RELOAD SAFETY EVALUATION

SAN ONOFRE NUCLEAR GENERATING STATION

UNIT 1 CYCLE 10

REVISION 1

March 1989

Edited by: J. Skaritka

Approved: E H Novendstern

E. H. Novendstern, Manager
T/H Design and Fuel Licensing
Commercial Nuclear Fuel Division

5900L:6/890228

Attachment to THFL-89-131

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

1.0 INTRODUCTION AND SUMMARY

The San Onofre Nuclear Generating Station Unit 1 has completed its ninth cycle of operation. The unit will be ready for Cycle 10 startup during early 1989.

This report presents an evaluation for Cycle 10 operation which demonstrates that the core reload will not adversely affect the safety of the plant. Those incidents analyzed and reported in the Updated FSAR(1) and other incidents subsequently analyzed(2)(3) which could potentially be affected by the fuel reload have been reviewed for the Cycle 10 design described herein. Boron Dilution is not evaluated since SCE performs the analysis of this event. The results of new analyses have been included, and the justification for the applicability of previous results from the remaining analyses is presented. These analyses assume that: 1) Cycle 9 operation is terminated between 10900 and 11900 MWD/MTU, 2) Cycle 10 burnup is limited to 10,500 MWD/MTU for the Revision 1 operating condition stated below and 11,200 MWD/MTU for the Revision 2 operating condition stated below, or end-of-full power capability* for either condition (whichever occurs first), 3) there is adherence to plant operating requirements given in Section 3.3.1 and the technical specifications and proposed changes noted in Section 4 of this report.

The San Onofre 1, Cycle 10 core loading pattern is shown in Figure 1. The one Region 8 and 51 Region 9 fuel assemblies from Cycle 9 will be removed and replaced by 52 Region 12A and 12B fuel assemblies. A Region 9 fuel assembly will be reused in the central core position. Region 12B consists of four demonstration fuel assemblies each having eight Integral Fuel Burnable Absorber (IFBA) fuel rods.

Nominal design parameters for Cycle 10 are 1347 Mwt core power, 2100 psia system pressure, and 4.64 kw/ft average linear fuel power density. This Reload Safety Evaluation (RSE) covers Cycle 8 RSE(4) conditions for Revision 1 (nominal vessel average temperature 575.15°F and a 195,000 gpm Reactor Coolant System (RCS) thermal design flow which accounts for up to an equivalent 20% steam generator tube plugging in any steam generator).

* Definition: Full rated power and nominal core inlet temperature with control rods fully withdrawn, and zero ppm of residual boron.

This RSE also covers an increase in steam generator tube plugging level up to an equivalent 20% tube plugging level in any steam generator for the Cycle 8 RSE[4] Revision 2 conditions (nominal vessel average temperature of 551.5°F and a RCS thermal design flow of 201,900 gpm which accounted for up to an equivalent 15% steam generator plugging in any steam generator). The new RCS thermal design flow for Cycle 8 RSE Revision 2 conditions is 195,000 gpm which accounts for up to an equivalent 20% steam generator tube plugging in any steam generator. The vessel average temperature remains at 551.5°F.

2.0 REACTOR DESIGN

2.1 MECHANICAL DESIGN

The mechanical design of the Region 12A and 12B fuel assemblies is the same as the Region 11 assemblies, except for the use of (1) the standardized chamfered fuel pellet design, (2) fuel rod end plug with an internal gripper design, (3) a new top nozzle spring screw design, and (4) the use of IFBA fuel rods in the four Region 12B assemblies.

The Region 12 pellets have a reduced pellet length, a small chamfer at the outer edge of the fuel pellets, and a reduction in the dish diameter and depth compared to the previous unchamfered fuel pellets. The chamfer improves pellet chip resistance during manufacturing and handling. The mass per unit length for a fuel pellet stack in a rod is identical to the original non-chamfered pellet design in previous fuel regions.

The bottom end plugs for the Region 12 fuel rods are modified with an internal gripper device to facilitate rod insertion during fabrication and for post irradiation rod removal by pulling fuel rods rather than the previous method of pushing fuel rods through the fuel assembly grids.

The new top nozzle spring screw design includes a fillet between the head end shank, which reduces the stresses at this point, and therefore, the likelihood of screw failure. The chamfer in the uppermost spring was increased to accommodate this new screw design.

The Region 12B assemblies have IFBA rods for demonstration purposes. Each assembly has eight IFBA rods in assembly locations noted in Figure 2. An IFBA rod has a thin boride coating on the fuel pellets cylindrical surface which covers most of the centered axial length of the 120 inch fuel stack. Additional information on IFBA rods is covered in the VANTAGE 5 design report(5) and the Westinghouse core experience report(6).

Table 1 compares pertinent design parameters of the various fuel regions. The Region 12A and 12B fuel has been designed according to the fuel performance model in Reference 7. For all fuel regions, the fuel rod internal pressure design basis, which is discussed and shown acceptable in Reference 8, is satisfied.

Clad flattening will not occur during Cycle 10. All fuel regions have a predicted clad flattening time equal to or greater than 50,000 EFPH. No fuel region will receive this exposure.

2.2 NUCLEAR DESIGN

The Cycle 10 nuclear design was performed using ANC[9] for static 2D and 3D spatial calculations. The core loading pattern satisfies an ECCS analysis limit on F_Q^T of 2.78 as shown in Figure 3. The limitations on F_Q^T include the effects of local power peaking due to fuel densification and ECCS performance uncertainty to assure that the allowable value for LOCA is satisfied. The points plotted on Figure 3 include maneuvers typically performed at San Onofre Unit 1 and variants on these maneuvers done at a number of control rod insertions, times, and burnups. The axial shape analysis confirms that if the axial offset limits defined in the current Technical Specifications are followed over the full range of operating powers, no violation of the F_Q limit will occur.

The maximum F_Q^T is determined by combining the most adverse Fxy and F_Z^N occurring at the limiting time in life. The results shown for F_Q^T in Figure 3 include uncertainty factors of 10.6% for measurement and 4% for manufacturing tolerances.

For Cycle 10, the xenon transient analysis has been modified slightly from previous cycles. The axial core power profiles are generated in the same manner. However, the evaluation of these profiles has been performed explicitly as part of the Thermal and Hydraulic Design, rather than as part of the Nuclear Design.

The Cycle 10 Nuclear Design accounts for the presence of four IFBA demonstration assemblies. The location of the IFBA rods within these assemblies was chosen to preserve symmetry, allow visual inspection during refueling, and provide depletion characteristics via the INCORE detector system.

Table 2 provides a comparison of Cycle 10 kinetics characteristics with the current limit based on previously submitted accident analysis. The effect of the Table 2 parameters are evaluated in Section 3. Table 3 provides the end-of-life control rod worths and requirements at the most limiting condition during the cycle. The required shutdown margin is based on the Steamline Break Accident Analysis reported in Section 3.3.3 of this report. The available shutdown margin exceeds the minimum required to meet the accident analysis.

2.3 THERMAL AND HYDRAULIC DESIGN

The Cycle 10 safety analysis was based on the use of the design axial power shape of F_Z^N = 1.95 at 85 percent core elevation and a $F_{\Delta H}^N$ = 1.57. A total of 4.4 percent DNBR margin is available(4) if a limiting F_Z^N = 1.92 at 85 percent core elevation is assumed. The design has confirmed that the F_Z^N = 1.92 axial design shape bounded all axial shapes generated during the Cycle 10 nuclear design axial shape analysis. For Cycle 10 operation even more margin is available due to the difference between the design shape and the actual limiting shapes analyzed for the Cycle 10 core. The 4.4 percent DNBR margin is comprised of two parts(4). The difference between F_Z^N = 1.95 and F_Z^N = 1.92 provides a 1.1 percent DNBR margin. Pitch reduction gives the other 3.3 percent DNBR margin. This 4.4 percent DNBR margin was used to accommodate the reduction in DNBR margin resulting from the use of a $F_{\Delta H}^N$ = 1.57 rather than a $F_{\Delta H}^N$ = 1.55.

With the use of the above peaking factors no significant variations in thermal margins will result from the Cycle 10 reload. The present DNB core limits are conservative for Cycle 10.

3.0 ACCIDENT EVALUATION

3.1 POWER CAPABILITY

The plant power capability is evaluated considering the consequences of those incidents examined in the UFSAR(1) and other incidents subsequently analyzed(2)(3) except for Boron Dilution, using the previously accepted design basis. It is concluded that the core reload will not adversely affect the ability to safely operate at 100% of rated power during Cycle 10. For Condition II overpower transients, the fuel centerline temperature limit of 4700°F can be accommodated with margin in the Cycle 10 core. The time dependent densification model(10) was used for fuel temperature evaluations.

The LOCA limit at rated power can be met by maintaining F^T_Q at or below 2.78 for the operating conditions given in Section 1.0. This limit is satisfied by the power control maneuvers allowed by the technical specifications, which assure that the IAC limits are met for a spectrum of small and large breaks.

3.2 ACCIDENT EVALUATION

The effects of the reload on the design basis and postulated incidents analyzed in the UFSAR(1) and other incidents subsequently analyzed(2)(3) were examined, except for Boron Dilution which is analyzed by Southern California Edison. The effects of the reload operating with the increase in steam generator tube plugging level up to 20% for the Cycle 8 RSE(4) Revision 2 conditions on the design basis and postulated incidents analyzed in the UFSAR(1) are evaluated in Appendix A (LOCA) and Appendix B (non-LOCA). Appendix A includes the effect of the increase in safety injection delay time on the LOCA events. Appendix B includes the effect of the increased safety injection delay time for the non-LOCA events and the unavailability of the low coolant flow reactor trip function for the Locked Rotor/Shaft Break event. In most cases, it was found that the effects were accommodated within the conservatism of the initial assumptions used in the previous applicable safety analysis. For those incidents which were reanalyzed, with the exception of the Locked Rotor event (See Section 3.3.1) it was determined that the applicable design bases are not exceeded, and, therefore, the conclusions presented in

the UFSAR are still valid. The reanalysis of the Locked Rotor/Shaft Break event showed that the conclusions presented in the UFSAR remain valid. This assumed the reactor trips on Reactor Coolant Pump (RCP) breaker opening due to overcurrent and undercurrent to the RCP motor are available and operable.

The impact of using standardized fuel pellets and IFBA pellets has been considered. Safety limits are satisfied during LOCA and non-LOCA events, and the conclusions presented in the UFSAR(1) remain valid.

An evaluation was performed to determine the maximum additional increase in safety injection delay time that could be supported by the loss-of-coolant accident analysis referenced in the Cycle 8 RSE-Rev. 1.

Using all available margin to the peak clad temperature limit and taking credit for ramped safety injection flow while the valves are opening, as computed by Southern California Edison, it has been concluded that an additional 4.30 seconds of delay time can be supported by the loss-of-coolant accident analysis referenced in the Cycle 8 RSE-Rev. 1 without violating the limits set by the Interim Acceptance Criteria.

A core reload can typically affect accident input parameters in the following areas: core kinetic characteristics, control rod worths, and core peaking factors. Cycle 10 parameters in each of these three areas were examined as discussed below to ascertain whether new accident analyses were required.

A comparison of Cycle 10 core physics parameters with current limits is given in Table 2. All the kinetics values, except the doppler temperature coefficient (see Table 2), remain within the bounds of the analysis limits.

All analyses, which assume a least negative Doppler temperature coefficient, used a value of -1.4 pcm/°F with the exception of the Loss of Flow analysis. The Loss of Flow analysis used a value of -1.63 pcm/°F compared to the reload value of -1.4 pcm/°F. This coefficient in conjunction with the Doppler power coefficient provides a correction to the power coefficient for fuel temperature changes in transients where the core water temperature changes. This difference, however, has been determined to result in a negligible effect on the Loss of Flow analysis.

Changes in control rod worths may affect differential rod worths, shutdown margin, ejected rod worths, and trip reactivity. Tables 2 and 3 show that the maximum reactivity withdrawal rate and the shutdown margin with the worst stuck RCCA are within the current limits. The ejected rod worths and trip reactivity curve are within the bounds of the current limits.

Peaking factor evaluations were performed for the rod out of position, dropped RCCA bank, dropped RCCA, and hypothetical steamline break accident to ensure that the minimum DNB ratio remains above 1.45 for the steamline break accident(11) and 1.30 for the other accidents. These evaluations were performed utilizing Cycle 10 transient statepoint information and peaking factors. In each case, it was found that the peaking factor for Cycle 10 was lower than the value for which DNBR equals 1.45 for the steamline break and 1.30 for other accidents. Consequently, no further investigation or analysis was required. The peaking factors following control rod ejection are within the limits of previous analysis for both beginning-of-life (BOL) and end-of-life (EOL) zero power and full power cases.

The Loss of Normal Feedwater and Feedline Break events (UFSAR Sections 15.5 and 15.6 respectively) were analyzed employing the 1979 version of the ANS 5.1 decay heat standard(12) as the basis for the calculation of core residual heat generation. The application of this decay heat model has been accepted for use in non-LOCA analysis by the NRC.

3.3 INCIDENTS REANALYZED

3.3.1 LOCKED ROTOR

The Locked Rotor/Shaft Break event was reanalyzed to address the unavailability of the low coolant flow reactor trip function. A single active failure of a low flow transmitter (one per loop) in the same loop as the locked rotor/shaft break could prevent this trip from occurring. The reanalysis of the Locked Rotor/Shaft Break is presented in Appendix B.

The reanalysis assumed that a reactor trip is actuated by RCP breaker opening due to either overcurrent (locked rotor) or undercurrent (shaft break) to the RCP motor. For the analysis of the Cycle 8 RSE(4) Revision 1 operating conditions, the results showed that 12.3% of the fuel rods in the core undergo DNB. This analysis also determined that the peak clad temperature limit has been satisfied. For the analysis of the increased steam generator tube plugging level for the Cycle 8 RSE(4) Revision 2 operating conditions, the results showed that no fuel rods in the core undergo DNB. Therefore, the core will remain in place and intact with no loss of core cooling capability. Thus, the applicable safety criteria related to the Locked Rotor/Shaft Break event have been met for either operating condition.

The reanalysis of the Locked Rotor/Shaft Break showed that rod motion must begin within 6.1 seconds following the locked rotor/shaft break to ensure that the applicable safety criteria are met. It is the responsibility of Southern California Edison to provide the assurance that a Locked Rotor/Shaft Break will actuate a reactor trip by the RCP opening due to either overcurrent or undercurrent to the RCP motor. It must also be assured that the rods begin to fall within 6.1 seconds following the locked rotor/shaft break. Also, it is the responsibility of SCE to incorporate the RCP break opening reactor trips due to overcurrent and undercurrent to the RCP motor into SONGS 1 Technical Specifications.

This analysis was not a direct result of the Cycle 10 reload design. It is included here because it has been reanalyzed since the Cycle 9 reload and extended operation safety evaluations, and it is considered part of the San Onofre Unit 1 licensing basis for the Locked Rotor/Shaft Break accident.

3.3.2 DROPPED ROD

The Dropped Rod accident was reanalyzed as a result of the Nuclear Instrumentation System upgrade. This analysis is documented in Reference 2. The results show that the safety conclusions presented in the UFSAR remain valid.

3.3.3 STEAMLINE BREAK

The Steamline Break accident was reanalyzed to change surveillance requirements on the boron concentration in the Safety Injection lines. This analysis is documented in Reference 3. The results showed that the conclusions presented in UFSAR remain valid.

During Cycle 9/Cycle 10 refueling outage, this Reference 3 analysis was reanalyzed to support an increase safety injection time delay. This reanalysis is presented in Appendix B. The results show that the conclusions presented in the UFSAR remain valid.

This reanalysis was not a direct result of the Cycle 10 reload design. It is included here because it has been reanalyzed since the Cycle 9 reload and extended operation safety evaluations, and it is considered part of the San Onofre Unit 1 licensing basis for the steamline break accident.

3.3.4 LOSS OF COOLANT ACCIDENT

The loss-of-coolant accident was re-analyzed to bound operation with up to 20% equivalent steam generator tube plugging at reduced thermal conditions and an increase in safety injection initiation time. The results of this analysis are presented in Appendix A.

4.0 TECHNICAL SPECIFICATIONS

This section contains the technical content of proposed changes to the San Onofre Unit 1 Technical Specifications. These changes, shown in Appendix C, are consistent with the plant operation necessary for the design, safety analyses and evaluation conclusions stated previously to remain valid.

A. Changes to TS 3.5.2 Basis are necessary due to a reanalysis of the large break Loss of Coolant Accident (LOCA). This reanalysis was required to bound operation of the San Onofre Unit 1 with up to 20% equivalent tube plugging in any Steam Generator at reduced thermal conditions and an increase in the safety injection initiation time.

Update the following section of the Technical Specifications with the appropriate revisions:

1. TS 3.5.2, Basis 1, Page 3-50

   Values of specific power, and F_q should be changed to 13.2 kw/ft and 2.78 respectively.

B. Changes in TS and Basis 3.11, Continuous Power Distribution Monitoring, are provided to: 1) reflect the revised LOCA F_q limits which have been discussed above, 2) change the applicability of the specification to cover applicable range of operation and 3) simplify the subject equations by revising the constants in the conservative direction.

1. TS and Basis 3.11, Specification, Pages 3-93 and 3-94.

   Change applicability to MODE 1,
   Revise 2.89 to 2.78 (both equations),
   Revise numerator minus value to 2.10 (both equations),
   Revise denominator to 0.033 (both equations).
   Use acronym once provided (IAO), and
   Revise actions A and C to be consistent with the MODE applicability.

C. Changes to TS and Basis 3.10, Incore Instrumentation were provided to ensure adequate core monitoring for MODE 1 operation/consistency with TS 3.11 changes.

1. TS and Basis 3.10, Pages 3-91 and 3-92.

   Change applicability to MODE 1,
   Use acronyms once provided (EFPDs),
   Revise action B to be consistent with the MODE applicability.

5.0 REFERENCES

1. Docket Number 50-206, "San Onofre Nuclear Generating Station, Unit 1, Part 2, Final Safety Analysis."

2. "Southern California Edison, San Onofre Unit 1, Safety Review Report for NIS Upgrade," Attachment to letter SCE-88-590, L. E. Elder to J. R. Rainsberry, April 12, 1988.

3. Skaritka, J., Editor, "Evaluation of the San Onofre Unit 1 Cycle 9 Extended Operation," November 1988.

4. Skaritka, J., Editor, "Reload Safety Evaluation - San Onofre Unit 1, Cycle 8," Revision 1, October 1980 and Revision 2, April 1981.

5. Davidson, S. L. (Ed.), "VANTAGE 5 Fuel Assembly Reference Core Report," WCAP-10444-P-A, September 1985.

6. Foley, J. and Skaritka, J., "Operational Experience with Westinghouse Cores," (through December 31, 1987), WCAP-8183-Rev. 16, August 1988.

7. Miller, J. V. (Ed.), "Improved Analytical Model Used in Westinghouse Fuel Rod Design Computations," WCAP-8785, October 1976.

8. Risher, D. H. et. al., "Safety Analysis for The Revised Fuel Rod Internal Pressure Design Basis," WCAP-8964, June 1977.

9. Davidson, S. L. (Ed.), et. al., "ANC: Westinghouse Advanced Nodal Computer Code," WCAP-10965-P-A, September 1986.

10. Hellman, J. M. (Ed.), "Fuel Densification Experimental Results and Model for Reactor Operation," WCAP-8218-P-A, march 1975 (Proprietary) and WCAP-8219-A, March 1975 (Non-Proprietary).

11. Westinghouse Letter dated March 25, 1986, NS-NRC-86-3116, Westinghouse Response to Additional Request on WCAP-9226-P/WCAP-9227-N-P, "Reactor Core Response to Excessive Secondary Steam Release," (Non-Proprietary)."

12. ANSI/ANS 5.1 - 1979, "American National Standard for Decay Heat Power in Light Water Reactors," August 1979.

13. "Description and Safety Analysis Including Fuel Densification San Onofre Nuclear Generating System, Unit 1, Cycle 5, Attachment to letter from Jack B. Moore to Edison G. Case, March 7, 1975.

TABLE 1
SAN ONOFRE UNIT 1 - CYCLE 10
FUEL ASSEMBLY DESIGN PARAMETERS

Region	9	10	11	12A	12B**
Enrichment (w/o U-235), Nominal	4.00	4.00	4.00	4.00	4.00
Density (% Theoretical)*	94.66	94.45	94.68	95.28	95.28
Number of Assemblies	1	52	52	48	4
Approximate Burnup at Beginning of Cycle 10 (EFPD)	1157	986	472	0	0

* All regions are as-built values.

** Contains 8 IFBA rods per fuel assembly.

TABLE 2
SAN ONOFRE UNIT 1, CYCLE 10
CORE PHYSICS PARAMETERS

	Current Limit	Cycle 10
Moderator Temperature Coefficient (pcm/°F)	-40.0 to 0[4]	>-40 to <0
Doppler Coefficient, (pcm/°F)	-2.75 to -1.63[1,4]	>-2.75 to <-1.4
Delayed Neutron Fraction, β_{eff}, (%)	0.50 to 0.70[4]	>0.50 to <0.70
Maximum Prompt Neutron Lifetime (μ sec)	26[13]	<26
Maximum Reactivity Withdrawal Rate, (pcm/sec)*	62.5[3]	<62.5

*pcm = 10^{-5} $\Delta\rho$

TABLE 3
SAN ONOFRE UNIT 1 - CYCLE 10
SHUTDOWN REQUIREMENTS AND MARGINS

Control Rod Worth (PCM)	BOL	EOL
All Rods Inserted	7234	7707
All Rods Inserted Less Worst Stuck Rod	5409	6634
(1) Less 10%	4868	5971
Control Rod Requirements (PCM)		
Reactivity Defects (Doppler, Tavg, Void; Redistribution)	1499	2260
Rod Insertion Allowance	1750	1550
(2) Total Requirements	3249	3810
Shutdown Margin [(1)-(2)] (PCM)	1619	2161
Required Shutdown Margin (PCM)	1250	1900

FIGURE 1

CORE LOADING PATTERN
SAN ONOFRE UNIT 1 CYCLE 10

	1	2	3	4	5	6	7	8 (270)	9	10	11	12	13	14	15	
A							10	12B	10							
B					12A	12A	12A	12A	12A	12A	12A					
C				11	12A	10	11	10	11	10	12A	11				
D			11	12A	11	11	10	12A	10	11	11	12A	11			
E		12A	12A	11	11	10	11	10	11	10	11	11	12A	12A		
F		12A	10	11	10	12A	10	10	10	12A	10	11	10	12A		
G	10	12A	11	10	11	10	11	11	11	10	11	10 SS	11	12A	10	
H (180)	12B	12A	10	12A	10	10	11	9	11	10	10	12A	10	12A	12B	0
J	10	12A	11	10 SS	11	10	11	11	11	10	11	10	11	12A	10	
K		12A	10	11	10	12A	10	10	10	12A	10	11	10	12A		
L		12A	12A	11	11	10	11	10	11	10	11	11	12A	12A		
M			11	12A	11	11	10	12A	10	11	11	12A	11			
N				11	12A	10	11	10	11	10	12A	11				
P					12A	12A	12A	12A	12A	12A	12A					
R							10	12B	10							

90 DEG

Fuel Region
Source

XX
SS

FIGURE 2

INTER-ASSEMBLY IFBA LOCATIONS
SAN ONOFRE UNIT 1 CYCLE 10

	1	2	3	4	5	6	7	8	9	10	11	12	13	14
1	X													X
2														
3			GT			GT			GT			GT		
4				X							X			
5					GT					I				
6			GT									GT		
7														
8														
9			GT									GT		
10					GT					GT				
11				X							X			
12			GT			GT			GT			GT		
13														
14	X													X

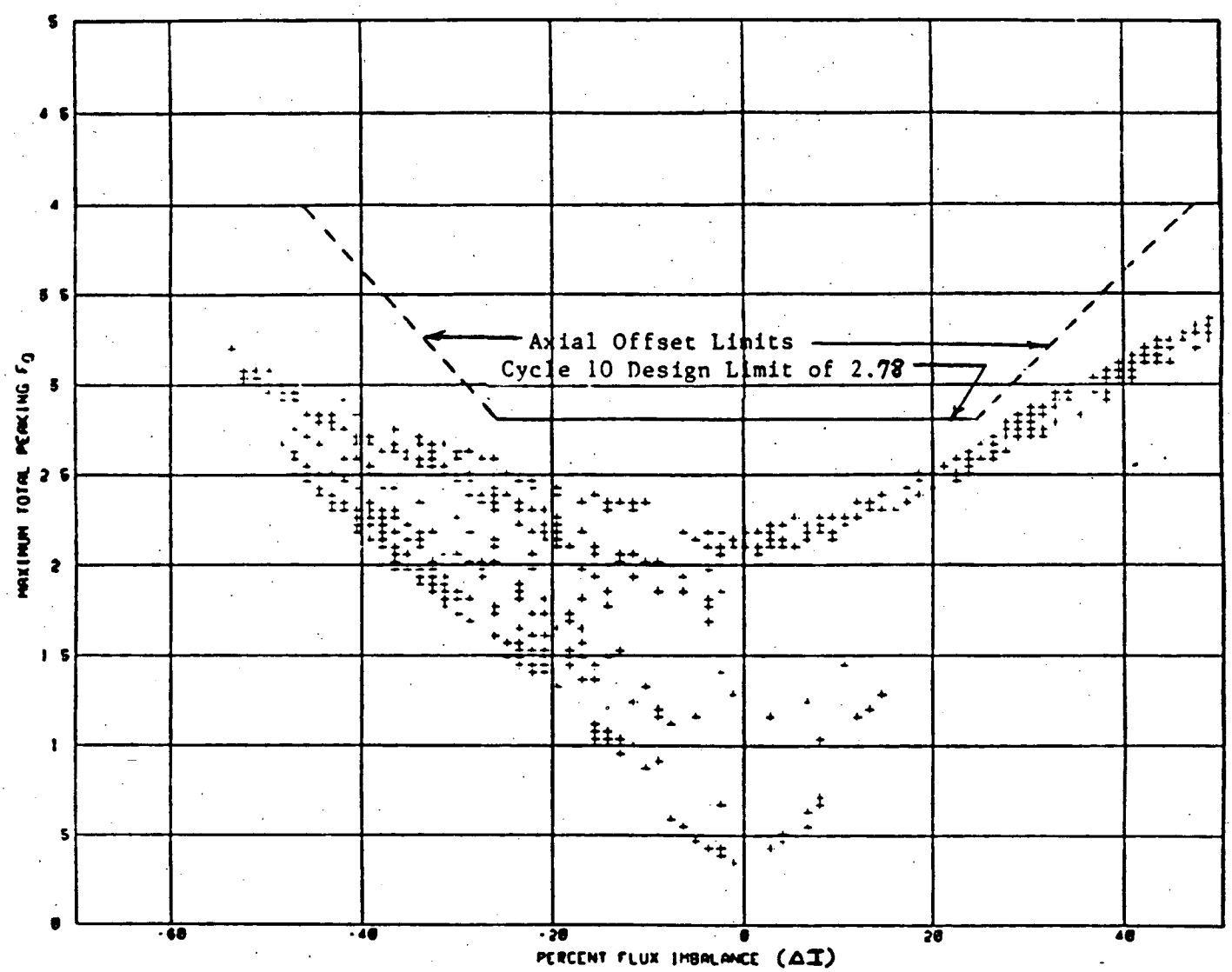
X — IFBA LOCATIONS

GT — GUIDE THIMBLE LOCATIONS

I — INSTRUMENT LOCATION (If Present)

FIGURE 3

F_Q TOTAL VERSUS FLUX IMBALANCE
SAN ONOFRE UNIT 1 CYCLE 10



APPENDIX A

LOSS OF COOLANT ACCIDENT ANALYSIS TO BOUND OPERATION WITH UP TO 20% TUBE PLUGGING IN ANY STEAM GENERATOR AT REDUCED THERMAL CONDITIONS AND INCREASED SAFETY INJECTION INITIATION TIME

APPENDIX A

TABLE OF CONTENTS

LIST OF FIGURES

A.1. LOCA SUMMARY

The Emergency Core Cooling System (ECCS) performance following a Loss of Coolant Accident (LOCA) has been re-evaluated for the San Onofre Nuclear Generating Station (SONGS) Unit 1. This analysis bounds operation up to a uniform equivalent tube plugging level of 20% (i.e., equivalent resistance assuming maximum sleeving and plugging) for the following case:

(Full power primary T&P) 100% license core power, 2100 psia system pressure, 195000 gpm RCS flow, 551.5^{o}F vessel average temperature, 13.2 kw/ft, and a 2.78 F_Q.

The reanalyses has demonstrated that SONGS Unit 1 is in compliance with the AEC Interim Policy Statement, "Criteria for Emergency core Cooling Systems for Light Water Reactors", published in the Federal Register June 29, 1971. The limiting break is a Double Ended Cold Leg Guillotine (DECLG) with a discharge coefficient of (C_D) of 0.8.

To accomplish the reanalysis for increased steam generator tube plugging and reduced RCS condition, the Interim Acceptance Criteria (IAC) assumptions and the 1971 IAC analytical models were used. The Double Ended Cold Leg Guillotine break with discharge coefficients of 0.6, 0.8, and 1.0 were analyzed.

The following is a discussion of all the pertinent methods and results of the new analysis, and justification that the scope of the new analysis is sufficient to satisfy licensing requirements.

A.2 RCS BLOWDOWN CALCULATION

The reactor coolant system blowdown hydraulic transient was calculated using the SATAN-V computer code. The temperature of the fluid in the reactor vessel upper head was assumed to be equal to the hot leg temperature.

In the analysis, it was assumed that offsite power was lost coincident with the pipe break and that the reactor coolant pumps tripped. It was also assumed that an equivalent tube plugging level, that bounds operation with 20% of the tubes plugged in each steam generator, was modelled.

A.3 LOWER PLENUM REFILL/CORE REFLOOD CALCULATIONS

The lower plenum refill time was recalculated based on the modified ECCS.[1] To bound the modified design, it was assumed that full safety injection flow (720 lb/sec) is delivered to the reactor vessel at 38.5 seconds. The "free fall" time required for the safety injection water to drop from the cold leg nozzle to the lower plenum is approximately 0.9 seconds. It was also assumed that the lower plenum was empty (no liquid water) at the end of blowdown. The lower plenum is therefore filled, and bottom of core recovery occurs, at 80.2 seconds after the break.

---

[1] Letter to D. Eisenhut, NRC from K.P. Baskin, SCE, May 30, 1978.

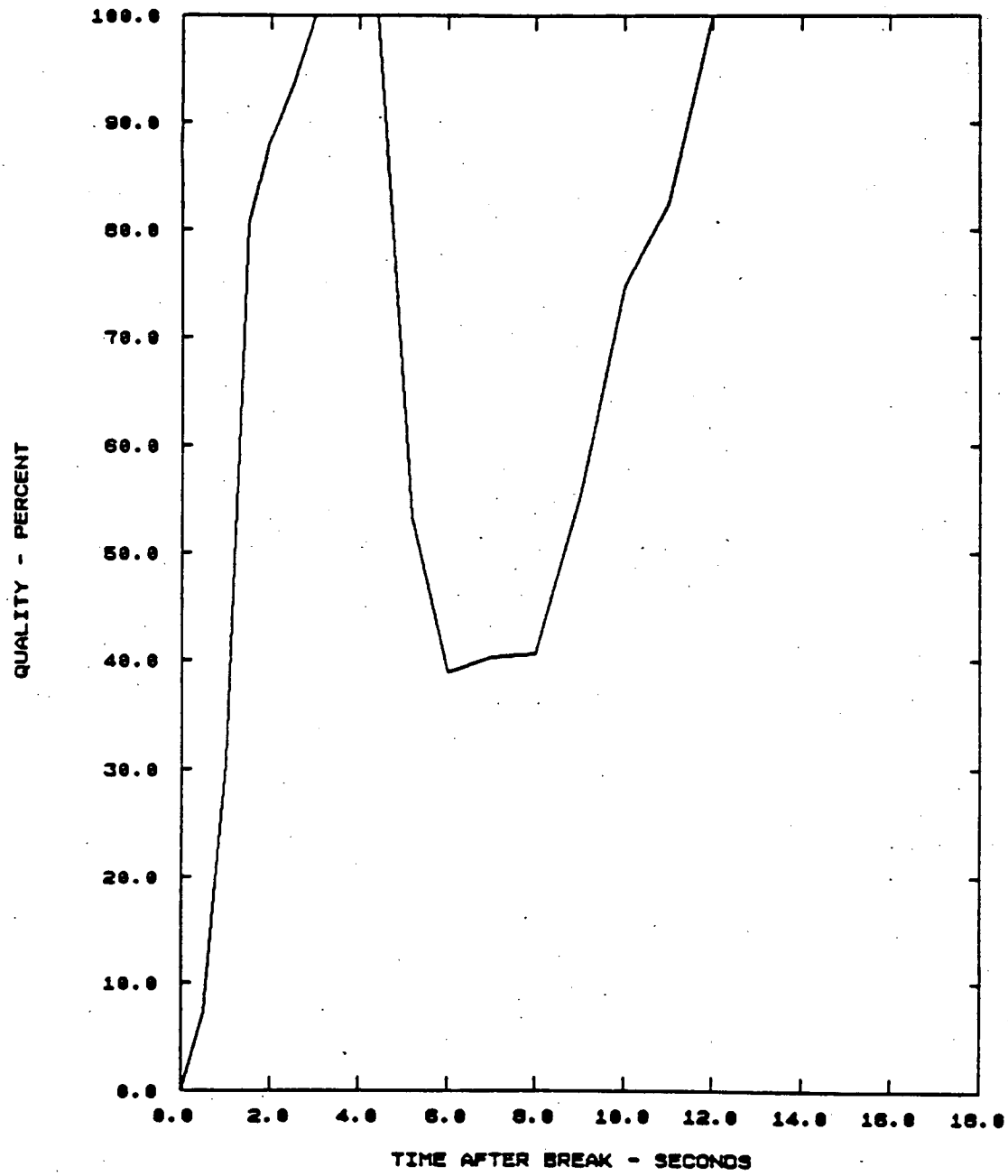
The core reflood calculation assumed that the resistance in the steam generators was modelled to reflect the equivalent tube plugging level that bounds operation with up to 20 percent of the steam generator tubes plugged. As in the blowdown calculation (SATAN-V), the plugged tubes were assumed to be uniformly distributed among the three steam generators.

A.4 HOT ROD THERMAL TRANSIENT CALCULATION

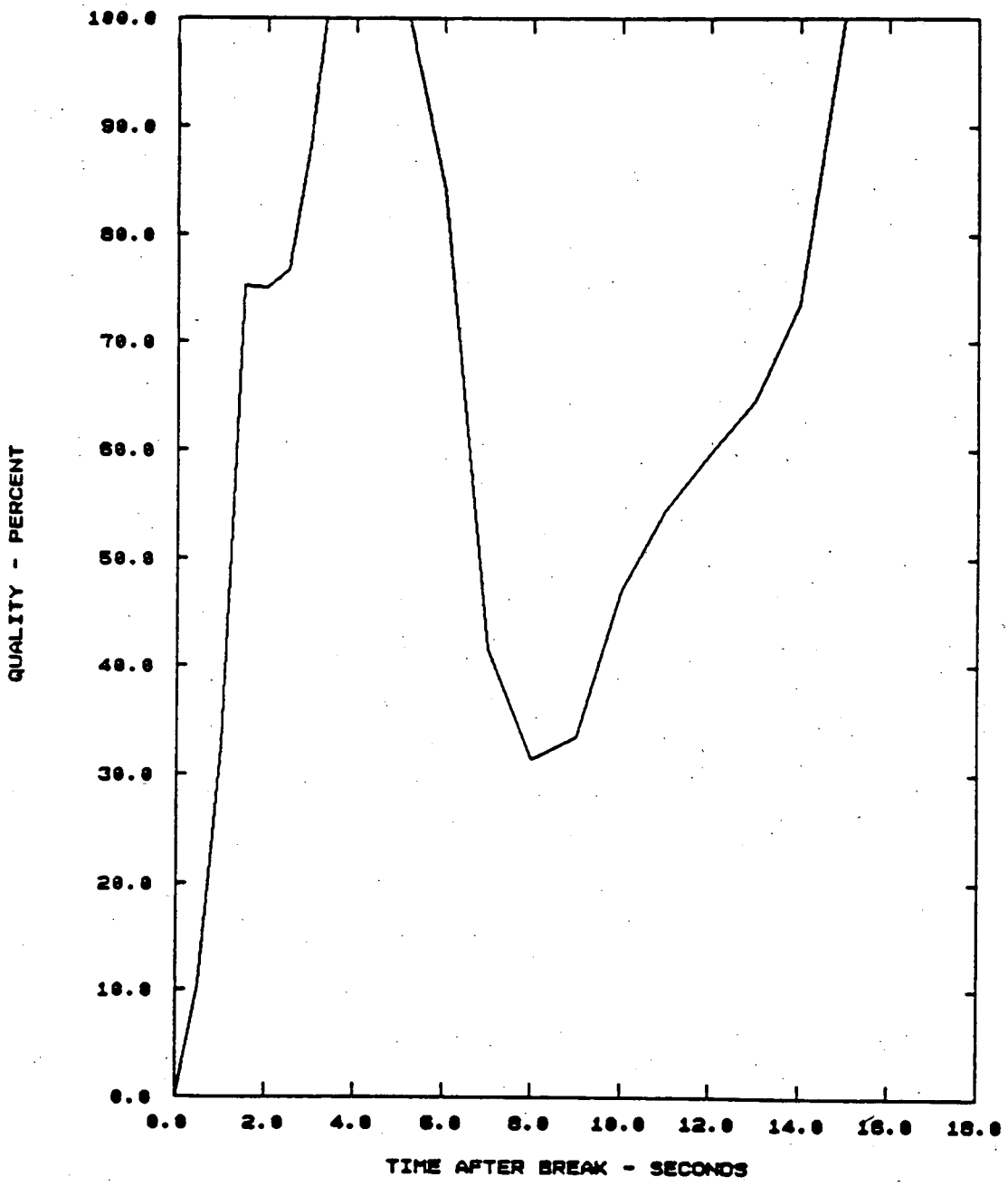
The hot rod thermal transient calculation was performed using the LOCTA-R2 computer program. There were no differences in the application of the LOCTA-R2 code between the previous analysis and the new analysis, except for the reduction in peak linear heat generation rate.

A.5 RESULTS AND CONCLUSIONS

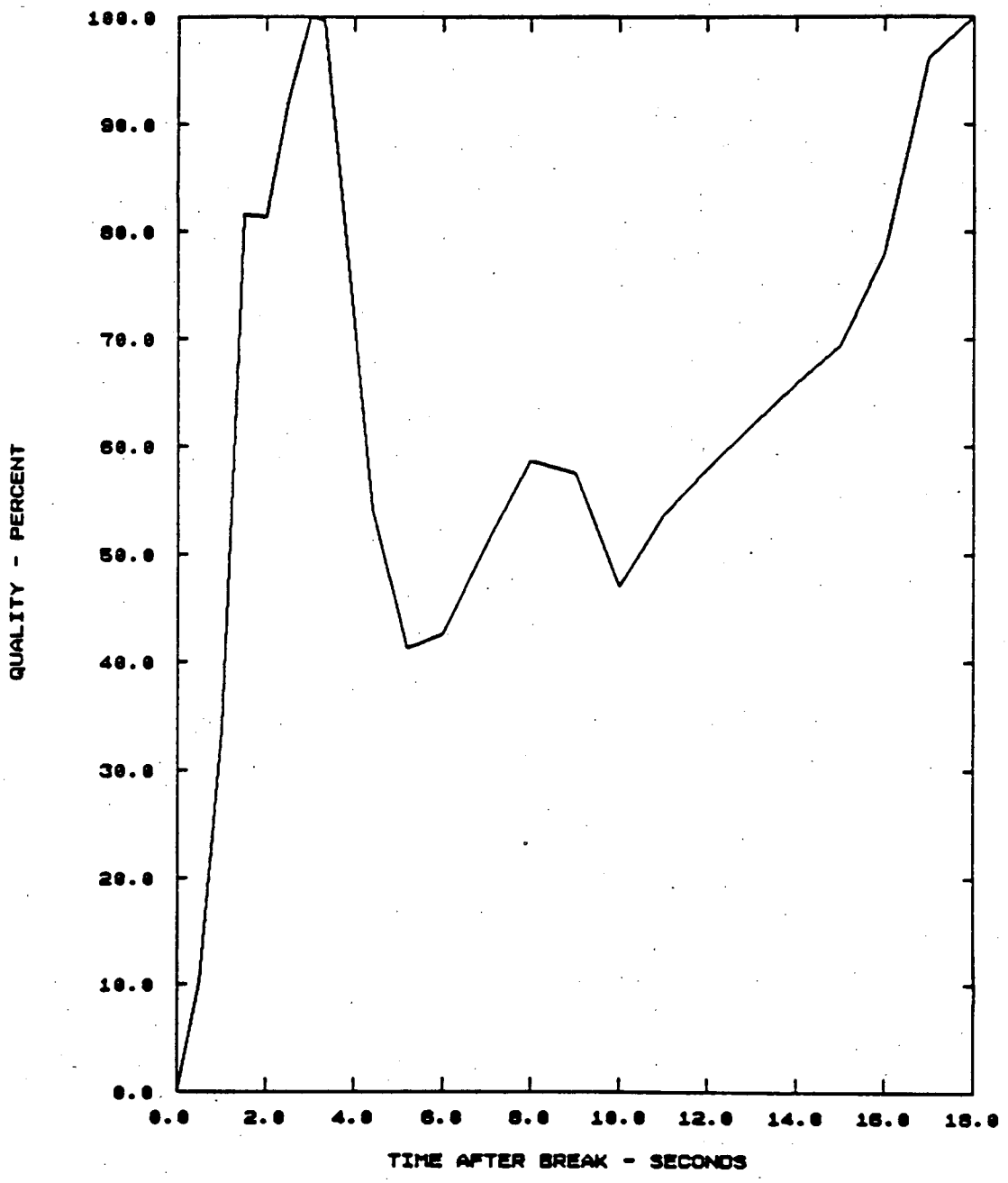
Figures A.1a through A.10c show the transient behavior for key parameters during the accident. A spectrum of break sizes (DECLG with CD = 1.0, 0.8, 0.6) is shown. As shown in Figure A.10b, the limiting peak clad temperature is 2260.3^{o}F for the DECLG,CD=0.8 break, which satisfies the Interim Acceptance Criteria PCT of 2300°F. Therefore, even with up to an equivalent of 20% tube plugging and the increase in safety injection initiation time, the ECCS IAC PCT safety limit is satisfied by not exceeding an F_Q of 2.78



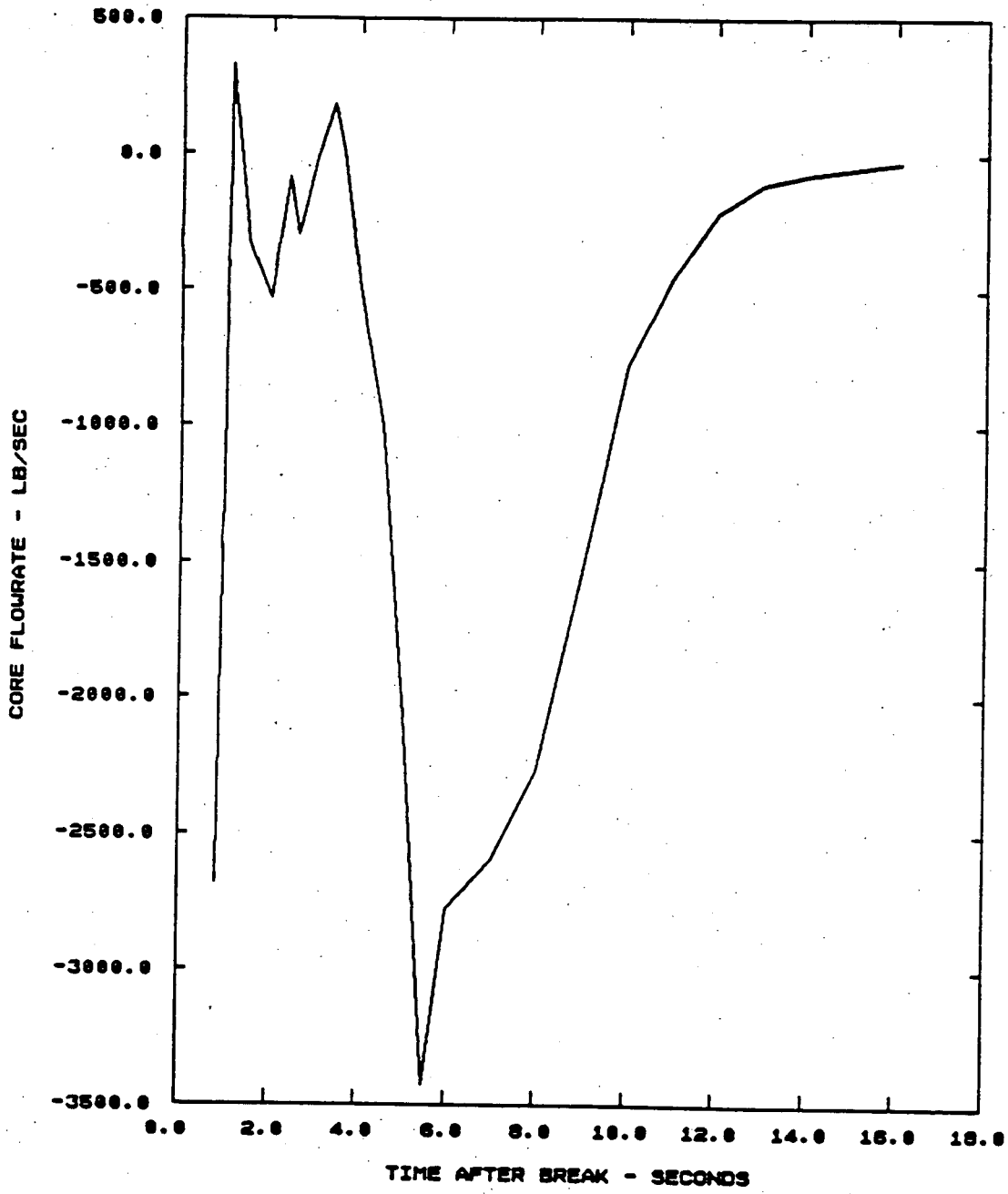
San Onofre Unit 1
Double-Ended Cold Leg Guillotine Break , CD=1.0
Figure A.1a QUALITY



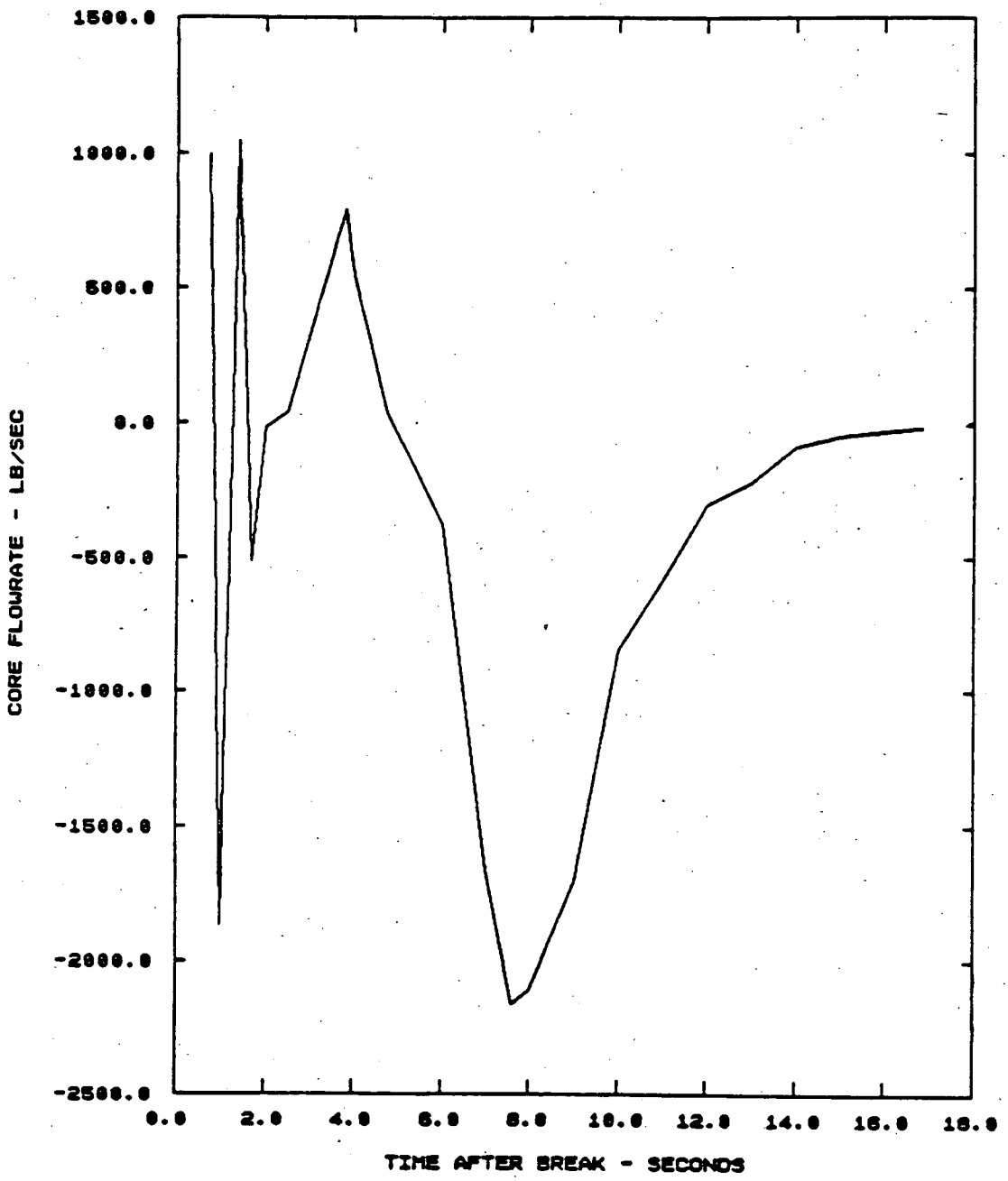
San Onofre Unit 1
Double-Ended Cold Leg Guillotine Break , CD=0.8
Figure A.1b QUALITY



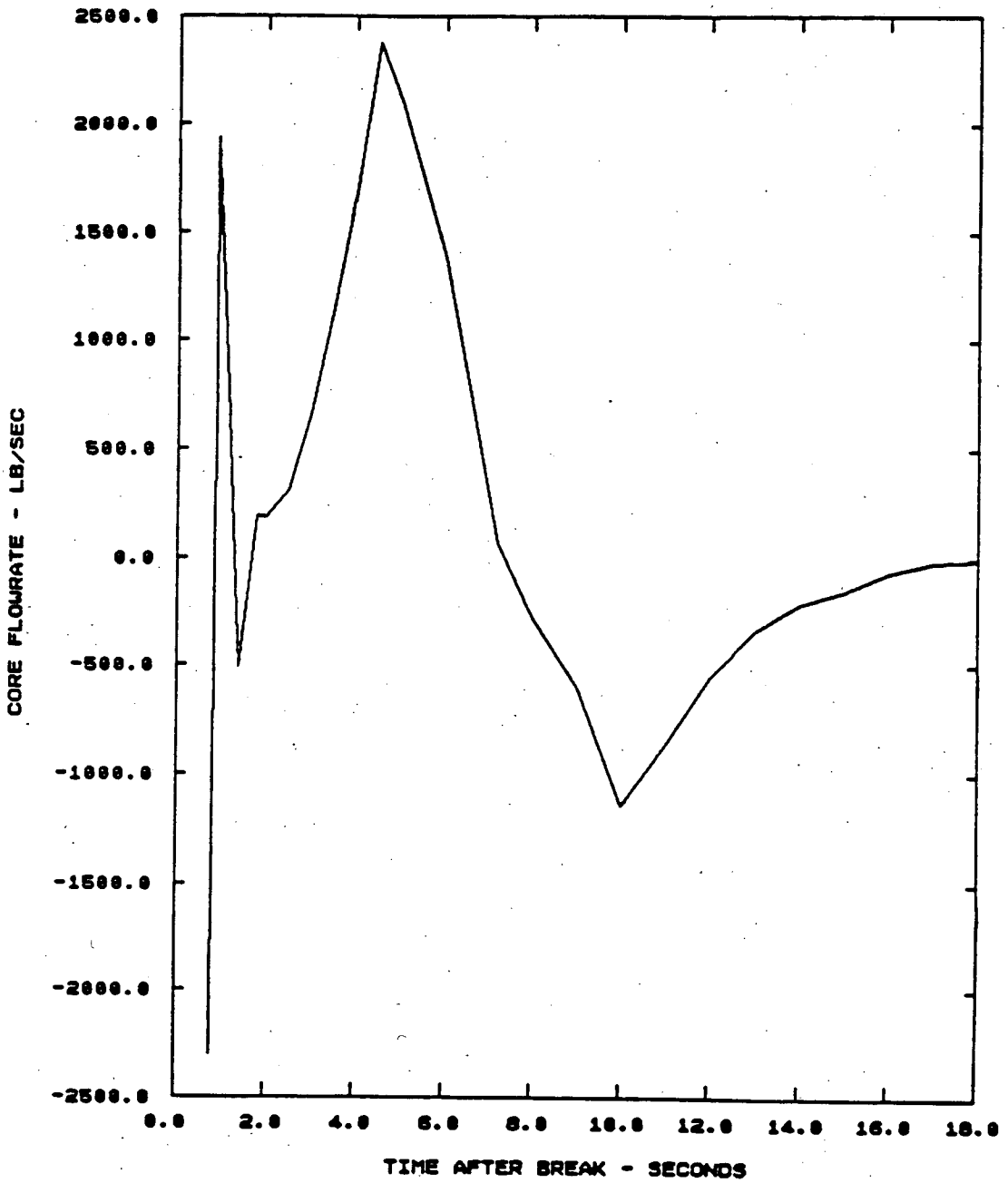
San Onofre Unit 1
Double-Ended Cold Leg Guillotine Break , CD=0.6
Figure A.1c QUALITY



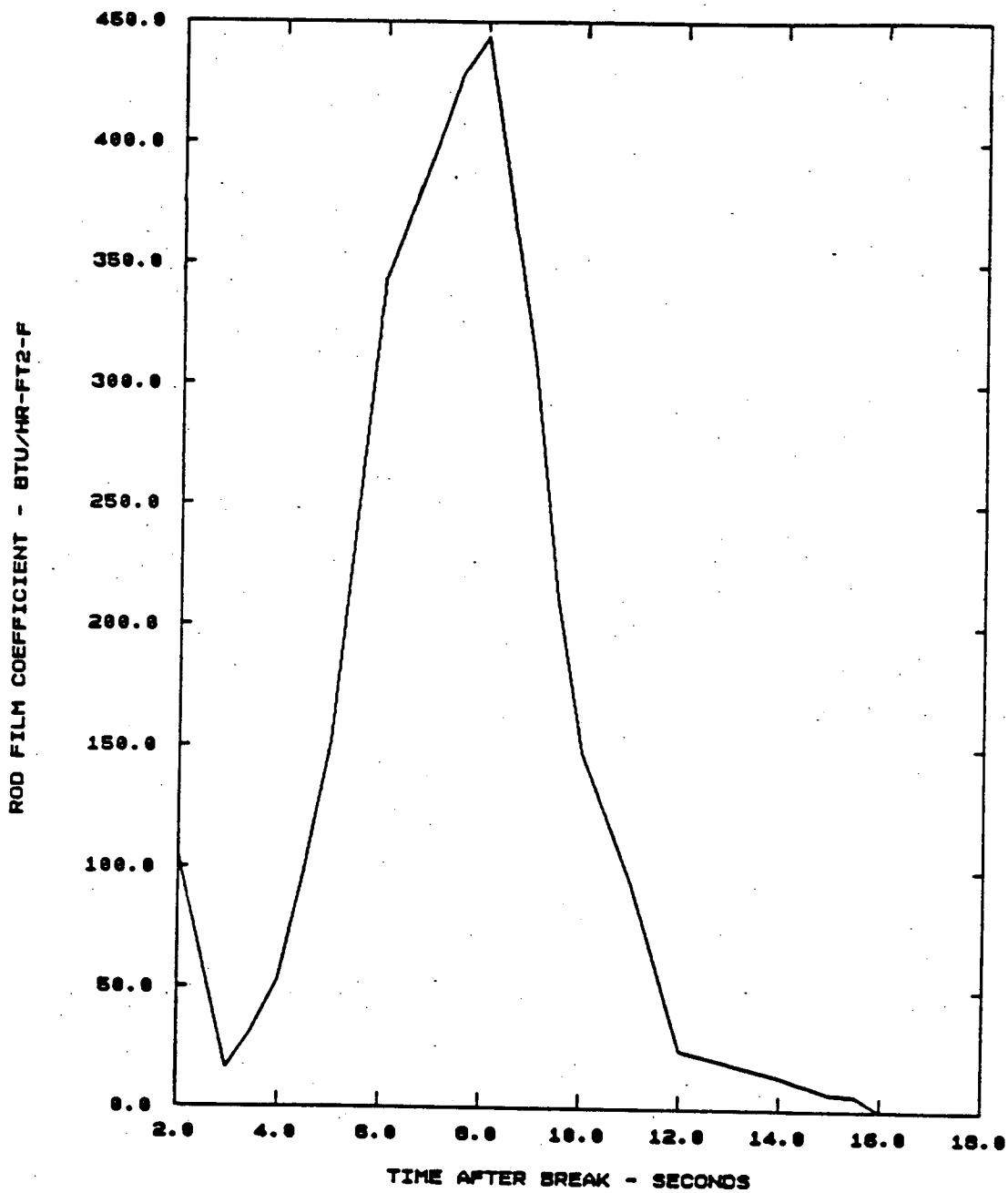
San Onofre Unit 1
Double-Ended Cold Leg Guillotine Break , CD=1.0
Figure A.2a CORE FLOWRATE



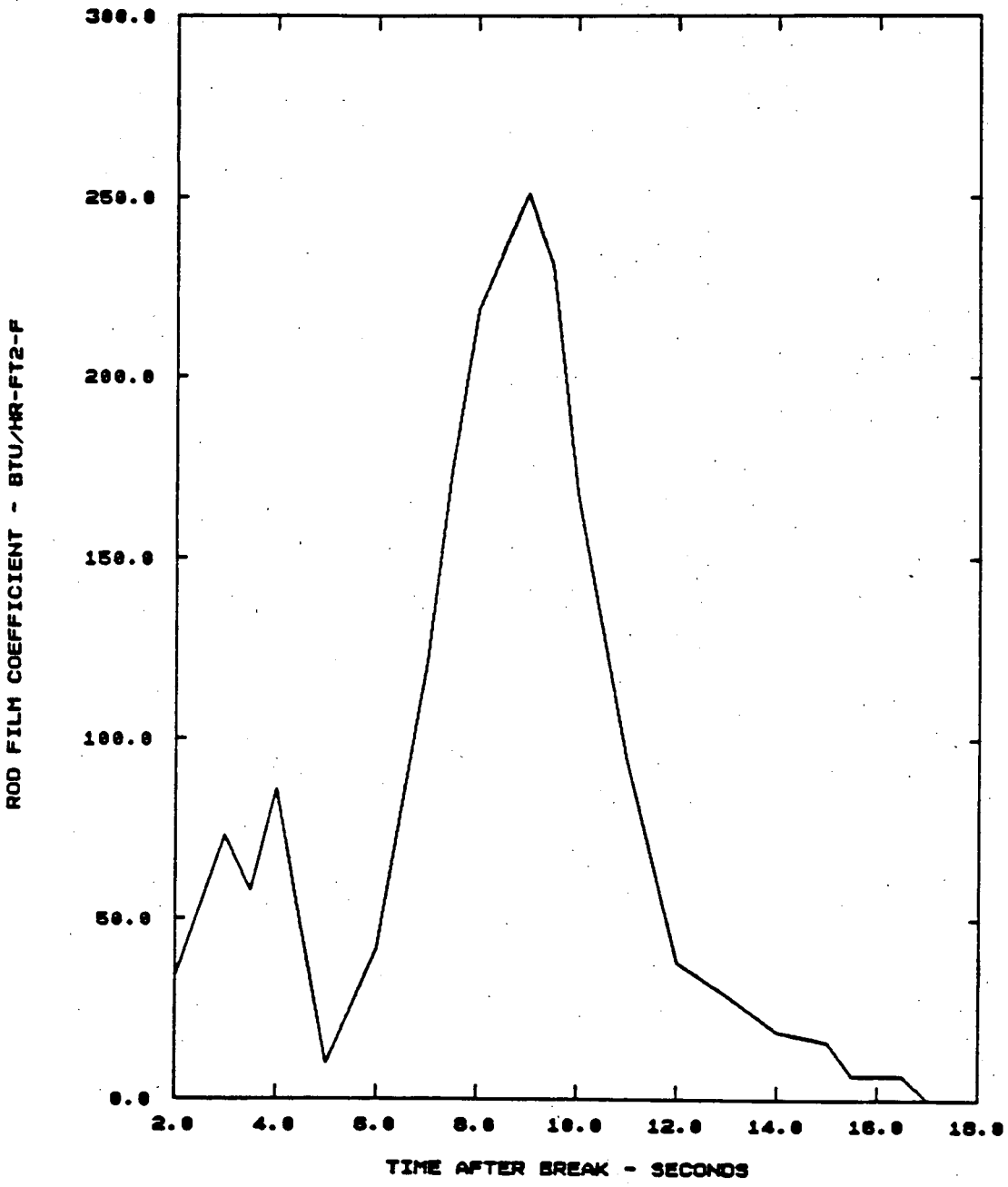
San Onofre Unit 1
Double-Ended Cold Leg Guillotine Break , CD=0.8
Figure A.2b CORE FLOWRATE



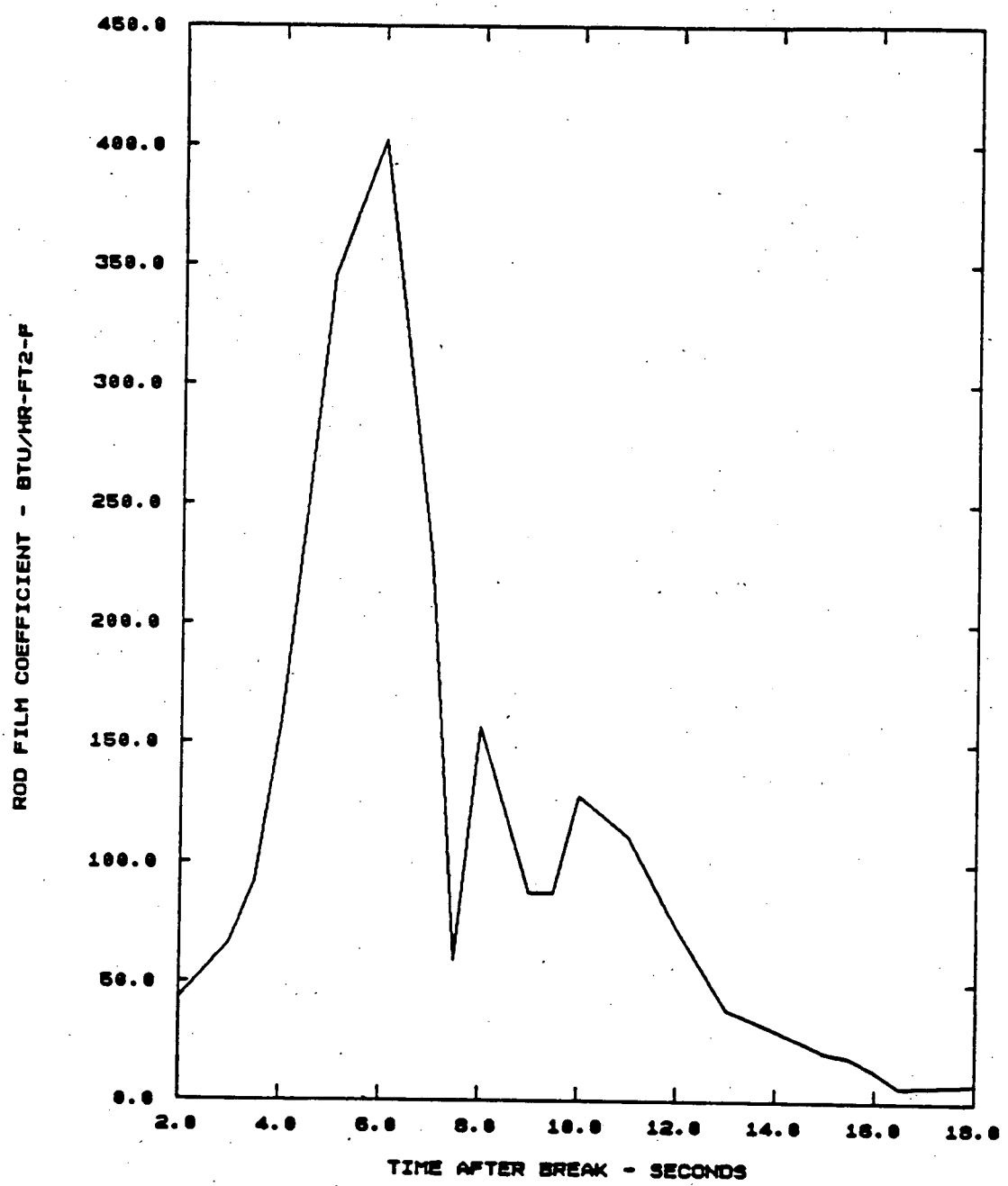
San Onofre Unit 1
Double-Ended Cold Leg Guillotine Break , CD=0.6
Figure A.2c CORE FLOWRATE



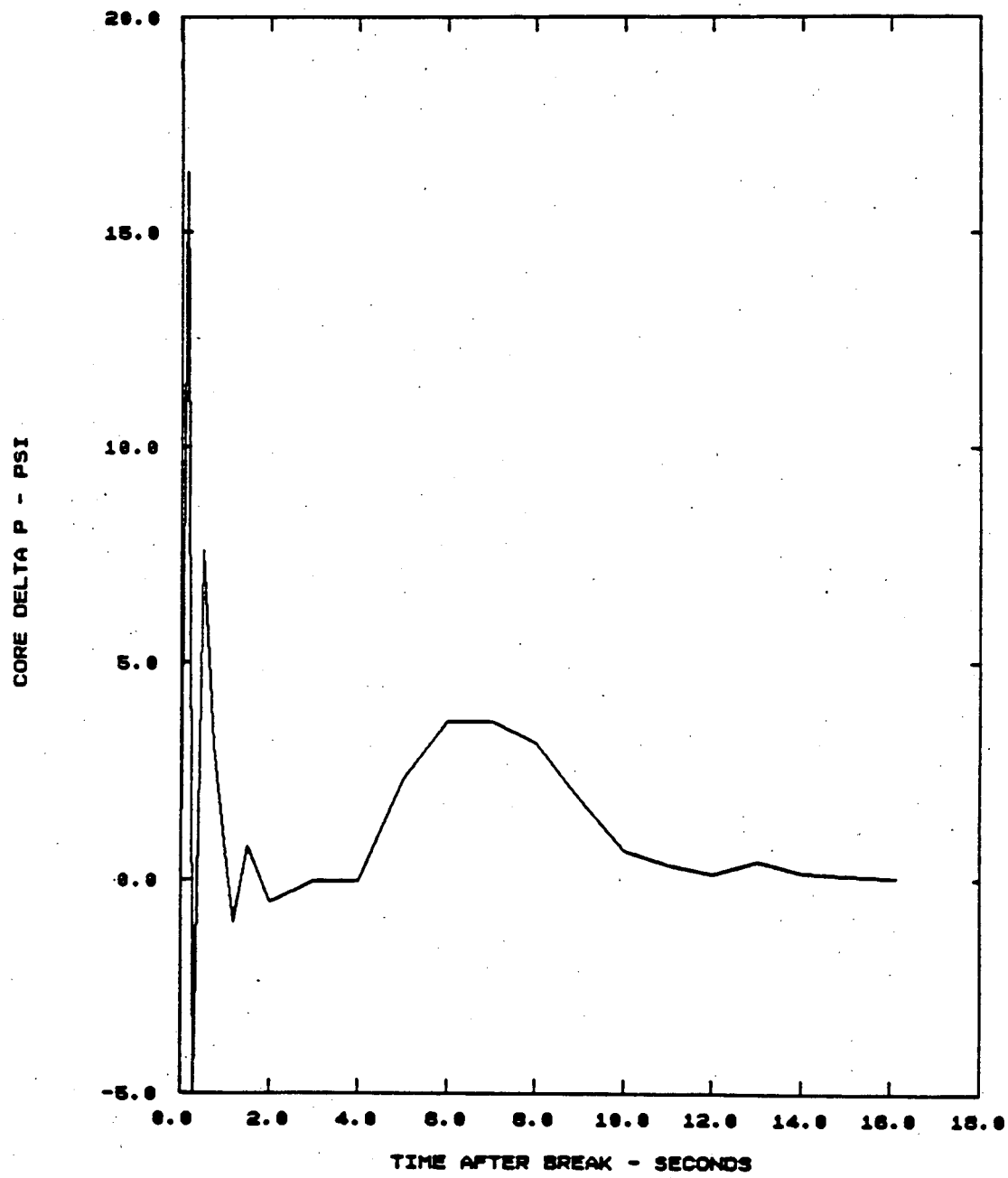
San Onofre Unit 1
Double-Ended Cold Leg Guillotine Break , CD=1.0
Figure A.3a ROD FILM COEFFICIENT



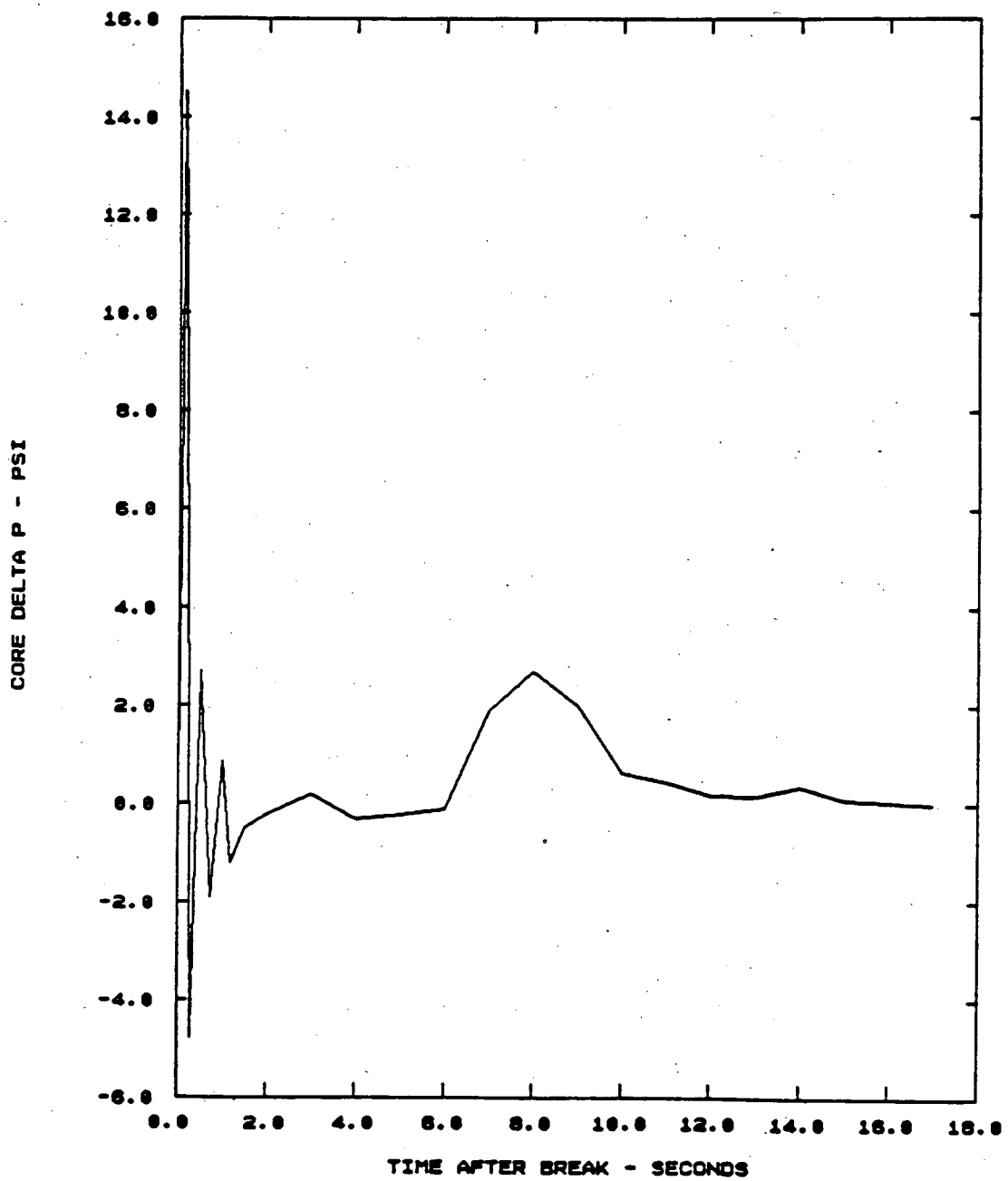
San Onofre Unit 1
Double-Ended Cold Leg Guillotine Break , CD=0.8
Figure A.3b ROD FILM COEFFICIENT



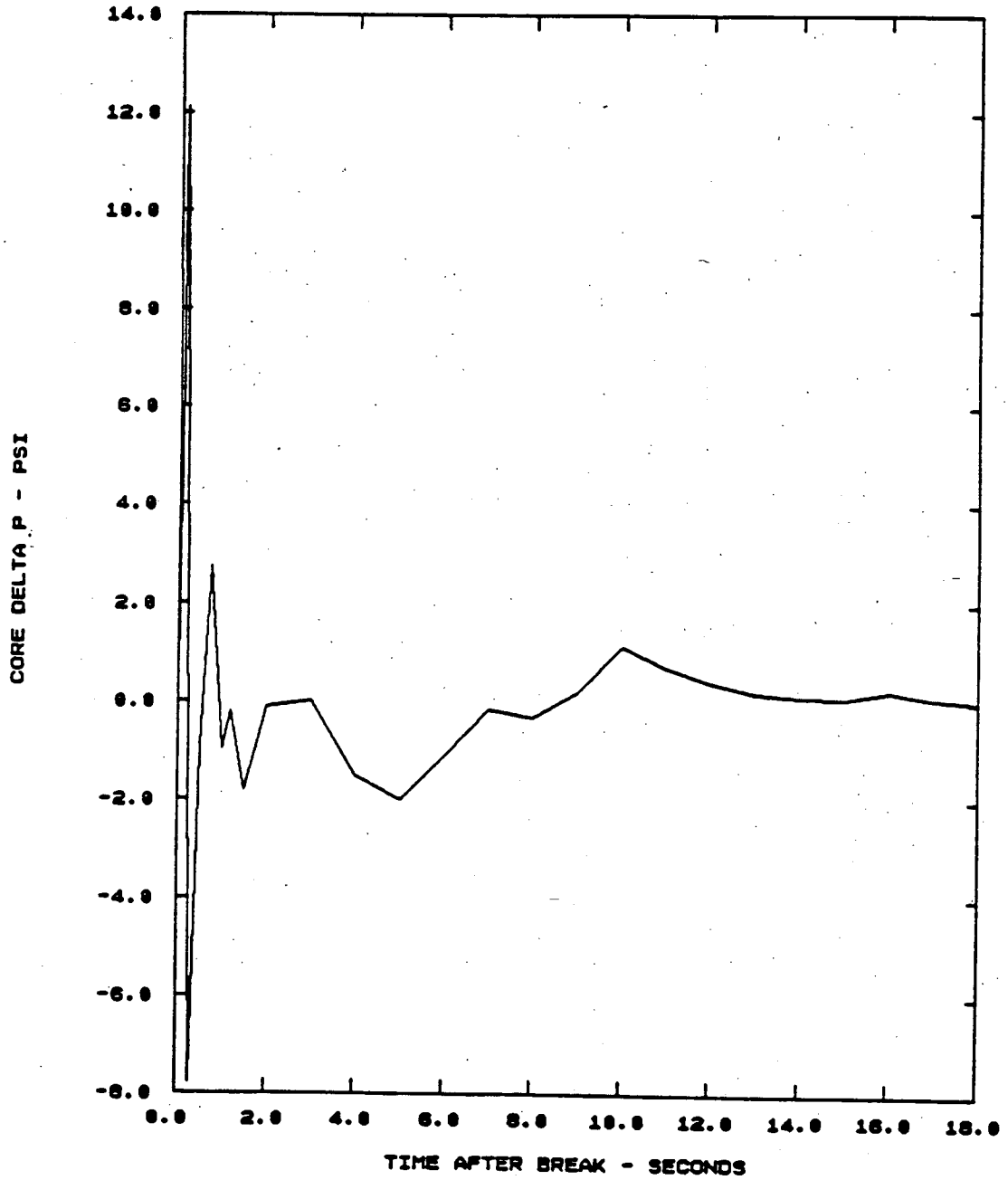
San Onofre Unit 1
Double-Ended Cold Leg Guillotine Break , CD=0.6
Figure A.3c ROD FILM COEFFICIENT



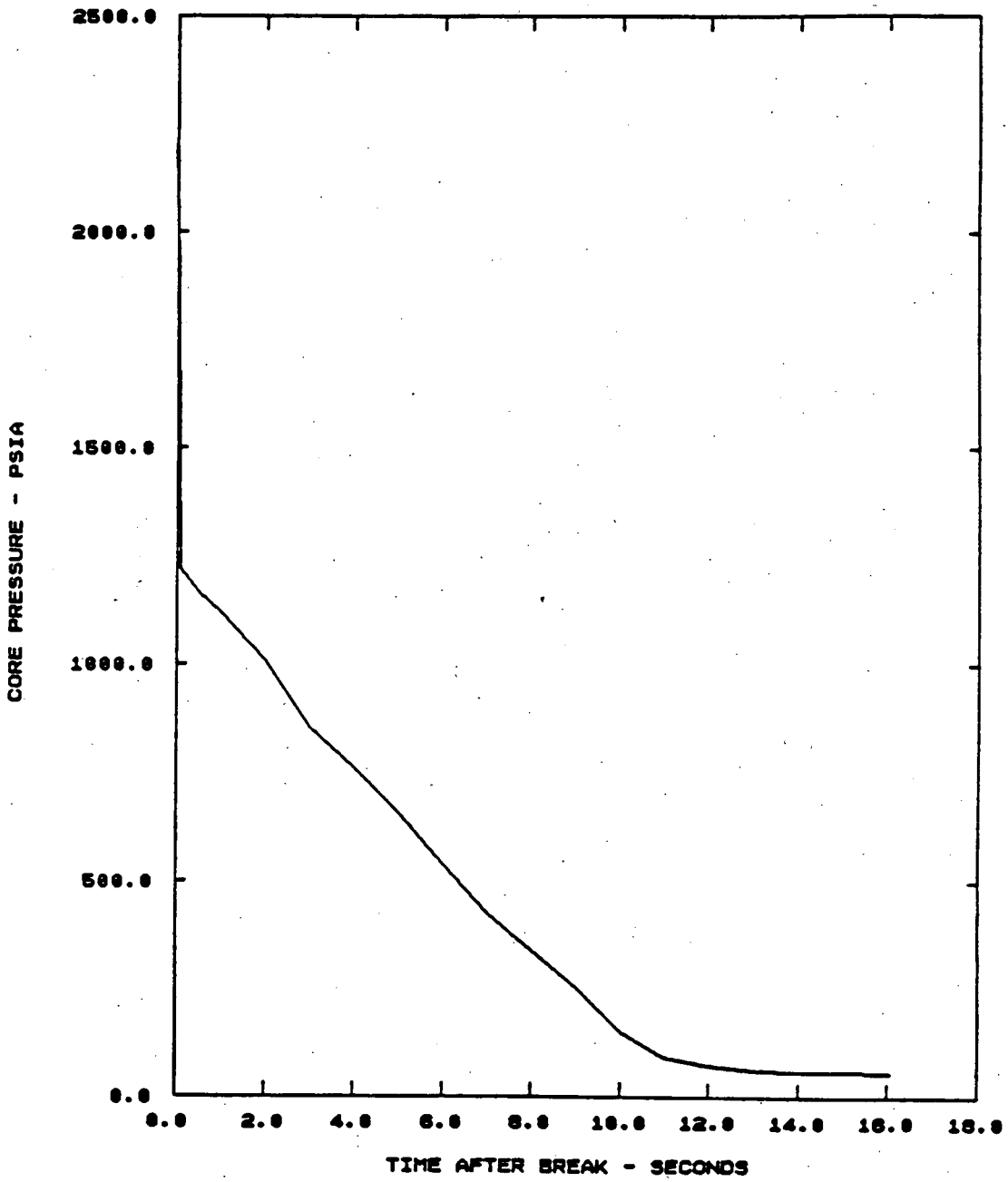
San Onofre Unit 1
Double-Ended Cold Leg Guillotine Break , CD=1.0
Figure A.4a CORE DELTA P



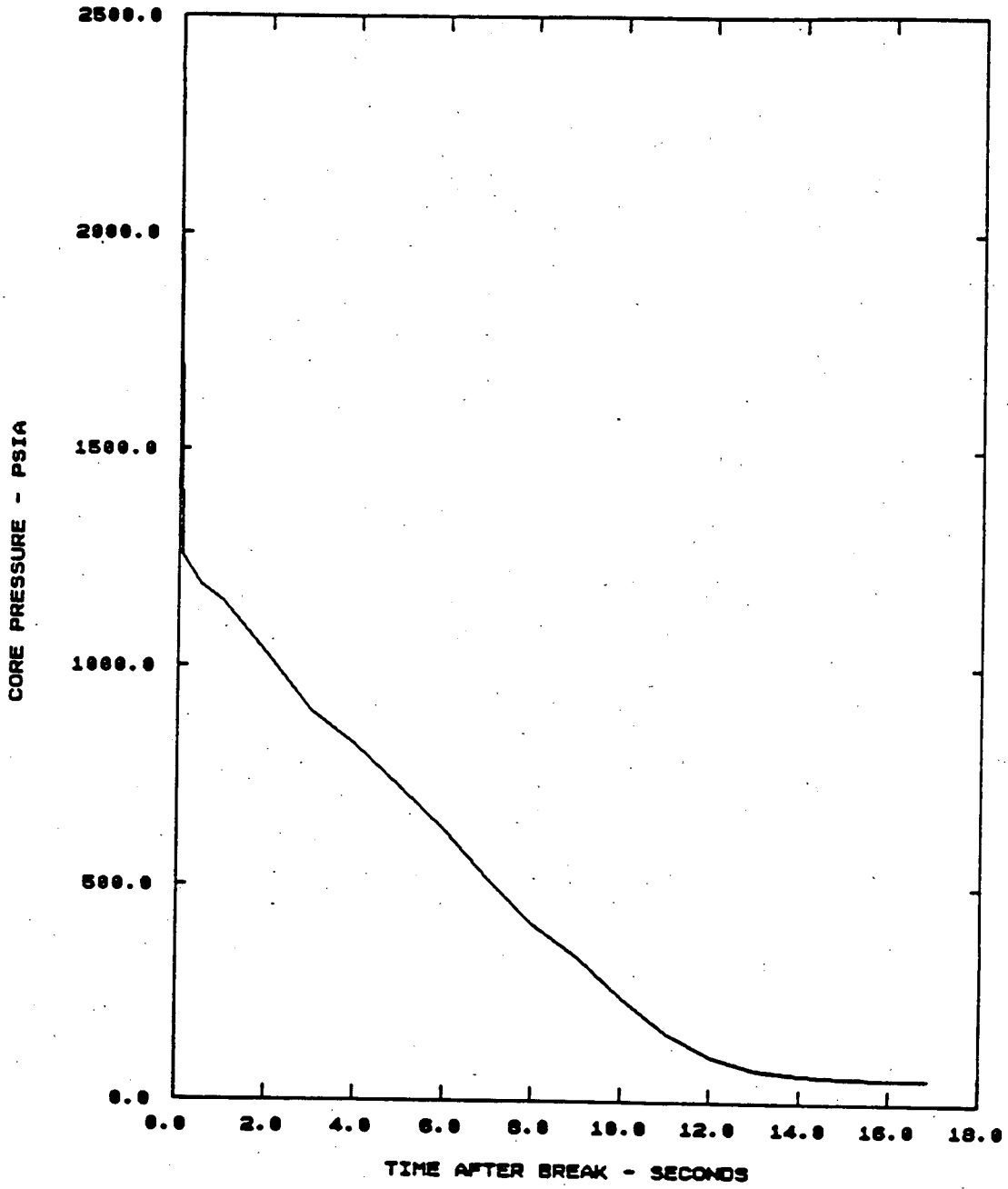
San Onofre Unit 1
Double-Ended Cold Leg Guillotine Break , CD=0.8
Figure A.4b CORE DELTA P



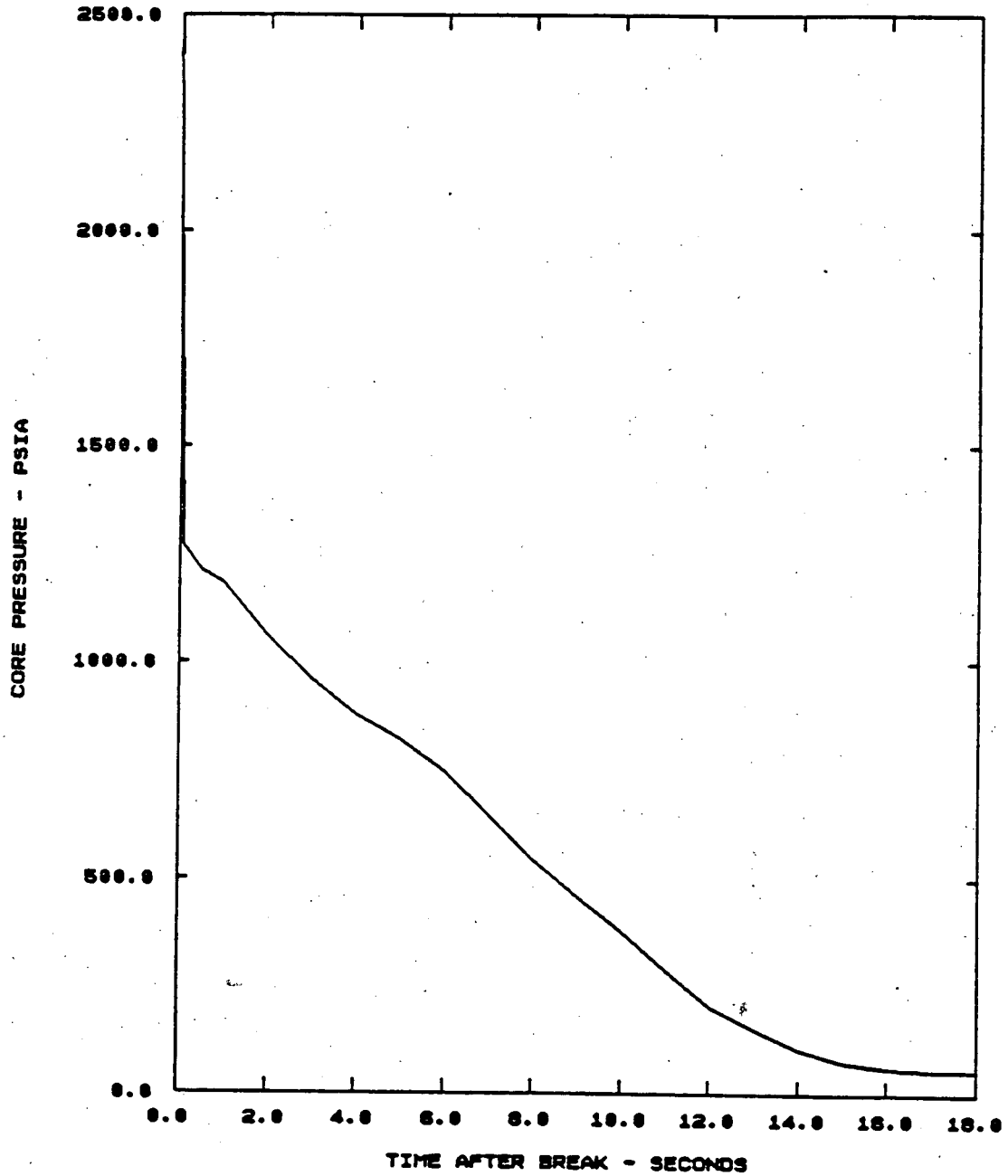
San Onofre Unit 1
Double-Ended Cold Leg Guillotine Break , CD=0.6
Figure A.4c CORE DELTA P



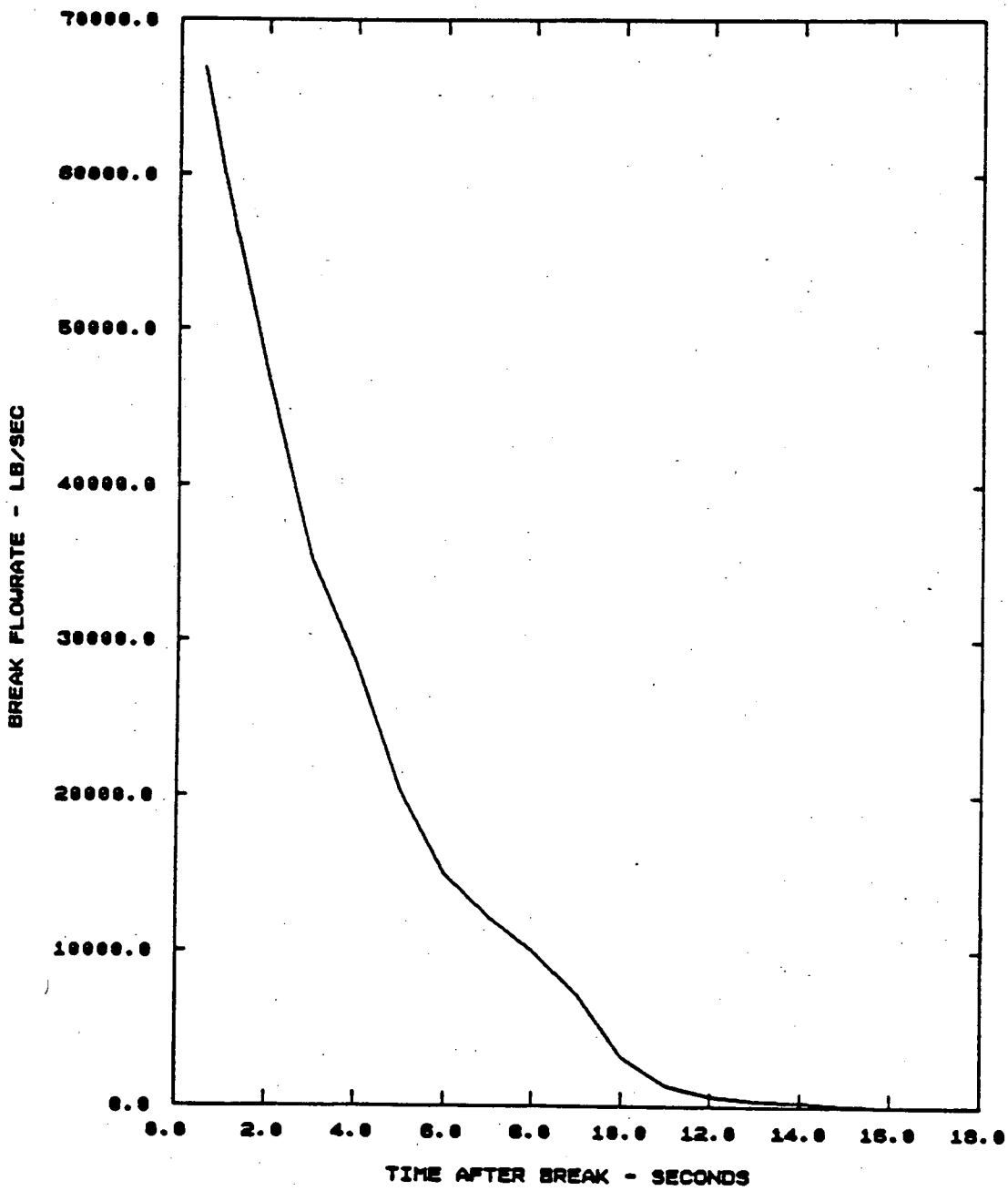
San Onofre Unit 1
Double-Ended Cold Leg Guillotine Break , CD=1.0
Figure A.5a CORE PRESSURE



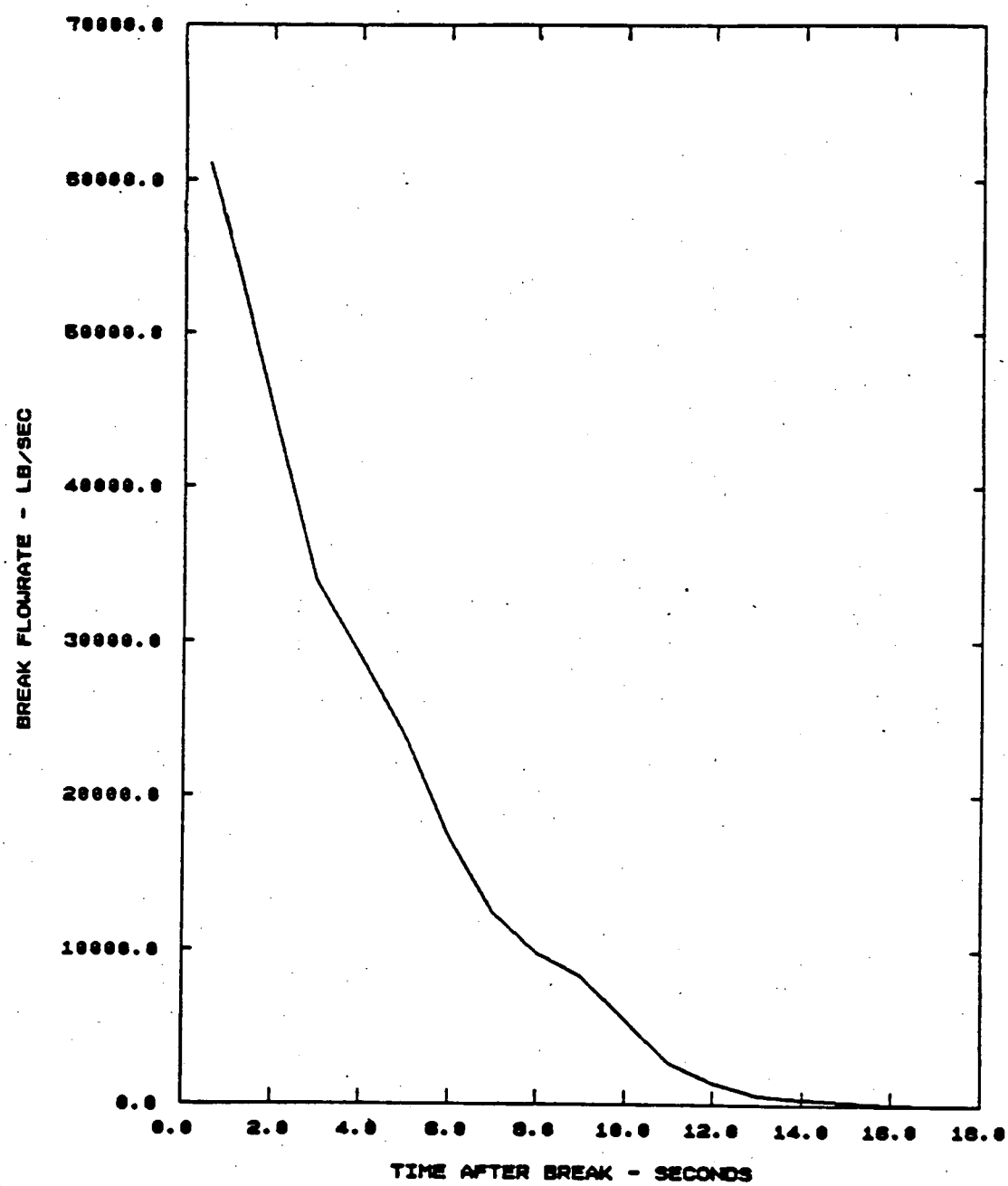
San Onofre Unit 1
Double-Ended Cold Leg Guillotine Break , CD=0.8
Figure A.5b CORE PRESSURE



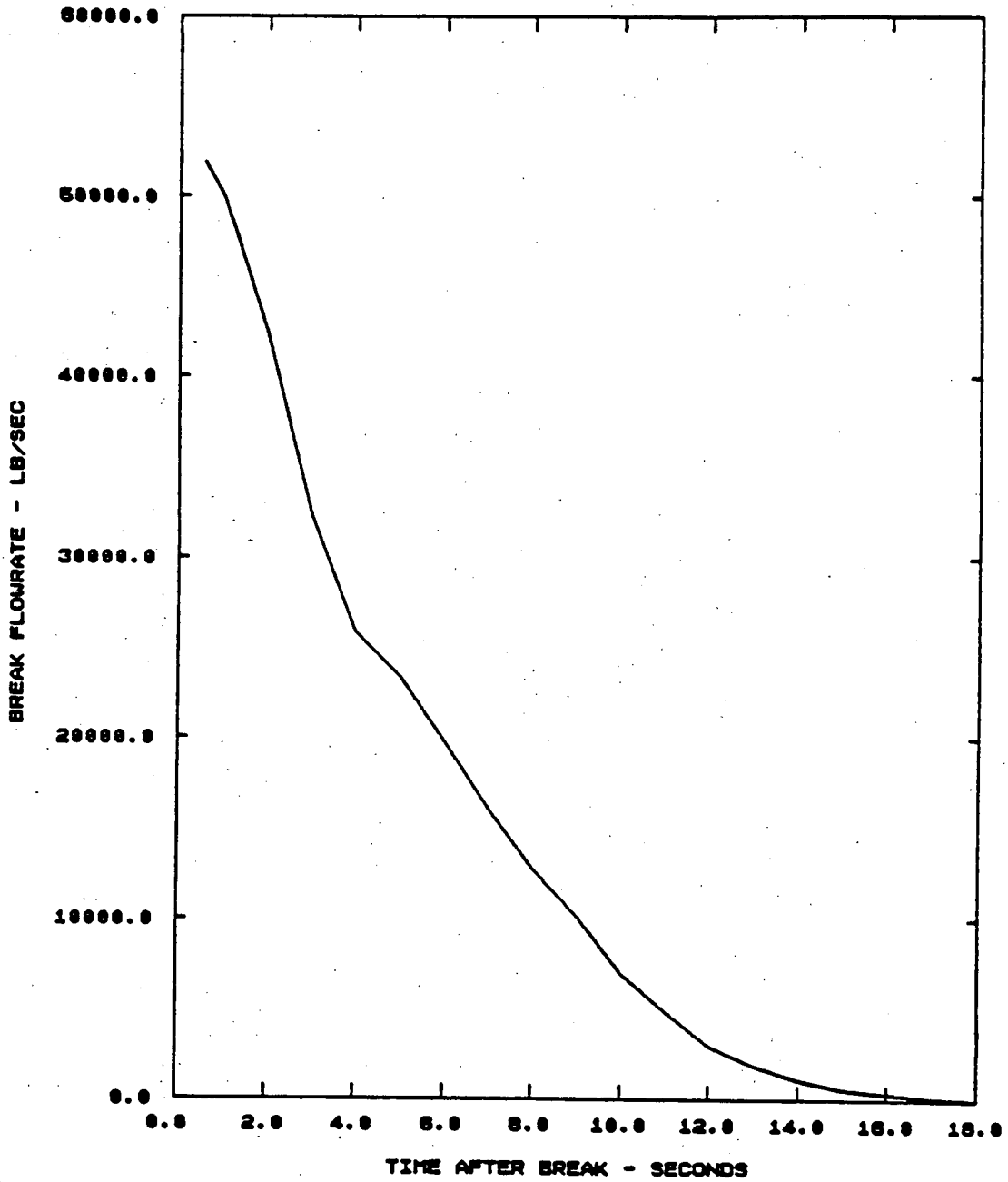
San Onofre Unit 1
Double-Ended Cold Leg Guillotine Break , CD=0.6
Figure A.5c CORE PRESSURE



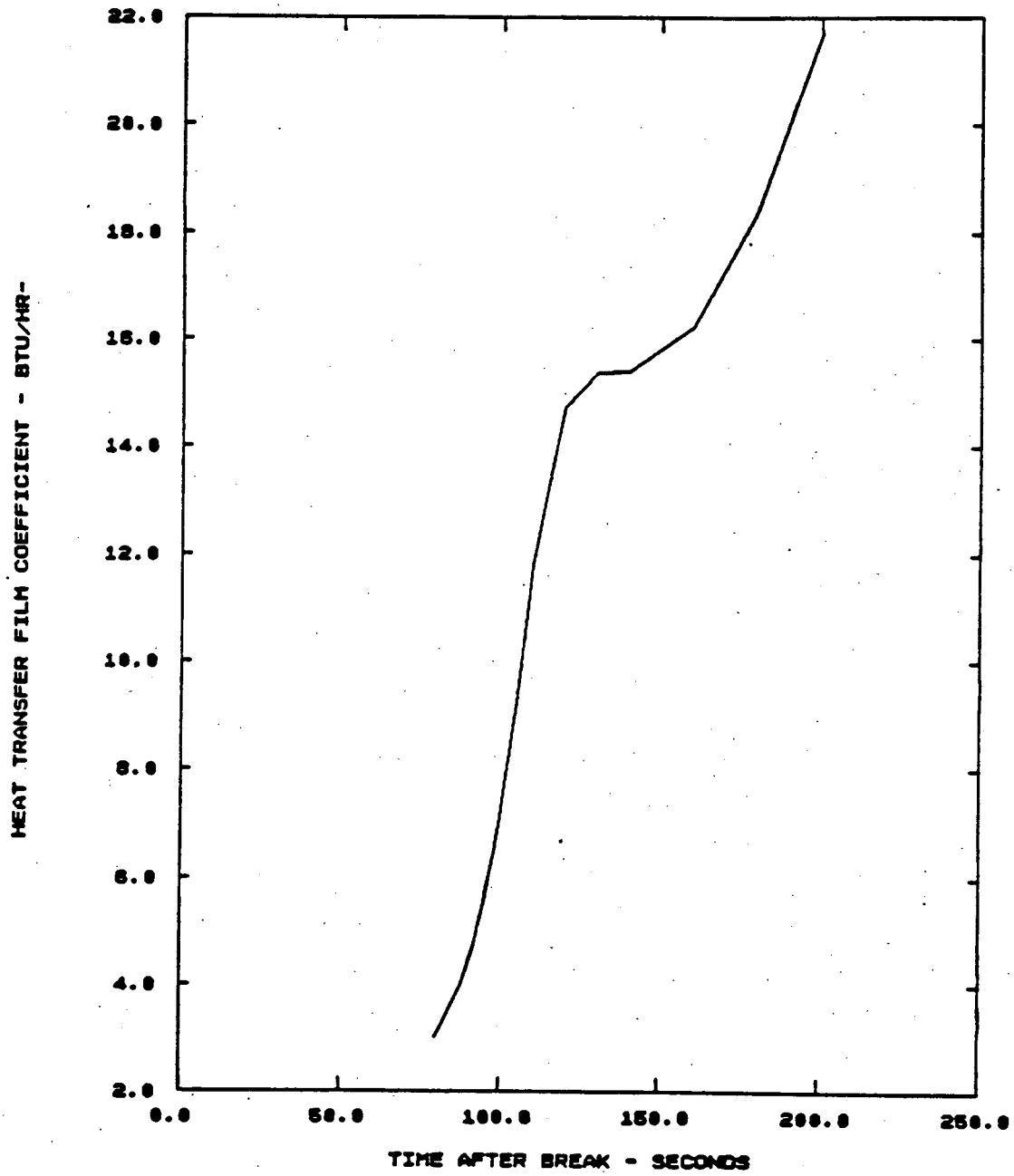
San Onofre Unit 1
Double-Ended Cold Leg Guillotine Break , CD=1.0
Figure A.6a BREAK FLOWRATE



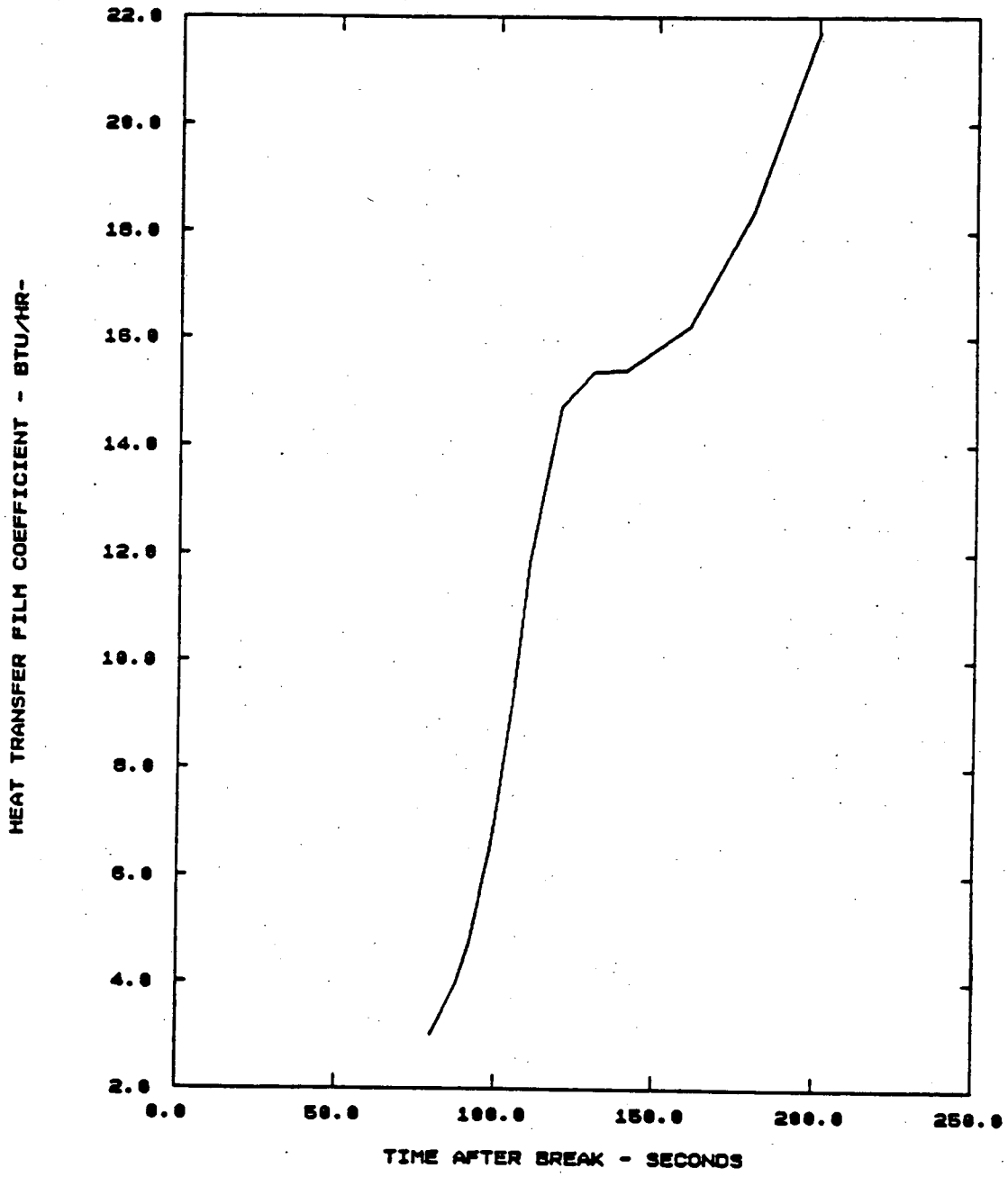
San Onofre Unit 1
Double-Ended Cold Leg Guillotine Break , CD=0.8
Figure A.6b BREAK FLOWRATE



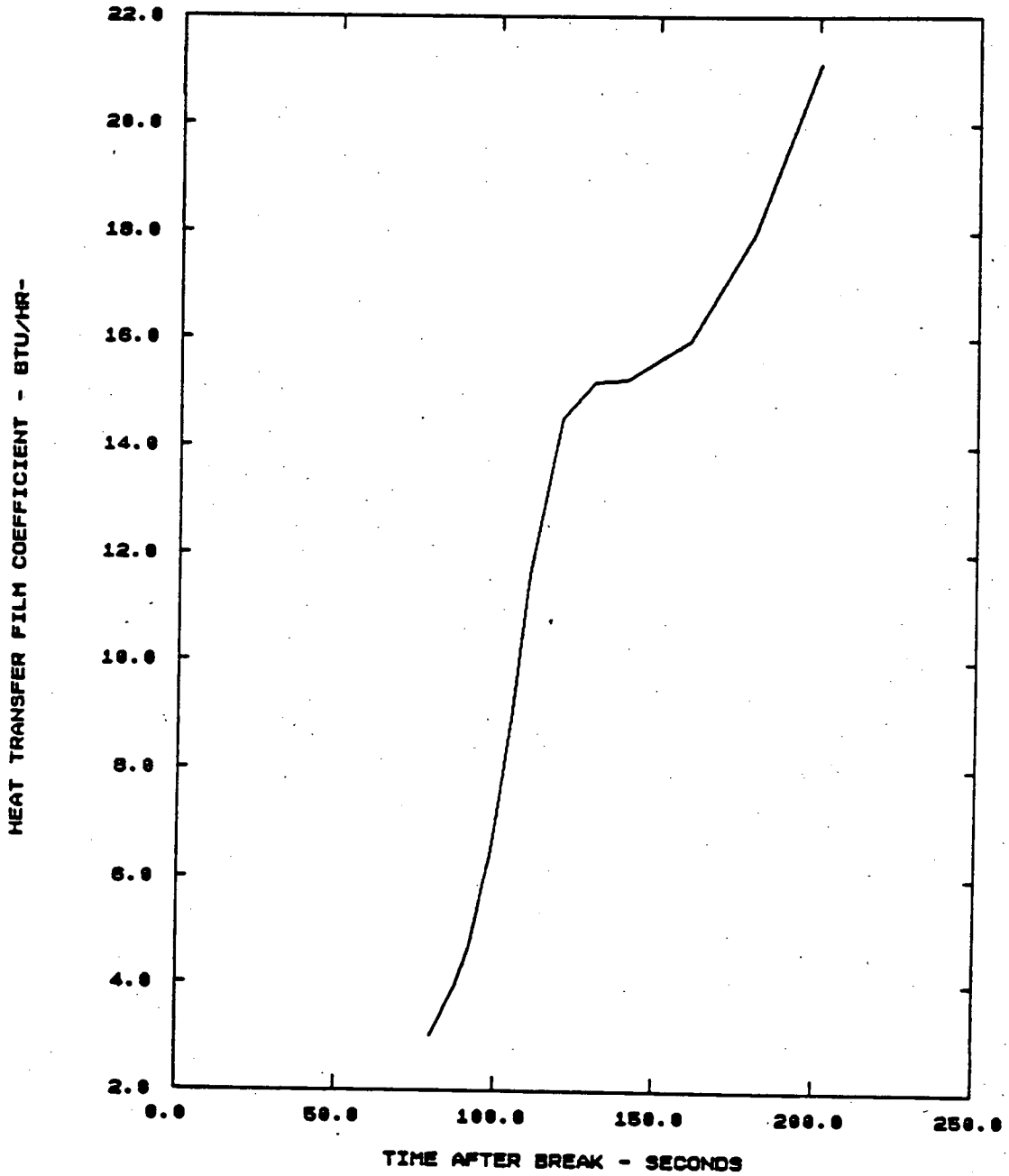
San Onofre Unit 1
Double-Ended Cold Leg Guillotine Break , CD=0.6
Figure A.6c BREAK FLOWRATE



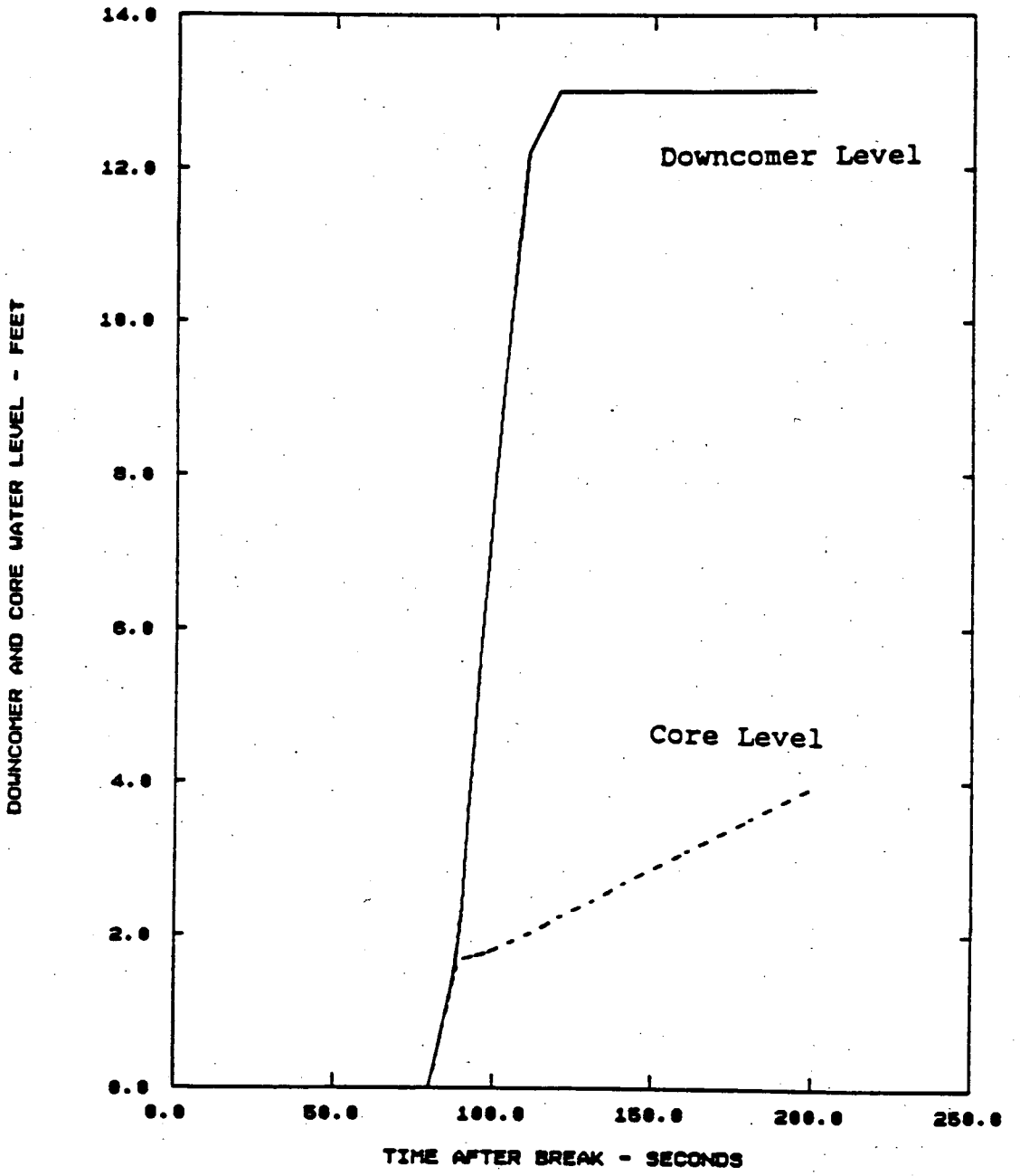
San Onofre Unit 1
Double-Ended Cold Leg Guillotine Break , CD=1.0
Figure A.7a HEAT TRANSFER FILM COEFFICIENT



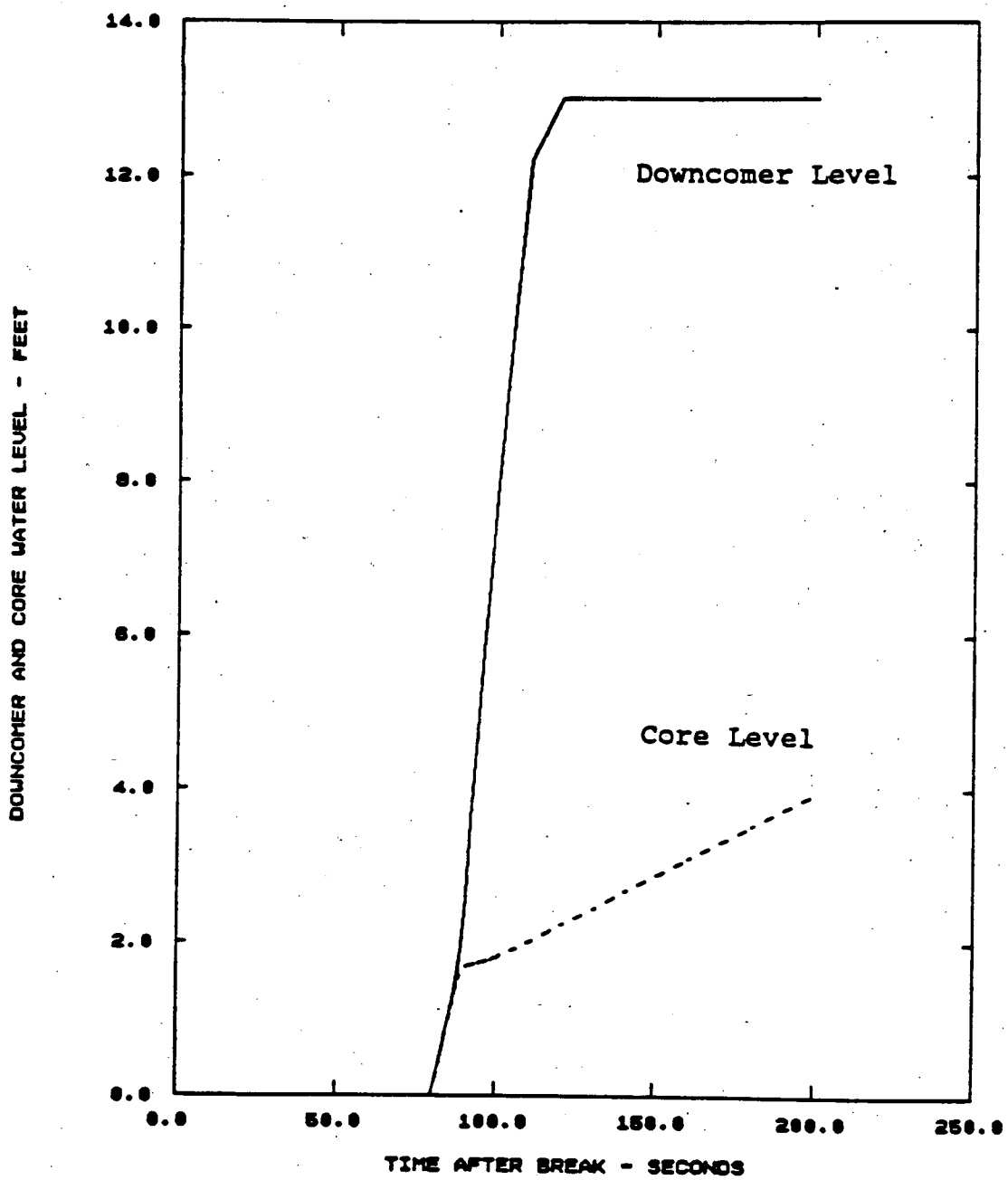
San Onofre Unit 1
Double-Ended Cold Leg Guillotine Break , CD=0.8
Figure A.7b HEAT TRANSFER FILM COEFFICIENT



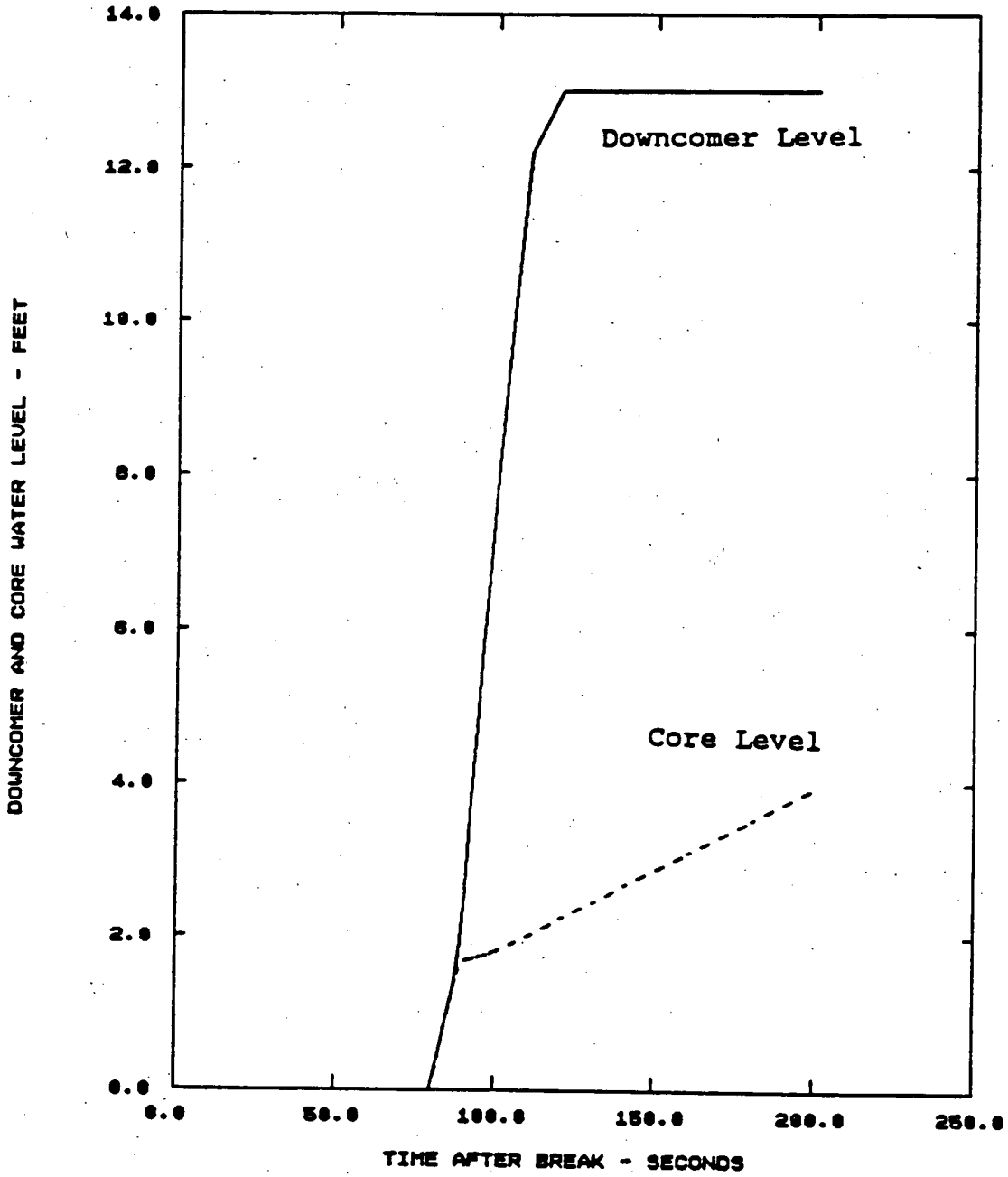
San Onofre Unit 1
Double-Ended Cold Leg Guillotine Break , CD=0.6
Figure A.7c HEAT TRANSFER FILM COEFFICIENT



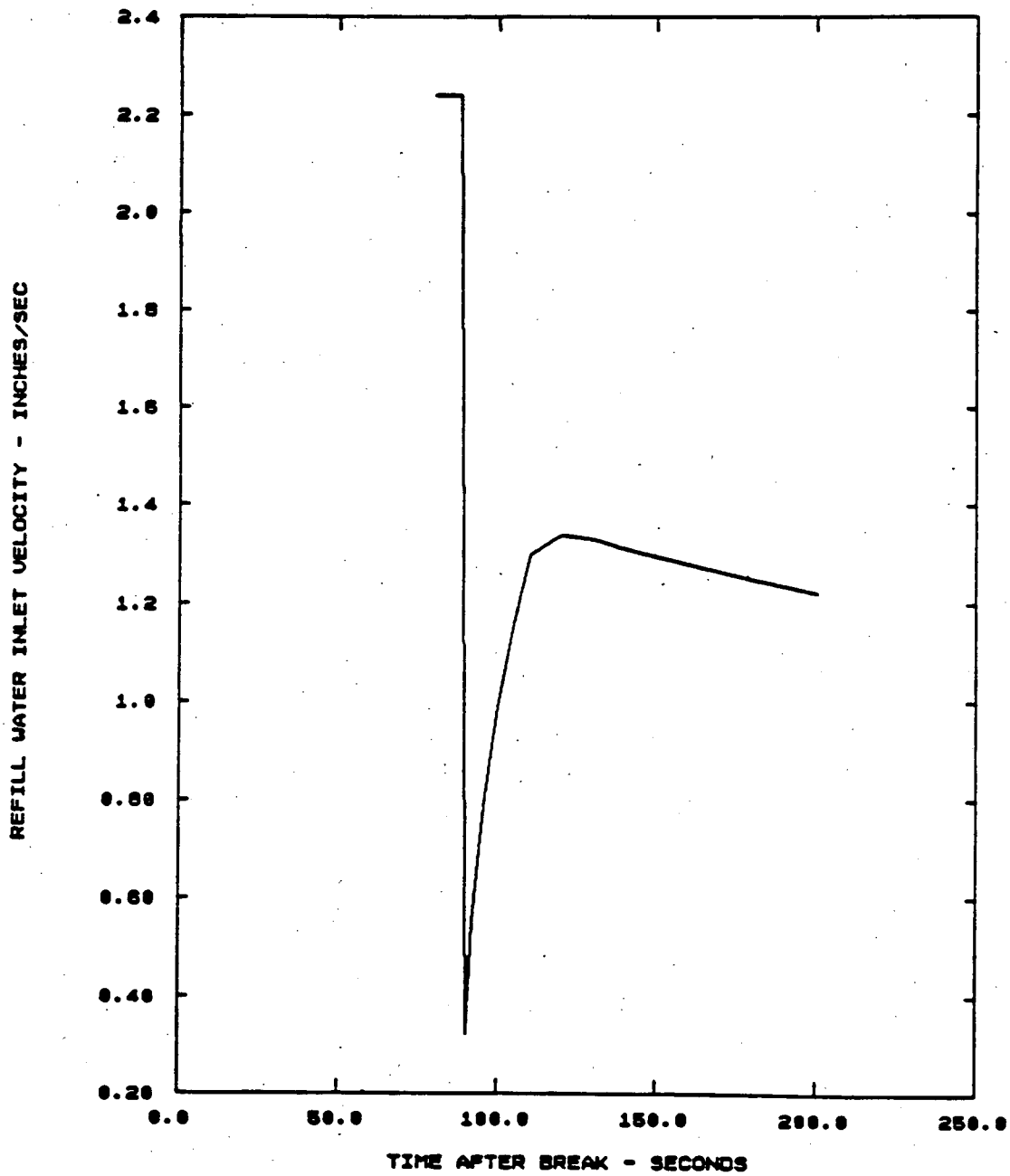
San Onofre Unit 1
Double-Ended Cold Leg Guillotine Break , CD=1.0
Figure A.8a DOWNCOMER and CORE WATER LEVEL



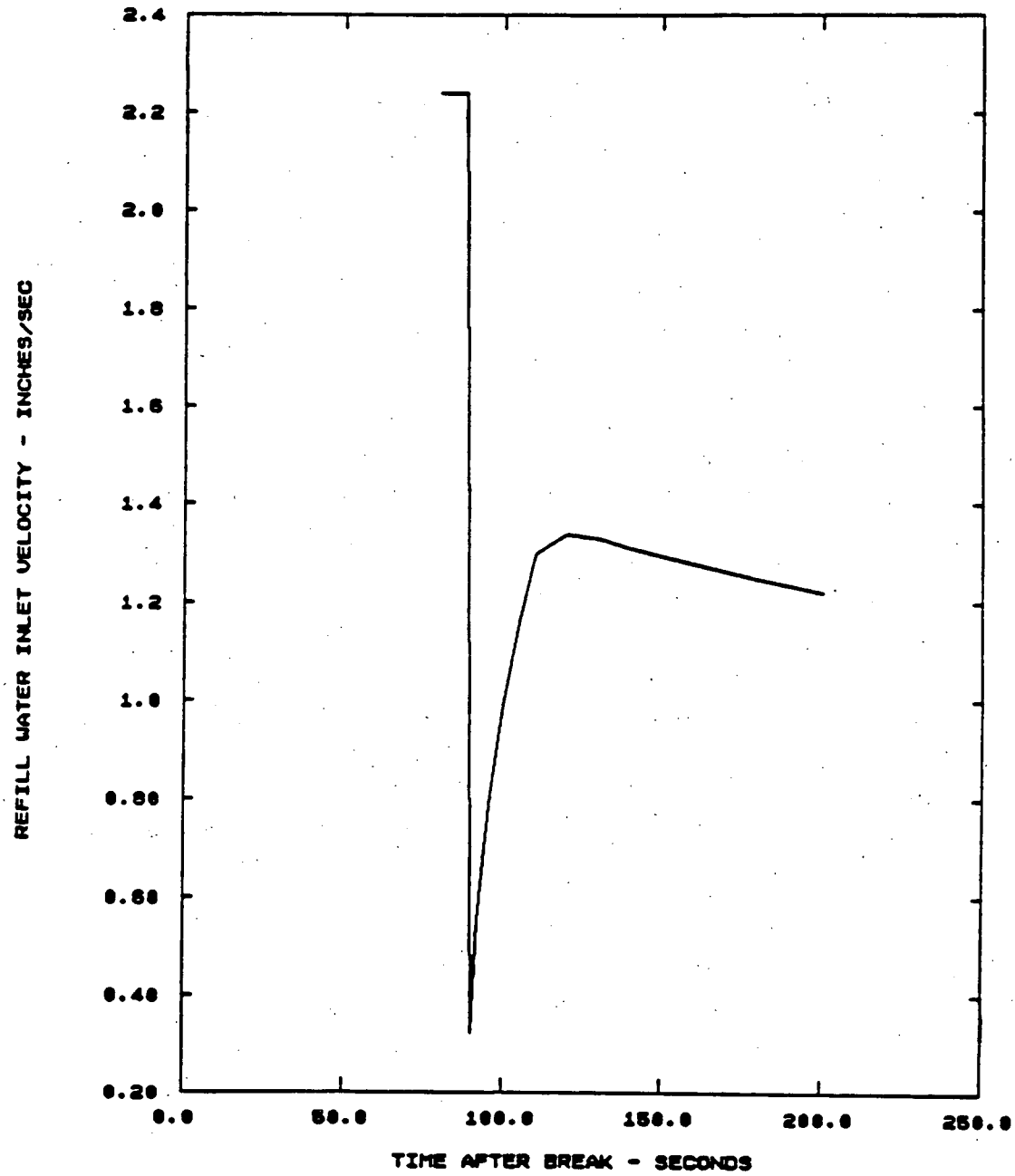
San Onofre Unit 1
Double-Ended Cold Leg Guillotine Break , CD=0.8
Figure A.8b DOWNCOMER and CORE WATER LEVEL



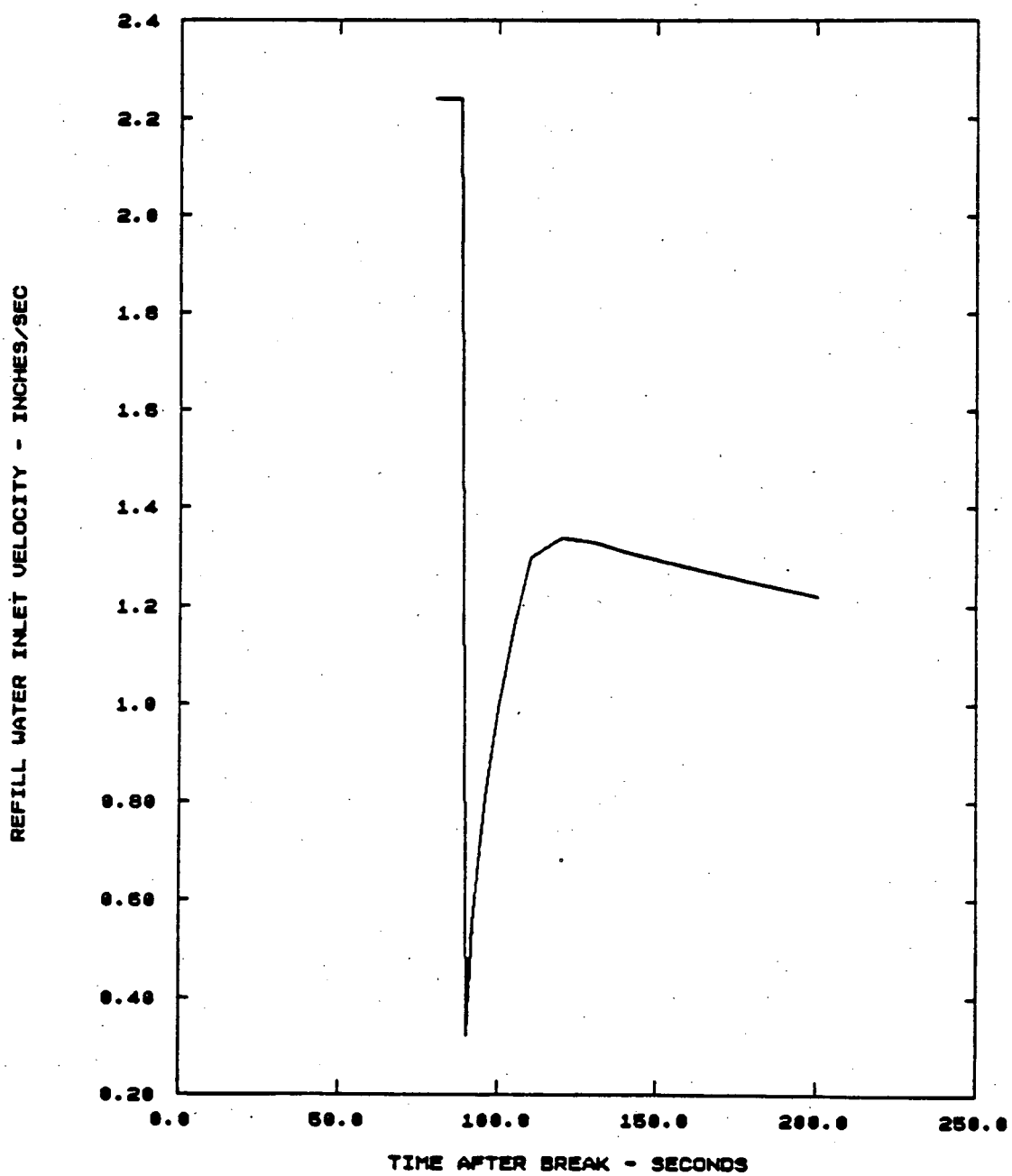
San Onofre Unit 1
Double-Ended Cold Leg Guillotine Break , CD=0.6
Figure A.8c DOWNCOMER and CORE WATER LEVEL



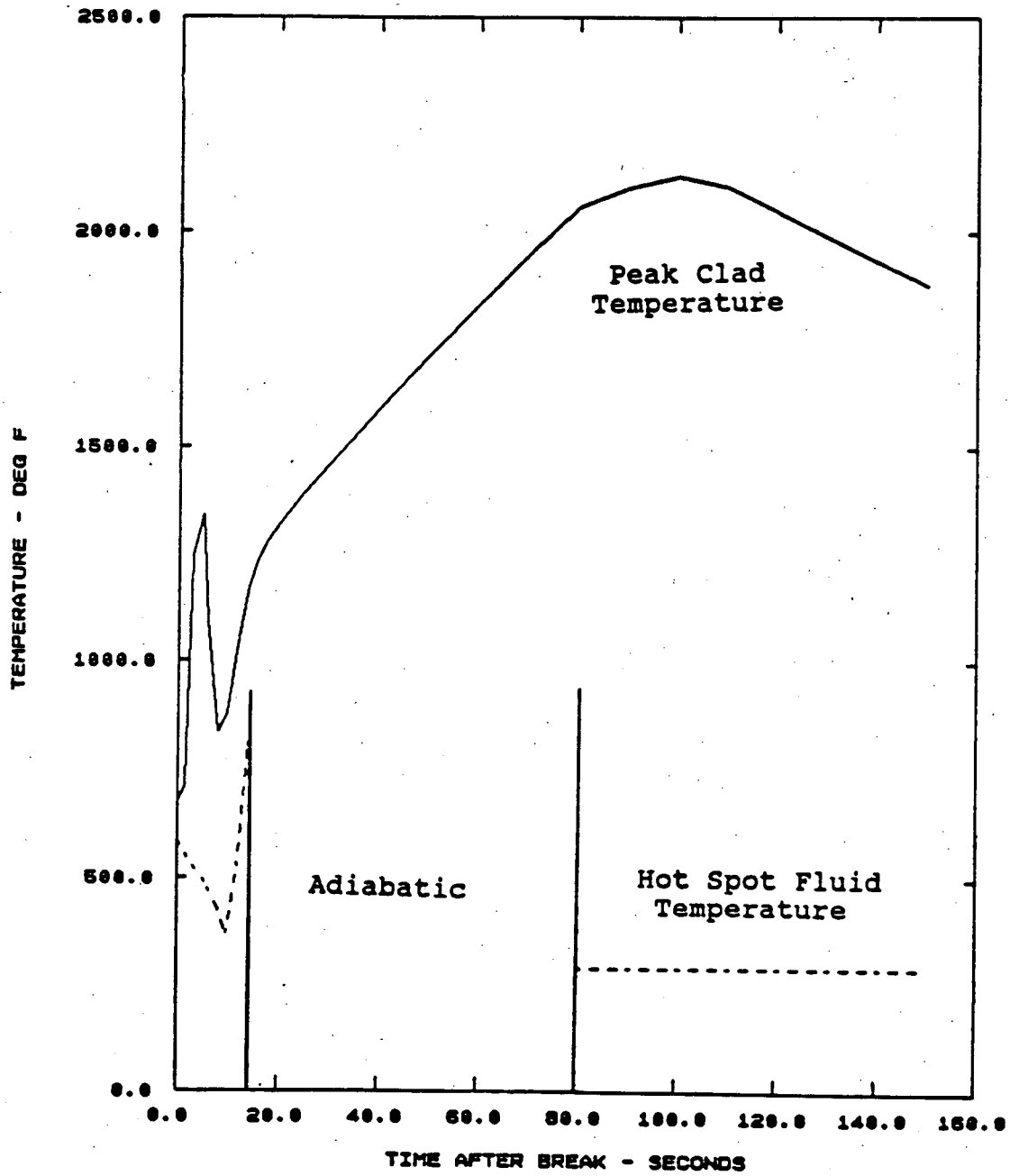
San Onofre Unit 1
Double-Ended Cold Leg Guillotine Break , CD=1.0
Figure A.9a REFILL WATER INLET VELOCITY



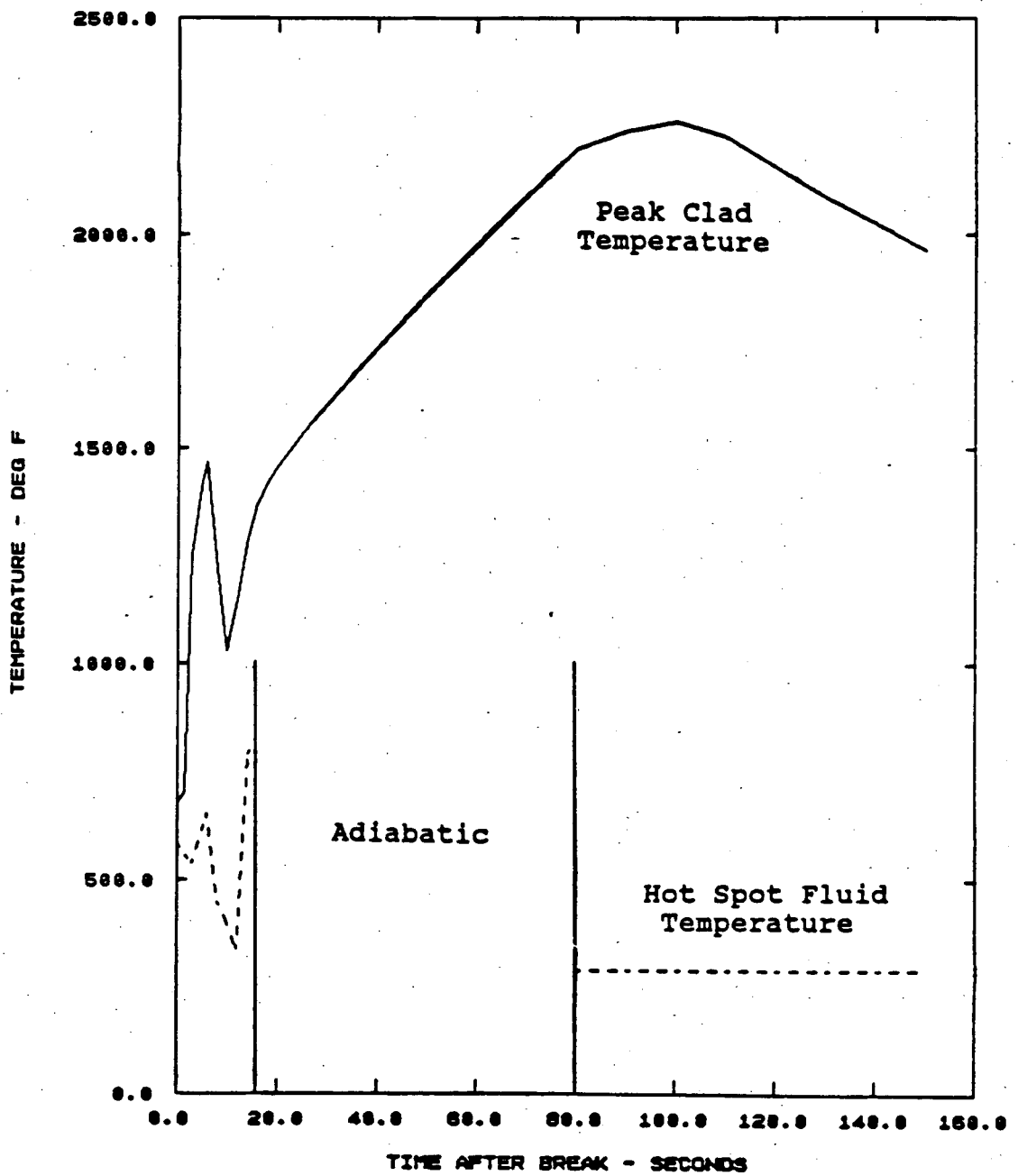
San Onofre Unit 1
Double-Ended Cold Leg Guillotine Break , CD=0.8
Figure A.9b REFILL WATER INLET VELOCITY



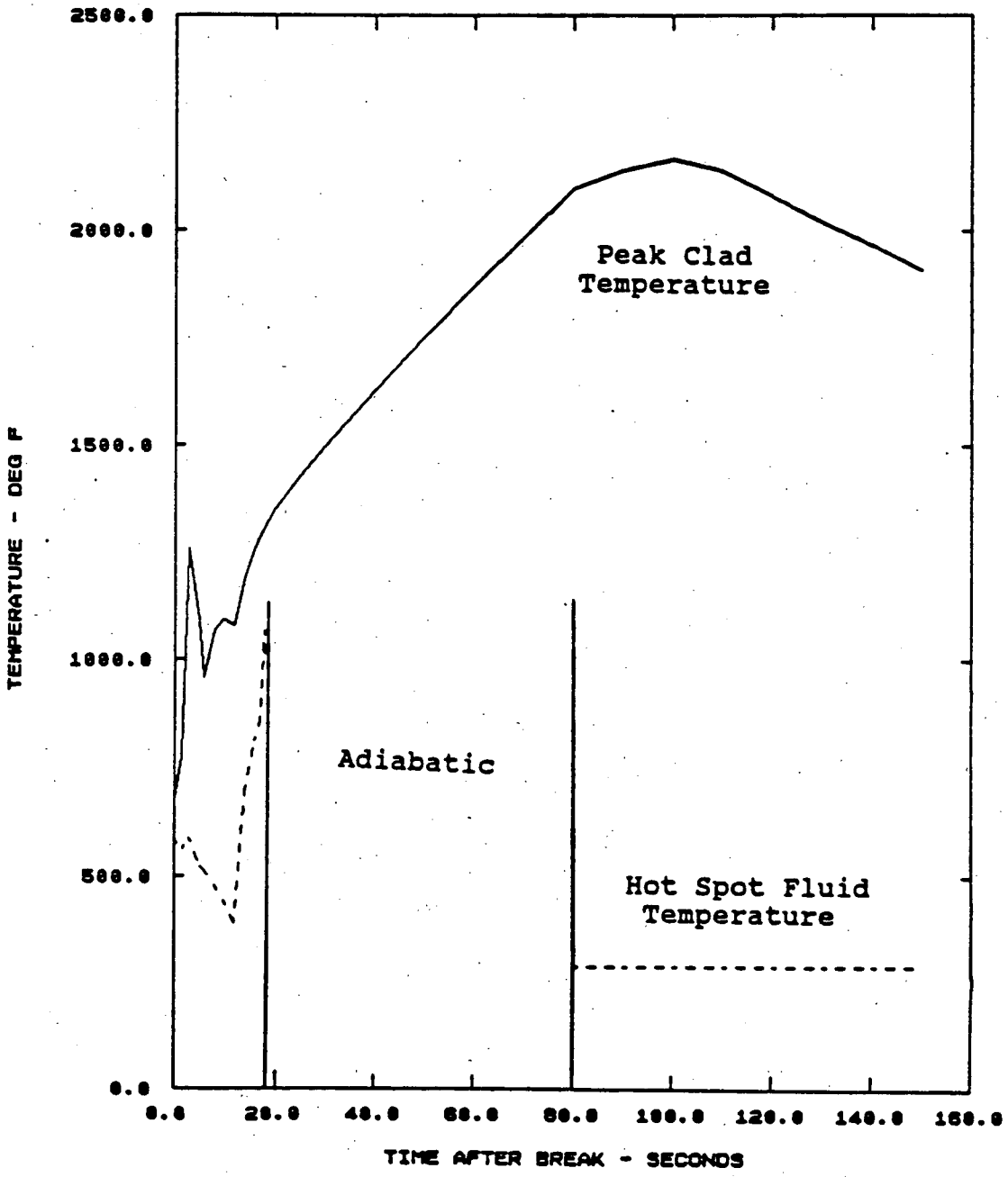
San Onofre Unit 1
Double-Ended Cold Leg Guillotine Break , CD=0.6
Figure A.9c REFILL WATER INLET VELOCITY



San Onofre Unit 1
Double-Ended Cold Leg Guillotine Break , CD=1.0
Figure A.10a PEAK CLAD and HOT SPOT FLUID TEMPERATURE



San Onofre Unit 1
Double-Ended Cold Leg Guillotine Break , CD=0.8
Figure A.10b PEAK CLAD and HOT SPOT FLUID TEMPERATURE



San Onofre Unit 1
Double-Ended Cold Leg Guillotine Break , CD=0.6
Figure A.10c PEAK CLAD and HOT SPOT FLUID TEMPERATURE

APPENDIX B

NON-LOCA SAFETY EVALUATION FOR 20% STEAM GENERATOR TUBES PLUGGED WITH RCS REDUCED T_{AVG} PROGRAM OPERATION

APPENDIX B

TABLE OF CONTENTS

APPENDIX B
LIST OF TABLES

LIST OF FIGURES

LIST OF FIGURES

LIST OF FIGURES

B.1 Background

This section provides the non-LOCA safety evaluation to support San Onofre Nuclear Generating Station 1 (SONGS 1) operation on the Reduced Tavg Program with up to 20% tube plugging level in any one steam generator. Also included in this safety evaluation is the impact of two other plant changes for SONGS 1:

a. The unavailability of the RCS Low Flow reactor trip function to provide protection during the Locked Rotor/Shaft Break analysis. A single active failure of a low flow transmitter (one per loop) in the same loop as the reactor coolant pump locked rotor/shaft break could prevent this trip from occurring.

b. An increase in the safety injection delay time assumed in the steamline break analysis.

The current non-LOCA safety analyses and evaluations for SONGS 1 (Reference 1) support operation at the following conditions:

I. Nominal Tavg Program

Full Core Power	= 1347 MWt
Full Power Tavg	= 575.15°F
RCS Pressure	= 2100 psia
Thermal Design Flow	= 65000 gpm/loop
S.G. Tube Plugging Level	$\leq$ 20%
Full Power Steam Pressure	= 673.4 psia

II. Reduced Tavg Program

Full Core Power	= 1347 MWt
Full Power Tavg	= 551.5°F
RCS Pressure	= 2100 psia
Thermal Design Flow	= 67300 gpm/loop
S.G. Tube Plugging Level	$\leq$ 15%
Full Power Steam Pressure	= 576.2 psia

The primary effect of the increased steam generator tube plugging level for the Reduced Tavg Program operation is to decrease the Thermal Design Flow. Although the increased tube plugging level also reduces the steam generator heat transfer area and the primary coolant mass inventory, the decrease due to the 5% increase in tube plugging level is not considered significant to the current non-LOCA safety analyses and evaluations. The new operating conditions of the Reduced Tavg Program with 20% steam generator tube plugging level are as follows:

III. Reduce Tavg Program (20% Tube Plugging)

Full Core Power	= 1347 MWt
Full Power Tavg	= 551.5°F
RCS Pressure	= 2100 psia
Thermal Design Flow	= 65000 gpm/loop
S.G. Tube Plugging Level	≤ 20%
Full Power Steam Pressure	= 547.0 psia

The impact of the reduced Thermal Design Flow for SONGS 1 operation on the Reduced Tavg Program for the non-LOCA transients is addressed in the following sections. Table 1 presents the non-LOCA transients addressed in this safety evaluation. The safety evaluation is based on the operation conditions listed above for the Reduced Tavg Program with 20% Steam Generator Tube Plugging Level. This safety evaluation is based on a maximum effective steam generator tube plugging level of 20%. Based on the current steam generator tube plugging level for SONGS 1 and the minor asymmetry of the tube plugging levels among the steam generator, all combinations of tube plugging and sleeving yielding an effective plugging level of less than 20% per steam generator are bounded by this safety evaluation. As discussed in the following sections, no reanalyses are required to support the increase in tube plugging level for Reduced Tavg Program operation for SONGS 1. However, reanalyses are required to address the unavailability of the RCS Low Flow reactor trip function for the locked rotor/shaft break analysis and the increase in safety injection delay time for the steamline break core response analysis.

B.2 Reactor Protection System and Engineered Safeguards Feature Setpoints

The Reactor Protection System and Engineered Safeguards Feature setpoints assumed in the current safety analyses are evaluated for the increase in steam generator tube plugging level for Reduced for Reduced Tavg Program operation for SONGS 1. The only protection function directly impacted by the increased tube plugging level is the Variable Low Pressure reactor trip.

The Variable Low Pressure reactor trip, in combination with the Overpower reactor trip, provide protection for the core thermal safety limits (Figure 1). Table 2 presents the Variable Low Pressure reactor trip equations. The current core thermal safety limits are based on a full core power of 1347 MWt and a Thermal Design Flow of 195000 gpm. Since the reduced Thermal Design Flow associated with the increase in steam generator tube plugging for the Reduced Tavg Program operation for SONGS 1 is not less than 195000 gpm, the current core thermal safety limits remain valid. The steam generator safety valve limit line, along with the Overpower reactor trip function, provides a boundary for the protection required by the Variable Low Pressure reactor trip. With the reduction in nominal full power steam pressure for the increased tube plugging level, the range of protection required by the Variable Low Pressure trip is increased. A reduced steam pressure would cause the steam generator safety valve line of Figure 1 to shift downward. However, the current steam generator safety valve limit line is conservative and bounds the steam generator safety valve limit line associated with the reduced nominal full load steam pressure of the Reduced Tavg Program with 20% tube plugging. Thus, no changes to the Variable Low Pressure reactor trip equation are required to support the conditions associated with the Reduced Tavg Program with 20% steam generator tube plugging.

B.3 Non-LOCA Events Evaluated

B.3.1 Uncontrolled RCCA Bank Withdrawal From a Subcritical Condition

This event, as discussed in UFSAR Section 15.8.1, is examined to show that the core and reactor coolant system are not adversely affected. This is done by showing that the DNBR limit is met and that the peak RCS pressure does not exceed 110% of design.

The uncontrolled RCCA bank withdrawal from a subcritical condition was recently analyzed to support SONGS 1 Cycle 9 extended operation (Reference 2). The analysis assumed a RCS flow corresponding to 20% steam generator tube plugging level to bound the tube plugging level associated with the Nominal Tavg Program operation (20%) and the Reduced Tavg Program operation (15%). Since the no load temperature is the same for both Tavg programs, the analysis documented in Reference 2 is applicable for both Tavg programs. As such, the analysis to support the Cycle 9 extended operation also supports the Reduced Tavg Program operation with 20% steam generator tube plugging level since the reduced Thermal Design Flow (195000 gpm) for the increased tube plugging level for Reduced Tavg Program operation is not less than the Thermal Design Flow (195000) for Nominal Tavg Program with 20% tube plugging level. Thus, the conclusions presented in the UFSAR and the Cycle 9 extended operation safety evaluation remain valid.

B.3.2 Uncontrolled RCCA Bank Withdrawal at Power

The current analyses for the uncontrolled RCCA bank withdrawal at power (RWAP) transient to support the Nominal Tavg Program with 20% tube plugging operation and the Reduced Tavg Program with 15% tube plugging operation are presented in UFSAR Section 15.8.2. This event is primarily performed to demonstrate the adequacy of the reactor protection system to protect the core thermal safety limits. Core protection is provided by the Power Range High Neutron Flux, high setting, reactor trip and the Variable Low Pressure reactor trip. This evaluation of the uncontrolled RCCA bank withdrawal at power transient to support the increase in tube plugging for the Reduced Tavg Program operation assumes no change to the Variable Low Pressure reactor trip function (Figure 1 and Table 2) used in the UFSAR analyses. As stated previously, the core thermal safety limits remain unchanged.

The UFSAR analysis for the Nominal Tavg Program with 20% tube plugging is applicable for SONGS 1 operation on Reduced Tavg Program with 20% tube plugging. The Thermal Design Flows for the two conditions are the same. The higher initial Tavg associated with the Nominal Tavg Program is conservative for the DNB evaluation of the cases where reactor trip is provided by the Power Range High Neutron Flux, high setting. It is expected that, since the Nominal Tavg Program RWAP analysis showed that the Variable Low Pressure reactor trip is adequate for Nominal Tavg Program 20% tube plugging operation, the Variable Low Pressure reactor trip equation is adequate for Reduced Tavg Program 20% tube plugging operation. The only difference is that, with the Reduced Tavg Program, it will take longer to reach the Variable Low Pressure setpoint. This is because the Variable Low Pressure reactor trip function is based on Tavg and ΔT. The lower Tavg of the Reduced Tavg Program puts operation further away from the setpoint (see Figure 1).

Although it will take longer to reach the Variable Low Pressure trip setpoint, the Variable Low Pressure reactor trip will provide protection of the core thermal safety limits. Sensitivity studies show that the increased time to reactor trip does not retard the ability of the Variable Low Pressure reactor trip, in combination with the Power Range High Neutron Flux, high setting, reactor trip, to protect the core thermal safety limits. As such, the uncontrolled RCCA bank withdrawal at power safety analysis for Nominal Tavg Program with 20% tube plugging supports SONGS 1 operation on the Reduced Tavg Program with 20% steam generator tube plugging. Thus, the conclusions presented in the UFSAR remain valid.

B.3.3 Startup of an Inactive Reactor Coolant Loop

This transient is examined in UFSAR Section 15.9 to determine the effect on core integrity. Core integrity is assured by calculating a minimum DNBR above the limit value. An inadvertent startup of an idle reactor coolant pump results in the injection of cold water into the core. This causes an increase in reactivity due to the increase in moderator density.

This incident need not be addressed due to the Technical Specification restrictions which prohibit operation with a loop out of service for power levels greater than 10 percent. However, a brief discussion of the impact of Reduced Tavg Program with 20% tube plugging level operation is included. Previous evaluations presented in the SONGS 1 Cycle 8 Reload Safety Evaluation (Reference 3) support operation on the Nominal Tavg Program with 20% tube plugging and Reduced Tavg with 15% tube plugging. The only difference between the Nominal Tavg Program and Reduced Tavg Program operations is the initial Tavg. (The Thermal Design Flows are now the same for the two conditions due to the increase in tube plugging for the Reduced Tavg Program.) The higher initial Tavg associated with the Nominal Tavg Program bounds the initial Tavg of the Reduced Tavg Proram with respect to the DNB evaluation. As such, the evaluation of the startup of an inactive reactor coolant loop transient to support Nominal Tavg Program with 20% tube plugging level presented in the Cycle 8 Reload Safety Evalaution (Reference 3) is bounding for SONGS 1 operation on the Reduced Tavg Program with 20% steam generator tube plugging level. Thus, the conclusions presented in the UFSAR and Reference 3 remain valid.

B.3.4 Addition of Excess Feedwater

This event, as discussed in UFSAR Section 15.1.2, is examined to show that the core and reactor coolant system are not adversely affected. This is done by showing that the DNBR limit is met and that the peak pressure does not exceed 110% of design pressure.

The addition of excessive feedwater is an excessive heat removal incident which results in a power increase due to moderator feedback. UFSAR Section 15.1.2 presents two cases. The first case assumes that all three feedwater control valves fully open together at full load. The second case assumes the startup of a feedwater pump with one pump already running while at 50 percent power; the control valves are in manual.

The results presented in the UFSAR show that there is no significant reduction in core inlet temperature and there is very little response to this condition by the Reactor Coolant System for both cases. Manual trip of the reactor is assumed to occur following high level alarms on the steam generators. The core never approaches the DNBR safety limit, and the RCS pressure never exceeds 110% of design during this transient.

As the case with the startup of an inactive loop event, the addition of excess feedwater transient was evaluated for Nominal Tavg Program operation with 20% tube plugging and for Reduced Tavg Program with 15% tube plugging in the Cycle 8 Reload Safety Evaluation (Reference 3). The Nominal Tavg Program with 20% tube plugging evaluation bounds SONGS 1 operation on the Reduced Tavg Program with 20% tube plugging since the Cycle 8 evaluation assumed a higher Tavg, which is conservative. Thus, the conclusions presented in the UFSAR and Reference 3 remain valid.

B.3.5 Large Load Increase

This event, as discussed in UFSAR Section 15.1.3, is examined to show that the core and reactor coolant system are not adversely affected. This is done by showing that the DNBR limit is met and that the peak pressure does not exceed 110% of design pressure.

An excessive load increase event, in which the steam load exceeds the core power, results in a decrease in reactor coolant system temperature which may lead to a power increase due to moderator feedback. The maximum thermal power level evaluated in the UFSAR corresponds to the situation with the turbine control valves fully open. The power level associated with the Reduced Tavg Program also corresponds to the situation with the turbine control valves fully open. This eliminates the possibility of a large load increase above this power level. Therefore, as was shown in UFSAR Section 15.1.3, a step load increase of 30 percent to the maximum achievable steam flow, is not expected to result in a reactor trip since sufficient margin to the reactor protection setpoints (including uncertainties) exists. If required, protection for this event is provided by the overpower and variable low pressure reactor trip functions. The adequacy of the protection was verified in the uncontrolled RCCA bank withdrawal at power evaluation for Reduced Tavg Program operation with 20% tube plugging.

The large load increase transient was evaluated for Nominal Tavg Program operation with 20% tube plugging and for Reduced Tavg Program operation with 15% tube plugging in the Cycle 8 Reload Safety Evaluation (Reference 3). The Nominal Tavg Program with 20% tube plugging evaluation bounds SONGS 1 operation on the Reduced Tavg Program with 20% tube plugging since the Cycle 8 evaluation assumed a higher Tavg, which is conservative. Thus, the conclusions presented in the UFSAR and Reference 3 remain valid.

B.3.6 Dropped Rod

This event is examined to show that the core and reactor coolant system are not adversely affected. This is done by showing that the DNBR limit is met and that the peak pressure does not exceed 110% of design pressure. UFSAR Section 15.8.3 presents the safety analyses for the dropped rod event.

The safety analyses presented in the UFSAR address two modes of operation for SONGS 1, with turbine runback and without turbine runback. The analysis to address the with turbine runback case supports both Nominal Tavg Program and Reduced Tavg Program operations. A conservative high initial Tavg associated with the Nominal Tavg Program and a conservative low Thermal Design Flow associated with 20% steam generator tube plugging were assumed to bound both set of operating conditions. The analysis to address the without turbine runback case supports only the Reduced Tavg Program operation. The analysis assumed a conservative low Thermal Design Flow (195000 gpm) associated with 20% tube plugging. As such, SONGS 1 operation with a Reduced Tavg Program with 20% steam generator tube plugging is supported by the UFSAR analysis. Thus, the conclusions presented in the UFSAR remain valid.

B.3.7 Control Rod Ejection

This incident, as presented in UFSAR Section 15.11, is examined to ensure that the average fuel pellet enthalpy remains below the limit, that the hot spot clad temperature remains below 2450°F, that the peak reactor coolant pressure is less than a value which would cause stresses to exceed the Faulted Conditions stress limit, and that fuel melting is limited to less than 10% at the hot spot

This event was recently reanalyzed to support the SONGS 1 Cycle 9 extended operation (Reference 2). All four cases of the rod ejection safety analysis were reanalyzed (Hot Zero Power at Beginning of Core Life, Hot Full Power at Beginning of Core Life, Hot Zero Power at End of Core Life, and Hot Full Power at End of Core Life). The analysis was performed to bound both the Nominal Tavg Program operation with 20% tube plugging and the Reduced Tavg Program operation with 15% tube plugging. This was accomplished by assuming initial Tavg's associated with the Nominal Tavg Program and conservative RCS flows associated with 20% steam generator tube plugging. As such, SONGS 1 operation with a Reduced Tavg Program with 20% tube plugging is supported by the analysis presented in the Cycle 9 extended operation report (Reference 2). Thus, the conclusions presented in the UFSAR and Reference 2 remain valid.

B.3.8 Loss of Coolant Flow

This event, as discussed in UFSAR Section 15.7.1, is examined to demonstrate that the DNB design safety limit is met. The UFSAR presents a bounding safety analysis to support SONGS 1 operation with the Nominal Tavg Program with 20% steam generator tube plugging and to support operation with the Reduced Tavg Program with 15% steam generator tube plugging. The safety analysis is also applicable for the increase in tube plugging level for the Reduced Tavg Program. The conservative direction for initial conditions for temperature and flow for the loss of coolant flow analysis is to assume a high Tavg and a low Thermal Design Flow. The safety analysis assumed an initial Tavg associated with the Nominal Tavg Program and a RCS Thermal Design Flow (195000 gpm) associated with 20% tube plugging. As such, SONGS 1 operation with a Reduced Tavg Program with 20% steam generator tube plugging level is supported by the loss of flow safety analysis presented in the UFSAR. Thus, the conclusions presented in the UFSAR remain valid.

B.3.9 Loss of Load

This event, as discussed in UFSAR Section 15.3, is examined to show that the core and reactor coolant system are not adversely affected. This is done by showing that the DNBR limit is met and that the peak pressure does not exceed 110% of design pressure.

The loss of load in combination with failure of the steam dump system causes an increase in steam generator temperature and pressure. This in turn causes an increase in RCS temperature and pressure. As described in UFSAR Section 15.3, core protection is provided by High Pressurizer Water Level, High Pressurizer Pressure, or Variable Low Pressure reactor trip.

The loss of load event was evaluated in the Cycle 8 Reload Safety Evaluation (Reference 3) to support SONGS 1 operation with a Nominal Tavg Program with 20% steam generator tube plugging level and with a Reduced Tavg Program with 15% steam generator tube plugging level. For the loss of load event, the conservative direction on initial conditions for temperature and flow is to assume a high Tavg and a low RCS flow. The Tavg associated with a Nominal Tavg Program bounds the Tavg associated with a Reduced Tavg Program, and the assumed Thermal Design Flow (195000 gpm) associated with 20% tube plugging remains the same for Reduced Tavg Program operation with 20% tube plugging. As such, SONGS 1 operation with a Reduced Tavg Program with 20% steam generator tube plugging level is supported by the Nominal Tavg Program operation with 20% tube plugging evaluation presented in the Cycle 8 Reload Safety Evaluation (Reference 3). Thus, the conclusions presented in the UFSAR and Reference 3 remain valid.

B.3.10 Loss of Normal Feedwater

This event, as discussed in UFSAR Section 15.5, is examined to show that the core and reactor coolant system are not adversely affected. This is done by showing that the DNBR limit is met, that the peak pressure does not exceed 110% of design pressure, and that the pressurizer does not become water solid.

The current loss of normal feedwater safety analyses presented in Reference 4 assumed conservative initial conditions to bound both Nominal Tavg Program with 20% tube plugging operation and Reduced Tavg Program with 15% tube plugging. The conservative direction for initial conditions for temperature and RCS flow is to assume a high Tavg and a low RCS flow. As used in the Reference 4 analysis, the high Tavg of the Nominal Tavg Program operation is bounding for the Reduced Tavg Program. Also the RCS Thermal Design Flow (195000 gpm) corresponding to 20% tube plugging is the conservative assumption for flow and is applicable for the increased tube plugging level (20%) for the Reduced Tavg Program operation. As such, SONGS 1 operation with the Reduced Tavg Program with 20% steam generator tube plugging level is supported by the current loss of normal feedwater safety analyses presented in Reference 4. Thus, the conclusions presented in the UFSAR and Reference 4 remain valid.

B.3.11 Feedline Break

This event, as discussed in UFSAR Section 15.6, is examined to ensure that the reactor coolant and main steam pressures are maintained below 110% of their design pressures and the core remains in a coolable geometry.

The current feedline break safety analyses presented in Reference 4 assumed conservative initial conditions to bound both Nominal Tavg Program with 20% tube plugging operation and Reduced Tavg Program with 15% tube plugging. The conservative direction for initial conditions for temperature and RCS flow is to assume a high Tavg and a low RCS flow. As used in the Reference 4 analyses, the high Tavg of the Nominal Tavg Program operation is bounding for the Reduced Tavg Program. Also the RCS Thermal Design Flow (195000 gpm) corresponding to 20% tube plugging is the conservative assumption for flow and is applicable for the increased tube plugging level (20%) for the Reduced Tavg Program operation. As such, SONGS 1 operation with the Reduced Tavg Program with 20% steam generator tube plugging level is supported by the current feedline break safety analyses presented in Reference 4. Thus, the conclusions presented in the UFSAR and Reference 4 remain valid.

B.3.12 Steam Line Break Mass/Energy Release Inside and Outside Containment

Mass/energy releases following a steamline rupture inside containment are used to determine the maximum pressure peaks for containment integrity evaluations. The mass/energy releases following a steamline rupture outside containment are used to determine the temperature profiles for qualification of equipment. The temperature profile is a function of both the steam blowdown and the compartment in which the equipment is located. The outside containment steamline break mass/energy analysis (Reference 5) provides information for use in evaluating the effects of steam generator tube bundle uncovery and the associated superheated steam generation for areas outside containment.

The increase in steam generator tube plugging level is acceptable since the mass/energy release analyses assumed heat transfer characteristics to support SONGS 1 steam generator tube plugging levels . Also, the analyses assumed initial Tavg's corresponding to the Nominal Tavg Program, which bound Reduced Tavg Program operation since higher Tavg is conservative. As such, the steamline break mass/energy release analyses support Reduced Tavg Program operation with 20% steam generator tube plugging.

Also, the increase in safety injection delay time of 4 seconds does not significantly impact the mass/energy releases for a steamline break inside containment. Due to the low shutoff head (around 1190 psia) of the safety injection pumps, safety injection water reaching the RCS is typically delayed beyond the electrical and mechanical delays. An increase in the electrical and mechanical delays of safety injection of 4 seconds would not significantly delay the time that safety injection water reaches the RCS. Also, the mass/energy releases are not very sensitive to any resulting small delay in time that safety injection would reach the RCS. As such, the steamline break mass/energy release analyses are applicable for an increase in the safety injection delay time of 4 seconds.

B.4. Non-LOCA Events Reanalyzed

Although the increase in steam generator tube plugging level to 20% for SONGS 1 operation on the Reduced Tavg Program does not require any specific reanalyses, the other plant parameter changes discussed in Section B.1 require reanalysis of two transients.

Reanalysis of the locked rotor/shaft break event is required to address the unavailability of the RCS Low Flow reactor trip function assuming a single active failure of the low flow channel located in the loop with the affected reactor coolant pump. The reanalysis (Section B.4.1) is performed to address Nominal Tavg Program operation with 20% steam generator tube plugging level and to address Reduced Tavg Program operation with up to 20% tube plugging.

Reanalysis (Section B.4.2) of the steamline break core response transient is required to address the increase in safety injection delay time of 4 seconds. The steamline break core response transient used in the DNBR evaluation is sensitive to the time that safety injection water reaches the RCS.

B.4.1 Locked Rotor/Shaft Break

Reanalysis of the locked rotor/shaft break event is required to address the unavailability of the RCS Low Flow reactor trip function assuming a single active failure of the low flow channel located in the loop with the affected reactor coolant pump. The reanalysis is performed to address Nominal Tavg Program operation with up to 20% steam genertor tube plugging level and to address Reduced Tavg Program operation with up to 20% steam generator tube plugging level.

Identification of Causes and Accident Description

The accident postulated is an instantaneous seizure of an RCP rotor or an instantaneous failure of an RCP shaft. Flow through the affected reactor coolant loop is rapidly reduced, typically leading to an immediate reactor trip on low reactor coolant flow in the affected loop. For San Onofre Unit 1, however, a single active failure of a low flow transmitter (one per loop) in the same loop as the RCP locked rotor/shaft break could prevent this trip from occurring. The following reactor protection system functions are available to provide backup protection:

Variable Low Pressure reactor trip
High Pressurizer Pressure reactor trip
High Pressurizer Water Level reactor trip
RCP Breaker Opening reactor trip

Following the RCP locked rotor/shaft break, heat transfer to the shell side of the steam generators is reduced, initially because the reduced flow results in a decreased tube side film coefficient and then because the reactor coolant in the tubes cools down while the shell side temperature increases following reactor trip (turbine steam flow is reduced to zero upon plant trip). Heat stored in the fuel rods continues to be transferred to the coolant causing the coolant to expand. The expansion of the coolant in the reactor core, combined with reduced heat transfer in the steam generators causes an insurge into the pressurizer and a pressure increase throughout the reactor coolant system. The insurge into the pressurizer compresses the steam volume, actuates the automatic spray system, and opens the power-operated relief valves. The power-operated relief valves are designed for reliable operation and would be expected to function properly during the accident. However, for conservatism, the pressure reducing effect of the automatic spray system and the power-operated relief valves are not included in the analysis.

In general, the consequences of a locked rotor are very similar to those of a pump shaft break. The initial rate of reduction of coolant flow is slightly greater for the locked rotor event. However, with a failed shaft, the impeller could conceivably be free to spin in the reverse direction as opposed to being fixed in position as assumed for a locked rotor. The effect of such reverse spinning is a slight decrease in the endpoint (steady-state) core flow when compared to the locked rotor. Only one analysis is performed, representing the most limiting condition for the locked rotor and pump shaft break accidents.

The RCPs in the unfaulted loops are assumed to operate at full speed (no coastdown) for the duration of the transient, since loss of offsite power will not result in loss of power to the RCPs for at least one minute.

Analysis of Effects and Consequences

Method of Analysis

Three digital computer codes are used to analyze this transient. The LOFTRAN (Reference 6) code is used to calculate the resulting loop and core flow transients following the pump seizure/shaft break, the nuclear power transient, and the pressure transient. The thermal behavior of the fuel located at the core hot spot is investigated using the FACTRAN (Reference 7) code, using the core flow and the nuclear power calculated by LOFTRAN. The FACTRAN code includes the use of a film boiling heat transfer coefficient. The THINC digital computer program (Reference 8) adapted for transients, was used in the DNB evaluation to determine what percentage, if any, of the fuel rods are expected to be in DNB during the transient.

Assuming the unavailability of the low flow reactor trip, the following reactor protection system functions are available to provide backup protection: High Pressurizer Pressure, High Pressurizer Water Level, Variable Low Pressure, and RCP Breaker Opening reactor trips. Although the High Pressurizer Pressure and High Pressurizer Water Level reactor trip functions are available, the RCS Pressure Control System (power-operated relief valves and automatic pressurizer sprays) and the Chemical Volume Control System (charging and letdown) may prevent these reactor trip functions from actuating. As such, credit was not taken for the High Pressurizer Pressure reactor trip and the High Pressurizer Water Level reactor trip.

The Variable Low Pressure (VLP) reactor trip setpoint is based on Tavg and ΔT (see Table 1 for VLP trip equation). Figure 1 depicts the VLP reactor trip function and the initial operating points (as well as the operating margins) for the Nominal Tavg Program (Tavg = 575.15°F, ΔT = 47.3°F) and the Reduced Tavg Program (Tavg = 551.5°F, ΔT = 48.6°F).

For a locked rotor/shaft break event, the Tavg and ΔT of the unaffected loops increase which results in an approach to the VLP setpoint. However, the increase in Tavg and ΔT may not be sufficient to actuate reactor trip on VLP. As the core proceeds through cycle life, the increased reactivity feedback may retard the increase in Tavg and ΔT that would occur for a shaft break accident. The moderator temperature coefficient becomes more negative throughout the cycle.

A more negative moderator temperature coefficient results in negative reactivity insertion due to the increase in core Tavg that results from the reduced core flow. This negative reactivity insertion limits the increase in Tavg and ΔT, inhibiting the RCS conditions from reaching the VLP setpoint. As such, credit was also not taken for the Variable Low Pressure reactor trip.

The existing reactor protection system for SONGS 1 provides a reactor trip on RCP breaker opening due to overcurrent to the RCP motor. For the case of a locked rotor, it is assumed that the RCP breaker opening trip will occur. For the specific case of a shaft break, an overcurrent condition to the RCP motor is not expected. SCE has committed to modifying this function so that a breaker opening trip will also occur for an undercurrent condition to the RCP motor. It is then assumed that the RCP breaker opening trip will occur for the case of a shaft break. Thus, this reanalysis assumes that a reactor trip is actuated on RCP breaker opening due to either overcurrent (locked rotor) or undercurrent (shaft break) to the RCP motor.

Acceptance Criteria

The acceptance criteria for the locked rotor/shaft break event are based on the Standard Review Plan:

> Pressure in the RCS and Main Steam System should be maintained below acceptable design limits, considering potential brittle and ductile failures.
>
> The potential for core damage is evaluated on the basis that it is acceptable if the minimum DNBR remains above the 95/95 limit, based on an acceptable correlation. If the DNBR falls below these values, fuel failure (rod perforation) must be assumed for all rods that do not meet these criteria unless it can be shown that fewer failures occur. Any fuel damage calculated to occur must be of sufficiently limited extent that the core will remain in place and intact with no loss of core cooling capability.

To meet the requirements of the second criterion listed above for the cases where fuel rod failure must be assumed, the peak clad temperature for a locked rotor/shaft break event must not exceed 2450°F. This is the temperature criterion established for demonstrating clad integrity for stainless steel 304. Meeting this limit, for the cases where fuel rod failures must be assumed, ensures that the core will remain in place and intact with no loss of core cooling capability.

Initial Conditions and Assumptions

The current safety analyses and evaluations for Unit 1 (Reference 1) support operation at the following nominal conditions for the Nominal Tavg Program and the Reduced Tavg Program:

	Nominal Tavg Program	Reduced Tavg Program
Full Core Power	1347 MWt	1347 MWt
Full Power Tavg	575.15°F	551.5°F
RCS Pressure	2100 psia	2100 psia
RCS Thermal Design Flow	195000 gpm	201900 gpm
Steam Generator Tube Plugging Level	≤ 20%	≤ 15%

At the beginning of the postulated shaft break accident (i.e., at the time the shaft in one of the RCPs is assumed to seize/break) the plant is assumed to be in operation under the most adverse steady-state operating conditions (i.e., maximum power level, maximum pressure, and maximum coolant average temperature). To conservatively calculate the power transient, a moderator temperature coefficient of 0 pcm/°F is assumed. Manual rod control is modeled since it is assumed that the effect of automatic rod control is insignificant due to the short duration (less than 10 seconds) of the transient. To conservatively calculate the peak pressure, the initial system pressure is conservatively assumed to be 30 psi above nominal pressure (2100 psia) to allow for errors in the pressurizer pressure measurement and control channels. The RCS pressure response shown in the results (Figure 3 and 7) corresponds to the point in the RCS having the maximum pressure (discharge of the unfaulted RCPs).

An analysis was performed for each of the plant operating conditions. LOFTRAN (Reference 6) does not have the capability to simulate the overcurrent or undercurrent characteristics of the RCP motor during the locked rotor/shaft break event. The time that the rods begin to fall due to the reactor trip signal was inputted in the analysis. The validity of this assumed rod motion time was verified by the results of the analysis.

The following list describes the initial conditions assumed in the Nominal Tavg Program analysis and the Reduced Tavg Program analysis. RCS Thermal Design Flow corresponding to 20% steam generator tube plugging level is assumed to address the increase in tube plugging level for Reduced Tavg Program operation.

	Nominal Tavg Program	Reduced Tavg Program
Core Power (includes 3% power uncertainty)	1387.4 MWt	1387.4 MWt
Tavg (+4°F uncertainty)	579.15°F	555.5°F
RCS Pressure (+30 psi uncertainty)	2130 psia	2130 psia
RCS Thermal Design Flow	195000 gpm	195000 gpm
Steam Generator Tube Plugging Level	20%	20%

Evaluation of the Pressure Transient

The analysis includes an evaluation of the RCS pressure transient. Rapid expansion of the coolant in the reactor core, combined with reduced heat transfer in the affected loop's steam generator causes an insurge into the pressurizer and a pressure increase throughout the reactor coolant system. The RCS pressure transient is calculated by conservatively simulating the expansion of the coolant.

The pressurizer safety valves are assumed to initially open at 2500 psia and achieve rated flow at 2575 psia. For the RCS pressure evaluation, no credit is taken for the pressurizer power operated relief valves or the pressurizer sprays.

Evaluation of DNB in the Core During the Accident

An evaluation is made for this transient to determine what percentage, if any, of the fuel rods are expected to be in DNB during the transient. The FACTRAN (Reference 7) code is used to calculate the core heat flux as a function of time, using as input the nuclear power and mass flow rate transient data. For the DNB evaluation, predicted core conditions are used as input to a THINC (Reference 8) calculation of the minimum DNBR during the transient. Results of the THINC evaluation are then used to determine the percentage of fuel rods which experience DNB.

If the evaluation determines that DNB is predicted to occur, a second evaluation is made to demonstrate clad integrity. An evaluation of the consequences with respect to fuel rod thermal transients is performed. For this evaluation, departure from nucleate boiling (DNB) in the core is conservatively modeled to occur at the beginning of the transient. Results obtained from analysis of this "hot spot" condition represent the upper limit with respect to clad temperature. In the evaluation, the rod power at the hot spot is assumed to be 3.1 times the average rod power (i.e., $F_Q = 3.1$, which includes the power spike factor) at the initial core power level.

Film Boiling Coefficient

The film boiling coefficient is calculated in the FACTRAN (Reference 7) code using the Bishop-Sandberg-Tong film boiling correlation. The fluid properties are evaluated at film temperature (average between wall and bulk temperatures). The program calculates the film coefficient at every time step based upon the actual heat transfer conditions at the time. The neutron flux, system pressure, bulk density, and mass flow rate as a function of time may be used as program input.

For this analysis, the initial values of the pressure and the bulk density are used throughout the transient since they are the most conservative with respect to clad temperature response. For conservatism in evaluating the peak clad temperature, DNB was assumed to exist at the initiation of the event.

Fuel Clad Gap Coefficient

The magnitude and time dependence of the heat transfer coefficient between fuel and clad (gap coefficient) has a pronounced influence on the thermal results. The larger the value of the gap coefficient, the more heat is transferred between pellet and clad. Based on investigations on the effect of the gap coefficient upon the maximum clad temperature during the transient, the gap coefficient was assumed to increase from a steady-state value consistent with initial fuel temperature to 10,000 Btu/hr-ft^2-^{o}F at the initiation of the transient. Thus, the large amount of energy stored in the fuel because of the small initial value is released to the clad at the initiation of the transient.

Results

Nominal Tavg Program

The calculated sequence of events for the case analyzed is shown in Table 3. The transient results for the limiting locked rotor/pump shaft break accident Nominal Tavg Program operation are shown in Figures 2 through 5. The analysis assumed that at 6.1 seconds the reactor trip signal released the rods to fall into the core.

The peak RCS pressure (2371 psia) reached during the transient is less than that which would cause stresses to exceed the faulted condition stress limits. Calculations indicate that 12.3% of the fuel rods in the core undergo DNB assuming the unavailability of the low flow signal in the affected loop with protection provided by the RCP breaker opening trip due to either overcurrent or undercurrent to the RCP motor. Since the peak clad average temperature (2214°F) is less than the temperature criterion (2450°F) established for demonstrating clad integrity for stainless steel 304, the core will remain in place and intact with no loss of core cooling capability. It should be noted that the clad temperature was conservatively calculated assuming that DNB occurs at the initiation of the transient.

Figure 2 shows that the core flow reaches a new equilibrium value by 10 seconds. With the reactor tripped, a stable plant condition will eventually be attained. Normal plant shutdown may then proceed.

Reduced Tavg Program

The calculated sequence of events for the case analyzed is shown in Table 4. The transient results for the limiting locked rotor/pump shaft break accident during Reduced Tavg Program operation are shown in Figures 6 through 8. The analysis assumed that at 6.8 seconds the reactor trip signal released the rods to fall into the core.

The peak RCS pressure (2297 psia) reached during the transient is less than that which would cause stresses to exceed the faulted condition stress limits. Calculations indicate that no fuel rods in the core experience DNB assuming the unavailability of the low flow signal in the affected loop with protection provided by the RCP breaker opening trip due to either overcurrent or undercurrent to the RCP motor. Thus, no fuel rod failures are predicted.

Figure 6 shows that the core flow reaches a new equilibrium value by 10 seconds. With the reactor tripped, a stable plant condition will eventually be attained. Normal plant shutdown may then proceed.

Conclusions

A. Since the peak RCS pressure reached during the transient for any of the cases analyzed is less than that which would cause stresses to exceed the faulted condition stress limits, the integrity of the primary coolant system is assured.

B. For plant operation on the Nominal Tavg Program, since the peak clad average temperature calculated for the hot spot during the worst transient remains less than the temperature criterion (2450°F) established for demonstrating clad integrity for stainless steel 304, the core will remain in place and intact with no loss of core cooling capability.

C. For plant operation on the Reduced Tavg Program, since no fuel rods were calculated to undergo DNB, no fuel rod failures were predicted.

D. The reanalysis of the Locked Rotor/Shaft Break assumed that a reactor trip is actuated by the RCP breaker opening due to either overcurrent (locked rotor) or undercurrent (shaft break) to the RCP motor. The reanalysis was required to address the unavailability of the low coolant flow reactor trip function. A single active failure of a low flow transmitter (one per loop) in the same loop as the locked rotor/shaft break could prevent this trip from occurring.

   The reanalysis of the Locked Rotor/Shaft Break showed that rod motion must begin within 6.1 seconds following the locked rotor/shaft break to ensure that the applicable safety criteria are met. It is the responsibility of Southern California Edison to provide the assurance that the reactor trip actuated by the RCP breaker opening due to either overcurrent or undercurrent to the RCP motor releases the rods to fall within 6.1 seconds following the locked rotor/shaft break. Also, it is the responsibility of SCE to incorporate the RCP breaker opening reactor trips due to overcurrent and undercurrent to the RCP motor into SONGS 1 Technical Specifications.

B.4.2 Steamline Break Core Response

The current safety analysis for steamline break core response is presented in Reference 10. The analysis assumed a Thermal Design Flow of 195000 gpm to bound SONGS 1 operation with 15% or 20% steam generator tube plugging level. The analysis is performed at Hot Zero Power conditions, which are the same for either Nominal Tavg Program operation or Reduced Tavg Program operation. As such, the analysis is applicable for SONGS 1 operation on the Reduced Tavg Program with 20% tube plugging. However, reanalysis of the steamline break core response transient is required to address the increase in safety injection delay time of 4 seconds. The steamline break core response transient used in the DNBR evaluation is sensitive to the time that safety injection water reaches the RCS. The analysis assumed a safety injection delay time of 22 seconds from the time that the low pressurizer pressure SI setpoint is reached until the safety injection pumps reach full speed. The analysis also assumed one train of SI injecting into one line of the RCS with a safety injection line boron concentration of 1500 ppm.

For the credible break case at Hot Zero Power conditions (Case 4.1 of Reference 10), the RCS pressure does not go below the shutoff head of the safety injection pumps until 61 seconds after the low pressurizer pressure SI setpoint is reached. As such, the increased safety injection delay time of 26 seconds from 22 seconds does not impact the credible break case since safety injection flow does not start for 61 seconds after the setpoint is reached. Thus, the credible break analysis remains valid for the increase of 4 seconds in the safety injection delay time.

For the hypothetical break cases at Hot Zero Power conditions (Cases 3.1, 3.2, 3.3 of Reference 10), the RCS pressure is below the shutoff head of the safety injection pumps by the end of the assumed 22 second delay. The borated water of the safety injection flow is the main contributor to the magnitude of the core heat flux transient. The borated water supplies negative reactivity to limit the peak return to power associated with the steamline break event. This peak return to power is a critical parameter in the DNBR evaluation. Any additional delay in the safety injection flow would result in a higher peak return to power. As such, reanalysis of the hypothetical break cases is required for the steamline break transient.

A hypothetical steamline break is defined as the double ended rupture of a main steamline. This event is classified as an ANS Condition IV event, a limiting fault. Condition IV occurrences are faults which are not expected to take place, but are postulated because their consequences would include the potential for the release of significant amounts of radioactive material. They are the most drastic which must be designed against and represent limiting design cases. Condition IV faults are not to cause a fission product release to the environment resulting in an undue risk to the public health and safety in excess of guideline values of 10 CFR 100. A single Condition IV fault is not to cause a consequential loss of required functions of systems needed to cope with the fault including those of the Emergency Core Cooling System and Containment.

The purpose of this analysis is to show that the acceptance criteria stated above are met for the hypothetical break cases (Case 3.1, 3.2, and 3.3 of Reference 10) analyzed with the increase in safety injection delay time of 4 seconds to a total delay time of 26 seconds from the time of low pressurizer pressure SI setpoint is reached until the safety injection pumps reach full speed. The acceptance criteria for hypothetical breaks is demonstrated by showing that no DNB occurs. This ensures that there is no damage to the fuel cladding and no release of fission products from the fuel to the RCS.

The cases reanalyzed are:

3.1 Hypothetical break outside the flow restrictor. SIS configuration: 1 train injecting through 1 line.

3.2 Hypothetical break inside the flow restrictor. SIS configuration: 1 train injecting through 1 line into an intact loop.*

3.3 Hypothetical break inside the flow restrictor. SIS configuration: 1 train injecting through 1 line into the faulted loop.*

* The faulted loop is defined as the loop in which the steamline ruptures. The other two loops are referred to as the intact loops.

Transient Description

The steam releases arising from a rupture of a main steamline would result in an initial increase in steam flow from all three steam generators which decreases during the transient as steam pressure decreases. The increase in energy removal from the RCS causes a reduction of coolant temperature. In the presence of a negative moderator temperature coefficient, the cooldown results in an insertion of positive reactivity which may cause a return to power. The decrease in reactor coolant temperature also causes the water in the RCS to shrink which reduces pressurizer level and pressure. The shrink in the RCS inventory may be severe enough to cause the pressurizer to empty and the fluid in the upper head of the reactor vessel to saturate.

In the event that the reactor is at power, a reactor trip would be generated manually or by the reactor protection system from one of the following signals.

1. High nuclear flux
2. Steam and feedwater flow mismatch
3. Safety injection initiation

Following the reactor trip or if the transient is initiated from zero power, there is a possibility that the core will return to power due to the positive reactivity insertion. The return to power is limited by Doppler reactivity feedback and the introduction of borated water from the safety injection system. The core is ultimately shutdown by borated water from the safety injection system and/or from the chemical and volume control system.

Safety injection may be actuated during the transient manually or by a signal generated from low pressurizer pressure or high containment pressure.

Feedwater, which enhances the RCS cooldown, would be isolated manually or by safety injection initiation.

Analysis Methodology

The analysis of the steamline rupture has been performed to determine:

1. The core heat flux and RCS temperature and pressure resulting from the cooldown following the steamline rupture. The LOFTRAN code (Reference 6) was used.

2. The thermal and hydraulic behavior of the core following a steamline rupture. A detailed thermal and hydraulic digital-computer code, THINC, was used to determine if DNB occurs for the conditions computed in item 1.

Assumptions

Studies have been performed to determine the sensitivity of steamline break analysis results to various input assumptions (Reference 11). Based on this study, the following assumptions are used for the analysis of the main steamline rupture for SONGS 1.

1. Initial conditions - The plant is assumed to be operating at hot zero power with RCS pressure equal to nominal RCS pressure (2100 psia), RCS flow rate equal to nominal RCS Thermal Design Flow (195000 gpm), RCS temperature equal to no load Tavg (535 °F) and steam generator pressure equal to the no load pressure. Initial pressurizer water volume is assumed to be 345 ft^3. This corresponds to a pressurizer level of approximately 20%. The effect of assuming a pressurizer level of 20%, compared to plant operation at a level of 25% for no load temperature, is negligible for this analysis. Initial Core boron concentration is assumed to be 0 ppm.

2. Offsite power - Offsite power is assumed to be available throughout the transient. This results in reactor coolant pump (RCP) operation throughout the transient. (Actually, for SONGS 1 the RCPs will trip as a result of the SI signal even with offsite power available.) This enhances the heat transfer between the RCS and the secondary causing a more severe cooldown and return to power. This assumption is shown to be conservative in Reference 3 and in the past SONGS 1 licensing basis steamline break analysis.

3. Shutdown margin - the initial shutdown margin assumed for the analysis is calculated assuming no load, end of life (EOL), equilibrium xenon conditions and the most reactive RCCA stuck in its fully withdrawn position. A value of 1.9% $\Delta k/k$ is assumed. This is the SONGS 1 EOL shutdown margin requirement.

4. Reactivity coefficients - A negative moderator coefficient is assumed corresponding to the end of life rodded core with the most reactive RCCA in its fully withdrawn position. The k_{eff} versus temperature at 1000 psia corresponding to the negative moderator temperature coefficient used is shown in Figure 9. The effect of power generation in the core on overall reactivity is shown in Figure 10.

   For hypothetical breaks inside the flow restrictor, the core properties associated with the sector nearest the faulted steam generator and those associated with the remaining sectors were conservatively combined to obtain average core properties for reactivity feedback calculations. Further, it was conservatively assumed for all of the breaks (credible and hypothetical inside and outside of the flow restrictor) that the core power distribution was uniform. These two conditions cause underprediction of the Doppler reactivity feedback in the high power region near the stuck rod.

   To verify the conservatism of this method, the reactivity as well as the power distribution was checked for the limiting statepoints of the cases analyzed. This core analysis considered the Doppler reactivity from the high fuel temperature near the stuck RCCA, moderator feedback from the high water enthalpy near the stuck RCCA, power redistribution and nonuniform core inlet temperature effects in the case of the hypothetical breaks inside the flow restrictor. For cases in which steam generation occurs in the high flux regions of the core, the effect of void formation was also included. It was determined that the reactivity employed in the kinetics analysis was always larger than the reactivity calculated including the above local effects for the statepoints. These results verify conservatism; i.e., underprediction of negative reactivity feedback from power generation.

5. Feedwater - For hypothetical breaks nominal feedwater flow is assumed at the transient initiation and continues until 26 seconds after the safety injection setpoint is reached. The 26 second delay is a conservatively long time for signal processing, valve realignment, etc. The temperature of the feedwater is assumed to be 72°F.

6. Auxiliary Feedwater - Auxiliary feedwater flow is assumed to start at the transient initiation and continue throughout the transient. A flow rate of 1419 gpm (10% of nominal feedwater flow) is assumed. Flow is divided equally between all three steam generators. The temperature of the auxiliary feedwater is assumed to be 32°F.

7. Safety Injection - Safety injection flow is assumed to start 26 seconds after the low pressurizer pressure SI setpoint is reached. The low pressurizer pressure setpoint assumed in the analysis is 1680 psia. This represents a nominal setpoint of 1750 psia minus uncertainties, instrument errors, etc. The 26 second delay is a conservatively long time for signal processing, valve realignment, etc.

   Flow rates are calculated based on the operation of only one train of safety injection. The failure of the other train is the worst active single failure assumption. Flow rates are calculated based on injection into the RCS via one line. The SI flow rates vs. RCS pressure used in the analysis are shown in Figure 11.

   The temperature of the safety injection water is assumed to be 32°F.

8. Decay Heat - No credit is taken for decay heat since this would inhibit the cooldown of the RCS.

9. Metal Heat - No credit is taken for heat transfer from the thick metal throughout the RCS to the coolant.

10. Accident Simulation - In computing the steam flow during a steamline break or the inadvertent opening of a steam dump valve, the Moody Curve (Reference 12) for f(L/D) = 0 is used.

    The break area assumed for hypothetical breaks outside the flow restrictor is 1.12 ft^2 per loop. This is the area of the steamline flow restrictor. All three steam generators are assumed to blow down to atmospheric pressure through their respective flow restrictors.

    The break areas assumed for hypothetical breaks inside the flow restrictor are 1.842 ft^2 for the faulted loop and 0.56 ft^2 for the intact loops. 1.842 ft^2 is the area of the main steamline and 0.56 ft^2 is one half the area of the steamline flow restrictor. The faulted steam generator is assumed to blow down to atmospheric pressure through the ruptured steamline and the intact steam generators are assumed to blow down through the flow restrictor in the faulted loop.

11. Steam Generator Water Entrainment - Perfect moisture separation in the steam generators is assumed. This assumption leads to conservative results, especially for large breaks, since there would be considerable entrainment of the water in the steam generators following a steamline break. Entrainment of water would reduce the magnitude of the cooldown of the RCS.

Results

The results of the Case 3 LOFTRAN runs are shown in Figures 12-29. The calculated sequences of events for the Case 3 LOFTRAN runs are listed in Tables 5 - 7.

The analysis of the thermal and hydraulic behavior of the core following the steamline break for the above cases determined that no DNB occurs for any of the cases.

Conclusions

The results of the analysis show that the DNBR remained above the limit value for all of the cases analyzed. This ensures that DNB will not occur following the hypothetical cases analyzed. (As shown in Reference 10, the credible break case does not result in a DNBR below the limit value.) Therefore, no releases of fission products from the fuel will result from a hypothetical break with a total safety injection delay time of 26 seconds from the time the low pressurizer pressure SI setpoint is reached until the safety injection pumps reach full speed.

B.5 Conclusions of Non-LOCA Safety Evaluation

The non-LOCA safety evaluation supports SONGS 1 operation with the Reduced Tavg Program with up to 20% tube plugging level in any steam generator. Also, supported in this safety evaluation is the increase in safety injection delay time of 4 seconds. The hypothetical break cases of the steamline break core response transient were reanalyzed to support the increase in safety injection delay time.

The reanalysis of the Locked Rotor/Shaft Break assumed that a reactor trip is actuated by the RCP breaker opening due to either overcurrent (locked rotor) or undercurrent (shaft break) to the RCP motor. The reanalysis was required to address the unavailability of the low coolant flow reactor trip function. A single active failure of a low flow transmitter (one per loop) in the same loop as the locked rotor/shaft break could prevent this trip from occurring.

The reanalysis of the Locked Rotor/Shaft Break showed that rod motion must begin within 6.1 seconds following the locked rotor/shaft break to ensure that the applicable safety criteria are met. It is the responsibility of Southern California Edison to provide the assurance that the reactor trip actuated by the RCP breaker opening due to either overcurrent or undercurrent to the RCP motor releases the rods to fall within 6.1 seconds following the locked rotor/shaft break. Also, it is the responsibility of SCE to incorporate the RCP breaker opening reactor trips due to overcurrent and undercurrent to the RCP motor into SONGS 1 Technical Specifications.

B.6 References

1. Updated Final Safety Analysis Report (UFSAR) for San Onofre 1.

2. Skaritka, J. (Ed.), "Evaluation of the San Onofre Unit 1 Cycle 9 Extended Operation," November 1988.

3. Skaritka, J. (Ed.), "Reload Safety Evaluation San Onofre Nuclear Generating Station Unit 1, Cycle 8," January 1980.

   Skaritka, J. (Ed.), "Reload Safety Evaluation San Onofre Nuclear Generating Station Unit 1, Cycle 8, Revision 1," October 1980.

   Skaritka, J. (Ed.), "Reload Safety Evaluation San Onofre Nuclear Generating Station Unit 1, Cycle 8, Revision 2," April 1981.

4. "SCE SONGS Unit 1 Third Auxiliary Feedwater Pump Reanalysis," SCE-87-612, Letter from L. E. Elder (W) to J. L. Rainsberry (SCE), August 7, 1987.

   "San Onofre Unit 1 LONF/FLB Reanalysis," SCE-86-540, Letter from L. E. Elder (W) to J. L. Rainsberry (SCE), April 8, 1986.

5. Rinkacs, W. J., "SCE SONGS Unit 1 Steamline Break Outside Containment Mass/Energy Release Analysis," WCAP-11294, (Westinghouse Proprietary Class 2), September 1986.

6. Burnett, T. W. T., et al., "LOFTRAN Code Description," WCAP-7907-A, April 1984.

7. Hargrove, H. B., "FACTRAN, a FORTRAN IV Code for Thermal Transients in a UO_2 Fuel Rod," WCAP-7908, June 1972.

8. Chelemer, H., Weisman, J., and Tong, L. S., "THINC - Subchannel Thermal Analysis of Rod Bundle Core," WCAP-7015, June 1967.

9. NUREG-0800 Revision 1, "Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants - LWR Edition," July 1981.

10. "Southern California Edison (SCE) San Onofre Unit 1 Steamline Break Analysis," SCE-88-712, Letter from L. E. Elder (W) to J. T. Reilly (SCE), July 15, 1988.

11. Hollingsworth, S. D. and Wood, D. C., "Reactor Core Response To Excessive Secondary Steam Releases," WCAP-9227, January 1978.

12. Moody, F. S., "Transactions of the ASME, Journal of Heat Transfer," Figure 3, page 134, February 1965.

TABLE 1

SONGS 1 NON-LOCA TRANSIENTS

Transient
Uncontrolled RCCA Bank Withdrawal From a Subcritical Condition
Uncontrolled RCCA Bank Withdrawal at Power
Startup of an Inactive Loop
Addition of Excess Feedwater
Large Load Increase
Dropped Rod
Control Rod Ejection
Loss of Coolant Flow
Steam Line Break Core Response
Loss of Load
Loss of Normal Feedwater
Feedline Break
Locked Rotor/Pump Shaft Break
Steam Line Break Mass/Energy Release Outside Containment
Steam Line Break Mass/Energy Release Inside Containment

TABLE 2
SAN ONOFRE UNIT 1

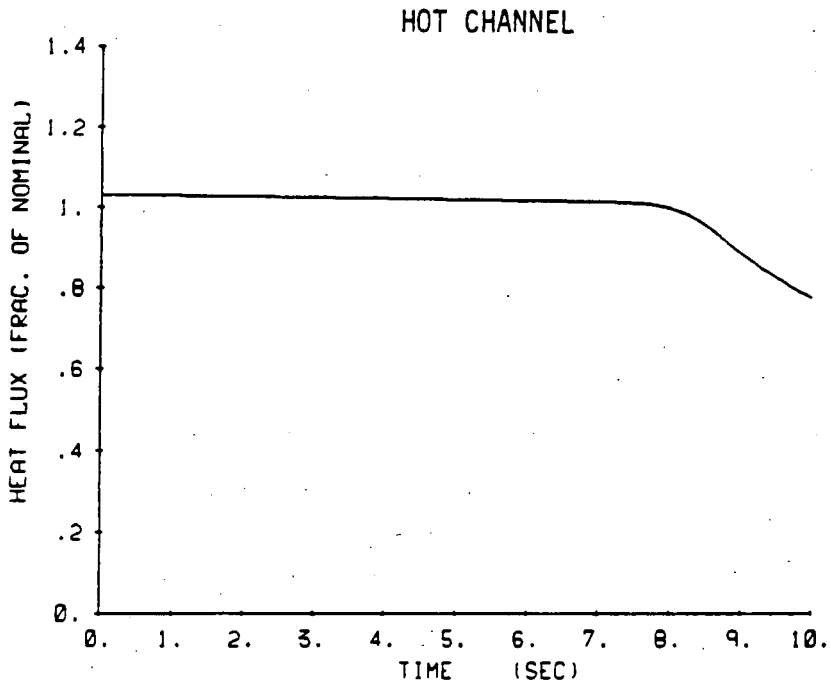
VARIABLE LOW PRESSURE REACTOR TRIP EQUATIONS
USED IN SAFETY ANALYSES

Safety Analysis Equation:

$$26.15(0.894\ \Delta T + Tavg) - 14555$$

Existing Tech Spec Equation:

$$26.15(0.894\ \Delta T + Tavg) - 14341$$



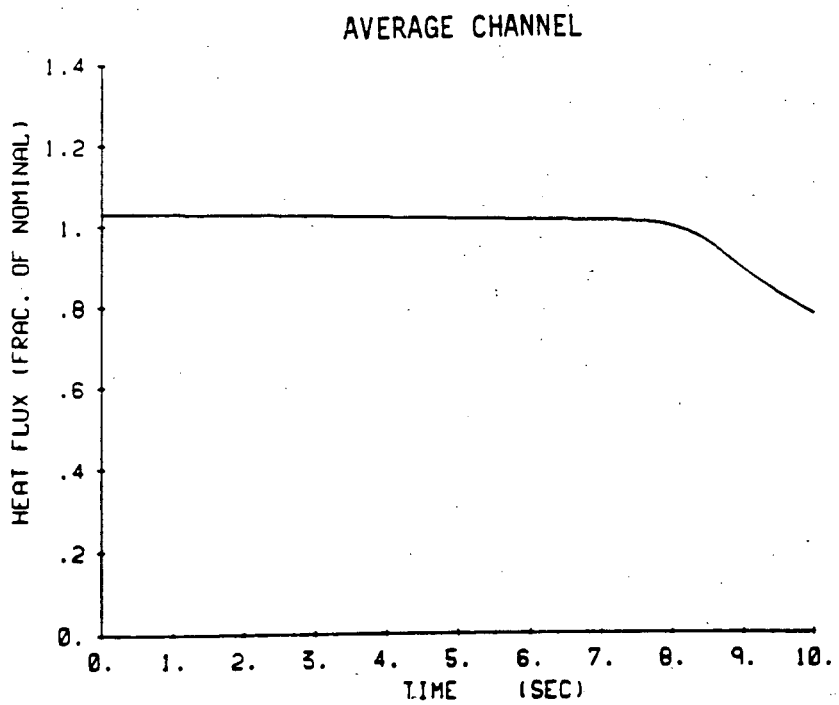
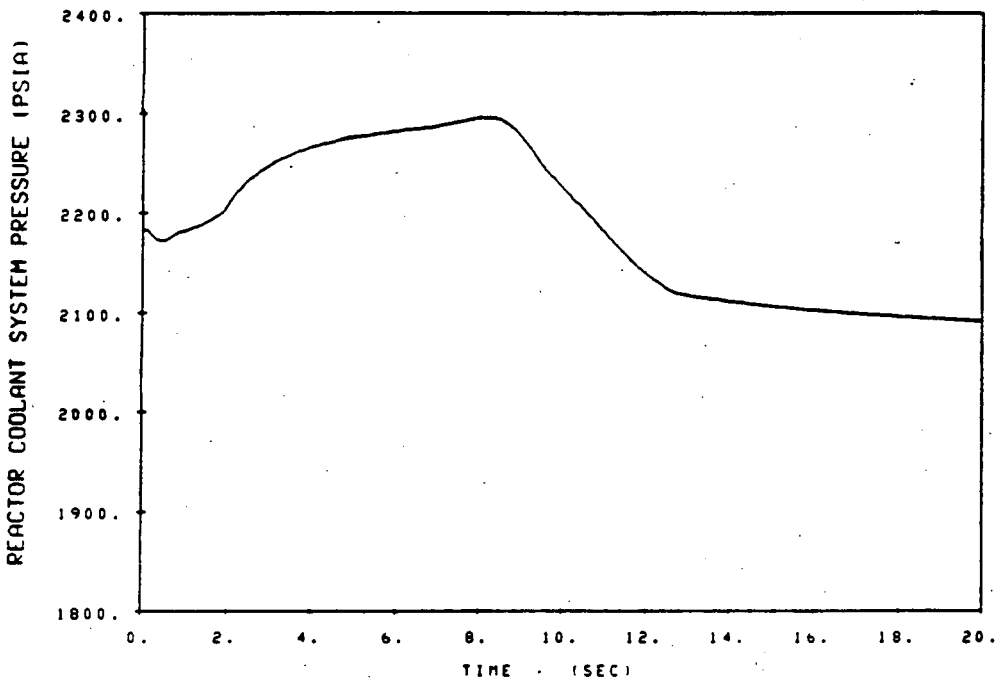


FIGURE 8 San Onofre Unit 1, One Pump Shaft Seizure/Break
Hot Channel Heat Flux and Average Channel Heat Flux vs. Time
Reduced Tavg Program Analysis



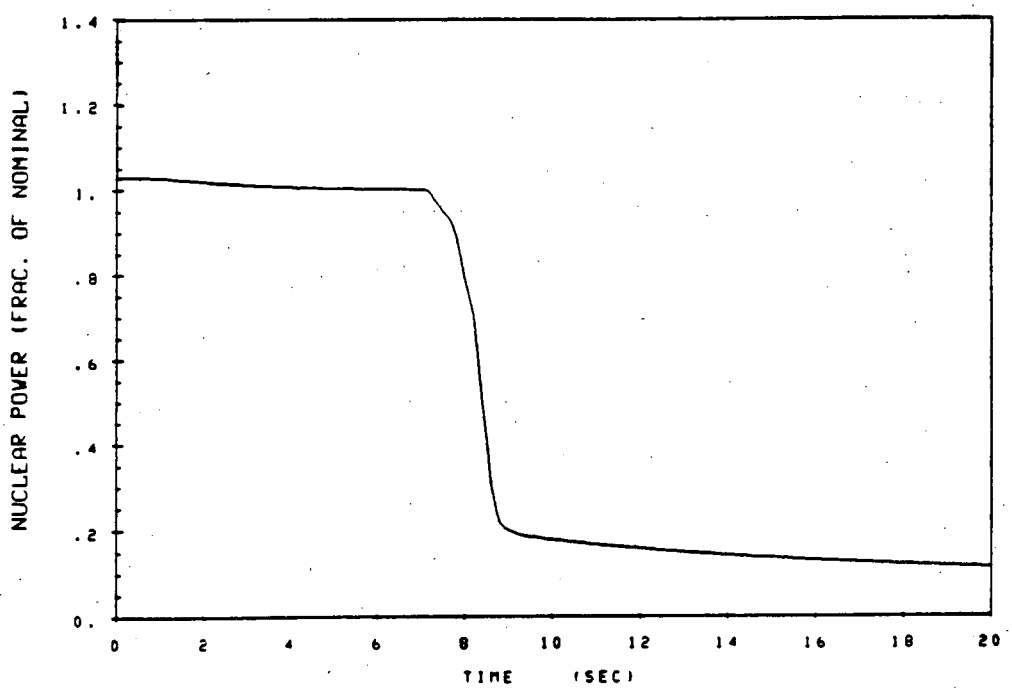
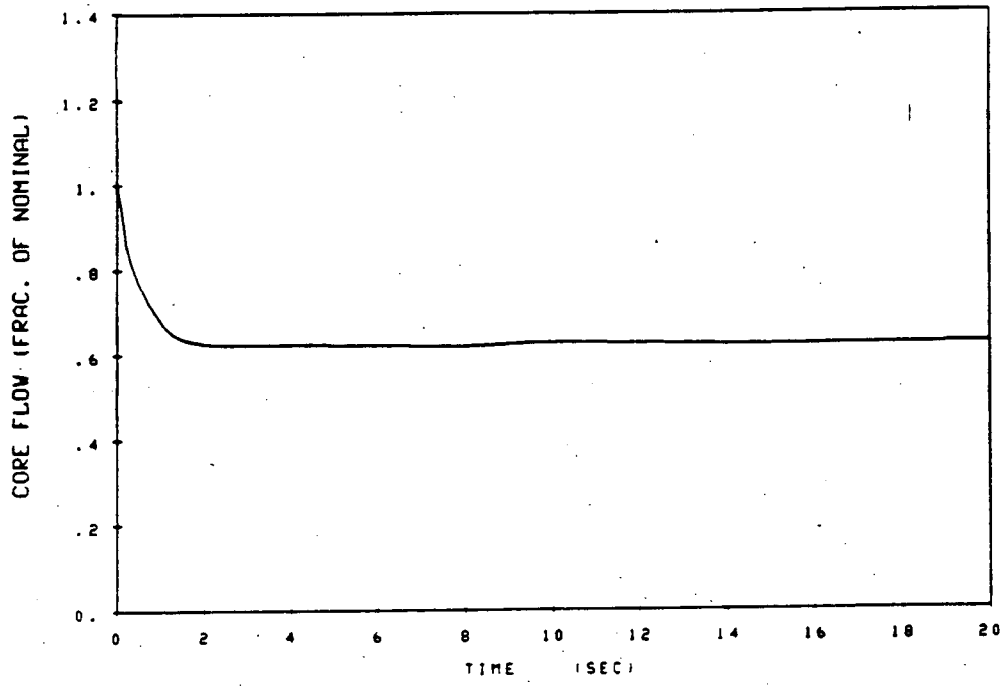


FIGURE 7 San Onofre Unit 1, One Pump Shaft Seizure/Break
RCS Pressure and Nuclear Power vs. Time
Reduced Tavg Program Analysis



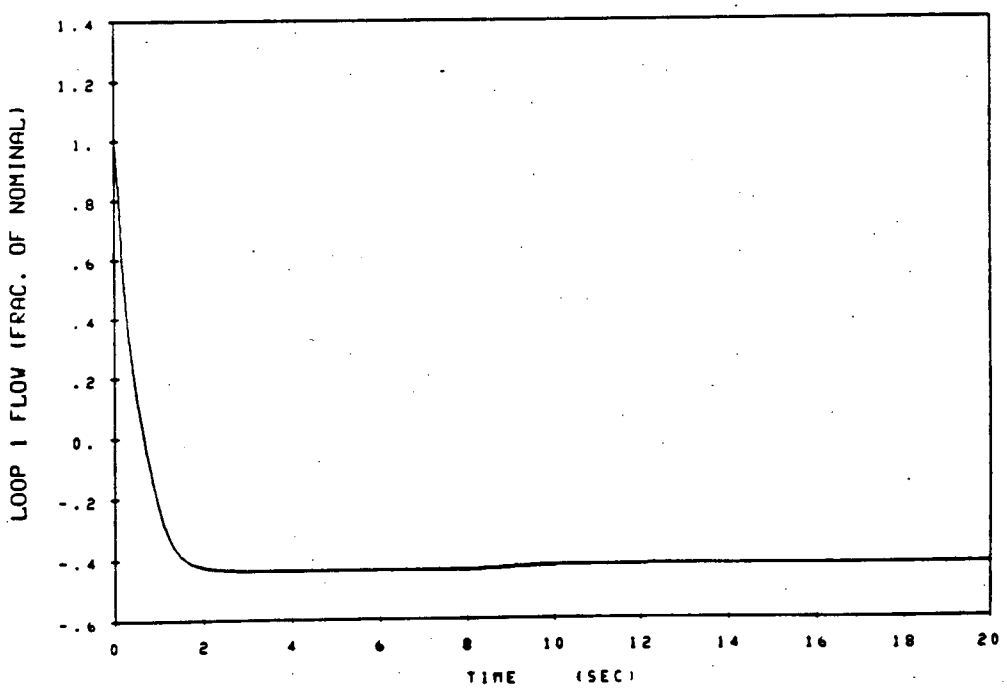
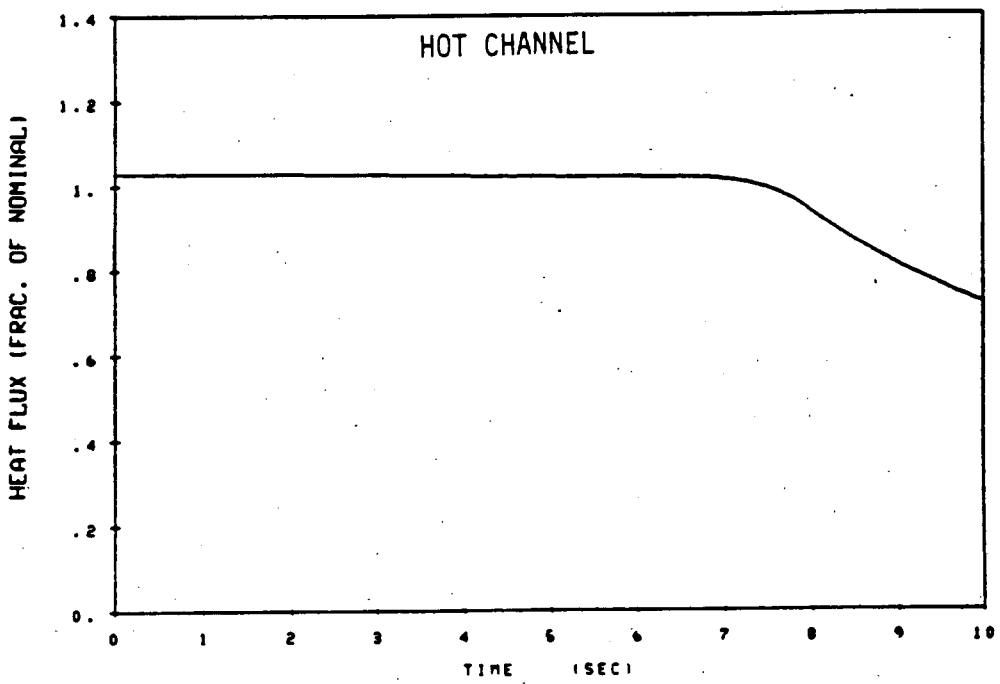


FIGURE 6 San Onofre Unit 1, One Pump Shaft Seizure/Break
Core and Faulted Loop Flow vs. Time
Reduced Tavg Program Analysis



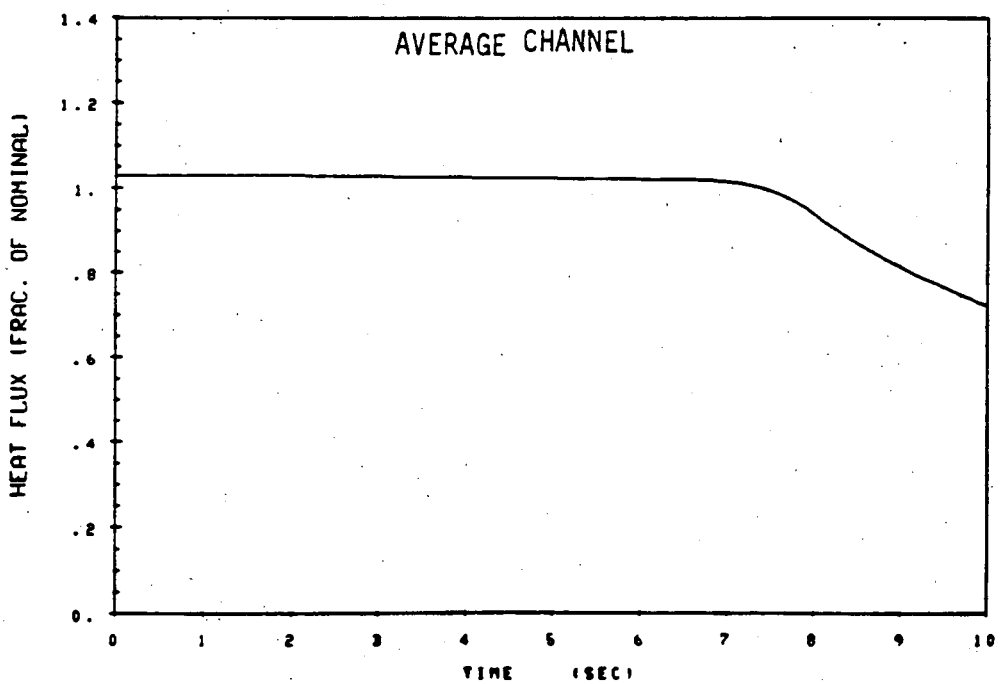


FIGURE 5 San Onofre Unit 1, One Pump Shaft Seizure/Break
Hot Channel Heat Flux and Average Channel Heat Flux vs. Time
Nominal Tavg Program Analysis

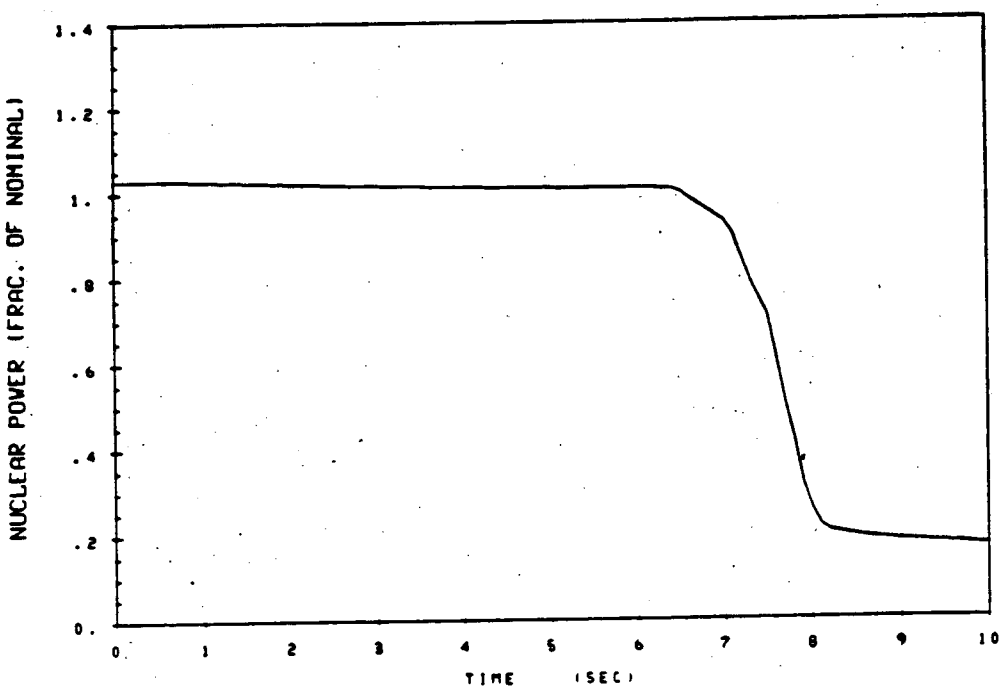
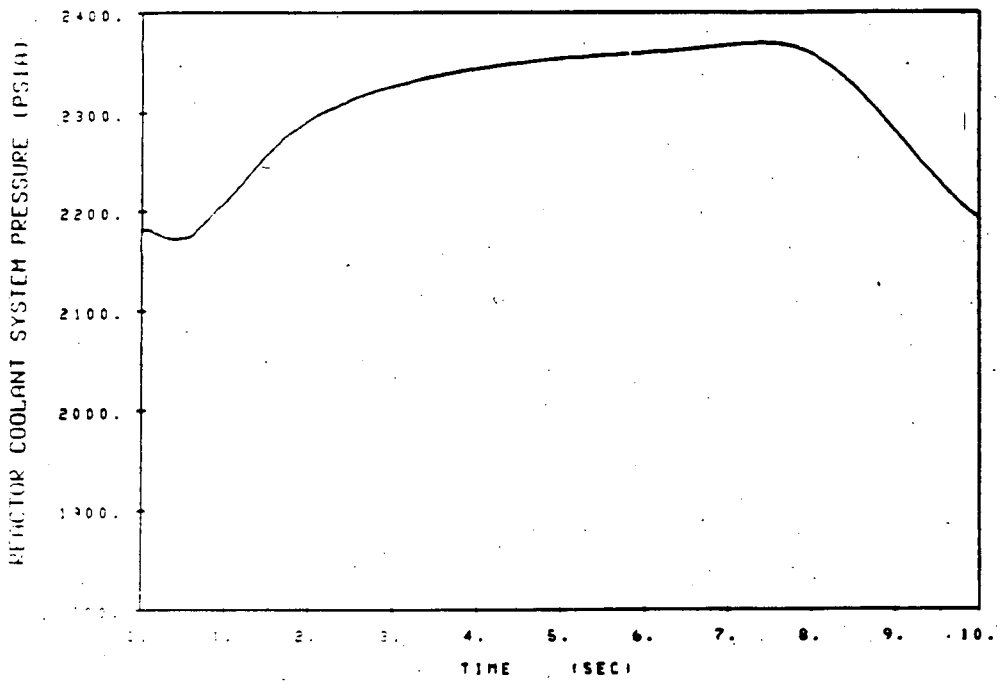


FIGURE 4 San Onofre Unit 1, One Pump Shaft Seizure/Break
Nuclear Power vs. Time
Nominal Tavg Program Analysis



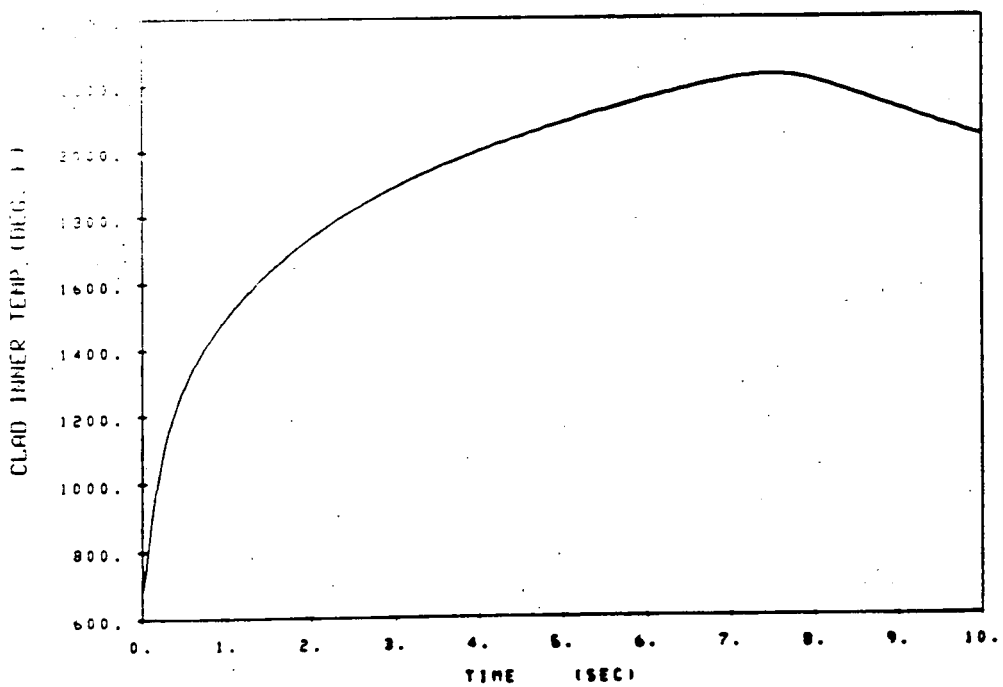
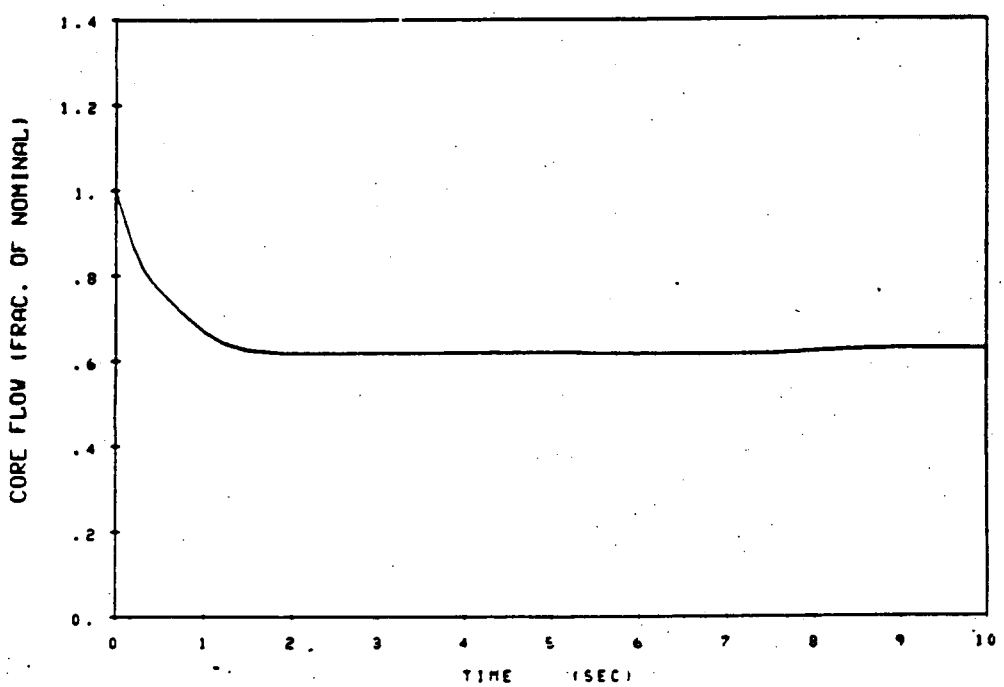


FIGURE 3 San Onofre Unit 1, One Pump Shaft Seizure/Break
RCS Pressure and Clad Temperature at Hot Spot vs. Time
Nominal Tavg Program Analysis



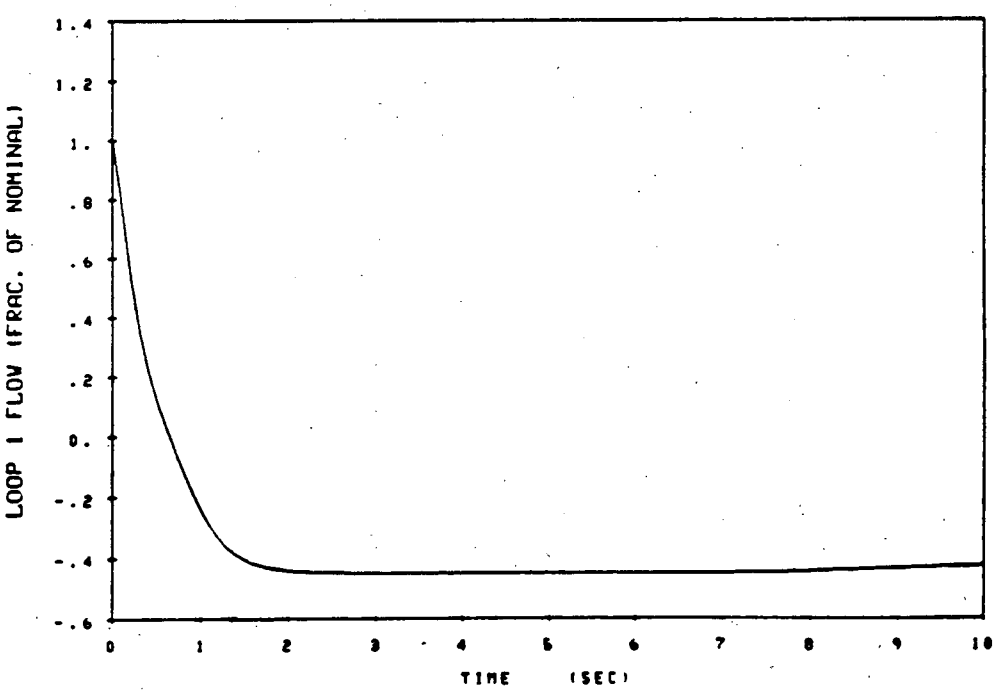


FIGURE 2 San Onofre Unit 1, One Pump Shaft Seizure/Break
Core and Faulted Loop Flow vs. Time
Nominal Tavg Program Analysis

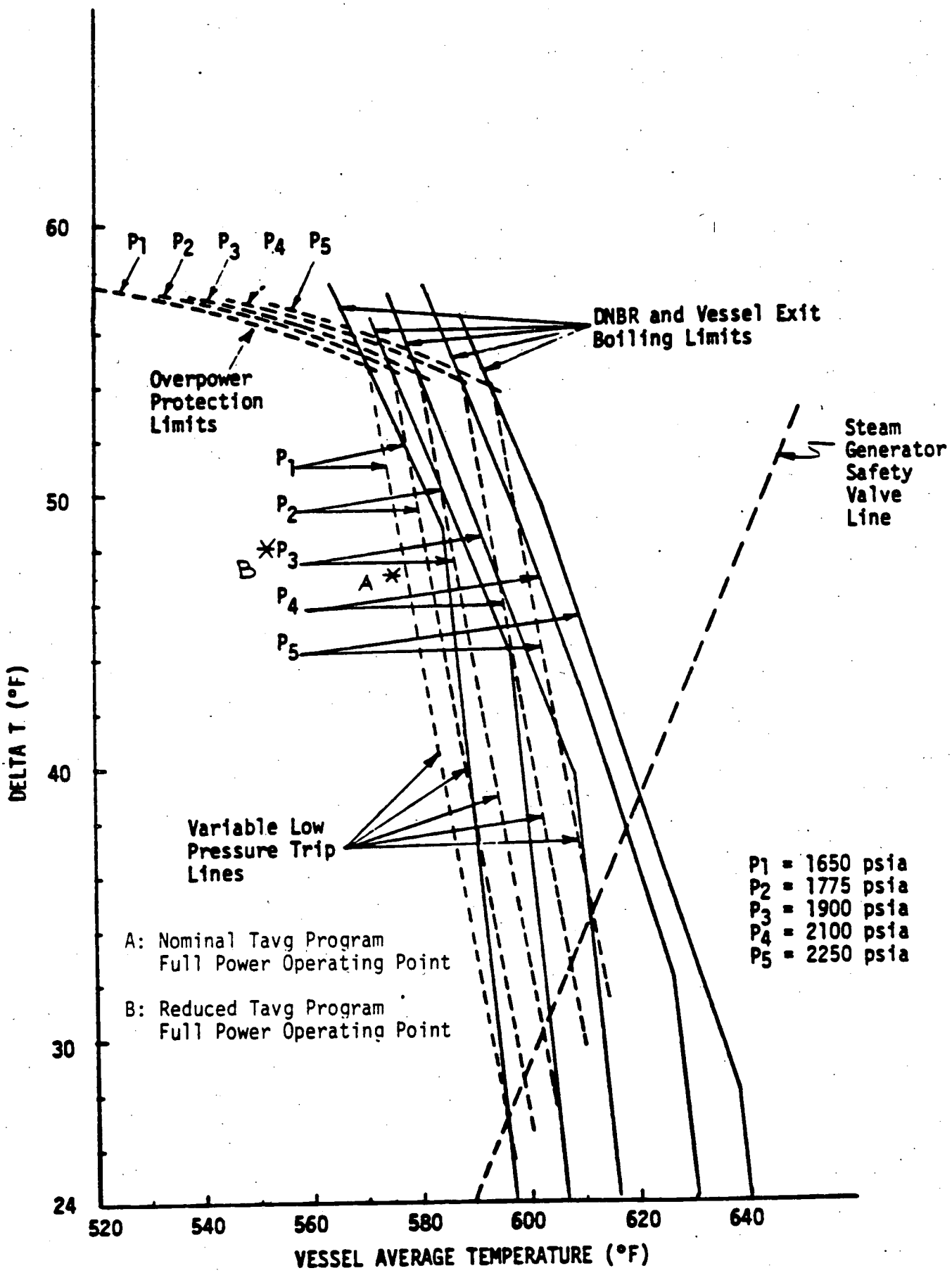


FIGURE 1 OVERPOWER AND OVERTEMPERATURE PROTECTION DIAGRAM

EXISTING VARIABLE LOW PRESSURE REACTOR TRIP FUNCTION

TABLE 7

TIME SEQUENCE OF EVENTS

CASE 3.3

Hypothetical Break Inside The Flow Restrictor

SIS Configuration: 1 train injecting through 1 line into the faulted loop *

Event	Time, sec
Steam line ruptures inside the flow restrictor (double ended)	0.
AFW flow to all 3 Steam Generators starts	0.
Low pressurizer pressure SI setpoint is reached	19.
Pressurizer empties	20.
Shutdown margin is lost (reactor is critical)	21.
Fluid in the upper head saturates	26.
Main Feedwater flow to all three Steam Generators stops	45.
SI flow to the RCS starts	45.
Borated SI water reaches the core	46.
Pressurizer starts to refill	48.
Peak power level (57% of nominal) is reached	56.

* The faulted loop is defined as the loop in which the steamline ruptures. The other two loops are referred to as intact loops.

TABLE 6

TIME SEQUENCE OF EVENTS

CASE 3.2

Hypothetical Break Inside The Flow Restrictor

SIS Configuration: 1 train injecting through 1 line into an intact loop *

Event	Time, sec
Steam line ruptures inside the flow restrictor (double ended)	0.
AFW flow to all 3 Steam Generators starts	0.
Low pressurizer pressure SI setpoint is reached	19.
Pressurizer empties	20.
Shutdown margin is lost (reactor is critical)	21.
Fluid in the upper head saturates	26.
Main Feedwater flow to all three Steam Generators stops	45.
SI flow to the RCS starts	45.
Borated SI water reaches the core	46.
Pressurizer starts to refill	48.
Peak power level (60% of nominal) is reached	58.

* The faulted loop is defined as the loop in which the steamline ruptures. The other two loops are referred to as intact loops.

TABLE 5

TIME SEQUENCE OF EVENTS

CASE 3.1

Hypothetical Break Outside The Flow Restrictor

SIS Configuration: 1 train injecting through 1 line

Event	Time, sec
Steam line ruptures outside the flow restrictor (double ended)	0.
AFW flow to all 3 Steam Generators starts	0.
Low pressurizer pressure SI setpoint is reached	17.
Pressurizer empties	18.
Shutdown margin is lost (reactor is critical)	21.
Fluid in the upper head saturates	24.
Main Feedwater flow to all three Steam Generators stops	43.
SI flow to the RCS starts	43.
Borated SI water reaches the core	44.
Pressurizer starts to refill	46.
Peak power level (64% of nominal) is reached	62.

TABLE 4

TIME SEQUENCE OF EVENTS FOR REACTOR COOLANT PUMP SHAFT SEIZURE/BREAK TRANSIENT

Reduced Tavg Program Analysis

Event	Time (sec)
Rotor in one pump locks/breaks	0.0
Rods begin to drop	6.8
Maximum RCS pressure occurs	8.2

TABLE 3

TIME SEQUENCE OF EVENTS FOR REACTOR COOLANT PUMP SHAFT SEIZURE/BREAK TRANSIENT

Nominal Tavg Program Analysis

Event	Time (sec)
Rotor in one pump locks/breaks	0.0
Rods begin to drop	6.1
Maximum RCS pressure occurs	7.4
Maximum clad temperature occurs	7.5

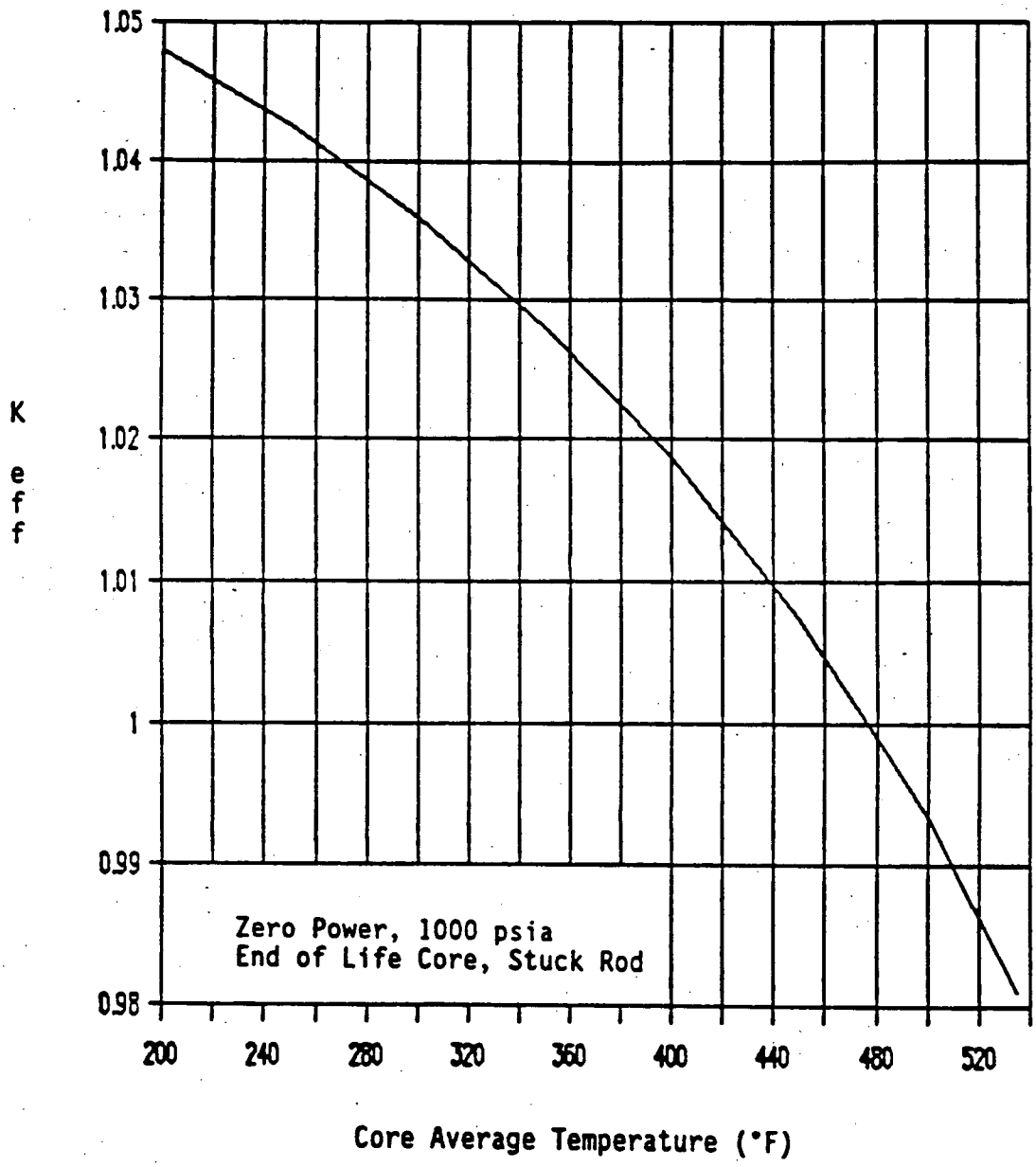


FIGURE 9 k_{eff} vs Temperature

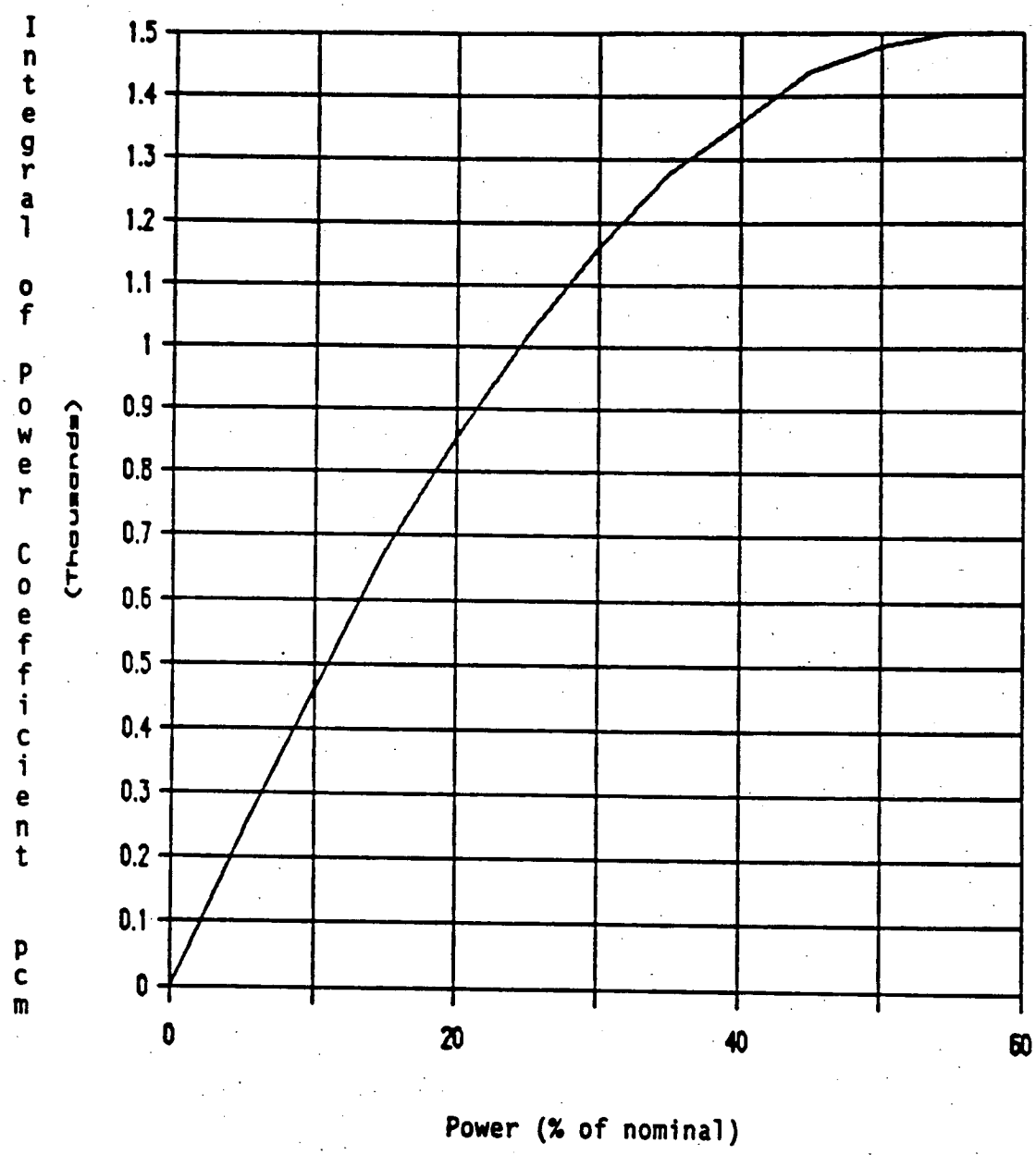


FIGURE 10 **Doppler Power Defect vs Reactor Power**

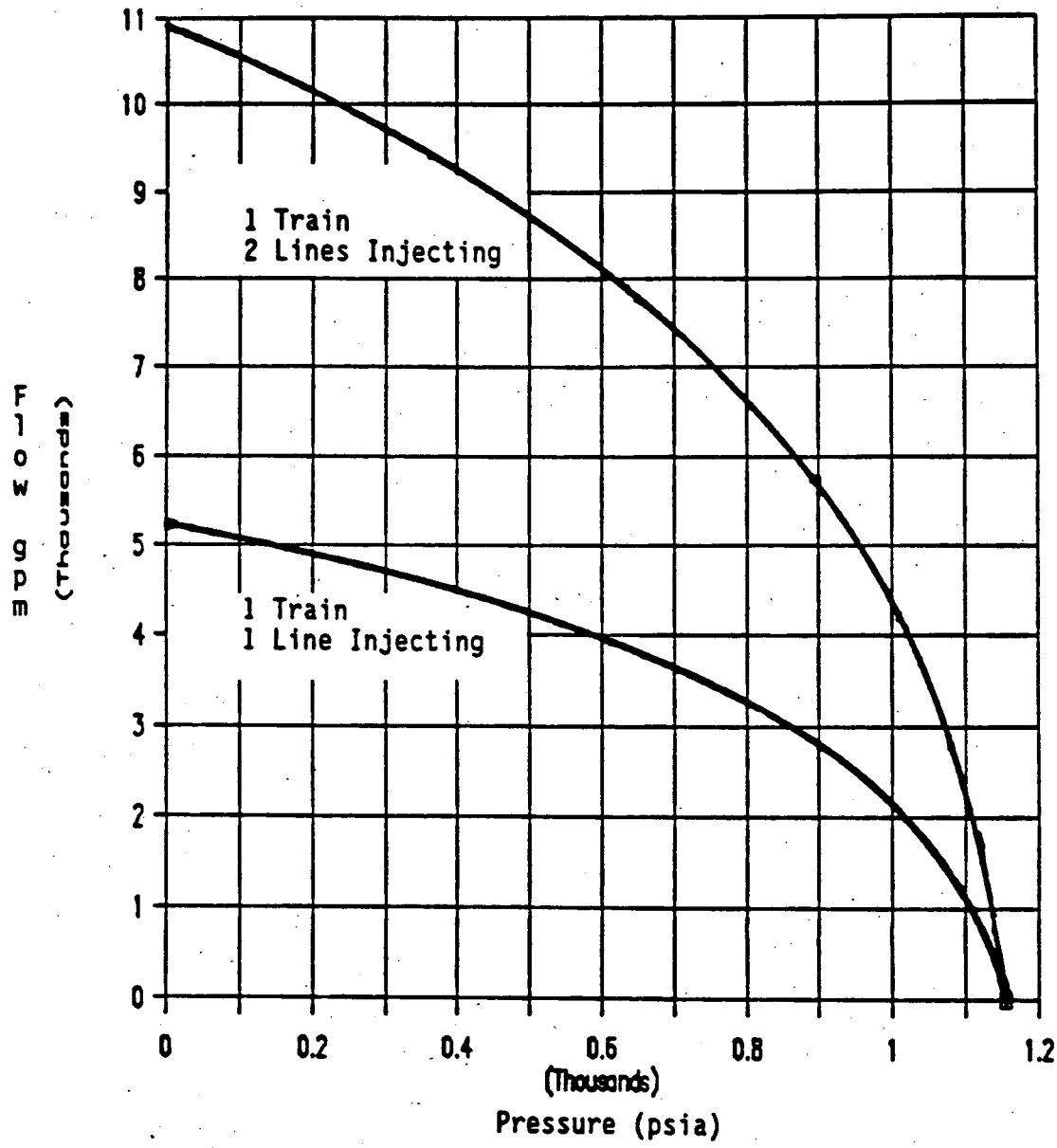
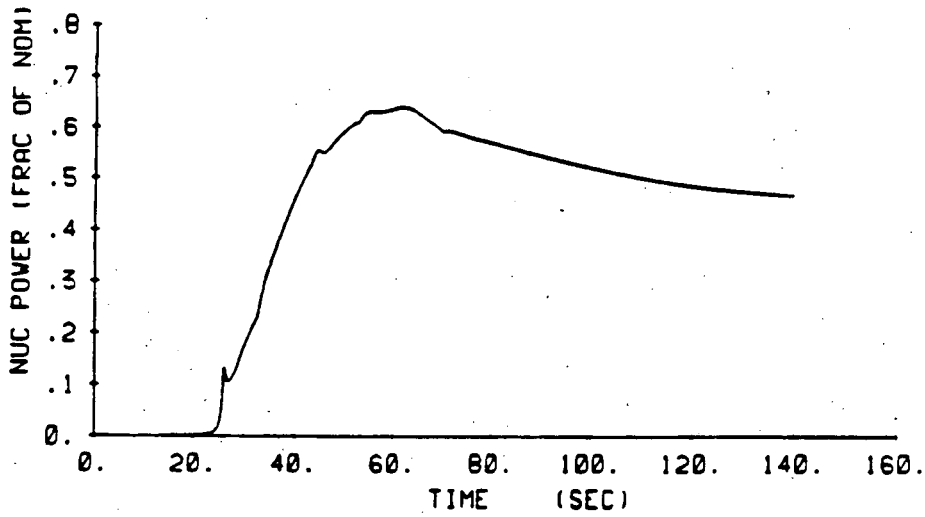


FIGURE 11 **Safety Injection Flow vs RCS Pressure**



Nuclear Power

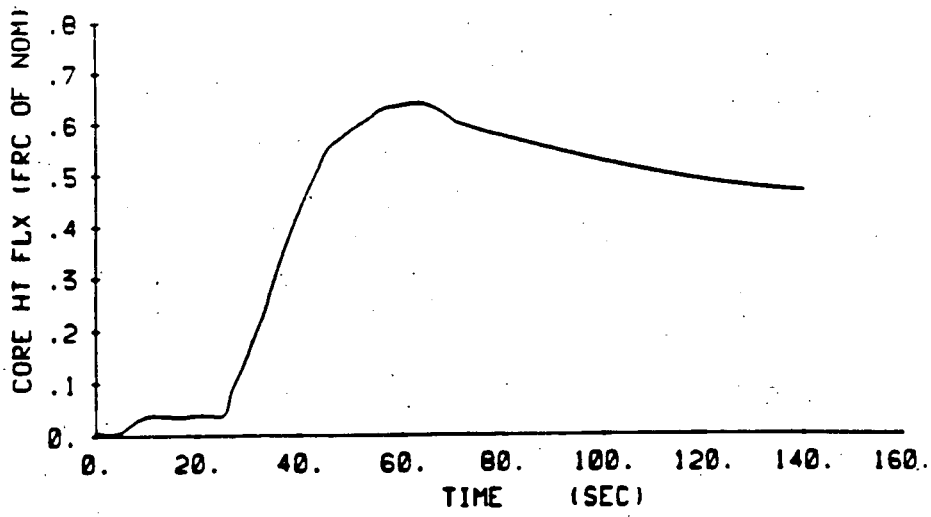
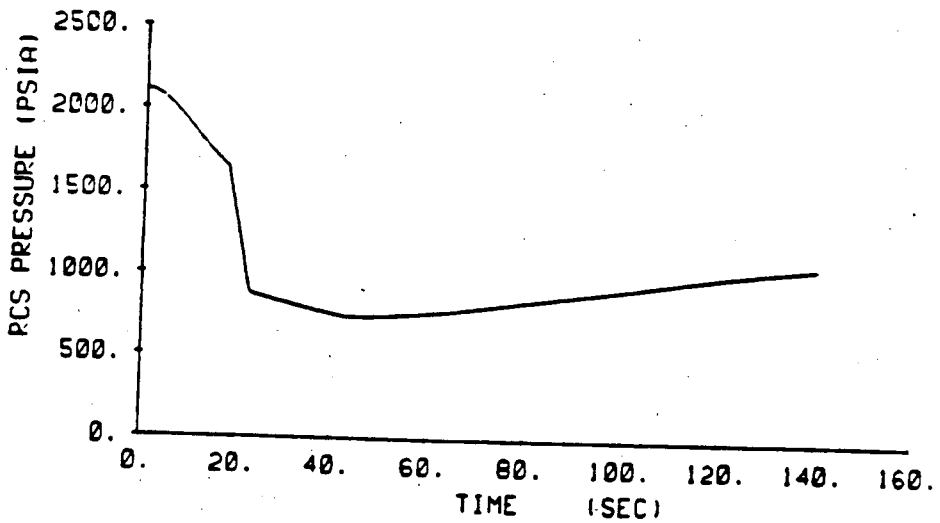


FIGURE 12 **Core Heat Flux**



RCS Pressure

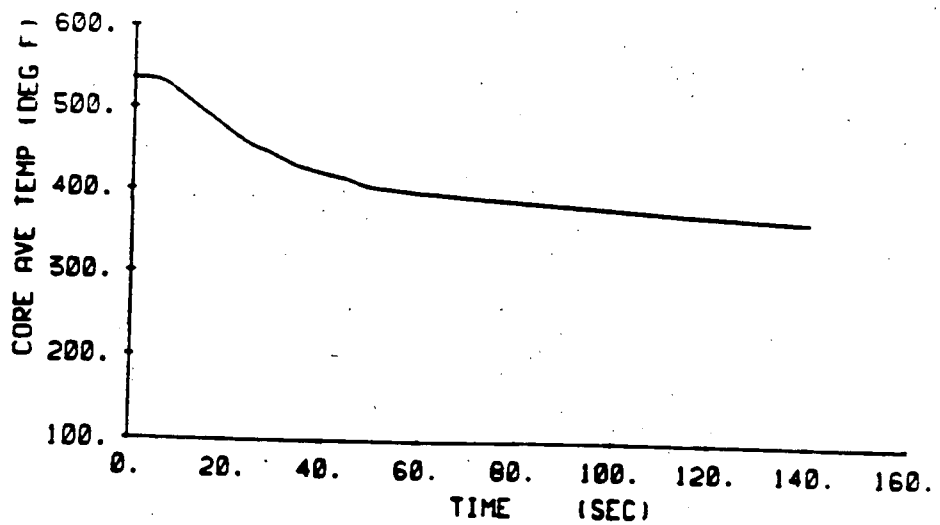
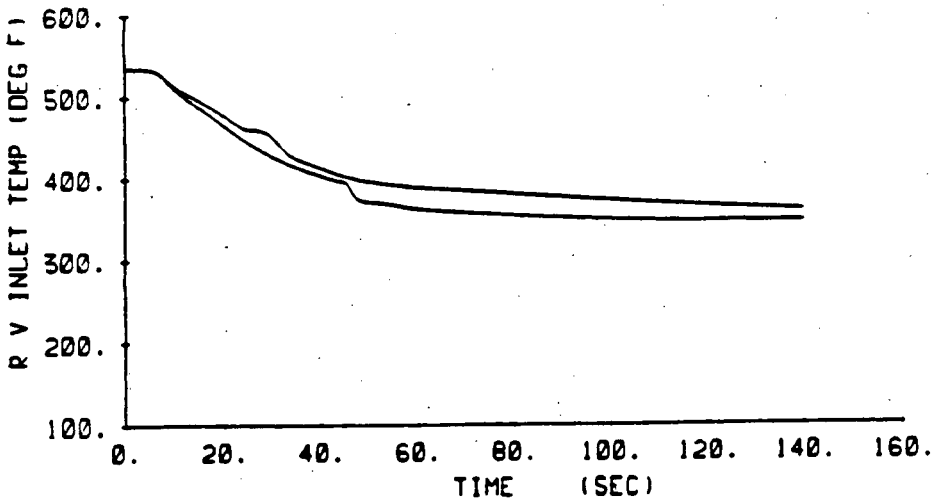


FIGURE 13 **Core Average Temperature**

CASE 3.1



Reactor Vessel Inlet Temperatures

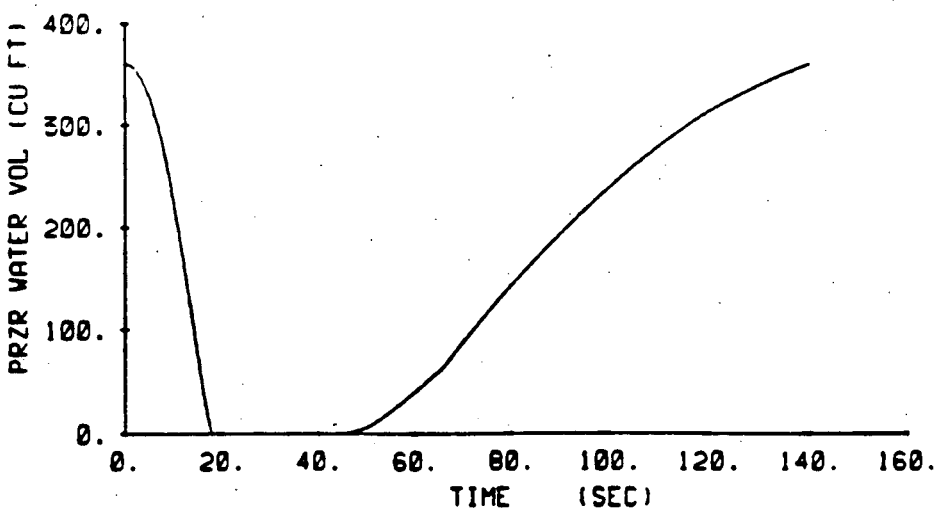
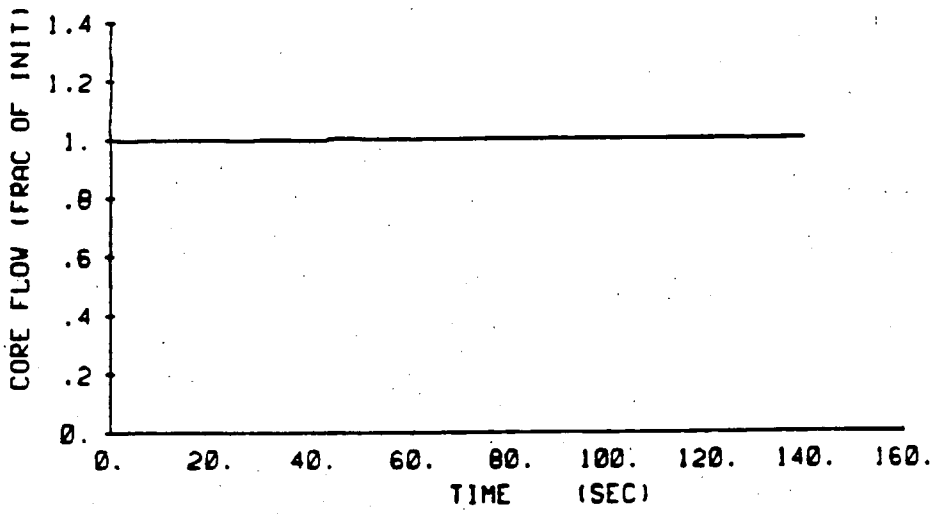


FIGURE 14 **Pressurizer Water Volume**

CASE 3.1



Core Flow

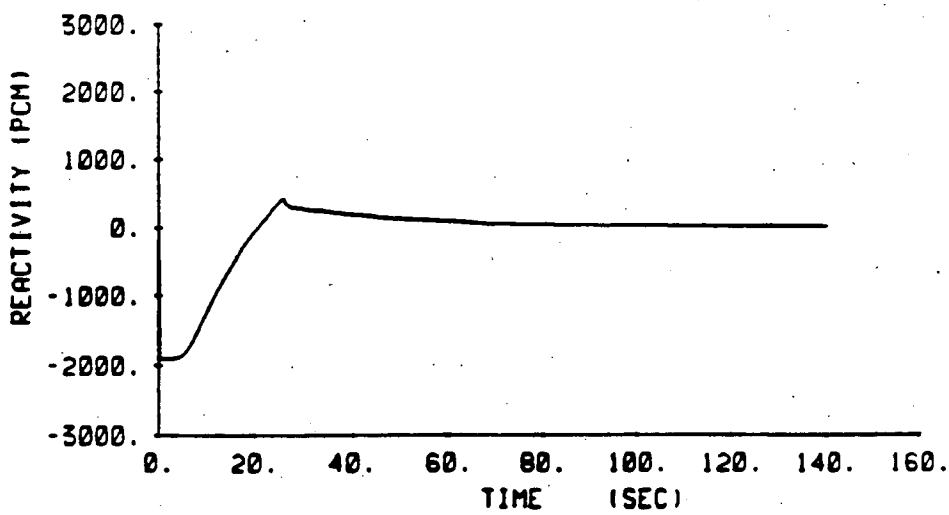
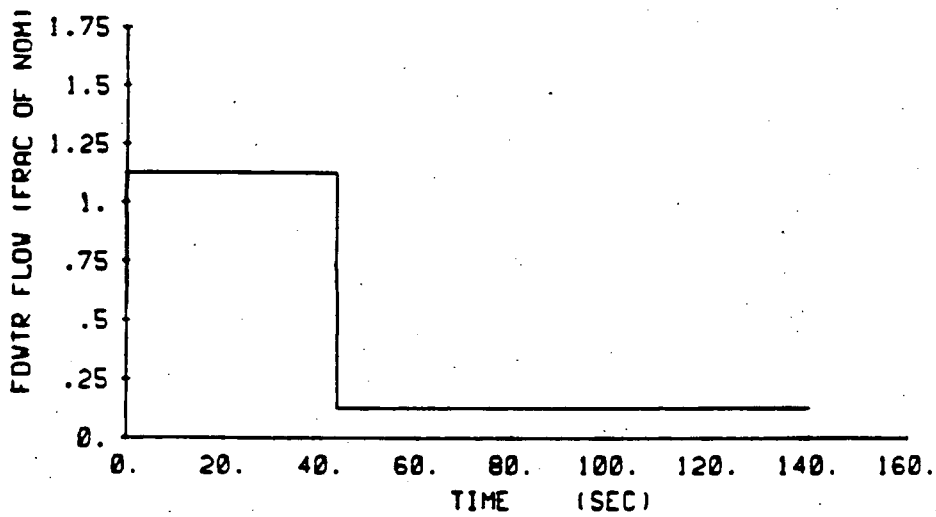


FIGURE 15 **Reactivity**



Feedwater Flow

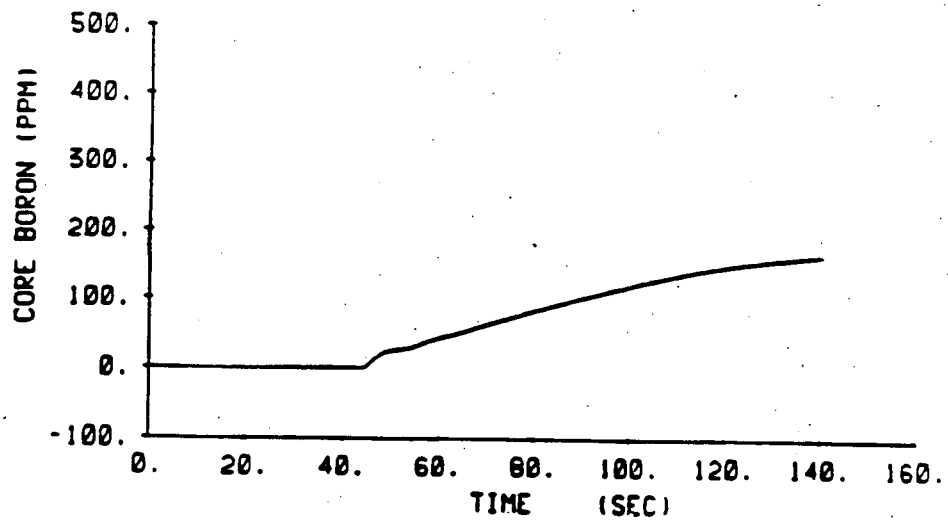
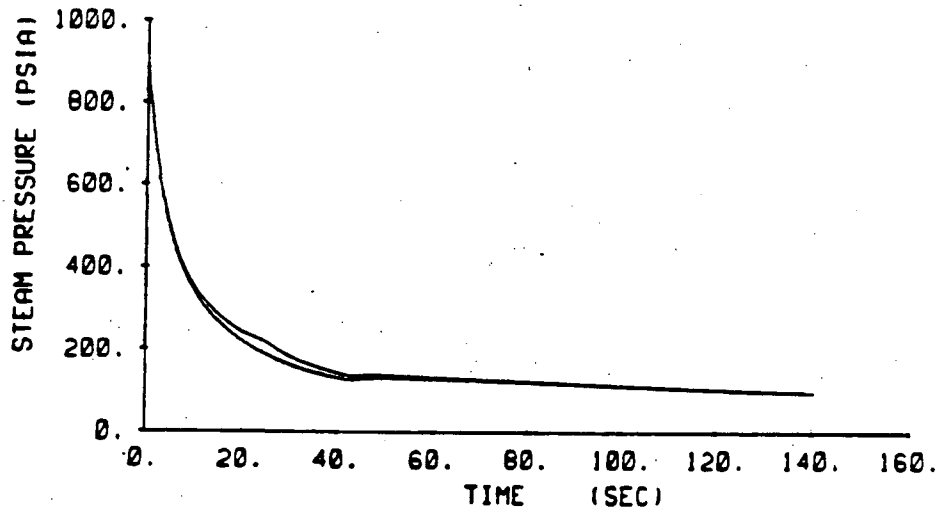


FIGURE 16 **Core Boron**

CASE 3.1



Steam Pressure

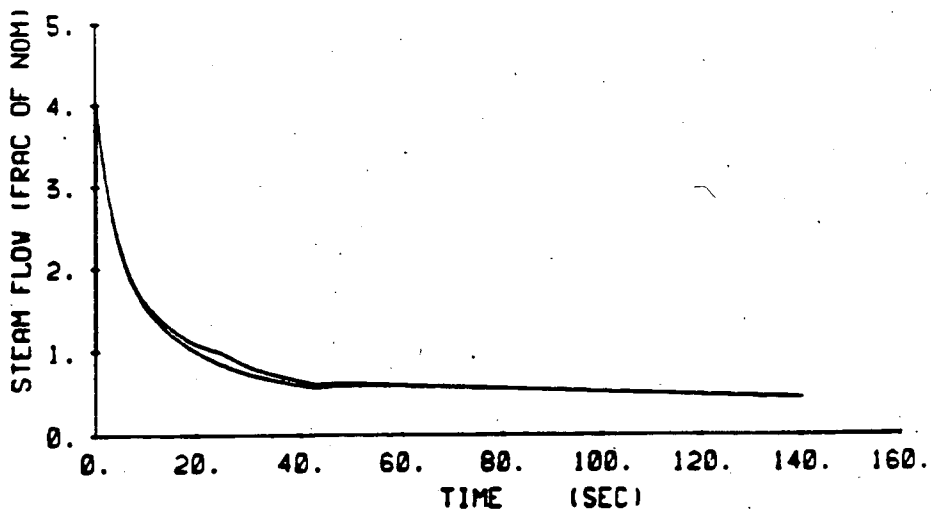
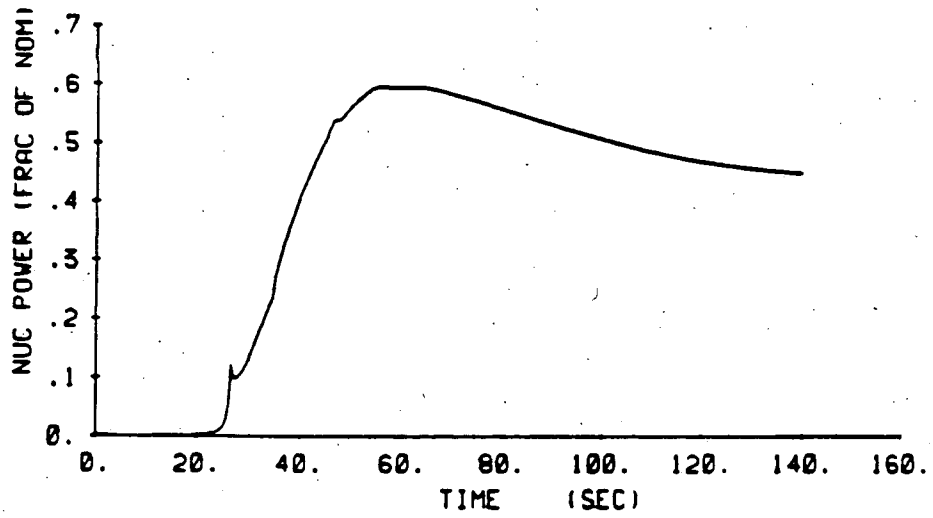


FIGURE 17 Steam Flow

CASE 3.2



Nuclear Power

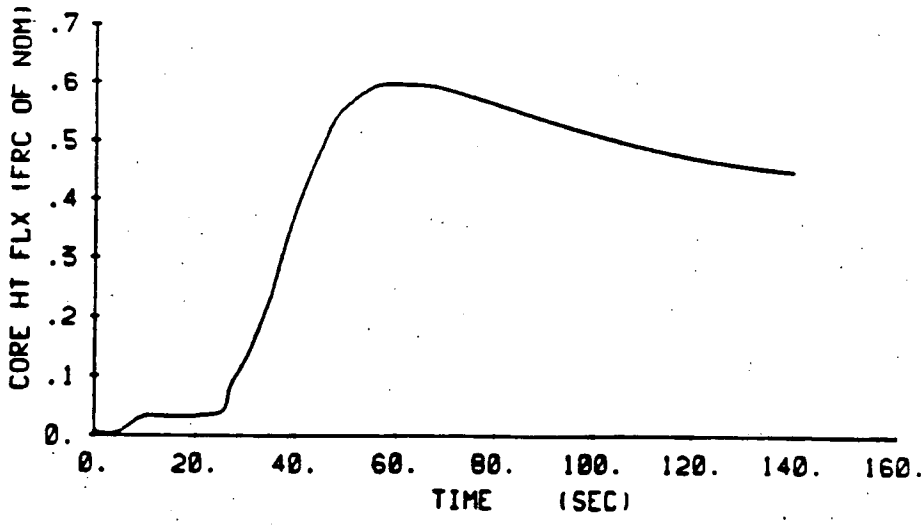
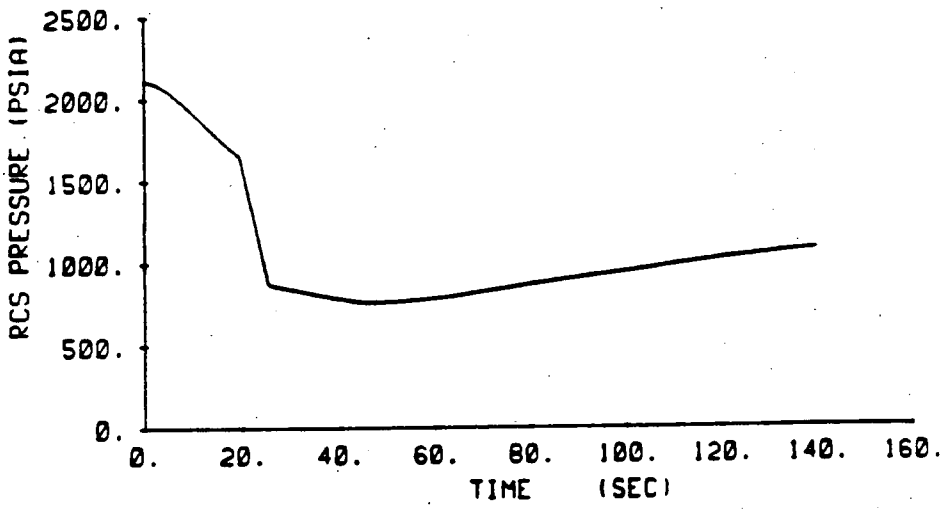


FIGURE 18 **Core Heat Flux**

CASE 3.2



RCS Pressure

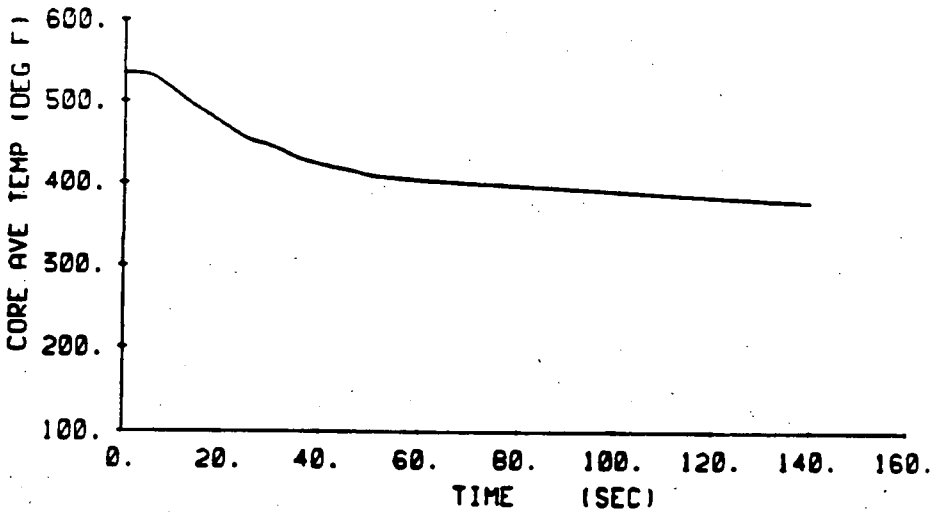
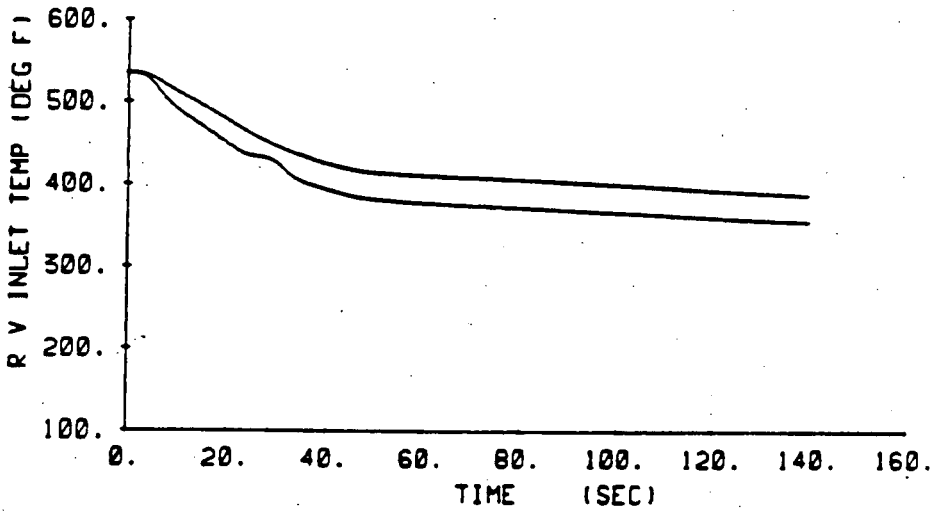


FIGURE 19 **Core Average Temperature**

CASE 3.2



Reactor Vessel Inlet Temperatures

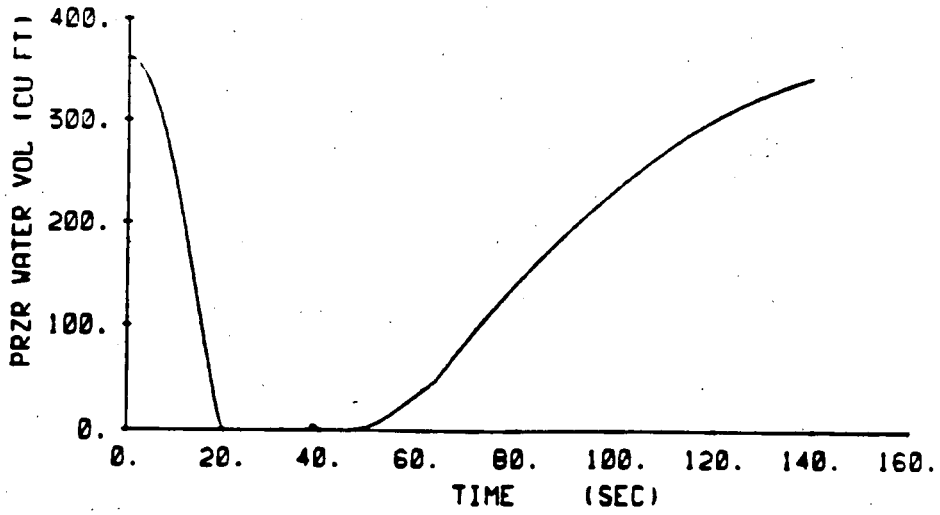
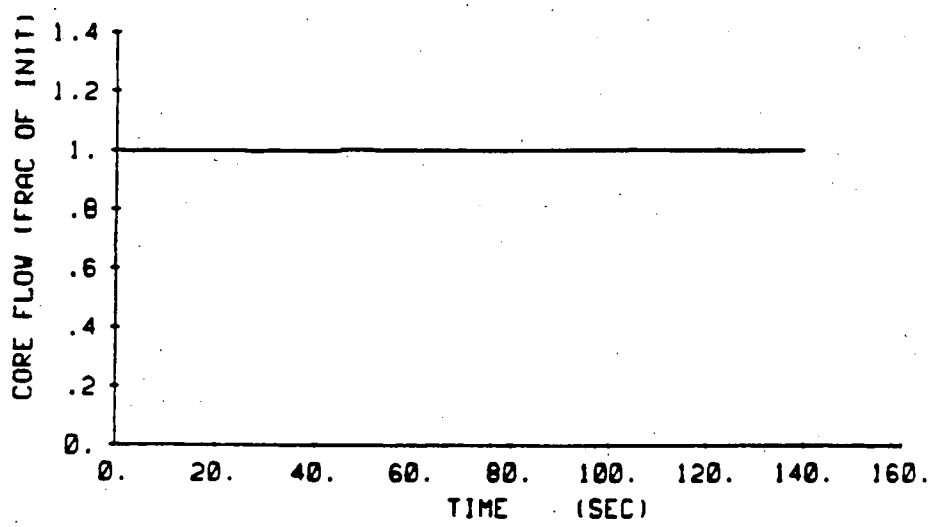


FIGURE 20 **Pressurizer Water Volume**

CASE 3.2



Core Flow

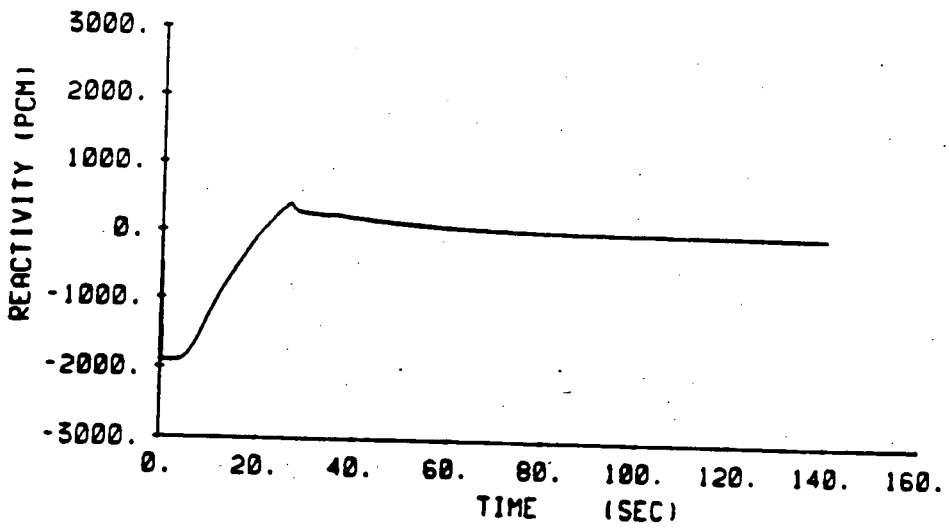
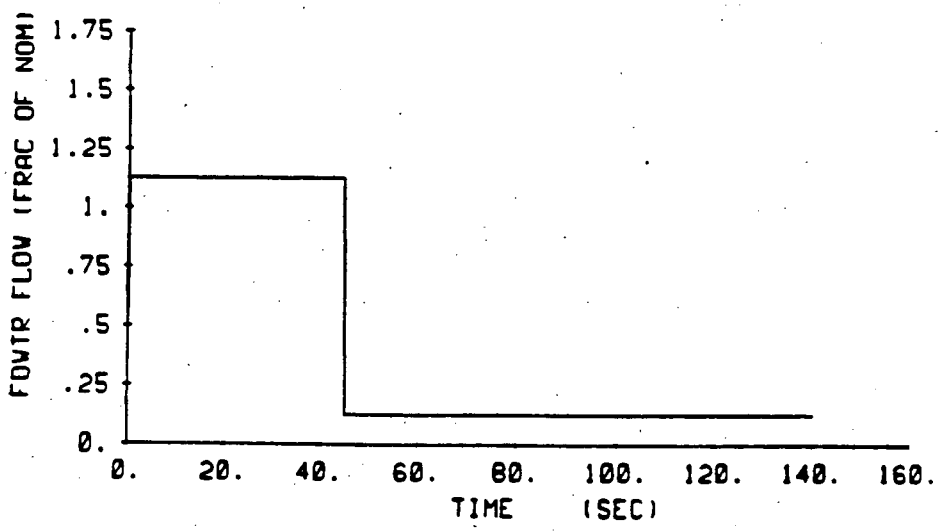


FIGURE 21 **Reactivity**

CASE 3.2



Feedwater Flow

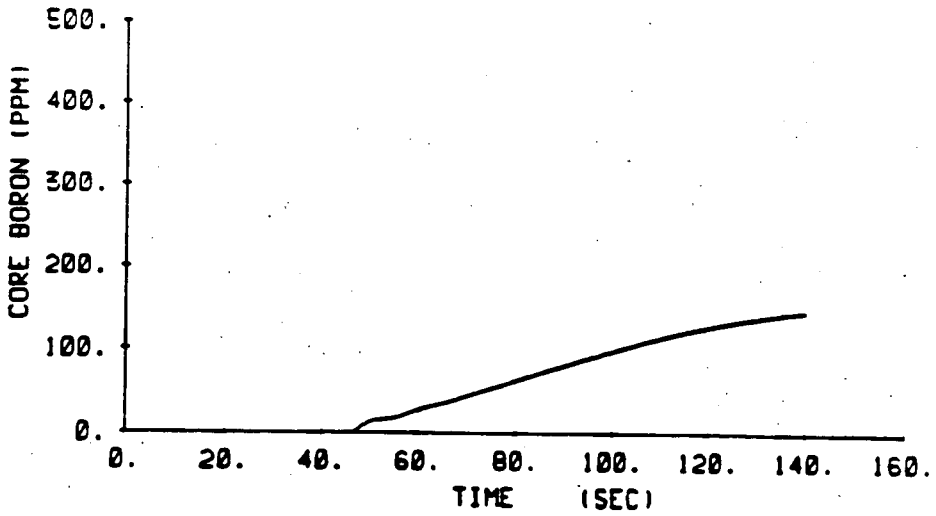
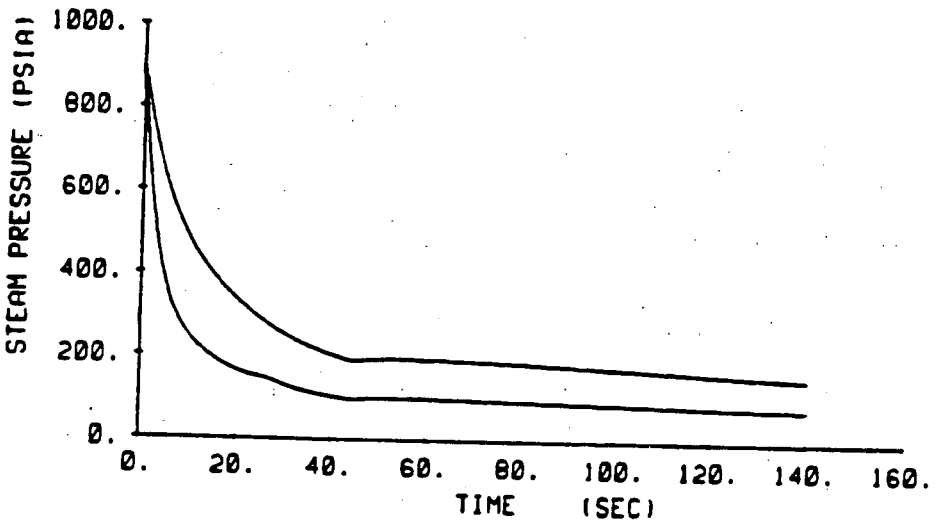


FIGURE 22 **Core Boron**

CASE 3.2



Steam Pressure

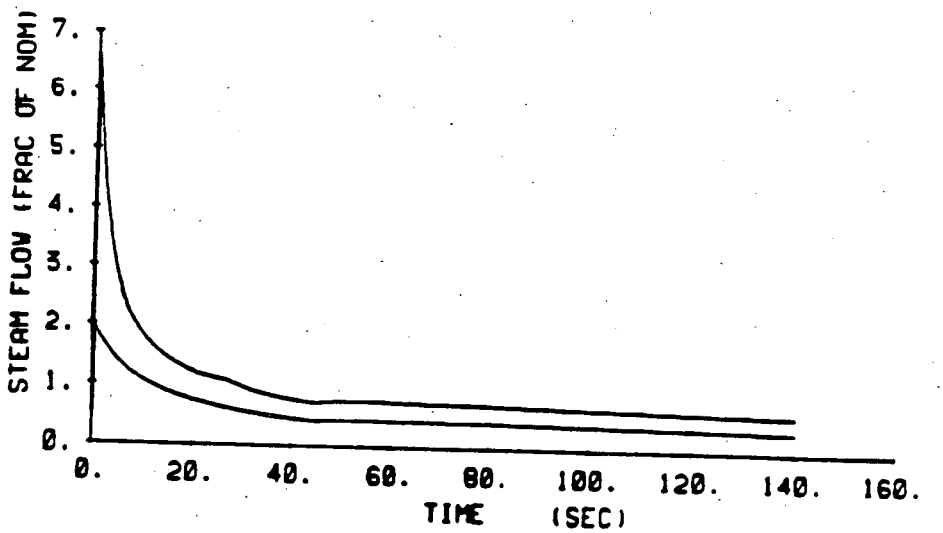
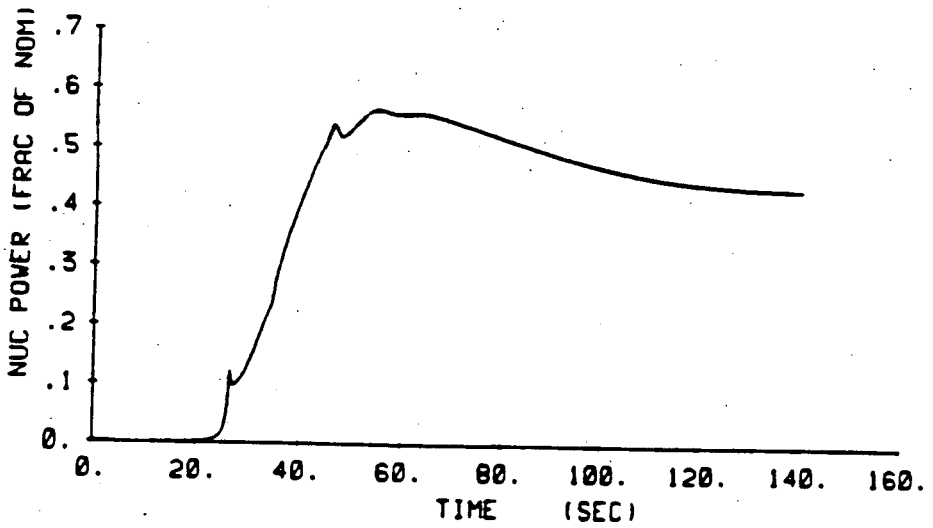


FIGURE 23 Steam Flow

CASE 3.3



Nuclear Power

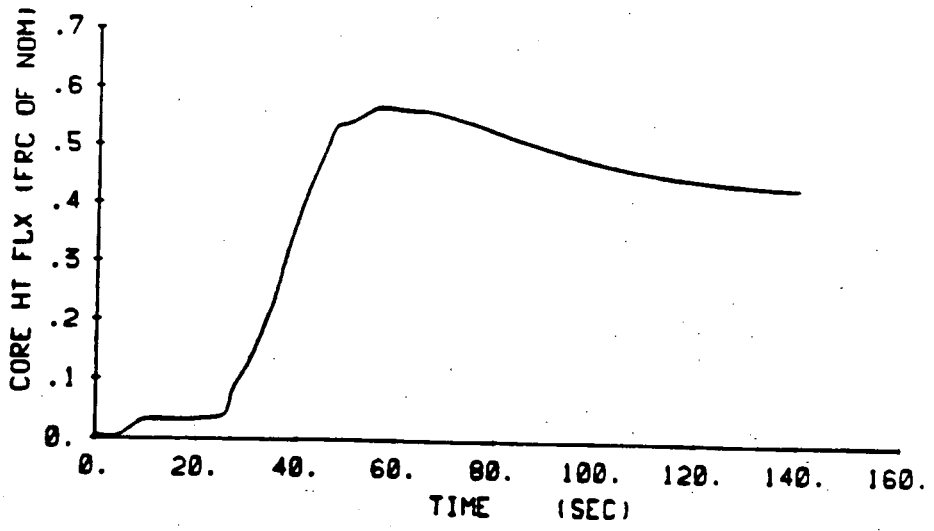
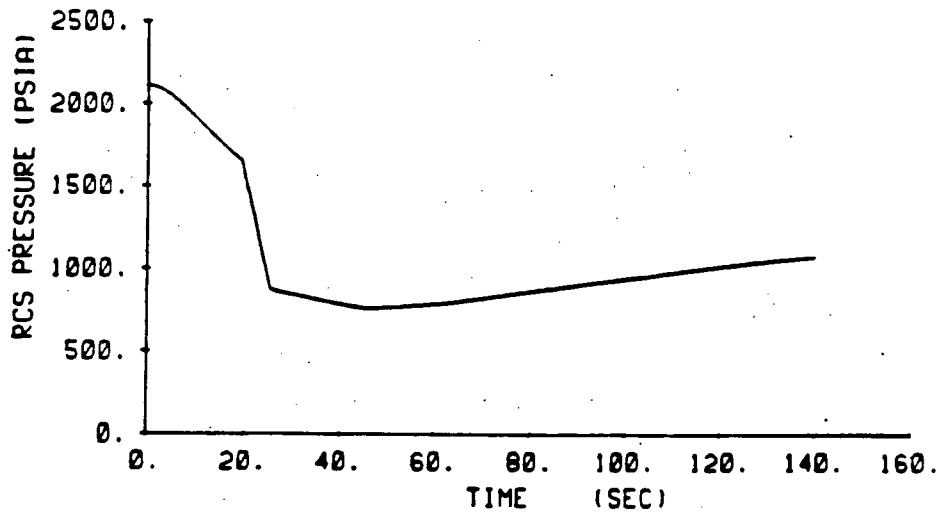


FIGURE 24 **Core Heat Flux**

CASE 3.3



RCS Pressure

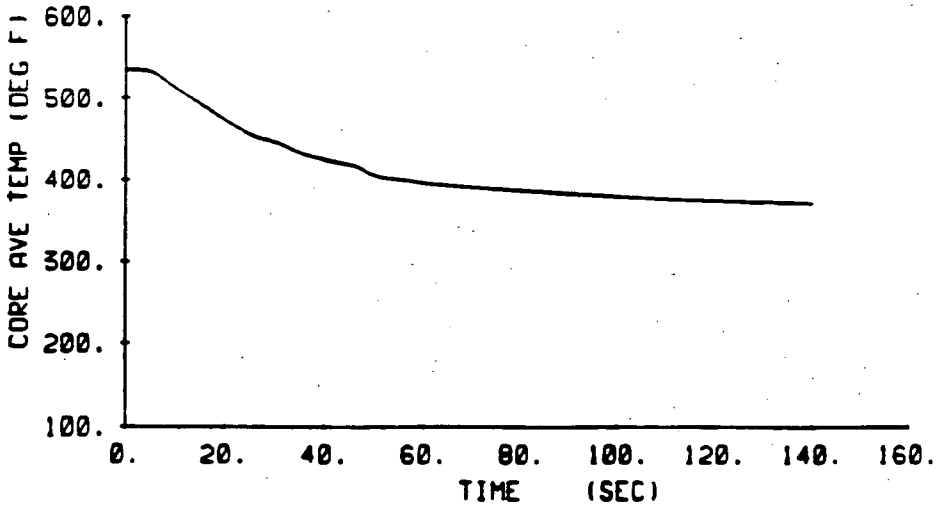
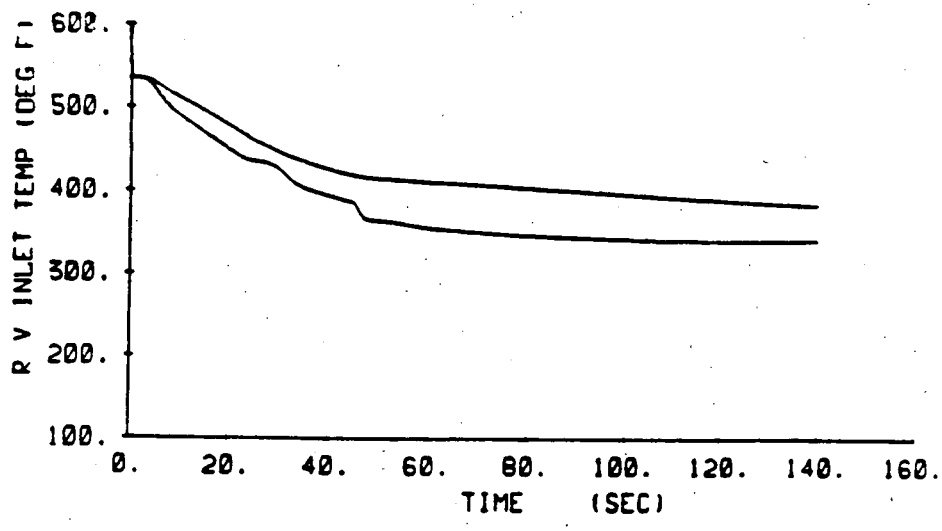


FIGURE 25 **Core Average Temperature**

CASE 3.3



Reactor Vessel Inlet Temperatures

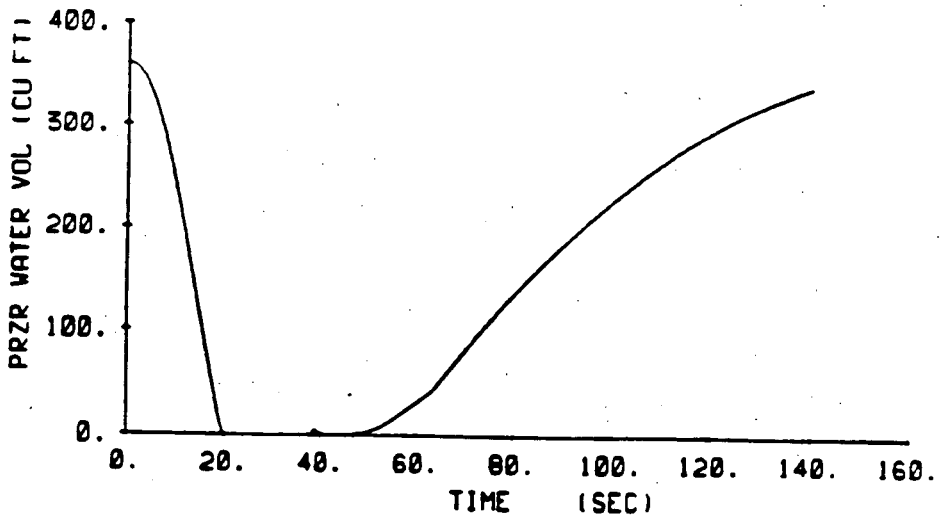
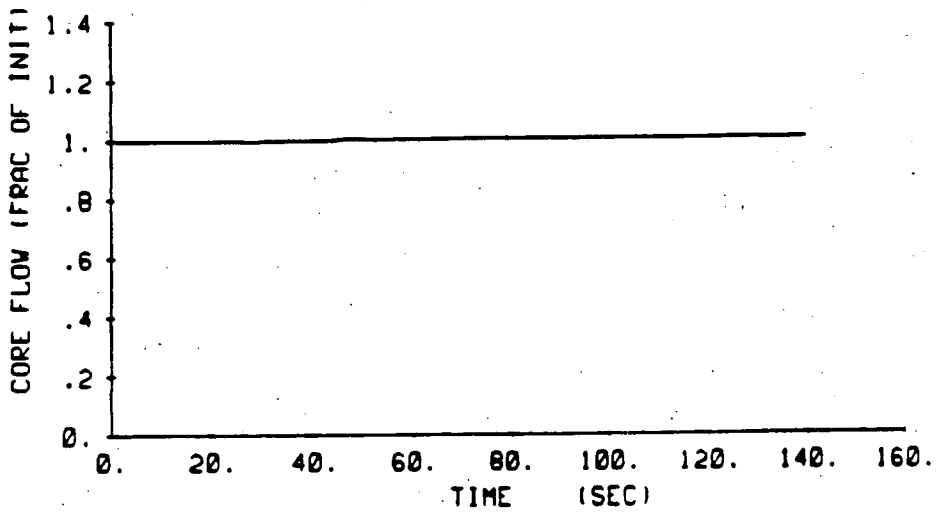


FIGURE 26 Pressurizer Water Volume

CASE 3.3



Core Flow

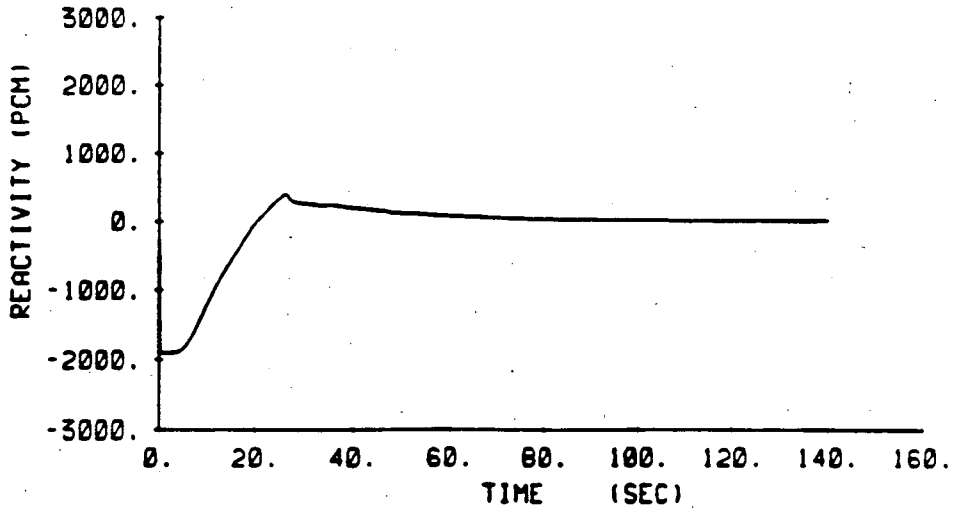
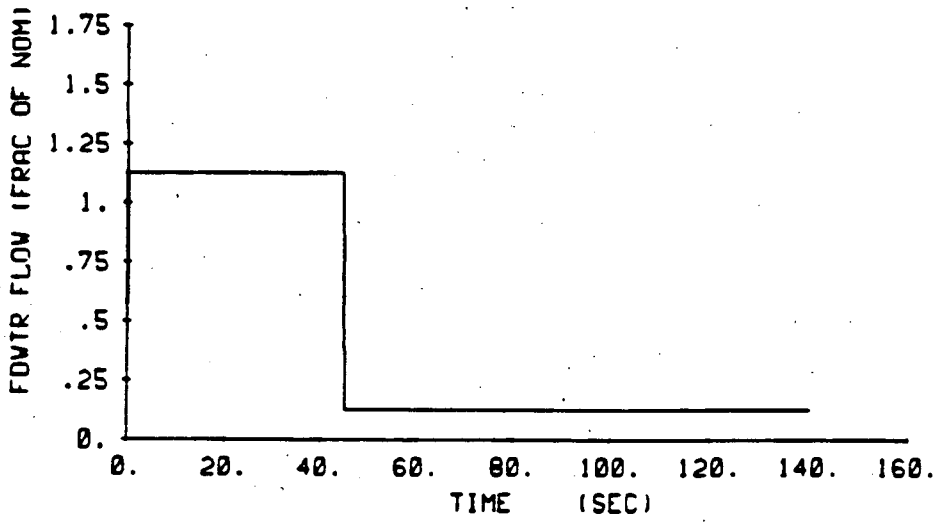


FIGURE 27 Reactivity

CASE 3.3



Feedwater Flow

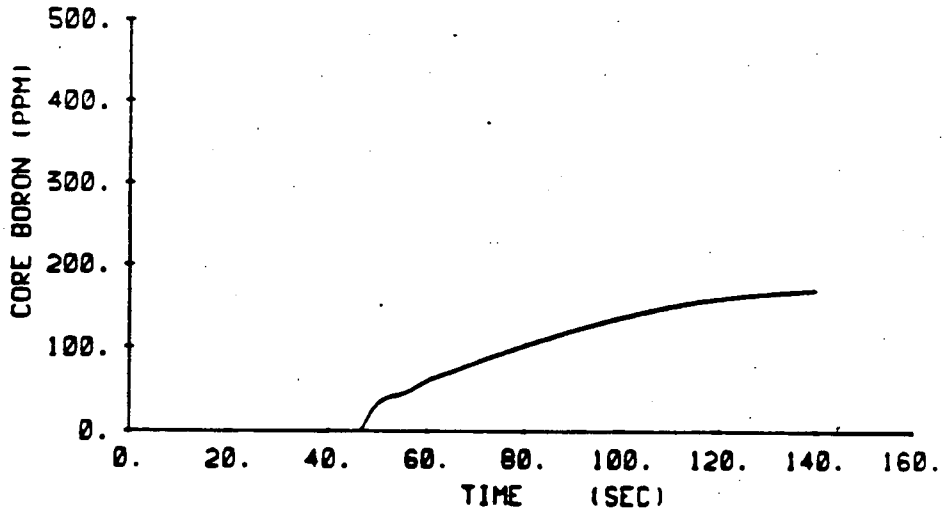
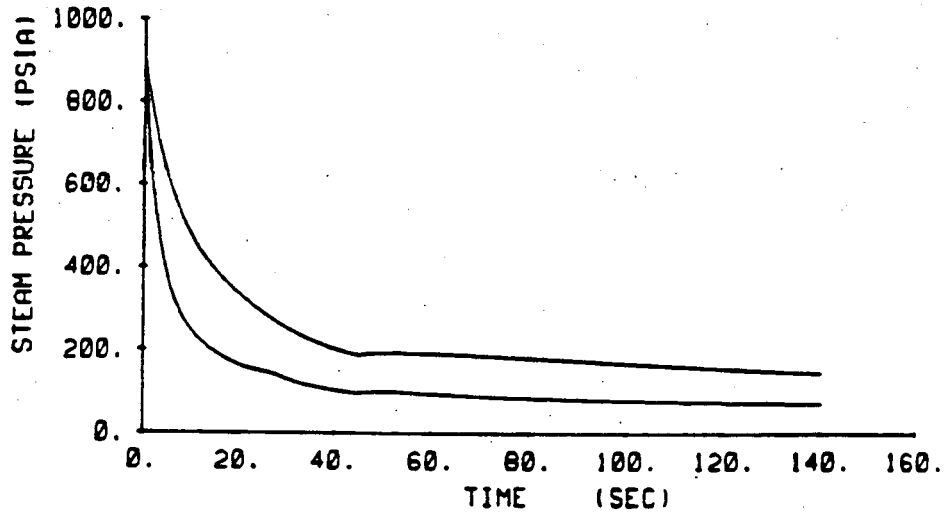


FIGURE 28 Core Boron

CASE 3.3



Steam Pressure

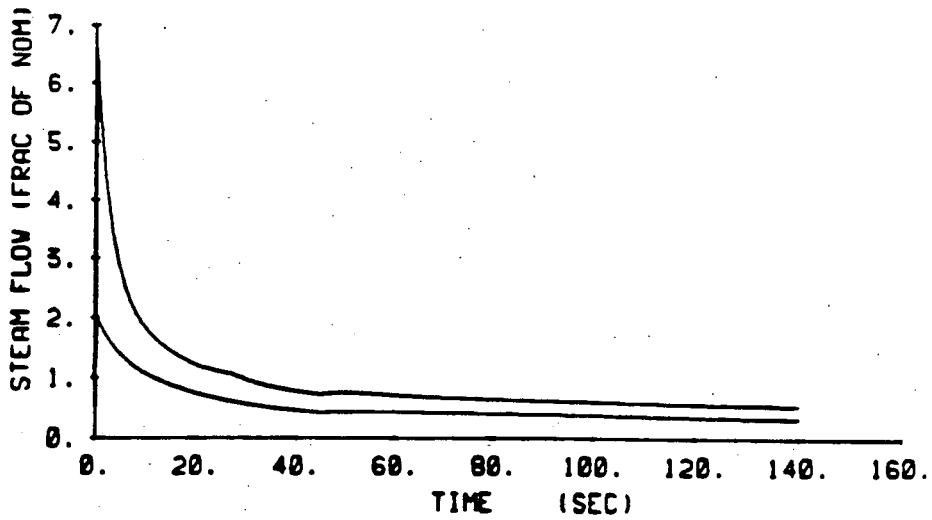


FIGURE 29 Steam Flow

APPENDIX C

TECHNICAL SPECIFICATION CHANGE PAGES

3.5.2 CONTROL ROD INSERTION LIMITS

APPLICABILITY: MODES 1 and 2 — 111 10/21/8

OBJECTIVE: This specification defines the insertion limits for the control rods in order to ensure (1) an acceptable core power distribution during power operation, (2) a limit on potential reactivity insertions for a hypothetical control rod ejection, and (3) core subcriticality after a reactor trip.

SPECIFICATION:

A. Except during low power physics tests or surveillance testing pursuant to Specification 4.1.1.G, the Shutdown Groups and Control Group 1 shall be fully withdrawn, and the position of Control Group 2 shall be at or above the 21-step uncertainty limit shown in Figure 3.5.2.1. — 111 10/21/8

B. The energy weighted average of the positions of Control Group 2 shall be at least 90% (i.e. > Step 288) withdrawn after the first 20% burnup of a core cycle. The average shall be computed at least twice every month and shall consist of all Control Group 2 positions during the core cycle. — 21 5/13/75

ACTION:

A. With the control groups inserted beyond the above insertion limits either:

1. Restore the control groups to within the limits within 2 hours, or

2. Reduce THERMAL POWER within 2 hours to less than or equal to that fraction of RATED THERMAL POWER which is allowed by the group position using the above figure, or

3. Be in at least HOT STANDBY within 6 hours. — 111 10/21/88

B. With a single dropped rod from a shutdown group or control group, the provisions of Action A are not applicable, and retrieval shall be performed without increasing THERMAL POWER beyond the THERMAL POWER level prior to dropping the rod. An evaluation of the effect of the dropped rod shall be made to establish permissible THERMAL POWER levels for continued operation. If retrieval is not successful within 3 hours from the time the rod was dropped, appropriate action, as determined from the evaluation, shall be taken. In no case shall operation longer than 3 hours be permitted if the dropped rod is worth more than 0.4% Δ k/k.

BASIS: During Startup and Power Operation, the shutdown groups and control group 1 are fully withdrawn and control of the reactor is maintained by control group 2. The control group insertion limits are set in consideration of maximum specific

power, shutdown capability, and the rod ejection accident. The considerations associated with each of these quantities are as follows:

1. The initial design maximum value of specific power is 15 kW/ft. The values of $F^N_{\Delta H}$ and F_Q total associated with this specific power are 1.75 and 3.23, respectively.

   A more restrictive limit on the design value of specific power, $F^N_{\Delta H}$ and F_Q is applied to operation in accordance with the current safety analysis including fuel densification and ECCS performance. The values of the specific power, $F^N_{\Delta H}$ and F_Q are ~~13.7~~ kW/ft, 1.57 and ~~2.09~~, respectively. At partial power, the $F^N_{\Delta H}$ maximum values (limits) increase according to the following equation, $F^N_{\Delta H}(P) = 1.57\,[1 + 0.2\,(1-P)]$, where P is the fraction of RATED THERMAL POWER. The control group insertion limits in conjunction with Specification B prevent exceeding these values even assuming the most adverse Xe distribution.

   2.78 13.2

   60 6/8/81 | 88 11/23/8 | 111 10/21/8 | 60 6/8/81

2. The minimum shutdown capability required is 1.25% Δρ at BOL, 1.9% Δρ at EOL and defined linearly between these values for intermediate cycle lifetimes. The rod insertion limits ensure that the available SHUTDOWN MARGIN is greater than the above values.

   21 5/13/7 | 111 10/21/8

3. The worst case ejected rod accident (8) covering HFP-BOL, HZP-BOL, HFP-EOL shall satisfy the following accident safety criteria:

   a) Average fuel pellet enthalpy at the hot spot below 225 cal/gm for nonirradiated fuel and 220 cal/gm for irradiated fuel.

   b) Fuel melting is limited to less than the innermost 10% of the fuel pellet at the hot spot.

   54 5/29/8

   Low power physics tests are conducted approximately one to four times during the core cycle at or below 10% RATED THERMAL POWER. During such tests, rod configurations different from those specified in Figure 3.5.2.1 may be employed.

   111 10/21/8

   It is understood that other rod configurations may be used during physics tests. Such configurations are permissible based on the low probability of occurrence of steam line break or rod ejection during such rod configurations.

Operation of the reactor during cycle stretch out is conservative relative to the safety considerations of the control rod insertion limits, since the positioning of the rods during stretch out results in an increasing net available SHUTDOWN MARGIN.

Compliance with Specification B prevents unfavorable axial power distributions due to operation for long intervals at deep control rod insertions.

The presence of a dropped rod leads to abnormal power distribution in the core. The location of the rod and its worth in reactivity determines its effect on the temperatures of nearby fuel. Under certain conditions, continued operation could result in fuel damage, and it is the intent of ACTION B to avoid such damage. 111 10/21/

References:

(1) Final Engineering Report and Safety Analysis, revised July 28, 1970.

(2) Amendment No. 18 to Docket No. 50-206.

(3) Amendment No. 22 to Docket No. 50-206.

(4) Amendment No. 23 to Docket No. 90-206.

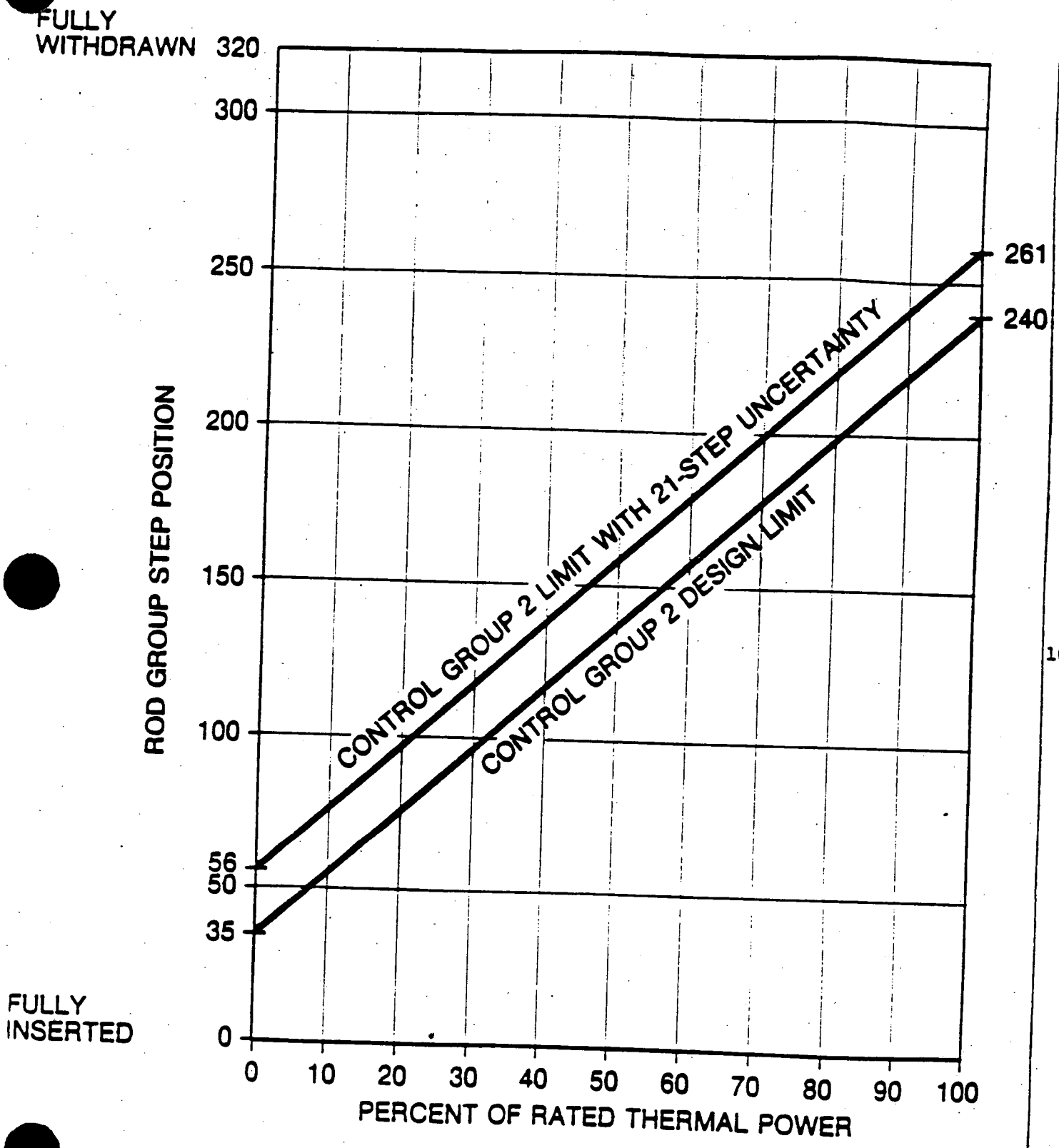
(5) Description and Safety Analysis, Proposed Change No. 7, dated October 22, 1971.

(6) Description and Safety Analysis Including Fuel Densification, San Onofre Nuclear Generating Station, Unit 1, Cycle 4, WCAP 8131, May, 1973.

(7) Description and Safety Analysis Including Fuel Densification, San Onofre Nuclear Generating Station, Unit 1, Cycle 5, January, 1975, Westinghouse Non-Proprietary Class 3.

(8) An Evaluation of the Rod Ejection Accident in Westinghouse Pressurized Water Reactors Using Spatial Kinetics Methods, WCAP-7588, Revision 1-A, January, 1975.

CONTROL GROUP INSERTION LIMITS



111
10/21/8

FIGURE 3.5.2.1

3.10 INCORE INSTRUMENTATION

APPLICABILITY: MODE 1 ~~above 90% RATED THERMAL POWER~~ 112 10/28/88

OBJECTIVE: To specify the type and frequency of incore measurements used to verify linear power density values.

SPECIFICATION:

a. A power distribution measurement shall be performed every 30 ~~effective full power days~~ (EFPD) and after attainment of equilibrium xenon upon return to power following a refueling shutdown. 112 10/28/88

b. The incore instrumentation system shall be used to accomplish the Correlation Verification of incore versus excore data for the axial offset monitoring system prior to exceeding 90% of RATED THERMAL POWER following each refueling and at least once per 180 ~~effective full power days~~ (EFPD) thereafter. Subsequent to the Correlation Verification and for the duration of each cycle, incore instrumentation shall be used to perform a Correlation Check of the axial offset monitoring system every 30 EFPDs. 112 10/28/88

c. A core thermocouple map shall be taken every 30 EFPDs and after attainment of equilibrium xenon upon return to power following a refueling shutdown. 112 10/28/88

ACTION:

A. If the correlation check, power distribution measurement or core thermocouple map described above cannot be made within the prescribed time, a maximum of 15 EFPDs will be allowed for equipment correction. 112 10/28/88

B. In the event that Specification a, b and c cannot be met during the 15 EFPDs allowed for corrective action, ~~within one hour action shall be taken such that THERMAL POWER is restricted to less than or equal to 90% of RATED THERMAL POWER until these specifications can be met.~~ be in MODE 2 within 4 hours. 112 10/28/88

BASIS: The flux mapping system is used to measure the core power distribution and to correlate incore versus excore data for the axial offset system. Measurements made with the flux mapping system every 30 ~~effective full power days~~ EFPDs and upon return to power following a refueling shutdown will monitor the core power distribution to confirm that the maximum linear power density remains below allowable values. The

axial offset system will monitor the axial core power distribution in a continuous manner. ~~If the Correlation Verification or Correlation Check is not performed, the 90% of full thermal power restriction assures safe operation of the reactor.~~ In addition, core thermocouples provide an independent means of measuring the balance of power among the core quadrants.

The flux mapping system and the thermocouple system are not integral parts of the Reactor Protection System. These systems are, rather, surveillance systems which may be required in the event of an abnormal condition such as a power tilt or a control rod misalignment. Since such a condition cannot be predicted, it is prudent to have the surveillance systems ~~in an operable state.~~ OPERABLE ~~The 90% of full power restriction, used when these measurements cannot be taken as scheduled, is applied to minimize the probability of exceeding allowed peaking factors.~~

Operation for a 180 ~~effective full power day~~ EFPD period prior to reperforming the correlation verification is acceptable on the basis that the allowed incore axial offset limits are reduced by the amount in percent of incore axial offset that the monthly correlation check differs from the correlation. 112 10/28/88

If the measurements cannot be taken as specified, the plant will be placed in MODE 2 within 4 hours as specified by the actions.

3.11 CONTINUOUS POWER DISTRIBUTION MONITORING

112 10/28/88

APPLICABILITY: MODE 1 ~~above 90% RATED THERMAL POWER~~

OBJECTIVE: To provide corrective action in the event that the axial offset monitoring system limits are approached.

SPECIFICATION: The Incore Axial Offset Limits (IAOL) shall not exceed the functional relationship defined by:

For positive offsets: IAO = $\frac{2.78\ \cancel{2.89}/P - 2.10\ \cancel{2.1225}}{0.033\ \cancel{0.03021}}$ - FCC

For negative offsets: IAO = $\frac{2.78\ \cancel{2.89}/P - 2.10\ \cancel{2.1181}}{0.033\ \cancel{.03068}}$ + FCC

112 10/28/88

where

IAO = Incore Axial Offset determined from excore nuclear instrumentation

P = fraction of RATED THERMAL POWER

FCC = The larger of 3.0 or the value in percent of IAO ~~incore axial offset~~ by which the current correlation check differs from the incore-excore correlation.

112 10/28/8

ACTION:

A. With IAO exceeding the limit defined by the specification, within 1 hour action shall be taken to reduce THERMAL POWER until IAO is within specified limits. ~~or such that THERMAL POWER is restricted to less than 90% of RATED THERMAL POWER.~~

B. With one or both excore axial offset channel(s) inoperable, as an alternate, one OPERABLE NIS channel for each inoperable excore axial offset channel, shall be logged every two hours to determine IAO.

117 12/13/8

C. With no method for determining IAO available, ~~within 1 hour action shall be taken such that THERMAL POWER is reduced to less than 90% of RATED THERMAL POWER until a method of determining axial offset is restored.~~ be in MODE 2 within 4 hours.

BASIS:

The percent full power axial offset limits are conservatively established considering the core design peaking factor, analytical determination of the relationship between core peaking factors and ~~incore axial offset~~ IAO considering a wide range of maneuvers and core conditions, and actual measurements relating ~~incore axial offset~~ IAO to the axial offset monitoring systems. The axial offset limit established from the incore versus excore data have been reduced by an amount equivalent to FCC to allow for burnup and time dependent differences between the periodic correlation verification and the monthly correlation check. Correcting the allowed ~~incore axial offset limits~~ IAOL by an amount equal to FCC maintains plant operation within the original safety analysis assumptions. Should a specific cycle analysis establish that the analytical determination of the relationship between core peaking factors and ~~incore axial offset~~ IAO has changed in a manner warranting modification to the existing envelope of peaking factor (1,2), then a change to functional relationship of the specification shall be submitted to the Commission. The incore-excore data correlation is checked or verified periodically as delineated in Specification 3.10, INCORE INSTRUMENTATION. 112 10/28/88

until IAO is within the specified limits

Reducing power in cases when limits are ~~approached or~~ exceeded, will assure that design limits which were set in consideration of accident conditions are not exceeded. In the event that no method exists for determining IAO, actions are specified to ~~reduce THERMAL POWER to 90% of RATED THERMAL POWER.~~ place the plant in MODE 2 within 4 hours. However, if axial offset channel(s) are inoperable, hand calculational methods of determining IAO from OPERABLE NIS channels can be employed until OPERABILITY of the axial offset channel(s) is restored. 117 12/13/88

References:

(1) Supporting Information on Periodic Axial Offset Monitoring, San Onofre Nuclear Generating Station, Unit 1, September, 1973

(2) Supporting Information on the Continuous Axial Offset Monitoring System, San Onofre Nuclear Generating Station, Unit 1, July, 1974

(3) Description and Safety Analysis, Including Fuel Densification, San Onofre Nuclear Generating Station, Unit 1 Cycle 5, January, 1975, Westinghouse Non-Proprietary Class 3.