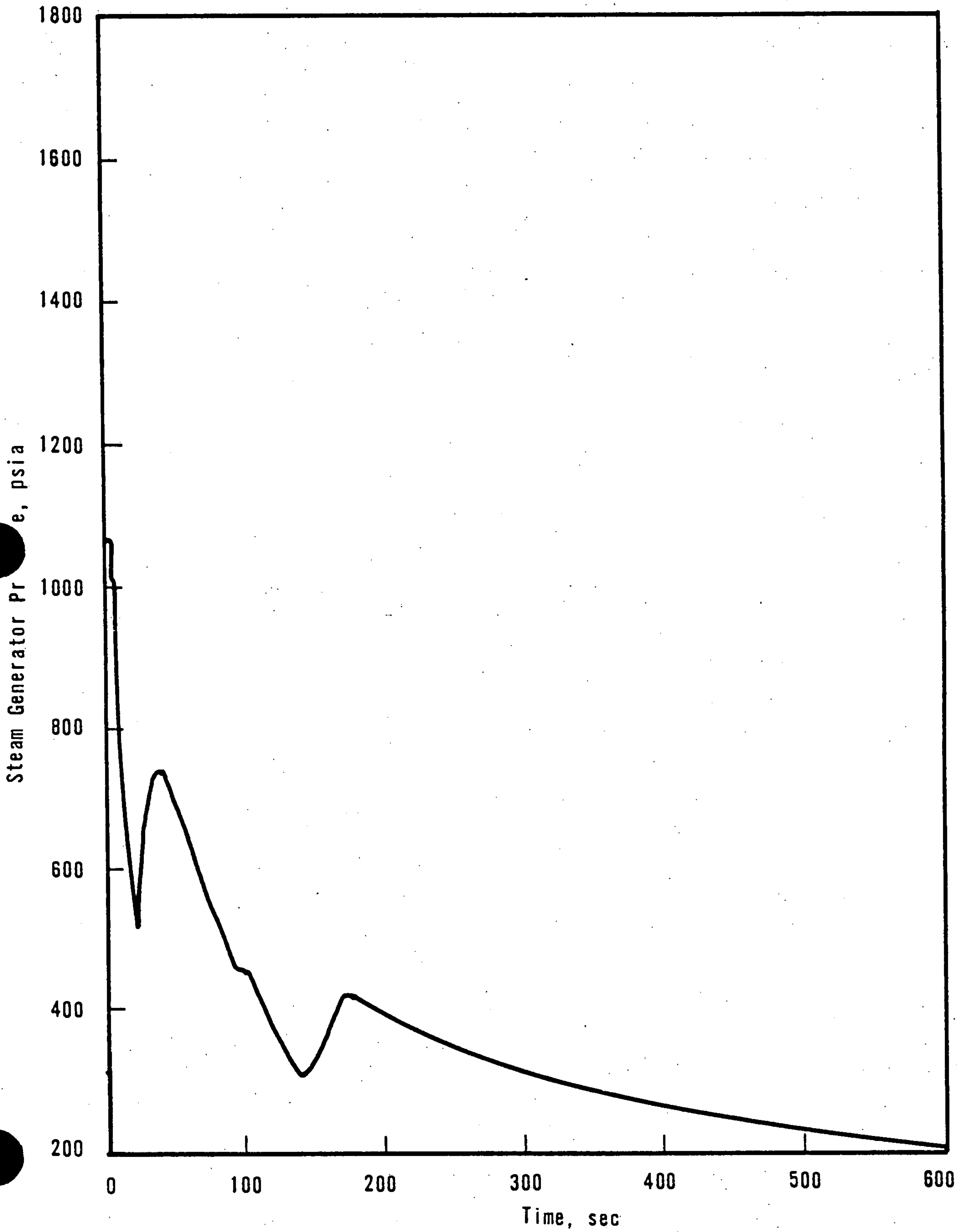


FIGURE 4-36. STEAM LINE BREAK CASE 3, 205 FA

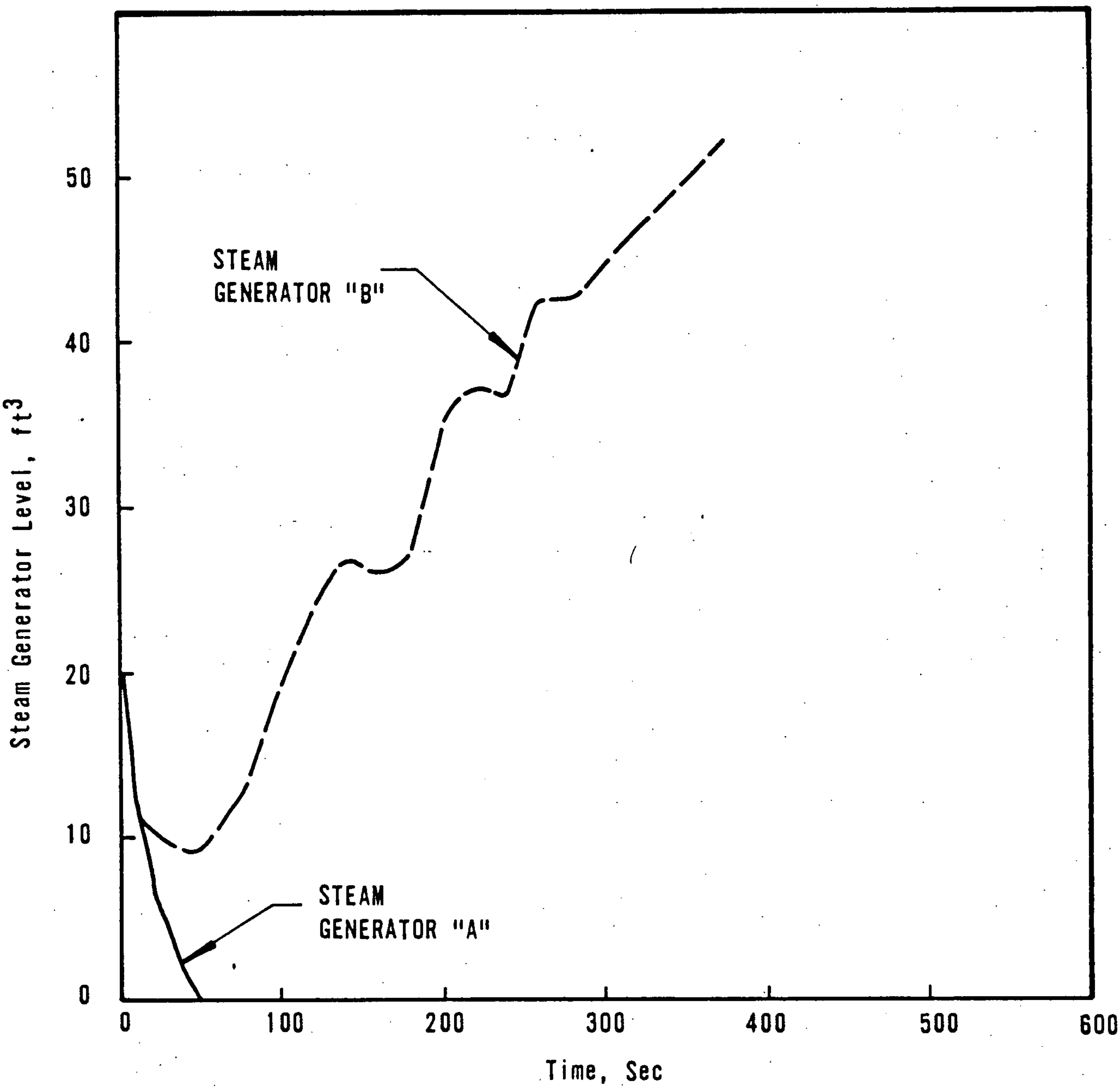


FIGURE 4-37. STEAM LINE BREAK CASE 3, 205 FA

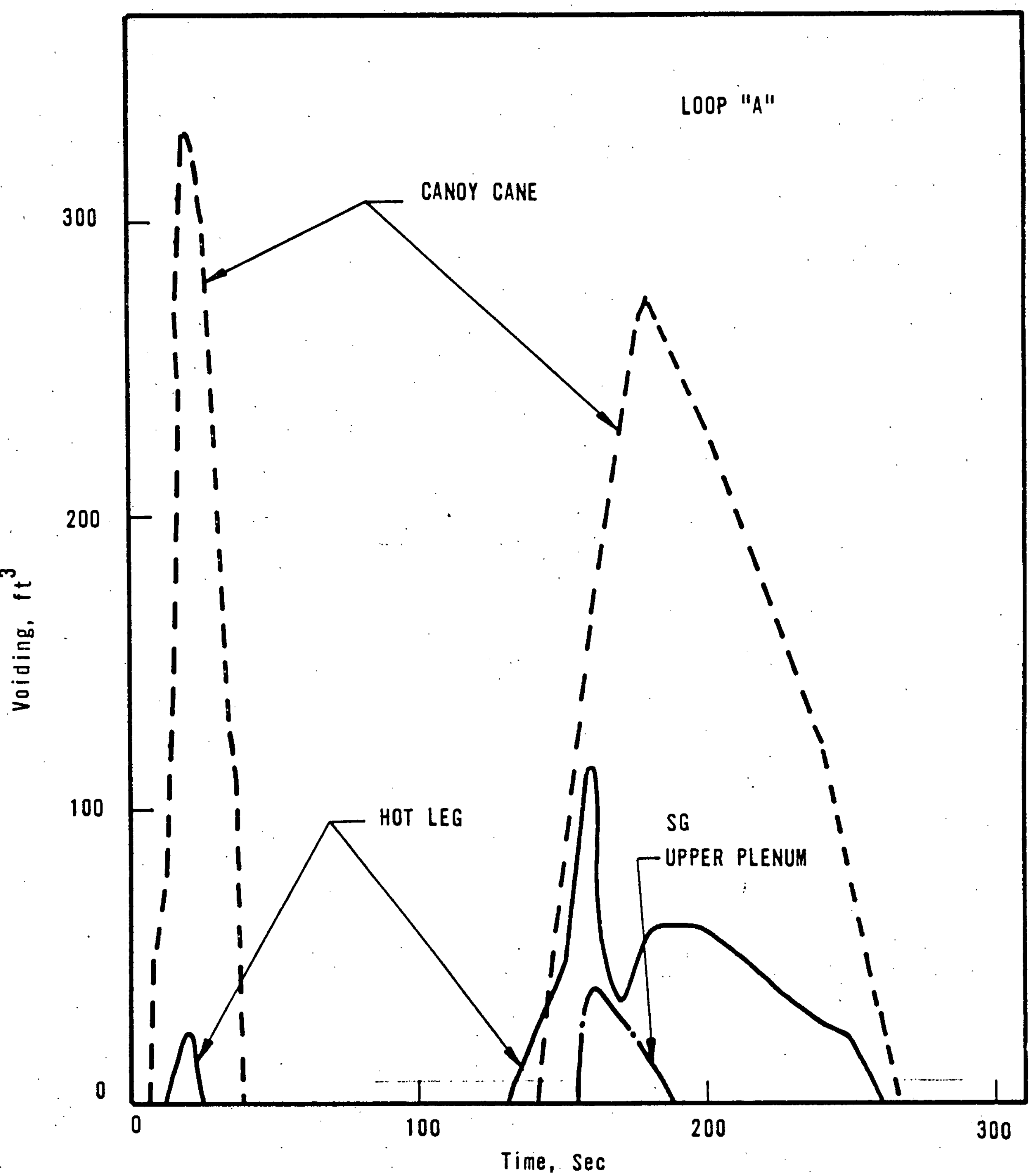


FIGURE 4-38. STEAM LINE BREAK CASE 3, 205 FA

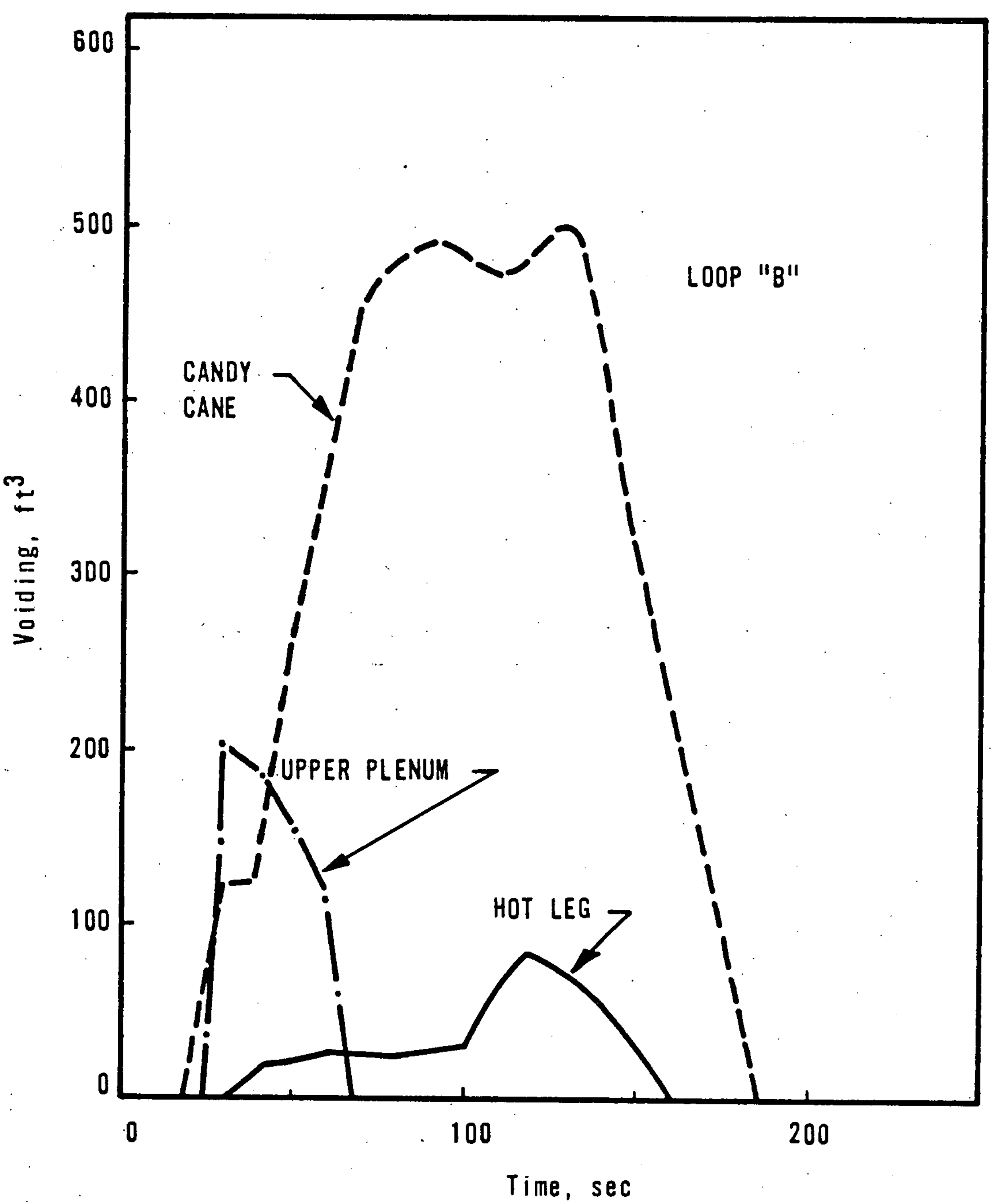


FIGURE 4-39. STEAM LINE BREAK CASE 4, 205 FA

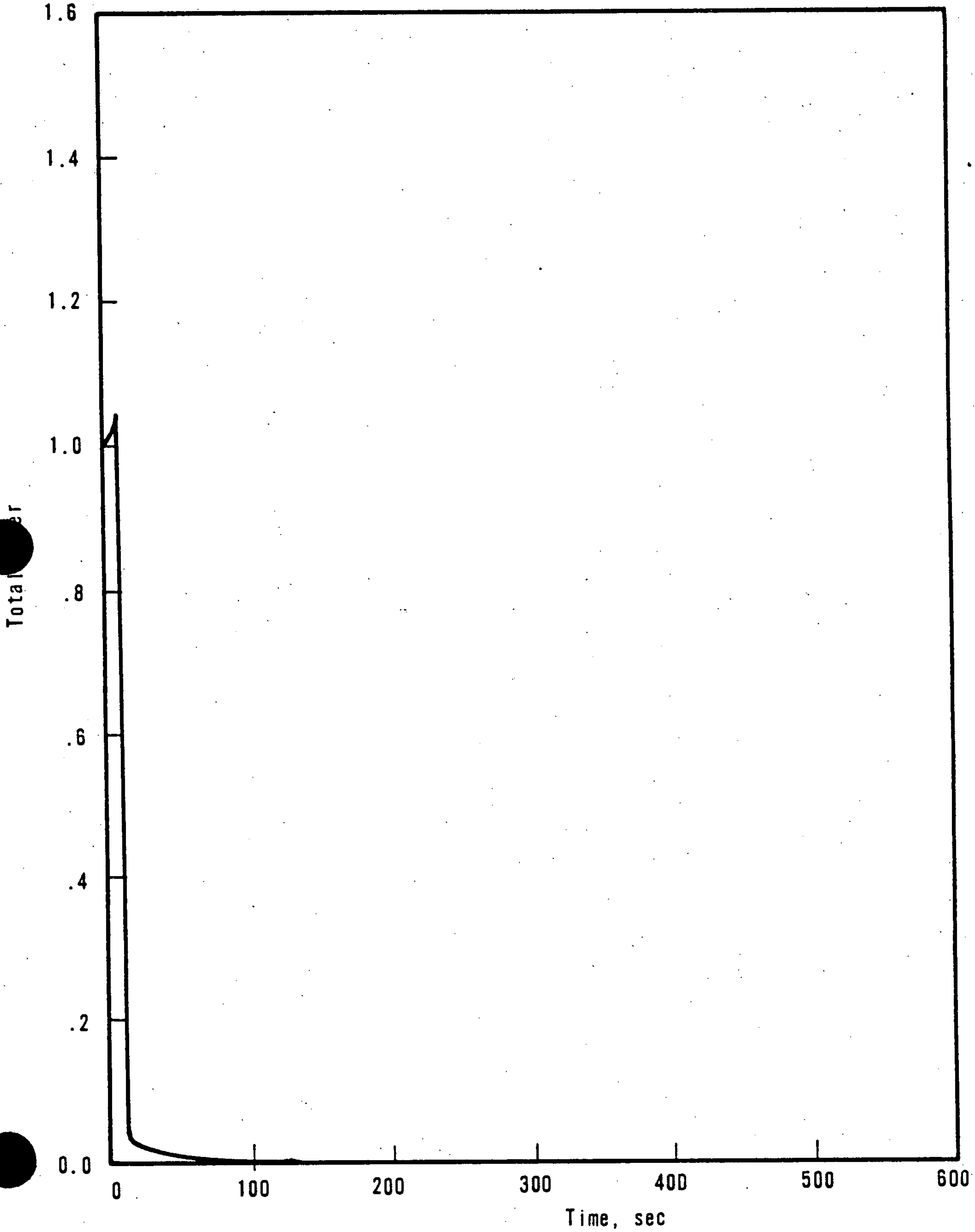


FIGURE 4-40. STEAM LINE BREAK CASE 4, 205 FA

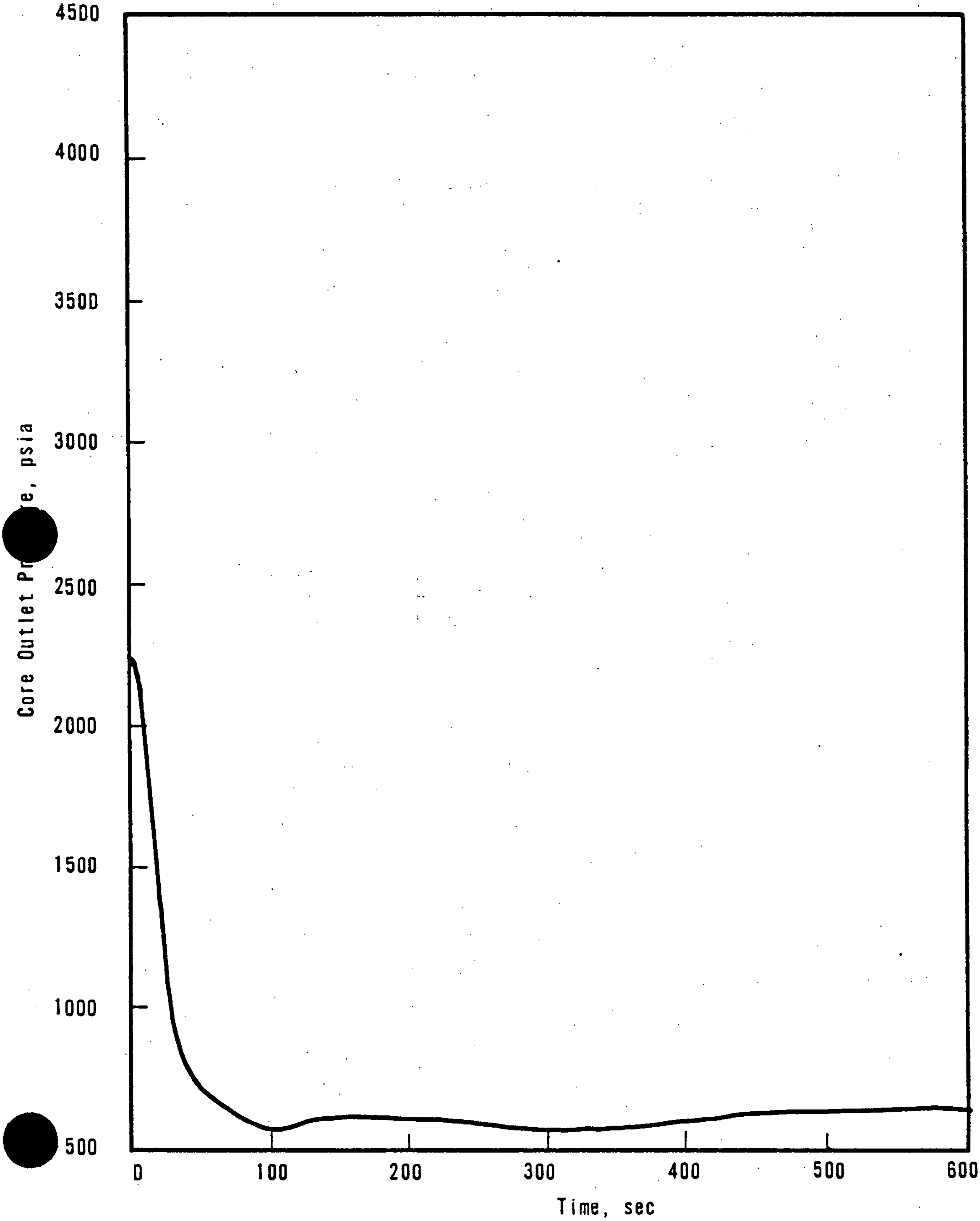


FIGURE 4-41. STEAM LINE BREAK CASE 4, 205 FA

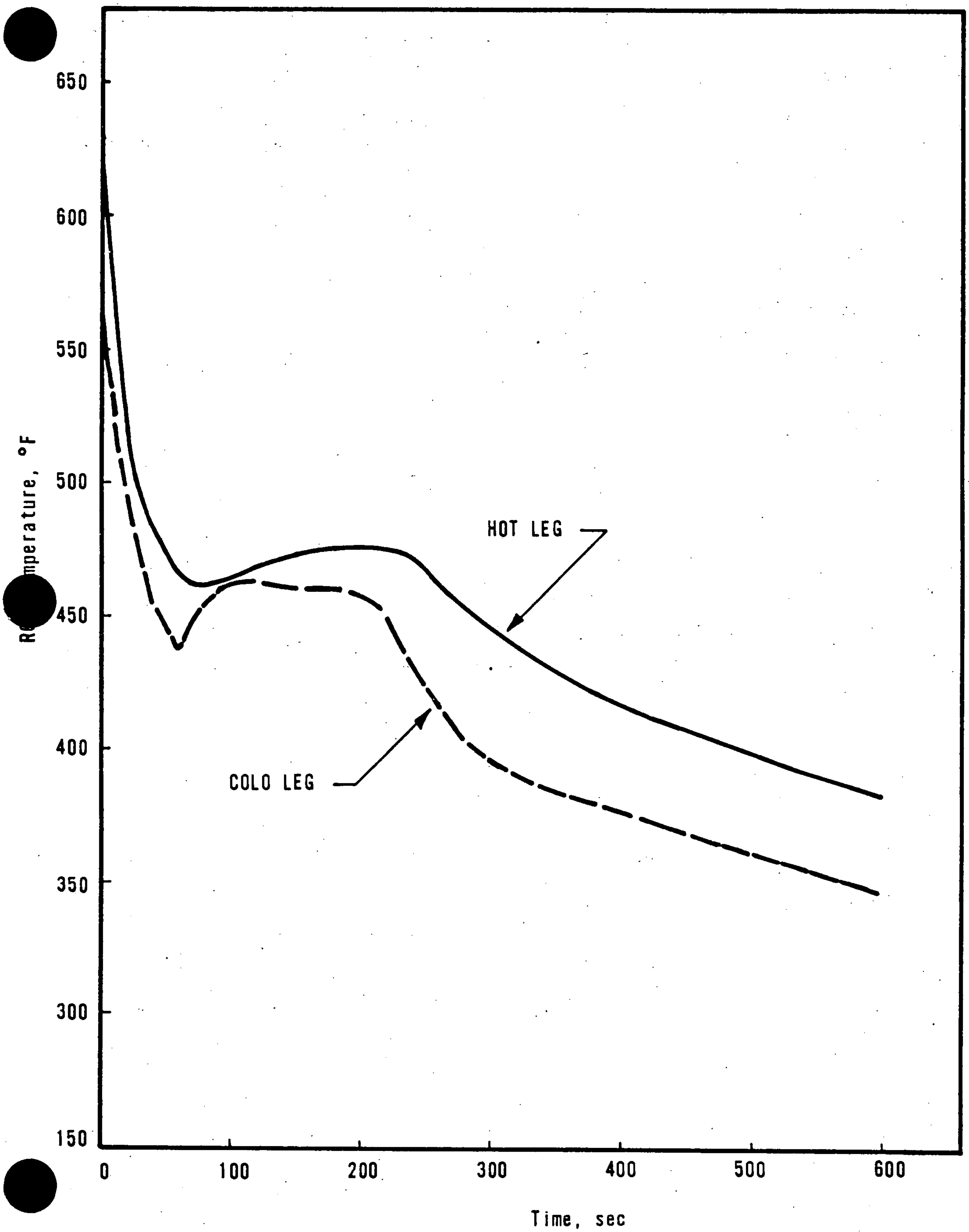


FIGURE 4-42. STEAM LINE BREAK CASE 4, 205 FA

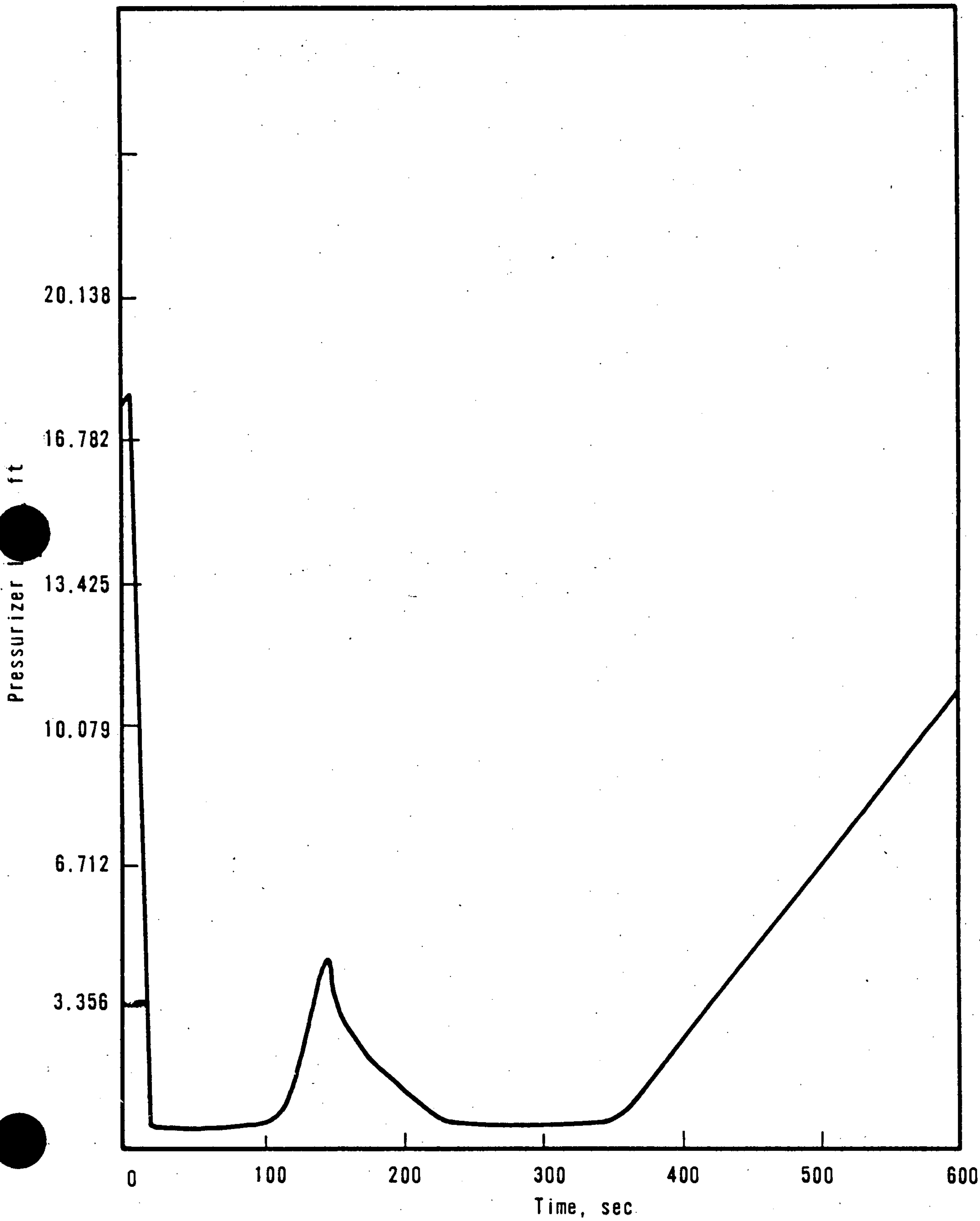


FIGURE 4-43. STEAM LINE BREAK CASE 4, 205 FA
STEAM GENERATOR A PRESSURE

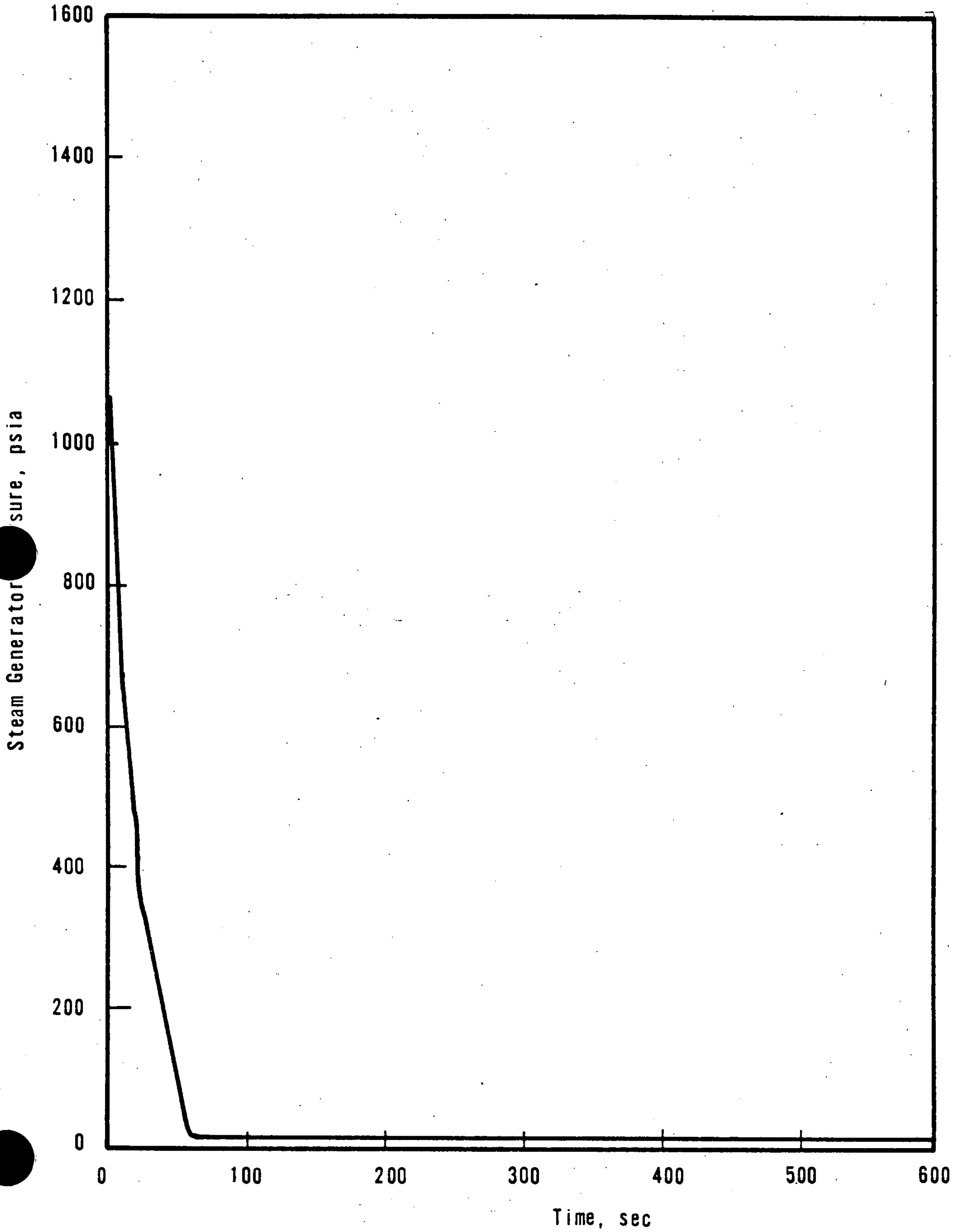


FIGURE 4-44. STEAM LINE BREAK CASE 4, 205 FA
STEAM GENERATOR B PRESSURE

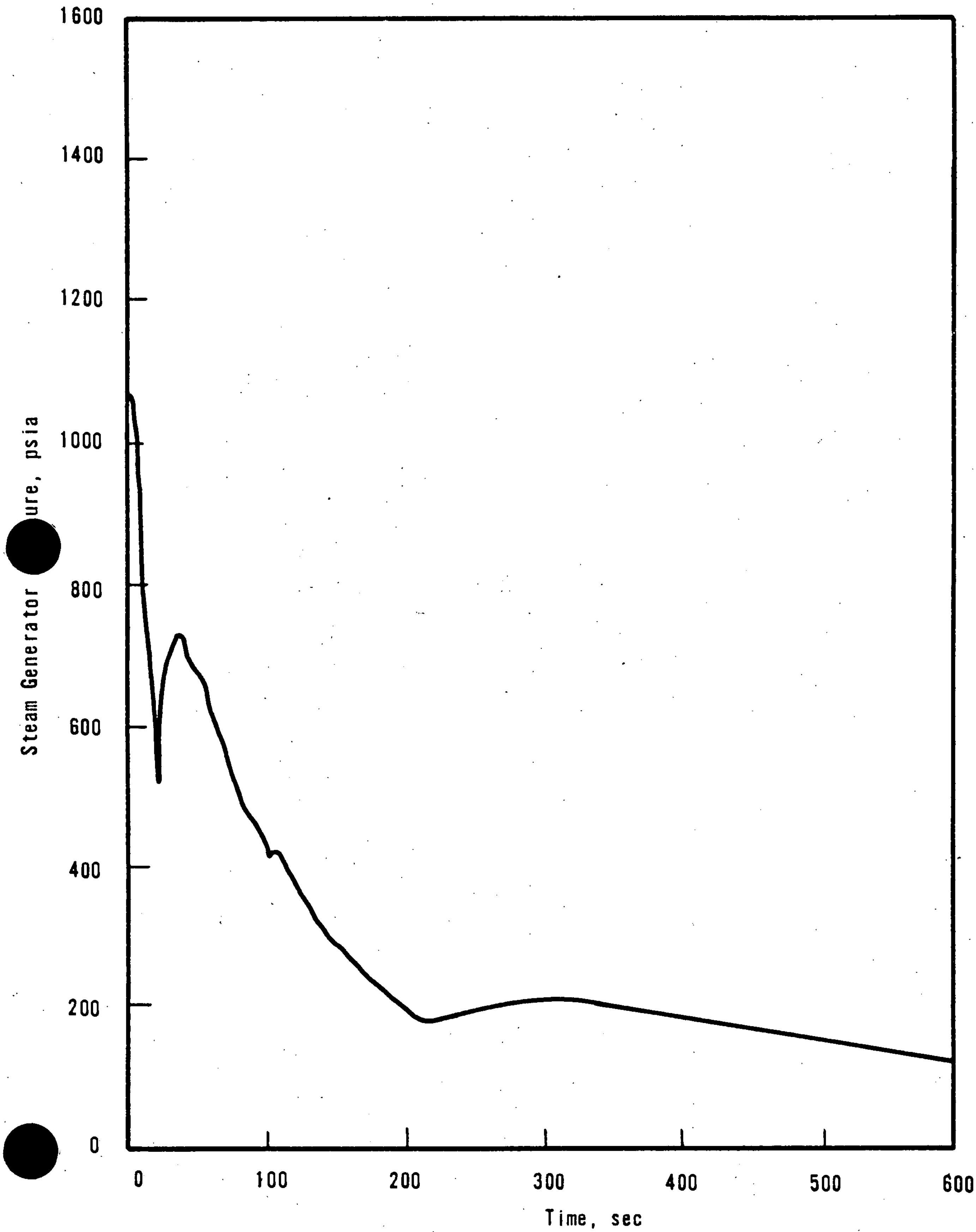


FIGURE 4-45. STEAM LINE BREAK CASE 4, 205 FA

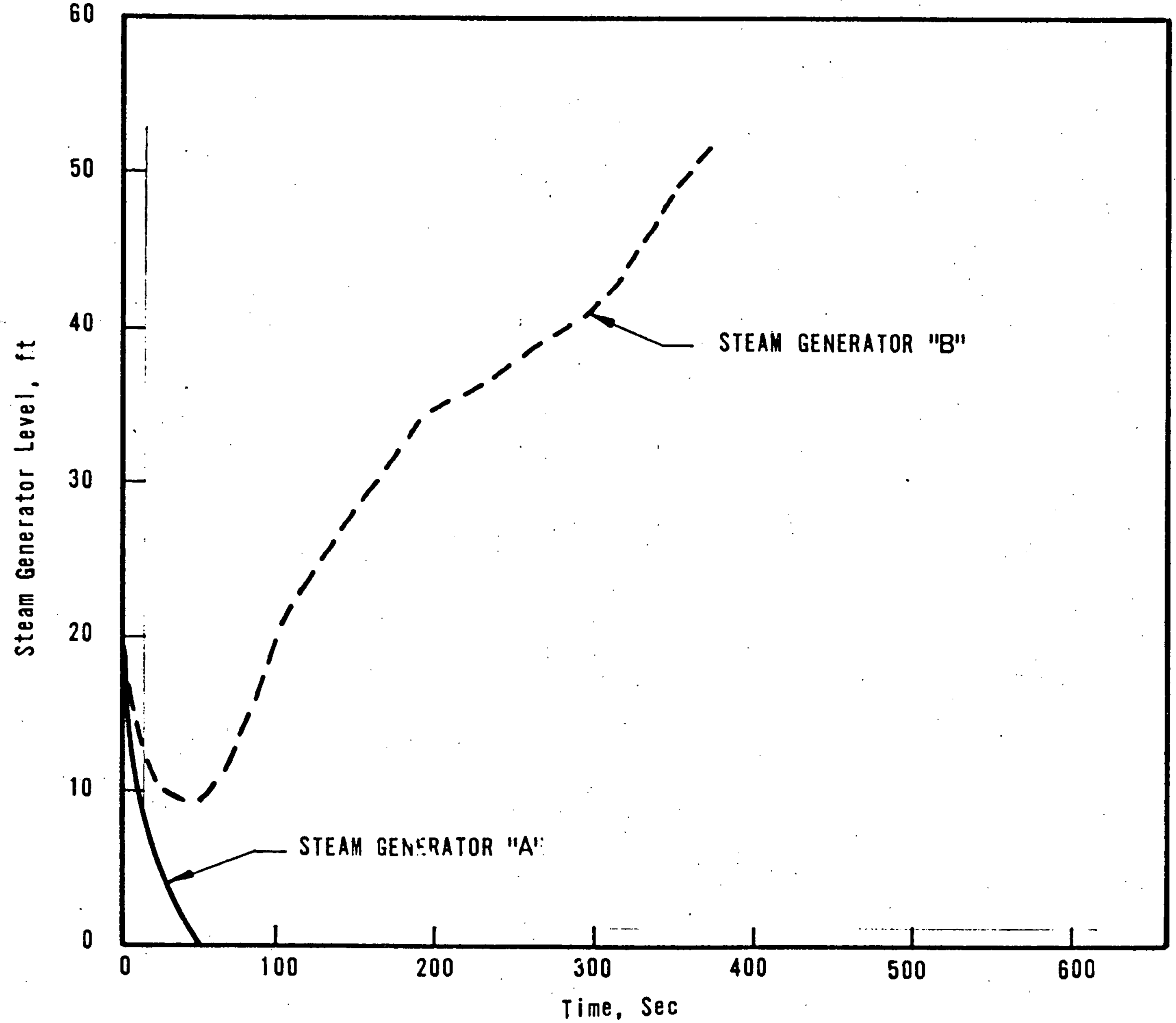


FIGURE 4-46. STEAM LINE BREAK CASE 4, 205 FA

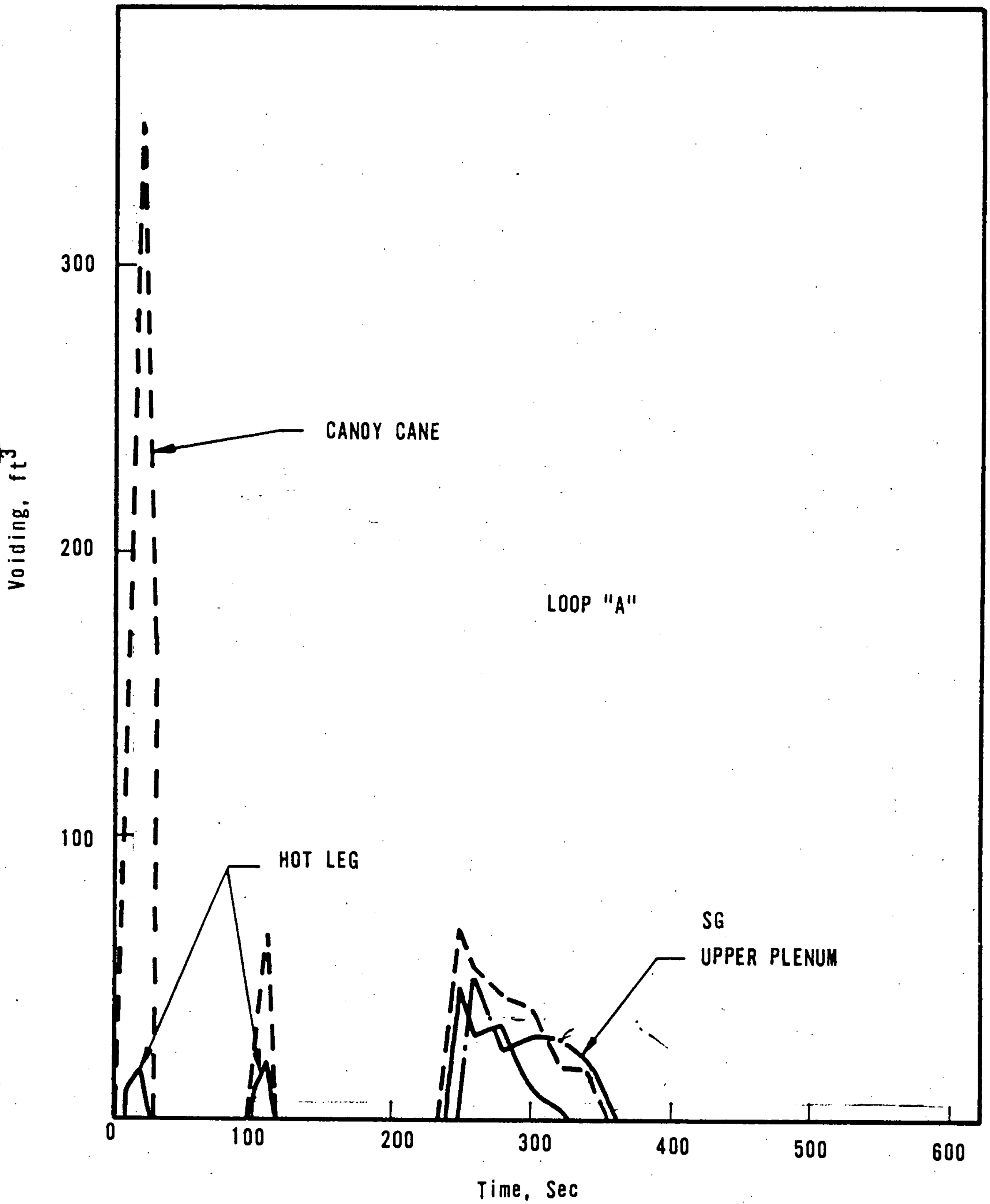


FIGURE 4-47. STEAM LINE BREAK CASE 4, 205 FA

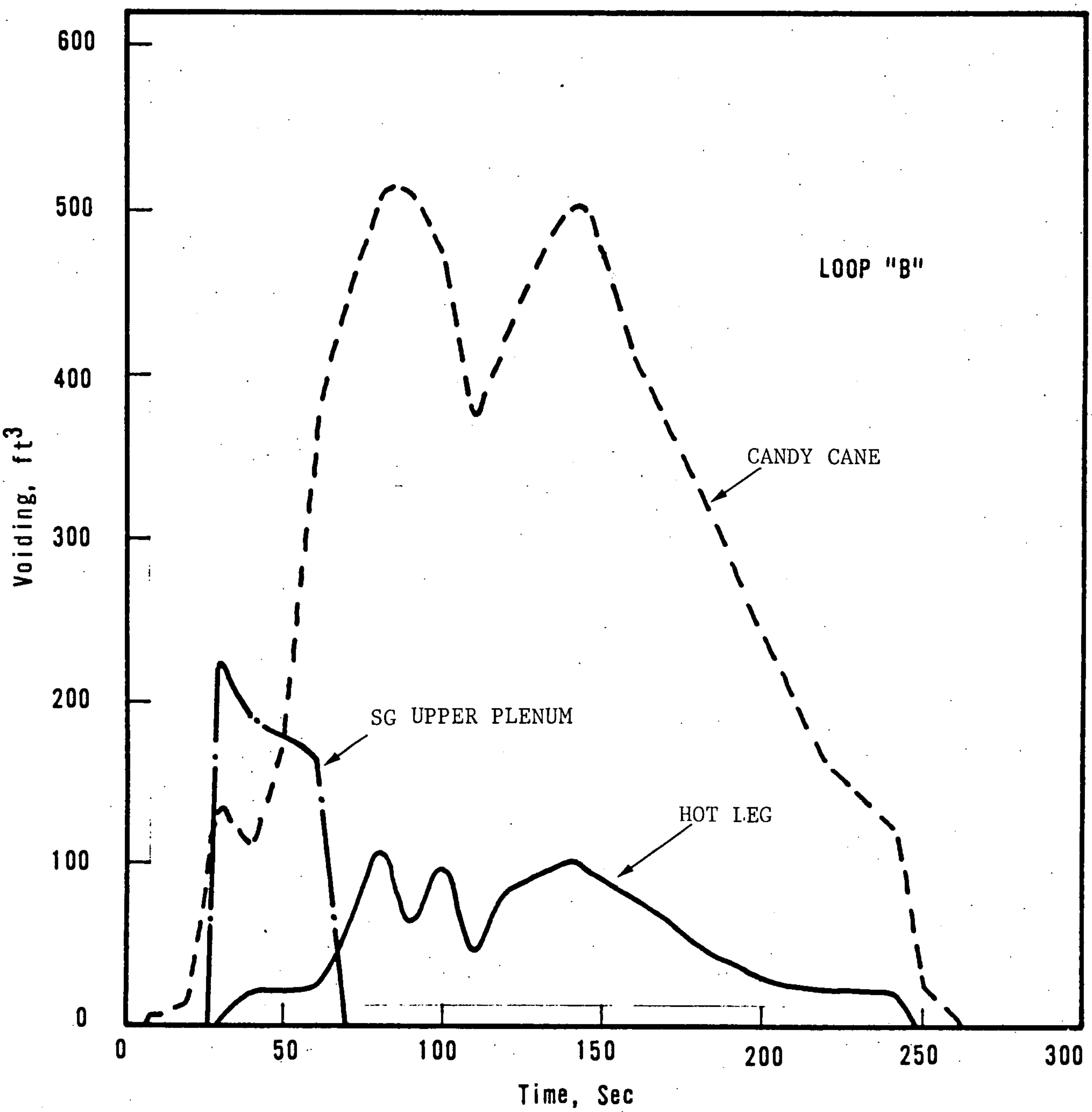


FIGURE 4-48. STEAM LINE BREAK CASE 5,205 FA

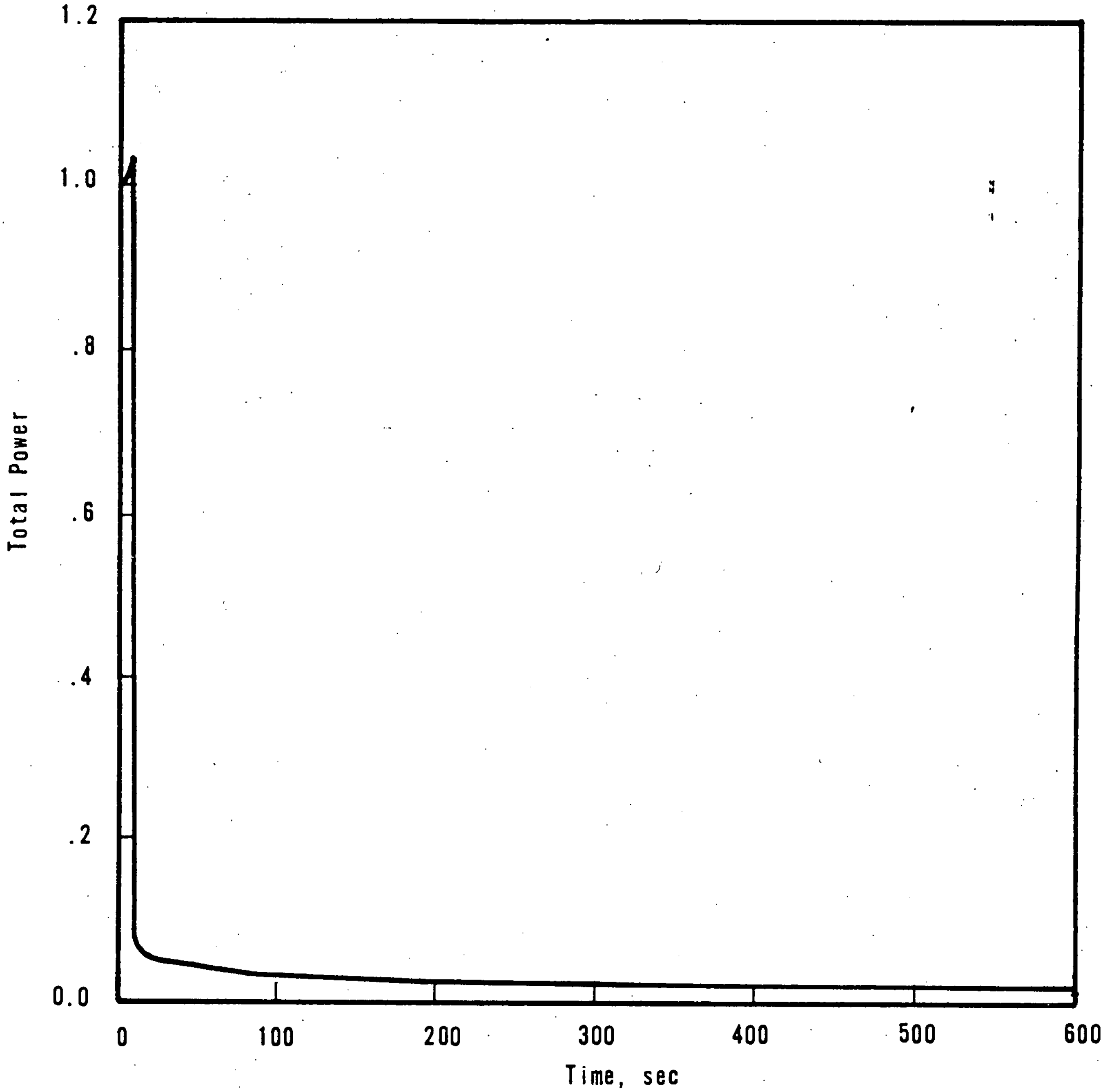


FIGURE 4-49. STEAM LINE BREAK CASE 5, 205 FA

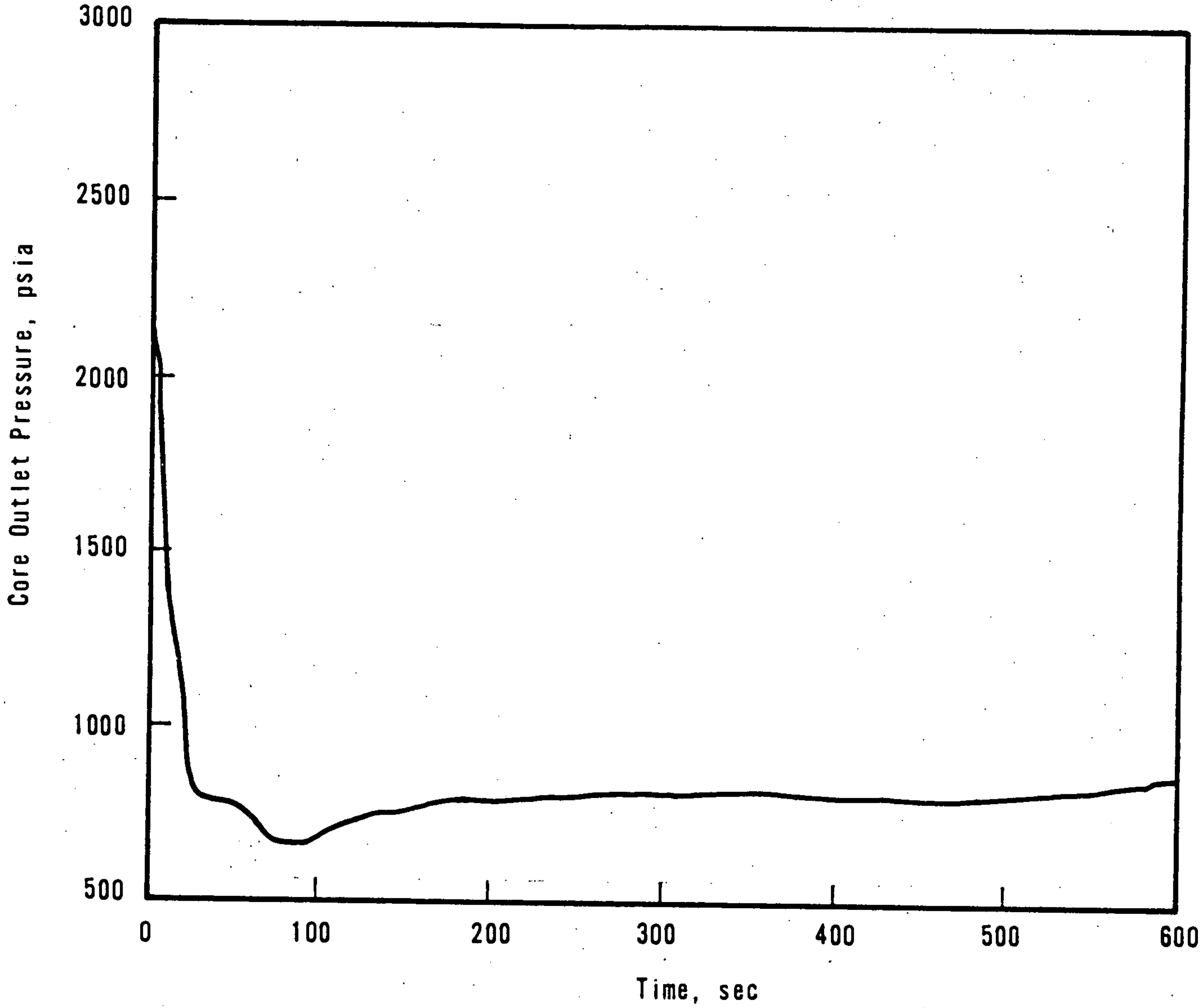


FIGURE 4-50. STEAM LINE BREAK CASE 5, 205 FA

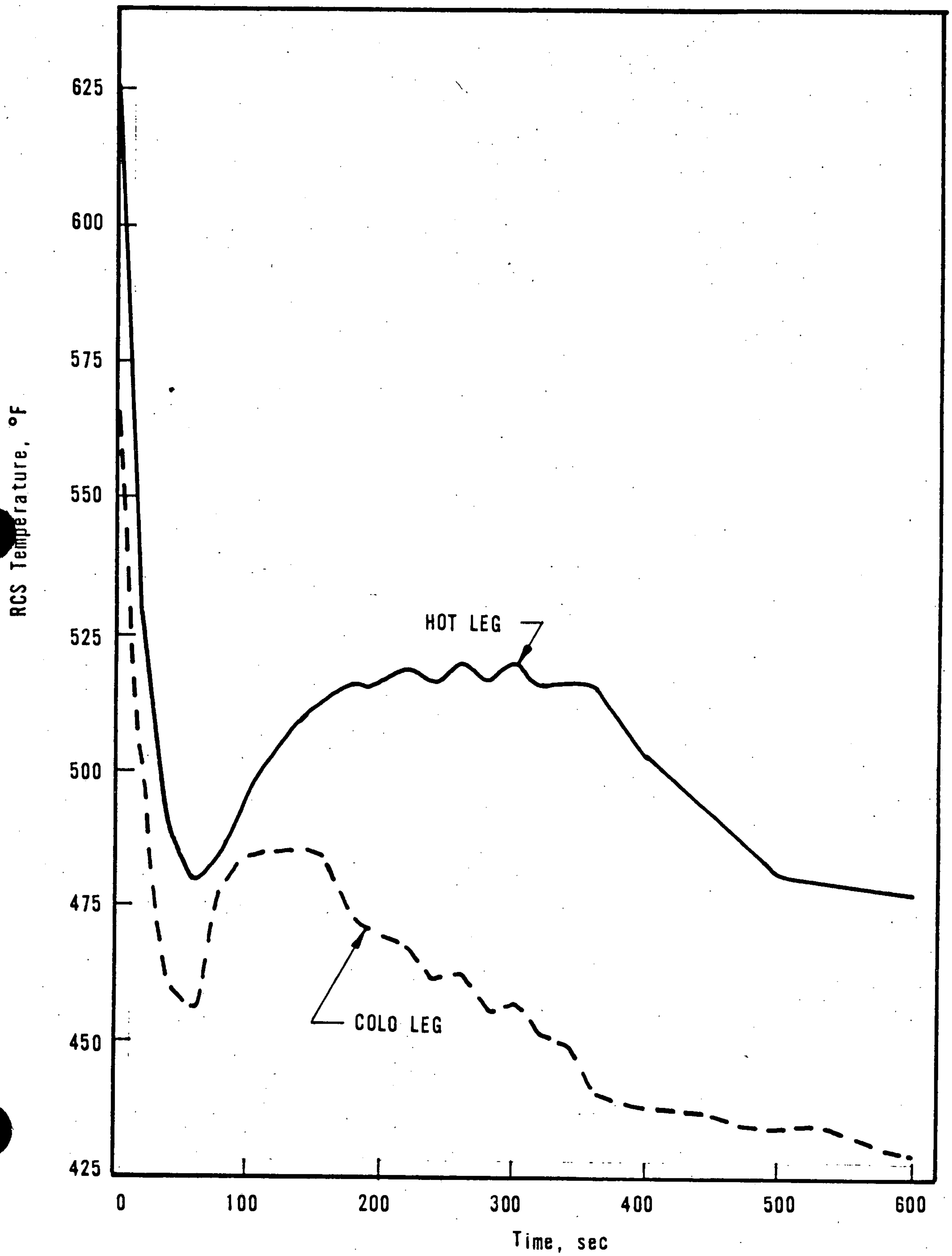


FIGURE 4-51. STEAM LINE BREAK CASE 5, 205 FA

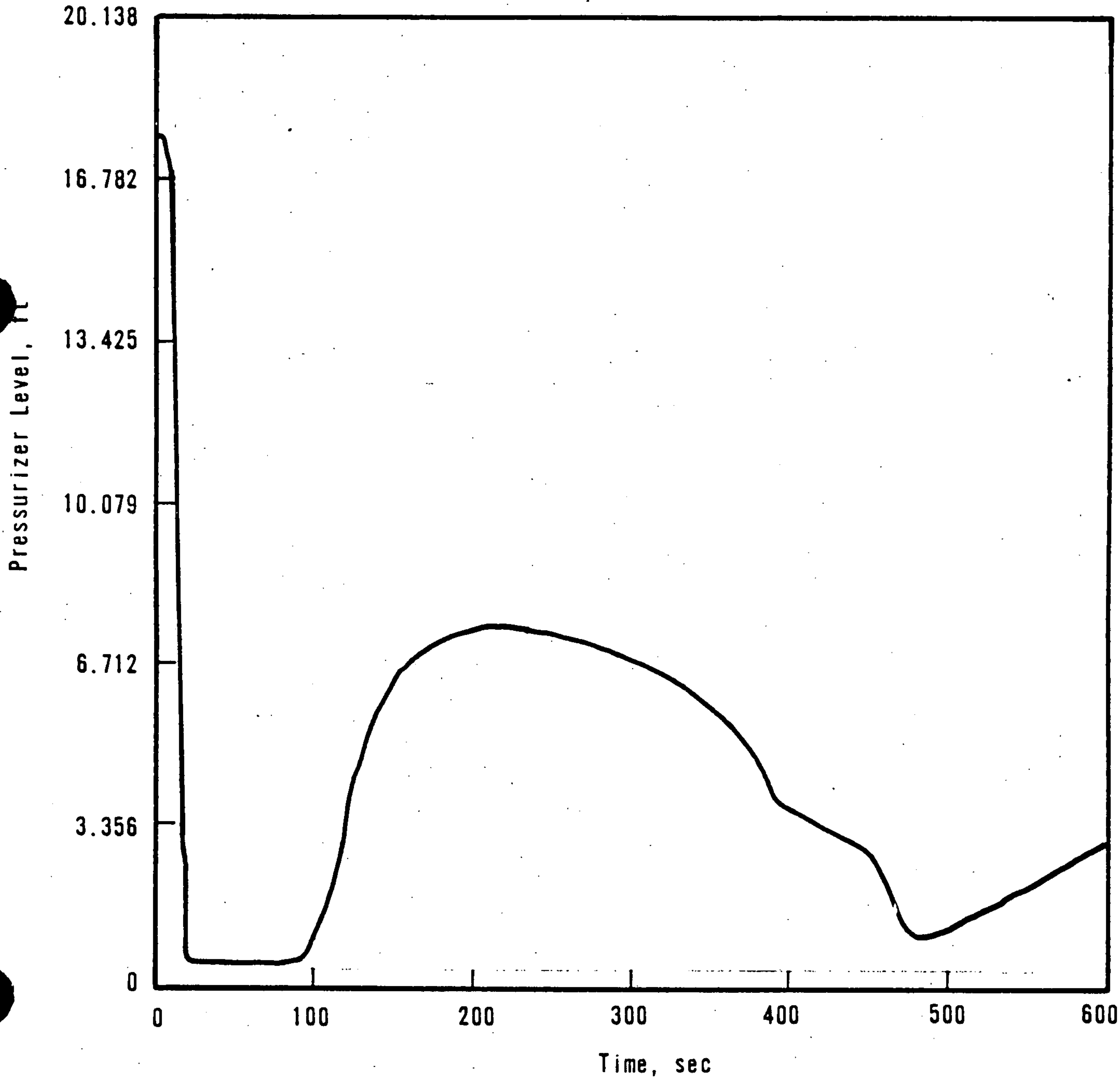


FIGURE 4-52. STEAM LINE BREAK CASE 5, 205 FA
STEAM GENERATOR A PRESSURE

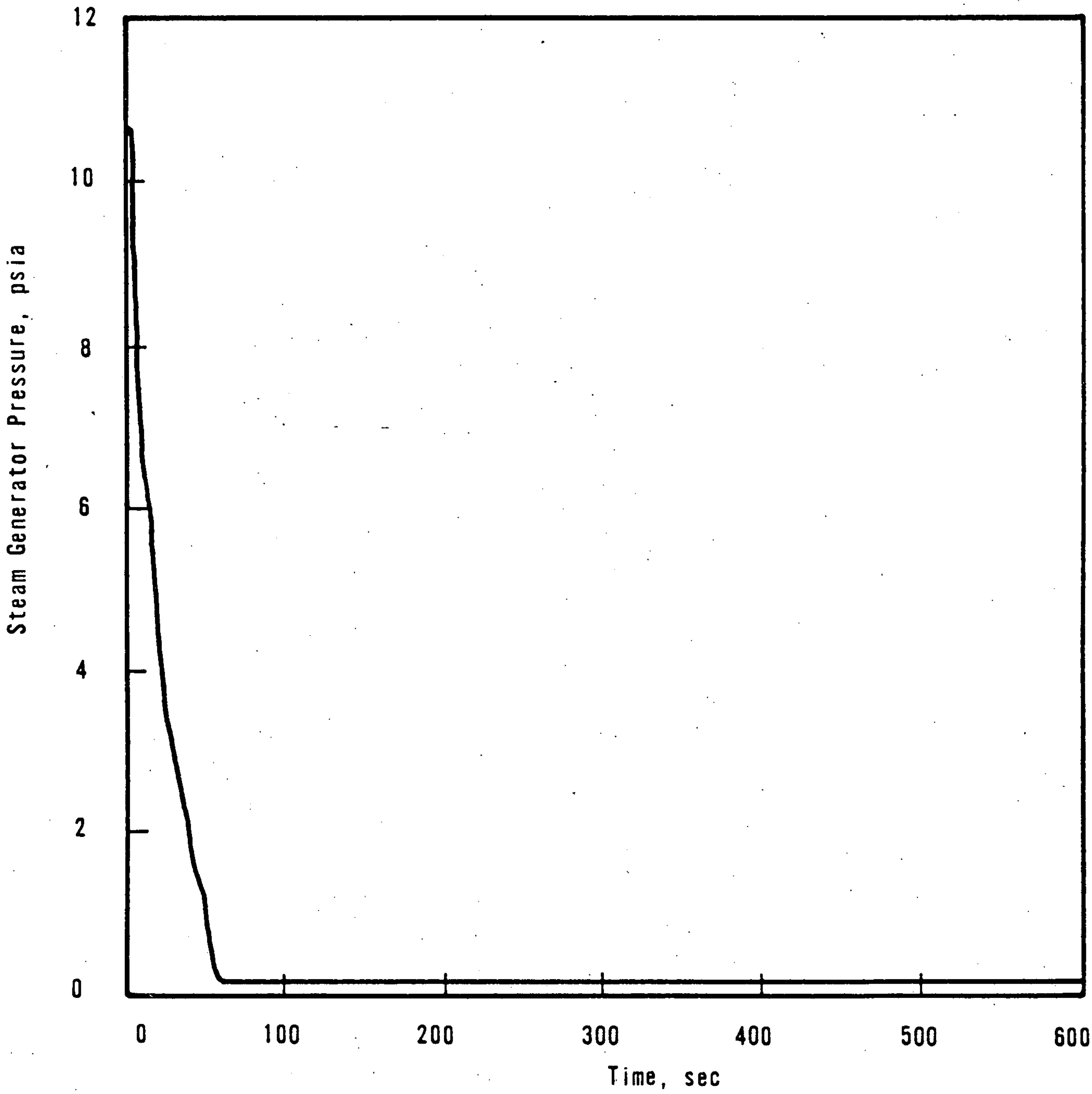


FIGURE 4-53. STEAM LINE BREAK CASE 5, 205 FA
STEAM GENERATOR B PRESSURE

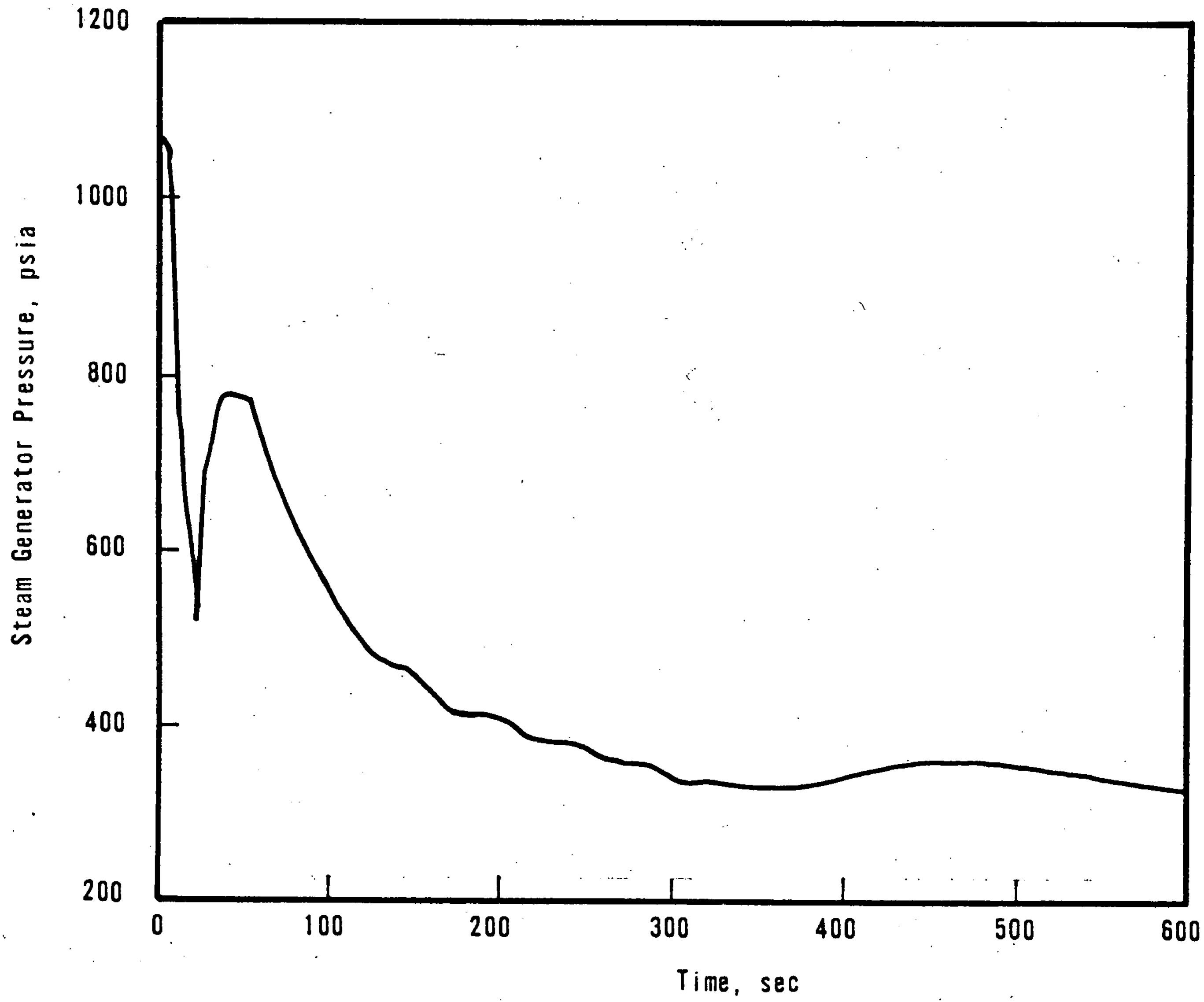


FIGURE 4-54. STEAM LINE BREAK CASE 5, 205 FA

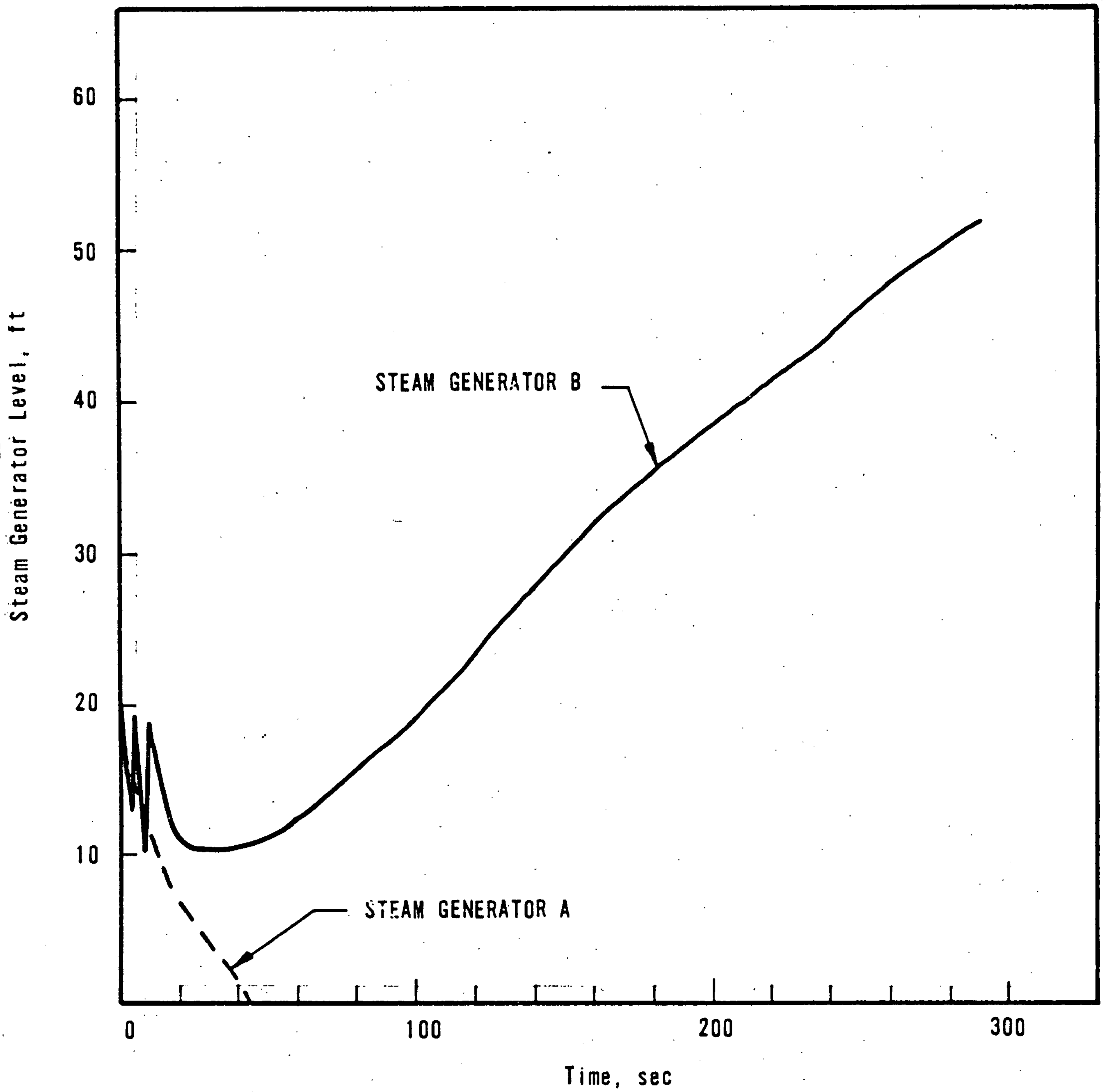


FIGURE 4-55. STEAM LINE BREAK CASE 5, 205 FA

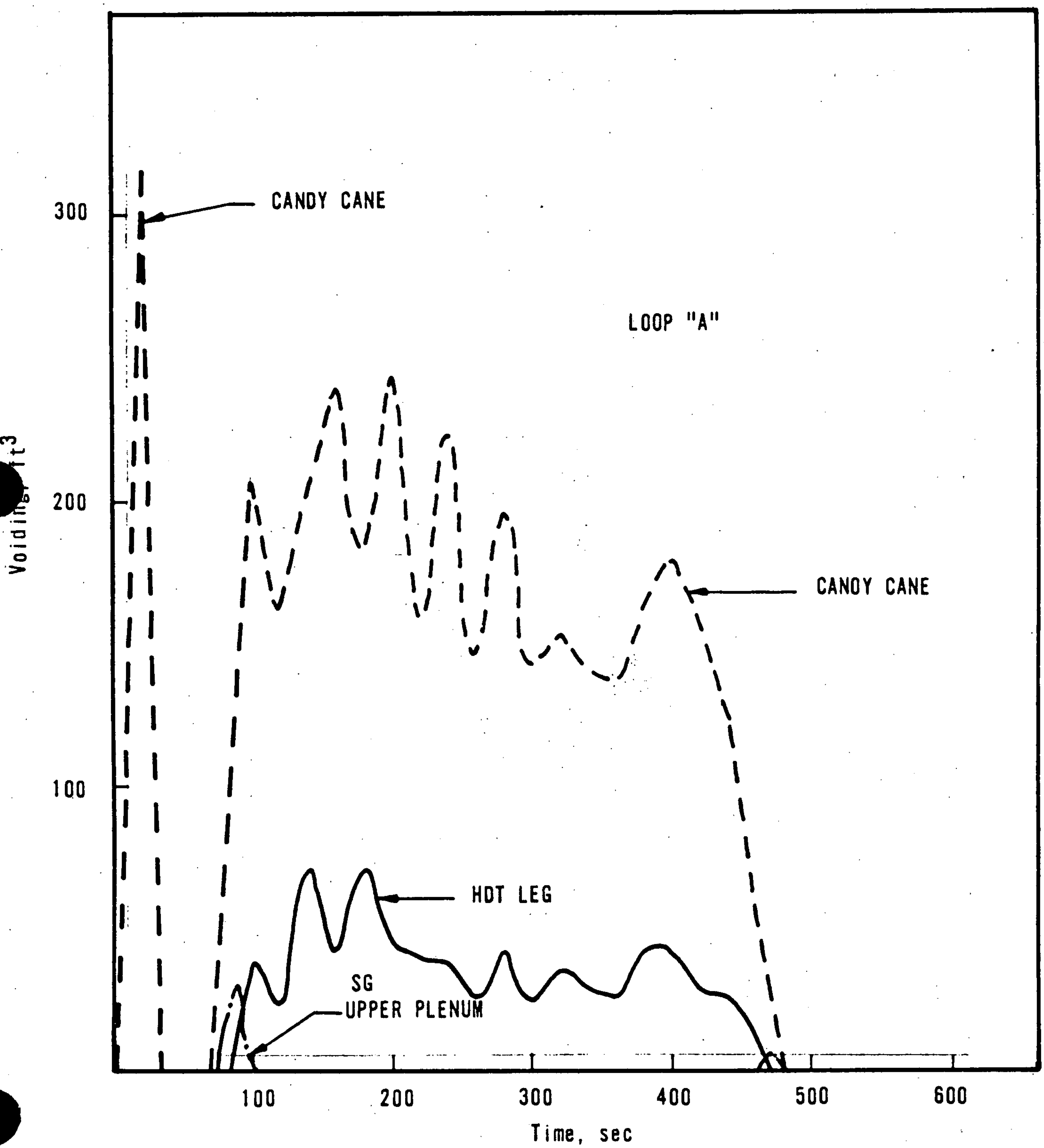


FIGURE 4-56. STEAM LINE BREAK CASE 5, 205 FA

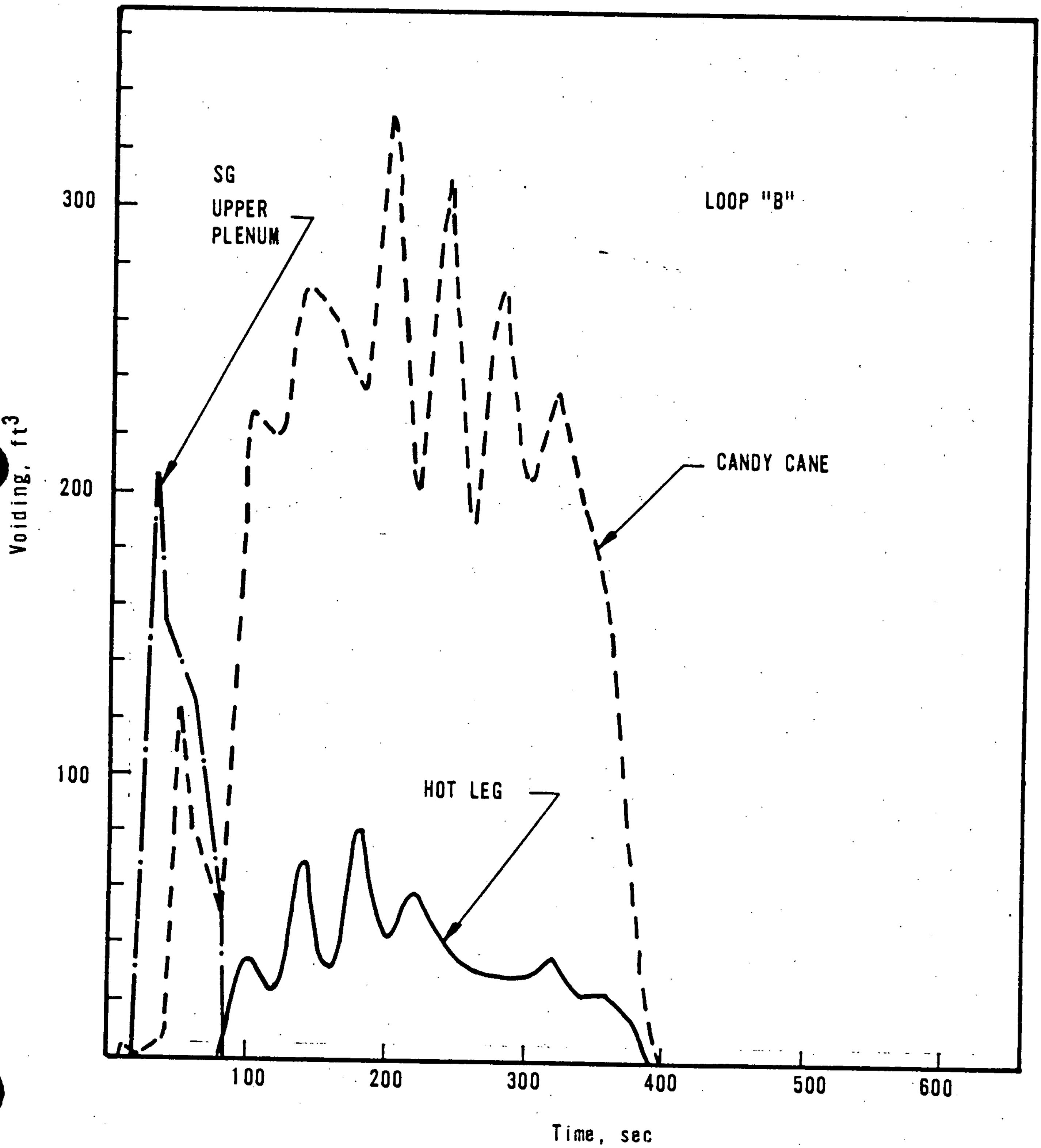


FIGURE 4-57. STEAM LINE BREAK CASE 6, 205 FA

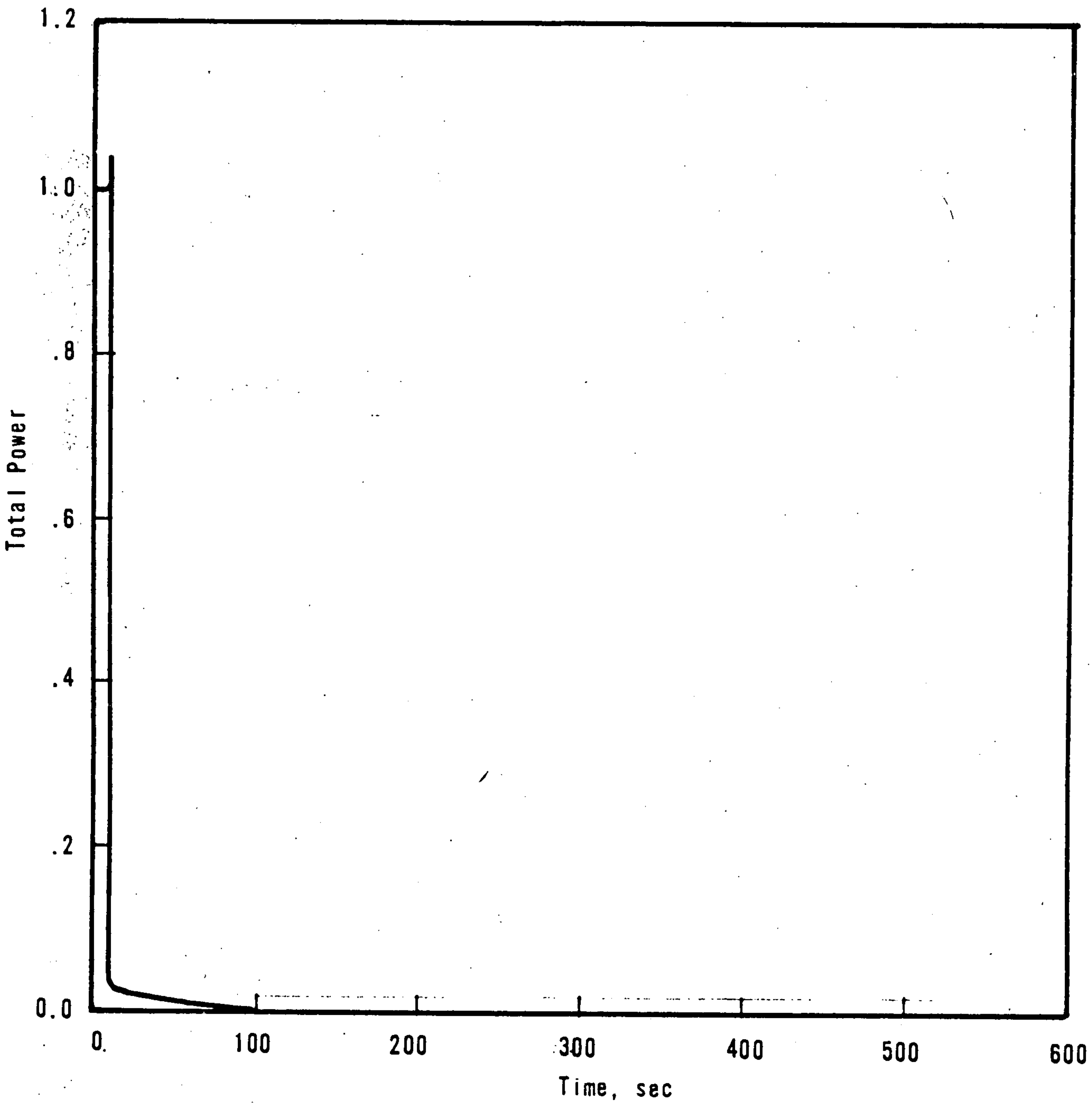


FIGURE 4-58. STEAM LINE BREAK CASE 6, 205 FA

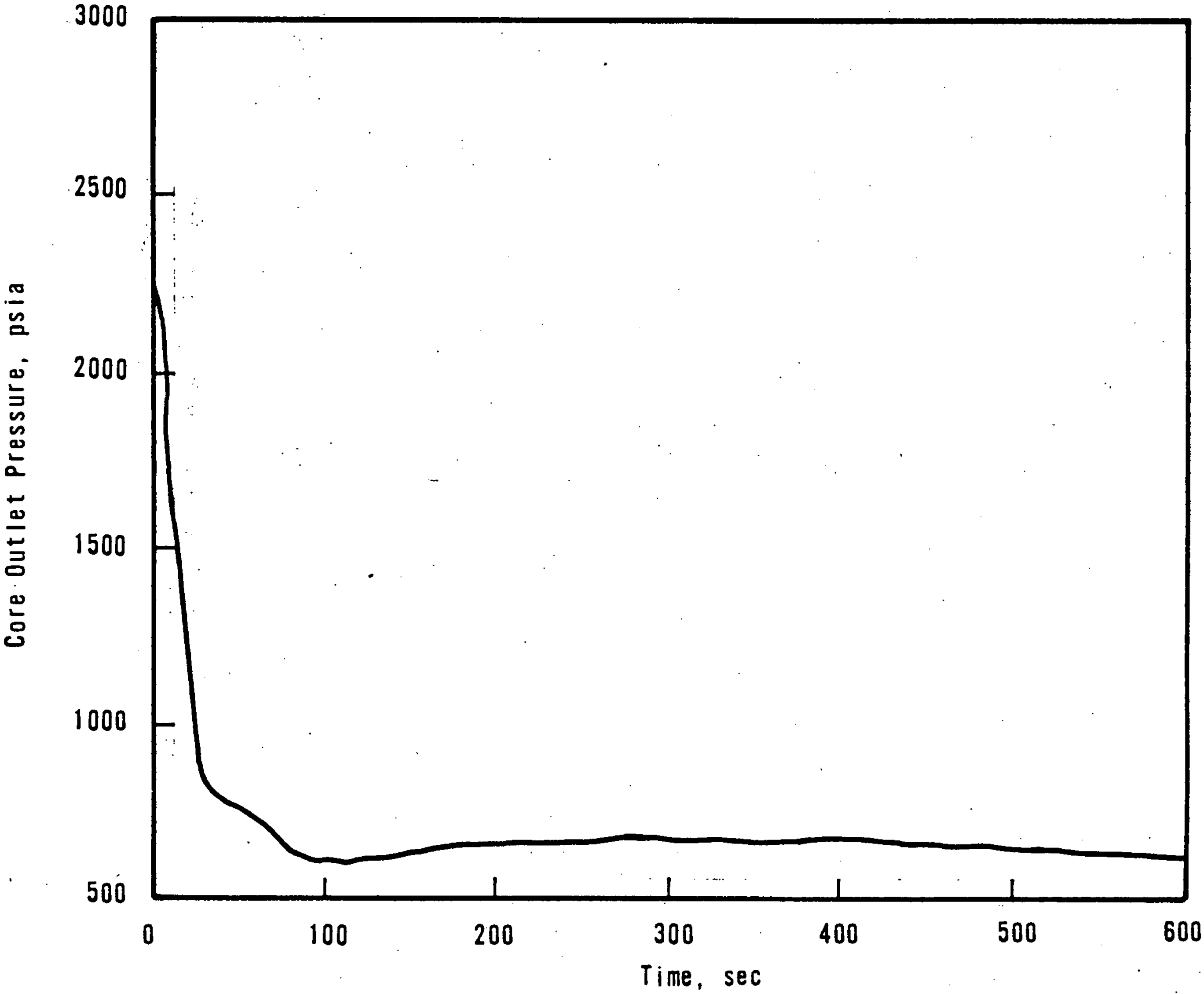


FIGURE 4-59. STEAM LINE BREAK CASE 6, 205 FA

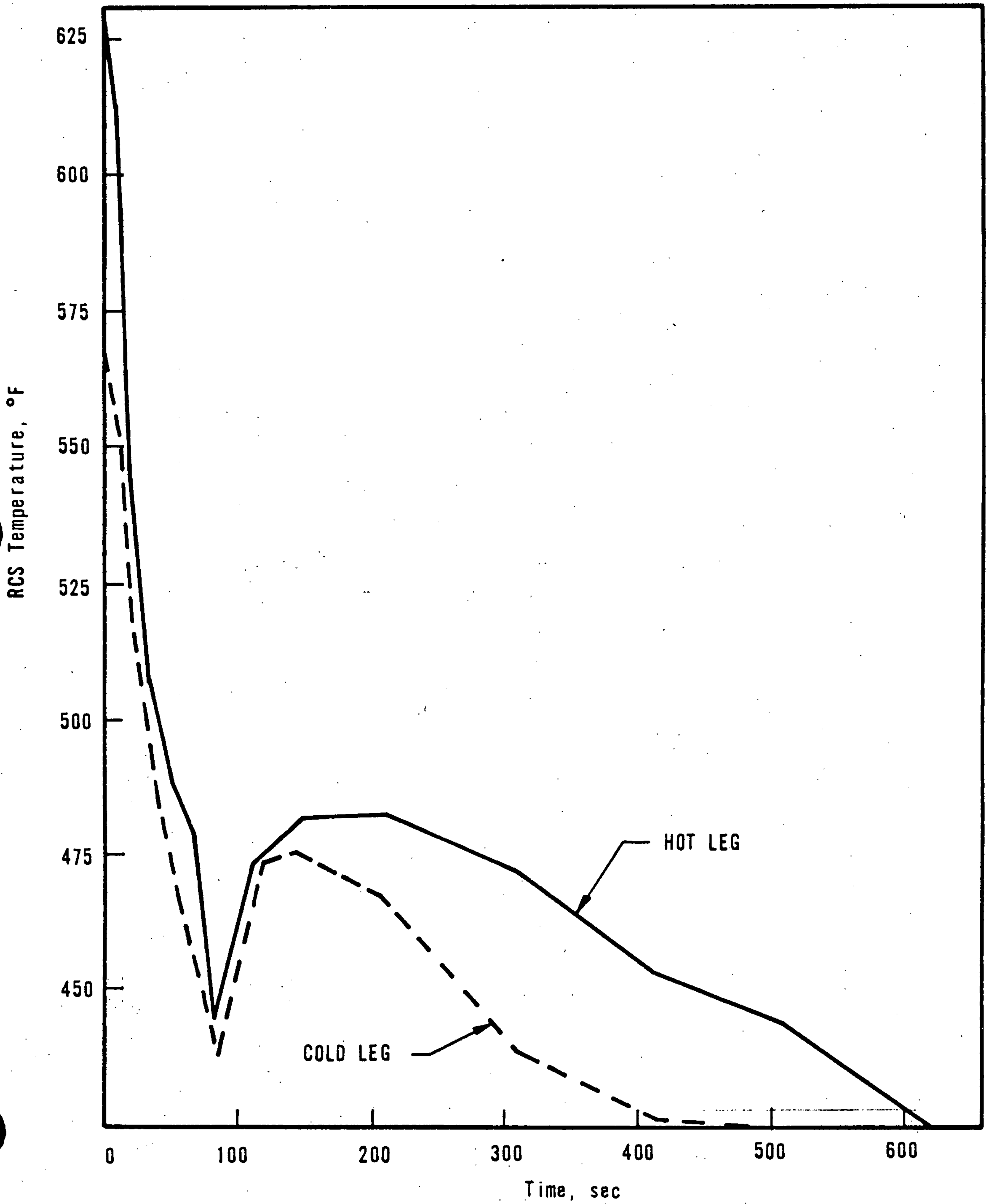


FIGURE 4-60. STEAM LINE BREAK CASE 6, 205 FA

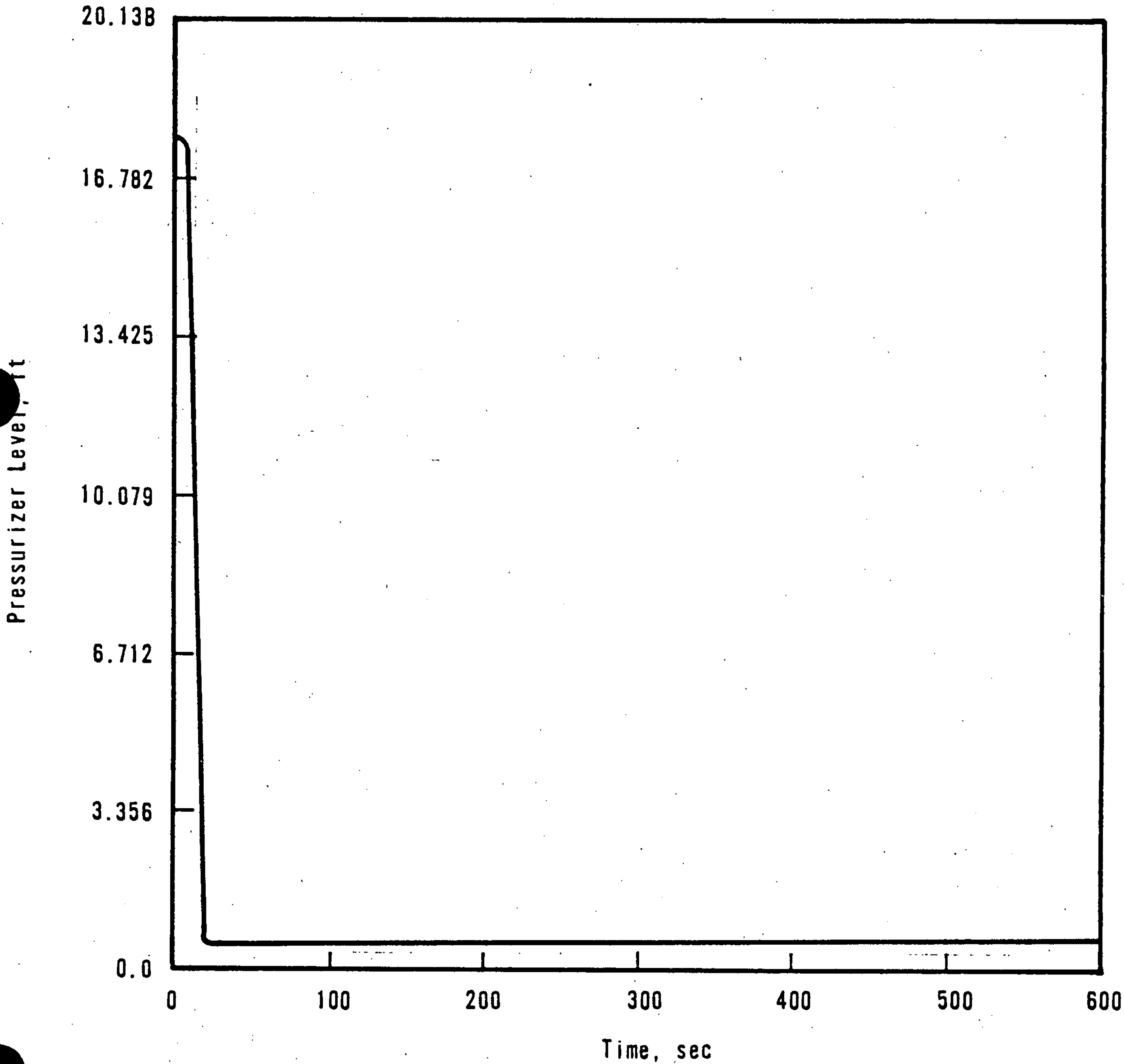


FIGURE 4-61. STEAM LINE BREAK CASE 6, 205 FA
STEAM GENERATOR A PRESSURE

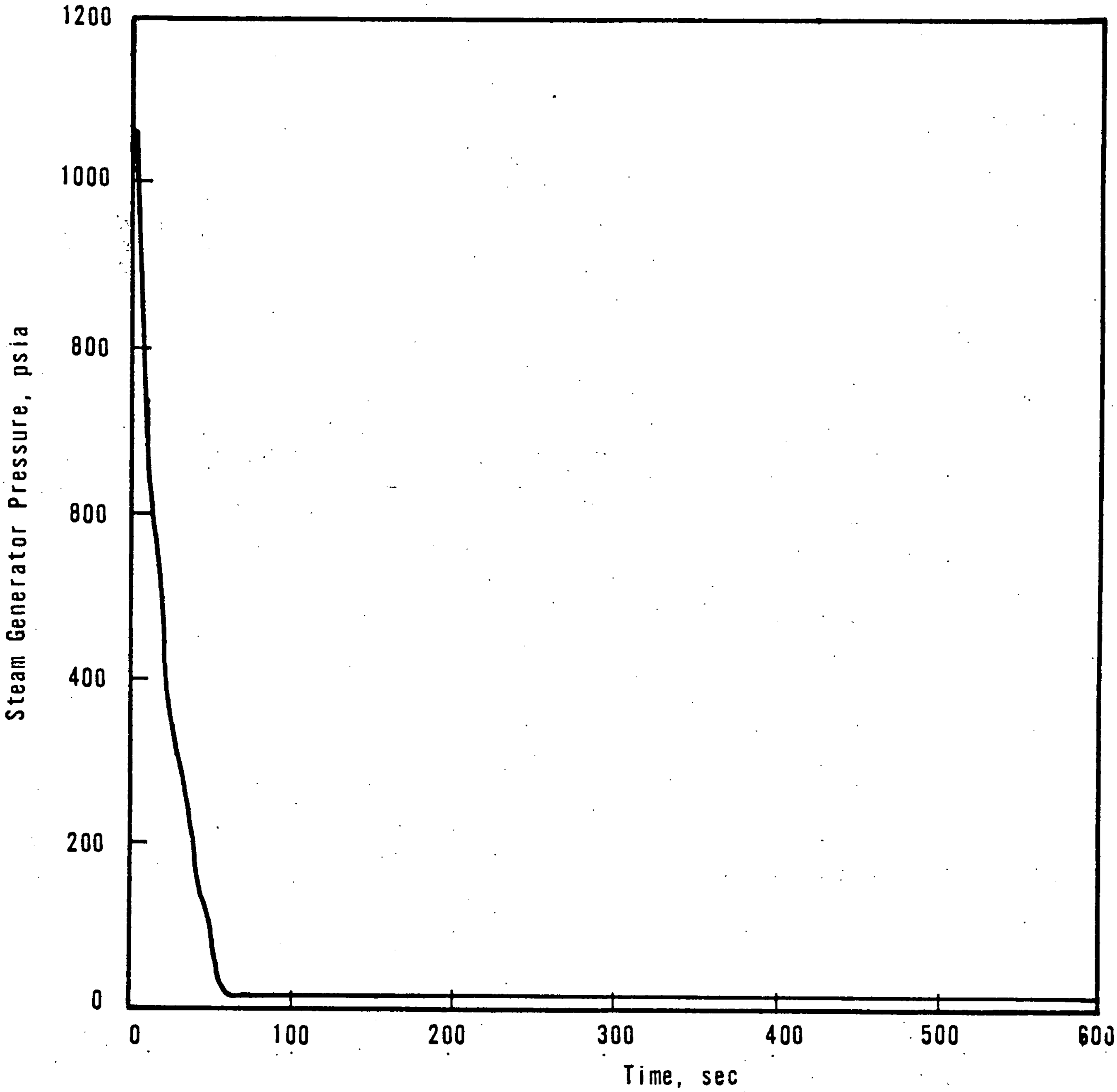


FIGURE 4-62. STEAM LINE BREAK CASE 6, 205 FA

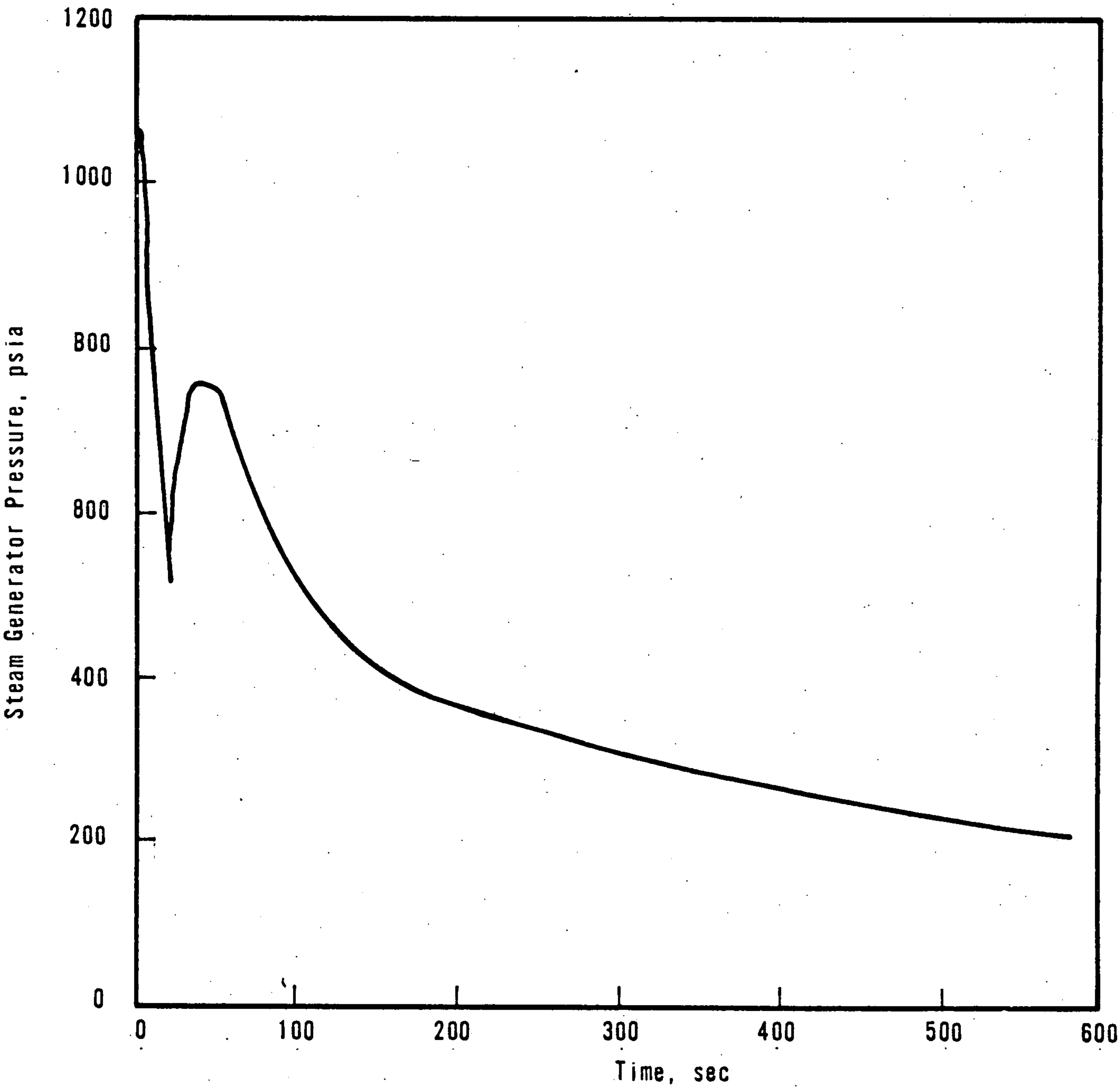


FIGURE 4-63. STEAM LINE BREAK CASE 6, 205 FA

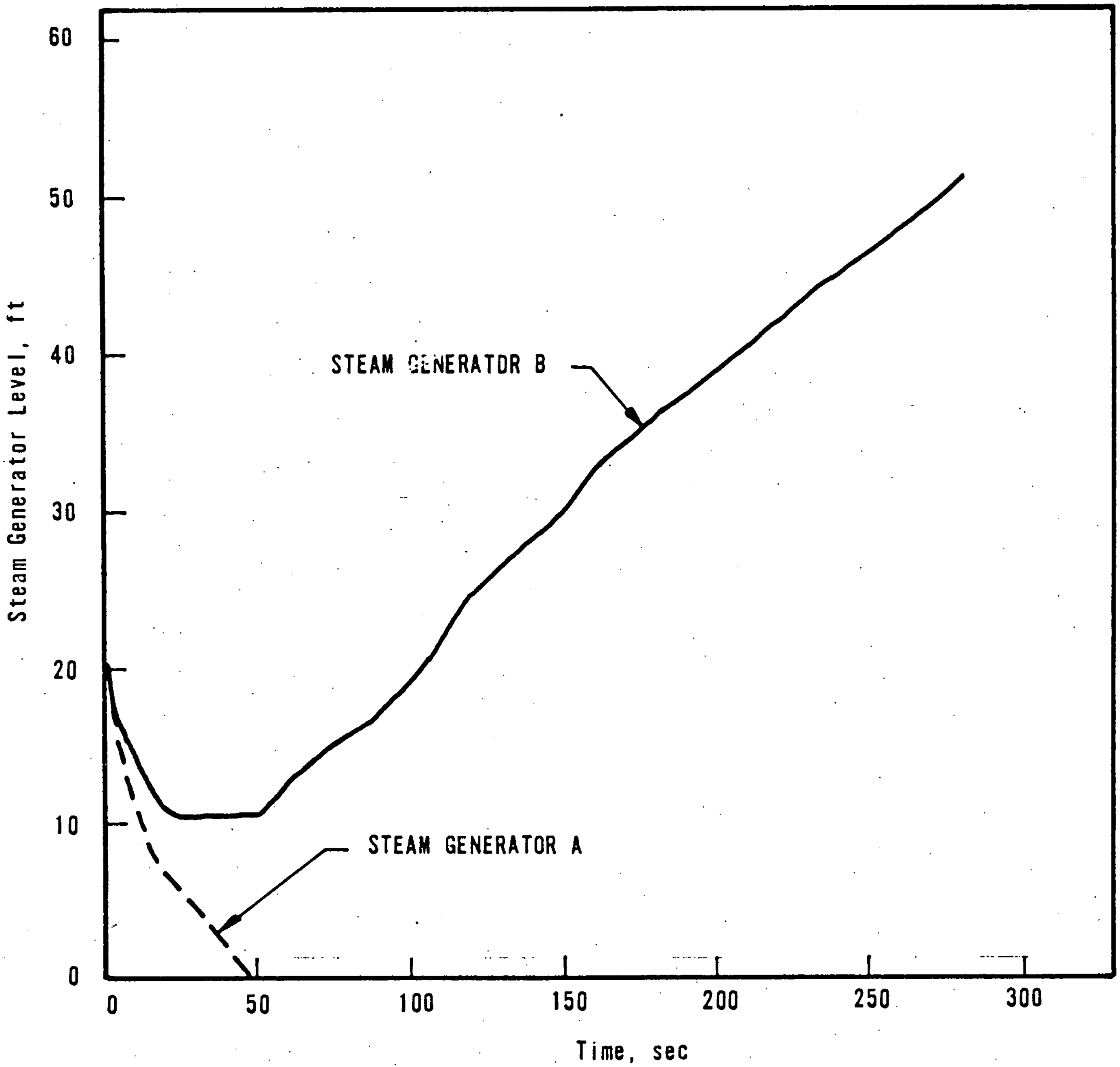


FIGURE 4-64. STEAM LINE BREAK CASE 8, 205 FA

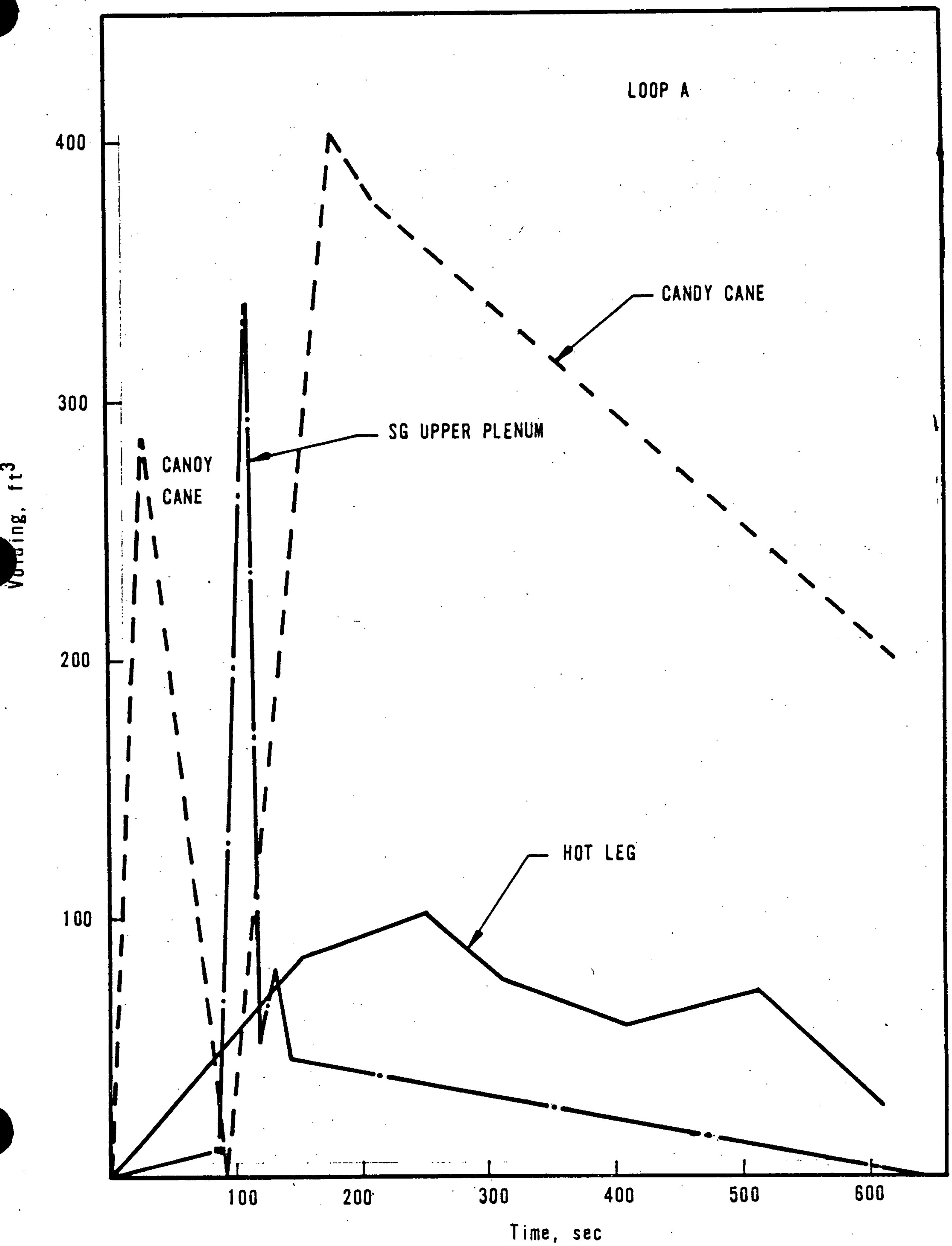


FIGURE 4-65. STEAM LINE BREAK CASE 6, 205 FA

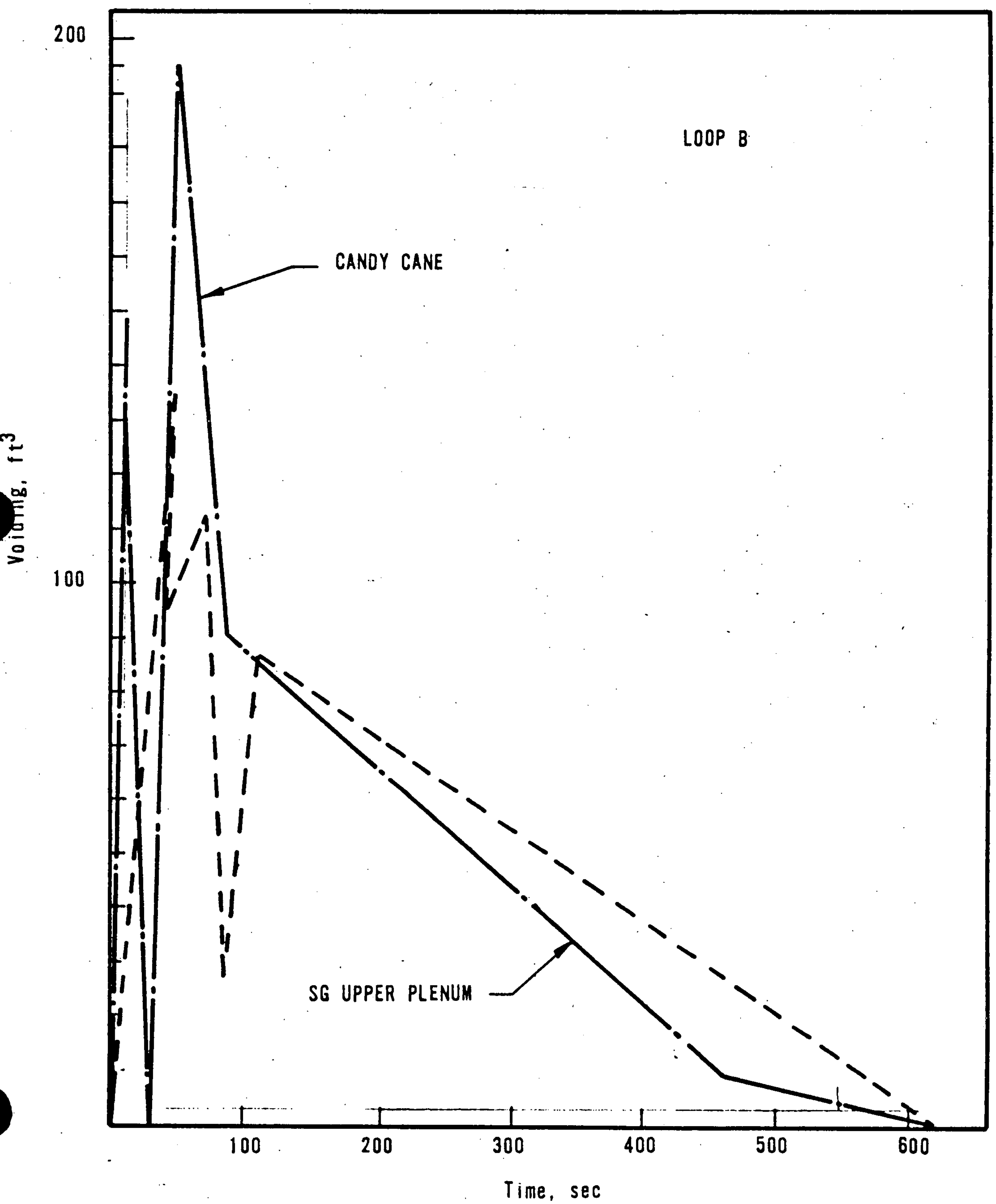


FIGURE 4-66. STEAM LINE BREAK CASE 7, 205 FA

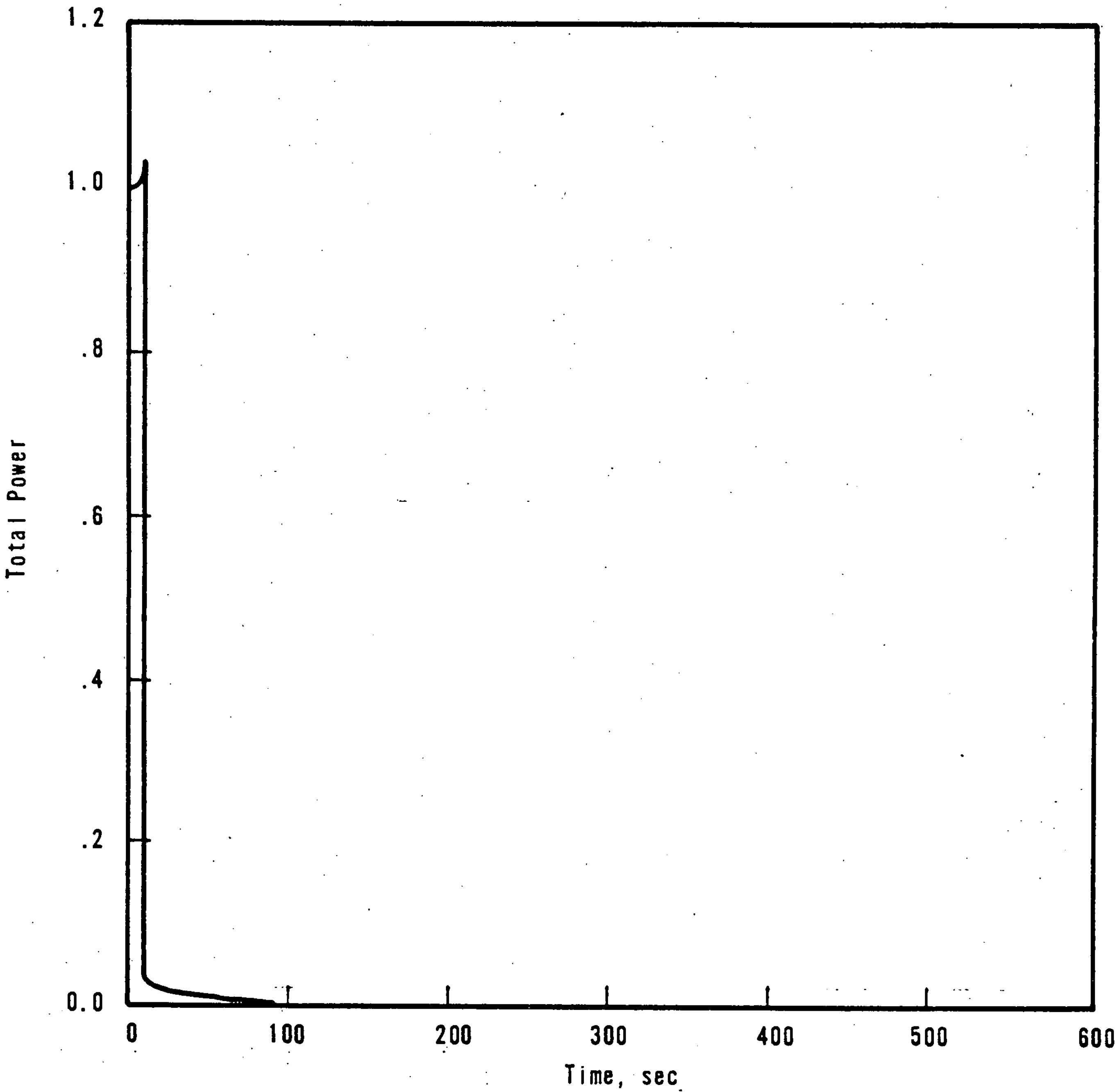


FIGURE 4-67. STEAM LINE BREAK CASE 7, 205 FA

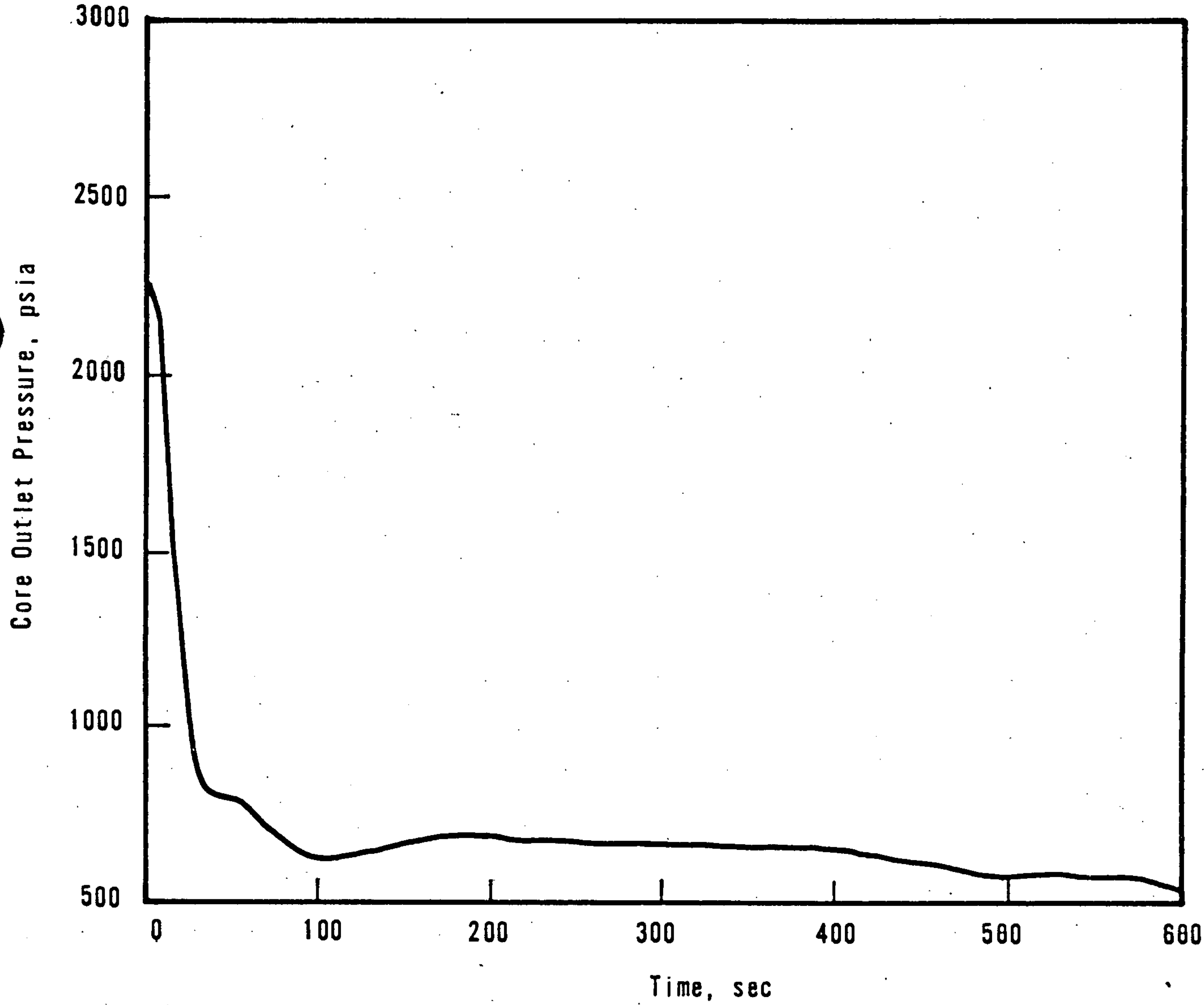


FIGURE 4-6B. STEAM LINE BREAK CASE 7, 205 FA

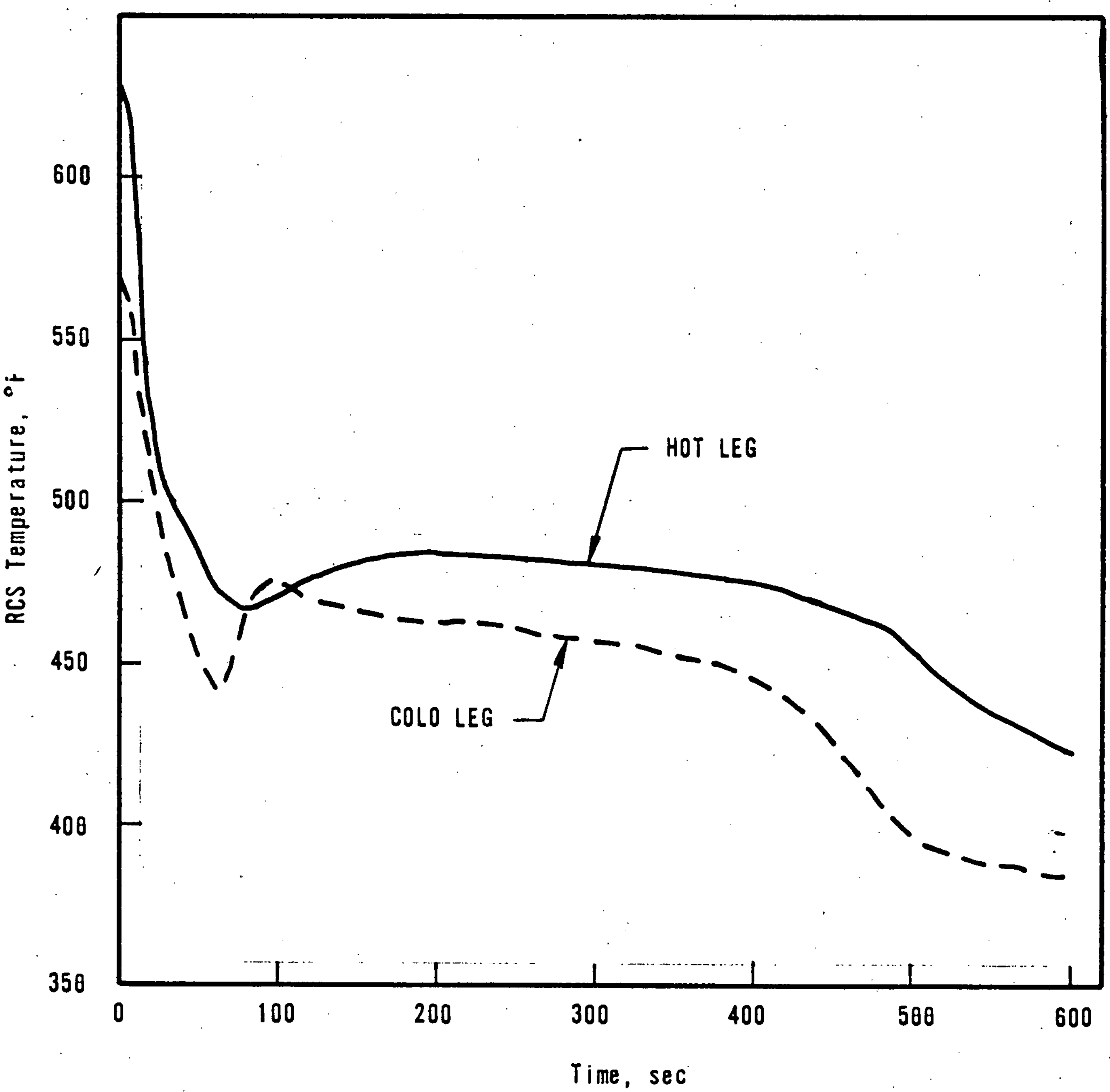


FIGURE 4-69. STEAM LINE BREAK CASE 7, 205 FA

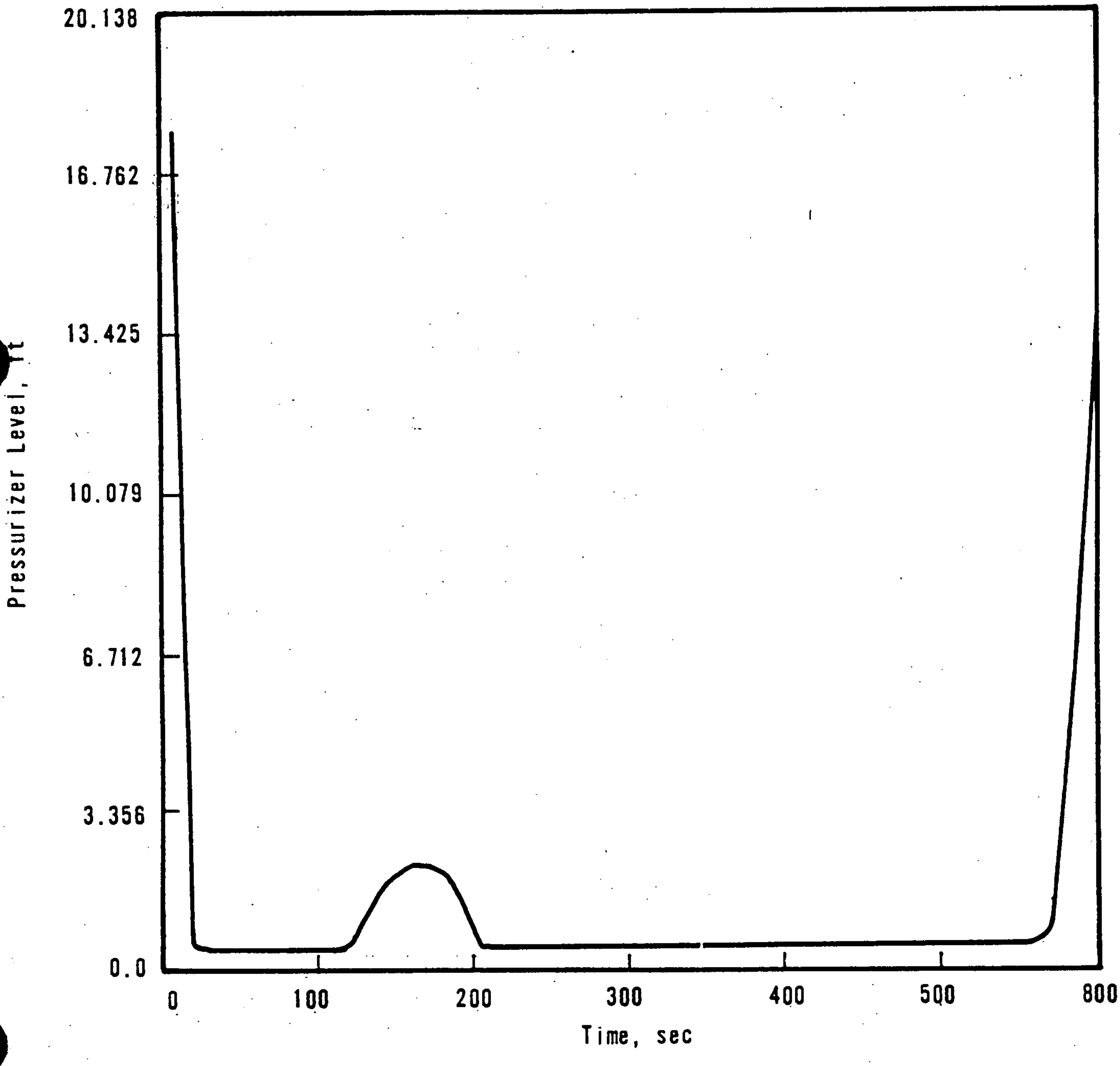


FIGURE 4-70. STEAM LINE BREAK CASE 7, 205 FA
STEAM GENERATOR A PRESSURE

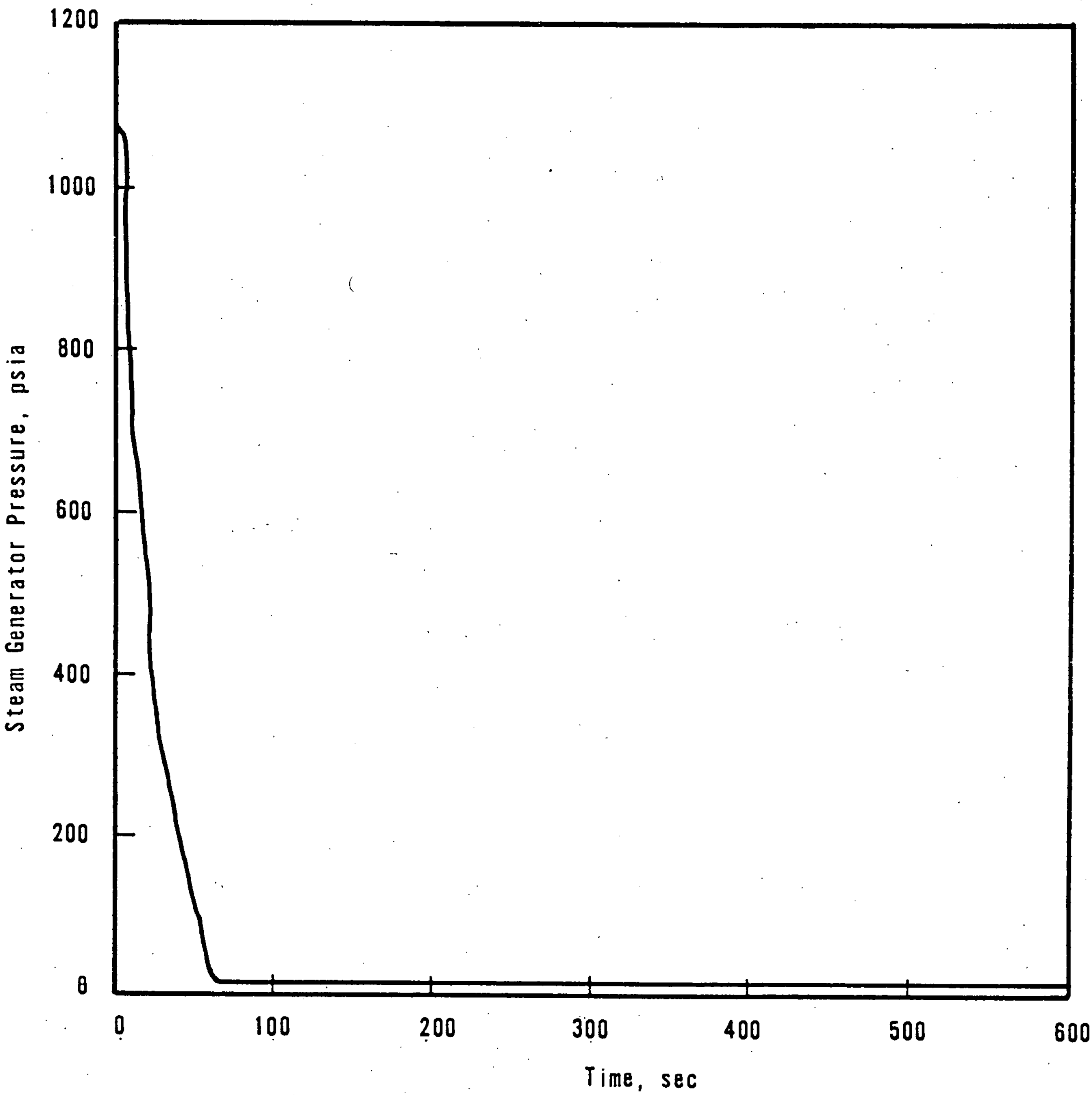


FIGURE 4-71. STEAM LINE BREAK CASE 7, 205 FA
STEAM GENERATOR B PRESSURE

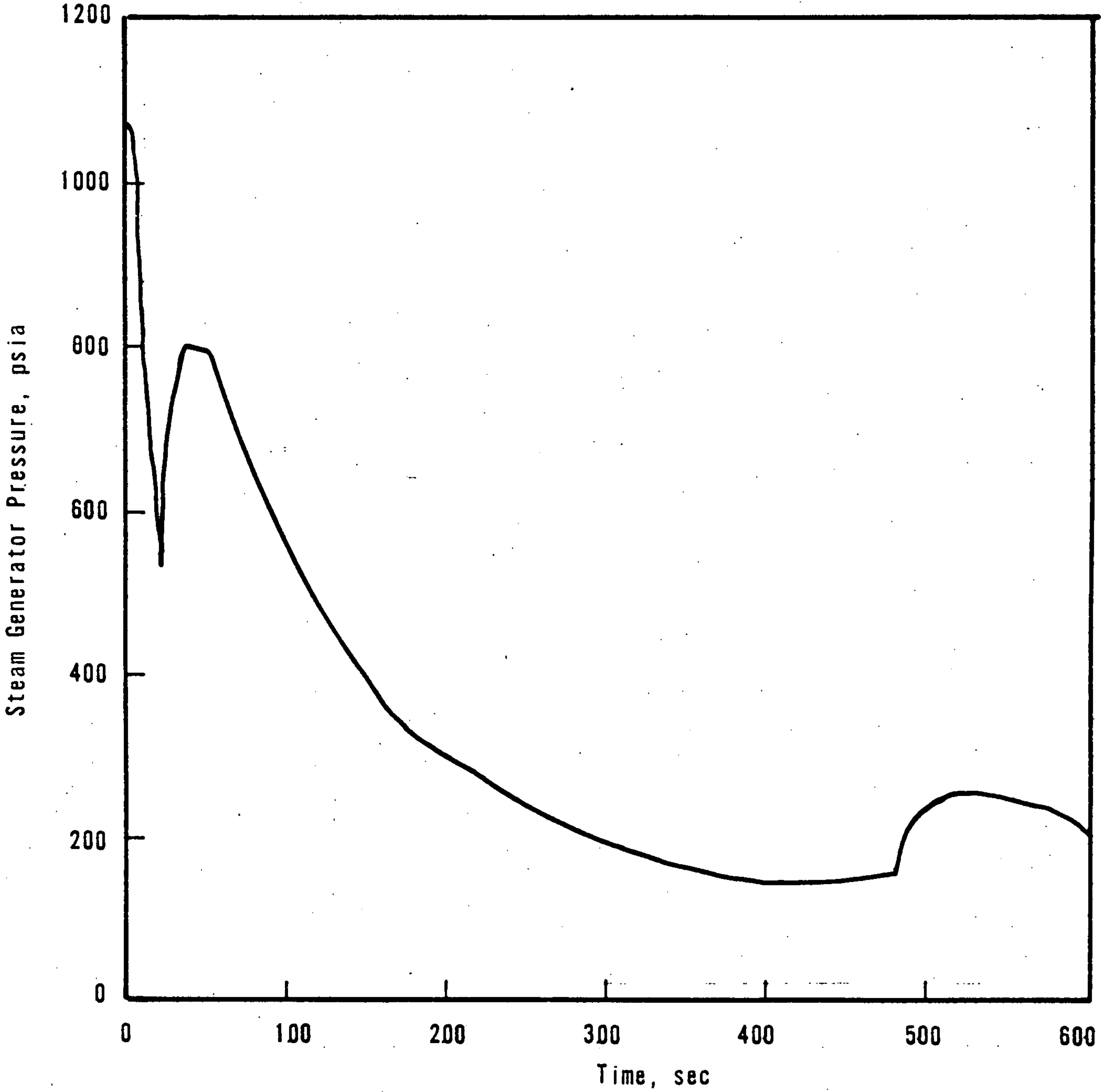


FIGURE 4-72. STEAM LINE BREAK CASE 7, 205 FA

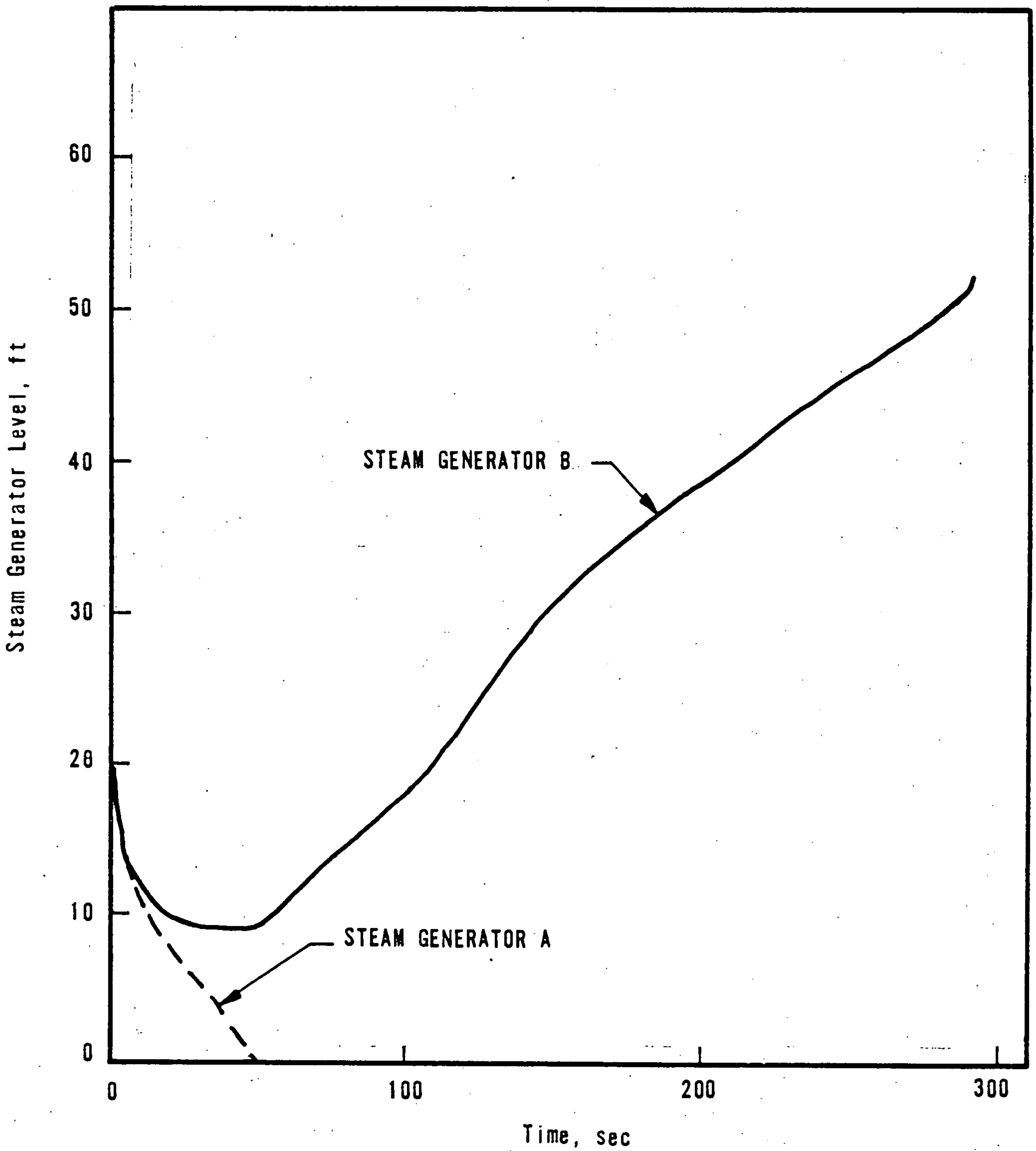


FIGURE 4-73. STEAM LINE BREAK, CASE 7, 205 FA - STEAM GENERATOR A

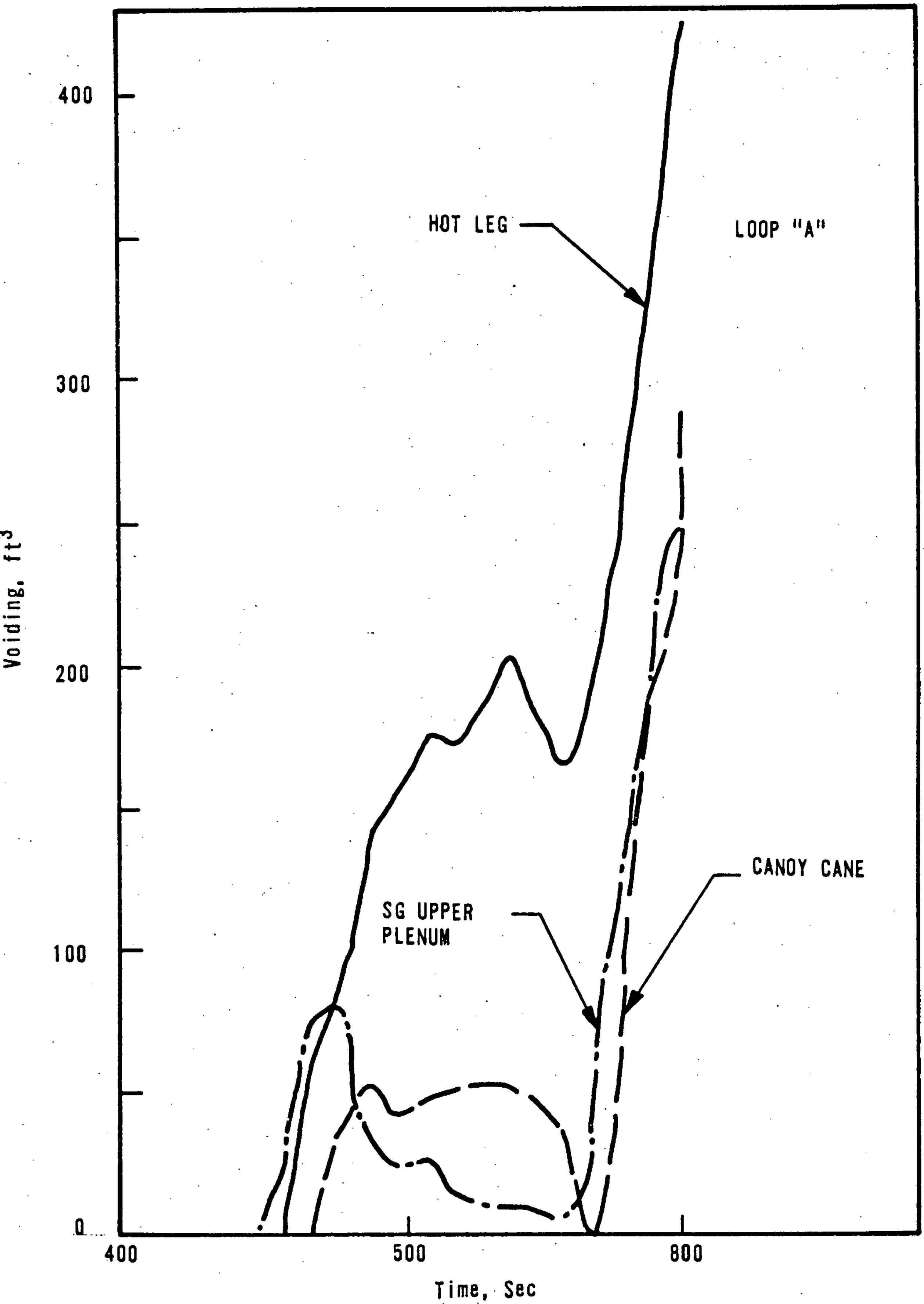


FIGURE 4-74. STEAM LINE BREAK CASE 7, 205 FA - STEAM GENERATOR B

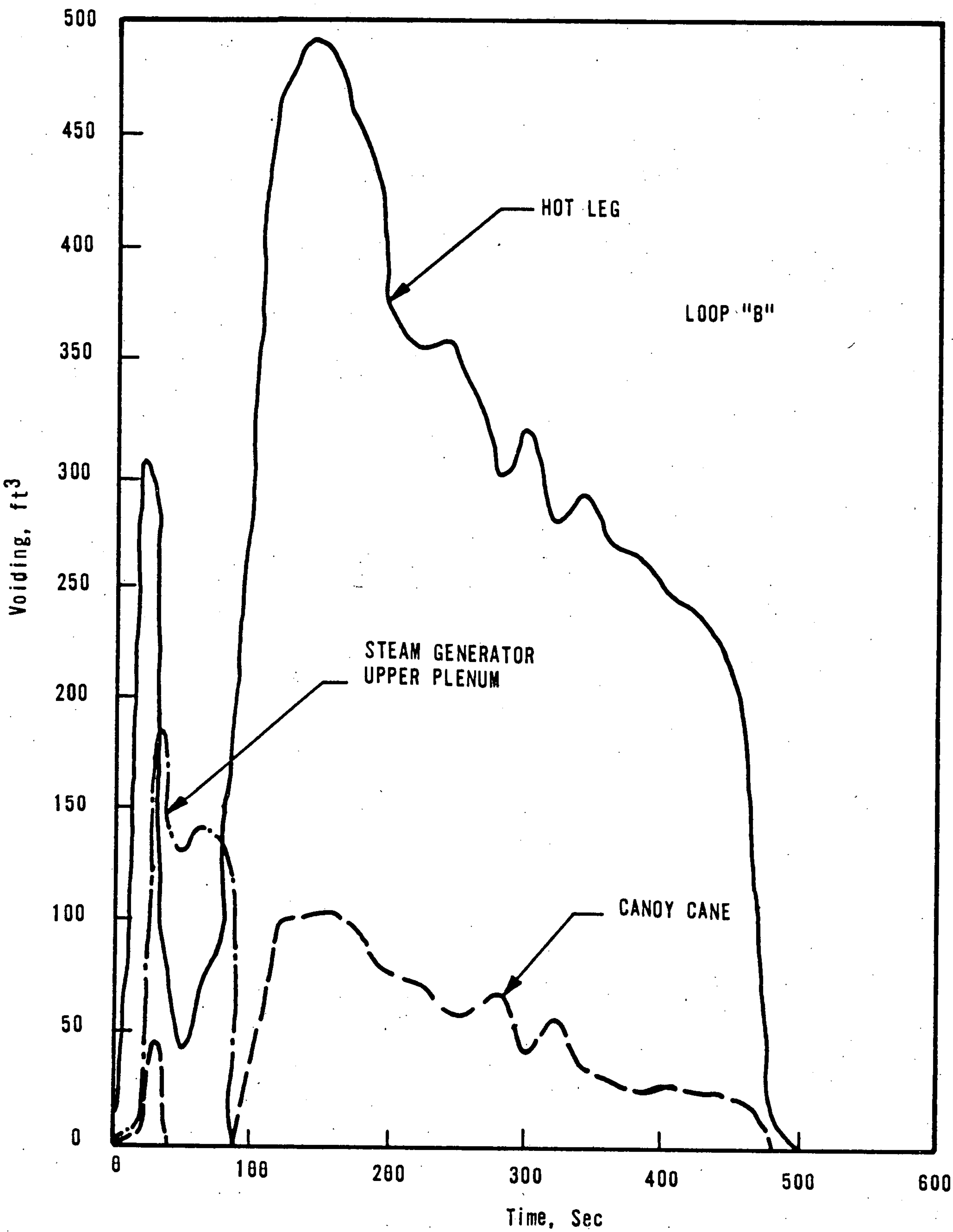


FIGURE 4-75. STEAM LINE BREAK CASE 8, 205 FA

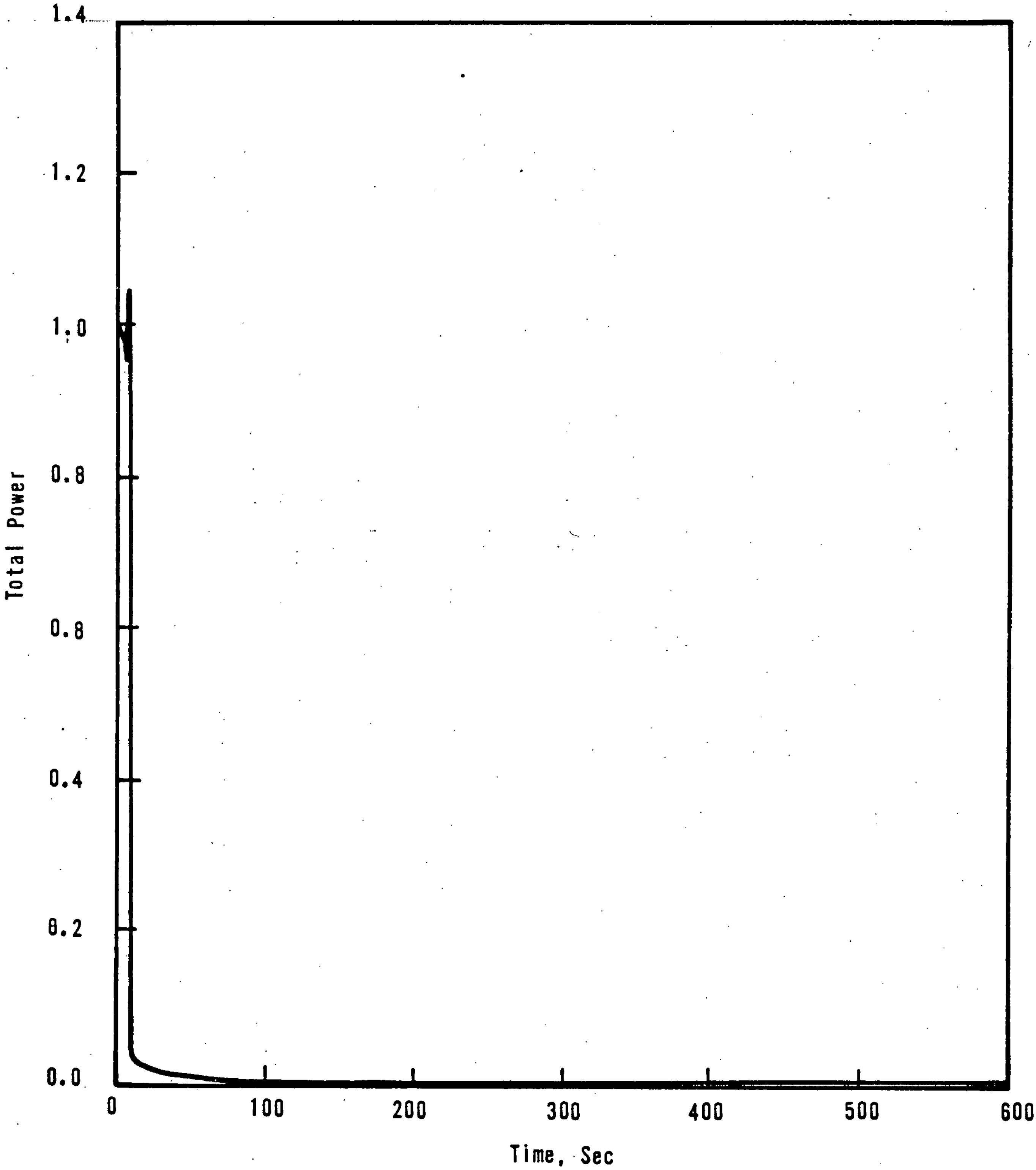


FIGURE 4-76. STEAM LINE BREAK CASE 8, 205 FA

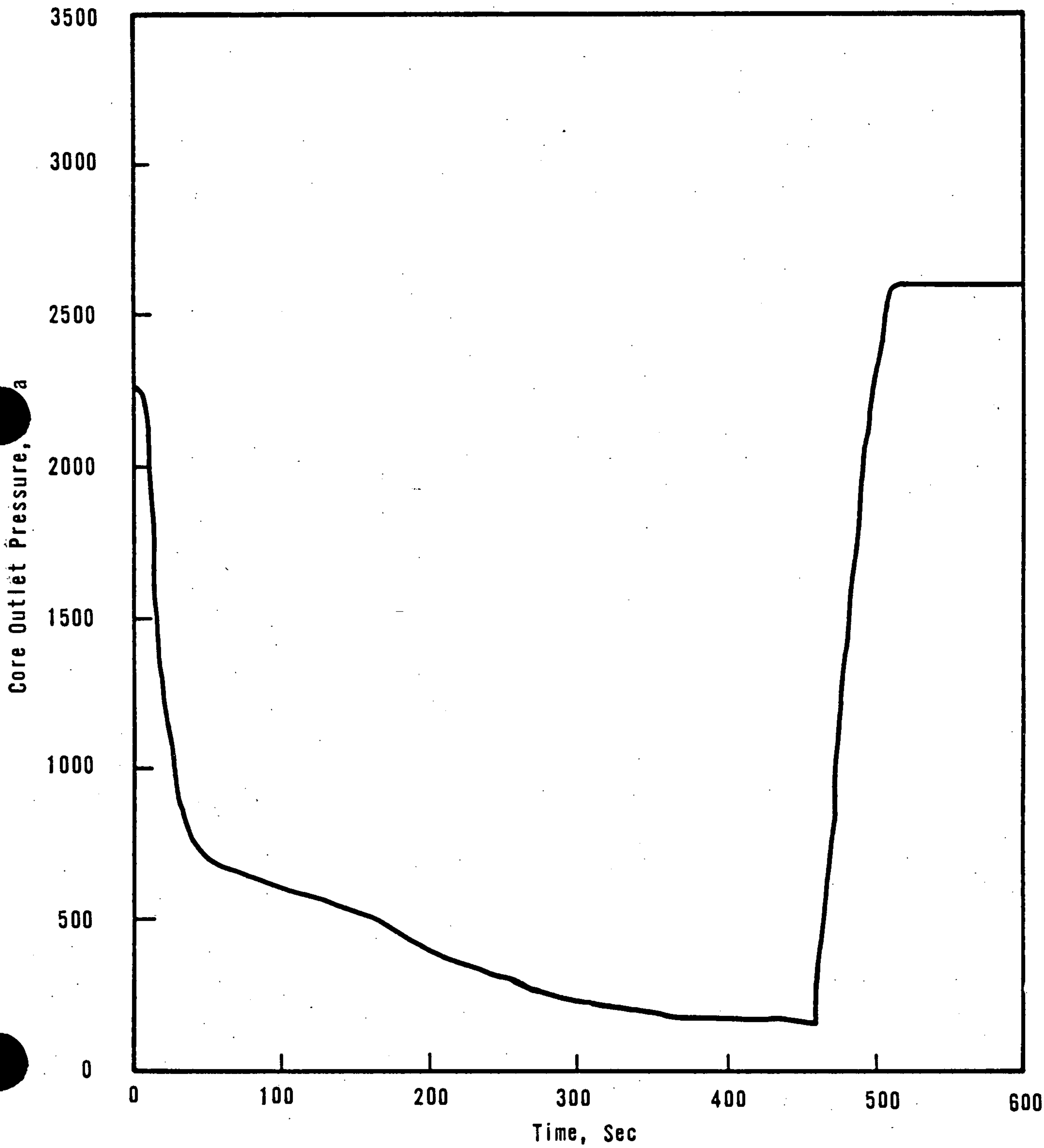


FIGURE 4-77. STEAM LINE BREAK CASE 8, 205 FA

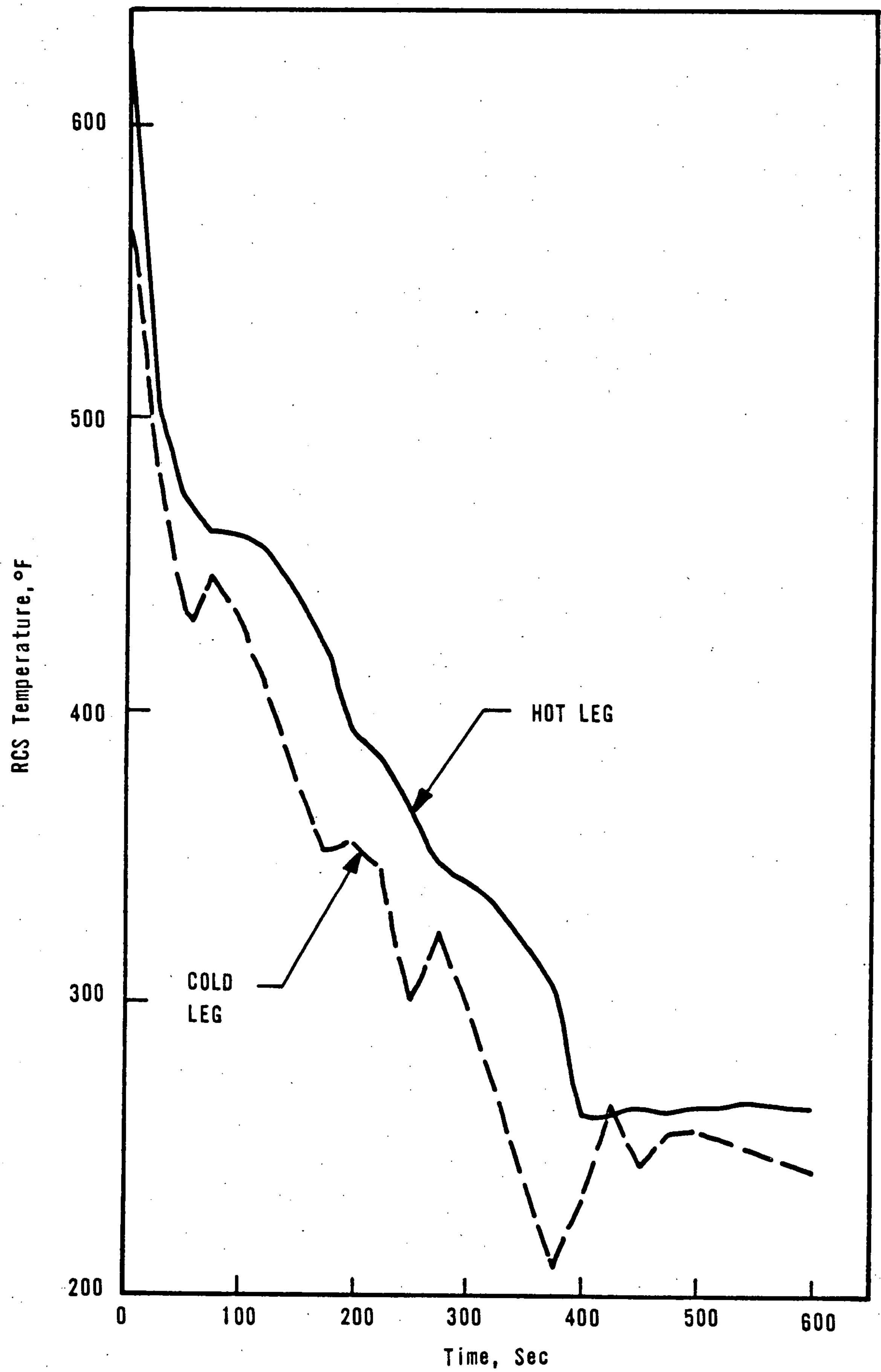


FIGURE 4-78. STEAM LINE BREAK CASE 8, 205 FA

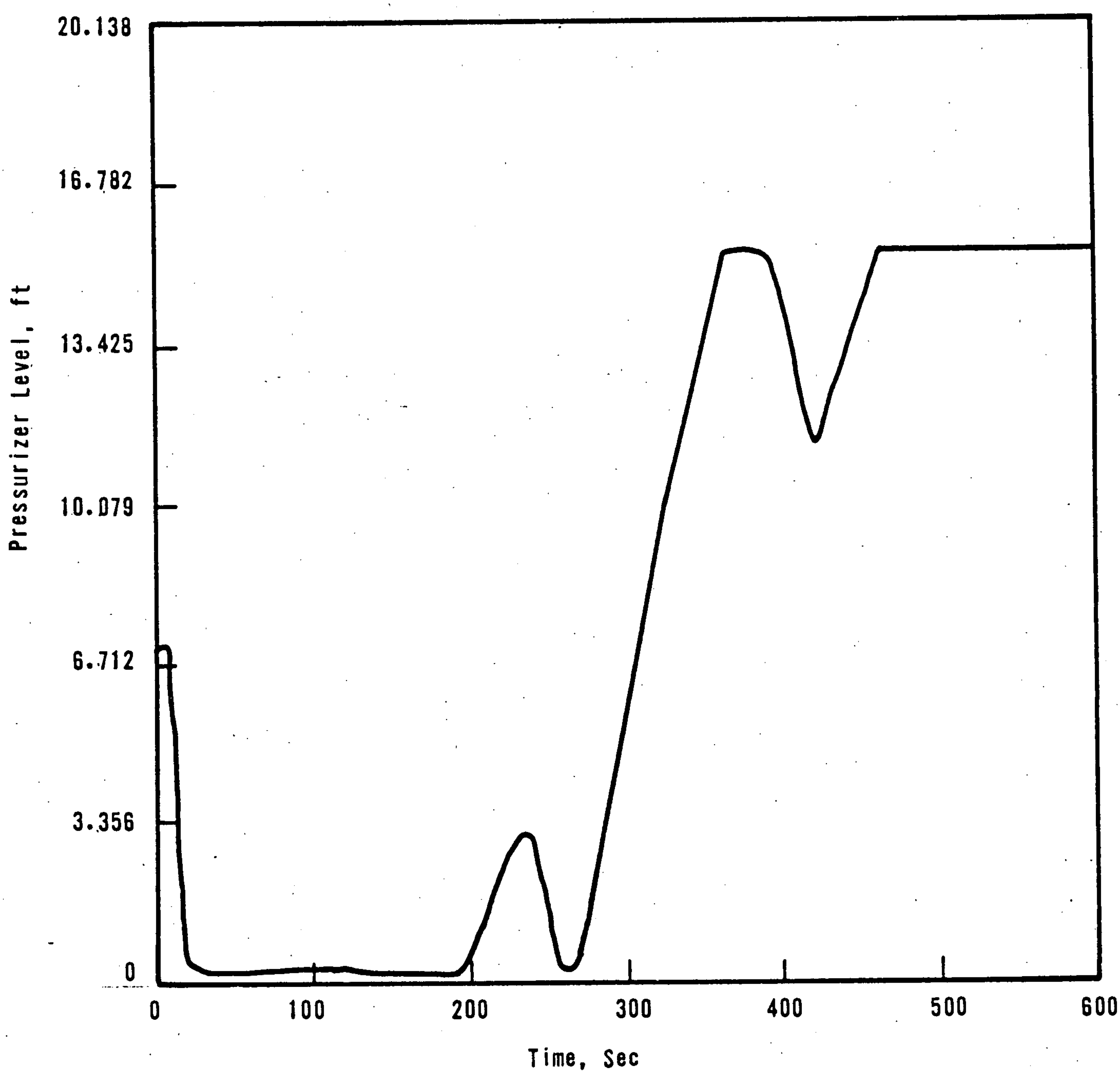


FIGURE 4-79. STEAM LINE BREAK CASE 8, 205 FA
STEAM GENERATOR A PRESSURE

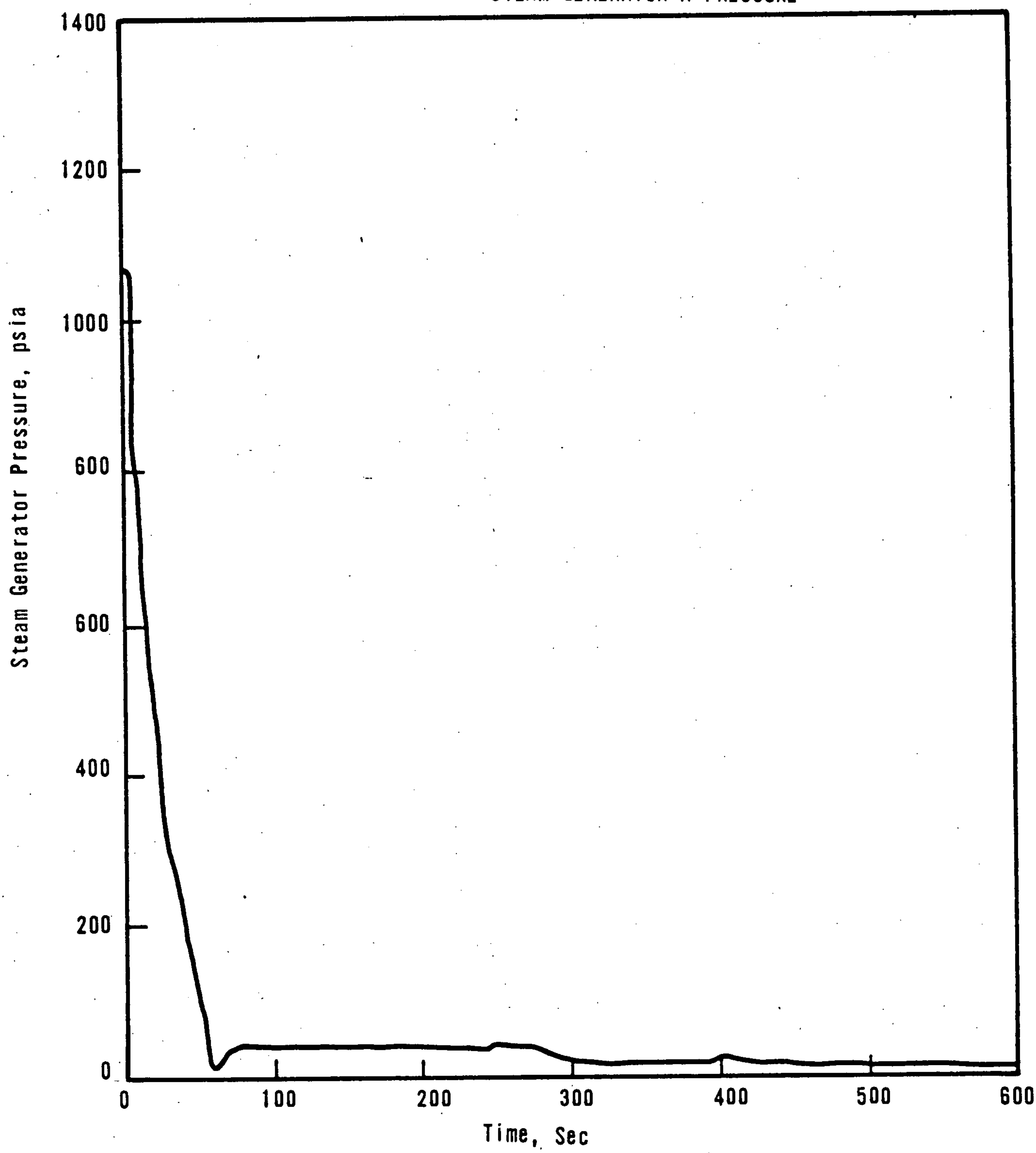


FIGURE 4-80. STEAM LINE BREAK CASE 8, 205 FA
STEAM GENERATOR B PRESSURE

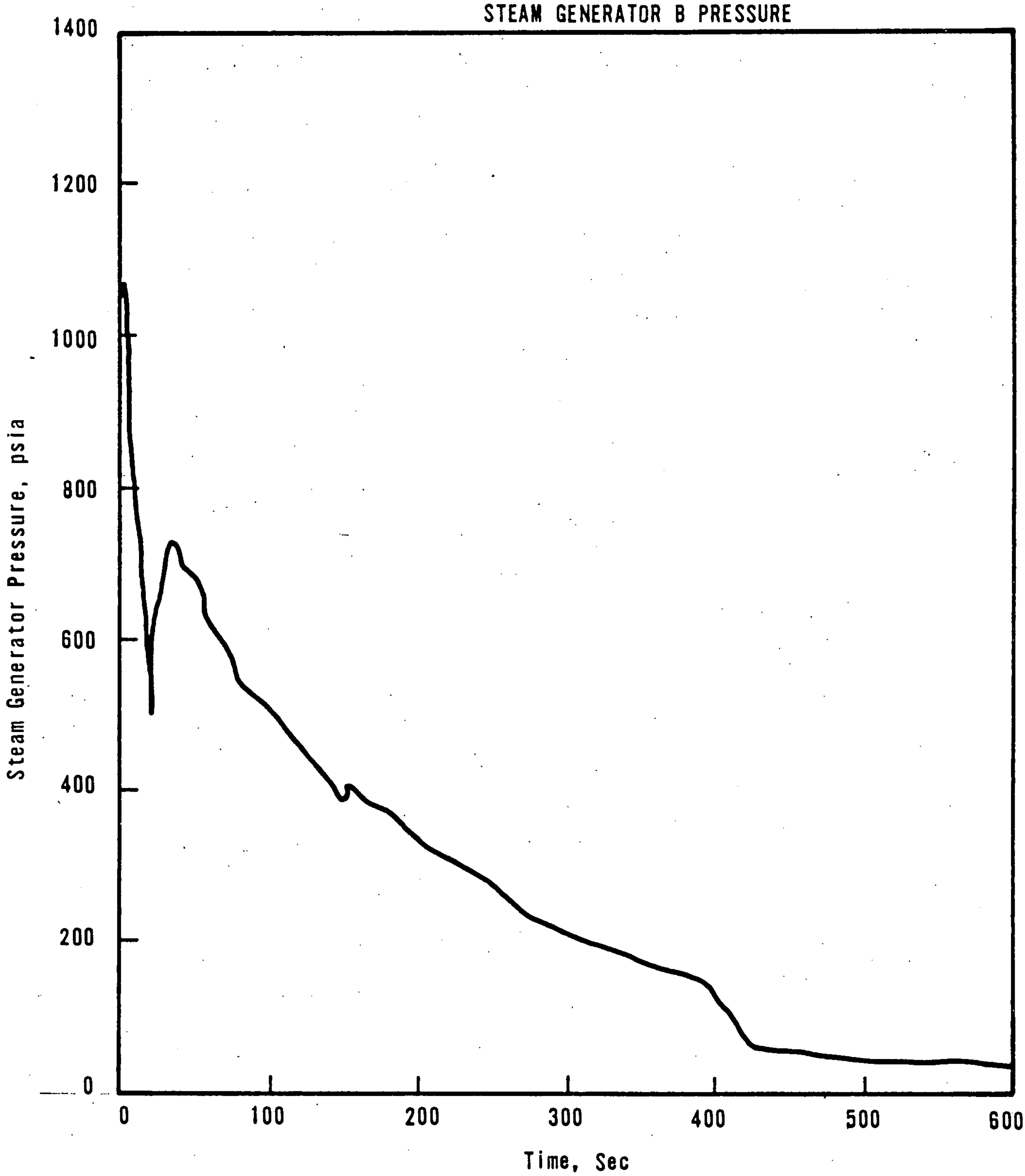


FIGURE 4-81. STEAM LINE BREAK CASE 8, 205 FA

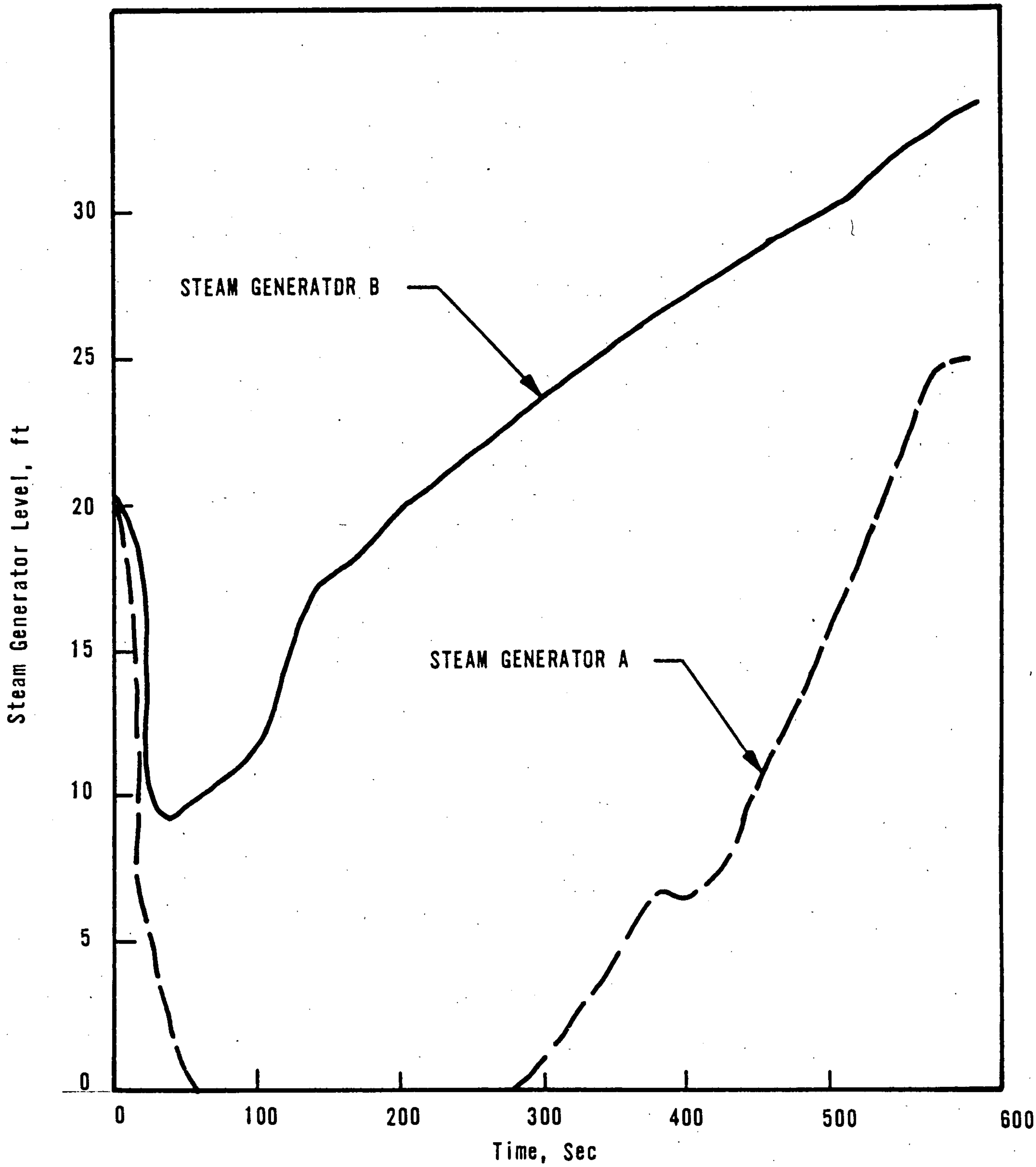


FIGURE 4-82. STEAM LINE BREAK CASE 8, 205 FA, STEAM GENERATOR A

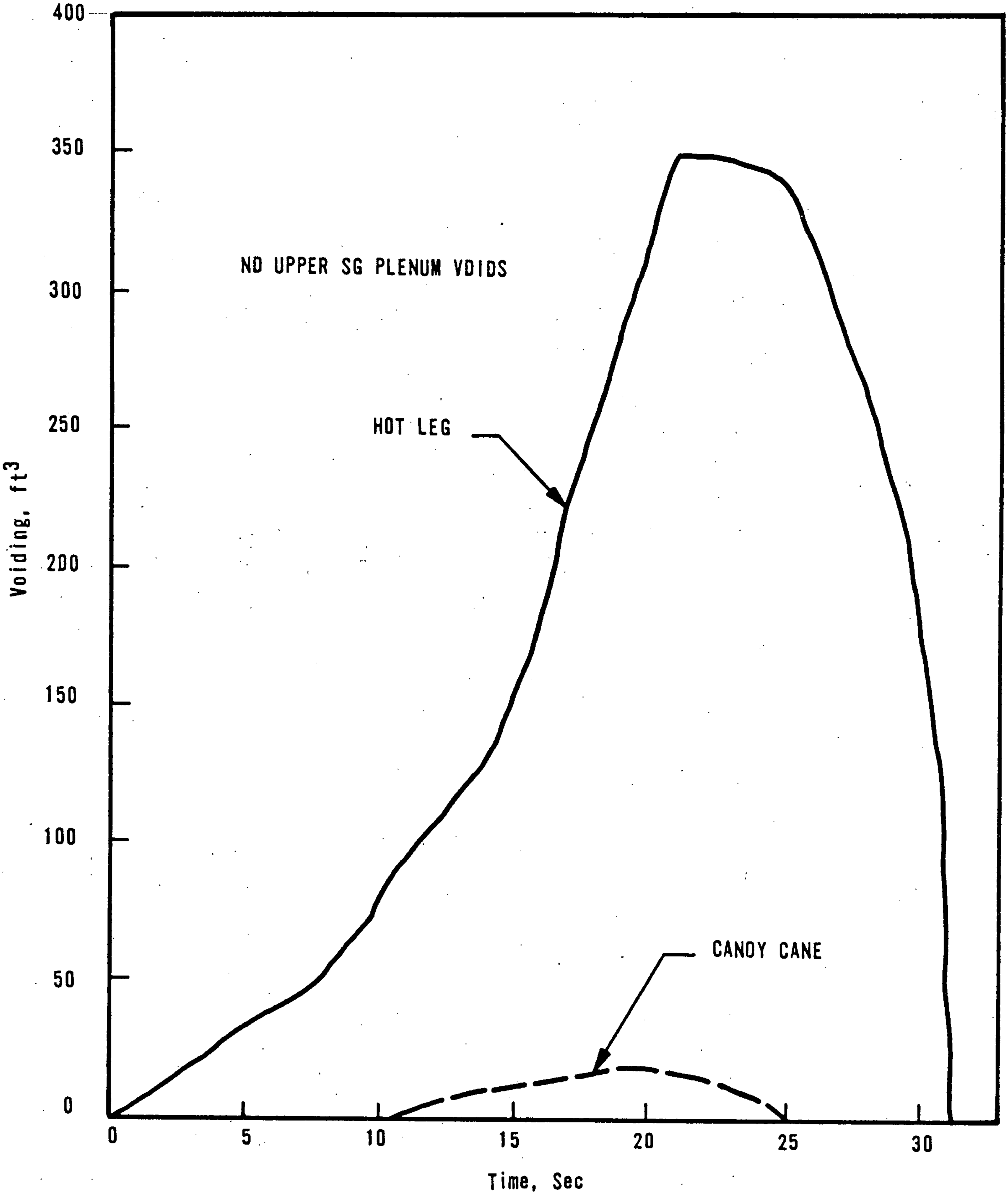
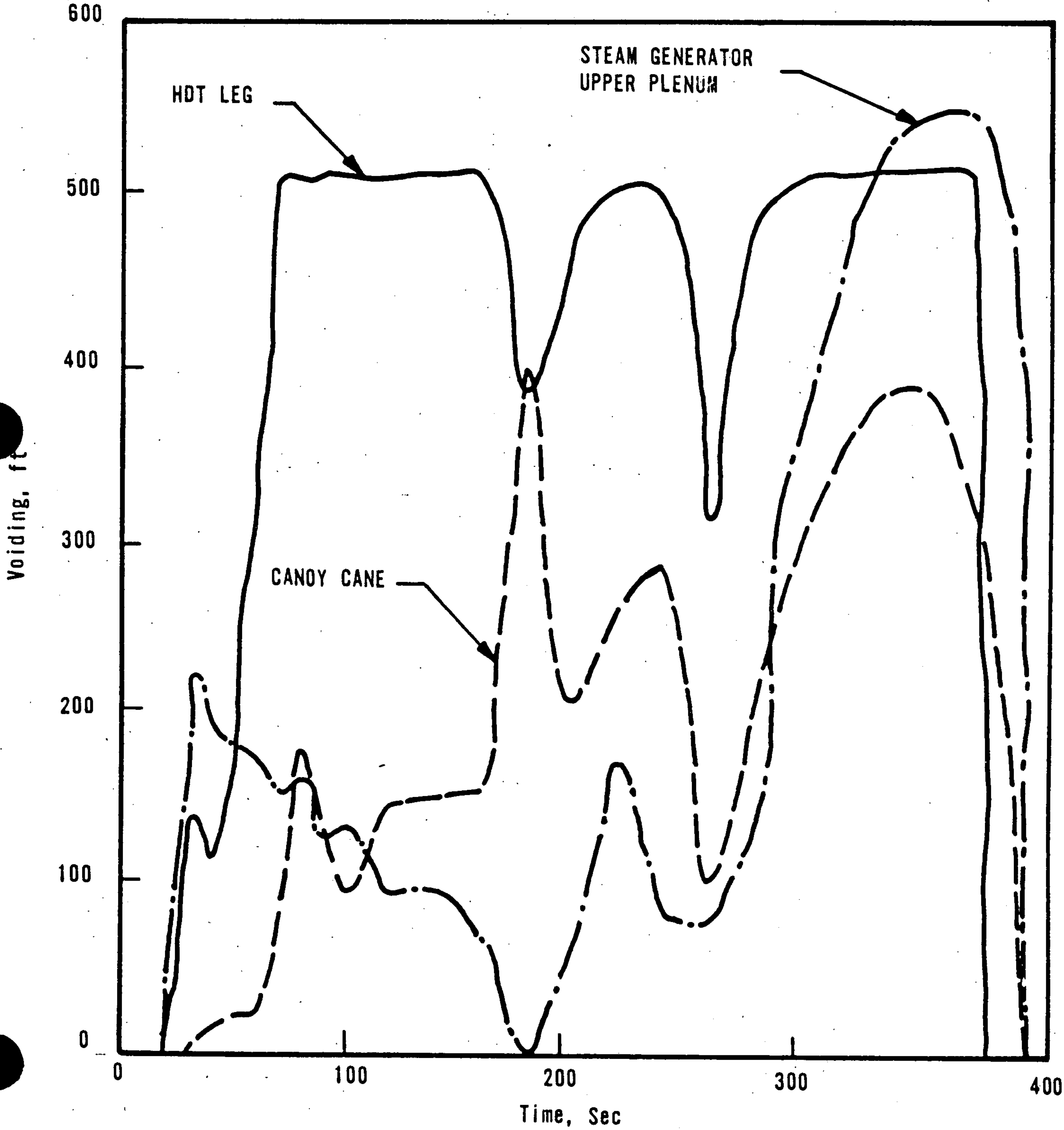


FIGURE 4-83. STEAM LINE BREAK CASE 8, 205 FA - STEAM GENERATOR B



ENCLOSURE B

Item b). Identify whether action of the ECCS or RPS (or operator action) is necessary to protect the core following the most severe overcooling transient identified. If these systems are required, you should show that its design criterion for the number of actuation cycles is adequate, considering arrival rates for excessive cooling transients.

Response

See report entitiled, "Overcooling Event Consequence Review." Time constraints have not allowed a detailed review of this report by TVA. If our review indicates the need for any major revisions, you will be promptly notified.

ENCLOSURE C

Item c). Provide a schedule of completion of installation of the identified systems and components.

Response

The attached Table contains the systems and components identified in Enclosure 3 of your October 25, 1979, letter plus the addition of the main feedwater system.

The table consists of a matrix for both units showing, for each system/component, the estimated completion date. Completion date is defined as the date when construction is 100% complete for all the equipment and/or components within the scope of the system or components and when the system or components are ready for turnover to Power.

The completion dates reflected in the table are effective as of November 16, 1979, and supports current fuel load dates of September 1982 and September 1983 for units 1 and 2.

TABLE 1

System or Component	Scheduled Completion Date	
	Unit 1	Unit 2
1. HPI/Makeup/Letdown System*	11/25/80	9/25/81
2. Auxiliary Feedwater System	8/1/80	7/29/81
3. Decay Heat Removal System	10/6/80	7/9/81
4. Core Flood System	8/5/80	7/14/81
5. Reactor Coolant System	7/2/80	5/21/81
6. Steam Generator	Complete	Complete
7. Pressurizer	Complete	Complete
8. RC Drain Tank (Quench Tank)	Complete	Complete
9. RCS Pressure Control System	11/11/80	9/11/81
10. Steam Generator Pressure Control System	11/11/80	9/11/81
11. Control Room Layout	Complete	Complete
12. Main Feedwater System	7/23/80	4/23/81

*For the Bellefonte facility, the HPI System and the Makeup/Letdown System are the same system.

ENCLOSURE D

Item d). Identify the feasibility of halting installation of these systems and components as compared to the feasibility of completing installation and then effecting significant changes in these systems and components.

Response

For the items identified in Enclosure 3 of your letter of October 25, 1979, plus the MFW system, a detailed description of construction status and a brief summary of the effect of halting construction on the specific system/component are provided.

1. HPI/Makeup/Letdown System

   A. Equipment - The equipment has been installed 100% complete on on both units 1 and 2.

   B. Pipe - A major portion of the piping (60%) has been installed and welded in unit 1, and no piping has been installed (0%) in unit 2.

   C. Valves - A major portion of the valves (60%) have been installed and welded in unit 1, and no valves have been installed (0%) in unit 2.

   D. Supports - 20% of the permanent piping supports have been installed in unit 1, and no supports have been installed in unit 2 (0%).

Stopping work on this system would also stop work on large pipe restraints on other piping systems and prevent further protective coating work in this area for both units 1 and 2. It would also delay piping and component flushes; subsequent construction tests; preoperational testing; hot functional tests; and fuel loading.

2. Auxiliary Feedwater System

   A. Equipment - The equipment has been installed 100% complete on both units 1 and 2.

   B. Pipe - A major portion of pipe (95%) has been installed and welded and lacks only trim work for unit 1, and no piping has been installed on unit 2.

C. Valves - Installation of large valves is essentially complete and welded out and lacks only smaller valves on trim for unit 1, and no supports have been installed on unit 2.

D. Supports - 10% of the permanent piping supports have been installed on unit 1, and no supports have been installed in unit 2.

Stopping work on this sytem would also stop work on large pipe restraints on other piping systems and prevent further protective coating work in this area for both units 1 and 2. It would also delay piping and component flushes; subsequent construction tests; preoperational testing; hot function tests; and fuel loading.

3. Decay Heat Removal System

A. Equipment - The equipment has been installed 100% complete on both units 1 and 2.

B. Pipe - A major portion of pipe (90%) has been installed and welded and lacks only trim work for unit 1, and no piping has been installed on unit 2.

C. Valves - Installation of valves is 90% complete and welded on unit 1, and no valves have been installed on unit 2.

D. Supports - 15% of the permanent piping supports have been installed on unit 1, and no supports have been installed on unit 2.

Stopping work on this system would also stop work on large pipe restraints on other piping systems in this area and prevent further protective coating work in this area for both units 1 and 2. Delay of this system would also delay installation of reactor vessel and reactor coolant pump internals and delay the sump qualification test. It would also delay piping and component flushes; subsequent construction tests; preoperational testing; hot functional tests; and fuel loading.

4. Core Flood System

A. Equipment - The equipment has been installed 100% complete on both units 1 and 2.

B. Pipe - A major portion of piping (90%) has been installed and welded and lacks trim work on unit 1, and 10% of the piping has been installed and welded on unit 2.

C. Valves - A major portion of the valves (90%) has been installed and welded on unit 1, and 10% of the valves have been installed and welded on unit 2.

D. Supports - 50% of the permanent piping supports have been installed on Unit 1, and 10% of the permanent piping supports have been installed on unit 2.

Stopping work on this system would also stop work on large pipe restraints on other piping systems and prevent further protective coating work in this area for both units 1 and 2. It would also delay piping and components flushes; subsequent construction tests; preoperational testing; hot functional testing; and fuel loading.

5. Reactor Coolant System Piping

Unit 1 - This system is installed (100%) complete and welded.

Unit 2 - Pipe is in place and aligned except for the candy canes.

Stopping work will not affect unit 1 as it is complete. Stopping work in unit 2 will also stop all other related NSSS work in the Reactor Building.

6. Steam Generator - Units 1 and 2 - The steam generators are installed 100% complete.

Stopping work on these components will not affect our schedule or other related activities.

7. Pressurizer - Units 1 and 2 - The pressurizers are installed in both units.

They lack final alignment but continuing work would not add significantly to extra work in case a design change takes place.

8. R. C. Drain Tank (Quench Tank) - Units 1 and 2 - These tanks are installed in both units.

Stopping work would not affect our schedule or other related activities.

9. RCS Pressure Control System - Unit 1 - This system is better than 50% complete. All control panels have been set but lacks tubing installation.

Tubing installation should continue and even if a significant design change does take place, there should be no significantly greater problem in modifying this installation.

Unit 2 - Only 10% complete with few control panels installed.

10. Steam Generator Pressure Control System - Unit 1 - This system is better than 50% complete and the greater part of the work not completed is instrument tubing.

Tubing installation should continue and even if a significant design change does take place, there should be no significantly greater problem in modifying this installation.

Unit 2 - Only 10% complete with few control panels installed.

11. Control Room Layout - Units 1 and 2 - This installation is complete with all boards, cabinents, and controls installed. A major portion of the cable and wiring has been installed and we are in the process of making termination.

Cable pulling and terminations should continue on both units as the amount of work we do in the next six months will be insignificant compared to the work already completed in case of a major design change.

12. Main Feedwater System

A. Equipment - 85% has been installed in unit 1 and 66% in unit 2.

B. Pipe - 58% has been installed and welded in unit 1 and 2% has been installed and welded in unit 2.

C. Valves - 63% has been installed in unit 1 and 0% in unit 2.

D. Supports - 40% of permanent hangers has been installed in unit 1 and 6% in unit 2.

Stopping work on this system would also stop work on large pipe restraints on other piping systems and prevent further protective coating work in this area for both units 1 and 2. It would also delay piping and component flushes; subsequent construction tests; preoperational testing; hot functional tests; and fuel loading.

It is TVA's view that any changes to the major components could have an impact on the construction schedule. Further, changes of a major nature may not be possible because of physical space limitations. However, the small pipe, instrumentation and control, and electrical cable design can accommodate changes without major impact or dismantling installed equipment. As can be seen in the response to Item c, all of the systems are essentially in place mechanically, and all that remains is to complete the small pipe, electrical and instrumentation portion. With respect to making changes on these systems, the impact on the overall construction schedule and costs is large whether we continue or stop construction at this time; however, TVA believes that the impact would be less if construction is continued. Therefore, TVA concluded that it is much more feasible to continue construction and effect any required changes later than it is to halt construction, wait for the changes to be identified, and then make the required changes.

ENCLOSURE E

Item e). Comment on the OTSG sensitivity to feedwater transients.

Response

The design of the Once Through Steam Generator has yielded superior performance both in safety and efficiency in pressurized water reactors. The Once Through Steam Generator has exhibited exceptional tube integrity record over its operating experience; this not only maximizes generator availability but also minimizes the risk of radioactive release by a tube rupture. One inherent feature of this design is the responsiveness to feedwater control. This responsiveness makes possible an accuracy of control which has both operational and safety advantages. Safety Analysis of limiting feedwater and secondary system pressure disturbances has demonstrated the ability to maintain safe core cooling without radioactive release under the applicable licensing assumptions. However, the frequency of feedwater transients leading to disturbances of pressure and/or pressurizer level in the primary system of B&W plants has been higher than desired. This has been somewhat exacerbated by changes to plant operation which have been required since the TMI-2 accident. B&W has concluded that it is neither necessary nor desirable to modify the fundamental operating characteristics of the Once Through Steam Generator in view of its excellent performance record.

Attachment 1 is a point-by-point discussion of Enclosure 1 to your October 25, 1979, letter. These comments are correlated to your Enclosure 1 by the attached annotated copy of that enclosure.

ATTACHMENT 1

COMMENTS IN RESPONSE TO ENCLOSURE 1
OF THE LETTER FROM H. R. DENTON DATED 10/25/79
"10 CFR 50.54 REQUEST REGARDING THE DESIGN ADEQUACY OF B&W
NUCLEAR STEAM SUPPLY SYSTEMS UTILIZING ONCE THROUGH STEAM GENERATORS"

*1. At Bellefonte Nuclear Plant (BLNP), the Auxiliary Feedwater System (AFW) is a safety grade system. Improved reliability of the AFW will minimize system fluctuations following the initiation of auxiliary feedwater. It should be noted that for BLNP, the AFW is injected into the less sensitive lower section of the Once Through Steam Generator (OTSG).

2. The addition of an anticipatory reactor trip on loss of main feedwater is being considered for BLNP. Operating plant experience indicates that the anticipatory reactor trip on loss of main feedwater has, in fact, yielded very smooth system response. This has been confirmed by recent B&W field data. However, use of anticipatory trips should be eliminated for those disturbances (such as turbine trip) which can be handled by the plant control system action without challenging the plant safety systems. This will reduce the number of plant trips. See item 4 below.

3. The addition of an automatic reactor coolant pump trip is being studied to eliminate the necessity for the operator to manually trip the reactor coolant pumps and raise the OTSG water level when a small break LOCA is indicated. Reactor coolant pump trip should occur only for actual small breaks in the primary system; it should not occur for overcooling events initiated by feedwater transients.

4. The raising of the Power Operated Relief Valve (PORV) setpoint and lowering of the high pressure reactor trip appear to have increased the number of reactor trips on the B&W operating plants. As a result of the Short Term Lessons Learned, TVA is proposing certain modifications which

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*NOTE: These numbers refer to the marginal notations on the attached copy of Enclosure 1 to the October 25, 1979, letter.

will restore the controlled relief capability of the PORV while maintaining a high level of protection against PORV malfunction. A resetting of the reactor protection system high pressure setpoint and the PORV setpoint will restore the capability of the B&W Nuclear Steam System (NSS) to sustain a wide range of operational transients without a high pressure reactor trip.

5. The B&W OTSG and NSS are designed to avoid reactor trip during minor secondary system transients. This responsiveness is an inherent feature of the design. Some B&W operating plants do place reliance upon the operator to limit feedwater excursions which may result from control system failure. However, BLNP already employs a number of automatic measures to reduce this reliance upon the operator. Several additional modifications will be evaluated which could further reduce the requirements for the operator to act in response to a control system failure in order to further improve our defense-in-depth against primary system parameter excursions resulting from minor secondary system transients.

6. Overcooling transients in all PWR systems proceed initially like a small break LOCA, and this is not a unique problem of the OTSG. For example, on a recent reactor trip at the North Anna Power Station, a stuck-open turbine bypass valve with approximately 5 percent capacity caused an excessive overcooling which resulted in a prompt loss of reactor system pressure to the setpoint of the automatic safeguards injection system, and contraction of primary coolant sufficient to take pressurizer level below the range of indication. TVA is evaluating design modifications for BLNP which, in conjunction with improved operator training, should improve the tolerance of the feedwater control system for this type of transient and contribute to minimizing events of this nature.

7. The loss of pressurizer level indication following a reactor trip is an operational concern and should be minimized for expected abnormal occurrences. However, it should be noted that the loss of indicated pressurizer level on B&W operating plants is not synonymous with a loss of liquid in the pressurizer. Certain B&W plants, such as Davis Besse unit 1, have pressurizer level indicators which do not cover the full span of the pressurizer volume. In the case of Davis Besse, more than 40 inches of pressurizer capacity remains below the zero point of the level indication system. For BLNP, the indicated pressurizer level range more closely relates to the full fluid volume of the pressurizer. With this expanded indication range at BLNP, pressurizer level is expected to remain on scale for feedwater transients such as those that have occurred at Davis Besse.

8. Operation of the pressurizer heaters when not covered by liquid should be eliminated as a potential occurrence. B&W operating plants now include a control grade circuit to remove power from the pressurizer heaters when liquid level is low, and in no instance on an operating plant have the pressurizer heaters been energized while uncovered. For BLNP, evaluations will be made to assess whether this circuit should be upgraded to incorporate a safety grade feature to ensure that the pressurizer heaters will not be energized when liquid level is low.

9. For BLNP, evaluations will be made to assess whether an automatic reactor coolant pump trip associated with low reactor coolant pressure only should be installed. In addition, main feedwater overfeed limiting equipment, independent of the Integrated Control System (ICS), is being investigated by TVA as a means to terminate main feedwater flow upon high OTSG water level.

10. TVA believes that the BLNP AFW control scheme minimizes the degree of AFW induced overcooling. We note that in part the severity of operating B&W plant overcooling transients apparently can be attributed to the post TMI-2 requirement to fill the OTSG to 95 percent of the operating range. The BLNP AFW control system automatically regulates AFW to the OTSG six-foot level using safety grade controls separate from the ICS.

11. B&W calculations do not predict an interruption of core cooling or heat transfer to the OTSG as a result of the events sequence outlined. Delivery of cold water by the high pressure injection system will refill the reactor coolant system and quench any voids to provide additional assurance of adequate core cooling.

12. Criteria for restart of a reactor coolant pump are already provided in the current Small Break Operating Guidelines to permit forced flow to be reestablished promptly following repressurization of the reactor coolant system.

13. The B&W ICS is designed to provide smooth and stable operation of the complete power plant during power operation. One of its functions is to maintain the reactor online for minor secondary system disturbances and eliminate unnecessary challenges to the reactor trip system. Following reactor trip, the ICS has a function in maintaining plant conditions stable and within design limits. Additional control functions independent of the ICS are being

evaluated to limit the effects of failures in the ICS. For example, the auxiliary feedwater control is already performed by a safety-grade system independent of the ICS on BLNP, also as noted in item 9 above, a system separate from the ICS is being investigated to limit main feedwater introduction which might occur as a result of ICS failure. The combination of these improvements should reduce the potential for failures in the ICS from contributing to the severity of an overcooling transient.

14. Limiting safety analysis has shown that adequate core cooling will be maintained and radioactive release will be avoided even for the most severe secondary system accidents within the plant's licensing basis. Bellefonte already incorporates a number of design features which address the issues raised in this paper by improving system reliability and reducing the consequences of secondary system upsets. In addition to this, a group of modifications will be evaluated to further reduce primary system response to feedwater disturbances and to reduce the magnitude and frequency of secondary system feedwater upsets. These modifications could further improve plant performance and enhance safety through the defense-in-depth concept by terminating or mitigating transients early in their course before they result in seriously off-normal conditions.

Primary System Perturbations Induced by Once Through Steam Generator

I. Introduction

B&W plants employ a once through steam generator (OTSG) design, rather than U-tube steam generators which are used in other pressurized water reactors. Each steam generator has approximately 15,000 vertical straight tubes, with the primary coolant entering the top at 603-608°F and exiting the bottom at about 555°F. Primary coolant flows down inside the steam generator tubes, while the secondary coolant flows up from the bottom on the shell side of the OTSG. The secondary coolant turns to steam about half way up, with the remaining length of the steam generator being used to superheat the steam.

The secondary-side heat transfer coefficient, in the steam space of the OTSG, is much less than that in the bottom liquid section. This results in a heat transfer rate from the primary system which is quite sensitive to the liquid level in the steam generators. If a feedwater increase event occurs, the liquid-vapor interface rises, increasing the overall heat transfer. This decreases the outlet temperature below 555°F and initiates an overcooling event, which can lead to primary system depressurization. By contrast, if a feedwater decrease event occurs, the overall heat transfer decreases, the outlet primary temperature increases, and a pressurization transient ensues.

In either of these cases, the response of the primary system pressure and pressurizer level to a change in main feedwater flow rate (or temperature) is comparatively rapid. These rapid primary system pressure changes due to changes in feedwater conditions is known herein as system "sensitivity" and is unique to the B&W OTSG design.

Following the incident at Three Mile Island, various actions were taken to increase the reliability of the auxiliary feedwater systems and improve plant transient response. System modifications to increase the reliability of the AFW may have resulted in more frequent AFW initiation. However, use of AFW results in introduction of cold (100°F vs. 400°F) feedwater into the more sensitive upper section of the steam generators. This may act to enhance system sensitivity. (1)

Further system modifications provide control-grade reactor trips based on secondary system malfunctions, such as turbine or feedwater pump trip. While these reactor trips do serve to reduce undercooling feedwater transients by reducing reactor power promptly following LOMFW, they may amplify subsequent overcooling. (2)

A reexamination was made of small break and loss of feedwater events for B&W plants. This resulted in a modification of operator procedures for dealing with a small break, which include prompt RCP trip and raising the water level in the steam generators to (95%) to promote natural circulation. Both these actions are taken when a prescribed low pressure set point is reached in the reactor coolant system and for anticipated transients such as loss of feedwater these actions may amplify undesirable primary system responses. (3)

In addition to the post-TMI changes discussed above, actions were also taken to reduce the challenges to the power operated relief valve (PORV) by raising the PORV set point and lowering the high pressure reactor trip. While these actions have been successful in reducing the frequency of PORV operation, they have resulted in an increased number of reactor trips. This occurs because the reactor will now trip for transients it previously would have ridden through by ICS and PORV operation. (4)

The staff is concerned by the inherent responsiveness of B&W OTSG design. While some specific instances are presented in the next section of this paper, the staff concerns are also of a general nature. It is felt that good design practice and maintenance of the defense-in-depth concept requires a stable well-behaved system. To a large part, meticulous operator attention and prompt manual action is used on these plants to compensate for the system sensitivity, rather than any inherent design features. (5)

The staff believes that the general stability of the B&W plant control systems should be improved, and that plant response to OTSG feedwater perturbations be dampened.

II. Recent Feedwater Transients

On August 23, 1979 the staff met with the B&W Licensees to discuss recent feedwater transients. One aspect which is of interest is the relationship of the operator to the functioning of the main feedwater system. In at least one instance an operator manually opened a block valve in series with a control valve (partly open but thought to be closed). This resulted in an overfeed condition. In several recent events the feed flow was reduced to the point where the reactor tripped on high pressure. Subsequent overfeed reduced pressure to below 1600 psi, where HPI was initiated, reactor coolant pumps tripped, and auxiliary feedwater flow introduced into the top of the steam generators, which increased the severity of the cooldown transient.

It appears that in many cases the main feedwater control system does not react kly enough or is not sufficiently stable to meet feedwater requirements. Rather, the system will often oscillate from underfeed to overfeed conditions causing a reactor trip and sometimes a high pressure injection initiation. One undesirable element of this lack of stability is that overcooling transients (6) on the primary side proceed very much like a small break LOCA (decrease in pressurizer level and pressure). Thus, for a certain period of time the operators may not know whether they are having a LOCA or an overcooling event. The same type of behavior can be initiated by the normal reactor control system. This was demonstrated by a December 1978 event at Oconee, where failure of a control-grade T_{avg} recorder led to reactor trip, a feedwater transient, and ESF actuation. A partial list of recent B&W transients and their effects is contained in the Appendix to this report.

Role of the Pressurizer Level Indicator

A major area of concern arising from the B&W OTSG sensitivity, is the response of pressurizer level indication. Several B&W feedwater transients have led to loss of pressurizer level indication. Most notable was a November 1977 incident at Davis Besse where level indication was lost for several minutes. The arrival rate for this event appears to be on the order of .1-.2 per reactor year, but could be on the increase due to the potential for more reactor trips and feed- (7) water transients resulting from post-TMI-2 system modifications. This is of concern because an overcooling event could empty the pressurizer, thereby creating the potential for forming a steam bubble in the hot leg which may interrupt natural circulation, following RCP trip on low pressure. The staff feels that e uncertainties associated with two phase natural circulation are somewhat high for an event with a recurrence interval of a few years.

Additionally, the staff believes that good design practice and adherence to the defense-in-depth concept, would require that plant operators be aware of the reactor's status during expected transients. A low-level off-scale reading pressurizer levels makes it impossible for the operators to assess system inventory and more difficult to differentiate between an accident and an excessive cooldown transient. The staff feels that the frequency with which this situation occurs is undesirable.

Some concerns also exist with regard to the operation of the pressurizer heaters when loss of level takes place. Nonsafety grade control circuitry trips the heaters off when pressurizer level is low. If these nonsafety grade cutoffs should fail, the heaters would be kept on while uncovered. This situation has the potential of overheating the pressurizer to the failure point, as happened with a test reactor at Idaho Falls. 8

e of ICS-MFW

The ICS appears to play a significant role in the plant's feedwater response. The staff is currently reviewing an FMEA study on the ICS. However, review of operating experience suggests that the ICS often is a contributor to feedwater transients. In come cases the ICS appeared inadequate to provide sufficient plant control and stability. Some of the utility descriptions of feedwater transients (as summarized in the minutes of a meeting on August 23, 1979) emphasized the role of the operator in operating the MFW system. The following sequence illustrates the type of event and system response which the staff feels could potentially occur.

1. Reactor at 100% power.
2. Reactor trip, from arbitrary cause (does not matter).
3. Plant stabilizes in hot shutdown, for a few minutes, heat rejection to condenser (and/or secondary dump valves).

4. Overfeed transient (MFW) (not uncommon to B&W) causes overcooling; pressurizer level shrinks, pressure reaches 1600 psi, RS actuates; RCP tripped; AFW on (Possible RCP seal failure). (9)

5. Operator manually controls AFW (possibly MFW instead or in addition, if MFW not isolated such that OTSG level comes up to 95% of operating range. This massive addition of cold water may lead to emptying of pressurizer and interruption of natural circulation (or, the hot leg may flash due to depressurization and interrupt natural circulation even if pressurizer does not empty). (10)

6. HPI delivers cold water, no heat transfer in OTSG, vapor from core leads to system repressurization; steam may condense or PORV may lift. (11)

7. No pump restart criteria available, circulation may not be reestablished. (12)

It appears that an upgraded safety quality ICS, which is designed to balance power to OTSG level in a better fashion, could reduce the sensitivity, illustrated in the above sequence. (13)

7. Role of ECCS and Auxiliary Feedwater

It is known that some feedwater transients result in overcooling to the extent that the HPI actuation setpoint is reached. Traditionally, the operator isolates letdown and turns on an extra makeup pump following trip so as to avert this actuation. If this manual action is not performed quickly enough, or if the cooldown transient is too severe, the HPI set point will be reached and the pumps automatically started. Following procedures, the operator would then trip all main coolant pumps and utilize recovery procedures based on the plant symptoms. If the incident was actually a feedwater event and not a small LOCA, he would then presumably go to the loss of forced circulation procedures. When pressure has recovered such that the coolant system has become 50°F subcooled, the operator can secure HPI. One problem is the difficulty in differentiating between a small break LOCA and an excessive feedwater transient. The operator would be forced to assume a small LOCA until proven otherwise. However, following the small break procedures and introducing cold auxiliary feedwater, may increase the severity of an overcooling event. Initiation of AFW and delivery to the OTSG, especially if accompanied by filling to the high level required by new procedures (95%) will continue the cooldown and depressurization. Thus, the AFW system acts to increase the responsiveness of the reactor to feedwater transients where excessive cooldown is occurring.

VI. Conclusions

The staff believes that the current B&W plants are overly responsive to feedwater transients because of the OTSG design, pressurizer sizing and PORV and high pressure trip set point. Some of the sensitivity also arises from inadequacies in the ICS to deal with expected plant perturbations.

Regardless of the reasons, B&W plants are currently experiencing a number of feedwater transients which the staff feels are undesirable. The staff believes that modifications should be considered to reduce the plant sensitivity to these events and thereby improve the defense-in-depth which will enhance the safety of the plant.

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ENCLOSURE F

Item f). Provide recommendations on hardware and procedural changes related to the need for and methods for damping primary system sensitivity to perturbations in the OTSG. Include details on any design adequacy studies you have done or have in progress.

Response

Much of the concern expresses in your October 25, 1979, letter about the "sensitivity" of the B&W OTSG PWR design is based on the currently operating 177 FA plants, and particularly that experience accumulated since the changes required by the NRC after TMI-2. However, it is important to recognize that the normal evolution of design that has occurred on BLNP as a result of new regulatory requirements, improvements in the state-of-the-art in hardware, and the feedback of operating experience has resulted in the incorporation of several new features. These features serve to improve the reliability of systems and equipment and thereby reduce the frequency of challenges to the safety systems, improve the response of the NSS to those events that do occur, and improve the capability to mitigate the events which occur. These changes to BLNP include:

- Addition of a safety grade, class IE Essential Control and Instrumentation (ECI) system which automatically maintains AFW at the six-foot OTSG level and provides post-accident monitoring instrumentation for the operator.

- Initiation of auxiliary feedwater by the IEEE 279 Engineered Safety Features Actuation System (ESFAS).

- Addition of Feed Only Good Generator (FOGG) logic to the ESFAS to help ensure that auxiliary feedwater is delivered to the intact steam generator following secondary system breaks.

- Moving the pressurizer level sensing taps to the top and bottom heads of the pressurizer to expand the range of level indication.

- Raising the level of the OTSG with respect to the level of the reactor.

- Provision for the automatic bypassing of the condensate polishing demineralizers on high delta pressure drop across the demineralizers.

- Improved main feedwater (MFW) reliability is provided by the use of three condensate booster pumps each with a capacity of 50 percent of required flow and continuously in operation. The same arrangement is also provided for the hotwell pumps.

- Improved MFW system reliability is also provided by the use of an automatic MFW pump runback on low MFW pump NPSH, rather than a low NPSH trip for the MFW pumps.

These operational improvements have already been adopted for BLNP. However, TVA is evaluating additional means to reduce adverse primary system responses to perturbations in the secondary system. As part of our evaluation, TVA is considering the results of the studies and analytical efforts ongoing or already completed by B&W.

These studies have resulted in B&W recommending that some changes should be considered to (1) retain the basic design operating characteristics of the OTSG, (2) improve the reliability of the systems whose failure can lead to overcooling transients (thereby enhancing plant availability and reducing the frequency of challenges to the safety systems), (3) further improve the response of the NSS to the transients which do occur, and (4) further improve the capability to mitigate these transients. TVA will also follow the progress and outcome of the IREP study at Crystal River 3. Some of the hardware modifications being considered are briefly addressed in Enclosure E. However, TVA's evaluation of the proposed changes is not sufficiently advanced to justify a listing of specific hardware modifications and operating procedural changes at this time. The effectiveness of each modification being evaluated to reduce the frequency and/or severity of an overcooling transient must be considered against the impact such a change would have on the response of the total plant to a wide spectrum of postulated events. TVA intends to determine the degree of desirability for each of the changes being considered by performing evaluations in the following areas as applicable:

Potential for the proposed modification to adversely affect the safety and availability of the plant in response to postulated events other than an overcooling transient.

Computer analyses to determine the degree of effectiveness in dampening the response of the primary system to the initiating event.

Studies and analytical efforts already accomplished by B&W.

Operating plant experience.

Reliability of the proposed modification.