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JAMES A. FITZPATRICK NUCLEAR POWER PLANT LOCA DRYWELL TEMPERATURE ANALYSIS AT POWER UPRATE CONDITIONS

T. H. Chuang
S. K. Rhow

NEW YORK POWER AUTHORITY
DOCUMENT REVIEW STATUS

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1 ☒ ACCEPTED
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Approved by: C. H. Stoll
C. H. Stoll, Project Manager
FitzPatrick Power Uprate Project

GE Nuclear Energy
175 Curtner Avenue
San Jose, CA 95125

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ABSTRACT

An analysis of the drywell temperature response to a postulated loss-of-coolant accident (LOCA) has been performed for the James A. FitzPatrick Nuclear Power Plant at 104.1 % power uprate conditions to update the drywell temperature envelope for equipment qualification. Three different sizes of steam line break (0.01, 0.1 and 0.75 ft^2) were evaluated. Containment sprays were assumed to be initiated according to the EOPs, with a minimum ten-minute operator action time for both drywell and wetwell sprays.

A new drywell temperature envelope at the power uprate conditions is provided as a function of time in a table as well as a plot. The calculated drywell temperature never exceeds the peak value of 340 °F specified in NUREG-0588. The highest temperature of 330 °F occurs in the first 200 seconds. The temperature decreases to 210 °F at 86,400 seconds (one day) into the event, and to 100 °F at one year.

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1. INTRODUCTION

In the event of a postulated loss-of-coolant accident (LOCA), high energy coolant is released from the reactor vessel. For breaks inside the drywell of the primary containment, the release of steam or liquid will increase the temperature and pressure of the drywell atmosphere. Spray cooling is provided in both the drywell and wetwell of the primary containment at the James A. FitzPatrick Nuclear Power Plant (FitzPatrick), via the containment spray mode of the Residual Heat Removal (RHR) system. As described in Reference 1, water pumped from the suppression pool flows through the RHR heat exchangers and can be diverted to either or both of the drywell and wetwell. These containment spray systems condense steam that may exist in either compartment and, therefore, substantially reduce the pressure and temperature in the containment. Two separate lines with separate spray ring headers provide spray cooling in the drywell. Each of these spray ring headers has a series of spray nozzle headers connected to the ring header. These spray nozzle headers in turn have a number of spray nozzles along the length of the spray nozzle headers.

Containment sprays are utilized during emergency scenarios as part of the Emergency Operating Procedures (EOPs) (Ref. 2) to mitigate excessive containment temperature and pressure, and to limit the duration of high drywell temperature for equipment qualification. Safety related equipment within the drywell must be capable of operating under accident conditions. NUREG-0588 (Ref. 3) requires that safety-related equipment is to be qualified for the temperature profile specified in that document or, alternatively, a plant specific containment analysis can be performed to establish a plant-specific profile, if appropriate.

For FitzPatrick, a plant-unique drywell temperature analysis was previously performed, as reported in Reference 4, to provide a drywell temperature time history for use in equipment qualification. This drywell temperature history was based on the analysis of steam line breaks at the current rated conditions. Since then, power uprate has been planned for FitzPatrick (Ref. 5). Consequently, steam line breaks analyzed in Reference 3 have been re-analyzed at power uprate conditions to update the drywell temperature time history. This report provides the results of the drywell temperature evaluation performed at the uprated power.

Thus, for FitzPatrick power uprate the present analysis reported in this report supersedes the Reference 4 analysis.

2. SUMMARY

Steam line breaks (0.01, 0.1, and 0.75 ft^2), which were previously analyzed at the current rated conditions, have been re-analyzed for the 104.1 % power uprate (Ref. 5) to develop a drywell temperature history for use in equipment qualification at power uprate conditions. To analyze these breaks over a period of one year, two types of calculations were performed: 1) detailed calculations for the early part of the accident, and 2) long-term energy balance calculations from the end of the detailed calculations to one year. Containment parameters (such as the drywell volume and initial temperature) used in the present analysis are consistent with those used in the containment evaluation described in the Reference 5 power uprate report. The containment sprays were assumed to be initiated according to the EOPs, with minimum time requirements imposed on the operator's action to allow for a reasonable amount of time required to initiate the sprays. A ten (10) minute operator action time, as a minimum, is assumed for actuation of wetwell sprays, and for drywell spray actuation, as well. The containment spray flow rates were assumed to be 7,150 gpm for drywell spray and 600 gpm for wetwell spray, as specified in the FitzPatrick RHR design basis document (Ref. 1).

Table 2-1 shows the drywell temperature profile enveloping the drywell temperature responses obtained from the analysis of the three steam line break sizes at power uprate conditions for FitzPatrick. These tabulated values are plotted in Figure 2-1. The calculated drywell temperature for FitzPatrick never exceeds the peak temperature value of 340 °F specified in NUREG-0588. The highest temperature envelope is 330 °F for the first 200 seconds. The drywell temperature envelope decreases to 210 °F at 86,400 seconds (1 day) into the accident, and to 100 °F at one year.

Table 2-1

FitzPatrick Drywell Temperature Envelope at Power Uprate Conditions

Time After Accident	Drywell Temperature (°F)
0 - 200 sec	330
200 - 600 sec	330 - 325 linearly
600 - 2400 sec	325 - 295 linearly
2400 - 54,000 sec (40 min - 15 hr)	295 - 215 linearly
54,000 - 86,400 sec (15 hr - 1 day)	215 - 210 linearly
86,400 - 1.728E+05 sec (1 - 2 days)	210 - 190 linearly
1.728E+05 - 4.32E+05 sec (2 - 5 days)	190 - 160 linearly
4.32E+05 - 8.64E+05 sec (5 - 10 days)	160 - 140 linearly
8.64E+05 - 1.728E+06 sec (10 - 20 days)	140 - 130 linearly
1.728E+06 - 3.456E+06 sec (20 - 40 days)	130 - 120 linearly
3.456E+06 - 8.64E+06 sec (40 - 100 days)	120 - 110 linearly
8.64E+06 - 1.728E+07 sec (100 - 200 days)	110 - 105 linearly
1.728E+07 - 3.154E+07 sec (200 days - 1 year)	105 - 100 linearly

3. ANALYSIS

3.1 Method of Analysis

As in Reference 4, three different steam line break sizes: 0.01, 0.1, and 0.75 ft^2, were analyzed as long-term limiting break transients in the present evaluation. Steam line breaks, rather than liquid line breaks, will result in higher drywell temperatures since they transfer higher energy to the drywell. As discussed in Reference 4, steam line breaks larger than 0.75 ft^2 will result in rapid depressurization, which will cause flashing of saturated water, two-phase level swell, and, consequently, two-phase flow from the break. The drywell temperature resulting from the two-phase break flow will be less than the temperature from a steam break.

The drywell and suppression chamber (wetwell airspace and suppression pool), initially at different temperatures, approach thermal equilibrium as the accident progresses over a long period of time. To analyze these breaks over a period of one year, two types of calculations were performed: 1) detailed calculations until the drywell temperature is comparable to the suppression pool temperature (15 hours into the accident), and 2) long-term (from 15 hours to one year) energy balance calculations.

3.2 Detailed Short-Term Calculations

The detailed calculations use the GE computer code SHEX to calculate the drywell temperature response for the early part (15 hours) of the accident (up to one year). At the end of this period, both compartments approach thermal equilibrium.

The SHEX code was used for the FitzPatrick power uprate containment analysis (Ref. 5). SHEX is based on analytical models described in References 6 and 7. SHEX uses a coupled reactor pressure vessel and containment model to calculate the containment pressure and temperature response during transient events or for LOCAs. The code performs fluid mass and energy balance calculations separately on the reactor pressure vessel, drywell, suppression pool, and suppression chamber airspace. SHEX calculates the reactor water level and pressure, the pressure and temperature for the drywell and suppression chamber airspace, and the suppression pool bulk pool temperature. SHEX also models various modes of operation of related auxiliary systems, such as the Safety Relief Valves (SRVs), Main Steam

Isolation Valves (MSIVs), Emergency Core Cooling System (ECCS), Residual Heat Removal (RHR) system, and the feedwater flow.

The values of containment parameters (such as drywell airspace volume, suppression pool volume, etc.) used as input to the SHEX analysis were the same as those for the Reference 5 power uprate containment evaluation for FitzPatrick. The key input parameters used in the analysis are listed in Table 3-1. The containment sprays were assumed to be initiated according to the EOPs, with minimum time requirements imposed on the operator's action to allow for a reasonable amount of time required to initiate the sprays. If the containment pressure and temperature response reaches the EOP-specified conditions for spray actuation later than the minimum operator action times, the spray actuation times determined by the EOPs are used in the analysis. Specifically, the key assumptions for the present SHEX analysis include the following:

a) The reactor is initially at 102 % of uprated thermal power (102 % of 2,536 MWt or 2,587 MWt) and 1,058 psia steam dome pressure.

b) The ANSI/ANS 5.1-1979 decay heat model (Ref. 8) is used assuming an exposure of 25,700 MWD/st to calculate decay heat power. The same decay heat model was used in the Reference 5 power uprate containment analysis for FitzPatrick.

c) The initial suppression pool temperature is at the technical specification maximum (95 °F). The initial wetwell airspace is the same as this temperature.

d) The initial suppression pool water is at the technical specification minimum (105,923 ft^2).

e) The initial drywell temperature is at its maximum expected value of 135 °F.

f) Initial containment pressure are set to yield low containment pressure responses, which may delay initiation of drywell sprays, which is triggered by high containment pressure according to the EOPs.

g) Heat transfer to the suppression chamber shell from the wetwell airspace and suppression pool is neglected.

h) The drywell heat sink, including the drywell shell and vent system, is considered.

i) The offsite power is lost at the initiation of the accident and is not restored during the entire duration of the accident.

j) Only one RHR loop is available.

k) The RHR system is dedicated to containment spray operation. Reactor cooling is maintained by other available systems (HPCI and LPCS).

l) The drywell and wetwell spray flow rates are 7,150 gpm and 600 gpm, respectively, as specified in the RHR design basis document (Ref. 1).

m) The service water temperature for the RHR system remains at 82 °F throughout the accident.

n) Drywell and wetwell sprays are initiated in accordance with the EOPs. The wetwell sprays are actuated when the wetwell pressure exceeds 2.7 psig (17.4 psia). The drywell sprays are actuated either when the wetwell pressure exceeds 16 psig, or before the drywell temperature reaches 309 F. In addition, minimum operator action times, as described below, are conservatively imposed in actuating containment sprays.

o) A ten (10) minute operator action time, as a minimum, is assumed for actuation of wetwell sprays in those cases where the wetwell pressure reaches 2.7 psig (17.4 psia) earlier than 10 minutes into the accident. A ten (10) minute minimum operator action time is assumed for drywell spray actuation in those cases where drywell sprays should be actuated earlier than this minimum time according to the EOPs.

Thus, three steam line break sizes: 0.01, 0.1, and 0.75 ft^2, have been analyzed and the following describes the analysis results for each break size.

3.2.1 Results for 0.01 ft^2 Steam Line Break

The containment response to a 0.01 ft^2 steam line break is analyzed using the SHEX code. The containment temperature and pressure, and the reactor vessel pressure for this break are plotted in Figures 3-1 through 3-3 for a time period up to 2,400 seconds. Table 3-2 shows the sequence of events for this break.

The reactor scrams automatically on loss of off-site power. At approximately 10 seconds into the accident, SRVs begin actuating on high vessel pressure and closing and opening of SRVs continue to maintain vessel pressure. This SRV cycling of opening and closing can be seen in Figure 3-3. At approximately 140 seconds, the wetwell pressure reaches 2.7 psig (17.4 psia), above which wetwell sprays are to be actuated according to the EOPs. But, it is assumed that wetwell sprays are actuated at 600 seconds. Operation of wetwell sprays has a relatively minor impact on the containment (particularly drywell) pressure and temperature response.

The wetwell pressure continues to increase, and so does the drywell temperature. At approximately 2,400 seconds, drywell sprays are actuated according to the EOPs since the wetwell pressure exceeds 16 psig (30.7psia). The drywell temperature peaks at 292 °F, just prior to actuation of drywell sprays. Operation of drywell sprays results in a rapid decrease in the drywell temperature and pressure due to condensation of steam in the drywell. Wetwell-to-drywell vacuum breakers open and the wetwell pressure also decreases.

The drywell temperature increases again as decay heat generated in the reactor vessel continues to be transferred to the containment. Also, the drywell and wetwell (airspace and pool) temperatures become closer. A second peak of the drywell temperature occurs around 50,000 seconds and the peak value is approximately 210 °F. At the end of the detailed calculations (54,000 seconds) the drywell temperature, which is close to the suppression pool temperature, is decreasing slowly, since heat removal through the RHR exchanger is larger than decay heat plus pump heat from operation of LPCS and containment spray pumps. From this point on, a simple energy balance is performed to calculate the drywell temperature, as described in Section 3.3 of this report.

3.2.2 Results for 0.1 ft^2 Steam Line Break

The containment response to a 0.1 ft^2 steam line break is analyzed using the SHEX code. The containment temperature and pressure, and the reactor vessel pressure for this break are plotted in Figures 3-4 through 3-6 for a time period up to 2,400 seconds. Table 3-3 shows the sequence of events for this break.

The reactor scrams automatically on loss of off-site power. Steam flow from the break (much higher rate than a 0.01 ft^2 break) results in a rapid rise in the drywell temperature. The wetwell pressure also rises quickly. At approximately 8 seconds, the wetwell pressure reaches 2.7 psig (17.4 psia), which is the EOP-specified value for actuation of wetwell sprays. The present analysis delays actuation of wetwell sprays until 600 seconds to allow for a reasonable amount of time to actuate wetwell sprays.

The wetwell pressure continues to increase and at 100 seconds reaches 16 psig (30.7 psia), which is the EOP-specified value for actuation of drywell sprays. Again, the present analysis assumed that the drywell spray actuation is delayed until 600 seconds into the accident to allow for a reasonable time required for spray actuation. At approximately 600 seconds the drywell temperature peaks at 323 °F. At 600 seconds when the drywell sprays are actuated, the drywell experiences a rapid decrease in its airspace temperature due to sprays. Once the drywell sprays are operated, the drywell temperature remains relatively low. As in the case of 0.01 ft^2 break, a second peak of the drywell temperature occurs around 50,000 seconds into the accident and the peak value is approximately 210 °F. Also, the drywell temperature is comparable to the suppression pool temperature and a simple energy balance, as described in Section 3.3, is applied to calculate a long-term temperature response.

3.2.3 Results for 0.75 ft^2 Steam Line Break

The containment response to a 0.75 ft^2 steam line break is analyzed using the SHEX code. The containment temperature and pressure, and the reactor vessel pressure for this break are plotted in Figures 3-7 through 3-9 for a time period up to 2,400 seconds. Table 3-4 shows the sequence of events for this break.

The reactor scrams automatically on loss of off-site power. Steam flow from the break results in a rapid rise in the drywell temperature. At approximately 200 seconds the drywell temperature peaks at 330 °F. The wetwell pressure also rises quickly. At approximately 1 second, the wetwell pressure reaches 2.7 psig (17.4 psia), which is the EOP-specified value for actuation of wetwell sprays. The present analysis delays actuation of wetwell sprays until 600 seconds to allow for a reasonable amount of time to actuate wetwell sprays.

The wetwell pressure continues to increase and, at 10 seconds, reaches 16 psig (30.7 psia), which is the EOP-specified value for actuation of drywell sprays. Again, the present analysis assumed that the drywell spray actuation is delayed until 600 seconds into the accident to allow for a reasonable time required for spray actuation. During this period prior to drywell spray actuation, the drywell temperature decreases slowly from its peak value of 330 °F experienced at 200 seconds. At 600 seconds when the drywell sprays are actuated, the drywell experiences a rapid decrease in its airspace temperature due to sprays. Once the drywell sprays are operated, the drywell temperature remains relatively low. As in the case of 0.01 or 0.1 ft^2 break, a second peak of the drywell temperature occurs around 50,000 seconds into the accident and the peak value is approximately 210 F. Also, the drywell temperature is comparable to the suppression pool temperature and a simple energy balance, as described in Section 3.3, is applied to calculate a long-term temperature response.

3.3 Long-Term Energy Balance Calculations

After the early dynamic response dies out, the drywell, wetwell airspace, and suppression pool approach thermal equilibrium. From this point on, a simple energy balance can be applied to calculate the containment temperature response (i.e., the drywell temperature response) for an extended period of time. Energy input to the containment includes decay heat (which is transferred from the reactor to the containment), and heat from LPCS and RHR pumps. On the other hand, energy is removed from the containment by the RHR heat exchanger (through which the containment spray flow passes). Using the temperature output from the detailed calculations as initial temperature input, the drywell temperature response is calculated over a time period of one year. The results of this long-term energy balance calculation is incorporated into the drywell temperature envelope provided in Table 2-1.

Table 3-1

Key Input Parameters Used in Analysis

Input Parameter	Unit	Value
Initial Reactor Thermal Power (102% of Uprated Power)	MWt	2,587
Initial Reactor Dome Pressure	psia	1,058
Drywell Free Volume	ft^3	154,476
Initial Suppression Pool Volume	ft^3	105,923
Initial Wetwell Airspace Volume	ft^3	114,557
Initial Drywell Pressure (Note 1)	psia	15.9
Initial Drywell Temperature	°F	135
Initial Wetwell Airspace Pressure (Note 1)	psia	14.2
Initial Suppression Pool Temp.	°F	95
Initial Wetwell Airspace Temperature	°F	95
RHR Heat Exchanger K-Value	Btu/sec-°F	141.8
RHR Service Water Temp.	°F	82
Core Spray Flow Rate	gpm	4,725
Drywell Spray Flow Rate	gpm	7,150
Wetwell Spray Flow Rate	gpm	600

Table 3-1 (continued)

Key Input Parameters Used in Analysis

Input Parameter	Unit	Value
Minimum Time to Actuate Containment Sprays (Note 2)	sec	
Drywell Spray	sec	600
Wetwell Spray	sec	600

Notes: (1) Lower initial containment pressures are used to delay actuation of containment sprays.

(2) The 600-second minimum initiation time is the earliest that containment sprays can be actuated even if the wetwell pressure reaches the spray setpoint specified in the EOPs before this minimum initiation time.

Table 3-2

0.01 ft^2 Steam Line Break Accident Sequence

Time (sec)	Event Description
0	A 0.01 ft^2 break in the main steam line occurs inside the drywell. Reactor scram and loss of off-site power occur.
3.5	MSIVs are fully closed.
10	SRVs first open on vessel pressure.
140	The wetwell pressure reaches 2.7 psig (17.4 psia), above which wetwell sprays are to be actuated according to the EOPs. However, wetwell sprays are assumed to be actuated at 600 seconds in the analysis.
600	Wetwell sprays are manually actuated, as assumed in the analysis. The wetwell pressure is 22.7 psia.
2,400	The wetwell pressure has reached 30.7psia. Drywell sprays are manually actuated according to the EOPs. The drywell temperature peaks at 292°F.

Table 3-3

0.1 ft^2 Steam Line Break Accident Sequence

Time (sec)	Event Description
0	A 0.1 ft^2 break in the main steam line occurs inside the drywell. Reactor scram and loss of off-site power occur.
3.5	MSIVs are fully closed.
8	The wetwell pressure reaches 2.7 psig (17.4 psia), above which wetwell sprays are to be actuated according to the EOPs. However, wetwell sprays are assumed to be actuated at 600 seconds in the analysis.
100	Wetwell pressure reaches 16 psig (30.7 psia), above which dry-well sprays are to be actuated per the EOPs. However, drywell sprays are assumed to be actuated at 600 seconds in the analysis.
600	Drywell and wetwell sprays are manually actuated as assumed in the analysis. The drywell temperature peaks at 323°F. The wetwell pressure is 37.4 psia.

Table 3-4

0.75 ft^2 Steam Line Break Accident Sequence

Time (sec)	Event Description
0	A 0.75 ft^2 break in the main steam line occurs inside the drywell. Reactor scram and loss of off-site power occur.
1	The wetwell pressure reaches 2.7 psig (17.4 psia), above which wetwell sprays are to be actuated according to the EOPs. However, wetwell sprays are assumed to be actuated at 600 seconds in the analysis.
3.5	MSIVs are fully closed.
10	Wetwell pressure reaches 16 psig (30.7 psia), above which dry-well sprays are to be actuated per EOP. However, drywell sprays are assumed to be actuated at 600 seconds in the analysis.
200	Drywell temperature peaks at 330°F
600	Drywell and wetwell sprays are manually actuated as assumed in the analysis. The wetwell pressure is 40.1 psia.

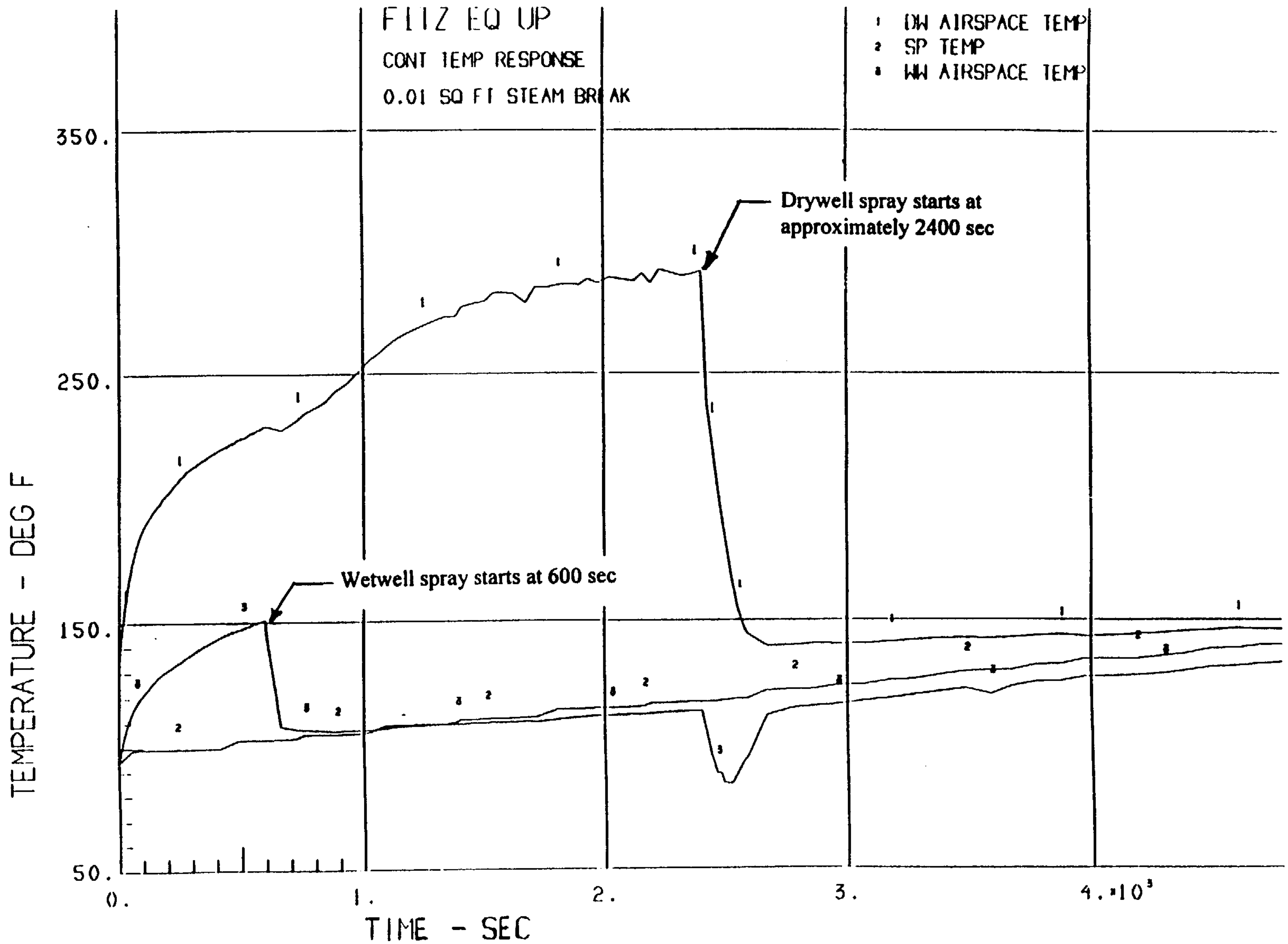

Figure 3-1 **Containment Temperature Response to A 0.01 ft^2 Steam Line Break - FitzPatrick Power Uprate Drywell Temperature Response Analysis**

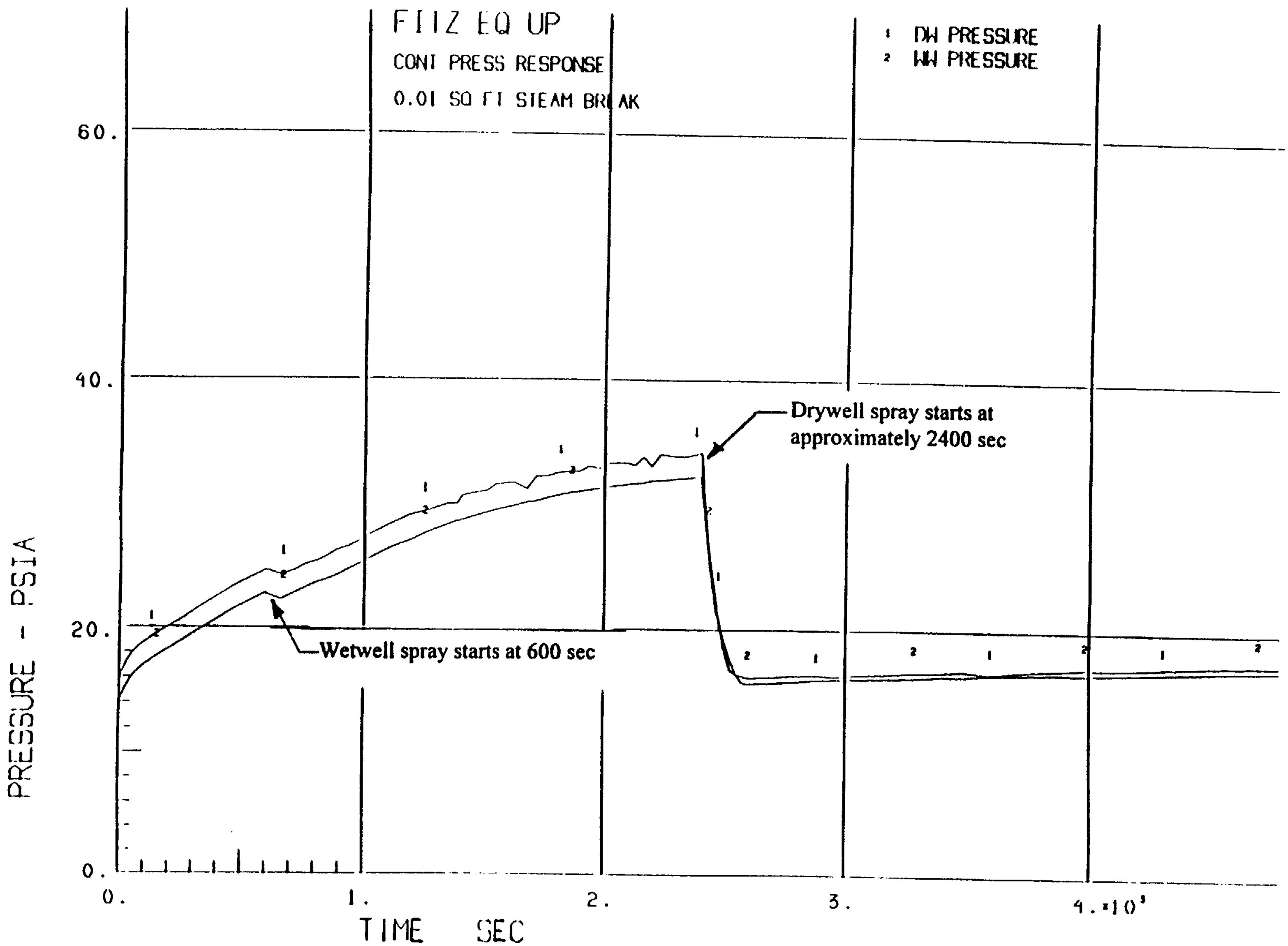

Figure 3-2 Containment Pressure Response to A 0.01 ft² Steam Line Break - FitzPatrick Power Uprate Drywell Temperature Response Analysis

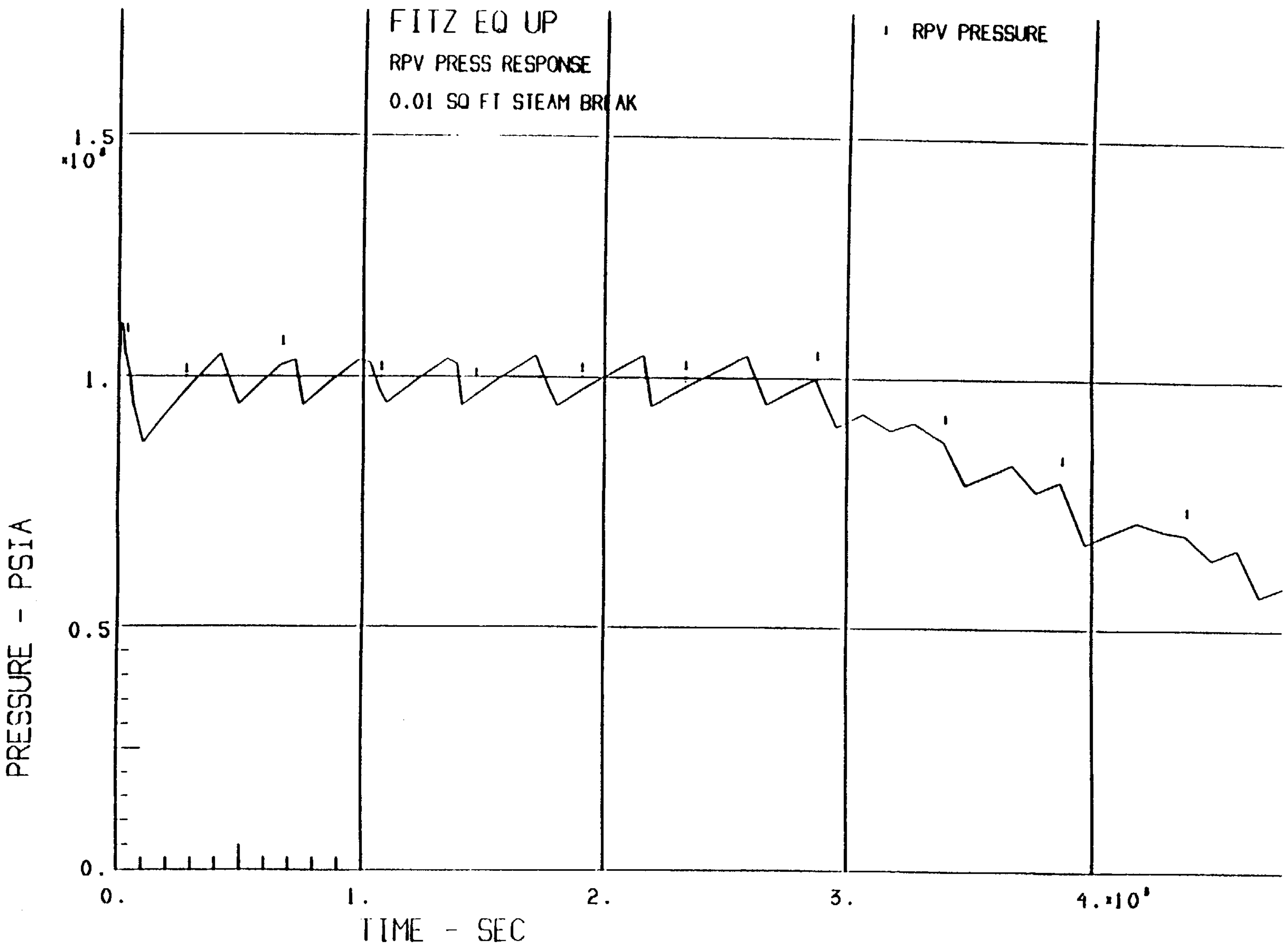

Figure 3-3 RPV Pressure Response to A 0.01 ft² Steam Line Break - FitzPatrick Power Uprate Drywell Temperature Response Analysis

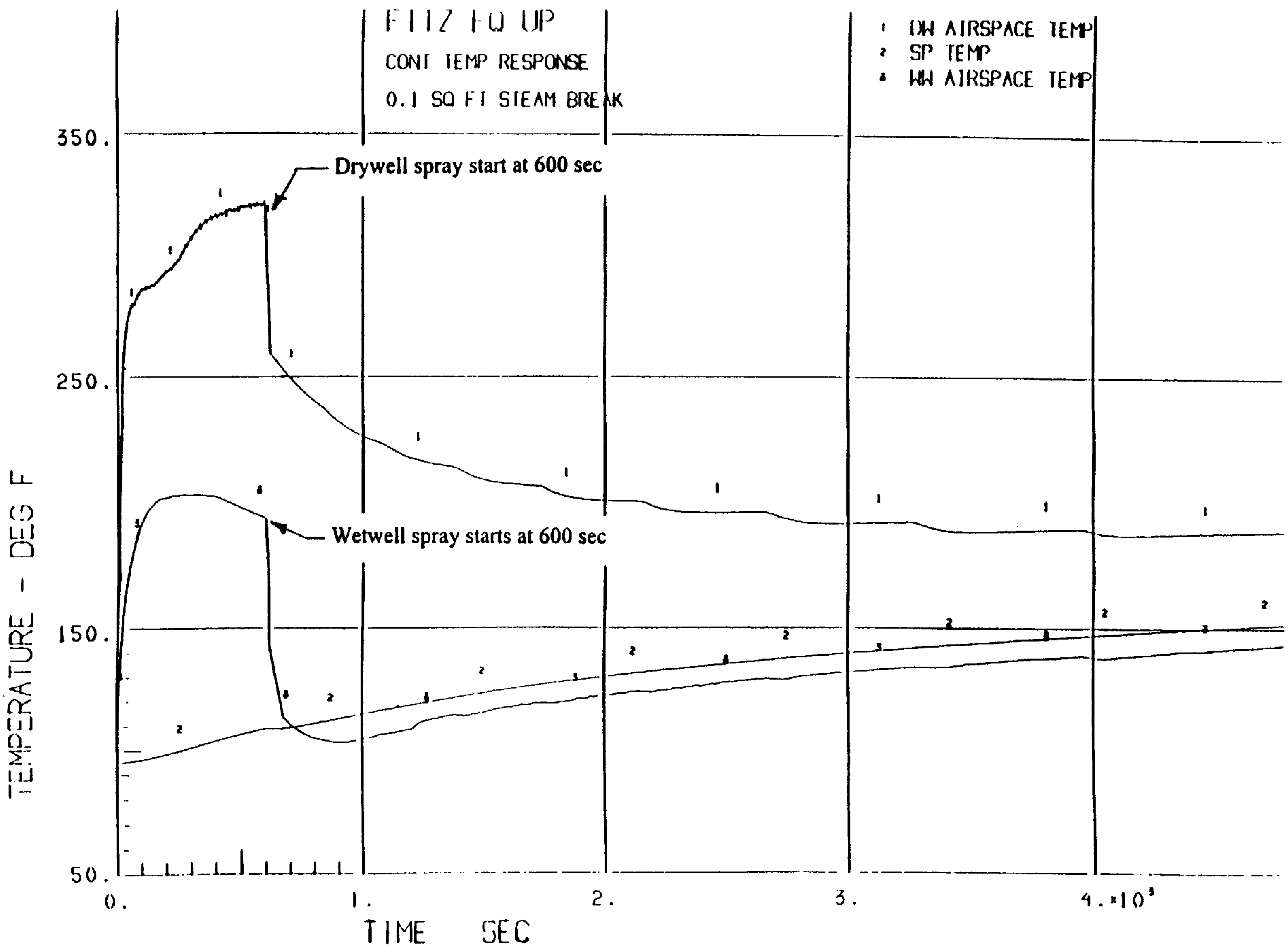

Figure 3-4 Containment Temperature Response to A 0.1 ft^2 Steam Line Break - FitzPatrick Power Uprate Drywell Temperature Response Analysis

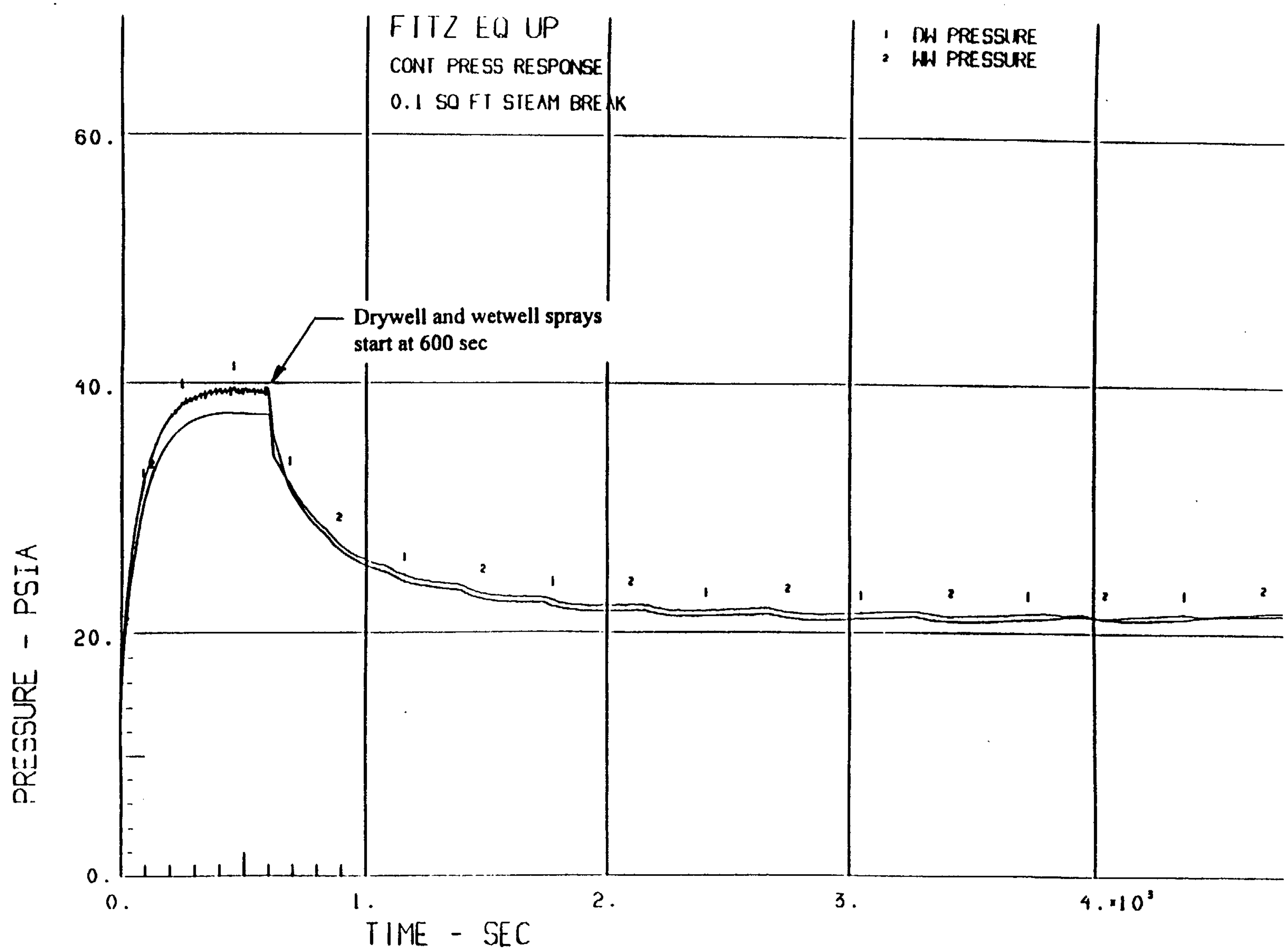

Figure 3-5 **Containment Pressure Response to A 0.1 ft^2 Steam Line Break - FitzPatrick Power Uprate Drywell Temperature Response Analysis**

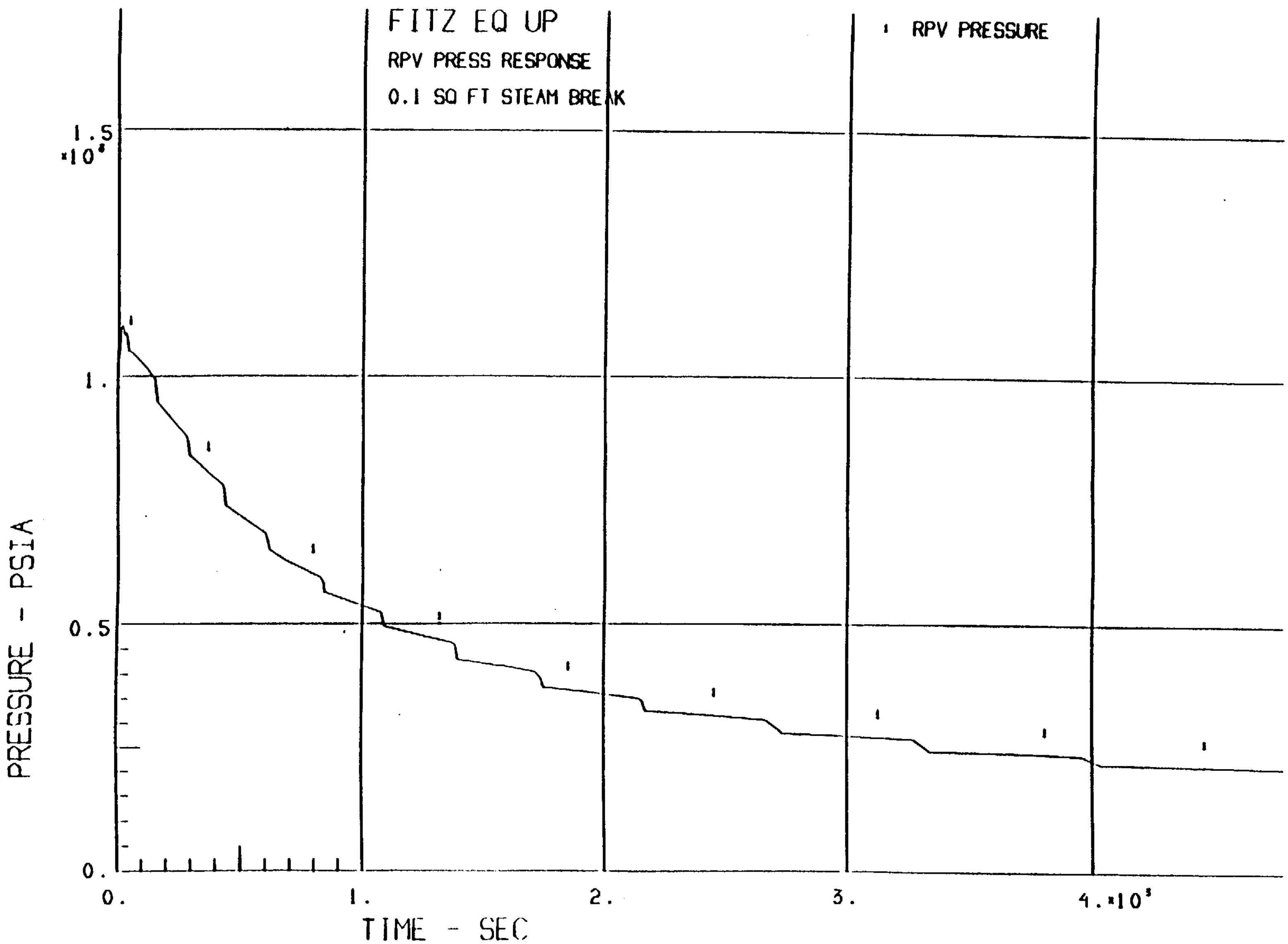

Figure 3-6 RPV Pressure Response to A 0.1 ft^2 Steam Line Break - FitzPatrick Power Uprate Drywell Temperature Response Analysis

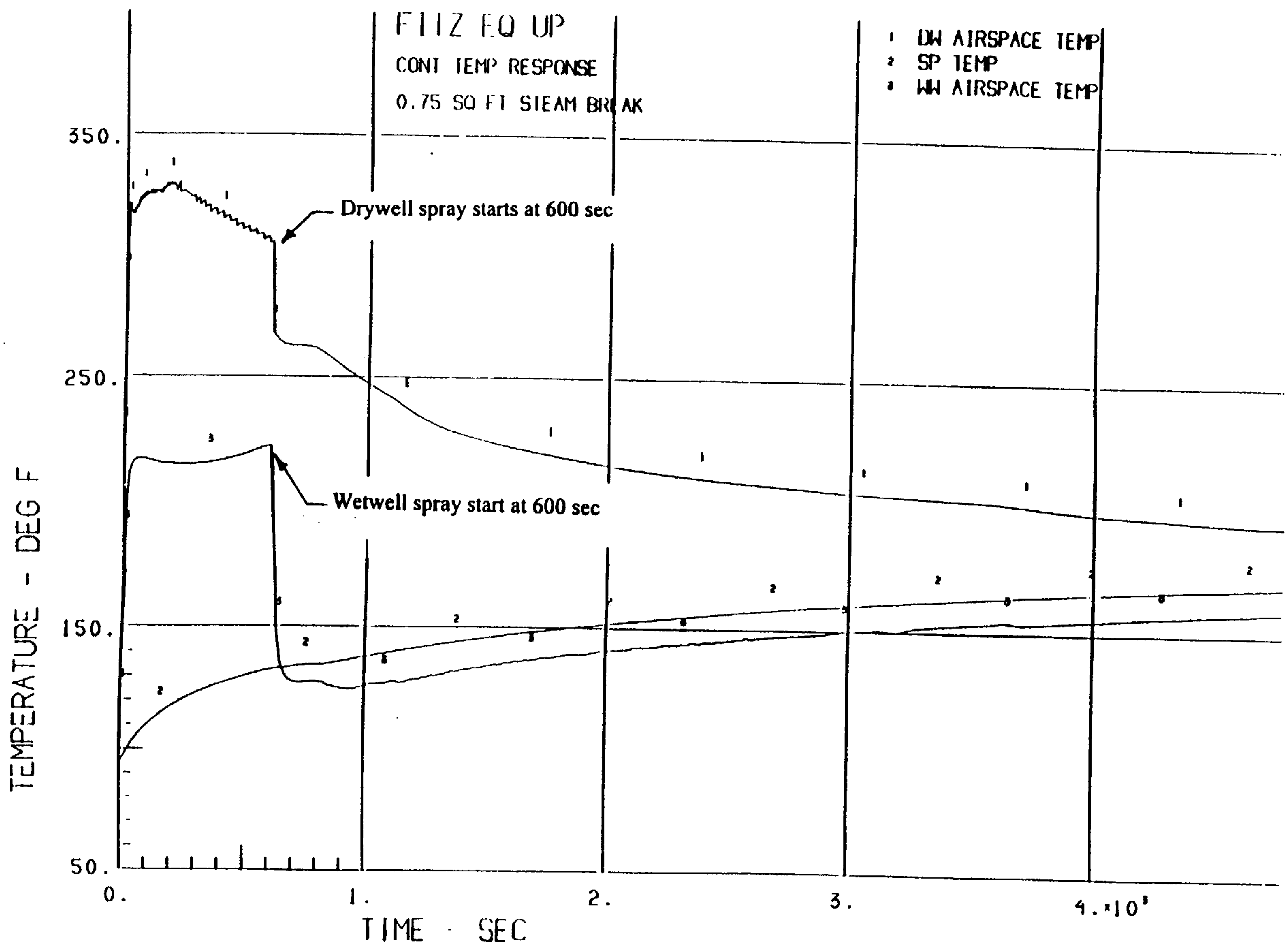

Figure 3-7 **Containment Temperature Response to A 0.75 ft^2 Steam Line Break - FitzPatrick Power Uprate Drywell Temperature Response Analysis**

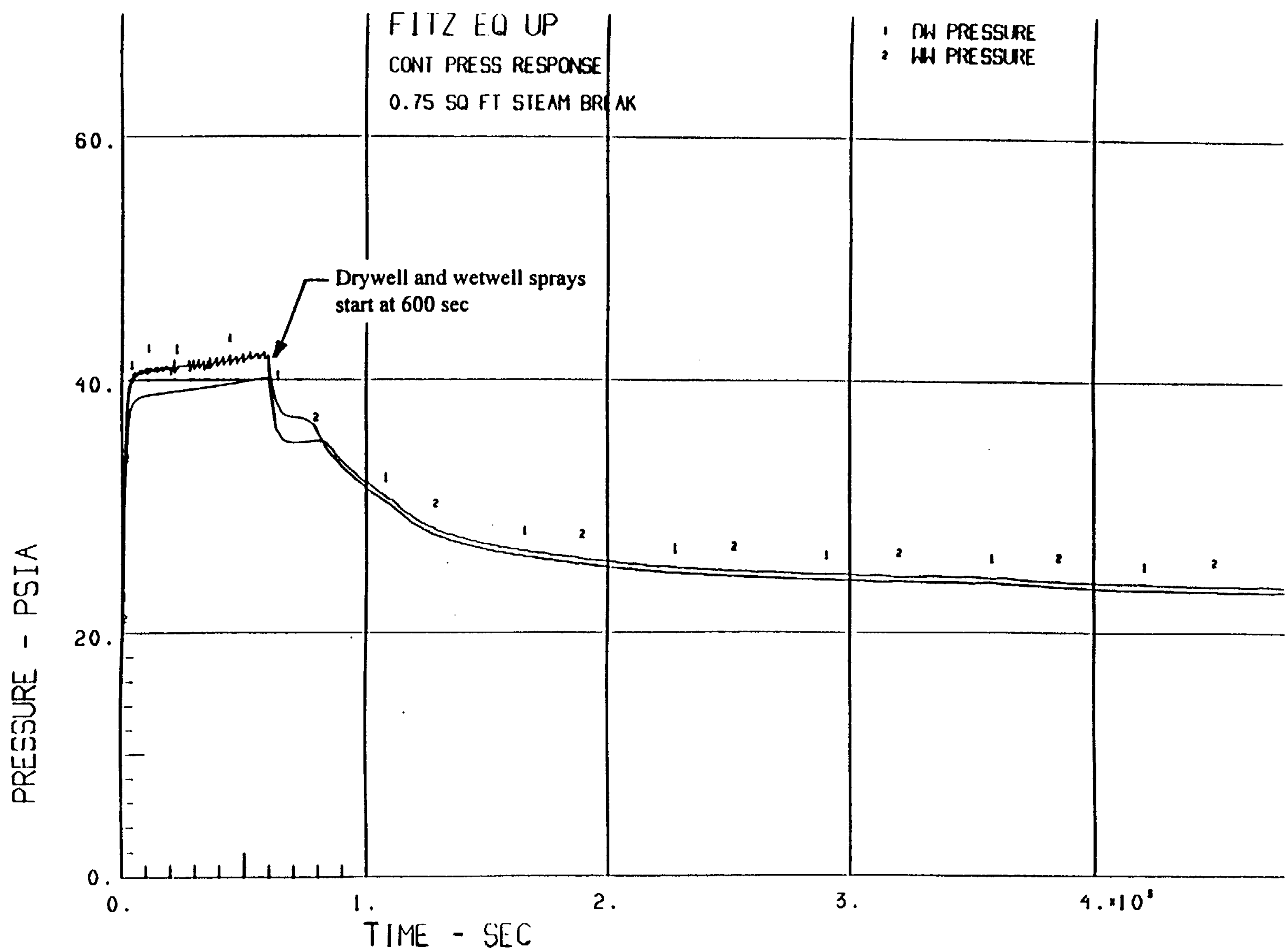

Figure 3-8 **Containment Pressure Response to A 0.75 ft^2 Steam Line Break - FitzPatrick Power Uprate Drywell Temperature Response Analysis**

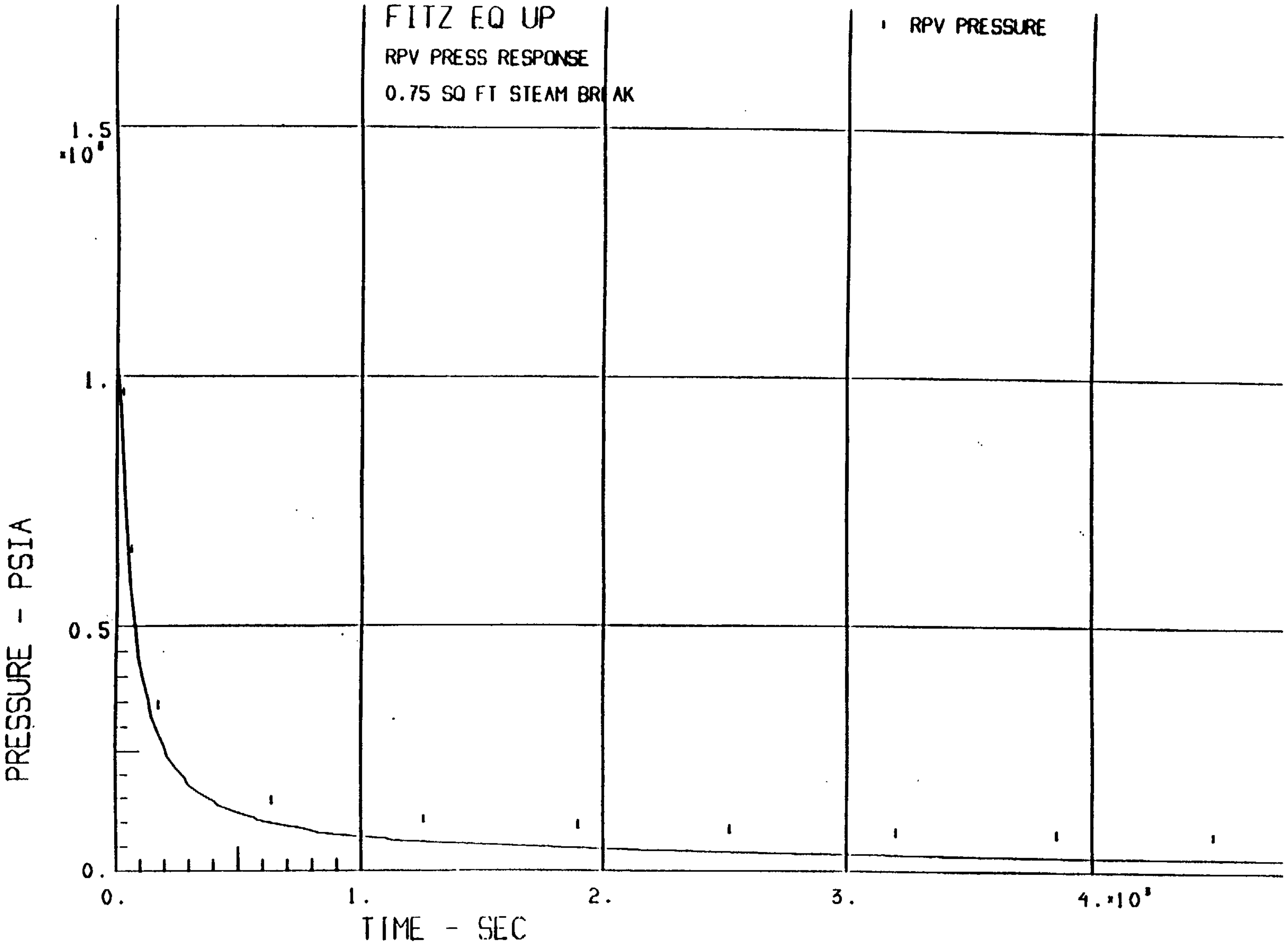

Figure 3-9 RPV Pressure Response to A 0.75 ft² Steam Line Break - FitzPatrick Power Uprate Drywell Temperature Response Analysis

4. REFERENCES

1) Design Basis Document DBD-010, Rev. 0, New York Power Authority, James A. FitzPatrick Nuclear Power Plant, Residual Heat Removal System, August 1993.

2) FitzPatrick Emergency Operating Procedure, EOP-4, "Primary Containment Control," Rev. 0, June 1990.

3) NUREG-0588, "Environmental Qualification of Safety-Related Electrical Equipment," Rev. 1, U.S. NRC, July 1981.

4) General Electric Report AE-89-0984, "James A. FitzPatrick Nuclear Power Plant Small and Intermediate Break LOCA Drywell Temperature Analysis and Drywell Spray Study," October 1984.

5) GE Document NEDC-32016P-1, "Power Uprate Safety Analysis for James A. FitzPatrick Nuclear Power Plant," Rev. 1, April 1993.

6) GE Document NEDO-10320, "The GE Pressure Suppression Containment System Analytical Model," March 1971.

7) GE Document NEDO-20533, "The General Electric Mark III Pressure Suppression Containment System Analytical Model," June 1974.

8) "Decay Heat Power in Light Water Reactor," ANSI/ANS 5.1 - 1979, Approved by the American National Standards Institute, August 29, 1979

9) GE Document 729E211BA, RHR Process Diagram, Rev. 4, December 1977.

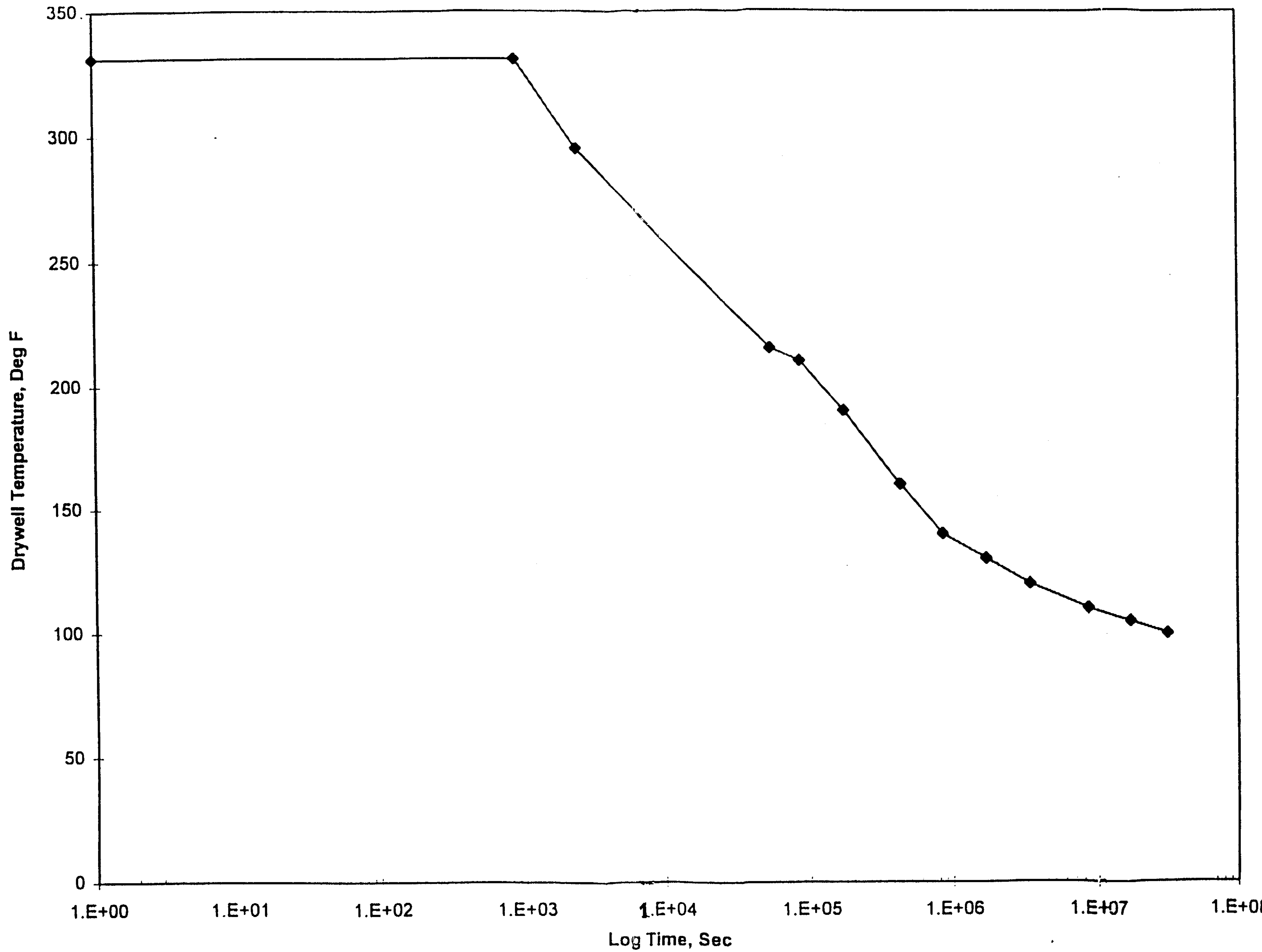

Figure 2-1 FitzPatrick Drywell Temperature Envelope for Power Uprate

NEW YORK POWER AUTHORITY
JAMES A. FITZPATRICK NUCLEAR POWER PLANT
ABNORMAL OPERATING PROCEDURE

LOSS OF SHUTDOWN COOLING*
AOP-30
REVISION 11

REVIEWED BY: PLANT OPERATING REVIEW COMMITTEE

MEETING NO. NA DATE NA

APPROVED BY: [signature] DATE 5/27/98
RESPONSIBLE PROCEDURE OWNER

APPROVED BY: [signature] for D. Lindsey DATE 5/27/98
GENERAL MANAGER - OPERATIONS

EFFECTIVE DATE: 6/1/98

FIRST ISSUE ☐ FULL REVISION ☐ LIMITED REVISION ☒

REFERENCE USE	TSR
TECHNICAL	

PERIODIC REVIEW DUE DATE 05/2003

REVISION SUMMARY SHEET

REV. NO.	CHANGE AND REASON FOR CHANGE
11	1. Updated title page to reflect completion of periodic review.
	2. Revised Step C.1.2.a and added Attachment 2 to provide guidance for verifying low RPV water level initiations/isolations.
	3. Added operating procedure references for performance of Steps C.1.2.c.2, C.2.2.a, C.2.2.c, C.2.3.a, C.2.3.e.3, and C.2.3.e.4.
	4. Updated Attachment 1 to include additional references.
	5. Added "RPV metal temperatures trending upward" to Section A, Symptoms.

TABLE OF CONTENTS

A. **SYMPTOMS**

- RHR pump trip
- Shutdown cooling isolation
- Reactor coolant temperature trending upward
- RPV metal temperatures trending upward
- Change (up or down) in RPV water level
- Drain sump high level alarms

B. **AUTOMATIC ACTIONS**

NOTE: Automatic actions occur if loss of shutdown cooling is due to a shutdown cooling isolation.

- Group II isolation of primary containment
- Reactor Building isolation
- Standby Gas Treatment System initiation

C. **PROCEDURE**

NOTE: Perform Subsections C.1 and C.2 concurrently.

C.1 **RPV Water Level Control**

C.1.1 **IF** the loss of shutdown cooling is due to a coolant leak,
AND the RPV head is removed,
THEN execute AOP-53, concurrently with this procedure.

C.1.2 **IF** the RPV head is installed,
THEN control RPV water level as follows:

a. **IF** RPV water level lowers to 177 inches while performing this procedure,
THEN verify isolation/initiations per Attachment 2.

b. Restore RPV water level to **BETWEEN** 234.5 inches and 270 inches using one or more of the following systems:

- CRD per OP-25
- Condensate/Feedwater per OP-2A and OP-3
- Core Spray per OP-14
- RHR per OP-13A

c. **IF** RPV water level cannot be maintained above 234.5 inches,
THEN perform the following:

1) Maintain RPV water level above 177 inches.

2) Start one or both RWR pumps per OP-27.

d. **IF** RPV water level cannot be maintained above 177 inches,
THEN maintain RPV water level above 0 inches.

e. **IF** RPV water level cannot be maintained above 0 inches,
AND all available systems in Step C.1.2.b are running,
THEN augment RPV water level control using one or both of the following systems:

- RHR Service Water Crosstie per OP-13A
- Fire Water Crosstie per OP-13A

C.2 Reactor Coolant Temperature Control

CAUTION

If RPV water level is **LESS THAN** 234.5 inches with no RWR pumps running, reactor coolant temperature indications could become invalid due to insufficient natural circulation.

C.2.1 Monitor reactor coolant temperature as follows:

a. **IF** an RWR pump is running,
THEN monitor inservice RWR loop inlet temperature.

b. **IF** there is flow through RWCU,
THEN monitor RWCU inlet temperature.

c. **IF** RWR pumps are shutdown,
AND RWCU is shutdown,
THEN monitor FDWTR NOZZLE N4B INBD temperature on RX VESSEL TEMP recorder 02-3TR-89 at panel 09-21.

NOTE: Step d uses a thermocouple reader to monitor feedwater nozzle inboard temperature.

d. **IF** a loss of power prevents monitoring reactor coolant temperature using permanent plant instrumentation,
THEN perform the following:

1) Obtain SM permission to connect thermocouple reader inside panel 09-21. ____ Init

2) Have I&C perform the following at panel 09-21:

a) Disconnect the following leads from input 1 on 02-3TR-89:

- Blue (+) (_)
- Red (-) (_)

____ I&C

b) Connect thermocouple reader to blue (+) and red (-) leads. ____ I&C

(Step d continued on next page)

d. (Cont)

3) Monitor reactor coolant temperature using thermocouple reader.

4) **WHEN** permanent plant instrumentation for monitoring reactor coolant temperature is available, perform the following:

a) Have I&C disconnect thermocouple reader from blue and red leads. ____ I&C

b) Have I&C connect the following leads to input 1 on 02-3TR-89:

- Blue (+) (_)
- Red (-) (_)

____ I&C

c) Notify SM that thermocouple is removed and leads are connected inside panel 09-21. ____

C.2.2 **IF** the RPV head is installed, **THEN** control reactor coolant temperature as follows:

a. Attempt to restore shutdown cooling per OP-13D.

NOTE: Shutdown cooling <u>cannot</u> be restored if both RPS Bus A and RPS Bus B are de-energized.

⬇COMD.1.1

b. **IF** shutdown cooling was lost due to a shutdown cooling isolation caused by a loss of an RPS bus,
AND the RPS bus <u>cannot</u> be immediately restored,
THEN restore shutdown cooling per Subsection C.3 (loss of RPS Bus A) or Subsection C.4 (loss of RPS Bus B).

c. **IF** shutdown cooling <u>cannot</u> be restored within one hour,
OR reactor coolant temperature exceeds 150°F,
THEN verify running or start one or both RWR pumps per OP-27.

(Step C.2.2 continued on next page)

C.2.2 (Cont)

d. Maintain reactor coolant temperature **BETWEEN** 100°F and 200°F as follows:

1) Estimate core decay heat using Attachment 3.

2) Establish an RPV cooldown rate of **LESS THAN** 80°F per hour, using one or more of the methods listed on Attachment 4.

NOTE: The following step must be completed prior to reaching a reactor water temperature of 212°F to satisfy Technical Specification requirements.

e. **IF** reactor coolant temperature cannot be maintained below 200°F, **THEN** perform the following **BEFORE** reactor coolant temperature reaches 212°F:

1) Establish Secondary Containment Integrity.

2) Establish Primary Containment Integrity, if practicable.

3) Secure and restore from any maintenance which has the potential for draining the reactor vessel.

f. **IF** reactor coolant temperature reaches 212°F, **THEN** review emergency action levels to determine if E-Plan entry is required.

g. **IF** reactor coolant temperature exceeds 212°F, **AND** an EOP entry condition exists, **THEN** enter the applicable EOP.

C.2.3 **IF** the RPV head is removed,
THEN control reactor coolant temperature as follows:

a. Attempt to restore shutdown cooling per OP-13D.

NOTE: Shutdown cooling cannot be restored if both RPS Bus A and RPS Bus B are de-energized.

!COMD.1.1

b. **IF** shutdown cooling was lost due to a shutdown cooling isolation caused by a loss of an RPS bus,
AND the RPS bus cannot be immediately restored,
THEN restore shutdown cooling per Subsection C.3 (loss of RPS Bus A) or Subsection C.4 (loss of RPS Bus B).

c. **IF** shutdown cooling cannot be restored within one hour,
OR reactor coolant temperature exceeds 110°F,
THEN verify running or start one or both RWR pumps.

d. Maintain reactor coolant temperature **BETWEEN** 68 and 125°F as follows:

1) Estimate core decay heat using Attachment 3.

2) Establish an RPV cooldown rate of **LESS THAN** 80°F per hour, using one or more of the methods listed in Attachment 4.

NOTE: The following step must be completed prior to reaching a reactor water temperature of 212°F to satisfy Technical Specification requirements.

e. **IF** reactor coolant temperature cannot be maintained below 125°F,
THEN commence the following **BEFORE** reactor coolant temperature reaches 130°F:

1) Establish Secondary Containment Integrity.

2) Evacuate the Reactor Building.

3) Start-up the Standby Gas Treatment System per OP-20.

4) Isolate Reactor Building Ventilation per OP-51A.

f. **IF** reactor coolant temperature reaches 212°F,
THEN review emergency action levels to determine if E-Plan entry is required.

C.3 Restoring Shutdown Cooling After Loss of RPS Bus A

C.3.1 Ensure the following motor control centers are energized to provide power to 10MOV-17 and 10MOV-18:

- 71MCC-156 (600v motor control center bus 115600)
- 71BMCC-4 (reactor building east crescent motor control center)

C.3.2 Obtain SM permission to disable shutdown cooling isolation.

C.3.3 Obtain three electrical jumpers, size #14 AWG or larger.

C.3.4 Do not break continuity between a terminal and the existing lead(s) on that terminal when installing jumpers.

C.3.5 Connect jumper with alligator or bulldog clips between the following terminals in panel 09-41 to allow opening of 10MOV-17:

- BB-19 (_)
- BB-20 (_)

Init

C.3.6 Connect jumper with alligator or bulldog clips between the following terminals in panel 09-41 to allow remote manual operation of 10MOV-18:

- BB-84 (_)
- CC-79 (_)

Init

C.3.7 Connect jumper with alligator or bulldog clips between the following terminals in panel 09-41 to allow remote manual operation of 10MOV-18:

- BB-85 (_)
- CC-80 (_)

Init

C.3.8 Disconnect lead from terminal 3 **OR** 4 on relay 16A-K29 in panel 09-41 and insulate with insulated boot to allow opening of 10MOV-18.

Init

C.3.9 Disconnect lead from terminal 3 **OR** 4 on relay 16A-K59 in panel 09-41 and insulate with insulated boot to allow opening of 10MOV-25A.

Init

C.3.10 Notify SM that shutdown cooling isolation is disabled.

C.3.11 Start up RHR shutdown cooling per Section D of OP-13D.

C.3.12 **WHEN** RPS Bus A is returned to normal, perform the following:

a. Obtain SM permission to enable shutdown cooling isolation.

b. Disconnect jumper from the following terminals in panel 09-41:

- BB-19 (_)
- BB-20 (_)

Init

c. Disconnect jumper from the following terminals in panel 09-41:

- BB-84 (_)
- CC-79 (_)

Init

(Step C.3.12 continued on next page)

C.3.12 (Cont)

d. Disconnect jumper from the following terminals in panel 09-41:

- BB-85 (_)
- CC-80 (_)

Init

e. Connect lead from terminal 3 **OR** 4 on relay 16A-K29 in panel 09-41.

Init

f. Connect lead from terminal 3 **OR** 4 on relay 16A-K59 in panel 09-41.

Init

g. Notify SM that shutdown cooling isolation is enabled.

C.4 Restoring Shutdown Cooling After Loss of RPS Bus B

C.4.1 Ensure the following motor control centers are energized to provide power to 10MOV-17 and 10MOV-18:

- 71MCC-156 (600v motor control center bus 115600)
- 71BMCC-4 (reactor building east crescent motor control center)

C.4.2 Obtain SM permission to disable shutdown cooling isolation.

C.4.3 Obtain three electrical jumpers, size #14 AWG or larger.

C.4.4 Do not break continuity between a terminal and the existing lead(s) on that terminal when installing jumpers.

C.4.5 Connect jumper with alligator or bulldog clips between the following terminals in panel 09-42 to allow opening of 10MOV-18:

- BB-21 (_)
- BB-22 (_)

Init

C.4.6 Connect jumper with alligator or bulldog clips between the following terminals in panel 09-42 to allow remote manual operation of 10MOV-17:

- BB-84 (_)
- CC-79 (_)

Init

C.4.7 Connect jumper with alligator or bulldog clips between the following terminals in panel 09-42 to allow remote manual operation of 10MOV-17:

- BB-85 (_)
- CC-80 (_)

Init

C.4.8 Disconnect lead from terminal 3 **OR** 4 on relay 16A-K30 in panel 09-42 and insulate with insulated boot to allow opening of 10MOV-17.

Init

C.4.9 Disconnect lead from terminal 3 **OR** 4 on relay 16A-K60 in panel 09-42 and insulate with insulated boot to allow opening of 10MOV-25B.

Init

C.4.10 Notify SM that shutdown cooling isolation is disabled.

C.4.11 Start up RHR shutdown cooling per Section D of OP-13D.

C.4.12 **WHEN** RPS Bus B is returned to normal, perform the following:

a. Obtain SM permission to enable shutdown cooling isolation.

b. Disconnect jumper from the following terminals in panel 09-42:

- BB-21 (_)
- BB-22 (_)

Init

c. Disconnect jumper from the following terminals in panel 09-42:

- BB-84 (_)
- CC-79 (_)

Init

(Step C.4.12 continued on next page)

C.4.12 (Cont)

d. Disconnect jumper from the following terminals in panel 09-42:

- BB-85 (_)
- CC-80 (_)

Init

e. Connect lead from terminal 3 **OR** 4 on relay 16A-K30 in panel 09-42.

Init

f. Connect lead from terminal 3 **OR** 4 on relay 16A-K60 in panel 09-42.

Init

g. Notify SM that shutdown cooling isolation is enabled.

D. REQUIREMENTS

D.1 Commitments

D.1.1 INPO OE 3788, OER #900036, Loss of Shutdown Cooling/Alert Declared, Revise AOP-30 to address a shutdown cooling isolation due to failure of the RPS power supply. (ACTS 8825)

E. ATTACHMENTS

1. REFERENCES
2. ISOLATION/INITIATION CHECKLIST
3. CORE DECAY HEAT VS. TIME AFTER SHUTDOWN
4. ALTERNATE COOLING METHODS

ATTACHMENT 1 Page 1 of 1

REFERENCES

1.0 **Performance References**

1.1 AOP-1, Reactor Scram*

1.2 AOP-53, Loss of Spent Fuel Storage Pool, Reactor Head Cavity Well, or Dryer Separator Storage Pit Water Level*

1.3 OP-2A, Feedwater System*

1.4 OP-3, Condensate System*

1.5 OP-13, Residual Heat Removal System*

1.6 OP-13A, RHR - Low Pressure Coolant Injection*

1.7 OP-13D, RHR - Shutdown Cooling*

1.8 OP-14, Core Spray System*

1.9 OP-20, Standby Gas Treatment System*

1.10 OP-22, Diesel Generator Emergency Power*

1.11 OP-25, Control Rod Drive Hydraulic System*

1.12 OP-27, Recirculation System*

1.13 OP-28, Reactor Water Clean-Up System*

1.14 OP-51A, Reactor Building Ventilation and Cooling System (RNV)*

ATTACHMENT 1 Page 2 of 2

REFERENCES

2.0 **Developmental References**

2.1 JGMO-92-066, Outage Risk Assessment Report, Item 5.5

2.2 JAF-SE-94-032, Evaluation for Revision 25 of OP-46A

2.3 JAF-SE-94-033, Evaluation for Removal of the 10500 Bus with the Reactor Vessel Head On per OP-46A

2.4 INPO OE 3788, Loss of Shutdown Cooling/Alert Declared

2.5 JTS-94-0713, ACTS 12630, WR 94-04294-00, NSE For AOP-30 Revision

2.6 Modification F1-95-121, Decay Heat Removal

2.7 JAF-CALC-MISC-02244, Assessment of the Combined Decay Heat Load of the Reactor Core and Spent Fuel Pool During Refueling Outages

2.8 ACTS Item 98-31209, Perform an assessment of AOP validity and effectiveness and revise AOPs as necessary. Revision 11 of AOP-30 incorporated comments from AOP Review Project.

ATTACHMENT 2

ISOLATION/INITIATION CHECKLIST

RPV Water Level: 177 inches

SYSTEM/COMPONENT	**STATUS**	✓
Reactor Protection System	Auto Scram per AOP-1	
Reactor Building Ventilation	Auto Isolation per Section G of OP-51A	
RWCU	Auto Isolation per Section G of OP-28	
20MOV-82 OR 20AOV-83 DW FLOOR DRAIN	CLOSED	
20MOV-94 OR 20AOV-95 DW EQUIPMENT DRAIN	CLOSED	
10MOV-57 OR 10MOV-67 RHR DISCHARGE TO RADWASTE	CLOSED	
07-104A, B, and C TIP VALVES	CLOSED	
10MOV-25A AND 10MOV-25B LPCI INBD INJ VALVE	CLOSED (RHR IN SHUTDOWN COOLING)	

RPV Water Level: 177 inches
CONTAINMENT ISOLATION DISPLAY PANEL 09-4
ALL VALVES CLOSED EXCEPT THOSE LISTED BELOW

VALVE	**STATUS**	✓
27SOV-145 NITROGEN INSTRUMENT HEADER ISOL	OPEN	
27SOV-141 NITROGEN INSTRUMENT HEADER ISOL	OPEN	
27AOV-101A and 27AOV-101B TORUS VACUUM BREAKER ISOLATIONS	OPEN (TORUS TO RX BLDG DP -0.5 PSID)	

ATTACHMENT 2 Page 2 of 2

ISOLATION/INITIATION CHECKLIST

RPV Water Level: 177 inches
REACTOR BUILDING SAMPLE PANEL 95SP-7

VALVE	STATUS	✓
10SOV-263A or 10SOV-264A RHR SAMPLE VALVES	CLOSED	
10SOV-263B or 10SOV-264B RHR SAMPLE VALVES	CLOSED	

RPV Water Level: 126.5 inches

SYSTEM	STATUS	✓
Recirc Pumps	TRIPPED	
ARI	INITIATED	

RPV Water Level: 59.5 inches

SYSTEM/COMPONENT	STATUS	✓
LPCI	Auto Initiation per Section G of OP-13A	
Core Spray	Auto Initiation per Section G of OP-14	
EDGs	Auto Startup per Section G of OP-22	
29AOV-80A or 29AOV-86A MSIV (A MAIN STEAM LINE)	CLOSED	
29AOV-80B or 29AOV-86B MSIV (B MAIN STEAM LINE)	CLOSED	
29AOV-80C or 29AOV-86C MSIV (C MAIN STEAM LINE)	CLOSED	
29AOV-80D or 29AOV-86D MSIV (D MAIN STEAM LINE)	CLOSED	
29MOV-77 or 29MOV-74 MAIN STEAM LINE DRAIN	CLOSED	
02-2AOV-39 or 02-2AOV-40 RWR SAMPLE VALVE	CLOSED	

ATTACHMENT 3

CORE DECAY HEAT VS. TIME AFTER SHUTDOWN

Days after shutdown	BTU/hr	Days after shutdown	BTU/hr
0	6.28E8	21	1.48E7
1	4.79E7	22	1.44E7
2	3.92E7	23	1.42E7
3	3.36E7	24	1.39E7
4	2.97E7	25	1.36E7
5	2.69E7	26	1.33E7
6	2.48E7	27	1.31E7
7	2.32E7	28	1.28E7
8	2.19E7	29	1.26E7
9	2.08E7	30	1.24E7
10	2.00E7	31	1.22E7
11	1.92E7	32	1.20E7
12	1.86E7	33	1.18E7
13	1.80E7	34	1.16E7
14	1.75E7	35	1.14E7
15	1.70E7	36	1.12E7
16	1.66E7	37	1.10E7
17	1.62E7	38	1.09E7
18	1.58E7	39	1.07E7
19	1.54E7	40	1.06E7
20	1.51E7	730	9.13E5

ALTERNATE COOLING METHODS

METHOD	APPROXIMATE HEAT REMOVAL CAPACITY (BTU/hr)	LIMITATIONS
Decay Heat Removal	3.00E7	• Gates removed between cavity and spent fuel pool
Fuel Pool Cooling	3.30E6	• Gates removed between cavity and spent fuel pool • RBC must be available • SW must be available
Fuel Pool Cooling Assist	2.40E7	• RHR must be available • RHRSW must be available • Gates removed between cavity and spent fuel pool
RWCU Blowdown Mode • 1 pump running • 125 gpm blowdown flow • 125 gpm makeup flow	2.06E6	• No isolation signal present • Makeup source must be available (see list below) • Main Condenser or Radwaste must be available
RWCU Recirc Mode	1.70E6	No isolation signal present
RWCU Blowdown Mode • gravity drain • 50 gpm blowdown flow • 50 gpm makeup flow	1.00E6	• No isolation signal present • Makeup source must be available (see list below) • Main Condenser or Radwaste must be available

Makeup Sources

- Condensate transfer keep-full using Core Spray or RHR
- Control Rod Drive System
- Condensate/Feedwater
- Condensate transfer to skimmer surge tanks (gates removed)
- Condensate transfer to fuel pool using DHR (gates removed)
- Condensate transfer using service box connections on the refuel floor (gates removed)
- Fire Protection System water from local fire hose stations or outside sources
- RHR service water cross-tie
- Fire Water Crosstie

NEW YORK POWER AUTHORITY
JAMES A. FITZPATRICK NUCLEAR POWER PLANT
EOP AND SAOG SUPPORT PROCEDURE

FIRE WATER CROSSTIE TO RHRSW LOOP A
WHEN DIRECTED BY EOP-4 OR SAOGs*
EP-10
REVISION 1

FOR INFORMATION ONLY

REVIEWED BY: PLANT OPERATING REVIEW COMMITTEE

MEETING NO. N/A DATE N/A

APPROVED BY: ______________________ DATE 12/12/98
RESPONSIBLE PROCEDURE OWNER

APPROVED BY: ______________________ DATE 12/12/98
GENERAL MANAGER - OPERATIONS

EFFECTIVE DATE: 12-13-98

FIRST ISSUE ☐ FULL REVISION ☒ LIMITED REVISION ☐

REFERENCE USE	TSR
TECHNICAL	

VALIDATED PER AP-02.02

FOR INFORMATION ONLY

PERIODIC REVIEW DUE DATE 12/2003

REVISION SUMMARY SHEET

REV. NO.	CHANGE AND REASON FOR CHANGE
1	1. Full revision to support implementation of Severe Accident Operating guidelines (SAOGs).
	2. Deleted Step 5.6 to ensure closed 10MOV-89A before starting fire pumps. This valve should already be closed due to both RHRSW Loop A pumps unavailable and this valve is not required to be closed to prevent fire pump runout. Subsequent steps provide direction for opening 10MOV-89A to provide flow through the heat exchanger. (PCR #1 dated 2/20/97)
	3. Revised Steps 5.9.1 and 5.11.1.B to provide better description of lead to be disconnected for disabling pump running interlock for 10MOV-89A. (PCR #2 dated 9/28/98)

TABLE OF CONTENTS

COM7.1.1
1.0 **PURPOSE**

To provide instructions for utilizing the fire protection system crosstie to RHRSW Loop A when directed by EOP-4 or SAOGs.

2.0 **PRECAUTIONS**

None

3.0 **PREREQUISITES**

Performance of this procedure has been directed by EOP-4 or the SAOGs due to a loss of all containment decay heat removal capability.

4.0 **SPECIAL INSTRUCTIONS**

4.1 This procedure shall be performed when a loss of all containment decay heat removal capability has occurred.

4.2 This procedure shall be performed only when adequate core cooling is assured. If fire water crosstie injection is required per EP-7, EP-8, or EP-14 while performing this procedure, then proceed to Step 5.11.

4.3 Notify RES Radiation Protection prior to entering RHR HX Room A due to potentially changing radiological conditions.

5.0 **PROCEDURE** (✓)

5.1 **IF** RHR Heat Exchanger B is operating with at least one RHR and RHRSW pump in service,
THEN exit this procedure and continue efforts to restore RHRSW Pumps A and C to service. (_)

5.2 Verify the following RHRSW pumps are unavailable:

- RHRSW PMP 10P-1A (_)
- RHRSW PMP 10P-1C (_)

5.3 Verify at least one of the following RHR pumps is running:

- RHR PMP 10P-3A (_)
- RHR PMP 10P-3C (_)

5.4 Remove caps from the following valves:

- 10RHR-432 (RHRSW to fire protection cross-tie isol valve) (_)
- 76FPS-720 (RHRSW/fire protection cross-tie isol valve) (_)

5.5 Connect hose (stored in cabinet 76CAB-1 on west wall of north emergency service water room) between the following valves:

- 10RHR-432 (_)
- 76FPS-720 (_)

CAUTION

Fire Protection Pumps 76P-1, 76P-2, and 76P-4 are designed to operate with screenwell forebay water level greater than or equal to 239 feet, 6 inches.

5.6 Start one or more of the following pumps:

- ELEC FIRE PMP 76P-2 (_)
- DIESEL FIRE PMP 76P-1 (_)
- DIESEL FIRE PMP 76P-4 (_)

(✓)

5.7 Unlock and open the following valves:

- 10RHR-432 (_)
- 76FPS-720 (_)

5.8 Ensure closed at least one of the following valves:

- RHRSW TO RHR 10MOV-148A (_)
- RHRSW TO RHR 10MOV-149A (_)

5.9 **IF** electrical power is available to 10MOV-89A, **THEN** perform the following:

5.9.1 Disconnect lead labeled "EP-10" from right side of terminal YY-22 in panel 09-3 to disable RHRSW pump running interlock for 10MOV-89A. ____ Init

5.9.2 Open RHRSW DISCH VLV FROM HX A 10MOV-89A at panel 09-3. (_)

5.10 **IF** electrical power <u>is not</u> available to 10MOV-89A, **THEN** perform the following:

5.10.1 Open circuit breaker 71MCC-151-OD2(CB) (10MOV-89A RHR heat exchanger A RHRSW outlet isol valve). (_)

CAUTION
High radiation levels could exist in RHR HX Room A.

5.10.2 Notify RES Radiation Protection that entry into RHR HX Room A is required. (_)

5.10.3 Declutch and manually open 10MOV-89A. (_)

(✓)

5.11 **IF** any of the following conditions occur:

- Fire water crosstie injection is required per EP-7, EP-8, or EP-14,

OR

- Either RHRSW Pump (10P-1A/10P-1C) becomes available

OR

- Fire water crosstie to RHRSW is <u>no longer</u> required,

THEN perform Steps 5.11.1 through 5.11.3.

5.11.1 **IF** electrical power is available to 10MOV-89A,
THEN perform the following:

A. Close RHRSW DISCH VLV FROM HX A 10MOV-89A at panel 09-3. (_)

B. Connect lead labeled "EP-10" to right side of terminal YY-22 in panel 09-3 to enable RHRSW pump running interlock for 10MOV-89A. ____ Init

5.11.2 **IF** electrical power <u>is not</u> available to 10MOV-89A,
THEN perform the following:

CAUTION
High radiation levels could exist in RHR HX Room A.

A. Notify RES Radiation Protection that entry into RHR HX Room A is required. (_)

B. Manually close 10MOV-89A. (_)

C. Close circuit breaker 71MCC-151-OD2(CB) (10MOV-89A RHR heat exchanger A RHRSW outlet isol valve). (_)

(Step 5.11 continued on next page)

(✓)

5.11 (Cont)

5.11.3 **IF** fire water crosstie <u>is not</u> required per EP-7, EP-8, or EP-14, **THEN** perform the following:

A. Close and lock the following valves:

- 10RHR-432 (_)
- 76FPS-720 (_)

B. Open 10RHR-792 (RHRSW to fire protection cross-tie bleed off valve) to depressurize hose. (_)

C. **WHEN** hose is depressurized, close 10RHR-792. (_)

D. Disconnect hose from the following valves:

- 10RHR-432 (_)
- 76FPS-720 (_)

E. Install caps on the following valves:

- 10RHR-432 (_)
- 76FPS-720 (_)

F. Store hose in cabinet 76CAB-1 on west wall of north emergency service water room. (_)

G. **WHEN** fire protection pump operation is <u>no longer</u> required, ensure the following pumps are stopped:

- West Diesel Fire Pump 76P-1 (_)
- Electric Fire Pump 76P-2 (_)
- East Diesel Fire Pump 76P-4 (_)

6.0 REFERENCES

6.1 Performance References

None

6.2 Developmental References

6.2.1 EP-8, Alternate Injection Systems*

6.2.2 POT-76AA, Fire Protection and RHR-Service Water Cross-Connection Preoperational Test (Mod F1-86-094)*

6.2.3 JAF-SE-89-082, Fire Protection and RHR-Service Water Removable Cross-Connection Preoperational Test

6.2.4 JAF-SE-96-056, 'A' RHR Hx Cooling Water Provided via Fire Protection to 'A' RHRSW Cross-Tie

6.2.5 REF-96-144, Closure of ACTS Item 16694

6.2.6 JTS-96-0332, Closure of ACTS 21572; Use of Fire Protection System for Decay Heat Removal

6.2.7 Drawings:

- ESK-5BQ
- ESK-6MZ
- FE-3GM
- FE-9GN
- SE-8AN

6.2.8 SAOGs

7.0 REQUIREMENTS

7.1 Commitments

7.1.1 NRCI-94-03, JAFP-94-0175, ACTS Item 10946. Created EOP Support Procedures (EPs).

7.2 Validation

Revision 1 validated per AP-02.02.

8.0 ATTACHMENTS

None

NEW YORK POWER AUTHORITY
JAMES A. FITZPATRICK NUCLEAR POWER PLANT
EOP AND SAOG SUPPORT PROCEDURE

EOP ENTRY AND USE*
EP-1
REVISION 4

FOR INFORMATION ONLY

APPROVED BY: ______________________ DATE 1/18/00
RESPONSIBLE PROCEDURE OWNER

FOR INFORMATION ONLY

EFFECTIVE DATE: January 20, 2000

FIRST ISSUE ☐ FULL REVISION ☐ LIMITED REVISION ☒

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**************************    **************************
*                        *    *                        *
*   INFORMATIONAL USE    *    *          TSR           *
*                        *    *                        *
**************************    **************************


**************************
*                        *
*       TECHNICAL        *
*                        *
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VALIDATED PER AP-02.02

REVISION SUMMARY SHEET

REV. NO.	CHANGE AND REASON FOR CHANGE
4	Revised Subsection 4.2.1 to clarify the following: • EOP-5 entry requirements during reactor building isolation (PCR dated 10/16/99) • EOP entry requirements while in SAOGs (PCR #3 dated 2/26/99) Added definition of reactor shutdown as Step 4.8.1. (PCR #4 dated 6/16/99) Revised Subsection 5.3 to reflect use of portable ARM for monitoring reactor building radiation levels. OP-32 allows use of a portable ARM. (PCR #2 dated 2/19/99) Added Step 4.2.3.B to allow preemptive isolation of a release path provided that isolation will not conflict with the EOPs.

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↓COM7.1.1

1.0 PURPOSE

To provide general guidance for use of EOPs and recognition of EOP entry conditions.

This procedure applies during all plant operating modes, except when reactor coolant temperature is less than 212°F and a reactor startup or shutdown is not in progress.

2.0 PRECAUTIONS

None

3.0 PREREQUISITES

None

4.0 SPECIAL INSTRUCTIONS

4.1 Plant Conditions and Parameters

4.1.1 Monitor the general state of the plant.

4.1.2 Monitor the following parameters using multiple indications:

- Reactor power
- RPV water level
- RPV pressure
- Drywell temperature
- Drywell pressure
- Torus water level
- Torus water temperature
- Containment hydrogen
- Secondary containment temperatures
- Secondary containment radiation levels
- Secondary containment differential pressure
- Crescent area water levels
- Reactor building floor sump levels
- Reactor building ventilation exhaust radiation levels

4.1.3 **IF** local monitoring of a plant parameter is required,
THEN perform the following:

A. Evaluate radiological and environmental conditions to determine accessibility.

B. **IF** access to Reactor Building is required,
THEN follow radiation protection requirements established by RES.

4.2 Use of EOPs

4.2.1 EOP Entry, Re-entry, and Exit

A. **IF** an EOP entry condition occurs,
THEN enter that EOP, or re-enter if that EOP has already been entered. Exceptions to this requirement are in Steps E and F below.

B. **IF** an EOP has been entered,
THEN determine whether concurrent entry into Emergency Plan is warranted.

C. **WHEN** an operating parameter is trending such that an EOP entry condition is imminent or inevitable, the SM or CRS may enter the applicable EOP.

D. **WHEN** an EOP exit condition is satisfied, or it has been determined that an emergency <u>no longer</u> exists, enter the appropriate operating and/or abnormal operating procedures.

E. **IF** primary containment flooding is or was required,
THEN exit the EOPs and enter the SAOGs. EOPs are not re-entered while in SAOGs, even if an EOP entry condition occurs.

F. Reactor building dP could momentarily meet the EOP-5 entry condition (at or above 0 inches of water) while manually isolating the reactor building during normal plant operation. This is an expected system response and EOP-5 entry is not required provided that dP becomes negative following isolation. Entry into EOP-5 is expected during an automatic isolation or emergency if reactor building dP meets the entry condition.

4.2.2 Adequate Core Cooling

Heat removal from the reactor sufficient to prevent rupturing the fuel clad. Submergence is the preferred mechanism for cooling the core. Steam cooling is relied upon only if RPV water level cannot be restored and maintained above TAF, cannot be determined, or must be intentionally lowered below TAF. The covered portion of the core remains cooled by boiling heat transfer which generates the steam that cools the uncovered portion. Steam cooling will maintain the hottest peak clad temperature below:

- Steam Cooling with injection - < 1500 °F
- Steam Cooling without injection - < 1800 °F

4.2.3 **Operator Actions/Strategies**

A. **IF** conditions or actions specified by a step are not applicable or cannot be implemented, **THEN** the operator shall proceed to the next step.

B. The SM/CRS may direct isolation of a release path at anytime during an event, provided that isolation of the release path will not conflict with the EOPs.

C. "Anticipation of Emergency RPV Depressurization" is defined as an expectation, based upon evaluation of plant conditions, that an emergency RPV depressurization requirement will soon be reached and cannot be averted by the actions of the EOPs. Before this conclusion can be drawn, the effectiveness of the steps preceding the emergency depressurization requirement must be evaluated. The anticipatory depressurization prescribed by the override requires the MSIVs be open, with the main condenser available and the turbine bypass valves operational (bypassing or defeating the MSIV interlocks is not authorized). Therefore, when performing EOP-2 Alternate RPV Level Control, Anticipation of Emergency RPV Depressurization is not allowed as adequate core cooling exists; this time is best used attempting to align additional injection sources since the MSIVs will automatically close and render the bypass valves inoperable. If the lowering RPV level trend is reversed, the requirement for emergency depressurization will be unnecessary.

D. Anytime the EOPs direct opening 7 ADS valves, this action is performed irrespective of the resulting RPV cooldown rate.

E. When performing Section ED of EOP-3, the RPV level band is established based upon whether or not level was previously intentionally lowered. Therefore, if RPV level was intentionally lowered below 110" TAF, this upper limit still applies after the emergency depressurization.

F. When performing Steam Cooling, direction is provided to establish a stable or lowering pressure trend. It is preferred to stabilize RPV pressure, to the extent possible, at its existing value. For example: If Steam Cooling is entered and RPV pressure is 500 psig, then RPV pressure should be controlled at or below 500 psig, depending upon the systems available for use. If SRVs are being used for pressure control, a band of 450-500 psig is appropriate. If RPV pressure cannot be stabilized, an alternate approach is to establish a lowering pressure trend. This preserves the assumption of the minimum zero injection RPV water level calculation but will accelerate the rate of inventory loss from the RPV. Therefore, the time that steam cooling can be maintained will be shortened.

G. "All Available Drywell Cooling" is defined as operating 3 of the 4 fans per drywell cooling assembly. Operating all 4 fans/assembly is prohibited as the drywell cooling fan motors could be overloaded causing one or more fans to trip.

H. When performing RPV Flooding, the Emergency Response Organization will generate a procedure for recovery. This procedure must restore RPV level instrumentation and should consider filling reference legs, piping integrity, drywell temperature, and power supplies. In addition, this procedure shall ensure the following:

- A method to intentionally lower RPV water level in order to return it on-scale.
- Instrument run temperatures are below 212°F.
- RPV pressure has remained at least 50 psig above torus pressure for the Minimum Core Flooding Interval (Attachment 2), prior to terminating all RPV injection sources.
- EOP-7 Shutdown Flooding shall be entered if RPV water level is not restored within the Maximum Core Uncovery Time Limit (Attachment 3).

4.3 Manual Control of Automatic Systems

⬇COM7.1.2

4.3.1 Do not override an automatic initiation of a safety function unless one of the following conditions exist:

- Adequate core cooling is assured by at least two independent indications
- Misoperation in automatic mode is confirmed by at least two independent indications
- Required by EOPs

⬇COM7.1.3

4.3.2 **IF** an operator cannot be dedicated to monitor systems placed in the manual mode,
THEN frequently check the system for proper operation and system response. The system is considered inoperable.

⬇COM7.1.3

4.3.3 **WHEN** manual operation is no longer required, return systems to automatic or standby mode.

⬇COM7.1.3

4.3.4 Before placing controls in manual for activities which require manual control for an extended period of time, review system response and actions to be taken during potential off-normal events.

4.3.5 **IF** manual control of an automatic system is desired,
THEN reset the initiation signal, if practicable. This will ensure the system returns to the design setpoint if the system automatically initiates.

4.4 SPDS (Safety Parameter Display System)

4.4.1 **IF** an SPDS input is inoperable,
THEN perform the following:

A. Perform Step 1 **OR** perform Steps 1 and 2:

1. Remove the input from scan.

2. Insert substitute value for the input.

B. SM or CRS log input out of service on Attachment 1, EPIC SPDS Point Status Log.

C. Initiate Priority B PID. Record PID number in Comments section on Attachment 1.

D. Record status of SPDS input (out of scan or substitute value inserted) on ODSO-4 Shift Turnover Checklist.

E. **IF** the associated SPDS display is inoperable, **THEN** frequently monitor indications listed in Section 5 of this procedure.

4.4.2 **IF** calibration of an SPDS input will cause an SPDS display to be inoperable or give false indication, **THEN** perform the following:

A. SM or CRS place copy of procedure page for affected SPDS point(s) in the EPIC SPDS Point Status Log with time and date noted on page.

B. Frequently monitor parameter being calibrated.

C. Multiple indications of the parameter may be monitored on EPIC, if available.

D. For secondary containment temperatures or radiation levels, the remaining operable computer points may be monitored on EPIC.

E. **IF** a plant transient occurs, **THEN** immediately return SPDS input to service.

F. **WHEN** SPDS input is returned to service, discard copy of procedure page containing SPDS points which were calibrated.

4.4.3 **IF** EPIC or SPDS <u>is not</u> available, **THEN** frequently monitor all indications listed in Section 5 of this procedure.

4.5 **Torus Water Temperature**

IF torus water temperature reaches 120°F,
THEN depressurize RPV to **LESS THAN** 200 psig at normal cooldown rates unless restrained by EOPs.

4.6 **Containment Instrument Nitrogen**

Use of containment instrument nitrogen for operation of components inside drywell; for example, MSIVs and SRVs, should take precedence over use of instrument air in order to maintain primary containment inerted during degraded plant conditions.

4.7 **RHR and Core Spray Operation**

COM7.1.4

4.7.1 Blockage of ECCS pump suction strainers could occur due to debris in the Torus. Within the latitude provided by EOPs to restore and maintain parameters within specified limits, potential mitigative actions may include:

- Minimizing ECCS flow or removing affected ECCS pumps from service
- Alternating ECCS pumps from one division to another, if available
- Shifting ECCS pump suction to another source, if available
- Operation of alternate injection sources

4.7.2 Whenever RHR is in the LPCI mode, inject into RPV through RHR heat exchangers as soon as possible and establish RHRSW flow.

4.7.3 Secure RHR and core spray pumps that <u>are not</u> needed to support required actions of EOPs.

4.7.4 Diverting low pressure coolant injection to spray the containment <u>should not</u> be done unless adequate core cooling can also be maintained, or as directed per EOPs.

4.7.5 When performing both EOP-2 and EOP-4, maintaining adequate core cooling normally takes precedence over maintaining containment parameters. Utilizing RHR flow for LPCI injection, containment spray, or torus cooling, singularly or in combination is permissible provided continuous LPCI injection is not required for adequate core cooling.

4.7.6 **IF** drywell or torus hydrogen concentration cannot be determined to be below 6%,
AND drywell or torus oxygen concentration cannot be determined to be below 5%,
THEN operate sprays irrespective of adequate core cooling.

CAUTION

Elevated crescent area temperature affects RHR and core spray pump motor winding temperatures and could lead to motor failure.

4.7.7 **IF** an RHR or core spray pump motor winding temperature reaches alarm setpoint,
AND that pump is needed to support required actions of EOPs,
THEN consider reducing pump flow rate or using an alternate system.

4.8 Reactor Shutdown Determination

4.8.1 The reactor is shutdown when subcritical with IRMs below range 6 (heating range).

4.8.2 The reactor will remain shutdown under all conditions without boron injection with one control rod fully withdrawn (or any other position), provided all other control rods are inserted to or beyond position 02.

4.8.3 **IF** reactor shutdown cannot be determined by Step 4.8.2,
THEN a Reactor Engineer must determine if the reactor will remain shutdown under all conditions without boron injection. The reactor condition will be unknown until this determination is made.

4.9 Procedure Use While Performing EOPs

4.9.1 AOP-1, Reactor Scram* immediate operator actions should be performed concurrently with initial entry into EOP-2.

4.9.2 AOP-1 subsequent operator actions, such as resetting the scram and balance of plant, should be performed concurrently with EOPs to aid in recovery. However, actions taken shall not contradict or subvert actions specified by the EOPs and shall not cause the loss or unavailability of equipment required by the EOPs.

4.9.3 AOP-39, Loss of Coolant*, should be performed concurrently with applicable EOPs for events involving a loss of coolant inside the primary containment. However, actions taken per AOP-39 shall not contradict or subvert actions specified by the EOPs and shall not cause the loss or unavailability of equipment required by the EOPs.

4.9.4 AOP-40, Main Steam Line Break*, should be performed concurrently with applicable EOPs for events involving a piping break in a main steam line or unisolable branch piping outside the primary containment. However, actions taken per AOP-39 shall not contradict or subvert actions specified by the EOPs and shall not cause the loss or unavailability of equipment required by the EOPs.

4.9.5 Other plant procedures may be used in conjunction with EOPs to enhance emergency response and recovery. However, actions taken per other plant procedures shall not contradict or subvert actions specified by the EOPs and shall not cause the loss or unavailability of equipment required by the EOPs.

5.0 PROCEDURE

Monitor parameters using multiple indications specified by this procedure to determine actual status of parameter.

NOTE: Indications are listed in order of preference under each parameter.

5.1 RPV Control

- **RPV Water Level**
  - SPDS display
  - RX WATER LVL 02-3LI-85A and 02-3LR-85B at panel 09-5
  - Annunciator 09-5-1-31 RPS RX VESSEL LO LVL TRIP
  - RX WTR LVL FUEL ZONE 02-3LR-98 and O2-3LI-91 at panel 09-3
- **RPV Pressure**
  - SPDS display
  - RX VESSEL PRESS 06PI-61A and B, and 06PR-61A and B at panel 09-3
  - Annunciator 09-5-1-22 RPS HI RX PRESS TRIP
- **Reactor Power**
  - SPDS display
  - APRM chart recorders at panel 09-5
  - APRM meters at panel 09-14
  - IRM chart recorders at panel 09-5
  - IRM meters at panel 09-12

5.2 **Primary Containment Control**

- **Torus Temperature**
  - SPDS display
  - TORUS TEMP A 16-1TR-131A and TORUS TEMP B 16-1TR-131B at panel 09-3
  - Average of bay temperatures obtained individually at 16-1TI-131A and 16-1TI-131B at MAP panel
- **Drywell Temperature**
  - SPDS display
  - Average of temperatures on DW TEMP A 16-1TR-108 and DW TEMP B 16-1TR-107 at panel 09-3
  - Average air inlet and outlet temperature for any drywell cooling assembly that has at least one fan operating (68TI-100 or 68TI-101 at panel 09-75).
- **Drywell Pressure**
  - SPDS display
  - NR PC PRESS 27PI-115A1 and 27PR-115A1, and 27PI-115B1 and 27PR-115B1 at panel 09-3
  - Annunciator 09-5-1-21 RPS HI DW PRESS TRIP
  - WR PC PRESS 27PI-115A2 and 27PR-115A2, and 27PI-115B2 and 27PR-115B2 at panel 09-3
- **Torus Level**
  - SPDS display
  - TORUS LVL 23LI-202A and 23LR-202A, and TORUS LVL 23LI-202B and 23LR-202B at panel 09-3
- **Containment Hydrogen**
  - SPDS display
  - Panel 27PCX-101A and 27PCX-101B in Relay Room
  - Grab samples

5.3 Secondary Containment Control

- **Differential Pressure**
  - SPDS display
  - RB DIFF PRESS 01-125DPI-100A and 01-125DPI-100B at panel 09-75
- **Area Temperature High**
  - SPDS display
  - Panels 09-95, 09-96, 09-75, and 09-21, per Table 5-1 of EOP-5
  - **IF** an area does not have remote temperature indication, **THEN** monitor that area locally.

    IF that area is inaccessible,
    AND a primary system is discharging into Secondary Containment,
    THEN assume the area is above the maximum safe level.
- **Reactor Building Radiation Levels**
  - SPDS display
  - ARM at panel 09-11
  - Portable ARM, if ARM is out of service

    IF a portable ARM is being used,
    AND the radiation levels in that area are not available from the ARM or by RES survey,
    THEN assume the area is above the maximum safe level.

(Subsection 5.3 continued on next page)

5.3 (Cont)

- **Reactor Building Vent Exhaust**

  - SPDS display
  - RX BLDG VENT RAD MON A 17RIS-452A and RX BLDG VENT RAD MON B 17RIS-452B at panel 09-12
  - REFUEL FLOOR EXH RAD MONITOR 17RM-456A at panel 66HV-3A and REFUEL FLOOR EXH RAD MONITOR 17RM-456B at panel 66HV-3B (Reactor Building 272')
  - Annunciators 09-3-2-29 RX BLDG VENT RAD MON HI and 09-75-1-15 REFUELING FLOOR EXH RAD MON INOP OR HI

  IF Reactor Building is inaccessible,
  THEN assume Refuel Floor exhaust monitor is
  GREATER THAN 10^3 counts per minute.

- **Reactor Building Floor Sump Level**

  - SPDS display
  - Annunciators 25-17-1-1 RB FLR SUMP A LVL HI and 25-17-1-2 RB FLR SUMP B LVL HI at panel 25-17 in Radwaste Control Room
  - Local observation

  IF Reactor Building is inaccessible,
  THEN assume reactor building floor sump level is
  GREATER THAN high alarm setpoint.

- **Crescent Area Water Level**

  - SPDS display
  - Local observation

  IF Reactor Building is inaccessible,
  AND a primary system is discharging into Secondary Containment,
  THEN assume crescent area water level is
  GREATER THAN 18 inches.

5.4 **Radioactivity Release Control**

Offsite release rates and emergency classification are determined by Site Emergency Plan.

6.0 REFERENCES

6.1 Performance References

6.1.1 AOP-1, Reactor Scram*

6.1.2 EOP-2, RPV Control*

6.2 Developmental References

6.2.1 ODSO-28, Revision 4, EOP Entry and Use*

6.2.2 EOP-2, RPV Control*

6.2.3 EOP-3, Failure to Scram*

6.2.4 EOP-4, Primary Containment Control*

6.2.5 EOP-5, Secondary Containment Control*

6.2.6 EOP-6, Radioactivity Release Control*

6.2.7 JTS-95-0221, Operability Assessment for DER 95-0740 - 0748; Industry Notification of B-Fill Qualification Limits for Certain ITT-Barton Indicating Switches

6.2.8 JSED-95-0100, Impact of ITT Barton Industry Advisory on the Environmental Qualification of 10DPIS-125A&B, 14FIS-45A&B, and 27PS-110A&B

6.2.9 GE Letter JAB-N8075, dated 11/2/98, MSBWP Results for FitzPatrick Cycle 14 (GE letter 262-98-172 and DRF J11-03359)

7.0 REQUIREMENTS

7.1 Commitments

7.1.1 NRCI-94-03, JAFP-94-0175, ACTS Item 10946. Created EOP Support Procedures (EPs).

7.1.2 NRCN-92-47, Intentional Bypassing of Automatic Actuation of Plant Protective Features (OER 920483, JTS-92-0799)

7.1.3 ACTS Item 5899, incorporate INPO SER 87-34 (OER #870335).

7.1.4 JAFP-94-0228, Response to NRC Bulletin No. 93-02, Supplement 1, Debris Plugging of Emergency Core Cooling Suction Strainers. Added special instruction to alert operators of the potential for ECCS suction strainer clogging and to adjust flow consistent with required needs to mitigate the clogging.

7.2 Validation

Validated per AP-02.02.

8.0 ATTACHMENTS

1. <u>EPIC SPDS POINT STATUS LOG</u>
2. <u>MINIMUM CORE FLOODING INTERVAL</u>
3. <u>MAXIMUM CORE UNCOVERY TIME</u>

ATTACHMENT 1

EPIC SPDS POINT STATUS LOG

SPDS POINT	COMPONENT ID	DESCRIPTION	REASON OUT-OF-SERVICE/ COMMENTS	DATE/TIME OUT	DATE/TIME IN

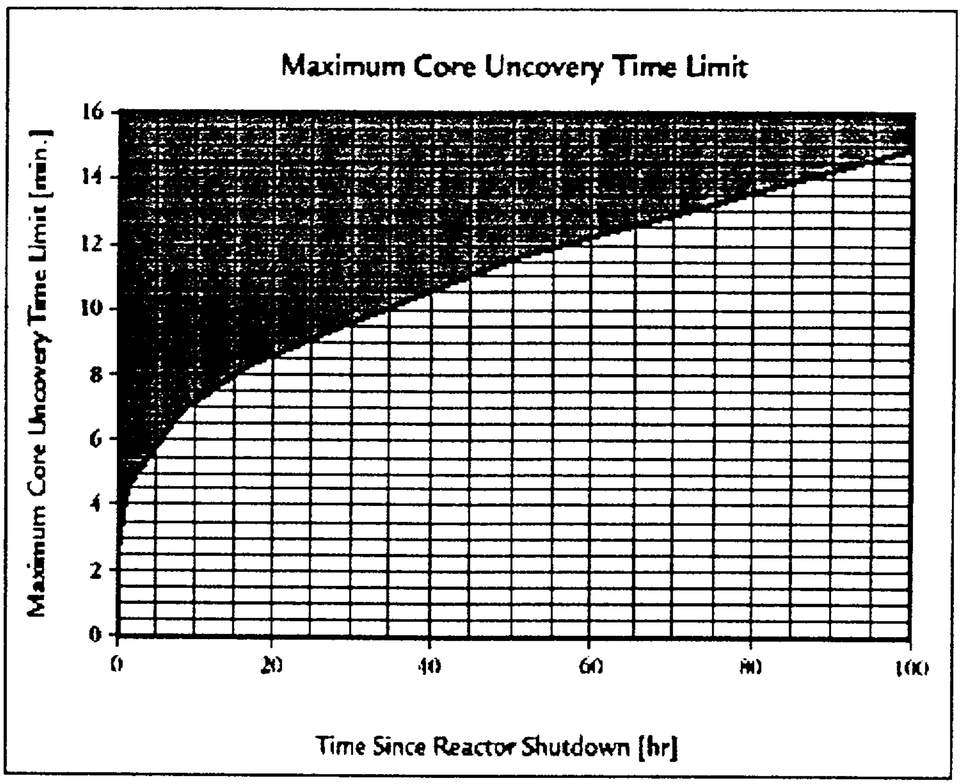
ATTACHMENT 2 Page 1 of 1

MINIMUM CORE FLOODING INTERVAL

Number of Open SRVs	Flooding Interval (min.)
7 or more	22
6	29
5	43

ATTACHMENT 3 Page 1 of 1

MAXIMUM CORE UNCOVERY TIME



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