MAINE YANKEE ATOMIC POWER COMPANY

EDISON DRIVE
AUGUSTA, MAINE 04336
(207) 623-3521

December 30, 1982
MN-82-255 JHG-82-250

United States Nuclear Regulatory Commission
Washington, D. C. 20555

Attention: Office of Nuclear Reactor Regulation
Division of Licensing
Operating Reactor Branch No. 3
Mr. Robert A. Clark, Chief

References:
(a) License No. DPR-36 (Docket No. 50-309)
(b) USNRC Letter dated September 29, 1981, Generic Letter 81-36
(c) MYAPCo Letter to NSNRC, MN-82-65, dated March 30, 1982
(d) MYAPCo Letter to USNRC, MN-82-124, dated June 30, 1982
(e) MYAPCo Letter to USNRC, MN-82-155, dated August 5, 1982
(f) Letter from R. Wells, C. E. Owners Group to H. R. Denton, NRC, dated October 18, 1982
(g) MYAPCo Letter to USNRC, MN-82-241, dated November 30, 1982

Subject: Evaluation of Safety and Relief Valve Operation

Dear Sir:

This letter transmits additional information which supplements References (c), (d), and (e) regarding the pressurizer safety valves installed at Maine Yankee.

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Safety Valve Operability

Item II.D.1.A of NUREG 0737 required that utilities operating and/or constructing Pressurized Water Reactor (PWR) power plants, provide evidence supported by tests of safety and relief valve functionability.

Reference (d) addressed the on-site testing experience of the pressurizer safety valves and associated discharge piping at Maine Yankee and in summary, reported the successful results of as-installed tests. However, Maine Yankee also committed, in Reference (d), to further improve the assurance of smooth safety valve operation, consistent with the EPRI Test Program results which demonstrated that stable valve operation can best be assured with low-pressure drop inlet lines.



0330L - AJC

Redesign of the inlet piping for each of the three safety valves and portions of the outlet piping has been ongoing since the submittal of Reference (d). Various piping layouts have been evaluated. It is anticipated that the new design will result in inlet line lengths of less than 6 feet. Reference (d), as corrected by Reference (e), scheduled a final report to be submitted on December 31, 1982. The difficulty of laying out the piping and performing the necessary Safety Class 1 piping analysis, and the dynamic analysis, has caused delay in the final layout determination. Therefore, Maine Yankee's final safety valve operability and piping evaluations will be submitted, as indicated in Reference (g), on or before April 1, 1983. However, as discussed above and in Reference (d), the as-installed safety valves and piping were successfully tested during the original plant Hot Functional Testing Program.

Maine Yankee participated in the CE Owners Group efforts as mentioned in Reference (d). However, portions of their program to demonstrate valve operability could not be directly applied to Maine Yankee because of inlet piping geometry differences. In addition, Maine Yankee has a slightly smaller Dresser safety valve than the two Dresser valves tested in the EPRI Test Program. The Dresser valve tested by EPRI was a model 31739A which has a #3 orifice with an area of 2.545 $in^2$, while the Maine Yankee valves are model 31709KA which has a K orifice with an area of 1.841 $in^2$. The justification for enveloping the Maine Yankee valve by the EPRI test valve was addressed in detail in EPRI Report EPRI-NP-2292-LD, PWR Safety and Relief Valve Test Program, Valve Selection/Justification Report, submitted by Dave Hoffman of Consumers Power for the EPRI Test Program participants. Reference (c) docketed this submittal for Maine Yankee.

Maine Yankee Response to Reference (f)

In response to concerns by Dresser (Reference f), Maine Yankee, on a recent shutdown, determined the actual ring settings on each of the three safety valves. After consultation with Dresser Engineering, Maine Yankee readjusted the rings to settings which were recommended based upon the successful results in the EPRI Test Program. The new rings settings are as follows:

Upper Ring = -48 notches
Middle Ring = -40 notches
Lower Ring = 0 notches (flush)

These new settings will increase valve stability and provide greater assurance of full-rated lift.

United Stated Nuclear Regulatory Commission
Attention: Mr. Robert A. Clark, Chief



Extended Safety Valve Blowdown

Maine Yankee, as a participant in the CE Owners Group, had an analysis performed by CE to determine the effect of pressurizer safety valve extended blowdown upon pressurizer liquid level and primary loop subcooling. A copy of the evaluation is attached at Appendix A. Basically, that evaluation demonstrates that blowdown to 20% below setpoint will result in acceptable safety valve and primary coolant conditions for Maine Yankee.

Schedule

As stated in Reference (g) and discussed above, Maine Yankee will provide its final Discharge Piping Analysis and Safety Valve Operability Reports on or before April 1, 1983.

Very truly yours,

MAINE YANKEE ATOMIC POWER COMPANY

for J. H. Garrity, Senior Director
Nuclear Engineering & Licensing

JHG/WGJ/kac

cc: Mr. Ronald C. Haynes
Mr. Paul A. Swetland

Attachment -*Effect of Pressurizer Safety Valve Extended Blowdown Upon Pressurizer Liquid Level and Primary Loop Subcooling for CE Plants (49 Pages)

1982

APPENDIX "A"

EFFECT OF PRESSURIZER SAFETY VALVE EXTENDED BLOWDOWN

UPON PRESSURIZER LIQUID LEVEL AND

PRIMARY LOOP SUBCOOLING FOR C-E PLANTS

TABLE OF CONTENTS

TABLES

LIST OF FIGURES

Effect of Pressurizer Safety Valve Extended Blowdown
Upon Pressurizer Liquid Level and Primary Loop Subcooling for CE Plants

## 1.0 PURPOSE

The purpose of this effort is to determine for CE NSSSs the effect of extended blowdown of pressurizer safety valves upon pressurizer two-phase level. This information is required for the justification of the acceptability of pressurizer safety valve ring adjustments that result in blowdowns greater than the maximum of five percent below setpressure specified by the ASME Code. The objective is to demonstrate that steam conditions are maintained at the safety valve inlets during the blowdown. Another objective of this effort is to verify that flashing of the reactor coolant does not occur in the primary loop or the reactor vessel as a result of the extended safety valve blowdown.

## 2.0 BACKGROUND

The full scale performance testing of nuclear primary safety valves conducted by EPRI in 1981 demonstrated that safety valve operating stability is dependent upon valve inlet piping configuration, valve ring adjustment, and valve inlet fluid conditions. Further, it was found that changes in safety valve ring adjustments to promote stability tended to increase valve blowdown. Blowdown to a sufficiently low pressure could cause flashing in the pressurizer liquid and expansion of the liquid level to the elevation of the pressurizer safety valve nozzles. Flow of water through the safety valves would then result. Since water flow conditions and the resulting hydraulic loads were not considered in the design of the safety valves, it is desirable to limit valve inlet fluid conditions to steam only. Therefore, an effort was undertaken to determine an acceptable extended safety valve blowdown which would not result in passing liquid through the valve. Also, an investigation of the effect of safety valve blowdown to relatively low pressures upon primary loop or reactor vessel subcooling was required to verify that no steam bubbles formed in the primary loop or the reactor vessel. Avoidance of steam formation in the primary loop or the reactor vessel is good operational practice.

## 3.0 SCOPE

The evaluation of the extended safety valve blowdown was performed for all CE plants. Due to the differences in the design features of various CE plants, such as rated power, size of pressurizer, operating parameters, and safety valve type, number, capacity and setpoint, it was necessary to perform the evaluation on a plant-specific basis in most cases. However, some plants belonging to certain CE plant classes were similar enough in design so tha+ a single enveloping evaluation could be done. The following plants were analyzed: Palisades, Fort Calhoun, St. Lucie-1 (also applicable to St. Lucie-2), Millstone-2, Calvert Cliffs-1 (also applicable to Clavert Cliffs-2), Arkansas Nuclear One-2 (ANO-2), the 3410 MWt Class Plant (applicable to Waterford-3), and the 3817 MWt Class Plant (applicable to Palo Verde-1, -2, and -3 and to Washington Nuclear Power-3).

## 4.0 APPROACH

Since the Loss of Load event was the sizing design basis for the pressurizer safety valves, this event was also used as the basis for evaluating the acceptability of extended safety valve blowdown for the CE plants. Analyses were performed for CE plants to determine the maximum pressurizer level attained during an assumed 20% blowdown (down to 2000 psia) of pressurizer safety valves subsequent to their actuation. Conservative assumptions were made with respect to initial plant conditions and steam accumulation in the pressurizer liquid during the transient in order to maximize pressurizer liquid level. The results of the analyses were evaluated to determine a range of values of safety valve blowdown which would ensure that the safety valves would be exposed to steam flow only. Also, the calculated primary loop and upper reactor head temperatures were reviewed to determine whether subcooled conditions were maintained during the transient.

## 5.0 METHOD OF ANALYSIS

### 5.1 Introduction

The effect of extended blowdown of the pressurizer safety valves during the Loss of Load transient upon the pressurizer liquid level was calculated using CE's LTC computer Code (Reference 1). Input data was biased in a manner to provide increased pressurizer liquid levels. The calculated pressurizer liquid levels were then adjusted to provide additional conservatism. The LTC code and the adjustments of its results are described in the following sections.

### 5.2 Description of the LTC Computer Code

LTC is a versatile code which can be used either for best estimate analysis or, with conservative biases, for conservative predictions. Events may be analyzed from the initial transient through plant cooldown until the plant is in a cold shutdown condition. The code has been verified against plant data such as startup tests and post incident data including plant cooldown on natural circulation.

The LTC computer code models the major plant systems and components, as well as plant control and protection systems. Plant systems and components modeled include the reactor core, reactor coolant system (including pumps and steam generators), pressurizer, chemical and volume control system, shutdown cooling system, safety injection system, main steam lines, main and auxiliary feedwater lines, condenser, and the containment. Control and plant protection systems modeled include the following systems: reactor regulating, pressurizer pressure control, pressurizer level control, main feedwater control, steam dump and bypass control, turbine control, reactor protection, and engineered safety features actuation. With respect to the reactor coolant system and its associated components, the code accurately models nuclear, thermal, and hydraulic performance. The computer simulation includes consideration of reactor kinetics, steam generator thermal-hydraulic performance, reactor coolant pump performance, elevation heads, inertia of surge line water, friction drop in the surge line, and a pressurizer model involving heat and mass transfer between liquid and vapor.

## 5.3 Adjustment of the LTC Results

The LTC Code uses a non-equilibrium pressurizer model considering the mass and heat transfer across the liquid/vapor interface. Liquid insurge from the RCS during a transient is assumed to mix homogeneously with the pressurizer liquid. This mixing tends to reduce the pressurizer liquid temperature and the tendency of the liquid to flash to steam as a result of the pressure decrease due to an extended safety valve blowdown. Since the results of LTC analyses have been found to be in excellent agreement with plant performance data obtained for a wide range of events, the pressurizer model is considered to be a best estimate type of simulation.

For the LTC calculations, as discussed in Sections 5.1 and 5.3, some key input data were biased to produce conservative results. To introduce an additional conservatism, an adjustment was made to the pressurizer level determined from LTC to more conservatively account for flashing in the pressurizer liquid. The correction was made by adding to the pressurizer level as calculated by LTC (which also considers flashing) an additional expansion of the initial saturated pressurizer liquid. The additional expansion was calculated by assuming that the initial pressurizer liquid does not mix with the cooler insurge liquid, that the initial liquid remains in equilibrium with the pressurizer steam space, and that steam formed in this liquid volume when flashing occurs at reduced pressures does not escape into the steam space. As an additional conservatism, another additive correction was made to the pressurizer liquid level by assuming that steam calculated by the LTC Code to escape into the vapor space actually remains in the liquid.

# 6.0 ANALYSIS DATA

## 6.1 Introduction

Overpressure protection of CE reactor coolant systems is provided by primary (pressurizer) and secondary (main steam) safety valves and the Reactor Protection System. The Loss of Load transient, in conjunction with a delayed reactor trip, is the design basis for the sizing of the primary safety valves. The analysis of blowdown discussed herein assumes the Loss of Load transient as the cause of the safety valve actuation preceding the extended blowdown. Generally, except for certain initial conditions, which were biased so as to tend to maximize pressurizer levels, the assumptions and input to this analysis were basically the same as for a typical Loss of Load analysis used to size the safety valves.

6.2 Assumptions

Important assumptions made in the typical Loss of Load analyses are noted below:

a. Moderator temperature coefficient is zero. Since this coefficient is generally negative, this choice of coefficient tends to increase the severity of the transient.

b. A zero Doppler temperature coefficient is used so that the reduction in reactivity with increasing fuel temperature is minimized, thereby maximizing the rate of power rise.

c. No credit is taken for letdown, pressurizer spray, power operated relief valves, turbine bypass, or feedwater addition after turbine trip in the Loss of Load analysis. Letdown and pressurizer spray both act to reduce primary pressure. By not taking credit for these systems, the rate of pressurization is increased and the reactor trip on high pressure is hastened, but only by less than a second. Peak primary pressure is not significantly affected. By not taking credit for the addition of feedwater, the steam generator secondary inventory is depleted at a faster rate. This in turn reduces the capability of the steam generator to remove heat from the primary loop and results in increased pressurizer liquid levels.

d. The pressurizer safety valve blowdown assumed in typical analyses is generally with the limits (<5%) specified by the ASME Code. In this particular study, the effect of extended safety valve blowdown is of prime interest, and a blowdown of 20% is assumed. The 20% blowdown is large enough to bound the maximum blowdown observed in the EPRI test program for those valve adjustments which resulted in stable valve operation under steam discharge conditions.

6.3 Initial Conditions

In performing the LTC Loss of Load analysis for the various CE plants, it was necessary to select initial values for key parameters. Certain key parameter selections were conservatively biased in a direction which tended to increase transient pressurizer liquid levels. These selections are discussed below. Nominal values were used for other input parameters.

a. Power

A higher initial plant power level produces a greater mismatch between heat generated and heat dissipated during the transient, resulting in a greater volume of insurge and a higher level in the pressurizer. An initial value of approximately 102% of rated power was used in the LTC analysis.

b. Pressurizer Pressure

A higher initial pressurizer pressure, though it hastens reactor trip and thus reduces heat generation - heat dissipation mismatch as well as volume of insurge, results in a greater volume of flashed steam and an increased pressurizer level as the pressure decreases during the extended blowdown. The initial pressure selected for the LTC analysis was about 50 psi above the normal operating pressure. This increase above the normal value was to account for the normal operating band and instrument error.

c. Pressurizer Volume

A higher initial pressurizer liquid inventory, though it hastens reactor trip, provides a greater amount of liquid, of which a fixed fraction is flashed at a given pressure during blowdown. This tends to maximize pressurizer level. The initial pressurizer liquid volume selected for the LTC analysis was the value associated with the highest pressurizer high level alarm for the plant.

d. High Pressurizer Pressure Reactor Trip

An increased high pressurizer pressure reactor trip setpoint produces a delay in reactor trip, which increases the heat generation-heat dissipation mismatch, thus increasing the transient severity and pressurizer level. The high pressurizer pressure reactor trip setpoints were therefore increased by 22 psi to account for instrument error.

A listing of the nominal values of some key parameters as well as initial values used in the analyses of the Loss of Load event with extended safety valve blowdown are provided in Tables 1 through 9 for comparison purposes. In these tables the location of pressurizer levels and level alarms are expressed as the percentage of the distance from the lower level rozzle to the upper level nozzle. The lower and upper level nozzles are located in the lower and upper heads, respectively, of the pressurizer. Table 10 presents data for pressurizer safety valves in C-E plants.

## 7.0 RESULTS

### 7.1 Pressurizer Liquid Level

The results of the analyses of the Loss of Load event with extended safety valve blowdown are presented as pressurizer pressure and level curves versus time (Figures 1 through 20) for the various CE plants and plant classes.

For Fort Calhoun an additional set of pressure and level curves was calculated for the case of a four second delay in the release of steam subsequent to safety valve actuation. The purpose for considering this additional case was to simulate the time for discharging the water from the loop seal at the safety valve inlet on Fort Calhoun. The assumed four second delay was conservative, since loop seal tests in the EPRI test program had indicated steam release delays of the order of one second. Thus, the zero and four secod delay analyses for Fort Calhoun bounded the actual delay time in steam release for this plant. Besides Fort Calhoun, the only other C-E plant having a loop seal at the safety valve is Millstone-2. However, since this loop seal is to be eliminated, no analysis of its impact was done.

Two pressurizer level curves are presented for each plant. The lower curve represents the pressurizer level as calculated by the LTC code. This curve is considered to be conservative since it was obtained by assuming conservatively biased initial conditions to maximize pressurizer level. The upper curve was generated from the lower curve by adding additional conservatisms in the pressurizer model, i.e. no mixing of initial pressurizer liquid inventory with insurge, and no disengagement of flashed steam from the liquid phase, as described in Section 5.3. Consequently, the upper curve has a high degree of conservatism with respect to high pressurizer level. The elevation of the pressurizer safety valve nozzles is also shown on these graphs to indicate the magnitude of the elevation margin between the maximum liquid level and the safety valve nozzles. A review of the pressurizer level curves shows that in no case, for the Loss of Load event, does pressurizer liquid level reach the elevation of the pressurizer safety valve nozzles. The results are summarized in Table 11, which shows, for all the plants evaluated, the maximum pressurizer liquid level attained during the transient as well as the relative elevation of the pressurizer safety valve nozzles.

For Fort Calhoun, a comparison of the curves for a zero and four second delay in the release of steam after safety valve actuation (Figures 11-14) indicates that the delay has no significant effect on maximum pressurizer level. Maximum pressurizer pressure increases significantly, but not to an unacceptable level. Based on the loop seal tests of a Fort Calhoun-type safety valve in the EPRI safety valve test program, the delay in the release of steam due to the discharge of water from the Fort Calhoun loop seal is expected to be of the order of one second, so that Figures 11-14 represent bounding pressurizer pressures and levels.

Additional LTC runs were made for Palisades, the 3410 MWt Class, and the 3817 MWt class in which credit was taken for the pressurizer spray.

Compared to the runs for which the pressurizer spray was assumed to be inoperative, reactor trip was delayed by less than one second, and maximum pressurizer level increased by less than 1.5%. It is concluded that taking credit for the pressurizer spray in the LTC analyses does not significantly affect maximum pressurizer level.

A feature of the pressurizer pressure vs time curves should be noted. For those plants in which all the safety valves have a common setpoint, the pressure begins to drop immediately when the safety valves open. For those plants in which the safety valve setpoints are staggered, the pressure continues to increase after the safety valve with the lowest setpoint opens.

7.2 Reactor Coolant Subcooling

An extended blowdown of the primary system, if great enough, can reduce the pressure below the saturation pressure of the coolant in the reactor vessel or primary loop, causing formation of a steam bubble. A likely place for steam bubble formation is in the reactor vessel upper head, since the highest coolant temperatures, and hence the highest coolant saturation pressure, exist at the core outlet. During the blowdown of the safety valves the reactor is in a post-trip condition. Therefore, loop and reactor temperatures are generally decreasing along with the pressure, tending to maintain reactor coolant temperatures below saturation. Figure 21 presents a pair of limiting temperature curves vs time which demonstrate that flashing will not occur in the primary loop or reactor vessel during the extended safety valve blowdowns (20%) considered here. The upper curve in Figure 21 represents the plant (Palisades) with the lowest reactor vessel upper head fluid pressures, and hence, the lowest saturation temperatures during blowdown. The lower curve represents the plant (3817 MWt Class) which has the highest reactor vessel upper head fluid temperatures during the blowdown. Figure 21 shows that the upper reactor vessel head fluid temperatures for the 3817 MWt Class plant remain lower (by at least 9°F) than the reactor vessel upper head fluid saturation temperatures for the Palisades plant at all times during the transient. Since the 3817 MWt Class and the Palisades curves represent bounding conditions with respect to the highest reactor vessel upper head fluid temperatures and lowest fluid saturation temperatures, respectively, they envelop all the plants under consideration. It is concluded that, for all C-E plants considered, reactor vessel and primary coolant loop fluid will always be in a subcooled condition during the transient, so that steam bubble formation will not occur at these locations.

## 8.0 CONCLUSIONS

(a) The results of the analyses described herein have demonstrated that, for CE plants, the pressurizer liquid level does not reach the elevation of the pressurizer safety valve nozzles during safety valve actuation in a Loss of Load event with a 20% safety valve blowdown down to 2000 psia.

(b) It has also been demonstrated that, for CE plants, steam bubble formation will not occur in the reactor vessel or the reactor coolant loops during Loss of Load events associated with a pressurizer safety valve blowdown to 2000 psia.

## 9.0 REFERENCES

9.1 CEN-128, "Response of Combustion Engineering Nuclear Steam Supply System to Transients and Accidents," April, 1980, page 4, Nuclear Power Systems Division of CE Power Systems, C-E, Inc.

# TABLES

TABLE 1

PALISADES PARAMETERS

| | Nominal | Analysis Initial Conditions |
|---|---|---|
| Power, MWt | 2541 | 2593 |
| Cold leg temperature, °F | 536 | 536 |
| Pressurizer pressure, psia | 2010 | 2100 |
| Steam generator pressure, psia | 680 | 690 |
| High pressurizer pressure trip, psia | 2255 | 2277 |
| Pressurizer level, % | 49 | 75 |
| Pressurizer high level alarm, % | 75 | N/A |
| Pressurizer total volume, $ft^3$ | 1500 | N/A |

TABLE 2

FORT CALHOUN PARAMETERS

| | Nominal | Analysis Initial Conditions |
|---|---|---|
| Power, MWt | 1506 | 1536 |
| Cold leg temperature, °F | 540 | 540 |
| Pressurizer pressure, psia | 2100 | 2150 |
| Steam generator pressure, psia | 820 | 820 |
| High pressurizer pressure trip, psia | 2400 | 2422 |
| Pressurizer level, % | 65 | 73 |
| Pressurizer high level alarm, % | 73 | N/A |
| Pressurizer total volume, $ft^3$ | 900 | N/A |

TABLE 3

MILLSTONE 2 PARAMETERS

| | Nominal | Analysis Initial Conditions |
|---|---|---|
| Power, MWt | 2710 | 2764 |
| Cold leg temperature, °F | 548 | 548 |
| Pressurizer pressure, psia | 2250 | 2300 |
| Steam generator pressure, psia | 890 | 890 |
| High pressurizer pressure trip, psia | 2400 | 2422 |
| Pressurizer level, % | 65 | 75.5 |
| Pressurizer high level alarm, % | 75.5 | N/A |
| Pressurizer total volume, $ft^3$ | 1500 | N/A |

TABLE 4

ST. LUCIE 1 AND 2 PARAMETERS

| | Nominal | | Analysis Initial Conditions |
|---|---|---|---|
| | St. Lucie 1 | St. Lucie 2 | |
| Power, MWt | 2710 | 2570 | 2764 |
| Cold leg temperature, °F | 549 | 550 | 549 |
| Pressurizer pressure, psia | 2250 | 2250 | 2300 |
| Steam generator pressure, psia | 875 | 815 | 810 |
| High pressurizer pressure trip, psia | 2400 | 2400 | 2422 |
| Pressurizer level, % | 55.6 | 55.6 | 66.3 |
| Pressurizer high level alarm, % | 65.6 | 66.2 | N/A |
| Pressurizer total volume, $ft^3$ | 1500 | 1500 | N/A |

TABLE 5

3410 MWt CLASS PARAMETERS

| | Nominal | Analysis Initial Conditions |
|---|---|---|
| Power, MWt | 3410 | 3478 |
| Cold leg temperature, °F | 553 | 553 |
| Pressurizer pressure, psia | 2250 | 2300 |
| Steam generator pressure, psia | 900 | 900 |
| High pressurizer pressure trip, psia | 2400 | 2422 |
| Pressurizer level, % | 55.7 | 66.2 |
| Pressurizer high level alarm, % | 66.1 | N/A |
| Pressurizer total volume, $ft^3$ | 1800 | N/A |

TABLE 6

3817 MWt CLASS PARAMETERS

| | Nominal | Analysis Initial Conditions |
|---|---|---|
| Power, MWt | 3817 | 3893 |
| Cold leg temperature, °F | 564.5 | 564.5 |
| Pressurizer pressure, psia | 2250 | 2300 |
| Steam generator pressure, psia | 1067 | 1070 |
| High pressurizer pressure trip, psia | 2400 | 2425 |
| Pressurizer level, % | 52.6 | 61.5 |
| Pressurizer high level alarm, % | 61.5 | N/A |
| Pressurizer total volume, $ft^3$ | 1800 | N/A |

## TABLE 7

## MAINE YANKEE PARAMETERS

| | Nominal | Analysis Initial Conditions |
|---|---|---|
| Power, MWt | 2640 | 2693 |
| Cold leg temperature, °F | 550 | 550 |
| Pressurizer pressure, psia | 2250 | 2300 |
| Steam generator pressure, psia | 890 | 890 |
| High pressurizer pressure trip, psia | 2400 | 2422 |
| Pressurizer level, % | 57 | 68 |
| Pressurizer high level alarm, % | 68 | N/A |
| Pressurizer total volume, $ft^3$ | 1500 | N/A |

TABLE 8

CALVERT CLIFFS 1 AND 2 PARAMETERS

| | Nominal | Analysis Initial Conditions |
|---|---|---|
| Power, MWt | 2710 | 2764 |
| Cold leg temperature, °F | 548 | 548 |
| Pressurizer pressure, psia | 2250 | 2300 |
| Steam generator pressure, psia | 850 | 850 |
| High pressurizer pressure trip, psia | 2400 | 2422 |
| Pressurizer level, % | 59.7 | 70.6 |
| Pressurizer high level alarm, % | 70.6 | N/A |
| Pressurizer total volume, $ft^3$ | 1500 | N/A |

TABLE 9

ARKANSAS NUCLEAR ONE 2 PARAMETERS

| | Nominal | Analysis Initial Conditions |
|---|---|---|
| Power, MWt | 2815 | 2881 |
| Cold leg temperature, °F | 553.5 | 553.5 |
| Pressurizer pressure, psia | 2250 | 2300 |
| Steam generator pressure, psia | 900 | 900 |
| High pressurizer pressure trip, psia | 2400 | 2422 |
| Pressurizer level, % | 55.6 | 68.8 |
| Pressurizer high level alarm, % | 68.8 | N/A |
| Pressurizer total volume, $ft^3$ | 1200 | N/A |

TABLE 10

PRESSURIZER SAFETY VALVE DATA
FOR C-E PLANTS

| Plant | Vendor | Model | Number | Setpoint psia | ASME Rated Min. Capacity lb/hr |
|---|---|---|---|---|---|
| Palisades | Dresser | 31739A | 3 | 2500 | 230,000 |
| | | | | 2540 | |
| | | | | 2580 | |
| Fort Calhoun | Crosby | HB-BP-86 | 2 | 2500 | 216,002 |
| | | | | 2545 | 212,182 |
| St. Lucie 1 & 2 | Crosby | HB-BP-86 | 3 | 2500 | 212,182 |
| Millstone 2 | Dresser | 31739A | 2 | 2500 | 296,069 |
| Waterford 3 (3410 MWt Class) | Dresser | 31709NA | 2 | 2500 | 504,874 |
| Palo Verde 1,2 &3 (3817 MWt Class) | Dresser | 31709NA | 4 | 2500 | 504,874 |
| WNP 3 (3817 MWt Class) | Crosby | HB-BP-86 | 4 | 2500 | 504,953 |
| Maine Yankee | Dresser | 31709KA | 3 | 2500 | 214,159 |
| | | | | 2525 | 216,301 |
| | | | | 2550 | 218,442 |
| Calvert Cliffs 1 and 2 | Dresser | 31739A | 2 | 2500 | 296,065 |
| | | | | 2565 | 303,765 |
| ANO-2 | Crosby | HB-BP-86 | 2 | 2500 | 420,006 |

TABLE 11

MAXIMUM PRESSURIZER LEVELS
AND
SAFETY VALVE NOZZLE ELEVATIONS

| | Pressurizer Level, % | | Safety Valve |
|---|---|---|---|
| | LTC | Adjusted | Nozzle Elev., % |
| Palisades | 89.2 | 106.1 | 110.5 |
| Fort Calhoun | 82.3 | 91.1 | 110.0 |
| Millstone 2 | 88.0 | 100.5 | 107.0 |
| St. Lucie 1 and 2 | 83.2 | 95.5 | 107.0 |
| 3410 MWt Class (Waterford 3) | 86.0 | 98.6 | 100.0 |
| 3817 MWt Class (Palo Verde 1, 2 and 3, WNP 3) | 89.0 | 97.8 | 100.0 |
| Maine Yankee | 75.8 | 84.0 | 100.0 |
| Calvert Cliffs 1 and 2 | 83.2 | 94.5 | 100.0 |
| Arkansas Nuclear One 2 | 89.4 | 102.4 | 110.0 |

FIGURES

FIGURE 1
PALISADES
PRESSURIZER PRESSURE RESPONSE FOLLOWING A
LOSS OF LOAD TRANSIENT WITH 20%
PRIMARY SAFETY VALVE BLOWDOWN

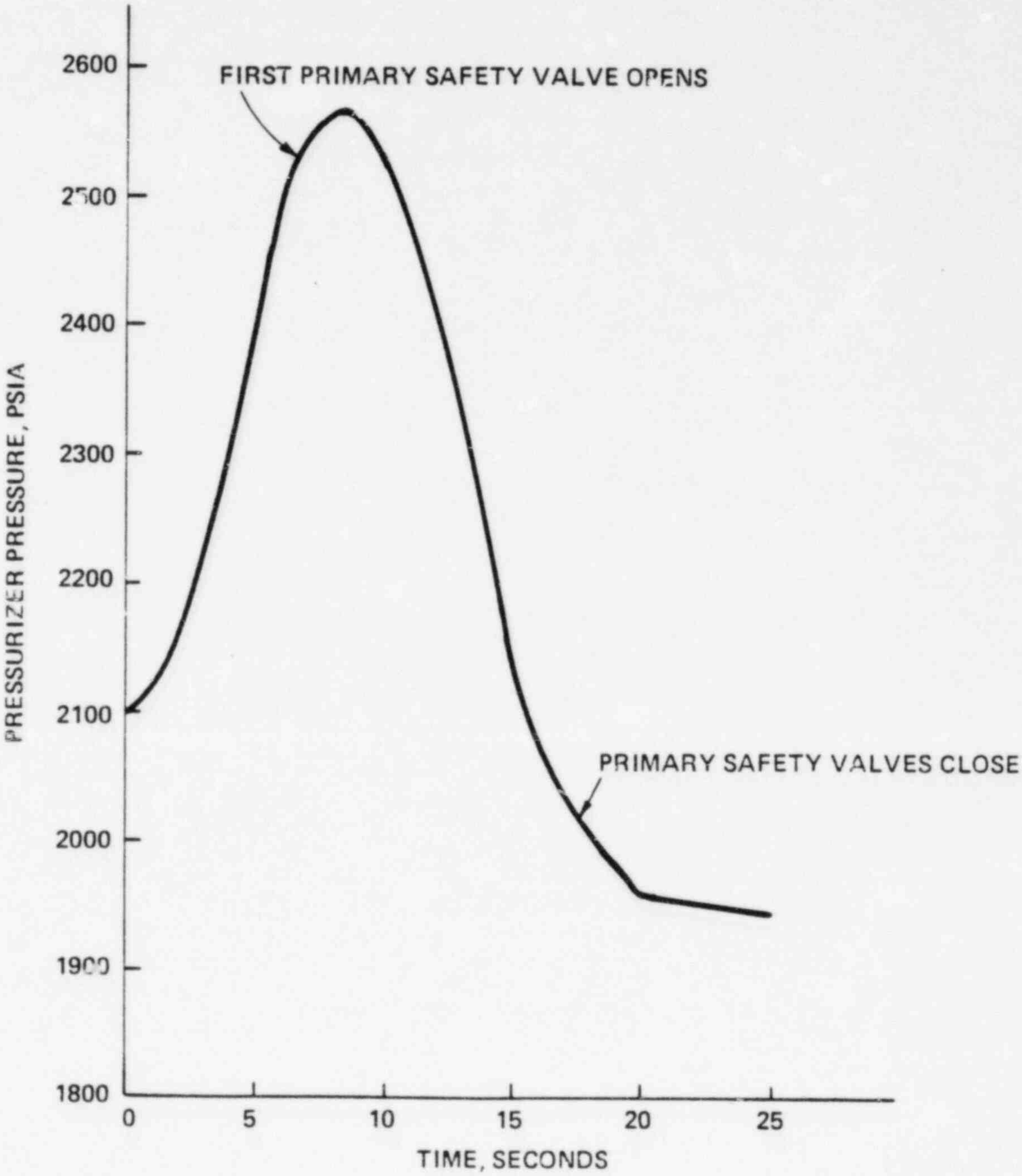

FIGURE 2
PALISADES
PRESSURIZER LEVEL RESPONSE FOLLOWING A
LOSS OF LOAD TRANSIENT WITH 20%
PRIMARY SAFETY VALVE BLOWDOWN

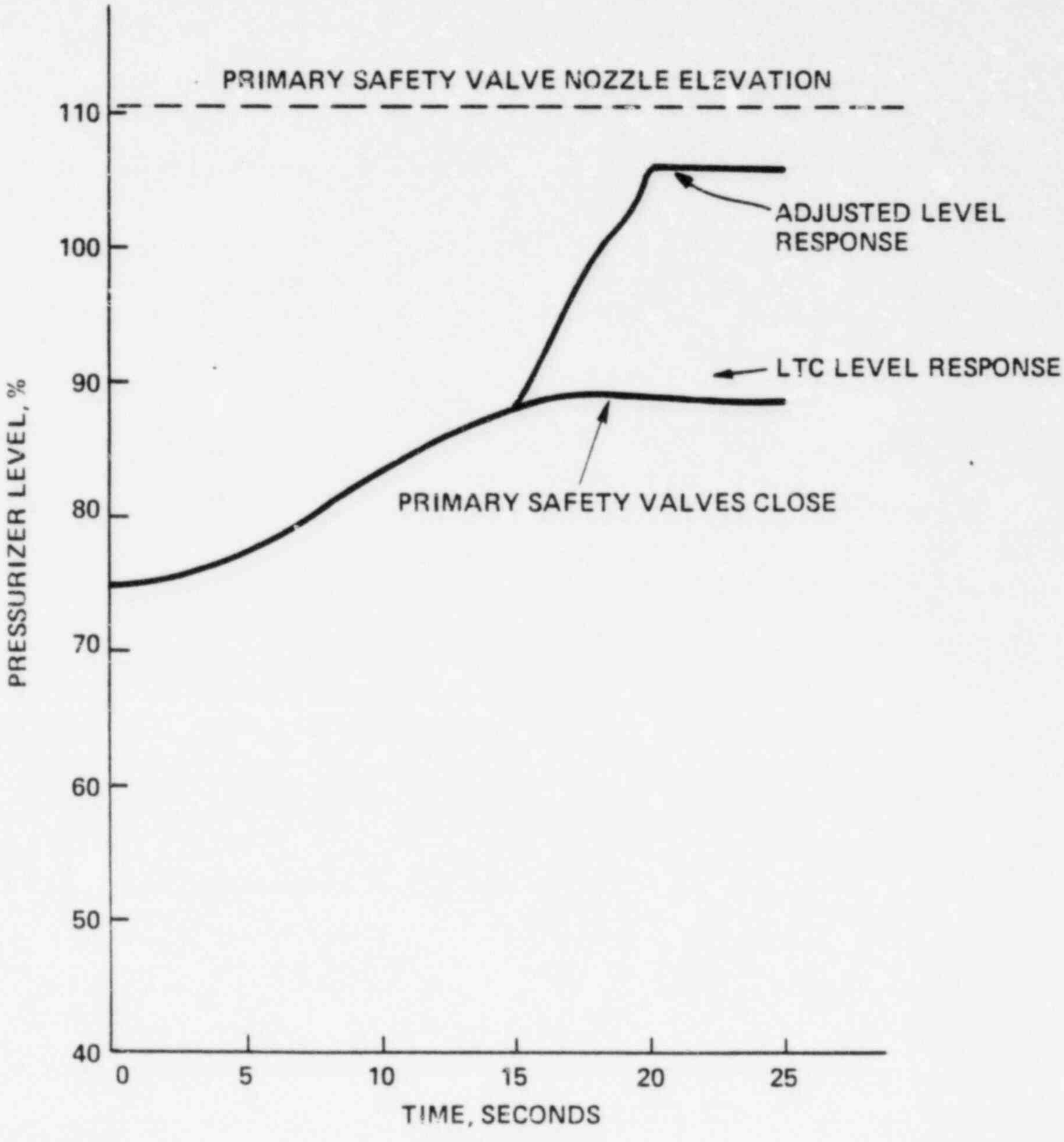

FIGURE 3
MILLSTONE 2
PRESSURIZER PRESSURE RESPONSE FOLLOWING A
LOSS OF LOAD TRANSIENT WITH 20%
PRIMARY SAFETY VALVE BLOWDOWN

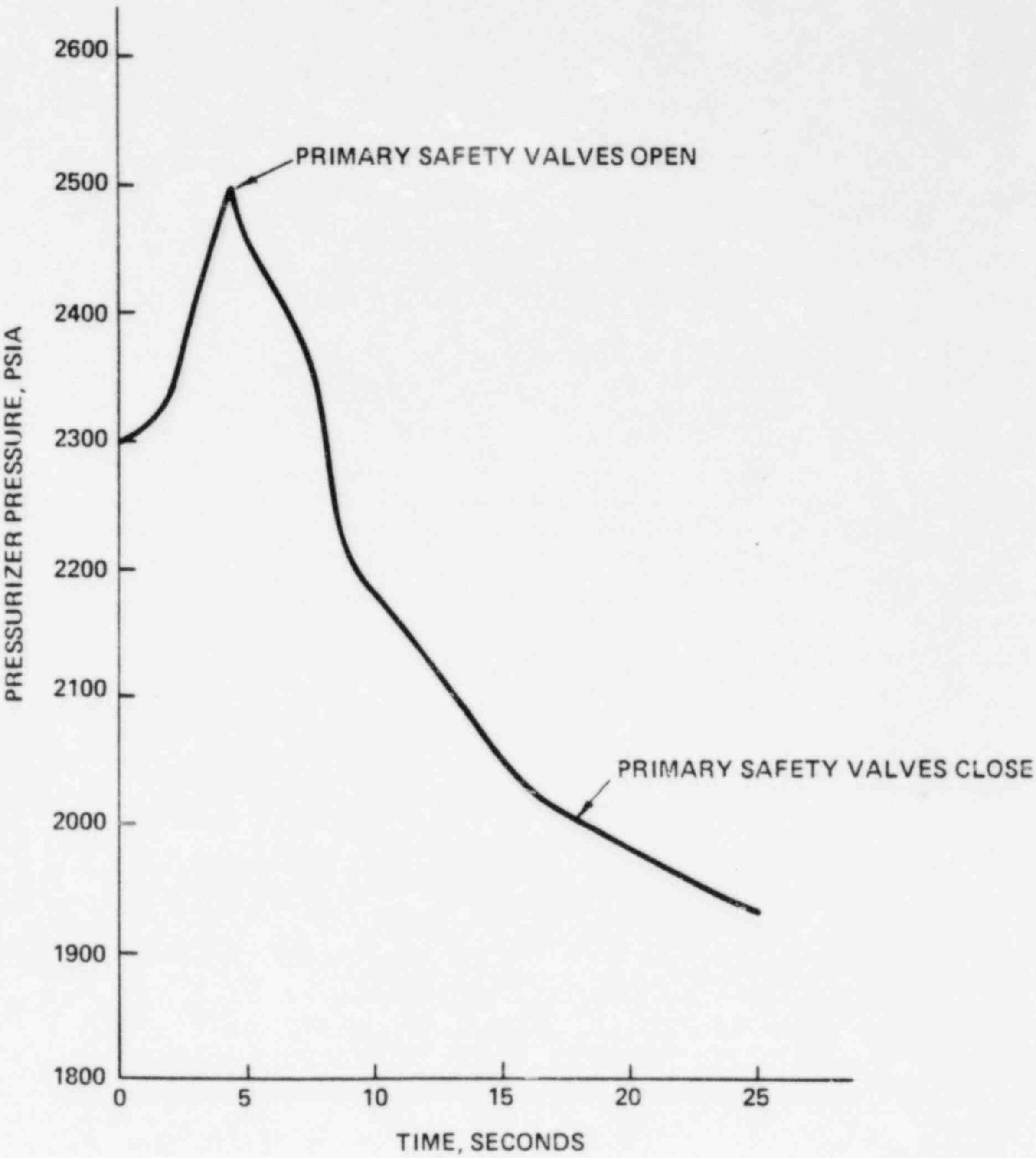

FIGURE 4
MILLSTONE 2
PRESSURIZER LEVEL RESPONSE FOLLOWING A
LOSS OF LOAD TRANSIENT WITH 20%
PRIMARY SAFETY VALVE BLOWDOWN

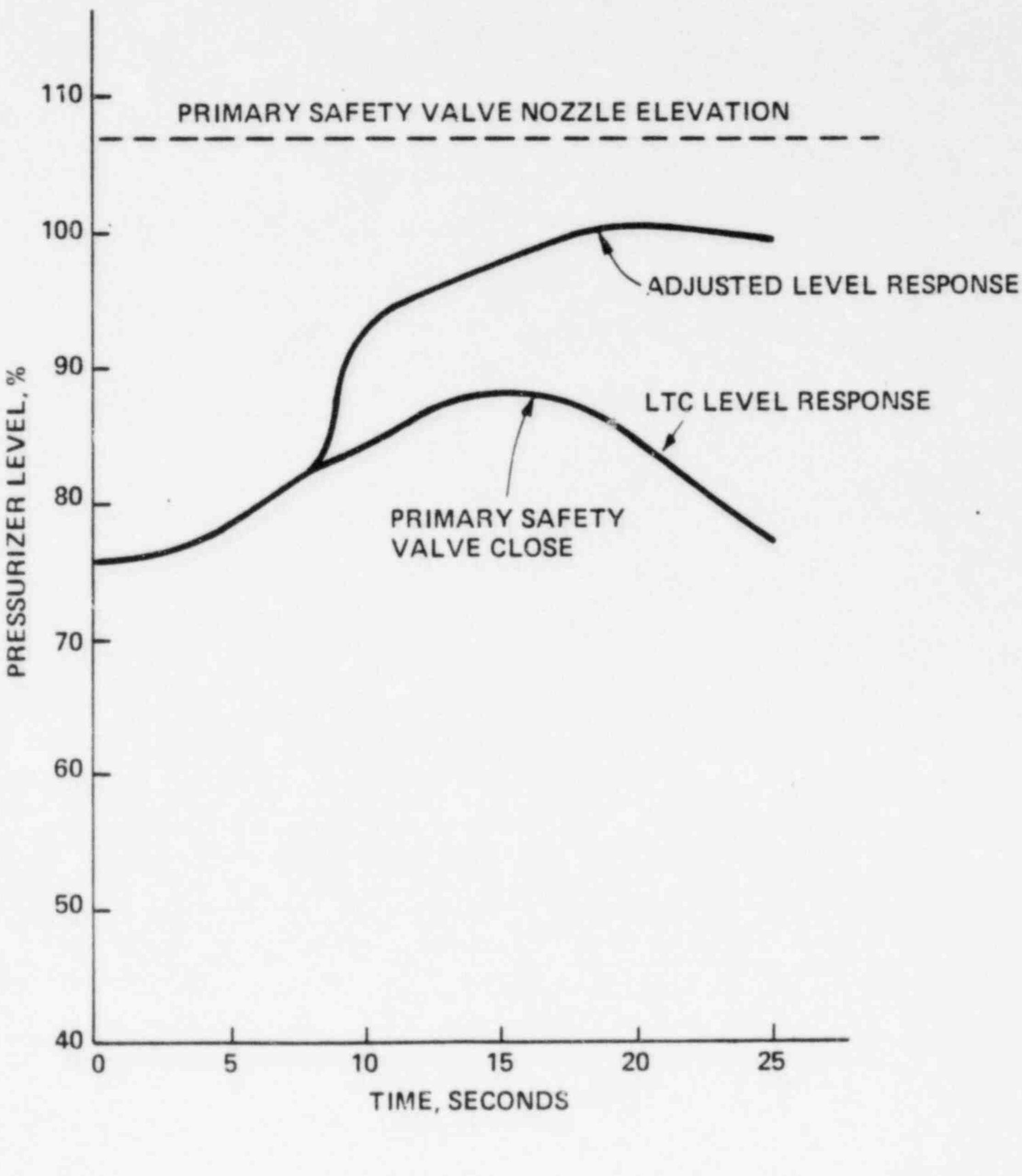

FIGURE 5
ST. LUCIE 1 & 2
PRESSURIZER PRESSURE RESPONSE FOLLOWING A
LOSS OF LOAD TRANSIENT WITH 20%
PRIMARY SAFETY VALVE BLOWDOWN

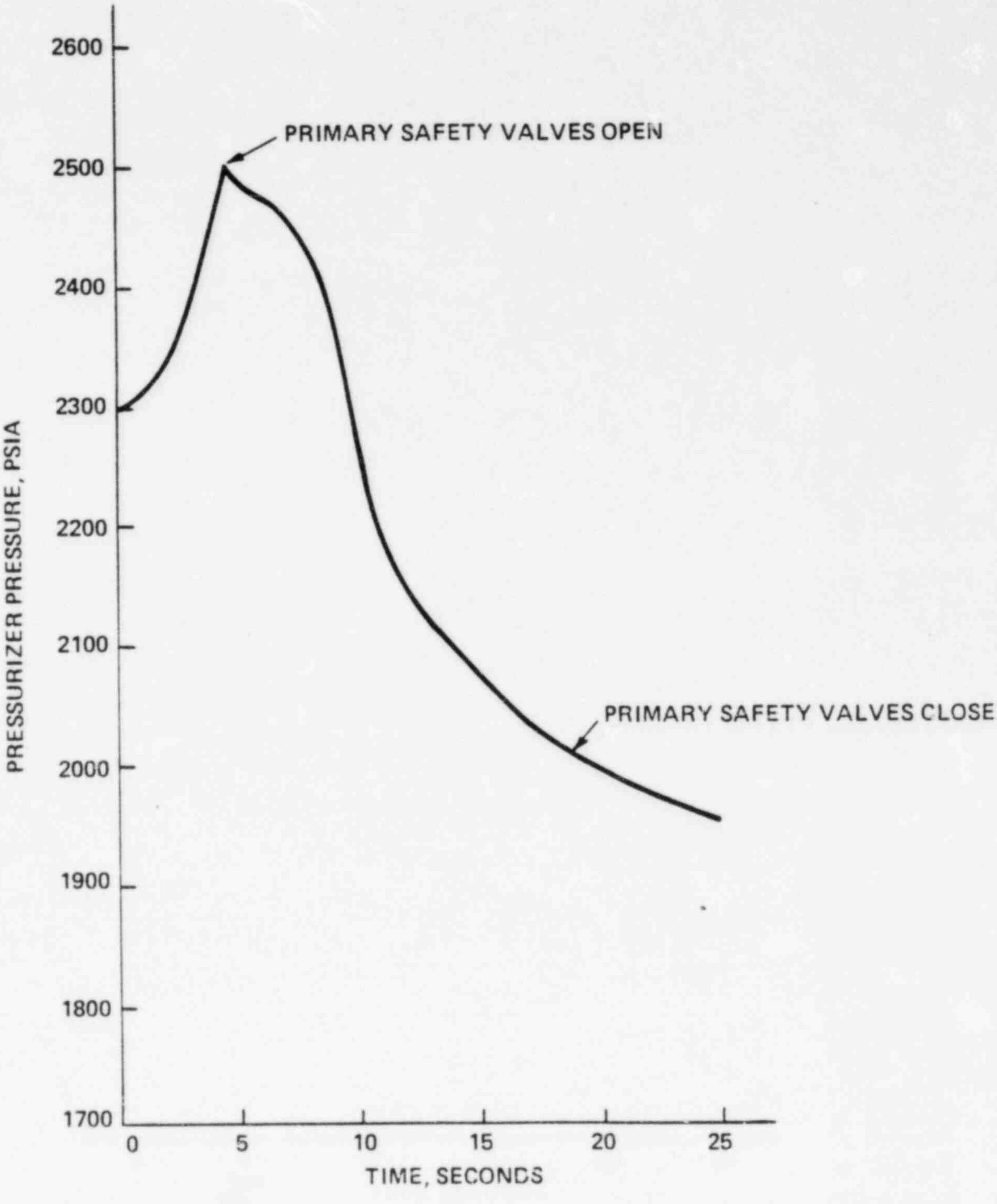

FIGURE 6
ST. LUCIE 1 & 2
PRESSURIZER LEVEL RESPONSE FOLLOWING A
LOSS OF LOAD TRANSIENT WITH 20%
PRIMARY SAFETY VALVE BLOWDOWN

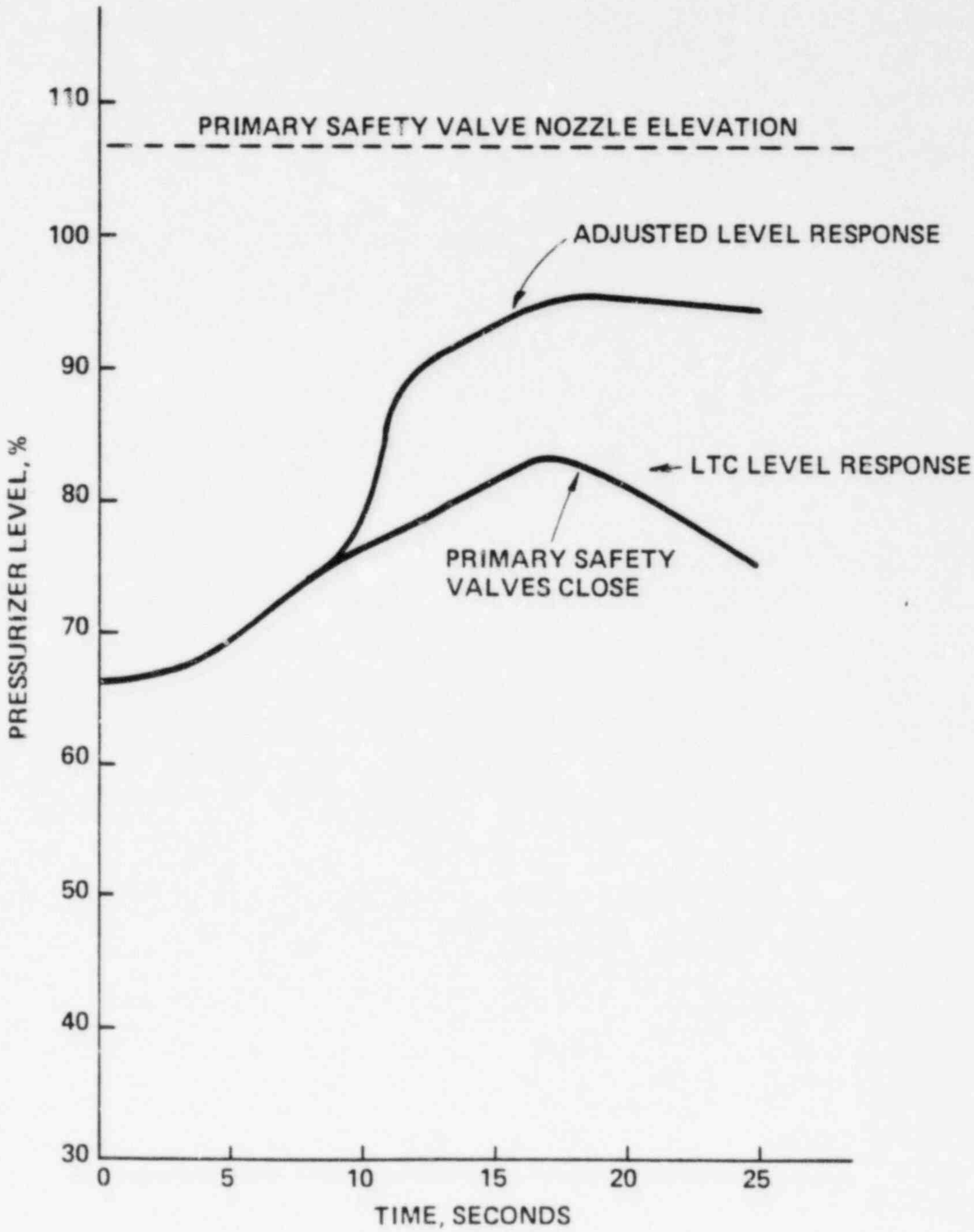

FIGURE 7
3410 CLASS PLANTS
PRESSURIZER PRESSURE RESPONSE FOLLOWING A
LOSS OF LOAD TRANSIENT WITH 20%
PRIMARY SAFETY VALVE BLOWDOWN

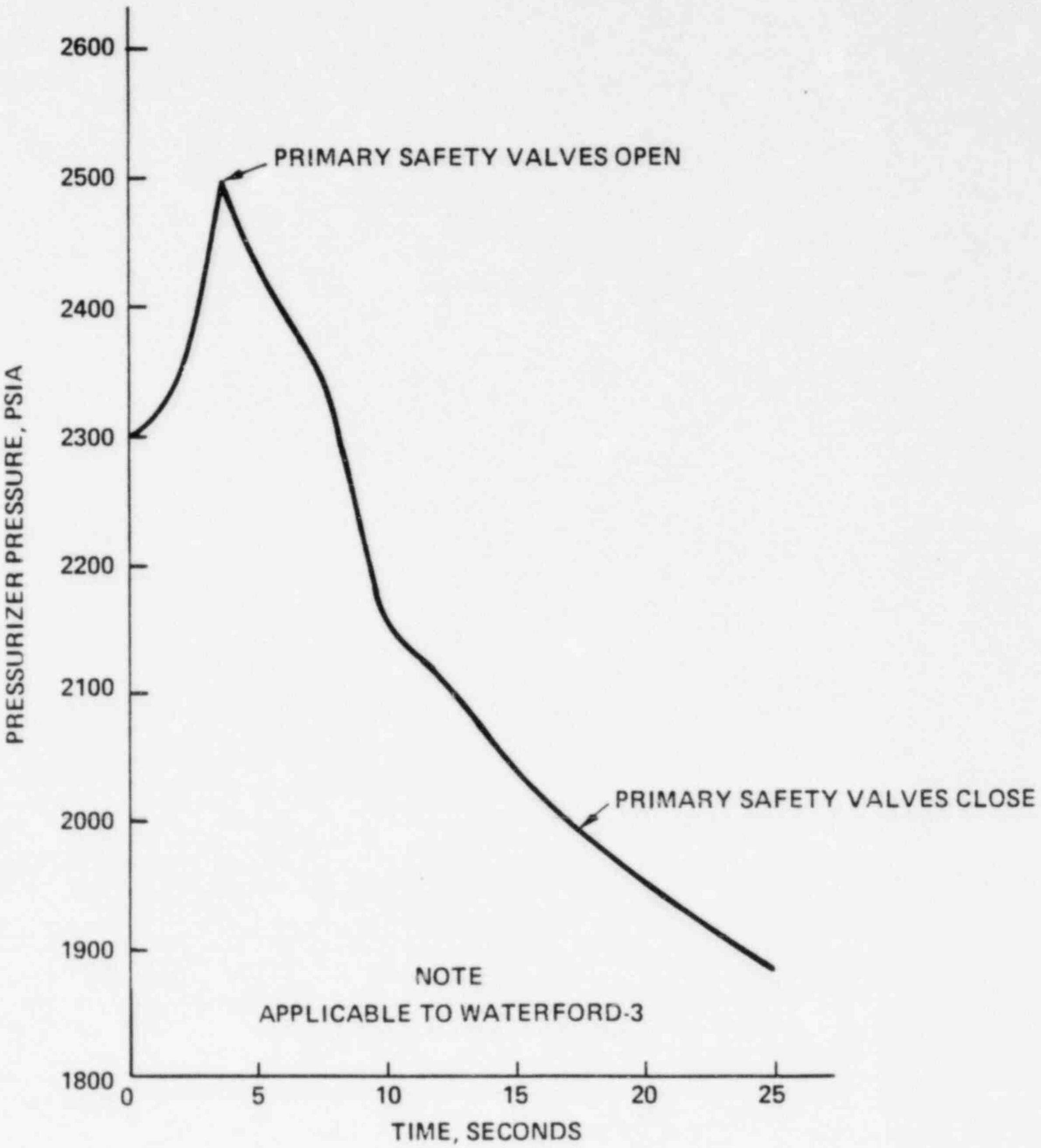

FIGURE 8
3410 CLASS PLANTS
PRESSURIZER LEVEL RESPONSE FOLLOWING A
LOSS OF LOAD TRANSIENT WITH 20%
PRIMARY SAFETY VALVE BLOWDOWN

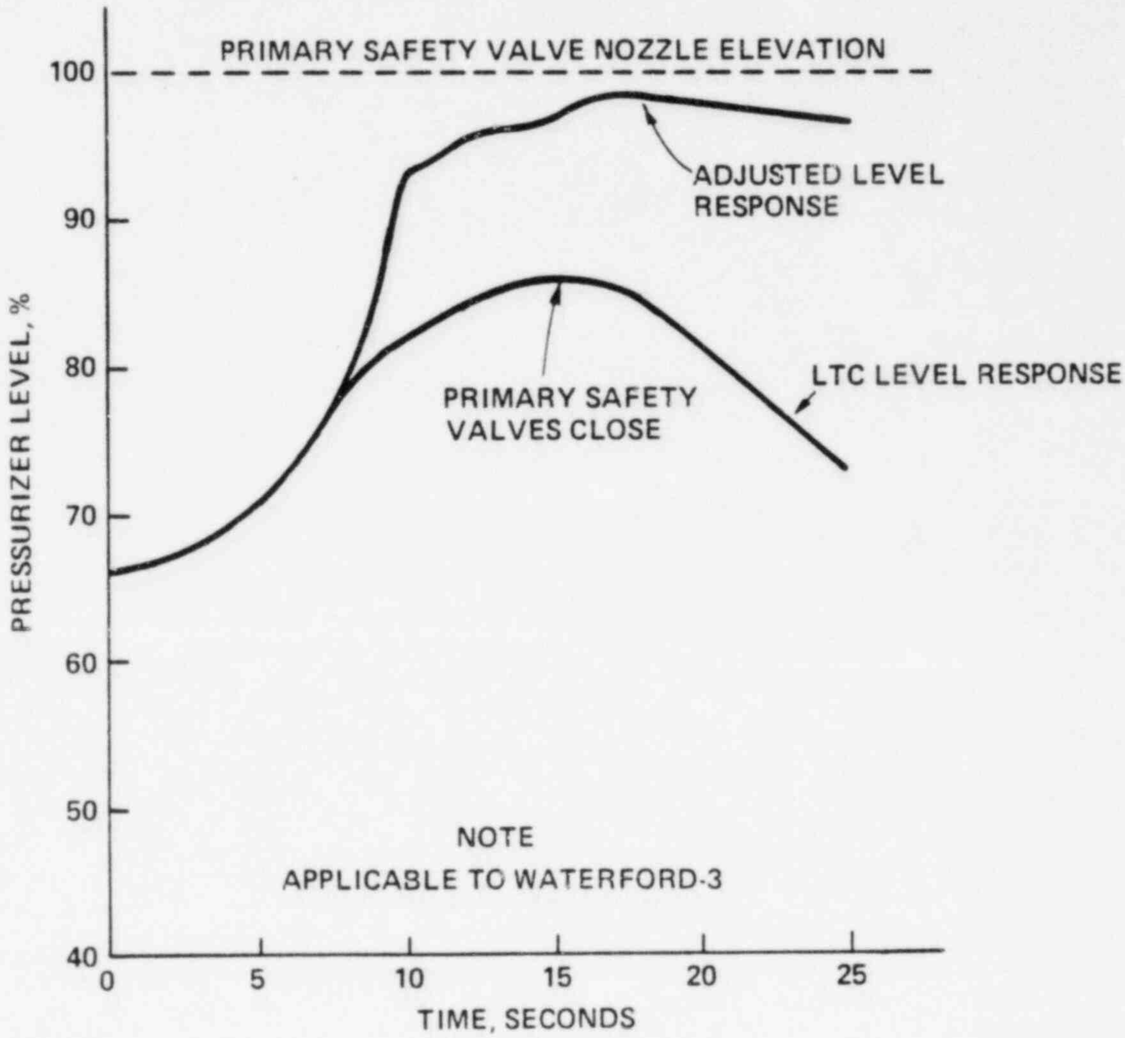

FIGURE 9
3817 MWT CLASS PLANT
PRESSURIZER PRESSURE RESPONSE FOLLOWING A
LOSS OF LOAD TRANSIENT WITH 20%
PRIMARY SAFETY VALVE BLOWDOWN

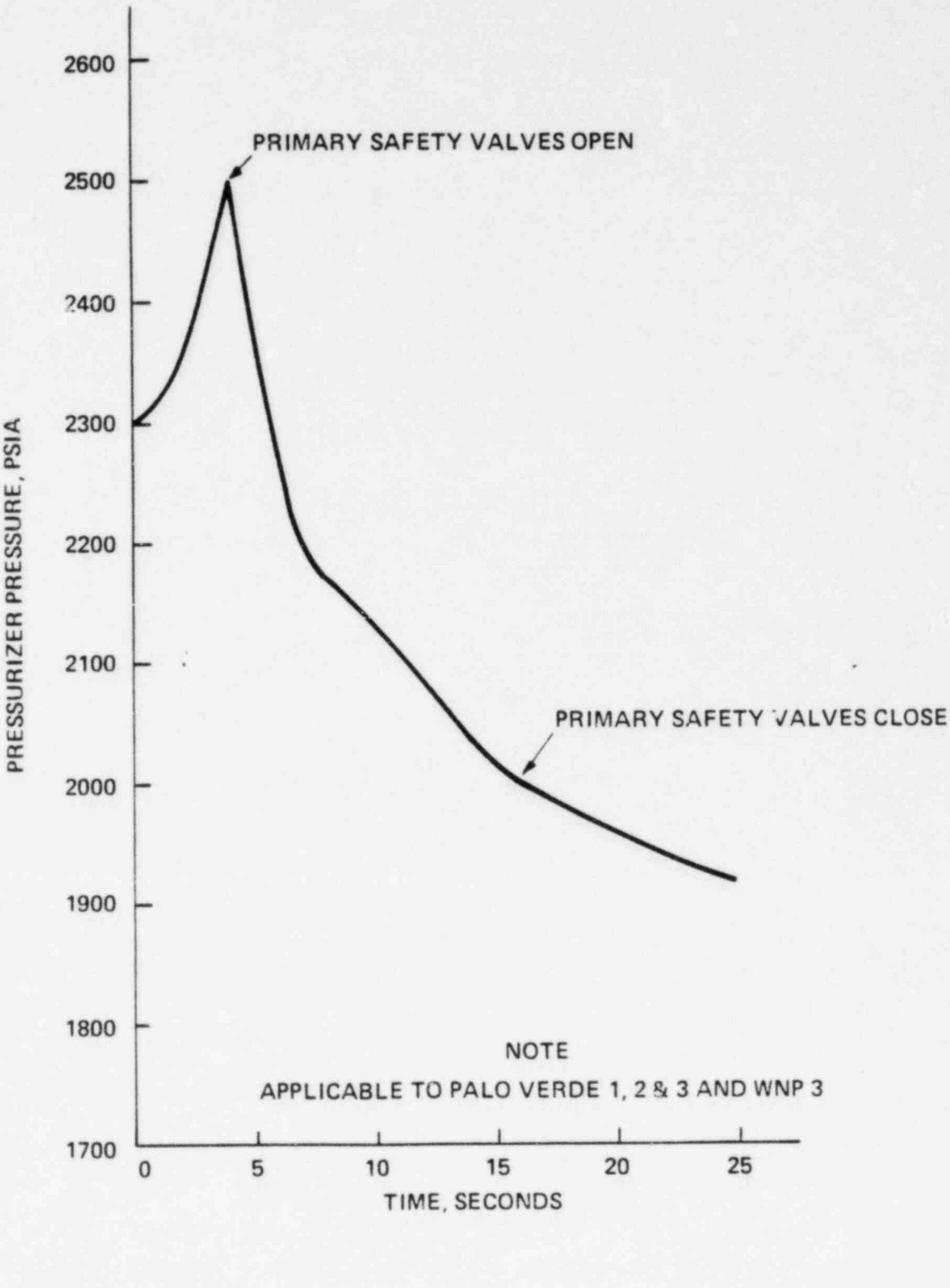

FIGURE 10
3817 MWT CLASS PLANT
PRESSURIZER LEVEL RESPONSE FOLLOWING A
LOSS OF LOAD TRANSIENT WITH 20%
PRIMARY SAFETY VALVE BLOWDOWN

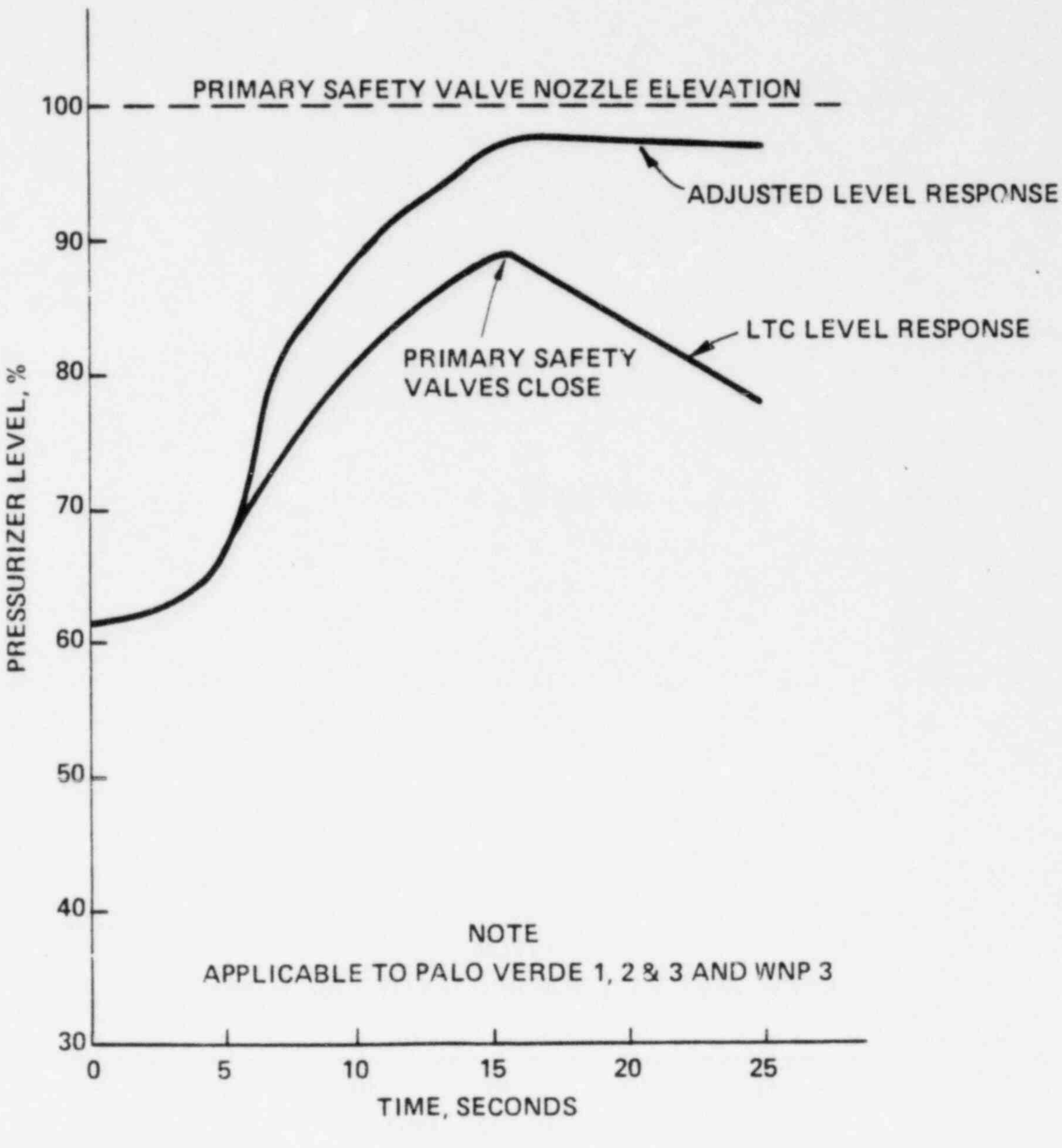

FIGURE 11
FORT CALHOUN
PRESSURIZER PRESSURE RESPONSE FOLLOWING A
LOSS OF LOAD TRANSIENT WITH 20%
PRIMARY SAFETY VALVE BLOWDOWN

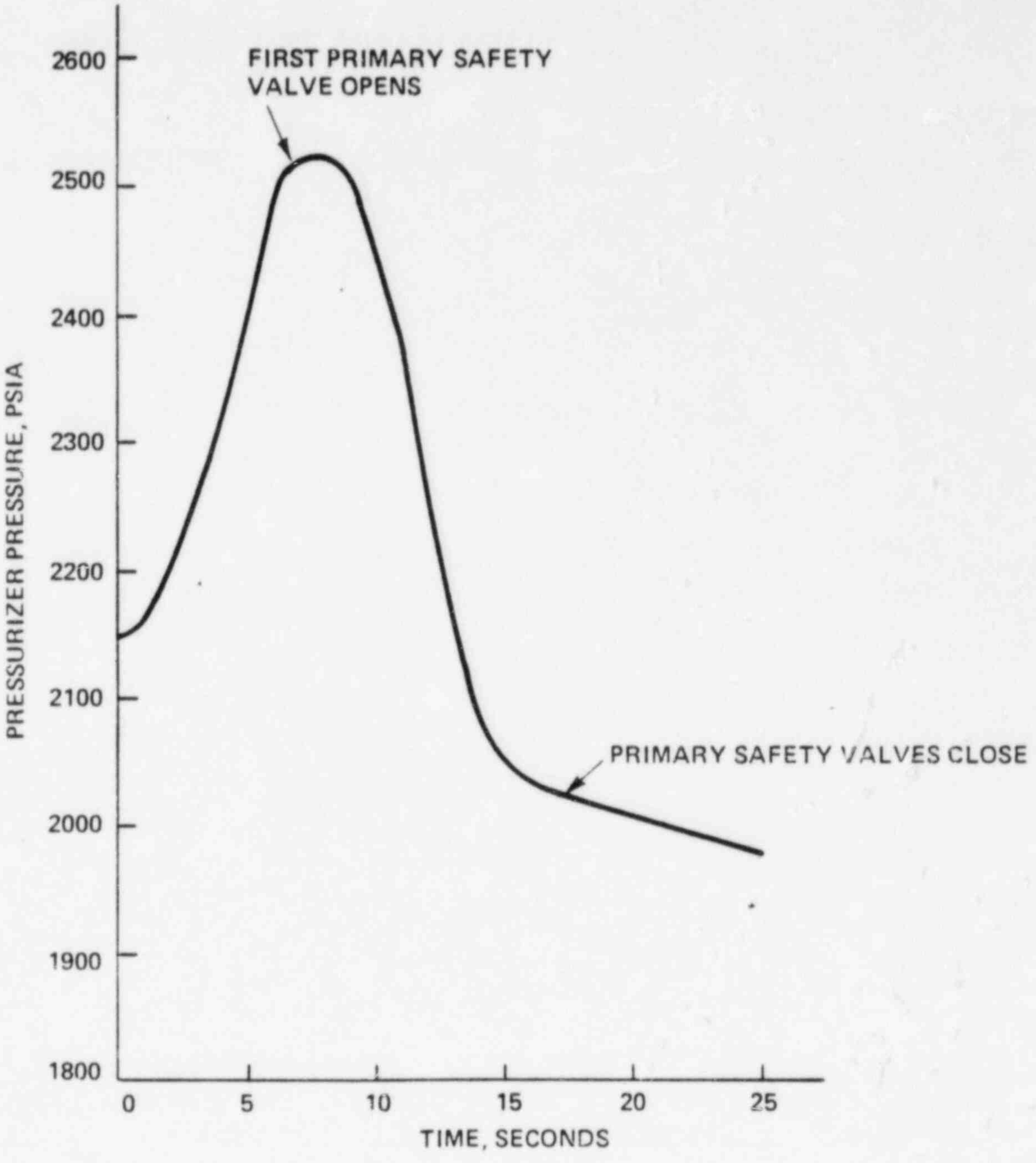

FIGURE 12
FORT CALHOUN
PRESSURIZER LEVEL RESPONSE FOLLOWING A
LOSS OF LOAD TRANSIENT WITH 20%
PRIMARY SAFETY VALVE BLOWDOWN

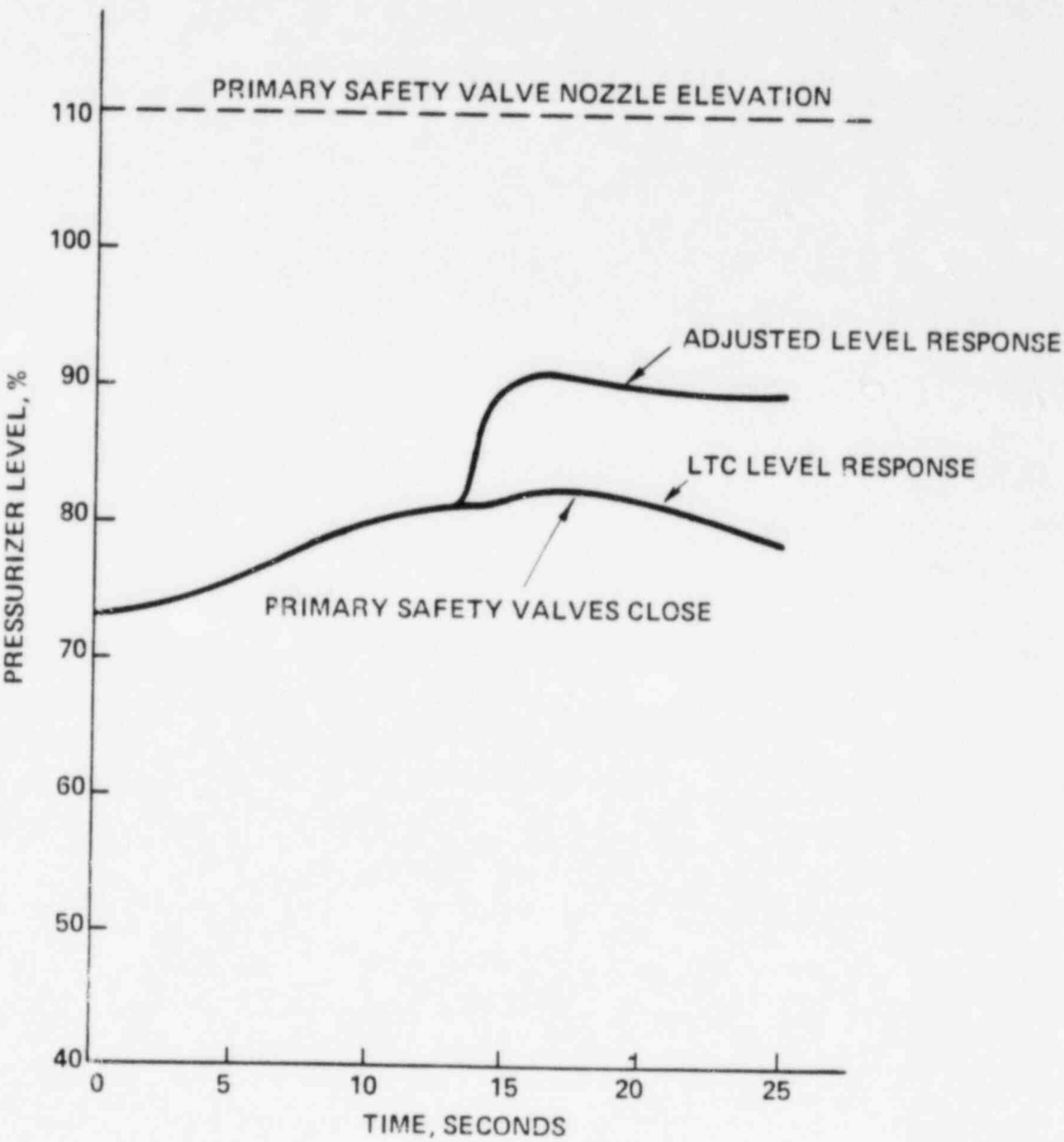

FIGURE 13
FORT CALHOUN
PRESSURIZER PRESSURE RESPONSE FOLLOWING A LOSS OF LOAD TRANSIENT WITH 20% BLOWDOWN AND 4.0 SECOND DELAY IN RELIEVING STEAM THROUGH PRIMARY SAFETY VALVES

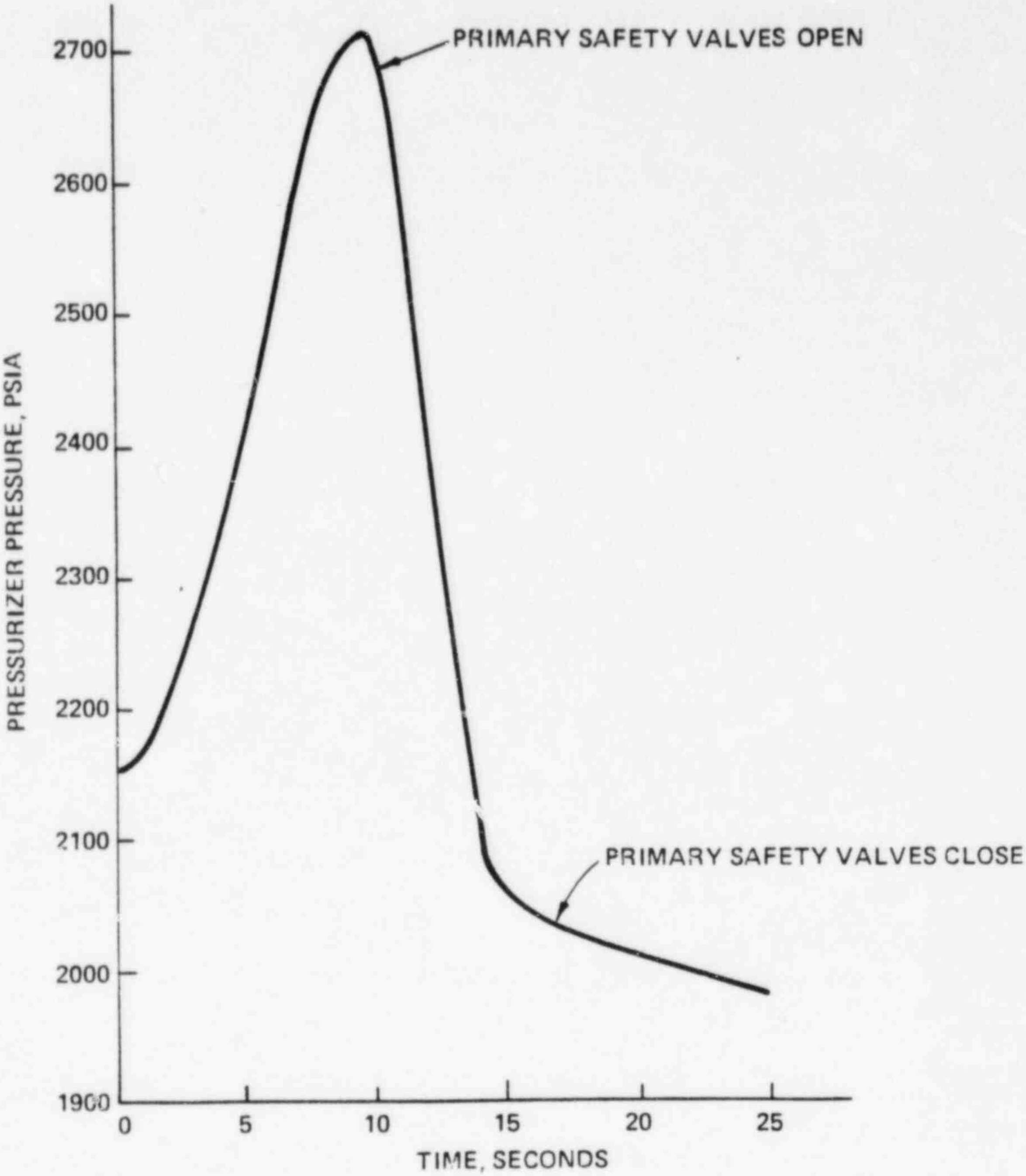

FIGURE 14
FORT CALHOUN
PRESSURIZER LEVEL RESPONSE FOLLOWING A
LOSS OF LOAD TRANSIENT WITH 20% BLOWDOWN
AND 4.0 SECOND DELAY IN RELIEVING STEAM
THROUGH PRIMARY SAFETY VALVES

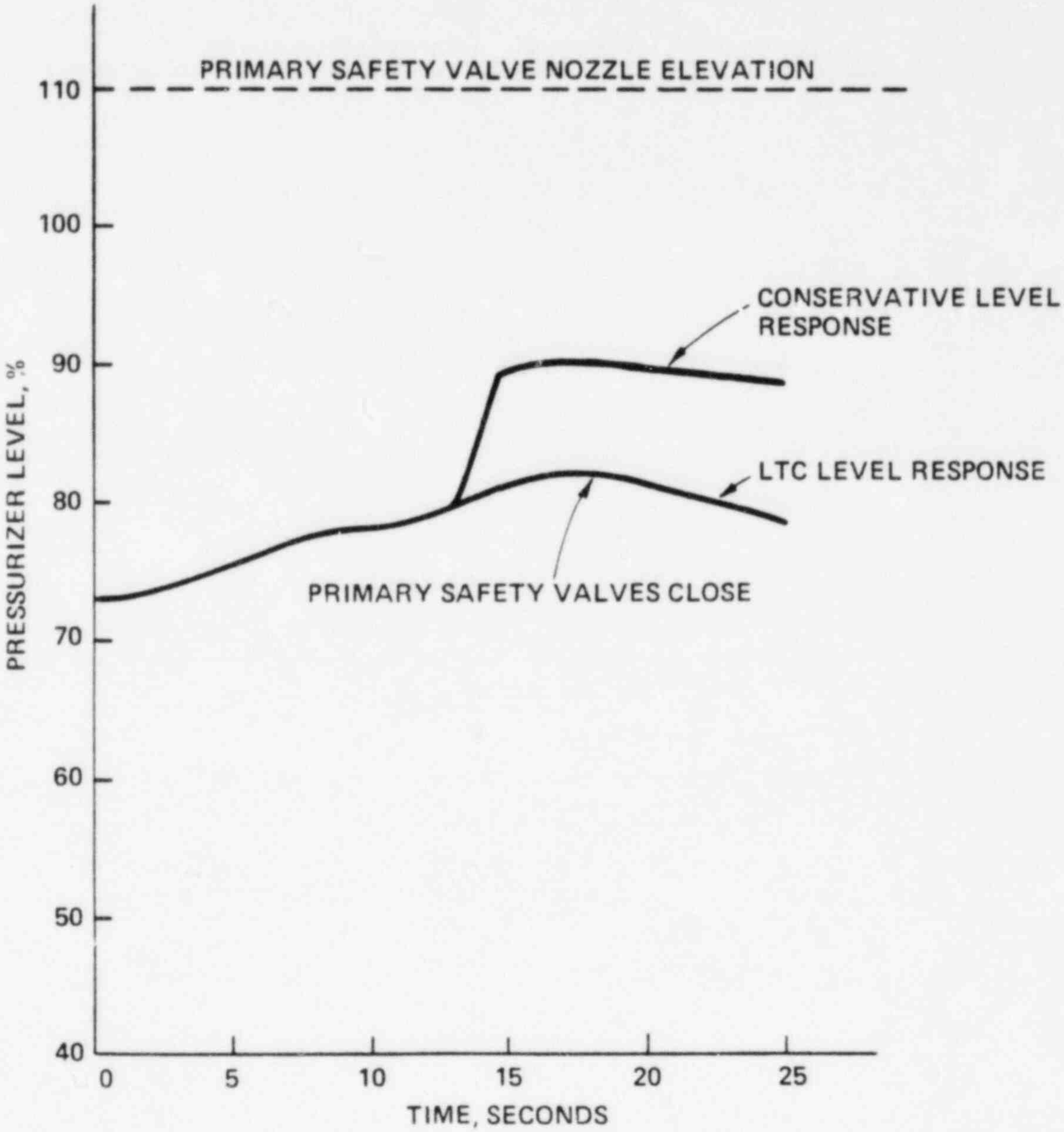

FIGURE 15
MAINE YANKEE
PRESSURIZER PRESSURE RESPONSE FOLLOWING A
LOSS OF LOAD TRANSIENT WITH 20%
PRIMARY SAFETY VALVE BLOWDOWN

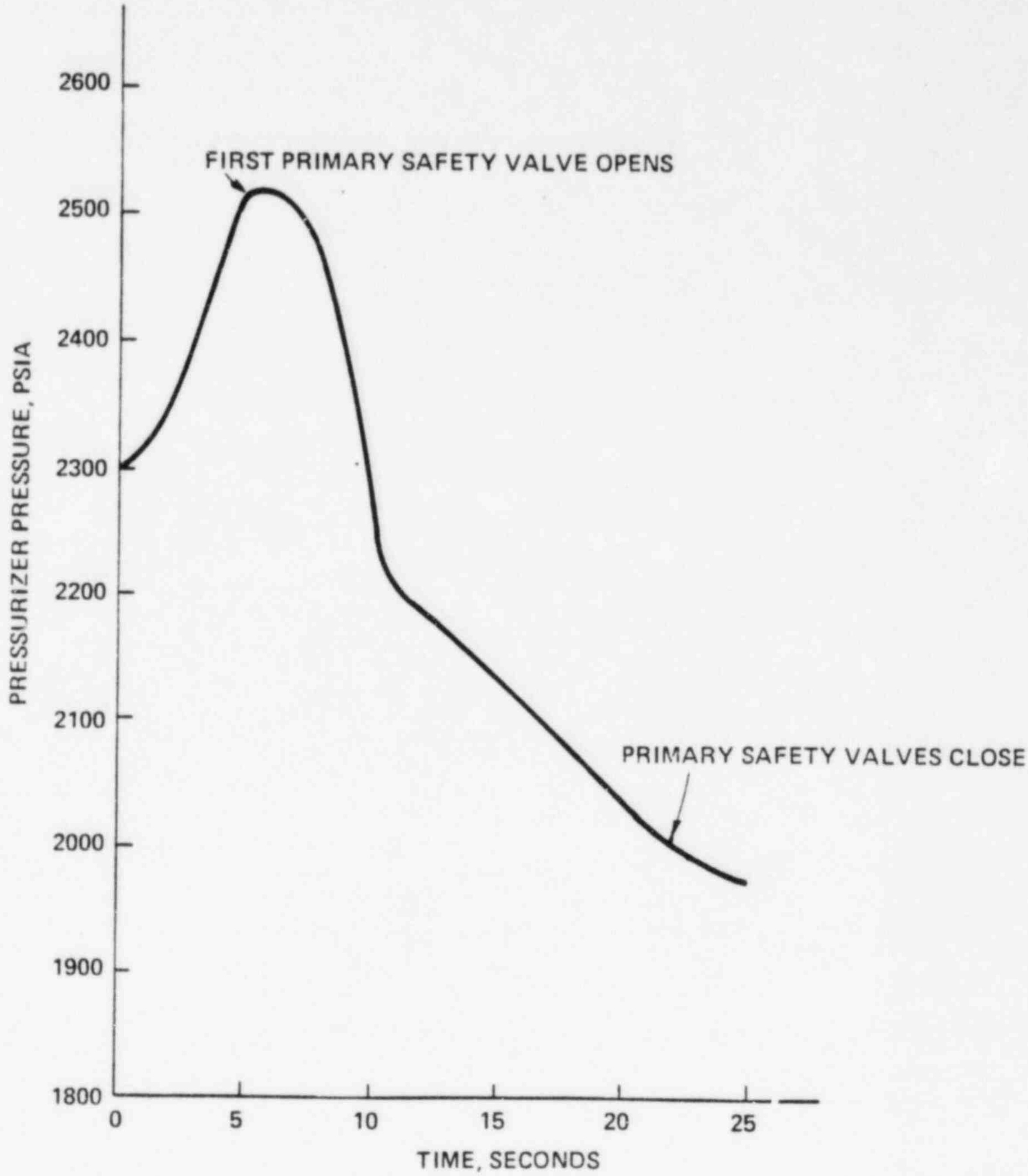

FIGURE 16
MAINE YANKEE
PRESSURIZER LEVEL RESPONSE FOLLOWING A
LOSS OF LOAD TRANSIENT WITH 20%
PRIMARY SAFETY VALVE BLOWDOWN

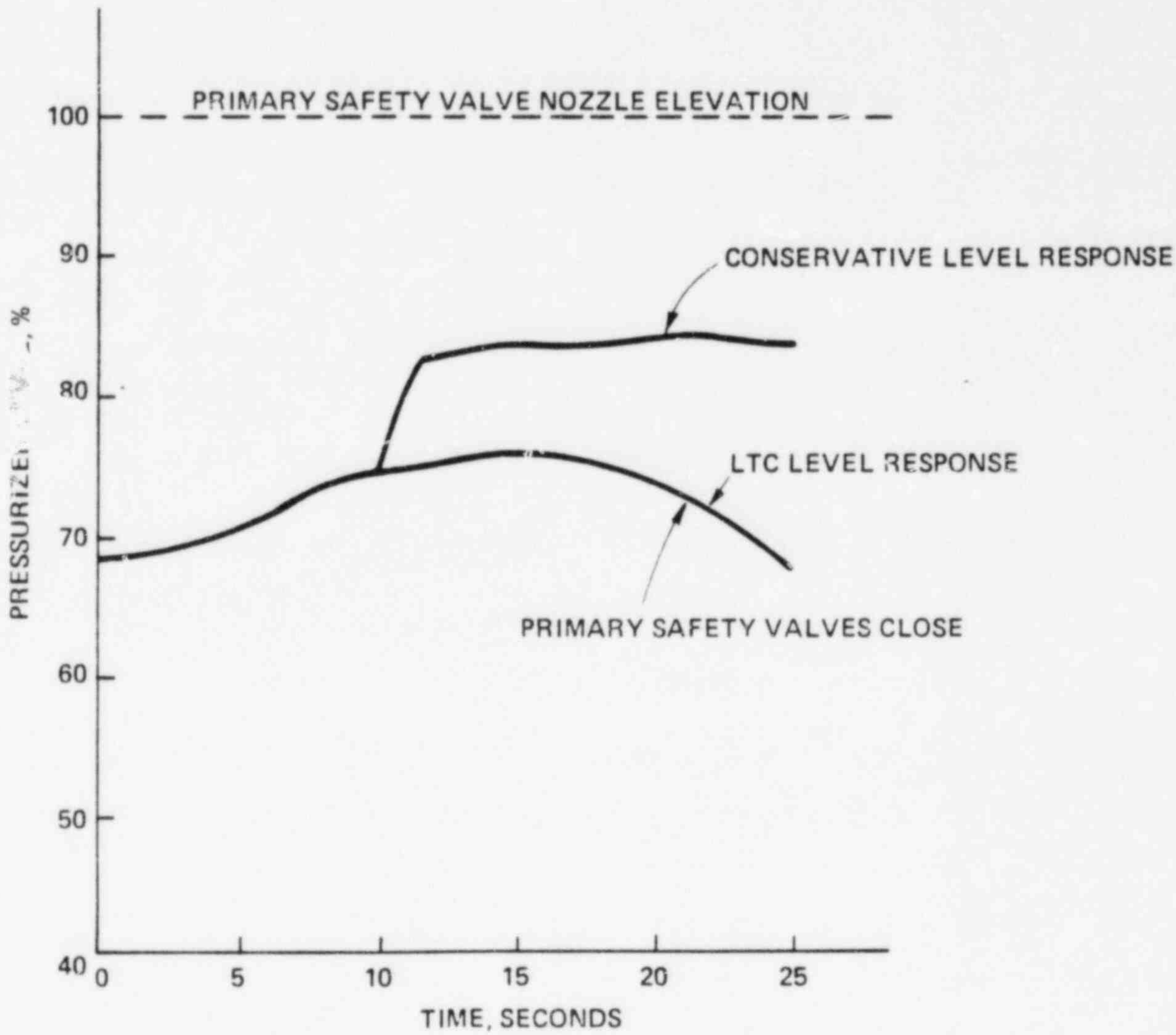

FIGURE 17
CALVERT CLIFFS 1 & 2
PRESSURIZER PRESSURE RESPONSE FOLLOWING A
LOSS OF LOAD TRANSIENT WITH 20%
PRIMARY SAFETY VALVE BLOWDOWN

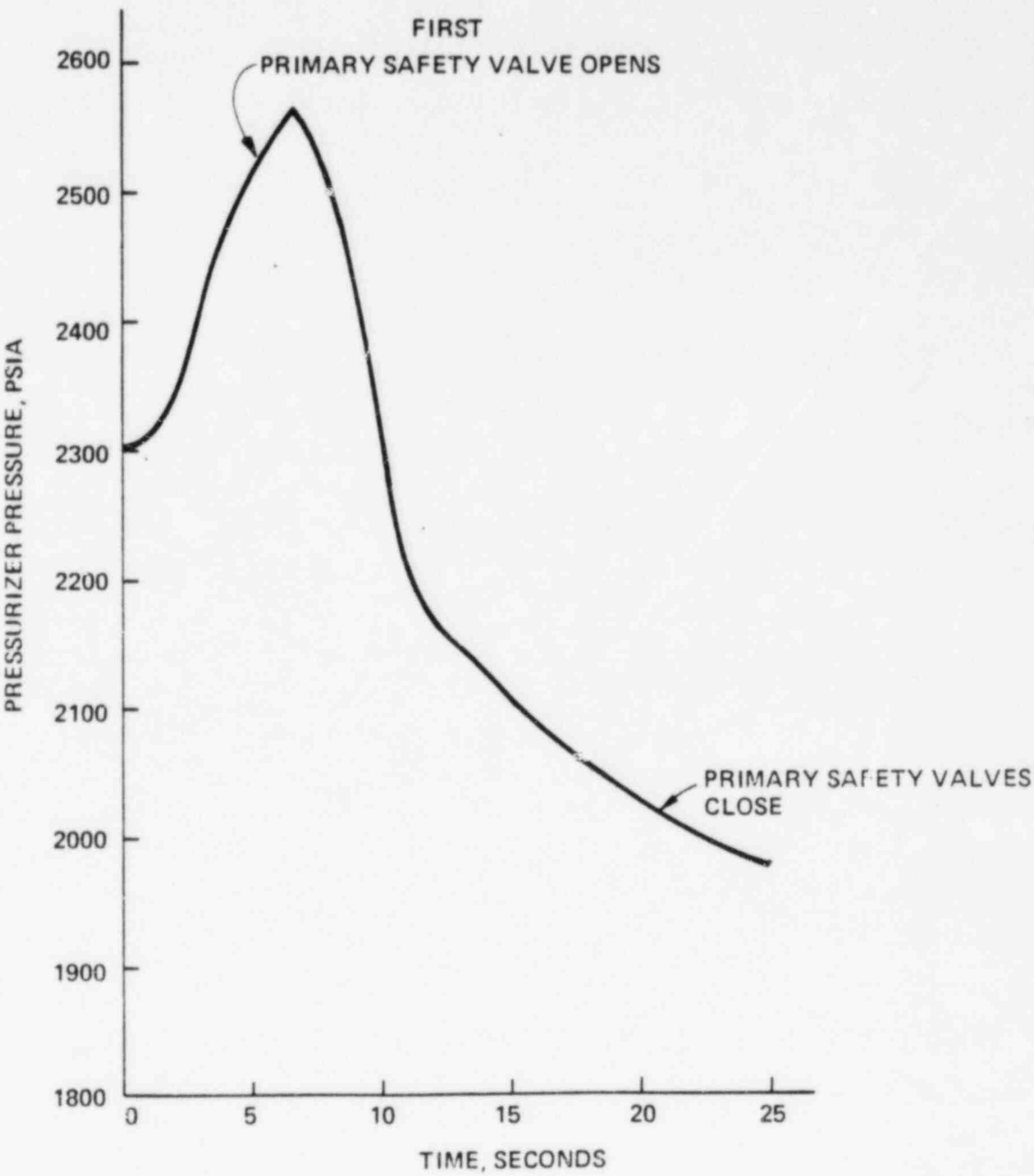

FIGURE 18
CALVERT CLIFFS 1 & 2
PRESSURIZER LEVEL RESPONSE FOLLOWING A
LOSS OF LOAD TRANSIENT WITH 20%
PRIMARY SAFETY VALVE BLOWDOWN

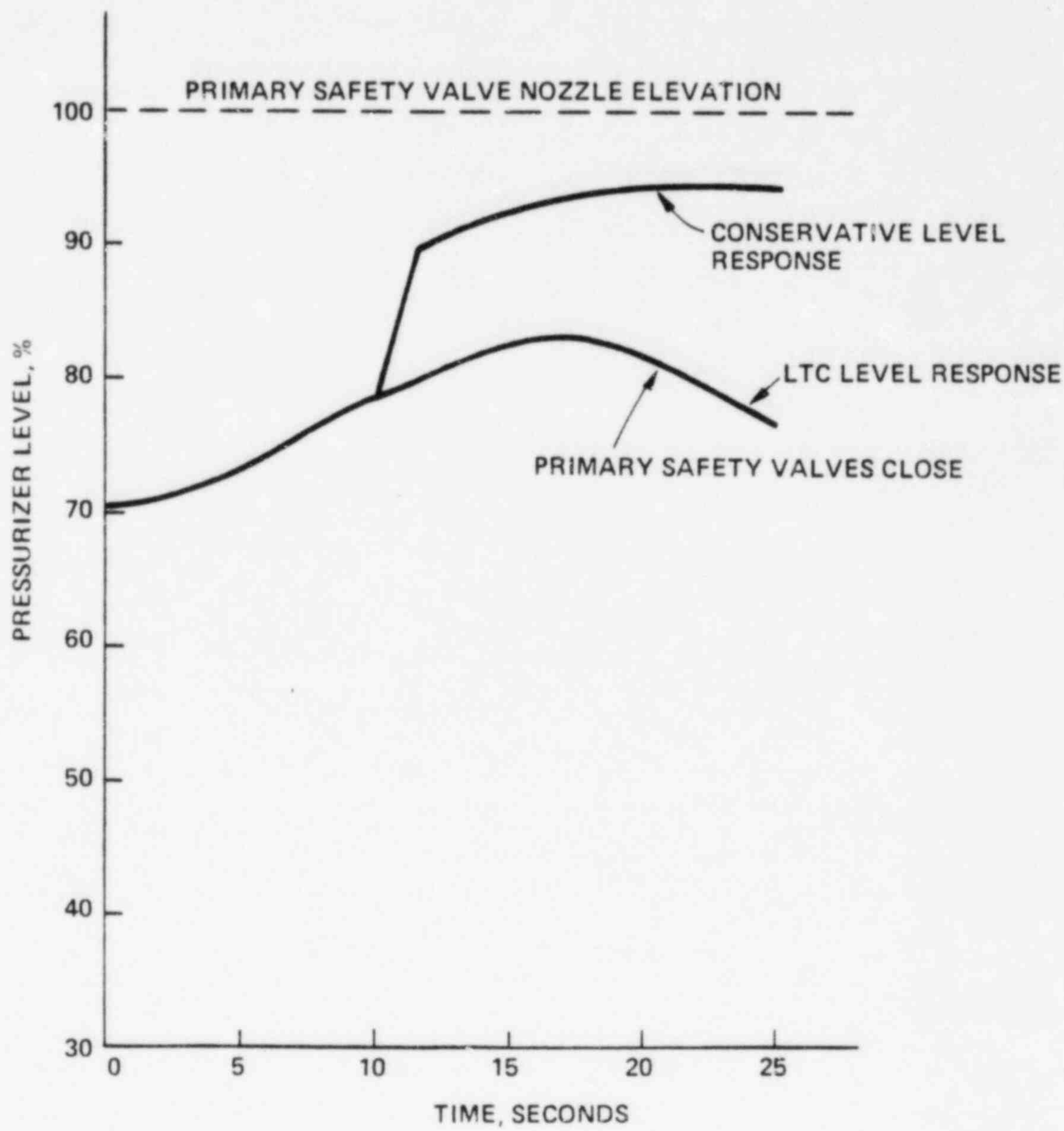

FIGURE 19
ARKANSAS NUCLEAR ONE - 2
PRESSURIZER PRESSURE RESPONSE FOLLOWING A
LOSS OF LOAD TRANSIENT WITH 20%
PRIMARY SAFETY VALVE BLOWDOWN

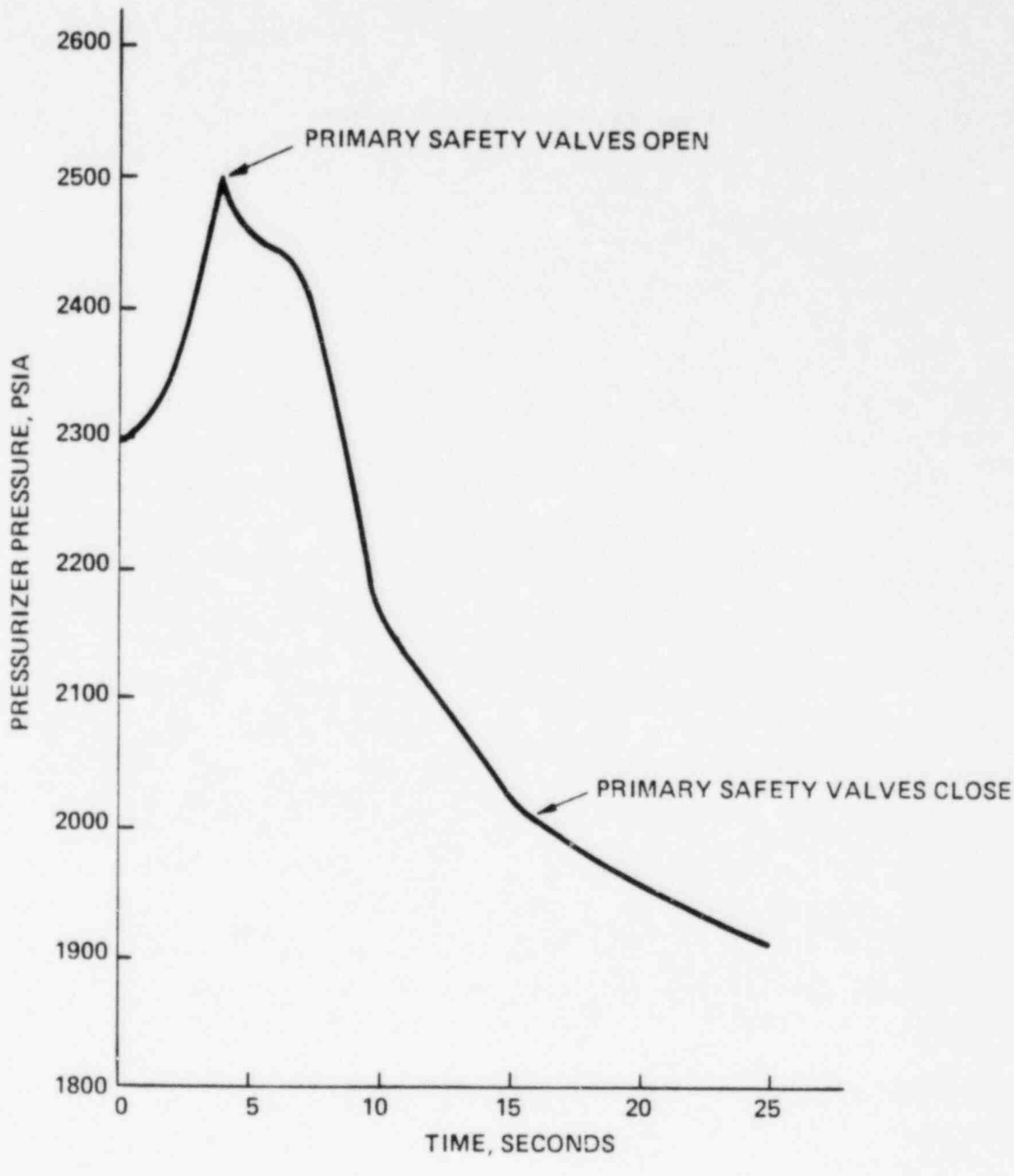

FIGURE 20
ARKANSAS NUCLEAR ONE - 2
PRESSURIZER LEVEL RESPONSE FOLLOWING A
LOSS OF LOAD TRANSIENT WITH 20%
PRIMARY SAFETY VALVE BLOWDOWN

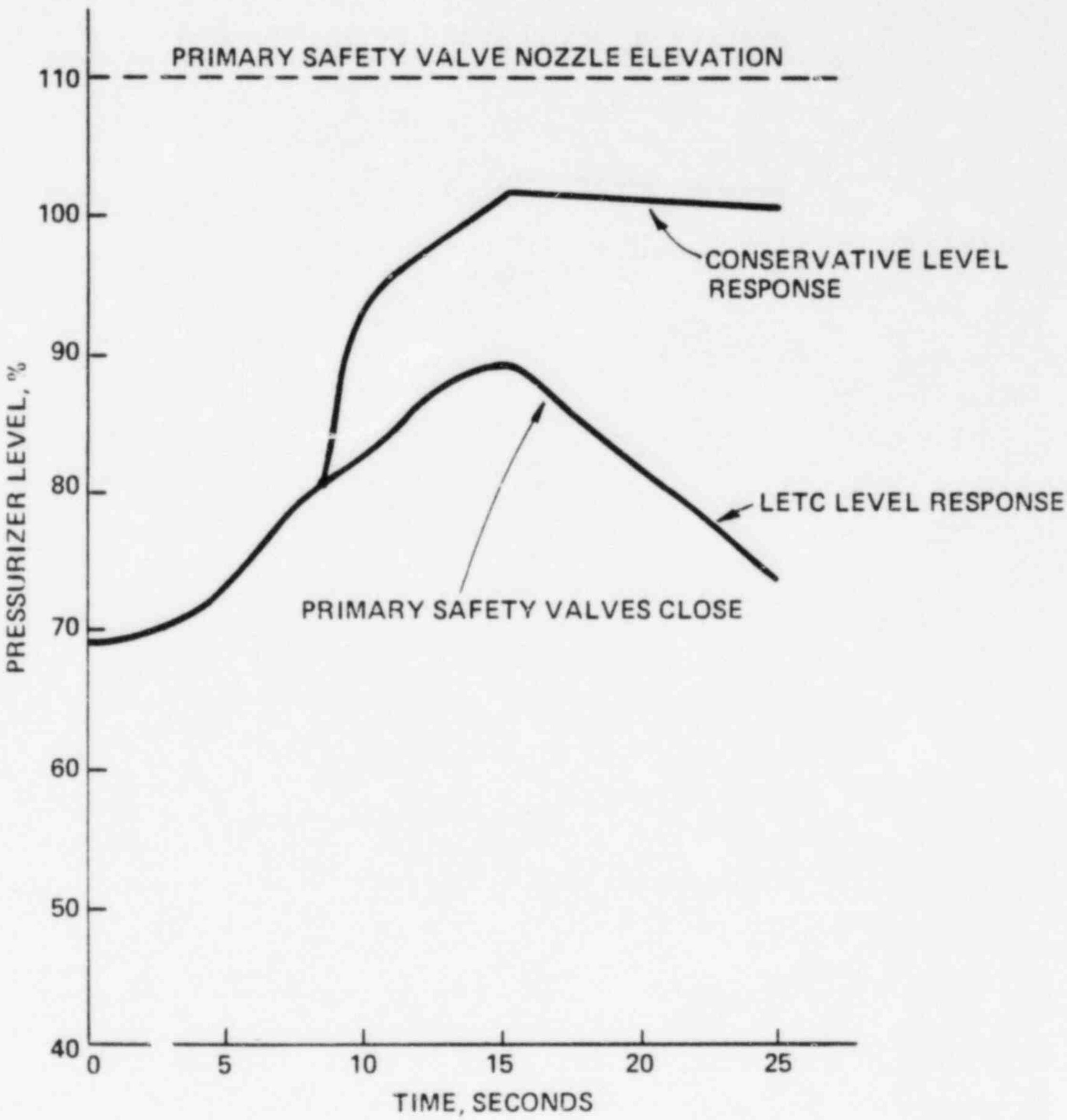

FIGURE 21
UPPER HEAD MAXIMUM TEMPERATURES AND
MINIMUM SATURATION TEMPERATURES