MISSISSIPPI POWER & LIGHT COMPANY
Helping Build Mississippi
P. O. BOX 1640, JACKSON, MISSISSIPPI 39205

NUCLEAR PRODUCTION DEPARTMENT

July 31, 1981

U.S. Nuclear Regulatory Commission
Office of Nuclear Reactor Regulation
Washington, D.C. 20555

Attention: Mr. Harold R. Denton, Director

Dear Mr. Denton:

SUBJECT: Grand Gulf Nuclear Station
Units 1 and 2
Docket Nos. 50-416 and 50-417
File 0260/0862
Transmittal of Proposed FSAR Changes and Responses to NRC Questions
AECM-81/277

References:
1) Reactor Systems Branch Questions 211.131, 39, 211, 126, 212.20
2) Instrumentation and Control Systems Branch Question 31.60
3) Seismology-Geology Branch Question 362.7
4) LOCA Analysis FSAR Section 6.3

In response to your request for additional information, Mississippi Power & Light Company is submitting the enclosed materials updating information pertaining to the above referenced items.

This information represents changes to the Grand Gulf Nuclear Station Final Safety Analysis Report (FSAR).

These proposed FSAR changes will be incorporated into the next available amendment to the FSAR. If you have any questions or require further information, please contact this office.

Yours truly,

John D Richardson for

L. F. Dale
Manager of Nuclear Services

JTB/JGC/JDR:lm

Attachments: (See Next Page)

A1W1

B001 S 1/1

MISSISSIPPI POWER & LIGHT COMPANY

Attachments:
1. Question & Response 211.131
2. Question & Response 211.39
3. Question & Response 211.211
4. Question & Response 211.126
5. Question & Response 212.20
6. Question & Response 31.60
7. Question & Response 362.7
8. LOCA Analysis FSAR Section 6.3

cc: Mr. N. L. Stampley
Mr. G. B. Taylor
Mr. R. B. McGehee
Mr. T. B. Conner

Mr. Victor Stello, Jr., Director
Office of Inspection & Enforcement
U.S. Nuclear Regulatory Commission
Washington, D.C. 20555

A1W2

211.131 (5.4.7) In response to Question 211.39, you state that pumps of similar construction and design to the Grand Gulf RHR pump were tested. In order that these endurance tests may qualify for applicability to Grand Gulf, it must be demonstrated that there were no significant differences between the pumps tested and the Grand Gulf pumps. Describe the similarities and differences between these pumps.

RESPONSE

The pumps that were endurance tested were

1) A low pressure core spray pump (LPCS)

2) A high pressure core spray pump (HPCS)

The LPCS pump was tested for 50 hours. The HPCS pump was tested for 150 hours. These tested pumps are similar though not identical to the RHR pumps for Grand Gulf.

The RHR pump for Grand Gulf is a three-stage pump with a 37-inch OD casing and a length of 281 inches below its mounting flange. The approximate length of the column plus pump stages is 320 inches. The pump has 24-inch suction and 18-inch discharge nozzles. The pump is specified and tested to deliver 7620 gpm at 301-foot total dynamic head.

The LPCS pump that was tested is a four-stage pump rated at 5125 gpm at 725-foot total dynamic head. This pump has a 20-inch suction and a 14-inch discharge nozzle. Its length below mount is 251 inches and its barrel diameter is 34 inches. The approximate length of the pump and motor is 478 inches.

The HPCS pump is a 13-stage unit rated at 6250 gpm at 955-foot total dynamic head. The HPCS pump has a length below mounting flange of 283 inches, a barrel diameter of 37 inches, and the length of the pump and motor is approximately 472 inches.

All pumps run at 1780 rpm.

Although there exists a slight size factor difference and the number of stages varies, the pump design is basically the same, exhibiting similar hydraulic and mechanical characteristics.

Furthermore the two pumps which were tested span the Grand Gulf RHR pump in terms of dimensions and number of stages.

On the above basis it is concluded that the two pumps which were tested reasonably represent the Grand Gulf RHR pump.

For further testing, please see the revised response to question 211.39.

211.39 (5.4.7) Discuss the RHR pump reliability for long-term operation. Long-term reliability should be demonstrated by either operational experience or testing. If previous operational experience should be cited as the basis for qualifying the pumps, state any pump design differences and conditions of previous pump operations.

RESPONSE

A 200-hour endurance test was performed in two parts on two different pumps of similar construction and design to the Grand Gulf RHR pump. A 150-hour portion of the test was conducted to demonstrate that the pump could operate for an extended time without resulting in binding in the throttle bushing or other running clearances that would affect the pump performance. A total of ten spin-downs were recorded throughout the test to determine if any binding was occurring.

The pump operated as intended throughout the entire test. The post-endurance performance was essentially the same as the pre-endurance performance. All of the spin-down times were normal which indicates that no binding occurred during the testing. The post-test teardown inspection revaled no abnormal conditions of pump parts. The dimensions of all parts remained within print tolerances. There were some minor indications on the throttle bushings, one bearing, and some of the wear rings which were probably caused by foreign material, but this was not detrimental to the pump operation.

These test results, in addition to many thousands of hours of pump operation with the same general pump design logged in nuclear plant operations, demonstrate the reliability for long-term operation of the RHR pumps.

Grand Gulf will perform additional testing of an installed RHR pump to demonstrate reliability under long-term operations. This test shall consist of running a single RHR pump for a continuous 24 hour period during the preoperational test phase (E12-PT01). The test plan will include provisions for taking data as follows:

1. Motor Bearing Temperatures
2. Pump Vibrational Measurements
3. Pump Discharge Pressure
4. Pump Suction Pressure

211.211 Calculations of NPSH available to ECCS pumps in BWRs are normally provided with reference to the pump suction. We are concerned that under certain post accident conditions the potential may exist for damage to ECCS pumps from cavitation because of local flashing in the system suction lines. The potential can result for example from local elevation changes in the piping runs. Calculations of NPSH available at the pump suction may erroneously assume liquid continuity up to the point of pump suction. We require therefore that the applicants provide calculations demonstrating that all points in all safety related suction piping, the NPSH available is adequate to preclude local flashing under the worst postulated conditions.

RESPONSE

The following calculations determine the pressures at various locations along the ECCS pumps' suction piping. As concluded from the calculations, adequate pressures exist along the suction piping to preclude local flashing under the worst postulated conditions. That is, the pressure at each point exceeds the vapor pressure of the fluid. For the calculations, a suppression pool water temperature of 212°F with a corresponding vapor pressure of 14.7 psia was assumed. This is an extremely conservative assumption since the maximum analyzed pool water temperature is 181°F as specified in Table 6.2-13. Since the vapor pressure for water at 181°F is 7.7 psia, more than adequate margin exists to preclude flashing in the suction piping.

Other conservative assumptions used for the calculations are:

1. Pump design maximum runout flow rate

2. Atmospheric containment pressure

3. Minimum suppression pool design water level

4. Maximum suction strainer pressure drop (for 50 percent clogged)

Calculations of Pressures in ECCS Pumps Suction Piping

$P_{(D.P.)} = P + H_s - \Delta P_L - \Delta P_s$

Where $P_{(D.P.)}$ = absolute pressure at data points (i.e., P_1, P_2, ...)

P = containment pressure (minimum pressure coincident with drawdown is 14.7 psia)

H_s = net static head from drawdown suppression pool level at 107'-6" elevation to data point elevation

ΔP_L = line losses at maximum pump flow

ΔP_s = suction strainer maximum differential pressure

NOTE: Velocity head neglected for added conservatism

RHR "A" Pump

Reference Figure 211.211-1 (same as Figure 5.4-27 with the addition of data points) for suction line geometry.

Static head at minimum pool water density (ρ @ 212°F) at each data point.

D.P. 1 - H_s = (107.5' - 103.5') (59.8 lb/ft^3) (ft^2/144 in^2) = 1.66 psi

D.P. 2 - H_s = (107.5' - 103.5') (59.8 lb/ft^3) (ft^2/144 in^2) = 1.66 psi

D.P. 3 - H_s = (107.5' - 96') (59.8 lb/ft^3) (ft^2/144 in^2) = 4.77 psi

D.P. 4 - H_s = (107.5' - 96') (59.8 lb/ft^3) (ft^2/144 in^2) = 4.77 psi

D.P. 5 - H_s = (107.5' - 96') (59.8 lb/ft^3) (ft^2/144 in^2) = 4.77 psi

Line losses (ΔP_L) at maximum pump flow of 8940 gpm @ 212°F

For 24" Schedule 20 pipe:

$Re = 4.15 \times 10^6$; $f = 0.012$; $\Delta P/_{100ft} = 0.18$ psi$/_{100ft}$

For 24" Schedule 30 pipe:

$Re = 4.2 \times 10^6$; $f = 0.012$; $\Delta P/_{100ft} = 0.20$ psi$/_{100ft}$

For 20" Schedule 20 pipe:

$Re = 5.0 \times 10^6$; $f = 0.012$; $\Delta P/_{100ft} = 0.47$ psi$/_{100ft}$

From strainer to D.P. 1:

L (Equivalent Length of 24" Schedule 20 Pipe, Fittings and Entrance) = 233 ft.

L (Equivalent Length of 24" Schedule 30 Pipe, Valve and Fittings) = 101 ft.

L (Equivalent Length of 20" Schedule 20 Pipe and Fittings) = 39 ft.

$\Delta P_L = (233 \times 0.18/_{100}) + (101 \times 0.20/_{100}) + (39 \times 0.47/_{100}) = 0.80$ psi

From D.P. 1 to D.P. 2:

L (Equivalent Length of 24" Pipe and Fittings) = 97.0 ft.

$\Delta P_L = 97.0 \times 0.20/_{100} = 0.19$ psi

From D.P. 2 to D.P. 3:

L (Equivalent Length of 24" Pipe and Fittings) = 84.0 ft.

$\Delta P_L = 84.0 \times 0.20/_{100} = 0.17$ psi

From D.P. 3 to D.P. 4:

L (Equivalent Length of 24" Pipe and Fittings) = 246.0 ft.

$\Delta P_L = 246 \times 0.20/_{100} = 0.49$ psi

From D.P. 4 to D.P. 5:

L (Equivalent Length of 24" Pipe and Fittings) = 10.0 ft.

$\Delta P_L = 10.0 \times 0.20/_{100} = 0.02$ psi

Suppression pool strainer head loss:

$\Delta P_s = 0.43$ psi (from vendor flow tests for 50% clogged strainer)

Pressure @ data points:

@ D.P. 1 $P_1 = 14.7 + 1.66 - 0.80 - 0.43 = 15.13$ psia

@ D.P. 2 $P_2 = 14.7 + 1.66 - 0.80 - 0.19 - 0.43 = 14.94$ psia

@ D.P. 3 $P_3 = 14.7 + 4.77 - 0.80 - 0.19 - 0.17 - 0.43 = 17.88$ psia

@ D.P. 4 $P_4 = 14.7 + 4.77 - 0.80 - 0.19 - 0.17 - 0.49 - 0.43 = 17.39$ psia

@ D.P. 5 $P_5 = 14.7 + 4.77 - 0.80 - 0.19 - 0.17 - 0.49 - 0.02 - 0.43 = 17.36$ psia

Summary: The pressure at all points along the suction piping exceeds the vapor pressure (14.7 psia) at 212°F.

RHR "B" Pump

Reference Figure 211.211-2 (same as Figure 5.4-28 with the addition of data points) for suction line geometry.

Static head at minimum pool water density (ρ @ 212°F) at each data point.

D.P. 1 - H_s = (107.5' - 103.5') (59.8 lb/ft^3) ($ft^2/144\ in^2$) = 1.66 psi

D.P. 2 - H_s = (107.5' - 103.5') (59.8 lb/ft^3) ($ft^2/144\ in^2$) = 1.66 psi

D.P. 3 - H_s = (107.5' - 96') (59.8 lb/ft^3) ($ft^2/144\ in^2$) = 4.77 psi

D.P. 4 - H_s = (107.5' - 96') (59.8 lb/ft^3) ($ft^2/144\ in^2$) = 4.77 psi

D.P. 5 - H_s = (107.5' - 96') (59.8 lb/ft^3) ($ft^2/144\ in^2$) = 4.77 psi

Line losses (ΔP_L) at maximum pump flow of 8940 gpm @ 212°F

For 24" Schedule 20 pipe:

$Re = 4.15 \times 10^6$; f = 0.012; $\Delta P/_{100ft}$ = 0.18 $psi/_{100ft}$

For 24" Schedule 30 pipe:

$Re = 4.2 \times 10^6$; f = 0.012; $\Delta P/_{100ft}$ = 0.20 $psi/_{100ft}$

For 20" Schedule 20 pipe:

$Re = 5.0 \times 10^6$; f = 0.012; $\Delta P/_{100ft}$ = 0.47 $psi/_{100ft}$

From strainer to D.P. 1:

L (Equivalent Length of 24" Schedule 20 Pipe, Fittings and Entrance) = 233 ft.

L (Equivalent Length of 24" Schedule 30 Pipe, Valve and Fittings) = 101 ft.

L (Equivalent Length of 20" Schedule 20 Pipe and Fittings) = 39 ft.

$\Delta P_L = (233 \times 0.18/_{100}) + (101 \times 0.20/_{100}) + (40 \times 0.47/_{100}) = 0.81$ psi

From D.P. 1 to D.P. 2:

L (Equivalent Length of 24" Pipe and Fittings) = 97.0 ft.

$\Delta P_L = 97.0 \times 0.20/_{100} = 0.19$ psi

From D.P. 2 to D.P. 3:

L (Equivalent Length of 24" Pipe and Fittings) = 84.0 ft.

$\Delta P_L = 84.0 \times 0.20/_{100} = 0.17$ psi

From D.P. 3 to D.P. 4:

L (Equivalent Length of 24" Pipe and Fittings) = 246.0 ft.

$\Delta P_L = 246 \times 0.20/_{100} = 0.49$ psi

From D.P. 4 to D.P. 5:

L (Equivalent Length of 24" Pipe and Fittings) = 86.0 ft.

$\Delta P_L = 86.0 \times 0.20/_{100} = 0.17$ psi

Suppression pool strainer head loss:

$\Delta P_s = 0.43$ psi (from vendor flow tests for 50% clogged strainer)

Pressure @ data points:

@ D.P. 1 $P_1 = 14.7 + 1.66 - 0.81 - 0.43 = 15.12$ psia

@ D.P. 2 $P_2 = 14.7 + 1.66 - 0.81 - 0.19 - 0.43 = 14.93$ psia

@ D.P. 3 $P_3 = 14.7 + 4.77 - 0.81 - 0.19 - 0.17 - 0.43 = 17.87$ psia

@ D.P. 4 $P_4 = 14.7 + 4.77 - 0.81 - 0.19 - 0.17 - 0.49 - 0.43 = 17.38$ psia

@ D.P. 5 $P_5 = 14.7 + 4.77 - 0.81 - 0.19 - 0.17 - 0.49 - 0.17 - 0.43 = 17.21$ psia

Summary: The pressure at all points along the suction piping exceeds the vapor pressure (14.7 psia) at 212°F.

<u>RHR "C" Pump</u>

Reference Figure 211.211-3 (same as Figure 5.4-29 with the addition of data points) for suction line geometry.

Static head at minimum pool water density (ρ @ 212°F) at each data point.

D.P. 1 - H_s = (107.5' - 103.5') (59.8 lb/ft^3) (ft^2/144 in^2) = 1.66 psi

D.P. 2 - H_s = (107.5' - 103.5') (59.8 lb/ft^3) (ft^2/144 in^2) = 1.66 psi

D.P. 3 - H_s = (107.5' - 103.5') (59.8 lb/ft^3) (ft^2/144 in^2) = 1.66 psi

D.P. 4 - H_s = (107.5' - 96') (59.8 lb/ft^3) (ft^2/144 in^2) = 4.77 psi

D.P. 5 - H_s = (107.5' - 96') (59.8 lb/ft^3) (ft^2/144 in^2) = 4.77 psi

Line losses (ΔP_L) at maximum pump flow of 8940 gpm @ 212°F

For 24" Schedule 20 pipe:

$$Re = 4.15 \times 10^6;\ f = 0.012;\ \Delta P/_{100ft} = 0.18\ psi/_{100ft}$$

For 24" Schedule 30 pipe:

$Re = 4.2 \times 10^6$; $f = 0.012$; $\Delta P/_{100ft} = 0.20\ psi/_{100ft}$

For 20" Schedule 20 pipe:

$Re = 5.0 \times 10^6$; $f = 0.012$; $\Delta P/_{100ft} = 0.47\ psi/_{100ft}$

From strainer to D.P. 1:

L (Equivalent Length of 24" Schedule 20 Pipe, Fittings and Entrance) = 233 ft.

L (Equivalent Length of 24" Schedule 30 Pipe, Valve and Fittings) = 140 ft.

L (Equivalent Length of 20" Schedule 20 Pipe and Fittings) = 42 ft.

$\Delta P_L = (233 \times 0.18/_{100}) + (140 \times 0.20/_{100}) + (42 \times 0.47/_{100}) = 0.89$ psi

From D.P. 1 to D.P. 2:

L (Equivalent Length of 24" Pipe and Fittings) = 57.0 ft.

$\Delta P_L = 57.0 \times 0.20/_{100} = 0.11$ psi

From D.P. 2 to D.P. 3:

L (Equivalent Length of 24" Pipe and Fittings) = 93.0 ft.

$\Delta P_L = 93.0 \times 0.20/_{100} = 0.18$ psi

From D.P. 3 to D.P. 4:

L (Equivalent Length of 24" Pipe and Fittings) = 84.0 ft.

$\Delta P_L = 84 \times 0.20/_{100} = 0.17$ psi

From D.P. 4 to D.P. 5:

L (Equivalent Length of 24" Pipe and Fittings) = 209.0 ft.

$\Delta P_L = 209 \times 0.20/_{100} = 0.42$ psi

Suppression pool strainer head loss:

$\Delta P_s = 0.43$ psi (from vendor flow tests for 50% clogged strainer)

Pressure @ data points:

@ D.P. 1 $P_1 = 14.7 + 1.66 - 0.89 - 0.43 = 15.04$ psia

@ D.P. 2 $P_2 = 14.7 + 1.66 - 0.89 - 0.43 - 0.11 = 14.93$ psia

@ D.P. 3 $P_3 = 14.7 + 1.66 - 0.89 - 0.11 - 0.18 - 0.43 = 14.75$ psia

@ D.P. 4 P_4 = 14.7 + 4.77 - 0.89 - 0.11 - 0.18 - 0.17 - 0.43 = 17.69 psia

@ D.P. 5 P_5 = 14.7 + 4.77 - 0.89 - 0.11 - 0.18 - 0.43 - 0.17 - 0.42 = 17.27 psia

Summary: The pressure at all points along the suction piping exceeds the vapor pressure (14.7 psia) at 212°F.

LPCS Pump

Reference Figure 211.211-4 (same as Figure 6.3-70 with the addition of data points) for suction line geometry.

Static head at minimum pool water density (ρ @ 212°F) at each data point.

D.P. 1 - H_s = (107.5' - 103.5') (59.8 lb/ft^3) (ft^2/144 in^2) = 1.66 psi

D.P. 2 - H_s = (107.5' - 103.5') (59.8 lb/ft^3) (ft^2/144 in^2) = 1.66 psi

D.P. 3 - H_s = (107.5' - 103.5') (59.8 lb/ft^3) (ft^2/144 in^2) = 1.66 psi

D.P. 4 - H_s = (107.5' - 96') (59.8 lb/ft^3) (ft^2/144 in^2) = 4.77 psi

D.P. 5 - H_s = (107.5' - 96') (59.8 lb/ft^3) (ft^2/144 in^2) = 4.77 psi

Line losses (ΔP_L) at maximum pump flow of 9100 gpm @ 212°F

For 24" Schedule 20 pipe:

$Re = 4.4 \times 10^6$; $f = 0.012$; $\Delta P/_{100ft} = 0.205\ psi/_{100ft}$

For 20" Schedule 20 pipe:

$Re = 5.3 \times 10^6$; $f = 0.012$; $\Delta P/_{100ft} = 0.53\ psi/_{100ft}$

From strainer to D.P. 1:

L (Equivalent Length of 24" Pipe, Valve, Fittings and Entrance) = 275 ft.

L (Equivalent Length of 20" Pipe and Fittings) = 36 ft.

$\Delta P_L = (275 \times 0.205/_{100}) + (36 \times 0.53/_{100}) = 0.75$ psi

From D.P. 1 to D.P. 2:

L (Equivalent Length of 24" Pipe and Fittings) = 57.0 ft.

$\Delta P_L = 57.0 \times 0.205/_{100} = 0.12$ psi

From D.P. 2 to D.P. 3:

L (Equivalent Length of 24" Pipe and Fittings) = 55.0 ft.

$\Delta P_L = 55.0 \times 0.205/_{100} = 0.11$ psi

From D.P. 3 to D.P. 4:

L (Equivalent Length of 24" Pipe and Fittings) = 85.0 ft.

$\Delta P_L = 85.0 \text{ X } 0.205/_{100} = 0.17$ psi

From D.P. 4 to D.P. 5:

L (Equivalent Length of 24" Pipe and Fittings) = 182.0 ft.

$\Delta P_L = 182.0 \text{ X } 0.205/_{100} = 0.37$ psi

Suppression pool strainer head loss:

$\Delta P_s = 0.43$ psi (from vendor flow tests for 50% clogged strainer)

Pressure @ data points:

@ D.P. 1 $P_1 = 14.7 + 1.66 - 0.75 - 0.43 = 15.18$ psia

@ D.P. 2 $P_2 = 14.7 + 1.66 - 0.75 - 0.12 - 0.43 = 15.06$ psia

@ D.P. 3 $P_3 = 14.7 + 1.66 - 0.75 - 0.12 - 0.11 - 0.43 = 14.95$ psia

@ D.P. 4 $P_4 = 14.7 + 4.77 - 0.75 - 0.12 - 0.11 - 0.17 - 0.43 = 17.89$ psia

@ D.P. 5 $P_5 = 14.7 + 4.77 - 0.75 - 0.12 - 0.11 - 0.17 - 0.37 - 0.43 = 17.52$ psia

Summary: The pressure at all points along the suction piping exceeds the vapor pressure (14.7 psia) at 212°F.

<u>HPCS Pump</u>

Reference Figure 211.211-5 (same as Figure 6.3-68 with the addition of data points) for suction piping geometry.

Static head at minimum pool water density (ρ @ 212°F) at each data point.

D.P. 1 - $H_s = (107.5' - 103.5')\ (59.8 \text{ lb/ft}^3)\ (\text{ft}^2/144 \text{ in}^2) = 1.66$ psi

D.P. 2 - $H_s = (107.5' - 96')\ (59.8 \text{ lb/ft}^3)\ (\text{ft}^2/144 \text{ in}^2) = 4.77$ psi

D.P. 3 - $H_s = (107.5' - 96')\ (59.8 \text{ lb/ft}^3)\ (\text{ft}^2/144 \text{ in}^2) = 4.77$ psi

D.P. 4 - $H_s = (107.5' - 96')\ (59.8 \text{ lb/ft}^3)\ (\text{ft}^2/144 \text{ in}^2) = 4.77$ psi

D.P. 5 - $H_s = (107.5' - 96')\ (59.8 \text{ lb/ft}^3)\ (\text{ft}^2/144 \text{ in}^2) = 4.77$ psi

Line losses (ΔP_L) at maximum pump flow of 9100 gpm @ 212°F

For 24" Schedule 20 pipe:

$Re = 4.4 \text{ X } 10^6$; $f = 0.012$; $\Delta P/_{100ft} = 0.205 \text{ psi}/_{100ft}$

For 20" Schedule 20 pipe:

$Re = 5.3 \times 10^6$; $f = 0.012$; $\Delta P/_{100ft} = 0.53\ psi/_{100ft}$

From strainer to D.P. 1:

L (Equivalent Length of 24" Pipe, Valve, Fittings and Entrance) = 231 ft.

L (Equivalent Length of 20" Pipe and Fittings) = 37 ft.

$\Delta P_L = (37 \times 0.53/_{100}) + (231 \times 0.205/_{100}) = 0.67$ psi

From D.P. 1 to D.P. 2:

L (Equivalent Length of 24" Pipe and Fittings) = 85.0 ft.

$\Delta P_L = 85.0 \times 0.205/_{100} = 0.17$ psi

From D.P. 2 to D.P. 3:

L (Equivalent Length of 24" Pipe and Fittings) = 51.0 ft.

$\Delta P_L = 51.0 \times 0.205/_{100} = 0.10$ psi

From D.P. 3 to D.P. 4:

L (Equivalent Length of 24" Pipe and Fittings) = 55.0 ft.

$\Delta P_L = 55.0 \times 0.205/_{100} = 0.11$ psi

From D.P. 4 to D.P. 5:

L (Equivalent Length of 24" Pipe and Fittings) = 564.0 ft.

$\Delta P_L = 564.0 \times 0.205/_{100} = 1.15$ psi

Suppression pool strainer head loss:

$\Delta P_s = 0.43$ psi (from vendor flow tests for 50% clogged strainer)

Pressure @ data points:

@ D.P. 1 $P_1 = 14.7 + 1.66 - 0.67 - 0.43 = 15.26$ psia

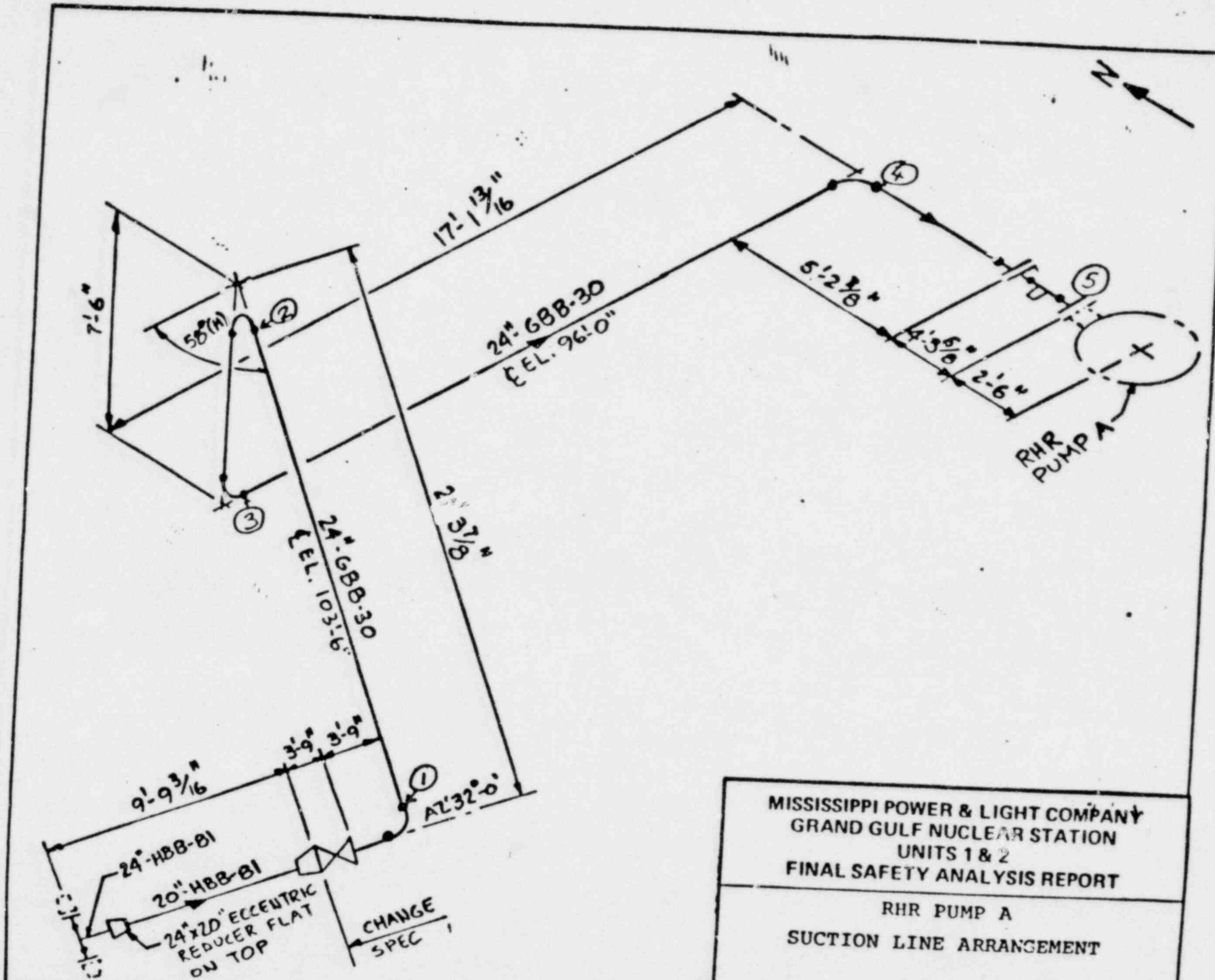
@ D.P. 2 $P_2 = 14.7 + 4.77 - 0.67 - 0.17 - 0.43 = 18.2$ psia

@ D.P. 3 $P_3 = 14.7 + 4.77 - 0.67 - 0.17 - 0.1 - 0.43 = 18.1$ psia

@ D.P. 4 $P_4 = 14.7 + 4.77 - 0.67 - 0.17 - 0.1 - 0.11 - 0.43 = 17.99$ psia

@ D.P. 5 $P_5 = 14.7 + 4.77 - 0.67 - 0.17 - 0.1 - 0.11 - 1.15 - 0.43 = 16.84$ psia

Summary: The pressure at all points along the suction piping exceeds the vapor pressure (14.7 psia) at 212°F.



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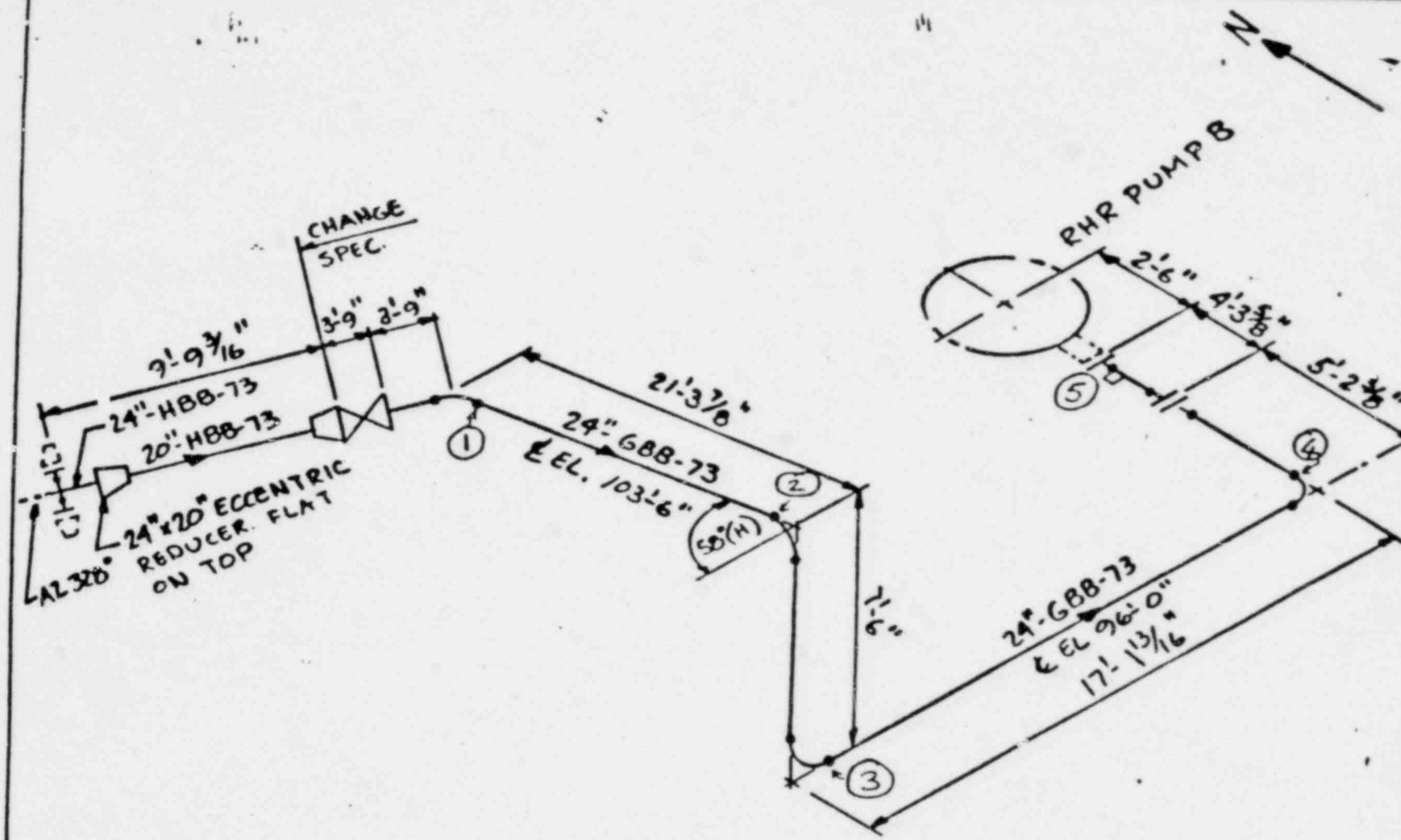
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

RHR PUMP A
SUCTION LINE ARRANGEMENT

FIGURE 211.211-1



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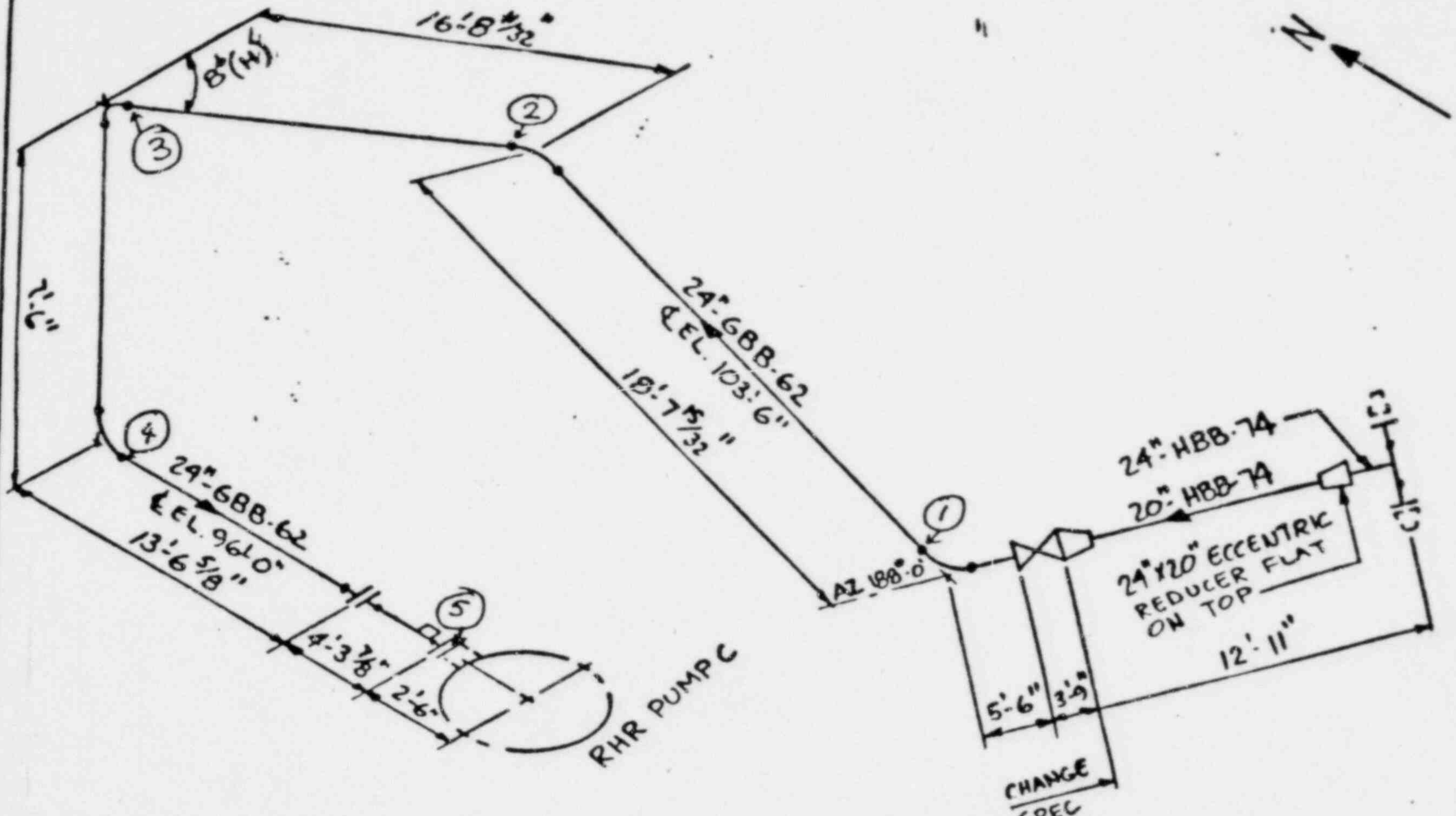
GRAND GULF NUCLEAR STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

RHR PUMP B

SUCTION LINE ARRANGEMENT

FIGURE 211.211-2



MISSISSIPPI POWER & LIGHT COMPANY
GRAND GULF NUCLEAR STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

RHR PUMP C

SUCTION LINE ARRANGEMENT

FIGURE 211.211-3

Attachment 3 to AECM-81/277
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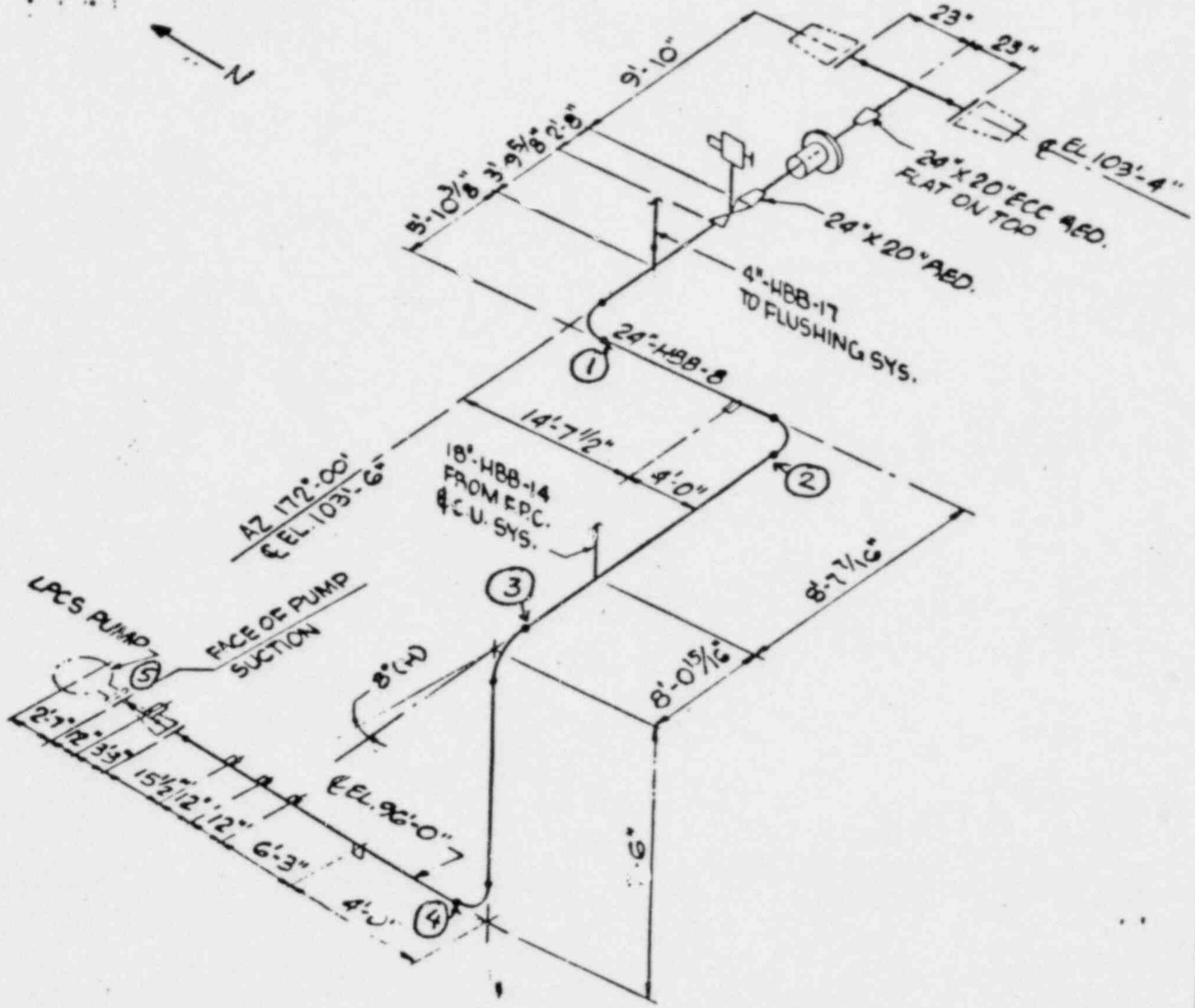

MISSISSIPPI POWER & LIGHT COMPANY
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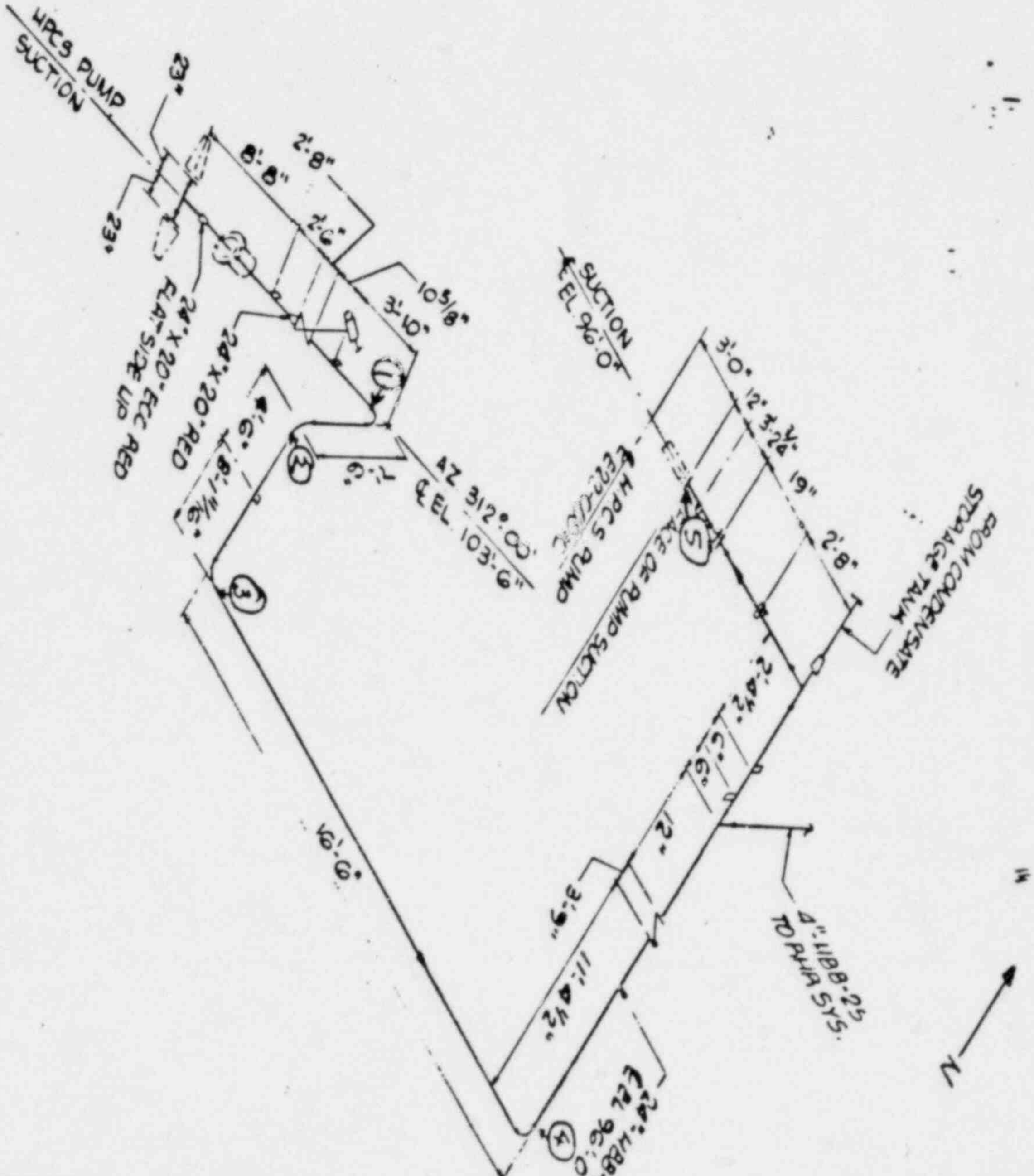
FINAL SAFETY ANALYSIS REPORT

LPCS PUMP SUCTION PIPING ARRANGEMENT

FIGURE 211.211-4



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UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

HPCS PUMP SUCTION PIPING ARRANGEMENT

FIGURE 211.211-5

211.126 (5.4.7) The alternate method to achieve cold shutdown requires additional clarification (See Question 211.26 and 211.20.). Verify that the combination safety/relief valves are qualified to pass water as well as steam. Provide justification for not functionally testing this method during the preoperational testing period. Branch Technical Position RSB 5-1 requires testing of the alternate method.

RESPONSE

In response to Requirement 2.1.2 of NUREG-0578, the BWR Owners Group (TMI) has tested the safety/relief valves (S/RV) for conditions that would be experienced during alternate shutdown. The test results indicate flow capacities in excess of 8000 gpm per valve.

To address the concern expressed at the September 24, 1980, meeting with the NRC, the following is discussed. Subsection 15.2.9 evaluates failure of the RHR shutdown cooling. This analysis demonstrates the capability to safely transfer fission product decay heat and other residual heat from the reactor core. The removal of heat is shown to be at a rate such that specified acceptable fuel design limits and the design conditions of the reactor coolant pressure boundary are not exceeded. Based on the analysis in subsection 15.2.9, (Table 15.2-14) the flow rate required to sustain alternate shutdown cooling is 7450 gpm. The performance data obtained during S/RV testing demonstrates a flow capacity greater than that required to sustain alternate shutdown cooling. Thus, proving the adequacy of the alternate shutdown cooling system design and the conservatism of the analysis presented in subsection 15.2.9.

Preoperational testing is performed on the components of the alternate shutdown system to provide assurance of operability.

212.20 (5.4.7) The SRP 5.4.7 states the residual heat removal system (RHRS) should meet the requirements of General Design Criterion (GDC) 34 of Appendix A to 10 CFR Part 50. The RHR by itself cannot accomplish the heat removal functions as required by GDC 34. To comply with the single failure criterion the FSAR describes an alternate method of achieving cold shutdown in Section 5.4.7.1.5. Insufficient information is provided to allow an adequate evaluation of this alternate method. In particular, the staff has recently approved Revision 2 to SRP 5.4.7 (containing Branch Technical Position RSB 5-1) which delineates acceptable methods for meeting the single failure criterion. This Branch Technical Position requires testing to demonstrate the expected performance of the alternate method for achieving cold shutdown. The applicant should describe plans to meet this requirement. In addition, we require that all components of the alternate system be safety grade (seismic Category I and IEEE-279). As a result of this requirement, the air supply to the automatic depressurization system (ADS) valves, including the system upstream of the accumulators, must be safety grade. This air supply must be sufficient to account for air consumption necessary for valve operation plus air loss due to system leakage over a prolonged period with loss of offsite power.

RESPONSE

Additional clarification of the alternate shutdown cooling method is provided in response to Question 211.126.

In response to requirement II.D.1 of NUREG 0737 the BWR Owners Group (TMI) has performed all testing required for the safety/relief valve test program ensuring that the test conditions simulated the conditions expected during the alternate shutdown cooling mode. Results of the test demonstrate the operational adequacy of the S/RV's to pass water as well as steam. In addition, preoperational testing described in subsection 14.2.12.1.5 is performed on the components of the alternate shutdown cooling system to provide assurance of operability.

All components of the alternate method including the air supply system to the automatic depressurization system (ADS) which is described in subsection 5.2.2.4.1 are safety grade and seismic category 1.

031.60 (7.3.1.2) Section 7.3.1.2 identifies and defines "Operational Limits" and implies that they are the level at which the trip unit initiates the ESF function. "Levels Requiring Protective Action" is not defined but is identified as one of the parameters tabulated in the 7.3 tables. "Margin" is defined as the difference between the "Operational Limit" and undefined "limiting conditions." Both "Operational Limits" and "Levels Requiring Protective Action" are said to be tabulated in the 7.3 tables but only one value is tabulated in some tables and none are identified by either of the two defined titles. Amend your FSAR to fully define the terms used in specifying the design basis and to utilize consistent terminology throughout the discussion and tabulations. Indicate the method used to include the effect of the rate of change of the variable initiating the trip and the transient overshoot as a result of the incident. For reactor water level transmitters confirm that the setpoints, limits and margins include worst case effects of drywell and/or containment temperature on the sensed reactor level. For each case in which the trip setpoint is 10% or less from end of scale, provide the actual margin between the trip point and the worst case response limits of the measuring circuit (For example, what would be the highest signal level that could exist with the water level below the measuring side pressure tap for a low water level trip circuit).

RESPONSE

The tables in FSAR Sections 7.2, 7.3, 7.4, and 7.6 which provide the information addressed in this question have been revised to provide the following information:

a. Variable - "Plant Variable"

b. Sensor type - "Instrument"

c. Number of sensors - "Sensor Channels Provided"

d. Instrument range - "Range"

e. Allowable setpoint range (based on instrument capabilities) - "Allowable Setpoint Range"

The actual setpoints, margins, minimum channels required to be operational, and number of channels per trip system will be provided in the Technical Specifications which will be submitted separately.

The effect of the rate of change on variables provided in Tables 7.3-13, -16, -25, and -28, initiating an action and the transient overshoot as a result of the incident are not significant for the parameters specified in these tables. In no case is the actuation setpoint within 10 percent from the end of the scale for the variables presented in Tables 7.3-13, -16, -25, and -28.

A review has been conducted on the effects of high drywell temperature on reactor vessel water level instrumentation. Instrument accuracy is not markedly affected by varying drywell temperatures since the vertical drop of the sensing lines within the drywell are approximately equal. This ensures cancellation of temperature effects between lines, should elevated drywell temperature conditions (as in a LOCA) occur, and thereby ensures continued instrument setpoint accuracy under these conditions.

The design configuration for the reactor water level instrumentation complies to the following two criteria:

1. The change in elevation of the level sensing lines for the narrow and wide range instruments must be equal ±1 foot and,

2. The elevation change must be limited such that, following reactor depressurization and assuming the reference leg in the drywell is boiled dry due to high drywell temperature, the operator would have at least 10 minutes from receipt of a low reactor water level 2 alarm until the core would become uncovered.

In summary, there would be little or no impact on the scram or other level trip function, nor would post-accident monitoring be impaired.

Subsections 7.3.1.1.2.4.3.1.2.3, 7.3.1.1.2.4.1.7.1, 7.3.1.1.2.4.1.7.9.2, 7.3.2.1.1, 7.4.1.1.5.3, 7.6.1.2, 7.6.1.5.4.1.1, 7.6.1.5.5.1.1, 7.6.1.5.6.1.1, and 7.6.1.8.6 have also been revised to show the inclusion of this information in the Technical Specifications.

Instrument Setpoint Margin Bases (Hardware)

Introduction

The following bases relate to the establishment of instrument setpoint margins for the instrumentation employed in the reactor protection system, isolation actuation systems, emergency core cooling systems, and neutronic rod block systems as delineated in the BWR Standard Technical Specifications.

More specifically, these bases are concerned with the accuracy, calibration capability and potential for drift of the established setpoints as applied to the various functions, and describe the corresponding allowacnes made to compensate for those factors. With reference to the overall plant safety analysis, the choice of actual setpoint for each parameter relative to its designated safety function is discussed in the technical specification bases. When the technical

362.7 (2.5.4.13.1) Your response to NRC Question 362.5 (page Q&R 2.5-14, Amendment 30) is not complete. Indicate what measured value of differential settlement would cause code allowable stresses to be exceeded for individual buildings and buried piping and require notification of NRC. Provide a table of these values and the limiting stress criteria. Update the plots which show settlement recorded to date versus time; this is particularly important since construction of Unit 2 was still underway when your response to Ouestion 362.5 was being developed.

RESPONSE

The response to this question is given in revised subsection 2.5.4.13.1, revised Table 2.5-10 and revised Figures 2.5-75a through 2.5-75h.

The settlement markers will be read at one-month intervals until construction is complete and all pools are filled with water, at which time the results of the settlement monitoring program will be evaluated and long-term monitoring of the structures will be assessed. Total settlement will not be a Geotechnical concern until the following measured values are observed:

Turbine building	3"
Radwaste building	3"
Control building	3"
Containment building	3.5"
Auxiliary building	3.5"
Diesel generator building	3"

Differential vertical settlements between buildings, as well as foundation rotation or tilt of an individual building, have been insignificant with respect to the foundation structural aspects and are not a concern. However, this is important w .h regard to maintaining proper isolation gaps between adjacent buildings and has been considered in the design. The maximum allowable differential settlement of the containment structure is 0.6 inches and of the auxiliary building is 1.15 inches in order to prevent these buildings touching during an operating basis earthquake (OBE).

Differential vertical settlements between buildings and foundation rotation also affect piping passing between these buildings and to surrounding soil and are being considered in the design. The predicted and measured settlements on Table 2.5-10 are less than 1 inch (except for a measured settlement of 1.1 inches on the Unit 1 Auxiliary Building), with differential settlements between adjacent buildings with piping passing between them being less than 1/2 inch. Since the structures with the largest measured settlements are essentially completed from a loading aspect, these values should remain at this level in the future. It is anticipated that differential settlements between adjacent edges of the buildings will be even less than the recorded settlements due to overlapping pressure influence. In addition, a substantial portion of the building settlement has usually occurred before the installation of the penetrations is complete. Thus, any differential settlement experienced by pipes passing between buildings will be very small. In the case of the Category I standby service water piping which runs between the auxiliary building and the standby service water cooling tower basin, there will be no significant settlement between the building and the surrounding soil, since movement of the soil adjacent to the building will take place as building movement occurs. In addition, any differential settlement between the building and the soil will be slow enough to ensure that stresses built up in the soil due to penetration movements will be redistributed with time, reducing the level of stress in the pipes and anchors.

2.5.4.13.2 Tieback Wall Instrumentation

A soldier pile and lagging tieback wall was installed for the construction of the power block. The wall had a perimeter of 4200 linear ft with a surface area of 180,000 sq ft. The average height of the wall was 43 ft. The wall was retained by approximately 2400 earth tiebacks, each with a capacity of 50 to 60 tons. In addition to the

ordinary surveying done to monitor the movement of the wall, load cells to measure the load in each tieback at various elevations and to compare the actual loading with the design loading were installed. Load cell data indicated that the actual load ranged from 50 percent to 90 percent of the design load. Wall deflection and ground movement were continually monitored during and after wall construction. Borehole deflectometers were installed behind soldier piles. Multiple position borehole extensometers were installed between tiebacks at approximately 20 degrees from the horizontal. This electronic instrumentation compared favorably with the regular surveying measurements for horizontal and vertical movement. Surveying methods were the primary source of monitoring the wall. Lateral and vertical movements were generally less than 1 inch.

TABLE 2.5-10

PREDICTED VS MEASURED TOTAL SETTLEMENT VALUES
(Based on Data up to April 1981)

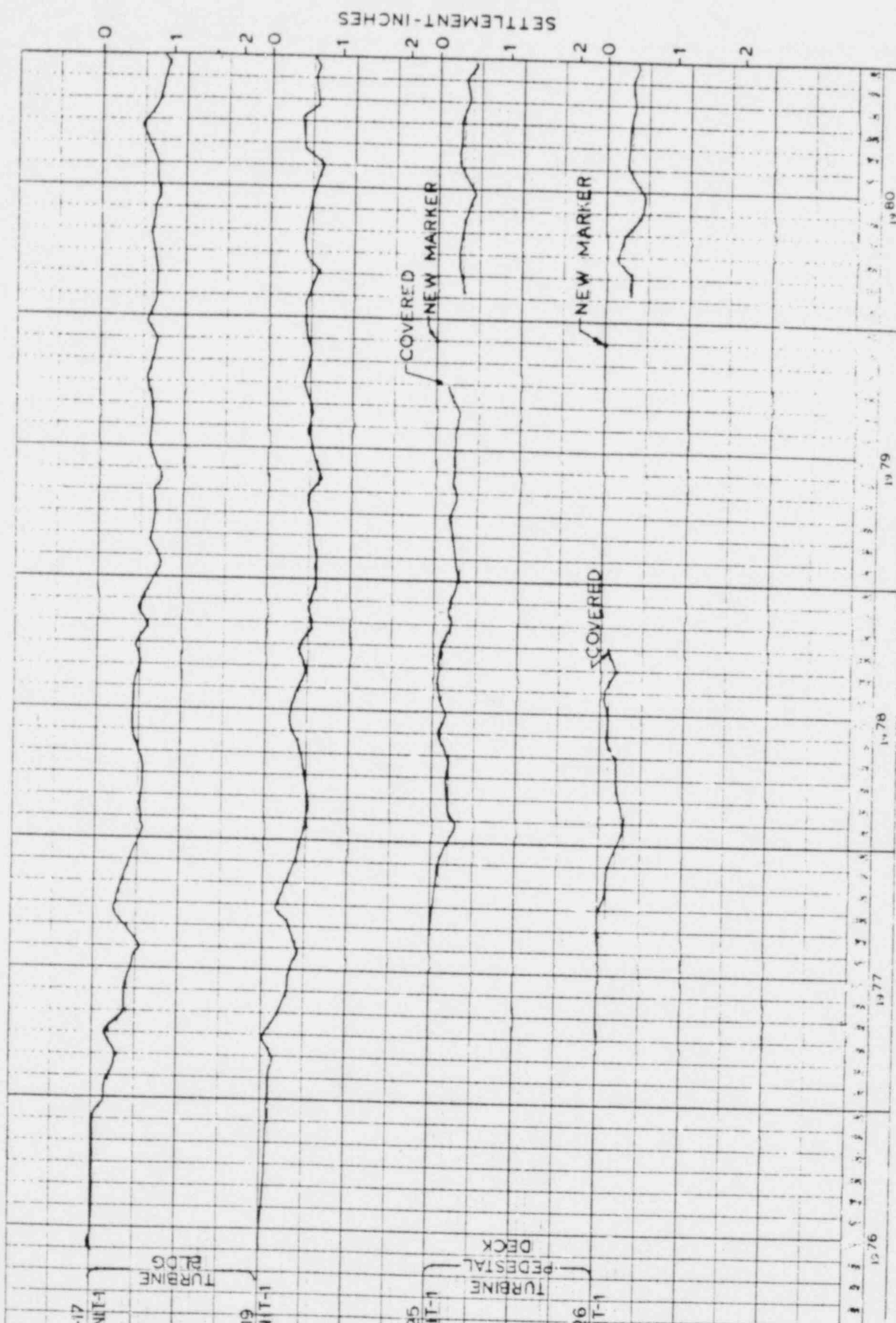
Structure	Settlement: Maximum *Predicted (in.)	Settlement: Measured (in.)	Percent of Dead Load Completed
Containment - Unit 1	0.8	0.8	96
Containment - Unit 2	0.8	0.4	40
Auxiliary Building - Unit 1	1.0	1.1	96
Auxiliary Building - Unit 2	1.0	0.2	10
Radwaste Building	0.8	0.9	96
Control Building	0.5	0.9	96
SSW Basin	0.7	0.7	100% Water
Diesel General Building - Unit 1	0.8	0.4	98

*Based on elastic modulus values as determined from rebound measurements. Refer to Figure 2.5-90 for predicted total settlements for differential assumed groundwater levels.

TABLE OF CONTENTS (Cont.)

LIST OF FIGURES (Cont.)

Amend 50 8/81



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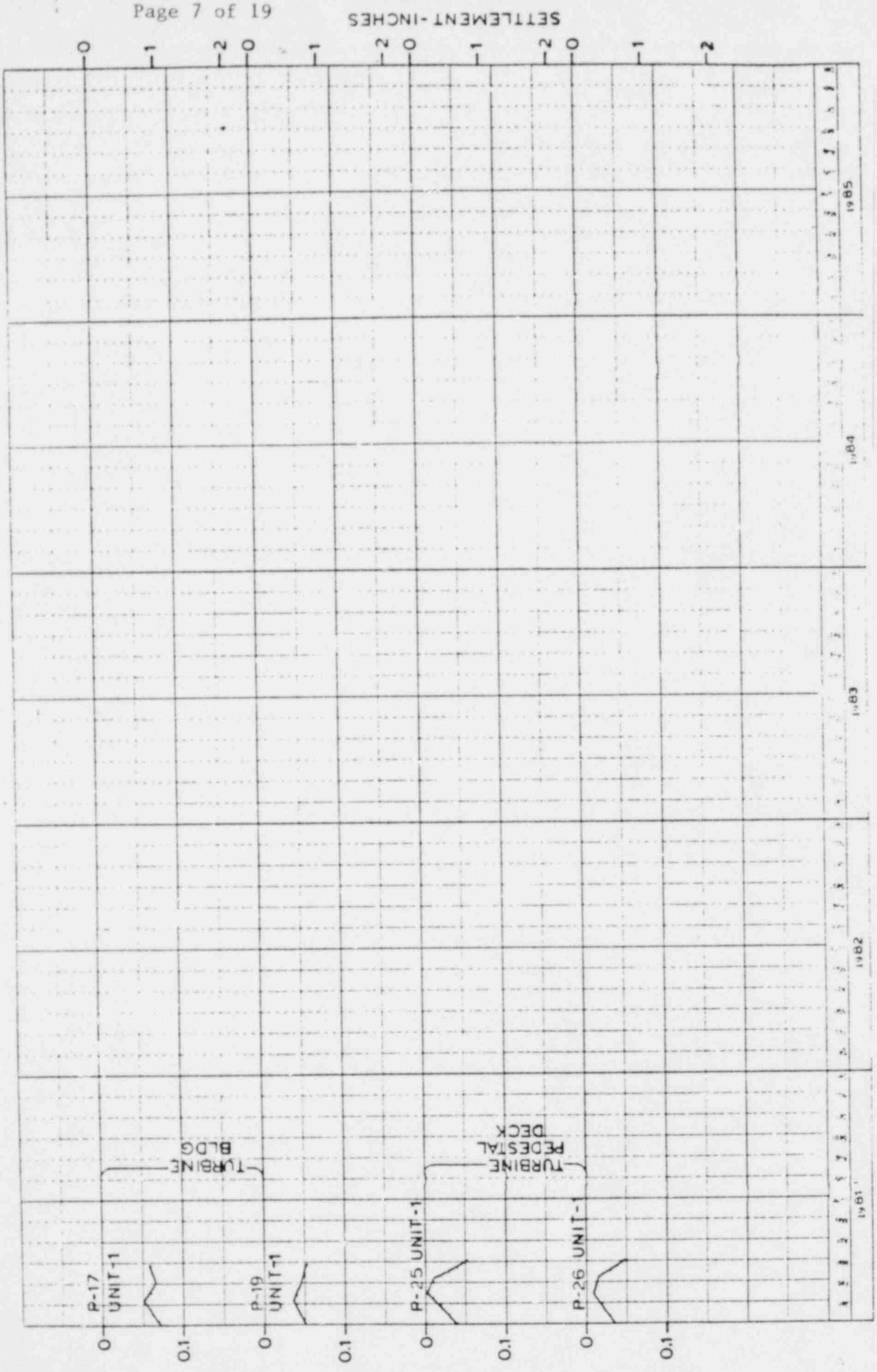
SETTLEMENT VS TIME
UNIT 1
TURBINE BUILDING SHEET 1
FIGURE 2.5-75a



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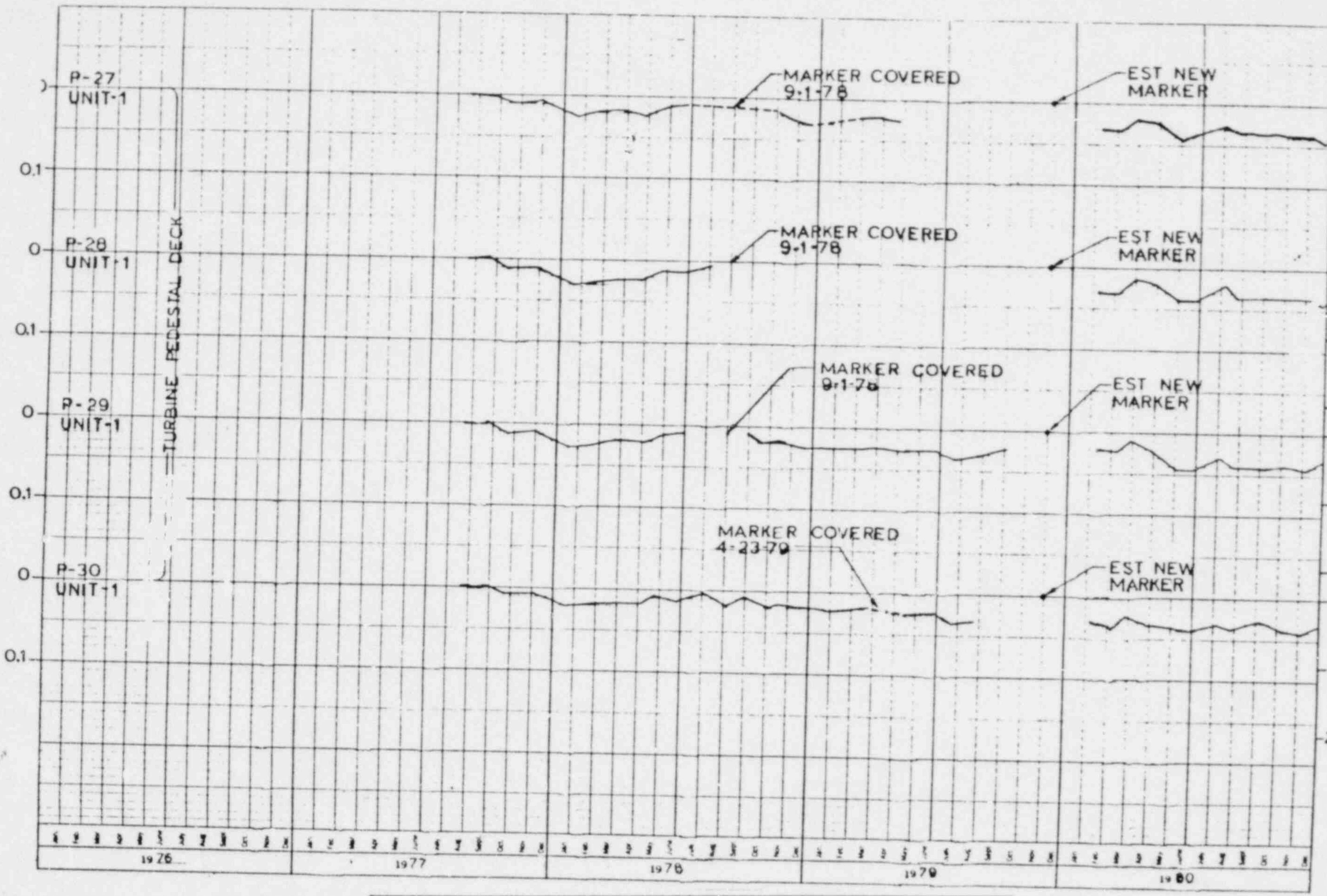
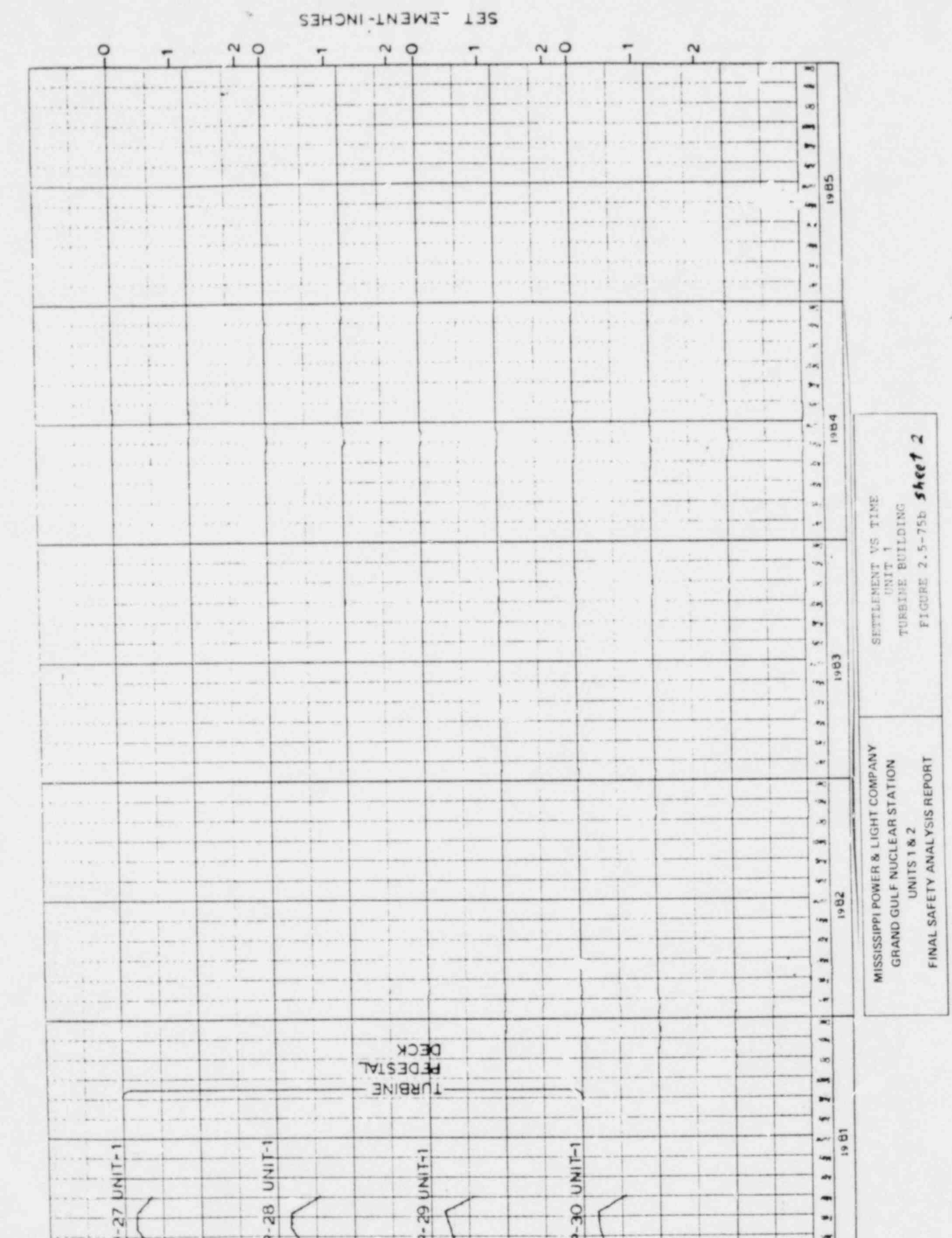
SETTLEMENT VS TIME
UNIT 1
TURBINE BUILDING
FIGURE 2.5-75a
SHEET 2

Amend 50 8/81



MISSISSIPPI POWER & LIGHT COMPANY GRAND GULF NUCLEAR STATION UNITS 1 & 2 FINAL SAFETY ANALYSIS REPORT	SETTLEMENT VS TIME UNIT 1 TURBINE BUILDING FIGURE 2.5-75b Sheet 1

Amend 50 8/81



SETTLEMENT VS TIME
UNIT 1
TURBINE BUILDING
FIGURE 2.5-75b sheet 2

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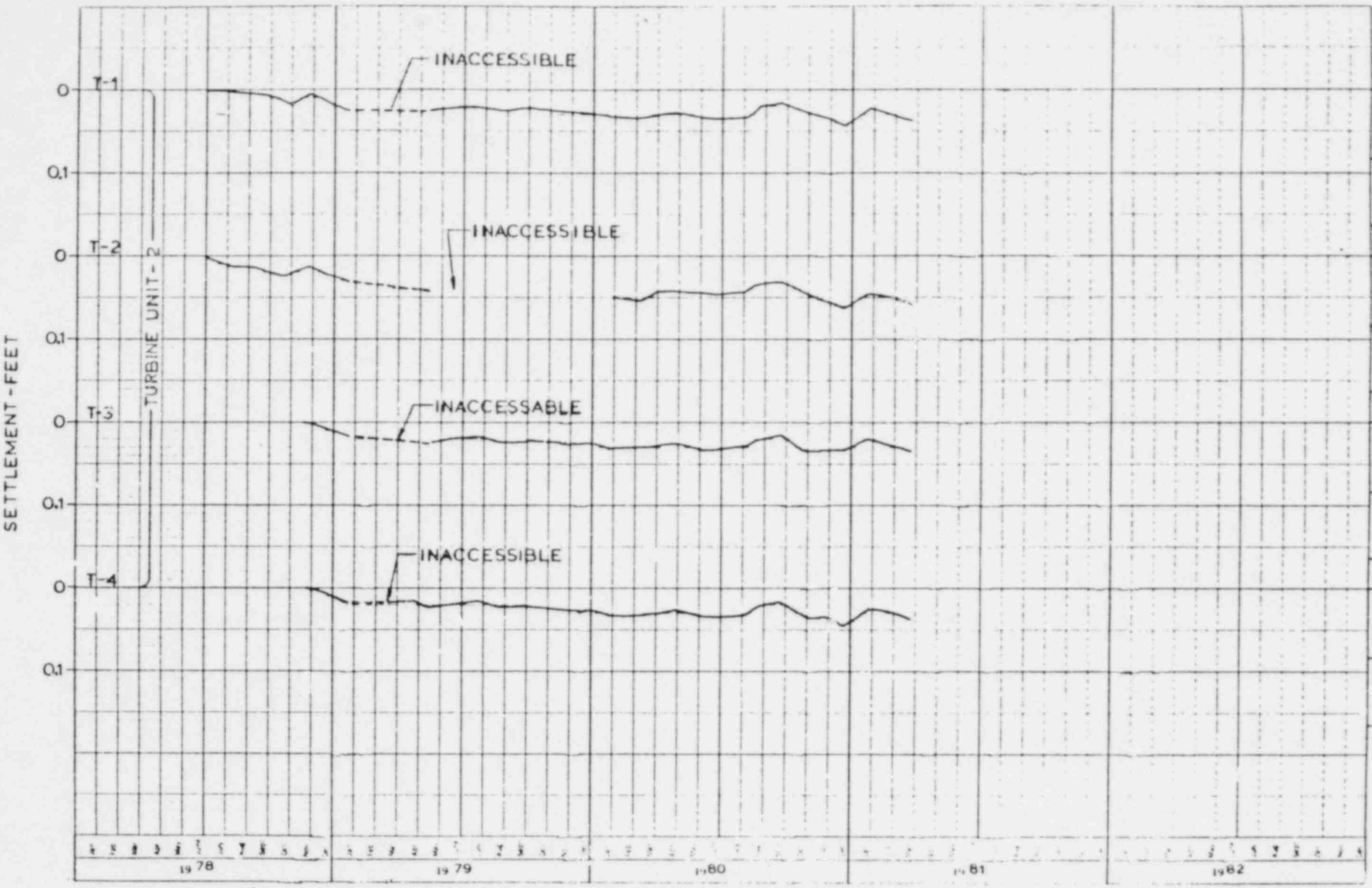
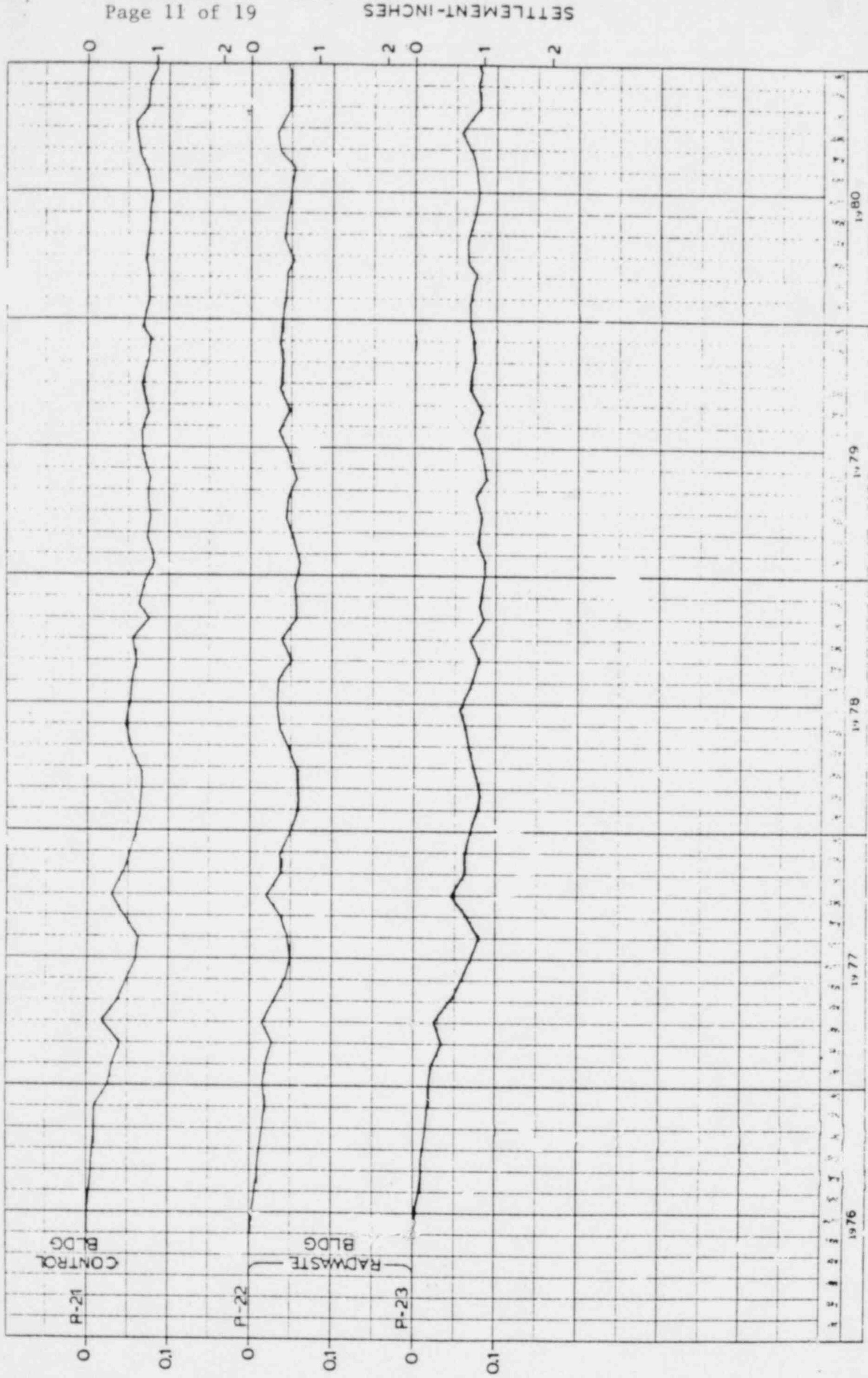


MISSISSIPPI POWER & LIGHT COMPANY GRAND GULF NUCLEAR STATION UNITS 1 & 2 FINAL SAFETY ANALYSIS REPORT	SETTLEMENT VS TIME UNIT 2 TURBINE BUILDING FIGURE 2.5-75c

Amend 50 8/81



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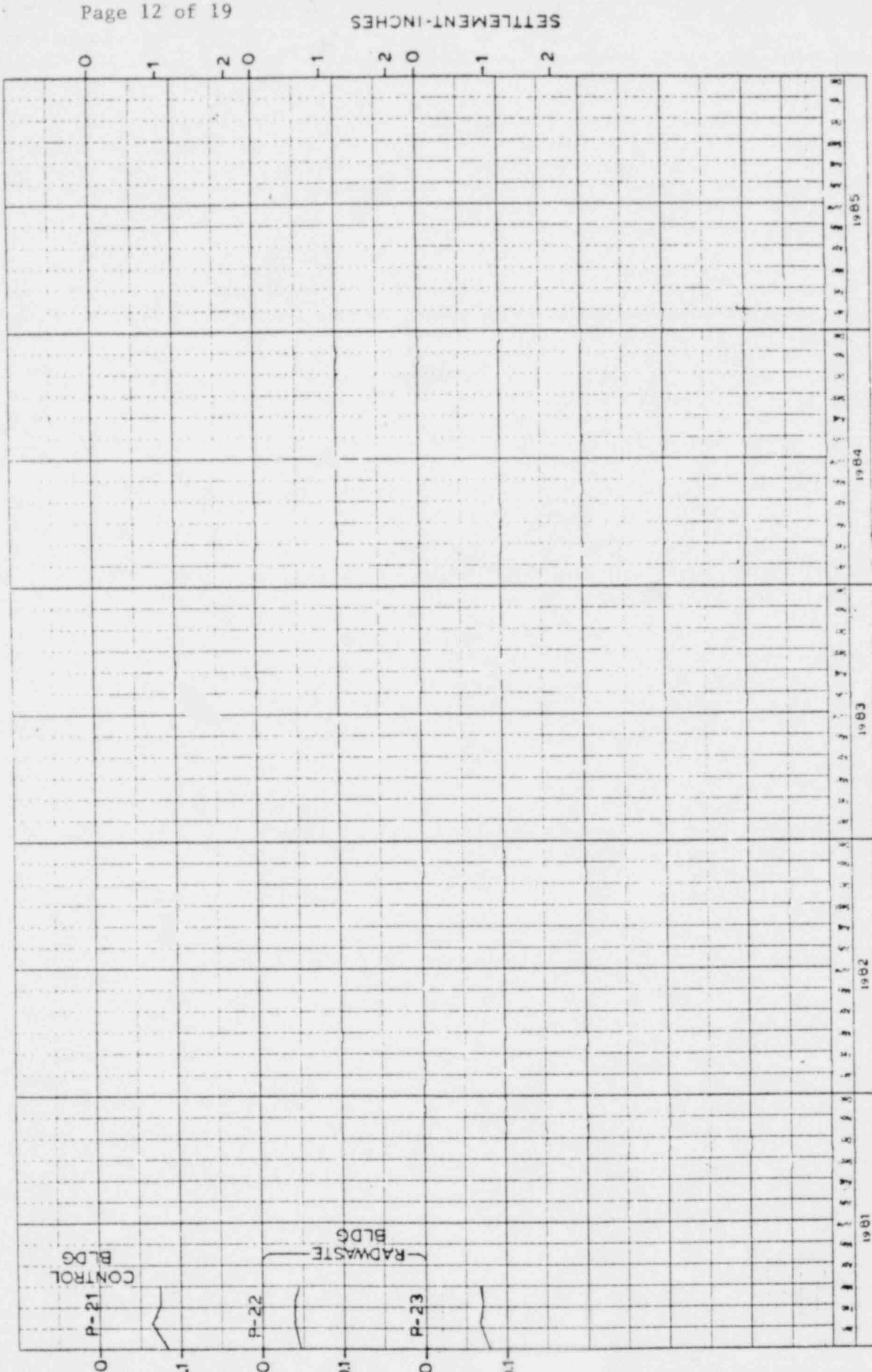
SETTLEMENT VS TIME
RADWASTE BLDG/CONTROL BLDG

FIGURE 2.5-75d Sheet 1

Amend 50 8/81



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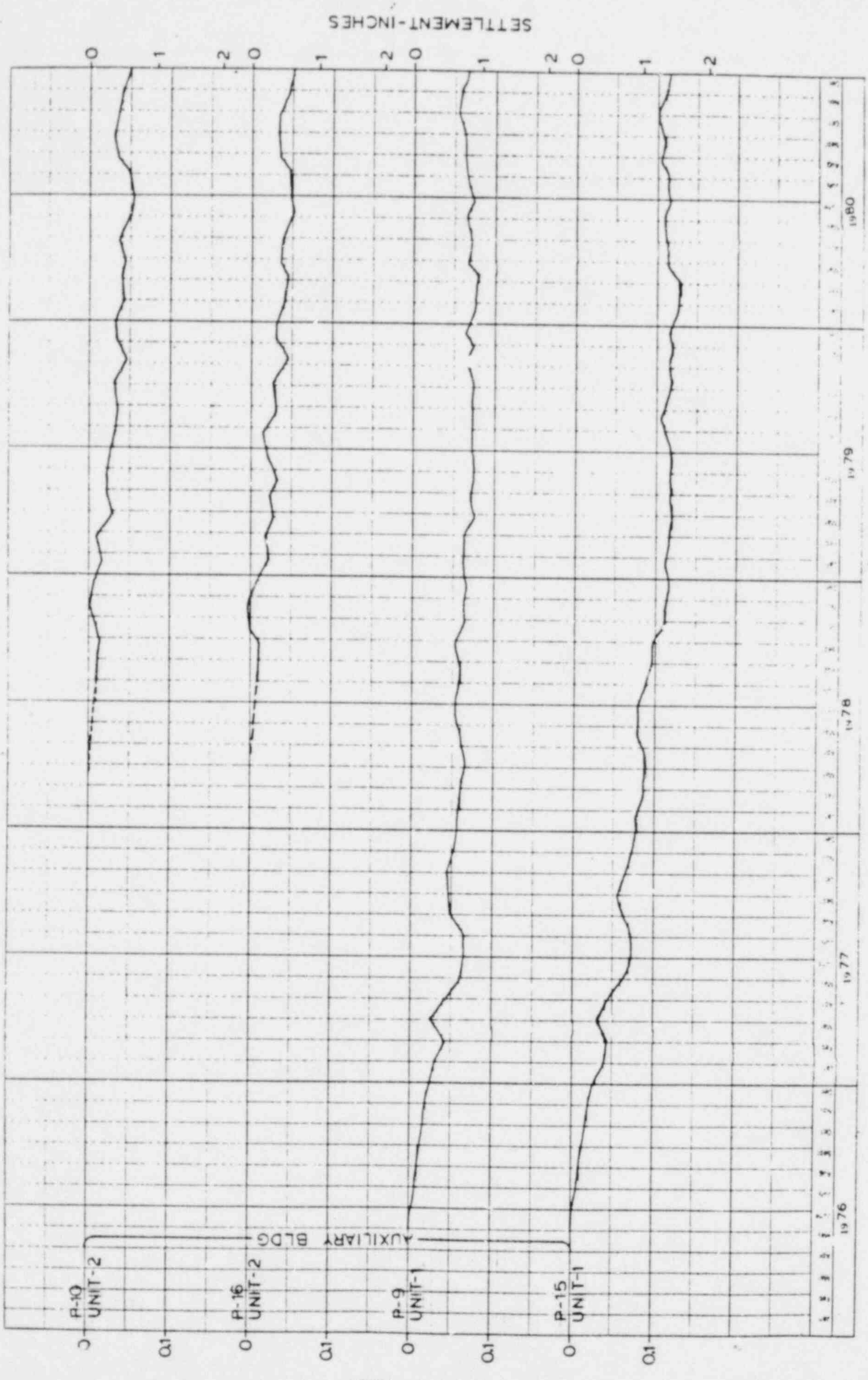
FINAL SAFETY ANALYSIS REPORT

SETTLEMENT VS TIME
RADWASTE BLDG/CONTROL BLDG

FIGURE 2.5-75d sheet 2

Amend 50 8/81



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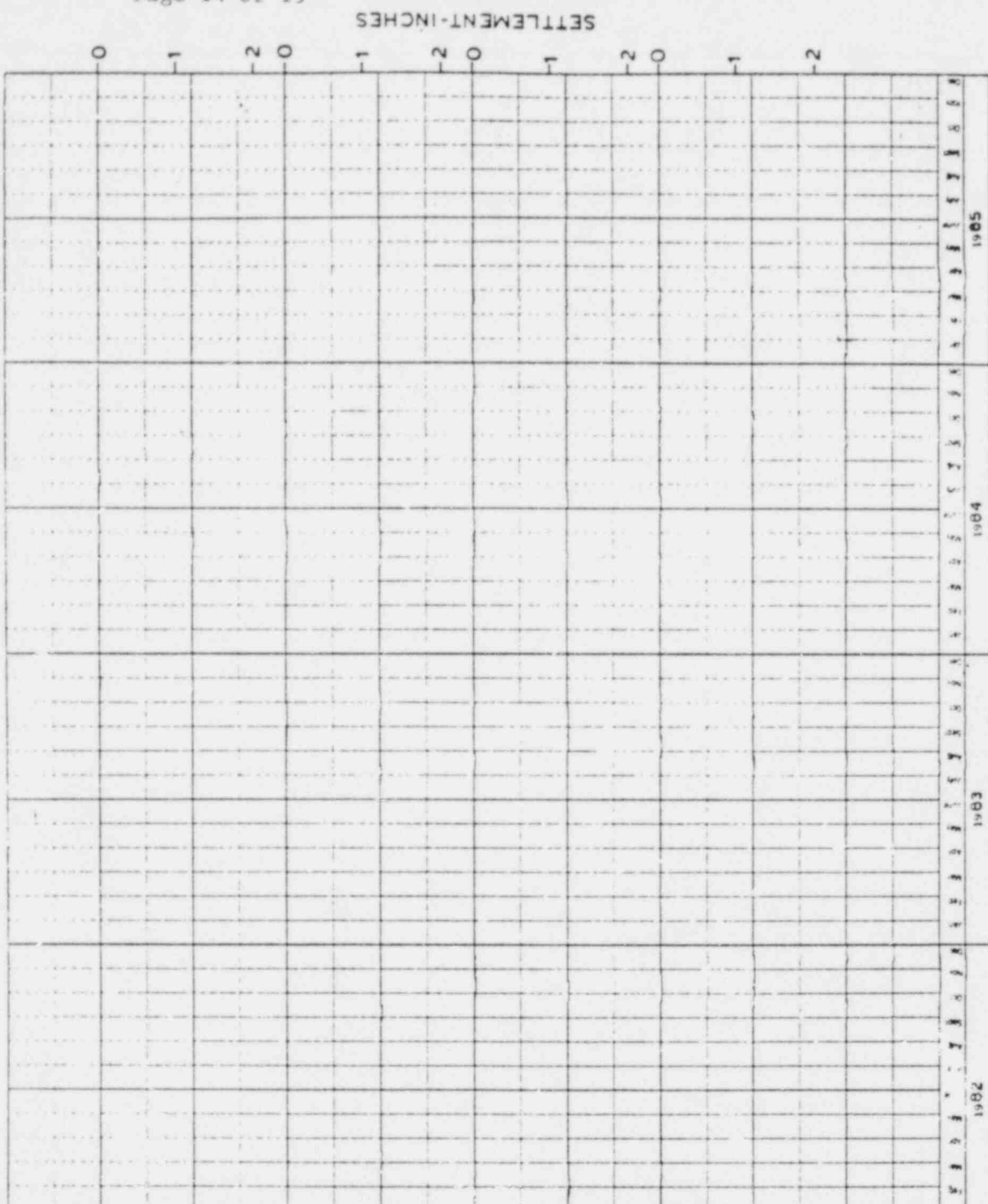
FINAL SAFETY ANALYSIS REPORT

SETTLEMENT VS TIME
UNITS 1 & 2
AUXILIARY BUILDING
FIGURE 2.5-75e sheet 1

Amend 50 9/81



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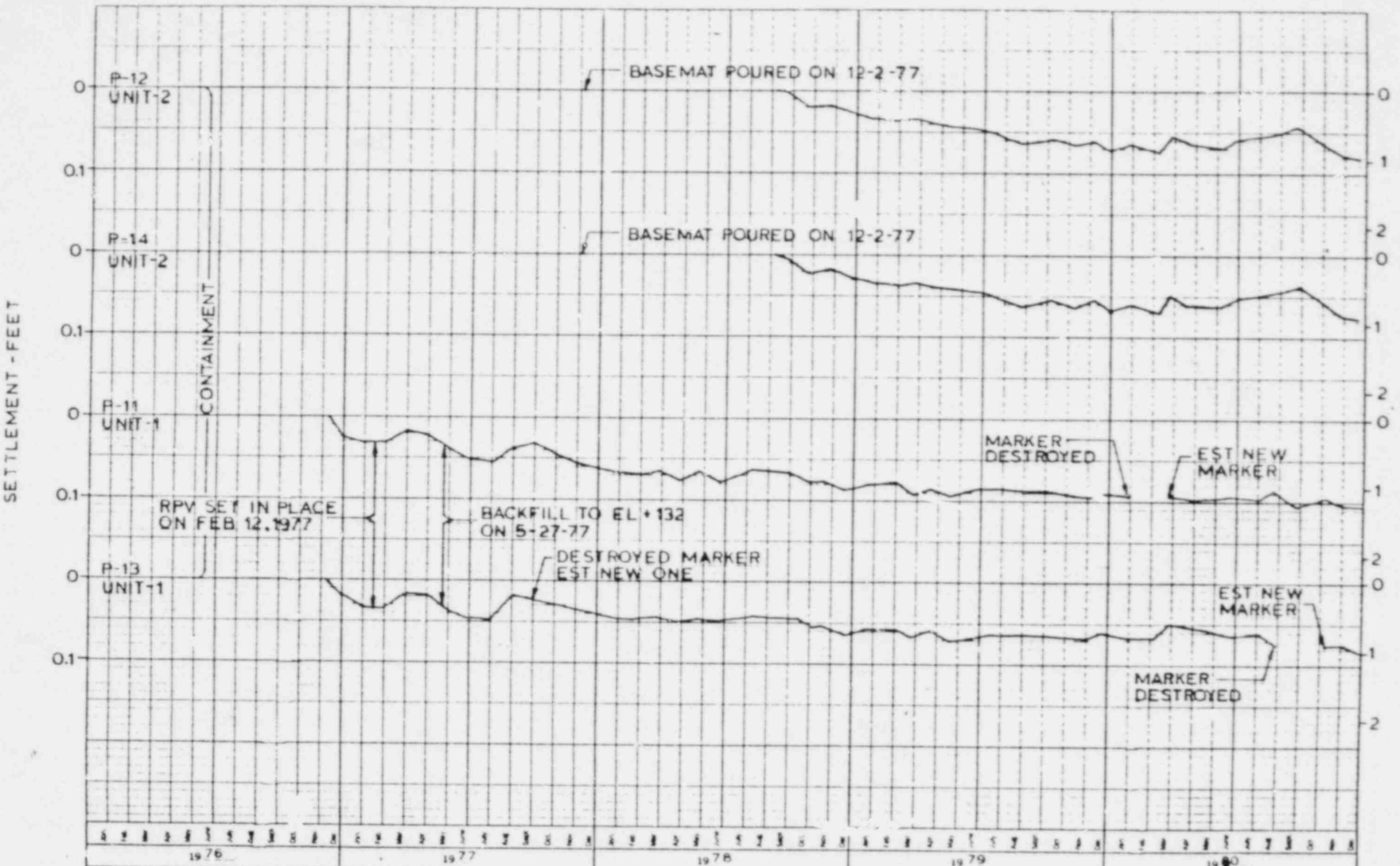
FINAL SAFETY ANALYSIS REPORT

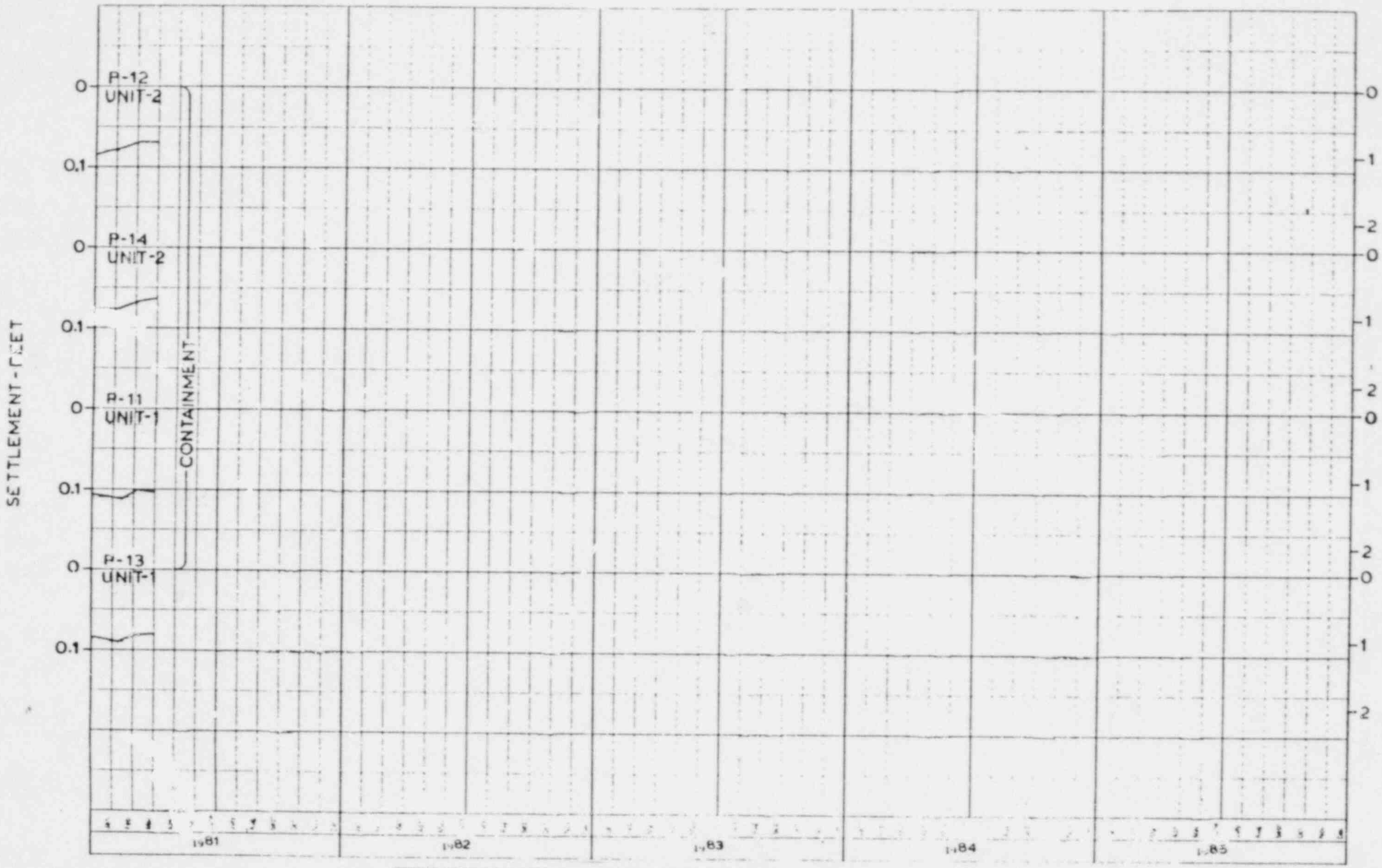
SETTLEMENT VS TIME
UNITS 1 & 2
AUXILIARY BUILDING
FIGURE 2.5-75e Sheet 2

Amend 00 8/81



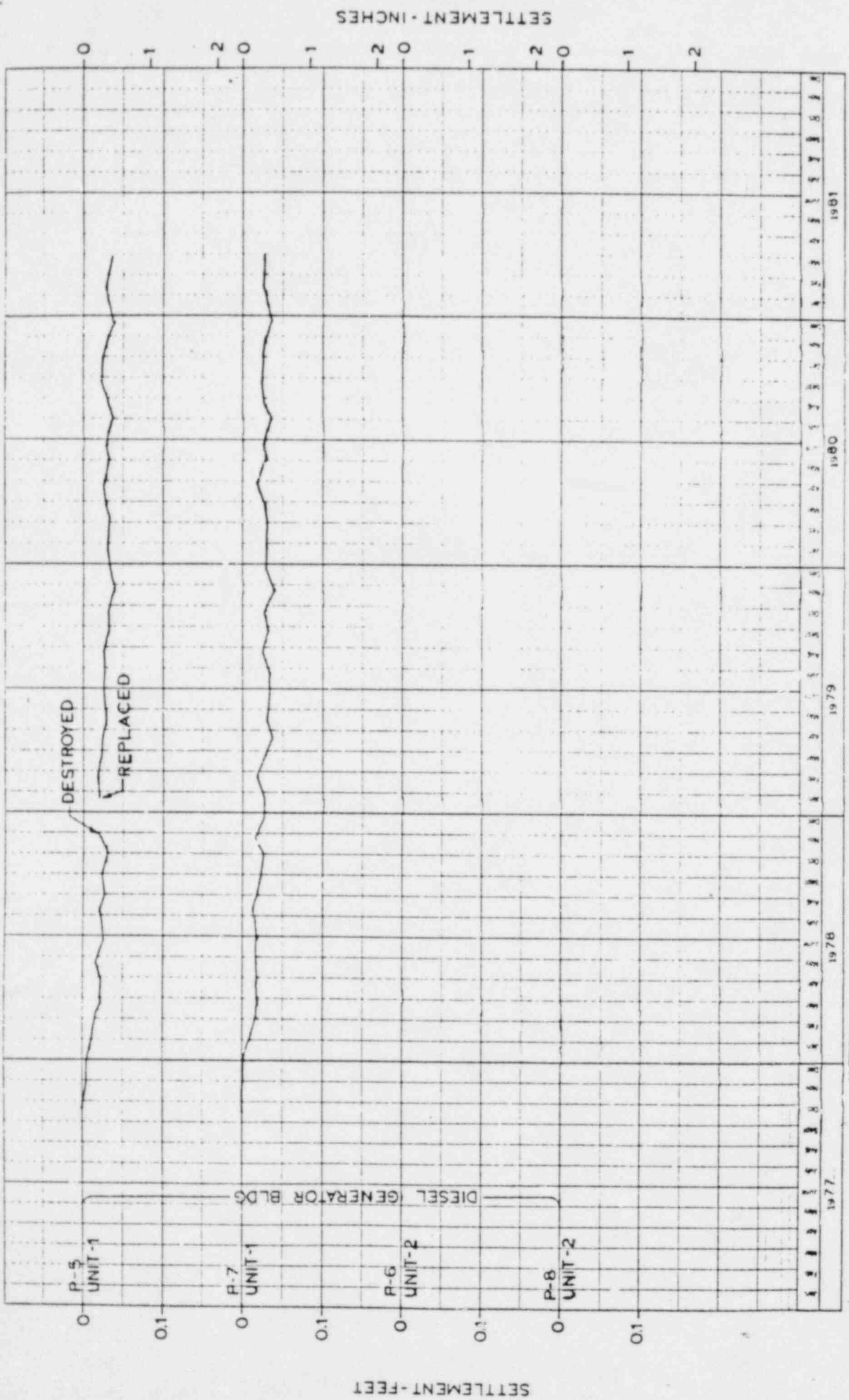
MISSISSIPPI POWER & LIGHT COMPANY GRAND GULF NUCLEAR STATION UNITS 1 & 2 FINAL SAFETY ANALYSIS REPORT	SETTLEMENT VS TIME UNITS 1 & 2 CONTAINMENT BUILDING FIGURE 2.5-75f Sheet 1

Amend 50 - 8/81



MISSISSIPPI POWER & LIGHT COMPANY GRAND GULF NUCLEAR STATION UNITS 1 & 2 FINAL SAFETY ANALYSIS REPORT	SETTLEMENT VS TIME UNITS 1 & 2 CONT NMENT BUILDING FIGURE 2.5-75f sheet 2

Amend 50 8/81



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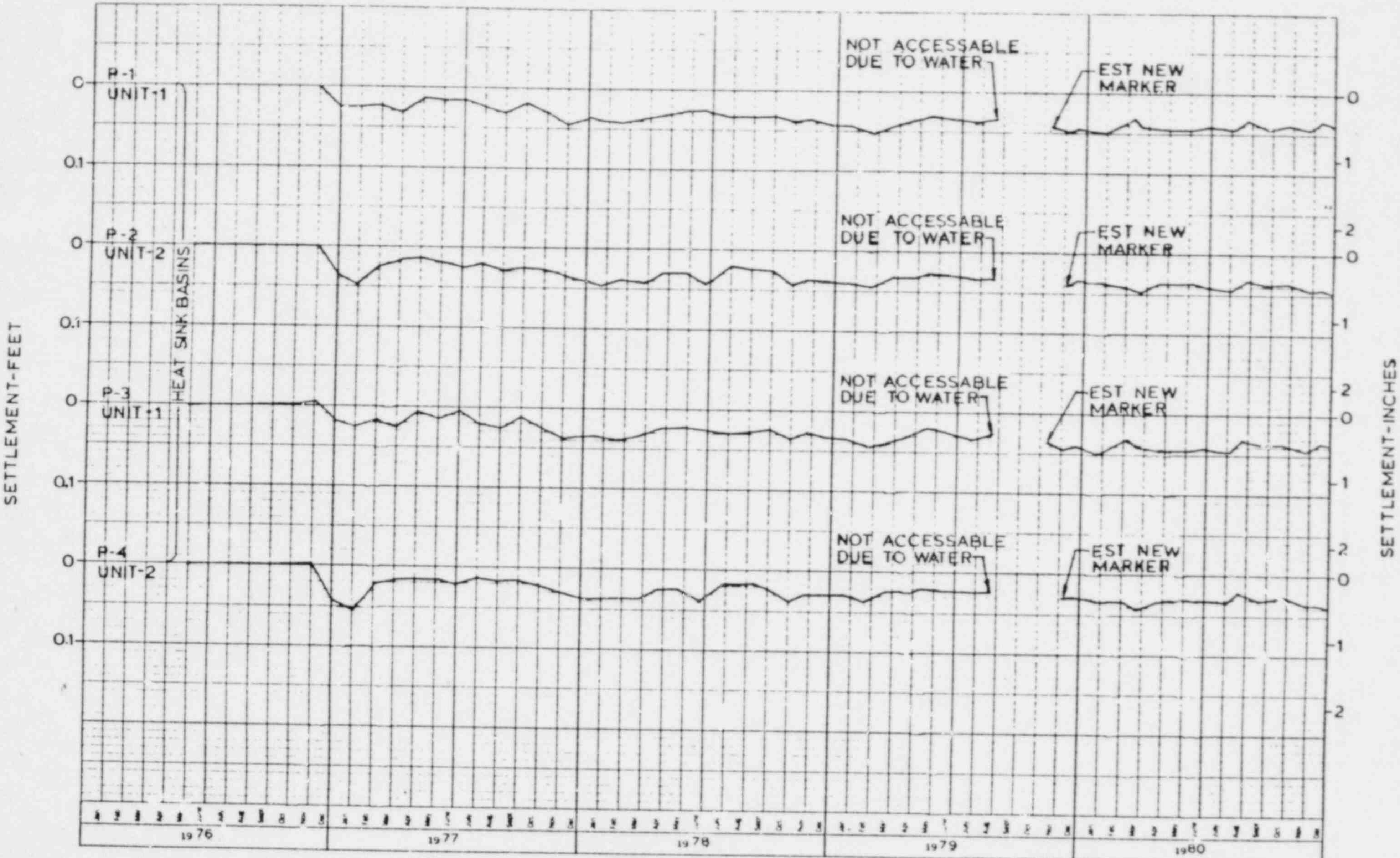
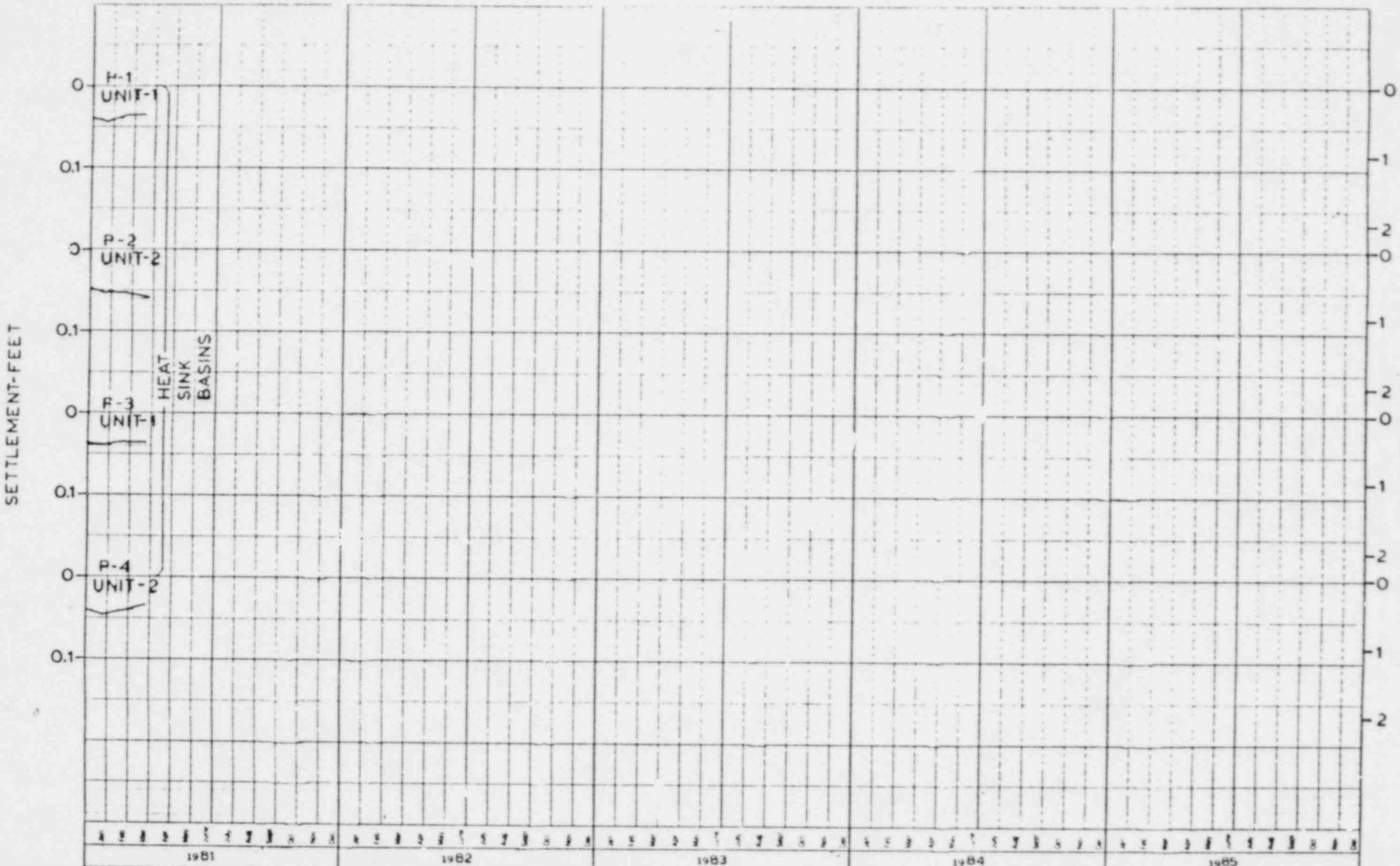
GRAND GULF NUCLEAR STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

SETTLEMENT VS TIME
UNITS 1 & 2
DIESEL GENERATOR BUILDING
FIGURE 2.5-75g

Amend 50 8/81



MISSISSIPPI POWER & LIGHT COMPANY GRAND GULF NUCLEAR STATION UNITS 1 & 2 FINAL SAFETY ANALYSIS REPORT	SETTLEMENT VS TIME UNITS 1 & 2 STANDBY SERVICE WATER COOLING TOWER BASINS FIGURE 2.5-75h *Sheet 1*



MISSISSIPPI POWER & LIGHT COMPANY
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FINAL SAFETY ANALYSIS REPORT

SETTLEMENT VS TIME
UNITS 1 & 2
STANDBY SERVICE WATER
COOLING TOWER BASINS
FIGURE 2.5-75h Sheet 2

Amend 50 8/81

ECCS (6.3)*

3.2 Since the applicant did not submit analyses for the full break spectrum for LOCA, we are requiring that the results of one additional DBA analysis using a discharge coefficient between those used in the analyses already provided.

RESPONSE

Grand Gulf specific analyses for 60 and 80 percent DBA are provided in Figures 6.3-19 through 6.3-34. As can be seen in Figures 6.3-26 and 6.3-34, the maximum peak cladding temperature (PCT) does not exceed 2000°F, and thus remains well below the requirements of 10 CFR 50.46.

*This concern was directed to MP&L informally in meetings with the Reactor Systems Branch (RSB) held the week of May 13, 1981. The above referenced FSAR revisions will be incorporated into the next available FSAR amendment. The above statement of the RSB concern and response is provided for information only and will not be incorporated into the FSAR.

FIGURE 6.3-19

NORMALIZED CORE AVERAGE INLET FLOW VERSUS TIME AFTER BREAK
GRAND GULF

80% DESIGN BASIS ACCIDENT, RECIRCULATION SUCTION BREAK, LPCI DIESEL GENERATOR FAILURE

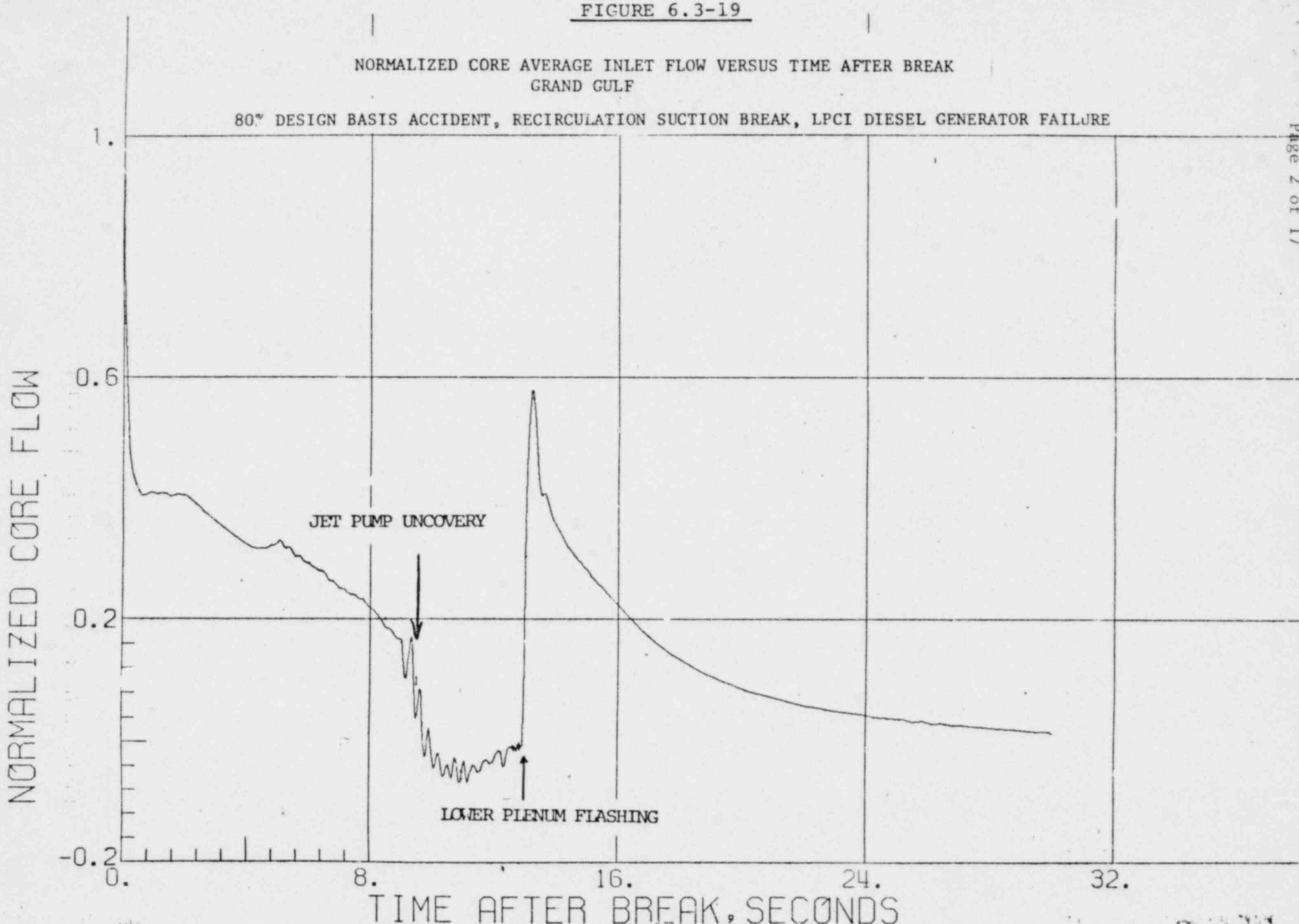

FIGURE 6.3-20

CORE INLET ENTHALPY VERSUS TIME AFTER BREAK
GRAND GULF

80% DESIGN BASIS ACCIDENT, RECIRCULATION SUCTION BREAK, LPCI DIESEL GENERATOR FAILURE

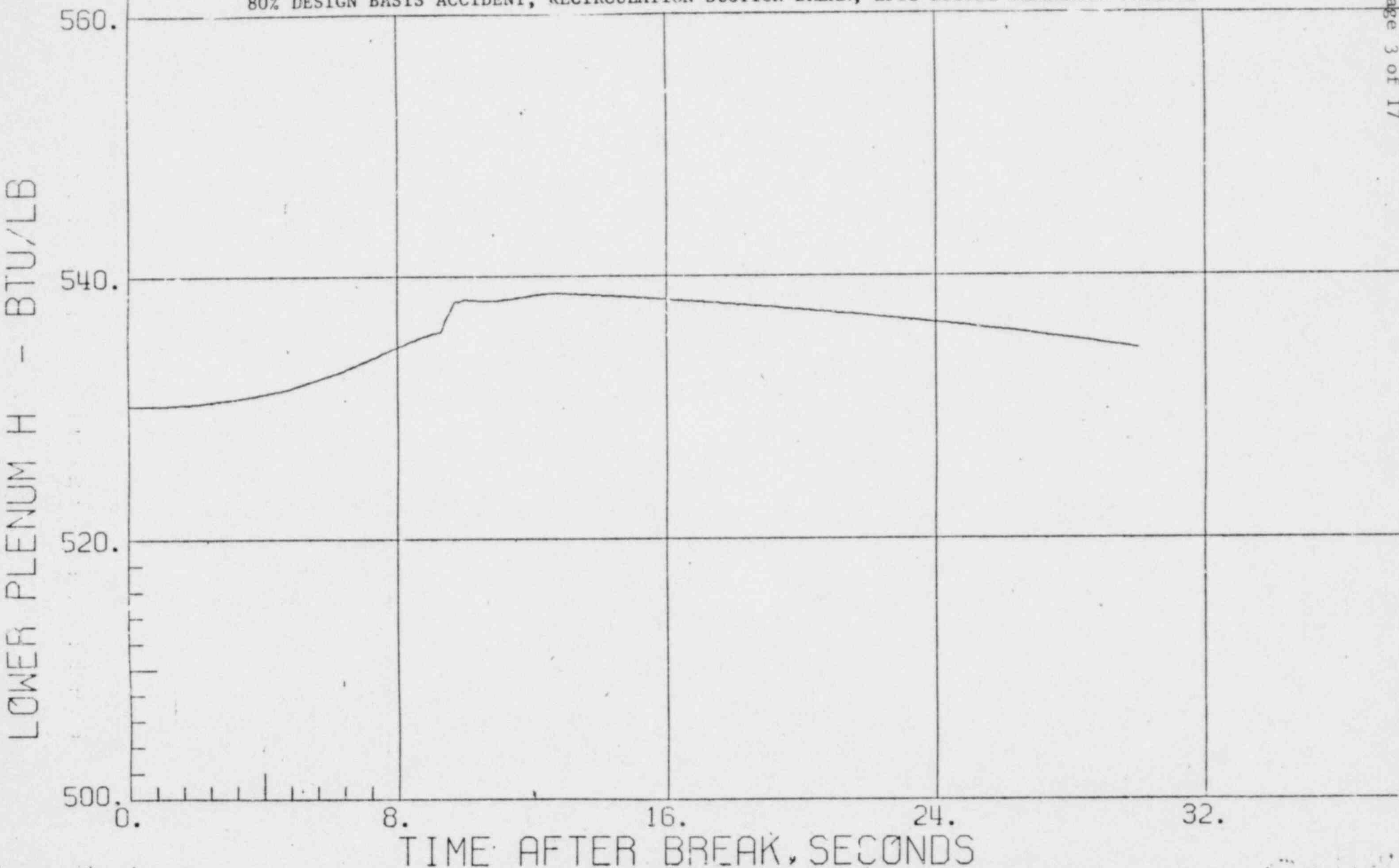

FIGURE 6.3-21

CORE AVERAGE PRESSURE VERSUS TIME AFTER BREAK
GRAND GULF
80% DESIGN BASIS ACCIDENT, RECIRCULATION SUCTION BREAK, LPCI DIESEL GENERATOR FAILURE

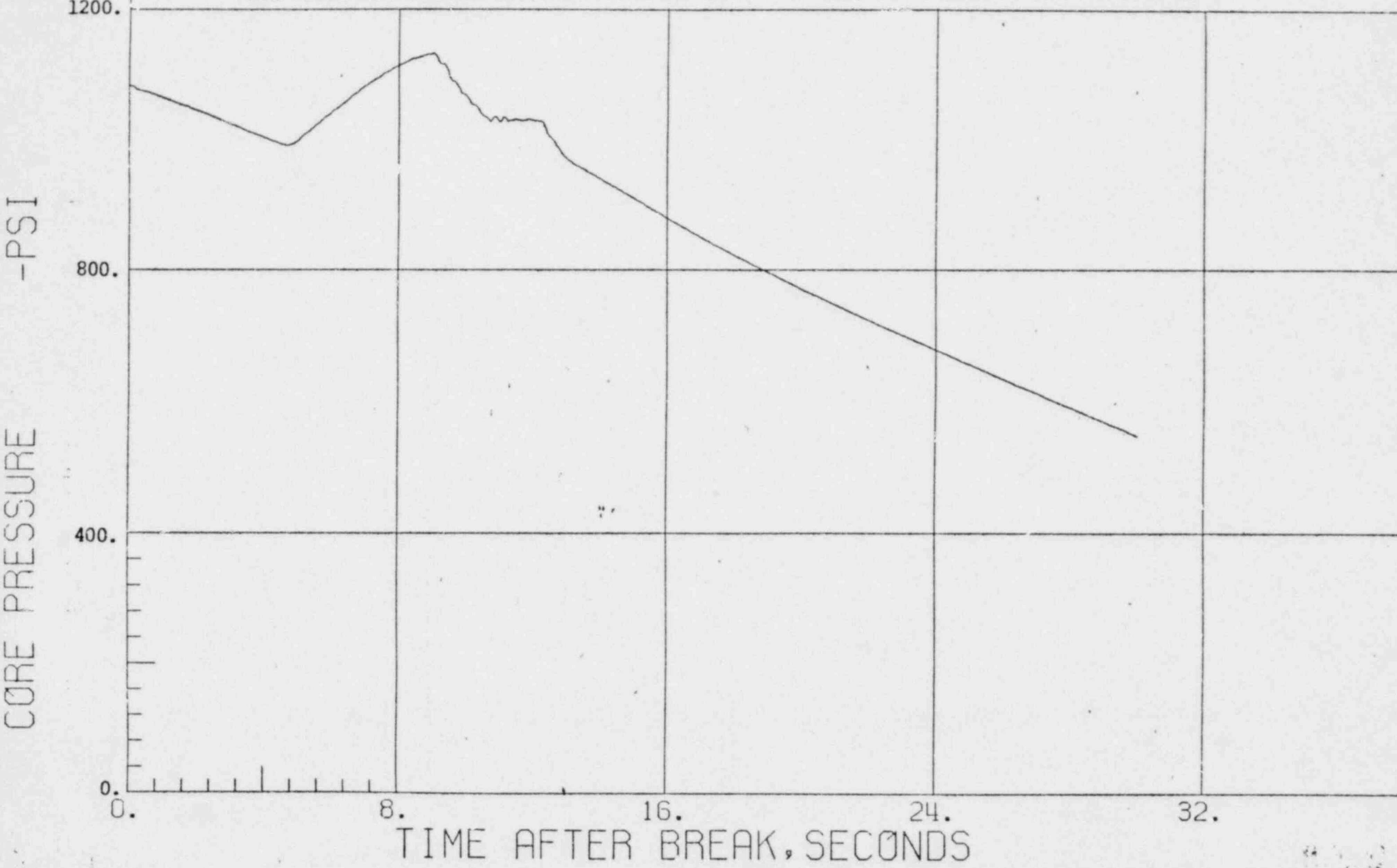

FIGURE 6.3-22

MINIMUM CRIITCAL POWER RATIO VERSUS TIME AFTER BREAK
GRAND GULF

80% DESIGN BASIS ACCIDENT, RECIRCULATION SUCTION BREAK, LPCI DIESEL GENERATOR FAILURE

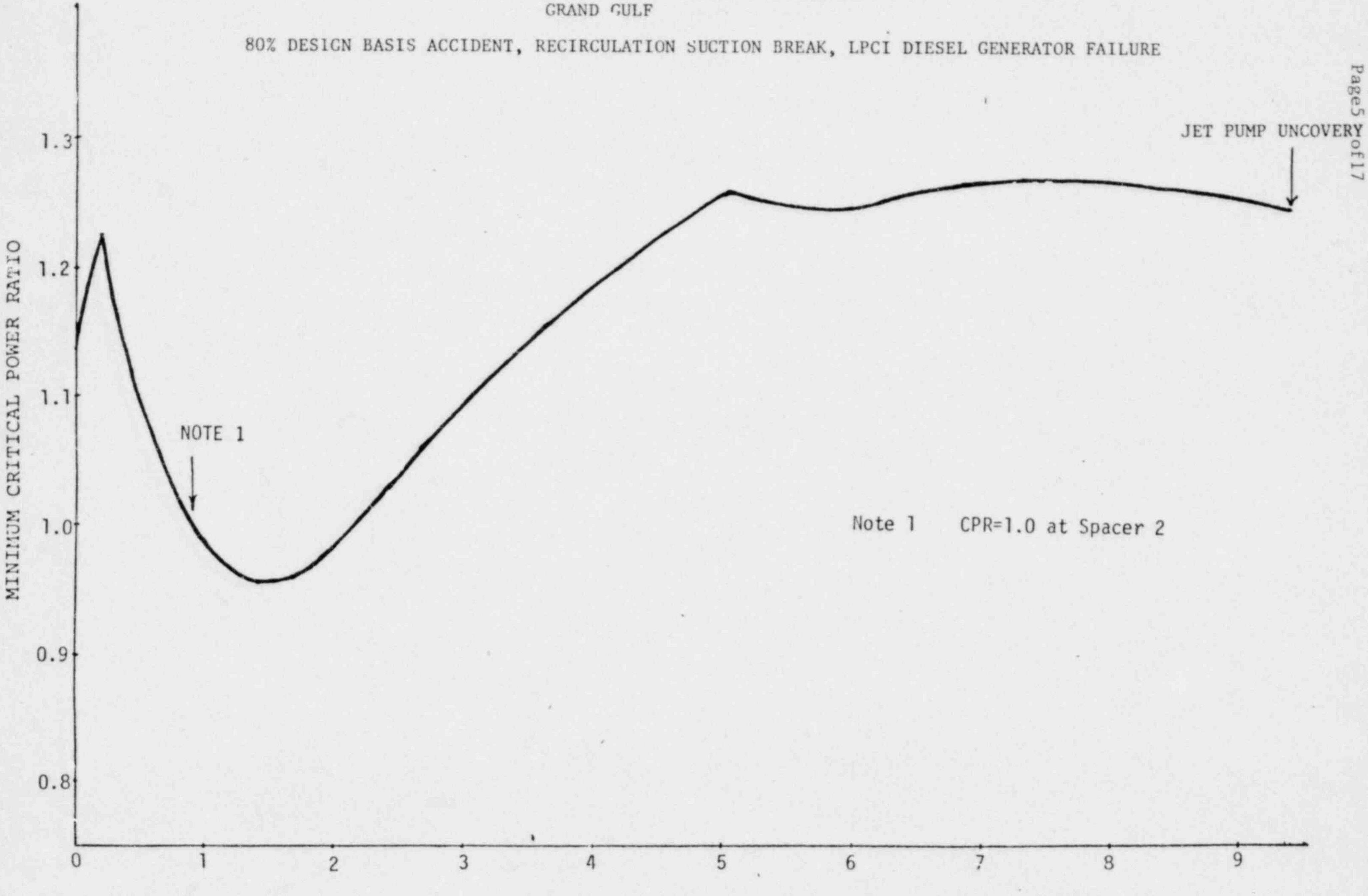

FIGURE 6.3-23

CONVECTIVE HEAT TRANSFER COEFFICIENT VERSUS TIME AFTER BREAK

GRAND GULF

80% DESIGN BASIS ACCIDENT, RECIRCULATION SUCTION BREAK, LPCI DIESEL GENERATOR FAILURE

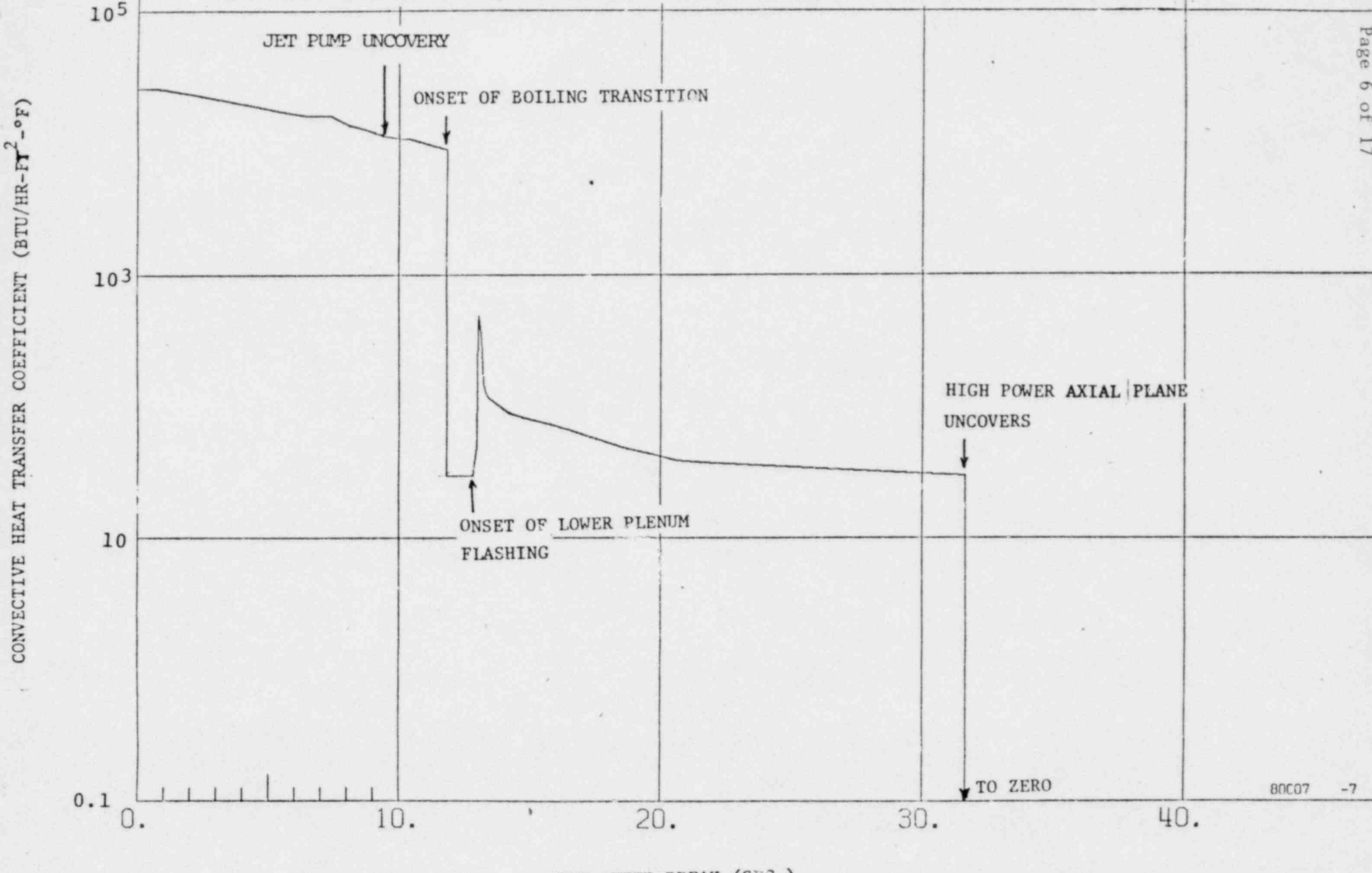

FIGURE 6.3-24

WATER LEVEL INSIDE THE SHROUD VERSUS TIME AFTER BREAK

GRAND GULF

80% DESIGN BASIS ACCIDENT, RECIRCULATION SUCTION BREAK, LPCI DIESEL GENERATOR FAILURE

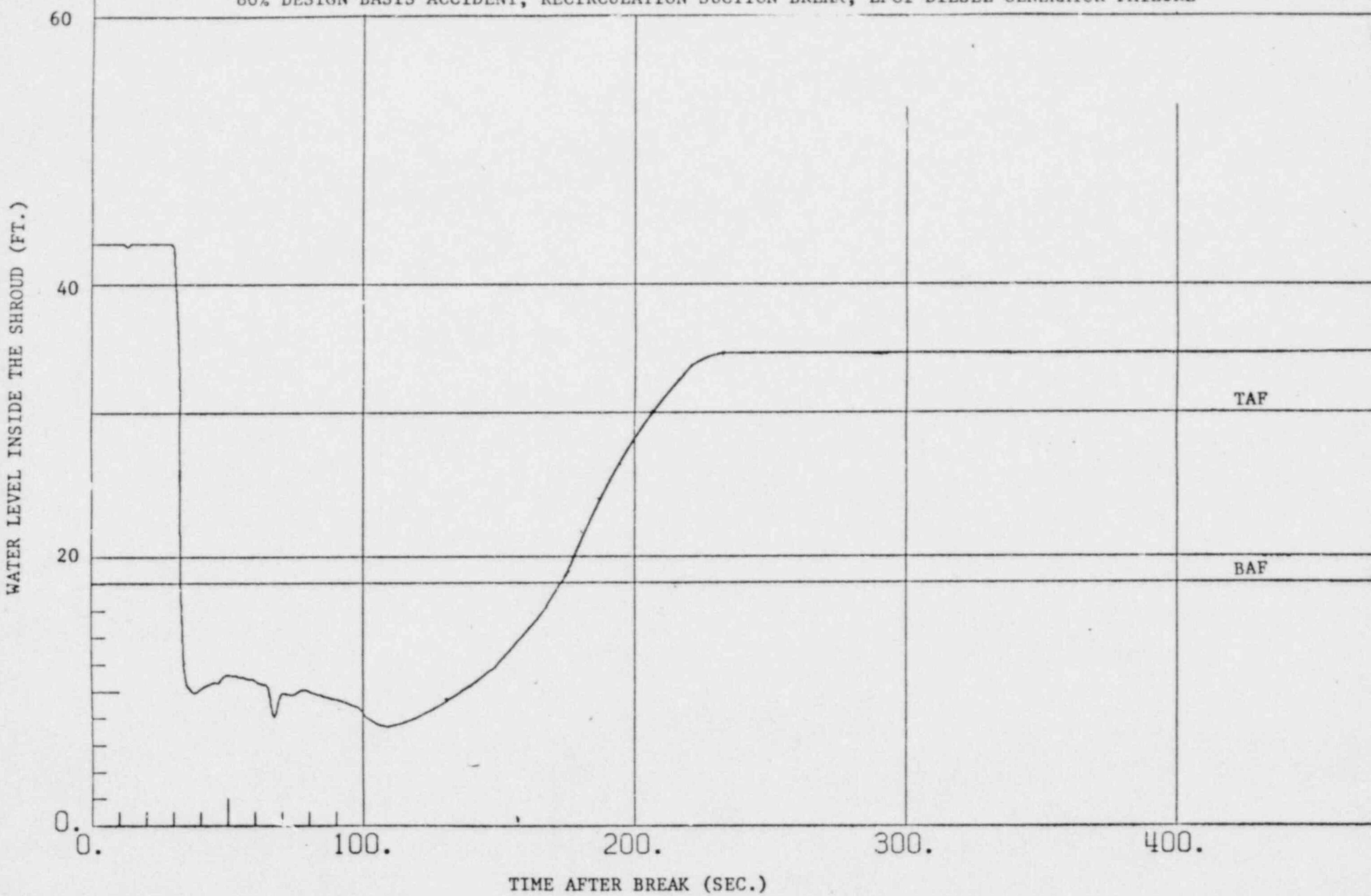

FIGURE 6.3-25

REACTOR VESSEL PRESSURE VERSUS TIME AFTER BREAK

GRAND GULF

80% DESIGN BASIS ACCIDENT, RECIRCULATION SUCTION BREAK, LPCI DIESEL GENERATOR FAILURE

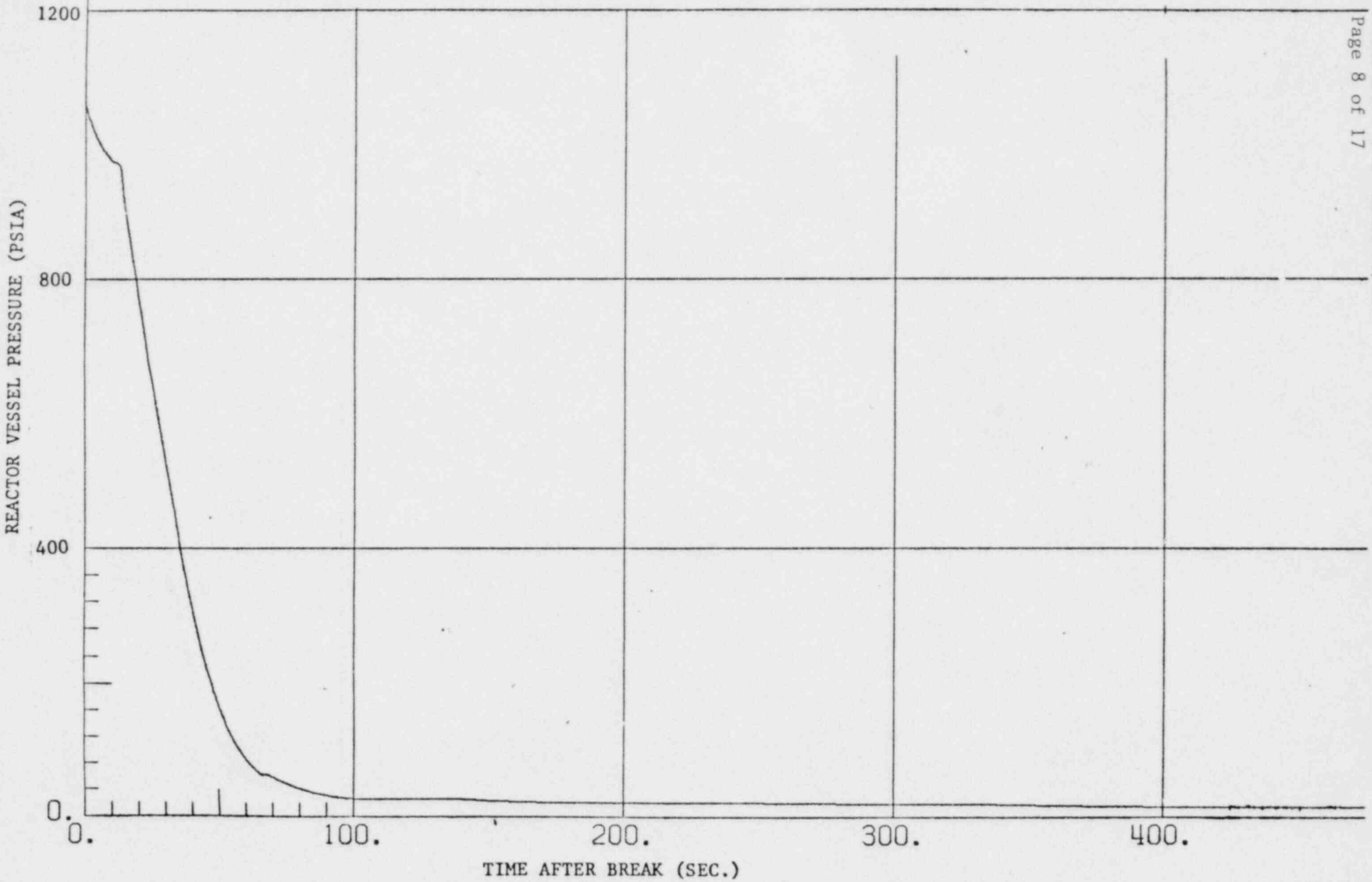

FIGURE 6.3-26

PEAK CLADDING TEMPERATURE VERSUS TIME AFTER BREAK

GRAND GULF

80% DESIGN BASIS ACCIDENT, RECIRCULATION SUCTION BREAK, LPCI DIESEL GENERATOR FAILURE

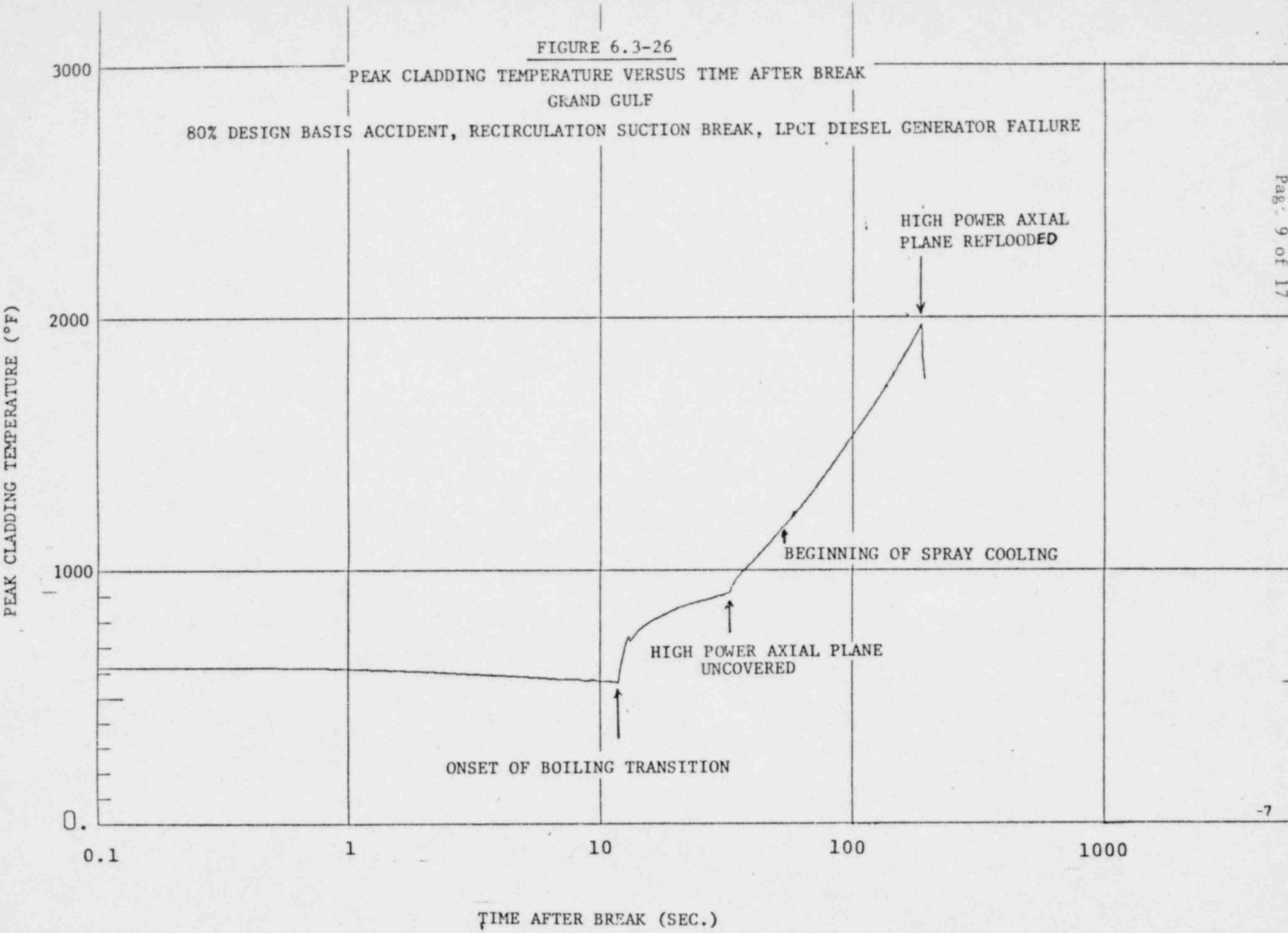

FIGURE 6.3-27

NORMALIZED CORE AVERAGE INLET FLOW VERSUS TIME AFTER BREAK
GRAND GULF
60% DESIGN BASIS ACCIDENT, RECIRCULATION SUCTION BREAK, LPCI DIESEL GENERATOR FAILURE

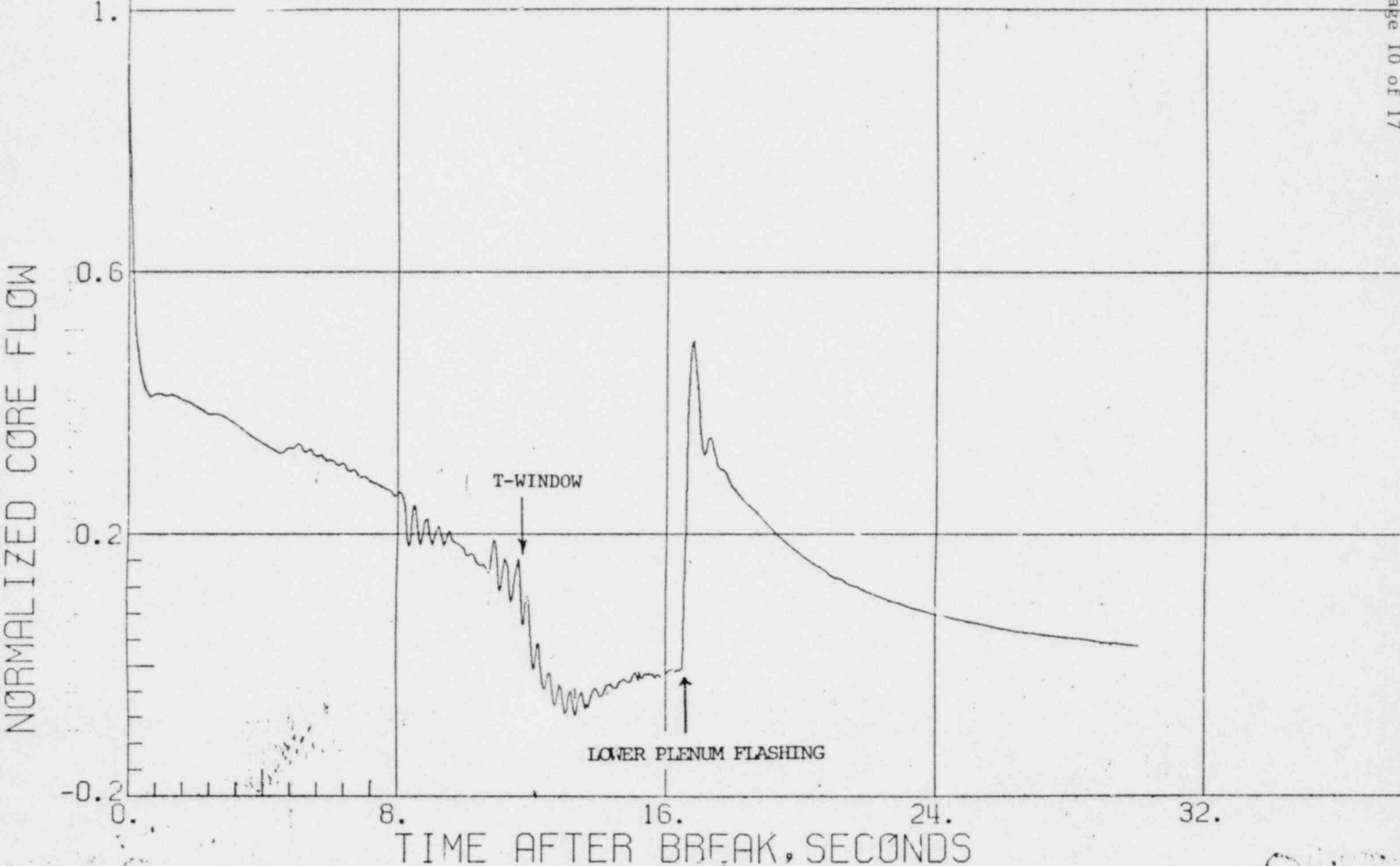

FIGURE 6.3-28

CORE INLET ENTHALPY VERSUS TIME AFTER BREAK
GRAND GULF
60% DESIGN BASIS ACCIDENT, RECIRCULATION SUCTION BREAK, LPCI DIESEL GENERATOR FAILURE

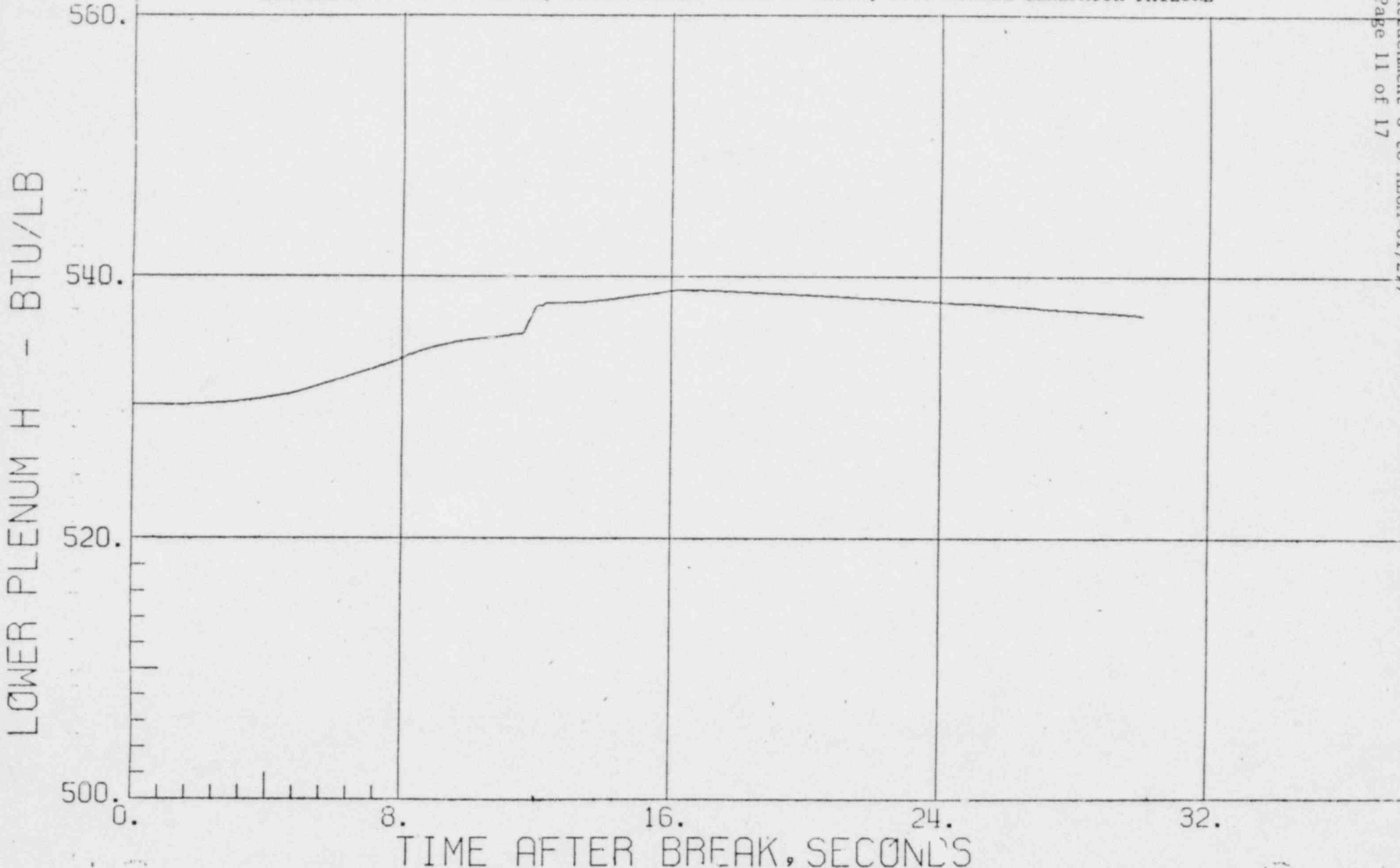

FIGURE 6.3-29

CORE AVERAGE PRESSURE VERSUS TIME AFTER BREAK
GRAND GULF
60% DESIGN BASIS ACCIDENT, RECIRCULATION SUCTION BREAK, LPCI DIESEL GENERATOR FAILURE

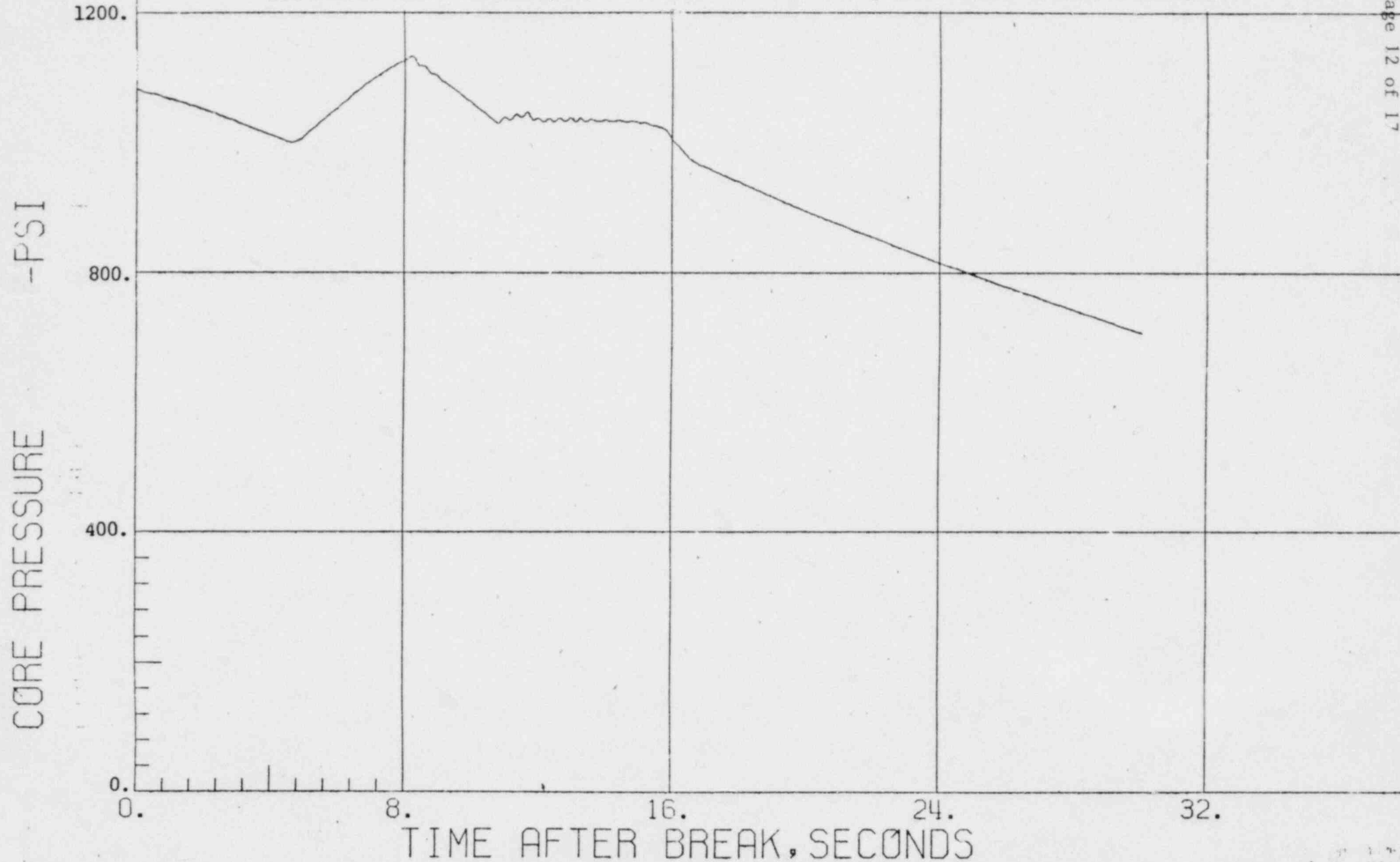

FIGURE 6.3-30

MINIMUM CRITICAL POWER RATIO VERSUS TIME AFTER BREAK
GRAND GULF

60% DESIGN BASIS ACCIDENT, RECIRCULATION SUCTION BREAK, LPCI DIESEL GENERATOR FAILURE

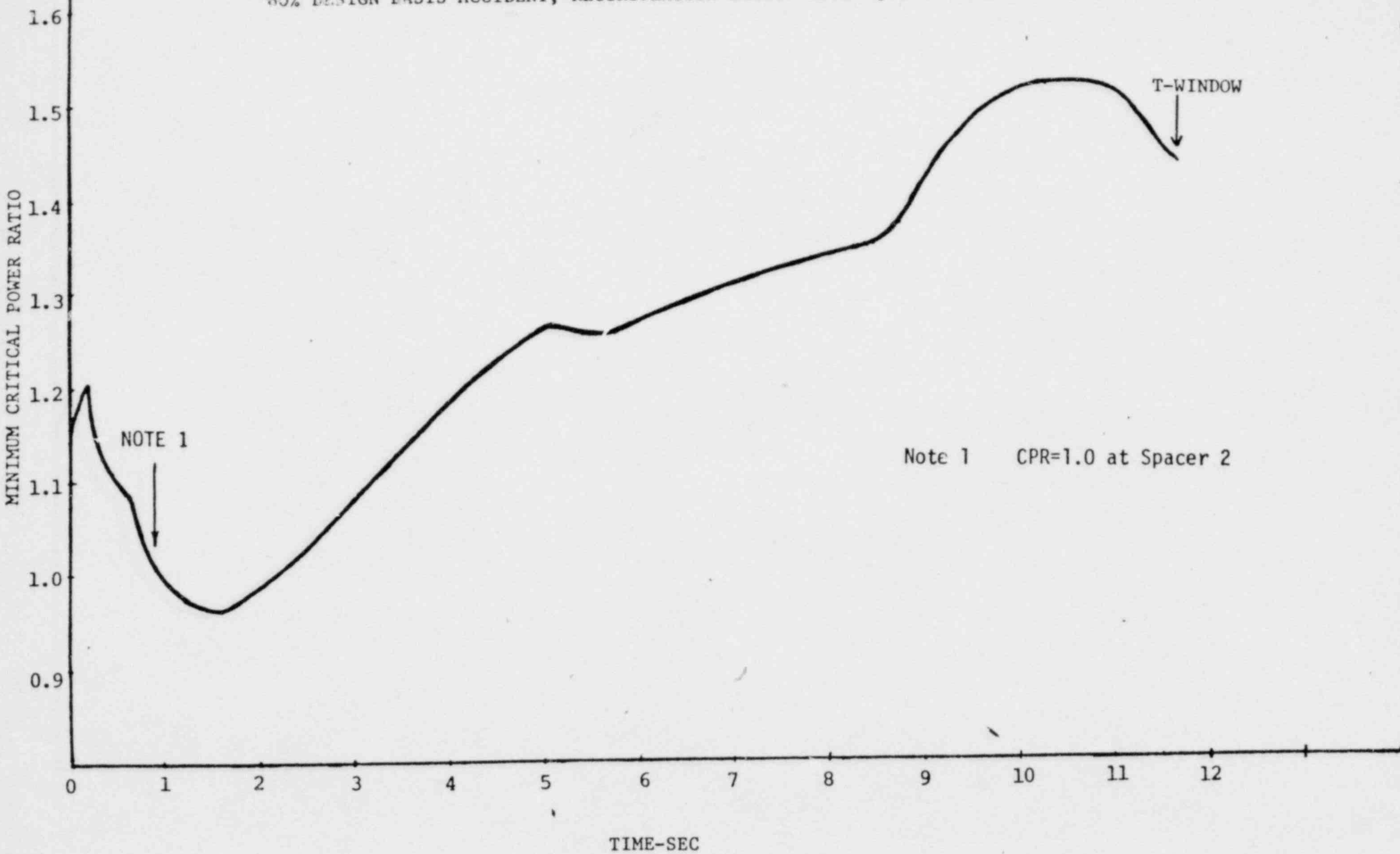

FIGURE 6.3-31

CONVECTIVE HEAT TRANSFER COEFFICIENT VERSUS TIME AFTER BREAK

GRAND GULF

60% DESIGN BASIS ACCIDENT, RECIRCULATION SUCTION BREAK, LPCI DIESEL GENERATOR FAILURE

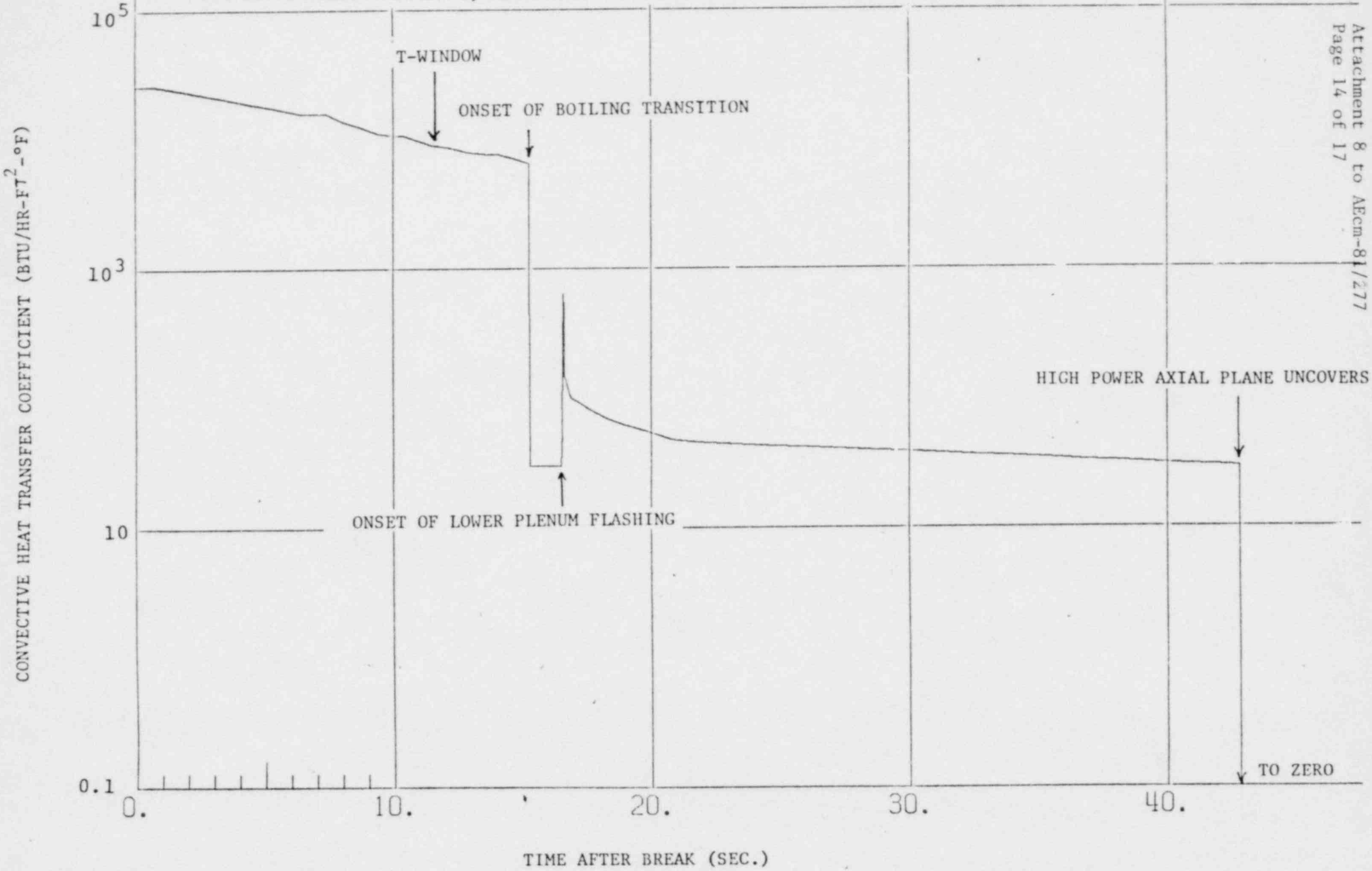

FIGURE 6.3-32

WATER LEVEL INSIDE THE SHROUD VERSUS TIME AFTER BREAK

GRAND GULF

60% DESIGN BASIS ACCIDENT, RECIRCULATION SUCTION BREAK, LPCI DIESEL GENERATOR FAILURE

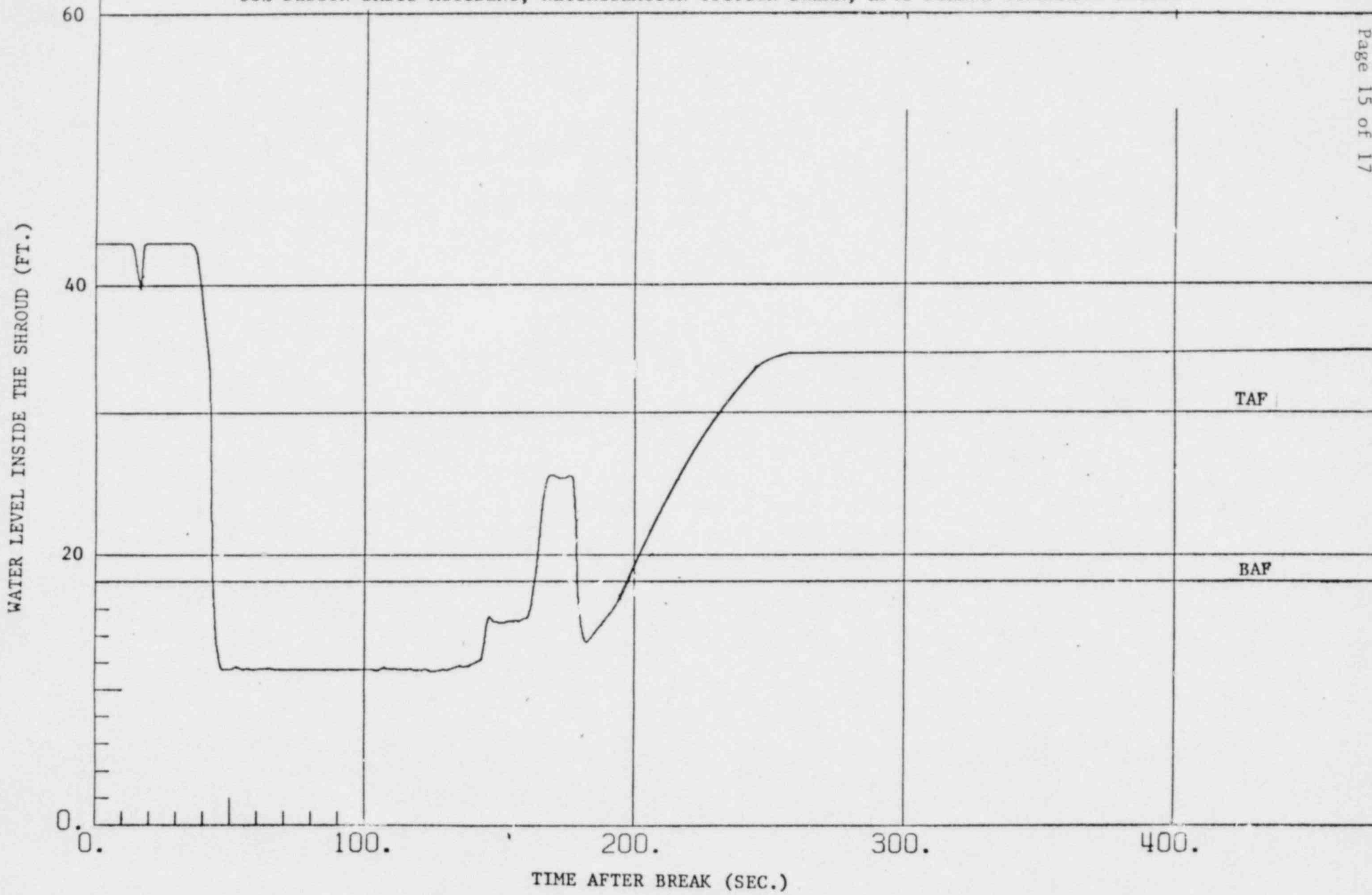

FIGURE 6.3-33

REACTOR VESSEL PRESSURE VERSUS TIME AFTER BREAK

GRAND GULF

60% DESIGN BASIS ACCIDENT, RECIRCULATION SUCTION BREAK, LPCI DIESEL GENERATOR FAILURE

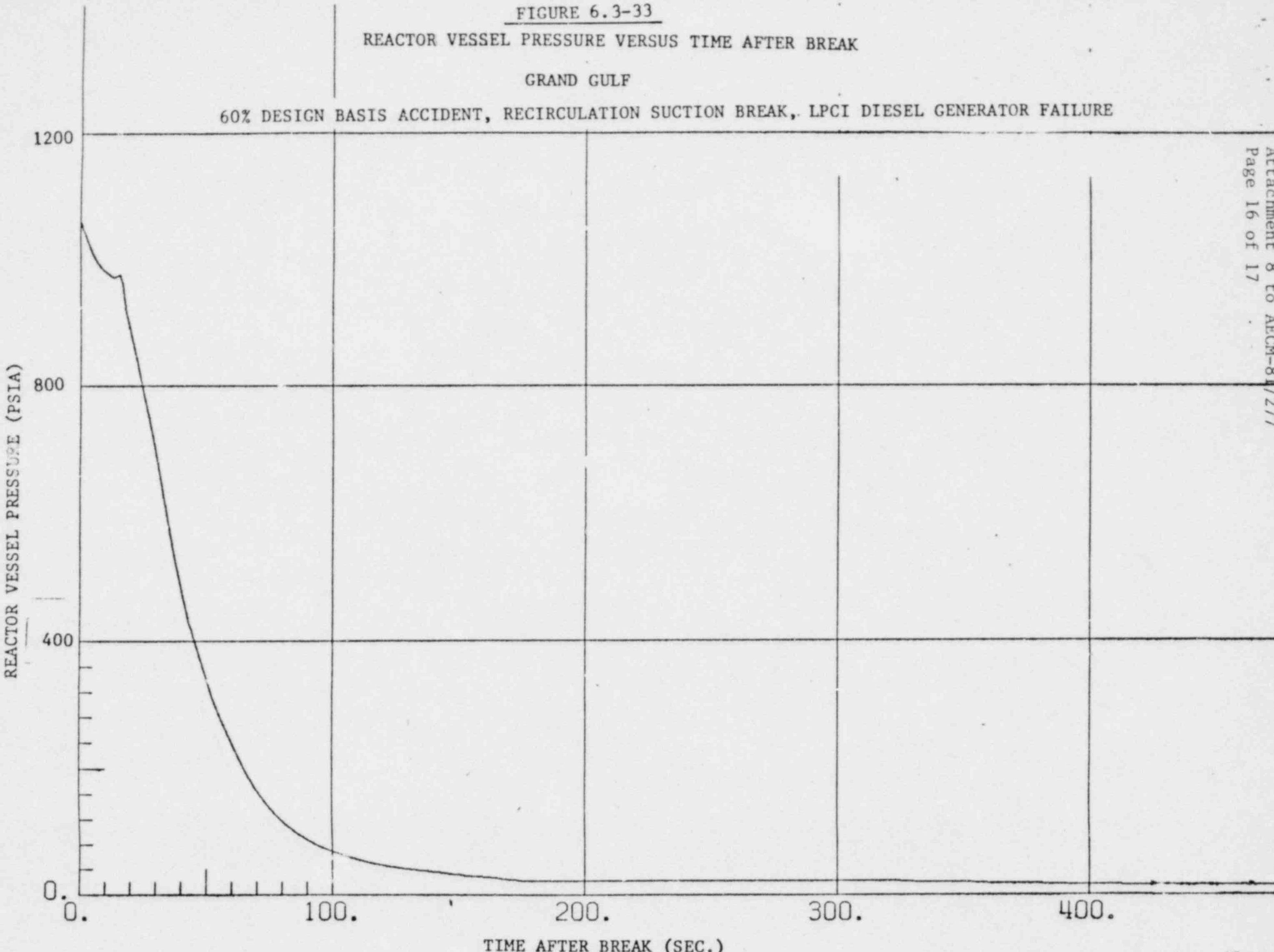

FIGURE 6.3-34

PEAK CLADDING TEMPERATURE VERSUS TIME AFTER BREAK

GRAND GULF

60% DESIGN BASIS ACCIDENT, RECIRCULATION SUCTION BREAK, LPCI DIESEL GENERATOR FAILURE