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NUCLEAR REGULATORY COMMISSION
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Docket No. 50-416

June 29, 1984

NOTE TO: FILE

LICENSEE: Mississippi Power & Light

FACILITY: Grand Gulf Unit 1

SUBJECT: INFORMATION GIVEN TO MISSISSIPPI POWER AND LIGHT COMPANY REGARDING THE GRAND GULF TECHNICAL SPECIFICATION REVIEW

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Technical Specifications

Grand Gulf Nuclear Station, Unit No. 1

As Amended Through Amendment 12
and April 18, 1984
Order,

Docket No. 50-416

Appendix "A" to
License No. NPF-13

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Commission

Office of Nuclear Reactor Regulation

June 1982

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MISSISSIPPI POWER AND LIGHT COMPANY

GRAND GULF NUCLEAR STATION

UNIT 1

(GRAND GULF-UNIT 1)

TECHNICAL SPECIFICATIONS

APPENDIX "A"

TO

LICENSE NO. NPF-13

TECHNICAL SPECIFICATIONS
EFFECTIVE PAGES LIST

AMENDMENT NUMBER	EFFECTIVE PAGE NUMBERS	DATE
1	3/4 6-49, 3/4 6-50	July 6, 1982
2	No Tech Spec Changes	August 17, 1983
3	3/4 3-99, 3/4 5-4, 3/4 5-5, 3/4 6-30, 3/4 8-38	September 20, 1982
4	3/4 6-45, 3/4 6-45a, 3/4 8-22, 3/4 8-23, 3/4 8-24, 3/4 8-25, 3/4 8-26, 3/4 8-27, 3/4 8-28, 3/4 8-29, 3/4 8-30, 3/4 8-31, 3/4 8-32, 3/4 8-33, 3/4 8-34, 3/4 8-35, 3/4 8-36, 3/4 8-37	October 14, 1982
N/A	3/4 3-29, 3/4 6-45a, 3/4 8-19	November 22, 1982
5	3/4 4-24, 3/4 4-25	December 20, 1982
6	No Tech Spec Changes	February 7, 1983
7	1-9, 3/4 1-7, 3/4 1-17, B 2-6, 3/4 3-8, 3/4 3-10, 3/4 3-14, 3/4 3-15, 3/4 3-18, 3/4 3-19, 3/4 3-20, 3/4 3-28, 3/4 3-40, 3/4 3-52, 3/4 3-53, 3/4 3-54, 3/4 3-56, 3/4 3-57, 3/4 3-59, 3/4 3-61, 3/4 3-62, 3/4 3-64, 3/4 3-65, 3/4 3-71, 3/4 3-85, 3/4 3-88, 3/4 3-91, 3/4 3-92, 3/4 3-94, 3/4 5-1, 3/4 6-28, 3/4 6-29, 3/4 6-30, 3/4 6-37, 3/4 6-42, 3/4 6-44, 3/4 6-45a, 3/4 6-48, 3/4 6-56, 3/4 6-57, 3/4 6-58, 3/4 6-59, 3/4 7-5, 3/4 7-10, 3/4 7-27, 3/4 7-36, 3/4 7-37, 3/4 7-43, 3/4 8-3, 3/4 8-4, 3/4 8-5, 3/4 8-6, 3/4 8-7, 3/4 8-16, 3/4 8-18, 3/4 9-1, 3/4 9-18, 3/4 11-6, 6-20, B 3/4 0-1, B 3/4 3-2, B 3/4 3-3, B 3/4 3-7, B 3/4 6-2, B3/4 7-1	July 1, 1983
8	2-4, 3/4 1-5, 3/4 2-5, 3/4 3-11, 3/4 3-14, 3/4 3-15, 3/4 3-16, 3/4 3-17, 3/4 3-28, 3/4 3-29, 3/4 3-30, 3/4 3-31, 3/4 3-32, 3/4 3-33, 3/4 3-41, 3/4 3-56,	August 8, 1983

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8 (cont.)	3/4 3-57, 3/4 3-95, 3/4 4-18, 3/4 5-9, 3/4 6-5, 3/4 6-6, 3/4 6-7, 3/4 6-15, 3/4 6-16, 3/4 6-21, 3/4 6-22, 3/4 6-45a, 3/4 6-54, 3/4 6-58, 3/4 7-4, 3/4 7-6, 3/4 7-16, 3/4 7-26, 3/4 7-45, 3/4 8-1, 3/4 8-3, 3/4 8-6, 3/4 8-13, 3/4 8-21, 3/4 8-40, 3/4 8-41, 3/4 8-42, 3/4 8-43, 3/4 8-44, 3/4 8-45, 3/4 8-45a, 3/4 11-1, 3/4 11-5, 3/4 11-12, 3/4 11-13, 6-11.	
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10	3/4 3-26, 3/4 3-32, 3/4 3-33, 3/4 6-30, 3/4 6-32, 3/4 6-38, 3/4 6-40, B 3/4 3-7	September 23, 1983
11	No Technical Specification Changes	September 23, 1983
12	3/4 3-10, 3/4 3-14, 3/4 3-23a 3/4 3-39, 3/4 3-52, 3/4 3-73, 3/4 4-5, 3/4 7-30, 3/4 8-12	February 24, 1984
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ADMINISTRATIVE CONTROLS

SECTION 1.0

DEFINITIONS

1.0 DEFINITIONS

The following terms are defined so that uniform interpretation of these specifications may be achieved. The defined terms appear in capitalized type and shall be applicable throughout these Technical Specifications.

ACTION

1.1 ACTION shall be that part of a Specification which prescribes remedial measures required under designated conditions.

AVERAGE PLANAR EXPOSURE

1.2 The AVERAGE PLANAR EXPOSURE shall be applicable to a specific planar height and is equal to the sum of the exposure of all the fuel rods in the specified bundle at the specified height divided by the number of fuel rods in the fuel bundle.

AVERAGE PLANAR LINEAR HEAT GENERATION RATE

1.3 The AVERAGE PLANAR LINEAR HEAT GENERATION RATE (APLHGR) shall be applicable to a specific planar height and is equal to the sum of the LINEAR HEAT GENERATION RATES for all the fuel rods in the specified bundle at the specified height divided by the number of fuel rods in the fuel bundle.

CHANNEL CALIBRATION

1.4 A CHANNEL CALIBRATION shall be the adjustment, as necessary, of the channel output such that it responds with the necessary range and accuracy to known values of the parameter which the channel monitors. The CHANNEL CALIBRATION shall encompass the entire channel including the sensor and alarm and/or trip functions, and shall include the CHANNEL FUNCTIONAL TEST. The CHANNEL CALIBRATION may be performed by any series of sequential, overlapping or total channel steps such that the entire channel is calibrated.

CHANNEL CHECK

1.5 A CHANNEL CHECK shall be the qualitative assessment of channel behavior during operation by observation. This determination shall include, where possible, comparison of the channel indication and/or status with other indications and/or status derived from independent instrument channels measuring the same parameter.

CHANNEL FUNCTIONAL TEST

1.6 A CHANNEL FUNCTIONAL TEST shall be:

a. Analog channels - the injection of a simulated signal into the channel as close to the sensor as practicable to verify OPERABILITY including alarm and/or trip functions and channel failure trips.

b. Bistable channels - the injection of a simulated signal into the sensor to verify OPERABILITY including alarm and/or trip functions.

The CHANNEL FUNCTIONAL TEST may be performed by any series of sequential, overlapping or total channel steps such that the entire channel is tested.

CORE ALTERATION

1.7 CORE ALTERATION shall be the addition, removal, relocation or movement of fuel, sources, incore instruments or reactivity controls within the reactor pressure vessel with the vessel head removed and fuel in the vessel. Suspension of CORE ALTERATIONS shall not preclude completion of the movement of a component to a safe conservative position.

CRITICAL POWER RATIO

1.8 The CRITICAL POWER RATIO (CPR) shall be the ratio of that power in the assembly which is calculated by application of the GEXL correlation to cause some point in the assembly to experience boiling transition, divided by the actual assembly operating power.

DOSE EQUIVALENT I-131

1.9 DOSE EQUIVALENT I-131 shall be that concentration of I-131, microcuries per gram, which alone would produce the same thyroid dose as the quantity and isotopic mixture of I-131, I-132, I-133, I-134, and I-135 actually present. The thyroid dose conversion factors used for this calculation shall be those listed in Table III of TID-14844, "Calculation of Distance Factors for Power and Test Reactor Sites."

DRYWELL INTEGRITY

1.10 DRYWELL INTEGRITY shall exist when:

a. All drywell penetrations required to be closed during accident conditions are either:

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

   2. Closed by at least one manual valve, blind flange, or deactivated automatic valve secured in its closed position, except as provided in Table 3.6.4-1 of Specification 3.6.4.

b. The drywell equipment hatch is closed and sealed.

c. The drywell airlock is ~~OPERABLE pursuant to~~ in compliance with the requirements of Specification 3.6.2.3.

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d. The drywell leakage rates are within the limits of Specification 3.6.2.2.

e. The suppression pool is ~~OPERABLE pursuant to~~ in compliance with the requirements of Specification 3.6.3.1.

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f. The sealing mechanism associated with each drywell penetration; e.g., welds, bellows or O-rings, is OPERABLE.

$\bar{E}$-AVERAGE DISINTEGRATION ENERGY

1.11 $\bar{E}$ shall be the average, weighted in proportion to the concentration of each radionuclide in the reactor coolant at the time of sampling, of the sum of the average beta and gamma energies per disintegration, in MeV, for isotopes, with half lives greater than 15 minutes, making up at least 95% of the total non-iodine activity in the coolant.

EMERGENCY CORE COOLING SYSTEM (ECCS) RESPONSE TIME

1.12 The EMERGENCY CORE COOLING SYSTEM (ECCS) RESPONSE TIME shall be that time interval from when the monitored parameter exceeds its ECCS actuation setpoint at the channel sensor until the ECCS equipment is capable of performing its safety function, i.e., the valves travel to their required positions, pump discharge pressures reach their required values, etc. Times shall include diesel generator starting and sequence loading delays where applicable. The response time may be measured by any series of sequential, overlapping or total steps such that the entire response time is measured.

END-OF-CYCLE RECIRCULATION PUMP TRIP SYSTEM RESPONSE TIME

1.13 The END-OF-CYCLE RECIRCULATION PUMP TRIP SYSTEM RESPONSE TIME shall be that time interval to complete suppression of the electric arc between the fully open contacts of the recirculation pump circuit breaker from initial movement of the associated:

a. Turbine stop valves, and
b. Turbine control valves.

The response time may be measured by any series of sequential, overlapping or total steps such that the entire response time is measured.

FRACTION OF LIMITING POWER DENSITY

1.14 The FRACTION OF LIMITING POWER DENSITY (FLPD) shall be the LHGR existing at a given location divided by the limiting LHGR for that bundle type.

FRACTION OF RATED THERMAL POWER

1.15 The FRACTION OF RATED THERMAL POWER (FRTP) shall be the measured THERMAL POWER divided by the RATED THERMAL POWER.

FREQUENCY NOTATION

1.16 The FREQUENCY NOTATION specified for the performance of Surveillance Requirements shall correspond to the intervals defined in Table 1.1.

GASEOUS RADWASTE TREATMENT (OFFGAS) SYSTEM

1.17 The GASEOUS RADWATE TREATMENT (OFFGAS) SYSTEM is the system designed and installed to reduce radioactive gaseous effluents by collecting primary coolant system offgases from the primary system and providing for delay or holdup for the purpose of reducing the total radioactivity prior to release to the environment.

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IDENTIFIED LEAKAGE

1.18 IDENTIFIED LEAKAGE shall be:

a. Leakage into collection systems, such as pump seal or valve packing leaks, that is captured and conducted to a sump or collecting tank, or

b. Leakage into the drywell atmosphere from sources that are both specifically located and known either not to interfere with the operation of the leakage detection systems or not to be PRESSURE BOUNDARY LEAKAGE.

ISOLATION SYSTEM RESPONSE TIME

1.19 The ISOLATION SYSTEM RESPONSE TIME shall be that time interval from when the monitored parameter exceeds its isolation actuation setpoint at the channel sensor until the isolation valves travel to their required positions. Times shall include diesel generator starting and sequence loading delays where applicable. The response time may be measured by any series of sequential, overlapping or total steps such that the entire response time is measured.

LIMITING CONTROL ROD PATTERN

1.20 A LIMITING CONTROL ROD PATTERN shall be a pattern which results in the core being on a thermal hydraulic limit, i.e., operating on a limiting value for APLHGR, LHGR, or MCPR.

LINEAR HEAT GENERATION RATE

1.21 LINEAR HEAT GENERATION RATE (LHGR) shall be the heat generation per unit length of fuel rod. It is the integral of the heat flux over the heat transfer area associated with the unit length.

LOGIC SYSTEM FUNCTIONAL TEST

1.22 A LOGIC SYSTEM FUNCTIONAL TEST shall be a test of all logic components, i.e., all relays and contacts, all trip units, solid state logic elements, etc., of a logic circuit, from sensor through and including the actuated device, to verify OPERABILITY. The LOGIC SYSTEM FUNCTIONAL TEST may be performed by any series of sequential, overlapping or total system steps such that the entire logic system is tested.

MAXIMUM FRACTION OF LIMITING POWER DENSITY

1.23 The MAXIMUM FRACTION OF LIMITING POWER DENSITY (MFLPD) shall be the highest value of the FLPD which exists in the core.

MINIMUM CRITICAL POWER RATIO

1.~~24~~ 25 The MINIMUM CRITICAL POWER RATIO (MCPR) shall be the smallest CPR which exists in the core.

MEMBER(S) OF THE PUBLIC

1.24 MEMBER(S) OF THE PUBLIC shall include all persons who are not occupationally associated with the plant. This category does not include employees of the utility, its contractors or vendors. Also excluded from this category are persons who enter the site to service equipment or to make deliveries. This category does include persons who use portions of the site for recreational, occupational or other purposes not associated with the plant.

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OFFSITE DOSE CALCULATION MANUAL (ODCM)

1.~~25~~ 26 The OFFSITE DOSE CALCULATION MANUAL shall contain the methodology and parameters used in the calculation of offsite doses due to radioactive gaseous and liquid effluents and in the calculation of gaseous and liquid effluent monitoring alarm/trip setpoints. It shall also contain a table and figure defining current radiological environmental monitoring sample locations.

OPERABLE - OPERABILITY

1.~~26~~ 27 A system, subsystem, train, component or device shall be OPERABLE or have OPERABILITY when it is capable of performing its specified function(s) and when all necessary attendant instrumentation, controls, electrical power, cooling or seal water, lubrication or other auxiliary equipment that are required for the system, subsystem, train, component or device to perform its function(s) are also capable of performing their related support function(s).

OPERATIONAL CONDITION - CONDITION

1.~~27~~ 28 An OPERATIONAL CONDITION, i.e., CONDITION, shall be any one inclusive combination of mode switch position and average reactor coolant temperature as specified in Table 1.2.

PHYSICS TESTS

1.~~28~~ 29 PHYSICS TESTS shall be those tests performed to measure the fundamental nuclear characteristics of the reactor core and related instrumentation and 1) described in Chapter 14 of the FSAR, 2) authorized under the provisions of 10 CFR 50.59, or 3) otherwise approved by the Commission.

PRESSURE BOUNDARY LEAKAGE

1.~~29~~ 30 PRESSURE BOUNDARY LEAKAGE shall be leakage through a non-isolable fault in a reactor coolant system component body, pipe wall or vessel wall.

PRIMARY CONTAINMENT INTEGRITY

1.~~30~~ 31 PRIMARY CONTAINMENT INTEGRITY shall exist when:

a. All containment penetrations required to be closed during accident conditions are either:

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

   2. Closed by at least one manual valve, blind flange, or deactivated automatic valve secured in its closed position, except as provided in Table 3.6.4-1 of Specification, 3.6.4.

b. The containment equipment hatch is closed and sealed.

c. Each containment air lock is ~~OPERABLE pursuant to~~ in compliance with the requirements of Specification 3.6.1.3.

d. The containment leakage rates are within the limits of Specification 3.6.1.2.

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e. The suppression pool is ~~OPERABLE pursuant to~~ in compliance with the requirements of Specification 3.6.3.1.

f. The sealing mechanism associated with each primary containment penetration; e.g., welds, bellows or O-rings, is OPERABLE.

PROCESS CONTROL PROGRAM (PCP)

1.~~31~~ 32 The PROCESS CONTROL PROGRAM shall contain the current formula, sampling, analyses, tests, and determinations to be made to ensure that the processing and packaging of solid radioactive wastes based on demonstrated processing of actual or simulated wet solid wastes will be accomplished in such a way as to assure compliance with 10 CFR Part 20, ~~10 CFR Part 71~~ 10 CFR Part 61 and Federal and State regulations, "burial ground requirements" and other requirements governing the disposal of the radioactive waste. 685

of discharging air or gas from a confinement to maintain temperature, pressure, humidity, concentration or other operating condition, in such a manner that replacement air or gas is required to purify the confinement.

RATED THERMAL POWER

1.~~33~~ 34 RATED THERMAL POWER shall be a total reactor core heat transfer rate to the reactor coolant of 3833 MWT.

REACTOR PROTECTION SYSTEM RESPONSE TIME

1.~~34~~35 REACTOR PROTECTION SYSTEM RESPONSE TIME shall be the time interval from when the monitored parameter exceeds its trip setpoint at the channel sensor until de-energization of the scram pilot valve solenoids. The response time may be measured by any series of sequential, overlapping or total steps such that the entire response time is measured.

REPORTABLE ~~OCCURRENCE~~ EVENT

1.~~35~~36 A REPORTABLE ~~OCCURRENCE~~ EVENT shall be any of those conditions specified in ~~Specifications 6.9.1.12 and 6.9.1.13.~~ Section 50.73 to 10 CFR Part 50. 1093

ROD DENSITY

1.~~36~~37 ROD DENSITY shall be the number of control rod notches inserted as a fraction of the total number of control rod notches. All rods fully inserted is equivalent to 100% ROD DENSITY.

SECONDARY CONTAINMENT INTEGRITY

1.~~37~~38 SECONDARY CONTAINMENT INTEGRITY shall exist when:

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

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

   2. Closed by at least one manual valve, blind flange, rupture disc or deactivated automatic valve or damper, as applicable, secured in its closed position, except as provided in Table 3.6.6.2-1 of Specification 3.6.6.2. 1818

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

c. The standby gas treatment system is OPERABLE pursuant to Specification 3.6.6.3.

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

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

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SITE BOUNDARY

1.~~27~~ 40 The SITE BOUNDARY shall be that line beyond which the land is neither owned, nor leased, nor otherwise controlled by the licensee.

SHU

1.~~38~~ 3 SHUTDOWN MARGIN shall be the amount of reactivity by which the reactor is subcritical or would be subcritical assuming all control rods are fully inserted except for the single control rod of highest reactivity worth which is assumed to be fully withdrawn and the reactor is in the shutdown condition; cold, i.e. 68°F; and xenon free.

SOLIDIFICATION

41 1.~~39~~ SOLIDIFICATION shall be the conversion of wet wastes into a form that meets shipping and burial ground requirements. 225|

~~outline on all sides (free standing)~~.

SOURCE CHECK

42 1.~~40~~ A SOURCE CHECK shall be the qualitative assessment of channel response when the channel sensor is exposed to a radioactive source.

STAGGERED TEST BASIS

1.~~41~~ A STAGGERED TEST BASIS shall consist of:

~~42~~ 43 a. A test schedule for n systems, subsystems, trains or other designated components obtained by dividing the specified test interval into n equal subintervals.

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

THERMAL POWER

44 1.~~42~~ THERMAL POWER shall be the total reactor core heat transfer rate to the reactor coolant.

UNIDENTIFIED LEAKAGE

45 1.~~43~~ UNIDENTIFIED LEAKAGE shall be all leakage which is not IDENTIFIED LEAKAGE.

UNRESTRICTED AREA

1.~~18~~ 46 An UNRESTRICTED AREA shall be any area at or beyond the SITE BOUNDARY access to which is not controlled by the licensee for purposes of protection of individuals from exposure to radiation and radioactive materials, or any area within the SITE BOUNDARY used for residential quarters or for industrial, commercial, institutional, and/or recreational purposes.

1.~~46~~ 47 249|

system is not considered to have any effect on noble gas effluents). Engineered Safety Feature (ESF) atmospheric cleanup systems are not considered to be VENTILATION EXHAUST TREATMENT SYSTEM components.

48 VENTING

1.~~49~~ ~~1.45~~ VENTING is the controlled process of discharging air or gas from a confinement to maintain temperature, pressure, humidity, concentration or other operating condition, in such a manner that replacement air or gas is not provided or required during VENTING. Vent, used in system names, does not imply a VENTING process.

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TABLE 1.1

SURVEILLANCE FREQUENCY NOTATION

NOTATION	FREQUENCY
S	At least once per 12 hours.
D	At least once per 24 hours.
W	At least once per 7 days.
M	At least once per 31 days.
Q	At least once per 92 days.
SA	At least once per 184 days.
A	At least once per 366 days.
R	At least once per 18 months (550 days).
S/U	Prior to each reactor startup.
N.A.	Not applicable.
P	Completed prior to each release.

TABLE 1.2

OPERATIONAL CONDITIONS

CONDITION	MODE SWITCH POSITION	AVERAGE REACTOR COOLANT TEMPERATURE
1. POWER OPERATION	Run	Any temperature
2. STARTUP	Startup/Hot Standby	Any temperature
3. HOT SHUTDOWN	Shutdown[#],[***]	> 200°F
4. COLD SHUTDOWN	Shutdown[#],[##],[***]	≤ 200°F
5. REFUELING*	Shutdown or Refuel[**],[#]	≤ 140°F

[#] The reactor mode switch may be placed in the Run or Startup/Hot Standby position to test the switch interlock functions provided that the control rods are verified to remain fully inserted by a second licensed operator or other technically qualified member of the unit technical staff.

[##] The reactor mode switch may be placed in the Refuel position while a single control rod drive is being removed from the reactor pressure vessel per Specification 3.9.10.1.

[*] Fuel in the reactor vessel with the vessel head closure bolts less than fully tensioned or with the head removed.

[**] See Special Test Exceptions 3.10.1 and 3.10.3.

[***] The reactor mode switch may be placed in the Refuel position while a single control rod is being recoupled provided that the one-rod-out interlock is OPERABLE.

SECTION 2.0
SAFETY LIMITS
AND
LIMITING SAFETY SYSTEM SETTINGS

2.0 SAFETY LIMITS AND LIMITING SAFETY SYSTEM SETTINGS

2.1 SAFETY LIMITS

THERMAL POWER, Low Pressure or Low Flow

2.1.1 THERMAL POWER shall not exceed 25% of RATED THERMAL POWER with the reactor vessel steam dome pressure less than 785 psig or core flow less than 10% of rated flow.

APPLICABILITY: OPERATIONAL CONDITIONS 1 and 2.

ACTION:

With THERMAL POWER exceeding 25% of RATED THERMAL POWER and the reactor vessel steam dome pressure less than 785 psig or core flow less than 10% of rated flow, be in at least HOT SHUTDOWN within 2 hours and comply with the requirements of Specification 6.7.1.

THERMAL POWER, High Pressure and High Flow

2.1.2 The MINIMUM CRITICAL POWER RATIO (MCPR) shall not be less than 1.06 with the reactor vessel steam dome pressure greater than 785 psig and core flow greater than 10% of rated flow.

APPLICABILITY: OPERATIONAL CONDITIONS 1 and 2.

ACTION:

With MCPR less than 1.06 and the reactor vessel steam dome pressure greater than 785 psig and core flow greater than 10% of rated flow, be in at least HOT SHUTDOWN within 2 hours and comply with the requirements of Specification 6.7.1.

REACTOR COOLANT SYSTEM PRESSURE

2.1.3 The reactor coolant system pressure, as measured in the reactor vessel steam dome, shall not exceed 1325 psig.

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

ACTION:

With the reactor coolant system pressure, as measured in the reactor vessel steam dome, above 1325 psig, be in at least HOT SHUTDOWN with reactor coolant system pressure less than or equal to 1325 psig within 2 hours and comply with the requirements of Specification 6.7.1.

SAFETY LIMITS (Continued)

REACTOR VESSEL WATER LEVEL

2.1.4 The reactor vessel water level shall be above the top of the active irradiated fuel.

APPLICABILITY: OPERATIONAL CONDITIONS 3, 4 and 5

ACTION:

With the reactor vessel water level at or below the top of the active irradiated fuel, manually initiate the ECCS to restore the water level. ~~after depressurizing the reactor vessel, if required~~. Comply with the requirements of Specification 6.7.1.

053 | Depressurize the reactor vessel as necessary for ECCS operation.

2.2 LIMITING SAFETY SYSTEM SETTINGS

REACTOR PROTECTION SYSTEM INSTRUMENTATION SETPOINTS

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

APPLICABILITY: As shown in Table 3.3.1-1.

ACTION:

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

TABLE 2.1-1

REACTOR PROTECTION SYSTEM INSTRUMENTATION SETPOINTS

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUES
1. Intermediate Range Monitor, Neutron Flux-High	≤ 120/125 divisions of full scale	≤ 122/125 divisions of full scale
2. Average Power Range Monitor:		
a. Neutron Flux-High, Setdown	≤ 15% of RATED THERMAL POWER	≤ 20% of RATED THERMAL POWER
b. Flow Biased Simulated Thermal Power-High		
1) Flow Biased	≤ 0.66 W+48%, with a maximum of	≤ 0.66 W+51%, with a maximum of
2) High Flow Clamped	≤ 111.0% of RATED THERMAL POWER	≤ 113.0% of RATED THERMAL POWER
c. Neutron Flux-High	≤ 118% of RATED THERMAL POWER	≤ 120% of RATED THERMAL POWER
d. Inoperative	NA	NA
3. Reactor Vessel Steam Dome Pressure - High	≤ 1064.7 psig	≤ 1079.7 psig
4. Reactor Vessel Water Level - Low, Level 3	≥ 11.4 inches above instrument zero*	≥ 10.8 inches above instrument zero*
5. Reactor Vessel Water Level-High, Level 8	≤ 53.5 inches above instrument zero*	≤ 54.1 inches above instrument zero*
6. Main Steam Line Isolation Valve - Closure	≤ 6% closed	≤ 7% closed
7. Main Steam Line Radiation - High	≤ 3.0 x full power background	≤ 3.6 x full power background
8. Drywell Pressure - High	≤ 1.23 psig	≤ 1.43 psig
9. Scram Discharge Volume Water Level - High	≤ 60% of full scale	≤ 63% of full scale
10. Turbine Stop Valve - Closure	≥ 40 psig**	≥ 37 psig
11. Turbine Control Valve Fast Closure, Trip Oil Pressure - Low	≥ 44.3 psig**	≥ 42 psig
12. Reactor Mode Switch Shutdown Position	NA	NA
13. Manual Scram	NA	NA

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

**Initial setpoint. Final setpoint to be determined during startup test program. Any required change to this setpoint shall be submitted to the Commission within 90 days of test completion.

BASES

FOR

SECTION 2.0

SAFETY LIMITS

AND

LIMITING SAFETY SYSTEM SETTINGS

NOTE

The BASES contained in succeeding pages summarize the reasons for the Specifications in Section 2.0, but in accordance with 10 CFR 50.36 are not part of these Technical Specifications.

2.0 INTRODUCTION

The fuel cladding, reactor pressure vessel and primary system piping are the principal barriers to the release of radioactive materials to the environs. Safety Limits are established to protect the integrity of these barriers during normal plant operations and anticipated transients. The fuel cladding integrity Safety Limit is set such that no fuel damage is calculated to occur if the limit is not violated. Because fuel damage is not directly observable, a step-back approach is used to establish a Safety Limit such that the MCPR is not less than 1.06. MCPR greater than 1.06 represents a conservative margin relative to the conditions required to maintain fuel cladding integrity. The fuel cladding is one of the physical barriers which separate the radioactive materials from the environs. The integrity of this cladding barrier is related to its relative freedom from perforations or cracking. Although some corrosion or use related cracking may occur during the life of the cladding, fission product migration from this source is incrementally cumulative and continuously measurable. Fuel cladding perforations, however, can result from thermal stresses which occur from reactor operation significantly above design conditions and the Limiting Safety System Settings. While fission product migration from cladding perforation is just as measurable as that from use related cracking, the thermally caused cladding perforations signal a threshold beyond which still greater thermal stresses may cause gross rather than incremental cladding deterioration. Therefore, the fuel cladding Safety Limit is defined with a margin to the conditions which would produce onset of transition boiling, MCPR of 1.0. These conditions represent a significant departure from the condition intended by design for planned operation.

2.1.1 THERMAL POWER, Low Pressure or Low Flow

The use of the GEXL correlation is not valid for all critical power calculations at pressures below 785 psig or core flows less than 10% of rated flow. Therefore, the fuel cladding integrity Safety Limit is established by other means. This is done by establishing a limiting condition on core THERMAL POWER with the following basis. Since the pressure drop in the bypass region is essentially all elevation head, the core pressure drop at low power and flows will always be greater than 4.5 psi. Analyses show that with a bundle flow of 28×10^3 lbs/hr, bundle pressure drop is nearly independent of bundle power and has a value of 3.5 psi. Thus, the bundle flow with a 4.5 psi driving head will be greater than 28×10^3 lbs/hr. Full scale ATLAS test data taken at pressures from 14.7 psia to 800 psia indicate that the fuel assembly critical power at this flow is approximately 3.35 MWt. With the design peaking factors, this corresponds to a THERMAL POWER of more than 50% of RATED THERMAL POWER. Thus, a THERMAL POWER limit of 25% of RATED THERMAL POWER for reactor pressure below 785 psig is conservative.

2.1.2 THERMAL POWER, High Pressure and High Flow

The fuel cladding integrity Safety Limit is set such that no fuel damage is calculated to occur if the limit is not violated. Since the parameters which result in fuel damage are not directly observable during reactor operation, the thermal and hydraulic conditions resulting in a departure from nucleate boiling have been used to mark the beginning of the region where fuel damage could occur. Although it is recognized that a departure from nucleate boiling would not necessarily result in damage to BWR fuel rods, the critical power at which boiling transition is calculated to occur has been adopted as a convenient limit. However, the uncertainties in monitoring the core operating state and in the procedures used to calculate the critical power result in an uncertainty in the value of the critical power. Therefore, the fuel cladding integrity Safety Limit is defined as the CPR in the limiting fuel assembly for which more than 99.9% of the fuel rods in the core are expected to avoid boiling transition considering the power distribution within the core and all uncertainties.

The Safety Limit MCPR is determined using the General Electric Thermal Analysis Basis, GETAB[a], which is a statistical model that combines all of the uncertainties in operating parameters and the procedures used to calculate critical power. The probability of the occurrence of boiling transition is determined using the General Electric Critical Quality (X) Boiling Length (L), GEXL, correlation. The GEXL correlation is valid over the range of conditions used in the tests of the data used to develop the correlation.

The required input to the statistical model are the uncertainties listed in Bases Table B2.1.2-1 and the nominal values of the core parameters listed in Bases Table B2.1.2-2.

The bases for the uncertainties in the core parameters are given in
0741 NEDO-20340[b] and the basis for the uncertainty in the GEXL correlation is given in NEDO-10958-A[a]. The power distribution is based on a typical 764 assembly core in which the rod pattern was arbitrarily chosen to produce a skewed power distribution having the greatest number of assemblies at the highest power levels. The worst distribution during any fuel cycle would not be as severe as the distribution used in the analysis.

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a. "General Electric BWR Thermal Analysis Bases (GETAB) Data, Correlation and Design Application," NEDO-10958-A.

b. General Electric "Process Computer Performance Evaluation Accuracy" NEDO-20340 and Amendment 1, NEDO-20340-1 dated June 1974 and December 1974, respectively.

Bases Table B2.1.2-1

UNCERTAINTIES USED IN THE DETERMINATION OF THE FUEL CLADDING SAFETY LIMIT*

Quantity	Standard Deviation (% of Point)
Feedwater Flow	1.76
Feedwater Temperature	0.76
Reactor Pressure	0.5
Core Inlet Temperature	0.2
Core Total Flow	2.5
Channel Flow Area	3.0
Friction Factor Multiplier	10.0
Channel Friction Factor Multiplier	5.0
TIP Readings	6.3
R Factor	1.5
Critical Power	3.6

---

* The uncertainty analysis used to establish the core wide Safety Limit MCPR is based on the assumption of quadrant power symmetry for the reactor core.

Bases Table B2.1.2-2

NOMINAL VALUES OF PARAMETERS USED IN THE STATISTICAL ANALYSIS OF FUEL CLADDING INTEGRITY SAFETY LIMIT

THERMAL POWER	3323 MW
Core Flow	108.5 Mlb/hr
Dome Pressure	1010.4 psig
Channel Flow Area	0.1089 ft^2
R-Factor	High enrichment - 1.043 Medium enrichment - 1.039 Low enrichment - 1.030

2.1.3 REACTOR COOLANT SYSTEM PRESSURE

The Safety Limit for the reactor coolant system pressure has been selected such that it is at a pressure below which it can be shown that the integrity of the system is not endangered. The reactor pressure vessel is designed to Section III of the ASME Boiler and Pressure Vessel Code ~~1974~~ 1971 Edition, including Addenda through ~~Summer 1975~~ Winter 1972, which permits a maximum pressure transient of 110%, 1375 psig, of design pressure, 1250 psig. The Safety Limit of 1325 psig, as measured by the reactor vessel steam dome pressure indicator, is equivalent to 1375 psig at the lowest elevation of the reactor coolant system. The pressure Safety Limit is selected to be the transient overpressure allowed by the ASME Boiler and Pressure Vessel Code, Section III, Class I. 319

2.1.4 REACTOR VESSEL WATER LEVEL

With fuel in the reactor vessel during periods when the reactor is shutdown, consideration must be given to water level requirements due to the effect of decay heat. If the water level should drop below the top of the active irradiated fuel during this period, the ability to remove decay heat is reduced. This reduction in cooling capability could lead to elevated cladding temperatures and clad perforation in the event that the water level became less than two-thirds of the core height. The Safety Limit has been established at the top of the active irradiated fuel to provide a point which can be monitored and also provide adequate margin for effective action.

2.2.1 REACTOR PROTECTION SYSTEM INSTRUMENTATION SETPOINTS

The Reactor Protection System instrumentation setpoints specified in Table 2.2.1-1 are the values at which the reactor trips are set for each parameter. The Trip Setpoints have been selected to ensure that the reactor core and reactor coolant system are prevented from exceeding their Safety Limits during normal operation and design basis anticipated operational occurrences and to assist in mitigating the consequences of accidents. Operation with a trip set less conservative than its Trip Setpoint but within its specified Allowable Value is acceptable on the basis that the difference between each Trip Setpoint and the Allowable Value is equal to or greater than the drift allowance assumed for each trip in the safety analyses.

1. Intermediate Range Monitor, Neutron Flux - High

The IRM system consists of 8 chambers, 4 in each of the reactor trip systems. The IRM is a 5 decade 10 range instrument. The trip setpoint of 120 divisions of scale is active in each of the 10 ranges. Thus as the IRM is ranged up to accommodate the increase in power level, the trip setpoint is also ranged up. The IRM instruments provide for overlap with both the APRM and SRM systems.

The most significant source of reactivity changes during the power increase is due to control rod withdrawal. In order to ensure that the IRM provides the required protection, a range of rod withdrawal accidents have been analyzed. The results of these analyses are in Section 15.4 of the FSAR. The most severe case involves an initial condition in which THERMAL POWER is at approximately 1% of RATED THERMAL POWER. Additional conservatism was taken in this analysis by assuming the IRM channel closest to the control rod being withdrawn is bypassed. The results of this analysis show that the reactor is shutdown and peak power is limited to 21% of RATED THERMAL POWER with the peak fuel enthalpy well below the fuel failure threshold criterion of 170 cal/gm. Based on this analysis, the IRM provides protection against local control rod errors and continuous withdrawal of control rods in sequence and provides backup protection for the APRM.

2. Average Power Range Monitor

For operation at low pressure and low flow during STARTUP, the APRM scram setting of 15% of RATED THERMAL POWER provides adequate thermal margin between the setpoint and the Safety Limits. The margin accommodates the anticipated maneuvers associated with power plant startup. Effects of increasing pressure at zero or low void content are minor and cold water from sources available during startup is not much colder than that already in the system. Temperature coefficients are small and control rod patterns are constrained by the RPCS. Of all the possible sources of reactivity input, uniform control rod withdrawal is the most probable cause of significant power increase. Because the flux distribution associated with uniform rod withdrawals does not involve high local peaks and because several rods must be moved to change power by a significant

REACTOR PROTECTION SYSTEM INSTRUMENTATION SETPOINTS (Continued)

Average Power Range Monitor (Continued)

amount, the rate of power rise is very slow. Generally the heat flux is in near equilibrium with the fission rate. In an assumed uniform rod withdrawal approach to the trip level, the rate of power rise is not more than 5% of RATED THERMAL POWER per minute and the APRM system would be more than adequate to assure shutdown before the power could exceed the Safety Limit. The 15% neutron flux trip remains active until the mode switch is placed in the Run position.

The APRM trip system is calibrated using heat balance data taken during steady state conditions. Fission chambers provide the basic input to the system and therefore the monitors respond directly and quickly to changes due to transient operation for the case of the Neutron Flux-High 118% setpoint; i.e, for a power increase, the THERMAL POWER of the fuel will be less than that indicated by the neutron flux due to the time constants of the heat transfer associated with the fuel. For the Flow Biased Simulated Thermal Power-High setpoint, a time constant of 6 ± 1 seconds is introduced into the flow biased APRM in order to simulate the fuel thermal transient characteristics. A more conservative maximum value is used for the flow biased setpoint as shown in Table 2.2.1-1.

The APRM setpoints were selected to provide adequate margin for the Safety Limits and yet allow operating margin that reduces the possibility of unnecessary shutdown. The flow referenced trip setpoint must be adjusted by the specified formula in Specification 3.2.2 in order to maintain these margins when MFLPD is $\geq$ to FRTP.

3. Reactor Vessel Steam Dome Pressure-High

High pressure in the nuclear system could cause a rupture to the nuclear system process barrier resulting in the release of fission products. A pressure increase while operating will also tend to increase the power of the reactor by compressing voids thus adding reactivity. The trip will quickly reduce the neutron flux, counteracting the pressure increase. The trip setting is slightly higher than the operating pressure to permit normal operation without spurious trips. The setting provides for a wide margin to the maximum allowable design pressure and takes into account the location of the pressure measurement compared to the highest pressure that occurs in the system during a transient. This trip setpoint is effective at low power/flow conditions when the turbine stop valve closure trip is bypassed. For a turbine trip under these conditions, the transient analysis indicated an adequate margin to the thermal hydraulic limit.

REACTOR PROTECTION SYSTEM INSTRUMENTATION SETPOINTS (Continued)

4. Reactor Vessel Water Level-Low

The reactor vessel water level trip setpoint was chosen far enough below the normal operating level to avoid spurious trips but high enough above the fuel to assure that there is adequate protection for the fuel and pressure limits.

5. Reactor Vessel Water Level-High

A reactor scram from high reactor water level, approximately two feet above normal operating level, is intended to offset the addition of reactivity effect associated with the introduction of a significant amount of relatively cold feedwater. An excess of feedwater entering the vessel would be detected by the level increase in a timely manner. This scram feature is only effective when the reactor mode switch is in the Run position because at THERMAL POWER levels below 10% to 15% of RATED THERMAL POWER, the approximate range of power level for changing to the Run position, the safety margins are more than adequate without a reactor scram.

6. Main Steam Line Isolation Valve-Closure

The main steam line isolation valve closure trip was provided to limit the amount of fission product release for certain postulated events. The MSIV's are closed automatically from measured parameters such as high steam flow, high steam line radiation, low reactor water level, high steam tunnel temperature and low steam line pressure. The MSIV's closure scram anticipates the pressure and flux transients which could follow MSIV closure and thereby protects reactor vessel pressure and fuel thermal/hydraulic Safety Limits.

7. Main Steam Line Radiation-High

The main steam line radiation detectors are provided to detect a gross failure of the fuel cladding. When the high radiation is detected, a trip is initiated to reduce the continued failure of fuel cladding. At the same time the main steam line isolation valves are closed to limit the release of fission products. The trip setting is high enough above background radiation levels to prevent spurious trips yet low enough to promptly detect gross failures in the fuel cladding.

and to the primary containment

8. Drywell Pressure-High

or a loss of drywell cooling.

High pressure in the drywell could indicate a break in the primary pressure boundary systems. The reactor is tripped in order to minimize the possibility of fuel damage and reduce the amount of energy being added to the coolant. The
to
trip setting was selected ~~as low as possible without causing~~ spurious trips. Negative barometric pressure fluctuations are accounted for in the trip setpoints and allowable values specified for drywell pressure-high.

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to be as low as possible to minimize heat loads of equipment located in the primary containment and to avoid

REACTOR PROTECTION SYSTEM INSTRUMENTATION SETPOINTS (Continued)

9. Scram Discharge Volume Water Level-High

The scram discharge volume receives the water displaced by the motion of the control rod drive pistons during a reactor scram. Should this volume fill up to a point where there is insufficient volume to accept the displaced water at pressures below 65 psig, control rod insertion would be hindered. The reactor is therefore tripped when the water level has reached a point high enough to indicate that it is indeed filling up, but the volume is still great enough to accommodate the water from the movement of the rods at pressures below 65 psig when they are tripped. The trip setpoint for each scram discharge volume is equivalent to a contained volume of 26 gallons of water.

10. Turbine Stop Valve-Closure

The turbine stop valve closure trip anticipates the pressure, neutron flux, and heat flux increases that would result from closure of the stop valves. With a trip setting of 40 psig, the resultant increase in heat flux is such that adequate thermal margins are maintained during the worst case transient assuming the turbine bypass valves fail to operate.

11. Turbine Control Valve Fast Closure, Trip Oil Pressure-Low

The turbine control valve fast closure trip anticipates the pressure, neutron flux, and heat flux increase that could result from fast closure of the turbine control valves due to load rejection coincident with failure of the turbine bypass valves. The Reactor Protection System initiates a trip when fast closure of the control valves is initiated by a low EHC fluid pressure in the control valve and in less than 100 milliseconds after the start of control valve fast closure. This loss of pressure is sensed by pressure transmitters which output to trip units whose contacts form the one-out-of-two twice logic input to the Reactor Protection System. This trip setting and a different valve characteristic from that of the turbine stop valve combine to produce transients which are very similar to that for the stop valve. Relevant transient analyses are discussed in Section 15.2.2 of the Final Safety Analysis Report. The trip setpoint is 43.3 psig. 298/

12. Reactor Mode Switch Shutdown Position

298/ The reactor mode switch Shutdown position ~~is a redundant channel~~ to the automatic protective instrumentation channels and provides additional manual reactor trip capability.

provides trip signals into system trip channels which are redundant.

13. Manual Scram

298/ The Manual Scram ~~is a redundant channel~~ to the automatic protective instrumentation channels and provides manual reactor trip capability.

pushbutton switches introduce trip signals into system trip channels which are redundant

SECTIONS 3.0 and 4.0
LIMITING CONDITIONS FOR OPERATION
AND
SURVEILLANCE REQUIREMENTS

3/4.0 APPLICABILITY

LIMITING CONDITION FOR OPERATION

3.0.1 Compliance with the Limiting Conditions for Operation contained in the succeeding Specifications is required during the OPERATIONAL CONDITIONS or other conditions specified therein; except that upon failure to meet the Limiting Conditions for Operation, the associated ACTION requirements shall be met.

3.0.2 Noncompliance with a Specification shall exist when the requirements of the Limiting Condition for Operation and associated ACTION requirements are not met within the specified time intervals. If the Limiting Condition for Operation is restored prior to expiration of the specified time intervals, completion of the Action requirements is not required.

3.0.3 When a Limiting Condition for Operation is not met, except as provided in the associated ACTION requirements, within one hour action shall be initiated to place the unit in an OPERATIONAL CONDITION in which the Specification does not apply by placing it, as applicable, in:

1. At least STARTUP within the next 6 hours,
2. At least HOT SHUTDOWN within the following 6 hours, and
3. At least COLD SHUTDOWN within the subsequent 24 hours.

Where corrective measures are completed that permit operation under the ACTION requirements, the ACTION may be taken in accordance with the specified time limits as measured from the time of failure to meet the Limiting Condition for Operation. Exceptions to these requirements are stated in the individual Specifications.

This specification is not applicable in OPERATIONAL CONDITION 4 or 5.

3.0.4 Entry into an OPERATIONAL CONDITION or other specified condition shall not be made unless the conditions for the Limiting Condition for Operation are met without reliance on provisions contained in the ACTION requirements. This provision shall not prevent passage through or to OPERATIONAL CONDITIONS as required to comply with ACTION requirements. Exceptions to these requirements are stated in the individual Specifications.

SURVEILLANCE REQUIREMENTS

4.0.1 Surveillance Requirements shall be met during the OPERATIONAL CONDITIONS or other conditions specified for individual Limiting Conditions for Operation unless otherwise stated in an individual Surveillance Requirement.

4.0.2 Each Surveillance Requirement shall be performed within the specified time interval with:

a. A maximum allowable extension not to exceed 25% of the surveillance interval, but

b. The combined time interval for any 3 consecutive surveillance intervals shall not exceed 3.25 times the specified surveillance interval.

4.0.3 Failure to perform a Surveillance Requirement within the specified time interval shall constitute a failure to meet the OPERABILITY requirements for a Limiting Condition for Operation. Exceptions to these requirements are stated in the individual Specificatons. Surveillance requirements do not have to be performed on inoperable equipment.

4.0.4 Entry into an OPERATIONAL CONDITION or other specified applicable condition shall not be made unless the Surveillance Requirement(s) associated with the Limiting Condition for Operation have been performed within the applicable surveillance interval or as otherwise specified.

4.0.5 Surveillance Requirements for inservice inspection and testing of ASME Code Class 1, 2, & 3 components shall be applicable as follows:

a. Inservice inspection of ASME Code Class 1, 2, and 3 components and inservice testing of ASME Code Class 1, 2, and 3 pumps and valves shall be performed in accordance with Section XI of the ASME Boiler and Pressure Vessel Code and applicable Addenda as required by 10 CFR 50, Section 50.55a(g), except where specific written relief has been granted by the Commission pursuant to 10 CFR 50, Section 50.55a(g) (6) (i).

b. Surveillance intervals specified in Section XI of the ASME Boiler and Pressure Vessel Code and applicable Addenda for the inservice inspection and testing activities required by the ASME Boiler and Pressure Vessel Code and applicable Addenda shall be applicable as follows in these Technical Specifications:

ASME Boiler and Pressure Vessel Code and applicable Addenda terminology for inservice inspection and testing activities	Required frequencies for performing inservice inspection and testing activities
Weekly	At least once per 7 days
Monthly	At least once per 31 days
Quarterly or every 3 months	At least once per 92 days
Semiannually or every 6 months	At least once per 184 days
Every 9 months	At least once per 276 days
Yearly or annually	At least once per 366 days

APPLICABILITY

SURVEILLANCE REQUIREMENTS

4.0.1 Surveillance Requirements shall be met during the OPERATIONAL CONDITIONS or other conditions specified for individual Limiting Conditions for Operation unless otherwise stated in an individual Surveillance Requirement.

4.0.2 Each Surveillance Requirement shall be performed within the specified time interval with:

a. A maximum allowable extension not to exceed 25% of the surveillance interval, but

b. The combined time interval for any 3 consecutive surveillance intervals shall not exceed 3.25 times the specified surveillance interval.

4.0.3 Failure to perform a Surveillance Requirement within the specified time interval shall constitute a failure to meet the OPERABILITY requirements for a Limiting Condition for Operation. Exceptions to these requirements are stated in the individual Specificatons. Surveillance requirements do not have to be performed on inoperable equipment.

4.0.4 Entry into an OPERATIONAL CONDITION or other specified applicable condition shall not be made unless the Surveillance Requirement(s) associated with the Limiting Condition for Operation have been performed within the applicable surveillance interval or as otherwise specified.

4.0.5 Surveillance Requirements for inservice inspection and testing of ASME Code Class 1, 2, & 3 components shall be applicable as follows:

a. Inservice inspection of ASME Code Class 1, 2, and 3 components and inservice testing of ASME Code Class 1, 2, and 3 pumps and valves shall be performed in accordance with Section XI of the ASME Boiler and Pressure Vessel Code and applicable Addenda as required by 10 CFR 50, Section 50.55a(g), except where specific written relief has been granted by the Commission pursuant to 10 CFR 50, Section 50.55a(g) (6) (i).

b. Surveillance intervals specified in Section XI of the ASME Boiler and Pressure Vessel Code and applicable Addenda for the inservice inspection and testing activities required by the ASME Boiler and Pressure Vessel Code and applicable Addenda shall be applicable as follows in these Technical Specifications:

ASME Boiler and Pressure Vessel Code and applicable Addenda terminology for inservice inspection and testing activities	Required frequencies for performing inservice inspection and testing activities
Weekly	At least once per 7 days
Monthly	At least once per 31 days
Quarterly or every 3 months	At least once per 92 days
Semiannually or every 6 months	At least once per 184 days
Every 9 months	At least once per 276 days
Yearly or annually	At least once per 366 days

SURVEILLANCE REQUIREMENTS (Continued)

c. The provisions of Specification 4.0.2 are applicable to the above required frequencies for performing inservice inspection and testing activities.

d. Performance of the above inservice inspection and testing activities shall be in addition to other specified Surveillance Requirements.

e. Nothing in the ASME Boiler and Pressure Vessel Code shall be construed to supersede the requirements of any Technical Specification.

3/4.1 REACTIVITY CONTROL SYSTEMS

3/4.1.1 SHUTDOWN MARGIN

LIMITING CONDITION FOR OPERATION

3.1.1 The SHUTDOWN MARGIN shall be equal to or greater than:

a. 0.38% delta k/k with the highest worth rod analytically determined, or
b. 0.28% delta k/k with the highest worth rod determined by test.

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

ACTION:

With the SHUTDOWN MARGIN less than specified:

a. In OPERATIONAL CONDITION 1 or 2, reestablish the required SHUTDOWN MARGIN within 6 hours or be in at least HOT SHUTDOWN within the next 12 hours.

b. In OPERATIONAL CONDITION 3 or 4, immediately verify all insertable control rods to be inserted and suspend all activities that could reduce the SHUTDOWN MARGIN. In OPERATIONAL CONDITION 4, establish SECONDARY CONTAINMENT INTEGRITY within 8 hours.

c. In OPERATIONAL CONDITION 5, suspend CORE ALTERATIONS* and other activities that could reduce the SHUTDOWN MARGIN and insert all insertable control rods within 1 hour. Establish SECONDARY CONTAINMENT INTEGRITY within 8 hours.

SURVEILLANCE REQUIREMENTS

4.1.1 The SHUTDOWN MARGIN shall be determined to be equal to or greater than specified at any time during the fuel cycle:

a. By measurement, prior to or during the first startup after each refueling.

b. By measurement, within 500 MWD/T prior to the core average exposure at which the predicted SHUTDOWN MARGIN, including uncertainties and calculation biases, is equal to the specified limit.

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c. Within ~~one~~ 12 hours after detection of a withdrawn control rod that is immovable, as a result of excessive friction or mechanical interference, or is untrippable, except that the above required SHUTDOWN MARGIN shall be verified acceptable with an increased allowance for the withdrawn worth of the immovable or untrippable control rod.

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*Except movement of IRMs, SRMs or special moveable detectors.

3/4.1.2 REACTIVITY ANOMALIES

LIMITING CONDITION FOR OPERATION

3.1.2 The reactivity equivalence of the difference between the actual ROD DENSITY and the predicted ROD DENSITY shall not exceed 1% delta k/k.

APPLICABILITY: OPERATIONAL CONDITIONS 1 and 2.

ACTION:

With the reactivity different by more than 1% delta k/k:

a. Within 12 hours, perform an analysis to determine and explain the cause of the reactivity difference; operation may continue if the difference is explained and corrected.

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

SURVEILLANCE REQUIREMENTS

4.1.2 The reactivity equivalence of the difference between the actual ROD DENSITY and the predicted ROD DENSITY shall be verified to be less than or equal to 1% delta k/k:

a. During the first startup following CORE ALTERATIONS, and

b. At least once per ~~31 effective full power days~~ during POWER OPERATION.
1000 MWD/T

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3/4.1.3 CONTROL RODS

CONTROL ROD OPERABILITY

LIMITING CONDITION FOR OPERATION

3.1.3.1 All control rods shall be OPERABLE.

APPLICABILITY: OPERATIONAL CONDITIONS 1 and 2.

ACTION:.

a. With one control rod inoperable due to being immovable, as a result of excessive friction or mechanical interference, or known to be untrippable:

   1. Within one hour:

      a) Verify that the inoperable control rod, if withdrawn, is separated from all other inoperable control rods by at least two control cells in all directions.

      b) Disarm the associated directional control valves** either:

         1) Electrically, or

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

   2. ~~c)~~ Comply with Surveillance Requirement 4.1.1.c within 12 hours.

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

   3. Comply with Surveillance Requirement 4.1.3.1.2.b.

   4 ~~2.~~ Restore the inoperable control rod to OPERABLE status within 48 hours or be in at least HOT SHUTDOWN within the next 12 hours.

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b. With one or more control rods trippable but inoperable for causes other than addressed in ACTION a, above:

   1. If the inoperable control rod(s) is withdrawn, within one hour verify:

      a) That the inoperable withdrawn control rod(s) is separated from all other inoperable control rods by at least two control cells in all directions, and withdrawn

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      b) The insertion capability of the inoperable withdrawn control rod(s) by inserting the control rod(s) at least one notch by drive water pressure within the normal operating range*.

      Otherwise, insert the inoperable withdrawn control rod(s) and disarm the associated directional control valves** either:

      a) Electrically, or

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

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

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

LIMITING CONDITION FOR OPERATION (Continued)

ACTION (Continued)

2. If the inoperable control rod(s) is inserted, within one hour disarm the associated directional control valves** either:
    a) Electrically, or
    b) Hydraulically by closing the drive water and exhaust water isolation valves.

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

3. The provisions of Specification 3.0.4 are not applicable.

1241

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

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

close the inoperable valve(s) within 1 hour,

demonstrated OPERABLE by:

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

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

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

a. At least once per 7 days, and

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

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

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

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

SURVEILLANCE REQUIREMENTS (Continued)

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

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

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

   2. Open when the scram signal is reset.

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

CONTROL ROD MAXIMUM SCRAM INSERTION TIMES

LIMITING CONDITION FOR OPERATION

3.1.3.2 The maximum scram insertion time of each control rod from the fully withdrawn position, based on de-energization of the scram pilot valve solenoids as time zero, shall not exceed the following limits:

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

APPLICABILITY: OPERATIONAL CONDITIONS 1 and 2.

ACTION:

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

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

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

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

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

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

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

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

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

LIMITING CONDITION FOR OPERATION (Continued)

ACTION: (Continued)

b. With a "slow" control rod(s) not satisfying ACTION a.1, above:

   1. Declare the "slow" control rod(s) inoperable, and

   2. Perform the Surveillance Requirements of Specification 4.1.3.2.c at least once per 60 days when operation is continued with three or more "slow" control rods declared inoperable.

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

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

   1. "Slow" control rods, i.e., those which exceed the limits of Specification 3.1.3.2, do not make up more than 20% of the 10% sample of control rods tested.

   2. Each of these "slow" control rods satisfies the limits of ACTION a.1.

   3. The eight adjacent control rods surrounding each "slow" control rod are:

      a) Demonstrated through measurement within 12 hours to satisfy the maximum scram insertion time limits of Specification 3.1.3.2, and

      b) OPERABLE.

   4. The total number of "slow" control rods, as determined by Specification ~~3~~4.1.3.2.c, when added to the sum of ACTION a.3, as determined by Specification 4.1.3.2.a and b, does not exceed 7. |154

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

d. The provisions of Specification 3.0.4 are not applicable. |108

SURVEILLANCE REQUIREMENTS

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

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

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

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

---

*Except movement of SRM, IRM, or special removable detectors or normal control rod movement.

**The provisions of Specification 4.0.4 are not applicable for entry into OPERATIONAL CONDITION 2 provided this surveillance is completed prior to entry into OPERATIONAL CONDITION 1.

REACTIVITY CONTROL SYSTEMS

CONTROL ROD SCRAM ACCUMULATORS

LIMITING CONDITION FOR OPERATION

3.1.3.3 All control rod scram accumulators shall be OPERABLE:

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2 and 5*.

ACTION:

a. In OPERATIONAL CONDITIONS 1 and 2:

1. With one control rod scram accumulator inoperable, within 8 hours:

    a) Restore the inoperable accumulator to OPERABLE status, or

    b) Declare the control rod associated with the inoperable accumulator inoperable.

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

2. With more than one control rod scram accumulator inoperable, declare the associated control rods inoperable and:

    a) If the control rod associated with any inoperable scram accumulator is withdrawn, immediately verify that at least one control rod drive pump is operating by inserting at least one withdrawn control rod at least one notch or place the reactor mode switch in the Shutdown position.

    b) Insert the inoperable control rods 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 12 hours.

b. In OPERATIONAL CONDITION 5*:

1. With one withdrawn control rod with its associated scram accumulator inoperable, insert the affected control rod and disarm the associated directional control valves within one hour, either:

    a) Electrically, or

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

2. With more than one withdrawn control rod with the associated scram accumulator inoperable or with no control rod drive pump operating, immediately place the reactor mode switch in the Shutdown position.

108 c. The provisions of Specification 3.0.4 are not applicable.

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

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 indicated pressure is greater than the alarm setpoint unless the control rod is inserted and disarmed or scrammed.

b. At least once per 18 months by:

   1. Performance of a:

      a) CHANNEL FUNCTIONAL TEST of the leak detectors, and

      b) CHANNEL CALIBRATION of the pressure detectors, and verifying an alarm setpoint of 1520 + 30, -0 psig on decreasing pressure.

   2. ~~Measuring and recording the time, for up to 10 minutes, that each individual accumulator check valve maintains the associated accumulator pressure above the alarm set point, starting at normal system operating pressure, with no control rod drive pump operating.~~ 214

REACTIVITY CONTROL SYSTEMS

CONTROL ROD DRIVE COUPLING

LIMITING CONDITION FOR OPERATION

3.1.3.4 All control rods shall be coupled to their drive mechanisms.

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

ACTION:

a. In OPERATIONAL CONDITION 1 and 2 with one control rod not coupled to its associated drive mechanism, within 2 hours:

   1. If permitted by the RPCS, insert the control rod drive mechanism to accomplish recoupling and verify recoupling by withdrawing the control rod, and:

      a) Observing any indicated response of the nuclear instrumentation, and

      b) Demonstrating that the control rod will not go to the overtravel position.

   2. If recoupling is not accomplished on the first attempt or, if not permitted by the RPCS, then until permitted by the RPCS, declare the control rod inoperable, insert the control rod, and disarm the associated directional control valves** either:

      a) Electrically, or

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

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

b. In OPERATIONAL CONDITION 5* with a withdrawn control rod not coupled to its associated drive mechanism, within 2 hours either:

   1. Insert the control rod to accomplish recoupling and verify recoupling by withdrawing the control rod and demonstrating that the control rod will not go to the overtravel position, or

   2. If recoupling is not accomplished, insert the control rod and disarm the associated directional control valves** either:

      a) Electrically, or

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

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. 1371

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

SURVEILLANCE REQUIREMENTS

4.1.3.4 Each affected control rod shall be demonstrated to be coupled to its drive mechanism by observing any indicated response of the nuclear instrumentation while withdrawing the control rod to the fully withdrawn position and then verifying that the control rod drive does not go to the overtravel position:

a. Prior to reactor criticality after completing CORE ALTERATIONS that could have affected the control rod drive coupling integrity,

b. Anytime the control rod is withdrawn to the "full out" position in subsequent operation, and

c. Following maintenance on or modification to the control rod or control rod drive system which could have affected the control rod drive coupling integrity.

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 with one or more control rod position indicators inoperable, within one hour:

   1. Determine the position of the control rod by the alternate control rod position indicator, or
   2. Move the control rod to a position with an OPERABLE position indicator, or
   3. When THERMAL POWER is:
      a) Within 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 members 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: 1155
         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 control rod position indicators for a withdrawn control rod inoperable, move the control rod to a position with an OPERABLE position indicator or insert the control rod.

155| 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 or 3.9.10.2.

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

SURVEILLANCE REQUIREMENTS

4.1.3.5 The above required control rod position indication system shall be determined OPERABLE by verifying:

a. At least once per 24 hours that the position of each control rod is indicated,

b. That the indicated control rod position changes during the movement of the control rod drive when performing Surveillance Requirement 4.1.3.1.2,

c. That the control rod position indicator corresponds to the control rod position indicated by the "Full out" position indicator when performing Surveillance Requirement 4.1.3.4.b, and

d. When the alternate control rod position indicator is OPERABLE, by performance of a CHANNEL CHECK at least once per 12 hours.

CONTROL ROD DRIVE HOUSING SUPPORT

LIMITING CONDITION FOR OPERATION

3.1.3.6 The control rod drive housing support shall be in place.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2 and 3.

ACTION:

With the control rod drive housing support not in place, be in at least HOT SHUTDOWN within 12 hours and in COLD SHUTDOWN within the following 24 hours.

SURVEILLANCE REQUIREMENTS

4.1.3.6 The control rod drive housing support shall be verified to be in place by a visual inspection prior to startup any time it has been disassembled or when maintenance has been performed in the control rod drive housing support area.

3/4.1.4 CONTROL ROD PROGRAM CONTROLS

CONTROL ROD WITHDRAWAL

LIMITING CONDITION FOR OPERATION

3.1.4.1. Control rods shall not be withdrawn.

APPLICABILITY: OPERATIONAL CONDITIONS 1 and 2, when the main turbine bypass valves are not fully closed and when THERMAL POWER is greater than the low power setpoint of the rod control and information system (RC & IS).

ACTION:

0511 With any control rod withdraw~~al,~~n when the main turbine bypass valves are not fully closed and THERMAL POWER is greater than the low power setpoint of the RC & IS, immediately return the control rod(s) to the position prior to control rod withdrawal.

0511

SURVEILLANCE REQUIREMENTS

4.1.4.1 Control rod withdrawal shall be prevented when the main turbine bypass valves are not fully closed and THERMAL POWER is greater than the low power setpoint of the RC & IS, by a second licensed operator or other technically qualified member of the unit technical staff.

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 Low Power Setpoint ~~20% of RATED THERMAL POWER~~, control rod movement shall not be permitted, except by a scram. |334

   2. THERMAL POWER greater than the Low Power Setpoint ~~20% of RATED THERMAL POWER~~, 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: |334

   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 action control ~~gang drive~~ system (RACS ~~RGDS~~) provided that the SHUTDOWN MARGIN has been determined to be equal to or greater than required by Specification 3.1.1. |334

   2. With up to eight control rods inoperable for causes other than addressed in ACTION b.1, above, ~~one of~~ these inoperable control rods may be bypassed in the RACS ~~RGDS~~ provided that: |334

      a) The control rod(s) to be bypassed is inserted and the directional control valves are disarmed either: |334

         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.

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*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.

** Bypassing of control rod(s) in the RPCS shall be performed under administrative control. |334

SURVEILLANCE REQUIREMENTS

4.1.4.2 The RPCS shall be demonstrated OPERABLE by verifying the OPERABILITY of the:

a. Rod pattern controller function when THERMAL POWER is less than the low power setpoint by selecting and attempting to move an inhibited control rod: /334

1. After withdrawal of the first insequence control rod or gang for each reactor startup. /334

2. As soon as the rod inhibit mode is automatically initiated at the RPCS low power setpoint, 20 +15, -0% of RATED THERMAL POWER, during power reduction.

3. The first time only that a banked position, N1, N2, or N3, is reached during startup or during power reduction below the RPCS low power setpoint. function

Stet

b. Rod ~~withdrawal limiter~~ when THERMAL POWER is greater than or equal to the low power setpoint by selecting and attempting to move a restricted control rod in excess of the allowable distance: /334

1. As each power range above the RPCS low power setpoint is entered during a power increase or decrease.

2. At least once per 31 days while operation continues within a given power range above the RPCS low power setpoint.

REACTIVITY CONTROL SYSTEMS

3/4.1.5 STANDBY LIQUID CONTROL SYSTEM

LIMITING CONDITION FOR OPERATION

3.1.5 ~~The~~ Two standby liquid control system subsystems shall be OPERABLE. /156

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2 and 5*.

ACTION:

a. In OPERATIONAL CONDITION 1 or 2:
   1. With one ~~pump and/or one explosive valve~~ System subsystem inoperable, restore the inoperable ~~pump and/or explosive valve~~ subsystem to OPERABLE status within 7 days or be in at least HOT SHUTDOWN within the next 12 hours. /156
   2. With ~~the~~ both standby liquid control system subsystems ~~otherwise~~ inoperable, restore at least one subsystem ~~the system~~ to OPERABLE status within 8 hours or be in at least HOT SHUTDOWN within the next 12 hours. /156

b. In OPERATIONAL CONDITION 5*:
   1. With one ~~pump and/or one explosive~~ System subsystem valve inoperable, restore the inoperable ~~pump and/or explosive valve~~ subsystem to OPERABLE status within 30 days or insert all insertable control rods within the next hour.
   2. With ~~the~~ both standby liquid control system subsystems ~~otherwise~~ inoperable, insert all insertable control rods within one hour. /156

SURVEILLANCE REQUIREMENTS

4.1.5 ~~The~~ Each standby liquid control system subsystem shall be demonstrated OPERABLE: /156

a. At least once per 24 hours by verifying that;
   1. The temperature of the sodium pentaborate solution is within the limits of Figure 3.1.5-1.
   2. The available volume of sodium pentaborate solution is greater than or equal to 4587 gallons.
   3. The heat tracing circuit is OPERABLE by determining the temperature of the pump suction piping to be greater than or equal to 70°F.

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

b. At least once per 31 days by;

   1. Starting both pumps and recirculating demineralized water to the test tank.

   2. Verifying the continuity of the explosive charge.

   3. Determining that the available weight of sodium pentaborate is greater than or equal to 5500 lbs and the concentration of boron in solution is within the limits of Figure 3.1.5-1 by chemical analysis.*

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

c. Demonstrating that, when tested pursuant to Specification 4.0.5, the minimum flow requirement of 41.2 gpm at a pressure of greater than or equal to 1220 psig is met.

d. At least once per 18 months during shutdown by;

   1. Initiating one of the standby liquid control system ~~loops~~ subsystems, including an explosive valve, and verifying that a flow path from the pumps to the reactor pressure vessel is available by pumping demineralized water into the reactor vessel. The replacement charge for the explosive valve shall be from the same manufactured batch as the one fired or from another batch which has been certified by having one of that batch successfully fired. Both ~~injection loops~~ ~~system~~ subsystems shall be tested in 36 months. | 156 | 156

   2. Demonstrating that the pump relief valve setpoint is less than or equal to 1386 psig and verifying that the relief valve does not actuate during recirculation to the test tank.

   3. **Demonstrating that all heat traced piping between the storage tank and the reactor vessel is unblocked by pumping from the storage tank to the test tank and then draining and flushing the piping with demineralized water.

   4. Demonstrating that the storage tank heater~~s~~ ~~are~~ is OPERABLE by verifying the expected temperature rise for the sodium pentaborate solution in the storage tank after the heater~~s~~ ~~are~~ is energized. | 313

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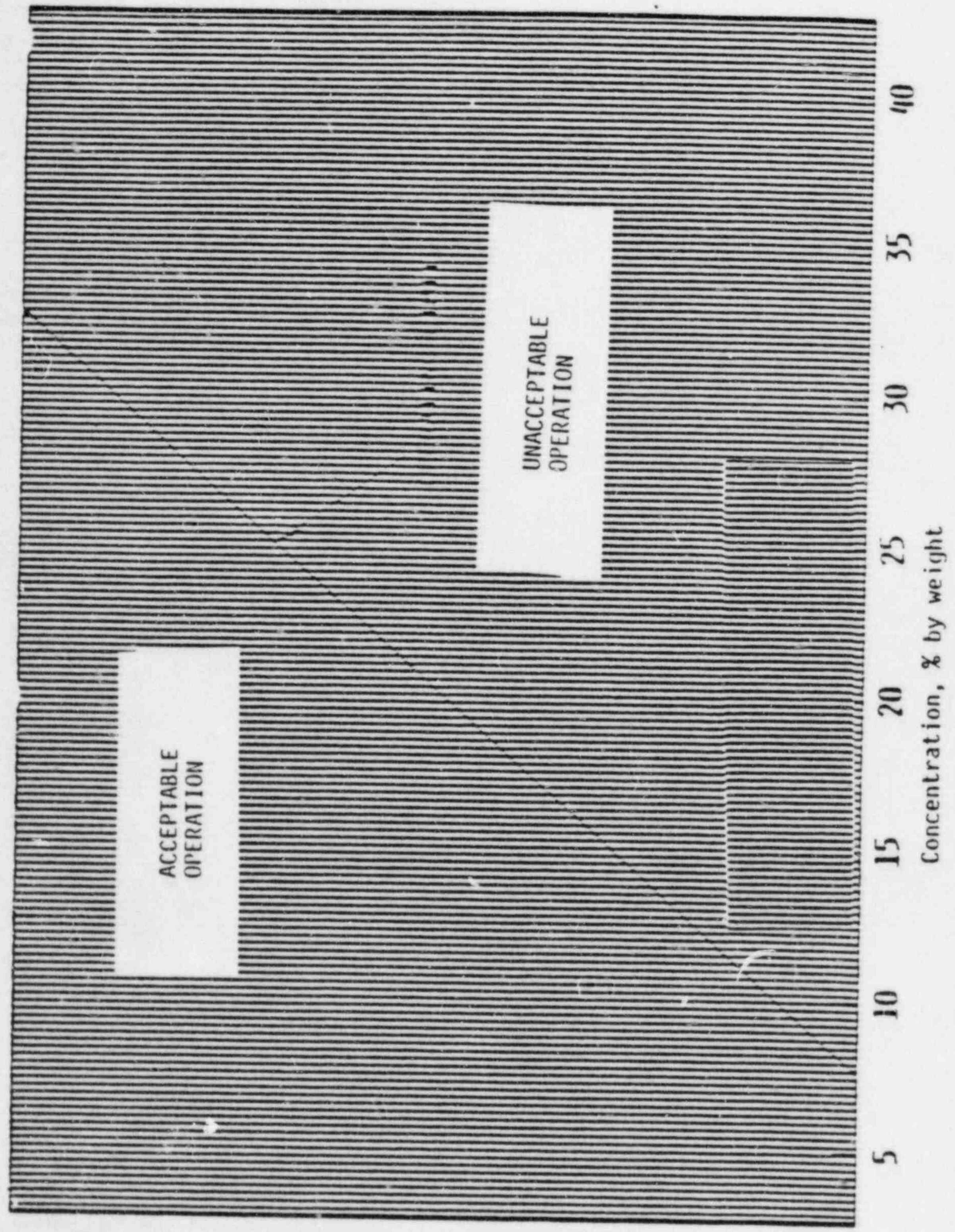
*This test shall also be performed anytime water or boron is added to the solution or when the solution temperature drops below the limit of Figure 3.1.5-1.

**This test shall also be performed whenever both heat tracing circuits have been found to be inoperable and may be performed by any series of sequential, overlapping or total flow path steps such that the entire flow path is included.



SODIUM PENTABORATE SOLUTION
TEMPERATURE/CONCENTRATION REQUIREMENTS

Figure 3.1.5-1

3/4.2 POWER DISTRIBUTION LIMITS

3/4.2.1 AVERAGE PLANAR LINEAR HEAT GENERATION RATE

LIMITING CONDITION FOR OPERATION

3.2.1 All AVERAGE PLANAR LINEAR HEAT GENERATION RATES (APLHGRs) for each type of fuel as a function of AVERAGE PLANAR EXPOSURE shall not exceed the limits shown in Figure 3.2.1-1, 3.2.1-2, and 3.2.1-3..

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

ACTION:

With an APLHGR exceeding the limits of Figure 3.2.1-1, 3.2.1-2, or 3.2.1-3, initiate corrective action within 15 minutes and restore APLHGR to within the required limits within 2 hours or reduce THERMAL POWER to less than 25% of RATED THERMAL POWER within the next 4 hours.

SURVEILLANCE REQUIREMENTS

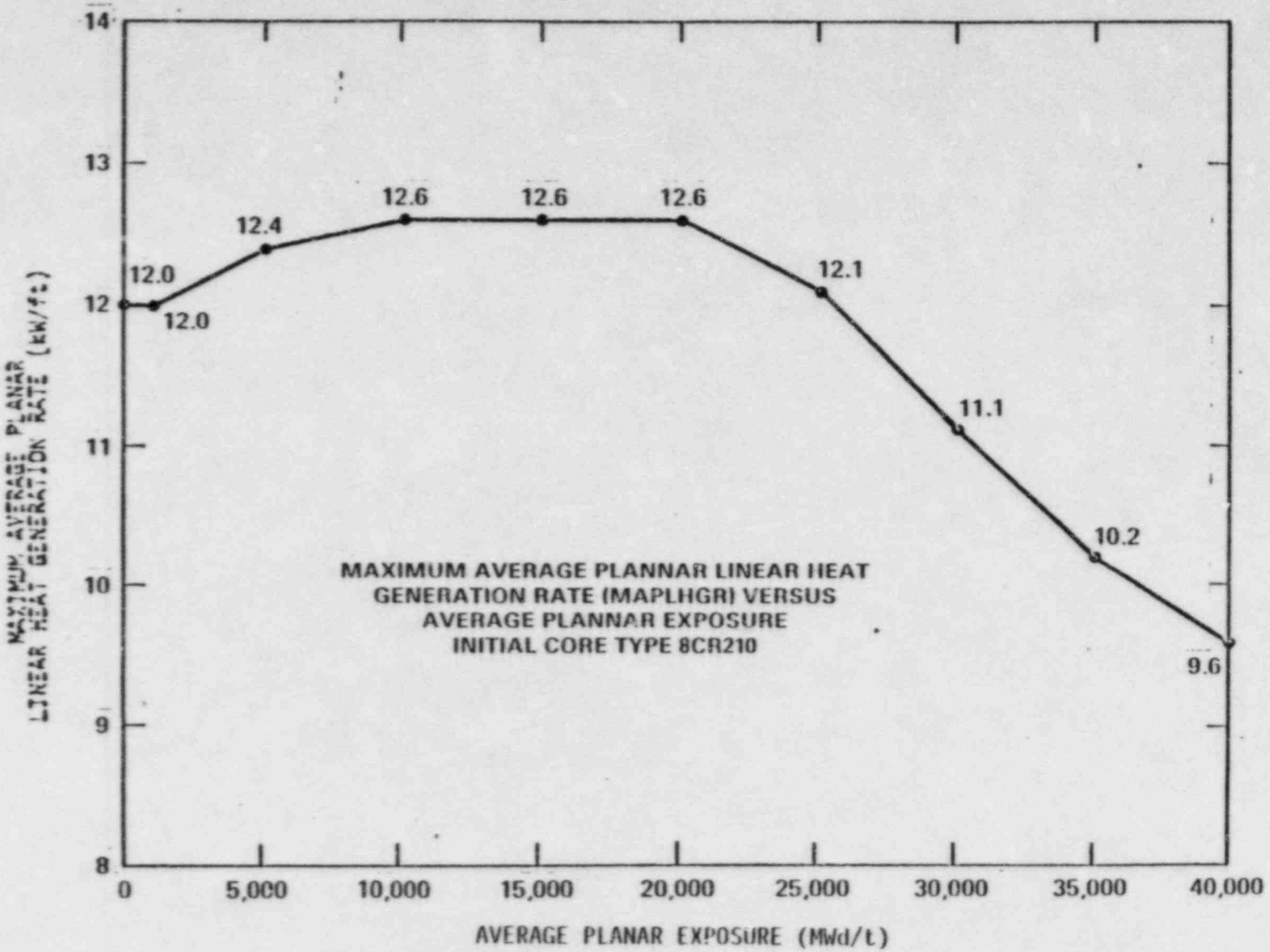
4.2.1 All APLHGRs shall be verified to be equal to or less than the limits determined from Figures 3.2.1-1, 3.2.1-2, and 3.2.1-3:

a. At least once per 24 hours,

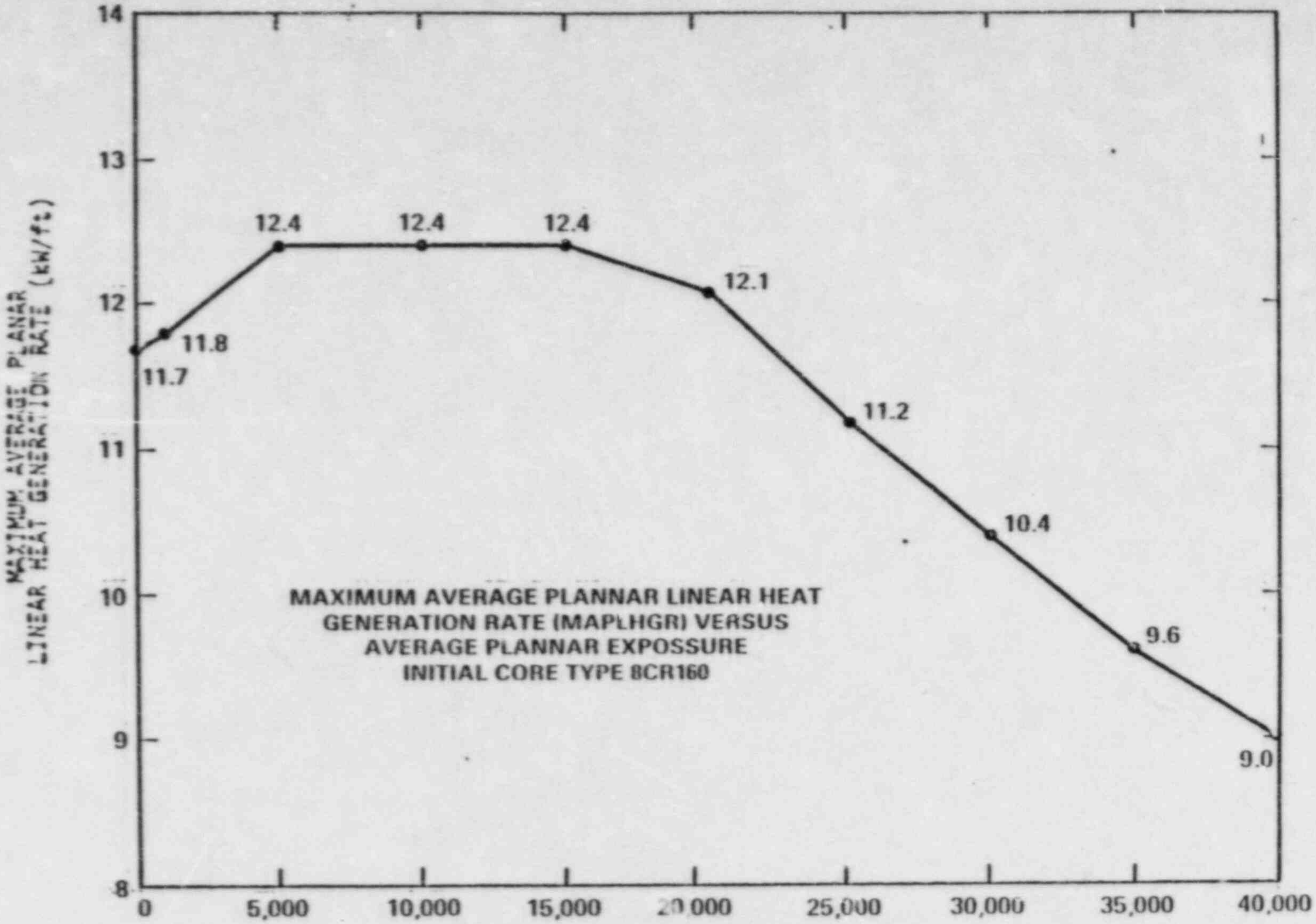
b. Within 12 hours after completion of a THERMAL POWER increase of at least 15% of RATED THERMAL POWER, and

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

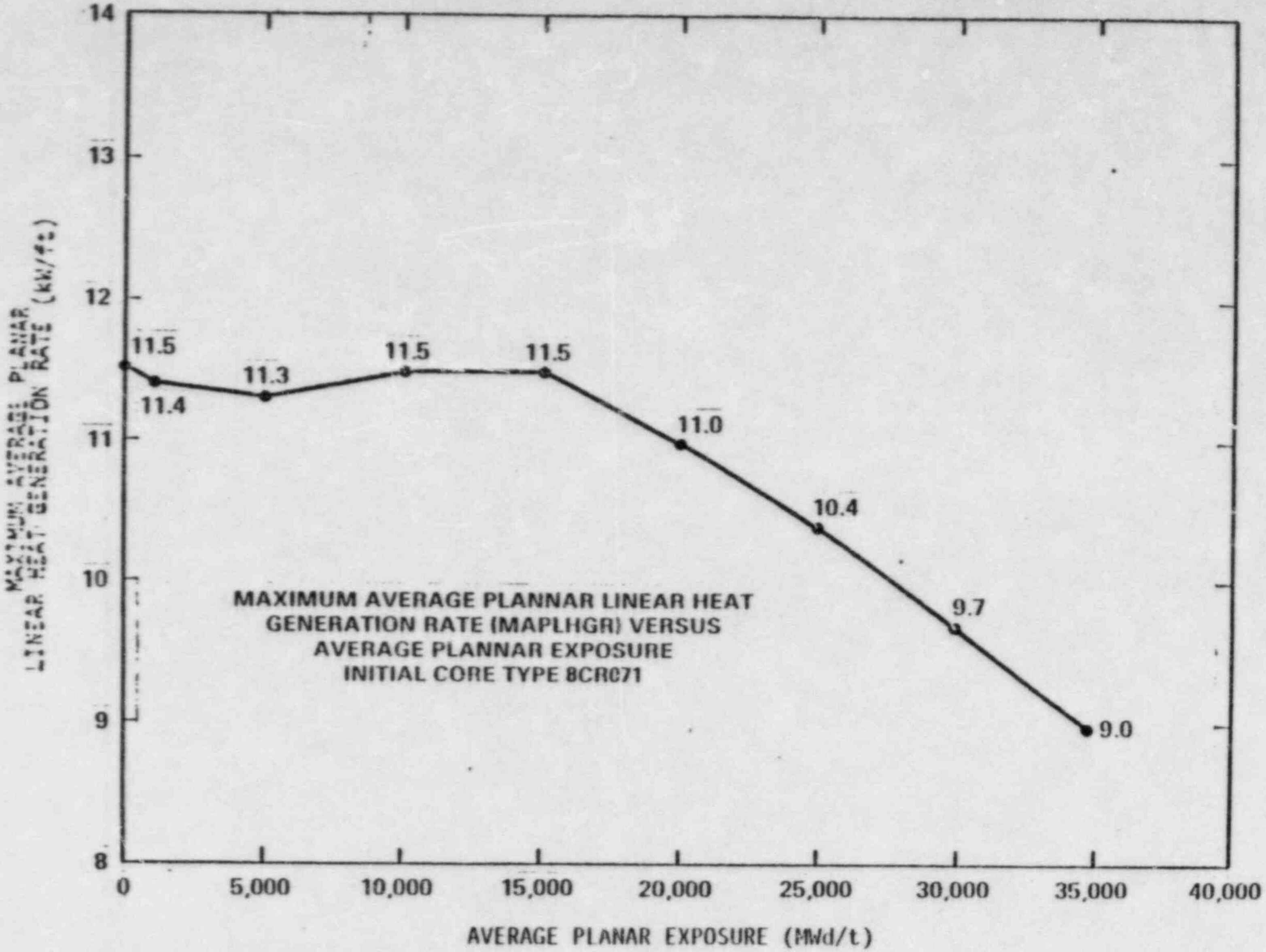
d. The provisions of Specification 4.0.4 are not applicable. /049



MAXIMUM AVERAGE PLANAR LINEAR HEAT
GENERATION RATE (MAPLHGR) VERSUS
AVERAGE PLANAR EXPOSURE
INITIAL CORE FUEL TYPE 8CR210
Figure 3.2.1-1



MAXIMUM AVERAGE PLANAR LINEAR HEAT
GENERATION RATE (MAPLHGR) VERSUS
AVERAGE PLANAR EXPOSURES
INITIAL CORE FUEL TYPE 8CR160
Figure 3.2.1-2



MAXIMUM AVERAGE PLANAR LINEAR HEAT
GENERATION RATE (MAPLHGR) VERSUS
AVERAGE PLANAR EXPOSURE
INITIAL CORE FUEL TYPE 8 CR071
Figure 3.2.1-3

POWER DISTRIBUTION LIMITS

3/4.2.2 APRM SETPOINTS

LIMITING CONDITION FOR OPERATION

3.2.2 The APRM flow biased simulated thermal power-high scram trip setpoint (S) and flow biased neutron flux-upscale control rod block trip setpoint (S_{RB}) shall be established according to the following relationships:

Trip Setpoint	Allowable Value
$S \leq (0.66W + 48\%)T$	$S \leq (0.66W + 51\%)T$
$S_{RB} \leq (0.66W + 42\%)T$	$S_{RB} \leq (0.66W + 45\%)T$

where: S and S_{RB} are in percent of RATED THERMAL POWER.

W = Loop recirculation flow as a percentage of the loop recirculation flow which produces a rated core flow of 112.5 million lbs/hr.

T = Lowest value of the ratio of FRACTION OF RATED THERMAL POWER (FRTP) divided by the MAXIMUM FRACTION OF LIMITING POWER DENSITY (MFLPD). T is ~~always less than or equal to 1.0.~~ applied only if less than or equal to 1.0. /158

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

ACTION:

With the APRM flow biased simulated thermal power-high scram trip setpoint and/or the flow biased neutron flux-upscale control rod block trip setpoint less conservative than the value shown in the allowable value-column for S or S_{RB}, as above determined, initiate corrective action within 15 minutes and restore S and/or S_{RB} to within the required limits* within ~~2~~ 8 hours or reduce THERMAL POWER to less than 25% of RATED THERMAL POWER within the next 4 hours. /049

SURVEILLANCE REQUIREMENTS

4.2.2 The FRTP AND MFLPD for each class of fuel shall be determined, the value of T calculated, and the most recent actual APRM flow biased simulated thermal power-high scram and flow biased neutron flux-upscale control rod block trip setpoints verified to be within the above limits or adjusted, as required:

- a. At least once per 24 hours,
- b. Within 12 hours after completion of a THERMAL POWER increase of at least 15% of RATED THERMAL POWER, and
- c. Initially and at least once per 12 hours when the reactor is operating with MFLPD greater than or equal to FRTP.
- d. The provisions of Specification 4.0.4 are not applicable. /049

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*With MFLPD greater than the FRTP during power ascension up to 90% of RATED THERMAL POWER, rather than adjusting the APRM setpoints, the APRM gain may be adjusted such that APRM readings are greater than or equal to 100% times MFLPD provided that the adjusted APRM reading does not exceed 100% of RATED THERMAL POWER, ~~the required gain adjustment increment does not exceed 10% of RATED THERMAL POWER~~ and a notice of adjustment is posted on the reactor control panel. /049

POWER DISTRIBUTION LIMITS

3/4.2.3 MINIMUM CRITICAL POWER RATIO

LIMITING CONDITION FOR OPERATION

3.2.3 The MINIMUM CRITICAL POWER RATIO (MCPR) shall be equal to or greater than both $MCPR_f$ and $MCRP_p$ limits at indicated core flow and THERMAL POWER as shown in Figures 3.2.3-1 and 3.2.3-2.

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

ACTION:

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

SURVEILLANCE REQUIREMENTS

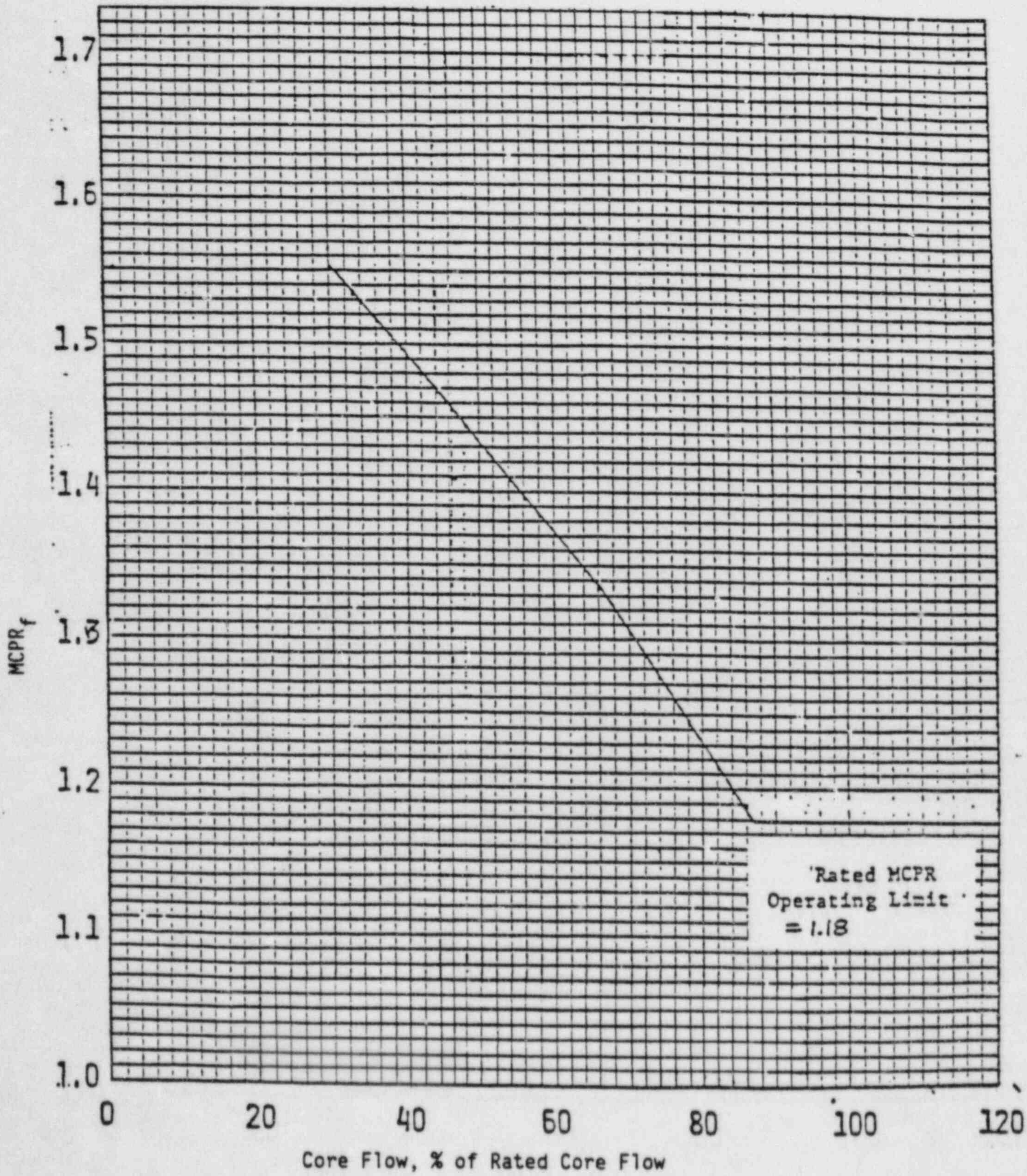
4.2.3 MCPR shall be determined to be equal to or greater than the applicable MCPR limits determined from Figures 3.2.3-1 and 3 2.3-2:

a. At least once per 24 hours,

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

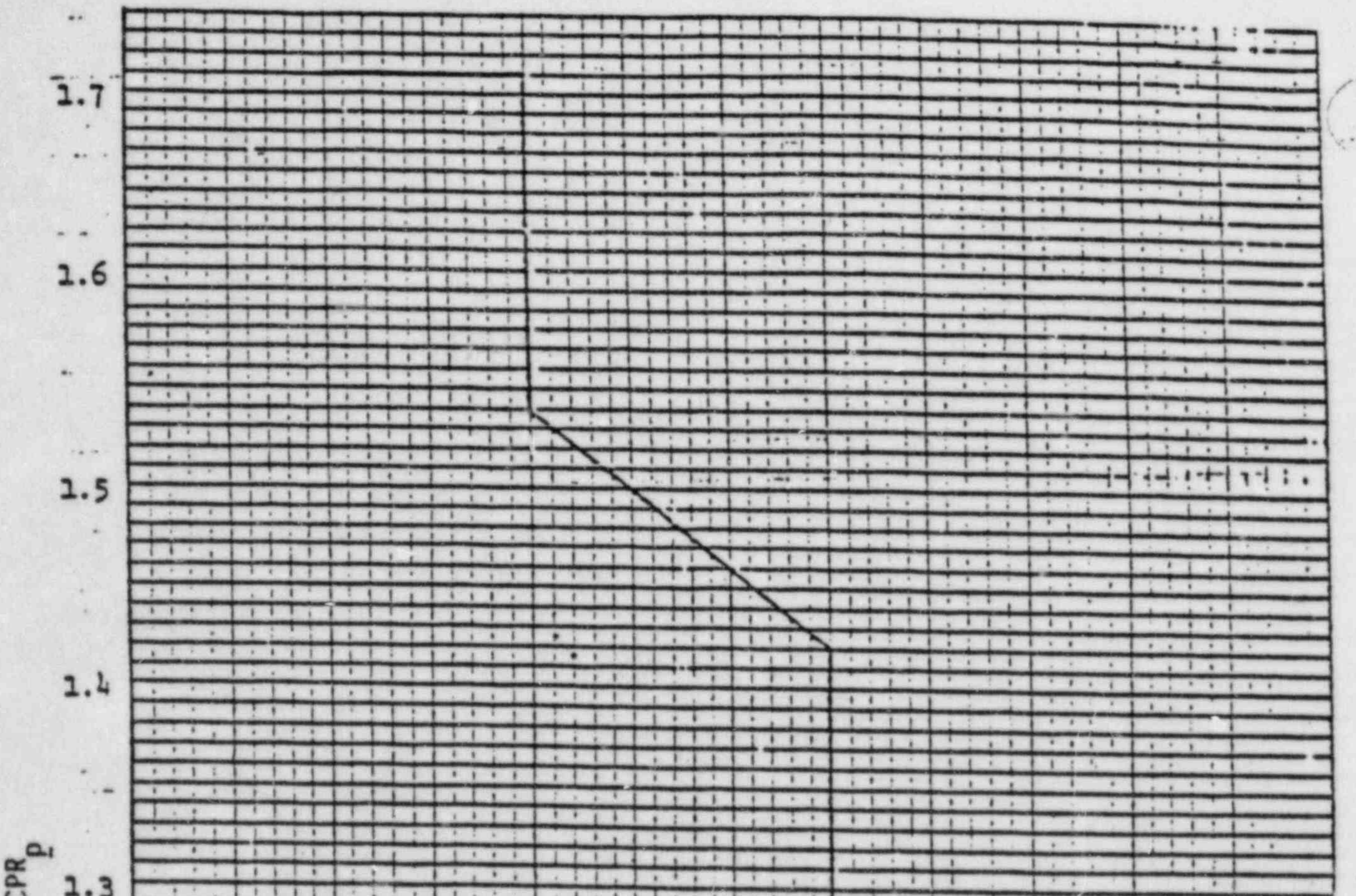
c. Initially and at least once per 12 hours when the reactor is operating with a LIMITING CONTROL ROD PATTERN for MCPR.

d. The provisions of Specification 4.0.4 are not applicable. /049



MCPR$_f$

Figure 3.2.3-1



MCPR$_p$

Figure 3.2.3-2

3/4.2.4 LINEAR HEAT GENERATION RATE

LIMITING CONDITION FOR OPERATION

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

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

ACTION:

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

SURVEILLANCE REQUIREMENTS

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

a. At least once per 24 hours,

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

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

d. The provisions of Specification 4.0.4 are not applicable. /049

3/4.3 INSTRUMENTATION

3/4.3.1 REACTOR PROTECTION SYSTEM INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.1 As a minimum, the reactor protection system instrumentation channels shown in Table 3.3.1-1 shall be OPERABLE with the REACTOR PROTECTION SYSTEM RESPONSE TIME as shown in Table 3.3.1-2.

APPLICABILITY: As shown in Table 3.3.1-1.

ACTION:

a. With the number of OPERABLE channels less than required by the Minimum OPERABLE Channels per Trip System requirement for one trip system, place the inoperable channel and/or that trip system in the tripped condition* within one hour. The provisions of Specification 3.0.4 are not applicable.

b. With the number of OPERABLE channels less than required by the Minimum OPERABLE Channels per Trip System requirement for both trip systems, place at least one trip system** in the tripped condition within one hour and take the ACTION required by Table 3.3.1-1.

SURVEILLANCE REQUIREMENTS

4.3.1.1 Each reactor protection system instrumentation channel shall be demonstrated OPERABLE by the performance of the CHANNEL CHECK, CHANNEL FUNCTIONAL TEST and CHANNEL CALIBRATION operations for the OPERATIONAL CONDITIONS and at the frequencies shown in Table 4.3.1.1-1.

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

4.3.1.3 The REACTOR PROTECTION SYSTEM RESPONSE TIME of each reactor trip functional unit shown in Table 3.3.1-2 shall be demonstrated to be within its limit at least once per 18 months. Each test shall include at least one channel per trip system such that all channels are tested at least once every N times 18 months where N is the total number of redundant channels in a specific reactor trip system.

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* ~~With a design providing only one channel per trip system~~, An inoperable channel need not be placed in the tripped condition where this would cause the Trip Function to occur. In these cases, the inoperable channel shall be restored to OPERABLE status within 2 hours or the ACTION required by Table 3.3.1-1 for that Trip Function shall be taken. 112

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

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TABLE 3.3.1-1

REACTOR PROTECTION SYSTEM INSTRUMENTATION

FUNCTIONAL UNIT	APPLICABLE OPERATIONAL CONDITIONS	MINIMUM OPERABLE CHANNELS PER TRIP SYSTEM (a)	ACTION	
1. Intermediate Range Monitors:				
a. Neutron Flux - High	2	3	1	
	3, 4	~~2~~ 3	2	1253
	5^(b)	3	3	
b. Inoperative	2	3	1	
	3, 4	~~2~~ 3	2	1253
	5	3	3	
2. Average Power Range Monitor (c):				
a. Neutron Flux - High, Setdown	2	3	1	
	3	3	2	
	5^(b)	3	3	
b. Flow Biased Simulated Thermal Power - High	1	3	4	
c. Neutron Flux - High	1	3	4	
d. Inoperative	1, 2	3	1	
	3	3	2	
	5	3	3	
3. Reactor Vessel Steam Dome Pressure - High	1, 2^(d)	2	1	
4. Reactor Vessel Water Level - Low, Level 3	1, 2	2	1	
5. Reactor Vessel Water Level-High, Level 8	1^(e)	2	4	
6. Main Steam Line Isolation Valve - Closure	1^(e)	4	4	
7. Main Steam Line Radiation - High	1, 2^(d)	2	5	
8. Drywell Pressure - High	1, 2^(f)	2	1	

TABLE 3.3.1-1 (Continued)

REACTOR PROTECTION SYSTEM INSTRUMENTATION

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

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TABLE 3.3.1-1 (Continued)

REACTOR PROTECTION SYSTEM INSTRUMENTATION

ACTION

ACTION 1 - Be in at least HOT SHUTDOWN within 12 hours. /109

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

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

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

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

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

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

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

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

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

TABLE 3.3.1-1 (Continued)

REACTOR PROTECTION SYSTEM INSTRUMENTATION

TABLE NOTATIONS

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

(b) The "shorting links" shall be removed from the RPS circuitry or the rod pattern control system shall be OPERABLE prior to and during the time any control rod is withdrawn* and shutdown margin demonstrations performed per Specification 3.10.3.

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

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

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

(f) This function is not required to be OPERABLE when DRYWELL INTEGRITY is not required.

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

(h) This function shall be automatically bypassed when turbine first stage pressure is less than 30%** of the value of turbine first stage pressure in psia, at valves wide open (VWO) steam flow, equivalent to THERMAL POWER less than 40% of RATED THERMAL POWER.

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

**Initial setpoint. Final setpoint to be determined during startup test program. Any required change to this setpoint shall be submitted to the Commission within 90 days of test completion.

TABLE 3.3.1-2

REACTOR PROTECTION SYSTEM RESPONSE TIMES

FUNCTIONAL UNIT	RESPONSE TIME (Seconds)
1. Intermediate Range Monitors:	
a. Neutron Flux - High	NA
b. Inoperative	NA
2. Average Power Range Monitor*:	
a. Neutron Flux - High, Setdown	NA
b. Flow Biased Simulated Thermal Power - High	≤ 0.09**
c. Neutron Flux - High	≤ 0.09
d. Inoperative	NA
3. Reactor Vessel Steam Dome Pressure - High	≤ 0.35
4. Reactor Vessel Water Level - Low, Level 3	≤ 1.05
5. Reactor Vessel Water Level - High, Level 8	≤ 1.05
6. Main Steam Line Isolation Valve - Closure	≤ 0.06
7. Main Steam Line Radiation - High	NA
8. Drywell Pressure - High	NA
9. Scram Discharge Volume Water Level - High	NA
10. Turbine Stop Valve - Closure	≤ 0.10
11. Turbine Control Valve Fast Closure, Valve Trip System Oil Pressure - Low	≤ 0.10#
12. Reactor Mode Switch Shutdown Position	NA
13. Manual Scram	NA

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*Neutron detectors are exempt from response time testing. Response time shall be measured from the detector output or from the input of the first electronic component in the channe

**Not including simulated thermal power time constant.

#Measured from start of turbine control valve fast closure.

TABLE 4.3.1.1-1

REACTOR PROTECTION SYSTEM INSTRUMENTATION SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL FUNCTIONAL TEST	CHANNEL CALIBRATION(a)	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRED	
1. Intermediate Range Monitors:					
a. Neutron Flux - High	S/U,S,(b) S	S/U~~(c)~~ e, W W	R R	2 3, 4, 5	355
b. Inoperative	NA	W	NA	2, 3, 4, 5	
2. Average Power Range Monitor:(f)					
a. Neutron Flux - High, Setdown	S/U,S,(b) S	S/U~~(c)~~ e, W W	SA SA	2 3, 5	355
b. Flow Biased Simulated Thermal Power - High	S, D(h)	~~S/U(c),~~ W	W(d)(e), SA, R(i)	1	355
c. Neutron Flux - High	S	~~S/U(c)~~, W	W(d), SA	1	
d. Inoperative	NA	W	NA	1, 2, 3, 5	
3. Reactor Vessel Steam Dome Pressure - High	S	M	R(g)	1, 2 (j)	369
4. Reactor Vessel Water Level - Low, Level 3	S	M	R(g)	1, 2	
5. Reactor Vessel Water Level - High, Level 8	S	M	R(g)	1	
6. Main Steam Line Isolation Valve - Closure	NA	M	R	1	
7. Main Steam Line Radiation - High	S	M	R	1, 2 (j)	369
8. Drywell Pressure - High	S	M	R(g)	1, 2 (k)	

TABLE 4.3.1.1-1 (Continued)

REACTOR PROTECTION SYSTEM INSTRUMENTATION SURVEILLANCE REQUIREMENTS

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

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(a) Neutron detectors may be excluded from CHANNEL CALIBRATION.

(b) The IRM and SRM channels shall be determined to overlap for at least 1/2 decade during each startup after entering OPERATIONAL CONDITION 2 and the IRM and APRM channels shall be determined to overlap for at least 1/2 decade during each controlled shutdown, if not performed within the previous 7 days.

(c) ~~Within 24 hours prior to startup, if not performed within the previous 7 days~~. [DELETED] 355

(d) This calibration shall consist of the adjustment of the APRM channel to conform to the power values calculated by a heat balance during OPERATIONAL CONDITION 1 when THERMAL POWER ≥ 25% of RATED THERMAL POWER. Adjust the APRM channel if the absolute difference is greater than 2% of RATED THERMAL POWER. Any APRM channel gain adjustment made in compliance with Specification 3.2.2 shall not be included in determining the absolute difference.

(e) This calibration shall consist of the adjustment of the APRM flow biased channel to conform to a calibrated flow signal.

(f) The LPRMs shall be calibrated at least once per 1000 ~~effective full power hours (EFPH)~~ MWD/T using the TIP system. 265

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

(h) Verify measured drive flow to be less than or equal to established drive flow at the existing flow control valve position.

(i) This calibration shall consist of verifying the 6 ± 1 second simulated thermal power time constant.

(j) Not applicable when the reactor pressure vessel head is unbolted or removed per Specification 3.10.1

(k) Not applicable when drywell integrity is not required.

(l) Applicable with any control rod withdrawn. Not applicable to control rods removed per Specification 3.9.10.1 or 3.9.10.2.

3/4.3.2 ISOLATION ACTUATION INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

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

APPLICABILITY: As shown in Table 3.3.2-1.

ACTION:

a. With an isolation actuation instrumentation channel trip setpoint less conservative than the value shown in the Allowable Values column of Table 3.3.2-2, declare the channel inoperable until the channel is restored to OPERABLE status with its trip setpoint adjusted consistent with the Trip Setpoint value.

b. With the number of OPERABLE channels less than required by the Minimum OPERABLE Channels per Trip System requirement for one trip system, place the inoperable channel(s) and/or that trip system in the tripped condition* within one hour. The provisions of Specification 3.0.4 are not applicable. |112

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

SURVEILLANCE REQUIREMENTS

4.3.2.1 Each isolation actuation instrumentation channel shall be demonstrated OPERABLE by the performance of the CHANNEL CHECK, CHANNEL FUNCTIONAL TEST and CHANNEL CALIBRATION operations for the OPERATIONAL CONDITIONS and at the frequencies shown in Table 4.3.2.1-1.

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

4.3.2.3 The ISOLATION SYSTEM RESPONSE TIME of each isolation trip function shown in Table 3.3.2-3 shall be demonstrated to be within its limit at least once per 18 months. Each test shall include at least one channel per trip system such that all channels are tested at least once every N times 18 months, where N is the total number of redundant channels in a specific isolation trip system.

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*~~With a design providing only one channel per trip system~~, An inoperable channel need not be placed in the tripped condition where this would cause the Trip Function to occur. In these cases, the inoperable channel shall be restored to OPERABLE status within 2 hours or the ACTION required by Table 3.3.2-1 for that Trip Function shall be taken. |112

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

TABLE 3.3.2-1

ISOLATION ACTUATION INSTRUMENTATION

TRIP FUNCTION	VALVE GROUPS OPERATED BY SIGNAL (a)	MINIMUM OPERABLE CHANNELS PER TRIP SYSTEM (b)	APPLICABLE OPERATIONAL CONDITION	ACTION	
1. PRIMARY CONTAINMENT ISOLATION					
a. Reactor Vessel Water Level-Low Low, Level 2	6A, 7, 8, 10(c)(d)	2	1, 2, 3 and #	20	
b. Reactor Vessel Water Level-Low Low Level 2 (ECCS - Division 3)	6B	4	1, 2, 3 and #	29	
c. Reactor Vessel Water Level-Low Low Low, Level 1 (ECCS - Division 1 and Division 2)	5(n)(o)	2	1, 2, 3 and #	29	1013
d. Drywell Pressure - High	6A, 7(c)(d)	2	1, 2, 3	20	
e. Drywell Pressure-High (ECCS - Division 1 and Division 2)	5(n)(o)	2	1, 2, 3	29	1013
f. Drywell Pressure-High (ECCS - Division 3)	6B	4	1, 2, 3	29	
g. Containment and Drywell Ventilation Exhaust Radiation - High High	7	2(e)	1, 2, 3 and *	21	
h. Manual Initiation	6A, 7, 8, 10(c)(d)	2	1, 2, 3 and *#	22	
2. MAIN STEAM LINE ISOLATION					
a. Reactor Vessel Water Level-Low Low Low, Level 1	1	2	1, 2, 3	20	
b. Main Steam Line Radiation - High	1, 10(f)	2	1, 2, 3	23	
c. Main Steam Line Pressure - Low	1	2	1	24	
d. Main Steam Line Flow - High	1	8	1, 2, 3	23	
e. Condenser Vacuum - Low	1	2	1, 2,** 3**	23	

TABLE 3.3.2-1 (Continued)

ISOLATION ACTUATION INSTRUMENTATION

TRIP FUNCTION	VALVE GROUPS OPERATED BY SIGNAL (a)	MINIMUM OPERABLE CHANNELS PER TRIP SYSTEM (b)	APPLICABLE OPERATIONAL CONDITION	ACTION
2. **MAIN STEAM LINE ISOLATION** (Continued)				
f. Main Steam Line Tunnel Temperature - High	1	2	1, 2, 3	23
g. Main Steam Line Tunnel Δ Temp.- High	1	2	1, 2, 3	23
h. Manual Initiation	1, 10	2	1, 2, 3	22
3. **SECONDARY CONTAINMENT ISOLATION**				
a. Reactor Vessel Water Level-Low Low, Level 2	N.A.$^{(c)(d)(h)}$	2	1, 2, 3, and #	25
b. Drywell Pressure - High	N.A.$^{(c)(d)(h)}$	2	1, 2, 3	25
c. Fuel Handling Area Ventilation Exhaust Radiation - High High	N.A.$^{(j)}$	2	1, 2, 3, and *	25
d. Fuel Handling Area Pool Sweep Exhaust Radiation - High High	N.A.$^{(j)}$	2	1, 2, 3, and *	25
e. Manual Initiation	N.A.$^{(c)(d)\cancel{(f)}g(h)}$ N.A.$^{(c)(d)\cancel{(f)}g(h)}$ N.A.	2 2	1, 2, 3 *	26 25
4. **REACTOR WATER CLEANUP SYSTEM ISOLATION**				
a. Δ Flow - High	8	1	1, 2, 3	27
b. Δ Flow Timer	8	1	1, 2, 3	27
c. Equipment Area Temperature - High	8	1/room	1, 2, 3	27
d. Equipment Area Δ Temp. - High	8	1/room	1, 2, 3	27
e. Reactor Vessel Water Level - Low Low, Level 2	8	2	1, 2, 3	27

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TABLE 3.3.2-1 (Continued)

ISOLATION ACTUATION INSTRUMENTATION

TRIP FUNCTION	VALVE GROUPS OPERATED BY SIGNAL (a)	MINIMUM OPERABLE CHANNELS PER TRIP SYSTEM (b)	APPLICABLE OPERATIONAL CONDITION	ACTION
4. REACTOR WATER CLEANUP SYSTEM ISOLATION (Continued)				
f. Main Steam Line Tunnel Ambient Temperature - High	8	1	1, 2, 3	27
g. Main Steam Line Tunnel Δ Temp. - High	8	1	1, 2, 3	27
h. SLCS Initiation	$8^{(i)}$	1	1, 2, 5##	30
i. Manual Initiation	8	2	1, 2, 3	26
5. REACTOR CORE ISOLATION COOLING SYSTEM ISOLATION				
a. RCIC Steam Line Flow - High	~~4~~	~~1~~	~~1, 2, 3~~	~~27~~
1. Pressure	4	1	1, 2, 3	27
2. Time Delay	4	1	1, 2, 3	27
b. RCIC Steam Supply Pressure - Low	$4, 9^{(m)}$	1	1, 2, 3	27
c. RCIC Turbine Exhaust Diaphragm Pressure - High	4	2	1, 2, 3	27
d. RCIC Equipment Room Ambient Temperature - High	4	1	1, 2, 3	27
e. RCIC Equipment Room Δ Temp. - High	4	1	1, 2, 3	27
f. Main Steam Line Tunnel Ambient Temperature - High	4	1	1, 2, 3	27
g. Main Steam Line Tunnel Δ Temp. - High	4	1	1, 2, 3	27
h. Main Steam Line Tunnel Temperature Timer	4	1	1, 2, 3	27

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Order

TABLE 3.3.2-1 (Continued)

ISOLATION ACTUATION INSTRUMENTATION

TRIP FUNCTION	VALVE GROUPS OPERATED BY SIGNAL (a)	MINIMUM OPERABLE CHANNELS PER TRIP SYSTEM (b)	APPLICABLE OPERATIONAL CONDITION	ACTION
5. REACTOR CORE ISOLATION COOLING SYSTEM ISOLATION				
i. RHR Equipment Room Ambient Temperature - High	4	1/room	1, 2, 3	27
j. RHR Equipment Room Δ Temp. - High	4	1/room	1, 2, 3	27
k. RHR/RCIC Steam Line Flow - High	4	1	1, 2, 3	27
l. Manual Initiation	$4^{(k)}$	1	1, 2, 3	26
m. Drywell Pressure-High (ECCS-Division 1 and Division 2)	$9^{(m)}$	1	1, 2, 3	27
6. RHR SYSTEM ISOLATION				
a. RHR Equipment Room Ambient Temperature - High	3	1/room	1, 2, 3	28
b. RHR Equipment Room Δ Temp. - High	3	1/room	1, 2, 3	28
c. Reactor Vessel Water Level - Low, Level 3	3	2	1, 2, 3	28
d. Reactor Vessel (RHR Cut-in Permissive) Pressure - High	$3^{(l)}$	2	1, 2, 3	28
e. Drywell Pressure - High	$3^{(l)}$	2	1, 2, 3	28
f. Manual Initiation	3	2	1, 2, 3	26

TABLE 3.3.2-1 (Continued)
ISOLATION ACTUATION INSTRUMENTATION

ACTION

ACTION 20 - Be in at least HOT SHUTDOWN within 12 hours and in COLD SHUTDOWN within the next 24 hours.

ACTION 21 - Close the affected system isolation valve(s) within one hour or:
- a. In OPERATIONAL CONDITION 1, 2, or 3, be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.
- b. In Operational Condition *, suspend CORE ALTERATIONS, handling of irradiated fuel in the primary containment and operations with a potential for draining the reactor vessel.

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ACTION 22 - Restore the manual initiation function to OPERABLE status within 48 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

ACTION 23 - Be in at least STARTUP with the associated isolation valves closed within 6 hours or be in at least HOT SHUTDOWN within 12 hours and in COLD SHUTDOWN within the next 24 hours.

ACTION 24 - Be in at least STARTUP within 6 hours.

ACTION 25 - Establish SECONDARY CONTAINMENT INTEGRITY with the standby gas treatment system operating within one hour.

ACTION 26 - Restore the manual initiation function to OPERABLE status within 8 hours or close the affected system isolation valves within the next hour and declare the affected system inoperable.

ACTION 27 - Close the affected system isolation valves within one hour and declare the affected system inoperable.

ACTION 28 - Within one hour Lock the affected system isolation valves closed ~~within one hour~~ and declare the affected system inoperable.

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, or verify, by remote indication, that the valve is closed ~~and~~ ~~valve closure and electrically~~ ~~de-energize the valves~~, or isolate the penetration(s) electrically ~~deenergized~~

ACTION 29 - Close the affected system isolation valves within one hour and declare the affected system or component inoperable or:
- a. In OPERATIONAL CONDITION 1, 2 or 3 be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.
- b. In OPERATIONAL CONDITION # suspend CORE ALTERATIONS and operations with a potential for draining the reactor vessel.

ACTION 30 - Declare the affected SLCS pump inoperable.

NOTES

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

** The low condenser vacuum MSIV closure may be manually bypassed during reactor SHUTDOWN or for reactor STARTUP when condenser vacuum is below the trip setpoint to allow opening of the MSIVs. The manual bypass shall be removed when condenser vacuum exceeds the trip setpoint.

\# During CORE ALTERATIONS and operations with a potential for draining the reactor vessel.

\#\# With any control rod withdrawn. Not applicable to control rods removed per Specification 3.9.10.1 or 3.9.10.2.

(a) See Specification 3.6.4, Table 3.6.4-1 for valves in each valve group.

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

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TABLE 3.3.2-1 (Continued)
ISOLATION ACTUATION INSTRUMENTATION

NOTES (Continued)

(c) Also actuates the standby gas treatment system.

(d) Also actuates the control room emergency filtration system in the isolation mode of operation.

(e) Two upscale-Hi Hi, one upscale-Hi Hi and one downscale, or two downscale signals from the same trip system actuate the trip system and initiate isolation of the associated containment and drywell isolation valves.

(f) Also trips and isolates the mechanical vacuum pumps.

(g) Deleted.

(h) Also actuates secondary containment ventilation isolation dampers and valves per Table 3.6.6.2-1.

(i) Closes only RWCU system isolation valves G33-F001, G33-F004, and G33-F251.

(j) Actuates the Standby Gas Treatment System and isolates Auxiliary Building penetration of the ventilation systems within the Auxiliary Building.

(k) Closes only RCIC outboard valves. A concurrent RCIC initiation signal is required for isolation to occur.

(l) Valves E12-F037A and E12-F037B are closed by high drywell pressure. All other Group 3 valves are closed by high reactor pressure.

(m) Valve Group 9 requires concurrent drywell high pressure and RCIC Steam Supply Pressure-Low signals to isolate.

(n) Valves E12-F042A and E12-F042B are closed by Containment Spray System initiation signals.

(o) Also isolates valves E61-F009, E61-F010, E61-F056, and E61-F057 from Valve Group 7. 013

TABLE 3.3.2-2

ISOLATION ACTUATION INSTRUMENTATION SETPOINTS

TRIP FUNCTION	TRIP SETPOINT	ALLOWABLE VALUE
1. PRIMARY CONTAINMENT ISOLATION		
a. Reactor Vessel Water Level - Low Low, Level 2	≥ -41.6 inches *	≥ -43.8 inches
b. Reactor Vessel Water Level- Low Low, Level 2 (ECCS - Division 3)	≥ -41.6 inches*	≥ -43.8 inches
c. Reactor Vessel Water Level- Low Low Low, Level 1 (ECCS Division 1 and Division 2)	≥ -150.3 inches*	≥ -152.5 inches
d. Drywell Pressure - High	≤ 1.23 psig	≤ 1.43 psig
e. Drywell Pressure-High (ECCS - Division 1 and Division 2)	≤ 1.39 psig	≤ 1.44 psig
f. Drywell Pressure-High (ECCS - Division 3)	≤ 1.39 psig	≤ 1.44 psig
g. Containment and Drywell Ventilation Exhaust Radiation - High High	≤ ~~2.0~~ 3.6 mr/hr**	≤ 4.0 mr/hr**
h. Manual Initiation	NA	NA
2. MAIN STEAM LINE ISOLATION		
a. Reactor Vessel Water Level - Low Low Low, Level 1	≥ -150.3 inches*	≥ -152.5 inches
b. Main Steam Line Radiation - High	≤ 3.0 x full power background	≤ 3.6 x full power background
c. Main Steam Line Pressure - Low	≥ 849 psig	≥ 837 psig
d. Main Steam Line Flow - High	≤ 169 psid	≤ 176.5 psid
e. Condenser Vacuum - Low	≥ 9 inches Hg. Vacuum	≥ 8.7 inches Hg. Vacuum
f. Main Steam Line Tunnel Temperature - High	≤ 185°F**	≤ 191°F**

TABLE 3.3.2-2 (Continued)

ISOLATION ACTUATION INSTRUMENTATION SETPOINTS

TRIP FUNCTION	TRIP SETPOINT	ALLOWABLE VALUE	
2. **MAIN STEAM LINE ISOLATION** (Continued)			
g. Main Steam Line Tunnel Δ Temp. - High	≤ 101°F**	≤ 104°F**	
h. Manual Initiation	NA	NA	
3. **SECONDARY CONTAINMENT ISOLATION**			
a. Reactor Vessel Water Level - Low Low, Level 2	≥ -41.6 inches*	≥ -43.8 inches	
b. Drywell Pressure - High	≤ 1.23 psig	≤ 1.43 psig	
c. Fuel Handling Area Ventilation Exhaust Radition - High High	≤ ~~2.0~~ 3.6 mR/hr**	≤ 4.0 mR/hr**	
d. Fuel Handling Area Pool Sweep Exhaust Radiation - High High	≤ ~~18~~ 30 mR/hr**	≤ 35 mR/hr**	
e. Manual Initiation	NA	NA	
4. **REACTOR WATER CLEANUP SYSTEM ISOLATION**			
a. Δ Flow - High	≤ 79 gpm	≤ 89** gpm	
b. Δ Flow Timer	≤ 45 seconds	≤ 57 seconds	
c. Equipment Area Temperature - High			
1. RWCU Hx Room	≤ 120°F	≤ 126°F	
2. RWCU Pump Rooms	≤ 170°F	≤ 176°F	
3. RWCU Valve Nest Room	≤ 135°F	≤ 141°F	
~~4. RWCU Demin. Rooms~~	~~≤ 130°F~~	~~≤ 145°F~~	308
~~5. RWCU Rec. Tank Room~~	~~≤ 139°F~~	~~≤ 145°F~~	
~~6. RWCU Demin. Valve Room~~	~~≤ 135°F~~	~~≤ 141°F~~	
d. Equipment Area Δ Temp. - High			
1. RWCU Hx Room	≤ 65°F	≤ 66°F	
2. RWCU Pump Rooms	≤ 115°F	≤ 118°F	
3. RWCU Valve Nest Room	≤ 70°F	≤ 73°F	
~~4. RWCU Demin. Rooms~~	~~≤ 70°F~~	~~≤ 73°F~~	
~~5. RWCU Rec. Tank Room~~	~~≤ 70°F~~	~~≤ 73°F~~	308
~~6. RWCU Demin. Valve Room~~	~~≤ 71°F~~	~~≤ 74°F~~	

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TABLE 3.3.2-2 (Continued)

ISOLATION ACTUATION INSTRUMENTATION SETPOINTS

TRIP FUNCTION		TRIP SETPOINT	ALLOWABLE VALUE	
4.	**REACTOR WATER CLEANUP SYSTEM ISOLATION** (Continued)			
e.	Reactor Vessel Water Level - Low Low, Level 2	≥ -41.6 inches*	≥ -43.8 inches	
f.	Main Steam Line Tunnel Ambient Temperature - High	≤ 185°F**	≤ 191°F**	
g.	Main Steam Line Tunnel Δ Temp. - High	≤ 101°F**	≤ 104°F**	
h.	SLCS Initiation	NA	NA	
i.	Manual Initiation	NA	NA	
5.	**REACTOR CORE ISOLATION COOLING SYSTEM ISOLATION**			
a.	RCIC Steam Line Flow - High	~~≤ 363" H_2O~~	~~≤ 371" H_2O~~	
	1. Pressure	≤363" H_2O	≤ 371" H_2O	
	2. Time Delay	5±2 seconds	5 ± 2 seconds	
b.	RCIC Steam Supply Pressure - Low	≥ 60 psig	≥ 53 psig	/110
c.	RCIC Turbine Exhaust Diaphragm Pressure - High	≤ 10 psig	≤ 20 psig	
d.	RCIC Equipment Room Ambient Temperature - High	≤ 185°F**	≤ 191°F**	
e.	RCIC Equipment Room Δ Temp. - High	≤ 125°F**	≤ 128°F**	
f.	Main Steam Line Tunnel Ambient Temperature - High	≤ 185°F**	≤ 191°F**	
g.	Main Steam Line Tunnel Δ Temp. - High	≤ 101°F**	≤ 104°F**	
h.	Main Steam Line Tunnel Temperature Timer	≤ 30 minutes	≤ 30 minutes	
i.	RHR Equipment Room Ambient Temperature - High	≤ 165°F**	≤ 171°F**	
j.	RHR Equipment Room Δ Temperature - High	≤ 99°F**	≤ 102°F**	
k.	RHR/RCIC Steam Line Flow - High	≤ 145" H_2O	≤ ~~160~~ 151" H_2O	/315

TABLE 3.3.2-2 (Continued)

ISOLATION ACTUATION INSTRUMENTATION SETPOINTS

TRIP FUNCTION		TRIP SETPOINT	ALLOWABLE VALUE
5.	**REACTOR CORE ISOLATION COOLING SYSTEM ISOLATION** (Continued)		
l.	Manual Initiation	NA	NA
m.	Drywell Pressure-High (ECCS Division 1 and Division 2)	≤ 1.39 psig	≤ 1.44 psig
6.	**RHR SYSTEM ISOLATION**		
a.	RHR Equipment Room Ambient Temperature - High	≤ 165°F**	≤ 171°F**
b.	RHR Equipment Room Δ Temperature - High	≤ 99°F**	≤ 102°F**
c.	Reactor Vessel Water Level - Low, Level 3	≥ 11.4 inches*	≥ 10.8 inches
d.	Reactor Vessel (RHR Cut-in Permissive) Pressure - High	≤ 135 psig	≤ 150 psig
e.	Drywell Pressure - High	≤ 1.23 psig	≤ 1.43 psig
f.	Manual Initiation	NA	NA

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

**Initial setpoint. Final setpoint to be determined during startup test program. Any required change to this setpoint shall be submitted to the Commission within 90 days of test completion.

TABLE 3.3.2-3

ISOLATION SYSTEM INSTRUMENTATION RESPONSE TIME

TRIP FUNCTION	RESPONSE TIME (Seconds)#
1. PRIMARY CONTAINMENT ISOLATION	
a. Reactor Vessel Water Level - Low Low, Level 2	≤ ~~13~~ 10 (a)
b. Reactor Vessel Water Level - Low Low, Level 2 (ECCS - Division 3)	≤ ~~13~~ 10 (a)
c. Reactor Vessel Water Level-Low Low Low, Level 1 (ECCS - Division 1 and Division 2)	≤ ~~13~~ 10 (a)
d. Drywell Pressure - High	≤ ~~13~~ 10 (a)
e. Drywell Pressure-High (ECCS - Division 1 and Division 2)	≤ ~~13~~ 10 (a)
f. Drywell Pressure-High (ECCS - Division 3)	≤ ~~13~~ 10 (a)
g. Containment and Drywell Ventilation Exhaust Radiation - High High(b)	≤ ~~13~~ 10 (a)**
h. Manual Initiation	NA
2. MAIN STEAM LINE ISOLATION	
a. Reactor Vessel Water Level - Low Low Low, Level 1	≤ 1.0*/≤ ~~13~~ 10 (a)**
b. Main Steam Line Radiation - High(b)	≤ 1.0*/≤ ~~13~~ (a)** 10
c. Main Steam Line Pressure - Low	≤ 1.0*/≤ ~~13~~ (a)** 10
d. Main Steam Line Flow - High	≤ 0.5*/≤ ~~13~~ (a)** 10
e. Condenser Vacuum - Low	NA
f. Main Steam Line Tunnel Temperature - High	NA
g. Main Steam Line Tunnel Δ Temp. - High	NA
h. Manual Initiation	NA
3. SECONDARY CONTAINMENT ISOLATION	
a. Reactor Vessel Water Level - Low Low, Level 2	≤ ~~13~~ 10 (a)
b. Drywell Pressure - High	≤ ~~13~~ 10 (a)
c. Fuel Handling Area Ventilation Exhaust Radiation - High High(b)	≤3.0**/≤ ~~13~~ 10 (a)
d. Fuel Handling Area Pool Sweep Exhaust Radiation - High High(b)	≤3.0**/≤ ~~13~~ 10 (a)
e. Manual Initiation	NA
4. REACTOR WATER CLEANUP SYSTEM ISOLATION	
a. Δ Flow - High	NA
b. Δ Flow Timer	NA
c. Equipment Area Temperature - High	NA
d. Equipment Area Δ Temp. - High	NA
e. Reactor Vessel Water Level - Low Low, Level 2	≤ ~~13~~ 10 (a)
f. Main Steam Line Tunnel Ambient Temperature - High	NA
g. Main Steam Line Tunnel Δ Temp. - High	NA
h. SLCS Initiation	NA
i. Manual Initiation	NA

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TABLE 3.3.2-3 (Continued)

ISOLATION SYSTEM INSTRUMENTATION RESPONSE TIME

TRIP FUNCTION	RESPONSE TIME (Seconds)#	
5. REACTOR CORE ISOLATION COOLING SYSTEM ISOLATION		
a. RCIC Steam Line Flow - High	≤ ~~13~~ 10(a)###	1040
b. RCIC Steam Supply Pressure - Low	≤ ~~13~~(a)	
c. RCIC Turbine Exhaust Diaphragm Pressure - High	NA 10	
d. RCIC Equipment Room Ambient Temperature - High	NA	
e. RCIC Equipment Room Δ Temp. - High	NA	
f. Main Steam Line Tunnel Ambient Temp. - High	NA	
g. Main Steam Line Tunnel Δ Temp. - High	NA	
h. Main Steam Line Tunnel Temperature Timer	NA	
i. RHR Equipment Room Ambient Temperature - High	NA	
j. RHR Equipment Room Δ Temp. - High	NA	
k. RHR/RCIC Steam Line Flow - High	NA	
l. Manual Initiation	NA	
m. Drywell Pressure - High (ECCS Division 1 and Division 2)	≤ ~~13~~(a) 10	1040
6. RHR SYSTEM ISOLATION		
a. RHR Equipment Room Ambient Temperature - High	NA	
b. RHR Equipment Room Δ Temp. - High	NA	
c. Reactor Vessel Water Level - Low, Level 3	≤ ~~13~~(a) 10	1040
d. Reactor Vessel (RHR Cut-in Permissive) Pressure - High	NA	
e. Drywell Pressure - High	NA	
f. Manual Initiation	NA	

(a) The isolation system instrumentation response time shall be measured and recorded as a part of the ISOLATION SYSTEM RESPONSE TIME. Isolation system instrumentation response time specified includes the delay for diesel generator starting assumed in the accident analysis.

(b) Radiation detectors are exempt from response time testing. Response time shall be measured from detector output or the input of the first electronic component in the channel.

*Isolation system instrumentation response time for MSIVs only. No diesel generator delays assumed.

**Isolation system instrumentation response time for associated valves except MSIVs.

*** Isolation system instrumentation response time for air operated dampers. No diesel generator delays assumed.

#Isolation system instrumentation response time specified for the Trip Function actuating each valve group shall be added to isolation time shown in Tables 3.6.4-1 and 3.6.~~5~~6.2-1 for valves in each valve group to obtain ISOLATION SYSTEM RESPONSE TIME for each valve.

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###~~Without 13 second time delay~~.

~~###~~ Includes time delay of 5 to 7 seconds.

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 Low, Level 2	S	M	$R^{(c)}$	1, 2, 3 and #
b. Reactor Vessel Water Level-Low Low, Level 2 (ECCS - Division 3)	S	M	$R^{(c)}$	1, 2, 3 and #
c. Reactor Vessel Water Level-Low Low Low, Level 1 (ECCS - Division 1 and Division 2)	S	M	$R^{(c)}$	1, 2, 3 and #
d. Drywell Pressure - High	S	M	$R^{(c)}$	1, 2, 3
e. Drywell Pressure-High (ECCS - Division 1 and Division 2)	S	M	$R^{(c)}$	1, 2, 3
f. Drywell Pressure-High (ECCS - Division 3)	S	M	$R^{(c)}$	1, 2, 3
g. Containment and Drywell Ventilation Exhaust Radiation - High High	S	M	A	1, 2, 3 and *
h. Manual Initiation	NA	$M^{(a)}$	NA	1, 2, 3 and *#
2. MAIN STEAM LINE ISOLATION				
a. Reactor Vessel Water Level - Low Low Low, Level 1	S	M	$R^{(c)}$	1, 2, 3
b. Main Steam Line Radiation - High	S	M	R	1, 2, 3
c. Main Steam Line Pressure - Low	S	M	$R^{(c)}$	1
d. Main Steam Line Flow - High	S	M	$R^{(c)}$	1, 2, 3
e. Condenser Vacuum - Low	S	M	$R^{(c)}$	1, 2**, 3**

TABLE 4.3.2.1-1 (Continued)

ISOLATION ACTUATION INSTRUMENTATION SURVEILLANCE REQUIREMENTS

TRIP FUNCTION	CHANNEL CHECK	CHANNEL FUNCTIONAL TEST	CHANNEL CALIBRATION	OPERATIONAL CONDITIONS IN WHICH SURVEILLANCE REQUIRED
2. MAIN STEAM LINE ISOLATION (Continued)				
f. Main Steam Line Tunnel Temperature - High	S	M	A	1, 2, 3
g. Main Steam Line Tunnel Δ Temp. - High	S	M	A	1, 2, 3
h. Manual Initiation	NA	$M^{(a)}$	NA	1, 2, 3
3. SECONDARY CONTAINMENT ISOLATION				
a. Reactor Vessel Water Level - Low Low, Level 2	S	M	$R^{(c)}$	1, 2, 3 and #
b. Drywell Pressure - High	S	M	$R^{(c)}$	1, 2, 3
c. Fuel Handling Area Ventilation Exhaust Radiation - High High	S	M	A	1, 2, 3 and *
d. Fuel Handling Area Pool Sweep Exhaust Radiation - High High	S	M	A	1, 2, 3 and *
e. Manual Initiation	NA	$M^{(a)}$	NA	1, 2, 3 and *
4. REACTOR WATER CLEANUP SYSTEM ISOLATION				
a. Δ Flow - High	S	M	R	1, 2, 3
b. Δ Flow Timer	NA	M	Q	1, 2, 3
c. Equipment Area Temperature - High	S	M	A	1, 2, 3
d. Equipment Area Ventilation Δ Temp. - High	S	M	A	1, 2, 3
e. Reactor Vessel Water Level - Low Low, Level 2	S	M	$R^{(c)}$	1, 2, 3

TABLE 4.3.2.1-1 (Continued)

ISOLATION ACTUATION INSTRUMENTATION SURVEILLANCE REQUIREMENTS

TRIP FUNCTION	CHANNEL CHECK	CHANNEL FUNCTIONAL TEST	CHANNEL CALIBRATION	OPERATIONAL CONDITIONS IN WHICH SURVEILLANCE REQUIRED
4. REACTOR WATER CLEANUP SYSTEM ISOLATION (Continued)				
f. Main Steam Line Tunnel Ambient Temperature - High	S	M	A	1, 2, 3
g. Main Steam Line Tunnel Δ Temp. - High	S	M	A	1, 2, 3
h. SLCS Initiation	NA	M$^{(b)}$	NA	1, 2, 5##
i. Manual Initiation	NA	M$^{(a)}$	NA	1, 2, 3
5. REACTOR CORE ISOLATION COOLING SYSTEM ISOLATION				
a. RCIC Steam Line Flow - High	~~S~~	~~M~~	~~R$^{(c)}$~~	~~1, 2, 3~~
b. RCIC Steam Supply Pressure - Low	S	M	R$^{(c)}$	1, 2, 3
c. RCIC Turbine Exhaust Diaphragm Pressure - High	S	M	R$^{(c)}$	1, 2, 3
d. RCIC Equipment Room Ambient Temperature - High	S	M	A	1, 2, 3
e. RCIC Equipment Room Δ Temp. - High	S	M	A	1, 2, 3
f. Main Steam Line Tunnel Ambient Temperature - High	S	M	A	1, 2, 3
g. Main Steam Line Tunnel Δ Temp. - High	S	M	A	1, 2, 3
1. Pressure	S	M	R$^{(c)}$	1,2,3
2. Time Delay	S	M	Q	1,2,3

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TABLE 4.3.2.1-1 (Continued)

ISOLATION ACTUATION INSTRUMENTATION SURVEILLANCE REQUIREMENTS

TRIP FUNCTION	CHANNEL CHECK	CHANNEL FUNCTIONAL TEST	CHANNEL CALIBRATION	OPERATIONAL CONDITIONS IN WHICH SURVEILLANCE REQUIRED
5. REACTOR CORE ISOLATION COOLING SYSTEM ISOLATION (Continued)				
h. Main Steam Line Tunnel Temperature Timer	NA	M	Q	1, 2, 3
i. RHR Equipment Room Ambient Temperature - High	S	M	A	1, 2, 3
j. RHR Equipment Room Δ Temp. - High	S	M	A	1, 2, 3
k. RHR/RCIC Steam Line Flow - High	S	M	$R^{(c)}$	1, 2, 3
l. Manual Initiation	NA	$M^{(a)}$	NA	1, 2, 3
m. Drywell Pressure-High (ECCS Division 1 and Division 2)	S	M	$R^{(c)}$	1, 2, 3
6. RHR SYSTEM ISOLATION				
a. RHR Equipment Room Ambient Temperature - High	S	M	A	1, 2, 3
b. RHR Equipment Room Δ Temp. - High	S	M	A	1, 2, 3
c. Reactor Vessel Water Level - Low, Level 3	S	M	$R^{(c)}$	1, 2, 3
d. Reactor Vessel (RHR Cut-in Permissive) Pressure - High	S	M	$R^{(c)}$	1, 2, 3

TABLE 4.3.2.1-1 (Continued)

ISOLATION ACTUATION INSTRUMENTATION SURVEILLANCE REQUIREMENTS

TRIP FUNCTION	CHANNEL CHECK	CHANNEL FUNCTIONAL TEST	CHANNEL CALIBRATION	OPERATIONAL CONDITIONS IN WHICH SURVEILLANCE REQUIRED
6. **RHR SYSTEM ISOLATION** (Continued)				
e. Drywell Pressure - High	S	M	$R^{(c)}$	1, 2, 3
f. Manual Initiation	NA	$M^{(a)}$	NA	1, 2, 3

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

**The low condenser vacuum MSIV closure may be [redacted] manually bypassed during reactor SHUTDOWN or for reactor STARTUP when condenser vacuum is below the trip setpoint to allow opening of the MSIVs. The manual bypass shall be removed when condenser vacuum exceeds the trip setpoint. /074

#During CORE ALTERATION and operations with a potential for draining the reactor vessel.

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

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

(b) Each train or logic channel shall be tested at least every other 31 days.

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

3/4.3.3 EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

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

APPLICABILITY: As shown in Table 3.3.3-1.

ACTION:

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

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

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

   1. 7 days, provided that the HPCS and RCIC systems are OPERABLE.
   2. 72 hours.

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

SURVEILLANCE REQUIREMENTS

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

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

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

TABLE 3.3.3-1

EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION

TRIP FUNCTION	MINIMUM OPERABLE CHANNELS PER TRIP FUNCTION$^{(a)}$	APPLICABLE OPERATIONAL CONDITIONS	ACTION	
A. DIVISION I TRIP SYSTEM				
1. RHR-A (LPCI MODE) & LPCS SYSTEM				
a. Reactor Vessel Water Level - Low Low Low, Level 1	$2^{(b)}$	1, 2, 3, 4*, 5*	30	
b. Drywell Pressure - High	$2^{(b)}$	1, 2, 3	30	
c. LPCI Pump A Start Time Delay Relay	1	1, 2, 3, 4*, 5*	31	1278
d. Manual Initiation	1/system (b)	1, 2, 3, 4*, 5*	32	
2. AUTOMATIC DEPRESSURIZATION SYSTEM TRIP SYSTEM "A"#				
a. Reactor Vessel Water Level - Low Low Low, Level 1	$2^{(b)}$	1, 2, 3	30	
b. Drywell Pressure - High	$2^{(b)}$	1, 2, 3	30	
c. ADS Timer	1	1, 2, 3	31	
d. Reactor Vessel Water Level - Low, Level 3 (Permissive)	1	1, 2, 3	31	
e. LPCS Pump Discharge Pressure-High (Permissive)	2	1, 2, 3	31	
f. LPCI Pump A Discharge Pressure-High (Permissive)	2	1, 2, 3	31	
g. Manual Initiation	2/system	1, 2, 3	32	
B. DIVISION 2 TRIP SYSTEM				
1. RHR B & C (LPCI MODE)				
a. Reactor Vessel Water Level - Low, Low Low, Level 1	$2^{(b)}$	1, 2, 3, 4*, 5*	30	
b. Drywell Pressure - High	$2^{(b)}$	1, 2, 3	30	
c. LPCI Pump B Start Time Delay Relay	1	1, 2, 3, 4*, 5*	31	
d. Manual Initiation	1/system (b)	1, 2, 3, 4*, 5*	32	1278
2. AUTOMATIC DEPRESSURIZATION SYSTEM TRIP SYSTEM "B"#				
a. Reactor Vessel Water Level - Low Low Low, Level 1	$2^{(b)}$	1, 2, 3	30	
b. Drywell Pressure - High	$2^{(b)}$	1, 2, 3	30	
c. ADS Timer	1	1, 2, 3	31	
d. Reactor Vessel Water Level - Low, Level 3 (Permissive)	1	1, 2, 3	31	
e. LPCI Pump B and C Discharge Pressure - High (Permissive)	2/pump	1, 2, 3	31	
f. Manual Initiation	2/system	1, 2, 3	32	

TABLE 3.3.3-1 (Continued)

EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION

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

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

TABLE 3.3.3-1 (Continued)

EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION

ACTION

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

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

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

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

ACTION 32 - With the number of OPERABLE channels less than required by the Minimum OPERABLE Channels per Trip Function requirement, restore the inoperable channel to OPERABLE status within 8 hours or declare the associated ADS trip system or ECCS inoperable.

ACTION 33 - With the number of OPERABLE channels less than required by the Minimum OPERABLE Channels per Trip Function requirement,

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a. For one trip system, place that trip system in the tripped condition within one hour* or declare the HPCS system inoperable.

b. For both trip systems, declare the HPCS system inoperable.

ACTION 34 - With the number of OPERABLE channels less than required by the Minimum OPERABLE Channels per Trip Function requirement, place at least one inoperable channel in the tripped condition within one hour* or declare the HPCS system inoperable.

---

*The provisions of Specification 3.0.4 are not applicable.

place the inoperable channel(s) in the tripped condition within one hour* or declare the HPCS system inoperable.

TABLE 3.3.3-2

EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION SETPOINTS

TRIP FUNCTION	TRIP SETPOINT	ALLOWABLE VALUE	
A. DIVISION 1 TRIP SYSTEM			
1. RHR-A (LPCI MODE) AND LPCS SYSTEM			
a. Reactor Vessel Water Level - Low Low Low, Level 1	≥ -150.3 inches*	≥ -152.5 inches	
b. Drywell Pressure - High	≤ 1.39 psig	≤ 1.44 psig	
c. LPCI Pump A Start Time Delay Relay	≤ 5 seconds	≤ 5.25 seconds	
d. Manual Initiation	NA	NA	
2. AUTOMATIC DEPRESSURIZATION SYSTEM TRIP SYSTEM "A"			
a. Reactor Vessel Water Level - Low Low Low, Level 1	≥ -150.3 inches*	≥ -152.5 inches	
b. Drywell Pressure - High	≤ 1.39 psig	≤ 1.44 psig	
c. ADS Timer	≤ 105 seconds	≤ 117 seconds	
d. Reactor Vessel Water Level-Low, Level 3	≥ 11.4 inches*	≥ 10.8 inches	
e. LPCS Pump Discharge Pressure-High	145 psig, increasing	125-165 psig, increasing	
f. LPCI Pump A Discharge Pressure-High	125 psig, increasing	115-135 psig, increasing	
g. Manual Initiation	NA	NA	
B. DIVISION 2 TRIP SYSTEM			
1. RHR B AND C (LPCI MODE)			
a. Reactor Vessel Water Level - Low Low Low, Level 1	≥ -150.3 inches*	≥ -152.5 inches	
b. Drywell Pressure - High	≤ 1.39 psig	≤ 1.44 psig	
c. LPCI Pump B Start Time Delay Relay	≤ 5 seconds	≤ 5.25 seconds	
d. Manual Initiation	NA	NA	
2. AUTOMATIC DEPRESSURIZATION SYSTEM TRIP SYSTEM "B"			
a. Reactor Vessel Water Level - Low Low Low, Level 1	≥ -150.3 inches*	≥ -152.5 inches	
b. Drywell Pressure - High	≤ 1.39 psig	≤ 1.44 psig	
c. ADS Timer	≤ 105 seconds	≤ 117 seconds	
d. Reactor Vessel Water Level-Low, Level 3	≥ 11.4 inches*	≥ 10.8 inches	
e. LPCI Pump B and C Discharge Pressure-High	125 psig, increasing	~~115~~ psig, increasing	
f. Manual Initiation	NA	NA 115-135	1075
C. DIVISION 3 TRIP SYSTEM			
1. HPCS SYSTEM			
a. Reactor Vessel Water Level - Low Low, Level 2	≥-41.6 inches*	≥-43.8 inches	
b. Drywell Pressure - High	≤ 1.39 psig	≤ 1.44 psig	
c. Reactor Vessel Water Level - High, Level 8	≤ 53.5 inches*	≤ 55.7 inches	
d. Condensate Storage Tank Level - Low	≥ 0 inches	≥ -3 inches	
e. Suppression Pool Water Level - High	≤ 5.9 inches	≤ ~~6.5~~ inches	
f. Manual Initiation	NA	NA 7.0	1114

TABLE 3.3.3-2 (Continued)

EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION SETPOINTS

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

---

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

~~#These are inverse time delay voltage relays or instantaneous voltage relays with a time delay. The voltages shown are the maximum that will not result in a trip. Lower voltage conditions will result in decreased trip times.~~

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TABLE 3.3.3-3

EMERGENCY CORE COOLING SYSTEM RESPONSE TIMES (SECONDS)

1. LOW PRESSURE CORE SPRAY SYSTEM	$\leq$ 40
2. LOW PRESSURE COOLANT INJECTION MODE OF RHR SYSTEM PUMPS A, B AND C	$\leq$ 40
3. AUTOMATIC DEPRESSURIZATION SYSTEM	NA
4. HIGH PRESSURE CORE SPRAY SYSTEM	$\leq$ 27
5. LOSS OF POWER	NA

TABLE 4.3.3.1-1

EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION SURVEILLANCE REQUIREMENTS

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

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TABLE 4.3.3.1-1 (Continued)

EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION SURVEILLANCE REQUIREMENTS

TRIP FUNCTION	CHANNEL CHECK	CHANNEL FUNCTIONAL TEST	CHANNEL CALIBRATION	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRED
B. DIVISION 2 TRIP SYSTEM (Continued)				
2. AUTOMATIC DEPRESSURIZATION SYSTEM TRIP SYSTEM "B"#				
a. Reactor Vessel Water Level - Low Low Low, Level 1	S	M	$R^{(a)}$	1, 2, 3
b. Drywell Pressure-High	S	M	$R^{(a)}$	1, 2, 3
c. ADS Timer	NA	M	Q	1, 2, 3
d. Reactor Vessel Water Level - Low, Level 3	S	M	$R^{(a)}$	1, 2, 3
e. LPCI Pump B and C Discharge Pressure-High	S	M	$R^{(a)}$	1, 2, 3
f. Manual Initiation	NA	$R^{(b)}$	NA	1, 2, 3
C. DIVISION 3 TRIP SYSTEM				
1. HPCS SYSTEM				
a. Reactor Vessel Water Level - Low Low, Level 2	S	M	$R^{(a)}$	1, 2, 3, 4*, 5*
b. Drywell Pressure-High##	S	M	$R^{(a)}$	1, 2, 3
c. Reactor Vessel Water Level-High, Level 8	S	M	$R^{(a)}$	1, 2, 3, 4*, 5*
d. Condensate Storage Tank Level - Low	S	M	$R^{(a)}$	1, 2, 3, 4*, 5*
e. Suppression Pool Water Level - High	S	M	$R^{(a)}$	1, 2, 3, 4*, 5*
f. Manual Initiation##	NA	$R^{(b)}$	NA	1, 2, 3, 4*, 5*
D. LOSS OF POWER				
1. Division 1 and 2				
a. 4.16 kV Bus Undervoltage (Loss of Voltage)	NA	$M^{(e)}$	R	1, 2, 3, 4**, 5**
b. 4.16 kV Bus Undervoltage (BOP Load Shed)	NA	$M^{(e)}$	R	1, 2, 3, 4**, 5**
c. 4.16 kV Bus Undervoltage (Degraded Voltage)	NA	$M^{(e)}$	R	1, 2, 3, 4**, 5**
2. Division 3				
a. 4.16 kV Bus Undervoltage (Loss of Voltage)	NA	NA	R	1, 2, 3, 4**, 5**

TABLE 4.3.3.1-1 (Continued)

EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION SURVEILLANCE REQUIREMENTS

NOTATION

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

\#\# Prior to STARTUP following the first refueling outage, the injection function of Drywell Pressure - High and Manual Initiation are not required to be OPERABLE with indicated reactor vessel water level on the wide range instrument greater than Level 8 setpoint coincident with the reactor pressure less than 600 psig.

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

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

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

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

(c) ~~Manual initiation test shall include verification of the OPERABILITY of the LPCS and LPCI injection valve interlocks. (See Note 1)~~ | 206

(d) ~~This calibration shall consist of the CHANNEL CALIBRATION of the LPCS and LPCI injection valve interlocks with the interlock setpoint verified to be ≤ 150 psig. (See Note 1)~~

(e) Functional Testing of Time Delay Not Required

~~Note 1. Until restart after the first refueling outage, the requirements of (c) and (d) above do not apply.~~

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b. With the number of OPERABLE channels one less than ~~required by the Required Number of Channels per Trip System requirement for one or both trip systems,~~ restore the ~~inoperable channel(s) to OPERABLE status~~ within 14 days or be in at least STARTUP within the next 6 hours.

3/4.3.4 RECIRCULATION PUMP TRIP ACTUATION INSTRUMENTATION

ATWS RECIRCULATION PUMP TRIP SYSTEM INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.4.1 The anticipated transient without scram recirculation pump trip (ATWS-RPT) system instrumentation channels shown in Table 3.3.4.1-1 shall be OPERABLE with their trip setpoints set consistent with values shown in the Trip Setpoint column of Table 3.3.4.1-2.

APPLICABILITY: OPERATIONAL CONDITION 1.

ACTION:

a. With an ATWS-RPT system instrumentation channel trip setpoint less conservative than the value shown in the Allowable Values column of Table 3.3.4.1-2, declare the channel inoperable until the channel is restored to OPERABLE status with the channel setpoint adjusted consistent with the Trip Setpoint value.

022 b. ~~b.~~ With the number of OPERABLE channels one less than required by the Minimum OPERABLE Channels per Trip System requirement for one ~~or both trip systems, place the inoperable channel(s) in the tripped condition within one hour.~~ or both trip system(s) restore the inoperable channel 14 to OPERABLE status within [illegible] days or be in at least STARTUP within the next 6 hours

~~c. With the number of OPERABLE channels two or more less than required by the Minimum OPERABLE Channels per Trip System requirement for one trip system and:~~

~~1. If the inoperable channels consist of one reactor vessel water level channel and one reactor vessel pressure channel, place both inoperable channels in the tripped condition within one hour.~~

~~2. If the inoperable channels include two reactor vessel water level channels or two reactor vessel pressure channels, declare the trip system inoperable.~~

~~d. With one trip system inoperable, restore the inoperable trip system to OPERABLE status within 72 hours or be in at least STARTUP within the next 6 hours.~~

~~e. With both trip systems inoperable, restore at least one trip sytem to OPERABLE status within one hour or be in at least STARTUP within the next 6 hours.~~

SURVEILLANCE REQUIREMENTS

4.3.4.1.1 Each ATWS recirculation pump trip system instrumentation channel shall be demonstrated OPERABLE by the performance of the CHANNEL CHECK, CHANNEL FUNCTIONAL TEST, and CHANNEL CALIBRATION operations at the frequencies shown in Table 4.3.4.1-1.

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

TABLE 3.3.4.1-1

ATWS RECIRCULATION PUMP TRIP SYSTEM INSTRUMENTATION

TRIP FUNCTION	MINIMUM OPERABLE CHANNELS PER TRIP SYSTEM(a)
1. Reactor Vessel Water Level - Low Low, Level 2	1 [redacted]
2. Reactor Vessel Pressure - High	2 [redacted]

Skt
add

~~Required Number of Channels Per Trip System(a)~~

~~2~~

(a) One channel may be placed in an inoperable status for up to 2 hours for required surveillance provided the other channel is OPERABLE.

TABLE 3.3.4.1-2

ATWS RECIRCULATION PUMP TRIP SYSTEM INSTRUMENTATION SETPOINTS

TRIP FUNCTION	TRIP SETPOINT	ALLOWABLE VALUE
1. Reactor Vessel Water Level - Low Low, Level 2	≥ -41.6 inches*	≥ -43.8 inches
2. Reactor Vessel Pressure - High	≤ 1125 psig	≤ 1140 psig

---

*See Bases Figure B3/4 3-1.

TABLE 4.3.4.1-1

ATWS RECIRCULATION PUMP TRIP ACTUATION INSTRUMENTATION SURVEILLANCE REQUIREMENTS

TRIP FUNCTION	CHANNEL CHECK	CHANNEL FUNCTIONAL TEST	CHANNEL CALIBRATION
1. Reactor Vessel Water Level - Low Low, Level 2	S	M	R*
2. Reactor Vessel Pressure - High	S	M	R*

---

*Calibrate trip unit at least once per 31 days.

END-OF-CYCLE RECIRCULATION PUMP TRIP SYSTEM INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.4.2 The end-of-cycle recirculation pump trip (EOC-RPT) system instrumentation channels shown in Table 3.3.4.2-1 shall be OPERABLE with their trip setpoints set consistent with the values shown in the Trip Setpoint column of Table 3.3.4.2-2 and with the END-OF-CYCLE RECIRCULATION PUMP TRIP SYSTEM RESPONSE TIME as shown in Table 3.3.4.2-3.

APPLICABILITY: OPERATIONAL CONDITION 1, when THERMAL POWER is greater than or equal to 40% of RATED THERMAL POWER.

ACTION:

a. With an end-of-cycle recirculation pump trip system instrumentation channel trip setpoint less conservative than the value shown in the Allowable Values column of Table 3.3.4.2-2, declare the channel inoperable until the channel is restored to OPERABLE status with the channel setpoint adjusted consistent with the Trip Setpoint value.

b. With the number of OPERABLE channels one less than required by the Minimum OPERABLE Channels per Trip System requirement for one or both trip systems, place the inoperable channel(s) in the tripped condition within one hour.

c. With the number of OPERABLE channels two or more less than required by the Minimum OPERABLE Channels per Trip System requirement for one trip system and:

    1. If the inoperable channels consist of one turbine control valve channel and one turbine stop valve channel, place both inoperable channels in the tripped condition within one hour.

    2. If the inoperable channels include two turbine control valve channels or two turbine stop valve channels, declare the trip system inoperable.

d. With one trip system inoperable, restore the inoperable trip system to OPERABLE status within 72 hours or reduce THERMAL POWER to less than 40% of RATED THERMAL POWER within the next 6 hours.

e. With both trip systems inoperable, restore at least one trip system to OPERABLE status within one hour or reduce THERMAL POWER to less than 40% of RATED THERMAL POWER within the next 6 hours.

SURVEILLANCE REQUIREMENTS

4.3.4.2.1 Each end-of-cycle recirculation pump trip system instrumentation channel shall be demonstrated OPERABLE by the performance of the CHANNEL FUNCTIONAL TEST and CHANNEL CALIBRATION operations at the frequencies shown in Table 4.3.4.2.1-1.

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

4.3.4.2.3 The END-OF-CYCLE RECIRCULATION PUMP TRIP SYSTEM RESPONSE TIME of each trip function shown in Table 3.3.4.2-3 shall be demonstrated to be within its limit at least once per 18 months. * ~~Each test shall include at least the logic of one type of channel input, turbine control valve fast closure or turbine stop valve closure, such that both types of channel inputs are tested at least once per 36 months.~~ The time allotted for breaker arc suppression, 50 ms, shall be verified at least once per 60 months.*

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*Prior to STARTUP after the first refueling outage, the breaker arc suppression time of 12 ms, as determined by the manufacturer, shall apply.

Each test shall include two turbine control valve channels from one trip system and two turbine stop valve channels from the other trip system such that all channels are tested at least once per 36 months.

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TABLE 3.3.4.2-1

END-OF-CYCLE RECIRCULATION PUMP TRIP SYSTEM INSTRUMENTATION

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

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

(b) This function shall be automatically bypassed when turbine first stage pressure is less than 30%* of the value of turbine first stage pressure, in psia, at valves wide open (VWO) steam flow, equivalent to THERMAL POWER less than 40% of RATED THERMAL POWER.

*Initial setpoint, final setpoint to be determined during startup test program. Any required change to this setpoint shall be submitted to the Commission within 90 days of test completion.

TABLE 3.3.4.2-2

END-OF-CYCLE RECIRCULATION PUMP TRIP SYSTEM SETPOINTS

TRIP FUNCTION	TRIP SETPOINT	ALLOWABLE VALUE
1. Turbine Stop Valve - Closure	≥ 40 psig*	≥ 37 psig
2. Turbine Control Valve - Fast Closure	≥ 44.3 psig*	≥ 42 psig

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*Initial setpoint. Final setpoint to be determined during startup test program. Any required change to this setpoint shall be submitted to the Commission within 90 days of test completion.

TABLE 3.3.4.2-3

END-OF-CYCLE RECIRCULATION PUMP TRIP SYSTEM RESPONSE TIME

TRIP FUNCTION	RESPONSE TIME (Milliseconds)
1. Turbine Stop Valve - Closure	$\leq$ 190
2. Turbine Control Valve - Fast Closure	$\leq$ 190

TABLE 4.3.4.2.1-1

END-OF-CYCLE RECIRCULATION PUMP TRIP SYSTEM SURVEILLANCE REQUIREMENTS

TRIP FUNCTION	CHANNEL FUNCTIONAL TEST	CHANNEL CALIBRATION
1. Turbine Stop Valve - Closure	M*	R#
2. Turbine Control Valve - Fast Closure	M*	R#

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*Including Trip system logic testing.

#Calibrate trip units and logic at least once per 31 days.

3/4.3.5 REACTOR CORE ISOLATION COOLING SYSTEM ACTUATION INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.5 The reactor core isolation cooling (RCIC) system actuation instrumentation channels shown in Table 3.3.5-1 shall be OPERABLE with their trip setpoints set consistent with the values shown in the Trip Setpoint column of Table 3.3.5-2.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2 and 3 with reactor steam dome pressure greater than 135 psig.

ACTION:

a. With a RCIC system actuation instrumentation channel trip setpoint less conservative than the value shown in the Allowable Values column of Table 3.3.5-2, declare the channel inoperable until the channel is restored to OPERABLE status with its trip setpoint adjusted consistent with the Trip Setpoint value.

b. With one or more RCIC system actuation instrumentation channels inoperable, take the ACTION required by Table 3.3.5-1.

SURVEILLANCE REQUIREMENTS

4.3.5.1 Each RCIC system actuation instrumentation channel shall be demonstrated OPERABLE by the performance of the CHANNEL CHECK, CHANNEL FUNCTIONAL TEST and CHANNEL CALIBRATION operations at the frequencies shown in Table 4.3.5.1-1.

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

TABLE 3.3.5-1

REACTOR CORE ISOLATION COOLING SYSTEM ACTUATION INSTRUMENTATION

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FUNCTIONAL UNITS	MINIMUM OPERABLE CHANNELS† ~~PER TRIP SYSTEM~~(a)	ACTION
a. Reactor Vessel Water Level - Low Low, Level 2	4	50
b. Reactor Vessel Water Level - High, Level 8	2~~(b)~~	51
c. Condensate Storage Tank Water Level - Low	2~~(c)~~	52
d. Suppression Pool Water Level - High	2~~(c)~~	52
e. Manual Initiation	1~~/system(d)~~	53

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

~~(b) One trip system with two-out-of-two logic.~~

~~(c) One trip system with one out of two logic.~~

~~(d) One trip system with one channel.~~

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TABLE 3.3.5-1 (Continued)

REACTOR CORE ISOLATION COOLING SYSTEM

ACTUATION INSTRUMENTATION

ACTION 50 - With the number of OPERABLE channels less than required by the Minimum OPERABLE Channels ~~per Trip System~~ requirement ~~for one trip system~~, place the inoperable channel(s) or ~~that~~ trip system in the tripped condition within one hour or declare the RCIC system inoperable. 1360

ACTION 51 - With the number of OPERABLE channels less than required by the minimum OPERABLE channels ~~per Trip System~~ requirement, declare the RCIC system inoperable. 1360

ACTION 52 - With the number of OPERABLE channels less than required by the Minimum OPERABLE Channels ~~per Trip System~~ requirement, place at least one inoperable channel in the tripped condition within one hour or declare the RCIC system inoperable. 1360

ACTION 53 - With the number of OPERABLE channels less than required by the Minimum OPERABLE Channels ~~per Trip System~~ requirement, restore the inoperable channel to OPERABLE status within 8 hours or declare the RCIC system inoperable. 1360

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TABLE 3.3.5-2

REACTOR CORE ISOLATION COOLING SYSTEM ACTUATION INSTRUMENTATION SETPOINTS

FUNCTIONAL UNITS	TRIP SETPOINT	ALLOWABLE VALUE
a. Reactor Vessel Water Level - Low Low, Level 2	≥ -41.6 inches*	≥ -43.8 inches
b. Reactor Vessel Water Level - High, Level 8	≤ 53.5 inches*	≤ 55.7 inches
c. Condensate Storage Tank Level - Low	≥ 0 inches	≥ -3 inches
d. Suppression Pool Water Level - High	≤ 5.9 inches	≤ ~~6.5~~ 7.0 inches
e. Manual Initiation	NA	NA

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

TABLE 4.3.5.1-1

REACTOR CORE ISOLATION COOLING SYSTEM ACTUATION INSTRUMENTATION SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNITS	CHANNEL CHECK	CHANNEL FUNCTIONAL TEST	CHANNEL CALIBRATION
a. Reactor Vessel Water Level - Low Low, Level 2	S	M	R(a)
b. Reactor Vessel Water Level - High, Level 8	S	M	R
c. Condensate Storage Tank Level - Low	S	M	R
d. Suppression Pool Water Level - High	S	M	R
e. Manual Initiation	NA	M(b)	NA

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

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

3/4.3.6 CONTROL ROD BLOCK INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.6. The control rod block instrumentation channels shown in Table 3.3.6-1 shall be OPERABLE with their trip setpoints set consistent with the values shown in the Trip Setpoint column of Table 3.3.6-2.

APPLICABILITY: As shown in Table 3.3.6-1.

ACTION:

a. With a control rod block instrumentation channel trip setpoint less conservative than the value shown in the Allowable Values column of Table 3.3.6-2, declare the channel inoperable until the channel is restored to OPERABLE status with its trip setpoint adjusted consistent with the Trip Setpoint value.

b. With the number of OPERABLE channels less than required by the Minimum OPERABLE Channels per Trip Function requirement, take the ACTION required by Table 3.3.6-1.

SURVEILLANCE REQUIREMENTS

4.3.6 Each of the above required control rod block trip systems and instrumentation channels shall be demonstrated OPERABLE by the performance of the CHANNEL CHECK, CHANNEL FUNCTIONAL TEST and CHANNEL CALIBRATION operations for the OPERATIONAL CONDITIONS and at the frequencies shown in Table 4.3.6-1.

TABLE 3.3.6-1

CONTROL ROD BLOCK INSTRUMENTATION

TRIP FUNCTION	MINIMUM OPERABLE CHANNELS PER TRIP FUNCTION	APPLICABLE OPERATIONAL CONDITIONS	ACTION	
1. ROD PATTERN CONTROL SYSTEM				
a. Low Power Setpoint	2	1, 2	60	
b. ~~Intermediate Rod Withdrawal Limiter Setpoint~~ High Power Setpoint	2	1, 2	60	1334
2. APRM				
a. Flow Biased Neutron Flux-Upscale	6	1	61	
b. Inoperative	6	1, 2, 5	61	
c. Downscale	6	1	61	
d. Neutron Flux - Upscale, Startup	6	2, 5	61	
3. SOURCE RANGE MONITORS				
a. Detector not full in ~~(a)~~ (a, e)	4 2**	2~~, 5~~ e 5	61 62	1118
b. Upscale(b)	4 2**	2~~, 5~~ e 5	61 62	1009
c. Inoperative(b)	4 2**	2~~, 5~~ e 5	61 62	
d. Downscale(c)	4 2**	2~~, 5~~ e 5	61 62	
4. INTERMEDIATE RANGE MONITORS				
a. Detector not full in ~~(d)~~ e	6	2, 5	61	1011
b. Upscale	6	2, 5	61	
c. Inoperative(d)	6	2, 5	61	
d. Downscale	6	2, 5	61	
5. SCRAM DISCHARGE VOLUME				
a. Water Level-High	2	1, 2, 5*	62	
6. REACTOR COOLANT SYSTEM RECIRCULATION FLOW				
a. Upscale	3	1	62	
7. Reactor Mode Switch Shutdown Position	2	3, 4	63	1197

TABLE 3.3.6-1 (Continued)

CONTROL ROD BLOCK INSTRUMENTATION

ACTION

ACTION 60 - Declare the RPCS inoperable and take the ACTION required by Specification 3.1.4.2.

ACTION 61 - With the number of OPERABLE Channels:

a. One less than required by the Minimum OPERABLE Channels per Trip Function requirement, restore the inoperable channel to OPERABLE status within 7 days or place the inoperable channel in the tripped condition within the next hour.

b. Two or more less than required by the Minimum OPERABLE Channels per Trip Function requirement, place at least one inoperable channel in the tripped condition within one hour.

ACTION 62 - With the number of OPERABLE channels less than required by the Minimum OPERABLE Channels per Trip Function requirement, place the inoperable channel in the tripped condition within one hour.

ACTION 63 - With the number of OPERABLE channels less than required by the Minimum OPERABLE Channels per Trip Function requirement, initiate a rod block.

NOTES

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

** OPERABLE channels must be associated with SRMs required OPERABLE per Specification 3.9.2.

00'1

(a) This function shall be automatically bypassed if detector count rate is > 100 cps or the IRM channels are on range 3 or higher.

(b) This function shall be automatically bypassed when the associated IRM channels are on range 8 or higher.

(c) This function shall be automatically bypassed when the IRM channels are on range 3 or higher.

(d) This function shall be automatically bypassed when the IRM channels are on range 1.

(e) The provisions of Specification 3.0.4 are not applicable for entering OPERATIONAL CONDITION 5. /118

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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. ~~Intermediate Rod Withdrawal Limiter Setpoint~~ High Power Setpoint	≤ 70% of RATED THERMAL POWER	≤ 70% of RATED THERMAL POWER	/334
2. APRM			
a. Flow Biased Neutron Flux-Upscale	$\leq (0.66\ W + 42\%)^{2}\ T$ *	$\leq (0.66\ W + 45\%)^{2}\ T$ *	/354
b. Inoperative	NA	NA	
c. Downscale	≥ ~~5~~ 4% of RATED THERMAL POWER	≥ 3% of RATED THERMAL POWER	/237
d. Neutron Flux - Upscale Startup	≤ 12% of RATED THERMAL POWER	≤ 14% of RATED THERMAL POWER	
3. SOURCE RANGE MONITORS			
a. Detector not full in	NA	NA	
b. Upscale	$< 1 \times 10^5$ cps	$< 1.5 \times 10^5$ cps	
c. Inoperative	NA	NA	
d. Downscale	≥ 0.7 cps	≥ 0.5 cps	
4. INTERMEDIATE RANGE MONITORS			
a. Detector not full in	NA	NA	
b. Upscale	< 108/125 of full scale	< 110/125 of full scale	
c. Inoperative	NA	NA	
d. Downscale	≥ 5/125 of full scale	≥ 3/125 of full scale	
5. SCRAM DISCHARGE VOLUME			
a. Water Level-High	≤ 32 inches	≤ 33.5 inches	
6. REACTOR COOLANT SYSTEM RECIRCULATION FLOW			
a. Upscale	≤ 108% of rated flow	≤ 111% of rated flow	
7. REACTOR MODE SWITCH SHUTDOWN POSITION	NA	NA	/197

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*The Average Power Range Monitor rod block function is varied as a function of recirculation loop flow (W)2 and the ratio of FRACTION of RATED THERMAL POWER to the MAXIMUM FRACTION of LIMITING POWER DENSITY (T factor). The trip setting of this function must be maintained in accordance with Specification 3.2.2. /354

TABLE 4.3.6-1

CONTROL ROD BLOCK INSTRUMENTATION SURVEILLANCE REQUIREMENTS

TRIP FUNCTION	CHANNEL CHECK	CHANNEL FUNCTIONAL TEST	CHANNEL CALIBRATION$^{(a)}$	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRED	
1. ROD PATTERN CONTROL SYSTEM					
a. Low Power Setpoint	NA	S/U$^{(b)}$~~$^{(e)}$~~e, D$^{(c)}$~~$^{(e)}$~~e, M$^{(d)}$~~$^{(e)}$~~e	Q	1, 2	356
b. ~~Intermediate Rod Withdrawal Limiter Setpoint~~ High Power Setpoint	NA	S/U$^{(b)}$~~$^{(e)}$~~e, D$^{(c)}$~~$^{(e)}$~~e, M$^{(d)}$~~$^{(e)}$~~e	Q	1, 2	334
2. APRM					
a. Flow Biased Neutron Flux- Upscale	NA	~~S/U$^{(b)}$~~,W	W$^{(f)(g)}$, SA	1	
b. Inoperative	NA	S/U~~$^{(b)}$~~,W	NA	1, 2, 5	
c. Downscale	NA	~~S/U$^{(b)}$~~,W	W$^{(h)}$, SA	1	
d. Neutron Flux - Upscale, Startup	NA	S/U$^{(b)}$,M	Q	2, 5	
3. SOURCE RANGE MONITORS					
a. Detector not full in	NA	S/U~~$^{(b)}$~~,W	NA	2, 5	356
b. Upscale	NA	S/U~~$^{(b)}$~~,W	Q	2, 5	
c. Inoperative	NA	S/U~~$^{(b)}$~~,W	NA	2, 5	
d. Downscale	NA	S/U~~$^{(b)}$~~,W	Q	2, 5	
4. INTERMEDIATE RANGE MONITORS					
a. Detector not full in	NA	S/U~~$^{(b)}$~~,W	NA	2, 5	356
b. Upscale	NA	S/U~~$^{(b)}$~~,W	Q	2, 5	
c. Inoperative	NA	S/U~~$^{(b)}$~~,W	NA	2, 5	
d. Downscale	NA	S/U~~$^{(b)}$~~,W	Q	2, 5	
5. SCRAM DISCHARGE VOLUME					
a. Water Level-High	NA	M	R	1, 2, 5*	
6. REACTOR COOLANT SYSTEM RECIRCULATION FLOW					
a. Upscale	NA	~~S/U$^{(b)}$~~,M	Q	1	1356
7. Reactor Mode Switch Shutdown Position	NA	R	NA	3, 4	/197

TABLE 4.3.6-1 (Continued)

CONTROL ROD BLOCK INSTRUMENTATION SURVEILLANCE REQUIREMENTS

NOTES:

a. Neutron detectors may be excluded from CHANNEL CALIBRATION.

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

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

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d. At least once per 31 days while operation continues within a given power range above the RPCS low power setpoint.

e. ~~Includes reactor manual control multiplexing system input~~. [Deleted]

f. This calibration shall consist of the adjustment of the APRM channel to conform to the power values calculated by a heat balance during OPERATIONAL CONDITION 1 when THERMAL POWER is greater than or equal to 25% of RATED THERMAL POWER. Adjust the APRM channel if the absolute difference is greater than 2% of RATED THERMAL POWER. Any APRM Channel gain adjustment made in compliance with Specification 3.2.2 shall not be included in determining the absolute difference.

g. This calibration shall consist of the adjustment of the APRM flow biased channel to conform to a calibrated flow signal.

h. This calibration shall consist of verifying the trip setpoint only.

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

3/4.3.7 MONITORING INSTRUMENTATION

RADIATION MONITORING INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.7.1 The radiation monitoring instrumentation channels shown in Table 3.3.7.1-1 shall be OPERABLE with their alarm/trip setpoints within the specified limits.

APPLICABILITY: As shown in Table 3.3.7.1-1.

ACTION:

a. With a radiation monitoring instrumentation channel alarm/trip setpoint exceeding the value shown in Table 3.3.7.1-1, adjust the setpoint to within the limit within 4 hours or declare the channel inoperable.

b. With one or more radiation monitoring channels inoperable, take the ACTION required by Table 3.3.7.1-1.

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

SURVEILLANCE REQUIREMENTS

4.3.7.1 Each of the above required radiation monitoring instrumentation channels shall be demonstrated OPERABLE by the performance of the CHANNEL CHECK, CHANNEL FUNCTIONAL TEST and CHANNEL CALIBRATION operations for the conditions and at the frequencies shown in Table 4.3.7.1-1.

TABLE 3.3.7.1-1

RADIATION MONITORING INSTRUMENTATION

INSTRUMENTATION	MINIMUM CHANNELS OPERABLE	APPLICABLE CONDITIONS	ALARM/TRIP SETPOINT	MEASUREMENT RANGE	ACTION
1. Component Cooling Water Radiation Monitor	1	At all times	$\leq 1 \times 10^5$ cpm/NA	10 to 10^6 cpm	70
2. Standby Service Water System Radiation Monitor	1/heat exchanger train	1, 2, 3, and*	$\leq 1 \times 10^5$ cpm/NA	10 to 10^6 cpm	70
[DELETED] 3. ~~Offgas Pre-treatment Radiation Monitor~~	~~1~~	~~1, 2~~	~~$\leq 5 \times 10^3$ mR/hr/NA~~	~~1 to 10^6 mR/hr~~	~~70~~
4. ~~Offgas Post-treatment Radiation Monitor~~ [DELETED]	~~$2^{(a)}$~~	~~1, 2~~	~~$\leq 1 \times 10^5$ cpm (Hi),~~ ~~$\leq 1.0 \times 10^6$ cpm (Hi-Hi-Hi)~~	~~10 to 10^6 cpm~~	~~71~~
5. Carbon Bed Vault Radiation Monitor	1	1, 2	$\leq$ 2 x full power background/NA	1 to 10^6 mR/hr	72
6. Control Room Ventilation Radiation Monitor	2/trip system$^{(h)}$	1,2,3,5 and**	≤ 4 mR/hr/ ≤ 5 mR/hr$^{\#}$	10^{-2} to 10^2 mR/hr	73
7. Containment and Drywell Ventilation Exhaust Radiation Monitor	2/trip system$^{(h)}$	At all times	≤ 2.0 mR/hr/ ≤ 4 mR/hr$^{(b)\#}$	10^{-2} to 10^2 mR/hr	74
8. Fuel Handling Area Ventilation Exhaust Radiation Monitor	2/trip system$^{(h)}$	1,2,3,5 and**	$\leq$ 2mR/hr/ ≤ 4 mR/hr$^{(d)\#}$	10^{-2} to 10^2 mR/hr	75
9. Fuel Handling Area Pool Sweep Exhaust Radiation Monitor	2/trip system$^{(h)}$	(c)	$\leq$ 18 mR/hr/ ≤ 35 mR/hr$^{(d)\#}$	10^{-2} to 10^2 mR/hr	75

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TABLE 3.3.7.1-1 (Continued)

RADIATION MONITORING INSTRUMENTATION

INSTRUMENTATION	MINIMUM CHANNELS OPERABLE	APPLICABLE CONDITIONS	ALARM/TRIP SETPOINT	MEASUREMENT RANGE	ACTION
10. Area Monitors					
a. Fuel Handling Area Monitors					
1) New Fuel Storage Vault	1	(e)	$\leq$2.5 mR/hr/NA	10^{-2} to 10^{3} mR/hr	72
2) Spent Fuel Storage Pool	1	(f)	$\leq$2.5 mR/hr/NA	10^{-2} to 10^{3} mR/hr	72
3) Dryer Storage Area	1	(g)	$\leq$2.5 mR/hr/NA	10^{-2} to 10^{3} mR/hr	72
b. Control Room Radiation Monitor	1	At all times	$\leq$0.5 mR/hr/NA	10^{-2} to 10^{3} mR/hr	72

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* With RHR heat exchangers in operation.

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

\# Initial setpoint. Final Setpoint to be determined during startup test program. Any required change to this setpoint shall be submitted to Commission within 90 days after test completion.

(a) Trips system with 2 channels upscale-Hi Hi Hi, or one channel upscale Hi Hi Hi and one channel downscale or 2 channels downscale.

(b) Isolates containment/drywell purge penetrations.

(c) With irradiated fuel in spent fuel storage pool.

(d) Also isolates the Auxiliary Building and Fuel Handling Area Ventilation Systems.

(e) With fuel in the new fuel storage vault.

(f) With fuel in the spent fuel storage pool.

(g) With fuel in the dryer storage area.

(h) Two upscale Hi Hi, one upscale Hi Hi and one downscale, or two downscale signals from the same trip system actuate the trip system and initiate isolation of the associated isolation valves.

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TABLE 3.3.7.1-1 (Continued)

RADIATION MONITORING INSTRUMENTATION

ACTION

ACTION 70 - With the required monitor inoperable, obtain and analyze at least one grab sample of the monitored parameter at least once per 24 hours.

ACTION 71 - [DELETED]

~~a. With one of the required monitors inoperable, place the inoperable channel in the downscale tripped condition within one hour.~~

~~b. With both of the required monitors inoperable, be in at least HOT SHUTDOWN within 12 hours.~~ 1120

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

ACTION 73 -

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

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

ACTION 74 -

a. With one of the required monitors in a trip system inoperable, place the inoperable channel in the downscale tripped condition within one hour.

b. With two of the required monitors in a trip system inoperable, isolate the containment and drywell purge and vent penetrations within 12 hours.

ACTION 75 -

a. With one of the required monitors in a trip system inoperable, place the inoperable channel in the downscale tripped condition within one hour.

b. With two of the required monitors in a trip system inoperable, ~~initiate and maintain operation of at least one standby gas treatment subsystem within 12 hours.~~ establish SECONDARY CONTAINMENT INTEGRITY with at least one standby gas treatment subsystem operating within 12 hours. 1349

TABLE 4.3.7.1-1

RADIATION MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS

[DELETED]

INSTRUMENTATION	CHANNEL CHECK	CHANNEL FUNCTIONAL TEST	CHANNEL CALIBRATION	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRED
1. Component Cooling Water Radiation Monitor	S	M	A	At all times
2. Standby Service Water System Radiation Monitor	S	M	A	1, 2, 3, and*
3. ~~Offgas Pre-treatment Radiation Monitor~~	~~S~~	~~M~~	~~A~~	~~1, 2~~
4. ~~Offgas Post-treatment Radiation Monitor~~	~~S~~	~~M~~	~~A~~	~~1, 2~~
5. Carbon Bed Vault Radiation Monitor	S	M	A	1, 2
6. Control Room Ventilation Radiation Monitor	S	M$^{(a)}$	A	1, 2, 3, 5 and**
7. Containment and Drywell Ventilation Exhaust Radiation Monitor	S	M	A	At all times
8. Fuel Handling Area Ventilation Radiation Monitor	S	M	A	1, 2, 3, 5 and**
9. Fuel Handling Area Pool Sweep Exhaust Radiation Monitor	S	M	A	(b)
10. Area Monitors				
a. Fuel Handling Area Monitors				
1) New Fuel Storage Vault	S	M	R	(c)
2) Spent Fuel Storage Pool	S	M	R	(d)
3) Dryer Storage Area	S	M	R	(e)
b. Control Room Radiation Monitor	S	M	R	At all times

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* With RHR heat exchangers in operation.

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

(a) The CHANNEL FUNCTIONAL TEST shall demonstrate that control room annunciation occurs if any of the following conditions exist.

1. Instrument indicates measured levels above the alarm/trip setpoint.
2. Circuit failure.
3. Instrument indicates a downscale failure.
4. Instrument controls not in Operate mode.

(b) With irradiated fuel in the spent fuel storage pool.

(c) With fuel in the new fuel storage vault.

(d) With fuel in the spent fuel storage pool.

(e) With fuel in the dryer storage area.

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, ~~in lieu of any other report required by Specification 6.9.1,~~ 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. 093

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

SURVEILLANCE REQUIREMENTS

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

4.3.7.2.2 Each of the above required seismic monitoring instruments actuated during a seismic event greater than or equal to 0.01 g shall be restored to OPERABLE status within 24 hours and a CHANNEL CALIBRATION performed within 5 days following the seismic event. Data shall be retrieved from actuated instruments and analyzed to determine the magnitude of the vibratory ground motion. ~~In lieu of any other report required by Specification 6.9.1, a~~ A Special Report shall be prepared and submitted ~~to the Commission~~ pursuant to Specification 6.9.2 within 10 days describing the magnitude, frequency stet spectrum and resultant effect upon unit features important to safety.

TABLE 3.3.7.2-1

SEISMIC MONITORING INSTRUMENTATION

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

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*With control room annunciation.

TABLE 4.3.7.2-1

SEISMIC MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS

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

METEOROLOGICAL MONITORING INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

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

APPLICABILITY: At all times.

ACTION:

a. With one or more required meteorological monitoring instrumentation channels inoperable for more than 7 days, ~~in lieu of any other report required by Specification 6.9.1~~, prepare and submit a Special Report to the Commission pursuant to Specification 6.9.2 within the next 10 days outlining the cause of the malfunction and the plans for restoring the instrumentation to OPERABLE status. |348 /093

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

SURVEILLANCE REQUIREMENTS

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

TABLE 3.3.7.3-1

METEOROLOGICAL MONITORING INSTRUMENTATION

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INSTRUMENT	MINIMUM CHANNELS ~~INSTRUMENTS~~ OPERABLE
a. Wind Speed	
1. Elev. 33 ft and 162 ft	1 each
b. Wind Direction	
1. Elev. 33 ft and 162 ft	1 each
c. Air Temperature	
1. Elev. 33 ft	1
d. Air Temperature Difference	
1. Elev. 33/162 ft	1

TABLE 4.3.7.3-1

METEOROLOGICAL MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS

INSTRUMENT	CHANNEL CHECK	CHANNEL CALIBRATION
a. Wind Speed		
1. Elev. 33 ft and 162 ft	D	SA
b. Wind Direction		
1. Elev. 33 ft and 162 ft	D	SA
c. Air Temperature		
1. Elev. 33 ft	D	SA
d. Air Temperature Difference		
1. Elev. 33/162 ft	D	SA

REMOTE SHUTDOWN ~~MONITORING~~ SYSTEM INSTRUMENTATION AND CONTROLS

LIMITING CONDITION FOR OPERATION

3.3.7.4 The remote shutdown ~~monitoring~~ system instrumentation ~~channels~~ and controls shown in Table 3.3.7.4-1 shall be OPERABLE. ~~with readouts on the remote shutdown panel~~.

APPLICABILITY: OPERATIONAL CONDITIONS 1 and 2.

ACTION:

a. With the number of OPERABLE remote shutdown ~~monitoring~~ system instrumentation less than required by Table 3.3.7.4-1, restore the inoperable channel(s) to OPERABLE status within 7 days or be in at least HOT SHUTDOWN within the next 12 hours.

b. With the number of OPERABLE remote shutdown system controls less than required by Table 3.3.7.4-1, restore the inoperable control(s) to OPERABLE status within 7 days or be in at least HOT SHUTDOWN within the next 12 hours.

c ~~b~~. The provisions of Specification 3.0.4 are not applicable.

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SURVEILLANCE REQUIREMENTS

4.3.7.4.1 Each of the above required remote shutdown ~~monitoring~~ system instrumentation channels shall be demonstrated OPERABLE by performance of the CHANNEL CHECK and CHANNEL CALIBRATION operations at the frequencies shown in Table 4.3.7.4-1.

4.3.7.4.2 Each of the above ~~R~~remote ~~S~~shutdown control switch and control~~s~~ circuit~~s~~ shall be demonstrated OPERABLE by verifying its capability to perform its intended function(s) at least once per 18 months.

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TABLE 3.3.7.4-1

REMOTE SHUTDOWN ~~MONITORING~~ System INSTRUMENTATION

INSTRUMENT	MINIMUM ~~INSTRUMENTS OPERABLE~~ CHANNELS OPERABLE Div 1	Div 2
1. Reactor Vessel Pressure	1	2
2. Reactor Vessel Water Level	1	2
3. Suppression Pool Water Level	1	2
4. Suppression Pool Water Temperature	1	2
5. RHR System Flow	1	2
6. Standby Service Water System Flow	1	2
7. RCIC Turbine Speed	1	NA
8. Condensate Storage Tank Level	1	NA

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Remote Shutdown System Controls

Control	Minimum Channels Operable Div 1	Div 2
1. SSW Pump	1	1
2. SSW Pump Discharge Vlv	1	1
3. SSW Basin Transfer Vlv	1	1
4. SSW Pump Recirc Vlv	1	1
5. SSW Return Vlv to Cooling Tower	1	1
6. SSW Cooling Tower Fans	2^b	2^b
7. SSW Bypass Vlvs	NA	2^a
8. RHR HX Inlet/Outlet/Bypass Vlvs	5^a	5^a

9.	RHR Pump	1	1
10.	RHR Pump Suction Vlv	1	1
11.	RHR Shutdown Cooling-Vlv	3^a	3^a
12.	RHR Injection Vlvs	2^a	2^a
13.	RHR Test Line Vlv	1	1
14.	RHR Hx Cond to RCIC Vlv	1	1
15.	RHR Hx Flow to Suppr Pool Vlv	1	1
16.	RHR Discharge To Radwaste Vlv	1	1
17.	RCIC Steam to RHR Hx Vlv	2^a	2^a
18.	Diesel Generator Hx Inlet Vlv	1	1
19.	Safety/Relief Vlvs	6^a	6^a
20.	RHR to RCIC Head Spray Line Vlv	NA	1
21.	RCIC Turbine Flow Controller	1	NA
22.	RCIC Suct Flow Suppr Pool Vlv	1	NA
23.	RCIC Inj Shutoff Vlv	1	NA
24.	RCIC Suct From CST	1	NA
25.	RCIC Recirc Main Flow Byp Vlv	1	NA
26.	RCIC Test FCV to CST	1	NA
27.	RCIC Test RTN to CST Vlv	1	NA
28.	Steam to RCIC Turb Vlv	1	NA
29.	RCIC Turbine Trip & Throttle Vlv	1	NA
30.	RCIC Turb Cooling Wtr Vlv	1	NA
31.	RCIC Turb Local Cont Sel Sw	1	NA
32.	RCIC Gland Seal Compressor	1	NA
33.	Shutdown Cooling Isolation Vlv Reset Sw	1	1

NOTE: a. 1 per valve
b. 1 per cooling tower fan

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TABLE 4.3.7.4-1

REMOTE SHUTDOWN MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS

INSTRUMENT	CHANNEL CHECK	CHANNEL CALIBRATION
1. Reactor Vessel Pressure	M	R
2. Reactor Vessel Water Level	M	R
3. Suppression Pool Water Level	M	R
4. Suppression Pool Water Temperature	M	R
5. RHR System Flow	M	R
6. Standby Service Water System Flow	M	R
7. RCIC Turbine Speed	M	R
8. Condensate Storage Tank Level	M	R

ACCIDENT MONITORING INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.7.5 The accident monitoring instrumentation channels shown in Table 3.3.7.5-1 shall be OPERABLE.

APPLICABILITY: As shown in Table 3.3.7.5-1.

ACTION:

With one or more accident monitoring instrumentation channels inoperable, take the ACTION required by Table 3.3.7.5-1.

SURVEILLANCE REQUIREMENTS

4.3.7.5 Each of the above required accident monitoring instrumentation channels shall be demonstrated OPERABLE by performance of the CHANNEL CHECK and CHANNEL CALIBRATION operations at the frequencies shown in Table 4.3.7.5-1.

TABLE 3.3.7.5-1
ACCIDENT MONITORING INSTRUMENTATION

INSTRUMENT	APPLICABLE OPERATIONAL CONDITIONS	REQUIRED NUMBER OF CHANNELS	MINIMUM CHANNELS OPERABLE	ACTION
1. Reactor Vessel Pressure	1, 2, 3	2	1	80
2. Reactor Vessel Water Level	1, 2, 3, 4, 5	2	1	82
3. Suppression Pool Water Level	1, 2, 3	2	1	80
4. Suppression Pool Water Temperature	1, 2, 3	6, 1/sector	6, 1/sector	80
5. Drywell/Containment Differential Pressure	1, 2, 3	2	1	80
6. Drywell Pressure	1, 2, 3	2	1	80
7. Drywell and Control Rod Drive Cavity Temperature	1, 2, 3	2 (each)	1 (each)	80
8. Containment Hydrogen Concentration Analyzer and Monitor	1, 2, 3	2	1	80
9. Drywell Hydrogen Concentration Analyzer and Monitor	1, 2, 3	2	1	80
10. Containment Pressure (wide and narrow range)	1, 2, 3	2 (each)	1 (each)	80
11. Containment Air Temperature	1, 2, 3	2	1	80
12. Safety/Relief Valve Tail Pipe Pressure Switch Position Indicators	1, 2, 3	1/valve	1/valve	80
13. Containment/Drywell Area Radiation Monitors	1, 2, 3, 4, 5	2#	2 ~~1~~#	81
14. Containment Ventilation Exhaust Radiation Monitor	1, 2, 3, 4, 5	1	1	81
15. Off-gas and Radwaste Bldg. Ventilation Exhaust Radiation Monitor	1, 2, 3, 4, 5	1	1	81
16. Fuel Handling Area Ventilation Exhaust Radiation Monitor	1, 2, 3, 4, 5	1	1	81
17. Turbine Bldg. Ventilation Exhaust Radiation Monitor	1, 2, 3	1	1	81
18. Standby Gas Treatment System A & B Exhaust Radiation Monitors	*	1/each	1/each	81

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#Each for containment and drywell.
*When its associated train of the standby gas treatment system is required operable (Ref. 3.6.6.3).

TABLE 3.3.7.5-1 (Continued)
ACCIDENT MONITORING INSTRUMENTATION

ACTION STATEMENTS

ACTION 80 -

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

ACTION 81 -

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

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

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

ACTION 82 - For OPERATIONAL CONDITIONS 1, 2, 3

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 be in COLD SHUTDOWN within the next 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 be in COLD SHUTDOWN within the next 24 hours.

For OPERATIONAL CONDITIONS 4, 5

With the number of OPERABLE accident monitoring instrumentation channels less than required by the Minimum Channels OPERABLE requirement, either restore the inoperable channel(s) to OPERABLE status within 72 hours, or initiate the preplanned alternate method of monitoring the appropriate parameter(s).

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TABLE 4.3.7.5-1

ACCIDENT MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS

INSTRUMENT	CHANNEL CHECK	CHANNEL CALIBRATION
1. Reactor Vessel Pressure	M	R
2. Reactor Vessel Water Level	M	R
3. Suppression Pool Water Level	M	R
4. Suppression Pool Water Temperature	M	R
5. Drywell/Containment Differential Pressure	M	R
6. Drywell Pressure	M	R
7. Drywell and Control Rod Cavity Temperature	M	R
8. Containment Hydrogen Concentration Analyzer and Monitor	NA	M*
9. Drywell Hydrogen Concentration Analyzer and Monitor	NA	M*
10. Containment Pressure	M	R
11. Containment Air Temperature	M	R
12. Safety/Relief Valve Tail Pipe Pressure Switch Position Indicators	M	R
13. Containment/Drywell Area Radiation Monitors	M	R**
14. Containment Ventilation Exhaust Radiation Monitor	M	A
15. Off-gas and Radwaste Bldg. Ventilation Exhaust Radiation Monitor	M	A
16. Fuel Handling Area Ventilation Exhaust Radiation Monitor	M	A
17. Turbine Bldg. Ventilation Exhaust Radiation Monitor	M	A
18. Standby Gas Treatment System A & B Exhaust Radiation Monitors	M	A

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*Using sample gas containing:

a. One volume percent hydrogen, remainder nitrogen.

b. Four volume percent hydrogen, remainder nitrogen.

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

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a. In OPERATIONAL CONDITION 2*, four.
b. In OPERATIONAL CONDITION 3 or 4, two.

INSTRUMENTATION

SOURCE RANGE MONITORS

LIMITING CONDITION FOR OPERATION

3.3.7.6 At least ~~three~~ the following source range monitor channels shall be OPERABLE:

APPLICABILITY: OPERATIONAL CONDITIONS 2*, 3 and 4. 1009

ACTION:

a. In OPERATIONAL CONDITION 2* with one of the above required source range monitor channels inoperable, restore at least ~~3~~ 4 source range monitor channels to OPERABLE status within 4 hours or be in at least HOT SHUTDOWN within the next 12 hours. 1009

b. In OPERATIONAL CONDITION 3 or 4 with ~~two~~ one or more of the above required source range monitor channels inoperable, verify all insertable control rods to be fully inserted in the core and lock the reactor mode switch in the Shutdown position within one hour. 1009

SURVEILLANCE REQUIREMENTS

4.3.7.6 Each of the above required source range monitor channels shall be demonstrated OPERABLE by:

a. Performance of a:

1. CHANNEL CHECK at least once per:

   a) 12 hours in CONDITION 2*, and

   b) 24 hours in CONDITION 3 or 4.

2. CHANNEL CALIBRATION** at least once per 18 months.

b. Performance of a CHANNEL FUNCTIONAL TEST:

1. Within 24 hours prior to moving the reactor mode switch from the Shutdown position, if not performed within the previous 7 days, and

2. At least once per 31 days.

c. Verifying, prior to withdrawal of control rods, that the SRM count rate is at least 0.7 cps with the detector fully inserted.

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*With IRM's on range 2 or below.
**Neutron detectors may be excluded from CHANNEL CALIBRATION.

TRAVERSING IN-CORE PROBE SYSTEM

LIMITING CONDITION FOR OPERATION

3.3.7.7. The traversing in-core probe system shall be OPERABLE with:

a.* ~~Three~~ Five movable detectors, drives and readout equipment to map the core, and /10

b. Indexing equipment to allow all ~~three~~ five detectors to be calibrated in a common location. /010

APPLICABILITY: When the traversing in-core probe is used for:

a. Recalibration of the LPRM detectors, and

b.* Monitoring the APLHGR, LHGR, MCPR, or MFLPD.

ACTION:

With the traversing in-core probe system inoperable, do not use the system for the above applicable monitoring or calibration functions. The provisions of Specifications 3.0.3 and 3.0.4 are not applicable.

SURVEILLANCE REQUIREMENTS

4.3.7.7 The traversing in-core probe system shall be demonstrated OPERABLE by normalizing each of the above required detector outputs within 72 hours prior to use when required for the ~~above applicable monitoring or~~ LPRM calibration function~~s~~. le /50

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*Only the detector(s) in the location(s) of interest are required to be OPERABLE.

CHLORINE DETECTION SYSTEM

LIMITING CONDITION FOR OPERATION

3.3.7.8 Two independent chlorine detection ~~systems~~ Channels shall be OPERABLE with their trip setpoints adjusted to actuate at a chlorine concentration of less than or equal to 5 ppm. 1346

APPLICABILITY: All OPERATIONAL CONDITIONS.

ACTION:

a. With one chlorine detection ~~system~~ Channels inoperable, restore the inoperable detection ~~system~~ Channels to OPERABLE status within 7 days, or within the next 6 hours, initiate and maintain operation of at least one control room emergency filtration system subsystem in the isolation mode of operation. 1346

b. With both chlorine detection ~~systems~~ Channels inoperable, within one hour initiate and maintain operation of at least one control room emergency filtration system subsystem in the isolation mode of operation. 1346

c. The provisions of Specification 3.0.4 are not applicable.

SURVEILLANCE REQUIREMENTS

4.3.7.8 Each of the above required chlorine detection ~~systems~~ Channels shall be demonstrated OPERABLE by 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 6 months. 1346

FIRE DETECTION INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.7.9 As a minimum, the fire detection instrumentation for each fire detection zone shown in Table 3.3.7.9-1 shall be OPERABLE.

APPLICABILITY: Whenever equipment protected by the fire detection instrument is required to be OPERABLE.

ACTION:

With the number of OPERABLE Function A or Function B fire detection instruments less than the Minimum Instruments OPERABLE requirement of Table 3.3.7.9-1:

a. Within 1 hour, establish a fire watch patrol to inspect the zone(s) with the Function A or room(s) with Function B, inoperable instrument(s) at least once per hour, unless the instrument(s) is located inside the containment, steam tunnel or drywell, then inspect the primary containment at least once per 8 hours or monitor the containment, steam tunnel and/or drywell air temperature at least once per hour at the locations listed in Specification 3.7.8, 4.6.1.8 and 4.6.2.6. /073

b. Restore the minimum number of instruments to OPERABLE status within 14 days or, ~~in lieu of any other report required by Specification 6.9.1~~, prepare and submit a Special Report to the Commission pursuant to Specification 6.9.2 within 30 days outlining the action taken, the cause of the inoperability and the plans and schedule for restoring the instrument(s) to OPERABLE status. /093

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

SURVEILLANCE REQUIREMENTS

4.3.7.9.1 Each of the above required fire detection instruments which are accessible during unit operation shall be demonstrated OPERABLE at least once per 6 months by performance of a CHANNEL FUNCTIONAL TEST. Fire detectors which are not accessible during unit operation shall be demonstrated OPERABLE by the performance of a CHANNEL FUNCTIONAL TEST during each COLD SHUTDOWN exceeding 24 hours unless performed in the previous 6 months.

4.3.7.9.2 The NFPA Standard 72D supervised circuits supervision associated with the detector alarms of each of the above required fire detection instruments shall be demonstrated OPERABLE at least once per 6 months.

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TABLE 3.3.7.9-1

FIRE DETECTION INSTRUMENTATION

INSTRUMENT LOCATION				MINIMUM INSTRUMENTS OPERABLE*			
				ZONE(1)	HEAT(2)	FLAME	SMOKE(3)
a	Containment Building						
	1. Return Duct Mounted Detectors			NA	NA	NA	3
	ROOM NO.	ELEV.	ROOM NAME				
b.	Control Building						
1.	OC202	111'	DIV I SWGR RM	1-4	6	NA	4
2.	OC207	111'	DIV I BATTERY RM	1-4	NA	NA	1
3.	OC208	111'	DIV II REMOTE SHUTDOWN PANEL ROOM	1-27	1	NA	1
4.	OC208A	111'	DIV I REMOTE SHUTDOWN PANEL ROOM	1-27	1	NA	1
5.	OC209	111'	DIV III BATTERY RM	1-5	NA	NA	1
6.	OC210	111'	DIV III SWGR RM	1-5	4	NA	2
7.	OC211	111'	DIV II BATTERY RM	1-6	NA	NA	1
8.	OC215	111'	DIV II SWGR RM	1-6	7	NA	4
9.	OC307	133'	ELECTRICAL CHASE	1-10	NA	NA	1
10.	OC306	133'	ELECTRICAL CHASE	1-10	NA	NA	1
11.	OC302	133'	HVAL EQUIP. ROOM	1-11	NA	NA	13
12.	OC402	148'	CABLE SPREADING RM	1-15	7	NA	10
13.	OC403	148'	COMPUTER ROOM	1-14	12	NA	7
14.	OC407	148'	INSTR. MOTOR GEN ROOM	1-15	2	NA	1
15.	OC503 OC504	166'	CONTROL ROOM	1-18	NA	NA	16
16.	OC702	189'	CABLE SPREADING RM	1-23	12	NA	14
17.	OC703	189'	CONTROL CAB. ROOM	1-24	4	NA	6
18.	OC707	189'	INSTR MOTOR GEN. RM	1-23	NA	NA	1

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

(1) Zones apply only to smoke detectors.

(2) Heat detectors provide warning and activation of automatic extinguishing systems.

(3) Smoke detectors provide early warning capability.

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TABLE 3.3.7.9-1 (Continued)

FIRE DETECTION INSTRUMENTATION

INSTRUMENT LOCATION				MINIMUM INSTRUMENTS OPERABLE*			
	ROOM NO.	ELEV.	ROOM NAME	ZONE(1)	HEAT(2)	FLAME	SMOKE(3)
c.	Auxiliary Building						
1.	1A102	93'	RHR 'A' HT EX RM	2-4	NA	NA	1
2.	1A103	93'	RHR 'A' PUMP RM	2-4	NA	NA	2
3.	1A104	93'	RCIC PUMP RM	2-4	NA	NA	2
4.	1A105	93'	RHR 'B' PUMP RM	2-4	NA	NA	2
5.	1A106	93'	RHR 'B' HT EX RM	2-4	NA	NA	1
6.	1A109	93'	HPCS PUMP RM	2-17	NA	NA	2
7.	1A111	93'	PIPING PENETRATION RM	2-17	NA	NA	1
8.	1A114	93'	FAN COIL AREA	2-14	NA	NA	4
9.	1A115	93'	PIPING PENETRATION RM	2-14	NA	NA	1
10.	1A116	93'	PIPING PENETRATION RM	2-14	NA	NA	1
11.	1A117	93'	MISC. EQUIP AREA	2-14	NA	NA	4
12.	1A118	93'	RHR 'C' PUMP ROOM	2-14	NA	NA	2
13.	1A119	93'	LPCS PUMP ROOM	2-14	NA	NA	2
14.	1A120	93'	CCW PUMP AND HX AREA	2-14	NA	NA	3
15.	1A121	103'	EAST CORRIDOR	2-17	NA	NA	5
16.	1A122	103'	SOUTH CORRIDOR	2-17 2-14	NA NA	NA NA	3 0
17.	1A123	103'	NORTH CORRIDOR	2-17 2-14	NA NA	NA NA	5 0
18.	1A201	119'	EAST CORRIDOR	2-18	NA	NA	6
19.	1A202	119'	RHR 'A' HX RM	2-4	NA	NA	1
20.	1A203	119'	PIPING PENETRATION RM	2-4	NA	NA	2
21.	1A204	119'	PIPING PENETRATIOM RM	2-4	NA	NA	2
22.	1A205	119'	PIPING PENETRATION RM	2-4	NA	NA	2
23.	1A206	119'	RHR 'B' HX RM	2-4	NA	NA	1
24.	1A207	119'	ELECT. SWGR ROOM	2-4	3	NA	2
25.	1A208	119'	ELECT. SWGR ROOM	2-4	3	NA	2
26.	1A209	115'	RWCU RECIRC PUMP 'A' RM	2-4	NA	NA	1
27.	1A210	115'	RWCU RECIRC PUMP 'B' RM	2-4	NA	NA	1
28.	1A211	119'	NORTH CORRIDOR	2-18 2-2	NA NA	NA NA	14 0
29.	1A215	119'	SOUTH CORRIDOR	2-2	NA	NA	5
30.	1A219	119'	ELECT. SWGR RM	2-3	2	NA	2

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TABLE 3.3.7.9-1 (Continued)

FIRE DETECTION INSTRUMENTATION

INSTRUMENT LOCATION				MINIMUM INSTRUMENTS OPERABLE*			
	ROOM NO.	ELEV.	ROOM NAME	ZONE(1)	HEAT(2)	FLAME	SMOKE(3)
c. Auxiliary Building (Continued)							
31.	1A220	119'	PIPING PENETRATION RM	2-3	NA	NA	1
32.	1A221	119'	ELECT. SWGR RM	2-3	2	NA	2
33.	1A222	119'	WEST CORRIDOR	2-2	NA	NA	18
34.	1A301	139'	NORTHEAST CORRIDOR	2-6	NA	NA	2
35.	1A302	139'	SOUTHEAST CORRIDOR	2-6	NA	NA	1
36.	1A303	139'	RHR 'A' HX RM	2-6	NA	NA	1
37.	1A304	139'	PIPING PENETRATION RM	2-6	NA	NA	1
38.	1A305	139'	STEAM TUNNEL	2-20	NA	NA	2
39.	1A306	139'	PIPING PENETRATION RM	2-6	NA	NA	1
40.	1A307	139'	RHR 'B' HX RM	2-6	NA	NA	1
41.	1A308	139'	ELECT. PENETRATION RM	2-6	3	NA	2
42.	1A309	139'	ELECT. PENETRATION RM	2-6 2-6	3	NA	2 3
43.	1A314	139'	SOUTH CORRIDOR	2-19 2-6	NA NA	NA NA	3 0
44.	1A316	139'	NORTH CORRIDOR	2-6	NA	NA	12
45.	1A318	139'	ELECT. PENETRATION RM	2-5	2	NA	2
46.	1A319	139'	RPV INSTR. TEST RM	2-5	NA	NA	1
47.	1A320	139'	ELECT. PENETRATION RM	2-5	2	NA	2
48.	1A321	139'	MCC AREA	2-19	NA	NA	3
49.	1A322	139'	CENTRIFUGAL CHILLER AREA	2-19	NA	NA	4
50.	1A323	139'	SGTS AREA	2-19	NA	NA	1
51.	1A324	139'	HVAC EQUIP AREA	2-19	NA	NA	1
52.	1A326	139'	SGTS AREA	2-19	NA	NA	1
53.	1A401	166'	NORTHEAST CORRIDOR	2-8	NA	NA	2
54.	1A402	166'	STEAM TUNNEL ROOF	2-8	NA	NA	1
55.	1A403	166'	SOUTHEAST CORRIDOR	2-8	NA	NA	2
56.	1A404	166'	UNASSIGNED AREA	2-8	NA	NA	1
57.	1A405	166'	CNTMT VENT. EQUIP RM	2-8	NA	NA	1
58.	1A406	166'	CNTMT EXHAUST FILTER AND VENT ROOM	2-8	NA	NA	1

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TABLE 3.3.7.9-1 (Continued)

FIRE DETECTION INSTRUMENTATION

INSTRUMENT LOCATION				MINIMUM INSTRUMENTS OPERABLE*			
	ROOM NO.	ELEV.	ROOM NAME	ZONE(1)	HEAT(2)	FLAME	SMOKE(3)
c. Auxiliary Building (Continued)							
59.	1A407	166'	MCC AREA	2-8	2	NA	1
60.	1A410	166'	MCC AREA	2-8	2	NA	1
61.	1A417	166'	NORTH CORRIDOR	2-8	NA	NA	14
62.	1A420	166'	SOUTH CORRIDOR	2-7	NA	NA	4
63.	1A424	166'	SET DOWN AREA	2-7 2-8	NA NA	NA NA	1 1
64.	1A428	166'	WEST CORRIDOR	2-7	NA	NA	4
65.	1A432	166'	FPC AND CU PUMP RM	2-7	NA	NA	1
66.	1A434	166'	PASSAGE	2-7	NA	NA	1
67.	1A519	185'	STORAGE AREA	2-9	NA	NA	4
68.	1A527	185'	LOAD CENTER AREA	2-9	NA	NA	5
69.	1A539	185'	CABLE CHASE	2-15	NA	NA	1
70.	1A602	208'10"	STORAGE AREA	2-13	NA	NA	6
71.	1A603	208'10"	PASSAGE	2-13	NA	NA	3
72.	1A604	208'10"	FUEL HANDLING AREA	2-13	NA	NA	13
73.	1A606	245'	HVAC EQUIP AREA	2-13	NA	NA	9
d. Diesel Generator Building							
1.	Unit 1 El. 158'-0" HPCS Generator			2-10	7	6	NA
2.	Unit 1 El. 158'-0" Bus B Generator			2-11	7	6	NA
3.	Unit 1 El. 158'-0" Bus A Generator			2-12	7	6	NA
e. Standby Service Water Pump House							
1.	1M110		Pump House A	2-1	NA	NA	1
2.	1M112		Valve Room A	2-1	NA	NA	1
3.	2M110		Pump House B	2-1	NA	NA	1
4.	2M112		Valve Room B	2-1	NA	NA	1
f. Charcoal Filter Trains							
1.	Standby Gas Treatment System Filter Train Auxiliary Building El. 139'-0"			NA	1 (Allison Thermistor Wire)	NA	NA
2.	Control Room Standby Fresh Air System Filter Train, Control Building El. 133'-0"			NA	1 (Allison Thermistor Wire)	NA	NA

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TABLE 3.3.7.9-1
FIRE DETECTION INSTRUMENTATION

INSTRUMENT LOCATION			MINIMUM INSTRUMENTS OPERABLE* HEAT (X/Y)	FLAME(1) (X/Y)	SMOKE(1) (X/Y)
a. CONTAINMENT BUILDING #					
1. Return Duct Mounted Detectors					3/0
ROOM	ELEV	ROOM NAME			
b. CONTROL BUILDING					
1. Zone 1-3					12/0
OC103	93'	Emergency Laundry Rm			
OC109	93'	Decontamination Area			
OC115	93'	Corridor			
OC116	93'	Hot Machine Shop			
OC117	93'	Corridor			
OC128	93'	Hot Water Heater Rm			
2. Zone 1-4					6/0
OC201	111'	Stairwell			
OC202	111'	Div I Swgr Rm	0/6(CO_2)		
OC207	111'	Div I Battery Rm			

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

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

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

(a) Zone 1-27 detectors trip closed the door between the OC208/OC208A Remote Shutdown panel rooms.
(b) Containment building return duct mounted detectors trip the containment cooler fans.
(c) Zone 1-11 and 1-13 detectors initiate the control building purge fan system.
(d) Control Room HVAC Intake Plenum Detectors trip the control room A/C units unless a control room emergency filtration system isolation mode automatic actuation signal is present.

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TABLE 3.3.7.9-1
FIRE DETECTION INSTRUMENTATION

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

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TABLE 3.3.7.9-1
FIRE DETECTION INSTRUMENTATION

ROOM	ELEV	ROOM NAME	MINIMUM INSTRUMENTS OPERABLE* HEAT (X/Y)	FLAME(1) (X/Y)	SMOKE(1) (X/Y)
11. Zone 1-18					31/0
OC502	166'	U-2 Instr. Rack Area			
OC503	166'	Control Rm			
OC504	166'	U-1 Inst Rack Area			
OC516	166'	Electrical Space			
OC517	166'	Electrical Space			
12. Zone 1-19					9/0
OC506	166'	Shower and Drying Area			
OC507	166'	Aux Instrument Shop			
OC509	166'	Corridor			
OC510	166'	Office			
OC511	166'	Dining Area			
OC512	166'	Kitchen			
OC514	166'	Locker Room			
OC515	166'	Corridor			
13. Zone 1-20					1/0
OC708A	189'	HVAC Chase			
14. Zone 1-21					2/0
OC518	166'	Electrical Chase			
OC611	177'	Electrical Chase			
15. Zone 1-22					16/0
OC601	177'	Viewing Gallery			
OC602	177'	Corridor No. 1			
OC603	177'	Emergency Dormitory			
OC604	177'	Computer			
OC605	177'	Janitor's Closet			
OC608	177'	Technical Support			
OC608B	177'	HVAC Chase			
OC613	177'	Corridor			
OC614	177'	Corridor			
OC616	177'	Storage Closet			
OC617	177'	Electrical Chase			
OC618	177'	Electrical Chase			
OC619	177'	Electrical Chase			
OC03	177'	Stair			

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TABLE 3.3.7.9-1
FIRE DETECTION INSTRUMENTATION

	ROOM	ELEV	ROOM NAME	MINIMUM INSTRUMENTS OPERABLE* HEAT (X/Y)	FLAME(1) (X/Y)	SMOKE(1) (X/Y)
16.	Zone 1-23					21/0
	OC702	189'	Upper Cable Spreading Room	0/12(CO_2)		
	OC706	189'	West Corridor			
	OC707	189'	Instr. Motor Gen Rm			
	OC709	189'	Electrical Chase			
	OC711	189'	Passage			
	OC712	189'	HVAC Room			
17.	Zone 1-24					6/0
	OC703	139'	Control Cabinet Area	4/0(CO_2)		
18.	Zone 1-27					2/0
	OC208	1.1'	Div II Remote Shutdown Panel	0/1(CO_2)		
	OC208A	111'	Div I Remote Shutdown Panel	0/1(CO_2)		
19.	Control Room HVAC Intake Plenum Mounted Detectors					2/0
c.	AUXILIARY BUILDING					
1.	Zone 2-2					23/0
	1A211	119'	North Corridor (Partial)			
	1A215	119'	South Corridor (Partial)			
	1A222	119'	West Corridor			
2.	Zone 2-3					5/0
	1A219	119'	Electrical Swgr Rm	0/2(CO_2)		
	1A220	119'	Piping Penetration Rm			
	1A221	119'	Electrical Swgr Rm	0/2(CO_2)		
3.	Zone 2-4					22/0
	1A102	93'	RHR "A" Heat Ex Rm			
	1A103	93'	RHR "A" Pump Rm			
	1A104	93'	RCIC Pump Rm			
	1A105	93'	RHR "B" Pump Rm			
	1A106	93'	RHR "B" Heat Ex Rm			
	1A128	108'	RHR "A" Heat Ex Rm			

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TABLE 3.3.7.9-1
FIRE DETECTION INSTRUMENTATION

			MINIMUM INSTRUMENTS OPERABLE*		
ROOM	ELEV	ROOM NAME	HEAT (X/Y)	FLAME(1) (X/Y)	SMOKE(1) (X/Y)
3. Zone 2-4 (Continued)					
1A129	108'	RHR "B" Heat Ex Rm			
1A202	119'	RHR "A" Heat Ex Rm			
1A203	119'	Piping Penetration Rm			
1A204	119'	Piping Penetration Rm			
1A205	119'	Piping Penetration Rm			
1A206	119'	RHR "B" Heat Ex Rm			
1A207	119'	Electrical Swgr Rm	0/3(CO$_2$)		
1A208	119'	Electrical Swgr Rm	0/3(CO$_2$)		
1A209	115'	RWCU Recirc Pump "A" Rm			
1A210	115'	RWCU Recirc Pump "B" Rm			
1A223	128'	Passage			
4. Zone 2-5					5/0
1A318	139'	Electrical Penetration Room	0/2(CO$_2$)		
1A319	139'	RPV Instr Test Rm			
1A320	139'	Electrical Penetration Room	0/2(CO$_2$)		
5. Zone 2-6					26/0
1A301	139'	East Corridor			
1A302	139'	Southeast Corridor			
1A303	139'	RHR "A" Heat Ex Rm			
1A304	139'	Piping Penetration Rm			
1A306	139'	Piping Penetration Rm			
1A307	139'	RHR "B" Heat Ex Rm			
1A308	139'	Electrical Penetration Room	0/3(CO$_2$)		
1A309	139'	Electrical Penetration Room	0/3(CO$_2$)		
1A314	139'	South Corridor (Partial)			
1A316	139'	North Corridor (Partial)			
6. Zone 2-7					11/0
1A417	166'	North Corridor (Partial)			
1A420	166'	South Corridor (Partial)			
1A424	166'	Set Down Area (Partial)			
1A428	166'	West Corridor			
1A432	166'	FPC & CU Pump Rm			
1A434	166'	South Passage			

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TABLE 3.3.7.9-1
FIRE DETECTION INSTRUMENTATION

ROOM	ELEV	ROOM NAME	MINIMUM INSTRUMENTS OPERABLE* HEAT (X/Y)	FLAME(1) (X/Y)	SMOKE(1) (X/Y)
7. Zone 2-8					25/0
1A401	166'	Northeast Corridor			
1A402	166'	Steam Tunnel Roof			
1A403	166'	Southeast Corridor			
1A404	166'	Unassigned Area			
1A405	166'	Containment Vent. Equip Room			
1A406	166'	Containment Exhaust Filter Rm			
1A407	166'	MCC Area	0/2(CO_2)		
1A410	166'	MCC Area	0/2(CO_2)		
1A417	166'	North Corridor (Partial)			
1A420	166'	South Corridor (Partial)			
1A424	166'	Set Down Area (Partial)			
8. Zone 2-9					10/0
1A519	185'	Storage Area			
1A524	195'	Platform			
1A527	185'	Load Center Area			
1A529	185'	FPC & CU Rm			
1A538	185'	Platform			
9 Zone 2-13					31/0
1A602	208'	Storage Area			
1A603	208'	Passage			
1A604	208'	Fuel Handling Area			
1A606	245'	HVAC Equip Area			
10. Zone 2-14					17/0
1A114	93'	Fan Coil Area (Partial)			
1A115	93'	Piping Penetration Rm			
1A116	93'	Piping Penetration Rm			
1A117	93'	Misc Equip Area (Partial)			
1A118	93'	RHR "C" Pump Room			
1A119	93'	LPCS Pump Room			
1A120	93'	CCW Pump & Heat Ex Rm			
1A122	103'	South Corridor (Partial)			
1A123	103'	North Corridor (Partial)			
11. Zone 2-15					1/0
1A539	185'	Cable Chase			

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TABLE 3.3.7.9-1
FIRE DETECTION INSTRUMENTATION

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

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TABLE 3.3.7.9-1
FIRE DETECTION INSTRUMENTATION

	ROOM	ELEV	ROOM NAME	MINIMUM INSTRUMENTS OPERABLE*		
				HEAT (X/Y)	FLAME(1) (X/Y)	SMOKE(1) (X/Y)
3. Zone 2-12					6/0	
	1D302	133'	Day Tank Area			
	1D310	133'	Div I Diesel Gen Room			
	1D403	158'	Div I Diesel Gen Room	0/7 (Deluge)		
e. STANDBY SERVICE WATER PUMP HOUSE						
1. Zone 2-1						4/0
	1M110	133'	SSW Pump Rm A			
	1M112	133'	SSW Valve Rm A			
	2M110	133'	SSW Pump Rm B			
	2M112	133'	SSW Valve Rm B			
f. CHARCOAL FILTER TRAINS						
1. Standby Gas Treatment System Filter Trains A & B Auxiliary Building El. 139'				2/0 (Allison Thermistor Wire)		
2. Control Room Standby Fresh Air System Filter Trains A & B Control Building El. 133'				2/0 (Allison Thermistor Wire)		
g. CONTROL BUILDING (PGCC HALON SYSTEMS)						
	OC503	166'	Control Room (Unit 1 side)			
			Module/Halon Panel			
			1H13-U700/1H13-P900	0/10		10/0
			1H13-U701/1H13-P901	0/10		15/0
			1H13-U702/1H13-P902	0/9		14/0
			1H13-U703/1H13-P903	0/11		17/0
			1H13-U720/1H13-P920	0/7		13/0
			SH13-U730/1H13-P930	0/11		12/0
			1H13-U738/1H13-P938	0/10		12/0
			SH13-U739/5H13-P939	0/5		14/0

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TABLE 3.3.7.9-1
FIRE DETECTION INSTRUMENTATION

ROOM	ELEV	ROOM NAME	MINIMUM INSTRUMENTS OPERABLE*		
			HEAT (X/Y)	FLAME[1] (X/Y)	SMOKE[1] (X/Y)
OC504	166'	Unit 1 Instrument Rack Area			
		Module/Halon Panel			
		1H13-U710/1H13-P910	0/8		15/0
		1H13-U711/1H13-P911	0/8		14/0
		1H13-U712/1H13-P912	0/8		9/0
		1H13-U714/1H13-P914	0/10		13/0
		1H13-U732/1H13-P932	0/8		14/0
		1H13-U733/1H13-P933	0/8		13/0
		1H13-U734/1H13-P934	0/8		13/0
		1H13-U735/1H13-P935	0/8		11/0
OC703	189'	Unit 1 Instrument Rack Area			
		Module/Halon Panel			
		1H13-U713/1H13-P913	0/9		15/0
		1H13-U715/1H13-P915	0/8		10/0
		1H13-U717/1H13-P917	0/8		15/0
		1H13-U736/1H13-P936	0/8		14/0
		1H13-U737/1H13-P937	0/8		10/0

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LOOSE-PART DETECTION SYSTEM

LIMITING CONDITION FOR OPERATION

3.3.7.10 The loose-part detection system shall be OPERABLE.

APPLICABILITY: OPERATIONAL CONDITIONS 1 and 2.

ACTION:

a. With one or more loose part detection system channels inoperable for more than 30 days, ~~in lieu of any other report required by Specification 6.9.1,~~ 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 channel(s) to OPERABLE status. /093

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

SURVEILLANCE REQUIREMENTS

4.3.7.10 Each channel of the loose-part detection system shall be demonstrated OPERABLE by performance of a:

a. CHANNEL CHECK at least once per 24 hours,

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

c. CHANNEL CALIBRATION at least once per 18 months.

RADIOACTIVE LIQUID EFFLUENT MONITORING INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.7.11 The radioactive liquid effluent monitoring instrumentation channels shown in Table 3.3.7.11-1 shall be OPERABLE with their alarm/trip setpoints set to ensure that the limits of Specification 3.11.1.1 are not exceeded. The alarm/trip setpoints of these channels shall be determined in accordance with the Offsite Dose Calculation Manual (ODCM). /018

APPLICABILITY: At all times.

ACTION:

a. With a radioactive liquid effluent monitoring instrumentation channel alarm/trip setpoint less conservative than required by the above specification, immediately suspend the release of radioactive liquid effluents monitored by the affected channel or declare the channel inoperable.

-018 | b. With less than the minimum number of radioactive liquid effluent monitoring instrumentation channels OPERABLE, take the ACTION shown in Table 3.3.7.11-1. Restore the inoperable instrumentation to OPERABLE status within the time specified in the ACTION ~~or~~ and, if unsuccessful, explain why this inoperability was not corrected in a timely manner in the next Semiannual Radioactive Effluent Release Report.

c. The provisions of Specifications 3.0.3, and 3.0.4 ~~and 6.9.1.11~~ are not applicable. /093

SURVEILLANCE REQUIREMENTS

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

TABLE 3.3.7.11-1

RADIOACTIVE LIQUID EFFLUENT MONITORING INSTRUMENTATION

INSTRUMENT	MINIMUM CHANNELS OPERABLE	ACTION	
1. GROSS RADIOACTIVITY MONITORS PROVIDING ALARM AND AUTOMATIC TERMINATION OF RELEASE			/361
a. Liquid Radwaste Effluent Line	1	110	
2. FLOW RATE MEASUREMENT DEVICES			
a. Liquid Radwaste Effluent Line	1	111	
b. Discharge Canal or Circulating Water Blowdown	1	111	/361

TABLE 3.3.7.11-1 (Continued)

RADIOACTIVE LIQUID EFFLUENT MONITORING INSTRUMENTATION

ACTION STATEMENTS

ACTION 110 - With the number of channels OPERABLE less than required by the Minimum Channels OPERABLE requirement, effluent releases from this pathway may continue for up to 14 days provided that prior to initiating a release:

a. At least two independent samples are analyzed in accordance with Specification 4.11.1.1.1, and

b. At least two technically qualified members of the Facility Staff independently verify the release rate calculations and discharge line valving;

Otherwise, suspend release of radioactive effluents via this pathway.

ACTION 111 - With the number of channels OPERABLE less than required by the Minimum Channels OPERABLE requirement, effluent releases via this pathway may continue for up to 30 days provided the flow rate is estimated at least once per 4 hours during actual releases. Pump curves may be used to estimate flow.

TABLE 4.3.7.11-1

RADIOACTIVE LIQUID EFFLUENT MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS

INSTRUMENT	CHANNEL CHECK	SOURCE CHECK	CHANNEL CALIBRATION	CHANNEL FUNCTIONAL TEST
1. GROSS RADIOACTIVITY MONITORS PROVIDING ALARM AND AUTOMATIC TERMINATION OF RELEASE				
a. Liquid Radwaste Effluent Line	D	P	R(2)	Q(1)
2. FLOW RATE MEASUREMENT DEVICES				
a. Liquid Radwaste Effluent Line	D(3)	N.A.	R	Q
b. Discharge Canal or Circulating Water Blowdown	D(3)	N.A.	R	Q

/361

TABLE 4.3.7.11-1 (Continued)

RADIOACTIVE LIQUID EFFLUENT MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS

TABLE NOTATION

(1) The CHANNEL FUNCTIONAL TEST shall also demonstrate that automatic isolation of this pathway and control room alarm annunciation occur if any of the following conditions exists:

1. Instrument indicates measured levels above the alarm/trip setpoint.

2. Circuit failure.

3. Instrument indicates a downscale failure.

4. Instrument controls not set in operate mode.

(2) The initial CHANNEL CALIBRATION shall be performed using one or more of the reference standards certified by the National Bureau of Standards or using standards that have been obtained from suppliers that participate in measurement assurance activities with NBS. These standards shall permit calibrating the system over its intended range of energy and measurement range. For subsequent CHANNEL CALIBRATION, sources that have been related to the initial calibration shall be used.

(3) CHANNEL CHECK shall consist of verifying indication of flow during periods of release. CHANNEL CHECK shall be made at least once per 24 hours on days which batch releases are made.

INSTRUMENTATION

RADIOACTIVE GASEOUS EFFLUENT MONITORING INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.7.12 The radioactive gaseous effluent monitoring instrumentation channels shown in Table 3.3.7.12-1 shall be OPERABLE with their alarm/trip setpoints set to ensure that the limit of Specification 3.11.2.1* are not exceeded. The alarm/trip setpoints of ~~these~~ applicable channels shall be determined in accordance with the ODCM. /045

APPLICABILITY: As shown in Table 3.3.7.12-1

ACTION:

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

b. With less than the minimum number of radioactive gaseous effluent monitoring instrumentation channels OPERABLE, take the ACTION shown in Table 3.3.7.12-1. Restore the inoperable instrumentation to OPERABLE status within the time specified in the ACTION ~~or~~ and, if unsuccessful, explain why this inoperability was not corrected in a timely manner in the next Semiannual Radioactive Effluent Release Report. 018|

c. The provisions of Specifications 3.0.3, and 3.0.4 ~~and 6.9.1.11~~ are not applicable. /093

SURVEILLANCE REQUIREMENTS

4.3.7.12 Each radioactive gaseous effluent monitoring instrumentation channel shall be demonstrated OPERABLE by performance of the CHANNEL CHECK, SOURCE CHECK, CHANNEL CALIBRATION and CHANNEL FUNCTIONAL TEST operations at the frequencies shown in Table 4.3.7.12-1.

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* See Specification 3.11.2.6 and 3.11.2.7 for the Explosive Gas Monitor and Offgas Pretreatment Monitor limits. /045

TABLE 3.3.7.12-1

RADIOACTIVE GASEOUS EFFLUENT MONITORING INSTRUMENTATION

INSTRUMENT	MINIMUM CHANNELS OPERABLE	APPLICABILITY	ACTION
1. RADWASTE BUILDING VENTILATION MONITORING SYSTEM			
a. Noble Gas Activity Monitor - Providing Alarm	1	*	121
b. Iodine Sampler	1	*	122
c. Particulate Sampler	1	*	122
d. Effluent System Flow Rate Measuring Device	1	*	123
e. Sampler Flow Rate Measuring Device	1	*	123
2. MAIN CONDENSER OFFGAS TREATMENT SYSTEM EXPLOSIVE GAS MONITORING SYSTEM			
a. Hydrogen Monitor	1	**	124
3. CONTAINMENT VENTILATION MONITORING SYSTEM			
a. Noble Gas Activity Monitor Providing Alarm	1	*	121
b. Iodine Sampler	1	*	122
c. Particulate Sampler	1	*	122
d. Effluent System Flow Rate Monitor	1	*	123
e. Sampler Flow Rate Monitor	1	*	123

TABLE 3.3.7.12-1 (Continued)

RADIOACTIVE GASEOUS EFFLUENT MONITORING INSTRUMENTATION

INSTRUMENT	MINIMUM CHANNELS OPERABLE	APPLICABILITY	ACTION
4. TURBINE BLDG. VENTILATION MONITORING SYSTEM			
a. Noble Gas Activity Monitor	1	*	121
b. Iodine Sampler	1	*	122
c. Particulate Sampler	1	*	122
d. Effluent System Flow Rate Monitor	1	*	123
e. Sampler Flow Rate Monitor	1	*	123
5. FUEL HANDLING AREA VENTILATION MONITORING SYSTEM			
a. Noble Gas Activity Monitor	1	*	121
b. Iodine Sampler	1	*	122
c. Particulate Sampler	1	*	122
d. Flow Rate Monitor	1	*	123
e. Sampler Flow Rate Monitor	1	*	123

TABLE 3.3.7.12-1 (Continued)

RADIOACTIVE GASEOUS EFFLUENT MONITORING INSTRUMENTATION

INSTRUMENT	MINIMUM CHANNELS OPERABLE	APPLICABILITY	ACTION	
6. OFFGAS PRE-TREATMENT MONITOR				
a. Noble Gas Activity Monitor	1	***	126	
7. OFFGAS POST-TREATMENT MONITOR				
a. Noble Gas Activity Monitor Providing Alarm and Automatic Termination of Release	~~1~~ 2	**	~~121~~ 125	/120
8. STANDBY GAS TREATMENT EXHAUST MONITORING SYSTEM (A&B)				
a. Noble Gas Activity Monitor	1/system	*	127	/262

TABLE 3.3.7.12-1 (Continued)

RADIOACTIVE GASEOUS EFFLUENT MONITORING INSTRUMENTATION

TABLE NOTATION

* At all times.

** During main condenser offgas treatment system operation.

*** During operation of the main condenser air ejector.

ACTION 121 - With the number of channels OPERABLE less than required by the Minmum Channels OPERABLE requirement, effluent releases via this pathway may continue for up to 30 days provided grab samples are taken at least once per 8 hours and these samples are analyzed for gross activity within 24 hours.

ACTION 122 - With the number of channels OPERABLE less than required by the Minimum Channels OPERABLE requirement, effluent releases via this pathway may continue for up to 30 days provided samples are continuously collected with auxiliary sampling equipment as required by Table 4.11.2.1.2-1.

ACTION 123 - With the number of channels OPERABLE less than required by the Minimum Channels OPERABLE requirement, effluent release via this pathway may continue for up to 30 days provided the flow rate is estimated at least once per 8 hours.

ACTION 124 - With the number of channels OPERABLE less than required by the Minimum Channels OPERABLE requirement, operation of main condenser offgas treatment system may continue for up to 30 days provided grab samples are collected at least once per 4 hours and analyzed within the following 4 hours.

ACTION 125 - ~~[DELETED]~~

ACTION 126 - With the number of channels OPERABLE less than required by the Minimum Channels OPERABLE requirement, the SJAE effluent may be released to the environment for up to 72 hours provided:

a. The offgas system is not bypassed, except for filtration system bypass during plant startups, and

b. The offgas delay system noble gas activity effluent downstream monitor is OPERABLE;

Otherwise, be in at least HOT SHUTDOWN ~~STANDBY~~ within 12 hours, and in COLD SHUTDOWN within the following 24 hours. |185

a. With one of the required monitors inoperable, place the inoperable channel in the downscale tripped condition within one hour. |120

b. With both of the required monitors inoperable, effluent releases via this pathway may continue for up to 30 days provided grab samples are taken at least once per 8 hours and these samples are analyzed for gross activity within 24 hours.

ACTION 127 - With the number of channels OPERABLE less than required by the Minmum Channels OPERABLE requirement, effluent releases via this pathway may continue for up to 30 days provided grab samples are taken at least once per ~~8~~ 24 hours and these samples are analyzed for gross activity within 24 hours.

day

TABLE 4.3.7.12-1

RADIOACTIVE GASEOUS EFFLUENT MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS

INSTRUMENT	CHANNEL CHECK	SOURCE CHECK	CHANNEL CALIBRATION	CHANNEL FUNCTIONAL TEST	MODES IN WHICH SURVEILLANCE REQUIRED
1. RADWASTE BUILDING VENTILATION MONITORING SYSTEM					
a. Noble Gas Activity Monitor - Providing Alarm	D	M	A(3)	Q(2)	*
b. Iodine Sampler	W	N.A.	N.A.	N.A.	*
c. Particulate Sampler	W	N.A.	N.A.	N.A.	*
d. Flow Rate Monitor	D	N.A.	R	Q (5)	* /122
e. Sampler Flow Rate Monitor	D	N.A.	R	N.A.	*
2. MAIN CONDENSER OFFGAS TREATMENT SYSTEM EXPLOSIVE GAS MONITORING SYSTEM					
a. Hydrogen Monitor	D	N.A.	Q(4)	M	**
3. CONTAINMENT VENTILATION MONITORING SYSTEM					
a. Noble Gas Activity Monitor Providing Alarm	D	M	A(3)	Q(2)	*
b. Iodine Sampler	W	N.A.	N.A.	N.A.	*
c. Particulate Sampler	W	N.A.	N.A.	N.A.	*
d. Effluent System Flow Rate Monitor	D	N.A.	R	Q (5)	* /122
e. Sampler Flow Rate Monitor	D	N.A.	R	N.A.	*

TABLE 4.3.7.12-1 (Continued)

RADIOACTIVE GASEOUS EFFLUENT MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS

INSTRUMENT	CHANNEL CHECK	SOURCE CHECK	CHANNEL CALIBRATION	CHANNEL FUNCTIONAL TEST	MODES IN WHICH SURVEILLANCE REQUIRED
4. TURBINE BLDG. VENTILATION MONITORING SYSTEM					
a. Noble Gas Activity Monitor	D	M	A(3)	Q(2)	*
b. Iodine Sampler	W	N.A.	N.A.	N.A.	*
c. Particulate Sampler	W	N.A.	N.A.	N.A.	*
d. Flow Rate Monitor	D	N.A.	R	Q (5)	* /122
e. Sampler Flow Rate Monitor	D	N.A.	R	N.A.	*
5. FUEL HANDLING AREA VENTILATION MONTORING SYSTEM					
a. Noble Gas Activity Monitor	D	M	A(3)	Q(2)	*
b. Iodine Sampler	W	N.A.	N.A.	N.A.	*
c. Particulate Sampler	W.	N.A.	N.A.	N.A.	*
d. Flow Rate Monitor	D	N.A.	R	Q (5)	* /122
e. Sampler Flow Rate Monitor	D	N.A.	R	N.A.	*

TABLE 4.3.7.12-1 (Continued)

RADIOACTIVE GASEOUS EFFLUENT MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS

INSTRUMENT	CHANNEL CHECK	SOURCE CHECK	CHANNEL CALIBRATION	CHANNEL FUNCTIONAL TEST	MODES IN WHICH SURVEILLANCE REQUIRED
6. OFFGAS PRE-TREATMENT MONITOR					
a. Noble Gas Activity Monitor	D	M#	A(3)##	Q(2)	***
7. OFFGAS POST-TREATMENT MONITOR					
a. Noble Gas Activity Monitor Providing Alarm and Automatic Termination of Release	D	M	A(3)##	Q(1)	**
8. STANDBY GAS TREATMENT EXHAUST MONITORING SYSTEM (A&B)					
a. Noble Gas Activity Monitor	D	M	A(3)	Q(2)	** /262

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TABLE 4.3.7.12-~~2~~ (Continued)

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RADIOACTIVE GASEOUS EFFLUENT MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS

TABLE NOTATION

* At all times.

** During main condenser offgas treatment system operation.

*** During operation of the main condenser air ejector.

\# SOURCE CHECK may be deferred to the next shutdown of greater than 8 hours duration if unable to be performed at the monthly interval due to inaccessibility because of being in a high radiation area.

\#\# The sensor will be calibrated for mr/hr or cpm from the calibration standard. The conversion to release rate will be performed during subsequent unit operation, but within one week.

(1) The CHANNEL FUNCTIONAL TEST shall also demonstrate that automatic isolation of this pathway and control room alarm annunciation occurs if any of the following conditions exists:

1. Instrument indicates measured levels above the alarm/trip setpoint.
2. Circuit failure.
3. Instrument indicates a downscale failure.
4. Instrument controls not set in operate mode.

(2) The CHANNEL FUNCTIONAL TEST shall also demonstrate that control room alarm annuciation occurs if any of the following conditions exists:

1. Instrument indicates measured levels above the alarm setpoint.
2. Circuit failure.
3. Instrument indicates a downscale failure.
4. Instrument controls not set in operate mode.

(3) The initial CHANNEL CALIBRATION shall be performed using one or more of the reference standards certified by the National Bureau of Standards (NBS) or using standards that have been obtained from suppliers that participate in measurement assurance activities with NBS. These standards shall permit calibrating the system over its intended measurement range. For subsequent CHANNEL CALIBRATION, sources that have been related to the initial calibration shall be used.

(4) The CHANNEL CALIBRATION shall include the use of standard gas samples containing a nominal:

1. One volume percent hydrogen, balance nitrogen, and
2. Four volume percent hydrogen, balance nitrogen.

(5) Compare the measured flowrate to the expected design flowrate for existing plant conditions. /122

3/4.3.8 PLANT SYSTEMS ACTUATION INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.8 The plant systems actuation instrumentation channels shown in Table 3.3.8-1 shall be OPERABLE with their trip setpoints set consistent with the values shown in the Trip Setpoint column of Table 3.3.8-2.

APPLICABILITY: As shown in Table 3.3.8-1.

ACTION:

a. With a plant system actuation instrumentation channel trip setpoint less conservative than the value shown in the Allowable Values column of Table 3.3.8-2, declare the channel inoperable and take the ACTION required by Table 3.3.8-1.

b. With one or more plant systems actuation instrument channels inoperable, take the ACTION required by Table 3.3.8-1.

SURVEILLANCE REQUIREMENTS

4.3.8.1 Each plant system actuation instrumentation channel shall be demonstrated OPERABLE by the performance of the CHANNEL CHECK, CHANNEL FUNCTIONAL TEST and CHANNEL CALIBRATION operations for the OPERATIONAL CONDITIONS and at the frequencies shown in Table 4.3.8.1-1.

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

TABLE 3.3.8-1

PLANT SYSTEMS ACTUATION INSTRUMENTATION

TRIP FUNCTION	MINIMUM OPERABLE CHANNELS PER TRIP SYSTEM (a)	APPLICABLE OPERATIONAL CONDITIONS	ACTION
1. **CONTAINMENT SPRAY SYSTEM**			
a. Drywell Pressure-High	2	1, 2, 3	130
b. Containment Pressure-High	1	1, 2, 3	131
c. Reactor Vessel Water Level-Low Low Low, Level 1	2	1, 2, 3	130
d. Timers			
1) System A	1	1, 2, 3	131
2) System B	1	1, 2, 3	131
2. **FEEDWATER SYSTEM/MAIN TURBINE TRIP SYSTEM**			
a. Reactor Vessel Water Level-High, Level 8	3	1	132
3. SUPPRESSION POOL MAKEUP SYSTEM			
a. Drywell Pressure - High (ECCS)	2	1, 2, 3	135
b. Drywell Pressure - High (RPS)	2	1, 2, 3	135
c. Reactor Vessel Water Level - Low Low Low, Level 1	2	1, 2, 3	135
d. Reactor Vessel Water Level - Low Low, Level 2	2	1, 2, 3	135
e. Suppression Pool Water Level - Low	1	1, 2, 3	133
f. Suppression Pool Makeup Timer	1	1, 2, 3	133
g. SPMU Manual Initiation	2	1, 2, 3	134

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(a) A channel may be placed in an inoperable status for up to 2 hours during periods of required surveillance provided at least one other OPERABLE channel in the same trip system is monitoring that parameter.

TABLE 3.3.8-1 (Continued)

PLANT SYSTEMS ACTUATION INSTRUMENTATION

ACTION

ACTION 130 - a. With the number of OPERABLE channels one less than required by the Minimum OPERABLE Channels per Trip System requirement, place the inoperable channel in the tripped condition within one hour; otherwise, declare the associated containment spray system inoperable and take the action required by Technical Specification 3.6.3.2.

b. With the number of OPERABLE channels two less than required by the Minimum OPERABLE channels per Trip System requirement, declare the associated containment spray system inoperable and take the action required by Technical Specification 3.6.3.2.

ACTION 131 - With the number of OPERABLE channels less than required by the Minimum OPERABLE Channels per Trip System requirement, restore the channels to OPERABLE status within one hour; otherwise, declare the associated containment spray system inoperable and take the action required by Technical Specification 3.6.3.2.

ACTION 132 - For the feedwater system/main turbine trip system:

a. With the number of OPERABLE channels one less than required by the Minimum OPERABLE Channels requirement, restore the

ACTION 133 - With the number of OPERABLE channels less than required by the Minimum OPERABLE Channels per Trip System requirement, declare the the associated suppression pool makeup system inoperable and ~~take~~ the action required by ~~Technical~~ Specification 3.6.3.4.

AND

ACTION 134 - With the number of OPERABLE channels less than required by the Minimum OPERABLE Channels per Trip System requirement, restore the ~~[illegible]~~ inoperable channels to OPERABLE status within 8 hours; otherwise, declare the associated suppression pool makeup system inoperable and take the action required by ~~Technical~~ Specification 3.6.3.4.

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ACTION ~~[illegible]~~ ~~[illegible]~~ 135 - With the number of OPERABLE channels less than required by the Minimum OPERABLE Channels per Trip Function requirement:

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

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

---

* The provisions of Specification 3.0.4 are NOT applicable.

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TABLE 3.3.8-2

PLANT SYSTEMS ACTUATION INSTRUMENTATION SETPOINTS

TRIP FUNCTION	TRIP SETPOINT	ALLOWABLE VALUE	
1. **CONTAINMENT SPRAY SYSTEM**			
a. Drywell Pressure-High	≤ 1.39 psig	≤ 1.44 psig	|
b. Containment Pressure-High	≤ 7.84 psig	≤ 8.34 psig	|
c. Reactor Vessel Water Level-Low Low Low, Level 1	≥ - 150.3 inches	≥ - 152.5 inches	
d. Timers			
1) System A	10.85 ± 0.10 minutes	10.26 - 0.00, + 1.18 minutes	|
2) System B	10.85 ± 0.10 minutes**	10.26 - 0.00, + 1.18 minutes	|
2. **FEEDWATER SYSTEM/MAIN TURBINE TRIP SYSTEM**			
a. Reactor Vessel Water Level-High, Level 8	≤ 53.5 inches*	≤ ~~55.7~~ 54.1 inches	/345

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

**Setpoint for System B is the sum of E12-K093B plus E12-K116. E12-K116 is not to exceed 10.00 seconds. |

3. SUPPRESSION POOL MAKEUP SYSTEM			
a. Drywell Pressure - High (ECCS)	≤ 1.39 psig	≤ 1.44 psig	
b. Drywell Pressure - High (RPS)	≤ 1.23 psig	≤ 1.43 psig	
c. Reactor Vessel Water Level - Low Low Low, Level 1	≥ -150.3 inches *	≥ -152.5 inches	
d. Reactor Vessel Water Level - Low Low, Level 2	≥ -41.6 inches *	≥ -43.8 inches	/083
e. Suppression Pool Water Level - Low	≥ 16 ft 4 inches [redacted]	≥ 15 ft 6.5 inches [redacted]	
f. Suppression Pool Makeup Timer	≤ 29.0 minutes	≤ 29.5 minutes	
g. SPMU Manual Initiation	NA	NA	

TABLE 4.3.8.1-1

PLANT SYSTEMS ACTUATION INSTRUMENTATION SURVEILLANCE REQUIREMENTS

TRIP FUNCTION	CHANNEL CHECK	CHANNEL FUNCTIONAL TEST	CHANNEL CALIBRATION	OPERATIONAL CONDITIONS IN WHICH SURVEILLANCE REQUIRED
1. CONTAINMENT SPRAY SYSTEM				
a. Drywell Pressure-High	S	M	R(a)	1, 2, 3
b. Containment Pressure-High	S	M	R(a)	1, 2, 3
c. Reactor Vessel Water Level - Low Low Low, Level 1	S	M	R(a)	1, 2, 3
d. Timers	NA	M	Q	1, 2, 3
2. FEEDWATER SYSTEM/MAIN TURBINE TRIP SYSTEM				
a. Reactor Vessel Water Level-High, Level 8	S	M	R	1
3. SUPPRESSION POOL MAKEUP SYSTEM				
a. Drywell Pressure - High (ECCS)	S	M	R(a)	1, 2, 3
b. Drywell Pressure - High (RPS)	S	M	R(a)	1, 2, 3
c. Reactor Vessel Water Level - Low Low Low, Level 1	S	M	R(a)	1, 2, 3
d. Reactor Vessel Water Level - Low Low, Level 2	S	M	R(a)	1, 2, 3
e. Suppression Pool Water Level - Low	S	M	R(a)	1, 2, 3
f. Suppression Pool Makeup Timer	NA	M	Q	1, 2, 3
g. SPMU Manual Initiation	NA	R	NA	1, 2, 3

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

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3/4.3.~~8~~9 TURBINE OVERSPEED PROTECTION SYSTEM ~~(Optional)~~

LIMITING CONDITION FOR OPERATION

3.3.~~8~~9 At least one turbine overspeed protection system shall be OPERABLE.

APPLICABILITY: OPERATIONAL CONDITIONS 1 and 2.

ACTION:

a. With one turbine control valve, one turbine throttle stop valve or one turbine reheat stop valve per high pressure turbine steam lead inoperable and/or with one turbine interceptor valve per low pressure turbine steam lead inoperable, restore the inoperable valve(s) to OPERABLE status within 72 hours or close at least one valve in the affected steam lead 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~~9.1 The provisions of Specification 4.0.4 are not applicable.

4.3.~~8~~9.2 The above required turbine overspeed protection system shall be demonstrated OPERABLE:

a. At least once per 14 days by cycling each of the following valves through at least one complete cycle from the running position using the manual test or Automatic Turbine Tester (ATT):
   1) Four high pressure turbine stop valves,
   2) Four high pressure turbine control valves.
   3) Six low pressure turbine stop valves, and
   4) Six low pressure turbine control valves.

b. At least once per 14 days by testing of the two mechanical overspeed devices using the Automatic Turbine Tester or manual test.

c. At least once per 40 months by disassembling at least one of each of the above valves and performing a visual and surface inspection of all valve seats, disks and stems and verifying no unacceptable flaws or excessive corrosion. If unacceptable flaws or excessive corrosion are found, all other valves of that type shall be inspected.

~~2) Four high pressure turbine reheat stop valves,~~

~~3) Four high pressure turbine control valves, and~~

~~4) Four low pressure turbine interceptor valves.~~

3/4.4 REACTOR COOLANT SYSTEM

3/4.4.1 RECIRCULATION SYSTEM

RECIRCULATION LOOPS

LIMITING CONDITION FOR OPERATION

3.4.1.1 Two reactor coolant system recirculation loops shall be in operation.

APPLICABILITY: OPERATIONAL CONDITIONS 1* and 2*.

ACTION:

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a. With one reactor coolant system recirculation loop not in operation, immediately initiate an orderly reduction of THERMAL POWER to less than or equal to ~~the limit~~ specified in Figure ~~3.4.1.1-1~~, and be in at least HOT SHUTDOWN within the next 12 hours. B 3/4 2.3-1

b. With no reactor coolant system recirculation loops in operation, immediately initiate an orderly reduction of THERMAL POWER to less than or equal to ~~the limit~~ specified in Figure ~~3.4.1.1-1~~, and initiate measures to place the unit in at least STARTUP within 6 hours and in HOT SHUTDOWN within the next 6 hours. B 3/4 2.3-1

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4.4.1.1.2 Each reactor coolant system recirculation loop flow control valve shall be demonstrated OPERABLE at least once per 18 months by:

a. Verifying that the control valve fails "as is" on loss of hydraulic pressure at the hydraulic unit, and

b. Verifying that the average rate of control valve movement is:

1. Less than or equal to 11% of stroke per second opening, and
2. Less than or equal to 11% of stroke per second closing.

---

*See Special Test Exception 3.10.4.

4.4.1.1.1 Both reactor coolant system recirculation loops shall be verified to be in operation at least once per 24 hours.

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P/L ~~ITEM 024 (4.4.1.2~~)
P/L ~~ITEM 236 (4.4.1.2~~)

INFORMATION ONLY

REACTOR COOLANT SYSTEM

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

4.4.1.2.1 Each of the above required jet pumps shall be demonstrated OPERABLE with ~~prior to~~ THERMAL POWER ~~exceeding~~ in excess of 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.~~ both indicated recirculation loop flows are in compliance with Specification 3.4.1.3. | 024 | 236

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%.

4.4.1.2.2 The provisions of Specification 4.0.4 are not applicable provided the diffuser-to-lower plenum differential pressures of the individual jet pumps are determined to be within 50%* of the loop average within 72 hours after entering OPERATIONAL CONDITION 2 and at least once per 24 hours thereafter. | 024

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* Initial value. Final value to be determined during startup test program. Any required changes to this value shall be submitted to the Commission within 90 days of test completion.

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 require 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.

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*See Special Test Exception 3.10.4.

IDLE RECIRCULATION LOOP STARTUP

LIMITING CONDITION FOR OPERATION

3.4.1.4 An idle recirculation loop shall not be started unless the temperature differential between the reactor pressure vessel steam space coolant and the bottom head drain line coolant is less than or equal to 100°F, and:

a. When both loops have been idle, unless the temperature differential between the reactor coolant within the idle loop to be started up and the coolant in the reactor pressure vessel is less than or equal to 50°F, or

b. When only one loop has been idle, unless the temperature differential between the reactor coolant within the idle and operating recirculation loops is less than or equal to 50°F and the operating loop flow rate is less than or equal to 50% of rated loop flow.

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

ACTION:

With temperature differences and/or flow rates exceeding the above limits, suspend startup of any idle recirculation loop.

SURVEILLANCE REQUIREMENTS

4.4.1.4 The temperature differentials and flow rate shall be determined to be within the limits within 15 minutes prior to startup of an idle recirculation loop.

b. The safety/relief tail-pipe pressure switches for each safety/relief valve shall be OPERABLE. 1257

REACTOR COOLANT SYSTEM

3/4.4.2 SAFETY VALVES

SAFETY/RELIEF VALVES

LIMITING CONDITION FOR OPERATION

3.4.2.1 ~~Of~~ For the following safety/relief valves, a) the safety valve function of at least 7 valves and the relief valve function of at least 6 valves other than those satisfying the specified safety valve function requirement shall be OPERABLE with the specified lift settings; and /023

Number of Valves	Function	Setpoint* (psig)
8	Safety	1165 ± 11.6 psi
6	Safety	1180 ± 11.8 psi
6	Safety	1190 ± 11.9 psi
1	Relief	1103 ± 15 psi
10#	Relief	1113 ± 15 psi
9	Relief	1123 ± 15 psi

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2 and 3.

ACTION:

a. With the safety and/or relief valve function of one or more of the above required safety/relief valves inoperable, be in at least HOT SHUTDOWN within 12 hours and in COLD SHUTDOWN within the next 24 hours.

b. With one or more safety/relief valves stuck open, provided that suppression pool average water temperature is less than 105°F, close the stuck open relief valve(s); if unable to close the open valve(s) within 2 minutes or if suppression pool average water temperature is 105°F or greater, place the reactor mode switch in the Shutdown position.

c. With one or more safety/relief tail-pipe pressure switches inoperable, restore the inoperable switch(es) 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.

d. With either relief valve function pressure actuation trip system "A" or "B" inoperable, restore the inoperable trip system to OPERABLE status within 7 days; otherwise be in at least HOT SHUTDOWN within 12 hours and in COLD SHUTDOWN within the following 24 hours. /023

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

#Initial opening of 1B21-F051B is 1103 ± 15 psig due to low-low set function.

REACTOR COOLANT

SAFETY/RELIEF VA

LIMITING CONDITI

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c. with either relief valve/low-low set function pressure actuation trip system "A" or "B" inoperable, restore the inoperable trip system to OPERABLE status within 7 days; otherwise, be in at least HOT SHUTDOWN within 12 hours and in COLD SHUTDOWN within the following 24 hours.

F047G	1113	946
F051A	1113	946
F051F	1113	946

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2 and 3.

ACTION:

a. With the relief valve function and/or the low-low set function of one of the above required reactor coolant system safety/relief valves inoperable, restore the inoperable relief valve function and the low-low set function to OPERABLE status within 14 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 relief valve function and/or the low-low set function of more than one of the above required reactor coolant system safety/relief valves inoperable, be in at least HOT SHUTDOWN within 12 hours and in COLD SHUTDOWN within the next 24 hours.

SURVEILLANCE REQUIREMENTS /023

4.4.2.2.1 The relief valve function and the low-low set function pressure actuation instrumentation shall be demonstrated OPERABLE by performance of a:

a. CHANNEL FUNCTIONAL TEST, including calibration of the trip unit, at least once per 31 days.

b. CHANNEL CALIBRATION, LOGIC SYSTEM FUNCTIONAL TEST and simulated automatic operation of the entire system at least once per 18 months. /023

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*The lift setting pressure shall correspond to ambient conditions of the valves at nominal operating temperatures and pressures.

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

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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 radioactivity monitoring system,

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

c. Either the drywell air coolers condensate flow rate monitoring system or the drywell atmosphere gaseous radioactivity monitoring system.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2 and 3.

ACTION:

With only two of the above required leakage detection systems OPERABLE, operation may continue for up to 30 days provided grab samples of the drywell atmosphere are obtained and analyzed at least once per 24 hours when the required gaseous and/or particulate radioactive 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 and 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 and equipment drain sump level and flow monitoring systems-performance of a CHANNEL FUNCTIONAL TEST at least once per 31 days and a CHANNEL CALIBRATION TEST at least once per 18 months.

c. 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.

OPERATIONAL LEAKAGE

LIMITING CONDITION FOR OPERATION

3.4.3.2 Reactor coolant system leakage shall be limited to:

a. No PRESSURE BOUNDARY LEAKAGE.

b. 5 gpm UNIDENTIFIED LEAKAGE.

c. 30 gpm total leakage.

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

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

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2 and 3.

ACTION:

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

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

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

032 | and/or interlocks

d. With one or more high/low pressure interface valve ~~leakage~~ pressure monitors~~,~~ inoperable, ~~restore the inoperable monitor(s) to OPERABLE status within 7 days or verify the pressure to be less than the alarm point at least once per 12 hours;~~ restore the inoperable monitor(s) and/or interlocks to OPERABLE status within 30 days or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

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

SURVEILLANCE REQUIREMENTS

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

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

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

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

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

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

a. At least once per 18 months, and

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

In addition, until the LPCS system and the RHR system injection valve reactor coolant pressure-low permissive is modified during or before the first refueling outage, the LPCS system check valve 1E21-F006 and the RHR system check valves 1E12-F041 A, B, and C shall also be demonstrated OPERABLE by verifying leakage to be within its limit:

1. Whenever the unit has been in COLD SHUTDOWN or REFUELING, after the last valve disturbance prior to reactor coolant system temperature exceeding 200°F.

2. Within 24 hours following valve disturbance except when in COLD SHUTDOWN or REFUELING.

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

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

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

b. CHANNEL CALIBRATION at least once per 18 months.

TABLE 3.4.3.2-1

REACTOR COOLANT SYSTEM PRESSURE ISOLATION VALVES

VALVE NUMBER	SYSTEM
E21-F005	LPCS
E21-F006	
E22-F004	HPCS
E22-F005	
E12-F008	RHR
E12-F009	
E12-F023	
E12-F041 A,B,C	
E12-F042 A,B,C	
E12-F050 A,B	
E12-F053 A,B	
E12-F308	
E51-F063	RCIC
E51-F064	
E51-F065	
E51-F066	
E51-F076	
E51-F013	

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TABLE 3.4.3.2-2

REACTOR COOLANT SYSTEM INTERFACE VALVES ~~LEAKAGE~~ PRESSURE Monitors - Alarm ~~MONITORS~~

VALVE NUMBER	SYSTEM	ALARM SETPOINT (psig)
E21-F005 to E21-F006	LPCS	≤ 50
E12-F008 to E12-F006A	RHR	≤~~135~~ 183
E12-F008 to E12-F006B	RHR	≤ 183
E12-F041A to E12-F042A	RHR	≤ 50
~~E12-F052 to E51-F064~~	~~RCIC~~	~~≤480~~
E12-F~~401~~041B to E12-F042B	RHR	≤ 50
E12-F~~4~~041C to E12-F042C	RHR	≤ 50

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TABLE 3.4.3.2-3

REACTOR COOLANT SYSTEM INTERFACE VALVES PRESSURE INTERLOCKS

03 2

VALVE NUMBER	SYSTEM	INTERLOCK SETPOINT (psig)
E12-F052 to E51-F064	RCIC	≤ 465
E12-F041A to E12-F042A	RHR	≤ 50
E12-F041B to E12-F042B	RHR	≤ 50
E12-F041C to E12-F042C	RHR	≤ 50
E21-F005 to E21-F006	LPCS	≤ 50

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, for conductivity and chloride concentration, 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 as rapidly as practical within the cooldown rate limit.

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 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.

   2. With the chloride concentration exceeding the limit specified in Table 3.4.4-1 for more than 24 hours, 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.

   3. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.4.4 The reactor coolant shall be determined to be within the specified chemistry limit by:

a. Measurement prior to pressurizing the reactor during each startup, if not performed within the previous 72 hours.

b. Analyzing a sample of the reactor coolant:

   1. Chlorides at least once per:

      a) 72 hours, and

      b) 8 hours whenever conductivity is greater than the limit in Table 3.4.4-1.

   2. Conductivity at least once per 72 hours.

   3. pH at least once per:

      a) 72 hours, and

      b) 8 hours whenever conductivity is greater than the limit in Table 3.4.4-1.

c. Continuously recording the conductivity of the reactor coolant, or, when the continuous recording conductivity monitor is inoperable ~~for up to 31 days,~~ obtaining an in-line conductivity measurement at least once per: /055

   1. 4 hours in OPERATIONAL CONDITIONS 1, 2 and 3, and

   2. 24 hours at all other times.

d. Performance of a CHANNEL CHECK of the continuous conductivity monitor with an in-line flow cell at least once per:

   1. 7 days, and

   2. 24 hours whenever conductivity is greater than the limit in Table 3.4.4-1.

TABLE 3.4.4-1

REACTOR COOLANT SYSTEM
CHEMISTRY LIMITS

OPERATIONAL CONDITION	CHLORIDES	CONDUCTIVITY (μmhos/cm @25°C)	PH
1	≤ 0.2 ppm	≤ 1.0	$5.6 \le pH \le 8.6$
2 and 3	≤ 0.1 ppm	≤ 2.0	$5.6 \le pH \le 8.6$
At all other times	≤ 0.5 ppm	≤ 10.0	$5.3 \le pH \le 8.6$

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/Ē 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, operation may continue for up to 48 hours provided that the cumulative operating time under these circumstances does not exceed 800 hours in any consecutive 12-month period. With the total cumulative operating time at a primary coolant specific activity greater than 0.2 microcuries per gram DOSE EQUIVALENT I-131 exceeding 500 hours in any consecutive six-month period, prepare and submit a Special Report to the Commission pursuant to Specification 6.9.2 within 30 days indicating the number of hours of operation above this limit. The provisions of Specification 3.0.4 are not applicable.

2. Greater than 0.2 microcuries per gram DOSE EQUIVALENT I-131 for more than 48 hours during one continuous time interval or for more than 800 hours cumulative operating time in a consecutive 12-month period, or greater than 4.0 microcuries per gram, be in at least HOT SHUTDOWN with the main steam line isolation valves closed within 12 hours.

3. Greater than 100/Ē microcuries per gram, be in at least HOT SHUTDOWN with the main steamline isolation valves closed within 12 hours.

b. In OPERABLE 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/Ē 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. A Special Report ~~REPORTABLE OCCURRENC~~E shall be prepared and submitted to the Commission pursuant to Specification 6.9.~~1~~2 within 30 days. This report shall contain the results of the specific activity analyses and the time duration when the specific activity of the coolant exceeded 0.2 microcuries per gram DOSE EQUIVALENT I-131 together with the following additional information.

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LIMITING CONDITION FOR OPERATION (Continued)

ACTION (Continued)

c. In OPERATIONAL CONDITION 1 or 2, with:

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

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

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

perform the sampling and analysis requirements of Item 4b of Table 4.4.5-1 until the specific activity of the primary coolant is restored to within its limit. Prepare and submit to the Commission a Special Report pursuant to Specification 6.9.2 at least once per 92 days containing the results of the specific activity analysis together with the below additional information for each occurrence.

Additional Information

1. Reactor power history starting 48 hours prior to:
   a) The first sample in which the limit was exceeded, and/or
   b) The THERMAL POWER or off-gas level change.
2. Fuel burnup by core region.
3. Clean-up flow history starting 48 hours prior to:
   a) The first sample in which the limit was exceeded, and/or
   b) The THERMAL POWER or off-gas level change.
4. Off-gas level starting 48 hours prior to:
   a) The first sample in which the limit was exceeded, and/or
   b) The THERMAL POWER or off-gas level change.

SURVEILLANCE REQUIREMENTS

4.4.5 The specific activity of the reactor coolant shall be demonstrated to be within the limits by performance of the sampling and analysis program of Table 4.4.5-1.

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*Not applicable during the startup test program.

TABLE 4.4.5-1

PRIMARY COOLANT SPECIFIC ACTIVITY SAMPLE AND ANALYSIS PROGRAM

TYPE OF MEASUREMENT AND ANALYSIS	SAMPLE AND ANALYSIS FREQUENCY	OPERATIONAL CONDITIONS IN WHICH SAMPLE AND ANALYSIS REQUIRED
1. Gross Beta and Gamma Activity Determination	At least once per 72 hours	1, 2, 3
2. Isotopic Analysis for DOSE EQUIVALENT I-131 Concentration	At least once per 31 days	1
3. Radiochemical for Ē Determination	At least once per 6 months*	1
4. Isotopic Analysis for Iodine	a) At least once per 4 hours, whenever the specific activity exceeds a limit, as required by ACTION b.	1#, 2#, 3#, 4#
	b) At least one sample, between 2 and 6 hours following the change in THERMAL POWER or off-gas level, as required by ACTION c.	1, 2
5. Isotopic Analysis of an Off-gas Sample Including Quantitative Measurements for at least Xe-133, Xe-135 and Kr-88	At least once per 31 days	1

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*Sample to be taken after a minimum of 2 EFPD and 20 days of POWER OPERATION have elapsed since reactor was last subcritical for 48 hours or longer.

#Until the specific activity of the primary coolant system is restored to within its limits.

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 and reactor vessel metal temperature shall be limited in accordance with the limit lines shown on Figure 3.4.6.1-1 (1) curve A for hydrostatic or leak testing; (2) curve B for heatup by non-nuclear means, cooldown following a nuclear shutdown and low power PHYSICS TESTS; and (3) curve C for operations with a critical core other than low power PHYSICS TESTS, with: 160

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

b. A maximum reactor coolant cooldown of 100°F in any one hour period, 160

c. A maximum temperature change of less than or equal to 10°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 or ~~B,~~ B and B' as applicable, at least once per 30 minutes.

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the reactor
coolant system
pressure and
reactor vessel
metal temperature
shall be determined
to be

SURVEILLANCE REQUIREMENTS (Continued)

and reactor vessel metal temperature

4.4.6.1.2 The reactor coolant system ~~temperature and~~ pressure shall be determined to be to the right of the criticality limit line of Figure 3.4.6.1-1 curves C and C' within 15 minutes prior to the withdrawal of control rods to bring the reactor to criticality and at least once per 30 minutes during system heatup.

4.4.6.1.~~3~~ 4 The reactor vessel material specimens shall be removed and examined ~~to determine reactor pressure vessel fluence~~ as a function of time and THERMAL POWER as required by 10 CFR 50, Appendix H in accordance with the schedule in Table 4.4.6.1.3-1. T~~he results of these fluence determinations shall be used~~ to ~~update the curves of Figure 3.4.6.1-1. The adjusted reference temperature resulting from neutron irradiation shall be calculated based on the greater of the following:~~ 160

~~a. Actual shift in the RT_{NDT} for materials in the capsules as defined by the CVN impact test.~~

~~b. Predicted shift in RT_{NDT} for plate C2594-2 and weld 627260/B322A27AE (heat/lot) as determined by Regulatory Guide 1.99, "Effects of Residual Elements on Predicted Radiation Damage to Reactor Vessel Materials".~~

4.4.6.1.~~4~~ 3 The reactor vessel flange and head flange temperature shall be verified to be greater than or equal to 70°F:

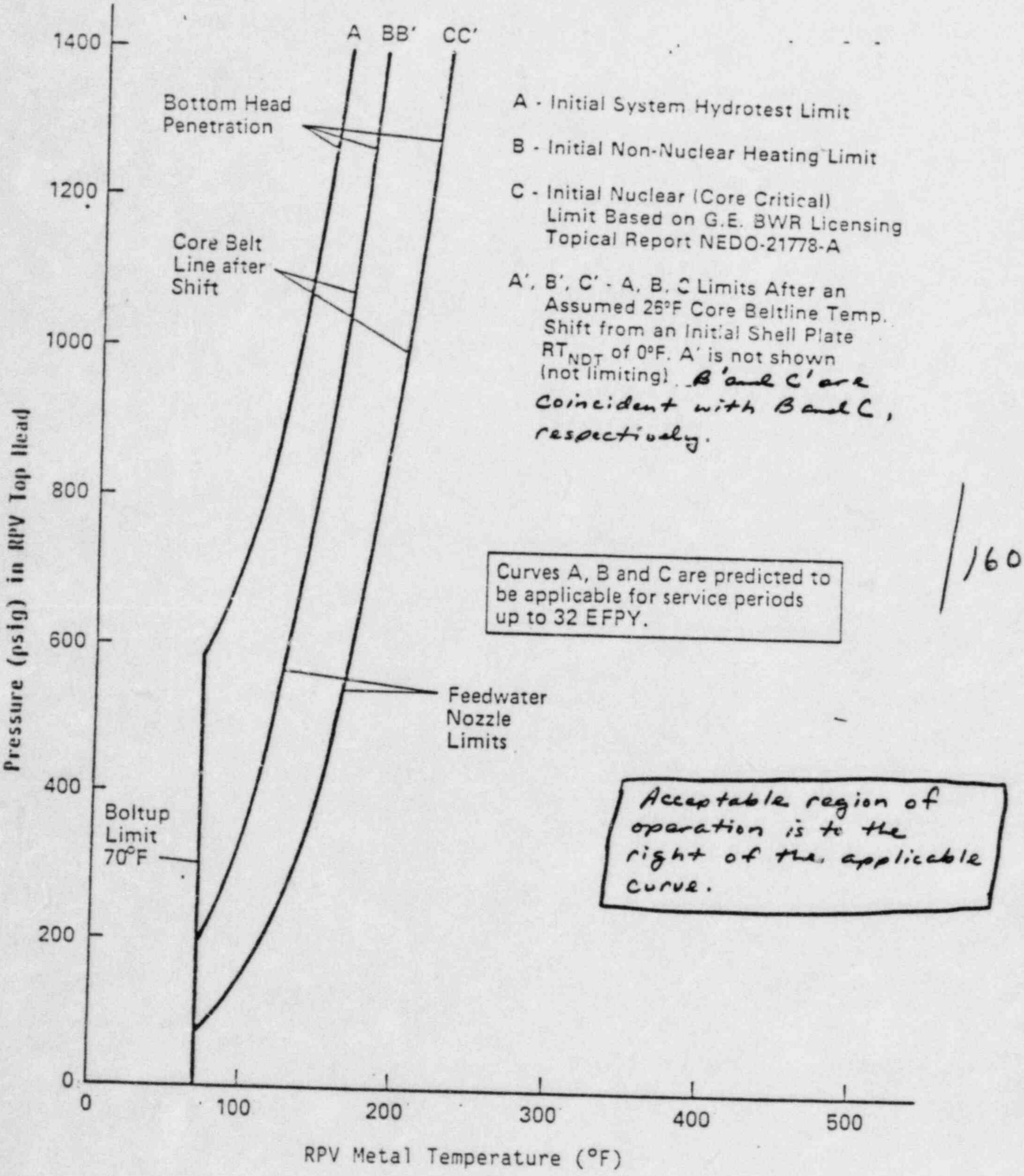
a. In OPERATIONAL CONDITION 4 when reactor coolant system temperature is:

1. $\leq$ 100°F, at least once per 12 hours.

2. $\leq$ 80°F, at least once per 30 minutes.

b. Within 30 minutes prior to and at least once per 30 minutes during tensioning of the reactor vessel head bolting studs.

4.4.6.1.5 The reactor flux wire specimens shall be removed at the first refueling outage and examined to determine reactor pressure vessel fluence as a function of time and power level and used to modify Figure B 3/4 4.6-1. The results of the fluence determinations, in conjunction with Figure B 3/4 4.6-2, shall be used to adjust the curves of Figure 3.4.6.1-1, as required. 160



Curves A, B and C are predicted to be applicable for service periods up to 32 EFPY.

Acceptable region of operation is to the right of the applicable curve.

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MINIMUM REACTOR PRESSURE VESSEL METAL TEMPERATURE VS. REACTOR VESSEL PRESSURE

Figure 3.4.6.1-1

TABLE 4.4.6.1.3-1

REACTOR VESSEL MATERIAL SURVEILLANCE PROGRAM-WITHDRAWAL SCHEDULE

CAPSULE NUMBER	VESSEL LOCATION	LEAD FACTOR	WITHDRAWAL TIME (EFPY)
1. 131C8981G1-N01	3°	0.46	8
2. 131C8981G1-N02	177°	0.46	24
3. 131C8981G1-N03	183°	0.46	Spare

REACTOR COOLANT SYSTEM

REACTOR STEAM DOME

LIMITING CONDITION FOR OPERATION

3.4.6.2 The pressure in the reactor steam dome shall be less than 1045 psig.

APPLICABILITY: OPERATIONAL CONDITION 1* and 2*.

ACTION:

With the reactor steam dome pressure exceeding 1045 psig, reduce the pressure to less than 1045 psig within 15 minutes or be in at least HOT SHUTDOWN within 12 hours.

SURVEILLANCE REQUIREMENTS

4.4.6.2 The reactor steam dome pressure shall be verified to be less than 1045 psig at least once per 12 hours.

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*Not applicable during anticipated transients.

REACTOR COOLANT SYSTEM

3/4.4.7 MAIN STEAM LINE ISOLATION VALVES

LIMITING CONDITION FOR OPERATION

3.4.7 Two main steam line isolation valves (MSIVs) per main steam line shall be OPERABLE with closing times greater than or equal to 3 and less than or equal to 5 seconds.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2 and 3.

ACTION:

a. With one or more MSIVs inoperable:

  1. Maintain at least one MSIV OPERABLE in each affected main steam line that is open and within 8 hours, either:

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

    b) Isolate the affected main steam line by use of a deactivated MSIV in the closed position.

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

b. The provisions of Specification 3.0.4 are not applicable.

SURVEILLANCE REQUIREMENTS

4.4.7 Each of the above required MSIVs shall be demonstrated OPERABLE by verifying full closure between 3 and 5 seconds* when tested pursuant to Specification 4.0.5. The provisions of Specification 4.0.4 are not applicable for entry into OPERATIONAL CONDITIONS 2 or 3 provided the surveillance is performed within 12 hours after reaching a reactor steam pressure of 600 psig and prior to entry into OPERATIONAL CONDITION 1. 1243

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* The 3 seconds is the time measured from start of valve motion to complete valve closure. The 5 seconds is the time measured from initiation of the actuating signal to complete valve closure. 1243

3/4.4.8 STRUCTURAL INTEGRITY

LIMITING CONDITION FOR OPERATION

3.4.8 The structural integrity of ASME Code Class 1, 2 and 3 components shall be maintained in accordance with Specification 4.4.8.

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

ACTION:

a. With the structural integrity of any ASME Code Class 1 component(s) not conforming to the above requirements, restore the structural integrity of the affected component(s) to within its limit or isolate the affected component(s) prior to increasing the Reactor Coolant System temperature more than 50°F above the minimum temperature required by NDT considerations.

b. With the structural integrity of any ASME Code Class 2 component(s) not conforming to the above requirements, restore the structural integrity of the affected component(s) to within its limit or isolate the affected component(s) prior to increasing the Reactor Coolant System temperature above 200°F.

c. With the structural integrity of any ASME Code Class 3 component(s) not conforming to the above requirements, restore the structural integrity of the affected component(s) to within its limit or isolate the affected component(s) from service.

d. The provisions of Specification 3.0.4 are not applicable.

SURVEILLANCE REQUIREMENTS

4.4.8 No requirements other than Specification 4.0.5.

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. One OPERABLE RHR heat exchanger.

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

ACTION:

1. 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 each inoperable RHR shutdown[**] cooling mode loop. Be in at least COLD SHUTDOWN within 24 hours.

or recirculation pump 1272

2. With no RHR shutdown cooling mode loop in operation, immediately initiate corrective action to return at least one loop 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.

or one recirculation pump 1272

SURVEILLANCE REQUIREMENTS

4.4.9.1 At least one shutdown cooling mode loop of the residual heat removal system or alternate method shall be determined to be in operation and circulating reactor coolant at least once per 12 hours. 1272

one recirculation pump

[#] 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.

REACTOR COOLANT SYSTEM

COLD SHUTDOWN

LIMITING CONDITION FOR OPERATION

3.4.9.2 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. One OPERABLE RHR heat exchanger.

APPLICABILITY: OPERATIONAL CONDITION 4.

ACTION

1. With less than the above required RHR shutdown cooling mode loops OPERABLE, 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 each inoperable RHR shutdown cooling mode loop.
2. With no RHR shutdown cooling mode loop in operation, within one hour establish reactor coolant circulation by an alternate method and monitor reactor coolant temperature and pressure at least once per hour.

SURVEILLANCE REQUIREMENTS

4.4.9.2 At least one shutdown cooling mode loop of the residual heat removal system 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 shutdown cooling mode loop may be removed from operation during hydrostatic testing.

3/4.5 EMERGENCY CORE COOLING SY

3/4.5.1 ECCS - OPERATING

LIMITING CONDITION FOR OPERATION

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

a. ECCS division 1 consisti

   1. The OPERABLE low pre core spray (LPCS) system with a flow path capable of takin tion from the suppression pool and transferring the wate ugh the spray sparger to the reactor vessel.

   2. The OPERABLE low pressu lant injection (LPCI) subsystem "A" of the RHR system wi low path capable of taking suction from the suppression pool ansferring 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*.

ACTION:

a. For ECCS division 1, provided that ECCS divisions 2 and 3 are OPERABLE:

   1. With the LPCS system inoperable, restore the inoperable LPCS system to OPERABLE status within 7 days.

   2. With LPCI subsystem "A" inoperable, restore the inoperable LPCI subsystem "A" to OPERABLE status within 7 days.

   3. With the LPCS system inoperable and LPCI subsystem "A" inoperable, restore at least the inoperable LPCI subsystem "A" or the inoperable LPCS system to OPERABLE status within 72 hours.

   4. Otherwise, be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.** | 162

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*The ADS is not required to be OPERABLE when reactor steam dome pressure is less than or equal to 135 psig.

#See Special Test Exception 3.10.5.

** 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.

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LIMITING CONDITION FOR OPERATION (Continued)

ACTION: (Continued)

b. For ECCS division 2, provided that ECCS divisions 1 and 3 are OPERABLE:

   1. With either LPCI subsystem "B" or "C" inoperable, restore the inoperable LPCI subsystem "B" or "C" to OPERABLE status within 7 days.

   2. With both LPCI subsystems "B" and "C" inoperable, restore at least the inoperable LPCI subsystem "B" or "C" to OPERABLE status within 72 hours.

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

c. For ECCS division 3, provided that ECCS divisions 1 and 2 and the RCIC system are OPERABLE:

   1. With ECCS division 3 inoperable, restore the inoperable division to OPERABLE status within 14 days.

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

d. For ECCS divisions 1 and 2, provided that ECCS division 3 is OPERABLE:

   1. With LPCI subsystem "A" and either LPCI subsystem "B" or "C" inoperable, restore at least the inoperable LPCI subsystem "A" or the inoperable LPCI subsystem "B" or "C" to OPERABLE status within 72 hours.

   2. With the LPCS system inoperable and either LPCI subsystems "B" or "C" inoperable, restore at least the inoperable LPCS system or the inoperable LPCI subsystem "B" or "C" to OPERABLE status within 72 hours.

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

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*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.

LIMITING CONDITION FOR OPERATION (Continued)

ACTION: (Continued)

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

1. With one of the above required ADS valves inoperable, restore the inoperable ADS valve to OPERABLE status within 14 days or be in at least HOT SHUTDOWN within the next 12 hours and reduce reactor steam dome pressure to ≤ 135 psig within the next 24 hours.

2. With two or more of the above required ADS valves inoperable, be in at least HOT SHUTDOWN within 12 hours and reduce reactor steam dome pressure to ≤ 135 psig within the next 24 hours.

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

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

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

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

SURVEILLANCE REQUIREMENTS

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

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

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

2. Performance of a CHANNEL FUNCTIONAL TEST of the:

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

   b) Header delta P instrumentation.

3. Verifing that each valve, manual, power operated or automatic, in the flow path that is not locked, sealed, or otherwise secured in position, is in its correct position.

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

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

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

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

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

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

2. Performing a CHANNEL CALIBRATION of the:

   a) Discharge line high pressure ~~and~~ "keep filled" low pressure alarm instrumentation and verifying the: |309

      1) High pressure setpoint of the:

         (a) LPCS system to be ~~500 + [illegible] - 0 psig~~ ≤ 600 psig. |310

         (b) LPCI subsystems to be ~~480 + 20, - 0 psig~~ ≤ 493 psig |309

2) Low pressure setpoint of the:

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

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

(c) HPCS system to be ≥ 18 psig.

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

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

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

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

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

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

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

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

Need AM 3
revised page

11/10/82

BMP-82347 response not needed.

SK

3/4 5.2 ECCS - SHUTDOWN

LIMITING CONDITION FOR OPERATION

3.5.2 At least two of the following shall be OPERABLE:

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

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

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

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

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

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

APPLICABILITY: OPERATIONAL CONDITION 4 and 5*.

ACTION:

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

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

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

SURVEILLANCE REQUIREMENTS

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

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

3/4.5.3 SUPPRESSION POOL#

LIMITING CONDITION FOR OPERATION

3.5.3 The suppression pool shall be OPERABLE:

a. In OPERATIONAL CONDITION 1, 2 or 3 with a contained water volume of at least 135,291 ft^3, equivalent to a level of 18'4-~~3/4~~ 1/12". /168

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

1. No operations are performed that have a potential for draining the reactor vessel,
2. The reactor mode switch is locked in the Shutdown or Refuel position,
3. The condensate storage tank contains at least 170,000 available gallons of water, equivalent to a level of 18', and
4. The HPCS system is OPERABLE per Specification 3.5.2 with an OPERABLE flow path capable of taking suction from the condensate storage tank and transferring the water through the spray sparger to the reactor vessel.

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

ACTION:

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

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

#See Specification 3.6.3.1 for pressure suppression requirements.

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

LIMITING CONDITION FOR OPERATION (Continued)

ACTION: (Continued)

c. With one suppression pool water level instrumentation division inoperable, restore the inoperable division to OPERABLE status within 7 days or verify the suppression pool water level to be greater than or equal to 18'4-~~3/4~~" 1/12" or 12'8", as applicable, at least once per 12 hours by an alternate indicator. /168

d. With both suppression pool water level instrumentation divisions inoperable, restore at least one inoperable division to OPERABLE status within 8 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours and verify the suppression pool water level to be greater than or equal to 18'4-~~3/4~~" 1/12" or 12'8", as applicable, at least once per 12 hours by at least one alternate indicator. /168

SURVEILLANCE REQUIREMENTS

4.5.3.1 The suppression pool shall be determined OPERABLE by verifying:

a. The water level to be greater than or equal to, as applicable: /168

1. 18'4-~~3/4~~" 1/12" at least once per 24 hours.

2. ~~12'5"~~ 12'8" at least once per 12 hours.

b. Two suppression pool water level instrumentation divisions, with 1 channel per division, OPERABLE with the low water level alarm setpoint ≥ 18'5½" or 12'8", as applicable, by performance of a: /126

1. CHANNEL CHECK at least once per 24 hours,

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

3. CHANNEL CALIBRATION at least once per 18 months.

ADDITIONAL ADMINISTRATIVE CONTROLS ARE IN EFFECT
For Tech Spec 4.5.3.1a2
See TSPS # 049

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.

3/4.6 CONTAINMENT SYSTEMS

3/4.6.1 PRIMARY CONTAINMENT

PRIMARY CONTAINMENT INTEGRITY

LIMITING CONDITION FOR OPERATION

3.6.1.1 PRIMARY CONTAINMENT INTEGRITY shall be maintained.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2* and 3.

ACTION:

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

SURVEILLANCE REQUIREMENTS

4.6.1.1 PRIMARY CONTAINMENT INTEGRITY shall be demonstrated:

a. After each closing of each penetration subject to Type B testing, except the containment air locks, if opened following Type A or B test, by leak rate testing the ~~equipment hatch~~ seals with gas at Pa, 11.5 psig, and verifying that when the measured leakage rate for these seals is added to the leakage rates determined pursuant to Surveillance Requirement 4.6.1.2.d for all other Type B and C penetrations, the combined leakage rate is less than or equal to 0.60 La. 144

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

c. By verifying each containment air lock ~~OPERABLE per~~ is in compliance with the requirements of Specification 3.6.1.3. 164

d. By verifying the suppression pool ~~OPERABLE per~~ is in compliance with the requirements of Specification 3.6.3.1.

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*See Special Test Exception 3.10.1

**Except valves, blind flanges, and deactivated automatic valves which are located inside the containment, steam tunnel or drywell and are locked, sealed or otherwise secured in the closed position. These penetrations shall be verified closed during each COLD SHUTDOWN except such verification need not be performed more often than once per 92 days.

CONTAINMENT LEAKAGE

LIMITING CONDITION FOR OPERATION

3.6.1.2 Containment leakage rates shall be limited to:

a. An overall integrated leakage rate of less than or equal to L_a, 0.437 percent by weight of the containment air per 24 hours at P_a, 11.5 psig.

b. A combined leakage rate of less than or equal to 0.60 L_a for all penetrations and all valves# ~~listed in Table 3.6.4-1, except for valves which are hydrostatically leak tested per Table 3.6.4-1~~, subject to Type B and C tests when pressurized to P_a, 11.5 psig. 294

c. Less than or equal to 100 scf per hour for all four main steam lines through the isolation valves when tested at P_a, 11.5 psig.

d. A combined leakage rate of less than or equal to 1 gpm times the total number of ~~ECCS and RCIC~~ containment isolation valves in hydrostatically tested lines which penetrate the primary containment, when tested at 1.10 P_a, 12.65 psig. 294

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

ACTION:

With:

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

b. The measured combined leakage rate for all penetrations and all valves# ~~listed in Table 3.6.4-1, except for valves which are hydrostatically leak tested per Table 3.6.4-1~~, subject to Type B and C tests exceeding 0.60 L_a, or 294

c. The measured leakage rate exceeding 100 scf per hour for all four main steam lines through the isolation valves, or

d. The measured combined leakage rate for all ~~ECCS and RCIC~~ containment isolation valves in hydrostatically tested lines which penetrate the primary containment exceeding 1 gpm times the total number of such valves, 294

restore:

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

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Includes all valves listed in Table 3.6.4-1, except for those that are hydrostatically leak tested.

CONTAINMENT SYSTEMS

LIMITING CONDITION FOR OPERATION (Continued)

ACTION (Continued)

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b. The combined leakage rate for all penetrations and all valves# ~~listed in Table 3.6.4-1, except for valves which are hydrostatically leak tested per Table 3.6.4-1~~, subject to Type B and C tests to less than or equal to 0.60 L_a, and

c. The leakage rate to less than 100 scf per hour for all four main steam lines through the isolation valves, and

d. The combined leakage rate for all ~~ECCS and RCIC~~ containment isolation valves in hydrostatically tested lines which penetrate the primary containment to less than or equal to 1 gpm times the total number of such valves, 294

prior to increasing reactor coolant system temperature above 200°F.

SURVEILLANCE REQUIREMENTS

4.6.1.2 The containment leakage rates shall be demonstrated at the following test schedule and shall be determined in conformance with the criteria specified in Appendix J of 10 CFR 50 using the methods and provisions of ANSI N45.4 - 1972:

a. Three Type A Overall Integrated Containment Leakage Rate tests shall be conducted at 40 ± 10 month intervals during shutdown at P_a, 11.5 psig, during each 10-year service period. The third test of each set shall be conducted during the shutdown for the 10-year plant inservice inspection.

b. If any periodic Type A test fails to meet 0.75 L_a, the test schedule for subsequent Type A tests shall be reviewed and approved by the Commission. If two consecutive Type A tests fail to meet 0.75 L_a, a Type A test shall be performed at least every 18 months until two consecutive Type A tests meet 0.75 L_a, at which time the above test schedule may be resumed.

c. The accuracy of each Type A test shall be verified by a supplemental test which:

1. **Confirms the accuracy of the test by verifying that the containment leakage rate, L'v, calculated in accordance with ANSI N 45.4 -1972, Appendix C, is within 25 percent of the containment leakage rate, Lv, measured prior to the introduction of the superimposed leak.** [redacted] fference within 67

2. in ~~the supplemental~~ test.

between 0.75 La and 1.25 La

3. Requires the quantity of gas injected into the containment or bled from the containment during the supplemental test to be ~~equivalent to at least 25 percent of the total measured leakage at P_a, 11.5 psig.~~ 67

Includes all valves listed in Table 3.6.4-1, except for those that are hydrostatically leak tested. 294

d. Type B and C tests shall be conducted with gas at P_a, 11.5 psig,* at intervals no greater than 24 months except for tests involving:

1. Air locks,
2. Main steam line isolation valves,
3. Penetrations using continuous leakage monitoring systems,
4. Valves pressurized with fluid from a seal system,
5. ~~ECCS and RCIC~~ Containment isolation valves in hydrostatically tested lines which penetrate the primary containment, and 294
6. Purge supply and exhaust isolation valves with resilient material seals.

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

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

g. Type B tests for penetrations employing a continuous leakage monitoring system shall be conducted at P_a, 11.5 psig, at intervals no greater than once per 3 years.

h. Leakage from isolation valves that are sealed with fluid from a seal system may be excluded, subject to the provisions of Appendix J, Section III.C.3, when determining the combined leakage rate provided the seal system and valves are pressurized to at least 1.10 P_a, 12.65 psig, and the seal system capacity is adequate to maintain system pressure for at least 30 days.

i. ~~ECCS and RCIC~~ Containment isolation valves in hydrostatically tested lines which penetrate the primary containment shall be leak tested at least once per 18 months.

j. Purge supply and exhaust isolation valves with resilient material seals shall be tested and demonstrated OPERABLE per Surveillance Requirement 4.6.1.9.2.

k. The provisions of Specification 4.0.2 are not applicable to ~~24 month or 40 ± 10 month surveillance intervals~~. Specifications 4.6.1.2.a, 4.6.1.2.b, 4.6.1.2.c, 4.6.1.2.d, ~~and~~ 4.6.1.2.e, and 4.6.1.2.g. /057

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*Unless a hydrostatic test is required per Table 3.6.4-1.

CONTAINMENT AIR LOCKS

LIMITING CONDITION FOR OPERATION

3.6.1.3 Each containment air lock shall be OPERABLE with:

a. Both doors closed except when the air lock is being used for normal transit entry and exit through the containment, then at least one air lock door shall be closed, and

b. An overall air lock leakage rate of less than or equal to 2 scf per hour at P_a, 11.5 psig.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2* and 3.

ACTION:

a. With one containment air lock door inoperable:

1. Maintain at least the OPERABLE air lock door closed and either restore the inoperable air lock door to OPERABLE status within 24 hours or lock the OPERABLE air lock door closed.

2. Operation may then continue until performance of the next required overall air lock leakage test provided that the OPERABLE air lock door is verified to be locked closed at least once per 31 days.

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

4. The provisions of Specification 3.0.4 are not applicable.

b. With the containment air lock inoperable, except as a result of an inoperable air lock door, maintain at least one air lock door closed; restore the inoperable air lock 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.

c. With one containment air lock door inflatable seal system seal pressure instrumentation channel inoperable, restore the inoperable channel to OPERABLE status within 7 days or verify the associated inflatable seal pressure to be $\geq$ 60 psig at least once per 12 hours.

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*See Special Test Exception 3.10.1.

SURVEILLANCE REQUIREMENTS

4.6.1.3 Each containment air lock shall be demonstrated OPERABLE:

a. Within 72 hours[#] after 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 scf per hour when the gap between the door seals is pressurized to Pa, 11.5 psig. 235

b. By conducting an overall air lock leakage test at P_a, 11.5 psig, and verifying that the overall air lock leakage rate is within its limit:

   1. At least once per 6 months[#], and

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

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

d. By verifying each airlock door inflatable seal system OPERABLE by:

   1. Demonstrating each of the two inflatable seal pressure instrumentation channels per airlock door OPERABLE by performance of a:

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

      b) CHANNEL CALIBRATION at least once per 18 months,

      with a low pressure setpoint of ≥ 60 psig.

   2. At least once per 7 days, verifying seal air flask pressure to be greater than or equal to 90 psig.

   3. At least once per 18 months, conducting a seal pneumatic system leak test and verifying that system pressure does not decay more than 2 psig from 90 psig within 48 hours.

[#] The provisions of Specification 4.0.2 are not applicable.

[*] Exemption to Appendix J of 10 CFR 50.

MSIV LEAKAGE CONTROL SYSTEM

LIMITING CONDITION FOR OPERATION

3.6.1.4 Two independent MSIV leakage control system (LCS) subsystems shall be OPERABLE.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2 and 3.

ACTION:

With one MSIV leakage control system subsystem inoperable, restore the inoperable subsystem 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.

SURVEILLANCE REQUIREMENTS

4.6.1.4 Each MSIV leakage control system subsystem shall be demonstrated OPERABLE:

a. At least once per 31 days by verifying:

   1. Blower OPERABILITY by starting the blowers from the control room and operating the blowers for at least 15 minutes.
   2. Inboard heater ~~Heater~~ OPERABILITY by demonstrating electrical continuity of the heating element circuitry, by verifying the inboard heater draws 8.65 ±10% amperes [redacted] per phase. /229

b. During each COLD SHUTDOWN, if not performed within the previous 92 days, by cycling each motor operated valve through at least one complete cycle of full travel.

c. At least once per 18 months by:

   1. Performance of a functional test which includes simulated actuation of the subsystem throughout its operating sequence, and verifying that each automatic valve actuates to its correct position, the blowers start and the inboard heater draws ~~7.8 to 9.5~~ 8.65 ± 10% amperes per phase. /229
   2. Verifying that the blower developed at least the below required vacuum at the rated capacity.*
      a) Inboard ~~valves, 60" H_2O at 100 scfm~~ subsystem, 10" ± 1" H_2O vacuum at ≥ 100 scfm. /195
      b) Outboard ~~valves, - 50" H_2O at 240 scfm~~ subsystem, ≥ 15" H_2O vacuum at ≥ 200 scfm.

d. By verifying the inboard flow, inboard and outboard pressure, and inboard temperature instrumentation to be OPERABLE by performance of a:

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

* The subsystems are not lined-up to the main steam lines during the performance of this test. /195

FEEDWATER LEAKAGE CONTROL SYSTEM

LIMITING CONDITION FOR OPERATION

3.6.1.5 Two independent feedwater leakage control (FWLC) system subsystems shall be OPERABLE.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, and 3.

ACTION:

With one FWLC system subsystem inoperable, restore the inoperable subsystem 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.

SURVEILLANCE REQUIREMENTS

4.6.1.5 Each FWLC system subsystem shall be demonstrated OPERABLE:

a. At least once per 31 day by observing proper operation of the RHR jockey pump.

b. At least once per 18 months by cycling each valve not testable during POWER OPERATION through at least one complete cycle of full travel.

CONTAINMENT SYSTEMS

CONTAINMENT STRUCTURAL INTEGRITY

LIMITING CONDITION FOR OPERATION

3.6.1.6 The structural integrity of the containment shall be maintained at a level consistent with the acceptance criteria in Specification 4.6.1.6.1. 276

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2 and 3.

ACTION:

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

SURVEILLANCE REQUIREMENTS

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

4.6.1.6.2 Reports Any abnormal degradation of the primary containment structure detected during the above required inspections shall be reported ~~to the Commission pursuant to Specification 6.9.1~~. This report shall include a description of the condition of the concrete, the inspection procedure, the tolerances on cracking, and the corrective actions taken.

in a Special Report to the
Commission pursuant to Specification 093
6.9.2 within 30 days.

CONTAINMENT INTERNAL PRESSURE

LIMITING CONDITION FOR OPERATION

3.6.1.7 Containment to Auxiliary Building differential pressure shall be maintained between -0.1 and 1.0 psid.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2 and 3.

ACTION:

With the containment to Auxiliary Building differential pressure outside of the specified limits, restore the differential pressure to within the limits within 1 hour or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

SURVEILLANCE REQUIREMENTS

4.6.1.7 The containment to Auxiliary Building differential pressure shall be determined to be within the limits at least once per 12 hours.

CONTAINMENT SYSTEMS

CONTAINMENT AVERAGE AIR TEMPERATURE

LIMITING CONDITION FOR OPERATION

3.6.1.8 Containment average air temperature shall not exceed 90°F.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2 and 3.

ACTION:

With the containment average air temperature greater than 90°F, reduce the average air temperature to within the limit within 8 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

SURVEILLANCE REQUIREMENTS

4.6.1.8 The containment average air temperature shall be the arithmetical average of the temperatures at the following locations and shall be determined to be within the limit at least once per 24 hours:

	Elevation	Azimuth
a.	~119'-0"	20° ≤ A ≤ 70°
b.	~119'-0"	110° ≤ A ≤ 160°
c.	~119'-0"	200° ≤ A ≤ 250°
d.	~119'-0"	290° ≤ A ≤ 340°
e.	~139'-0"	20° ≤ A ≤ 70°
f.	~139'-0"	110° ≤ A ≤ 160°
g.	~139'-0"	200° ≤ A ≤ 250°
h.	~139'-0"	290° ≤ A ≤ 340°
i.	~208'-0"	20° ≤ A ≤ 70°
j.	~208'-0"	110° ≤ A ≤ 160°
k.	~208'-0"	200° ≤ A ≤ 250°
l.	~208'-0"	290° ≤ A ≤ 340°
m.	~240'-0"	20° ≤ A ≤ 70°
n.	~240'-0"	110° ≤ A ≤ 160°
o.	~240'-0"	200° ≤ A ≤ 250°
p.	~240'-0"	290° ≤ A ≤ 340°

CONTAINMENT PURGE SYSTEM

LIMITING CONDITION FOR OPERATION

3.6.1.9 The containment purge system supply and exhaust isolation valves shall be OPERABLE and either the 20 inch or the 6 inch purge system may be in operation; however, the 20 inch purge system shall not be in operation nor shall the 20 inch valves be open for more than 1000 hours per 365 days.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2 and 3.

ACTION:

a. With a containment purge system supply and/or exhaust isolation valve(s) inoperable, close the inoperable valve(s) or otherwise isolate the penetration(s) 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. With the 20 inch containment purge system in operation and/or with the 20 inch supply and/or exhaust isolation valve(s) open for more than 1000 hours per 365 days, discontinue 20 inch purge system operation and close the open 20 inch valve(s) or otherwise isolate the penetration(s) within four hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

c. With a containment purge supply and/or exhaust isolation valve with resilient material seals having a measured leakage rate exceeding the limit of Surveillance Requirement 4.6.1.9.2, restore the inoperable valve(s) to OPERABLE status within 24 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

SURVEILLANCE REQUIREMENTS

4.6.1.9.1 The cumulative time that the 20 inch containment purge system has been in operation and the cumulative time that the 20 inch supply and/or exhaust isolation valves have been open during the past 365 days shall be determined at least once per 7 days.

4.6.1.9.2 At least once per 92 days each 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 0.01 L_a when pressurized to P_a.

3/4.6.2 DRYWELL

DRYWELL INTEGRITY

LIMITING CONDITION FOR OPERATION

3.6.2.1 DRYWELL INTEGRITY shall be maintained.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2* and 3.

ACTION:

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

SURVEILLANCE REQUIREMENTS

4.6.2.1 DRYWELL INTEGRITY shall be demonstrated:

a. At least once per 31 days by verifying that all drywell penetrations** not capable of being closed by OPERABLE drywell 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 drywell air lock ~~OPERABLE per~~ in compliance with the requirements of Specification 3.6.2.3.

c. By verifying the suppression pool ~~OPERABLE per~~ in compliance with the requirements of Specification 3.6.3.1.

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* See Special Test Exception 3.10.1.

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

CONTAINMENT SYSTEMS

DRYWELL BYPASS LEAKAGE

LIMITING CONDITION FOR OPERATION

3.6.2.2 Drywell bypass leakage shall be less than or equal to 10% of the acceptable $A/\sqrt{k}$ design value of 0.90 ft^2.

APPLICABILITY: When DRYWELL INTEGRITY is required per Specification 3.6.2.1.

ACTION:

With the drywell bypass leakage greater than 10% of the acceptable $A/\sqrt{k}$ design value of 0.90 ft^2, restore the drywell bypass leakage to within the limit prior to increasing reactor coolant system temperature above 200°F.

SURVEILLANCE REQUIREMENTS

4.6.2.2 The drywell bypass leakage rate test shall be conducted at least once per 18 months at an initial differential pressure of 3.0 psid and the $A/\sqrt{k}$ shall be calculated from the measured leakage. One drywell airlock door shall remain open during the drywell leakage test such that each drywell door is leak tested during at least every other drywell leakage rate test.

a. If any drywell bypass leakage rate test fails to meet the specified limit, the test schedule for subsequent tests shall be reviewed and approved by the Commission. If two consecutive tests fail to meet the limit, a test shall be performed at least once every 9 months until two consecutive tests meet the limit, at which time the above test schedule may be resumed.

b. Air locks shall be tested and demonstrated OPERABLE per Surveillance Requirement 4.6.2.3.

c. The provisions of Specification 4.0.2 are not applicable.

DRYWELL AIR LOCKS

LIMITING CONDITION FOR OPERATION

3.6.2.3 Each drywell air lock shall be OPERABLE with:

a. Both doors closed except when the air lock is being used for normal transit entry and exit through the drywell, then at least one air lock door shall be closed, and

b. An overall air lock leakage rate of less than or equal to 2 scf per hour at P_a, 11.5 psig.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2* and 3.

ACTION:

a. With one drywell air lock door inoperable:

   1. Maintain at least the OPERABLE air lock door closed and either restore the inoperable air lock door to OPERABLE status within 24 hours or lock the OPERABLE air lock door closed.

   2. Operation may then continue provided that the OPERABLE air lock door is verified to be locked closed at least once per 31 days.

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

   4. The provisions of Specification 3.0.4 are not applicable.

b. With the drywell air lock inoperable, except as a result of an inoperable air lock door, maintain at least one air lock door closed; restore the inoperable air lock 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.

c. With one drywell air lock door inflatable seal system seal pressure instrumentation channel inoperable, restore the inoperable channel to OPERABLE status within 7 days or verify the associated inflatable seal pressure to be $\geq$ 60 psig at least once per 12 hours.

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*See Special Test Exception 3.10.1.

SURVEILLANCE REQUIREMENTS

4.6.2.3 Each drywell air lock shall be demonstrated OPERABLE:

a. Within ~~8~~ 72 hours[#] after 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 scf per hour when the gap between the door seals is pressurized to P_a, 11.5 psig. 31

b. By conducting an overall air lock leakage test at P_a, 11.5 psig and verifying that the overall air lock leakage rate is within its limit: ge

c. 1. At least once per 6 months[#],

d. 2. Prior to establishing DRYWELL INTEGRITY when maintenance has been performed on the air lock that could affect the air lock sealing capability.[*] 31

1. Demonstrating each of the two inflatable seal pressure instrumentation channels per airlock door OPERABLE by performance of a:

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

   b) CHANNEL CALIBRATION at least once per 18 months,

   with a low pressure setpoint of ≥ 60 psig.

2. At least once per 7 days verifying seal air flask pressure to be greater than or equal to 90 psig. |

3. At least once per 18 months, conducting a seal pneumatic system leak test and verifying that system pressure does not decay more than 2 psig from 90 psig within 48 hours.

[#] The provisions of Specification 4.0.2 are not applicable.

[*] Exemption to Appendix J of 10 CFR 50. 31

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DRYWELL STRUCTURAL INTEGRITY

LIMITING CONDITION FOR OPERATION

3.6.2.4 The structural integrity of the drywell shall be maintained at a level consistent with the acceptance criteria in Specification 4.6.2.4.1. 269

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2 and 3.

ACTION:

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

SURVEILLANCE REQUIREMENTS

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

4.6.2.4.2 Reports Any abnormal degradation of the drywell structure detected during the above required inspections shall be reported ~~to the Commission pursuant to Specification 6.9.1.~~ This report shall include a description of the condition of the concrete, the inspection procedure, the tolerances on cracking, and the corrective actions taken.

in a Special Report to the Commission pursuant to Specification 6.9.2 within 30 days.

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DRYWELL INTERNAL PRESSURE

LIMITING CONDITION FOR OPERATION

3.6.2.5 Drywell to containment differential pressure shall be maintained between - ~~0.1~~ 0.26 and + 2.0 psid. 127

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2 and 3.

ACTION:

With the drywell to containment differential pressure outside of the specified limits, restore the differential pressure to within the limits within 1 hour or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

SURVEILLANCE REQUIREMENTS

4.6.2.5 The drywell to containment differential pressure shall be determined to be within the limits at least once per 12 hours.

DRYWELL AVERAGE AIR TEMPERATURE

LIMITING CONDITION FOR OPERATION

3.6.2.6 Drywell average air temperature shall not exceed 135°F.

APPLICABILITY: OPERATONAL CONDITIONS 1, 2 and 3.

ACTION:

With the drywell average air temperature greater than 135°F, reduce the average air temperature to within the limit within 8 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

SURVEILLANCE REQUIREMENTS

4.6.2.6 The drywell average air temperature shall be the arithmetical average of the temperatures at the following locations and shall be determined to be within the limit at least once per 24 hours:

	Elevation	Azimuth
a.	~119'-0"	20°≤A ≤70°
b.	~119'-0"	110°≤A ≤160°
c.	~119'-0"	200°≤A ≤250°
d.	~119'-0"	290°≤A ≤340°
e.	~139'-0"	20°≤A ≤70°
f.	~139'-0"	110°≤A ≤160°
g.	~139'-0"	200°≤A ≤250°
h.	~139'-0"	290°≤A ≤340°
i.	~166'-0"	20°≤A ≤70°
j.	~166'-0"	110°≤A ≤160°
k.	~166'-0"	200°≤A ≤250°
l.	~166'-0"	290°≤A ≤340°

3/4.6.3 DEPRESSURIZATION SYSTEMS

SUPPRESSION POOL[#]

LIMITING CONDITION FOR OPERATION

3.6.3.1 The suppression pool shall be OPERABLE with the pool water:

a. Volume between 135,291 ft³ and ~~138,851~~ 138,701 ft³, equivalent to a ~~level~~ depth between 18'4-~~3/4~~ 1/12" and 18'~~10~~ 9 3/4", and a /126

b. Maximum average temperature of 95°F ~~during OPERATIONAL CONDITION 1 or 2~~, except that the maximum average temperature may be permitted to increase to: /168

1. 105°F during testing which adds heat to the suppression pool.
2. 110°F with THERMAL POWER less than or equal to 1% of RATED THERMAL POWER.
3. 120°F with the main steam line isolation valves closed following a scram.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2 and 3.

ACTION:

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

b. ~~In OPERATIONAL CONDITION 1 or 2~~ With the suppression pool average water temperature greater than 95°F, restore the average temperature to less than or equal to 95°F within 24 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours, except, as permitted above: /168

1. With the suppression pool average water temperature greater than 105°F during testing which adds heat to the suppression pool, stop all testing which adds heat to the suppression pool and restore the average temperature to less than 95°F within 24 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.
2. With the suppression pool average water temperature greater than 110°F, place the reactor mode switch in the Shutdown position and operate at least one residual heat removal loop in the suppression pool cooling mode.
3. With the suppression pool average water temperature greater than 120°F, depressurize the reactor pressure vessel to less than 200 psig within 12 hours.

[#] See Specification 3.5.3 for ECCS requirements.

LIMITING CONDITION FOR OPERATION (Continued)

ACTION: (Continued)

c. With one suppression pool water level instrumentation division inoperable and/or with one suppression pool water temperature instrumentation channel in any pair(s) of temperature instrumentation channels in the same sector inoperable, restore the inoperable channel(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 both suppression pool water level instrumentation divisions inoperable and/or with both suppression pool water temperature instrumentation channels in any pair(s) of temperature instrumentation channels in the same sector inoperable, restore at least one inoperable water level division and at least one inoperable water temperature instrumentation channel in each pair of temperature instrumentation channels in the same sector to OPERABLE status within 8 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

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 95°F, except: /168

   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 95°F, by verifying suppression pool average water temperature to be less than or equal to 110°F and THERMAL POWER less than or equal to 1% of RATED THERMAL POWER.

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

SURVEILLANCE REQUIREMENTS (Continued

c. By verifying two suppression pool water level instrumentation divisions, with 1 channel per division, and at least twelve suppression pool water temperature instrumentation channels, at least two channels in each suppression pool sector shown below in Table 4.6.3.1-1, OPERABLE by performance of a:

1. CHANNEL CHECK at least once per 24 hours,

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

3. CHANNEL CALIBRATION at least once per 18 months,

with the water level and temperature alarm setpoint for:

1. High water level $\leq$ 18'9",

2. Low water level $\geq$ 18'5-1/2", and

3. High water temperature $\leq$ 90°F.

TABLE 4.6.3.1-1

SUPPRESSION POOL WATER TEMPERATURE INSTRUMENTATION CHANNELS

	INSTRUMENTATION	SECTOR (Azimuth)	MINIMUM OPERABLE CHANNELS
1.	Suppression Pool Temperature	40°	2
2.	Suppression Pool Temperature	82°	2
3.	Suppression Pool Temperature	142°	2
4.	Suppression Pool Temperature	180°	2
5.	Suppression Pool Temperature	262°	2
6.	Suppression Pool Temperature	318°	2

CONTAINMENT SPRAY

LIMITING CONDITION FOR OPERATION

3.6.3.2 The containment spray mode of the residual heat removal (RHR) system shall be OPERABLE with two independent loops, each loop consisting of:

a. One OPERABLE RHR pump, and

b. An OPERABLE flow path capable of recirculating water from the suppression pool through a ~~SSW~~ RHR heat exchanger, and the containment spray spargers.

X 12
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APPLICABILITY: OPERATIONAL CONDITIONS 1, 2 and 3.

ACTION:

a. With one containment spray loop inoperable, restore the inoperable loop 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 both containment spray loops inoperable, restore at least one loop to OPERABLE status within 8 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN* within the ~~next~~ following 24 hours.

X 12

SURVEILLANCE REQUIREMENTS

4.6.3.2 The containment spray mode of the RHR system shall be demonstrated OPERABLE:

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

b. By verifying that each of the required RHR pumps develops a flow of at least 5650 gpm on recirculation flow through the RHR heat exchange to the suppression pool when tested pursuant to Specification 4.0.5.

c. At least once per 18 months by performance of 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 spraying of coolant into the primary containment may be excluded from this test.

d. By performance of an air or smoke flow test of the containment spray nozzles and verifying that each spray nozzle is unobstructed following maintenance which could result in nozzle blockage.

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*Whenever both 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.

SUPPRESSION POOL COOLING

LIMITING CONDITION FOR OPERATION

3.6.3.3 The suppression pool cooling mode of the residual heat removal (RHR) system shall be OPERABLE with two independent loops, each loop consisting of:

a. One OPERABLE RHR pump; and

b. An OPERABLE flow path capable of recirculating water from the suppression pool through a ~~SSW~~ RHR heat exchanger.

× 12

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2 and 3.

ACTION:

a. With one suppression pool cooling loop inoperable, restore the inoperable loop to OPERABLE status within ~~7 days~~ 72 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

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b. With both suppression pool cooling loops inoperable, restore at least one loop to OPERABLE status within 8 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN* within the following 24 hours.

SURVEILLANCE REQUIREMENTS

4.6.3.3 The suppression pool cooling mode of the RHR system shall be demonstrated OPERABLE:

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

b. By verifying that each of the required RHR pumps develops a flow of at least 7450 gpm on recirculation flow through the RHR heat exchangers to the suppression pool when tested pursuant to Specification 4.0.5.

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*Whenever both 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.

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:

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

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

b. At least once per 31 days by verifying that each valve, manual, power operated or automatic, in the flow path that is not locked, sealed, or otherwise secure in position, is in its correct position, and both refueling gates are in the stored position or are otherwise removed from the upper containment pool. /312

c. At least once per 18 months by performing a system functional test which includes simulated automatic actuation of the system throughout its emergency operating sequence and verifying that each automatic valve in the flow path actuates to its correct position. Actual makeup of water to the suppression pool may be excluded from this test.

3/4.6.4 CONTAINMENT AND DRYWELL ISOLATION VALVES

LIMITING CONDITION FOR OPERATION

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

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

ACTION:

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

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

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

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

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

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

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

SURVEILLANCE REQUIREMENTS

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 during COLD SHUTDOWN or REFUELING 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.

4.6.4.4 [DELETED]

TABLE 3.6.4-1
CONTAINMENT AND DRYWELL ISOLATION VALVES

SYSTEM AND VALVE NUMBER		PENETRATION NUMBER	VALVE GROUP[(a)]	MAXIMUM ISOLATION TIME (Seconds)	
1. Automatic Isolation Valves#					
a. Containment					
Main Steam Lines	B21-F028A	5(O)*	1	5	
Main Steam Lines	B21-F022A	5(I)*	1	5	
Main Steam Lines	B21-F067A-A	5(O)*	1	~~6~~ 9	
Main Steam Lines	B21-F028B	6(O)*	1	5	
Main Steam Lines	B21-F022B	6(I)*	1	5	
Main Steam Lines	B21-F067B-A	6(O)*	1	~~6~~ 9	306
Main Steam Lines	B21-F028C	7(O)*	1	5	
Main Steam Lines	B21-F022C	7(I)*	1	5	
Main Steam Lines	B21-F067C-A	7(O)*	1	~~6~~ 9	
Main Steam Lines	B21-F028D	8(O)*	1	5	
Main Steam Lines	B21-F022D	8(I)*	1	5	
Main Steam Lines	B21-F067D-A	8(O)*	1	~~6~~ 9	
RHR Reactor Shutdown Cooling Suction	E12-F008-A	14(O)~~(c)~~ e	3	40	
RHR Reactor Shutdown Cooling Suction	E12-F009-B	14(I)~~(c)~~ e	3	40	20
Steam Supply to RHR and RCIC Turbine	E51-F063-B	17(I)	4	20	
Steam Supply to RHR and RCIC Turbine	E51-F064-A	17(O)	4	20	
Steam Supply to RHR and RCIC Turbine	E51-F076-B	17(I)	4	20	
RHR to Head Spray	E12-F023-A	18(O)~~(c)~~ e	3	~~50~~ 94	306
Main Steam Line Drains	B21-F019-A	19(O)	1	~~15~~ 20	

(a) See Specification 3.3.2, Table 3.3.2-1, for isolation signal(s) that operates each valve group.
(b) Hydrostatically tested to ASME Section XI criteria.
(c) Hydrostatically tested with water to 1.10 P_a, 12.65 psig.
(d) Hydrostatically tested by pressurizing system to 1.10 P_a, 12.65 psig.
(e) Hydrostatically tested during system functional tests.
(f) Hydrostatically sealed by feedwater leakage control system. Type C test not required.
(g) Normally closed ~~on~~ or locked closed manual valves may be opened on an intermittent basis under administrative control. 306

*The provisions of Specification 4.0.4 are not applicable for entry into OPERATIONAL CONDITIONS 2 or 3 provided the surveillance is performed within 12 hours after reaching a reactor steam pressure of 600 psig and prior to entry into OPERATIONAL CONDITION 1.

The -A, -B, -C, -(A), -(B) designators on the valve numbers indicate associated electrical divisions. 306

TABLE 3.6.4-1 (Continued)

CONTAINMENT AND DRYWELL ISOLATION VALVES

SYSTEM AND VALVE NUMBER		PENETRATION NUMBER	VALVE GROUP[a]	MAXIMUM ISOLATION TIME (Seconds)
Containment (Continued)				
Main Steam Line Drains	B21-F016-B	19(I)	1	~~15~~ 20
~~RHR Heat Exchanger "A" to LPCI~~	~~E12-F042A-A~~	~~20(I)~~ ~~(c)~~e	~~5~~	~~22~~
RHR Heat Exchanger "A" to LPCI	E12-F028A-A	20(I) ~~(c)~~e	5	~~78~~ 90
RHR Heat Exchanger "A" to LPCI	E12-F037A-A	20(I) ~~(c)~~e	3	~~63~~ 74
~~RHR Heat Exchanger "B" to LPCI~~	~~E12-F042B-B~~	~~21(I)~~ ~~(c)~~e	5	~~22~~
RHR Heat Exchanger "B" to LPCI	E12-F028B-B	21(I) ~~(c)~~e	5	~~78~~ 90
RHR Heat Exchanger "B" to LPCI	E12-F037B-B	21(I) ~~(c)~~e	3	~~63~~ 74
RHR "A" Test Line to Supp. Pool	E12-F024A-A	23(0)[d]	5	90 [redacted]
RHR "A" Test Line to Supp. Pool	E12-F011A-A	23(0)[d]	5	36
RHR "C" Test Line to Supp. Pool	E12-F021-B	24(0) ~~(d)~~e	5	~~101~~ 144
HPCS Test Line	E22-F023-C	27(0)[d]	6B	~~60~~ 75
RCIC Pump Suction	E51-F031-A	28(0)[d]	4	56
RCIC Turbine Exhaust	E51-F077-A	29(0)[c]	9	26
LPCS Test Line	E21-F012-A	32(0) ~~(d)~~e	5	144
Cont. Purge and Vent Air Supply	M41-F011-(A)	34(0)	7	4
Cont. Purge and Vent Air Supply	M41-F012-(B)	34(I)	7	4
Cont. Purge and and Vent Air Exh.	M41-F034-(B)	35(I)	7	4
Cont. Purge and and Vent Air Exh.	M41-F035-(A)	35(0)	7	4
Plant Service Water Return	P44-F070-B	36(I)	6A	33
Plant Service Water Return	P44-F069-A	36(0)	6A	~~24~~ 33
Plant Service Water Supply	P44-F053-A	37(0)	6A	~~24~~ 33
Chilled Water Supply	P71-F150-(A)	38(0)	6A	~~30~~ 12

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TABLE 3.6.4-1 (Continued)

CONTAINMENT AND DRYWELL ISOLATION VALVES

SYSTEM AND VALVE NUMBER		PENETRATION NUMBER	VALVE GROUP[a]	MAXIMUM ISOLATION TIME (Seconds)
Containment (Continued)				
Chilled Water Return	P71-F148-(A)	39(O)	6A	~~20~~ 12
Chilled Water Return	P71-F149-(B)	39(I)	6A	~~30~~ 12
Service Air Supply	P52-F105-(A)	41(O)	6A	~~4~~ 6
Inst. Air Supply	P53-F001-(A)	42(O)	6A	~~4~~ 6
RWCU to Main Condenser	G33-F034-A	43(O)	8	~~21~~ 35
RWCU to Main Condenser	G33-F028-B	43(I)	8	~~23~~ 35
RWCU Backwash to C/U Phase Sep. Tank	G36-F106-B	49(I)	6A	~~10~~ 11
RWCU Backwash to C/U Phase Sep. Tank	G36-F101-A	49(O)	6A	~~20~~ 11
Drywell & Cont. Equip. Drain Sump Disch.	P45-F067-(B)	50(I)	6A	~~4~~ 7
Drywell & Cont. Equip. Drain Sump Disch.	P45-F068-(A)	50(O)	6A	7
Drywell & Cont. Floor Drain Sump Disch.	P45-F061-(B)	51(I)	6A	~~4~~ 7
Drywell & Cont. Floor Drain Sump Disch.	P45-F062-(A)	51(O)	6A	~~4~~ 7
Condensate Supply	P11-F075-(A)	56(O)	6A	~~30~~ 10
FPC & CU to Upper Cont. Pool	G41-F028-A	57(O)	6A	~~44~~ 51
Upper Cont. Pool to Fuel Pool Drain Tank	G41-F029-A	58(O)	6A	~~40~~ 51
Upper Cont. Pool to Fuel Pool Drain Tank	G41-F044-B	58(I)	6A	40
Aux. Bldg. Flr. and Equip. Drn. Tks. to Supp. Pool	P45-F273-A	60(O)	6A	~~23~~ 32
Aux. Bldg. Flr. and Equip. Drn. Tks. to Supp. Pool	P45-F274-B	60(O)	6A	~~23~~ 32

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TABLE 3.6.4-1 (Continued)

CONTAINMENT AND DRYWELL ISOLATION VALVES

SYSTEM AND VALVE NUMBER		PENETRATION NUMBER	VALVE GROUP(a)	MAXIMUM ISOLATION TIME (Seconds)
Containment (Continued)				
Comb. Gas Control Cont. Purge (Outside Air Supply)	E61-F009-(A)	65(O)	7	4
Comb. Gas Control Cont. Purge (Outside Air Supply)	E61-F010-(B)	65(I)	7	4
Purge ~~Rad.~~ Filter Train ~~Detector~~ Isolation Valve	E61-F056-(B)	66(I)	7	4
Purge ~~Rad.~~ Filter Train ~~Detector~~ Isolation Valve	E61-F057-A	66(O)	7	4
RHR "B" Test Line To Suppr. Pool	E12-F024B-B	67(O)(d)	5	90
RHR "B" Test Line To Suppr. Pool	E12-F011B-B	67(O)(d)	5	~~27~~ 36
Refueling Water Transf. Pump Suction	P11-F130-(A)	69(O)(c)	6A	~~4~~ 8
Refueling Water Transf. Pump Suction	P11-F131-(B)	69(O)(c)	6A	8
Instr. Air to ADS	P53-F003-A	70(O)	6A	4
RCIC Turbine Exh. Vacuum Breaker	E51-F078-B	75(O)	9	~~7~~ 10
RWCU to Feedwater	G33-F040-B	83(I)	8	~~30~~ 35
RWCU to Feedwater	G33-F039-A	83(O)	8	~~29~~ 35
Chemical Waste Sump Discharge	P45-F098-(B)	84(I)	6A	~~4~~ 8
Chemical Waste Sump Discharge	P45-F099-(A)	84(O)	6A	~~4~~ 8
Supp. Pool Clean-up Return	P60-F009-A	85(O)	6A	8
Supp. Pool Clean-up Return	P60-F010-B	85(O)	6A	~~4~~ 8
Demin. Water Supply to Cont.	P21-F017-A	86(O)	6A	~~10~~ 19
Demin. Water Supply to Cont.	P21-F018-B	86(I)	6A	~~10~~ 19
RWCU Pump Suction	G33-F001-B	87(I)	8	~~30~~ 35

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TABLE 3.6.4-1 (Continued)

CONTAINMENT AND DRYWELL ISOLATION VALVES

SYSTEM AND VALVE NUMBER		PENETRATION NUMBER	VALVE GROUP$^{(a)}$	MAXIMUM ISOLATION TIME (Seconds)
Containment (Continued)				
RWCU Pump Suction	G33-F252-A	87(I)	8	~~20~~ 35
RWCU Pump Suction	G33-F004-A	87(0)	8	~~30~~ 35
RWCU Pump Disch.	G33-F053-B	88(I)	8	~~22~~ 35
RWCU Pump Disch.	G33-F054-A	88(0)	8	~~22~~ 35
b. Drywell				
Instrument Air	P53-F007-B	325 ~~327~~(0)	6A	~~4~~ 7
Plant Service Water Return	P44-F076-A	331(I)	6A	32
Plant Service Water Return	P44-F077-B	331(0)	6A	32
Plant Service Water Return	P44-F074-B	332(0)	6A	32
RWCU Pump Suction	G33-F250-A	337(I)	8	~~20~~ 35
RWCU Pump Suction	G33-F251-B	337(0)	8	~~30~~ 35
Combustible Gas Con.	E61-F003B-B	338(0)	5	~~60~~ 84
Combustible Gas Con.	E61-F003A-A	339(0)	5	~~60~~ 84
Combustible Gas Con.	E61-F005A-A	340(0)	5	84
Combustible Gas Con.	E61-F005B-B	340(0)	5	84
Combustible Gas Con.	E61-F007 -(A)	341(0)	5	9
Combustible Gas Con.	E61-F020 -(B)	341(0)	5	18
Drywell Air Purge Supply	M41-F015 -(A)	345(I)	7	4
Drywell Air Purge Supply	M41-F013 -(B)	345(0)	7	4
Drywell Air Purge Exhaust	M41-F016 -(A)	347(I)	7	4
Drywell Air Purge Exhaust	M41-F017 -(B)	347(0)	7	4
Equipment Drains	P45-F009 -(A)	348(I)	6A	~~4~~ 6
Equipment Drains	P45-F010 -(B)	348(0)	6A	~~4~~ 6
Floor Drains	P45-F003 -(A)	349(I)	6A	~~4~~ 6
Floor Drains	P45-F004 -(B)	349(0)	6A	~~4~~ 6
Service Air	P52-F195-B	363(0)	6A	16
Chemical Sump Disch.	P45-F096-A	364(I)	6A	~~8~~ 9
Chemical Sump Disch.	P45-F097-B	364(0)	6A	~~8~~ 9
RWCU to Heat Exch.	G33-F253 -(B)	366(0)	8	~~30~~ 35
Reactor Water Sample Line	B33-F019 -(B)	465(I)	10	~~28.4~~ 36
Reactor Water Sample Line	B33-F020 -(A)	465(0)	10	~~28.4~~ 36

TABLE 3.6.4-1 (Continued)

CONTAINMENT AND DRYWELL ISOLATION VALVES

2. Manual Isolation Valves(g) #

a. Containment

SYSTEM AND VALVE NUMBER		PENETRATION NUMBER
Main Steam Lines	E32-F001A-A	5(0)
Main Steam Lines	E32-F001E-A	6(0)
Main Steam Lines	E32-F001J-A	7(0)
Main Steam Lines	E32-F001N-A	8(0)
Feedwater Inlet	B21-F065A-A	9(0)(b)
Feedwater Inlet	B21-F065B-A	10(0)(b)
RHR Pump "A" Suction	E12-F004A-A	11(0)(d)
RHR Pump "B" Suction	E12-F004B-B	12(0)(d)
RHR Pump "C" Suction	E12-F004C-B	13(0)(d)
RHR Heat Exchanger "A" to LPCI	E12-F042A-A	20(I
RHR Heat Ex. "A" to LPCI	E12-F027A-A	20(0)~~(c)~~e
RHR Heat Exchanger "B" to LPCI	E12-F042B-B	21(
RHR Heat Ex. "B" to LPCI	E12-F027B-(B)	21(0)~~(c)~~e
RHR Pump "C" to LPCI	E12-F042C-B	22(0)~~(c)~~e
RHR "A" Test Line To Suppr. Pool	E12-F064A-A	23(0)(d)
RHR "C" Test Line To Suppr. Pool	E12-F064C-B	24(0)~~(d)~~e
HPCS Suction	E22-F015-C	25(0)(d)
HPCS Discharge	E22-F004-C	26(0)~~(c)~~e
HPCS Test Line	E22-F012-C	27(0)(d)
RCIC Turbine Exh.	E51-F068-A	29(0)(c)
LPCS Pump Suction	E21-F001-A	30(0)(d)
LPCS Pump Discharge	E21-F005-A	31(0)~~(c)~~e
LPCS Min. Flow	E21-F011-A	32(0)~~(d)~~e
CRD Pump Discharge	C11-F083-A	33(0)
CCW Supply	P42-F066-A	44(0)
CCW Return	P42-F067-A	45(0)
CCW Return	P42-F068-B	45(I)
RCIC Pump Discharge Min. Flow	E51-F019-A	46(0)(d)
Reactor Recirc. Post Accident Sampling	B33-F128-B	47(I)

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TABLE 3.6.4-1 (Continued)

CONTAINMENT AND DRYWELL ISOLATION VALVES

SYSTEM AND VALVE NUMBER		PENETRATION NUMBER
Containment (Continued)		
Reactor Recirc. Post Accident Sampling	B33-F127-A	47(O)
Vent Header to Supp. Pool	E12-F073B-B	48(O)(d)
RHR Pump "B" Test Line	E12-F064B-B	67(O)(d)
RHR "C" Relief Vlv. Vent Hdr. to Suppr. Pool & Post-Acc. Sample Ret.	E12-F346-B	71B(O)(c)
RHR Heat Ex. "A" Relief	E12-F073A-A	77(O)(d)
Reactor Recirc. Accident Sampling	B33-F126-B	81(I)
Reactor Recirc. Accident Sampling	B33-F125-A	81(O)
SSW Supply "A"	P41-F159A-A	89(O)(c)
SSW Return "A"	P41-F168A-A	90(I)(c)
SSW Return "A"	P41-F160A-A	90(O)(c)
SSW Return "B"	P41-F168B-B	91(I)(c)
SSW Return "B"	P41-F160B-B	91(O)(c)
SSW Supply "B"	P41-F159B-B	92(O)(c)
Drywell Press. Inst.	M71-F593-A	101C(O)
Drywell Press. Inst.	M71-F591A-A	101F(O)
Drywell Press. Inst.	M71-F591B-B	102D(O)
Ctmt. Press. Inst.	M71-F592A-A	103D(O)
Ctmt. Press. Inst.	M71-F592B-B	104D(O)
Drywell H_2 Analyzer Sample	E61-F595C - (A)	106A(O)
Drywell H_2 Analyzer Sample	E61-F595D - (B)	106A(I)
Drywell H_2 Analyzer Sample Ret.	E61-F597C - (A)	106B(O)
Drywell H_2 Analyzer Sample Ret.	E61-F597D - (B)	106B(I)
Ctmt. H_2 Analyzer Sample	E61-F596C - (A)	105A(O)
Ctmt. H_2 Analyzer Sample	E61-F596D - (B)	105A(I)
Ctmt. H_2 Analyzer Sample Ret.	E61-F598C - (A)	106E(O)
Ctmt. H_2 Analyzer Sample Ret.	E61-F598D - (B)	106E(I)

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TABLE 3.6.4-1 (Continued)

CONTAINMENT AND DRYWELL ISOLATION VALVES

Containment (Continued)

SYSTEM AND VALVE NUMBER		PENETRATION NUMBER
Ctmt. H_2 Analyzer Sample	E61-F596A-(A)	108A(O)
Ctmt. H_2 Analyzer Sample	E61-F596B-(B)	108A(I)
Ctmt. H_2 Analyzer Sample Ret.	E61-F598A-(A)	107B(O)
Ctmt. H_2 Analyzer Sample Ret.	E61-F598B-(B)	107B(I)
Drywell H_2 Analyzer Sample	E61-F595A-(A)	107D(O)
Drywell H_2 Analyzer Sample	E61-F595B-(B)	107D(I)
Drywell H_2 Analyzer Sample Ret.	E61-F597A-(A)	107E(O)
Drywell H_2 Analyzer Sample Ret.	E61-F597B-(B)	107E(I)
Drywell Fiss. Prod. Monitor Sample	D23-F592-A	109A(O)
Drywell Fiss. Prod. Monitor Sample	D23-F591-B	109A(I)
Drywell Fiss. Prod. Mon. Smpl. Ret.	D23-F594-A	109B(O)
Drywell Fiss. Prod. Mon. Smpl. Ret.	D23-F593-B	109B(I)
Ctmt. Press. Inst. (Post Acc. Smpl.)	M71-F594-B	109D(O)
Ctmt. Press. Inst. (Post Acc. Smpl.)	M71-F595-A	109D(I)
Suppr. Pool Level Inst.	E30-F593A-A	113(O)(c)
Suppr. Pool Level Inst.	E30-F592A-A	114(O)
Suppr. Pool Level Inst.	E30-F594A-A	115(O)(c)
Suppr. Pool Level Inst.	E30-F591A-A	116(O)
Suppr. Pool Level Inst.	E30-F593B-B	117(O)(c)
Suppr. Pool Level Inst.	E30-F592B-B	118(O)
Suppr. Pool Level Inst.	E30-F594B-B	119(O)(c)
Suppr. Pool Level Inst.	E30-F591B-B	120(O)

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TABLE 3.6.4-1 (Continued)

CONTAINMENT AND DRYWELL ISOLATION VALVES

SYSTEM AND VALVE NUMBER		PENETRATION NUMBER
b. Drywell		
Cont. Cooling Water Inlet	P42-F114-B	329(O)
Cont. Cooling Water Outlet	P42-F116-A	330(I)
Cont. Cooling Water Outlet	P42-F117-B	330(O)
3. Other Isolation Valves(g)#		
a. Containment		
Fuel Transfer Tube	F11-E015	4(I)
Feedwater Inlet	B21-F010A	9(I)(f)
Feedwater Inlet	B21-F032A	9(O)(f)
Feedwater Inlet	B21-F010B	10(I)(f)
Feedwater Inlet	B21-F032B	10(O)(f)
RHR "A" Suction	E12-F017A	11(O)(d)
RHR "B" Suction	E12-F017B	12(O)(d)
RHR "C" Suction	E12-F017C	13(O)(d)
RHR Shutdown Cooling Suction	E12-F308	14(I)~~(c)~~e
RHR Head Spray	E51-F066-A	18(I)~~(c)~~e
RHR Head Spray	E12-F344	18(I)~~(c)~~e
RHR Heat Ex. "A" to LPCI	E12-F044A	20(I)~~(c)~~e
RHR Heat Ex. "A" to LPCI	E12-F025A	20(I)~~(c)~~e
RHR Heat Ex. "A" to LPCI	E12-F107A	20(I)~~(c)~~e
RHR Heat Ex. "B" to LPCI	E12-F025B	21(I)~~(c)~~e
RHR Heat Ex. "B" to LPCI	E12-[illegible]4B	21(I)~~(c)~~e
RHR Heat Ex. "B" to LPCI	E12-F107B	21(I)~~(c)~~e

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TABLE 3.6.4-1 (Continued)

CONTAINMENT AND DRYWELL ISOLATION VALVES

SYSTEM AND VALVE NUMBER		PENETRATION NUMBER
Containment (Continued)		
RHR Heat Ex. "C" to LPCI	E12-F234	22(0)~~(c)~~e
RHR Pump "C" to LPCI	E12-F041C-B	22(I)~~(c)~~e
RHR Pump "A" Test Line to Suppr. Pool	E12-F259	23(0)(e)
RHR Pump "A" Test Line to Suppr. Pool	E12-F261	23(0)(e)
RHR Pump "A" Test Line to Suppr. Pool	E12-F227	23(0)(e)
RHR Pump "A" Test Line to Suppr. Pool	E12-F262	23(0)(e)
RHR Pump "A" Test Line to Suppr. Pool	E12-F228	23(0)(e)
RHR "A" Test Line to Supp. Pool	E12-F290A-A	23(0)(d)
RHR Pump "A" Test Line to Suppr. Pool	E12-F338	23(0)(c)
RHR Pump "A" Test Line to Suppr. Pool	E12-F339	23(0)(c)
RHR Pump "A" Test Line to Suppr. Pool	E12-F260	23(0)(e)
RHR Pump "C" Test Line to Suppr. Pool	E12-F280	24(0)~~(c)~~e
RHR Pump "C" Test Line to Suppr. Pool	E12-F281	24(0)~~(c)~~e
HPCS Suction	E22-F014	25(0)(d)
HPCS Discharge	E22-F005 -(C)	26(I)~~(c)~~e
HPCS Discharge	E22-F218	26(I)~~(c)~~e
HPCS Discharge	E22-F201	26(I)~~(c)~~e
HPCS Test Line	E22-F035	27(0)(d)
HPCS Test Line	E22-F302	27(0)(e)
HPCS Test Line	E22-F301	27(0)(e)
LPCS Pump Suction	E21-F031	30(0)(d)
LPCS Discharge	E21-F006 -(A)	31(I)~~(c)~~e
LPCS Discharge	E21-F200	31(I)~~(c)~~e
LPCS Discharge	E21-F207	31(I)~~(c)~~e
LPCS Test Line	E21-F217	32(0)~~(c)~~e
LPCS Test Line	E21-F218	32(0)~~(c)~~e

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TABLE 3.6.4-1 (Continued)

CONTAINMENT AND DRYWELL ISOLATION VALVES

SYSTEM AND VALVE NUMBER		PENETRATION NUMBER
Containment (Continued)		
CRD Pump Discharge	C11-F122	33(I)
PSW Supply	P44-F043	37(I)
Plant Chilled Water Supply	P71-F151	38(I)
Service Air Supply	P52-F122	41(I)
Instr. Air Supply	P53-F002	42(I)
CCW Supply	P42-F035	44(I)
RCIC Disch. Min. Flow	E51-F251	46(O)^{c}
RCIC Disch. Min. Flow	E51-F252	46(O)^{c}
RHR Heat Ex. "B" Relief Vent Header	E12-F055B	48(O)$^{(d)}$
RHR Heat Ex. "B" Relief Vent Header	E12-F103B	48(O)$^{(d)}$
RHR Heat Ex. "B" Relief Vent Header	E12-F104B	48(O)$^{(d)}$
Refueling Wtr. Stg. Tk. to Upper Ctmt. Pool	G41-F053	54(O)
Refueling Wtr. Stg. Tk. to Upper Ctmt. Pool	G41-F201	54(I)
Condensate Supply	P11-F004	56(I)
FPC & CU to Upper Cont. Pool	G41-F040	57(I)
Stby. Liquid Control Sys. Mix. Tk. (future use)	C41-F151	61(I)
Stby. Liquid Control Sys. Mix. Tk. (future use)	C41-F150	61(O)
RHR Pump "B" Test Line	E12-F276	67(O)$^{(e)}$
RHR Pump "B" Test Line	E12-F277	67(O)$^{(e)}$
RHR Pump "B" Test Line	E12-F212	67(O)$^{(e)}$

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TABLE 3.6.4-1 (Continued)

CONTAINMENT AND DRYWELL ISOLATION VALVES

SYSTEM AND VALVE NUMBER		PENETRATION NUMBER
Containment (Continued)		
RHR Pump "B" Test Line	E12-F213	67(0)(e)
RHR Pump "B" Test Line	E12-F249	67(0)(e)
RHR Pump "B" Test Line	E12-F250	67(0)(e)
RHR Pump "B" Test Line	E12-F334	67(0)(c)
RHR Pump "B" Test Line	E12-E335	67(0)(c)
RHR "B" Test Line To Suppr. Pool	E12-F290B-B	67(0)(d)
Inst. Air to ADS	P53-F006	70(I)
LPCS Relief Valve Vent Header	E21-F018	71A(0)(d)
RHR Pump "C" Relief Valve Vent Header	E12-F025C	71B(0)(d)
RHR Shutdown Vent Header	E12-F036	73(0)~~(d)~~a
RHR Shutdown Suction Relief Valve Disch.	E12-F005	76B(0)~~(d)~~a
RHR Heat Ex. "A" Relief Vent Header	E12-F055A	77(0)(d)
RHR Heat Ex. "A" Relief Vent Header	E12-F103A	77(0)(d)
RHR Heat Ex. "A" Relief Vent Header	E12-F104A	77(0)(d)
SSW "A" Supply	P41-F169A	89(I)(c)
SSW "B" Supply	P41-F169B	92(I)(c)
Ctmt. Leak Rate Test Inst.	M61-F015	110A(I)
Ctmt. Leak Rate Test Inst.	M61-F014	110A(0)
Ctmt. Leak Rate Test Inst.	M61-F019	110C(I)
Ctmt. Leak Rate Test Inst.	M61-F018	110C(0)
Ctmt. Leak Rate Test Inst.	M61-F017	110F(I)
Ctmt. Leak Rate Test Inst.	M61-F016	110F(0)

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TABLE 3.6.4-1 (Continued)

CONTAINMENT AND DRYWELL ISOLATION VALVES

SYSTEM AND VALVE NUMBER		PENETRATION NUMBER
b. Drywell		
LPCI "A"	E12-F041A	313(I)
LPCI "B"	E12-F041B	314(I)
LPCI "B"	E12-F236	314(O)
CRD to Recirc. Pump A Seals	B33-F013A	326(I)
CRD to Recirc. Pump A Seals	B33-F017A	326(O)
Instrument Air	P53-F008	335(I)
Standby Liquid Control	C41-F007	328(I)
Standby Liquid Control	C41-F006	328(O)
Cont. Cooling Water Supply	P42-F115	329(I)
Plant Service Water Supply	P44-F075	332(I)
Condensate Flush Conn.	B33-F204	333(I)
Condensate Flush Conn.	B33-F205	333(O)
Combustible Gas Control	E61-F002A	339(O)
Combustible Gas Control	E61-F002B	338(O)
Combustible Gas Control	E61-F004A	340(O)
Combustible Gas Control	E61-F004B	340(O)
Upper Containment Pool Drain	G41-F265	342(O)
CRD to Recirc. Pump B Seals	B33-F013B	346(I)
CRD to Recirc. Pump B Seals	B33-F017B	346(O)
Service Air	P52-F196	363(I)
Cont. Leak Rate Test Inst.	M61-F021	438A(I)
Cont. Leak Rate Sys.	M61-F020	438A(O)
BLIND FLANGES		
Cont. Leak Rate Sys.	NA	40(I)(O)
Cont. Leak Rate Sys.	NA	82(I)(O)
Containment Leak Rate System	NA	343(I)(O)

TABLE 3.6.4-1 (Continued)

CONTAINMENT AND DRYWELL ISOLATION VALVES

4. Test Connections(g)

a. Containment

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

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TABLE 3.6.4-1 (Continued)

CONTAINMENT AND DRYWELL ISOLATION VALVES

SYSTEM AND VALVE NUMBER		PENETRATION NUMBER
Containment (Continued)		
CRD T/C	C11-F128	33(0)
Cont. Purge Supply T/C	M41-F042	34(0)
Cont. Purge Exhaust T/C	M41-F051	35(0)
PSW Supply T/C	P44-F333	37(0)
Plant Chilled Water T/C	P71-F232	38(0)
Plant Chilled Water T/C	P71-F246	39(0)
Ctmt. Leak Rate T/C	M61-F009	40(I)
Service Air T/C	P52-F258	41(0)
Inst. Air T/C	P53-F036	42(0)
RWCU T/C	G33-F070	43(0)
CCW Supply T/C	P42-F161	44(0)
CCW Return T/C	P42-F162	45(I)
Condensate Supply T/C	P11-F095	56(0)
FPC & CU To Upper Cont. Pool T/C	G41-F340	57(I)
Aux. Bldg. Flr. & Equip. Drain Tk. to Suppr. Pool T/C	P45-F275	60(0)
Aux. Bldg. Flr. & Equip. Drain Tk. to Suppr. Pool T/C	P45-F290	60(0)
Stby. Liquid Control Sys. Mix. Tk. T/C (future use)	C41-F152	61(0)
Combustible Gas Control T/C	E61-F017	65(0)
Purge Radiation Detector T/C	M41-F054	66(0)
RHR "B" Test Line T/C	E12-F321	67(0)(c)
RHR "B" Test Line T/C	E12-F351	67(0,(c)
RHR "B" Test Line T/C	E12-F331	67(0)(c)

TABLE 3.6.4-1 (Continued)

CONTAINMENT AND DRYWELL ISOLATION VALVES

SYSTEM AND VALVE NUMBER		PENETRATION NUMBER
Containment (Continued)		
RHR "B" Test Line T/C	E12-F350	67(0)(c)
RHR "B" Test Line T/C	E12-F312	67(0)(c)
RHR "B" Test Line T/C	E12-F305	67(0)(c)
Refueling Water Transf. Pump Suction T/C	P11-F425	69(0)(c)
Refueling Water Transf. Pump Suction T/C	P11-F132	69(0)(c)
Inst. Air to ADS T/C	P53-F043	70(0)
Cont. Leak Rate T/C	M61-F010	82(I)
RWCU To Feedwater T/C	G33-F055	83(0)
Suppr. Pool Cleanup T/C	P60-F011	85(0)
Suppr. Pool Cleanup T/C	P60-F034	85(0)
RWCU Pump Suction T/C	G33-F002	87(0)
RWCU Pump Discharge T/C	G33-F061	88(0)
SSW T/C	P41-F163A	89(0)(c)
SSW T/C	P41-F163B	92(0)(c)
b. Drywell		
LPCI "A" T/C	E12-F056A	313(0)
LPCI "B" T/C	E12-F056B	314(0)
Instrument Air T/C	P53-F493	335 ~~327~~(0)
SLCS T/C	C41-F026	328(0)
Service Air T/C	P52-F476	363(0)
RWCU T/C	G33-F120	366(I)
Reactor Sample T/C	B33-F021	465(0)

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3/4.6.5 DRYWELL POST-LOCA VACUUM BREAKERS

LIMITING CONDITION FOR OPERATION

3.6.5 All drywell post-LOCA vacuum breakers shall be OPERABLE and closed..

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2 and 3.

ACTION:

a. With one drywell post-LOCA vacuum breaker inoperable for opening but known to be closed, restore the inoperable vacuum breaker to OPERABLE status within 72 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

b. With one drywell post-LOCA vacuum breaker open, restore the open vacuum breaker to the closed position within 1 hour or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

c. With the position indicator of an OPERABLE drywell post-LOCA vacuum breaker inoperable, verify the vacuum breaker to be closed at least once per 24 hours by local indication. Otherwise declare the vacuum breaker inoperable. (See Note 1)

SURVEILLANCE REQUIREMENTS

4.6.5 Each drywell post-LOCA vacuum breaker shall be:

a. Verified closed at least once per 7 days.

b. Demonstrated OPERABLE:

1. At least once per 31 days by:

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

   b) Verifying the position indicator OPERABLE by observing expected valve movement during the cycling test. (See Note 1)

2. At least once per 18 months by:

   a) Verifying the pressure differential required to open the vacuum breaker, from the closed position, to be less than or equal to 1.0 psid, and (See Note 1)

   b) Verifying the position indicator OPERABLE by performance of a CHANNEL CALIBRATION. (See Note 1)

SURVEILLANCE REQUIREMENTS (Continued)

3. By verifying the OPERABILITY of the vacuum breaker isolation valve differential pressure actuation instrumentation with the opening setpoint of -1.0 to 0.0 psid (Drywell minus Containment) by performance of a:

   a) CHANNEL CHECK at least once per 24 hours,

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

   c) CHANNEL CALIBRATION at least once per 18 months.

Note 1: Until restart after the first refueling outage, the following requirements shall apply:

3.6.5

c. With the position indicator of an OPERABLE drywell post-LOCA isolation valve for a vacuum breaker inoperable, verify the isolation valve to be closed at least once per 24 hours by local indication. Otherwise declare the isolation valve inoperable.

4.6.5.b.1

b. Verifying the position indicator for the vacuum breaker isolation valve OPERABLE by observing expected valve movement during the cycling test.

4.6.5.b.2

At least once per 18 months by:

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

b) Verifying the position indicator for the vacuum breaker isolation valve OPERABLE by performance of a CHANNEL CALIBRATION.

3/4.6.6 SECONDARY CONTAINMENT

SECONDARY CONTAINMENT INTEGRITY

LIMITING CONDITION FOR OPERATION

3.6.6.1 SECONDARY CONTAINMENT INTEGRITY shall be maintained.

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

ACTION:

Without SECONDARY CONTAINMENT INTEGRITY:

a. In OPERATIONAL CONDITION 1, 2 or 3, restore SECONDARY CONTAINMENT INTEGRITY within 4 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

b. In Operational Condition *, suspend handling of irradiated fuel in the primary or secondary containment, CORE ALTERATIONS and operations with a potential for draining the reactor vessel. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.6.6.1 SECONDARY CONTAINMENT INTEGRITY shall be demonstrated by:

a. Verifying at least once per 31 days that:

   1. All Auxiliary Building and Enclosure Building equipment hatches and blowout panels are closed and sealed.
   2. The door in each access to the Auxiliary Building and Enclosure Building is closed, except for routine entry and exit.
   3. All Auxiliary Building and Enclosure Building penetrations not capable of being closed by OPERABLE secondary containment automatic isolation dampers/valves and required to be closed during accident conditions are closed by valves, blind flanges, or deactivated automatic dampers/valves secured in position. rupture discs

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b. At least once per 18 months:

   1. Verifying that one standby gas treatment subsystem will draw down the secondary containment to greater than or equal to 0.25 inches of vacuum water gauge in less than or equal to 120 seconds, and
   2. Operating one standby gas treatment subsystem for one hour and maintaining greater than or equal to 0.266 inches of vacuum water gauge in the secondary containment at a flow rate not exceeding 4000 CFM.

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

SECONDARY CONTAINMENT AUTOMATIC ISOLATION DAMPERS/VALVES

LIMITING CONDITION FOR OPERATION

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

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

ACTION:

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

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

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

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

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

Otherwise, in Operational Condition *, suspend handling of irradiated fuel in the primary or secondary containment, CORE ALTERATIONS and operations with a potential for draining the reactor vessel. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

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

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

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

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

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

TABLE 3.6.6.2-1

SECONDARY CONTAINMENT VENTILATION SYSTEM AUTOMATIC ISOLATION DAMPERS/VALVES

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DAMPER/VALVE FUNCTION # ~~(Number)~~	MAXIMUM ISOLATION TIME (Seconds)
a. Dampers	
Auxiliary Building Ventilation Supply Damper (Q1T41F006)-(B)	4
Auxiliary Building Ventilation Supply Damper (Q1T41F007)-(A)	4
Fuel Handling Area Ventilation Exhaust Damper (Q1T42F003)-(B)	4
Fuel Handling Area Ventilation Exhaust Damper (Q1T42F004)-(A)	4
Fuel Handling Area Ventilation Supply Damper (Q1T42F011)-(A)	4
Fuel Handling Area Ventilation Supply Damper (Q1T42F012)-(B)	4
Fuel Pool Sweep Ventilation Supply Damper (Q1T42F019)-(A)	4
Fuel Pool Sweep Ventilation Supply Damper (Q1T42F020)-(B)	4
Containment & Drywell Area Ventilation Supply Damper (Q1M41F007)-(B)	4
Containment & Drywell Area Ventilation Supply Damper (Q1M41F008)-(A)	4
Containment & Drywell Area Ventilation Exhuast Damper (Q1M41F036)-(A)	4
Containment & Drywell Area Ventilation Exhaust Damper (Q1M41F037)-(B)	4

The -(A) and -(B) designators on the valve/damper numbers indicate associated electrical divisions. 1306

TABLE 3.6.6.2-1 (Continued)

SECONDARY CONTAINMENT VENTILATION SYSTEM AUTOMATIC ISOLATION DAMPERS/VALVES

VALVE FUNCTION ~~(Number)~~	MAXIMUM ISOLATION TIME (Seconds)
b. Valves	
Plant Chilled Water System Aux. Bldg. Isol. Valve (P71-F306)-(A)	30
Plant Chilled Water System Aux. Bldg. Isol. Valve (P71-F304)-(A)	30
Plant Chilled Water System Aux. Bldg. Isol. Valve (P71-F302)-(A)	4
Plant Chilled Water System Aux. Bldg. Isol. Valve (P71-F300)-(A)	4
Plant Chilled Water System Aux. Bldg. Isol. Valve (P71-F307)-(B)	30
Plant Chilled Water System Aux. Bldg. Isol. Valve (P71-F305)-(B)	30
Plant Chilled Water System Aux. Bldg. Isol. Valve (P71-F303)-(B)	4
Plant Chilled Water System Aux. Bldg. Isol. Valve (P71-F301)-(B)	4
Service Air System Aux. Bldg. Isol. Valve (P52-F221A)-(A)	4
Service Air System Aux. Bldg. Isol. Valve (P52-F160A)-(A)	4
Service Air System Aux. Bldg. Isol. Valve (P52-F221B)-(B)	4
Service Air System Aux. Bldg. Isol. Valve (P52-F160B)-(B)	4
Instrument Air System Aux. Bldg. Isol. Valve (P53-F026A)-(A)	4
Instrument Air System Aux. Bldg. Isol. Valve (P53-F026B)-(B)	4
FPCC Filt-Demin System Backwash Aux. Bldg. Isol. Valve (G46-F253)-(A&B)	30

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TABLE 3.6.6.2-1 (Continued)

SECONDARY CONTAINMENT VENTILATION SYSTEM AUTOMATIC ISOLATION DAMPERS/VALVES

VALVE FUNCTION ~~(Number)~~	MAXIMUM ISOLATION TIME (Seconds)
Valves (Continued)	
RWCU Backwash RCVG Tk. Aux. Bldg. Isol. Valve (G36-F108) - (A)	30
RWCU Backwash RCVG Tk. Aux. Bldg. Isol. Valve (G36-F109) - (B)	30
Nuclear Boiler System Aux. Bldg. Isol. Valve (B21-F113) - (A)	30
Nuclear Boiler System Aux. Bldg. Isol. Valve (B21-F114) - (B)	30
RWCU Aux. Bldg. Isol. Valve (G33-F235) - (A)	30
RWCU Aux. Bldg. Isol. Valve (G33-F234) - (B)	30
SPCU Aux. Bldg. Isol. Valve (P60-F003) - (A)	30
SPCU Aux. Bldg. Isol. Valve (P60-F004) - (B)	30
SPCU Aux. Bldg. Isol. Valve (P60-F007) - (B)	30
SPCU Aux. Bldg. Isol. Valve (P60-F008) - (A)	30
Fire Protection System Aux. Bldg. Isol. Valve (P64-F282A) - (A)	4
Fire Protection System Aux. Bldg. Isol. Valve (P64-F283A) - (A)	4
Fire Protection System Aux. Bldg. Isol. Valve (P64-F332A) - (A)	4
Fire Protection System Aux. Bldg. Isol. Valve (P64-F282B) - (B)	4
Fire Protection System Aux. Bldg. Isol. Valve (P64-F283B) - (B)	4
Fire Protection System Aux. Bldg. Isol. Valve (P64-F332B) - (B)	4
Cond. & Refuel Water Transfer Aux. Bldg. Isol. Valve (P11-F062) - (A)	9

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TABLE 3.6.6.2-1 (Continued)

SECONDARY CONTAINMENT VENTILATION SYSTEM AUTOMATIC ISOLATION DAMPERS/VALVES

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

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TABLE 3.6.6.2-1 (Continued)

SECONDARY CONTAINMENT VENTILATION SYSTEM AUTOMATIC ISOLATION DAMPERS/VALVES

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

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STANDBY GAS TREATMENT SYSTEM

LIMITING CONDITION FOR OPERATION

3.6.6.3 Two independent standby gas treatment subsystems shall be OPERABLE.

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

ACTION:

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

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

   2. In Operational Condition *, suspend handling of irradiated fuel in the primary or secondary containment, CORE ALTERATIONS and operations with a potential for draining the reactor vessel. The provisions of Specification 3.0.3 are not applicable.

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

SURVEILLANCE REQUIREMENTS

4.6.6.3 Each standby gas treatment subsystem shall be demonstrated OPERABLE:

a. At least once per 31 days by initiating, from the control room, flow through the HEPA filters and charcoal adsorbers and verifying that the subsystem operates for at least 10 Continous hours with the heaters OPERABLE. /062

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

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

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

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

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

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

d. At least once per 18 months by:

   1. Performing a system functional test which includes simulated automatic actuation of the system throughout its emergency operating sequence for the:

      a) LOCA, and
      b) Fuel handling accident.

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

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

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

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   4. Verifying that the fan can be manually started.

   5. Verifying that the heaters dissipate 50 ± 5.0 kW when tested in accordance with ANSI N510-1975 (except for the phase balance criteria stated in Section 14.2.3).

e. After each complete or partial replacement of a HEPA filter bank by verifying that the HEPA filter banks remove greater than or equal to 99.95% of the DOP when they are tested in-place in accordance with ANSI N510-1975 while operating the system at a flow rate of 4000 cfm ± 10%.

f. After each complete or partial replacement of a charcoal adsorber bank by verifying that the charcoal adsorbers remove greater than 99.95% of a halogenated hydrocarbon refrigerant test gas when they are tested in-place in accordance with ANSI N510-1975 while operating the system at a flow rate of 4000 cfm ± 10%.

3/4.6.7 ATMOSPHERE CONTROL

CONTAINMENT ~~AND DRYWELL~~ HYDROGEN RECOMBINER SYSTEMS 240

LIMITING CONDITION FOR OPERATION

3.6.7.1 Two independent containment ~~and drywell~~ hydrogen recombiner systems shall be OPERABLE. 240

APPLICABILITY: OPERATIONAL CONDITIONS 1 and 2.

ACTION:

With one containment ~~and drywell~~ hydrogen recombiner system inoperable, restore the inoperable system to OPERABLE status within 30 days or be in at least HOT SHUTDOWN within the next 12 hours. 240

SURVEILLANCE REQUIREMENTS

4.6.7.1 Each containment ~~and drywell~~ hydrogen recombiner system shall be demonstrated OPERABLE: 240

a. At least once per 6 months by verifying during a recombiner system functional test that the minimum heater sheath temperature increases to greater than or equal to 700°F within 90 minutes. Maintain $\geq$700°F for at least 2 hours.

b. At least once per 18 months by:

1. Performing a CHANNEL CALIBRATION of all control room recombiner instrumentation and control circuits.

2. Verifying the integrity of all heater electrical circuits by performing a resistance to ground test within 30 minutes following the above required functional test. The resistance to ground for any heater phase shall be greater than or equal to 10,000 ohms.

3. Verifying during a recombiner system functional test that the heater sheath temperature increases to greater than or equal to 1200°F within 5 hours and is maintained between 1150°F and 1300°F for at least 4 hours.

4. Verifying through a visual examination that there is no evidence of abnormal conditions within the recombiner enclosure; i.e. loose wiring or structural connections, deposits of foreign materials, etc.

c. [DELETED]

CONTAINMENT SYSTEMS

CONTAINMENT AND DRYWELL HYDROGEN IGNITION SYSTEM

LIMITING CONDITION FOR OPERATION

3.6.7.2 Two independent containment and drywell hydrogen ignition system subsystems shall be OPERABLE.

APPLICABILITY: OPERATIONAL CONDITIONS 1 and 2.

ACTION:

With one containment and drywell hydrogen ignition subsystem inoperable, restore the inoperable subsystem to OPERABLE status within 7 days or be in at least HOT SHUTDOWN within the next 12 hours.

SURVEILLANCE REQUIREMENTS

Delete

4.6.7.2 Each containment and drywell hydrogen ignition subsystem shall be demonstrated OPERABLE:

a. At least once per 92 days by energizing the supply breakers and verifying that at least 41 glow plugs are energized.

b. At least once per 18 months by:

  1. Verifying the cleanliness of each glow plug by a visual inspection.
  2. Energizing each glow plug and verifying a surface temperature of at least 1700°F.

CONTAINMENT SYSTEMS

CONTAINMENT AND DRYWELL HYDROGEN IGNITION SYSTEM

LIMITING CONDITION FOR OPERATION

3.6.7.2 The containment and drywell hydrogen ignition system consisting of the following:

a. At least two igniter assemblies in each enclosed area specified on Table 3.6.7.2-2,

b. All igniter assemblies adjacent to any inoperable igniter assembly in each open area specified on Table 3.6.7.2-2, and

c. Two independent containment and drywell hydrogen ignition subsystems each consisting of two circuits (as ~~specified~~ listed on Table 3.6.7.2-1) with no more than two igniter assemblies inoperable per circuit.

shall be OPERABLE.

APPLICABILITY: OPERATIONAL CONDITIONS 1 and 2

ACTION:

a. With less than two igniter assemblies OPERABLE in any enclosed area specified in Table 3.6.7.2-2, restore at least two igniter assemblies to OPERABLE status within 7 days or be in at least HOT SHUTDOWN within the next 12 hours.

b. With any adjacent igniter assemblies within an open area as specified on Table 3.6.7.2-2 inoperable, restore the igniter assemblies in that open area so that all igniter assemblies adjacent to an inoperable igniter assembly are OPERABLE within 7 days or be in at least HOT SHUTDOWN within the next 12 hours.

c. With one containment and drywell hydrogen igniter subsystem inoperable, restore the inoperable subsystem to OPERABLE status within 7 days or be in at least HOT SHUTDOWN within the next 12 hours.

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SURVEILLANCE REQUIREMENTS

4.6.7.2 The containment and drywell hydrogen ignition system shall be demonstrated OPERABLE:

a. At least once per 92 days by energizing the supply breakers and:

   1. Verifying a visible glow from the glow plug tip of each normally accessible igniter assembly specified in Table 3.6.7.2-2,

   2. Verifying that each circuit of each containment and drywell hydrogen igniter subsystem is conducting sufficient current to energize the minimum required number of igniter assemblies specified on Table 4.~~7~~.~~8~~.2-1.
   6 7

b. At every COLD SHUTDOWN, but no more frequently than once per 92 days, by energizing the supply breakers and verifying a visible glow from the glow plug tip of each normally inaccessible igniter assembly specified in Table 3.6.7.2-2.

c. At least once per 18 months by:

   1. Verifying the cleanliness of each glow plug by a visual inspection.

   2. Energizing each glow plug and verifying a surface temperature of at least 1700°F.

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Table 3.6.7.2-1

Hydrogen Igniter Circuits

Division I		Division II	
Circuit 1	Circuit 2	Circuit 1	Circuit 2
D124	D107	D125	D106
D126	D109	D127	D108
D128	D111	D129	D110
D130	D112	D136	D113
D132	D114	D138	D115
D134	D116	D140	D117
D137	D119	D149	D118
D139	D121	D151	D120
D141	D123	D153	D122
D143	D148	D161	D131
D145	D150	D162	D133
D147	D152	D165	D135
D155	D154	D166	D142
D157	D159	D168	D144
D172	D160	D170	D146
D174	D163	D171	D156
D176	D164	D178	D158
D183	D167	D180	D173
D192	D169	D182	D175
D185	D179	D187	D177
D186	D181	D189	D184
	D188	D191	D193
	D190		D194
	D195		

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Table 3.6.7.2-2

Hydrogen Igniters and Locations

*Igniter	Div./Circuit	Elevation	Azimuth	Dist. From Center Line of Reactor
NORMALLY ACCESSIBLE				
Open Areas				
Containment				
D124	I/1	136'-0"	21	57'-0"
D125	II/1	132'-10"	47	53'-0"
D126	I/1	132'-10"	75	51'-9"
D127	II/1	132'-10"	107	51'-9"
D128	I/1	132'-10"	135	51'-9"
D129	II/1	132'-10"	165	51'-9"
D130	I/1	132'-10"	195	51'-9"
D131	II/2	145'-7"	220	60'-0"
D132	I/1	134'-4"	253	51'-9"
D133	II/2	134'-4"	285	51'-9"
D134	I/1	134'-4"	317	52'-8"
D135	II/2	136'-0"	349	51'-9"
D137	I/1	160'-4"	36	53'-6"
D138	II/1	157'-10"	70	51'-9"
D139	I/1	157'-10"	100	51'-9"
D140	II/1	160'-4"	135	51'-2"
D141	I/1	155'-10"	164	51'-9"
D142	II/2	155'-10"	196	51'-9"
D143	I/1	165'-0"	226	61'-4"
D144	II/2	160'-4"	260	54'-2"
D145	I/1	159'-4"	285	51'-5"
D146	II/2	159'-4"	321	51'-5"
D148	I/2	182'-9"	30	61'-0"
D149	II/1	167'-8"	41	42'-0"
D154	I/2	182'-4"	136	51'-9"
D155	I/1	182'-4"	254	55'-9"
D156	II/2	183'-4"	274	48'-0"
D157	I/1	182'-4"	293	58'-11"
D158	II/2	183'-4"	320	53'-2"
D160	I/2	202'-0"	35	46'-0"
D161	II/1	207'-9"	59	44'-0"
D170	II/1	207'-7"	135	55'-8"
D171	II/1	206'-0"	216	46'-9"
D172	I/1	204'-11"	2[illegible]3	[illegible]6'-0"
D173	II/2	204'-4"	256	53'-8"
D174	I/1	204'-11"	284	53'-8"
D175	II/2	201'-11"	298	26'-8"
D176	I/1	207'-9"	31[illegible]	56'-6"

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*Igniter	Div./Circuit	Elevation	Azimuth	Dist. From Center Line of Reactor

NORMALLY ACCESSIBLE

Open Areas

Containment (Cont'd)

*Igniter	Div./Circuit	Elevation	Azimuth	Dist. From Center Line of Reactor
D178	II/1	262'-0"	6	55'-5"
D179	I/2	262'-0"	48	55'-5"
D180	II/1	262'-0"	91	55'-0"
D181	I/2	262'-0"	140	55'-0"
D182	II/1	262'-0"	183	55'-0"
D183	I/1	262'-0"	225	55'-0"
D184	II/2	262'-0"	268	55'-0"
D185	I/1	262'-0"	333	55'-0"
D186	I/1	283'-10"	349	39'-9"
D187	II/1	283'-10"	34	39'-9"
D188	I/2	283'-10"	81	39'-9"
D189	II/1	283'-10"	127	39'-9"
D190	I/2	283'-10"	152	39'-9"
D191	II/1	283'-10"	199	39'-9"
D192	I/1	283'-10"	242	39'-9"
D193	II/2	283'-10"	286	39'-9"
D194	II/2	295'-0"	349	15'-3"
D195	I/2	295'-0"	158	15'-3"

NORMALLY INACCESSIBLE

Open Areas

Drywell

*Igniter	Div./Circuit	Elevation	Azimuth	Dist. From Center Line of Reactor
D106	II/2	146'-3"	0	26'-6"
D107	I/2	145'-7"	63	29'-3"
D108	II/2	146'-2"	120	29'-8"
D109	I/2	147'-1"	180	26'-3"
D110	II/2	145'-7"	240	29'-[illegible]"
D111	I/2	145'-7"	313	25'-2"
D112	I/2	160'-6"	0	27'-4"
D113	II/2	160'-6	60	29'-9"
D114	I/2	160'-6"	135	27'-1"
D115	II/2	160'-6"	180	26'-10"
D116	I/2	160'-6"	232	26'-1"
D117	II/2	160'-6"	324	26'-5"
D118	II/2	179'-0"	0	26'-4"
D119	I/2	179'-0"	65	26'-4"
D120	II/2	179'-0"	125	26'-4"
D121	I/2	179'-0"	180	26'-4"
D122	II/2	179'-0"	245	26'-4"
D123	I/2	179'-0"	305	26'-4"

065

Table 4.6.7.2-1

NUMBER OF IGNITERS BY CIRCUIT

Division I	Minimum Required	Total On Circuit
Circuit 1	19	21
Circuit 2	22	24
Division II		
Circuit 1	20	22
Circuit 2	21	23

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DRYWELL PURGE SYSTEM

LIMITING CONDITION FOR OPERATION

3.6.7.3 Two independent drywell purge system subsystems shall be OPERABLE.

APPLICABILITY: OPERATIONAL CONDITIONS 1 and 2.

ACTION:

With one drywell purge system subsystem inoperable, restore the inoperable subsystem to OPERABLE status within 30 days or be in at least HOT SHUTDOWN within the next 12 hours.

SURVEILLANCE REQUIREMENTS ~~Continued~~

X 19

4.6.7.3 Each drywell purge system subsystem shall be demonstrated OPERABLE:

a. At least once per 92 days by:
   1. Starting the subsystem from the control room, and
   2. Verifying that the system operates for at least 15 minutes.

b. At least once per 18 months by:
   1. Verifying a subsystem flow rate of at least 1000 cfm during subsystem operation for at least 15 minutes.
   2. Verifying the pressure differential required to open the vacuum breakers on the drywell purge compressor discharge lines, from the closed position, to be less than or equal to 1.0 psid.

c. Verifying the OPERABILITY of the drywell purge compressor discharge line vacuum breaker isolation valve differential pressure actuation instrumentation with an opening setpoint of 0.0 to 1.0 psid (Drywell minus Containment) by performance of a:
   1. CHANNEL CHECK at least once per 24 hours,
   2. CHANNEL FUNCTIONAL TEST at least once per 31 days, and
   3. CHANNEL CALIBRATION at least once per 18 months.

3/4.7 PLANT SYSTEMS

3/4.7.1 SERVICE WATER SYSTEMS

STANDBY SERVICE WATER SYSTEM

LIMITING CONDITION FOR OPERATION

/ 129

3.7.1.1 ~~Two~~ Each of the following independent standby service water (SSW) system subsystems shall be CPERABLE with each subsystem comprised of:

a. One OPERABLE SSW pump, and
b. An OPERABLE flow path capable of taking suction from the associated SSW cooling tower basin and transferring the water through the RHR heat exchangers ~~, ECCS pump room seal coolers, and associated coolers and pump heat exchangers.~~ to associated plant equipment, as required,

and

APPLICABILITY: shall be OPERABLE as follows:

ACTION:

a. In O 1. In OPERATIONAL CONDITIONS 1, 2, and 3:
1. two subsystems; and

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2. 2. In OPERATIONAL CONDITIONS 4, 5, and *:
the subsystems associated with the systems and components required to

b. In OP assoc or 3. inope 3.4.9. be OPERABLE by Specifications ~~[illegible]~~ 3.4.9.2, 3.5.2, 3.8.1.2, 3.9.11.1 or 3.9.11.2.

c. In OPERATIONAL CONDITION 4 or 5 with the SSW subsystem, which is associated with an ECCS pump required OPERABLE by Specification 3.5.2, inoperable, declare the associated ECCS pump inoperable and take the ACTION required by Specification 3.5.2.

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

e. In Operational Condition *, with the SSW subsystem, which is associated with a diesel generator required OPERABLE by Specification 3.8.1.2, inoperable, declare the associated diesel generator inoperable and take the ACTION required by Specification 3.8.1.2. The provisions of Specification 3.0.3 are not applicable.

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f. In OPERATIONAL CONDITIONS 1, 2, 3, 4, and 5 [illegible], with the SSW subsystem, which is associated with a diesel generator required OPERABLE by Specification 3.8.1.2, inoperable, declare the associated diesel generator inoperable and take the ACTION required by Specification 3.8.1.2 or 3.8.1.2, as applicable.

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SURVEILLANCE REQUIREMENTS

4.7.1.1 ~~Each~~ At least the above required standby service water system subsystem(s) shall be demonstrated OPERABLE: 1129

a. At least once per 31 days by:

1. Verifying that each valve in the flow path that is not locked, sealed or otherwise secured in position, is in its correct position.
2. Verifying that the valves isolating service to the spent fuel storage pool cooler are locked closed.

b. At least once per 18 months during shutdown by verifying that each automatic valve servicing safety related equipment actuates to its correct position on a actuation test signal.

PLANT SYSTEMS

HIGH PRESSURE CORE SPRAY SERVICE WATER SYSTEM

LIMITING CONDITION FOR OPERATION

3.7.1.2 The high pressure core spray (HPCS) service water system shall be OPERABLE with:

a. One OPERABLE HPCS service water pump, and

b. An OPERABLE flow path capable of taking suction from the associated SSW cooling tower basin and transferring the water through the HPCS service water system heat exchangers.

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

ACTION:

With the HPCS service water system inoperable, declare the HPCS system inoperable and take the ACTION required by Specification 3.5.1 or 3.5.2, as applicable, and declare the associated diesel inoperable and take the ACTION required by Specification 3.8.1.1 or 3.8.1.2. /287

SURVEILLANCE REQUIREMENTS

4.7.1.2 The HPCS service water system shall be demonstrated OPERABLE: a. At least once per 31 days by verifying that each valve, manual, power operated or automatic, servicing safety related equipment that is not locked, sealed or otherwise secured in position, is in its correct position.

b. At least once per 18 months during shutdown by verifying that each automatic valve servicing safety-related equipment actuates to its correct position on a service water actuation test signal. /094

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*When the ~~HPSCS~~ HPCS system is required to be OPERABLE. /002

ULTIMATE HEAT SINK

LIMITING CONDITION FOR OPERATION

3.7.1.3 At least the following independent SSW cooling tower basins, each with:

a. A minimum basin water level at or above elevation 130'3" Mean Sea Level, USGS datum, equivalent to an indicated level of ≥ 87".

b. Two OPERABLE cooling tower fans,#

shall be OPERABLE:

a. In OPERATIONAL Condition 1, 2 and 3, two basins,

b. In OPERATIONAL Condition 4, 5 and *, the basins associated with systems and components required OPERABLE by Specifications 3.7.1.1 and 3.7.1.2.

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

ACTION:

a. In OPERATIONAL CONDITION 1, 2, 3, 4, 5 and * with one SSW cooling tower basin inoperable, declare the associated SSW subsystem inoperable and, if applicable, declare the HPCS service water system inoperable, and take the ACTION required by Specifications 3.7.1.1 and 3.7.1.2, as applicable.

b. In OPERATIONAL CONDITION 1, 2, 3, 4 or 5 with both SSW cooling tower basins inoperable, declare the SSW system and the HPCS service water system inoperable and take the ACTION required by Specifications 3.7.1.1 and 3.7.1.2.

c. In Operational Condition * with both SSW cooling tower basins inoperable, declare the SSW system inoperable and take the ACTION required by Specification 3.7.1.1. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.7.1.3 At least the above required SSW cooling tower basins shall be determined OPERABLE at least once per:

a. 24 hours by verifying basin water level to be greater than or equal to 87".

017 b. 31 days by starting from the control room each SSW cooling tower fan not already in operation ~~from the control room~~ and operating ~~the~~ each fan for at least 15 minutes.

c. 18 months by verifying that each SSW cooling tower fan starts automatically when the associated SSW subsystem is started.

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*When handling irradiated fuel in the primary or secondary containment.

#The basin cooling tower fans are not required to be OPERABLE for HPCS service water system OPERABILITY.

3/4.7.2 CONTROL ROOM EMERGENCY FILTRATION SYSTEM

LIMITING CONDITION FOR OPERATION

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

APPLICABILITY: All OPERATIONAL CONDITIONS and *.

ACTION:

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

b. In OPERATIONAL CONDITION 4, 5 or *:

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

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

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

SURVEILLANCE REQUIREMENTS

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

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

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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. [DELETED]

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

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

3. 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.

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

c. After every 720 hours of charcoal adsorber operation by verifying within 31 days after removal that a laboratory analysis of a representative carbon sample obtained in accordance with Regulatory 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.

d. At least once per 18 months by:

1. Verifying that the pressure drop across the combined HEPA filters and charcoal adsorber banks is less than 7.2 inches Water Gauge while operating the subsystem at a flow rate of 4000 cfm ± 10%.

2. Verifying that the subsystem receives an appropriate isolation actuation signal by each of the following test conditions. For at least one of the test conditions, verify that the subsystem automatically switches to the isolation mode of operation and the isolation valves close within 4 seconds.

   a) High high radiation in the outside air intake duct,
   b) High chlorine concentration in the outside air intake duct,
   c) High drywell pressure,
   d) Low low reactor water level, and
   e) Manual initiation from the Control Room.

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3. Verifying that the heaters dissipate 20.7 ± 2.1 kW when tested in accordance with ANSI N510-1975 (except for the phase balance criteria stated in Section 14.2.3).

e. After each complete or partial replacement of a HEPA filter bank by verifying that the HEPA filter banks remove greater than or equal to 99.95% of the DOP when they are tested in-place in accordance with ANSI N510-1975 while operating the system at a flow rate of 4000 cfm ± 10%.

f. After each complete or partial replacement of a charcoal adsorber bank by verifying that the charcoal adsorbers remove 99.95% of a halogenated hydrocarbon refrigerant test gas when they are tested in-place in accordance with ANSI N510-1975 while operating the system at a flow rate of 4000 cfm ± 10%.

PLANT SYSTEMS

3/4.7.3 REACTOR CORE ISOLATION COOLING SYSTEM

LIMITING CONDITION FOR OPERATION

3.7.3 The reactor core isolation cooling (RCIC) system shall be OPERABLE with an OPERABLE flow path capable of automatically taking suction from the suppression pool and transferring the water to the reactor pressure vessel.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, and 3 with reactor steam dome pressure greater than 135 psig.

ACTION:

With the RCIC system inoperable, operation may continue provided the HPCS system is OPERABLE; restore the RCIC system to OPERABLE status within 14 days Otherwise ~~or~~ be in at least HOT SHUTDOWN within the next 12 hours and reduce reactor steam dome pressure to less than or equal to 135 psig within the following 24 hours. |286

SURVEILLANCE REQUIREMENTS

4.7.3 The RCIC system shall be demonstrated OPERABLE:

a. At least once per 31 days by:

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

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

3. Verifying that the pump flow controller is in the correct position.

b. At least once per 92 days by verifying that the RCIC pump develops a flow of greater than or equal to 800 gpm in the test flow path with a system head corresponding to reactor vessel operating pressure when steam is being supplied to the turbine at 1025 + 20, -80 psig.*

c. At least once per 18 months by:

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

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

SURVEILLANCE REQUIREMENTS (Continued)

2. Verifying that the system will develop a flow of greater than or equal to 800 gpm in the test flow path when steam is supplied to the turbine at a pressure of 150 + 15, - 0 psig.*

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

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

3/4.7.~~6~~4 SNUBBERS

LIMITING CONDITION FOR OPERATION

3.7.~~6~~4 All hydraulic and mechanical snubbers shall be OPERABLE.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, and 3. OPERATIONAL CONDITIONS 4 and 5 for snubbers located on systems required OPERABLE in those OPERATIONAL CONDITIONS.

ACTION:

With one or more snubbers inoperable on any system, within 72 hours replace or restore the inoperable snubber(s) to OPERABLE status and perform an engineering evaluation per Specification 4.7.~~6~~4g. on the attached component or declare the attached system inoperable and follow the appropriate ACTION statement for that system.

SURVEILLANCE REQUIREMENTS

4.7.~~6~~4 Each snubber shall be demonstrated OPERABLE by performance of the following augmented inservice inspection program and the requirements of Specification 4.0.5.

a. Inspection Types

As used in this specification, type of snubber shall mean snubbers of the same design and manufacturer, irrespective of capacity.

b. Visual Inspections

Snubbers are categorized as inaccessible or accessible during reactor operation. Each of these groups (inaccessible and accessible) may be inspected independently according to the schedule below. The first inservice visual inspection of each type of snubber shall be performed after 4 months but within 10 months of commencing POWER OPERATION and shall include all hydraulic and mechanical snubbers. If all snubbers of each type on any system are found OPERABLE during the first inservice visual inspection, the second inservice visual inspection of that system shall be performed at the first refueling outage. Otherwise, subsequent visual inspections of a given system shall be performed in accordance with the following schedule:

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SURVEILLANCE REQUIREMENTS (Continued)

No. of Inoperable Snubbers of Each Type on Any System per Inspection Period	Subsequent Visual Inspection Period*#
0	18 months ± 25%
1	12 months ± 25%
2	6 months ± 25%
3,4	124 days ± 25%
5,6,7	62 days ± 25%
8 or more	31 days ± 25%

c. Visual Inspection Acceptance Criteria

Visual inspections shall verify that: (1) there are no visible indications of damage or impaired OPERABILITY and (2) attachments to the foundation or supporting structure are secure, and (3) fasteners for attachment of the snubber to the component and to the snubber anchorage are secure. Snubbers which appear inoperable as a result of visual inspections may be determined OPERABLE for the purpose of establishing the next visual inspection interval, provided that: (1) the cause of the rejection is clearly established and remedied for that particular snubber and for other snubbers irrespective of type on that system that may be generically susceptible; and (2) the affected snubber is functionally tested in the as-found condition and determined OPERABLE per Specifications 4.7.4f. All snubbers connected to an inoperable common hydraulic fluid reservoir shall be counted as inoperable snubbers. For those snubbers common to more than one system, the OPERABILITY of such snubbers shall be considered in assessing the surveillance schedule for each of the related systems.

d. Transient Event Inspection

An inspection shall be performed of all hydraulic and mechanical snubbers attached to sections of systems that have experienced unexpected, potentially damaging transients as determined from a review of operational data and a visual inspection of the systems within 6 months following such an event. In addition to satisfying the visual inspection acceptance criteria, freedom-of-motion of mechanical snubbers shall be verified using at least one of the following: (1) manually induced snubber movement; or (2) evaluation of in-place snubber piston setting; or (3) stroking the mechanical snubber through its full range of travel.

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*The inspection interval for each type of snubber on a given system shall not be lengthened more than one step at a time unless a generic problem has been identified and corrected; in that event the inspection interval may be lengthened one step the first time and two steps thereafter if no inoperable snubbers of that type are found on that system.

#The provisions of Specification 4.0.2 are not applicable.

e. Functional Tests

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

1) At least 10% of the total of each type of snubber shall be functionally tested either in-place or in a bench test. For each snubber of a type that does not meets the functional test acceptance criteria of Specification 4.7.~~6~~f., an additional 10% of that type of snubber shall be functionally tested until no more failures are found or until all snubbers of that type have been functionally tested; or

2) A representative sample of each type of snubbers shall be functionally tested in accordance with Figure 4.7.~~6~~-1. "C" is the total number of snubbers of a type found not meeting the acceptance requirements of Specification 4.7.~~6~~4f. The cumulative number of snubbers of a type tested is denoted by "N". At the end of each day's testing, the new values of "N" and "C" (previous day's total plus current day's increments) shall be plotted on Figure 4.7.~~6~~4-1. If at any time the point plotted falls in the "Reject" region all snubbers of that type shall be functionally tested. If at any time the point plotted falls in the "Accept" region, testing of snubbers of that type may be terminated. When the point plotted lies in the "Continue Testing" region, additional snubbers of that type shall be tested until the point falls in the "Accept" region or the "Reject" region, or all the snubbers of that type have been tested. Testing equipment failure during functional testing may invalidate that day's testing and allow that day's testing to resume anew at a later time, providing all snubbers tested with the failed equipment during the day of equipment failure are retested; or

3) An initial representative sample of 55 snubbers shall be functionally tested. For each snubber type which does not meet the functional test acceptance criteria, another sample of at least one-half the size of the initial sample shall be tested until the total number tested is equal to the initial sample size multiplied by the factor, 1 + C/2, where "C" is the number of snubbers found which do not meet the functional test acceptance criteria. The results from this sample plan shall be plotted using an "Accept' line which follows the equation N = 55(1 + C/2). Each snubber point should be plotted as soon as the snubber is tested. If the point plotted falls on or below the "Accept" line, testing of that type of snubber may be terminated. If the point plotted falls above the "Accept" line, testing must continue until the point falls in the "Accept" region or all the snubbers of that type have been tested.

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The representative sample selected for the functional test sample plans shall be randomly selected from the snubbers of each type and reviewed before beginning the testing. The review shall ensure as far as practical that they are representative of the various configurations, operating environments, range of size, and capacity of snubbers of each type. Snubbers placed in the same locations as snubbers which failed the previous functional test shall be retested at the time of the next functional test but shall not be included in the sample plan. If during the functional testing, additional sampling is required due to failure of only one type of snubber, the functional testing results shall be reviewed at the time to determine if additional samples should be limited to the type of snubber which has failed the functional testing.

f. Functional Test Acceptance Criteria

The snubber functional test shall verify that:

1) Activation (restraining action) is achieved within the specified range in both tension and compression;

2) Snubber bleed, or release rate where required, is present in both tension and compression, within the specified range;

3) Where required, the force required to initiate or maintain motion of the snubber is within the specified range in both directions of travel; and

4) For snubbers specifically required not to displace under continuous load, the ability of the snubber to withstand load without displacement.

Testing methods may be used to measure parameters indirectly or parameters other than those specified if those results can be correlated to the specified parameters through established methods.

g. Functional Test Failure Analysis

An engineering evaluation shall be made of each failure to meet the functional test acceptance criteria to determine the cause of the failure. The results of this evaluation shall be used, if applicable, in selecting snubbers to be tested in an effort to determine the OPERABILITY of other snubbers irrespective of type which may be subject to the same failure mode.

For the snubbers found inoperable, an engineering evaluation shall be performed on the components to which the inoperable snubbers are attached. The purpose of this engineering evaluation shall be to determine if the components to which the inoperable snubbers are attached were adversely affected by the inoperability of the snubbers in order to ensure that the component remains capable of meeting the designed service.

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If any snubber selected for functional testing either fails to lock up or fails to move, i.e., frozen-in-place, the cause will be evaluated and if caused by manufacturer or design deficiency all snubbers of the same type subject to the same defect shall be functionally tested. This testing requirement shall be independent of the requirements stated in Specification 4.7.~~1e~~g. for snubbers not meeting the functional test acceptance criteria.

h. Functional Testing of Repaired and Replaced Snubbers

Snubbers which fail the visual inspection or the functional test acceptance criteria shall be repaired or replaced. Replacement snubbers and snubbers which have repairs which might affect the functional test result shall be tested to meet the functional test criteria before installation in the unit. Mechanical snubbers shall have met the acceptance criteria subsequent to their most recent service, and the freedom-of-motion test must have been performed within 12 months before being installed in the unit.

i. Snubber Service Life Program

The service life of hydraulic and mechanical snubbers shall be monitored to ensure that the service life is not exceeded between surveillance inspections. The maximum expected service life for various seals, springs, and other critical parts shall be determined and established based on engineering information and shall be extended or shortened based on monitored test results and failure history. Critical parts shall be replaced so that the maximum service life will not be exceeded during a period when the snubber is required to be OPERABLE. The parts replacements shall be documented and the documentation shall be retained in accordance with Specification 6.10.~~1~~2.

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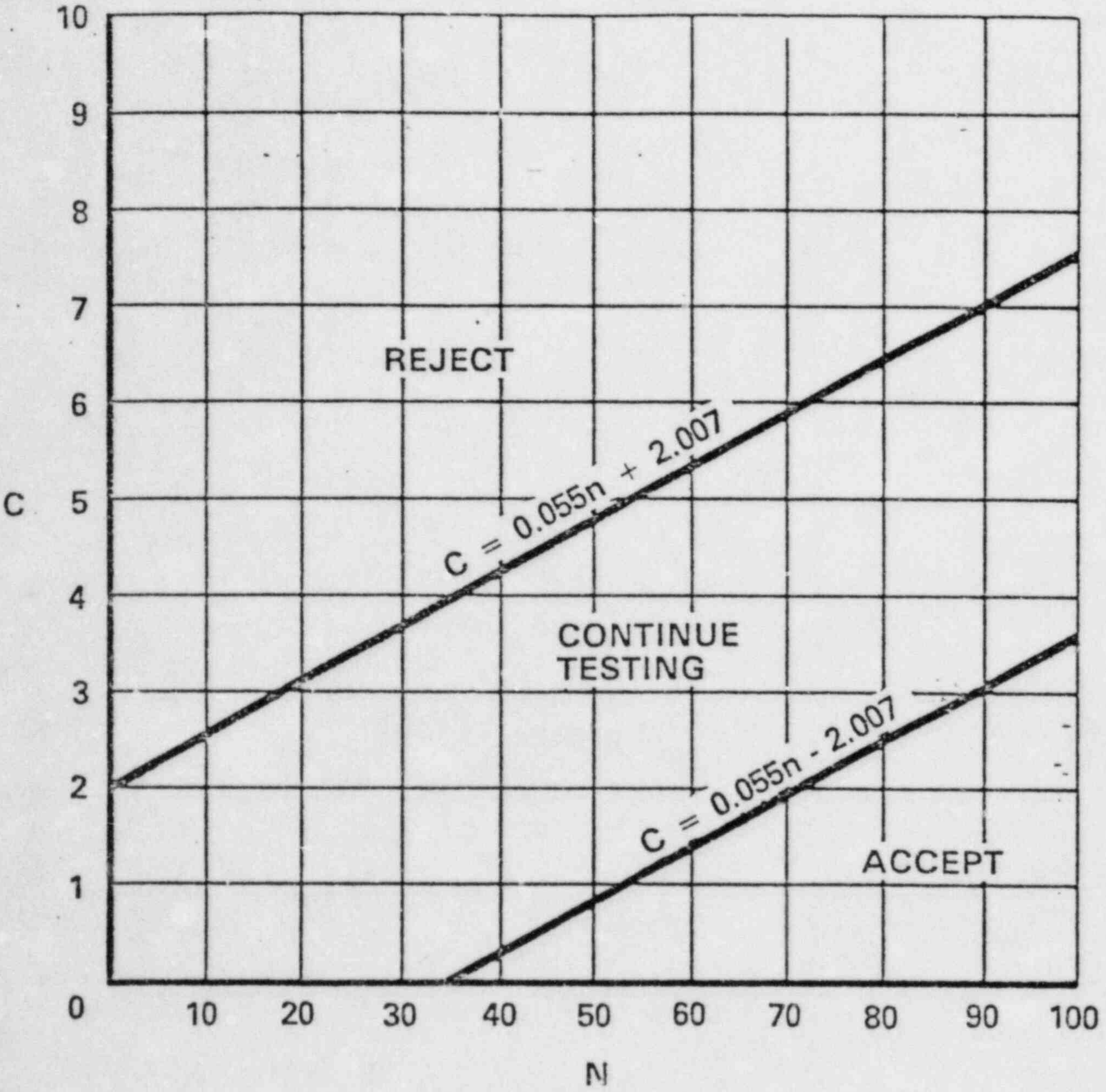

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FIGURE 4.7.~~6~~4-1
SAMPLE PLAN 2) FOR SNUBBER FUNCTIONAL TEST

3/4.7.4 SNUBBERS

LIMITING CONDITION FOR OPERATION

3.7.4 All snubbers listed in Tables 3.7.4-1 and 3.7.4-2 shall be OPERABLE.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2 and 3 and OPERATIONAL CONDITIONS 4 and 5 for snubbers located on systems required OPERABLE in those OPERATIONAL CONDITIONS.

ACTION:

With one or more snubbers inoperable, within 72 hours replace or restore the inoperable snubber(s) to OPERABLE status and perform an engineering evaluation per Specification 4.7.4.c on the supported component or declare the supported system inoperable and follow the appropriate ACTION statement for that system.

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SURVEILLANCE REQUIREMENTS

4.7.4 Each snubber shall be demonstrated OPERABLE by performance of the following augmented inservice inspection program and the requirements of Specification 4.0.5.

a. Visual Inspections

The first inservice visual inspection of snubbers shall be performed after 4 months but within 10 months of commencing POWER OPERATION and shall include all snubbers listed in Tables 3.7.4-1 and 3.7.4-2. If less than two snubbers are found inoperable during the first inservice visual inspection, the second inservice visual inspection shall be performed 12 months ±25% from the date of the first inspection. Otherwise, subsequent visual inspections shall be performed in accordance with the following schedule:

No. Inoperable Snubbers per Inspection Period	Subsequent Visual Inspection Period*#
0	18 months ± 25%
1	12 months ± 25%
2	6 months ± 25%
3,4	124 days ± 25%
5,6,7	62 days ± 25%
8 or more	31 days ± 25%

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The snubbers may be categorized into two groups: Those accessible and those inaccessible during reactor operation. Each group may be inspected independently in accordance with the above schedule.

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*The inspection interval shall not be lengthened more than one step at a time.
#The provisions of Specification 4.0.2 are not applicable.

b. Visual Inspection Acceptance Criteria
Visual inspections shall verify (1) that there are no visible indications of damage or impaired OPERABILITY, (2) that attachments to the foundation or supporting structure are secure, and (3) in those locations where snubber movement can be manually induced without disconnecting the snubber, that the snubber has freedom of movement and is not frozen up. Snubbers which appear inoperable as a result of these visual inspections may be determined OPERABLE for the purpose of establishing the next visual inspection interval, providing that (1) the cause of the rejection is clearly established and remedied for that particular snubber and for other snubbers that may be generically susceptible, and (2) the affected snubber is functionally tested in the as found condition and determined OPERABLE per Surveillance Requirements 4.7.4.d or 4.7.4.e, as applicable. However, when a fluid part of a hydraulic snubber is found to be uncovered, the snubber shall be declared inoperable and cannot be determined OPERABLE by functional testing for the purpose of establishing the next visual inspection interval. All snubbers connected to an inoperable common hydraulic fluid reservoir shall be counted as inoperable snubbers.

c. Functional Tests
During the first refueling shutdown and at least once per 18 months thereafter during shutdown, a representative sample of at least:

1. 10% of the total of the hydraulic snubbers listed in Table 3.7.4-1 shall be functionally tested either in place or in a bench test. For each snubber that does not meet the functional test acceptance criteria of Surveillance Requirement 4.7.4.d, an additional 10% of the hydraulic snubbers shall be functionally tested.

2. That number of mechanical snubbers which follows the expression $35 (1 + \frac{c}{2})$, where c = 2, the allowable number of snubbers not meeting the acceptance criteria, shall be functionally tested either in-place or in a bench test. For each number of snubbers above c which does not meet the functional test acceptance criteria of Specifications 4.7.4.e, an additional sample selected according to the expression $35 (1 + \frac{c}{2}) (\frac{2}{c + 1})^2 (a - c)$ shall be functionally tested, where a is the total number of snubbers found inoperable during the functional testing of the representative sample.

   Functional testing shall continue according to the expression $b [35 (1 + \frac{c}{2}) (\frac{2}{c + 1})^2]$ where b is the number of snubbers found inoperable in the previous re-sample, until no additional inoperable snubbers are found within a sample or until all snubbers in Table 3.7.4-2 have been functionally tested.

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Functional Tests (Continued)

The representative sample selected for functional testing shall include the various configurations, operating environments and the range of size and capacity of snubbers. At least 25% of the snubbers in the representative sample shall include snubbers from the following three categories:

1. The first snubber away from each reactor vessel nozzle
2. Each snubber within 5 feet of heavy equipment (valve, pump, turbine, motor, etc.)
3. Each snubber within 10 feet of the discharge from a safety relief valve

Tables 3.7.4-1 and 3.7.4-2 may be used jointly or separately as the basis for the sampling plan.

In addition to the regular sample, snubbers which failed the previous functional test shall be retested during the next test period. If a spare snubber has been installed in place of a failed snubber, then both the failed snubber, if it is repaired and installed in another position, and the spare snubber shall be retested. Test results of these snubbers may not be included for the re-sampling.

If any snubber selected for functional testing either fails to lockup or fails to move, i.e., frozen in place, the cause will be evaluated and if caused by manufacturer or design deficiency all snubbers of the same design subject to the same defect shall be functionally tested. This testing requirement shall be independent of the requirements stated above for snubbers not meeting the functional test acceptance criteria.

For any snubber(s) found inoperable, an engineering evaluation shall be performed on the components which are supported by the snubber(s). The purpose of this engineering evaluation shall be to determine if the components supported by the snubber(s) were adversely affected by the inoperability of snubber(s) in order to ensure that the supported component remains capable of meeting the designed service.

Delete

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SURVEILLANCE REQUIREMENTS (Continued)

d. Hydraulic Snubbers Functional Test Acceptance Criteria

The hydraulic snubber functional test shall verify that:

1. Activation (restraining action) is achieved within the specified range of velocity or acceleration in both tension and compression.

2. Snubber bleed, or release rate, where required, is within the specified range in compression or tension. For snubbers specifically required to not displace under continuous load, the ability of the snubber to withstand load without displacement shall be verified.

e. Mechanical Snubbers Functional Test Acceptance Criteria

The mechanical snubber functional test shall verify that:

1. The force that initiates free movement of the snubber rod in either tension or compression is less than the specified maximum drag force. Drag force shall not have increased more than 50% since the last surveillance test.

2. Activation (restraining action) is achieved within the specified range of velocity or acceleration in both tension and compression.

3. Snubber release rate, where required, is within the specified range in compression or tension. For snubbers specifically required not to displace under continuous load, the ability of the snubber to withstand load without displacement shall be verified.

Delete

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SURVEILLANCE REQUIREMENTS (Continued)

f. Snubber Service Life Monitoring

A record of the service life of each snubber, the date at which the designated service life commences and the installation and maintenance records on which the designated service life is based shall be maintained as required by Specification 6.10.2.

Concurrent with the first inservice visual inspection and at least once per 18 months thereafter, the installation and maintanenece records for each snubber listed in Tables 3.7.4-1 and 3.7.4-2 shall be reviewed to verify that the indicated service life has not been exceeded or will not be exceeded prior to the next scheduled snubber service life review. If the indicated service life will be exceeded prior to the next scheduled snubber service life review, the snubber service life shall be reevaluated or the snubber shall be replaced or reconditioned so as to extend its service life beyond the date of the next scheduled service life review. This reevaluation, replacement or reconditioning shall be indicated in the records.

Delete

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TABLE 3.7.4-1

SAFETY RELATED HYDRAULIC SNUBBERS*

Delete

SNUBBER NO.	AREA	ELEVATION	SNUBBER NO.	AREA	ELEVATION
a. RECIRCULATION SYSTEM			RECIRCULATION SYSTEM (Continued)		
Q1B33G006S354A	11	125	Q1B33G006S305A	11	131
Q1B33G006S354B	11	125	Q1B33G006S305B	11	131
Q1B33G006S356A	11	125	Q1B33G006S306A	11	131
Q1B33G006S356B	11	125	Q1B33G006S306B	11	131
Q1B33G006S357A	11	125	Q1B33G006S351A	11	134
Q1B33G006S357B	11	125	Q1B33G006S351B	11	134
Q1B33G006S358A	11	110	Q1B33G006S352A	11	125
Q1B33G006S358B	11	110	Q1B33G006S352B	11	125
Q1B33G006S359A	11	110	Q1B33G006S353A	11	134
Q1B33G006S359B	11	110	Q1B33G006S353B	11	134
Q1B33G006S360A	11	107	Q1B33G006S369A	11	123
Q1B33G006S360B	11	107	Q1B33G006S369B	11	123
Q1B33G006S361A	11	101	Q1B33G006S370A	11	125
Q1B33G006S361B	11	101	Q1B33G006S370B	11	125
Q1B33G006S362A	11	110	Q1B33G006S371A	11	123
Q1B33G006S362B	11	110	Q1B33G006S371B	11	123
Q1B33G006S363A	11	102	Q1B33G006S372A	11	101
Q1B33G006S363B	11	102	Q1B33G006S372B	11	101
Q1B33G006S301A	11	111	Q1B33G006S373A	11	101
Q1B33G006S301B	11	111	Q1B33G006S373B	11	101
Q1B33G006S302A	11	103	Q1B33G006S374A	11	101
Q1B33G006S302B	11	103	Q1B33G006S374B	11	101
Q1B33G006S303A	11	107	Q1B33G006S375A	11	101
Q1B33G006S303B	11	107	Q1B33G006S375B	11	101
Q1B33G006S304A	11	111	Q1B33G006S376A	11	107
Q1B33G006S304B	11	111	Q1B33G006S376B	11	107

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*Snubbers may be added to safety related systems without prior License Amendment to Table 3.7.4-1 provided that a revision to Table 3.7.4-1 is included with the next License Amendment request.

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TABLE 3.7.4-1 (Continued)

SAFETY RELATED HYDRAULIC SNUBBERS*

SNUBBER NO.	AREA	ELEVATION
MAIN STEAM SYSTEM		
Q1B21G006S102A	11	155
Q1B21G006S103A	11	150
Q1B21G006S104A	11	150
Q1B21G006S105A	11	150
Q1B21G006S101B	11	156
Q1B21G006S102B	11	156
Q1B21G006S103B	11	149
Q1B21G006S104B	11	150
Q1B21G006S105B	11	150
Q1B21G006S106B	11	150
Q1B21G006S107B	11	150
Q1B21G006S108B	11	150
Q1B21G006S101C	11	156
Q1B21G006S102C	11	156
Q1B21G006S103C	11	149
Q1B21G006S104C	11	150
Q1B21G006S105C	11	150
Q1B21G006S106C	11	150
Q1B21G006S107C	11	150
Q1B21G006S108C	11	150
Q1B21G006S102D	11	155
Q1B21G006S103D	11	150
Q1B21G006S104D	11	150
Q1B21G006S105D	11	150

Delete

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TABLE 3.7.4-2

MECHANICAL SNUBBERS*,**

1. SAFETY RELATED MECHANICAL SNUBBERS

a. RECIRCULATION SYSTEM

SNUBBER NO.	AREA	ELEVATION
Q1B33G023R01(2)	11	117
Q1B33G024R01	11	102
Q1B33G024R02(2)	11	102
Q1B33G024R05	11	101
Q1B33G105C01	11	101
Q1B33G105R01	11	101
Q1B33G105R02(2)	11	101
Q1B33G108C01	11	101
Q1B33G108R01(3)	11	101
Q1B33G108R02(2)	11	101
Q1B33G112R01	11	101
Q1B33G122R01	11	108
Q1B33G124R01	11	122

RECIRCULATION SYSTEM (Continued)

SNUBBER NO.	AREA	ELEVATION
Q1B33G128C01(2)	11	121
Q1B33G129C01	11	121
Q1B33G262R02	11	103
Q1B33G265C01	11	102
Q1B33G265R04	11	107
Q1B33G265R05	11	112
Q1B33G318R01	11	102
Q1B33G322R01(2)	11	112
Q1B33G331R02	11	111
Q1B33G337R02	11	109
Q1B33G339R01	11	111
Q1B33G346R01	11	105
Q1B33G355R01(2)	11	102

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*Snubbers may be added to safety related systems without prior License Amendment to Table 3.7.4-2 provided that a revision to Table 3.7.4-2 is included with the next License Amendment request.

**The number in parentheses is the number of snubbers associated with the component support. If no number in parentheses appears, there is only one snubber associated with the support.

TABLE 3.7.4-2 (Continued)

MECHANICAL SNUBBERS*,**

1. SAFETY RELATED MECHANICAL SNUBBERS

Deleted

SNUBBER NO.	AREA	ELEVATION	SNUBBER NO.	AREA	ELEVATION
b. MAIN STEAM SYSTEM			MAIN STEAM SYSTEM (Continued)		
Q1B21G021C04	11	141	Q1B21G024R11	11	138
Q1B21G022R01(2)	11	135	Q1B21G024R12(2)	11	127
Q1B21G022R03(2)	11	133	Q1B21G024R13	11	123
Q1B21G022R06(2)	11	124	Q1B21G024R17	11	128
Q1B21G022R12(2)	11	132	Q1B21G025R02	11	128
Q1B21G022R13(2)	11	131	Q1B21G025R03	11	125
Q1B21G022R14	11	126	Q1B21G025R04(2)	11	124
Q1B21G022R15	11	125	Q1B21G025R05	11	120
Q1B21G022R16	11	121	Q1B21G026C01(2)	11	143
Q1B21G023R03	11	137	Q1B21G026C02(2)	11	143
Q1B21G023R05	11	133	Q1B21G026R01	11	143
Q1B21G023R06(2)	11	133	Q1B21G026R02(2)	11	153
Q1B21G023R08	11	126	Q1B21G026R03	11	149
Q1B21G023R09	11	122	Q1B21G026R04(2)	11	153
Q1B21G023R10	11	122	Q1B21G026R05	11	143
Q1B21G023R11(2)	11	120	Q1B21G026R06(2)	11	143
Q1B21G023R14	11	141	Q1B21G026R07	11	143
Q1B21G023R15(2)	11	141	Q1B21G026R08	11	149
Q1B21G023R16	11	133	Q1B21G026R03(2)	8	143
Q1B21G023R17	11	121	Q1B21G030R03	11	129
Q1B21G023R18(2)	11	119	Q1B21G032R04	11	127
Q1B21G023R20	11	120	Q1B21G032R05	11	120
Q1B21G024C01	11	131	Q1B21G123R01	11	165
Q1B21G024R04	11	137	Q1B21G126R01	11	159
Q1B21G024R05(2)	11	132	Q1B21G127R01(2)	11	193
Q1B21G024R06	11	125	Q1B21G127R04	11	186
Q1B21G024R07(2)	11	119	Q1B21G127R01	11	150

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TABLE 3.7.4-2 (Continued)

MECHANICAL SNUBBERS*,**

1. SAFETY RELATED MECHANICAL SNUBBERS

MAIN STEAM SYSTEM (Continued)

SNUBBER NO.	AREA	ELEVATION
Q1B21G139R02	11	150
Q1B21G141R01	11	173
Q1B21G142R01(2)	11	173
Q1B21G144R01	11	173
Q1B21G146C03(2)	11	169
Q1B21G146C04	11	169
Q1B21G146R03	11	173
Q1B21G147C02	11	167
Q1B21G148C01(2)	11	173
Q1B21G1489R01(2)	11	172
Q1B21G153C01	11	174
Q1B21G153C02	11	182
Q1B21G153C03(2)	11	171
Q1B21G153R01	11	181
Q1B21G153R02(2)	11	175
Q1B21G153R03(2)	11	172
Q1B21G153R05(2)	11	170
Q1B21G162R01	11	113
Q1B21G163R01	11	113
Q1B21G163R02	11	113
Q1B21G171R01	11	165
Q1B21G174C01(2)	11	196
Q1B21G174R01	11	197
Q1B21G174R02	11	196
Q1B21G175R01(2)	11	153
Q1B21G175R02(2)	11	158
Q1B21G180R01	11	152

MAIN STEAM SYSTEM (Continued)

SNUBBER NO.	AREA	ELEVATION
Q1B21G180R02(2)	11	158
Q1B21G180R03	11	161
Q1B21G181C01	11	158
Q1B21G183R01(2)	11	152
Q1B21G189R02	11	151
Q1B21G189R01	11	153
Q1B21G194R01	11	161
Q1B21G194R02(2)	11	159
Q1B21G195R01	11	161
Q1B21G195R02(2)	11	160
Q1B21G196R01(2)	11	151
Q1B21G197R01(2)	11	157
Q1B21G201R01	11	158
Q1B21G201R02(2)	11	157
Q1B21G204R01	11	152
Q1B21G204R02(2)	11	160
Q1B21G205R01	11	159
Q1B21G205R02(2)	11	160
Q1B21G208R01	11	157
Q1B21G208R03	11	160
Q1B21G210R01(2)	11	157
Q1B21G213R01	11	151
Q1B21G213R02(2)	11	152
Q1B21G217R02	11	159
Q1B21G219R01(2)	11	157
Q1B21G222R01	11	160
Q1B21G224R01	11	152

DELETE

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TABLE 3.7.4-2 (Continued)

MECHANICAL SNUBBERS*,**

1. SAFETY RELATED MECHANICAL SNUBBERS

SNUBBER NO.	AREA	ELEVATION
MAIN STEAM SYSTEM (Continued)		
Q1B21G225R01	11	147
Q1B21G226C03	11	168
Q1B21G226R01(2)	11	173
Q1B21G304R01	11	156
Q1B21G306R01	11	151
Q1B21G311R01(2)	11	152
Q1B21G355R01	11	147
Q1B21G357C03	11	148
Q1B21G359C03	11	148
Q1B21G361C03	11	147
Q1B21G369R01(2)	11	148
Q1B21G372R01(2)	11	148
Q1B21G382R02(2)	11	152
Q1B21G384R01	11	152
Q1B21G423R01	11	147
Q1B21G424R01	11	147
Q1B21G490R03	11	152

SNUBBER NO.	AREA	ELEVATION
c. **SLC SYSTEM**		
Q1C41G113C02	11	185
Q1C41G113C03	11	181
Q1C41G113R02	11	181
Q1C41G113R03	11	181
Q1C41G117C02	11	145
Q1C41G117R01	11	151
Q1C41G119R01(2)	11	129
Q1C41G119R03	11	114
Q1C41G119R04	11	112
Q1C41G119R05	11	112
Q1C41G120C05	11	155
Q1C41G124R01	11	159
Q1C41G124R03	11	162
d. **RESIDUAL HEAT REMOVAL SYSTEM**		
Q1E12G009R03	7	134
Q1E12G009R04	7	134
Q1E12G009R05	8	134

Delete

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TABLE 3.7.4-2 (Continued)

MECHANICAL SNUBBERS*,**

1. SAFETY RELATED MECHANICAL SNUBBERS

RESIDUAL HEAT REMOVAL SYSTEM (Continued)

SNUBBER NO.	AREA	ELEVATION
Q1E12G009R06	8	134
Q1E12G010R02	8	105
Q1E12G010R04	8	103
Q1E12G010R05	8	125
Q1E12G010R07	8	133
Q1E12G010R10	8	142
Q1E12G010R11	8	142
Q1E12G010R13(2)	8	113
Q1E12G010R15	8	103
Q1E12G010R16	8	104
Q1E12G010R17(2)	8	104
Q1E12G010R18(2)	8	96
Q1E12G011R02(3)	8	99
Q1E12G012R02(2)	7	114
Q1E12G012R04	7	142
Q1E12G012R05	7	142
Q1E12G012R08	8	104
Q1E12G012R09	8	102
Q1E12G012R13	7	119
Q1E12G012R15	7	133
Q1E12G012R16	7	99
Q1E12G012R18	11	133
Q1E12G012R19	11	133
Q1E12G013C01	7	110
Q1E12G013C02	7	130
Q1E12G013R02(2)	7	115
Q1E12G013R03	7	110

RESIDUAL HEAT REMOVAL SYSTEM (Continued)

SNUBBER NO.	AREA	ELEVATION
Q1E12G013R04	7	119
Q1E12G013R05(2)	7	100
Q1E12G013R06(3)	7	120
Q1E12G013R07	7	121
Q1E12G013R08	7	105
Q1E12G013R11	7	97
Q1E12G014C01	8	110
Q1E12G014C03	8	106
Q1E12G014C04	8	130
Q1E12G014R01(2)	8	129
Q1E12G014R03(2)	8	98
Q1E12G014R04(3)	8	122
Q1E12G104R05	8	105
Q1E12G014R07	8	106
Q1E12G014R10(2)	8	109
Q1E12G014R11(2)	8	110
Q1E12G015R02	11	156
Q1E12G015R04(2)	11	143
Q1E12G015R06	11	143
Q1E12G015R07	11	214
Q1E12G015R08	11	210
Q1E12G015R11	11	143
Q1E12G015R17	11	210
Q1E12G015R19	11	214
Q1E12G015R20	11	144
Q1E12G015R21(2)	11	140
Q1E12G015R28(3)	11	192

Delete

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TABLE 3.7.4-2 (Continued)

MECHANICAL SNUBBERS*,**

1. SAFETY RELATED MECHANICAL SNUBBERS

SNUBBER NO.	AREA	ELEVATION
RESIDUAL HEAT REMOVAL SYSTEM (Continued)		
Q1E12G015R33(2)	11	205
Q1E12G015R38	11	157
Q1E12G016C01	11	143
Q1E12G016R01	11	146
Q1E12G016R02	11	143
Q1E12G016R03	11	143
Q1E12G016R05(2)	11	143
Q1E12G019R05(2)	8	139
Q1E12G019R07	8	149
Q1E12G019R08	7	149
Q1E12G019R09(2)	7	143
Q1E12G020R01(2)	8	148
Q1E12G020R02(2)	7	148
Q1E12G020R03	8	148
Q1E12G020R04(2)	8	148
Q1E12G020R05	7	147
Q1E12G020R07(2)	7	147
Q1E12G020R09	7	147
Q1E12G021R01	8	147

SNUBBER NO.	AREA	ELEVATION
RESIDUAL HEAT REMOVAL SYSTEM (Continued)		
Q1E12G021R03(2)	8	146
Q1E12G025C01(2)	8	95
Q1E12G025R01	8	110
Q1E12G119R02	7	152
Q1E12G159R01	7	126
Q1E12G159R03	7	126
Q1E12G159R04	7	131
e. LPCS SYSTEM		
Q1E21G001R05	9	96
Q1E21G001R07(2)	9	96
Q1E21G002R01	11	150
Q1E21G002R02	11	150
Q1E21G002R03	11	151
Q1E21G002R04	11	153
Q1E21G002R05	11	153
Q1E21G002R06	11	153
Q1E21G002R07	11	150

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TABLE 3.7.4-2 (Continued)

MECHANICAL SNUBBERS*,**

1. SAFETY RELATED MECHANICAL SNUBBERS

SNUBBER NO.	AREA	ELEVATION
f. HPCS SYSTEM		
Q1E22G001R10(2)	8	96
Q1E22G002R02(2)	8	96
Q1E22G002R03	8	96
Q1E22G003R01	11	153
Q1E22G003R02	11	153
Q1E22G003R03	11	149
Q1E22G003R04	11	150
Q1E22G003R05	11	151
g. RCS LEAK DETECTION SYSTEM		
Q1E31G116R01	11	169
Q1E31G122R01(2)	11	149
Q1E31G124R01(2)	11	151
Q1E31G126C01	11	149
Q1E31G140R01	11	159
Q1E31G140R02(2)	11	159
Q1E31G148R01(2)	11	151
Q1E31G149R01(2)	11	151
Q1E31G168R01	11	158
Q1E31G174R01(2)	11	151
Q1E31G176C01	11	147
Q1E31G178R08	11	179
Q1E31G178R09	11	179
Q1E31G181R01	11	156
Q1E31G243R01	11	144
Q1E31G243R02	11	140
Q1E31G246R01(2)	11	144

SNUBBER NO.	AREA	ELEVATION
h. MSIV LEAKAGE CONTROL SYSTEM		
Q1E32G103C01(2)	8	122
Q1E32G106C01	8	121
Q1E32G109C01	8	122
Q1E32G119C01	8	148
i. FEEDWATER LEAKAGE CONTROL SYSTEM		
Q1E38G102R01	8	145
j. RCIC SYSTEM		
Q1E51G001R05	8	104
Q1E51G001R06	8	109
Q1E51G001R09	11	133
Q1E51G001R10(2)	11	134
Q1E51G001R15	11	178
Q1E51G001R17(2)	11	190
Q1E51G001R18	11	194
Q1E51G001R19(2)	11	194
Q1E51G003R03	7	126
Q1E51G003R04	7	117
Q1E51G003R05(2)	7	127
Q1E51G003R07	8	112
Q1E51G003R08(2)	8	112
Q1E51G003R09(2)	8	109
Q1E51G003R10	8	105
Q1E51G003R11(2)	8	100
Q1E51G003R12(2)	8	106

Delete

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TABLE 3.7.4-2 (Continued)

MECHANICAL SNUBBERS*,**

1. SAFETY RELATED MECHANICAL SNUBBERS

SNUBBER NO.	AREA	ELEVATION
RCIC SYSTEM (Continued)		
Q1E51G004C02(2)	8	97
Q1E51G004R01(2)	8	98
Q1E51G004R05(2)	8	106
Q1E51G004R06(2)	8	96
Q1E51G004R07(2)	8	97
Q1E51G004R08(2)	11	164
Q1E51G004R11	8	97
Q1E51G004R13(2)	11	167
Q1E51G004R14(2)	11	152
Q1E51G158R03(2)	11	143
Q1E51G180R01	8	97
k. COMBUSTIBLE GAS CONTROL SYSTEM		
Q1E61G001R07	11	189
l. RWCU SYSTEM		
Q1G33G002C03(2)	11	113
Q1G33G002R03(2)	8	136
Q1G33G002R05(2)	11	140
Q1G33G002R08(2)	11	102
Q1G33G002R09(3)	11	102
Q1G33G002R10(2)	11	102
Q1G33G002R11	11	102
Q1G33G002R12	11	102
Q1G33G002R13(2)	11	102
Q1G33G002R14(2)	11	102
Q1G33G002R16	11	112
Q1G33G002R17(2)	8	125

SNUBBER NO.	AREA	ELEVATION
RWCU SYSTEM (Continued)		
Q1G33G002R18	8	116
Q1G33G002R19	8	116
Q1G33G002R21(2)	11	102
Q1G33G002R22	11	102
Q1G33G002R24	11	102
Q1G33G011R01	11	140
Q1G33G011R03(2)	11	145
Q1G33G012R01(2)	11	142
Q1G33G012R02	11	152
Q1G33G015R01(3)	11	103
m. FPCC SYSTEM		
Q1G41G006R01	9	114
Q1G41G006R07(3)	7	99
Q1G41G015R09	11	204
Q1G41G016C08	11	163
Q1G41G016R04	11	166
Q1G41G016R24	11	163
Q1G41G016R27(2)	11	203
Q1G41G016R28(2)	11	206
Q1G41G016R32	11	197
Q1G41G018R06	9	197
n. SSW SYSTEM		
Q1P41G001R14(2)	7	98
Q1P41G002R10(2)	8	106
Q1P41G002R12(2)	8	106
Q1P41G006C01	8	99

Delete

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TABLE 3.7.4-2 (Continued)

MECHANICAL SNUBBERS*,**

1. SAFETY RELATED MECHANICAL SNUBBERS

SNUBBER NO.	AREA	ELEVATION
SSW SYSTEM (Continued)		
Q1P41G006C17	8	99
Q1P41G007R19	025A	144
Q1P41G007R20	025A	144
Q1P41G007R23(2)	025A	138
Q1P41G007R24(2)	025A	137

SNUBBER NO.	AREA	ELEVATION
o. CCW SYSTEM		
Q1P42G002R06(2)	9	193
Q1P42G002R07(2)	9	186
Q1P42G002R11(2)	9	186
Q1P42G002R13(2)	9	186

DELETE

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TABLE 3.7.4-2 (Continued)

MECHANICAL SNUBBERS*, **

2. NON-Q MECHANICAL SNUBBERS

a. MAIN STEAM SYSTEM

SNUBBER NO.	AREA	ELEVATION
N1B21G118R01	11	148
N1B21G118R02	11	147
N1B21G191C02	11	137
N1B21G192C03	11	136
N1B21G193R01(2)	11	138
N1B21G193R04	11	136
N1B21G231R01(2)	11	163

b. RECIRCULATION SYSTEM

SNUBBER NO.	AREA	ELEVATION
N1B33G104R02	11	102
N1B33G105C01	11	101
N1B33G105C03	11	101
N1B33G105C04	11	101
N1B33G105C05	11	101
N1B33G105R01	11	101
N1B33G106R01	11	102
N1B33G107R01	11	102
N1B33G107R02	11	102
N1B33G108C02	11	101
N1B33G108R03(2)	11	101
N1B33G108R05	11	101
N1B33G108R06(2)	11	101
N1B33G108R07	11	101
N1B33G119R04	11	112
N1B33G120R03	11	101
N1B33G123C01	11	102
N1B33G362R03	11	102

c. RESIDUAL HEAT REMOVAL SYSTEM

SNUBBER NO.	AREA	ELEVATION
N1E12G172R02	11	129
N1E12G212R01	11	136
N1E12G212R03	11	133

d. REACTOR CORE ISOLATING COOLING SYSTEM

SNUBBER NO.	AREA	ELEVATION
N1E51G120R01	11	127

e. REACTOR WATER CLEANUP SYSTEM

SNUBBER NO.	AREA	ELEVATION
N1G33G002R01	7	120
N1G33G002R02	8	118
N1G33G002R03	8	123
N1G33G002R04	8	123
N1G33G002R05(2)	11	147
N1G33G002R08(2)	11	164
N1G33G002R10(2)	11	147
N1G33G002R11(3)	11	180
N1G33G002R12(3)	11	180
N1G33G002R13	11	178
N1G33G002R14	8	120
N1G33G002R21	8	120

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3/4.7.5 SEALED SOURCE CONTAMINATION

LIMITING CONDITION FOR OPERATION

3.7.5 Each sealed source containing radioactive material either in excess of 100 microcuries of beta and/or gamma emitting material or 10 microcuries of alpha emitting material shall be free of greater than or equal to 0.005 microcuries of removable contamination.

APPLICABILITY: At all times.

ACTION:

a. With a sealed source having removable contamination in excess of the above limit, withdraw the sealed source from use and either:

   1. Decontaminate and repair the sealed source, or

   2. Dispose of the sealed source in accordance with Commission Regulations.

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

SURVEILLANCE REQUIREMENTS

4.7.5.1 Test Requirements - Each sealed source shall be tested for leakage and/or contamination by:

a. The licensee, or

b. Other persons specifically authorized by the Commission or an Agreement State.

The test method shall have a detection sensitivity of at least 0.005 microcuries per test sample.

4.7.5.2 Test Frequencies - Each category of sealed sources, excluding startup sources and fission detectors previously subjected to core flux, shall be tested at the frequency described below.

a. Sources in use - At least once per six months for all sealed sources containing radioactive material:

   1. With a half-life greater than 30 days, excluding Hydrogen 3, and

   2. In any form other than gas.

b. Stored sources not in use - Each sealed source and fission detector shall be tested prior to use or transfer to another licensee unless tested within the previous six months. Sealed sources and fission detectors transferred without a certificate indicating the last test date shall be tested prior to being placed into use.

c. Startup sources and fission detectors - Each sealed startup source and fission detector shall be tested within 31 days prior to being subjected to core flux or installed in the core and following repair or maintenance to the source.

4.7.5.3 Reports - A ~~report~~ Special Report shall be prepared and submitted to the Commission pursuant to Specification 6.9.2. within 30 days if sealed source or fission detector leakage tests reveal the presence of greater than or equal to 0.005 microcuries of removable contamination.

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PLANT SYSTEMS

3/4.7.6 FIRE SUPPRESSION SYSTEMS

FIRE SUPPRESSION WATER SYSTEM

LIMITING CONDITION FOR OPERATION

3.7.6.1 The fire suppression water system shall be OPERABLE with:

a. At least two OPERABLE fire suppression fire pumps, each with a capacity of 1500 gpm, with their discharge aligned to the fire suppression header,

b. Separate fire water storage tanks, each with a minimum contained volume of 210,000 gallons, and

c. An OPERABLE flow path capable of taking suction from the "A" fire water storage tank and the "B" fire water storage tank and transferring the water through distribution piping with OPERABLE sectionalizing control or isolation valves to the yard hydrant curb valves, the last valve ahead of the water flow alarm device on each sprinkler or hose standpipe and the last valve ahead of the deluge valve on each deluge or spray system required to be OPERABLE per Specifications 3.7.6.2, 3.7.6.5, and 3.7.6.6.

APPLICABILITY: At all times.

ACTION:

the inoperable equipment

a. With one of the above required fire pumps and/or one fire water storage tank inoperable, restore ~~at least two fire pumps and two fire water storage tanks~~ to OPERABLE status within 7 days or~~, in lieu of any other report required by Specification 6.9.1, prepare and submit a Special Report to the Commission pursuant to Specification 6.9.2 within the next 30 days outlining the plans and procedures to be used to restore the inoperable equipment to OPERABLE status or to~~ provide an alternate backup pump or supply. The provisions of Specifications 3.0.3 and 3.0.4 are not applicable.

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b. With the fire suppression water system otherwise inoperable, e [redacted]

9 ~~1.~~ ~~E~~stablish a backup fire suppression water system within 24 hours. ~~and~~

~~2. In lieu of any other report required by Specification 6.9.1, submit a Special Report in accordance with Specification 6.9.2;~~
 ~~a) By telephone within 24 hours,~~
 ~~b) Confirmed by telegraph, mailgram or facsimile transmission no later than the first working day following the event, and~~
 ~~c) In writing 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.~~

071|

PLANT SYSTEMS

SURVEILLANCE REQUIREMENTS

4.7.6.1.1 The fire suppression water system shall be demonstrated OPERABLE:

a. At least once per 7 days by verifying the minimum contained water supply volume.

b. At least once per 31 days by starting the electric motor driven fire suppression pump and operating it for at least 15 minutes.

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

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

e. At least once per 12 months by performance of a system flush.

~~e.~~ f. At least once per 18 months by performing a system functional test which includes simulated automatic actuation of the system throughout its operating sequence, and: 1223

1. Verifying that each automatic valve in the flow path actuates to its correct position,

2. Verifying that each fire suppression pump develops at least 1500 gpm at a system head of 275 feet,

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

4. Verifying that each fire suppression pump starts sequentially to maintain the fire suppression water system pressure greater than or equal to 120 psig.

~~f.~~ g. At least once per 3 years by performing a flow test of the system in accordance with Chapter 5, Section 11 of the Fire Protection Handbook, 14th Edition, published by the National Fire Protection Association.

4.7.6.1.2 The diesel driven fire suppression pump shall be demonstrated OPERABLE:

a. At least once per 31 days by:

1. Verifying the fuel storage tank contains at least 300 gallons of fuel.

2. Starting the diesel driven pump from ambient conditions and operating for greater than or equal to 30 minutes.

SURVEILLANCE REQUIREMENTS (Continued)

b. At least once per 92 days by verifying that a sample of diesel fuel from the fuel storage tank, obtained in accordance with ASTM-D270-75, is within the acceptable limits specified in Table 1 of ASTM D975-77 when checked for viscosity, water and sediment.

c. At least once per 18 months, during shutdown, by subjecting the diesel to an inspection in accordance with procedures prepared in conjunction with its manufacturer's recommendations for the class of service.

4.7.6.1.3 The diesel driven fire pump starting 24-volt battery bank and charger shall be demonstrated OPERABLE:

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

1. The electrolyte level of each cell in each battery is above the plates, and
2. The overall battery set voltage is greater than or equal to 24 volts.

b. At least once per 92 days by verifying that the specific gravity for each cell is appropriate for continued service of the battery. The specific gravity, corrected to 77°F and full electrolyte level, shall be greater than or equal to 1.20.

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

1. The battery case and battery racks show no visual indication of physical damage or abnormal deterioration, and
2. Battery terminal connections are clean, tight, free of corrosion and coated with anti-corrosion material.

SPRAY AND/OR SPRINKLER SYSTEMS

LIMITING CONDITION FOR OPERATION

3.7.6.2 The following spray/sprinkler systems shall be operable: 1245

a. Diesel Generator Building

1. Diesel Generator A pre-action sprinkler system N1P64D142A
2. Diesel Generator B pre-action sprinkler system N1P64D142B
3. Diesel Generator C pre-action sprinkler system N1P64D142C

b. Auxiliary Building* 1245

1. Elevation 93'/103' Northeast Corridor N1P64D150
2. Elevation 119' Northeast Corridor N1P64D151
3. Elevation 139' Northeast Corridor N1P64D152
4. Elevation 166' Northeast Corridor N1P64D153
5. Elevation 119' West Corridor N1P64D158
6. Elevation 139' West Corridor N1P64D159

c. Control Building* 1245

1. Elevation 148' Lower Cable Room N1P64D154
2. Elevation 189' Upper Cable Room N1P64D155
3. Elevation 93' N~~1~~SP64D140 1203

d. Fire Pump House* NSP64D136A/B 1245

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

ACTION:

a. With one or more of the above required spray and/or sprinkler systems inoperable, within one hour establish a continuous fire watch with backup fire suppression equipment for those areas in which redundant systems or components could be damaged; for other areas, establish an hourly fire watch patrol. ~~Restore the system to OPERABLE status within 14 days or, in lieu of any other report required by Specification 6.9.1, prepare and submit a Special Report to the Commission pursuant to Specification 6.9.2 within the next 30 days outlining the action taken, the cause of the inoperability and the plans and schedule for restoring the system to OPERABLE status.~~ /071

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

SURVEILLANCE REQUIREMENTS

4.7.6.2 The above required spray and sprinkler systems shall be demonstrated OPERABLE:

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

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* Wet pipe sprinkler system.

1245

SURVEILLANCE REQUIREMENTS Continued)

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

c. At least once per 18 months:

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

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

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

  2. By a visual inspection of the dry pipe spray and sprinkler headers to verify their integrity, and

  3. By a visual inspection of each nozzle's spray area to verify that the spray pattern is not obstructed. /072

PLANT SYSTEMS

CO_2 SYSTEMS

LIMITING CONDITION FOR OPERATION

3.7.6.3 The following low pressure CO_2 systems shall be OPERABLE:

Area	Location	System Number	
Electrical Penetration Room	Auxiliary Bldg. El. 139'~~6~~0"	N1P64D201A, B, C, D	/299
Electrical Penetration Room	Auxiliary Bldg. El. 119'0"	N1P64D200A, B, C, D	
Control Cabinet Room	Control Bldg. El. 189'0"	N1P64D216	
Division I Switchgear Room	Control Bldg. El. 111'0"	N1P64D207	
Division III Switchgear Room	Control Bldg. El. 111'0"	N1P64D209	
Division II Switchgear Room	Control Bldg. El. 111'0"	N1P64D208	
Emergency Shutdown Panel Rm	Control Bldg. El. 111'0"	N1P64D212	
Motor Generator Room	Control Bldg. El. 148'0"	N1P64D214B	/299
Electrical Switchgear Room	Auxiliary Bldg. El. 166'0"	N1P64D217A, B	
Lower Cable Spreading Room	Control Bldg. El. 148'0"	N1P64D213	
Upper Cable Spreading Room	Control Bldg. El. 189'0"	N1P64D215	

APPLICABILITY: Whenever equipment protected by the CO_2 systems is required to be OPERABLE.

ACTION:

a. With one or more of the above required CO_2 systems inoperable, within one hour establish a continuous fire watch with backup fire suppression equipment for those areas in which redundant systems or components could be damaged; for other areas, establish an hourly fire watch patrol. ~~Restore the system to OPERABLE status within 14 days or, in lieu of any other report required by Specification 6.9.1, prepare and submit a Special Report to the Commission pursuant to Specification 6.9.2 within the next 30 days outlining the action taken, the cause of the inoperability and the plans and schedule for restoring the system to OPERABLE status.~~ /071

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

SURVEILLANCE REQUIREMENTS

4.7.6.3.1 Each of the above required CO_2 systems shall be demonstrated OPERABLE at least once per 31 days by verifying that each valve, manual, power operated or automatic, in the flow path is in its correct postion. Position verification of differential pressure selector valves is not required, however, the valves' release levers shall be verified to be in the correct position.

4.7.6.3.2 Each of the above required low pressure CO_2 systems shall be demonstrated OPERABLE:

- a. At least once per 7 days by verifying the CO_2 storage tank level to be greater than ~~50~~% 60 and pressure to be greater than 275 psig, and 1299
- b. At least once per 18 months by:
  1. Verifying that the system valves and associated ventilation system fire damper logic actuates automatically or manually, if applicable, upon receipt of a simulated actuation signal (actual CO_2 release, electrothermal link burning, and differential pressure valve opening may be excluded from this test), and
  2. Flow from each nozzle by performance of a "Puff Test", and
  3. Exercising each ventilation system fire damper to the closed position and verifying the dampers move freely.

HALON SYSTEMS

LIMITING CONDITION FOR OPERATION

3.7.6.4 The following Halon systems shall be OPERABLE with the storage tanks having at least 95% of full charge weight and 90% of full charge pressure:

a. Control Building, elev. 148'0", Computer and Control Panel Room

b. Control Building, elev. 163'0", PGCC Under Floor Area

c. Control Cabinet Room, elev. 189'0", PGCC Under Floor Area

APPLICABILITY: Whenever equipment protected by the Halon systems is required to be OPERABLE.

ACTION:

a. With one or more of the above required Halon systems inoperable, within one hour establish a continuous fire watch with backup fire suppression equipment for those areas in which redundant systems or components could be damaged; for other areas, establish an hourly fire watch patrol. ~~Restore the system to OPERABLE status within 14 days or, in lieu of any other report required by Specification 6.9.1, prepare and submit a Special Report to the Commission pursuant to Specification 6.9.2 within the next 30 days outlining the action taken, the cause of the inoperability and the plans and schedule for restoring the system to OPERABLE status.~~ /071

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

SURVEILLANCE REQUIREMENTS

4.7.6.4 Each of the above required Halon systems shall be demonstrated OPERABLE:

a. At least once per 31 days by verifying that each valve, manual, power operated or automatic, except for hazard area selector valves F497G and F497H, in the flow path is in its correct position. /244

b. At least once per 6 months by verifying Halon storage tank weight and pressure.

c. At least once per 18 months by:

1. Verifying that the system, including associated ventilation system fire damper logic, actuates automatically upon receipt of a simulated actuation signal (Actual Halon release, Halon bottle initiator valve acuation, and electro-thermal link burning may be excluded from the test), and

2. Performance of a flow test through headers and nozzles to assure no blockage, and

3. Exercising each ventilation system fire dampers to the closed position and verifying the dampers move freely.

FIRE HOSE STATIONS

LIMITING CONDITION FOR OPERATION

3.7.6.5 The fire hose stations shown in Table 3.7.6.5-1 shall be OPERABLE.

APPLICABILITY: Whenever equipment in the areas protected by the fire hose stations is required to be OPERABLE.

ACTION:

a. With one or more of the fire hose stations shown in Table 3.7.6.5-1 inoperable, route an additional fire hose of equal or greater diameter to the unprotected area(s) from an OPERABLE hose station within 1 hour if the inoperable fire hose is the primary means of fire suppression; otherwise, route the additional hose within 24 hours. ~~Restore the inoperable hose station(s) to OPERABLE status within 14 days or, in lieu of any other report required by Specificaton 6.9.1, prepare and submit a Special Report to the Commission pursuant to Specification 6.9.2 within the next 30 days outlining the action taken, the cause of the inoperability and the plans and schedule for restoring the system to OPERABLE status.~~

/071

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

SURVEILLANCE REQUIREMENTS

4.7.6.5 Each of the fire hose stations shown in Table 3.7.6.5-1 shall be demonstrated OPERABLE:

a. At least once per 31 days by a visual inspection of the fire hose stations accessible during plant operation to assure all required equipment is at the station.

b. At least once per 18 months by:

1. Visual inspection of the fire hose stations not accessible during plant operation to assure all required equipment is at the station.

2. Removing the hose for inspection and re-racking, and

3. Inspecting all gaskets and replacing any degraded gaskets in the couplings.

c. At least once per 3 years by:

1. Partially opening each hose station valve to verify valve OPERABILITY and no flow blockage.

2. Conducting a hose hydrostatic test at a pressure of 150 psig or at least 50 psig above the maximum fire main operating pressure, whichever is greater.

TABLE 3.7.6.5-1

FIRE HOSE STATIONS

LOCATION	ELEVATION	HOSE RACK INDENTIFICATION
AUXILIARY BUILDING		
Q.1-6.0	103'-0"	13A
Q-5.7	119'-0"	13B
Q.1-6.1	139'-0"	13C
Q-6.0	166'-0"	13D
Q-5.9	185'-0"	13E
Q-6.0< Q-5.8	208'-0"< 245'-0"	13F< 13G
Q-11.3	93'-0"	14A
P.4-9.0	119'-0"	14B
P.4-9.0	139'-0"	14C
P.4-8.6	166'-0"	14D
P.4-9.5	185'-0"	14E
P-10	208'-10"	14F
P.4-12.5	139'-0"	15A
P.4-12.5	166'-0"	15B
P.4-13.1	185'-0"	15C
R-13.7	208'-10"	15D
M.2-15.1	103'-0"	16A
M.7-15.1	119'-0"	16B
L.7-15.1	139'-0"	16C
L.7-15.1	166'-0"	16D
L.7-15.1	185'-0"	16E
M.7-15.1	208'-10"	16F
H.3-13.8	103'-0"	17A
J.4-13.8	119'-0"	17B
H-13.8	139'-0"	17C
J-13.8	166'-0"	17D
G.4-11	103'-0"	18A
G.4-11.7	119'-0"	18B
G.4-12.2	139'-0"	18C
G.4-11.3	166'-0"	18D
G.4-7.5	103'-0"	19A
G.4-8.3	119'-0"	19B
G.4-7.5	139'-0"	19C
G.4-8.4	166'-0"	19D
G.6-6.4	103'-0"	20A
G.6-6.4	119'-0"	20B
H-6.2	139"-0"	20C
H-6.2	166'-0"	20D
L-6.2	103'-0"	21A
L-6.2	119'-0"	21B
L-6.2	139"-0"	21C
L-6.2	166'-0"	21D

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TABLE 3.7.6.5-1 (Continued)

FIRE HOSE STATIONS

LOCATION	ELEVATION	HOSE RACK INDENTIFICATION
CONTAINMENT		
M.7-7.8	120'-10"	22A
H.8-8.1	135'-4"	23A
J.1-8.1	161'-10"	23B
J.8-7.2	184'-6"	23C
J.4-7.5	208'-10"	23D
M.2-7.2	135'-4"	24A
M.8-7.9	161'-10"	24B
M.2-7.2	184'-6"	24C
N-8.2	208'-10"	24D
M.6-12.4	135'-4"	25A
N.2-11.5	161'-10"	25B
N.3-11.3	208'-10"	25C
J.1-12.0	135'-4"	26A
J-11.6	161'-10"	26B
K.2-13.1	184'-6"	26C
J-11.8	208'-10"	26D
CONTROL BUILDING		
J.9-18.8	133'-0"	53A
K.2-18.8	111'-0"	53B
K.1-18.8	93'-0"	53C
G.1-18.4	93'-0"	54A
G.1-18.4	111'-0"	54B
G.2-18.4	133'-0"	54C
G.1-18.7	148'-0"	54D
G.2-18.8	166'-0"	54E
G.1-18.7	189'-0"	54F
K.2-18.8	148'-0"	55A
K.2-18.8	166'-0"	55B
K.2-18.8	177'-0"	55C
K.2-18.8	189'-0"	55D
DIESEL GENERATOR BUILDING		
R-10.6	133'-0"	66A
R-8.4	133'-0"	66B

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YARD FIRE HYDRANTS AND HYDRANT HOSE HOUSES

LIMITING CONDITION FOR OPERATION

3.7.6.6 The yard fire hydrants and associated hydrant hose houses shown in Table 3.7.6.6-1 shall be OPERABLE.

APPLICABILITY: Whenever equipment in the areas protected by the yard fire hydrants is required to be OPERABLE.

ACTION:

a. With one or more of the yard fire hydrants or associated hydrant hose houses shown in Table 3.7.6.6-1 inoperable, route sufficient additional lengths of fire hose of equal or greater diameter located in an adjacent OPERABLE hydrant hose house to provide service to the unprotected area(s) within 24 hours. ~~Restore the inoperable hydrant(s) and/or hose OPERABLE status within 14 days or, in lieu of any other report required by Specification 6.9.1, prepare and submit a Special Report to the Commission pursuant to Specification 6.9.2 within the next 30 days outlining the action taken, the cause of the inoperability and the plans and schedule for restoring the system to OPERABLE status.~~ /071

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

SURVEILLANCE REQUIREMENTS

4.7.6.6 Each of the yard fire hydrants and associated hydrant hose houses shown in Table 3.7.6.6-1 shall be demonstrated OPERABLE:

a. At least once per 31 days by visual inspection of the hydrant hose house to assure all required equipment is at the hose house.

b. At least once per 6 months, during March, April or May and during September, October or November, by visually inspecting each yard fire hydrant and verifying that the hydrant barrel is dry and that the hydrant is not damaged.

c. At least once per 12 months by:

   1. Conducting a hose hydrostatic test at a pressure of 150 psig or at least 50 psig above the maximum fire main operating pressure, whichever is greater.

   2. Replacement of all degraded gaskets in couplings.

   3. Performing a flow check of each hydrant.

TABLE 3.7.6.6-1

YARD FIRE HYDRANTS AND ASSOCIATED HYDRANT HOSE HOUSES

LOCATION			HYDRANT NUMBER/HYDRANT HOSE HOUSE NUMBER
North Coord.	East Coord.	Elevation	
9,616.00	10,500.00	133'0"	D021/HHD 029B
9,570.00	10,299.00	133'0"	D023/HHD 029C
9,570.00	10,012.50	133'0"	D024/HHD 029D
9,798.00	9,979.00	133'0"	D025/HHD 029E
10,112.50	9,753.92	133'0"	D010/HHD 029G
9,886.00	9,758.25	133'0"	D009/HHD 029Q
9,641.00	9,766.25	133'0"	D008/HHD 029F
10,097.12	10,500.00	133'0"	D019/HHD 029I
9,871.87	10,534.33	133'0"	D020/HHD 029A

3/4.7.7 FIRE RATED ASSEMBLIES

LIMITING CONDITION FOR OPERATION

3.7.7 All fire rated assemblies (walls, floor/ceilings, cable tray enclosures and other fire barriers) separating safety related fire areas or separating portions of redundant systems important to safe shutdown within a fire area, and all sealing devices in fire rated assembly penetrations (fire doors, fire windows, fire dampers, cable and piping penetration seals and ventilation seals) shall be OPERABLE.

APPLICABILITY: At all times.

ACTION:

a. With one or more of the above required fire rated assemblies and/or sealing devices inoperable, within one hour establish a continuous fire watch on at least one side of the affected assembly(s) and/or sealing device(s) or verify the OPERABILITY of fire detectors on at least one side of the inoperable assembly(s) and/or sealing device(s) and establish an hourly fire watch patrol. ~~Restore the inoperable fire rated assembly(s) and/or sealing device(s) to OPERABLE status within 7 days or, in lieu of any other report required by Specification 6.9.1, prepare and submit a Special Report to the Commission pursuant to Specification 6.9.2 within the next 30 days outlining the action taken, the cause of the inoperable fire rated assembly(s) and/or sealing device(s) and plans and schedule for restoring the fire rated assembly(s) and/or sealing device(s) to OPERABLE status~~. |071

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

SURVEILLANCE REQUIREMENTS

4.7.7.1 Each of the above required fire rated assemblies and sealing devices shall be verified OPERABLE at least once per 18 months by performing a visual inspection of:

a. The exposed surfaces of each fire rated assembly.

b. Each fire window/fire damper and associated hardware.

c. At least 10 percent of each type of sealed penetration. If apparent changes in appearance or abnormal degradations are found, a visual inspection of an additional 10 percent of each type of sealed penetration shall be made. This inspection process shall continue until a 10 percent sample with no apparent changes in appearance or abnormal degradation is found. Samples shall be selected such that each penetration seal will be inspected at least once per 15 years. |277

SURVEILLANCE REQUIREMENTS (Continued)

4.7.7.2 Each of the above required fire doors shall be verified OPERABLE by inspecting the automatic hold-open, release and closing mechanism and latches at least once per 6 months, and by verifying:

a. The OPERABILITY of the fire door supervision system for each electrically supervised fire door by performing a CHANNEL FUNCTIONAL TEST at least once per 31 days.

b. That each locked-closed fire door is closed at least once per 7 days.

c. That doors with automatic hold-open and release mechanisms are free of obstructions at least once per 24 hours and performing a functional test of these mechanisms at least once per 18 months.

d. That each unlocked fire door without electrical supervision is closed at least once per 24 hours.

3/4.7.8 AREA TEMPERATURE MONITORING

LIMITING CONDITION FOR OPERATION

3.7.8 The temperature of each area shown in Table 3.7.8-1 shall be maintained within the limits indicated in Table 3.7.8-1.

APPLICABILITY: Whenever the equipment in an affected area is required to be OPERABLE.

ACTION:

With one or more areas exceeding the temperature limit(s) shown in Table 3.7.8-1:

a. For more than eight hours, ~~in lieu of any report required by Specification 6.9.1~~ prepare and submit a Special Report to the Commission pursuant to Specification 6.9.2 within the next 30 days providing a record of the amount by which and the cumulative time the temperature in the affected area exceeded its limit and an analysis to demonstrate the continued OPERABILITY of the affected equipment.

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b. By more than 30°F, in addition to the Special Report required above, within 4 hours either restore the area to within its temperature limit or declare the equipment in the affected area inoperable.

SURVEILLANCE REQUIREMENTS

4.7.8 The temperature in each of the areas shown in Table 3.7.8-1 shall be determined to be within its limit at least once per 12 hours.

TABLE 3.7.8-1

AREA TEMPERATURE MONITORING

AREA		TEMPERATURE LIMIT (°F)	
		~~EQUIPMENT NOT OPERATING~~	~~EQUIPMENT OPERATING~~
a.	Containment		
	Inside Drywell	~~135~~	150
	CRD Cavity	~~135~~	185
	Outside Drywell	~~80~~	105
	Steam Tunnel	~~125~~	125
b.	Auxiliary Building		
	General	~~104~~	104
	ECCS Rooms	~~105~~	150
	ESF Electrical Rooms	~~104~~	104
	Steam Tunnel	~~125~~	125
c.	Control Building		
	ESF Switchgear and Battery Rooms	~~104~~	104
	Control Room	~~77~~	~~77~~ 90
d.	Diesel Generator Rooms	~~125~~	125
e.	SSW Pumphouse	~~104*~~	104*

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*For this area, the limit shall be the greater of 104°F or outside ambient temperature plus 20°F, not to exceed 122°F for greater than one hour.

3/4.7.9 SPENT FUEL STORAGE POOL TEMPERATURE

LIMITING CONDITION FOR OPERATION

3.7.9 The spent fuel storage pool temperature shall be maintained at less than or equal to 150°F.

APPLICABILITY: Whenever irradiated fuel is in the spent fuel storage pool.

ACTION: With the spent fuel storage pool temperature greater than 150°F, ~~72~~ ~~restore the pool temperature to less than or equal to 150°F within 8 hours, or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours; and, after achieving COLD SHUTDOWN, initiate the RHR alternate means of spent fuel storage pool cooling.~~ /826

SURVEILLANCE REQUIREMENTS

4.7.9.1 The spent fuel storage pool temperature shall be verified to be less than or equal to 150°F ~~by determining the pool cooling system inlet temperature~~ at least once per 12 hours. /1058

4.7.9.2 Start each fuel pool cooling and cleanup pump not already running at least once per 92 days and run each pump for at least 15 minutes. /826

for longer than 72 hours, prepare and submit a Special Report pursuant to Specification 6.9.2 within the next ~~[illegible]~~ 14 days outlining the cause of the high temperature condition, and the plan for restoring the ~~[illegible]~~ spent fuel storage pool temperature to normal for existing plant conditions.

3/4.7.10 EMBANKMENT STABILITY

LIMITING CONDITION FOR OPERATION

3.7.10 The downstream access road slope at Culvert No. 1 and the drainage basin slopes shall remain stable.

APPLICABILITY: At all times.

ACTION: If Culvert No. 1 has blockage exceeding 15% of its cross-sectional area, the Culvert shall be cleaned and the slope embankments verified to be stable.

SURVEILLANCE REQUIREMENTS

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4.7.10 The downstream access road slope at Culvert No. 1 and the drainage basin slopes shall be confirmed to be stable by:

a. At least once per year, performing a visual inspection of the embankments and Culvert No. 1.

b. At least once per five years, performing a five-year survey to confirm no significant degradation to the base-line data.

c. Following the occurrence of earthquakes, hurricanes, tornados, or intense local rainfalls, a visual inspection of the embankments and Culvert No. 1 will be made. If this special inspection reveals evidence of change, a survey will be performed to confirm no significant degradation to the base-line data.

DELETE

3/4.8 ELECTRICAL POWER SYSTEMS

3/4.8.1 A.C. SOURCES

A.C. SOURCES - OPERATING

LIMITING CONDITION FOR OPERATION

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

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

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

   1. Separate day fuel tanks containing a minimum of 220 gallons of fuel.

   2. A separate fuel storage system containing a minimum of:

      a) 48,000 gallons of fuel each for diesel generators 11 and 12, and

      b) 39,000 gallons of fuel for diesel generator 13.

   3. A separate fuel transfer pump.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, and 3.

ACTION:

a. With either one offsite circuit or diesel generator 11 or 12 of the above required A.C. electrical power sources inoperable, demonstrate the OPERABILITY of the remaining A.C. sources by performing Surveillance Requirements 4.8.1.1.1.a within one hour and 4.8.1.1.2.a.4,* for one diesel generator at a time, within ~~three~~ two hours and at least once per 8 hours therafter; restore at least two offsite circuits and diesel generators 11 and 12 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. |342 |175

b. With one offsite circuit and diesel generator 11 or 12 of the above required A.C. electrical power sources inoperable, demonstrate the OPERABILITY of the remaining A.C. sources by performing Surveillance Requirements 4.8.1.1.1.a within one hour and 4.8.1.1.2.a.4,* for one diesel generator at at time, within two hours and at least once per 8 hours thereafter; restore at least one of the inoperable A.C. sources to OPERABLE status within 12 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours. Restore at least two offsite circuits and diesel generators 11 and 12 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. |342

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* Specification 4.8.1.1.2.a.4 must be performed for ~~[illegible]~~ diesel generator 13 only when the HPCS system is OPERABLE. |342

ACTION (Continued)

c. With either diesel generator 11 or 12 of the above required A.C. electrical power sources inoperable, in addition to ACTION a or b, above as applicable, verify within 2 hours that all required systems, subsystems, trains, components and devices that depend on the remaining diesel generator 11 or 12 as a source of emergency power are also OPERABLE; otherwise, be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

d. With two of the above required offsite circuits inoperable, demonstrate the OPERABILITY of three diesel generators by performing 1342
Surveillance Requirement 4.8.1.1.2.a.4*, for one diesel generator at a time, within ~~three~~ two hours and at least once per 8 hours thereafter, 1175
unless the diesel generators are already operating; restore at least one of the inoperable 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.

e. With diesel generators 11 and 12 of the above required A.C. electrical power sources inoperable, demonstrate the OPERABILITY of 1342
the remaining A.C. sources by performing Surveillance Requirements 4.8.1.1.1.a, and 4.8.1.1.2.a.4* within ~~one~~ two hours and at least once per 1175
8 hours thereafter; restore at least one of the inoperable diesel generators 11 and 12 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 11 and 12 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.

within one hour

f. With diesel generator 13 of the above required A.C. electrical power sources inoperable, demonstrate the OPERABILITY of the remaining A.C. sources by performing Surveillance Requirements 4.8.1.1.1.a within one hour and 4.8.1.1.2.a.4, for one diesel generator at a time, within two hours and at least once per 8 hours thereafter; restore the inoperable diesel generator 13 to OPERABLE status within 72 hours or declare the HPCS system inoperable and take the ACTION required by Specification 3.5.1.

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* Specification 4.8.1.1.2.a.4 must be performed for diesel generator 13 only when the HPCS system is OPERABLE. 1342

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

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

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

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

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

   1. Verifying the fuel level in the day tank.
   2. Verifying the fuel level in the fuel storage tank.
   3. Verifying the fuel transfer pump starts and transfers fuel from the storage system to the day tank.
   4. Verifying the diesel starts from ambient condition and accelerates to at least 441 rpm for diesel generators 11 and 12 and 882 rpm for diesel generator 13 in less than or equal to 10 seconds. The generator voltage and frequency shall be 4160 ± 416 volts and 60 ± 1.2 Hz within 10 seconds after the start signal. The diesel generator shall be started for this test by using one of the following signals:
      a) Manual.
      b) Simulated loss of offsite power by itself.
      c) Simulated loss of offsite power in conjunction with an ESF actuation test signal.
      d) An ESF actuation test signal by itself.
   5. Verifying the diesel generator is synchronized, loaded to greater than or equal to 7000 kW for diesel generators 11 and 12 and 3300 kW for diesel generator 13 in less than or equal to 60 seconds, and operates with these loads for at least 60 minutes.
   6. Verifying the diesel generator is aligned to provide standby power to the associated emergency busses.
   7. Verifying the pressure in all diesel generator air start receivers to be greater than or equal to:
      a) 160 psig for diesel generator 11 and 12, and
      b) 175 psig for diesel generator 13.

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

c. At least once per 92 days and from new oil prior to addition to the storage tanks by verifying that a sample obtained in accordance with ASTM-D270-~~1975~~ 1965 (reapproved 1980) has a water and sediment content of less than or equal to .05 volume percent and a kinematic viscosity @ 40°C of greater than or equal to 1.9 but less than or equal to 4.1 when tested in accordance with ASTM-D975-77, and an impurity level of less than 2 mg. of insolubles per 100 ml. when tested in accordance with ASTM-D2274-70, except that the test of new fuel for impurity level shall be performed within 7 days after addition of the new fuel to the storage tank. /026

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

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

2. Verifying the diesel generator capability to reject a load of greater than or equal to 1200 kW (LPCS Pump) for diesel generator 11, greater than or equal to 550 kW (RHR B/C Pump) for diesel generator 12, and greater than or equal to 2180 kW (HPCS Pump) for diesel generator 13 while maintaining less than or equal to 75% of the difference between nominal speed and the overspeed trip setpoint, or 15% above nominal, whichever is less.

3. Verifying the diesel generator capability to reject a load of 7000 kW for diesel generators 11 and 12 and 3300 kW for diesel generator 13 without tripping. The generator voltage shall not exceed 5000 volts during and following the load rejection.

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

   a) For Divisions 1 and 2:

      1) Verifying deenergization of the emergency busses and load shedding from the emergency busses.

      2) Verifying the diesel generator starts on the auto-start signal, energizes the emergency busses with permanently connected loads within 10 seconds, energizes the auto-connected shutdown loads through the load sequencer and operates for greater than or equal to 5 minutes while its generator is loaded with the shutdown loads. After energization, the steady state voltage and frequency of the emergency busses shall be maintained at 4160 ± 416 volts and 60 ± 1.2 Hz during this test.

   b) For Division 3:

      1) Verifying de-energization of the emergency bus.

      2) Verifying the diesel generator starts on the auto-start signal, energizes the emergency bus with the loads within 10 seconds and operates for greater than or equal to 5 minutes while its generator is loaded with the shutdown loads. After energization, the steady state voltage and frequency of the emergency bus shall be maintained at 4160 ± 416 volts and 60 ± 1.2 Hz during this test.

5. Verifying that on an ECCS actuation test signal, without loss of offsite power, the diesel generator starts on the auto-start signal and operates on standby for greater than or equal to 5 minutes. The generator voltage and frequency shall be 4160 ± 416 volts and 60 ± 1.2 Hz within 10 seconds after the auto-start signal; the steady state generator voltage and frequency shall be maintained within these limits during this test.

6. [DELETED]

~~6. Verifying that on a simulated loss of the diesel generator, with offsite power not available:~~

~~a. For Divisions 1 and 2:~~

~~1. The loads are shed from emergency busses associated with Diesel Generators 11 and 12.~~

~~2. Subsequent loading of the diesel generators is in accordance with design requirements.~~

~~b. For Division 3:~~

~~1. The associated output breaker for Diesel Generator 13 opens automatically.~~

~~2. Subseqent loading of the diesel generator is in accordance with design requirements.~~

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

a) For Divisions 1 and 2:

1) Verifying deenergization of the emergency busses and load shedding from the emergency busses.

2) Verifying the diesel generator starts on the auto-start signal, energizes the emergency busses with permanently connected loads within 10 seconds, energizes the auto-connected shutdown loads through the load sequencer and operates for greater than or equal to 5 minutes while its generator is loaded with the emergency loads. After energization, the steady state voltage and frequency of the emergency busses shall be maintained at 4160 ± 416 volts and 60 ± 1.2 Hz during this test.

b) For Division 3:

1) Verifying de-energization of the emergency bus.

2) Verifying the diesel generator starts on the auto-start signal, energizes the emergency bus with the permanently connected loads within 10 seconds and the autoconnected emergency loads within 20 seconds and operates for greater than or equal to 5 minutes while its generator is loaded with the emergency loads. After energization, the steady state voltage and frequency of the emergency bus shall be maintained at 4160 ± 416 volts and 60 ± 1.2 Hz during this test.

SURVEILLANCE REQUIREMENTS (Continued)

[illegible] ~~8.~~ start Verifying that all automatic diesel generator trips are automatically bypassed upon an ECCS actuation signal except:

a) For Divisions 1 and 2, engine overspeed, generator differential current, low lube oil pressure, and generator ground overcurrent.

b) For Division 3, engine overspeed and generator differential current.

[illegible] ~~9.~~ start Verifying the diesel generator operates for at least 24 hours. During the first 2 hours of this test, the diesel generator shall be loaded to greater than or equal to 7700 kW for diesel generators 11 and 12 and 3630 kW for diesel generator 13 and during the remaining 22 hours of this test, the diesel generator shall be loaded to 7000 kW for diesel generators 11 and 12 and 3300 kW for diesel generator 13. The generator voltage and frequency shall be 4160 ± 416 volts and 60 ± 1.2 Hz within 10 seconds after the start signal; the steady state generator voltage and frequency shall be maintained within these limits during this test. Within 5 minutes after completing this 24-hour test, perform Surveillance Requirement 4.8.1.1.2.d.7.a).2) and b).2)*.

[illegible] ~~10.~~ start Verifying that the auto-connected loads to each diesel generator do not exceed the continuous rating of 7000 kW for diesel generators 11 and 12 and 3300 kW for diesel generator 13.

[illegible] ~~11.~~ start Verifying the diesel generator's capability to:

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

b) Transfer its loads to the offsite power source, and

c) Be restored to its standby status.

[illegible] ~~12.~~ start Verifying that with the diesel generator operating in a test mode and connected to its bus that a simulated ECCS actuation signal:

a) For Divisions 1 and 2, overrides the test mode by returning the diesel generator to standby operation.

b) For Division 3, overrides the test mode by bypassing the diesel generator automatic trips per Surveillance Requirement 4.8.1.1.2.d.8.b).

12. [DELETED] ~~13. Verifying that with all diesel generator air start receivers pressurized to less than or equal to 256 psig and the compressors secured, the diesel generator starts at least 5 times from ambient conditions and accelerates to at least 441 rpm for diesel generators 11 and 12 and 882 rpm for diesel generator 13 in less than or equal to 10 seconds.~~

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*If Surveillance Requirement 4.8.1.1.2.d.~~8~~7.a)2) or b)2) are not satisfactorily completed, it is not necessary to repeat the preceding 24 hour test. Instead, the diesel generator may be operated at rated load for one hour or until operating temperatures have stabilized.

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14. Verifying that the fuel transfer pump transfers fuel from each fuel storage tank to the day tank of each diesel via the installed lines. /043

~~15.~~ [redacted] Start Verifying that the automatic load sequence timer is OPERABLE with the interval between each load block within ± 10% of its design interval for diesel generators 11 and 12.

~~16.~~ Start [redacted] Verifying that the following diesel generator lockout features prevent diesel generator starting and/or trip the diesel generator only when required:

   a) Generator loss of excitation.
   b) Generator reverse power.
   c) High jacket water temperature.
   d) Generator overcurrent with voltage restraint.
   e) Bus underfrequency (11 and 12 only).
   f) Engine bearing temperature high (11 and 12 only).
   g) Low turbo charger oil pressure (11 and 12 only).
   h) High vibration (11 and 12 only).
   i) High lube oil temperature (11 and 12 only).
   j) Low lube oil pressure (13 only).
   k) High crankcase pressure.

e. At least once per 10 years or after any modifications which could affect diesel generator interdependence by starting all three diesel generators simultaneously, during shutdown, and verifying that the three diesel generators accelerate to at least 441 rpm for diesel generators 11 and 12 and 882 rpm for diesel generator 13 in less than or equal to 10 seconds.

f. At least once per 10 years by:

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

   2. Performing a pressure test of those portions of the diesel fuel oil system designed to Section III, subsection ND of the ASME Code in accordance with ASME Code Section ~~11~~ XI, Article IWD-5000.

0931 4.8.1.1.3 Reports - All diesel generator failures, valid or non-valid, shall be reported to the Commission in a Special Report pursuant to Specification 6.9.~~1~~2. Reports of diesel generator failures shall include the information recommended in Regulatory Position C.3.b of Regulatory Guide 1.108, Revision 1, August 1977. If the number of failures in the last 100 valid tests, on a per nuclear unit basis, is greater than or equal to 7, the report shall be supplemented to include the additional information recommended in Regulatory Position C.3.b of Regulatory Guide 1.108, Revision 1, August 1977. within 30 days.

TABLE 4.8.1.1.2-1

DIESEL GENERATOR TEST SCHEDULE

Number of Failures in Last 100 Valid Tests*	Test Frequency
≤ 1	At least once per 31 days
2	At least once per 14 days
3	At least once per 7 days
≥ 4	At least once per 3 days

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*Criteria for determining number of failures and number of valid test shall be in accordance with Regulatory Position C.2.e of Regulatory Guide 1.108, Revision 1, August 1977, where the last 100 tests are determined on a per nuclear unit basis. For the purposes of this test schedule, only valid tests conducted after the OL issuance date shall be included in the computation of the "last 100 valid tests." Entry into this test schedule shall be made at the 31 day test frequency.

ELECTRICAL POWER SYSTEMS

A.C. SOURCES - SHUTDOWN

LIMITING CONDITION FOR OPERATION

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

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

b. Diesel generator 11 ~~and~~/or 12, and diesel generator 13 when the HPCS system is required to be OPERABLE, with each diesel generator having: /060

   1. A day tank containing a minimum of 220 gallons of fuel.
   2. A fuel storage system containing a minimum of:
      a) 48,000 gallons of fuel ~~each~~ for ~~and~~ OPERABLE diesel generator~~s~~ 11 or ~~and~~ 12. /060
      b) 39,000 gallons of fuel for diesel generator 13.
   3. A fuel transfer pump.

APPLICABILITY: OPERATIONAL CONDITIONS 4, 5 and *.

ACTION:

a. With all offsite circuits inoperable [redacted] or with diesel generators 11 and~~/or~~ 12 ~~of the above required A.C. electrical power sources~~ inoperable, suspend CORE ALTERATIONS, handling of irradiated fuel in the primary or secondary containment, operations with a potential for draining the reactor vessel and crane operations over the spent fuel storage pool and the upper containment pool when fuel assemblies are stored therein. In addition, when in OPERATIONAL CONDITION 5 with the water level less than ~~22 feet~~ 22 feet 8 inches above the reactor pressure vessel flange, immediately initiate corrective action to restore the required power sources to OPERABLE status as soon as practical. /060 /176 /275

b. With diesel generator 13 ~~of the above required A.C. electrical power sources~~ inoperable, restore the inoperable diesel generator 13 to OPERABLE status within 72 hours or declare the HPCS system inoperable and take the ACTION required by Specification 3.5.2 and 3.5.3. /060

c. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

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

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*When handling irradiated fuel in the primary or secondary containment.

3/4.8.2 D.C. SOURCES

D.C. SOURCES - OPERATING

LIMITING CONDITION FOR OPERATION

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

a. Division 1, consisting of:
   1. 125 volt battery 1A3.
   2. 125 volt full capacity charger 1A4 or 1A5.

b. Division 2, consisting of:
   1. 125 volt battery 1B3.
   2. 125 volt full capacity charger 1B4 or 1B5.

c. Division 3, consisting of:
   1. 125 volt battery 1C3.
   2. 125 volt full capacity charger 1C4.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2 and 3.

ACTION:

a. With either Division 1 battery or Division 2 battery of the above required D.C. electrical power sources inoperable, restore the inoperable division battery to OPERABLE status within 2 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

b. With Division 3 battery of the above required D.C. electrical power sources inoperable, declare the HPCS system inoperable and take the ACTION required by Specification 3.5.1.

c. With one of the above required full capacity chargers inoperable, demonstrate the OPERABILITY of its associated battery bank by performing Surveillance Requirement 4.8.2.1.a.1 within one hour and at least once per 8 hours thereafter. If any Category A limit in Table 4.8.2.1-1 is not met, declare the battery inoperable.

4.8.2.1 Each of the above required 125-volt batteries and chargers shall be demonstrated OPERABLE:

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

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

2. Total battery terminal voltage is greater than or equal to 129-volts on float charge.

b. At least once per 92 days and within 7 days after a battery discharge with battery terminal voltage below 110-volts, or battery overcharge with battery terminal voltage above 150-volts, by verifying that:

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

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

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

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

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

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

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

4. The battery charger will supply:

    a) For Divisions 1 and 2, at least 400 amperes at a minimum of ~~105~~ 125 volts for at least ~~2~~ 10 hours.

    b) For Division 3, at least 50 amperes at a minimum of ~~105~~ 125 volts for at least ~~2~~ 3 hours.

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

   1. The battery capacity is adequate to supply and maintain in OPERABLE status all of the actual emergency loads for 4 hours for Divisions 1 and 2 and 2 hours for Division 3 when the battery is subjected to a battery service test, or

   2. The battery capacity is adequate to supply a dummy load of the following profile, which is verified to be greater than the actual emergency load, while maintaining the battery terminal voltage greater than or equal to 105 volts.

      a) Division 1

         ≥950 amperes for the first 60 seconds
         ≥128 amperes for the next 119 minutes
         ≥306 amperes for the next 60 seconds
         ≥128 amperes for the next 118 minutes
         ≥416 amperes for the last 60 seconds

      b) Division 2

         ≥427 amperes for the first 60 seconds
         ≥186 amperes for the next 119 minutes
         ≥357 amperes for the next 60 seconds
         ≥186 amperes for the next 118 minutes
         ≥243 amperes for the last 60 seconds

      c) Division 3

         ≥76 amperes for the first 60 seconds
         ≥16 amperes for the next 59 minutes
         ≥18 amperes for the last 60 minutes

e. At least once per 60 months during shutdown by verifying that the battery capacity is at least 80% of the manufacturer's rating when subjected to a performance discharge test. Once per 60 month interval, this performance discharge test may be performed in lieu of the battery service test.

f. Annual performance discharge tests of battery capacity shall be given to any battery that shows signs of degradation or has reached 85% of the service life expected for the application. Degradation is indicated when the battery capacity drops more than 10% of rated capacity from its average on previous performance tests, or is below 90% of the manufacturer's rating.

TABLE 4.8.2.1-1

BATTERY SURVEILLANCE REQUIREMENTS

	CATEGORY A(1)	CATEGORY B(2)	
Parameter	Limits for each designated pilot cell	Limits for each connected cell	Allowable(3) value for each connected cell
Electrolyte Level	>Minimum level indication mark, and ≤ ¼" above maximum level indication mark	>Minimum level indication mark, and ≤ ¼" above maximum level indication mark	Above top of plates, and not overflowing
Float Voltage	≥ 2.13 volts	≥ 2.13 volts(b)	> 2.07 volts
Specific Gravity(a)	≥ 1.195	≥ 1.190	Not more than .020 below the average of all connected cells
		Average of all connected cells > 1.200	Average of all connected cells ≥ 1.190

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(a) Corrected for electrolyte temperature and level.
(b) May be corrected for average electrolyte temperature.
(1) For any Category A parameter(s) outside the limit(s) shown, the battery may be considered OPERABLE provided that within 24 hours all the Category B measurements are taken and found to be within their allowable values, and provided all Category A and B parameter(s) are restored to within limits within the next 6 days.
(2) For any Category B parameter(s) outside the limit(s) shown, the battery may be considered OPERABLE provided that the Category B parameters are within their allowable values and provided the Category B parameter(s) are restored to within limits within 7 days.
(3) Any Category B parameter not within its allowable value indicates an inoperable battery.

D.C. SOURCES - SHUTDOWN

LIMITING CONDITION FOR OPERATION

3.8.2.2 As a minimum, Division 1 or Division 2, and, when the HPCS system is required to be OPERABLE, Division 3, of the D.C. electrical power sources shall be OPERABLE with:

a. Division 1 consisting of:
   1. 125 volt battery 1A3.
   2. 125 volt full capacity charger 1A4 or 1A5.

b. Division 2 consisting of:
   1. 125 volt battery 1B3.
   2. 125 volt full capacity charger 1B4 or 1B5.

c. Division 3 consisting of:
   1. 125 volt battery 1C3.
   2. 125 volt full capacity charger 1C4.

APPLICABILITY: OPERATIONAL CONDITIONS 4, 5 and *.

ACTION:

a. With both Division 1 battery and Division 2 battery of the above required D.C. electrical power sources inoperable, suspend CORE ALTERATIONS, handling of irradiated fuel in the primary or secondary containment and operations with a potential for draining the reactor vessel.

b. With Division 3 battery of the above required D.C. electrical power sources inoperable, declare the HPCS system inoperable and take the ACTION required by Specification 3.5.2 and 3.5.3.

c. With any of the above required full capacity chargers inoperable, demonstrate the OPERABILITY of its associated battery bank by performing Surveillance Requirement 4.8.2.1.a.1 within one hour and at least once per 8 hours thereafter. If any Category A limit in Table 4.8.2.1-1 is not met, declare the battery inoperable. /177

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d. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

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

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* When handling irradiated fuel in the primary or secondary containment.

3/4.8.3 ONSITE POWER DISTRIBUTION SYSTEMS

DISTRIBUTION - OPERATING

LIMITING CONDITION FOR OPERATION

3.8.3.1 The following power distribution system divisions shall be energized:

a. A.C. power distribution:

1. Division 1, consisting of:
   - a) 4160 volt A.C. bus 15AA.
   - b) 480 volt A.C. MCCs 15B11, 15B21, 15B31, 15B41, 15B51 and 15B61.
   - c) 120 volt A.C. distribution panels in 15P11, 15P21, 15P31, 15P41, 15P51 and 15P61.
   - d) LCCs 15BA1, 15BA2, 15BA3, 15BA4, 15BA5 and 15BA6.
2. Division 2, consisting of:
   - a) 4160 volt A.C. bus 16AB.
   - b) 480 volt A.C. MCCs 16B11, 16B21, 16B31, 16B41, 16B51 and 16B61.
   - c) 120 volt A.C. distribution panels in 16P11, 16P21, 16P31, 16P41, 16P51 and 16P61.
   - d) LCCs 16BB1, 16BB2, 16BB3, 16BB4, 16BB5 and 16BB6.
3. Division 3, consisting of:
   - a) 4160 volt A.C. bus 17AC.
   - b) 480 volt A.C. MCCs 17B01 and 17B11.
   - c) 120 volt A.C. distribution panels 17P11.
4. Two separate and independent OPERABLE load shedding and sequencing panels for the control of Division 1 and 2, respectively.

b. D.C. power distribution:

1. Division 1, consisting of 125 volt D.C. distribution panel 1DA1 and 1DA2.
2. Division 2, consisting of 125 volt D.C. distribution panel 1DB1 and 1DB2.
3. Division 3, consisting of 125 volt D.C. distribution panel 1DC1.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2 and 3.

LIMITING CONDITIONS FOR OPERATION (Continued)

ACTION:

a. For A.C. power distribution:

  1. With either Division 1 or Division 2 of the above required A.C. distribution system not energized, re-energize the division within 8 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.
  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 3.5.1.
  3. With one of the above required load shedding and sequencing panels inoperable, restore the inoperable panel to OPERABLE status within 8 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

b. For D.C. power distribution:

  1. With either Division 1 or Division 2 of the above required D.C. distribution system not energized, re-energize the division within 2 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.
  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 3.5.1.

SURVEILLANCE REQUIREMENTS

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

4.8.3.1.2 Each of the above required load shedding and sequencing panels shall be demonstrated OPERABLE:

a. At least once per 12 hours by determining that the auto-test system is operating and is not indicating a faulted condition.

b. At least once per 31 days by performance of a manual test and verifying response within the design criteria to the following test inputs:

  a) LOCA.
  b) Bus undervoltage.
  c) Bus undervoltage followed by LOCA.
  d) LOCA followed by bus undervoltage.

DISTRIBUTION - SHUTDOWN

LIMITING CONDITION FOR OPERATION

3.8.3.2 As a minimum, the following power distribution system divisions shall be energized:

a. For A.C. power distribution, Division 1 or Division 2, and when the HPCS system is required to be OPERABLE, Division 3, with:

   1. Division 1 consisting of:

      a) 4160 volt A.C. bus 15AA.
      b) 480 volt A.C. MCCs 15B11, 15B21, 15B31, 15B41, 15B51 and 15B61.
      c) 120 volt A.C. distribution panels in 15P11, 15P21, 15P31, 15P41, 15P51 and 15P61.
      d) LCCs 15BA1, 15BA2, 15BA3, 15BA4, 15BA5 and 15BA6.

   2. Division 2 consisting of:

      a) 4160 volt A.C. bus 16AB.
      b) 480 volt A.C. MCCs 16B11, 16B21, 16B31, 16B41, 16B51 and 16B61.
      c) 120 volt A.C. distribution panels in 16P11, 16P21, 16P31, 16P41, 16P51 and 16P61.
      d) LCCs 16BB1, 16BB2, 16BB3, 16BB4, 16BB5 and 16BB6.

   3. Division 3 consisting of:

      a) 4160 volt A.C. bus 17AC.
      b) 480 volt A.C. MCCs 17B01 and 17B11.
      c) 120 volt A.C. distribution panels 17P11.

   4. The OPERABLE load shedding and sequencing panel associated with the division(s) required to be energized.

b. For D.C. power distribution, Division 1 or Division 2, and when the HPCS system is required to be OPERABLE, Division 3, with:

   1. Division 1 consisting of 125 volt D.C. distribution panel 1DA1 and 1DA2.

   2. Division 2 consisting of 125 volt D.C. distribution panel 1DB1 and 1DB2.

   3. Division 3 consisting of 125 volt D.C. distribution panel 1DC1.

APPLICABILITY: OPERATIONAL CONDITIONS 4, 5 and *.

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*When handling irradiated fuel in the primary or secondary containment.

LIMITING CONDITION FOR OPERATION (Continued)

ACTION:

a. For A.C. power distribution:
   1. With both Division 1 and Division 2 of the above required A.C. distribution system not energized and/or with the load shedding and sequencing panel associated with the division(s) required to be energized inoperable, suspend CORE ALTERATIONS, handling of irradiated fuel in the primary or secondary 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 both Division 1 and Division 2 of the above required D.C. distribution system not energized, suspend CORE ALTERATIONS, handling of irradiated fuel in the primary or secondary 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

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

4.8.3.2.2 The above required load shedding and sequencing panel(s) shall be demonstrated OPERABLE:

a. At least once per 12 hours by determining that the auto-test system is operating and is not indicating a faulted condition.
b. At least once per 31 days by performance of a manual test and verifying response within the design criteria to the following test inputs:
   a) LOCA.
   b) Bus undervoltage.
   c) Bus undervoltage followed by LOCA.
   d) LOCA followed by bus undervoltage.

3/4.8.4 ELECTRICAL EQUIPMENT PROTECTIVE DEVICES

PRIMARY CONTAINMENT PENETRATION CONDUCTOR OVERCURRENT PROTECTIVE DEVICES

LIMITING CONDITION FOR OPERATION

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

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2 and 3.

ACTION:

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

   1. For 6.9 kV circuit breakers, de-energize the 6.9 kV circuit(s) by tripping the associated redundant circuit breaker(s) within 72 hours and verify the redundant circuit breaker to be tripped at least once per 7 days thereafter.

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

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

b. The provisions of Specification 3.0.4 are not applicable to overcurrent devices in 6.9 kV circuits which have their redundant circuit breakers tripped or to 480 volt circuits which have the inoperable circuit breaker racked out.

SURVEILLANCE REQUIREMENTS

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

a. At least once per 18 months:

   1. By verifying that the medium voltage 6.9 kV circuit breakers are OPERABLE by selecting, on a rotating basis, at least 10% of the circuit breakers and performing:

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

      b) An integrated system functional test which includes simulated automatic actuation of the system and verifying that each relay and associated circuit breakers and overcurrent control circuits function as designed and as specified in Table 3.8.4.1-1.

      c) For each circuit breaker found inoperable during these functional tests, an additional representative sample of at least 10% of all the circuit breakers of the inoperable type shall also be functionally tested until no more failures are found or all circuit breakers of that type have been functionally tested.

2. By selecting and functionally testing a representative sample of at least 10% of each type of lower voltage circuit breakers. Circuit breakers selected for functional testing shall be selected on a rotating basis. For the lower voltage circuit breakers the nominal trip setpoint and short circuit response times are listed in Table 3.8.4.1-1. Testing of these circuit breakers shall consist of injecting a current in excess of 120% of the breakers nominal setpoint and measuring the response time. The measured response time will be compared to the manufacturer's data to insure that it is less than or equal to a value specified by the manufacturer. Circuit breakers found inoperable during functional testing shall be restored to OPERABLE status prior to resuming operation of the affected equipment. For each circuit breaker found inoperable during these functional tests, an additional representative sample of at least 10% of all the circuit breakers of the inoperable type shall also be functionally tested until no more failures are found or all circuit breakers of that type have been functionally tested. /302

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

TABLE 3.8.4.1-1

PRIMARY CONTAINMENT PENETRATION CONDUCTOR OVERCURRENT PROTECTIVE DEVICES

DEVICE NUMBER AND LOCATION	TRIP SETPOINT (Amperes)	RESPONSE TIME (Cycles)	SYSTEM/ COMPONENT AFFECTED
a. 6.9 kV Circuit Breakers			
252-1103-B	7200/45/± 10%[#]	60	Reactor Recir. Pump
252-1103-C	7200/45/± 10%[#]	60	Pump B33C001A
252-1205-B	7200/45/± 10%[#]	60	Reactor Recir. Pump
252-1205-C	7200/45/± 10%[#]	60	Pump B33C001B

b. 480 VAC Circuit Breakers

Stored Energy Type K600S with SS3G3 Tripping Device

BREAKER NUMBER	TRIP SETPOINT (Amperes)	RESPONSE TIME (Seconds)	SYSTEM/COMPONENT AFFECTED
52-12202	1200	0.07	CONTAINMENT COOLING FILTER TRAIN HEATERS (N1M41D002B-N)
52-12209	2000	0.07	CNTMT POLAR CRANE (Q1F13E001-N)
51-11502	1200	0.07	CNTMT CLG. FILTER TRAIN HEATER (N1M41D002A-N)
52-15105	2000	0.07	DRYWELL PURGE COMPRESS. (Q1E61C001A-A)
52-16204	2000	0.07	DRYWELL PURGE COMPRESS. (Q1E61C001B-B)
52-16404	1200	0.07	HYDROGEN RECOMBINER (Q1E61C003B-B)
52-15205	1200	0.07	HYDROGEN RECOMBINER (Q1E61C003A-A)

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[#] Primary current/setpoint.

TABLE 3.8.4.1-1 (Continued)

PRIMARY CONTAINMENT PENETRATION CONDUCTOR OVERCURRENT PROTECTIVE DEVICES

c. 480 VAC Circuit Breakers

Molded Case, Type NZM

BREAKER NUMBER	TRIP SETPOINT (Amperes)	RESPONSE TIME (Seconds)	SYSTEM/COMPONENT AFFECTED
52-1112-01	500	0.100	NEUTRON MON SYS DRIVE MECHANISM (1C51-J001A)
52-1112-02	500	0.100	NEUTRON MON SYS DRIVE MECHANISM (1C51-J001B)
52-1112-03	500	0.100	NEUTRON MON SYS DRIVE MECHANISM (1C51-J001C)
52-1112-04	500	0.100	NEUTRON MON SYS DRIVE MECHANISM (1C51-J001D)
52-1112-05	175	0.100	STEAM TUNNEL CLR INSIDE CTMT FAN (N1M41C004A-N)
52-1112-06	500	0.100	NEUTRON MON SYS DRIVE MECHANISM (1C51-J001E)
52-1112-07	1200	0.100	LIGHTING XFMR 1X105 (N1R18S105-D)
52-1112-10	1200	0.100	LIGHTING XFRM 1X109 (N1R18S109-D)
52-1112-15	320	0.100	RWCU BACKWASH TRANSFER PUMP (N1G36C004-N)
52-1112-18	24	0.100	PRECOAT TANK AGITATOR (N1G36D019-N)
52-1112-20	90	0.100	RWCU FILTER DEMIN HOLDING PUMP (N1G36C001A-N)

TABLE 3.8.4.1-1 (Continued)

PRIMARY CONTAINMENT PENETRATION CONDUCTOR OVERCURRENT PROTECTIVE DEVICES

c. 480 VAC Circuit Breakers (Continued)

Molded Case, Type NZM

BREAKER NUMBER	TRIP SETPOINT (Amperes)	RESPONSE TIME (Seconds)	SYSTEM/COMPONENT AFFECTED
52-1112-21	800	0.100	480 V RECEPTACLE
52-1112-22	5	0.100	MOV-STM TUNNEL COOLER INLET (N1P44F105A-N)
52-1112-24	32	0.100	MOV CLEANUP LINE RECIRC LOOP A (Q1G33F100-N)
52-1112-27	24	0.100	RESIN TANK AGITATOR (N1G36D020-N)
52-1112-28	38	0.100	MOV RWCU HEAT EXCHANGER BYPASS (N1G33F104-N)
52-1112-31	38	0.100	MOV RWCU HEAT EXCHANGER BYPASS (N1G33F044-N)
52-1112-36	500	0.100	REAC. RECIRC. PUMP SPACE HEATER (TB1B33C001A)
52-1112-37	800	0.100	480 V RECEPTACLE
52-1112-41	6	0.100	REAC RECIRC SAMPLE PANEL ISOL MOV (N1B33F129)
52-1113-07	125	0.100	CNTMT FLOOR DRAIN SUMP PUMP (N1P45C019B-N)
52-1113-21	60	0.100	DRYWELL EQUIP DRAIN SUMP PUMP (N1P45C002B-N)
52-1113-30	28	0.100	MOV RWCU HX OUTL ISOL VLV (N1G33F254-N)

TABLE 3.8.4.1-1 (Continued)

PRIMARY CONTAINMENT PENETRATION CONDUCTOR OVERCURRENT PROTECTIVE DEVICES

c. 480 VAC Circuit Breakers (Continued)

Molded Case, Type NZM

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

TABLE 3.8.4.1-1 (Continued)

PRIMARY CONTAINMENT PENETRATION CONDUCTOR OVERCURRENT PROTECTIVE DEVICES

c. 480 VAC Circuit Breakers (Continued)

Molded Case, Type NZM

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

TABLE 3.8.4.1-1 (Continued)

PRIMARY CONTAINMENT PENETRATION CONDUCTOR OVERCURRENT PROTECTIVE DEVICES

c. 480 VAC Circuit Breakers (Continued)

Molded Case, Type NZM

BREAKER NUMBER.	TRIP SETPOINT (Amperes)	RESPONSE TIME (Seconds)	SYSTEM/COMPONENT AFFECTED
52-1251-13	800	0.100	CNTMT CLR FAN COIL UNIT FAN (N1M41B001C-N)
52-1251-15	32	0.100	MOV - RWCS HX INL ISOL VLV (N1G33F256-N)
52-1251-18	38	0.100	MOV - REGEN HEAT EXCHANGER BYPASS (Q1G33F107-N)
52-1251-19	38	0.100	MOV - RWCU DRAIN FLOW ORIFICE BYP (N1G33F031-N)
52-1251-20	320	0.100	CNTMT EQUIP DRAIN PUMP (N1P45C004B-N)
52-1251-22	32	0.100	MOV - RWCU TO FLT "S" ISOL VLV (N1G33F255-N)
52-1251-26	1200	0.100	LIGHTING XFMR 1X112 (N1R18S112-D)
52-1251-28	5	0.100	MOV - STM TUNNEL COOLER INLET (N1P44F105B-N)
52-1252-23	60	0.100	DRYWELL FLOOR DRAIN SUMP PUMP (N1P45C001B-N)
52-1411-01	38	0.100	MOV - VESSEL HEAD VENTILATION (Q1B21F002-N)

TABLE 3.8.4.1-1 (Continued)

PRIMARY CONTAINMENT PENETRATION CONDUCTOR OVERCURRENT PROTECTIVE DEVICES

c. 480 VAC Circuit Breakers (Continued)

Molded Case, Type NZM

BREAKER NUMBER	TRIP SETPOINT (Amperes)	RESPONSE TIME (Seconds)	SYSTEM/COMPONENT AFFECTED
52-1412-01	17.5	0.100	REAC RECIRC HPU OIL PUMP FAN (N1B33D003B3-N)
52-1412-02	60	0.100	CNTMT CHEM WASTE SUMP PUMP (N1P45C027B-N)
52-1412-03	60	0.100	DRYWELL FLOOR DRAIN SUMP PUMP (N1P45C001A-N)
52-1412-05	12.5	0.100	MOV CRD COOLWTR PRESS CONTROL (N1C11F003-N)
52-1412-08	105	0.100	MOV REAC RECIRC PUMP B SUCTION (Q1B33F023B-N)
52-1412-09	175	0.100	RWCU DEMIN PRECOAT PUMP (N1G36C002-N)
52-1412-12	90	0.100	RWCU DEMIN HOLDING PUMP (N1G36C001B-N)
52-1412-15	600	0.100	REAC RECIRC HPU OIL PUMP (N1B33D003B1-N)
52-1412-17	320	0.100	CNTMT EQUIP DRAIN SUMP PUMP (N1P45C004A-N)
52-1412-20	800	0.100	480 V RECEPTACLE
52-1412-23	600	0.100	REAC RECIRC HPU OIL PUMP (N1B33D003B2-N)

TABLE 3.8.4.1-1 (Continued)

PRIMARY CONTAINMENT PENETRATION CONDUCTOR OVERCURRENT PROTECTIVE DEVICES

c. 480 VAC Circuit Breakers (Continued)

Molded Case, Type NZM

BREAKER NUMBER	TRIP SETPOINT (Amperes)	RESPONSE TIME (Seconds)	SYSTEM/COMPONENT AFFECTED
52-1412-25	17.5	0.100	REAC RECIRC HPU OIL PUMP FAN (N1B33D003B4-N)
52-1412-26	38	0.100	MOV REACTOR VESSEL HEAT VENT (Q1B21F001-N)
52-1412-28	38	0.100	MOV REACTOR VESSEL HEAT VENT (Q1B21F005-N)
52-1412-32	800	0.100	CNTMT CLR FAN COIL UNIT FAN (N1M41B001A-N)
52-1412-33	105	0.100	MOV - REAC RECIRC PUMP A DISCHARGE (Q1B33F067B-N)
52-1412-35	500	0.100	CRD REMOVAL HOIST (N1M31E003-N)
52-1412-39	1200	0.100	DRYWELL VALVE HOIST (Q1M31E002-N)
52-1412-41	32	0.100	CNTMT AIRLOCK AIR SHOWER FAN (N1M41C005-N)
52-1511-07	50	0.100	MOV - RWCS INL INB ISOL VLV (Q1G33F250-A)
52-1511-24	50	0.100	MOV - RWSC OUT INB ISOL VLV (Q1G33F252-A)
52-1511-44	12.5	0.100	MOV - DRYWELL CLG WATER ISOL (Q1P42F116-A)

TABLE 3.8.4.1-1 (Continued)

PRIMARY CONTAINMENT PENETRATION CONDUCTOR OVERCURRENT PROTECTIVE DEVICES

c. 480 VAC Circuit Breakers (Continued)

Molded Case, Type NZM

BREAKER NUMBER	TRIP SETPOINT (Amperes)	RESPONSE TIME (Seconds)	SYSTEM/COMPONENT AFFECTED
52-1511-54	24	0.100	Spare
52-1521-02	6	0.100	MOV COMBUSTIBLE GAS CONTROL SYS (Q1E61F003A-A)
52-1521-03	6	0.100	MOV COMBUSTIBLE GAS CONTROL SYS (Q1E61F005A-A)
52-1521-07	10	0.100	MOV - SUPPR. POOL MAKE-UP VALVE (Q1E30F002A-A)
52-1521-14	600	0.100	SLC SYSTEM PUMP (Q1C41C001A-A)
52-1521-15	5	0.100	STORAGE TANK OUTLET VALVE (Q1C41F001A-A)
52-1521-28	12.5	0.100	MOV - INST LINE ISOL VALVE (Q1M71F595-A)
52-1521-44	10	0.100	MOV - SUPPR POOL MAKE-UP VALVE (Q1E30F001A-A)
52-1531-24	12.5	0.100	MOV - DRYWELL COOLER ISOLATION (Q1P44F076-A)
52-1531-25	8	0.100	MOV - REACTOR WATER SAMPLE (Q1B33F020-A)

TABLE 3.8.4.1-1 (Continued)

PRIMARY CONTAINMENT PENETRATION CONDUCTOR OVERCURRENT PROTECTIVE DEVICES

c. 480 VAC Circuit Breakers (Continued)

Molded Case, Type NZM

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

TABLE 3.8.4.1-1 (Continued)

PRIMARY CONTAINMENT PENETRATION CONDUCTOR OVERCURRENT PROTECTIVE DEVICES

c. 480 VAC Circuit Breakers (Continued)

Molded Case, Type NZM

BREAKER NUMBER	TRIP SETPOINT (Amperes)	RESPONSE TIME (Seconds)	SYSTEM/COMPONENT AFFECTED
52-1542-10	320	0.100	DRYWELL COOLER FAN COIL UNIT (N1M51B006A-A)
52-1542-14	5	0.100	MOV - DRYWELL COOLER INLET (N1P44F055-A)
52-1542-15	5	0.100	MOV - DRYWELL COOLER INLET (N1P44F057-A)
52-1542-16	5	0.100	MOV - DRYWELL COOLER INLET (N1P44F059-A)
52-1542-17	5	0.100	MOV - DRYWELL COOLER INLET (N1P44F061-A)
52-1542-18	5	0.100	MOV - DRYWELL COOLER INLET (N1P44F063-A)
52-1542-19	5	0.100	MOV - DRYWELL COOLER INLET (N1P44F065-A)
52-1542-21	800	0.100	SLCS OPERATING HEATER (N1C41D002)
52-1542-22	24	0.100	DRWL PURGE COMP AUX OIL PUMP (Q1E61C001A-A)
52-1542-23	500	0.100	REFUELING PLATFORM ASSY (Q1F15E003-A)
52-1542-26	175	0.100	DRYWELL RECIRC FAN (N1M51C001-A)

TABLE 3.8.4.1-1 (Continued)

PRIMARY CONTAINMENT PENETRATION CONDUCTOR OVERCURRENT PROTECTIVE DEVICES

c. 480 VAC Circuit Breakers (Continued)

Molded Case, Type NZM

BREAKER NUMBER	TRIP SETPOINT (Amperes)	RESPONSE TIME (Seconds)	SYSTEM/COMPONENT AFFECTED
52-1542-29	1200	0.100	STBY LIQ CONTROL SYS MIXING HEATER (Q1C41D003)
52-1611-10	12.5	0.100	MOV - DRYWELL COLL TK OUTLET ISOLATION (Q1G41F044-B)
52-1611-15	12.5	0.100	MOV - PSW CTMT STM TNL CLR ISOL (Q1P44F070-B)
52-1611-25	12.5	0.100	MOV - DRYWELL CLG WTR ISOL (Q1P42F117-B)
52-1611-31	12.5	0.100	MOV - DRYWELL CLG WTR INL ISOL (Q1P42F114-B)
52-1611-32	32	0.100	MOV - CTMT CLG WTR ISOLATION (Q1P42F068-B)
52-1611-42	12.5	0.100	MOV PSW STEAM TUNNEL CLR ISOL (Q1P44F074-B)
52-1611-43	12.5	0.100	MOV PSW STEAM TUNNEL CLR ISOL (Q1P44F077-B)
52-1611-44	38	0.100	MOV - SERVICE AIR DRYWELL ISOLATION (Q1P52F195-B)
52-1621-03	7	0.100	MOV - DRWL HYDR INST LINE ISO (Q1E61F595B-B)
52-1621-04	7	0.100	MOV - DRWL HYDR INST LINE ISO (Q1E61F597B-B)

TABLE 3.8.4.1-1 (Continued)

PRIMARY CONTAINMENT PENETRATION CONDUCTOR OVERCURRENT PROTECTIVE DEVICES

c. 480 VAC Circuit Breakers (Continued)

Molded Case, Type NZM

BREAKER NUMBER.	TRIP SETPOINT (Amperes)	RESPONSE TIME (Seconds)	SYSTEM/COMPONENT AFFECTED
52-1621-05	7	0.100	MOV - DRWL HYDR INST LINE ISO (Q1E61F595D-B)
52-1621-06	7	0.100	MOV - DRWL HYDR INST LINE ISO (Q1E61F597D-B)
52-1621-07	7	0.100	MOV CTMT HYDR INST LINE ISOL (Q1E61F596B-B)
52-1621-08	7	0.100	MOV CTMT HYDR INST LINE ISOL (Q1E61F598B-B)
52-1621-09	7	0.100	MOV CTMT HYDR INST LINE ISO (Q1E61F596D-B)
52-1621-10	7	0.100	MOV CTMT HYDR INST LINE ISO (Q1E61F598D-B)
52-1621-16	10	0.100	CONTAINMENT ISOL VALVE (Q1B33F128-B)
52-1621-17	6	0.100	MOV - DRWL PURGE INLET (Q1E61F003B-B)
52-1621-18	6	0.100	MOV - DRWL PURGE VACUUM RELIEF (Q1E61F005B-B)
52-1621-19	24	0.100	SPARE

TABLE 3.8.4.1-1 (Continued)

PRIMARY CONTAINMENT PENETRATION CONDUCTOR OVERCURRENT PROTECTIVE DEVICES

c. 480 VAC Circuit Breakers (Continued)

Molded Case, Type NZM

BREAKER NUMBER	TRIP SETPOINT (Amperes)	RESPONSE TIME (Seconds)	SYSTEM/COMPONENT AFFECTED
52-1621-40	32	0.100	MOV - COMB GAS CONT COMP B OUT (Q1P41F168B-B)
52-1631-06	125	0.100	MOV - RHR B UPPER CTMT POOL SPRAY (Q1E12F037B-B)
52-1631-13	320	0.100	MOV - RHR B LPCS (Q1E12F042B-B)
52-1631-15	105	0.100	MOV-SSW TO RHR SYSTEM (Q1E12F096B)
52-1631-20	12.5	0.100	MOV - MAIN STEAM LINE DRAIN INBD (Q1B21F016-B)
52-1631-29	600	0.100	STANDBY LIQUID CONTROL PUMP (Q1C41C001B-B)
52-1631-33	105	0.100	MOV - RHR B TO CONTAINMENT SPRAY (Q1E12F028B-B)
52-1631-34	105	0.100	MOV - RCIC STEAM SUPPLY LINE ISOL (Q1E51F063-B)
52-1631-35	5	0.100	STORAGE TANK OUTLET VALVE (Q1C41F001B-B)
52-1631-37	240	0.100	MOV - RHR A SHT DN CLG INBD ISO (Q1E12F009-B)
52-1631-38	32	0.100	MOV - RCIC STEAM WARMUP LINE ISOL (Q1E51F076-B)

TABLE 3.8.4.1-1 (Continued)

PRIMARY CONTAINMENT PENETRATION CONDUCTOR OVERCURRENT PROTECTIVE DEVICES

c. 480 VAC Circuit Breakers (Continued)

Molded Case, Type NZM

BREAKER NUMBER	TRIP SETPOINT (Amperes)	RESPONSE TIME (Seconds)	SYSTEM/COMPONENT AFFECTED
52-1631-41	8	0.100	MOV - REACTOR WATER SAMPLE (Q1B33F019-B)
52-1631-47	50	0.100	MOV - INST AIR DRWL OUTBD ISOL (Q1P53F007-B)
52-1631-50	32	0.100	MOV - RWCU OUTLET TO MAIN CONDENSER (Q1G33F028-B)
52-1631-51	32	0.100	MOV RWCU SYS ISOLATIN VALVE (Q1G33F053-B)
52-1631-52	50	0.100	MOV - RWCU SYS ISOLATION (Q1G33F040-B)
52-1631-53	50	0.100	MOV - RWCU SYS ISOLATION (Q1G33F001-B)
52-1641-06	32	0.100	MOV - MAKE UP WATER CNTMT ISOL (Q1P21F018-B)
52-1641-07	50	0.100	MOV - RWCS INL OUT ISOL VLV (Q1G33F251-B)
52-1641-08	50	0.100	MOV - RWCS INL OUT ISOL VLV (Q1G33F253-B)
52-1641-16	7	0.100	MOV INSTRUMENT LINE INBOARD ISO (Q1D23F591-B)

TABLE 3.8.4.1-1 (Continued)

PRIMARY CONTAINMENT PENETRATION CONDUCTOR OVERCURRENT PROTECTIVE DEVICES

c. 480 VAC Circuit Breakers (Continued)

Molded Case, Type NZM

BREAKER NUMBER	TRIP SETPOINT (Amperes)	RESPONSE TIME (Seconds)	SYSTEM/COMPONENT AFFECTED
52-1641-18	7	0.100	MOV - INSTRUMENT LINE INBOARD ISO (Q1D23F593-B)
52-1641-24	7	0.100	CONTAINMENT ISOL VALVE (Q1B33F126-B)
52-1641-26	32	0.100	MOV - DRYWELL CHEM WASTE ISOL (Q1P45F097-B)
52-1641-35	10	0.100	MOV - SUPPR POOL MAKE UP VALVE (Q1E30F001B-B)
52-1641-36	10	0.100	MOV - SUPPR POOL MAKE UP VALVE (Q1E30F002B-B)
52-1642-05	320	0.100	DRYWELL COOLER FAN COIL UNIT (N1M51B001B-B)
52-1642-06	320	0.100	DRYWELL COOLER FAN COIL UNIT (N1M51B002B-B)
52-1642-07	320	0.100	DRYWELL COOLER FAN COIL UNIT (N1M51B003B-B)
52-1642-08	320	0.100	DRYWELL COOLER FAN COIL UNIT (N1M51B004B-B)
52-1642-09	320	0.100	DRYWELL COOLER FAN COIL UNIT (N1M51B005B-B)

TABLE 3.8.4.1-1 (Continued)

PRIMARY CONTAINMENT PENETRATION CONDUCTOR OVERCURRENT PROTECTIVE DEVICES

c. 480 VAC Circuit Breakers (Continued)

Molded Case, Type NZM

BREAKER NUMBER	TRIP SETPOINT (Amperes)	RESPONSE TIME (Seconds)	SYSTEM/COMPONENT AFFECTED
52-1642-10	320	0.100	DRYWELL COOLER FAN COIL UNIT (N1M51B006B-B)
52-1642-14	12.5	0.100	MOV - DRYWELL COOLER INLET (N1P44F056-B)
52-1642-15	12.5	0.100	MOV - DRYWELL COOLER INLET (N1P44F058-B)
52-1642-16	12.5	0.100	MOV - DRYWELL COOLER INLET (N1P44F060-B)
52-1642-17	12.5	0.100	MOV - DRYWELL COOLER INLET (N1P44F062-B)
52-1642-18	12.5	0.100	MOV - DRYWELL COOLER INLET (N1P44F064-B)
52-1642-19	12.5	0.100	MOV - DRYWELL COOLER INLET (N1P44F066-B)
52-1642-21	24	0.100	DRWL PURGE COMP AUX OIL PUMP (Q1E61C001B-B)
52-1642-29	175	0.100	DRWL RECIRC FAN (N1M51C002B)

TABLE 3.8.4.1-1 (Continued)

PRIMARY CONTAINMENT PENETRATION CONDUCTOR

OVERCURRENT PROTECTIVE DEVICES

(c) 480 VAC CIRCUIT BREAKER
MOLDED CASE TYPE NZM

BREAKER NO.	INST. TRIP SET POINT (AMPERES)	RESPONSE TIME (SECONDS)	SYSTEM/COMPONENT AFFECTED
52-1642-14	12.5	0.100	MOV - DRYWELL COOLER INLET (N1P44F056-B)
52-1642-15	12.5	0.100	MOV - DRYWELL COOLER INLET (N1P44F058-B)
52-1642-16	12.5	0.100	MOV - DRYWELL COOLER INLET (N1P44F060-B)
52-1642-17	12.5	0.100	MOV - DRYWELL COOLER INLET (1P44F062-B)
52-1642-18	12.5	0.100	MOV - DRYWELL COOLER INLET (N1P44F064-B)
52-1642-19	12.5	0.100	MOV - DRYWELL COOLER INLET (N1P44F006-B)
52-1642-21	24	0.100	DRWL PURGE COMP AUX OIL PUMP Q1E61C001B-B)
52-1642-29	175	0.100	DRWL RECIRC FAN (N1M51C002B)

TABLE 3.8.4.1-1 (Continued)

PRIMARY CONTAINMENT PENETRATION CONDUCTOR

OVERCURRENT PROTECTIVE DEVICES

(d) 125V DC BREAKERS
GE-E-150 LINE TYPE THED

BREAKER NO.	TIME O.C. PICKUP (AMPERES)	RESPONSE TIME (SECONDS)	SYSTEM/COMPONENT AFFECTED
72-11A-23	30	5.0	AUTOMATIC DEPRESSURIZATION SYSTEM VALVES
72-11A-28	15	5.0	REMOTE SHUTDOWN PANEL/AUTOMATIC DEPRESSURIZATION SYSTEM VALVES
72-11A-30	15	5.0	REACTOR PROTECTION SYSTEM/BACKUP SCRAM VALVE
72-11A-33	15	5.0	CONTAINMENT & DRYWELL ISOLATION SYSTEM ANNUNCIATION
72-11A-38	15	5.0	RESIDUAL HEAT REMOVAL SYSTEM VALVES
72-11B-14	50	5.0	RESIDUAL HEAT REMOVAL SYSTEM
72-11B-28	15	5.0	REMOTE SHUTDOWN PANEL/ADS VALVES
72-11B-30	15	5.0	REACTOR PROTECTION SYSTEM/ BACKUP SCRAM VALVE

TABLE 3.8.4.1-1 (Continued)

PRIMARY CONTAINMENT PENETRATION CONDUCTOR

OVERCURRENT PROTECTIVE DEVICES

(d) 125V DC BREAKERS
GE-E-150 LINE TYPE THED

BREAKER NO.	TIME O.C. PICKUP (AMPERES)	RESPONSE TIME (SECONDS)	SYSTEM/COMPONENT AFFECTED
72-11B-34	30	5.0	AUTOMATIC DEPRESSURIZATION SYSTEM VALVES
72-11B-37	15	5.0	CONTAINMENT & DRYWELL ISOLATION SYSTEM
72-11D-39	15	5.0	CONTAINMENT PURGE ISOLATION VALVE F010
72-11D-71	15	5.0	CHARCOAL FILTER TRAIN N1M41D002A-N ALARMS
72-11D-72	15	5.0	FLOOR & EQUIPMENT DRAIN SYSTEM
72-11D-73	15	5.0	CONDENSATE AND REFUELING WATER STORAGE AND TRANSFER SYSTEM
72-11D-79	15	5.0	FILTER DEMIN CONT. VB G36-P002

TABLE 3.8.4.1-1 (Continued)

PRIMARY CONTAINMENT PENETRATION CONDUCTOR

OVERCURRENT PROTECTIVE DEVICES

(d) 125V DC BREAKERS
GE-E-150 LINE TYPE THED

BREAKER NO.	TIME O.C. PICKUP (AMPERES)	RESPONSE TIME (SECONDS)	SYSTEM/COMPONENT AFFECTED
72-11E-36	15	5.0	FIRE PROTECTION PANEL
72-11E-69	15	5.0	FLOOR & EQUIPMENT DRAIN SYSTEM
72-11E-73	15	5.0	CHARCOAL FILTER TRAIN N1M41D002B-N ALARM

TABLE 3.8.4.1-1 (Continued)

PRIMARY CONTAINMENT PENETRATION CONDUCTOR

OVERCURRENT PROTECTIVE DEVICES

(e) 208/120V AC CIRCUIT BREAKERS
GE TYPE TQB

BREAKER NO.	TIME O.C. PICKUP (AMPERES)	RESPONSE TIME (SECONDS)	SYSTEM/COMPONENT AFFECTED
52-1P112-12	40	4.0	RWCU REACTOR SAMPLE STATION (CONSTANT TEMP BATH)
52-1P112-13	35	4.0	RWCU SYSTEM FILTER DEMON CONT
52-1P112-14	15	4.0	CONT POWER SUPPLY NSSSS (1G33TSN008)
52-1P112-17	15	4.0	RWCU REACTOR SAMPLE STATION (INST POWER)
52-1P112-20	15	4.0	RWCU SYS DUSTER COLLECTOR TANK (N1G36D016)
52-1P112-22	15	4.0	RWCU SYS RESIN PUMP (N1G36C003-N)
52-1P112-23	15	4.0	AREA RAD MONIT SYSTEM CTMT BLDG. ALARMS
52-1P151-20	15	4.0	MOTOR SPACE HEATER FOR REACTOR RECIRC SYSTEM (N1B33D003A1-N)

TABLE 3.8.4.1-1 (Continued)

PRIMARY CONTAINMENT PENETRATION CONDUCTOR

OVERCURRENT PROTECTIVE DEVICES

(e) 208/120V AC CIRCUIT BREAKERS (Continued)
GE TYPE TQB

BREAKER NO.	TIME O.C. PICKUP (AMPERES)	RESPONSE TIME (SECONDS)	SYSTEM/COMPONENT AFFECTED
52-1P151-22	15	4.0	MOTOR SPACE HEATER FOR REACTOR RECIRC SYSTEM (N1B33D003A2-N)
52-1P151-23	15	4.0	CTMT CLG SYSTEM CHARCOAL FLTR TRAIN HEATER (N1M41D002A-N)
52-1P151-24	15	4.0	MOTOR SPACE HEATER FOR REACTOR RECIRC SYS (N1B33D003A3-N)
52-1P151-25	15	4.0	MAIN STEAM PIPING AREA DRWL COOLER SERVICE WATER CONT. TRANSMITTER (TT-N041)
52-1P151-26	15	4.0	MOTOR SPACE HEATER FOR REACTOR RECIRC SYSTEM (N1B33D003A4-N)
52-1P151-37	15*	4.0	DRWL PERSONNEL LOCK (120'-10" ELEV)
52-1P151-38	15*	4.0	CTMT PERSONNEL LOCK (LOWER)

TABLE 3.8.4.1-1 (Continued)

PRIMARY CONTAINMENT PENETRATION CONDUCTOR

OVERCURRENT PROTECTIVE DEVICES

(e) 208/120V AC CIRCUIT BREAKERS (Continued)
GE TYPE TQB

BREAKER NO.	TIME O.C. PICKUP (AMPERES)	RESPONSE TIME (SECONDS)	SYSTEM/COMPONENT AFFECTED
52-1P222-17	15	4.0	CTMT CLG SYSTEM CHARCOAL FLT TRAIN HTR (N1M41D002B-N)
52-1P222-24	15	4.0	CTMT & DRWL PERSONNEL AIR LOCK MONITORING SYSTEM IN CONT ROOM
52-1P222-27	15	4.0	DRWL COOLERS SERVICE WATER CONT TRANSMITTER (TT - N044)
52-1P251-13	15	4.0	PUMP VALVE SOLENOID CONT CKT & TEMPERATURE FOR REACTOR WATER CLEAN UP SYS
52-1P251-37	15	4.0	CONTAINMENT EQUIP HATCH (Q1M23Y007-1)
52-1P251-38	15*	4.0	CONTAINMENT EQUIP HATCH (Q1M23Y007-2)

TABLE 3.8.4.1-1 (Continued)

PRIMARY CONTAINMENT PENETRATION CONDUCTOR

OVERCURRENT PROTECTIVE DEVICES

(e) 208/120V AC CIRCUIT BREAKERS (Continued)
GE TYPE TQB

BREAKER NO.	TIME O.C. PICKUP (AMPERES)	RESPONSE TIME (SECONDS)	SYSTEM/COMPONENT AFFECTED
52-1P411-19	15	4.0	PLANT SERVICE WATER SYS CONTROL VALVE INDICATION (1P44ZLR001)
52-1P412-22	15	4.0	MOTOR SPACE HEATER FOR REACTOR RECIRC SYS (N1B33D003B1-N)
52-1P412-23	20	4.0	UTILITY POWER FOR REMOTE SIGNAL CONDITIONING PANEL
52-1P412-24	15	4.0	MOTOR SPACE HEATER FOR REACTOR RECIRC SYS (N1B33D003B2-N)
52-1P412-25	20	4.0	UTILITY POWER FOR REMOTE SIGNAL CONDITIONING PANEL
52-1P412-26	15	4.0	MOTOR SPACE HEATER FOR REACTOR RECIRC SYS (N1B33D003B3-N)

TABLE 3.8.4.1-1 (Continued)

PRIMARY CONTAINMENT PENETRATION CONDUCTOR

OVERCURRENT PROTECTIVE DEVICES

(e) 208/120V AC CIRCUIT BREAKERS (Continued)
GE TYPE TQB

BREAKER NO.	TIME O.C. PICKUP (AMPERES)	RESPONSE TIME (SECONDS)	SYSTEM/COMPONENT AFFECTED
52-1P412-28	16	4.0	MOTOR SPACE HEATER FOR REACTOR RECIRC SYS (N1B33D003B4-N)
52-1P511-10	15	4.0	MOTOR SPACE HEATER FOR DRYWL PURGE COMPRESSOR (Q1E61C001A-A)
52-1P511-21	15	4.0	MOTOR SPACE HEATER FOR SLCS (Q1C41C001A-A)
52-1P531-19	30	4.0	HYDROGEN IGNITOR CONTROL
52-1P531-21	30	4.0	HYDROGEN IGNITOR CONTROL
52-1P621-25	15	4.0	MOTOR SPACE HEATER FOR DRWL PURGE COMPRESSOR (Q1E61C001B-B)
52-1P631-15	30	4.0	HYDROGEN IGNITOR CONTROL
52-1P631-17	30	4.0	HYDROGEN IGNITOR CONTROL

TABLE 3.8.4.1-1 (Continued)

PRIMARY CONTAINMENT PENETRATION CONDUCTOR

OVERCURRENT PROTECTIVE DEVICES

(e) 208/120V AC CIRCUIT BREAKERS (Continued)
GE TYPE TQB/TQL

BREAKER NO.	TIME O.C. PICKUP (AMPERES)	RESPONSE TIME (SECONDS)	SYSTEM/COMPONENT AFFECTED
52-1P631-21	15	4.0	MOTOR SPACE HEATER FOR SLCS (Q1C41C001B-B)
52-1DP641-07**	15	4.0	CTMT CLG SMOKE DETECTOR POWER SUPPLY

* 3 Pole Breaker
** GE Type TQL

ELECTRICAL POWER SYSTEMS

MOTOR OPERATED VALVES THERMAL OVERLOAD PROTECTION

1. At least once per 92 days for the individual valve bypass circuitry.
2. At least once per 18 months for the ECCS portion of the channel.

LIMITING CONDITION FOR OPERATION

3.8.4.2 The thermal overload protection of each valve shown in Table 3.8.4.2-1 shall be OPERABLE or shall be bypassed either continuously or only under accident conditions, as indicated, by an OPERABLE bypass device.

APPLICABILITY: Whenever the motor operated valve is required to be OPERABLE.

ACTION:

With the thermal overload protection for one or more of the above required valves not OPERABLE or not bypassed either continuously or only under accident conditions, as indicated in Table 3.8.4.2-1, ~~take administrative action to~~ bypass the thermal overload within 8 hours or declare the affected valve(s) inoperable and apply the appropriate ACTION statement(s) for the affected system(s). 1061

SURVEILLANCE REQUIREMENTS

4.8.4.2.1 The thermal overload protection which is bypassed either continuously or only under accident conditions for the above required valves shall be verified to be bypassed continuously or only under accident conditions, as applicable, by an OPERABLE bypass device (1) by the performance of a CHANNEL FUNCTIONAL TEST of the bypass circuitry for those thermal overloads which are normally in force during plant operation and bypassed under accident conditions and (2) by verifying that the thermal overload protection is bypassed for those thermal overloads which are continuously bypassed and temporarily placed in force only when the valve motors are undergoing periodic or maintenance testing:

a. ~~At least once per 92 days~~ For those thermal overloads which are normally in force during plant operation and bypassed under accident conditions.

b. At least once per 18 months for those thermal overloads which are continuously bypassed and temporarily placed in force only when the valve motors are undergoing periodic or maintenance testing. 1137

c. Following maintenance on the motor starter.

4.8.4.2.2 The thermal overload protection which is not bypassed for the above required valves shall be demonstrated OPERABLE at least once per 18 months by the performance of a CHANNEL CALIBRATION of a representative sample of at least 25% of all thermal overloads for the above required valves.

4.8.4.2.3 The thermal overload protection for the above required valves which is continuously bypassed and temporarily placed in force only when the valve motor is undergoing periodic or maintenance testing shall be verified to be bypassed following periodic or maintenance testing during which the thermal overload protection was temporarily placed in force.

TABLE 3.8.4.2-1

MOTOR OPERATED VALVES THERMAL OVERLOAD PROTECTION

VALVE NUMBER	BYPASS DEVICE (CONTINUOUS) (ACCIDENT CONDITIONS) (NO)	SYSTEM(S) AFFECTED	
Q1E51F010~~A~~e	Continuous	RCIC System	
Q1E51F013~~A~~e	Continuous	RCIC System	
Q1E51F019~~A~~e	Continuous	RCIC System	
Q1E51F022~~A~~e	Continuous	RCIC System	
Q1E51F031~~A~~e	Continuous	RCIC System	228
Q1E51F045~~A~~e	Continuous	RCIC System	
Q1E51F046~~A~~e	Continuous	RCIC System	
Q1E51F059~~A~~e	Continuous	RCIC System	
Q1E51F068~~A~~e	Continuous	RCIC System	
RCIC Trip and Throttle → Valve on Turbine Q1E51C002	Continuous	RCIC System	1179
Q1B21F065A~~A~~e	No	Reactor Coolant System	
Q1B21F065B~~A~~e	No	Reactor Coolant System	
Q1B21F098A~~B~~e	No	Reactor Coolant System	
Q1B21F098B~~B~~e	No	Reactor Coolant System	228
Q1B21F098C~~B~~e	No	Reactor Coolant System	
Q1B21F098D~~B~~e	No	Reactor Coolant System	
Q1B21F019	Continuous	Reactor Coolant System	
Q1B21F067A	Continuous	Reactor Coolant System	
Q1B21F067B	Continuous	Reactor Coolant System	
Q1B21F067C	Continuous	Reactor Coolant System	
Q1B21F067D	Continuous	Reactor Coolant System	
Q1B21F016	Continuous	Reactor Coolant System	
Q1B21F147A	Continuous	MSL Drain Post LOCA Leakage Control	
Q1B21F147B	Continuous	MSL Drain Post LOCA Leakage Control	
Q1B33F019	Continuous	Recirculation System	
Q1B33F020	Continuous	Recirculation System	
Q1B33F125	Continuous	Recirculation System	
Q1B33F126	Continuous	Recirculation System	
Q1B33F127	Continuous	Recirculation System	
Q1B33F128	Continuous	Recirculation System	
Q1D23F591~~B~~e	*	Drywell Monitoring System	
Q1D23F592~~A~~e	*	Drywell Monitoring System	
Q1D23F593~~B~~e	*	Drywell Monitoring System	228
Q1D23F594~~A~~e	*	Drywell Monitoring System	
Q1E12F040	Continuous	RHR System	
Q1E12F023	Continuous	RHR System	
Q1E12F006A	Continuous	RHR System	
Q1E12F052A	Continuous	RHR System	
Q1E12F008	Continuous	RHR System	

TABLE 3.8.4.2-1 (Continued)

MOTOR OPERATED VALVES THERMAL OVERLOAD PROTECTION

VALVE NUMBER	BYPASS DEVICE (CONTINUOUS) (ACCIDENT CONDITIONS) (NO)	SYSTEM(S) AFFECTED
Q1E12F074A	Continuous	RHR System
Q1E12F026A	Continuous	RHR System
Q1E12F082A	No	RHR System
Q1E12F082B	No	RHR System
Q1E12E290A	Continuous	RHR System
Q1E12F047A	Continuous	RHR System
Q1E12F027A	Continuous	RHR System
Q1E12F073A	Continuous	RHR System
Q1E12F346	Continuous	RHR System
Q1E12F024A	Continuous	RHR System
Q1E12F087A	Continuous	RHR System
Q1E12F048A	Continuous	RHR System
Q1E12F042A	Continuous	RHR System
Q1E12F004A	Continuous	RHR System
Q1E12F003A	Continuous	RHR System
Q1E12F011A	Continuous	RHR System
Q1E12F053A	Continuous	RHR System
Q1E12F037A	Continuous	RHR System
Q1E12F028A	Continuous	RHR System
Q1E12F064A	Continuous	RHR System
Q1E12F290B	Continuous	RHR System
Q1E12F004C	Continuous	RHR System
Q1E12F021	Continuous	RHR System
Q1E12F064C	Continuous	RHR System
Q1E12F042C	Continuous	RHR System
Q1E12F048B	Continuous	RHR System
Q1E12F049	Continuous	RHR System
Q1E12F037B	Continuous	RHR System
Q1E12F053B	Continuous	RHR System
Q1E12F074B	Continuous	RHR System
Q1E12F042B	Continuous	RHR System
Q1E12F064B	Continuous	RHR System
Q1E12F096	Continuous	RHR System
Q1E12F094	Continuous	RHR System
Q1E12F006B	Continuous	RHR System
Q1E12F011B	Continuous	RHR System
Q1E12F052B	Continuous	RHR System
Q1E12F047B	Continuous	RHR System
Q1E12F027B	Continuous	RHR System
Q1E12F004B	Continuous	RHR System
Q1E12F087B	Continuous	RHR System
Q1E12F003B	Continuous	RHR System
Q1E12F026B	Continuous	RHR System
Q1E12F024B	Continuous	RHR System
Q1E12F028B	Continuous	RHR System
Q1E12F009	Continuous	RHR System
Q1E12F073B	Continuous	RHR System

TABLE 3.8.4.2-1 (Continued)

MOTOR OPERATED VALVES THERMAL OVERLOAD PROTECTION

VALVE NUMBER	BYPASS DEVICE (CONTINUOUS) (ACCIDENT CONDITIONS) (NO)	SYSTEM(S) AFFECTED
Q1C11F083	No	CRD Hydraulic System
Q1C11F322	Continuous	CRD Hydraulic System
Q1C41F001A	Continuous	Standby Liquid Control
Q1C41F001B	Continuous	Standby Liquid Control
Q1E21F001	Continuous	LPCS System
Q1E21F011	Continuous	LPCS System
Q1E21F012	Continuous	LPCS System
Q1E21F005	Continuous	LPCS System
Q1E30F002A	Continuous	Suppression Pool Makeup System
Q1E30F591A	*	Suppression Pool Makeup System
Q1E30F592A	*	Suppression Pool Makeup System
Q1E30F593A	*	Suppression Pool Makeup System
Q1E30F594A	*	Suppression Pool Makeup System
Q1E30F001A	Continuous	Suppression Pool Makeup System
Q1E30F001B	Continuous	Suppression Pool Makeup System
Q1E30F002B	Continuous	Suppression Pool Makeup System
Q1E30F591B	*	Suppression Pool Makeup System
Q1E30F592B	*	Suppression Pool Makeup System
Q1E30F593B	*	Suppression Pool Makeup System
Q1E30F594B	*	Suppression Pool Makeup System
Q1E31F100A	Continuous	Fuel Pool Cooling and Cleanup System
Q1E31F100B	Continuous	Fuel Pool Cooling and Cleanup System
Q1E32F001A	Continuous	MSIV - LCS
Q1E32F001E	Continuous	MSIV - LCS
Q1E32F003A	Continuous	MSIV - LCS
Q1E32F003E	Continuous	MSIV - LCS
Q1E32F003J	Continuous	MSIV - LCS
Q1E32F003N	Continuous	MSIV - LCS
Q1E32F001J	Continuous	MSIV - LCS
Q1E32F001N	Continuous	MSIV - LCS
Q1E32F002A	Continuous	MSIV - LCS
Q1E32F002E	Continuous	MSIV - LCS
Q1E32F002J	Continuous	MSIV - LCS
Q1E32F002N	Continuous	MSIV - LCS
Q1E32F006	Continuous	MSIV - LCS
Q1E32F007	Continuous	MSIV - LCS
Q1E32F008	Continuous	MSIV - LCS
Q1E32F009	Continuous	MSIV - LCS
Q1E38F001A	Continuous	Feedwater LCS
Q1E38F001B	Continuous	Feedwater LCS

TABLE 3.8.4.2-1 (Continued)

MOTOR OPERATED VALVES THERMAL OVERLOAD PROTECTION

VALVE NUMBER	BYPASS DEVICE (CONTINUOUS) (ACCIDENT CONDITIONS) (NO)	SYSTEM(S) AFFECTED
Q1E51F064	Continuous	RCIC System
Q1E51F063	Continuous	RCIC System
Q1E51F076	Continuous	RCIC System
Q1E51F077	Continuous	RCIC System
Q1E51F078	Continuous	RCIC System
Q1E22F001	Continuous	HPCS System
Q1E22F004	Continuous	HPCS System
Q1E22F010	Continuous	HPCS System
Q1E22F011	Continuous	HPCS System
Q1E22F012	Continuous	HPCS System
Q1E22F015	Continuous	HPCS System
Q1E22F023	Continuous	HPCS System
Q1E61F595A	*	Combustible Gas Control System
Q1E61F596A	*	Combustible Gas Control System
Q1E61F597A	*	Combustible Gas Control System
Q1E61F598A	*	Combustible Gas Control System
Q1E61F595C	*	Combustible Gas Control System
Q1E61F596C	*	Combustible Gas Control System
Q1E61F597C	*	Combustible Gas Control System
Q1E61F598C	*	Combustible Gas Control System
Q1E61F595B	*	Combustible Gas Control System
Q1E61F596B	*	Combustible Gas Control System
Q1E61F597B	*	Combustible Gas Control System
Q1E61F598B	*	Combustible Gas Control System
Q1E61F595D	*	Combustible Gas Control System
Q1E61F596D	*	Combustible Gas Control System
Q1E61F597D	*	Combustible Gas Control System
Q1E61F598D	*	Combustible Gas Control System
Q1E61F003A	Continuous	Combustible Gas Control System
Q1E61F005A	Continuous	Combustible Gas Control System
Q1E61F003B	Continuous	Combustible Gas Control System
Q1E61F005B	Continuous	Combustible Gas Control System
Q1G33F251	Continuous	RWCU System
Q1G33F253	Continuous	RWCU System
Q1G33F004	Continuous	RWCU System
Q1G33F039	Continuous	RWCU System
Q1G33F034	Continuous	RWCU System
Q1G33F054	Continuous	RWCU System
Q1G33F028	Continuous	RWCU System
Q1G33F053	Continuous	RWCU System
Q1G33F040	Continuous	RWCU System
Q1G33F001	Continuous	RWCU System
Q1G33F250	Continuous	RWCU System
Q1G33F252	Continuous	RWCU System

TABLE 3.8.4.2-1 (Continued)

MOTOR OPERATED VALVES THERMAL OVERLOAD PROTECTION

VALVE NUMBER	BYPASS DEVICE (CONTINUOUS) (ACCIDENT CONDITIONS) (NO)	SYSTEM(S) AFFECTED
Q1G41F028	Continuous	Spent Fuel Pool Cooling and Cleanup System
Q1G41F029	Continuous	Spent Fuel Pool Cooling and Cleanup System
Q1G41F044	Continuous	Spent Fuel Pool Cooling and Cleanup System
Q1G41F021	No	Spent Fuel Pool Cooling and Cleanup System
Q1G41F043	No	Spent Fuel Pool Cooling and Cleanup System
Q1M71F591A	*	Containment/Drywell I&C
Q1M71F593A	*	Containment/Drywell I&C
Q1M71F592B	*	Containment/Drywell I&C
Q1M71F595	*	Containment/Drywell I&C
Q1M71F591B	*	Containment/Drywell I&C
Q1M71F592A	*	Containment/Drywell I&C
Q1M71F594	*	Containment/Drywell I&C
Q1P21F017	Continuous	Makeup Water Treatment System
Q1P21F018	Continuous	Makeup Water Treatment System
Q1P41F237	Continuous	SSW System
Q1P41F018A	Continuous	SSW System
Q1P41F241	Continuous	SSW System
Q1P41F238	Continuous	SSW System
QSP41F081A	Continuous	SSW System
QSP41F064A	Continuous	SSW System
Q1P41F068A	Continuous	SSW System
Q1P41F014A	Continuous	SSW System
Q1P41F159A	Continuous	SSW System
Q1P41F160A	Continuous	SSW System
Q1P41F113	Continuous	SSW System
Q1P41F168A	Continuous	SSW System
Q1P41F001A	Continuous	SSW System
Q1P41F016A	Continuous	SSW System
Q1P41F015A	Continuous	SSW System
Q1P41F006A	Continuous	SSW System
Q1P41F005A	Continuous	SSW System
Q1P41F007A	Continuous	SSW System
QSP41F074A	Continuous	SSW System
QSP41F066A	Continuous	SSW System
QSP41F125	Continuous	SSW System
Q1P41F018B	Continuous	SSW System
Q1P41F160B	Continuous	SSW System
Q1P41F159B	Continuous	SSW System
Q1P41F168B	Continuous	SSW System
QSP41F154	Accident Conditions	SSW System

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TABLE 3.8.4.2-1 (Continued)

MOTOR OPERATED VALVES THERMAL OVERLOAD PROTECTION

VALVE NUMBER	BYPASS DEVICE (CONTINUOUS) (ACCIDENT CONDITIONS) (NO)	SYSTEM(S) AFFECTED
QSP41F155A	Accident Conditions	SSW System
Q1P41F068B	Continuous	SSW System
QSP41F155B	Accident Conditions	SSW System
Q1P41F014B	Continuous	SSW System
QSP41F064B	Continuous	SSW System
QSP41F081B	Continuous	SSW System
Q1P41F006B	Continuous	SSW System
Q1P41F007B	Continuous	SSW System
Q1P41F001B	Continuous	SSW System
Q1P41F016B	Continuous	SSW System
Q1P41F005B	Continuous	SSW System
Q1P41F015B	Continuous	SSW System
QSP41F066B	Continuous	SSW System
QSP41F074B	Continuous	SSW System
QSP41F189	Continuous	SSW System
Q1P41F011	Continuous	SSW System
Q1P41F119A	No	SSW System
Q1P41F119B	No	SSW System
Q1P41F121A	No	SSW System
Q1P41F121B	No	SSW System
Q1P41F122A	No	SSW System
Q1P41F122B	No	SSW System
QSZ51F007	Continuous	Control Room HVAC
QSZ51F008	Continuous	Control Room HVAC
QSZ51F014	Continuous	Control Room HVAC
QSZ51F016	Continuous	Control Room HVAC
Q1P42F067	Continuous	CCW System
Q1P42F116	Continuous	CCW System
Q1P42F028A	Continuous	CCW System
Q1P42F032A	Continuous	CCW System
Q1P42F201A	Continuous	CCW System
Q1P42F204	Continuous	CCW System
Q1P42F205	Continuous	CCW System
Q1P42F105	Continuous	CCW System
Q1P42F200A	Continuous	CCW System
Q1P42F203	Continuous	CCW System
Q1P42F117	Continuous	CCW System
Q1P42F114	Continuous	CCW System
Q1P42F068	Continuous	CCW System
Q1P42F200B	Continuous	CCW System
Q1P42F028B	Continuous	CCW System
Q1P42F201B	Continuous	CCW System
Q1P42F032B	Continuous	CCW System
Q1P42F066	Continuous	CCW System

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*Manual bypass of thermal overload protection of manually controlled valve.

TABLE 3.8.4.2-1 (Continued)

MOTOR OPERATED VALVES THERMAL OVERLOAD PROTECTION

VALVE NUMBER	BYPASS DEVICE (CONTINUOUS) (ACCIDENT CONDITIONS) (MO)	SYSTEM(S) AFFECTED
Q1P44F053	Continuous	Plant SW System
Q1P44F069	Continuous	Plant SW System
Q1P44F076	Continuous	Plant SW System
Q1P44F070	Continuous	Plant SW System
Q1P44F074	Continuous	Plant SW System
Q1P44F077	Continuous	Plant SW System
Q1P44F042	Continuous	Plant SW System
Q1P44F054	Continuous	Plant SW System
Q1P44F067	Continuous	Plant SW System
Q1P45F096	Continuous	Floor & Eqmt. Drain System
Q1P45F097	Continuous	Floor & Eqmt. Drain System
Q1P52F195	Continuous	Service Air System
Q1P53F003	Continuous	Instrument Air System
Q1P53F007	Continuous	Instrument Air System
Q1T48F005	Continuous	SGTS
Q1T48F006	Continuous	SGTS
Q1T48F024	Continuous	SGTS
Q1T48F026	Continuous	SGTS
Q1T48F023	Continuous	SGTS
Q1T48F025	Continuous	SGTS
Q1P45F273	Continuous	Floor & Eqmt. Drain System
Q1P45F274	Continuous	Floor & Eqmt. Drain System

REACTOR PROTECTION SYSTEM ELECTRIC POWER MONITORING

LIMITING CONDITION FOR OPERATION

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

APPLICABILITY: At all times.

ACTION:

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

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

SURVEILLANCE REQUIREMENTS

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

a. ~~At least once per six months by performance of a CHANNEL FUNCTIONAL TEST, and~~ By performance of a CHANNEL FUNCTIONAL TEST each time the plant is in COLD SHUTDOWN for a period of more than 24 hours, unless performed in the previous 6 months. /181

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

1. Over-voltage ~~≤ 132 VAC,~~
2. Under-voltage ~~≥ 117 VAC, and~~
3. Under-frequency ~~≥ 57 Hz.~~

1.	Bus A	≤ 132.9 VAC
	Bus B	≤ 133.0 VAC
2.	Bus A	≥ 115.0 VAC
	Bus B	≥ 115.9 VAC
3.	Bus A	≥ 57 Hz
	Bus B	≥ 57 Hz

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3/4.9 REFUELING OPERATIONS

3/4.9.1 REACTOR MODE SWITCH

LIMITING CONDITION FOR OPERATION

3.9.1 The reactor mode switch shall be OPERABLE and locked in the Shutdown or Refuel position. When the reactor mode switch is locked in the Refuel position:

a. A control rod shall not be withdrawn unless the Refuel position one-rod-out interlock is OPERABLE.

b. CORE ALTERATIONS shall not be performed using equipment associated with a Refuel position interlock unless at least the following associated Refuel position interlocks are OPERABLE for such equipment.

   1. ~~All rods in~~. One-rod-out. / 182
   2. Refuel platform position.
   3. Refuel platform main hoist fuel-loaded.

APPLICABILITY: OPERATIONAL CONDITION 5* #.

ACTION:

a. With the reactor mode switch not locked in the Shutdown or Refuel position as specified, suspend CORE ALTERATIONS and lock the reactor mode switch in the Shutdown or Refuel position.

b. With the one-rod-out interlock inoperable, lock the reactor mode switch in the Shutdown position.

c. With any of the above required Refuel position equipment interlocks inoperable, suspend CORE ALTERATIONS with equipment associated with the inoperable Refuel position equipment interlock.

---

* See Special Test Exceptions 3.10.1 and 3.10.3.##

\# The reactor shall be maintained in OPERATIONAL CONDITION 5 whenever fuel is in the reactor vessel with the vessel head closure bolts less than fully tensioned or with the head removed.

\## The reactor mode switch may be placed in the Run or Startup/Hot Standby position to test the switch interlock functions provided that all control rods are verified to remain fully inserted by a second licensed operator or other technically qualified member of the unit technical staff.

SURVEILLANCE REQUIREMENTS

4.9.1.1 The reactor mode switch shall be verified to be locked in the Shutdown or Refuel position as specified:

a. Within 2 hours prior to:

  1. Beginning CORE ALTERATIONS, and

  2. Resuming CORE ALTERATIONS when the reactor mode switch has been unlocked.

b. At least once per 12 hours.

4.9.1.2 Each of the above required reactor mode switch Refuel position interlocks shall be demonstrated OPERABLE by performance of a CHANNEL FUNCTIONAL TEST within 24 hours prior to the start of and at least once per 7 days during control rod withdrawal or CORE ALTERATIONS, as applicable.

4.9.1.3 Each of the above required reactor mode switch Refuel position interlocks that is affected shall be demonstrated OPERABLE by performance of a CHANNEL FUNCTIONAL TEST prior to resuming control rod withdrawal or CORE ALTERATIONS, as applicable, following repair, maintenance or replacement of any component that could affect the Refuel position interlock.

Unless adequate shutdown margin has been demonstrated, the shorting links shall be removed from the RPS circuitry prior to and during the time any control rod is withdrawn.#

REFUELING OPERATIONS

3/4.9.2 INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

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

a. Continuous visual indication in the control room,

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

c. ~~Prior to and during the time any control rod is withdrawn# and shutdown margin demonstrations are in progress, either:~~

323 ~~1. The "shorting links" removed from the RPS circuitry, or~~

~~2. The rod pattern control system OPERABLE per Specification 3.1.4.2~~

APPLICABILITY: OPERATIONAL CONDITION 5.

ACTION:

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

SURVEILLANCE REQUIREMENTS

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

a. At least once per 12 hours:

1. Performance of a CHANNEL CHECK,
2. Verifying the detectors are inserted to the normal operating level, and
3. During CORE ALTERATIONS, verifying that the detector of an OPERABLE SRM channel is located in the core quadrant where CORE ALTERATIONS are being performed and another is located in an adjacent quadrant.

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

**Except movement of IRM, SRM or special movable detectors.

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

b. Performance of a CHANNEL FUNCTIONAL TEST:

   1. Within 24 hours prior to the start of CORE ALTERATIONS, and

   2. At least once per 7 days.

c. Verifying that the channel count rate is at least ~~3~~ 0.7 cps: /251

   1. Prior to control rod withdrawal,

   2. Prior to and at least once per 12 hours during CORE ALTERATIONS, and

   3. At least once per 24 hours,

   except that:

   1. During spiral unloading, the required count rate may be permitted to be less than ~~3~~ 0.7 cps. /251

   2. Prior to and during spiral loading, until sufficient fuel has been loaded to maintain at least ~~3~~ 0.7 cps, the required count rate may be achieved by: /251

      a) Use of portable external source, or

      b) Loading up to 2 fuel assemblies[###] in cells containing inserted control rods around an SRM.

d. Verifying that the RPS circuitry "shorting links" have been removed ~~or that the rod pattern control system is OPERABLE~~ within 8 hours prior to and at least once per 12 hours during: /323

   1. The time any control rod is withdrawn,[##] or

   2. Shutdown margin demonstrations.

[##] Not required for control rods removed per Specification 3.9.10.1 or 3.9.10.2.

[###] These fuel assemblies may be loaded with the SRM count-rate less than ~~3~~ 0.7 cps. /251

REFUELING OPERATIONS

3/4.9.3 CONTROL ROD POSITION

LIMITING CONDITION FOR OPERATION

3.9.3 All control rods shall be inserted.*

APPLICABILITY: OPERATIONAL CONDITION 5, during CORE ALTERATIONS.**

ACTION:

With all control rods not inserted, suspend all other CORE ALTERATIONS. ~~except that one control rod may be withdrawn under control of the reactor mode switch Refuel position one-rod-out interlock.~~ 280

SURVEILLANCE REQUIREMENTS

4.9.3 All control rods shall be verified to be inserted, except as above specified:

a. Within 2 hours prior to:

1. The start of CORE ALTERATIONS.
2. The withdrawal of one control rod under the control of the reactor mode switch Refuel position one-rod-out interlock.

b. At least once per 12 hours.

---

* Except control rods removed per Specification 3.9.10.1 or 3.9.10.2 or one control rod withdrawn under control of the reactor mode switch Refuel position one-rod-out interlock.

**See Special Test Exception 3.10.3.

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3/4.9.4 DECAY TIME

LIMITING CONDITION FOR OPERATION

3.9.4 The reactor shall be subcritical for at least 24 hours.

APPLICABILITY: OPERATIONAL CONDITION 5, during movement of irradiated fuel in the reactor pressure vessel.

ACTION:

With the reactor subcritical for less than 24 hours, suspend all operations involving movement of irradiated fuel in the reactor pressure vessel.

SURVEILLANCE REQUIREMENTS

4.9.4 The reactor shall be determined to have been subcritical for at least 24 hours by verification of the date and time of subcriticality prior to movement of irradiated fuel in the reactor pressure vessel.

3/4.9.5 COMMUNICATIONS

LIMITING CONDITION FOR OPERATION

3.9.5 Direct communication shall be maintained between the control room and refueling platform personnel.

APPLICABILITY: OPERATIONAL CONDITION 5, during CORE ALTERATIONS.*

ACTION:

When direct communication between the control room and refueling platform personnel cannot be maintained, immediately suspend CORE ALTERATIONS.*

SURVEILLANCE REQUIREMENTS

4.9.5 Direct communication between the control room and refueling platform personnel shall be demonstrated within one hour prior to the start of and at least once per 12 hours during CORE ALTERATIONS.*

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*Except movement of incore instrumentation and control rods with their normal drive system.

3/4.9.6 REFUELING PLATFORM

LIMITING CONDITION FOR OPERATION

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

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

ACTION:

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

SURVEILLANCE REQUIREMENTS

4.9.6 Each refueling platform crane or hoist used for handling of control rods or fuel assemblies within the reactor pressure vessel shall be demonstrated OPERABLE within 7 days prior to the start of such operations with that crane or hoist by:

a. Demonstrating operation of the overload cutoff on the main hoist when the load exceeds 1200 ± 50 pounds.

b. Demonstrating operation of the overload cutoff on the frame mounted and monorail hoists when the load exceeds 500 ± 50 pounds.

c. Demonstrating operation of the uptravel mechanical stop on the frame mounted and monorail hoists when uptravel brings the top of a fuel assembly to 8 feet below the normal fuel storage pool water level.

d. Demonstrating operation of the downtravel mechanical cutoff on the main hoist when grapple hook down travel reaches 4 inches below fuel assembly handle.

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

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

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

Delete

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P/S: 035 Markup, Previously Submitted

REFUELING OPERATIONS

3/4.9.6 REFUELING EQUIPMENT

REFUELING PLATFORM

LIMITING CONDITION FOR OPERATION

3.9.6.1 The refueling platform shall be OPERABLE and only the main hoist shall be used for handling fuel assemblies.

APPLICABILITY: During handling of fuel assemblies or control rods in the primary containment with the refueling platform.

ACTION:

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

SURVEILLANCE REQUIREMENTS

4.9.6.1 Each refueling platform hoist to be used for handling fuel assemblies or control rods shall be demonstrated OPERABLE within 7 days prior to the handling of fuel assemblies or control rods:

a. In the containment fuel pool, reactor cavity or reactor pressure vessel by:

   1. Demonstrating operation of the slack cable cutoff on the main hoist when the total cable load is 50± 10 pounds.

   2. Demonstrating operation of the grapple engaged loaded interlock on the main hoist before the total cable load exceeds 535 pounds.

   035

   3. Demonstrating operation of the jam cutoff on the main hoist before the total cable load exceeds 1250 pounds.

   4. Demonstrating operation of the primary and redundant overload cutoff on the auxiliary hoists before the load exceeds 550 pounds.

b. In or over the reactor pressure vessel by:

   1. Demonstrating operation of the downtravel cutoff on the main hoist when the bottom of the grapple is 3.5 ± 0.5 inches below the top of the fuel assembly handles in the reactor core.

   2. Demonstrating operation of the primary and redundant fuel load interlocks on the main hoist before the total cable load exceeds 600 pounds.

~~A/S: 035~~ MARK, PREVIOUSLY SUBMITTED

REFUELING OPERATIONS

3/4.9.6 REFUELING EQUIPMENT

AUXILIARY PLATFORM

LIMITING CONDITION FOR OPERATION

9.6
3.~~6.9~~.2 The auxiliary platform shall be OPERABLE.

APPLICABILITY: During handling of control rods with the auxiliary platform.

ACTION:

With the requirements for auxiliary platform OPERABILITY not satisfied, suspend use of the auxiliary platform after placing the load in a safe condition.

SURVEILLANCE REQUIREMENTS

4.9.6.2 The auxiliary platform hoist shall be demonstrated OPERABLE within 7 days prior to the handling of control rods by: ~~demonstrating operation of the overload cutoff before the load exceeds 550 pounds~~. Stet

~~a. Demonstrating operation of the overload cutoff before the load exceeds 550 pounds.~~

~~b. Demonstrating operation of the auxiliary platform hoist uptravel stops when the grapple is lower than or equal to 8 feet below the platform rails.~~

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GRAND GULF - UNIT 1
~~F36(3651)~~

P/S: 035 MARKUP, PREVIOUSLY SUBMITTED

REFUELING OPERATIONS

3/4.9.6 REFUELING EQUIPMENT

FUEL HANDLING PLATFORM

LIMITING CONDITION FOR OPERATION

3.9.6.3 The fuel handling platform shall be OPERABLE and only the main hoist shall be used to move irradiated fuel.

APPLICABILITY: During handling of fuel assemblies or control rods in the auxiliary building with the fuel handling platform.

ACTION:

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

SURVEILLANCE REQUIREMENTS

4.9.6.3.1 Each fuel handling platform hoist to be used for handling fuel assemblies or control rods shall be demonstrated OPERABLE within 7 days prior to the handling of fuel assemblies or control rods by:

a. Demonstrating operation on the slack cable cutoff on the main hoist when the total cable load is 50±10 pounds.

b. Demonstrating operation of the grapple engaged loaded interlock on the main hoist before the total cable load exceeds 400 pounds.

c. Demonstrating operation of the jam cutoff on the main hoist before the total cable load exceeds 1150 pounds. 35

d. Demonstrating operation of the primary and redundant overload cutoff on the auxiliary hoist before the load exceeds 550 pounds with the load override switch at the 500 pound position.

e. Demonstrating operation of the primary and redundant overload cutoff on the auxiliary hoist before the load exceeds 1050 pounds with the load override switch at the 1000 pound position.

4.9.6.3.2 The auxiliary hoist load override switch shall be verified to be in the 500 pound position within 2 hours and at least once per 12 hours during hoist operation, except when engaged in new fuel movement in which case the switch may be in the 1000 pound position.

~~DEMONSTRATING OPERATION OF THE MAIN HOIST UP-TRAVEL STOPS WHEN THE GRAPPLE IS LOWER THAN OR EQUAL TO 8 FEET BELOW THE PLATFORM RAILS.~~

3/4.9.7 CRANE TRAVEL-SPENT FUEL AND UPPER CONTAINMENT FUEL STORAGE POOLS

LIMITING CONDITION FOR OPERATION

3.9.7 Loads in excess of 1140 pounds shall be prohibited from travel over fuel assemblies in the spent fuel or upper containment fuel storage pool racks.

APPLICABILITY: With fuel assemblies in the spent fuel or upper containment fuel storage pool racks.

ACTION:

With the requirements of the above specification not satisfied, place the crane load in a safe condition. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.9.7 Loads, other than fuel assemblies or control rods, shall be verified to weigh less than or equal to 1140 pounds before travel over fuel assemblies in the spent fuel and upper containment fuel storage pools racks.

3/4.9.8 WATER LEVEL - REACTOR VESSEL

LIMITING CONDITION FOR OPERATION

3.9.8 At least ~~23 feet~~ 22 feet 8 inches of water shall be maintained over the top of the reactor pressure vessel flange. 275

APPLICABILITY: During handling of fuel assemblies or control rods within the reactor pressure vessel while in OPERATIONAL CONDITION 5 when the fuel assemblies being handled are irradiated or the fuel assemblies seated within the reactor vessel are irradiated.

ACTION:

With the requirements of the above specification not satisfied, suspend all operations involving handling of fuel assemblies or control rods within the reactor pressure vessel after placing all fuel assemblies and control rods in a safe condition.

SURVEILLANCE REQUIREMENTS

4.9.8 The reactor vessel water level shall be determined to be at least its minimum required depth within 2 hours prior to the start of and at least once per 24 hours during handling of fuel assemblies or control rods within the reactor pressure vessel.

REFUELING OPERATIONS

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

LIMITING CONDITION FOR OPERATION

Set [redacted] [redacted]

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

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

ACTION:

With the requirements of the above specification not satisfied, suspend all movement of fuel assemblies and crane operations with loads in the spent fuel or upper containment fuel storage 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 spent fuel and upper containment fuel storage pools shall be determined to be at least at its minimum required depth at least once per 7 days.

3/4.9.10 CONTROL ROD REMOVAL

SINGLE CONTROL ROD REMOVAL

LIMITING CONDITION FOR OPERATION

3.9.10.1 One control rod and/or the associated control rod drive mechanism may be removed from the core and/or reactor pressure vessel provided that at least the following requirements are satisfied until a control rod and associated control rod drive mechanism are reinstalled and the control rod is fully inserted in the core.

a. The reactor mode switch is OPERABLE and locked in the Shutdown position or in the Refuel position per Table 1.2 and Specification 3.9.1.

b. The source range monitors (SRM) are OPERABLE per Specification 3.9.2.

c. The SHUTDOWN MARGIN requirements of Specification 3.1.1 are satisfied, except that the control rod selected to be removed;

   1. May be assumed to be the highest worth control rod required to be assumed to be fully withdrawn by the SHUTDOWN MARGIN test, and

   2. Need not be assumed to be immovable or untrippable.

d. All other control rods in a five-by-five array centered on the control rod being removed are inserted and electrically or hydraulically disarmed or the four fuel assemblies surrounding the control rod or control rod drive mechanism to be removed from the core and/or reactor vessel are removed from the core cell.

e. All other control rods are inserted.

APPLICABILITY: OPERATIONAL CONDITION 4 and 5.

ACTION:

With the requirements of the above specification not satisfied, suspend removal of the control rod and/or associated control rod drive mechanism from the core and/or reactor pressure vessel and initiate action to satisfy the above requirements.

SURVEILLANCE REQUIREMENTS

4.9.10.1 Within 4 hours prior to the start of removal of a control rod and/or the associated control rod drive mechanism from the core and/or reactor pressure vessel and at least once per 24 hours thereafter until a control rod and associated control rod drive mechanism are reinstalled and the control rod is inserted in the core, verify that:

a.. The reactor mode switch is OPERABLE and locked in the Shutdown position or in the Refuel position with the "one rod out" Refuel position interlock OPERABLE per Specification 3.9.1.

b. The SRM channels are OPERABLE per Specification 3.9.2.

c. The SHUTDOWN MARGIN requirements of Specification 3.1.1 are satisfied per Specification 3.9.10.1.c.

d. All other control rods in a five-by-five array centered on the control rod being removed are inserted and electrically or hydraulically disarmed or the four fuel assemblies surrounding the control rod or control rod drive mechanism to be removed from the core and/or reactor vessel are removed from the core cell.

e. All other control rods are inserted.

MULTIPLE CONTROL ROD REMOVAL

LIMITING CONDITION FOR OPERATION

3.9.10.2 Any number of control rods and/or control rod drive mechanisms may be removed from the core and/or reactor pressure vessel provided that at least the following requirements are satisfied until all control rods and control rod drive mechanisms are reinstalled and all control rods are inserted in the core.

a. The reactor mode switch is OPERABLE and locked in the Shutdown position or in the Refuel position per Specification 3.9.1, except that the Refuel position "one-rod-out" interlock may be bypassed, as required, for those control rods and/or control rod drive mechanisms to be removed, after the fuel assemblies have been removed as specified below.

b. The source range monitors (SRM) are OPERABLE per Specification 3.9.2.

c. The SHUTDOWN MARGIN requirements of Specification 3.1.1 are satisfied.

d. All other control rods are either inserted or have the surrounding four fuel assemblies removed from the core cell.

e. The four fuel assemblies surrounding each control rod or control rod drive mechanism to be removed from the core and/or reactor vessel are removed from the core cell.

307 | f. All fuel loading operations shall be suspended unless all control rods are inserted in the core.

APPLICABILITY: OPERATIONAL CONDITION 5.

ACTION:

With the requirements of the above specification not satisfied, suspend removal of control rods and/or control rod drive mechanisms from the core and/or reactor pressure vessel and initiate action to satisfy the above requirements.

SURVEILLANCE REQUIREMENTS

4.9.10.2.1 Within 4 hours prior to the start of removal of control rods and/or control rod drive mechanisms from the core and/or reactor pressure vessel and at least once per 24 hours thereafter until all control rods and control rod drive mechanisms are reinstalled and all control rods are inserted in the core, verify that:

a. The reactor mode switch is OPERABLE and locked in the Shutdown position or in the Refuel position per Specification 3.9.1.

b. The SRM channels are OPERABLE per Specification 3.9.2.

c. The SHUTDOWN MARGIN requirements of Specification 3.1.1 are satisfied.

d. All other control rods are either inserted or have the surrounding four fuel assemblies removed from the core cell.

e. The four fuel assemblies surrounding each control rod and/or control rod drive mechanism to be removed from the core and/or reactor vessel are removed from the core cell.

4.9.10.2.2 Following replacement of all control rods and/or control rod drive mechanisms removed in accordance with this specification, perform a functional test of the "one-rod-out" Refuel position interlock, if this function had been bypassed.

f. All fuel loading operations are suspended unless all control rods are inserted in the core.

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3/4.9.11 RESIDUAL HEAT REMOVAL AND COOLANT CIRCULATION

HIGH WATER LEVEL

LIMITING CONDITION FOR OPERATION

3.9.11.1 At least one shutdown cooling mode train of the residual heat removal (RHR) system shall be OPERABLE and in operation* with at least:

a. One OPERABLE RHR pump, and

b. One OPERABLE RHR heat exchanger train.

APPLICABILITY: OPERATIONAL CONDITION 5, when irradiated fuel is in the reactor vessel and the water level is greater than or equal to ~~23 feet~~ 22 feet 8 inches above the top of the reactor pressure vessel flange. /275

ACTION:

a. With no RHR shutdown cooling mode train OPERABLE, 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. Otherwise, suspend all operations involving an increase in the reactor decay heat load and establish SECONDARY CONTAINMENT INTEGRITY within 4 hours.

b. With no RHR shutdown cooling mode train in operation, within one hour establish reactor coolant circulation by an alternate method and monitor reactor coolant temperature at least once per hour.

SURVEILLANCE REQUIREMENTS

4.9.11.1 At least one shutdown cooling mode train of the residual heat removal system or alternate method shall be verified to be in operation and circulating reactor coolant at least once per 12 hours.

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*The shutdown cooling pump may be removed from operation for up to 2 hours per 8-hour period.

LOW WATER LEVEL

LIMITING CONDITION FOR OPERATION

3.9.11.2 Two shutdown cooling mode trains of the residual heat removal (RHR) system shall be OPERABLE and at least one train shall be in operation,* with each train consisting of at least:

a. One OPERABLE RHR pump, and

b. One OPERABLE RHR heat exchanger train.

APPLICABILITY: OPERATIONAL CONDITION 5, when irradiated fuel is in the reactor vessel and the water level is less than ~~23 feet~~ 22 feet 8 inches above the top of the reactor pressure vessel flange. |275

ACTION:

a. With less than the above required shutdown cooling mode trains of the RHR system OPERABLE, 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 each inoperable RHR shutdown cooling mode train.

b. With no RHR shutdown cooling mode train in operation, within one hour establish reactor coolant circulation by an alternate method and monitor reactor coolant temperature at least once per hour.

SURVEILLANCE REQUIREMENTS

4.9.11.2 At least one shutdown cooling mode train of the residual heat removal system or alternate method shall be verified to be in operation and circulating reactor coolant at least once per 12 hours.

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*The shutdown cooling pump may be removed from operation for up to 2 hours per 8-hour period.

REFUELING OPERATIONS

3/4.9.12 HORIZONTAL FUEL TRANSFER SYSTEM

LIMITING CONDITION FOR OPERATION

3.9.12 The horizontal fuel transfer system (HFTS) may be in operation provided that:

Room 1A525, Auxiliary Building, elevation 182'0", | 267

a. The room through which the transfer system penetrates, is sealed.

b. All interlocks with the refueling and fuel handling platforms are OPERABLE.

c. All HFTS primary carriage position indicators are OPERABLE.

APPLICABILITY: OPERATIONAL CONDITION 4* and 5*.

ACTION:

With the requirements of the above specification not satisfied, suspend HFTS operation with the HFTS at either the Spent Fuel Building pool or the Reactor Containment Building pool terminal point.

SURVEILLANCE REQUIREMENTS

4.9.12 Within 24 hours prior to the operation of HFTS and at least once per 7 days thereafter, verify that:

~~a.~~ b All interlocks with the refueling and fuel handling platforms are OPERABLE.

~~b.~~ c All HFTS primary carriage position indicators are OPERABLE.

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*When the reactor mode switch is in the Refuel position.

a. Room 1A525, Auxiliary Building, elevation 182'0", | 267
The room through which the transfer system penetrates, is sealed.

3/4.10 SPECIAL TEST EXCEPTIONS

3/4.10.1 PRIMARY CONTAINMENT INTEGRITY/DRYWELL INTEGRITY

LIMITING CONDITION FOR OPERATION

3.10.1 The provisions of Specifications 3.6.1.1, 3.6.1.3, 3.6.2.1, 3.6.2.3 and 3.9.1 and Table 1.2 may be suspended to permit the reactor pressure vessel closure head and the drywell head to be removed and the containment and drywell air lock doors to be open when the reactor mode switch is in the Startup position during low power PHYSICS TESTS with THERMAL POWER less than 1% of RATED THERMAL POWER and reactor coolant temperature less than 200°F.

APPLICABILITY: OPERATIONAL CONDITION 2, during low power PHYSICS TESTS.

ACTION:

With THERMAL POWER greater than or equal to 1% of RATED THERMAL POWER or with the reactor coolant temperature greater than or equal to 200°F, immediately place the reactor mode switch in the Shutdown position.

SURVEILLANCE REQUIREMENTS

4.10.1 The THERMAL POWER and reactor coolant temperature shall be verified to be within the limits at least once per hour during low power PHYSICS TESTS.

3/4.10.2 ROD PATTERN CONTROL SYSTEM

LIMITING CONDITION FOR OPERATION

3.10.2 The sequence constraints imposed on control rod groups by the rod pattern control system (RPCS) per Specification 3.1.4.2 may be suspended by means of the individual rod position bypass switches* for the following tests:

a. Shutdown margin demonstrations, Specification 4.1.1.

b. Control rod scram, Specification 4.1.3.2.

c. Control rod friction measurements.

d. Startup Test Program with the THERMAL POWER less than 20% of RATED THERMAL POWER.

APPLICABILITY: OPERATIONAL CONDITIONS 1 and 2.

ACTION:

With the requirements of the above specification not satisfied, verify that the RPCS is OPERABLE per Specification 3.1.4.2.

SURVEILLANCE REQUIREMENTS

4.10.2 When the sequence constraints imposed on control rod groups by the RPCS are bypassed, verify;

a. Within 8 hours prior to bypassing any sequence constraint and at least once per 12 hours while any sequence constraint is bypassed, that ~~That~~ movement of the control rods from 75% ROD DENSITY to the RPCS low power setpoint is limited to the established control rod sequence for the specified test, and

b. Conformance with this specification and test procedures by a second licensed operator or other technically qualified member of the unit technical staff.

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3/4.10.3 SHUTDOWN MARGIN DEMONSTRATIONS

LIMITING CONDITION FOR OPERATION

3.10.3 The provisions of Specification 3.9.1, Specification 3.9.3 and Table 1.2 may be suspended to permit the reactor mode switch to be in the Startup position and to allow more than one control rod to be withdrawn for shutdown margin demonstration, provided that at least the following requirements are satisfied.

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a. The source range monitors are OPERABLE per Specification 3.9.2 with the RPS circuitry "shorting links" removal.

~~1. RPS circuitry "shorting links" removed, or~~

b. ~~1~~ ~~2.~~ The rod patten control system OPERABLE per Specification 3.1.4.2, or

~~b.~~ ~~C~~onformance with the shutdown margin demonstration procedure is verified by a second licensed operator or other technically qualified member of the unit technical staff.

c. The "~~rod-out-notch-override~~" "continous withdrawal" control shall not be used during out-of-sequence movement of the control rods. /184

d. No other CORE ALTERATIONS are in progress.

APPLICABILITY: OPERATIONAL CONDITION 5, during shutdown margin demonstrations.

ACTION:

With the requirements of the above specification not satisfied, immediately place the reactor mode switch in the Shutdown or Refuel position.

SURVEILLANCE REQUIREMENTS

4.10.3 Within 30 minutes prior to and at least once per 12 hours during the performance of a shutdown margin demonstration, verify that;

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a. The source range monitors are OPERABLE per Specification 3.9.2 with the RPS circuitry "shorting links" removed.
~~1. The "shorting links" removed, or~~

b. ~~1~~ ~~2.~~ The rod pattern control system OPERABLE, ~~or~~

~~b.~~ ~~A~~ second licensed operator or other technically qualified member of the unit technical staff is present and verifies compliance with the shutdown demonstration procedures, and

c. No other CORE ALTERATIONS are in progress.

3/4.10.4 RECIRCULATION LOOPS

LIMITING CONDITION FOR OPERATION

3.10.4 The requirements of Specifications 3.4.1.1 and 3.4.1.3 that recirculation loops be in operation may be suspended for up to 24 hours for the performance of:

a. PHYSICS TESTS, provided that THERMAL POWER does not exceed 5% of RATED THERMAL POWER, or

b. The Startup Test Program.

APPLICABILITY: OPERATIONAL CONDITIONS 1 and 2, during PHYSICS TESTS and the Startup Test Program.

ACTION:

a. With the above specified time limit exceeded, insert all control rods.

b. With the above specified THERMAL POWER limit exceeded during PHYSICS TESTS, immediately place the reactor mode switch in the Shutdown position.

SURVEILLANCE REQUIREMENTS

4.10.4.1 The time during which the above specified requirement has been suspended shall be verified to be less than 24 hours at least once per hour during PHYSICS TESTS and the Startup Test Program.

4.10.4.2 THERMAL POWER shall be determined to be less than 5% of RATED THERMAL POWER at least once per hour during PHYSICS TESTS.

3/4.10.5 TRAINING STARTUPS

LIMITING CONDITION FOR OPERATION

3.10.5 The provisions of Specification 3.5.1 may be suspended to permit one RHR subsystem to be aligned in the shutdown cooling mode during training startups provided that the reactor vessel is not pressurized, THERMAL POWER is less than or equal to 1% of RATED THERMAL POWER and reactor coolant temperature is less than 200°F.

APPLICABILITY: OPERATIONAL CONDITION 2, during training startups.

ACTION:

With the requirements of the above specification not satisfied, immediately place the reactor mode switch in the Shutdown position.

SURVEILLANCE REQUIREMENTS

4.10.5 The reactor vessel shall be verified to be unpressurized and the THERMAL POWER and reactor coolant temperature shall be verified to be within the limits at least once per hour during training startups.

3/4.11 RADIOACTIVE EFFLUENTS

3/4.11.1 LIQUID EFFLUENTS

CONCENTRATION

LIMITING CONDITION FOR OPERATION

249| 3.11.1.1 The concentration of radioactive material released ~~from the site to~~ in liquid effluents to unrestricted areas (see Figure 5.1.3-1) shall be limited to the concentrations specified in 10 CFR Part 20, Appendix B, Table II, Column 2 for radionuclides other than dissolved or entrained noble gases. For dissolved or entrained noble gases, the concentration shall be limited to 2 x 10^{-4} microcuries/ml total activity. |

APPLICABILITY: At all times.

ACTION:

With the concentration of radioactive material released ~~from the site~~ in liquid effluents to UNRESTRICTED AREAS exceeding the above limits, immediately restore the concentration to within the above limits. /249

SURVEILLANCE REQUIREMENTS

4.11.1.1.1 The radioactivity content of each batch of radioactive liquid waste shall be determined prior to release by sampling and analysis in accordance with Table 4.11.1.1.1-1. The results of pre-release analyses shall be used with the calculational methods in the ODCM to assure that the concentration at the point of release is maintained within the limits of Specification 3.11.1.1.

4.11.1.1.2 Post-release analyses of samples composited from batch releases shall be performed in accordance with Table 4.11.1.1.1-1. The results of the ~~previous post-release analyses shall be used with the calculational methods in the ODCM to assure that the concentrations at the point of release were maintained within the limits of Specification 3.11.1.1.~~ /249

radioactivity analysis shall be used in accordance with the methodology and parameters in the ODCM to assure that the concentrations at the point of release are maintained within the limits of Specification 3.11.1.1.

TABLE 4.11.1.1.1-1

RADIOACTIVE LIQUID WASTE SAMPLING AND ANALYSIS PROGRAM

Liquid Release Type	Sampling Frequency	Minimum Analysis Frequency	Type of Activity Analysis	Lower Limit of Detection (LLD) (μCi/ml)[a]
A. Batch Waste Release Tanks[c]	P Each batch	P Each Batch	Principal Gamma Emitters[d]	5×10^{-7}
			I-131	1×10^{-6}
	P One Batch/M	M	Dissolved and Entrained Gases (Gamma emitters)	1×10^{-5}
	P Each Batch	M Composite[b]	H-3	1×10^{-5}
			Gross Alpha	1×10^{-7}
	P Each Batch	Q Composite[b]	Sr-89, Sr-90	5×10^{-8}
			Fe-55	1×10^{-6}
B. SSW Basin (prior to blowdown)	Each Blowdown	Each Batch	Principal Gamma Emitters[d]	5×10^{-7}
			I-131	1×10^{-6}

TABLE 4.11.1.1.1-1 (Continued)

RADIOACTIVE LIQUID WASTE SAMPLING AND ANALYSIS PROGRAM

TABLE NOTATION

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

For a particular measurement system (which may include radiochemical separation):

$$LLD = \frac{4.66\ s_b}{E \cdot V \cdot \underset{x10^{6}}{2.22} \cdot Y \cdot \exp(-\lambda\Delta t)}$$ 1249

where

LLD	is the "a priori" lower limit of detection as defined above (as ~~pCi~~ μCi per unit mass or volume). (Current literature defines the LLD as the detection capability for the instrumentation only, and the MDC, minimum detectable concentration, as the detection capability for a given instrument, procedure, and type of sample.) 1249
s_b	is the standard deviation of the background counting rate or of the counting rate of a blank sample as appropriate (as counts per minute)
E	is the counting efficiency (as counts per disintegration)
V	is the sample size (in units of mass or volume)
2.22 x10^6	is the number of disintegrations per minute per ~~picocurie~~ microcurie 1249
Y	is the fractional radiochemical yield (when applicable)
λ	is the radioactive decay constant for the particular radionuclide
Δt	is the elasped time between sample collection (or end of the sample collection period) and time of counting

The value of s_b used in the calculation of the LLD for a particular measurement system should be based on the actual observed variance of the background counting rate or of the counting rate of the blank samples (as appropriate) rather than on an unverified theoretically predicated variance.

I~~n calculating the LLD for a radionuclide determined by gamma r~~ay s~~pectrometry, the background should include the typical contributions of~~ o~~ther radionuclides normally present in the sample~~s. Typical values of E, V, Y and Δt should be used in the calculation. 1249

It should be recognized that the LLD is defined as an a priori (before the fact) limit representing the capability of a measurement system and not as a posteriori (after the fact) limit for a particular measurement.

1249

TABLE 4.11.1.1.1-1 (Continued)

RADIOACTIVE LIQUID WASTE SAMPLING AND ANALYSIS PROGRAM

TABLE NOTATION (Continued)

b. A composite sample is one in which the quantity of liquid sampled is proportional to the quantity of liquid waste discharged and in which the method of sampling employed results in a specimen which is representative of the liquids released.

c. A batch release is the discharge of liquid wastes of a discrete volume. Prior to sampling for analyses, each batch shall be isolated, and then thoroughly mixed to assure representative sampling.

d. The principal gamma emitters for which the LLD specification applies exclusively are the following radionuclides: Mn-54, Fe-59, Co-58, Co-60, Zn-65, Mo-99, Cs-134, Cs-137, Ce-141, and Ce-144. This list does not mean that only these nuclides are to be detected and reported. Other peaks which are measurable and identifiable, together with the above nuclides, shall also be identified and reported.

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~~*For a more complete discussion of the LLD, and other detection limits, see the following:~~

~~(1) HASL Procedures Manual, HASL-300 (revised annually).~~

~~(2) Currie, L. A., "Limits for Qualitative Detection and Quantitative Determination - Application to Radiochemistry" Anal. Chem. 40, 586-93 (1968).~~

~~(3) Hartwell, J. K., "Detection Limits for Radioisotopic Counting Techniques," Atlantic Richfield Hanford Company Report ARH-2537 (June 22, 1972).~~

RADIOACTIVE EFFLUENTS

DOSE

LIMITING CONDITION FOR OPERATION

3.11.1.2 The dose or dose commitment to a MEMBER OF THE PUBLIC ~~an individual~~ from radioactive materials in liquid effluents released, from each reactor unit, to UNRESTRICTED AREAS ~~from the site~~ (see Figure 5.1.3-1) shall be limited: 1249

a. During any calendar quarter to less than or equal to 1.5 mrem to the total body and to less than or equal to 5 mrem to any organ, and

b. During any calendar year to less than or equal to 3 mrem to the total body and to less than or equal to 10 mrem to any organ.

APPLICABILITY: At all times.

ACTION:

a. With the calculated dose from the release of radioactive materials in liquid effluents exceeding any of the above limits, i~~n lieu of any other report required by Specification 6.9.1, pre~~pare and submit to the Commission within 30 days, pursuant to Specification 6.9.2, a Special Report which identifies the cause(s) for exceeding the limit(s) and defines the corrective actions that have been taken to reduce the release and the corrective actions to be taken to ensure that future releases will be in compliance with ~~Specification 3.11.1.2.~~ the above limits. This Special Report shall also include (1) the results of radiological analyses of the drinking water source and (2) the radiological impact on ble. finished drinking water supplies with regard to the requirements of 40 CFR Part 141.* 093 1249

SURVEILLANCE REQUIREMENTS

4.11.1.2 Dose Calculations. Cumulative dose contributions from liquid effluents for the current calendar quarter and the current calendar year shall be determined in accordance with the methodology and parameters of the ODCM at least once per 31 days. 089

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*Applicable only if drinking water supply is taken from the receiving water body within 3 miles downstream of the plant discharge. 1249

RADIOACTIVE EFFLUENTS

LIQUID WASTE TREATMENT

from each reactor unit to UNRESTRICTED AREAS

LIMITING CONDITION FOR OPERATION

3.11.1.3 The liquid radwaste system ~~components as specified in the ODCM shall be OPERABLE. The appropriate portions of the system~~ shall be used to reduce the radioactive materials in liquid wastes prior to their discharge when the ~~cumulative~~ projected doses due to the liquid effluent ~~from the site~~ (see Figure 5.1.3-1) ~~in a 31 day period~~ would exceed 0.06 mrem to the total body or 0.2 mrem to any organ in a 31 day period. /086

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APPLICABILITY: At all times.

ACTION:

a. With ~~the liquid radwaste treatment system inoperable for more than 31 days or with~~ radioactive liquid waste being discharged without treatment and in excess of the above limits, ~~in lieu of any other report required by Specification 6.9.1~~, prepare and submit ~~to the~~ SL* Commission within 30 days pursuant to Specification 6.9.2, a Special Report which includes ~~the~~ following information: /249 /093

~~Report~~

1. Explanation of why liquid radwaste was being discharged without treatment, identification of any inoperable equipment or subsystems which resulted in liquid radwaste being discharged without treatment, and the reason for the inoperability, /249

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2. E

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 ~~and 6.9.1.11~~ are not applicable. /093

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 liquid radwaste system components specified in the ODCM shall be demonstrated OPERABLE by operating the liquid radwaste treatment system equipment for at least 30 minutes at least once per 92 days unless the liquid radwaste system has been utilized to process radioactive liquids during the previous 92 days.~~ The installed liquid radwaste system shall be demonstrated OPERABLE by meeting Specifications 3.11.1.1 and 3.11.1.2.

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LIQUID HOLDUP TANKS

LIMITING CONDITION FOR OPERATION

3.11.1.4 The quantity of radioactive material contained in any outside temporary tank, not including liners for shipping radwaste, shall be limited to less than or equal to 10 curies, excluding tritium and dissolved or entrained noble gases.

APPLICABILITY: At all times.

ACTION:

a. With the quantity of radioactive material in any of the above specified tanks exceeding the above limit, immediately suspend all additions of radioactive material to the tanks and within 48 hours reduce the tank contents to within the limit, and describe the events leading to the condition in the next Semiannual Radioactive Effluent Release Report. /249

b. The provisions of Specifications 3.0.3, and 3.0.4 ~~and 6.9.1.11~~ are not applicable. /093

SURVEILLANCE REQUIREMENTS

4.11.1.4 The quantity of radioactive material contained in each of the above specified tanks shall be determined to be within the above limit by analyzing a representative sample of the tank's contents at least once per 7 days when radioactive materials are being added to the tank. /249

3/4.11.2 GASEOUS EFFLUENTS

DOSE RATE

LIMITING CONDITION FOR OPERATION

3.11.2.1 The dose rate due to radioactive materials released in gaseous effluents from the site, to areas at and beyond the SITE BOUNDARY (see Figure 5.1.3-1) shall be limited to the following:

a. For noble gases: Less than or equal to 500 mrem/yr to the total body and less than or equal to 3000 mrem/yr to the skin, and

b. For all ~~radioiodines~~ iodine-131, iodine-133, tritium and all ~~radioactive materials~~ radionuclides in particulate form with half lives greater than 8 days: Less than or equal to 1500 mrem/yr to any organ. /191

APPLICABILITY: At all times.

ACTION:

With the dose rate exceeding the above limits, immediately decrease the release rate to within the above limit(s).

SUREVEILLANCE REQUIREMENTS

249/ 4.11.2.1.1 The dose rate due to noble gases in gaseous effluents shall be determined to be within the above limits in accordance with the ~~methods and procedures~~ methodology and parameters of the ODCM.

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1911 4.11.2.1.2 The dose rate due to iodine-131, iodine-133 ~~radioiodines~~, tritium and to ~~radioactive materials~~ radionuclides in particulate form with half lives greater than 8 days, ~~other than noble gases~~, in gaseous effluents shall be determined to be within the above limits in accordance with the ~~methods and procedures~~ methodology and parameters of the ODCM by obtaining representative samples and performing analyses in accordance with the sampling and analysis program specified in Table 4.11.2.1.2-1.

~~by obtaining~~
~~representative samples and~~
~~performing analyses in~~
~~accordance with the~~
~~sampling and analysis~~
~~program specified in~~
~~Table 4.11.2.1-1.~~

[redacted]

TABLE 4.11.2.1.2-1

RADIOACTIVE GASEOUS WASTE SAMPLING AND ANALYSIS PROGRAM

Gaseous Release Type	Sampling Frequency	Minimum Analysis Frequency	Type of Activity Analysis	Lower Limit of Detection (LLD) (μCi/ml)[a]
A. (1) Radwaste Building Ventilation Exhaust (2) Fuel Handling Area Ventilation Exhaust (3) Containment Ventilation Exhaust (4) Turbine Building Ventilation Exhaust	M^{e} Grab Sample	M^{be}	Principal Gamma Emitters^{b,e}	$1x10^{-4}$
			H-3	$1x10^{-6}$
	Continuous^{d}	W^{c} Charcoal Sample	I-131	$1x10^{-12}$
			I-133	$1x10^{-10}$
	Continuous^{d}	W^{c} Particulate Sample	Principal Gamma Emitters^{e} (I-131, Others)	$1x10^{-11}$
	Continuous^{d}	M Composite Particulate Sample	Gross Alpha	$1x10^{-11}$
	Continuous^{d}	Q Composite Particulate Sample	Sr-89, Sr-90	$1x10^{-11}$
	Continuous^{e}	Noble Gas Monitor	Noble Gases Gross Beta or Gamma	$1x10^{-6}$
B. (1) Offgas Post Treatment Exhaust, whenever there is flow	M Grab Sample	M	Principal Gamma Emitters^{e}	$1x10^{-4}$

(2) Standby Gas Treatment A Exhaust, whenever there is flow.

(3) Standby Gas Treatment B Exhaust, whenever there is flow.

1381

TABLE 4.11.2.1.2-1 (Continued)

RADIOACTIVE GASEOUS WASTE SAMPLING AND ANALYSIS PROGRAM

TABLE NOTATION

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

For a particular measurement system (which may include radiochemical separation):

$$LLD = \frac{4.66\ s_b}{E \cdot V \cdot 2.22 \underset{x10^6}{\wedge} \cdot Y \cdot \exp(-\lambda \Delta t)}$$ /249

where

LLD is the "a priori" lower limit of detection as defined above (as ~~pCi~~ μCi ↗ per unit mass or volume). (Current literature defines the LLD as the detection capability for the instrumentation only, and the MDC, minimum detectable concentration, as the detection capability for a given instrument, procedure, and type of sample.) /249

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

E is the counting efficiency (as counts per disintegration)

V is the sample size (in units of mass or volume)

2.22 x10⁶ is the number of disintegrations per minute per ~~picocurie~~ microcurie /249

Y is the fractional radiochemical yield (when applicable)

λ is the radioactive decay constant for the particular radionuclide

Δt is the elasped time between sample collection (or end of the sample collection period) and time of counting

The value of s_b used in the calculation of the LLD for a particular measurement system should be based on the actual observed variance of the background counting rate or of the counting rate of the blank samples (as appropriate) rather than on an unverified theoretically predicated variance.

~~In calculating the LLD for a radionuclide determined by gamma ray spectrometry, the background should include the typical contributions of other radionuclides normally present in the samples.~~ Typical values of E, V, Y and Δt should be used in the calculation. /249

It should be recognized that the LLD is defined as an a priori (before the fact) limit representing the capability of a measurement system and not as a posteriori (after the fact) limit for a particular measurement. /249

TABLE 4.11.2.1.2-1 (Continued)

RADIOACTIVE GASEOUS WASTE SAMPLING AND ANALYSIS PROGRAM

TABLE NOTATION (Continued)

b. Analyses shall also be performed following startup from cold shutdown, or a THERMAL POWER change exceeding 15 percent of the RATED THERMAL POWER within a one hour period. 1087

c. Samples shall be changed at least once per 7 days and analyses shall be completed within 48 hours after changing or after removal from sampler. Sampling and analyses shall also be performed at least once per 24 hours for at least 7 days following each shutdown, startup or THERMAL POWER change exceeding 15 percent of RATED THERMAL POWER in one hour. When samples collected for 24 hours are analyzed, the corresponding LLD's may be increased by a factor of 10.

1087

d. The ratio of the sample flow rate to the sampled stream flow rate shall be known for the time period covered by each dose or dose rate calculation made in accordance with Specifications 3.11.2.1 and 3.11.2.3.

e. The principal gamma emitters for which the LLD specification applies exclusively are the following radionuclides: Kr-87, Kr-88, Xe-133, Xe-133m, Xe-135, and Xe-138 for gaseous emissions and Mn-54, Fe-59, Co-58, Co-60, Zn-65, Mo-99, Cs-134, Cs-137, Ce-141 and Ce-144 for particulate emissions. This list does not mean that only these nuclides are to be detected and reported. Other peaks which are measurable and identifiable, together with the above nuclides, shall also be identified and reported.

This requirement does not apply if (1) analysis shows that the DOSE EQUIVALENT I-131 concentration in the primary coolant has not increased more than a factor of 3; and (2) the noble gas monitor shows that effluent activity has not increased more than a factor of 3.

249

~~*For a more complete discussion of the LLD, and other detection limits, see the following:~~

~~(1) HASL Procedures Manual, HASL-300 (revised annually).~~

~~(2) Currie, L. A., "Limits for Qualitative Detection and Quantitative Determination - Application to Radiochemistry" Anal. Chem. 40, 586-93 (1968).~~

~~(3) Hartwell, J. K., "Detection Limits for Radioisotopic Counting Techniques," Atlantic Richfield Hanford Company Report ARH-2537 (June 22, 1972).~~

RADIOACTIVE EFFLUENTS

DOSE - NOBLE GASES

LIMITING CONDITION FOR OPERATION

2491 3.11.2.2 The air dose due to noble gases released in gaseous effluents, from each reactor unit, from the site to areas at and beyond the SITE BOUNDARY (see Figure 5.1.3-1) shall be limited to the following:

a. During any calendar quarter: Less than or equal to 5 mrad for gamma radiation and less than or equal to 10 mrad for beta radiation, and

b. During any calendar year: Less than or equal to 10 mrad for gamma radiation and less than or equal to 20 mrad for beta radiation.

APPLICABILITY: At all times.

ACTION:

a. With the calculated air dose from the radioactive noble gases in gaseous effluents exceeding any of the above limits, ~~in lieu of any other report required by Specification 6.9.1~~, prepare and submit to the Commission within 30 days, pursuant to Specification 6.9.2, a Special Report which identifies the cause(s) for exceeding the limit(s) and defines the corrective actions to be taken to ensure that future releases will be in compliance with Specification 3.11.2.2. /093

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

SURVEILLANCE REQUIREMENTS

4.11.2.2 Dose Calculations. Cumulative dose contributions for noble gases ~~from gaseous effluents~~ for the current calendar quarter and current calendar year shall be determined in accordance with the methodology and paramaters in the ODCM at least once per 31 days. /249

RADIOACTIVE EFFLUENTS

IODINE-131, IODINE-133, TRITIUM AND RADIONUCLIDES

DOSE - ~~RADIOIODINES,~~ ~~RADIOACTIVE MATERIALS~~ IN PARTICULATE FORM, ~~AND TRITIUM~~

LIMITING CONDITION FOR OPERATION

a MEMBER OF THE PUBLIC iodine-131, iodine-133, tritium and radionuclides

191/

3.11.2.3 The dose to ~~an individual~~ from ~~tritium~~, ~~radioiodines and radioacti~~ve ~~materials in~~ particulate form with half-lives greater than 8 days in gaseous effluents released, from each reactor unit, from the site to areas at and beyond the SITE BOUNDARY (see Figure 5.1.3-1) shall be limited to the following:

[redacted]/ 105/

a. During any calendar quarter: Less than or equal to 7.5 mrem to any organ, and

b. During any calendar year: Less than or equal to 15 mrem to any organ.

APPLICABILITY: At all times.

ACTION:

io[redacted]-131, iodine 133, tritium and radio-nuclides

a. With the calculated dose from the release of ~~tritium, radioiodine~~s, ~~or radioactive materials~~ in paticulate form, with half-lives greater than 8 days, in gaseous effluents exceeding any of the above limits, ~~in lieu of any other report required by Specification 6.9.1,~~ prepare and submit to the Commission within 30 days, pursuant to Specification 6.9.2, a Special Report which identifies the cause(s) for exceeding the limit and defines the corrective actions ~~to be taken~~ to ensure that future releases will be in compliance with Specification 3.11.2.3.

1093

191 /[redacted]

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

SURVEILLANCE REQUIREMENTS

4.11.2.3 Dose Calculations. Cumulative dose contributions from ~~tritium,~~ ~~radioiodines, and radioactive materials,~~ with in particulate form ~~wth~~ half-lives greater than 8 days for the current calendar quarter and current calendar year shall be determined in accordance with the methodology and parameters in the ODCM at least once per 31 days.

/191

iodine-131, iodine-133, tritium and radionuclides

that have been taken to reduce releases and the proposed corrective actions to be taken

RADIOACTIVE EFFLUENTS

GASEOUS RADWASTE TREATMENT

LIMITING CONDITION FOR OPERATION

3.11.2.4 The GASEOUS RADWASTE TREATMENT (OFFGAS) SYSTEM ~~components as specified in the ODCM~~ shall be in operation. /192

APPLICABILITY: Whenever the main condenser air ejector system is in operation.

192

ACTION:

a. With ~~the GASEOUS RADWASTE TREATMENT (OFFGAS) SYSTEM inoperable for~~ gaseous radwaste from the main condenser air ejector system being discharged without treatment for more than 7 consecutive days, ~~in lieu of any other report required by Specification 6.9.1,~~ prepare and submit to the Commission within 30 days, pursuant to Specification 6.9.2, a Special Report which includes the following information: /1093

1. Explanation of why gaseous radwaste was being discharged without treatment, identification of the inoperable equipment or subsystems which resulted in gaseous radwaste being discharged without treatment, and the reason for 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 ~~and 6.9.1.11~~ are not applicable. /1093

SURVEILLANCE REQUIREMENTS

4.11.2.4 ~~The GASEOUS RADWASTE TREATMENT (OFFGAS) SYSTEM components specified in the ODCM shall be demonstrated OPERABLE by operating the GASEOUS RADWASTE TREATMENT SYSTEM components as described in the ODCM for at least 30 minutes at least once per 92 days unless the system has been utilized to process radioactive gas during the previous 92 days.~~

192 [redacted] /

The instruments specified in the ODCM shall be [redacted] checked every 12 hours whenever the main condenser air ejector system is in operation to ensure that the GASEOUS RADWASTE TREATMENT (OFFGAS) SYSTEM is functioning.

RADIOACTIVE EFFLUENTS

VENTILATION EXHAUST TREATMENT

LIMITING CONDITION FOR OPERATION

105 [redacted]

3.11.2.5 The ~~appropriate portions of the~~ VENTILATION EXHAUST TREATMENT SYSTEM shall ~~be OPERABLE and~~ be used to reduce radioactive materials in gaseous waste prior to their discharge when the projected ~~cumulative~~ dose due to gaseous effluent releases from ~~the site~~ each reactor unit to areas at and beyond the SITE BOUNDARY (see Figure 5.1.3-1) in a 31 day period would exceed 0.3 mrem to any organ.

086

APPLICABILITY: At all times, Other than when the VENTILATION EXHAUST TREATMENT SYSTEM is undergoing routine maintenance.*

ACTION:

a. With ~~the VENTILATION EXHAUST TREATMENT SYSTEM inoperable for more than 31 days, or with~~ gaseous waste being discharged without treatment and in excess of the above limits, ~~in lieu of any other report required by Specification 6.9.1~~, prepare and submit to the Commission within 30 days, pursuant to Specification 6.9.2, a Special Report which includes the following information: 086 093

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 ~~and 6.9.1.11~~ are not applicable. [redacted] 093

SURVEILLANCE REQUIREMENTS

4.11.2.5.1 Doses due to gaseous releases from ~~the site~~ 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. 105

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4.11.2.5.2 ~~The VENTILATION EXHAUST TREATMENT SYSTEM shall be demonstrated OPERABLE by operating the VENTILATION EXHAUST TREATMENT SYSTEM equipment for at least 30 minutes, at least once per 92 days unless the appropriate system has been utilized to process radioactive gaseous effluents during the previous 92 days.~~ The installed VENTILATION EXHAUST TREATMENT SYSTEM shall be demonstrated OPERABLE by meeting Specification 3.11.2.1 and 3.11.2.2 or 3.11.2.3.

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*Not applicable to Turbine Building ventilation exhaust unless filtration media is installed

RADIOACTIVE EFFLUENTS

EXPLOSIVE GAS MIXTURE

LIMITING CONDITION FOR OPERATION

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

APPLICABILITY: ~~At all times~~. Whenever the main condenser offgas treatment system is in operation. /193

ACTION:

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

b. The provisions of Specifications 3.0.3 and 3.0.4 ~~and 6.9.1.11~~ are not applicable. /093

SURVEILLANCE REQUIREMENTS

4.11.2.6 The concentration of hydrogen in the main condenser offgas treatment system shall be determined to be within the above limits by monitoring ~~maintainin~~g the waste gas in the main condenser off-gas treatment system with the hydrogen monitor OPERABLE as required by Table 3.3.7.12-1 of Specification 3.3.7.12. /193

MAIN CONDENSER

LIMITING CONDITION FOR OPERATION

3.11.2.7 The gross radioactivity (gamma) rate of the noble gases ~~Xe-135m, Xe-133, Xe-135, Xe-138, Kr-85m, Kr-87, Kr-88~~ measured at the offgas recombiner effluent shall be limited to less than or equal to 380 millicuries/second, after 30 minutes decay. 1185

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2*, and 3* 1185

ACTION:

With the gross radioactivity rate of the noble gases ~~Xe-135m, Xe-133, Xe-135, Xe-138, Kr-85, Kr-87m, and Kr-88~~ at the offgas recombiner effluent exceeding 380 millcuries/second, after 30 minutes decay restore the gross radioactivity release rate to within its limit within 72 hours or be in at least HOT ~~STANDBY~~ SHUTDOWN within the next 12 hours ~~and~~ in COLD SHUTDOWN within the following 24 hours. 1185

SURVEILLANCE REQUIREMENTS

4.11.2.7.1 The radioactivity release rate of noble gases near the outlet of the main condenser air ejector shall be continuously monitored in accordance with Specification 3.3.7.12.

4.11.2.7.2 The gross ~~radioactivity~~ radioactivity release rate of the noble gases ~~Xe-135m, Xe-133, Xe-135, Xe-138, Kr-85m, Kr-87, and Kr-88~~ from the main condenser air ejector shall be determined to be within the limits of Specification 3.11.2.7 at the following frequencies** by performing an isotopic analysis of a representative sample of gases taken at the ~~discharge (prior to dilution and/or discharge) of the main condenser air ejector~~: offgas recombiner effluent. 1185

a. At least once per 31 days.

b. Within 4 hours following an increase, as indicated by the ~~Condenser Air Ejector Noble Gas Activity~~ Offgas Pretreatment Monitor, of greater than 50%, after factoring out increases due to changes in THERMAL POWER level, in the nominal steady state fission gas release from the primary coolant.

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* When the main condenser air ejector is in operation.

** The provisions of Specification 4.0.4 are not applicable. 1185

RADIOACTIVE EFFLUENTS

3/4.11.3 SOLID RADIOACTIVE WASTE

LIMITING CONDITION FOR OPERATION

3.11.3 The solid radwaste system shall be used in accordance with a PROCESS CONTROL PROGRAM to process wet radioactive wastes to meet shipping and burial ground requirements.

APPLICABILITY: At all times.

ACTION:

a. With the provisions of the PROCESS CONTROL PROGRAM not satisfied, suspend shipments of defectively processed or defectively packaged solid radioactive wastes from the site.

b. The provisions of Specifications 3.0.3 and 3.0.4, ~~and 6.9.1.9.b~~ are not applicable.

1093

SURVEILLANCE REQUIREMENTS

4.11.3 ~~THE~~ 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, boric acid solutions, 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 additional 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.

b. If the initial test specimen from a batch of waste fails to verify SOLIDIFICATION*, the PROCESS CONTROL PROGRAM shall provide for the collection and testing of representative test specimens from each consecutive batch of the same type of wet waste until at least 3 consecutive initial test specimens demonstrate SOLIDIFICATION.* The PROCESS CONTROL PROGRAM shall be modified as required, as provided in Specification 6.13, to assure SOLIDIFICATION* of subsequent batches of waste.

~~92 days in accordance with the PROCESS CONTROL PROGRAM, or~~

~~b. Verification of the existence of a valid contract for SOLIDIFICATION to be performed by a contractor in accordance with a PROCESS CONTROL PROGRAM.~~

* Except dewatering.

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SURVEILLANCE REQUIREMENTS (Continued)

4.11.3.2 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, categorized as "non-specific" waste, except Equipment Filter Sludge and Floor Filter Sludge wastes which are required at least one representative test specimen from at least every twentieth batch. For batches categorized as "specific" waste, sampling shall be as outlined in the PROCESS CONTROL PROGRAM.

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

b. If the initial test specimen from a batch of "non-specific" waste fails to verify SOLIDIFICATION, the PROCESS CONTROL PROGRAM shall provide for the collection and testing of representative test specimens from each consecutive batch of the same type of wet waste until at least 3 consecutive initial test specimens demonstrate SOLIDICAITION. The PROCESS CONTROL PROGRAM shall be modified as required, as provided in Specification 6.13.2, to assure SOLIDIFICATION of subsequent batches of waste.

Delete

3/4.11.4 TOTAL DOSE

LIMITING CONDITION FOR OPERATION

3.11.4 The annual (calendar year) dose or dose commitment to any MEMBER OF THE PUBLIC due to releases of radioactivity and to radiation from uranium fuel cycle sources shall be limited to less than or equal to 25 mrems to the total body or any organ, except the thyroid, which shall be limited to less than or equal to 75 mrems. X

APPLICABILITY: At all times.

ACTION:

a. With the calculated dose from the release of radioactive materials in liquid or gaseous effluents exceeding twice the limits of Specification 3.11.1.2.a, 3.11.1.2.b, 3.11.2.2.a, 3.11.2.2.b, 3.11.2.3.a, or 3.11.2.3.b, calculations should be made including direct radiation contributions from the reactor units and from outside storage tanks to determine whether the above limits of Specification 3.11.4 have been exceeded. If such is the case ~~in lieu of a Licensee Event Report~~, prepare and submit to the Commission within 30 days, pursuant to Specification 6.9.2, a Special Report that defines the corrective action to be taken to reduce subsequent releases to prevent recurrence of exceeding the above limits and includes the schedule for achieving conformance with the above limits. This Special Report, as defined in 10 CFR Part 20.405c, shall include an analysis that estimates the radiation exposure (dose) to a MEMBER OF THE PUBLIC from uranium fuel cycle sources, including all effluent pathways and direct radiation, for the calendar year that includes the release(s) covered by this report. It shall also describe levels of radiation and concentrations of radioactive material involved, and the cause of the exposure levels or concentrations. If the estimated dose(s) exceeds the above limits, and if the release condition resulting in violation of 40 CFR Part 190 has not already been corrected, the Special Report shall include a request for a variance in accordance with the provisions of 40 CFR Part 190. Submittal of the report is considered a timely request, and a variance is granted until staff action on the request is complete. 1095 B

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

SURVEILLANCE REQUIREMENTS

4.11.4.1 Cumulative dose contributions from liquid and gaseous effluents shall be determined in accordance with Specifications 4.11.1.2, 4.11.2.2, and 4.11.2.3, and in accordance with the methodology and parameters in the ODCM.

4.11.4.2 Cumulative dose contributions from direct radiation from the reactor units and from radwaste storage tanks shall be determined in accordance with the methodology and parameters in the ODCM. This requirement is applicable only under conditions set forth in Specification 3.11.4.a.

3/4.12 RADIOLOGICAL ENVIRONMENTAL MONITORING

3/4.12.1 MONITORING PROGRAM

LIMITING CONDITION FOR OPERATION

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

APPLICABILITY: At all times.

ACTION:

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

b. With the level of radioactivity as the result of plant effluent in an environmental sampling medium at a specified location exceeding the reporting levels of Table 3.12.1-2 when averaged over any calendar quarter, prepare and submit to the Commission within 30 days ~~from the end of the affected calendar quarter~~ pursuant to Specification 6.9.2 a Special Report that identifies the cause(s) for exceeding the limit(s) and defines the corrective actions to be taken to reduce radioactive effluents so that the potential annual dose to ~~an individual~~ a MEMBER OF THE PUBLIC is less than the calendar year limits of Specification 3.11.1.2, 3.11.2.2 and 3.11.2.3. pursuant to Specification 6.9.1.13.f. When more than one of the radionuclides in Table ~~3.12-2~~ 3.12.1-2 are detected in the sampling medium, this report shall be submitted if:

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

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

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c. If ~~With~~ milk or broad leaf vegetation ~~fresh leafy vegetable samples unavailable~~ sampling [redacted] is relocated from one or more of the sample locations required by Table 3.12.1-1, ~~in lieu of any other report required by Specification 6.9.1, prepare and submit to the Commission within 30 days, pursuant to Specification 6.9.2, a Special Report which identifies the cause of the unavailability of samples and identifies locations for obtaining replacement samples.~~ INSERT FROM NEXT PAGE The specific locations from which samples were unavailable may then be deleted from the radiological environmental monitoring program and the table(s) in the ODCM provided the locations from which the replacement samples were obtained are added to the table(s) as replacement locations.

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

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identify new locations for obtaining replacement samples and add them to the radiological environmental monitoring program within 30 days. In addition, report the cause(s) of the unavailability of samples and the new locations for obtaining replacement samples in the next Semiannual Radioactive Effluent Release Report. Include in this report the revised ODCM figure(s) and table(s) reflecting the new locations.

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SURVEILLANCE REQUIREMENTS

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

TABLE 3.12.1-1

OPERATIONAL RADIOLOGICAL ENVIRONMENTAL MONITORING PROGRAM

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Exposure Pathway and/or Sample	Number of Samples[a] and Locations	Sampling and Collection Frequency[a]	Type and Frequency of Analysis
AIRBORNE			
Radioiodine and Particulates	Samples from 5 locations: 3 samples ~~from offsite locations~~ close to the SITE BOUNDARY (in different sectors) ~~of~~ having the highest calculated annual average groundlevel ~~X/Q~~ D/Q. 1 sample from the vicinity of a community having the highest calculated annual average groundlevel ~~X/Q~~ D/Q. 1 sample from a control location 15-30 km (10-20 miles) distance~~e~~ d	Continuous sampler operation with sample collection weekly or as required by dust loading, whichever is more frequent~~[illegible]~~	Radioiodine Cannister: analyze weekly for I-131 Particulate Sampler: Gross beta radioactivity following filter change,[b] composite (by location) for gamma isotopic[c] ~~quatorly~~ quarterly
DIRECT RADIATION ~~1~~ 2	INSERT 248 ~~40 stations with two or more dosimeters or one instrument for measuring and recording dose rate continuously to be placed as follows: 1) an inner ring of stations in the general area of the site boundary and an outer ring in the 4 to 5 mile range from the site with a station in each sector of each ring (16 sectors x 2 rings = 32 stations). The balance of the stations should be placed in special interest areas such as population centers, nearby residences, schools, and in 2 or 3 areas to serve as control stations.~~	Quarterly	Gamma dose ~~quatorly~~ quarterly

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INSERT
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40 stations with two or more dosimeters or one instrument for measuring and recording dose rate continuously to be placed in each ~~[illegible]~~ accessible * sector as follows:

1) an inner ring of stations in the general area of the site boundary

2) an outer ring approximately 3 to 5 miles from the site.

The balance of the stations should be placed in special interest areas such as population centers, nearby residences, schools, and in 1 or 2 areas to serve as control stations.

~~* As described in the ODCM~~

TABLE 3.12.1-1 (Continued)

OPERATIONAL RADIOLOGICAL ENVIRONMENTAL MONITORING PROGRAM

Exposure Pathway and/or Sample	Number of Samples[a] and Locations	Sampling and Collection Frequency[a]	Type and Frequency of Analysis
WATERBORNE			
Surface~~[g]~~[f]	1 sample upstream 1 sample downstream	Monthly	Gamma isotopic analysis monthly.[c] Composite for tritium analyses quarterly
	Discharge Basin	Composite sample over one-month period†[g]	
Ground	Samples from 2 sources	Quarterly	Gamma isotopic[c] and tritium analysis quarterly
Cistern Water	1 sample of the nearest source that could be affected 1 sample from a control location	Monthly	I-131, Gross β and gamma isotopic analyses[c] monthly. Composite for tritium analysis quarterly
Sediment from Shoreline	1 sample from downstream area	Semiannually	Gamma isotopic analyses[c] semiannually
INGESTION			
Milk	Samples from milking animals in 3 locations within 5 km distant having the highest dose potential. If there are none then, 1 sample from milking animals in each of 3 areas between 5 to 8 km distant where doses are calculated to be greater than 1 mrem per year*[h]	Semimonthly when animals are on pasture, monthly at other times	Gamma isotopic[c] and I-131 analysis semimonthly when animals are on pasture; monthly at other times.

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~~#1~~

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~~#1~~

TABLE 3.12.1-1 (Continued)

OPERATIONAL RADIOLOGICAL ENVIRONMENTAL MONITORING PROGRAM

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Exposure Pathway and/or Sample	Number of Samples^a and Locations	Sampling and Collection Frequency^a	Type and Frequency of Analysis
Milk (cont'd)	1 sample from milking animals at a control location (15-30 km distant)		
Fish and Invertebrates	1 sample of ~~catfish~~ one species of commercially or recreationally important fish in vicinity of discharge point	Semiannually	Gamma isotopic^c analysis on edible portions
	1 sample of same species in areas ~~no~~ not influenced by plant discharge		
Food Products	Samples of 3 different kinds of broad leaf vegetation grown nearest each of two different offsite locations ~~3 samples of broad leaf vegetation grown near site Boundary Location~~ with highest anticipated annual average ground-level D/Q if milk sampling is not performed	Monthly when available	Gamma isotopic^c ~~analysis on edible~~ and I-131 analysis
	1 sample of each of the similar vegetation grown 15-30 km distant if milk sampling is not performed	Monthly when available	Gamma isotopic^c and I-131 analysis

TABLE 3.12.1-1 (Continued)

OPERATIONAL RADIOLOGICAL ENVIRONMENTAL MONITORING PROGRAM

* As described in the ODCM.

TABLE NOTATION

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INSERT

[a]~~Sample locations are indicated in the ODCM~~.

[b]Particulate sample filters should be analyzed for gross beta 24 hours or more after sampling to allow for radon and thoron daughter decay. If gross beta activity in air or water is greater than ten times the yearly mean of control samples for any medium, gamma isotopic analysis should be performed on the individual samples.

[c]Gamma isotopic analysis means the identification and quantification of gamma-emitting radionuclides that may be attributable to the effluents from the facility.

[d]The purpose of this sample is to obtain background information.

~~[e]Canisters for the collection of radioiodine in air are subject to channeling. These devices should be carefully checked before operation in the field to prevent loss of iodine.~~

e ~~[f]~~~~Regulatory Guide 4.13 provides minimum acceptable performance criteria for thermoluminescence dosimetry~~ (TLD) s~~ystems used for environmental monitoring~~. One or more instruments, such as a pressurized ion chamber, for measuring and recording dose rate continuously ~~my~~ may be used in place of, or in addition to, integrating dosimeters. For the purposes of this table, a thermoluminescent dosimeter may be considered to be one phosphor and two or more phosphors in a packet may be considered as two or more dosimeters. Film badges should not be used for measuring direct radiation.

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f ~~[g]~~The "upstream sample" should be taken at a distance beyond significant influence of the discharge. The "downstream"sample should be taken in an area beyond but near the mixing zone.

g ~~[h]~~Composite samples should be collected with equipment (or equivalent) which is capable of collecting an aliquot at time intervals which are very short (e.g., hourly) relative to the compositing period (e.g., monthly).

h ~~[i]~~The dose shall be calculated using methodology contained in the ODCM.

P/S: 036 } Markup
P/S: 249 }

INSERT 036 a

Insert for Table Notation
on Page 3/4 12-6

[a] Specific parameters of distance and direction sector from the centerline of one reactor, and additional description where pertinent, shall be provided for each and every sample location in Table 3.12.1-1 in the table(s) and figure(s) in the ODCM. Refer to NUREG-0133, "Preparation of Radiological Effluent Technical Specifications for Nuclear Power Plants," October 1978, and to Radiological Assessment Branch Technical Position, Revision 1, November 1979. Deviations are permitted from the required sampling schedule if specimens are unobtainable due to hazardous conditions, seasonal unavailability, malfunction of automatic sampling equipment and other legitimate reasons. If specimens are unobtainable due to sampling equipment malfunction, every effort shall be made to complete corrective action prior to the end of the next sampling period. All Above deviations from the sampling schedule shall be documented in the Annual Radiological Environmental Operating Report pursuant to Technical Specification 6.9.1.6. ~~It~~ is recognized that, at times, it may not be possible or practicable to continue to obtain samples of the media of choice at the most desired location or time. In these instances suitable alternative media and locations may be chosen for the particular pathway in question and appropriate substitutions made within 30 days in the radiological environmental monitoring program. ~~In lieu of a Licensee Event Report and pursuant to Technical Specification 6.9.1.9,~~ Identify the cause of the unavailability of samples for the pathway and identify the new location(s) for obtaining replacement samples in the next Semiannual Radioactive Effluent Release Report and also include in the report a revised figure(s) and table (s) for the ODCM reflecting the new location(s).

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TABLE 3.12.1-2

REPORTING LEVELS FOR RADIOACTIVITY CONCENTRATIONS IN ENVIRONMENTAL SAMPLES

Reporting Levels

Analysis	Water (pCi/l)	Airborne Particulate or Gases (pCi/m³)	Fish (pCi/Kg, wet)	Milk (pCi/l)	Food Products (pCi/Kg, wet)
H ~~H~~-3	2×10^{4}(a)	NA	NA	NA	NA
Mn-54	1×10^{3}	NA	3×10^{4}	NA	NA
Fe-59	4×10^{2}	NA	1×10^{4}	NA	NA
Co-58	1×10^{3}	NA	3×10^{4}	NA	NA
Co-60	3×10^{2}	NA	1×10^{4}	NA	NA
Zn-65	3×10^{2}	NA	2×10^{4}	NA	NA
Zr-Nb-95	4×10^{2}	NA	NA	NA	NA
I-131	2	0.9	NA	3	1×10^{2}
Cs-134	30	10	1×10^{3}	60	1×10^{3}
Cs-137	50	20	2×10^{3}	70	2×10^{3}
Ba-La-140	2×10^{2}	NA	NA	3×10^{2}	NA

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(a) For drinking water samples. This is a 40 CFR Part 141 value. If no drinking water pathway exists, a value of 30,000 pCi/l may be used.

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TABLE 4.12.1-1

MAXIMUM VALUES FOR THE LOWER LIMITS OF DETECTION (LLD)[a,b]

Analysis	Water (pCi/l)	Airborne Particulate or Gas (pCi/m^3)	Fish (pCi/kg,wet)	Milk (pCi/l)	Broad Leaf Vegetation (pCi/kg,wet)	Sediment (pCi/kg,dry)
gross beta	4	1×10^{-2}	NA	NA	NA	NA
H-3	2000[d]	NA	NA	NA	NA	NA
Mn-54	15	NA	130	NA	NA	NA
Fe-59	30	NA	260	NA	NA	NA
Co-58,60	15	NA	130	NA	NA	NA
Zn-65	30	NA	260	NA	NA	NA
Zr-95	30	NA	NA	NA	NA	NA
Nb-95	15	NA	NA	NA	NA	NA
I-131	1[c]	7×10^{-2}	NA	1	60	NA
Cs-134	15	5×10^{-2}	130	15	60	150
Cs-137	18	6×10^{-2}	150	18	80	180
Ba-140	60	NA	NA	60	NA	NA
La-140	15	NA	NA	15	NA	NA

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TABLE 4.12.1-1 (Continued)

MAXIMUM VALUES FOR THE LOWER LIMITS OF DETECTION (LLD)

TABLE NOTATION

[a] Acceptable detection capabilities for thermoluminescent dosimeters used for environmental measurements are given in Regulatory Guide 4.13.

[b] Table 4.12-1 indicates acceptable detection capabilities for radioactive materials in environmental samples. These detection capabilities are tabulated in terms of the lower limits of detection (LLDs). The LLD is defined, for purposes of this guide, as the smallest concentration of radioactive material in a sample that will yield a net count (above system background) that will be detected with 95% probability with only 5% probability of falsely concluding that a blank observation represents a "real" signal.

For a particular measurement system (which may include radiochemical separation):

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

[redacted]

where

LLD is the "a priori" lower limit of detection as defined above (as ~~pCi~~ [redacted] ster per unit mass or volume). (Current literature defines the LLD as the detection capability for the instrumentation only, and the MDC, minimum detectable concentration, as the detection capability for a given instrument, procedure, and type of sample.)

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

E is the counting efficiency (as counts per disintegration)

V is the sample size (in units of mass or volume)

[redacted]

2.22 is the number of disintegrations per minute per ~~picocurie~~ ster ~~microcurie~~ .

Y is the fractional radiochemical yield (when applicable)

λ is the radioactive decay constant for the particular radionuclide

Δt is the elasped time between sample collection (or end of the sample collection period) and time of counting

The value of s_b used in the calculation of the LLD for a particular measurement system should be based on the actual observed variance of the background counting rate or of the counting rate of the blank samples (as appropriate) rather than on an unverified theoretically predicated variance.

MAXIMUM VALUES FOR THE LOWER LIMITS OF DETECTION (LLD)

TABLE NOTATION (Continued)

~~In calculating the LLD for a radionuclide determined by gamma-ray spectrometry, the background should include the typical contributions of other radionuclides normally present in the samples (e.g., potassium 40 in milk samples).~~ Typical values of E, V, Y and Δt should be used in the calculation. 1249

It should be recognized that the LLD is defined as an a priori (before the fact) limit representing the capability of a measurement system and not as a posteriori (after the fact) limit for a particular measurement.~~*~~

[c] LLD for drinking water samples. If no drinking water pathway exists, the LLD of gamma isotopic may be used. 1190

[d] If no drinking water pathway exists, a value of 3000 pCi/l may be used. 1190

Occasionally background fluctuations, unavoidable small sample size, the presence of interfering Nuclides, or other uncontrollable circumstances may render these LLDs unachievable. In such cases, the contributing factors should be identified and described in the Annual Radiological Environmental Operating Report pursuant to Specification 6.9.1.6. 1249

~~*For a more complete discussion of the LLD, and other detection limits, see the following:~~
~~(1) HASL Procedures Manual, HASL-300 (revised annually).~~
~~(2) Currie, L. A., "Limits for Qualitative Detection and Quantitative Determination - Application to Radiochemistry" Anal. Chem. 40, 586-93 (1968).~~
~~(3) Hartwell, J. K., "Detection Limits for Radioisotopic Counting Techniques," Atlantic Richfield Hanford Company Report ARH-2537 (June 22, 1972).~~ 1249

3/4.12.2 LAND USE CENSUS

LIMITING CONDITION FOR OPERATION

3.12.2 A land use census shall be conducted and shall identify within a distance of 8 km (5 miles) the location in each of the 16 meteorological sectors of the nearest milk animal, the nearest residence and the nearest garden* of greater than 50 m^2 (500 ft^2) producing broad leaf vegetation. Broad leaf vegetation sampling of at least three different kinds of vegetation may be performed at the site boundary in each of two different direction sectors with the highest predicted D/Qs in lieu of the garden census. Specifications for broad leaf vegetation sampling in Table 3.12-1. I shall be followed, including analysis of control samples.

ACTION:

a. With a land use census identifying a location(s) that yields a calculated dose or dose commitment greater than the values currently being calculated in Specification 4.11.2.3, ~~in lieu of a Licensee Event Repo~~ identify the new location(s) in the next Semiannual Radioactive Effluen Release Report, pursuant to Specification 6.9.1.~~12~~9.

b. With a land use census identifying a location(s) that yields a calculated dose or dose commitment (via the same exposure pathway) 20 percent greater than at a location from which samples are currently being obtained in accordance with Specification 3.12.1, add the new location(s) to the radiological environmental monitoring program within 30 days. The sampling location(s), excluding the control station location, having the lowest calculated dose or dose commitment(s), via the same exposure pathway, may be deleted from this monitoring program after (October 31) of the year in which this land use census was conducted. ~~In lieu of a Licensee Event Report and pursuant to Specification 6.9.1.13~~, Identify the new location(s) in the next Semiannual Radioactive Effluent Release Report and also include in the report a revised figure(s) and table(s) for the ODCM reflecting the new location(s).

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

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SURVEILLANCE REQUIREMENTS

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4.12.2 The land use census shall be conducted during the growing season at least once per 12 months using that information that will provide the best results, such as by a door-to-door survey, aerial survey, or by consulting local agriculture authorities. The results of the land use census shall be included in the Annual Radiological Environmental Operating Report pursuant to Specification 6.9.1.~~11~~7.

RADIOLOGICAL ENVIRONMENTAL MONITORING

3/4.~~12.~~3 INTERLABORATORY COMPARISON PROGRAM

that correspond to samples required by Table 3.12.1-1. These materials are 1249

LIMITING CONDITION FOR OPERATION

3.12.3 Analyses shall be performed on radioactive materials supplied as part of an Interlaboratory Comparison Program which has been approved by the Commission.

APPLICABILITY: At all times.

ACITON:

a. With analyses not being performed as required above, report the corrective actions taken to prevent a recurrence to the Commission in the Annual Radiological Environmental Operating Report pursuant to Specification 6.9.1.7.

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

SURVEILLANCE REQUIREMENTS

4.12.3 A summary of the results obtained as part of the above required Interlaboratory Comparison Program shall be included in the Annual Radiological Environmental Operating Report pursuant to Specification 6.9.1.7. ~~Participants in the EPA crosscheck program may provide the EPA program code for NRC review in lieu of the summary of results.~~ /092

BASES FOR
SECTIONS 3.0 AND 4.0
LIMITING CONDITIONS FOR OPERATION
AND
SURVEILLANCE REQUIREMENTS

NOTE

The BASES contained in succeeding pages summarize the reasons for the Specifications in Section 3.0 and 4.0, but in accordance with 10 CFR 50.36 are not part of these Technical Specifications.

The specifications of this section provide the general requirements applicable to each of the Limiting Conditions for Operation and Surveillance Requirements within Section 3/4.

3.0.1 This specification states the applicability of each specification in terms of defined OPERATIONAL CONDITION or other specified applicability condition and is provided to delineate specifically when each specification is applicable.

3.0.2 This specification defines those conditions necessary to constitute compliance with the terms of an individual Limiting Condition for Operation and associated ACTION requirement.

3.0.3 This specification delineates the measures to be taken for those circumstances not directly provided for in the ACTION statements and whose occurrence would violate the intent of the specification. For example, Specification 3.7.2 requires two control room emergency filtration subsystems to be OPERABLE and provides explicit ACTION requirements if one subsystem is inoperable. Under the requirements of Specification 3.0.3, if both of the required subsystems are inoperable, within one hour measures must be initiated to place the unit in at least STARTUP within the next 6 hours, in at least HOT SHUTDOWN within the following 6 hours and in at least COLD SHUTDOWN within the subsequent 24 hours. As a further example, Specification 3.6.7.1 requires two primary containment hydrogen recombiner systems to be OPERABLE and provides explicit ACTION requirements if one recombiner system is inoperable. Under the requirements of Specification 3.0.3, if both of the required systems are inoperable, within one hour measures must be initiated to place the unit in at least STARTUP within the next 6 hours and in at least HOT SHUTDOWN within the following 6 hours.

3.0.4 This specification provides that entry into an OPERATIONAL CONDITION must be made with (a) the full complement of required systems, equipment or components OPERABLE and (b) all other parameters as specified in the Limiting Conditions for Operation being met without regard for allowable deviations and out of service provisions contained in the ACTION statements.

The intent of this provision is to ensure that unit operation is not initiated with either required equipment or systems inoperable or other limits being exceeded.

Exceptions to this provision have been provided for a limited number of specifications when startup with inoperable equipment would not affect plant safety. These exceptions are stated in the ACTION statements of the appropriate specifications.

4.0.1 This specification provides that surveillance activities necessary to ensure the Limiting Conditions for Operation are met and will be performed during the OPERATIONAL CONDITIONS or other conditions for which the Limiting Conditions for Operation are applicable. Provisions for additional surveillance activities to be performed without regard to the applicable OPERATIONAL CONDITIONS or other conditions are provided in the individual Surveillance Requirements. Surveillance Requirements for Special Test Exceptions need only be performed when the Special Test Exception is being utilized as an exception to an individual specification.

4.0.2 The provisions of this specification provide allowable tolerances for performing surveillance activities beyond those specified in the nominal surveillance interval. These tolerances are necessary to provide operational flexibility because of scheduling and performance considerations. The phrase "at least" associated with a surveillance frequency does not negate this allowable tolerance; instead, it permits the more frequent performance of surveillance activities.

The tolerance values, taken either individually or consecutively over 3 test intervals, are sufficiently restrictive to ensure that the reliability associated with the surveillance activity is not significantly degraded beyond that obtained from the nominal specified interval.

4.0.3 The provisions of this specification set forth the criteria for determination of compliance with the OPERABILITY requirements of the Limiting Conditions for Operation. Under this criteria, equipment, systems or components are assumed to be OPERABLE if the associated surveillance activities have been satisfactorily performed within the specified time interval. Nothing in this provision is to be construed as defining equipment, systems or components OPERABLE, when such items are found or known to be inoperable although still meeting the Surveillance Requirements.

4.0.4 This specification ensures that surveillance activities associated with a Limiting Conditions for Operation have been performed within the specified time interval prior to entry into an applicable OPERATIONAL CONDITION or other specified applicability condition. The intent of this provision is to ensure that surveillance activities have been satisfactorily demonstrated on a current basis as required to meet the OPERABILITY requirements of the Limiting Condition for Operation.

Under the terms of this specification, for example, during initial plant startup or following extended plant outage, the applicable surveillance activities must be performed within the stated surveillance interval prior to placing or returning the system or equipment into OPERABLE status.

4.0.5 This specification ensures that inservice inspection of ASME Code Class 1, 2 and 3 components and inservice testing of ASME Code Class 1, 2 and 3 pumps and valves will be performed in accordance with a periodically updated version of Section XI of the ASME Boiler and Pressure Vessel Code and Addenda as required by 10 CFR 50, Section 50.55a. Relief from any of the above requirements has been provided in writing by the Commission and is not a part of these Technical Specifications.

This specification includes a clarification of the frequencies of performing the inservice inspection and testing activities required by Section XI of the ASME Boiler and Pressure Vessel Code and applicable Addenda. This clarification is provided to ensure consistency in surveillance intervals throughout these Technical Specifications and to remove any ambiguities relative to the frequencies for performing the required inservice inspection and testing activities.

Under the terms of this specification, the more restrictive requirements of the Technical Specifications take precedence over the ASME Boiler and Pressure Vessel Code and applicable Addenda. For example, the requirements of Specification 4.0.4 to perform surveillance activities prior to entry into an OPERATIONAL CONDITION or other specified applicability condition takes precedence over the ASME Boiler and Pressure Vessel Code provision which allows pumps to be tested up to one week after return to normal operation. And for example, the Technical Specification definition of OPERABLE does not grant a grace period before a device that is not capable of performing its specified function is declared inoperable and takes precedence over the ASME Boiler and Pressure Vessel provision which allows a valve to be incapable of performing its specified function for up to 24 hours before being declared inoperable.

3/4.1.1 SHUTDOWN MARGIN

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

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

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

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

3/4.1.2 REACTIVITY ANOMALIES

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

, non-accident and transient

3/4.1.3 CONTROL RODS

The specifications of this section ensure that (1) the minimum SHUTDOWN MARGIN is maintained, (2) the control rod insertion times are consistent with those used in the accident analyses, and (3) ~~limit~~ the potential effects of the rod drop accident, The ACTION statements permit variations from the basic requirements but at the same time impose more restrictive criteria for continued operation. A limitation on inoperable rods is set such that the resultant effect on total rod worth and scram shape will be kept to a minimum. The requirements for the various scram time measurements ensure that any indication of systematic problems with rod drives will be investigated on a timely basis.

and rod withdrawal error event are limited.

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Damage within the control rod drive mechanism could be a generic problem, therefore with a control rod immovable because of excessive friction or mechanical interference, operation of the reactor is limited to a time period which is reasonable to determine the cause of the inoperability and at the same time prevent operation with a large number of inoperable control rods.

Control rods that are inoperable for other reasons are permitted to be taken out of service provided that those in the nonfully-inserted position are consistent with the SHUTDOWN MARGIN requirements.

but trippable

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The number of control rods permitted to be inoperable could be more than the eight allowed by the specification, but the occurrence of eight inoperable rods could be indicative of a generic problem and the reactor must be shutdown for investigation and resolution of the problem.

The control rod system is designed to bring the reactor subcritical at a rate fast enough to prevent the MCPR from becoming less than 1.06 during the limiting power transient analyzed in Section 15.4 of the FSAR. This analysis shows that the negative reactivity rates resulting from the scram with the average response of all the drives as given in the specifications, provide the required protection and MCPR remains greater than 1.06. The occurrence of scram times longer then those specified should be viewed as an indication of a systemic problem with the rod drives and therefore the surveillance interval is reduced in order to prevent operation of the reactor for long periods of time with a potentially serious problem.

The scram discharge volume is required to be OPERABLE so that it will be available when needed to accept discharge water from the control rods during a reactor scram and will isolate the reactor coolant system from the containment when required.

Control rods with inoperable accumulators are declared inoperable and Specification 3.1.3.1 then applies. This prevents a pattern of inoperable accumulators that would result in less reactivity insertion on a scram than has been analyzed even though control rods with inoperable accumulators may still be inserted with normal drive water pressure. Operability of the accumulator ensures that there is a means available to insert the control rods even under the most unfavorable depressurization of the reactor.

slowly scrammed via reactor pressure or

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CONTROL RODS (Continued)

Control rod coupling integrity is required to ensure compliance with the analysis of the rod drop accident in the FSAR. The overtravel position feature provides the only positive means of determining that a rod is properly coupled and therefore this check must be performed prior to achieving criticality after completing CORE ALTERATIONS that could have affected the control rod coupling integrity. The subsequent check is performed as a backup to the initial demonstration.

In order to ensure that the control rod patterns can be followed and therefore that other parameters are within their limits, the control rod position indication system must be OPERABLE.

The control rod housing support restricts the outward movement of a control rod to less than 3 inches in the event of a housing failure. The amount of rod reactivity which could be added by this small amount of rod withdrawal is less than a normal withdrawal increment and will not contribute to any damage to the primary coolant system. The support is not required when there is no pressure to act as a driving force to rapidly eject a drive housing.

The required surveillance intervals are adequate to determine that the rods are OPERABLE and not so frequent as to cause excessive wear on the system components.

3/4.1.4 CONTROL ROD PROGRAM CONTROLS

The rod withdrawal limiter system input power signal orginates from the first stage turbine pressure. When operating with the steam bypass valves open, this signal indicates a core power level which is less than the true core power. Consequently, near the low power setpoint and high power setpoint of the rod pattern control system, the potential exists for nonconservative control rod withdrawals. Therefore, when operating at a sufficiently high power level, there is a small probability of violating fuel Safety Limits during a licensing basis rod withdrawal error transient. To ensure that fuel Safety Limits are not violated, this specification prohibits control rod withdrawal when a biased power signal exists and core power exceeds the specified level.

Control rod withdrawal and insertion sequences are established to assure that the maximum insequence individual control rod or control rod segments which are withdrawn at any time during the fuel cycle could not be worth enough to result in a peak fuel enthalpy greater than 280 cal/gm in the event of a control rod drop accident. The specified sequences are characterized by homogeneous, scattered patterns of control rod withdrawal. When THERMAL POWER is greater than 20% of RATED THERMAL POWER, there is no possible rod worth which, if dropped at the design rate of the velocity limiter, could result in a peak enthalpy of 280 cal/gm. Thus requiring the RPCS to be OPERABLE when THERMAL POWER is less than or equal to 20% of RATED THERMAL POWER provides adequate control.

CONTROL ROD PROGRAM CONTROLS (Continued)

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The RPCS provides automatic supervision to assure that out-of-sequence rods will not be withdrawn or inserted.

The analysis of the rod drop accident is presented in Section 15.4 of the FSAR and the techniques of the analysis are presented in a topical report, Reference 1, and two supplements, References 2 and 3.

The RPCS is also designed to automatically prevent fuel damage in the event of erroneous rod withdrawal from locations of high power density during higner power operation.

A dual channel system is provided that, above the low power setpoint, restricts the withdrawal distances of all non-peripheral control rods. This restriction is greatest at highest power levels.

3/4.1.5 STANDBY LIQUID CONTROL SYSTEM

The standby liquid control system provides a backup capability for bringing the reactor from full power to a cold, Xenon-free shutdown, assuming that the withdrawn control rods remain fixed in the rated power pattern. To meet this objective it is necessary to inject a quantity of boron which produces a concentration of 660 ppm in the reactor core in approximately 90 to 120 minutes. A minimum available quantity of 4587 gallons of sodium pentaborate solution containing a minimum of 5500 lbs. of sodium pentaborate is required to meet a shutdown requirement of 3%. There is an additional allowance of 165 ppm in the reactor core to account for imperfect mixing and the filling of other piping systems connected to the reactor vessel. The time requirement was selected to override the reactivity insertion rate due to cooldown following the Xenon poison peak and the required pumping rate is 41.2 gpm. The minimum storage volume of the solution is established to allow for the portion below the pump suction that cannot be inserted. The temperature requirement is necessary to ensure that the sodium pentaborate remains in solution.

With redundant pumps and explosive injection valves and with a highly reliable control rod scram system, operation of the reactor is permitted to continue for short periods of time with the system inoperable or for longer periods of time with one of the redundant components inoperable.

Surveillance requirements are established on a frequency that assures a high reliability of the system. Once the solution is established, boron concentration will not vary unless more boron or water is added, thus a check on the temperature and volume once each 24 hours assures that the solution is available for use.

Replacement of the explosive charges in the valves at regular intervals will assure that these valves will not fail because of deterioration of the charges.

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1. C. J. Paone, R. C. Stirn and J. A. Woolley, "Rod Drop Accident Analysis for Large BWR's," G. E. Topical Report NEDO-10527, March 1972
2. C. J. Paone, R. C. Stirn and R. M. Young, Supplement 1 to NEDO-10527, July 1972
3. J. M. Haun, C. J. Paone and R. C. Stirn, Addendum 2, "Exposed Cores," Supplement 2 to NEDO-10527, January 1973

The daily requirement for calculating APLHGR when THERMAL POWER is greater than or equal to 25% of RATED THERMAL POWER is sufficient since power distribution shifts are very slow when there have not been significant power or control rod changes. The requirement to calculate APLHGR within 12 hours after the completion of a THERMAL POWER increase of at least 15% of RATED THERMAL POWER ensures thermal limits are met after power distribution shifts while still allotting time for the power distribution to stabilize. The requirement for calculating APLHGR after initially determining a LIMITING CONTROL ROD PATTERN exists ensures that APLHGR will be known following a change in THERMAL POWER or power shape, that could place operation exceeding a thermal limit.

design basis loss-of-coolant accident will not exceed the 2200°F limit specified in 10 CFR 50.46.

3/4.2.1 AVERAGE PLANAR LINEAR HEAT GENERATION RATE

This specification assures that the peak cladding temperature following the postulated design basis loss-of-coolant accident will not exceed the limit specified in 10 CFR 50.46.

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

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

a. Input Changes

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

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

3. Corrected guide tube thermal resistance.

4. Correct heat capacity of reactor internals heat nodes.

AVERAGE PLANAR LINEAR HEAT GENERATION RATE (Continued)

b. Model Change

1.. Core CCFL pressure differential - 1 psi - Incorporate the assumption that flow from the bypass to lower plenum must overcome a 1 psi pressure drop in core.

2. Incoporate NRC pressure transfer assumption - The assumption used in the SAFE-REFLOOD pressure transfer when the pressure is increasing was changed.

A few of the changes affect the accident calculation irrespective of CCFL. These changes are listed below.

a. Input Change

1. Break Areas - The DBA break area was calculated more accurately.

b. Model Change

1. Improved Radiation and Conduction Calculation - Incorporation of CHASTE 05 for heatup calculation.

A list of the significant plant input parameters to the loss-of-coolant accident analysis is presented in Bases Table B 3.2.1-1.

3/4.2.2 APRM SETPOINTS

The fuel cladding integrity Safety Limits of Specification 2.1 were based on a power distribution which would yield the design LHGR at RATED THERMAL POWER. The flow biased simulated thermal power-high scram setting and flow biased simulated thermal power-upscale control rod block functions of the APRM instruments must be adjusted to ensure that the MCPR does not become less than 1.06 or that ≥ 1% plastic strain does not occur in the degraded situation. The scram settings and rod block settings are adjusted in accordance with the formula in this specification when the combination of THERMAL POWER and MFLPD indicates a peak power distribution to ensure than an LHGR transient would not be increased in degraded conditions.

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The daily requirement to verify the APRM control rod block and scram setpoints when THERMAL POWER is greater than or equal to 25% of RATED THERMAL POWER is sufficient since power distribution shifts are very slow when there have not been significant power or control rod changes. The requirement to verify the APRM setpoints within 12 hours after the completion of a THERMAL POWER increase of at least 15% of RATED THERMAL POWER ensures thermal limits are met after power distribution shifts while still allotting time for the power distribution to stabilize. The requirement to verify the APRM setpoints once per 12 hours after initially determining MFLPD to be greater than FRTP ensures that the consequences of an LHGR transient would not be increased in degraded conditions.

Bases Table B 3.2.1-1

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

Plant Parameters;

Core THERMAL POWER .... 3993 MWt* which corresponds to 105% of rated steam flow

Vessel Steam Output .... 17.3×10^6 lbm/hr which corresponds to 105% of rated steam flow

Vessel Steam Dome Pressure............. 1060 psia

Design Basis Recirculation Line Break Area for:

a. Large Breaks 3.1 ft^2.

b. Small Breaks 0.1 ft^2.

Fuel Parameters:

FUEL TYPE	FUEL BUNDLE GEOMETRY	PEAK TECHNICAL SPECIFICATION LINEAR HEAT GENERATION RATE (kW/ft)	DESIGN AXIAL PEAKING FACTOR	INITIAL MINIMUM CRITICAL POWER RATIO
Initial Core	8 x 8 RP	13.4	1.4	1.17

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

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

The reference core flow increase event used to establish the MCPR$_f$ is a hypothesized slow flow runout to maximum, that does not result in a scram from neutron flux overshoot exceeding the APRM neutron flux-high level (Table 2.2.1-1 item 2). With this basis the MCPR$_f$ curve is generated from a series of steady state core thermal hydraulic calculations performed at several core power and flow conditions along the steepest flow control line. This corresponds to the 105% steamflow flow control line (Figure B 3/4 2.3-1). In the actual calculations a conservative highly steep generic representation of the 105% steamflow flow control line has been used. Assumptions used in the original calculations of this generic flow control line were consistent with a slow flow increase transient duration of several minutes: a) the plant heat balance was assumed to be in equilibrium, and b) core xenon concentration was assumed to be constant. The generic flow control line is used to define several core power/flow states at which to perform steady-state core thermal-hydraulic evaluations.

The first state analyzed corresponded to the maximum core power at maximum core flow (102.5% of rated) after the flow runout. Several evaluations were performed at this state iterating on the normalized core power distribution input until the limiting bundle MCPR just exceeded the safety limit Specification (2.1.2). Next, similar calculations of core MCPR performance were determined at other power/flow conditions on the generic flow control line, assuming the same normalized core power distribution. The result is a definition of the MCPR$_f$ performance requirement such that a flow increase event to maximum (102.5%) will not violate the safety limit. (The assumption of constant power distribution during the runout power increase has been shown to be conservative. Increased negative reactivity feedback in the high power limiting bundle due to doppler and voids would reduce the limiting bundle relative power in an actual runout).

The MCPR$_p$ is established to protect the core from plant transients other than core flow increase including the localized rod withdrawal error event. Core power dependent setpoints are incorporated (incremental control rod withdrawal limits) in the Rod Withdrawal Limiter (RWL) System Specification (3.3.6). These setpoints allow greater control rod withdrawal at lower core powers where core thermal margins are large. However, the increased rod withdrawal requires higher initial MCPR's to assure the MCPR safety limit Specification (2.1.2) is not violated. The analyses that establishes the power dependent MCPR requirements that support the RWL system are presented in GESSAR II, Appendix 15B. Since the severity of other (core-wide) transients at off-rated conditions is limited by the requirement to setdown the APRM flow biased simulated thermal power-high scram trip setpoint, Specification (3.2.2), the rod withdrawal error is the limiting transient and establishes MCPR$_p$ requirements.

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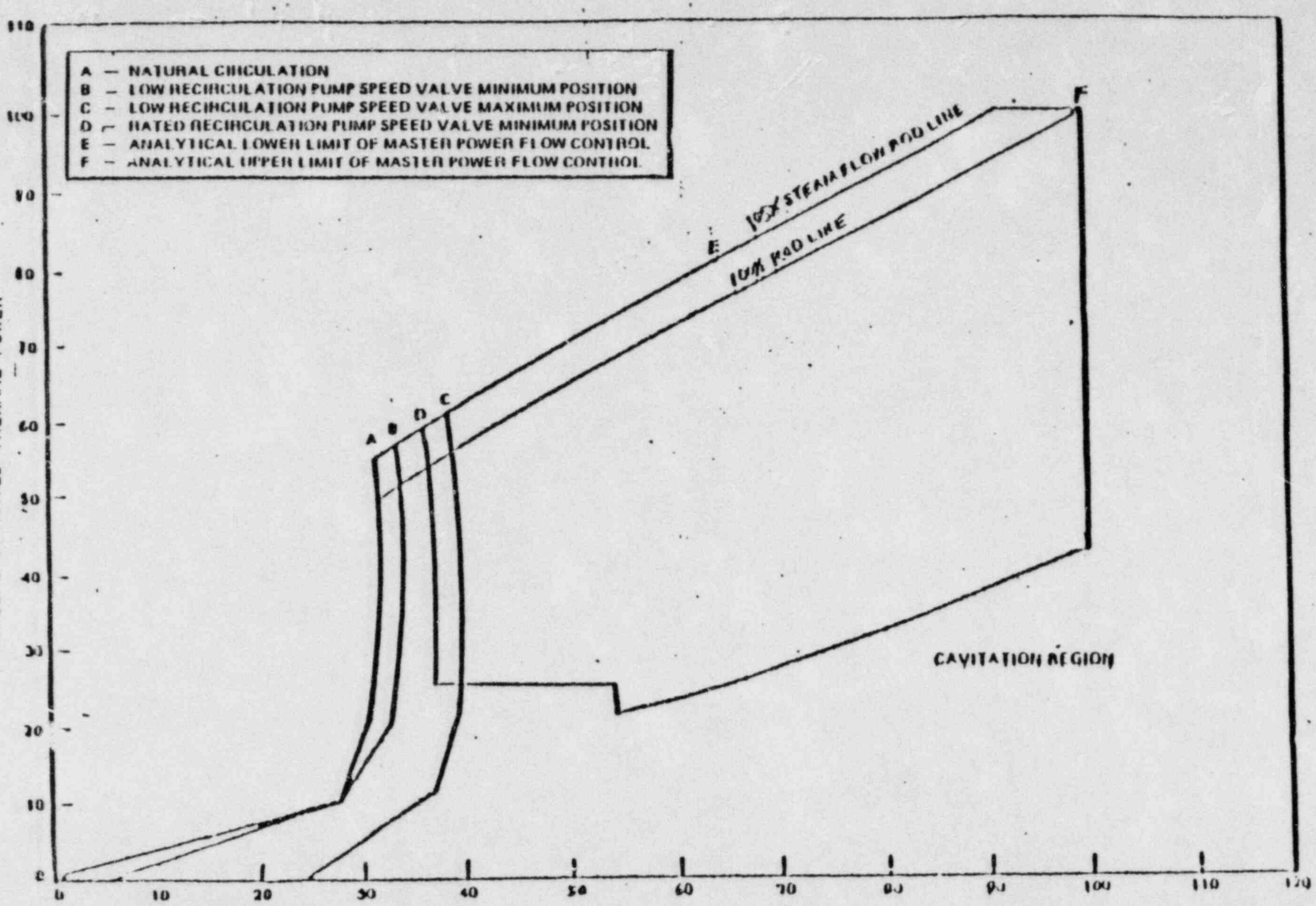
~~the limiting bundle's relative power was adjusted until the MCPR was slightly above the Safety Limit. Using this relative bundle power, the MCPRs were calculated at different points along the 105% of rated steam flow control line corresponding to different core flows. The calculated MCPR at a given point of core flow is defined as MCPR$_f$.~~

~~The MCPR$_p$s are established to protect the core from plant transients other than core flow increases, including the localized event such as rod withdrawal error. The MCPR$_p$s were calculated based upon the most limiting transient at the given core power level.~~



Power - Flow Operating Map

Figure B 3/4 2.3-1

The daily requirement for calculating MCPR when THERMAL POWER is greater than or equal to 25% of RATED THERMAL POWER is sufficient since power distribution shifts are very slow when there have not been significant power or control rod changes. The requirement to calculate MCPR within 12 hours after the completion of a THERMAL POWER increase of at least 15% of RATED THERMAL POWER ensures thermal limits are met after power distribution shifts while still allotting time for the power distribution to stabilize. The requirement for calculating MCPR after initially determining a LIMITING CONTROL ROD PATTERN exists ensures that MCPR will be known following a change in THERMAL POWER or power shape, that could place operation exceeding a thermal limit.

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

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3/4.2.4 LINEAR HEAT GENERATION RATE

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

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The daily requirement for calculating LHGR when THERMAL POWER is greater than or equal to 25% of RATED THERMAL POWER is sufficient since power distribution shifts are very slow when there have not been significant power or control rod changes. The requirement to calculate LHGR within 12 hours after the completion of a THERMAL POWER increase of at least 15% of RATED THERMAL POWER ensures thermal limits are met after power distribution shifts while still allotting time for the power distribution to stabilize. The requirement for calculating LHGR after initially determining a LIMITING CONTROL ROD PATTERN exists ensures that LHGR will be known following a change in THERMAL POWER or power shape that, could place operation exceeding a thermal limit.

4. TASC 01-A Computer Program For The Transient Analysis of a Single Channel, Technical Description, NEDE-25149, January 1980.

3/4.3.1 REACTOR PROTECTION SYSTEM INSTRUMENTATION

The reactor protection system automatically initiates a reactor scram to:

a. Preserve the integrity of the fuel cladding.

b. Preserve the integrity of the reactor coolant system.

c. Minimize the energy which must be adsorbed following a loss-of-coolant accident, and

d. Prevent inadvertent criticality.

This specification provides the limiting conditions for operation necessary to preserve the ability of the system to perform its intended function even during periods when instrument channels may be out of service because of maintenance. When necessary, one channel may be made inoperable for brief intervals to conduct required surveillance.

The reactor protection system is made up of two independent trip systems. There are usually four channels to monitor each parameter with two channels in each trip system. The outputs of the channels in a trip system are combined in a logic so that either channel will trip that trip system. The tripping of both trip systems will produce a reactor scram. ~~The system meets the intent of IEEE-279 for nuclear power plant protection systems~~. The bases for the trip settings of the RPS are discussed in the bases for Specification 2.2.1. /079

The measurement of response time at the specified frequencies provides assurance that the protective functions associated with each channel are completed within the time limit assumed in the accident analysis. No credit was taken for those channels with response times indicated as not applicable. Response time may be demonstrated by any series of sequential, overlapping or total channel test measurement, provided such tests demonstrate the total channel response time as defined. Sensor response time verification may be demonstrated by either (1) inplace, onsite or offsite test measurements, or (2) utilizing replacement sensors with certified response times.

3/4.3.2 ISOLATION ACTUATION INSTRUMENTATION

This specification ensures the effectiveness of the instrumentation used to mitigate the consequences of accidents by prescribing the OPERABILITY trip setpoints and response times for isolation of the reactor systems. When necessary, one channel may be inoperable for brief intervals to conduct required surveillance. Some of the trip settings may have tolerances explicitly stated where both the high and low values are critical and may have a substantial effect on safety. Negative barometric pressure fluctuations are accounted for in the trip setpoints and allowable values specified for drywell pressure-high. The setpoints of other instrumentation, where only the high or low end of the setting have a direct bearing on safety, are established at a level away from the normal operating range to prevent inadvertent actuation of the systems involved.

Except for the MSIVs, the safety analysis does not address individual sensor response times or the response times of the logic systems to which the sensors are connected. For D.C. operated valves, a 3 second delay is assumed before the valve starts to move. For A.C. operated valves, it is assumed that

ISOLATION ACTUATION INSTRUMENTATION (continued)

the A.C. power supply is lost and is restored by startup of the emergency diesel generators. In this event, a time of 13 seconds is assumed before the valve starts to move. In addition to the pipe break, the failure of the D.C. operated valve is assumed; thus the signal delay (sensor response) is concurrent with the 13 second diesel startup. The safety analysis considers an allowable inventory loss in each case which in turn determines the valve speed in conjunction with the 13 second delay. It follows that checking the valve speeds and the 13 second time for emergency power establishment will establish the response time for the isolation functions. However, to enhance overall system reliability and to monitor instrument channel response time trends, the isolation actuation instrumentation response time shall be measured and recorded as a part of the ISOLATION SYSTEM RESPONSE TIME.

Operation with a trip set less conservative than its Trip Setpoint but within its specified Allowable Value is acceptable on the basis that the difference between each Trip Setpoint and the Allowable Value is equal to or greater than the drift allowance assumed for each trip in the safety analyses.

3/4.3.3 EMERGENCY CORE COOLING SYSTEM ACTUATION INSTRUMENTATION

The emergency core cooling system actuation instrumentation is provided to initiate actions to mitigate the consequences of accidents that are beyond the ability of the operator to control. This specification provides the OPERABILITY requirements, trip setpoints and response times that will ensure effectiveness of the systems to provide the design protection. Negative barometric pressure fluctuations are accounted for in the trip setpoints and allowable values specified for drywell pressure-high. Although the instruments are listed by system, in some cases the same instrument may be used to send the actuation signal to more than one system at the same time.

Operation with a trip set less conservative than its Trip Setpoint but within its specified Allowable Value is acceptable on the basis that the difference between each Trip Setpoint and the Allowable Value is equal to or greater than the drift allowance assumed for each trip in the safety analyses.

3/4.3.4 RECIRCULATION PUMP TRIP ACTUATION INSTRUMENTATION

The anticipated transient without scram (ATWS) recirculation pump trip system provides a means of limiting the consequences of the unlikely occurrence of a failure to scram during an anticipated transient. The response of the plant to this postulated event falls within the envelope of study events in General Electric Company Topical Report NEDO-10349, dated March 1971 and NEDO-24222, dated December 1979, and Section 15.8 Appendix 15A of the FSAR.

The end-of-cycle recirculation pump trip (EOC-RPT) system is a part of the Reactor Protection System and is an essential safety supplement to the reactor trip. The purpose of the EOC-RPT is to recover the loss of thermal margin which occurs at the end-of-cycle. The physical phenomenon involved is that the void reactivity feedback due to a pressurization transient can add positive reactivity to the reactor system at a faster rate than the control rods add negative scram reactivity. Each EOC-RPT system trips both recirculation pumps, reducing coolant flow in order to reduce the void collapse in the core during two of the most limiting pressurization events. The two events for which the EOC-RPT protective

The OPERABILITY of the control rod block instrumentation in OPERATIONAL CONDITION 5 is to provide diversity of rod block protection to the one-rod-out-interlock.

RECIRCULATION PUMP TRIP ACTUATION INSTRUMENTATION (Continued)

feature will function are closure of the turbine stop valves and fast closure of the turbine control valves.

A fast closure sensor from each of two turbine control valves provides input to the EOC-RPT system; a fast closure sensor from each of the other two turbine control valves provides input to the second EOC-RPT system. Similarly, a closure sensor for each of two turbine stop valves provides input to one EOC-RPT system; a closure sensor from each of the other two stop valves provides input to the other EOC-RPT system. For each EOC-RPT system, the sensor relay contacts are arranged to form a 2-out-of-2 logic for the fast closure of turbine control valves and a 2-out-of-2 logic for the turbine stop valves. The operation of either logic will actuate the EOC-RPT system and trip both recirculation pumps.

Each EOC-RPT system may be manually bypassed by use of a keyswitch which is administratively controlled. The manual bypasses and the automatic Operating Bypass at less than 40% of RATED THERMAL POWER are annunciated in the control room.

The EOC-RPT system response time is the time assumed in the analysis between initiation of valve motion and complete suppression of the electric arc, i.e., 190 ms, less the time allotted from start of motion of the stop valve or turbine control valve until the sensor relay contact supplying the input to the reactor protection system opens, i.e., 70 ms, and less the time allotted for breaker arc suppression determined by test, as correlated to manufacturer's test results, i.e., 50 ms, and plant pre-operational test results.

Operation with a trip set less conservative than its Trip Setpoint but within its specified Allowable Value is acceptable on the basis that the difference between each Trip Setpoint and the Allowable Value is equal to or greater than the drift allowance assumed for each trip in the safety analyses.

3/4.3.5 REACTOR CORE ISOLATION COOLING SYSTEM ACTUATION INSTRUMENTATION

The reactor core isolation cooling system actuation instrumentation is provided to initiate actions to assure adequate core cooling in the event of reactor isolation from its primary heat sink and the loss of feedwater flow to the reactor vessel without providing actuation of any of the emergency core cooling equipment.

Operation with a trip set less conservative than its Trip Setpoint but within its specified Allowable Value is acceptable on the basis that the difference between each Trip Setpoint and the Allowable Value is equal to or greater than the drift allowance assumed for each trip in the safety analyses.

3/4.3.6 CONTROL ROD BLOCK INSTRUMENTATION

The control rod block functions are provided consistent with the requirements of the specifications in Section 3/4.1.4, Control Rod Program Controls and Section 3/4.2 Power Distribution Limits. The trip logic is arranged so that a trip in any one of the inputs will result in a control rod block. 1009

Operation with a trip set less conservative than its Trip Setpoint but within its specified Allowable Value is acceptable on the basis that the difference between each Trip Setpoint and the Allowable Value is equal to or greater than the drift allowance assumed for each trip in the safety analyses.

3/4.3.7 MONITORING INSTRUMENTATION

3/4.3.7.1 RADIATION MONITORING INSTRUMENTATION

The OPERABILITY of the radiation monitoring instrumentation ensures that; (1) the radiation levels are continually measured in the areas served by the individual channels; (2) the alarm or automatic action is initiated when the radiation level trip setpoint is exceeded; and (3) sufficient information is available on selected plant parameters to monitor and assess these variables following an accident. This capability is consistent with the recommendations of NUREG-0737, "Clarification of TMI Action Plan Requirements," November, 1980.

3.4.3.7.2 SEISMIC MONITORING INSTRUMENTATION

The OPERABILITY of the seismic monitoring instrumentation ensures that sufficient capability is available to promptly determine the magnitude of a seismic event and evaluate the response of those features important to safety. This capability is required to permit comparison of the measured response to that used in the design basis for the unit.

3/4.3.7.3 METEOROLOGICAL MONITORING INSTRUMENTATION

The OPERABILITY of the meteorological monitoring instrumentation ensures that sufficient meteorological data is available for estimating potential radiation doses to the public as a result of routine or accidental release of radioactive materials to the atmosphere. This capability is required to evaluate the need for initiating protective measures to protect the health and safety of the public. This instrumentation is consistent with the recommendations of Regulatory Guide 1.23 "Onsite Meteorological Programs," February, 1972.

3/4.3.7.4 REMOTE SHUTDOWN ~~MONITORING~~ System INSTRUMENTATION And Controls

The OPERABILITY of the remote shutdown ~~monitoring~~ system instrumentation and controls ensures that sufficient capability is available to permit shutdown and maintenance of HOT SHUTDOWN of the unit from locations outside of the control room. This capability is required in the event control room habitability is lost and is consistent with General Design Criteria 19 of 10 CFR 50. 1077

3/4.3.7.5 ACCIDENT MONITORING INSTRUMENTATION

The OPERABILITY of the accident monitoring instrumentation ensures that sufficient information is available on selected plant parameters to monitor and assess important variables following an accident. This capability is consistent with the recommendations of NUREG-0578, "TMI-2 Lessons Learned Task Force Status Report and Short-Term Recommendations".

The system consists of 16 sensors, of which only
INST 8 are selected and need to be OPERABLE at a time,
BASE to provide the inputs to the 8 monitoring channels.
The remaining 8 sensors may be used as
3/4. replacement sensor inputs for failed sensors or
to provide a change in location of the area
stat being monitored. tup
and e
withou er-
mediate range monitors are on scale adequate information is available without the SRMs and they can be retracted. The SRMs are required OPERABLE in OPERATIONAL CONDITION 2 to provide for rod block capability, and are required OPERABLE in OPERATIONAL CONDITIONS 3 and 4 to provide monitoring capability which provides diversity of protection to the Mode Switch interlocks.

3/4.3.7.7 TRAVERSING IN-CORE PROBE SYSTEM

The OPERABILITY of the traversing in-core probe system with the specified minimum complement of equipment ensures that the measurements obtained from use of this equipment accurately represent the spatial neutron flux distribution of the reactor core.

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3/4.3.7.8 CHLORINE DETECTION SYSTEM

The OPERABILITY of the chlorine detection system ensures that an accidental chlorine release will be detected promptly and the necessary protective actions will be automatically initiated to provide protection for control room personnel. Upon detection of a high concentration of chlorine, the control room emergency ventilation system will automatically be placed in the isolation mode of operation to provide the required protection. The detection systems required by this specification are consistent with the recommendations of Regulatory Guide 1.95 "Protection of Nuclear Power Plant Control Room Operators against an Accidental Chlorine Release", Revision 1, January 1977.

3/4.3.7.9 FIRE DETECTION INSTRUMENTATION

OPERABILITY of the detection instrumentation ensures that both adequate warning capability is available for prompt detection of fires and that fire suppression systems, that are actuated by fire detectors, will discharge extinguishing agent in a timely manner. Prompt detection and suppression of fires will reduce the potential for damage to safety-related equipment and is an integral element in the overall facility fire protection program. ed 1073

In the event that a portion of the fire detection instrumentation is inoperable, increasing the frequency of fire watch patrols in the affected area(s), or zone(s), is required to provide detection capability until the inoperable instrumentation is restored to OPERABILITY.

3/4.3.7.10 LOOSE-PART DETECTION SYSTEM

The OPERABILITY of the loose-part detection system ensures that sufficient capability is available to detect loose metallic parts in the primary system and avoid or mitigate damage to primary system components. The allowable out-of-service times and surveillance requirements are consistent with the recommendations of Regulatory Guide 1.133, "Loose-Part Detection Program for the Primary System of Light-Water-Cooled Reactors," May 1981. 1352

The TIP System Operability is demonstrated by normalizing all probes (i.e., detectors) prior to performing an LPRM calibration function. Monitoring core thermal limits may involve utilizing individual detectors to monitor selected areas of the reactor core, thus all detectors may not be required to OPERABLE. The operability of individual detectors to be used for monitoring is demonstrated by comparing the detector(s) output with data obtained during the previous LPRM calibration. 1050 methods

- Those instruments that monitor the activity of gaseous effluents being released to the environment shall have their alarm/trip setpoints calculated in accordance with the ~~procedures~~ in the ODCM to ensure that the alarm/trip will occur prior to exceeding the limits of 10 CFR Part 20. Other instruments that monitor [illegible] offgas processing, (i.e., the Explosive Gas Monitor, Offgas Pre-Treatment Monitor, and Offgas Post-Treatment Monitor) are [illegible] calibrated according to plant procedures.

3/4.3.7.1

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monitor

liquid effluents during actual or potential releases of liquid alarm/trip setpoints for these instruments shall be calculated in accordance with the procedures in the ODCM to ensure that the alarm/trip will occur prior to exceeding the limits of 10 CFR Part 20. The OPERABILITY and use of this instrumentation is consistent with the requirements of General Design Criteria 60, 63 and 64 of Appendix A to 10 CFR Part 50.

3/4.3.7.12 RADIOACTIVE GASEOUS EFFLUENT MONITORING INSTRUMENTATION

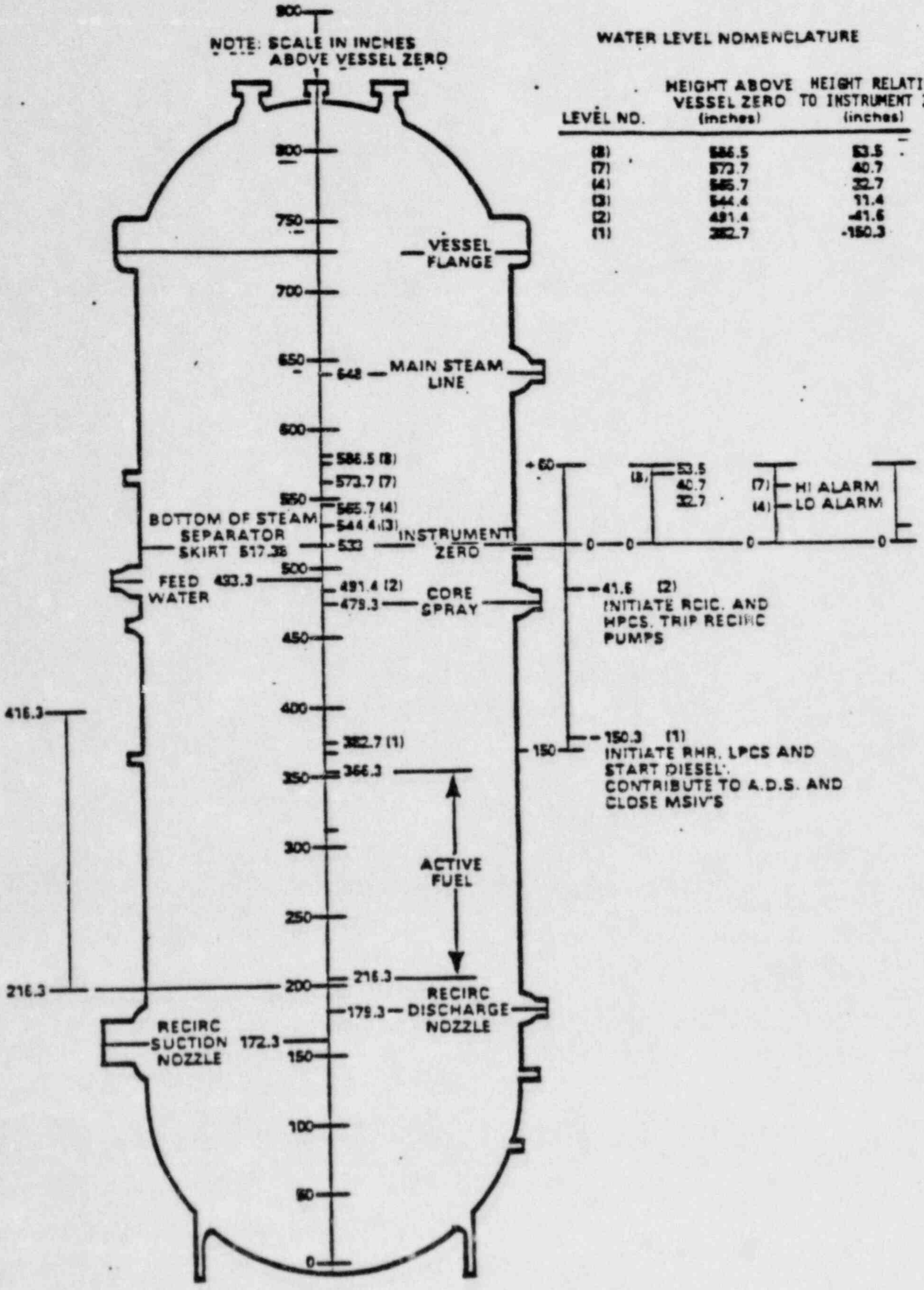
The radioactive gaseous effluent monitoring instrumentation is provided to monitor and control, as applicable, ~~the releases of radioactive materials in~~ gaseous effluents during actual or potential releases. ~~of gaseous effluents~~. ~~The alarm/trip setpoints for these instruments shall be calculated in accordance with the procedures in the ODCM to ensure that the alarm/trip will occur prior to exceeding the limits of 10 CFR Part 20~~. ~~This instrumentation of potentially explosive gas mixtures in the waste gas holdup system~~. The OPERABILITY and use of this instrumentation is consistent with the requirements of General Design Criteria 60, 63 ~~and~~ and 64 of Appendix A to 10 CFR Part 50. 1045

3/4.3.8 PLANT SYSTEMS ACTUATION INSTRUMENTATION

The plant systems actuation instrumentation is provided to initiate action to mitigate the consequences of accidents that are beyond the ability of the operator to control. The LPCI mode of the RHR system is automatically initiated on a high drywell pressure signal and/or a low reactor water level, level 1, signal. The containment spray system will then actuate automatically following high drywell and high containment pressure signals. Negative barometric pressure fluctuations are accounted for in the trip setpoints and allowable values specified for drywell and containment pressure-high. A 10-minute minimum, 13-minute maximum time delay exists between initiation of LPCI and containment spray actuation. A high reactor water level, level 8, signal will actuate the feedwater system/main turbine trip system.

3/4.3.9 TURBINE OVERSPEED PROTECTION

This specification is provided to ensure that the turbine overspeed protection [illegible] instrumentation and the turbine speed control valves are OPERABLE and will protect the turbine from excessive overspeed. Protection from turbine excessive overspeed is required since excessive overspeed of the turbine could generate potentially damaging missiles which could impact and damage safety related components, equipment or structures. 1148



WATER LEVEL NOMENCLATURE

LEVEL NO.	HEIGHT ABOVE VESSEL ZERO (inches)	HEIGHT RELATIVE TO INSTRUMENT ZERO (inches)
(8)	586.5	53.5
(7)	573.7	40.7
(4)	565.7	32.7
(3)	544.4	11.4
(2)	491.4	-41.6
(1)	382.7	-150.3

Bases Figure B 3/4 3-1

REACTOR VESSEL WATER LEVEL

Amendment No. 7, 10

3/4.4.1 RECIRCULATION SYSTEM

Operation with one reactor core coolant recirculation loop inoperable is prohibited until an evaluation of the performance of the ECCS during one loop operation has been performed, evaluated and determined to be acceptable.

An inoperable jet pump is not, in itself, a sufficient reason to declare a recirculation loop inoperable, but it does, in case of a design-basis-accident, increase the blowdown area and reduce the capability of reflooding the core; thus, the requirement for shutdown of the facility with a jet pump inoperable. Jet pump failure can be detected by monitoring jet pump performance on a prescribed schedule for significant degradation. Recirculation loop flow mismatch limits are in compliance with ECCS LOCA analysis design criteria. The limits will ensure an adequate core flow coastdown from either recirculation loop following a LOCA.

In order to prevent undue stress on the vessel nozzles and bottom head region, the recirculation loop temperatures shall be within 50°F of each other prior to startup of an idle loop. The loop temperature must also be within 50°F of the reactor pressure vessel coolant temperature to prevent thermal shock to the recirculation pump and recirculation nozzles. Since the coolant in the bottom of the vessel is at a lower temperature than the coolant in the upper regions of the core, undue stress on the vessel would result if the temperature difference was greater than 100°F.

041 1

The recirculation flow control valves provide regulation of individual recirculation loop drive flows; which, in turn, will vary the flow rate of coolant through the reactor core over a range consistent with the rod pattern and recirculation pump speed. The recirculation flow control system consists of the electronic and hydraulic components necessary for the positioning of the two hydraulically actuated flow control valves. Solid state control logic will generate a flow control valve "motion inhibit" signal in response to any one of several hydraulic power unit or analog control circuit failure signals. The "motion inhibit" signal causes hydraulic power unit shutdown and hydraulic isolation such that the flow control valve fails "as is". This design feature insures that the flow control valves do not respond to potentially erroneous control signals.

Electronic limiters exist in the position control loop of each flow control valve to limit the flow control valve stroking rate to 10±1% per second in the opening and closing directions on a control signal failure. The analysis of the recirculation flow control failures on increasing and decreasing flow are presented in Sections 15.3 and 15.4 of the FSAR respectively.

The required surveillance interval is adequate to ~~i~~ensure that the flow control valves remain OPERABLE and not so frequent as to cause excessive wear on the system components.

3/4.4.3 REACTOR COOLANT SYSTEM LEAKAGE

3/4.4.3.1 LEAKAGE DETECTION SYSTEMS

The RCS leakage detection systems required by this specification are provided to monitor and detect leakage from the reactor coolant pressure boundary. These systems provide the ability to measure leakage / 632 from fluid systems from the drywell.

3/4.4.3.2 OPERATIONAL LEAKAGE

The allowable leakage rates from the reactor coolant system have been based on the predicted and experimentally observed behavior of cracks in pipes. The normally expected background leakage due to equipment design and the detection capability of the instrumentation for determining system leakage was also considered. The evidence obtained from experiments suggests that for leakage somewhat greater than that specified for UNIDENTIFIED LEAKAGE the probability is small that the imperfection or crack associated with such leakage would grow rapidly. However, in all cases, if the leakage rates exceed the values specified or the leakage is located and known to be PRESSURE BOUNDARY LEAKAGE, the reactor will be shutdown to allow further investigation and corrective action. Service sensitive reactor coolant system Type 304 and 316 austenitic stainless steel piping; i.e., those that are subject to high stress or that certain relatively stagnant, intermittent, or low flow fluids, requires additional surveillance and leakage limits.

The Surveillance Requirements for RCS pressure isolation valves provide added assurance of valve integrity thereby reducing the probability of gross valve failure and consequent intersystem LOCA. Leakage from the RCS pressure isolation valves is IDENTIFIED LEAKAGE and will be considered as a portion of the allowed limit.

3/4.4.4 CHEMISTRY

The water chemistry limits of the reactor coolant system are established to prevent damage to the reactor materials in contact with the coolant. Chloride limits are specified to prevent stress corrosion cracking of the stainless steel. The effect of chloride is not as great when the oxygen concentration in the coolant is low, thus the 0.2 ppm limit on chlorides is permitted during POWER OPERATION. During shutdown and refueling operations, the temperature necessary for stress corrosion to occur is not present so a 0.5 ppm concentration of chlorides is not considered harmful during these periods.

Conductivity measurements are required on a continuous basis since changes in this parameter are an indication of abnormal conditions. When the conductivity is within limits, the pH, chlorides and other impurities affecting conductivity must also be within their acceptable limits. With the conductivity meter inoperable, additional samples must be analyzed to ensure that the chlorides are not exceeding the limits.

The surveillance requirements provide adequate assurance that concentrations in excess of the limits will be detected in sufficient time to take corrective action.

3/4.4.5 SPECIFIC ACTIVITY

The limitations on the specific activity of the primary coolant ensure that the 2 hour thyroid and whole body doses resulting from a main steam line failure outside the containment during steady state operation will not exceed small fractions of the dose guidelines of 10 CFR 100. The values for the limits on specific activity represent interim limits based upon a parametric evaluation by the NRC of typical site locations. These values are conservative in that specific site parameters, such as site boundary location and meteorological conditions, were not considered in this evaluation.

The ACTION statement permitting POWER OPERATION to continue for limited time periods with the primary coolant's specific activity 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, accommodates possible iodine spiking phenomenon which may occur following changes in THERMAL POWER. Operation with specific activity levels exceeding 0.2 microcuries per gram DOSE EQUIVALENT I-131 but less than or equal to 4.0 microcuries per gram DOSE EQUIVALENT I-131 must be restricted to no more than 800 hours per year, approximately 10 percent of the unit's yearly operating time, since these activity levels increase the 2 hour thyroid dose at the site boundary by a factor of up to 20 following a postulated steam line rupture. The reporting of cumulative operating time over 500 hours in any 6 month consecutive period with greater than 0.2 microcuries per gram DOSE EQUIVALENT I-131 will allow sufficient time for Commission evaluation of the circumstances prior to reaching the 800 hour limit.

Information obtained on iodine spiking will be used to assess the parameters associated with spiking phenomena. A reduction in frequency of isotopic analysis following power changes may be permissible if justified by the data obtained.

Closing the main steam line isolation valves prevents the release of activity to the environs should a steam line rupture occur outside containment.

The surveillance requirements provide adequate assurance that excessive specific activity levels in the reactor coolant will be detected in sufficient time to take corrective action.

3/4.4.6 PRESSURE/TEMPERATURE LIMITS

All components in the reactor coolant system are designed to withstand the effects of cyclic loads due to system temperature and pressure changes. These cyclic loads are introduced by normal load transients, reactor trips, and startup and shutdown operations. The various categories of load cycles used for design purposes are provided in Section 3.9 of the FSAR. During startup and shutdown, the rates of temperature and pressure changes are limited so that the maximum specified heatup and cooldown rates are consistent with the design assumptions and satisfy the stress limits for cyclic operation.

During heatup, the thermal gradients in the reactor vessel wall produce thermal stresses which vary from compressive at the inner wall to tensile at the outer wall. These thermal induced compressive stresses tend to alleviate the tensile stresses induced by the internal pressure. Therefore, a pressure-temperature curve based on steady state conditions, i.e., no thermal stresses, represents a lower bound of all similar curves for finite heatup rates when the inner wall of the vessel is treated as the governing location.

The heatup analysis also covers the determination of pressure-temperature limitations for the case in which the outer wall of the vessel becomes the controlling location. The thermal gradients established during heatup produce tensile stresses which are already present. The thermal induced stresses at the outer wall of the vessel are tensile and are dependent on both the rate of heatup and the time along the heatup ramp; therefore, a lower bound curve similar to that described for the heatup of the inner wall cannot be defined. Subsequently, for the cases in which the outer wall of the vessel becomes the stress controlling location, each heatup rate of interest must be analyzed on an individual basis.

The RT_{NDT} for welds and base material in the closure flange region is ≤10°F. The initial hydrostatic test pressure was 1563 psig

The reactor vessel materials have been tested to determine their initial RT_{NDT}. The results of these tests are shown in Table B 3/4.4.6-1. Reactor operation and resultant fast neutron, E greater than 1 Mev, irradiation will cause an increase in the RT_{NDT}. Therefore, an adjusted reference temperature, based upon the fluence, phosphorus content and copper content of the material in question, can be predicted using Bases Figure B 3/4.4.6-1 and the recommendations of Regulatory Guide 1.99, Revision 1, "Effects of Residual Elements on Predicted Radiation Damage to Reactor Vessel Materials." The pressure/ temperature limit curve, Figure 3.4.6.1-1, curves A', B' and C', includes predicted adjustments for this shift in RT_{NDT} for the end of life fluence as well as adjustments for possible errors in the pressure and temperature sensing instruments. Curves B' and C' are coincident with curves B and C, respectively. |219 |160

The actual shift in RT_{NDT} of the vessel material will be established periodically during operation by removing and evaluating in accordance with ASTM E185-73 and 10 CFR 50, Appendix H, irradiated reactor vessel material specimens installed near the inside wall of the reactor vessel in the core area. The irradiated specimens can be used with confidence in predicting reactor vessel material transition temperature shift. The operating limit curves of Figure 3.4.6.1-1 shall be adjusted, as required, on the basis of the specimen data and recommendations of Regulatory Guide 1.99, Revision 1.

PRESSURE/TEMPERATURE LIMITS (Continued)

The pressure-temperature limit lines shown in Figures 3.4.6.1-1, curves C, and C', and A. ~~and A'~~, for reactor criticality and for inservice leak and hydrostatic testing have been provided to assure compliance with the minimum temperature requirements of Appendix G to 10 CFR Part 50 for reactor criticality and for inservice leak and hydrostatic testing. with the modification to Paragraph IV.A.2.c per GE BWR Licensing Topical Report NEDO-21778-A. | 160

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3/4.4.7 MAIN STEAM LINE ISOLATION VALVES

Double isolation valves are provided on each of the main steam lines to minimize the potential leakage paths from the containment in case of a line break. Only one valve in each line is required to maintain the integrity of the containment. The surveillance requirements are based on the operating history of this type valve. The maximum closure time has been selected to contain fission products and to ensure the core is not uncovered following line breaks.

3/4.4.8 STRUCTURAL INTEGRITY

The inspection programs for ASME Code Class 1, 2 and 3 components ensure that the structural integrity of these components will be maintained at an acceptable level throughout the life of the plant.

Components of the reactor coolant system were designed to provide access to permit inservice inspections in accordance with Section XI of the ASME Boiler and Pressure Vessel Code, 1977 Edition, and Addenda through Summer 1978.

The inservice inspection program for ASME Code Class 1, 2 and 3 components will be performed in accordance with Section XI of the ASME Boiler and Pressure Vessel Code and applicable addenda as required by 10 CFR Part 50.55a(g) except where specific written relief has been granted by the NRC pursuant to 10 CFR Part 50.55a(g)(6)(i).

3/4.4.9 RESIDUAL HEAT REMOVAL

A single shutdown cooling mode loop provides sufficient heat removal capability for removing core decay heat and mixing to assure accurate temperature indication; however, single failure considerations require that two loops be OPERABLE or that alternate methods capable of decay heat removal be demonstrated and that an alternate method of coolant mixing be in operation.

BASES TABLE B 3/4.4.6-1

REACTOR VESSEL TOUGHNESS

Beltline Component	Weld Seam I.D. or Material Type	Heat No.-Slab No. or Heat No./Lot No.	Cu %	P (%)	Starting RT_{NDT} (°F)	Maximum** ΔRT_{NDT} (°F)	Minimum Upper Shelf (ft-lb)	Maximum EOL RT_{NDT} (°F)
Plate	SA-533 Gr.B, CL.1 SA-533 Gr.B, CL.1	C2594-2	0.04	0.012	0	+26	96 (C2594-2)	+26*
Weld	#2 Shell Long. ~~Seam~~ Seams	627260/B322A27AE	0.06	0.020	-30	44	N/A	+14

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Non-Beltline Component	Material Type or Weld Seam I.D.	Heat No.-Slab No. or Heat No./Lot No.	Highest Starting RT_{NDT} (°F)
Shell Ring	SA-533 Gr.B, CL.1	C2815-2, C2779-2, C2779-1, C2780-2, C2780-1, C2741-1	+10
Bottom Head Dollar Plate	SA-533 Gr.B, CL.1	A1113-1 C2630-2	0
Bottom Head Radial Plates	SA-533 Gr.B, CL.1	C2539-2, A1145-1	+10
Top Head Dollar Plate	SA-533 Gr.B, CL.1	C2448-3	-30
Top Head Side Plates	SA-533 Gr.B, CL.1	C2944-1	+10
Top Head Flange	SA-508 CL.2	4BD1682	-30
Vessel Flange	SA-508 CL.2	4BD1141	-30
Feedwater Nozzle	SA-508 CL.2	Forging No. 249A-1, 2, 3, 4, 5, & 6, Q2Q65W	-20
Weld	N/A	N/A	-20***
Closure Stud	SA-540 Gr.B24	84025, 84299	+10

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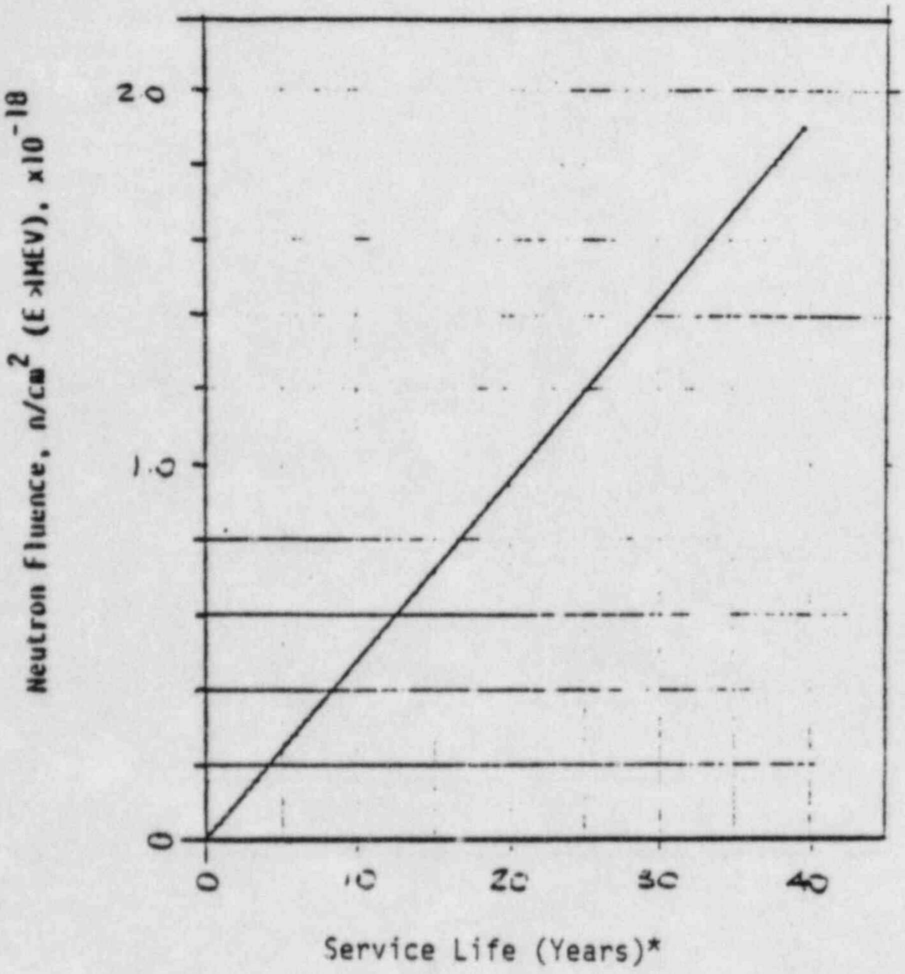
*Combination of the highest starting RT_{NDT} plate and the highest ΔRT_{NDT} plate.

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

***Based on purchase spec. requirements.



Fast Neutron Fluence (E>1 MeV) at 1/4 T As a Function of Service Life*

Bases Figure B 3/4.4.6-1

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

3/4.5.1 and 3/4.5.2 ECCS - OPERATING and SHUTDOWN

ECCS division 1 consists of the low pressure core spray system and low pressure coolant injection subsystem "A" of the RHR system and the automatic depressurization system (ADS) as actuated by trip system "A". ECCS division 2 consists of low pressure coolant injection subsystems "B" and "C" of the RHR system and the automatic depressurization system as actuated by trip system "B".

The low pressure core spray (LPCS) system is provided to assure that the core is adequately cooled following a loss-of-coolant accident and, together with the LPCI system, provides adequate core cooling capacity for all break sizes up to and including the double-ended reactor recirculation line break, and for smaller breaks following depressurization by the ADS.

The LPCS is a primary source of emergency core cooling after the reactor vessel is depressurized and a source for flooding of the core in case of accidental draining.

The surveillance requirements provide adequate assurance that the LPCS 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 requires reactor shutdown. The pump discharge piping is maintained full to prevent water hammer damage to piping and to start cooling at the earliest moment.

The low pressure coolant injection (LPCI) mode of the RHR system is provided to assure that the core is adequately cooled following a loss-of-coolant accident. The LPCI system, together with the LPCS system, provide adequate core flooding for all break sizes up to and including the double-ended reactor recirculation line break, and for small breaks following depressurization by the ADS.

The surveillance requirements provide adequate assurance that the LPCI 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 requires reactor shutdown. The pump discharge piping is maintained full to prevent water hammer damage to piping and to start cooling at the earliest moment.

ECCS division 3 consists of the high pressure core spray system. The high pressure core spray (HPCS) system is provided to assure that the reactor core is adequately cooled to limit fuel clad temperature in the event of a small break in the reactor coolant system and loss of coolant which does not result in rapid depressurization of the reactor vessel. The HPCS system permits the reactor to be shut down while maintaining sufficient reactor vessel water level inventory until the vessel is depressurized. The HPCS system operates over a range of ~~1160~~ psid, differential pressure between the 1256
reactor vessel and the HPCS suction source, to 0 psid.

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ECCS-OPERATING and SHUTDOWN (Continued)

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The capacity of the system is selected to provide the required core cooling. The HPCS pump is designed to deliver greater than or equal to ~~1440/5010~~ gpm at differential pressures of ~~1160~~/200 psid. Initially, water from the condensate storage tank is used instead of injecting water from the suppression pool into the reactor, but no credit is taken in the safety analyses for the condensate storage tank water.

1147 1256

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 135 psig even though ~~low pressure core cooling systems provide adequate core cooling up to 350 psig.~~

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 CONDITION 4 or 5.

LPCS has incipiant flow into the reactor pressure vessel at 295 psid and 7115 gpm rated flow at 128 psid, and LPCI has incipiant flow into the reactor pressure vessel at 229 psid and 7450 gpm rated flow at 24 psid

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SUPPRESSION POOL (Continued)

In OPERATIONAL CONDITION 4 and 5 the suppression chamber minimum required water volume is reduced because the reactor coolant is maintained at or below 200°F. Since pressure suppression is not required below 212°F, the minimum required water volume is based on NPSH, recirculation volume, and vortex prevention plus a 1'2" safety margin for conservatism.

3/4.6.1 PRIMARY CONTAINMENT

3/4.6.1.1 PRIMARY CONTAINMENT INTEGRITY

PRIMARY CONTAINMENT INTEGRITY ensures that the release of radioactive materials from the containment atmosphere will be restricted to those leakage paths and associated leak rates assumed in the accident analyses. This restriction, in conjunction with the leakage rate limitation, will limit the site boundary radiation doses to within the limits of 10 CFR Part 100 during accident conditions.

3/4.6.1.2 CONTAINMENT LEAKAGE

The limitations on containment leakage rates ensure that the total containment leakage volume will not exceed the value assumed in the accident analyses at the peak accident pressure of 11.5 psig, P_a. As an added conservatism, the measured overall integrated leakage rate is further limited to less than or equal to 0.75 L_a during performance of the periodic tests to account for possible degradation of the containment leakage barriers between leakage tests.

Operating experience with the main steam line isolation valves has indicated that degradation has occasionally occurred in the leak tightness of the valves; therefore the special requirement for testing these valves.

The surveillance testing for measuring leakage rates is consistent with the requirements of Appendix J to 10 CFR 50 with the exception of exemption(s) granted for main steam isolation valve leak testing and testing the airlocks after each opening.

3/4.6.1.3 CONTAINMENT AIR LOCKS

The limitations on closure and leak rate for the containment air locks are required to meet the restrictions on PRIMARY CONTAINMENT INTEGRITY and the containment leakage rate given in Specifications 3.6.1.1 and 3.6.1.2. The specification makes allowances for the fact that there may be long periods of time when the air locks will be in a closed and secured position during reactor operation. Only one closed door in each air lock is required to maintain the integrity of the containment.

3/4.6. Verification that each air lock door inflatable seal system is OPERABLE by the performance of a local leak-detection test for a period of less than 48 hours is permissible if it can be demonstrated that the leakage rate can be accurately determined for this shorter period. ~~and prior approval is obtained.~~ (This is in accordance with Section 6.4 and 7.6 of ANSI N45.4-1972.)

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3/4.6.1.5 FEEDWATER LEAKAGE CONTROL SYSTEM

The feedwater leakage control system consists of two independent subsystems designed to eliminate through-line leakage in the feedwater piping by pressurizing the feedwater lines to a higher pressure than the containment and drywell pressure. This ensures that no release of radioactivity through the feedwater line isolation valves will occur following a loss of all offsite power coincident with the postulated design basis loss-of-coolant accident.

3/4.6.1.6 CONTAINMENT STRUCTURAL INTEGRITY

This limitation ensures that the structural integrity of the containment will be maintained comparable to the original design standards for the life of the unit. Structural integrity is required to ensure that the containment will withstand the maximum pressure of 11.5 psig in the event of a LOCA. A visual inspection in conjunction with Type A leakage tests is sufficient to demonstrate this capability.

3/4.6.1.7 CONTAINMENT INTERNAL PRESSURE

The limitations on containment-to-Auxiliary Building and Enclosure Building differential pressure ensure that the containment peak pressure of 11.5 psig does not exceed the design pressure of 15.0 psig during LOCA conditions or that the external pressure differential does not exceed the design maximum external pressure differential of 3.0 psid. The limit of ~~-2.0 to 0.0~~ psid for initial 107
containment-to-Auxiliary Building and Enclosure Building differential pressure will limit the containment pressure to 11.5 psid which is less than the design pressure and is consistent with the safety analysis. -0.1 to 1.0

3/4.6.1.8 CONTAINMENT AVERAGE AIR TEMPERATURE

The limitation on containment average air temperature ensures that the containment peak air temperature does not exceed the design temperature of 185°F during LOCA conditions and is consistent with the safety analysis.

3/4.6.1.9 CONTAINMENT PURGE SYSTEM

The continuous use of the containment purge lines during all operational conditions is restricted to the 6-inch purge supply and exhaust isolation valves; whereas, continuous containment purge using the 20-inch purge system is limited to only OPERATIONAL CONDITIONS 4 and 5. Intermittent use of the 20-inch purge system during OPERATIONAL CONDITIONS 1, 2 and 3 is allowed only to reduce airborne activity levels and shall not exceed 1000 hours of use per 365 days.

The design of the 6-inch purge supply and exhaust isolation valves meets the requirements of Branch Technical Position CSB 6-4, "Containment Purging During Normal Plant Operations."

CONTAINMENT PURGE SYSTEM (Continued)

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

3/4.6.2 DRYWELL

3/4.6.2.1 DRYWELL INTEGRITY

Drywell integrity ensures that the steam released for the full spectrum of drywell pipe breaks is condensed inside the primary containment either by the suppression pool or by containment spray. By utilizing the suppression pool as a heat sink, energy released to the containment is minimized and the severity of the transient is reduced.

3/4.6.2.2 DRYWELL BYPASS LEAKAGE

INSERT A

The limitation on drywell bypass leakage rate ensures that the maximum leakage which could bypass the suppression pool during an accident would not result in the containment exceeding its design pressure of 15.0 psig. The integrated drywell leakage value is limited to 10% of the ~~design drywell leakage rate.~~ maximum allowable leakage rate capability. INSERT B

INSERT C

The limiting case accident is a very small reactor coolant system break which will not automatically result in a reactor depressurization. The long term differential pressure created between the drywell and containment will result in a significant pressure buildup in the containment due to this bypass leakage. 172

3/4.6.2.3 DRYWELL AIR LOCKS

The limitations on closure for the drywell air locks are required to meet the restrictions on DRYWELL INTEGRITY and the drywell leakage rate given in Specifications 3.6.2.1 and 3.6.2.2. The specification makes allowances for the fact that there may be long periods of time when the air locks will be in a closed and secured position during reactor operation. Only one closed door in each air lock is required to maintain the integrity of the drvwell

Verification that each air lock door inflatable seal system is OPERABLE by the performance of a local leak-detection test for a period of less than 48 hours is permissible if it can be demonstrated that the leakage rate can be accurately determined for this shorter period. ~~and prior approval is obtained~~. (This is in accordance with Section 6.4 and 7.6 of ANSI N45.4-1972.)

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INSERT "A"

THE DESIGN DRYWELL LEAKAGE RATE IS EXPRESSED AS $A/\sqrt{K}$ AND HAS A VALUE OF 0.90 FT^2. $A/\sqrt{K}$ IS DEPENDENT ONLY ON THE GEOMETRY OF DRYWELL LEAKAGE PATHS WHERE A = FLOW AREA OF LEAKAGE PATHS IN FT^2 AND $\sqrt{K}$ IS A LUMPED CONSTANT WHICH CONSIDERS GEOMETRIC AND FRICTION LOSS COEFFICIENTS SUCH AS DISCONTINUITIES AND REYNOLDS NUMBER. AT A 3 PSID DIFFERENTIAL PRESSURE FROM DRYWELL TO CONTAINMENT AN $A/\sqrt{K}$ OF 0.90 FT^2 HAS AN EQUIVALENT MASS FLOW OF 35000 SCFM.

INSERT "B" WHICH IS EQUIVALENT TO 3500~~0~~ SCFM AT 3 PSID DRYWELL TO CONTAINMENT.

INSERT "C" THE $A\sqrt{K}$ VALUE OF 0.90 FT^2 IS DERIVED FROM THE ANALYIS OF "BYPASS CAPABILITY WITH CONTAINMENT SPRAY AND HEAT SINKS" (FSAR 6.2.1.1.5.5)

Whenever maintenance activities are performed that could result in nozzle obstruction, a surveillance will be performed to verify that flow through the nozzles is unobstructed.

3/4.6.2.6 DRYWELL AVERAGE AIR TEMPERATURE

The limitation on drywell average air temperature ensures that peak drywell temperature does not exceed the design temperature of 330°F during LOCA conditions and is consistent with the safety analysis.

3/4.6.3 DEPRESSURIZATION SYSTEMS

The specifications of this section ensure that the drywell and containment pressure will not exceed the design pressure of 30 psig and 15 psig, respectively, during primary system blowdown from full operating pressure.

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The suppression pool water volume must absorb the associated decay and structural sensible heat released during a reactor blowdown from ~~1089 psig.~~ 1060 psia. Using conservative parameter inputs, the maximum calculated containment pressure during and following a design basis accident is below the containment design pressure of 15 psig. Similarly the drywell pressure remains below the design pressure of 30 psig. The maximum and minimum water volumes for the suppression pool are ~~138,851~~ 138,701 cubic feet and ~~136,146~~ 135,291 cubic feet, respectively. These values include the water volume of the containment pool, horizontal vents, and weir annulus. Testing in the Mark III Pressure Suppression Test Facility and analysis have assured that the suppression pool temperature will not rise above 185°F for the full range of break sizes.

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INSERT ATTACHMENT 168

Should it be necessary to make the suppression pool inoperable, this shall only be done as specified in Specification 3.5.3.

Experimental data indicates that effective steam condensation without excessive loads on the containment pool walls will occur with a quencher device and pool temperature below 200°F during relief valve operation. Specifications have been placed on the envelope of reactor operating conditions to assure the bulk pool temperature does not rise above 185°F in compliance with the containment structural design criteria.

In addition to the limits on temperature of the suppression pool water, operating procedures define the action to be taken in the event a safety-relief valve inadvertently opens or sticks open. As a minimum this action shall include: (1) use of all available means to close the valve, (2) initiate suppression pool water cooling, (3) initiate reactor shutdown, and (4) if other safety-relief valves are used to depressurize the reactor, their discharge shall be separated from that of the stuck-open safety relief valve to assure mixing and uniformity of energy insertion to the pool.

The containment spray system consists of two 100% capacity trains, each with three spray rings located at different elevations about the inside circumference of the containment. RHR A pump supplies one train and RHR pump B supplies the other. RHR pump C cannot supply the containment spray system. Dispersion of the flow of water is effected by 350 nozzles in each train, enhancing the condensation of water vapor in the containment volume and preventing overpressurization. Heat rejection is through the RHR heat exchangers. The turbulence caused by the spray system aids in mixing the containment air volume to maintain a homogeneous mixture for H_2 control.

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The suppression pool cooling function is a mode of the RHR system and functions as part of the containment heat removal system. The purpose of the system is to ensure containment integrity following a LOCA by preventing

The surveillance requirements, which include system losses for surveillance testing, provide adequate assurance that the containment spray system will be OPERABLE when required.

and have corresponding pool water depths of 18'-4 1/12" and 18'-9 3/4", respectively.

The minimum suppression pool volume of 135,291 ft³ is based on satisfying the Mark III suppression pool sizing criteria established as a G.E. design review file (DRF T23-0408). The 135,291 ft³ and 138,701 ft³ pool water volumes were used in the Grand Gulf Containment Analysis (G.E. DRF 699-0010) to verify their adequacy to perform all required functions following the design basis limiting condition of a main steam line break from 105% of full power. (FSAR 6.2.1.1.3.3.3).

The 18'-4 1/12" and 18'-9 3/4" pool water depths are nominal values derived analytically, considering pool geometry, from the above pool volumes which were used in the pool design analyses. The pool levels (depths) satisfy criteria or constraints imposed by: (1) 2 ft minimum post LOCA horizontal vent coverage to assure steam condensation/pressure suppression, (2) adequate ECCS pump NPSH (3) adequate depth for vortex prevention (4) adequate depth for minimum recirculation volume (5) adequate weir-wall free-board for inadvertent upper pool dump and (6) to limit hydrodynamic loads on submerged structures during SRV and vent steam discharges.

The suppression pool temperatures are based as follows:

95°F is the initial condition for the analysis determining pool volume adequacy and satisfies the post LOCA long term peak pool temperature of 185°F

120°F is analytically based and is derived to satisfy the 170°F post-blowdown peak pool temperature assuming a LOCA when the reactor is isolated

110°F and 105°F are derived from the analytically based 95°F and 120°F using engineering judgement considering operator response time, reactor pressure vessel energy and pool heat capacity to meet the 170°F limit and also to avoid unnecessary scrams and/or depressurizations.

DEPRESSURIZATION SYSTEMS (Continued)

excessive containment pressures and temperatures. The suppression pool cooling mode is designed to limit the long term bulk temperature of the pool to 185°F considering all of the post-LOCA energy additions. The suppression pool cooling trains, being an integral part of the RHR system, are redundant, safety-related component systems that are initiated following the recovery of the reactor vessel water level by ECCS flows from the RHR system. Heat rejection to the standby service water is accomplished in the RHR heat exchangers.

The suppression pool make-up system provides water from the upper containment pool to the suppression pool by gravity flow through two 100% capacity dump lines following a LOCA. The quantity of water provided is sufficient to account for all conceivable post-accident entrapment volumes, ensuring the long term energy sink capabilities of the suppression pool and maintaining the water coverage over the uppermost drywell vents. The minimum freeboard distance above the suppression pool high water level to the top of the weir wall is adequate ~~to~~ preclude flooding of the drywell in the event of an inadvertent dump. ~~During~~ INSERT

During refueling, an inadvertent dump would create a radiation hazard due to a loss of shield water if irradiated fuel were in an elevated position. However, GGNS procedures require that both logic trains of the suppression pool makeup dump valves be ~~disabled~~ bypassed whenever the reactor mode switch is in the REFUEL position, ~~OPERATIONAL CONDITION 5,~~ thus preventing the valves from opening by either automatic or manual initiation. 4 ly

004

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

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

DRYWELL POST-LOCA VACUUM BREAKERS (Continued)

drywell purge system, is necessary to insure that the post-LOCA drywell H_2 concentration does not exceed 4% by volume.

Following vacuum relief, the drywell purge system pressurizes the drywell, forcing noncondensibles through the horizontal vents and into the containment at a rate designed to maintain the H_2 concentration below the flammable limits.

There are two 100% vacuum relief systems so that the plant may continue operation with one system out of service for a limited period of time.

3/4.6.6 SECONDARY CONTAINMENT

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

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

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

8/81

The OPERABILITY of the standby gas treatment systems ensures that sufficient iodine removal capability will be available in the event of a LOCA. The reduction in containment iodine inventory reduces the resulting site boundary radiation doses associated with containment leakage. The operation of this system and resultant iodine removal capacity are consistent with the assumptions used in the LOCA analyses. ~~Cumulative~~ Continous operation of the system with the heaters OPERABLE for 10 hours over a 31 day period is sufficient to reduce the buildup of moisture on the absorbers and HEPA filters. /062

The surveillance testing for verifying heat dissipation for the Standby Gas Treatment System heaters is performed in accordance with ANSI N510-1975 with the exception of the 5% current phase balance criteria of Section 14.2.3. The offsite power system for the Grand Gulf Nuclear Station consists of a nontranspositional 500 KV grid. The grid has an inherent unbalanced load distribution which results in unbalanced voltages in the plant. Voltage unbalances exceeding the ANSI N510-1975 5% criteria are not atypical

(FOR PAINTING, FIRE AND CHEMICAL RELEASES OTHER THAN) CARBON DIOXIDE IN ANY VENTILATION ZONE COMMUNICATING WITH THE standby gas treatment SYSTEM, THE SURVEILLANCE REQUIREMENTS ARE ADEQUATE TO ENSURE CHARCOAL ADSORBENCY IS MAINTAINED. A RELEASE OF CARBON DIOXIDE FOR ANY REASON OTHER THAN A FIRE WILL NOT ADVERSELY AFFECT THE CHARCOAL'S ADSORBENCY AND THE SURVEILLANCE REQUIREMENT NEED NOT BE PERFORMED.

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3/4.6.7 ATMOSPHERE CONTROL

The OPERABILITY of the systems required for the detection and control of hydrogen gas ensures that these systems will be available to maintain the hydrogen concentration within the containment below its flammable limit during post-LOCA conditions. The hydrogen recombiner and the hydrogen ignition systems are capable of controlling the expected hydrogen generation associated with (1) zirconium-water reactions, (2) radiolytic decomposition of water and (3) corrosion of metals within containment.

Two 100% drywell purge systems are the primary means of H_2 control within the drywell purging hydrogen produced following a LOCA into the containment volume. Hydrogen generated from the metal-water reaction and radiolysis is assumed to evolve to the drywell atmosphere and form a homogenous mixture through natural forces and mechanical turbulence (ECCS pipe break flow). The drywell purge system forces drywell atmosphere through the horizontal vents and into the containment and as a result no bypass path exists.

The hydrogen control system is consistent with the recommendations of Regulatory Guide 1.7, "Control of Combustible Gas Concentrations in Containment Following a LOCA", ~~March 1971.~~ September 1976. 128

The operability of at least 41 of 45 ignitors in either hydrogen ignition subsystem will maintain an effective coverage throughout the containment and drywell. Each subsystem of ignitors will initiate combustion of any significant amount of hydrogen released after a degraded core accident. This system will ensure burning in a controlled manner as the hydrogen is released instead of allowing it to be ignited at high concentrations by a random ignition source.

3/4.7.1 SERVICE WATER SYSTEMS

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

3/4.7.2 CONTROL ROOM EMERGENCY FILTRATION SYSTEM

The OPERABILITY of the control room emergency filtration system ensures that the control room will remain habitable for operations personnel during and following all design basis accident conditions. ~~Cumulative~~ Continuous operation of the system for 10 hours with the heaters OPERABLE over a 31 day period is sufficient to reduce the buildup of moisture on the adsorbers and HEPA filters. The OPERABILITY of this system in conjunction with control room design provisions is based on limiting the radiation exposure to personnel occupying the control room to 5 rem or less whole body, or its equivalent. This limitation is consistent with the requirements of General Design Criteria 19 of Appendix "A", 10 CFR Part 50.

/062

The surveillance testing for verifying heat dissipation for the Control Room Emergency Filtration System heaters is performed in accordance with ANSI N510-1975 with the exception of the 5% current phase balance criteria of Section 14.2.3. The offsite power system for the Grand Gulf Nuclear Station consists of a non-transpositional 500 KV grid. The grid has an inherent unbalanced load distribution which results in unbalanced voltages in the plant. Voltage unbalances exceeding the ANSI N510-1975 5% criteria are not atypical.

FOR PAINTING, FIRE AND CHEMICAL RELEASES OTHER THAN CARBON DIOXIDE IN ANY VENTILATION ZONE COMMUNICATING WITH THE control room emergency filtration SYSTEM, THE SURVEILLANCE REQUIREMENTS ARE ADEQUATE TO ENSURE CHARCOAL ADSORBENCY IS MAINTAINED. A RELEASE OF CARBON DIOXIDE FOR ANY REASON OTHER THAN A FIRE WILL NOT ADVERSELY AFFECT THE CHARCOAL'S ADSORBENCY AND THE SURVEILLANCE REQUIREMENT NEED NOT BE PERFORMED.

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... system and justifies the specified 14 day out of ... period.

The surveillance requirements provide adequate assurance that RCICS will be OPERABLE when required. Although all active components are testable and full flow can be demonstrated by recirculation during reactor operation, a complete functional test requires reactor shutdown. The pump discharge piping is maintained full to prevent water hammer damage and to start cooling at the earliest possible moment.

incipient flow into the reactor pressure vessel at 229 psid and 7450 gpm rated flow at 24 psid.

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3/4.7.4 SNUBBERS

All snubbers are required OPERABLE to ensure that the structural integrity of the Reactor Coolant System and all other safety-related systems is maintained during and following a seismic or other event initiating dynamic loads. Snubbers excluded from this inspection program are those installed on nonsafety-related systems and then only if their failure or failure of the system on which they are installed, would have no adverse effect on any safety-related system.

Snubbers are classified and grouped by design and manufacturer but not by size. For example, mechanical snubbers utilizing the same design features of the 2-kip, 10-kip, and 100-kip capacity manufactured by Company "A" are of the same type. The same design mechanical snubbers manufactured by Company "B" for the purposes of this Technical Specification would be of a different type, as would hydraulic snubbers from either manufacturer.

A list of individual snubbers with detailed information of snubber location and size and of system affected shall be available at the plant in accordance with Section 50.71(c) of 10 CFR Part 50. The accessibility of each snubber shall be determined and approved by the ~~Review of Operations Committee~~ Plant Safety Review Committee. The determination shall be based upon the existing radiation levels and the expected time to perform a visual inspection in each snubber location as well as other factors associated with accessibility during plant operations (e.g., temperature, atmosphere, location etc.), and the recommendations of Regulatory Guides 8.8 and 8.10. The addition or deletion of any hydraulic or mechanical snubber shall be made in accordance with Section 50.59 of 10 CFR Part 50.

The visual inspection frequency is based upon maintaining a constant level of snubber protection to each safety-related system. Therefore, the required inspection interval varies inversely with the observed snubber failures on a given system and is determined by the number of inoperable snubbers found during an inspection of each system. In order to establish the inspection frequency for each type of snubber on a safety-related system, it was assumed that the frequency of snubber failures and initiating events is constant with time and that the failure of any snubber on that system could cause the system to be unprotected and to result in failure during an assumed initiating event. Inspections performed before that interval has elapsed may be used as a new reference point to determine the next inspection. However, the results of such early inspections performed before the original required time interval has elapsed (nominal time less 25%) may not be used to lengthen the required inspection interval. Any inspection whose results require a shorter inspection interval will override the previous schedule.

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The acceptance criteria are to be used in the visual inspection to determine OPERABILITY of the snubbers. For example, if a fluid port of a hydraulic snubber is found to be uncovered, the snubber shall be declared inoperable and shall not be determined OPERABLE via functional testing.

INSERT 006

seal replaced, spring replaced, in high radiation area, in high tempe area, etc. . . . The requirement to monitor the snubber service life is included to enusre that the snubbers periodically undergo a performance evaluation in view of their age and operating conditions. These records will provide statistical bases for future consideration of snubber service life. The requirements for the maintenance of records and the snubber service life review are not intended to affect plant operation.

To provide assurance of snubber functional reliability one of three functional testing methods are used with the stated acceptance criteria:

1. Functionally test 10% of a type of snubber with an additional 10% tested for each functional testing failure, or
2. Functionally test a sample size and determine sample acceptance or rejection using Figure 4.7.~~6~~4-1, or
3. Functionally test a representative sample size and determine sample acceptance or rejection using the stated equation.

Figure 4.7.4-1 was developed using "Wald's Sequential Probability Ratio Plan" as described in "Quality Control and Industrial Statistics" by Acheson J. Duncan.

Permanent or other exemptions from the surveillance program for individual snubbers may be granted by the Commission if a justifiable basis for exemption is presented and, if applicable, snubber life destructive testing was performed to qualify the snubbers for the applicable design conditions at either the completion of their fabrication or at a subsequent date. Snubbers so exempted shall be listed in the list of individual snubbers indicating the extent of the exemptions.

The service life of a snubber is established via manufacturer input and information through consideration of the snubber service conditions and associated installation and maintenance records (newly installed snubber, seal replaced, spring replaced, in high radiation area, in high temperature area, etc.). The requirement to monitor the snubber service life is included to ensure that the snubbers periodically undergo a performance evaluation in view of their age and operating conditions. These records will provide statistical bases for future consideration of snubber service life.

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3/4.7.5 SEALED SOURCE CONTAMINATION

The limitations on removable contamination for sources requiring leak testing, including alpha emitters, is based on 10 CFR 70.39(c) limits for plutonium. This limitation will ensure that leakage from byproduct, source, and special nuclear material sources will not exceed allowable intake values. Sealed sources are classified into three groups according to their use, with surveillance requirements commensurate with the probability of damage to a source in that group. Those sources which are frequently handled are required to be tested more often than those which are not. Sealed sources which are continuously enclosed within a shielded mechanism, i.e., sealed sources within radiation monitoring or boron measuring devices, are considered to be stored and need not be tested unless they are removed from the shielded mechanism.

3/4 7.6 FIRE SUPPRESSION SYSTEMS

The OPERABILITY of the fire suppression systems ensures that adequate fire suppression capability is available to confine and extinguish fires occurring in any portion of the facility where safety related equipment is located. The fire suppression system consists of the water system, spray and/or sprinklers, CO_2 systems, Halon systems and fire hose stations. The collective capability of the fire suppression systems is adequate to minimize potential damage to safety related equipment and is a major element in the facility fire protection program.

In the event that portions of the fire suppression systems are inoperable, alternate backup fire fighting equipment is required to be made available in the affected areas until the inoperable equipment is restored to service. When the inoperable fire fighting equipment is intended for use as a backup means of fire suppression, a longer period of time is allowed to provide an alternate means of fire fighting than if the inoperable equipment is the primary means of fire suppression.

The surveillance requirements provide assurances that the minimum OPERABILITY requirements of the fire suppression systems are met. An allowance is made for ensuring a sufficient volume of Halon in the Halon storage tanks by verifying the weight and pressure of the tanks.

In the event the fire suppression water system becomes inoperable, immediate corrective measures must be taken since this system provides the major fire suppression capability of the plant. ~~The requirement for a twenty-four hour report to the Commission provides for prompt evaluation~~ of the ~~acceptability of the corrective measures to provide adequate fire suppression capability for the continued protection of the nuclear plant.~~

The surveillance requirements for spray and sprinkler systems provide for periodic visual inspections to ensure that temporary structures/objects do not impair the spray patterns which have been established in accordance with the GGNS fire protection design requirements. 072

3/4.7.7 FIRE RATED ASSEMBLIES

The OPERABILITY of the fire barriers and barrier penetrations ensure that fire damage will be limited. These design features minimize the possibility of a single fire involving more than one fire area prior to detection and extinguishment. The fire barriers, fire barrier penetrations for conduits, cable trays and piping, fire windows, fire dampers, and fire doors are periodically inspected to verify their OPERABILITY.

3/4.7.8 AREA TEMPERATURE MONITORING

The area temperature limitations ensure that safety-related equipment will not be subjected to temperatures in excess of their environmental qualification temperatures. Exposure to excessive temperatures may degrade equipment and can cause loss of its OPERABILITY. The temperature limits include allowance for instrument error.

3/4.7.9 SPENT FUEL STORAGE POOL TEMPERATURE

The temperature limit in the spent fuel storage pool ensures proper pool cooling to maintain building accessibility and prevents unacceptable radiological releases particularly during those times of increased fuel pool cooling heat loads, such as a fuel core offload, when supplemental fuel pool cooling utilizing the RHR system is required.

3/4.8.1, 3/4.8.2 and 3/4.8.3 A.C. SOURCES, D.C. SOURCES and ONSITE POWER DISTRIBUTION SYSTEMS

The OPERABILITY of the A.C. and D.C. power sources and associated distribution systems during operation ensures that sufficient power will be available to supply the safety related equipment required for (1) the safe shutdown of the facility and (2) the mitigation and control of accident conditions within the facility. The minimum specified independent and redundant A.C. and D.C. power sources and distribution systems satisfy the requirements of General Design Criteria 17 of Appendix "A" to 10 CFR 50. 1174

The ACTION requirements specified for the levels of degradation of the power sources provide restriction upon continued facility operation commensurate with the level of degradation. The OPERABILITY of the power sources are consistent with the initial condition assumptions of the accident analyses and are based upon maintaining at least Division 1 or 2 of the onsite A.C. and D.C. power sources and associated distribution systems OPERABLE during accident conditions coincident with an assumed loss of offsite power and single failure of the other onsite A.C. source. Division 3 supplies the high pressure core spray (HPCS) system only.

The A.C. and D.C. source allowable out-of-service times are based on Regulatory Guide 1.93, "Availability of Electrical Power Sources", December 1974. When diesel generator 11 or 12 is inoperable, there is an additional ACTION requirement to verify that all required systems, subsystems, trains, components and devices, that depend on the remaining OPERABLE diesel generator 11 or 12 as a source of emergency power, are also OPERABLE. This requirement is intended to provide assurance that a loss of offsite power event will not result in a complete loss of safety function of critical systems during the period diesel generator 11 or 12 is inoperable. The term verify as used in this context means to administratively check by examining logs or other information to determine if certain components are out-of-service for maintenance or other reasons. It does not mean to perform the surveillance requirements needed to demonstrate the OPERABILITY of the component.

The OPERABILITY of the minimum specified A.C. and D.C. power sources and associated distribution systems during shutdown and refueling ensures that (1) the facility can be maintained in the shutdown or refueling condition for extended time periods and (2) sufficient instrumentation and control capability is available for monitoring and maintaining the unit status.

The surveillance requirements for demonstrating the OPERABILITY of the diesel generators are in accordance with the recommendations of Regulatory Guide 1.9, "Selection of Diesel Generator Set Capacity for Standby Power Supplies", March 10, 1971, Regulatory Guide 1.108, "Periodic Testing of Diesel Generator Units Used as Onsite Electric Power Systems at Nuclear Power Plants", Revision 1, August 1977 and Regulatory Guide 1.137" Fuel-Oil Systems for Standby Diesel Generators", ~~Revision 1, October 1979.~~ January 1978, as addressed in the FSAR. 1174

The volume of fuel specified for each fuel storage system represents usable fuel.

A.C. SOURCES, D.C. SOURCES and ONSITE POWER DISTRIBUTION SYSTEMS (Continued)

The surveillance requirements for demonstrating the OPERABILITY of the unit batteries are in accordance with the recommendations of Regulatory Guide 1.129 "Maintenance Testing and Replacement of Large Lead Storage Batteries for Nuclear Power Plants," February 1978, and IEEE Std 450-1980, "IEEE Recommended Practice for Maintenance, Testing, and Replacement of Large Lead Storage Batteries for Generating Stations and Substations.".

Verifying average electrolyte temperature above the minimum for which the battery was sized, total battery terminal voltage onfloat charge, connection resistance values and the performance of battery service and discharge tests ensures the effectiveness of the charging system, the ability to handle high discharge rates and compares the battery capacity at that time with the rated capacity.

Table 4.8.2.1-1 specifies the normal limits for each designated pilot cell and each connected cell for electrolyte level, float voltage and specific gravity. The limits for the designated pilot cells float voltage and specific gravity, greater than 2.13 volts and 0.015 below the manufacturer's full charge specific gravity or a battery charger current that had stabilized at a low value, is characteristic of a charged cell with adequate capacity. The normal limits for each connected cell for float voltage and specific gravity, greater than 2.13 volts and not more than 0.020 below the manufacturer's full charge specific gravity with an average specific gravity of all the connected cells not more than 0.010 below the manufacturer's full charge specific gravity, ensures the OPERABILITY and capability of the battery.

Operation with a battery cell's parameter outside the normal limit but within the allowable value specified in Table 4.8.2.1-1 is permitted for up to 7 days. During this 7 day period: (1) the allowable values for electrolyte level ensures no physical damage to the plates with an adequate electron transfer capability; (2) the allowable value for the average specific gravity of all the cells, not more than 0.020 below the manufacturer's recommended full charge specific gravity, ensures that the decrease in rating will be less than the safety margin provided in sizing; (3) the allowable value for an individual cell's specific gravity ensures that an individual cell's specific gravity will not be more than 0.040 below the manufacturer's full charge specific gravity and that the overall capability of the battery will be maintained within an acceptable limit; and (4) the allowable value for an individual cell's float voltage, greater than 2.07 volts, ensures the battery's capability to perform its design function.

3/4.8.4 ELECTRICAL EQUIPMENT PROTECTIVE DEVICES

Primary containment electrical penetrations and penetration conductors are protected by either de-energizing circuits not required during reactor operation or demonstrating the OPERABILITY of primary and backup overcurrent protection circuit breakers by periodic surveillance.

The surveillance requirements applicable to lower voltage circuit breakers provides assurance of breaker reliability by testing at least one representative sample of each manufacturers brand of circuit breaker. Each manufacturer's molded case and metal case circuit breakers are grouped into representative samples which are than tested on a rotating basis to ensure that all breakers are tested. If a wide variety exists within any manufacturer's brand of circuit breakers, it is necessary to divide that manufacturer's breakers into groups and treat each group as a separate type of breaker for surveillance purposes.

The OPERABILITY or bypassing of the motor operated valve thermal overload protection continuously or under accident conditions by integral bypass devices ensures that the thermal overload protection during accident conditions will not prevent safety related valves from performing their function. The surveillance requirements for demonstrating the OPERABILITY or bypassing of the thermal overload protection continuously and or during accident conditions are in accordance with Regulatory Guide 1.106 "Thermal Overload Protection for Electric Motors on Motor Operated Valves", Revision 1, March 1977.

The reactor protection system (RPS) electric power monitoring assemblies provide redundant protection to the RPS and other systems which receive power from the RPS buses by acting to disconnect the RPS from the power source circuits in the presence of an electrical fault in the power supply. The BASES for the functional requirements of the RPS are discussed in the BASES for Specification 3/4.3.1. 18

3/4.9 REFUELING OPERATIONS

BASES

3/4.9.1 REACTOR MODE SWITCH

Locking the OPERABLE reactor mode switch in the Shutdown or Refuel position, as specified, ensures that the restrictions on control rod withdrawal and refueling platform movement during the refueling operations are properly activated. These conditions reinforce the refueling procedures and reduce the probability of inadvertent criticality, damage to reactor internals or fuel assemblies, and exposure of personnel to excessive radioactivity.

3/4.9.2 INSTRUMENTATION

The OPERABILITY of at least two source range monitors ensures that redundant monitoring capability is available to detect changes in the reactivity condition of the core.

3/4.9.3 CONTROL ROD POSITION

The requirement that all control rods be inserted during other CORE ALTERATIONS ensures that fuel will not be loaded into a cell without a control rod.

3/4.9.4 DECAY TIME

The minimum requirement for reactor subcriticality prior to fuel movement ensures that sufficient time has elapsed to allow the radioactive decay of the short lived fission products. This decay time is consistent with the assumptions used in the accident analyses.

3/4.9.5 COMMUNICATIONS

The requirement for communications capability ensures that refueling station personnel can be promptly informed of significant changes in the facility status or core reactivity condition during movement of fuel within the reactor pressure vessel.

3/4.9.6 REFUELING ~~PLATFORM~~ EQUIPMENT

The OPERABILITY requirements ensure that (1) only the main hoist of the refueling platform or the main hoist of the fuel handling platform will be used for handling ~~control rods and~~ fuel assemblies within the reactor pressure vessel, (2) ~~each crane and hoist has~~ platform hoists have sufficient load capacity for handling fuel assemblies and control rods, and (3) the core internals and pressure vessel are protected from excessive lifting force in the event they are inadvertently engaged during lifting operations. /035

3/4.9.7 CRANE TRAVEL - SPENT FUEL AND UPPER CONTAINMENT FUEL STORAGE POOLS

The restriction on movement of loads in excess of the nominal weight of a fuel assembly over other fuel assemblies in the storage pools ensures that in the event this load is dropped 1) the activity release will be limited to that contained in a single fuel assembly, and 2) any possible distortion of fuel in the storage racks will not result in a critical array. This assumption is consistent with the activity release assumed in the safety analyses.

3/4.9.8 and 3/4.9.9 WATER LEVEL - REACTOR VESSEL and WATER LEVEL -SPENT FUEL AND UPPER CONTAINMENT FUEL STORAGE POOLS

The restrictions on minimum water level ensure that sufficient water depth is available to remove 99% of the assumed 10% iodine gap activity released from the rupture of an irradiated fuel assembly. This minimum water depth is consistent with the assumptions of the accident analysis.

3/4.9.10 CONTROL ROD REMOVAL

These specifications ensure that maintenance or repair of control rods or control rod drives will be performed under conditions that limit the probability of inadvertent criticality. The requirements for simultaneous removal of more than one control rod are more stringent since the SHUTDOWN MARGIN specification provides for the core to remain subcritical with only one control rod fully withdrawn.

3/4.9.11 RESIDUAL HEAT REMOVAL AND COOLANT CIRCULATION

The requirement that at least one residual heat removal loop be OPERABLE and in operation or that an alternate method capable of decay heat removal be demonstrated and that an alternate method of coolant mixing be in operation ensures that 1) sufficient cooling capacity is available to remove decay heat and maintain the water in the reactor pressure vessel below 140°F as required during REFUELING, and 2) sufficient coolant circulation would be available through the reactor core to assure accurate temperature indication and to distribute and prevent stratification of the poison in the event it becomes necessary to actuate the standby liquid control system. |275

The requirement to have two shutdown cooling mode loops OPERABLE when there is less than ~~23 feet~~ 22 feet 8 inches of water above the reactor vessel flange ensures that a single failure of the operating loop will not result in a complete loss of residual heat removal capability. With the reactor vessel head removed and ~~23 feet~~ 22 feet 8 inches of water above the reactor vessel flange, a large heat sink is available for core cooling. Thus, in the event a failure of the operating RHR loop, adequate time is provided to initiate alternate methods capable of decay heat removal or emergency procedures to cool the core. |275

3/4.9.12 HORIZONTAL FUEL TRANSFER SYSTEM

The purpose of the horizontal fuel transfer system specification is to control personnel access to those potentially high radiation areas immediated adjacent to the system and to assure safe operation of the system.

3/4.10.1 PRIMARY CONTAINMENT INTEGRITY/DRYWELL INTEGRITY

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

3/4.10.2 ROD PATTERN CONTROL SYSTEM

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

3/4.10.3 SHUTDOWN MARGIN DEMONSTRATIONS

Performance of shutdown margin demonstrations with the vessel head removed requires additional restrictions in order to ensure that criticality does not occur. These additional restrictions are specified in this LCO.

3/4.10.4 RECIRCULATION LOOPS

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

3/4.10.5 TRAINING STARTUPS

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

3/4.11 RADIOACTIVE EFFLUENTS

BASES

3/4.11.1 LIQUID EFFLUENTS

to UNRESTRICTED AREAS

3/4.11.1.1 CONCENTRATION

in UNRESTRICTED AREAS

This specification is provided to ensure that the concentration of radioactive materials released in liquid waste effluents ~~from the site~~ will be less than the concentration levels specified in 10 CFR Part 20, Appendix B, Table II, Column 2. This limitation provides additional assurance that the levels of radioactive materials in bodies of water ~~outside the site~~ will result in exposures within (1) the Section II.A design objectives of Appendix I, 10 CFR 50, to ~~an individual~~, and (2) the limits of 10 CFR 20.106(e) to the population. The concentration limit for dissolved or entrained noble gases is based upon the assumption that Xe-135 is the controlling radioisotope and its MPC in air ~~from~~ (submersion) was converted to an equivalent concentration in water using the methods described in International Commission on Radiological Protection (ICRP) Publication 2. /249

a MEMBER OF THE PUBLIC

. THE REQUIRED DETECTION CAPABILITIES FOR RADIOACTIVE MATERIALS IN LIQUID WASTE SAMPLES ARE TABULATED IN TERMS OF THE LOWER LIMITS OF DETECTION (LLDs). DETAILED DISCUSSION OF THE LLD, AND OTHER DETECTION LIMITS CAN BE FOUND IN: /249

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(1) HASL Procedures Manual, HASL-300 (revised annually).
(2) Currie, L. A., "Limits for Qualitative Detection and Quantitative Determination - Application to Radiochemistry" Anal. Chem. 40, 586-93 (1968).
(3) Hartwell, J. K., "Detection Limits for Radioisotopic Counting Techniques," Atlantic Richfield Hanford Company Report ARH-2537 (June 22, 1972). /249

to UNRESTRICTED AREAS

based on models and data, such that the actual exposure of ~~an individual~~ through appropriate pathways is unlikely to be substantially underestimated. The equations specified in the ODCM for calculating the doses due to the actual release rates of radioactive materials in liquid effluents are consistent with the methodology provided in Regulatory Guide 1.109, "Calculation of Annual Doses to Man from Routine Releases of Reactor Effluents for the Purpose of Evaluating Compliance with 10 CFR Part 50, Appendix I," Revision 1, October 1977 and Regulatory Guide 1.113, "Estimating Aquatic Dispersion of Effluent from Accidental and Routine Reactor Releases for the Purpose of Implementing Appendix I," April 1977.

This specification applies to the release of liquid effluents from each reactor at the site. For units with shared radwaste treatment systems, the liquid effluents from the shared system are proportioned among the units sharing that system.

a MEMBER OF THE PUBLIC.

3/4.11.1.3 LIQUID WASTE TREATMENT

~~The OPERABILITY of the liquid radwaste treatment system ensures that this system will be available for use whenever liquid effluents require treatment prior to release to the environment.~~ The requirement that the appropriate portions of this system be used when specified provides assurance that the releases of radioactive materials in liquid effluents will be kept "as low as is reasonably achievable." This specification implements the requirements of 10 CFR Part 50.36a, General Design Criterion 60 of Appendix A to 10 CFR Part 50 and the design objective given in Section II.D of Appendix I to 10 CFR Part 50. The specified limit governing the use of appropriate portions of the liquid radwaste treatment system were specified as a suitable fraction of the dose design objectives set forth in Section II.A of Appendix I, 10 CFR Part 50, for liquid effluents. /086

0861 This specification applies to the release of ~~gaseous~~ liquid effluents from each reactor at the site. For units with shared radwaste treatment systems, the ~~gaseous~~ liquid effluents from the shared system are proportioned among the units sharing that system.

INS 0 ntity of radioactive material contained in the specified tanks provides assurance that in the event of an uncontrolled release of the tanks' contents, the resulting concentrations would be less than the limits of 10 CFR Part 20, Appendix B, Table II, Column 2, at the nearest potable water supply and the nearest surface water supply in an unrestricted area. /086

3/4.11.2 GASEOUS EFFLUENTS

3/4.11.2.1 DOSE RATE

This specification is provided to ensure that the dose ~~at~~ any time at and beyond the site boundary from gaseous effluents from all units on the site will be within the annual dose limits of 10 CFR Part 20 for unrestricted areas. The annual dose limits are the doses associated with the concentrations of 10 CFR Part 20, Appendix B, Table II, Column 1. These limits provide reasonable assurance that radioactive material discharged in gaseous effluents will not result in the exposure of a ~~individual~~ MEMBER OF THE PUBLIC in an unrestricted area outside the site boundary to annual average concentrations exceeding the limits specified in Appendix B, Table II of 10 CFR Part 20 (10 CFR Part 20.106(b)). For ~~individuals~~ MEMBERS OF THE PUBLIC who may at times be within the site boundary, the occupancy of the ~~individual~~ MEMBER OF THE PUBLIC will be sufficiently low to compensate for any increase in the atmospheric diffusion factor above that for the site boundary. The specified release rate limits restrict, at all times, the corresponding gamma and beta dose rates above background to a ~~individual~~ at or beyond the site boundary to less than or equal to 500 mrem/year to the total body or to less than or equal to 3000 mrem/year to the skin. These release rate limits also restrict, at all times, the corresponding thyroid dose rate above background to a child via the inhalation pathway to less than or equal to 1500 mrem/year. /249 [illegible] 086

The tanks listed in this specification include all those tanks containing radioactive material that are not surrounded by liners, dikes, or walls capable of holding the contents and that do not have overflows and surrounding area drains connected to the liquid radwaste treatment system.

This specification applies to the release of gaseous effluents from each reactor at the site. For units with shared radwaste treatment systems, the gaseous effluents from the shared system are proportioned among the units sharing that system.

BASES

DOSE RATE (Continued)

This specification applies to the release of gaseous effluents from all reactors at the site. ~~For units with shared radwaste treatment systems, the gaseous effluents from the shared system are proportioned among the units sharing that system~~. INSERT 249

to UNRESTRICTED AREAS /249

3/4.11.2.2 DOSE - NOBLE GASES

This specification is provided to implement the requirements of Sections II.B, III.A and IV.A of Appendix I, 10 CFR Part 50. The Limiting Condition for Operation implements the guides set forth in Section II.B of Appendix I. The ACTION statements provide the required operating flexibility and at the same time implement the guides set forth in Section IV.A of Appendix I to assure that the releases of radioactive material in gaseous effluents will be kept "as low as is reasonably achievable." The Surveillance Requirements implement the requirements in Section III.A of Appendix I that conformance with the guides of Appendix I be shown by calculational procedures based on models and data such that the actual exposure of ~~an individual~~ a MEMBER OF THE PUBLIC through appropriate pathways is unlikely to be substantially underestimated. The dose calculations established in the ODCM for calculating the doses due to the actual release rates of radioactive noble gases in gaseous effluents are consistent with the methodology provided in Regulatory Guide 1.109, "Calculation of Annual Doses to Man from Routine Releases of Reactor Effluents for the Purpose of Evaluating Compliance with 10 CFR Part 50, Appendix I," Revision 1, October 1977 and Regulatory Guide 1.111, "Methods for Estimating Atmospheric Transport and Dispersion of Gaseous Effluents in Routine Releases from Light-Water Cooled Reactors," Revision 1, July 1977. The ODCM equations provided for determining the air doses at the site boundary and beyond are based upon the historical average atmospheric conditions.

IODINE-131, IODINE 133, TRITIUM AND RADIONUCLIDES

3/4.11.2.3 DOSE - ~~RADIOIODINES~~, ~~RADIOACTIVE MATERIALS~~ IN PARTICULATE FORM ~~AND TRITIUM~~

to UNRESTRICTED AREAS /249

This specification is provided to implement the requirements of Sections II.C, III.A and IV.A of Appendix I, 10 CFR Part 50. The Limiting Conditions for Operation are the guides set forth in Section II.C of Appendix I. The ACTION statements provide the required operating flexibility and at the same time implement the guides set forth in Section IV.A of Appendix I to assure that the releases of radioactive materials in gaseous effluents will be kept "as low as is reasonably achievable." The ODCM calculational methods specified in the Surveillance Requirements implement the requirements in Section III.A. of Appendix I that conformance with the guides of Appendix I be shown by calculational procedures based on models and data, such that the actual exposure of ~~an individual~~ a MEMBER OF THE PUBLIC - through appropriate pathways is unlikely to be substantially underestimated. The ODCM calculational methods for calculating the doses due to the actual release rates of the subject materials

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INSERT 249

For a more complete discussion of the LLD, and other detection limits, see the following:

(1) HASL Procedures Manual, HASL-300 (revised annually).
(2) Currie, L. A., "Limits for Qualitative Detection and Quantitative Determination - Application to Radiochemistry" Anal. Chem. 40, 586-93 (1968).
(3) Hartwell, J. K., "Detection Limits for Radioisotopic Counting Techniques," Atlantic Richfield Hanford Company Report ARH-2537 (June 22, 1972).

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IODINE-131, IODINE 133, TRITIUM, AND RADIONUCLIDES

1911 DOSE - ~~RADIOIODINE~~S, ~~RADIOACTIVE MATERIAL~~S IN PARTICULATE FORM ~~[illegible]~~ ~~TRITIUM~~ (Continued)

are consistent with the methodology provided in Regulatory Guide 1.109, "Calculation of Annual Doses to Man from Routine Releases of Reactor Effluents for the Purpose of Evaluating Compliance with 10 CFR Part 50, Appendix I," Revision 1, October 1977 and Regulatory Guide 1.111, "Methods for Estimating Atmospheric Transport and Dispersion of Gaseous Effluents in Routine Releases from Light-Water-Cooled Reactors," Revison 1, July 1977. These equations also provide for determining the actual doses based upon the historical average atmospheric conditions. The release rate specifications for ~~radioiodines, radioactive materials~~ iodine-131, iodine 133, tritium and radionuclides in particulate form ~~and tritium~~ are dependent on the existing radionuclide pathway to man in the ~~unrestricted~~ areaS at and beyond the SITE BOUNDARY. The pathways which were examined in the development of these calculations were: 1) individual inhalation of airborne radionuclides, 2) deposition of radionuclides onto green leafy vegetation with subsequent consumption by man, 3) deposition onto grassy areas where milk animals and meat producing animals graze with consumption of the milk and meat by man, and 4) deposition on the ground with subsequent exposure of man. 1911

105

3/4.11.2.4 and 3/4.11.2.5 GASEOUS RADWASTE TREATMENT AND VENTILATION EXHAUST TREATMENT

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The OPERABILITY of the GASEOUS RADWASTE TREATMENT (OFFGAS) SYSTEM and the VENTILATION EXHAUST TREATMENT SYSTEM ensures that the system will be available for use whenever gaseous effluents require treatment prior to release to the environment. The requirement that the appropriate portions of the system be used, when specified, provides reasonable assurance that the releases of radioactive materials in gaseous effluents will be kept "as low as is reasonably achievable." This specification implements the requirements of 10 CFR Part 50.36a, General Design Criterion 60 of Appendix A to 10 CFR Part 50, and the design objectives given in Section II.D of Appendix I to 10 CFR Part 50. The specified limits governing the use of appropriate portions of the system were specified as a suitable fraction of the dose design objectives set forth in Sections II.B and II.C of Appendix I, 10 CFR Part 50, for gaseous effluents.

3/4.11.2.~~5~~6 EXPLOSIVE GAS MIXTURE

This specification is provided to ensure that the concentration of potentially explosive gas mixtures contained in the offgas holdup piping is maintained below the flammability limits of hydrogen. Maintaining the concentration of hydrogen below its flammability limit provides assurance that the releases of radioactive materials will be controlled in conformance with the requirements of General Design Criterion 60 of Appendix A to 10 CFR Part 50. 1248

This specification applies to the release of gaseous effluents from each reactor at the site. For units with shared radwaste treatment systems, the gaseous effluents from the shared system are proportioned among the units sharing that system. 1249

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3/4.11.2.7 MAIN CONDENSER

Restricting the gross radioactivity rate of noble gases from the main condenser provides reasonable assurance that the total body exposure to ~~an~~ a 1249
~~individual~~ MEMBER OF THE PUBLIC at ~~the exclusion area boundary~~ and beyond the SITE BOUNDARY will not exceed a small fraction of 1105
the limits of 10 CFR Part 100 in the event this effluent is inadvertently discharged directly to the environment without treatment. This specification implements the requirements of General Design Criteria 60 and 64 of Appendix A to 10 CFR Part 50.

3/4.11.3 SOLID RADIOACTIVE WASTE

~~The OPERABILITY of the solid radwaste system ensures that the system will be available for use whenever solid radwastes require processing and packaging prior to being shipped offsite.~~ This specification implements the requirements of 10 CFR Part 50.36a and General Design Criterion 60 of Appendix A to 10 CFR Part 50. The process parameters included in establishing the PROCESS CONTROL PROGRAM may include, but are not limited to waste type, waste pH, waste/liquid/solidification agent/catalyst ratios, waste oil content, waste principal chemical constituents, mixing and curing times. 1085

3/4.11.4 TOTAL DOSE

This specification is provided to meet the dose limitations of 40 CFR Part 190 ~~that have been incorporated into 10 CFR Part 20 by 46 FR 18525~~. The specification requires the preparation and submittal of a Special Report whenever the calculated doses from plant generated radioactive effluents and direct radiation exceed 25 mrems to the total body or any organ, except rs, the thyroid, which shall be limited to less than or equal to 75 mrems. For sites containing up to 4 reactors, it is highly unlikely that the resultant dose to a MEMBER OF THE PUBLIC will exceed the dose limits of 40 CFR Part 190 if the individual reactors remain within twice the dose design objectives of
249 Appendix I, and if direct radiation doses from the reactor units and outside storage tanks are kept small. The Special Report will describe a course of action that should result in the limitation of the annual dose to a MEMBER OF THE PUBLIC to within the 40 CFR Part 190 limits. For the purposes of the Special Report, it may be assumed that the dose commitment to the MEMBER OF THE PUBLIC from other uranium fuel cycle sources is negligible, with the exception that dose contributions from other nuclear fuel cycle facilities at the same site or within a radius of 8 km must be considered. If the dose to any MEMBER OF THE PUBLIC is estimated to exceed the requirements of 40 CFR Part 190, the Special Report with a request for a variance (provided the release conditions resulting in violation of 40 CFR Part 190 have not already been corrected), in accordance with the provisions of 40 CFR Part 190.11 and 10 CFR Part 20.405c, is considered to be a timely request and fulfills the requirements of 40 CFR Part 190 until NRC staff action is completed. The variance only relates to the limits of 40 CFR Part 190, and does not apply in any way to the other requirements for dose limitation of 10 CFR Part 20, as addressed in Specifications 3.11.1.1 and 3.11.2.1. An individual is not considered a MEMBER OF THE PUBLIC during any period in which he/she is engaged in carrying out any operation that is part of the nuclear fuel cycle.

3/4.12.1 MONITORING PROGRAM

MEMBERS OF THE PUBLIC

The radiological monitoring program required by this specification provides measurements of radiation and of radioactive materials in those exposure pathways and for those radionuclides, which lead to the highest potential radiation exposures of ~~individuals~~ resulting from the station operation. This monitoring program ~~thereby~~ supplements the radiological effluent monitoring program by verifying that the measurable concentrations of radioactive materials and levels of radiation are not higher than e[illegible]ed on the basis of the effluent measurements and modeling of the environmental exposure pathways. The initially specified monitoring program will be effective for at least the first three years of commerical operation. Following this period, program changes may be initiated based on operational experience.

implements Section IV.B.2 of Appendix I to 10 CFR Part 50 and

/249

The detection capabilities required by Table 4.12.1-1 are state-of-the-art for routine environmental measurements in industrial laboratories. It should be recognized that the LLD is defined as an "a priori" (before the fact) limit representing the capability of a measurement system and not as "a posteriori" (after the fact) limit for a particular measurement. Analyses shall be performed in such a manner that the stated LLDs will be achieved under routine conditions. Occasionally background fluctuations, unavoidably small sample sizes, the presence of interfering nuclides, or other uncontrollable circumstances may render these LLDs unachievable. In such cases, the contributing factors will be identified and described in the Annual Radiological Environmental Operating Report.

For a more complete discussion of the LL.D, and other detection limits, see the following:

(1) HASL Procedure Manual, HASL-300 (revised annually).

(2) Currie, L.A., "Limits for Qualitative Detection and Quantitative Determination - Application to Radiochemistry" Anal. Chem. 40, 586-93 (1968).

(3) Hartwell, J. K., "Detection Limits for Radioisotopic Counting Techiques," Atlantic Richfield Hanford Company Report ARH-2537 (June 22, 1972).

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~~The requirement for participation in an interlaboratory comparison program is provided to ensure that independent checks on the precision and accuracy of the measurements of radioactive material in environmental sample matrices are performed as part of the quality assurance program for environmental monitoring in order to demonstrate that the results are reasonably valid.~~

3/4.12.2 LAND USE CENSUS

This specification is provided to ensure that changes in the use of areas at and beyond the SITE BOUNDARY are identified and that modifications to the radiological environmental monitoring program are made if required by the results of this census. The best information from the door-to-door survey, visual or ~~from~~ aerial survey or from consulting with local agricultural authorities shall be used. This census satisfies the requirements of Section IV.B.3 of Appendix I to 10 CFR Part 50. Restricting the census to gardens of greater than 50 m^2 provides assurance that significant exposure pathways via leafy vegetables will be identified and monitored since a garden of this size is the minimum required to produce the quantity (26 kg/year) of leafy vegetables assumed in Regulatory Guide 1.109 for consumption by a child. To determine this minimum garden size, the following assumptions were made: 1) 20% of the garden was used for growing broad leaf vegetation (i.e., similar to lettuce and cabbage), and 2) a vegetation yield of 2 kg/m^2.

3/4.12.3 INTERLABORATORY COMPARISON PROGRAM

The requirement for participation in an approved Interlaboratory Comparison Program is provided to ensure that independent checks on the precision and accuracy of the measurements of radioactive material in environmental sample matrices are performed as part of the quality assurance program for environmental monitoring in order to demonstrate that the results are valid for the purposes of Section IV.B.2 of Appendix I to 10 CFR Part 50.

SECTION 5.0

DESIGN FEATURES

5.0 DESIGN FEATURES

5.1 SITE

EXCLUSION AREA

5.1.1 The exclusion area shall be as shown in Figure 5.1.1-1.

LOW POPULATION ZONE

5.1.2 .The low population zone shall be as shown in Figure 5.1.2-1. 1225

UNRESTRICTED AREA AND SITE BOUNDARY FOR GASEOUS EFFLUENTS AND FOR LIQUID EFFLUENTS

5.1.3 The unrestricted area ~~boundary~~ and SITE BOUNDARY for gaseous effluents and for liquid effluents shall be as shown in Figure 5.1.3-1. The gaseous effluent release points are shown in Figure 5.1.1-1. 105

1225

5.2 CONTAINMENT

CONFIGURATION

5.2.1 The containment is a steel lined, reinforced concrete structure composed of a vertical right cylinder and a hemispherical dome. Inside and at the bottom of the containment is a reinforced concrete drywell composed of a vertical right cylinder and a steel head which contains an approximately eighteen to nineteen foot deep water filled suppression pool connected to the drywell through a series of horizontal vents. The containment has a minimum net free air volume of 1,400,000 cubic feet. The drywell has a minimum net free air volume of 270,000 cubic feet.

DESIGN TEMPERATURE AND PRESSURE

5.2.2 The containment and drywell are designed and shall be maintained for:

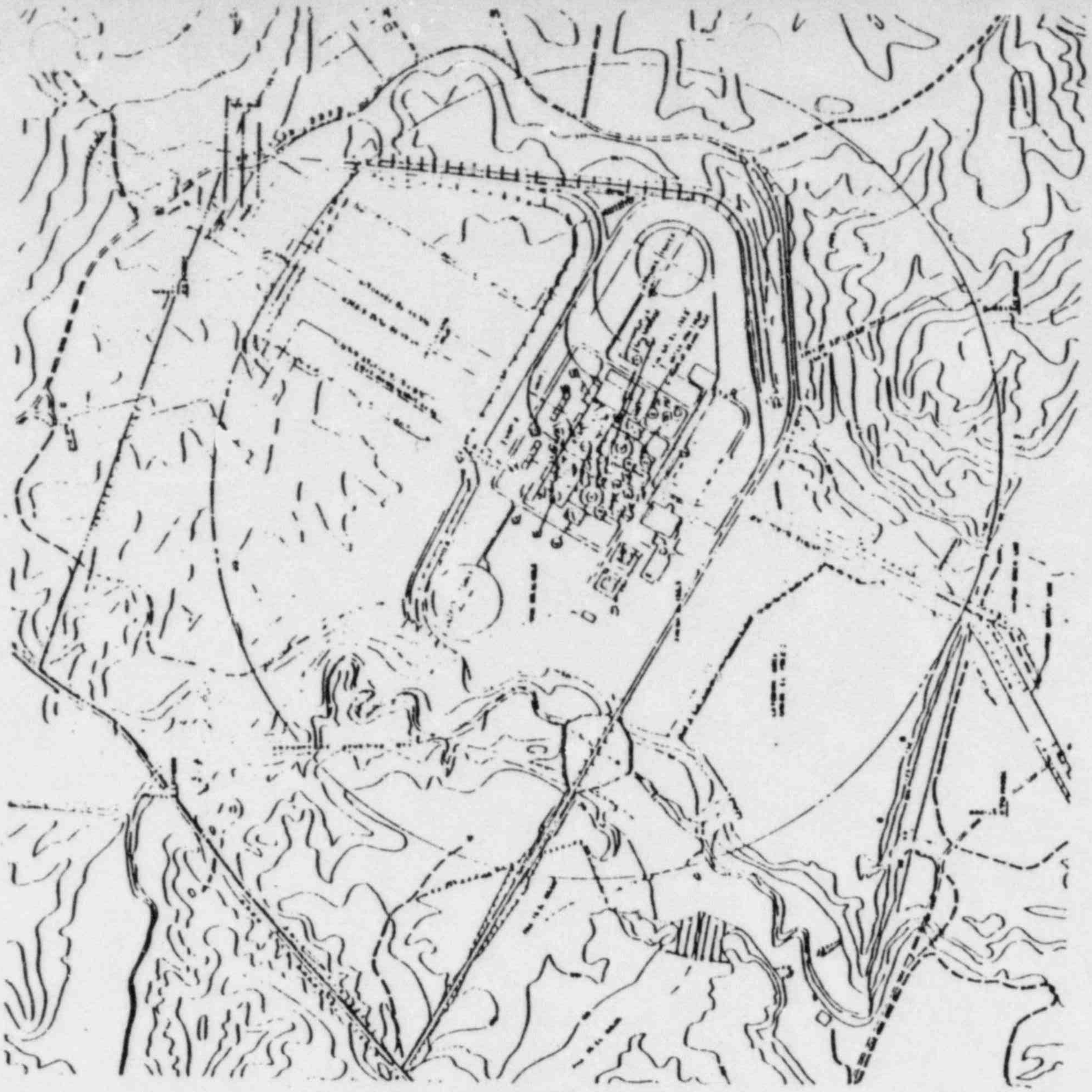
a. Maximum internal pressure:
   1. Drywell 30 psig.
   2. Containment 15 psig.

b. Maximum internal temperature:
   1. Drywell 330°F.
   2. Suppression pool 185°F.

c. Maximum external-to-internal differential pressure:
   1. Drywell 21 psid.
   2. Containment 3 psid.

SECONDARY CONTAINMENT

5.2.3 The secondary containment consists of the ~~Reactor~~ Auxiliary Building and the Enclosure Building, and has a minimum free volume of 3,640,000 cubic feet. 283



NOTES

1. GRID COORDINATES SHOWN ARE BASED ON MISSISSIPPI COORDINATE SYSTEM, WEST ZONE.
2. DATUM FOR ELEVATIONS SHOWN IS MEAN SEA LEVEL EL. 0.0'.
3. SEE FIGURE 6.1.4-1 FOR UNRESTRICTED AREA BOUNDARY
4. SEE FIGURE 6.1.2-1 FOR METEOROLOGICAL TOWER LOCATION

200 0 200 400
FEET

CATEGORY I STRUCTURES

- Ⓐ CONTAINMENT STRUCTURE
- Ⓑ AUXILIARY BUILDING
- Ⓒ MAIN STEAM PIPE CHASE
- Ⓓ DIESEL GENERATOR BUILDING
- Ⓔ DIESEL GEN FUEL OIL STORAGE TANK
- Ⓕ CONTROL BUILDING
- Ⓖ CONDENSATE STORAGE TANK
- Ⓗ STANDBY SERVICE WATER COOLING TOWER BASIN

GASEOUS EFFLUENT RELEASE POINTS

NO	VENT	MIN DISTANCE TO BOUNDARY LINE	RELEASE ELEV.
①	RADWASTE BLDG	2030 ±FT	EL 164.0'
②	TURBINE BLDG	2090 ±FT	EL 232.0'
③	STANDBY GAS TREATMENT	2350 ±FT	EL 272.0'
④	FUEL HANDLING AREA	2340 ±FT	EL 272.0'
⑤	CONTROL BLDG	2350 ±FT	EL 195.0'
⑥	CONTAINMENT	2240 ±FT	EL 195.0'
⑦	CONTROL ROOM	2420 ±FT	EL 195.0'
⑧	CONTROL RM PURGE	2420 ±FT	EL 195.0'
⑨	CONTROL RM VTR EXH	2420 ±FT	EL 195.0'
⑩	BATTERY RM EXH UNIT 1	2030 ±FT	EL 170.0'
⑪	LUBE OIL RM EXH UNIT 1	2160 ±FT	EL 193.0'
⑫	BATTERY RM EXH UNIT 2	2320 ±FT	EL 156.0'
⑬	LUBE OIL RM EXH UNIT 2	2500 ±FT	EL 141.0'
⑭	TURBINE BLDG SMOKE PURGE EXH UNIT 1	1990 ±FT	EL 190.0'
⑮	TURBINE BLDG SMOKE PURGE EXH UNIT 2	2540 ±FT	EL 186.0'

① NORMAL CONTROL RM OA INTAKE: EL 204.0'
② STANDBY CONTROL RM OA INTAKE: EL 139.0

EXCLUSION AREA AND GASEOUS EFFLUENT RELEASE POINTS

FIGURE 5.1.1-1

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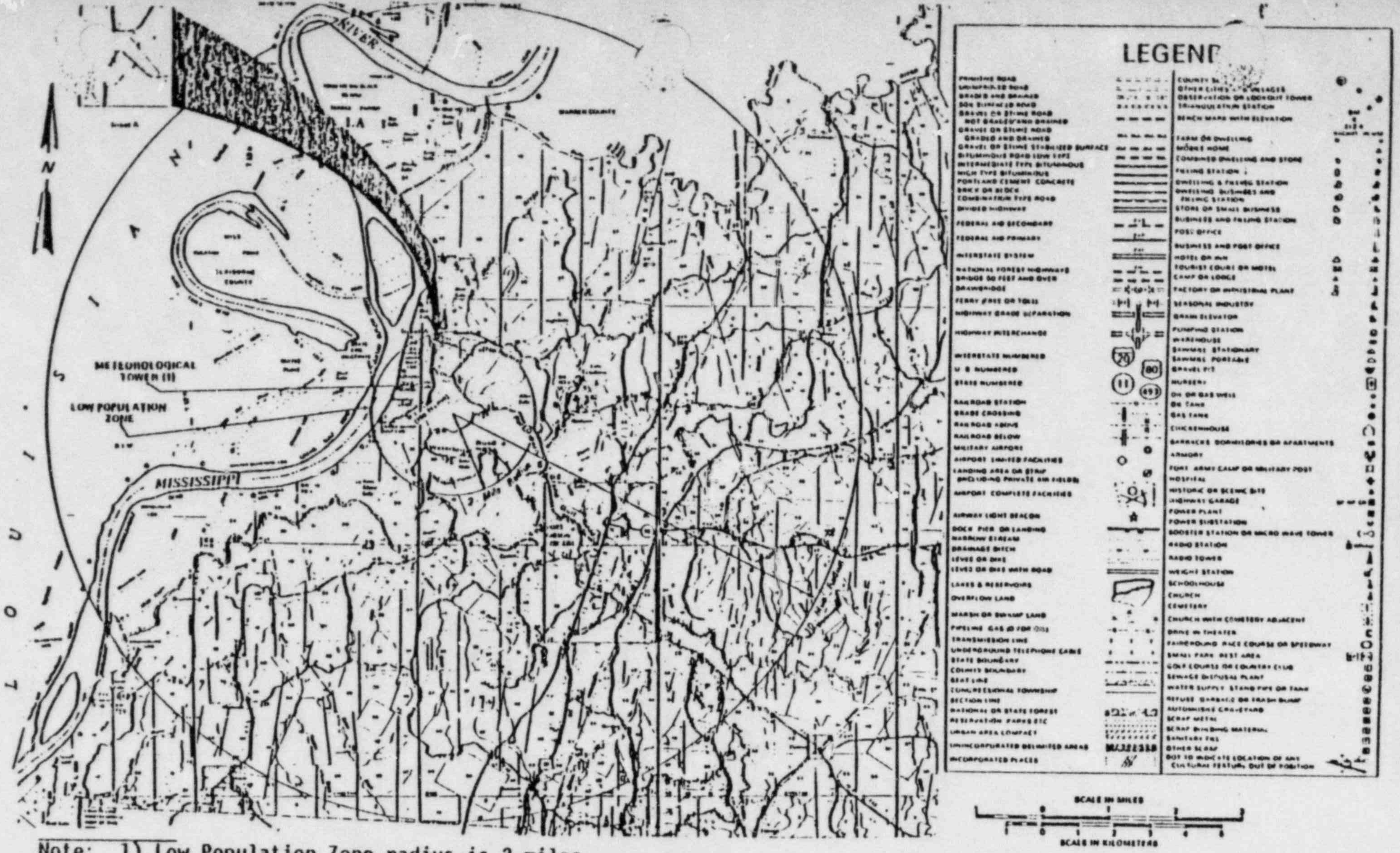
* Exclusion Area radius is 696 meters from the centerline of the Unit 1 Reactor

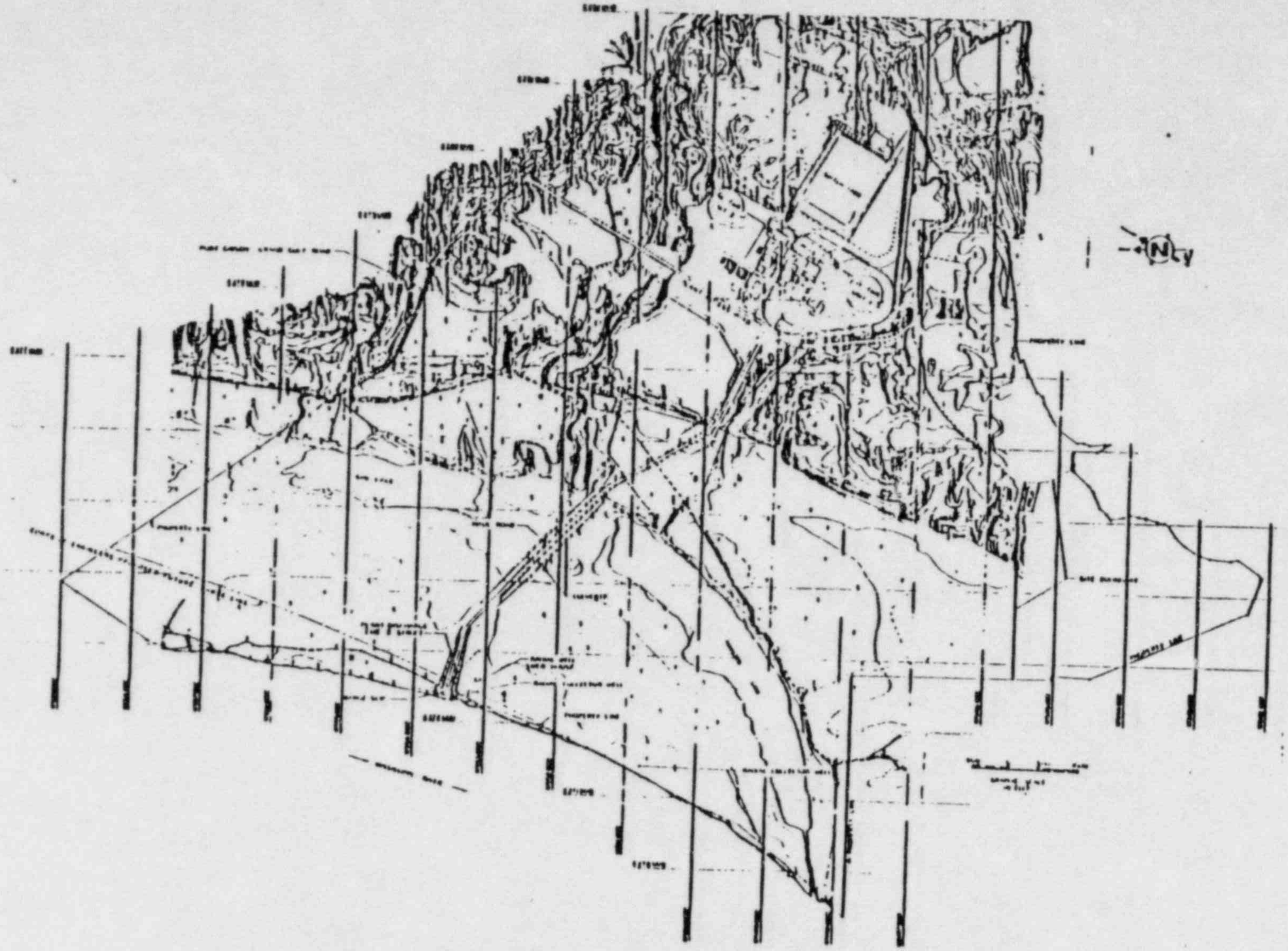


Note: 1) Low Population Zone radius is 2 miles
2) Meteorological tower location ~~is~~ approximately 5000 feet NNW of the centerline of the Unit 1 reactor is

1074

LOW POPULATION ZONE AND METEOROLOGICAL TOWER LOCATION

FIGURE 5.1.2-1



UNRESTRICTED AREA BOUNDARY FOR LIQUID AND GASEOUS EFFLUENTS

FIGURE 5.1.3-1

5.3 REACTOR CORE

design nominal enrichment of 1.708 weight percent U-235.

FUEL ASSEMBLIES

5.3.1 The reactor core shall contain 800 fuel assemblies with each fuel design assembly containing 62 fuel rods and two water rods clad with Zircaloy -2. Each fuel rod shall have a nominal active fuel length of 150 inches. The initial core loading shall have a ~~maximum average enrichment of 1.70 weight percent U-235~~. Reload fuel shall be similar in physical design to the initial core loading. ~~and shall have a maximum average enrichment of 2.82 weight percent U-235~~. 1281

CONTROL ROD ASSEMBLIES

a design nominal

5.3.2 The reactor core shall contain 193 control rod assemblies, each consisting of a cruciform array of stainless steel tubes containing ~~143~~ 143.7 inches of boron carbide, B_4C, powder surrounded by a cruciform shaped stainless steel sheath. 1282

5.4 REACTOR COOLANT SYSTEM

DESIGN PRESSURE AND TEMPERATURE

5.4.1 The reactor coolant system is designed and shall be maintained:

a. In accordance with the code requirements specified in Section 5.2 of the FSAR, with allowance for normal degradation pursuant to the applicable Surveillance Requirements,

b. For a pressure of:

1. 1250 psig on the suction side of the recirculation pump.
2. 1650 psig from the recirculation pump discharge to the outlet side of the discharge shutoff valve.
3. 1550 psig from the discharge shutoff valve to the jet pumps.

c. For a temperature of 575°F.

VOLUME

5.4.2 The total water and steam volume of the reactor vessel and recirculation system is approximately 22,000 cubic feet at a nominal T_{ave} of 533°F.

5.5 METEOROLOGICAL TOWER LOCATION

5.5.1 The meteorological tower shall be located as shown on Figure 5.1.2-1.

5.6 FUEL STORAGE

CRITICALITY

5.6.1 The spent fuel storage racks are designed and shall be maintained with:

a. A k_{eff} equivalent to less than or equal to 0.95 when flooded with unborated water, including all calculational uncertainties and biases as described in Section 4.3 of the FSAR.

b. A nominal 12 inch center-to-center distance between fuel assemblies placed in the storage racks.

5.6.1.2 The k_{eff} for new fuel for the first core loading stored dry in the spent fuel storage racks shall not exceed 0.98 when aqueous foam moderation is assumed.

DRAINAGE

5.6.2 The spent fuel storage pool is designed and shall be maintained to prevent inadvertent draining of the pool below elevation ~~202'6"~~. 202'5 1/4" |258

CAPACITY

5.6.3 The spent fuel storage pool is designed and shall be maintained with a storage capacity limited to no more than 1270 fuel assemblies.

5.7 COMPONENT CYCLIC OR TRANSIENT LIMIT

5.7.1 The components identified in Table 5.7.1-1 are designed and shall be maintained within the cyclic or transient limits of Table 5.7.1-1.

TABLE 5.7.1-1

COMPONENT CYCLIC OR TRANSIENT LIMITS

COMPONENT	CYCLIC OR TRANSIENT LIMIT	DESIGN CYCLE OR TRANSIENT
Reactor	120 heatup and cooldown cycles	70°F to 560°F to 70°F
	80 step change cycles	Loss of feedwater heaters
	200 reactor trip cycles	100% to 0% of RATED THERMAL POWER
	40 hydrostatic pressure or leak tests	Pressurized to $\geq$ 930 psig and $\leq$ 1250 psig

SECTION 6.0

ADMINISTRATIVE CONTROLS

6.0 ADMINISTRATIVE CONTROLS

6.1 RESPONSIBILITY

6.1.1 The ~~Plant~~ GGNS General Manager shall be responsible for overall unit operation and shall delegate in writing the succession to this responsibility during his absence. 052

6.1.2 The Shift Superintendent or, during his absence from the Control Room, a designated individual shall be responsible for the Control Room command function. A management directive to this effect, signed by the Senior Vice President, Nuclear shall be reissued to all station personnel on an annual basis.

6.2 ORGANIZATION

OFFSITE

6.2.1 The offsite organization for unit management and technical support shall be as shown on Figure 6.2.1-1.

UNIT STAFF

6.2.2 The unit organization shall be as shown on Figure 6.2.2-1 and:

a. Each on duty shift shall be composed of at least the minimum shift crew composition shown in Table 6.2.2-1.

b. At least one licensed Reactor Operator shall be in the control room when fuel is in the reactor. In addition, while the reactor is in OPERATIONAL CONDITION 1, 2 or 3, at least one licensed Senior Reactor Operator shall be in the Control Room.

c. A health physics technician* shall be onsite when fuel is in the reactor.

289 d. All CORE ALTERATIONS# shall be observed and directly supervised by either a licensed Senior Reactor Operator or Senior Reactor Operator Limited to Fuel Handling who has no other concurrent responsibilities during this operation.

e. A site Fire Brigade of at least 5 members shall be maintained onsite at all times*. The Fire Brigade shall not include the Shift Superintendent, the STA, the two other members of the minimum shift crew necessary for safe shutdown of the unit, and any personnel required for other essential functions during a fire emergency. At least one AO shall be available to respond to non-fire fighting commands from the control room.

074 The number of health physicians technicians and Fire Brigade personnel

*~~The health physics technician and Fire Brigade composition~~ may be less than the minimum requirements for a period of time not to exceed 2 hours in order to accommodate unexpected absence provided immediate action is taken to fill the required positions.

289 # Except neutron monitor replacement from under the reactor pressure vessel which will be observed and directly supervised by the maintenance foreman in charge of the work and indirectly supervised by a Senior Reactor Operator or a Senior Reactor Operator limited to the Control Room.

UNIT STAFF (Continued)

f. Administrative procedures shall be developed and implemented to limit the working hours of unit staff who perform safety-related functions; e.g., senior reactor operators, reactor operators, health physicists, auxiliary operators, and key maintenance personnel.

Adequate shift coverage shall be maintained without routine heavy use of overtime. However, in the event that unforeseen problems require substantial amounts of overtime to be used, the following guidelines shall be followed:

1. An individual should not be permitted to work more than 16 hours straight, excluding shift turnover time.
2. An individual should not be permitted to work more than 16 hours in any 24-hour period, nor more than 24 hours in any 48-hour period, nor more than 72 hours in any seven day period, all excluding shift turnover time.
3. A break of at least eight hours should be allowed between work periods, including shift turnover time.
4. Except during extended shutdown periods, the use of overtime should be considered on an individual basis and not for the entire staff on a shift.

Any deviation from the above guidelines shall be authorized by the ~~Plant Superintendent~~ GGNS General Manager or his ~~deputy~~ designee, or higher levels of management, in accordance with established procedures and with documentation of the basis for granting the deviation. Controls shall be included in the procedures such that individual overtime shall be reviewed monthly by the ~~Plant Superintendent~~ GGNS General Manager or his designee to assure that excessive hours have not been assigned. Routine deviation from the above guidelines is not authorized. 052

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 plant design and operating experience information, including plants of similar design, which may indicate areas for improving plant safety.

COMPOSITION

6.2.3.2 The ISEG shall be composed of a multi-disciplined dedicated, onsite, group with a minimum assigned complement of five engineers or appropriate specialists.

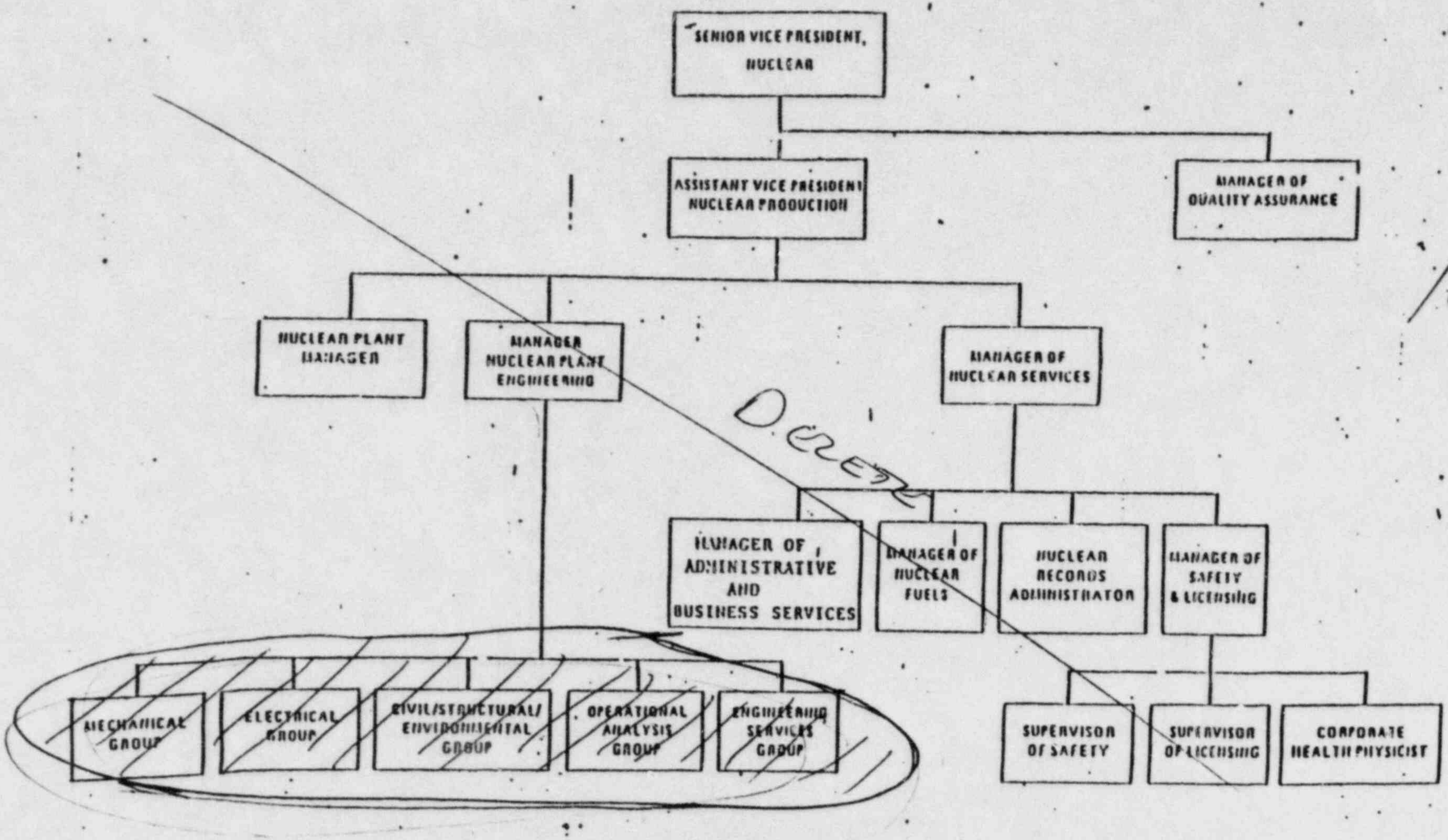


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Figure 6.2.1-1

OFFSITE ORGANIZATION

95/

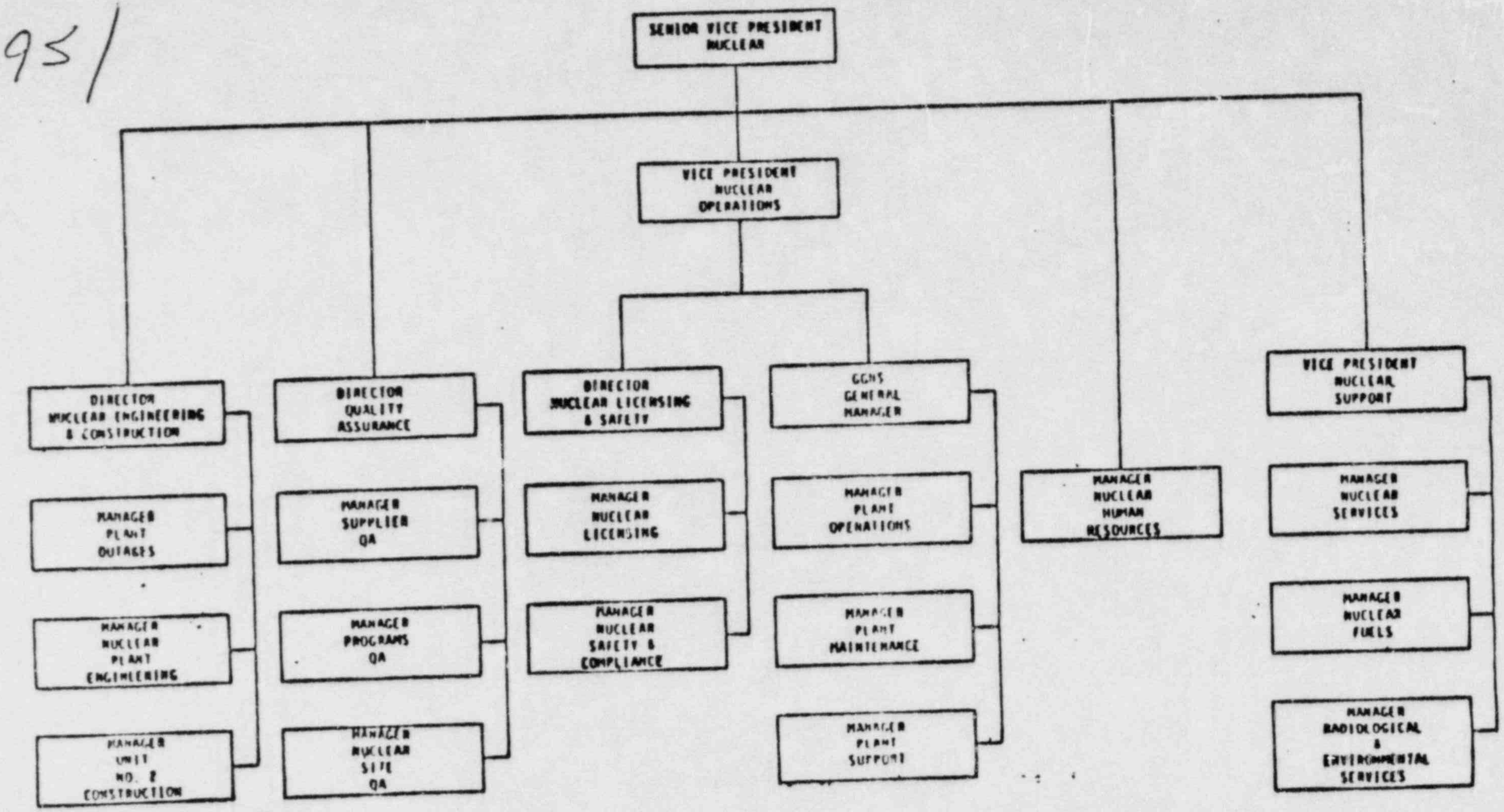

Figure 6.2.1-1

OFFSITE ORGANIZATION

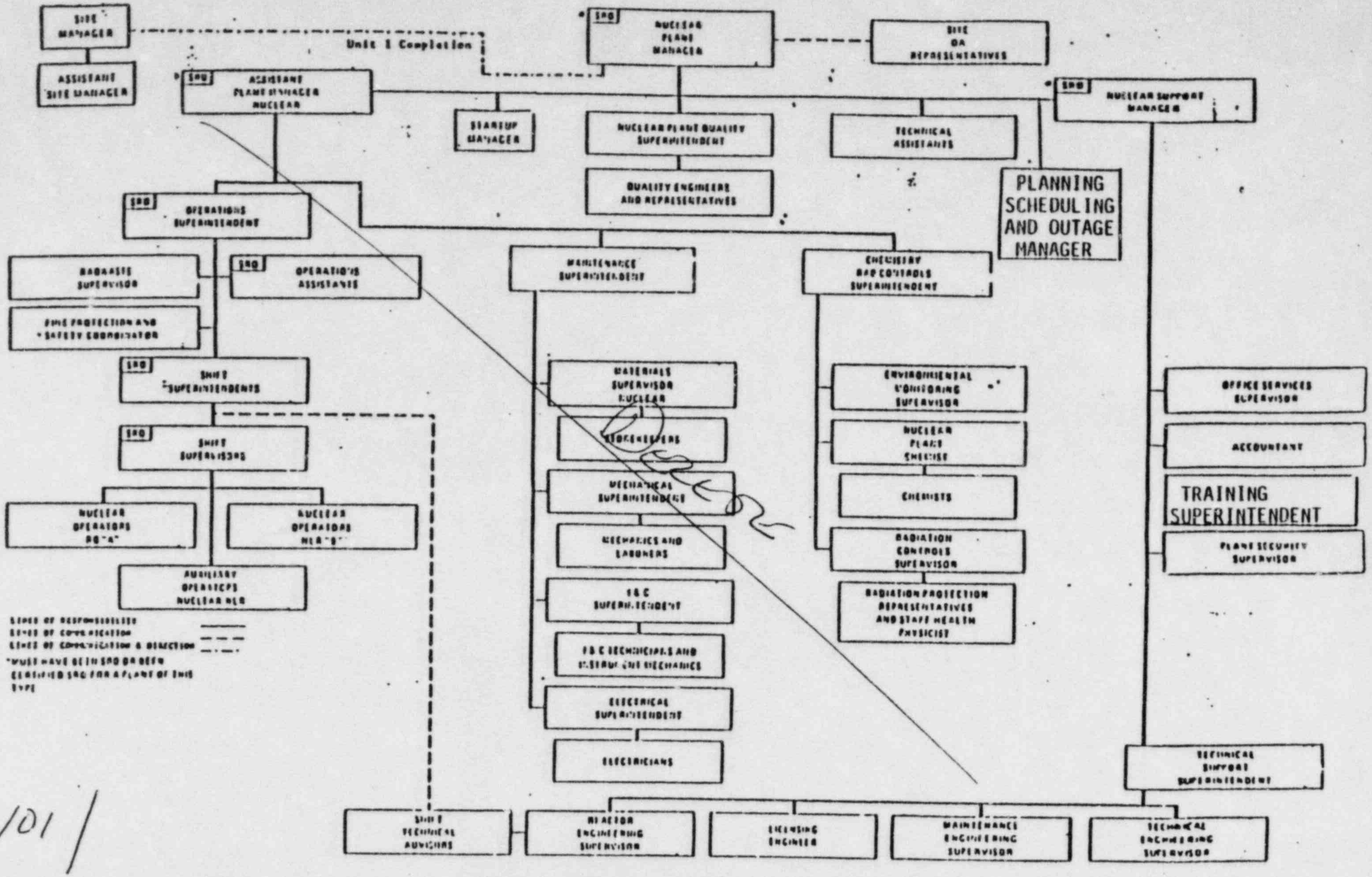

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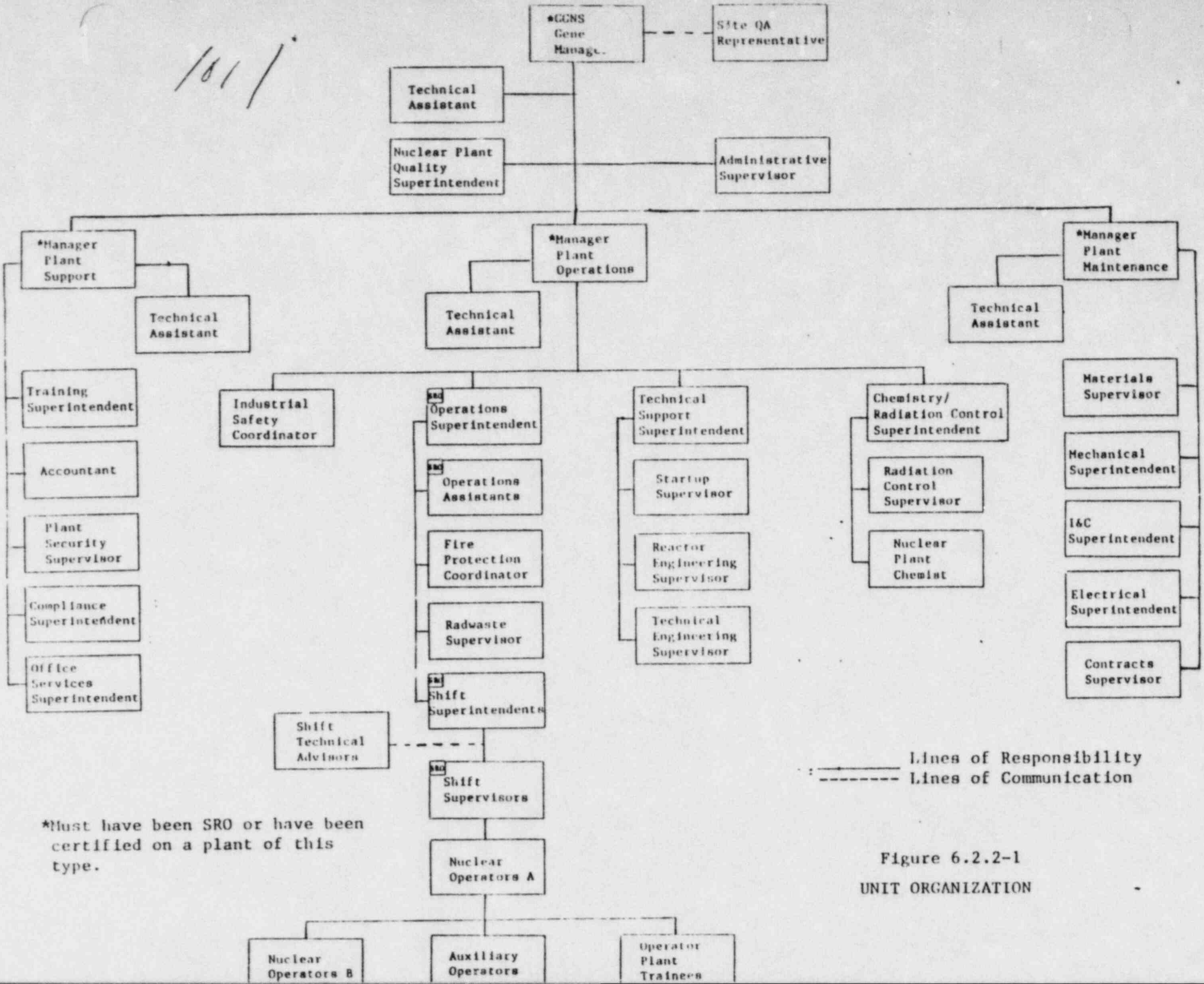
Figure 6.2.2-1

UNIT ORGANIZATION

/61/



*Must have been SRO or have been certified on a plant of this type.

Figure 6.2.2-1

UNIT ORGANIZATION

TABLE 6.2.2-1

MINIMUM SHIFT CREW COMPOSITION

POSITION	NUMBER OF INDIVIDUALS REQUIRED TO FILL POSITION	
	CONDITIONS 1, 2, & 3	CONDITIONS 4 & 5
SS	1	1
SRO	1	None
RO	2	1
AO	2	1
STA	1	None

TABLE NOTATION

SS - Shift Superintendent with a Senior Reactor Operators License on Unit 1.
SRO - Individual with a Senior Reactor Operators License on Unit 1.
RO - Individual with a Reactor Operators License on Unit 1.
AO - Auxiliary Operator.
STA - Shift Technical Advisor.

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

During any absence of the Shift Superintendent from the Control Room while the unit is in OPERATIONAL CONDITION 1, 2 or 3 an individual, other than the Shift Technical Advisor, with a valid SRO license shall be designated to assume the Control Room command function. During any absence of the Shift Superintendent from the Control Room while the unit is in OPERATIONAL CONDITION 4 or 5, an individual with a valid SRO or RO license shall be designated to assume the Control Room command function.

INDEPENDENT SAFETY ENGINEERING GROUP (ISEG) (Continued)

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.

AUTHORITY

6.2.3.4 The ISEG shall make detailed recommendations for revised procedures, equipment modifications, maintenance activities, operations activities or other means of improving unit safety to the ~~Assistant~~ Senior Vice President, ~~for~~ Nuclear. ~~Production~~. /063

6.2.4 SHIFT TECHNICAL ADVISOR

6.2.4.1 The Shift Technical Advisor shall provide technical support to the Shift Superintendent in the areas of thermal hydraulics, reactor engineering and plant analysis with regard to safe operation of the unit.

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 and the supplemental requirements specified in Section A and C of Enclosure 1 of the March 28, 1980 NRC letter to all licensees, except for the Chemistry/~~and~~ Radiation P~~rotectio~~n Control Superintendent who shall meet or exceed the qualifications of Regulatory Guide 1.8, September 1975; the Shift Technical Advisor who shall meet or exceed the qualifications referred to in Section 2.2.1.b of Enclosure I of the October 30, 1979 NRC letter to all operating nuclear power plants; and ~~the~~ those members of the Independent Safety Engineering Group used for meeting the minimum complement specified in Section 6.2.3.2, each of whom shall have a Bachelor of Science degree or be registered as a Professional Engineer and shall have at least two years experience in their field, at least one year of which experience shall be in the nuclear field. /063

6.4 TRAINING

6.4.1 A retraining and replacement training program for the unit staff shall be maintained under the direction of the Training Superintendent, shall meet or exceed the requirements and recommendations of Section 5.5 of ANSI N18.1-1971 and Appendix "A" of 10 CFR Part 55 and the supplemental requirements specified in Section A and C of Enclosure 1 of the March 28, 1980 NRC letter to all licensees, and shall include familiarization with relevant industry operational experience.

6.5 REVIEW AND AUDIT

6.5.1 PLANT SAFETY REVIEW COMMITTEE (PSRC)

FUNCTION

6.5.1.1 The PSRC shall function to advise the ~~Plant~~ GGNS General Manager on all matters related to nuclear safety. /052

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*Not responsible for sign-off function.

PLANT SAFETY REVIEW COMMITTEE (PSRC) (Continued)

COMPOSITION

6.5.1.2 The PSRC shall be composed of the: 106

Chairman: ~~Assistant Plant~~ Manager, Plant Operations
Vice Chairman: ~~Nuclear Support~~ Manager, Plant Maintenance
Member: Operations Superintendent
Member: Technical Support Superintendent
Member: Quality Superintendent
Member: Chemistry/~~and~~ Radiation Control ~~Protection~~ Superintendent
Member: I&C ~~Maintenance~~ Superintendent
Member: Technical Engineering Supervisor

ALTERNATES

052 6.5.1.3 All alternate members shall be appointed in writing by the ~~Plant Manager~~ GGNS General Manager to serve on a temporary basis; however, no more than two alternates shall participate as voting members in PSRC activities at any one time.

MEETING FREQUENCY

6.5.1.4 The PSRC shall meet at least once per calendar month and as convened by the PSRC Chairman or Vice Chairman.

QUORUM

6.5.1.5 The ~~minimum~~ quorum of the PSRC necessary for the performance of the PSRC responsibility and authority provisions of these Technical Specifications shall consist of the Chairman or Vice Chairman and four members including alternates. 106

RESPONSIBILITIES

6.5.1.6 The PSRC shall be responsible for review of:

a. Station administrative procedures and changes thereto.

b. The safety evaluations for 1) procedures, 2) changes to procedures, equipment or systems, and 3) tests or experiments completed under the provision of Section 50.59, 10 CFR, to verify that such actions did not constitute an unreviewed safety question and all programs required by Specification 6.8 and changes thereto.

c. Proposed procedures and changes to procedures, equipment or systems which may involve an unreviewed safety question as defined in Section 50.59, 10 CFR.

d. Proposed tests or experiments which may involve an unreviewed safety question as defined in Section 50.59, 10 CFR.

e. Proposed changes to Technical Specifications or the Operating License.

RESPONSIBILITIES (Continued)

f. Reports of violations of codes, regulations, orders, Technical Specifications, or Operating License requirements having nuclear safety significance or reports of abnormal degradation of systems designed to contain radioactive material.

g. Reports of significant operating abnormalities or deviations from normal and expected performance of plant equipment that affect nuclear safety.

h. Review of All REPORTABLE EVENTS. ~~All written reports concerning events requiring 24 hour notification to the Commission.~~ 1093

i. All recognized indications of an unanticipated deficiency in some aspect of design or operation of safety related structures, systems, or components.

j. The plant Security Plan and changes thereto.

k. The Emergency Plan and changes thereto.

l. Items which may constitute a potential nuclear safety hazard as identified during review of facility operations.

m. Investigations or analyses of special subjects as requested by the Chairman of the ~~Nuclear~~ Safety Review Committee. 1106

~~n. The unexpected offsite release of radioactive material and the report as described in 6.9.1.13(e).~~ 1093

n ~~o~~. Changes to the PROCESS CONTROL PROGRAM, OFFSITE DOSE CALCULATION MANUAL, and radwaste systems.

AUTHORITY

6.5.1.7 The PSRC shall:

a. Recommend in writing to the GGNS General Manager ~~Plant Manager~~ approval or disapproval of items considered under 6.5.1.6(a), (c), (d), (e), (j), and (k), above.

b. Render determinations in writing to the GGNS General ~~Plant~~ Manager with regard to whether or not each item considered under 6.5.1.6(a), (c) and (d), above constitutes an unreviewed safety question. 052

c. Provide written notification within 24 hours to the SRC of disagreement between the PSRC and the GGNS General ~~Plant~~ Manager; however, the GGNS General ~~Plant~~ Manager shall have responsibility for resolution of such disagreements pursuant to 6.1.1 above.

RECORDS

6.5.1.8 The PSRC shall maintain written minutes of each PSRC meeting that, at a minimum, document the results of all PSRC activities performed under the responsibility and authority provisions of these Technical Specifications. Copies shall be provided to the SRC.

6.5.2 SAFETY REVIEW COMMITTEE (SRC)

FUNCTION

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

a. nuclear power plant operations
b. nuclear engineering
c. chemistry and radiochemistry
d. metallurgy
e. instrumentation and control
f. radiological safety
g. mechanical and electrical engineering
h. quality assurance practices

COMPOSITION

6.5.2.2 The SRC shall be composed of the:

1106

Chairman: Vice President, Nuclear Operations
Member: Manager of Nuclear Plant Engineering
Member: Director, ~~Manager of~~ Quality Assurance
Member: Designated Representative, Middle South Services, Inc.
Member: GGNS General ~~Nuclear Plant~~ Manager
Member: ~~Manager of Nuclear Services~~ Director, Nuclear Licensing and Safety
Member: Manager, ~~of~~ Radiological and Environmental Services
Member: Principal Engineer, Operations Analysis
Member:* Advisor to the Vice President, Nuclear Operations

Two or more additional voting members shall be consultants to Mississippi Power and Light Company consistent with the recommendations of the Advisory Committee on Reactor Safeguards letter, Mark to Palladino dated October 20, 1981.

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

ALTERNATES

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

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*Non-voting member.

CONSULTANTS

6.5.2.4 Consultants, in addition to those required in Specification ~~6.5.2.3,~~ 6.5.2.2 shall be utilized as determined by the SRC Chairman to provide expert advice to the SRC. No more than three consultants ~~[illegible] [illegible] [illegible] members shall vote on any issue.~~ shall participate as voting members in SRC activities at any one time. /290 /096

MEETING FREQUENCY

6.5.2.5 The SRC shall meet at least once per calendar quarter during the initial year of unit operation following fuel loading and at least once per six months thereafter.

QUORUM

6.5.2.6 The minimum quorum of the SRC necessary for the performance of the SRC review and audit functions of these Technical Specifications shall consist of the Chairman or his designated alternate and at least 6 SRC voting members including alternates. No more than a minority of the quorum shall have line responsibility for operation of the unit.

REVIEW

6.5.2.7 The SRC shall ~~review:~~ be responsible for the review of: /096

a. The safety evaluations for 1) changes to procedures, equipment or systems and 2) tests or experiments completed under the provision of Section 50.59, 10 CFR, to verify that such actions did not constitute an unreviewed safety question.

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

c. Proposed tests or experiments which involve an unreviewed safety question as defined in Section 50.59, 10 CFR.

d. Proposed changes to Appendix A Technical Specifications or this Operating License.

e. Violations of codes, regulations, orders, Technical Specifications, license requirements, or of internal procedures or instructions having nuclear safety significance.

f. Significant operating abnormalities or deviations from normal and expected performance of unit equipment that affect nuclear safety.

g. ~~Events requiring 24 hour written notification to the Commission.~~ All REPORTABLE EVENTS. /093

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

i. Reports and meetings minutes of the PSRC.

j. Written reports from audits of the ALARA program. /096

AUDITS

6.5.2.8 Audits of unit activities shall be performed under the cognizance of the SRC. These audits shall encompass:

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

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

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

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

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

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

g. Any other area of unit operation considered appropriate by the SRC or the Senior Vice President - Nuclear.

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

i. An independent fire protection and loss prevention inspection and audit shall be performed at least once per 12 months utilizing either qualified offsite licensee personnel or an outside fire protection firm.

j. An inspection and audit of the fire protection and loss prevention program shall be performed by an outside qualified fire consultant at intervals no greater than 36 months.

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

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

m. The PROCESS CONTROL PROGRAM and implementing procedures for solidification of radioactive wastes at least once per 24 months.

n. The performance of activities required by the Quality Assurance Program to meet the criteria of Regulatory Guide 4.15, February 1979, at least once per 12 months.

AUTHORITY

6.5.2.9 The SRC shall report to and advise the Senior Vice President, Nuclear on those areas of responsibility specified in Sections 6.5.2.7 and 6.5.2.8. 106

RECORDS

6.5.2.10 Records of SRC activities shall be prepared, approved and distributed as indicated below:

a. Minutes of each SRC meeting shall be prepared, approved and forwarded to the Senior Vice President, Nuclear within 14 days following each meeting. 106

b. Reports of reviews encompassed by Section 6.5.2.7 above, shall be prepared, approved and forwarded to the Senior Vice President, Nuclear within 14 days following completion of the review. 106

c. Audit reports encompassed by Section 6.5.2.8 above, shall be forwarded to the Senior Vice President, Nuclear and to the management positions responsible for the areas audited within 30 days after completion of the audit by the auditing organization. 106

6.5.3 TECHNICAL REVIEW AND CONTROL

ACTIVITIES

6.5.3.1 Activities which affect nuclear safety shall be conducted as follows:

a. Procedures required by Technical Specification 6.8 and other procedures which affect plant nuclear safety, and changes thereto, shall be prepared, reviewed and approved. Each such procedure or procedure change shall be reviewed by an individual/group other than the individual/group which prepared the procedure or procedure change, but who may be from the same organization as the individual/group which prepared the procedure or procedure change. Procedures other than Administrative Procedures shall be approved as delineated in writing by the ~~Plant~~ GGNS General Manager. The ~~Plant~~ Manager shall approve administrative procedures, security implementing procedures and emergency plant implementing procedures. Temporary approval to procedures which clearly do not change the intent of the approved procedures may be made by two members of the plant management staff, at least one of whom holds a Senior Reactor Operator's License. Temporary changes shall be reviewed by the reviewing authority within 14 days of being issued. For changes to procedures which may involve a change in intent of the approved procedures, the person authorized above to approve the procedure shall approve the change. 052

Proposed changes or modifications to plant nuclear safety-related structures, systems and components shall be reviewed as designated by the ~~Plant~~ GGNS General Manager. Each such modification shall be reviewed by an individual/group other than the individual/group which designed the modification, but who may be from the same organization as the individual/group which designed the modifications. Implementation of proposed modifications to plant nuclear safety-related structures, systems and components shall be approved by the ~~Plant~~ Manager.

GGNS General

ACTIVITIES (Continued)

c. Proposed tests and experiments which affect plant nuclear safety and are not addressed in the Final Safety Analysis Report shall be reviewed by an individual/group other than the individual/group which prepared the proposed test or experiment.

'093

d. Events ~~Occurrences~~ reportable pursuant to ~~the Technical Specification 6.9 and violations of Technical Specifications~~ Section 50.73 to 10CFR Part 50 shall be investigated and a report prepared which evaluates the ~~occurrence~~ event and which provides recommendations to prevent recurrence. Such report shall be approved by the ~~Plant~~ GGN General Manager. ~~and forwarded to the Chairman of the Safety Review Committee.~~ /052

e. Individuals responsible for reviews performed in accordance with 6.5.3.1.a, 6.5.3.1.b, 6.5.3.1.c and 6.5.3.1.d shall be members of the plant staff who meet or exceed the qualification requirements of Section 4.4 of ANSI 18.1, 1971, as previously designated by the ~~Plant~~ GGNS General Manager. Each such review shall include a determination of whether or not additional, cross-disciplinary review is necessary. If deemed necessary, such review shall be performed by the review personnel of the appropriate discipline. /052

f. Each review shall include a determination of whether or not an unreviewed safety question is involved.

g. Records of the above activities shall be provided to the ~~Station~~ GGNS General Manager, PSRC and/or as necessary for required reviews. /052

6.6 REPORTABLE ~~OCCURRENCE~~ EVENT ACTION

6.6.1 The following actions shall be taken for REPORTABLE ~~OCCURRENCES~~ EVENTS pursuant to the requirements of Section 50.72 to 10 CFR Part 50,:

'093

a. The Commission shall be notified ~~and/or~~ and a report submitted pursuant to the requirements of ~~Specification 6.9~~ Section 50.73 to 10CFR Part 50, and

b. Each REPORTABLE ~~OCCURRENCE~~ EVENT ~~requiring 24 hour notification to the Commission~~ shall be reviewed by the PSRC and submitted to the SRC and the Senior Vice President, - Nuclear ~~[illegible]~~. /052

6.7 SAFETY LIMIT VIOLATION

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

a. The NRC Operations Center shall be notified by telephone as soon as possible and in all cases within one hour. The Senior Vice President, - Nuclear and the SRC shall be notified within 24 hours. /052

b. A Safety Limit Violation Report shall be prepared. The report shall be reviewed by the PSRC. This report shall describe (1) applicable circumstances preceding the violation, (2) effects of the violation upon unit components, systems or structures, and (3) corrective action taken to prevent recurrence.

SAFETY LIMIT VIOLATION (Continued)

c. The Safety Limit Violation Report shall be submitted to the Commission, the SRC and the Senior Vice President - Nuclear within 14 days of the violation.

d. Critical operation of the unit shall not be resumed until authorized by the Commission.

6.8 PROCEDURES AND PROGRAMS

6.8.1 Written procedures shall be established, implemented and maintained covering the activities referenced below:

a. The applicable procedures recommended in Appendix "A" of Regulatory Guide 1.33, Revision 2, February 1978.

b. Refueling operations.

c. Surveillance and test activities of safety related equipment.

d. Security Plan implementation.

e. Emergency Plan implementation.

f. Fire Protection Program implementation.

g. PROCESS CONTROL PROGRAM implementation.

h. OFFSITE DOSE CALCULATION MANUAL implementation.

i. Quality Assurance Program for effluent and environmental monitoring, using the guidance in Regulatory Guide 4.15, February 1979.

j. Embankment Stability verification program. 113B

6.8.2 Each procedure of 6.8.1 above, and changes thereto, shall be reviewed as required by 6.5, above, prior to implementation and shall be reviewed periodically as set forth in administrative procedures.

6.8.3 The following programs shall be established, implemented, and maintained:

a. Primary Coolant Sources Outside Containment

A program to reduce leakage from those portions of systems outside containment that could contain highly radioactive fluids during a serious transient or accident to as low as practical levels. The systems include the:

1. RCIC system outside containment containing steam or water, except the drain line to the main condenser.
2. RHR system outside containment containing steam or water, except the line to the LRW system and headers that are isolated by manual valves.
3. HPCS system.
4. LPCS system.
5. Hydrogen analyzers of the combustible gas control system.

PROCEDURES AND PROGRAMS (Continued)

6. Feedwater leakage control system.
7. Post-accident sampling system.
8. Suppression pool level detection portion of the suppression pool makeup system.

The program shall include the following:

1. Preventive maintenance and periodic visual inspection requirements, and
2. Integrated leak test requirements for each system at refueling cycle intervals or less.

b. In-Plant Radiation Monitoring

A program which will ensure the capability to accurately determine the airborne iodine concentration in vital areas under accident conditions. This program shall include the following:

1. Training of personnel,
2. Procedures for monitoring, and
3. Provisions for maintenance of sampling and analysis equipment.

c. Post-accident Sampling

A program which will ensure the capability to obtain and analyze reactor coolant, radioactive iodines and particulates in plant gaseous effluents, and containment atmosphere samples under accident conditions. The program shall include the following:

1. Training of personnel,
2. Procedures for sampling and analysis,
3. Provisions for maintenance of sampling and analysis equipment.

6.9 REPORTING REQUIREMENTS

ROUTINE REPORTS ~~AND REPORTABLE OCCURRENCES~~

1093

6.9.1 In addition to the applicable reporting requirements of Title 10, Code of Federal Regulations, the following reports shall be submitted to the Regional Administrator of the Regional Office, unless otherwise noted.

STARTUP REPORTS

6.9.1.1 A summary report of plant startup and power escalation testing shall be submitted following (1) receipt of an operating license, (2) amendment to the license involving a planned increase in power level, (3) installation of fuel that has a different design or has been manufactured by a different fuel supplier, and (4) modifications that may have significantly altered the nuclear, thermal, or hydraulic performance of the unit.

STARTUP REPORTS (Continued)

6.9.1.2 The startup report shall address each of the tests identified in the FSAR and shall include a description of the measured values of the operating conditions or characteristics obtained during the test program and a comparison of these values with design predictions and specifications. Any corrective actions that were required to obtain satisfactory operation shall also be described. Any additional specific details required in license conditions based on other commitments shall be included in this report.

6.9.1.3 Startup reports shall be submitted within (1) 90 days following completion of the startup test program, (2) 90 days following resumption or commencement of commercial power operation, or (3) 9 months following initial criticality, whichever is earliest. If the Startup Report does not cover all three events, i.e., initial criticality, completion of startup test program, and resumption or commencement of commercial operation, supplementary reports shall be submitted at least every three months until all three events have been completed.

ANNUAL REPORTS[1/]

6.9.1.4 Annual reports covering the activities of the unit as described below for the previous calendar year shall be submitted prior to March 1 of each year. The initial report shall be submitted prior to March 1 of the year following initial criticality.

6.9.1.5 Reports required on an annual basis shall include a tabulation on an annual basis of the number of station, utility, and other personnel, including contractors, receiving exposures greater than 100 mrem/yr and their associated manrem exposure according to work and job functions,[2/] e.g., reactor operations and surveillance, inservice inspection, routine maintenance, special maintenance (describe maintenance), waste processing, and refueling. The dose assignments to various duty functions may be estimated based on pocket dosimeter, TLD, or film badge measurements. Small exposures totalling less than 20 percent of the individual total dose need not be accounted for. In the aggregate, at least 80 percent of the total whole body dose received from external sources should be assigned to specific major work functions. Reports shall also include documentation of all challenges to safety and relief valves.

[1/] A single submittal may be made for a multiple unit station. The submittal should combine those sections that are common to all units at the station.

[2/] This tabulation supplements the requirements of §20.407 of 10 CFR Part 20.

Deviations from the sampling program identified in Technical Specification 3.12.1 shall be reported.

ANNUAL RADIOLOGICAL ENVIRONMENTAL OPERATING REPORT[3/]

6.9.1.6 Routine radiological environmental operating reports covering the operation of the unit during the previous calendar year shall be submitted prior to May 1 of each year. The initial report shall be submitted prior to May 1 of the year following initial criticality.

6.9.1.7 The annual radiological environmental operating reports shall include summaries, interpretations, and an analysis of trends of the results of the radiological enviromental 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. If harmful effects or evidence of irreversible damage are detected by the monitoring, the report shall provide an analysis of the problem and a planned course of action to alleviate the problem.

The annual radiological environmental operating reports shall include summarized and tabulated results in the format of Regulatory Guide 4.8, December 1975 of all radiological environmental samples taken during the report period. In the event that some 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. 1249

The reports shall also include the following: a summary description of the radiological environmental monitoring program; a map of all sampling locations keyed to a table giving distances and directions from one reactor; and the results of licensee participation in the Interlaboratory Comparison Program, required by Specification 3.12.3.

SEMIANNUAL RADIOACTIVE EFFLUENT RELEASE REPORT[3/]

6.9.1.8 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.

[3/] A single submittal may be made for a multiple unit station. The submittal should combine those sections that are common to all units at the station; however, for units with separate radwaste systems, the submittal shall specify the releases of radioactive material for each unit.

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 5.1.3-1 ~~5.1-3~~) 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.

SEMIANNUAL RADIOACTIVE EFFLUENT RELEASE REPORT (Continued)

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

The radioactive effluent release report to be submitted within 60 days after January 1 of each year shall include an annual summary of hourly meteorological data collected over the previous year. This annual summary may be either in the form of an hour-by-hour listing of wind speed, wind direction, and atmospheric stability, and precipitation (if measured) on magnetic tape, or in the form of joint frequency distributions of wind speed, wind direction, and atmospheric stability. This same report shall include an assessment of the radiation doses due to the radioactive liquid and gaseous effluents released from the unit or station during the previous calendar year. The meteorological conditions concurrent with the time of release of radioactive materials in gaseous effluents (as determined by sampling frequency and measurement) shall be used for determining the gaseous pathway doses. The assessment of radiation doses shall be performed in accordance with the OFFSITE DOSE CALCULATION MANUAL (ODCM).

INSERT

The radioactive effluent release report to be submitted within 60 days after January 1 of each year shall also include an assessment of radiation doses to the likely most exposed member of the public from reactor releases and other nearby uranium fuel cycle sources (including doses from primary effluent pathways and direct radiation) for the previous 12 consecutive months to show conformance with 40 CFR 190, Environmental Radiation Protection Standards for Nuclear Power Operation. Acceptable methods for calculating the dose contribution from liquid and gaseous effluents are given in Regulatory Guide 1.109, Rev. 1. 1249

The radioactive effluents release shall include the following information for each type of solid waste shipped offsite during the report period:

a. Container volume,

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

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

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

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

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

The radioactive effluent release reports shall include unplanned releases from the site to the unrestricted area of radioactive materials in gaseous and liquid effluents on a quarterly basis. 1249

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

249 | OFFSITE DOSE CALCULATION MANUAL (ODCM)

INSERT 6-18

The Semiannual Radioactive Effluent Release Report shall identify those radiological environmetal sample parameters and locations where it is not possible or practicable to continue to obtain samples of the media of choice at the most desired location or time. In addition, the cause of the unavailability of samples for the pathway and the new location(s) for obtaining replacement samples should be identified. The report should also include a revised Figure(s) and Table(s) for the ODCM reflecting the new location(s).

MONTHLY OPERATING REPORTS

6.9.1.10 Routine reports of operating statistics and shutdown experience, including documentation of all challenges to main steam system safety/relief valves, shall be submitted on a monthly basis to the Director, Office of Management and Program Analysis, U.S. Nuclear Regulatory Commission, Washington, D.C. 20555, with a copy to the Regional Administrator of the Regional Office no later than the 15th of each month following the calendar month covered by the report.

~~Any changes to the OFFSITE DOSE CALCULATION MANUAL shall be submitted with the Monthly Operating Report within 90 days of the date the change(s) was made effective. In addition, a report of any major changes to the radioactive waste treatment systems shall be submitted with the Monthly Operating Report for the period in which the evaluation was reviewed and accepted by the (PSRC).~~

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REPORTABLE OCCURRENCES

6.9.1.11 The REPORTABLE OCCURRENCES of Specifications 6.9.1.12 and 6.9.1.13 below, including corrective actions and measures to prevent recurrence, shall be reported to the NRC. Supplemental reports may be required to fully describe final resolution of occurrence. In case of corrected or supplemental reports, a licensee event report shall be completed and reference shall be made to the original report date.

PROMPT NOTIFICATION WITH WRITTEN FOLLOWUP

6.9.1.12 The types of events listed below shall be reported within 24 hours by telephone and confirmed by telegraph, mailgram, or facsimile transmission to the Regional Administrator of the Regional Office, or his designate no later than the first working day following the event, with a written followup report within 14 days. The written followup report shall include, as a minimum, a completed copy of a licensee event report form. Information provided on the licensee event report form shall be supplemented, as needed, by additional narrative material to provide complete explanation of the circumstances surrounding the event.

a. Failure of the reactor protection system or other systems subject to limiting safety system settings to initiate the required protective function by the time a monitored parameter reaches the setpoint specified as the limiting safety system setting in the technical specifications or failure to complete the required protective function.

b. Operation of the unit or affected systems when any parameter or operation subject to a limiting condition for operation is less conservative than the least conservative aspect of the limiting condition for operation established in the technical specifications.

c. Abnormal degradation discovered in fuel cladding, reactor coolant pressure boundary, or primary containment.

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PROMPT NOTIFICATION WITH WRITTEN FOLLOWUP (Continued)

d. Reactivity anomalies involving disagreement with the predicted value of reactivity balance under steady state conditions during power operation greater than or equal to 1% delta k/k; a calculated reactivity balance indicating a SHUTDOWN MARGIN less conservative than specified in the technical specifications; short-term reactivity increases that correspond to a reactor period of less than 5 seconds or, if subcritical, an unplanned reactivity insertion of more than 0.5% delta k/k; or occurrence of any unplanned criticality.

e. Failure or malfunction of one or more components which prevents or could prevent, by itself, the fulfillment of the functional requirements of system(s) used to cope with accidents analyzed in the SAR.

f. Personnel error or procedural inadequacy which prevents or could prevent, by itself, the fulfillment of the functional requirements of systems required to cope with accidents analyzed in the SAR.

g. Conditions arising from natural or man-made events that, as a direct result of the event, require unit shutdown, operation of safety systems, or other protective measures required by technical specifications.

h. Errors discovered in the transient or accident analyses or in the methods used for such analyses as described in the safety analysis report or in the bases for the technical specifications that have or could have permitted reactor operation in a manner less conservative than assumed in the analyses.

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i. Performance of structures, systems, or components that requires remedial action or corrective measures to prevent operation in a manner less conservative than assumed in the accident analyses in the safety analysis report or technical specifications bases; or discovery during unit life of conditions not specifically considered in the safety analysis report or technical specifications that require remedial action or corrective measures to prevent the existence or development of an unsafe condition.

j. Offsite releases of radioactive materials in liquid and gaseous effluents which exceed the limits of Specification 3.11.1.1 or 3.11.2.1.

k. Exceeding the limits in Specification 3.11.1.4 for the storage of radioactive materials in the listed tanks. The written follow-up report shall include a schedule and a description of activities planned and/or taken to reduce the contents to within the specified limits.

l. Failure or malfunction of the safety or relief valves.

THIRTY DAY WRITTEN REPORTS

6.9.1.13 The types of events listed below shall be the subject of written reports to the Regional Administrator of the Regional Office within thirty days of occurrence of the event. The written report shall include, as a minimum, a completed copy of a licensee event report form. Information provided on the licensee event report form shall be supplemented, as needed, by additional narrative material to provide complete explanation of the circumstances surrounding the event.

a. Reactor protection system or engineered safety feature instrument settings which are found to be less conservative than those established by the technical specifications but which do not prevent the fulfillment of the functional requirements of affected systems.

b. Conditions leading to operation in a degraded mode permitted by a limiting condition for operation or plant shutdown required by a limiting condition for operation.

c. Observed inadequacies in the implementation of administrative or procedural controls which threaten to cause reduction of degree of redundancy provided in reactor protection systems or engineered safety feature systems.

d. Abnormal degradation of systems other than those specified in 6.9.1.8.c above designed to contain radioactive material resulting from the fission process.

e. An unplanned offsite release of 1) more than 1 curie of radioactive material in liquid effluents, 2) more than 150 curies of noble gas in gaseous effluents, or 3) more than 0.05 curies of radioiodine in gaseous effluents. The report of an unplanned offsite release of radioactive material shall include the following information:

   1. A description of the event and equipment involved.
   2. Causes(s) for the unplanned release.
   3. Actions taken to prevent recurrence.
   4. Consequences of the unplanned release.

f. Offsite releases of radioactive materials in liquid and gaseous effluents which exceed the limits of Specification 3.11.1.1 or 3.11.2.1.

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SPECIAL REPORTS

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

6.10 RECORD RETENTION

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

6.10.1 The following records shall be retained for at least five years:

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

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

c. ALL REPORTABLE EVENTS, ~~OCCURRENCES submitted to the Commission.~~

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

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

f. Records of radioactive shipments.

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

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

6.10.2 The following records shall be retained for the duration of the Unit Operating License:

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

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

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

RECORD RETENTION (Continued)

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

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

f. Records of reactor tests and experiments.

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

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

i. Records of Quality Assurance activities required by the Operational Quality Assurance Manual.

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

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

l. Records of the service lives of all hydraulic and mechanical snubbers ~~listed on Tables 3.7.5-1 and 3.7.5-2~~ including the date at which the service life commences and associated installation and maintenance records. 1006

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

6.11 RADIATION PROTECTION PROGRAM

6.11.1 Procedures for personnel radiation protection shall be prepared consistent with the requirements of 10 CFR Part 20 and shall be approved, maintained and adhered to for all operations involving personnel radiation exposure.

6.12 HIGH RADIATION AREA

6.12.1 In lieu of the "control device" or "alarm signal" required by paragraph 20.203(c)(2) of 10 CFR 20, each high radiation area in which the intensity of radiation is greater than 100 mrem/hr but less than 1000 mrem/hr shall be barricaded and conspicuously posted as a high radiation area and entrance thereto shall be controlled by requiring issuance of a Radiation Work Permit (RWP).* Any individual or group of individuals permitted to enter such areas shall be provided with or accompanied by one or more of the following:

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

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*Health Physics personnel or personnel escorted by Health Physics personnel shall be exempt from the RWP issuance requirement during the performance of their assigned radiation protection duties, provided they are otherwise following plant radiation protection procedures for entry into high radiation areas.

HIGH RADIATION AREA (Continued)

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

c. A health physics qualified individual, i.e., qualified in radiation protection procedures, with a radiation dose rate monitoring device, who is responsible for providing positive control over the activities within the area and shall perform periodic radiation surveillance at the frequency specified by the unit Health Physicist in the Radiation Work Permit.

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

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*Measurement made at 18" from source of radioactivity.

6.13 PROCESS CONTROL PROGRAM (PCP)

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

6.13.2 Licensee initiated changes to the PCP:

1. Shall be submitted to the Commission in the Semiannual ~~Semi-Annual~~ Radioactive Effluent Release Report for the period in which the change(s) was made. This submittal shall contain: |249

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

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

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

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

6.14 OFFSITE DOSE CALCULATION MANUAL (ODCM)

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

6.14.2 Licensee initiated changes to the ODCM:

1. Shall be submitted to the Commission in the ~~Monthly Operating Report~~ Semiannual Radioactive Effluent Release Report for the period in which the change(s) was made ~~within 90 days of the data the change(s) was made effective~~. This submittal shall contain:

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

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

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

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

6.15 MAJOR CHANGES TO RADIOACTIVE WASTE TREATMENT SYSTEMS*

6.15.1 Licensee initiated major changes to the radioactive waste systems, liquid, gaseous and solid:

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1. Shall be reported to the Commission in the ~~Monthly Operating Report~~ Semiannual Radioactive Effluent Release Report for the period in which the evaluation was reviewed by the PSRC. The discussion of each change shall contain:

   a. A summary of the evaluation that led to the determination that the change could be made in accordance wth 10 CFR 50.59;

   b. Sufficient detailed information to totally support the reason for the change without benefit of additional or supplemental information;

   c. A detailed description of the equipment, components and processes involved and the interface with other plant systems;

   d. An evaluation of the change which shows the predicted releases of radioactive materials in liquid and gaseous effluents and/or quantity of solid waste that differ from those previously predicted in the license application and amendments thereto;

   e. An evaluation of the change which shows the expected maximum exposures to ~~individual~~ Members of the Public in the unrestricted area and to the general population that differ from those previously estimated in the license application and amendments thereto; /249

   f. A comparison of the predicted releases of radioactive materials, in liquid and gaseous effluents and in solid waste, to the actual releases for the period prior to when the changes are to be maae;

   g. An estimate of the exposure to plant operating personnel as a result of the change; and

   h. Documentation of the fact that the change was reviewed and found acceptable by the PSRC.

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

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* Licensee may chose to submit the information called for in this Specification as part of the annual FSAR update. /088