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NUCLEAR REGULATORY COMMISSION
WASHINGTON, D. C. 20555

APR 09 1986

Docket No. 50-354

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Mr. Corbin A. McNeill, Jr., Vice President - Nuclear
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Dear Mr. McNeill:

Subject: Hope Creek Technical Specifications

Enclosed are page changes to the final draft of the Hope Creek Technical Specifications. These changes are the result of staff and PSE&G comments to the final draft technical specifications sent to you in our letter dated February 14, 1986. These page changes are sent to you in order that your certification of the Hope Creek Technical Specifications can be completed in time to support licensing of Hope Creek.

If you have any questions, please contact us.

Sincerely,

Elinor G. Adensam

Elinor G. Adensam, Director
BWR Project Directorate No. 3
Division of BWR Licensing

Enclosure:
As stated

cc: See next page

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Certified By

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FINAL DRAFT

INDEX

LIMITING CONDITIONS FOR OPERATION AND SURVEILLANCE REQUIREMENTS

MAR 31 1986

INDEX

LIMITING CONDITIONS FOR OPERATION AND SURVEILLANCE REQUIREMENTS

FINAL DRAFT

INDEX

LIMITING CONDITIONS FOR OPERATION AND SURVEILLANCE REQUIREMENTS

SECTION PAGE

RADIOACTIVE EFFLUENTS (Continued)

SECTION PAGE

MAR 31 1986

TABLE 2.2.1-1

REACTOR PROTECTION SYSTEM INSTRUMENTATION SETPOINTS
(continued)

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUES
7. Drywell Pressure - High	≤ 1.68 psig	≤ 1.88 psig
8. Scram Discharge Volume Water Level - High		
a. Float Switch	Elevation 110' 10.5"	Elevation 111' 0.5"
b. Level Transmitter/Trip Unit	Elevation 110' 10.5"*	Elevation 111' 4.5"*
9. Turbine Stop Valve - Closure	≤ 5% closed	≤ 7% closed
10. Turbine Control Valve Fast Closure, Trip Oil Pressure - Low	≥ 530 psig	≥ 465 psig
11. Reactor Mode Switch Shutdown Position	NA	NA
12. Manual Scram	NA	NA

*80.5" above instrument zero EL 104' 2" for Level Transmitter/Trip Unit A&B (South Header)
83.25" above instrument zero EL 103' 11.25" for Level Transmitter/Trip Unit C&D (North Header)

CONTROL ROD MAXIMUM SCRAM INSERTION TIMES

LIMITING CONDITION FOR OPERATION

3.1.3.2 The maximum scram insertion time of each control rod from the fully withdrawn position to notch position 5, based on de-energization of the scram pilot valve solenoids as time zero, shall not exceed 7.0 seconds.

APPLICABILITY: OPERATIONAL CONDITIONS 1 and 2.

ACTION:

a. With the maximum scram insertion time of one or more control rods exceeding 7.0 seconds:

   1. Declare the control rod(s) with the slow insertion time inoperable, and

   2. Perform the Surveillance Requirements of Specification 4.1.3.2.c at least once per 60 days when operation is continued with three or more control rods with maximum scram insertion times in excess of 7.0 seconds.

   Otherwise, be in at least HOT SHUTDOWN within 12 hours.

b. The provisions of Specification 3.0.4 are not applicable.

SURVEILLANCE REQUIREMENTS

4.1.3.2 The maximum scram insertion time of the control rods shall be demonstrated through measurement with reactor coolant pressure greater than or equal to 950 psig and, during single control rod scram time tests, the control rod drive pumps isolated from the accumulators:

a. For all control rods prior to THERMAL POWER exceeding 40% of RATED THERMAL POWER following CORE ALTERATIONS or after a reactor shutdown that is greater than 120 days.

b. For specifically affected individual control rods following maintenance on or modification to the control rod or control rod drive system which could affect the scram insertion time of those specific control rods, and

c. For at least 10% of the control rods, on a rotating basis, at least once per 120 days of POWER OPERATION.

FINAL DRAFT

CONTROL ROD AVERAGE SCRAM INSERTION TIMES

LIMITING CONDITION FOR OPERATION

3.1.3.3 The average scram insertion time of all OPERABLE control rods from the fully withdrawn position, based on de-energization of the scram pilot valve solenoids as time zero, shall not exceed any of the following:

Position Inserted From Fully Withdrawn	Average Scram Insertion Time (Seconds)
45	0.43
39	0.86
25	1.93
05	3.49

APPLICABILITY: OPERATIONAL CONDITIONS 1 and 2.

ACTION:

With the average scram insertion time exceeding any of the above limits, be in at least HOT SHUTDOWN within 12 hours.

SURVEILLANCE REQUIREMENTS

4.1.3.3 All control rods shall be demonstrated OPERABLE by scram time testing from the fully withdrawn position as required by Surveillance Requirement 4.1.3.2.

MAR 3 1 1986

FINAL DRAFT

FOUR CONTROL ROD GROUP SCRAM INSERTION TIMES

LIMITING CONDITION FOR OPERATION

3.1.3.4 The average scram insertion time, from the fully withdrawn position, for the three fastest control rods in each group of four control rods arranged in a two-by-two array, based on deenergization of the scram pilot valve solenoids as time zero, shall not exceed any of the following:

Position Inserted From Fully Withdrawn	Average Scram Insertion Time (Seconds)
45	0.45
39	0.92
25	2.05
05	3.70

APPLICABILITY: OPERATIONAL CONDITIONS 1 and 2.

ACTION:

a. With the average scram insertion times of control rods exceeding the above limits:

   1. Declare the control rods with the slower than average scram insertion times inoperable until an analysis is performed to determine that required scram reactivity remains for the slow four control rod group, and

   2. Perform the Surveillance Requirements of Specification 4.1.3.2.c at least once per 60 days when operation is continued with an average scram insertion time(s) in excess of the average scram insertion time limit.

   Otherwise, be in at least HOT SHUTDOWN within the next 12 hours.

b. The provisions of Specification 3.0.4 are not applicable.

SURVEILLANCE REQUIREMENTS

4.1.3.4 All control rods shall be demonstrated OPERABLE by scram time testing from the fully withdrawn position as required by Surveillance Requirement 4.1.3.2.

MAR 31 1986

SURVEILLANCE REQUIREMENTS

4.1.3.5 Each control rod scram accumulator shall be determined OPERABLE:

a. At least once per 7 days by verifying that the indicated pressure is greater than or equal to 940 psig unless the control rod is inserted and disarmed or scrammed.

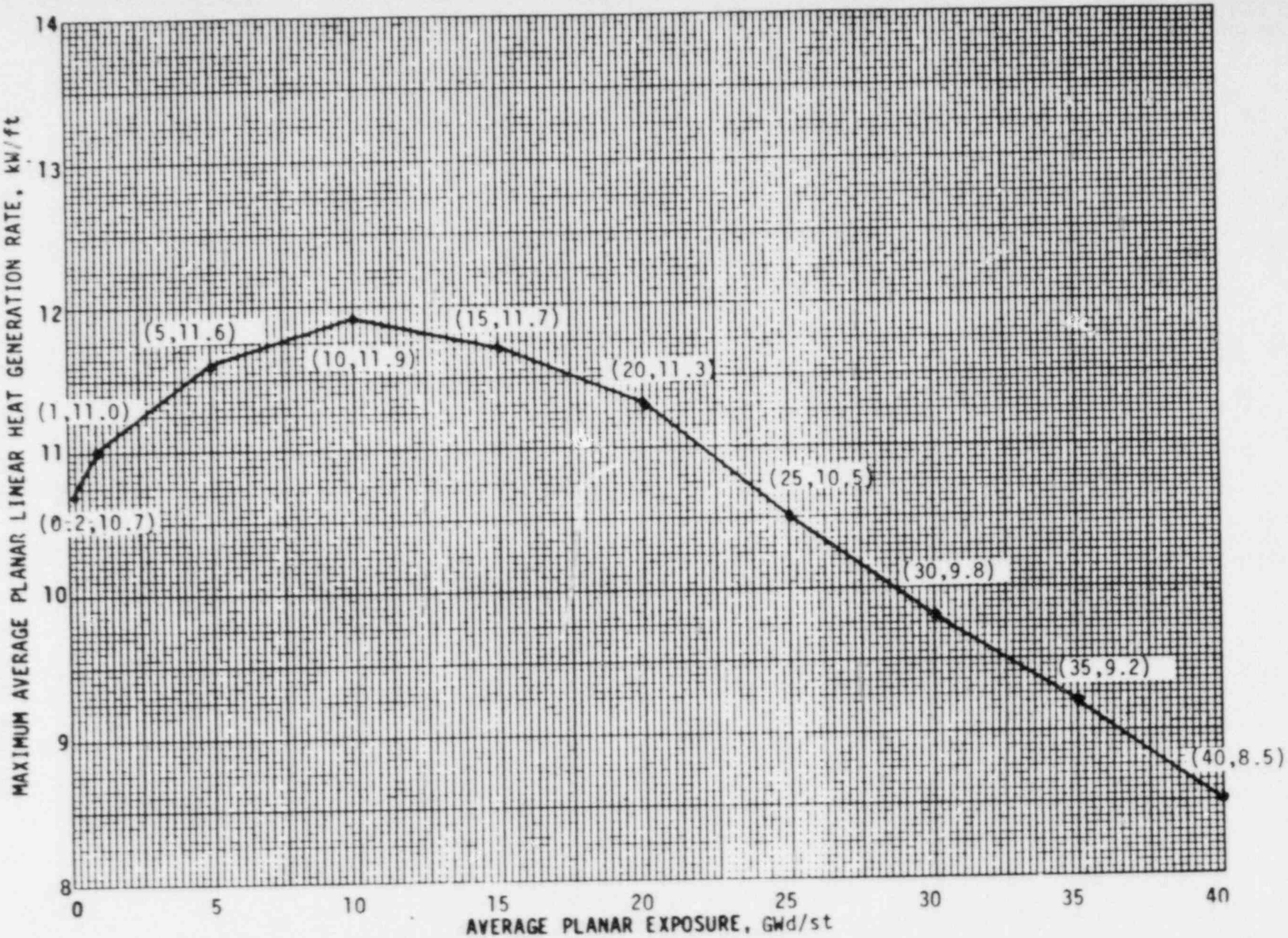
b. At least once per 18 months by:

1. Performance of a:

a) CHANNEL FUNCTIONAL TEST of the leak detectors, and

b) CHANNEL CALIBRATION of the pressure detectors, and verifying an alarm setpoint of 940 + 95, -0 psig on decreasing pressure.

MAR 3 1 1986



MAXIMUM AVERAGE PLANAR LINEAR HEAT
GENERATION RATE (MAPLHGR) VERSUS
AVERAGE PLANAR EXPOSURE
INITIAL CORE FUEL TYPE P8CIB094
Figure 3.2.1-2

POWER DISTRIBUTION LIMITS

3/4.2.3 MINIMUM CRITICAL POWER RATIO

LIMITING CONDITION FOR OPERATION

3.2.3 The MINIMUM CRITICAL POWER RATIO (MCPR) shall be equal to or greater than the MCPR limit shown in Figure 3.2.3-1 times the K_f shown in Figure 3.2.3-2, with:

$$\tau = \frac{(\tau_{ave} - \tau_B)}{\tau_A - \tau_B}$$

where:

τ_A = 0.86 seconds, control rod average scram insertion time limit to notch 39 per Specification 3.1.3.3,

$$\tau_B = 0.688 + 1.65\left[\frac{N_1}{\sum_{i=1}^{n} N_i}\right]^{\frac{1}{2}}(0.052),$$

$$\tau_{ave} = \frac{\sum_{i=1}^{n} N_i \tau_i}{\sum_{i=1}^{n} N_i},$$

n = number of surveillance tests performed to date in cycle,

N_i = number of active control rods measured in the ith surveillance test,

τ_i = average scram time to notch 39 of all rods measured in the ith surveillance test, and

N_1 = total number of active rods measured in Specification 4.1.3.2.a.

APPLICABILITY:

OPERATIONAL CONDITION 1, when THERMAL POWER is greater than or equal to 25% of RATED THERMAL POWER.

POWER DISTRIBUTION LIMITS

MINIMUM CRITICAL POWER RATIO

LIMITING CONDITION FOR OPERATION

ACTION:

With MCPR less than the applicable MCPR limit shown in Figures 3.2.3-1 and 3.2.3-2, initiate corrective action within 15 minutes and restore MCPR to within the required limit within 2 hours or reduce THERMAL POWER to less than 25% of RATED THERMAL POWER within the next 4 hours.

SURVEILLANCE REQUIREMENTS

4.2.3 MCPR, with:

a. $\tau = 1.0$ prior to performance of the initial scram time measurements for the cycle in accordance with Specification 4.1.3.2, or

b. τ as defined in Specification 3.2.3 used to determine the limit within 72 hours of the conclusion of each scram time surveillance test required by Specification 4.1.3.2,

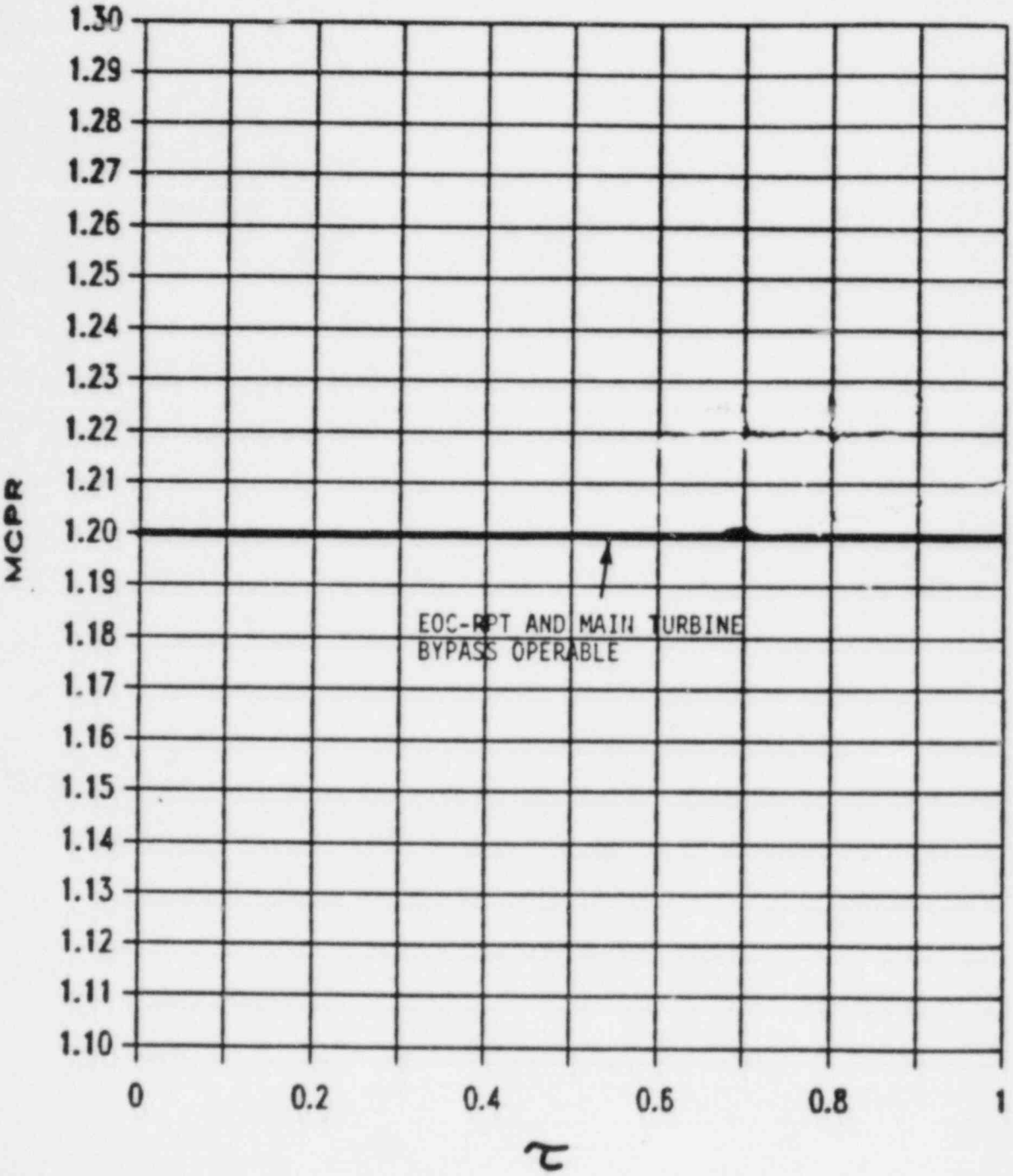
shall be determined to be equal to or greater than the applicable MCPR limit determined from Figures 3.2.3-1 and 3.2.3-2:

a. At least once per 24 hours,

b. Within 12 hours after completion of a THERMAL POWER increase of at least 15% of RATED THERMAL POWER, and

c. Initially and at least once per 12 hours when the reactor is operating with a LIMITING CONTROL ROD PATTERN for MCPR.

d. The provisions of Specification 4.0.4 are not applicable.

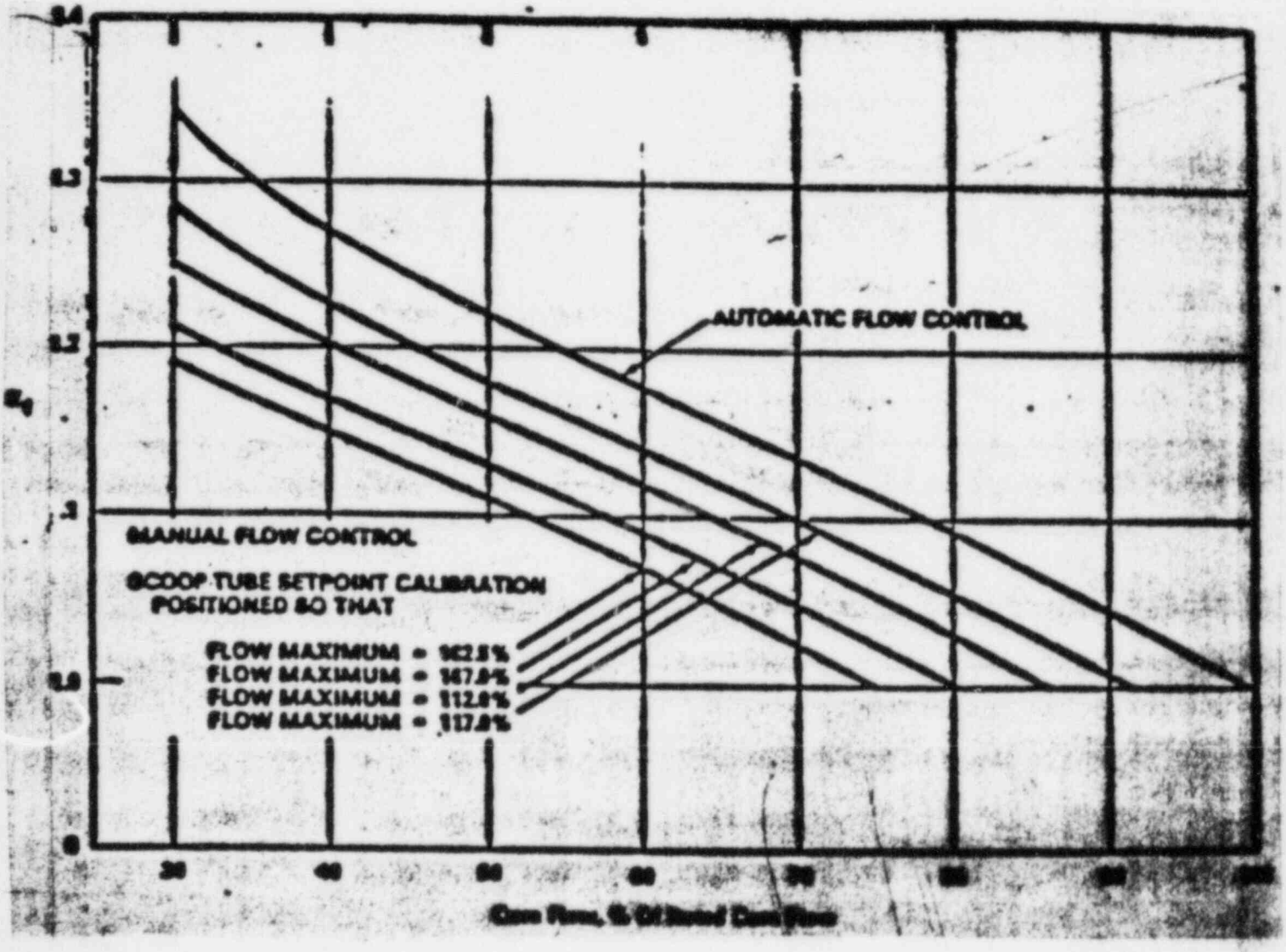


MINIMUM CRITICAL POWER RATIO (MCPR)

VERSUS τ AT RATED FLOW

Figure 3.2.3-1

FINAL DRAFT



K_f FACTOR

Figure 3.2.3-2

MAR 3 1 1986

FINAL DRAFT

3/4.2.4 LINEAR HEAT GENERATION RATE

LIMITING CONDITION FOR OPERATION

3.2.4 The LINEAR HEAT GENERATION RATE (LHGR) shall not exceed 13.4 kw/ft.

APPLICABILITY: OPERATIONAL CONDITION 1, when THERMAL POWER is greater than or equal to 25% of RATED THERMAL POWER.

ACTION:

With the LHGR of any fuel rod exceeding the limit, initiate corrective action within 15 minutes and restore the LHGR to within the limit within 2 hours or reduce THERMAL POWER to less than 25% of RATED THERMAL POWER within the next 4 hours.

SURVEILLANCE REQUIREMENTS

4.2.4 LHGR's shall be determined to be equal to or less than the limit:

a. At least once per 24 hours,

b. Within 12 hours after completion of a THERMAL POWER increase of at least 15% of RATED THERMAL POWER, and

c. Initially and at least once per 12 hours when the reactor is operating on a LIMITING CONTROL ROD PATTERN for LHGR.

d. The provisions of Specification 4.0.4 are not applicable.

MAR 3 1 1986

FINAL DRAFT

TABLE 3.3.1-1 (Continued)

REACTOR PROTECTION SYSTEM INSTRUMENTATION

TABLE NOTATIONS

(a) A channel may be placed in an inoperable status for up to 2 hours for required surveillance without placing the trip system in the tripped condition provided at least one OPERABLE channel in the same trip system is monitoring that parameter.

(b) This function shall be automatically bypassed when the reactor mode switch is in the Run position.

(c) Unless adequate shutdown margin has been demonstrated per Specification 3.1.1, the "shorting links" shall be removed from the RPS circuitry prior to and during the time any control rod is withdrawn*.

(d) The non-coincident NMS reactor trip function logic is such that all channels go to both trip systems. Therefore, when the "shorting links" are removed, the Minimum OPERABLE Channels Per the Trip System are 4 APRMS, 6 IRMS and 2 SRMS.

(e) An APRM channel is inoperable if there are less than 2 LPRM inputs per level or less than 14 LPRM inputs to an APRM channel.

(f) This function is not required to be OPERABLE when the reactor pressure vessel head is removed per Specification 3.10.1.

(g) This function shall be automatically bypassed when the reactor mode switch is not in the Run position.

(h) This function is not required to be OPERABLE when PRIMARY CONTAINMENT INTEGRITY is not required.

(i) With any control rod withdrawn. Not applicable to control rods removed per Specification 3.9.10.1 or 3.9.10.2.

(j) This function shall be automatically bypassed when turbine first stage pressure is $\leq$ 153.3 psig** equivalent to THERMAL POWER less than 30% of RATED THERMAL POWER. To allow for instrument accuracy, calibration, and drift, a setpoint of $\leq$ 132.4 psig** is used.

(k) Also actuates the EOC-RPT system.

---

*Not required for control rods removed per Specification 3.9.10.1 or 3.9.10.2.

**Initial setpoint. Final setpoint to be determined during the startup test program.

MAR 31 1986

TABLE 3.3.2-2 (Continued)

ISOLATION ACTUATION INSTRUMENTATION SETPOINTS

TRIP FUNCTION	TRIP SETPOINT	ALLOWABLE VALUE
7. RHR SYSTEM SHUTDOWN COOLING MODE ISOLATION		
a. Reactor Vessel Water Level - Low, Level 3	≥ 12.5 inches*	≥ 11.0 inches
b. Reactor Vessel (RHR Cut-in Permissive) Pressure - High	≤ 82.0 psig	≤ 102.0 psig
c. Manual Initiation	NA	NA

*See Bases Figure B 3/4 3-1.
**Initial setpoint. Final setpoint to be determined during startup test program.
***These setpoints are as follows:
160°F - RWCU pipe chase room 4402
140°F - RWCU pump room and heat exchanger rooms
135°F - RWCU pipe chase room 4505
#30 minute time delay.
##15 minute time delay.

FINAL DRAFT

TABLE 3.3.2-3

ISOLATION SYSTEM INSTRUMENTATION RESPONSE TIME

TRIP FUNCTION	RESPONSE TIME (Seconds)#
1. PRIMARY CONTAINMENT ISOLATION	
a. Reactor Vessel Water Level	
1) Low Low, Level 2	NA
2) Low Low Low, Level 1	NA
b. Drywell Pressure - High	NA
c. Reactor Building Exhaust Radiation - High	NA
d. Manual Initiation	NA
2. SECONDARY CONTAINMENT ISOLATION	
a. Reactor Vessel Water Level-Low Low, Level 2	NA
b. Drywell Pressure - High	NA
c. Refueling Floor Exhaust Radiation - High[(b)]	≤ 4.0
d. Reactor Building Exhaust Radiation - High[(b)]	≤ 4.0
e. Manual Initiation	NA
3. MAIN STEAM LINE ISOLATION	
a. Reactor Vessel Water Level - Low Low Low, Level 1	≤ 1.0*/≤ 13[(a)]**
b. Main Steam Line Radiation - High, High[(a)(b)]	≤ 1.0*/≤ 13[(a)]**
c. Main Steam Line Pressure - Low	≤ 1.0*/≤ 13[(a)]**
d. Main Steam Line Flow-High	≤ 0.5*/≤ 13[(a)]**
e. Condenser Vacuum - Low	NA
f. Main Steam Line Tunnel Temperature - High	NA
g. Manual Initiation	NA
4. REACTOR WATER CLEANUP SYSTEM ISOLATION	
a. RWCU Δ Flow - High	NA
b. RWCU Δ Flow - High, Timer	NA
c. RWCU Area Temperature - High	NA
d. RWCU Area Ventilation Δ Temperature - High	NA
e. SLCS Initiation	NA
f. Reactor Vessel Water Level - Low Low, Level 2	NA
g. Manual Initiation	NA
5. REACTOR CORE ISOLATION COOLING SYSTEM ISOLATION	
a. RCIC Steam Line Δ Pressure (Flow) - High	NA
b. RCIC Steam Line Δ Pressure (Flow) - High, Timer	NA
c. RCIC Steam Supply Pressure - Low	NA
d. RCIC Turbine Exhaust Diaphragm Pressure - High	NA

MAR 31 1986

TABLE 4.3.2.1-1

ISOLATION ACTUATION INSTRUMENTATION SURVEILLANCE REQUIREMENTS

TRIP FUNCTION	CHANNEL CHECK	CHANNEL FUNCTIONAL TEST	CHANNEL CALIBRATION	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRED
1. PRIMARY CONTAINMENT ISOLATION				
a. Reactor Vessel Water Level -				
1) Low Low, Level 2	S	M	R	1, 2, 3
2) Low Low Low, Level 1	S	M	R	1, 2, 3
b. Drywell Pressure - High	S	M	R	1, 2, 3
c. Reactor Building Exhaust Radiation - High	S	M	R	1, 2, 3
d. Manual Initiation	NA	M(a)	NA	1, 2, 3
2. SECONDARY CONTAINMENT ISOLATION				
a. Reactor Vessel Water Level - Low Low, Level 2	S	M	R	1, 2, 3 and *
b. Drywell Pressure - High	S	M	R	1, 2, 3
c. Refueling Floor Exhaust Radiation - High	S	M	R	1, 2, 3 and *
d. Reactor Building Exhaust Radiation - High	S	M	R	1, 2, 3 and *
e. Manual Initiation	NA	M(a)	NA	1, 2, 3 and *
3. MAIN STEAM LINE ISOLATION				
a. Reactor Vessel Water Level - Low Low Low, Level 1	S	M	R	1, 2, 3
b. Main Steam Line Radiation - High, High	S	M	R	1, 2, 3
c. Main Steam Line Pressure - Low	S	M	R	1
d. Main Steam Line Flow - High	S	M	R	1, 2, 3

FINAL DRAFT

TABLE 4.3.2.1-1 (Continued)

ISOLATION ACTUATION INSTRUMENTATION SURVEILLANCE REQUIREMENTS

TRIP FUNCTION	CHANNEL CHECK	CHANNEL FUNCTIONAL TEST	CHANNEL CALIBRATION	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRED
MAIN STEAM LINE ISOLATION (Continued)				
e. Condenser Vacuum - Low	S	M	R	1, 2**, 3**
f. Main Steam Line Tunnel Temperature - High	NA	M	R	1, 2, 3
g. Manual Initiation	NA	M(a)	NA	1, 2, 3
4. REACTOR WATER CLEANUP SYSTEM ISOLATION				
a. RWCU Δ Flow - High	S	M	R	1, 2, 3
b. RWCU Δ Flow - High, Timer	NA	M	R	1, 2, 3
c. RWCU Area Temperature - High	NA	M	R	1, 2, 3
d. RWCU Area Ventilation Δ Temperature - High	NA	M	R	1, 2, 3
e. SLCS Initiation	NA	M(b)	NA	1, 2, 5#
f. Reactor Vessel Water Level - Low Low, Level 2	S	M	R	1, 2, 3
g. Manual Initiation	NA	M(a)	NA	1, 2, 3
5. REACTOR CORE ISOLATION COOLING SYSTEM ISOLATION				
a. RCIC Steam Line Δ Pressure (Flow) - High	NA	M	R	1, 2, 3
b. RCIC Steam Line Δ Pressure (Flow) - High, Timer	NA	M	R	1, 2, 3
c. RCIC Steam Supply Pressure - Low	NA	M	R	1, 2, 3
d. RCIC Turbine Exhaust Diaphragm Pressure - High	NA	M	R	1, 2, 3

3/4.3.3 EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION

FINAL DRAFT

LIMITING CONDITION FOR OPERATION

3.3.3 The emergency core cooling system (ECCS) actuation instrumentation channels shown in Table 3.3.3-1 shall be OPERABLE with their trip setpoints set consistent with the values shown in the Trip Setpoint column of Table 3.3.3-2 and with EMERGENCY CORE COOLING SYSTEM RESPONSE TIME as shown in Table 3.3.3-3.

APPLICABILITY: As shown in Table 3.3.3-1.

ACTION:

a. With an ECCS actuation instrumentation channel trip setpoint less conservative than the value shown in the Allowable Values column of Table 3.3.3-2, declare the channel inoperable until the channel is restored to OPERABLE status with its trip setpoint adjusted consistent with the Trip Setpoint value.

b. With one or more ECCS actuation instrumentation channels inoperable, take the ACTION required by Table 3.3.3-1.

SURVEILLANCE REQUIREMENTS

4.3.3.1 Each ECCS actuation instrumentation channel shall be demonstrated OPERABLE by the performance of the CHANNEL CHECK, CHANNEL FUNCTIONAL TEST and CHANNEL CALIBRATION operations for the OPERATIONAL CONDITIONS and at the frequencies shown in Table 4.3.3.1-1.

4.3.3.2 LOGIC SYSTEM FUNCTIONAL TESTS and simulated automatic operation of all channels shall be performed at least once per 18 months.

4.3.3.3 The ECCS RESPONSE TIME of each ECCS trip function shown in Table 3.3.3-3 shall be demonstrated to be within the limit at least once per 18 months. Each test shall include at least one channel per trip system such that all channels are tested at least once every N times 18 months where N is the total number of redundant channels in a specific ECCS trip system.

MAR 31 1986

TABLE 3.3.3-1

EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION

TRIP FUNCTION	MINIMUM OPERABLE CHANNELS PER TRIP FUNCTION[a]	APPLICABLE OPERATIONAL CONDITIONS	ACTION
1. CORE SPRAY SYSTEM			
a. Reactor Vessel Water Level - Low Low Low, Level 1	2[b][e]	1, 2, 3, 4*, 5*	30
b. Drywell Pressure - High	2[b][e]	1, 2, 3	30
c. Reactor Vessel Pressure - Low (Permissive)	4/division[f]	1, 2, 3	31
		4*, 5*	32
d. Core Spray Pump Discharge Flow - Low (Bypass)***	1/subsystem	1, 2, 3, 4*, 5*	37
e. Core Spray Pump Start Time Delay - Normal Power***	1/subsystem	1, 2, 3, 4*, 5*	31
f. Core Spray Pump Start Time Delay - Emergency Power***	1/subsystem	1, 2, 3, 4*, 5*	31
g. Manual Initiation	1/division[b][g]	1, 2, 3, 4*, 5*	33
2. LOW PRESSURE COOLANT INJECTION MODE OF RHR SYSTEM			
a. Reactor Vessel Water Level - Low Low Low, Level 1	2/valve	1, 2, 3, 4*, 5*	30
b. Drywell Pressure - High	2/valve	1, 2, 3	30
c. Reactor Vessel Pressure - Low (Permissive)	1/valve	1, 2, 3	31
		4*, 5*	32
d. LPCI Pump Discharge Flow - Low (Bypass)***	1/pump	1, 2, 3, 4*, 5*	37
e. LPCI Pump Start Time Delay - Normal Power***	1/pump[i]	1, 2, 3, 4*, 5*	31
f. Manual Initiation	1/subsystem	1, 2, 3, 4*, 5*	33
3. HIGH PRESSURE COOLANT INJECTION SYSTEM#			
a. Reactor Vessel Water Level - Low Low Level 2	4	1, 2, 3	34
b. Drywell Pressure - High	4	1, 2, 3	34
c. Condensate Storage Tank Level - Low	2[c]	1, 2, 3	35
d. Suppression Pool Water Level - High	2[c]	1, 2, 3	35
e. Reactor Vessel Water Level - High, Level 8	4[d]	1, 2, 3	31
f. HPCI Pump Discharge Flow - Low (Bypass)***	1	1, 2, 3	37
g. Manual Initiation	1/system	1, 2, 3	33
4. AUTOMATIC DEPRESSURIZATION SYSTEM##			
a. Reactor Vessel Water Level - Low Low Low, Level 1	4	1, 2, 3	30
b. Drywell Pressure - High	4	1, 2, 3	30
c. ADS Timer	2	1, 2, 3	31
d. Core Spray Pump Discharge Pressure - High (Permissive)	1/pump	1, 2, 3	31

FINAL DRAFT

MAR 31 1986

TABLE 3.3.3-1 (Cont'd)

EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION

TRIP FUNCTION	MINIMUM OPERABLE CHANNELS PER TRIP FUNCTION(a)	APPLICABLE OPERATIONAL CONDITIONS	ACTION
4. AUTOMATIC DEPRESSURIZATION SYSTEM##			
e. RHR LPCI Mode Pump Discharge Pressure - High (Permissive)	2/pump	1, 2, 3	31
f. Reactor Vessel Water Level - Low, Level 3 (Permissive)	2	1, 2, 3	31
g. ADS Drywell Pressure Bypass Timer	4	1, 2, 3	31
h. ADS Manual Inhibit Switch	2	1, 2, 3	31
i. Manual Initiation	4	1, 2, 3	33

	TOTAL NO OF CHANNELS(h)	CHANNELS TO TRIP(h)	MINIMUM CHANNELS OPERABLE(h)	APPLICABLE OPERATIONAL CONDITIONS	ACTION
5. LOSS OF POWER					
1. 4.16 kv Emergency Bus Under-voltage (Loss of Voltage)	4/bus	2/bus	3/bus	1, 2, 3, 4**, 5**	36
2. 4.16 kv Emergency Bus Under-voltage (Degraded Voltage)	2/source/bus	2/source/bus	2/source/bus	1, 2, 3, 4**, 5**	36

(a) A channel may be placed in an inoperable status for up to 2 hours for required surveillance without placing the trip system in the tripped condition provided at least one OPERABLE channel in the same trip system is monitoring that parameter.
(b) Also actuates the associated emergency diesel generators.
(c) One trip system. Provides signal to HPCI pump suction valve only.
(d) Provides a signal to trip HPCI pump turbine only.
(e) In divisions 1 and 2, the two sensors are associated with each pump and valve combination. In divisions 3 and 4, the two sensors are associated with each pump only.
(f) Division 1 and 2 only.
(g) In divisions 1 and 2, manual initiation is associated with each pump and valve combination; in divisions 3 and 4, manual initiation is associated with each pump only.
(h) Each voltage detector is a channel.
(i) Start time delay is applicable to LPCI Pump C and D only.
* When the system is required to be OPERABLE per Specification 3.5.2.
** Required when ESF equipment is required to be OPERABLE.
*** Not required to be OPERABLE prior to initial criticality.
\# Not required to be OPERABLE when reactor steam dome pressure is less than or equal to 200 psig.
Not required to be OPERABLE when reactor steam dome pressure is less than or equal to 100 psig.

FINAL DRAFT

TABLE 3.3.3-1 (Continued)

EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION

ACTION

ACTION 30 - With the number of OPERABLE channels less than required by the Minimum OPERABLE Channels per Trip Function requirement:

a. With one channel inoperable, place the inoperable channel in the tripped condition within one hour* or declare the associated system inoperable.

b. With more than one channel inoperable, declare the associated system inoperable.

ACTION 31 - With the number of OPERABLE channels less than required by the Minimum OPERABLE Channels per Trip Function requirement, declare the associated ECCS inoperable.

ACTION 32 - With the number of OPERABLE channels less than required by the Minimum OPERABLE Channels per Trip Function requirement, place the inoperable channel in the tripped condition within one hour.

ACTION 33 - With the number of OPERABLE channels less than required by the Minimum OPERABLE Channels per Trip Function requirement, restore the inoperable channel to OPERABLE status within 8 hours or declare the associated ECCS inoperable.

ACTION 34 - With the number of OPERABLE channels less than required by the Minimum OPERABLE Channels per Trip Function requirement:

a. For one channel inoperable, place the inoperable channel in the tripped condition within 1 hour* or declare the HPCI system inoperable.

b. With more than one channel inoperable, declare the HPCI system inoperable.

ACTION 35 - With the number of OPERABLE channels less than required by the Minimum OPERABLE Channels per Trip Function requirement, place at least one inoperable channel in the tripped condition within one hour* or declare the HPCI system inoperable.

ACTION 36 - With the number of OPERABLE channels one less than the Total Number of Channels, place the inoperable channel in the tripped condition within 1 hour;* operation may then continue until performance of the next required CHANNEL FUNCTIONAL TEST.

ACITON 37 - With the number of OPERABLE channels less than required by the Minimum OPERABLE channels per Trip Function requirement, open the minimum flow bypass valve within one hour. Restore the inoperable channel to OPERABLE status within 7 days or declare the associated ECCS inoperable.

*The provisions of Specification 3.0.4 are not applicable.

TABLE 3.3.3-2

EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION SETPOINTS

TRIP FUNCTION	TRIP SETPOINT	ALLOWABLE VALUE
1. CORE SPRAY SYSTEM		
a. Reactor Vessel Water Level - Low Low Low, Level 1	≥-129 inches*	≥-136 inches
b. Drywell Pressure - High	≤ 1.68 psig	≤ 1.88 psig
c. Reactor Vessel Pressure - Low	461 psig	≤ 481 psig and ≥ 441 psig
d. Core Spray Pump Discharge Flow - Low (Bypass)	≥ 775 gpm	≥ 650 gpm
e. Core Spray Pump Start Time Delay - Normal Power	10 seconds	≥ 9 seconds and ≤ 11 seconds
f. Core Spray Pump Start Time Delay - Emergency Power	6 seconds	≥ 5 seconds and ≤ 7 seconds
g. Manual Initiation	NA	NA
2. LOW PRESSURE COOLANT INJECTION MODE OF RHR SYSTEM		
a. Reactor Vessel Water Level - Low Low Low, Level 1	≥-129 inches*	≥-136 inches
b. Drywell Pressure - High	≤ 1.68 psig	≤ 1.88 psig
c. Reactor Vessel Pressure - Low (Permissive)	450 psig	≤ 460 psig and ≥ 440 psig
d. LPCI Pump Discharge Flow - Low (Bypass)	≥ 1250 gpm	≥ 1100 gpm
e. LPCI Pump Start Time Delay - Normal Power	5 seconds	≥ 4 seconds and ≤ 6 seconds
f. Manual Initiation	NA	NA
3. HIGH PRESSURE COOLANT INJECTION SYSTEM		
a. Reactor Vessel Water Level - (Low Low, Level 2)	≥-38 inches*	≥-45 inches
b. Drywell Pressure - High	≤ 1.68 psig	≤ 1.88 psig
c. Condensate Storage Tank Level - Low	≥ 22,558 gallons	≥ 19,174 gallons
d. Suppression Pool Water Level - High	≤ 78.5 inches	≤ 80.3 inches
e. Reactor Vessel Water Level - High, Level 8	≤ 54 inches	≤ 61 inches
f. HPCI Pump Discharge Flow - Low (Bypass)	≥ 550 gpm	≥ 500 gpm
g. Manual Initiation	NA	NA

TABLE 3.3.3-2 (Continued)

EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION SETPOINTS

TRIP FUNCTION	TRIP SETPOINT	ALLOWABLE VALUE
4. AUTOMATIC DEPRESSURIZATION SYSTEM		
a. Reactor Water Level - Low Low Low, Level 1	≥-129 inches*	≥-136 inches
b. Drywell Pressure - High	≤ 1.68 psig	≤ 1.88 psig
c. ADS Timer	≤ 105 seconds	≤ 117 seconds
d. Core Spray Pump Discharge Pressure - High	145 psig	≤ 155 psig ≥ 125 psig
e. RHR LPCI Mode Pump Discharge Pressure-High	125 psig	≤ 135 psig ≥ 115 psig
f. Reactor Vessel Water Level-Low, Level 3	≥ 12.5 inches	≥ 11.0 inches
g. ADS Drywell Pressure Bypass Timer	≤ 5.0 minutes	≤ 5.5 minutes
h. ADS Manual Inhibit Switch	NA	NA
i. Manual Initiation	NA	NA
5. LOSS OF POWER		
a. 4.16 kv Emergency Bus Undervoltage (Loss of Voltage)	a. 4.16 kv Basis - 2975 ± 30 volts b. 120 v Basis - 85 ± 0.85 volts	2975 ± 63 volts 85 ± 1.8 volts
b. 4.16 kv Emergency Bus Undervoltage (Degraded Voltage)**	a. 4.16 kv Basis - ≥ 3857 volts b. 120 v Basis - ≥ 110.2 volts c. 20 sec @ 109.0 volts	≥ 3857 volts ≥ 109.0 volts 20 + 15, - 5 sec @ 109.0 volts

*See Bases Figure B 3/4 3-1.

**This is an inverse time delay voltage relay. The voltages shown are the maximum that will not result in a trip. Some voltage conditions will result in decreased trip times.

TABLE 4.3.3.1-1

EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION SURVEILLANCE REQUIREMENTS

TRIP FUNCTION	CHANNEL CHECK	CHANNEL FUNCTIONAL TEST	CHANNEL CALIBRATION	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRED
1. CORE SPRAY SYSTEM				
a. Reactor Vessel Water Level - Low Low Low, Level 1	S	M	R	1, 2, 3, 4*, 5*
b. Drywell Pressure - High	S	M	R	1, 2, 3
c. Reactor Vessel Pressure - Low	S	M	R	1, 2, 3, 4*, 5*
d. Core Spray Pump Discharge Flow - Low (Bypass)	S	M	R	1, 2, 3, 4*, 5*
e. Core Spray Pump Start Time Delay - Normal Power	NA	M	R	1, 2, 3, 4*, 5*
f. Core Spray Pump Start Time Delay - Emergency Power	NA	M	R	1, 2, 3, 4*, 5*
g. Manual Initiation	NA	R	NA	1, 2, 3, 4*, 5*
2. LOW PRESSURE COOLANT INJECTION MODE OF RHR SYSTEM				
a. Reactor Vessel Water Level - Low Low Low, Level 1	S	M	R	1, 2, 3, 4*, 5*
b. Drywell Pressure - High	S	M	R	1, 2, 3
c. Reactor Vessel Pressure - Low (Permissive)	S	M	R	1, 2, 3, 4*, 5*
d. LPCI Pump Discharge FLow - Low (Bypass)	S	M	R	1, 2, 3, 4*, 5*
e. LPCI Pump Start Time Delay - Normal Power	NA	M	R	1, 2, 3, 4*, 5*
f. Manual Initiation	NA	R	NA	1, 2, 3, 4*, 5*
3. HIGH PRESSURE COOLANT INJECTION SYSTEM#				
a. Reactor Vessel Water Level - Low Low, Level 2	S	M	R	1, 2, 3
b. Drywell Pressure - High	S	M	R	1, 2, 3
c. Condensate Storage Tank Level - Low	S	M	R	1, 2, 3
d. Suppression Pool Water Level - High	S	M	R	1, 2, 3
e. Reactor Vessel Water Level - High, Level 8	S	M	R	1, 2, 3
f. HPCI Pump Discharge FLow - Low (Bypass)	S	M	R	1, 2, 3
g. Manual Initiation	NA	R	NA	1, 2, 3

FINAL DRAFT

TABLE 3.3.4.2-1

END-OF-CYCLE RECIRCULATION PUMP TRIP SYSTEM INSTRUMENTATION

TRIP FUNCTION	MINIMUM OPERABLE CHANNELS PER TRIP SYSTEM[a]
1. Turbine Stop Valve - Closure	2[b]
2. Turbine Control Valve-Fast Closure	2[b]

[a] A trip system may be placed in an inoperable status for up to 2 hours for required surveillance provided that the other trip system is OPERABLE.

[b] This function shall be automatically bypassed when turbine first stage pressure is ≤ 153.3 psig* equivalent to THERMAL POWER less than 30% of RATED THERMAL POWER. To allow for instrument accuracy, calibration and drift, a setpoint of ≤ 132.4 psig* is used.

*Initial Setpoint. Final setpoint to be determined during the startup test program.

TABLE 3.3.5-1

REACTOR CORE ISOLATION COOLING SYSTEM ACTUATION INSTRUMENTATION

TRIP FUNCTION	MINIMUM OPERABLE CHANNELS PER TRIP FUNCTION[a]	ACTION
a. Reactor Vessel Water Level - Low Low, Level 2	4[b]	50
b. Reactor Vessel Water Level - High, Level 8	4[b]	50
c. Condensate Storage Tank Water Level - Low[e]	2[c]	51
d. Manual Initiation	1[d]	52

(a) A channel may be placed in an inoperable status for up to 2 hours for required surveillance without placing the trip system in the tripped condition provided all other channels monitoring that parameter are OPERABLE.
(b) One trip system with one-out-of-two twice logic.
(c) One trip system with one-out-of-two logic.
(d) One trip system with one channel.
(e) Initiates RCIC suction switchover from the condensate storage tank to the torus.

TABLE 3.3.6-2

CONTROL ROD BLOCK INSTRUMENTATION SETPOINTS

TRIP FUNCTION	TRIP SETPOINT	ALLOWABLE VALUE
1. ROD BLOCK MONITOR		
a. Upscale	$\leq$ 0.66 W + 40%	$\leq$ 0.66 W + 43%
b. Inoperative	NA	NA
c. Downscale	$\geq$ 5% of RATED THERMAL POWER	$\geq$ 3% of RATED THERMAL POWER
2. APRM		
a. Flow Biased Neutron Flux - Upscale	$\leq$ 0.66 W + 42%*	$\leq$ 0.66 W + 45%*
b. Inoperative	NA	NA
c. Downscale	$\geq$ 4% of RATED THERMAL POWER	$\geq$ 3% of RATED THERMAL POWER
d. Neutron Flux - Upscale, Startup	$\leq$ 12% of RATED THERMAL POWER	$\leq$ 14% of RATED THERMAL POWER
3. SOURCE RANGE MONITORS		
a. Detector not full in	NA	NA
b. Upscale	$\leq 1.0 \times 10^5$ cps	$\leq 1.6 \times 10^5$ cps
c. Inoperative	NA	NA
d. Downscale	$\geq$ 3 cps**	$\geq$ 1.8 cps
4. INTERMEDIATE RANGE MONITORS		
a. Detector not full in	NA	NA
b. Upscale	$\leq$ 108/125 divisions of full scale	$\leq$ 110/125 divisions of full scale
c. Inoperative	NA	NA
d. Downscale	$\geq$ 5/125 divisions of full scale	$\geq$ 3/125 divisions of full scale
5. SCRAM DISCHARGE VOLUME		
a. Water Level-High (Float Switch)	109'1" (North Volume) 108'11.5" (South Volume)	109'3" (North Volume) 109'1.5" (South Volume)
6. REACTOR COOLANT SYSTEM RECIRCULATION FLOW		
a. Upscale	$\leq$ 108% of rated flow	$\leq$ 111% of rated flow
b. Inoperative	NA	NA
c. Comparator	$\leq$ 10% flow deviation	$\leq$ 11% flow deviation
7. REACTOR MODE SWITCH SHUTDOWN POSITION	NA	NA

*The Average Power Range Monitor rod block function is varied as a function of recirculation loop flow (W). The trip setting of this function must be maintained in accordance with Specification 3.2.2.
**May be reduced to 0.7 cps provided the signal-to-noise ratio is $\geq$ 2.

TABLE 4.3.6-1

CONTROL ROD BLOCK INSTRUMENTATION SURVEILLANCE REQUIREMENTS

TRIP FUNCTION	CHANNEL CHECK	CHANNEL FUNCTIONAL TEST	CHANNEL CALIBRATION[a]	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRED
1. ROD BLOCK MONITOR				
a. Upscale	NA	S/U[b][c],M[c]	SA	1*
b. Inoperative	NA	S/U[b][c],M[c]	NA	1*
c. Downscale	NA	S/U[b][c],M[c]	SA	1*
2. APRM				
a. Flow Biased Neutron Flux - Upscale	NA	S/U[b],M	SA	1
b. Inoperative	NA	S/U[b],M	NA	1, 2, 5
c. Downscale	NA	S/U[b],M	SA	1
d. Neutron Flux - Upscale, Startup	NA	S/U[b],M	SA	2, 5
3. SOURCE RANGE MONITORS				
a. Detector not full in	NA	S/U[b],W	NA	2, 5
b. Upscale	NA	S/U[b],W	SA	2, 5
c. Inoperative	NA	S/U[b],W	NA	2, 5
d. Downscale	NA	S/U[b],W	SA	2, 5
4. INTERMEDIATE RANGE MONITORS				
a. Detector not full in	NA	S/U[b],W	NA	2, 5
b. Upscale	NA	S/U[b],W	SA	2, 5
c. Inoperative	NA	S/U[b],W	NA	2, 5
d. Downscale	NA	S/U[b],W	SA	2, 5
5. SCRAM DISCHARGE VOLUME				
a. Water Level-High (Float Switch)	NA	M	R	1, 2, 5**
6. REACTOR COOLANT SYSTEM RECIRCULATION FLOW				
a. Upscale	NA	S/U[b],M	SA	1
b. Inoperative	NA	S/U[b],M	NA	1
c. Comparator	NA	S/U[b],M	SA	1
7. REACTOR MODE SWITCH SHUTDOWN POSITION	NA	R	NA	3, 4

FINAL DRAFT

TABLE 3.3.7.1-1 (Continued)

RADIATION MONITORING INSTRUMENTATION

ACTION

ACTION 71 -

a. With one of the required monitors inoperable, place the inoperable channel in the tripped condition within one hour; restore the inoperable channel to OPERABLE status within 7 days, or, within the next 6 hours, initiate and maintain operation of the control room emergency filtration system in the pressurization mode of operation.

b. With both of the required monitors inoperable, initiate and maintain operation of the control room emergency filtration system in the pressurization mode of operation within one hour.

ACTION 72 - With the required monitor inoperable, perform area surveys of the monitored area with portable monitoring instrumentation at least once per 24 hours.

ACTION 73 - With the required monitor inoperable, obtain and analyze at least one sample of the monitored parameter at least once per 24 hours.*

ACTION 74 - With the number of channels OPERABLE less than required by Minimum Channels OPERABLE requirement, release(s) via this pathway may continue for up to 30 days provided:

a. The offgas system is not bypassed, and

b. The offgas post-treatment monitor is OPERABLE, and

c. Grab samples are taken at least once per 8 hours and analyzed within the following 4 hours;

Otherwise, be in at least HOT SHUTDOWN within 12 hours.

*Radiation level readings may be taken at the Local Radiation Processor (LRP) at least once per 24 hours in lieu of obtaining and analyzing grab samples at least once per 24 hours prior to 120 days after initial fuel load.

FINAL DRAFT

TABLE 3.3.7.3-1

METEOROLOGICAL MONITORING INSTRUMENTATION

INSTRUMENT	MINIMUM INSTRUMENTS OPERABLE
a. Wind Speed	
1. Elev. 33 ft.	1
2. Elev. 150 ft.	1
b. Wind Direction	
1. Elev. 30 ft.	1
2. Elev. 150 ft.	1
c. Air Temperature Difference	
1. Elev. 150-33 ft.	1

MAR 31 1986

TABLE 4.3.7.3-1

METEOROLOGICAL MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS

INSTRUMENT	CHANNEL CHECK	CHANNEL CALIBRATION
a. Wind Speed		
1. Elev. 33 ft.	D	SA
2. Elev. 150 ft.	D	SA
b. Wind Direction		
1. Elev. 33 ft.	D	SA
2. Elev. 150 ft.	D	SA
c. Air Temperature Difference		
1. Elev. 150-33 ft.	D	SA

TABLE 3.3.7.4-1

REMOTE SHUTDOWN MONITORING INSTRUMENTATION

INSTRUMENT	MINIMUM INSTRUMENTS OPERABLE*
1. Reactor Vessel Pressure	2
2. Reactor Vessel Water Level	2
3. Safety/Relief Valve Position, (3) valves	1/valve
4. Suppression Chamber Water Level	2
5. Suppression Chamber Water Temperature	2
6. RHR System Flow	1
7. Safety Auxiliaries Cooling System Flow	1
8. Safety Auxiliaries Cooling System Temperature	1
9. RCIC System Flow	1
10. RCIC Turbine Speed	1
11. RCIC Turbine Bearing Oil Pressure Low Indication	1
12. RCIC High Pressure/Low Pressure Turbine Bearing Temperature High Indication	1
13. Condensate Storage Tank Level Low-Low Indication	1
14. Standby Diesel Generator 1AG400 Breaker Indication	1

*Either primary location (Remote Shutdown Panel, 10C399) or alternate location.

FINAL DRAFT

TABLE 3.3.7.5-1

ACCIDENT MONITORING INSTRUMENTATION

INSTRUMENT	REQUIRED NUMBER OF CHANNELS	MINIMUM CHANNELS OPERABLE	APPLICABLE OPERATIONAL CONDITIONS	ACTION
1. Reactor Vessel Pressure	2	1	1,2,3	80
2. Reactor Vessel Water Level	2	1	1,2,3	80
3. Suppression Chamber Water Level	2	1	1,2,3	80
4. Suppression Chamber Water Temperature*	2	2	1,2,3	80[a]
5. Suppression Chamber Pressure	2	1	1,2,3	80
6. Drywell Pressure	2	1	1,2,3	80
7. Drywell Air Temperature	2	1	1,2,3	80
8. Primary Containment Hydrogen/Oxygen Concentration Analyzer and Monitor	2	1	1,2,3	80
9. Safety/Relief Valve Position Indicators	2/valve**	1/valve**	1,2,3	80
10. Drywell Atmosphere Post-Accident Radiation Monitor	2	1	1,2,3	81
11. North Plant Vent Radiation Monitor#	1	1	1,2,3	81
12. South Plant Vent Radiation Monitor#	1	1	1,2,3	81
13. FRVS Vent Radiation Monitor#	1	1	1,2,3	81
14. Primary Containment Isolation Valve Position Indication[b] ##	2/valve	1/valve	1,2,3	82

#High range noble gas monitors.
*Average bulk pool temperature.
**Acoustic monitoring and tail pipe temperature.
(a)Suppression chamber water temperature instrumentation must satisfy the availability requirements specified in Specification 3.6.2.1.
(b)One channel consists of the open limit switch, and the other channel consists of the closed limit switch.
##Not required to be OPERABLE prior to exceeding 5% of RATED THERMAL POWER.

Table 3.3.7.5-1 (Continued)

ACCIDENT MONITORING INSTRUMENTATION
ACTION STATEMENTS

ACTION 80 -

a. With the number of OPERABLE accident monitoring instrumentation channels less than the Required Number of Channels shown in Table 3.3.7.5-1, restore the inoperable channel(s) to OPERABLE status within 7 days or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

b. With the number of OPERABLE accident monitoring instrumentation channels less than the Minimum Channels OPERABLE requirements of Table 3.3.7.5-1, restore the inoperable channel(s) to OPERABLE status within 48 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

ACTION 81 - With the number of OPERABLE accident monitoring instrumentation channels less than required by the Minimum Channels OPERABLE requirement, either restore the inoperable channel(s) to OPERABLE status within 72 hours, or:

a. Initiate the preplanned alternate method of monitoring the appropriate parameter(s), and

b. Prepare and submit a Special Report to the Commission pursuant to Specification 6.9.2 within 14 days following the event outlining the action taken, the cause of the inoperability and the plans and schedule for restoring the system to OPERABLE status.

The provisions of Specification 3.0.4 are not applicable.

ACTION 82 -

a. With the number of OPERABLE accident monitoring instrumentation channels less than the Required Number of Channels shown in Table 3.3.7.5-1, verify the valve(s) position by use of alternate indication methods; restore the inoperable channel(s) to OPERABLE status within 30 days or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

b. With the number of OPERABLE accident monitoring instrumentation channels less than the Minimum Channels OPERABLE requirements of Table 3.3.7.5-1, verify the valve(s) position by use of alternate indication methods; restore the inoperable channel(s) to OPERABLE status within 7 days or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

TABLE 4.3.7.5-1

ACCIDENT MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS

INSTRUMENT	CHANNEL CHECK	CHANNEL CALIBRATION	APPLICABLE OPERATIONAL CONDITIONS
1. Reactor Vessel Pressure	M	R	1,2,3
2. Reactor Vessel Water Level	M	R	1,2,3
3. Suppression Chamber Water Level	M	R	1,2,3
4. Suppression Chamber Water Temperature	M	R	1,2,3
5. Suppression Chamber Pressure	M	R	1,2,3
6. Drywell Pressure	M	R	1,2,3
7. Drywell Air Temperature	M	R	1,2,3
8. Primary Containment Hydrogen/Oxygen Concentration Analyzer and Monitor	M	Q*	1,2,3
9. Safety/Relief Valve Position Indicators	M	R	1,2,3
10. Drywell Atmosphere Post-Accident Radiation Monitor	M	R**	1,2,3
11. North Plant Vent Radiation Monitor#	M	R	1,2,3
12. South Plant Vent Radiation Monitor#	M	R	1,2,3
13. FRVS Vent Radiation Monitor#	M	R	1,2,3
14. Primary Containment Isolation Valve Position Indication##	M	R	1,2,3

*Using sample gas containing:
a. Five volume percent oxygen balance nitrogen (oxygen analyzer channel).
b. Five volume percent hydrogen, balance nitrogen (hydrogen analyzer channel).

**CHANNEL CALIBRATION shall consist of an electronic calibration of the channel, not including the detector, for range decades above 10 R/hr and a one point calibration check of the detector below 10 R/hr with an installed or portable gamma source.

#High range noble gas monitors.

##Not required to be OPERABLE prior to exceeding 5% of RATED THERMAL POWER.

TABLE 3.3.7.8-1 (Continued)

FIRE DETECTION INSTRUMENTATION

DETECTION ZONE	ELEV.	ROOM OR AREA (FIRE ZONE/ROOM NO.)	HEAT (x/y)	FLAME (x/y)	SMOKE (x/y)
b. Auxiliary Building Control & D/G Areas (Cont'd)					
5407	124'	Corridor (5401)	0/9	N/A	6/0
5403	130'	D/G Control Room (5410)	N/A	N/A	1/0
5403	130'	Class 1E Swgr. Room (5411)	N/A	N/A	3/0
5404	130'	D/G Control Room (5412)	N/A	N/A	1/0
5404	130'	Class 1E Swgr. Room (5413)	N/A	N/A	3/0
5405	130'	D/G Control Room (5414)	N/A	N/A	1/0
5405	130'	Class 1E Swgr. Room (5415)	N/A	N/A	3/0
5406	130'	D/G Control Room (5416)	N/A	N/A	1/0
5406	130'	Class 1E Swgr. Room (5417)	N/A	N/A	3/0
5501	137'	Conference and Storage Rooms (5508, 5520, 5523)	N/A	N/A	3/0
5501	137'	Corridors (5502, 5503, 5507, 5512, 5522)	N/A	N/A	5/0
5502	137'	Control Room and Ready Room (5509, 5510, 5511)	N/A	N/A	15/0
5503	137'	Control Room Computer Room (5515)	N/A	N/A	6/0
5504	137'	Control Room Console	N/A	N/A	8/0
5505	137'	Control Room Vert. Board (Right)	N/A	N/A	4/0
5506	137'	Control Room Vert. Board (Middle)	N/A	N/A	3/0
5507	137'	Control Room Vert. Board (Left)	N/A	N/A	4/0
5515	137'	Elec. Access Area (5501)	N/A	N/A	5/0
5516	146'	Battery Charger Room (5538)	N/A	N/A	2/0
5516	146'	Battery Room (5539)	N/A	N/A	1/0
5517	156'	Battery Charger Room (5540)	N/A	N/A	2/0
5517	146'	Battery Room (5541)	N/A	N/A	1/0
5518	146'	Battery Charger Room (5542)	N/A	N/A	2/0
5518	146'	Battery Room (5543)	N/A	N/A	1/0
5519	146'	Battery Charger Room (5544)	N/A	N/A	2/0
5519	146'	Battery Room (5545)	N/A	N/A	1/0
5521	77', 102', 124', 120', 137', 150'	Elec. Cable Chase, Channel D (5203, 5323, 5331, 5405, 5419, 5531)	0/15	N/A	6/0

FINAL DRAFT

TABLE 3.3.7.8-1 (Continued)

FIRE DETECTION INSTRUMENTATION

DETECTION ZONE	ELEV.	ROOM OR AREA (FIRE ZONE/ROOM NO.)	HEAT (x/y)	FLAME (x/y)	SMOKE (x/y)
e. Auxiliary Building Control Area					
-	153'	Control Room Emerg. Char. Filter Units	1/0	N/A	N/A
-	153'	Control Room Emerg. Char. Filter Units	1/0	N/A	N/A
f. Auxiliary Building Radwaste & Service Areas					
3104	54'	Corridor (3110)	N/A	N/A	9/0
3203	77'	Electrical Access Area (3204)	0/19	N/A	8/0
3307	102'	Electrical Access Area (3314)	N/A	N/A	3/0
3410	124'	Electrical Access Area (3425)	0/5	N/A	4/0
3312	102'	Corridor, Lobby & Vestibule (3301, 3302, 3304, 3313)	N/A	N/A	12/0
3312	102'	Janitor's Room (3304)	N/A	N/A	1/0
3312	102'	Hot Water Heater Room (3342)	N/A	N/A	1/0
3313	102'	Men's Toilet Rm (3303)	N/A	N/A	4/0
3408	124'	Equipment Removal Area (3442)	N/A	N/A	7/0
3408	124'	Controlled Locker Area & Corridor (3443, 3444)	N/A	N/A	3/0
3408	124'	Clean Issue Room (3414)	N/A	N/A	1/0
3409	124'	Uncontrolled Maint. Locker Area & Corridor (3409, 3413)	N/A	N/A	4/0
3503	137'	Remote Shutdown Panel Room (3576)	N/A	N/A	2/0
3504	137'	Uncontrolled Laundry and Towel Storage (3506, 3508)	N/A	N/A	1/0
3519	137'	TSC Vestibule and Radio Equipment Room (3579, 3510)	N/A	N/A	3/0
3604	155'3"	H&V Equip. Room (3606)	N/A	N/A	6/0
3605	155'3"	H&V Equip. Area (3605)	N/A	N/A	4/0
3610	155'3"	TSC Electrical Room (5619)	N/A	N/A	2/0
N/A	155'3"	Service Area Exhaust Duct (3605)	N/A	N/A	1/0
N/A	137' & 155'3"	Service Area Supply Duct (3555, 3609)	N/A	N/A	2/0
N/A	124' & 137'	Solid Radwaste Supply and Exhaust Duct (3457 & 3580)	N/A	N/A	2/0

*(x/y): x is number of Function A (early warning fire detection and notification only) instruments.
y is number of Function B (actuation of fire suppression systems and early warning notification) instruments.

FINAL DRAFT

INSTRUMENTATION

RADIOACTIVE GASEOUS EFFLUENT MONITORING INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.7.11 The radioactive gaseous effluent monitoring instrumentation channels shown in Table 3.3.7.11-1 shall be OPERABLE with their Alarm/Trip Setpoints set to ensure that the limits of Specifications 3.11.2.1 and 3.11.2.6 are not exceeded. The Alarm/Trip Setpoints of these channels meeting Specification 3.11.2.1 shall be determined and adjusted in accordance with the methodology and parameters in the ODCM.

APPLICABILITY: As shown in Table 3.3.7.11-1.

ACTION:

a. With a radioactive gaseous effluent monitoring instrumentation channel Alarm/Trip Setpoint less conservative than required by the above specification, immediately suspend the release of radioactive gaseous effluents monitored by the affected channel, or declare the channel inoperable.

b. With less than the minimum number of radioactive gaseous effluent monitoring instrumentation channels OPERABLE, take the ACTION shown in Table 3.3.7.11-1. Restore the inoperable instrumentation to OPERABLE status within the time specified in the ACTION, or explain in the next Semiannual Radioactive Effluent Release Report pursuant to Specification 6.9.1.7 why this inoperability was not corrected in a timely manner.

c. The provisions of Specifications 3.0.3 and 3.0.4 are not applicable.

SURVEILLANCE REQUIREMENTS

4.3.7.11 Each radioactive gaseous effluent monitoring instrumentation channel shall be demonstrated OPERABLE by performance of the CHANNEL CHECK, SOURCE CHECK, CHANNEL CALIBRATION and CHANNEL FUNCTIONAL TEST at the frequencies shown in Table 4.3.7.11-1.

FINAL DRAFT

3/4.4.3 REACTOR COOLANT SYSTEM LEAKAGE

LEAKAGE DETECTION SYSTEMS

LIMITING CONDITION FOR OPERATION

3.4.3.1 The following reactor coolant system leakage detection systems shall be OPERABLE:

a. The drywell atmosphere gaseous radioactivity monitoring system,*
b. The drywell floor and equipment drain sump monitoring system,
c. The drywell air cooler condensate flow rate monitoring system,
d. The drywell pressure monitoring system, and
e. The drywell temperature monitoring system.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2 and 3.

ACTION:

With only four of the above required leakage detection systems OPERABLE, operation may continue for up to 30 days provided grab samples of the containment atmosphere are obtained and analyzed at least once per 24 hours when the required drywell atmosphere gaseous radioactivity monitoring system, the drywell pressure monitoring system, the drywell temperature monitoring system and/or the drywell air cooler condensate flow rate monitoring system is inoperable; otherwise, be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

SURVEILLANCE REQUIREMENTS

4.4.3.1 The reactor coolant system leakage detection systems shall be demonstrated OPERABLE by:

a. Drywell atmosphere gaseous radioactivity monitoring system-performance of a CHANNEL CHECK at least once per 12 hours, a CHANNEL FUNCTIONAL TEST at least once per 31 days and a CHANNEL CALIBRATION at least once per 18 months.

b. The drywell pressure shall be monitored at least once per 12 hours and the drywell temperature shall be monitored at least once per 24 hours.

c. Drywell floor and equipment drain sump monitoring system-performance of a CHANNEL FUNCTIONAL TEST at least once per 31 days and a CHANNEL CALIBRATION TEST at least once per 18 months.

d. Drywell air coolers condensate flow rate monitoring system-performance of a CHANNEL FUNCTIONAL TEST at least once per 31 days and a CHANNEL CALIBRATION at least once per 18 months.

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* Not required to be OPERABLE prior to 150 days after initial fuel load.

MAR 31 1986

4.4.3.2.1 The reactor coolant system leakage shall be demonstrated to be within each of the above limits by:

a. Monitoring the drywell atmospheric gaseous radioactivity at least once per 12 hours (not a means of quantifying leakage),

b. Monitoring the drywell floor and equipment drain sump flow rate at least once per 12 hours, and

c. Monitoring the drywell air coolers condensate flow rate at least once per 12 hours, and

d. Monitoring the drywell pressure at least once per 12 hours (not a means of quantifying leakage), and

e. Monitoring the reactor vessel head flange leak detection system at least once per 24 hours (not a means of quantifying leakage), and

f. Monitoring the drywell temperature at least once per 24 hours (not a means of quantifying leakage).

4.4.3.2.2 Each reactor coolant system pressure isolation valve specified in Table 3.4.3.2-1 shall be demonstrated OPERABLE by leak testing pursuant to Specification 4.0.5 and verifying the leakage of each valve to be within the specified limit:

a. At least once per 18 months, and

b. Prior to returning the valve to service following maintenance, repair or replacement work on the valve which could affect its leakage rate.

The provisions of Specification 4.0.4 are not applicable for entry into OPERATIONAL CONDITION 3.

4.4.3.2.3 The high/low pressure interface valve leakage pressure monitors shall be demonstrated OPERABLE with alarm setpoints per Table 3.4.3.2-2 by performance of a:

a. CHANNEL FUNCTIONAL TEST at least once per 31 days, and

b. CHANNEL CALIBRATION at least once per 18 months.

3/4.4.5 SPECIFIC ACTIVITY

LIMITING CONDITION FOR OPERATION

3.4.5 The specific activity of the primary coolant shall be limited to:

a. Less than or equal to 0.2 microcuries per gram DOSE EQUIVALENT I-131, and

b. Less than or equal to 100/$\bar{E}$ microcuries per gram.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, 3 and 4.

ACTION:

a. In OPERATIONAL CONDITIONS 1, 2 or 3 with the specific activity of the primary coolant;

   1. Greater than 0.2 microcuries per gram DOSE EQUIVALENT I-131 but less than or equal to 4.0 microcuries per gram DOSE EQUIVALENT I-131 for more than 48 hours during one continuous time interval or greater than 4.0 microcuries per gram DOSE EQUIVALENT I-131, be in at least HOT SHUTDOWN with the main steam line isolation valves closed within 12 hours.

   2. Greater than 100/$\bar{E}$ microcuries per gram, be in at least HOT SHUTDOWN with the main steam line isolation valves closed within 12 hours.

b. In OPERATIONAL CONDITIONS 1, 2, 3 or 4, with the specific activity of the primary coolant greater than 0.2 microcuries per gram DOSE EQUIVALENT I-131 or greater than 100/$\bar{E}$ microcuries per gram, perform the sampling and analysis requirements of Item 4a of Table 4.4.5-1 until the specific activity of the primary coolant is restored to within its limit.

c. In OPERATIONAL CONDITION 1 or 2, with:

   1. THERMAL POWER changed by more than 15% of RATED THERMAL POWER in one hour*, or

   2. The off-gas level, at the SJAE, increased by more than 10,000 microcuries per second in one hour during steady state operation at release rates less than 75,000 microcuries per second, or

   3. The off-gas level, at the SJAE, increased by more than 15% in one hour during steady state operation at release rates greater than 75,000 microcuries per second,

   perform the sampling and analysis requirements of Item 4b of Table 4.4.5-1 until the specific activity of the primary coolant is restored to within its limit.

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*Not applicable during the startup test program.

ACTION: (Continued)

1. With the HPCI system inoperable, restore the HPCI system to OPERABLE status within 14 days or be in at least HOT SHUTDOWN within the next 12 hours and reduce reactor steam dome pressure to ≤ 200 psig within the following 24 hours.

d. For the ADS:

1. With one of the above required ADS valves inoperable, provided the HPCI system, the core spray system and the LPCI system are OPERABLE, restore the inoperable ADS valve to OPERABLE status within 14 days or be in at least HOT SHUTDOWN within the next 12 hours and reduce reactor steam dome pressure to ≤ 100 psig within the next 24 hours.

2. With two or more of the above required ADS valves inoperable, be in at least HOT SHUTDOWN within 12 hours and reduce reactor steam dome pressure to ≤ 100 psig within the next 24 hours.

e. With a CSS and/or LPCI header ΔP instrumentation channel inoperable, restore the inoperable channel to OPERABLE status within 7 days or determine the ECCS header ΔP locally at least once per 12 hours; otherwise, declare the associated ECCS subsystem inoperable.

f. With a LPCI and/or CCS discharge line "keep filled" alarm instrumentation inoperable, perform Surveillance Requirement 4.5.1.a.1.a.

g. In the event an ECCS system is actuated and injects water into the Reactor Coolant System, a Special Report shall be prepared and submitted to the Commission pursuant to Specification 6.9.2 within 90 days describing the circumstances of the actuation and the total accumulated actuation cycles to date. The current value of the usage factor for each affected safety injection nozzle shall be provided in this Special Report whenever its value exceeds 0.70.

SURVEILLANCE REQUIREMENTS

4.5.1 The emergency core cooling systems shall be demonstrated OPERABLE by:

a. At least once per 31 days:

1. For the core spray system, the LPCI system, and the HPCI system:

a) Verifying by venting at the high point vents that the system piping from the pump discharge valve to the system isolation valve is filled with water.

b) Verifying that each valve, manual, power operated or automatic, in the flow path that is not locked, sealed, or otherwise secured in position, is in its correct* position.

2. For the HPCI system, verifying that the HPCI pump flow controller is in the correct position.

b. Verifying that, when tested pursuant to Specification 4.0.5:

1. The two core spray system pumps in each subsystem together develop a flow of at least 6350 gpm against a test line pressure corresponding to a reactor vessel pressure of $\geq$ 105 psi above suppression pool pressure.

2. Each LPCI pump in each subsystem develops a flow of at least 10,000 gpm against a test line pressure corresponding to a reactor vessel to primary containment differential pressure of $\geq$ 20 psid.

3. The HPCI pump develops a flow of at least 5600 gpm against a test line pressure corresponding to a reactor vessel pressure of 1000 psig when steam is being supplied to the turbine at 1000, +20, -80 psig.**

c. At least once per 18 months:

1. For the core spray system, the LPCI system, and the HPCI system, performing a system functional test which includes simulated automatic actuation of the system throughout its emergency operating sequence and verifying that each automatic valve in the flow path actuates to its correct position. Actual injection of coolant into the reactor vessel may be excluded from this test.

*Except that an automatic valve capable of automatic return to its ECCS position when an ECCS signal is present may be in position for another mode of operation.

**The provisions of Specification 4.0.4 are not applicable provided the surveillance is performed within 12 hours after reactor steam pressure is adequate to perform the test.

2. For the HPCI system, verifying that:

   a) The system develops a flow of at least 5600 gpm against a test line pressure corresponding to a reactor vessel pressure of ≥ 200 psig, when steam is being supplied to the turbine at 200 + 15, -0 psig.**

   b) The suction is automatically transferred from the condensate storage tank to the suppression chamber on a condensate storage tank water level - low signal and on a suppression chamber - water level high signal.

3. Performing a CHANNEL CALIBRATION of the CSS, and LPCI system discharge line "keep filled" alarm instrumentation.

4. Performing a CHANNEL CALIBRATION of the CSS header ΔP instrumentation and verifying the setpoint to be ≤ the allowable value of 4.4 psid.#

5. Performing a CHANNEL CALIBRATION of the LPCI header ΔP instrumentation and verifying the setpoint to be ≤ the allowable value of 1.0 psid.#

d. For the ADS:

1. At least once per 31 days, performing a CHANNEL FUNCTIONAL TEST of the Primary Containment Instrument Gas System low-low pressure alarm system.

2. At least once per 18 months:

   a) Performing a system functional test which includes simulated automatic actuation of the system throughout its emergency operating sequence, but excluding actual valve actuation.

   b) Manually opening each ADS valve when the reactor steam dome pressure is greater than or equal to 100 psig** and observing that either:

      1) The control valve or bypass valve position responds accordingly, or

      2) There is a corresponding change in the measured steam flow.

   c) Performing a CHANNEL CALIBRATION of the Primary Containment Instrument Gas System low-low pressure alarm system and verifying an alarm setpoint of 85 ± 2 psig on decreasing pressure.

**The provisions of Specification 4.0.4 are not applicable provided the surveillance is performed within 12 hours after reactor steam pressure is adequate to perform the test.

#Initial setpoint. Final setpoint to be determined during the startup test program.

FINAL DRAFT

LIMITING CONDITION FOR OPERATION

3.5.2 At least two of the following shall be OPERABLE:

a. Core spray system subsystems with a subsystem comprised of:

1. Two OPERABLE core spray pumps, and

2. An OPERABLE flow path capable of taking suction from at least one of the following water sources and transferring the water through the spray sparger to the reactor vessel:

a) From the suppression chamber, or

b) When the suppression chamber water level is less than the limit or is drained, from the condensate storage tank containing at least 135,000 available gallons of water.

b. Low pressure coolant injection (LPCI) system subsystems each with a subsystem comprised of:

1. One OPERABLE LPCI pump, and

2. An OPERABLE flow path capable of taking suction from the suppression chamber and transferring the water to the reactor vessel.

APPLICABILITY: OPERATIONAL CONDITION 4 and 5*.

ACTION:

a. With one of the above required subsystems inoperable, restore at least two subsystems to OPERABLE status within 4 hours or suspend all operations with a potential for draining the reactor vessel.

b. With both of the above required subsystems inoperable, suspend CORE ALTERATIONS and all operations with a potential for draining the reactor vessel. Restore at least one subsystem to OPERABLE status within 4 hours or establish SECONDARY CONTAINMENT INTEGRITY within the next 8 hours.

*The ECCS is not required to be OPERABLE provided that the reactor vessel head is removed, the cavity is flooded, the spent fuel pool gates are removed, and water level is maintained within the limits of Specification 3.9.8 and 3.9.9.

3/4.5.3 SUPPRESSION CHAMBER

LIMITING CONDITION FOR OPERATION

3.5.3 The suppression chamber shall be OPERABLE:

a. In OPERATIONAL CONDITION 1, 2 and 3 with a contained water volume of at least 118,000 ft^3, equivalent to an indicated level of 74.5".

b. In OPERATIONAL CONDITION 4 and 5* with a contained volume of at least 57,390 ft^3, equivalent to an indicated level of 5.0" except that the suppression chamber level may be less than the limit or may be drained provided that:

1. No operations are performed that have a potential for draining the reactor vessel,

2. The reactor mode switch is locked in the Shutdown or Refuel position,

3. The condensate storage tank contains at least 135,000 available gallons of water, and

4. The core spray system is OPERABLE per Specification 3.5.2 with an OPERABLE flow path capable of taking suction from the condensate storage tank and transferring the water through the spray sparger to the reactor vessel.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, 3, 4 and 5*.

ACTION:

a. In OPERATIONAL CONDITION 1, 2 or 3 with the suppression chamber water level less than the above limit, restore the water level to within the limit within 1 hour or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

b. In OPERATIONAL CONDITION 4 or 5* with the suppression chamber water level less than the above limit or drained and the above required conditions not satisfied, suspend CORE ALTERATIONS and all operations that have a potential for draining the reactor vessel and lock the reactor mode switch in the Shutdown position. Establish SECONDARY CONTAINMENT INTEGRITY within 8 hours.

---

*The suppression chamber is not required to be OPERABLE provided that the reactor vessel head is removed, the cavity is flooded or being flooded from the suppression pool, the spent fuel pool gates are removed when the cavity is flooded, and the water level is maintained within the limits of Specification 3.9.8 and 3.9.9.

3/4.6 CONTAINMENT SYSTEMS

FINAL DRAFT

3/4.6.1 PRIMARY CONTAINMENT

PRIMARY CONTAINMENT INTEGRITY

LIMITING CONDITION FOR OPERATION

3.6.1.1 PRIMARY CONTAINMENT INTEGRITY shall be maintained.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2* and 3.

ACTION:

Without PRIMARY CONTAINMENT INTEGRITY, restore PRIMARY CONTAINMENT INTEGRITY within 1 hour or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

SURVEILLANCE REQUIREMENTS

4.6.1.1 PRIMARY CONTAINMENT INTEGRITY shall be demonstrated:

a. After each closing of each penetration subject to Type B testing, except the primary containment air locks, if opened following Type A or B test, by leak rate testing the seals with gas at Pa, 48.1 psig, and verifying that when the measured leakage rate for these seals is added to the leakage rates determined pursuant to Surveillance Requirement 4.6.1.2.d for all other Type B and C penetrations, the combined leakage rate is less than or equal to 0.60 La.

b. At least once per 31 days by verifying that all primary containment penetrations** not capable of being closed by OPERABLE containment automatic isolation valves and required to be closed during accident conditions are closed by valves, blind flanges, or deactivated automatic valves secured in position, except as provided in Table 3.6.3-1 of Specification 3.6.3.

c. By verifying each primary containment air lock is in compliance with the requirements of Specification 3.6.1.3.

d. By verifying the suppression chamber is in compliance with the requirements of Specification 3.6.2.1.

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*See Special Test Exception 3.10.1

**Except valves, blind flanges, and deactivated automatic valves which are located inside the primary containment, and are locked, sealed or otherwise secured in the closed position. These penetrations shall be verified closed during each COLD SHUTDOWN except such verification need not be performed when the primary containment has not been de-inerted since the last verification or more often than once per 92 days.

LIMITING CONDITION FOR OPERATION

3.6.1.2 Primary containment leakage rates shall be limited to:

a. An overall integrated leakage rate of less than or equal to L_a, 0.5 percent by weight of the containment air per 24 hours at P_a, 48.1 psig.

b. A combined leakage rate of less than or equal to 0.60 L_a for all penetrations and all valves listed in Table 3.6.3-1, except for main steam line isolation valves*, valves which form the boundary for the long-term seal of the feedwater lines, and other valves which are hydrostatically tested per Table 3.6.3-1, subject to Type B and C tests when pressurized to P_a, 48.1 psig.

c. *Less than or equal to 46.0 scfh combined through all four main steam lines when tested at 5 psig (seal system ΔP).

d. A combined leakage rate of less than or equal to 10 gpm for all containment isolation valves which form the boundary for the long-term seal of the feedwater lines in Table 3.6.3-1, when tested at 1.10 Pa, 52.9 psig.

e. A combined leakage rate of less than or equal to 10 gpm for all other containment isolation valves in hydrostatically tested lines in Table 3.6.3-1 which penetrate the primary containment, when tested at Pa, 48.1 psig Δp.

APPLICABILITY: When PRIMARY CONTAINMENT INTEGRITY is required per Specification 3.6.1.1.

ACTION:

With:

a. The measured overall integrated primary containment leakage rate exceeding 0.75 L_a or

b. The measured combined leakage rate for all penetrations and all valves listed in Table 3.6.3-1, except for main steam line isolation valves*, valves which form the boundary for the long-term seal of the feedwater lines, and other valves which are hydrostatically tested per Table 3.6.3-1, subject to Type B and C tests exceeding 0.60 L_a, or

c. The measured leakage rate exceeding 46.0 scfh combined through all four main steam lines, or

d. The measured combined leakage rate for all containment isolation valves which form the boundary for the long-term seal of the feedwater lines in Table 3.6.3-1 exceeding 10 gpm, or

e. The measured combined leakage rate for all other containment isolation valves in hydrostatically tested lines in Table 3.6.3-1 which penetrate the primary containment exceeding 10 gpm,

restore:

a. The overall integrated leakage rate(s) to less than or equal to 0.75 La, and

*Exemption to Appendix "J" of 10 CFR 50.

SURVEILLANCE REQUIREMENTS (Continued)

The formula to be used is: $[L_o + L_{am} - 0.25\ L_a] \leq L_c \leq [L_o + L_{am} + 0.25\ L_a]$ where $L_c \equiv$ supplement test result; $L_o \equiv$ superimposed leakage; and $L_a \equiv$ measured Type A leakage.

d. Type B and C tests shall be conducted with gas at P_a, 48.1 psig*, at intervals no greater than 24 months except for tests involving:

1. Air locks,

2. Main steam line isolation valves,

3. Valves pressurized with fluid from a seal system,

4. All containment isolation valves in hydrostatically tested lines in Table 3.6.3-1 which penetrate the primary containment, and

5. Purge supply and exhaust isolation valves with resilient material seals.

e. Air locks shall be tested and demonstrated OPERABLE per Surveillance Requirement 4.6.1.3.

f. Main steam line isolation valves shall be leak tested at least once per 18 months.

g. Containment isolation valves which form the boundary for the long-term seal of the feedwater lines in Table 3.6.3-1 shall be hydrostatically tested at 1.10 P_a, 52.9 psig, at least once per 18 months.

h. All containment isolation valves in hydrostatically tested lines in Table 3.6.3-1 which penetrate the primary containment shall be leak tested at least once per 18 months.

i. Purge supply and exhaust isolation valves with resilient material seals shall be tested and demonstrated OPERABLE per Surveillance Requirements 4.6.1.8.2 and 4.6.1.8.3.

j. The provisions of Specification 4.0.2 are not applicable to Specifications 4.6.1.2.a, 4.6.1.2.b, 4.6.1.2.c, 4.6.1.2.d, and 4.6.1.2.e.

*Unless a hydrostatic test is required per Table 3.6.3-1.

SURVEILLANCE REQUIREMENTS

4.6.1.3 Each primary containment air lock shall be demonstrated OPERABLE:

a. Within 72 hours following each closing, except when the air lock is being used for multiple entries, then at least once per 72 hours, by verifying seal leakage rate less than or equal to 5 scf per hour when the gap between the door seals is pressurized to 10.0 psig.

b. By conducting an overall air lock leakage test at P_a, 48.1 psig, and by verifying that the overall air lock leakage rate is within its limit:

1. At least once per 6 months#, and

2. Prior to establishing PRIMARY CONTAINMENT INTEGRITY when maintenance has been performed on the air lock that could affect the airlock sealing capability*, and

3. Prior to establishing PRIMARY CONTAINMENT INTEGRITY when maintenance has not been performed on the air lock that could affect the air lock sealing capability, a seal test may be performed in lieu of the overall air lock leakage test. The acceptance criteria and test pressure shall be as specified in 4.6.1.3.a.

c. At least once per 6 months by verifying that only one door in each air lock can be opened at a time.**

#The provisions of Specification 4.0.2 are not applicable.

*Exemption to Appendix J of 10 CFR 50.

**Except that the inner door need not be opened to verify interlock OPERABILITY when the primary containment is inerted, provided that the inner door interlock is tested within 8 hours after the primary containment has been de-inerted.

LIMITING CONDITION FOR OPERATION

3.6.1.5 The structural integrity of the primary containment shall be maintained at a level consistent with the acceptance criteria in Specification 4.6.1.5.1.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2 and 3.

ACTION:

With the structural integrity of the primary containment not conforming to the above requirements, restore the structural integrity to within the limits within 24 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

SURVEILLANCE REQUIREMENTS

4.6.1.5.1 The structural integrity of the exposed accessible interior and exterior surfaces of the primary containment shall be determined during the shutdown for each Type A containment leakage rate test by a visual inspection of those surfaces. This inspection shall be performed prior to the Type A containment leakage rate test to verify no apparent changes in appearance or other abnormal degradation.

4.6.1.5.2 Reports Any abnormal degradation of the primary containment structure detected during the above required inspections shall be reported to the Commission pursuant to Specification 6.9.2 within 30 days. This report shall include a description of the condition of the containment, the inspection procedure, and the corrective actions taken.

MAR 31 1995

CONTAINMENT SYSTEMS

DRYWELL AND SUPPRESSION CHAMBER PURGE SYSTEM

LIMITING CONDITION FOR OPERATION

3.6.1.8 The 26-inch drywell purge supply and exhaust isolation valves and the 24-inch suppression chamber purge supply and exhaust isolation valves, and the 6-inch nitrogen supply valve shall be OPERABLE and sealed closed.*

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2 and 3.

ACTION:

a. With a 26-inch drywell purge supply or exhaust isolation valve, or a 24-inch suppression chamber purge supply or exhaust isolation valve or the 6-inch nitrogen supply valve open or not sealed closed,* close or seal the valves(s) or otherwise isolate the penetration within four hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

b. With a drywell purge supply or exhaust isolation valve, or a suppression chamber purge supply or exhaust isolation valve or the nitrogen supply valve, with resilient material seals having a measured leakage rate exceeding the limit of Surveillance Requirements 4.6.1.8.2 and/or 4.6.1.8.3, restore the inoperable valve(s) to OPERABLE status within 24 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

SURVEILLANCE REQUIREMENTS

4.6.1.8.1 Each 26-inch drywell purge supply and exhaust isolation valve, and 24-inch suppression chamber purge supply and exhaust isolation valve and the 6-inch nitrogen supply valve, shall be verified to be sealed closed* at least once per 31 days.

4.6.1.8.2 At least once per 6 months on a STAGGERED TEST BASIS each sealed closed 26-inch drywell purge supply and exhaust isolation valve, and 24-inch suppression chamber purge supply and exhaust isolation valve, and the 6-inch nitrogen supply valve, with resilient material seals shall be demonstrated OPERABLE by verifying that the measured leakage rate is less than or equal to 0.05 L_a per penetration when pressurized to P_a 48.1 psig.

4.6.1.8.3 At least once per 92 days the 26-inch drywell purge inboard exhaust isolation valve with resilient material seals shall be demonstrated OPERABLE by verifying that the measured leakage rate is less than or equal to 0.05 L_a per penetration when pressurized to P_a 48.1 psig.

*The 26-inch drywell purge inboard exhaust valve is not required to be sealed closed and may be opened in series with the 2 inch vent line bypass valve during periods of containment pressure control.

3/4.6.2 DEPRESSURIZATION SYSTEMS

FINAL DRAFT

SUPPRESSION CHAMBER

LIMITING CONDITION FOR OPERATION

3.6.2.1 The suppression chamber shall be OPERABLE with:

a. The pool water:

1. Volume between 118,000 ft^3 and 122,000 ft^3, equivalent to an indicated level between 74.5" and 78.5" and a

2. Maximum average temperature of 95°F during OPERATIONAL CONDITION 1 or 2, except that the maximum average temperature may be permitted to increase to:

a) 105°F during testing which adds heat to the suppression chamber.

b) 110°F with THERMAL POWER less than or equal to 1% of RATED THERMAL POWER.

3. Maximum average temperature of 95°F during OPERATIONAL CONDITION 3, except that the maximum average temperature may be permitted to increase to 120°F with the main steam line isolation valves closed following a scram.

b. A total leakage between the suppression chamber and drywell of less than the equivalent leakage through a 1-inch diameter orifice at a differential pressure of 0.80 psig.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2 and 3.

ACTION:

a. With the suppression chamber water level outside the above limits, restore the water level to within the limits within 1 hour or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

b. With the suppression chamber average water temperature greater than 95°F and THERMAL POWER greater than 1% of RATED THERMAL POWER, restore the average temperature to less than or equal to 95°F within 24 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours, except, as permitted above:

1. With the suppression chamber average water temperature greater than 105°F during testing which adds heat to the suppression chamber, stop all testing which adds heat to the suppression chamber and restore the average temperature to less than 95°F within 24 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

2. With the suppression chamber average water temperature greater than 110°F, place the reactor mode switch in the Shutdown position and operate at least one residual heat removal loop in the suppression pool cooling mode.

LIMITING CONDITION FOR OPERATION (Continued)

ACTION: (Continued)

3. With the suppression chamber average water temperature greater than 120°F, depressurize the reactor pressure vessel to less than 200 psig within 12 hours.

c. With one suppression pool water temperature monitoring channel inoperable, restore the inoperable channel(s) to OPERABLE status within 7 days or verify suppression pool temperature to be within the limits at least once per 12 hours.

d. With both suppression pool water temperature monitoring channels inoperable, restore at least one inoperable channel to OPERABLE status within 8 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

e. With one suppression chamber water level instrumentation channel inoperable, restore the inoperable narrow range suppression chamber water level channel to OPERABLE status within 7 days or verify suppression pool water level to be within the limits at least once per 12 hours.

f. With both suppression chamber water level instrumentation channels inoperable, restore at least one narrow range suppression chamber water level channel to OPERABLE status within 48 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

g. With the drywell-to-suppression chamber bypass leakage in excess of the limit, restore the bypass leakage to within the limit prior to increasing reactor coolant temperature above 200°F.

SURVEILLANCE REQUIREMENTS

4.6.2.1 The suppression chamber shall be demonstrated OPERABLE:

a. By verifying the suppression chamber water volume to be within the limits at least once per 24 hours.

b. At least once per 24 hours in OPERATIONAL CONDITION 1 or 2 by verifying the suppression chamber average water temperature to be less than or equal to 95°F, except:

1. At least once per 5 minutes during testing which adds heat to the suppression chamber, by verifying the suppression chamber average water temperature less than or equal to 105°F.

2. At least once per hour when suppression chamber average water temperature is greater than 95°F, by verifying:

a) Suppression chamber average water temperature to be less than or equal to 110°F, and

b) THERMAL POWER to be less than or equal to 1% of RATED THERMAL POWER.

c) At least once per 30 minutes in OPERATIONAL CONDITION 3 following a scram with suppression chamber average water temperature greater than 95°F, by verifying suppression chamber average water temperature less than or equal to 120°F.

c. By an external visual examination of the suppression chamber after safety/relief valve operation with the suppression chamber average water temperature greater than or equal to 177°F and reactor coolant system pressure greater than 100 psig.

d. At least once per 18 months by a visual inspection of the accessible interior and exterior of the suppression chamber.

e. By verifying all temperature elements used by the suppression pool water temperature monitoring system OPERABLE by performance of a:

1. CHANNEL CHECK at least once per 24 hours,
2. CHANNEL FUNCTIONAL TEST at least once per 31 days, and
3. CHANNEL CALIBRATION at least once per 18 months,

with the water high temperature alarm setpoint for:

1. First setpoint $\leq$ 95°F
2. Second setpoint $\leq$ 105°F
3. Third setpoint $\leq$ 110°F
4. Fourth setpoint $\leq$ 120°F

f. By verifying both suppression chamber water level instrumentation channels OPERABLE by performance of a:

1. CHANNEL CHECK at least once per 24 hours,
2. CHANNEL FUNCTIONAL TEST at least once per 31 days, and
3. CHANNEL CALIBRATION at least once per 18 months,

With the water level alarm setpoint for:

1. High water level $\leq$ 78.5"
2. Low water level $\geq$ 65.0"

g. At least once per 18 months by conducting a drywell-to-suppression chamber bypass leak test at an initial differential pressure of 0.80 psi and verifying that the differential pressure does not decrease by more than 0.24 inch of water per minute for a period of 10 minutes. If any drywell-to-suppression chamber bypass leak test fails to meet the specified limit, the test schedule for subsequent tests shall be reviewed and approved by the Commission. If two consecutive tests fail to meet the specified limit, a test shall be performed at least every 9 months until two consecutive tests meet the specified limit, at which time the 18 month test schedule may be resumed.

TABLE 3.6.3-1 (Continued)

PRIMARY CONTAINMENT ISOLATION VALVES

VALVE FUNCTION AND NUMBER	PENETRATION NUMBER	MAXIMUM ISOLATION TIME (Seconds)	NOTE(S)	P&ID
(c) Suppression Chamber Purge Supply Isolation Valves				M-57-1
Outside:				
HV-4980 (GS-V020)	P22/P220	15	3, 8	
HV-4958 (GS-V022)	P220	15	3, 8	
(d) Suppression Chamber Purge Exhaust Isolation Valves				M-57-1
Outside:				
HV-4963 (GS-V076)	P219	15	3	
HV-4962 (GS-V027)	P219	15	3, 8	
HV-4964 (GS-V028)	P219	15	3, 8	
(e) Nitrogen Purge Isolation Valves				M-57-1
Outside:				
HV-4974 (GS-V053)	J7D/J202	45	3	
HV-4978 (GS-V023)	P22/P220	15	3, 8	
13. Group 13 - Hydrogen/Oxygen (H2/O2) Analyzer System				
(a) Drywell H2/O2 Analyzer Inlet Isolation Valves				M-57-1
Outside:				
Loop A: HV-4955A (GS-V045)	J9E	45	3	
HV-4983A (GS-V046)	J9E	45	3	
HV-4984A (GS-V048)	J10C	45	3	
HV-5019A (GS-V047)	J10C	45	3	
Outside:				
Loop B: HV-4955B (GS-V031)	J3B	45	3	
HV-4983B (GS-V032)	J3B	45	3	
HV-4984B (GS-V034)	J7D/J202	45	3	
HV-5019B (GS-V033)	J7D	45	3	

TABLE 3.6.3-1 (Continued)

PRIMARY CONTAINMENT ISOLATION VALVES

VALVE FUNCTION AND NUMBER	PENETRATION NUMBER	MAXIMUM ISOLATION TIME (Seconds)	NOTE(S)	P&ID
Outside:				
Loop B: HV-5053B (GS-V006)	P219	45	3	M-58-1
HV-5054B (GS-V007)	P219	45	3	
15. Group 15 - Primary Containment Instrument Gas System (PCIGS)				
(a) PCIGS Drywell Supply Header Isolation Valves				M-59-1
Inside:				
Loop A: HV-5152A (KL-V028)	P28B	45	3	
Loop B: HV-5152B (KL-V026)	P28A	45	3	
Outside:				
Loop A: HV-5126A (KL-V027)	P28B	45	3	
Loop B: HV-5126B (KL-V025)	P28A	45	3	
(b) PCIGS Drywell Suction Isolation Valves				M-59-1
Inside:				
HV-5148 (KL-V001)	P39	45	3	
Outside:				
Loop A: HV-5147 (KL-V002)	P39	45	3	
Loop B: HV-5162 (KL-V049)	P39	45	3	
(c) PCIGS Suppression Chamber Supply Isolation Valves				M-59-1
Outside:				
HV-5154 (KL-V018)	J211	15	3	
HV-5155 (KL-V019)	J211	15	3	

FINAL DRAFT

TABLE 3.6.3-1 (Continued)
PRIMARY CONTAINMENT ISOLATION VALVES

VALVE FUNCTION AND NUMBER	PENETRATION NUMBER	MAXIMUM ISOLATION TIME (Seconds)	NOTE(S)	P&ID
(b) DLD-RMS Return Isolation Valves				M-25-1
Outside:				
HV-4957 (SK-V008)	J5A	45	3	
HV-4981 (SK-V009)	J5A	45	3	
B. Remote Manual Isolation Valves				
1. Group 21 - Feedwater System				
(a) Feedwater Isolation Valves				M-41-1
Outside Check Valves				
HV-F032B (AE-V001)	P2A	NA	2	
HV-F032A (AE-V005)	P2B	NA	2	
(b) Reactor Water Cleanup System Return Outside:				
HV-F039 (AE-V021)	P2A&B	NA	2	M-44-1
2. Group 22 - High Pressure Coolant Injection (HPCI) System				
(a) Core Spray Discharge Valve				
Outside:				
HV-F006 (BJ-V001)	P5B	NA	3	M-55-1
(b) Turbine Exhaust Valve				
Outside:				
HV-F071 (FD-V006)	P201	NA	4	M-55-1
(c) HPCI Minimum Return Line Valve				
Outside:				
HV-F012 (BJ-V016)	P203	NA	4	M-55-1
(d) Feedwater Line Discharge Valve Outside:				
HV-8278 (BJ-V059)	P2B	NA	2	M-55-1
3. Group 23 - Reactor Core Isolation Cooling (RCIC) System				
(a) RCIC Turbine Exhaust Valve				
Outside:				
HV-F059 (FC-V005)	P207	NA	4	M-49-1

FINAL DRAFT

TABLE 3.6.3-1 (Continued)

PRIMARY CONTAINMENT ISOLATION VALVES

VALVE FUNCTION AND NUMBER	PENETRATION NUMBER	MAXIMUM ISOLATION TIME (Seconds)	NOTE(S)	P&ID
Outside:				
(b) RCIC Pump Suction Isolation Valve				
HV-F031 (BD-V003)	P208	NA	4	M-49-1
Outside:				
(c) RCIC Minimum Return Line Isolation Valve				
SV-F019	P209	NA	4	M-49-1
Outside:				
(d) RCIC Vacuum Pump Discharge				
HV-F060 (FC-V011)	P210	NA	4	M-49-1
(e) Feedwater Line Discharge Valve				
Outside:				
HV-F013 (BD-V005)	P2A	NA	2	M-49-1
4. Group 25 - Core Spray System				
(a) Core Spray injection Valves				M-52-1
Outside:				
Loop A&C HV-F005A (BE-V007)	P5B	NA	3	
Loop B&D HV-F005B (BE-V003)	P5A	NA	3	
(b) Core Spray Suppression Pool Suction Valves				M-52-1
Outside:				
Loop A HV-F001A (BE-V017)	P216D	NA	4	
Loop B HV-F001B (BE-V019)	P216A	NA	4	
Loop C HV-F001C (BE-V018)	P216C	NA	4	
Loop D HV-F001D (BE-V020)	P216B	NA	4	
(c) Core Spray Minimum Flow Valves				M-52-1
Outside:				
Loop A&C HV-F031A (BE-V035)	P217B	NA	4	
Loop B&D HV-F031B (BE-V036)	P217A	NA	4	
(d) Core Spray Injection Line Bypass Valves				M-52-1
Inside:				
HV-F039A (BE-V071)	P5B	NA	3	
HV-F039B (BE-V072)	P5A	NA	3	

FINAL DRAFT

TABLE 3.6.3-1 (Continued)

PRIMARY CONTAINMENT ISOLATION VALVES

VALVE FUNCTION AND NUMBER	PENETRATION NUMBER	MAXIMUM ISOLATION TIME (Seconds)	NOTE(S)	P&ID
C. Primary Containment (Other Isolation Valves)				
1. Group 31 - Feedwater System				
(a) Feedwater Isolation Valves				M-41-1
Inside Check Valves				
AE-V003	P2A	NA	3	
AE-V007	P2B	NA	3	
Outside Check Valves (Air Assisted)				
HV-F074B (AE-V002)	P2A	NA	3	
HV-F074A (AE-V006)	P2B	NA	3	
2. Group 32 - Standby Liquid Control System				
Inside Check Valve				M-48-1
BH-V029	P18	NA	3	
3. Group 33 - Primary Containment Atmosphere Control System				
Containment Vacuum Breakers				M-57-1
Outside:				
GS-PSV-5032	P220	NA	3	
GS-PSV-5030	P219	NA	3	
4. Group 34 - Service Air System				M-15-0
Outside KA-V038	P27	NA	3	
Inside KA-V039	P27	NA	3	

FINAL DRAFT

TABLE 3.6.3-1 (Continued)

PRIMARY CONTAINMENT ISOLATION VALVES

VALVE FUNCTION AND NUMBER	PENETRATION NUMBER	MAXIMUM ISOLATION TIME (Seconds)	NOTE(S)	P&ID
5. Group 35 - Breathing Air System				M-15-1
Inside KG-V016	P31	NA	3	
Outside KG-V034	P31	NA	3	
6. Group 36 - TIP Purge System				
Inside:				
Check Valve: SE-V006	P34F	NA	3	M-59-1
7. Group 37 - HPCI System				
Outside:				
HPCI Turbine Exhaust: FD-V004	P201	NA	4	M-55-1
8. Group 38 - RCIC System				
Outside:				
RCIC Turbine Exhaust: FC-V003	P207	NA	4	M-49-1
Vacuum Pump Discharge: FC-V010	P210	NA	4	M-49-1
9. Group 39 - RHR System				
(a) Thermal Relief Valves				M-51-1
Outside:				
Loop A: BC-PSV-F025A	P212B	NA	5	
Loop B: BC-PSV-F025B	P212A	NA	5	
Loop C: BC-PSV-F025C	P212B	NA	5	
Loop D: BC-PSV-F025D	P212A	NA	5	
(b) Jockey Pump Discharge Check Valves				M-51-1
Outside:				
Loops A & C: (BC-V206)	P212B	NA	4	
Loops B & D: (BC-V260)	P212A	NA	4	
(c) RHR Heat Exchanger Thermal Relief Valves				M-51-1
Outside:				
BC-PSV-4431A	P213B	NA	5	
BC-PSV-4431B	P213A	NA	5	

FINAL DRAFT

TABLE 3.6.3-1 (Continued)

PRIMARY CONTAINMENT ISOLATION VALVES

VALVE FUNCTION AND NUMBER	PENETRATION NUMBER	MAXIMUM ISOLATION TIME (Seconds)	NOTE(S)	P&ID
(d) RHR Shutdown Cooling Suction Thermal Relief Valve				M-51-1
Inside:				
BC-PSV-4425	P3	NA	3	
(e) LPCI Injection Line Check Valves				M-51-1
Inside:				
HV-F041A (BC-V114)	P6C	NA	3	
HV-F041B (BC-V017)	P6B	NA	3	
HV-F041C (BC-V102)	P6D	NA	3	
HV-F041D (BC-V005)	P6A	NA	3	
(f) Shutdown Cooling Return Line Check Valves				M-51-1
Inside:				
HV-F050A (BC-V111)	P4B	NA	3	
HV-F050B (BC-V014)	P4A	NA	3	
10. Group 40 - Core Spray System				
(a) Thermal Relief Valves				M-52-1
Outside:				
Loop A&C: BE-PSV-F012A	P217B	NA	5	
Loop B&D: BE-PSV-F012B	P217A	NA	5	
(b) Core Spray Injection Line Check Valves				M-52-1
Inside:				
HV-F006A (BE-V006)	P5B	NA	3	
HV-F006B (BE-V002)	P5A	NA	3	
11. Group 41 - Drywell Pressure Instrumentati				M-42-1
Outside:				
BB-V563	J6A	NA	6	
BB-V564	J8D	NA	6	
BB-V565	J7A	NA	6	
BB-V566	J10D	NA	6	

FINAL DRAFT

TABLE 3.6.3-1

FINAL DRAFT

PRIMARY CONTAINMENT ISOLATION VALVES

NOTES

NOTATION

1. Main Steam Isolation Valves are sealed with a seal system that maintains a positive pressure of 5 psig above reactor pressure. Leakage is in-leakage and is not added to 0.60 La allowable leakage.*

2. Containment Isolation Valves are sealed with a water seal from the HPCI and/or RCIC system to form the long-term seal boundary of the feedwater lines. The valves are tested with water at 1.10 Pa, 52.9 psig, to ensure the seal boundary will prevent by-pass leakage. Seal boundary liquid leakage will be limited to 10 gpm.

3. Containment Isolation Valve, Type C gas test at Pa, 48.1 psig. Leakage added to 0.60La allowable leakage.

4. Containment Isolation Valve, Type C water test at Pa, 48.1 psig Δ P. Leakage added to 10 gpm allowable leakage.

5. Containment boundary is discharge nozzle of relief valve, leakage tested during Type A test.*

6. Drywell and suppression chamber pressure and level instrument root valves and excess flow check valves leakage tested during Type A.*

7. Explosive shear valves (SE-V024 through SE-V025) not Type C tested.*

8. Surveillances to be performed per Specification 3.6.1.8.

9. All valve I.D. numbers are preceded by a numeral 1 which represents an Unit 1 valve.

*Exemption to Appendix J of 10 CFR Part 50.

MAR 31 1986

FINAL DRAFT

3/4.7.1 SERVICE WATER SYSTEMS

SAFETY AUXILIARIES COOLING SYSTEM

LIMITING CONDITION FOR OPERATION

3.7.1.1 At least the following independent safety auxiliaries cooling system (SACS) subsystems, with each subsystem comprised of:

a. Two OPERABLE SACS pumps, and

b. An OPERABLE flow path consisting of a closed loop through the SACS heat exchangers and SACS pumps and to associated safety related equipment

shall be OPERABLE:

a. In OPERATIONAL CONDITION 1, 2 and 3, two subsystems.

b. In OPERATIONAL CONDITION 4, 5, and ** the subsystems associated with systems and components required OPERABLE by Specification 3.4.9.1, 3.4.9.2, 3.5.2, 3.8.1.2, 3.9.11.1 and 3.9.11.2.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, 3, 4, 5, and **.

ACTION:

a. In OPERATIONAL CONDITION 1, 2, or 3:

1. With one SACS pump or heat exchanger inoperable, restore the inoperable pump or heat exchanger to OPERABLE status within 72 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

2. With one SACS subsystem otherwise inoperable, realign the affected diesel generators to the OPERABLE SACS subsystem within 2 hours, and restore the inoperable subsystem to OPERABLE status with at least one OPERABLE pump and heat exchanger within 72 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

3. With one SACS pump or heat exchanger in each subsystem inoperable, immediately initiate measures to place the unit in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

4. With both SACS subsystems otherwise inoperable, immediately initiate measures to place the unit in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN* in the following 24 hours.

*Whenever both SACS subsystems are inoperable, if unable to attain COLD SHUTDOWN as required by this ACTION, maintain reactor coolant temperature as low as practical by use of alternate heat removal methods.

**When handling irradiated fuel in the secondary containment.

MAR 31 1986

LIMITING CONDITION FOR OPERATION (Continued)

ACTION: (Continued)

b. In OPERATIONAL CONDITION 3 or 4 with the SACS subsystem, which is associated with an RHR loop required OPERABLE by Specification 3.4.9.1 or 3.4.9.2, inoperable, declare the associated RHR loop inoperable and take the ACTION required by Specification 3.4.9.1 or 3.4.9.2, as applicable.

c. In OPERATIONAL CONDITION 4 or 5 with the SACS subsystem, which is associated with safety related equipment required OPERABLE by Specification 3.5.2, inoperable, declare the associated safety related equipment inoperable and take the ACTION required by Specification 3.5.2.

d. In OPERATIONAL CONDITION 5 with the SACS subsystem, which is associated with an RHR loop required OPERABLE by Specification 3.9.11.1 or 3.9.11.2, inoperable, declare the associated RHR system inoperable and take the ACTION required by Specification 3.9.11.1 or 3.9.11.2, as applicable.

e. In OPERATIONAL CONDITION 4, 5, or **, with one SACS subsystem, which is associated with safety related equipment required OPERABLE by Specification 3.8.1.2, inoperable, realign the associated diesel generators within 2 hours to the OPERABLE SACS subsystem, or declare the associated diesel generators inoperable and take the ACTION required by Specification 3.8.1.2. The provisions of Specification 3.0.3 are not applicable.

f. In OPERATIONAL CONDITION 4, 5, or **, with only one SACS pump and heat exchanger and its associated flowpath OPERABLE, restore at least two pumps and two heat exchangers and associated flowpaths to OPERABLE status within 72 hours or, declare the associated safety related equipment inoperable and take the associated ACTION requirements.

SURVEILLANCE REQUIREMENTS

4.7.1.1 At least the above required safety auxiliaries cooling system subsystems shall be demonstrated OPERABLE:

a. At least once per 31 days by verifying that each valve in the flow path that is not locked, sealed or otherwise secured in position, is in its correct position.

b. At least once per 18 months during shutdown by verifying that: 1) Each automatic valve servicing safety-related equipment actuates to its correct position on the appropriate test signal(s), and 2) Each pump starts automatically when its associated diesel generator automatically starts.

MAR 31 1986

SURVEILLANCE REQUIREMENTS

4.7.1.2 At least the above required station service water system loops shall be demonstrated OPERABLE:

a. At least once per 31 days by verifying that each valve (manual, power operated or automatic), servicing safety related equipment that is not locked, sealed or otherwise secured in position, is in its correct position.

b. At least once per 18 months during shutdown, by verifying that:

   1. Each automatic valve servicing non-safety related equipment actuates to its isolation position on an isolation test signal.

   2. Each pump starts automatically when its associated diesel generator automatically starts.

FINAL DRAFT

3/4.7.2 CONTROL ROOM EMERGENCY FILTRATION SYSTEM

LIMITING CONDITION FOR OPERATION

3.7.2 Two independent control room emergency filtration system subsystems shall be OPERABLE with each subsystem consisting of:

a) One control room supply unit,
b) One filter train, and
c) One control room return air fan.

APPLICABILITY: All OPERATIONAL CONDITIONS and *.

ACTION:

a. In OPERATIONAL CONDITION 1, 2 or 3 with one control room emergency filtration subsystem inoperable, restore the inoperable subsystem to OPERABLE status within 7 days or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

b. In OPERATIONAL CONDITION 4, 5 or *:

   1. With one control room emergency filtration subsystem inoperable, restore the inoperable subsystem to OPERABLE status within 7 days or initiate and maintain operation of the OPERABLE subsystem in the pressurization/recirculation mode of operation.

   2. With both control room emergency filtration subsystems inoperable, suspend CORE ALTERATIONS, handling of irradiated fuel in the secondary containment and operations with a potential for draining the reactor vessel.

c. The provisions of Specification 3.0.3 are not applicable in Operational Condition *.

SURVEILLANCE REQUIREMENTS

4.7.2 Each control room emergency filtration subsystem shall be demonstrated OPERABLE:

a. At least once per 12 hours by verifying that the control room air temperature is less than or equal to 85°F#.

b. At least once per 31 days on a STAGGERED TEST BASIS by initiating, from the control room, the control area chilled water pump, flow

*When irradiated fuel is being handled in the secondary containment.

#This does not require starting the non-running control emergency filtration subsystem.

through the HEPA filters and charcoal adsorbers and verifying that the subsystem operates for at least 10 hours with the heaters and humidity control instrumentation OPERABLE.

c. At least once per 18 months or (1) after any structural maintenance on the HEPA filter or charcoal adsorber housings, or (2) following painting, fire or chemical release in any ventilation zone communicating with the subsystem by:

1. Verifying that the subsystem satisfies the in-place penetration testing acceptance criteria of less than 0.05% and uses the test procedure guidance in Regulatory Positions C.5.a, C.5.c and C.5.d of Regulatory Guide 1.52, Revision 2, March 1978, and the system filter train flow rate is 4000 cfm ± 10%.

2. Verifying within 31 days after removal that a laboratory analysis of a representative carbon sample obtained in accordance with Regulatory Position C.6.b of Regulatory Guide 1.52, Revision 2, March 1978, meets the laboratory testing criteria of Regulatory Position C.6.a of Regulatory Guide 1.52, Revision 2, March 1978, by showing a methyl iodide penetration of less than 0.175% when tested at a temperature of 30°C and at a relative humidity of 70% in accordance with ASTM D3803 with a 4 inch bed; and

3. Verifying a subsystem filter train flow rate of 4000 cfm ± 10% during subsystem operation when tested in accordance with ANSI N510-1980.

d. After every 720 hours of charcoal adsorber operation by verifying within 31 days after removal that a laboratory analysis of a representative carbon sample obtained in accordance with Regulatory Position C.6.b of Regulatory Guide 1.52, Revision 2, March 1978, meets the laboratory testing criteria of Regulatory Position C.6.a of Regulatory Guide 1.52, Revision 2, March 1978, by showing a methyl iodide penetration of less than 0.175% when tested at a temperature of 30°C and at a relative humidity of 70% in accordance with ATSM D3803 with a 4 inch bed.

e. At least once per 18 months by:

1. Verifying that the pressure drop across the combined HEPA filters and charcoal adsorber banks is less than 7.5 inches Water Gauge while operating the filter train subsystem at a flow rate of 4000 cfm ± 10%.

2. Verifying with the control room hand switch in the recirculation mode that on each of the below recirculation mode actuation test signals, the subsystem automatically switches to the isolation mode of operation and the isolation dampers close within 5 seconds:

FINAL DRAFT

3/4.7.3 FLOOD PROTECTION

LIMITING CONDITION FOR OPERATION

3.7.3 Flood protection shall be provided for all safety related systems, components and structures when the water level of the Delaware River reaches 6.0 feet Mean Sea Level (MSL) USGS datum (95.0 feet PSE&G datum) at the Service Water Intake Structure.

APPLICABILITY: At all times.

ACTION:

a. With severe storm warnings from the National Weather Service which may impact Artificial Island in effect or with the water level at the service water intake structure above elevation 6.0 feet MSL USGS datum (95.0 feet PSE&G datum), initiate and complete:

   1. The closing of all service water intake structure watertight perimeter flood doors identified in Table 3.7.3-1 within 1 hour, and

   2. The closing of all power block watertight perimeter flood doors identified in Table 3.7.3-1 within 1.5 hours.

   Once closed, all access through the doors shall be administratively controlled.

b. With the water level at the service water intake structure above elevation 10.5 feet MSL USGS datum (99.5 feet PSE&G datum), be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

SURVEILLANCE REQUIREMENTS

4.7.3 The water level at the service water intake structure shall be determined to be within the limit by:

a. Measurement at least once per 24 hours when the water level is below elevation 6.0 MSL USGS datum (95.0 feet PSE&G datum), and

b. Measurement at least once per 4 hours when severe storm warnings from the National Weather Service which may impact Artificial Island are in effect.

c. Measurement at least once per hour when the water level is equal to or above elevation 6.0 MSL USGS datum (95.0 feet PSE&G datum).

MAR 31 1986

SURVEILLANCE REQUIREMENTS (Continued)

c. At least once per 18 months by:

1. Performing a system functional test which includes simulated automatic actuation and restart# and verifying that each automatic valve in the flow path actuates to its correct position. Actual injection of coolant into the reactor vessel may be excluded.

2. Verifying that the system will develop a flow of greater than or equal to 600 gpm in the test flow path when steam is supplied to the turbine at a pressure of 150 + 15, - 0 psig.*

3. Verifying that the suction for the RCIC system is automatically transferred from the condensate storage tank to the suppression pool on a condensate storage tank water level-low signal.

*The provisions of Specification 4.0.4 are not applicable provided the surveillance is performed within 12 hours after reactor steam pressure is adequate to perform the tests.

#Automatic restart on a low water level signal which is subsequent to a high water level trip.

e. Functional Tests

During the first refueling shutdown and at least once per 18 months thereafter during shutdown, a representative sample of snubbers shall be tested using one of the following sample plans for each type of snubber. The sample plan shall be selected prior to the test period and cannot be changed during the test period. The NRC Regional Administrator shall be notified in writing of the sample plan selected prior to the test period or the sample plan used in the prior test period shall be implemented:

1) At least 10% of the total of each type of snubber shall be functionally tested either in-place or in a bench test. For each snubber of a type that does not meet the functional test acceptance criteria of Specification 4.7.5.f., an additional 10% of that type of snubber shall be functionally tested until no more failures are found or until all snubbers of that type have been functionally tested. Testing equipment failure during functional testing may invalidate that day's testing and allow that day's testing to resume anew at a later time, providing all snubbers tested with the failed equipment during the day of equipment failure are retested; or

2) A representative sample of each type of snubber shall be functionally tested in accordance with Figure 4.7.5-1. "C" is the total number of snubbers of a type found not meeting the acceptance requirements of Specification 4.7.5.f. The cumulative number of snubbers of a type tested is denoted by "N". At the end of testing "N" snubbers, the results shall be plotted on Figure 4.7.5-1. If at any time the point plotted falls on or above the "Reject" line all snubbers of that type shall be functionally tested. If at any time the point plotted falls on or below the "Accept" line, testing of snubbers of that type may be terminated. When the point plotted lies in the "Continue Testing" region, additional snubbers of that type shall be tested until the point falls in the "Accept" region or the "Reject" region, or all the snubbers of that type have been tested. Testing equipment failure during functional testing may invalidate that day's testing and allow that day's testing to resume anew at a later time, providing all snubbers tested with the failed equipment during the day of equipment failure are retested; or

3) An initial representative sample of 55 snubbers of each type shall be functionally tested. For each snubber type which does not meet the functional test acceptance criteria, another sample of at least one-half the size of the initial sample shall be tested until the total number tested is equal to the initial sample size multiplied by the factor, $1 + C/2$, where "C" is the number of snubbers found which do not meet the functional test acceptance criteria. The results from this sample plan shall be plotted using an "Accept" line which follows the equation $N = 55(1 + C/2)$. Each snubber point should be plotted when "N" snubbers have been tested. If the

SURVEILLANCE REQUIREMENTS (Continued)

APPLICABILITY: Whenever equipment protected by the spray and/or sprinkler systems is required to be OPERABLE.

ACTION:

a. With one or more of the above required spray and/or sprinkler systems inoperable, within one hour establish a continuous fire watch with backup fire suppression equipment for those areas in which redundant systems or components could be damaged; for other areas, establish an hourly fire watch patrol.

b. The provisions of Specification 3.0.3 and 3.0.4 are not applicable.

SURVEILLANCE REQUIREMENTS

4.7.7.2 Each of the above required spray and sprinkler systems shall be demonstrated OPERABLE:

a. At least once per 31 days by verifying that each valve, manual, power operated or automatic, in the flow path is in its correct position.

b. At least once per 12 months by cycling each testable valve in the flow path through at least one complete cycle of full travel.

c. At least once per 18 months:

1. By performing a system functional test which includes simulated automatic actuation of the system, and:

a) Verifying that the automatic valves in the flow path actuate to their correct positions on a test signal, and

b) Cycling each valve in the flow path that is not testable during plant operation through at least one complete cycle of full travel.

2. By a visual inspection of the dry pipe spray and sprinkler headers, except for headers located inside charcoal filter units, to verify their integrity, and

3. By a visual inspection of each sprinkler or deluge nozzle's spray area, except for nozzles and perforated pipe located inside charcoal filter units, to verify that the spray pattern is not obstructed.

d. At least once per 3 years by performing an air flow test through each deluge sprinkler header and verifying each open head deluge sprinkler is unobstructed.

FINAL DRAFT

TABLE 3.7.7.5-1 (Continued)

ELEVATION	COLUMN	HOSE RACK IDENTIFICATION
b. Auxiliary Building Control & D/G Areas (continued)		
77'	S-25	1LHR400
77'	T-29	1MHR400
102'	N-25	1AHR401
102'	V-25	1BHR401
102'	S-25	1DHR401
102'	T-30	1SHR401
102'	Vd-28.1	1QHR400
124'	N-25	1RHR400
124'	R-25	1HHR401
130'	W-29	1SHR400
130'	T-29	1CHR401
130'	X-25	1GHR401
130'	U-29	1THR401
137'	R-24.2	1THR400
146'	W-29	1JHR401
146'	U-29	1UHR401
146'	S-29	1VHR400
150'	X-25	1UHR400
155'-3"	N-25	1YHR400
163'	V-29	1WHR400
163'	T-29	1XHR400
163'	U-29	1KHR401
163'	V-26	1PHR401
178'	S-29	1RHR401
178'	V-29	1QHR401
c. Auxiliary Building Radwaste & Service Areas		
54'	Md-21.4	1FHR400
54'	L-15.8	0AHR300
77'	Md-21.4	1JHR400
102'	Md-21.4	1NHR400
102'	Mc-19	1PHR400
102'	L-15.8	0QHC300
124'	L-21.4	0XHC300
124'	L-25.9	0ZHC300
124'	L-34	0YHC300
137'	K-19.9	0EHC301
137'	Ha-19.9	0FHC301
137'	K-25.9	0HHC301
137'	K-25.9	0JHC301
137'	K-33.1	0LHC301
137'	Ha-34.6	0KHC301
137'	Mc-29	0MHC301
137'	K-21.4	0GHC301
155'-3"	K-25	0SHR301
155'-3"	L-25.9	0XHR301
153'-6"	Md-21.4	1DHR201
d. Intake Structure		
100'	--	1AHR500
100'	--	1BHR500

FINAL DRAFT

3/4.8.1 A.C. SOURCES

A.C. SOURCES - OPERATING

LIMITING CONDITION FOR OPERATION

3.8.1.1 As a minimum, the following A.C. electrical power sources shall be OPERABLE:

a. Two physically independent circuits between the offsite transmission network and the onsite Class 1E distribution system, and

b. Four separate and independent diesel generators, each with:

   1. A separate fuel oil day tank containing a minimum of 200 gallons of fuel,
   2. A separate fuel storage system consisting of two storage tanks containing a minimum of 48,800 gallons of fuel, and
   3. A separate fuel transfer pump for each storage tank.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, and 3.

ACTION:

a. With one offsite circuit of the above required A.C. electrical power sources inoperable, demonstrate the OPERABILITY of the remaining A.C. sources by performing Surveillance Requirement 4.8.1.1.1.a within 1 hour and at least once per 8 hours thereafter. If any diesel generator has not been successfully tested within the past 24 hours, demonstrate its OPERABILITY by performing Surveillance Requirement 4.8.1.1.2.a.4 and 4.8.1.1.2.a.5 for each such diesel generator separately within 24 hours. Restore the inoperable offsite circuit to OPERABLE status within 72 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

b. With one diesel generator of the above required A.C. electrical power sources inoperable, demonstrate the OPERABILITY of the above required A.C. offsite sources by performing Surveillance Requirement 4.8.1.1.1.a within 1 hour and at least once per 8 hours thereafter. If the diesel generator became inoperable due to any cause other than preplanned preventive maintenance or testing, demonstrate the OPERABILITY of the remaining diesel generators by performing Surveillance Requirement 4.8.1.1.2.a.4 and 4.8.1.1.2.a.5 separately for each diesel generator within 24 hours*; restore the inoperable diesel generator to OPERABLE status within 72 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

c. With one offsite circuit of the above required A.C. sources and one diesel generator of the above required A.C. electrical power sources inoperable, demonstrate the OPERABILITY of the remaining A.C. sources by performing Surveillance Requirement 4.8.1.1.1.a within 1 hour and

*This test is required to be completed regardless of when the inoperable diesel generator is restored to OPERABILITY.

MAR 31 1986

ACTION: (Continued)

at least once per 8 hours thereafter. If a diesel generator became inoperable due to any causes other than preplanned preventive maintenance or testing, demonstrate the OPERABILITY of the remaining OPERABLE diesel generators separately for each diesel generator by performing Surveillance Requirement 4.8.1.1.2.a.4 and 4.8.1.1.2.a.5 within 24 hours.* Restore at least two offsite circuits and all four of the above required diesel generators to OPERABLE status within 72 hours from time of the initial loss or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours. A successful test(s) of diesel generator OPERABILITY per Surveillance Requirement 4.8.1.1.2.a.4 and 4.8.1.1.2.a.5 performed under this ACTION statement for the OPERABLE diesel generators satisfies the diesel generator test requirements of ACTION Statement b.

d. With both of the above required offsite circuits inoperable, demonstrate the OPERABILITY of all of the above required diesel generators by performing Surveillance Requirement 4.8.1.1.2.a.4 and 4.8.1.1.2.a.5 separately for each diesel generator within 8 hours unless the diesel generators are already operating; restore at least one of the above required offsite circuits to OPERABLE status within 24 hours or be in at least HOT SHUTDOWN within the next 12 hours. With only one offsite circuit restored to OPERABLE status, restore at least two offsite circuits to OPERABLE status within 72 hours from time of initial loss or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours. A successful test(s) of diesel generator OPERABILITY per Surveillance Requirement 4.8.1.1.2.a.4 and 4.8.1.1.2.a.5 performed under this ACTION statement for the OPERABLE diesel generators satisfies the diesel generator test requirements of ACTION statement a.

e. With two diesel generators of the above required A.C. electrical power sources inoperable, demonstrate the OPERABILITY of the above required A.C. offsite sources by performing Surveillance Requirement 4.8.1.1.1.a within 1 hour and at least once per 8 hours thereafter and demonstrate the OPERABILITY of the remaining diesel generators by performing Surveillance Requirement 4.8.1.1.2.a.4 and 4.8.1.1.2.a.5 separately for each diesel generator within 8 hours.* Restore at least one of the inoperable diesel generators to OPERABLE status within 2 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours. Restore both of the inoperable diesel generators to OPERABLE status within 72 hours from time of initial loss or be in at least HOT SHUTDOWN within the next 12 hours and in

*This test is required to be completed regardless of when the inoperable diesel generator is restored to OPERABILITY.

SURVEILLANCE REQUIREMENTS

4.8.1.1.1 Each of the above required independent circuits between the offsite transmission network and the onsite Class 1E distribution system shall be:

a. Determined OPERABLE at least once per 7 days by verifying correct breaker alignments and indicated power availability, and

b. Demonstrated OPERABLE at least once per 18 months during shutdown by transferring, manually and automatically, unit power supply from the normal circuit to the alternate circuit.

4.8.1.1.2 Each of the above required diesel generators shall be demonstrated OPERABLE:

a. In accordance with the frequency specified in Table 4.8.1.1.2-1 on a STAGGERED TEST BASIS by:

1. Verifying the fuel level in the fuel oil day tank.

2. Verifying the fuel level in the fuel oil storage tank.

3. Verifying the fuel transfer pump starts and transfers fuel from the storage system to the fuel oil day tank.

4. Verifying the diesel starts from ambient conditions and accelerates to at least 514 rpm in less than or equal to 10 seconds after receipt of the start signal.* The generator voltage and frequency shall be 4160 ± 420 volts and 60 ± 1.2 Hz within 10 seconds after receipt of the start signal. The diesel generator shall be started for this test by using one of the following signals:

a) Manual.

b) Simulated loss of offsite power by itself.

c) Simulated loss of offsite power in conjunction with an ESF actuation test signal.

d) An ESF actuation test signal by itself.

5. Verifying the diesel generator is synchronized, loaded to between 4300 and 4400** kw in less than or equal to 130 seconds,* and operates with this load for at least 60 minutes.

*The diesel generator start (10 sec) and subsequent loading (130 sec) from ambient conditions shall be performed at least once per 184 days in these surveillance tests. All other engine starts and loading for the purpose of this surveillance testing may be preceded by an engine prelube period and/or other warmup procedures recommended by the manufacturer so that mechanical stress and wear on the diesel engine is minimized.

**This band is meant as guidance to avoid routine overloading of the engine. Loads in excess of this band shall not invalidate the test; the loads, however, shall not be less than 4300 kw nor greater than 4430 kw.

ACTION: (Continued)

COLD SHUTDOWN within the following 24 hours. A successful test(s) of diesel generator OPERABILITY per Surveillance Requirement 4.8.1.1.2.a.4 and 4.8.1.1.2.a.5 performed under this ACTION statement for the OPERABLE diesel generators satisfies the diesel generator test requirements of ACTION Statements a and b.

f. With two diesel generators of the above required A.C. electrical power sources inoperable, in addition to ACTION e., above, verify within 2 hours that all required systems, subsystems, trains, components, and devices that depend on the remaining diesel generators as a source of emergency power are also OPERABLE; otherwise, be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

g. With one offsite circuit and two diesel generators of the above required A.C. electrical power sources inoperable, demonstrate the OPERABILITY of the remaining A.C. sources by performing Surveillance Requirement 4.8.1.1.1.a within 1 hour and at least once per 8 hours thereafter and demonstrate the OPERABILITY of the remaining diesel generators by performing Surveillance Requirements 4.8.1.1.2.a.4 and 4.8.1.1.2.a.5 separately for each diesel generator within 8 hours.* Restore at least one of the above required inoperable A.C. sources to OPERABLE status within 2 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours. Restore the inoperable offsite circuit and both of the inoperable diesel generators to OPERABLE status within 72 hours from time of initial loss or be in at least HOT SHUTDOWN within 12 hours and in COLD SHUTDOWN within the following 24 hours.

*This test is required to be completed regardless of when the inoperable diesel generator is restored to OPERABILITY.

SURVEILLANCE REQUIREMENTS (Continued)

6. Verifying the diesel generator is aligned to provide standby power to the associated emergency busses.

7. Verifying the pressure in all diesel generator air start receivers to be greater than or equal to 380 psig.

8. Verifying the lube oil pressure, temperature and differential pressure across the lube oil filters to be within manufacturer's specifications.

b. At least once per 31 days by visually examining a sample of lube oil from the diesel engine to verify absence of water.

c. At least once per 31 days and after each operation of the diesel where the period of operation was greater than or equal to 1 hour by checking for and removing accumulated water from the fuel oil day tank.

d. At least once per 92 days by removing accumulated water from the fuel oil storage tanks.

e. At least once per 31 days by performing a functional test on the emergency load sequencer to verify operability.

f. At least once per 92 days and from new fuel oil prior to addition to the storage tanks by obtaining a sample in accordance with ASTM-D270-1975 and by verifying that the sample meets the following minimum requirements and is tested within the specified time limits:

1. As soon as sample is taken or from new fuel prior to addition to the storage tank, as applicable, verify in accordance with the tests specified in ASTM-D975-77 that the sample has:

   a) A water and sediment content of less than or equal to 0.05 volume percent.

   b) A kinematic viscosity @ 40°C of greater than or equal to 1.9 centistokes, but less than or equal to 4.1 centistokes or a Saybolt Second Universal (ssu) viscosity at 100°F of greater than or equal to 32 ssu but less than or equal to 45 ssu.

   c) A specific gravity as specified by the manufacturer as API gravity @ 60°F of greater than or equal to 28 degrees but less than or equal to 42 degrees.

2. Within one week after obtaining the sample, verify an impurity level of less than 2 mg of insolubles per 100 ml. when tested in accordance with ASTM-D2274-70.

SURVEILLANCE REQUIREMENTS (Continued)

3. Within 2 weeks after obtaining the sample, verify that the other properties specified in Table 1 of ASTM-D975-77 and Regulatory Guide 1.137, Position 2.a, are met when tested in accordance with ASTM-D975-77.

g. At least once per 2 months, by verifying the buried fuel oil transfer piping's cathodic protection system is OPERABLE and at least once per year by subjecting the cathodic protection system to a performance test.

h. At least once per 18 months#, during shutdown, by:

1. Subjecting the diesel to an inspection in accordance with procedures prepared in conjunction with its manufacturer's recommendations for this class of standby service.

2. Verifying the diesel generator capability to reject a load of greater than or equal to that of the RHR pump motor (1003 kW) for each diesel generator while maintaining voltage at 4160 ± 420 volts and frequency at 60 ± 1.2 Hz.

3. Verifying the diesel generator capability to reject a load of 4430 kW without tripping. The generator voltage shall not exceed 4580 volts during and following the load rejection.

4. Simulating a loss of offsite power by itself, and:

a) Verifying loss of power is detected and deenergization of the emergency busses and load shedding from the emergency busses.

b) Verifying the diesel generator starts* on the auto-start signal, energizes the emergency busses with permanently connected loads within 10 seconds after receipt of the start signal, energizes the autoconnected shutdown loads through the load sequencer and operates for greater than or equal to 5 minutes while its generator is loaded with the shutdown loads. After energization, the steady state voltage and frequency of the emergency busses shall be maintained at 4160 ± 420 volts and 60 ± 1.2 Hz during this test.

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*This diesel generator start (10 sec) and subsequent loading (130 sec) from ambient conditions may be preceded by an engine prelube period and/or other warmup procedures recommended by the manufacturer so that mechanical stress and wear on the diesel engine is minimized.

#For any start of a diesel generator, the diesel must be loaded in accordance with the manufacturer's recommendations.

5. Verifying that on an ECCS actuation test signal, without loss of offsite power, the diesel generator starts on the auto-start signal and operates on standby for greater than or equal to 5 minutes. The generator voltage and frequency shall be 4160 ± 420 volts and 60 ± 1.2 Hz within 10 seconds after the auto-start signal; the steady state generator voltage and frequency shall be maintained within these limits during this test.

6. Simulating a loss of offsite power in conjunction with an ECCS actuation test signal, and:

   a) Verifying loss of power is detected and deenergization of the emergency busses and load shedding from the emergency busses.

   b) Verifying the diesel generator starts* on the auto-start signal, energizes the emergency busses with permanently connected loads within 10 seconds after receipt of the start signal, energizes the autoconnected shutdown loads through the load sequencer and operates for greater than or equal to 5 minutes while its generator is loaded with the emergency loads. After energization, the steady state voltage and frequency of the emergency busses shall be maintained at 4160 ± 420 volts and 60 ± 1.2 Hz during this test.

7. Verifying that all automatic diesel generator trips, except engine overspeed, generator differential current, generator overcurrent, bus differential current and low lube oil pressure are automatically bypassed upon loss of voltage on the emergency bus concurrent with an ECCS actuation signal.#

8. Verifying the diesel generator operates for at least 24 hours. During the first 22 hours of this test, the diesel generator shall be loaded to between 4300 and 4400 kW** and during the remaining 2 hours of this test, the diesel generator shall be loaded to between 4800 and 4873 kW. The generator voltage and

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*This diesel generator start (10 sec) and subsequent loading (130 sec) from ambient conditions may be preceded by an engine prelube period and/or other warmup procedures recommended by the manufacturer so that mechanical stress and wear on the diesel engine is minimized.

**This band is meant as guidance to avoid routine overloading of the engine. Loads in excess of this band shall not invalidate the test; the loads; however, shall not be less than 4300 kW nor greater than 4873 kW.

#Generator differential current, generator overcurrent, and bus differential current is two-out-of-three logic and low lube oil pressure is two-out-of-four logic.

frequency shall be 4160 ± 420 volts and 60 ± 1.2 Hz within 10 seconds after the start signal; the steady state generator voltage and frequency shall be maintained within these limits during this test. Within 5 minutes after completing this 24-hour test, perform Surveillance Requirement 4.8.1.1.2.h.4.b).**

9. Verifying that the auto-connected loads to each diesel generator do not exceed the continuous rating of 4430 kW.

10. Verifying the diesel generator's capability to:

    a) Synchronize with the offsite power source while the generator is loaded with its emergency loads upon a simulated restoration of offsite power,

    b) Transfer its loads to the offsite power source,

    c) Be restored to its standby status, and

    d) Diesel generator circuit breaker is open.

11. Verifying that with the diesel generator operating in a test mode and connected to its bus, a simulated ECCS actuation signal overrides the test mode by (1) returning the diesel generator to standby operation, and (2) automatically energizes the emergency loads with offsite power.

12. Verifying that the fuel oil transfer pump transfers fuel oil from each fuel storage tank to the day tank of each diesel via the installed cross connection lines.

13. Verifying that the automatic load sequence timer is OPERABLE with the interval between each load block within ± 10% of its design interval.

14. Verifying that the following diesel generator lockout features prevent diesel generator starting only when required:

    a) Engine overspeed, generator differential, and low lube oil pressure (regular lockout relay, (1) 86R).
    b) Backup generator differential and generator overcurrent (backup lockout relay, (1) 86B)
    c) Generator ground and lockout relays-regular, backup and test, energized (breaker failure lockout relay, (1) 86F)

**If Surveillance Requirement 4.8.1.1.2.h.4.b) is not satisfactorily completed, it is not necessary to repeat the preceding 24 hour test. Instead, the diesel generator may be operated at between 4300 kw and 4400 kw for one hour or until operating temperature has stabilized prior to repeating Surveillance Requirement 4.8.1.1.2.h.4.b).

SURVEILLANCE REQUIREMENTS (Continued)

i. At least once per 10 years or after any modifications which could affect diesel generator interdependence by starting all diesel generators simultaneously, during shutdown, and verifying that all diesel generators accelerate to at least 514 rpm in less than or equal to 10 seconds.

j. At least once per 10 years by:

1. Draining each fuel oil storage tank, removing the accumulated sediment and cleaning the tank using a sodium hypochlorite solution or equivalent, and

2. Performing a pressure test of those portions of the diesel fuel oil system designed to Section III, subsection ND of the ASME Code in accordance with ASME Code Section XI Article IWD-5000.

4.8.1.1.3 Reports - All diesel generator failures, valid or non-valid, shall be reported to the Commission within 30 days pursuant to Specification 6.9.2. Reports of diesel generator failures shall include the information recommended in Regulatory Position C.3.b of Regulatory Guide 1.108, Revision 1, August 1977. If the number of failures in the last 100 valid tests, on a per nuclear unit basis, is greater than or equal to 7, the report shall be supplemented to include the additional information recommended in Regulatory Position C.3.b of Regulatory Guide 1.108, Revision 1, August 1977.

TABLE 4.8.1.1.2-1

DIESEL GENERATOR TEST SCHEDULE

Number of Failures in Last 20 Valid Tests*	Number of Failures in Last 100 Valid Tests*	Test Frequency
≤ 1	≤ 4	Once per 31 days
≥ 2**	≥ 5	Once per 7 days

*Criteria for determining number of failures and number of valid tests shall be in accordance with Regulatory Position C.2.e of Regulatory Guide 1.108, but determined on a per diesel generator basis.

For the purposes of determining the required test frequency, the previous test failure count may be reduced to zero if a complete diesel overhaul to like-new condition is completed, provided that the overhaul including appropriate post-maintenance operation and testing, is specifically approved by the manufacturer and if acceptable reliability has been demonstrated. The reliability criterion shall be the successful completion of 14 consecutive tests in a single series. Ten of these tests shall be in accordance with the routine Surveillance Requirement 4.8.1.1.2.a.4 and 4.8.1.1.2.a.5, four tests, in accordance with the 184-day testing requirement of Surveillance Requirement 4.8.1.1.2.a.4 and 4.8.1.1.2.a.5. If this criterion is not satisfied during the first series of tests, any alternate criterion to be used to transvalue the failure count to zero requires NRC approval.

**The associated test frequency shall be maintained until seven consecutive failure free demands have been performed and the number of failures in the last 20 valid demands has been reduced to one.

A.C. SOURCES - SHUTDOWN

LIMITING CONDITION FOR OPERATION

3.8.1.2 As a minimum, the following A.C. electrical power sources shall be OPERABLE:

a. One circuit between the offsite transmission network and the onsite Class 1E distribution system, and

b. Two diesel generators, one of which shall be diesel generator A or diesel generator B, each with:

1. A separate fuel oil day tank containing a minimum of 200 gallons of fuel.

2. A fuel storage system consisting of two storage tanks containing a minimum of 48,800 gallons of fuel.

3. A separate fuel transfer pump for each storage tank.

APPLICABILITY: OPERATIONAL CONDITIONS 4, 5 and *.

ACTION:

a. With less than the above required A.C. electrical power sources OPERABLE, suspend CORE ALTERATIONS, handling of irradiated fuel in the secondary containment, operations with a potential for draining the reactor vessel and crane operations over the spent fuel storage pool when fuel assemblies are stored therein. In addition, when in OPERATIONAL CONDITION 5 with the water level less than 22'-2" above the reactor pressure vessel flange, immediately initiate corrective action to restore the required power sources to OPERABLE status as soon as practical.

b. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.8.1.2 At least the above required A.C. electrical power sources shall be demonstrated OPERABLE per Surveillance Requirements 4.8.1.1.1, 4.8.1.1.2, and 4.8.1.1.3, except for the requirement of 4.8.1.1.2.a.5.

*When handling irradiated fuel in the secondary containment.

3/4.8.2 D.C. SOURCES

D.C. SOURCES - OPERATING

LIMITING CONDITION FOR OPERATION

3.8.2.1 As a minimum, the following D.C. electrical power sources shall be OPERABLE:

a. Channel A, consisting of:
   1. 125 volt battery 1AD411
   2. 125 volt full capacity charger 1AD413 or 1AD414
   3. 250 volt battery 10D421;
   4. 250 volt full capacity charger 10D423

b. Channel B, consisting of:
   1. 125 volt battery 1BD411
   2. 125 volt full capacity charger 1BD413 or 1BD414
   3. 250 volt battery 10D431;
   4. 250 volt full capacity charger 10D433

c. Channel C, consisting of:
   1. 125 volt battery 1CD411
   2. 125 volt full capacity charger 1CD413 or 1CD414
   3. 125 volt battery 1CD447
   4. 125 volt full capacity charger 1CD444

d. Channel D, consisting of:
   1. 125 volt battery 1DD411
   2. 125 volt full capacity charger 1DD413 or 1DD414
   3. 125 volt battery 1DD447
   4. 125 volt full capacity charger 1DD444

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2 and 3.

ACTION:

a. With any 125v battery and/or all associated chargers of the above required D.C. electrical power sources inoperable, restore the inoperable channel to OPERABLE status within 2 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

b. With any 250v battery and/or charger of the above required DC electrical power sources inoperable, declare the associated HPCI or RCIC system inoperable and take the appropriate ACTION required by the applicable Specification.

MAR 31 1986

SURVEILLANCE REQUIREMENTS

4.8.2.1 Each of the above required batteries and chargers shall be demonstrated OPERABLE:

a. At least once per 7 days by verifying that:

1. The parameters in Table 4.8.2.1-1 meet the Category A limits, and

2. Total battery terminal voltage for each 125-volt battery is greater than or equal to 129 volts on float charge and for each 250-volt battery the terminal voltage is greater than or equal to 258 volts on float charge.

b. At least once per 92 days and within 7 days after a battery discharge with battery terminal voltage below 105 volts for a 125-volt battery or 210 volts for a 250-volt battery, or battery overcharge with battery terminal voltage above 140 volts for a 125-volt battery or 280 volts for a 250-volt battery, by verifying that:

1. The parameters in Table 4.8.2.1-1 meet the Category B limits,

2. There is no visible corrosion at either terminals or connectors, or the connection resistance of these items is less than 150×10^{-6} ohms, excluding cable intercell connections, and

3. The average electrolyte temperature of each sixth cell of connected cells is above 60°F.

c. At least once per 18 months by verifying that:

1. The cells, cell plates and battery racks show no visual indication of physical damage or abnormal deterioration,

2. The cell-to-cell and terminal connections are clean, tight, free of corrosion and coated with anti-corrosion material,

3. The resistance of each cell-to-cell and terminal connection is less than or equal to 150×10^{-6} ohms, excluding cable intercell connections, and

4. The battery charger will supply the current listed below at the voltage listed below for at least 8 hours.*

CHARGER	Minimum Voltage	CURRENT (AMPERES)
1AD413, 1AD414 1BD413, 1BD414 1CD413, 1CD414 1CD444, 1DD414 1DD444, 1DD413	129	200
10D423, 10D433	258	50

*Prior to startup following the first refueling outage, this test may be performed for at least 4 hours.

LIMITING CONDITION FOR OPERATION

3.8.2.2 As a minimum, two of the following four channels of the D.C. electrical power sources, one of which shall be channel A or channel B, shall be OPERABLE with:

a. Channel A, consisting of:
   1. 125 volt battery 1AD411
   2. 125 volt full capacity charger# 1AD413 or 1AD414

b. Channel B, consisting of:
   1. 125 volt battery 1BD411
   2. 125 volt full capacity charger# 1BD413 or 1BD414.

c. Channel C, consisting of:
   1. 125 volt battery 1CD411
   2. 125 volt full capacity charger# 1CD413 or 1CD414
   3. 125 volt battery 1CD447
   4. 125 volt full capacity charger 1CD444

d. Channel D, consisting of:
   1. 125 volt battery 1DD411
   2. 125 volt full capacity charger# 1DD413 or 1DD414
   3. 125 volt battery 1DD447
   4. 125 volt full capacity charger 1DD444

APPLICABILITY: OPERATIONAL CONDITIONS 4, 5 and *.

ACTION:

a. With less than two channels of the above required D.C. electrical power sources OPERABLE, suspend CORE ALTERATIONS, handling of irradiated fuel in the secondary containment and operations with a potential for draining the reactor vessel.

b. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.8.2.2 At least the above required battery and charger shall be demonstrated OPERABLE per Surveillance Requirement 4.8.2.1.

*When handling irradiated fuel in the secondary containment.
#Only one full capacity charger per battery is required for the channel to be OPERABLE.

PRIMARY CONTAINMENT PENETRATION CONDUCTOR OVERCURRENT PROTECTIVE DEVICES

LIMITING CONDITION FOR OPERATION

3.8.4.1 All primary containment penetration conductor overcurrent protective devices shown in Table 3.8.4.1-1 shall be OPERABLE.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2 and 3.

ACTION:

a. With one or more of the primary containment penetration conductor overcurrent protective devices shown in Table 3.8.4.1-1 inoperable, declare the affected system or component inoperable and apply the appropriate ACTION statement for the affected system, and

   1. For 4.16 kV circuit breakers, de-energize the 4.16 kV circuit(s) by tripping the associated redundant circuit breaker(s) within 72 hours and verify the redundant circuit breaker to be tripped at least once per 7 days thereafter.

   2. For 480 volt circuit breakers, remove the inoperable circuit breaker(s) from service by disconnecting* the breaker within 72 hours and verify the inoperable breaker(s) to be disconnected at least once per 7 days thereafter.

   Otherwise, be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

b. The provisions of Specification 3.0.4 are not applicable to overcurrent devices in 4.16 kV circuits which have their redundant circuit breakers tripped or to 480 volt circuits which have the inoperable circuit breaker disconnected.*

SURVEILLANCE REQUIREMENTS

4.8.4.1 Each of the primary containment penetration conductor overcurrent protective devices shown in Table 3.8.4.1-1 shall be demonstrated OPERABLE:

   a. At least once per 18 months:

      1. By verifying that each of the medium voltage 4.16 kV circuit breakers are OPERABLE by performing:

         a) A CHANNEL CALIBRATION of the associated protective relays, and

         b) An integrated system functional test which includes simulated automatic actuation of the system and verifying that each relay and associated circuit breakers and overcurrent control circuits function as designed.

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*After being disconnected, these breakers shall be maintained disconnected under administrative control.

SURVEILLANCE REQUIREMENTS (Continued)

2. By selecting and functionally testing a representative sample of at least 10% of each type of lower voltage circuit breakers. Circuit breakers selected for functional testing shall be selected on a rotating basis. Testing of these circuit breakers shall consist of injecting a current with a value between 150% and 300% of the pickup of the long time delay trip element and verifying that the circuit breaker operates within the time delay bandwidth for that current specified by the manufacturer. The instantaneous element shall be tested by injecting a current in excess of 120% the pickup value of the element and verifying that the circuit breaker trips instantaneously with no intentional time delay. Molded case circuit breaker testing shall also follow this procedure except that generally no more than two trip elements, time delay and instantaneous, will be involved. Circuit breakers found inoperable during functional testing shall be restored to OPERABLE status prior to resuming operation. For each circuit breaker found inoperable during these functional tests, an additional representative sample of at least 10% of all the circuit breakers of the inoperable type shall also be functionally tested until no more failures are found or all circuit breakers of that type have been functionally tested.

b. At least once per 60 months by subjecting each circuit breaker to an inspection and preventive maintenance in accordance with procedures prepared in conjunction with its manufacturer's recommendations.

TABLE 3.8.4.1-1 (Continued)

PRIMARY CONTAINMENT PENETRATION CONDUCTOR OVERCURRENT PROTECTIVE DEVICES

2. 480-VOLT MOLDED CASE CIRCUIT BREAKERS (Continued)

CIRCUIT BREAKER NO.	LOCATION	TYPES	SYSTEMS OR EQUIPMENT POWERED
52-253064	10B253	IM HFB150 TM HFB150	Reactor Vessel Head Vent to Steam Line 1BB-HV-F005
52-263011	10B263	IM HFB150 TM HFB150	Reactor Vessel Head Vent Outboard Isolation 1BB-HV-F002
52-263012*	10B263	IM HFB150 TM HFB150	Recirc Pump Motor Hoist 1BH201 Disconnect Switch 1BS204
52-263022*	10B263	TM HFB150	CRD Equipment Handling Platform 10S270
52-263042*	10B263	IM HFB150 TM HFB150	Main Steam Relief Valve Hoist 10H202 Disconnect Switch 10S207
52-263054	10B263	IM HFB150 TM HFB150	RWCU Suction from Recirc Loop A 1BG-HV-F100
52-263081	10B263	IM HFB150 TM HFB150	RWCU Suction from RPV Drain Valve 1BG-HV-F101
52-263082	10B263	IM HFB150 TM HFB150	RWCU Suction Valve 1BG-HV-F102
52-263083	10B263	IM HFB150 TM HFB150	RWCU Suction from Recirc Loop B Valve 1BG-HV-F106
52-264053	10B264	IM HFB150 TM HFB150	Recirc Pump A Discharge Valve 1BB-HV-F031A
52-264062	10B264	IM HFB150 TM HFB150	Feedwater Inlet B Shutoff Valve 1AE-HV-F011B
52-264071	10B264	IM HFB150 TM HFB150	Reactor Recirc Pump 1AP201 Space Heater 1AS220
52-264072	10B264	IM HFB150 TM HFB150	Reactor Recirc Pump 1BP201 Space Heater 1BS220
52-264083	10B264	IM HFB150 TM HFB150	Recirc Pump A Suction Valve 1BB-HV-F023A

*These breakers shall be administratively maintained open in OPERATIONAL CONDITIONS 1, 2 and 3 and are not required to be tested.

FINAL DRAFT

MOTOR OPERATED VALVES - THERMAL OVERLOAD PROTECTION (BYPASSED)

LIMITING CONDITION FOR OPERATION

3.8.4.2 The thermal overload protection bypass circuit of each motor operated valve (MOV) shown in Table 3.8.4.2-1 shall be OPERABLE.

APPLICABILITY: Whenever the MOV is required to be OPERABLE.

ACTION:

With the thermal overload protection bypass circuit for one or more of the above required MOVs inoperable, restore the inoperable thermal overload protection bypass circuit(s) to OPERABLE status within 8 hours or declare the affected MOV(s) inoperable and apply the appropriate ACTION statement(s) for the affected system(s).

SURVEILLANCE REQUIREMENTS

4.8.4.2.1 The thermal overload protection bypass circuit for each of the above required MOVs shall be demonstrated OPERABLE:

a. At least once per 18 months by the performance of a CHANNEL FUNCTIONAL TEST for:

   1. Those thermal overload protection devices which are normally in force during plant operation and bypassed only under accident conditions.

   2. A representative sample of at least 25% of those thermal overload protection devices which are bypassed continuously and temporarily placed in force only when the MOVs are undergoing periodic or maintenance testing, such that the bypass circuitry for each thermal overload protection device of this type is tested at least once per 6 years.

   3. A representative sample of at least 25% of those thermal overload protection devices which are in force during normal manual (momentary push button contact) MOV operation and bypassed during remote manual (push button held depressed) MOV operation, such that the bypass circuitry for each thermal overload protection device of this type is tested at least once per 6 years.

b. Following maintenance on the motor starter.

4.8.4.2.2 The thermal overload protection for the above required MOVs which are continuously bypassed and temporarily placed in force only when the MOV is undergoing periodic or maintenance testing shall be verified to be continuously bypassed following such testing.

TABLE 3.8.4.2-1

MOTOR OPERATED VALVES - THERMAL OVERLOAD PROTECTION (BYPASSED)

VALVE NUMBER	THERMAL OVERLOAD PROTECTION STATUS	SYSTEM(S) AFFECTED
1AB-HV-F016	2	Main Steam
1AB-HV-F019	2	Main Steam
1AB-HV-F067A	2	Main Steam
1AB-HV-F067B	2	Main Steam
1AB-HV-F067C	2	Main Steam
1AB-HV-F067D	2	Main Steam
1AB-HV-F071	3	Main Steam
1AB-HV-3631A	3	Main Steam
1AB-HV-3631B	3	Main Steam
1AB-HV-3631C	3	Main Steam
1AB-HV-3631D	3	Main Steam
1AE-HV-F032A	3	Feedwater
1AE-HV-F032B	3	Feedwater
1AE-HV-F039	3	Feedwater
1AE-HV-4144	3	Feedwater
1AN-HV-2600	3	Demineralized Water
0AP-HV-2072	3	Condensate Storage & Transfer
0AP-HV-2073	3	Condensate Storage & Transfer
1AP-HV-F011	1	Condensate Storage & Transfer
1BC-HV-F004A	3	Residual Heat Removal (RHR)
1BC-HV-F004B	3	RHR
1BC-HV-F004C	3	RHR
1BC-HV-F004D	3	RHR
1BC-HV-F006A	3	RHR
1BC-HV-F006B	3	RHR
1BC-HV-F007A	1	RHR
1BC-HV-F007B	1	RHR
1BC-HV-F007C	1	RHR
1BC-HV-F007D	1	RHR
1BC-HV-F008	2	RHR
1BC-HV-F009	2	RHR
1BC-HV-F010A	2	RHR
1BC-HV-F010B	2	RHR
1BC-HV-F015A	2	RHR
1BC-HV-F015B	2	RHR
1BC-HV-F016A	3	RHR
1BC-HV-F016B	3	RHR
1BC-HV-5017A	1	RHR
1BC-HV-5017B	1	RHR
1BC-HV-F017C	1	RHR
1BC-HV-F017D	1	RHR
1BC-HV-F021A	3	RHR
1BC-HV-F021B	3	RHR
1BC-HV-F022	2	RHR
1BC-HV-F023	2	RHR

TABLE 3.8.4.2-1 (Continued)

MOTOR OPERATED VALVES - THERMAL OVERLOAD PROTECTION (BYPASSED)

VALVE NUMBER	THERMAL OVERLOAD PROTECTION STATUS	SYSTEM(S) AFFECTED
1BC-HV-F024A	2	RHR
1BC-HV-F024B	2	RHR
1BC-HV-F027A	2	RHR
1BC-HV-F027B	2	RHR
1BC-HV-F040	2	RHR
1BC-HV-F047A	3	RHR
1BC-HV-F047B	3	RHR
1BC-HV-F048A	1	RHR
1BC-HV-F048B	1	RHR
1BC-HV-F049	2	RHR
1BC-HV-F075	3	RHR
1BC-HV-443[illegible]	3	RHR
1BC-HV-50[illegible]	2	Containment Atmosphere Control
1BC-HV-5055B	2	Containment Atmosphere Control
1BD-HV-F010	2	Reactor Core Isolation Cooling (RCIC)
1BD-HV-F012	1	RCIC
1BD-HV-F013	1	RCIC
1BD-HV-F022	2	RCIC
1BD-HV-F031	1	RCIC
1BD-HV-F046	1	RCIC
1BE-HV-F001A	3	Core Spray
1BE-HV-F001B	3	Core Spray
1BE-HV-F001C	3	Core Spray
1BE-HV-F001D	3	Core Spray
1BE-HV-F004A	1	Core Spray
1BE-HV-F004B	1	Core Spray
1BE-HV-F005A	1	Core Spray
1BE-HV-F005B	1	Core Spray
1BE-HV-F015A	2	Core Spray
1BE-HV-F015B	2	Core Spray
1BE-HV-F031A	1	Core Spray
1BE-HV-F031B	1	Core Spray
1BF-HV-3800A	3	Control Rod Drive
1BF-HV-3800B	3	Control Rod Drive
1BF-HV-4005	3	Control Rod Drive
1BG-HV-F001	2	Reactor Water Cleanup
1BG-HV-F004	2	Reactor Water Cleanup
1BG-HV-F034	3	Reactor Water Cleanup
1BG-HV-F035	3	Reactor Water Cleanup
1BG-HV-3980	3	Reactor Water Cleanup
1BH-HV-F006A	3	Standby Liquid Control
1BH-HV-F006B	3	Standby Liquid Control

FINAL DRAFT

TABLE 3.8.4.2-1 (Continued)

MOTOR OPERATED VALVES - THERMAL OVERLOAD PROTECTION (BYPASSED)

VALVE NUMBER	THERMAL OVERLOAD PROTECTION STATUS	SYSTEM(S) AFFECTED
1BJ-HV-F004	1	High Pressure Coolant Injection (HPCI)
1BJ-HV-F006	1	HPCI
1BJ-HV-F007	1	HPCI
1BJ-HV-F008	2	HPCI
1BJ-HV-F012	1	HPCI
1BJ-HV-F042	1	HPCI
1BJ-HV-F059	1	HPCI
1BJ-HV-4803	3	HPCI
1BJ-HV-4804	3	HPCI
1BJ-HV-4865	3	HPCI
1BJ-HV-4866	3	HPCI
1BJ-HV-8278	1	HPCI
0BN-HV-2069	3	Refueling Water Transfer
1EA-HV-F073	3	Station Service Water
1EA-HV-2197A	3	Station Service Water
1EA-HV-2197B	3	Station Service Water
1EA-HV-2197C	3	Station Service Water
1EA-HV-2197D	3	Station Service Water
1EA-HV-2198A	2	Station Service Water
1EA-HV-2198B	2	Station Service Water
1EA-HV-2198C	2	Station Service Water
1EA-HV-2198D	2	Station Service Water
1EA-HV-2203	3	Station Service Water
1EA-HV-2204	3	Station Service Water
1EA-HV-2207	3	Station Service Water
1EA-HV-2234	3	Station Service Water
1EA-HV-2236	3	Station Service Water
1EA-HV-2238	3	Station Service Water
1EA-HV-2346	3	Station Service Water
1EA-HV-2355A	2	Station Service Water
1EA-HV-2355B	2	Station Service Water
1EA-HV-2356A	3	Station Service Water
1EA-HV-2356B	3	Station Service Water
1EA-HV-2357A	3	Station Service Water
1EA-HV-2357B	3	Station Service Water
1EA-HV-2371A	2	Station Service Water
1EA-HV-2371b	2	Station Service Water
1EC-HV-4647	3	Fuel Pool Cooling
1EC-HV-4648	3	Fuel Pool Cooling
1EC-HV-4689A	3	Fuel Pool Cooling
1EC-HV-4689B	3	Fuel Pool Cooling
1ED-HV-2553	2	Reactor Auxiliaries Cooling
1ED-HV-2554	2	Reactor Auxiliaries Cooling

MAR 31 1986

TABLE 3.8.4.2-1 (Continued)

MOTOR OPERATED VALVES - THERMAL OVERLOAD PROTECTION (BYPASSED)

VALVE NUMBER	THERMAL OVERLOAD PROTECTION STATUS	SYSTEM(S) AFFECTED
1ED-HV-2555	2	Reactor Auxiliaries Cooling
1ED-HV-2556	2	Reactor Auxiliaries Cooling
1ED-HV-2598	3	Reactor Auxiliaries Cooling
1ED-HV-2599	3	Reactor Auxiliaries Cooling
1EE-HV-4652	2	Torus Water Cleanup
1EE-HV-4679	2	Torus Water Cleanup
1EE-HV-4680	2	Torus Water Cleanup
1EE-HV-4681	2	Torus Water Cleanup
1EG-HV-2314A	3	Safety Auxiliaries Cooling
1EG-HV-2314B	3	Safety Auxiliaries Cooling
1EG-HV-2317A	3	Safety Auxiliaries Cooling
1EG-HV-2317B	3	Safety Auxiliaries Cooling
1EG-HV-2320A	3	Safety Auxiliaries Cooling
1EG-HV-2320B	3	Safety Auxiliaries Cooling
1EG-HV-2321A	2	Safety Auxiliaries Cooling
1EG-HV-2321B	2	Safety Auxiliaries Cooling
1EG-HV-2446	3	Safety Auxiliaries Cooling
1EG-HV-2447	3	Safety Auxiliaries Cooling
1EG-HV-2452A	3	Safety Auxiliaries Cooling
1EG-HV-2452B	3	Safety Auxiliaries Cooling
1EG-HV-2453A	2	Safety Auxiliaries Cooling
1EG-HV-2453B	2	Safety Auxiliaries Cooling
1EG-HV-2491A	3	Safety Auxiliaries Cooling
1EG-HV-2491B	3	Safety Auxiliaries Cooling
1EG-HV-2494A	3	Safety Auxiliaries Cooling
1EG-HV-2494B	3	Safety Auxiliaries Cooling
1EG-HV-2496A	3	Safety Auxiliaries Cooling
1EG-HV-2496B	3	Safety Auxiliaries Cooling
1EG-HV-2496C	3	Safety Auxiliaries Cooling
1EG-HV-2496D	3	Safety Auxiliaries Cooling
1EG-HV-2512A	3	Safety Auxiliaries Cooling
1EG-HV-2512B	3	Safety Auxiliaries Cooling
1EG-HV-7921A	3	Safety Auxiliaries Cooling
1EG-HV-7921B	3	Safety Auxiliaries Cooling
1EG-HV-7922A	3	Safety Auxiliaries Cooling
1EG-HV-7922B	3	Safety Auxiliaries Cooling
1EP-HV-2225A	3	Station Service Water
1EP-HV-2225B	3	Station Service Water
1EP-HV-2225C	3	Station Service Water
1EP-HV-2225D	3	Station Service Water
1FC-HV-F007	2	Reactor Core Isolation Cooling (RCIC)
1FC-HV-F008	2	RCIC

FINAL DRAFT

TABLE 3.8.4.2-1 (Continued)

MOTOR OPERATED VALVES - THERMAL OVERLOAD PROTECTION (BYPASSED)

VALVE NUMBER	THERMAL OVERLOAD PROTECTION STATUS	SYSTEM(S) AFFECTED
1FC-HV-F045	2	RCIC
1FC-HV-F059	3	RCIC
1FC-HV-F060	3	RCIC
1FC-HV-F062	2	RCIC
1FC-HV-F076	2	RCIC
1FC-HV-F084	2	RCIC
1FC-HV-4282	3	RCIC
1FD-HV-F001	1	High Pressure Coolant Injection (HPCI)
1FD-HV-F002	2	HPCI
1FD-HV-F003	2	HPCI
1FD-HV-F071	3	HPCI
1FD-HV-F075	2	HPCI
1FD-HV-F079	2	HPCI
1FD-HV-F100	2	HPCI
1FD-HV-4922	2	HPCI
1GB-HV-9531A1	2	Chilled Water
1GB-HV-9531A2	2	Chilled Water
1GB-HV-9531A3	2	Chilled Water
1GB-HV-9531A4	2	Chilled Water
1GB-HV-9531B1	2	Chilled Water
1GB-HV-9531B2	2	Chilled Water
1GB-HV-9531B3	2	Chilled Water
1GB-HV-9531B4	2	Chilled Water
1GB-HV-9532-1	3	Chilled Water
1GB-HV-9532-2	3	Chilled Water
1GH-HV-5543	3	Radwaste Area Vent
1GS-HV-4955A	2	Containment Atmosphere Control
1GS-HV-4955B	2	Containment Atmosphere Control
1GS-HV-4959A	2	Containment Atmosphere Control
1GS-HV-4959B	2	Containment Atmosphere Control
1GS-HV-4965A	2	Containment Atmosphere Control
1GS-HV-4965B	2	Containment Atmosphere Control
1GS-HV-4966A	2	Containment Atmosphere Control
1GS-HV-4966B	2	Containment Atmosphere Control
1GS-HV-4974	2	Containment Atmosphere Control
1GS-HV-4983A	2	Containment Atmosphere Control
1GS-HV-4983B	2	Containment Atmosphere Control
1GS-HV-4984A	2	Containment Atmosphere Control
1GS-HV-4984B	2	Containment Atmosphere Control
1GS-HV-5019A	2	Containment Atmosphere Control
1GS-HV-5019B	2	Containment Atmosphere Control
1GS-HV-5022A	2	Containment Atmosphere Control
1GS-HV-5022B	2	Containment Atmosphere Control

MAR 31 1986

FINAL DRAFT

TABLE 3.8.4.2-1 (Continued)

MOTOR OPERATED VALVES - THERMAL OVERLOAD PROTECTION (BYPASSED)

VALVE NUMBER	THERMAL OVERLOAD PROTECTION STATUS	SYSTEM(S) AFFECTED
1GS-HV-5050A	2	Containment Atmosphere Control
1GS-HV-5050B	2	Containment Atmosphere Control
1GS-HV-5052A	2	Containment Atmosphere Control
1GS-HV-5052B	2	Containment Atmosphere Control
1GS-HV-5053A	2	Containment Atmosphere Control
1GS-HV-5053B	2	Containment Atmosphere Control
1GS-HV-5054A	2	Containment Atmosphere Control
1GS-HV-5054B	2	Containment Atmosphere Control
1GS-HV-5057A	2	Containment Atmosphere Control
1GS-HV-5057B	2	Containment Atmosphere Control
1HB-HV-F003	2	Liquid Radwaste
1HB-HV-F004	2	Liquid Radwaste
1HB-HV-F019	2	Liquid Radwaste
1HB-HV-F020	2	Liquid Radwaste
1HB-HV-5262	3	Liquid Radwaste
1HB-HV-5275	3	Liquid Radwaste
1HC-HV-5551	3	Solid Radwaste
1KA-HV-7626	3	Service Compressed Air
1KB-HV-7629	3	Instrument Air (Backup to PCIG System)
1KL-HV-5124A	2	Primary Containment Instrument Gas (PCIG)
1KL-HV-5124B	2	PCIG
1KL-HV-5126A	2	PCIG
1KL-HV-5126B	2	PCIG
1KL-HV-5147	2	PCIG
1KL-HV-5148	2	PCIG
1KL-HV-5152A	2	PCIG
1KL-HV-5152B	2	PCIG
1KL-HV-5160A	3	PCIG
1KL-HV-5160B	3	PCIG
1KL-HV-5162	2	PCIG
1KL-HV-5172A	2	PCIG
1KL-HV-5172B	2	PCIG
1KP-HV-5829A	3	Main Steam Isolation Valve Sealing
1KP-HV-5829B	3	Main Steam Isolation Valve Sealing
1KP-HV-5834A	2	Main Steam Isolation Valve Sealing
1KP-HV-5834B	3	Main Steam Isolation Valve Sealing
1KP-HV-5835A	2	Main Steam Isolation Valve Sealing
1KP-HV-5835B	3	Main Steam Isolation Valve Sealing
1KP-HV-5836A	2	Main Steam Isolation Valve Sealing
1KP-HV-5836B	3	Main Steam Isolation Valve Sealing

MAR 31 1988

TABLE 3.8.4.2-1 (Continued)

MOTOR OPERATED VALVES - THERMAL OVERLOAD PROTECTION (BYPASSED)

VALVE NUMBER	THERMAL OVERLOAD PROTECTION STATUS	SYSTEM(S) AFFECTED
1KP-HV-5837A	2	Main Steam Isolation Valve Sealing
1KP-HV-5837B	3	Main Steam Isolation Valve Sealing
1SK-HV-4953	2	Plant Leak Detection
1SK-HV-4957	2	Plant Leak Detection
1SK-HV-4981	2	Plant Leak Detection
1SK-HV-5018	2	Plant Leak Detection

THERMAL OVERLOAD PROTECTION STATUS CODES

1. Normally in force during plant operation and bypassed only under accident conditions.

2. Bypassed continuously and temporarily placed in force only when the MOVs are undergoing periodic or maintenance testing.

3. In force during normal remote manual (momentary push button contact) MOV operation and bypassed during remote manual (push button held depressed) MOV operation.

MOTOR OPERATED VALVES - THERMAL OVERLOAD PROTECTION (NOT BYPASSED)

LIMITING CONDITION FOR OPERATION

3.8.4.3 The thermal overload protection of each motor operated valve (MOV) shown in Table 3.8.4.3-1 shall be OPERABLE.

APPLICABILITY: Whenever the MOV is required to be OPERABLE.

ACTION:

With the thermal overload protection for one or more of the above required MOVs inoperable, restore the inoperable thermal overload(s) to OPERABLE status within 8 hours or declare the affected MOV(s) inoperable and apply the appropriate ACTION statement(s) for the affected system(s).

SURVEILLANCE REQUIREMENTS

4.8.4.3 The thermal overload protection for each of the above required MOVs shall be demonstrated OPERABLE at least once per 18 months and following maintenance on the motor starter by the performance of a CHANNEL CALIBRATION.

TABLE 3.8.4.3-1

FINAL DRAFT

MOTOR OPERATED VALVES - THERMAL OVERLOAD PROTECTION (NOT BYPASSED)

VALVE NUMBER	SYSTEM(S) AFFECTED
1BC-HV-F003A	Residual Heat Removal
1BC-HV-F003B	Residual Heat Removal
1GS-HV-5741A	Containment Atmosphere Control
1GS-HV-5741B	Containment Atmosphere Control
1KC-HV-3408M	Fire Protection

MAR 31 1986

FINAL DRAFT

REACTOR PROTECTION SYSTEM ELECTRICAL POWER MONITORING

LIMITING CONDITION FOR OPERATION

3.8.4.4 Two RPS electric power monitoring channels for each inservice RPS MG set or alternate power supply shall be OPERABLE.

APPLICABILITY: At all times.

ACTION:

a. With one RPS electric power monitoring channel for an inservice RPS MG set or alternate power supply inoperable, restore the inoperable power monitoring channel to OPERABLE status within 72 hours or remove the associated RPS MG set or alternate power supply from service.

b. With both RPS electric power monitoring channels for an inservice RPS MG set or alternate power supply inoperable, restore at least one electric power monitoring channel to OPERABLE status within 30 minutes or remove the associated RPS MG set or alternate power supply from service.

SURVEILLANCE REQUIREMENTS

4.8.4.4 The above specified RPS electric power monitoring channels shall be determined OPERABLE:

a. At least once per 6 months by performance of a CHANNEL FUNCTIONAL TEST, and

b. At least once per 18 months by demonstrating the OPERABILITY of over-voltage, under-voltage, and under-frequency protective instrumentation by performance of a CHANNEL CALIBRATION including simulated automatic actuation of the protective relays, tripping logic and output circuit breakers and verifying the following setpoints.

   1. Over-voltage $\leq$ 132 VAC, (Bus A), 132 VAC (Bus B)

   2. Under-voltage $\geq$ 108 VAC, (Bus A), 108 VAC (Bus B)

   3. Under-frequency $\geq$ 57 Hz. (Bus A and Bus B)

MAR 31 1986

CLASS 1E ISOLATION BREAKER OVERCURRENT PROTECTIVE DEVICES

LIMITING CONDITION FOR OPERATION

3.8.4.5 All Class 1E isolation breaker (tripped by a LOCA signal) overcurrent protective devices shown in Table 3.8.4.5-1 shall be OPERABLE.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2 and 3.

ACTION:

a. With one or more of the overcurrent protective devices shown in Table 3.8.4.5-1 inoperable, declare the affected isolation breaker inoperable and remove the inoperable circuit breaker(s) from service within 72 hours and verify the inoperable breaker(s) to be disconnected at least once per 7 days thereafter.

b. The provisions of Specification 3.0.4 are not applicable to overcurrent devices in 480 volt circuits which have the inoperable circuit breaker disconnected.

SURVEILLANCE REQUIREMENTS

4.8.4.5 Each of the Class 1E isolation breaker overcurrent protective devices shown in Table 3.8.4.5-1 shall be demonstrated OPERABLE:

a. At least once per 18 months:

By selecting and functionally testing a representative sample of at least 10% of each type of lower voltage circuit breakers. Circuit breakers selected for functional testing shall be selected on a rotating basis. Testing of these circuit breakers shall consist of injecting a current with a value between 150% and 300% of the pickup of the long time delay trip element and a value between 150% and 250% of the pickup of the short time delay, and verifying that the circuit breaker operates within the time delay band width for that current specified by the manufacturer. The instantaneous element shall be tested by injecting a current in excess of 120% of the pickup value of the element and verifying that the circuit breaker trips instantaneously with no intentional time delay. Molded case circuit breaker testing shall also follow this procedure except that generally no more than two trip elements, time delay and instantaneous, will be involved. For circuit breakers equipped with solid state trip devices, the functional testing may be performed with use of portable instruments designed to verify the time-current characteristics and pickup calibration of the trip elements. Circuit breakers found inoperable during functional testing shall be restored to OPERABLE status prior to resuming operation. For each circuit breaker found inoperable during these functional tests, an additional representative sample of at least 10% of all the circuit breakers of the inoperable type shall also be functionally tested until no more failures are found or all circuit breakers of that type have been functionally tested.

b. At least once per 60 months by subjecting each circuit breaker to an inspection and preventive maintenance in accordance with procedures prepared in conjunction with its manufacturer's recommendations.

FINAL DRAFT

TABLE 3.8.4.5-1

CLASS 1E ISOLATION BREAKER

OVERCURRENT PROTECTIVE DEVICES
(BREAKER TRIPPED BY A LOCA SIGNAL)

480 VAC POWER CIRCUIT BREAKERS

1. TYPE AKR-5A-30

Class 1E Circuit Breaker No.	Class 1E Bus	Non-Class 1E Load Description
52-41011	10B410	Reactor Auxiliaries Cooling System Pump 1AP209
52-41014	10B410	Radwaste and Service Area MCC 10B313
52-41024	10B410	Reactor Building Supply Air Handling Unit 1BVH300
52-42011	10B420	Reactor Auxiliaries Cooling System Pump 1BP209
52-42014	10B420	Radwaste and Service Area MCC 10B323
52-42024	10B420	Reactor Building Exhaust Fan 1BV301
52-43024	10B430	Reactor Building Supply Air Handling Unit 1CVH300
52-43014	10B430	Control Rod Drive Pump 1AP207
52-44014	10B440	Control Rod Drive Pump 1BP207
52-44024	10B440	Reactor Building Supply Air Handling Unit 1AVH300
52-44034	10B440	Radwaste Area Supply Fan 0BV316
52-45011	10B450	Reactor Area MCC 10B252
52-45014	10B450	Radwaste Area Exhaust Fan 0AV305
52-45024	10B450	Emergency Instrument Air Compressor 10K100

MAR 31 1986

TABLE 3.8.4.5-1 (Continued)

FINAL DRAFT

480 VAC POWER CIRCUIT BREAKERS

1. Type AKR-5A-30 (Continued)

Class 1E Circuit Breaker No.	Class 1E Bus	Non-Class 1E Load Description
52-45034	10B450	Reactor Building Exhaust Fan 1CV301
52-46011	10B460	Reactor Area MCC 10B262
52-46014	10B460	Radwaste Area Exhaust Fan 0BV305
52-47011	10B470	Reactor Area MCC 10B272
52-47014	10B470	Radwaste Area Exhaust Fan 0CV305
52-47024	10B470	Radwaste Area Supply Fan 0AV316
52-47031	10B470	Technical Support Center MCC 00B474
52-48011	10B480	Reactor Area MCC 10B282
52-48024	10B480	Reactor Building Exhaust Fan 1AV301

480 VAC MOLDED CASE CIRCUIT BREAKERS

1. Type HFB150

Class 1E Circuit Breaker No.	Class 1E Bus	Non-Class 1E Load Description
52-441043	10B441	NSSS Computer Inverter 10D485
52-451023	10B451	Public Address System Inverter 10D496
52-471023	10B471	Security System Inverter 0AD495

MAR 31 1986

POWER RANGE NEUTRON MONITORING SYSTEM ELECTRICAL POWER MONITORING

LIMITING CONDITION FOR OPERATION

3.8.4.6 The power range neutron monitoring system (NMS) electric power monitoring channels for each inservice power range NMS power supply shall be OPERABLE.

APPLICABILITY: At all times.

ACTION:

a. With one power range NMS electric power monitoring channel for an inservice power range NMS power supply inoperable, restore the inoperable power monitoring channel to OPERABLE status within 72 hours or deenergize the associated power range NMS power supply feeder circuit.

b. With both power range NMS electric power monitoring channels for an inservice power range NMS power supply inoperable, restore at least one electric power monitoring channel to OPERABLE status within 30 minutes or deenergize the associated power range NMS power supply feeder circuit.

SURVEILLANCE REQUIREMENTS

4.8.4.6 The above specified power range NMS electric power monitoring channels shall be determined OPERABLE:

a. At least once per 6 months by performance of a CHANNEL FUNCTIONAL TEST, and

b. At least once per 18 months by demonstrating the OPERABILITY of over-voltage, under-voltage, and under-frequency protective instrumentation by performance of a CHANNEL CALIBRATION including simulated automatic actuation of the protective relays, tripping logic and output circuit breakers and verifying the following setpoints.

1. Over-voltage $\leq$ 132 VAC (BUS A), 132 VAC (BUS B)

2. Under-voltage $\geq$ 108 VAC (BUS A), 108 VAC (BUS B)

3. Under-frequency $\geq$ 57 Hz. -0, +2%

MAR 31 1986

3/4.9.2 INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.9.2 At least 2 source range monitor* (SRM) channels shall be OPERABLE and inserted to the normal operating level with:##

a. Annunciation and continuous visual indication in the control room,

b. One of the required SRM detectors located in the quadrant where CORE ALTERATIONS are being performed and the other required SRM detector located in an adjacent quadrant, and

c. Unless adequate shutdown margin has been demonstrated per Specification 3.1.1, the "shorting links" removed from the RPS# circuitry prior to and during the time any control rod is withdrawn.#

APPLICABILITY: OPERATIONAL CONDITION 5.**

ACTION:

With the requirements of the above specification not satisfied, immediately suspend all operations involving CORE ALTERATIONS and insert all insertable control rods.

SURVEILLANCE REQUIREMENTS

4.9.2 Each of the above required SRM channels shall be demonstrated OPERABLE by:

a. At least once per 12 hours:

1. Performance of a CHANNEL CHECK,

2. Verifying the detectors are inserted to the normal operating level, and

3. During CORE ALTERATIONS, verifying that the detector of an OPERABLE SRM channel is located in the core quadrant where CORE ALTERATIONS are being performed and another is located in an adjacent quadrant.

---

*The use of special movable detectors during CORE ALTERATIONS in place of the normal SRM nuclear detectors is permissible as long as these special detectors are connected to the normal SRM circuits.

#Not required for control rods removed per Specification 3.9.10.1 and 3.9.10.2.

**See Special Test Exception 3.10.7.

##Three SRM channels shall be OPERABLE for critical shutdown margin demonstrations. An SRM detector may be retracted provided a channel indication of at least 100 cps is maintained and THERMAL POWER is less than 1% of RATED THERMAL POWER.

3/4.9.6 REFUELING PLATFORM

LIMITING CONDITION FOR OPERATION

3.9.6 The refueling platform shall be OPERABLE and used for handling fuel assemblies or control rods within the reactor pressure vessel.

APPLICABILITY: During handling of fuel assemblies or control rods within the reactor pressure vessel.

ACTION:

With the requirements for refueling platform OPERABILITY not satisfied, suspend use of any inoperable refueling platform equipment from operations involving the handling of control rods and fuel assemblies within the reactor pressure vessel after placing the load in a safe condition.

SURVEILLANCE REQUIREMENTS

4.9.6.1 The refueling platform main hoist used for handling of control rods or fuel assemblies within the reactor pressure vessel shall be demonstrated OPERABLE within 7 days prior to the start of such operations by:

a. Demonstrating operation of the overload cutoff on the main hoist when the load exceeds 1200 + 0, -50 pounds.

b. Demonstrating operation of the main hoist uptravel stops when uptravel brings the top of active fuel to 8 feet below the normal water level.

c. Demonstrating operation of the slack cable cutoff on the main hoist when the load is less than 50 ± 10 pounds.

d. Demonstrating operation of the loaded rod block interlock on the main hoist when the load exceeds 485 ± 50 pounds.

e. Demonstrating operation of the redundant loaded interlock on the main hoist when the load exceeds 550 ± 50 pounds.

RADIOACTIVE EFFLUENTS

VENTING OR PURGING

LIMITING CONDITION FOR OPERATION

3.11.2.8 VENTING or PURGING of the Mark I containment drywell shall be through either the reactor building ventilation system or the filtration, recirculation and ventilation system.

APPLICABILITY: Whenever the containment is vented or purged.

ACTION:

a. With the requirements of the above specification not satisfied, suspend all VENTING and PURGING of the drywell.

b. The provisions of Specifications 3.0.3 and 3.0.4 are not applicable.

SURVEILLANCE REQUIREMENTS

4.11.2.8 The containment shall be determined to be aligned for VENTING or PURGING through either the reactor building ventilation system or the filtration, recirculation and ventilation system within 4 hours prior to start of and at least once per 12 hours during VENTING or PURGING of the drywell.

RADIOACTIVE EFFLUENTS

3/4.11.3 SOLID RADIOACTIVE WASTE TREATMENT

LIMITING CONDITION FOR OPERATION

3.11.3 Radioactive wastes shall be SOLIDIFIED or dewatered in accordance with the PROCESS CONTROL PROGRAM to meet shipping and transportation requirements during transit, and disposal site requirements when received at the disposal site.

APPLICABILITY: At all times.*

ACTION:

a. With SOLIDIFICATION or dewatering not meeting disposal site and shipping and transportation requirements, suspend shipment of the inadequately processed wastes and correct the PROCESS CONTROL PROGRAM, the procedures and/or the solid waste system as necessary to prevent recurrence.

b. With SOLIDIFICATION or dewatering not performed in accordance with the PROCESS CONTROL PROGRAM, (1) demonstrate by test or analysis that the improperly processed waste in each container meets the requirements for transportation to the disposal site and for receipt at the disposal site and (2) take appropriate administrative action to prevent recurrence.

c. The provisions of Specifications 3.0.3 and 3.0.4 are not applicable.

SURVEILLANCE REQUIREMENTS

4.11.3.1 The PROCESS CONTROL PROGRAM shall be followed to verify that the properties of the packaged waste meet the minimum stability requirements of 10 CFR Part 61 and other requirements for transportation to the disposal site and receipt at the disposal site.

4.11.3.2 The PROCESS CONTROL PROGRAM shall include sufficient quality control and assurance methods to assure the solidified waste product from any process (either in-house or contracted vendor) meets the requirements for transportation and receipt at the disposal site.

*Not required to be OPERABLE prior to initial criticality.

TABLE 3.12.1-1 (Continued)

RADIOLOGICAL ENVIRONMENTAL MONITORING PROGRAM

Exposure Pathway and/or Sample	Number of Representative Samples and Sample Locations[1]	Sampling and Collection Frequency	Type and Frequency of Analysis
2. AIRBORNE			
Radioiodine and Particulates	Samples from 5 locations. Three samples from close to the SITE BOUNDARY locations, in different sectors, of a high calculated annual average ground-level D/Q.	Continuous sampler operation with sample collection weekly, or more frequently if required by dust loading.	Radioiodine Cannister: I-131 analysis weekly. Particulate Sampler: Gross beta radioactivity analysis following filter change;[3]
	One sample from the vicinity of a community having a high calculated annual average groundlevel D/Q.		Gamma isotopic analysis[4] of composite (by location) quarterly.
	One sample from a control location, as for example 15-30 km distant and in the least prevalent wind direction.		
3. WATERBORNE			
a. Surface[5]	One sample upstream. One sample downstream. One sample crosstream.	Grab sample monthly.	Gamma isotopic analysis[4] monthly. Composite for tritium analysis quarterly.
b. Ground	Samples from one or two sources only if likely to be affected[7].	Monthly	Gamma isotopic[4] and tritium analysis monthly.

TABLE 3.12.1-1 (Continued)

RADIOLOGICAL ENVIRONMENTAL MONITORING PROGRAM

Exposure Pathway and/or Sample	Number of Representative Samples and Sample Locations[1]	Sampling and Collection Frequency	Type and Frequency of Analysis
4. INGESTION (Continued)			
b. Fish and Invertebrates	One sample of each commercially and recreationally important species in vicinity of plant discharge area. One sample of same species in areas not influenced by plant discharge.	Sample in season, or semiannually if they are not seasonal	Gamma isotopic analysis[4] on edible portions.
c. Food Products	One sample of each principal class of food products from any area that is irrigated by water in which liquid plant wastes have been discharged.	At time of harvest[9]	Gamma isotopic analysis[4] on edible portion.

TABLE 4.12.1-1 (Continued)

TABLE NOTATIONS

(1)This list does not mean that only these nuclides are to be considered. Other peaks that are identifiable, together with those of the above nuclides, shall also be analyzed and reported in the Annual Radiological Environmental Operating Report pursuant to Specification 6.9.1.6.

(2)Required detection capabilities for thermoluminescent dosimeters used for environmental measurements shall be in accordance with the recommendations of Regulatory Guide 4.13.

(3)The LLD is defined, for purposes of these specifications, as the smallest concentration of radioactive material in a sample that will yield a net count, above system background, that will be detected with 95% probability with only 5% probability of falsely concluding that a blank observation represents a "real" signal.

For a particular measurement system, which may include radiochemical separation:

$$LLD = \frac{4.66\ s_b}{E \cdot V \cdot 2.22 \cdot Y \cdot \exp(-\lambda\Delta t)}$$

Where:

LLD is the "a priori" lower limit of detection as defined above, as picocuries per unit mass or volume,

s_b is the standard deviation of the background counting rate or of the counting rate of a blank sample as appropriate, as counts per minute,

E is the counting efficiency, as counts per disintegration,

V is the sample size in units of mass or volume,

2.22 is the number of disintegrations per minute per picocurie,

Y is the fractional radiochemical yield, when applicable,

λ is the radioactive decay constant for the particular radionuclide (sec^{-1}), and

Δt for environmental samples is the elapsed time between sample collection, or end of the sample collection period, and time of counting (sec)

Typical valves of E, V, Y, and Δt should be used in the calculation.

3/4.1.1 SHUTDOWN MARGIN

A sufficient SHUTDOWN MARGIN ensures that 1) the reactor can be made subcritical from all operating conditions, 2) the reactivity transients associated with postulated accident conditions are controllable within acceptable limits, and 3) the reactor will be maintained sufficiently subcritical to preclude inadvertent criticality in the shutdown condition.

Since core reactivity values will vary through core life as a function of fuel depletion and poison burnup, the demonstration of SHUTDOWN MARGIN will be performed in the cold, xenon-free condition and shall show the core to be subcritical by at least R + 0.38% delta k/k or R + 0.28% delta k/k, as appropriate. The value of R in units of % delta k/k is the difference between the calculated value of maximum core reactivity during the operating cycle and the calculated beginning-of-life core reactivity. The value of R must be positive or zero and must be determined for each fuel loading cycle.

Two different values are supplied in the Limiting Condition for Operation to provide for the different methods of demonstration of the SHUTDOWN MARGIN. The highest worth rod may be determined analytically or by test. The SHUTDOWN MARGIN is demonstrated by an insequence control rod withdrawal at the beginning of life fuel cycle conditions, and, if necessary, at any future time in the cycle if the first demonstration indicates that the required margin could be reduced as a function of exposure. Observation of subcriticality in this condition assures subcriticality with the most reactive control rod fully withdrawn.

This reactivity characteristic has been a basic assumption in the analysis of plant performance and can be best demonstrated at the time of fuel loading, but the margin must also be determined anytime a control rod is incapable of insertion.

3/4.1.2 REACTIVITY ANOMALIES

Since the SHUTDOWN MARGIN requirement for the reactor is small, a careful check on actual conditions to the predicted conditions is necessary, and the changes in reactivity can be inferred from these comparisons of rod patterns. Since the comparisons are easily done, frequent checks are not an imposition on normal operations. A 1% delta k/k change is larger than is expected for normal operation so a change of this magnitude should be thoroughly evaluated. A change as large as 1% delta k/k would not exceed the design conditions of the reactor and is on the safe side of the postulated transients.

The specifications of this section assure that the peak cladding temperature following the postulated design basis loss-of-coolant accident will not exceed the 2200°F limit specified in 10 CFR 50.46.

3/4.2.1 AVERAGE PLANAR LINEAR HEAT GENERATION RATE

The peak cladding temperature (PCT) following a postulated loss-of-coolant accident is primarily a function of the average heat generation rate of all the rods of a fuel assembly at any axial location and is dependent only secondarily on the rod to rod power distribution within an assembly. The peak clad temperature is calculated assuming a LHGR for the highest powered rod which is equal to or less than the design LHGR corrected for densification. This LHGR times 1.02 is used in the heatup code along with the exposure dependent steady state gap conductance and rod-to-rod local peaking factor. The Technical Specification AVERAGE PLANAR LINEAR HEAT GENERATION RATE (APLHGR) is this LHGR of the highest powered rod divided by its local peaking factor. The limiting value for APLHGR is shown in Figures 3.2.1-1, 3.2.1-2, 3.2.1-3, 3.2.1-4 and 3.2.1-5.

The calculational procedure used to establish the APLHGR shown on Figures 3.2.1-1, 3.2.1-2, 3.2.1-3, 3.2.1-4 and 3.2.1-5 is based on a loss-of-coolant accident analysis. The analysis was performed using General Electric (GE) calculational models which are consistent with the requirements of Appendix K to 10 CFR 50. A complete discussion of each code employed in the analysis is presented in Reference 1. Differences in this analysis compared to previous analyses can be broken down as follows.

a. Input Changes

1. Corrected Vaporization Calculation - Coefficients in the vaporization correlation used in the REFLOOD code were corrected.

2. Incorporated more accurate bypass areas - The bypass areas in the top guide were recalculated using a more accurate technique.

3. Corrected guide tube thermal resistance.

4. Corrected heat capacity of reactor internals heat nodes.

Bases Table B 3.2.1-1

SIGNIFICANT INPUT PARAMETERS TO THE LOSS-OF-COOLANT ACCIDENT ANALYSIS

Plant Parameters:

Core THERMAL POWER ..... 3430 Mwt* which corresponds to 105% of rated steam flow

Vessel Steam Output ..... 14.87×10^6 lbm/hr which corresponds to 105% of rated steam flow

Vessel Steam Dome Pressure..... 1055 psia

Design Basis Recirculation Line Break Area for:

a. Large Breaks 4.1 ft^2

b. Small Breaks 0.09 ft^2,

Fuel Parameters:

FUEL TYPE	FUEL BUNDLE GEOMETRY	PEAK TECHNICAL SPECIFICATION LINEAR HEAT GENERATION RATE (kw/ft)	DESIGN AXIAL PEAKING FACTOR	INITIAL MINIMUM CRITICAL POWER RATIO
Initial Core	8 x 8	13.4	1.4	1.20

A more detailed listing of input of each model and its source is presented in Section II of Reference 1 and subsection 6.3.3 of the FSAR.

*This power level meets the Appendix K requirement of 102%. The core heatup calculation assumes a bundle power consistent with operation of the highest powered rod at 102% of its Technical Specification LINEAR HEAT GENERATION RATE limit.

3/4.2.3 MINIMUM CRITICAL POWER RATIO

The required operating limit MCPRs at steady state operating conditions as specified in Specification 3.2.3 are derived from the established fuel cladding integrity Safety Limit MCPR of 1.06, and an analysis of abnormal operational transients. For any abnormal operating transient analysis evaluation with the initial condition of the reactor being at the steady state operating limit, it is required that the resulting MCPR does not decrease below the Safety Limit MCPR at any time during the transient assuming instrument trip setting given in Specification 2.2.

To assure that the fuel cladding integrity Safety Limit is not exceeded during any anticipated abnormal operational transient, the most limiting transients have been analyzed to determine which result in the largest reduction in CRITICAL POWER RATIO (CPR). The type of transients evaluated were loss of flow, increase in pressure and power, positive reactivity insertion, and coolant temperature decrease. The limiting transient yields the largest delta MCPR. When added to the Safety Limit MCPR of 1.06, the required minimum operating limit MCPR of Specification 3.2.3 is obtained.

The evaluation of a given transient begins with the system initial parameters shown in FSAR Table 15.0-3 that are input to a GE-core dynamic behavior transient computer program. The code used to evaluate pressurization events is described in NEDO-24154[3] and the program used in non-pressurization events is described in NEDO-10802[2]. The outputs of this program along with the initial MCPR form the input for further analyses of the thermally limiting bundle with the single channel transient thermal hydraulic TASC code described in NEDE-25149[4]. The principal result of this evaluation is the reduction in MCPR caused by the transient.

The purpose of the K_f factor of Figure 3.2.3-2 is to define operating limits at other than rated core flow conditions. At less than 100% of rated flow the required MCPR is the product of the MCPR and the K_f factor. The K_f factors assure that the Safety Limit MCPR will not be violated during a flow increase transient resulting from a motor-generator speed control failure. The K_f factors may be applied to both manual and automatic flow control modes.

The K_f factors values shown in Figure 3.2.3-2 were developed generically and are applicable to all BWR/2, BWR/3 and BWR/4 reactors. The K_f factors were derived using the flow control line corresponding to RATED THERMAL POWER at rated core flow.

For the manual flow control mode, the K_f factors were calculated such that for the maximum flow rate, as limited by the pump scoop tube set point and the corresponding THERMAL POWER along the rated flow control line, the limiting bundle's relative power was adjusted until the MCPR changes with different core flows. The ratio of the MCPR calculated at a given point of core flow, divided by the operating limit MCPR, determines the K_f.

MINIMUM CRITICAL POWER RATIO (Continued)

For operation in the automatic flow control mode, the same procedure was employed except the initial power distribution was established such that the MCPR was equal to the operating limit MCPR at RATED THERMAL POWER and rated thermal flow.

The K_f factors shown in Figure 3.2.3-2 are conservative for the General Electric plant operation because the operating limit MCPRs of Specification 3.2.3 is the same as the original 1.20 operating limit MCPR used for the generic derivation of K_f.

At THERMAL POWER levels less than or equal to 25% of RATED THERMAL POWER, the reactor will be operating at minimum recirculation pump speed and the moderator void content will be very small. For all designated control rod patterns which may be employed at this point, operating plant experience indicates that the resulting MCPR value is in excess of requirements by a considerable margin. During initial start-up testing of the plant, a MCPR evaluation will be made at 25% of RATED THERMAL POWER level with minimum recirculation pump speed. The MCPR margin will thus be demonstrated such that future MCPR evaluation below this power level will be shown to be unnecessary. The daily requirement for calculating MCPR when THERMAL POWER is greater than or equal to 25% of RATED THERMAL POWER is sufficient since power distribution shifts are very slow when there have not been significant power or control rod changes. The requirement for calculating MCPR when a limiting control rod pattern is approached ensures that MCPR will be known following a change in THERMAL POWER or power shape, regardless of magnitude, that could place operation at a thermal limit.

3/4.2.4 LINEAR HEAT GENERATION RATE

This specification assures that the Linear Heat Generation Rate (LHGR) in any rod is less than the design linear heat generation even if fuel pellet densification is postulated.

References:

1. General Electric Company Analytical Model for Loss-of-Coolant Analysis in Accordance with 10 CFR 50, Appendix K, NEDE-20566, November 1975.
2. R. B. Linford, Analytical Methods of Plant Transient Evaluations for the GE BWR, NEDO-10802, February 1973.
3. Qualification of the One Dimensional Core Transient Model for Boiling Water Reactors, NEDO-24154, October 1978.
4. TASC 01-A Computer Program for the Transient Analysis of a Single Channel, Technical Description, NEDE-25149, January 1980.

Neutron flux noise limits are also established to ensure early detection of limit cycle neutron flux oscillations. BWR cores typically operate with neutron flux noise caused by random boiling and flow noise. Typical neutron flux noise levels of 1-12% of rated power (peak-to-peak) have been reported for the range of low to high recirculation loop flow during both single and dual recirculation loop operation. Neutron flux noise levels which significantly bound these values are considered in the thermal/mechanical design of GE BWR fuel and are found to be of negligible consequence. In addition, stability tests at operating BWRs have demonstrated that when stability related neutron flux limit cycle oscillations occur they result in peak-to-peak neutron flux limit cycles of 5-10 times the typical values. Therefore, actions taken to reduce neutron flux noise levels exceeding three (3) times the typical value are sufficient to ensure early detection of limit cycle neutron flux oscillations.

Typically, neutron flux noise levels show a gradual increase in absolute magnitude as core flow is increased (constant control rod pattern) with two reactor recirculation loops in operation. Therefore, the baseline neutron flux noise level obtained at a specific core flow can be applied over a range of core flows. To maintain a reasonable variation between the low flow and high flow end of the flow range, the range over which a specific baseline is applied should not exceed 20% of rated core flow with two recirculation loops in operation. Data from tests and operating plants indicate that a range of 20% of rated core flow will result in approximately a 50% increase in neutron flux noise level during operation with two recirculation loops. Baseline data should be taken near the maximum rod line at which the majority of operation will occur. However, baseline date taken at lower rod lines (i.e., lower power) will result in a conservative value since the neutron flux noise level is proportional to the power level at a given core flow.

3/4.4.2 SAFETY/RELIEF VALVES

The safety valve function of the safety/relief valves operates to prevent the reactor coolant system from being pressurized above the Safety Limit of 1375 psig in accordance with the ASME Code. A total of 13 OPERABLE safety/relief valves is required to limit reactor pressure to within ASME III allowable values for the worst case transient.

Demonstration of the safety/relief valve lift settings will occur only during shutdown. The safety/relief valves will be removed and either set pressure tested or replaced with spares which have been previously set pressure tested and stored in accordance with manufacturer's recommendations at the specified frequency.

The low-low set system ensures that safety/relief valve discharges are minimized for a second opening of these valves, following any overpressure transient. This is achieved by automatically lowering the closing setpoint of two valves and lowering the opening setpoint of two valves following the initial opening. In this way, the frequency and magnitude of the containment blowdown duty cycle is substantially reduced. Sufficient redundancy is provided for the low-low set system such that failure of any one valve to open or close at its reduced setpoint does not violate the design basis.

BASES TABLE B 3/4.4.6-1

REACTOR VESSEL TOUGHNESS

BELTLINE COMPONENT	WELD SEAM I.D. OR MAT'L TYPE	HEAT/SLAB OR HEAT/LOT	CU(%)	P(%)	HIGHEST RT_{NDT}(°F)	PREDICTED ΔRT_{NDT}(°F)	UNIRRADIATED UPPER SHELF (FT-LBS)	MAX. EOL RT_{NDT}(°F)
Plate	SA-533 GR B CL.1	5K3025-1	.15	.012	+19	20	76	+39
Weld	Long. seams for shells 4&5 and girth weld between 4&5	D55040/ 1125-02000	.08	.010	-30	17	135	-13

NOTE: * These values are given only for the benefit of calculating the end-of-life (EOL) RT_{NDT}.

NON-BELTLINE COMPONENT	MT'L TYPE OR WELD SEAM I.D.	HEAT/SLAB OR HEAT/LOT	HIGHEST REFERENCE TEMPERATURE RT_{NDT} (°F)
Shell Ring Connected to Vessel Flange	SA 533, GR.B, Cl.1	All Heats	+19
Bottom Head Dome	SA 533, GR.B, Cl.1	All Heats	+30
Bottom Head Torus	SA 533, GR.B, Cl.1	All Heats	+30
LPCI Nozzles	SA 508, Cl.2	All Heats	-20
Top Head Torus	SA 533, GR.B, Cl.1	All Heats	+19
Top Head Flange	SA 508, Cl.2	All Heats	+10
Vessel Flange	SA 508, Cl.2	All Heats	+10
Feedwater Nozzle	SA 508, Cl.2	All Heats	-20
Weld Metal	All RPV Welds	All Heats	0
Closure Studs	SA 540, GR.B, 24	All Heats	Meet 45 ft-lbs & 25 mils lateral expansion at +10°F

The design of the Hope Creek vessel results in these nozzles experiencing a predicted EOL fluence at 1/4T of the vessel thickness of 1.6×10^{17} n/cm^2. Therefore, these nozzles are predicted to have an EOL RT_{NDT} of -6°F.

ECCS-OPERATING and SHUTDOWN (Continued)

With the HPCI system inoperable, adequate core cooling is assured by the OPERABILITY of the redundant and diversified automatic depressurization system and both the CSS and LPCI systems. In addition, the reactor core isolation cooling (RCIC) system, a system for which no credit is taken in the safety analysis, will automatically provide makeup at reactor operating pressures on a reactor low water level condition. The HPCI out-of-service period of 14 days is based on the demonstrated OPERABILITY of redundant and diversified low pressure core cooling systems and the RCIC system.

The surveillance requirements provide adequate assurance that the HPCI system will be OPERABLE when required. Although all active components are testable and full flow can be demonstrated by recirculation through a test loop during reactor operation, a complete functional test with reactor vessel injection requires reactor to be in HOT SHUTDOWN with vessel pressure not less than 200 psig. The pump discharge piping is maintained full to prevent water hammer damage and to provide cooling at the earliest moment.

Upon failure of the HPCI system to function properly after a small break loss-of-coolant accident, the automatic depressurization system (ADS) automatically causes selected safety-relief valves to open, depressurizing the reactor so that flow from the low pressure core cooling systems can enter the core in time to limit fuel cladding temperature to less than 2200°F. ADS is conservatively required to be OPERABLE whenever reactor vessel pressure exceeds 100 psig. This pressure is substantially below that for which the low pressure core cooling systems can provide adequate core cooling for events requiring ADS.

ADS automatically controls five selected safety-relief valves although the safety analysis only takes credit for four valves. It is therefore appropriate to permit one valve to be out-of-service for up to 14 days without materially reducing system reliability.

3/4.5.3 SUPPRESSION CHAMBER

The suppression chamber is required to be OPERABLE as part of the ECCS to ensure that a sufficient supply of water is available to the HPCI, CSS and LPCI systems in the event of a LOCA. This limit on suppression chamber minimum water volume ensures that sufficient water is available to permit recirculation cooling flow to the core. The OPERABILITY of the suppression chamber in OPERATIONAL CONDITIONS 1, 2 or 3 is also required by Specification 3.6.2.1.

Repair work might require making the suppression chamber inoperable. This specification will permit those repairs to be made and at the same time give assurance that the irradiated fuel has an adequate cooling water supply when the suppression chamber must be made inoperable, including draining, in OPERATIONAL CONDITION 4 or 5.

In OPERATIONAL CONDITION 4 and 5 the suppression chamber minimum required water volume is reduced because the reactor coolant is maintained at or below 200°F. Since pressure suppression is not required below 212°F, the minimum water volume is based on NPSH, recirculation volume and vortex prevention plus a safety margin for conservatism.

DRYWELL AND SUPPRESSION CHAMBER PURGE SYSTEM (Continued)

The use of the drywell and suppression chamber purge lines for pressure control is restricted with the following exception, the inboard 26-inch valve on the drywell purge outlet vent line when used in conjunction with the 2-inch purge outlet vent line bypass valve since the 2-inch valves will close during a LOCA or steam line break accident and therefore the site boundary dose guidelines of 10 CFR Part 100 would not be exceeded in the event of an accident during purging operations. In addition due to the limited flow rate through the 2-inch bypass valve, the inboard 26-inch valve is also capable of closing under these conditions. The design of the 2-inch purge supply and exhaust isolation valves meets the requirements of Branch Technical Position CSB 6-4, "Containment Purging During Normal Plant Operations".

Leakage integrity tests with a maximum allowable leakage rate for purge supply and exhaust isolation valves will provide early indication of resilient material seal degradation and will allow the opportunity for repair before gross leakage failure develops. The 0.60 L_a leakage limit shall not be exceeded when the leakage rates determined by the leakage integrity tests of these valves are added to the previously determined total for all valves and penetrations subject to Type B and C tests.

3/4.6.2. DEPRESSURIZATION SYSTEMS

The specifications of this section ensure that the primary containment pressure will not exceed the design pressure of 62 psig during primary system blowdown from full operating pressure.

The suppression chamber water provides the heat sink for the reactor coolant system energy release following a postulated rupture of the system. The suppression chamber water volume must absorb the associated decay and structural sensible heat released during reactor coolant system blowdown from 1020 psig. Since all of the gases in the drywell are purged into the suppression chamber air space during a loss of coolant accident, the pressure of the liquid must not exceed 62 psig, the suppression chamber maximum internal design pressure. The design volume of the suppression chamber, water and air, was obtained by considering that the total volume of reactor coolant to be considered is discharged to the suppression chamber and that the drywell volume is purged to the suppression chamber.

Using the minimum or maximum water volumes given in this specification, containment pressure during the design basis accident is approximately 48.1 psig which is below the design pressure of 62 psig. Maximum water volume of 122,000 ft^3 results in a downcomer submergence of 3.33 ft and the minimum volume of 118,000 ft^3 results in a submergence of approximately 3.0 ft. The majority of the Bodega tests were run with a submerged length of four feet and with complete condensation. Thus, with respect to the downcomer submergence, this specification is adequate. The maximum temperature at the end of the blowdown

3/4.7.1 SERVICE WATER SYSTEMS

The OPERABILITY of the station service water and the safety auxiliaries cooling systems ensures that sufficient cooling capacity is available for continued operation of the SACS and its associated safety-related equipment during normal and accident conditions. The redundant cooling capacity of these systems, assuming a single failure, is consistent with the assumptions used in the accident conditions within acceptable limits.

3/4.7.2 CONTROL ROOM EMERGENCY FILTRATION SYSTEM

The OPERABILITY of the control room emergency filtration system ensures that 1) the ambient air temperature does not exceed the allowable temperature for continuous duty rating for the equipment and instrumentation cooled by this system and 2) the control room will remain habitable for operations personnel during and following all design basis accident conditions. Continuous operation of the system with the heaters and humidity control instruments OPERABLE for 10 hours during each 31 day period is sufficient to reduce the buildup of moisture on the adsorbers and HEPA filters. The OPERABILITY of this system in conjunction with control room design provisions is based on limiting the radiation exposure to personnel occupying the control room to 5 rem or less whole body, or its equivalent. This limitation is consistent with the requirements of General Design Criteria 19 of Appendix "A", 10 CFR Part 50.

3/4.7.3 FLOOD PROTECTION

The requirement for flood protection ensures that facility flood protection features are in place in the event of flood conditions. The limit of elevation 10.5' Mean Sea Level is based on the elevation at which facility flood protection features provide protection to safety related equipment.

3/4.7.4 REACTOR CORE ISOLATION COOLING SYSTEM

The reactor core isolation cooling (RCIC) system is provided to assure adequate core cooling in the event of reactor isolation from its primary heat sink and the loss of feedwater flow to the reactor vessel without requiring actuation of any of the Emergency Core Cooling System equipment. The RCIC system is conservatively required to be OPERABLE whenever reactor steam dome pressure exceeds 150 psig. This pressure is substantially below that for which the RCIC system can provide adequate core cooling for events requiring the RCIC system.

The RCIC system specifications are applicable during OPERATIONAL CONDITIONS 1, 2 and 3 when reactor vessel steam dome pressure exceeds 150 psig because RCIC is the primary non-ECCS source of emergency core cooling when the reactor is pressurized.

With the RCIC system inoperable, adequate core cooling is assured by the OPERABILITY of the HPCI system and justifies the specified 14 day out-of-service period.

FIRE RATED ASSEMBLIES (Continued)

The barrier penetrations, including cable penetration barriers, fire doors and dampers are considered functional when the visually observed condition is the same as the as-designed condition. For those fire barrier-penetrations that are not in the as-designed condition, an evaluation shall be performed to show that the modification has not degraded the fire rating of the fire barrier penetration.

During periods of time when the barriers are not functional, either, 1) a continuous fire watch is required to be maintained in the vicinity of the affected barrier, 2) the fire detectors on at least one side of the affected barrier must be verified OPERABLE and a hourly fire watch patrol established until the barrier is restored to functional status, or 3) the fire detectors on both sides of the affected barrier must be verified OPERABLE and a daily fire watch patrol established until the barrier is restored to functional status.

3/4.7.9 MAIN TURBINE BYPASS SYSTEM

The main turbine bypass system is required to be OPERABLE consistent with the assumptions of the feedwater controller failure analysis for FSAR Chapter 15.

3/4.10 SPECIAL TEST EXCEPTIONS

BASES

3/4.10.1 PRIMARY CONTAINMENT INTEGRITY

The requirement for PRIMARY CONTAINMENT INTEGRITY is not applicable during the period when open vessel tests are being performed during the low power PHYSICS TESTS.

3/4.10.2 ROD SEQUENCE CONTROL SYSTEM

In order to perform the tests required in the technical specifications it is necessary to bypass the sequence restraints on control rod movement. The additional surveillance requirments ensure that the specifications on heat generation rates and shutdown margin requirements are not exceeded during the period when these tests are being performed and that individual rod worths do not exceed the values assumed in the safety analysis.

3/4.10.3 SHUTDOWN MARGIN DEMONSTRATIONS

Performance of shutdown margin demonstrations during open vessel testing requires additional restrictions in order to ensure that criticality is properly monitored and controlled. These additional restrictions are specified in this LCO.

3/4.10.4 RECIRCULATION LOOPS

This special test exception permits reactor criticality under no flow conditions and is required to perform certain startup and PHYSICS TESTS while at low THERMAL POWER levels.

3/4.10.5 OXYGEN CONCENTRATION

Relief from the oxygen concentration specifications is necessary in order to provide access to the primary containment during the initial startup and testing phase of operation. Without this access the startup and test program could be restricted and delayed.

3/4.10.6 TRAINING STARTUPS

This special test exception permits training startups to be performed with the reactor vessel depressurized at low THERMAL POWER and temperature while controlling RCS temperature with one RHR subsystem aligned in the shutdown cooling mode in order to minimize contaminated water discharge to the radioactive waste disposal system.

3/4.10.7 SPECIAL INSTRUMENTATION - INITIAL CORE LOADING

This special test exception permits relief from the requirements for a minimum count rate while loading the first 16 fuel bundles to allow sufficient source-to-detector coupling such that minimum count rate can be achieved on an SRM. This is acceptable because of the significant margin to criticality while loading the initial 16 fuel bundles.

EXPLOSIVE GAS MIXTURE (Continued)

limits. These automatic control features include isolation of the source of hydrogen and/or oxygen on loss of dilution steam. Maintaining the concentration of hydrogen below the flammability limit provides assurance that the releases of radioactive materials will be controlled in conformance with the requirements of General Design Criterion 60 of Appendix A to 10 CFR Part 50.

3/4.11.2.7 MAIN CONDENSER

Restricting the gross radioactivity rate of noble gases from the main condenser provides reasonable assurance that the total body exposure to an individual at the exclusion area boundary will not exceed a small fraction of the limits of 10 CFR Part 100 in the event this effluent is inadvertently discharged directly to the environment without treatment. This specification implements the requirements of General Design Criteria 60 and 64 of Appendix A to 10 CFR Part 50.

3/4.11.2.8 VENTING OR PURGING

This specification provides reasonable assurance that releases from drywell purging operations will not exceed the annual dose limits of 10 CFR Part 20 for UNRESTRICTED AREAS.

3/4.11.3 SOLID RADIOACTIVE WASTE TREATMENT

This specification implements the requirements of General Design Criterion 60 of Appendix A to 10 CFR Part 50. The process parameters included in establishing the PROCESS CONTROL PROGRAM may include, but are not limited to waste type, waste pH, waste/liquid/solidification agent/catalyst ratios, waste oil content, waste principal chemical constituents, and mixing and curing times. The purpose of the PROCESS CONTROL PROGRAM is to provide quality assurance that the solidified waste meets 10 CFR Part 61 requirements.

3/4.11.4 TOTAL DOSE

This specification is provided to meet the dose limitations of 40 CFR Part 190 that have been incorporated into 10 CFR Part 20 by 46 FR 18525. The specification requires the preparation and submittal of a Special Report whenever the calculated doses from plant generated radioactive effluents and direct radiation exceed 25 mrems to the total body or any organ, except the thyroid, which shall be limited to less than or equal to 75 mrems. For sites containing up to 4 reactors, it is highly unlikely that the resultant dose to a MEMBER OF THE PUBLIC will exceed the dose limits of 40 CFR Part 190 if the individual reactors remain within twice the dose design objectives of Appendix I, and if direct radiation doses from the reactor units including outside storage tanks,etc. are kept small. The Special Report will describe a course of action that should result in the limitation of the annual dose to a MEMBER OF THE PUBLIC to within the 40 CFR Part 190 limits. For the purposes of the Special Report, it may be assumed that the dose commitment to the MEMBER OF

TABLE 5.7.1-1

COMPONENT CYCLIC OR TRANSIENT LIMITS

COMPONENT	CYCLIC OR TRANSIENT LIMIT	DESIGN CYCLE OR TRANSIENT
Reactor	120 heatup and cooldown cycles	70°F to 546°F to 70°F
	80 step change cycles	Loss of feedwater heaters
	180 reactor trip cycles	100% to 0% of RATED THERMAL POWER
	130 hydrostatic pressure and leak tests	Pressurized to ≥ 930 and ≤1250 psig

UNIT STAFF (continued)

f. Administrative procedures shall be developed and implemented to limit the working hours of unit staff who perform safety-related functions e.g., licensed Senior Reactor Operators, licensed Reactor Operators, radiation protection technicians, equipment operators, and key maintenance personnel.

Adequate shift coverage shall be maintained without routine heavy use of overtime. The objective shall be to have operating personnel work a normal 8-hour day, 40-hour week while the unit is operating. However, in the event that unforeseen problems require substantial amounts of overtime to be used, or during extended periods of shutdown for refueling, major maintenance on major unit modifications, on a temporary basis the following guidelines shall be followed:

1. An individual should not be permitted to work more than 16 hours straight, excluding shift turnover time.

2. An individual should not be permitted to work more than 16 hours in any 24-hour period, nor more than 24 hours in any 48-hour period, nor more than 72 hours in any 7 day period, all excluding shift turnover time.

3. A break of at least 8 hours should be allowed between work periods, including shift turnover time.

4. Except during extended shutdown periods, the use of overtime should be considered on an individual basis and not for the entire staff on a shift.

Any deviation from the above guidelines shall be authorized by the appropriate department manager, or higher levels of management, in accordance with established procedures and with documentation of the basis for granting the deviation. Controls shall be included in the procedures such that individual overtime shall be reviewed monthly by the General Manager-Hope Creek Operations or his designee to assure that excessive hours have not been assigned. Routine deviation from the above guidelines is not authorized.

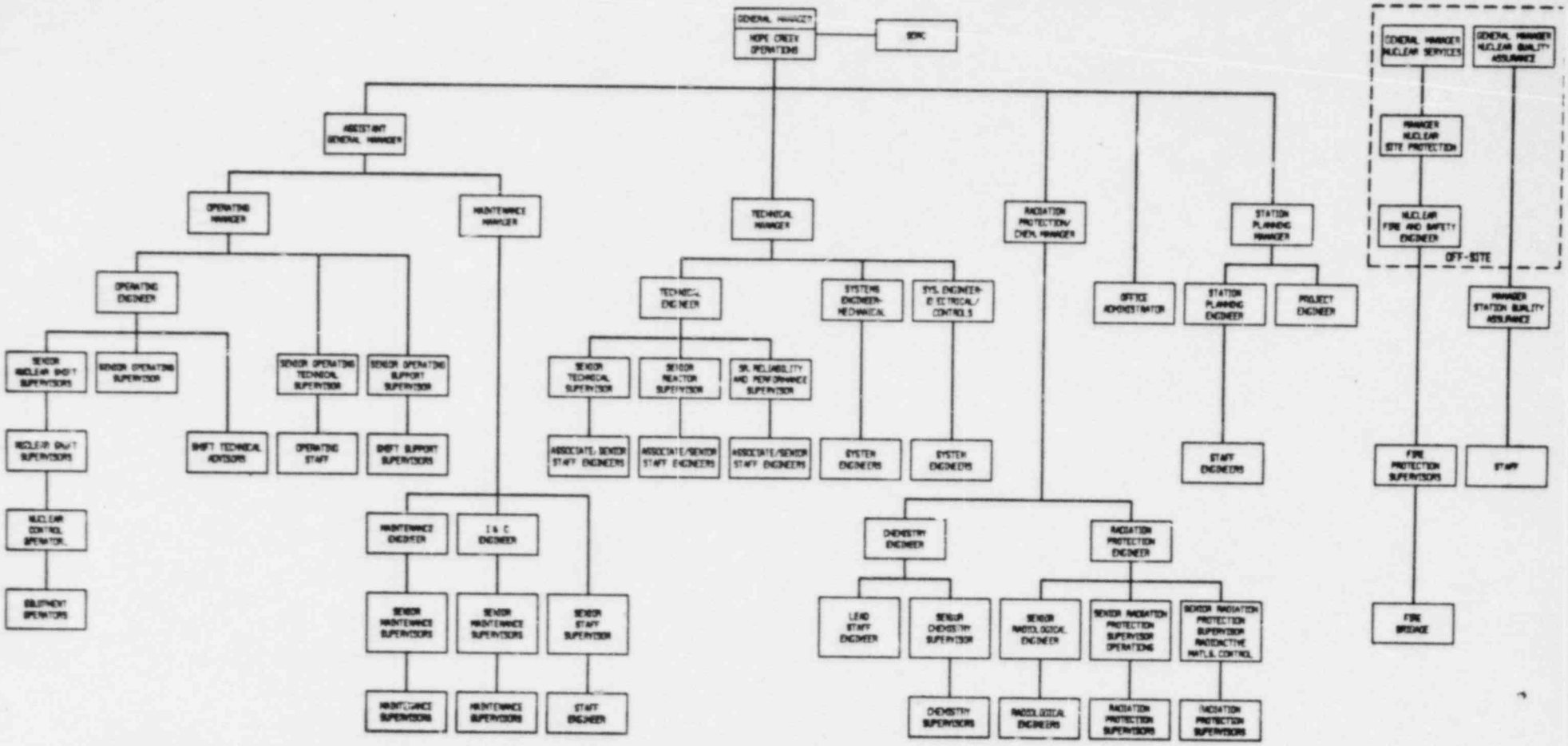

FIGURE 6.2.2-1

UNIT ORGANIZATION

TABLE 6.2.2-1

MINIMUM SHIFT CREW COMPOSITION

SINGLE UNIT FACILITY

POSITION	NUMBER OF INDIVIDUALS REQUIRED TO FILL POSITION	
	CONDITION 1, 2, or 3	CONDITION 4 or 5
SNSS*	1	1
NSS*	1	None
NCO	2	1
EO	2	1
STA	1	None

TABLE NOTATION

SNSS - Senior Nuclear Shift Supervisor with a Senior Reactor Operator license on the Unit
NSS - Nuclear Shift Supervisor with a Senior Reactor Operator license on the Unit
NCO - Nuclear Control Operator with a Reactor Operator license on the Unit
EO - Equipment Operator
STA - Shift Technical Advisor

Except for the Senior Nuclear Shift Supervisor, the shift crew composition may be one less than the minimum requirements of Table 6.2.2-1 for a period of time not to exceed 2 hours in order to accommodate unexpected absence of on-duty shift crew members provided immediate action is taken to restore the shift crew composition to within the minimum requirements of Table 6.2.2-1. This provision does not permit any shift crew position to be unmanned upon shift change due to an oncoming shift crewman being late or absent.

During any absence of the Senior Nuclear Shift Supervisor from the control room while the unit is in OPERATIONAL CONDITION 1, 2 or 3, an individual with a valid Senior Reactor Operator license shall be designated to assume the control room command function. During any absence of the Senior Nuclear Shift Supervisor from the control room while the unit is in OPERATIONAL CONDITION 4 or 5, an individual with a valid Senior Reactor Operator license or Operator license shall be designated to assume the control room command function.

*In cases where an individual has a Senior Reactor Operator's license on the unit, is a qualified STA, and has a Professional Engineers License by virtue of successful completion of the Professional Engineers examination or a bachelor's degree in a scientific, engineering, or engineering technology discipline from an accredited institution, the individual can serve in a dual role capacity as either the SNSS/STA or NSS/STA. (Note: For those individuals with a bachelor's degree in a scientific or engineering technology discipline, course work must have included physical, mathematical, or engineering science.) Otherwise, there shall be a qualified STA as well as a SNSS and NSS on-shift.

6.2.3 SHIFT TECHNICAL ADVISOR

6.2.3.1 The Shift Technical Advisor shall provide advisory technical support to the Senior Nuclear Shift Supervisor in the areas of thermal hydraulics, reactor engineering, and plant analysis with regard to safe operation of the unit. The Shift Technical Advisor shall have a bachelor's degree or equivalent in a scientific or engineering discipline and shall have received specific training in the response and analysis of the unit for transients and accidents, and in unit design and layout, including the capabilities of instrumentation and controls in the control room.

6.3 UNIT STAFF QUALIFICATIONS

6.3.1 Each member of the unit staff shall meet or exceed the minimum qualifications of ANSI/ANS 3.1-1981 for comparable positions, except for the Radiation Protection Manager who shall meet or exceed the qualifications of Regulatory Guide 1.8, September 1975. The licensed Reactor Operators and Senior Reactor Operators shall also meet or exceed the minimum qualifications of the supplemental requirements specified in Sections A and C of Enclosure 1 of the March 28, 1980 NRC letter to all licensees.

6.4 TRAINING

6.4.1 A retraining and replacement training program for the unit staff shall be maintained under the direction of the Manager-Nuclear Training, shall meet or exceed the requirements and recommendations of Section 5.5 of ANSI/ANS 3.1-1981 and Appendix A of 10 CFR Part 55 and the supplemental requirements specified in Sections A and C of Enclosure 1 of the March 28, 1980 NRC letter to all licensees, and shall include familiarization with relevant industry operational experience.

6.4.2 A training program for the Fire Brigade shall be maintained under the direction of the Manager - Site Protection and shall meet or exceed the requirements of the SRP (NUREG-0800) Section 13.2.2.II.6, 10 CFR 50 Appendix R and Branch Technical Position CMEB 9.5.1, Section C.3.d.

6.5 REVIEW AND AUDIT

6.5.1 STATION OPERATIONS REVIEW COMMITTEE (SORC)

FUNCTION

6.5.1.1 The SORC shall function to advise the General Manager - Hope Creek Operations on all matters related to nuclear safety.

AUTHORITY

6.5.1.8 The SORC shall:

a. Recommend in writing to the General Manager - Hope Creek Operations approval or disapproval of items considered under Specification 6.5.1.6.a. through e. prior to their implementation.

b. Provide written notification within 24 hours to the Vice President - Nuclear and to the General Manager - Nuclear Safety Review of disagreement between the SORC and the General Manager - Hope Creek Operations; however, the General Manager - Hope Creek Operations shall have responsibility for resolution of such disagreements pursuant to Specification 6.1.1.

RECORDS

6.5.1.9 The SORC shall maintain minutes of each SORC meeting, and copies shall be provided to the Vice President - Nuclear, General Manager - Nuclear Safety Review and Manager - Offsite Safety Review.

6.5.2 NUCLEAR SAFETY REVIEW

FUNCTION

6.5.2.1 The Nuclear Safety Review Department (NSR) shall function to provide the independent safety review program and audit of designated activities.

COMPOSITION

6.5.2.2 NSR shall consist of the General Manager - Nuclear Safety Review, the Manager - Offsite Safety Review, who is supported by at least four dedicated, full-time engineers, and the Onsite Safety Review Group, which is managed by the Onsite Safety Review Engineer and is supported by at least three dedicated, full-time engineers located onsite.

The Manager - Offsite Safety Review and staff shall meet or exceed the qualifications described in Section 4.7 of ANS 3.1 - 1981 and shall be guided by the provisions for independent review described in Section 4.3 of ANSI N18.7 - 1976 (ANS 3.2).

The Offsite Safety Review staff shall generally possess experience and competence in the areas listed in Section 6.5.2.4.1. A system of qualified reviewers from other technical organizations shall be utilized to augment expertise in the disciplines of Section 6.5.2.4.1, where appropriate. Such qualified reviewers shall meet the same qualification requirements as the Offsite Safety Review staff, and shall not have been involved with performance of the original work.

The Onsite Safety Review Engineer and staff shall meet or exceed the qualifications described in Section 4.4 of ANS 3.1 - 1981.

CONSULTANTS

6.5.2.3 Consultants or other technical experts shall be utilized by NSR to the extent necessary as determined by the General Manager - Nuclear Safety Review.

6.5.2.4 OFFSITE SAFETY REVIEW (OSR)

FUNCTION

6.5.2.4.1 The OSR organization shall function to provide independent review and audit of designated activities in the areas of:

a. Nuclear power plant operations,

b. Nuclear engineering,

c. Chemistry and radiochemistry,

d. Metallurgy,

e. Instrumentation and control,

f. Radiological safety,

g. Mechanical engineering,

h. Electrical engineering

i. Quality assurance

j. Nondestructive testing

k. Emergency preparedness

REVIEW

6.5.2.4.2 The OSR shall review:

a. The safety evaluations for changes to procedures, equipment, or systems; and tests or experiments completed under the provision of 10 CFR 50.59 to verify that such actions did not constitute an unreviewed safety question;

b. Proposed changes to procedures, equipment, or systems and tests or experiments which involve an unreviewed safety question as defined in 10 CFR 50.59;

c. Proposed changes to Technical Specifications or this Operating License;

d. Violations of codes, [illegible]ations, orders, Technical Specifications, license requirements, or of internal procedures or instructions having nuclear safety significance;

e. Significant operating abnormalities or deviations from normal and expected performance of facility equipment that affect nuclear safety;

f. All REPORTABLE EVENTS.

g. All recognized indications of an unanticipated deficiency in some aspect of design or operation of structures, systems, or components that could affect nuclear safety; and

h. Reports and meeting minutes of the SORC.

AUDITS

6.5.2.4.3 Audits of facility activities shall be performed under the cognizance of the OSR. These audits shall encompass:

a. The conformance of facility operation to provisions contained within the Technical Specifications and applicable license conditions at least once per 12 months;

b. The performance, training and qualifications of the entire facility staff at least once per 12 months;

c. The results of actions taken to correct deficiencies occurring in facility equipment, structures, systems, or method of operation that affect nuclear safety, at least once per 6 months;

d. The performance of activities required by the Operational Quality Assurance Program to meet the criteria of Appendix B, 10 CFR Part 50, at least once per 24 months;

e. The Facility Emergency Plan and implementing procedures at least once per 12 months;

f. The Facility Security Plan and implementing procedures at least once per 12 months;

g. Any other area of facility operation considered appropriate by the General Manager - Nuclear Safety Review or the Vice President - Nuclear;

h. The facility Fire Protection Program and the implementing procedures at least once per 24 months;

i. The fire protection and loss prevention program implementation at least once per 12 months utilizing either a qualified off-site licensee fire protection engineer(s) or an outside independent fire protection consultant. An outside independent fire protection consultant shall be utilized at least once per 36 months; and

j. The radiological environmental monitoring program and the results thereof at least once per 12 months.

k. The OFFSITE DOSE CALCULATION MANUAL and implementing procedures at least once per 24 months;

l. The PROCESS CONTROL PROGRAM and implementing procedures for processing and packaging of radioactive wastes at least once per 24 months; and,

m. The performance of activities required by the Quality Assurance Program for effluent and environmental monitoring at least once per 12 months.

The above audits shall be conducted by the Nuclear Quality Assurance Department or an independent consultant. Audit plans and final audit reports shall be reviewed by the OSR prior to issuance.

RECORDS

6.5.2.4.4 Records of OSR activities shall be maintained. Reports of reviews and audits shall be prepared and distributed as indicated below:

a. The results of reviews performed pursuant to Section 6.5.2.4.2 shall be reported to the Vice President - Nuclear at least monthly.

b. Audit reports prepared pursuant to Specification 6.5.2.4.3 shall be forwarded by the auditing organization to the Vice President - Nuclear and to the management positions responsible for the areas audited (1) within 30 days after completion of the audit for those audits conducted by the Nuclear Quality Assurance Department, and (2) within 60 days after completion of the audit for those audits conducted by an independent consultant.

6.5.2.5 ONSITE SAFETY REVIEW GROUP (SRG)

6.5.2.5.1 The SRG shall function to provide: the review of plant design and operating experience for potential opportunities to improve plant safety; evaluation of plant operations and maintenance activities; and advice to management on the overall quality and safety of plant operations.

The SRG shall make recommendations for revised procedures, equipment modifications, or other means of improving plant safety to appropriate station/corporate management.

RESPONSIBILITIES

6.5.2.5.2 The SRG shall be responsible for:

a. Review of selected plant operating characteristics, NRC issuances, industry advisories, and other appropriate sources of plant design and operating experience information which may indicate areas for improving plant safety.

b. Review of selected facility features, equipment, and systems.

c. Review of selected procedures and plant activities including maintenance, modification, operational problems, and operational analysis.

d. Surveillance of selected plant operations and maintenance activities to provide independent verification* that they are performed correctly and that human errors are reduced to as low as reasonably achievable.

AUTHORITY

6.5.2.6 NSR shall report to and advise the Vice President - Nuclear on those areas of responsibility specified in Sections 6.5.2.4 and 6.5.2.5.

6.5.3 TECHNICAL REVIEW AND CONTROL

ACTIVITIES

6.5.3.1 All programs and procedures required by Technical Specification 6.8 and changes thereto, and any other proposed procedures or changes thereto, which affect plant nuclear safety as determined by the General Manager - Hope Creek Operations, other than editorial or typographical changes, shall be reviewed as follows:

PROCEDURE RELATED DOCUMENTS

6.5.3.2 Procedures, Programs and changes thereto shall be reviewed as follows:

a. Each newly created procedure, program or change thereto shall be independently reviewed by an individual knowledgeable in the area affected other than the individual who prepared the procedure, program or procedure change, but who may be from the same organization as the individual/group which prepared the procedure or procedure change. Procedures other than Station Administrative procedures will be approved by the appropriate station Department Manager or by the Assistant General Manager - Hope Creek Operations. Each station Department Manager shall be responsible for a pre-designated class of procedures. The General Manager - Hope Creek Operations shall approve Station Administrative Procedures, Security Plan implementing procedures and Emergency Plan implementing procedures.

b. On-the-spot changes to procedures which clearly do not change the intent of the approved procedures shall be approved by two members of the plant management staff, at least one of whom holds a Senior Reactor Operator's License. Revisions to procedures which may involve a change in intent of the approved procedures, shall be reviewed in accordance with Section 6.5.3.2.a above.

c. Individuals responsible for reviews performed in accordance with item 6.5.3.2.a above shall be approved by the SORC Chairman and designated as a Station Qualified Reviewer. A system of Station Qualified Reviewers shall be maintained by the SORC Chairman. Each review shall include a written determination of whether or not additional

*Not responsible for sign-off function.

cross-disciplinary review is necessary. If deemed necessary, such review shall be performed by the appropriate designated review personnel. The Station Qualified Reviewers shall meet or exceed the qualifications described in Section 4.4 of ANS 3.1, 1981.

d. If the Department Manager determines that the documents involved contain significant safety issues, the documents shall be forwarded for SORC review and also to NSR for an independent review to determine whether or not an unreviewed safety question is involved. Pursuant to 10 CFR 50.59, NRC approval of items involving unreviewed safety questions or requiring Technical Specification changes shall be obtained prior to implementation.

NON-PROCEDURE RELATED DOCUMENTS

6.5.3.3 Tests or experiments, and changes to equipment or systems shall be forwarded for SORC review and also to NSR for an independent review to determine whether or not an unreviewed safety question is involved. The results of NSR reviews will be provided to SORC. Recommendations for approval are made by SORC to the General Manager - Hope Creek Operations. Pursuant to 10 CFR 50.59, NRC approval of items involving unreviewed safety questions or requiring Technical Specification changes shall be obtained prior to implementation.

RECORDS

6.5.3.4 Written records of reviews performed in accordance with item 6.5.3.2a above, including recommendations for approval or disapproval, shall be maintained. Copies shall be provided to the General Manager - Hope Creek Operations, SORC, NSR, and/or NRC as necessary when their reviews are required.

6.6 REPORTABLE EVENT ACTION

6.6.1 The following actions shall be taken for REPORTABLE EVENTS:

a. The Commission shall be notified pursuant to the requirements of Section 50.72 to 10 CFR Part 50 and a report submittal pursuant to the requirements of Section 50.73 to 10 CFR Part 50, and

b. Each REPORTABLE EVENT shall be reviewed by the SORC, and the results of this review shall be submitted to the NSR and the Vice President - Nuclear.

6.7 SAFETY LIMIT VIOLATION

6.7.1 The following actions shall be taken in the event a Safety Limit is violated:

a. The NRC Operations Center shall be notified by telephone as soon as possible and in all cases within 1 hour. The Vice President - Nuclear and the General Manager - NSR shall be notified within 24 hours.

ANNUAL RADIOLOGICAL ENVIRONMENTAL OPERATING REPORT (Continued)

after the radioiodine activity was reduced to less than limit. Each result should include date and time of sampling and the radioiodine concentrations; (3) Clean-up system flow history starting 48 hours prior to the first sample in which the limit was exceeded; (4) Graph of the I-131 concentration and one other radioiodine isotope concentration in microcuries per gram as a function of time for the duration of the specific activity above the steady-state level; and (5) The time duration when the specific activity of the primary coolant exceeded the radioiodine limit.

SEMIANNUAL RADIOACTIVE EFFLUENT RELEASE REPORT

6.9.1.7 Routine radioactive release reports covering the operation of the unit during the previous 6 months of operation shall be submitted within 60 days after January 1 and July 1 of each year. The period of the first report shall begin with the date of initial criticality.

The radioactive effluent release reports shall include a summary of the quantities of radioactive liquid and gaseous effluents and solid waste released from the unit as outlined in Regulatory Guide 1.21, "Measuring, Evaluating, and Reporting Radioactivity in Solid Wastes and Releases of Radioactive Materials in Liquid and Gaseous Effluents from Light-Water-Cooled Nuclear Power Plants," Revision 1, June 1974, with data summarized on a quarterly basis following the format of Appendix B thereof.

The radioactive effluent release report to be submitted within 60 days after January 1 of each year shall include an annual summary of hourly meteorological data collected over the previous year. This annual summary may be either in the form of an hour-by-hour listing of wind speed, wind direction, and atmospheric stability, and precipitation (if measured) on magnetic tape, or in the form of joint frequency distributions of wind speed, wind direction, and atmospheric stability. This same report shall include an assessment of the radiation doses due to the radioactive liquid and gaseous effluents released from the unit or station during the previous calendar year. This same report shall also include an assessment of the radiation doses from radioactive liquid and gaseous effluents to MEMBERS OF THE PUBLIC due to their activities inside the SITE BOUNDARY (Figure 5.1.1-1) during the report period. All assumptions used in making these assessments, i.e., specific activity, exposure time and location, shall be included in these reports. The historical annual average meteorology or the meteorological conditions concurrent with the time of release of radioactive materials in gaseous effluents (as determined by sampling frequency and measurement) shall be used for determining the gaseous pathway doses. The assessment of radiation doses shall be performed in accordance with the OFFSITE DOSE CALCULATION MANUAL (ODCM). The Semiannual Radioactive Effluent Release Report shall identify those radiological environmental sample parameters and locations where it is not possible or practicable to continue to obtain samples of the media of choice at the most desired location or time. In addition, the cause of the unavailability of samples for the pathway and the new location(s) for obtaining replacement samples should be identified. The report should also include a revised figure(s) and table(s) for the ODCM reflecting the new location(s).

SEMIANUAL RADIOACTIVE EFFLUENT RELEASE REPORT (Continued)

The radioactive effluent release report to be submitted within 60 days after January 1, of each year shall also include an assessment of radiation doses to the likely most exposed MEMBER OF THE PUBLIC from reactor releases and other nearby uranium fuel cycle sources (including doses from primary effluent pathways and direct radiation) for the previous 12 consecutive months to show conformance with 40 CFR 190, Environmental Radiation Protection Standards for Nuclear Power Operation. Acceptable methods for calculating the dose contribution from liquid and gaseous effluents are given in Regulatory Guide 1.109, Rev. 1.

The radioactive effluents release shall include the following information for each class of solid waste (as defined by 10 CFR 61) shipped offsite during the report period:

a. Container volume,

b. Total curie quantity (specify whether determined by measurement or estimate),

c. Principal radionuclide (specify whether determined by measurement or estimate),

d. Type of waste (e.g., spent resin, compact dry waste, evaporator bottoms),

e. Type of container (e.g., LSA, Type A, Type B, Large Quantity), and

f. Solidification agent (e.g., cement, urea formaldehyde).

The radioactive effluent release reports shall include unplanned releases from the site to the UNRESTRICTED AREA of radioactive materials in gaseous and liquid effluents on a quarterly basis.

The radioactive effluent release reports shall include any changes to the PROCESS CONTROL PROGRAM (PCP), OFFSITE DOSE CALCULATION MANUAL (ODCM) or radioactive waste systems made during the reporting period.

MONTHLY OPERATING REPORTS

6.9.1.8 Routine reports of operating statistics and shutdown experience shall be submitted on a monthly basis to the Director, Office of Management and Program Analysis, U.S. Nuclear Regulatory Commission, Washington, D.C. 20555, with a copy to the Regional Administrator of the Regional Office no later than the 15th of each month following the calendar month covered by the report.

SPECIAL REPORTS

6.9.2 Special reports shall be submitted to the Regional Administrator of the Regional Office of the NRC within the time period specified for each report.

6.10 RECORD RETENTION

6.10.1 In addition to the applicable record retention requirements of Title 10, Code of Federal Regulations, the following records shall be retained for at least the minimum period indicated.

SPECIAL REPORTS

6.10.2 The following records shall be retained for at least 5 years:

a. Records and logs of unit operation covering time interval at each power level.

b. Records and logs of principal maintenance activities, inspections, repair, and replacement of principal items of equipment related to nuclear safety.

c. All REPORTABLE EVENTS submitted to the Commission.

d. Records of surveillance activities, inspections, and calibrations required by these Technical Specifications.

e. Records of changes made to the procedures required by Specification 6.8.1.

f. Records of radioactive shipments.

g. Records of sealed source and fission detector leak tests and results.

h. Records of annual physical inventory of all sealed source material of record.

6.10.3 The following records shall be retained for the duration of the unit Operating License:

a. Records and drawing changes reflecting unit design modifications made to systems and equipment described in the Final Safety Analysis Report.

b. Records of new and irradiated fuel inventory, fuel transfers, and assembly burnup histories.

c. Records of radiation exposure for all individuals entering radiation control areas.

d. Records of gaseous and liquid radioactive material released to the environs.

e. Records of transient or operational cycles for those unit components identified in Table 5.7.1-1.

a. A radiation monitoring device which continuously indicates the radiation dose rate in the area.

b. A radiation monitoring device which continuously integrates the radiation dose rate in the area and alarms when a preset integrated dose is received. Entry into such areas with this monitoring device may be made after the dose rate levels in the area have been established and personnel have been made knowledgeable of them.

c. A radiation protection qualified individual (i.e., qualified in radiation protection procedures) with a radiation dose rate monitoring device who is responsible for providing positive control over the activities within the area and shall perform periodic radiation surveillance at the frequency specified by the Radiation Protection Supervisor in the RWP.

6.12.2 In addition to the requirements of Specification 6.12.1, areas accessible to personnel with radiation levels such that a major portion of the body could receive in 1 hour a dose greater than 1000 mrem* shall be provided with locked doors to prevent unauthorized entry, and the keys shall be maintained under the administrative control of the Senior Nuclear Shift Supervisor on duty and/or the radiation protection supervision. Doors shall remain locked except during periods of access by personnel under an approved RWP which shall specify the dose rate levels in the immediate work area and the maximum allowable stay time for individuals in that area. For individual areas accessible to personnel with radiation levels such that a major portion of the body could receive in 1 hour a dose in excess of 1000 mrem* that are located within large areas, such as the containment, where no enclosure exists for purposes of locking, and no enclosure can be reasonably constructed around the individual areas, then that area shall be roped off, conspicuously posted, and a flashing light shall be activated as a warning device. In lieu of the stay time specification of the RWP, continuous surveillance direct or remote (such as use of closed circuit TV cameras), may be made by personnel qualified in radiation protection procedures to provide positive exposure control over the activities within the area.

6.13 PROCESS CONTROL PROGRAM (PCP)

6.13.1 The PCP shall be approved by the Commission prior to implementation.

6.13.2 Licensee initiated changes to the PCP:

1. Shall be submitted to the Commission in the Semiannual Radioactive Effluent Release Report for the period in which the change(s) was made. This submittal shall contain:

   a. Sufficiently detailed information to totally support the rationale for the change without benefit of additional or supplemental information;

*Measurement made at 18 inches from source of radioactivity.

PROCESS CONTROL PROGRAM (PCP) (Continued)

a. Sufficiently detailed information to totally support the rationale for the change without benefit of additional or supplemental information;

b. A determination that the change did not reduce the overall conformance of the solidified waste product to existing criteria for solid wastes; and

c. Documentation of the fact that the change has been reviewed and found acceptable by the SORC.

2. Shall become effective upon review and acceptance by the SORC.

6.14 OFFSITE DOSE CALCULATION MANUAL (ODCM)

6.14.1 The ODCM shall be approved by the Commission prior to implementation.

6.14.2 Licensee initiated changes to the ODCM:

1. Shall be submitted to the Commission in the Semiannual Radioactive Effluent Release Report for the period in which the change(s) was made. This submittal shall contain:

a. Sufficiently detailed information to totally support the rationale for the change without benefit of additional or supplemental information. Information submitted should consist of a package of those pages of the ODCM to be changed with each page numbered and provided with an approval and date box, together with appropriate analyses or evaluations justifying the change(s);

b. A determination that the change will not reduce the accuracy or reliability of dose calculations or setpoint determination; and

c. Documentation of the fact that the change has been reviewed and found acceptable by the SORC.

2. Shall become effective upon review and acceptance by the SORC.

6.15 MAJOR CHANGES TO RADIOACTIVE LIQUID, GASEOUS AND SOLID WASTE TREATMENT SYSTEMS

6.15.1 Licensee initiated major changes to the radioactive waste system (liquid, gaseous and solid):

1. Shall be reported to the Commission in the FSAR for the period in which the evaluation was reviewed by SORC. The discussion of each changes shall contain:

MAJOR CHANGES TO RADIOACTIVE LIQUID, GASEOUS AND SOLID WASTE TREATMENT SYSTEMS (Continued)

a. A summary of the evaluation that led to the determination that the change could be made in accordance with 10 CFR Part 50.59;

b. Sufficient detailed information to totally support the reason for the change without benefit of additional or supplemental information;

c. A detailed description of the equipment, components and processes involved and the interfaces with other plant systems;

d. An evaluation of the change, which shows the predicted releases of radioactive materials in liquid and gaseous effluents and/or quantity of solid waste that differ from those previously predicted in the license application and amendments thereto;

e. An evaluation of the change, which shows the expected maximum exposures to individual in the unrestricted area and to the general population that differ from those previously estimated in the license application and amendments thereto;

f. A comparison of the predicted releases of radioactive materials, in liquid and gaseous effluents and in solid waste, to the actual releases for the period prior to when the changes are to be made;

g. An estimate of the exposure to plant operating personnel as a result of the change; and

h. Documentation of the fact that the change was reviewed and found acceptable by the SORC.

2. Shall become effective upon review and acceptance by the SORC.