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POWER
SYSTEMS

STN 50-470F

December 5, 1984
LD-84-069

Darrell G. Eisenhut, Director
Division of Licensing
U.S. Nuclear Regulatory Commission
Washington, D.C. 20555

Subject: CESSAR Consistency Review Changes

Dear Mr. Eisenhut:

As a result of a review of the technical specifications for the first System 80™ plant, several CESSAR-F changes have been found to be necessary. These changes provide clarification and technical consistency of information given in CESSAR-F. The marked-up affected pages of the CESSAR FSAR are attached.

The attachment provides clarification and consistency of the response times used in the CESSAR safety analyses. These changes do not in any way affect the results and conclusions of the safety analyses, which remain valid. The following information is provided.

(1) A revision of the CESSAR interface requirements for MSIV and MFIV closure time to ensure consistency with the safety analysis assumptions.

(2) A revision of the CESSAR Chapter 6 and 15 Sequence of Event tables, and supporting text (including Section 7.2) to avoid the appearance of any inconsistency with Technical Specifications and interface requirements.

If you have any questions or comments concerning these changes, please feel free to contact me or Mr. G. A. Davis of my staff at (203) 285-5207.

Very truly yours,

COMBUSTION ENGINEERING, INC.

A. E. Scherer
Director
Nuclear Licensing

AES:las
Attach.
cc: P. Moriette

E003
1/1

CESSAR INTERFACE REQUIREMENTS AND
SEQUENCE OF EVENTS CHANGES
TO CLARIFY RESPONSE TIMES

NOTES:

1. Whenever the Sequence of Events Table shows response time to equal 0.0 seconds, the minimum response time is the conservative direction for the analyses.

4. The full open to close stroke time of each MSIV and MSIV bypass valve shall be ~~8~~ 4.6 seconds or less upon receipt of an MSIS.

5. The ADV's shall be fail close and shall be capable of being remote manually positioned to control the plant cooldown rate.

6. The ADV's shall be provided with manual operators such that the valves may be hand operated from the control room and remote shutdown panel in the event of a loss of normal power supply.

7. In the combined event of either a steam line break or steam generator tube rupture and the loss of power operation of the ADV's, personnel access to the manual operators of the intact valves on the other steam generator shall be possible.

8. A MSIS actuation signal shall close the MSIV's, MSIV bypass valve, MFIV's and the steam generator blowdown valves.

9. Redundant feedwater system isolation valving shall be provided in both the economizer feedlines and the downcomer feedlines such that the following criteria are met when the effects of single failure criteria are imposed:

   a. Complete termination of forward feedwater flow is assumed within ~~8~~ 4.6 seconds after receipt of an MSIS.

   b. Abrupt complete termination of reverse feedwater flow with the existance of a reverse flow condition. Check valves are considered to be an acceptable means of achieving the above.

10. The economizer and downcomer feedwater line isolation valves (MFIV's) in each main feedwater line shall be remote-operated and be capable of maintaining leak rate of less than 1000 cc/hr under the main feedwater line pressure, temperature and flow resulting from the transient conditions associated with a pipe break on either side of the valves.

11. The Emergency Feedwater System shall be controllable in a post-accident environment from either the control room or a remote shutdown station.

12. The Emergency Feedwater System shall be controllable such that post accident operation will not result in overfilling the intact steam generator(s).

13. If the Emergency Feedwater System is used as an auxiliary feedwater system, the emergency feedwater pumps shall be designed for operation when steam generator pressure is negligible and not result in damage to the pumps or effect the ability of the system to deliver the required emergency feedwater flow. Such a condition can exist during startup or shutdown operation subsequent to an EFAS which starts the emergency feedwater pumps and fully opens the system isolation and control valves.

5.4.5.2 System Design

5.4.5.2.1 General Description

Each of the four main steam lines is provided with a power-actuated main steam isolation valve designed to stop flow from either direction when it is tripped closed. Each valve is located outside containment and is provided with means of actuation from the engineered safety features actuation system, meeting the requirements of IEEE Standard 279.

The logic circuitry required to isolate the main steam lines is discussed in Section 7.3. The main steam system valves and arrangement will be discussed in the Applicant's SAR.

5.4.5.2.2 Component Description

The main steam isolation system consists of the main steam isolation valves and their associated controls and instrumentation. The main steam isolation valves are remotely operated valves designed to either fail closed or be guaranteed to close upon receipt of Main Steam Isolation Signal. The main steam isolation valves can be monitored and controlled locally and in the control room.

5.4.5.2.3 System Operation

The main steam isolation valves are designed to isolate the main steam lines and the steam generators as required during operation and under accident conditions.

A steam line break inside containment would result in a pressure rise in the containment. Reverse flow protection is also achieved through the main steam isolation valves. To achieve reverse flow protection in the case of the main steam pipe rupture, the valve is fully closed within 5 seconds from receipt of the initiating signal.

The main steam line isolation system components are qualified to serve in the environment specified in Section 3.11.

5.4.5.3 Design Evaluation

Design evaluations are listed to correspond with the design bases listing.

A. The main steam isolation valves are capable of isolating the steam generators within ~~5~~ 4.6 seconds after receiving a signal from the engineered safety features actuation system. In the event of a steam line break, this action prevents continuous uncontrolled steam release from more than one steam generator. Protection is offered for breaks inside or outside the containment.

B. The main steam isolation valves, their operators, and associated circuitry are Seismic Category I, and are protected against missiles and the effect of high-energy line breaks.

For MSLB cases with small break areas, steam can escape fast enough from the two-phase region of the affected steam generator so that the level swell does not reach the steam line nozzle. A pure steam blowdown results. Because of the pressure reducing effects of active and passive containment heat sinks, the highest peak containment pressure resulting from a MSLB for a given set of initial steam generator conditions occurs for that case where the break area is the maximum at which a pure steam blowdown can occur. The potential for steam generator two-phase level swell following a MSLB increases as power level decreases; therefore, a spectrum of power levels must be analyzed to determine which one results in the peak MSLB containment pressures.

The feedwater distribution box is below the steam generator water level; therefore, MFLB cases always result in two-phase blowdowns and do not produce peak containment pressures as severe as MSLB cases.

To permit a determination of the effect of MSLB upon containment pressure, analyses are performed with SGNIII (described in Appendix 6B of Reference 1) at 102, 75, 50, 25, and 0 percent power. The largest slot and guillotine breaks at which a pure steam blowdown can occur are determined. The breaks are conservatively assumed to be at the nozzle of one of the steam generators. The cases analyzed are listed in Table 6.2.1-1.

The System 80 plants have integral flow restrictors in the nozzles of the steam generators. Credit for the flow restrictors is taken in the analysis.

In the plant, the main steam isolation signal (MSIS) of the engineered safety features actuation system (ESFAS) closes the MSIV's, MFIV's and the emergency feedwater isolation valves. MSIS is generated either by a steam generator low pressure signal or a containment high pressure signal. The MSIV's close in ~~5~~ 4.6 seconds. The valve closures have been considered in the analysis.

The main steam line isolation interface requirements are discussed in Section 5.1.4. The main feedwater line isolation interface requirements are discussed in Section 5.1.4. The emergency feedwater line isolation interface requirements are discussed in Section 5.1.4.

The emergency feedwater system functions automatically during MSLB to ensure that a heat sink is always available to the reactor coolant system by supplying cold feedwater to maintain an adequate water inventory in the unaffected steam generator. The affected steam generator is identified and isolated while a controlled flow path is provided to the unaffected steam generator. No credit for emergency feedwater flow to the unaffected steam generator is taken in the MSLB analysis.

Interface requirements on the maximum steam line and feedwater line volumes are discussed in Section 5.1.4. The total volume of fluid between the MSIV's and each steam generator is assumed to be 2000 cubic feet (total for two steam lines). The volume of fluid between the MSIV's and the turbine stop valves is assumed to be 14000 cubic feet maximum. The maximum volumes

TABLE 6.2.1-11

DATA FOR CONTAINMENT PEAK PRESSURE/TEMPERATURE ANALYSES
102% POWER/SLOT/8.78 SQ. FT./LOSS OF CONTAINMENT COOLING

Sheet 7 of 7

PART D. Accident Chronology

Setpoint

Replace with Insert A

Time (Seconds)	Event
0.00	Break Occurs
3.80	Reactor Trip Signal
3.80	Main Steam Isolation Signal
3.80	Main Feedwater Isolation Signal
4.70	Turbine Admission Valve Closed
4.70	Reactor Trip Begins
4.70	Main Steam Isolation Valves Start To Close
4.70	Main Feedwater Isolation Valves Start To Close
9.70	Main Steam Isolation Valves Closed
9.70	Main Feedwater Isolation Valves Closed
A*	Containment Spray Actuation Signal
A*	Peak Containment Temperature
A*	Peak Containment Pressure
170.00	End Of Blowdown

* See Applicant's SAR

Insert A

3.80	Containment Pressure Reaches Reactor Trip Analysis Setpoint	6.0 psig
3.80	Containment Pressure Reaches Main Steam Isolation Signal (MSIS) Analysis Setpoint	6.0 psig
4[illegible]	High Containment Pressure Reactor Trip Signal Generated and MSIS	
4[illegible]	[illegible]actor Trip Breakers Open [illegible] Turbine Admission Valves Closed	

TABLE 6.2.1-12

DATA FOR CONTAINMENT PEAK PRESSURE/TEMPERATURE ANALYSES
102% POWER/GUILLOTINE/8.78 SQ. FT./LOSS OF CONTAINMENT COOLING

Sheet 9 of 9

PART D: Accident Chronology

Setpoint
Replace with Insert B

Time (Seconds)	Event
0.00	Break Occurs
5.25	Reactor Trip Signal
5.25	Main Steam Isolation Signal
5.25	Main Feedwater Isolation Signal
6.15	Turbine Admisssion Valve Closed
6.15	Reactor Trip Begins
6.15	Main Steam Isolation Valves Start To Close
6.15	Main Feedwater Isolation Valves Start To Close
11.15	Main Steam Isolation Valves Closed
11.15	Main Feedwater Isolation Valves Closed
A*	Containment Spray Actuation Signal
A*	Peak Containment Temperature
A*	Peak Containment Pressure
175.00	End Of Blowdown

* See Applicant's SAR

Insert B

5.25 Containment Pressure Reaches Reactor Trip Analysis Setpoint 6.0 psig

5.25 Containment Pressure Reaches Main Steam Isolation Signal (MSIS) Analysis Setpoint 6.0 psig.

6.25 High Containment Pressure Reactor Trip Signal & Generated and MSIS

6.40 Reactor Trip Breakers Open
6.40 Turbine admission valves Closed

TABLE 6.2.1-13

DATA FOR CONTAINMENT PEAK PRESSURE/TEMPERATURE ANALYSES
75% POWER/SLOT/8.78 SQ. FT./LOSS OF CONTAINMENT COOLING

Sheet 7 of 7

PART D: Accident Chronology

setpoint

Time (Seconds)	Event
0.00	Break Occurs
3.70	Reactor Trip Signal
3.70	Main Steam Isolation Signal
3.70	Main Feedwater Isolation Signal
4.60	Turbine Admission Valve Closed
4.60	Reactor Trip Begins
4.60	Main Steam Isolation Valves Start To Close
4.60	Main Feedwater Isolation Valves Start To Close
9.60	Main Steam Isol. Valves Closed
9.60	Main Feedwater Isol. Valves Closed
A*	Containment Spray Actuation Signal
A*	Peak Containment Temperature
A*	Peak Containment Pressure
185.00	End Of Blowdown

Replace with Insert C

* See Applicant's SAR

Insert C

3.70	Containment Pressure Reaches Reactor Trip Analysis Setpoint	6.0 psig
3.70	Containment Pressure Reaches Main Steam Isolation Signal (MSIS) Analysis Setpoint	6.0 psig
4.70	High Containment Pressure Reactor Trip Signal and MSIS Generated	
4.85	Reactor Trip Breakers Open	
4.85	Turbine Admission Valves Closed	

TABLE 6.2.1-14

DATA FOR CONTAINMENT PEAK PRESSURE/TEMPERATURE ANALYSES
75% POWER/GUILLOTINE/8.78 SQ. FT./LOSS OF CONTAINMENT COOLING

Sheet 9 cf 9

PART D: Accident Chronology

setpoint

Replace with Insert D

Time (Seconds)	Event
0.00	Break Occurs
5.15	Reactor Trip Signal
5.15	Main Steam Isolation Signal
5.15	Main Feedwater Isolation Signal
6.05	Turbine Admission Valve Closed
6.05	Reactor Trip Begins
6.05	Main Steam Isolation Valves Start To Close
6.05	Main Feedwater Isolation Valves Start To Close
11.05	Main Steam Isol. Valves Closed
11.05	Main Feedwater Isol. Valves Closed
A*	Containment Spray Actuation Signal
A*	Peak Containment Temperature
A*	Peak Containment Pressure
190.0?	End of Blowdown

* See Applicant's SAR

Insert D

5.15 Containment Pressure Reaches Reactor Trip Analysis Setpoint 6.0 psig

5.15 Containment Pressure Reaches Main Steam Isolation Signal (MSIS) Analysis Setpoint 6.0 psig

6.15 High Containment Pressure Reactor Trip Signal and MSIS Generated

6.30 Reactor Trip Breakers Open

6.30 Turbine Admission Valves Closed

TABLE 6.2.1-15

DATA FOR CONTAINMENT PEAK PRESSURE/TEMPERATURE ANALYSES
50% POWER/SLOT/8.78 SQ. FT./LOSS OF CONTAINMENT COOLING

Sheet 7 of 7

PART D: Accident Chronology

setpoint replace with Part E

Time (Seconds)	Event
0.00	Break Occurs
3.55	Reactor Trip Signal
3.55	Main Steam Isolation Signal
3.55	Main Feedwater Isolation Signal
4.45	Turbine Admission Valve Closed
4.45	Reactor Trip Begins
4.45	Main Steam Isolation Valves Start To Close
4.45	Main Feedwater Isolation Valves Start To Close
9.45	Main Steam Isol. Valves Closed
9.45	Main Feedwater Isol. Valves Closed
A*	Containment Spray Actuation Signal
A*	Peak Containment Temperature
A*	Peak Containment Pressure
215.00	End of Blowdown

* See Applicant's SAR

Insert E

3.55	Containment Pressure Reaches Reactor Trip analysis Setpoint	6.0 psig
3.55	Containment Pressure Reaches Main Steam Isolation Signal (MSIS) Analysis Setpoint	6.0 psig
4.55	High Containment Pressure Reactor Trip Signal and MSIS Generated	
4.70	Reactor Trip Breakers Open	
4.70	Turbine Admission Valves Closed	

TABLE 6.2.1-16

DATA FOR CONTAINMENT PEAK PRESSURE/TEMPERATURE ANALYSES
50% POWER/GUILLOTINE/8.78 SQ. FT./LOSS OF CONT. COOLING

Sheet 9 of 9

PART D: Accident Chronology

setpoint

Time (Seconds)	Event
0.00	Break Occurs
5.00	Reactor Trip Signal
5.00	Main Steam Isolation Signal
5.00	Main Feedwater Isolation Signal
5.90	Turbine Admission Valve Closed
5.90	Reactor Trip Begins
5.90	Main Steam Isolation Valves Start To Close
5.90	Main Feedwater Isolation Valves Start To Close
10.90	Main Steam Isol. Valves Closed
10.90	Main Feedwater Isol. Valves Closed
A*	Containment Spray Actuation Signal
A*	Peak Containment Temperature
A*	Peak Containment Pressure
220.000	End of Blowdown

Replace with insert F

* See Applicant's SAR

Insert F

5.00	Containment Pressure Reaches Reactor Trip Analysis Setpoint	6.0 psig
5.00	Containment Pressure Reaches Main Steam Isolation Signal (MSIS) Analysis Setpoint	6.0 psig
6.00	High Containment Pressure Reactor Trip Signal and MSIS Generated	
6.15	Reactor Trip Breakers Open	
6.15	Turbine Admission Valves Closed.	

TABLE 6.2.1-17

DATA FOR CONTAINMENT PEAK PRESSURE/TEMPERATURE ANALYSES
25% POWER/SLOT/8.78 SQ. FT./LOSS OF CONTAINMENT COOLING

Sheet 7 of 7

PART D: Accident Chronology

Setpoint

Replace with Insert G

Time (Seconds)	Event
0.00	Break Occurs
3.45	Reactor Trip Signal
3.45	Main Steam Isolation Signal
3.45	Main Feedwater Isolation Signal
4.35	Turbine Admission Valve Closed
4.35	Reactor Trip Begins
4.35	Main Steam Isolation Valves Start To Close
4.35	Main Feedwater Isolation Valves Start To Close
9.35	Main Steam Isol. Valves Closed
9.35	Main Feedwater Isol. Valves Closed
A*	Containment Spray Actuation Signal
A*	Peak Containment Temperature
A*	Peak Containment Pressure
315.8	End of Blowdown

* See Applicant's SAR

Insert G

3.45	Containment Pressure Reaches Reactor Trip Analysis Setpoint	6.0 psig
3.45	Containment Pressure Reaches Main Steam Isolation Signal (MSIS) Analysis Setpoint	6.0 psig
4.45	High Containment Pressure Reactor Trip Signal Generated and MSIS	
4.60	Reactor Trip Breakers Open	
4.60	Turbine Admission Valves Closed	

TABLE 6.2.1-18

DATA FOR CONTAINMENT PEAK PRESSURE/TEMPERATURE ANALYSES
25% POWER/GUILLOTINE/8.78 SQ. FT./LOSS OF CONTAINMENT COOLING

Sheet 9 of 9

PART D: Accident Chronology

Time (Seconds)	Event
0.00	Break Occurs
4.86	Reactor Trip Signal
4.86	Main Steam Isolation Signal
4.86	Main Feedwater Isolation Signal
5.76	Turbine Admission Valve Closed
5.76	Reactor Trip Begins
5.76	Main Steam Isolation Valves Start To Close
5.76	Main Feedwater Isolation Valves Start To Close
10.76	Main Steam Isol. Valves Closed
10.76	Main Feedwater Isol. Valves Closed
A*	Containment Spray Actuation Signal
A*	Peak Containment Temperature
A*	Peak Containment Pressure
315.80	End of Blowdown

Setpoint

Replace with Insert H

* See Applicant's SAR

Insert H

4.86 Containment Pressure Reaches Reactor Trip Analysis Setpoint 6.0 psig

4.86 Containment Pressure Reaches Main Steam Isolation Signal (MSIS) Analysis Setpoint 6.0 psig

5.86 High Containment Pressure Reactor Trip Signal and MSIS Generated

6.01 Reactor Trip Breakers Open

6.01 Turbine Admission Valves Closed.

TABLE 6.2.1-19

DATA FOR CONTAINMENT PEAK PRESSURE/TEMPERATURE ANALYSES
0% POWER/SLOT/4.00 SQ. FT./LOSS OF CONTAINMENT COOLING

Sheet 7 of 7

PART D: Accident Chronology

Setpoint

Replace with Insert I

Time (Seconds)	Event
0.00	Break Occurs
4.55	Reactor Trip Signal
4.55	Main Steam Isolation Signal
4.55	Main Feedwater Isolation Signal
5.45	Turbine Admission Valve Closed
5.45	Reactor Trip Begins
5.45	Main Steam Isolation Valves Start To Close
5.45	Main Feedwater Isolation Valves Start To Close
10.45	Main Steam Isol. Valves Closed
10.45	Main Feedwater Isol. Valves Closed
A*	Containment Spray Actuation Signal
A*	Peak Containment Temperature
A*	Peak Containment Pressure
210.00	End of Blowdown

* See Applicant's SAR

Insert I

4.55	Containment Pressure Reaches Reactor Trip Analysis Setpoint	6.0 psig
4.55	Containment Pressure Reaches Main Steam Isolation Signal (MSIS) Analysis Setpoint	6.0 psig
5.55	High Containment Pressure Reactor Trip Signal Generated and MSIS	
5.70	Reactor Trip Breakers Open	
5.70	Turbine Admission Valves Closed.	

TABLE 6.2.1-20

DATA FOR CONTAINMENT PEAK PRESSURE/TEMPERATURE ANALYSES
0% POWER/GUILLOTINE/8.78 SQ. FT./LOSS OF CONTAINMENT COOLING

Sheet 9 of 9

PART D: Accident Chronology

Time (Seconds)	Event
0.00	Break Occurs
4.75	Reactor Trip Signal
4.75	Main Steam Isolation Signal
4.75	Main Feedwater Isolation Signal
5.65	Turbine Admission Valve Closed
5.65	Reactor Trip Begins
5.65	Main Steam Isolation Valves Start To Close
5.65	Main Feedwater Isolation Valves Start To Close
10.65	Main Steam Isol. Valves Closed
10.65	Main Feedwater Isol. Valves Closed
A*	Containment Spray Actuation Signal
A*	Peak Containment Temperature
A*	Peak Containment Pressure
210.00	End of Blowdown

Setpoint

Replace with Insert J

* See Applicant's SAR

Insert J

4.75	Containment Pressure Reaches Reactor Trip Analysis Setpoint	6.0 psig
4.75	Containment Pressure Reaches Main Steam Isolation Signal (MSIS) Analysis Setpoint	6.0 psig
5.75	High Containment Pressure Reactor Trip Signal and MSIS Generated	
5.90	Reactor Trip Breakers Open	
5.90	Turbine Admission Valves Closed.	

TABLE 6.3.3.3-6

TIMES OF INTEREST FOR SMALL BREAKS

(Seconds)

Break Size (ft^2)	HPSI PUMP FLOW DELIVERED TO RCS (c) ~~HPSI Pump On~~	LPSI PUMP FLOW DELIVERED TO RCS (c) ~~LPSI Pump On~~	SI TANKS FLOW DELIVERED TO RCS ~~SI Tanks On~~	Hot Spot Peak Clad Temp. Occurs
0.50 ft^2/PD	46.5	158.0	142.0	160.0
0.35 ft^2/PD	50.0	248.0	204.0	235.0
0.20 ft^2/PD	62.0	a.	400.0	442.0
0.05 ft^2/PD	208.0	a.	b.	2010.0
0.02 ft^2/PD	486.0 ~~482.0~~	a.	b.	437.0
0.03 ft^2/HL	585.0	a.	b.	540.0

(a) Calculation terminated before time of LPSI pump activation.

(b) Calculation terminated before initiation of SI tank discharge.

(c) This time includes a 30 second delay from the time that the pressurizer pressure reaches the low pressurizer pressure SIAS analysis setpoint. till the time when the SI pump flow is delivered to RCS at design capacity.

TABLE 6.3.3.5-1
(Sheet 1 of 2)

SEQUENCE OF EVENTS FOR REPRESENTATIVE LARGE AND SMALL BREAK LOCAs

Event	Large Break (0.8 DEG/PD)		Small Break (0.02 ft^2)		
	Setpoint Or Value	Time, Seconds	Setpoint Or Value	Time, Seconds	Success Path
Break occurs		0.0		0.0	
Core peak power	117%	0.15	105%	96.0	
INSERT 1 ~~Low pressurizer pressure trip signal~~	1600 psia	9.43	1600 psia	456.0	Reactivity Control
REACTOR TRIP AND Safety injection actuation ~~signals~~ signal GENERATED	~~1600 psia~~	10.43 ~~9.43~~	~~1600 psia~~	457.0 ~~456.0~~	Reactivity Control
SIT discharge begins	607.7 psia	16.2	607.7 psia	7500	Reactivity Control
Reflood begins		37.7		NA	
Main steam safety valves begin to open		NA	1295 psia	456.0	Sec. Sys. Integrity
Maximum secondary pressure	1239 psia		1340 psia	184.0	
HPSI pumps ~~start to deliver~~ flow delivered to RCS		68.2		456.0 ~~492.0~~	Reactivity Control
SITs empty		68.2		NA	
LPSI pumps ~~start to deliver~~ flow DELIVERED to RCS		68.2		NA	Reactivity Control

INSERT L TO TABLE 6.3.3.5-1.

PRESSURIZER PRESSURE REACHES REACTOR TRIP + SIAS ANALYSIS SETPOINT

f. The system is designed to determine the following generating station conditions in order to provide protective action assistance to the ESF during Limiting Faults:

1. Core power;

2. RCS pressure;

3. Steam generator pressure; and

4. Containment pressure.

g. The system is designed to monitor all generating station variables that are needed to assure adequate determination of the conditions given in listings e. and f. above, over the entire range of normal operation and transient conditions. The full power nominal values and the maximum and minimum values that can be sensed for each monitored plant variable are given in Table 7.2-2. The type, number, and location of the sensors provided to monitor these variables are given in Table 7.2-3.

h. The system is designed to alert the operator when any monitored plant condition is approaching a condition that would initiate protective action.

i. The system is designed so that protective action will not be initiated due to normal operation of the generating station.

Nominal full power values of monitored conditions and their corresponding protective action (trip) setpoints are given in Table 7.2-4.

The selection of these trip setpoints is such that adequate protection is provided when all sensor and processing time delays and inaccuracies are taken into account. Reactor trip delay ~~Response~~ times and analysis setpoints used in the Chapter 15 safety analyses are given in ~~Chapter 15.0~~. Table 15.0-4.

Insert C

The trip delay times and analysis setpoints ~~provided~~ used in Chapter 15.0 are representative of the manner in which the RPS and associated instrumentation will operate. These quantities ~~are used~~ in the transient analysis ~~done~~ documented in Chapter 15.0. Actual RPS Equipment uncertainties, ~~and~~ delay times will be obtained from calculations and tests performed on the RPS and associated instrumentation. The verified system uncertainties are factored into all RPS settings and/or setpoints to assure that the system adequately performs its intended function when the errors and uncertainties combine in an adverse manner.

Insert D

Insert E

j. All system components are qualified for environmental and seismic conditions in accordance with IEEE Standard 323-1974, and IEEE Standard 344-1971. Compliance is addressed in Section 3.11 and in CENPD-255, "Qualification of Combustion Engineering Class 1E Instrumentation", (Reference 3); and in Section 3.10 and CENPD-182, "Seismic Qualification

Insert C p. 7.2-17

reactor protective system sensor response times, reactor

Insert D p. 7.2-17

Note that the reactor trip delay times shown in Table 15.0-4 do not include the sensor response times.

Insert E p. 7.2-17

response times and reactor trip

Manual operations performed on a given system or component are indicated by placing an "M" in the lower left-hand corner of the system block. When a manual action is required, the sensed variables necessary to perform the action are shown as inputs and the location of the input signal is shown above the input signal circle.

The system setpoint values assumed in the transient analysis, e.g., trip signal setpoints, will be noted along the success path. Time delays or the time required to perform an action are shown as a number with square brackets.

All events presented in Sequence of Events Diagrams (SED) in this chapter are shown from event initiation to achievement of the Cold Shutdown operating mode (see Chapter 16). Not all events require that the plant be taken to Cold Shutdown. The SED's only demonstrate that for any event presented here it is possible to take them to Cold Shutdown by means of the safety actions indicated.

15.0.2 SYSTEMS OPERATION

During the course of any event various systems may be called upon to function. Some of these systems are described in Chapter 7 and include those electrical, instrumentation, and control systems designed to perform a safety function (i.e., those systems which must operate during an event to mitigate the consequences) and those systems not required to perform a safety function (see Sections 7.2 through 7.6 and 7.7, respectively).

The Reactor Protection System (RPS) is described in Section 7.2. Table 15.0-4 lists the RPS trips for which credit is taken in the analyses discussed in this section, including the setpoints and the trip delay times associated with each trip. The analyses take into consideration the response times of actuated devices after the ~~trip setting is reached.~~ Insert A

Insert B - The reactor trip delay time~~s~~ ~~shown in~~ (Table 15.0-4) ~~are~~ is defined as the elapsed time from the time the sensor output ~~reaches~~ EQUALS OR exceeds the trip setpoint to the time the reactor trip breakers are fully open. ~~The sensor response is modeled by using the transfer function for the particular sensor used.~~

The interval between trip breaker opening and the time at which the magnetic flux of the Control Element Assembly (CEA) holding coils has decayed enough to allow CEA motion is conservatively assumed to be 0.34 seconds. Finally, a conservative value of 3.66 seconds is assumed for CEA insertion, defined as the elapsed time from the beginning of CEA motion to the time of 90% insertion of the CEAs in the reactor core.

The Engineered Safety Feature Actuation Systems (ESFAS) and electrical, instrumentation, and control systems required for safe shutdown are described in Sections 7.3 and 7.4, respectively. The manner in which these systems function during events is discussed in each event description. The instrumentation which is required to be available to the operator in order to assist him in evaluating the nature of the event and determining required action is described in Section 7.5. The use of this instrumentation by the operator is discussed in each event description.

Insert A p. 15.0-4

value of the monitored parameter at the sensor equals or exceeds the trip setpoint.

Insert B p. 15.0-4

The reactor protective system response time is the sum of the sensor response time and the reactor trip delay time. The sensor response time is defined as the time from when the value of the monitored parameter at the sensor equals or exceeds the reactor protective system trip setpoint until the sensor output equals or exceeds the trip setpoint. The sensor response is modeled by using a transfer functim for the particular sensor used.

TABLE 15.0-4

REACTOR PROTECTION SYSTEM TRIPS USED IN THE SAFETY ANALYSIS

Event	RPS	Analysis Setpoint[f]	Reactor Trip Delay Time[c]
Events not Mentioned Below	High logarithmic Power Level	2%	550 ms
	Variable Overpower	17% or 130%[a]	
	High Pressurizer Pressure	2450 psia	550 ms
	Low Pressurizer Pressure	1580 psia	550 ms
	Low Steam Generator Pressure	820 psia	550 ms
	Low Steam Generator Water Level	40% wide range[b]	550 ms
	High Steam Generator Water Level	99% narrow range[e]	550 ms
	Low DNBR	1.19	150 ms
	High Local Power Density	21 kw/ft[d]	150 ms
	Steam Generator ΔP Low Flow	90% [g]	[h]
Feedwater and Steam Line Breaks	Variable Overpower	17% or 130%[a]	
	High Pressurizer Pressure	2475 psia	550 ms
	Low Pressurizer Pressure	1600 psia	550 ms
	Low Steam Generator Pressure	810 psia	550 ms
	Low Steam Generator Water Level	35% wide range[b]	550 ms
	High Steam Generator Water Level	99% narrow range[e]	550 ms
	Low DNBR	1.19	150 ms
	High Local Power Density	21 kw/ft [d]	150 ms

a. See discussion in Section 7.2.

b. Percent of distance between the wide range instrument taps above the lower tap. See Chapter 5 for details.

c. The reactor trip delay times are also discussed in Section 7.2. ~~and include signal and sensor delay.~~

d. Setpoint value is set below the value at which fuel centerline melting would occur. See Section 4.4.

e. Percent of distance between the narrow range instrument taps above the lower tap. See Chapter 5 for details.

f. Some Chapter 15 analyses assumed more conservative setpoints for specific events.

g. Percent of hot leg flow.

h. 1.0 second from time of occurrence of low flow trip condition until the reactor trip breakers open.

TABLE 15.0-5

INITIAL CONDITIONS

Parameter	Units	Range
Core Power	% of 3800 Mwt	0 - 102
Radial 1-pin peaking factor (with uncertainty)	-	1.40 to 1.63
Axial Shape Index (1)		$-0.3 \leq$ ASI $\leq +0.3$
Reactor Vessel Inlet Coolant Flowrate	% of 445600 gpm	95 - 116
Pressurizer Water Level	% distance between upper tap and lower tap above lower tap	26 to 60
Core Inlet Coolant Temperature	F	500 - 580 (2)
Reactor Coolant System Pressure	psia	1785 - 2400
Steam Generator Water Level	% distance between upper tap and lower tap above lower tap	40 - 88

(1) $\text{ASI} = \dfrac{\text{area under axial shape in lower half of core} - \text{area under axial shape in upper half of core}}{\text{total area under axial shape}}$

(2) Additional restrictions were applied to: Section 15.2.3, minimum core inlet coolant temperature equals 560°F; and Section 15.1.5, maximum core inlet coolant temperature equals 570°F.

above 90% power

B. Input Parameters and Initial Conditions

Table 15.1.4-3 lists the assumptions and initial conditions used for these analyses in addition to those discussed in section 15.0. Conditions were chosen such that the overpower condition caused by the increase in steam flow results in the closest approach to the specified acceptable fuel design limits (SAFDL) without causing a reactor trip. If core power increases more than the 11% due to the increasing steam flow, the Core Protection Calculators (CPC) will initiate a reactor trip and there will be no further degradation in thermal margin. For transients initiated at other sets of initial conditions, a trip may or may not be required depending on whether the initial thermal margin is as low as for the combination of conditions used in these analyses.

C. Results

Case 1: Inadvertent Opening of a Steam Generator Atmospheric Dump Valve (IOSGADV)

The dynamic behavior of the salient NSSS parameters following the IOSGADV is presented in Figures 15.1.4-1.1 to 15.1.4-1.15. Table 15.1.4-1 summarizes the major events, times and results for this transient.

The opening of an ADV increases the rate of heat removal by the steam generators causing cooldown of the RCS. Due to the negative moderator reactivity coefficient, core power increases from 102% of rated core power,reaching a new, stabilized value of 113% after approximately 30 seconds. The feedwater control system, which is assumed to be in the automatic mode supplies feedwater to the steam generators such that the steam generator water levels are maintained.

During the IOSGADV transient the minimum transient DNBR of 1.19 first occurs at approximately 30 seconds and remains there until 1850 seconds when the 1850.4 operator manually trips the reactor. At 1850.55 seconds the trip breakers open. ~~After a 0.34 second coil decay delay the CEA's begin to drop into the core at 1850.89 seconds~~. At this point, both the local and core average power decrease rapidly and DNBR increases. From 1858 seconds to 1886 seconds the MSSV's release steam.

at 2152.4 seconds

2149.4 At 2150 seconds the steam generator pressure drops below the MSIS setpoint of 820 psia. The MSIS initiates closure of the MSIV's and MFIV's. The MFIV's and MSIV's close by 2155 seconds. The affected steam generator dries out at 2650 seconds. At 3000 seconds the operator manually closes the open ADV. The operator initiates plant cooldown at 3600 seconds.

Case 2: Inadvertent Opening of a Steam Generator Atmospheric Dump Valve with Loss of Offsite Power after Turbine Trip (IOSGADV + LOP)

The dynamic behavior of the salient NSSS parameters following IOSGADV with loss of offsite power is presented in Figures 15.1.4-2.1 to 15.1.4-2.15. Table 15.1.4-2 summarizes the major events, times and results for this transient.

The opening of an ADV increases the rate of heat removal by the steam generators causing cooldown of the RCS. Due to the negative moderator reactivity coefficient core power increases from 102% of rated core

power,reaching a new, stabilized value of 113% after approximately 30 seconds. The feedwater control system, which is assumed to be in the automatic mode, supplies feedwater to the steam generators such that the steam generator water levels are maintained until the time of loss offsite power.

During the IOSGADV + LOP transient the minimum transient DNBR of 1.195 first occurs at approximately 30 seconds and remains there until the assumed turbinetrip followed by loss of offsite power at 45 seconds. Due to decreasing core flow following the loss of power to the reactor coolant pumps, conditions existfor a low DNBR trip. At 45.6 seconds a low DNBR trip signal is initiated by the core protection calculators. The reactor trip breakers open at 45.75 seconds ~~and after a 0.34 second coil decay delay the CEA's begin to drop into the core at 46.09 seconds~~. At 46.1 seconds the minimum transient DNBR of 1.05 is calculated to occur, after which DNBR rapidly increases as shown by Figure 15.1.4-2.15. ~~By 50.5 seconds the CEA's are fully inserted.~~ At 52 seconds the MSSV's open and release steam until 81 seconds. Voids begin to form in the upper head of the reactor vessel at 74 seconds.

312.4 At ~~324~~ seconds the steam generator pressure drops below the MSIS setpoint of 820 psia. The MSIS initiates closure of the MSIV's and MFIV's at 313.4 seconds. The MFIV's and the MSIV's close by 318 seconds. At 1150 seconds the affected steam generator dries out.

At 1800 seconds the operator manually closes the open ADV. The operator initiates plant cooldown at 3600 seconds.

Due to the coastdown of the reactor coolant flow a reduction of DNBR below 1.19 is calculated to occur. Approximately 8% of the fuel pins are predicted to experience DNB. However, within 3 seconds of reactor trip, the local and average core heat flux have decreased enough such that no pins remain in DNB.

15.1.4.4 Conclusions

The IOSGADV event results in a DNBR greater than 1.19 throughout the transient. The event in combination with a loss of off-site power (IOSGADV + LOP) results in a small fraction of the fuel pins being predicted to be in DNB for a few seconds. Thus at the most a limited number of fuel rod cladding perforations could occur for the IOSGADV + LOP event. For both cases, the RCS pressure remains well below 2750 psia, ensuring that the integrity of the RCS is maintained.

TABLE 15.1.4-1
SEQUENCE OF EVENTS FOR FULL POWER INADVERTENT OPENING OF A STEAM GENERATOR ATMOSPHERIC DUMP VALVE (IOSGADV)

Time (sec)	Event	Setpoint or Value
1.0	One atmospheric dump valve opens fully	--
30.0	Steady-state hot channel DNBR achieved	1.19
1850.4	Operator initiates manual trip ~~signal~~	--
1850.55	Trip breakers open	--
~~1850.89~~	~~CEA's begin to drop~~	~~--~~
1858	Main steam safety valves open, psia	1282
1886	Main steam safety valves close, psia	1218
1872	Void begins to form in RV upper head	--
2150.4	Main steam isolation signal ~~data~~ generated	~~800~~
2155	MFIV's close completely	--
2155	MSIV's close completely	--
2650	Affected steam generator dries out	--
3000	Operator manually closes ADV	--
3600	Operator initiates plants cooldown	--
2149.4	Steam generator pressure reaches main steam isolation signal (MSIS) analysis setpoint, psia	820

TABLE 15.1.4-2
SEQUENCE OF EVENTS FOR FULL POWER INADVERTENT OPENING OF A STEAM GENERATOR ATMOSPHERIC DUMP VALVE WITH LOSS OF OFFSITE POWER AFTER TURBINE TRIP

Time (sec)	Event	Setpoint or Value
0.0	One atmospheric dump valve opens fully	--
30.0	Steady state hot channel DNBR achieved	1.19
45.0	Turbine trips	--
45.0	Loss of offsite power occurs	--
45.6	Low DNBR trip ~~occurs~~ signal generated	--
45.75	Trip breakers open	--
~~46.09~~	~~CEA's begin to drop~~	~~--~~
46.1	Minimum transient DNBR	1.05
48	Hot channel DNBR increases above 1.195	--
~~50.5~~	~~CEA's fully inserted~~	
52	Main steam safety valves open, psia	1282
81	Main steam safety valves close, psia	1218
74	Void begins to form in RV upper head	--
~~315~~ 313.4	Main steam isolation signal ~~psia~~ generated	~~[illegible]~~
318	MFIV's close completely	--
318	MSIV's close completely	--
1150	Affected steam generator dries out	--
1800	Operator manually closes ADV	
3600	Operator initiates plant cooldown	--
312.4	Steam generator pressure reaches main steam isolation signal (MSIS) analysis setpoint, psia	820

of offsite power (Case 2) the most adverse effect is caused by failure of a MSIV on one of the steam lines on the intact generator to close following MSIS. Consequently for this case steam is assumed to continue to be released from the intact steam generator after MSIS at a rate consistent with the interface requirement of a maximum of 11% design steam flow rate non-isolable steam flow. This open flow path is represented by an effective flow area for steam blowdown from the intact steam generator of 0.2556 square feet. For case 5 (SLBFPD) there is no single failure which increases the potential for degradation in fuel cladding performance or which increases the offsite dose. However the failure of a MSIV was used in the analysis to be consistent with Case 2 (SLBFP).

The sequence of events for Cases 1 through 5 above are presented in Tables 15.1.5-1 through 5, respectively. The sequence of events for Case 6 is the same as for Case 3.

15.1.5.3 Analysis of Effects and Consequences

A. Mathematical Models

The mathematical models and data transfer between codes used in the SLB analysis are presented in Appendix C.

B. Input Parameters and Initial Conditions

The initial conditions assumed in the analysis of the NSSS response to Cases 1 through 5 are presented in Tables 15.1.5-6 through 10, respectively. The initial conditions for Case 6 are the same as those for Case 3. Justification of the selection of initial conditions and input parameters is presented in Appendix C.

C. Results

Case 1: Large Steam Line Break During Full Power Operation with Concurrent Loss of Offsite Power (SLBFPLOP)

The dynamic behavior of the salient NSSS parameters following the SLBFPLOP is presented in Figures 15.1.5-1.1 through 15.1.5-1.16. Table 15.1.5-1 summarizes the major events, times, and results for this transient.

Concurrent with the steam line break, a loss of offsite power occurs. At this time an actuation signal for the emergency diesel generators is initiated. Due to decreasing core flow following loss of power to the reactor coolant pumps, conditions exist for a low DNBR trip. At 0.6 second a low DNBR trip signal is initiated by the core protection calculators. At 0.75 second the reactor trip breakers open. ~~After a 0.34 second coil decay delay, the CEAs begin to drop into the core at 1.09 seconds. At 8.0 seconds voids begin to form in the upper head of the reactor vessel.~~ 7.7 At 8.3 seconds the steam generator pressure drops below the MSIS setpoint of 810 psia. The MSIS initiates closure of the MSIVs and MFIVs. The MFIVs and MSIVs close by 13.3 seconds. EFW is automatically initiated to the intact steam generator, assuming no delay after the EFAS signal on low level in the intact steam generator, at 13.3 seconds. At 120 177.4 seconds the pressurizer empties. At 178 seconds the pressurizer pressure has dropped below 1600 psia and initiates a SIAS. Within 30 seconds of SIAS the 29.6 operable HPSI pump is loaded on the diesels and reaches full speed and the HPSI valves are fully open. At 237 seconds the affected steam generator empties.

at 178.4 seconds

at 8.7 seconds

At 8.0 seconds voids begin to form in the upper head of the reactor vessel.

At 259 seconds the maximum core reactivity (+ 0.09 % $\Delta\rho$) occurs. Safety injection boron begins to reach the core at 280 seconds. As shown by Figure 15.1.5-1.16, the values of DNBR remain above those for which fuel damage would be indicated. At a maximum of 30 minutes the operator, via the appropriate emergency procedure, initiates plant cooldown by manual control of the atmospheric dump valves, assuming that offsite power has not been restored. Shutdown cooling is initiated when the RCS reaches 350°F and 400 psia.

Case 2: Large Steam Line Break During Full Power Operation with Offsite Power Available (SLBFP)

The dynamic behavior of the salient NSSS parameters following the SLBFP is presented in Figures 15.1.5-2.1 through 15.1.5-2.15. Table 15.1.5-2 summarizes the major events, times, and results for this transient.

At 6.95 seconds after the initiation of the steam line break a trip signal is initiated by the core protection calculators on a projected DNBR of 1.19. At 7.1 seconds the reactor trip breakers open. ~~After a 0.34 second coil decay delay, the CEAs begin to drop into the core at 7.44 seconds.~~ At 11.9 seconds 12.9 voids begin to form in the upper head of the reactor vessel. At ~~13.6~~ seconds the steam generator pressure drops below the MSIS setpoint of 810 psia. The at 13.9 seconds MSIS initiates closure of the MSIVs and MFIVs. The MFIVs and the operable MSIVs close by 18.5 seconds. EFW is automatically initiated to the intact steam generator, assuming no delay after the EFAS signal on low level in the intact steam generator, at 18.5 seconds. At 67 seconds the pressurizer 89.4 empties. At ~~90~~ seconds the pressurizer pressure drops below 1600 psia and 29.6 initiates a SIAS. Within ~~XX~~ seconds of SIAS the HPSI pumps reach full speed and the HPSI valves are fully open. At 149 seconds the affected steam at 90.4 seconds generator empties. At 151 seconds the maximum core reactivity (-0.18% $\Delta\rho$) occurs. Safety injection boron begins to reach the core at 160 seconds. The values of DNBR remain above 10 during the post-trip approach-to-criticality portion of this transient. At a maximum of 30 minutes the operator, via the appropriate emergency procedure, initiates plant cooldown by manual control of the turbine bypass valves. Shutdown cooling is initiated when the RCS reaches 350°F and 400 psia.

Case 3: Large Steam Line Break During Zero Power Operation with Concurrent Loss of Offsite Power

The dynamic behavior of the salient NSSS parameters following the SLBZPLOP is presented in Figures 15.1.5-3.1 through 15.1.5-3.15. Table 15.1.5-3 summarizes the major events, times, and results for this transient.

Concurrent with the steam line break, a loss of offsite power occurs. At this time an actuation signal for the emergency diesel generators is initiated. Due to decreasing core flow following loss of power to the reactor coolant pumps, conditions exist for a low DNBR trip. At 0.6 second a low DNBR trip signal is initiated by the core protection calculators. At 0.75 second the reactor trip breakers open. ~~After a 0.34 second coil decay delay, the CEAs begin to drop~~ 5.0 ~~into the core at 1.09 seconds.~~ At ~~5.7~~ seconds the steam generator pressure drops below the MSIS setpoint of 810 psia. The MSIS initiates closure of the MSIVs and MFIVs. The MFIVs and MSIVs close by ~~10.7~~ seconds. EFW is 10.6 automatically initiated to the intact steam generator, assuming no delay after the EFAS signal on low level in the intact steam generator, at ~~10.7~~ seconds.

10.6

at 6.0 seconds

At ~~45~~ 44.6 seconds the pressurizer pressure drops below 1600 psia and initiates a SIAS. Within ~~30~~ 29.6 seconds of SIAS the operable HPSI pump is loaded on the diesels and reaches full speed and the HPSI valves are fully open. At 55 seconds voids begin to form in the upper head of the reactor vessel. At 59 seconds the pressurizer empties. Safety injection boron begins to reach the core at 120 seconds. At 189 seconds the maximum core reactivity (-0.06% $\Delta\rho$) occurs. At 1240 seconds the affected steam generator empties. The values of DNBR remain above 10 during this transient. At a maximum of 30 minutes the operator, via the appropriate emergency procedure, initiates plant cooldown by manual control of the atmospheric dump valves, assuming that offsite power has not been restored. Shutdown cooling is initiated when the RCS reaches 350°F and 400 psia.

t 45.6 seconds

Case 4: Large Steam Line Break Zero Power Operation with Offsite Power Available (SLBZP)

The dynamic behavior of the salient NSSS parameters following the SLBZP is presented in Figures 15.1.5-4.1 through 15.1.5-4.15. Table 15.1.5-4 summarizes the major events, times, and results of this transient.

At ~~6.24~~ 5.64 seconds after initiation of the steam line break, the steam generator pressure drops below the low steam generator pressure trip and MSIS setpoint of 810 psia. At 6.79 seconds the reactor trip breakers open. ~~After a 0.34 second coil decay delay, the CEAs begin to drop into the core at 7.13 seconds.~~ The MSIS initiates closure of the MSIVs and MFIVs at 11.2 seconds. The MFIVs and MSIVs close by ~~12.3~~ 11.2 seconds. EFW is automatically initiated to the intact steam generator, assuming no delay after the EFAS signal on low level in the intact steam generator, at ~~12.3~~ 11.2 seconds. At ~~41~~ 40.6 seconds the pressurizer pressure drops below 1600 psia and initiates a SIAS. Within ~~30~~ 29.6 seconds of SIAS the operable HPSI pump reaches full speed and the HPSI valves are fully open. At 48 seconds voids begin to form in the upper head of the reactor vessel. At 52 seconds the pressurizer empties. Safety injection boron begins to reach the core at 110 seconds. At 310 seconds the maximum core reactivity (-0.02% $\Delta\rho$) occurs. At 418 seconds the affected steam generator empties. The values of DNBR remain above 10 for this transient. At a maximum of 30 minutes the operator, via the appropriate emergency procedure, initiates plant cooldown by manual control of the MSIV bypass valves associated with the unaffected steam generator and turbine bypass valves. Shutdown cooling is initiated when the RCS reaches 350°F and 400 psia.

at 41.6 seconds

Case 5: Steam Line Break Outside Containment During Full Power Operation with Offsite Power available (SLBFPD)

The dynamic behavior of the salient NSSS parameters following a typical limiting SLBFPD is presented in Figures 15.1.5-5.1 through 15.1.5-5.8. Table 15.1.5-5 summarizes the major events, times and results for this transient.

The consequences of this transient -- fraction of fuel rods predicted to experience DNB -- are nearly the same as those for SLBFPDs for a spectrum of break sizes, due to the protective action of the core protection calculators (CPCs). See the discussion in Section 15C.3.2 and Figure 15C-1 of Appendix 15C. The largest break size yields the minimum DNBR. Therefore the transient presented here is that which results from the double ended break of a main steam line.

Not later than 5.85 seconds after initiation of the steam line break, a trip signal is initiated by the CPCs on a projected DNBR of 1.19. At 6.00 seconds

the reactor trip breakers open. ~~After a 0.34 second coil decay delay, the CEAs begin to drop into the core at 6.34 seconds~~. At 7.49 seconds a minimum transient DNBR of ~~[illegible]~~ 1.11 is calculated to occur, after which DNBR rapidly increases, as shown in Figure 15.1.5-5.9. At 8.94 seconds voids begin to form in the upper head of the reactor vessel. At ~~[illegible]~~ 12.2 seconds the steam generator pressure drops below the MSIS setpoint of 810 psia. The MSIS initiates closure of the MSIVs and MFIVs at 13.2 seconds. The MFIVs and the operable MSIVs close by 17.8 seconds.

Subsequently, the events of this transient follow a sequence similar to those of the SLBFP (Case 2), Since the cooldown is less severe the potential for post-trip degradation in fuel cladding performance is less for this case (SLBFPD) than for Case 2 (SLBFP). At a maximum of 30 minutes the operator, using the appropriate emergency procedure, initiates plant cooldown by manual control of the turbine bypass valves. Shutdown cooling is initiated when the RCS reaches 350°F and 400 psia.

At the point of the minimum transient DNBR no more than 0.4% of the fuel rods are predicted to experience DNB. However, as a bounding assumption, 0.7% of the fuel pins are assumed to fail. All of the activity in the fuel gap for fuel rods that are assumed to fail is assumed to be uniformly mixed with the reactor coolant. The activity in the fuel clad gap is assumed to be 10% of the iodines and 10% of the noble gases accumulated in the fuel at the end of core life, assuming continuous full power operation, This results in a primary coolant activity of 618 μCi/gm. Assuming one gpm steam generator tube leakage, during a period of two hours after initiation of the SLBFPD the integral leakage from the RCS through the affected steam generator is 720 lbm, which is assumed to be released to the atmosphere with a DF of 1. This mass release results in a contribution to the inhalation thyroid dose at the Exclusion Area Boundary (EAB) of not more than 220 rem.

The total steam released from the affected steam generator is 153,000 lbm. The affected steam generator will empty in two hours; therefore all the mass release from the affected steam generator to the atmosphere has a DF of 1. The calculated inhalation thyroid dose is not more than 9.8 rem for the blowdown originating from the secondary system fluid discharge from the affected steam generator.

Less than 86,000 lbm of steam from the unaffected steam generator will be released through the steam line break. During the SLBFPD the MSIVs will isolate the unaffected steam generator from the break and prevent it from emptying. Therefore, a DF of 100 is assumed in calculating iodine activity released from the unaffected steam generator. The resulting contribution to the inhalation thyroid dose at the EAB is less than 0.1 rem. Should condensor vacuum be lost during this transient, up to an additional ~~[illegible]~~ 860000 lbm of steam from the unaffected steam generator would be released to the atmosphere through the atmospheric steam dump valves. This would result in an additional contribution to the dose of not more than ~~[illegible]~~ 0.5 rem.

The foregoing doses are calculated by the methods outlined in Section 15.0.4. Table 15.1.5-11 presents the major assumptions, parameters, and radiological consequences for this transient.

In summary, the total two-hour inhalation thyroid dose at the EAB as a consequence of the SSLBFP is no more than 231 rem.

Case 6: **Large Steam Line Break Outside Containment from Zero Power Operation with Loss of Offsite Power (SLBZPLOPD)**

Case 6 is included in Case 3, since the break of the latter can be either inside or outside of containment. The Figures, Tables, and Discussion for Case 3 apply to Case 6.

Assuming one gpm steam generator tube leakage, during a period of two hours after initiation of the SLBZPLOPD the integral leakage from the RCS through the affected steam generator is 720 lbm, which is assumed to be released to the atmosphere with a DF of 1. This mass release results in a contribution to the inhalation thyroid doses at the EAB of:

(a) 1.6 rem, assuming technical specification primary coolant activity;
(b) 20.1 rem, assuming a pre-existing iodine spike; or
(c) 41.5 rem, assuming an event-induced iodine spike.

The total steam released from the affected steam generator is 300,000 lbm, which is the total initial mass inventory. The affected steam generator will empty in two hours; therefore all the mass release from the affected steam generator to atmosphere has a DF of 1. The calculated inhalation thyroid dose is ~~14.0~~ 15.0 rem for the blowdown steam originating from the initial steam generator mass inventory.

Less than 850,000 lbm of steam from the unaffected steam generator will be released through the atmospheric steam dump valves and through the steam line break within two hours. During the SLBZPLOPD the MSIVs will isolate the unaffected steam generator and prevent it from emptying. Therefore, a DF of 100 is assumed in calculating iodine activity released from the unaffected steam generator. The resulting contribution to the inhalation thyroid dose at the EAB is 0.4 rem.

The foregoing doses are calculated by the methods outlined in Section 15.0.4. Table 15.1.5-11 presents the major assumptions, parameters, and radiological consequences for this transient.

In summary, the total two-hour inhalation thyroid dose at the EAB as a consequence of the SLBZPLOPD is no more than 56 rem.

15.1.5.4 Conclusion

For the large steam line break in combination with a single failure and stuck CEA, with or without a loss of offsite power, fission power remains sufficiently low following reactor trip to preclude fuel damage as a result of post-trip return to power.

For a large steam line break during zero power operation in combination with a loss of offsite power and technical specification tube leakage the two-hour inhalation thyroid dose at the EAB is well within 10CFR100 guidelines:

(a) 16 rem, assuming technical specification primary coolant activity;
(b) 35 rem, assuming a pre-existing iodine spike; or
(c) ~~56~~ 57 rem, assuming an event-induced iodine spike.

TABLE 15.1.5-1

SEQUENCE OF EVENTS FOR A LARGE STEAM LINE BREAK DURING FULL POWER OPERATION WITH CONCURRENT LOSS OF OFFSITE POWER (SLBFPLOP)

Time (Sec)	Event	Setpoint or Value
0.0	Steam Line Break and Loss of Offsite Power Occur	--
0.6	Low DNBR Trip ~~Condition Occurs,~~ Signal Generated, Projected DNBR	1.19
0.75	Trip Breakers Open	--
INSERT "A" ~~1.00~~	~~GEAs Begin to Drop~~	—
8.0	Voids Begin to Form in RV Upper Head	--
~~9.5~~ 8.7	Main Steam Isolation Signal ~~(MSIS)~~ Generated	~~810~~
13.3	MFIVs Close Completely	--
13.3	MSIVs Close Completely	--
INSERT "C" 13.3	EFW Initiated to Intact Steam Generator	--
120	Pressurizer Empties	--
INSERT "B" ~~175~~ 178.4	Safety Injection Actuation Signal ~~(SIAS)~~ Generated	~~1600~~
208	Safety Injection Flow Begins	--
237	Affected Steam Generator Empties	--
259	Maximum Transient Reactivity, 10^{-2} $\Delta\rho$	+0.09
277	Minimum Post-Trip DNBR	2.7
280	Safety Injection Boron Begins to Reach Reactor Core	--
1800	Operator Initiates Cooldown	--

T. 15.1.5-1

"A" 7.7 Steam Generator Pressure Reaches Main Steam Isolation Signal (MSIS) Analysis Setpoint, psia 810

"B" 177.4 Pressurizer Pressure Reaches Safety Injection Actuation Signal (SIAS) Analysis Setpoint, psia 1600

"C" 13.3 Steam Generator Level Reaches Emergency Feedwater Actuation Signal Analysis Setpoint, % of wide range 25

TABLE 15.1.5-2

SEQUENCE OF EVENTS FOR A LARGE STEAM LINE BREAK DURING FULL POWER OPERATION WITH OFFSITE POWER AVAILABLE (SLBFP)

Time (Sec)	Event	Setpoint or Value
0.0	Steam Line Break Occurs	--
6.95	Low DNBR Trip ~~[illegible]~~ Signal Generated, Projected DNBR	1.19
7.10	Trip Breakers Open	--
~~7.44~~	~~CEAs Begin to Drop~~	
11.9	Voids Begin to Form in RV Upper Head	--
INSERT "A" ~~12.5~~ 13.9	Main Steam Isolation Signal (MSIS) Generated	~~[illegible]~~
18.5	MFIVs Close Completely	--
18.5	MSIVs Close Completely	--
INSERT "B" 18.5	EFW Initiated to Intact Steam Generator	--
67	Pressurizer Empties	--
INSERT "C" ~~88~~ 90.4	Safety Injection Actuation Signal (SIAS) Generated	~~1600~~
120	Safety Injection Flow Begins	--
149	Affected Steam Generator Empties	--
151	Maximum Transient Reactivity, $10^{-2}\ \Delta\rho$	-0.18
151	Minimum Post-Trip DNBR	26
160	Safety Injection Boron Begins to Reach Reactor Core	--
1800	Operator Initiates Cooldown	--

T 15.1.5-2

"A"

12.9 Steam Generator Pressure Reaches Main Steam Isolation Signal Analysis Setpoint, psia 810

"B"

18.5 Steam Generator Water Level Reaches Emergency Feedwater Actuation Signal Analysis Setpoint, percent of wide range. 25

"C"

-89.4 Pressurizer Pressure Reaches Safety Injection Actuation Signal Analysis Setpoint, psia 1600

TABLE 15.1.5-3

SEQUENCE [redacted] EVENTS FOR A LARGE STEAM LINE BREAK DURING ZERO POWER OPERATI[redacted] CONCURRENT LOSS OF OFFSITE POWER (SLBZPLOP AND SLBZPLOPD)

Time (Sec)	Event	Setpoint or Value
0.0	Steam Line Break and Loss of Offsite Power Occur	--
0.6	Low DNBR Trip ~~Condition Occurs,~~ Signal Generated, Projected DNBR	1.19
0.75	Trip Breakers Open	--
~~1.09~~	~~CEAs Begin to Drop~~	~~--~~
INSERT "A"		
~~5.1~~ 6.0	Main Steam Isolation Signal ~~(MSIS)~~ Generated	~~[illegible]~~
~~10.7~~ 10.6	MFIVs Close Completely	--
~~10.7~~ 10.6	MSIVs Close Completety	--
INSERT "B"		
~~10.7~~ 10.6	EFW Initiated to Intact Steam Generator	--
INSERT "C"		
~~48~~ 45.6	Safety Injection Actuation Signal ~~(SIAS)~~ Generated	~~1600~~
55	Voids Begin to Form in RV Upper Head	--
59	Pressurizer Empties	
75.2	Safety Injection Flow Begins	--
120	Safety Injection Boron Begins to Reach Reactor core	--
189	Maximum Transient Reactivity, 10^{-2} $\Delta\rho$	-0.06
1240	Affected Steam Generator Empties	--
1800	Operator Initiates Cooldown	--

T 15.1.5-3

"A"	5.0	Steam Generator Pressure Reaches Main Steam Isolation Signal Analysis Setpoint, psia	810
(B)	10.6	Steam Generator Level Reaches Emergency Feedwater Actuation Signal Analysis Setpoint, % wide range	25
(C)	44.6	Pressurizer Pressure Reaches Safety Injection Actuation Signal Analysis Setpoint, psia	1600

TABLE 15.1.5-4

~~SEQUENCE OF EVENTS FOR A LARGE STEAM LINE BREAK DURING ZERO POWER OPERATION WITH OFFSITE POWER AVAILABLE (SLBZP)~~

	Time (Sec)	Event	Setpoint or Value
	0.0	Steam Line Break Occurs	--
INSERT "A"	~~5.24~~ 6.64	Low Steam Generator Pressure Reactor Trip and Main Steam Isolation Signal~~s (LSP)~~ Generated	~~[illegible]~~
	6.79	Trip Breakers Open	--
	~~7.13~~	~~CEAs Begin to Drop~~	
	~~11.5~~ 11.2	MFIVs Close Completely	--
	~~11.5~~ 11.2	MSIVs Close Completely	--
INSERT "B"	~~11.5~~ 11.2	EFW Initiated to Intact Steam Generator	--
INSERT "C"	~~3x~~ 41.6	Safety Injection Actuation Signal~~s (SIAS)~~ Generated	~~1800~~
	48	Voids Begin to Form in RV Upper Head	--
	52	Pressurizer Empties	--
	~~3x~~ 71.2	Safety Injection Flow Begins	
	110	Safety Injection Boron Begins to Reach Reactor Core	--
	310	Maximum Transient Reactivity, $10^{-2}\ \Delta\rho$	-0.02
	418	Affected Steam Generator Empties	--
	1800	Operator Initiates Cooldown	--

Table 15.1.5-4

"A"		
5.64	Steam Generator Pressure Reaches Reactor Trip Analysis Setpoint, psia	810
5.64	Steam Generator Pressure Reaches Main Steam Isolation Signal Analysis Setpoint, psia	810
"B"		
11.2	Steam Generator Water Level Reaches Emergency Feedwater Actuation Signal, Analysis Setpoint, % wide range	25
"C"		
40.6	Pressurizer Pressure Reaches Safety Injection Actuation Signal Analysis Setpoint, psia	1600

TABLE 15.1.5-5

SEQUENCE OF EVENTS FOR A STEAM LINE BREAK OUTSIDE CONTAINMENT DURING FULL POWER OPERATION WITH OFFSITE POWER AVAILABLE (SLBFPO)

	Time (Sec)	Event	Setpoint or Value
	0.0	Steam Line Break Occurs	--
	5.85	Low DNBR Trip ~~Condition~~ ~~[illegible]~~ Projected DNBR Signal Generated	1.19
	6.00	Trip Breakers Open	--
	~~6.34~~	~~CEAs Begin to Drop~~	—
	7.49	Minimum Transient DNBR	1.11
	8.94	Voids Begin to Form in RV Upper Head	--
INSERT "A" →	~~12.8~~ 13.2	Main Steam Isolation Signal ~~[illegible]~~ Generated	~~[illegible]~~
INSERT "B" →	17.8	EFW Initiated to Intact Steam Generator	
	17.8	MFIVs Close Completely	--
	17.8	MSIVs Close Completely	--
INSERT "C" →	~~65~~ 65.6	Safety Injection Actuation Signal ~~[illegible]~~ Generated	~~[illegible]~~
	75	Maximum Post-trip Transient Reactivity, 10^{-2} $\Delta\rho$	1.92
	~~98~~ 95.2	Safety Injection Flow Begins	—
	100	Affected Steam Generator Empties	—
	200	Safety Injection Boron Begins to Reach Reactor Core	—
	430	Secondary Post-trip Transient Reactivity Peak, 10^{-2} $\Delta\rho$	-2.06
	1800	Operator Initiates Cooldown	--

T. 15.1.5-5

"A" 12.2 Steam Generator Pressure Reaches Main Steam Isolation Signal Analysis Setpoint, psia 810

"B" Steam Generator Water Level Reaches Emergency
17.8 Feedwater Actuation Signal
Analysis Setpoint, percent of wide range 25

"C" 6.6 Pressurizer Pressure Reaches Safety Injection Actuation Signal (SIAS) Analysis Setpoint, psia 1600

15.2.3.3 <u>Analysis of Effects and Consequences</u>

A. Mathematical Model

The NSSS response to a LOCV was simulated using the CESEC-II computer program described in Section 15.0. The initial DNBR was calculated using the TORC computer code (see Section 15.0.3.1.6) which uses the CE-1 CHF correlation described in Reference 19 of Section 15.0.

B. Input Parameters and Initial Conditions

The input parameters and initial conditions used to analyze the NSSS response to a LOCV are discussed in Section 15.0. Table 15.2.3-4 contains the initial conditions and assumptions used for this event. The initial conditions for the principal process variables were varied within the ranges given in Table 15.0-5 to determine the set of initial conditions that would produce the most adverse consequences following a LOCV. Various combinations of initial core inlet temperature, core inlet flow, pressurizer pressure, steam generator level and pressurizer water level were considered in order to evaluate the effects on peak reactor coolant system (RCS) pressure.

Decreasing the initial core inlet temperature reduces the initial steam generator pressure, thereby delaying the heat removal associated with the opening of the main steam safety valves. However, the initial inlet temperature for this event was restricted to a minimum of 560°F. Decreasing the initial inlet temperature (as well as increasing the initial core flow rate) also minimizes the core average coolant temperature which results in the most positive moderator temperature coefficient.

Reduction of the initial pressurizer pressure delays the occurrence of reactor trip on high pressurizer pressure and allows the maximum reduction in steam generator heat removal prior to and following trip. As a result maximum RCS overpressurization occurs, provided that the delay does not allow the main steam safety valves to open prior to reaching the peak pressure condition. Decreasing the initial pressurizer water level produces similar trip delays.

C. Results

The dynamic behavior of important NSSS parameters following the loss of condenser vacuum is presented in Figures 15.2.3-2 to 15.2.3-14.

The sudden reduction of steam flow, caused by the LOCV leads to a reduction of the primary-to-secondary heat transfer. The moderator reactivity increases slightly prior to the reactor trip due to a positive MTC as the average core temperature increases from the initial conditions. This added reactivity causes the core power to reach a maximum at 6.8 seconds. The rapid heatup of the reactor coolant results in a high pressurizer pressure trip condition at 5.84 6.4 seconds. The ~~CEAs begin dropping in at the core~~ at 7.3 seconds and limit the maximum core power to 102% of full power. 6.99

reactor trip breakers open

The pressurizer safety valves open at 6.9 seconds and the maximum RCS pressure of 2742 psia is reached at 8.6 seconds. The main steam safety valves open at 6.9 seconds and the maximum secondary pressure of 1353 psia is reached at 14.0 seconds.

6.7

44.1

The RCS pressure decreases rapidly due to the combined effects of reactor trip and primary and main steam safety valves. The pressurizer safety valves close at 12.0 seconds and the main steam safety valves close at 346.0 seconds. Emergency feedwater flow automatically begins at 42.3 seconds and continues to fill the stam generators until a normal level is reached at 1408 seconds. At 764.1 963.0 seconds a safety injection actuation signal is generated when the pressurizer pressure decreases below 1580 psia. Borated water enters the RCS at 1150.0 seconds from the high pressure injection pumps. Thirty minutes after initiation of the events, the operator commences a cooldown using the atmospheric dump valves to release steam.

The DNBR during the event, remains above its initial value of 1.4; therefore, DNB does not occur.

D. Single Failures

The LOCV event is assumed to abruptly and completely terminate both main steam and feedwater flow. Considering peak pressure criteria, the only mechanisms for mitigation of the reactor coolant system (RCS) pressurization are the pressurizer safety valves, the reactor coolant flow and main steam safety valves. The last two influence the RCS-to-steam generator heat transfer rate.

There are no credible failures which can degrade pressurizer safety valve or main steam safety valve capacity. A decrease in RCS-to-steam generator heat transfer due to reactor coolant flow coastdown can only be caused by a failure to fast transfer (FFT) to offsite power or a loss of offsite power (LOP) following turbine trip (i.e., two or four pump coastdown, respectively). The two and four pump coastdowns result in an immediate reactor trip, generated by the Core Protection Calculators (CPC's). Due to the rapid reactor trip, both of these failures reduce the peak pressure relative to the LOCV itself.

With regard to fuel performance, decreased coolant flow is the only parameter which can significantly reduce the minimum DNBR during the LOCV event. FFT and LOP are the only single failures which impact coolant flow. LOCV by itself, however, produces an increasing DNBR (see Figure 15.2.3-2). This results in a greater thermal margin than is required to preclude a DNBR below 1.19 for either single failure. Consequently neither will cause fuel failure. LOP, however, because of the more rapid flow coastdown, causes a greater degradation in DNBR and hence is more limiting. The decrease in DNBR is shown in Figure 15.3.1-9.

15.2.3.4 Conclusions

For both the loss of condenser vacuum event, and LOCV with a single failure, the maximum RCS pressure remains below 2750 psia, thus ensuring primary system integrity. The minimum DNBR remains above 1.19, thus ensuring fuel cladding integrity.

TABLE 15.2.3-1

SEQUENCE OF EVENTS FOR THE LOCV

Time (Sec)	Event	Setpoint or Value	Success Path
0.0	Loss of Condenser Vacuum		
INSERT "A"			
~~[illegible]~~ 6.84	High Pressurizer Pressure Trip Signal, psia Generated	[redacted]	Reactivity Control
6.7	Main Steam Safety Valves Open psia	1282	Secondary System Integrity
* INSERT "B"			
~~6.7~~	~~Low Steam Generator Water Level, percent of wide range~~	[redacted]	~~Reactivity Control~~
6.8	Maximum Core Power, % of Design Power	102	Reactivity Control
6.9	Pressurizer Safety Valves, Open, psia	2525	Priamry Integrity System
~~7.3~~ 6.99	Trip Breakers Open ~~CEA's Begin To Drop~~		Reactivity Control
8.6	Maximum RCS Pressure, psia	2742	
12.0	Pressurizer Safety Valves Close, psia	2462	Primary System Integrity
14.0	Maximum Steam Generator Pressure, psia	1353	
INSERT "C"			
~~32.0~~ 34.1	Emergency Feedwater Actuation Signal, percent of wide range Generated	[redacted]	
~~42.0~~ 44.1	Emergency Feedwater Flow Initiated, gpm	875	Secondary System Integrity
INSERT "D"			
346.0	Main Safety Valves Close, psia	1218	Secondary System Integrity
~~963.0~~ 964.1	Safety Injection Actuation Signal, psia Generated	[redacted]	Reactor Heat Removal
~~1005.0~~ 993.7	Safety Injection Flow Initiated		Primary System Integrity

15.2.3-1

"A" Pressurizer Pressure Reaches Reactor
5.84 Trip Analysis Setpoint, psia

2450 Reactivity Control

"B" Steam Generator Water Level Reaches
6.7 Reactor Trip Analysis Setpoint,
percent of wide range

40

"C" Steam Generator Water Level Reaches
Emergency Feedwater Actuation Signal
33.1 Analysis Setpoint, percent of
wide range

15

D" Pressurizer Pressure Reaches Safety
Injection Actuation Signal
963.1 Analysis Setpoint, psia

1580

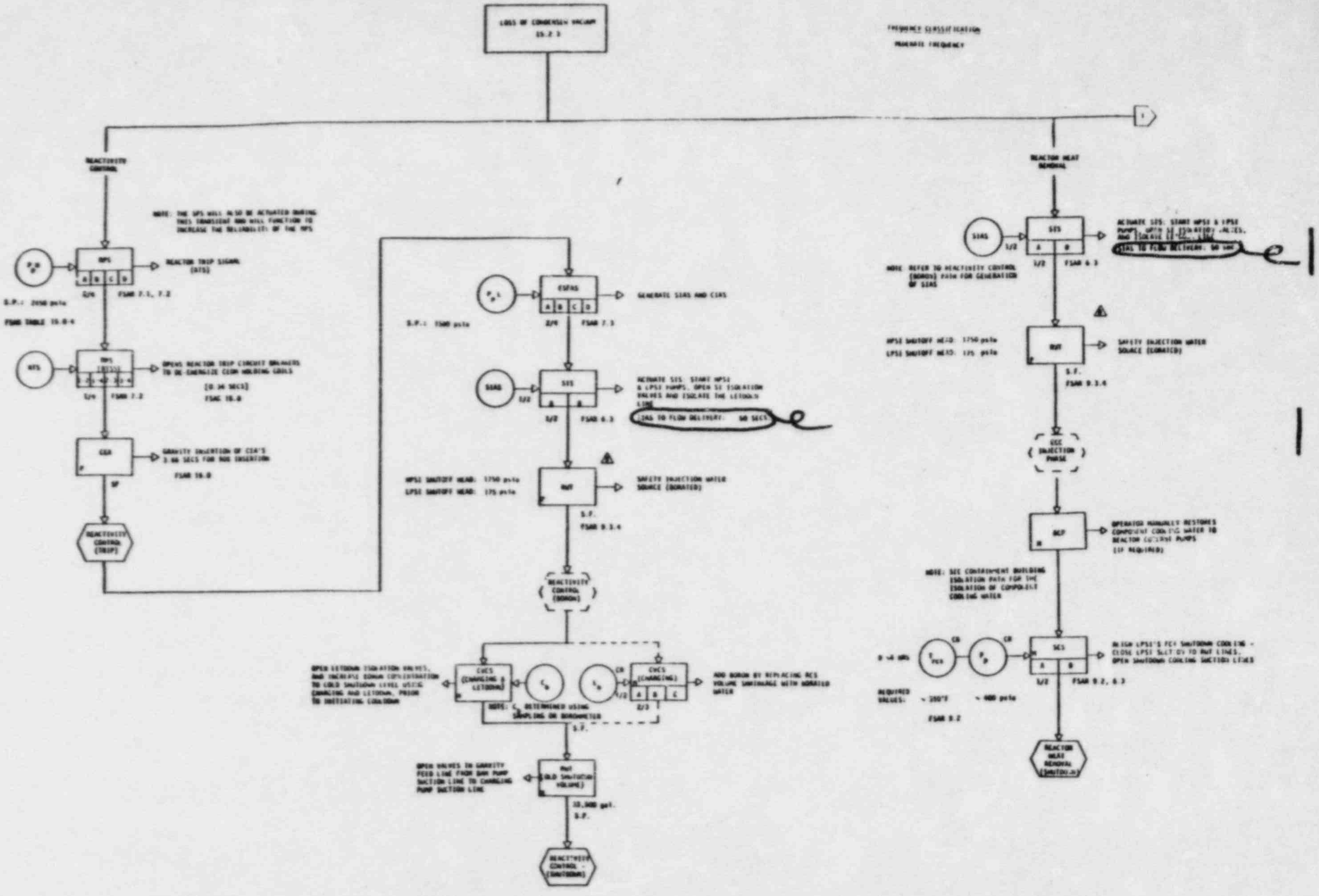
Reactor Heat Removal

TABLE [illegible]5.2.[illegible]-1 ([illegible]ont'd)

SEQUENCE OF EVENTS FOR THE LOCV

Time (Sec)	Event	Setpoint or Value	Success Path
1150.0	Borated HPSI Flow Enters the Core		Reactivity Control
1408.0	EFAS ~~Withdrawn, percent of wide range~~	80	Secondary System Integrity
1800.0	Operator Initiates Plant Cooldown		Reactor Heat Removal

Steam Generator Water Level
Reaches EFAS Reset Analysis
Setpoint, percent of wide range



C - E SYSTEM 80

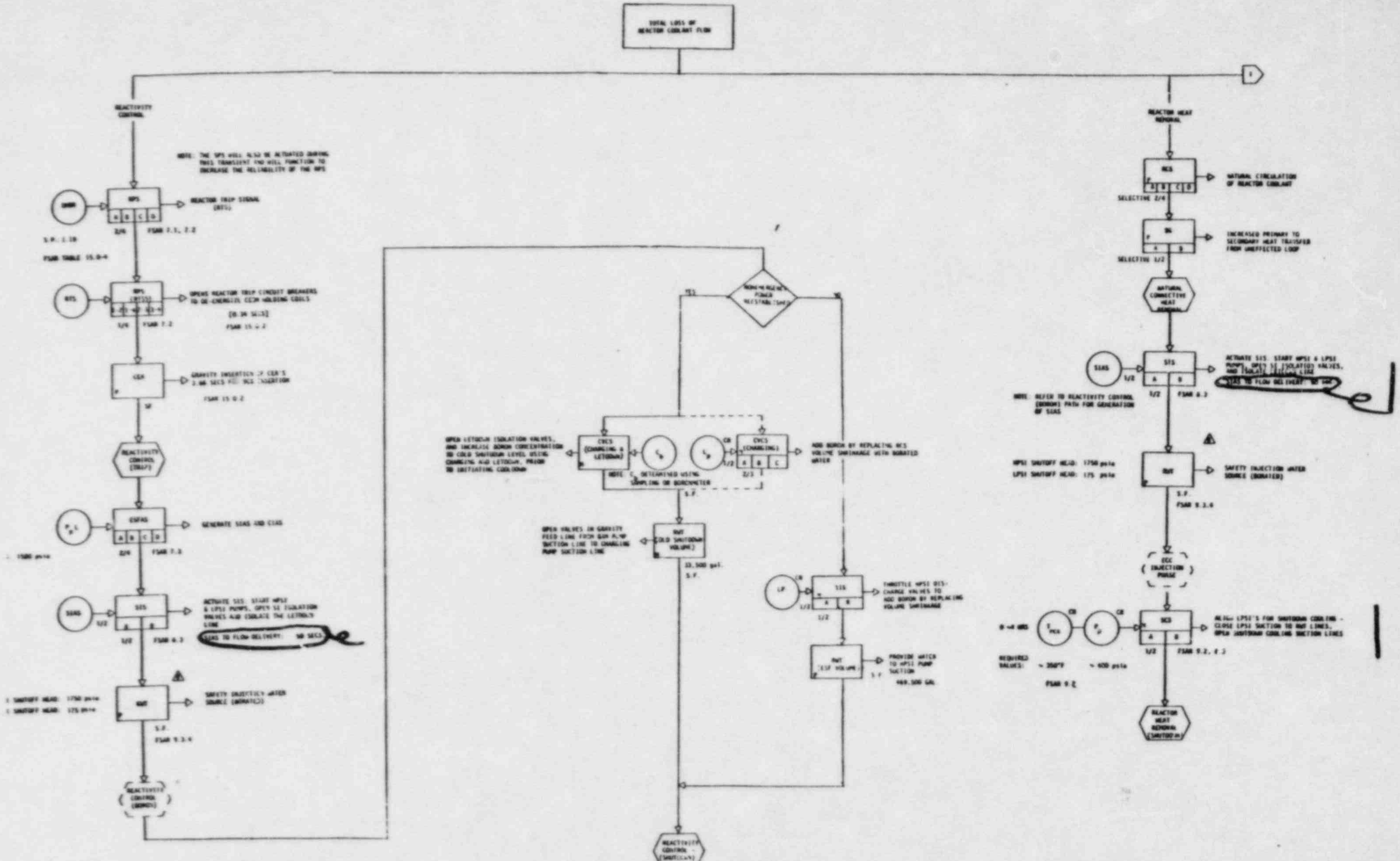
SEQUENCE OF EVENTS DIAGRAM FOR LOCV

Figure 15.2.3 a1A

TABLE 15.3.1-1

SEQUENCE OF EVENTS FOR TOTAL LOSS OF REACTOR COOLANT FLOW

Time (Sec)	Event	Setpoint Or Value	Success Path
0.0	Loss of Offsite Power - Turbine Trip - Diesel Generator Starting Signal - Reactor Coolant Pumps Coast Down - ~~Main Feedwater is Lost~~ Loss of Main Feedwater		
0.6	Low DNBR Trip Signal Generated, Projected DNBR	1.19 ~~Projected~~	Reactivity Control
0.75	Trip Breakers Open		Reactivity Control
1.09	CEA's Begin to Drop		Reactivity Control
2.6	Minimum Transient DNBR	1.19	
4.3	Pressurizer Safety Valves Open, psia	2525	Primary System Integrity
5.3	Maximum RCS Pressure, psia	2576	
5.4	Main Steam ~~Steam Generator~~ Safety Valves Open, psia	1282	Secondary System Integrity
11.7	Maximum Steam Generator Pressure, psia	1338	
12.2	Pressurizer Safety Valves Closed, psia	2463	Primary System Integrity
1800.0	Operator Initiates Plant Cooldown		



C-E SYSTEM 80

SEQUENCE OF EVENTS DIAGRAM FOR

TOTAL LOSS OF REACTOR COOLANT FLOW

Figure 15.3.1-1A

Table 15.3.3-1

(Sheet 1 of 2)

SEQUENCE OF EVENTS FOR THE SINGLE REACTOR COOLANT PUMP ROTOR SEIZURE WITH LOSS OF OFFSITE POWER RESULTING FROM TURBINE TRIP

Time (sec.)	Event	Setpoint or Value	Total Integrated Safety Valve Flow (lbm)	Success Path
0.0	Seizure of a Single Reactor Coolant Pump	—	—	—
0.76	Low DNBR Trip Signal Generated, projected	1.19	—	Reactivity Control
1.25	CEAs Begin to Drop Into the Core	—	—	Reactivity Control
1.25	Turbine Trip/Generator Trip	—	—	—
1.4	Minimum Transient DNBR	0.967	—	—
4.1	Main Steam Safety Valves Open, Unaffected Loop, psia	1280	—	Secondary System Integrity
4.2	Maximum RCS Pressure, psia	2387	—	—
4.25	Loss of Offsite Power Occurs	—	—	—
4.5	Main Steam Safety Valves Open, Affected Loop, psia	1280	—	Secondary System Integrity
6.8	Maximum Steam Generator Pressure, Unaffected Loop, psia	1347	3,492	—
7.4	Maximum Steam Generator Pressure, Affected Loop, psia	1340	5,451	—
0.91	Reactor Trip Breakers Open	—	—	Reactivity Control

Table 15.3.3-1 (Continued)

(Sheet 2 of 2)

SEQUENCE OF EVENTS FOR THE SINGLE REACTOR COOLANT PUMP ROTOR SEIZURE WITH LOSS OF OFFSITE POWER RESULTING FROM TURBINE TRIP

INSERT "A"

Time (Sec.)	Event	Setpoint or Value	Total Integrated Safety Valve Flow (lbm)	Success Path
218 (Replace with "B")	~~Low Water Level EFAS Setpoint Reached in the Steam Generator, Unaffected Loop, percent of wide range~~	~~[illegible]~~	85,679	Secondary System Integrity
263	Emergency Feedwater Begins Entering Steam Generator, Unaffected Loop, lbm/sec	119	91,407	Secondary System Integrity
INSERT "C"				
697 (Replace with "D")	~~Low Water Level EFAS Setpoint Reached in the Steam Generator, Affected Loop, percent of wide range~~	~~[illegible]~~	115,189	Secondary System Integrity
	Emergency Feedwater Begins Entering the Steam Generator, Affected Loop, lbm/sec	119		
821	Steam Generator Safety Valves Close, Affected and Unaffected Loop, psia	1218	120,398	Secondary System Integrity
1800	Atmospheric Dump Valves Opened to Initiate Plant Cooldown, °F/hour. One Atmospheric Dump Valve Sticks Open	-100.0	120,398	Secondary System Integrity
7200	Total Steam Release to Atmosphere, lbm	—	1,128,293	—

T 15.3.3-1 (2)

"A"

217	Steam Generator Water Level Reaches Emergency Feedwater Actuation Signal Analysis Setpoint in the Unaffected Loop, percent of wide range	20	Secondary System Integrity

"B"

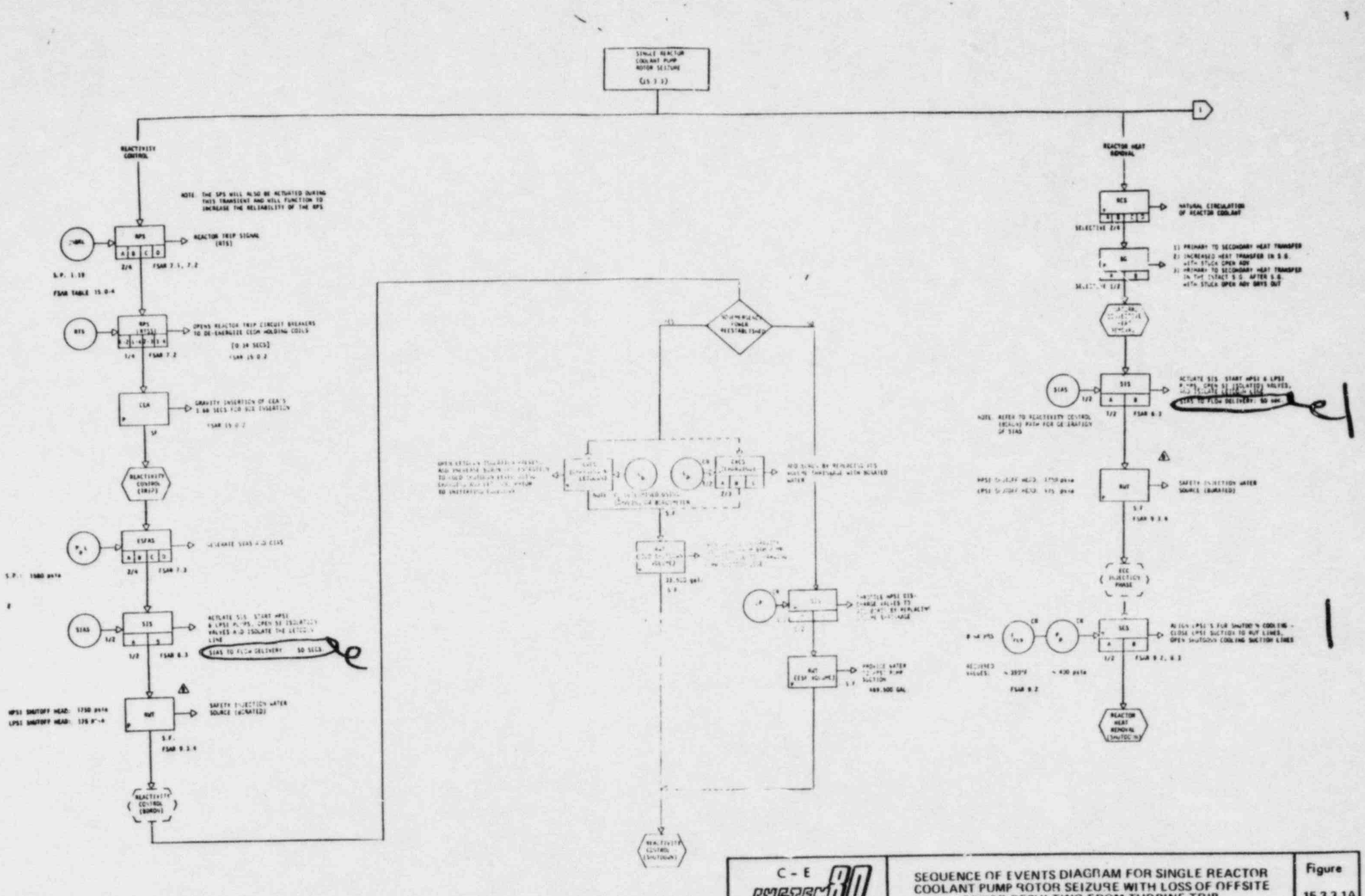
Emergency Feedwater Actuation Signal Generated

"C"

696	Steam Generator Water Level Reaches Emergency Feedwater Actuation Signal Analysis Setpoint in the Affected Loop, percent of wide range	20	Secondary System Integrity

"D"

Emergency Feedwater Actuation Signal Generated



C - E SYSTEM 80

SEQUENCE OF EVENTS DIAGRAM FOR SINGLE REACTOR COOLANT PUMP ROTOR SEIZURE WITH LOSS OF OFFSITE POWER RESULTING FROM TURBINE TRIP

Figure 15.3.3 1A

corresponds to the largest insertion rate expected from the sequential withdrawal of the CEA groups with 40% overlap at the maximum speed of 30 in./minute.

C. Results

The dynamic behavior of important NSSS parameters following a CEA withdrawal from low power conditions is presented in Figures 15.4.1-1 through 15.4.1-8.

The withdrawal of CEA's from low power conditions (1 MWt power) adds reactivity to the reactor core, causing both the core power level and the core heat flux to increase. The power transient causes increasing temperature and pressure transients, which together with a top peaked axial power distribution, produce the closest approach to the specified acceptable fuel design limit on DNBR. Since the transient is initiated at low power levels, one of the normal reactor feedback mechanisms, moderator feedback, does not contribute to any appreciable
23.75 extent to the power excursion transient. At 23.4 seconds into the transient, a variable overpower trip is actuated. The CEA's begin dropping into the core
and at 24.2 seconds which terminates the transient with a hot channel minimum DNBR of 5.4. If the maximum rod radial peaking factor occurs in the region of the axial power peak, the peak linear heat generation rate during the transient reaches ~~13.1~~ 13.9 KW/ft.

15.4.1.4 Conclusions

The uncontrolled CEA withdrawal from a subcritical or low power condition event meets general design criteria 25 and 20. These criteria require that the specified acceptable fuel design limits are not exceeded and the protection system action is initiated automatically. The withdrawal of CEA's from low power conditions meets the following fuel design limits which serve as the acceptance criteria for this event: the transient terminates with a hot channel minimum DNBR greater than or equal to 1.19 and the peak linear heat generation rate during the transient is less than 21 KW/ft.

The hot channel minimum DNBR reached during the transient is 4.84 at 27.30 seconds.

TABLE 15.4.1-1

SEQUENCE OF EVENTS FOR THE SEQUENTIAL CEA WITHDRAWAL EVENT

Time(sec)	Event	Setpoint or Value	Success Path
0.00	Withdrawal of CEA's - Initiating Event	--	Reactivity Control
23.75 ← 23.4	Variable Overpower Trip, ~~% of Design Power~~ Signal Generated	~~17.0~~	Reactivity Control
23.90	~~CEDM Power Supply~~ Trip Breakers Open	--	Reactivity Control
~~24.2~~	~~CEA's Begin to Drop~~	--	~~Reactivity Control~~
25.40 ← 25.2	Maximum Core Power, % of Design Power	43.5 → 45.8	
26.65 ← 26.7	Maximum Core Average Heat Flux, % of Full Power Heat Flux	16.9 — 17.53	
27.0	Minimum DNBR	5.40 — 4.84	
35.20	Maximum Pressurizer Pressure, psia	1894	
23.35	Core Power Reaches Variable Overpower Reactor Trip Analysis Setpoint, percent of design power.	17.0	Reactivity control

TABLE 15.4.1-4

ASSUMPTIONS AND INITIAL CONDITION FOR THE LOW POWER CEA WITHDRAWAL ANALYSIS

Parameter	Value
Initial core power level, MWt	1
Core inlet coolant temperature, ^{o}F	564.5
Core mass flowrate, 10^{6} lb_{m}/h	142.1 — 148.4
Reactor coolant system pressure, psia	1785
One pin radial peaking factor, with uncertainty	2.53
Steam generator pressure, psia	1178.
Moderator temperature coefficient, 10^{-4} $\Delta\rho$ /^{o}F	+0.5
Doppler coefficient multiplier	.85
CEA reactivity addition rate, 10^{-4} $\Delta\rho$/^{o}sec	2.5
CEA Worth on trip, 10^{-2} $\Delta\rho$	-3.5[a] — -6.4
Steam bypass control system	Manual

a. The scram worth used in this analysis does not take credit for the additional worth available from the withdrawn CEA's and is therefore considered conservative. Furthermore, the worth assumed is less negative than that calculated or expected.

Other input parameters which are important to this analysis are the Moderator Temperature Coefficient (MTC) and Fuel Temperature Coefficient (FTC) of reactivity. A moderator temperature coefficient was assumed in this analysis which corresponds to beginning-of-life core conditions. This MTC has the smallest impact on retarding the rate of change of power, coolant temperature, and DNBR. A fuel temperature coefficient corresponding to beginning-of-life conditions was used in the analysis, since this FTC causes the least amount of negative reactivity change for mitigating the transient increases in core power, heat flux, and the reactor coolant temperatures. The uncertainty on the fuel temperature coefficients used in the analyses is listed in Table 15.4.2-4.

The regulating CEA position from which the CEA withdrawal is initiated corresponds to 25% insertion of the first regulating bank. This particular insertion was selected based on the calculated CEA worth and associated uncertainties to produce the worst transient. A corresponding maximum differential worth of 0.01% $\Delta\rho$ per inch of rod motion was conservatively assumed in the present analysis. This corresponds to a maximum reactivity withdrawal rate of 0.5×10^{-4} $\Delta\rho$ per second based on the maximum CEA withdrawal speed of 30 inches per minute, including all uncertainties.

All the control systems listed in Table 15.4.2-2, except the steam bypass control system, were assumed to be in the automatic mode since these systems have no impact on the minimum DNBR obtained during the transient. The steam bypass control system is assumed to be in manual mode because this minimizes DNBR during the transient.

C. Results

The dynamic behavior of important NSSS parameters following an uncontrolled CEA group withdrawal are presented in Figures 15.4.2-1 2 to 15.4.2-11 12.

The withdrawal of CEA's causes a positive reactivity change, resulting in an increase in the core power and heat flux. As a consequence, the reactor 9.51 coolant temperature and pressurizer pressure increase. At 9.5 seconds after initiation of the transient, a reactor trip on low DNBR is actuated. At 9.7 9.66 seconds the trip breakers are opened. The CEA's begin dropping into the core and 10.0 seconds which terminates the transient. The minimum DNBR reached during the transient is 1.19 at 11.0 seconds. If the maximum rod radial peaking factor occurs in the region of the axial power peak, the peak linear generation rate during the transient reaches 16.7 KW/ft. Table 15.4.2-1 lists the sequence of events for the limiting DNBR case.

15.4.2.4 Conclusions

The uncontrolled CEA withdrawal event meets general design criteria 25 and 20. These criteria require that the specified acceptable fuel design limits are not exceeded and the protection system action is initiated automatically. The withdrawal of CEA's from full power conditions meets meets the following fuel design limits which serve as the acceptance criteria for this event: the transient terminates with a hot channel minimum DNBR greater than or equal to 1.19 and the peak linear heat generation rate during the transient is less than 21 KW/ft.

TABLE 15.4.2-1

SEQUENCE OF EVENTS FOR THE SEQUENTIAL CEA WITHDRAWAL EVENT

TIME(sec)	Event	SETPOINT OR VALUE	SUCCESS PATH
0.0	Withdrawal of CEA's - Initiating Event	--	Reactivity Control
9.51 ← 9.5	Low DNBR Trip Signal Generated, projected DNBR	1.19	Reactivity Control
9.66 ← 9.7	~~CEDM Power Supply~~ TRIP Breakers Open	--	Reactivity Control
~~10.0~~	~~CEA's Begin to Drop~~	--	Reactivity Control
10.1	Maximum Core Power, % of Design Power	108.2	
11.0	Minimum DNBR	1.19	
11.4	Maximum Core Average Heat Flux, % of Full Power Heat Flux	105.6	
12.3	Maximum Pressurizer Pressure, psia	2363	

TABLE 15.4.8-1
(Sheet 1 of 2)

SEQUENCE OF EVENTS FOR
THE CEA EJECTION EVENT

Time (sec)	Event	Setpoint or Value	Success Path
0.0	Mechanical Failure of CEDM Causes CEA to Eject	--	
~~0.05~~ 0.43	Variable Overpower ~~High Power~~ Trip Signal ~~% of design power~~ Generated	~~[illegible]~~	Reactivity Control
0.05	CEA Fully Ejected	--	
0.08	Maximum Core power, % of design power	138.3	
~~0.92~~ 0.58	~~CEAs Begin to Drop~~ Trip Breakers open	--	Reactivity Control
0.92	Turbine Trip Occurs	--	Secondary Integrity
2.53	Main Steam Safety Valves Open, psia	1282	Secondary System Integrity
2.6	Maximum Clad Surface Temperature in the Hot Node, F	936	
3.8	Maximum Fuel Centerline Temperature in the Hot Node, F	3779	
3.9	Pressurizer Safety Valves Open, psia	2525	Primary System Integrity
0.03	Core Power Reaches Variable Overpower Reactor Trip Analysis Setpoint, percent of design power	117	Reactivity Control

TABLE 15.4.8-1 (Cont'd) (Sheet 2 of 2)

SEQUENCE OF EVENTS FOR THE CEA EJECTION EVENT

Time (Sec)	Event	Setpoint or Value	Success Path
3.9	Maximum Pressurizer Pressure, psia	2525	
4.7	Pressurizer Safety Valves Closed, psia	2462	Primary System Integrity
4.9	Maximum Steam Generator Pressure, psia	1348	
~~5.3~~	~~CEAs Fully Inserted, Core Power Reduced to below 15% of design power~~		
INSERT "A"			
40.2 40.5	Safety Injection Actuation Signal (SIAS) Generated [illegible]	~~1580~~	Reactor Heat Removal
INSERT "B"			
850	Main Steam Safety Valves Closed, psia	1250	Secondary System Integrity
1800	Operator begins plant cooldown	--	Secondary System Integrity
12230	Shutdown cooling initiated, RCS pressure, temperature, ^{o}F	400/350	Reactor Heat Removal

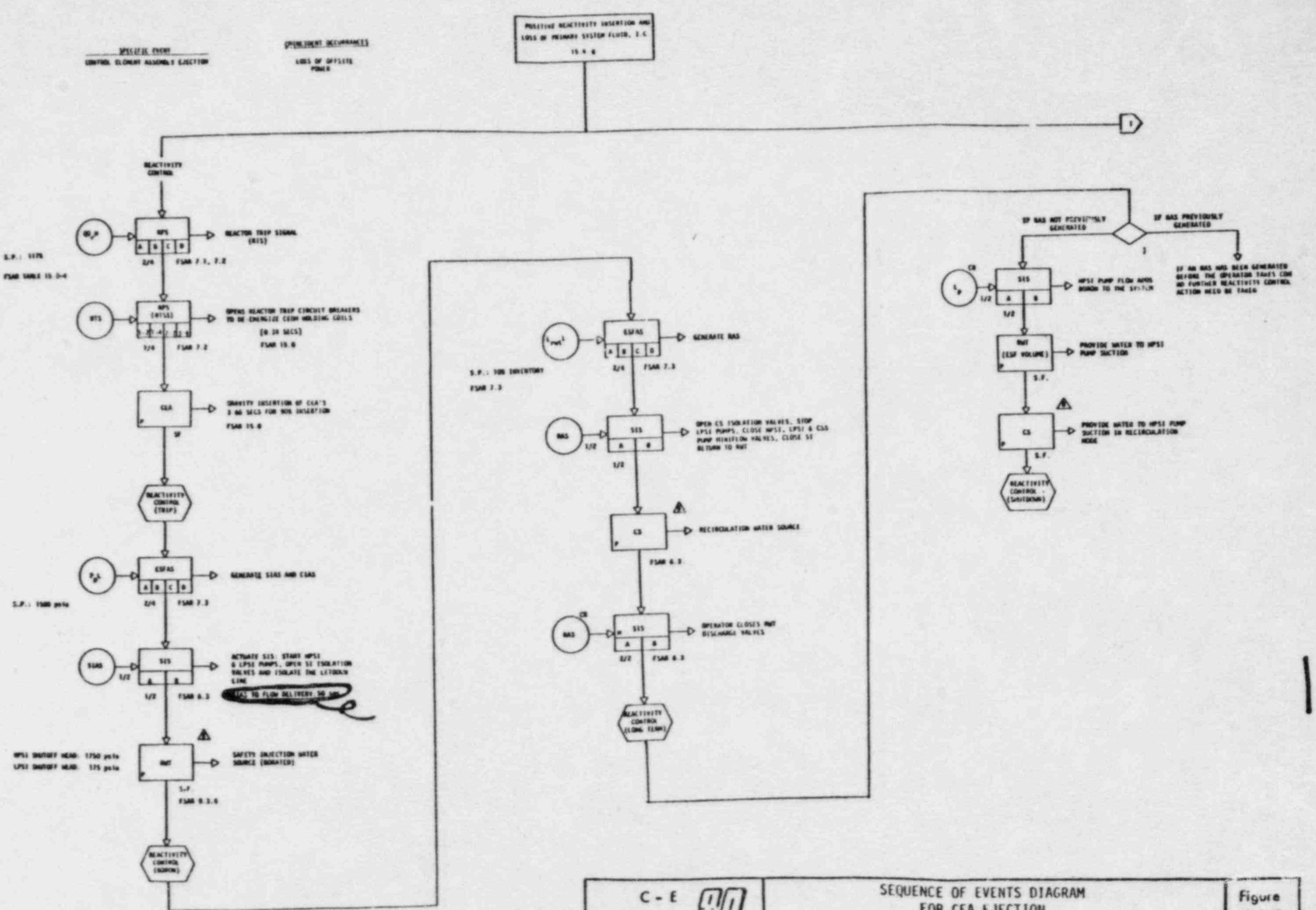
T. 15.4.8-1

"A"

39.5	Pressurizer Pressure Reaches Safety Injection Actuation Signal Analysis Setpoint, psia	1580	Reactor Heat Removal

"B"

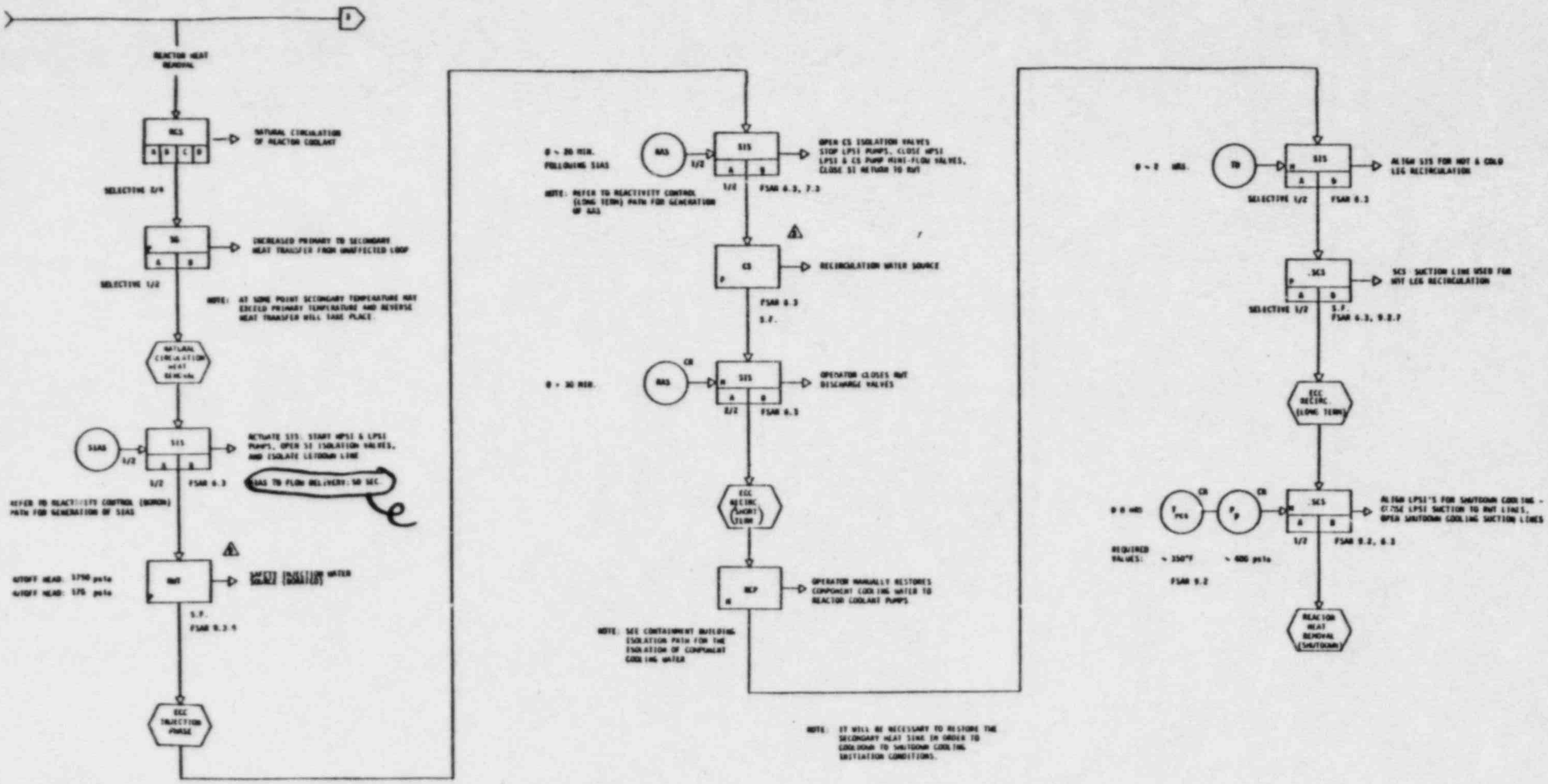
70.1	Safety Injection Flow Initiated	--	Reactor Heat Removal



C - E SYSTEM 80

SEQUENCE OF EVENTS DIAGRAM
FOR CEA EJECTION
WITH LOSS OF OFFSITE POWER

Figure 15.4.8



C - E SYSTEM 80

SEQUENCE OF EVENTS DIAGRAM
FOR CEA EJECTION
WITH LOSS OF OFFSITE POWER

Figure 15.4.8-1C

15.4.8-1 contains the sequence of events that occur during a CEA Ejection initiated from full power BOC initial conditions.

Ejection of a CEA causes the core power to increase rapidly due to the almost instantaneous addition of positive reactivity. However, the rapid increase in core power is terminated by a combination of Doppler feedback and delayed neutron effects. This increase in power results in a high power trip and the reactor power begins to decrease as the CEA's enter the core. Reactivity effects are shown in Figure 15.4.8-7.

In the hot channel, the increase in heat flux is such that DNB is calculated to occur, resulting in:

1. A rapid decrease in the surface heat transfer coefficient.

2. A rapid decrease in heat flux.

3. A rapid increase in clad temperature.

The rapid increase in clad temperature is sufficient to override the decreased surface heat transfer coefficient, resulting in a second peak in the hot channel heat flux. At this time the CEAs are nearly fully inserted, resulting in a rapid reduction in the core power level. The heat flux continues to decrease for the remainder of the transient.

Initial RCS pressure for calculation of the limiting fuel performance and radiological release event was 2200 psia. RCS pressure vs. time for this case is given on Figure 15.4.8-8. The long term RCS pressure response is shown on Figure 15.4.8-10. Initial RCS pressure for the limiting peak pressure case is 2400 psia. RCS pressure vs. time for this case is given on Figure 15.4.8-9

Steam generator pressures, and steam generator safety valve flow rate following a FPBOC CEA ejection with a postulated loss of offsite power following turbine trip are shown in Figures 15.4.8-11 through 15.4.8-13.

The transient behavior of the NSSS following a postulated CEA Ejection is as follows. The steam generator pressure increases rapidly due to the closure of the turbine control valve following reactor and turbine trip. The steam bypass control system is inoperable on loss of offsite power and therefore is unavailable. The steam generator pressure reaching a maximum of 1348 psia at 4.8 seconds. The pressurizer pressure increases to a maximum of 2525 psia at
4.9 3.9 seconds due to the decreased heat removal of the steam generators.

Subsequently, the reduced reactor power following the reactor trip, in addition to the postulated break in the primary system, cause the RCS pressure and temperature to decrease.

The steam generator pressure decreases slowly until the main steam safety valves close. The total released through the safety valves is approximately 136,800 lbm.

Following a postulated CEA Ejection Event, 9.8% of the fuel is calculated to experience DNB. Regulatory Guide 1.77 recommends that the onset of DNB be used as the basis for predicting clad failure. C-E does not equate onset of DNB with cladding failure. Nevertheless, this criterion was used to determine the percentage of pins that suffer clad failure.

TABLE 15.5.2-1

SEQUENCE OF EVENTS FOR THE PLCS MALFUNCTION WITH A LOSS OF OFFSITE POWER AT TURBINE TRIP

Time (Sec)	Event	Setpoint or Value	Success Path
0	Charging Flow Maximized & Letdown Flow Minimized	--	
1250.7	High Pressurizer Pressure Trip and Loss of A.C. at the Time of Turbine Trip, psia	2450	Reactivity Control
1252.7	Pressurizer Safety Valves open, psia	2525	Primary System Integrity
1253.2	Maximum Pressurizer Pressure, psia	2561	
1262.3	Pressurizer Safety Valves Close, psia	2525	Secondary System Integrity
1265.5	Main Steam Safety Valves Open, psia	1282	Secondary System Integrity
1270.3	Maximum Steam Generator Pressure, psia	1298	
1800.0	Operator Initiates Plant Cooldown	--	Reactor Heat Removal

REPLACE WITH "A"

"A"

1250.1	Pressurizer Pressure Reaches Reactor Trip Analysis Setpoint, psia	2450	Reactivity Control
1251.1	High Pressurizer Pressure Trip Signal Generated	--	
1251.25	Trip Breakers Open	--	Reactivity Control
1251.6	Turbine Trip, Loss of Offsite Power	--	

charging pumps is decreased significantly. Therefore, the most negative value of MTC was selected to maximize the positive reactivity addition from injection of cold makeup water.

Total charging flow due to all three pumps is 132 GPM. Considering 16 GPM for the control bleed takeoff and 30 GPM for the minimum letdown flow, net flow increase to the RCS is 86 GPM. The Pressurizer Pressure Control System (PPCS) is assumed to be in the manual mode with the proportional sprays off preventing the PPCS from suppressing the resulting pressure transient.

C. Results

The dynamic behavior of NSSS parameters following PLCS malfunction with loss of offsite power at turbine trip is presented in Figures15.5.2-2 to 15.5.2-11.

Failure of the Pressurizer Level Control System (PLCS) causes an increase in reactor coolant sysem inventory initiated by the startup of the third charging pump coupled with the decrease in letdown flow to its minimum. With the PPCS in the manual mode and the proportional sprays turned off, increase in RCS inventory results in a pressurizer pressure increase to the reactor ~~high pressure~~ trip analysis setpoint of 2450 psia ~~and trips the reactor at 1250.7 seconds.~~ at 1250.1 seconds. The trip breakers open at 1251.25 seconds.

Since the steam bypass control system is in the manual mode and the rate of closure of the turbine stop valves is faster than the rate of control rod insertion, pressurizer pressure increases to 2561 psia which opens the primary safety valves. Decreasing core heat flux and the opening of the primary safety valves causes the pressure to drop; however, the decrease in primary to secondary heat transfer due to four pump loss of flow causes pressurizer pressure to again increase, reaching a peak value of 2480 psia.

The unavailability of the steam bypass valves causes the steam generator pressure to increase, causing the main steam safety valves to open at 1265.5 seconds. The decreasing core power and the safety valves function to limit the steam generator pressure to 1298 psia.

The 796.5 lbs of steam discharged by the pressurizer safety valve is contained in the quench tank with no releases to the atmosphere. The main steam safety valves discharge 22,714 lbs of steam to the atmosphere prior to 1800 seconds. At 1800 seconds, the operator stabilizes the plant and initiates plant cooldown, using steam dump valves.

15.5.2.4 Conlcusion

The peak pressurizer pressure reached during the Pressurizer Level Control System malfunction with a loss of offsite power at turbine trip is 2561 psia and is less than 110% of the design pressure. Since this transient causes an increase in RCS pressure due to an increase in primary coolant inventory the DNBR increases. Therefore, the acceptance criterion regarding fuel performance is met.

For a double-ended rupture, the primary to secondary leak rate exceeds the capacity of the charging pumps. As a result, the pressurizer pressure gradually decreases from an initial value of 2400 psia. The primary to secondary leak rate and drop in pressurizer water level causes the third CVCS charging pump to turn on Even with all three CVCS charging pumps on line the pressurizer pressure and level continue to drop. This results in the pressurizer heaters being de-energized 1148.3 at 560 seconds. At ~~1148~~ seconds a reactor trip signal is generated due to exceeding the CPC low pressure boundary ~~of 1785 psia~~. The 1181.8 pressurizer empties at approximately 1151 seconds. At ~~1181~~ seconds a safety injection actuation signal is generated, and ~~by 1231 seconds~~ the safety injection flow is initiated. After the pressurizer empties, the reactor vessel upper head begins to behave like a pressurizer, and controls the reactor coolant system pressure until the pressurizer begins to refill at approximately 1447 seconds. Due to flashing caused by the depressurization, and the boiloff due to metal structure to coolant heat transfer, small amounts of voids form in the reactor vessel upper head at about 1151 seconds. Consequently, the RCS pressure begins to decay at a lower rate at this time. However, under the combined action of safety injection and charging flows, and reduced primary to secondary leakage, the upper head voids completely collapse at about 1447 seconds. Prior to this time, the RCS pressure begins to slowly increase helping to collapse the reactor vessel upper head voids. The pressurizer water level is reestablished at about the same time due to the net mass influx which increase the RCS inventory.

Following reactor trip and with turbine bypass assumed to be unavailable (i.e., in the manual mode), the main steam system pressure increases until the main steam safety valves open at 1209 seconds to control the main steam system pressure. A maximum main steam system pressure of 1283 psia occurs at 0.1 seconds after the MSSVs open. Subsequent to this peak in the pressure, the main steam system pressure decreases, resulting in the closure of the main steam safety valves at 1316 seconds.

Prior to reactor trip, the feedwater control system is assumed to be in the automatic mode and supplies feedwater to the steam generators such that steam generator water levels are maintained. Following reactor trip, the feedwater flow decreases to approximately 5% of the full power flow rate. Since the steam flow out of the steam generators is less than this feedwater flow, the liquid inventory in the steam generators gradually increases. At 1690 seconds a HLO mode terminates feedwater flow to the damaged steam generator. At 1778 seconds a HLO mode terminates feedwater flow to the intact steam generator.

After 1800 seconds, the operator identifies and isolate the affected steam generator by closing the main steam isolation valves and by securing the reactor coolant pumps in the affected loop. The operator then initiates an orderly cooldown via the steam bypass system and the condenser, and with manually-controlled feedwater flow to the unaffected steam generator. After the pressure and temperature of the reactor coolant are reduced to 400 psia and 350°F respectively, the operator activates the shutdown cooling system and isolates the unaffected steam generator.

TABLE 15.6.3-1
(Sheet 1 of 2)

SEQUENCE OF EVENTS FOR THE STEAM GENERATOR TUBE RUPTURE

Time (Sec)	Event	Setpoint or Value	Success Path
0.0	Tube Rupture Occurs	--	
30.0	Third Charging Pump Started, feet below program level	-0.75	Primary System Integrity
30.0	Letdown Control Valve Throttled Back to Minimum Flow, feet below program level	-0.75	Primary System
53.8	Backup Heaters Energized, psia	2360	Primary System Integrity
560.0	Pressurizer Heaters De-energized due to Low Pressurizer Liquid Volume, ft^3	400	
1148.3	CPC Low Pressure Boundary Trip Signal, ~~psia~~ Generated	~~[illegible]~~	Reactivity Control
INSERT "A"	Feedwater Flow Starts Ramp Down to 5% of Initial Full power Flow		
~~[illegible]~~	~~CEAs Begin to Drop~~	—	~~Reactivity~~
1149	Turbine Trip: Stop Valves Start to Close	-- --	Control Secondary System Integrity
1151	Pressurizer Empties	--	--
1152	Turbine Stop Valves Closed	--	Secondary System Integrity
INSERT "B"			
1181.8	Safety Injection Actuation Signal, ~~psia~~ Generated	~~[illegible]~~	Reactivity Control and Reactor Heat Removal
INSERT "C"			
1181.8	Letdown Isolation Valves Closed on SIAS	--	Primary System Integrity

TABLE 15.6.3-1 (Cont'd.) (Sheet 2 of 2)

SEQUENCE OF EVENTS FOR THE STEAM GENERATOR TUBE RUPTURE

Time (Sec)	Event	Setpoint or Value	Success Path
1209	Main Steam Safety Valves Open, psia	1282	Secondary System Integrity
1210	Maximum Steam Generator Pressure, psia	1283	
~~1221.74~~	~~Safety Injection Flow Initiated~~	~~--~~	
1316	Main Steam Safety Valves Close, psia	1218	Secondary System Integrity
1447	Pressurizer begins to refill	--	
1690	HLO Mode Terminates Feedwater Flow to Damaged Steam Generator, % wide range	80	Secondary System Integrity
1778	HLO Mode Terminates Feedwater Flow to Intact Steam Generator, % wide range	80	Secondary System Integrity
1800	Operator Isolates the Damaged Steam Generator and Initiates Plant Cooldown at 100°F/hr for the 1.5 hour time period	--	Reactor Heat Removal
28,800	Shutdown Cooling Entry Conditions are Assumed to be reached, RCS Pressure, psia/RCS Temperature, °F	400/350	Reactor Heat Removal

T 15.6.3-1

"A"

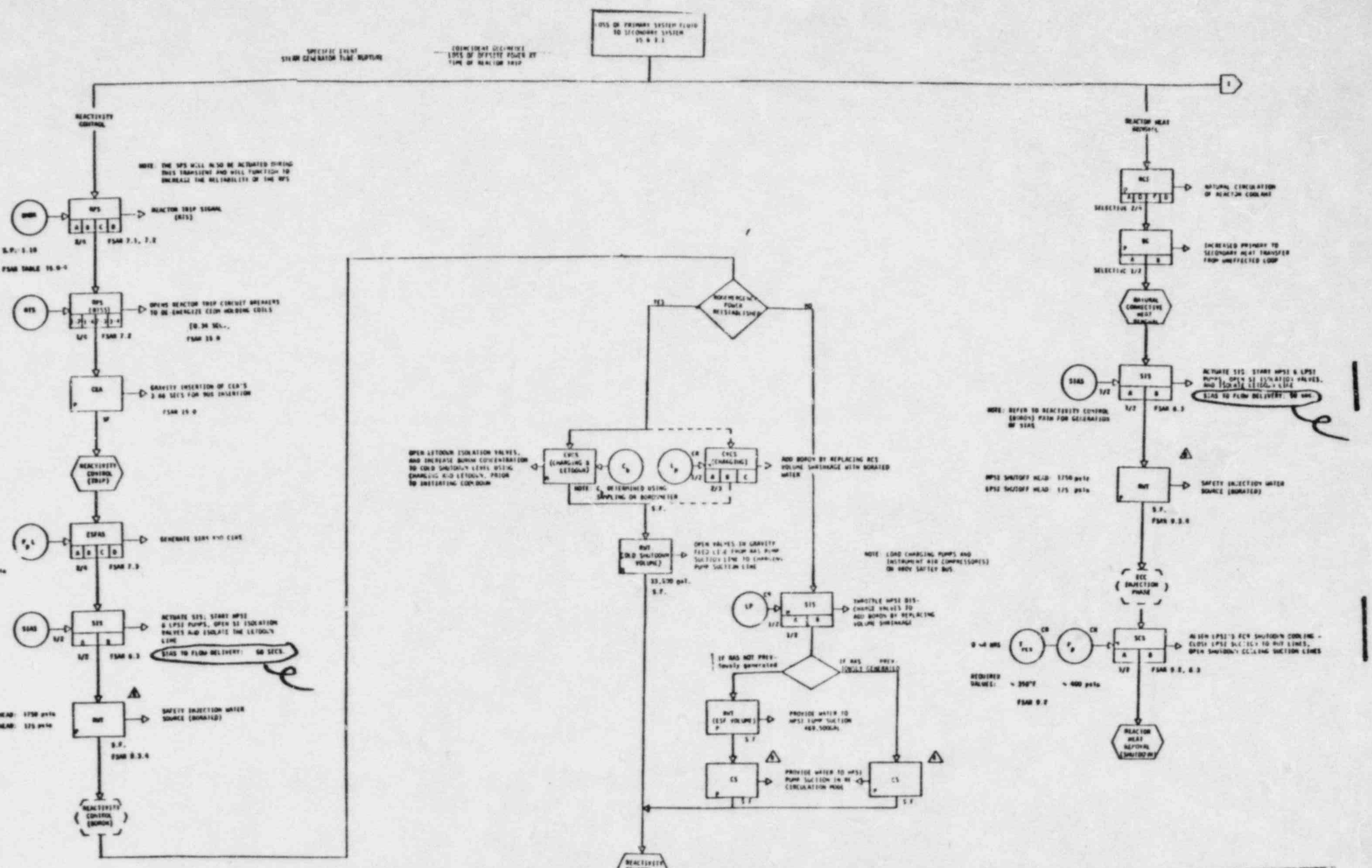
1148.45	Trip Breakers Open	--	Reactivity Control

"B"

1180.8	Pressurizer Pressure Reaches Safety Injection Actuation Signal (SIAS) Analysis Setpoint, psia	1578	Reactor Heat Removal

"C"

1181.8	Safety Injection Flow Initiated	--	



C - E	SEQUENCE OF EVENTS DIAGRAM FOR STEAM GENERATOR TUBE RUPTURE WITH LOSS OF OFFSITE POWER OR REACTOR TRIP	Figure 15.6.3 -10A

15.6.3.2.3 Analysis of Effects and Consequences

15.6.3.2.3.1 Core and System Performance

A. Mathematical Model

The mathematical used for evaluation of core and system performance is identical to that described in Section 15.6.3.1.3.1.

B. Input Parameters and Initial Conditions

The input parameters and initial conditions used for the evaluation of core and systems performance are similar to those described in Section 15.6.3.1.3 and are given in Table 15.6.3-9. Both the initial core mass flow rates and the one pin radial peaking factor were chosen to: (1) maximize the primary-to-secondary integrated leak, and the steam releases through the main steam safety valves, and (2) at the same time, obtain a simultaneous reactor trip on a low DNBR (=1.19) as well as a low pressurizer pressure. Consequently, a slightly lower core mass flow rate (104% instead of 116%) as well as a slightly lower radial peaking factor (1.53 instead of 1.55) were employed in the analysis.

C. Results

The dynamic behavior of important NSSS parameters following a steam generator tube rupture with a loss of normal ac power are presented in Figures 15.6.3-19 through 15.6.3-34.

a reactor trip signal is generated due to exceeding

Prior to reactor trip, the dynamic behavior of the NSSS following a steam generator tube rupture with a loss of offsite power is similar to that following a steam generator tube rupture without a loss of offsite power which is described in Section 15.6.3.1.3. At ~~about 1187~~ 186.75 seconds after the initiation of the tube rupture the CPC low pressure boundary ~~of 1763 psia is reached, resulting in a reactor trip signal.~~

Subsequent to the reactor trip, the RCS pressure begins to decrease rapidly, and the pressurizer empties at about 1201 seconds due to the continued primary-to-secondary leak. After the pressurizer empties, the reactor vessel upper head begins to behave like a pressurizer and controls the RCS pressure response. Due to the loss of offsite power, the reactor coolant pumps begin to coast down reducing the core coolant flow rate, and the mass flow into the upper head region. This region becomes thermalhydraulically decoupled from the rest of the RCS, and due to flashing caused by the depressurization and boiloff from the metal structure to coolant heat transfer, voids form in this region at about 1196 seconds. The void formation is enhanced by the decoupling effect, since the RCS pressure reduction due to primary system cooling is felt in this region, while the RCS temperature reduction is not. The significant impact of voids in the upper head region is a slower RCS pressure decay resulting in the generation of the safety injection actuation signal (SIAS) at ~~1613~~ 1563.2 seconds and the initiation of the safety injection flow. ~~The High Pressure Safety Injection (HPSI) pumps begin delivery of safety injection fluid to the~~

RC~~S in about 50 seconds after the SIAS, and~~ As a result, the upper head voids begin to collapse at about 1677 seconds.

Following turbine trip and loss of offsite power, the main steam system pressure increases until the main steam safety valves open at about 1197 seconds to control the main steam system pressure. A maximum main steam system pressure of 1310 psia occurs at about 1205 seconds. Subsequent to this peak in pressure, the main steam system pressure decreases resulting in the closure of the safety valves at 1721 seconds.

Prior to turbine trip, the feedwater control system is in the automatic mode, and supplies feedwater to the steam generators to match the steam flow through the turbine. Following turbine trip and loss of offsite power, the feedwater flow ramps down to zero. Consequently the steam generator water levels decrease due to the steam flow out through the main steam safety valves, and a low steam generator level
1714.6 signal is generated at ~~about 1713~~ seconds. Subsequently, at ~~about~~
1759.6 ~~1758~~ seconds, emergency feedwater flow is initiated, and the steam generator water levels begin to recover.

After 1800 seconds, the operator identifies and isolates the affected steam generator by closing the main steam isolation valves. The operator then initiates an orderly cooldown by means of the atmospheric dump valves and emergency feedwater flow to the unaffected steam generator. After the pressure and temperature are reduced to 400 psia and 350°F, respectively, the operator activates the shutdown cooling system and isolates the unaffected steam generator.

The reduction in the RCS pressure due to the loss of primary coolant through the ruptured steam generator tube results in a reduction in the thermal margin to DNB (see Figure 15.6.3-34). The transient minimum DNBR of 1.19 occurs at the time of reactor trip. The DNBR shows an increasing trend after reactor trip due to the rapidly decreasing heat flux. The RCPs do not begin their normal coastdown until after the loss of offsite power three seconds after turbine trip. However, there is a slight decrease in the core flow during the three seconds immediately after turbine trip and prior to the loss of offsite power due to decreasing pump speed caused by frequency degradation (approximately 1 Hertz/second) of the electrical grid. The resultant calculation demonstrates that no violation of the fuel thermal limits occurs, since the minimum DNBR stays above the value of 1.19 throughout the transient.

The maximum RCS and secondary pressures do not exceed 110% of design pressure following a steam generator tube rupture event with a concurrent loss of offsite power, thus, assuring the integrity of the RCS and the main steam system.

Figure 15.6.3-29 gives the main steam safety valve integrated flow rates versus time for the steam generator tube rupture event with a loss of offsite power. At 1800 seconds, when operator action is assumed, no more than 54,936 lbm of steam from the damaged steam generator and 54,730 lbm from the intact steam generator are discharged

TABLE 15.6.3-6
(Sheet 1 of 2)

SEQUENCE OF EVENTS FOR A
STEAM GENERATOR TUBE RUPTURE WITH A
LOSS OF OFFSITE POWER

Time (Sec)	Event	Setpoint or Value	Success Path
0.0	Tube Rupture Occurs	--	
30.0	Third Charging Pump Started, feet below program level	-0.75	Primary System Integrity
30.0	Letdown Control Valve Throttled Back to Minimum Flow, feet below program level	-0.75	Primary System Integrity
53.8	Backup Heaters Energized, psia	2360	Primary System Integrity
560.0	Pressurizer Heaters De-energized due to Low Pressurizer Liquid Volume, ft^3	400	
INSERT "A" 1186.75 ~~1187~~	CPC Low Pressure Boundary Trip Signal ~~[illegible]~~ Generated	~~[illegible]~~	Reactivity Control
1188	Turbine/Generator Trip ~~[illegible]~~ ~~Valves Start to Close~~ ~~CEAs Begin to Drop~~	--	Secondary System Integrity ~~Reactivity Control~~
~~1191~~	~~Turbine Stop Valves Closed~~	~~--~~	~~Secondary System~~
1191	Loss of Offsite Power	--	Integrity
1197	LH Main Steam Safety Valves open, psia	1282	Secondary System Integrity
1197	RH Main Steam Safety Valves open, psia	1282	Secondary Sytem Integrity
1201	Pressurizer Empties	--	
1205	Maximum Steam Generator Pressures Both Steam Generator, psia	1310	
1563.2	Safety Injection Actuation Signal ~~[illegible]~~ Generated	~~1578~~	Reactivity Control

INSERT "B"

1563.2 Safety Injection Flow Initiates -- Reactivity Control

TABLE 15.6.3-6
(Sheet 2 of 2)

SEQUENCE OF EVENTS FOR THE
STEAM GENERATOR TUBE RUPTURE WITH A
LOSS OF OFFSITE POWER

Time (Sec)	Event	Setpoint or Value	Success Path
~~1563~~ 1563.2	Letdown Isolation Valves Closed on SIAS	--	Primary System Integrity
~~1613~~	~~Safety Injection Flow Initiated~~	~~--~~	~~Reactivity Control~~ ~~Reactor Heat Removal~~
1714.6	Emergency Feedwater Actuation signal ~~on Low Steam Generator Level Trip Signal, ft above tube sheet~~ Generated	~~[illegible]~~	Secondary System Integrity
1721	Main Steam Safety Values Closed, psia	1218	Secondary System Integrity
1759.6	Emergency Feedwate Flow Begins	--	Secondary System Integrity
1800	Operator Isolates the Damaged Steam Generator and Initiates Plant Cooldown	--	Reactor Heat Removal
28,800	Shutdown Cooling Entry Conditions are Assumed to be Reached, RCS Pressure, psia/Temperature, °F	400/350	Reactor Heat Removal
1713.6	Steam Generator Water Level Reaches Emergency Feedwater Actuation Signal Analysis Setpoint, percent of wide range	25	Secondary System Integrity

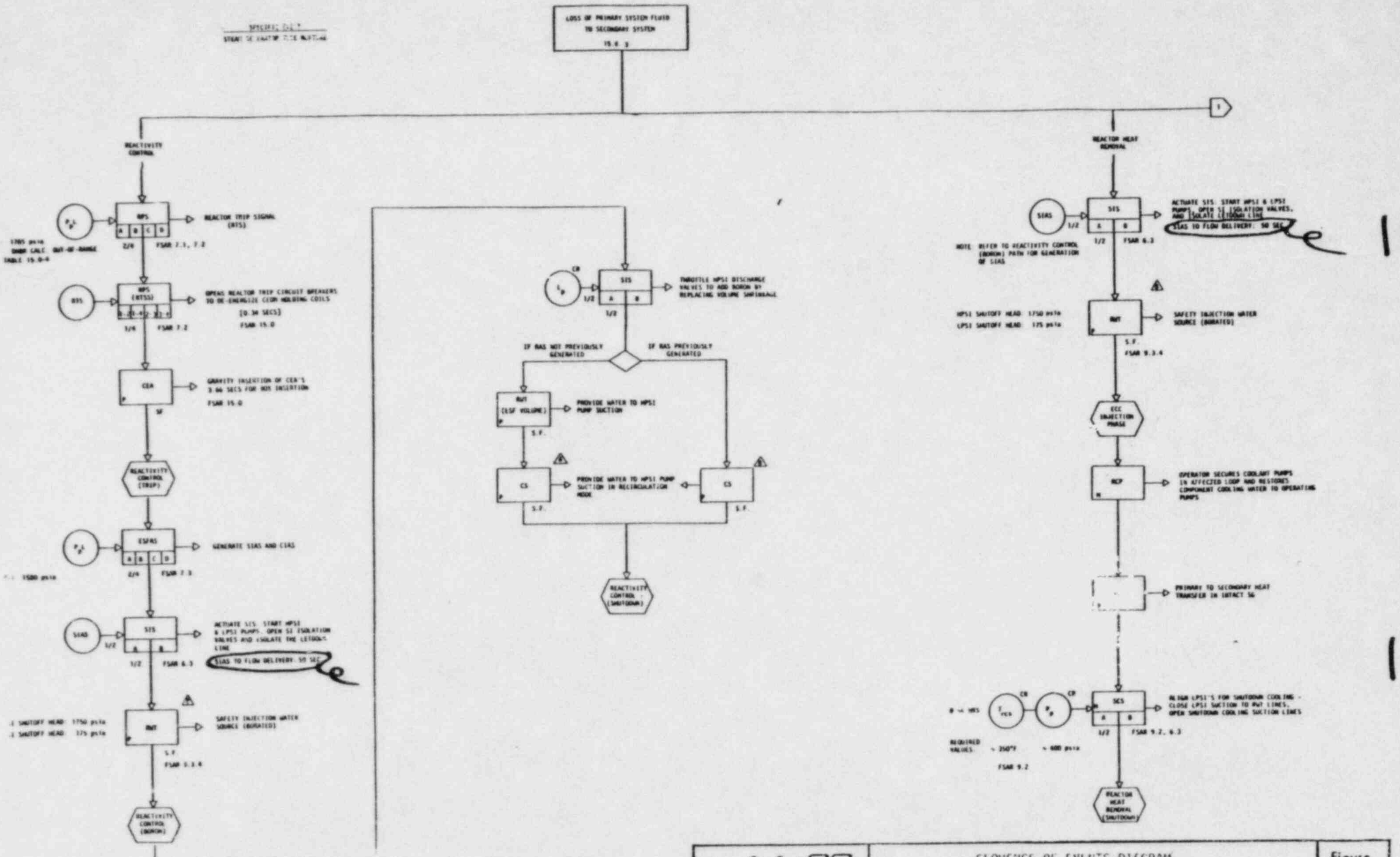
T. 15.6.3-6

"A"

1186.90	Trip Breakers Open	–	Reactivity Control

"B"

1562.2	Pressurizer Pressure Reaches Safety Injection Actuation Signal Analysis Setpoint, psia	1578	Reactivity Control



C - E SYSTEM 80

SEQUENCE OF EVENTS DIAGRAM FOR STEAM GENERATOR TUBE RUPTURE

Figure 15.6.3-1A

15B.4 RESULTS

An example limiting analysis of the LFI transient suggested by Reference 1 was performed applying the conservative methods with the most adverse set of initial plant conditions and transient parameters discussed above. Table 15B-1 lists the assumptions utilized in this worst case. The sequence of events and the dynamic response of the important NSSS parameters are provided in Table 15B-2 and Figures 15B-13 through 15B-30, respectively.

A 0.2 ft^2 crack in the main feedwater line is assumed to instantaneously terminate feedwater flow to both steam generators and establish critical flow (~2000 lbm/sec of saturated liquid) from the generator nearest the break. The absence of subcooled feedwater flow causes a constant heatup and pressurization of the steam generators during the first 33.8 seconds 33.82 which reduces the primary-to-secondary heat transfer rate. Rising reactor coolant temperatures and pressure result. Due to temperature reactivity feedback during this period the core power decreases slightly from 102 percent to 98 percent of design full power.

At 33.8 33.82 seconds the ruptured steam generator is assumed to instantaneously lose all heat transfer capability due to total depletion of its liquid inventory by boil-off and the break discharge flow. This initiates a rapid heatup and pressurization of the reactor coolant system and depressurization of the steam generators. Once emptied, credit is taken for a low water level trip condition in the ruptured steam generator which leads to a reactor trip signal at 34.4 34.82 seconds simultaneous with a high pressurizer pressure trip signal. The rate of reactor coolant system pressurization is further aggravated at 38.5 35.8 seconds. Closure of the turbine leaves the pipe break as the only steam relief path, thereby reducing the energy flow from the intact steam generator below that of the primary-to-secondary heat transfer rate. The resulting steam generator pressurization reduces the primary-to-secondary temperature difference. In addition, the loss of reactor coolant flow following the loss of electrical power decreases the heat transfer coefficient of the coolant in the steam generator tubes. A significant heat transfer reduction occurs.

Compression of the pressurizer steam volume due to the high insurge flow raises the pressure to the safety valve setpoint at 34.6 seconds. Thereafter every increase in the surge flow causes a slight pressurization which opens the safety valves such that their volumetric discharge rate matches that of the insurge. The reactor coolant system pressure continues to increase to a maximum of 2843 psia at 38.2 seconds. At that time the increased pressure establishes a surge line pressure gradient which provides sufficient flow to allow the reactor coolant to expand under the existing heatup with no further pressurization. Pressurizer pressure and surge line flow are also at their maxima of 2587 psia and 2206 lbm/sec, respectively.

The rate of heatup decreases subsequent to core heat flux decay causing the primary pressures to drop. At 40.5 seconds the main steam safety valves open thus stabilizing the secondary side temperature and allowing the

rising primary coolant temperature to develop greater heat transfer to the intact steam generator. The intact generator is forced to a maximum of 1318 psia before the heat transfer begins to decrease. However, the core-to-steam generator heat rate mismatch is reduced sufficiently by 45.4 seconds to allow closure of the pressurizer safety valves and by 45.8 seconds the reactor coolant system enters a cooldown. Under the influence of steam blowdown through the ruptured steam generator to the break, the cooldown proceeds even after the steam generator safety valves close at 73.8 seconds.

166.0

A main steam isolation signal is generated at 165.6 seconds on low steam generator pressure which closes the main steam isolation valves decoupling the intact steam generator from the ruptured steam generator and the break. The intact steam generator repressurizes, thereby reducing its heat transfer and eventually causing a primary system heatup by 300 seconds. With the main steam safety valves open by 314.2 seconds, the primary-to-secondary heat inbalance is eliminated by approximately 600 seconds. Thereafter the NSSS enters into a quasi-steady state with a very gradual cooldown and depressurization due to decreasing core decay heat and with emergency feedwater flow which was initiated at 89.6 seconds maintaining an adequate liquid inventory within the intact steam generator for heat removal. By 1800 seconds the operator initiates a controlled cooldown to shutdown cooling utilizing the atmospheric dump valves. 90.0

The minimum DNBR vs. Time as shown on Figure 15B-30 remains above 1.19 throughout the transient.

During the first 30 minutes following the initiation of this LFI event mass releases from the system amount to 2970 lbm of steam from the pressurizer safety valves to the reactor drain tank, 79,700 lbm of steam from the main steam safety valves to atmosphere, and 69,200 lbm of liquid and 34,200 lbm of steam from the feedwater line break to containment. Steam release to the reactor drain tank may burst the tank's rupture disc discharging its contents to containment.

During this event, two sources of radioactivity contribute to the site boundary dose, the initial activity in the steam generator inventory, and the activity associated with primary to secondary leakage from the steam generator tubes which are assumed to be at the technical specification limits of 0.1 μCi/gm and 4.6 μCi/gm dose equivalent I-131 respectively. During the first two hours of this event, the total activity from the steam generators includes 8.9 Ci from the affected steam generator to the containment building including 1.6 Ci associated with technical specification tube leakage (1 gpm) and 0.33 Ci total activity released from unaffected steam generator to the containment and atmosphere. Assuming all the radioactivity is released to the atmosphere, the offsite dose due to feedwater line break with loss of offsite power results in no more than 9.5 rem two hour inhalation thyroid dose at exclusion area boundary.

TABLE 15B-2

(Sheet 1 of 2)

SEQUENCE OF EVENTS FOR THE LIMITING CASE LOSS OF FEEDWATER INVENTORY EVENT

Time (Sec)	Event	Setpoint or Value
0.0	Break in the Main Feedwater Line, ft²	0.2 ~~ft²~~
0.0	Instantaneous Loss of All Feedwater Flow to Both Steam Generators	
0.0	Instantaneous Development of Critical Flow from the Ruptured Steam Generator to the Break	
33.82	INSERT "A" Instantaneous Loss of All Heat Transfer to the Ruptured Steam Generator	
~~34.4~~ 34.82	Low Water Level Trip Signal ~~from the Ruptured Steam Generator~~ Generated	~~[illegible]~~
~~34.4~~ 34.82	Emergency Feedwater Actuation Signal Generated ~~from the Ruptured Steam Generator~~	~~[illegible]~~
~~34.4~~ 34.82	High Pressurizer Pressure Trip Signal Generated	~~2475 psia~~
34.6	Pressurizer Safety Valves Open, psia	2525 ~~psia~~
~~35.0~~ 34.97	Trip Breakers Open	--
~~35.3~~	~~CEA's Begin to Drop~~	
35.8	Instantaneous Closure of the Turbine Stop Valves	--
35.8	Loss of Normal On-Site and Off-Site Electrical Power	--
~~[illegible]~~	INSERT "B" ~~Low Water Level Trip Signal from the Intact Steam Generator~~	~~35% of wide range instrument span~~
38.2	Maximum Reactor Coolant Pressure, psia	2843 ~~psia~~
	Maximum Pressurizer Pressure, psia	2587 ~~psia~~
	Maximum Pressurizer Surge Line Flow, lbm/sec	2206 ~~lbm/sec~~

TABLE 15B-2 (Cont'd.) (Sheet 2 of 2)

SEQUENCE OF EVENTS FOR THE LIMITING CASE LOSS OF FEEDWATER INVENTORY EVENT

Time (Sec)	Event	Setpoint or Value
40.5	Main Steam Safety Valves Open, psia	1282 ~~psia~~
INSERT "C" ~~34.6~~ 45.0	Emergency Feedwater Actuation Signal Generated ~~from the Intact Steam Generator~~	~~10% of wide range instrument span~~
44.8	Maximum Steam Generator Pressure, psia	1318 ~~psia~~
45.4	Pressurizer Safety Valves Close, psia	2525 ~~psia~~
45.8	Minimum Pressurizer Steam Volume, ft^3	138 ~~ft^3~~
73.8	Main Steam Safety Valves Close, psia	1218 ~~psia~~
~~79.4~~	~~Emergency Feedwater Flow Initiated to the Ruptured Steam Generator~~	~~875 gpm~~
~~80.6~~ 90.0	Emergency Feedwater Flow Initiated to the Intact Steam Generator, gpm	875 ~~gpm~~
INSERT "D" ~~165.6~~	~~Low Pressure Trip Signal from the Ruptured Steam Generator~~	~~[illegible]~~
~~165.6~~ 166.0	Main Steam Isolation Signal Generated	~~[illegible]~~
170.6	Minimum Intact Steam Generator Liquid Mass, lbm	8100 ~~lbm~~
~~173.6~~	~~Emergency Feedwater Flow Terminated to the Ruptured Steam Generator~~	~~[illegible]~~
314.2	Main Steam Safety Valves Open, psia	1282 ~~psia~~
1800.0	Operator Opens the Atmospheric Steam Dump Valves to Begin Plant Cooldown to Shutdown Cooling	

170.6 Main Steam Isolation Valves Closed

T 15B-2 (1)

"A"

33.82	Steam Generator Water Level Reaches Reactor Trip Analysis Setpoint in the Ruptured Generator	Empty
33.82	Steam Generator Water Level Reaches Emergency Feedwater Actuation Signal Analysis Setpoint in the Ruptured Generator	Empty
33.82	Pressurizer Pressure Reaches Reactor Trip Analysis Setpoint, psia	2475

"B"

36.4	Steam Generator Water Level Reaches Reactor Trip Analysis Setpoint in the Intact Generator, percent of wide range	35

"C"

44.0	Steam Generator Water Level Reaches Emergency Feedwater Actuation Signal Analysis Setpoint in the Intact Generator, percent of wide range	10

"D"

165.0	Steam Generator Pressure Reaches Main Steam Isolation Signal Analysis Setpoint, psia	810

A 0.20 ft^2 rupture in the main feedwater line is assumed to instantaneously terminate feedwater flow to both steam generators, and establish critical flow from the generator nearest the break at an initial rate of 1979 lbm/sec. This causes a decrease in steam generator liquid mass as shown by Figure 15B-39.

The break discharge enthalpy is assumed to remain that of saturated liquid until the ruptured steam generator empties, at which time saturated vapor enthalpy is assumed.

25.98

The absence of subcooled feedwater flow causes a constant heatup and pressurization of the steam generators during the first 26.6 seconds which reduces the primary-to-secondary heat transfer rate. Rising primary coolant temperatures and pressures result. Due to the temperature reactivity feedback during this period core power is reduced from an initial value of 102% to 99.8% at 26.6 seconds.
25.98

26.98

At 26.6 seconds the ruptured steam generator produces a low water level reactor trip signal. This reactor trip signal is coincident with a high pressurizer pressure trip signal. ~~Also at this time,~~ heat transfer in the ruptured steam generator begins to degrade due to insufficient inventory. This degradation initiates a rapid heat up and pressurization of the reactor coolant system. At 27.5 27.13 seconds the reactor trip breakers open followed by an assumed instantaneous turbine trip. Immediately following turbine trip, the failure to fast transfer to offsite power occurs, resulting in the coastdown of two reactor coolant pumps. These occurrences further aggravate the primary pressurization.

At 25.98 seconds

at 27.97 seconds

Closure of the turbine leaves the pipe break as the only steam relief path, thereby reducing the energy flow from the intact steam generator below that of the primary-to-secondary heat transfer rate. The resulting steam generator pressurization reduces the primary-to-secondary temperature difference. In addition, the loss of reactor coolant flow following the loss of electrical power to two pumps decreases the heat transfer coefficient of the coolant in the steam generator tubes. A significant heat transfer reduction occurs.

Compression of the pressurizer steam volume due to the high insurge flow raises the pressure to the safety valve setpoint at 28.3 seconds. Thereafter, every increase in the surge flow causes a slight pressurization which opens the safety valves such that their volumetric discharge rate matches that of the insurge. At 30.2 seconds, the surge line flow reaches its maximum value of 1458 lbm/sec.

At this point in time, the reactor coolant system pressure is at a maximum of 2712 psia. Also, the increased pressure establishes a surge line pressure gradient which provides sufficient flow to allow

TABLE 15B-4

SEQUENCE OF EVENTS FOR THE REANALYSIS OF THE LIMITING SMALL BREAK LOSS OF FEEDWATER INVENTORY EVENT

Time (sec)	Event	Setpoint or Value
0.0	Rupture in the Main Feedwater Line, ft^2	0.20
0.0	Complete Loss of Feedwater to Both Steam Generators	----
0.0	Initial Steam Generator Break Flow, lbm/sec	1979
~~26.0~~ 25.98	~~High~~ Pressurizer Pressure Trip ~~Condition~~ ~~Reached, psia~~ Reaches Reactor Trip Analysis Setpoint, psia	2475
~~26.6~~ 26.98	High Pressurizer Pressure Trip Signal Generated	----
~~26.6~~ 26.98	Low Water Level Trip Signal ~~in Ruptured SG~~ Generated	----
~~26.0~~ 25.98	Heat Transfer Degradation in Ruptured SG Begins	----
~~27.5~~ 27.13	Reactor Trip Breakers Open	----
~~27.5~~ 27.97	Turbine Trip on Reactor Trip	----
~~27.5~~ 27.97	Failure to Fast Transfer - Two Reactor Coolant Pumps Coast Down	----
~~27.8~~	~~CEAs Begin to Drop into Core~~	~~----~~
28.3	Pressurizer Safety Valves, psia	2525
30.0	Main Steam Safety Valves Open	1282
30.2	Maximum Surge Line Flow, lbm/sec	1458
30.2	Maximum RCS Pressure, psia	2712
33.8	Maximum Steam Generator Pressure, psia	1342
36.8	Ruptured SG Dries Out	----
37.4	Primary Safety Valves Close, psia	2523
25.98	Steam Generator Water Level Reaches Reactor Trip Analysis Setpoint in the Ruptured Generator, lb_m liquid remaining	35000

core coolant flow, and maximum core coolant inlet temperature. This combination of initial conditions results in an early generation of a reactor trip signal due to exceeding the CPC hot leg saturation temperature range limit.

C. Results

The dynamic behavior of important NSSS parameters following a steam generator tube rupture is presented in Figures 15D-1 to 15D-15.

For a double-ended rupture, the primary to secondary leak rate exceeds the capacity of the charging pumps. As a result, the pressurizer pressure gradually decreases from an initial value of 2100 psia. The primary to secondary leak rate and drop in pressurizer water level causes the second and third CVCS charging pumps to turn on. Even with all three CVCS charging pumps on line the pressurizer pressure and level continue to drop. At 47 seconds a reactor trip signal is generated due to exceeding the CPC hot leg saturation temperature range limit. The pressurizer empties at approximately 546 seconds (Figure 15D-5). At 570 seconds a safety injection actuation signal is generated, and [redacted] the safety injection flow is initiated. After the pressurizer empties, the reactor vessel upper head begins to behave like a pressurizer, and controls the reactor coolant system pressure until the pressurizer begins to refill at approximately 4020 seconds. Due to flashing caused by the depressurization, and the boil off due to the metal structure to coolant heat transfer, the reactor vessel upper head begins to void at about 77 seconds (Figure 15D-6). Consequently, the RCS pressure (Figure 15D-2) begins to decrease at a lower rate at this time.

Following reactor trip and with turbine bypass unavailable, the main steam system pressure increases until the MSSVs open at 52 seconds to control the main steam system pressure. A maximum main steam system pressure of 1330 psia occurs at 56 seconds. Subsequent to this peak in the pressure, the main steam system pressure decreases, resulting in the closure of the main steam safety valves at 95 seconds. The MSSVs cycle twice more in this manner until the operator takes control of the plant.

Prior to reactor trip, the main feedwater control system is assumed to be in the automatic mode and supplies feedwater to the steam generators such that steam generator water levels are maintained. Following reactor trip, the main feedwater flow is terminated due to the loss of offsite power. As the level in the steam generators decrease an Emergency Feedwater Actuation Signal (EFAS) is generated resulting in, auxiliary feedwater flow which acts to restore the SG level.

At 460 seconds the operator takes control of the plant and opens one ADV on each SG to cool down the plant. This is consistent with the EPGs. At 2100 seconds the RCS has been cooled to 550°F. The operator isolates the auxiliary feedwater to the affected generator, closes the main steam isolation valves of both steam generators, and attempts to close the ADV of the affected generator. The operator recognizes that the ADV did not close and has the appropriate block valve closed within 30 minutes. The operator then initiates an orderly cooldown by means of the atmospheric

TABLE 15D-1

SEQUENCE OF EVENTS FOR A STEAM GENERATOR TUBE RUPTURE WITH A LOSS OF OFFSITE POWER AND STUCK OPEN ADV

Time (Sec)	Event	Setpoint or Value	Success Path
0.0	Tube Rupture Occurs	---	
40	Third Charging Pump Started, feet below program level	-0.75	Primary System Integrity
40	Letdown Control Valve Throttled Back to Minimum Flow, feet below program level	-0.75	Primary System Integrity
INSERT 47	CPC Hot Leg Saturation Trip Signal	---	Reactivity Control
A 48	Turbine/Generator Trip~~, [illegible] Valves Start to Close~~	---	Secondary System Integrity
	~~CEAs Begin to Drop~~	---	Reactivity Control
~~51~~	~~Turbine Stop Valves Closed~~	~~---~~	~~Secondary System Integrity~~
51	Loss of Offsite Power	---	
52	LH Main Steam Safety Valves open, psia	1265	Secondary System Integrity
52	RH Main Steam Safety Valves open, psia	1265	Secondary System Integrity
56	Maximum Steam Generator Pressures Both Steam Generator, psia	1330	
95	Main Steam Safety Valves Closed, psia	1218	Secondary System Integrity
167	Auxiliary Feedwater Actuation on Low Steam Generator Level Trip Signal, Intact Steam Generator, feet above tube sheet	19.76	Secondary System Integrity
177	Auxiliary Feedwater Actuation on Low Steam Generator Level Trip Signal, Ruptured Steam Generator, feet above tube sheet	19.76	Secondary System Integrity

Replace with "B"

TABLE 15D-1 (Cont'd.)

Time (Sec)	Event	Setpoint or Value	Success Path
460	Operator Initiates Plant Cooldown by Opening One ADV on each SG	---	Reactor Heat Removal
546	Pressurizer Empties	---	
570	Safety Injection Actuation Signal ~~(SIAS)~~ Generated	~~[illegible]~~	Reactivity Control
570 ~~[illegible]~~	Safety Injection Flow Initiated	---	Reactivity Control
2100	Operator Attempts to Isolate the Damaged Generator, RCS Tem., °F	550	Secondary System Integrity
3900	Operator Closes the ADV Block Valve	---	Secondary System Integrity
4020	Operator Initiates Auxiliary Spray Flow		Primary System Inventory
4500	Operator Controls Auxiliary Spray Flow, Backup Pressurizer Heater Output, and HPSI Flow to Reduce RCS Pressure and Control Subcooling, °F	20	Primary System Integrity
28,800	Shutdown Cooling Entry Conditions Reached, RCS Pressure, psia/ Temperature, °F	400/350	Reactor Heat Removal
570	Pressurizer Pressure Reaches Safety Injection Actuation Signal (SIAS) Analysis's Setpoint, psia	1578	Reactivity Control

T15D-1

"A"

47.15	Trip Breakers Open	--	Reactivity Control

"B"

121.0	Steam Generator Water Level Reaches Emergency Feedwater Actuation Signal (EFAS) Analysis Setpoint in the Unaffected Generator, percent wide range	25	Secondary System Integrity.
122.0	EFAS Generated	--	
131.0	Steam Generator Water Level Reaches EFAS Analysis Setpoint in the Affected Generator, percent wide range	25	Secondary System Integrity
132.0	EFAS Generated	--	
167.0	Emergency Feedwater Initiated to Unaffected Steam Generator	--	Secondary System Integrity
177.0	Emergency Feedwater Initiated to affected Steam Generator	--	Secondary System Integrity

TABLE 15D-4

ASSUMPTIONS AND INITIAL CONDITIONS FOR THE STEAM GENERATOR TUBE RUPTURE WITH A LOSS OF OFFSITE POWER AND STUCK OPEN ADV

Parameter	Assumed Value
Core Power Level, MWt	3876
Core Inlet Coolant Temperature, °F	570
Reactor Coolant System Pressure, psia	2100
Core Mass Flow Rate, 10^6 lbm/hr	155
One Pin Integrated Radial Peaking Factor, with Uncertainty	1.53
Steam Generator Pressure, psia	1126
Moderator Temperature Coefficient, 10^{-4} $\Delta\rho$/°F	~~[illegible]~~ -1.1
Doppler Coefficient Multiplier	~~1.15~~ 1.0
CEA Worth at Trip, % $\Delta\rho$ (most reactive CEA fully withdrawn)	-10.0