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

October 6, 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

RE: GRAND GULF NUCLEAR STATION, UNIT 1

The Commission has issued the enclosed Amendment No. 20 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) in response to: Item 13 of your August 12, 1985 application, as amended September 25, 1985, and supplemented October 5 and October 22, 1985 and May 30, 1986; your March 21, 1986 application as supplemented May 30, 1986; and, your July 15, 1986 application.

This amendment would change Technical Specifications to: reflect the installation of pressure interlocks for the injection valves in the low pressure emergency core cooling systems; reflect the modification of the logic for actuation of the automatic depressurization systems; and the installation of a strong motion seismic accelerometer on a support for the high pressure core spray system; and, reflect the deletion of four peak recording seismic accelerographs which are presently mounted on reactor coolant piping. Changes to the Technical Specification pages in this amendment are effective when the equipment modifications necessitating the changes are completed and the affected systems are made operable, but not later than startup following the first refueling outage. You are requested to inform the NRR by letter of the effective dates for each page in this amendment within 7 days of the date the affected systems are made operable.

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PDR ADOCK 05000416
P PDR

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

Sincerely,

Lester L. Kintner

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

Enclosures:
1. Amendment No. 20 to
   License No. NPF-29
2. Safety Evaluation

cc w/enclosures:
See next page

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

Sincerely,

Original signed by

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

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cc w/enclosures:
See next page

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Previously concurred*: MC

LK for PD#4/LA*	PD#4/PM*	OGC*	PD#4/D
MO'Brien	LKintner:lb	Young	WButler
09/18/86	09/18/86	09/25/86	10/6/86
	10/6/86		

WB

Mr. Oliver D. Kingsley, Jr.
Mississippi Power & Light Company

Grand Gulf Nuclear Station

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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. 20
License No. NPF-29

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

   A. The applications for amendment by Mississippi Power & Light Company, Middle South Energy, Inc., and South Mississippi Electric Power Association, (the licensees) dated August 12, 1985 (as amended September 25, 1985 and supplemented October 5 and October 22, 1985 and May 30, 1986), March 21, 1986 (as supplemented May 30, 1986), and July 15, 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, the license is 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. 20 , 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.

3. The Technical Specification pages in this amendment are effective when the equipment modifications necessitating the changes on these pages are completed and the affected systems are made operable but not later than startup following the first refueling outage.

FOR THE NUCLEAR REGULATORY COMMISSION

Original signed by

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

Attachment:
Changes to the Technical
Specifications

Date of Issuance: October 6, 1986

Previously concurred*
LK for

PD#4/LA*	PD#4/PM*	OGC*	PD#4/D
MO'Brien	LKintner:lb	MYoung	WButler
09/19/86	09/19/86	09/25/86	10/6/86
	10/6/86		

3. The Technical Specification pages in this amendment are effective when the equipment modifications necessitating the changes on these pages are completed and the affected systems are 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 6, 1986

ATTACHMENT TO LICENSE AMENDMENT NO. 20

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 page(s) provided to maintain document completeness.*

Remove	Insert
3/4 3-27	3/4 3-27*
3/4 3-28	3/4 3-28
-	3/4 3-28a
3/4 3-29	3/4 3-29*
3/4 3-30	3/4 3-30
3/4 3-31	3/4 3-31
-	3/4 3-31a
3/4 3-32	3/4 3-32*
3/4 3-32a	3/4 3-32a*
3/4 3-33	3/4 3-33
3/4 3-34	3/4 3-34
-	3/4 3-34a
3/4 3-35	3/4 3-35
-	3/4 3-35a
3/4 3-36	3/4 3-36*
3/4 3-63	3/4 3-63*
3/4 3-64	3/4 3-64
3/4 3-65	3/4 3-65
3/4 3-66	3/4 3-66*
3/4 4-9	3/4 4-9*
3/4 4-10	3/4 4-10
3/4 4-11	3/4 4-11
3/4 4-12	3/4 4-12
3/5 5-5	3/4 5-5
3/4 5-6	3/4 5-6*

3/4.3.3 EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

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

APPLICABILITY: As shown in Table 3.3.3-1.

ACTION:

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

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

c. With either ADS trip system "A" or "B" inoperable, restore the inoperable trip system to OPERABLE status within:

    1. 7 days, provided that the HPCS and RCIC systems are OPERABLE.

    2. 72 hours.

    Otherwise, be in at least HOT SHUTDOWN within the next 12 hours and reduce reactor steam dome pressure to less than or equal to 135 psig within the following 24 hours.

SURVEILLANCE REQUIREMENTS

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

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

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

TABLE 3.3.3-1

EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION

TRIP FUNCTION	MINIMUM OPERABLE CHANNELS PER TRIP FUNCTION[(a)]	APPLICABLE OPERATIONAL CONDITIONS	ACTION
A. DIVISION I TRIP SYSTEM			
1. RHR-A (LPCI MODE) & LPCS SYSTEM			
a. Reactor Vessel Water Level - Low Low Low, Level 1	2[(b)]	1, 2, 3, 4*, 5*	30
b. Drywell Pressure - High	2[(b)]	1, 2, 3	30
c. LPCI Pump A Start Time Delay Relay	1	1, 2, 3, 4*, 5*	31
d. Manual Initiation	1/system[(b)]	1, 2, 3, 4*, 5*	32
e. Reactor Vessel Pressure - Low (Injection Permissive)	3	1, 2, 3	31
		4* 5*	35
2. AUTOMATIC DEPRESSURIZATION SYSTEM TRIP SYSTEM "A"#			
a. Reactor Vessel Water Level - Low Low Low, Level 1	2[(b)]	1, 2, 3	30
b. Drywell Pressure - High	2[(b)]	1, 2, 3	30
c. ADS Initiation Timer	1	1, 2, 3	31
d. Reactor Vessel Water Level - Low, Level 3 (Permissive)	1	1, 2, 3	31
e. LPCS Pump Discharge Pressure-High (Permissive)	2	1, 2, 3	31
f. LPCI Pump A Discharge Pressure-High (Permissive)	2	1, 2, 3	31
g. Manual Initiation	2/system	1, 2, 3	32
h. ADS Bypass Timer (High Drywell Pressure)	2	1, 2, 3	32
i. Manual Inhibit	1	1, 2, 3	32
B. DIVISION 2 TRIP SYSTEM			
1. RHR B & C (LPCI MODE)			
a. Reactor Vessel Water Level - Low, Low Low, Level 1	2[(b)]	1, 2, 3, 4*, 5*	30
b. Drywell Pressure - High	2[(b)]	1, 2, 3	30
c. LPCI Pump B Start Time Delay Relay	1	1, 2, 3, 4*, 5*	31
d. Manual Initiation	1/system[(b)]	1, 2, 3, 4*, 5*	32
e. Reactor Vessel Pressure - Low (Injection Permissive)	3	1, 2, 3	31
		4* 5*	35

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
B. DIVISION 2 TRIP SYSTEM (Continued)			
2. AUTOMATIC DEPRESSURIZATION SYSTEM TRIP SYSTEM "B"#			
a. Reactor Vessel Water Level - Low Low Low, Level 1	2[(b)]	1, 2, 3	30
b. Drywell Pressure - High	2[(b)]	1, 2, 3	30
c. ADS Initiation Timer	1	1, 2, 3	31
d. Reactor Vessel Water Level - Low, Level 3 (Permissive)	1	1, 2, 3	31
e. LPCI Pump B and C Discharge Pressure - High (Permissive)	2/pump	1, 2, 3	31
f. Manual Initiation	2/system	1, 2, 3	32
g. ADS Bypass Timer (High Drywell Pressure)	2	1, 2, 3	32
h. Manual Inhibit	1	1, 2, 3	32

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.
\#\# Prior to STARTUP following the first refueling outage, 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 3.3.3-2

EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION SETPOINTS

TRIP FUNCTION	TRIP SETPOINT	ALLOWABLE VALUE
A. DIVISION 1 TRIP SYSTEM		
1. RHR-A (LPCI MODE) AND LPCS SYSTEM		
a. Reactor Vessel Water Level - Low Low Low, Level 1	$\geq$ -150.3 inches*	$\geq$ -152.5 inches
b. Drywell Pressure - High	$\leq$ 1.39 psig	$\leq$ 1.44 psig
c. LPCI Pump A Start Time Delay Relay	$\leq$ 5 seconds	$\leq$ 5.25 seconds
d. Manual Initiation	NA	NA
e. Reactor Vessel Pressure--Low (Injection Permissive)	516 psig, decreasing	452-534 psig, decreasing
2. AUTOMATIC DEPRESSURIZATION SYSTEM TRIP SYSTEM "A"		
a. Reactor Vessel Water Level - Low Low Low, Level 1	$\geq$ -150.3 inches*	$\geq$ -152.5 inches
b. Drywell Pressure - High	$\leq$ 1.39 psig	$\leq$ 1.44 psig
c. ADS Initiation Timer	$\leq$ 105 seconds	$\leq$ 117 seconds
d. Reactor Vessel Water Level-Low, Level 3	$\geq$ 11.4 inches*	$\geq$ 10.8 inches
e. LPCS Pump Discharge Pressure-High	145 psig, increasing	125-165 psig, increasing
f. LPCI Pump A Discharge Pressure-High	125 psig, increasing	115-135 psig, increasing
g. Manual Initiation	NA	NA
h. ADS Bypass Timer (High Drywell Pressure)	< 9.2 minutes	< 9.4 minutes
i. Manual Inhibit	NA	NA
B. DIVISION 2 TRIP SYSTEM		
1. RHR B AND C (LPCI MODE)		
a. Reactor Vessel Water Level - Low Low Low, Level 1	$\geq$ -150.3 inches*	$\geq$ -152.5 inches
b. Drywell Pressure - High	$\leq$ 1.39 psig	$\leq$ 1.44 psig
c. LPCI Pump B Start Time Delay Relay	$\leq$ 5 seconds	$\leq$ 5.25 seconds
d. Manual Initiation	NA	NA
e. Reactor Vessel Pressure--Low (Injection Permissive)	516 psig, decreasing	452-534 psig, decreasing
2. AUTOMATIC DEPRESSURIZATION SYSTEM TRIP SYSTEM "B"		
a. Reactor Vessel Water Level - Low Low Low, Level 1	$\geq$ -150.3 inches*	$\geq$ -152.5 inches
b. Drywell Pressure - High	$\leq$ 1.39 psig	$\leq$ 1.44 psig
c. ADS Initiation Timer	$\leq$ 105 seconds	$\leq$ 117 seconds

TABLE 3.3.3-2 (Continued)

EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION SETPOINTS

TRIP FUNCTION	TRIP SETPOINT	ALLOWABLE VALUE
B. DIVISION 2 TRIP SYSTEM (Continued)		
2. AUTOMATIC DEPRESSURIZATION SYSTEM TRIP SYSTEM "B" (continued)		
d. Reactor Vessel Water Level-Low, Level 3	$\geq$ 11.4 inches*	$\geq$ 10.8 inches
e. LPCI Pump B and C Discharge Pressure-High	125 psig, increasing	115-135 psig, increasing
f. Manual Initiation	NA	NA
g. ADS Bypass Timer (High Drywell Pressure)	$\leq$ 9.2 minutes	$\leq$ 9.4 minutes
h. Manual Inhibit	NA	NA
C. DIVISION 3 TRIP SYSTEM		
1. HPCS SYSTEM		
a. Reactor Vessel Water Level - Low Low, Level 2	$\geq$-41.6 inches*	$\geq$-43.8 inches
b. Drywell Pressure - High	$\leq$ 1.39 psig	$\leq$ 1.44 psig
c. Reactor Vessel Water Level - High, Level 8	$\leq$ 53.5 inches*	$\leq$ 55.7 inches
d. Condensate Storage Tank Level - Low	$\geq$ 0 inches	$\geq$ -3 inches
e. Suppression Pool Water Level - High	$\leq$ 5.9 inches	$\leq$ 7.0 inches
f. Manual Initiation	NA	NA

TABLE 3.3.3-2 (Continued)

EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION SETPOINTS

TRIP FUNCTION	TRIP SETPOINT	ALLOWABLE VALUE
D. LOSS OF POWER		
1. Division 1 and 2		
a. 4.16 kV Bus Undervoltage (Loss of Voltage)	1. 4.16 kV Basis 2912 volts	2912 +0, -291 volts
	2. 120 volt Basis 83.2 volts	83.2 +0, -8.3 volts
	3. Time Delay 0.5 seconds	0.5 +0.5, -0.1 seconds
b. 4.16 kV Bus Undervoltage (BOP Load Shed)	1. 4.16 kV Basis 3328 volts	3328 +0, -167 volts
	2. 120 volt Basis 95.1 volts	95.1 +0, -4.8 volts
	3. Time delay 0.5 seconds	0.5 +0.5, -0.1 seconds
c. 4.16 kV Bus Undervoltage (Degraded Voltage)	1. 4.16 kV Basis 3744 volts	3744 +93.6, -0 volts
	2. 120 volt Basis 107 volts	107 +2.7, -0 volts
	3. Time Delay 9.0 seconds	9.0 ± 0.5 seconds
2. Division 3		
a. 4.16 kV Bus Undervoltage (Loss of Voltage)	1. 4.16 kV Basis 3045 volts	3045 ± 61 volts
	2. 120 volt Basis 87 volts	87 ± 1.7 volts
	3. Time Delay 2.3 seconds	2.3 + 0.2, -0.3 seconds

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

TABLE 3.3.3-2 (Continued)

EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION SETPOINTS

TRIP FUNCTION	TRIP SETPOINT	ALLOWABLE VALUE
D. LOSS OF POWER (Continued)		
2. Division 3 (Continued)		
b. 4.16 kV Bus Undervoltage (Degraded Voltage)	1. 4.16 kV Basis 3661 volts	3661 ± 102.5 volts
	2. 120 volt Basis 104.6 volts	104.6 ± 2.93 volts
	3. Time Delay	
	5 minutes/No LOCA	5 minutes ± 30 seconds
	4 seconds/LOCA	(4.0 ± 0.4 seconds)

TABLE 3.3.3-3

EMERGENCY CORE COOLING SYSTEM RESPONSE TIMES (SECONDS)

1.	LOW PRESSURE CORE SPRAY SYSTEM	NA
2.	LOW PRESSURE COOLANT INJECTION MODE OF RHR SYSTEM PUMPS A, B AND C	NA
3.	AUTOMATIC DEPRESSURIZATION SYSTEM	NA
4.	HIGH PRESSURE CORE SPRAY SYSTEM	$\leq$ 27
5.	LOSS OF POWER	NA

TABLE 4.3.3.1-1

EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION SURVEILLANCE REQUIREMENTS

TRIP FUNCTION	CHANNEL CHECK	CHANNEL FUNCTIONAL TEST	CHANNEL CALIBRATION	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRED
A. DIVISION I TRIP SYSTEM				
1. RHR-A (LPCI MODE) AND LPCS SYSTEM				
a. Reactor Vessel Water Level - Low Low Low, Level 1	S	M	R(a)	1, 2, 3, 4*, 5*
b. Drywell Pressure - High	S	M	R(a)	1, 2, 3
c. LPCI Pump A Start Time Delay Relay	NA	M	Q	1, 2, 3, 4*, 5*
d. Manual Initiation	NA	R(b)	Q	1, 2, 3, 4*, 5*
e. Reactor Vessel Pressure - Low (Injection Permissive)	S	M	R(a)	1, 2, 3, 4*, 5*
2. AUTOMATIC DEPRESSURIZATION SYSTEM TRIP SYSTEM "A"#				
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. LPCS Pump Discharge Pressure-High	S	M	R(a)	1, 2, 3
f. LPCI Pump A Discharge Pressure-High	S	M	R(a)	1, 2, 3
g. Manual Initiation	NA	R(b)	NA	1, 2, 3
h. ADS Bypass Timer (High Drywell Pressure)	NA	M	Q	1, 2, 3
i. Manual Inhibit	NA	R	NA	1, 2, 3

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				
1. RHR B AND C (LPCI MODE)				
a. Reactor Vessel Water Level - Low Low Low, Level 1	S	M	R(a)	1, 2, 3, 4*, 5*
b. Drywell Pressure - High	S	M	R(a)	1, 2, 3
c. LPCI Pump B Start Time Delay Relay	NA	M	Q	1, 2, 3, 4*, 5*
d. Manual Initiation	NA	R(b)	Q	1, 2, 3, 4*, 5*
e. Reactor Vessel Pressure - Low (Injection Permissive)	S	M	R(a)	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
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	R(a)	1, 2, 3
f. Manual Initiation	NA	R(b)	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	R(a)	1, 2, 3, 4*, 5*
f. Manual Initiation##	NA	R(b)	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.

Prior to STARTUP following the first refueling outage, 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

SEISMIC MONITORING INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.7.2 The seismic monitoring instrumentation shown in Table 3.3.7.2-1 shall be OPERABLE.

APPLICABILITY: At all times.

ACTION:

a. With one or more of the above required seismic monitoring instruments inoperable for more than 30 days, prepare and submit a Special Report to the Commission pursuant to Specification 6.9.2 within the next 10 days outlining the cause of the malfunction and the plans for restoring the instrument(s) to OPERABLE status.

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

SURVEILLANCE REQUIREMENTS

4.3.7.2.1 Each of the above required seismic monitoring instruments shall be demonstrated OPERABLE by the performance of the CHANNEL CHECK, CHANNEL FUNCTIONAL TEST and CHANNEL CALIBRATION operations at the frequencies shown in Table 4.3.7.2-1.

4.3.7.2.2 Each of the above required seismic monitoring instruments actuated during a seismic event greater than or equal to 0.01 g shall be restored to OPERABLE status within 24 hours and a CHANNEL CALIBRATION performed within 5 days following the seismic event. Data shall be retrieved from actuated instruments and analyzed to determine the magnitude of the vibratory ground motion. A Special Report shall be prepared and submitted to the Commission pursuant to Specification 6.9.2 within 10 days describing the magnitude, frequency spectrum and resultant effect upon unit features important to safety.

TABLE 3.3.7.2-1

SEISMIC MONITORING INSTRUMENTATION

INSTRUMENTS AND SENSOR LOCATIONS		MEASUREMENT RANGE	MINIMUM INSTRUMENTS OPERABLE
1.	Triaxial Strong Motion Accelerometer		
a.	Containment foundation	0.001 to 1.0g	1
b.	Drywell	0.001 to 1.0g	1
c.	SGTS Filter Train	0.001 to 1.0g	1
d.	SSW Pump House A	0.001 to 1.0g	1
e.	Free Field	0.001 to 1.0g	1
f.	Reactor Piping Support	0.001 to 1.0g	1
2.	Triaxial Peak Recording Accelerograph		
a.	Containment Dome	0.01 to 2.0g	1
b.	Auxiliary Building Foundation	0.01 to 2.0g	1
c.	Diesel Generator 11	0.01 to 2.0g	1
d.	Control Building Foundation	0.01 to 2.0g	1
e.	Control Room	0.01 to 2.0g	1
f.	Reactor Vessel Support	0.01 to 2.0g	1
g.	Deleted		
h.	Deleted		
i.	Deleted		
j.	Deleted		
k.	SSW Pump House B	0.01 to 2.0g	1
3.	Triaxial Seismic Switches		
a.	Containment Foundation (SSE)	0.025 to 0.25g	1*
b.	Containment Foundation (OBE)	0.025 to 0.25g	1*
c.	Drywell (SSE)	0.025 to 0.25g	1*
d.	Drywell (OBE)	0.025 to 0.25g	1*
4.	Vertical Seismic Trigger		
a.	Containment Foundation	0.005 to 0.05g	1*
5.	Horizontal Seismic Trigger		
a.	Drywell	0.005 to 0.05g	1*

*With control room annunciation.

TABLE 4.3.7.2-1

SEISMIC MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS

INSTRUMENTS AND SENSOR LOCATIONS	CHANNEL CHECK	CHANNEL FUNCTIONAL TEST	CHANNEL CALIBRATION
1. Triaxial Strong Motion Accelerometer			
a. Containment Foundation	M	SA	R
b. Drywell	M	SA	R
c. SGTS Filter Train	M	SA	R
d. SSW Pump House A	M	SA	R
e. Free Field	M	SA	R
f. Reactor Piping Support	M	SA	R
2. Triaxial Peak Recording Accelerograph			
a. Containment Dome	NA	NA	R
b. Auxiliary Building Foundation	NA	NA	R
c. Diesel Generator 11	NA	NA	R
d. Control Building Foundation	NA	NA	R
e. Control Room	NA	NA	R
f. Reactor Vessel Support	NA	NA	R
g. Deleted			
h. Deleted			
i. Deleted			
j. Deleted			
k. SSW Pump House B	NA	NA	R
3. Triaxial Seismic Switches			
a. Containment Foundation (SSE)	M	SA	R
b. Containment Foundation (OBE)	M	SA	R
c. Drywell (SSE)	M	SA	R
d. Drywell (OBE)	M	SA	R
4. Vertical Seismic Trigger			
a. Containment Foundation	M	SA	R
5. Horizontal Seismic Trigger			
a. Drywell	M	SA	R

METEOROLOGICAL MONITORING INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.7.3 The meteorological monitoring instrumentation channels shown in Table 3.3.7.3-1 shall be OPERABLE.

APPLICABILITY: At all times.

ACTION:

a. With one or more required meteorological monitoring instrumentation channels inoperable for more than 7 days, prepare and submit a Special Report to the Commission pursuant to Specification 6.9.2 within the next 10 days outlining the cause of the malfunction and the plans for restoring the instrumentation to OPERABLE status.

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

SURVEILLANCE REQUIREMENTS

4.3.7.3 Each of the above required meteorological monitoring instrumentation channels shall be demonstrated OPERABLE by the performance of the CHANNEL CHECK and CHANNEL CALIBRATION operations at the frequencies shown in Table 4.3.7.3-1.

REACTOR COOLANT SYSTEM

OPERATIONAL LEAKAGE

LIMITING CONDITION FOR OPERATION

3.4.3.2 Reactor coolant system leakage shall be limited to:

a. No PRESSURE BOUNDARY LEAKAGE.

b. 5 gpm UNIDENTIFIED LEAKAGE.

c. 30 gpm total leakage.

d. 1 gpm leakage at a reactor coolant system pressure of 1050 ± 10 psig from any reactor coolant system pressure isolation valve specified in Table 3.4.3.2-1.

e. 2 gpm increase in UNIDENTIFIED LEAKAGE within any 4-hour period.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2 and 3.

ACTION:

a. With any PRESSURE BOUNDARY LEAKAGE, be in at least HOT SHUTDOWN within 12 hours and in COLD SHUTDOWN within the next 24 hours.

b. With any reactor coolant system leakage greater than the limits in b and/or c, above, reduce the leakage rate to within the limits within 4 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

c. With any reactor coolant system pressure isolation valve leakage greater than the above limit, isolate the high pressure portion of the affected system from the low pressure portion within 4 hours by use of at least two closed manual or deactivated automatic valves, or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

d. With one or more high/low pressure interface valve pressure monitors and/or interlocks inoperable, restore the inoperable monitor(s) and/or interlock(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.

e. With any reactor coolant system UNIDENTIFIED LEAKAGE increase greater than 2 gpm within any 4-hour period, identify the source of leakage increase as not service sensitive Type 304 or 316 austenitic stainless steel within 4 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

SURVEILLANCE REQUIREMENTS

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

a. Monitoring the drywell atmospheric particulate and gaseous radioactivity at least once per 4 hours,

b. Monitoring the drywell floor and equipment drain sump level and flow rate at least once per 4 hours,

c. Monitoring the drywell air coolers condensate flow rate at least once per 4 hours, and

d. Monitoring the reactor vessel head flange leak detection system at least once per 24 hours.

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

a. At least once per 18 months, and

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

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

4.4.3.2.3 The high/low pressure interface valves leakage pressure monitors shall be demonstrated OPERABLE with alarm and interlock setpoints per Table 3.4.3.2-2 and Table 3.4.3.2-3 by performance of a:

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

b. CHANNEL CALIBRATION at least once per 18 months.

TABLE 3.4.3.2-1

REACTOR COOLANT SYSTEM PRESSURE ISOLATION VALVES

VALVE NUMBER	SYSTEM
E21-F005 E21-F006	LPCS
E22-F004 E22-F005	HPCS
E12-F008 E12-F009 E12-F023 E12-F041 A, B, C E12-F042 A, B, C E12-F050 A, B E12-F053 A, B E12-F308 E12-F394	RHR
E51-F063 E51-F064 E51-F065 E51-F076 E51-F013	RCIC

TABLE 3.4.3.2-2

REACTOR COOLANT SYSTEM INTERFACE VALVES PRESSURE MONITORS - ALARM

VALVE NUMBER	SYSTEM	ALARM SETPOINT (psig)
E21-F005 to E21-F006	LPCS	≤ 575
E12-F008 to E12-F006A	RHR	≤ 183
E12-F008 to E12-F006B	RHR	≤ 183
E12-F041A to E12-F042A	RHR	≤ 475
E12-F041B to E12-F042B	RHR	≤ 475
E12-F041C to E12-F042C	RHR	≤ 475

TABLE 3.4.3.2-3

REACTOR COOLANT SYSTEM INTERFACE VALVES
PRESSURE INTERLOCKS

VALVE NUMBER	SYSTEM	INTERLOCK SETPOINT (psig)
E12-F052 to E51-F064	RCIC	$\leq$ 465
E12-F041A to E12-F042A	RHR	$\leq$ 475
E12-F041B to E12-F042B	RHR	$\leq$ 475
E12-F041C to E12-F042C	RHR	$\leq$ 475
E21-F005 to E21-F006	LPCS	$\leq$ 575

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.

*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.

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.

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

SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

SUPPORTING AMENDMENT NO. 20 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 letter dated August 12, 1985, as amended September 25, 1985 and supplemented October 5 and October 22, 1985 and May 30, 1986, Mississippi Power & Light Company (the licensee) requested an amendment to Facility Operating License No. NPF-29 for the Grand Gulf Nuclear Station (GGNS), Unit 1. The proposed amendment would change the Technical Specifications to reflect the installation of pressure interlocks for the injection valves in the low pressure emergency core cooling (ECC) systems. Specifications would be added to Table 3.3.3-1 and Table 3.3.3-2, for instrumentation designed to permit opening of injection valves in the low pressure coolant injection (LPCI) system and the low pressure core spray (LPCS) system only when the reactor coolant system pressure is below a permissible value. Table 3.3.3-3 and Surveillance Requirement 4.5.1 would be changed to reflect the appropriate response time requirement for these injection valves, after the interlocks are installed. Table 4.3.3.1-1 would be changed by adding surveillance requirements for the new interlock instrumentation. The amendment would delete surveillance requirements for check valves in the LPCI and LPCS systems (Surveillance Requirement 4.4.3.2.2) which were included in the Technical Specifications because the interlock instrumentation was not installed. Finally, alarm setpoints and interlock setpoints would be included in Table 3.4.3.2-2 and Table 3.4.3.2-3 respectively, for the reactor coolant system leakage pressure monitors in the LPCI and LPCS systems.

By letter dated March 21, 1986, as supplemented May 30, 1986, the licensee requested an amendment to the GGNS operating license to reflect modification of the actuation instrumentation for the automatic depressurization system (ADS) and installation of a strong motion seismic accelerometer in a support for the high pressure core spray (HPCS) system. Table 3.3.3-1, Table 3.3.3-2 and Table 4.3.3.1-1 would be changed to include limiting conditions for operation, setpoints, and surveillance requirements, respectively, for the new ADS bypass timers and manual inhibit switches. Table 3.3.7.2-1 and Table 4.3.7.2-1 would be changed to include limiting conditions for operation and surveillance requirements, respectively, for the new seismic monitoring instrumentation.

By letter dated July 15, 1986, the licensee requested an amendment to delete the requirements for four peak recording accelerographs mounted on reactor piping systems. One accelerograph is mounted on reactor recirculation piping, one on main steam piping, one on low pressure core spray piping, and one on high pressure core spray piping. Table 3.3.7.2-1 and Table 4.3.7.2-1 would be changed to delete limiting conditions for operation and surveillance requirement, respectively, for this seismic monitoring instrumentation.

The results of the staff's safety evaluation of these three applications for license amendments is provided separately below.

2.0 EVALUATION

2.1 Addition of pressure interlock instrumentation for low pressure ECC systems. (August 12, 1985 application)

Facility Operating License NPF-29, Condition 2.C.(18) requires the licensee to implement isolation protection against overpressurization of the low pressure emergency core cooling systems (LPCI and LPCS) through the implementation of reactor vessel pressure permissive interlocks. The licensee had designed interlock instrumentation to be installed during the first refueling outage and proposed Technical Specification (T.S.) changes to support the design changes. This interlock instrumentation is designed to minimize the likelihood of opening injection valves in the LPCI and LPCS systems when the reactor pressure is greater than that allowed by the ASME Code for these low design pressure systems.

The licensee proposed limiting conditions for operation for the new pressure permissive interlock instrumentation in T.S. Table 3.3.3-1 "ECCS Actuation Instrumentation." The Technical Specifications will require a minimum of three instrument channels to be operable for all operating conditions with Action 31 (declare ADS trip system or ECCS inoperable) applicable for Operating Conditions 4 and 5. In response to staff's request, the licensee provided information by letter dated October 5, 1985 to clarify what constitutes a channel for the pressure permissive interlocks. The licensee states that the minimum requirement of 3 operating channels per trip function is applicable to the "one-out-of-two twice" logic utilized in the design change and is adequate to assure operability of the required low pressure injection function considering the diversity of injection systems and logic channels available (four per trip function). The staff finds that these instrument channel operability requirements are acceptable.

The licensee proposed surveillance requirements for the new interlock channels in T.S. Table 4.3.3.1-1 "ECCS Actuation Instrumentation Surveillance Requirements." The surveillance frequencies will be once per

12 hours for channel check, once per month for channel functional test, and once per refueling cycle for channel calibration for all operating conditions. The staff finds that the channel surveillance frequencies proposed in T.S. Table 4.3.3.1-1 are acceptable.

The pressure permissive interlocks for the low pressure ECCS injection valves are designed to be active for both automatic and manual operation from the control room. The licensee proposed not to include such an interlock for the remote shutdown panel (RSP) control circuits for the ECCS injection valves. The staff found this proposal unacceptable based on the position that interlocks should be installed as part of the RSP control circuits consistent with the corresponding control room control circuits design and in accordance with Standard Review Plan Section 7.4 as related to the interpretation of GDC 19. By letter dated November 22, 1985, the staff informed the licensee of its position and provided acceptable alternatives to the implementation of pressure permissive interlocks which included administrative control over the operation of these valves. The staff met with the licensee on April 1, 1986 to discuss potential resolutions of this issue. By letter dated May 30, 1986, the licensee committed to install keylocked control switches that will be in series but separate from the existing return-to-auto control switches implemented for control from the remote shutdown panel (RSP). The keylocked switch will block operation of the LPCI injection valves Q1E12-F042A and Q1E12-F042B from the RSP. Installation of these keylocked control switches will be completed prior to startup after the first refueling outage. The licensee has further committed to have administrative controls in place to ensure that the RSP control of the subject valves will require deliberate action before the valves can be opened (i.e., the keylocked switch will be key removable in the "disable" position with the key controlled through administrative procedures to ensure that the valve is in the closed position during normal plant operation). The licensee has confirmed that valve position indication will not be negated in the control room nor at the RSP through the implementation of this special control scheme. The use of spring-return-to-auto control switches on the RSPs alleviates the concern related to change-of-state of equipment since no transfer of control is involved. The staff concludes that the use of spring-return control switches in combination with the separate keylocked control feature provides reasonable assurance that operator error is not likely to result in an intersystem LOCA during testing or actual safe shutdown operation from the remote shutdown panels. Accordingly, the staff concludes that the proposed implementation of interlocks for automatic operation of ECCS injection valves and for manual operation of ECCS injection valves from the control room only is acceptable.

The licensee proposed setpoints for the new interlock instrumentation for manual operation of the LPCI and LPCS injection valves in Table 3.4.3.2-2 (for the alarm function) and Table 3.4.3.2-3 (for the interlock function). The setpoints are 25 psi below the design pressures of the LPCI system (500 psig) and of the LPCS system (600 psig), and are therefore acceptable.

The licensee proposed setpoints for the new interlock instrumentation for automatic actuation of the LPCI and LPCS systems in Table 3.3.3-2. The maximum allowable value of the trip setpoint proposed by the licensee (534 psig) is less than the design pressure of the LPCS system (600 psig), but it exceeds the design pressure of the LPCI system (500 psig). The nominal trip setpoint which makes allowance for drift was proposed to be 516 psig. By letter dated May 30, 1986, the licensee provided additional analyses to support the proposed setpoints. Two considerations were addressed in the selection of the setpoint for ECCS valve pressure interlocks. First, from a loss of coolant accident (LOCA) perspective, it is desirable to open the valves as soon as possible during a LOCA in order to minimize the resulting peak cladding temperature (PCT). The highest possible setpoint is therefore desirable for this consideration. The second consideration is protection of the low pressure ECC systems from overpressurization as a result of premature valve opening. From this perspective it is desirable to have the setpoint as low as possible. The licensee addressed the first consideration by providing the results of loss-of-coolant accident analyses. The analyses were performed to determine the limiting (lowest) setpoint value which would still result in the calculated PCT being less than the 10 CFR 50.46 limit of 2200° F. Approved evaluation models were used for the analyses. It was determined that a lower analytical limit of 436 psig results in a calculated PCT of 2149° F. When adjusted for loop accuracy, system static head, and other uncertainties this translates into a technical specification allowable value of 452 psig. A lower bound allowable value greater than or equal to 452 psig is therefore acceptable. To address the overpressurization consideration the licensee performed an analysis of the LPCI system piping. The LPCI system is designed for a working pressure of 500 psig. However, the ASME B&PV Code Section III specifies an overpressurization protection limit of 110% of the design pressure, or 550 psig. Analyses performed by the licensee indicated that stresses caused by this pressure (550 psig), combined with other loadings at every operating plant condition, satisfy the requirements of the Code with adequate margins. Taking uncertainties such as instrument loop accuracy, calibration allowances, and system static head into consideration, the maximum allowable value for the technical specifications was determined to be 534 psig. An allowable value higher than 534 psig may result in the pressure on the LPCI system exceeding 110% of design pressure. Based on its review of the above licensee analysis, the staff concludes that a technical specification allowable value for this interlock setpoint greater than 452 psig and less than 534 psig is acceptable, and that the proposed nominal trip setpoint of 516 psig is therefore acceptable.

In its application dated August 12, 1985, the licensee proposed to delete the ECCS response times specified for the LPCS and the LPCI systems in Table 3.3.3-2. The licensee stated that this deletion was necessary because the system response with valve interlocks would vary, depending on the rate of depressurization during a loss of coolant accident. The presently specified system response time (40 seconds) includes 10 seconds for starting an emergency diesel generator and 30 seconds for opening the injection valve in the system. In response to staff questions, regarding surveillance tests of injection valve opening, the licensee proposed by letter dated September 25, 1985 to include in Surveillance Requirement 4.5.1 a requirement of 29 seconds for the time for LPCI and LPCS injection valves to move from the closed position to the open position. Surveillance tests of emergency diesel generator starting times (10 seconds) are presently included in Surveillances Requirement 4.8.1.1.2. The proposed response time for LPCS and LPCI injection valves in Surveillance Requirement 4.5.1 in conjunction with the present response time for emergency diesel generator starting in Surveillance Requirement 4.8.1.1.2 is not significantly different from the presently specified response time for the LPCS and LPCI systems in Table 3.3.3-3. Accordingly, the staff concludes that deletion of response times for LPCS and LPCI in Table 3.3.3-3 is acceptable.

The licensee proposed to eliminate that portion of Surveillance Requirement 4.4.3.2.2 which requires leak-rate testing after each disturbance of three check valves in the LPCI system (1E12-F041A, B and C) and one check valve in the LPCS system (1E21-F006). This requirement was put in the present Technical Specifications until pressure interlocks, pressure alarms and continuous control room valve position indicators for the motor operated injection valves in the LPCI and LPCS are installed and made operable. Accordingly, the staff concludes that deletion of this surveillance requirement is acceptable when the above instrumentation is installed and made operable during the first refueling outage.

2.2 Modification of actuation instrumentation for the automatic depressurization system and addition of a seismic strong motion accelerometer (March 21, 1986 application)

The licensee proposed limiting conditions for operation, setpoints, and surveillance requirements for ADS bypass timers and manual inhibit switches for the ADS instrumentation in Table 3.3.3-1, Table 3.3.3-2 and Table 4.3.3.1-1, respectively. In addition, the name of the presently identified "ADS timer" is changed to "ADS initiation timer." The proposed design change associated with this technical specification change modifies the ADS design to meet the requirements of NUREG-0737, Item II.K.3.18, "Modification of Automatic Depressurization System Logic - feasibility for increased diversity for some event sequences." It was required by the Grand Gulf Unit 1 Operating License Condition 2.C.(33)(f). In 1981, the BWR Owners Group submitted a response to TMI Action Plan Item II.K.3.18. In 1982, the Owners Group proposed additional ADS logic modifications to satisfy the NUREG-0737 requirements and address ATWS considerations. The staff has reviewed the modifications proposed by the Owners Group and concluded that the following two options are acceptable:

(1) Removal of the high drywell pressure trip in conjunction with the addition of a manual switch which inhibits ADS actuation.

(2) Addition of a manual inhibit switch in conjunction with a timer which bypasses the high drywell pressure trip after a sustained low water level indication.

Operating License Condition 2.C.(33)(f) requires the licensee to modify the ADS in accordance with the second option. In addition to the modifications, the licensee was required to provide justification for the timer delay settings, revise the emergency procedures for use of the manual inhibit switch, and submit proposed Technical Specification Surveillance procedures for the timer and switch.

The proposed modification will provide a bypass of the drywell high pressure signal after a set time delay. This modification provides automatic ADS initiation, if required, for events such as a break external to the drywell or a stuck open safety relief valve. The bypass timer is actuated on low reactor pressure vessel water level - level 1. The manual inhibit switch provides the capability to inhibit ADS operation without repeatedly pressing the reset pushbutton as required with the current design. One manual inhibit switch for each ADS division is provided. The inhibit action will activate a white indicating light and an annunciator to alert the operator. The inhibit switch will not affect the manual ADS actuation or the high pressure safety relief function. The licensee stated that the use of manual inhibit switch will be incorporated into the plant emergency operating procedures. The licensee has provided the results of analyses which show that a bypass timer setting of 10 minutes results in a calculated fuel element peak cladding temperature (PCT) of 1862°F, which is below the criteria of 2200°F given in 10 CFR 50.46. Approved evaluation models were used for the analyses. Based on its review of the licensee's application including logic diagrams, the staff concludes that the licensee's proposed modification of ADS actuation instrumentation and the associated changes to the Technical Specifications in Tables 3.3.3-1, 3.3.3-2, and 4.3.3.1-1 are consistent with the BWR Owners Group responses to TMI Action Plan Item II.K.3.18, and therefore, are acceptable.

In its application dated March 21, 1986, the licensee also proposed to add a strong motion accelerometer for a reactor piping support in Technical Specification Table 3.3.7.2-1 "Seismic Monitoring Instrumentation" and in Table 4.3.7.2-1 "Seismic Monitoring Instrumentation Surveillance Requirements." This change results from License Condition 2.C.(7) which requires the completion of installation of triaxial strong motion accelerometers on reactor supports. Currently, there are five strong motion accelerometers (SMA's) installed in GGNS Unit 1. One SMA is located on the Unit 1 containment attached to the drywell wall at El. 150'-6" and on the same containment azimuth as the base slab SMA. A third SMA is located in the Unit 1 auxiliary building attached to one of the standby gas treatment system filter train supports which is seismic Category I equipment. A fourth SMA is located in the standby service water pump house A, which is an independent Category I structure. The fifth SMA is located in the free field approximately 250 feet from any station structure, with axes oriented in the same direction as the containment building accelerometers. The SMA to be mounted on a support for the high pressure core spray system will complete the installation of SMAs for GGNS Unit 1. Because installation of the SMA on a reactor piping support and inclusion of this instrumentation in the Technical Specifications fulfills License Condition 2.C.(7), the staff concludes that the proposed TS change is acceptable.

2.3 Deletion of seismic peak recording accelerographs (July 15, 1986 application)

The licensee proposed to remove four seismic peak recording accelerographs (PRAs) mounted on reactor piping and to delete this instrumentation from Technical Specifications in Table 3.3.7.2-1 and Table 4.3.7.2-1. The four PRAs are mounted on reactor recirculation piping, main steam piping, low pressure core spray (LPCS) piping and high pressure core spray (HPCS) piping.

The licensee in its letter dated May 4, 1984, reported that these four instruments were found non-functional during surveillance. The licensee's commitments to review this matter were documented in its letter dated May 31, 1984. This included a commitment to implement appropriate design changes prior to restart following the first refueling outage, as well as a commitment to submit a proposed Technical Specification change on a schedule consistent with the implementation of these modifications. The NRC staff review of this issue was subsequently documented in Supplement No. 6 to the SER (Section 16.3.1). It was concluded that no change to the Technical Specifications would be required until the first refueling outage because the instruments were not used to actuate engineered safety features and post-seismic damage could be evaluated, if necessary, using conservative analyses based on the measurements of other seismic instruments which were operable. In its follow-up letter dated January 10, 1986, the licensee described its proposed deletion of the above four PRAs, in fulfillment of the commitments made in its May 31, 1984 letter. The licensee's justification for such a proposed action is as follows.

(1) The vendor (Kinematrics) has confirmed that a passive device (PRA) is not suitable for installation on a system which is subjected to frequent transients.

(2) The peak acceleration response due to a seismic event can not be separated from the response due to the system transients. In many cases the predicted peak seismic response is less than that due to the system transients.

(3) A meaningful and conclusive evaluation of the piping response due to a seismic event cannot be performed by relying on a peak acceleration value at a single location on the piping system.

(4) Currently there are five strong motion accelerometers (SMAs) installed in the plant. One SMA is installed on the containment foundation, one on the drywell wall, one in the standby service water pump house, and one on the standby gas treatment system filter drain. The fifth SMA is installed on the free field. These recorders will provide reliable acceleration time history, which can be converted to seismic response spectra. These can easily be compared with the respective GGNS design seismic spectra for post-seismic damage evaluation.

(5) A sixth SMA will be installed on a reactor piping support for the high pressure core spray system by restart from the first refueling outage (See Section 2.2 of this evaluation). This SMA will provide an acceleration time history at the support location, which can better serve to confirm the post-seismic evaluation for this plant component than the PRA which is currently located on the corresponding piping system.

(6) There are seven PRAs mounted at various locations inside and outside the containment which will provide reliable and meaningful information for post-seismic damage evaluation.

The staff has reviewed the proposed deletion of these four PRAs in the light of the guidelines in Regulatory Guide 1.12 "Instrumentation for Earthquakes" Revision 1, and Standard Review Plan Section 3.7.4 (NUREG-0800). Regulatory Guide 1.12 and SRP Section 3.7.4 recommend that three triaxial peak recording accelerographs be provided; one on reactor equipment, one on reactor piping, and one on Seismic Category I equipment or piping outside of containment.

There are currently 11 PRAs provided. One is located on a reactor vessel support, four on reactor piping systems as stated previously, one on the containment dome, one on the control building foundation, one in the control room, one on the standby diesel generator, one on the auxiliary building foundation, and one in standby service water pump house B. The seven PRAs remaining after deletion of the four PRAs on reactor piping meet regulatory guidelines for PRAs to be mounted on reactor equipment and on equipment or piping outside containment. The strong motion accelerometer (SMA) to be installed on the support for the high pressure core spray piping during the first refueling outage (See Section 2.2 of this evaluation) is an acceptable alternative to a PRA mounted on reactor piping. Therefore guidelines in Regulatory Guide 1.12 and SRP Section 3.7.4 will continue to be satisfied after deletion of the four PRAs and addition of the one SMA.

The probable cause of malfunction of the PRAs which are mounted on the reactor piping is believed to be the following. A PRA is a passive device capable of recording peak acceleration during a transient event. The reactor piping is subjected to various transients during startup and normal plant operation. During these transients, the peak acceleration recorded by instruments mounted on the piping can be very high, and can exceed the range of the PRAs (0.01 to 2.0g), making them inoperable.

Based on its review of the licensee's submittals, the staff concludes that the four PRAs which are mounted on the reactor piping do not serve any meaningful purpose for post-seismic damage evaluation. The staff also concludes that with the sixth SMA which will be installed when the four PRAs are removed and the already available devices there are sufficient seismic instruments to provide required information for post-seismic damage evaluation. The staff further concludes that Regulatory Guide 1.12, Revision 1, and Standard Review Plan Section 3.7.4 (NUREG-0800) are met without credit for the four pipe - mounted PRAs. Therefore the proposed deletion of the four PRAs from the Technical Specifications 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 amendments involve no significant hazards consideration, which were published in the Federal Register (51 FR 31740 on September 4, 1986, 51 FR 15402 on April 23, 1986, and 51 FR 30577 on August 27, 1986), 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 considerations 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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