MAR 7 1986

Docket No. 50-440

DISTRIBUTION
Docket File
NRC PDR
Local PDR
PD#1 Reading
RBernero
OELD
EJordan
BGrimes
JPartlow
JStefano
WButler
ACRS (10)

Mr. Murray R. Edelman
Vice President - Nuclear Group
The Cleveland Electric Illuminating Company
P.O. Box 5000
Cleveland, Ohio 44101

Dear Mr. Edelman:

SUBJECT: TRANSMITTAL OF TECHNICAL SPECIFICATION CHANGES FOR PERRY NUCLEAR POWER PLANT, UNIT 1

B. J. Youngblood's letter to you dated November 19, 1985 transmitted for your certification the final draft of the Perry Unit 1 Technical Specifications. However, since that letter was issued, we have received additional staff comments which correct several editorial and typographical errors. These changes are reflected in the enclosed Technical Specification pages, which have been discussed with your representatives.

As indicated in Mr. Youngblood's November 19th letter, you should certify that the previously transmitted Technical Specifications (as amended by the enclosed pages) are consistent with the Final Safety Analysis Report, the NRC Safety Evaluation Report (NUREG-0887), and the as-built facility. The resources and processes used to review and certify the Technical Specifications should be detailed in your response.

If there are any questions, please direct them to the Project Manager, John J. Stefano.

Sincerely,

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

Enclosure:
As stated

cc: See next page

DBL:PD#4
JStefano:jg
3/7/86

DBL:PD#4
WButler
3/7/86

WB

8603130442 860307
PDR ADOCK 05000440
A PDR

MAR 7 1986

Docket No. 50-440

DISTRIBUTION

Docket File	EJordan
NRC PDR	BGrimes
Local PDR	JPartlow
PD#1 Reading	JStefano
RBernero	WButler
OELD	ACRS (10)

Mr. Murray R. Edelman
Vice President - Nuclear Group
The Cleveland Electric Illuminating Company
P.O. Box 5000
Cleveland, Ohio 44101

Dear Mr. Edelman:

SUBJECT: TRANSMITTAL OF TECHNICAL SPECIFICATION CHANGES FOR PERRY NUCLEAR POWER PLANT, UNIT 1

B. J. Youngblood's letter to you dated November 19, 1985 transmitted for your certification the final draft of the Perry Unit 1 Technical Specifications. However, since that letter was issued, we have received additional staff comments which correct several editorial and typographical errors. These changes are reflected in the enclosed Technical Specification pages, which have been discussed with your representatives.

As indicated in Mr. Youngblood's November 19th letter, you should certify that the previously transmitted Technical Specifications (as amended by the enclosed pages) are consistent with the Final Safety Analysis Report, the NRC Safety Evaluation Report (NUREG-0887), and the as-built facility. The resources and processes used to review and certify the Technical Specifications should be detailed in your response.

If there are any questions, please direct them to the Project Manager, John J. Stefano.

Sincerely,

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

Enclosure:
As stated

cc: See next page

DBL:PD#4	DBL:PD#4 WB
JStefano:jg	WButler
3/7/86	3/7/86

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

MAR 7 1986

Docket No. 50-440

Mr. Murray R. Edelman
Vice President - Nuclear Group
The Cleveland Electric Illuminating Company
P.O. Box 5000
Cleveland, Ohio 44101

Dear Mr. Edelman:

SUBJECT: TRANSMITTAL OF TECHNICAL SPECIFICATION CHANGES FOR PERRY NUCLEAR POWER PLANT, UNIT 1

B. J. Youngblood's letter to you dated November 19, 1985 transmitted for your certification the final draft of the Perry Unit 1 Technical Specifications. However, since that letter was issued, we have received additional staff comments which correct several editorial and typographical errors. These changes are reflected in the enclosed Technical Specification pages, which have been discussed with your representatives.

As indicated in Mr. Youngblood's November 19th letter, you should certify that the previously transmitted Technical Specifications (as amended by the enclosed pages) are consistent with the Final Safety Analysis Report, the NRC Safety Evaluation Report (NUREG-0887), and the as-built facility. The resources and processes used to review and certify the Technical Specifications should be detailed in your response.

If there are any questions, please direct them to the Project Manager, John J. Stefano.

Sincerely,

Walter R. Butler

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

Enclosure:
As stated

cc: See next page

Mr. Murray R. Edelman
The Cleveland Electric
Illuminating Company

Perry Nuclear Power Plant
Units 1 and 2

cc:
Jay Silberg, Esq.
Shaw, Pittman, & Trowbridge
1800 M Street, N. W.
Washington, D. C. 20006

Donald H. Hauser, Esq.
The Cleveland Electric
Illuminating Company
P. O. Box 5000
Cleveland, Ohio 44101

Resident Inspector's Office
U. S. Nuclear Regulatory Commission
Parmly at Center Road
Perry, Ohio 44081

Regional Administrator, Region III
U. S. Nuclear Regulatory Commission
799 Roosevelt Road
Glen Ellyn, Illinois 60137

Donald T. Ezzone, Esq.
Assistant Prosecuting Attorney
105 Main Street
Lake County Administration Center
Painesville, Ohio 44077

Ms. Sue Hiatt
OCRE Interim Representative
8275 Munson
Mentor, Ohio 44060

Terry J. Lodge, Esq.
618 N. Michigan Street
Suite 105
Toledo, Ohio 43624

John G. Cardinal, Esq.
Prosecuting Attorney
Ashtabula County Courthouse
Jefferson, Ohio 44047

Mr. Larry O. Beck
The Cleveland Electric
Illuminating Company
P. O. Box 97 E-210
Perry, Ohio 44081

SECTION		PAGE
PLANT SYSTEMS (Continued)		
3/4.7.2	CONTROL ROOM EMERGENCY RECIRCULATION SYSTEM.............	3/4 7-3
3/4.7.3	REACTOR CORE ISOLATION COOLING SYSTEM..................	3/4 7-6
3/4.7.4	SNUBBERS..	3/4 7-8
	Figure 4.7.4-1 Sample Plan 2) For Snubber Functional Test....................	3/4 7-13
3/4.7.5	SEALED SOURCE CONTAMINATION.............................	3/4 7-14
3/4.7.6	MAIN TURBINE BYPASS SYSTEM..............................	3/4 7-16
3/4.7.7	FUEL HANDLING BUILDING	
	Fuel Handling Building Ventilation System...............	3/4 7-17
	Fuel Handling Building Integrity.......................	3/4 7-19
3/4.8 ELECTRICAL POWER SYSTEMS		
3/4.8.1	A.C. SOURCES	
	A.C. Sources - Operating...............................	3/4 8-1
	Table 4.8.1.1.2-1 Diesel Generator Test Schedule........................	3/4 8-10
	A.C. Sources - Shutdown................................	3/4 8-11
3/4.8.2	D.C. SOURCES	
	D.C. Sources - Operating...............................	3/4 8-12
	Table 4.8.2.1-1 Battery Surveillance Requirements......................	3/4 8-15
	D.C. Sources - Shutdown................................	3/4 8-16
3/4.8.3	ONSITE POWER DISTRIBUTION SYSTEMS	
	Distribution - Operating...............................	3/4 8-17
	Distribution - Shutdown................................	3/4 8-19

SECTION		PAGE
3/4.8.4	ELECTRICAL EQUIPMENT PROTECTIVE DEVICES	
	Containment Penetration Conductor Overcurrent Protective Devices....................................	3/4 8-21
	Table 3.8.4.1-1 Primary Containment Penetration Conductor Overcurrent Protective Devices..........................	3/4 8-23
	Reactor Protection System Electric Power Monitoring.....	3/4 8-25
3/4.9 REFUELING OPERATIONS		
3/4.9.1	REACTOR MODE SWITCH..................................	3/4 9-1
3/4.9.2	INSTRUMENTATION......................................	3/4 9-3
3/4.9.3	CONTROL ROD POSITION.................................	3/4 9-5
3/4.9.4	DECAY TIME...	3/4 9-6
3/4.9.5	COMMUNICATIONS.......................................	3/4 9-7
3/4.9.6	REFUELING PLATFORM...................................	3/4 9-8
3/4.9.7	CRANE TRAVEL - SPENT FUEL STORAGE POOL, NEW FUEL STORAGE VAULTS, AND UPPER CONTAINMENT POOL....................	3/4 9-9
3/4.9.8	WATER LEVEL - REACTOR VESSEL.........................	3/4 9-10
3/4.9.9	WATER LEVEL - SPENT FUEL STORAGE AND UPPER CONTAINMENT POOLS...............................	3/4 9-11
3/4.9.10	CONTROL ROD REMOVAL	
	Single Control Rod Removal............................	3/4 9-12
	Multiple Control Rod Removal..........................	3/4 9-14
3/4.9.11	RESIDUAL HEAT REMOVAL AND COOLANT CIRCULATION	
	High Water Level......................................	3/4 9-16
	Low Water Level.......................................	3/4 9-17
3/4.9.12	INCLINED FUEL TRANSFER SYSTEM.........................	3/4 9-18

SECTION	PAGE
3/4.10 SPECIAL TEST EXCEPTIONS	
3/4.10.1 PRIMARY CONTAINMENT INTEGRITY............................	3/4 10-1
3/4.10.2 ROD PATTERN CONTROL SYSTEM..............................	3/4 10-2
3/4.10.3 SHUTDOWN MARGIN DEMONSTRATIONS..........................	3/4 10-3
3/4.10.4 RECIRCULATION LOOPS.....................................	3/4 10-4
3/4.10.5 TRAINING STARTUPS.......................................	3/4 10-5
3/4.11 RADIOACTIVE EFFLUENTS	
3/4.11.1 LIQUID EFFLUENTS	
Concentration...	3/4 11-1
Table 4.11.1.1.1-1 Radioactive Liquid Waste Sampling and Analysis Program......................	3/4 11-2
Dose..	3/4 11-5
Liquid Radwaste Treatment System................................	3/4 11-6
Liquid Holdup Tanks...	3/4 11-7
3/4.11.2 GASEOUS EFFLUENTS	
Dose Rate...	3/4 11-8
Table 4.11.2.1.2-1 Radioactive Gaseous Waste Sampling and Analysis Program......................	3/4 11-9
Dose - Noble Gases..	3/4 11-12
Dose - Iodine-131, Iodine-133, Tritium, and Radionuclides in Particulate Form....................	3/4 11-13
Gaseous Radwaste (Offgas) Treatment.............................	3/4 11-14
Ventilation Exhaust Treatment Systems...........................	3/4 11-15
Explosive Gas Mixture...	3/4 11-16
Main Condenser..	3/4 11-17

SECTION PAGE

RADIOACTIVE EFFLUENTS (Continued)

3/4.11.3 SOLID RADWASTE TREATMENT.................................. 3/4 11-18

3/4.11.4 TOTAL DOSE... 3/4 11-20

3/4.12 RADIOLOGICAL ENVIRONMENTAL MONITORING

3/4.12.1 MONITORING PROGRAM....................................... 3/4 12-1

Table 3.12.1-1 Radiological Environmental Monitoring Program................. 3/4 12-3

Table 3.12.1-2 Reporting Levels For Radioactivity Concentrations In Environmental Samples.............. 3/4 12-9

Table 4.12.1-1 Detection Capabilities For Environmental Sample Analysis...... 3/4 12-10

3/4.12.2 LAND USE CENSUS.. 3/4 12-13

3/4.12.3 INTERLABORATORY COMPARISON PROGRAM........................ 3/4 12-14

SECTION PAGE

3/4.0 APPLICABILITY.. B 3/4 0-1

3/4.1 REACTIVITY CONTROL SYSTEMS

3/4.1.1 SHUTDOWN MARGIN.................................. B 3/4 1-1

3/4.1.2 REACTIVITY ANOMALIES............................. B 3/4 1-1

3/4.1.3 CONTROL RODS..................................... B 3/4 1-2

3/4.1.4 CONTROL ROD PROGRAM CONTROLS..................... B 3/4 1-3

3/4.1.5 STANDBY LIQUID CONTROL SYSTEM.................... B 3/4 1-4

3/4.2 POWER DISTRIBUTION LIMITS

3/4.2.1 AVERAGE PLANAR LINEAR HEAT GENERATION RATE.. B 3/4 2-1

Bases Table B 3/4 2.1-1 Significant Input Parameters to the Loss-Of-Cooling Accident Analysis................ B 3/4 2-3

3/4.2.2 APRM SETPOINTS.................................... B 3/4 2-2

3/4.2.3 MINIMUM CRITICAL POWER RATIO...................... B 3/4 2-4

Bases Figure B 3/4 2.3-1 Power to Flow Operating Map.................... B 3/4 2-6

3/4.2.4 LINEAR HEAT GENERATION RATE....................... B 3/4 2-5

3/4.3 INSTRUMENTATION

3/4.3.1 REACTOR PROTECTION SYSTEM INSTRUMENTATION......... B 3/4 3-1

3/4.3.2 ISOLATION ACTUATION INSTRUMENTATION................ B 3/4 3-2

3/4.3.3 EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION..................................... B 3/4 3-2

3/4.3.4 RECIRCULATION PUMP TRIP ACTUATION INSTRUMENTATION..... B 3/4 3-3

3/4.3.5 REACTOR CORE ISOLATION COOLING SYSTEM ACTUATION INSTRUMENTATION..................................... B 3/4 3-4

3/4.3.6 CONTROL ROD BLOCK INSTRUMENTATION.................. B 3/4 3-4

SECTION PAGE

INSTRUMENTATION (Continued)

3/4.3.7 MONITORING INSTRUMENTATION

Radiation Monitoring Instrumentation.................... B 3/4 3-4

Seismic Monitoring Instrumentation...................... B 3/4 3-4

Meteorological Monitoring Instrumentation............... B 3/4 3-4

Remote Shutdown System Instrumentation and Controls..... B 3/4 3-5

Accident Monitoring Instrumentation..................... B 3/4 3-5

Source Range Monitors................................... B 3/4 3-5

Traversing In-Core Probe System......................... B 3/4 3-5

Loose-Part Detection System............................. B 3/4 3-6

Radioactive Liquid Effluent Monitoring Instrumentation.................................. B 3/4 3-6

Radioactive Gaseous Effluent Monitoring Instrumentation.................................. B 3/4 3-6

3/4.3.8 TURBINE OVERSPEED PROTECTION SYSTEM.................. B 3/4 3-6

3/4.3.9 PLANT SYSTEMS ACTUATION INSTRUMENTATION................ B 3/4 3-6

Bases Figure B 3/4 3-1 Reactor Vessel Water Level...................... B 3/4 3-8

3/4.4 REACTOR COOLANT SYSTEM

3/4.4.1 RECIRCULATION SYSTEM.................................. B 3/4 4-1

3/4.4.2 SAFETY/RELIEF VALVES.................................. B 3/4 4-2

3/4.4.3 REACTOR COOLANT SYSTEM LEAKAGE

Leakage Detection Systems............................... B 3/4 4-3

Operational Leakage..................................... B 3/4 4-3

3/4.4.4 CHEMISTRY.. B 3/4 4-4

SECTION		PAGE
REACTOR COOLANT SYSTEM (Continued)		
3/4.4.5	SPECIFIC ACTIVITY..	B 3/4 4-4
3/4.4.6	PRESSURE/TEMPERATURE LIMITS............................	B 3/4 4-5
	Bases Table B 3/4 4.6-1 Reactor Vessel Toughness.................	B 3/4 4-7
	Bases Figure B 3/4 4.6-1 Fast Neutron Fluence (E>1 MeV) At 1/4 T As A Function of Service Life.....................	B 3/4 4-8
3/4.4.7	MAIN STEAM LINE ISOLATION VALVES.......................	B 3/4 4-6
3/4.4.8	STRUCTURAL INTEGRITY.....................................	B 3/4 4-6
3/4.4.9	RESIDUAL HEAT REMOVAL....................................	B 3/4 4-6
3/4.5 EMERGENCY CORE COOLING SYSTEMS		
3/4.5.1 and 3/4.5.2	ECCS - OPERATING and SHUTDOWN.................	B 3/4 5-1
3/4.5.3	SUPPRESSION POOL...	B 3/4 5-2
3/4.6 CONTAINMENT SYSTEMS		
3/4.6.1	PRIMARY CONTAINMENT	
	Primary Containment Integrity.........................	B 3/4 6-1
	Primary Containment Leakage...........................	B 3/4 6-1
	Containment Air Locks..................................	B 3/4 6-1
	MSIV Leakage Control System...........................	B 3/4 6-2
	Containment Structural Integrity......................	B 3/4 6-2
	Containment Internal Pressure.........................	B 3/4 6-2
	Containment Average Air Temperature...................	B 3/4 6-2
	Drywell and Containment Purge System..................	B 3/4 6-2
	Feedwater Leakage Control System......................	B 3/4 6-3

SECTION		PAGE
6.1 RESPONSIBILITY		6-1
6.2 ORGANIZATION		6-1
6.2.1	Corporate	6-1
	Figure 6.2.1-1 Corporate Organization	6-3
6.2.2	Unit Staff	6-1
	Figure 6.2.2-1 Unit Organization	6-4
	Table 6.2.2-1 Minimum Shift Crew Composition	6-6
6.2.3	INDEPENDENT SAFETY ENGINEERING GROUP	
	Function	6-7
	Composition	6-7
	Responsibilities	6-7
	Records	6-7
6.2.4	SHIFT TECHNICAL ADVISOR	6-7
6.3 UNIT STAFF QUALIFICATIONS		6-7
6.4 TRAINING		6-8
6.5 REVIEW AND AUDIT		
6.5.1	PLANT OPERATIONS REVIEW COMMITTEE (PORC)	
	Function	6-8
	Composition	6-8
	Alternates	6-8
	Meeting Frequency	6-8
	Quorum	6-8
	Responsibilities	6-9
	Records	6-10

REACTOR PROTECTION SYSTEM INSTRUMENTATION SETPOINTS (Continued)

12. Reactor Mode Switch Shutdown Position

The reactor mode switch Shutdown position provides additional manual reactor trip capability.

13. Manual Scram

The Manual Scram provides manual reactor trip capability. The manual scram function is composed of four push button switches in a one-out-of-two taken twice logic.

SURVEILLANCE REQUIREMENTS

4.1.3.3 Each control rod scram accumulator shall be determined OPERABLE:

a. At least once per 7 days by verifying that the pressure is greater than or equal to 1520 psig unless the control rod is inserted and disarmed or scrammed.

b. At least once per 18 months by performance of a:

1. CHANNEL FUNCTIONAL TEST of the leak detectors, and

2. CHANNEL CALIBRATION of the pressure detectors, and verifying an alarm setpoint of 1535 ±15 psig on decreasing pressure.

CONTROL ROD POSITION INDICATION

LIMITING CONDITION FOR OPERATION

3.1.3.5 At least one control rod position indication system shall be OPERABLE.***

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2 and 5*.

ACTION:

a. In OPERATIONAL CONDITION 1 or 2 when the position of any OPERABLE control rod cannot be determined by at least one OPERABLE control rod position indicator, within 1 hour:

   1. Move the control rod to a position with an OPERABLE position indicator, or

   2. When THERMAL POWER is:

      a) Less than or equal to the low power setpoint of the RPCS:

         1) Declare the control rod inoperable, and

         2) Verify the position and bypassing of control rods with inoperable "Full-in" and/or "Full-out" position indicators by a second licensed operator or other technically qualified member of the unit technical staff.

      b) Greater than the low power setpoint of the RPCS, declare the control rod inoperable, insert the control rod and disarm the associated directional control valves** either:

         1) Electrically, or

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

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

b. In OPERATIONAL CONDITION 5* with both position indicators of a withdrawn control rod inoperable, move the control rod to a position with an OPERABLE position indicator or insert the control rod.

c. The provisions of Specification 3.0.4 are not applicable.

---

*At least each withdrawn control rod. Not applicable to control rods removed per Specification 3.9.10.1 or 3.9.10.2.

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

***This requirement shall be satisfied if the position of each OPERABLE control rod can be determined by at least one OPERABLE control rod position indicator.

ROD PATTERN CONTROL SYSTEM

LIMITING CONDITION FOR OPERATION

3.1.4.2 The rod pattern control system (RPCS) shall be OPERABLE.

APPLICABILITY: OPERATIONAL CONDITIONS 1 and 2*#.

ACTION:

a. With the RPCS inoperable or with the requirements of ACTION b, below, not satisfied and with:

   1. THERMAL POWER less than or equal to the RPCS low power setpoint, control rod movement shall not be permitted, except by a scram.

   2. THERMAL POWER greater than the RPCS low power setpoint, control rod withdrawal shall not be permitted.

b. With an inoperable control rod(s), OPERABLE control rod movement may continue by bypassing the inoperable control rod(s) in the RPCS provided that:

   1. With one control rod inoperable due to being immovable, as a result of excessive friction or mechanical interference, or known to be untrippable, this inoperable control rod may be bypassed in the rod gang drive system (RGDS) and/or the rod action control system (RACS) provided that the SHUTDOWN MARGIN has been determined to be equal to or greater than required by Specification 3.1.1.

   2. With up to eight control rods inoperable for causes other than addressed in ACTION b.1, above, these inoperable control rods may be bypassed in the RACS provided that:

      a) The control rod to be bypassed is inserted and the directional control valves are disarmed either:

         1) Electrically, or

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

      b) All inoperable control rods are separated from all other inoperable control rods by at least two control cells in all directions.

      c) There are not more than 3 inoperable control rods in any RPCS group.

   3. The position and bypassing of an inoperable control rod(s) is verified by a second licensed operator or other technically qualified member of the unit technical staff.

*See Special Test Exception 3.10.2

#Entry into OPERATIONAL CONDITION 2 and withdrawal of selected control rods is permitted for the purpose of determining the OPERABILITY of the RPCS prior to withdrawal of control rods for the purpose of bringing the reactor to criticality.

TABLE 3.3.2-1

ISOLATION ACTUATION INSTRUMENTATION

TRIP FUNCTION	VALVE GROUPS OPERATED BY SIGNAL	MINIMUM OPERABLE CHANNELS PER TRIP SYSTEM (a)	APPLICABLE OPERATIONAL CONDITION	ACTION
1. PRIMARY CONTAINMENT ISOLATION				
a. Reactor Vessel Water Level - Low, Level 2	1,5,7,8	2	1, 2, 3 and #	20
b. Drywell Pressure - High	1,2,5,8,9(b)(c)	2	1, 2, 3	20
c. Containment and Drywell Purge Exhaust Plenum Radiation - High	8	2(g)	1, 2, 3 and *	21
d. Reactor Vessel Water Level - Low, Level 1	2(b)(c)	2	1, 2, 3 and #	20
e. Manual Initiation	1,2,5,7,8,9	2(k)	1, 2, 3 and *	22
2. MAIN STEAM LINE ISOLATION				
a. Reactor Vessel Water Level - Low, Level 1	6	2	1, 2, 3	20
b. Main Steam Line Radiation - High	6(d)	2	1, 2	23
c. Main Steam Line Pressure - Low	6	2	1	24
d. Main Steam Line Flow - High	6	2/line	1, 2, 3	23
e. Condenser Vacuum - Low	6	2	1, 2**, 3**	23
f. Main Steam Line Tunnel Temperature - High	6	2	1, 2, 3	23
g. Main Steam Line Tunnel Δ Temperature - High	6	2	1, 2, 3	23
h. Turbine Building Main Steam Line Temperature - High	6	2	1, 2, 3	23
i. Manual Initiation	6	2	1, 2, 3	22

TABLE 3.3.2-1 (Continued)

ISOLATION ACTUATION INSTRUMENTATION

TRIP FUNCTION	VALVE GROUPS OPERATED BY SIGNAL	MINIMUM OPERABLE CHANNELS PER TRIP SYSTEM (a)	APPLICABLE OPERATIONAL CONDITION	ACTION
3. SECONDARY CONTAINMENT ISOLATION				
a. Reactor Vessel Water Level - Low, Level 2	1	2	1, 2, 3 and #	25
b. Drywell Pressure - High	1(b)(c)	2	1, 2, 3	25
c. Manual Initiation	1	2	1, 2, 3	22
	1	2	*	25
4. REACTOR WATER CLEANUP SYSTEM ISOLATION				
a. Δ Flow - High	7	1	1, 2, 3	27
b. Δ Flow Timer	7	1	1, 2, 3	27
c. Equipment Area Temperature - High	7	1	1, 2, 3	27
d. Equipment Area Δ Temperature - High	7	1	1, 2, 3	27
e. Reactor Vessel Water Level - Low, Level 2	7	2	1, 2, 3	27
f. Main Steam Line Tunnel Ambient Temperature - High	7	1	1, 2, 3	27
g. Main Steam Line Tunnel Δ Temperature - High	7	1	1, 2, 3	27
h. SLCS Initiation	7(e)	1	1, 2, 3	27
i. Manual Initiation	7	2	1, 2, 3	26

TABLE 4.3.2.1-1

ISOLATION ACTUATION INSTRUMENTATION SURVEILLANCE REQUIREMENTS

TRIP FUNCTION	CHANNEL CHECK	CHANNEL FUNCTIONAL TEST	CHANNEL CALIBRATION	OPERATIONAL CONDITIONS IN WHICH SURVEILLANCE REQUIRED
1. PRIMARY CONTAINMENT ISOLATION				
a. Reactor Vessel Water Level - Low, Level 2	S	M	$R^{(b)}$	1, 2, 3 and #
b. Drywell Pressure - High	S	M	$R^{(b)}$	1, 2, 3
c. Containment and Drywell Purge Exhaust Plenum Radiation - High	S	M	R	1, 2, 3 and *
d. Reactor Vessel Water Level - Low, Level 1	S	M	$R^{(b)}$	1, 2, 3 and #
e. Manual Initiation	NA	R	NA	1, 2, 3 and *
2. MAIN STEAM LINE ISOLATION				
a. Reactor Vessel Water Level - Low, Level 1	S	M	$R^{(b)}$	1, 2, 3
b. Main Steam Line Radiation - High	S	M	R	1, 2
c. Main Steam Line Pressure - Low	S	M	$R^{(b)}$	1
d. Main Steam Line Flow - High	S	M	$R^{(b)}$	1, 2, 3
e. Condenser Vacuum - Low	S	M	$R^{(b)}$	1, 2**, 3**
f. Main Steam Line Tunnel Temperature - High	S	M	R	1, 2, 3
g. Main Steam Line Tunnel Δ Temperature - High	S	M	R	1, 2, 3
h. Turbine Building Main Steam Line Temperature - High	S	M	R	1, 2, 3
i. Manual Initiation	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
C. DIVISION 3 TRIP SYSTEM				
1. HPCS SYSTEM				
a. Reactor Vessel Water Level - 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. HPCS Pump Discharge Pressure - High	S	M	R(a)	1, 2, 3, 4*, 5*
g. HPCS System Flow Rate - Low#	S	M	R(a)	1, 2, 3, 4*, 5*
h. Manual Initiation##	NA	R	NA	1, 2, 3, 4*, 5*
D. LOSS OF POWER				
1. 4.16 kv Emergency Bus Under-voltage (Loss of Voltage)	NA	NA	R	1, 2, 3, 4**, 5**
2. 4.16 kv Emergency Bus Under-voltage (Degraded Voltage)	S	M	R	1, 2, 3, 4**, 5**

#Not required to be OPERABLE when reactor steam dome pressure is less than or equal to 100 psig.

##The injection function of Drywell Pressure - High and Manual Initiation are not required to be OPERABLE with indicated reactor vessel water level on the wide range instrument greater than the Level 8 setpoint coincident with reactor pressure less than 450 psig.

*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 setpoint at least once per 31 days.

TABLE 3.3.6-2
CONTROL ROD BLOCK INSTRUMENTATION SETPOINTS

TRIP FUNCTION	TRIP SETPOINT	ALLOWABLE VALUE
1. ROD PATTERN CONTROL SYSTEM		
a. Low Power Setpoint	20 + 15, - 0% of RATED THERMAL POWER**	20 + 15, - 0% of RATED THERMAL POWER**
b. RWL - High Power Setpoint	70 + 0, - 15% of RATED THERMAL POWER**	70 + 0, - 15% of RATED THERMAL POWER**
2. APRM		
a. Flow Biased Neutron Flux - Upscale	$\leq$ 0.66 W + 42%*#	$\leq$ 0.66 W + 45%*#
b. Inoperative	NA	NA
c. Downscale	$\geq$ 4% of RATED THERMAL POWER	$\geq$ 3% of RATED THERMAL POWER
d. Neutron Flux - Upscale Startup	$\leq$ 12% of RATED THERMAL POWER	$\leq$ 14% of RATED THERMAL POWER
3. SOURCE RANGE MONITORS		
a. Detector not full in	NA	NA
b. Upscale	$\leq 1 \times 10^5$ cps	$\leq 1.6 \times 10^5$ cps
c. Inoperative	NA	NA
d. Downscale	$\geq$ 0.7 cps##	$\geq$ 0.5 cps##
4. INTERMEDIATE RANGE MONITORS		
a. Detector not full in	NA	NA
b. Upscale	$\leq$ 108/125 division of full scale	$\leq$ 110/125 division of full scale
c. Inoperative	NA	NA
d. Downscale	$\geq$ 5/125 division of full scale	$\geq$ 3/125 division of full scale
5. SCRAM DISCHARGE VOLUME		
a. Water Level - High	$\leq$ 16.6 inches*** (624' 3.3" elevation)	$\leq$ 17.48 inches*** (624' 4.17" elevation)
6. REACTOR COOLANT SYSTEM RECIRCULATION FLOW		
a. Upscale	$\leq$ 108% of rated flow	$\leq$ 110% of rated flow
7. REACTOR MODE SWITCH SHUTDOWN POSITION	NA	NA

*The Average Power Range Monitor rod block function is varied as a function of recirculation loop flow (W). The trip setting of this function must be maintained in accordance with Specification 3.2.2.

**The actual setpoints are the corresponding values of the turbine first stage pressure for these power levels.

***Level zero is 622' 10.69" elevation; level transmitter readout.

#During the startup test program, the APRM trip setpoint and allowable value may be permitted to be increased to the MEOD values (trip setpoint of 0.66 W + 58% and allowable value of 0.66 W + 61%).

##Provided signal to noise ratio $\geq$ 2.

TABLE 4.3.6-1 (Continued)

CONTROL ROD BLOCK INSTRUMENTATION SURVEILLANCE REQUIREMENTS

NOTES:

a. Neutron detectors may be excluded from CHANNEL CALIBRATION.

b. Within 24 hours prior to startup, if not performed within the previous 7 days.

c. Within one hour prior to control rod movement, unless performed within the previous 24 hours, and as power is increased above the RPCS low power setpoint and the RPCS high power setpoint and as power is decreased below the RPCS high power setpoint for the first time during any 24 hour period during power increase or decrease.

d. At least once per 31 days while operation continues with power above the RPCS low power setpoint.

e. The CHANNEL CALIBRATION shall exclude the flow reference transmitters, these transmitters shall be calibrated at least once per 18 months.

---

*With more than one control rod withdrawn. Not applicable to control rods removed per Specification 3.9.10.1 or 3.9.10.2.

#Calibrate trip unit setpoint at least once per 31 days.

INSTRUMENTATION

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 0.05g shall be restored to OPERABLE status within 24 hours and a CHANNEL CALIBRATION performed within 30 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 3.3.7.4-1

REMOTE SHUTDOWN SYSTEM INSTRUMENTATION

INSTRUMENT	MINIMUM CHANNELS OPERABLE Division 1	MINIMUM CHANNELS OPERABLE Division 2
1. Reactor Vessel Pressure	1	1
2. Reactor Vessel Water Level	1	1
3. Safety/Relief Valve Position*, 3 valves	1/valve	1/valve
4. Suppression Pool Water Level	1	1
5. Suppression Pool Water Temperature	1	1
6. Drywell Pressure	1	1
7. Drywell Temperature	1	1
8. RHR System Flow	1	1
9. Emergency Service Water Flow to RHR Heat Exchanger	1	1
10. Emergency Service Water Flow to Emergency Closed Cooling Heat Exchanger	1	1
11. RCIC System Flow	1	NA
12. RCIC Turbine Speed	1	NA
13. Emergency Closed Cooling System Flow	1	1
14. Inboard MSIV Position**, 4 valves	NA	1

*Indicating lights to indicate valve solenoid energized/de-energized.
**Indicating lights to indicate valve position.

TABLE 3.3.7.4-1 (Continued)

REMOTE SHUTDOWN SYSTEM CONTROLS

CONTROL	MINIMUM CHANNELS OPERABLE Division 1	Division 2
ESW Pump	1	1
ESW Pump Discharge Valve	1	1
RHR HX's ESW Inlet/Outlet Valves	2(a)	2(a)
RHR HX's Inlet/Outlet/Bypass Valves	3(a)	3(a)
RHR Pump	1	1
RHR to Containment Shutoff Valve	1	1
RHR Pump Suppression Pool Suction Valve	1	1
LPCI Injection Valve	1	1
RHR A Shutdown Cooling Suction Valve	1	NA
RHR Upper Pool Suction Valve	1	1
RHR Head Spray Isolation Valve	1	NA
RHR HX's Dump Valve	1	1
Containment Spray First Shutoff	1	1
Shutdown Cooling to Feedwater Shutoff	1	1
RHR Test Valve to Suppression Pool	1	1
Shutdown Cooling Outboard Suction Isolation Valve	1	NA
RHR A to Radwaste Second Isolation Valve	1	NA
Steam Condensing Shutoff Valve to RCIC	1	1
RHR HX's Steam Shutoff Valve	1	1
RHR Pump Minimum Flow Valve	1	1
ECC Pump	1	1
RCIC Turbine Gland Seal Compressor	1	NA
RHR & RCIC Steam Supply Outboard Isolation Valve	1	NA
RCIC Second Test Valve to CST	1	NA
RCIC Turbine Trip	1	NA
RCIC Steam Shutoff Valve	1	NA
RCIC First Test Valve to CST	1	NA
RCIC Pump CST Suction Valve	1	NA
RCIC Injection Valve	1	NA
RCIC Pump Suppression Pool Suction Isolation Valve	1	NA
RCIC Turbine Trip Throttle Valve	1	NA
RCIC Pump Minimum Flow Valve	1	NA
RCIC Turbine Exhaust Shutoff Valve	1	NA
RCIC Exhaust Vacuum Breaker Outboard Isolation Valve	1	NA
RCIC Pump Discharge to L.O. Cooler Valve	1	NA
RCIC Exhaust Vacuum Breaker Inboard Isolation Valve	NA	1*
RHR B Shutdown Cooling Suction Valve	NA	1*
Shutdown Cooling Inboard Suction Isolation Valve	NA	1*
RHR & RCIC Steam Supply Inboard Isolation Valve	NA	1*
RHR & RCIC Steam Supply Warmup Isolation Valve	NA	1*
Safety Relief Valves	3(a)	3(a)
Control Room to Shutdown Panel Transfer Switches	14	2*
APRM Power Supply Breakers	1**(b)	1**(b)
Inboard Main Steam Isolation Valve	NA	2(c)*
Diesel Generator Room Fan 1A Temperature Controller	1	NA

(a) 1 per valve

(b) One breaker constitutes one channel for ATWS Division 1 and Division 2.

(c) One switch for Solenoid "A" per 4 valves, one switch for Solenoid "B" per 4 valves.

* These Division 2 controls are physically located on the Division 1 panel.

** These breakers are physically located on ATWS Distribution Panels 1R14-S014 and 1R14-S015.

TABLE 3.3.7.5-1

ACCIDENT MONITORING INSTRUMENTATION

INSTRUMENT	REQUIRED NUMBER OF CHANNELS	MINIMUM CHANNELS OPERABLE	APPLICABLE OPERATIONAL CONDITIONS	ACTION
1. Reactor Vessel Pressure	2	1	1,2,3	80
2. Reactor Vessel Water Level	2	1	1,2,3	80
3. Suppression Pool Water Level	2	1	1,2,3	80
4. Suppression Pool Water Temperature	16, 2/sector	8, 1/sector	1,2,3	80
5. Primary Containment Pressure	2	1	1,2,3	80
6. Primary Containment Air Temperature	2	1	1,2,3	80
7. Drywell Pressure	2	1	1,2,3	80
8. Drywell Air Temperature	2	1	1,2,3	80
9. Primary Containment and Drywell Hydrogen Concentration Analyzer and Monitor	2	1	1,2,3	80
10. Safety/Relief Valve Position Indicators**	2/valve	1/valve	1,2,3	80
11. Primary Containment/Drywell Area Gross Gamma Radiation Monitors##	2*	1*	1,2,3	81
12. Offgas Ventilation Exhaust Monitor#,##	1	1	1,2,3	81
13. Turbine Building/Heater Bay Ventilation Exhaust Monitor#,##	1	1	1,2,3	81
14. Unit 1 Vent Monitor#,##	1	1	1,2,3	81
15. Unit 2 Vent Monitor#,##	1	1	1,2,3	81
16. Neutron Flux##				
a. Average Power Range	2	1	1,2,3	80
b. Intermediate Range	2	1	1,2,3	80
c. Source Range	2	1	1,2,3	80
17. Primary Containment Isolation Valve Position***,##	2/valve	1/valve	1,2,3	82

*Each for primary containment and drywell.

**One channel consists of a pressure switch on the SRV discharge pipe, the other channel consists of a temperature sensor on the SRV discharge pipe.

***One channel consists of the open limit switch, and the other channel consists of the closed limit switch for each automatic containment isolation valve in Table 3.6.4-1,a.

#High and intermediate range D19 system noble gas monitors.

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

Table 3.3.7.5-1 (Continued)

ACCIDENT MONITORING INSTRUMENTATIONS

ACTION STATEMENTS

ACTION 80 -

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

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

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

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

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

ACTION 82 -

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

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

TABLE 4.3.7.5-1

ACCIDENT MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS

INSTRUMENT	CHANNEL CHECK	CHANNEL CALIBRATION	APPLICABLE OPERATIONAL CONDITIONS
1. Reactor Vessel Pressure	M	R	1, 2, 3
2. Reactor Vessel Water Level	M	R	1, 2, 3
3. Suppression Pool Water Level	M	R	1, 2, 3
4. Suppression Pool Water Temperature	M	R	1, 2, 3
5. Primary Containment Pressure	M	R	1, 2, 3
6. Primary Containment Air Temperature	M	R	1, 2, 3
7. Drywell Pressure	M	R	1, 2, 3
8. Drywell Air Temperature	M	R	1, 2, 3
9. Primary Containment and Drywell Hydrogen Concentration Analyzer and Monitor	NA	Q*	1, 2, 3
10. Safety/Relief Valve Position Indicators	M	R	1, 2, 3
11. Primary Containment/Drywell Area Gross Gamma Radiation Monitors##	M	R**	1, 2, 3
12. Offgas Ventilation Exhaust Monitor#,##	M	R	1, 2, 3
13. Turbine Building/Heater Bay Ventilation Exhaust Monitor#,##	M	R	1, 2, 3
14. Unit 1 Vent Monitor#,##	M	R	1, 2, 3
15. Unit 2 Vent Monitor#,##	M	R	1, 2, 3
16. Neutron Flux##			
a. Average Power Range	M	R	1, 2, 3
b. Intermediate Range	M	R	1, 2, 3
c. Source Range	M	R	1, 2, 3
17. Primary Containment Isolation Valve Position##	M	R	1, 2, 3

*Using sample gas containing:
a. One volume percent hydrogen, balance nitrogen.
b. Four volume percent hydrogen, balance nitrogen.

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

#High and intermediate range D19 system noble gas monitors.

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

3/4.3.8 TURBINE OVERSPEED PROTECTION SYSTEM

LIMITING CONDITION FOR OPERATION

3.3.8 At least one turbine overspeed protection system shall be OPERABLE.

APPLICABILITY: OPERATIONAL CONDITIONS 1 and 2*.

ACTION:

a. With one turbine control valve or one turbine stop valve per high pressure turbine steam line inoperable, and/or with one turbine intercept or intermediate stop valve per low pressure turbine steam line inoperable, restore the inoperable valve(s) to OPERABLE status within 72 hours or close at least one valve in the affected steam line or isolate the turbine from the steam supply within the next 6 hours.

b. With the above required turbine overspeed protection system otherwise inoperable, within 6 hours isolate the turbine from the steam supply.

SURVEILLANCE REQUIREMENTS

4.3.8.1 The provisions of Specification 4.0.4 are not applicable.

4.3.8.2 The above required turbine overspeed protection system shall be demonstrated OPERABLE:

a. At least once per 7 days by:

    1. Cycling each of the following valves through at least one complete cycle from the running position:

        a) For the overspeed protection control system;

            1) Six low pressure turbine intercept valves, and

            2) Four high pressure turbine control valves.

        b) For the electrical overspeed trip system and the mechanical overspeed trip system;

            1) Four high pressure turbine stop valves, and

            2) Six low pressure turbine intermediate stop valves, and

            3) Four high pressure turbine control valves.

*Not required to be OPERABLE prior to exceeding 1% of RATED THERMAL POWER for the first time.

TABLE 3.3.9-2

PLANT SYSTEMS ACTUATION INSTRUMENTATION SETPOINTS

TRIP FUNCTION	TRIP SETPOINT	ALLOWABLE VALUE
1. CONTAINMENT SPRAY SYSTEM		
a. Drywell Pressure - High	$\leq$ 1.68 psig	$\leq$ 1.88 psig
b. Containment Pressure - High	$\leq$ 8.35 psig	$\leq$ 8.85 psig
c. Reactor Vessel Water Level - Low, Level 1	$\geq$ 16.5 inches*	$\geq$ 14.3 inches
d. Timers		
(1) System A and B	10.85 ± 0.3 minutes	10.85 ± 0.6 minutes
(2) System B	35 ± 2 seconds	35 ± 3 seconds
e. Manual Initiation	NA	NA
2. FEEDWATER SYSTEM/MAIN TURBINE TRIP SYSTEM		
a. Reactor Vessel Water Level - High, Level 8	$\leq$ 219.5 inches*	$\leq$ 221.7 inches
3. SUPPRESSION POOL MAKEUP SYSTEM		
a. Drywell Pressure - High	$\leq$ 1.68 psig	$\leq$ 1.88 psig
b. Reactor Vessel Water Level - Low, Level 1	$\geq$ 16.5 inches*	$\geq$ 14.3 inches
c. Suppression Pool Water Level - Low	$\geq$ 591' 6.9" elevation	$\geq$ 591' 5.64" elevation
d. Suppression Pool Makeup Timer	$\leq$ 29.4 minutes	$\leq$ 30.0 minutes
e. SPMU Manual Initiation	NA	NA

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

JET PUMPS

LIMITING CONDITION FOR OPERATION

3.4.1.2 All jet pumps shall be OPERABLE.

APPLICABILITY: OPERATIONAL CONDITIONS 1 and 2*.

ACTION:

With one or more jet pumps inoperable, be in at least HOT SHUTDOWN within 12 hours.

SURVEILLANCE REQUIREMENTS

4.4.1.2 Each of the above required jet pumps shall be demonstrated OPERABLE prior to THERMAL POWER exceeding 25% of RATED THERMAL POWER and at least once per 24 hours by determining recirculation loop flow, total core flow and diffuser-to-lower plenum differential pressure for each jet pump and verifying that no two of the following conditions occur when the recirculation loops are operating at the same flow control valve position.

a. The indicated recirculation loop flow differs by more than 10% from the established flow control valve position-loop flow characteristics.

b. The indicated total core flow differs by more than 10% from the established total core flow value derived from recirculation loop flow measurements.

c. The indicated diffuser-to-lower plenum differential pressure of any individual jet pump differs from established patterns by more than 10%.

*Not required to be OPERABLE prior to nuclear heatup.

RECIRCULATION LOOP FLOW

LIMITING CONDITION FOR OPERATION

3.4.1.3 Recirculation loop flow mismatch shall be maintained within:

a. 5% of rated recirculation flow with core flow greater than or equal to 70% of rated core flow.

b. 10% of rated recirculation flow with core flow less than 70% of rated core flow.

APPLICABILITY: OPERATIONAL CONDITIONS 1* and 2*#.

ACTION:

With recirculation loop flows different by more than the specified limits, either:

a. Restore the recirculation loop flows to within the specified limit within 2 hours, or

b. Declare the recirculation loop with the lower flow not in operation and take the ACTION required by Specification 3.4.1.1.

SURVEILLANCE REQUIREMENTS

4.4.1.3 Recirculation loop flow mismatch shall be verified to be within the limits at least once per 24 hours.

*See Special Test Exception 3.10.4.
#Not required to be OPERABLE prior to nuclear heatup.

3/4.4.3 REACTOR COOLANT SYSTEM LEAKAGE

LEAKAGE DETECTION SYSTEMS

LIMITING CONDITION FOR OPERATION

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

a. The drywell atmosphere particulate or gaseous radioactivity monitoring system,

b. The drywell floor drain sump and equipment drain sump flow monitoring system, and

c. The upper drywell air coolers condensate flow rate monitoring system.

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

ACTION:

With only two of the required leakage detection systems OPERABLE, operation may continue for up to:

a. 30 days when the required gaseous and particulate radioactive monitoring system is inoperable provided grab samples of the drywell atmosphere are obtained and analyzed at least once per 24 hours, or

b. 30 days when the drywell floor drain sump or equipment drain sump flow monitoring system is inoperable, or

c. 30 days when the upper drywell air coolers condensate flow rate monitoring system is inoperable.

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

SURVEILLANCE REQUIREMENTS

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

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

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

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

*The drywell floor drains sump and equipment drain sump flow monitoring system and the upper drywell air coolers condensate flow rate monitoring system are not required to be OPERABLE prior to nuclear heatup.

3/4.4.4 CHEMISTRY

LIMITING CONDITION FOR OPERATION

3.4.4 The chemistry of the reactor coolant system shall be maintained within the limits specified in Table 3.4.4-1.

APPLICABILITY: At all times.

ACTION:

a. In OPERATIONAL CONDITION 1:

1. With the conductivity, chloride concentration or pH exceeding the limit specified in Table 3.4.4-1 for less than 72 hours during one continuous time interval and, for conductivity and chloride concentration, for less than 336 hours per year, but with the conductivity less than 10 µmho/cm at 25°C and with the chloride concentration less than 0.5 ppm, this need not be reported to the Commission and the provisions of Specification 3.0.4 are not applicable.

2. With the conductivity, chloride concentration or pH exceeding the limit specified in Table 3.4.4-1 for more than 72 hours during one continuous time interval or with the conductivity and chloride concentration exceeding the limit specified in Table 3.4.4-1 for more than 336 hours per year, be in at least STARTUP within the next 6 hours.

3. With the conductivity exceeding 10 µmho/cm at 25°C or chloride concentration exceeding 0.5 ppm, be in at least HOT SHUTDOWN within 12 hours and in COLD SHUTDOWN within the next 24 hours.

b. In OPERATIONAL CONDITION 2 and 3, with the conductivity, chloride concentration or pH exceeding the limit specified in Table 3.4.4-1 for more than 48 hours during one continuous time interval, be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

c. At all other times:

1. With the:

   a) Conductivity or pH exceeding the limit specified in Table 3.4.4-1, restore the conductivity and pH to within the limit within 72 hours, or

   b) Chloride concentration exceeding the limit specified in Table 3.4.4-1, restore the chloride concentration to within the limit within 24 hours, or

   perform an engineering evaluation to determine the effects of the out-of-limit condition on the structural integrity of the reactor coolant system. Determine that the structural integrity of the reactor coolant system remains acceptable for continued operation prior to proceeding to OPERATIONAL CONDITION 3.

2. The provisions of Specification 3.0.3 are not applicable.

3/4.4.5 SPECIFIC ACTIVITY

LIMITING CONDITION FOR OPERATION

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

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

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

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

ACTION:

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

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

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

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

c. In OPERATIONAL CONDITION 1 or 2, with:

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

   2. The offgas level, at the outlet of main condenser air ejector, increased by more than 10,000 microcuries per second in one hour during steady state operation at release rates less than 75,000 microcuries per second, or

   3. The offgas level, at the outlet of main condenser air ejector, increased by more than 15% in one hour during steady state operation at release rates greater than 75,000 microcuries per second,

*Not applicable during the startup test program.

3/4.4.6 PRESSURE/TEMPERATURE LIMITS

REACTOR COOLANT SYSTEM

LIMITING CONDITION FOR OPERATION

3.4.6.1 The reactor coolant system temperature and pressure shall be limited in accordance with the limit lines shown on Figure 3.4.6.1-1: (1) curves A and A' for hydrostatic or leak testing; (2) curves B and B' for heatup by non-nuclear means, cooldown following a nuclear shutdown and low power PHYSICS TESTS; and (3) curves C and C' for operations with a critical core other than low power PHYSICS TESTS, with:

a. A maximum heatup of 100°F in any one hour period,

b. A maximum cooldown of 100°F in any one hour period,

c. A maximum temperature change of less than or equal to 20°F in any one hour period during inservice hydrostatic and leak testing operations above the heatup and cooldown limit curves, and

d. The reactor vessel flange and head flange temperature greater than or equal to 70°F when reactor vessel head bolting studs are under tension.

APPLICABILITY: At all times.

ACTION:

With any of the above limits exceeded, restore the temperature and/or pressure to within the limits within 30 minutes; perform an engineering evaluation to determine the effects of the out-of-limit condition on the structural integrity of the reactor coolant system; determine that the reactor coolant system remains acceptable for continued operations or be in at least HOT SHUTDOWN within 12 hours and in COLD SHUTDOWN within the following 24 hours.

SURVEILLANCE REQUIREMENTS

4.4.6.1.1 During system heatup, cooldown and inservice leak and hydrostatic testing operations, the reactor coolant system temperature and pressure shall be determined to be within the above required heatup and cooldown limits and to the right of the limit lines of Figure 3.4.6.1-1 curves A and A', B and B', or C and C', as applicable, at least once per 30 minutes.

3/4.4.9 RESIDUAL HEAT REMOVAL

HOT SHUTDOWN

LIMITING CONDITION FOR OPERATION

3.4.9.1 Two# shutdown cooling mode loops of the residual heat removal (RHR) system shall be OPERABLE and ,unless at least one recirculation pump is in operation, at least one shutdown cooling mode loop shall be in operation*,## with each loop consisting of at least:

a. One OPERABLE RHR pump, and

b. Two OPERABLE RHR heat exchangers.

APPLICABILITY: OPERATIONAL CONDITION 3, with reactor vessel pressure less than the RHR cut-in permissive setpoint.

ACTION:

a. With less than the above required RHR shutdown cooling mode loops OPERABLE, immediately initiate corrective action to return the required loops to OPERABLE status as soon as possible. Within one hour and at least once per 24 hours thereafter, demonstrate the operability of at least one alternate method capable of decay heat removal for eac. noperable RHR shutdown cooling mode loop. Be in at least COLD SHUTDO . within 24 hours.**

b. With no RHR shutdown cooling mode loop or recirculation pump in operation, immediately initiate corrective action to return at least one RHR shutdown cooling mode loop or recirculation pump to operation as soon as possible. Within one hour establish reactor coolant circulation by an alternate method and monitor reactor coolant temperature and pressure at least once per hour.

c. The provisions of Specifications 3.0.4 are not applicable.

SURVEILLANCE REQUIREMENTS

4.4.9.1 At least one shutdown cooling mode loop of the residual heat removal system, one recirculation pump or alternate method shall be determined to be in operation and circulating reactor coolant at least once per 12 hours.

#One RHR shutdown cooling mode loop may be inoperable for up to 2 hours for surveillance testing provided the other loop is OPERABLE and in operation.

*The shutdown cooling pump may be removed from operation for up to 2 hours per 8 hour period provided the other loop is OPERABLE.

##The RHR shutdown cooling mode loop may be removed from operation during hydrostatic testing.

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

3/4.5.1 ECCS - OPERATING

LIMITING CONDITION FOR OPERATION

3.5.1 ECCS divisions 1, 2 and 3 shall be OPERABLE with:

a. ECCS division 1 consisting of:

1. The OPERABLE 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.

2. The OPERABLE low pressure coolant injection (LPCI) subsystem "A" of the RHR system with a flow path capable of taking suction from the suppression pool and transferring the water to the reactor vessel.

3. Eight OPERABLE ADS valves.

b. ECCS division 2 consisting of:

1. The OPERABLE low pressure coolant injection (LPCI) subsystems "B" and "C" of the RHR system, each with a flow path capable of taking suction from the suppression pool and transferring the water to the reactor vessel.

2. Eight OPERABLE ADS valves.

c. ECCS division 3 consisting of the OPERABLE high pressure core spray (HPCS) 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.

APPLICABILITY: OPERATIONAL CONDITION 1, 2*,# and 3*,##.

*The ADS is not required to be OPERABLE when reactor steam dome pressure is less than or equal to 100 psig.

#See Special Test Exception 3.10.5.

##One LPCI subsystem of the RHR system may be aligned in the shutdown cooling mode when reactor vessel pressure is less than the cut-in permissive setpoint.

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 and 3, with a contained water volume of at least 115,612 ft^3, equivalent to a level of 18'0".

b. In OPERATIONAL CONDITION 4 and 5*, with a contained water volume of at least 106,508 ft^3, equivalent to a level of 16'6", 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 150,000 available gallons of water, equivalent to a level of 47% (220,000 gallons of water), 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 PRIMARY CONTAINMENT INTEGRITY within 8 hours.

---

*The suppression pool is not required to be OPERABLE provided that the reactor vessel head is removed, the cavity is flooded, the steam dryer storage/reactor well gate is removed and the water level in these upper containment pools is maintained within the limits of Specification 3.9.8 and 3.9.9.

SURVEILLANCE REQUIREMENTS

4.5.3.1 The suppression pool shall be determined OPERABLE by verifying the water level to be greater than or equal to:

a. 18'0" at least once per 24 hours in OPERATIONAL CONDITIONS 1, 2, and 3.

b. 16'6" at least once per 12 hours in OPERATIONAL CONDITIONS 4 and 5.

4.5.3.2 With the suppression pool level less than the above limit or drained in OPERATIONAL CONDITION 4 or 5*, at least once per 12 hours:

a. Verify the required conditions of Specification 3.5.3.b to be satisfied, or

b. Verify footnote conditions * to be satisfied.

*The suppression pool is not required to be OPERABLE provided that the reactor vessel head is removed, the cavity is flooded, the steam dryer storage/reactor well gate is removed and the water level in these upper containment pools is maintained within the limits of Specification 3.9.8 and 3.9.9.

3/4.6.1 PRIMARY CONTAINMENT

PRIMARY CONTAINMENT INTEGRITY - SHUTDOWN

LIMITING CONDITION FOR OPERATION

3.6.1.1.2 PRIMARY CONTAINMENT INTEGRITY* shall be maintained.

APPLICABILITY:

When irradiated fuel is being handled in the primary containment, and during CORE ALTERATIONS#, and operations with a potential for draining the reactor vessel. Under these conditions, the requirements of PRIMARY CONTAINMENT INTEGRITY do not apply to normal operation of the inclined fuel transfer system.

ACTION:

Without PRIMARY CONTAINMENT INTEGRITY, suspend handling of irradiated fuel in the primary containment, CORE ALTERATIONS, and operations with a potential for draining the reactor vessel.

SURVEILLANCE REQUIREMENTS

4.6.1.1.2 PRIMARY CONTAINMENT INTEGRITY shall be demonstrated:

a. At least once per 31 days by verifying that all primary containment penetrations not capable of being closed by OPERABLE primary containment automatic isolation valves and required to be closed during accident conditions are closed by valves, blind flanges, or deactivated automatic valves secured in position, except as provided in Table 3.6.4-1 of Specification 3.6.4.

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

---

*The primary containment leakage rates in accordance with Specification 3.6.1.2 are not applicable.

#The primary containment equipment hatch is not required to be closed and sealed during initial fuel load.

4.6.1.3 Each primary containment air lock shall be demonstrated OPERABLE:

a. By verifying seal leakage rate less than or equal to 2.5 scf per hour when the gap between the door seals is pressurized to Pa, 11.31 psig:

   1. within 72 hours# following each closing, except when the air lock is being used for multiple entries, then at least once per 72 hours#; and

   2. prior to establishing PRIMARY CONTAINMENT INTEGRITY when the air lock has been used and no maintenance has been performed on the airlock.*

b. By verifying at least once per 7 days that the service and instrument air system pressure in the header to the primary containment air lock is ≥ 90 psig.

c. By conducting an overall air lock leakage test at P_a, 11.31 psig, and verifying that the overall air lock leakage rate is within its limit:

   1. At least once per 6 months#,

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

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

e. By verifying the door inflatable seal system OPERABLE at least once per 18 months by conducting a seal pneumatic system leak test and verifying that system pressure does not decay more than 1.5 psig from 90 psig within 24 hours.

#The provisions of Specification 4.0.2 are not applicable.

*Exemption to Appendix J of 10 CFR 50.

DRYWELL AND CONTAINMENT PURGE SYSTEM

LIMITING CONDITION FOR OPERATION

3.6.1.8 The drywell and containment purge 42-inch outboard (1M14-F040, F090) supply and exhaust isolation valves and the 18-inch supply and exhaust isolation valves (1M14-F190, F195, F200, F205) shall be OPERABLE and:

a. Each 42-inch inboard purge valve (1M14-F045, F085) shall be sealed closed.

b. Each 42-inch outboard purge valve (1M14-F040, F090) may be open limited to an opening angle of 50° or less for purge system operation* with such operation limited to 3000 hours** per 365 days for reducing airborne activity and pressure control.

c. Each 24-inch (1M14-F055A, B and F060A, B) and 36-inch (1M14-F065, F070) drywell purge valve shall be sealed closed.

d. Each 2-inch (1M51-F090 and F110) backup hydrogen purge system isolation valves may be open for controlling drywell pressure.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2 and 3.

ACTION:

a. With a 42-inch inboard drywell and containment purge supply and/or exhaust isolation valve(s) open or not sealed closed, within 4 hours close and/or seal the 42-inch valve(s) or otherwise isolate the penetration or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

b. With a 18-inch or 42-inch outboard drywell and containment purge supply and/or exhaust isolation valves inoperable or open for more than 3000 hours per 365 days for purge system operation*, within four hours close the open 18- or 42-inch valve(s) or otherwise isolate the penetration(s) or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

c. With a 24- or 36-inch drywell purge supply and/or exhaust isolation valve(s) open or not sealed closed, within 4 hours close and/or seal close the 24- or 36-inch valve(s) or otherwise isolate the penetration, or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

d. With a drywell and containment purge supply and/or exhaust isolation valve(s) with resilient material seals having a measured leakage rate exceeding the limit of Surveillance Requirement 4.6.1.8.3 and/or

---

*Purge system operation shall be defined as any time that both 18-inch and the 42-inch outboard purge valves are open concurrently in either the supply or exhaust line.

**Applicable from initial fuel load until 3 months following the completion of the first refueling outage; otherwise, a 1000-hour-per-365-day limit applies.

LIMITING CONDITION FOR OPERATION

DRYWELL AND CONTAINMENT PURGE SYSTEM (Continued)

4.6.1.8.4, restore the inoperable valve(s) to OPERABLE status within 24 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

e. With one or more 2-inch backup hydrogen purge system isolation valve(s) not closed except as permitted above, close the 2-inch valves within 4 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

f. The provisions of specification 3.0.4 are not applicable to ACTIONS a, b, c, and e above.

SURVEILLANCE REQUIREMENTS

4.6.1.8.1 Each 42-inch inboard drywell and containment purge supply and exhaust isolation valve shall be verified to be sealed closed at least once per 31 days.

4.6.1.8.2 The cumulative time that the 18-inch and the 42-inch outboard drywell and containment purge supply and exhaust isolation valves have been open limited to an opening angle of 50° or less for the 42-inch valves during the past 365 days for purge system operation* shall be determined at least once per 7 days.

4.6.1.8.3 At least once per 6 months each sealed closed 42-inch inboard containment purge supply and exhaust isolation valve with resilient material seals shall be demonstrated OPERABLE by verifying that the measured leakage rate is less than or equal to 0.05 L_a when pressurized to P_a.

4.6.1.8.4 At least once per 92 days each 18-inch and the 42-inch outboard containment purge supply and exhaust isolation valves with resilient material seals shall be demonstrated OPERABLE by verifying that the measured leakage rate is less than or equal to 0.05 L_a when pressurized to P_a.

4.6.1.8.5 Each 24-inch and 36-inch drywell purge valve shall be verified to be sealed closed at least once per 31 days.

4.6.1.8.6 At least once per 18 months each 42-inch outboard drywell and containment purge supply and exhaust isolation valve shall be verified to be limited to an opening angle of 50° or less.

4.6.1.8.7 Each 2-inch backup hydrogen purge system isolation valve shall be verified to be closed within 4 hours following each purge.

---

*Purge system operation shall be defined as any time that both 18-inch and the 42-inch outboard purge valves are open concurrently in either the supply or exhaust line.

SURVEILLANCE REQUIREMENTS

4.6.2.3 The drywell air lock shall be demonstrated OPERABLE:

a. Within 72 hours following each closing, except when the air lock is being used for multiple entries, then at least once per 72 hours, by verifying seal leakage rate less than or equal to 2.5 scf per hour when the gap between the door seals is pressurized to 2.5 psig.

b. By verifying at least once per 7 days that the service and instrument air system pressure in the header to the drywell air lock is $\geq$ 60 psig.

c. By conducting an overall air lock leakage test at 2.5 psig and verifying that the overall air lock leakage rate is within its limit:

   1. Each COLD SHUTDOWN if not performed within the previous 6 months.

   2. Prior to establishing DRYWELL INTEGRITY when maintenance has been performed on the air lock that could affect the air lock sealing capability.

d. By verifying that only one door in the air lock can be opened at a time prior to drywell entry, if not performed in the previous 18 months.

e. By verifying the door inflatable seal system OPERABLE at least once per 18 months by conducting a seal pneumatic system leak test and verifying that system pressure does not decay more than 3 psig from 60 psig within 24 hours.

LIMITING CONDITION FOR OPERATION (Continued)

ACTION: (Continued)

c) 120°F, depressurize the reactor pressure vessel to less than 200 psig within 12 hours.

c. With only one suppression pool water level indicator OPERABLE and/or with less than eight suppression pool water temperature indicators, one in each of the eight locations OPERABLE, restore the inoperable indicators(s) to OPERABLE status within 7 days or verify suppression pool water level and/or temperature to be within the limits at least once per 12 hours.

d. With no suppression pool water level indicators OPERABLE and/or with less than seven suppression pool water temperature indicators covering at least seven locations OPERABLE, restore at least one water level indicator and at least seven water temperature indicators to OPERABLE status within 48 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

SURVEILLANCE REQUIREMENTS

4.6.3.1 The suppression pool shall be demonstrated OPERABLE:

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

b. At least once per 24 hours in OPERATIONAL CONDITION 1 or 2 by verifying the suppression pool average water temperature to be less than or equal to 90°F, except:

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

2. At least once per hour when suppression pool average water temperature is greater than or equal to 90°F, by verifying suppression pool average water temperature to be less than or equal to 110°F, and THERMAL POWER to be less than or equal to 1% of RATED THERMAL POWER after suppression pool average water temperature has exceeded 90°F for more than 24 hours.

3. At least once per 30 minutes following a scram with suppression pool average water temperature greater than or equal to 90°F, by verifying suppression pool average water temperature less than or equal to 120°F.

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 22'10" above the reactor pressure vessel flange, and
    2. Temperature to be less than or equal to 100°F.

b. At least once per 31 days by verifying that:
    1. The steam dryer storage/reactor well pool gate is removed and the fuel transfer pool gate is in place.
    2. Each valve, manual, power operated or automatic, in the flow path that is not locked, sealed, or otherwise secure in position, is in its correct position.

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.

SURVEILLANCE REQUIREMENTS

4.6.4.1 Each isolation valve shown in Table 3.6.4-1 shall be demonstrated OPERABLE prior to returning the valve to service after maintenance, repair or replacement work is performed on the valve or its associated actuator, control or power circuit by cycling the valve through at least one complete cycle of full travel and verifying the specified isolation time.

4.6.4.2 Each automatic isolation valve shown in Table 3.6.4-1 shall be demonstrated OPERABLE at least once per 18 months by verifying that on an isolation test signal each automatic isolation valve actuates to its isolation position.

4.6.4.3 The isolation time of each power operated or automatic valve shown in Table 3.6.4-1 shall be determined to be within its limit when tested pursuant to Specification 4.0.5.

b. CONTAINMENT MANUAL ISOLATION VALVES

Valve Number	Penetration Number	Valve Group[c]	Maximum Isolation Time (Seconds)	Secondary Containment Bypass Path (Yes/No)	Test Pressure (Psig)
1B21-F065A[e]	P121		100*	Yes[h]	11.31
1B21-F065B[e]	P414		100*	Yes[h]	11.31
1C11-F083[e]	P204		12.5*	Yes	11.31
1C41-F518	P315	NA	NA	Yes	11.31
1D23-F010A[e]	P434		3	No	(a)
1D23-F010B[e]	P320		3	No	(a)
1D23-F020A[e]	P434		3	No	(a)
1D23-F020B[e]	P320		3	No	(a)
1D23-F030A[e]	P433		3	No	(a)
1D23-F030B[e]	P319		3	No	(a)
1D23-F040A[e]	P433		3	No	(a)
1D23-F040B[e]	P319		3	No	(a)
1D23-F050[e]	P425		3	No	(a)
1E12-F004A[e]	P102		120*	No	(b)
1E12-F004B[e]	P402		120*	No	(b)
1E12-F027A[e]	P113		60*	No[h]	11.31
1E12-F027B[e]	P412		60*	No[h]	11.31
1E12-F028A[e]	P113		60	No	11.31
1E12-F028B[e]	P412		60	No	11.31
1E12-F042C[e]	P411		27	No[h]	11.31
1E12-F073A(e)	P118		15*	No	11.31
1E12-F073B(e)	P431		15*	No	11.31
1E12-F105(e)	P403		120*	No	(b)
1E21-F001[e]	P103	NA	120*	No	(b)
1E21-F005[e]	P112	NA	27	No[h]	11.31
1E22-F015[e]	P401	NA	24	No	(b)

b. CONTAINMENT MANUAL ISOLATION VALVES (Continued)

Valve Number	Penetration Number	Valve Group[c]	Maximum Isolation Time (Seconds)	Secondary Containment Bypass Path (Yes/No)	Test Pressure (Psig)
1N27-F751	P106, P107, P115, P429	NA	NA	Yes	11.31
1P53-F030[e]	P305	NA	3	No	11.31
1P53-F035[e]	P305	NA	3	No	11.31
1P53-F040[e]	P312	NA	3	No	11.31
1P53-F045[e]	P312	NA	3	No	11.31
1P53-F536[d]/ F570[d]	P305	NA	NA	Yes	11.31
1P53-F541[d]/ F571[d]	P312	NA	NA	Yes	11.31
1P54-F726	P406	NA	NA	Yes	11.31
1P54-F727	P406	NA	NA	Yes	11.31
1P57-F015A[e]	P304	NA	15*	No	11.31
1P57-F015B[e]	P116	NA	15*	No	11.31
1P87-F037[e]	P401	NA	3	Yes	(b)
1P87-F065[e]	P318	NA	3	Yes	(a)
1P87-F071[e]	P318	NA	3	Yes	(a)
1P87-F074[e]	P318	NA	3	Yes	(a)
1P87-F077[e]	P318	NA	3	Yes	(a)
1P87-F049[e]	P413	NA	3	Yes	11.31
1P87-F055[e]	P413	NA	3	Yes	11.31
1P87-F046[e]	P413	NA	3	Yes	11.31
1P87-F052[e]	P413	NA	3	Yes	11.31
1P87-F083[e]	P106, P107 P115, P429	NA	3	Yes	11.31
1P87-F264[e]	P106, P107 P115, P429	NA	3	Yes	11.31

c. OTHER CONTAINMENT ISOLATION VALVES

Valve Number	Penetration Number	Valve Group[c]	Maximum Isolation Time (Seconds)	Secondary Containment Bypass Path (Yes/No)	Test Pressure (Psig)
1B21-F032A[f]	P121	NA	NA	No	(b)
1B21-F032B[f]	P414	NA	NA	No	(b)
1C11-F122[f]	P204	NA	NA	Yes	11.31
1C41-F520[f]	P315	NA	NA	Yes	11.31
1E12-F005	P106, P107, P115, P429	NA	NA	No[h]	11.31
1E12-F025A	P106, P107, P115, P429	NA	NA	No[h]	11.31
1E12-F025B	P106, P107, P115, P429	NA	NA	No[h]	11.31
1E12-F025C	P106, P107, P115, P429	NA	NA	No[h]	11.31
1E12-F041C[f]	P411	NA	NA	No	11.31
1E12-F055A	P106, P107, P115, P429	NA	NA	No[h]	11.31
1E12-F055B	P106, P107, P115, P429	NA	NA	No[h]	11.31
1E12-F550[f]	P421	NA	NA	No	11.31
1E12-F558A[f]	P118	NA	NA	No	11.31
1E12-F558B[f]	P431	NA	NA	No	11.31
1E21-F006[f]	P112	NA	NA	No	11.31
1E21-F018	P106, P107, P115, P429	NA	NA	No[h]	11.31
1E22-F005[f]	P410	NA	NA	No	11.31
1E22-F035	P409	NA	NA	No[h]	11.31
1E51-F066[f][i]	P123	NA	NA	No	11.31
1G41-F522[f]	P203	NA	NA	Yes	11.31
1M17-F010[f]	P114	NA	NA	Yes	11.31
1M17-F020[f]	P208	NA	NA	Yes	11.31
1M17-F030[f]	P428	NA	NA	Yes	11.31
1M17-F040[f]	P436	NA	NA	Yes	11.31

c. OTHER CONTAINMENT ISOLATION VALVES (Continued)

Valve Number	Penetration Number	Valve Group(c)	Maximum Isolation Time (Seconds)	Secondary Containment Bypass Path (Yes/No)	Test Pressure (Psig)
1N27-F559A(f)	P121	NA	NA	No	(b)
1N27-F559B(f)	P414	NA	NA	No	(b)
1P11-F545(f)	P108	NA	NA	Yes	11.31
1P22-F577(f)	P309	NA	NA	Yes	11.31
1P43-F721(f)	P310	NA	NA	Yes	11.31
1P50-F539(f)	P404	NA	NA	Yes	11.31
1P51-F530(f)	P308	NA	NA	Yes	11.31
1P52-F550(f)	P306	NA	NA	Yes	11.31
1P54-F1038(f)	P210	NA	NA	Yes	11.31
1P86-F528(f)	P117	NA	NA	Yes	11.31
1P57-F524A(f)	P304	NA	NA	No	11.31
1P57-F524B(f)	P116	NA	NA	No	11.31

d. DRYWELL ISOLATION VALVES

Valve Number	Penetration Number	Valve Group(c)	Maximum Isolation Time (Seconds)
1B33-F013A(f)(i)	PRB3049	NA	NA
1B33-F013B(f)(i)	PRB3090	NA	NA
1B33-F017A(f)(i)	PRB3049	NA	NA
1B33-F017B(f)(i)	PRB3090	NA	NA
1B33-F019(i)	PRB3105	11	5
1B33-F020(i)	PRB3105	11	5
1C41-F006(f)(i)	PRB4031	NA	NA
1C41-F007(f)(i)	PRB4031	NA	NA
1G61-F030(i)	PRB2030	1	22
1G61-F035(i)	PRB2030	1	22
1G61-F150(i)	PRB2042	1	22
1G61-F155(i)	PRB2042	1	22
1M14-F055A(j)(i)	VRB3003	8	4
1M14-F055B(j)(i)	VRB3003	8	4
1M14-F060A(j)(i)	VRB3002	8	4
1M14-F060B(j)(i)	VRB3002	8	4
1M14-F065(j)(i)	VRB5001	8	4
1M14-F070(j)(i)	VRB5001	8	4
1M16-F010A(i)	PRB5012	13	5
1M16-F010B(i)	PRB5011	13	5
1M16-F020A(f)(i)	PRB5012	NA	NA
1M16-F020B(f)(i)	PRB5011	NA	NA
1M51-F010A(i)	PRB5012	12	37
1M51-F010B(i)	PRB5011	12	37
1P22-F593(f)(i)	PRB3050	NA	NA
1P22-F015(i)	PRB3050	1	18.8

d. <u>DRYWELL ISOLATION VALVES</u> (Continued)

Valve Number	Penetration Number	Valve Group(c)	Maximum Isolation Time (Seconds)
1P43-F355(i)	PRB2039	2	10
1P43-F722(f)(i)	PRB2039	NA	NA
1P43-F400(i)	PRB2038	2	10
1P43-F410(i)	PRB2038	2	10
1P51-F653(f)(i)	PRB3050	NA	NA
1P51-F652(i)	PRB3050	1	22.5
1P52-F639(f)(i)	PRB3050	NA	NA
1P52-F646(i)	PRB3050	2	30*
1P54-F395(i)	PRB2037	1	20*

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 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 24 hours that the pressure within the secondary containment is less than or equal to 0.40 inches of vacuum water gauge.

b. Verifying at least once per 31 days that:

   1. The primary containment equipment hatch is closed and sealed and the shield blocks are installed adjacent to the shield building.

   2. The door in each access to the secondary containment is closed, except for routine entry and exit.

   3. All penetrations terminating in the annulus not capable of being closed by OPERABLE automatic isolation valves and required to be closed during accident conditions are closed by valves, blind flanges, or deactivated automatic valves secured in position.

*When irradiated fuel is being handled in the primary containment and during CORE ALTERATIONS and operations with a potential for draining the reactor vessel.
#The primary containment equipment hatch is not required to be closed and sealed and the shield blocks are not required to be installed adjacent to the shield building during initial fuel load. Surveillance Requirements 4.6.6.1.a and 4.6.6.1.b.1 are not required to demonstrate secondary containment integrity during initial fuel load.

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 penetration testing acceptance criteria of less than 0.05% and uses the test procedure guidance in Regulatory Positions C.5.a, C.5.c and C.5.d of Regulatory Guide 1.52, Revision 2, March 1978, and the system flow rate is 2000 scfm ± 10%.

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

   3. Verifying a subsystem flow rate of 2000 scfm ± 10% during system operation when tested in accordance with ANSI N510-1980. The installed air flow monitor can be used to determine flow in lieu of the pitot traverse.

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, by showing a methyl iodide penetration of less than 0.175% when tested at a temperature of 30°C and at a relative humidity of 70% in accordance with ASTM D3803;

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 LOCA.

   2. Verifying that the pressure drop across the combined HEPA filters and charcoal adsorber banks is less than 6.0 inches water gauge while operating the filter train at a flow rate of 2000 scfm ± 10%.

   3. Verifying that the filter train starts and isolation dampers open on each of the following test signals:

      a. Manual initiation from the control room, and

      b. Simulated automatic initation signal.

   4. Verifying that the heaters dissipate 20 kw ± 10% when tested in accordance with ANSI N510-1980.

3/4.7.2 CONTROL ROOM EMERGENCY RECIRCULATION SYSTEM

LIMITING CONDITION FOR OPERATION

3.7.2 Two independent control room emergency recirculation system subsystems shall be OPERABLE.

APPLICABILITY: All OPERATIONAL CONDITIONS and *.

ACTION:

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

b. In OPERATIONAL CONDITION 4, 5 or *:

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

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

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

SURVEILLANCE REQUIREMENTS

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

a. At least once per 12 hours by verifying that the control room air temperature is less than or equal to 90°F.

b. 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 hours with the heaters OPERABLE.

---

*When irradiated fuel is being handled in the Fuel Handling Building or primary containment.

SURVEILLANCE REQUIREMENTS (Continued)

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

   1. Verifying that the subsystem satisfies the in-place penetration testing acceptance criteria of less than 0.05% and uses the test procedure guidance in Regulatory Positions C.5.a, C.5.c and C.5.d of Regulatory Guide 1.52, Revision 2, March 1978, and the system flow rate is 30000 scfm ± 10%.

   2. Verifying within 31 days after removal that a laboratory analysis of a representative carbon sample obtained in accordance with Regulatory Position C.6.b of Regulatory Guide 1.52, Revision 2, March 1978, meets the laboratory testing criteria of Regulatory Position C.6.a of Regulatory Guide 1.52, Revision 2, March 1978 by showing a methyl iodide penetration of less than 1% when tested at a temperature of 30°C and at a relative humidity of 70% in accordance with ASTM D3803; and

   3. Verifying a subsystem flow rate of 30000 scfm ± 10% during subsystem operation when tested in accordance with ANSI N510-1980. The installed air flow monitor can be used to determine flow in lieu of a pitot traverse.

d. After every 720 hours of charcoal adsorber operation by verifying within 31 days after removal that a laboratory analysis of a representative carbon sample obtained in accordance with Regulatory Positon C.6.b of Regulatory Guide 1.52, Revision 2, March 1978, meets the laboratory testing criteria of Regulatory Position C.6.a of Regulatory Guide 1.52, Revision 2, March 1978, by showing a methyl iodide penetration of less than 1% when tested at a temperature of 30°C and at a relative humidity of 70% in accordance with ASTM D3803.

e. At least once per 18 months by:

   1. Verifying that the pressure drop across the combined HEPA filters and charcoal adsorber banks is less than 4.9 inches water gauge while operating the subsystem at a flow rate of 30000 scfm ± 10%.

   2. Verifying that on each of the below emergency recirculation mode actuation test signals, the subsystem automatically switches to the emergency recirculation mode of operation and the isolation dampers close within 10 seconds:
      a) High Drywell Pressure
      b) Low Reactor Water Level-Level 1
      c) High radiation from control room ventilation duct

3/4.7.7 FUEL HANDLING BUILDING

FUEL HANDLING BUILDING VENTILATION SYSTEM

LIMITING CONDITION FOR OPERATION

3.7.7.1 At least three Fuel Handling Building (FHB) ventilation exhaust subsystems shall be OPERABLE.

APPLICABILITY: When irradiated fuel is being handled in the Fuel Handling Building.

ACTION:

With one FHB ventilation exhaust subsystem inoperable, restore the inoperable system to OPERABLE status within 7 days or suspend handling of irradiated fuel in the FHB. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.7.7.1 Each of the required FHB ventilation exhaust 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 hours with the heaters OPERABLE.

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

   1. Verifying that the subsystem satisfies the in-place penetration testing acceptance criteria of less than 0.05% and uses the test procedure guidance in Regulatory Positions C.5.a, C.5.c and C.5.d of Regulatory Guide 1.52, Revision 2, March 1978, and the system flow rate is 15000 scfm ± 10%.

   2. Verifying within 31 days after removal that a laboratory analysis of a representative carbon sample obtained in accordance with Regulatory Position C.6.b of Regulatory Guide 1.52, Revision 2, March 1978, meets the laboratory testing criteria of Regulatory Position C.6.a of Regulatory Guide 1.52, Revision 2, March 1978, by showing a methyl iodide penetration of less than 1% when tested at a temperature of 30°C and a relative humidity of 70% in accordance with ASTM D3803; and

   3. Verifying a subsystem flow rate of 15000 scfm ± 10% during system operation when tested in accordance with ANSI N510-1980.

SURVEILLANCE REQUIREMENTS (Continued)

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, by showing a methyl iodide penetration of less than 1% when tested at a temperature of 30°C and a relative humidity of 70% in accordance with ASTM D3803.

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 fuel handling accident.

2. Verifying that the pressure drop across the combined HEPA filters and charcoal adsorber banks is less than 4.9 inches water gauge while operating the filter train at a flow rate of 15000 scfm ± 10%.

3. Verifying that the filter train starts on manual initiation from the control room.

4. Verifying that the heaters dissipate 50 kW ± 10% when tested in accordance with ANSI N510-1980.

e. After each complete or partial replacement of a HEPA filter bank by verifying that the HEPA filter bank satisfies the inplace penetration acceptance criteria of less than 0.05% in accordance with Regulatory Positions C.5.a and C.5.c of Regulatory Guide 1.52, Revision 2, March 1978, while operating the subsystem at a flow rate of 15000 scfm ± 10%.

f. After each complete or partial replacement of a charcoal adsorber bank by verifying that the charcoal adsorber bank satisfies the inplace penetration acceptance criteria of less than 0.05% in accordance with Regulatory Positions C.5.a and C.5.d of Regulatory Guide 1.52, Revision 2, March 1978, for a halogenated hydrocarbon refrigerant test gas while operating the subsystem at a flow rate of 15000 scfm ± 10%.

LIMITING CONDITION FOR OPERATION (Continued)

ACTION (Continued)

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

g. With diesel generators Div 1 and Div 2 of the above required A.C. electrical power sources inoperable, demonstrate the OPERABILITY of the remaining A.C. sources by performing Surveillance Requirement 4.8.1.1.1.a within 1 hour and at least once per 8 hours thereafter and Surveillance Requirements 4.8.1.1.2.a.4 and 4.8.1.1.2.a.5 for diesel generator Div 3 within 8 hours*. Restore at least one of the inoperable diesel generators Div 1 and Div 2 to OPERABLE status within 2 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours. Restore both diesel generators Div 1 and Div 2 to OPERABLE status within 72 hours from time of initial loss or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

h. With one offsite circuit of the above required A.C. electrical power sources and diesel generator Div 3 inoperable, apply the requirements of ACTION a and d specified above.

i. With either diesel generator Div 1 or Div 2 inoperable and diesel generator Div 3 inoperable, apply the requirements of ACTION b, d and e specified above.

*This test is required to be completed regardless of when the inoperable diesel generator is restored to OPERABILITY. The provisions of Specification 3.0.2 are not applicable.

LIMITING CONDITION FOR OPERATION (Continued)

3. Division 3 consisting of 125 volt D.C. distribution panel 1R42-S037.

APPLICABILITY: OPERATIONAL CONDITIONS 4, 5 and *.

ACTION:

a. For A.C. power distribution:

   1. With less than Division 1 and/or Division 2 of the above required A.C. distribution system energized, suspend CORE ALTERATIONS, handling of irradiated fuel in the Fuel Handling Building and primary containment and operations with a potential for draining the reactor vessel.

   2. With Division 3 of the above required A.C. distribution system not energized, declare the HPCS system inoperable and take the ACTION required by Specification 3.5.2 and 3.5.3.

b. For D.C. power distribution:

   1. With less than Division 1 and/or Division 2 of the above required D.C. distribution system energized, suspend CORE ALTERATIONS, handling of irradiated fuel in the Fuel Handling Building and primary containment and operations with a potential for draining the reactor vessel.

   2. With Division 3 of the above required D.C. distribution system not energized, declare the HPCS system inoperable and take the ACTION required by Specification 3.5.2 and 3.5.3.

c. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.8.3.2 At least the above required power distribution system divisions shall be determined energized at least once per 7 days by verifying voltage and correct breaker alignment on the busses/MCCs/panels.

*When handling irradiated fuel in the Fuel Handling Building or primary containment.

3/4.9.9 WATER LEVEL - SPENT FUEL STORAGE AND UPPER CONTAINMENT FUEL POOLS

LIMITING CONDITION FOR OPERATION

3.9.9 At least 23 feet of water shall be maintained over the top of irradiated fuel assemblies seated in the Fuel Handling Building spent fuel storage and upper containment fuel pool racks.

APPLICABILITY: Whenever irradiated fuel assemblies are in the Fuel Handling Building spent fuel storage or upper containment fuel pools.

ACTION:

With the requirements of the above specification not satisfied, suspend all movement of fuel assemblies and crane operations with loads in the Fuel Handling Building spent fuel storage or upper containment fuel pool areas, as applicable after placing the fuel assemblies and crane load in a safe condition. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.9.9 The water level in the Fuel Handling Building spent fuel storage and upper containment fuel pools shall be determined to be at least at its minimum required depth at least once per 7 days.

3/4.9.12 INCLINED FUEL TRANSFER SYSTEM

LIMITING CONDITION FOR OPERATION

3.9.12 The inclined fuel transfer system (IFTS) may be in operation provided that:

a. The access door and floor plugs of all rooms through which the transfer system penetrates are closed and locked.

b. All access interlocks and palm switches are OPERABLE.

c. The Versa blocking valve located in the Fuel Handling Building IFTS hydraulic power unit is OPERABLE.

d. At least one IFTS carriage position indicator is OPERABLE at each of the twelve proximity sensors and at least one liquid level sensor is OPERABLE.

e. All keylock switches which provide IFTS access control-transfer system lockout are OPERABLE.

f. The warning light outside of the access door is OPERABLE.

APPLICABILITY: When the IFTS blank flange is removed.

ACTION:

a. With one or more access interlocks, warning lights, and/or palm switches inoperable, operation of the IFTS may continue provided that entry into the area is prohibited by establishing a continuous watch and conspicuously posting as a high radiation area.

b. With the requirements of the above specification not satisfied, suspend IFTS operation with the IFTS at either terminal point. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.9.12.1 Within 4 hours prior to the startup of the IFTS, verify that no personnel are in areas immediately adjacent to the IFTS tube and that the access door and floor plugs to rooms through which the IFTS tube penetrates are closed and locked.

SURVEILLANCE REQUIREMENTS (Continued)

4.9.12.2 Within 4 hours prior to the operation of IFTS and at least once per 12 hours thereafter, when the IFTS in in operation verify that:

a. At least one IFTS carriage position indicator is OPERABLE at each of the twelve proximity sensors and at least one liquid level sensor is OPERABLE.

b. The warning light outside of the access door is OPERABLE.

4.9.12.3 Within 4 hours prior to the operation of IFTS and at least once per 7 days thereafter, when the IFTS is in operation verify that:

a. All access interlocks for the IFTS Valve Room are OPERABLE.

b. The Versa blocking valve in the Fuel Handling Building IFTS hydraulic power unit is OPERABLE.

c. All keylock switches which provide IFTS access control-transfer system lockout are OPERABLE.

4.9.12.4 Within 4 hours prior to installation of the floor plugs, after they have been removed, verify that the access interlocks and palm switches for the shield building annulus room and/or mid-support room, as applicable, are OPERABLE.

LIQUID RADWASTE TREATMENT SYSTEM

LIMITING CONDITION FOR OPERATION

3.11.1.3 The LIQUID RADWASTE TREATMENT SYSTEM shall be OPERABLE and appropriate portions of the system shall be used to reduce the release of radioactivity when the projected doses due to the liquid effluent from each reactor unit to UNRESTRICTED AREAS (see Figure 5.1.1-1) would exceed 0.06 mrem to the total body or 0.2 mrem to any organ, in a 31-day period.

APPLICABILITY: At all times*.

ACTION:

a. With radioactive liquid waste being discharged without treatment and in excess of the above limits, and any portion of the liquid radwaste treatment system not in operation, prepare and submit to the Commission, within 30 days pursuant to Specification 6.9.2, a Special Report which includes the following information:

   1. Explanation of why liquid radwaste was being discharged without treatment, identification of any inoperable equipment or subsystems, and the reason for the inoperability, and

   2. Action(s) taken to restore the inoperable equipment to OPERABLE status, and

   3. Summary description of action(s) taken to prevent a recurrence.

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

SURVEILLANCE REQUIREMENTS

4.11.1.3.1 Doses due to liquid releases from each reactor unit to UNRESTRICTED AREAS shall be projected at least once per 31 days, in accordance with methodology and parameters in the ODCM.

4.11.1.3.2 The installed LIQUID RADWASTE TREATMENT SYSTEM shall be demonstrated OPERABLE by meeting Specifications 3.11.1.1 and 3.11.1.2.

*Not required to be OPERABLE prior to initial criticality.

LIMITING CONDITION FOR OPERATION

3.11.2.5 The VENTILATION EXHAUST TREATMENT SYSTEMS shall be OPERABLE and appropriate portions of the system shall be used to reduce releases of radioactivity when the projected dose due to gaseous effluent releases from each reactor unit to areas at and beyond the SITE BOUNDARY (see Figure 5.1.1-1) in a 31 day period would exceed 0.3 mrem to any organ of a MEMBER OF THE PUBLIC.

APPLICABILITY: At all times*.

ACTION:

a. With radioactive gaseous waste being discharged without treatment and in excess of the above limits, prepare and submit to the Commission within 30 days, pursuant to Specification 6.9.2, a Special Report which includes the following information:

   1. Explanation of why gaseous radwaste was being discharged without treatment, identification of any inoperable equipment or subsystems which resulted in gaseous radwaste being discharged without treatment, and the reason for the inoperability,

   2. Action(s) taken to restore the inoperable equipment to OPERABLE status, and

   3. Summary description of action(s) taken to prevent a recurrence.

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

SURVEILLANCE REQUIREMENTS

4.11.2.5.1 Doses due to gaseous releases from each reactor unit to areas at and beyond the SITE BOUNDARY shall be projected at least once per 31 days in accordance with the methodology and parameters in the ODCM.

4.11.2.5.2 The installed VENTILATION EXHAUST TREATMENT SYSTEMS shall be demonstrated OPERABLE by meeting Specifications 3.11.2.1 and 3.11.2.3.

*Not required to be OPERABLE prior to initial criticality.

EXPLOSIVE GAS MIXTURE

LIMITING CONDITION FOR OPERATION

3.11.2.6 The concentration of hydrogen in the offgas treatment system shall be limited to less than or equal to 4% by volume.

APPLICABILITY: Whenever the offgas treatment system is in operation.

ACTION:

a. With the concentration of hydrogen in the offgas treatment system exceeding the limit, restore the concentration to within the limit within 48 hours.

b. With the continuous monitor inoperable, utilize grab sampling procedures.

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

SURVEILLANCE REQUIREMENTS

4.11.2.6 The concentration of hydrogen in the offgas treatment system shall be determined to be within the above limits by continuously monitoring the waste gas in the offgas treatment system whenever the main condenser evacuation system is in operation with the hydrogen monitor OPERABLE as required by Table 3.3.7.10-1 of Specification 3.3.7.10.

3/4.11.3 SOLID RADWASTE TREATMENT

LIMITING CONDITION FOR OPERATION

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

APPLICABILITY: At all times*.

ACTION:

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

b. With the SOLIDIFICATION or dewatering not performed in accordance with the PROCESS CONTROL PROGRAM, (1) test the improperly processed waste in each container to ensure that it meets burial ground and shipping requirements and (2) take appropriate administrative action to prevent recurrence.

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

SURVEILLANCE REQUIREMENTS

4.11.3.1 If the SOLIDIFICATION method is used, the PROCESS CONTROL PROGRAM shall be used to verify the SOLIDIFICATION of at least one representative test specimen from at least every tenth batch of each type of wet radioactive waste (e.g., filter sludges, spent resins, evaporator bottoms, and sodium sulfate solutions).

a. If any test specimen fails to verify SOLIDIFICATION, the SOLIDIFICATION of the batch under test shall be suspended until such time as additonal test specimens can be obtained, alternative SOLIDIFICATION parameters can be determined in accordance with the PROCESS CONTROL PROGRAM, and a subsequent test verifies SOLIDIFICATION. SOLIDIFICATION of the batch may then be resumed using the alternative SOLIDIFICATION parameters determined by the PROCESS CONTROL PROGRAM.

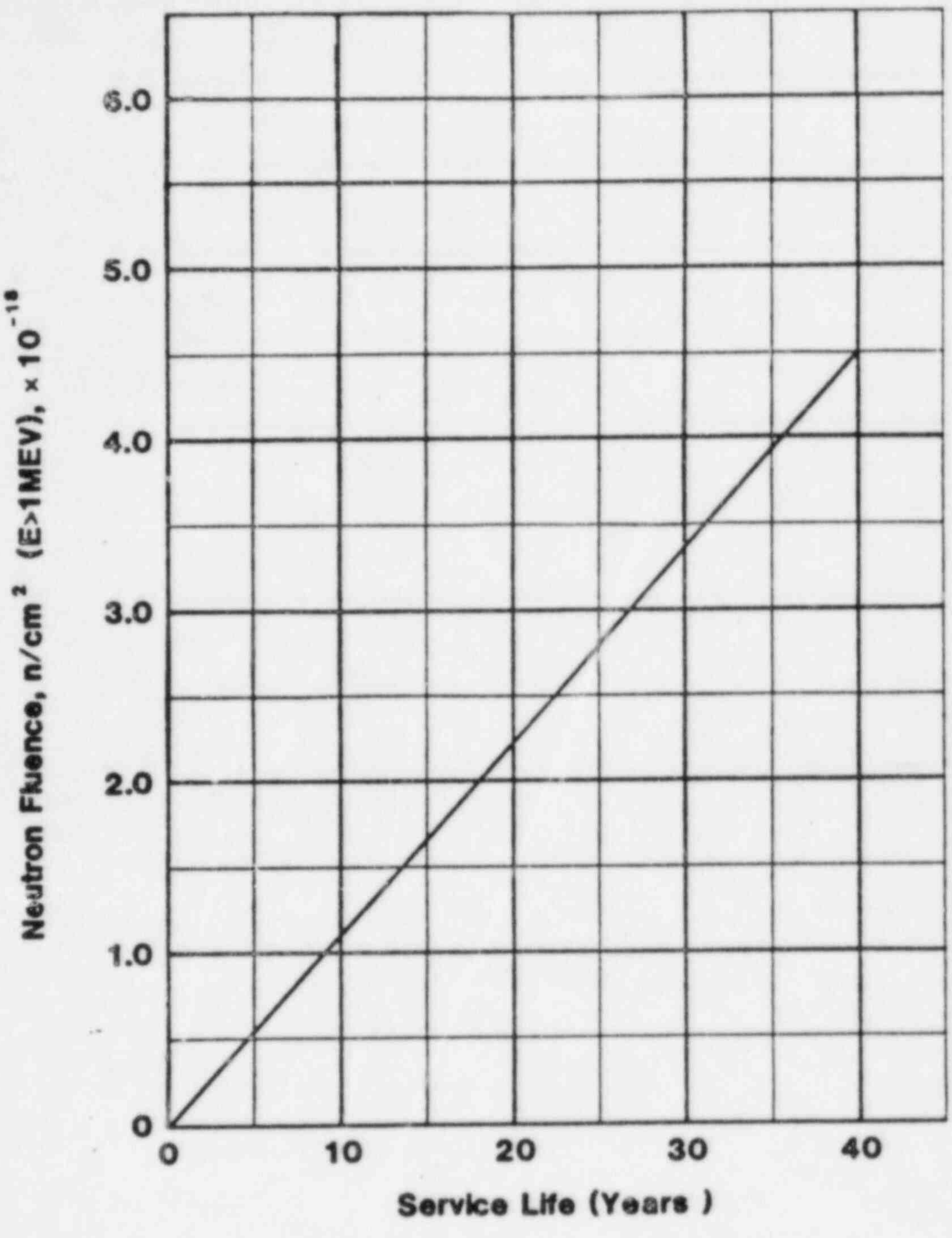
*Not required to be OPERABLE prior to initial criticality.

BASES TABLE B 3/4 4.6-1

REACTOR VESSEL TOUGHNESS

I. BELTLINE COMPONENT	MATERIAL	HEAT#/LOT#	CU(%)	P(%)	HIGHEST STARTING RT_{NDT}(°F)	MINIMUM UPPER SHELF ENERGY (Ft-Lb)	END OF LIFE RT_{NDT}(°F)
Plate	SA533 GrB Class 1	C2557-1	.06	.010	+10	75	+44
Weld	BD,BF	627260/B322A27AE	.06	.020	-30	75	+37

II. NON-BELTLINE COMPONENT	MATERIAL	HIGHEST STARTING RT_{NDT}(°F)
Shell Ring	SA 533 Gr.B, Cl.1	+10
Bottom Head	SA 533 Gr.B, Cl.1	+10
Top Head	SA 533 Gr.B, Cl.1	+10
Top Head Flange	SA 508, Cl.2	+10
Vessel Flange	SA 508, Cl.2	+10
Feedwater Nozzle	SA 508, Cl.2	-20
Weld	Low alloy steel per GE purchase specification	-20
Closure Studs	SA 540 Gr.B23	45 ft-lb & 25 mils lat. exp. requirement met at +10(°F)



Fast Neutron Fluence (E>1 Mev) at ¼T As a Function of Service Life*

Bases Figure B 3/4 4.6-1

*At 90% of RATED THERMAL POWER and 90% availability

ECCS-OPERATING and SHUTDOWN (Continued)

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

The surveillance requirements provide adequate assurance that the HPCS system will be OPERABLE when required. Flow and total developed head values for surveillance testing include system losses to ensure design requirements are met. Although all active components are testable and full flow can be demonstrated by recirculation through a test loop during reactor operation, a complete functional test with reactor vessel injection requires reactor shutdown. The pump discharge piping is maintained full to prevent water hammer damage and to provide cooling at the earliest moment.

Upon failure of the HPCS system to function properly after a small break loss-of-coolant accident, the automatic depressurization system (ADS) automatically causes selected safety-relief valves to open, depressurizing the reactor so that flow from the low pressure core cooling systems can enter the core in time to limit fuel cladding temperature to less than 2200°F. ADS is conservatively required to be OPERABLE whenever reactor vessel pressure exceeds 100 psig even though LPCS flow is 6110 gpm rated flow at 128 psid, and LPCI flow is 7100 gpm rated flow at 24 psid.

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

3/4.5.3 SUPPRESSION POOL

The supression pool is required to be OPERABLE as part of the ECCS to ensure that a sufficient supply of water is available to the HPCS, LPCS and LPCI systems in the event of a LOCA. This limit on suppression pool minimum water volume ensures that sufficient water is available to permit recirculation cooling flow to the core. The OPERABILITY of the suppression pool in OPERATIONAL CONDITIONS 1, 2 or 3 is required by Specification 3.6.3.1.

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

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

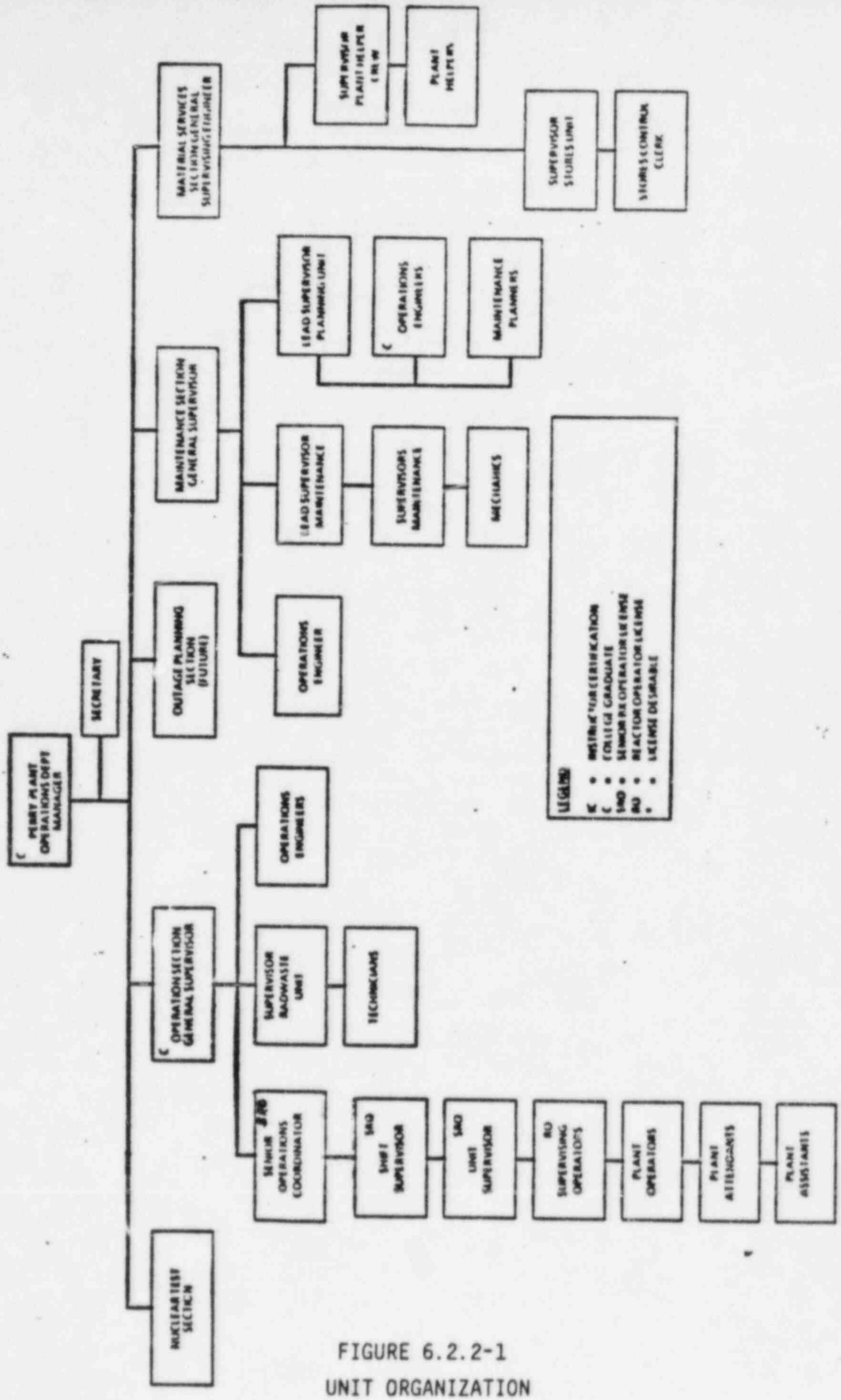


FIGURE 6.2.2-1
UNIT ORGANIZATION

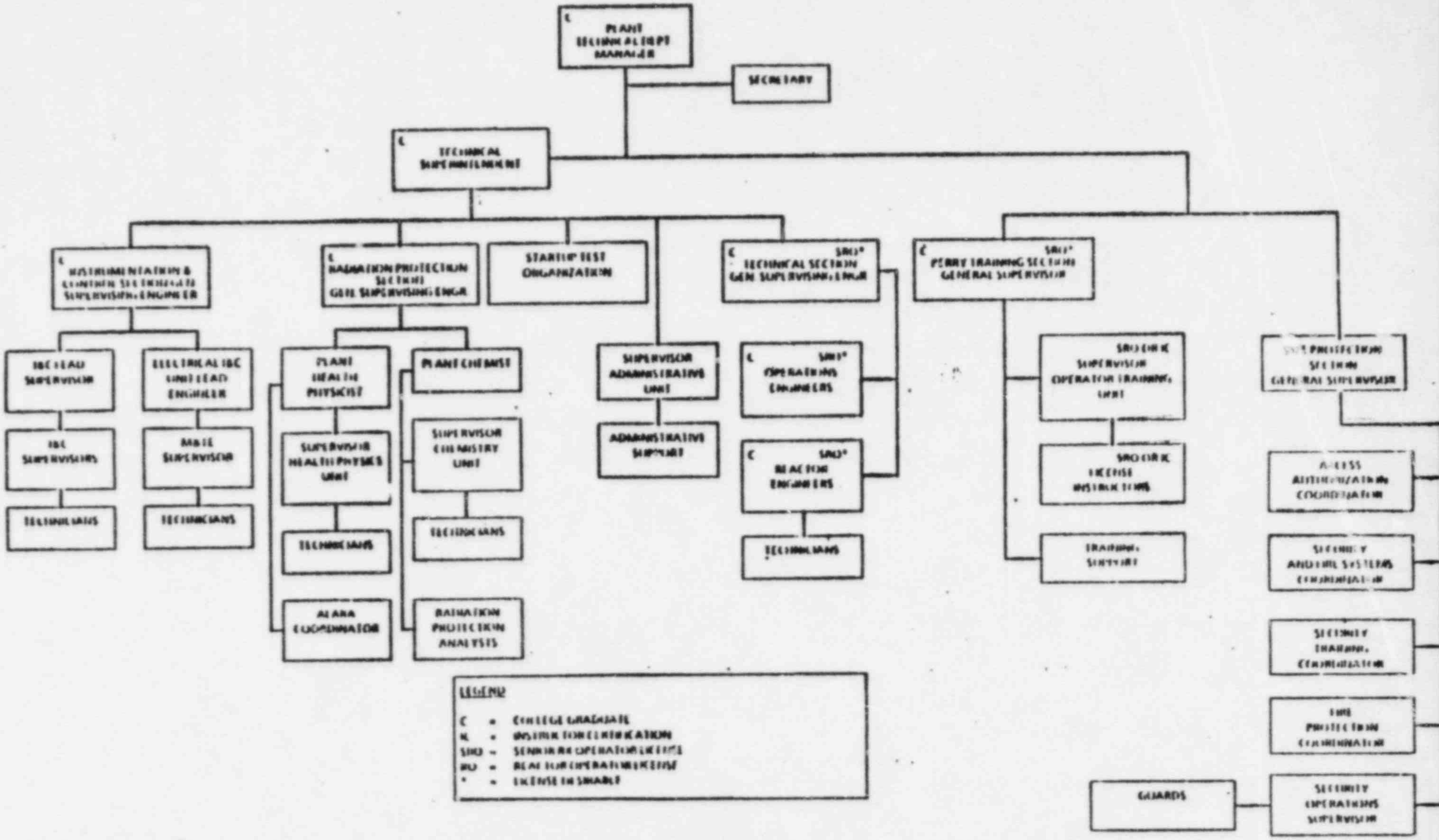


FIGURE 6.2.2-1 (Continued)

UNIT ORGANIZATION

6.2.3 INDEPENDENT SAFETY ENGINEERING GROUP (ISEG)

FUNCTION

6.2.3.1 The ISEG shall function to examine unit operating characteristics, NRC issuances, industry advisories, Licensee Event Reports, and other sources of unit design and operating experience information, including units of similar design, which may indicate areas for improving unit safety. The ISEG shall make detailed recommendations for revised procedures, equipment modifications, maintenance activities, operations activities, or other means of improving unit safety to the Manager, Nuclear Engineering Department.

COMPOSITION

6.2.3.2 The ISEG shall be composed of at least five, dedicated, full-time engineers or technically oriented individuals located onsite. Each shall have either (1) a bachelor's degree in engineering or related science and at least 2 years professional level experience in his field, at least 1 year of which experience shall be in the nuclear field, or (2) equivalent work experience as described in Section 4.1 of ANSI/ANS 3.1, December 1981.

RESPONSIBILITIES

6.2.3.3 The ISEG shall be responsible for maintaining surveillance of unit activities to provide independent verification* that these activities are performed correctly and that human errors are reduced as much as practical.

RECORDS

6.2.3.4 Records of activities performed by the ISEG shall be prepared, maintained, and forwarded each calendar month to the Manager, Nuclear Engineering Department.

6.2.4 SHIFT TECHNICAL ADVISOR

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

6.3 UNIT STAFF QUALIFICATIONS

6.3.1 Each member of the unit staff shall meet or exceed the minimum qualifications of ANSI N18.1-1971 for comparable positions, except for the Senior Operations Coordinator for the first cycle and the Plant Health Physicist who shall meet or exceed the qualifications of Regulatory Guide 1.8, September 1975. The licensed Operators and Senior Operators shall also meet or exceed the minimum qualifications of the supplemental requirements specified in Sections A and C of Enclosure 1 of the March 28, 1980 NRC letter to all licensees.

---

*Not responsible for sign-off function.

ANNUAL RADIOLOGICAL ENVIRONMENTAL OPERATING REPORT (Continued)

prior to May 1 of each year. The initial report shall be submitted prior to May 1 of the year following initial criticality and shall include copies of reports of the preoperational Radiological Environmental Monitoring Program of the unit for at least two years prior to initial criticality in addition to the following.

The Annual Radiological Environmental Operating Reports shall include summaries, interpretations, and an analysis of trends of the results of the radiological environmental surveillance activities for the report period, including a comparison with preoperational studies, operational controls (as appropriate), and previous environmental surveillance reports and an assessment of the observed impacts of the plant operation on the environment. The reports shall also include the results of land use censuses required by Specification 3.12.2.

The Annual Radiological Environmental Operating Reports shall include the results of analysis of all radiological environmental samples and of all locations specified in the table and figures in the Offsite Dose Calculation Manual, as well as summarized and tabulated results of these analyses and measurements in the format of the table in the Radiological Assessment Branch Technical Position, Revision 1, November 1979. In the event that some individual results are not available for inclusion with the report, the report shall be submitted noting and explaining the reasons for the missing results. The missing data shall be submitted as soon as possible in a supplementary report.

The reports shall also include the following: a summary description of the Radiological Environmental Monitoring Program; at least two legible maps* covering all sampling locations keyed to a table giving distances and directions from the centerline of one reactor; the results of licensee participation in the Interlaboratory Comparison Program and the corrective action taken if the specified program is not being performed as required by Specification 3.12.3; reasons for not conducting the Radiological Environmental Monitoring Program as required by Specification 3.12.1, and discussion of all deviations from the sampling schedule of Table 3.12.1-1; discussion of environmental sample measurements that exceed the reporting levels of Table 3.12.1-2 but are not the result of plant effluents, pursuant to ACTION b of Specification 3.12.1; and discussion of all analyses in which the LLD required by Table 4.12.1-1 was not achievable.

SEMIANNUAL RADIOACTIVE EFFLUENT RELEASE REPORT

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

*One map shall cover stations near the SITE BOUNDARY; a second shall include the more distant stations.

SEMIANNUAL RADIOACTIVE EFFLUENT RELEASE REPORT (Continued)

The Semiannual Radioactive Effluent Release Reports shall include a summary of the quantities of radioactive liquid and gaseous effluents and solid waste released from the unit as outlined in Regulatory Guide 1.21, "Measuring, Evaluating, and Reporting Radioactivity in Solid Wastes and Releases of Radioactive Materials in Liquid and Gaseous Effluents from Light-Water-Cooled Nuclear Power Plants," Revision 1, June 1974, with data summarized on a quarterly basis following the format of Appendix B thereof. For solid wastes, the format for Table 3 in Appendix B shall be supplemented with three additional categories: class of solid wastes (as defined by 10 CFR Part 61), type of container (e.g., LSA, Type A, Type B, Large Quantity) and SOLIDIFICATION agent or absorbent (e.g., cement, urea formaldehyde).

The Semiannual Radioactive Effluent Release Report to be submitted within 60 days after January 1 of each year shall include an annual summary of hourly meteorological data collected over the previous year. This annual summary may be either in the form of an hour-by-hour listing on magnetic tape of wind speed, wind direction, atmospheric stability, and precipitation (if measured), or in the form of joint frequency distributions of wind speed, wind direction, and atmospheric stability.* This same report shall include an assessment of the radiation doses due to the radioactive liquid and gaseous effluents released from the unit or station during the previous calendar year. This same report shall also include an assessment of the radiation doses from radioactive liquid and gaseous effluents to MEMBERS OF THE PUBLIC due to their activities inside the SITE BOUNDARY (Figure 5.1.1-1) during the report period. All assumptions used in making these assessments, i.e., specific activity, exposure time, and location, shall be included in these reports. The meteorological conditions concurrent with the time of release of radioactive materials in gaseous effluents, as determined by sampling frequency and measurement, shall be used for determining the gaseous pathway doses. The assessment of radiation doses shall be performed in accordance with the methodology and parameters in the OFFSITE DOSE CALCULATION MANUAL (ODCM).

The Semiannual Radioactive Effluent Release Report to be submitted within 60 days after January 1 of each year shall also include an assessment of radiation doses to the likely most exposed MEMBER OF THE PUBLIC from reactor releases and other nearby uranium fuel cycle sources, including doses from primary effluent pathways and direct radiation, for the previous calendar year to show conformance with 40 CFR Part 190, "Environmental Radiation Protection Standards for Nuclear Power Operation." Acceptable methods for calculating the dose contribution from liquid and gaseous effluents are given in Regulatory Guide 1.109, Rev. 1, October 1977.

The Semiannual Radioactive Effluent Release Reports shall include a list and description of unplanned releases from the site to UNRESTRICTED AREAS of radioactive materials in gaseous and liquid effluents made during the reporting period.

*In lieu of submission with the Semiannual Radioactive Effluent Release Report, the licensee has the option of retaining this summary of required meteorological data on site in a file that shall be provided to the NRC upon request.

SEMIANNUAL RADIOACTIVE EFFLUENT RELEASE REPORT (Continued)

The Semiannual Radioactive Effluent Release Reports shall include any changes made during the reporting period to the PROCESS CONTROL PROGRAM (PCP) and to the OFFSITE DOSE CALCULATION MANUAL (ODCM), pursuant to Specifications 6.13 and 6.14, respectively, as well as any major change to Liquid, Gaseous, or Solid Radwaste Treatment Systems pursuant to Specification 6.15. It shall also include a listing of new locations for dose calculations and/or environmental monitoring identified by the Land Use Census pursuant to Specification 3.12.2.

The Semiannual Radioactive Effluent Release Reports shall also include the following: an explanation as to why the inoperability of liquid or gaseous effluent monitoring instrumentation was not corrected within the time specified in Specification 3.3.7.9 or 3.3.7.10, respectively; and description of the events leading to liquid holdup tanks exceeding the limits of Specification 3.11.1.4.

MONTHLY OPERATING REPORTS

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

SPECIAL REPORTS

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

6.9.3 Safety/relief valve failures will be reported to the Regional Administrator of the Regional Office of the NRC via the Licensee Event Report system within 30 days.

6.10 RECORD RETENTION

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

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

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

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

c. All REPORTABLE EVENTS.

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