UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D. C. 20555

October 17, 1986

Docket No.: 50-416

Mr. Oliver D. Kingsley, Jr.
Vice President, Nuclear Operations
Mississippi Power & Light Company
Post Office Box 23054
Jackson, Mississippi 39205

Dear Mr. Kingsley:

SUBJECT: CHANGES TO TECHNICAL SPECIFICATIONS AND OPERATING LICENSE CONDITION

RE: GRAND GULF NUCLEAR STATION, UNIT 1

The Commission has issued the enclosed Amendment No. 21 to Facility Operating License No. NPF-29 for the Grand Gulf Nuclear Station, Unit 1. This amendment consists of changes to the Technical Specifications (TSs) and the license condition in response to: your application dated January 29, 1986 as amended April 14, July 16 and August 26, 1986; your application dated June 13, 1986 as amended August 26, 1986; and, your application dated July 25, 1986 as amended August 11, 1986.

This amendment changes Technical Specifications (TSs) pursuant to the licensee's January 29 and June 13, 1986 applications and changes License Condition 2.C.(33)(b) pursuant to the licensee's July 25, 1986 application. With respect to the January 29, 1986 application, as amended, six changes are made in the Technical Specifications: (1) the names and designation of certain plant service water valves are changed to reflect the incorporation of these valves into the dry-well chilled water system; (2) records retention specifications in Section 6.0, "Administrative Controls" are clarified; (3) TSs pertaining to the drywell post-accident vacuum relief capability are changed to reflect the installation of position indicators on the vacuum breakers, and certain portions of the specifications are clarified; (4) an error in referencing a reporting requirement for the radiological environmental monitoring TSs is corrected; (5) TSs pertaining to the control rod scram discharge volume are changed to reflect the installation of redundant level instrumentation, a redundant vent valve and a redundant drain valve; and (6) temporary TS notes that allow inoperability of certain actuation signals for the high pressure core spray system for applicable reactor operating conditions are made permanent. With respect to the June 13, 1986 application, as amended, TSs pertaining to the automatic depressurization system accumulators are added to reflect the installation of pressure instrumentation. With respect to the July 25, 1986 application, as amended, License Condition 2.C.(33)(b) pertaining to TMI Action Plan Item I.G.1, "Special Low-Power Testing and Training" is changed to make it consistent with present staff requirements. Changes in the TSs on Pages 3/4 6-31, 3/4 6-39, 3/4 6-42, 3/4 6-44, 3/4 12-1 and 6-20 and the revised License Condition 2.C.(33)(b) are effective upon issuance of this amendment. The remainder of the changes in the TSs are effective when the equipment necessitating the changes on the affected TS pages is installed and operable but not later than startup following the first refueling outage. For those changes to the Technical Specifications that are not effective upon issuance, you are requested to inform the NRC by letter of their effective dates within seven days of the date the equipment is made operable.

A copy of our Safety Evaluation is also enclosed. Notice of Issuance will be included in the Commission's biweekly Federal Register notice.

Sincerely,

/s/

Lester L. Kintner, Project Manager
BWR Project Directorate No. 4
Division of BWR Licensing

Enclosures:
1. Amendment No. 21 to
   License No. NPF-29
2. Safety Evaluation

cc w/enclosures:
See next page

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requirements. Changes in the TSs on Pages 3/4 6-31, 3/4 6-39, 3/4 6-42, 3/4 6-44, 3/4 12-1 and 6-20 and the revised License Condition 2.C.(33)(b) are effective upon issuance of this amendment. The remainder of the changes in the TSs are effective when the equipment necessitating the changes on the affected TS pages is installed and operable but not later than startup following the first refueling outage. For those changes to the Technical Specifications that are not effective upon issuance, you are requested to inform the NRC by letter of their effective dates within seven days of the date the equipment is made operable.

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L L Kintner

Lester L. Kintner, Project Manager
BWR Project Directorate No. 4
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See next page

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UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D. C. 20555

MISSISSIPPI POWER & LIGHT COMPANY
MIDDLE SOUTH ENERGY, INC.
SOUTH MISSISSIPPI ELECTRIC POWER ASSOCIATION
DOCKET NO. 50-416
GRAND GULF NUCLEAR STATION, UNIT 1
AMENDMENT TO FACILITY OPERATING LICENSE

Amendment No. 21
License No. NPF-29

1. The Nuclear Regulatory Commission (the Commission) has found that

   A. The application for amendment by Mississippi Power & Light Company, Middle South Energy, Inc., and South Mississippi Electric Power Association, (the licensees) dated January 29, 1986 (as amended April 14, July 16 and August 26, 1986), June 13, 1986 (as amended August 26, 1986), and July 25, 1986 (as amended August 11, 1986), complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act), and the Commission's rules and regulations set forth in 10 CFR Chapter I;

   B. The facility will operate in conformity with the application, the provisions of the Act, and the rules and regulations of the Commission;

   C. There is reasonable assurance (i) that the activities authorized by this amendment can be conducted without endangering the health and safety of the public, and (ii) that such activities will be conducted in compliance with the Commission's regulations;

   D. The issuance of this amendment will not be inimical to the common defense and security or to the health and safety of the public; and

   E. The issuance of this amendment is in accordance with 10 CFR Part 51 of the Commission's regulations and all applicable requirements have been satisfied.

2. Accordingly, Facility Operating License NPF-29 is amended as follows:

   A. Change paragraph 2.C.(33)(b) to read as follows:

      (b) Training During Low Power Testing (I.G.1, SER)
      Prior to restart following the first refueling outage, MP&L shall complete the additional training and testing related to TMI Action Plan I.G.1 as described in Section 2.3 of the MP&L submittal dated April 3, 1986.

3. The license is further amended by changes to the Technical Specifications as indicated in the attachment to this license amendment, and paragraph 2.C.(2) of Facility Operating License No. NPF-29 is hereby amended to read as follows:

Technical Specifications

The Technical Specifications contained in Appendix A and the Environmental Protection Plan contained in Appendix B, as revised through Amendment No. 21 , are hereby incorporated into this license. Mississippi Power & Light Company shall operate the facility in accordance with the Technical Specifications and the Environmental Protection Plan.

4. The changes to the Technical Specifications on Pages 3/4 6-31, 3/4 6-39, 3/4 6-42, 3/4 6-44, 3/4 12-1 and 6-20 and amended License Condition 2.C.(33)(b) are effective upon issuance of this amendment and the remainder of the changes to the Technical Specifications are effective when equipment necessitating the changes is installed and made operable but not later than startup following the first refueling outage.

FOR THE NUCLEAR REGULATORY COMMISSION

/s/

Walter R. Butler, Director
BWR Project Directorate No. 4
Division of BWR Licensing

Attachment:
Changes to the Technical
Specifications

Date of Issuance: October 17, 1986

wrote revisions to SE
check state & SECY
before issuance

PD#4/LA	PD#4/PM	OGC	PD#4/D
MO'Brien	LKintner:lb	MYoung	WButler
10/ /86	10/ 7/86	10/10/86	10/ 7/86

Technical Specifications

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4. The changes to the Technical Specifications on Pages 3/4 6-31, 3/4 6-39, 3/4 6-42, 3/4 6-44, 3/4 12-1 and 6-20 and amended License Condition 2.C.(33)(b) are effective upon issuance of this amendment and the remainder of the changes to the Technical Specifications are effective when equipment necessitating the changes is installed and made operable but not later than startup following the first refueling outage.

FOR THE NUCLEAR REGULATORY COMMISSION

Walter R. Butler

Walter R. Butler, Director
BWR Project Directorate No. 4
Division of BWR Licensing

Attachment:
Changes to the Technical
Specifications

Date of Issuance: October 17, 1986

ATTACHMENT TO LICENSE AMENDMENT NO. 21

FACILITY OPERATING LICENSE NO. NPF-29

DOCKET NO. 50-416

Replace the following pages of the Appendix "A" Technical Specifications with the attached pages. The revised pages are identified by Amendment number and contain vertical lines indicating the area of change. Asterisk pages provided to maintain document completeness.*

Remove	Insert
vii	vii*
viii	viii
xiii	xiii*
xiv	xiv
2-3	2-3*
2-4	2-4
2-4a	2-4a
3/4 1-3	3/4 1-3*
3/4 1-4	3/4 1-4
-	3/4 1-4a
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3/4 1-6	3/4 1-6*
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3/4 3-7	3/4 3-7*
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3/4 6-33	3/4 6-33*
3/4 6-34	3/4 6-34
3/4 6-39	3/4 6-39
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2.2 LIMITING SAFETY SYSTEM SETTINGS

REACTOR PROTECTION SYSTEM INSTRUMENTATION SETPOINTS

2.2.1 The reactor protection system instrumentation setpoints shall be set consistent with the Trip Setpoint values shown in Table 2.2.1-1.

APPLICABILITY: As shown in Table 3.3.1-1.

ACTION:

With a reactor protection system instrumentation setpoint less conservative than the value shown in the Allowable Values column of Table 2.2.1-1, declare the channel inoperable and apply the applicable ACTION statement requirement of Specification 3.3.1 until the channel is restored to OPERABLE status with its setpoint adjusted consistent with the Trip Setpoint value.

TABLE 2.2.1-1

REACTOR PROTECTION SYSTEM INSTRUMENTATION SETPOINTS

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUES
1. Intermediate Range Monitor, Neutron Flux-High	≤ 120/125 divisions of full scale	≤ 122/125 divisions of full scale
2. Average Power Range Monitor:		
a. Neutron Flux-High, Setdown	≤ 15% of RATED THERMAL POWER	≤ 20% of RATED THERMAL POWER
b. Flow Biased Simulated Thermal Power-High		
1) During two recirculation loop operation:		
a) Flow Biased	≤ 0.66 W+64%, with a maximum of	≤ 0.66 W+67%, with a maximum of
b) High Flow Clamped	≤ 111.0% of RATED THERMAL POWER	≤ 113.0% of RATED THERMAL POWER
2) During single recirculation loop operation:		
a) Flow Biased	≤ 0.66 W+40%	≤ 0.66 W+43%
b) High Flow Clamped	Not Required OPERABLE	Not Required OPERABLE
c. Neutron Flux-High	≤ 118% of RATED THERMAL POWER	≤ 120% of RATED THERMAL POWER
d. Inoperative	NA	NA
3. Reactor Vessel Steam Dome Pressure - High	≤ 1064.7 psig	≤ 1079.7 psig
4. Reactor Vessel Water Level - Low, Level 3	≥ 11.4 inches above instrument zero*	≥ 10.8 inches above instrument zero*
5. Reactor Vessel Water Level-High, Level 8	≤ 53.5 inches above instrument zero*	≤ 54.1 inches above instrument zero*

TABLE 2.2.1-1 (Continued)

REACTOR PROTECTION SYSTEM INSTRUMENTATION SETPOINTS

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUES
6. Main Steam Line Isolation Valve - Closure	≤ 6% closed	≤ 7% closed
7. Main Steam Line Radiation - High	≤ 3.0 x full power background	≤ 3.6 x full power background
8. Drywell Pressure - High	≤ 1.23 psig	≤ 1.43 psig
9. Scram Discharge Volume Water Level - High		
a. Transmitter/Trip Unit	≤ 60% of full scale	≤ 63% of full scale
b. Float Switch	≤ 64"	≤ 65"
10. Turbine Stop Valve - Closure	≥ 40 psig**	≥ 37 psig
11. Turbine Control Valve Fast Closure, Trip Oil Pressure - Low	≥ 44.3 psig**	≥ 42 psig
12. Reactor Mode Switch Shutdown Position	NA	NA
13. Manual Scram	NA	NA

*See Bases Figure B 3/4 3-1.
**Initial setpoint. Final setpoint to be determined during startup test program. Any required change to this setpoint shall be submitted to the Commission within 90 days of test completion.

3/4.1.3 CONTROL RODS

CONTROL ROD OPERABILITY

LIMITING CONDITION FOR OPERATION

3.1.3.1 All control rods shall be OPERABLE.

APPLICABILITY: OPERATIONAL CONDITIONS 1 and 2.

ACTION:

a. With one control rod inoperable due to being immovable, as a result of excessive friction or mechanical interference, or known to be untrippable:
   1. Within one hour:
      a) Verify that the inoperable control rod, if withdrawn, is separated from all other inoperable control rods by at least two control cells in all directions.
      b) Disarm the associated directional control valves** either:
         1) Electrically, or
         2) Hydraulically by closing the drive water and exhaust water isolation valves.

      Otherwise, be in at least HOT SHUTDOWN within the next 12 hours.
   2. Comply with Surveillance Requirement 4.1.1.c within 12 hours.
   3. Comply with Surveillance Requirement 4.1.3.1.2.b.
   4. Restore the inoperable control rod to OPERABLE status within 48 hours or be in at least HOT SHUTDOWN within the next 12 hours.

b. With one or more control rods trippable but inoperable for causes other than addressed in ACTION a, above:
   1. If the inoperable control rod(s) is withdrawn, within one hour verify:
      a) That the inoperable withdrawn control rod(s) is separated from all other inoperable withdrawn control rods by at least two control cells in all directions, and
      b) The insertion capability of the inoperable withdrawn control rod(s) by inserting the control rod(s) at least one notch by drive water pressure within the normal operating range*.

      Otherwise, insert the inoperable withdrawn control rod(s) and disarm the associated directional control valves** either:
      a) Electrically, or
      b) Hydraulically by closing the drive water and exhaust water isolation valves.

---

*The inoperable control rod may then be withdrawn to a position no further withdrawn than its position when found to be inoperable.

**May be rearmed intermittently under administrative control to permit testing associated with restoring the control rod to OPERABLE status.

LIMITING CONDITION FOR OPERATION (Continued)

ACTION (Continued)

2. If the inoperable control rod(s) is inserted, within one hour disarm the associated directional control valves** either:

   a) Electrically, or

   b) Hydraulically by closing the drive water and exhaust water isolation valves.

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

3. The provisions of Specification 3.0.4 are not applicable.

c. With more than 8 control rods inoperable, be in at least HOT SHUTDOWN within 12 hours.

d. With one scram discharge volume vent valve and/or one scram discharge volume drain valve inoperable and open, restore the inoperable valve(s) to OPERABLE status within 24 hours or be in at least HOT SHUTDOWN within the next 12 hours.

e. With two scram discharge volume vent valves and/or two scram discharge volume drain valves inoperable and open, restore one valve in the vent line and one valve in the drain line to OPERABLE status within 8 hours and restore all valves to OPERABLE status within the next 16 hours or close at least one vent valve and one drain valve and be in a least HOT SHUTDOWN within the next 12 hours.

f. With any scram discharge volume vent valve(s) and/or any scram discharge volume drain valve(s) inoperable and closed except when required by ACTION statement e. above, restore all valves to OPERABLE status within 8 hours or be in at least HOT SHUTDOWN within the next 12 hours.

SURVEILLANCE REQUIREMENTS

4.1.3.1.1 The scram discharge volume drain and vent valves shall be demonstrated OPERABLE by:

a. At least once per 31 days verifying each valve to be open,* and

b. At least once per 92 days cycling each valve through at least one complete cycle of full travel.

---

*These valves may be closed intermittently for testing under administrative controls.

**May be rearmed intermittently, under administrative control, to permit testing associated with restoring the control rod to OPERABLE status.

LIMITING CONDITION FOR OPERATION (Continued)

4.1.3.1.2 When above the low power setpoint of the RPCS, all withdrawn control rods not required to have their directional control valves disarmed electrically or hydraulically shall be demonstrated OPERABLE by moving each control rod at least one notch:

a. At least once per 7 days, and

b. At least once per 24 hours when any control rod is immovable as a result of excessive friction or mechanical interference.

4.1.3.1.3 All control rods shall be demonstrated OPERABLE by performance of Surveillance Requirements 4.1.3.2, 4.1.3.3, 4.1.3.4 and 4.1.3.5.

SURVEILLANCE REQUIREMENTS (Continued)

4.1.3.1.4 The scram discharge volume shall be determined OPERABLE by demonstrating:

a.* The scram discharge volume drain and vent valves OPERABLE, when control rods are scram tested from a normal control rod configuration of less than or equal to 50% ROD DENSITY at least once per 18 months, by verifying that the drain and vent valves:

1. Close within 30 seconds after receipt of a signal for control rods to scram, and

2. Open when the scram signal is reset.

b. Proper level sensor response by performance of a CHANNEL FUNCTIONAL TEST of the scram discharge volume scram and control rod block level instrumentation at least once per 31 days.

*The provisions of Specification 4.0.4 are not applicable provided this surveillance is performed at least once per 18 months.

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, based on de-energization of the scram pilot valve solenoids as time zero, shall not exceed the following limits:

Reactor Vessel Dome Pressure (psig)*	Maximum Insertion Times to Notch Position (Seconds) 43	29	13
950	0.31	0.81	1.44
1050	0.32	0.86	1.57

APPLICABILITY: OPERATIONAL CONDITIONS 1 and 2.

ACTION:

a. With the maximum scram insertion time of one or more control rods exceeding the maximum scram insertion time limits of Specification 3.1.3.2 as determined by Surveillance Requirement 4.1.3.2.a or b, operation may continue provided that:

1. For all "slow" control rods, i.e., those which exceed the limits of Specification 3.1.3.2, the individual scram insertion times do not exceed the following limits:

Reactor Vessel Dome Pressure (psig)*	Maximum Insertion Times to Notch Position (Seconds) 43	29	13
950	0.38	1.09	2.09
1050	0.39	1.14	2.22

2. For "fast" control rods, i.e., those which satisfy the limits of Specification 3.1.3.2, the average scram insertion times do not exceed the following limits:

Reactor Vessel Dome Pressure (psig)*	Maximum Average Insertion Times to Notch Position (Seconds) 43	29	13
950	0.30	0.78	1.40
1050	0.31	0.84	1.53

3. The sum of "fast" control rods with individual scram insertion times in excess of the limits of ACTION a.2 and of "slow" control rods does not exceed 7.

4. No "slow" control rod, "fast" control rod with individual scram insertion time in excess of the limits of ACTION a.2, or otherwise inoperable control rod occupy adjacent locations in any direction, including the diagonal, to another such control rod.

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

*For intermediate reactor vessel dome pressure, the scram time criteria is determined by linear interpolation at each notch position.

TABLE 3.3.1-1 (Continued)

REACTOR PROTECTION SYSTEM INSTRUMENTATION

FUNCTIONAL UNIT	APPLICABLE OPERATIONAL CONDITIONS	MINIMUM OPERABLE CHANNELS PER TRIP SYSTEM (a)	ACTION
9. Scram Discharge Volume Water Level - High			
a. Transmitter/Trip Unit	1, 2,	2	1
	$5^{(g)}$	2	3
b. Float Switch	1, 2,	2	1
	$5^{(g)}$	2	3
10. Turbine Stop Valve - Closure	$1^{(h)}$	4	6
11. Turbine Control Valve Fast Closure, Valve Trip System Oil Pressure - Low	$1^{(h)}$	2	6
12. Reactor Mode Switch Shutdown Position	1, 2	2	1
	3, 4	2	7
	5	2	3
13. Manual Scram	1, 2	2	1
	3, 4	2	8
	5	2	9

TABLE 3.3.1-1 (Continued)

REACTOR PROTECTION SYSTEM INSTRUMENTATION

ACTION

ACTION 1 - Be in at least HOT SHUTDOWN within 12 hours.

ACTION 2 - Verify all insertable control rods to be inserted in the core and lock the reactor mode switch in the SHUTDOWN position within one hour.

ACTION 3 - Suspend all operations involving CORE ALTERATIONS*, and insert all insertable control rods within one hour.

ACTION 4 - Be in at least STARTUP within 6 hours.

ACTION 5 - Be in STARTUP with the main steam line isolation valves closed within 6 hours or in at least HOT SHUTDOWN within 12 hours.

ACTION 6 - Initiate a reduction in THERMAL POWER within 15 minutes and reduce turbine first stage pressure to less than the automatic bypass setpoint within 2 hours.

ACTION 7 - Verify all insertable control rods to be inserted within one hour.

ACTION 8 - Lock the reactor mode switch in the SHUTDOWN position within one hour.

ACTION 9 - Suspend all operations involving CORE ALTERATIONS*, and insert all insertable control rods and lock the reactor mode switch in the SHUTDOWN position within one hour.

*Except movement of IRM, SRM or special movable detectors, or replacement of LPRM strings provided SRM instrumentation is OPERABLE per Specification 3.9.2.

TABLE 4.3.1.1-1

REACTOR PROTECTION SYSTEM INSTRUMENTATION SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL FUNCTIONAL TEST	CHANNEL CALIBRATION[a]	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRED
1. Intermediate Range Monitors:				
a. Neutron Flux - High	S/U,S,[b] S	S/U, W W	R R	2 3, 4, 5
b. Inoperative	NA	W	NA	2, 3, 4, 5
2. Average Power Range Monitor:[f]				
a. Neutron Flux - High, Setdown	S/U,S,[b] S	S/U, W W	SA SA	2 3, 5
b. Flow Biased Simulated Thermal Power - High	S, D[h]	W	W[d][e], SA, R[i]	1
c. Neutron Flux - High	S	W	W[d], SA	1
d. Inoperative	NA	W	NA	1, 2, 3, 5
3. Reactor Vessel Steam Dome Pressure - High	S	M	R[g]	1, 2[i]
4. Reactor Vessel Water Level - Low, Level 3	S	M	R[g]	1, 2
5. Reactor Vessel Water Level - High, Level 8	S	M	R[g]	1
6. Main Steam Line Isolation Valve - Closure	NA	M	R	1
7. Main Steam Line Radiation - High	S	M	R	1, 2[j]
8. Drywell Pressure - High	S	M	R[g]	1, 2[k]

TABLE 4.3.1.1-1 (Continued)

REACTOR PROTECTION SYSTEM INSTRUMENTATION SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL FUNCTIONAL TEST	CHANNEL CALIBRATION	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRED
9. Scram Discharge Volume Water Level - High				
a. Transmitter/Trip Unit	S	M	R(g)	1, 2, 5(l)
b. Float Switch	NA	M	R	1, 2, 5(l)
10. Turbine Stop Valve - Closure	S	M	R(g)	1
11. Turbine Control Valve Fast Closure Valve Trip System Oil Pressure - Low	S	M	R(g)	1
12. Reactor Mode Switch Shutdown Position	NA	R	NA	1, 2, 3, 4, 5
13. Manual Scram	NA	M	NA	1, 2, 3, 4, 5

(a) Neutron detectors may be excluded from CHANNEL CALIBRATION.
(b) The IRM and SRM channels shall be determined to overlap for at least 1/2 decade during each startup after entering OPERATIONAL CONDITION 2 and the IRM and APRM channels shall be determined to overlap for at least 1/2 decade during each controlled shutdown, if not performed within the previous 7 days.
(c) [DELETED]
(d) This calibration shall consist of the adjustment of the APRM channel to conform to the power values calculated by a heat balance during OPERATIONAL CONDITION 1 when THERMAL POWER ≥ 25% of RATED THERMAL POWER. Adjust the APRM channel if the absolute difference is greater than 2% of RATED THERMAL POWER.
(e) This calibration shall consist of the adjustment of the APRM flow biased channel to conform to a calibrated flow signal.
(f) The LPRMs shall be calibrated at least once per 1000 MWD/T using the TIP system.
(g) Calibrate trip unit at least once per 31 days.
(h) Verify measured drive flow to be less than or equal to established drive flow at the existing flow control valve position.
(i) This calibration shall consist of verifying the 6 ± 1 second simulated thermal power time constant.
(j) Not applicable when the reactor pressure vessel head is unbolted or removed per Specification 3.10.1.
(k) Not applicable when DRYWELL INTEGRITY is not required.
(l) Applicable with any control rod withdrawn. Not applicable to control rods removed per Specification 3.9.10.1 or 3.9.10.2.

TABLE 3.3.3-1 (Continued)

EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION

TRIP FUNCTION	MINIMUM OPERABLE CHANNELS PER TRIP FUNCTION(a)	APPLICABLE OPERATIONAL CONDITIONS	ACTION
C. DIVISION 3 TRIP SYSTEM			
1. HPCS SYSTEM			
a. Reactor Vessel Water Level - Low, Low, Level 2	4(b)	1, 2, 3, 4*, 5*	33
b. Drywell Pressure - High##	4(b)	1, 2, 3	33
c. Reactor Vessel Water Level-High, Level 8	2(c)	1, 2, 3, 4*, 5*	31
d. Condensate Storage Tank Level-Low	2(d)	1, 2, 3, 4*, 5*	34
e. Suppression Pool Water Level-High	2(d)	1, 2, 3, 4*, 5*	34
f. Manual Initiation##	1	1, 2, 3, 4*, 5*	32
D. LOSS OF POWER			
1. Division 1 and 2			
a. 4.16 kV Bus Undervoltage (Loss of Voltage)	4	1, 2, 3, 4**, 5**	30
b. 4.16 kV Bus Undervoltage (BOP Load Shed)	4	1, 2, 3, 4**, 5**	30
c. 4.16 kV Bus Undervoltage (Degraded Voltage)	4	1, 2, 3, 4**, 5**	30
2. Division 3			
a. 4.16 kV Bus Undervoltage (Loss of Voltage)	4	1, 2, 3, 4**, 5**	30
b. 4.16 kV Bus Undervoltage (Degraded Voltage)	4	1, 2, 3, 4**, 5**	30

(a) A channel may be placed in an inoperable status for up to 2 hours during periods of required surveillance without placing the trip system in the tripped condition provided at least one other OPERABLE channel in the same trip system is monitoring that parameter.
(b) Also actuates the associated division diesel generator.
(c) Provides signal to close HPCS pump discharge valve only.
(d) Provides signal to HPCS pump suction valves only.
* Applicable when the system is required to be OPERABLE per Specification 3.5.2 or 3.5.3.
** Required when applicable ESF equipment is required to be OPERABLE.
\# Not required to be OPERABLE when reactor steam dome pressure is less than or equal to 135 psig.
\#\# The injection function of Drywell Pressure - High and Manual Initiation are not required to be OPERABLE with indicated reactor vessel water level on the wide range instrument greater than Level 8 setpoint coincident with the reactor pressure less than 600 psig.

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(s) inoperable.

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

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

ACTION 32 - 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 ADS trip system or ECCS inoperable.

ACTION 33 - With the number of OPERABLE channels less than required by the Minimum OPERABLE Channels per Trip Function requirement, place the inoperable channel(s) in the tripped condition within one hour* or declare the HPCS system inoperable.

ACTION 34 - 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 HPCS system inoperable.

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

*The provisions of Specification 3.0.4 are not applicable.

TABLE 4.3.3.1-1 (Continued)

EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION SURVEILLANCE REQUIREMENTS

TRIP FUNCTION	CHANNEL CHECK	CHANNEL FUNCTIONAL TEST	CHANNEL CALIBRATION	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRED
B. DIVISION 2 TRIP SYSTEM (Continued)				
2. AUTOMATIC DEPRESSURIZATION SYSTEM				
TRIP SYSTEM "B"#				
a. Reactor Vessel Water Level - Low Low Low, Level 1	S	M	R(a)	1, 2, 3
b. Drywell Pressure-High	S	M	R(a)	1, 2, 3
c. ADS Initiation Timer	NA	M	Q	1, 2, 3
d. Reactor Vessel Water Level - Low, Level 3	S	M	R(a)	1, 2, 3
e. LPCI Pump B and C Discharge Pressure-High	S	M(b)	R(a)	1, 2, 3
f. Manual Initiation	NA	R	NA	1, 2, 3
g. ADS Bypass Timer (High Drywell Pressure)	NA	M	Q	1, 2, 3
h. Manual Inhibit	NA	R	NA	1, 2, 3
C. DIVISION 3 TRIP SYSTEM				
1. HPCS SYSTEM				
a. Reactor Vessel Water Level - Low Low, Level 2	S	M	R(a)	1, 2, 3, 4*, 5*
b. Drywell Pressure-High##	S	M	R(a)	1, 2, 3
c. Reactor Vessel Water Level-High, Level 8	S	M	R(a)	1, 2, 3, 4*, 5*
d. Condensate Storage Tank Level - Low	S	M	R(a)	1, 2, 3, 4*, 5*
e. Suppression Pool Water Level - High	S	M(b)	R(a)	1, 2, 3, 4*, 5*
f. Manual Initiation##	NA	R	NA	1, 2, 3, 4*, 5*

TABLE 4.3.3.1-1 (Continued)

EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION SURVEILLANCE REQUIREMENTS

TRIP FUNCTION	CHANNEL CHECK	CHANNEL FUNCTIONAL TEST	CHANNEL CALIBRATION	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRED
D. LOSS OF POWER				
1. Division 1 and 2				
a. 4.16 kV Bus Undervoltage (Loss of Voltage)	NA	M(e)	R	1, 2, 3, 4**, 5**
b. 4.16 kV Bus Undervoltage (BOP Load Shed)	NA	M(e)	R	1, 2, 3, 4**, 5**
c. 4.16 kV Bus Undervoltage (Degraded Voltage)	NA	M(e)	R	1, 2, 3, 4**, 5**
2. Division 3				
a. 4.16 kV Bus Undervoltage (Loss of Voltage)	NA	NA	R	1, 2, 3, 4**, 5**
b. 4.16 kV Bus Undervoltage (Degraded Voltage)	NA	NA	R	1, 2, 3, 4**, 5**

TABLE 4.3.3.1-1 (Continued)

EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION SURVEILLANCE REQUIREMENTS

NOTATION

Not required to be OPERABLE when reactor steam dome pressure is less than or equal to 135 psig.

The injection function of Drywell Pressure - High and Manual Initiation are not required to be OPERABLE with indicated reactor vessel water level on the wide range instrument greater than Level 8 setpoint coincident with the reactor pressure less than 600 psig.

* Applicable when the system is required to be OPERABLE per Specification 3.5.2 or 3.5.3.

** Required when ESF equipment is required to be OPERABLE.

(a) Calibrate trip unit at least once per 31 days.

(b) Manual initiation switches shall be tested at least once per 18 months during shutdown. All other circuitry associated with manual initiation shall receive a CHANNEL FUNCTIONAL TEST at least once per 31 days as a part of circuitry required to be tested for automatic system actuation.

(c) DELETED

(d) DELETED

(e) Functional Testing of Time Delay Not Required

LIMITING CONDITION FOR OPERATION (Continued)

ACTION: (Continued)

e. For ECCS divisions 1 and 2, provided that ECCS division 3 is OPERABLE and divisions 1 and 2 are otherwise OPERABLE:

1. With one of the above required ADS valves inoperable, 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 $\leq$ 135 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 $\leq$ 135 psig within the next 24 hours.

f. With an ECCS discharge line "keep filled" pressure alarm instrumentation channel inoperable, perform Surveillance Requirement 4.5.1.a.1 at least once per 24 hours.

g. With an ECCS header delta P instrumentation channel inoperable, restore the inoperable channel to OPERABLE status with 72 hours or determine ECCS header delta P locally at least once per 12 hours; otherwise declare the associated ECCS inoperable.

h. 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 useage factor for each affected safety injection nozzle shall be provided in this Special Report whenever its value exceeds 0.70.

i. With an ADS accumulator low pressure alarm system instrumentation channel(s) inoperable, determine the associated ADS accumulator pressure locally at least once per 12 hours; restore the inoperable channel(s) to OPERABLE status within 7 days; otherwise declare the associated ADS valves inoperable.

*Whenever two or more RHR 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.

SURVEILLANCE REQUIREMENTS

4.5.1 ECCS division 1, 2 and 3 shall be demonstrated OPERABLE by:

a. At least once per 31 days for the LPCS, LPCI and HPCS systems:

1. 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.

2. Performance of a CHANNEL FUNCTIONAL TEST of the:

   a) Discharge line "keep filled" pressure alarm instrumentation, and

   b) Header delta P instrumentation.

3. Verifing 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.

b. Verifing that, when tested pursuant to Specification 4.0.5, each:

1. LPCS pump develops a flow of at least 7115 gpm with a total developed head of greater than or equal to 290 psid.

2. LPCI pump develops a flow of at least 7450 gpm with a total developed head of greater than or equal to 125 psid.

3. HPCS pump develops a flow of at least 7115 gpm with a total developed head of greater than or equal to 445 psid.

c. For the LPCS, LPCI and HPCS systems, at least once per 18 months:

1. 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.

2. Performing a CHANNEL CALIBRATION of the:

   a) Discharge line high pressure and "keep filled" low pressure alarm instrumentation and verifying the:

      1) High pressure setpoint of the:

         (a) LPCS system to be $\leq$ 575 psig.

         (b) LPCI subsystems to be $\leq$ 475 psig.

SURVEILLANCE REQUIREMENTS (Continued)

2) Low pressure setpoint of the:

(a) LPCI A and B subsystem loop to be ≥ 38 psig.

(b) LPCI C subsystem loop and LPCS system to be ≥ 22 psig.

(c) HPCS system to be ≥ 18 psig.

b) Header delta P instrumentation and verifying the setpoint of the HPCS system and LPCS system and LPCI subsystems to be 1.2 ± 0.1 psid change from the normal indicated ΔP.

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

4. Verifying that the time required for each LPCI and LPCS injection valve to travel from fully closed to fully open is ≤ 29 seconds when tested pursuant to Specification 4.0.5.

d. For the ADS at least once per 18 months by:

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

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

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

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

3. Performing an extrapolated pressure decay test on the ADS air system to demonstrate system pressure will be maintained for 7 days at a value ≥ 110 psig without makeup air available.

*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.

SURVEILLANCE REQUIREMENTS (Continued)

4. Performing a CHANNEL CALIBRATION of the accumulator low pressure alarm channels and verifying an alarm setpoint of $\geq$ 150 psig on decreasing pressure.

e. For the ADS at least once per 31 days by performing a CHANNEL FUNCTIONAL TEST of the accumulator low pressure alarm channels.

3/4 5.2 ECCS - SHUTDOWN

LIMITING CONDITION FOR OPERATION

3.5.2 At least two of the following shall be OPERABLE:

a. The low pressure core spray (LPCS) system with a flow path capable of taking suction from the suppression pool and transferring the water through the spray sparger to the reactor vessel.

b. Low pressure coolant injection (LPCI) subsystem "A" of the RHR system with a flow path capable of taking suction from the suppression pool upon being manually realigned and transferring the water to the reactor vessel.

c. Low pressure coolant injection (LPCI) subsystem "B" of the RHR system with a flow path capable of taking suction from the suppression pool upon being manually realigned and transferring the water to the reactor vessel.

d. Low pressure coolant injection (LPCI) subsystem "C" of the RHR system with a flow path capable of taking suction from the suppression pool upon being manually realigned and transferring the water to the reactor vessel.

e. The high pressure core spray (HPCS) system with a flow path capable of taking suction from one of the following water sources and transferring the water through the spray sparger to the reactor vessel:

1. From the suppression pool, or
2. When the suppression pool level is less than the limit or is drained, from the condensate storage tank containing at least 170,000 available gallons of water, equivalent to a level of 18 feet.

APPLICABILITY: OPERATIONAL CONDITION 4 and 5*.

ACTION:

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

b. With both of the above required subsystems/systems inoperable, suspend CORE ALTERATIONS and all operations that have a potential for draining the reactor vessel. Restore at least one subsystem/system 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 upper containment fuel pool gates are removed, the spent fuel pool gates are removed, and water level is maintained within the limits of Specifications 3.9.8 and 3.9.9.

TABLE 3.6.4-1 (Continued)

CONTAINMENT AND DRYWELL ISOLATION VALVES

SYSTEM AND VALVE NUMBER		PENETRATION NUMBER	VALVE GROUP[a]	MAXIMUM ISOLATION TIME (Seconds)
Containment (Continued)				
Main Steam Line Drains	B21-F019-A	19(0)	1	20
Main Steam Line Drains	B21-F016-B	19(I)		20
RHR Heat Exchanger "A" to CTMT SPR Sparger INL	E12-F028A-A	20(I)	5	90
RHR Heat Exchanger "A" to CTMT Pool	E12-F037A-A	20(I)	3	74
RHR Heat Exchanger "B" to CTMT SPR Sparger INL	E12-F028B-B	21(I)	5	90
RHR Heat Exchanger "B" to CTMT Pool	E12-F037B-B	21(I)	3	74
RHR "A" Test Line to Supp. Pool	E12-F024A-A	23(0)[d]	5	90
RHR "A" Test Line to Supp. Pool	E12-F011A-A	23(0)[d]	5	36
RHR "C" Test Line to Supp. Pool	E12-F021-B	24(0)[d]	5	144
HPCS Test Line	E22-F023-C	27(0)[d]	6B	75
RCIC Pump Suction	E51-F031-A	28(0)[d]	4	56
RCIC Turbine Exhaust	E51-F077-A	29(0)[c]	9	26
LPCS Test Line	E21-F012-A	32(0)[d]	5	144
Cont. Purge and Vent Air Supply	M41-F011-(A)	34(0)	7	4
Cont. Purge and Vent Air Supply	M41-F012-(B)	34(I)	7	4
Cont. Purge and Vent Air Exh.	M41-F034-(B)	35(I)	7	4
Cont. Purge and Vent Air Exh.	M41-F035-(A)	35(0)	7	4
Drywell Chilled Water Return	P72-F123-B	36(I)	6A	33
Drywell Chilled Water Return	P72-F122-A	36(0)	6A	33
Drywell Chilled Water Supply	P72-F121-A	37(0)	6A	33
Chilled Water Supply	P71-F150-(A)	38(0)	6A	12

TABLE 3.6.4-1 (Continued)

CONTAINMENT AND DRYWELL ISOLATION VALVES

SYSTEM AND VALVE NUMBER		PENETRATION NUMBER	VALVE GROUP(a)	MAXIMUM ISOLATION TIME (Seconds)
Containment (Continued)				
Chilled Water Return	P71-F148-(A)	39(0)	6A	12
Chilled Water Return	P71-F149-(B)	39(I)	6A	12
Service Air Supply	P52-F105-(A)	41(0)	6A	6
Inst. Air Supply	P53-F001-(A)	42(0)	6A	6
RWCU to Main Condenser	G33-F034-A	43(0)	8	35
RWCU to Main Condenser	G33-F028-B	43(I)	8	35
RWCU Backwash to C/U Phase Sep. Tank	G36-F106-(B)	49(I)	6A	11
RWCU Backwash to C/U Phase Sep. Tank	G36-F101-(A)	49(0)	6A	11
Drywell & Cont. Equip. Drain Sump Disch.	P45-F067-(B)	50(I)	6A	7
Drywell & Cont. Equip. Drain Sump Disch.	P45-F068-(A)	50(0)	6A	7
Drywell & Cont. Floor Drain Sump Disch.	P45-F061-(B)	51(I)	6A	7
Drywell & Cont. Floor Drain Sump Disch.	P45-F062-(A)	51(0)	6A	7
Condensate Supply	P11-F075-(A)	56(0)	6A	10
FPC & CU to Upper Cont. Pool	G41-F028-A	57(0)	6A	51
Upper Cont. Pool to Fuel Pool Drain Tank	G41-F029-A	58(0)	6A	51
Upper Cont. Pool to Fuel Pool Drain Tank	G41-F044-B	58(I)	6A	40
Aux. Bldg. Flr. and Equip. Drn. Tks. to Supp. Pool	P45-F273-A	60(0)	6A	32
Aux. Bldg. Flr. and Equip. Drn. Tks. to Supp. Pool	P45-F274-B	60(0)	6A	32

TABLE 3.6.4-1 (Continued)

CONTAINMENT AND DRYWELL ISOLATION VALVES

SYSTEM AND VALVE NUMBER		PENETRATION NUMBER	VALVE GROUP[a]	MAXIMUM ISOLATION TIME (Seconds)
Containment (Continued)				
Comb. Gas Control Cont. Purge (Outside Air Supply)	E61-F009-(A)	65(0)	7	4
Comb. Gas Control Cont. Purge (Outside Air Supply)	E61-F010-(B)	65(I)	7	4
Purge Filter Train Isolation	E61-F056-(B)	66(I)	7	4
Purge Filter Train Isolation	E61-F057-(A)	66(0)	7	4
RHR "B" Test Line To Suppr. Pool	E12-F024B-B	67(0)[d]	5	90
RHR "B" Test Line To Suppr. Pool	E12-F011B-B	67(0)[d]	5	36
Refueling Water Transf. Pump Suction	P11-F130-(A)	69(0)[c]	6A	8
Refueling Water Transf. Pump Suction	P11-F131-(B)	69(0)[c]	6A	8
Instr. Air to ADS	P53-F003-A	70(0)	6A	4
RCIC Turbine Exh. Vacuum Breaker	E51-F078-B	75(0)	9	10
RWCU to Feedwater	G33-F040-B	83(I)	8	35
RWCU to Feedwater	G33-F039-A	83(0)	8	35
Chemical Waste Sump Discharge	P45-F098-(B)	84(I)	6A	8
Chemical Waste Sump Discharge	P45-F099-(A)	84(0)	6A	8
Supp. Pool Clean-up Return	P60-F009-A	85(0)	6A	8
Supp. Pool Clean-up Return	P60-F010-B	85(0)	6A	8
Demin. Water Supply to Cont.	P21-F017-A	86(0)	6A	19
Demin. Water Supply to Cont.	P21-F018-B	86(I)	6A	19
RWCU Pump Suction	G33-F001-B	87(I)	8	35

TABLE 3.6.4-1 (Continued)

CONTAINMENT AND DRYWELL ISOLATION VALVES

SYSTEM AND VALVE NUMBER		PENETRATION NUMBER	VALVE GROUP[(a)]	MAXIMUM ISOLATION TIME (Seconds)
Containment (Continued)				
RWCU Pump Suction	G33-F252-A	87(I)	8	35
RWCU Pump Suction	G33-F004-A	87(O)	8	35
RWCU Pump Disch.	G33-F053-B	88(I)	8	35
RWCU Pump Disch.	G33-F054-A	88(O)	8	35
b. Drywell				
Instrument Air	P53-F007-B	335(O)	6A	7
Drywell Chilled Water Return	P72-F125-A	331(I)	6A	32
Drywell Chilled Water Return	P72-F126-B	331(O)	6A	32
Drywell Chilled Water Return	P72-F124-B	332(O)	6A	32
RWCU Pump Suction	G33-F250-A	337(I)	8	35
RWCU Pump Suction	G33-F251-B	337(O)	8	35
Combustible Gas Con.	E61-F003B-B	338(O)	5	84
Combustible Gas Con.	E61-F003A-A	339(O)	5	84
Combustible Gas Con.	E61-F005A-A	340(O)	5	84
Combustible Gas Con.	E61-F005B-B	340(O)	5	84
Combustible Gas Con.	E61-F007-(A)	341(O)	5	9
Combustible Gas Con.	E61-F020-(B)	341(O)	5	18
Drywell Air Purge Supply	M41-F015-(A)	345(I)	7	4
Drywell Air Purge Supply	M41-F013-(B)	345(O)	7	4
Drywell Air Purge Exhaust	M41-F016-(A)	347(I)	7	4
Drywell Air Purge Exhaust	M41-F017-(B)	347(O)	7	4
Equipment Drains	P45-F009-(A)	348(I)	6A	6
Equipment Drains	P45-F010-(B)	348(O)	6A	6
Floor Drains	P45-F003-(A)	349(I)	6A	6
Floor Drains	P45-F004-(B)	349(O)	6A	6
Service Air	P52-F195-B	363(O)	6A	16
Chemical Sump Disch.	P45-F096-A	364(I)	6A	9
Chemical Sump Disch.	P45-F097-B	364(O)	6A	9
RWCU to Heat Exch.	G33-F253-B	366(O)	8	35
Reactor Water Sample Line	B33-F019-B	465(I)	10	36
Reactor Water Sample Line	B33-F020-A	465(O)	10	36

TABLE 3.6.4-1 (Continued)

CONTAINMENT AND DRYWELL ISOLATION VALVES

SYSTEM AND VALVE NUMBER		PENETRATION NUMBER
Containment (Continued)		
RHR Pump "A" Test Line to Suppr. Pool	E12-F227	23(O)(e)
RHR Pump "A" Test Line to Suppr. Pool	E12-F262	23(O)(e)
RHR Pump "A" Test Line to Suppr. Pool	E12-F228	23(O)(e)
RHR "A" Test Line to Supp. Pool	E12-F290A-A	23(O)(d)
RHR Pump "A" Test Line to Suppr. Pool	E12-F338	23(O)(c)
RHR Pump "A" Test Line to Suppr. Pool	E12-F339	23(O)(c)
RHR Pump "A" Test Line to Suppr. Pool	E12-F260	23(O)(e)
RHR Pump "C" Test Line to Suppr. Pool	E12-F280	24(O)(d)
RHR Pump "C" Test Line to Suppr. Pool	E12-F281	24(O)(d)
HPCS Suction	E22-F014	25(O)(d)
HPCS Discharge	E22-F005-(C)	26(I)
HPCS Discharge	E22-F218	26(I)
HPCS Discharge	E22-F201	26(I)
HPCS Test Line	E22-F035	27(O)(d)
HPCS Test Line	E22-F302	27(O)(e)
HPCS Test Line	E22-F301	27(O)(e)
LPCS Pump Suction	E21-F031	30(O)(d)
LPCS Discharge	E21-F006-(A)	31(I)
LPCS Discharge	E21-F200	31(I)
LPCS Discharge	E21-F207	31(I)
LPCS Test Line	E21-F217	32(O)(d)
LPCS Test Line	E21-F218	32(O)(d)
CRD Pump Discharge	C11-F122	33(I)
DCW Supply	P72-F165	37(I)
Plant Chilled Water Supply	P71-F151	38(I)
Service Air Supply	P52-F122	41(I)

TABLE 3.6.4-1 (Continued)

CONTAINMENT AND DRYWELL ISOLATION VALVES

SYSTEM AND VALVE NUMBER		PENETRATION NUMBER
Containment (Continued)		
Instr. Air Supply	P53-F002	42(I)
CCW Supply	P42-F035	44(I)
RCIC Disch. Min. Flow	E51-F251	46(O)(c)
RCIC Disch. Min. Flow	E51-F252	46(O)(c)
RHR Heat Ex. "B" Relief Vent Header	E12-F055B	48(O)(d)
RHR Heat Ex. "B" Relief Vent Header	E12-F103B	48(O)(d)
RHR Heat Ex. "B" Relief Vent Header	E12-F104B	48(O)(d)
Refueling Wtr. Stg. Tk. to Upper Ctmt. Pool	G41-F053	54(O)
Refueling Wtr. Stg. Tk. to Upper Ctmt. Pool	G41-F201	54(I)
Condensate Supply	P11-F004	56(I)
FPC & CU to Upper Cont. Pool	G41-F040	57(I)
Stby. Liquid Control Sys. Mix. Tk. (future use)	C41-F151	61(I)
Stby. Liquid Control Sys. Mix. Tk. (future use)	C41-F150	61(O)
RHR Pump "B" Test Line	E12-F276	67(O)(e)
RHR Pump "B" Test Line	E12-F277	67(O)(e)
RHR Pump "B" Test Line	E12-F212	67(O)(e)
RHR Pump "B" Test Line	E12-F213	67(O)(e)
RHR Pump "B" Test Line	E12-F249	67(O)(e)
RHR Pump "B" Test Line	E12-F250	67(O)(e)
RHR Pump "B" Test Line	E12-F334	67(O)(c)

TABLE 3.6.4-1 (Continued)

CONTAINMENT AND DRYWELL ISOLATION VALVES

SYSTEM AND VALVE NUMBER		PENETRATION NUMBER
Containment (Continued)		
RHR Pump "B" Test Line	E12-F335	67(0)(c)
RHR "B" Test Line To Suppr. Pool	E12-F290B-B	67(0)(d)
Inst. Air to ADS	P53-F006	70(I)
LPCS Relief Valve Vent Header	E21-F018	71A(0)(d)
RHR Pump "C" Relief Valve Vent Header	E12-F025C	71B(0)(d)
RHR Shutdown Vent Header	E12-F036	73(0)
RHR Shutdown Suction Relief Valve Disch.	E12-F005	76B(0)
RHR Heat Ex. "A" Relief Vent Header	E12-F055A	77(0)(d)
RHR Heat Ex. "A" Relief Vent Header	E12-F103A	77(0)(d)
RHR Heat Ex. "A" Relief Vent Header	E12-F104A	77(0)(d)
SSW "A" Supply	P41-F169A	89(I)(c)
SSW "B" Supply	P41-F169B	92(I)(c)
Ctmt. Leak Rate Test Inst.	M61-F015	110A(I)
Ctmt. Leak Rate Test Inst.	M61-F014	110A(0)
Ctmt. Leak Rate Test Inst.	M61-F019	110C(I)
Ctmt. Leak Rate Test Inst.	M61-F018	110C(0)
Ctmt. Leak Rate Test Inst.	M61-F017	110F(I)
Ctmt. Leak Rate Test Inst.	M61-F016	110F(0)
b. Drywell		
LPCI "A"	E12-F041A	313(I)
LPCI "B"	E12-F041B	314(I)
LPCI "B"	E12-F236	314(0)
CRD to Recirc. Pump A Seals	B33-F013A	326(I)

TABLE 3.6.4-1 (Continued)

CONTAINMENT AND DRYWELL ISOLATION VALVES

SYSTEM AND VALVE NUMBER		PENETRATION NUMBER
Drywell (Continued)		
CRD to Recirc. Pump A Seals	B33-F017A	326(0)
Instrument Air	P53-F008	335(I)
Standby Liquid Control	C41-F007	328(I)
Standby Liquid Control	C41-F006	328(0)
Cont. Cooling Water Supply	P42-F115	329(I)
Drywell Chilled Water Supply	P72-F147	332(I)
Condensate Flush Conn.	B33-F204	333(I)
Condensate Flush Conn.	B33-F205	333(0)
Combustible Gas Control	E61-F002A	339(0)
Combustible Gas Control	E61-F002B	338(0)
Combustible Gas Control	E61-F004A	340(0)
Combustible Gas Control	E61-F004B	340(0)
Upper Containment Pool Drain	G41-F265	342(0)
CRD to Recirc. Pump B Seals	B33-F013B	346(I)
CRD to Recirc. Pump B Seals	B33-F017B	346(0)
Service Air	P52-F196	363(I)
Cont. Leak Rate Test Inst.	M61-F021	438A(I)
Cont. Leak Rate Sys.	M61-F020	438A(0)
BLIND FLANGES		
Cont. Leak Rate Sys.	NA	40(I)(0)
Cont. Leak Rate Sys.	NA	82(I)(0)
Containment Leak Rate System	NA	343(I)(0)

TABLE 3.6.4-1 (Continued)

CONTAINMENT AND DRYWELL ISOLATION VALVES

SYSTEM AND VALVE NUMBER		PENETRATION NUMBER
4. Test Connections[g]		
a. Containment		
Main Steam T/C	B21-F025A	5(0)
Main Steam T/C	B21-F025B	6(0)
Main Steam T/C	B21-F025C	7(0)
Main Steam T/C	B21-F025D	8(0)
Feedwater T/C	B21-F030A	9(0)
Feedwater T/C	B21-F063A	9(0)
Feedwater T/C	B21-F063B	10(0)
Feedwater T/C	B21-F030B	10(0)
RHR Shutdown Cool. Suction T/C	E12-F002	14(0)
RCIC Steam Line T/C	E51-F072	17(0)
RHR to Head Spray T/C	E12-F342	18(0)
RHR to Head Spray T/C	E12-F061	18(0)
LPCI "C" T/C	E12-F056C	22(0)
RHR "A" Pump Test Line T/C	E12-F322	23(0)(c)
RHR "A" Pump Test Line T/C	E12-F336	23(0)(c)
RHR "A" Pump Test Line T/C	E12-F349	23(0)(c)
RHR "A" Pump Test Line T/C	E12-F303	23(0)(c)
RHR "A" Pump Test Line T/C	E12-F310	23(0)(c)
RHR "A" Pump Test Line T/C	E12-F348	23(0)(c)
RHR"C" Pump Test Line T/C	E12-F311	24(0)(c)
RHR"C" Pump Test Line T/C	E12-F304	24(0)(c)
HPCS Discharge T/C	E22-F021	26(0)
HPCS Test Line T/C	E22-F303	27(0)(c)
HPCS Test Line T/C	E22-F304	27(0)(c)
RCIC Turbine Exhaust T/C	E51-F258	29(0)(c)
RCIC Turbine Exhaust T/C	E51-F257	29(0)(c)
LPCS T/C	E21-F013	31(0)
LPCS Test Line T/C	E21-F222	32(0)(c)
LPCS Test Line T/C	E21-F221	32(0)(c)

TABLE 3.6.4-1 (Continued)

CONTAINMENT AND DRYWELL ISOLATION VALVES

SYSTEM AND VALVE NUMBER		PENETRATION NUMBER
Containment (Continued)		
CRD T/C	C11-F128	33(0)
Cont. Purge Supply T/C	M41-F042	34(0)
Cont. Purge Exhaust T/C	M41-F051	35(0)
DCW Supply T/C	P72-F167	37(0)
Plant Chilled Water T/C	P71-F232	38(0)
Plant Chilled Water T/C	P71-F246	39(0)
Ctmt. Leak Rate T/C	M61-F009	40(I)
Service Air T/C	P52-F258	41(0)
Inst. Air T/C	P53-F036	42(0)
RWCU T/C	G33-F070	43(0)
CCW Supply T/C	P42-F161	44(0)
CCW Return T/C	P42-F162	45(I)
Condensate Supply T/C	P11-F095	56(0)
FPC & CU To Upper Cont. Pool T/C	G41-F340	57(I)
Aux. Bldg. Flr. & Equip. Drain Tk. to Suppr. Pool T/C	P45-F275	60(0)
Aux. Bldg. Flr. & Equip. Drain Tk. to Suppr. Pool T/C	P45-F290	60(0)
Stby. Liquid Control Sys. Mix. Tk. T/C (future use)	C41-F152	61(0)
Combustible Gas Control T/C	E61-F017	65(0)
Purge Radiation Detector T/C	M41-F054	66(0)
RHR "B" Test Line T/C	E12-F321	67(0)(c)
RHR "B" Test Line T/C	E12-F351	67(0)(c)
RHR "B" Test Line T/C	E12-F331	67(0)(c)

TABLE 3.6.4-1 (Continued)

CONTAINMENT AND DRYWELL ISOLATION VALVES

SYSTEM AND VALVE NUMBER		PENETRATION NUMBER
Containment (Continued)		
RHR "B" Test Line T/C	E12-F350	67(0)(c)
RHR "B" Test Line T/C	E12-F312	67(0)(c)
RHR "B" Test Line T/C	E12-F305	67(0)(c)
Refueling Water Transf. Pump Suction T/C	P11-F425	69(0)(c)
Refueling Water Transf. Pump Suction T/C	P11-F132	69(0)(c)
Inst. Air to ADS T/C	P53-F043	70(0)
Cont. Leak Rate T/C	M61-F010	82(I)
RWCU To Feedwater T/C	G33-F055	83(0)
Suppr. Pool Cleanup T/C	P60-F011	85(0)
Suppr. Pool Cleanup T/C	P60-F034	85(0)
RWCU Pump Suction T/C	G33-F002	87(0)
RWCU Pump Discharge T/C	G33-F061	88(0)
SSW T/C	P41-F163A	89(0)(c)
SSW T/C	P41-F163B	92(0)(c)
b. Drywell		
LPCI "A" T/C	E12-F056A	313(0)
LPCI "B" T/C	E12-F056B	314(0)
Instrument Air T/C	P53-F493	335(0)
SLCS T/C	C41-F026	328(0)
Service Air T/C	P52-F476	363(0)
RWCU T/C	G33-F120	366(I)
Reactor Sample T/C	B33-F021	465(0)

3/4.6.5 DRYWELL VACUUM RELIEF

LIMITING CONDITION FOR OPERATION

3.6.5 Both drywell post-LOCA vacuum relief subsystems and both drywell purge vacuum relief subsystems shall be OPERABLE with associated vacuum breakers and isolation valves closed.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2 and 3.

ACTION:

a. With one of the drywell post-LOCA vacuum relief subsystems and/or one of the drywell purge vacuum relief subsystems inoperable for opening but known to be closed, restore the inoperable subsystem(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 two of the post-LOCA vacuum relief subsystems inoperable for opening but known to be closed, provided that both of the drywell purge vacuum relief subsystems are OPERABLE, restore the inoperable subsystems to OPERABLE status within 30 days or be in a least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

c. With two of the post-LOCA vacuum relief subsystems and one of the drywell purge vacuum relief subsystems inoperable for opening but known to be closed, restore one inoperable subsystem 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.

d. With one of the drywell isolation vacuum breakers open, restore the open vacuum breaker to the closed position within 1 hour or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

e. With the position indicator of an OPERABLE drywell vacuum breaker or associated isolation valve of the drywell vacuum relief subsystems inoperable, verify the vacuum breaker or isolation valve to be closed at least once per 24 hours by local indication. Otherwise be in a least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

SURVEILLANCE REQUIREMENTS

4.6.5 Each post-LOCA and purge system vacuum breaker and associated isolation valve shall be:

a. Verified closed at least once per 7 days.

SURVEILLANCE REQUIREMENTS (Continued)

b. Demonstrated OPERABLE:

1. At least once per 31 days by:

   a) Cycling the vacuum breaker and associated isolation valve through at least one complete cycle of full travel.

   b) Verifying the position indicators OPERABLE by observing expected vacuum breaker and associated isolation valve movements during the cycling test.

2. At least once per 18 months by:

   a) Verifying the pressure differential required to open the vacuum breaker, from the closed position, to be less than or equal to 1.0 psid, and

   b) Verifying the position indicators of the vacuum breaker and associated isolation valve OPERABLE by performance of CHANNEL CALIBRATIONs.

3. By verifying the OPERABILITY of the isolation valve differential pressure actuation instrumentation with the opening setpoint of 0.0 to 1.0 psid for the drywell purge subsystems and -1.0 to 0.0 psid for the post-LOCA vacuum relief subsystems (Drywell minus Containment) by performance of a:

   a) CHANNEL CHECK at least once per 24 hours,

   b) CHANNEL FUNCTIONAL TEST at least once per 31 days, and

   c) CHANNEL CALIBRATION at least once per 18 months.

3/4.6.6 SECONDARY CONTAINMENT

SECONDARY CONTAINMENT INTEGRITY

LIMITING CONDITION FOR OPERATION

3.6.6.1 SECONDARY CONTAINMENT INTEGRITY shall be maintained.

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

ACTION:

Without SECONDARY CONTAINMENT INTEGRITY:

a. In OPERATIONAL CONDITION 1, 2 or 3, restore SECONDARY CONTAINMENT INTEGRITY within 4 hours 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 *, suspend handling of irradiated fuel in the primary or secondary containment, CORE ALTERATIONS and operations with a potential for draining the reactor vessel. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.6.6.1 SECONDARY CONTAINMENT INTEGRITY shall be demonstrated by:

a. Verifying at least once per 31 days that:

   1. All Auxiliary Building and Enclosure Building equipment hatches and blowout panels are closed and sealed.

   2. The door in each access to the Auxiliary Building and Enclosure Building is closed, except for routine entry and exit.

   3. All Auxiliary Building and Enclosure Building penetrations not capable of being closed by OPERABLE secondary containment automatic isolation dampers/valves and required to be closed during accident conditions are closed by valves, blind flanges, rupture discs or deactivated automatic dampers/valves secured in position.

b. At least once per 18 months:

   1. Verifying that one standby gas treatment subsystem will draw down the secondary containment to greater than or equal to 0.25 inches of vacuum water gauge in less than or equal to 120 seconds, and

   2. Operating one standby gas treatment subsystem for one hour and maintaining greater than or equal to 0.266 inches of vacuum water gauge in the secondary containment at a flow rate not exceeding 4000 CFM.

*When irradiated fuel is being handled in the primary or secondary containment and during CORE ALTERATIONS and operations with a potential for draining the reactor vessel.

TABLE 3.8.4.1-1 (Continued)

PRIMARY CONTAINMENT PENETRATION CONDUCTOR
OVERCURRENT PROTECTIVE DEVICES

c. 480 VAC Circuit Breakers (Continued)

Molded Case, Type NZM

BREAKER NUMBER	TRIP SETPOINT (Amperes)	RESPONSE TIME (Seconds)	SYSTEM/COMPONENT AFFECTED
52-1112-20	90	0.100	RWCU FILTER DEMIN HOLDING PUMP (N1G36C001A-N)
52-1112-21	800	0.100	480 V RECEPTACLE
52-1112-22	5	0.100	MOV-STM TUNNEL COOLER INLET (N1P72F150A-N)
52-1112-24	32	0.100	MOV CLEANUP LINE RECIRC LOOP A (Q1G33F100-N)
52-1112-27	24	0.100	RESIN TANK AGITATOR (N1G36D020-N)
52-1112-28	38	0.100	MOV RWCU HEAT EXCHANGER BYPASS (N1G33F104-N)
52-1112-31	38	0.100	MOV RWCU HEAT EXCHANGER BYPASS (N1G33F044-N)
52-1112-36	500	0.100	REAC. RECIRC. PUMP SPACE HEATER (TB1B33C001A)
52-1112-37	800	0.100	480 V RECEPTACLE
52-1112-38	44	0.100	REAC WATER SAMPLE STA FILTER TRAIN FAN (N1M41-D006-N)
52-1112-41	6	0.100	REAC RECIRC SAMPLE PANEL ISOL MOV (N1B33F129)
52-1113-07	125	0.100	CNTMT FLOOR DRAIN SUMP PUMP (N1P45C019B-N)

TABLE 3.8.4.1-1 (Continued)

PRIMARY CONTAINMENT PENETRATION CONDUCTOR OVERCURRENT PROTECTIVE DEVICES

c. 480 VAC Circuit Breakers (Continued)

Molded Case, Type NZM

BREAKER NUMBER	TRIP SETPOINT (Amperes)	RESPONSE TIME (Seconds)	SYSTEM/COMPONENT AFFECTED
52-1113-21	60	0.100	DRYWELL EQUIP DRAIN SUMP PUMP (N1P45C002B-N)
52-1113-30	28	0.100	MOV RWCU HX OUTL ISOL VLV (N1G33F254-N)

TABLE 3.8.4.1-1 (Continued)

PRIMARY CONTAINMENT PENETRATION CONDUCTOR
OVERCURRENT PROTECTIVE DEVICES

c. 480 VAC Circuit Breakers (Continued)

Molded Case, Type NZM

BREAKER NUMBER	TRIP SETPOINT (Amperes)	RESPONSE TIME (Seconds)	SYSTEM/COMPONENT AFFECTED
52-1113-44	800	0.100	480 V RECEPTACLE
52-1113-47	500	0.100	SPARE
52-1151-06	240	0.100	CNTMT COOLING FILTER TRAIN FAN (N1M41D002A-N)
52-1151-07	17.5	0.100	REAC. RECIRC. HPU OIL PUMP FAN (N1B33D003A3-N)
52-1151-10	600	0.100	REAC. RECIRC. HPU OIL PUMP (N1B33D003A1-N)
52-1151-12	75	0.100	MOV - RECIRC PUMP SUCTION (Q1B33F023A-N)
52-1151-19	75	0.100	MOV RECIRC PUMP DISCHARGE (Q1B33F067A-N)
52-1151-20	600	0.100	REAC. RECIRC. HPU OIL PUMP (N1B33D003A2-N)
52-1151-21	17.5	0.100	REAC. RECIRC. HPU OIL PUMP FAN (N1B33D003A4-N)
52-1151-22	60	0.100	DRYWELL CHEMICAL WASTE SUMP PUMP (N1P45C029-N)
52-1151-27	60	0.100	DRYWELL EQPT. DR. SUMP PUMP (N1P45C002A-N)
52-1151-28	125	0.100	CNTMT FLOOR DR. SUMP PUMP (N1P45C019A-N)

TABLE 3.8.4.1-1 (Continued)

PRIMARY CONTAINMENT PENETRATION CONDUCTOR OVERCURRENT PROTECTIVE DEVICES

c. 480 VAC Circuit Breakers (Continued)

Molded Case, Type NZM

BREAKER NUMBER	TRIP SETPOINT (Amperes)	RESPONSE TIME (Seconds)	SYSTEM/COMPONENT AFFECTED
52-1222-04	800	0.100	CNTMT CLR FAN COIL UNIT FAN (N1M41B001B-N)
52-1222-05	240	0.100	CNTMT COOLING SYS CHAR TRAIN FAN (N1M41D002B-N)
52-1222-09	1200	0.100	LIGHTING XFMR 1X104 (N1R18S204-E)
52-1222-11	800	0.100	480 V RECEPTACLES
52-1222-18	500	0.100	REAC. RECIRC. PUMP SPACE HEATER (TB1B33C001B)
52-1222-19	75	0.100	MOV - RWCU RETURN TO REACTOR (N1G33F042-N)
52-1222-20	32	0.100	MOV - VESSEL DRAIN LINE RECIRC. (Q1G33F101-N)
52-1222-21	75	0.100	MOV - CLEANUP LINE SUCT. IN DRYWELL (Q1G33F102-N)
52-1222-22	32	0.100	MOV - CLEANUP LINE RECIRC LOOP B (Q1G33F106-N)
52-1251-01	175	0.100	STEAM TUNNEL CLR. INSIDE CNTMT (N1M41C004B-N)
52-1251-07	60	0.100	CNTMT CHEM WASTE SUMP PUMP (N1P45C027A-N)

TABLE 3.8.4.1-1 (Continued)

PRIMARY CONTAINMENT PENETRATION CONDUCTOR OVERCURRENT PROTECTIVE DEVICES

c. 480 VAC Circuit Breakers (Continued)

Molded Case, Type NZM

BREAKER NUMBER	TRIP SETPOINT (Amperes)	RESPONSE TIME (Seconds)	SYSTEM/COMPONENT AFFECTED
52-1251-13	800	0.100	CNTMT CLR FAN COIL UNIT FAN (N1M41B001C-N)
52-1251-15	32	0.100	MOV - RWCS HX INL ISOL VLV (N1G33F256-N)
52-1251-18	38	0.100	MOV - REGEN HEAT EXCHANGER BYPASS (Q1G33F107-N)
52-1251-19	38	0.100	MOV - RWCU DRAIN FLOW ORIFICE BYP (N1G33F031-N)
52-1251-20	320	0.100	CNTMT EQUIP DRAIN PUMP (N1P45C004B-N)
52-1251-22	32	0.100	MOV - RWCU TO FLT "S" ISOL VLV (N1G33F255-N)
52-1251-26	1200	0.100	LIGHTING XFMR 1X112 (N1R18S112-D)
52-1251-28	5	0.100	MOV - STM TUNNEL COOLER INLET (N1P72F150B-N)
52-1252-23	60	0.100	DRYWELL FLOOR DRAIN SUMP PUMP (N1P45C001B-N)
52-1252-27	500	0.100	FUEL TRANSFER SYS MN CONSOLE (N1F11E015-MC)
52-1411-01	38	0.100	MOV - VESSEL HEAD VENTILATION (Q1B21F002-N)

TABLE 3.8.4.1-1 (Continued)

PRIMARY CONTAINMENT PENETRATION CONDUCTOR OVERCURRENT PROTECTIVE DEVICES

c. 480 VAC Circuit Breakers (Continued)

Molded Case, Type NZM

BREAKER NUMBER	TRIP SETPOINT (Amperes)	RESPONSE TIME (Seconds)	SYSTEM/COMPONENT AFFECTED
52-1511-54	24	0.100	Spare
52-1521-02	6	0.100	MOV COMBUSTIBLE GAS CONTROL SYS (Q1E61F003A-A)
52-1521-03	6	0.100	MOV COMBUSTIBLE GAS CONTROL SYS (Q1E61F005A-A)
52-1521-07	10	0.100	MOV SUPPR. POOL MAKE-UP VALVE (Q1E30F002A-A)
52-1521-14	600	0.100	SCL SYSTEM PUMP (Q1C41C001A-A)
52-1521-15	5	0.100	STORAGE TANK OUTLET VALVE (Q1C41F001A-A)
52-1521-28	12.5	0.100	MOV INST LINE ISOL VALVE (Q1M71F595-A)
52-1521-44	10	0.100	MOV - SUPPR POOL MAKE-UP VALVE (Q1E30F001A-A)
52-1531-24	12.5	0.100	MOV - DRYWELL COOLER ISOLATION (Q1P72F125-A)
52-1531-25	8	0.100	MOV - REACTOR WATER SAMPLE (Q1B33F020-A)

TABLE 3.8.4.1-1 (Continued)

PRIMARY CONTAINMENT PENETRATION CONDUCTOR OVERCURRENT PROTECTIVE DEVICES

c. 480 VAC Circuit Breakers (Continued)

Molded Case, Type NZM

BREAKER NUMBER	TRIP SETPOINT (Amperes)	RESPONSE TIME (Seconds)	SYSTEM/COMPONENT AFFECTED
52-1531-36	320	0.100	MOV - LPCI A INJECTION ISOL (Q1E12F042A-A)
52-1531-44	125	0.100	MOV - RHR A UPPER CMT POOL SPRAY (Q1E12F037A-A)
52-1531-49	32	0.100	MOV - DRYWELL CHEM WASTE ISOL (Q1P45F096-A)
52-1531-50	105	0.100	MOV - RHR A CONTAINMENT SPRAY (Q1E12F028A-A)
52-1541-32	32	0.100	MOV - COMB GAS CONT COMP A OUT (Q1P41F168A-A)
52-1542-05	320	0.100	DRYWELL COOLER FAN COIL UNIT (N1M51B001A-A)
52-1542-06	320	0.100	DRYWELL COOLER FAN COIL UNIT (N1M5B002A-A)
52-1542-07	320	0.100	DRYWELL COOLER FAN COIL UNIT (N1M51B003A-A)
52-1542-08	320	0.100	DRYWELL COOLER FAN COIL UNIT (N1M51B004A-A)
52-1542-09	320	0.100	DRYWELL COOLER FAN COIL UNIT (N1M51B005A-A)

TABLE 3.8.4.1-1 (Continued)

PRIMARY CONTAINMENT PENETRATION CONDUCTOR
OVERCURRENT PROTECTIVE DEVICES

c. 480 VAC Circuit Breakers (Continued)

Molded Case, Type NZM

BREAKER NUMBER	TRIP SETPOINT (Amperes)	RESPONSE TIME (Seconds)	SYSTEM/COMPONENT AFFECTED
52-1542-10	320	0.100	DRYWELL COOLER FAN COIL UNIT (N1M51B006A-A)
52-1542-14	5	0.100	MOV - DRYWELL COOLER INLET (N1P72F145-A)
52-1542-15	5	0.100	MOV - DRYWELL COOLER INLET (N1P72F116-A)
52-1542-16	5	0.100	MOV - DRYWELL COOLER INLET (N1P72F139-A)
52-1542-17	5	0.100	MOV - DRYWELL COOLER INLET (N1P72F111-A)
52-1542-18	5	0.100	MOV - DRYWELL COOLER INLET (N1P72F101-A)
52-1542-19	5	0.100	MOV - DRYWELL COOLER INLET (N1P72F134-A)
52-1542-21	800	0.100	SLCS OPERATING HEATER (N1C41D002)
52-1542-22	24	0.100	DRWL PURGE COMP AUX OIL PUMP (Q1E61C001A-A)
52-1542-23	500	0.100	REFUELING PLATFORM ASSY (Q1F15E003-A)
52-1542-26	175	0.100	DRYWELL RECIRC FAN (N1M51C001-A)

TABLE 3.8.4.1-1 (Continued)

PRIMARY CONTAINMENT PENETRATION CONDUCTOR
OVERCURRENT PROTECTIVE DEVICES

c. 480 VAC Circuit Breakers (Continued)

Molded Case, Type NZM

BREAKER NUMBER	TRIP SETPOINT (Amperes)	RESPONSE TIME (Seconds)	SYSTEM/COMPONENT AFFECTED
52-1542-29	1200	0.100	STBY LIQ CONTROL SYS MIXING HEATER (Q1C41D003)
52-1611-10	12.5	0.100	MOV - DRYWELL COLL TK OUTLET ISOLATION (Q1G41F044-B)
52-1611-15	12.5	0.100	MOV - DCW CTMT STM TNL CLR ISOL (Q1P72F123-B)
52-1611-16	50	0.100	MOV-RHR RX HD SPR INBD ISOL (Q1E12F394-B)
52-1611-25	12.5	0.100	MOV - DRYWELL CLG WTR ISOL (Q1P42F117-B)
52-1611-31	12.5	0.100	MOV - DRYWELL CLG WTR INL ISOL (Q1P42F114-B)
52-1611-32	32	0.100	MOV - CTMT CLG WTR ISOLATION (Q1P42F068-B)
52-1611-42	12.5	0.100	MOV DCW STEAM TUNNEL CLR ISOL (Q1P72F124-B)
52-1611-43	12.5	0.100	MOV DCW STEAM TUNNEL CLR ISOL (Q1P72F126-B)
52-1611-44	38	0.100	MOV - SERVICE AIR DRYWELL ISOLATION (Q1P52F195-B)

TABLE 3.8.4.1-1 (Continued)

PRIMARY CONTAINMENT PENETRATION CONDUCTOR
OVERCURRENT PROTECTIVE DEVICES

c. 480 VAC Circuit Breakers (Continued)

Molded Case, Type NZM

BREAKER NUMBER	TRIP SETPOINT (Amperes)	RESPONSE TIME (Seconds)	SYSTEM/COMPONENT AFFECTED
52-1642-10	320	0.100	DRYWELL COOLER FAN COIL UNIT (N1M51B006B-B)
52-1642-14	12.5	0.100	MOV - DRYWELL COOLER INLET (N1P72F146-B)
52-1642-15	12.5	0.100	MOV - DRYWELL COOLER INLET (N1P72F117-B)
52-1642-16	12.5	0.100	MOV - DRYWELL COOLER INLET (N1P72F140-B)
52-1642-17	12.5	0.100	MOV - DRYWELL COOLER INLET (N1P72F112-B)
52-1642-18	12.5	0.100	MOV - DRYWELL COOLER INLET (N1P72F102-B)
52-1642-19	12.5	0.100	MOV - DRYWELL COOLER INLET (N1P72F135-B)
52-1642-21	24	0.100	DRWL PURGE COMP AUX OIL PUMP (Q1E61C001B-B)
52-1642-29	175	0.100	DRWL RECIRC FAN (N1M51C002B)

TABLE 3.8.4.1-1 (Continued)

PRIMARY CONTAINMENT PENETRATION CONDUCTOR
OVERCURRENT PROTECTIVE DEVICES

(d) 125 VDC Circuit Breakers
GE Type THED

BREAKER NUMBER	TIME O.C. PICKUP (Amperes)	RESPONSE TIME (Seconds)	SYSTEM/COMPONENT AFFECTED
72-11A-23	30	5.0	AUTOMATIC DEPRESSURIZATION SYSTEM VALVES
72-11A-28	15	5.0	REMOTE SHUTDOWN PANEL/AUTOMATIC DEPRESSURIZATION SYSTEM VALVES
72-11A-30	15	5.0	REACTOR PROTECTION SYSTEM/BACKUP SCRAM VALVE
72-11A-33	15	5.0	CONTAINMENT & DRYWELL ISOLATION SYSTEM ANNUNCIATION
72-11A-38	15	5.0	RESIDUAL HEAT REMOVAL SYSTEM VALVES
72-11B-14	50	5.0	RESIDUAL HEAT REMOVAL SYSTEM
72-11B-28	15	5.0	REMOTE SHUTDOWN PANEL/ADS VALVES
72-11B-30	15	5.0	REACTOR PROTECTION SYSTEM/ BACKUP SCRAM VALVE
72-11B-34	30	5.0	AUTOMATIC DEPRESSURIZATION SYSTEM VALVES
72-11B-37	15	5.0	CONTAINMENT & DRYWELL ISOLATION SYSTEM

TABLE 3.8.4.1-1 (Continued)

PRIMARY CONTAINMENT PENETRATION CONDUCTOR
OVERCURRENT PROTECTIVE DEVICES

(e) 208/120 VAC Circuit Breakers (Continued)
GE Type THQB

BREAKER NUMBER	TIME O.C. PICKUP (Amperes)	RESPONSE TIME (Seconds)	SYSTEM/COMPONENT AFFECTED
52-1P151-23	15	4.0	CTMT. CLG. SYSTEM CHARCOAL FLTR. TRAIN HEATER (N1M41D002A-N)
52-1P151-24	15	4.0	MOTOR SPACE HEATER FOR REACTOR RECIRC. SYS. (N1B33D003A3-N)
52-1P151-25	15	4.0	MAIN STEAM PIPING AREA DRWL. COOLER SERVICE WATER CONT. TRANSMITTER (TT-N041)
52-1P151-26	15	4.0	MOTOR SPACE HEATER FOR REACTOR RECIRC. SYSTEM (N1B33D003A4-N)
52-1P151-37	15*	4.0	DRWL. PERSONNEL LOCK (120'-10" ELEV)
52-1P151-38	15*	4.0	CTMT. PERSONNEL LOCK (LOWER)
52-1P222-17	15	4.0	CTMT. CLG. SYSTEM CHARCOAL FLTR. TRAIN HTR. (N1M41D002B-N)
52-1P222-24	15	4.0	CTMT. & DRWL. PERSONNEL AIR LOCK MONITORING SYSTEM IN CONT. ROOM

TABLE 3.8.4.1-1 (Continued)

PRIMARY CONTAINMENT PENETRATION CONDUCTOR
OVERCURRENT PROTECTIVE DEVICES

(e) 208/120 VAC Circuit Breakers (Continued)

GE Type THQB

BREAKER NUMBER	TIME O.C. PICKUP (Amperes)	RESPONSE TIME (Seconds)	SYSTEM/COMPONENT AFFECTED
52-1P222-27	15	4.0	DRWL. COOLERS SERVICE WATER CONT. TRANSMITTER (TT - N044)
52-1P251-13	15	4.0	PUMP VALVE SOLENOID CONT. CKT. & TEMPERATURE FOR REACTOR WATER CLEAN UP SYS.
52-1P252-37	15*	4.0	CONTAINMENT EQUIP. HATCH (Q1M23Y007-1)
52-1P252-38	15*	4.0	CONTAINMENT EQUIP. HATCH (Q1M23Y007-2)
52-1P411-19	15	4.0	DRYWELL CHILLED WATER SYS. CONTROL VALVE INDICATION (1P72ZLR018)
52-1P412-22	15	4.0	MOTOR SPACE HEATER FOR REACTOR RECIRC. SYSTEM (N1B33D003B1-N)
52-1P412-23	20	4.0	UTILITY POWER FOR REMOTE SIGNAL CONDITIONING PANEL
52-1P412-24	15	4.0	MOTOR SPACE HEATER FOR REACTOR RECIRC. SYSTEM (N1B33D003B2-N)
52-1P412-25	20	4.0	UTILITY POWER FOR REMOTE SIGNAL CONDITIONING PANEL

TABLE 3.8.4.2-1 (Continued)

MOTOR OPERATED VALVES THERMAL OVERLOAD PROTECTION

VALVE NUMBER	BYPASS DEVICE (CONTINUOUS) (ACCIDENT CONDITIONS) (MO)	SYSTEM(S) AFFECTED
Q1P72F121	Continuous	Drywell CW System
Q1P72F122	Continuous	Drywell CW System
Q1P72F125	Continuous	Drywell CW System
Q1P72F123	Continuous	Drywell CW System
Q1P72F124	Continuous	Drywell CW System
Q1P72F126	Continuous	Drywell CW System
Q1P44F042	Continuous	Plant SW System
Q1P44F054	Continuous	Plant SW System
Q1P44F067	Continuous	Plant SW System
Q1P45F096	Continuous	Floor & Eqmt. Drain System
Q1P45F097	Continuous	Floor & Eqmt. Drain System
Q1P52F195	Continuous	Service Air System
Q1P53F003	Continuous	Instrument Air System
Q1P53F007	Continuous	Instrument Air System
Q1T48F005	Continuous	SGTS
Q1T48F006	Continuous	SGTS
Q1T48F024	Continuous	SGTS
Q1T48F026	Continuous	SGTS
Q1T48F023	Continuous	SGTS
Q1T48F025	Continuous	SGTS
Q1P45F273	Continuous	Floor & Eqmt. Drain System
Q1P45F274	Continuous	Floor & Eqmt. Drain System

REACTOR PROTECTION SYSTEM ELECTRIC POWER MONITORING

LIMITING CONDITION FOR OPERATION

3.8.4.3 Two RPS electric power monitoring assemblies 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 assembly for an inservice RPS MG set or alternate power supply inoperable, restore the inoperable power monitoring system 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 assemblies for an inservice RPS MG set or alternate power supply inoperable, restore at least one electric power monitoring assembly to OPERABLE status within 30 minutes or remove the associated RPS MG set or alternate power supply from service.

SURVEILLANCE REQUIREMENTS

4.8.4.3 The above specified RPS electric power monitoring assemblies shall be determined OPERABLE:

a. By performance of a CHANNEL FUNCTIONAL TEST at least once per 6 months.

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	Bus A	$\leq$ 132.9 VAC
		Bus B	$\leq$ 133.0 VAC
2.	Under-voltage	Bus A	$\geq$ 115.0 VAC
		Bus B	$\geq$ 115.9 VAC
3.	Under-frequency	Bus A	$\geq$ 57 Hz
		Bus B	$\geq$ 57 Hz

3/4.12 RADIOLOGICAL ENVIRONMENTAL MONITORING

3/4.12.1 MONITORING PROGRAM

LIMITING CONDITION FOR OPERATION

3.12.1 The radiological environmental monitoring program shall be conducted as specified in Table 3.12.1-1.

APPLICABILITY: At all times.

ACTION:

a. With the radiological environmental monitoring program not being conducted as specified in Table 3.12.1-1, prepare and submit to the Commission, in the Annual Radiological Environmental Operating Report per Specification 6.9.1.7, a description of the reasons for not conducting the program as required and the plans for preventing a recurrence.

b. With the level of radioactivity as the result of plant effluent in an environmental sampling medium at a specified location exceeding the reporting levels of Table 3.12.1-2 when averaged over any calendar quarter, prepare and submit to the Commission within 30 days pursuant to Specification 6.9.2 a Special Report that identifies the cause(s) for exceeding the limit(s) and defines the corrective actions to be taken to reduce radioactive effluents so that the potential annual dose to a MEMBER OF THE PUBLIC is less than the calendar year limits of Specifications 3.11.1.2, 3.11.2.2 and 3.11.2.3. When more than one of the radionuclides in Table 3.12.1-2 are detected in the sampling medium, this report shall be submitted if:

$$\frac{\text{concentration (1)}}{\text{reporting level (1)}} + \frac{\text{concentration (2)}}{\text{reporting level (2)}} + \ldots \geq 1.0$$

When radionuclides other than those in Table 3.12.1-2 are detected and are the result of plant effluents, this report shall be submitted if the potential annual dose to a MEMBER OF THE PUBLIC is equal to or greater than the calendar year limits of Specifications 3.11.1.2, 3.11.2.2 and 3.11.2.3. This report is not required if the measured level of radioactivity was not the result of plant effluents; however, in such an event, the condition shall be reported and described in the Annual Radiological Environmental Operating Report.

c. If milk or broad leaf vegetation sampling is relocated from one or more of the sample locations required by Table 3.12.1-1, identify new locations for obtaining replacement samples and add them to the radiological environmental monitoring program within 30 days. In addition, report the cause(s) of the unavailability of samples and the new locations for obtaining replacement samples in the next Semi-annual Radioactive Effluent Release Report. Include in this report the revised ODCM figure(s) and table(s) reflecting the new locations. The specific locations from which samples were unavailable may then be deleted from the radiological environmental monitoring program and the table(s) in the ODCM, provided the locations from which the replacement samples were obtained are added to the table(s) as replacement locations.

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

SURVEILLANCE REQUIREMENTS

4.12.1 The radiological environmental monitoring samples shall be collected pursuant to Table 3.12.1-1 from the locations given in the table and figures in the ODCM and shall be analyzed pursuant to the requirements of Tables 3.12.1-1 and 4.12.1-1.

3/4.6.4 CONTAINMENT AND DRYWELL ISOLATION VALVES

The OPERABILITY of the containment isolation valves ensures that the containment atmosphere will be isolated from the outside environment in the event of a release of radioactive material to the containment atmosphere or pressurization of the containment and is consistent with the requirements of GDC 54 through 57 of Appendix A to 10 CFR Part 50. Containment isolation within the time limits specified for those isolation valves designed to close automatically ensures that the release of radioactive material to the environment will be consistent with the assumptions used in the analyses for a LOCA.

The operability of the drywell isolation valves ensures that the drywell atmosphere will be directed to the suppression pool for the full spectrum of pipe breaks inside the drywell. Since the allowable value of drywell leakage is so large, individual drywell penetration leakage is not measured. By checking valve operability on any penetration which could contribute a large fraction of the design leakage, the total leakage is maintained at less than the design value.

Table 3.6.4-1 lists the Containment and Drywell Isolation Valves in four sections. Section 1 contains the Automatic Isolation Valves which are those valves that receive an automatic isolation signal from Table 3.3.2-1 instrumentation and are located on the Containment or Drywell penetrations. The valves included in Section 2 are Manual Isolation Valves which receive a remote manual signal from a handswitch and are located on the Containment or Drywell Penetrations. Some of the valves in Section 2 may receive automatic signals, but not automatic isolation signals from instrumentation in Table 3.3.2-1. The valves included in Section 3 are those which do not receive isolation signals from instrumentation listed in Table 3.3.2-1 and do not utilize a remote manual handswitch. Section 3 includes check valves, local manual operated valves and power operated valves that do not utilize a handswitch. Section 4 of Table 3.6.4-1 contains test connection valves.

The maximum isolation times for containment and drywell automatic isolation valves are the times used in the FSAR accident analysis for valves with analytical closing times. For automatic isolation valves not having analytical closing times, closing times are derived by applying margins to previous valve closing test data obtained by using ASME Section XI criteria. Maximum closing times for these valves was determined by using a factor of two times the allowable (from previous test closure to next test closure) ASME Section XI margin and adding this to the previous test closure time.

3/4.6.5 DRYWELL VACUUM RELIEF

The safety-related functions of the four drywell vacuum relief subsystems are drywell isolation, proper operation of the drywell purge compressors, and OPERABILITY in a large-break LOCA to control weir wall overflow drag and impact loads. The drywell isolation and drywell purge OPERABILITY functions are discussed in Bases 3/4.6.4 and 3/4.6.7, respectively. Drywell vacuum relief is not required for hydrogen dilution or to protect drywell structural integrity in a design-basis accident.

DRYWELL VACUUM RELIEF (Continued)

To provide drywell vacuum relief, containment air is drawn through subsystems associated with three 10-inch lines penetrating the drywell. Two drywell post-LOCA vacuum relief subsystems are in a parallel arrangement connected to one of the three 10-inch vacuum relief lines penetrating the drywell. Each drywell post-LOCA vacuum relief subsystem consists of a motor-operated isolation valve in series with a check valve. OPERABILITY of either drywell post-LOCA vacuum relief subsystem assures OPERABILITY of the associated 10-inch vacuum relief line penetrating the drywell. Each of the two remaining 10-inch vacuum relief lines penetrating the drywell contains a drywell purge vacuum relief subsystem. Each drywell purge vacuum relief subsystem consists of a series arrangement of a motor-operated isolation valve and two check valves. Vacuum relief initiates at a differential pressure across the check valves of less than or equal to 1 psi.

Rapid weir wall overflow in a large-break LOCA could cause drag and impact loadings to essential equipment and systems in the drywell above the weir wall. Drywell negative pressure analysis for rapid weir wall overflow in a large-break LOCA assumes a vacuum breaker capability of $A/\sqrt{K} = 0.38\ ft^2$ thus requiring a minimum of two 10-inch drywell vacuum relief paths.

OPERABILITY requirements for the four drywell vacuum relief subsystems in relationship to continued plant operation are based on maintaining at least two of the three 10-inch drywell vacuum relief paths OPERABLE. However, to ensure that essential equipment is returned to service in a timely manner, continued plant operation is limited with only one 10-inch drywell vacuum relief line out of service. Plant operation is further limited when two of the three 10-inch lines are out of service to ensure prompt response to restore equipment to service or to place the plant in a condition where the equipment is not required. Plant operation is also limited with a drywell isolation vacuum breaker in the open position to help ensure that design drywell bypass leakage is not potentially exceeded. Position indication is required to be OPERABLE on all drywell vacuum breakers and motor-operated isolation valves to help identify potential drywell bypass leakage paths.

Surveillance requirements and intervals were chosen to reflect the importance associated with the drywell vacuum relief function and are based on good engineering judgement using previous accepted testing methods.

3/4.6.6 SECONDARY CONTAINMENT

Secondary containment is designed to minimize any ground level release of radioactive material which may result from an accident. The Auxiliary Building and Enclosure Building provide secondary containment during normal operation when the containment is sealed and in service. When the reactor is in COLD SHUTDOWN or REFUELING, the containment may be open and the Auxiliary Building and Enclosure Building then become the only containment.

The maximum isolation times for secondary containment automatic isolation dampers/valves are the times used in the FSAR accident analysis for dampers/valves with analytical closing times. For automatic isolation valves not having

SECONDARY CONTAINMENT (Continued)

analytical closing times, closing times are derived by applying margins to previous valve closing test data obtained by using ASME Section XI criteria. Maximum closing times for these valves was determined by using a factor of two times the allowable (from previous test closure to next test closure) ASME Section XI margin and adding this to the previous test closure time.

Establishing and maintaining a vacuum in the Auxiliary Building and Enclosure Building with the standby gas treatment system once per 18 months, along with the surveillance of the doors, latches, dampers, valves, blind flanges, and rupture discs is adequate to ensure that there are no violations of the integrity of the secondary containment.

The OPERABILITY of the standby gas treatment systems ensures that sufficient iodine removal capability will be available in the event of a LOCA. The reduction in containment iodine inventory reduces the resulting site boundary radiation doses associated with containment leakage. The operation of this system and resultant iodine removal capacity are consistent with the assumptions used in the LOCA analyses. Continuous operation of the system with the heaters OPERABLE for 10 hours over a 31-day period is sufficient to reduce the buildup of moisture on the adsorbers and HEPA filters.

SEMIANNUAL RADIOACTIVE EFFLUENT RELEASE REPORT (Continued)

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

6.9.1.10 Routine reports of operating statistics and shutdown experience, including documentation of all challenges to main steam system safety/relief valves, 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 within the time period specified for each report.

6.10 RECORD RETENTION

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.

6.10.1 The following records shall be retained for at least five 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.

6.10 RECORD RETENTION (Continued)

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.

6.10.2 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.

f. Records of reactor tests and experiments.

g. Records of training and qualification for current members of the unit staff.

h. Records of in-service inspections performed pursuant to these Technical Specifications.

i. Records of Quality Assurance activities required by the Operational Quality Assurance Manual not listed in Section 6.10.1.

j. Records of reviews performed for changes made to procedures or equipment or reviews of tests and experiments pursuant to 10 CFR 50.59.

k. Records of meetings of the PSRC and the SRC.

l. Records of the service lives of all hydraulic and mechanical snubbers including the date at which the service life commences and associated installation and maintenance records.

m. Records of analyses required by the radiological environmental monitoring program.

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D. C. 20555

SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

SUPPORTING AMENDMENT NO. 21 TO FACILITY OPERATING LICENSE NO. NPF-29

MISSISSIPPI POWER & LIGHT COMPANY

MIDDLE SOUTH ENERGY, INC.

SOUTH MISSISSIPPI ELECTRIC POWER ASSOCIATION

GRAND GULF NUCLEAR STATION, UNIT 1

DOCKET NO. 50-416

1.0 INTRODUCTION

By letters dated January 29, 1986 (as amended April 14, July 16, and August 26, 1986), June 13, 1986 (as amended August 26, 1986) and July 25, 1986 (as amended August 11, 1986), Mississippi Power & Light Company (the licensee) requested amendments to Facility Operating License No. NPF-29 for the Grand Gulf Nuclear Station, Unit 1 (GGNS-1).

These three applications are addressed separately in this section and in the evaluation below.

1.1 January 29, 1986 application

The proposed amendment would make six changes in the Technical Specifications: (1) change the names and valve numbers of certain plant service water system valves listed in Technical Specification Table 3.6.4-1, 3.8.4.1-1, and 3.8.4.2-1 to reflect the incorporation of those valves into the drywell chilled water system; (2) clarify which quality assurance records specified in Technical Specification 6.10.2.i must be retained for the duration of the operating license; (3) change Technical Specification 3/4.6.5, "Drywell Post-LOCA Vacuum Breakers" to reflect the installation of position indicators for the vacuum breaker check valves and to clarify the specification and associated bases; (4) delete reference to Specification 6.9.1.13.f in Technical Specification 3.12, "Radiological Environmental Monitoring"; (5) change Technical Specification 3/4.1.3, "Control Rods" to reflect installation in the control rod scram discharge volume system of diverse and redundant level instrumentation and redundant vent and drain valves and to allow an alternate system test in lieu of a scram test following valve installation and maintenance; and, (6) change notes in Technical Specification Tables, 3.3.3-1 and 4.3.3.1-1 to make permanent the temporary condition allowing the HPCS actuation signals of Drywell Pressure-High and Manual Initiation to be inoperable when the reactor water level is higher than Level 8 and reactor pressure is less than 600 psig.

Change (1) relates to the designation of the isolation valves for the newly installed drywell chilled water (DCW) system. The system circulates chilled water from freon chillers through the drywell coolers and the steam tunnel cooler during normal operation. It utilizes existing valves and piping that have previously been components of the plant service water (PSW) system, which was originally intended to perform the above mentioned cooling functions. However, during pre-operational testing at the facility, tests indicated that additional drywell cooling beyond that provided by the PSW would be required to support full power operation of the facility. The newly installed DCW system significantly increases the heat removal capacity of the drywell cooling system. Specifically, the licensee proposed a revision of the table listing the containment and drywell isolation valves (Table 3.6.4-1). This revision involves only changing the system name and associated valve numbers for certain PSW system isolation valves listed in the table to indicate that these valves are now components of the newly installed DCW system. The licensee further stated that the TS requirements that ensure the isolation function of these valves remain unaffected by the proposed revision. The licensee also proposed a revision to the Technical Specification Table 3.8.4.1-1 and Table 3.8.4.2-1 to include changes of the nomenclature of the penetration conductor overcurrent protective devices and the motor-operated valve thermal overload protective devices associated with the renamed isolation valves.

With regard to change (2), an inconsistency regarding the quality assurance (QA) record retention requirements of the Catawba Nuclear Station, Unit 1, Technical Specifications has recently been called to the staff's attention by Duke Power Company. These requirements are relatively standard for all newly licensed plants. TS Section 6.10.1 indicates that a number of records of QA activities required by the Operational Quality Assurance Manual (OQAM) "shall be retained for at least 5 years." (For example, Items a, b, and d in the second paragraph of 6.10.1) The inconsistency is that Item i of Section 6.10.2 requires that records of QA activities required by the OQAM (i.e., these same records) "be retained for the duration of the Unit Operating License." Accordingly, the staff requested Mississippi Power & Light Company to consider applicable changes to the Technical Specifications.

In change (3), the licensee proposed changes to Technical Specification (TS) 3/4.6.5. This TS provides the limiting conditions for operation (LCO), the action statements, and the surveillance requirements (SR) for the drywell post-LOCA vacuum relief subsystems, which are utilized for providing vacuum relief for the drywell in post-LOCA situations. The licensee, particularly, sought deletion of all temporary requirements from the current TS (i.e., those required until restart after the first refueling outage). These requirements were included in the existing TS to account for the lack of separate position indicators for the vacuum breakers (i.e., check valves) of the post-LOCA vacuum relief subsystems at the time the the GGNS-1 license was issued. License Condition 2.C.(35) requires that these be installed prior to startup following the first refueling outage. The licensee justified the proposed deletion of the temporary requirements on the basis of staff's previous (July 23, 1985 letter) approval of the position indicator design submittal (May 24, 1986) and the planned installation of these indicators during the first refueling outage. Based on its review, the staff agreed with the licensee's proposed deletion of the temporary requirements. The staff, however, suggested that the revised TS 3/4.6.5 should (1) include the drywell purge vacuum relief subsystems since these are also used to provide vacuum relief for the drywell in the post-LOCA situations, (2) retain the 31-day surveillance requirement for the components of the drywell vacuum relief subsystems since these are consistent with the standard TS for similar BWRs (the licensee proposed deletion of this requirement), (3) include the position indicators for the associated motor-operated isolation valves (MOVs) in series with the vacuum breakers, since staff's acceptance of the licensee's proposed separate position indicators of limited qualification (i.e., for normal operation environment only) for the vacuum breakers is based on the availability of LOCA environmentally qualified position indicators for the MOVs, and (4) include a revised bases section for TS 3/4.6.5 to reflect the inclusion of the drywell purge vacuum relief subsystems. In response to the above suggestions, by letter dated July 16, 1986, the licensee proposed revised changes to TS 3/4.6.5 with justification and also proposed a revised bases section and revised index pages to reflect the above changes. These revised proposed changes delete the temporary requirements and incorporate all of the above staff suggestions.

With regard to change (4), the licensee requested deletion of a reference to reporting requirements in TS Section 6.0 because these reporting requirements had been previously deleted. Deletion of reporting requirements in TS Section 6.0 from Technical Specifications was requested by staff after publication of specific reporting requirements as rules in 10 CFR 50.72 and 10 CFR 50.73.

In change (5) the licensee requested changes to allow implementation of a design change to add redundant scram discharge volume (SDV) vent and drain valves. In the submittal made on April 14, 1986 the licensee proposed new action requirements and withdrew new License Condition 2.C.(41) proposed in the January 29, 1986 submittal. This license condition was proposed to be replaced with deletion of the 50% rod density scram test in Surveillance Requirement 4.1.3.1.4.a. The August 26, 1986 submittal was made after NRR staff expressed concerns regarding deletion of the 50% rod density scram test. The proposed changes to the previous submittal include retaining the 50% rod density scram test and adding a footnote which will provide an exception to the provisions of Specification 4.0.4 provided the surveillance is performed at least once per 18 months. In change (5), the licensee also requested changes to the Technical Specifications to allow implementation of diverse and redundant scram discharge volume (SDV) level instrumentation after its installation during the first refueling outage. TS Table 3.3.1-1 and Table 4.3.1.1-1, are revised in a manner such that the applicable Technical Specification requirements for the SDV Water Level - High instrumentation apply to the transmitter/trip unit, and the redundant float switch separately. This amendment also revises TS Table 2.2.1-1 by adding a list of both types of level instruments to identify individual setpoint requirements.

With regard to change (6), the licensee requested a change to the high pressure core spray (HPCS) system actuation instrumentation operability requirements in TS Table 3.3.3-1 and Table 4.3.3.1-1. Table 3.3.3-1 and Table 4.3.3.1-1 presently permit the HPCS injection function for Drywell Pressure-High and Manual Initiation signals to be inoperable at times when the indicated Reactor Vessel Water Level-High (Level 8) isolation signal is present coincident with the reactor pressure below 600 psig. The original notes to the tables included a phrase "Prior to STARTUP following the first refueling outage" to allow the utility to consider the necessity for a design modification to the water level instrumentation. Deletion of the phrase, as proposed by the licensee, would extend the subject operability requirements beyond the first refueling outage into subsequent plant operations (i.e., the temporary requirements would become permanent).

1.2 <u>June 13, 1986 application</u>

The proposed amendment would change Technical Specification 3/4.5.1, "ECCS - Operating," with respect to the automatic depressurization system (ADS) air system by adding surveillance requirements and an associated action statement for the accumulator low pressure alarm system instrumentation channels and by adding a leakage test for the ADS air system. The proposed changes result from prior commitments made by the licensee to install a pressure instrument to monitor and test the ADS air system. These commitments were subsequently placed in License Condition 2.C.(33)g with implementation to be completed prior to start-up following the first refueling outage.

1.3 <u>July 25, 1986 application</u>

License Condition 2.C.(33)(b) requires the licensee to conduct a test simulating loss of all alternating current power (station blackout) in order to satisfy the requirements in TMI Action Plan Item I.G.1. By Generic Letter 83-24, "TMI-2 Task Action Plan Item I.G.1, Special Low Power Testing and Training, Recommendations for BWRs," holders of an operating license were requested to commit to the recommendations of the BWR Owners Group with respect to this additional testing, and to respond to the Generic Letter by determining whether a proposed station blackout (SBO) test would have the potential for damaging plant equipment.

In a letter from O. D. Kingsley, Jr., Mississippi Power and Light Company (MP&L) to H. R. Denton, NRC, dated April 3, 1986, MP&L presented the results of an analysis of a postulated SBO event for the Grand Gulf Nuclear Station which is evaluated below.

2.0 EVALUATION

2.1 January 29, 1986 application

Change (1) Drywell chilled water system isolation valves.

The staff has reviewed the licensee's proposed revision of Table 3.6.4-1 and supporting justification. Based on the review, the staff agrees with the licensee that the proposed revision is administrative in nature. It involves only a change in system name and changes in associated valve numbers for certain plant service water (PSW) system valves listed in the table. The purpose of the change is to indicate that these valves are now components of the newly installed drywell chilled water DCW system. Also, the revision of the table does not impact the isolation function of these valves as required by the current GGNS-1 TS. The staff agrees with the licensee that the proposed change will accurately reflect the newly installed DCW system. Also, it will facilitate preparation of associated documentation such as piping and instrument diagrams to show that certain PSW system valves are now DCW system components. The staff concludes that proposed revision of Table 3.6.4-1 is acceptable.

The staff has also reviewed the licensee's proposed revision of Table 3.8.4.1-1, "Primary Containment Penetration Conductor Overcurrent Protective Devices" and Table 3.8.4.2-1, "Motor Operated Valves Thermal Overload Protection." The revision consists solely of changing the nomenclature of the protective devices to indicate that these components are now included in the newly installed chilled water system. The breaker numbers, their trip setpoints and response times in Table 3.8.4.1-1 and the thermal overload protection devices for MOVs in Table 3.8.4.2-1 are not affected by this change. The staff has reviewed the licensee's submittal and concludes that the proposed Technical Specifications include changes only in the designation of the system and its associated components and are therefore acceptable.

Change (2) Retention of QA records.

The staff has reviewed the proposed change to TS 6.10.2 regarding retention of records of QA activities. The licensee proposed changing TS 6.10.2.i to require retention of QA records required by the Operational Quality Assurance Manual if they are not listed in TS 6.10.1. Those listed in TS 6.10.1 are presently and would continue to be retained for 5 years. This change is in accordance with the staff's recommendation and is therefore acceptable.

Change (3) Drywell vacuum relief system

The staff has reviewed the licensee's proposed Technical Specification 3/4.6.5 and the associated Bases 3/4.6.5 for the modified drywell vacuum relief system which equalizes pressure between the containment and drywell following a loss of coolant accident (LOCA). The licensee states that post-LOCA vacuum relief for the drywell is required to control rapid steam condensation in the drywell due to weirwall overflow that may result from a vacuum in the drywell following a LOCA. The water swell from rapid condensation in the drywell could cause drag and impact loadings to essential equipment and systems in the drywell above the weirwall. The licensee states that the vacuum relief function for the drywell in the above situation is provided by four drywell vacuum relief subsystems (an independent drywell vacuum relief capability also exists via a normal drywell vacuum relief line which handles normal operating transients and small pipe ruptures in the containment). The four drywell vacuum relief subsystems are comprised of two drywell purge vacuum relief subsystems (part of the combustible gas control purge system) associated with two 10-inch drywell vacuum relief lines, and two drywell post-LOCA vacuum relief subsystems arranged in parallel and associated with one 10-inch drywell vacuum relief line. The latter two subsystems are redundant, since operability of either one will ensure the availability of the common associated 10-inch vacuum relief line. Each drywell post-LOCA vacuum relief subsystem consists of a drywell vacuum breaker (i.e., check valves F004A & B for the A and B subsystems) in series with a motor-operated butterfly isolation valve (F005A & B for the A and B subsystems). Each drywell purge vacuum relief subsystem consists of two vacuum breakers (I.E., check valves F001A and F002A for the subsystem A; check valves F001B and F002B for the subsystem B) and one motor-operated butterfly isolation valve (F003A and F003B for the subsystems A and B) all in series. Vacuum relief is initiated automatically by flow of containment air through all three 10-inch drywell vacuum relief lines via the valves mentioned above to the drywell at a differential pressure of less than or equal to 1 psi across the check valves. The above subsystems also ensure that the design drywell bypass leakage is not exceeded if a LOCA should occur during plant operational conditions 1, 2 and 3. All the above subsystems also include separate position indicators for all the 10 valves, which help to identify potential drywell bypass leakage paths during the above operational conditions. Licensee's proposed limiting condition for operation (LCO) 3.6.5 and surveillance requirement (SR) 4.6.5 for the above drywell vacuum relief subsystems ensure the above objectives. Specifically, the proposed LCO requires that all the four subsystems be operable with their associated valves in the closed position in plant operational conditions 1, 2 and 3. The proposed SR require periodic surveillance tests or verifications (i.e., at least once every 7 days, 31 days or 18 months depending upon the type of the test or verification) for the check valves, isolation valves, differential pressure actuation instrumentation for the isolation valves, and the position indicators to demonstrate that these are operable and that all the valves are in closed position during plant operational conditions 1, 2 and 3.

Assuming a vacuum breaker capability of $A/(K)^{0.5}$ equal to 0.38 ft^2, the licensee has performed a drywell negative pressure analysis and determined that a minimum of two 10-inch drywell vacuum relief lines will be required to control possible rapid weirwall overflow that can result from a large break LOCA. The staff agrees with the above determination, particularly, because the licensee has previously demonstrated the acceptability of the dynamic loads from the pool created by reverse differential pressure calculated for the drywell, assuming no credit for the operation of drywell vacuum breakers (see GGNS, Units 1 and 2 Updated Final Safety Analysis

Report, Section 6.2 and GGNS Safety Evaluation Report (SER) Supplement No. 3, Section 22, July 1982). The licensee states that the above minimum requirement for drywell vacuum relief lines can be ensured by requiring that either both the drywell purge vacuum relief subsystems or one drywell purge vacuum relief subsystem and one drywell post-LOCA vacuum relief subsystem be operable during operational conditions 1, 2 and 3. Licensee's proposed Action Statements 3.6.5a, b and c cover the situations arising from inoperable drywell vacuum relief subsystem(s) (i.e., inoperable in the sense that the associated valve(s) is (are) inoperable for opening but known to be closed) during plant operational conditions 1, 2 and 3 and follow from the above mentioned minimum requirement and how it can be met. Specifically, for such situations, these action statements allow continued plant operation, provided corrective action(s), i.e., restoring the inoperable valve(s) to operable status, is (are) completed within 30 days or 72 hours depending upon whether one or two 10-inch drywell vacuum relief line(s) is (are) affected. However, the above 72-hour time limit for corrective actions to continue plant operation is not allowed for the situation in which both purge vacuum relief subsystems are affected. The requirement that the affected valve(s) be known to be closed stipulated in the above action statements ensures that the design drywell bypass leakage will not be exceeded should a LOCA occur in plant operational conditions 1, 2 and 3. Additionally, licensee's proposed Action Statement 3.6.5.d covers the situation arising from an open drywell isolation breaker (i.e., check valve F002A, F002B, F004A or F004B) in plant operational conditions 1, 2 and 3. Specifically, for such a situation, the action statement allows continued plant operation, provided the open valve is closed within one hour to prevent a potential drywell bypass leakage path in a timely manner. Since the other vacuum breaker(s) of the drywell purge subsystem(s) (i.e., check valves F001A and/or F001B) being open in operational conditions 1, 2 and 3 does (do) not result in drywell bypass leakage paths, provided the upstream vacuum breakers (i.e., F002A and F002B) are in a closed position, the Action Statement 3.6.5.d does not cover them. However, these valves(s) being in open position(s) correspond to inoperable purge subsystem(s) which are covered by plant TS 3.6.7.3, "Combustible Gas Control Purge System." Licensee's proposed Action Statement 3.6.5.e allows continued plant operation, in the event, the position indicator of any operable valve is inoperable, provided the operable valve is verified closed at least once per 24 hours by local indication.

The staff concludes that the licensee's proposed changes to TS 3/4.6.5 and the associated TS bases as identified in the July 16, 1986 submittal, are acceptable. The staff's acceptance is based on the following findings:

a. The LCO includes all four drywell vacuum relief subsystems which provide drywell vacuum relief in post-LOCA situations;

b. The proposed corrective actions and the times for completing them for continuing plant operation are consistent with applicable Standard Technical Specifications;

c. The proposed changes to TS 3/4.6.5 provide reasonable assurance that the needed vacuum relief will be available for the drywell in post-LOCA situations and that the drywell design basis bypass leakage will not be exceeded should a LOCA occur during plant operational conditions 1, 2 and 3; and

d. The proposed bases for TS 3/4.6.5 adequately describe the safety functions of the vacuum relief subsystems, from which the TSs were derived.

Change (4) Reporting of radiological environmental monitoring results.

The staff has reviewed the licensee's requested deletion from TS 3.12.1.b of a reference to TS 6.9.1.13.f for reporting requirements in the event radiological monitoring results exceed specified reporting levels. The GGNS-1 Technical Specifications currently in effect, do not contain a TS 6.9.1.13.f because it was deleted to conform to recently effective Commission rules, 10 CFR 50.72 and 10 CFR 50.73. Section 3.12.1.b of the TS already refers to a Special Report pursuant to TS 6.9.2. Thus, the reference to TS 6.9.1.13.f on Page 3/4 12-1 is superfluous and should be deleted as a typographical error. Accordingly, the staff concludes the proposed change is acceptable.

Change (5) Scram discharge volume redundant level instrumentation, vent valve and drain valve.

The proposed design change associated with this technical specification change, modifies the scram discharge volume (SDV) design to meet the requirements of the NRC generic study, "BWR Scram Discharge Volume System Safety Evaluation", dated December 1, 1980. The design change is required by the Grand Gulf Unit 1 Operating License Condition 2.C.(15).

As a part of the required design change, two float-type level switches per trip system are added. These new switches provide independent trip signals to the reactor protection system in addition to the existing analog level transmitters. The purpose of this modification is to minimize the potential for a common mode failure due to a drain or a vent valve not closing and resulting in an uncontrolled loss of coolant. The licensee has stated that this design modification conforms to the requirements of IEEE Standard 279-1971 and other design commitments with respect to the reactor protection system. The new float switches are qualified to the same requirements of the existing level transmitters. The trip setpoints and allowable values for both the transmitter/trip units and the float switches are based on an available SDV of 645 gallons. This corresponds to a level of 10" below the lowest elevation of the SDV or, equivalently, a level of 64" in the scram discharge instrument volume. The zero for the trip unit scale is equivalent to 46" in the instrument volume and the scale range is 0-30". The trip setpoint is 46" + (60% of 30") = 64" and the allowable value is 46" + (63% of 30") = 64.9" or 65". Therefore, the setpoints and allowable values for both the transmitter/trip units and the float switches are equivalent. The staff finds that the licensee's design modification and the technical specification changes in Tables 3.3.1-1, 4.3.1.1-1 and 2.2.1-1 are acceptable.

The other part of the design change required by License Condition 2.C.(15) is the addition of a redundant vent valve and a redundant drain valve to the SDV. The changes to TS 3/4.1.3.1 resulting from this design change are evaluated below.

Proposed Action Statement d of TS 3.1.3.1 gives the required action if one SDV vent valve and/or one drain valve is found to be inoperable and open. During normal operation, the SDV is vented and drained to the suppression pool through a vent line and a drain line. In the present design there is one drain valve and one vent valve. In the modified design, each line contains two valves in series which are actuated to close upon a scram, thus allowing the control rod drive effluent to be contained in the SDV. In the event of a scram, and failure of all SDV vent and drain valves to close, there would be a slight heat-up of the suppression pool. The capacity of the residual heat removal system would be more than adequate to remove this heat load. Reactor vessel makeup water would be assured from either the condensate and feedwater system, or the high pressure core spray system. Therefore, the safe shutdown capability of the unit is not adversely affected. The present TS prescribes steps to be taken when one SDV vent and/or one drain valve is inoperable and open. The required action is the closing of the inoperable valve within one hour. No action is required for an inoperable closed valve. The proposed change applies to an inoperable condition while the subject valves are open and eliminates the requirement to close them. The allowed time of operation with inoperable valves is 24 hours. The licensee states that the present requirement to close the inoperable valve(s) could cause the plant to undergo an unnecessary transient if operational leakage into the SDV is enough to reach the scram level setpoint. In addition, by this change, the action statement will conform to that of the Perry Plant and the Clinton Plant, which are also BWR-6, Mark III plants. The staff concludes that proposed Action Statement d is acceptable because in the event of a scram, the remaining operable vent and drain valves can still be expected to perform their function of preventing blowdown of reactor coolant via the SDV. In addition, unnecessary scrams may be reduced and the safe shutdown capability of the plant will not be adversely affected.

Proposed Action Statement e of TS 3.1.3.1 gives the required action if two SDV vent and/or drain valves are found to be inoperable and open. In the event of a scram, while operating in this condition, there could be a blowdown of the reactor coolant, via the SDV, into the suppression pool. This would slightly raise the temperature of the suppression pool. The proposed action includes requiring having one vent valve and one drain valve operable (permitting closure on scram) within 8 hours. This is more restrictive than the 24 hours allowed for operating with one vent valve and one drain valve inoperable and open as discussed in proposed Action Statement d. The action further requires restoring all valves to operable status within the next 16 hours, or closing at least one vent valve and one drain valve and being in hot shutdown within the next 12 hours. This additional 16 hour restoration time for the remaining inoperable vent valve and/or drain valve is consistent with the proposed Action Statement d. The required action is that all vent valves and drain valves be made operable within 24 hours. The staff concludes that proposed Action Statement e is acceptable.

Proposed Action Statement f of TS 3.1.3.1 gives required action if the SDV vent valves and/or drain valves are found to be inoperable and closed. The action is to restore all valves to operable status within 8 hours or be in hot shutdown within the next 12 hours. The staff finds this to be acceptable because if a scram does occur the SDV vent and drain valves are in their preferred position. When there is no scram and these valves are shut, water will accumulate in the SDV. Although this may initiate a scram, the valves are in their preferred closed position and therefore the safe shutdown capability of the plant would not be adversely affected. The staff concludes that proposed Action Statement f is acceptable.

Proposed Surveillance Requirement a of TS 4.1.3.1.4 gives the required surveillance test to determine operability of the vent valves and the drain valves by means of a scram test from a normal control configuration of less than or equal to 50% control rod density. This rod configuration requires the reactor to be in Operational Condition 1, Power Operation, or 2, Startup, when the test is run. The present surveillance requirement is that the SDV vent valves and drain valves be demonstrated operable by performing such a scram test at least once every eighteen months. A demonstration of operability is also required when major modifications are made to the SDV which could affect operability including the installation of the new vent valve and the new drain valve. However, by TS 4.0.4, entry into either of the Operational Conditions cannot be made unless the surveillance has been performed. Thus, an exception to TS 4.0.4 is required to run the initial test. The proposed change adds a footnote which provides an exception to TS 4.0.4, as long as the surveillance is performed at least once per eighteen months. Hence, operational condition 1 or 2 may be entered without having run the surveillance test and the operation may be continued as long as the surveillance is performed within eighteen months, and at least once per eighteen months thereafter. The above provisions address periodic demonstration of SDV system operability under normal plant operation conditions. However, the staff was concerned that there is no provision for showing operability prior to any startup following significant SDV system modification. The licensee has responded to this concern by making a commitment to evaluate each maintenance activity affecting SDV operability and to perform retests of parts, or of the entire SDV, as necessary, to ensure operability of affected components. In particular, with respect to the first startup following the installation of the additional vent valve and drain valve, the licensee has provided information regarding the location of the work area, number of personnel involved and a method of installation to ensure proper installation of the valves. The licensee also has committed to special testing to ensure proper vent and drain flow. A scram injection signal test is also to be performed after the modification is complete. This test is to demonstrate that all SDV vent valves and drain valves closure times meet the 30 second closure criteria. A reset will follow and the vent valves and drain valves will be verified to open and the SDV checked to ensure proper drainage. The staff has reviewed the above information and finds that the licensee's approach is reasonable and provides adequate assurance of SDV system operability. Based on its review of the proposed changes to TS 3/4.1.3.1, the staff concludes that proposed Surveillance Requirement a of TS 4.1.3.1 is acceptable because unnecessary scrams for testing will be eliminated and acceptable alternative tests following SDV system modification will be run to demonstrate SDV operability.

Change (6) Operability requirements for high pressure core spray (HPCS) actuation instrumentation.

To justify the non-operability of the HPCS injection function on Drywell Pressure-High and Manual Initiation when the reactor pressure vessel Level 8 isolation signal is present coincident with reactor pressure below 600 psig, the licensee has provided a discussion and accident analysis in the January 29, 1986 submittal to demonstrate that the calculated peak clad temperature (PCT) remains well below the 2220°F limit. Specifically, a steam line break inside the containment was reanalyzed with the assumption that the high drywell pressure initiation feature is defeated and HPCS is initiated only by low water level. Other assumptions in the calculation were the same as the previous Final Safety Analysis Report (FSAR) analysis (e.g., worst single failure); the PCT was calculated to be 1322°F. The ECCS performance analysis was done with analytical methods previously approved by the staff (General Electric company Analytical Model for Loss of Coolant Analysis in Accordance with 10 CFR 50 Appendix R, NEDO-20566, August 1974).

A previous concern with water level instrumentation was that the upset, narrow and wide range water level instruments are calibrated for normal operating conditions and would read higher than actual level at low coolant temperatures and pressures. This would result in the actuation of the Level 8 interlock with actual water level lower than at operating conditions. The staff agrees with the licensee's conclusion that for the purpose of preventing vessel overfill, this actuation of the interlock would not compromise plant safety.

In addition, the reanalysis of the steam line break for no HPCS injection on a high drywell pressure signal shows that the HPCS injection function is not required at times when a false Level 8 isolation signal is present.

Based on our review of the licensee's reanalysis of the relevant LOCA and accompanying discussion, we conclude that the predicted PCT of 1322°F remains well below the 2220°F limit of 10 CFR 50.46 for the condition of no HCS Injection when the Level 8 isolation signal is present coincident with reactor pressure below 600 psig.

General Design Criterion 13 states, in part, that "Instrumentation shall be provided to monitor variables and systems over their anticipated ranges for normal operation, for anticipated operational occurrences, and for accident conditions as appropriate to assure adequate safety...". The proposed Technical Specification change for Grand Gulf would retain the necessary safety functions on low water level at RCS pressures below 600 psig, because the measurement error in water level decreases as the water level decreases and actuation of emergency systems would still occur. Since (1) the actuation of the interlock for the purpose of preventing vessel overfill would not compromise plant safety, (2) the reanalysis of the steam line break shows that HPCS injection is not required when a false Level 8 isolation signal is present and (3) initiation of HPCS on low water level is not adversely affected by this change, the staff concludes that the requirement of General Design Criterion 13 for adequate instrumentation remains satisfied.

Thus, the staff concludes that the proposed change (6) to the TSs is acceptable because it meets 10 CFR 50.46 and General Design Criterion 13.

2.2 June 13, 1986 application

The purpose of the air accumulators for the automatic depressurization system (ADS) is to provide the safety relief valves that are in the ADS with sufficient air supply to cycle the valves open two times at design reactor coolant pressure should the normal ADS air supply fail. The air accumulators and associated equipment and instrumentation are designed to perform their safety function in an accident environment for 100 days following an accident. Air leakage from the accumulators must be accounted for in order to assure that the inventory of compressed air in the accumulators is available for their safety function.

The licensee previously submitted the design of the air accumulators and the associated equipment and instrumentation. The NRC staff approved the design by letters dated March 15, 1985 and November 22, 1985. The staff concluded that the requirements of TMI Action Plan Item II.K.3.28, "Verify Qualification of Accumulators on ADS Valves" (NUREG-0737) were satisfied by the proposed design.

The NRC staff has reviewed the licensee's June 13, 1986 application as amended August 26, 1986 which requests changes to the Technical Specifications to implement the previously approved design. The changes include: surveillance tests for a low pressure alarm system channel function test and channel calibration including the low pressure alarm setpoint; an action statement if the instrumentation is inoperable; and, a leakage test of the ADS air system every 18 months.

The leakage test is initiated by turning off the instrument air booster compressors and by venting the booster compressor discharge to atmosphere. The pressure decay rate in each of the two ADS air headers is monitored, and the air pressure at the end of the seven days is determined by extrapolation. The leakage test is considered acceptable if the air pressure after seven days (based on extrapolation from test data) is above 110 psig. Tests have shown that with the ADS air system at 110 psig, each ADS valve can be actuated two times against 70% of drywell design pressure. The staff concludes this test acceptance criterion is acceptable because it meets the previously approved design requirements in staff's March 15, 1986 letter.

Instrumentation to monitor ADS air receiver pressure will consist of a separate alarm and pressure indicator in the control room for each of two redundant divisions. Environmental Qualification of pressure transmitters will be in accordance with 10CFR50.49. Design codes for installation will be in accordance with IEEE-323, 1974 and all applicable codes listed in the Final Safety Analysis Report (FSAR). The trip setpoint for the ADS air receiver pressure alarm is based on an analytical lower limit of 147 psig. The lower limit is determined by the minimum pressure required to provide two actuations for each ADS valve and then hold the ADS valves open for five days under the most limiting accident conditions. The upper limit for the alarm will be administratively controlled to ensure that it is below the ADS booster compressor start signal trip setpoint and is currently set at a nominal 160 psig. To ensure that an alarm is generated well before the minimum required ADS air receiver pressure is reached, the nominal trip setpoint will be 150 psig. This nominal trip setpoint will be maintained to ensure that an alarm is generated, operators will take appropriate action in accordance with alarm response instructions including declaring the ADS system inoperable. These alarm response instructions will replace the administrative controls currently used to monitor the pressure every 24 hours and take action if the pressure reads less than 150 psig. The action statement for inoperable low pressure alarm system instrumentation channels requires monitoring the pressure locally every 12 hours and restoring the inoperable channels to operable status within 7 days or declare the associated ADS valves to be inoperable. The surveillance requirements are acceptable to the staff because they meet previously approved design requirements in the staffs March 15, 1986 letter. The action statement is acceptable to the staff because the present surveillance interval of once per 24 hours has been demonstrated to be adequate and the 7 day allowance is adequate to effect most repairs to the instrumentation.

In addition to the proposed changes to the Technical Specifications, the licensee will implement administrative procedures to test the instrument air quality of the ADS air system. A sample of instrument air will be taken every 6 months to ensure that the proper air quality is maintained. These air samples will be analyzed for moisture content, particle size, and oil content and will be required to meet the General Electric design requirements for ADS system safety-related components. This General Electric design specification requires that the ADS air supply be oil-free (less than 1 ppm), dried to a dew point of - 40°F at 100 psig, and filtered to 50 microns. The proposed administrative procedure will require that the instrument air quality be verified to be within the required limits at least once every 6 months. The 6 month test interval will allow for comparisons of test data for determining if system degradation is taking place. In the event the instrument air quality fails to meet the design requirements, an engineering evaluation will be performed within 7 days. The licensee presently contracts the sampling of ADS instrument air quality to an off-site laboratory. The laboratory supplies the evacuated cylinder used to collect the air sample. These cylinders must be requested from the laboratory just prior to collecting a sample. Once the sample is drawn, the cylinder is shipped back to the laboratory for analysis. Total analysis time from the time the cylinder is requested until results are received from the sample is approximately 3 to 4 weeks. The licensee concluded that a testing interval of less than six months would place undue constraints on the operation of the plant. The staff concludes that a six month testing interval will allow for the comparison of previous tests and the early detection of system degradation, and is, therefore, acceptable.

In summary, the staff concludes that the proposed changes to the Technical Specifications and the administrative control of testing instrument air quality meet the design requirements previously approved by the staff in its March 18, 1986 letter and are therefore acceptable.

2.3 July 25, 1986 application

The staff has reviewed the results of the licensee's response to Generic Letter 83-24 and its request to revise License Condition 2.C.(33)(b).

In its analysis of a station blackout (SBO) test, the licensee concluded that a SBO test could damage equipment in the drywell due to drywell temperature levels above normal. The safety-related equipment would not be endangered and could survive a SBO; however, the non-safety-related equipment could be damaged. In addition, the safety-related equipment in the drywell would suffer accelerated thermal aging from a SBO test. The licensee's analysis complies with Generic Letter 83-24 and is sufficient justification for not performing a SBO test at Grand Gulf Nuclear Station. Further, the staff notes that the licensee's evaluation is consistent with similar evaluations made for Clinton, Susquehanna, Hope Creek, LaSalle, and other BWRs.

In its April 3, 1986 submittal, the licensee committed to comply with the recommendations of the BWR Owners Group letter to the NRC dated February 4, 1981 regarding augmented testing (BWROG-8120). This augmented testing will be completed during the first refueling outage, scheduled to begin in September 1986 and end in November 1986.

Based on its review the staff concludes that the SBO test need not be performed at Grand Gulf Nuclear Station. Also, since the Grand Gulf Nuclear Station has committed to the BWR Owners Group recommendations for augmented testing, we conclude that the Grand Gulf Nuclear Station Test Program described in the FSAR, without the SBO test, meets TMI-2 Action Plan Item I.G.1 requirements. Since the proposed License Condition 2.C.(33)(b) replaces the requirement for the SBO test with the requirement for augmented testing recommended by the BWR Owners Group, the proposed license condition is acceptable.

3.0 ENVIRONMENTAL CONSIDERATION

This amendment involves changes to requirements with respect to the installation or use of facility components located within the restricted area as defined in 10 CFR Part 20 and changes to the surveillance requirements. The staff has determined that the amendment involves no significant increase in the amounts, and no significant change in the types, of any effluents that may be released offsite and that there is no significant increase in individual or cumulative occupational radiation exposure. The Commission has previously issued proposed findings that this amendment involves no significant hazards consideration and there has been no public comment on such findings. Accordingly, this amendment meets the eligibility criteria for categorical exclusion set forth in 10 CFR 51.22(c)(9). Pursuant to 10 CFR 51.22(b), no environmental impact statement or environmental assessment need be prepared in connection with the issuance of this amendment.

4.0 CONCLUSION

The Commission made proposed determinations that the amendment involves no significant hazards consideration which were published in the Federal Register on August 13, 1986 , (51 FR 29002) and on September 10, 1986, (51 FR 32275, 32276, and 32277) and consulted with the state of Mississippi. No public comments were received, and the state of Mississippi did not have any comments.

The staff has concluded, based on the consideration discussed above, that: (1) there is reasonable assurance that the health and safety of the public will not be endangered by operation in the proposed manner, and (2) such activities will be conducted in compliance with the Commission's regulations and the issuance of this amendment will not be inimical to the common defense and the security nor to the health and safety of the public.

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