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

December 30, 1987

Docket No.: 50-416

Mr. Oliver D. Kingsley, Jr.
Vice President, Nuclear Operations
System Energy Resources, Inc.
Post Office Box 23054
Jackson, Mississippi 39205

Dear Mr. Kingsley:

SUBJECT: ISSUANCE OF AMENDMENT NO. 42 FACILITY OPERATING LICENSE NO. NPF-29, GRAND GULF NUCLEAR STATION, UNIT 1, REGARDING SPECIFICATIONS AND THE ENVIRONMENTAL PROTECTION PLAN (TAC NOS. 65908 AND 63175)

The Commission has issued the enclosed Amendment No. 42 to Facility Operating License No. NPF-29 for the Grand Gulf Nuclear Station, Unit 1. This amendment consists of changes to the Technical Specifications (TS) and the Environmental Protection Plan (EPP), in response to your applications dated October 17, 1986, and August 6, 1987, as supplemented December 15, 1987.

The August 6, 1987 application for license amendment, as supplemented December 15, 1987, requested changes to the TS (Appendix A to the operating license) in eight areas: (1) a clarification to the definition of secondary containment integrity; (2) a change in the name of a supporting organization represented on the Safety Review Committee; (3) a nomenclature change for a secondary containment isolation valve; (4) deletion of the manual initiation handswitch calibration requirement for ECCS pumps; (5) deletion of expired footnotes; (6) a change to reflect new upper containment pool gates; (7) a change to add certain smoke detectors; and (8) a modification to the setpoint for residual heat removal (RHR)/reactor core isolation cooling (RCIC) steam line high flow. These changes are made in this amendment.

The October 17, 1986 application for license amendment requested four changes to the TS. Three of the changes were made in Amendment 29 to the operating license, issued March 31, 1987. The fourth requested change, the addition of TS for smoke detectors in the control rod drive repair room, is made in this amendment.

This amendment also changes the Environmental Protection Plan (Appendix B to the operating license), as requested in the August 6, 1987 application, by increasing from two years to five years the time for keeping records of erosion problems and the corrective measures taken.

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

Sincerely,

/S/

Lester L. Kintner, Project Manager
Project Directorate II-1
Division of Reactor Projects-I/II
Office of Nuclear Reactor Regulation

Enclosures:
1. Amendment No. 42 to NPF-29
2. Safety Evaluation

cc w/enclosures:
See next page

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*See previous concurrence

LA:PD2-1	PM:PD2-1	*CEB	D:PD2-1
PAnderson	LKintner:bd	CMcCracken	EAdensam
12/30/87	12/21/87	11/20/87	12/30/87

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

MISSISSIPPI POWER & LIGHT COMPANY

SYSTEM ENERGY RESOURCES, INC.

SOUTH MISSISSIPPI ELECTRIC POWER ASSOCIATION

DOCKET NO. 50-416

GRAND GULF NUCLEAR STATION, UNIT 1

AMENDMENT TO FACILITY OPERATING LICENSE

Amendment No. 42
License No. NPF-29

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

   A. The application for amendment by Mississippi Power & Light Company dated October 17, 1986 and the application for amendment by System Energy Resources, Inc., dated August 6, 1987, as supplemented December 15, 1987, comply 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.

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2. Accordingly, the license is amended by changes to the Technical Specifications and the Environmental Protection plan, 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:

   (2) Technical Specifications

   The Technical Specifications contained in Appendix A and the Environmental Protection Plan contained in Appendix B, as revised through Amendment No. 42 , are hereby incorporated into this license. System Energy Resources, Inc. shall operate the facility in accordance with the Technical Specifications and the Environmental Protection Plan.

3. This license amendment is effective as of its date of issuance.

FOR THE NUCLEAR REGULATORY COMMISSION

Elinor G. Adensam, Director
Project Directorate II-1
Division of Reactor Projects-I/II
Office of Nuclear Reactor Regulation

Attachment:
Changes to the Technical
Specifications

Date of Issuance: December 30, 1987

*See previous concurrence

LA:PD21:DRPR	PM:PD21:DRPR*	OGC*	D:PD21:DRPR
PAnderson	LKintner	JScinto	EAdensam
12/30/87	12/28/87	12/29/87	12/30/87

ATTACHMENT TO LICENSE AMENDMENT NO. 42

FACILITY OPERATING LICENSE NO. NPF-29

DOCKET NO. 50-416

Replace the following pages of the Appendix A Technical Specifications and Appendix B Environmental Protection Plan with the attached pages. The revised pages are identified by Amendment number and contain vertical lines indicating the area of change. The corresponding overleaf page(s) have been provided to maintain document completeness.

Remove	Insert
Appendix A	
1-7	1-7
1-8	1-8(overleaf)
3/4 3-9	3/4 3-9
3/4 3-9a	---
3/4 3-17	3/4 3-17(overleaf)
3/4 3-18	3/4 3-18
3/4 3-34	3/4 3-34
3/4 3-34a	3/4 3-34a
3/4 3-81	3/4 3-81
3/4 3-82	3/4 3-82
3/4 3-84	3/4 3-84
3/4 3-85	3/4 3-85
3/4 3-86	3/4 3-86
3/4 3-87	3/4 3-87
3/4 3-88	3/4 3-88(overleaf)
3/4 5-6	3/4 5-6
3/4 5-7	3/4 5-7(overleaf)
3/4 5-8	3/4 5-8
3/4 6-27	3/4 6-27
3/4 6-28	3/4 6-28
3/4 6-47	3/4 6-47(overleaf)
3/4 6-48	3/4 6-48
3/4 6-48a	---
3/4 6-49	3/4 6-49
3/4 6-49a	---
3/4 6-53	3/4 6-53
3/4 6-54	3/4 6-54(overleaf)
3/4 6-55	3/4 6-55
3/4 6-56	3/4 6-56(overleaf)
6-9	6-9
Appendix B	
4-2	4-2

REACTOR PROTECTION SYSTEM RESPONSE TIME

1.35 REACTOR PROTECTION SYSTEM RESPONSE TIME shall be the time interval from when the monitored parameter exceeds its trip setpoint at the channel sensor until de-energization of the scram pilot valve solenoids. The response time may be measured by any series of sequential, overlapping or total steps such that the entire response time is measured.

REPORTABLE EVENT

1.36 A REPORTABLE EVENT shall be any of those conditions specified in Section 50.73 to 10 CFR Part 50.

ROD DENSITY

1.37 ROD DENSITY shall be the number of control rod notches inserted as a fraction of the total number of control rod notches. All rods fully inserted is equivalent to 100% ROD DENSITY.

SECONDARY CONTAINMENT INTEGRITY

1.38 SECONDARY CONTAINMENT INTEGRITY shall exist when:

a. All Auxiliary Building and Enclosure Building penetrations required to be closed during accident conditions are either:

   1. Capable of being closed by an OPERABLE secondary containment automatic isolation system, or

   2. Closed by at least one manual valve, blind flange, rupture disc or deactivated automatic valve or damper, as applicable, secured in its closed position, except as provided in Table 3.6.6.2-1 of Specification 3.6.6.2.

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

c. The standby gas treatment system is in compliance with the requirements of Specification 3.6.6.3.

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

e. The sealing mechanism associated with each Auxiliary Building and Enclosure Building penetration, e.g., welds, bellows or O-rings, is OPERABLE.

SHUTDOWN MARGIN

1.39 SHUTDOWN MARGIN shall be the amount of reactivity by which the reactor is subcritical or would be subcritical assuming all control rods are fully inserted except for the single control rod of highest reactivity worth which is assumed to be fully withdrawn and the reactor is in the shutdown condition; cold, i.e. 68°F; and xenon free.

SITE BOUNDARY

1.40 The SITE BOUNDARY shall be that line beyond which the land is neither owned, nor leased, nor otherwise controlled by the licensee.

SOLIDIFICATION

1.41 SOLIDIFICATION shall be the conversion of wet wastes into a form that meets shipping and burial ground requirements.

SOURCE CHECK

1.42 A SOURCE CHECK shall be the qualitative assessment of channel response when the channel sensor is exposed to a radioactive source.

STAGGERED TEST BASIS

1.43 A STAGGERED TEST BASIS shall consist of:

a. A test schedule for n systems, subsystems, trains or other designated components obtained by dividing the specified test interval into n equal subintervals.

b. The testing of one system, subsystem, train or other designated component at the beginning of each subinterval.

THERMAL POWER

1.44 THERMAL POWER shall be the total reactor core heat transfer rate to the reactor coolant.

UNIDENTIFIED LEAKAGE

1.45 UNIDENTIFIED LEAKAGE shall be all leakage which is not IDENTIFIED LEAKAGE.

UNRESTRICTED AREA

1.46 An UNRESTRICTED AREA shall be any area at or beyond the SITE BOUNDARY access to which is not controlled by the licensee for purposes of protection of MEMBERS OF THE PUBLIC from exposure to radiation and radioactive materials, or any area within the SITE BOUNDARY used for residential quarters or for industrial, commercial, institutional, and/or recreational purposes.

VENTILATION EXHAUST TREATMENT SYSTEM

1.47 A VENTILATION EXHAUST TREATMENT SYSTEM is any system designed and installed to reduce gaseous radioiodine or radioactive material in particulate form in effluents by passing ventilation or vent exhaust gases through charcoal adsorbers and/or HEPA filters for the purpose of removing iodines or particulates from the gaseous exhaust stream prior to the release to the environment (such a system is not considered to have any effect on noble gas effluents). Engineered Safety Feature (ESF) atmospheric cleanup systems are not considered to be VENTILATION EXHAUST TREATMENT SYSTEM components.

3/4.3.2 ISOLATION ACTUATION INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.2 The isolation actuation instrumentation channels shown in Table 3.3.2-1 shall be OPERABLE with their trip setpoints set consistent with the values shown in the Trip Setpoint column of Table 3.3.2-2 and with ISOLATION SYSTEM RESPONSE TIME as shown in Table 3.3.2-3.

APPLICABILITY: As shown in Table 3.3.2-1.

ACTION:

a. With an isolation actuation instrumentation channel trip setpoint less conservative than the value shown in the Allowable Values column of Table 3.3.2-2, 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 the number of OPERABLE channels less than required by the Minimum OPERABLE Channels per Trip System requirement for one trip system, place the inoperable channel(s) and/or that trip system in the tripped condition* within one hour. The provisions of Specification 3.0.4 are not applicable.

c. With the number of OPERABLE channels less than required by the Minimum OPERABLE Channels per Trip System requirement for both trip systems, place at least one trip system** in the tripped condition within one hour and take the ACTION required by Table 3.3.2-1.

SURVEILLANCE REQUIREMENTS

4.3.2.1 Each isolation 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 4.3.2.1-1.

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

4.3.2.3 The ISOLATION SYSTEM RESPONSE TIME of each isolation trip function shown in Table 3.3.2-3 shall be demonstrated to be within its 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 isolation trip system.

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*An inoperable channel need not be placed in the tripped condition where this would cause the Trip Function to occur. In these cases, the inoperable channel shall be restored to OPERABLE status within 2 hours or the ACTION required by Table 3.3.2-1 for that Trip Function shall be taken.

**The trip system need not be placed in the tripped condition if this would cause the Trip Function to occur. When a trip system can be placed in the tripped condition without causing the Trip Function to occur, place the trip system with the most inoperable channels in the tripped condition; if both systems have the same number of inoperable channels, place either trip system in the tripped condition.

TABLE 3.3.2-2 (Continued)

ISOLATION ACTUATION INSTRUMENTATION SETPOINTS

TRIP FUNCTION	TRIP SETPOINT	ALLOWABLE VALUE
2. MAIN STEAM LINE ISOLATION (Continued)		
g. Main Steam Line Tunnel Δ Temp. - High	≤ 101°F**	≤ 104°F**
h. Manual Initiation	NA	NA
3. SECONDARY CONTAINMENT ISOLATION		
a. Reactor Vessel Water Level - Low Low, Level 2	≥ -41.6 inches*	≥ -43.8 inches
b. Drywell Pressure - High	≤ 1.23 psig	≤ 1.43 psig
c. Fuel Handling Area Ventilation Exhaust Radition - High High	≤ 3.6 mR/hr**	≤ 4.0 mR/hr**
d. Fuel Handling Area Pool Sweep Exhaust Radiation - High High	≤ 30 mR/hr**	≤ 35 mR/hr**
e. Manual Initiation	NA	NA
4. REACTOR WATER CLEANUP SYSTEM ISOLATION		
a. Δ Flow - High	≤ 79 gpm	≤ 89** gpm
b. Δ Flow Timer	≤ 45 seconds	≤ 57 seconds
c. Equipment Area Temperature - High		
1. RWCU Hx Room	≤ 120°F	≤ 126°F
2. RWCU Pump Rooms	≤ 170°F	≤ 176°F
3. RWCU Valve Nest Room	≤ 135°F	≤ 141°F
d. Equipment Area Δ Temp. - High		
1. RWCU Hx Room	≤ 65°F	≤ 66°F
2. RWCU Pump Rooms	≤ 115°F	≤ 118°F
3. RWCU Valve Nest Room	≤ 70°F	≤ 73°F
e. Reactor Vessel Water Level - Low Low, Level 2	≥ -41.6 inches*	≥ -43.8 inches

TABLE 3.3.2-2 (Continued)

ISOLATION ACTUATION INSTRUMENTATION SETPOINTS

TRIP FUNCTION	TRIP SETPOINT	ALLOWABLE VALUE
4. REACTOR WATER CLEANUP SYSTEM ISOLATION (Continued)		
f. Main Steam Line Tunnel Ambient Temperature - High	≤ 185°F**	≤ 191°F**
g. Main Steam Line Tunnel Δ Temp. - High	≤ 101°F**	≤ 104°F**
h. SLCS Initiation	NA	NA
i. Manual Initiation	NA	NA
5. REACTOR CORE ISOLATION COOLING SYSTEM ISOLATION		
a. RCIC Steam Line Flow - High		
1. Pressure	≤ 56" H_2O	≤ 64" H_2O
2. Time Delay	5±2 seconds	5±2 seconds
b. RCIC Steam Supply Pressure - Low	≥ 60 psig	≥ 53 psig
c. RCIC Turbine Exhaust Diaphragm Pressure - High	≤ 10 psig	≤ 20 psig
d. RCIC Equipment Room Ambient Temperature - High	≤ 185°F**	≤ 191°F**
e. RCIC Equipment Room Δ Temp. - High	≤ 125°F**	≤ 128°F**
f. Main Steam Line Tunnel Ambient Temperature - High	≤ 185°F**	≤ 191°F**
g. Main Steam Line Tunnel Δ Temp. - High	≤ 101°F**	≤ 104°F**
h. Main Steam Line Tunnel Temperature Timer	≤ 30 minutes	≤ 30 minutes
i. RHR Equipment Room Ambient Temperature - High	≤ 165°F**	≤ 171°F**
j. RHR Equipment Room Δ Temperature - High	≤ 99°F**	≤ 102°F**
k. RHR/RCIC Steam Line Flow - High	≤ 37" H_2O	≤ 43" H_2O

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)	NA	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]	NA	1, 2, 3, 4*, 5*
e. Reactor Vessel Pressure - Low (Injection Permissive)	S	M	R[a]	1, 2, 3, 4*, 5*

TABLE 3.3.7.9-1
FIRE DETECTION INSTRUMENTATION

INSTRUMENT LOCATION			MINIMUM INSTRUMENTS OPERABLE* HEAT (X/Y)	FLAME(1) (X/Y)	SMOKE(1) (X/Y)
a. CONTAINMENT BUILDING #					
1. Return Duct Mounted Detectors					3/0
ROOM	ELEV	ROOM NAME			
b. CONTROL BUILDING					
1. Zone 1-3					12/0
0C103	93'	Emergency Laundry Rm.			
0C109	93'	Decontamination Area			
0C115	93'	Corridor			
0C116	93'	Hot Machine Shop			
0C117	93'	Corridor			
0C128	93'	Hot Water Heater Rm.			
2. Zone 1-4					12/0
0C201	111'	Stairwell			
0C202	111'	Div. I Swgr. Rm.		0/13(CO_2)	
0C207	111'	Div. I Battery Rm.			

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

\# The fire detection instruments located within the primary containment are not required to be OPERABLE during the performance of Type A Containment Leakage Rate Tests.

(1) Smoke and flame detectors provide only early warning capability with the exception of:

(a) Zone 1-27 detectors trip closed the door between the 0C208/0C208A Remote Shutdown panel rooms.
(b) Containment building return duct mounted detectors trip the containment cooler fans.
(c) Zone 1-11 and 1-13 detectors initiate the control building purge fan system.
(d) Control Room HVAC Intake Plenum Detectors trip the control room A/C units unless a control room emergency filtration system isolation mode automatic actuation signal is present.

TABLE 3.3.7.9-1 (Continued)
FIRE DETECTION INSTRUMENTATION

	ROOM	ELEV	ROOM NAME	MINIMUM INSTRUMENTS OPERABLE* HEAT (X/Y)	FLAME(1) (X/Y)	SMOKE(1) (X/Y)
3.	Zone 1-5					3/0
	OC209	111'	Div. III Battery Rm.			
	OC210	111'	Div. III Swgr. Rm.	0/4(CO_2)		
4.	Zone 1-6					10/0
	OC211	111'	Div. II Battery Rm.			
	OC215	111'	Div. II Swgr. Rm.	0/7(CO_2)		
	OC216	111'	West Corridor			
5.	Zone 1-07					5/0
	OC212	111'	U-2 Div. I Battery Rm.			
	OC214	111'	U-2 Div. I Swgr. Rm.			
6.	Zone 1-08					5/0
	OC203	111'	U-2 Div. II Swgr. Rm.			
	OC206	111'	U-2 Div II Battery Rm.			
7.	Zone 1-10					2/0
	OC306	133'	Electrical Chase			
	OC307	133'	Electrical Chase			
8.	Zone 1-11					13/0
	OC302	133'	HVAC Equipment Rm.			
	OC308	133'	Corridor			
9.	Zone 1-12					2/0
	OC304	133'	Electrical Space			
	OC305	133'	Electrical Space			
	OC412	133'	Electrical Space			
10.	Zone 1-13					16/0
	OC303	133'	HVAC Equipment Rm.			
11.	Zone 1-14					9/0
	OC402A	148'	HVAC Chase			
	OC403	148'	Computer Room	0/12(Halon)		
	OC410	148'	Battery Room			
12.	Zone 1-15					15/0
	OC401	148'	Corridor			
	OC402	148'	Lower Cable Spreading Room	0/9(CO_2)		
	OC407	148'	Instr. Motor Gen. Rm.	0/2(CO_2)		
	OC408	148'	Corridor			
	OC409	148'	Electrical Chase			

TABLE 3.3.7.9-1 (Continued)
FIRE DETECTION INSTRUMENTATION

	ROOM	ELEV	ROOM NAME	MINIMUM INSTRUMENTS OPERABLE* HEAT (X/Y)	FLAME(1) (X/Y)	SMOKE(1) (X/Y)
19.	Zone 1-23					21/0
	OC702	189'	Upper Cable Spreading Room	0/12(CO_2)		
	OC706	189'	West Corridor			
	OC707	189'	Instr. Motor Gen. Rm.			
	OC709	189'	Electrical Chase			
	OC711	189'	Passage			
	OC712	189'	HVAC Room			
20.	Zone 1-24					6/0
	OC703	189'	Control Cabinet Area	4/0 (CO_2)		
21.	Zone 1-26					16/0
	OC705	189'	U-2 Upper Cable Spreading Room			
	OC708	189'	U-2 Instr. Motor Gen. Rm.			
22.	Zone 1-27					2/0
	OC208	111'	Div. II Remote Shutdown Panel	0/1(CO_2)		
	OC208A	111'	Div. I Remote Shutdown Panel	0/1(CO_2)		
23.	Control Room HVAC Intake Plenum Mounted Detectors					2/0
c.	AUXILIARY BUILDING					
1.	Zone 2-2					28/0
	1A211	119'	North Corridor (Partial)			
	1A215	119'	South Corridor (Partial)			
	1A222	119'	West Corridor			
2.	Zone 2-3					5/0
	1A219	119'	Electrical Swgr. Rm.	0/2(CO_2)		
	1A220	119'	Piping Penetration Room			
	1A221	119'	Electrical Swgr. Rm.	0/2(CO_2)		
3.	Zone 2-4					22/0
	1A102	93'	RHR "A" Heat Ex. Rm.			
	1A103	93'	RHR "A" Pump Rm.			
	1A104	93'	RCIC Pump Rm.			
	1A105	93'	RHR "B" Pump Rm.			
	1A106	93'	RHR "B" Heat Ex. Rm.			
	1A128	108'	RHR "A" Heat Ex. Rm.			

TABLE 3.3.7.9-1 (Continued)
FIRE DETECTION INSTRUMENTATION

	ROOM	ELEV	ROOM NAME	MINIMUM INSTRUMENTS OPERABLE* HEAT (X/Y)	FLAME(1) (X/Y)	SMOKE(1) (X/Y)
3.	Zone 2-4 (Continued)					
	1A129	108'	RHR "B" Heat Ex. Rm.			
	1A202	119'	RHR "A" Heat Ex. Rm.			
	1A203	119'	Piping Penetration Rm.			
	1A204	119'	Piping Penetration Rm.			
	1A205	119'	Piping Penetration Rm.			
	1A206	119'	RHR "B" Heat Ex. Rm.			
	1A207	119'	Electrical Swgr. Rm.	0/3(CO_2)		
	1A208	119'	Electrical Swgr. Rm.	0/3(CO_2)		
	1A209	115'	RWCU Recirc Pump "A" Rm.			
	1A210	115'	RWCU Recirc Pump "B" Rm.			
	1A223	128'	Passage			
4.	Zone 2-5					5/0
	1A318	139'	Electrical Penetration Room	0/2(CO_2)		
	1A319	139'	RPV Instr. Test Rm.			
	1A320	139'	Electrical Penetration Room	0/2(CO_2)		
5.	Zone 2-6					27/0
	1A301	139'	East Corridor			
	1A302	139'	Southeast Corridor			
	1A303	139'	RHR "A" Heat Ex. Rm.			
	1A304	139'	Piping Penetration Rm.			
	1A306	139'	Piping Penetration Rm.			
	1A307	139'	RHR "B" Heat Ex. Rm.			
	1A308	139'	Electrical Penetration Room	0/3(CO_2)		
	1A309	139'	Electrical Penetration Room	0/3(CO_2)		
	1A314	139'	South Corridor (Partial)			
	1A316	139'	North Corridor (Partial)			
6.	Zone 2-7					18/0
	1A417	166'	North Corridor (Partial)			
	1A420	166'	South Corridor (Partial)			
	1A424	166'	Set Down Area (Partial)			
	1A428	166'	West Corridor			
	1A430	166'	CRD Repair Rm.			
	1A432	166'	FPC & CU Pump Rm.			
	1A434	166'	South Passage			

TABLE 3.3.7.9-1 (Continued)
FIRE DETECTION INSTRUMENTATION

	ROOM	ELEV	ROOM NAME	MINIMUM INSTRUMENTS OPERABLE* HEAT (X/Y)	FLAME(1) (X/Y)	SMOKE(1) (X/Y)
7.	Zone 2-8					27/0
	1A401	166'	Northeast Corridor			
	1A402	166'	Steam Tunnel Roof			
	1A403	166'	Southeast Corridor			
	1A404	166'	Unassigned Area			
	1A405	166'	Containment Vent. Equip. Room			
	1A406	166'	Containment Exhaust Filter Rm.			
	1A407	166'	MCC Area	0/2(CO_2)		
	1A410	166'	MCC Area	0/2(CO_2)		
	1A417	166'	North Corridor (Partial)			
	1A420	166'	South Corridor (Partial)			
	1A424	166'	Set Down Area (Partial)			
8.	Zone 2-9					10/0
	1A519	185'	Storage Area			
	1A524	195'	Platform			
	1A527	185'	Load Center Area			
	1A529	185'	FPC & CU Rm.			
	1A538	185'	Platform			
9.	Zone 2-13					31/0
	1A602	208'	Storage Area			
	1A603	208'	Passage			
	1A604	208'	Fuel Handling Area			
	1A606	245'	HVAC Equip. Area			
10.	Zone 2-14					17/0
	1A114	93'	Fan Coil Area (Partial)			
	1A115	93'	Piping Penetration Rm.			
	1A116	93'	Piping Penetration Rm.			
	1A117	93'	Misc. Equip. Area (Partial)			
	1A118	93'	RHR "C" Pump Room			
	1A119	93'	LPCS Pump Room			
	1A120	93'	CCW Pump & Heat Ex. Rm.			
	1A122	103'	South Corridor (Partial)			
	1A123	103'	North Corridor (Partial)			
11.	Zone 2-15					1/0
	1A539	185'	Cable Chase			

TABLE 3.3.7.9-1 (Continued)
FIRE DETECTION INSTRUMENTATION

	ROOM	ELEV	ROOM NAME	MINIMUM INSTRUMENTS OPERABLE* HEAT (X/Y)	FLAME(1) (X/Y)	SMOKE(1) (X/Y)
12.	Zone 2-17					18/0
	1A101	93'	Passage			
	1A109	93'	HPCS Pump Rm.			
	1A111	93'	Piping Penetration Rm.			
	1A114	93'	Fan Coil Area (Partial)			
	1A117	93'	Misc. Equip. Area (Partial)			
	1A121	103'	East Corridor			
	1A122	103	South Corridor (Partial)			
	1A123	103'	North Corridor (Partial)			
13.	Zone 2-18					20/0
	1A201	119'	East Corridor			
	1A211	119'	North Corridor (Partial)			
	1A215	119'	South Corridor (Partial)			
14.	Zone 2-19					15/0
	1A314	139'	South Corridor (Partial)			
	1A316	139'	North Corridor (Partial)			
	1A321	139'	MCC Area			
	1A322	139'	Centrifugal Chiller Area			
	1A323	139'	SGTS Area			
	1A324	139'	HVAC Equip. Area			
	1A326	139'	SGTS Area			
15.	Zone 2-20					2/0
	1A305	139'	Steam Tunnel			
16.	Zone 2-21					4/0
	1A12	185'	Stairwell			
	1A12	208'	Stairwell			
	1A12	245'	Stairwell			
d.	DIESEL GENERATOR BUILDING					
1.	Zone 2-10				9/0	
	1D301	133'	Corridor	0/3 (Deluge)		
	1D304	133'	Day Tank Area			
	1D306	133'	Div. III Diesel Gen. Room			
	1D401	158'	Div. III Diesel Gen. Room	0/7 (Deluge)		
2.	2-11				6/0	
	1D303	133'	Day Tank Area			
	1D308	133'	Div. II Diesel Gen. Room			
	1D402	158'	Div. II Diesel Gen. Room	0/7 (Deluge)		

TABLE 3.3.7.9-1 (Continued)
FIRE DETECTION INSTRUMENTATION

ROOM	ELEV	ROOM NAME	MINIMUM INSTRUMENTS OPERABLE* HEAT (X/Y)	FLAME(1) (X/Y)	SMOKE(1) (X/Y)
3. Zone 2-12				6/0	
1D302	133'	Day Tank Area			
1D310	133'	Div. I Diesel Gen. Room			
1D403	158'	Div. I Diesel Gen. Room	0/7 (Deluge)		
e. STANDBY SERVICE WATER PUMP HOUSE					
1. Zone 2-1					4/0
1M110	133'	SSW Pump Rm. A			
1M112	133'	SSW Valve Rm. A			
2M110	133'	SSW Pump Rm. B			
2M112	133'	SSW Valve Rm. B			
f. CHARCOAL FILTER TRAINS					
1. Standby Gas Treatment System Filter Trains A & B			2/0 (Allison Thermistor Wire)		
Auxiliary Building El. 139'					
2. Control Room Standby Fresh Air System Filter Trains A & B			2/0 (Allison Thermistor Wire)		
Control Building El. 133'					
g. CONTROL BUILDING (PGCC HALON SYSTEMS)					
0C503	166'	Control Room (Unit 1 side)			
		Module/Halon Panel			
		1H13-U700/1H13-P900	0/10		10/0
		1H13-U701/1H13-P901	0/10		15/0
		1H13-U702/1H13-P902	0/9		14/0
		1H13-U703/1H13-P903	0/11		17/0
		1H13-U720/1H13-P920	0/7		13/0
		SH13-U730/SH13-P930	0/11		12/0
		1H13-U738/1H13-P938	0/10		12/0
		SH13-U739/SH13-P939	0/5		14/0

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. The provisions of Specification 3.0.4 are not applicable.#

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 reactor cavity and transfer canal gates in the upper containment pool are removed, and water level is maintained within the limits of Specifications 3.9.8 and 3.9.9.

#This exception is applicable until startup from the second refueling outage.

SURVEILLANCE REQUIREMENTS

4.5.2.1 At least the above required ECCS divisions shall be demonstrated OPERABLE per Surveillance Requirement 4.5.1, except that the header ΔP instrumentation is not required to be OPERABLE.

4.5.2.2 The HPCS system shall be determined OPERABLE at least once per 12 hours by verifying the condensate storage tank required volume when the condensate storage tank is required to be OPERABLE per Specification 3.5.2.e.

3/4.5.3 SUPPRESSION POOL#

LIMITING CONDITION FOR OPERATION

3.5.3 The suppression pool shall be OPERABLE:

a. In OPERATIONAL CONDITION 1, 2 or 3 with a contained water volume of at least 135,291 ft^3, equivalent to a level of 18'4-1/12."

b. In OPERATIONAL CONDITION 4 or 5* with a contained water volume of at least 93,600 ft^3, equivalent to a level of 12'8", except that the suppression pool level may be less than the limit or may be drained provided that:

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

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

   3. The condensate storage tank contains at least 170,000 available gallons of water, equivalent to a level of 18', and

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

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

ACTION:

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

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

#See Specification 3.6.3.1 for pressure suppression requirements.

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

SUPPRESSION POOL MAKEUP SYSTEM

LIMITING CONDITION FOR OPERATION

3.6.3.4 The suppression pool makeup system shall be OPERABLE.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2 and 3.

ACTION:

a. With one suppression pool makeup line inoperable, restore the inoperable makeup line to OPERABLE status within 72 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

b. With the upper containment pool water level less than the limit, restore the water level to within the limit 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 upper containment pool water temperature greater than the limit, restore the upper containment pool water temperature to within the limit within 24 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

SURVEILLANCE REQUIREMENTS

4.6.3.4 The suppression pool makeup system shall be demonstrated OPERABLE:

a. At least once per 24 hours by verifying the upper containment pool water:

   1. Level to be greater than or equal to 23'3" above the pool bottom in the dryer/separator storage area, and

   2. Temperature to be less than or equal to 125°F.

b. At least once per 31 days by verifying that each valve, manual, power operated or automatic, in the flow path that is not locked, sealed, or otherwise secured in position, is in its correct position, and that all upper containment pool gates are in the stored position or are otherwise removed from the upper containment pool.

c. At least once per 18 months by 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 makeup of water to the suppression pool may be excluded from this test.

3/4.6.4 CONTAINMENT AND DRYWELL ISOLATION VALVES

LIMITING CONDITION FOR OPERATION

3.6.4 The containment and drywell isolation valves shown in Table 3.6.4-1 shall be OPERABLE with isolation times less than or equal to those shown in Table 3.6.4-1.

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

ACTION:

With one or more of the containment or drywell isolation valves shown in Table 3.6.4-1 inoperable, maintain at least one isolation valve OPERABLE in each affected penetration that is open and within 4 hours either:

a. Restore the inoperable valve(s) to OPERABLE status, or

b. Isolate each affected penetration by use of at least one deactivated automatic valve secured in the isolated position,* or

c. Isolate each affected penetration by use of at least one closed manual valve or blind flange.*

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

*Isolation valves, except MSIVs, closed to satisfy these requirements may be reopened on an intermittent basis under administrative controls.

#Isolation valves shown in Table 3.6.4-1 are also required to be OPERABLE when their associated actuation instrumentation is required to be OPERABLE per Table 3.3.2-1.

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.

SECONDARY CONTAINMENT AUTOMATIC ISOLATION DAMPERS/VALVES

LIMITING CONDITION FOR OPERATION

3.6.6.2 The secondary containment ventilation system automatic isolation dampers/ valves shown in Table 3.6.6.2-1 shall be OPERABLE with isolation times less than or equal to the times shown in Table 3.6.6.2-1.

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

ACTION:

With one or more of the secondary containment ventilation system automatic isolation dampers/valves shown in Table 3.6.6.2-1 inoperable, maintain at least one isolation damper/valve OPERABLE in each affected penetration that is open, and within 8 hours either:

a. Restore the inoperable damper/valve(s) to OPERABLE status, or

b. Isolate each affected penetration by use of at least one deactivated automatic damper/valve secured in the isolation position, or

c. Isolate each affected penetration by use of at least one closed manual valve or blind flange.

Otherwise, in OPERATIONAL CONDITION 1, 2 or 3, be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

Otherwise, 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

4.6.6.2 Each secondary containment ventilation system automatic isolation damper/ valve shown in Table 3.6.6.2-1 shall be demonstrated OPERABLE:

a. Prior to returning the damper/valve to service after maintenance, repair or replacement work is performed on the damper/valve or its associated actuator, control or power circuit by cycling the damper/valve through at least one complete cycle of full travel and verifying the specified isolation time.

b. During COLD SHUTDOWN or REFUELING at least once per 18 months by verifying that on a containment isolation test signal each isolation damper/valve actuates to its isolation position.

c. By verifying the isolation time to be within its limit when tested pursuant to Specification 4.0.5.

*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 3.6.6.2-1 (Continued)

SECONDARY CONTAINMENT VENTILATION SYSTEM AUTOMATIC ISOLATION DAMPERS/VALVES

VALVE FUNCTION	MAXIMUM ISOLATION TIME (Seconds)
Valves (Continued)	
Cond. & Refuel Water Transfer Aux. Bldg. Isol. Valve (P11-F064)-(A)	4
Cond. & Refuel Water Transfer Aux. Bldg. Isol. Valve (P11-F066)-(A)	4
Cond. & Refuel Water Transfer Aux. Bldg. Isol. Valve (P11-F047)-(A)	4
Cond. & Refuel Water Transfer Aux. Bldg. Isol. Valve (P11-F063)-(B)	4
Cond. & Refuel Water Transfer Aux. Bldg. Isol. Valve (P11-F065)-(B)	4
Cond. & Refuel Water Transfer Aux. Bldg. Isol. Valve (P11-F067)-(B)	4
Cond. & Refuel Water Transfer Aux. Bldg. Isol. Valve (P11-F061)-(B)	4
Floor and Equipment Drains System Aux. Bldg. Isol. Valve (P45-F158)-(A)	9
Floor and Equipment Drains System Aux. Bldg. Isol. Valve (P45-F160)-(A)	9
Floor and Equipment Drains System Aux. Bldg. Isol. Valve (P45-F163)-(A&B)	9
Floor and Equipment Drains System Aux. Bldg. Isol. Valve (P45-F159)-(B)	9
Floor and Equipment Drains System Aux. Bldg. Isol. Valve (P45-F161)-(B)	9
Makeup Water Treatment Sys. Aux. Bldg. Isol. Valve (P21-F024)-(A&B)	30
Domestic Water System Aux. Bldg. Isol. Valve (P66-F029A)-(A&B)	4
PSW Aux. Bldg. Isol. Valve (P44-F121)-(A)	100

TABLE 3.6.6.2-1 (Continued)

SECONDARY CONTAINMENT VENTILATION SYSTEM AUTOMATIC ISOLATION DAMPERS/VALVES

VALVE FUNCTION	MAXIMUM ISOLATION TIME (Seconds)
Valves (Continued)	
PSW Aux. Bldg. Isol. Valve (P44-F122)-(A)	100
PSW Aux. Bldg. Isol. Valve (P44-F117)-(A)	100
PSW Aux. Bldg. Isol. Valve (P44-F118)-(A)	100
PSW Aux. Bldg. Isol. Valve (P44-F120)-(B)	100
PSW Aux. Bldg. Isol. Valve (P44-F123)-(B)	100
PSW Aux. Bldg. Isol. Valve (P44-F116)-(B)	100
PSW Aux. Bldg. Isol. Valve (P44-F119)-(B)	100
RHR Discharge To Liquid Radwaste Valve (E12-F203)-(A&B)	30

STANDBY GAS TREATMENT SYSTEM

LIMITING CONDITION FOR OPERATION

3.6.6.3 Two independent standby gas treatment subsystems shall be OPERABLE.

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

ACTION:

a. With one standby gas treatment subsystem inoperable, restore the inoperable subsystem to OPERABLE status within 7 days, or:

   1. In OPERATIONAL CONDITION 1, 2 or 3, be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

   2. 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.

b. With both standby gas treatment subsystems inoperable in Operational Condition *, suspend handling of irradiated fuel in the primary or secondary containment, CORE ALTERATIONS or operations with a potential for draining the reactor vessel. The provisions of Specification 3.0.3. are not applicable.

SURVEILLANCE REQUIREMENTS

4.6.6.3 Each standby gas treatment subsystem shall be demonstrated OPERABLE:

a. At least once per 31 days by initiating, from the control room, flow through the HEPA filters and charcoal adsorbers and verifying that the subsystem operates for at least 10 continuous hours with the heaters OPERABLE.

*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.

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

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

2. Verifying within 31 days after removal that a laboratory analysis of a representative carbon sample obtained in accordance with Regulatory Position C.6.b of Regulatory Guide 1.52, Revision 2, March 1978, meets the laboratory testing criteria of Regulatory Position C.6.a of Regulatory Guide 1.52, Revision 2, March 1978.

3. Verifying a subsystem flow rate of 4000 cfm ± 10% during system operation when tested in accordance with ANSI N510-1975.

c. After every 720 hours of charcoal adsorber operation by verifying within 31 days after removal that a laboratory analysis of a representative carbon sample obtained in accordance with Regulatory Position C.6.b of Regulatory Guide 1.52, Revision 2, March 1978, meets the laboratory testing criteria of Regulatory Position C.6.a of Regulatory Guide 1.52, Revision 2, March 1978.

d 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 for the:

   a) LOCA, and
   b) Fuel handling accident.

2. Verifying that the pressure drop across the combined HEPA filters and charcoal adsorber banks is less than 9.2 inches Water Gauge while operating the filter train at a flow rate of 4000 cfm ± 10%.

3. Verifying that the filter train and isolation dampers receive the appropriate actuation signal by each of the following test conditions. For at least one of these test conditions, verify that the filter train starts and isolation dampers open on receipt of the actuation signal.

   a. Drywell pressure - high,
   b. Reactor vessel water level - low low, level 2,
   c. Fuel handling area ventilation exhaust radiation - high high,
   d. Fuel handling area pool sweep exhaust radiation - high high, and
   e. Manual initiation from the Control Room.

4. Verifying that the fan can be manually started.

5. Verifying that the heaters dissipate 48 ± 5.0 kW when tested in accordance with ANSI N510-1975 (except for the phase balance criteria stated in Section 14.2.3).

6.5.2 SAFETY REVIEW COMMITTEE (SRC)

FUNCTION

6.5.2.1 The SRC shall function to provide independent review and audit of designated activities in the areas of:

a. nuclear power plant operations

b. nuclear engineering

c. chemistry and radiochemistry

d. metallurgy

e. instrumentation and control

f. radiological safety

g. mechanical and electrical engineering

h. quality assurance practices

COMPOSITION

6.5.2.2 The SRC shall be composed of the:

Chairman:	Vice President, Nuclear Operations
Member:	Vice President, Nuclear Engineering & Support
Member:	Director, Nuclear Plant Engineering
Member:	Site Director, GGNS
Member:	Director, Quality Programs
Member:	Designated Representative, MSU System Services, Inc.
Member:	GGNS General Manager
Member:	Director, Nuclear Licensing
Member:	Manager, Radiological and Environmental Services
Member:	Manager, Operational Analysis

Two or more additional voting members shall be consultants to System Energy Resources, Inc. consistent with the recommendations of the Advisory Committee on Reactor Safeguards letter, Mark to Palladino dated October 20, 1981.

The SRC members shall hold a Bachelor's degree in an engineering or physical science field or equivalent experience and a minimum of five years of technical experience of which a minimum of three years shall be in one or more of the disciplines of 6.5.2.1a through h. In the aggregate, the membership of the committee shall provide specific practical experience in the majority of the disciplines of 6.5.2.1a through h.

ALTERNATES

6.5.2.3 All alternate members shall be appointed in writing by the SRC Chairman to serve on a temporary basis; however, no more than two alternates shall participate as voting members in SRC activities at any one time.

by the aerial surveys, and walking patrols will be directed to the problem areas to evaluate the extent of the problem to be corrected.

The Erosion Control Inspection Program shall begin upon commencement of normal transmission line inspection procedures. Semi-annual surveys shall continue until stabilization of soil and vegetation (i.e., ground cover establishment) is achieved.

A summary of the field inspection program and any procedures implemented to control abnormal erosion conditions associated with transmission line maintenance activities shall be reported in the Annual Environmental Operation Report in accordance with Subsection 5.4.1. Field logs indicating locations of erosion damage and measures taken to rectify erosion problem areas and estimation of the time to achieve effective stabilization will be maintained and available for inspection for a period of five years. Results reported shall contain information encompassing but not limited to inspection date, estimated size of erosion problem area, probable cause of erosion, type of stabilization program, and date of effective stabilization, as appropriate.

4.2.2 Cooling Tower Drift Program

Seven sampling sites will be utilized to measure cooling tower drift-deposition. At least two of the sampling sites will have duplicate sampling devices. Six of the seven sampling sites will be located in areas where maximum salt deposition is predicted. These areas were extrapolated from the Bechtel Salt Deposition Model developed for the SERI Final Environmental Report. The seventh sampling site will be a control site located south of Raymond, Mississippi.

Fallout samples will be collected using buckets with a known volume of deionized water in each. The buckets will be located four to six feet above the ground, fitted with bird rings, and covered with fine mesh screens to exclude leaves and insects. The samples will be collected on a quarterly basis and analyzed for calcium, magnesium, sodium, iron, phosphates, nitrates, chloride, fluorides, sulfates, and total dissolved solids. These parameters were selected because past analyses have shown them to be prevalent in the cooling water source water. The results of these analyses will be correlated with local rainfall data and

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

SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

SUPPORTING AMENDMENT NO. 42 TO FACILITY OPERATING LICENSE NO. NPF-29

MISSISSIPPI POWER & LIGHT COMPANY

SYSTEM ENERGY RESOURCES, INC.

SOUTH MISSISSIPPI ELECTRIC POWER ASSOCIATION

GRAND GULF NUCLEAR STATION, UNIT 1

DOCKET NO. 50-416

SGH

1.0 INTRODUCTION

By letter dated August 6, 1987, as supplemented December 15, 1987, 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 (TS), Appendix A to the operating license, in eight areas: (1) clarify the definition of secondary containment integrity; (2) change the name of a supporting organization represented on the Safety Review Committee; (3) change the nomenclature for a secondary containment isolation valve; (4) delete the manual initiation handswitch calibration requirement for ECCS pumps; (5) delete expired footnotes; (6) change specifications for the upper containment pool to reflect new upper containment pool gates; (7) add certain smoke detectors; and (8) modify the setpoint for high steam flow in the residual heat removal (RHR)/reactor core isolation cooling (RCIC) steam line. The amendment would also change the Environmental Protection Plan (EPP), Appendix B to the operating license, by increasing from two years to five years the time for keeping records of erosion problems and the corrective measures taken. The evaluation of these eight TS changes and the one EPP change are described separately below. The licensee's letter dated December 15, 1987, provided supplemental information concerning the change to the upper containment pool gates. This letter, which transmitted an analysis performed by General Electric in support of the proposed change, provided clarifying information and did not alter the licensee's request nor the staff's initial determination of no significant hazards considerations as noticed in the Federal Register on September 23, 1987 (52 FR 35796).

*On December 20, 1986, the Commission issued License Amendment No. 27 which authorized the transfer of control and performance of licensed activities from Mississippi Power & Light Company to System Energy Resources, Inc. (SERI). "The licensee" refers to Mississippi Power & Light Company before December 20, 1986, and to SERI on or after December 20, 1986.

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By letter dated October 17, 1986, the licensee requested four changes to the TS. Three of the changes were made in Amendment 29 to the operating license, issued March 31, 1987. The evaluation of the fourth requested change, the addition of TS for smoke detectors in the control rod drive repair room, is described below together with the evaluation of the proposed addition of TS for smoke detectors in other areas (change (7) in the August 6, 1987 letter).

2.0 EVALUATION

2.1 Changes To Technical Specifications (Appendix A)

Change (1) Definition of Secondary Containment Integrity

The definition of secondary containment in Section 1.38 of the TS presently states, in part, that secondary containment integrity shall exist when the standby gas treatment system (SGTS) is "operable pursuant to Specification 3.6.6.3." The phrase "operable pursuant to Specification 3.6.6.3" means that both the SGTS subsystems must be operable for secondary containment to exist. However, the action statements in TS 3.6.6.3 allow one or both subsystems to be inoperable, if certain additional requirements are met.

The proposed definition would state that secondary containment integrity shall exist when the SGTS is "in compliance with the requirements of Specification 3.6.6.3." This changed definition would allow the use of the action statements in meeting the requirements for secondary containment integrity. This change makes the definition for secondary containment consistent with other similar definitions (for example, 1.10, Drywell Integrity, and 1.31, Primary Containment Integrity).

The staff has reviewed the requested change and concludes it is consistent with the intent of the TS and, therefore, is acceptable.

Change (2) Organization Name Change

One of the members of the GGNS, Unit 1, Safety Review Committee (SRC) is listed as Designated Representative, Middle South Services, Inc. in the present TS 6.5.2.2. The name of this organization has been changed to MSU System Services, Inc. The proposed change to the TS would change the name of the organization to its present name.

The organization represented on the SRC is a service organization providing support functions for the licensee and other operating companies in the Middle South Utilities System. The name change was requested to more accurately reflect the company's role. The Designated Representative will meet the qualification requirements of SRC membership as defined in TS 6.5.2.2.

Since the company represented on the SRC and the qualifications of the Designated Representative will not change, the proposed name change is acceptable.

Change (3) Isolation Valve Power Supply

The present designation of the makeup water treatment system auxiliary building isolation valve in TS Table 3.6.6.2-1 is (P21-F024)-(A). The "(A)" in the designation indicates that electrical Division I is the power source for a solenoid-operated pilot valve for Valve P21-F024. The as-built valve has two solenoid-operated pilot valves for Valve P21-F024 - one powered from electrical Division I and the other from electrical Division II. Therefore, the correct designation for Valve P21-F024 is (P21-F024)(A&B).

The change in the designation of the valve to indicate the power source for both solenoid valves provides assurance that both "A" and "B" valves will be operable, whereas the incorrect designation could be interpreted to mean that only the "A" valve must be operable. Therefore, this change is acceptable.

Change (4) Manual Initiation Handswitch

The present TS Table 4.3.3.1-1 includes surveillance requirements to calibrate manual initiation handswitches for two ECCS systems. The manual initiation handswitches are on-off devices and do not have components that can be calibrated. The proposed change was requested to indicate that channel calibration is not applicable (NA). This change is acceptable.

Change (5) Expired Footnotes

The proposed change would delete footnotes which provided temporary exceptions to certain TS during the first refueling outage. These footnotes expired October 10, 1986. This administrative change will improve readability of the TS and is, therefore, acceptable.

Change (6) Upper Containment Pool Gates

By letter dated August 6, 1987, the licensee proposed certain changes to TS 3/4.5.2, 3/4.5.3, and 3/4.6.3.4 to accommodate a design change to increase the height of the upper containment pool weir wall by 18 inches and to include two removable gates in the new wall extension. This weir wall separates the reactor cavity and the moisture separator storage area, which are two compartments of the upper containment pool. The modification is an ALARA radiation enhancement to provide complete submergence of the separator when in its stored position in the pool with the reactor cavity drained. The new weir wall will include two removable gates that are required to be in a stored position or otherwise removed from the upper containment pool during Operational Conditions 1, 2, and 3 to ensure that the suppression pool makeup capability is not affected.

Current TS 3/4.5.2, 3/4.5.3, and 3/4.6.3.4 specify the required positions of existing upper containment pool gates and the spent fuel pool gate. With the addition of the two new weir wall gates, the subject TS would be revised to clarify the distinctions among the new and existing gates and their proper positions. TS 3/4.5.2 and 3/4.5.3 require revision to indicate that the upper

containment fuel pool gates currently referenced in the footnotes are actually the reactor cavity gate and the transfer canal gate. TS 3/4.6.3.4 requires revision to indicate that all the upper containment pool gates, including the two new weir wall gates, must be in their stored position or removed from the upper containment pool during Operational Conditions 1, 2, and 3 to ensure that suppression pool make-up capability is not affected. In a change not directly related to the modification, the requirement in the footnote of TS 3/4.5.2 to have the spent fuel pool gate removed is being deleted because the spent fuel pool and upper containment pool do not need to be in communication in order to allow the ECCS to be inoperable.

The upper containment pool is a rectangular, stainless steel lined structure crossing the top of the drywell area. The pool is filled with water and provides shielding for the operating floor during normal and refueling operations. A portion of this water has a safety function in that, during an accident, it is designed to drain into the suppression pool to make up for the water inventory pumped into the vessel and the drywell from the emergency core cooling systems. The upper containment pool is divided by interior crosswalls into the following distinct areas:

(a) steam (moisture) separator storage;
(b) reactor cavity;
(c) steam dryer and fuel storage; and
(d) fuel transfer canal.

Presently, one removable stainless steel gate is provided in the wall between the reactor cavity and the fuel storage pool and a second removable gate is provided in the wall between the fuel storage pool and the fuel transfer canal. These gates are used to isolate the reactor cavity and fuel transfer canal for refueling and maintenance activities in Operational Conditions 4 and 5. The weir wall between the reactor cavity and the separator storage area controls the volume of water dumped by the suppression pool makeup system. The existing top elevation of the wall ensures that, during refueling operations, an inadvertent dump to the suppression pool will maintain at least one foot of water shielding over the top of active fuel when a fuel bundle is fully withdrawn from the reactor during transfer. An additional function of the weir wall is to allow draining of the reactor cavity with the steam separator in a stored position.

It was discovered that the weir wall separating the reactor cavity and the separator storage area was of insufficient height to allow for complete water coverage of the moisture separator during refueling activities with the reactor cavity drained. To provide complete water coverage of the moisture separator, modifications would be made to the upper containment pool weir wall to increase its height by 18 inches across the full width of the upper containment pool between the reactor cavity area and moisture separator storage area.

The 18-inch extension will contain two (2) weir wall gates which will be installed in the weir wall during refueling and removed prior to the

commencement of normal plant operation. The removal of the weir wall gates during Operational Conditions 1, 2, and 3 is required to ensure that the suppression pool makeup capability is not affected.

The proposed change to the footnotes of TS 3/4.5.2 and 3/4.5.3 is required to distinguish between the different upper containment pool gates and to further clarify the required conditions or gate positions which allow the ECCS and suppression pool to be inoperable during Operational Condition 5. This change specifically identifies the reactor cavity and transfer canal gates and requires that these gates be removed. Also, this change allows the weir wall gates to be installed while the ECCS and suppression pool are out-of-service.

The weir wall is presently 16 feet high (measured from the reactor vessel flange); the 18-inch extension will increase the wall height to 17.5 feet. With the pool water level at a required minimum of 22 feet 8 inches above the reactor vessel flange, the wall extension and gates will be submerged, thereby maintaining adequate heat removal capability. In a letter dated December 15, 1987, the licensee has provided an analysis by General Electric that also makes this conclusion.

The proposed change to TS Surveillance Requirement 3/4.6.3.4.b is required to include the weir wall gates and the requirement that they be removed during Operational Conditions 1, 2, and 3. This change will ensure that the modifications that will be made to the upper containment pool weir wall will not affect the capability of the suppression pool makeup system.

The footnote to TS 3/4.5.2 would also be changed to delete the requirement for the spent fuel pool gates to be removed when the ECCS is inoperable. The spent fuel pool is outside containment. The fuel transfer canal passes through the containment wall and joins the spent fuel pool; the spent fuel pool gates are located at this juncture. The licensee's letter dated December 15, 1987, provided the results of a review performed by General Electric which determined that the spent fuel pool is not required to be in communication with the upper containment pool in order to allow the ECCS to be inoperable during Operational Condition 5 (refueling) because an adequate volume of water is available in the upper containment pool for core cooling during an accident. The proposed TS change is consistent with the TS of three other domestic BWR/6 MARK III Plants (River Bend, Perry and Clinton) The staff further notes that the fuel transfer canal contains two containment isolation valves and that there is no requirement for these valves to be open when ECCS is inoperable in Operational Condition 5. This renders the position of the spent fuel pool gates at such times irrelevant.

For reasons cited above, the staff finds the proposed changes to TS 3/4.6.3.4 and the footnotes to TS 3/4.5.2 and 3/4.5.3 concerning the upper containment pool gates and the spent fuel pool gates, to be acceptable.

Change (7) Heat and Smoke Detectors

The proposed changes to TS Table 3.3.7.9-1, "Fire Detection Instrumentation" involve the addition of Function A (early warning fire detection and notification only) smoke detectors and Function B (actuate fire suppression systems and provide early warning and notification) heat detectors in order to enhance the existing fire detection capabilities of the fire detection system. The actual changes to the system by fire zone are as follows:

Fire Zone	Description	Heat Detectors Added	Smoke Detectors Added
0C202	Fire Area 31 - Control Building Division I Switchgear Area, Elevation 111' - 0".	7	6
0C215	Fire Area 38 - Control Building Division II Switchgear Area, Elevation 111' - 0".	0	3
0C402	Fire Area 42 - Control Building Lower Cable Spreading Room, Elevation 148' - 0".	2	0
1A101	Fire Area 1 - Auxiliary Building Passage, Elevation 93' - 0" and 103' - 0".	0	1
1A117	Fire Area 1 - Auxiliary Building Corridor and Miscellaneous Equipment Area, elevation 93' - 0" 103' - 0".	0	1
1A222	Fire Area 6 - Auxiliary Building Motor Control Center Area, Elevation 119' - 0".	0	5
1A301	Fire Area 11 - Auxiliary Building Corridor, Elevation 139' - 0".	0	1
1A321	Fire Area 11 - Auxiliary Building Motor Control Center, Elevation 139' - 0".	0	1

Fire Zone	Description	Heat Detectors Added	Smoke Detectors Added
1A322	Fire Area 11 - Auxiliary Building Centrifugal Chiller Area, Elevation 139' - 0".	0	1
1A401	Fire Area 19 - Auxiliary Building Passage, Elevation 166' - 0".	0	1
1A417	Fire Area 19 - Auxiliary Building Miscellaneous Equipment Area, Elevation 166' - 0".	0	1
1A428	Fire Area 19 - Auxiliary Building Passage, Elevation 166' - 0".	0	4
1A430*	Fire Area 19 - Control Rod Drive Repair Room, Elevation 166' - 0".	0	3

The 1984 Triennial Fire Protection Audit of Grand Gulf Nuclear Station, Unit 1 identified a finding related to the location of ionization-type smoke detectors and thermal heat detectors and the adherence to the requirement of NFPA 72D-1975. NFPA 72-1975 states that automatic fire detectors shall be located in accordance with NFPA 72E. Specifically identified was that fire detection equipment in some areas was not mounted on the ceiling and not spaced adequately in beam pockets. As a result of this finding, System Energy Resources, Inc. (SERI) conducted a detailed fire protection evaluation to determined the adequacy of the existing configuration and, if found necessary determine where relocation and/or addition of detectors are required to meet SERI's commitment to meet the functional requirements of NFPA 72D-1975. UFSAR Table 9.5-11, Section E.1.a describes SERI's commitment to meet the functional requirements of NFPA 72D. SERI defines the functional requirements to be those requirements delineated in NFPA 72D pertaining to the performance of initiating device circuits, signaling line circuits and indicating device circuits, as well as power supply sources, overcurrent protection, audible signal appliances, signal capacity of circuits and electrical supervision.

*Requested in the October 17, 1986 application

The SERI evaluation was conducted by qualified fire protection engineers and was based on the licensee commitments described in the Updated Final Safety Analysis Report, the requirements of NFPA 72E (1978), the manufacturer's installation instructions, the fire hazards analysis and the GGNS combustible heat load calculation. In all cases, the as-installed configuration, although not necessarily in strict conformance with the installation requirements of NFPA 72E, was determined to meet the license commitments as required by Operating License Condition 2.C(23).

The primary function of the fire detection systems is to provide early warning of a fire and/or to actuate the appropriate suppression system such that safe shutdown of the plant is not inhibited. In some cases, improvements in the existing configuration were recommended in order to enhance the early warning capability of the fire detection system. The recommended improvements were in zones which contained redundant safe shutdown equipment separated by less than 50 feet horizontally and not separated by 3-hour fire barriers. The detection systems located in those zones are to be enhanced as necessary to meet the strict location requirements of NFPA 72E (referenced by NFPA 72D). The proposed enhancements will include relocation of some detectors within their respective zones but changes to the TS are not required for those zones.

The proposed enhancements described above will assure that the detectors installed in those zones will be in compliance with the location requirements of NFPA 72E (1978). Detectors installed in the remaining zones have been determined through the fire protection evaluation to be adequate to perform their required function and no changes are proposed for those zones.

The NRC staff has evaluated the changes to the fire protection system proposed in the August 6, 1987 and the October 17, 1986 applications. The proposed changes would be enhancements of the early warning capability of the fire detection system. Specifically, additional smoke and heat detectors will be located in areas near structural beams. The system design bases and functions would not be changed. The proposed changes would not delete fire detection instruments from any fire zone nor would they affect any other safety-related systems or equipment in the plant. Changes are made in accordance with the Updated Final Safety Analysis Report. Because the changes are enhancements to the fire detection capability, the staff concludes the changes are acceptable.

Change (8) Setpoint for RHR/RCIC Steamline

TS Table 3.3.2-2, "Isolation Actuation Instrumentation Setpoint," Item 5.K, "RHR/RCIC Steam Line High Flow," presently identifies a trip setpoint of less than or equal to 145" H_2O with an allowable value of less than or equal to 151" H_2O. These values were found by the licensee to be too high because of the use of an incorrect flow for the RHR system and incorrect use of a formula for calculating differential pressure in an elbow flowmeter.

The proposed RHR/RCIC steam line high flow trip setpoint and allowable value are less than or equal to 37" H_2O and less than or equal to 43" H_2O, respectively. These values are based on an analytic limit of 125% of rated flow to RHR loops A and B in the steam condensing mode (207.8 x 10^3 lbs/hr) and to the RCIC turbine (38.85 x 10^3 lbs/hr.). By applying the correct RHR flow and the appropriate formula for differential pressure in an elbow tap flowmeter, the new trip setpoint and allowable value were determined.

The purpose of the RHR/RCIC steam line high flow trip is to provide an isolation signal to the RHR/RCIC steam supply and RCIC pump suction isolation valves when a leak or break in the steam line is sensed as indicated by high steam flow. The proposed TS change would decrease the allowable steam line flow to cause a system isolation. The affected instruments sense the differential pressure across two separate elbows in the common RHR/RCIC steam supply line that branches off main steam line A. This RHR/RCIC line is used to supply steam to the RCIC turbine and can also provide steam to the RHR heat exchangers when the plant is in the RHR steam condensing mode (currently prohibited by a licensee commitment).

Since the proposed TS change corrects an error in the calculation of the steam line high flow trip setpoint and does not change the margin between allowable value and trip setpoint, the staff finds the proposed RHR/RCIC steam line high flow trip setpoint and allowable value to be acceptable.

2.2 Change to the Environmental Protection Plan (Appendix B)

The present EPP Section 4.2.1, "Erosion Control Inspection," requires that field logs indicating locations of erosion damage and measures taken to rectify erosion problem areas be maintained for a period of two years. Section 5.2, "Records Retention," states that, "Records of modifications to plant structures, systems and components determined to potentially affect the continued protection of the environment shall be retained for the life of the plant. All other records data and logs relating to this EPP shall be retained for five years or, where applicable, in accordance with the requirements of other agencies."

The proposed change in Section 4.2.1 from "two years" to "five years" for retention of field logs of erosion control measures is a conservative change and would make Section 4.2.1 consistent with Section 5.2 and is, therefore, acceptable.

3.0 ENVIRONMENTAL CONSIDERATION

This amendment involves changes to requirements with respect to the installation or use of a facility component 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 a proposed finding that this amendment involves no significant hazards consideration and there has been no public comment on such finding. Accordingly, this amendment meets the eligibility criteria for categorical exclusion set forth in 10 CFR 51.22(c)(9). This amendment also involves changes in recordkeeping, reporting or administrative procedures or requirements. Accordingly, with respect to these items, the amendment meets the eligibility criteria for categorical exclusion set forth in 10 CFR 51.22(c)(10). 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 a proposed determination that this amendment involves no significant hazards consideration, which was published in the Federal Register on September 23, 1987 (52 FR 35796), and consulted with the State of Mississippi. No public comments or requests for hearing 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.

Dated: December 30, 1987

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