ATTACHMENT VI

CORE OPERATING LIMIT REPORT FOR
OCONEE UNIT 2 CYCLE 18

Duke Power Company

Oconee 2 Cycle 18

Core Operating Limits Report

QA Condition 1

Prepared By : J. L. Ellis Date : Ø5 Feb 99

Checked By : T. P. Phelps Date : 05FEb99

Approved By : R. R. St. Clair Date : Ø8 FEB99

Oconee 2 Cycle 18

Core Operating Limits Report

Insertion Sheet for Revision 10

This revision is not valid until the end of operation for Oconee 2 Cycle 17.

Remove these revision 9 pages	Insert these revision 10 pages
1 - 31	1 - 31

Revision Log

Revision	Effective Date	Pages Revised	Pages Added	Pages Deleted	Total Effective Pages
Oconee 2 Cycle 18 revisions below					
10	Mar-99	1 - 31	-	31	31
Oconee 2 Cycle 17 revisions below					
9	Feb-99	1 - 31	-	32 - 38	31
8	May-98	1-3,5,11,32,35		-	38
7	Mar-98	1 - 38	-	-	38
Oconee 2 Cycle 16 revisions below					
6	Oct-96	1-3, 18	-	-	38
5	Mar-96	1 - 34	35 - 38	-	38

Oconee 2 Cycle 18

1.0 Error Adjusted Core Operating Limits

The Core Operating Limits Report for O2C18 has been prepared in accordance with the requirements of ITS 5.6.5. The core operating limits within this report have been developed using NRC approved methodology identified in references 1, 2, 3, 4, 5, 6, and 7. The RPS protective limits and maximum allowable setpoints are documented in references 8 and 9. These limits are validated for use in O2C18 by references 10, 11, and 12. The O2C18 analyses assume a design flow of 107.5% of 88,000 gpm per RCS pump, radial local peaking (FDh) of 1.714, and axial peaking factor (Fz) of 1.5.

The error adjusted core operating limits included in section 1 of the report incorporate all necessary uncertainties and margins required for operation of the O2C18 reload core.

1.1 References

1. Nuclear Design Methodology Using CASMO-3 / SIMULATE-3P, DPC-NE-1004A, Revision 0, (SER dated November 23, 1992).

2. Oconee Nuclear Station Reload Design Methodology II, DPC-NE-1002A, Revision 1, (SER dated October 1, 1985).

3. Oconee Nuclear Station Reload Design Methodology, NFS-1001A, Revision 4, (SER dated July 29, 1981).

4. ONS Core Thermal Hydraulic Methodology Using VIPRE-01, DPC-NE-2003P-A, (SER dated July 19, 1989).

5. Thermal Hydraulic Statistical Core Design Methodology, DPC-NE-2005P-A, Revision 1, (SER dated November 7, 1996).

6. Fuel Mechanical Reload Analysis Methodology Using TACO3, DPC-NE-2008P-A, (SER dated April 3, 1995).

7. UFSAR Chapter 15 Transient Analysis Methodology, DPC-NE-3005-PA, Revision 1, (SER Pending).

8. Variable Low Pressure Safety Limit, OSC-4048, Revision 3, July 1998.

9. Power Imbalance Safety Limits and Tech Spec Setpoints Using Error Adjusted Flux-Flow Ratio of 1.094, OSC-5604, Revision 1, November 1998.

10. O2C18 Maneuvering Analysis, OSC-7273, Revision 1, April 1999.

11. O2C18 Specific DNB Analysis, OSC-7333, Revision 0, January 1999.

12. O2C18 Reload Safety Evaluation , OSC-7361, Revision 0.

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Miscellaneous Setpoints

BWST boron concentration shall be greater than 2220 ppm and less than 3000 ppm.
Referred to by ITS 3.5.4.

Spent fuel pool boron concentration shall be greater than 2220 ppm and less than 3000 ppm.
Referred to by ITS 3.7.12.

The equivalent of at least 1100 cubic feet of 11,000 ppm boron shall be maintained in the CBAST.
Referred to by ITS SLC 16.5.13.

CFT boron concentration shall be greater than 1835 ppm. The average boron concentration in the CFT's shall be less than 4000 ppm. Referred to by ITS 3.5.1.

RCS and Refueling canal boron concentration shall be greater than 2220 ppm.
Referred to by ITS 3.9.1.

Shutdown Margin (SDM) shall be greater than 1% $\Delta k/k$.
Referred to by ITS 3.1.1.

Moderator Temperature Coefficient (MTC) shall be less than :
Linear interpolation is valid within table provided.
Referred to by ITS 3.1.3.

MTC x 10-4 $\Delta\rho$ / °F	% FP
0.700	0
0.030	15
-0.281	95
-0.300	100
-0.375	120

Departure from Nucleate Boiling (DNB) parameter for RCS loop pressure shall be
Referred to by ITS 3.4.1.

4 RCP:	measured hot leg pressure $\geq$ 2125 psig
3 RCP:	measured hot leg pressure $\geq$ 2125 psig

DNB parameter for RCS loop average temperature shall be:
Referred to by ITS 3.4.1. Typical values provided will be finalized prior to cycle operation.
The measured Tavg must be less than the temperature specified by an amount equal to the uncertainty corresponding to the instrument from which it is read.
ΔTc is the setpoint value selected by the operators.

Max Loop Tavg Incl 2°F unc	ΔTc, °F
582.20	5
582.00	4
581.75	3
581.50	2
581.25	1
581.00	0

DNB parameter for RCS loop total flow shall be:
Referred to by ITS 3.4.1.

4 RCP:	Measured $\geq$ 107.5 %df
3 RCP:	Measured $\geq$ 74.7 % of 4 RCP min flow

Regulating rod groups shall be withdrawn in sequence starting with group 5, group 6, and finally group 7.
Referred to by ITS 3.2.1.

Regulating rod group overlap shall be 25% ± 5% between two sequential groups.
Referred to by ITS 3.2.1.

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Steady State Operating Band

	Rod Index		APSR %WD	
EFPD	Min	Max	Min	Max
0 to 457	292 ± 5	300	30	40
457 to EOC	292 ± 5	300	100	100

Quandrant Power Tilt Setpoints

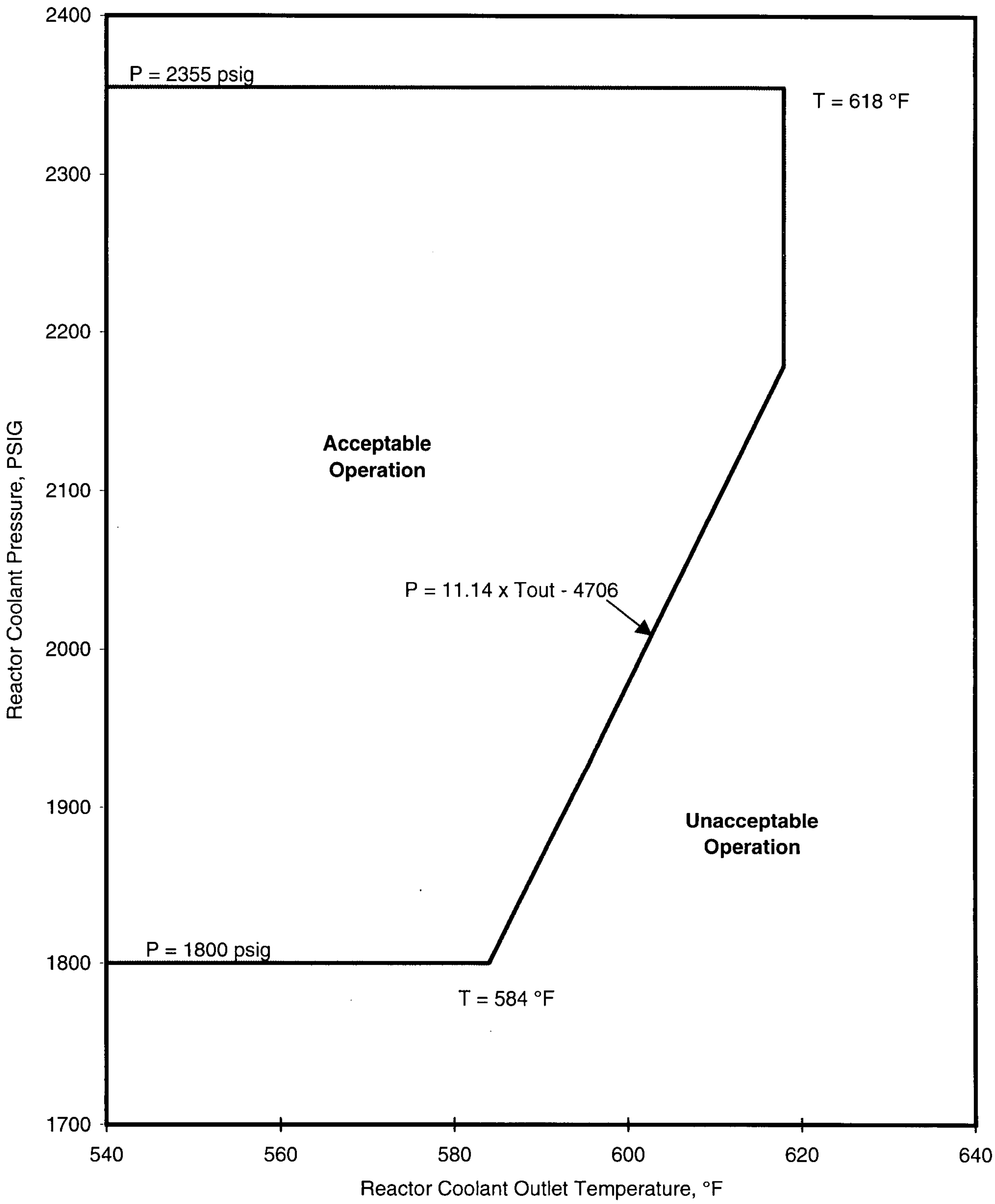
	Steady State		Transient		Maximum
Core Power Level, %FP	30 - 100	0 - 30	30 - 100	0 - 30	0 - 100
Full Incore	3.50	8.01	7.51	9.80	16.95
Out of Core	1.98	6.09	5.63	7.72	14.22
Backup Incore	2.14	3.87	3.63	4.81	10.07

Referred to by ITS 3.2.3.

Oconee 2 Cycle 18

Variable Low RCS Pressure RPS Setpoints

Referred to by ITS 3.3.1.



Oconee 2 Cycle 18

RPS Power Imbalance Setpoints

	% FP	% Imbalance
4 Pumps	0	-33.0
	90.4	-33.0
	107.9	-14.4
	107.9	14.4
	90.4	33.0
	0	33.0
3 Pumps	0	-33.0
	63.1	-33.0
	80.6	-14.4
	80.6	14.4
	63.1	33.0
	0	33.0

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Operational Power Imbalance Setpoints

	%FP	Full Incore	Backup Incore	Out of Core
4 Pumps	0	-31.5	-31.2	-31.5
	80	-31.5	-31.2	-31.5
	90	-28.9	-28.7	-28.9
	100	-19.1	-18.9	-19.1
	102	-17.0	-16.9	-17.0
	102	17.0	17.0	17.0
	100	19.1	18.9	19.1
	90	27.9	27.4	27.9
	80	27.9	27.4	27.9
	0	27.9	27.4	27.9
3 Pumps	0	-31.5	-31.2	-31.5
	63.3	-31.5	-	-31.5
	63.6	-	-31.2	-
	77	-17.0	-16.9	-17.0
	77	17.0	17.0	17.0
	67.2	-	27.4	-
	66.7	27.9	-	27.9
	0	27.9	27.4	27.9

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Operational Power Imbalance Setpoints

Operation with 4 RCS Pumps, BOC to EOC

% FP	RPS Trip		Full Incore Alarm		Out of Core Alarm	
107.9	-14.4	14.4				
107	-15.4	15.4				
106	-16.4	16.4				
105	-17.5	17.5				
104	-18.5	18.5				
103	-19.6	19.6				
102	-20.7	20.7	-17.0	17.0	-17.0	17.0
101	-21.7	21.7	-18.1	18.1	-18.1	18.1
100	-22.8	22.8	-19.1	19.1	-19.1	19.1
99	-23.9	23.9	-20.1	20.0	-20.1	20.0
98	-24.9	24.9	-21.1	20.9	-21.1	20.9
97	-26.0	26.0	-22.0	21.7	-22.0	21.7
96	-27.0	27.0	-23.0	22.6	-23.0	22.6
95	-28.1	28.1	-24.0	23.5	-24.0	23.5
94	-29.2	29.2	-25.0	24.4	-25.0	24.4
93	-30.2	30.2	-26.0	25.3	-26.0	25.3
92	-31.3	31.3	-26.9	26.1	-26.9	26.1
91	-32.4	32.4	-27.9	27.0	-27.9	27.0
90.4	-33.0	33.0	-28.5	27.5	-28.5	27.5
90	-33.0	33.0	-28.9	27.9	-28.9	27.9
89	-33.0	33.0	-29.2	27.9	-29.2	27.9
88	-33.0	33.0	-29.4	27.9	-29.4	27.9
87	-33.0	33.0	-29.7	27.9	-29.7	27.9
86	-33.0	33.0	-29.9	27.9	-29.9	27.9
85	-33.0	33.0	-30.2	27.9	-30.2	27.9
84	-33.0	33.0	-30.5	27.9	-30.5	27.9
83	-33.0	33.0	-30.7	27.9	-30.7	27.9
82	-33.0	33.0	-31.0	27.9	-31.0	27.9
81	-33.0	33.0	-31.2	27.9	-31.2	27.9
80	-33.0	33.0	-31.5	27.9	-31.5	27.9
0	-33.0	33.0	-31.5	27.9	-31.5	27.9
% FP	RPS Trip		Full Incore Alarm		Out of Core Alarm	

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Operational Power Imbalance Setpoints

Operation with 3 RCS Pumps, BOC to EOC

% FP	RPS Trip		Full Incore Alarm		Out of Core Alarm	
80.6	-14.4	14.4				
80	-15.0	15.0				
79	-16.1	16.1				
78	-17.2	17.2				
77.0	-18.2	18.2	-17.0	17.0	-17.0	17.0
76	-19.3	19.3	-18.1	18.1	-18.1	18.1
75	-20.4	20.4	-19.1	19.1	-19.1	19.1
74	-21.4	21.4	-20.2	20.2	-20.2	20.2
66.7	-29.2	29.2	-27.9	27.9	-27.9	27.9
73	-22.5	22.5	-21.2	27.9	-21.2	27.9
72	-23.5	23.5	-22.3	27.9	-22.3	27.9
71	-24.6	24.6	-23.4	27.9	-23.4	27.9
70	-25.7	25.7	-24.4	27.9	-24.4	27.9
69	-26.7	26.7	-25.5	27.9	-25.5	27.9
68	-27.8	27.8	-26.5	27.9	-26.5	27.9
67	-28.9	28.9	-27.6	27.9	-27.6	27.9
66	-29.9	29.9	-28.6	27.9	-28.6	27.9
65	-31.0	31.0	-29.7	27.9	-29.7	27.9
64	-32.0	32.0	-30.8	27.9	-30.8	27.9
63.3	-32.8	32.8	-31.5	27.9	-31.5	27.9
63.1	-33.0	33.0	-31.5	27.9	-31.5	27.9
63	-33.0	33.0	-31.5	27.9	-31.5	27.9
62	-33.0	33.0	-31.5	27.9	-31.5	27.9
61	-33.0	33.0	-31.5	27.9	-31.5	27.9
60	-33.0	33.0	-31.5	27.9	-31.5	27.9
0	-33.0	33.0	-31.5	27.9	-31.5	27.9
% FP	RPS Trip		Full Incore Alarm		Out of Core Alarm	

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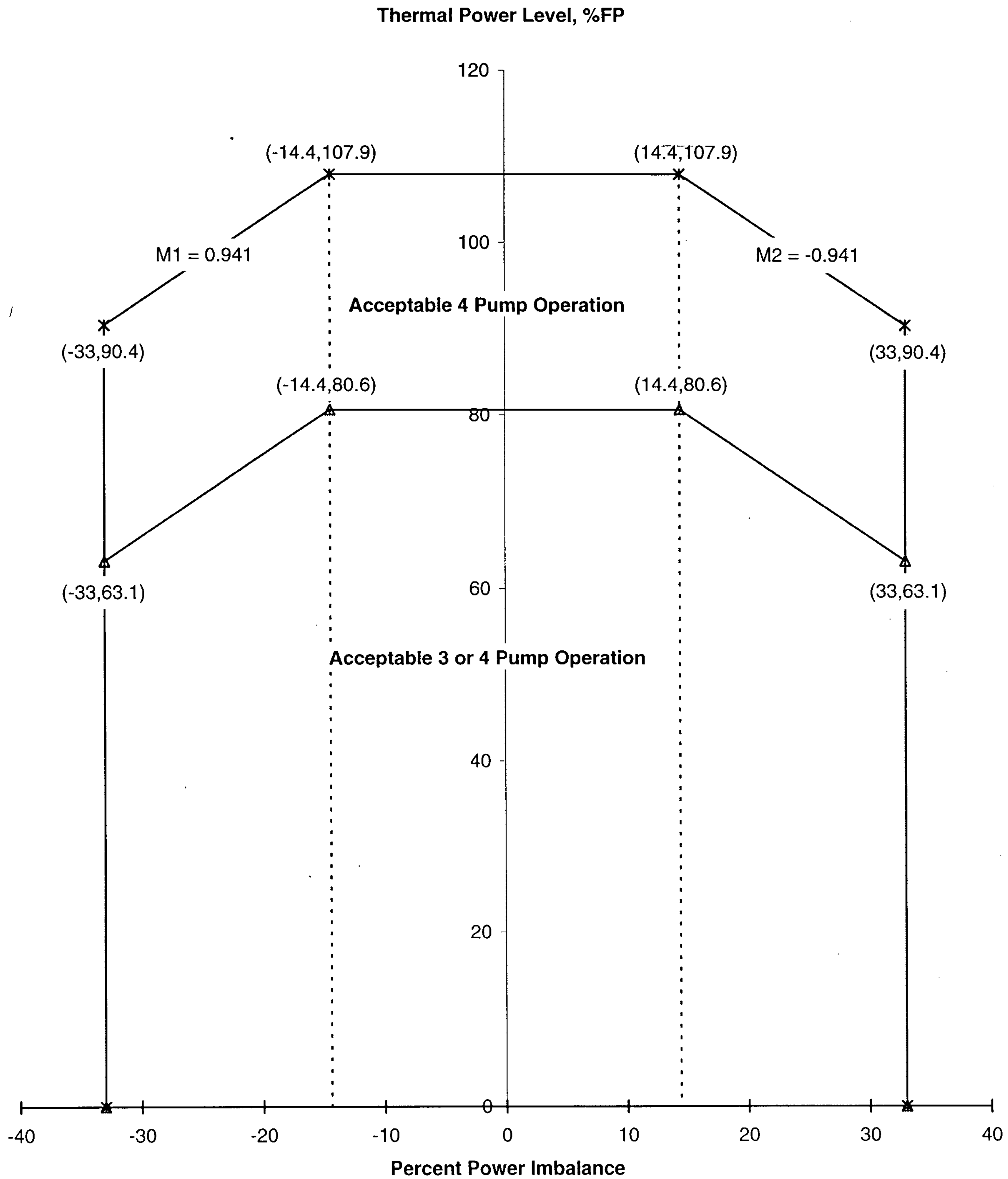
RPS Power Imbalance Setpoints

Referred to by ITS 3.3.1.



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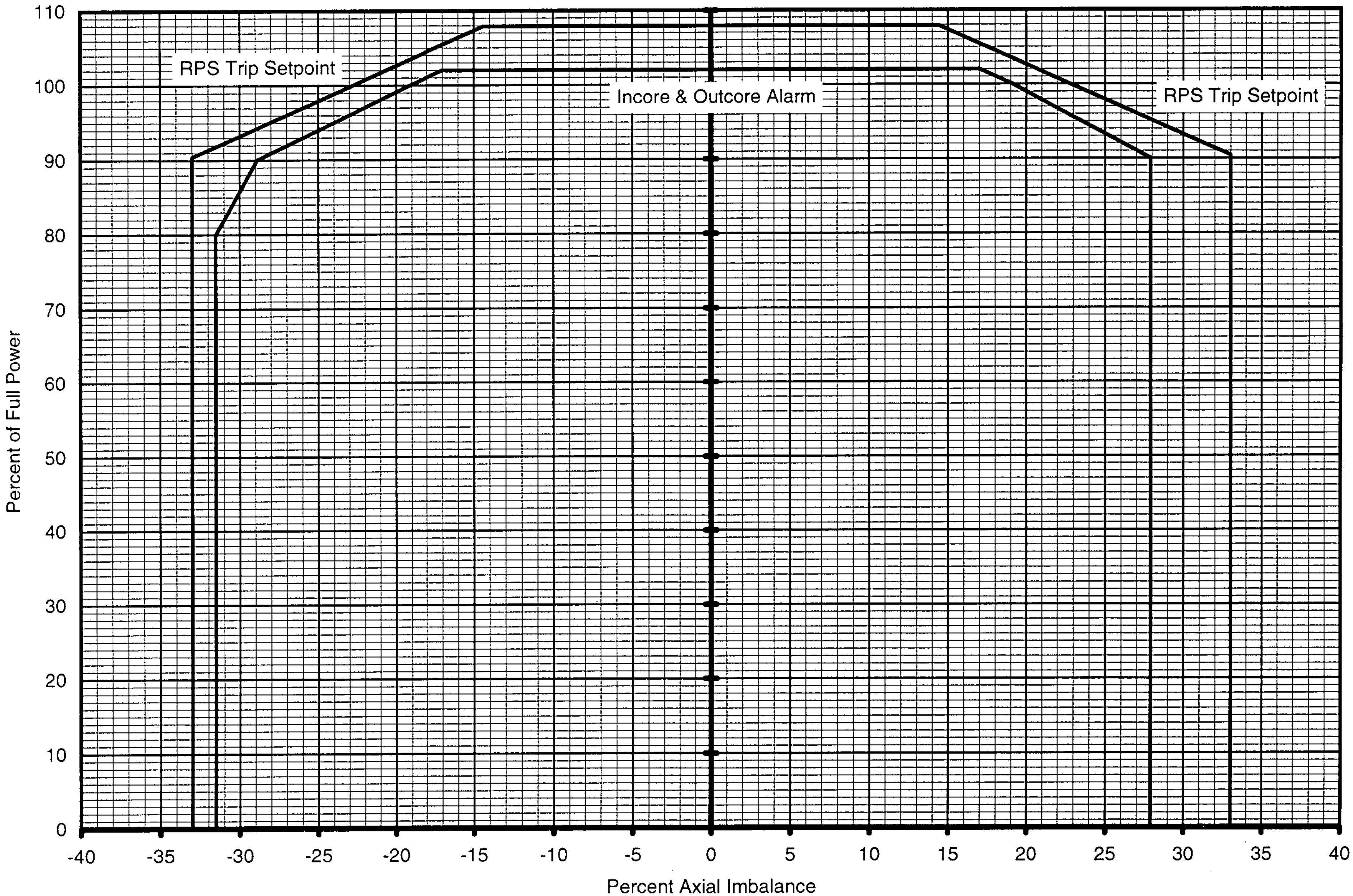
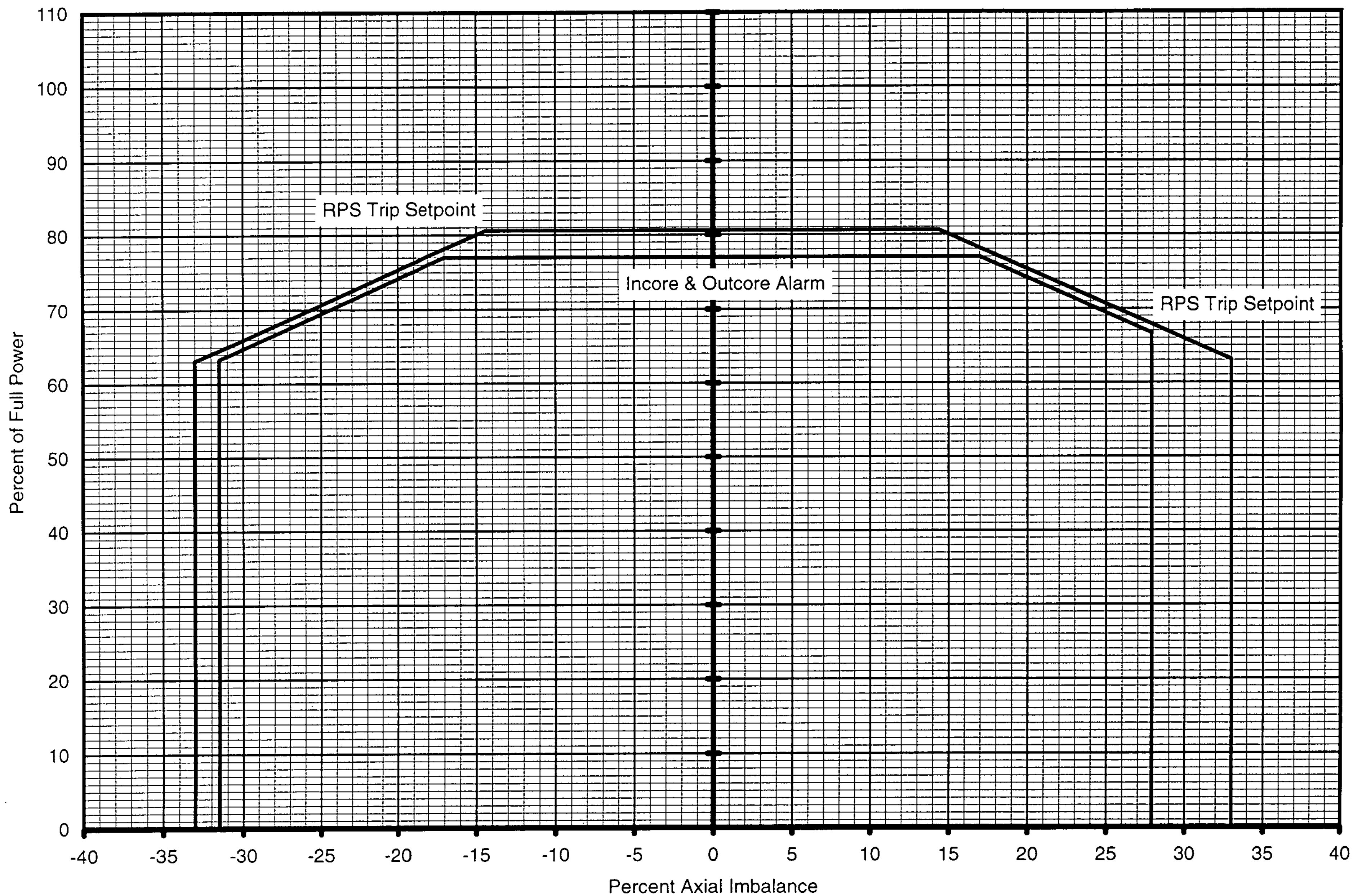
Imbalance Setpoints for 4 Pump Operation, BOC to EOC



Oconee 2 Cycle 18

Imbalance Setpoints for 3 Pump Operation, BOC to EOC



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Operational Rod Index Setpoints

	%FP	RI Insertion Setpoint No Inop Rod	RI Insertion Setpoint 1 Inop Rod	RI Withdrawal Setpoint
4 Pump	102.0	263.5	283.4	300
	100.0	261.5	281.5	300
	90.0	251.5	271.9	300
	80.0	241.5	262.3	300
	50.0	201.5	233.4	300
	48.0	195.2	231.5	300
	15.0	91.5	165.5	300
	13.0	76.5	161.5	300
	5.0	16.5	93.5	300
	3.0	1.5	76.5	300
	2.8	0.0	74.8	300
	0.0	0.0	51.0	300
3 Pump	77.0	237.5	285.2	300
	75.0	234.8	281.5	300
	50.0	201.5	235.2	300
	48.0	195.2	231.5	300
	15.0	91.5	165.5	300
	13.0	76.5	161.5	300
	5.0	16.5	93.5	300
	3.0	1.5	76.5	300
	2.8	0.0	74.8	300
	0.0	0.0	51.0	300

Oconee 2 Cycle 18

Shutdown Margin Rod Index Setpoints

	%FP	RI Insertion Setpoint No Inop Rod	RI Insertion Setpoint 1 Inop Rod	RI Withdrawal Setpoint
4 Pump	102.0	224.6	283.4	300
	100.0	221.5	281.5	300
	48.0	141.5	231.5	300
	13.0	76.5	161.5	300
	3.0	1.5	76.5	300
	2.8	0.0	74.8	300
	0.0	0.0	51.0	300
3 Pump	77.0	227.4	285.2	300
	75.0	221.5	281.5	300
	48.0	141.5	231.5	300
	13.0	76.5	161.5	300
	3.0	1.5	76.5	300
	2.8	0.0	74.8	300
	0.0	0.0	51.0	300

% FP	Shutdown Margin Setpoint			Operational Alarm Setpoint		
	CRGP 5	CRGP 6	CRGP 7	CRGP 5	CRGP 6	CRGP 7
102	100	99.8	24.8	100	100	63.5
101	100	99.0	24.0	100	100	62.5
100	100	98.2	23.2	100	100	61.5
99	100	97.5	22.5	100	100	60.5
98	100	96.7	21.7	100	100	59.5
97	100	95.9	20.9	100	100	58.5
96	100	95.2	20.2	100	100	57.5
95	100	94.4	19.4	100	100	56.5
94	100	93.6	18.6	100	100	55.5
93	100	92.9	17.9	100	100	54.5
92	100	92.1	17.1	100	100	53.5
91	100	91.3	16.3	100	100	52.5
90	100	90.6	15.6	100	100	51.5
89	100	89.8	14.8	100	100	50.5
88	100	89.0	14.0	100	100	49.5
87	100	88.2	13.2	100	100	48.5
86	100	87.5	12.5	100	100	47.5
85	100	86.7	11.7	100	100	46.5
84	100	85.9	10.9	100	100	45.5
83	100	85.2	10.2	100	100	44.5
82	100	84.4	9.4	100	100	43.5
81	100	83.6	8.6	100	100	42.5
80	100	82.9	7.9	100	100	41.5
79	100	82.1	7.1	100	100	40.2
78	100	81.3	6.3	100	100	38.8
77	100	80.6	5.6	100	100	37.5
76	100	79.8	4.8	100	100	36.2
75	100	79.0	4.0	100	100	34.8
74	100	78.2	3.2	100	100	33.5
73	100	77.5	2.5	100	100	32.2
72	100	76.7	1.7	100	100	30.8
71	100	75.9	0.9	100	100	29.5
70	100	75.2	0.2	100	100	28.2
69.8	100	75.0	0	100	100	27.9
69	100	73.8	0	100	100	26.8
68	100	72.3	0	100	100	25.5
67.6	100	71.7	0	100	100	25.0
67	100	70.7	0	100	99.6	24.6
66	100	69.2	0	100	98.9	23.9
65	100	67.7	0	100	98.2	23.2
64	100	66.1	0	100	97.6	22.6
63	100	64.6	0	100	96.9	21.9
62	100	63.0	0	100	96.2	21.2
61	100	61.5	0	100	95.6	20.6
60	100	60.0	0	100	94.9	19.9
59	100	58.4	0	100	94.2	19.2
58	100	56.9	0	100	93.6	18.6
57	100	55.3	0	100	92.9	17.9
56	100	53.8	0	100	92.2	17.2
55	100	52.3	0	100	91.6	16.6
54	100	50.7	0	100	90.9	15.9
53	100	49.2	0	100	90.2	15.2
52	100	47.7	0	100	89.6	14.6
51	100	46.1	0	100	88.9	13.9
50	100	44.6	0	100	88.2	13.2
% FP	CRGP 5	CRGP 6	CRGP 7	CRGP 5	CRGP 6	CRGP 7
	Shutdown Margin Setpoint			Operational Alarm Setpoint		

RI = 300 is withdrawal limit at all power levels.

Continued on next page.

% FP	Shutdown Margin Setpoint			Operational Alarm Setpoint		
	CRGP 5	CRGP 6	CRGP 7	CRGP 5	CRGP 6	CRGP 7
49	100	43.0	0	100	86.7	11.7
48	100	41.5	0	100	85.1	10.1
47	100	39.6	0	100	83.5	8.5
46	100	37.8	0	100	82.0	7.0
45	100	35.9	0	100	80.4	5.4
44	100	34.1	0	100	78.8	3.8
43	100	32.2	0	100	77.2	2.2
42	100	30.4	0	100	75.7	0.7
41.6	100	29.6	0	100	75.0	0
41	100	28.5	0	100	73.2	0
40	100	26.6	0	100	70.1	0
39.1	100	25.0	0	100	67.3	0
39	99.9	24.9	0	100	66.9	0
38	99.0	24.0	0	100	63.8	0
37	98.0	23.0	0	100	60.6	0
36	97.1	22.1	0	100	57.5	0
35	96.2	21.2	0	100	54.3	0
34	95.2	20.2	0	100	51.2	0
33	94.3	19.3	0	100	48.1	0
32	93.4	18.4	0	100	44.9	0
31	92.5	17.5	0	100	41.8	0
30	91.5	16.5	0	100	38.6	0
29	90.6	15.6	0	100	35.5	0
28	89.7	14.7	0	100	32.4	0
27	88.8	13.8	0	100	29.2	0
26	87.8	12.8	0	100	26.1	0
25.7	87.5	12.5	0	100	25.0	0
25	86.9	11.9	0	99.0	24.0	0
24	86.0	11.0	0	97.4	22.4	0
23	85.0	10.0	0	95.8	20.8	0
22	84.1	9.1	0	94.2	19.2	0
21	83.2	8.2	0	92.7	17.7	0
20	82.2	7.2	0	91.1	16.1	0
19	81.3	6.3	0	89.5	14.5	0
18	80.4	5.4	0	88.0	13.0	0
17	79.5	4.5	0	86.4	11.4	0
16	78.5	3.5	0	84.8	9.8	0
15	77.6	2.6	0	83.2	8.2	0
14	76.7	1.7	0	79.5	4.5	0
13	75.8	0.8	0	75.8	0.8	0
12.8	75.0	0	0	75.0	0	0
12	69.0	0	0	69.0	0	0
11	61.5	0	0	61.5	0	0
10	54.0	0	0	54.0	0	0
9	46.5	0	0	46.5	0	0
8	39.0	0	0	39.0	0	0
7	31.5	0	0	31.5	0	0
6	24.0	0	0	24.0	0	0
5	16.5	0	0	16.5	0	0
4	9.0	0	0	9.0	0	0
3	1.5	0	0	1.5	0	0
2.8	0	0	0	0	0	0
2	0	0	0	0	0	0
1	0	0	0	0	0	0
0	0	0	0	0	0	0
% FP	CRGP 5	CRGP 6	CRGP 7	CRGP 5	CRGP 6	CRGP 7
	Shutdown Margin Setpoint			Operational Alarm Setpoint		

RI = 300 is withdrawal limit at all power levels.

Oconee 2 Cycle 18
Rod Index Setpoints
3 Pump Operation, No Inoperable Rods, BOC to EOC

% FP	Shutdown Margin Setpoint			Operational Alarm Setpoint		
	CRGP 5	CRGP 6	CRGP 7	CRGP 5	CRGP 6	CRGP 7
77	100	100	27.4	100	100	37.5
76.2	100	100	25.0	100	100	36.4
76	100	99.7	24.7	100	100	36.1
75	100	98.2	23.2	100	100	34.8
74	100	96.8	21.8	100	100	33.5
73	100	95.3	20.3	100	100	32.1
72	100	93.8	18.8	100	100	30.8
71	100	92.3	17.3	100	100	29.5
70	100	90.8	15.8	100	100	28.1
69	100	89.4	14.4	100	100	26.8
68	100	87.9	12.9	100	100	25.5
67.6	100	87.4	12.4	100	100	25.0
67	100	86.4	11.4	100	99.6	24.6
66	100	84.9	9.9	100	98.9	23.9
65	100	83.4	8.4	100	98.2	23.2
64	100	82.0	7.0	100	97.6	22.6
63	100	80.5	5.5	100	96.9	21.9
62	100	79.0	4.0	100	96.2	21.2
61	100	77.5	2.5	100	95.6	20.6
60	100	76.0	1.0	100	94.9	19.9
59.3	100	75.0	0	100	94.4	19.4
59	100	74.1	0	100	94.2	19.2
58	100	71.1	0	100	93.6	18.6
57	100	68.2	0	100	92.9	17.9
56	100	65.2	0	100	92.2	17.2
55	100	62.2	0	100	91.6	16.6
54	100	59.3	0	100	90.9	15.9
53	100	56.3	0	100	90.2	15.2
52	100	53.4	0	100	89.6	14.6
51	100	50.4	0	100	88.9	13.9
50	100	47.4	0	100	88.2	13.2
49	100	44.5	0	100	86.7	11.7
48	100	41.5	0	100	85.1	10.1
47	100	39.6	0	100	83.5	8.5
46	100	37.8	0	100	82.0	7.0
45	100	35.9	0	100	80.4	5.4
44	100	34.1	0	100	78.8	3.8
43	100	32.2	0	100	77.2	2.2
42	100	30.4	0	100	75.7	0.7
41.6	100	29.6	0	100	75.0	0
41	100	28.5	0	100	73.2	0
40	100	26.6	0	100	70.1	0
39.1	100	25.0	0	100	67.3	0
39	99.9	24.9	0	100	66.9	0
38	99	24.0	0	100	63.8	0
37	98	23.0	0	100	60.6	0
36	97.1	22.1	0	100	57.5	0
35	96.2	21.2	0	100	54.3	0
34	95.2	20.2	0	100	51.2	0
33	94.3	19.3	0	100	48.1	0
32	93.4	18.4	0	100	44.9	0
31	92.5	17.5	0	100	41.8	0
30	91.5	16.5	0	100	38.6	0
29	90.6	15.6	0	100	35.5	0
28	89.7	14.7	0	100	32.4	0
% FP	CRGP 5	CRGP 6	CRGP 7	CRGP 5	CRGP 6	CRGP 7
	Shutdown Margin Setpoint			Operational Alarm Setpoint		

RI = 300 is withdrawal limit at all power levels.

Continued on next page.

Oconee 2 Cycle 18
Rod Index Setpoints
3 Pump Operation, No Inoperable Rods, BOC to EOC

% FP	Shutdown Margin Setpoint			Operational Alarm Setpoint		
	CRGP 5	CRGP 6	CRGP 7	CRGP 5	CRGP 6	CRGP 7
27	88.8	13.8	0	100	29.2	0
26	87.8	12.8	0	100	26.1	0
25.7	87.5	12.5	0	100	25.0	0
25	86.9	11.9	0	99.0	24.0	0
24	86.0	11.0	0	97.4	22.4	0
23	85.0	10.0	0	95.8	20.8	0
22	84.1	9.1	0	94.2	19.2	0
21	83.2	8.2	0	92.7	17.7	0
20	82.2	7.2	0	91.1	16.1	0
19	81.3	6.3	0	89.5	14.5	0
18	80.4	5.4	0	88.0	13.0	0
17	79.5	4.5	0	86.4	11.4	0
16	78.5	3.5	0	84.8	9.8	0
15	77.6	2.6	0	83.2	8.2	0
14	76.7	1.7	0	79.5	4.5	0
13	75.8	0.8	0	75.8	0.8	0
12.8	75.0	0	0	75.0	0	0
12	69.0	0	0	69.0	0	0
11	61.5	0	0	61.5	0	0
10	54.0	0	0	54.0	0	0
9	46.5	0	0	46.5	0	0
8	39.0	0	0	39.0	0	0
7	31.5	0	0	31.5	0	0
6	24.0	0	0	24.0	0	0
5	16.5	0	0	16.5	0	0
4	9.0	0	0	9.0	0	0
3	1.5	0	0	1.5	0	0
2.8	0	0	0	0	0	0
2	0	0	0	0	0	0
1	0	0	0	0	0	0
0	0	0	0	0	0	0
% FP	CRGP 5	CRGP 6	CRGP 7	CRGP 5	CRGP 6	CRGP 7
	Shutdown Margin Setpoint			Operational Alarm Setpoint		

RI = 300 is withdrawal limit at all power levels.

% FP	Shutdown Margin Setpoint			Operational Alarm Setpoint		
	CRGP 5	CRGP 6	CRGP 7	CRGP 5	CRGP 6	CRGP 7
102	100	100	83.4	100	100	83.4
101	100	100	82.5	100	100	82.5
100	100	100	81.5	100	100	81.5
99	100	100	80.5	100	100	80.5
98	100	100	79.6	100	100	79.6
97	100	100	78.6	100	100	78.6
96	100	100	77.7	100	100	77.7
95	100	100	76.7	100	100	76.7
94	100	100	75.7	100	100	75.7
93	100	100	74.8	100	100	74.8
92	100	100	73.8	100	100	73.8
91	100	100	72.8	100	100	72.9
90	100	100	71.9	100	100	71.9
89	100	100	70.9	100	100	70.9
88	100	100	70.0	100	100	70.0
87	100	100	69.0	100	100	69.0
86	100	100	68.0	100	100	68.1
85	100	100	67.1	100	100	67.1
84	100	100	66.1	100	100	66.1
83	100	100	65.2	100	100	65.2
82	100	100	64.2	100	100	64.2
81	100	100	63.2	100	100	63.3
80	100	100	62.3	100	100	62.3
79	100	100	61.3	100	100	61.3
78	100	100	60.3	100	100	60.4
77	100	100	59.4	100	100	59.4
76	100	100	58.4	100	100	58.4
75	100	100	57.5	100	100	57.5
74	100	100	56.5	100	100	56.5
73	100	100	55.5	100	100	55.6
72	100	100	54.6	100	100	54.6
71	100	100	53.6	100	100	53.6
70	100	100	52.7	100	100	52.7
69	100	100	51.7	100	100	51.7
68	100	100	50.7	100	100	50.7
67	100	100	49.8	100	100	49.8
66	100	100	48.8	100	100	48.8
65	100	100	47.8	100	100	47.8
64	100	100	46.9	100	100	46.9
63	100	100	45.9	100	100	45.9
62	100	100	45.0	100	100	45.0
61	100	100	44.0	100	100	44.0
60	100	100	43.0	100	100	43.0
59	100	100	42.1	100	100	42.1
58	100	100	41.1	100	100	41.1
57	100	100	40.2	100	100	40.2
56	100	100	39.2	100	100	39.2
55	100	100	38.2	100	100	38.2
54	100	100	37.3	100	100	37.3
53	100	100	36.3	100	100	36.3
52	100	100	35.3	100	100	35.3
51	100	100	34.4	100	100	34.4
50	100	100	33.4	100	100	33.4
49	100	100	32.5	100	100	32.5
48	100	100	31.5	100	100	31.5
% FP	CRGP 5	CRGP 6	CRGP 7	CRGP 5	CRGP 6	CRGP 7
	Shutdown Margin Setpoint			Operational Alarm Setpoint		

RI = 300 is withdrawal limit at all power levels.

Continued on next page.

Oconee 2 Cycle 18
Rod Index Setpoints
4 Pump Operation, 1 Inoperable Rod, BOC to EOC

% FP	Shutdown Margin Setpoint			Operational Alarm Setpoint		
	CRGP 5	CRGP 6	CRGP 7	CRGP 5	CRGP 6	CRGP 7
47	100	100	29.5	100	100	29.5
46	100	100	27.5	100	100	27.5
45	100	100	25.5	100	100	25.5
44.8	100	100	25.0	100	100	25.0
44	100	99.2	24.2	100	99.2	24.2
43	100	98.2	23.2	100	98.2	23.2
42	100	97.2	22.2	100	97.2	22.2
41	100	96.2	21.2	100	96.2	21.2
40	100	95.2	20.2	100	95.2	20.2
39	100	94.2	19.2	100	94.2	19.2
38	100	93.2	18.2	100	93.2	18.2
37	100	92.2	17.2	100	92.2	17.2
36	100	91.2	16.2	100	91.2	16.2
35	100	90.2	15.2	100	90.2	15.2
34	100	89.2	14.2	100	89.2	14.2
33	100	88.2	13.2	100	88.2	13.2
32	100	87.2	12.2	100	87.2	12.2
31	100	86.2	11.2	100	86.2	11.2
30	100	85.2	10.2	100	85.2	10.2
29	100	84.2	9.2	100	84.2	9.2
28	100	83.2	8.2	100	83.2	8.2
27	100	82.2	7.2	100	82.2	7.2
26	100	81.2	6.2	100	81.2	6.2
25	100	80.2	5.2	100	80.2	5.2
24	100	79.2	4.2	100	79.2	4.2
23	100	78.2	3.2	100	78.2	3.2
22	100	77.2	2.2	100	77.2	2.2
21	100	76.2	1.2	100	76.2	1.2
20	100	75.2	0.2	100	75.2	0.2
19.8	100	75.0	0	100	75.0	0
19	100	73.5	0	100	73.5	0
18	100	71.5	0	100	71.5	0
17	100	69.5	0	100	69.5	0
16	100	67.5	0	100	67.5	0
15	100	65.5	0	100	65.5	0
14	100	63.5	0	100	63.5	0
13	100	61.5	0	100	61.5	0
12	100	53.0	0	100	53.0	0
11	100	44.5	0	100	44.5	0
10	100	36.0	0	100	36.0	0
9	100	27.5	0	100	27.5	0
8.7	100	25.0	0	100	25.0	0
8	97.0	22.0	0	97.0	22.0	0
7	92.8	17.8	0	92.8	17.8	0
6	88.5	13.5	0	88.5	13.5	0
5	84.2	9.2	0	84.2	9.2	0
4	80.0	5.0	0	80.0	5.0	0
3	75.8	0.8	0	75.8	0.8	0
2.8	75.0	0	0	75.0	0	0
2	68.0	0	0	68.0	0	0
1	59.5	0	0	59.5	0	0
0	51.0	0	0	51.0	0	0
% FP	CRGP 5	CRGP 6	CRGP 7	CRGP 5	CRGP 6	CRGP 7
	Shutdown Margin Setpoint			Operational Alarm Setpoint		

RI = 300 is withdrawal limit at all power levels.

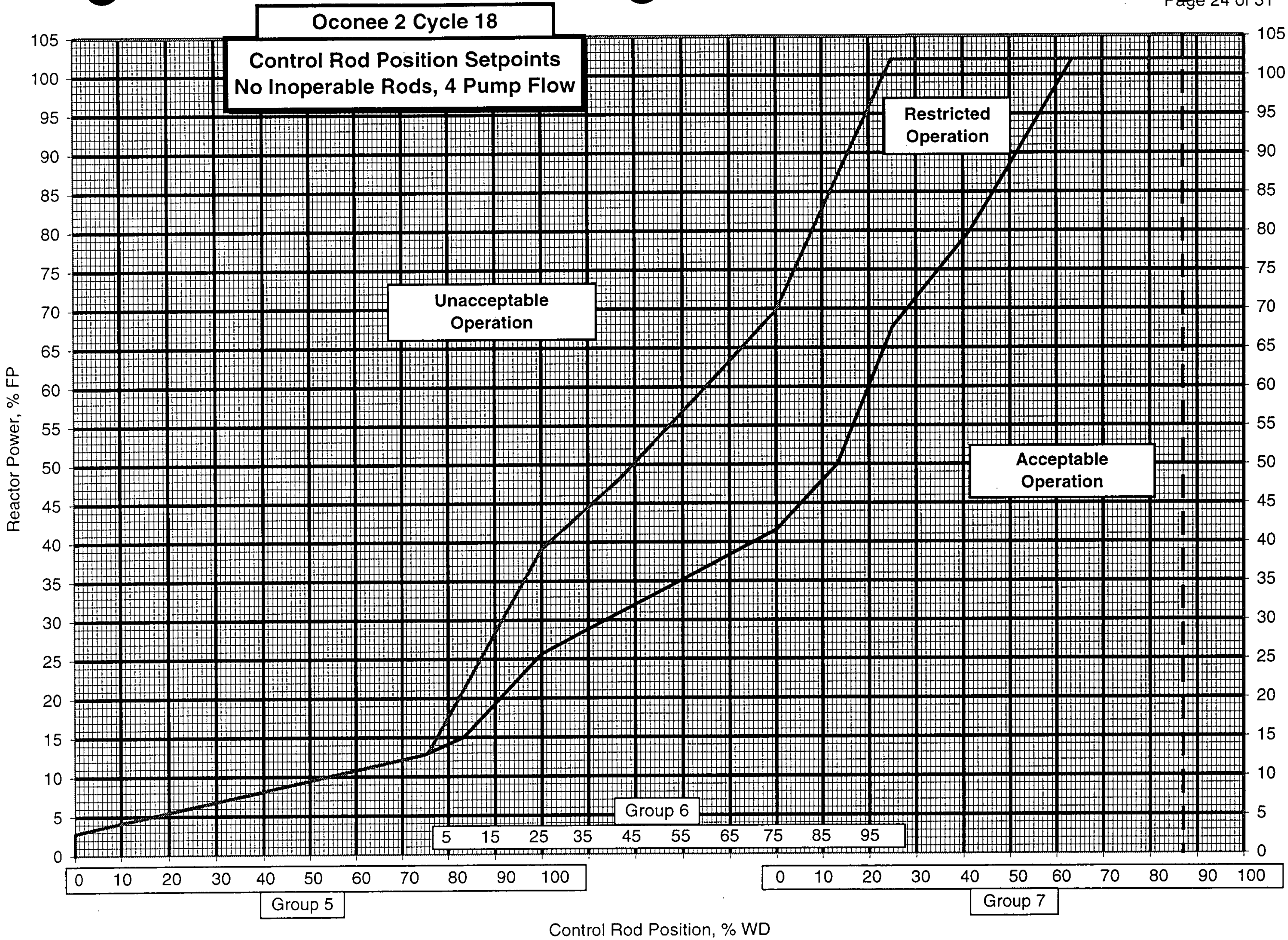
% FP	Shutdown Margin Setpoint			Operational Alarm Setpoint		
	CRGP 5	CRGP 6	CRGP 7	CRGP 5	CRGP 6	CRGP 7
77	100	100	85.2	100	100	85.2
76	100	100	83.4	100	100	83.4
75	100	100	81.5	100	100	81.5
74	100	100	79.6	100	100	79.6
73	100	100	77.8	100	100	77.8
72	100	100	75.9	100	100	75.9
71	100	100	74.1	100	100	74.1
70	100	100	72.2	100	100	72.2
69	100	100	70.4	100	100	70.4
68	100	100	68.5	100	100	68.5
67	100	100	66.7	100	100	66.7
66	100	100	64.8	100	100	64.8
65	100	100	63.0	100	100	63.0
64	100	100	61.1	100	100	61.1
63	100	100	59.3	100	100	59.3
62	100	100	57.4	100	100	57.4
61	100	100	55.6	100	100	55.6
60	100	100	53.7	100	100	53.7
59	100	100	51.9	100	100	51.9
58	100	100	50.0	100	100	50.0
57	100	100	48.2	100	100	48.2
56	100	100	46.3	100	100	46.3
55	100	100	44.5	100	100	44.5
54	100	100	42.6	100	100	42.6
53	100	100	40.8	100	100	40.8
52	100	100	38.9	100	100	38.9
51	100	100	37.1	100	100	37.1
50	100	100	35.2	100	100	35.2
49	100	100	33.4	100	100	33.4
48	100	100	31.5	100	100	31.5
47	100	100	29.5	100	100	29.5
46	100	100	27.5	100	100	27.5
45	100	100	25.5	100	100	25.5
44.8	100	100	25.0	100	100	25.0
44	100	99.2	24.2	100	99.2	24.2
43	100	98.2	23.2	100	98.2	23.2
42	100	97.2	22.2	100	97.2	22.2
41	100	96.2	21.2	100	96.2	21.2
40	100	95.2	20.2	100	95.2	20.2
39	100	94.2	19.2	100	94.2	19.2
38	100	93.2	18.2	100	93.2	18.2
37	100	92.2	17.2	100	92.2	17.2
36	100	91.2	16.2	100	91.2	16.2
35	100	90.2	15.2	100	90.2	15.2
34	100	89.2	14.2	100	89.2	14.2
33	100	88.2	13.2	100	88.2	13.2
32	100	87.2	12.2	100	87.2	12.2
31	100	86.2	11.2	100	86.2	11.2
30	100	85.2	10.2	100	85.2	10.2
29	100	84.2	9.2	100	84.2	9.2
28	100	83.2	8.2	100	83.2	8.2
27	100	82.2	7.2	100	82.2	7.2
26	100	81.2	6.2	100	81.2	6.2
25	100	80.2	5.2	100	80.2	5.2
24	100	79.2	4.2	100	79.2	4.2
% FP	CRGP 5	CRGP 6	CRGP 7	CRGP 5	CRGP 6	CRGP 7
	Shutdown Margin Setpoint			Operational Alarm Setpoint		

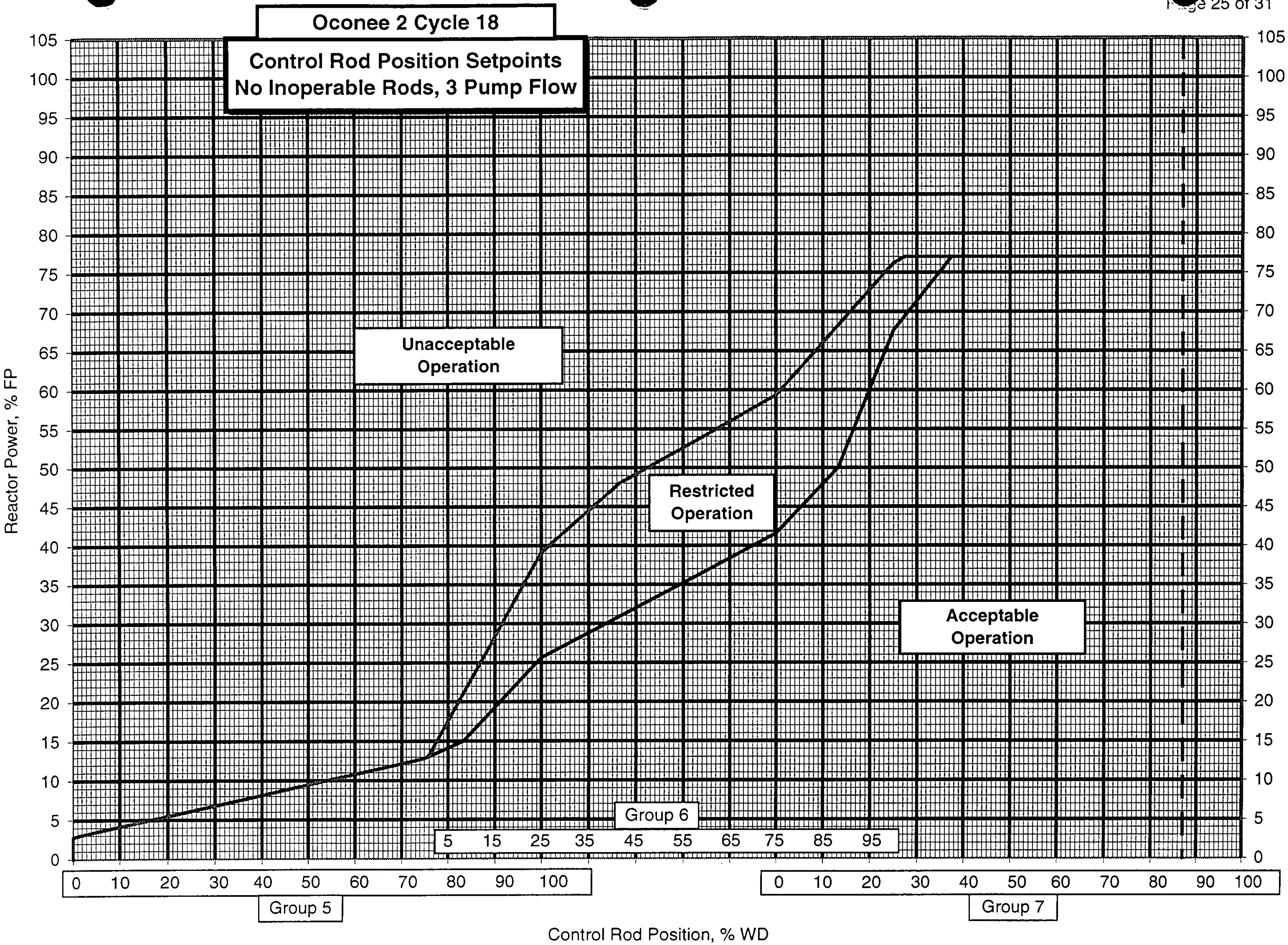
RI = 300 is withdrawal limit at all power levels. Continued on next page.

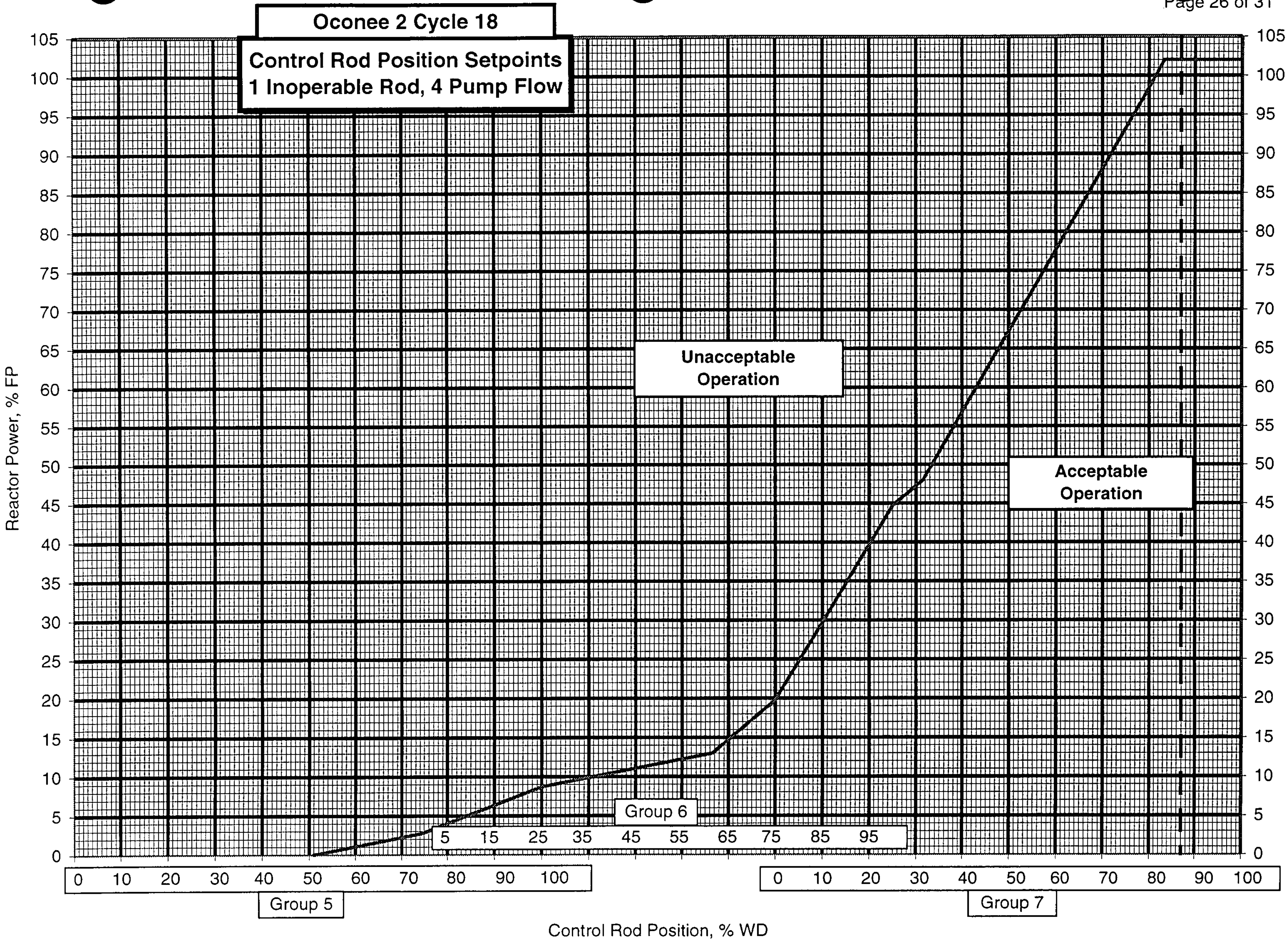
Oconee 2 Cycle 18
Rod Index Setpoints
3 Pump Operation, 1 Inoperable Rod, BOC to EOC

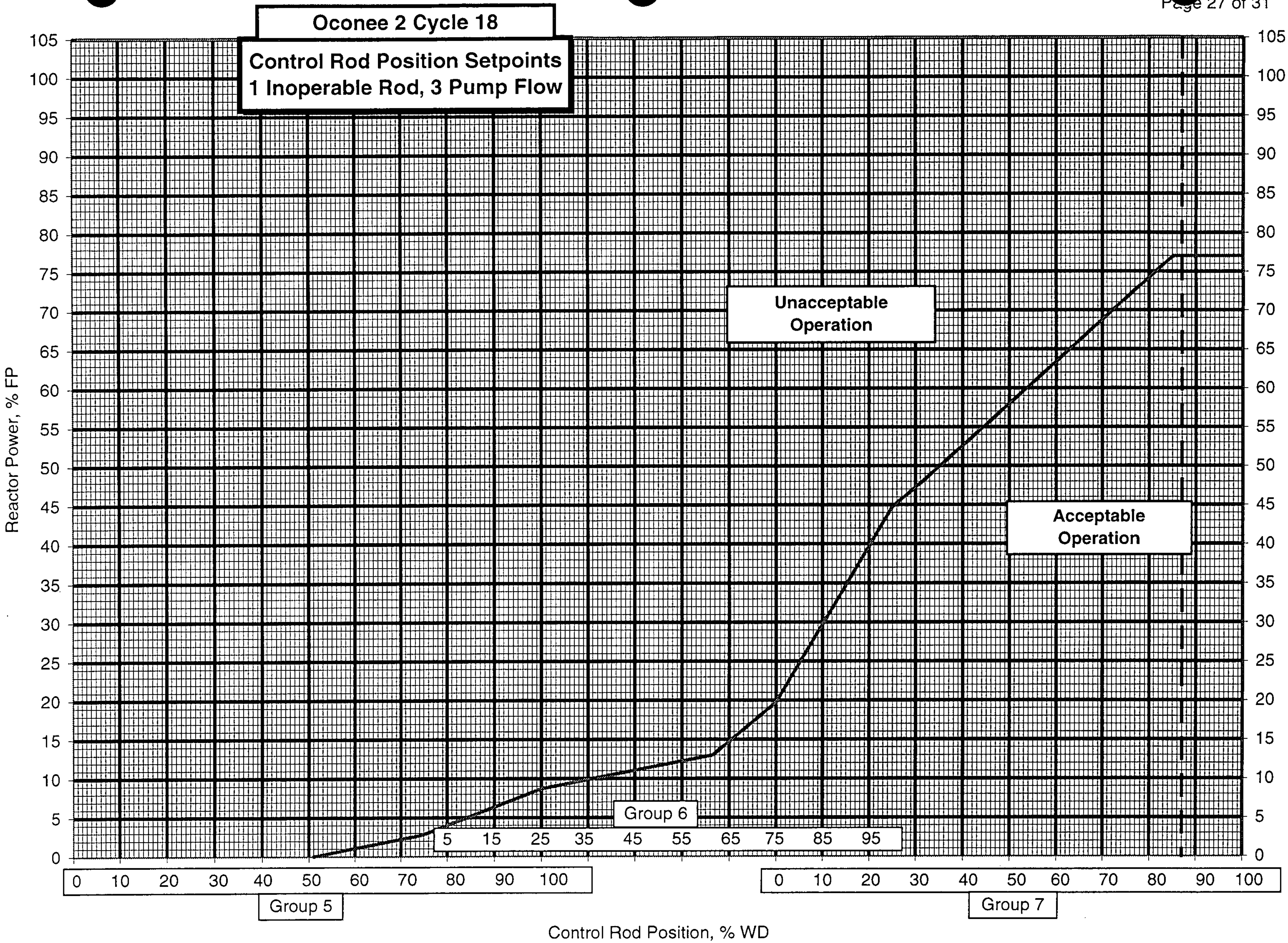
% FP	Shutdown Margin Setpoint			Operational Alarm Setpoint		
	CRGP 5	CRGP 6	CRGP 7	CRGP 5	CRGP 6	CRGP 7
23	100	78.2	3.2	100	78.2	3.2
22	100	77.2	2.2	100	77.2	2.2
21	100	76.2	1.2	100	76.2	1.2
20	100	75.2	0.2	100	75.2	0.2
19.8	100	75.0	0	100	75.0	0
19	100	73.5	0	100	73.5	0
18	100	71.5	0	100	71.5	0
17	100	69.5	0	100	69.5	0
16	100	67.5	0	100	67.5	0
15	100	65.5	0	100	65.5	0
14	100	63.5	0	100	63.5	0
13	100	61.5	0	100	61.5	0
12	100	53.0	0	100	53.0	0
11	100	44.5	0	100	44.5	0
10	100	36.0	0	100	36.0	0
9	100	27.5	0	100	27.5	0
8.7	100	25.0	0	100	25.0	0
8	97.0	22.0	0	97.0	22.0	0
7	92.8	17.8	0	92.8	17.8	0
6	88.5	13.5	0	88.5	13.5	0
5	84.2	9.2	0	84.2	9.2	0
4	80.0	5.0	0	80.0	5.0	0
3	75.8	0.8	0	75.8	0.8	0
2.8	75.0	0	0	75.0	0	0
2	68.0	0	0	68.0	0	0
1	59.5	0	0	59.5	0	0
0	51.0	0	0	51.0	0	0
% FP	CRGP 5	CRGP 6	CRGP 7	CRGP 5	CRGP 6	CRGP 7
	Shutdown Margin Setpoint			Operational Alarm Setpoint		

RI = 300 is withdrawal limit at all power levels.


Oconee 2 Cycle 18
Control Rod Position Setpoints
No Inoperable Rods, 4 Pump Flow
Restricted Operation
Unacceptable Operation
Acceptable Operation
Reactor Power, % FP
0
5
10
15
20
25
30
35
40
45
50
55
60
65
70
75
80
85
90
95
100
105
Group 6
5 15 25 35 45 55 65 75 85 95
0 10 20 30 40 50 60 70 80 90 100
Group 5
0 10 20 30 40 50 60 70 80 90 100
Group 7
Control Rod Position, % WD


Oconee 2 Cycle 18
Control Rod Position Setpoints
No Inoperable Rods, 3 Pump Flow
Unacceptable Operation
Restricted Operation
Acceptable Operation
Reactor Power, % FP
105 100 95 90 85 80 75 70 65 60 55 50 45 40 35 30 25 20 15 10 5 0
Group 6
5 15 25 35 45 55 65 75 85 95
0 10 20 30 40 50 60 70 80 90 100
Group 5
0 10 20 30 40 50 60 70 80 90 100
Group 7
Control Rod Position, % WD


Oconee 2 Cycle 18
Control Rod Position Setpoints
1 Inoperable Rod, 4 Pump Flow
Reactor Power, % FP
Unacceptable Operation
Acceptable Operation
Group 5
0 10 20 30 40 50 60 70 80 90 100
Group 6
5 15 25 35 45 55 65 75 85 95
Group 7
0 10 20 30 40 50 60 70 80 90 100
Control Rod Position, % WD
0 5 10 15 20 25 30 35 40 45 50 55 60 65 70 75 80 85 90 95 100 105


Oconee 2 Cycle 18
Control Rod Position Setpoints
1 Inoperable Rod, 3 Pump Flow
Reactor Power, % FP
0
5
10
15
20
25
30
35
40
45
50
55
60
65
70
75
80
85
90
95
100
105
Unacceptable Operation
Acceptable Operation
Group 6
5 15 25 35 45 55 65 75 85 95
0 10 20 30 40 50 60 70 80 90 100
Group 5
0 10 20 30 40 50 60 70 80 90 100
Group 7
Control Rod Position, % WD

Oconee 2 Cycle 18

2.0 Core Operating Limits -- Not Error Adjusted

The data provided on the following pages satisfies a licensing commitment to identify specific parameters before instrumentation uncertainties are incorporated.

References provided in section 1 of this COLR identify the sources for the data which follows.

Information provided in this section should not be used in plant procedures.

Quadrant Power Tilt Limits

Referred to by ITS 3.2.3.

	Steady State		Transient		Maximum
Core Power Level, %FP	30 - 100	0 - 30	30 - 100	0 - 30	0 - 100
Quadrant Power Tilt, %	4.95	10.00	9.44	12.00	20.00

Variable Low RCS Pressure Protective Limits

Referred to by ITS 2.1.1.

Core Outlet Pressure psia	Reactor Coolant Outlet Temperature, °F 3 RCS Pumps	4 RCS Pumps
1800	581.0	578.3
1900	590.0	587.3
2000	598.9	596.3
2100	607.9	605.2
2200	616.9	614.2
2300	625.9	623.2

Oconee 2 Cycle 18

Axial Power Imbalance Protective Limits

Referred to by ITS 2.1.1.

Not for Plant Use

	%FP	RPS	Operational
4 Pumps	0	-48.0	-43.8
	80	-	-43.8
	90	-	-41.3
	100	-48.0	-30.0
	112	-31.1	-
	112	31.1	-
	100	48.0	30.0
	90	-	39.4
	80	-	39.4
	0	48.0	39.4
3 Pumps	0	-48.0	-43.8
	74.6	-48.0	-
	77.0	-	-43.8
	86.6	-31.1	-
	86.6	31.1	-
	77.0	-	39.4
	74.6	48.0	-
	0	48.0	39.4

Oconee 2 Cycle 18

Rod Index Limits

Referred to by ITS 3.2.1.

Not for Plant Use

	%FP	Operational RI Insertion Limit	Shutdown Margin RI Insertion Limit No Inop Rod	Shutdown Margin RI Insertion Limit 1 Inop Rod	RI Withdrawal Limit
4 Pump	102	262	220	280	300
	100	260	-	-	300
	90	250	-	-	300
	80	240	-	-	300
	50	200	140	230	300
	15	90	75	160	300
	5	0	0	75	300
3 Pump	77	236	220	280	300
	50	200	140	230	300
	15	90	75	160	300
	5	0	0	75	300

Oconee 2 Cycle 18

LOCA LHR Limits

Not for Plant Use

	Core Elevation Feet	LOCA LHR kw/ft Limit Versus Burnup		
Mk-B10 Fuel		28 GWd/mtU	45 GWd/mtU	62 GWd/mtU
	0.000	15.8	15.8	13.36
	2.506	16.6	16.6	13.36
	4.264	17.0	17.0	13.36
	6.021	17.0	17.0	13.36
	7.779	17.0	17.0	13.36
	9.536	16.6	16.6	13.36
	12.00	15.8	15.8	13.36
Mk-B10L Fuel		0 GWd/mtU	30 GWd/mtU	62 GWd/mtU
	0.000	16.2	16.2	11.9
	2.506	17.0	17.0	11.9
	4.264	17.3	17.3	11.9
	6.021	17.3	17.3	11.9
	7.779	17.3	17.3	11.9
	9.536	17.0	17.0	11.9
	12.00	16.2	16.2	11.9
Mk-B11 Fuel		0 GWd/mtU	30 GWd/mtU	60 GWd/mtU
	0.000	14.3	14.3	9.2
	2.506	15.1	15.1	9.2
	4.264	15.4	15.4	9.2
	6.021	15.8	15.8	9.2
	7.779	15.6	15.6	9.2
	9.536	15.1	15.1	9.2
	12.00	14.3	14.3	9.2

ATTACMENT VII

MARKUP OF THE UPDATED FINAL SAFETY ANALYSIS REPORT

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CHAPTER 15. ACCIDENT ANALYSES

This section details the expected response of the plant to the spectrum of transients and accidents which constitute the design basis events. The analyses presented show that the plant response is either inherently limited by the characteristics of the system or is terminated by the normal functions of the Reactor Protective System (RPS) and the Engineered Safeguards Protective System (ESPS). The analyses are evaluated for an initial core power of 2,568 MWt unless specified otherwise. The consequences of the worst case loss of coolant accident (LOCA) are demonstrated to be within the limits specified in 10CFR50.46. For all transients and accidents resulting in a release of fission products to the environment, the dose consequences using the dispersion model developed in Section 2.3, "Meteorology" are shown to be within the limits specified in 10CFR100.

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15.1 METHODOLOGY

15.1.1 Overview

This chapter details the expected response of the plant to the spectrum of transients and accidents which constitute the design basis events. The methodologies used to analyze the Chapter 15 transients and accidents fall into three general categories. These are the non-LOCA transient and accident analysis methodologies which are detailed in the Duke Power topical report DPC-NE-3005-PA (Reference 1), the Framatome Technologies Inc. LOCA analysis methodologies (References 2 and 3) described in Section 15.14, and the Duke Power offsite dose analysis methodology described in Section 15.1.10.

The DPC-NE-3005-PA topical report methodology was used to establish a new set of licensing basis analyses beginning with Oconee Unit 2 Cycle 18 in 1999. The following transients and accidents are analyzed with the new methodology. The specific cases analyzed for each transient or accident are listed in Table 15-32.

- 15.2 Startup Accident
- 15.3 Rod Withdrawal at Power Accident
- 15.4 Moderator Dilution Accidents
- 15.5 Cold Water Accident
- 15.6 Loss of Coolant Flow Accidents
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Section 15.1, "Uncompensated Operating Reactivity Changes", in the original FSAR was deleted since the plant transient response due to the effects of fuel depletion and xenon buildup are insignificant and do not challenge the Reactor Protective and Engineered Safeguards Systems or approach any design limits. Sections 15.10, 15.11, 15.15, and 15.16 do not require thermal-hydraulic transient analyses methods and were not reanalyzed in DPC-NE-3005-PA.

15.1.2 Topical Reports

The topical reports which describe the analysis methodologies used in this chapter are as follows:

<u>DPC-NE-3000-PA</u>
DPC-NE-3000-PA, "Thermal-Hydraulic Transient Analysis Methodology," (Reference 4) describes the RETRAN-02 (Reference 5) system transient thermal-hydraulic models and the VIPRE-01 (Reference 6) core transient thermal-hydraulic models used by Duke Power to analyze most of the non-LOCA transients and accidents. This report includes the standard nodalization model and the various code options that are used.

DPC-NE-3005-PA

DPC-NE-3005-PA, "UFSAR Chapter 15 Transient Analysis Methodology," (Reference 1) describes the Duke Power methodology for analyzing the UFSAR Chapter 15 non-LOCA transients and accidents for the Oconee Nuclear Station. This report includes a description of the computer codes used, the physics parameters, the setpoint methodology, and details of the initial conditions, boundary conditions, acceptance criteria, and all other aspects of the methodology. The computer codes comprising this methodology are RETRAN-02 (Reference 5), VIPRE-01 (Reference 6), CASMO-3 (Reference 7), SIMULATE-3P (Reference 8), SIMULATE-3K (Reference 9), TACO-3 (Reference 10), and ARROTTA (Reference 26).

DPC-NE-1004 -A

DPC-NE-1004-A, "Nuclear Design Methodology Using CASMO-3 / SIMULATE-3P," (Reference 11) describes the Duke Power methodology for the neutronic simulation of the Oconee reactors with the CASMO-3 (Reference 7) / SIMULATE-3P (Reference 8) codes.

DPC-NE-2003-PA

DPC-NE-2003-PA, "Core Thermal-Hydraulic Methodology Using VIPRE-01," (Reference 12) describes the Duke Power methodology for core thermal-hydraulic analysis for Oconee using the VIPRE-01 code. The non-statistical DNBR limit using the BWU CHF correlation is developed in this report.

DPC-NE-2005-PA

DPC-NE-2005-PA, "Thermal-Hydraulic Statistical Core Design Methodology," (Reference 13) describes the Duke Power methodology for determining the statistical DNBR limits using the VIPRE-01 code. This methodology allows the uncertainty in many of the DNB-related parameters to be combined into a statistical DNBR limit, rather than to include each uncertainty explicitly in the thermal-hydraulic analysis. For some of the transients and accidents the primary flowrate associated with less than four pumps in operation, and the higher flow uncertainty at reduced flowrates, result in different statistical DNBR design limits. The applicable limit is given for each analysis. The non-statistical DNBR limits using the BWU correlations are developed in this report.

BAW-10192P

BAW-10192P, "BWNT Loss-of-Coolant Accident Evaluation Model for Once-Through Steam Generator Plants," (Reference 2) describes the RELAP5-based Framatome Technologies, Inc., LOCA Evaluation Model. This topical report has been accepted by the NRC as in compliance with 10 CFR Appendix K (Reference 14). The computer codes which comprise this methodology are RELAP5/MOD2-B&W (Reference 15), CONTEMPT (Reference 16), REFLOD3B (Reference 17), and BEACH (Reference 18). The Oconee large-break LOCA spectrum is analyzed with this Evaluation Model.

BAW-10154P

BAW-10154P, "B&W's Small-Break LOCA ECCS Evaluation Model," (Reference 3) describes the CRAFT2-based Framatome Technologies, Inc., small-break LOCA Evaluation Model. This topical report has been accepted by the NRC as in compliance with 10 CFR Appendix K (Reference 14). The computer codes which comprise this methodology are CRAFT2 (Reference 19), FOAM2 (Reference 20), and THETA1-B (Reference 21). The Oconee small-break LOCA spectrum is analyzed with this Evaluation Model.

15.1.3 Computer Codes and CHF Correlations

RETRAN-02
The non-LOCA system transient thermal-hydraulic analyses use the RETRAN-02 code (Reference 5) developed by the Electric Power Research Institute. RETRAN-02 has the flexibility to model any general fluid system by partitioning the system into a one-dimensional network of fluid volumes and connecting junctions. The mass, momentum, and energy equations are then solved by employing a semi-implicit solution method. The equations are based on a homogeneous two-phase mixture, with capability for phase separation via bubble rise and slip models. A non-equilibrium pressurizer model, special component models for pumps, valves, and control systems, and general heat transfer modeling are included. For transients which challenge the DNBR limit, RETRAN-02 provides core boundary conditions to VIPRE-01 and SIMULATE-3P.

VIPRE-01
The core thermal-hydraulic and fuel pin analyses use the VIPRE-01 code (Reference 6) developed by the Electric Power Research Institute. VIPRE-01 uses the subchannel analysis approach in which the fuel assembly is divided into a number of quasi-one-dimensional channels that communicate laterally by diversion crossflow and turbulent mixing. Conservation equations of mass, axial and lateral flow, and momentum are solved. The flow field is assumed to be incompressible and homogeneous, with models for subcooled boiling and co-current phase slip. VIPRE-01 accepts boundary conditions from RETRAN-02 and SIMULATE-3P and determines the DNBR using the applicable CHF correlations.

CASMO-3:
Nuclear constants are generated with the Studsvik of America code CASMO-3 (Reference 7) for use in Oconee reload design (Reference 11). CASMO-3 is used for generating data used as input to the SIMULATE codes.

SIMULATE-3P
Nuclear parameters and core power distributions are generated with the Studsvik of America code SIMULATE-3P (Reference 8) for use in Oconee reload design (Reference 11). Nuclear constants are input to SIMULATE-3P from the CASMO-3 code. SIMULATE-3P outputs are input to the RETRAN-02 and VIPRE-01 codes.

SIMULATE-3K
The Studsvik of America code SIMULATE-3K (Reference 9) is used for transient three-dimensional modeling of the rod ejection accident. SIMULATE-3K provides the same neutronics solution to steady-state 3-D calculations as SIMULATE-3P. Nuclear constants are input to SIMULATE-3P from the CASMO-3 code. SIMULATE-3K rod ejection analysis results are input to RETRAN-02 and VIPRE-01.

ARROTTA/1.10: The EPRI code ARROTTA (Reference 26) is used for transient three-dimensional (3-D) modeling of the rod ejection accident. Nuclear constants are input to ARROTTA from the CASMO-3 code. ARROTTA rod ejection analysis results are input to RETRAN-02 and VIPRE-01.

TACO-3

The TACO-3 code (Reference 10) developed by Framatome Technologies is used to calculate the initial fuel pin thermal and mechanical conditions for the non-LOCA analyses performed by Duke Power, and for the LOCA analyses performed by Framatome Technologies, Inc.

RELAP5/MOD2-B&W

The RELAP5/MOD2-B&W code (Reference 15) developed by Framatome Technologies, Inc., is used for best-estimate and licensing transient simulation of pressurized water reactors. It has also been modified to include the conservative models required for LOCA analysis per Appendix K to 10 CFR 50 (Reference 14). The solution technique contains two energy equations, a two-step numerics option, a gap conductance model, constitutive models, and control and component system models. This code is used for the blowdown simulation in Oconee large-break LOCA analyses.

CONTEMPT

The CONTEMPT code (Reference 16) as modified by Framatome Technologies, Inc., is used to calculate the containment pressure following LOCA. The containment pressure is used as an input to the RELAP5 blowdown analysis and the REFLOD3 refill and reflood analysis.

REFLOD3B

The REFLOD3B code (Reference 17) developed by Framatome Technologies, Inc., is used for simulation of the refill and reflood periods of the large-break LOCA analysis. The program calculates flows, mass and energy inventories, pressures, temperatures, and steam qualities along with variables associated with the refilling of the reactor lower plenum and the recovery of the core.

BEACH

The BEACH code (Reference 18) developed by Framatome Technologies, Inc., is used for the prediction of reflood heat transfer during the large-break LOCA analysis. It calculates the peak cladding temperature and the local oxidation for comparison with the 10 CFR 50.46 (Reference 22) acceptance criteria.

CRAFT2

The CRAFT2 code (Reference 19) developed by Framatome Technologies, Inc., is used to calculate the hydrodynamic behavior of the Reactor Coolant System during small-break LOCAs.

FOAM2

The FOAM2 code (Reference 20) developed by Framatome Technologies, Inc., is used to calculate the core mixture level for small-break LOCAs that uncover the core.

THETA-1B

The THETA-1B code (Reference 21) as revised by Framatome Technologies, Inc., is used to calculate the fuel pin thermal and mechanical response, including the peak cladding temperature for small-break LOCAs.

BWC Critical Heat Flux Correlation

The BWC critical heat flux correlation (Reference 23) is used in the VIPRE-01 code to calculate the DNBR for non-LOCA transient and accident analyses for fuel assemblies without mixing vane grids.

BWU-Z Critical Heat Flux Correlation
The BWU-Z critical heat flux correlation (Reference 24) is used in the VIPRE-01 code to calculate the DNBR for non-LOCA transient and accident analyses for fuel assemblies with mixing vane grids.

BWU-N Critical Heat Flux Correlation
The BWU-N critical heat flux correlation (Reference 24) is used in the VIPRE-01 code to calculate the DNBR for non-LOCA transient and accident analyses for fuel assemblies with mixing vane grids, but in the lower part of the fuel assembly where there are no mixing vane grids. This correlation can also be used for the steam line break DNBR analysis.

W-3S Critical Heat Flux Correlation
The W-3S critical heat flux correlation as programmed in the VIPRE-01 code (Reference 6) is used to calculate the DNBR for the steam line break accident, when the core conditions are beyond the correlation ranges for the other critical heat flux correlations.

15.1.4 Initial Conditions

The generic initial conditions assumed in the transient and accident analyses are summarized in Table 15-34 and referenced figures. These values have been selected to ensure that the results of each analysis have an appropriate level of overall conservatism. Many of the initial conditions are determined based on the nominal value of the plant parameter plus or minus the uncertainty associated with each parameter. Parameters for which the uncertainty is included in the statistical DNBR limit are set to the nominal value. Initial conditions which are not included in this table are provided in the detailed description of each analysis.

15.1.5 Setpoints and Delay Times

The Reactor Protective System and Engineered Safeguards Protective System trip setpoints and delay times are summarized in Table 15-35. The setpoints are based on the technical specification values, and are either increased or decreased to account for setpoint drift depending on whether an earlier or later reactor trip is conservative. Trip delay times account for instrument string delays and component delays, such as the control rod gripper coil release delay.

15.1.6 Reactivity Insertion Following Reactor Trip

The reactivity insertion following reactor trip is a combination of a minimum available tripped rod worth and a normalized insertion rate. The minimum available tripped rod worth assumed in safety analyses must ensure, as a minimum, that the shutdown margin in the technical specifications is preserved. This shutdown margin assumes that the most reactive rod remains in the fully withdrawn position and that the other control rods drop from their power dependent insertion limits. The normalized reactivity insertion rate is determined by bounding control rod drop times as determined by plant testing, and by developing a conservative relationship between rod position and normalized reactivity worth.

15.1.7 Decay Heat

In the non-LOCA transients and accident analyses for which the post-trip decay heat is an important modeling consideration, the ANSI/ANS-5.1-1979 Standard (Reference 25) is used. The inputs to the calculation of the time-dependent decay heat per the ANS Standard are based on Oconee-specific core physics parameters. This modeling is implemented in the application of the RETRAN-02 code using either the built-in ANS standard with inputs to account for Oconee-specific core parameters, or as an input table of decay heat vs. time. The decay heat modeled by Framatome Technologies, Inc. in the LOCA analysis is 1.2 times the 1971 ANS Standard as required by 10 CFR 50 Appendix K (Reference 14).

15.1.8 Single Failure and Loss of Offsite Power Assumptions

A limiting active single failure in the Reactor Protective System or in the Engineered Safeguards is assumed. A single failure in the Emergency Feedwater System is also considered. A failure of the manual atmospheric dump valves is not considered. A loss of offsite power is only applied to the Section 15.13 steam line break accident, for which it is assumed to be lost at time zero, and for the Section 15.14 LOCA analyses.

15.1.9 Credit for Control Systems and Non-Safety Components and Systems

Control systems are generally assumed to respond as designed or remain in manual control (inactive), whichever assumption is more conservative. Non-safety components and systems are generally not credited in the analyses. The following are specific exceptions to the general modeling philosophy on control systems, and the situations where non-safety components and systems are credited in the analyses:

1) In the dropped rod event, the Integrated Control System will respond by initiating a plant runback to a reduced power level. Since this plant runback assists in the mitigation of the dropped rod event, no credit is taken for this control system design feature. This assumption is an additional conservatism that is not required by the methodology philosophy.

2) For a loss of all reactor coolant pumps without a loss of the Main Feedwater System, the Integrated Control System is credited for raising steam generator levels to the natural circulation setpoint. This design feature is implicitly credited in the loss of coolant flow event, and involves non-safety equipment. A failure of this design function would be mitigated manually by operator action to start the Emergency Feedwater (EFW) System.

3) The moderator dilution accident credits the non-safety high-flux-at-shutdown alarm and the control rod insertion limit alarm to alert the operator that a boron dilution event is in progress. Both of these alarms rely on non-safety equipment. The rod insertion alarm relies on the plant computer.

4) Many of the transient and accident analyses involve control rod movement. These analyses credit the normal withdrawal sequence, overlap, and rod speed, which are controlled by non-safety control systems.

5) For certain failures in the EFW System, credit is taken for realigning EFW flow through the non-safety MFW System.

6) Steaming of the steam generators with manual non-safety atmospheric dump valves is credited.

7) The turbine trip circuitry has two channels, one with a one second response time, and one with a fifteen second response time. The faster response time is credited in the methodology. The turbine trip circuitry is not completely safety-grade.

8) The capability to remotely throttle certain valves is credited. Some of the controls required to remotely throttle these valves are not safety-grade.

9) Electrical bus voltage and frequency control are credited. These are controlled by non-safety components.

10) The Integrated Control System trips both main feedwater pumps on a high steam generator level indication. A high level indication may occur following a main steam line break due to the pressure drops that result from the blowdown of the steam generator. Tripping of the main feedwater pumps will be assumed to occur in the steam line break analysis only if the plant response is more limiting.

15.1.10 Environmental Consequences Calculation Methodology

(TO BE SUBMITTED LATER)

15.1.11 Reload Safety Evaluation

Each fuel reload cycle design is reviewed to determine if the values of the safety analysis physics parameters assumed in the UFSAR Chapter 15 licensing basis transient and accident analyses remain valid. If the licensing basis assumptions remain bounding for the reload core, then no additional actions are required. If the predicted values violate the licensing basis assumptions for any of the key parameters, then reanalysis of the affected transients and accidents is required.

15.1.12 References

1. UFSAR Chapter 15 Transient Analysis Methodology, DPC-NE-3005-P, Revision 1, Duke Power, February 1999
2. BWNT Loss-of-Coolant Accident Evaluation Model for Once-Through Steam Generator Plants, BAW-10192P, B&W Nuclear Technologies, February 1994
3. B&W's Small-Break LOCA ECCS Evaluation Model, BAW-10154P, Babcock & Wilcox, November 1982
4. Thermal-Hydraulic Transient Analysis Methodology, DPC-NE-3000-PA, Revision 1, Duke Power, December 1997

5. RETRAN-02 - A Program for Transient Thermal-Hydraulic Analysis of Complex Fluid Flow Systems, EPRI NP-1850-CCM, Revision 4, EPR, November 1988
6. VIPRE-01: A Thermal-Hydraulic Code for Reactor Cores, EPRI NP-2511-CCM, Revision 3, EPRI, August 1989
7. CASMO-3: A Fuel Assembly Burnup Program User's Manual, NFA-88/48, Studsvik of America, September 1988
8. SIMULATE-3: Advanced Three-Dimensional Two-Group Reactor Analysis Code, SOA-92/01, Studsvik of America, April 1992
9. SIMULATE-3 Kinetics Theory and Model Description, SOA-96/26, Studsvik of America, April 1996
10. TACO-3 - Fuel Pin Thermal Analysis Code, BAW-10162-PA, Babcock & Wilcox, November 1989
11 Nuclear Design Methodology Using CASMO-3 / SIMULATE-3P, DPC-NE-1004-A, Duke Power, November 1992
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14. Appendix K to Part 50 - ECCS Evaluation Models, Code of Federal Regulations, Volume 10
15. RELAP5/MOD2-B&W - An Advanced Computer Program for Light Water Reactor LOCA and Non-LOCA Transient Analysis, BAW-10164P, Revision 3, B&W Nuclear Technologies, July 1996
16. CONTEMPT - Computer Program for Predicting Containment Pressure, BAW-10095A, Rev. 1, Babcock & Wilcox, April 1978
17. REFLOD3B - Model for Multinode Core Reflooding Analysis, BAW-10171P, Revision 2, Babcock & Wilcox, January 1989
18. BEACH -A Computer Code for Reflood Heat Transfer During LOCA, BAW-10166P, Rev. 2, Babcock & Wilcox, September 1989
19. CRAFT2 - FORTRAN Program for Digital Simulation of a Multinode Reactor Plant During Loss of Coolant, BAW-10092PA, Revision 3, Babcock & Wilcox, July 1985
20. FOAM2 - Computer Program to Calculate Core Swell Level and Mass Flow Rate During Small-Break LOCA, BAW-10155A, Babcock & Wilcox, October 1987
21. THETA1-B - A Computer Code for Nuclear Reactor Core Analysis, BAW-10094, Babcock & Wilcox, July 1974
22. Acceptance Criteria for Emergency Core Cooling Systems for Light-Water Nuclear Power Reactors, 10 Code of Federal Regulations, Part 50.46
23. BWC Correlation of Critical Heat Flux, BAW-10143-PA, Babcock & Wilcox, April 1985
24. The BWU Critical Heat Flux Correlation, BAW-10199-PA, April 1996
25. American National Standard for Decay Heat Power in Light Water Reactors, ANSI/ANS-5.1-1979, American Nuclear Society, August 1979
26. ARROTTA: Advanced Rapid Reactor Operational Transient Analysis, EPRI NP-7375-CCML, Rev. 1, EPRI, August 1993.

15.2 STARTUP ACCIDENT

15.2.1 Identification of Causes and Description

The startup accident is an uncontrolled withdrawal of a control rod group from a zero power initial condition. It is caused by an operator error or a malfunction in the Rod Control System and can result in a nuclear power excursion. Since the heat removal capability of the secondary system is not increased during the power excursion, the resultant power mismatch would cause an increase in the Reactor Coolant System (RCS) and secondary system temperatures and pressures. The control rod motion would also cause the core power peaking to change. The reactor would be expected to trip on high flux or high RCS pressure.

The startup accident is analyzed from a hot zero power beginning-of-cycle condition, with three reactor coolant pumps (RCPs) in operation. The maximum control rod withdrawal rate is assumed. The system analysis determines the transient peak RCS pressure, and the transient core boundary conditions for the detailed core thermal-hydraulic analysis. In the peak RCS pressure analysis, the pressurizer spray and the pressurizer PORV are assumed to be inoperable. The pressurizer code safety valves (PSVs) are modeled using conservative assumptions for drift, blowdown, and valve capacity that minimize relief flow. The analysis methodology and the computer codes used in the analysis are given in Table 15-33. The initial conditions are given in Table 15-34. The Reactor Protective System and Engineered Safeguards Protective System setpoints and delay times are given in Table 15-35.

The reactivity addition rate assumed in the analysis is based on control rod group overlap, rod speed, and withdrawal sequence, which are controlled by non-safety systems. The loop with two RCPs in operation will indicate a lower hot leg pressure than the loop with only one active RCP. Therefore, the analysis assumes a single failure of one of the narrow range pressure channels on the loop with only one active RCP. This requires the high pressure reactor trip to be generated by the loop with a lower RCS pressure, which is conservative since it will delay reactor trip.

The startup accident is considered to be a fault of moderate frequency. The acceptance criteria for this accident are that the peak RCS pressure does not exceed 110% (2750 psig) of the design pressure, and that the minimum DNBR remains above the 1.50 design limit.

15.2.2 Analysis

The startup accident analysis assumes three RCPs in operation and a maximum control rod withdrawal rate of 11.5 pcm/sec. The analysis duration of 100 seconds is sufficient to demonstrate the peak thermal power and peak RCS pressure. The analysis results are shown in Figures 15-1 through 15-6, and the sequence of events is given in Table 15-36. Figure 15-1 shows the neutron power and thermal power transients. Neutron power does not begin to appreciably increase until the inserted reactivity begins to approach one dollar at approximately 45 seconds. Reactor trip occurs on high RCS pressure at 51.8 seconds with neutron power at approximately 125%. The thermal power rises to a peak value of 73% at 52 seconds. Since the peak core thermal power remains less than the permissible power level (75%) with three RCPs in operation, DNB is not a concern for this transient, and a detailed core thermal-hydraulic analysis is not necessary. Figure 15-2 shows the reactivity response. The reactivity insertion rate due to rod withdrawal is constant until reactor trip. Fuel heatup causes negative reactivity insertion due to Doppler temperature feedback until reactor trip. System heatup prior to reactor trip causes the moderator temperature to increase, which inserts positive reactivity due to the assumed positive

moderator temperature coefficient of reactivity. Figures 15-3 and 15-4 show the cold leg and hot leg temperature transients. Because of the reduced flow due to the inactive RCP, the temperature response in the loop with the inactive RCP is delayed. After reactor trip and the opening of the PSVs, the temperatures in both loops decrease. Figure 15-5 shows the pressurizer level response. During the thermal power excursion level rises rapidly due to the insurge of liquid into the pressurizer. After reactor trip and the opening of the PSVs, the pressurizer level rises more slowly and then stabilizes. Figure 15-6 shows the RCS pressure as a function of time. RCS pressure rises to a maximum value of approximately 2660.4 psig at 54.3 seconds, and then decreases due to PSV lift. The peak RCS pressure of 2746.9 psig occurs at the bottom of the reactor vessel.

15.2.3 Conclusions

The startup accident results in a peak core thermal power of 73%. Since this power level is below the permissible steady-state power level with three RCPs in operation, DNB is not a concern for this transient. The peak RCS pressure for this transient is 2746.9 psig. All of the acceptance criteria are met.

15.3 ROD WITHDRAWAL AT POWER ACCIDENT

15.3.1 Identification of Causes and Description

The rod withdrawal at power accident is caused by an operator error or a failure in the Rod Control System which results in an uncontrolled withdrawal of a control rod group while the reactor is at power. The rod withdrawal causes a nuclear power excursion and a resultant heatup and pressurization of the Reactor Coolant System (RCS). The expected plant response to a rod withdrawal event would include the following. Feedwater flow would follow the increase in reactor power, thereby maintaining adequate RCS heat removal until the reactor is tripped on high flux or flux/flow/imbalance. Following reactor trip, the Turbine Bypass System (TBS) and main steam code safety valves would relieve steam in order to control the post-trip steam generator pressures. RCS pressure would be controlled by the pressurizer spray, PORV, and heaters. In addition, feedwater would be automatically controlled to maintain the post-trip steam generator level.

Separate analyses are performed to investigate the peak RCS pressure and the core cooling capability following the rod withdrawal event. The core cooling analysis covers a spectrum of initial power levels that bounds the range of permissible power levels given the number of operating reactor coolant pumps (RCPs). Four and three RCPs in operation are considered. Initial power levels below 15% are assumed to be bounded by the startup accident. In the peak RCS pressure analysis, the pressurizer spray, pressurizer PORV, and the Turbine Bypass System are assumed to be inoperable. In addition, the pressurizer and main steam code safety valves are modeled using conservative assumptions for drift, blowdown, and valve capacity that minimize relief flow. Both the peak RCS pressure and the core cooling analyses hold main feedwater and main steam flow rates constant prior to reactor trip. The analysis methodology and the computer codes used in this analysis are given in Table 15-33. The initial conditions are given in Table 15-34. The Reactor Protective System and Engineered Safeguards System setpoints and delay times are given in Table 15-35.

The reactivity addition rates assumed in the analyses are bounded by minimum and maximum values which are calculated based on control rod group overlap, rod speed, and withdrawal sequence, which are controlled by non-safety systems. No single failure has been identified which adversely impacts the results of the cases initiated from four RCP operation. For the cases initiated from three RCP operation, the analysis assumes a single failure of one of the narrow range pressure channels on the loop with only one active RCP. This requires the high pressure reactor trip to be generated by the loop with a lower RCS pressure, which is conservative since it will delay reactor trip.

The rod withdrawal at power accident is considered to be a fault of moderate frequency. The acceptance criteria for this accident are that the minimum DNBR remains above the 1.50 design limit and the peak RCS pressure does not exceed 110% (2750 psig) of design pressure.

15.3.2 Peak RCS Pressure Analysis

The limiting peak RCS pressure case assumes a full power initial condition and a withdrawal rate equivalent to 2.4 pcm/sec. Since the maximum RCS pressure is expected to occur near the time of reactor trip, the analysis duration is 10 seconds following the reactor trip. The transient response for this limiting case is shown in Figures 15-11 through 15-14 and the sequence of events is given in Table 15-37. Neutron power (Figure 15-11) increases at a constant rate until the reactor trips on high RCS pressure at about 39 seconds. Since the reactivity insertion is fairly slow, the thermal power essentially stays in equilibrium with the neutron power prior to reactor trip. RCS hot and cold leg temperatures are

given in Figure 15-12. The cold leg temperature increases gradually prior to trip and then increases rapidly following the turbine trip due to increasing saturation temperature in the steam generators. Hot leg temperatures increase both due to the rising cold leg temperatures and due to the increasing reactor power. Pressurizer level (Figure 15-13) increases steadily as the RCS heats up, expands, and causes an insurge into the pressurizer. The RCS pressure response (Figure 15-14) essentially mirrors the pressurizer level, with a peak value reached at about 43 seconds. At this point, a peak pressure of 2611.5 psig is reached at the bottom of the reactor vessel.

15.3.3 Core Cooling Capability Analysis

The limiting DNBR case assumes a full power initial condition and a withdrawal rate equivalent to 1.0 pcm/sec. The transient response for this limiting case is shown in Figures 15-15 through 15-17, 15-113, and 15-114, and the sequence of events is given in Table 15-38. While the trends are very similar to those shown in the peak RCS pressure case, the duration of the analysis is much longer due to a significantly lower reactivity insertion rate. Since the minimum DNBR occurs near the time of reactor trip, the analysis duration is 10 seconds following the reactor trip. In order to evaluate the transient DNBR, the system analysis results are input to a detailed core thermal-hydraulic analysis. Neutron power and thermal power (Figure 15-15) increase at a constant rate until the reactor trips on high RCS pressure at about 148 seconds. RCS hot and cold leg temperatures are given in Figure 15-16. The cold leg temperature increases gradually prior to trip and then increases rapidly following the turbine trip due to increasing saturation temperature in the steam generators. Hot leg temperatures increase both due to the rising cold leg temperatures and due to the increasing reactor power. Pressurizer level (Figure 15-17) increases steadily as the RCS heats up, expands, and causes an insurge into the pressurizer. The RCS pressure response (Figure 15-113) essentially mirrors the pressurizer level, although the increase is suppressed by pressurizer spray. The transient minimum DNBR (Figure 15-114) of 1.719 occurs at 148 seconds.

15.3.4 Conclusions

The rod withdrawal at power accident results in a peak RCS pressure of 2611.5 psig. The minimum DNBR is determined to be 1.719. All of the acceptance criteria are met.

15.4 MODERATOR DILUTION ACCIDENTS

15.4.1 Identification of Causes and Description

A moderator dilution accident occurs when the soluble boric acid concentration of makeup water supplied to the Reactor Coolant System (RCS) is less than the concentration of the existing reactor coolant, and the water is injected in an uncontrolled manner. The cause of such an event can be attributed to any one of a number of failure modes in the systems that are capable of supplying unborated water to the RCS. With the reactor initially at power, control rods would insert to offset the reduction in RCS boron concentration. The operator would be alerted by the control rod insertion and terminate the event by either identifying the dilution source and isolating it, or by tripping the reactor manually. In the refueling mode the operator would be alerted to the moderator dilution event by the high-flux-at-shutdown alarm. In response to this alarm the operator would identify the source of the dilution event and isolate it.

The moderator dilution accident is analyzed at the initial conditions of beginning-of-cycle power operation (Mode 1) with the Integrated Control System (ICS) in either the automatic or manual mode, and in the refueling mode (Mode 6). Manual operator action is relied on to terminate the dilution in both modes. Mode 1 is analyzed to demonstrate that there is adequate time for the operator to terminate the dilution when maximum dilution source flowrates are assumed. Mode 6 is analyzed assuming administrative controls on potential dilution sources such that the results of the accident analysis give exactly a 30 minute operator response time. Flowrates are restricted through administrative controls to values that are less than these analyzed flowrates. Mitigation of the event is not credited until an alarm is received. In Mode 1 with the ICS in manual, mitigation does not begin until reactor trip occurs. This conservatively ignores any other alarms or indications of the increase in reactor power, pressurizer level, and RCS pressure. In Mode 1 with the ICS in automatic, mitigation of the event does not begin until the rod insertion limit alarm actuates. This conservatively ignores the indications of the control rods inserting to control the power level and temperature. In Mode 6 mitigation of the event does not begin until the source range high-flux-at-shutdown alarm actuates. The analysis assumes conservatively high dilution flowrates, high initial boron concentrations, and small mixing volumes. The moderator dilution accident potentially results in a loss of shutdown margin and an inadvertent criticality, approaching the DNBR limit, or challenging the peak RCS pressure limit. This accident is conservatively analyzed to ensure that the operator terminates the boron dilution prior to exceeding these criteria.

As discussed in the preceding paragraph, alarm actuation is credited for alerting the operator that a boron dilution event is in progress. Both the rod insertion limit alarm and the high-flux-at-shutdown alarm rely on non-safety equipment. No single failure has been identified that would prevent the operators from successfully isolating the possible dilution sources and terminating the accident.

The moderator dilution accident is considered to be a fault of moderate frequency. The acceptance criteria for manual operator action to terminate the dilution event are 15 minutes during Mode 1 and 30 minutes during Mode 6 following the actuation of the alarm credited for alerting the operator of the event. The Mode 6 analysis also requires administrative controls to limit the flowrate from unborated water sources. By meeting these operator action times and preventing core re-criticality, it is assured that the plant response will not approach the DNBR limit or the peak RCS pressure limit.

15.4.2 Full Power Initial Condition Analysis

Mode 1 With ICS in Automatic

A conservative upper bound on the dilution flowrate of 300 gpm of unborated water is assumed, which is the design capacity of two bleed transfer pumps. At this flowrate re-criticality would not occur until 17.5 minutes following the rod insertion limit alarm which alerts the operator. Therefore there is sufficient time for the operator to terminate the dilution event.

Mode 1 With ICS in Manual

A conservative upper bound on the dilution flowrate of 300 gpm of unborated water is assumed, which is the design capacity of two bleed transfer pumps. At this flowrate re-criticality would not occur until 15.9 minutes following the reactor trip alarm which alerts the operator. Therefore there is sufficient time for the operator to terminate the dilution event.

15.4.3 Refueling Initial Condition Analysis

Given the maximum allowed operator action time of 30 minutes, the maximum flowrate from the bleed transfer pumps must be less than 62 gpm.

15.4.4 Conclusions

Three moderator dilution accident cases were performed corresponding to Mode 1 with the ICS in automatic, Mode 1 with the ICS in manual, and Mode 6. The Mode 1 analyses calculate 17.5 minutes and 15.9 minutes operator action times for the ICS in automatic and manual cases, respectively. The Mode 6 analysis calculates a maximum bleed transfer pump flowrate of less than 62 gpm in order to meet the 30 minute operator action time. The 62 gpm limit is controlled administratively in Mode 6. All of the acceptance criteria are met.

15.5 COLD WATER ACCIDENT

15.5.1 Identification of Causes and Description

The cold water accident is caused by an inadvertent startup of the fourth reactor coolant pump (RCP) from an initial three RCP operating condition. The increase in core flow as a result of the fourth RCP starting causes a decrease in the core average temperature. If the moderator temperature coefficient of reactivity is negative, an insertion of positive reactivity and an increase in reactor power will occur. Administrative controls limit the power level at which the fourth RCP can be started to less than 50% power. The normal plant response to this event would be for the Integrated Control system (ICS) to insert control rods in an attempt to maintain the initial power level.

The cold water accident is analyzed from an 80% power end-of-cycle initial condition. A conservative RCP start time is assumed. The system analysis determines the transient core boundary conditions for the detailed core thermal-hydraulic analysis. It is assumed that rod control is in manual and the pressurizer heaters are inoperable. The pump control circuitry interlock that prevents startup of an idle pump if the power is above 50 percent full power is assumed to be inoperable. The analysis methodology and the computer codes used in this analysis are given in Table 15-33. The initial conditions are given in Table 15-34. The Reactor Protective System and Engineered Safeguards Protective System setpoints and delay times are given in Table 15-35.

No single failure has been identified which adversely affects this accident.

The cold water accident is considered to be a fault of moderate frequency. The acceptance criteria for this accident are that the minimum DNBR remains above the 1.50 design limit, and the peak RCS pressure does not exceed 110% (2750 psig) of design pressure. Since this event results in a minor RCS pressurization that does not approach the limit, only the minimum DNBR acceptance criterion is of concern.

15.5.2 Analysis

The cold water accident analysis results are shown in Figures 15-18 and 15-115 through 15-118 and the sequence of events is given in Table 15-39. Since the minimum DNBR occurs near the time the RCP has come up to speed, the analysis is terminated 11 seconds after the RCP achieves full speed. Following the start of the fourth RCP, RCS flow (Figure 15-18) rapidly increases to full flow, resulting in a decrease in the core average temperature (Figure 15-115). Neutron power and thermal power (Figure 15-116) increase during this time period due to the positive reactivity insertion from the decrease in the core average temperature, and reach maximum values of 108.4% and 96.7%, respectively. No reactor trip setpoints are exceeded. A combination of Doppler feedback and increasing RCS cold leg temperatures (Figure 15-117) after the pump has reached full speed stop the power excursion, with power returning to its initial condition by the end of the analysis. The RCS pressure response (Figure 15-118) reaches a pressure of only 2165 psig during the simulation. Since the maximum thermal power that occurs during this event is less than 100% full power, and the other core conditions are relatively close to nominal full power conditions, DNB is not a concern during this event.

15.5.3 Conclusions

The results of the cold water accident demonstrate that since the maximum power level remains less than 100%, the minimum DNBR remains well above the limit. The RCS pressure transient does not approach the peak RCS pressure limit. All of the acceptance criteria are met.

15.6 LOSS OF COOLANT FLOW ACCIDENTS

15.6.1 Identification of Causes and Description

A loss of coolant flow accident occurs if one or more of the reactor coolant pumps (RCPs) stops due to a loss of electrical power or a mechanical failure. The loss of coolant flow accident resulting from an electrical failure results in one or more RCPs coasting down. The limiting loss of coolant flow accident resulting from a mechanical failure is a locked rotor in one pump. If the reactor is at power at the time of the accident, the immediate effect of a loss of coolant flow is a rapid increase in the core coolant temperature. This temperature increase could result in approaching DNB with subsequent fuel damage if the reactor is not tripped promptly. During the loss of coolant flow accident, the Reactor Protective System (RPS) will trip the reactor on the flux/flow/imbalance trip, or on the pump monitor trip. If all RCPs trip, the plant transitions to the natural circulation mode of core cooling.

During a RCP coastdown event, the flux/flow/imbalance trip function trips the reactor when the setpoint is reached, and the pump monitor trip trips the reactor when any two of the four RCPs trip if the reactor power is greater than 2%. The pump monitor trip function has only one channel per pump. Therefore, assuming a single failure of the pump monitor trip on one pump, the possible RCP coastdown events with four or three RCPs in operation are determined. In order to evaluate the transient DNBR, the system analysis results are input to a detailed core thermal-hydraulic analysis. Since some of the RCP coastdown events are bounded by others, only the following five RCP coastdown events are analyzed. Results for Cases 2, 3, and 4 are presented since they bound the other cases.

Case	RCP Coastdown*	Power Level (%)	Trip Function
1	4/1	100	flux/flow
2	4/2**	100	flux/flow
3	4/4	100	pump monitor
4	3/1**	80	flux/flow
5	3/3	80	pump monitor

* 4/1 means 1 RCP coasting down with 4 RCPs in operation

** The RCP(s) coasting down can be in the same loop or in different loops

For the locked rotor accident analysis a single failure in the pump monitor trip is assumed for both four and three RCPs in operation. Therefore, the flux/flow/imbalance trip provides DNB protection for the locked rotor event. With three RCPs in operation, a locked rotor in the loop with both RCPs operating is the limiting case. In order to evaluate the transient DNBR, the system analysis results are input to a detailed core thermal-hydraulic analysis.

The analysis methodology and the computer codes used in the loss of flow accident analyses are given in Table 15-33. The initial conditions are given in Table 15-34. Beginning-of-cycle conditions are limiting. The RPS and Engineered Safeguards Protective System setpoints and delay times are given in Table 15-35.

A single failure in the pump monitor trip function is assumed in the loss of flow accident analyses. This failure results in relying on the flux/flow/imbalance trip function to trip the reactor in most of the analyzed cases. The RCS will transition to the natural circulation cooling mode if all RCPs have stopped. Natural circulation is then established by raising steam generator

levels to the natural circulation setpoint. If the Main Feedwater System is in operation, the increase in steam generator levels is controlled by the non-safety Integrated Control System. Otherwise, the Emergency Feedwater System actuates and the safety-grade Emergency Feedwater Control System controls the steam generator level to the natural circulation setpoint.

The RCP coastdown accidents are considered to be faults of moderate frequency (fewer than all RCPs coast down) or infrequent fault (all RCPs coast down) events. The acceptance criterion for all RCP coastdown accidents is that the minimum DNBR remains above the design limit. The DNBR design limit for each accident is identified in the analysis results discussion. The RCP locked rotor accident is categorized as a limiting fault. The acceptance criteria for the RCP locked rotor accident are that any fuel damage calculated to occur must be of a sufficiently limited extent that the core will remain in place and intact with no loss of core cooling capability, that the peak RCS pressure does not exceed 110% (2750 psig) of the design pressure, and that the calculated offsite doses are less than 100% of the 10CFR Part 100 limits. To evaluate the third criterion on offsite doses, the extent of fuel failures are quantified with the assumption that any fuel pin that exceeds the DNB limit is considered failed. The fuel failure results are then used in the offsite dose calculations to verify that the offsite dose criteria are satisfied. The results of the locked rotor analysis demonstrates that the peak RCS pressure limit is not challenged.

15.6.2 Four RCP Coastdown from Four RCP Initial Conditions Analysis

The 4/4 RCP coastdown accident analysis results are shown in Figures 15-19 through 15-24, and the sequence of events is given in Table 15-40. Since the transient minimum DNBR occurs near the time of reactor trip, the duration of the analysis is 19 seconds. The flow in both loops (Figure 15-19) behaves identically since the 4/4 RCP coastdown event is essentially symmetrical. The loop flows decrease towards zero flow during the transient. Prior to control rod motion, the neutron power (Figure 15-20) has already decreased due to the negative moderator temperature feedback as a result of the increase in the core coolant temperature. The pump monitor trip function trips the reactor at 0.61 seconds. The core thermal power (Figure 15-20) follows the trend of the neutron power with a thermal delay. The hot and cold leg temperatures (Figure 15-21) change only slightly in response to the change in flow during the transient. The pressurizer level (Figure 15-22) increases due to the increase in the RCS average temperature, and then decreases following the reactor trip. RCS pressure (Figure 15-23) increases initially due to the increase in pressurizer level, and decreases post-trip. The transient minimum DNBR (Figure 15-24) of 1.93 occurs at 1.5 seconds, which is greater than the design limit of 1.69.

15.6.3 Two RCP Coastdown from Four RCP Initial Conditions Analysis

The results of the 4/2 RCP coastdown accident analysis are presented since it is the bounding event for the four RCP initial conditions. The results are shown in Figures 15-25 and 15-119 through 15-123, and the sequence of events is given in Table-41. Since the transient minimum DNBR occurs near the time of reactor trip, the duration of the analysis is 19 seconds. The transient behavior of many of the key parameters trend those of the 4/4 RCP coastdown accident. The flux/flow imbalance trip function trips the reactor at 4.71 seconds. The core flow (Figure 15-25) decreases after the RCPs trip, and approaches the equilibrium two RCP flowrate at the end of the analysis. The faulted loop flow decreases toward zero flow, while the intact loop flow increases from its initial value. The hot leg temperatures (Figure 15-120) change only slightly in response to the change in flow during the transient. The cold leg temperatures in the affected

loop decrease due to the decrease in primary flow, and then increase due to the post-trip increase in steam pressure. The cold leg temperatures in the unaffected loop initially remain stable and then increase due to the flow reversal in the loop. The transient minimum DNBR (Figure 15-123) of 1.69 occurs at 5.3 seconds, which is equal to the design limit of 1.69.

15.6.4 One RCP Coastdown from Three RCP Initial Conditions Analysis

The results of the 3/1 RCP coastdown accident analysis with the tripped RCP in the same loop as the initially idle RCP are presented since it is the bounding event for the three pump initial conditions. The results are shown in Figures 15-124 through 15-129 and the sequence of events is given in Table 15-42. Since the transient minimum DNBR occurs near the time of reactor trip, the duration of the analysis is 19 seconds. The transient behavior of many of the key parameters trend those of the 4/2 RCP coastdown accident. The flux/flow imbalance trip function trips the reactor at 4.25 seconds. The RCS flow transient (Figure 15-124) approaches the two RCP equilibrium flowrate at the end of the analysis. While the affected loop flow decreases and reverses direction, the intact loop flow increases from its initial value. The transient minimum DNBR (Figure 15-129) of 2.02 occurs at 4.8 seconds, which is greater than the design limit of 1.77.

15.6.5 Locked Rotor from Four RCP Initial Conditions Analysis

The locked rotor accident from four RCP initial conditions analysis results are shown in Figures 15-130 through 15-135, and the sequence of events is given in Table 15-43. Since the transient minimum DNBR occurs near the time of reactor trip, the analysis is terminated at 9 seconds. The core flow (Figure 15-130) rapidly decreases after the locked rotor occurs, and approaches the equilibrium three RCP flowrate at the end of the analysis. The locked rotor cold leg flow rapidly decreases to a negative value, and the other cold leg flow increases towards the three RCP flowrate. Prior to reactor trip, the neutron power (Figure 15-131) has already decreased due to the negative moderator temperature feedback as a result of the increase in core coolant temperature. The flux/flow trip function trips the reactor at 1.71 seconds. The core thermal power (Figure 15-131) follows the trend of the neutron power with a thermal delay. The hot leg temperatures (Figure 15-132) increase initially due to the decrease in flow. After the reactor trips, the hot leg temperatures begin to decrease. The cold leg temperature in the affected loop decreases slightly due to the decrease in primary flow. The cold leg temperature of the unaffected loop remains stable initially, and then increases post-trip due to the increase in steam pressure. The pressurizer level (Figure 15-133) increases initially due to the increase in RCS temperatures, and then decreases post-trip. The RCS pressure response (Figure 15-134) trends with the change in pressurizer level. The transient minimum DNBR (Figure 15-135) of 1.50, which occurs at 2.1 seconds, is less than the design limit of 1.61. Consequently, DNBR margin may not exist, and a fuel pin census analysis is performed to determine if DNBR margin exists or the number of fuel pins that exceed the DNBR limit. A range of pin radial peaks and axial shapes are assumed to determine the peaking factors at which the DNBR limit is exceeded. These limiting peaking factors are the maximum allowable radial peak (MARP) limits. Each fuel pin in the core is then evaluated against the MARP limits at the limiting DNBR statepoint to determine if the DNBR limit is exceeded. All fuel pins that exceed the DNBR limit are assumed to experience cladding failure and are counted in the source term for the offsite dose calculation. The results of the fuel pin census analysis

for the locked rotor accident from four RCP initial conditions is that DNBR margin exists for all of the fuel pins. Due to no fuel failures, the offsite dose consequences for the locked rotor accident are bounded by the offsite dose consequences for the steam line break accident.

15.6.6 Locked Rotor from Three RCP Initial Conditions Analysis

The locked rotor accident from three RCP initial conditions analysis results are shown in Figures 15-136 through 15-141, and the sequence of events is given in Table 15-44. Since the transient minimum DNBR occurs near the time of reactor trip, the analysis is terminated at 9 seconds. The analysis results are similar to those of the four RCP initial condition analysis. The flows in the unaffected loop and the core (Figure 15-136) approach the two RCP equilibrium flowrates at the end of the analysis. The transient minimum DNBR (Figure 15-141) of 1.33, which occurs at 2.2 seconds, is less than the design limit of 1.62. Consequently, DNBR margin does not exist, and a fuel pin census analysis is performed. The results of the fuel pin census analysis for the locked rotor accident from three RCP initial conditions is that DNBR margin exists for all of the fuel pins. Due to no fuel failures, the offsite dose consequences for the locked rotor accident are bounded by the offsite dose consequences for the steam line break accident.

15.6.7 Natural Circulation Capability Analysis

The natural circulation capability analysis determines the stable natural circulation flowrates for a range of post-trip decay heat values. The natural circulation flowrates are shown to be greater than the decay heat power levels on a percentage basis, thereby limiting the temperature rise across the core to less than that at full power conditions. Therefore, adequate core cooling will be maintained during natural circulation.

Decay Heat Power		Natural Circulation Flowrate	Time After Reactor
(MW_{th})	(% Power)	(% Full Flow)	Trip (sec)
80	3.1	3.9	120
70	2.7	3.7	240
60	2.3	3.5	540
50	1.9	3.3	1,200
40	1.6	3.0	2,110
30	1.2	2.7	5,520
20	0.8	2.4	26,400
10	0.4	1.9	280,800

15.6.8 Conclusions

The results of the RCP coastdown accident analyses show that the limiting RCP coastdown event is two RCPs coasting down from a four RCP initial condition. The minimum DNBR result of 1.69 is equal to the DNBR limit of 1.69. The results of the locked rotor accident analyses show that the limiting locked rotor event is from a three RCP initial condition. The results of a pin census analysis for the locked rotor show that DNBR margin exists for all of the fuel rods. Therefore, no fuel rod failures are assumed in the offsite dose analysis. The results of the locked rotor analysis demonstrate that the peak RCS pressure limit is not challenged. The results of the

natural circulation capability analysis show adequate flow for core cooling and decay heat removal by natural circulation after all RCPs trip. All of the acceptance criteria are met.

15.7 CONTROL ROD MISALIGNMENT ACCIDENTS

15.7.1 Identification of Causes and Description

Control rods are normally grouped into patterns which maintain a symmetric core power distribution. A mechanical or electrical failure can cause a control rod to become misaligned from its group, causing an asymmetric reactivity distribution and, if the control rod is stuck, a reduction in the total available control rod worth for shutdown of the reactor. Three modes of misalignment can occur. The first mode, the statically misaligned rod accident, occurs during withdrawal or insertion of a control rod group when one rod becomes stuck at some position as the rod group continues in motion. This condition will affect the power distribution in the core and could lead to excessive power peaking. The second mode of misalignment, the stuck rod accident, can occur on reactor trip if one rod fails to insert. This condition requires an evaluation to determine that sufficient negative reactivity is available for tripping the reactor when considering the maximum worth stuck rod. The third mode, the dropped rod accident, can occur when one rod drops partially or fully into the core. The resulting plant transient response is a rapid reduction in power and a possible subsequent increase in power due to a negative moderator coefficient of reactivity. The expected plant response is that the Integrated Control System (ICS) will respond to an indicated dropped control rod by initiating a power runback and by inhibiting control rod withdrawal. A reactor trip may occur on variable low pressure-temperature for some dropped rod accidents.

For the statically misaligned rod accident, the core designs are evaluated to confirm that the resulting core power distribution is acceptable. For the stuck rod accident, each core design is required to be capable of maintaining a 1% $\Delta k/k$ shutdown margin at hot shutdown conditions with the assumption of the maximum worth rod stuck in the fully withdrawn position. The dropped rod accident is analyzed for a set of dropped rod worths for initial conditions of 100% power with four reactor coolant pumps (RCPs) in operation, and for 80% power with three RCPs in operation. Physics parameters for both beginning-of-cycle (BOC) and end-of-cycle (EOC) conditions are analyzed. The expected action taken by the ICS on indication of a dropped rod is to inhibit control rod withdrawal and to run back power demand to 55 percent of rated load at 1 percent per minute. This non-safety action by the ICS is not credited in the analysis. The ICS is assumed to respond to the decrease in reactor power by withdrawing control rods to meet the load demand, which is a conservative assumption. A reactor trip on high pressure or flux/flow/imbalance may occur for some cases. The system analysis determines the transient core boundary conditions for the detailed core thermal-hydraulic analysis. The analysis methodology and the computer codes used in this analysis are given in Table 15-33. The initial conditions are given in Table 15-34. The Reactor Protective System (RPS) and Engineered Safeguards Protective System setpoints and delay times are given in Table 15-35.

Due to the asymmetric core power distribution resulting from the dropped rod, the excore power range flux channels which input to the RPS high flux trip function will indicate different transient power responses. The limiting single failure for the dropped rod analysis is the excore power range flux channel adjacent to the quadrant with the highest indicated core power level. This assumption results in the third highest excore flux channel determining whether the high flux trip setpoint is reached based on the 2/4 RPS logic design.

The three identified modes of control rod misalignment accidents are considered to be faults of moderate frequency. The acceptance criteria for these accidents are that the minimum DNBR remains above the 1.50 limit, that the centerline fuel melt limit is not exceeded, and that the peak RCS pressure does not exceed 110% (2750 psig) of design pressure. Since this event results in a minor RCS pressurization

which does not approach the limit, only the minimum DNBR and centerline fuel melt acceptance criteria are of concern.

15.7.2 Dropped Rod Analysis

The limiting dropped rod accident is a 20 pcm dropped rod from full power at BOC conditions. The duration of the analysis is 50 seconds, which is sufficient for the time of minimum DNBR. The transient response is shown in Figures 15-26 through 15-28, 15-143 and 15-144, and the sequence of events is given in Table 15-45. The initial decrease in reactor power (Figure 15-26) is caused by the reactivity inserted by the dropped rod. The ICS response, due to the asymmetric power distribution, causes control rods to be withdrawn and results in an increase in reactor power. Hot and cold leg temperatures (Figure 15-27) increase at a steady rate prior to reactor trip due to the power mismatch between reactor power and steam generator heat removal. This mismatch results in a reactor trip on high RCS pressure. The trends of pressurizer level (Figure 15-28) and RCS pressure(Figure 15-143) also reflect this power mismatch. RCS pressure increases until a high RCS pressure reactor trip occurs at 35.3 seconds. The peak RCS pressure is 2443 psig. The transient minimum DNBR (Figure 15-144) of 1.532 occurs at about 35.5 seconds.

15.7.3 Statically Misaligned Rod Analysis

The results of the generic evaluation of the statically misaligned rod event show that this event is bounded by the dropped rod event.

15.7.4 Conclusions

The stuck rod accident cannot result in insufficient negative reactivity insertion on reactor trip due to the core design criteria. The statically misaligned rod accident has been shown to be bounded by the dropped rod accident. The minimum DNBR is determined to be 1.532. No fuel centerline melt is predicted. The RCS pressure transient does not approach the peak primary pressure limit. All of the acceptance criteria are met.

15.8 TURBINE TRIP ACCIDENT

15.8.1 Identification of Causes and Description

The turbine trip accident is caused by events including a generator trip, low condenser vacuum, loss of turbine lubrication oil, turbine thrust bearing failure, turbine overspeed, main feedwater pump trip, high steam generator level, or a reactor trip. The rapid closure of the main turbine stop valves results in a rapid increase in the secondary pressure and temperature. This degradation in the secondary heat sink creates a mismatch between power generated in the Reactor Coolant System (RCS) and heat removed by the secondary. As a result, the RCS temperature and pressure increase. The expected plant response to a turbine trip would be an immediate reactor trip initiated by the turbine trip signal. The Turbine Bypass System (TBS) and main steam code safety valves would then relieve steam in order to control the post-trip steam generator pressures. RCS pressure would be controlled by the pressurizer spray, PORV, and heaters. In addition, feedwater would be automatically controlled by the Integrated Control System (ICS) to maintain the post-trip steam generator levels at setpoint.

The turbine trip accident is analyzed from a full power initial condition at beginning-of-cycle. The analysis assumes that the pressurizer spray, pressurizer PORV, and the TBS are inoperable. In addition, the pressurizer and main steam code safety valves are modeled using conservative assumptions for drift, blowdown and valve capacity that minimize relief flow. The anticipatory reactor trip on turbine trip is not credited. Main feedwater is isolated coincident with the turbine trip in order to maximize the steam generator pressure. Also, no credit is taken for the Emergency Feedwater System (EFW), since the peak pressure will be reached before EFW flow can start and have an effect on the transient response. The analysis methodology and the computer codes used in this analysis are given in Table 15-33. The initial conditions are given in Table 15-34. The Reactor Protective System and Engineered Safeguards System setpoints and delay times are given in Table 15-35.

No single failure has been identified which adversely impacts the results of the turbine trip analysis.

The turbine trip accident is considered to be a fault of moderate frequency. The acceptance criteria for this accident are that the minimum DNBR remains above the 1.50 design limit, and that the peak RCS pressure does not exceed 110% (2750 psig) of design pressure. The DNBR limit is not challenged since the increase in RCS pressure more than offsets the slight increase in RCS temperature.

15.8.2 Analysis

The turbine trip accident analysis results are shown in Figures 15-145 through 15-149, and the sequence of events is given in Table 15-46. The analysis duration of 50 seconds is sufficient to demonstrate the peak RCS pressure. The closure of the main turbine stop valves results in a rapid increase in steam line pressure (Figure 15-145) and temperature. The RCS hot and cold leg temperatures (Figure 15-146) increase due to the increasing secondary side temperature. The increase in RCS temperatures causes pressurizer level (Figure 15-147) and RCS pressure (Figure 15-148) to increase, resulting in a reactor trip on high RCS pressure at 4.0 seconds. Following the reactor trip the RCS temperatures, pressurizer level, and RCS pressure all decrease towards the post-trip values. The reactor power response (Figure 15-149) shows a slight increase due to reactivity feedback prior to trip. At 7.5 seconds, RCS pressure at the bottom of the reactor vessel reaches a maximum value of 2614.1 psig.

15.8.3 Conclusions

The turbine trip accident analysis results in a peak RCS pressure of 2614.1 psig. All of the acceptance criteria are met.

15.9 STEAM GENERATOR TUBE RUPTURE ACCIDENT

15.9.1 Identification of Causes and Description

The steam generator tube rupture (SGTR) accident is caused by a double-ended rupture of a single steam generator tube. The expected plant response is as follows. The tube rupture initiates a blowdown of primary coolant into a steam generator. The plant response to this event is similar to a small break LOCA in that the Reactor Coolant System (RCS) pressure and pressurizer level would decrease as coolant inventory is lost through the ruptured steam generator tube. Makeup flow to the RCS would increase in response to the decrease in pressurizer level. The Integrated Control System (ICS) would reduce main feedwater (MFW) to the ruptured steam generator to compensate for the break flow. Without operator action, the reactor would trip on the variable low pressure-temperature trip function. With operator action, actions would be taken to initiate a rapid shutdown of the reactor. This would be accomplished by making up for the loss of RCS inventory through the break with flow from the High Pressure Injection System (HPIS). When the reactor power level has been reduced to below the capacity of the Turbine Bypass System (TBS), a manual reactor trip would be performed. Following the reactor trip, the TBS would relieve steam to control steam generator pressure. MFW would be automatically controlled by the ICS to maintain the post-trip steam generator level at setpoint. The operator would then isolate the ruptured steam generator and depressurize the RCS to decrease the subcooled margin, thereby minimizing primary-to-secondary leakage. A plant cooldown and depressurization would then be initiated using the TBS and the unaffected steam generator to bring the plant to the conditions where the Low Pressure Injection System (LPIS) can be aligned for decay heat removal, and break flow could then be terminated. The ruptured steam generator would be steamed and/or drained as necessary to prevent overfill during the course of the event.

The SGTR accident is analyzed from a full power initial condition at end-of-cycle with maximum decay heat. Analysis assumptions are selected to maximize the environmental consequences. Offsite power remains available. A conservatively long delay time is assumed for the Reactor Protective System to trip the reactor to maximize the pre-trip primary coolant leakage into the ruptured steam generator. It is further assumed that the operator takes action to maintain RCS pressure and pressurizer level at the initial conditions such that the primary-to-secondary leakage is maximized. The reactor is then assumed to trip from a full power condition which results in the largest post-trip steam release through the main steam safety valves (MSSVs). The MFW pumps are assumed to trip on reactor trip to minimize the secondary heat sink, which actuates the emergency feedwater (EFW) pumps. The non-safety turbine-driven EFW pump is credited in the analysis since the steam supply to its turbine originates from the SG with the tube rupture and exhausts directly to the atmosphere. The non-safety TBS is not credited in the analysis. The analysis methodology and the computer codes used in this analysis are given in Table 15-33. The initial conditions are given in Table 15-34. The RPS and Engineered Safeguards Protective System setpoints and delay times are given in Table 15-35.

The analysis credits the non-safety manual steam line atmospheric dump valves (ADVs) to cool down the plant. The single failure assumed in this event is the EFW control valve on the unaffected steam generator failing to open following the reactor trip. This results in only the ruptured steam generator being available for cooling down the plant until operator action is taken to establish an alternate EFW alignment. The following operator actions are credited during this event:

- Immediate action to maximize HPI flow.
- Identify the failed-closed position of the EFW control valve and restore EFW to the unaffected steam generator. A delay time of 23 minutes after reactor trip is assumed.
- The ruptured steam generator is identified 10 minutes after EFW restoration to the unaffected steam generator.
- Cooldown of the plant to 532°F begins 40 minutes after the ruptured steam generator is identified.
- The ruptured steam generator is isolated 10 minutes after the plant has been cooled down to 532°F.
- The RCS subcooled margin is minimized 12 minutes after the ruptured steam generator is identified.
- One reactor coolant pump (RCP) per loop is tripped off 10 minutes after the RCS has been cooled down to 532°F.
- A shift changeover delay of one hour is assumed after the RCS has been cooled down to 532 °F and one RCP per loop has been tripped.
- An RCS cooldown to 450°F begins after the shift changeover is complete.
- Cooldown of the RCS is stopped upon reaching 450°F while the RCS boron concentration is determined. A delay time of 90 minutes is assumed.
- Boration of the RCS is performed to achieve the cold shutdown boron concentration requirement. A delay time of 30 minutes is assumed.
- Cooldown to decay heat removal conditions resumes 5 minutes after the cold shutdown boron concentration has been achieved.
- Periodic steaming of the ruptured steam generator is performed to prevent water from entering the steam lines.
- A 45 minute delay is assumed to align the LPIS for decay heat removal. RCS temperature and pressure are held constant during this time.

The steam generator tube rupture accident is considered to be a limiting fault event. The acceptance criterion for this event is that the calculated doses at the site boundary are less than 100% of the 10CFR100 guidelines.

15.9.2 Analysis

The SGTR accident analysis results are shown in Figures 15-150 through 15-156 and the sequence of events is given in Table 15-47. The duration of the analysis is until the plant has been cooled down and steam releases to the atmosphere have terminated, which is 48,367 seconds (13.5 hours). As a result of the tube rupture and immediate operator action to increase HPIS flow to compensate for the loss of RCS inventory, RCS conditions remain relatively stable until the RPS is assumed to trip the reactor at 1200 seconds. The reactor power response is shown in Figure 15-150. MFW flow is automatically throttled to compensate for the break flow (Figure 15-151) entering the ruptured steam generator. A normal post-trip response occurs, with RCS pressure (Figure 15-152) and pressurizer level (Figure 15-153) decreasing due to RCS shrinkage and steam generator pressures (Figure 15-154) increasing to the MSSV lift setpoints. MFW flow is lost on reactor trip. Steam generator levels (Figure 15-155) decrease to the post-trip setpoints, and then the unaffected steam generator continues to boil down to a dried out condition due to the failure of its EFW control valve to open. Post-trip heat removal is provided by the ruptured steam generator until an alternate EFW flowpath to the unaffected steam generator is aligned at 2580 seconds. After restoration of EFW to both steam generators, the

ruptured steam generator is identified at 3180 seconds due to the EFW flow imbalance between the steam generators. The RCS subcooled margin is reduced at 3900 seconds to minimize primary-to-secondary leakage. At 5580 seconds, the unit is cooled down to 532°F (Figure 15-156) using the ADVs on both steam lines. The ruptured steam generator is isolated after reaching 532°F (~6689 seconds), with all steam release flowpaths and EFW being isolated by 7289 seconds. After one RCP is tripped per loop, the RCS is held at a constant temperature and pressure while a shift changeover occurs. During the shift changeover, steaming of the ruptured steam generator begins due to the water level reaching the high level setpoint (11,112 seconds). Steaming the ruptured steam generator continues for the remainder of the analysis. The plant cooldown is resumed following the shift changeover, with RCS temperatures reaching 450°F at 17,080 seconds. Boron sampling and boration to cold shutdown conditions is accomplished by 24,280 seconds, with the plant cooldown resuming at 24,580 seconds. LPIS decay heat removal conditions are reached at 41,123 seconds, where RCS pressure and temperature are held constant while this system is aligned. The plant cooldown continues at 43,823 seconds, with the RCS reaching 212°F at 48,367 seconds. The analysis is terminated at this time since steam releases to the atmosphere have stopped.

15.9.3 Environmental Consequences

(TO BE SUBMITTED LATER)

15.9.4 Conclusions

The steam generator tube rupture accident is analyzed to provide conservative inputs to the environmental consequences analysis. The results of the environmental consequences analyses are within the 10CFR100 limits. All of the acceptance criteria are met.

15.12 ROD EJECTION ACCIDENT

15.12.1 Identification of Causes and Description

The rod ejection accident is caused by a failure of a control rod drive mechanism housing, which allows a control rod to be rapidly ejected from the reactor by the Reactor Coolant System (RCS) pressure. The control rod is ejected in 0.15 seconds from the fully inserted position. A power excursion will result, and if the reactivity worth of the ejected control rod is large enough, the reactor will become prompt critical. The resulting power excursion will be limited by the fuel temperature feedback and the accident will be terminated when the Reactor Protective System (RPS) trips the reactor on high neutron flux or high RCS pressure. RCS pressure increases due to the core power excursion, and pressurizer spray, the pressurizer PORV, and the pressurizer code safety valves will respond to mitigate the pressure increase. If a rod ejection were to occur, the nuclear design of the reactor and limits on control rod insertion will limit any potential fuel damage to acceptable levels. Cladding failure can result from the core power excursion and the highly peaked core power distribution near the ejected rod location. The failure of the control rod drive mechanism housing also constitutes a 1.50 inch diameter small-break LOCA (SBLOCA). The Emergency Core Cooling System (ECCS) will actuate on low RCS pressure or high Reactor Building pressure and will maintain core cooling. This type of SBLOCA is bounded by the limiting SBLOCA analyses presented in Sections 6.2 and 15.14.

Six rod ejection accident cases with different initial core conditions and number of reactor coolant pumps (RCPs) in operation are analyzed. Two cases initiate at zero power (1E-7 % of full power) with two RCPs in operation, at both beginning-of-cycle (BOC) and at end-of-cycle (EOC). Two cases initiate at 82% power with three RCPs in operation, at both BOC and EOC. Two cases initiate at 102% power with four RCPs in operation, at both BOC and EOC. Since cladding failure due to exceeding the DNBR limit will result, the different possible RCP operating conditions are analyzed to bound the effect of core flowrate on DNBR. Zero power and full power are both analyzed to bound the range of ejected rod worths, initial fuel temperatures, and core power distributions. The ejected rod worth for each case is based on the power level dependent rod insertion limit including uncertainty. The negative reactivity inserted on reactor trip assumes that the most reactive control rod remains in the fully withdrawn position. The pressurizer spray and PORV are not credited for mitigating the pressure transient in the evaluation of the peak RCS pressure response. The analysis methodology and the computer codes used in this analysis are given in Table 15-33. The initial conditions are given in Table 15-34. The RPS and Engineered Safeguards Protective System setpoints and delay times are given in Table 15-35.

Due to the asymmetric core power distribution resulting from the rod ejection, the excore power range flux channels which input to the RPS high flux trip function will indicate different transient power responses. The analyses assume a single failure of the excore flux channel which indicates the highest power level. This assumption results in the third highest excore flux channel determining the time of reactor trip based on the 2/4 RPS trip logic design.

The rod ejection accident is considered to be a limiting fault. The acceptance criteria for the rod ejection accident analysis are that the accident will not further damage the RCS, and that the offsite doses will be less than 100% of the 10CFR100 limits. The first criterion of no further damage to the RCS is interpreted to mean that the peak RCS pressure and the peak pellet radial average enthalpy both remain below a specified limit. The peak primary pressure limit is to

remain within Service Limit C as defined by the ASME Code (Reference 1), which is 120% of the 2500 psig design pressure, or 3000 psig. The peak enthalpy limit is such that the radially averaged fuel pellet enthalpy shall not exceed 280 cal/gm at any location in the core. To evaluate the second criterion of offsite dose being with the 10CFR100 limits, the extent of fuel failures are quantified with the assumption that any fuel pin that exceeds the DNB limit of 1.24 is considered failed. The fuel failure results are used in the offsite dose calculations to verify that the offsite dose criteria are satisfied. The offsite dose analysis also considers the SBLOCA release to the Reactor Building.

15.12.2 Core Kinetics Analysis

The rod ejection accident core kinetics response is determined with a three-dimensional space/time analysis for each of the six cases. The analysis duration of 5 seconds is sufficient to determine the results of interest. The assumed ejected rod worths are 200 pcm at 102% power, 400 pcm at 82% power, and 800 pcm at 1E-7 % of full power. Only the ejected rod worth at 1E-7 % of full power is large enough to cause prompt criticality (reactivity greater than one dollar). The results of the SIMULATE-3K analyses are summarized in Table 15-2. The 102% power cases trip in 0.05 seconds and reach maximum neutron power levels of 140% and 137% at BOC and EOC, respectively. The 82% power cases trip in 0.08 seconds, and reach maximum neutron power levels of 194% and 214% at BOC and EOC, respectively. The 1E-7 % FP cases trip in 0.25 seconds, and reach maximum neutron power levels of 1841% and 1752% at BOC and EOC, respectively. The results of the ARROTTA analyses are summarized in Table 15-3. The 102% power cases trip in 0.05 seconds and reach maximum neutron power levels of 144% and 148% at BOC and EOC, respectively. The 82% power cases trip in 0.08 seconds, and reach maximum neutron power levels of 195% and 223% at BOC and EOC, respectively. The 1E-7 % FP cases trip in 0.25 seconds, and reach maximum neutron power levels of 2098% and 1918% at BOC and EOC, respectively. The neutron power transients for all six cases and for both computer codes are shown in Figures 15-29 through 15-34. In each case the power excursion is terminated by the Doppler temperature feedback, and then the reactor is shut down by the reactor trip on high flux. Figure 15-35 shows the core power distribution at the time of peak power for the ARROTTA 102% power BOC case. This figure illustrates the high assembly peaking factors near the ejected rod location.

15.12.3 Fuel Pellet Enthalpy Analysis

For each of the six rod ejection accident cases, the core power excursion and the time-dependent three-dimensional power distribution from the ARROTTA core kinetics analysis is used as input to the calculation of the fuel pellet peak radial average enthalpy. The results for the six cases are shown in Table 15-3. The limiting case is the 102% power case at BOC conditions, with a peak enthalpy of 132.8 cal/gm.

15.12.4 Core Cooling Capability Analysis

For each of the six rod ejection accident cases, the core power excursion from the ARROTTA core kinetics analysis is combined with the core flowrate, temperature, and pressure transients from the system analysis to determine the DNBR response. A range of assembly peaking factors and axial shapes are assumed to determine the peaking factors at which the DNBR limit is

exceeded for each of the six cases. These limiting peaking factors are the maximum allowable radial peak (MARP) limits. Each fuel rod in the core is then evaluated against the MARP limits at the limiting DNBR statepoint to determine if the fuel rod exceeds the DNBR limit. All fuel rods that exceed the DNBR limit are assumed to experience cladding failure and are included in the source term for the offsite dose calculation. Table 15-3 shows the percentage of fuel pins that exceed the DNBR limit for each case. The limiting case is the 102% power case at BOC, with 40.6% of the fuel rods predicted to exceed the DNBR limit.

15.12.5 Peak RCS Pressure Analysis

The peak RCS pressure for the ARROTTA rod ejection accident is determined by a system analysis simulation that uses a boundary condition of the coolant expansion rate in the core. The core coolant expansion rate is calculated for each fuel assembly and is summed into a total expansion rate. The total coolant expansion rate is then input to the system analysis, which results in a pressurizer insurge and a compression of the pressurizer steam bubble. The peak RCS pressure results from the 82% power BOC case. Figure 15-36 shows the pressure transient, which peaks at 2885 psig at 2.3 seconds.

15.12.6 Environmental Consequences

(TO BE SUBMITTED LATER)

15.12.7 Conclusions

The rod ejection accident is analyzed for six cases which include different initial conditions for power level, number of RCPs in operation, ejected rod worth, and core physics parameters associated with BOC and EOC conditions. The limiting peak fuel pellet average enthalpy is 132.8 cal/gm. The maximum predicted fuel cladding failure percentage is 40.6%. The peak RCS pressure is 2885 psig. The environmental consequences analysis results are within the 10CFR100 limits. All of the acceptance criteria are met.

15.12.8 References

1. ASME Boiler and Pressure Vessel Code, Section III, "Nuclear Power Plant Components", ASME

15.13 STEAM LINE BREAK

15.13.1 Identification of Causes and Description

The steam line break accident is caused by a double-ended rupture of one of the two main steam lines. The expected plant response to a large steam line break is as follows. The break initially results in a rapid blowdown of both steam generators. The steam generator depressurization initiates a rapid Reactor Coolant System (RCS) cooldown and depressurization, which results in a reactor trip on variable low pressure-temperature within the first few seconds of the accident. The reactor trip causes the main turbine stop valves to close, thereby isolating the affected steam generator from the unaffected steam generator. The affected steam generator continues to depressurize while the unaffected steam generator repressurizes. The main feedwater (MFW) pumps are tripped, all MFW valves are closed, and the turbine-driven emergency feedwater (EFW) pump is inhibited from starting, when the steam line break detection and mitigation circuitry is actuated on low steam generator pressure. The motor-driven EFW pumps start on main feedwater pump trip. The operator will manually trip all reactor coolant pumps (RCPs) on a loss of the subcooled margin. The operator will then manually isolate EFW flow to the affected steam generator to terminate the overcooling transient. EFW flow is automatically controlled to the unaffected steam generator to provide the secondary heat sink. The High Pressure Injection System (HPI) will actuate on low RCS pressure and will begin restoring RCS inventory. The operator will then throttle HPI flow to maintain pressurizer level to the normal post-trip level.

The steam line break accident is analyzed both with and without offsite power. The with offsite power maintained case analyzes end-of-cycle core conditions to maximize the positive reactivity addition resulting from the RCS cooldown and any resulting return-to-power. The without offsite power case analyzes beginning-of-cycle (BOC) core conditions to conservatively predict the approach to DNB as the reactor coolant pumps (RCPs) coast down. No credit is taken for the steam line break detection and mitigation circuitry since some of the components that actuate are non-safety grade. The non-safety grade Integrated Control System (ICS) is assumed to maintain the minimum post trip steam generator level, since this assumption has been demonstrated to be conservative relative to assuming no ICS control of MFW. Since MFW is available and controlling steam generator level to the ICS setpoint, EFW will not be actuated. The analysis methodology and the computer codes used in the analysis are given in Table 15-33. The initial conditions are given in Table 15-34. The Reactor Protective System and Engineered Safeguards Protective System setpoints and delay times are given in Table 15-35.

Operator action to isolate MFW flow to the broken steam generator is credited at 10 minutes. The limiting single failure for the with offsite power analysis is the failure of a train of engineered safeguards that results in only one train of HPI. No single failure was identified which affects the results of the without offsite power analysis. The maximum worth control rod is assumed to remain in the fully withdrawn position.

The steam line break accident is considered to be a limiting fault. The acceptance criteria for this event are that the core will remain intact for effective core cooling and that the offsite doses will be within 100% of the 10CFR100 limits.

15.13.2 With Offsite Power Analysis

The steam line break accident with offsite power analysis is concerned with the magnitude of any post-trip return-to-power. A significant return-to-power with the presence of a stuck rod may challenge the DNB limit. The limiting scenario with respect to maximizing the overcooling and reactivity addition has been determined to be the case with the ICS controlling MFW flow to the post-trip steam generator level setpoint increased by an allowance for uncertainty. EFW is not actuated for this scenario. This limiting scenario has been determined to bound scenarios with the ICS in manual control with no operator action, which results in uncontrolled MFW flow and actuation of the EFW System. The duration of the analysis is 10 minutes, which includes the core conditions of minimum DNB margin. The results of the analysis are shown in Figures 15-40 through 15-43 and Figures 15-157 through 15-160, and the sequence of events is given in Table 15-5.

The steam line break initially causes the pressure to decrease in both steam generators (Figure 15-40). The reactor trips in 0.8 seconds. Break flowrates (Figure 15-41) for both steam generators rapidly increase. After the turbine stop valves close, break flow from the unaffected steam generator stops. Break flow from the affected steam generator decreases with decreasing pressure, and the unaffected steam generator repressurizes and opens the turbine bypass valves and the first bank of main steam safety valves. Both steam generators are nearly fully depressurized by the end of the simulation. The cooldown in the affected loop is initially much more severe than in the unaffected loop, as shown in the cold leg and hot leg temperature responses (Figure 15-42). The bulk of the RCS has cooled to approximately 270 °F by the end of the simulation.

The total, moderator, Doppler, boron and control rod reactivities are presented in Figure 15-43. The negative reactivity insertion at the beginning of the transient is due to the reactor trip and control rod insertion. The cooldown causes positive reactivity insertion due to the negative moderator and Doppler coefficients. The core returns to a critical condition at approximately 140 seconds. Injected boron from the HPI system and the CFTs reaches the core at approximately 160 seconds. The negative reactivity inserted by the boron returns the core to a subcritical condition by approximately 200 seconds. Subcriticality is maintained for the remainder of the simulation. The reactor power (Figure 15-157) decreases rapidly on reactor trip. The thermal power generally follows the neutron power response. The fluctuations in the heat flux are caused by flow surges in the core which result from flow degradation due to two-phase conditions in the unaffected loop. A peak return-to-power of 13.09 %FP heat flux occurs at approximately 160 seconds. RCS pressure (Figure 15-158) rapidly decreases until the affected loop and reactor vessel head begin to saturate at approximately 4 seconds. After this time, RCS pressure continues to decrease for the remainder of the simulation.

Core inlet mass flow (Figure 15-159) initially increases with time due to the decreasing RCS temperatures. However, as the unaffected loop begins to void and RCP performance degrades, core inlet flow decreases to approximately half of the initial flow. After the RCPs in the unaffected loop are tripped at 100 seconds, the flow oscillations diminish. The system analysis results and the core power distribution (Figure 15-160) at the limiting DNB statepoint are input to the detailed core thermal-hydraulic analysis to determine the limiting DNBR. The minimum DNBR at the peak return-to-power statepoint has been determined to be 3.28. Therefore the core does not approach conditions for which DNB would occur, and the core will remain intact for effective core cooling.

15.13.3 Without Offsite Power Analysis

The steam line break accident without offsite power analysis assumes a loss of offsite power coincident with the break which trips the reactor and causes the RCPs to coast down. For this scenario the steam line break accident is a loss of flow accident with a coincident depressurization. The minimum DNBR statepoint occurs within the first few seconds of the RCP coastdown, therefore the duration of the analysis is 10 seconds. Due to the loss of power, the MFW pumps will begin to coast down due to loss of the condensate booster pumps. The results of the analysis are shown in Figures 15-161 through 15-167, and the sequence of events is given in Table 15-48. The steam line break initially causes the pressure to decrease in both steam generators (Figure 15-161). Once the main turbine stop valves close, the unaffected steam generator repressurizes and opens the turbine bypass valves. The affected steam generator has depressurized to about 400 psig by the end of the analysis. The break flow response is similar to the with offsite power analysis. The cooldown in the affected loop is much more severe than in the unaffected loop, as shown in the cold leg temperature response (Figure 15-162). The increase in hot leg temperatures is caused by the flow coastdown. The affected loop hot leg temperature is slightly higher than the unaffected loop hot leg temperature due to the post-trip outsurge from the pressurizer. The RCS volumetric flow decreases for the duration of the simulation (Figure 15-163). The control rod insertion on loss of offsite power determines the core kinetics response (Figure 15-164). Due to the assumed BOC kinetics parameters and the short duration of the analysis, the moderator and Doppler reactivity feedback is negligible. The reactor neutron power decreases rapidly on reactor trip (Figure 15-165), with the thermal power responding slower due to the thermal delay. RCS pressure (Figure 15-166) rapidly decreases due to the effects of the overcooling from the steam line break and from the control rod insertion. As flow and primary-to-secondary heat transfer begin to degrade, RCS pressure stabilizes.

The system analysis results are input to the detailed core thermal-hydraulic analysis to determine the limiting DNBR. The minimum DNBR assuming a standard reference power distribution is 1.45, which is less than the design limit of 1.50. Consequently, DNBR margin may not exist, and a fuel pin census analysis is performed to determine if DNBR margin exists or the number of fuel pins that exceed the DNBR limit. A range of pin radial peaks and axial shapes are assumed to determine the peaking factors at which the DNBR limit is exceeded. These limiting peaking factors are the maximum allowable radial peak (MARP) limits. Each fuel pin in the core is then evaluated against the MARP limits at the limiting DNBR statepoint to determine if the DNBR limit is exceeded. All fuel pins that exceed the DNBR limit are assumed to experience cladding failure and are counted in the source term for the offsite dose calculation. The results of the fuel pin census analysis for the steam line break accident without offsite power is that DNB margin exists for all of the fuel pins.

15.13.4 Environmental Consequences

(TO BE SUBMITTED LATER)

15.13.5 Conclusions

The steam line break accident has been analyzed both with and without offsite power. The results of the analysis show that DNBR margin exists. The results of the environmental consequences analyses are within the 10CFR100 limits. All of the acceptance criteria are met.

15.17 SMALL STEAM LINE BREAK

15.17.1 Identification of Causes and Description

The small steam line break accident is caused by small breaks in the steam lines or by failures of valves connected to the steam lines. The break flowrate, the reactor kinetic behavior, and the status of the control systems have a large effect on the plant response. The initial plant response to the increase in steam flow is a decrease in steam generator pressure and an overcooling of the Reactor Coolant System (RCS). The expected plant response with the Integrated Control System (ICS) in automatic would be for the main turbine control valves to close to return turbine header pressure to the setpoint, the control rods would insert to offset the increase in the reactor power due to the negative moderator coefficient of reactivity, and main feedwater (MFW) flow would be controlled to maintain the secondary heat sink in balance with the reactor power. This automatic response may be successful in not tripping the reactor. With the ICS in automatic or manual control, a reactor trip on high neutron flux, flux/flow/imbalance, variable low pressure-temperature, on turbine trip due to main feedwater pump trip, or by manual operator action would be expected.

The small steam line break accident analyses assume that the ICS is in manual control for initial conditions of full power with four reactor coolant pumps (RCPs) in operation, and 80% power with three RCPs in operation. The ICS in manual control is more limiting than with the ICS in automatic. A range of break sizes and moderator temperature coefficients are analyzed to determine the combination that approaches the most limiting conditions relative to the DNBR limit. The effect of a decrease in the reactor vessel downcomer temperature on the indicated excore power range flux is modeled. Several non-safety systems could cause a trip of the MFW pumps thereby mitigating the consequences of the transient. These include the steam line break mitigation circuitry (which actuates some non-safety grade components), the ICS high steam generator level trip, and the low MFW pump discharge pressure trip. None of these non-safety systems are credited in the analyses. The analysis methodology and the computer codes used in this analysis are given in Table 15-33. The initial conditions are given in Table 15-34. The Reactor Protective System and Engineered Safeguards Protective System setpoints and delay times are given in Table 15-35.

Operator action is credited with manually tripping the reactor at 10 minutes if an automatic reactor trip has not occurred. No single failure has been identified which adversely affects this transient.

A small steam line break accident is considered to be either a fault of moderate frequency (valves failing open) or an infrequent fault (pipe break). To bound both types of events, the analysis assumes pipe breaks as initiating events, with acceptance criteria corresponding to the less severe fault of moderate frequency category. The acceptance criteria for this accident are that the minimum DNBR remains above the limit (1.50 for four RCP operation and 1.53 for three RCP operation), that the centerline fuel melt limit is not exceeded, and that the offsite doses will be within 10% of the 10CFR100 limits.

15.17.2 Analysis

The limiting small steam line break accident for DNB considerations is a break size of 1.2 ft^2 initiated from three RCP operation, with a moderator temperature coefficient of -12 pcm/°F. The transient response is given in Figures 15-168 through 15-173 and the sequence of events is given in Table 15-49. The duration of the analysis is 250 seconds, which includes the core conditions of minimum DNBR margin. The blowdown out the break increases the steam flow exiting the steam generators by approximately 30% (Figure 15-168). The steam generator pressure decrease (Figure 15-169) propagates throughout the secondary system, causing main feedwater flow to increase (Figure 15-170) and a decrease in main feedwater temperature. RCS temperatures decrease (Figure 15-171) causing a power increase (Figure 15-172) due to the negative moderator temperature coefficient of reactivity. As the power level increases, the temperature increases and the moderator and Doppler feedback mitigates the power excursion. The transient reaches a sustained power level of approximately 113%. The high flux and the flux/flow/imbalance trips do not actuate due to the effect of the decrease in the reactor vessel downcomer temperature. The RCS pressure response (Figure 15-173) follows RCS average temperature. The system analysis results are input to a detailed core thermal-hydraulic analysis assuming a standard reference power distribution. The minimum DNBR of 1.301 is less than the design limit of 1.53. Consequently, DNBR margin may not exist, and a fuel pin census analysis is performed to determine if DNBR margin exists or the number of fuel pins that exceed the DNBR limit. A range of pin radial peaks and axial shapes are assumed to determine the peaking factors at which the DNBR limit is exceeded. These limiting peaking factors are the maximum allowable radial peak (MARP) limits. Each fuel rod in the core is then evaluated against the MARP limits at the limiting DNBR statepoint to determine if the fuel rod exceeds the DNBR limit. All fuel rods that exceed the DNBR limit are assumed to experience cladding failure and are counted in the source term for the offsite dose calculation. The results of the fuel pin census analysis for the small steam line break accident is that DNB margin exists for all of the fuel pins. The centerline fuel melt limit has been evaluated and it is not violated.

15.17.3 Environmental Consequences

(TO BE SUBMITTED LATER)

15.17.4 Conclusions

The small steam line break accident analysis results show that DNBR margin exists for all of the fuel rods, and that no fuel failures due to centerline fuel melt occur. The environmental consequences meet the acceptance criteria. All of the acceptance criteria are met.

NOTE REGARDING TABLES

The following revised and new tables are presented in numerical order rather than the order in which they are referred to in the revised text

Table 15-2
Rod Ejection Accident
SIMULATE-3K Analysis Results

Parameter	BOC 4 RCP	BOC 3 RCP	BOC HZP	EOC 4 RCP	EOC 3 RCP	EOC HZP
Initial rod position (% wd)	58	38	0	58	38	0
Ejected rod worth (pcm)	200	400	800	200	400	800
Delayed neutron fraction	0.0058	0.0058	0.0058	0.0049	0.0049	0.0049
Begin rod ejection (sec)	0	0	0	0	0	0
End rod ejection (sec)	0.063	0.093	0.150	0.063	0.093	0.150
Maximum neutron power (% FP)	140	194	1841	137	214	1752
Time of maximum power (sec)	0.076	0.109	0.288	0.081	0.117	0.277
Peak assembly power	2.29	2.93	4.17	2.25	3.00	4.33
Peak nodal power	3.14	4.20	6.40	3.09	4.81	10.5
High flux trip time (sec)	0.054	0.082	0.248	0.057	0.083	0.245
Begin scram rod motion (sec)	0.454	0.482	0.648	0.457	0.483	0.645
End scram rod motion (sec)	2.854	2.882	3.048	2.857	2.883	3.045

Table 15-3
Rod Ejection Accident
ARROTTA Analysis Results

Parameter	BOC 4 RCP	BOC 3 RCP	BOC HZP	EOC 4 RCP	EOC 3 RCP	EOC HZP
Initial rod position (% wd)	58	38	0	58	38	0
Ejected rod worth (pcm)	200	400	800	200	400	800
Delayed neutron fraction	0.0058	0.0058	0.0058	0.0049	0.0049	0.0049
Begin rod ejection (sec)	0	0	0	0	0	0
End rod ejection (sec)	0.063	0.093	0.150	0.063	0.093	0.150
Maximum neutron power (% FP)	144	195	2098	148	223	1918
Time of maximum power (sec)	0.076	0.106	0.270	0.079	0.112	0.262
Peak assembly power	2.38	3.01	4.28	2.45	3.12	4.51
Peak nodal power	3.33	4.37	6.66	3.44	4.77	9.99
High flux trip time (sec)	0.054	0.082	0.248	0.057	0.083	0.245
Begin scram rod motion (sec)	0.454	0.482	0.648	0.457	0.483	0.645
End scram rod motion (sec)	2.854	2.882	3.048	2.857	2.883	3.045
Peak pellet average enthalpy (cal/gm)	132.8	129.0	55.1	109.7	118.3	58.5
Percent pins exceeding DNBR (%)	40.6	39.2	<1	27.6	36.3	2.1

Table 15-5
Steam Line Break Accident - With Offsite Power Case
Sequence of Events

Event	Time (sec)
Break opens	0.0
Reactor trip on variable low pressure-temperature	0.7
Control rod insertion begins	0.8
Third CBP starts	1.5
Turbine stop valves closed Control rods fully inserted	1.8
MSSV opens on unaffected SG	6.9
HPI actuates	20.8
MSSV closes on unaffected SG	26.9
Boron injection from HPI begins	103.4
CFT injection begins	131.5
Boron from CFT B starts	152.0
Boron from CFT A starts	157.2
Peak return-to-power occurs	160.0
End of simulation	600.0

Table 15-32
Summary of Transient and Accident Cases Analyzed

15.2	Startup Accident	Peak RCS pressure
15.3	Rod Withdrawal at Power	1. Core cooling capability 2. Peak RCS pressure
15.4	Moderator Dilution Accidents	1. Power operation 2. Refueling
15.5	Cold Water Accident	Core cooling capability
15.6	Loss of Coolant Flow	Core cooling capability: 1. Four RCP trip from four RCPs 2. Two RCP trip from four-RCPs 3. One RCP trip from three-RCPs 4. Locked rotor from four-RCPs 5. Locked rotor from three-RCPs
15.7	Control Rod Misalignment Accidents	Core cooling capability 1. Dropped rod from four-pumps 2. Dropped rod from three-pumps 3. Statically misaligned rod
15.8	Turbine Trip	Peak RCS pressure
15.9	Steam Generator Tube Rupture	Offsite dose
15.10	Waste Gas Tank Rupture	Offsite dose
15.11	Fuel Handling Accidents	Offsite dose 1. Fuel handling accident in Spent Fuel Pool 2. Fuel handling accident in containment 3. Fuel shipping cask drop 4. Dry storage canister cask drop
15.12	Rod Ejection	Peak fuel enthalpy 1/2. Four-pump BOC and EOC 3/4. Three-pump BOC and EOC 5/6. Three-pump BOC and EOC, HZP Core cooling capability 1/2. Four-pump BOC and EOC 3/4. Three-pump BOC and EOC 5/6. Three-pump BOC and EOC, HZP Peak RCS pressure 7. Three-pump BOC

Table 15-32
Summary of Transient and Accident Cases Analyzed
(Cont.)

15.13 Steam Line Break	Core cooling capability 1. With offsite power 2. Without offsite power
15.14 Loss of Coolant Accidents	10 CFR 50.46 and offsite dose 1. Large-break LOCA spectrum Mk-B9 fuel LOCA limit cases Mk-B10 fuel LOCA limit cases 2. Small-break LOCA spectrum
15.15 Maximum Hypothetical Accident	Large Break LOCA - offsite dose
15.16 Post-Accident Hydrogen Control	Large Break LOCA - flammability limit
15.17 Small Steam Line Break	Core cooling capability

Table 15-33
Methodology Topical Reports and Computer Codes Used in Analyses

UFSAR Section		Topical Reports	Computer Codes
15.2	Startup Accident	DPC-NE-3005-PA	RETRAN-02 SIMULATE-3P
15.3	Rod Withdrawal at Power Accident	DPC-NE-3005-PA	RETRAN-02 VIPRE-01 SIMULATE-3P
15.4	Moderator Dilution Accidents	DPC-NE-3005-PA	N/A
15.5	Cold Water Accident	DPC-NE-3005-PA	RETRAN-02
15.6	Loss of Coolant Flow Accidents	DPC-NE-3005-PA	RETRAN-02 VIPRE-01 SIMULATE-3P
15.7	Control Rod Misalignment Accidents	DPC-NE-3005-PA	RETRAN-02 VIPRE-01 SIMULATE-3P
15.8	Turbine Trip Accident	DPC-NE-3005-PA	RETRAN-02
15.9	Steam Generator Tube Rupture Accident	DPC-NE-3005-PA	RETRAN-02
15.12	Rod Ejection Accident	DPC-NE-3005-PA	SIMULATE-3K SIMULATE-3P ARROTTA RETRAN-02 VIPRE-01
15.13	Steam Line Break Accident	DPC-NE-3005-PA	RETRAN-02 VIPRE-01 SIMULATE-3P
15.14	Loss of Coolant Accident		
	Large-Breaks	BAW-10192-P	RELAP5/MOD2-B&W CONTEMPT REFLOD3 BEACH
	Small Breaks	BAW-10154-P	CRAFT2 FOAM2 THETA-1B
15.17	Small Steam Line Break Accident	DPC-NE-3005-PA	RETRAN-02 VIPRE-01 SIMULATE-3P

Table 15-34
Summary of Input Parameters for Accident Analyses Using Computer Codes (Page 1 of 5)

UFSAR Section	Case Identifier	Power Level (% FP)	RCS T-ave (° F)	RCS Pressure (psig)	RCS Flow (gpm)	Pressurizer Level (inches)	MTC (Δk/k/°F)	DTC (Δk/k/°F)	β-effective	SG Tube Plugging (%)
15.2	N/A	1.0E-7	532	2155	272,976	285	+7.0E-5	Note 2	0.0065	15
15.3	1	100	579	2125	378,400	195	-3.0E-5	Note 2	0.0065	1
	2	102	581	2185	371,360	285	-3.0E-5	Note 2	0.0065	15
15.5	N/A	80	579	2125	282,665	195	-35.0E-5	Note 3	0.0049	1
15.6	1	100	579	2125	378,400	195	-3.00E-5	Note 2	0.0065	1
	2	100	579	2125	378,400	195	-3.00E-5	Note 2	0.0065	1
	3	80	579	2125	282,665	195	-2.2235E-5	Note 2	0.0065	1
	4	100	579	2125	378,400	195	-3.0E-5	Note 2	0.0065	1
	5	80	579	2125	282,665	195	-2.2235E-5	Note 2	0.0065	1
15.7	1	100	579	2125	378,400	195	-3.0E-5	Note 2	0.0065	1
	2	80	579	2125	282,665	195	-3.0E-5	Note 2	0.0065	1
15.8	N/A	102	581	2185	371,360	285	-3.075E-5	Note 2	0.0065	15
15.9	N/A	102	577	2185	371,360	245	-35.0E-5	Note 4	0.0049	15
15.12	1	102	581	2095	371,360	N/A	-3.0E-5 Note 7	-1.25E-5	0.0058	N/A
	2	82	581	2095	272,985	N/A	-2.2E-5	-1.30E-5	0.0058	N/A
	3	10E-9	540	2095	173,448	N/A	+7.0E-5	-1.65E-5	0.0058	N/A
	4	102	581	2095	371,360	N/A	-25.0E-5	-1.35E-5	0.0049	N/A
	5	82	581	2095	272,985	N/A	-25.0E-5	-1.38E-5	0.0049	N/A
	6	10E-9	540	2095	173,448	N/A	-15.0E-5	-1.75E-5	0.0049	N/A
	7	82	581	2095	272,985	245	0.0	0.0	N/A	15
15.13	1	102	577	2095	371,360	195	Note 8	Note 5	0.0049	1
	2	100	579	2125	378,400	245	Note 9	Note 6	0.0065	1
15.14	1	102	580.5	2190	355,232 Note 1	220	0.0	Note 4	0.007	20
	2	110.3	581.9	2116.6	371,360 Note 10	260	0.0	-1.3896E-5	0.0071	0
15.17	N/A	80	579	2155	282,665	245	-12.0E-5	Note 3	0.0054	1

Table 15-34
Summary of Input Parameters for Accident Analyses Using Computer Codes (Page 2 of 5)

Note 1: LB LOCA analysis assumed 131.9 Mlb/hr or 100.9% of design flow.

Note 2: Doppler reactivity assumption as function of average fuel temperature:

Accident Analyses: 15.2, 15.3, 15.6, 15.7, 15.8

Average Fuel Temperature (°F)	Doppler Coefficient $\Delta k/k$-°F (x10^{-5})
231.4	-2.129
449.65	-1.7959
727.61	-1.4773
1424.01	-1.1856

Note 3: Doppler reactivity assumption as function of average fuel temperature:

Accident Analyses: 15.5, 15.17

Average Fuel Temperature (°F)	Doppler Coefficient $\Delta k/k$-°F (x10^{-5})
457.73	-1.9084
629.14	-1.6884
889.38	-1.4683
1346.34	-1.3447

Note 4: Doppler reactivity assumption as function of average fuel temperature:

Accident Analysis: 15.9, 15.14 Case 1

Average Fuel Temperature (°F)	Doppler Coefficient $\Delta k/k$-°F (x10^{-5})
452.38	-2.1782
754.3	-1.8795
1149.79	-1.6651
1350	-1.5566

Table 15-34

Summary of Input Parameters for Accident Analyses Using Computer Codes (Page 3 of 5)

Note 5: Doppler reactivity assumption as function of average fuel temperature:

Accident Analysis: 15.13 Case 1

Average Fuel Temperature (°F)	Doppler Reactivity %Δk/k
953.8	0
940.55	0.0221
920.55	0.0531
900.55	0.0854
532	0.9144
512	0.9556
500	0.979
450	1.0821
400	1.187
350	1.2948
300	1.4059
250	1.5205
200	1.639

Note 6: Doppler reactivity assumption as function of average fuel temperature:

Accident Analysis: 15.13 Case 2

Average Fuel Temperature (°F)	Doppler Reactivity %Δk/k
1250	0
1200	0.0533
1150	0.1073
1112	0.1493
1052	0.2158
1000	0.2736
900	0.3898
800	0.509
700	0.6326
600	0.7611
532	1.0265

Note 7: Actual physics parameters values determined from code cross section library for 15.12 Cases 1-6, target values listed for moderator and doppler reactivities and β-effective.

Note 8: Moderator reactivity assumption as a function of moderator density.

Accident Analysis: 15.13 Case 1

Moderator Density (lbm/ft^3)	Moderator Reactivity %Δk/k
44.6805	0
45.2685	0.2294
46.0051	0.5095
46.6294	0.7376
47.6658	1.101
47.8133	1.6696
49.1185	2.2695
49.5917	2.4735
51.5476	3.283
52.0171	3.4673
53.7633	4.124
54.1503	4.2632
55.7105	4.8038
56.0313	4.9109
57.6164	5.4401
59.1166	5.9409

Note 9: Moderator reactivity assumption as a function of moderator density.

Accident Analysis: 15.13 Case 2

Moderator Density (lbm/ft^3)	Moderator Reactivity %Δk/k
41.767	-0.06
42.941	-0.0214
43.828	-0.0048
44.296	0
44.538	0.003
45.363	-0.0042
46.1	-0.0177
46.724	-0.0351
47.813	-0.0626

Table 15-34

Summary of Input Parameters for Accident Analyses Using Computer Codes (Page 5 of 5)

Note 10: SB LOCA analysis assumed 137.9 Mlb/hr or 105.5% of design flow.

Table 15-35
Trip Setpoints and Time Delays Assumed in Accident Analyses

Trip Function	Nominal Setpoint	Limiting Trip Setpoint Assumed in Analyses	Time Delay (seconds)
RPS:			
High Flux	105.5 % FP	106.5% FP	0.4
High Pressure	2355 psig	2362 psig	0.5
Low Pressure	1800 psig	1793 psig (Note 2)	0.5
Variable Low Pressure-Temperature	Trip if: (Note 1) $P < 11.14 \cdot T_{hot} - 4706$	Trip if: (Note 1) $P < 11.14 \cdot T_{hot} - 4716$	0.7
High Temperature	618 °F	618.85 °F	0.7
Flux/Flow	Trip if: (Note 3) $\phi > 109.4$ %FP/flow $\cdot$ Fm	Trip if: (Note 3) $\phi > 109.4$ %FP/flow $\cdot$ Fm + 2.2 %FP	1.2
Pump Monitor		NA	0.6
ESPS:			
HPI	1590 psig	1480 psig 1400 psig (Note 6)	15 (no-LOOP) 38 (LOOP)
CFT	2 psid	+ 6.5 psid (CFT-A) -2.5 psid (CFT B) (Note 4)	NA
LPI		N/A (Note 5)	39 + 14 sec ramp

Note 1: “P” is gauge pressure.
Note 2: SBLOCA analyses assume 1900 psig.
Note 3: “Fm” is measured flow.
Note 4: SBLOCA analyses assume 600 psig Nitrogen pressure.
Note 5: Trip setpoint not explicitly assumed, initiation on time delay with LBLOCA.
Note 6: Large steam line break assumes HPI actuation at 1400 psig because of degraded containment conditions.

Table 15-36
Startup Accident
Sequence of Events

Event	Time (sec)
Rod withdrawal begins	0.0
Pressurizer control heaters de-energize	49.5
High RCS pressure reactor trip	51.3
Control rod insertion begins	51.8
Pressurizer safety valves open	53.6
Peak RCS pressure occurs	54.3
Pressurizer safety valves reseat	56.6
End of simulation	100.0

Table 15-37
Rod Withdrawal at Power Accident - Peak RCS Pressure Analysis
Sequence of Events

Event	Time (sec)
Rod withdrawal begins	0.0
High RCS pressure reactor trip setpoint reached	38.7
Control rod insertion begins	39.2
Turbine trip on reactor trip	39.2
Main steam safety valves lift	41.9 - 43.3
Peak RCS pressure occurs	42.6
Main steam safety valves begin to reseat	44.5
End of simulation	49.2

Table 15-38
Rod Withdrawal at Power Accident - Core Cooling Capability Analysis
Sequence of Events

Event	Time (sec)
Rod withdrawal begins	0.0
Pressurizer spray actuates	54.1
High pressure reactor trip setpoint reached	147.1
Control rod insertion begins	147.6
Turbine trip on reactor trip	147.6
Main steam safety valves lift	152 - 153
Pressurizer spray terminates	154.5
End of simulation	157.6

Table 15-39
Cold Water Accident
Sequence of Events

Event	Time (sec)
Fourth RCP starts	0.1
RCP reaches full speed	4.1
Maximum heat flux occurs (96.7 %FP)	6.0
End of simulation	15.0

Table 15-40
Loss of Flow Accidents
Four RCP Coastdown from Four RCP Initial Conditions
Sequence of Events

Event	Time (sec)
All RCPs trip	0.0
Pump monitor reactor trip	0.01
Rod motion begins	0.61
Turbine trip on reactor trip	0.77
Pressurizer spray initiates	2.90
MSSVs lift	3.43 - 4.36
End of simulation	19.0

Table 15-41
Loss of Flow Accidents
Two RCP Coastdown from Four RCP Initial Conditions
Sequence of Events

Event	Time (sec)
Two RCPs trip	0.0
Flux/flow reactor trip setpoint reached	3.51
Rod motion begins	4.71
Turbine trip on reactor trip	4.87
Pressurizer spray initiates	5.99
MSSVs lift	7.15 - 10.32
End of simulation	19.0

Table 15-42
Loss of Flow Accidents
One RCP Coastdown from Three RCP Initial Conditions
Sequence of Events

Event	Time (sec)
One RCPs trip	0.0
Flux/flow reactor trip setpoint reached	3.05
Rod motion begins	4.25
Turbine trip on reactor trip	4.41
MSSVs lift	6.56 - 8.93
End of simulation	19.0

Table 15-43
Loss of Flow Accidents
Locked Rotor from Four RCP Initial Conditions
Sequence of Events

Event	Time (sec)
Locked rotor occurs	0.0
Flux/flow reactor trip setpoint reached	0.51
Rod motion begins	1.71
Turbine trip on reactor trip	1.87
Pressurizer spray initiates	3.01
MSSVs lift	4.18 - 7.05
End of simulation	9.0

1.2 sec Rx Trip delay

Table 15-44
Loss of Flow Accidents
Locked Rotor from Three RCP Initial Conditions
Sequence of Events

Event	Time (sec)
Locked rotor occurs	0.0
Flux/flow reactor trip setpoint reached	0.13
Rod motion begins	1.33
Turbine trip on reactor trip	1.49
Pressurizer spray initiates	3.27
MSSVs lift	5.04 - 6.55
End of simulation	9.0

Table 15-45
Control Rod Misalignment Accidents - Dropped Rod Accident
Sequence of Events

Event	Time (sec)
Control rod drops	0.0
ICS initiates control rod withdrawal	0.6
Pressurizer spray initiates	20.2
Control rod withdrawal terminates	34.6
Reactor trip on high RCS pressure	35.3
Turbine trip on reactor trip	35.5
Main steam safety valves lift	37.8 – 43.1
Pressurizer spray stops	43.6
End of simulation	50.3

Table 15-46
Turbine Trip Accident
Sequence of Events

Event	Time (sec)
Turbine trip	0.1
MFW isolation	0.1
Main steam safety valves lift	3.00 - 9.17
High RCS pressure trip	3.50
Control rod insertion begins	4.00
Peak RCS pressure occurs	7.50
Main steam safety valves reseat	10.62
End of simulation	50.0

Table 15-47
Steam Generator Tube Rupture Accident
Sequence of Events

Event	Seconds
SGTR occurs	0.1
HPIS injection flow starts	0.1
Reactor trip	1200
Turbine trip on reactor trip	1200
MFW pumps trip	1200
MSSVs lift and begin cycling	1201
EFW flow to ruptured SG begins	1380
Operator identifies EFW control valve is failed closed	1980
EFW to both SG is restored	2580
Operator identifies ruptured SG	3180
Operator begins minimizing subcooled margin	3900
Operator begins cooldown to 532°F with ADVs	5580
All MSSVs have reseated	6130
RCS cooled down to 532°F	6688
Operator completes isolation of the ruptured SG	7289
Operator trips one RCP per loop	7289
Shift changeover begins	7289
Shift changeover completed	10,889
Steaming of ruptured SG due to high SG level begins	11,112
Operator begins RCS cooldown to 450°F	11,189
RCS temperature reaches 450°F. Boron sampling and boration to cold shutdown begins	17,080
Operator begins cooldown to LPIS conditions	24,580
LPIS conditions reached	41,122
Start cooldown with LPIS	43,822
Plant cooled down to 212°F	48,366

Table 15-48
Steam Line Break Accident - Without Offsite Power Case
Sequence of Events

Event	Time (sec)
Break initiates, offsite power lost	0.0
RCPs begin to coast down	
MFW pumps begin to coast down	
Control rod insertion begins	0.14
Turbine stop valves closed	1.76
Control rods fully inserted	2.54
End of simulation	10

Table 15-49
Small Steam Line Break Accident
Sequence of Events

Event	Time (sec)
Break occurs	10
Third Condensate Booster Pump actuates	72
Peak neutron power	194
MDNBR occurs	198
Problem termination	250

NOTE REGARDING FIGURES

The following revised and new figures are presented in the order that they are referred to in the revised text (i.e. by revised UFSAR section beginning with the figures for Section 15.2 and ending with Section 15.17) rather than by the figure number, since the assigned figure numbers are not in numerical sequence in many cases.

Figure 15-1
Startup Accident

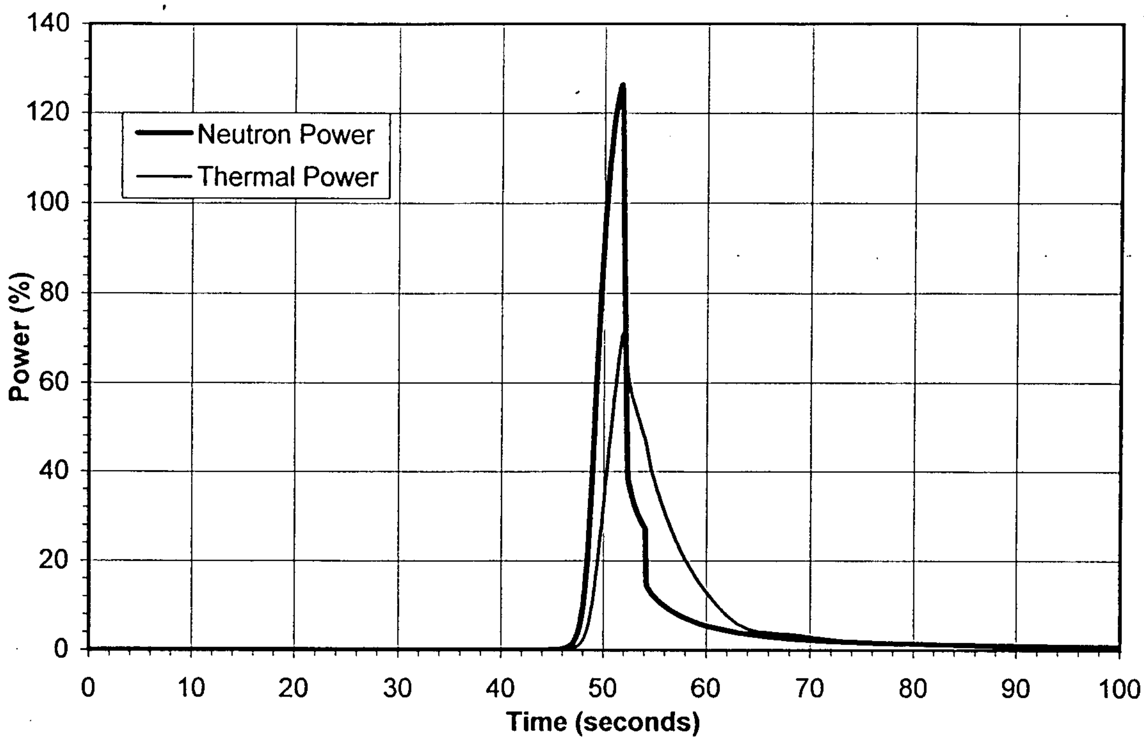


Figure 15-2
Startup Accident

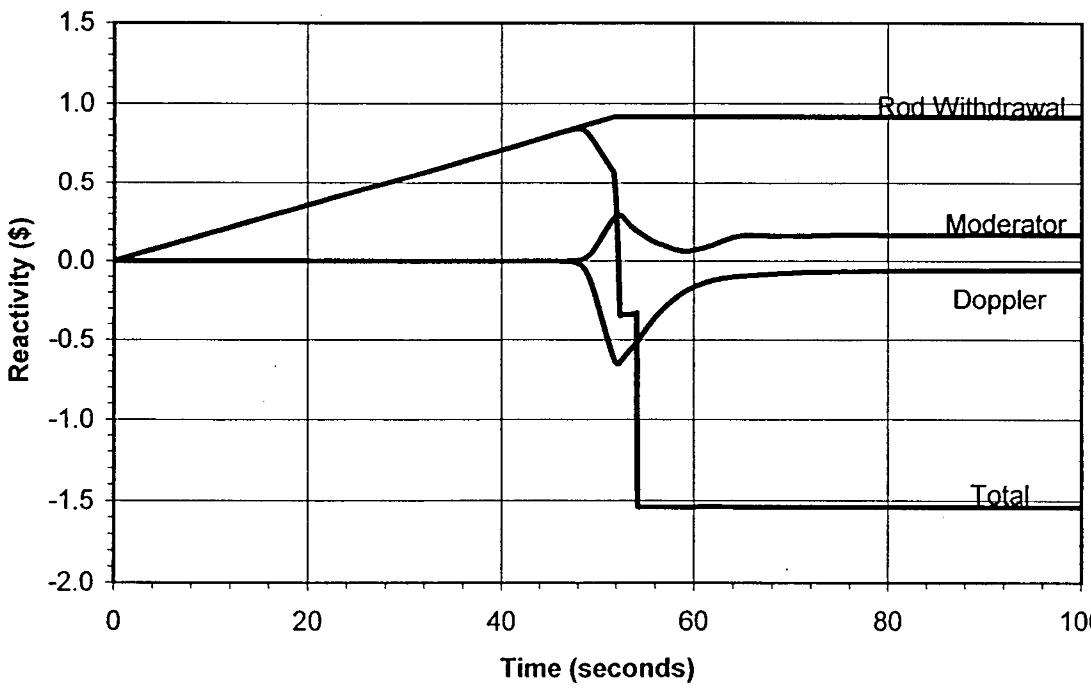


Figure 15-3
Startup Accident

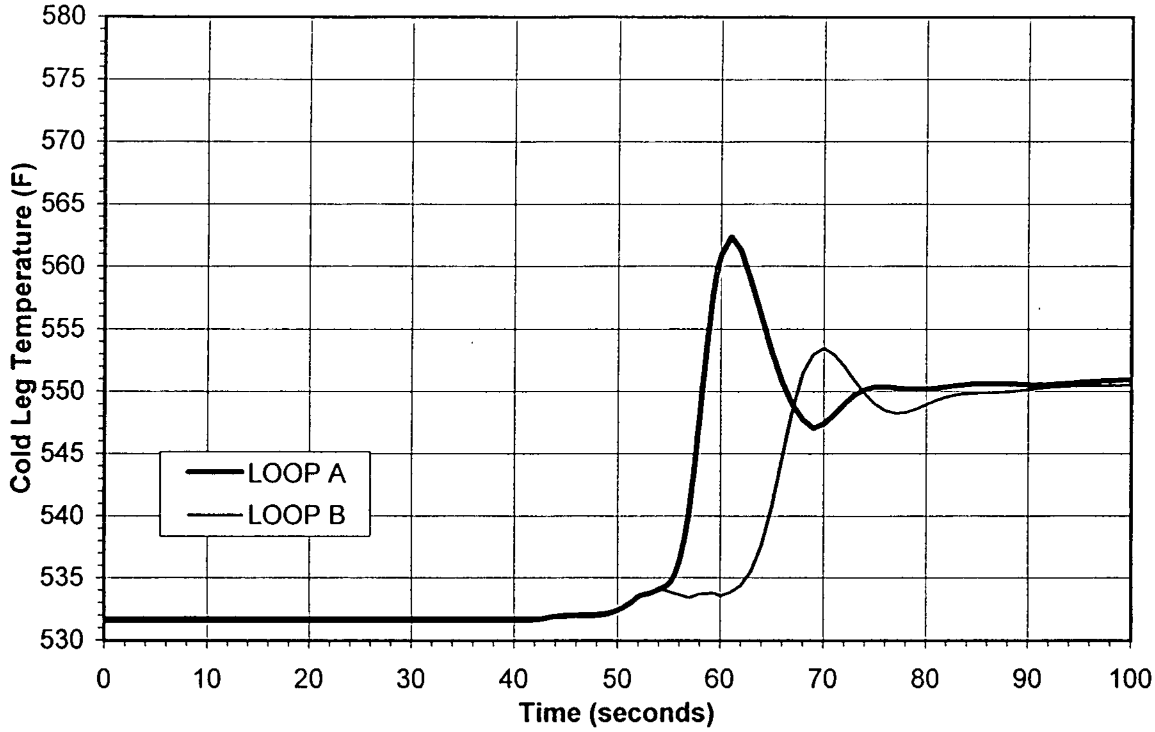


Figure 15-4
Startup Accident

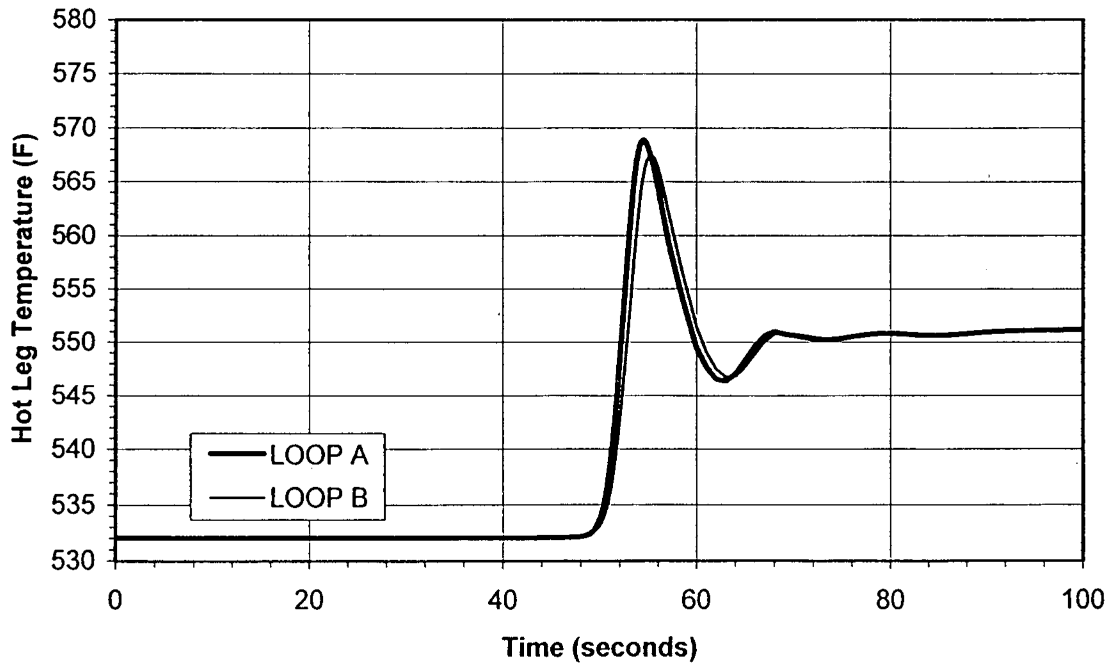


Figure 15-5
Startup Accident

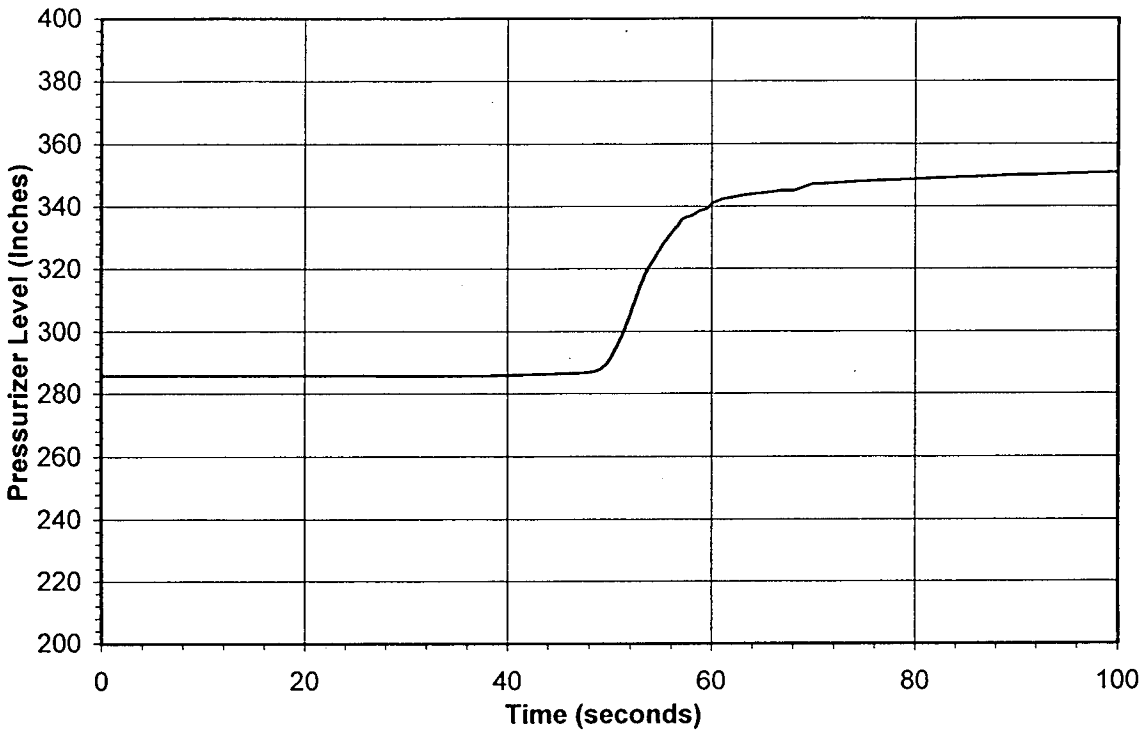


Figure 15-6
Startup Accident

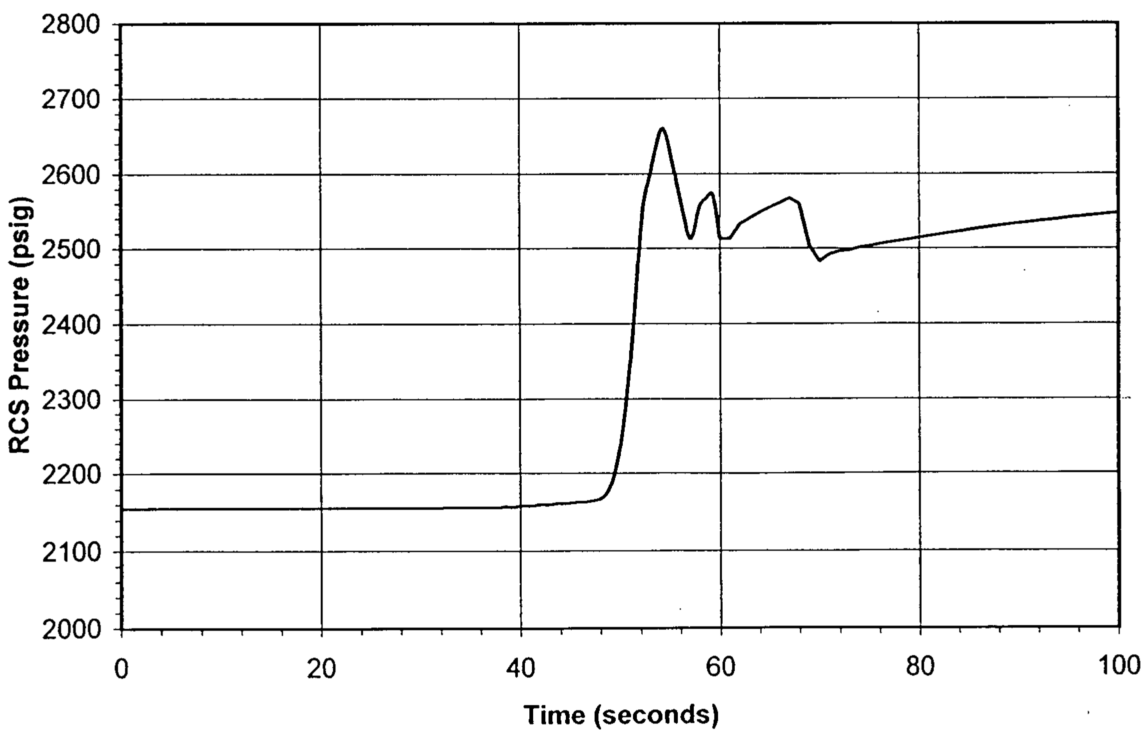


Figure 15-11
Rod Withdrawal at Power Accident
Peak RCS Pressure Analysis

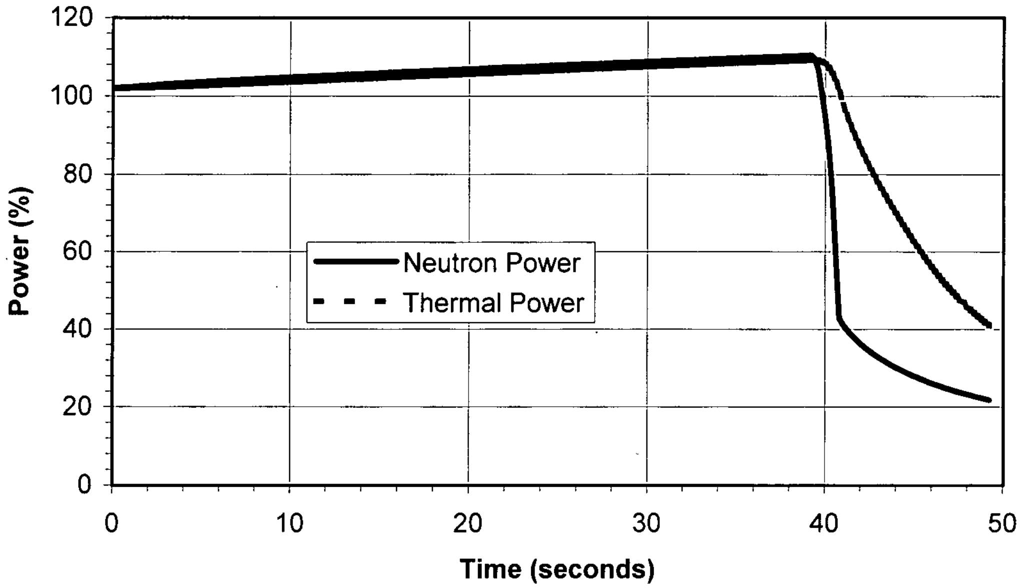


Figure 15-12
Rod Withdrawal at Power Accident
Peak RCS Pressure Analysis

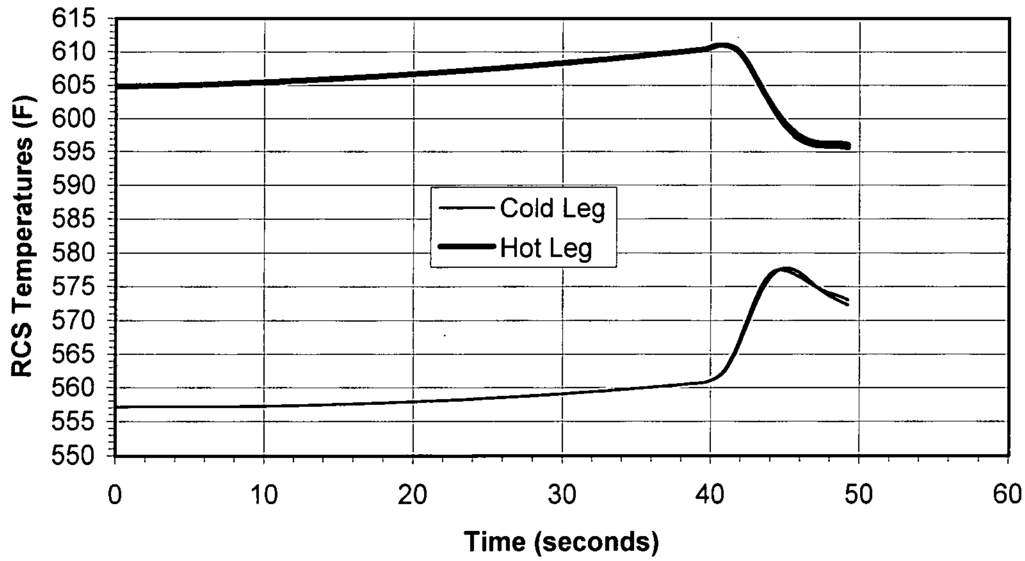


Figure 15-13
Rod Withdrawal at Power Accident
Peak RCS Pressure Analysis

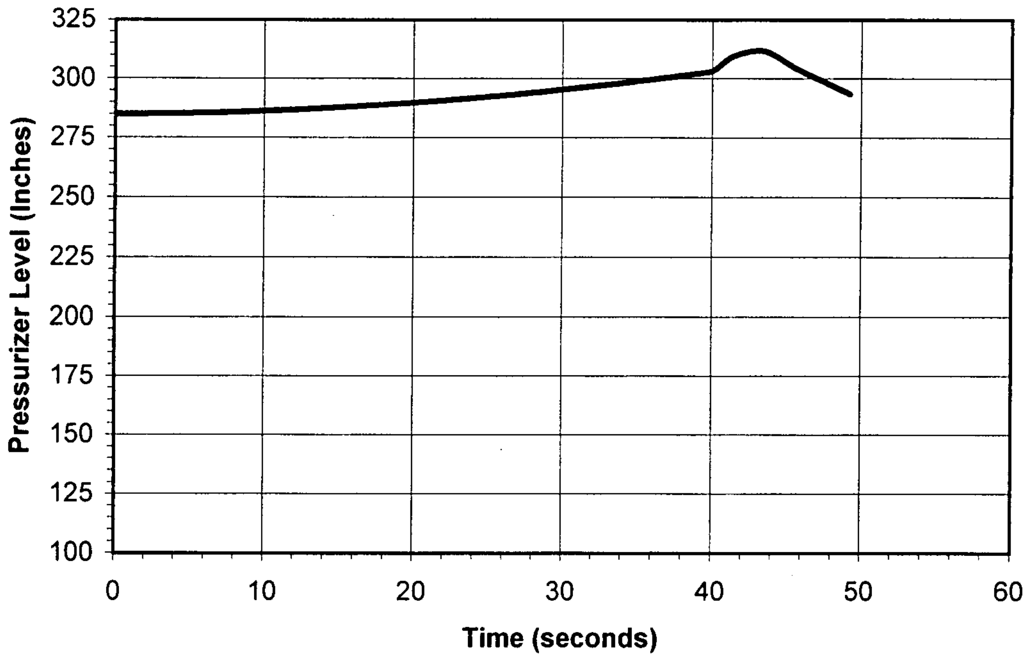


Figure 15-14
Rod Withdrawal at Power Accident
Peak RCS Pressure Analysis

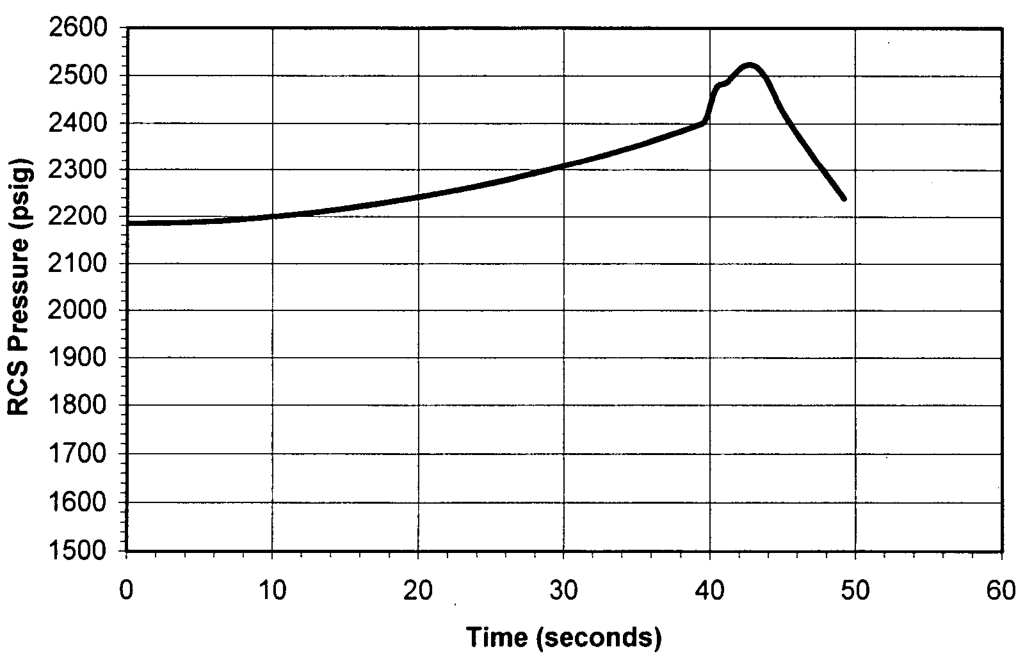


Figure 15-15
Rod Withdrawal at Power Accident
Core Cooling Capability Analysis

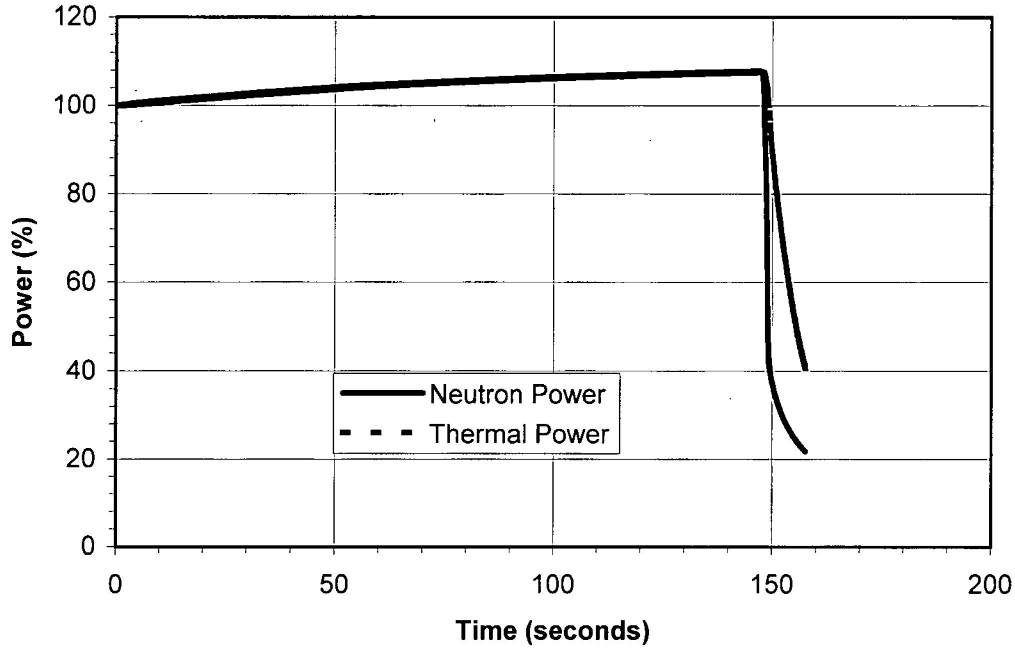


Figure 15-16
Rod Withdrawal at Power Accident
Core Cooling Capability Analysis

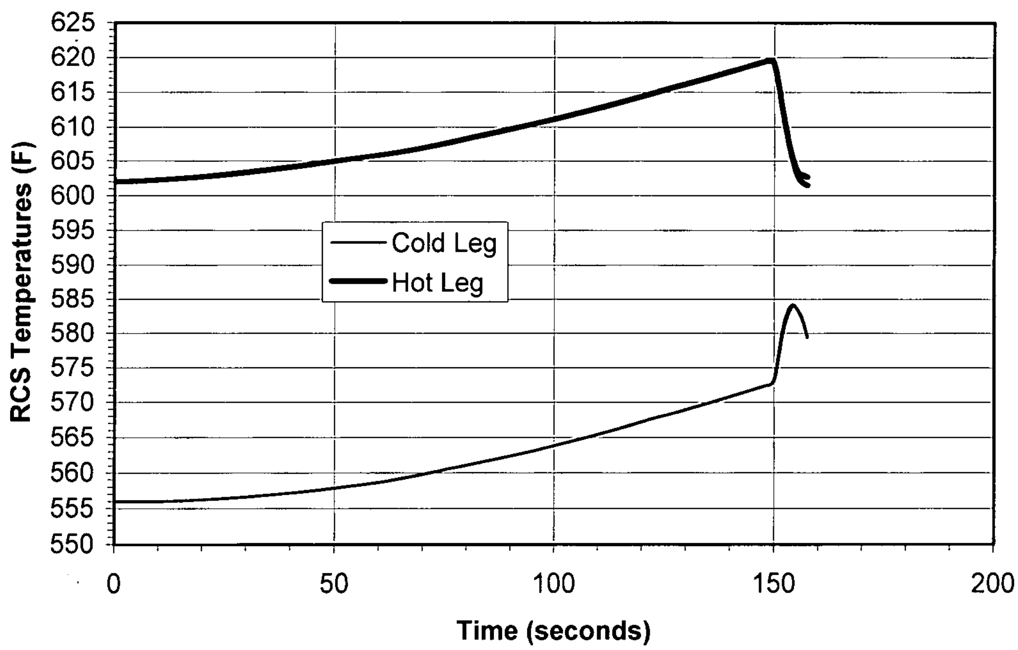


Figure 15-17
Rod Withdrawal at Power Accident
Core Cooling Capability Analysis

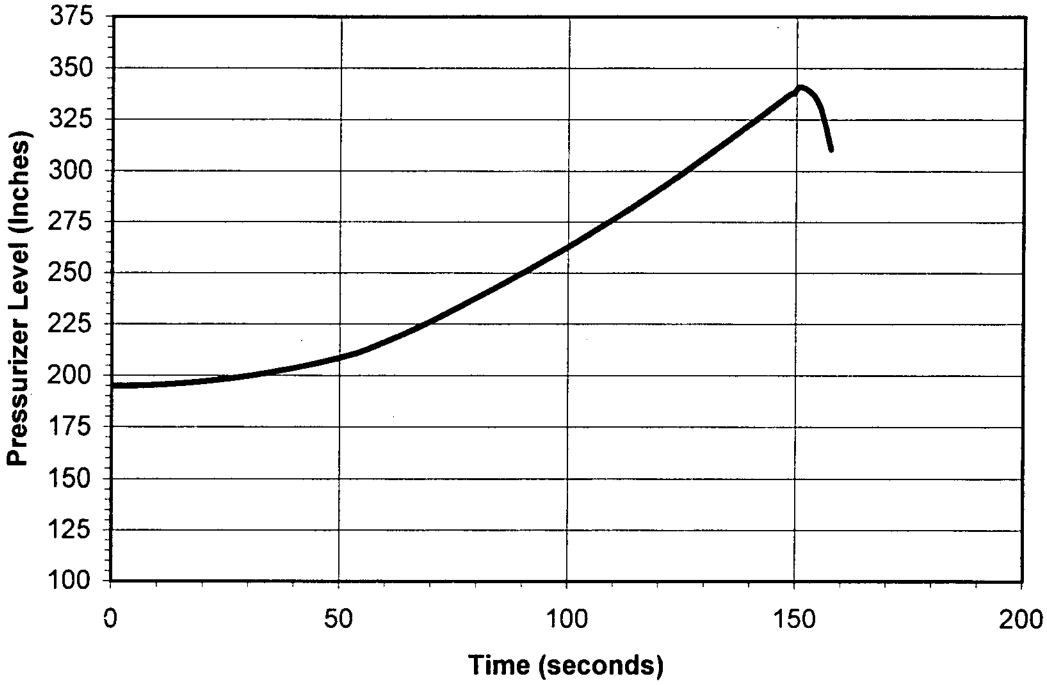


Figure 15-113
Rod Withdrawal at Power Accident
Core Cooling Capability Analysis

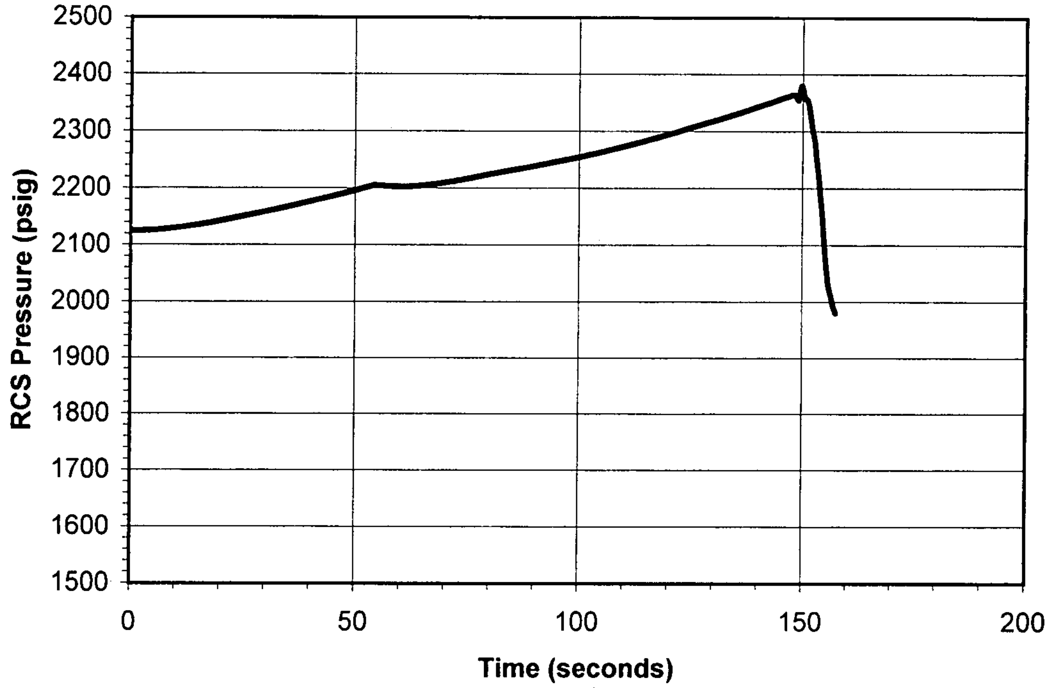


Figure 15-114
Rod Withdrawal at Power Accident
Core Cooling Capability Analysis

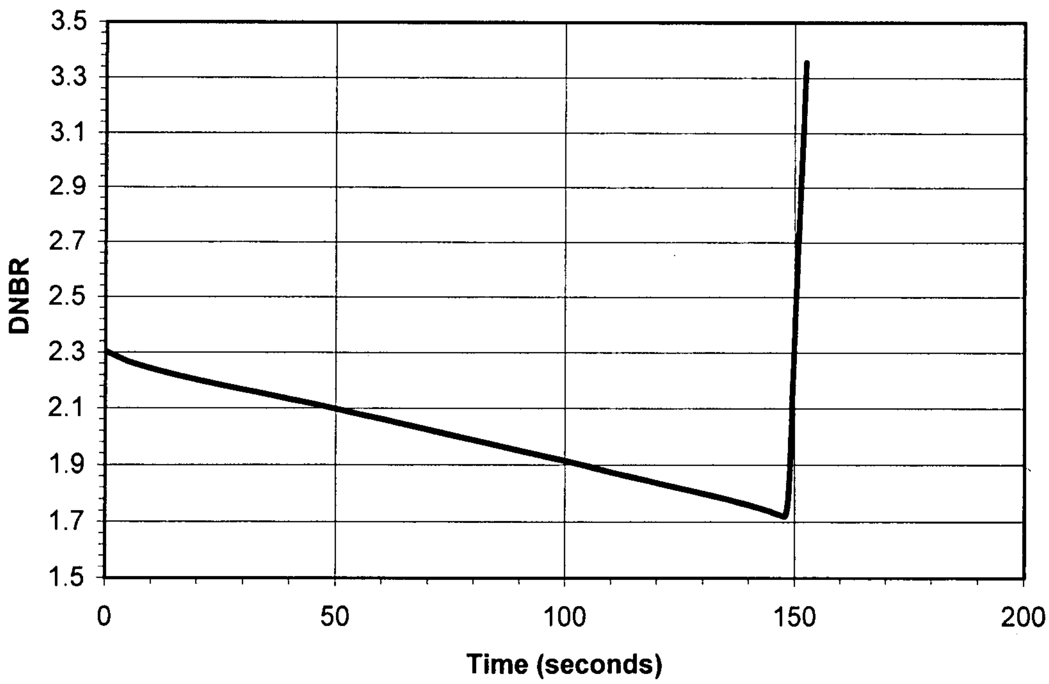


Figure 15-18
Cold Water Accident

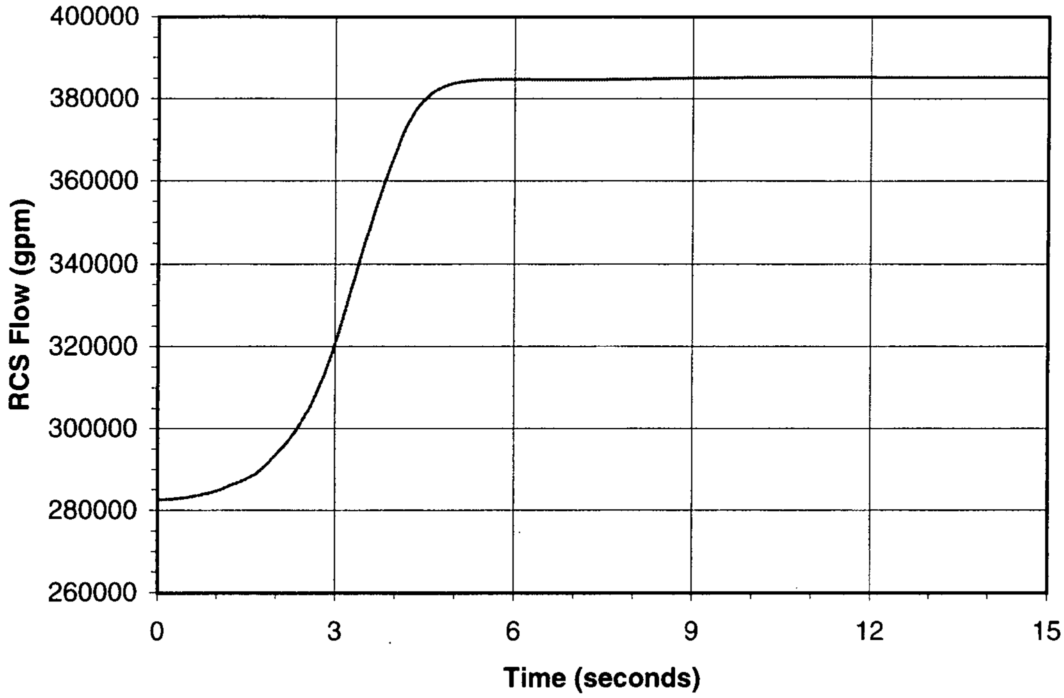


Figure 15-115
Cold Water Accident

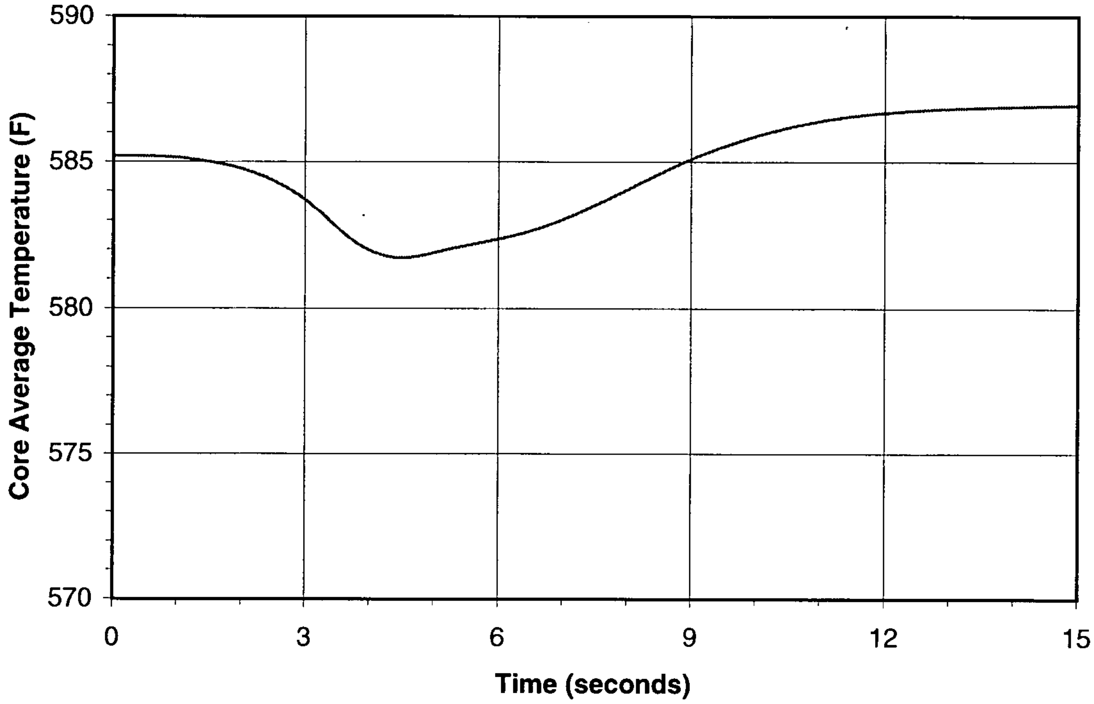


Figure 15-116
Cold Water Accident

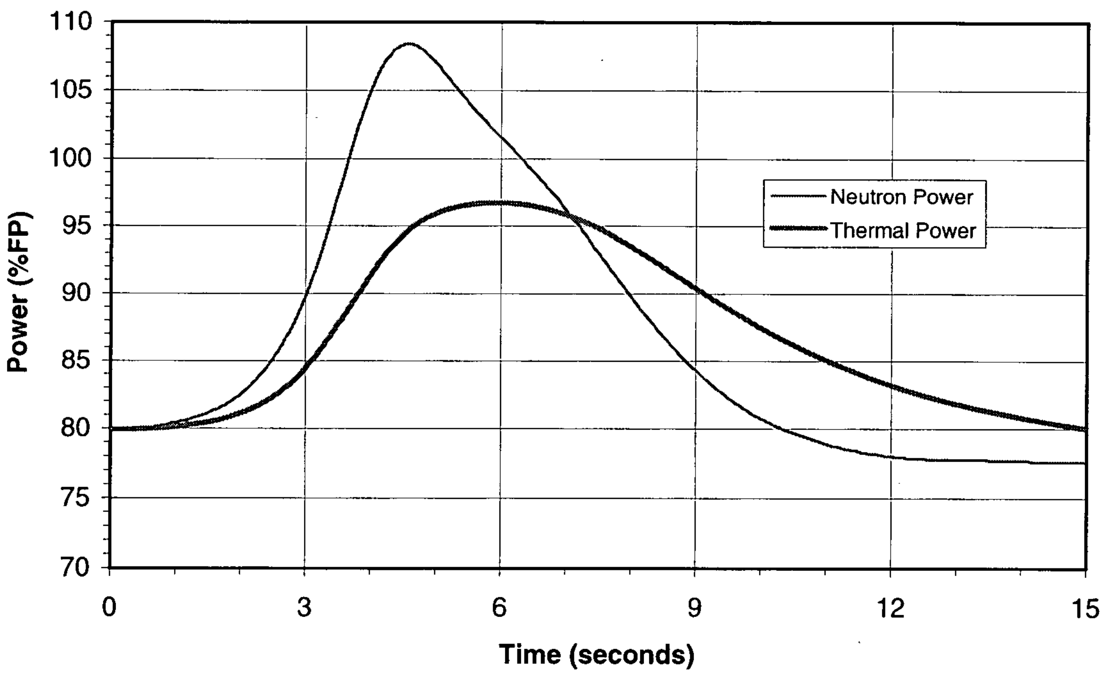


Figure 15-117
Cold Water Accident

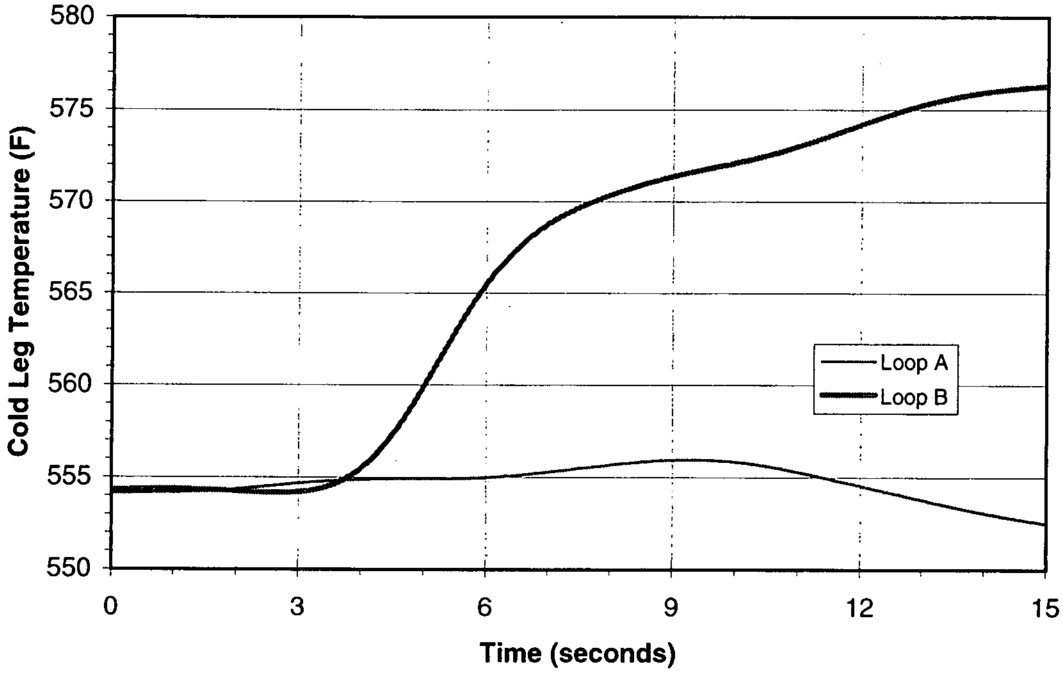


Figure 15-118
Cold Water Accident

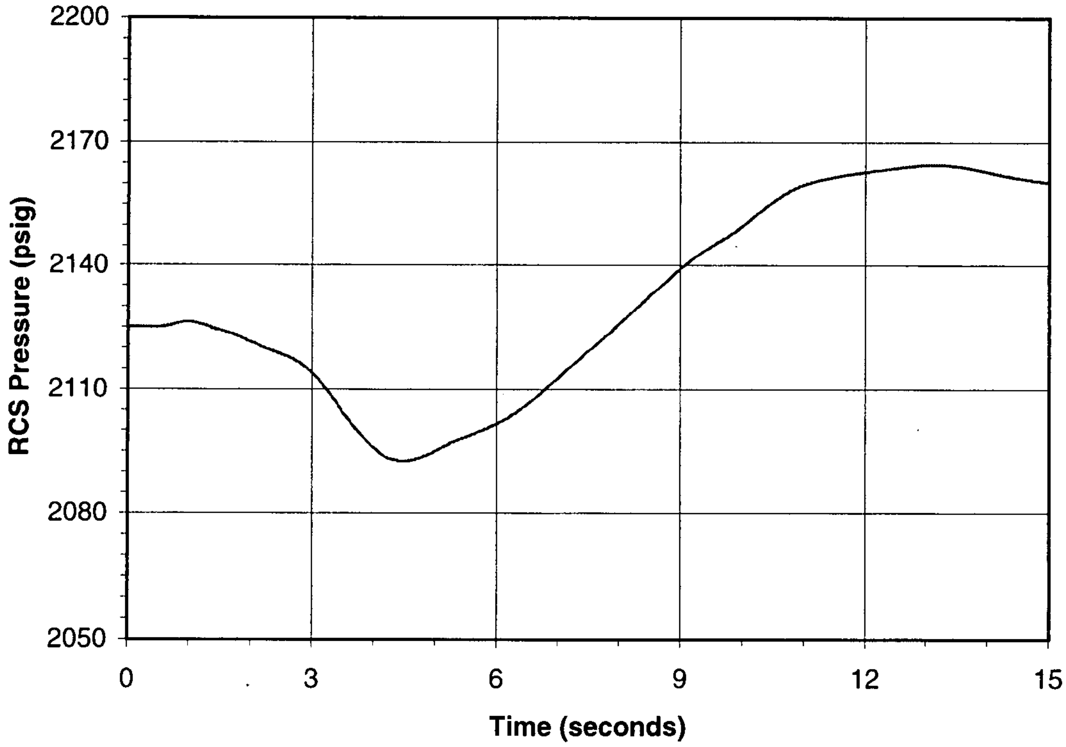


Figure 15-19
Loss of Coolant Flow Accidents
Four RCP Coastdown from Four RCP Initial Conditions Analysis

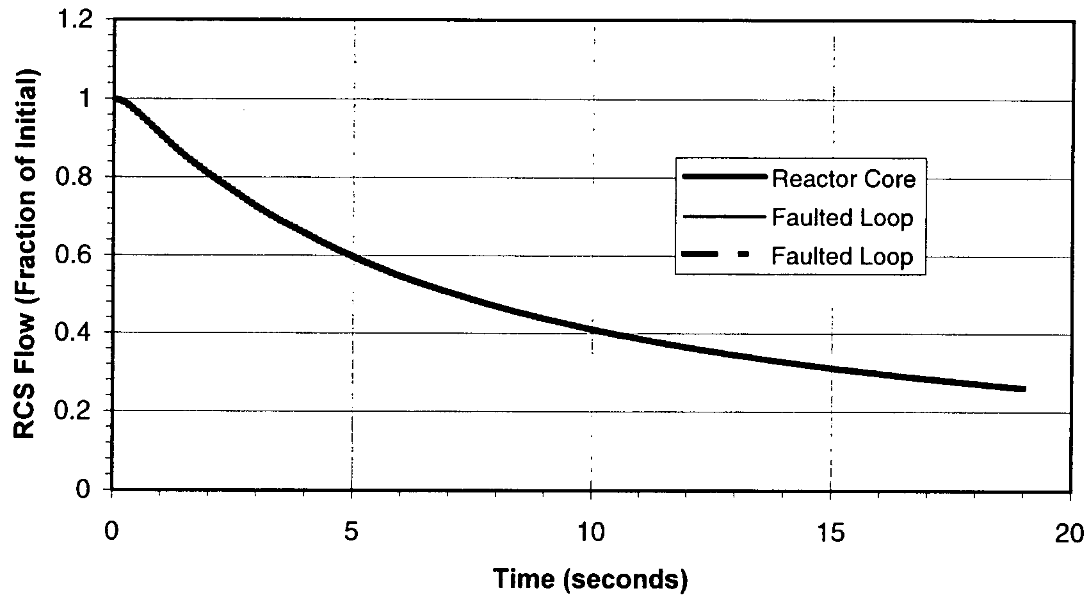


Figure 15-20
Loss of Coolant Flow Accidents
Four RCP Coastdown from Four RCP Initial Conditions Analysis

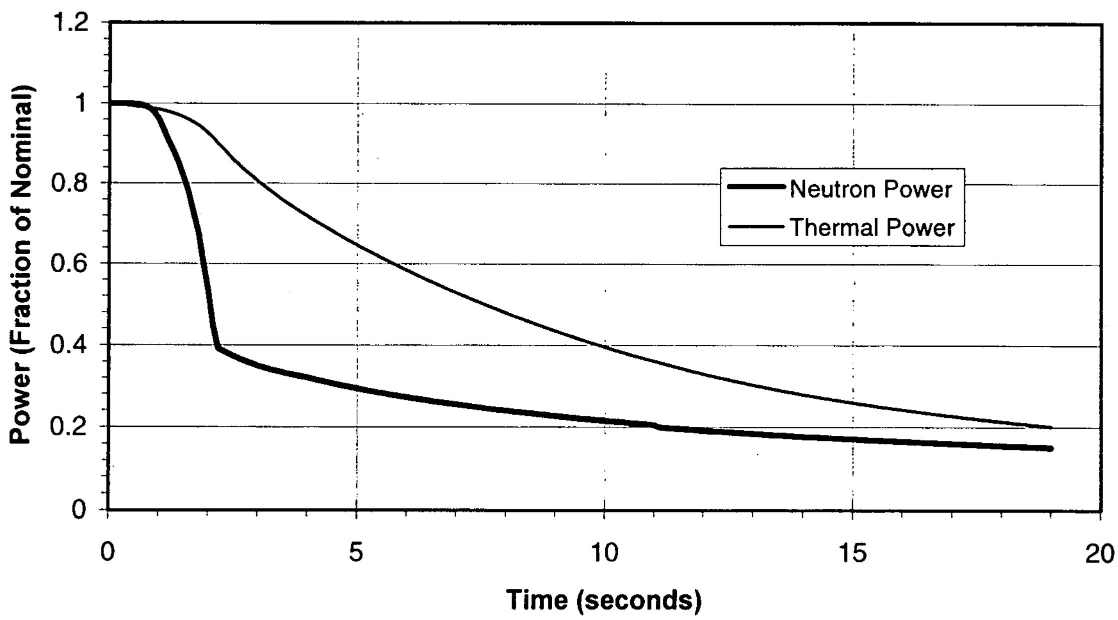


Figure 15-21
Loss of Coolant Flow Accidents
Four RCP Coastdown from Four RCP Initial Conditions Analysis

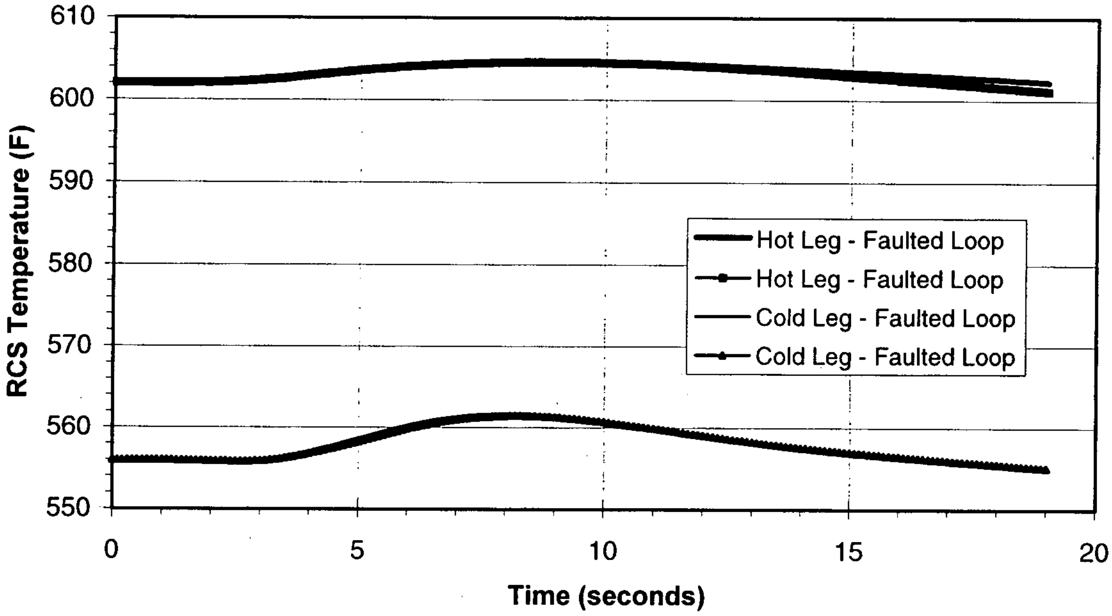


Figure 15-22
Loss of Coolant Flow Accidents
Four RCP Coastdown from Four RCP Initial Conditions Analysis

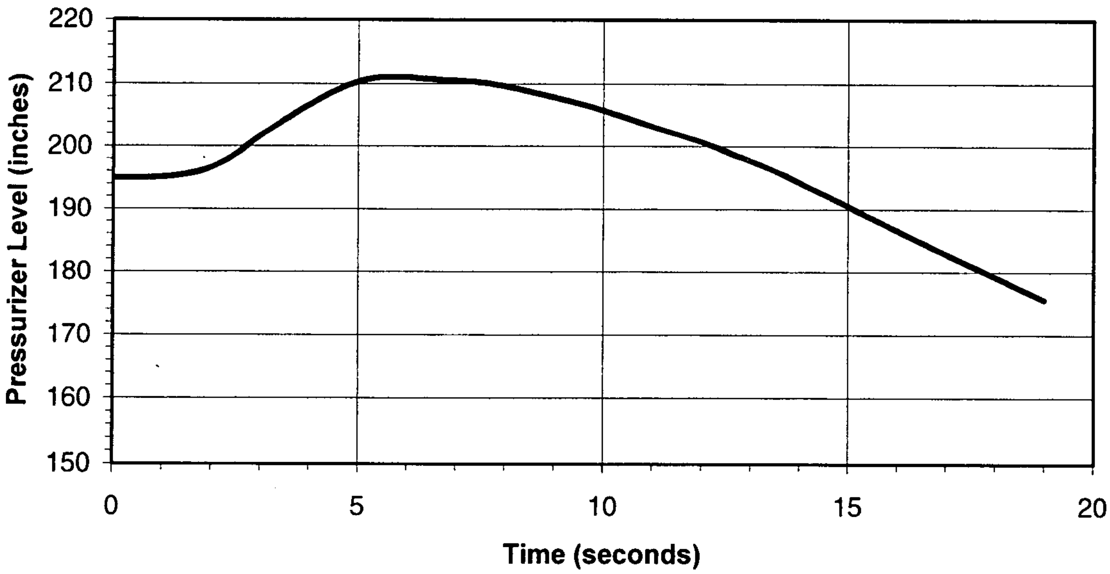


Figure 15-23
Loss of Coolant Flow Accidents
Four RCP Coastdown from Four RCP Initial Conditions Analysis

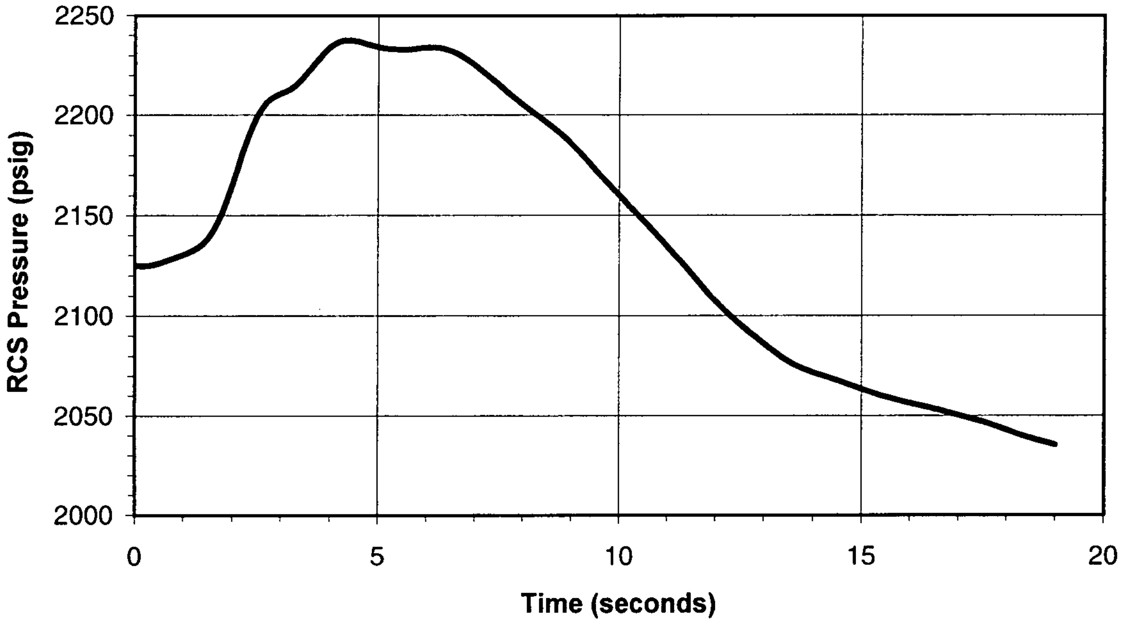


Figure 15-24
Loss of Coolant Flow Accidents
Four RCP Coastdown from Four RCP Initial Conditions Analysis

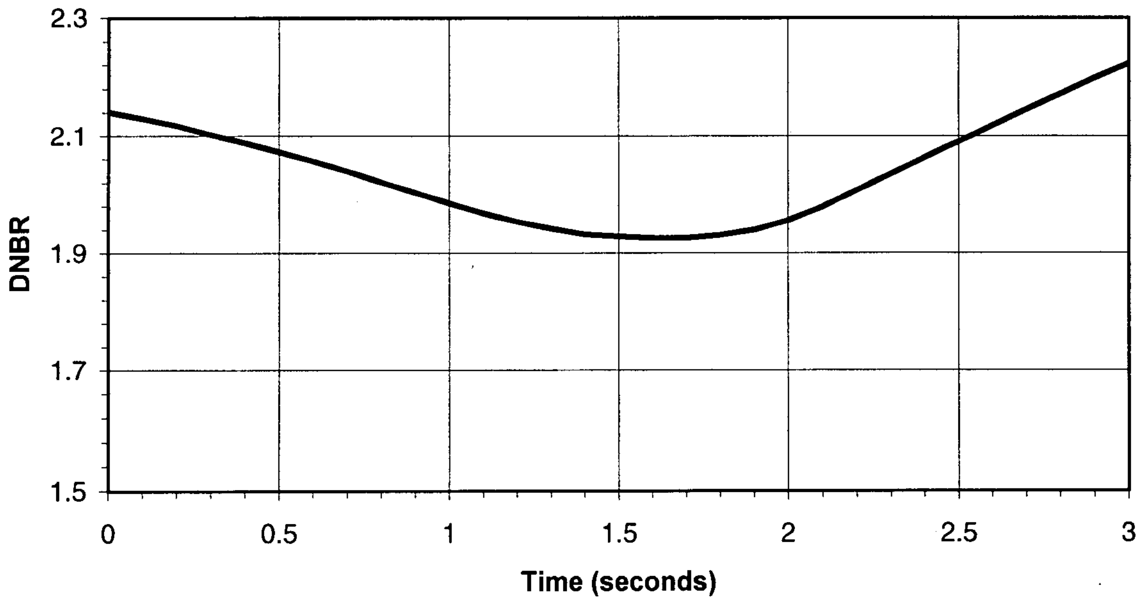


Figure 15-25
Loss of Coolant Flow Accidents
Two RCP Coastdown from Four RCP Initial Conditions Analysis

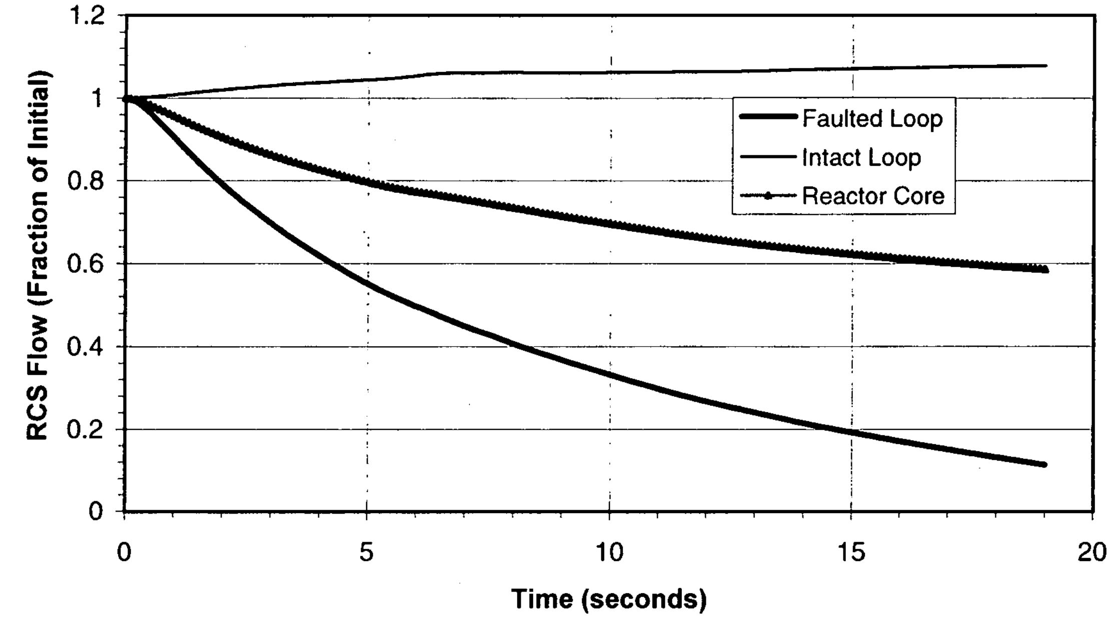


Figure 15-119
Loss of Coolant Flow Accidents
Two RCP Coastdown from Four RCP Initial Conditions Analysis

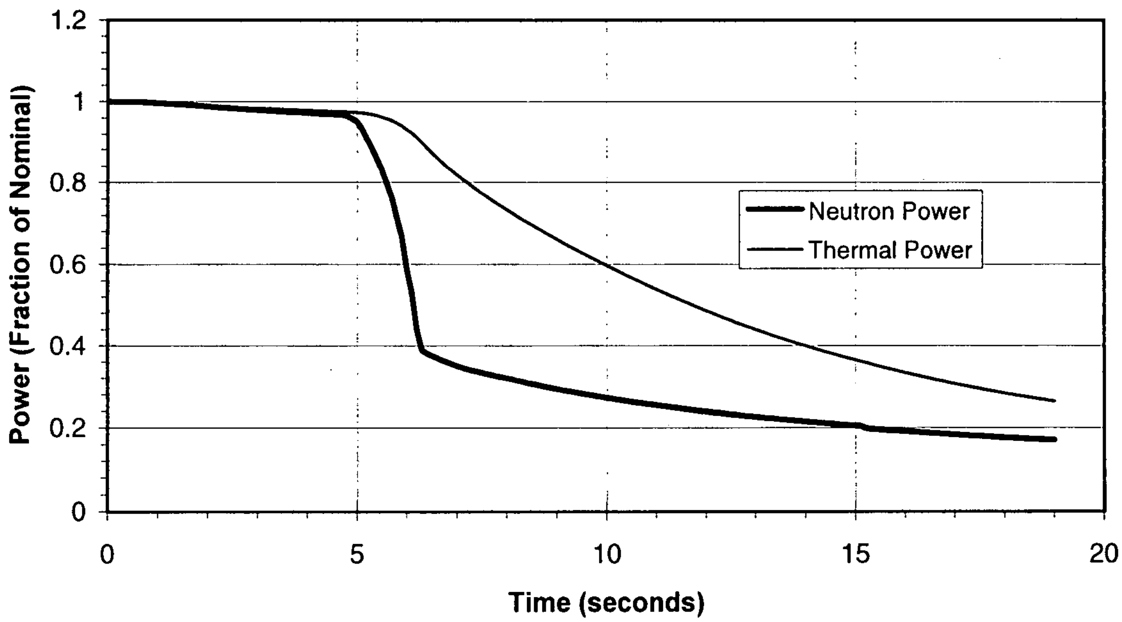


Figure 15-120
Loss of Coolant Flow Accidents
Two RCP Coastdown from Four RCP Initial Conditions Analysis

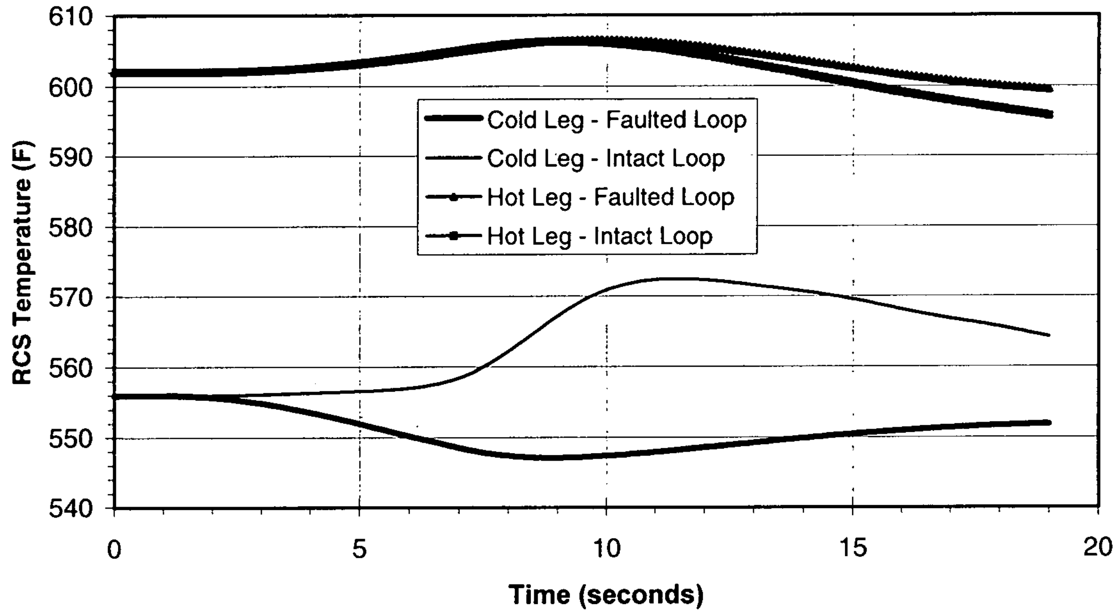


Figure 15-121
Loss of Coolant Flow Accidents
Two RCP Coastdown from Four RCP Initial Conditions Analysis

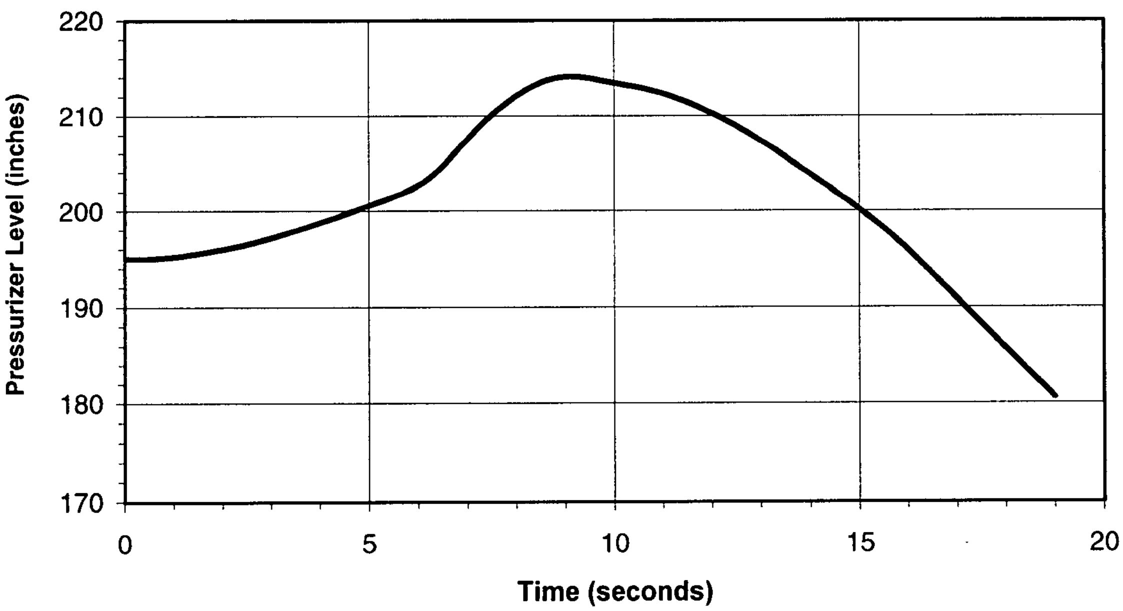


Figure 15-122
Loss of Coolant Flow Accidents
Two RCP Coastdown from Four RCP Initial Conditions Analysis

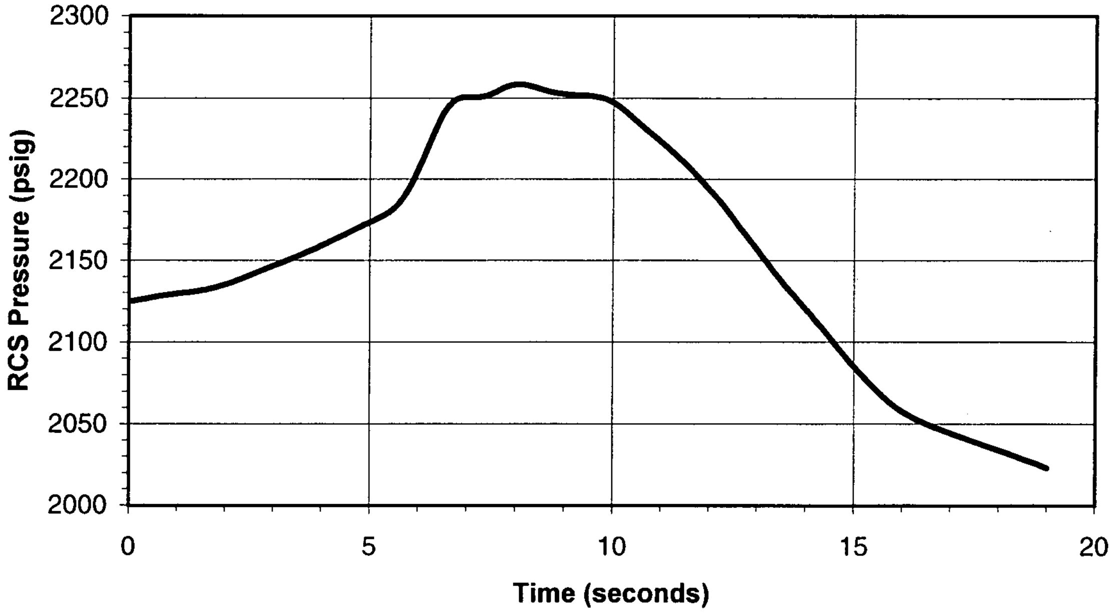


Figure 15-123
Loss of Coolant Flow Accidents
Two RCP Coastdown from Four RCP Initial Conditions Analysis

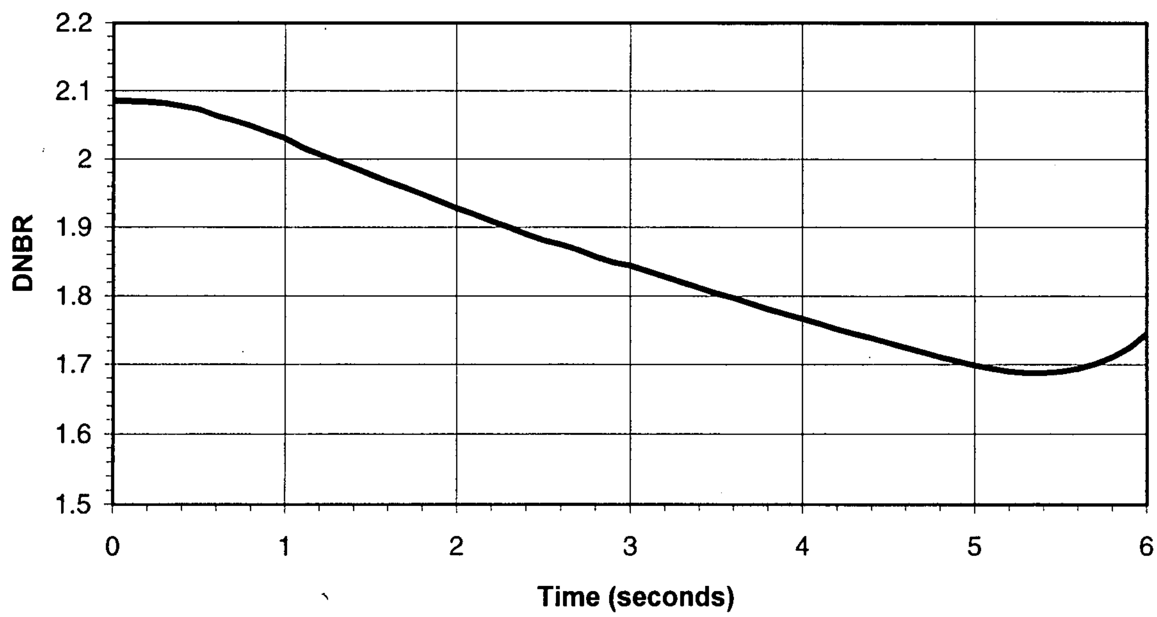


Figure 15-124
Loss of Coolant Flow Accidents
One RCP Coastdown from Three RCP Initial Conditions Analysis

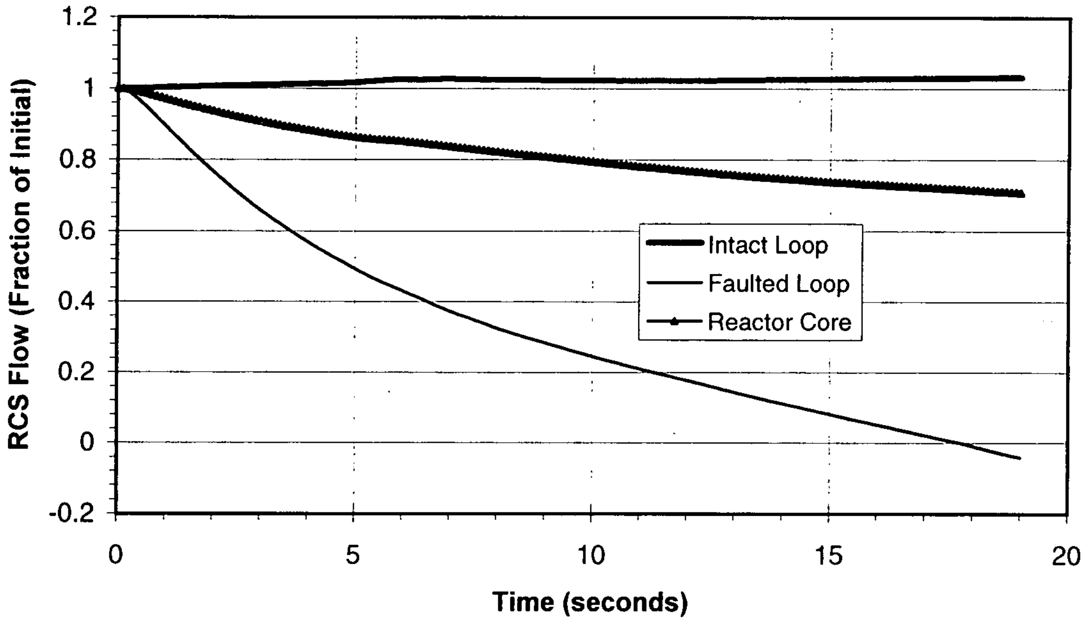


Figure 15-125
Loss of Coolant Flow Accidents
One RCP Coastdown from Three RCP Initial Conditions Analysis

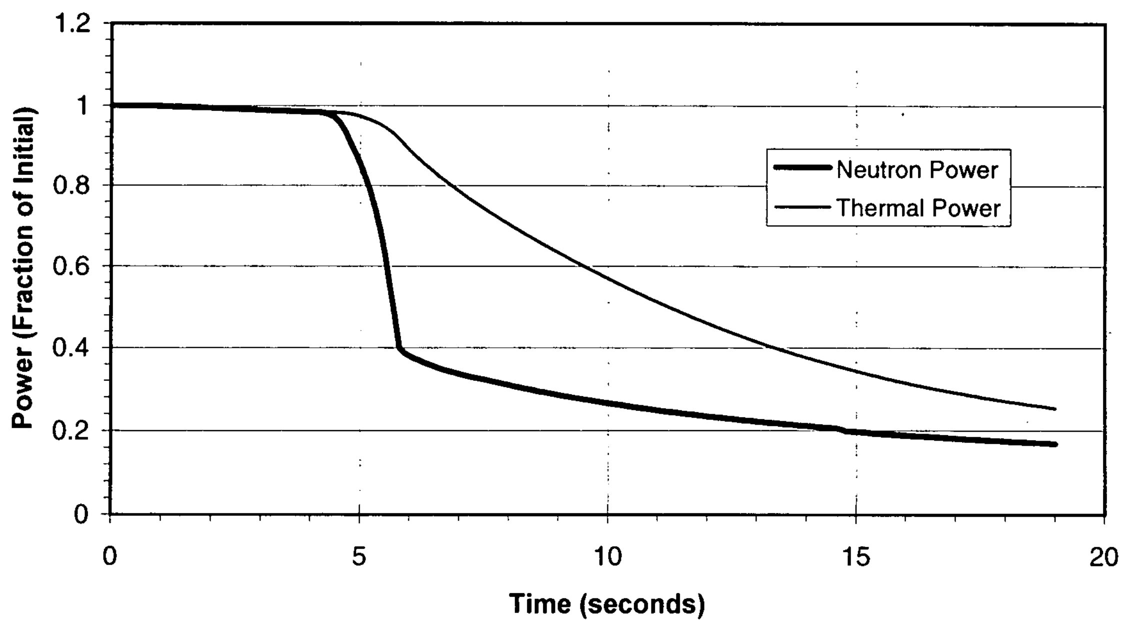


Figure 15-126
Loss of Coolant Flow Accidents
One RCP Coastdown from Three RCP Initial Conditions Analysis

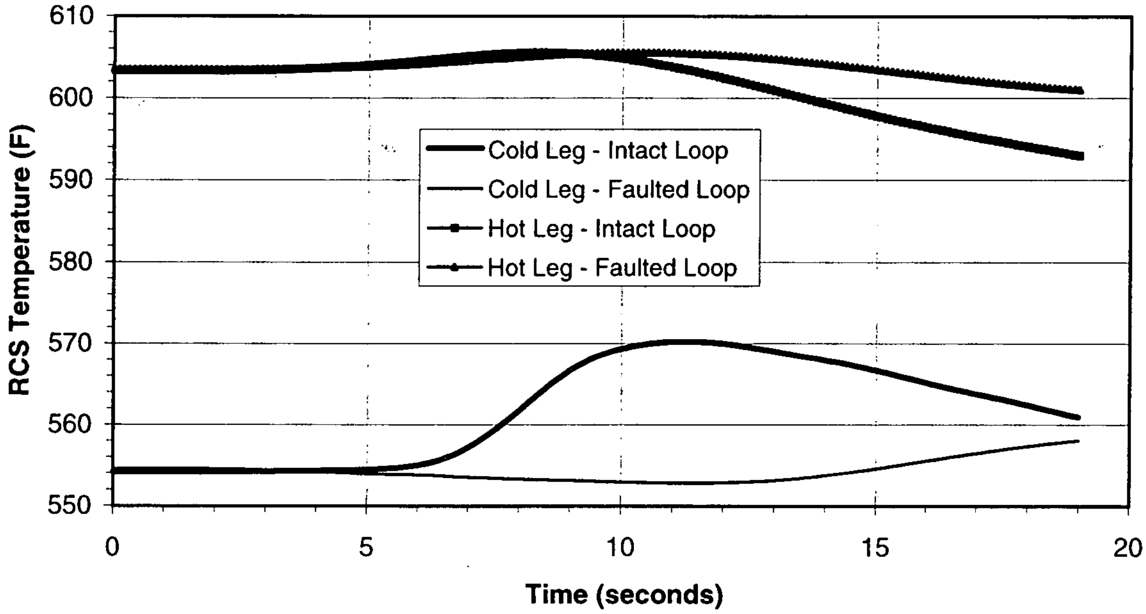


Figure 15-127
Loss of Coolant Flow Accidents
One RCP Coastdown from Three RCP Initial Conditions Analysis

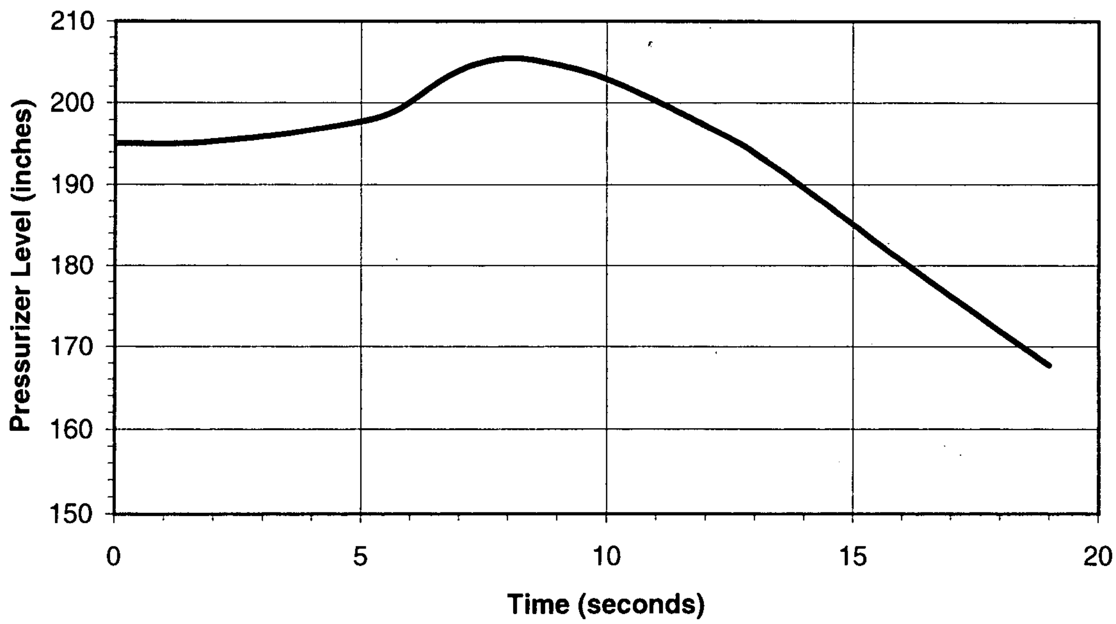


Figure 15-128
Loss of Coolant Flow Accidents
One RCP Coastdown from Three RCP Initial Conditions Analysis

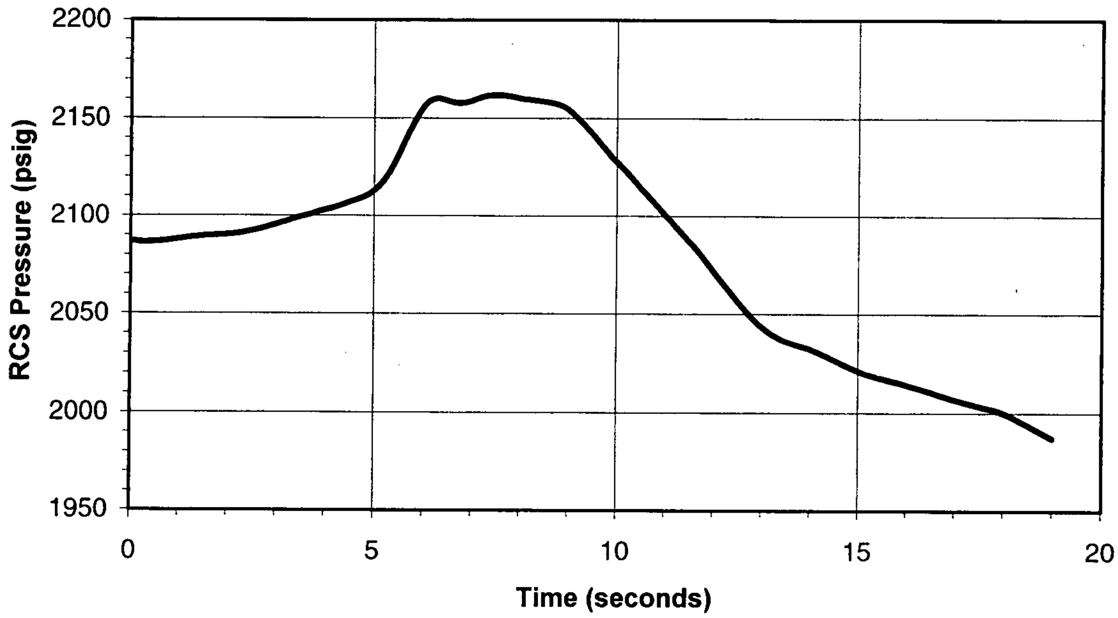


Figure 15-129
Loss of Coolant Flow Accidents
One RCP Coastdown from Three RCP Initial Conditions Analysis

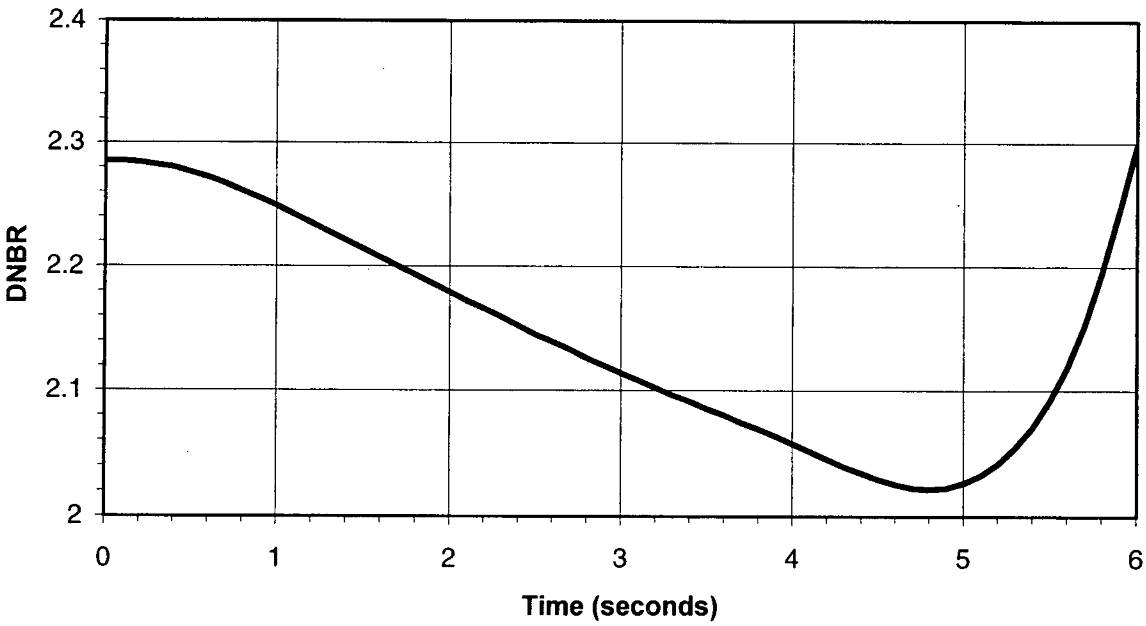


Figure 15-130
Loss of Coolant Flow Accidents
Locked Rotor from Four RCP Initial Conditions Analysis

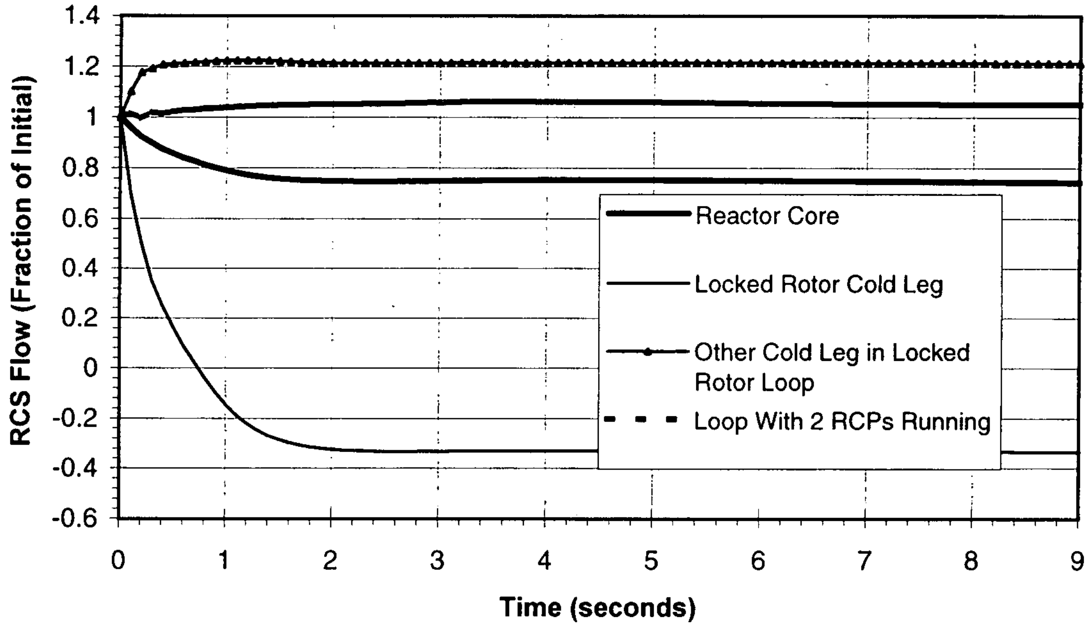


Figure 15-131
Loss of Coolant Flow Accidents
Locked Rotor from Four RCP Initial Conditions Analysis

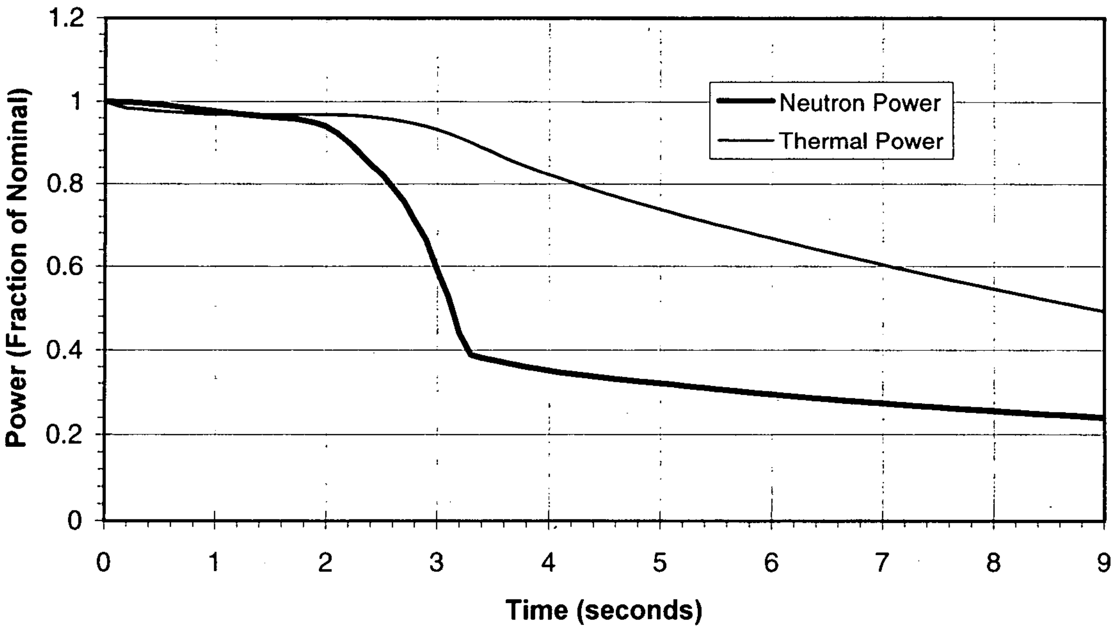


Figure 15-132
Loss of Coolant Flow Accidents
Locked Rotor from Four RCP Initial Conditions Analysis

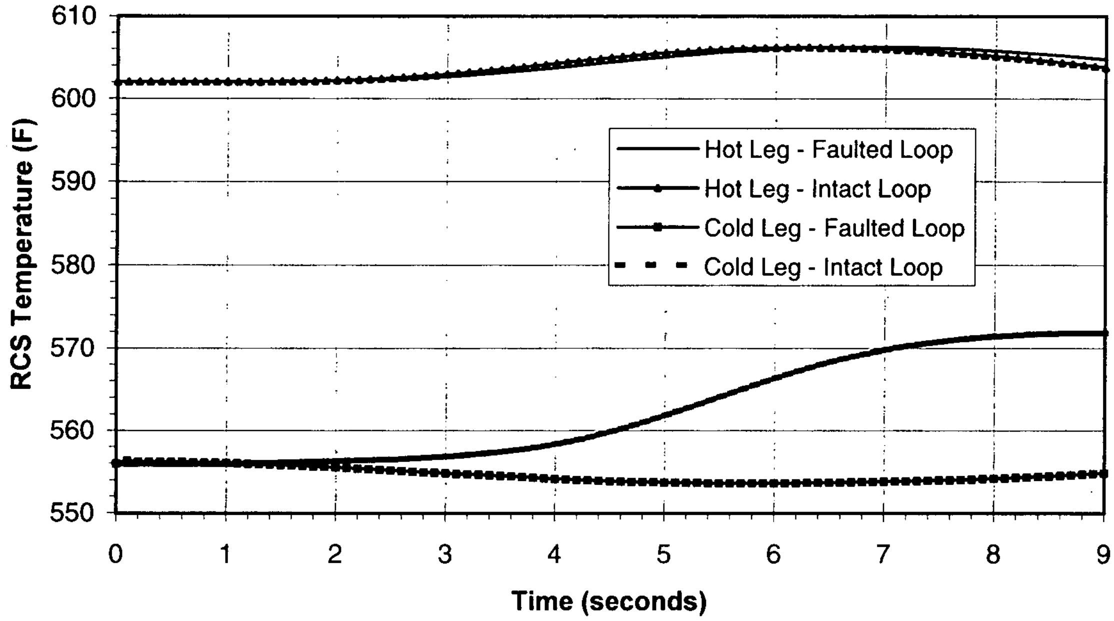


Figure 15-133
Loss of Coolant Flow Accidents
Locked Rotor from Four RCP Initial Conditions Analysis

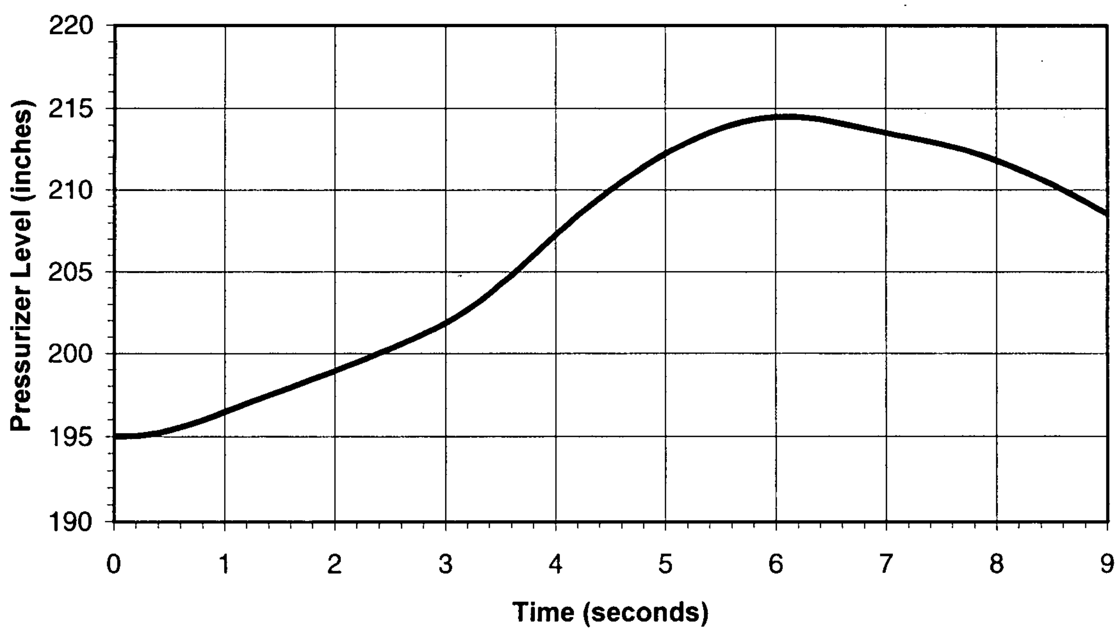


Figure 15-134
Loss of Coolant Flow Accidents
Locked Rotor from Four RCP Initial Conditions Analysis

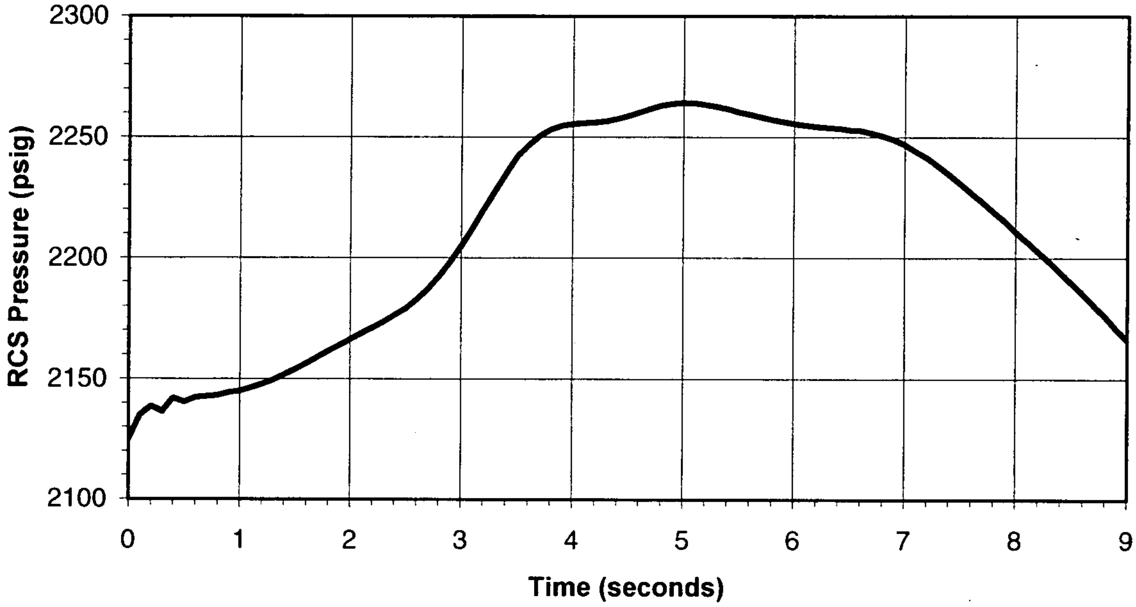


Figure 15-135
Loss of Coolant Flow Accidents
Locked Rotor from Four RCP Initial Conditions Analysis

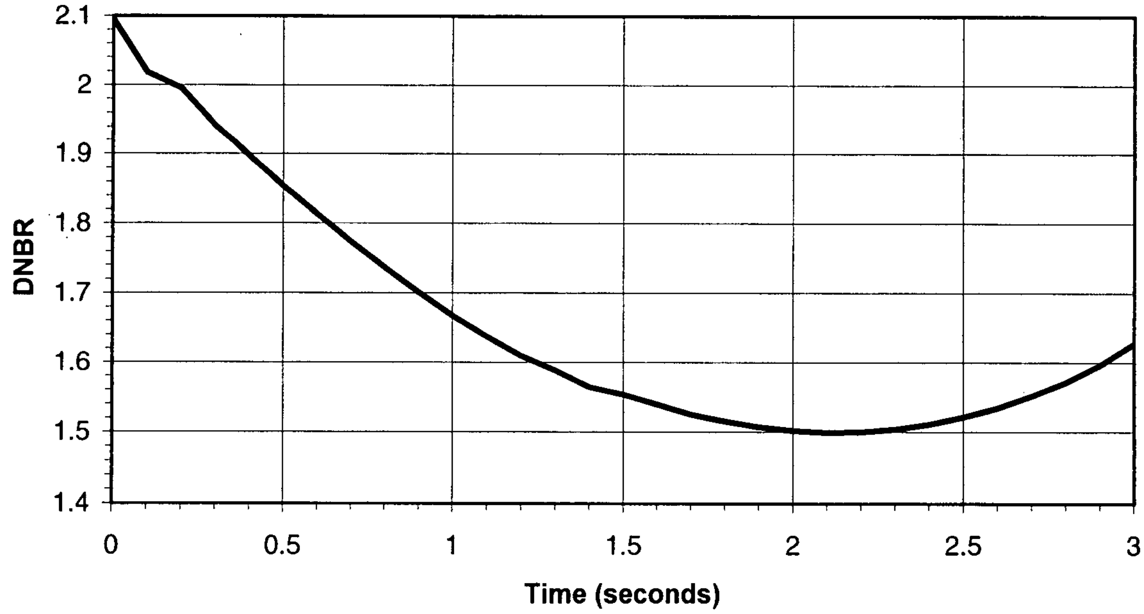


Figure 15-136
Loss of Coolant Flow Accidents
Locked Rotor from Three RCP Initial Conditions Analysis

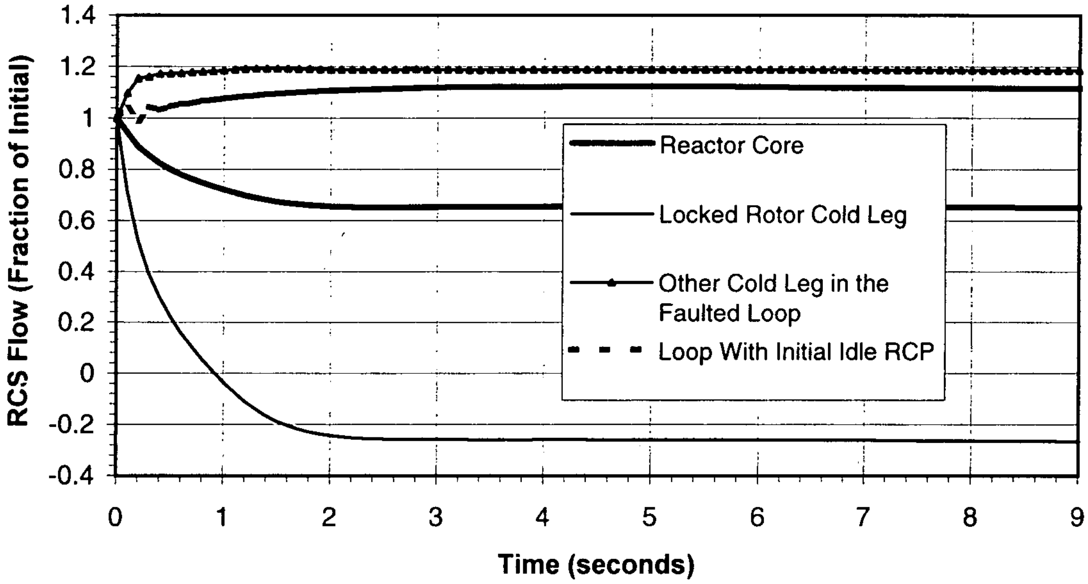


Figure 15-137
Loss of Coolant Flow Accidents
Locked Rotor from Three RCP Initial Conditions Analysis

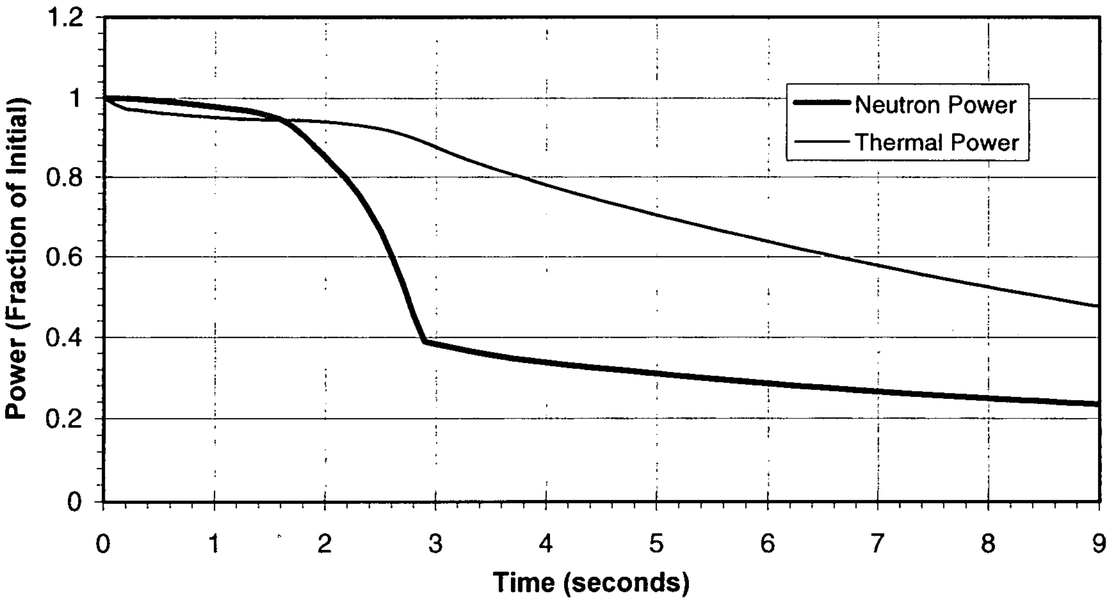


Figure 15-138
Loss of Coolant Flow Accidents
Locked Rotor from Three RCP Initial Conditions Analysis

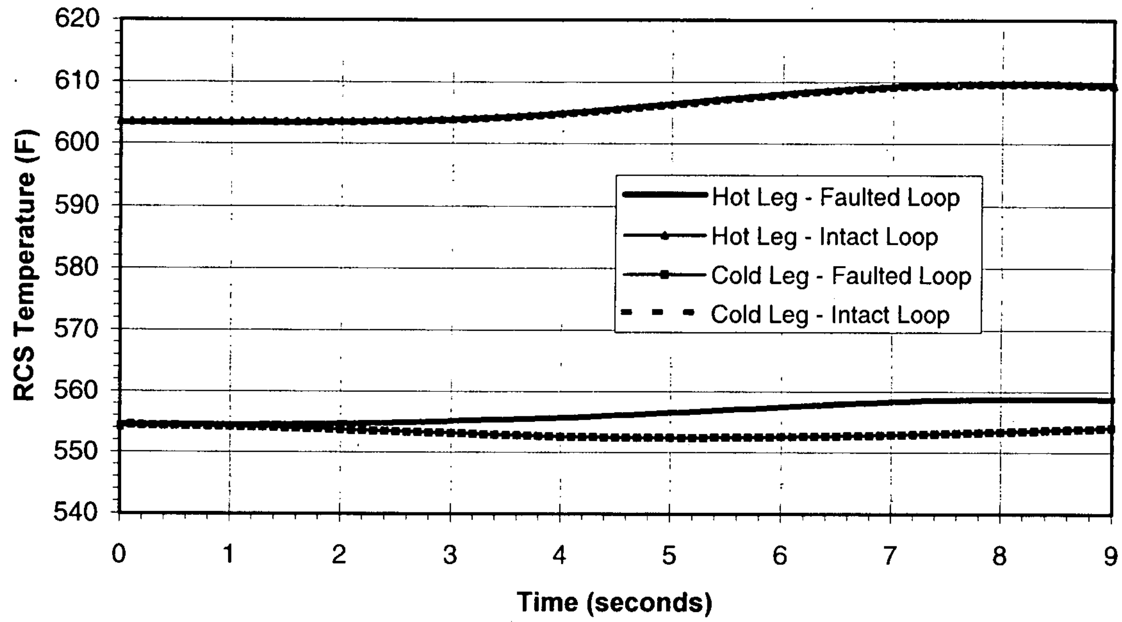


Figure 15-139
Loss of Coolant Flow Accidents
Locked Rotor from Three RCP Initial Conditions Analysis

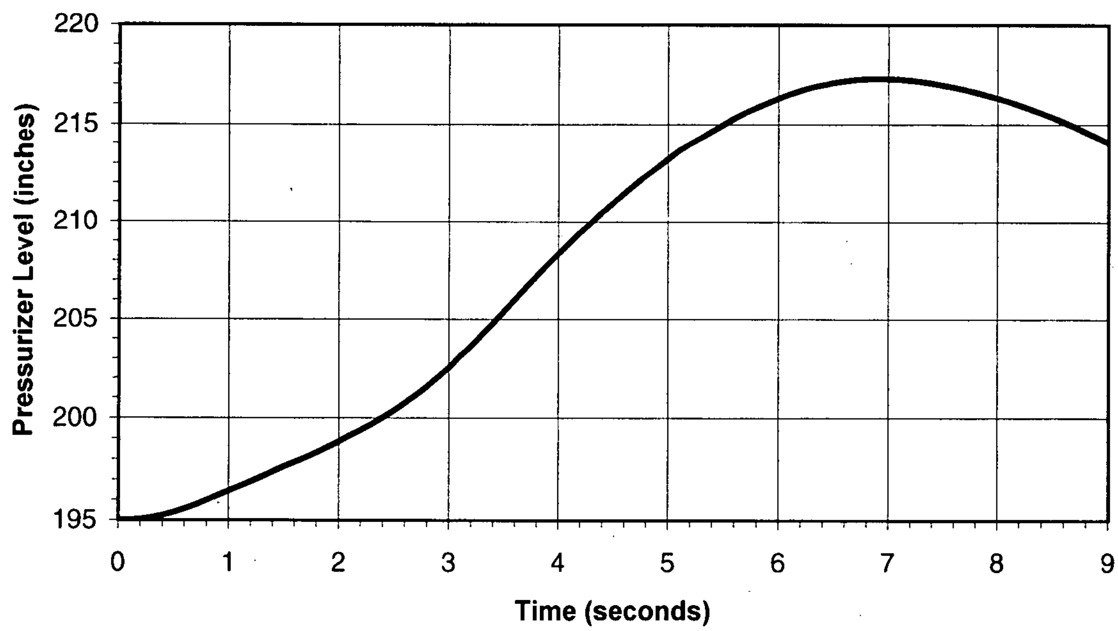


Figure15-140
Loss of Coolant Flow Accidents
Locked Rotor from Three RCP Initial Conditions Analysis

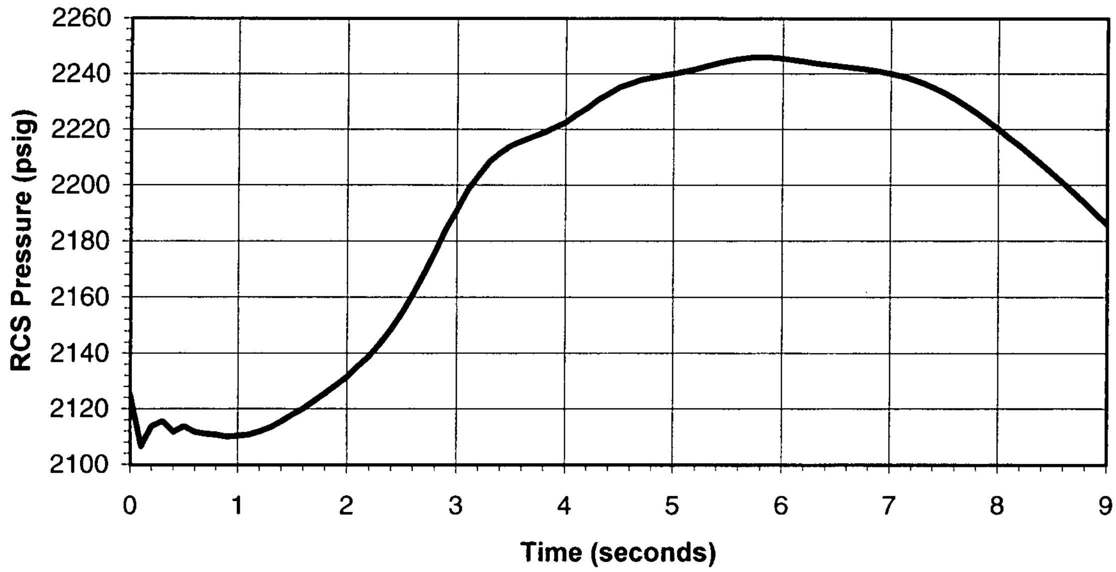


Figure 15-141
Loss of Coolant Flow Accidents
Locked Rotor from Three RCP Initial Conditions Analysis

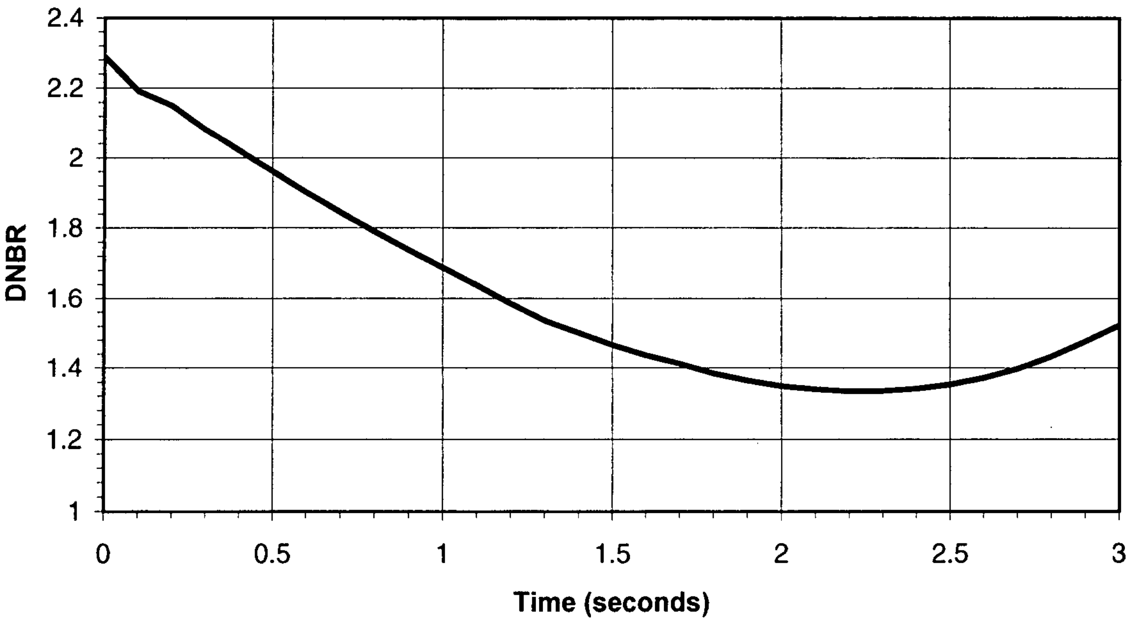


Figure 15-26

Control Rod Misalignment Accidents
Dropped Rod Analysis

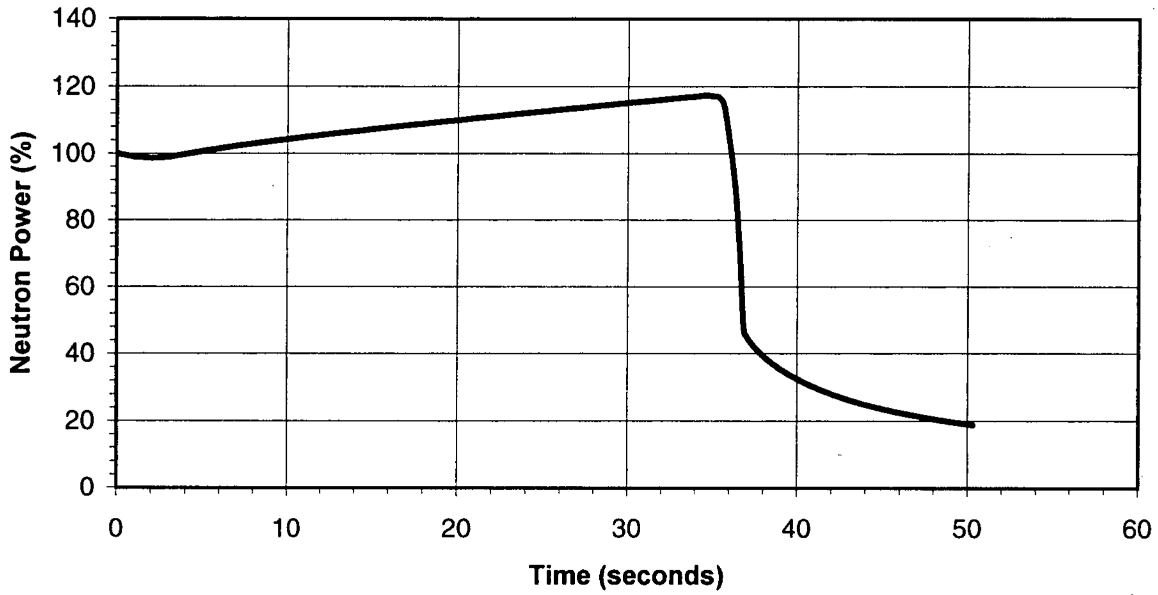


Figure 15-27

Control Rod Misalignment Accidents
Dropped Rod Analysis

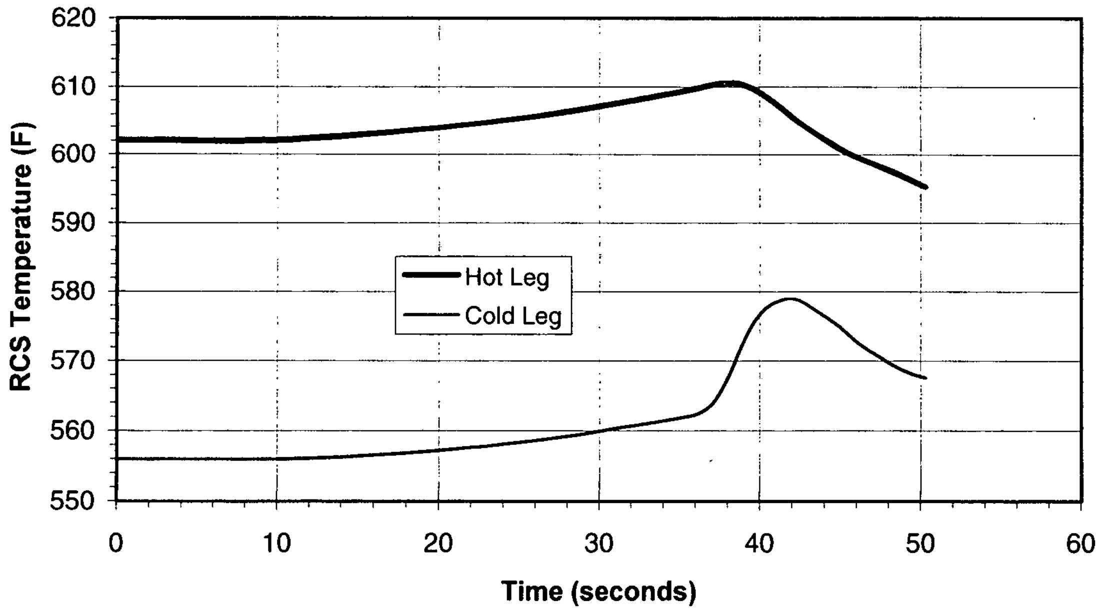


Figure 15-28

Control Rod Misalignment Accidents

Dropped Rod Analysis

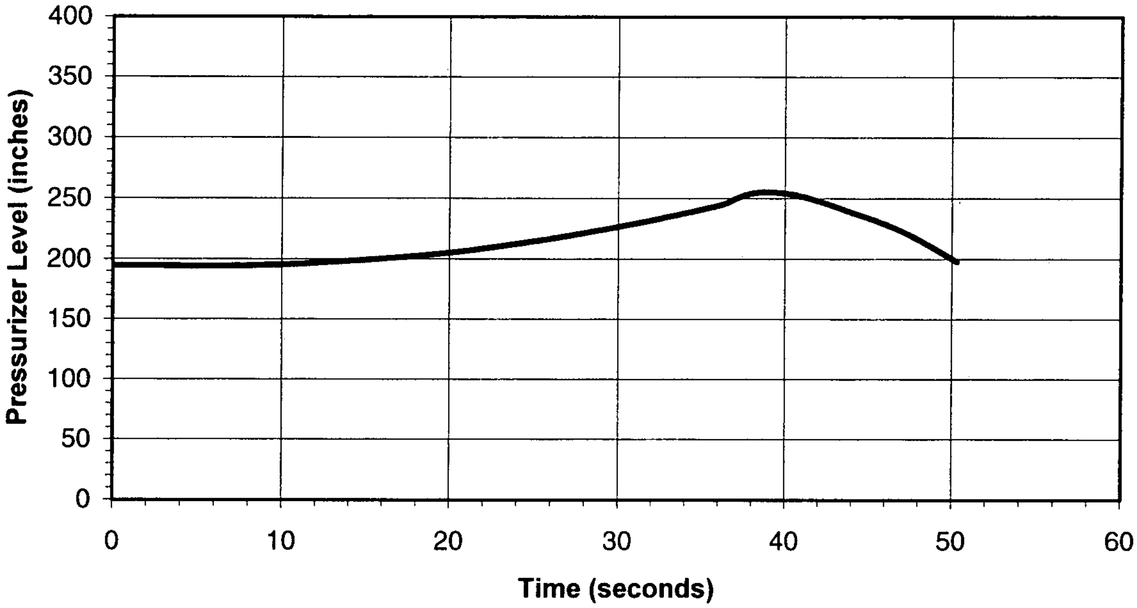


Figure 15-143
Control Rod Misalignment Accidents
Dropped Rod Analysis

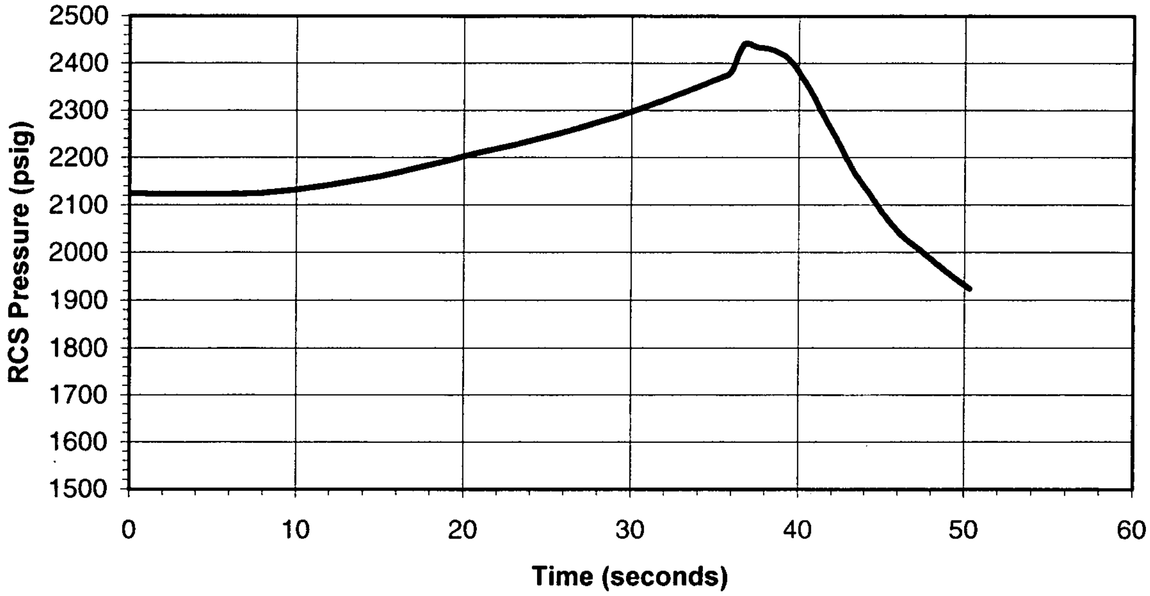


Figure 15-144
Control Rod Misalignment Accidents
Dropped Rod Analysis

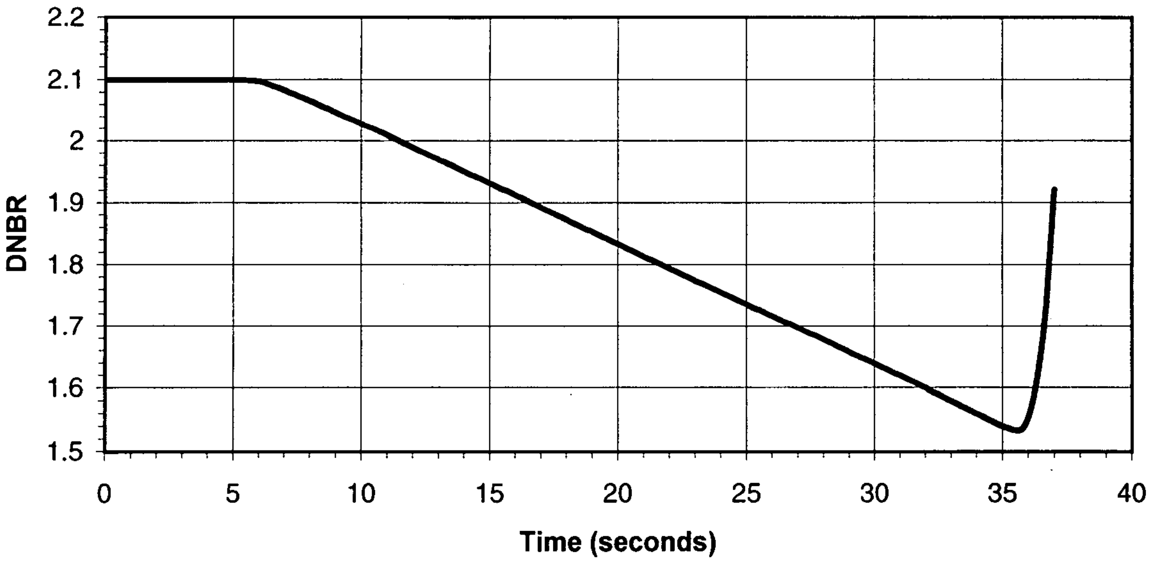


Figure 15-145
Turbine Trip Accident

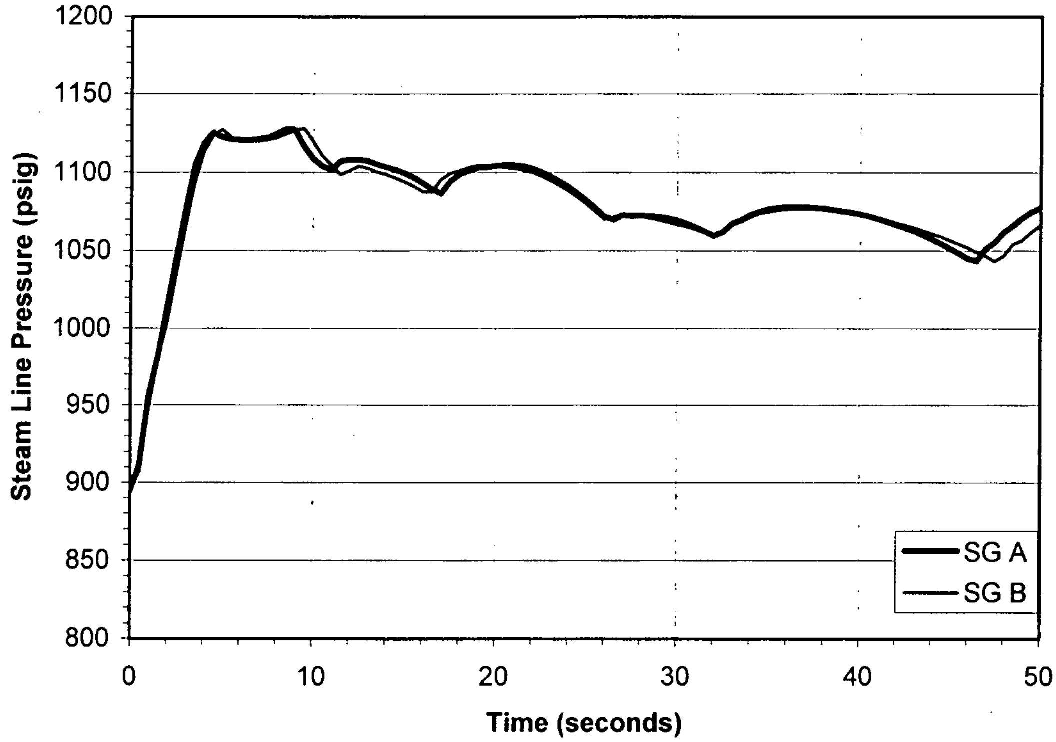


Figure 15-146
Turbine Trip Accident

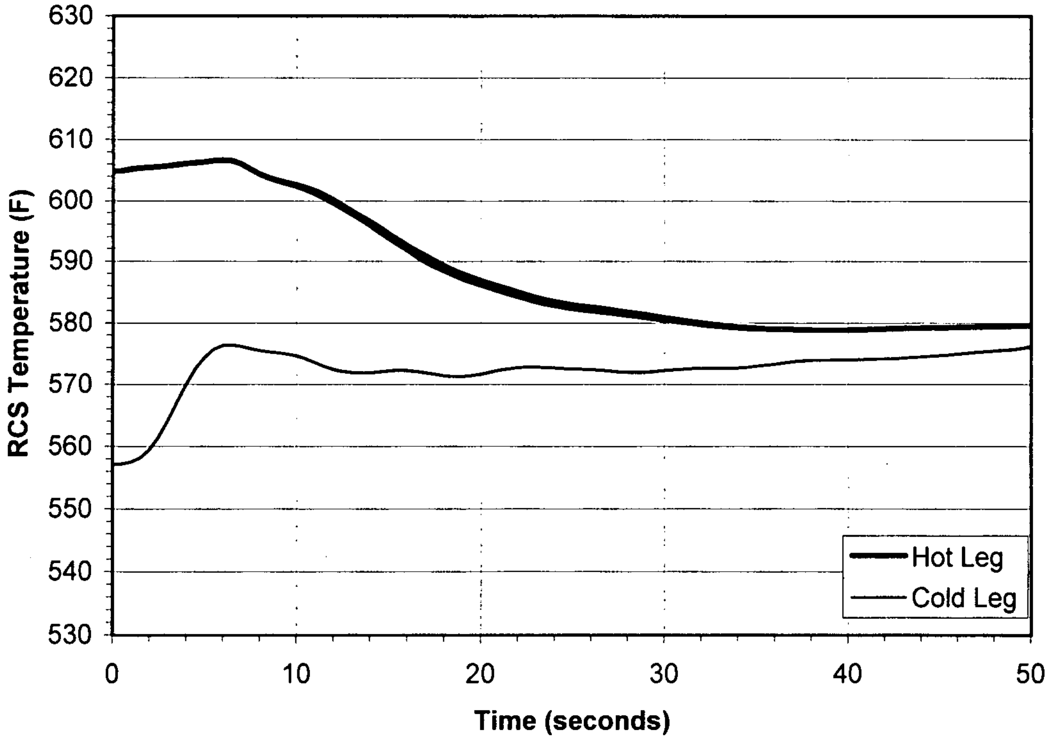


Figure 15-147
Turbine Trip Accident

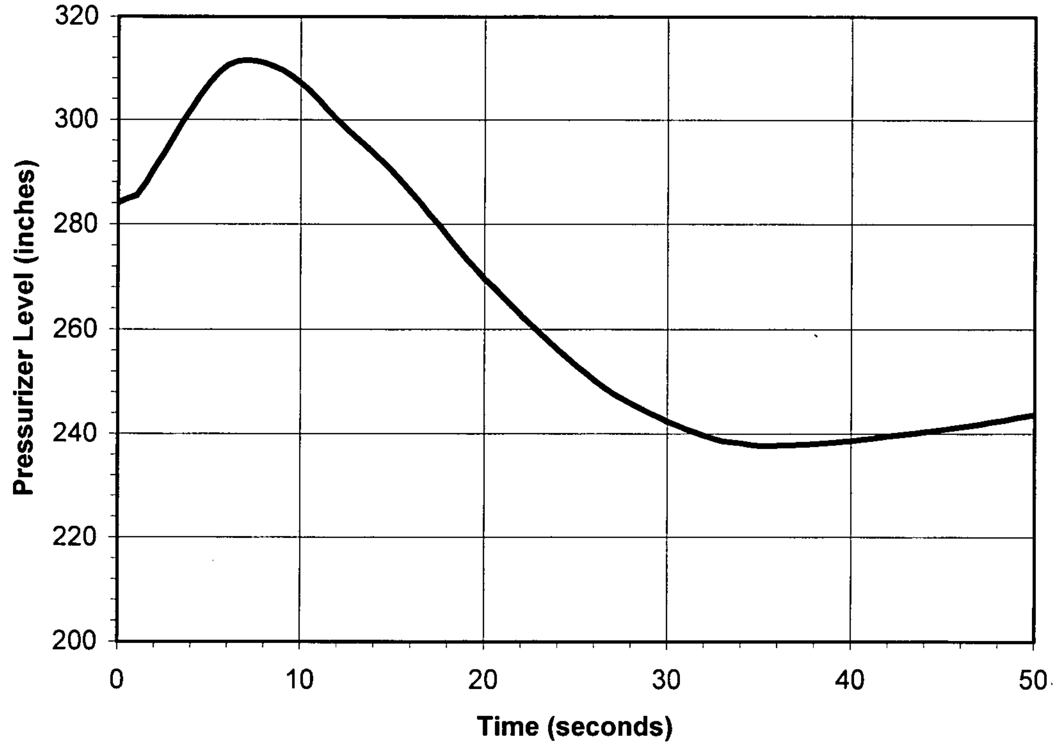


Figure 15-148
Turbine Trip Accident

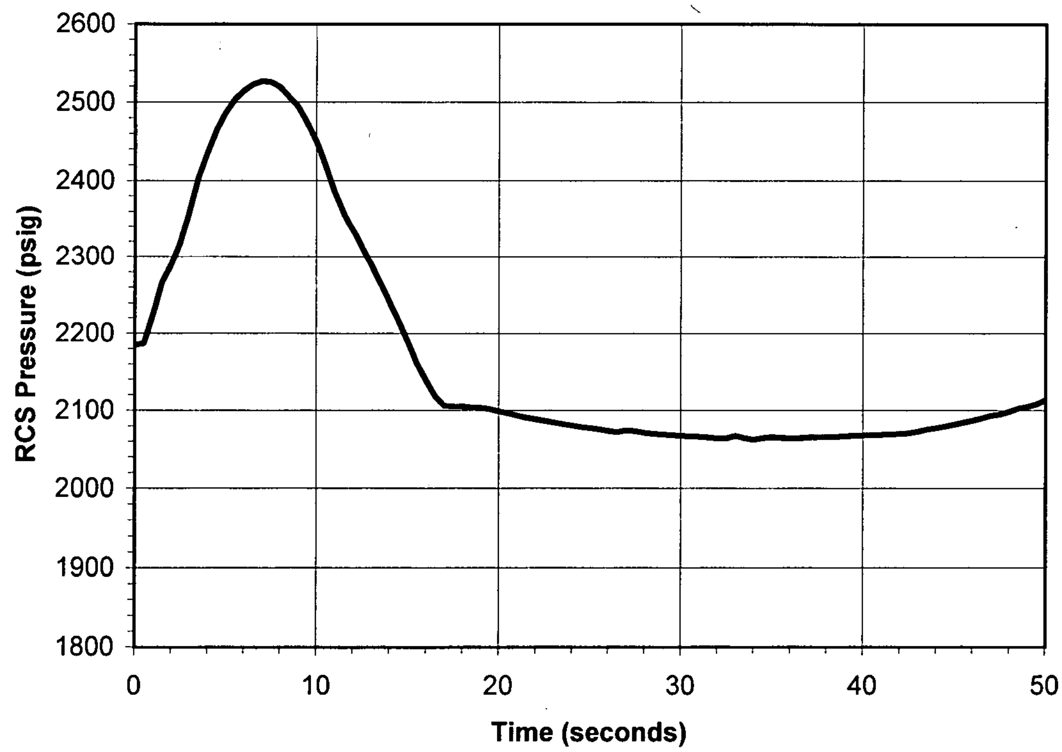


Figure 15-149
Turbine Trip Accident

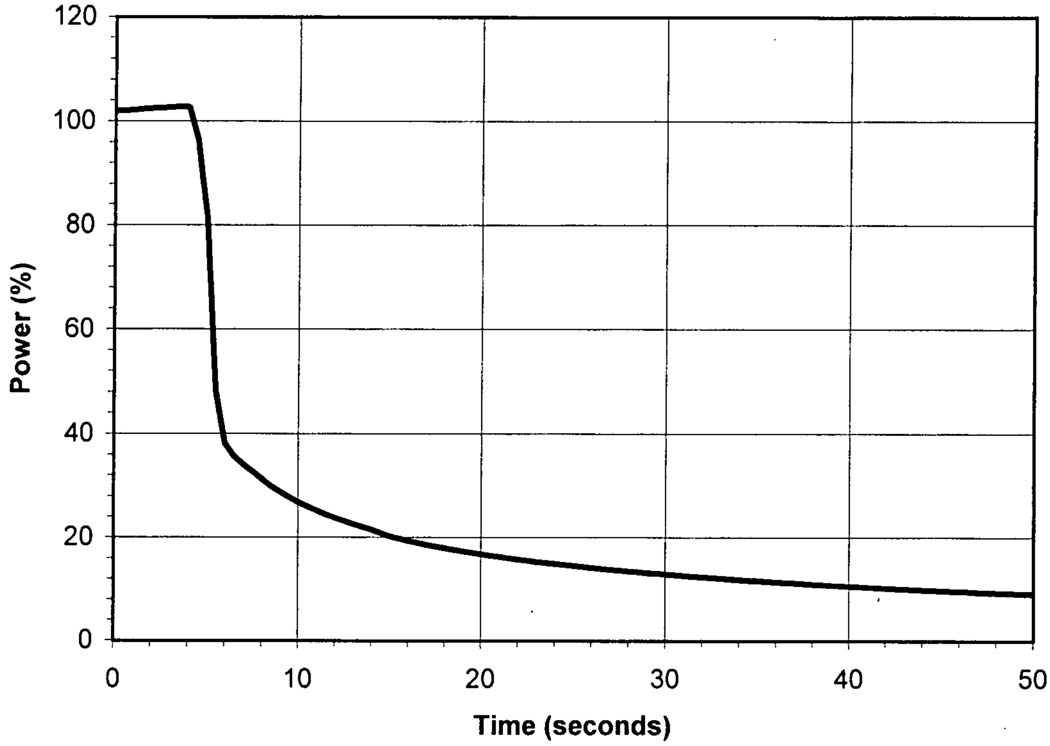


Figure 15-150
Steam Generator Tube Rupture

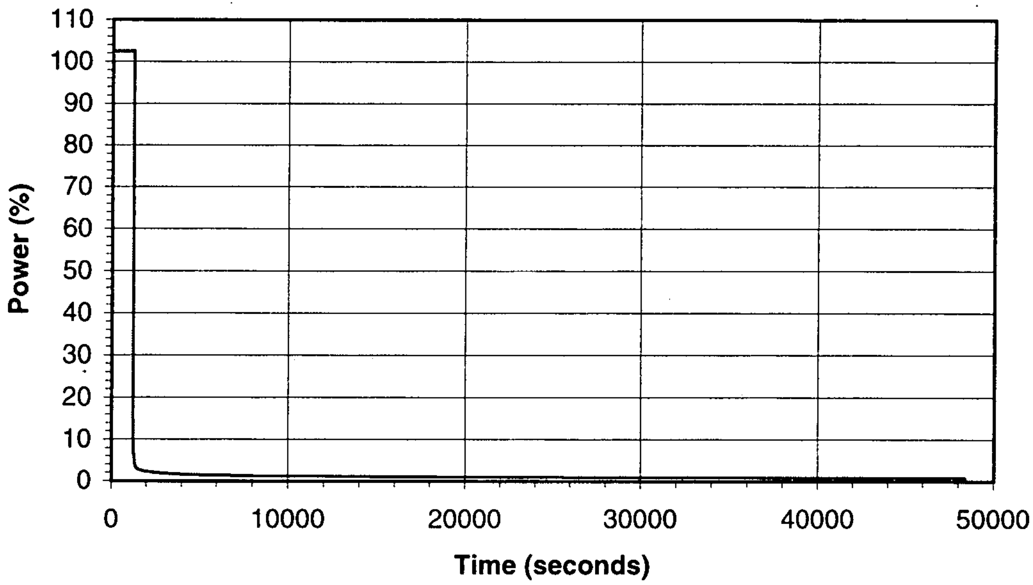


Figure 15-151
Steam Generator Tube Rupture

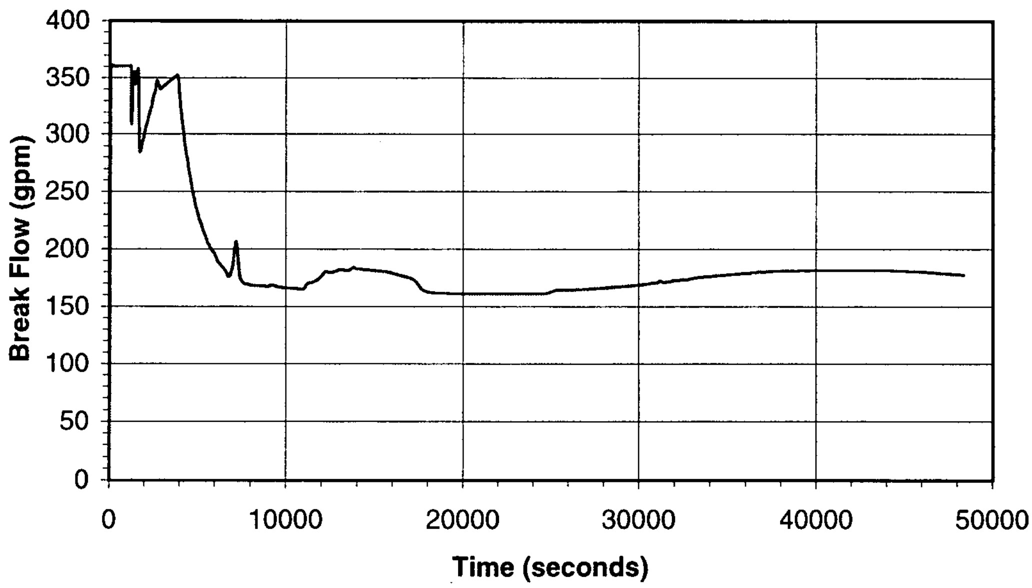


Figure 15-152
Steam Generator Tube Rupture

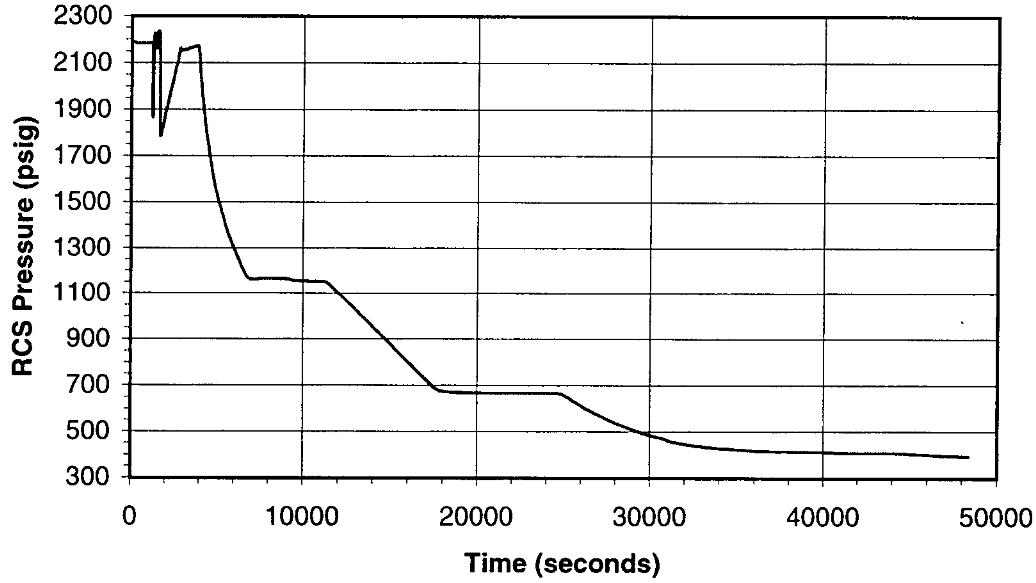


Figure 15-153
Steam Generator Tube Rupture

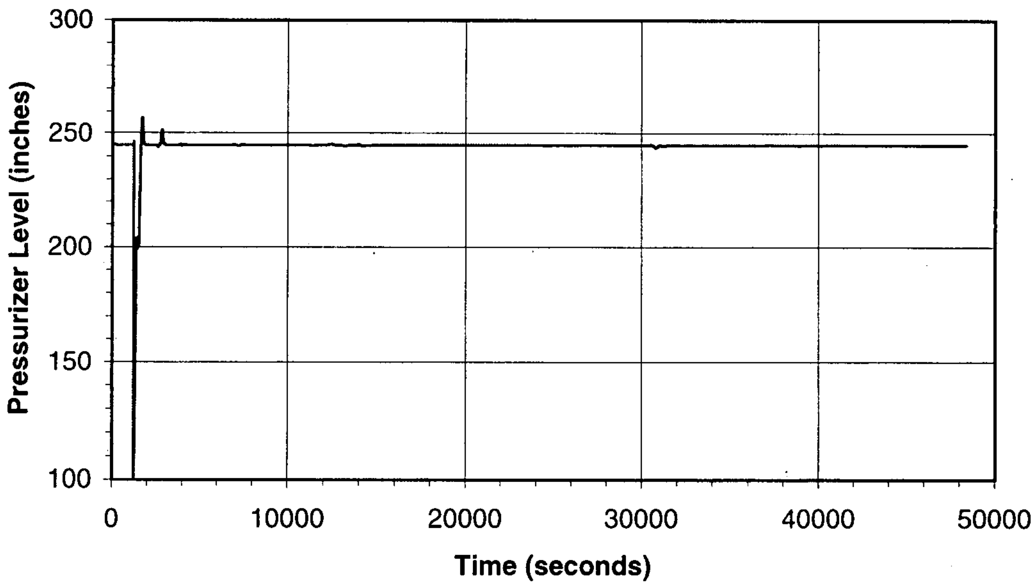


Figure 15-154
Steam Generator Tube Rupture

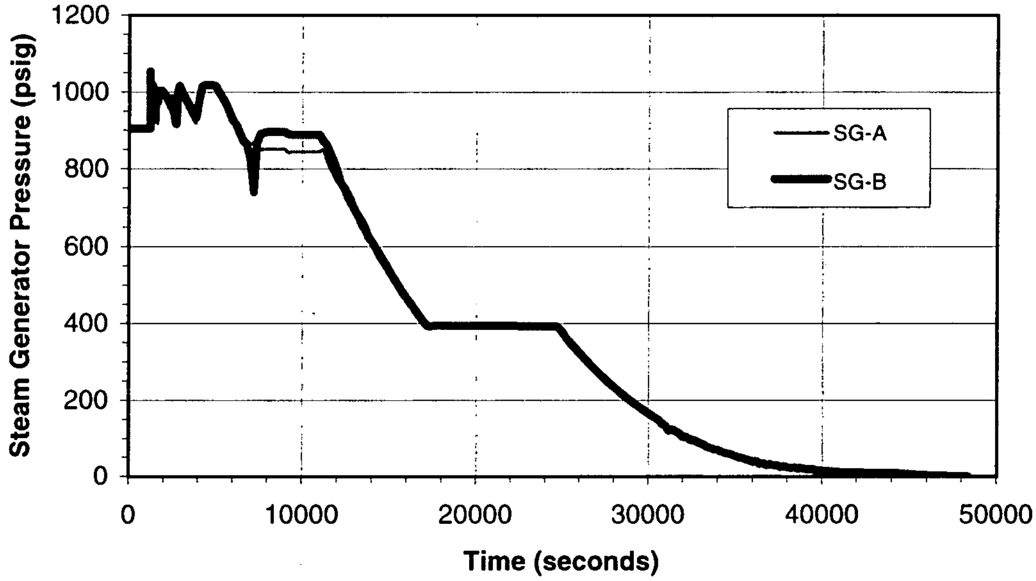


Figure 15-155
Steam Generator Tube Rupture

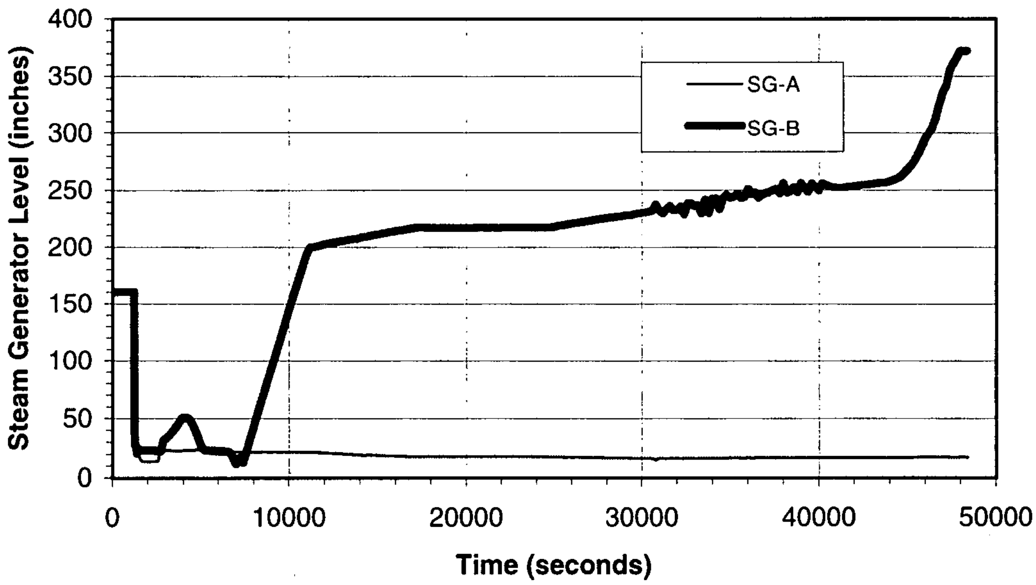


Figure 15-156
Steam Generator Tube Rupture

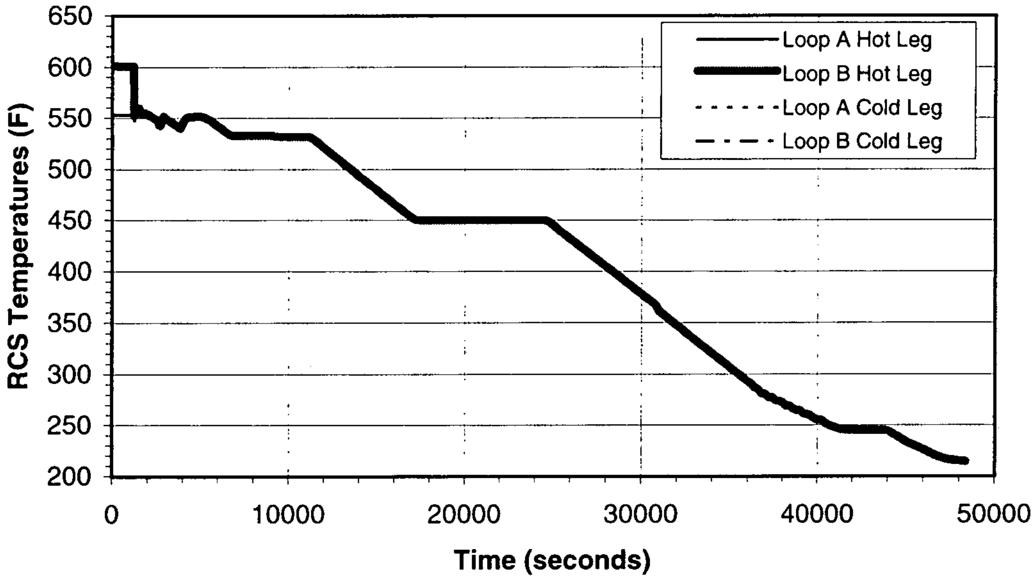


Figure 15-29
Rod Ejection Accident
BOC Four RCPs

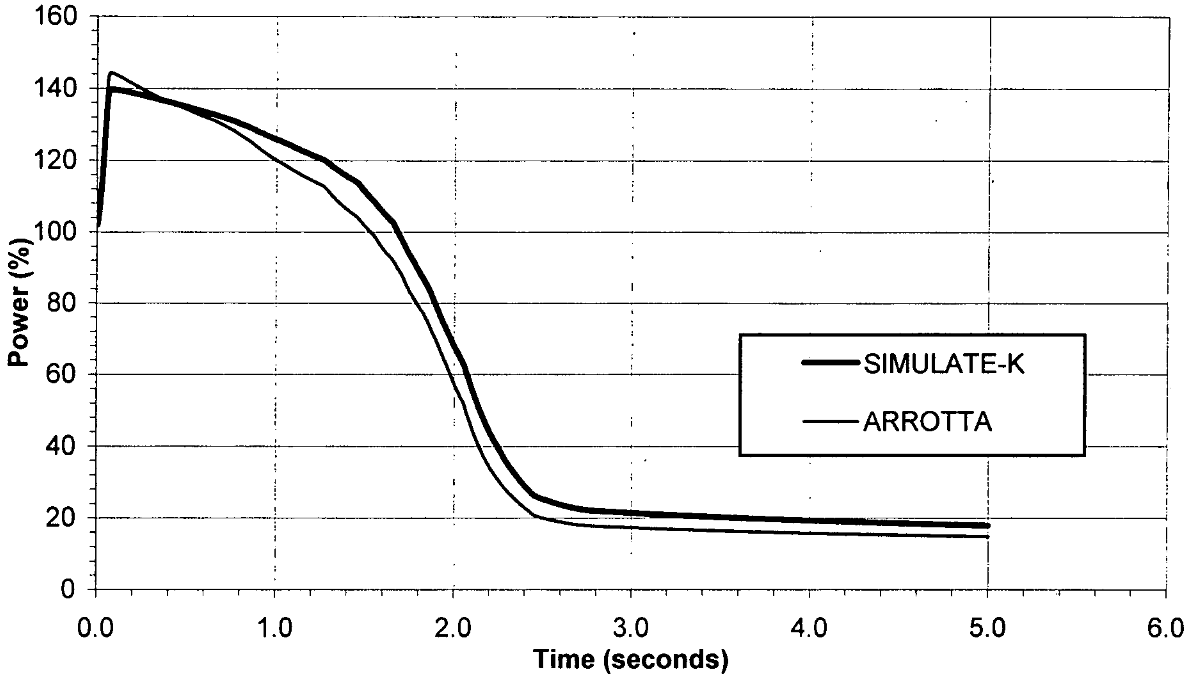


Figure 15-30
Rod Ejection Accident
BOC Three RCPs

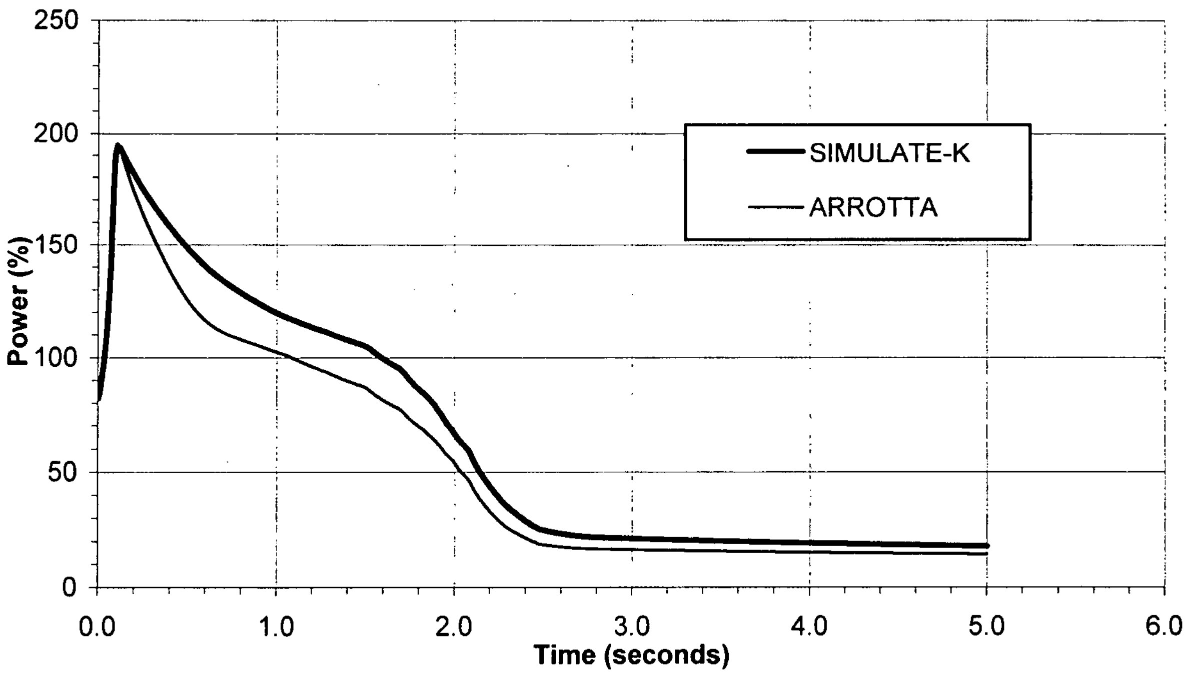


Figure 15-31
Rod Ejection Accident
BOC HZP

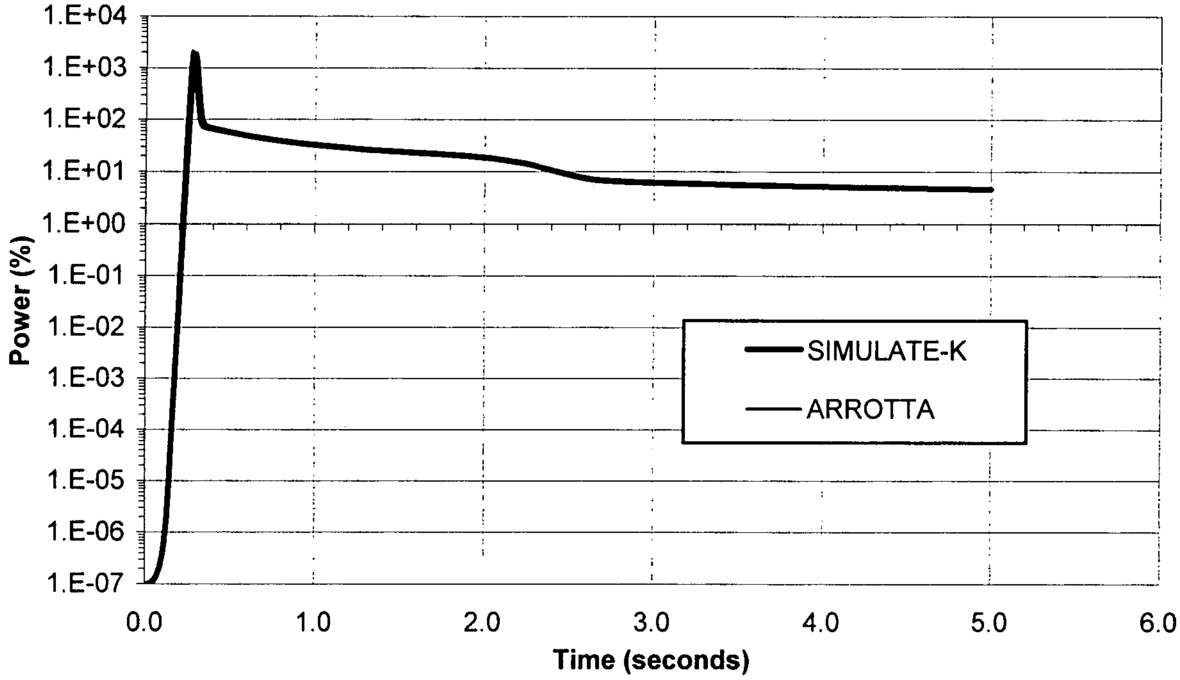


Figure 15-32
Rod Ejection Accident
EOC Four RCPs

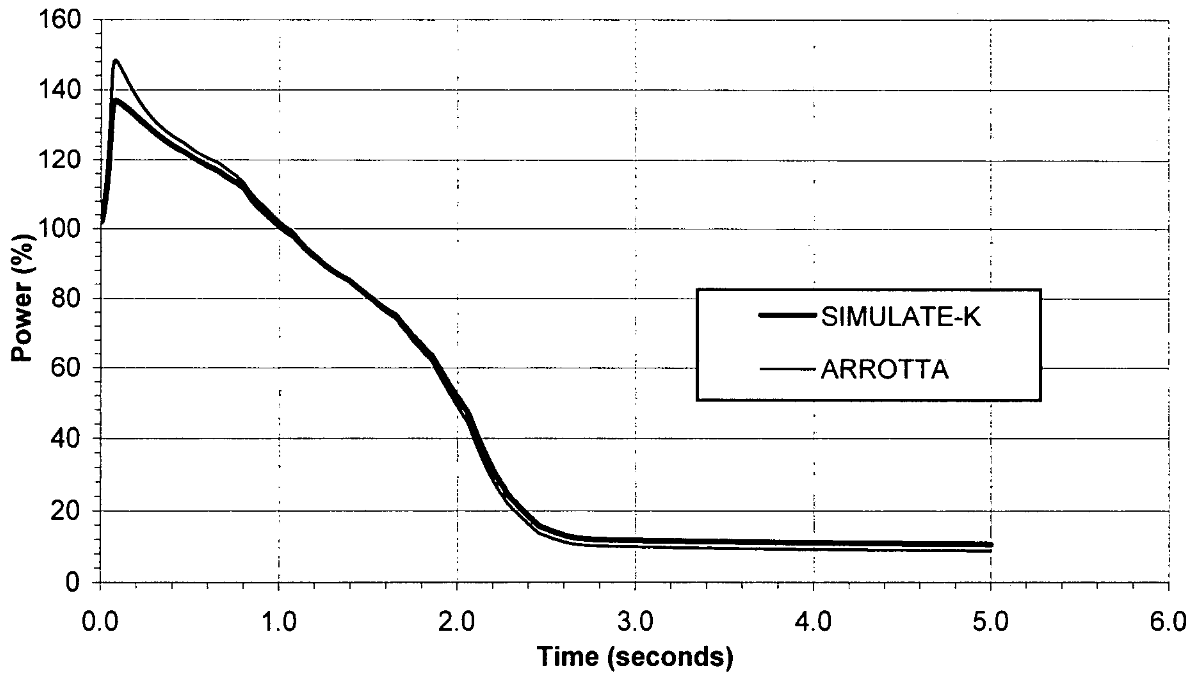


Figure 15-33
Rod Ejection Accident
EOC Three RCPs

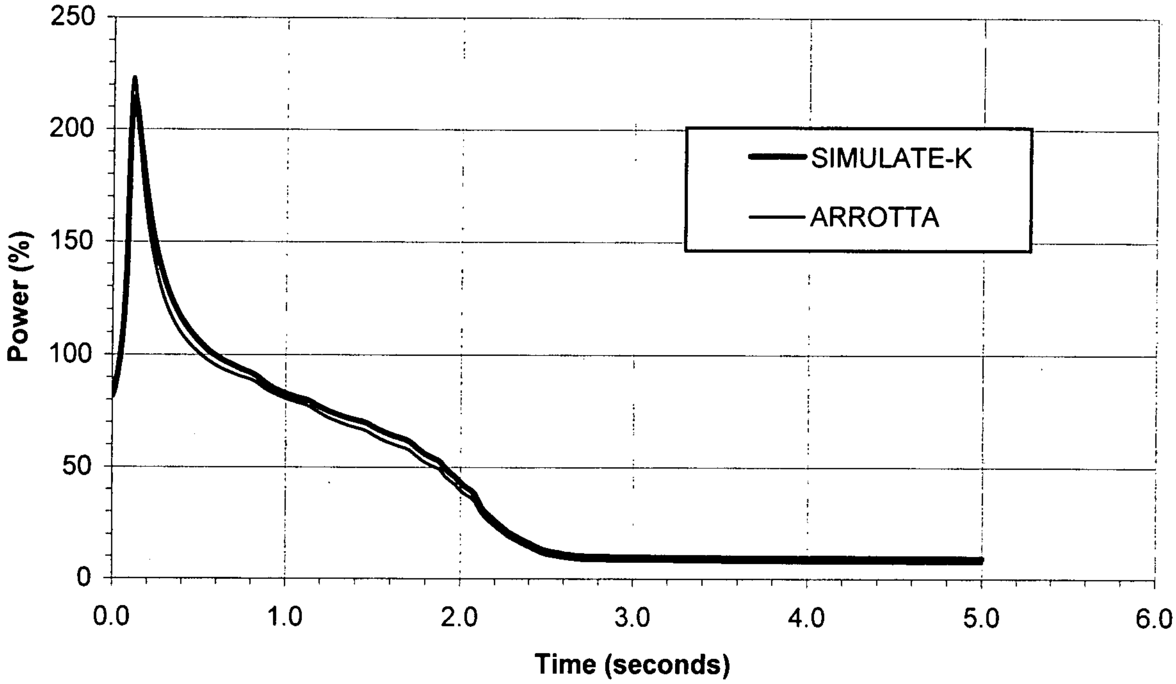


Figure 15-34
Rod Ejection Accident
EOC HZP

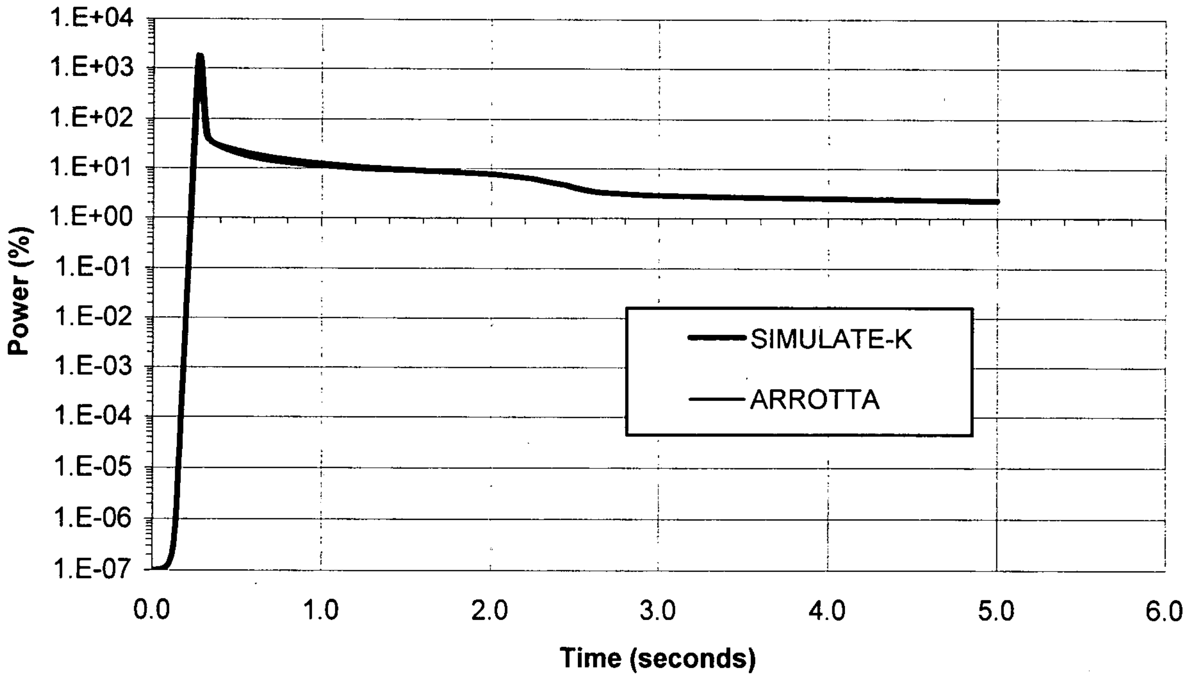


Figure 15-35
Rod Ejection Accident
BOC Four RCPs - Core Power Distribution

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
A						0.181	0.270	0.288	0.278	0.192					
B				0.160	0.315	0.698	1.099	0.920	1.138	0.748	0.353	0.185			
C			0.207	0.623	0.744	1.112	1.391	1.389	1.451	1.212	0.857	0.753	0.264		
D		0.153	0.612	0.679	0.994	0.943	1.371	1.282	1.450	1.063	1.195	0.849	0.827	0.222	
E		0.302	0.720	0.975	0.998	1.222	1.448	1.439	1.569	1.441	1.289	1.344	1.052	0.462	
F	0.170	0.659	1.057	0.906	1.190	0.924	1.298	1.251	1.453	1.170	1.670	1.372	1.665	1.066	0.281
G	0.250	1.025	1.302	1.290	1.370	1.249	1.051	1.048	1.233	1.683	2.093	2.151	2.196	1.708	0.424
H	0.263	0.844	1.278	1.190	1.315	1.144	0.978	0.752	1.176	1.590	2.107	2.384	2.233	1.441	0.452
K	0.250	1.025	1.302	1.290	1.370	1.249	1.051	1.048	1.233	1.683	2.093	2.150	2.195	1.707	0.424
L	0.170	0.659	1.057	0.906	1.190	0.924	1.298	1.251	1.453	1.170	1.669	1.372	1.665	1.066	0.281
M		0.303	0.721	0.976	0.998	1.222	1.447	1.439	1.569	1.441	1.289	1.343	1.051	0.461	
N		0.157	0.614	0.679	0.993	0.943	1.370	1.282	1.450	1.063	1.196	0.849	0.824	0.217	
O			0.207	0.621	0.743	1.111	1.391	1.389	1.452	1.212	0.858	0.754	0.264		
P				0.156	0.314	0.698	1.099	0.920	1.138	0.748	0.355	0.190			
R						0.181	0.269	0.288	0.278	0.192					

Figure 15-36
Rod Ejection Accident
BOC Three RCPs

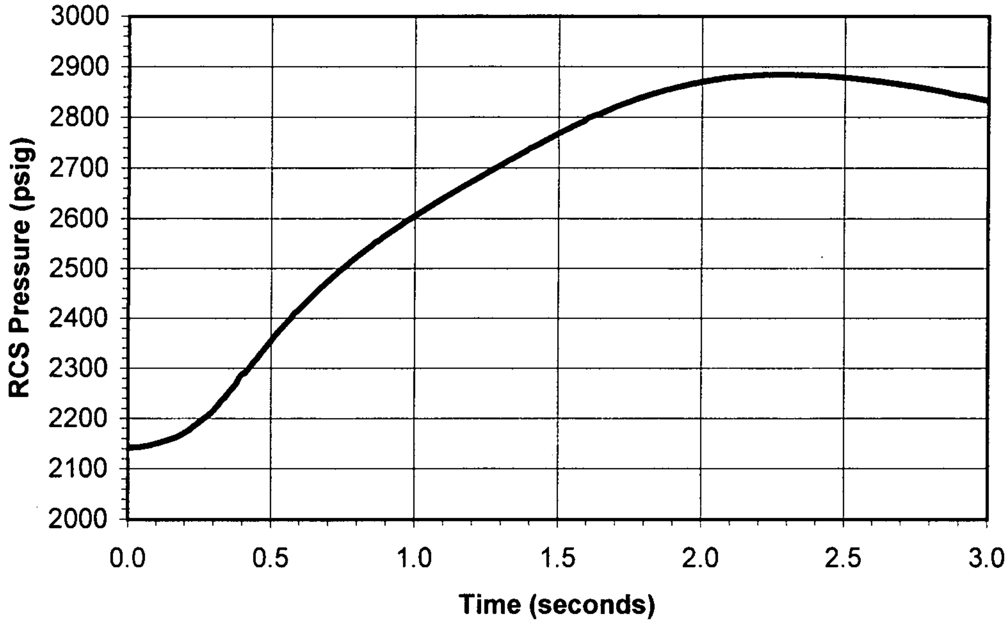


Figure 15-40
Steam Line Break Accident
With Offsite Power

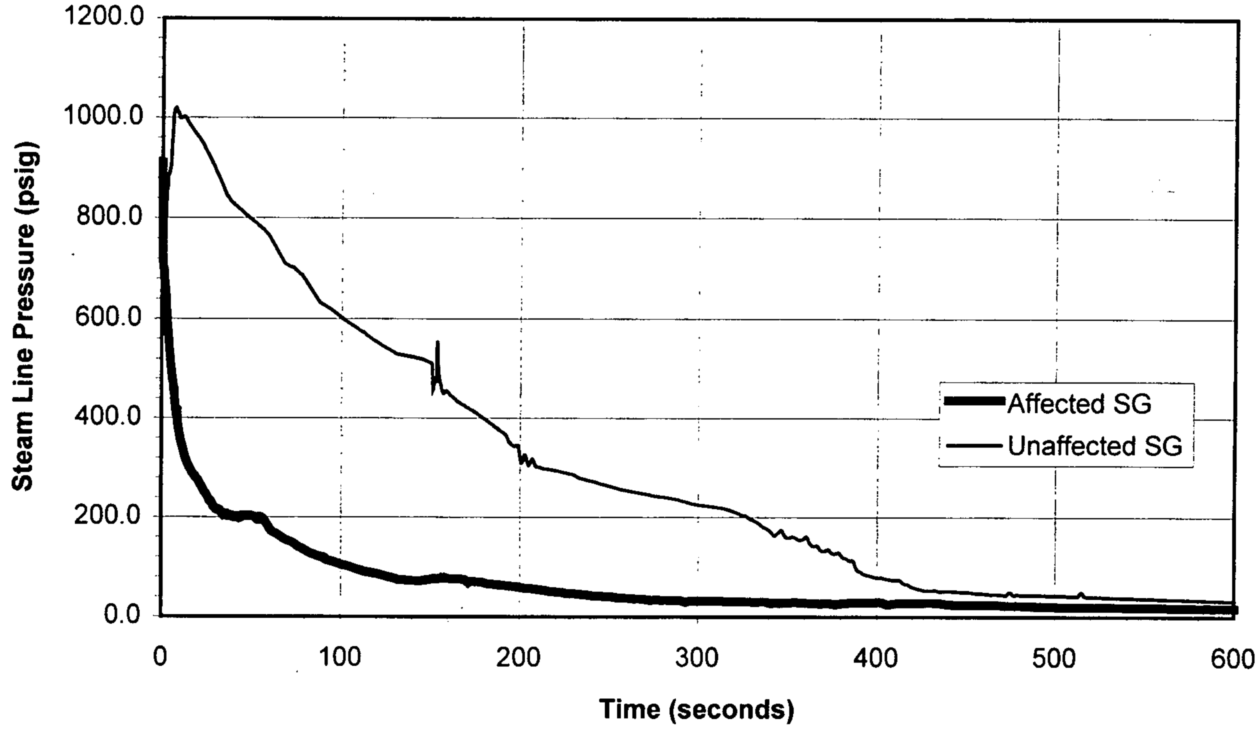


Figure 15-41
Steam Line Break Accident
With Offsite Power

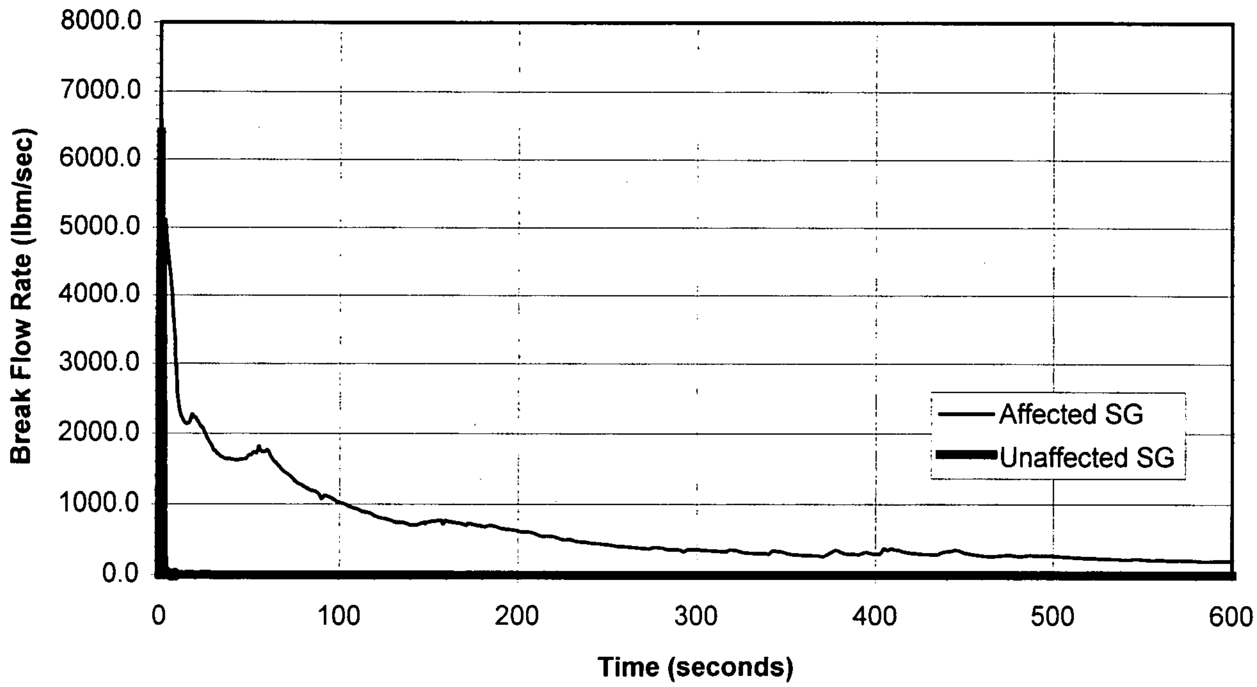


Figure 15-42
Steam Line Break Accident
With Offsite Power

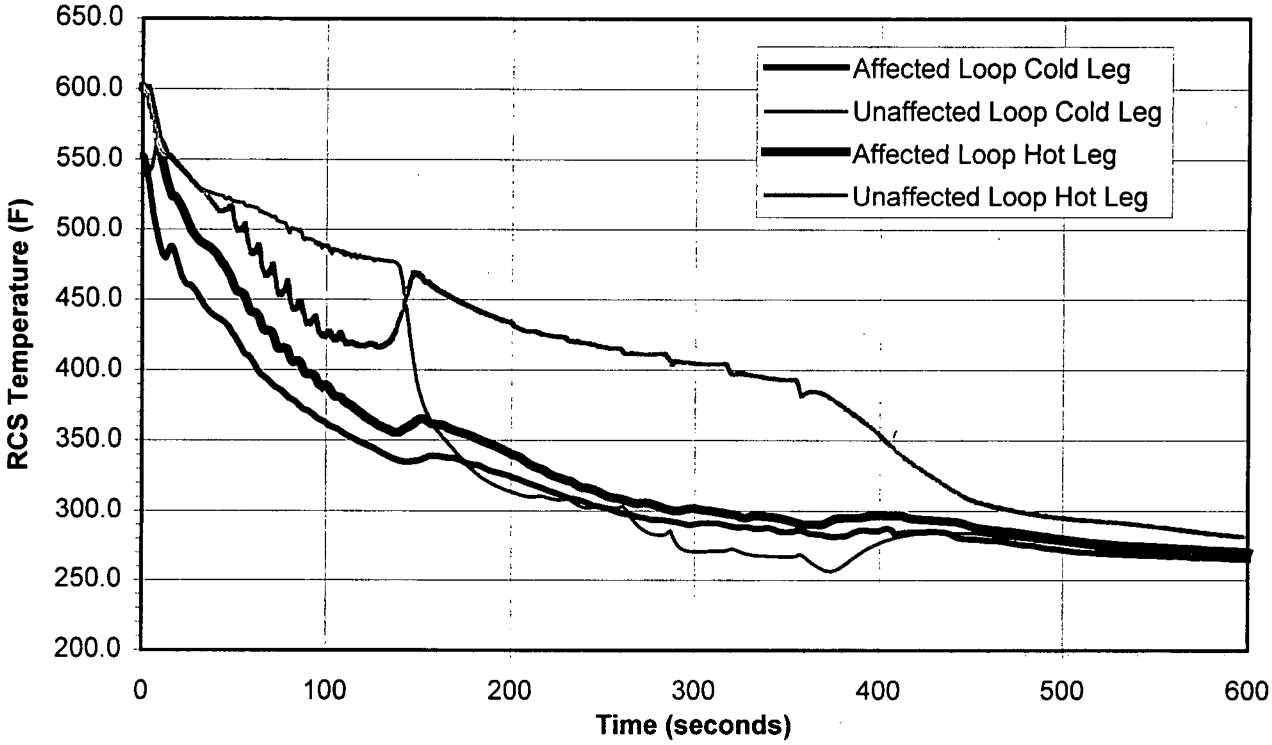


Figure 15-43
Steam Line Break Accident
With Offsite Power

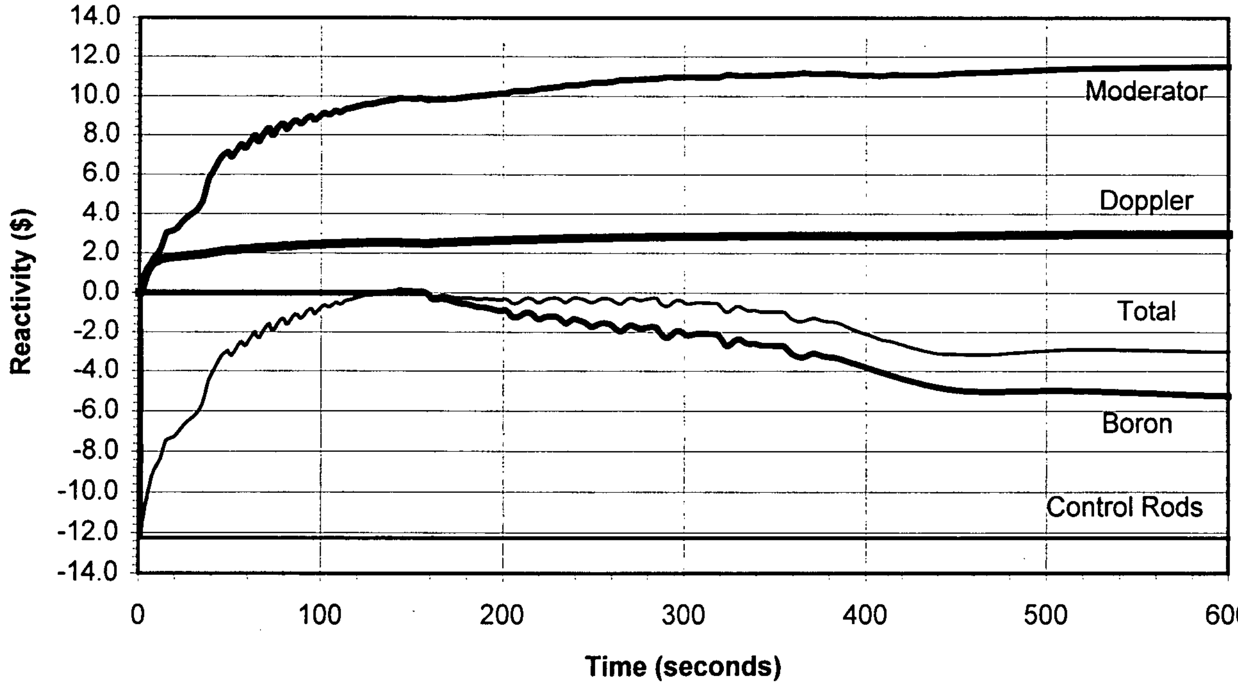


Figure 15-157
Steam Line Break Accident
With Offsite Power

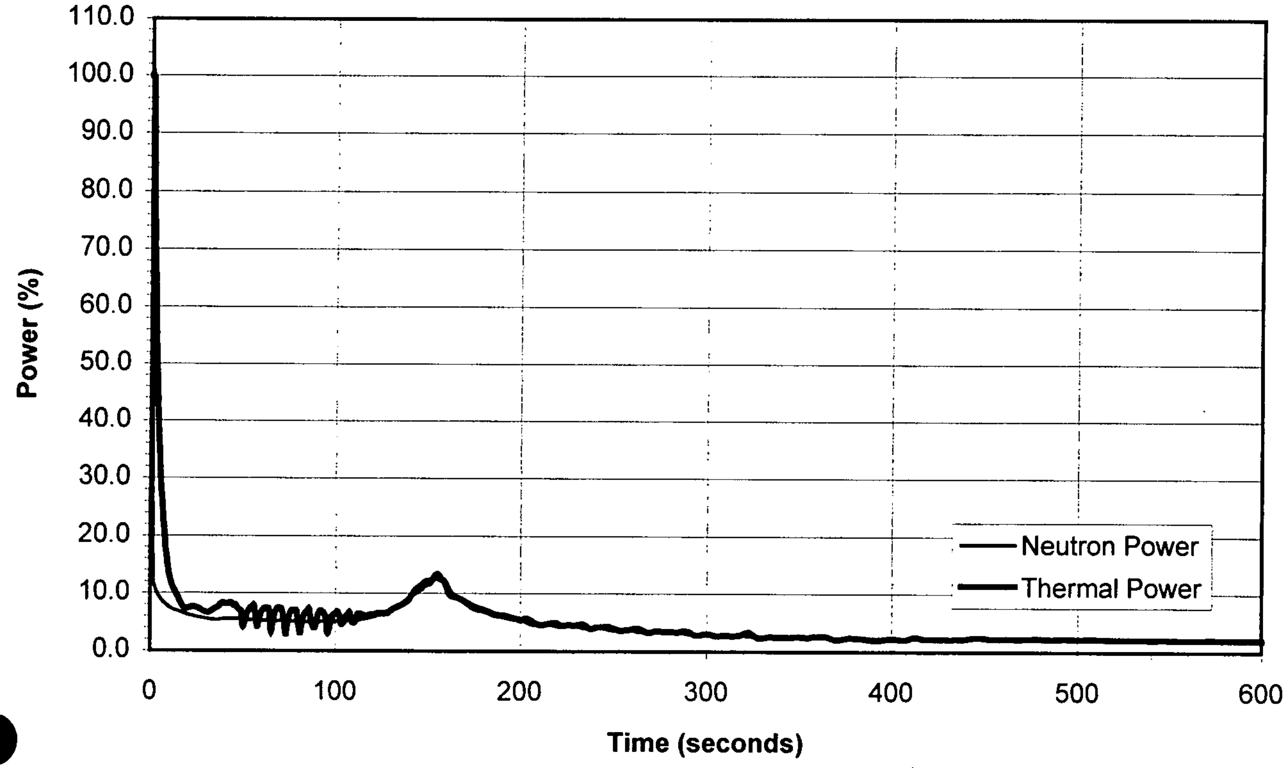


Figure 15-158
Steam Line Break Accident
With Offsite Power

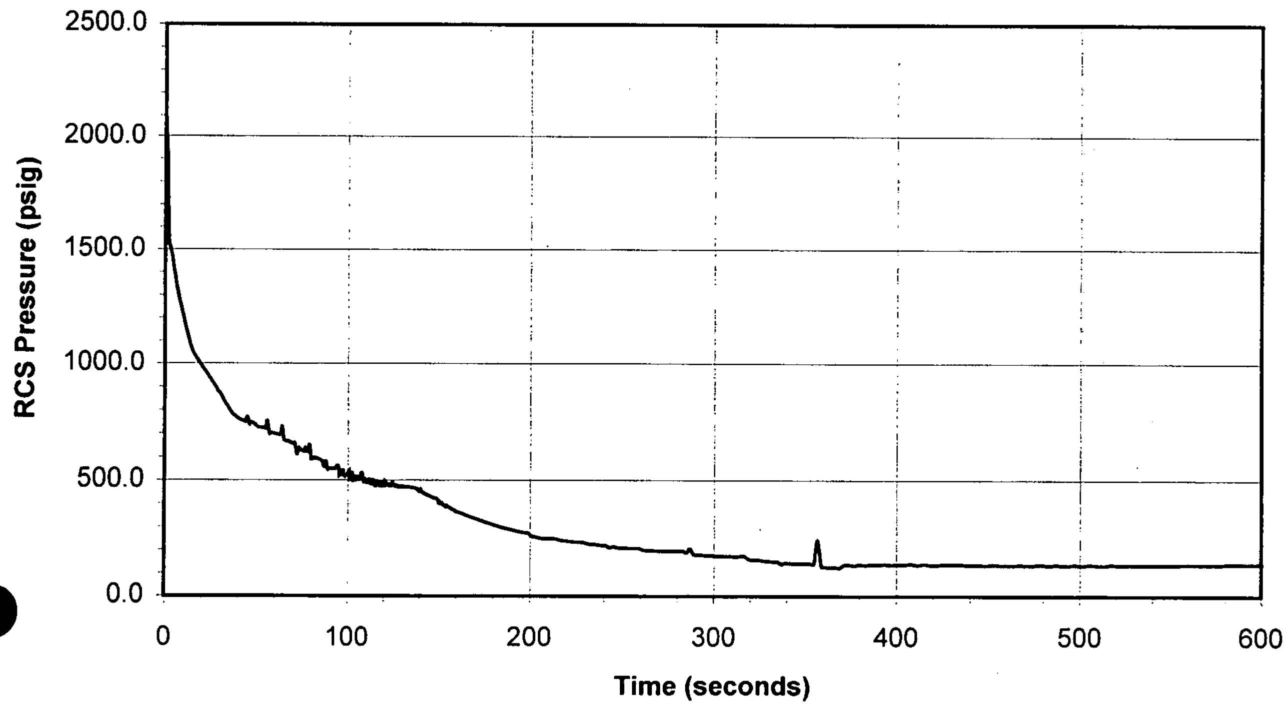


Figure 15-159
Steam Line Break Accident
With Offsite Power

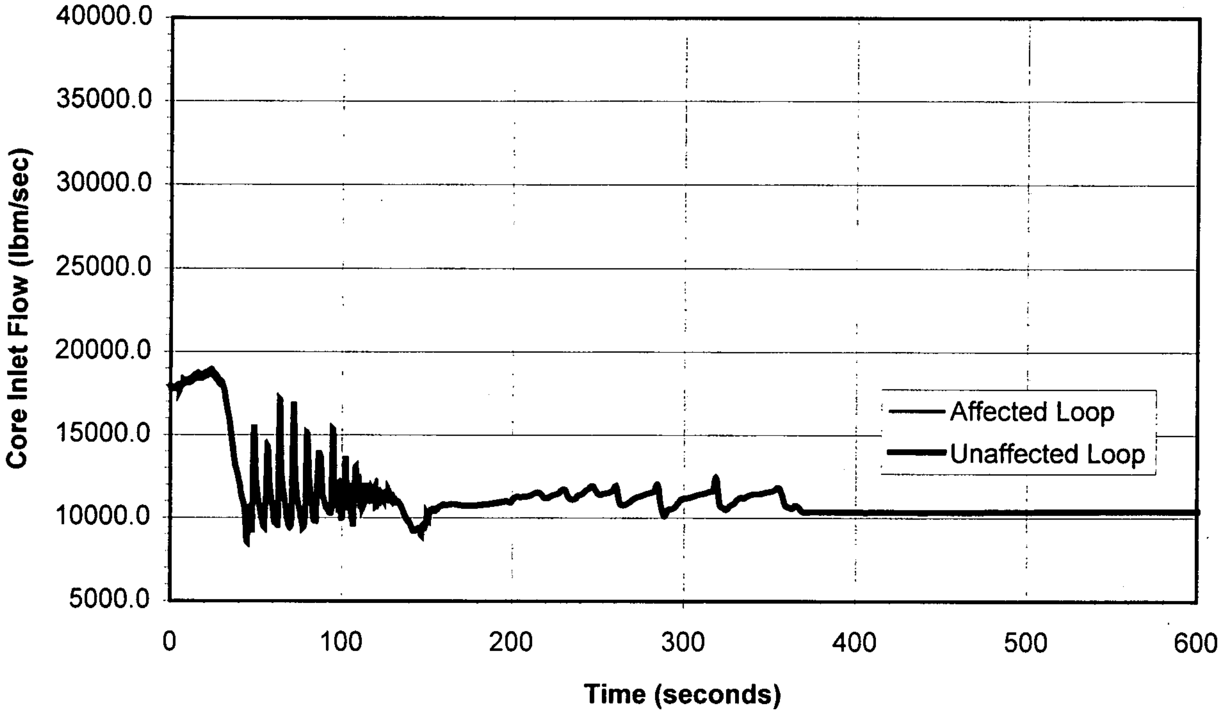
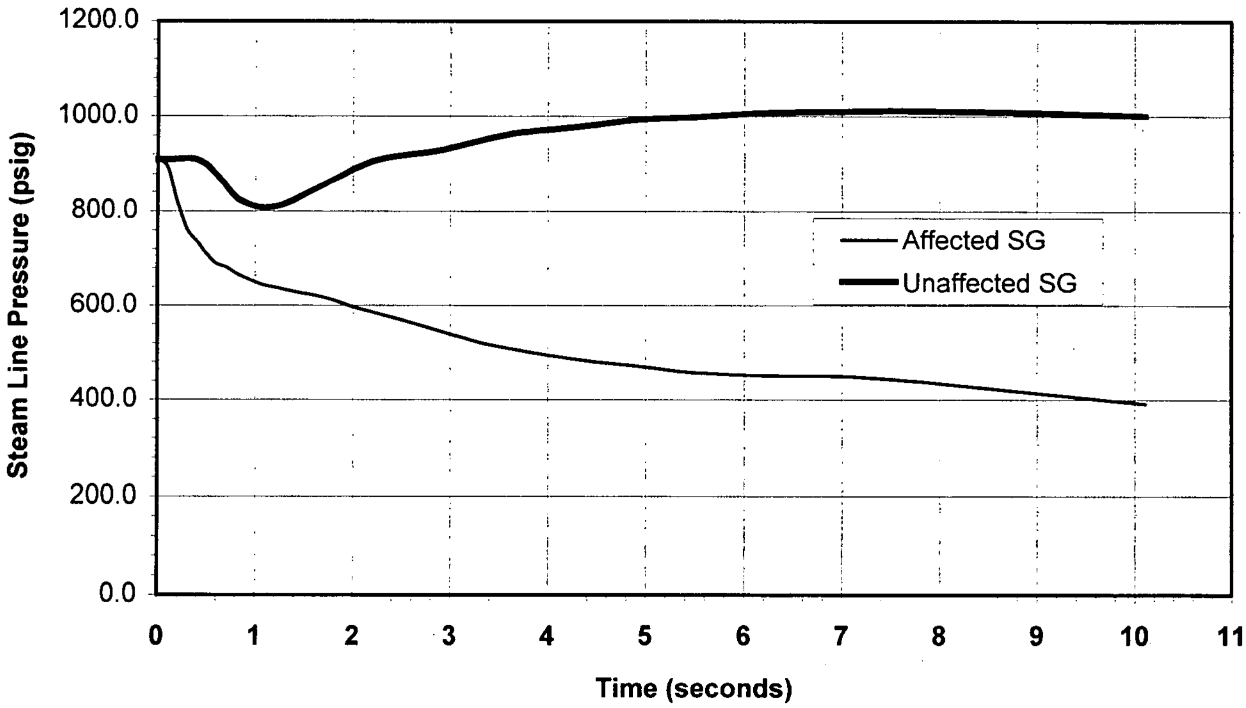


Figure 15-161
Steam Line Break Accident
Without Offsite Power



V11-120

Radial Assembly Power Distribution

**	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	**
A						0.124	0.180	0.193	0.202	0.150						A
B				0.201	0.249	0.290	0.521	0.327	0.597	0.368	0.347	0.300				B
C			0.284	0.617	0.413	0.681	0.404	0.610	0.480	0.903	0.593	0.942	0.452			C
D		0.201	0.616	0.460	0.765	0.664	0.662	0.351	0.817	0.915	1.140	0.735	1.027	0.346		D
E		0.249	0.413	0.765	0.470	0.667	0.354	0.425	0.451	0.969	0.758	1.323	0.745	0.465		E
F	0.124	0.290	0.682	0.665	0.667	0.295	0.443	0.291	0.592	0.472	1.192	1.262	1.357	0.615	0.277	F
G	0.180	0.521	0.405	0.662	0.354	0.443	0.253	0.340	0.369	0.805	0.720	1.431	0.928	1.248	0.443	G
H	0.194	0.327	0.611	0.351	0.425	0.291	0.340	0.247	0.552	0.622	1.061	0.948	1.692	0.920	0.547	H
K	0.202	0.598	0.480	0.818	0.452	0.593	0.369	0.551	0.638	1.434	1.347	2.651	1.588	1.950	0.650	K
L	0.150	0.368	0.904	0.916	0.971	0.472	0.805	0.622	1.436	1.232	3.215	3.400	3.439	1.384	0.538	L
M		0.348	0.595	1.142	0.759	1.193	0.721	1.062	1.348	3.218	2.824	5.266	2.825	1.596		M
N		0.300	0.944	0.736	1.324	1.263	1.433	0.948	2.652	3.402	5.270	5.505	5.369	1.585		N
O			0.453	1.028	0.745	1.359	0.929	1.693	1.589	3.441	2.827	5.374	2.547			O
P				0.346	0.466	0.616	1.248	0.921	1.953	1.385	1.597	1.587				P
R						0.277	0.442	0.548	0.652	0.539						R
**	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	**

Peak Pin Power Distribution

**	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	**
A						0.259	0.294	0.310	0.330	0.306						A
B				0.360	0.386	0.527	0.610	0.504	0.725	0.652	0.532	0.538				B
C			0.484	0.737	0.683	0.797	0.609	0.673	0.782	1.093	0.961	1.122	0.771			C
D		0.360	0.736	0.614	0.847	0.723	0.767	0.518	1.002	1.012	1.256	0.985	1.230	0.619		D
E		0.386	0.683	0.847	0.646	0.780	0.582	0.498	0.779	1.133	1.132	1.491	1.263	0.747		E
F	0.259	0.527	0.798	0.723	0.780	0.452	0.503	0.429	0.705	0.728	1.427	1.389	1.564	1.146	0.596	F
G	0.293	0.611	0.609	0.768	0.582	0.502	0.362	0.400	0.575	0.919	1.140	1.586	1.257	1.481	0.731	G
H	0.316	0.506	0.674	0.516	0.499	0.427	0.394	0.427	0.797	1.076	1.439	1.560	1.981	1.524	0.943	H
K	0.331	0.727	0.783	1.003	0.780	0.707	0.573	0.785	1.182	2.010	2.596	3.438	2.752	2.541	1.075	K
L	0.307	0.654	1.095	1.014	1.136	0.728	0.920	1.070	2.014	2.219	4.301	4.022	4.513	2.474	1.047	L
M		0.533	0.962	1.258	1.127	1.428	1.142	1.440	2.596	4.307	4.707	6.057	5.092	2.719		M
N		0.539	1.125	0.986	1.492	1.391	1.589	1.553	3.439	4.024	6.065	6.029	6.695	2.883		N
O			0.772	1.231	1.264	1.566	1.259	1.981	2.753	4.515	5.097	6.699	4.595			O
P				0.620	0.748	1.147	1.481	1.531	2.542	2.475	2.721	2.886				P
R						0.596	0.730	0.963	1.077	1.049						R
**	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	**

Figure 15-160
Steam Line Break Accident
With Offsite Power

Figure 15-162
Steam Line Break Accident
Without Offsite Power

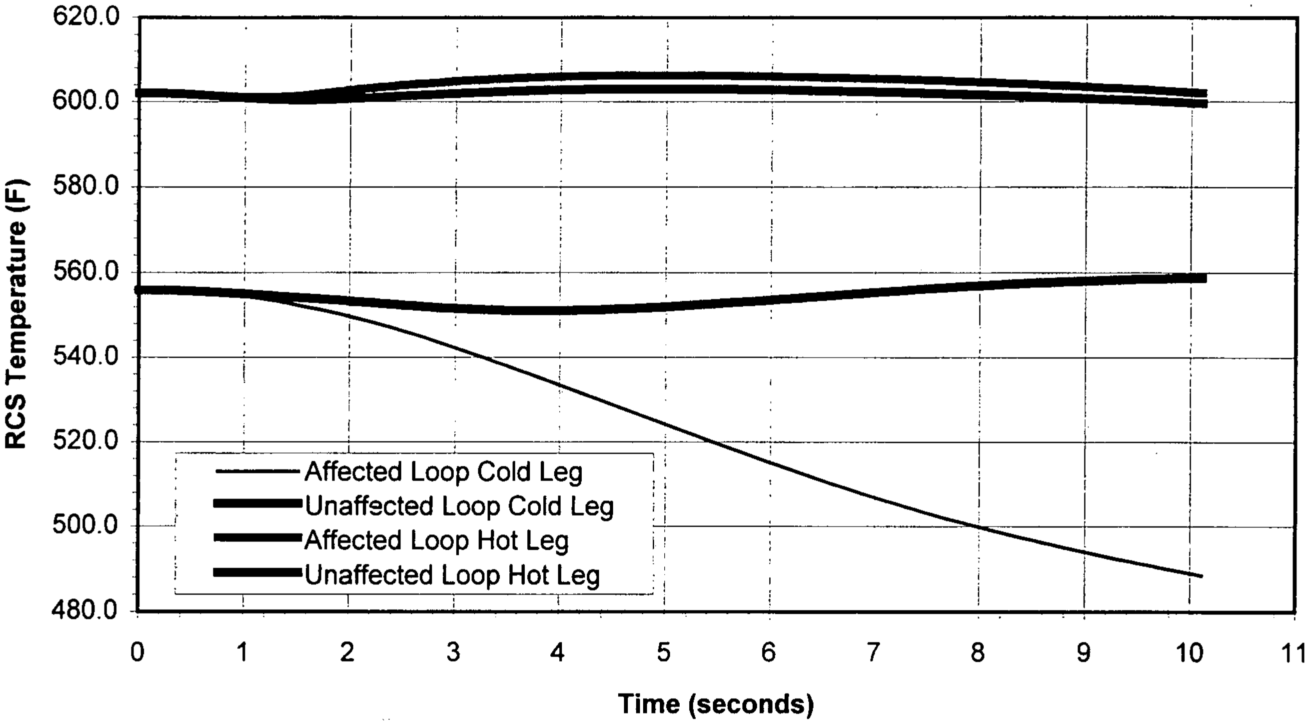


Figure 15-163
Steam Line Break Accident
Without Offsite Power

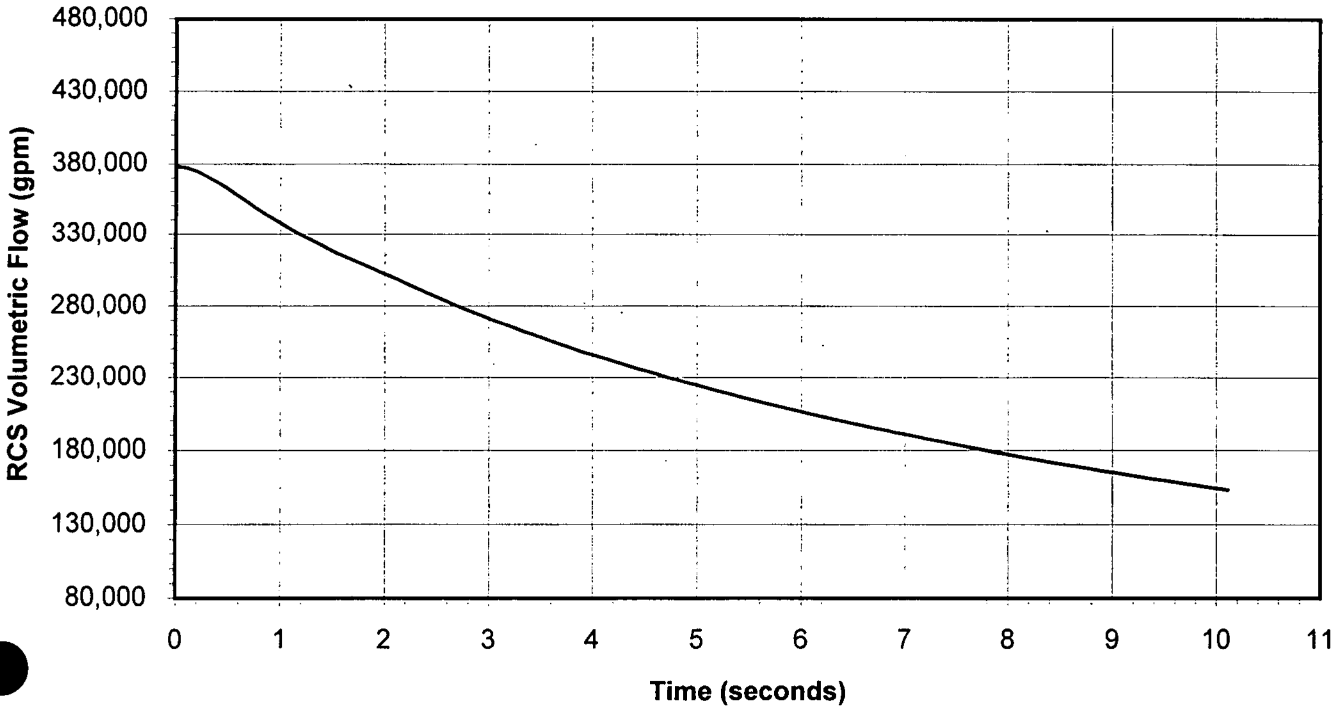


Figure 15-164
Steam Line Break Accident
Without Offsite Power

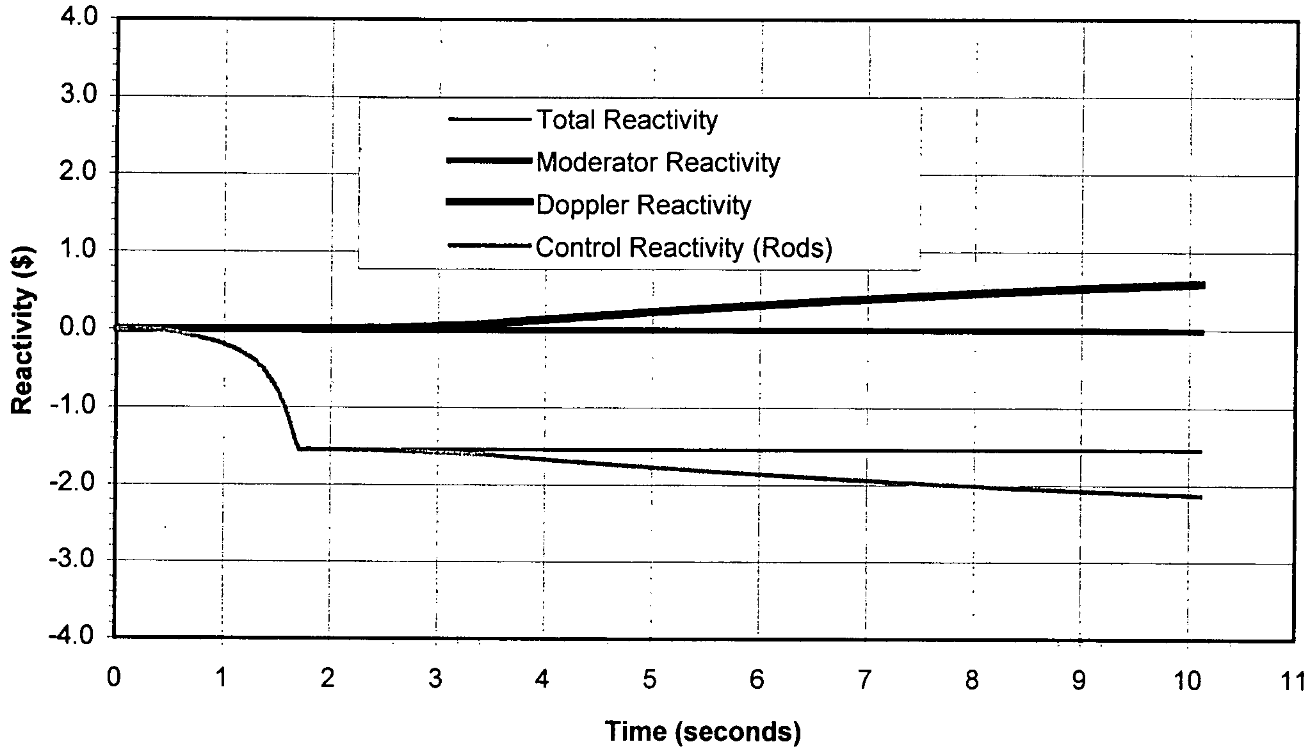


Figure 15-165
Steam Line Break Accident
Without Offsite Power

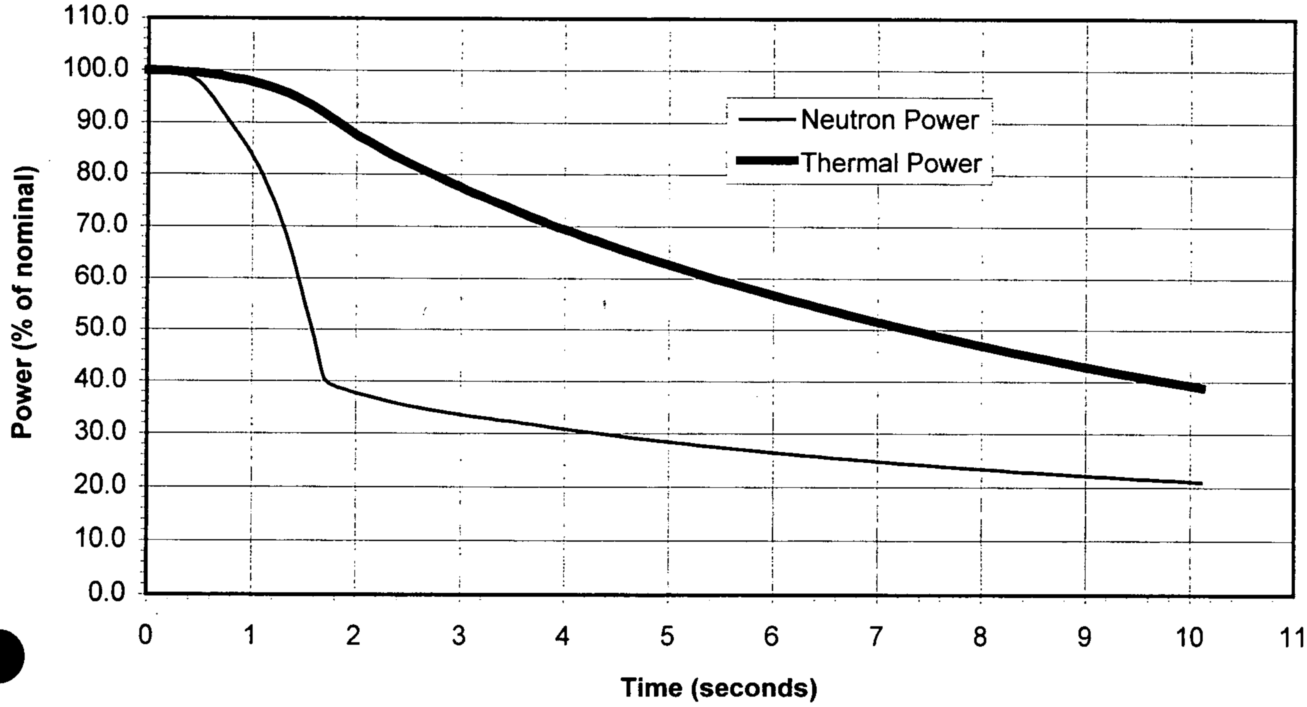


Figure 15-166
Steam Line Break Accident
Without Offsite Power

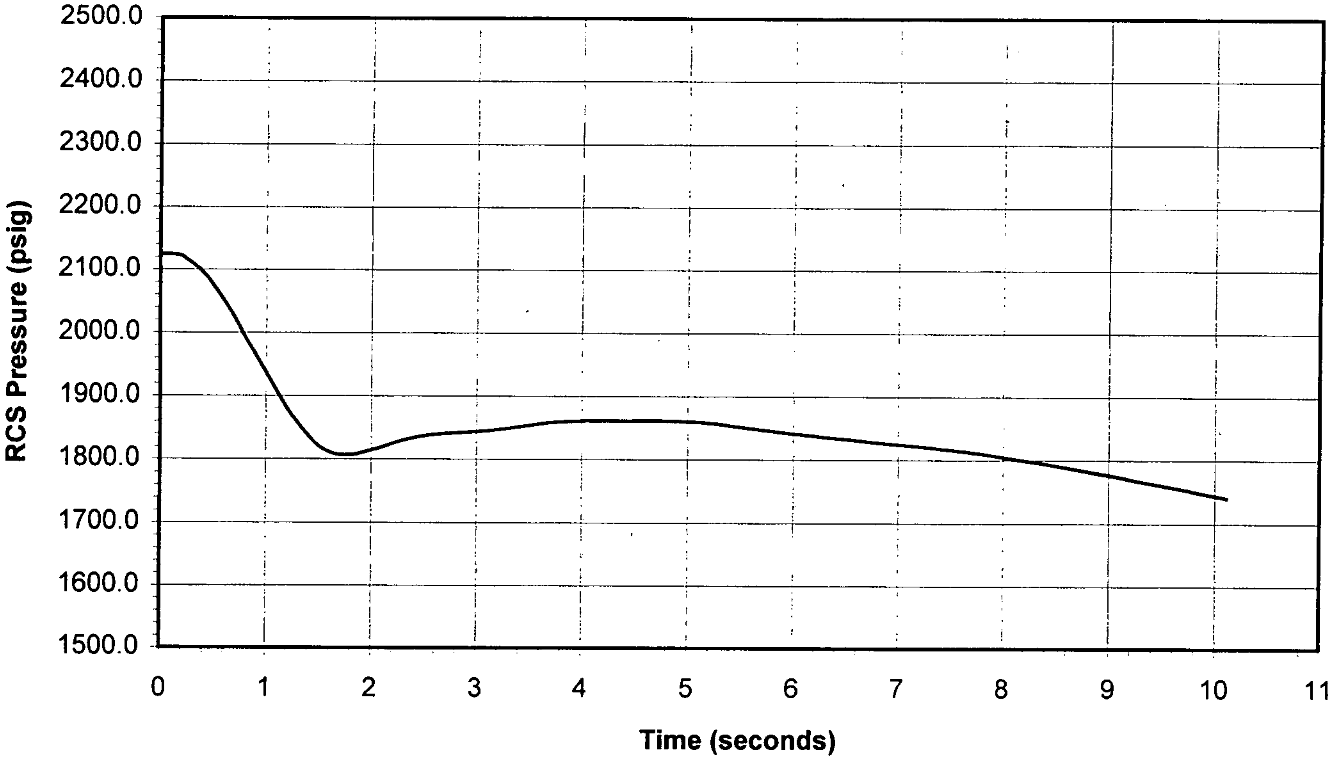


Figure 15-167
Steam Line Break Accident
Without Offsite Power

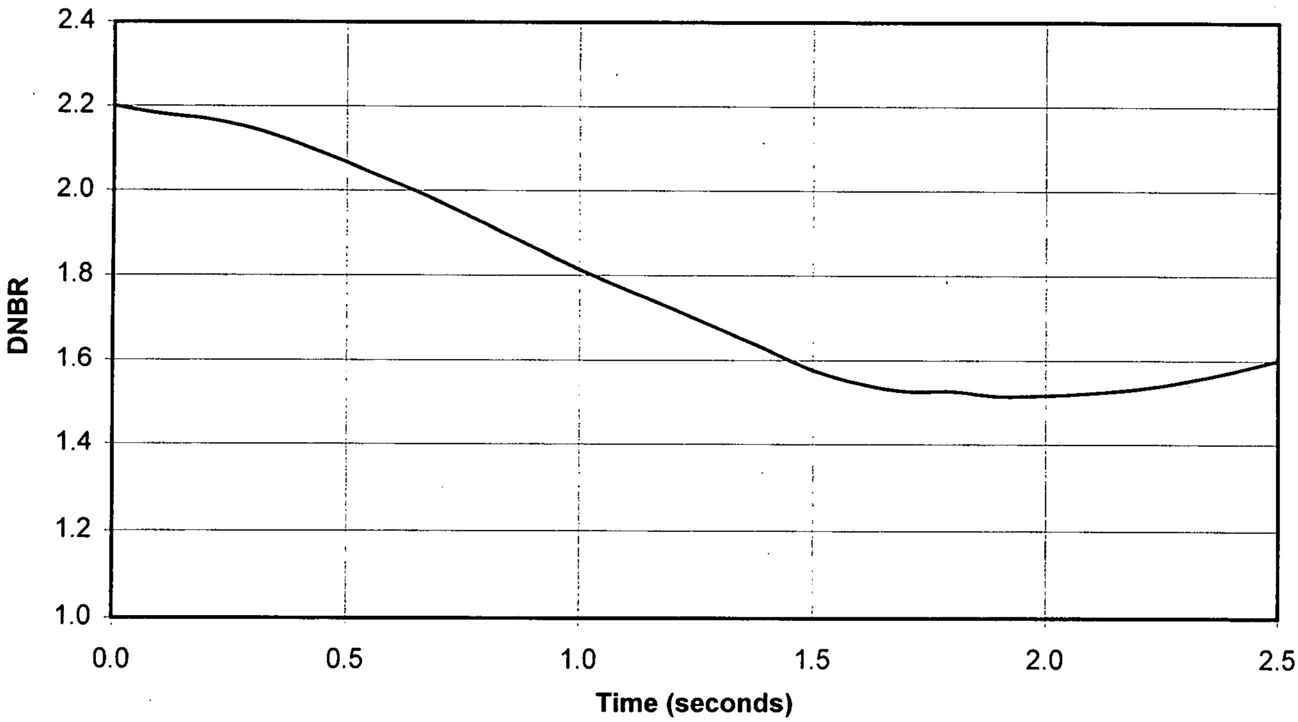


Figure 15-168
Small Steam Line Break

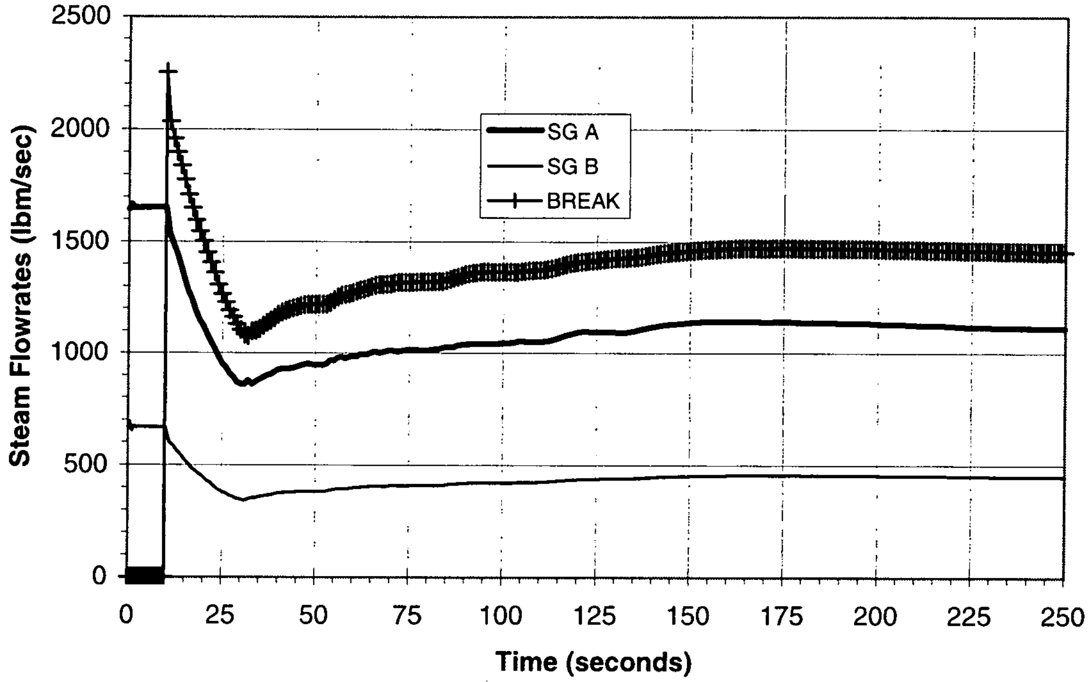


Figure 15-169
Small Steam Line Break

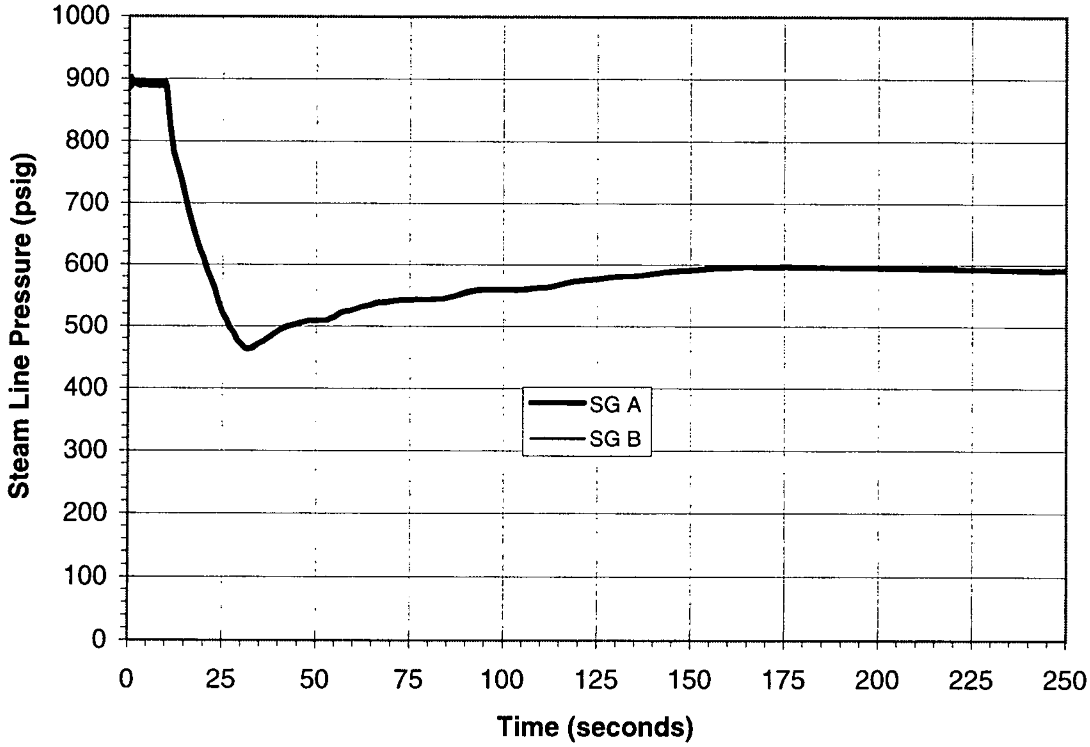


Figure 15-170
Small Steam Line Break

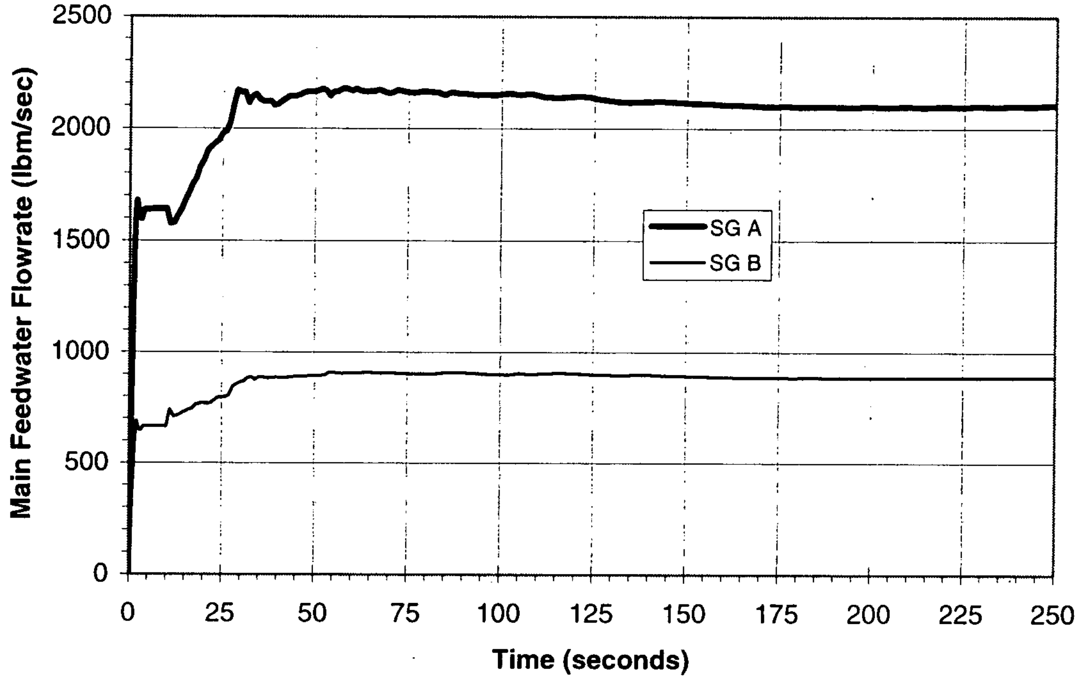


Figure 15-171
Small Steam Line Break

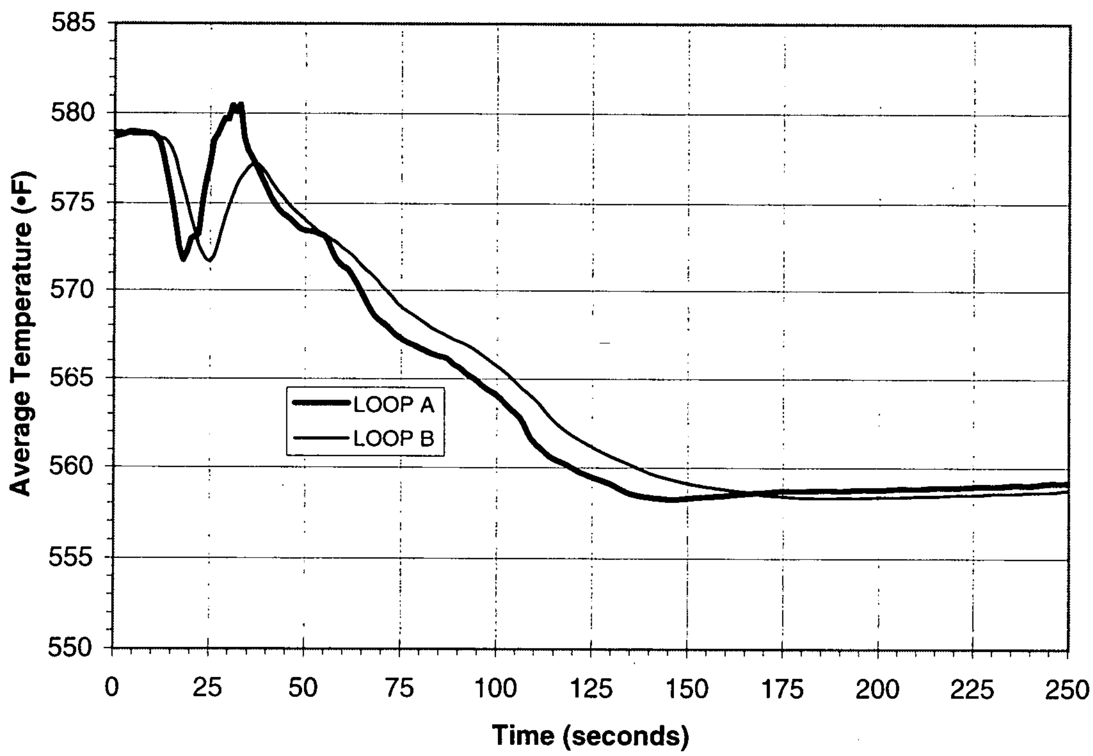


Figure 15-172
Small Steam Line Break

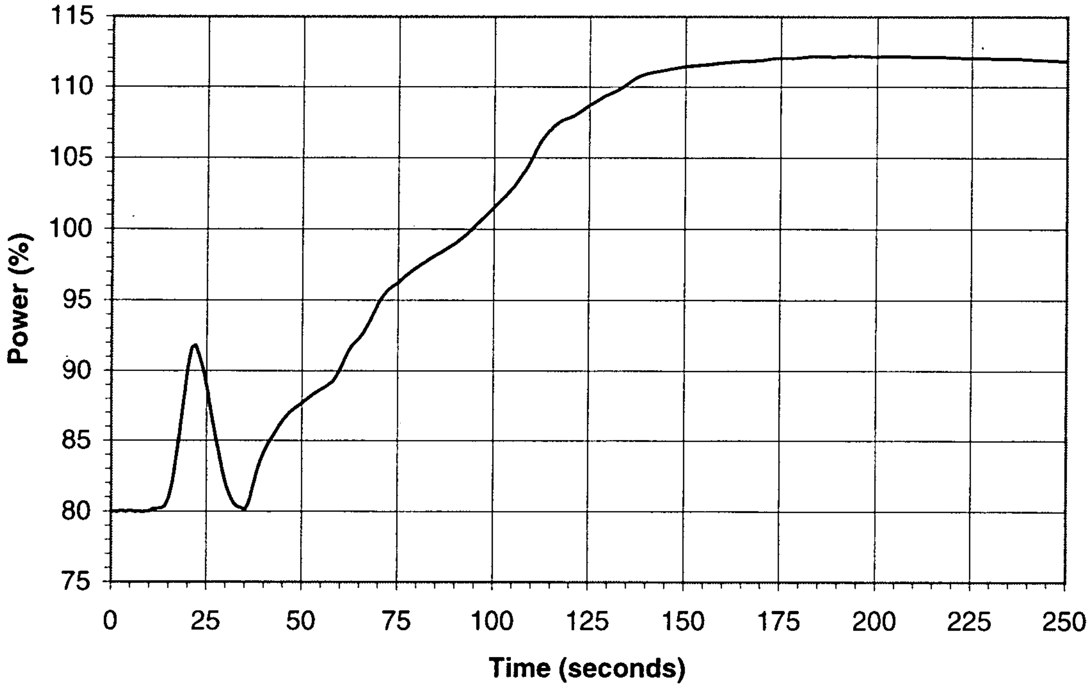
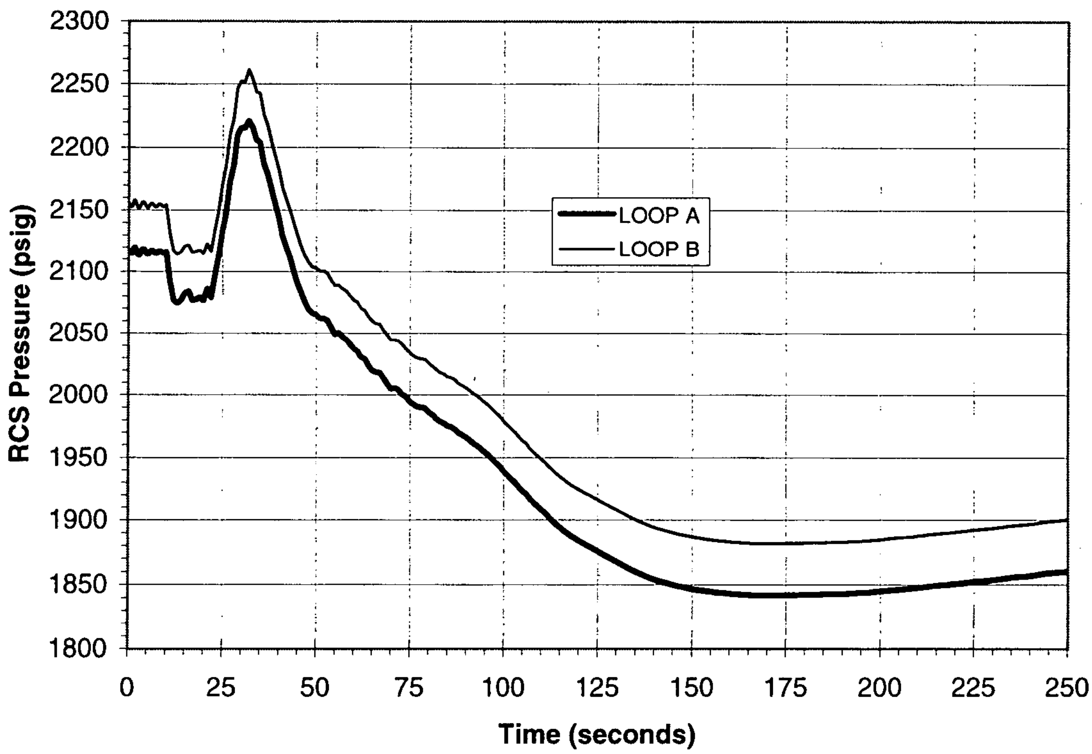


Figure 15-173
Small Steam Line Break



ATTACHMENT VIII

DESIGN INFORMATION RELATIVE TO
OCONEE UNIT 2 CYCLE 18

CONTENTS

List of Tables

List of Figures

1. INTRODUCTION AND SUMMARY

This report justifies the operation of the eighteenth cycle of Oconee Nuclear Station, Unit 2, at the rated core power of 2568 MWth. Included are the required analyses as outlined in the USNRC document "Guidance for Proposed License Amendments Relating to Refueling", June 1975.

Cycle 18 for Oconee Unit 2 will be the first Oconee cycle for which Duke Power analyses of the UFSAR non-LOCA transients will be applied. To support Cycle 18 operation of Oconee Unit 2, this report employs analytical techniques and design bases established in reports that have been previously submitted to the USNRC. The Duke Power non-LOCA transient analysis methods are documented in topical report DPC-NE-3005 (Reference 1).

Section 2 of this report is the operating history for fuel in Oconee Unit 2. Section 3 is a general description of the reactor core, and the fuel system design is provided in Section 4. Reactor and system parameters and conditions are summarized in Sections 5, 6 and 7. All of the accidents analyzed in the UFSAR (Reference 2) have been reviewed for Cycle 18 operation. In those cases where Cycle 18 characteristics were conservative compared to those analyzed for the generic analysis, a new analysis was not performed. The results of any reanalyzed transients are included in Section 8. Changes to the Technical Specifications, Core Operating Limits Report (COLR), and Updated Final Safety Analysis Report (UFSAR) are provided in Section 8.

The Technical Specifications have been reviewed, and the modifications for Cycle 18 are justified in this report. Based on the analyses performed, it has been concluded that Oconee Unit 2 Cycle 18 can be safely operated at a core power level of 2568 MWth.

2. OPERATING HISTORY

The referenced fuel cycle for the nuclear and thermal-hydraulic analyses of Oconee Unit 2, Cycle 18, is the currently operating Cycle 17. Cycle 17 achieved initial criticality on May 22, 1998. The fuel cycle design length for Cycle 18 - 477 $\pm$ 10 EFPD - is based on an assumed Cycle 17 length of 507 $\pm$ 10 EFPD. No operating anomalies have occurred during previous cycle operations that would adversely affect fuel performance in Cycle 18.

Cycle 18 will operate in a feed-and-bleed mode for its entire design length, as did Cycle 17.

3. GENERAL DESCRIPTION

The Oconee Unit 2 reactor core and fuel design basis are described in detail in Chapter 4 of the UFSAR (Reference 2). The Cycle 18 core consists of 177 fuel assemblies, each of which is a 15 by 15 array containing 208 fuel rods, 16 control rod guide tubes, and one incore instrument guide tube. The fuel consists of dished-end, cylindrical pellets of uranium dioxide clad in cold-worked Zircaloy-4. The fuel assemblies in batch 17 have an average nominal fuel loading of 463.6 kg uranium. The fuel assemblies in batches 18, 19, and 20 all have an average nominal fuel loading of 487.2 kg uranium, except for the one remaining batch 18 LTA which is 459.0 kg. The undensified nominal active fuel lengths, theoretical densities, fuel and fuel rod dimensions, and other related fuel parameters are given in Table 4-1.

Figure 3-1 is the core loading diagram for Oconee 2, Cycle 18. All assemblies in all batches will have axial blankets consisting of 6 inches of 2.00 wt% ^{235}U on the top and bottom of each assembly. The 8 assemblies remaining from the original 60 included in Batch 17 (3.82 wt% ^{235}U) will be designated as Batch 17C. The 49 assemblies remaining from the original 56 included in Batches 18A, 18B, and 18C (2.80, 3.80, and 4.02 wt% ^{235}U, respectively) will retain their batch designators. The 60 Batch 19 assemblies (4.23 wt% ^{235}U) will be retained along with the 60 Batch 20 feed assemblies (3.44 wt% ^{235}U). The core periphery is composed of Batch 17 and Batch 18 assemblies. The Batch 20 assemblies are distributed relatively evenly throughout the core interior with the rest of the Batch 18 and Batch 19 assemblies. Figure 3-2 is a quarter-core map showing the assembly burnup and enrichment distribution at the beginning of Cycle 18.

Cycle 18 will operate in a rods-out, feed-and-bleed mode. Core reactivity control is supplied mainly by soluble boron and supplemented by 61 full-length Ag-In-Cd control rods and 44 burnable poison rod assemblies (BPRAs). In addition to the full-length control rods, eight Inconel gray axial power shaping rods (APSRs) are provided for additional control of the axial power distribution. The Cycle 18 locations of the 69 control rods and the group designations are indicated in Figure 3-3. The Cycle 18 locations and enrichments of the BPRAs are shown in Figure 3-4.

FIGURE 3-1

OCONEE 2, CYCLE 18
CORE LOADING DIAGRAM

X

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
A						E09 18	K06 18	R09 17	K10 18	E07 18					
B				O09 18	M03 18	N09 19	20	H11 19	20	N07 19	M13 18	O07 18			
C			R08 17	20	P07 19	20	C06 19	20	C10 19	20	P09 19	20	H01 17		
D		K13 18	20	H03 19	20	N11 19	20	B08 18	20	N05 19	20	C08 19	20	K03 18	
E		C11 18	G14 19	20	N12 18	20	E06 19	20	E10 19	20	N04 18	20	G02 19	C05 18	
F	K05 18	K12 19	20	M12 19	20	P10 18	N03 19	H09 19	N13 19	L02 18	20	M04 19	20	K04 19	K11 18
G	F09 18	20	F03 19	20	F05 19	C12 19	F02 18	20	B10 18	C04 19	F11 19	20	F13 19	20	F07 18
H W	G15 17	E08 19	20	H02 18	20	G08 19	20	A09 18	20	K08 19	20	H14 18	20	M08 19	K01 17
K	L09 18	20	L03 19	20	L05 19	O12 19	P06 18	20	L14 18	O04 19	L11 19	20	L13 19	20	L07 18
L	G05 18	G12 19	20	E12 19	20	F14 18	D03 19	H07 19	D13 19	B06 18	20	E04 19	20	G04 19	G11 18
M		O11 18	K14 19	20	D12 18	20	M06 19	20	M10 19	20	D04 18	20	K02 19	O05 18	
N		G13 18	20	O08 19	20	D11 19	20	P08 18	20	D05 19	20	H13 19	20	G03 18	
O			H15 17	20	B07 19	20	O06 19	20	O10 19	20	B09 19	20	A08 17		
P				C09 18	E03 18	D09 19	20	H05 19	20	D07 19	E13 18	C07 18			
R						M09 18	G06 18	A07 17	G10 18	M07 18					

Z

XX	Previous Cycle Location
X	Batch Number

FIGURE 3-2

OCONEE 2, CYCLE 18
ENRICHMENT AND BURNUP

	8	9	10	11	12	13	14	15
H	2.80 24618	3.44 0	4.23 21437	3.44 0	3.80 35246	3.44 0	4.23 22130	3.82 34260
K	3.44 0	3.80 31189	4.23 15318	4.23 21827	3.44 0	4.23 20115	3.44 0	4.02 33877
L	4.23 21386	4.23 15319	3.80 31176	3.44 0	4.23 21438	3.44 0	4.23 21901	3.80 39156
M	3.44 0	4.23 21814	3.44 0	3.80 37274	3.44 0	4.23 18048	4.02 33033	
N	3.80 35246	3.44 0	4.23 21442	3.44 0	4.23 21689	3.44 0	3.80 38804	
O	3.44 0	4.23 20112	3.44 0	4.23 18118	3.44 0	3.82 38904		
P	4.23 22125	3.44 0	4.23 21901	4.02 33038	3.80 38776			
R	3.82 34260	4.02 33847	3.80 39178					

X.XX	Initial Enrichment in wt% ^{235}U
XXXXX	BOC Burnup in MWd/mtU

FIGURE 3-3

OCONEE 2, CYCLE 18
CONTROL ROD LOCATIONS

X

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
A															
B						4		6		4					
C					2		5		5		2				
D				7		8		7		8		7			
E			2		5		1		1		5		2		
F		4		8		6		3		6		8		4	
G			5		1		3		3		1		5		
H		6		7		3		4		3		7		6	
W															
K			5		1		3		3		1		5		
L		4		8		6		3		6		8		4	
M			2		5		1		1		5		2		
N				7		8		7		8		7			
O					2		5		5		2				
P						4		6		4					
R															

Group Number

Z

Group	# of Rods	Function	Group	# of Rods	Function
1	8	Safety	5	12	Control
2	8	Safety	6	8	Control
3	8	Safety	7	8	Control
4	9	Safety	8	8	APSRs
			Total:	69	

FIGURE 3-4

OCONEE 2, CYCLE 18
BPRA ENRICHMENT AND DISTRIBUTION

	8	9	10	11	12	13	14	15
H		0.8		1.1		0.5		
K	0.8				1.1			
L				1.1		0.5		
M	1.1		1.1		0.5			
N		1.1		0.5				
O	0.5		0.5					
P								
R								

X.X	BPRA Concentration in wt% B_4C in Al_2O_3

4. FUEL SYSTEM DESIGN

4.1 Fuel Assembly Mechanical Design

The types of fuel assemblies and pertinent fuel design parameters for Oconee 2 Cycle 18 are listed in Table 4-1. All fuel assemblies are mechanically interchangeable. The Batch 20 feed assemblies are of the Mark-B10L design, which is a B10 fuel assembly with radial zoned enriched fuel and is similar to the previous Mark-B10L reload batch deployed in Oconee 2 Cycle 17. The Mk-B10 fuel assembly design was presented in the Oconee 2 Cycle 14 reload report (Reference 3).

Duke has performed generic mechanical analyses, as described below, which envelope the Cycle 18 design. All methods are consistent with the approved methodologies of Reference 4, except where specifically stated.

4.2 Fuel Rod Design

The fuel rod design for the Mk-B10L fuel assembly is the Mk-B10. The mechanical evaluation of the Mk-B10 rod design is discussed in this section.

4.2.1 Cladding Collapse

Batches 17, 18, 19 and 20 were analyzed for creep-collapse using the CROV computer code and procedures described in topical report BAW-10084P, Rev. 3 (Reference 5). The CROV analyses are performed generically for a specific fuel rod design. The TAC03 (Reference 6) code was used to calculate internal pin pressures and clad temperatures used as input to CROV. As shown in Table 4-1, the collapse burnup limit for each batch was conservatively determined to be greater than the maximum assembly burnup.

4.2.2 Cladding Stress

Duke has performed a generic and conservative fuel rod cladding stress analysis in accordance with the guidelines set forth in Section III, Division 1 - Subsection NB, of the ASME Boiler and Pressure Vessel Code. All methods are consistent with Reference 4. Compliance with ASME Code criteria verifies the structural integrity of the cladding throughout the most limiting design conditions. Duke's reload analysis of the Mk-B10L fuel design demonstrates that the generic analysis is bounding. This analysis includes the following conservatisms.

High external cladding pressure (110% of design system pressure)
Low internal pressure (HZP—min. specified pre-pressure)
Maximum possible radial temperature gradient through clad (fuel melt conditions)
Conservative cladding dimensions with regard to stress

4.2.3 Cladding Strain

Duke has performed a cladding strain calculation using TAC03 (Reference 6) in accordance with the approved methodology (Reference 4). This analysis demonstrated that the uniform, circumferential strain of the cladding was less than 1.0%.

4.2.4 Cladding Fatigue

Duke has performed a generic cladding fatigue analysis for the Mk-B10L fuel design with TACO3 (Reference 6). The reload analysis confirmed that the generic fuel rod fatigue analysis is bounding.

4.3 Thermal Design

Centerline fuel melt is avoided by ensuring that the maximum fuel temperature is less than the melting temperature of the fuel. Duke has performed a generic Linear Heat Rate to Melt analysis for the B10L fuel design with TACO3 (Reference 6). TACO3 reduces the best estimate fuel temperature to account for the effects of manufacturing variations, code predictions, transient fission gas release, and cladding oxide formation. The reload analysis indicates that the generic linear heat rate to melt analysis is bounding.

TACO3 was used to calculate the internal pin pressure in accordance with the methodology described in Reference 4. Depending on available margins, the analyses are performed on a generic or batch specific basis. The reload analysis confirmed that the generic pin pressure analysis is bounding. Therefore, the internal pin pressure will be less than the criteria given in Reference 4 and cladding liftoff will not occur.

For cycle 18, the maximum assembly and rod average burnups are 52,182 MWd/mtU and 55,854 MWd/mtU, respectively.

4.4 Material Compatibility

The batch 20 fuel assemblies do not utilize component materials different from previous cycles. Therefore, the chemical compatibility of all possible fuel-cladding-coolant-assembly interactions for the batch 20 fuel assemblies is identical to that of previous fuel.

Table 4-1
Fuel Design Parameters and Dimensions

Batch number	17	18	18A	19	20
Fuel assembly type	B10E	B10G	B11	B10L	B10L
Number of assemblies	8	48	1	60	60
Fuel rod OD, inches	0.430	0.430	0.416	0.430	0.430
Fuel rod ID, inches	0.377	0.380	0.368	0.380	0.380
Flex spacers, type	Spring	Spring	Spring	Spring	Spring
Rigid spacers, type	None	None	None	None	None
Undensified active fuel length, inches	140.733	142.29	143.05	142.29	142.29
Fuel pellet OD (mean spec), inches	0.370	0.3735	0.3615	0.3735	0.3735
Fuel pellet initial density (mean spec), %TD	95.0	96.0	96.0	96.0	96.0
Initial fuel enrichment, w/o ^{235}U Axial blanket initial enrichment, w/o ^{235}U	3.82 2.00	18B 3.80 18C 4.02 2.00	2.80 2.00	4.23/3.93 2.00	3.44/3.14 2.00
Max. EOC pin burnup (Mwd/mtU)	47,736	55,854	43,074	39,888	21,068
Cladding collapse burnup, Mwd/mtU	62,000	62,000	62,000	62,000	62,000
Average linear heat rate @ 100% of 2568 MW, kw/ft	5.79	5.72	5.69	5.72	5.72
Representative linear heat rate to melt values, kw/ft	21.2	21.2	22.0	21.2	21.2

5. NUCLEAR DESIGN

5.1 Physics Characteristics

Table 5-1 compares the core physics parameters of design Cycle 18 with those of the reference Cycle 17. The Cycle 17 and 18 values were generated by Duke Power Company using the CASMO-3/SIMULATE-3 based reload design methods described in Reference 7. Since the core has not yet reached an equilibrium cycle, differences in core physics parameters are to be expected between the cycles. Figure 5-1 illustrates a representative relative power distribution for the beginning of Cycle 18 at full power with equilibrium xenon and nominal rod positions.

The primary reasons for the differences in the physics parameters between Cycles 17 and 18 are the variation in the shuffle pattern, fresh fuel enrichment, and previous end of cycle fuel assembly burnups for Cycle 18. Differences in ejected and stuck rod worths between cycles are due to changes in the radial flux and burnup distributions. All safety criteria associated with these rod worths are met. The adequacy of the shutdown margin with Cycle 18 stuck rod worths is demonstrated in Table 5-2. The following conservatisms were applied for the shutdown calculations:

1. Poison material depletion allowance.
2. 10% uncertainty on net rod worth.

Flux redistribution was explicitly accounted for since the shutdown analysis was calculated using a three-dimensional model.

5.2 Analytical Input

The Cycle 18 incore measurement calculation constants to be used to compute core power distributions were obtained using CASMO-3/SIMULATE-3 in a similar manner for Cycle 18 as for the reference cycle.

5.3 Changes in Nuclear Design

The methodology described in Reference 7 has been implemented for both Oconee 2 Cycle 18 and the reference cycle.

Table 5-1 Oconee 2 Physics Parameters [a]

	Cycle 17 [b]	Cycle 18 [c]
Cycle length, EFPD (Nominal)	507	477
Cycle burnup, MWd/mtU (Nominal)	15,346	14,230
Average core burnup, EOC, MWd/mtU (Nominal)	33,598	32,413
Initial core loading, mtU	84.8	86.0
Critical boron - BOC (no xenon), ppm		
HZP, groups 7 and 8 at nominal positions	2231	2041
HFP, groups 7 and 8 at nominal positions	2037	1854
Critical boron - EOC (equilibrium xenon), ppm		
HZP, groups 7 and 8 at nominal positions	346	333
HFP, groups 7 and 8 at nominal positions	0	7
Control rod worths - HFP, BOC, %Dk/k		
Group 7	0.88	0.88
Group 8[d]	0.11	0.16
Control rod worths - HFP, EOC, %Dk/k		
Group 7	1.05	1.02
Group 8	(e)	(e)
Max ejected rod worth - HZP, %Dk/k [f]		
BOC, groups 5-8 inserted	0.21(I10)	0.26(L10)
EOC, groups 5-8 inserted	0.29(I10)	0.29(L10)
Max stuck rod worth - HZP, %Dk/k		
BOC	0.85(N12)	0.78(K13)
EOC	1.33(N12)	1.14(N12)
Power deficit, HFP to HZP, %Dk/k		
BOC	1.09	1.12
EOC	2.61	2.56
Doppler coeff - HFP, 10^{-5} (Dk/k-°F)		
BOC (equilibrium xenon)	-1.40	-1.42
EOC (equilibrium xenon)	-1.63	-1.63

Table 5-1. (cont'd)

	Cycle 17 [(b)]	Cycle 18 [(c)]
Moderator coeff - HFP, 10^{-4} (Dk/k-°F)		
BOC (no xenon)	-0.26	-0.37
EOC (equilibrium xenon)	-3.37	-3.34
Boron worth - HFP, ppm/%Dk/k		
BOC	157	151
EOC	123	121
Xenon worth - HFP, %Dk/k		
BOC (4 days)	2.50	2.52
EOC (equilibrium)	2.74	2.77
Effective delayed neutron fraction - HFP		
BOC	0.00622	0.00619
EOC	0.00518	0.00515

(a) EOC Physics Parameters are provided at the end of the burnup window (nominal + 10 EFPD) except where indicated to be nominal.
(b) Based on a 500 $\pm$ 10 EFPD Cycle 16 (Actual Cycle 16 length was 490.50 EFPD).
(c) Based on an assumed Cycle 17 length of 507 $\pm$ 10 EFPD.
(d) Worth is calculated from 35% to 100% WD for both cycles.
(e) CRGP8 = 100% WD. Therefore, there is no CRGP8 worth at EOC.
(f) Ejected rod worths for both cycles include a 15% uncertainty penalty.

Table 5-2. Shutdown Margin Calculation for

Oconee 2, Cycle 18

	BOC, %Dk/k	EOC, %Dk/k
Available Rod Worth		
Total rod worth, HZP	7.41	8.18
Worth reduction due to poison burnup	-0.40	-0.40
Maximum stuck rod, HZP	-0.78	-1.14
Net worth	6.23	6.64
Less 10% uncertainty	-0.62	-0.66
Total available worth	5.61	5.98
Required Rod Worth		
Power deficit, HFP to HZP	1.11	2.56
Max inserted rod worth, HFP	0.30	0.50
SDM Boron Bias, HFP to HZP	0.28	0.48
Total required worth	1.69	3.54
Shutdown Margin		
Total available worth minus total required worth	3.92	2.44

Note: Required shutdown margin is 1.00% Dk/k.

FIGURE 5-1

OCONEE 2, CYCLE 18
TWO DIMENSIONAL RELATIVE POWER DISTRIBUTION

HFP, 004 EFPD, EQXE
NOMINAL ROD POSITIONS

	8	9	10	11	12	13	14	15
H	0.912	1.254	1.328	1.389	1.100	1.393	1.023	0.340
K	1.248	1.050	1.347	1.368	1.391	1.354	1.138	0.350
L	1.328	1.344	1.079	1.314	1.308	1.288	0.784	0.215
M	1.388	1.366	1.312	1.012	1.319	1.071	0.432	
N	1.100	1.390	1.305	1.316	1.122	0.899	0.242	
O	1.393	1.353	1.285	1.066	0.898	0.309		
P	1.023	1.138	0.783	0.431	0.242			
R	0.340	0.350	0.214					

6. THERMAL-HYDRAULIC DESIGN

The generic and cycle-specific analyses supporting Oconee 2 Cycle 18 operation were performed by Duke Power Company using the methodology described in References 2, 8, 9 and 10. Oconee 2 Cycle 18 was analyzed using Duke's Statistical Core Design (SCD) methodology (Reference 10). Uncertainties on parameters that affect DNB performance are statistically combined to determine a Statistical DNBR limit (SDL). Using BW-C CHF correlation, Reference 9, a generic SDL of 1.43 was calculated using a set of generic uncertainties specifically calculated for Oconee. The system parameter uncertainties used in Reference 10 and given in Table 6-1 bound the uncertainties specifically calculated for Oconee. The Oconee 2 Cycle 18 nominal thermal-hydraulic design conditions are given in Table 6-2.

To provide design flexibility, margin is added to the SDL to determine a design DNBR limit (DDL). For the generic Mark-B10E/G/L and Oconee 2 Cycle 18 analyses, the DDL is 1.50 (5.0% margin above the SDL). In order to allow for up to 5 °F ΔTc operation, either a 2% DNB penalty will be applied to the available SDL margin and/or the maximum operational allowable radial peaks will be penalized by 1%.

One Mk-B11 Lead Test Assembly (LTA) will be reinserted for the third and final cycle in the O2C18 core design.

Table 6-1
System Uncertainties Included in the
Statistical Core Design Analysis

Reference 10

Parameter		Uncertainty	Distribution
Core power		+/- 2 %	Normal
RCS flow	4 Pump:	+/- 2.0 %	Normal
	3 Pump:	+/- 3.2 %	
	2 Pump:	+/- 4.2 %	
Pressure		+/- 30 psi	Normal
Inlet Temperature		+/- 2 deg F	Normal

Table 6-2.
Nominal Thermal-Hydraulic Design Conditions
Oconee 2 Cycle 18

		Generic	Cycle 18
Design Power level, MW_{th}		2568	2568
System pressure, psia		2200	2200
Reactor coolant flow, % design flow		107.5	107.5
Design flow, gpm		352,000	352,000
Core bypass flow, %		7.0	6.3
Vessel temperature at 100% FP, °F			
	Inlet	555.8	555.8
	Outlet	602.2	602.2
Reference design FΔH		1.714	1.714
Reference design axial shape		1.5 Cosine	1.5 Cosine
Active Fuel Length, inches		142.3	142.29 (B10G/L) 140.733 (B10E) 143.05 (B11)
Average heat flux at 100%FP, 10^3 Btu/hr-ft^2		178	178 (B10G/L) 176 (B10E) 183 (B11)
CHF correlation		BW-C	BW-C (B10E/G/L) BWCMV (B11)
Statistical DNBR limit		1.43	1.43
Design DNBR limit		1.50	1.50
Hot Channel Factors	Power Factor, Fq	Note 1	Note 1
	Local Heat Flux, Fq"	N/A	N/A
	Flow Area	Note 1	Note 1

Note:
1. A Fq Hot Channel Factor of 1.0132 (Mark-B10 fuel)/1.0133 (Mark-B11 fuel) and a flow area of 0.97 was used in the derivation of the SDL.

7. ACCIDENT ANALYSES

7.1 Safety Analysis

In order to determine the effects of this reload and to ensure that the thermal performance during hypothetical incidents is not degraded, each UFSAR accident analysis has been evaluated.

The following thermal-hydraulic system transients are reanalyzed utilizing the Duke Power transient analysis methods:

- Startup Accident
- Rod Withdrawal At Power Accident
- Moderator Dilution Accident
- Cold Water Accident
- Loss of Coolant Flow Accidents
- Locked Rotor Accident
- Control Rod Misalignment Accidents
- Turbine Trip Accident
- Steam Generator Tube Rupture Accident
- Rod Ejection Accident
- Steam Line Break Accidents
- Small Steam Line Break Accidents

The analytical models employed in all of the above analyses are based upon those given in Reference 1. The results of these analyses (i.e., UFSAR markups) are presented in Section 8 of this report.

The radiological consequences for the following events are reanalyzed due to changes in the thermal-hydraulic analysis results, as well as changes in the dose analysis methodology.

- Steam Generator Tube Rupture
- Rod Ejection
- Steam Line Break Accidents
- Waste Gas Tank Rupture Accident

The dose analysis methodology and associated UFSAR changes will be presented in a subsequent submittal.

7.2 ECCS Analysis

LOCA analyses, applicable to the B&W designed Oconee Units 1, 2 and 3 operated by Duke Power Company, have been performed by Framatome Technologies Incorporated (FTI). The LOCA evaluation model, which has been approved by the NRC, is described in topical report BAW-10192P-A (Reference 11). The LOCA analyses comply with the criteria outlined in 10 CFR 50.46:

1. Peak cladding temperature (PCT) shall not exceed 2200 °F.
2. The percentage of local cladding oxidation shall not exceed 17%.
3. The maximum hydrogen generated during the transient shall not exceed that which would be generated by the oxidation of 1% of the fuel cladding.

4. Calculated changes in core geometry shall be such that the core remains amenable to cooling.
5. The mode of long term cooling shall be established.

Recently, FTI has identified significant PCT increases associated with both reactor coolant pump (RCP) type and two-phase degradation models used in current Oconee RELAP5-based LOCA linear heat rate (LHR) licensing analyses (PSC 1-99). Duke notified the NRC of this LOCA error via Reference 12. FTI reanalyzed the LHR limits expected to have the most significant PCT increase (BOL Mark-B10F fuel) and found that the PCT could increase by 186 °F, but the maximum PCT for this case was 2150 °F. The PCT increases for all other LHR limits are expected to be bounded by this result. This maximum PCT value remains below the 2200 °F limit required by 10 CFR 50.46. As shown in the Core Operating Limits Report for Oconee 2 Cycle 18, no changes to the linear heat rates or core operating limits are required as a result of this reanalysis. All other LOCA results were found to be in conformance with the five criteria of 10 CFR 50.46, thus demonstrating conservative results for the operation of Oconee 2 Cycle 18.

8. PROPOSED MODIFICATIONS TO LICENSING BASIS DOCUMENTS

Revisions to the Technical Specifications, Core Operating Limits Report (COLR) and the Updated Final Safety Analysis Report (UFSAR) have been proposed for Cycle 18 operation. These revisions reflect changes in reload analysis methodology beginning with this core. Although many of the changes to the Technical Specification Bases are editorial in nature, they are included in this submittal for completeness. Table 8-1 lists the Technical Specification and Bases changes.

Changes to the COLR were recently initiated with implementation of the Improved Technical Specifications (ITS) at Oconee Nuclear Station. The ITS-related changes are not identified again in this submittal. Table 8-2 lists the changes in the COLR that are a result of implementing the new DPC-NE-3005-P methodology. The entire Oconee Unit 2 Cycle 18 COLR is included in this submittal for completeness.

Changes to Chapter 15 of the UFSAR are generally wholesale in nature, with the exception of the following events which are unchanged at this time:

15.10 – Waste Gas Tank Rupture Accident
15.11 – Fuel Handling Accidents
15.14 – Loss of Coolant Accidents
15.15 – Maximum Hypothetical Accident
15.16 – Post-Accident Hydrogen Control

The dose analysis methodology and associated UFSAR changes will be presented in a subsequent submittal.

Table 8-1 Technical Specification Changes

Specification	Description of Change
ITS 3.4.1	Modifies a note in the "Surveillance Requirements" for "RCS Pressure, Temperature and Flow DNB Limits" specification concerning how the loop average temperature (Tavg) limits are applied
ITS 3.4.10	Increases PSV lift setpoint tolerance from 1% to 3%
ITS 3.7.4	Modifies ADV flow path requirements consistent with SGTR, integrates SBLOCA requirements
ITS 3.9.7	Specification added to require isolation of unborated water sources during refueling
ITS 5.6.5	Updates referenced topical reports utilized to determine the core operating limits.
B 3.1.4	Revises ejected rods worths consistent with DPC-NE-3005-PA
B 3.3.1	Revises Applicable Safety Analyses section to be consistent with DPC-NE-3005-PA with respect to MSLB analysis.
B 3.3.15	Revises Background and Applicable Safety Analyses sections to be consistent with MSLB analyses documented in DPC-NE-3003 and DPC-NE-3005
B 3.4.1	Revises LCO and SR wording on how the loop average temperature (Tavg) limits are applied
B 3.4.10	Revises text per increasing PSV lift setpoint tolerance from 1% to 3%
B3.7.2	Revises Applicable Safety Analyses section to be consistent with MSLB analyses documented in DPC-NE-3003 and DPC-NE-3005
B 3.7.4	Modifies ADV flow path wording consistent with SGTR, integrates SBLOCA requirements
B 3.9.7	Adds Bases per new specification ITS 3.9.7

Table 8-2 Core Operating Limits Report Changes

Specification	Description of Change
ITS 3.1.3	Revised the Moderator Temperature Coefficient (MTC) limits to reflect assumptions in the new UFSAR Chapter 15 methodology
ITS 3.4.1	Revised the Departure from Nucleate Boiling (DNB) parameter for RCS loop pressure to reflect assumptions in the new UFSAR Chapter 15 methodology.
ITS 3.4.1	Revised Tave vs ΔTc requirements to reflect assumptions in the new UFSAR Chapter 15 methodology
ITS 3.4.1	Revised DNB parameter for RCS loop total flow to reflect assumptions in the new UFSAR Chapter 15 methodology.

REFERENCES

1. DPC-NE-3005-P, “UFSAR Chapter 15 Transient Analysis Methodology,” Duke Power Company, Oconee Nuclear Station, Rev. 1 (SER Pending).

2. Updated Final Safety Analysis Report, Oconee Nuclear Station, Duke Power Company.

3. Oconee Unit 2, Cycle 14 - Reload Report, DPC-RD-2022, Duke Power Company, May 1993.

4. DPC-NE-2008P-A, Duke Power Company Fuel Mechanical Reload Analysis Methodology using TACO3, (SER Dated April 3, 1995).

5. Program to determine In-reactor Performance of B&W Fuels – Cladding Creep Collapse, BAW-10084P-A, Rev. 3, Babcock & Wilcox Co., Lynchburg, Virginia, July 1991.

6. TACO3 – Fuel Pin Thermal Analysis Computer Code, BAW-10162P-A, Babcock & Wilcox, November 1989.

7. Oconee Nuclear Station Nuclear Design Methodology Using CASMO-3/SIMULATE-3P, DPC-NE-1004A, Duke Power Company, Charlotte, North Carolina, November 1992.

8. DPC-NE-2003P-A, Oconee Nuclear Stations Core Thermal- Hydraulic Methodology Using VIPRE-01, Duke Power Company, (SER Dated July 19, 1989).

9. BAW-10143P-A, BWC Correlation of Critical Heat Flux, Babcock & Wilcox, April 1985.

10. DPC-NE-2005P-A, Rev. 1, Duke Power Company, Thermal-Hydraulic Statistical Core Design Methodology, November 1996.

11. BAW-10192-PA, “BWNT LOCA – BWNT Loss-of-Coolant Accident Evaluation Model for Once-Through Steam Generator Plants,” Rev. 0, (SER Dated February 18, 1997).

12. Letter from M. S. Tuckman (Duke) to USNRC, “Duke Energy Corporation, Oconee Nuclear Station, Units 1, 2 and 3, Docket Numbers 50-269, 50-270, and 50-287, Report Pursuant to 10CFR50.46, Error in LOCA Analysis,” February 4, 1999.